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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application Of NextEra Energy Transmission MidAtlantic, Inc., for All of the Necessary Authority, Approvals, and Certificates of Public Convenience (1) to Begin to Furnish and Supply Electric Transmission Service in Greene County and Fayette County, Pennsylvania; (2) for Certain Affiliated Interest Agreements; and (3) for any Other Approvals Necessary to Complete the Contemplated Transactions

Docket No. A-2026-____________

and

Application of NextEra Energy Transmission MidAtlantic, Inc., Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Site and Construct a 500 kV Transmission Line Associated with the MidAtlantic Resiliency Link Project Located in Portions Of Greene County and Fayette County, Pennsylvania, Pennsylvania

Docket No. A-2026-____________

A-2026-3060856-AEL-3/4/26

NextEra Energy Transmission MidAtlantic, Inc.
MidAtlantic Resiliency Link Project – Pennsylvania Segment

Statement No. 4

Direct Testimony of Andrew Gledhill
Manager of Resource Adequacy, PJM Interconnection, L.L.C.

Topics Addressed: **PJM's Load Forecasting Process**
The Load Forecast Reports Upon Which PJM Relied to Identify the Reliability Violations for Which PJM Sought Solutions in the 2022 Window 3 Competitive Solicitation Process

Date: March 3, 2026

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A1. My name is Andrew Gledhill. I am the Manager of the Resource Adequacy Planning department in the System Planning division of PJM Interconnection, L.L.C. ("PJM"). My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403.

Q2. WHAT ARE YOUR RESPONSIBILITIES AT PJM?

A2. In my current position of Manager of Resource Adequacy, I am responsible for overseeing long-term resource adequacy studies and production of the PJM load forecast. Prior to this role, my primary responsibility at PJM was the development and production of the PJM load forecast.

Q3. PLEASE PROVIDE A SUMMARY OF YOUR EDUCATIONAL BACKGROUND.

A3. I hold a Bachelor of Science degree in Mathematics from the Pennsylvania State University and a Master's degree in Economics from the North Carolina State University.

Q4. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A4. I am testifying in this proceeding in support of NextEra Energy Transmission MidAtlantic, Inc. ("NEET MA" or the "Company"). As part of PJM's 2022 Window 3 competitive solicitation process ("2022 Window 3") – which is described in detail in the direct testimony of my colleague Dr. Sami Abdulsalam at NEET MA St. No. 3 – PJM designated NEET MA, and its affiliate, NextEra Energy Transmission Virginia, Inc., to construct, own, and maintain the MidAtlantic Resiliency Link ("MARL" or the "Project")[1] to address

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[1] As explained in Dr. Abdulsalam's testimony, the MARL is a component of a set of solutions that were selected by PJM to address reliability violation conditions that PJM observed in both the 2027 and 2028 study years resulting from the high demand for west to east regional flows. The MARL refers to the component of that broader solution that has been designated to NEET MA. *See* Dr. Abdulsalam's Direct Testimony at Response to Question 8.

and prevent certain reliability violations forecasted to impact the bulk electric transmission system that serves the PJM Region.[2]

Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A5. The purpose of my testimony is to support NEET MA's "*Application of NextEra Energy Transmission MidAtlantic, Inc., Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Site and Construct a 500 kV Transmission Line Associated with the MidAtlantic Resiliency Link Project Located in Portions Of Greene County and Fayette County, Pennsylvania*" (hereinafter, "Siting Application"). I also support NEET MA's "*Application Of NextEra Energy Transmission MidAtlantic, Inc., for All of the Necessary Authority, Approvals, and Certificates of Public Convenience (1) to Begin to Furnish and Supply Electric Transmission Service in Greene County and Fayette County, Pennsylvania; (2) for Certain Affiliated Interest Agreements; and (3) for any Other Approvals Necessary to Complete the Contemplated Transactions*" (hereinafter, the "CPC Application"). My direct testimony provides the Pennsylvania Public Utility Commission ("Commission") with information regarding PJM's load forecasting process and the specific load forecasts upon which PJM relied to identify the reliability violations for which PJM sought solutions in the 2022 Window 3 competitive solicitation process.

Q6. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AUTHORITIES?

A6. Yes. I previously provided testimony in the following proceedings:

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[2] The PJM Region includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

- proceedings related to NEET MA's applications for approval of the MARL Project before the West Virginia Public Service Commission in Docket No. 26-0075-E-CN, and before the Maryland Public Service Commission in Case No. 9857;
- the ongoing proceeding addressing the application of PSEG Renewable Transmission LLC for a Certificate of Public Convenience and Necessity to Construct a New 500 kV Transmission Line in Portions of Baltimore, Carroll and Frederick Counties, Maryland, docketed as Commission Case No. 9773;
- the ongoing proceeding addressing the application of The Potomac Edison Company for a Certificate of Public Convenience and Necessity to Upgrade a 24-mile transmission line between the Hunterstown Substation in Adams County, Pennsylvania, and the Carroll Substation in Carroll County, Maryland, docketed as Commission Case No. PSC Case No. 9803; and
- the ongoing proceeding addressing the application of Mid-Atlantic Interstate Transmission, LLC for a Certificate of Public Convenience and Necessity to Upgrade a 24-mile transmission line between the Hunterstown Substation in Adams County, Pennsylvania, and the Carroll Substation in Carroll County, Maryland, docketed as Pennsylvania Public Utility Commission Docket No. A-2025-3056951.

Q7. ARE YOU SPONSORING ANY EXHIBITS ALONG WITH YOUR DIRECT TESTIMONY?

A7. Yes, I am including the following as Exhibits to my testimony:

- **Exhibit AG-1**: PJM Manual 19: Load Forecasting and Analysis
- **Exhibit AG-2**: PJM 2024 Load Forecast Supplement
- **Exhibit AG-3**: Itron Inc.'s 2022 PJM Model Review Report

- **Exhibit AG-4**: PJM 2022 Load Forecast Report
- **Exhibit AG-5**: PJM 2023 Load Forecast Report
- **Exhibit AG-6**: PJM 2024 Load Forecast Report
- **Exhibit AG-7**: PJM 2025 Load Forecast Report
- **Exhibit AG-8**: PJM 2026 Load Forecast Report

Q8. WHAT WAS YOUR ROLE IN THE DEVELOPMENT OF THE LOAD FORECASTS UPON WHICH PJM RELIED TO IDENTIFY THE RELIABILITY VIOLATIONS FOR WHICH PJM SOUGHT SOLUTIONS IN THE 2022 WINDOW 3 COMPETITIVE SOLICITATION PROCESS?

A8. The Resource Adequacy Planning department of PJM's System Planning division has overall responsibility for the development of the long-term load forecasts for the PJM Region that are used in the Regional Transmission Expansion Plan ("RTEP") process, including the performance of all analyses, the development and evaluation of sensitivity analyses, interaction with PJM stakeholders, and documentation of the load forecasting data and results. I was involved in each of these capacities as PJM prepared its 2022 Window 3 solicitation, through which PJM selected the MARL as part of the package of solutions to address the reliability violations identified in 2022 Window 3.

II. <u>THE PJM LOAD FORECASTING PROCESS</u>

Q9. PLEASE PROVIDE AN OVERVIEW OF THE PJM LOAD FORECAST.

A9. The PJM load forecast is an independent work product of PJM. It is a report consisting of a range of hourly and expected peak electricity loads over the next twenty years under a range of historical weather conditions that is produced on an annual basis.[3] The report

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[3] Starting with the 2025 Load Forecast Report, PJM's load forecast covers a 20-year horizon, compared with 15 years in previous forecasts. The change reflects the Federal Energy Regulatory Commission's ("FERC") new requirement that transmission providers develop transmission plans on a 20-year planning horizon, whereas PJM had previously based its long-term transmission planning-related analyses on a 15-year planning horizon.

includes long-term forecasts of peak loads, net energy, load management, and other such information for each PJM zone, region, locational deliverability area, and the total PJM Region.

The purpose of the PJM load forecast is to provide an accurate signal of expected load conditions in the future, taking into consideration such factors as economic growth, distributed generation, electric vehicles, and equipment/appliance usage trends. The PJM load forecast ultimately supports PJM planning and market functions, including, as relevant to this proceeding, the development of the PJM RTEP, which evaluates the need for enhancements to the high-voltage transmission system.

Q10. PLEASE EXPLAIN HOW PJM DEVELOPS THE PJM LOAD FORECAST.

A10. PJM uses rigorous statistical techniques and procures data from reliable sources to complete its load forecast studies. The PJM load forecast uses estimating practices and modeling methods that are widely employed within the utility industry.

Modeling begins with Statistically Adjusted End-Use (“SAE”) models. SAE models forecast energy at a sector level (Residential, Commercial, and Industrial) considering customer behavior, appliance trends, economics, and energy efficiency to help infer present and future weather-sensitive (e.g., space heating and cooling) and non-weather-sensitive demand. Results from the SAE process are then used in hourly models where PJM additionally takes into account weather variables and calendar variables, along with behind-the-meter solar and electric vehicle charging.

Methodological enhancements to the PJM load forecast are made frequently to acknowledge ongoing patterns and best align the forecast with actual load trends or anticipated factors. Improving the PJM load forecast is an iterative process aimed at making the forecast as accurate as possible. As I discuss in further detail below, PJM develops and updates the PJM load forecast in collaboration with PJM stakeholders, including the local Transmission Owners.

The method for developing the PJM load forecast is further described in PJM Manual 19: Load Forecasting and Analysis, which is attached to this testimony as Exhibit AG-1. More detail can be found in the annual Load Forecast Supplement, the most recent version of which is attached to this testimony as **Exhibit AG-2**.

Q11. YOU STATED ABOVE THAT THE PJM LOAD FORECAST IS AN INDEPENDENT WORK PRODUCT OF PJM. DOES PJM INCORPORATE STAKEHOLDER FEEDBACK ON THE LOAD FORECAST OR ENGAGE WITH OUTSIDE CONSULTANTS REGARDING POTENTIAL ENHANCEMENTS TO THE LOAD FORECAST PROCESS?

A11. Yes. PJM has been performing independent load forecasting for nearly 20 years and regularly seeks and incorporates stakeholder feedback on the load forecast. PJM's methodology and modeling results are discussed and reviewed at various stages of the PJM stakeholder process, primarily through the Load Analysis Subcommittee and Planning Committee. To the extent PJM has contracted with qualified experts to provide data, such as data on behind-the-meter solar and electric vehicle charging trends, PJM circulates the experts' assumptions to stakeholders, including state agencies, and solicits their feedback, which PJM then passes along to the qualified experts. In this way, PJM facilitates an ongoing dialogue between the experts providing the data and PJM's stakeholders.

PJM also engages with outside consultants to help identify potential enhancements to the load forecast process. For example, in 2022, PJM commissioned Itron, Inc. ("Itron") to prepare a publicly available report on the load forecast process to assess then-current forecast models and recommend enhancements.[4] Following publication of the Itron Report, Itron presented its analysis and findings to the Load Analysis Subcommittee and answered stakeholder questions.

Q12. PLEASE DESCRIBE THE TECHNICAL ENHANCEMENTS OR OTHER IMPROVEMENTS PJM HAS MADE TO ITS LOAD FORECAST METHODOLOGY AS A RESULT OF THIS INDEPENDENT REVIEW.

A12. Itron's recommendations led to several key enhancements:

- Moving to higher frequency data in construction of the SAE sector models. PJM started using SAE models back in 2015, and with Itron's help and recommendations was able to move to using monthly data as opposed to annual data. Incorporating more frequent monthly data into its SAE modeling has resulted in better inferences on trends in weather-sensitive demand and non-weather-sensitive demand.
- Transitioning to an hourly model. Prior to the 2023 load forecast, PJM utilized a daily model. Technologies like behind-the-meter solar and electric vehicles are changing the shape of electricity demand and their impacts are tracked more accurately with hourly modeling. To anticipate how these new technologies will impact peak demand, modeling needs to be more granular than previously.

Q13. HAS PJM INCORPORATED ITRON'S RECOMMENDATIONS INTO ITS LOAD FORECASTING MODELING AND METHODOLOGIES?

A13. Yes, Itron's recommendations and suggested improvements regarding PJM's load forecasting methodology and modeling were initially incorporated into the 2023 load forecast.

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[4] Itron's resulting "2022 PJM Model Review" report ("Itron Report") is included as **Exhibit AG-3** to this testimony.

Q14. HOW OFTEN DOES PJM UPDATE ITS LOAD FORECASTS?

A14. PJM updates its load forecasts on an annual basis, and generally publishes each year's new load forecast in January of each calendar year. PJM also simultaneously publishes a Load Forecast Supplement, which provides additional detail about the load forecast for the relevant year.

III. THE LOAD FORECASTS LEADING TO PJM OPENING THE 2022 WINDOW 3 COMPETITIVE SOLICITATION PROCESS

Q15. WERE YOU INVOLVED IN THE DEVELOPMENT OF THE LOAD FORECAST REPORTS THAT WERE USED FOR THE 2022 RTEP WINDOW 3 SOLICITATION?

A15. Yes, I was a part of the team that developed, reviewed, and published the "2022 Load Forecast Report" and the "2023 Load Forecast Report," which are included as Exhibits AG-4 and AG-5 to this testimony, respectively, and which are both relevant to the 2022 Window 3 competitive window solicitation process.

Q16. PLEASE EXPLAIN THE RESULTS OF THE 2022 LOAD FORECAST REPORT.

A16. In the 2022 Load Forecast Report, PJM presented the results of its load forecast model for 15 years (*i.e.*, the period 2022 through 2037). Specifically, PJM presented 15 years of forecasted annual summer and winter peaks for the total PJM Region, transmission zones, and select combinations of zones (Locational Deliverability Areas).

The 2022 Load Forecast Report showed that electricity demand in the PJM Region is expected to steadily increase over the next 10 and 15 years. Summer peak load growth for the PJM Region was projected to average 0.4% per year over the reported periods, with zonal growth rates ranging from -0.3% to 2%. In the 2022 Load Forecast Report, PJM identified several zones, including the APS zone in Maryland, DOM, American

Transmission Systems, Inc. ("ATSI"), and Commonwealth Edison ("COMED") zones, that had to be adjusted to account for large, unanticipated load changes.

Q17. DID PJM MODIFY THE 2022 LOAD FORECAST DURING THE 2022 ANNUAL RTEP CYCLE?

A17. Yes. As explained in more detail in Dr. Abdulsalam's Direct Testimony, each year, PJM commences an RTEP cycle to determine the needs of the transmission system. PJM develops an RTEP baseline power flow model which incorporates, among other things, the Load Forecast Report for the calendar year in which PJM is commencing the RTEP cycle. In the case of the 2022 RTEP planning cycle, PJM used the 2022 Load Forecast Report, which was issued in January 2022, to develop the 2022 RTEP baseline power flow model.

Throughout 2022, PJM facilitated several competitive windows as part of the 2022 RTEP cycle to address reliability criteria violations and market efficiency congestion needs resulting from the increased load forecast and other drivers necessitating the need for transmission development. These windows are described in Dr. Abdulsalam's Direct Testimony. As part of the 2022 RTEP cycle, PJM also directed that certain Immediate-need Reliability Projects[5] be incorporated into the 2022 RTEP, which were needed to (i) enable the integration of the forecasted data center load up in the Dominion Virginia Power ("DOM") zone to and including year 2025 and (ii) address reliability violations caused by the proposed deactivation of a number of generation facilities, most notably the Brandon

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[5] An "Immediate-need Reliability Project" is a "reliability-based transmission enhancement or expansion that [PJM] has identified to resolve a need that must be addressed within three years or less from the year [PJM] identified the existing or projected limitations on the Transmission System that gave rise to the need for such enhancement or expansion pursuant to the study process described in Operating Agreement, Schedule 6, section 1.5.3." PJM Operating Agreement, Definitions I-L.

Shores generation units in Maryland (Baltimore Gas and Electric Company ("BGE") zone) (*see* Abdulsalam Direct Testimony).[6]

In late 2022, PJM observed that data center loads within northern Virginia (DOM zone) were projected to continue increasing at an unprecedented rate, and new data center load was being proposed in Maryland near the Doubs substation (APS zone). This was in contrast to the relatively flat demand trends throughout much of PJM for the preceding decade. In an effort to stay ahead of these rapid load increases, rather than wait for the 2023 RTEP cycle, PJM consulted with transmission and distribution owners in the APS and DOM zones to refine the 2022 load forecast and further enhance its need assessment. This effort resulted in a modified 2022 load forecast that PJM used to develop the 2027 study year base case for Window 3 ("Modified 2022 Load Forecast"). As a result of these consultation efforts and in an effort to address the results of the Modified 2022 Load Forecast, PJM decided to open 2022 Window 3 in February 2023 as the final competitive solicitation window in the 2022 RTEP cycle.

As described more fully in Dr. Abdulsalam's Direct Testimony, to develop the base case suite for 2022 Window 3, PJM developed a 2027 study year base case (which was based on the Modified 2022 Load Forecast, as well as additional assumptions as described in Dr. Abdulsalam's Direct Testimony) and a 2028 study year sensitivity analysis (which incorporated updated load forecast information from the 2023 Load Forecast, as well as additional assumptions as described in Dr. Abdulsalam's Direct Testimony).

Q18. YOU EXPLAIN ABOVE THAT PJM MODIFIED THE 2022 LOAD FORECAST TO REFLECT ADDITIONAL LOAD IN THE APS AND DOM ZONES. CAN YOU PROVIDE ADDITIONAL DETAIL ABOUT THE INCREASED LOAD?

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[6] A map depicting the transmissions zones in the PJM Region is included in Attachment J of the PJM Open Access Transmission Tariff.

A18. Yes, based on the discussions we had with the relevant transmission owners and distribution owners as part of the annual process to update to the 2023 Load Forecast, PJM created a 2022 Modified Load Forecast for 2027 for the Maryland (APS) and DOM (Virginia) zones that considered approximately 1,200 MW and 2,700 MW of additional load, respectively.

Q19. PLEASE EXPLAIN THE RESULTS OF THE 2023 LOAD FORECAST REPORT.

A19. In the 2023 Load Forecast Report, PJM presented the results of its load forecast model for 15 years (*i.e.*, the period 2023 through 2038). Specifically, PJM presented 15 years of forecasted annual summer and winter peaks for the total PJM Region, transmission zones, and select combinations of zones (Locational Deliverability Areas).

The 2023 Load Forecast Report showed that electricity demand in the PJM Region is expected to steadily increase over the next 15 years. Summer peak load growth for the PJM Region was projected to average 0.8% per year over the reported periods, with zonal growth rates ranging from -0.5% to +4.4%. The DOM and APS zones exhibited the highest growth rates, due to anticipated large growth in load demand over the forecast horizon. Growth in the PJM Region is driven by economic growth, large block load additions, and electric vehicles, which is partly offset by continued energy efficiency gains and growing penetration of rooftop solar.

Q20. WHAT ARE THE KEY FACTORS IN THE PJM LOAD FORECAST REPORTS?

A20. There are a variety of factors that PJM's load forecasting model takes into consideration, and which drive the 2022 and 2023 Load Forecast Reports, including:

- **Weather:** Temperature, humidity, cloudiness, and wind conditions are among the most significant components in setting the short-term load forecast. A heat wave will spur consumers to run their air conditioners more and drive up the demand for power. Similarly, a period of extreme cold will prompt consumers' heating equipment to run more often. Moderate weather in the spring and fall tends to minimize the use of such equipment and reduces the demand for power.

- **Day of the Week:** The load forecast can differ significantly between a weekday – when many people are at work or school and electricity usage is high – and a weekend day or holiday, when many businesses are closed and usage is typically lower.
- **Economic Trends:** In preparing the long-term forecast, planners examine the state of the economy. The amount of electricity needed by commercial and industrial users is a major factor in overall demand. In a vigorous economy, manufacturers with electricity-intensive machinery will likely consume more power than when the economy is slack.
- **End-Use Trends:** PJM planners examine the volume and efficiency of electric-powered equipment that consumers have in service and that they plan to install. This includes central air conditioning, heat pumps, lighting, and major appliances – water heaters, refrigerators, freezers, washers, and dryers.
- **Rooftop Solar:** Solar panels and other types of generation installed on the customer's side of the electric meter can reduce the amount of electricity the customer draws from the grid. Knowing this capacity helps PJM develop accurate forecasts.
- **Plug-In Electric Vehicles:** Charging a battery-powered car requires a significant amount of electricity, in some cases the equivalent of half the power

needed for an entire home. As consumers buy increasing numbers of plug-in electric vehicles, the bigger impact they have on the grid. As a result, PJM planners factor the proliferation of these vehicles into their forecasts.

- **Large load additions:** PJM annually solicits information from electric distribution companies on trends they are observing that may not be well captured by the suite of models used to forecast load. In recent years this has been largely data centers, and PJM has been taking this input to help generate more accurate peak demand projections.

Q21. DID PJM'S 2022 AND 2023 LOAD FORECASTS TAKE INTO CONSIDERATION STATE POLICY GOALS REGARDING RENEWABLE ENERGY INTEGRATION?

A21. Yes. In load forecasting, it is important to capture those renewable resources that are netting with load (i.e., behind-the-meter resources), as they do impact the load forecast. For behind-the-meter resources, PJM annually contracts with a vendor to provide projections of future additions of behind-the-meter solar and storage resources. The outlook for public policy is a key driver of those projections such as renewable portfolio standards and solar carve-outs.

For example, PJM's 2023 Load Forecast incorporated several state policy goals specific to Pennsylvania regarding its renewable portfolio standard (RPS) policy.

Q22. DID PJM CONDUCT ANY ANALYSES TO VET THE INPUTS TO PJM'S 2022 AND 2023 LOAD FORECAST MODELS?

A22. PJM presented the 2022 and 2023 Load Forecast Reports to the PJM Load Analysis Subcommittee and the PJM Planning Committee for PJM Member and stakeholder review and comment. Additionally, for the behind-the-meter solar and storage forecasts, assumptions from our vendor are circulated to stakeholders (including state agencies via the Organization of PJM States Inc.) for review and comment each Summer.

Q23. DID PJM CONSULT WITH LOCAL DISTRIBUTION COMPANIES IN THE PJM REGION ON ITS 2022 AND 2023 LOAD FORECAST PROJECTIONS?

A23. Yes. In cases where a PJM zone has experienced or is anticipated to experience a load change (beyond the historical norm) that may not be captured in the load forecast, PJM may elect to apply a load forecast adjustment by either adjusting model inputs or by an explicit adjustment to the modeled forecast. These adjustments are based on further PJM assessments and discussions with stakeholders, including the specific transmission owners and electric distribution companies within the zone. In cases where the load change has not yet occurred, PJM will base any adjustment on information received from local electric distribution company load forecasters in response to PJM's annual request for details on large load changes that are known to the local distribution company. PJM will handle these requests on a case-by-case basis and perform (or have performed) whatever analysis is required to establish the degree of certainty and magnitude of the load change.

For the 2022 Load Forecast Report, for example, PJM was informed by local distribution companies in the APS, ATSI, COMED, and DOM zones of needed load adjustments. For the 2023 Load Forecast Report, PJM was informed by local distribution companies in the American Electric Power, APS, and DOM zones of anticipated growth in data center load. PJM incorporated this information into the 2022 and 2023 Load Forecast Reports as adjustments to the forecasted peak loads in these zones.

Q24. CAN THE COMMISSION RELY ON THE 2022 AND 2023 LOAD FORECAST REPORTS AS A REASONABLE FORECAST OF LOAD IN THE PJM REGION?

A24. Yes. The 2022 and 2023 Load Forecast Reports were developed using PJM's robust forecasting methodology and vetted through numerous internal reviews and external reviews through PJM's Load Analysis Subcommittee and Planning Committee. The Commission can rely on the 2022 and 2023 Load Forecast Reports as reasonable forecasts of load in the PJM Region for the period 2023 through 2038.

IV. MORE RECENT UPDATES TO LOAD FORECAST

Q25. THE PJM BOARD OF MANAGERS INITIALLY APPROVED THE MARL PROJECT FOR INCLUSION IN THE RTEP IN DECEMBER 2023. SINCE THAT TIME, HAS PJM PUBLISHED A MORE RECENT LOAD FORECAST REPORT?

A25. Yes. Since the PJM Board approved the 2022 Window 3 projects, PJM has published three more load forecast reports: (i) the 2024 Load Forecast Report, published in January 2024 and included as **Exhibit AG-6** to this testimony; (ii) the 2025 Load Forecast Report, published in January 2025 and included as **Exhibit AG-7** to this testimony; and (iii) the 2026 Load Forecast Report, published in January 2026 and included as **Exhibit AG-8** to this testimony. Each of these Load Forecast Reports were developed using a load forecasting methodology that was consistent with the methodology used for the 2023 Load Forecast Report that I have discussed previously in my testimony.[7]

Q26. WERE THE 2024, 2025, AND 2026 LOAD FORECASTS MATERIALLY DIFFERENT FROM THE 2023 LOAD FORECAST?

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[7] In the 2025 Load Forecast Report, PJM's load forecast covers a 20-year horizon compared with 15 years in previous forecasts. The change reflects the Federal Energy Regulatory Commission's ("FERC") new requirement that transmission providers develop transmission plans on a 20-year planning horizon, whereas PJM had previously based its long-term transmission planning-related analyses on a 15-year planning horizon.

A26. What is notable about the 2024 Load Forecast Report is that, as compared to the 2023 Load Forecast Report, PJM has now ***<u>significantly increased</u>*** its load forecast in both the near term (*i.e.*, a 1.7% PJM wide increase in 2025 as compared to previous forecast) and mid-term (*i.e.*, a 5.6% increase in 2029 as compared to previous forecast). And, in the 2024 Load Forecast Report, PJM continues to project steady growth over the next 15 years (*i.e.*, summer peak growth of 1.6% and winter peak growth of 1.8% over the next 15 years). Growth was broader in the 2024 Load Forecast Report reflecting several additional large load adjustments as well as PJM adopting a vendor-supplied electric vehicle forecast that showed more anticipated electric vehicle growth than PJM had previously included.

Additionally, as reflected in the 2025 Load Forecast Report, PJM continues to see significant load growth in the PJM Region. PJM expects that its summer peak load will increase by 3.1% per year over the next 10-year period and by 2.0% per year over the next 20-year period, whereas its winter peak load will increase by 3.8% per year over the next 10-year period, and 2.4% over the next 20 years, up from the predicted summer peak growth of 1.6% and winter peak growth of 1.8% reflected in the 2024 Load Forecast Report. Growth was broader in the 2025 Load Forecast Report as a result of several anticipated additional large load adjustments across the PJM Region, as well as PJM adopting a vendor-supplied electric vehicle forecast that showed more anticipated electric vehicle growth than PJM had previously included.

Similarly, the 2026 Long-Term Load Forecast Report confirms the trend of significant growth in electricity demand over the next 20 years, but slightly decreases expected load for near-term years as compared to the 2025 Load Forecast Report primarily due to changes to how PJM models large load adjustment requests in the near-term.

Specifically, PJM expects that its summer peak load will increase by 3.6% over the next 10-year period and by 2.4% over the next 20-year period, whereas its winter peak load will increase by 4.0% per year over the next 10-year period, and 2.7% over the next 20 years.

IV. CONCLUSION

Q27. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A27. Yes, it does, although I reserve the right to supplement this testimony as appropriate.

NEET MA Exhibit AG-1
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PJM Manual 19:

Load Forecasting and Analysis

Revision: 37

Effective Date: December 18, 2024

Prepared By
Resource Adequacy Planning

Table of Contents

Approval

Approval Date: 12/19/2024
Effective Date: 12/18/2024

Andrew Gledhill, Manager

Resource Adequacy Planning Department

Current Revision

Revision 37 (12/18/2024):

- Updates to Attachment A: Clarification on use of estimated load drops for load management in the Load Forecast.

Introduction

Welcome to the ***PJM Manual for Load Forecasting and Analysis***. In this Introduction you will find the following information:

- What you can expect from the PJM Manuals in general (see "*About PJM Manuals*").
- What you can expect from this PJM Manual (see "*About This Manual*")
- How to use this manual (see "*Using This Manual*").

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by the PJM Office of the Interconnection for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and billing
- PJM administrative services
- Miscellaneous

For a complete list of all PJM manuals, go to the Library section on PJM.com.

About This Manual

The ***PJM Manual for Load Forecasting and Analysis*** is one of a series of manuals within the Reserve group of manuals. This manual focuses on load-related topics. This manual describes the data input requirements, the processing performed on the data, computer programs involved in processing the data, and the reports that are produced. It then describes processes used to analyze load data and produce a long-term planning forecast.

The ***PJM Manual for Load Forecasting and Analysis*** consists of four sections. These sections are listed in the table of contents beginning on page 2.

Intended Audience

The intended audiences for the PJM Manual for Load Forecasting and Analysis are:

- *Electric Distribution Company (EDC) planners* — The EDC planners are responsible for supplying historical load data in the required format, for using coincident peaks to allocate normalized peaks, and for input data verification.
- *Load Serving Entity (LSE) planners* — LSEs use allocated peaks and the Load Management systems to determine their capacity obligations.
- *PJM staff* — PJM is responsible for the calculation of hourly PJM loads, normalizing PJM seasonal peaks, forecasting RTO and zonal peaks for system planning and capacity obligations, compiling the PJM Load Forecast Report, and administering Load Management. This information is used in calculating the capacity obligations.
- *Planning Committee members* — The Planning Committee is responsible for the stakeholder review of the peak forecasts and techniques for their determination.
- *Reliability Assurance Agreement Signatories* — The Markets & Reliability Committee is involved in the review of rules, methods and parameters associated with Load Forecasting and Analysis.

References

There are several references to other documents that provide background or additional detail. The ***PJM Manual for Load Forecasting and Analysis*** does not replace any information in these reference documents. The following documents are the primary source of specific requirements and implementation details:

- Power Meter documentation
- DR Hub documentation
- PJM Load Forecast Report
- PJM Manual for Emergency Operations (M-13)
- Reliability Assurance Agreement
- Behind-the-Meter Generation Business Rules (in Manual M-14D)

Using This Manual

We believe that explaining concepts is just as important as presenting the procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with an overview. Then, we present details, procedures or references to procedures found in other PJM manuals. The following provides an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections.

- An approval page that lists the required approvals and a brief outline of the current revision.
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions.
- Attachments that include additional supporting documents, forms, or tables in this PJM Manual.
- A section at the end detailing all previous revisions of this PJM manual.

Section 1: Overview

Welcome to the *Overview* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the Load Forecasting and Analysis (see “Overview of Load Forecasting and Analysis”)

1.1 Overview of Load Forecasting and Analysis

Load Forecasting and Analysis utilizes PJM Power Meter load data, Load Management, PJM Load Forecast Model, and Weather Normalization and Peak Allocation.

PJM Hourly Load Data — After-the-fact hourly load data are entered by EDCs and used by PJM for deriving seasonal load profiles, weather normalized peak and energy, 1CP zonal load contributions for Network Service billing, RTO unrestricted seasonal peak loads for capacity obligation allocation (5CP), charts contained in the PJM Load Forecast Report, Operations reports, and NERC compliance reporting.

PJM Load Forecast Model — PJM staff produces an independent forecast of monthly and seasonal peak load and load management, for each PJM zone, region, the RTO, and selected combinations of zones. The PJM Load Forecast Report includes tables and charts presenting the results.

Weather Normalization and Peak Allocation — PJM uses approved techniques for weather-normalizing historical summer and winter zonal peaks.

Section 2: PJM Hourly Load Data

Welcome to the *PJM Hourly Load Data* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the historic hourly load data file (see “Load Data Overview”)
- Guidelines for reporting load data to PJM (see “Load Data Reporting Business Rules”)

2.1 Load Data Overview

Official historic hourly load data for each EDC with revenue-metered tie data reported to PJM are collected via the Power Meter application. For EDCs submitting all internal generation, Power Meter will calculate a revenue-quality load based on submitted tie and generation meter values. This ensures that all customer demand is counted once and only once, on an aggregated and dispersed basis. EDCs may accept these values as their reported hourly service territory load, with the option to input data directly through the application's user interface or via uploaded XML files. The entered data are available through Power Meter screens, postings on the PJM website, or in several reports produced by the Performance Compliance Department.

[For details on submitting data into Power Meter, refer to the information posted on the PJM Website (under "Tools Sign In", select "Power Meter.")]

Load Data Definitions

Actual Net Metered Interchange: The sum of allocated tie metered values to which the EDC is a party.

Total Internal Generation: The sum of all meter values for non-500kV generators electrically located in the EDC's zone. For PJM Western and Southern regions, 500kV generation will be counted as part of internal generation.

Allocated Mid-Atlantic 500kV Losses: Participant's share of total PJM Mid-Atlantic 500kV losses

Calculated Load = Actual Net Metered Interchange + Total Internal Generation + Allocated 500kV Losses.

2.2 Load Data Reporting Business Rules

As established by the PJM Planning Committee, the following guidelines govern the reporting of load data into the PJM Power Meter application:

Data Reporting Responsibility

- It will be the responsibility of each PJM electric distribution company (EDC) with fully-metered tie flows to report hourly load data for its metered area(s), regardless of which entity is responsible for serving end-use customers.
- For all entities using network transmission service, it will be the responsibility of the signatory to the Network Integration Transmission Service Agreement to ensure that hourly load data are reported to PJM for its customers via PJM InSchedule.
- Curtailment Service Providers (CSPs) are responsible for providing information to estimate load management impacts as detailed in Attachment A.

Data Specifications

- Load data supplied to Power Meter will reflect each entity's total impact to the system, counting all customer demand once and only once, and will therefore need to properly account for system losses and flows. PJM will adjust loads for their assigned share of Extra High Voltage losses. LSEs providing load management impact estimates will adjust loads for system losses. Data are accepted in Power Meter in 0.001 MWh increments.

Reporting Schedule

- The data for each day should initially be entered within the following ten calendar days, except during peak periods, when the data must be entered daily. PJM contacts EDCs when daily reporting is needed.
- Edits to load data should be made by the tenth calendar day of the following month.
- PJM may adjust submitted load data, as necessary, to reflect additional load that is determined by PJM after-the-fact, resulting from third-party supply of generator station power requirements.
- EDC ability to submit loads via Power Meter is subject to a reporting window that includes the current month and three previous months. For example, in April, values for April, March, February, and January can be freely edited. For updates to months older than three full months prior, the participant must have PJM make the submission on their behalf. PJM may be contacted at mrkt_settlement_ops@pjm.com to arrange for assistance.
- Failure to report data to PJM in a timely and complete manner will subject responsible parties to Data Submission Charges, as outlined in Schedule 11 of the Reliability Assurance Agreement.

EDC/CSP Actions

- Enter Hourly Load Data — PJM EDCs submit aggregate hourly load values into Power Meter, as required. CSPs provide resource-specific settlements data to quantify Load Management impacts into the DR Hub application. (See Attachment A).
- Edit the Data as necessary — All hourly load value changes for a given month must be entered and edited by the 10th of the following month.

- Notify PJM of All Changes — Without this notification, PJM can only determine that changes have been made but cannot readily identify specific changes which were made.

PJM Actions

- Allocate Extra High Voltage Losses: — 500kV losses in the PJM Mid-Atlantic region are calculated as the total 500kV system energy injections minus withdrawals. Hourly 500kV losses are allocated to each PJM Mid-Atlantic EDC with revenue metered tie flows reported to Power Meter, in proportion to their real-time load ratio share.
- Post Zonal Data: — PJM will publish zonal load data in an electronic format on a monthly basis.
- Data Usage: — PJM uses the hourly load data for operational analysis, for calculating seasonal load factors, developing weather normalization curves, for allocating the PJM weather normalized seasonal peaks, for preparing various charts and tables in the PJM Load Forecast Report, and for reporting to regulatory and other authorities.

Section 3: PJM Load Forecast Model

Welcome to the *PJM Load Forecast Model* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the PJM Load Forecast Model (see “Forecast Model Overview”).
- A description of the methodology used to produce the PJM forecast (see “Development of the Forecast”).
- A description of the forecast review and approval process (see “Review and Approval the Forecast”).

3.1 Forecast Model Overview

The PJM Load Forecast Model produces 15-year monthly forecasts of unrestricted peaks assuming a range of weather conditions for each PJM zone, locational deliverability area (LDA) and the RTO. The model uses trends in equipment and appliance usage, anticipated economic growth, distributed solar generation and battery storage, plug-in electric vehicles, and historical weather patterns to estimate growth in peak load and energy use. It is used to set the peak loads for capacity obligations, for reliability studies, and to support the Regional Transmission Expansion Plan. Net energy forecasts are used in reporting requirements of FERC and NERC, and for market efficiency studies. The forecast is produced by PJM and released prior to each Planning Period, typically in January.

3.2 Development of the Forecast

The PJM Load Forecast employs multiple regression models to estimate hourly peak load for each PJM zone. Models for each PJM zone share the same general specification. Variables considered are:

Dependent Variable – Unrestricted Load

Hourly metered load data are supplemented with estimated load drops (as outlined in Attachment A), estimated load drops associated with peak shaving programs, estimated distributed solar generation, and battery storage to obtain unrestricted hourly loads.

Calendar Effects

Days of the week, month of the year, holiday, and Daylight Saving Time impacts may be included in the model.

Weather Data

A full collection of the weather variables and transformations used for each PJM zone is provided in the corresponding year's Load Forecast Supplement. These variables include temperature, humidity, wind speed, and cloud cover. Additionally, the below weather equations are used for weather sensitive energy efficiency demand reduction. The Winter Weather Parameter is defined as:

$$\text{inlinescrollIf WIND} > 10 \text{ mph,}$$

$$\text{inlinescrollWWP} = \text{DB} - \left(0.5 * (\text{WIND} - 10)\right)$$

$$\text{inlinescrollIf WIND} \leq 10 \text{ mph,}$$

$$\text{inlinescrollWWP} = \text{DB}$$

Where:

WIND	Wind velocity, in miles per hour
WWP	Wind speed adjusted dry bulb temperature
DB	Dry bulb temperature (^{O}F)

The Summer Weather Parameter, as reference in the Peak Shaving Adjustments section below,Temperature-Humidity Index (THI) is defined as:

$$\text{inlinescrollIf DB} \geq 58,$$

$$\text{inlinescrollTHI} = \text{DB} - 0.55 * (1 - \text{HUM}) * (\text{DB} - 58)$$

$$\text{inlinescrollIf DB} < 58,$$

$$\text{inlinescrollTHI} = \text{DB}$$

Where:

THI	Temperature-humidity index
DB	Dry bulb temperature (^{O}F)
HUM	Relative Humidity (where 100% = 1)

Additionally, measures of heating and cooling degree days are included, using the current and previous day's weather. Weather data for each PJM zone are calculated according to the mapping presented in the annual Load Forecast Supplement.

Economic Drivers

Measures of economic and demographic activity are included in the forecast models, representing total U.S., state, or metropolitan areas, depending upon their predictive value. Economic drivers for states and metropolitan areas are assigned to each PJM zone according to the mapping presented in the annual Load Forecast Supplement.

End-Use Trends

Measures of the stock and efficiency of various electrical equipment and appliances used in residential and commercial settings are included in the forecast models, grouped by heating, cooling, and other. End-use variables for each PJM zone are applied by Census Division. In some instances, PJM supplements this data with zone-supplied information.

PJM annually solicits information from stakeholders regarding electrification policies that pertain to end-uses.

Peak Shaving

In cases where a zone contains a peak shaving program with an approved Peak Shaving Adjustment Plan, the zone's forecast will be adjusted to reflect the program's impact.

Load Adjustments

In cases where a zone has experienced or is anticipated to experience a significant load change that may not be captured in the load forecast, PJM may elect to apply a load forecast adjustment by either adjusting model inputs or by an explicit adjustment to the modeled forecast.

In cases where the load change has not yet occurred, PJM will base any adjustment on information received from EDC load forecasters in response to PJM's annual request for details on large load changes that are known to the EDC. PJM will handle these requests on a case-by-case basis and perform (or have performed) whatever analysis is required to establish the degree of certainty and magnitude of the load change. Attachment B provides load forecast adjustment guidelines. PJM and the requesting EDC/LSE will produce documentation on and discuss load adjustments at the Load Analysis Subcommittee upon presentation of the annual load forecast.

Peak Shaving Adjustments

In cases where a zone has an approved Peak Shaving Adjustment Plan (as described in Attachment D), PJM will develop a load forecast adjustment to capture the impact of the program. Initially, existing load history will be compared with modified load history that assumes the program's anticipated curtailment behavior occurred in all historical years used in the forecast model to determine the program's ability to reduce daily peaks. Programs will then be incorporated into the weather rotation simulation process to establish the program's initial forecast adjustment MW value.

Once incorporated into the PJM load forecast, the program's performance will be measured against its committed MW curtailment value (as dictated by the program specifications) and scored over a rolling three-year period[1]. Results of this measurement may result in a revision of the program's forecast adjustment MW value, as described in Attachment D.

Any program receiving a peak shaving adjustment will be required to peak shave on any day in which its "trigger" is met or exceeded. The trigger will be based on the actual maximum daily temperature–humidity index (THI) for the relevant PJM zone as determined in advance by the relevant entity. If triggered, the peak shaving must comply with its pre-established parameters regarding number of hours of interruption, dispatch sequence, etc. Failure to operate to these parameters will lead to a reduction in the peak shaving adjustment.

Non-Coincident Base and 90/10 Scenarios

For each PJM zone, a distribution of non-coincident peak (NCP) forecasts is produced using a weather rotation simulation process. Using this approach, load forecasts are developed for each zone using the actual weather patterns that were observed in that zone over many years. The simulation process produces a distribution of monthly forecast results by selecting the 12 monthly peak values per forecast year for each weather scenario. For each year, by weather scenario, the maximum daily NCP load for a zone over each season is found. For each zone and year, a distribution of zonal NCP by weather scenario is developed. From this distribution, the median values are used to shape the monthly profile within each season.

The median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands.

RTO and Coincident Forecasts

To obtain the RTO/LDA peak forecasts, the solution for each of the zonal coincident peak (CP) models are summed by day, hour, and weather scenario to obtain the RTO/LDA peak for the day. By weather scenario, the maximum daily RTO/LDA value for the season is found. For the RTO/LDA, a distribution of the seasonal RTO/LDA peak vs. weather scenario is developed. From this distribution, the median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 90/10 weather bands.

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[1] For programs with less than three years of history, a one- or two-year performance score will be used.

To determine the final zonal RTO/LDA-coincident peak (CP) forecasts, a methodology similar to the process for deriving zonal NCPs is applied. By weather scenario, the maximum daily CP load for a zone over the summer season is found. For each zone a distribution of zonal CP vs. weather scenario is developed. From this distribution the median value is selected. The median zonal CPs are summed and this sum is then used to apportion the forecasted RTO/LDA peak to produce the final zonal CP forecasts.

Net Energy for Load Forecasts

For each PJM zone, a distribution of forecasts is produced using a weather rotation simulation process. The weather distributions are developed using observed historical weather data. The simulation process produces a distribution of monthly forecast results by summing the hourly values per forecast year for each weather scenario.

Load Management, Price Responsive Demand and Behind-the-Meter Generation

PJM incorporates assumptions of load management, price responsive demand, behind-the-meter generation, and battery storage to supplement the base, unrestricted forecast.

For Demand Resources (DR) other than PRD, forecasted values for each zone are computed based on the PJM final summer season Committed DR amount, where the Committed DR means all DR other than PRD that has committed through RPM, Base Residual Auction and all Incremental Auctions, or a Fixed Resource Requirement plan.

1. Compute the final amount of Committed DR (by DR product) for each of the most recent three Delivery Years. Express the Committed DR amount (by DR product) as a percentage of the zone’s 50/50 forecast summer peak from the January Load Forecast Report immediately preceding the respective Delivery Year.
2. Compute the most recent three year average Committed DR percentage, by DR product, for each zone. For DR products with less than three years’ worth of Committed DR data, compute the most recent one or two-year average Committed DR percentage.
3. The DR forecast, by DR product, for each zone shall be equal to the zone’s 50/50 forecast summer peak multiplied by the corresponding result from Step 2 minus the amount of the PRD forecast (described below) that in previous years committed as a different DR product.

For Price Responsive Demand (PRD), forecasted values for each zone on or after Delivery Year 2020/21 are computed based on the procedure below. The forecast is based on the amount of Cleared PRD in Base Residual Auctions on or after Delivery Year2020/21.

1. Compute the final amount of Cleared PRD for the most recent three Base Residual Auctions targeting Delivery Years 2020/21 or afterwards. Express the Cleared PRD amount as a percentage of the zone’s 50/50 forecast summer peak for the corresponding Delivery Year from the most recent PJM Load Forecast Report.

2. Compute the most recent three year average Cleared PRD percentage for each zone. If there is less than three years' worth of Cleared PRD data, compute the most recent one or two-year average Cleared PRD percentage.
3. The PRD forecast for each zone shall be equal to the zone's 50/50 forecast summer peak multiplied by the corresponding result from Step 2 for delivery years for which no Base Residual Auction has been held; for delivery years for which a Base Residual Auction has been held, the PRD forecast for each zone shall be equal to the amount of PRD cleared in the Base Residual Auction.

The total amount of behind-the-meter solar generation and battery storage will be forecasted separately from the load forecast model. The forecasted amounts will be used to adjust the unrestricted load of each zone.

Note:
More information on behind-the-meter generation can be found in the Behind-the-Meter Generation Business Rules in the PJM Manual for Generator Operational Requirements (M-14D) posted on PJM.com.

3.3 Non-Zone Peak Forecast

For use in the Reliability Pricing Model (RPM), PJM staff develops summer peak forecasts of the recognized non-zone loads. These forecasts are produced separately from the PJM Load Forecast Model, and utilize methods appropriate for each situation. Non-zone forecasted loads are added to the associated PJM zone for RPM purposes only.

3.4 Review of the Forecast

The PJM Load Forecast is reviewed by the Load Analysis Subcommittee and the Planning Committee. Upon presentation of the final forecast, PJM will supply a Load Forecast Supplement describing the methodology, the assumptions, and description of the data used in the forecast. Additionally, PJM will post data used in constructing the final forecast (except in those cases where not contractually permitted).

A member of the Planning Committee may submit an appeal (detailing the issue and outlining a solution) for a review of part or all of the forecast, which will be forwarded by the Chair of the Planning Committee to PJM, upon a vote of the Committee.

Section 4: Weather Normalization and Coincident Peaks

Welcome to the *Weather Normalization and Coincident Peaks* section of the ***PJM Manual for Load Forecasting and Analysis***. In this section you will find the following information:

- An overview of the weather normalization process (see “Weather Normalization Overview”).
- A description of the weather normalization procedure (see “Weather Normalization Procedure”).
- A description of the identification and calculation of PJM unrestricted coincident peaks (see “Peak Load Allocation (5CP)”).

4.1 Weather Normalization Overview

PJM performs load studies on summer and winter loads, for both coincident and non-coincident peaks, according to the procedures described below. The weather normalized (W/N) coincident peaks are used by EDCs to determine capacity peak load shares for wholesale and retail customers. W/N non-coincident peaks are provided by PJM for use by stakeholders in reviewing the PJM load forecast.

4.2 Weather Normalization Procedure

The PJM weather normalization procedure consists of utilizing the PJM Load Forecast Model as described in Section 3 above. After each season, each zonal/RTO NCP and CP model is re-estimated, adding the most recent historical data. Then, the weather simulation process is run, including historical weather through the just-completed season. From the resulting distribution of results, the median value is selected as the weather normalized seasonal peak.

EDC/ CSP Actions

- Enter hourly load data into Power Meter as described in Section 2 of this manual.
- Provide resource-specific settlements data to quantify Load Management impacts into the DR Hub application
- Submit voltage reduction and loss of Load Drop Estimates as described in Attachment A of this manual.

PJM Actions

- Obtain weather observations
- Produce voltage reduction load drop estimates, as described in Attachment A of this manual.
- Weather-normalize the zonal RTO-coincident winter and summer peak loads.

4.3 Peak Load Allocation (5CP)

Zonal weather-normalized RTO-coincident summer peak loads are allocated to the wholesale and retail customers in the zones using EDC-specific methodologies that typically employ the customer's shares of RTO actual peaks. The resulting Peak Load Contributions are then used in the determination of capacity obligations.

PJM establishes and publishes information, referred to as the 5CP, to aid EDCs in the calculation of Peak Load Contributions (also known as "tickets"). For each summer:

- Hourly metered load and load drop estimate data are gathered for the period June 1 through September 30
- RTO unrestricted loads are created by adding load drop estimates to metered load
- From the unrestricted values, the five highest non-holiday weekday RTO unrestricted daily peaks (5CP) are identified

5CP data are typically released in mid-October.

Attachment A: Load Drop Estimate Guidelines

General

Load Drop Estimates (also referred to as addbacks) are produced for three types of occurrences:

1. Curtailment of load for customers registered in the PJM emergency or pre-emergency program either as a Load Management resource (Demand Resource) or an Emergency – Energy Only resource, or customers registered to meet a Price Responsive Demand (PRD) commitment for either the Reliability Pricing Model (RPM) or the FRR Alternative.
2. Voltage Reductions implemented by PJM or an EDC
3. Significant losses of load.

PJM is responsible for producing Load Management/Emergency/Pre-Emergency load drop estimates, from CSP and EDC input into the appropriate PJM system. EDCs are responsible for reporting the estimated impact of voltage reductions (optional) or significant losses of load on their systems.

PJM is responsible for producing PRD load drop estimates, from PRD Provider input into the appropriate PJM system. PRD Providers that registered price responsive demand to satisfy a PRD commitment for either RPM or FRR Alternative must provide PJM with meter data when PRD was required to be dispatched (LMP is greater than the offer price). Meter data is entered at the site level; load drop estimates will be calculated at the registration level.

Load drop estimates, as calculated in this manual or otherwise calculated by PJM to reflect the estimated hourly energy load reductions (with communication to the appropriate stakeholder group), are used to construct unrestricted loads used in the PJM Load Forecast Model, weather normalization of PJM seasonal peaks, and to calculate the unrestricted Peak Load Contributions used in formulating capacity obligations.

These rules also apply to Non-Retail Behind-the-Meter Generation as provided in Section G of Schedule 6 to the Reliability Assurance Agreement.

Load Drop Estimates for Load Management Customers

The table below summarizes the requirements for producing load drop estimates for customers registered as a Demand Resource, or in the Emergency– Energy Only option, or as Economic load response, depending upon the cause of the load curtailment. Following the table are descriptions of the methods used by PJM to calculate load drop estimates for each load management type (Firm Service Level, and Guaranteed Load Drop).

Requirements for Production of Load Drop Estimates

Reason for Load Drop		PJM-Initiated Emergency or Pre-Emergency Event or CSP-Initiated Test	Economic Event	EDC- or CSP-Initiated Event
Program Registration	Emergency/ Pre-Emergency Full (DR) or Emergency/ Pre-Emergency Capacity Only (DR)	Load Drop Estimates must be produced for any interruption that occurs during a product-type registration's required availability window set forth in PJM Manual 18 or any interruption outside the required availability window for which such registration received Bonus MWs in the Performance Assessment Hour.	Load Drop Estimates must be produced for any settled interruptions.	No Load Drop Estimates required.
	Emergency Energy Only	Load Drop Estimates must be produced for any interruptions during Emergency/Pre-Emergency hours.	No Load Drop Estimates required.	No Load Drop Estimates required.
	Economic	No Load Drop Estimates required.	No Load Drop Estimates required.	No Load Drop Estimates required.

Actual Emergency and Pre-Emergency Load Response and Economic Load Response load reductions for Load Management resources registered as Emergency Full or Emergency Capacity Only resources will be added back for the purpose of calculating peak load for capacity for the following Delivery Year and consistent with the load response recognized for capacity compliance as set forth in the Manual.

Non-Interval Metered Customers

The estimated load drop for residential customers without interval metering is determined in accordance with Attachment C, Residential Non-Interval Metered Guidelines.

Contractually Interruptible

The estimated load drop which shall be used to determine capacity compliance and may be used as an addback to determine the unrestricted peak load for Firm Service Level and Guaranteed Load Drop customers is calculated as follows:

For Guaranteed Load Drop end-use customers, the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the metered load (“Load”) and then multiplied by the loss factor (“LF”) or (b) the current Delivery Year peak load contribution (“PLC”) minus the metered load multiplied by the loss factor (“LF”)) is applicable in the summer period of June through October and May of the Delivery Year. For the non-summer period of November through April of the Delivery Year, the Winter Peak Load (“WPL”) times the Zonal Winter Weather Adjustment Factor (“ZWWAF”) times LF is used in the equation as opposed to the PLC. A load reduction will only be recognized for capacity compliance if the metered load multiplied by the loss factor is less than the current Delivery Year peak load contribution (in summer period) or the current Delivery Year WPL times ZWWAF times LF (in non-summer period).

The calculation is represented by:

$$\text{Summer: Minimum of } \{(\text{comparison load} - \text{Load}) * \text{LF},\ \text{PLC} - (\text{Load} * \text{LF})\}$$

$$\text{Non-summer: Minimum of } \{(\text{comparison load} - \text{Load}) * \text{LF},\ (\text{WPL*ZWWAF*LF}) - (\text{Load} * \text{LF})\}$$

For Firm Service Level end-use customers the current Delivery Year peak load contribution (“PLC”) minus the metered load (“Load”) multiplied by the loss factor (“LF”) is applicable in the summer period of June through October and May of the Delivery Year. For the non-summer period of November through April of the Delivery Year, the WPL times ZWWAF times LF is used in the equation as opposed to the PLC.

The calculation is represented by:

$$\text{Summer: PLC} - (\text{Load} * \text{LF})$$

$$\text{Non-summer: } (\text{WPL*ZWWAF*LF}) - (\text{Load} * \text{LF})$$

Note:
Winter Peak Load (“WPL”) and Zonal Winter Weather Adjustment Factor (“ZWWAF”) are defined in accordance with PJM Manual 18, PJM Capacity Market.

When Generation interval meter data is provided to determine test or event compliance, and interval metering on load is available, the interval metered load data should be provided to ensure load drop is below the PLC or (WPL*ZWWAF*LF). It is expected that interval load data will be available for all customers that have a PLC > 0.5 MW. If no interval meter load data exists, such Generation interval meter data multiplied by loss factor will be used as the estimated load drop.

Estimate of Comparison Load for Guaranteed Load Drop (GLD) Customers

For purposes of determining compliance with a PJM-initiated Load Management event or CSP-initiated test for Guaranteed Load Drop customers, several options are available to estimate comparison loads. The method used should result in the best possible estimate of what load level would have occurred in the absence of an emergency, pre-emergency or test event.

The CSP will be responsible for supplying all necessary load data to PJM in order to calculate the load reduction for each registered end use customer. PJM will calculate the load drop amount unless otherwise indicated below or approved by PJM. The amount of load data required will depend on the GLD method selected where the minimum amount shall be 24 hours for one full calendar day.

Comparable Day: The customer’s actual hourly loads on one of the prior 10 calendar days before the test or emergency or pre-emergency event day selected by the CSP which best represents what the load level would have been absent the emergency or pre-emergency or test event. The CSP may request use of an alternative day for extenuating circumstances with supporting documentation that clarifies why the alternative day should be utilized. PJM must approve the use of any alternative day. CSP must provide usage data for all 10 days such that PJM may validate an appropriate day was selected.

Same Day (Before/After Event): The customer’s average hourly integrated consumption for two full hours prior to notification of an emergency or pre-emergency event or prior to one full hour before a test and for two full hours after skipping first full hour after the event or test. This option is appropriate for high load factor customers with no weather sensitivity.

Customer Baseline: The Customer’s estimated baseline used to calculate load drops for PJM economic demand resources as defined on the applicable PJM economic registration.

Regression Analysis: The customer’s estimated hourly loads from a regression analysis of the customer’s actual loads versus weather. This option is appropriate for customers with significant weather sensitivity. The CSP will perform the regression analysis and provide results including supporting information to PJM. The information should include all load and weather data and associated regression statistics used to estimate the load impact on the event or test day.

Generation: The hourly integrated output from a generator used to provide Guaranteed Load Drop. This method may only be utilized if the generation would not have otherwise been deployed on the emergency or pre-emergency event or test day and must comply with the provisions contained in the PJM Manuals.

Load Drop Estimates for PRD Customers

Load Drop Estimates are applicable to price responsive demand registrations that are used to satisfy a PRD commitment for either RPM or FRR Alternative. Load Drop Estimates are not applicable to Energy Only PRD registrations.

*Load Drop Estimate = Customer Expected Peak Load – (Metered Load * EDC Loss Factor)*
*Load Drop Estimate = Peak Load Contribution – (Metered Load * EDC Loss Factor)*

Missing Data

If an end use customer meter malfunctions during a Load Management test, retest or emergency or pre-emergency event and the end use customer performed the required load reduction activity and no interval meter data is available to use for purposes of measuring capacity compliance or to determine applicable energy settlements, then PJM may allow CSP one of the following two remedies, otherwise the end use customer will be considered to have taken no load reduction actions during such period:

1. CSP may provide supporting information to quantify the load reduction amount which includes an engineering analysis or meter data from a comparable site that reduced load based on the same actions during a comparable time, or;
2. CSP may perform a separate test for the end use customer(s) to quantify the load reduction that will be used for the test, retest or event time period compliance and, as appropriate, energy settlement(s). The test will need to be performed at comparable time and conditions to when the test, retest or emergency or pre-emergency event occurred.

Remedies will only be considered if the CSP and associated metering entity followed Good Utility Practice as outlined in the OATT, no interval load data is available from the EDC, and the CSP can provide supporting information, such as building automation system logs, to verify the load reduction action was taken during the test, or retest or emergency or pre-emergency event when the meter malfunctioned. CSP must also provide evidence that the meter did malfunction.

PJM must approve any remedy and CSP must meet appropriate load data submission deadline.

Voltage Reduction

Whenever a part of the PJM system experiences a voltage reduction, whether it is PJM- or locally initiated, the distribution companies involved are to estimate its impact on hourly load levels. The estimated impact of a 5% voltage reduction will be 1.7% of the load in the affected area at the time of the voltage reduction. Variances from this guideline are acceptable in cases where a thorough analysis was performed. In such cases, a written explanation of the estimate must accompany the reported values.

Loss of Load

Whenever a part of the PJM system experiences a loss of load event (beyond the level of nominal localized outages), the Distribution Company involved is to estimate its impact on hourly load levels. The method used to estimate the impact of the loss of load event will vary by the circumstances involved, but the outcome of the estimation should represent the best approximation of the actual hourly loads that would have occurred if the loss of load event had not occurred. A written explanation of the loss of load event and how its impact was estimated is to accompany the report.

Attachment B: Load Forecast Adjustment Guidelines

The intention of these guidelines is to ensure that any adjustments made to PJM's load forecast model are properly identified, estimated, and reviewed prior to incorporation into the forecast.

Issue Identification

- PJM annually solicits information from its member Electric Distribution Companies (EDC) and/or Load Serving Entities (LSE; e.g. co-ops, munis) for large load shifts (either positive or negative and located in their territory) which are known to the EDC and/or LSE but may be unknown to PJM. PJM will send the request in mid-July with responses expected in time for any proposed adjustments to be reviewed with the Load Analysis Subcommittee in September/October. Industry groups and/or large end-use customers who anticipate large load adjustments should engage with their EDC and be transparent with as much information (historical and forecast) as possible.
- Requested load adjustments deemed appropriate by PJM will be used in the forecast that drives both market and reliability RTEP studies.

Issue Verification – verify that identified issue is real and significant, using the following methods:

- Determine if the load change has been publically acknowledged through the media, press release, regulatory process, etc.
- Verify that requesting EDC and/or LSE has or will adjusted its own financial/planning forecast. When appropriate the requesting EDC and/or LSE should provide PJM, on a confidential basis, with the certainty backed by a Letter of Agreement and/or Electric Service Agreement (LOA/ESA).
- Ascertain whether the load shift is related to a single site or a limited number of related sites (not a systemic cause)
- The EDC shall identify to PJM the Load Serving Entity (LSE) where the addition will occur.
- Identify if load would be captured in load forecast model to identify potential double counting. These steps may include: Discuss with economic forecast vendor(s) whether or not the load shift is reflected in its/their economic forecast(s). Also, determine if the requested load adjustment's load impact is consistent with its economic impact. Additionally, determine if the requested load adjustment is tied to any of the metro areas that PJM uses to define the economic variable of a zone.
- Verify that any behind-the-meter generation adjustment has complied with PJM's behind-the-meter process
- Determine adjustment's significance, either by sheer magnitude or percentage of a zone's load.
- For PJM's review, provide any available independent analysis of the impact of the load change.

Adjustment Estimation - for each identified and verified issue, PJM will estimate its impact on peak load using the following methods (which may be combined):

- Acquire load history for the load that has/will change and produce analysis to isolate the impact. Load history should be provided on an hourly granularity. In the event that no load history exists, EDC and/or LSE should provide PJM with expected hourly behavior of load.
- Acquire an extended forecast of the adjustment from the EDC and/or LSE for the length of the long-term load forecast.
- If available/appropriate, provide PJM with a high and low scenario for load adjustment request.

Adjustment Review – each proposed load forecast adjustment will be reviewed with the Load Analysis Subcommittee prior to inclusion in the load forecast. Each requesting EDC and/or LSE will be expected to present on their adjustment request including backup documentation at a September/October LAS meeting. The final decision on any load adjustment is made by PJM and will be reflected in the Load Forecast.

Any adjustment that is reflected in the Load Forecast will be summarized by the requesting EDC and/or LSE in a public document describing the method and forecasting approach followed. This public document will be posted by PJM with the load report materials.

Example 1: Single Large Load Change (positive or negative)

Issue Identification – EDC and/or LSE notifies PJM that a large industrial load is to increase/ decrease load

Issue Verification – PJM reviews request and specifically verifies:

- The industrial load change is widely reported in local media. A proof of requested load change validity is provided when a single load change is commercially sensitive;
- The EDC and/or LSE has or will adjust its own financial and planning forecasts to reflect the load change at the plant;
- The affected load is confined to one site/customer account.
- PJM consults with economic forecast supplier to determine if the load change is reflected in their economic forecast.

Adjustment Estimation – PJM requests historical hourly load data and/or hourly forecast load data for the end-use customer. If the large load is being removed, PJM may remove hourly loads from history. If the large load is being added adjustments to the hourly forecasted loads will be made. The final load adjustment will be included in the load forecast after review with LAS.

Example 2: Industry level load change

Issue Identification – EDC and/or LSE notifies PJM that it plans to integrate a large amount of load associated with one industry during the forecast horizon

Issue Verification – PJM meets with the EDC and/or LSE and through follow-up conference calls, e-mail exchanges and PJM independent investigation it is determined that:

- The load in question is confined to a single industry.
- The EDC has or will adjust its own financial and planning forecasts to reflect the change in load;
- The new load sites are not fully reflected in the economic variables included in the model.
- Updated expected near term growth (accounting for requested load changes) supported by contracts in place with the EDC and/or LSE, construction companies, and suppliers.

Adjustment Estimation – PJM requests historical hourly load data and/or hourly forecast load data for specific industry. PJM investigates its model inputs and makes modifications to history to reflect load impacts in order to avoid double counting. The accelerated load growth (or reduction) is layered on the forecast to reflect the expansion (contraction).

Attachment C: Residential Non-Interval Metered Guidelines

Statistical sampling for residential customers

Residential customers without interval metering may participate in the Synchronized Reserve, Capacity, and Energy markets using a statistical sample extrapolated to the population to determine compliance and energy settlements. The sample data must be from the same time interval as the event being settled.

Qualifications

A registration may participate using statistical sampling to determine compliance and energy settlements under the following conditions, and subject to PJM approval:

- The registration consists entirely of residential customers.
- Locations can be sampled to accurately reflect the population load data.
- Curtailment at each location uses Direct Load Control Technology.
- Synchronized Reserve: Locations otherwise qualify for participation in the Synchronized Reserve Market. Locations do not have meters that record load data at a period of 1 minute or shorter.
- Economic Energy: Locations otherwise qualify for participation in the Economic Energy Markets. Locations do not have meters that record load data at a period of 1 hour or shorter.
- Load Management: Locations otherwise qualify for Load Management. Locations do not have meters that record load data at a period of 1 hour or shorter.

Sample Design

Samples must be designed to achieve a maximum error of 10% at 90% confidence. The locations in the sample must be randomly selected from all the locations in the population group (a population group is a group of registrations that can share a sample based on the criteria listed below). The sample must be stratified by control device size (minimum of 2 strata) and geographic location, unless otherwise approved by PJM.

For Load Management registrations that participate in the capacity market, a sample is required for each combination of EDC, CSP, end-use device (such as air conditioner or water heater) or device grouping, curtailment algorithm and switch vintage if there is substantial variation among installed switch capability.

For economic registrations that participate in the Energy Markets, a sample is required for each combination of dispatch group or registration, end-use device or device grouping, curtailment algorithm, and switch vintage if switch capability is substantially different. For economic registrations that participate in the Synchronized Reserve market, a sample is required for each combination of SR subzone, dispatch group or registration, end-use device or device grouping, curtailment algorithm, and switch vintage if switch capability is substantially different.

Sample Size Determination

A variance study is used to determine the initial sample size. Interval data must be collected from at least 75 randomly selected and stratified customers during the season the end use device is in use in order to determine the variance of the load data for the sample. Synchronized Reserves: At least 2 weeks of continuous meter data collected at a period of 1 minute or smaller.

Load Management and Economic Energy: At least 4 weeks of continuous meter data collected at a period of 1 hour or smaller.

The number of locations in the sample is then calculated as follows, unless otherwise approved by PJM:

$$\text{inlinescroll}n = \text{number of sampled customers in variance study}, \quad \geq 75$$

$$\text{inlinescroll}X_{i,\,t} = \text{meter reading for customer } i \text{ during interval } t$$

Calculate the mean and variance of the meter data across all customers for each interval:

$$\text{inlinescrollMean}(X_t) = \text{3 children in mover} = \frac{1}{n}\sum_{i=1}^{n} X_{i,\,t}$$

$$\text{inlinescrollVar}(X_t) = s^2_{X_t} = \frac{1}{n}\sum_{i=1}^{n} \left(X_{i,\,t} - \text{3 children in mover}\right)^2$$

Calculate the sample size necessary to get 10% error at 90% confidence for each interval:

$$\text{inlinescroll}M_t = \left(\frac{Z_{\text{3 children in mfrac}}}{e}\right)^2 \frac{s_t^2}{\text{3 children in mover}^2}$$

Where

$$\text{inlinescroll}Z_{\text{3 children in mfrac}} = 1.645 = \text{critical value at 90\% confidence } (\alpha = 0.1)$$

$$\text{inlinescroll}e = 0.1 = \text{error}$$

Take the average sample size across all intervals to determine M, the sample size:

$$M = \frac{1}{T}\sum_{t=1}^{T} M_t$$

Where T is the total number of intervals. T should be at least 20,160 for SR (2 weeks of 1 minute intervals) and 672 for economic energy and Load management (4 weeks of hourly intervals).

Alternate calculations may be used subject to PJM approval.

Sample Recalibration

The sample must be recalibrated annually as follows:

1. The sample size must be recalculated using the same method listed above using data from all locations in the sample.
2. If the population was expanded in a non-random manner, the sample must be expanded appropriately, so that the sample is representative of the population.
3. The number of locations in each stratum in the sample must be adjusted so that the number of locations in each stratum is proportional to the population in that stratum within +/- 1 location.

Data Validation and Estimation

Data must be validated and estimated in accordance with the NAESB Validating, Editing, and Estimating (VEE) Protocol. This protocol should be used for validation and estimation of 1-minute data for the SR market as well as hourly data for capacity and energy markets. Note: All rules for hourly data shall apply to 1 minute data where the only difference is the use of 1 minute interval instead of 1 hour interval.

If 5 minutes or more are missing or faulty from 1 minute meter data for a single event, or 2 hours or more are missing or faulty from hourly meter data for a single event, data from that meter may not be used for that event. If there is 1 way switch communication, the data for that meter must be reported as the PLC value for every reported interval on the event day. If there is 2 way switch communication and a sufficient number of locations in the sample without the missing meter data to meet the minimum sample size, then an estimate for the missing meter data should not be reported for this event. If there is 2 way switch communication and an insufficient number of locations in the sample without the missing meter data to meet the minimum sample size, then the PLC value should be reported for every reported interval for the event day for each location with missing meter data such that there are enough locations to meet the sample requirements unless otherwise approved by PJM.

Example with one-way switch communication: The minimum required sample size is 300. There are 305 meters in the sample. 7 meters have missing or faulty data that cannot be corrected. The CSP must include data from the 298 correctly functioning meters, and report the data from the 7 faulty meters as the PLC value for each of the 7 EDC accounts for every reportable hour that day.

Example with two-way switch communication: The minimum required sample size is 300. There are 305 meters in the sample. 7 meters have missing or faulty data that cannot be corrected. The CSP must include data from the 298 correctly functioning meters, and report the data from 2 randomly selected faulty meters as the PLC value for those 2 EDC accounts for every reportable hour that day.

Switch Operability

Two-way switch communication: Two-way switch communication is when the CSP receives verification from the switch that it successfully cycled base on CSP instruction. When there is two way switch communication in place, the CSP will calculate the performance factor, *F,* as the total number of switches in the population that were sent the instruction to cycle for that event divided by number of switches in the population that successfully cycled for that event. The meter data will be multiplied by this value before submission to PJM to scale the sample average load data to the represent the population that performed the load reductions.

One-way switch communication: One-way switch communication is when the CSP cannot accurately determine if each switch in the population successfully cycled based on CSP instruction. In this case the operability value is implicit in the sample. The CSP must report all data from all meters in the sample, even if a switch in the sample is faulty. The CSP may not repair any faulty devices in the sample that could also be faulty in the population (for example an air conditioner cycling switch cannot be repaired/replaced but a 1-minute meter could be repaired/replaced) unless the CSP repairs/replaces those same devices that are faulty in the population. Switch failure in the sample must be reported to PJM within 2 business days.

Converting sample data to meter data

Note:
Note that the sample data must be from the same time interval being settled.

$X_{i,t}$	is the meter reading for customer ***i***during interval ***t*** after VEE protocol is applied per this manual
B	is the set of EDC accounts in sample that are to be included in estimation (after subject to rules in this manual
M_S	is the sample size (number of EDC accounts in B)
M_C	is the population of Cycled customers
F	is the operability factor, calculated subject to this manual (1 for one way switch communication)

The meter data value to be submitted to PJM for interval *t* is Y_t:

$$Y_t = F\frac{M_c}{M_s}\sum_{i \in B} X_{i,t}$$

Measurement and Verification Plan

The CSP must submit a Measurement and Verification (M&V) plan to PJM before the registration is submitted. The M&V plan must be approved by PJM before the registration is submitted. CSP is to resubmit an updated M&V plan annually to continue participation in the PJM markets.

The M&V plan must include details on: how the variance study was conducted and sample size was determined; sample selection and stratification; meter qualification and quality assurance; data validation and error correction protocol; and how sample meter data will be converted to population meter data. A template of the M&V plan is to be published on pjm.com.

Churn and Customer Documentation

Note:
Parts of this section apply to interval metered residential customers, as indicated below.

Applicable to all residential customer registrations (interval metered and non-interval metered):

- CSP to submit initial list of customers to PJM at time of registration, including all EDC account numbers PLCs and zip codes. Where legal or regulatory conditions prohibit provision of EDC account number as personally identifiable customer information the EDC may use unique identifying numbers for EDC account numbers, through 5/31/16 or as otherwise approved by PJM. EDC is responsible to maintain list of EDC account numbers and associated unique identifying numbers when used. EDC may need to check for duplicate as approved by PJM.
- Replacement allowed for customer who moves from their premises or customer terminates contract with CSP.
- CSP must maintain list of all replacement and furnish to PJM within 2 business days of request.
- CSP must maintain list of customers who were cycled during an event.
- All customer lists, meter data, and documentation must be furnished to PJM within 2 business days of request and be maintained by CSP for 2 years.

Applicable to interval-metered Load Management:

- CSP to submit list of PLC values for each EDC account at time of registration.
- Replacement customers must be selected to maintain PLC and load drop.
- CSP must maintain list of customers for each event and maintain for 2 years from event date.

- CSP may not add/remove customers (other than replacement). If number of customers falls below registered number, CSP must report to PJM within 2 business days and is subject to RPM Resource Deficiency Charges if applicable.

Applicable to non-interval metered Load Management:

- CSP to submit list of PLC values for each EDC account at time of registration.
- Replacement customers must be randomly selected to maintain integrity of strata, and if applicable PLC and load drop.
- CSP must maintain list of customers for each event and maintain for 2 years from event date.
- CSP may not add/remove customers (other than replacement). If the number of customers falls below registered number, CSP must report to PJM within 2 business days and is subject to RPM Resource Deficiency Charges if applicable.

Applicable to interval metered Economic Energy and Synchronized Reserve:

- There are no restrictions on replacement customers since actual meter data is submitted.
- CSP must maintain list of customers for each offer for 2 years from date of offer.
- CSP may add/remove customers at any time, but must maintain documentation and update the value on the location in DR Hub. This value must be accurate every day an offer is submitted.
- List of offered customers must be finalized at time of offer. Number of offered customers cannot exceed number of customers on location.

Applicable to non-interval metered Economic Energy and Synchronized Reserve:

- Replacement customers must be randomly selected to maintain the integrity of the strata.
- CSP must maintain list of customers for each offer for 2 years from date of offer.
- CSP may add/remove customers at any time, if it can be done such that the sample remains representative of the population. CSP must maintain documentation and update the value on the location in DR Hub. This value must be accurate every day an offer is submitted.
- If CSP offers partial list of customers to market, then such customers must be randomly assigned from pool of all registered customers. List of offered customers must be finalized at time of offer. Number of offered customers cannot exceed number of customers on location.

Attachment D: Peak Shaving Adjustment Plan and Performance Rating

Peak Shaving Adjustment Plan

The Peak Shaving Adjustment Plan is a PJM template document, requiring the information set forth below, together with an accompanying signed PJM Peak Shaving Officer Certification Form. A completed Peak Shaving Adjustment Plan (including a signed Peak Shaving Adjustment Officer Certification Form) must be submitted to PJM no later than 10 business days prior to September 30 to be effective for the next PJM load forecast update. The Peak Shaving Adjustment Plan must provide information that supports the authorized entity's intended Peak Shaving Adjustment and demonstrates that the peak shaving program(s) is/are being offered with the intention that the MW quantity is reasonably expected to be physically delivered through program registrations for the relevant summer period. The Peak Shaving registrations shall be finalized before the start of the Delivery Year and on same time line as Load Management registrations. The Peak Shaving registration process will be based on the Economic DR registration process to ensure the accuracy of the retail customer information with the electric distribution company.

The Peak Shaving Adjustment Plan encompasses both existing peak shaving and planned peak shaving. Existing peak shaving is identified as end-use customer sites that the authorized entity has under contract for the current summer period (i.e. end-use customer sites registered in the PJM DR Hub system for the current summer period) and that the authorized entity intends to have under contract for the summer period.

Both the signed PJM Peak Shaving Officer Certification Form and the completed Peak Shaving Adjustment Plan template must be submitted to PJM via email to rpm_hotline@pjm.com no later than 10 business days prior to September 30. PJM will review the Peak Shaving Adjustment Plan and notify the authorized entity via email no later than September 30 if another authorized entity has identified the same end-use customer site(s) in their Peak Shaving Adjustment Plan or DR Sell Offer Plan and request supporting documentation, such as a letter of support from the end-use customer indicating that the end-use customer and CSP are likely to execute a contract for the relevant period. Supporting documentation must be submitted via email to the rpm_hotline@pjm.com no later than October 15. PJM will notify all authorized entities via e-mail of the approved peak shaving MW quantity by zone that will be included in the next update of the PJM load forecast.

I. PJM Peak Shaving Officer Certification Form

A Peak Shaving Officer Certification Form is located in Attachment E of Manual 19 and is posted on the PJM web site. A signed Peak Shaving Officer Certification Form must accompany the Peak Shaving Adjustment Plan. The Peak Shaving Officer Certification Form specifies that the signing officer has reviewed the Peak Shaving Adjustment Plan, that the information provided therein is true and correct, and that the MW quantity that will be included in the PJM load forecast is reasonably expected to be physically delivered through customer registrations for the relevant summer period.

II. Peak Shaving Adjustment Plan Template

A Peak Shaving Adjustment Plan template (in Excel format) is provided on the PJM web site, and consists of the following five sections:

A. Peak Shaving Adjustment Plan Summary

B. Planned Peak Shaving Details

C. Program Details

D. Historic Program Impacts

E. Schedule

A. Peak Shaving Adjustment Plan Summary

The Peak Shaving Adjustment Plan requires the following information to be provided:

- Company name
- Contact information (name, phone number and email address of submitter)
- Expected peak shaving value in MWs by zone
- Copy of tariff or an order approved by the Relevant Electric Retail Regulatory Authority

Existing peak shaving is identified as end-use customer sites that the authorized entity has under contract and registered in the PJM DR Hub System for the current summer period and that the authorized entity also intends to have under contract for the forecasted summer period. Planned peak shaving is identified by the authorized entity as described in the Peak Shaving Plan Details section of the Peak Shaving Adjustment Plan template.

Based on the information provided above, a total peak shaving value in MWs will be calculated by PJM for each zone as the addition of the peak shaving value of existing peak shaving plus the peak shaving value of planned peak shaving. The total peak shaving value represents the maximum MW amount that the authorized entity intends to offer for the zone.

B. Peak Shaving Plan Details

The Peak Shaving Plan Details section describes the program(s) and provides the details and key assumptions behind the development of the peak shaving quantities contained in the entity's Peak Shaving Adjustment Plan. The Peak Shaving Plan Details section is comprised of three sub-sections.

1. Description and Key Assumptions of Peak Shaving Program

The authorized entity must describe the program(s) to be employed to achieve the peak shaving value indicated on the Peak Shaving Adjustment Plan Summary. This section must describe key program attributes and assumptions used to develop the peak shaving value.

This section must include, but is not limited to, discussion of:

- Method(s) of achieving load reduction at customer site(s)

- Equipment to be controlled or installed at customer site(s), if any

- Plan and ability to acquire customers

- Types of customer targeted

- Support of market potential and market share for the target customer base, with adjustments for existing peak shaving customers within this market and the potential for CSPs targeting the same customers

- Assumptions regarding regulatory approval of program(s), if applicable

- If offering a Legacy Direct Load Control (LDLC) program, the following additional LDLC program details must be provided:

o Description of the cycling control strategy

o A list of all load research studies (with study dates) used to develop the estimated nominated ICAP value (kW) per customer (i.e., the per-participant impact). A copy of all studies must be provided with the Peak Shaving Plan. If the LDLC program employs a radio signal, the CSP may elect to either submit a load research study to support the estimated nominated ICAP value per customer or utilize the per-participant impacts contained in the "Deemed Savings Estimates for Legacy Air Conditioning and Water Heating Direct Load Control Programs in the PJM Region" Report.

o Assumptions regarding switch operability rate (%)

2. Planned Peak Shaving Value by Customer Segment

For those planned peak shaving values for which an end-use customer site is not identified in section 3 of the Peak Shaving Plan Details, the program administrator must identify the planned peak shaving values by zone and by end-use customer segment. End-use customer segments include residential, commercial, small industrial (less than 3 MW), medium industrial (between 3

MW and 10 MW) and large industrial (greater than 10 MW). If known, the program administrator may identify more specific customer segments within the commercial and industrial category.

By zone and by end-use customer segment, the program administrator must provide estimates of the following information:

- Number of end-use customers to be registered for each summer period
- Average Peak Load Contribution (PLC) per end-use customer in kW
- Average Peak Shaving Value per customer in kW

Based on the above provided information, a total peak shaving value in MW will be calculated for each end-use customer segment and for each zone. The total peak shaving value identified by customer segment and aggregated for each zone in Section 2 of the Peak Shaving Plan Details plus the total peak shaving values identified by end-use customer site(s) and aggregated for each zone in Section 3 of the Peak Shaving Plan Details must equal the total peak shaving value for each zone as identified in the Peak Shaving Plan Summary.

3. Peak Shaving Value by End-Use Customer Site

This section must be completed by the program administrator when the end-use customer is known at the time of the submittal of the Peak Shaving Adjustment Plan. This section must also be completed for peak shaving quantities identified in the Peak Shaving Plan Summary as requiring site-specific information, since this identified quantity should reflect planned peak shaving associated with specific end-use customer sites for which the program administrator has a high degree of certainty that it will physically deliver for the relevant summer period.

The program administrator must provide the following information:

- Customer EDC account number (if known)
- Customer name
- Customer premise address
- Zone
- Customer segment
- Actual value (if known) or estimate of current PLC and estimate of expected PLC in kW
- Estimated Peak Shaving Value in kW

In the event that multiple entities identify the same end-use customer site, the MWs associated with such site will not be approved for offering into the RPM auction or inclusion in the peak shaving adjustment by any of the entities, unless it can be supported by evidence, such as a letter of support from the end-use customer indicating that they have been in contact with the CSP/program administrator and are likely to execute a contract with that CSP/program administrator for the relevant summer period. In the event that multiple letters of support indicating different entities are provided from the end use customer, the MWs associated with the end-use customer site will not be approved for inclusion in the load forecast by any of the entities.

C. Program Details

The Program Details section describes the operating characteristics of the program(s). The program administrator must provide a brief description of each submitted program, the THI threshold at which peak shaving must be operated, the hours over which the program will operate once triggered, the total peak shaving value (consistent with the Peak Shaving Plan Details), and a table of program impacts over a range of hours and THI, showing the impact for the hour/THI combination as a percentage of the total peak shaving value.

D. Historic Program Impacts

The program administrator must provide estimated hourly load impacts for each peak shaving program for every implementation back to January 1, 1998.

E. Schedule

The program administrator must provide an approximate timeline for procuring end-use customer sites in order to physically deliver the total peak shaving value (existing and planned peak shaving) by zone in the Peak Shaving Plan Summary. For each zone and for each customer segment, the program administrator must specify the cumulative number of customers and the cumulative Peak Shaving Value associated with that group of customers that the CSP expects to have under contract by the beginning of each of the summer periods in the PJM load forecast horizon.

Peak Shaving Performance Rating

The peak shaving performance rating is used to correct the impact of approved peak shaving programs in the load forecast to be consistent with how the programs have performed when required to reduce load.

For each hour of a required peak shaving event, a shortfall value is calculated as the aggregated metered load of all participants minus the difference between aggregated Customer Baseline (CBL) and Total Participating MW:

$$\text{Shortfall}_{\text{hour}} = \left(\text{Metered Load * Line Losses}\right) - \left(\left(\text{CBL * Line Losses}\right) - \text{Total Participating MW}\right)$$
.

For the event, the performance rating is one minus the average shortfall divided by the Total Participating MW:

Event Performance Rating = 1 − (Avg Shortfall MW / Total Participating MW
).

For the year, the performance rating is the average of the event performance ratings. PJM will apply a three-year rolling average of the annual peak shaving performance ratings to the program’s total participating MWs in order to determine its peak shaving adjustment. For programs with less than three years of experience, a one- or two-year average will be used.

Attachment E: Peak Shaving Officer Certification Form

PJM PEAK SHAVING OFFICER CERTIFICATION FORM

Market Participant Name: (“Participant”)

I, , a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. (“PJM”) and PJM Settlement, Inc. (“PJM Settlement”) are relying on this certification as evidence that Participant meets all requirements for inclusion in PJM’s load forecast, as set forth in the PJM Open Access Transmission Tariff (“PJM Tariff”), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement"), the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (“RAA”), and in the PJM Manuals, hereby certify that, as of the date of this certification, to my knowledge and belief:

1. I have reviewed Participant’s Peak Shaving Adjustment Plan (the “Plan”) and the information supplied to PJM in support of the Plan is true and correct as of the date of this certification.

2. The Participant is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of this certification, to physically deliver all megawatts of peak shaving by the specified summer period.

3. This certification does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Participant’s rights and obligations thereunder, including Participant’s ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

Date: By:

(Signature)

Print Name: Title:

Revision History

Revision 36 (11/15/2023):

- Periodic Review
- Updated manual ownership to Andew Gledhill
- Section 3.2: Updated to reflect to change to hourly model and provide more clarity to load management and price responsive demand forecast procedure.
- Conforming revisions related to FERC Order ER20-217-000 in Attachment A.
- Updated Attachment B to reflect more transparency in data needs and documentation from requesting EDCs/LSEs. Examples provided updated to reflect recent requests.
- Minor revisions to correct grammar, spelling, punctuation, consistency of terms and document references in Attachment D.

Revision 35 (12/31/2021):

- Revisions proposed from cover-to-cover periodic review:
  - Revised outdated language
  - Minor revisions to correct grammar, spelling, punctuation, consistency of terms and document references.
- Section 3: Added battery storage to forecasted items.

Revision 34 (12/05/2019):

- Periodic Review updated to address:
  - Section 3: Load forecast model details are being removed from the Manual in favor of an annual whitepaper documenting the details of the load forecast.
  - Section 4: The weather normalization procedure for peak load and energy is revised to be directly tied to the load forecast model.

Revision 33 (10/25/2018):

- The following changes were made to implement the solution package of the Summer-Only Demand Response Senior Task Force:
  - Section 3: Revisions to the load forecast development process to explicitly recognize approved summer-only peak shaving programs.
  - Attachment D (new): Creates the rules and timelines related to Peak Shaving Adjustment Plans.
  - Attachment E (new): A template for the Peak Shaving Officer Certification Form.

Revision 32 (12/01/2017):

- Cover to Cover Periodic Review

- Section 3: Revisions to the methods used to forecast Demand Response and Price Responsive Demand
- Attachment A: Conforming changes to clarify when load drop estimates are produced and definitions of calculations for load drop estimates in non-summer period, in accordance with FERC Order E17-367 approved on March 21, 2017.

Revision 31 (06/01/2016):

- Section 3: Corrected formulas in the End-Use/Weather Variables section
- Attachment B: Removed due to expiration of load research guidelines. The former Attachments C and D have been re-lettered.

Revision 30 (12/01/2015):

- Added the following changes that were endorsed at the MRC on 12/01/2015 but were omitted from the final version:
    - Section 3 - distributed solar generation is now reflected in the historical load used for zonal models and a separate solar forecast is used to adjust zonal forecasts.

Revision 29 (12/01/2015):

- Section 3: This extensive revision incorporates changes to the load forecast model to add variables to account for trends in appliance usage and energy efficiency, revisions in weather variables, and the introduction of an autoregressive error correction. It also adds assignment of Census Divisions to zones and updates the assignments of economic regions and weather stations to zones. Section 4: the weather normalization procedure used for coincident and non-coincident peaks has been revised. This revision serves as the required periodic review of the Manual.

Revision 28 (08/03/2015):

- Conforming revisions for FERC Order ER15-1849, accepted on 7/23/15 and effective 8/3/15, to improve measurement and verification procedures for CSPs with Residential Demand Response Customers. Direct Load Control is re-defined as Legacy Direct Load Control and is only effective through May 31, 2016. Statistical sampling may be used instead of customer-specific measurement and verification information for residential customers without interval metering, as outlined in Attachment D of this manual.

Revision 27 (03/26/2015):

- Section 3.2: Revised DR forecast methodology

Revision 26 (11/01/2014):

- Section 3: Revised to clarify the current process of applying adjustments to load forecasts.
- Attachment C: Added to provide guidelines for load forecast adjustments and examples.

Revision 25 (06/01/2014):

- Conforming revisions for FERC Order ER14-822, accepted on 05/09/2014, and effective on 06/01/2014 for various DR operational changes.
- Attachment A updated for new distinction between Emergency and Pre-Emergency DR.

Revision 24 (04/11/2014):

- Two of the eSuite Applications have been renamed. Moving forward EES will be known as ExSchedule and eMTR will be known as Power Meter.

Revision 23 (6/1/2013):

- Section 3: Exhibits 2 and 3 revised to reflect updated economic and weather station mappings. The definition of winter load management is revised.
- Attachment B; added specific requirements for load management switch operability studies.

Revision 22 (2/28/2013):

- Administrative Change: update all references of “eSchedule” to “InSchedule”

Revision 21 (10/01/2012):

- Attachment A revised to add guidelines for load drop estimates for Price Responsive Demand participants.

Revision 20 (06/28/2012):

- Attachment A updated based on PJM Interconnection, L.L.C., Docket No. ER11-3322 (Capacity measurement and verification). This tariff and RAA update specifically requires GLD to provide reductions below the PLC and aligns any recognized reductions used to determine capacity compliance with add back process.

Revision 19 (02/23/2012):

- Attachment A changed to update Comparable Day definition, clarify data required if Generation data is used to substantiate load reduction and have PJM perform the compliance calculation.

Revision 18 (11/16/2011):

- Section 3: Revisions reflect adoption of Itron, Inc recommendations regarding the economic driver used in the load forecast model. References to the now-defunct Interruptible Load for Reliability option of Load Management were removed.

Revision 17 (07/14/2011):

- Attachment A: 24 hour data submission required and additional clarification for use of generation data to substantiate compliance (FERC Docket #: ER11-2898-000, 4/18/11).

Also added revisions concerning how add backs are applied to DLC as approved by the MRC.

Revision 16 (04/01/2011):

- Section 3: Integrated the description of the net energy forecast model into the general model description.
- Revised Exhibits 2 and 3 to reflect updated economic and weather station mappings.
- Attachment A: Revised load drop estimate guidelines based on Load Management Task Force proposal approved at November 2010 Markets and Reliability Committee and January 2011 Members Committee. Corresponding tariff language changes were filed with FERC under Docket ER11-2898-000.

Revision 15 (10/01/2009):

- Attachment A: Revised load drop estimate guidelines to reflect the FERC-approved business rules. Section 3: added price responsive demand to the adjustments made to the load forecast.

Revision 14 (12/01/2008):

- Section 3: Revised load forecast model specification to allow for a load adjustment dummy variable. Clarified the review and approval process for the Load Forecast Report.
- Section 4: Revised the Weather Normalization approval process to clarify that Board approval is not required.

Revision 13 (06/01/2008):

- A new Exhibit 1 was added, presenting definitions of variables used in the load forecast model. Other exhibits were re-numbered.
- Exhibit 2 was revised to reflect a new weather station assignment for the DAY zone.
- Section 4: Removed note from Weather Normalization Procedure description (the process is finalized).
- Attachment A: Revised to reflect that the guidelines apply to both capacity- and energy-related load drop estimates.

Revision 12 (06/01/2007):

- Removed Section 3 and moved content to Manual 18.
- Removed Section 7 and moved content to Manual 18.

Revision 11 (06/01/07):

- This extensive revision incorporates changes to Load Data Systems due to the implementation of the Reliability Pricing Model (RPM). Sections on Active Load Management and Qualified Interruptible Load have been replaced with a new Load Management section. The Zonal Scaling Factor section reflects a revised calculation. The

Load Forecast Model section has been updated for enhancements made to the model specification as well as revised coincident peak forecast method. The Weather Normalization section was revised to reflect that seasonal peaks are now normalized using the load forecast model.

Revision 10 (06/01/06):

- Exhibit 1—Updated to include the new Manual 30: Alternative Collateral Program.
- Section 3—Revised to reflect changes in the handling of outlier observations in weather normalization of seasonal peaks.
- Section 4—Revised to incorporate the addition of the Full Emergency option of Load Response.
- Updated the penalties/rewards section under Compliance.

Revision 09 (01/01/06):

- This revision includes a complete revision to Section 6 to detail the PJM-produced load forecast which will be used for capacity and system planning purposes. The previous Section 3 (PJM Load Forecast Report) has been removed since Member input is no longer required for its production.

Revision 08 (06/01/05):

- Updated Exhibit 1 to include new PJM Manuals.
- This revision includes changes to Section 3 to reflect reporting requirements for sub-Zones. Section 4 was completely revised to reflect a new weather normalization method and revised basis for calculating 5CPs. Section 8 has been modified to reflect revised release dates for Zonal Scaling Factors.

Revision 07 (07/01/04):

- This revision includes changes to Section 2, to reflect that 500kV generation will be treated differently in the PJM Western and Southern regions than the Mid-Atlantic Region. Section 4 was revised to reflect that peak load allocation will be impacted for market integration. Section 5 has been modified to reflect that the Active Load Management program has been fully incorporated into the eCapacity application.

Revision 06 (10/01/03):

- This revision incorporates a new presentation format. Substantive changes were made to Section 4, to reflect changes in peak normalization procedures. Section 5 and Attachment B were revised to reflect the change in load research requirements for cycling programs to a five year cycle. The previous Section 6 (Forecast Peak Period Load) has been deleted. The section on Qualified Interruptible Load now reflects that it is the same as Active Load Management. New sections have been added for the PJM Entity Forecast and Zonal Scaling Factors. Attachment A includes an additional load drop estimate technique, Customer Baseline. Throughout the document, changes were made to reflect the new committee structure, and the Board of Managers enhanced authority.

- Changed all references from "*PJM Interconnection, L.L.C.*" to "*PJM.*"
- Changed all references from "the PJM OI" to "PJM."
- Renamed Exhibits to consecutive numbering.
- Reformatted to new PJM formatting standard.
- Renumbered pages to consecutive numbering.

Revision 05 (01/01/03):

- This revision contains changes to Section 2, which was revised to reflect that hourly load data are reported through the new Power Meter application. Section 5 was revised to clarify wording on existing Active Load Management rules and procedures.

Revision 04 (06/01/02):

- This revision contains changes to Section 3, which was revised to reflect a new reporting format for the PJM Load Forecast Report. Section 7 was revised to incorporate firm level customers into the Qualified Interruptible Load program.

Revision 03 (01/01/02):

- This revision incorporates changes resulting from the addition of PJM West into the Interconnection. Section 4 was revised to add a description of the peak normalization process for PJM West. Sections 6 (Qualified Interruptible Load) and 7 (Forecast Period Peak Load) were added.

Revision 02 (10/01/00):

- This revision contains changes to Section 4 to include a clarification of the weather normalization overview, and revises the summer season weather normalization to reflect the newly adopted PJM summer weather parameter. Also, the removal of Attachment A: Definitions and Abbreviations. Attachment A is being developed into a 'new' PJM Manual for *Definitions and Abbreviations (M-35)*. Attachments B, C, and D have been renamed A, B, and C respectively. Also, changes to the 'new' Attachment A: ALM Load Drop Estimate Guidelines (previously listed as Attachment B) have been in effect since 6/01/00; however, they are now being addressed in this revision.

Revision 01 (06/01/00):

- This revision contains changes to Sections 3, 4, and 5, to reflect the influence of retail choice, including the creation of a peak allocation, revamped Active Load Management rules and procedures, and revamped PJM Load Forecast Report. Also, it details a revised weather normalization procedure.

Revision 00 (07/15/97):

- This revision is the complete draft of the PJM Manual for Load Data Systems.

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2024 Load Forecast Supplement

PJM Resource Adequacy Planning Department

January 2024

For Public Use

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Contents

Introduction and Overview

This document serves as a supplement to the 2024 PJM Load Forecast report. It is intended as a reference, to provide details of the processes used to develop the load forecast and the data and assumptions used. It describes the load forecast model that produces the forecast as well as non-model adjustments to it.

This document acts as a resource to help describe the load forecast process. For details such as parameter estimates and model outputs, additional resources are available on the PJM website: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.

This is the second year in which PJM has employed the use of an hourly forecast model, as a result of a multi-month engagement in 2022 with Itron. Their final report can be found here (https://www.pjm.com/-/media/planning/res-adeq/load-forecast/pjm-model-review-final-report-from-itron.ashx) and should be viewed in conjunction with PJM documentation.

Summary of Changes from 2023 Methodology

PJM contracted with S&P Global to provide an electric vehicle forecast for use in the 2024 Load Forecast. S&P Global provided PJM with zonal vehicle counts and charging impacts for light, medium, and heavy duty electric vehicles.

PJM added a third cold variable to the forecast model that acts like a spline when weather gets very cold. The HD3 variable adds another breakpoint after our HD2 variable. These HD variables are meant to capture different relationships of load to weather under different conditions. The additional cold weather variable, HD3, was added in response to testing after Winter Storm Elliott.

Sector Models

Sector models are a key part of the load forecast process, providing insights into why load trends are happening. The job of a forecaster is to use models to understand what has happened such that they can make an informed judgment about the future. Looking at total peak and energy trends over time only tells us part of the story: what is happening. Sector models can give us greater insight into why things are happening.

Sector models are where we incorporate the independent assumptions on economic trends and end-use adoption and efficiency. The load forecast process considers three sectors: Residential, Commercial, and Industrial. Each sector has its own set of models and inputs.

Residential

The Residential Sector model is actually two models, a customer model and an average use model. The product of these two concepts—customers and average use—provides total residential use. Total Residential use is considered according to the three use classes of Heating, Cooling, and Other.

Customers are modeled for each zone as a function of households. Monthly customer data is obtained from the EIA 861 dataset. Households are an economic concept, with quarterly history and forecast provided by Moody's Analytics. The relationship of customers to economics is defined by the below equation.

Equation 1. **Residential Customers**

$$customers = B_1 * households + B_2 * y2021$$

Where

y2021 = 1 when year is greater than or equal to 2021 and 0 otherwise

Average use per customer is modeled as a function of Heating, Cooling, and Other. Average use data is obtained from the EIA 861 dataset. Heating, Cooling, and Other are functions of end-use concepts provided by Itron (based on data from the EIA's Annual Energy Outlook) and economic concepts that are provided by Moody's Analytics (household size and real household income). The relationship of average use to Heating (xheat), Cooling (xcool), and Other (xother) is defined by the below equation.

Equation 2. **Residential Average Use**

$$use_t = B_0 * xheat_t + B_1 * xheat_{t-1} + B_2 * xcool_t + B_3 * xcool_{t-1} + B_4 * xother_t$$

The table below provides a list of residential end-uses and indicates how they are allocated to Heating, Cooling, and Other. For each end-use, data provided by Itron includes saturation (% of customers with device), efficiency (relative efficiency of device), and intensity (use per device accounting for saturation and efficiency).

Table 1. **List of Residential End-Uses and Assignment**

Bucket	**Use Type**	**Definition**
Heating	EFurn	Electric furnace and resistant room space heaters
Heating	HPHeat	Heat pump space heating
Heating	GHPHeat	Ground-source heat pump space heating
Heating	SecHt	Secondary heating
Cooling	CAC	Central air conditioning
Cooling	HPCool	Heat pump space cooling
Cooling	GHPCool	Ground-source heat pump space cooling
Cooling	RAC	Room air conditioners
Other	EWHeat	Electric water heating

Other	ECook	Electric cooking
Other	Ref1	Refrigerator
Other	Ref2	Second refrigerator
Other	Frz	Freezer
Other	Dish	Dishwasher
Other	CWash	Electric clothes washer
Other	EDry	Electric clothes dryer
Other	TV	TV sets
Heating	FurnFan	Furnace fans
Other	Light	Lighting
Other	Misc	Miscellaneous electric appliances[1]

Heating (xheat) is a function of heating end-uses as identified in the above table with adjustments for weather, real income per household, population per household, and building shell efficiency.

Equation 3. **Residential Heating Variable (xheat)**

$$xheat_t = sae\_heat_t * hdd\_in_t$$

Where

$$sae\_heat_t = (EFurn_t + HPHeat_t + GHPHeat_t + SecHt_t + FurnFan_t) * (Population\_per\_houeshold_t)^x * (Income\_per\_household_t)^y * Structural\_Heating_t$$

Where x and y are elasticities provided by Itron and Structural_Heating is a measure of building size adjusted for relative building shell efficiency.

and

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[1] Residential end-use data has always included a category referred to as Miscellaneous, which represented a catch-all of the non-named appliances listed. In 1998, Miscellaneous represented about a fifth of non-weather sensitive uses and now represents about half; a trend spurred as much by growth in Miscellaneous as declines in non-Miscellaneous end-uses.

$$hdd\_in_t = \frac{hdd_t}{hdd_{2016}}$$

Cooling (xcool) is a function of cooling end-uses as identified in the above table with adjustments for weather, income per household, population per household, and building shell efficiency.

Equation 4. **Residential Cooling Variable (xcool)**

$$xcool_t = sae\_cool_t \; * cdd\_in_t$$

Where

$$sae_{cool_t} = (CAC_t + HPCool_t + GHPCool_t + RAC_t) * (Population\_per\_houeshold_t)^x \; * \\ (Income\_per\_household_t)^y \; * Structural\_Cooling_t$$

Where x and y are elasticities provided by Itron and Structural_Cooling is a measure of building size adjusted for relative building shell efficiency.

and

$$cdd\_in_t = \frac{cdd_t}{cdd_{2016}}$$

Other (xother) is a function of other end-uses as identified in the above table with adjustments for income per household, and population per household.

Equation 5. **Residential Other Variable (xother)**

$$xother_t = sae\_other_t * Days\_Idx_t$$

Where

$$sae_{other_t} = (EWHeat_t + ECook_t + Ref1_t + Ref2_t + Frz_t + Dish_t + CWash_t + EDry_t + TV_t \\ + Light_t + Misc_t) * (Population\_per\_houeshold_t)^x \; * \; (Income\_per\_household_t)^y$$

Where x and y are elasticities provided by Itron

and

$$Days\_Idx_t = \frac{Days\ in\ Month}{30.42}$$

The results of Equation 2 (Residential Average Use) are fitted values, which includes historical weather. For comparability in heating and cooling trends over time, this then needs to be transformed to be on a consistent weather basis.

Equation 6. **Formulation of HeatUse, CoolUse, and OtherUse**

Heading and Cooling are adjusted to be consistent with 2016 weather for all years.

$$HeatUse_t = B_0 * norm\_xheat_t + B_1 * norm\_xheat_{t-1}$$

$$CoolUse_t = B_2 * norm\_xcool_t + B_3 * norm\_xcool_{t-1}$$

$$OtherUse_t = B_4 * xother_t$$

where B0, B1, B2, B3, and B4 are from Equation 2

and

norm_xheat and *norm_xcool* are the same as *xheat* and *xcool* but using 2016 weather

Total residential use then is the product of customers and each of these defined average use terms.

Equation 7. **Total Residential Use**

$$ResHeat_t = Customers_{quarter,year} * HeatUse_{quarter,year}$$

$$ResCool_t = Customers_{quarter,year} * CoolUse_{quarter,year}$$

$$ResOther_t = Customers_{quarter,year} * OtherUse_{quarter,year}$$

Commercial

The starting point for analysis is Commercial energy provided through the EIA 861 dataset. The Commercial models utilize two sets of data: economic and end-use. Economic concepts used are service sector employment, working-age population, and real services output, and are provided by Moody's Analytics. End-use concepts are provided by Itron (based on data from the EIA's Annual Energy Outlook), and are summarized in the following table.

Table 2. **List of Commercial End-Uses and Assignment**

Bucket	Use Type	Definition
Heating	Heating	Heating
Cooling	Cooling	Cooling
Other	Ventilation	Ventilation
Other	WtrHeat	Water Heating
Other	Cooking	Cooking

Other	Refrig	Refrigeration
Other	Lighting	Lighting
Other	Office	Office Equipment (PCs)
Other	Misc	Miscellaneous

Equation 8. **Commercial Use**

$$use_t = B_0 * xheat_t + B_1 * xheat_{t-1} + B_2 * xcool_t + B_3 * xcool_{t-1} + B_4 * xother_t$$

Where

$$xheat_t = Heat_t * \ ComEconVar_t * hdd\_in_t$$

$$xcool_t = Cool_t \ * \ ComEconVar_t * cdd\_in_t$$

$$xother_t = Other_t \ * \ ComEconVar_t$$

Heat, *Cool*, and *Other* are end-use intensities from categories in the above table. *ComEconVar* is a 30/30/40 weighed combination of services employments, real services output, and working-age population, respectively.

For comparability in heating and cooling trends over time, this then needs to be transformed to be on a consistent weather basis.

Equation 9. **Formulation of HeatUse, CoolUse, and OtherUse**

Heating and Cooling are adjusted to be consistent with 2016 weather for all years.

$$Com\_Heat_t = B_0 * norm\_xheat_t + B_1 * norm\_xheat_{t-1}$$

$$Com\_Cool_t = B_2 * norm\_xcool_t + B_3 * norm\_xcool_{t-1}$$

$$Com\_Other_t = B_4 * xother_t$$

where B0, B1, B2, B3, and B4 are from Equation 8

and

norm_xheat and *norm_xcool* are the same as *xheat* and *xcool* but using 2016 weather

Industrial

The starting point for analysis is Industrial energy provided through the EIA 861 dataset. Industrial modeling utilizes two sets of data: economic and intensity. The economic concept used is real industrial output, using data from Moody's Analytics. Intensity data is pulled from national data from EIA on electricity per real output.

Real industrial output is an aggregate of output in goods-producing industries (see list). Moody's Analytics currently only forecasts employment for these series at the metro area level, not output. However, output is available at the state level and thus output at the metro level is imputed by using state productivity (output divided by employment).

Equation 10. **Metro Area Real Industrial Output**

$$\begin{aligned}\boldsymbol{Output}_{sector,metro,year} &\\ &= \boldsymbol{Employment}_{sector,metro,year}\\ &* \boldsymbol{Output}_{sector,state,year}/\boldsymbol{Employment}_{sector,state,year}\end{aligned}$$

$$\boldsymbol{Output}_{metro,year} = \sum_{sector} \boldsymbol{Output}_{sector,metro,year}$$

where metro areas are assigned to states based on location

And Sectors are defined as follows:

Natural Resources and Mining

Construction

Manufacturing – Machinery

Manufacturing - Transportation Equipment

Manufacturing - Chemicals; Energy; Plastics and Rubber

Manufacturing - Electronic and Electrical

Manufacturing - Furniture and Miscellaneous

Manufacturing - Metals and Mining

Manufacturing - Textile; Fiber and Printing

Industrial intensity is defined as industrial energy use per real output. The concept is based on national data, but is customized to zones through the availability of sector detail. Historical and forecast energy use by sector is compiled from the EIA Annual Energy Outlook (AEO) and the EIA Manufacturing Energy Consumption Survey (MECS). Economic data by sector is provided by Moody's Analytics as was described in the prior paragraph. Zonal industrial intensity series are then a weighted average of national sector indexes.

Equation 11. **Zonal Industrial Intensity**

$$\boldsymbol{Intensity_{year} = \sum_{sector} (Output_{sector,year} / Total\ Output_{year}) * Intensity_{sector,year}}$$

Discussed above are the types of inputs considered, but as discussed in Itron's model review[2] it is challenging to fit all zones with a structural end-use model. Candidate models that consider the above described variables are constructed, and are evaluated on a zone-by-zone basis for goodness of fit and reasonableness. Reasonableness checks include items such as ensuring coefficients have the right sign and how the model performs on out-of-sample observations. Zonal industrial model selections are provided in supplemental posted materials. Each zone results in an Industrial Base component (*Ind_Other*) and in some cases an Industrial Cooling component (*Ind_Cooling*).

Equation 12. **Industrial Cooling**

$$\boldsymbol{Ind\_Cooling_t = B * CDD_{2016}}$$

Where *B* is the coefficient on the cooling term in the industrial model. Cooling is included in zones for which it has a positive coefficient, and excluded for which it does not.

Usage Indexes

Heat, Cool, and Other Usage Indexes need to be constructed using the results from the Residential, Commercial, and Industrial Sector Models. First, monthly results are rolled up into single measures.

Equation 13. **Monthly Results**

$$\boldsymbol{Heat_t = Res\_Heating_t + Com\_Heating_t}$$

$$\boldsymbol{Cool_t = Res\_Cooling_t + Com\_Cooling_t + Ind\_Cooling_t}$$

$$\boldsymbol{Other_t = Res\_Other_t + Com\_Other_t + Ind\_Other_t}$$

At this point, *Other* is essentially complete and is simply converted from a monthly frequency to a daily frequency with each day's value within a month equal to the respective monthly value. *Heat* and *Cool* though at this point are still reflective of 2016 weather patterns in HDD and CDD. A 365 day moving average is taken of each to calculate *HeatIdx* and *CoolIdx*, such that these can later be interacted with hourly heating and cooling weather variables to capture weather sensitive load over time.

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[2] See pages 15 and 16 for Itron's discussion of Industrial modeling: https://www.pjm.com/-/media/planning/res-adeq/load-forecast/pjm-model-review-final-report-from-itron.ashx

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Weather Variables

Weather variables are defined at the zone level. Zonal weather is a weighted average of weather stations[3].

Table 3. **Weather Station Assignment**

Zone	Weather Station	Weight	Zone	Weather Station	Weight
AE	ACY	100.0%	JCPL	ACY	25.0%
AEP	CAK	15.1%	JCPL	EWR	75.0%
AEP	CMH	23.4%	METED	ABE	50.0%
AEP	CRW	22.6%	METED	PHL	50.0%
AEP	FWA	22.7%	PECO	PHL	100.0%
AEP	ROA	16.2%	PENLC	ERI	50.0%
APS	IAD	30.0%	PENLC	IPT	50.0%
APS	PIT	70.0%	PEPCO	DCA	100.0%
ATSI	CAK	46.5%	PL	ABE	25.0%
ATSI	CLE	30.0%	PL	AVP	25.0%
ATSI	PIT	8.5%	PL	IPT	25.0%
ATSI	TOL	15.0%	PL	MDT	25.0%
BGE	BWI	100.0%	PS	EWR	100.0%
COMED	ORD	100.0%	RECO	EWR	100.0%
DAYTON	DAY	100.0%	UGI	AVP	100.0%
DPL	ILG	70.0%	VEPCO	IAD	33.3%
DPL	WAL	30.0%	VEPCO	ORF	33.3%
DQE	PIT	100.0%	VEPCO	RIC	33.3%
DUKE	CVG	100.0%			
EKPC	CVG	25.0%			
EKPC	LEX	49.0%			
EKPC	SDF	26.0%			

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[3] Weather station weights are provided by Electric Distribution Companies (EDCs).

Cooling and Heating Degree Variables

Temperature-Humidity Index (THI) values are translated to CD1, CD2, and CD3 in order to allow the forecast the flexibility to capture different relationships of load to weather under different conditions (a spline). The goal in defining cut points for CD2 and CD3 is to try have it hot enough to capture any potential inflection points but not so hot such that there is limited ability to make a good statistical inference.

Equation 14. **Temperature-Humidity Index and Cooling Degrees Formulas**

$$\boldsymbol{THI_t = temperature_t + 0.55 * (humidity_t/100 - .4) * max(temp_t - 58, 0)}$$

Base-points are set for each hour to calculate CD1, CD2, and CD3

Hour Ending	Base Point
1	65
2	65
3	65
4	65
5	65
6	65
7	65
8	65
9	65
10	65
11	65
12	70
13	70
14	70
15	70
16	70
17	70
18	70
19	70
20	70
21	65
22	65
23	65
24	65

$$\boldsymbol{CD1_t = \max(THI_t - \text{Base\_Point}_{HE}, 0)}$$

$$\boldsymbol{CD2_t = \max(THI_t - \text{Base\_Point}_{HE} + 10, 0)}$$

$$\boldsymbol{CD3_t = \max(THI_t - \text{Base\_Point}_{HE} + 15, 0)}$$

Heating degree variables are then also used.

Equation 15. **Heating Degrees**

Base-points are set for each hour to calculate HD1, HD2, and HD3

Hour Ending	Base Point
1	55
2	55
3	55
4	55
5	55
6	55
7	55
8	55
9	55
10	55
11	55
12	60
13	60
14	60
15	60
16	60
17	60
18	60
19	60
20	60
21	55
22	55
23	55
24	55

$$\boldsymbol{HD1_t} = \mathbf{max}(\mathbf{Base\_Point}_{\boldsymbol{HE}} \ - \boldsymbol{Temp_t}\,, \mathbf{0})$$

$$\boldsymbol{HD2_t} = \mathbf{max}(\mathbf{Base\_Point}_{\boldsymbol{HE}} \ - \mathbf{10} \ - \boldsymbol{Temp_t}\,, \mathbf{0})$$

$$\boldsymbol{HD3_t} = \mathbf{max}(\mathbf{Base\_Point}_{\boldsymbol{HE}} \ - \mathbf{15} \ - \boldsymbol{Temp_t}\,, \mathbf{0})$$

These Cooling Degree and Heating Degree variables are used both contemporaneously as well as lagged transformations (Lag6CD, Lag24CD, Lag6HD, Lag24HD), interacted with weekend day-type (WkEndCD, WkEndHD), and interacted with seasons (SpringCD, FallCD, SpringHD, FallHD).

Additional Weather Variables

The load forecast model also includes variables to capture both wind speed and cloud cover.

Equation 16. **Wind and Cloud Variables**

$$\boldsymbol{WindHD_t} = \boldsymbol{WSP_t} * \mathbf{min}(\boldsymbol{HD1_t}/\mathbf{60}, \mathbf{1})$$

$$\boldsymbol{WindCD_t} = \boldsymbol{WSP_t} * \mathbf{min}(\boldsymbol{CD1_t}/\mathbf{60}, \mathbf{1})$$

Where *WSP* is a 3-period centered moving average of wind speed

$$CloudHD_t = Cloud_t * \min(HD1_t/60, 1)$$

$$CloudCD_t = Cloud_t * \min(CD1_t/60, 1)$$

Where *Cloud* is a 3-period centered moving average of wind speed

Forecast Model

Model Specification

The load forecast is constructed using 24 hourly models for each zone. In each model, load is the dependent variable. In the history, we start with metered load and then re-constitute with load management addbacks, load drops associated with peak shaving programs, and distributed solar generation estimates.

Each regression model has the same set-up, with load modeled against input variables: Weather Variables, Calendar effects, and Economic and End-Use considerations. Variable names align with documentations in the posted statistical appendix and are grouped below based on whether they are related to non-weather (XOther), heating (XHeat), or Cooling (XCool).

Equation 17. **Forecast Model Specification**

$$load = \sum_{variables} B_{variable} * variable$$

Where

Calendar-type variables (Interacts with XOther)

Intercept_XOther	JanWalk	Wednesday	XMasDay
Jan	FebWalk	Thursday	NYEve
Feb	MarWalk	Friday	NYDay
Mar	AprWalk	Saturday	WkAfterNewYear
MarDST	MayWalk	MLK	WkDayBeforeHol
Apr	JunWalk	PresDay	WkDayAfterHol
May	JulWalk	GoodFri	Phase1
Jun	AugWalk	MemDay	Phase2
Jul	SepWalk	July4th	Phase3
Aug	OctWalk	LaborDay	
Sep	NovWalk	Thanks	binary1
Oct	DecWalk	FriAThanks	binary2
Nov	Monday	WkBeforeXMas	trend1
NovDST	Tuesday	XMasEve	trend2

Heating-type Variables (Interacts with XHeat)

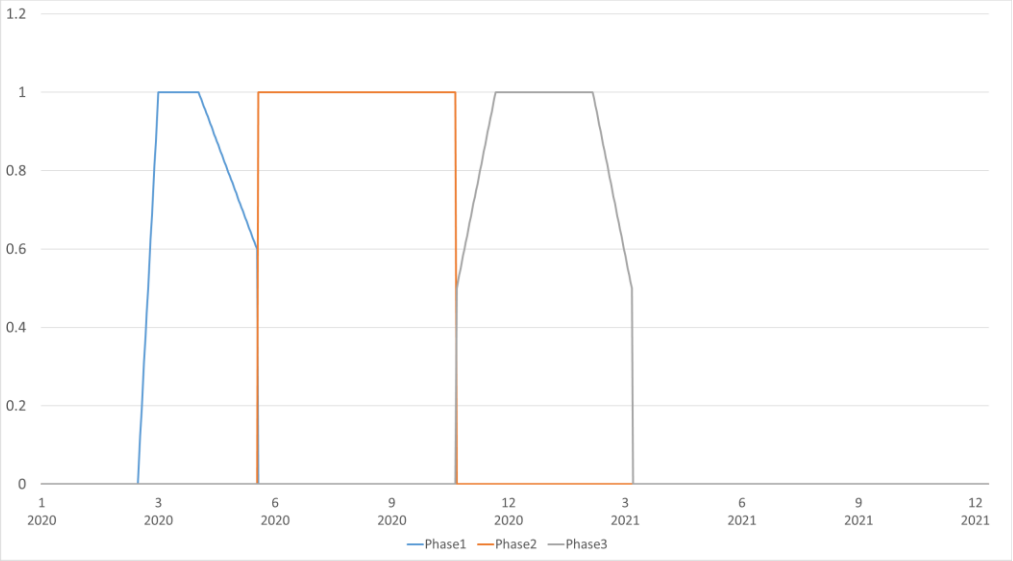
HD1	SpringHD
HD2	FallHD
HD3	WindHD
Lag6HD	CloudHD
Lag24HD	MA10_HDD
Lag24CD_HD	MA28_HDD
WkEndHD	

Cooling-type Variables (Interacts with XCool)

TD1	SpringCD
TD2	FallCD
TD3	WindCD
Lag6CD	CloudCD
Lag24CD	MA10_CDD
Lag24HD_CD	MA28_CDD
WkEndCD	

Binary and Trend Variables

COVID-19 had a large impact on electricity demand. Some of this impact is captured in aspects of the model construction via the economic inputs in the sector models. Nevertheless, it is often advisable in periods such as these to provide some controls for the abnormal event. The 2024 Load Forecast emplys an approach where a series of binaries are used *Phase1* through *Phase3* with the *Phase3* variable ending April 2021. This will continue to be re-visited each year.



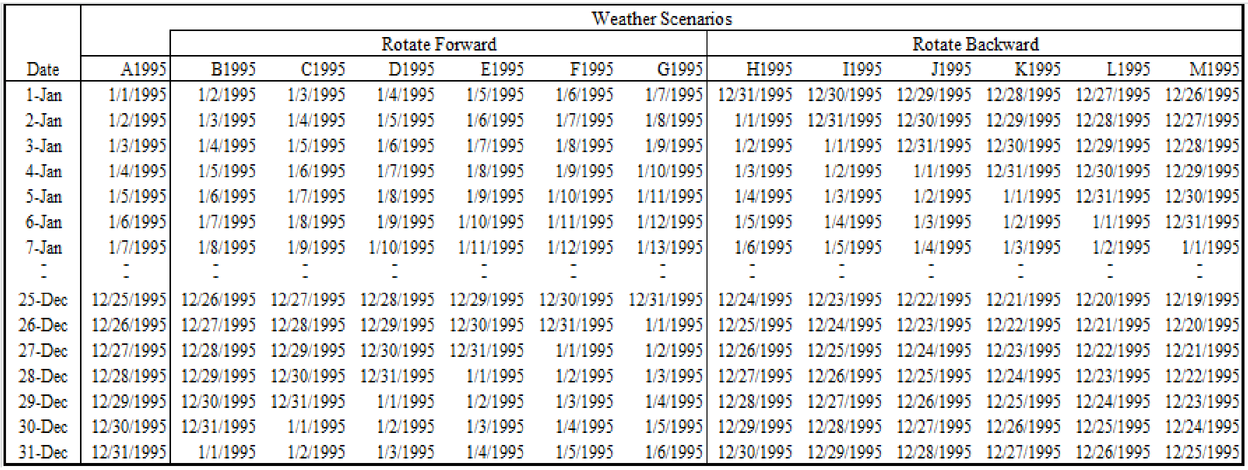
In addition to COVID treatments, *binary1/binary2* and *trend1/trend2* variables are defined for each zone. These are intended to help tune the model and capture abnormal events in the residuals after specifying the model. None of these trends are extended into the forecast period, so their effect is on the model parameterization and not on assumptions of future trends. Contained in the supplemental materials are hourly residual plots of before and after the inclusion of these additional model variables.

Simulation

Once the load model is estimated, forecasts for each PJM transmission zone are produced by solving the hourly zonal equations, moving through the year day by day and hour by hour applying historical weather patterns (including conditions for distributed solar generation), as well as forecast adjustments (data centers and peak shaving), behind-the-meter battery storage, and electric vehicles .

To model the most likely weather conditions (often referred to as normal or peak-eliciting weather), a weather rotation technique is used to simulate a distribution of hourly load scenarios generated by historical weather observations, representing actual weather patterns that occurred across the PJM control region.

To enhance the simulation process, each yearly weather pattern is shifted by each day of the week moving forward six days and backwards six days, providing 13 different weather scenarios for each historical year. For early January and late December dates, data from the same calendar year is applied. The table below illustrates the shift of weather data across the scenarios.



	Weather Scenarios												
		Rotate Forward						Rotate Backward					
Date	A1995	B1995	C1995	D1995	E1995	F1995	G1995	H1995	I1995	J1995	K1995	L1995	M1995
1-Jan	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995
2-Jan	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995
3-Jan	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995
4-Jan	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995
5-Jan	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995
6-Jan	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/12/1995	1/5/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995
7-Jan	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/12/1995	1/13/1995	1/6/1995	1/5/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995
:	:	:	:	:	:	:	:	:	:	:	:	:	:
25-Dec	12/25/1995	12/26/1995	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995	12/20/1995	12/19/1995
26-Dec	12/26/1995	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995	12/20/1995
27-Dec	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995
28-Dec	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995
29-Dec	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995
30-Dec	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995
31-Dec	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995

This approach has two key advantages. One, by rotating the data on the calendar, peak-producing weather will be applied to peak producing days. Two, by producing scenarios over a wide range of weather conditions, the weather rotation method is able to identify both the probable and possible levels of future peak load.

The process is repeated for the remaining years of historical weather data. The 2024 Load Forecast uses 29 years of weather history that results in 377 (29 weather years x 13 days) separate forecast simulations for each year in the forecast horizon. These simulations produce a frequency distribution of NCP demands by zone.

For each weather scenario, monthly NCPs are determined by obtaining the maximum NCP for the month. Seasonal NCPs are determined as the maximum over the summer/winter/spring/fall months. For each season, the ratio of each month’s peak to the highest monthly peak is taken, and then each month’s ratio is multiplied by the seasonal peak. In this way, one of the month's peaks is the seasonal peak while still preserving the relationship between monthly peaks.

For purposes of system planning, only a couple of the values in the forecast distribution are used. After ranking the scenario forecasts from lowest to highest MW value, the median value is selected as the base (or 50/50) forecast. This is the value used for most system planning studies. The 90th percentile (or 90/10) result is used for studies where the system is assumed to be at system emergency conditions.

Coincident Peaks

Hourly results from the method described above are rolled up to the the entire PJM RTO and Locational Deliverabity Areas (LDA). Weather rotation provides an additional benefit for identifying coincident peaks - the natural diversity of weather patterns that impact the PJM footprint is simulated. This is a more plausible approach to peak forecasting than traditional methods which tend to have all weather stations having peak producing weather on the same day. Using the latter approach would overstate the PJM or LDA peak forecast by minimizing diversity.

Monthly RTO/LDA peaks are determined by obtaining the maximum for each scenario for each month (377 possible peaks). Seasonal RTO/LDA peaks are determined over the summer/winter/spring/fall months by obtaining the maximum for each scenario for each season (377 possible peaks). For each season, the ratio of each month's peak to the highest monthly peak is taken, and then each month's ratio is multiplied by the seasonal peak. From this distribution, the median result is used as the base (50/50) forecast; the values at the 10th percentile and 90th percentile are assigned to the 10/90 and 90/10 weather bands.

At this point, the values of the overall RTO peaks are set, but not the contribution of each zone. To determine the final zonal RTO/LDA-coincident peak forecasts, each zone's average contribution across the peak distribution is calculated and applied to the RTO forecast.

Assumption Development

Weather

The 2024 Load Forecast uses historical weather data from 1994 to 2022 as the basis for constructing forecasts. No explicit assumption is being made about Climate Change, and thus the assumption is that future weather will resemble past weather.

Vendor Data

The 2024 Load Forecast relies on vendor and government sources.

For economic and demographic forecasts, PJM consults with Moody's Analytics and used their September 2023 forecast vintage. Zonal charts for concepts used have been posted with the supplemental materials.

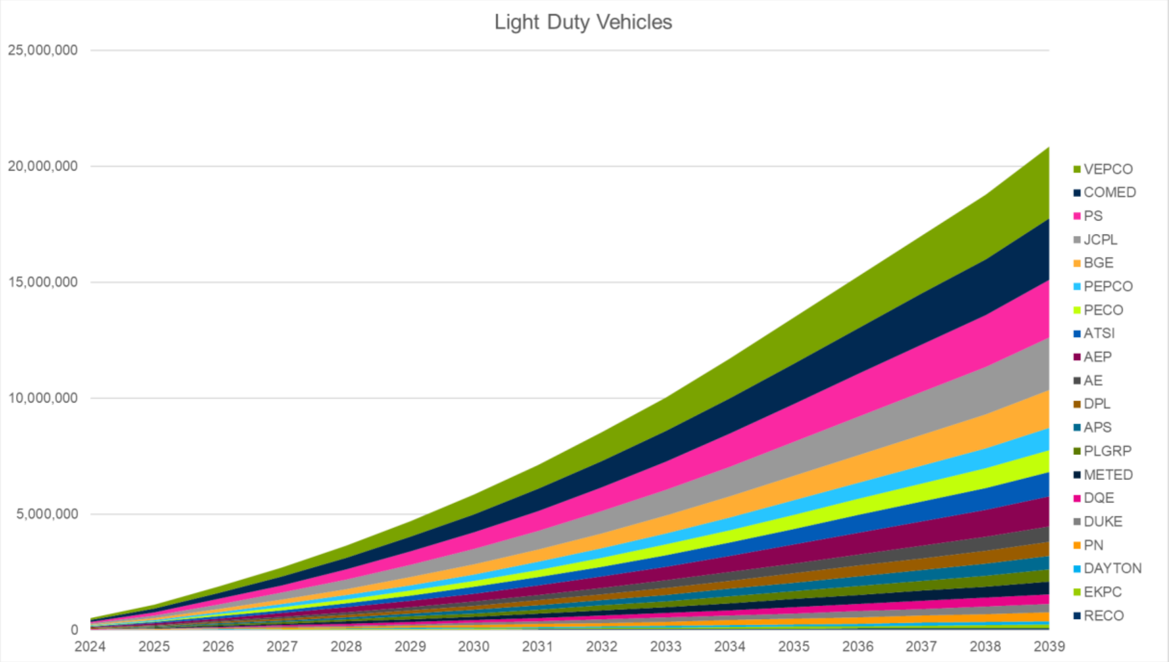
For end-use saturation/efficiency/intensity projections, PJM is a member of the Itron Energy Forecasting Group (EFG) that provides Census level history/projections for Residential/Commercial sectors. Their work derives from the Energy Information Administration's 2023 Annual Energy Outlook.

For distributed energy resources (BtM solar and storage), S&P Global provides a BtM solar and storage additions forecast. This is combined with historical Generation Attribute Tracking System (GATS) data in order to provide cumulative nameplate capacity by zone. UL provides zonal solar production estimates, which are used in both determining historical performance and expectations of future performance.

Plug-in Electric Vehicles

Forecasts of EVs were provided by S&P Global and their zonal forecasts take into account vehicle miles traveled (VMT), vehicle efficiency, and charging behavior in their hourly charging impacts. S&P Global uses federal, state, and metropolitan level data to produce their forecast. More information on the S&P Global electric vehicle forecast methodolgy and assumptions can be found under the November 27, 2023 Load Analysis Subcommittee materials[4].

Charts below show vehicle counts for light duty electric vehicles by zone followed by medium & heavy duty electric vehicle counts by zone. The medium & hevy duty category contains delivery vans, school bus, transit bus, medium truck, short haul, and long haul vehicles.



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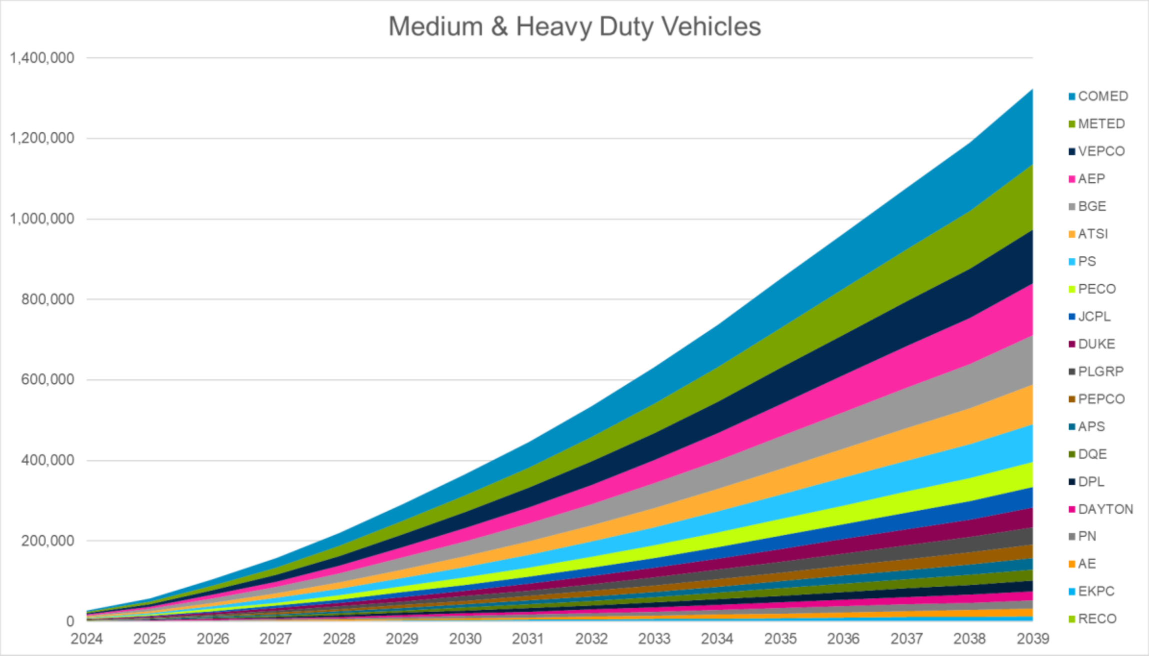
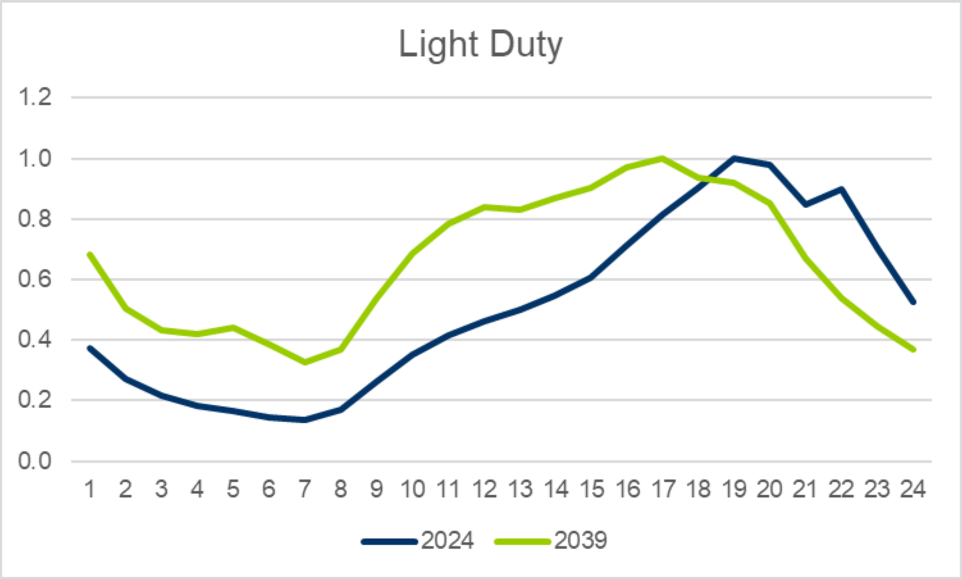
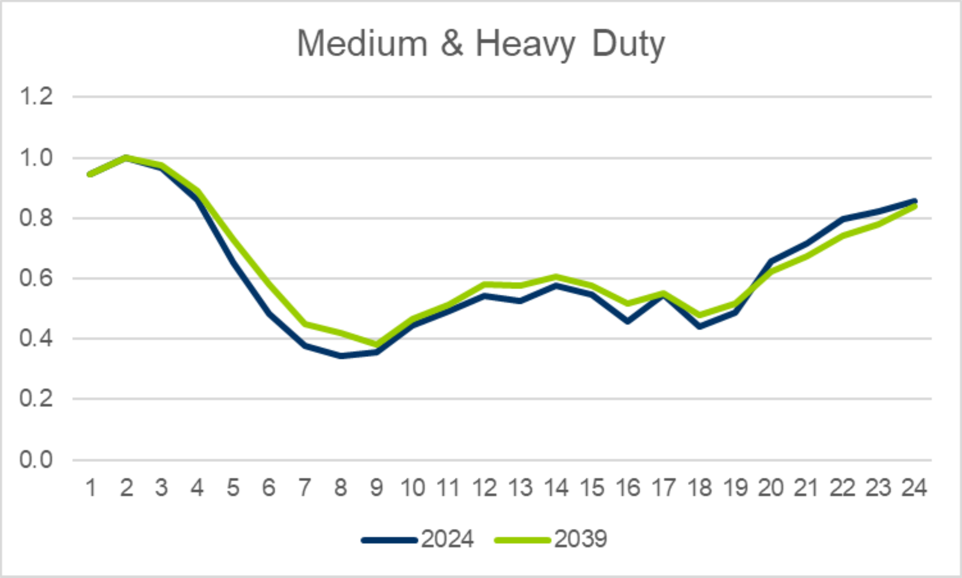
[4] https://www.pjm.com/-/media/committees-groups/subcommittees/las/2023/20231127/20231127-reference---12---spgci-consulting-methodology-and-assumptions---ev-forecast-.ashx



S&P Global provided an hourly charging impact for each zone throughout the forecast horizon. Below shows a total RTO average per-unitized charging shape from summer weekdays for light, medium, and heavy duty electric vehicles. The blue line is a charging shape for 2024 and the green line shows the per-unitized charging shape for 2039. For light duty electric vehicles, the 2024 charging shape shows more tendancy to charge later in the day around hour ending 17 – 20 while the 2039 charging shape shows more levelized charging throughout the day. The hourly charging shape for medium & heavy duty electric vehicles does not show a large shift in charging behavior due to the nature of these vehicles being out delivering goods, people, etc. during the day and then back to their depots at night to charge.





Behind-the-Meter Battery Storage Operation

As indicated above, the amount of behind-the-meter battery storage is based on a forecast from S&P Global. The methodology for their forecast is based on an attachment model (storage installed with solar), and thus are assumed to be used in conjunction with distributed solar. The assumption is made that batteries available to discharge at summer peak and thus subtract from loads on the summer peak distribution.

Exogenous Factors

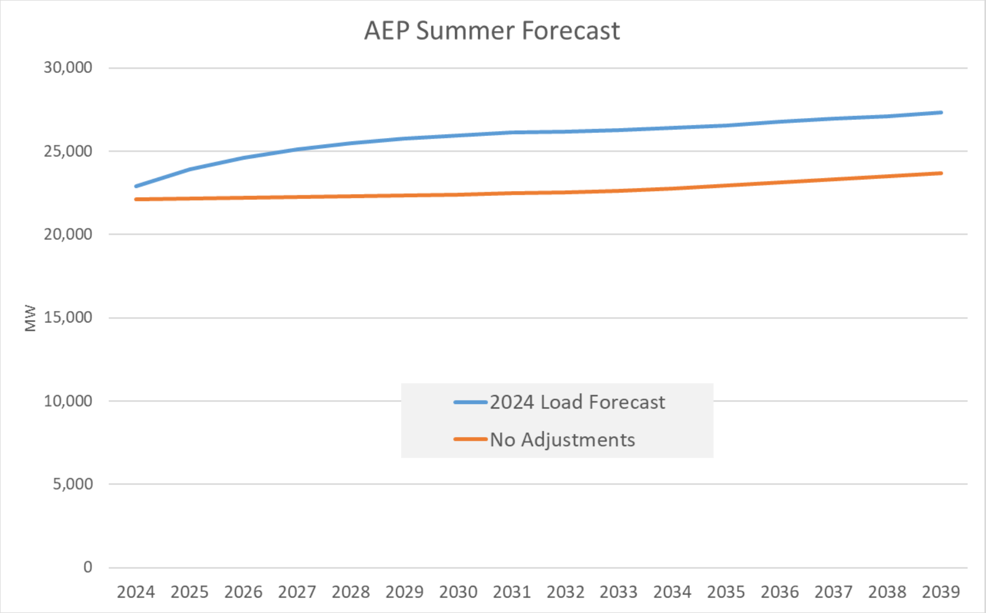
PJM annually solicits information from its member Electric Distribution Companies (EDC) for large load shifts (either positive or negative) that are known to the EDC but may be unknown to PJM. Once the request has been verified per the guidelines in Attachment B of Manual 19, PJM works towards accounting for it in its load forecast. Each request is considered on a case-by-case basis, with particular caution paid to avoid double-counting anticipated load increases or decreases. With each forecast adjustment, PJM quantifies the MW impact on the forecast that is due to this request.

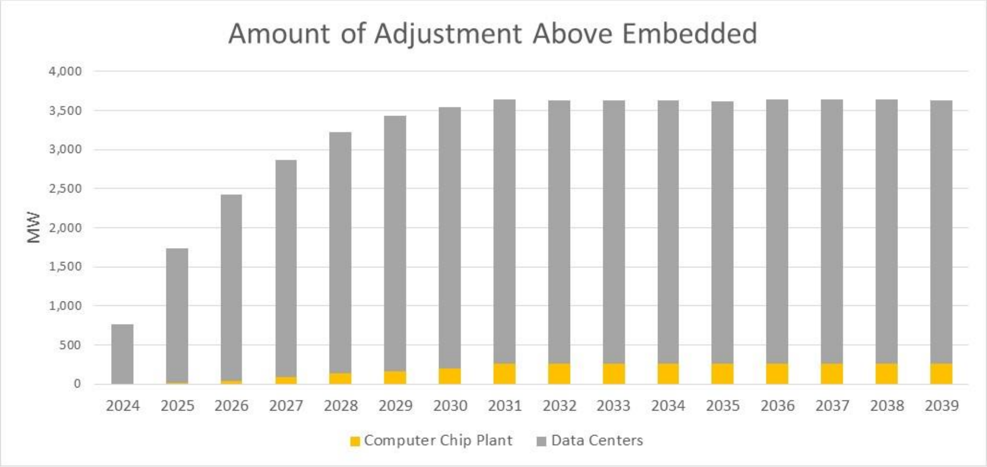
AEP – Data Centers and Computer Chip Plant

AEP requested that PJM consider load additions related to significant growth in data centers and a computer chip manufacturing site outside of Coumbus. AEP provided forecasted data center additions as well as historical cumulative data center information. Hourly information related to historical data center load was included in the data provided. PJM removed monthly data center load from the commercial EIA data in an effort to remove any double counting. PJM also removed hourly data center load from our historical loads that get used in our model estimation.

The computer chip plant will be a new facility so no historical data is available. PJM reviewed economic data for the computer chip plant and is using a percentage of their contract capacity.

The first chart below shows what the summer forecast would be for AEP without the adjustments in orange and with adjustments in blue. The bar chart at the bottom shows this amount above what is embedded in the forecast which is the difference between the blue and orange forecast lines.





PJM had multiple meetings with AEP staff to discuss this adjustment, and it is anticipated that there might be more data center load forthcoming. PJM will continue to be in contact with AEP to understand these trends as they develop.

APS – Data Centers

First Energy requested PJM consider load additions related to significant growth in data centers. These sites are coming online and growing through mid-2027. The load is predominately due to a single site called Quantum Loophole. This site does not have load history as it is new so no adjustment to history was made. PJM reviewed commercial base load and observed declines through the forecast horizon[5]. Thus, PJM concluded that there is no embedded load due to data centers in APS. Below shows what the APS summer forecast would be without the adjustment and with the adjustment. The final adjustment is shown in the bar chart. PJM has been and will continue to be in contact with First Energy to follow this development.

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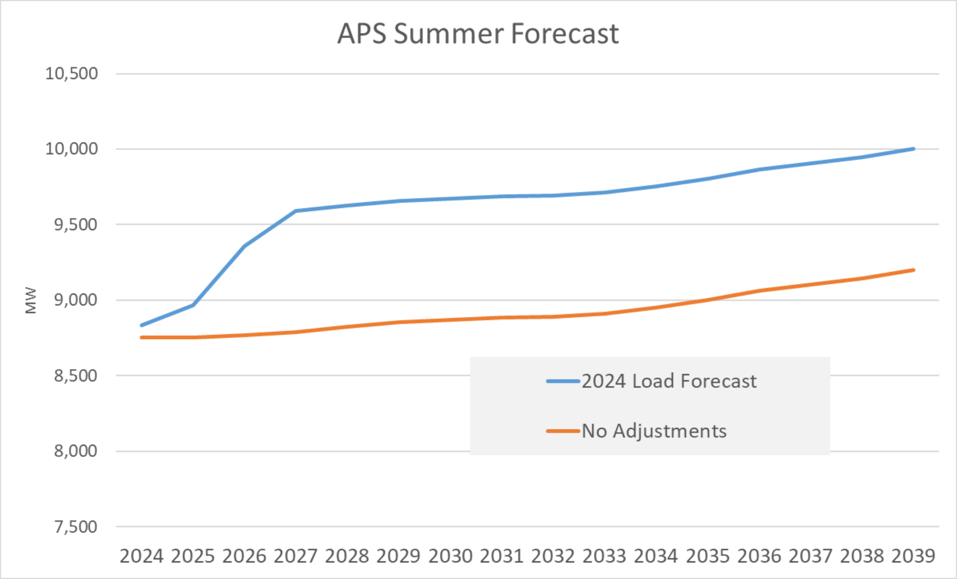
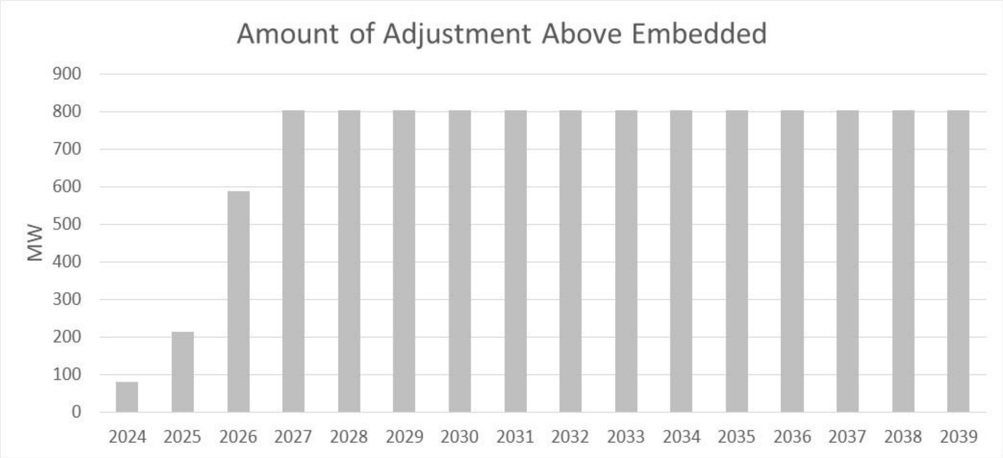
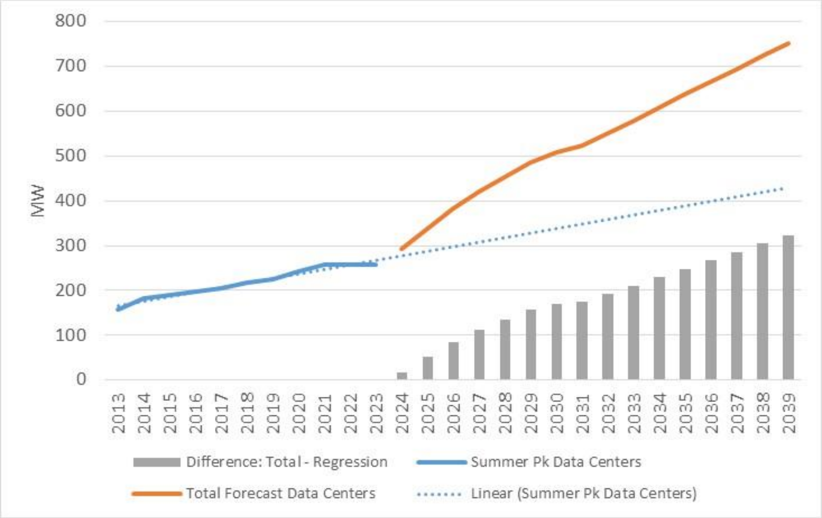
[5] See https://www.pjm.com/-/media/committees-groups/subcommittees/las/2023/20231127/20231127-reference---02---residential-commercial-industrial-sectors-and-indices.ashx



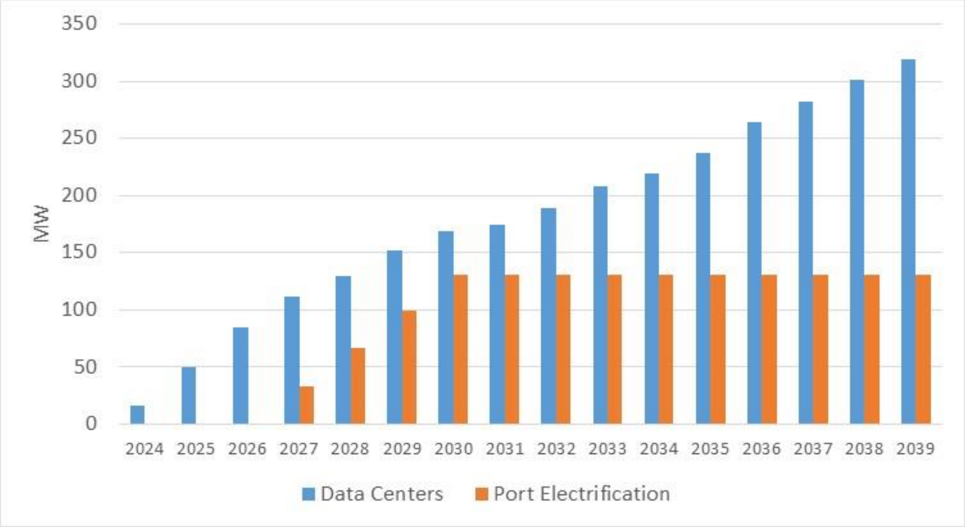


PS – Data Centers and Port Electrification

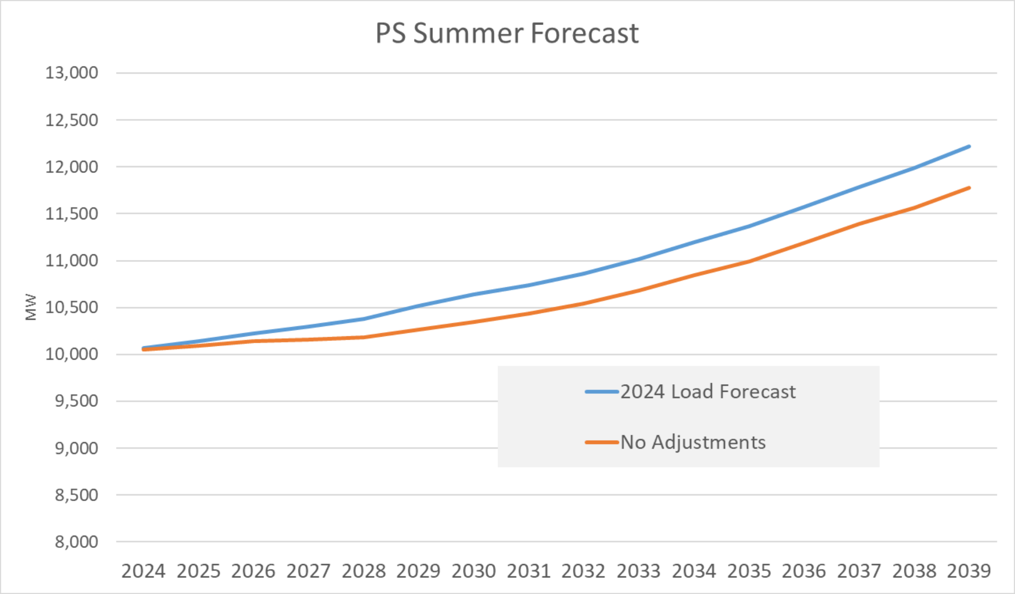
PS requested forecast adjustments for data center growth and port electrification. PS provided historical peak history back to 2013. Since we did not have hourly historical data for data centers to remove from history we did the following; created a trend with historical peaks (dotted blue line below), compared this trend with the total amount of data center load (existing and forecasted) that we received from PS (orange line below), calculated the difference as amount forecast is adjusted (grey bars below).

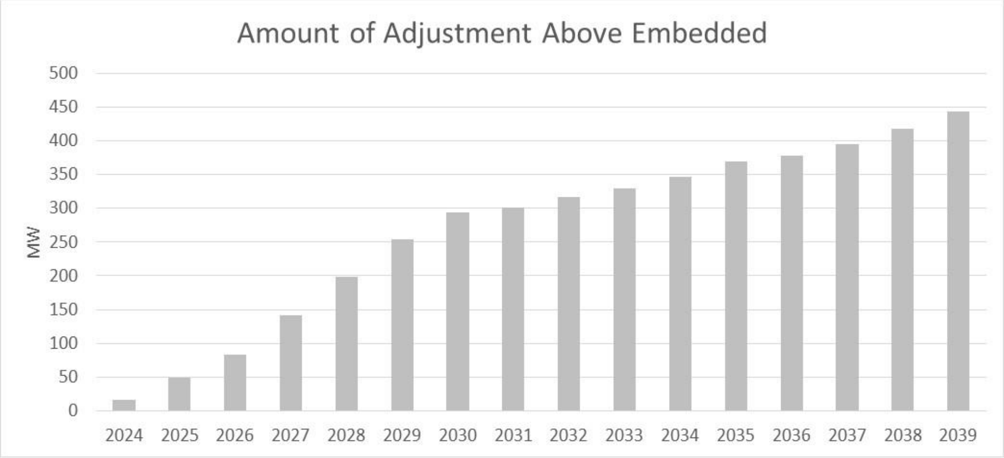


PS also submitted a request for port electrification at their Newark, Elizabeth, and Bayonne ports. The Inflation Reduction Act provides money to electify port equipment and docked ships. This load is forecasted to grow from 2027 to 2030 and then be constant.



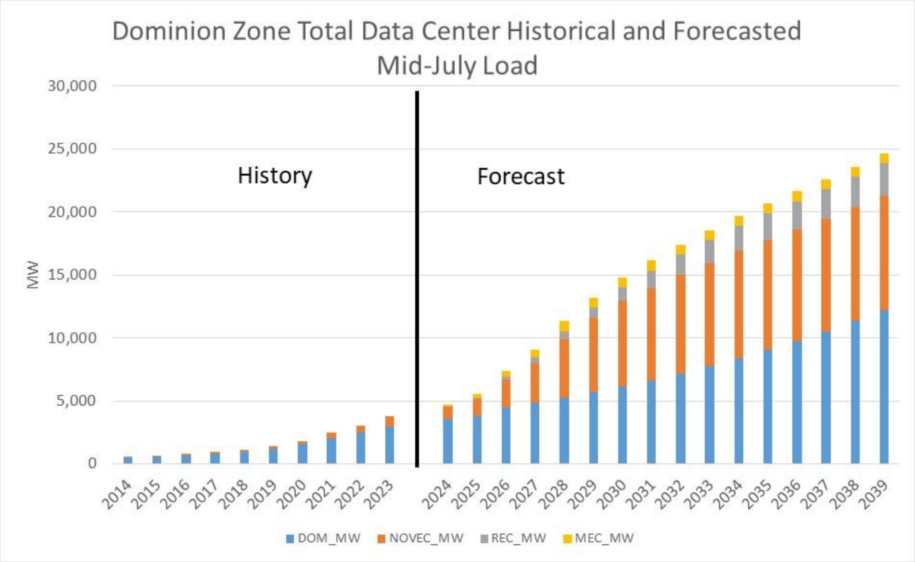
Below shows the PS summer forecast without the adjustments and with the adjustments. The final adjustment is shown in the bar chart. PJM has been and will continue to be in contact with PS to follow this development.





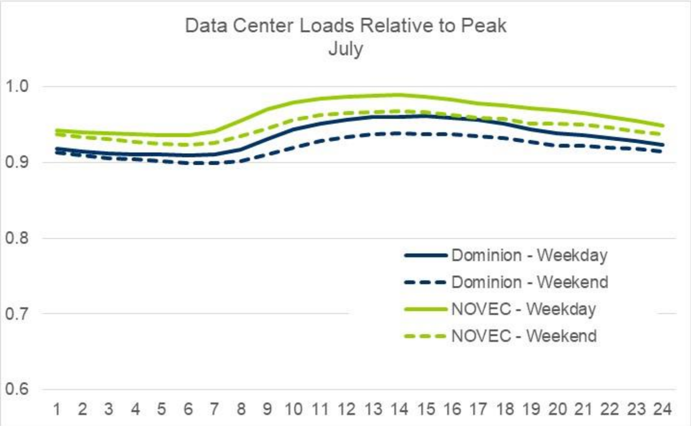
Dominion – Data Centers

Dominion requested that PJM consider a forecast adjustment to account for the growth of data centers in Virginia. This adjustment has been in place in some form since the 2014 Load Forecast Report. Dominion and Northern Virginia Electric Cooperative (NOVEC) provide PJM with historical hourly information as well as forecasted peak information for the next fifteen years. Dominion provided forecasted data center load for non-NOVEC cooperatives Mecklenburg (MEC) and Rappahannock (REC).



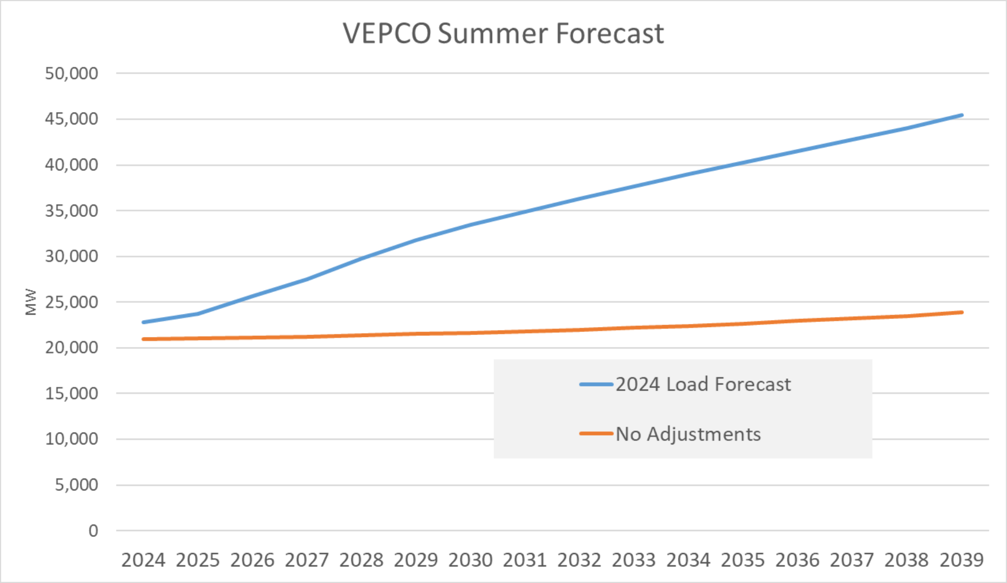
With the data provided, steps are taken to isolate the impact on the final forecast to mitigate double-counting concerns. Facility data is first removed from the historical data. This is done in both the historical hourly data used to feed the final load forecast model as well as the Commercial sector data used to help inform our understanding on usage trends.

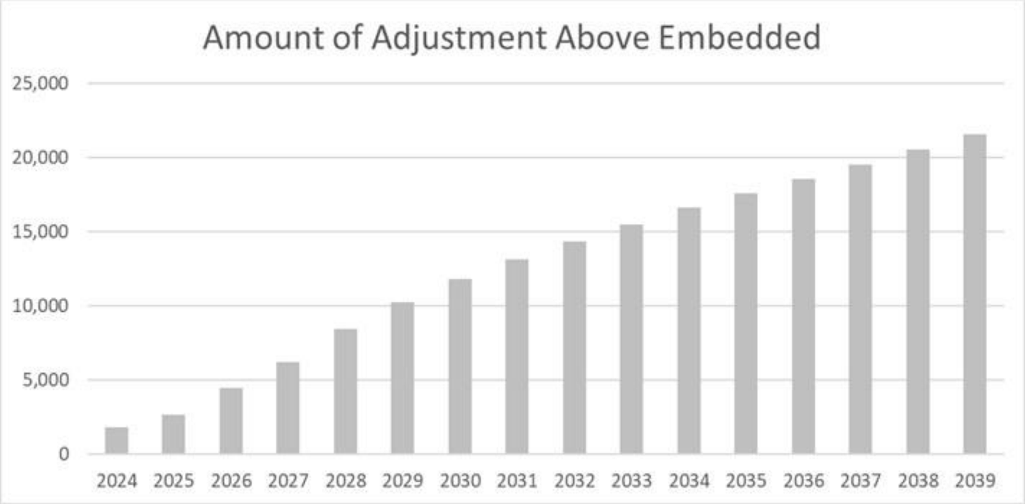
Given that we have hourly historical data center data and the PJM forecast model is hourly, forecasted hourly loads are derived. For each of Dominion and NOVEC, by month and weekday/weekend, historical hourly data center loads are calculated as a share of the provided monthly peaks. This provides us with a weekday and weekend shape that can be applied to the forecasted monthly peaks.



The final forecast needs to be re-constituted with the expected data center amount as the forecasted hourly loads coming from the model exclude data centers. Monthly peak amounts are combined with the calculated hourly shapes and these are added to the modeled forecast.

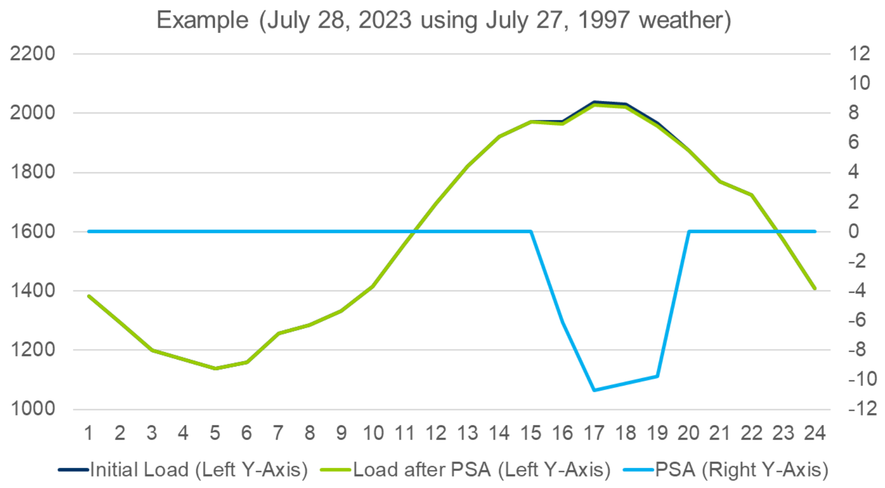
Below shows what the Dominion summer forecast would be without the adjustment and with the adjustment. The final adjustment for the Dominion zone is shown in the bar chart and shows the amount above what is embedded.





EKPC – Peak Shaving Adjustment

EKPC requested a peak shaving adjustment that began with the 2023 Delivery Year. EKPC provides PJM with weather triggers as well as program response matrixes for their three programs (smart thermostats, air conditioning switches, and water heater switches). In the forecast simulation process, on days that exceed the trigger, the programs are enacted. The chart below shows an example of program implementation in the forecast. On this day in the forecast, the program is triggered and reduces load in HE16 through HE19 resulting in a peak reduction of 10MW.



After summer 2023, PJM evaluated actual performance against expected performance and used this performance rating[6] in the 2024 Load Forecast.

NRBTMG to DR

PJM was notified of existing Non-Retail Behind-the-Meter Generation (NRBTMG) transitioning to participate as Demand Response starting in 2024. For the 2024 Load Forecast, these zones are adjusted upward to facilitate these resources' participation in RPM for a total of 21.2 MW.

- AEP: 8.7 MW
- ATSI: 1.6 MW
- DAYTON: 1.5 MW
- PPL: 2.9 MW
- PENLC: 0.5 MW
- DUKE: 6 MW

State Policy

The State Of New Jersey's Executive Order No. 316 is an executive order signed into law by Governor Phil Murphy on February 15th, 2023. The portion of the order that impacts PJM's long term load forecast is the goal that by December 31, 2030, 400,000 additional homes & 20,000 additional commercial spaces will be electrified. PJM incorporated this goal into our load forecast by modifying our end-use inputs for each zone in the state of New Jersey (AE, JCPL, PS, & RECO); specifically electric heating & electric water heating. We assumed that electrification of space heating means transitioning to electric heat pumps.

For both residential & commercial sectors, we added additional heat pumps & electric water heaters to our end-use forecast each year beginning in 2024. The total number of buildings with electric heating increases at a rate that

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[6] https://www.pjm.com/-/media/documents/manuals/m19.ashx Attachment D

allows the 400,000/20,000 additional goal to be reached by 2030. This increased saturation of electric heating & water heating drives up the heating load for zones located in the state of New Jersey. This is primarily reflected in the winter peak forecast for these zones as there is not a large amount of heating load during the summer. The impacts of this goal on winter peak loads are easily noticeable when looking at the zonal waterfall charts comparing the 2023/2024 load forecasts for future delivery years. These charts are available on the Load Forecast Development Process page of PJM's website.

Additional Model Detail

Calendar Variables

The forecast model includes a number of variables to capture calendar effects, represented primarily as either binary variables or fuzzy binary variables. Binary variables take a value of 1 or 0, whereas fuzzy binary variables have values ranging from 0 to 1. There is also a graduated variable to take into account the effect of the week leading up to Christmas and the week after the New Year.

Day of Week (=1 when that day, 0 otherwise)

Monday	Tuesday	Wednesday	Thursday	Friday	Saturday

Month (=1 when that month, 0 otherwise) and DST variables:

Jan	Feb	Mar	MarDST	Apr	May	Jun
Jul	Aug	Sep	Oct	Nov	NovDST	

Holiday variables are coded such that they have values for more than one day, and for some holidays, these values can differ year to year depending on the day of the week the holiday is observed. These variables are included because generally these days would be expected to have lower than normal loads.

MLK	PresDay	MemDay	LaborDay

MLK (Martin Luther King Day), *PresDay* (Presidents' Day), *MemDay* (Memorial Day), and *LaborDay* (Labor Day)

	Value
Day before Holiday	0.2
On Holiday	1
All other days	0

GoodFri	Thanks

GoodFri (Good Friday) and *Thanks* (Thanksgiving Day)

	Value
On Holiday	1

All other days	0

July4th

July4th (Independence Day)

	Value by Day of Week						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
July 2	0.10	0.00	0.00	0.15	0.15	0.10	0.15
July 3	0.70	0.25	0.15	0.20	0.80	0.20	0.20
July 4	1.00	1.00	0.80	1.00	1.00	0.40	0.30
July 5	0.80	0.15	0.15	0.25	0.70	0.30	0.15
July 6	0.00	0.00	0.00	0.00	0.10	0.20	0.00
All other days	0.00	0.00	0.00	0.00	0.00	0.00	0.00

FriAThanks

FriAThanks (After Thanksgiving Day)

	Value
On Holiday	1
Day After	0.2
All other days	0

WkBeforeXMas WkAfterNewYear

WkBeforeXMas(If day is weekday before Christmas Day)

	Value if Weekday
December 18	0.14
December 19	0.29
December 20	0.43
December 21	0.57
December 22	0.71
December 23	0.86
December 24	1
All other days	0

WkAfterNewYear(If day is weekday after New Year)

	Value
January 1	1.14
January 2	1.00
January 3	0.86
January 4	0.71
January 5	0.57
January 6	0.43
January 7	0.29
January 8	0.14
All other days	0

XMasEve

XmasEve (Christmas Eve)

	Value by Day of Week						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
December 24	1.00	1.00	0.80	0.67	1.00	0.50	0.33
All other days	0.00	0.00	0.00	0.00	0.00	0.00	0.00

XMasDay

XMasDay (Christmas Day)

	Value by Day of Week						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
December 25	1.00	1.00	1.00	1.00	1.00	0.50	0.50
All other days	0.00	0.00	0.00	0.00	0.00	0.00	0.00

NYEve

NYEve (New Year's Eve)

	Value by Day of Week						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
December 31	0.8	0.8	0.8	0.8	1.0	0.4	0.4
All other days	0.0	0.0	0.0	0.0	0.0	0.0	0.0

NYDay

NYDay (New Year's Day)

	Value by Day of Week						
	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
January 1	1.0	1.0	1.0	1.0	1.0	0.5	0.4
All other days	0.0	0.0	0.0	0.0	0.0	0.0	0.0

WkDayBeforeHol	WkDayAfterHol

WkDayBeforeHol (weekday before Holiday)

	Value (if Weekday)
Day Before Holiday	1.00
All other days	0.00

WkDayAfterHol(weekday after Holiday)

	Value (if Weekday)
Day After Holiday	1.00
All other days	0.00

Monthly Walk variables are graduated variables that start at 1 on the first day of the month and increase by 1 each day until the last day of the month to capture any potential inter-month trends.

JanWalk	FebWalk	MarWalk	AprWalk	MayWalk	JunWalk
JulWalk	AugWalk	SepWalk	OctWalk	NovWalk	DecWalk

Zonal End-Use Variable Calibration

The Energy Information Administration's (EIA) 2023 Annual Energy Outlook Reference Case is the starting point for data on residential end-uses. Residential end-uses fall into categories, which are then grouped according to weather and non-weather sensitive use types (i.e. Heating, Cooling, and Other). These categories are expressed as saturation rates (% of customers), efficiency metrics (use per year or efficiency term like Seasonal Energy Efficiency Ratio), and intensities (kWh per customer per year). Categories and groupings are as follows:

- Heating
  - Electric furnace and resistant room space heaters
  - Heat pump space heating
  - Ground-source heat pump space heating
  - Secondary heating
  - Furnace fans
- Cooling
  - Central air conditioning
  - Heat pump space cooling
  - Ground-source heat pump space cooling
  - Room air conditioners
- Other
  - Electric water heating
  - Electric cooking
  - Refrigerator
  - Second refrigerator
  - Freezer
  - Dishwasher
  - Electric clothes washer
  - Electric clothes dryer
  - TV sets
  - Lighting
  - Miscellaneous electric appliances

PJM receives this data at the Census division level through membership in Itron's Energy Forecasting Group. PJM then supplements this with two pieces of information:

- Zonal saturation and intensity data from NREL ResStock[7]
- Zonal saturation estimates from:
  - American Electric Power – all appliance categories through 2021
  - Allegheny Power – all appliance categories through 2016
  - American Transmission Systems, Inc. – all appliance categories through 2016
  - Commonwealth Edison – all appliance categories for 2019
  - Duke Energy Ohio and Kentucky – all appliance categories through 2014
  - East Kentucky Power Cooperative – Heat Pumps for Heating and Cooling, Electric Furnaces, Secondary Heating (Room Heating), Central A/C, Room Air Conditioners, and Water Heaters through 2013
  - Jersey Central Power & Light – all appliance categories through 2016
  - Metropolitan Edison – all appliance categories through 2016
  - Pennsylvania Electric – all appliance categories through 2016
  - Dominion Virginia Power – Heat Pumps for Cooling, Central A/C and Room Air Conditioners through 2014

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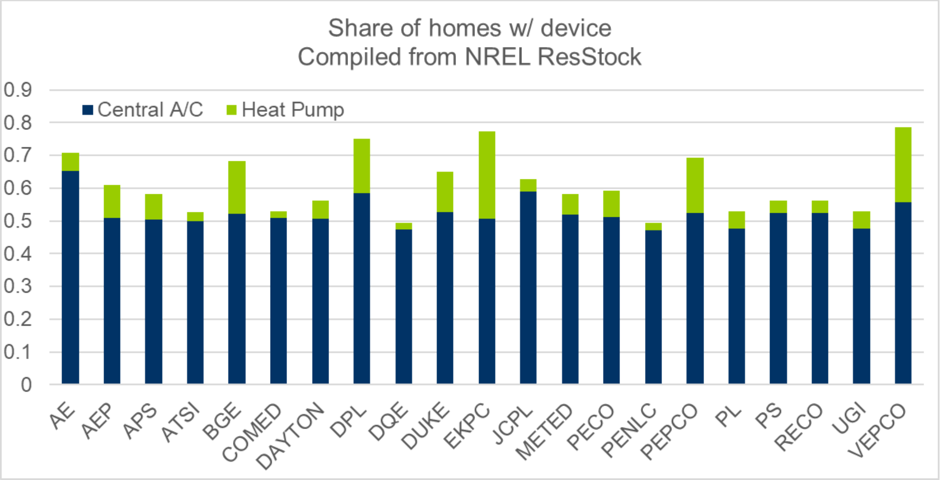
[7] https://resstock.nrel.gov/

Data from NREL ResStock is used to calibrate zones for 2018 to help provide granularity across PJM. Zones are mapped to counties, and then PJM uses the ResStock database to provide customized data at the zonal level on appliance saturations, appliance intensities, and average home sizes[8]. The below chart displays some of the information gleaned from this exercise on central cooling.



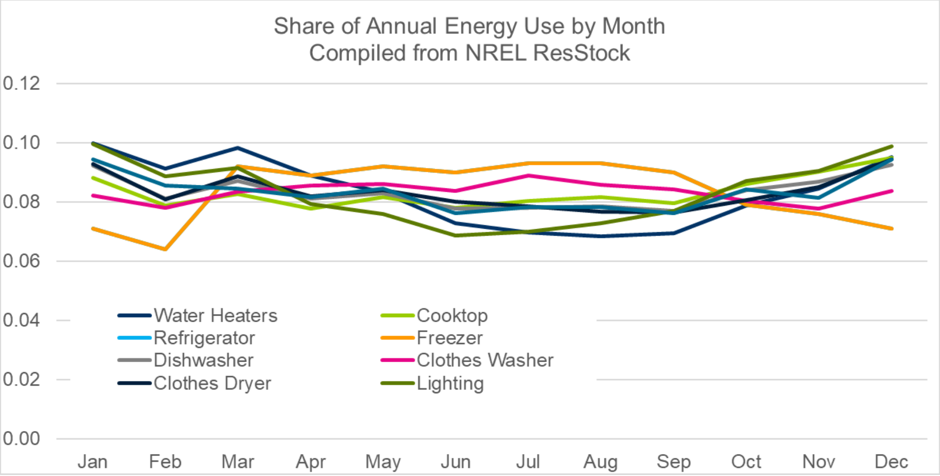
Resulting data is then aligned with zonal-supplied historical appliance saturation rates. Zones are subsequently assigned to Census Divisions for driving the forecasts. This process allows the forecast to be influenced by the historical relative mix of appliances. The below table shows the mapping of Zones to Census Divisions.

---

[8] In the case of RECO and UGI, this exercise yielded an insufficient sample size according to guidelines laid out by NREL for using their data. PS and PL were used, respectively, in this case.

Zone	*Census Division*
AE	Middle Atlantic
AEP	East North Central
APS	South Atlantic
ATSI	East North Central
BGE	South Atlantic
COMED	East North Central
DAYTON	East North Central
DPL	South Atlantic
DQE	Middle Atlantic
DUKE	East North Central
EKPC	East South Central
JCPL	Middle Atlantic
METED	Middle Atlantic
PECO	Middle Atlantic
PENLC	Middle Atlantic
PEPCO	Middle Atlantic
PL	Middle Atlantic
PS	Middle Atlantic
RECO	Middle Atlantic
UGI	Middle Atlantic
VEPCO	South Atlantic

Finally, monthly non-weather sensitive shapes are calculated from the NREL ResStock data as well. These are used to shape the end-use intensity variables used in the monthly Residential Average Use model. These can be seen below.

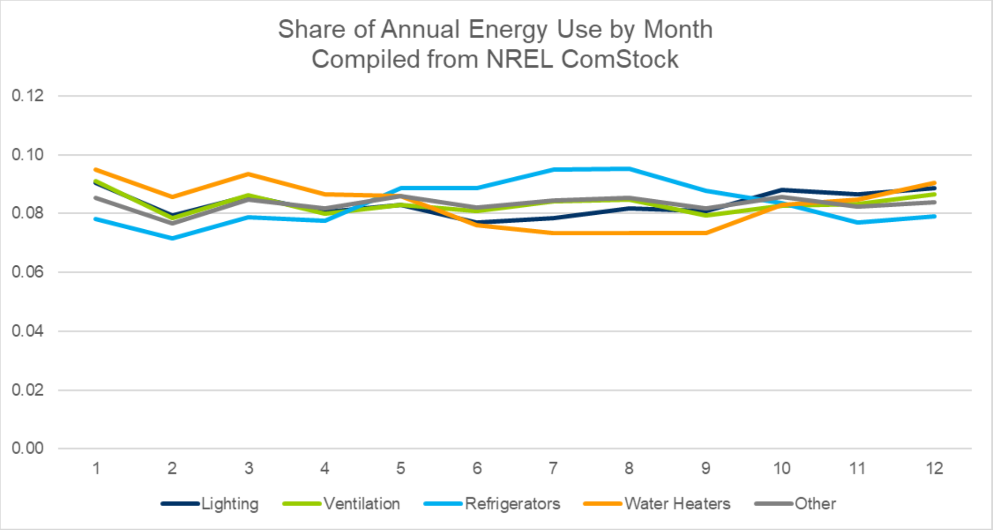


Commercial

The EIA's 2023 Annual Energy Outlook Reference Case is the starting point for data on commercial end-uses. Commercial end-uses fall into categories, which are then grouped according to weather and non-weather sensitive use types (i.e., Heating, Cooling, and Other). These categories are expressed as intensities (kWh per square foot per year). These categories and groupings are as follows:

- Heating
- Cooling
- Other
    - Ventilation
    - Water Heating
    - Cooking
    - Refrigeration
    - Lighting
    - Office Equipment
    - Miscellaneous

PJM receives this data at the Census Division level through membership in Itron's Energy Forecasting Group, and zones are assigned to Census Divisions using the same mapping as used for Residential end-uses. Like with Residential, NREL has also developed ComStock[9]. Monthly non-weather sensitive shapes are calculated from the NREL ComStock data. These are used to shape the end-use intensity variables used in the monthly Commercial Use model. These can be seen below.



Economics Zonal Geographic Assignment

Economic variables come from Moody's Analytics and geographical areas are assigned to zones per the table below.

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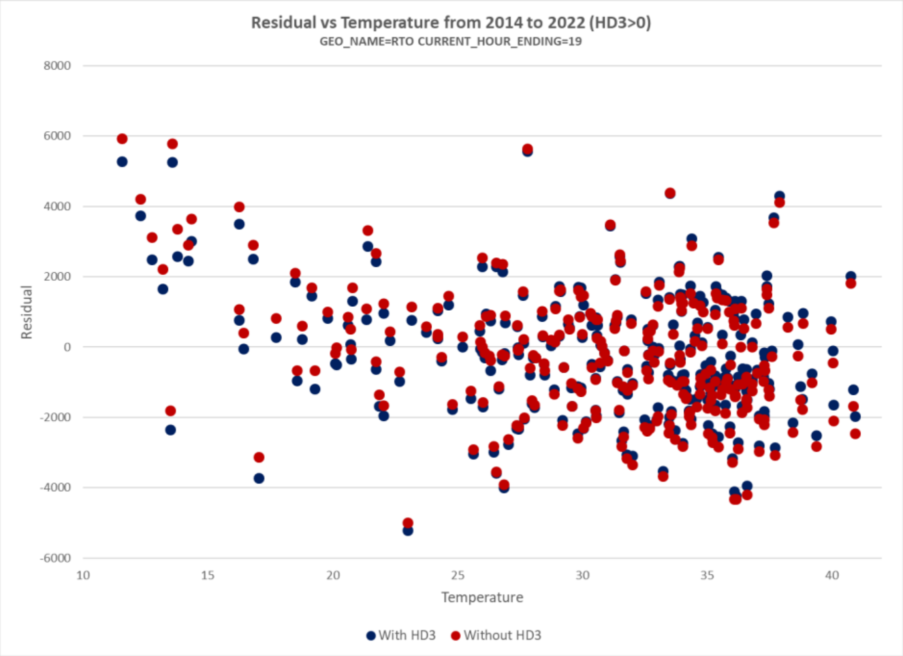
[9] https://comstock.nrel.gov/

Zone	Metro Area Name(s) or State
AE	Atlantic City-Hammonton NJ, Ocean City NJ, Vineland-Bridgeton NJ
AEP	Elkhart-Goshen IN, Fort Wayne IN, Muncie IN, South Bend-Mishawaka IN-MI, Niles-Benton Harbor MI, Canton-Massillon OH, Columbus OH, Lima OH, Kingsport-Bristol TN, Blacksburg-Christiansburg-Radford, VA, Lynchburg VA, Roanoke VA, Beckley, WV, Charleston WV, Huntington-Ashland WV-KY-OH, Weirton-Steubenville WV-OH
APS	Cumberland MD-WV, Hagerstown-Martinsburg MD-WV, Chambersburg-Waynesboro PA, State College PA, Winchester VA-WV, Morgantown WV, Parkersburg-Vienna WV
ATSI	Akron OH, Cleveland-Elyria OH, Mansfield OH, Springfield OH, Toledo OH, Youngstown-Warren-Boardman OH-PA, Pittsburgh PA
BGE	Baltimore-Columbia-Towson MD
COMED	Chicago-Naperville-Arlington Heights IL, Elgin IL, Kankakee IL, Lake County-Kenosha County IL-WI, Rockford IL
DAY	Dayton OH
DEOK	Cincinnati OH-KY-IN
DLCO	Pittsburgh PA
DOM	Virginia
DPL	Dover DE, Wilmington DE-MD-NJ, Salisbury MD-DE
EKPC	Cincinnati OH-KY-IN, Louisville/Jefferson County KY-IN, Elizabethtown-Fort Knox KY, Bowling Green KY, Lexington-Fayette KY, Huntington-Ashland WV-KY-OH
JCPL	Camden NJ, Newark NJ-PA, Trenton NJ
METED	Allentown-Bethlehem-Easton PA-NJ, East Stroudsburg PA, Gettysburg PA, Lebanon PA, Reading PA, York-Hanover PA,
PECO	Montgomery County-Bucks County-Chester County PA, Philadelphia PA
PENLC	Altoona PA, Erie PA, Johnstown PA
PEPCO	Washington D.C., California-Lexington Park MD
PL	Allentown-Bethlehem-Easton PA, Bloomsburg-Berwick PA, East Stroudsburg PA, Harrisburg-Carlisle PA, Lancaster PA, Scranton-Wilkes-Barre-Hazleton PA, Williamsport PA
PS	Camden NJ, Newark NJ-PA, Trenton NJ
RECO	Newark NJ-PA
UGI	Scranton-Wilkes-Barre-Hazleton PA

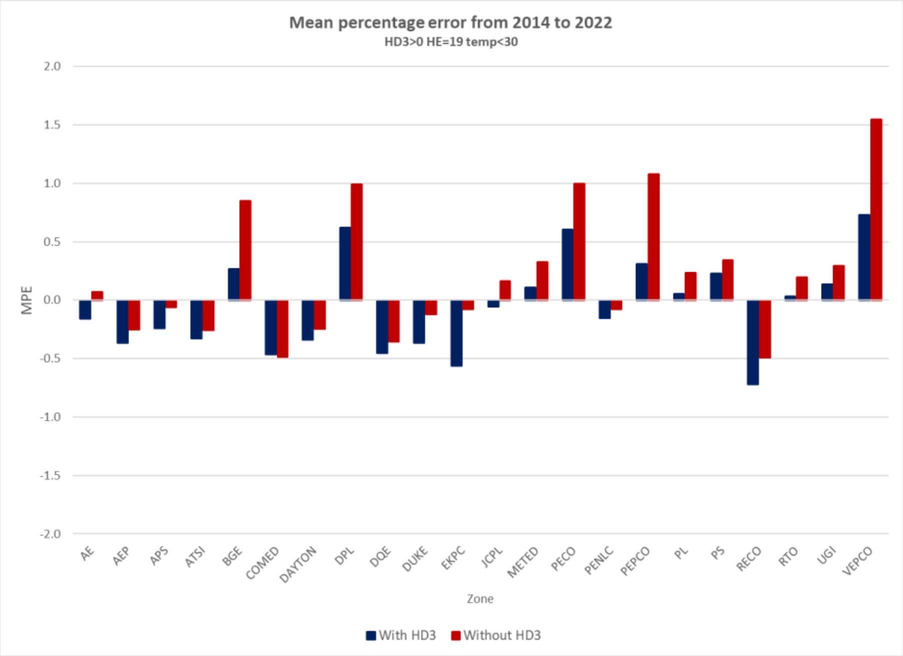
Addition of HD3 Variable

A new variable HD3 has been added to our model to reflect the relationship of load to cold weather conditions. As stated earlier in the document, HD3 is an additional spline in the heating season (15 degrees off the hourly base point). This additional variable provides symmetry with the cooling season (TD1 through TD3 variables) and helps to address potential for underfit at colder temperatures such as during Winter Storm Elliott.

The following charts help explain the rationale for HD3's inclusion. This first chart is of RTO residuals for HE19 and shows that inclusion of this variable helps to reduce some under-fit at very low temperatures.



This next chart demonstrates zonal performance, MPE (mean percentage error) values for model with HD3 showed improvement in several noticeable zones that had previously shown more tendency to under-fit when the temperature is below 30ºF.



We conclude that the addition of the new cold weather variable has improved our model, and we will continue to investigate whether further modifications may be warranted.

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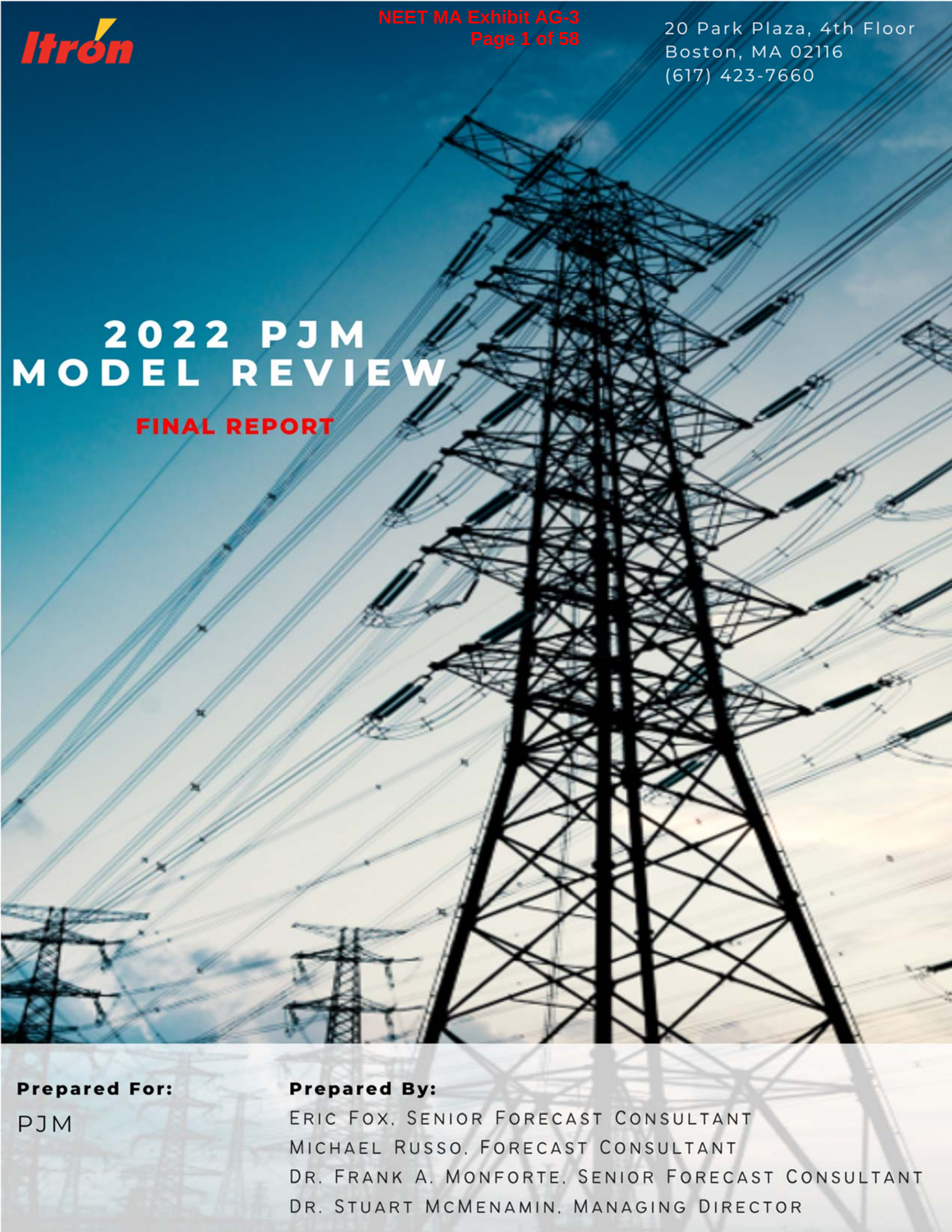

2022 PJM MODEL REVIEW

FINAL REPORT

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PJM

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1 OVERVIEW

Itron, Inc. (Itron) was contracted by PJM to review the current forecast models and develop a set of recommendations for transitioning to an hourly forecasting framework. This report discusses the forecast, recommendations, and addresses issues raised by the PJM Market Participants.

Over the last three months, Itron has worked closely with PJM forecast staff in reviewing current forecast approach, identifying forecast issues, and developing new models for evaluation and ultimately a set of recommendations for the next phase of model improvements. The core task is to transition from daily peak and energy models to hourly models where the need for hourly long-term models is driven by the penetration of new technologies that are either currently or are expected to reshape system hourly loads.

Each year, PJM updates long-term energy and demand forecast for 22 Planning Zones (EDC) that are mapped into 6 Load Deliverability Areas (LDA). PJM faces a unique and complex forecasting problem as the PJM service area stretches across a large section of the country that includes utilities from Chicago to Philadelphia. Planning Zones are spread across different time zones, include different mixes of residential, commercial, and industrial customers, and at any one point in time, significant differences in weather conditions. All this must be pulled together to not only generate load forecasts for individual zones, but for the entire PJM system.

The current approach entails estimating a set of daily energy, own-peak, and coincident peak models for each zone and simulating with historical zonal daily weather data. Simulation results are combined across zones with the system forecast based on the 50% (expected case) outcome. Model-based zone peaks and coincident peaks are then exogenously adjusted for solar demand, electric vehicles, battery storage, and zone-specific load impact programs and large changes in industrial loads including data centers. The problem is a forecast based on daily demand models implicitly assumes the timing of the peak is constant over time. This is a relative safe assumption when factors that potentially reshape loads are small. But this is no longer the case; the projected impact of electric vehicles, increase in solar load, battery storage, and other programs designed to address climate change will significantly reshape loads impacting both the level and timing of system peak demand. The only means to address the issue is to transition to hourly load modeling framework that still addresses the weather, time zones, and customer diversity across the PJM Zones.

The report is organized into the following sections:

1. Overview
2. Review of the Current PJM Model
3. Developing the Long-Term Model Drivers
4. Hourly Model Analysis and Recommendations
5. Reshaping Demand – Modeling Technology Impacts
6. Other Issues
    - Measuring Forecast Accuracy
    - Weather Normalization
    - Impact of State and Utility Energy Efficiency Programs
    - Capturing Temperature Trends
7. Recommendations

2 REVIEW OF THE CURRENT PJM MODEL

PJM's current Long-term Forecast System (LTFS) is presented in Figure 2-1. The current PJM modeling process includes three sets of daily models for each zone. These are daily energy, daily noncoincident zone peak (NCP), and daily CP (zone load at the time of the daily PJM peak). For each zone, CP models are estimated for daily loads coincident with the Locational Deliverability Area (LDA) peak and coincident with the overall PJM system peak. The LTFS gathers the data required to estimate and forecast the load zone models, estimates the models, and then develops long-term forecasts using a multi-year weather simulation approach. The LTFS is a SAS™ based software solution that can be summarized into four major sections. For a detailed description of the current LTFS see **2022 Load Forecast Supplement**, PJM Resource Adequacy Planning Department, January 2022 (https://www.pjm.com/-/media/planning/res-adeq/load-forecast/load-forecast-supplement.ashx)

Data Input Section. The data inputs that feed the LTFS come in a variety of electronic formats. This section prepares the raw input data to be ingested by the Data Transformation Section of the LTFS. Data inputs include:

- Economic history and forecasts,
- End-use saturation and efficiency trends (SAE),
- Sector (residential, commercial, and industrial) sales (MWh) by EDC,
- Hourly Loads by EDC,
- Weather data by weather station, and
- Solar PV, EV Charging, Battery Storage, and Demand Response peak demand impacts.

Data Transformation Section. This section converts the raw input into daily coincident and non-coincident model variables. Key modules within this section are:

Sector Models. This series of three modules – Residential, Commercial, Industrial – are used to combine historical and forecasted economic data, end-use appliance saturation and efficiency trends, and annual sector sales to construct Space Heating, Space Cooling, and Other Non-Weather sensitive load indices that are used to drive long-term coincident and non-coincident peak forecasts by Electric Distribution Company (EDC). Figure 2-2 shows a map of the EDCs that make up the PJM control region. The Space Heating index is combined with daily Heating Degree Days to form an estimate of daily space heating load (MWh). The Space Cooling index is combined with daily Cooling Degree Days to form an estimate of historical and forecasted daily space cooling load (MWh).

Historical Load & Weather Data. Hourly historical load & weather data by EDC and weather station are input into the LTFS. The non-weather sensitive portion of the load is extracted from these data and is used to scale the Other Non-Weather sensitive load index to daily MWh for both the historical and forecast period.

Reconstituted Coincident and Non-Coincident Peak Loads. To account for load loss due to embedded solar PV generation, historical estimates of aggregate embedded solar PV generation for each hour is added to the historical coincident and non-coincident peak loads that are computed directly from the historical measured load data with estimates of demand response added back. The coincident and non-coincident peak forecasts are then adjusted downward in the forecast period by subtracting off forecasted embedded solar generation values for hour ending 17:00.

Model and Forecast Engines Section. This section is used to specify and estimate the Daily Energy, and Coincident and Non-Coincident Peak Models by EDC. The second module generates the long-term daily energy, and coincident and non-coincident peak forecasts by EDC and Weather Simulation trace.

Daily Energy, and Coincident and Non-Coincident Peak Models. The Space Heating and Space Cooling indices are combined with historical Heating Degree and Cooling Day variables to form MWh estimates of daily space heating and cooling. The daily values are included along with the estimated Other Non-Weather sensitive load data as explanatory variables in a Daily Coincident Peak and Daily Non-Coincident Peak models. A separate set of Coincident and Non-Coincident Peak models is estimated for each EDC using the EDC specific daily Heating MWh, Cooling MWh, and Other MWh values.

Weather Simulations. To account for the geographical and temporal diversity of the large PJM operating footprint weather simulations are used to generate a distribution of daily coincident and non-coincident peak day forecasts for each EDC. The weather simulations use historical hourly weather data by weather station to form forecasts of daily Heating Degree Days and Cooling Degree days by EDC. The setup of the weather simulation traces is depicted in Figure 2-3. Each year of historical weather data is used to construct 13 separate load forecasts for each year in the forecast horizon. The 2022 vintage of the LTFS utilizes 27 years of historical weather data that drives 351 (computed as 13 x 27) daily load forecasts by EDC and year in the forecast horizon. Using the 351 forecast simulations, the LTFS constructed Cumulative Frequency Distributions of Coincident and Non-Coincident Peak Loads by Month/Season and EDC. The Cumulative Frequency Distributions are used to select load bands under design conditions (e.g., 50%, 10%, 90%). Advantages of the weather simulation framework are:

- Actual and Consistent Weather Patterns Across EDCs. Actual weather data for all weather stations are rotated together ensuring consistent and realistic weather patterns are used to drive the load forecasts.
- Consistency Across Weather Concepts. All weather concepts are rotated together ensuring consistent and realistic movements in temperatures, humidity, wind speed, wind direction, cloud cover, and solar irradiance. This is critical to align HVAC and solar PV generation interactions.

Forecast Adjustments. At the end of each weather simulation embedded Solar PV, EV Charging, and other technology impacts are applied to the coincident and non-coincident peak forecasts. The last step is to make adjustments for expected distribution system capacity projects that are not captured by the base case load forecast process.

Forecast Summary Report Module. This section is used to create formal and ad hoc summaries of the long-term forecasts.

FIGURE 2-1: LTFS 2022 MODEL FRAMEWORK

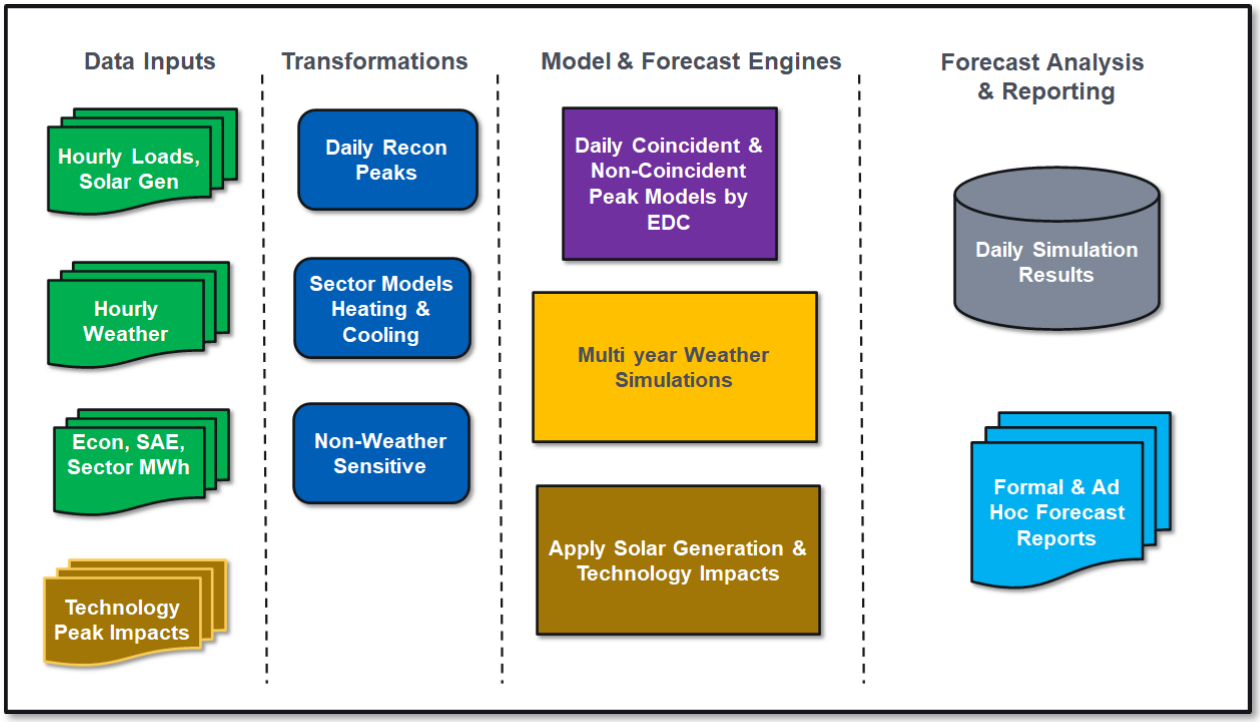


FIGURE 2-2: 2022 MAP OF PJM PARTICIPATING EDCS

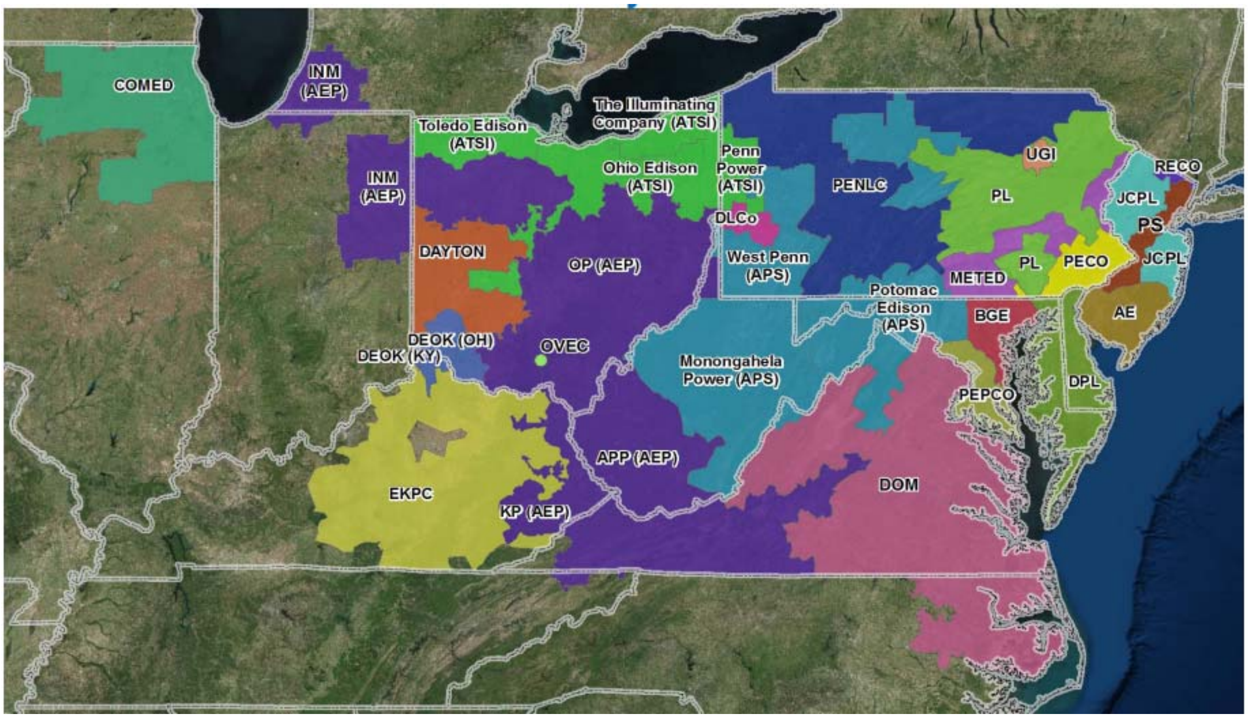
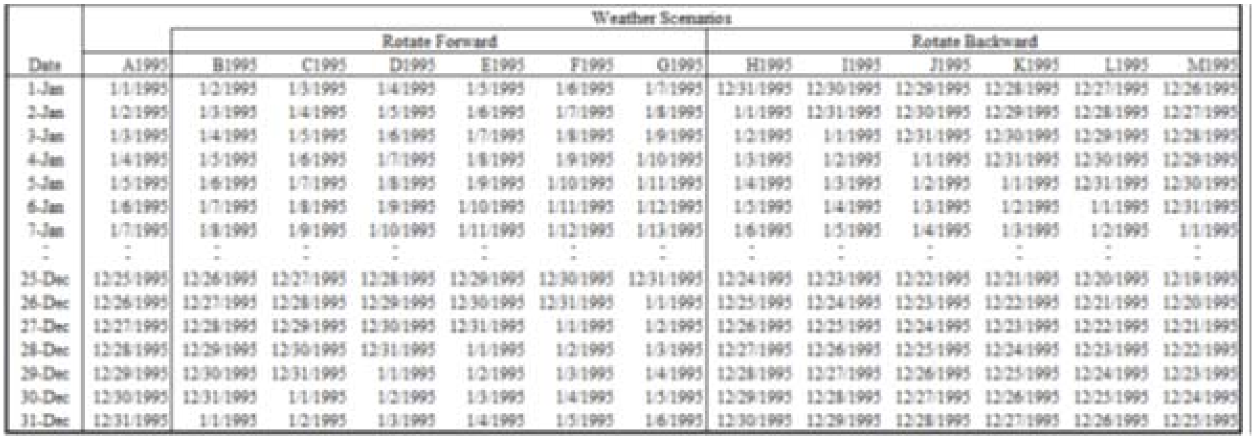


FIGURE 2-3: CONFIGURING WEATHER SIMULATION FORECAST TRACES



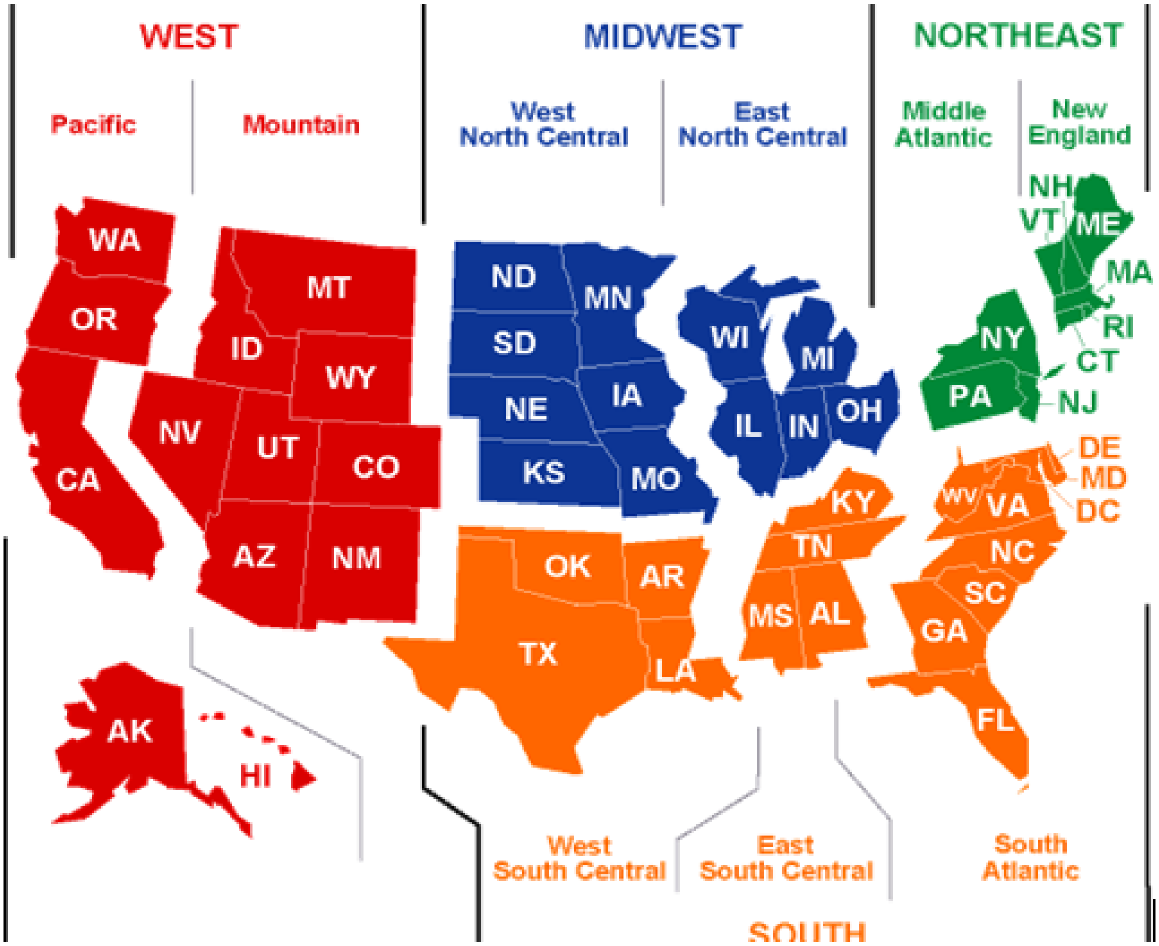
Date	Weather Scenarios												
		Rotate Forward						Rotate Backward					
Date	A1995	B1995	C1995	D1995	E1995	F1995	G1995	H1995	I1995	J1995	K1995	L1995	M1995
1-Jan	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995
2-Jan	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995
3-Jan	1/3/1995	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995	12/28/1995
4-Jan	1/4/1995	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995	12/29/1995
5-Jan	1/5/1995	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995	12/30/1995
6-Jan	1/6/1995	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/12/1995	1/5/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995	12/31/1995
7-Jan	1/7/1995	1/8/1995	1/9/1995	1/10/1995	1/11/1995	1/12/1995	1/13/1995	1/6/1995	1/5/1995	1/4/1995	1/3/1995	1/2/1995	1/1/1995
:	:	:	:	:	:	:	:	:	:	:	:	:	:
25-Dec	12/25/1995	12/26/1995	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995	12/20/1995	12/19/1995
26-Dec	12/26/1995	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995	12/20/1995
27-Dec	12/27/1995	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995	12/21/1995
28-Dec	12/28/1995	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995	12/22/1995
29-Dec	12/29/1995	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995	12/23/1995
30-Dec	12/30/1995	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995	12/24/1995
31-Dec	12/31/1995	1/1/1995	1/2/1995	1/3/1995	1/4/1995	1/5/1995	1/6/1995	12/30/1995	12/29/1995	12/28/1995	12/27/1995	12/26/1995	12/25/1995

3 LONG-TERM MODEL DRIVERS

PJM's long-term energy and demand forecast is driven by zone-level population, economic activity as captured by regional output and employment and end-use energy trends. In general, sales growth associated with new customers and business activity is offset by improvements in energy efficiency. The 2022 PJM baseline forecast (before forecast adjustments) is basically flat when end-use energy intensities are combined with population and economic projections; decline in use per customer is roughly equal to customer growth. Long-term demand is largely driven by expected electric vehicle and data center load growth.

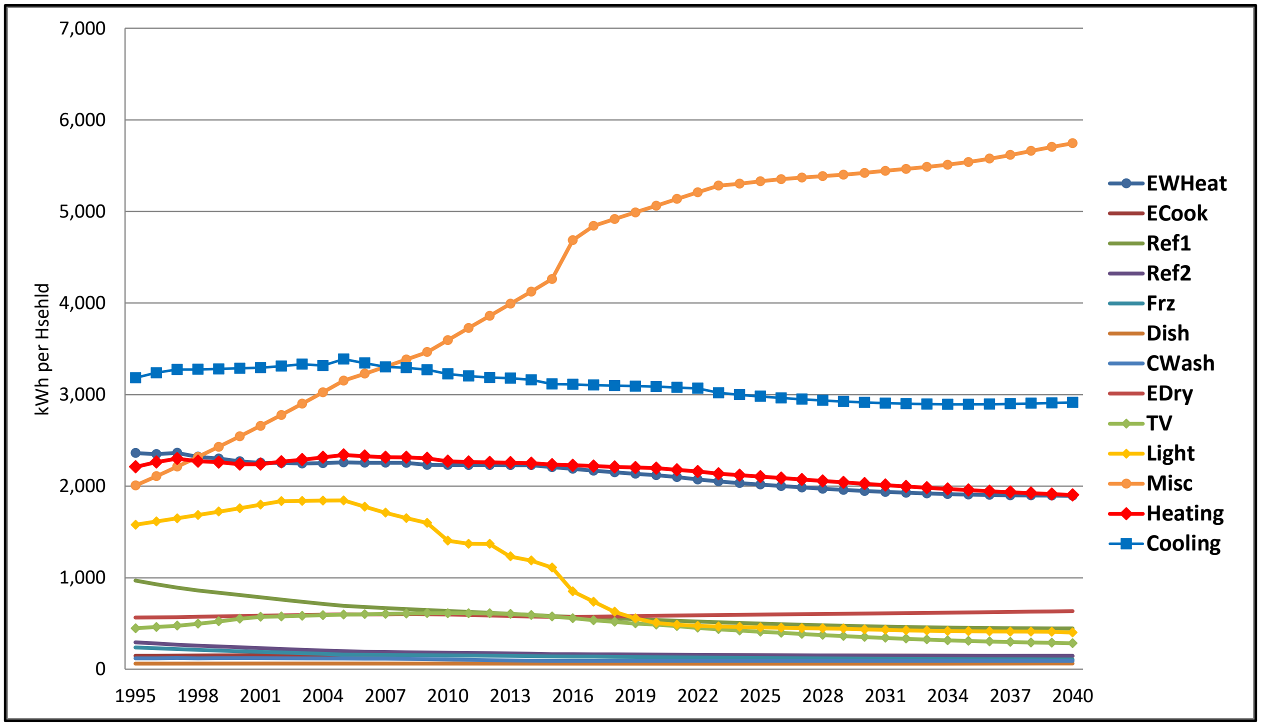
The PJM energy trend is consistent with other regions where long-term population and economic output are relatively slow. What has driven the decline in customer usage are end-use efficiency standards, utility efficiency programs that provide rebates for adoption of more efficient technology options such as lighting, and just the natural replacement of old appliances and commercial systems with new, more efficient equipment and thermal shell improvements. The current PJM model captures these energy efficiency impacts through incorporation of end-use saturation and efficiency projections. End-use saturation and average stock efficiency are derived from The Energy Information Administration (EIA) Annual Energy Outlook (AEO). The AEO forecast is based on a set of end-use models for the residential, commercial, and industrial sector. The AEO generates detail end-use information including number of households, number of end-use units, total consumption, and for many end-uses stock efficiency. Forecasts are generated for 9 census divisions as depicted in Figure 3-1.

FIGURE 3-1: FORECAST CENSUS DIVISIONS



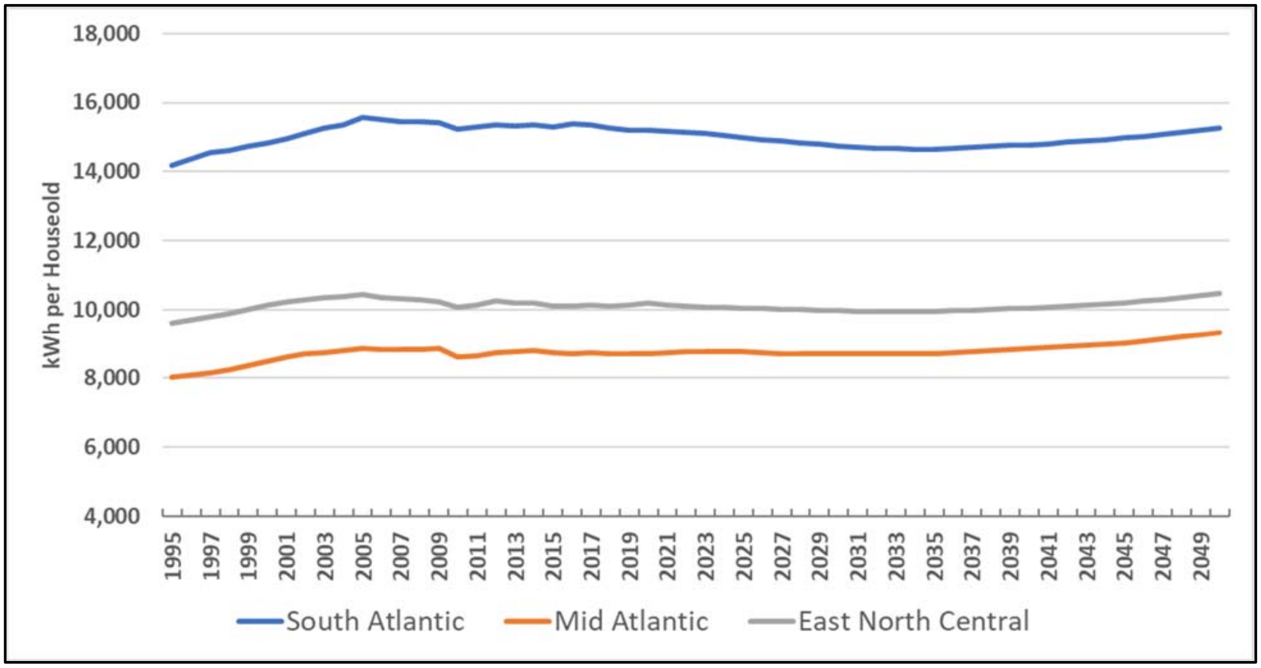
Each year, Itron processes the AEO forecast database and develops and maintains historical and projected end-use consumption, saturation, and efficiencies. Saturation and efficiency are used to construct end-use intensities. In the residential sector, intensities are on a kWh per household basis, and in the commercial sector on a kWh per square foot basis. At the national level, industrial intensities are calculated on a kWh per employee basis or kWh per $ GDP. The PJM models use intensities from the Mid-Atlantic, South Atlantic, East South Central, and East North Central Census Divisions; the specific set of intensities used in the zone model construction is determined by the zone's location. Figure 3-2 shows residential end-use intensities for the South Atlantic Census Division.

FIGURE 3-2: SOUTH ATLANTIC END-USE INTENSITIES



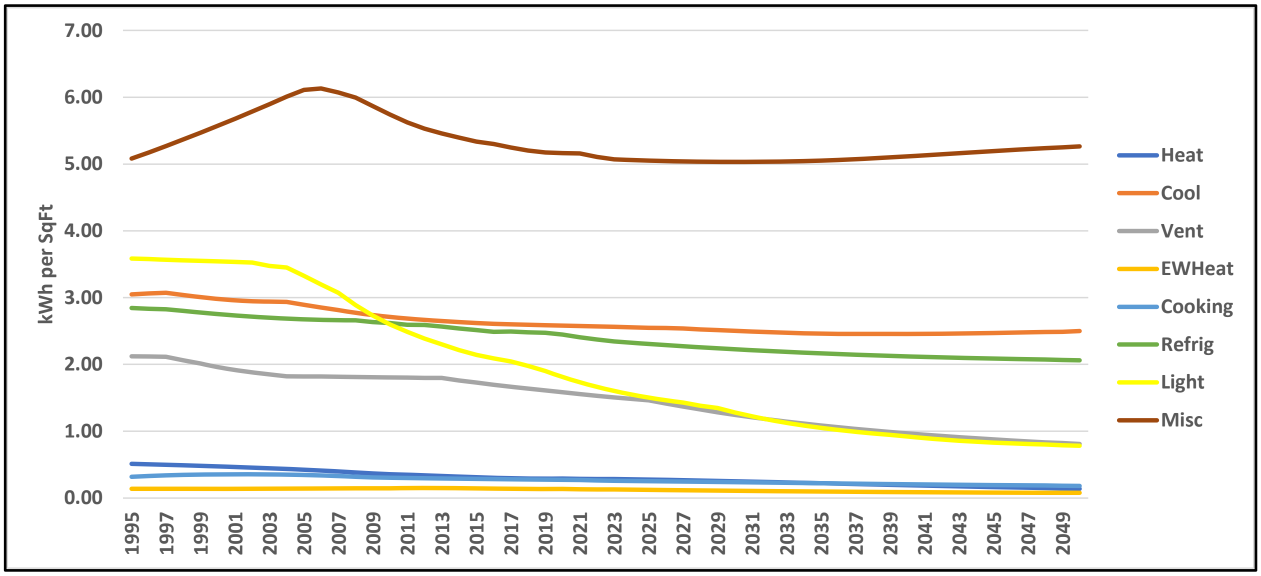
Like all Divisions, the miscellaneous category is the only end-use showing meaningful growth. Miscellaneous includes end-uses not specifically defined such as plug loads, pool pumps, spas, and wine coolers to name a few. In aggregate total intensity declines into through 2035; afterwards starts increasing as in the reference case, there are no new standards after that point in time. Figure 3-3 shows total residential intensity trend.

FIGURE 3-3: TOTAL RESIDENTIAL INTENSITIES



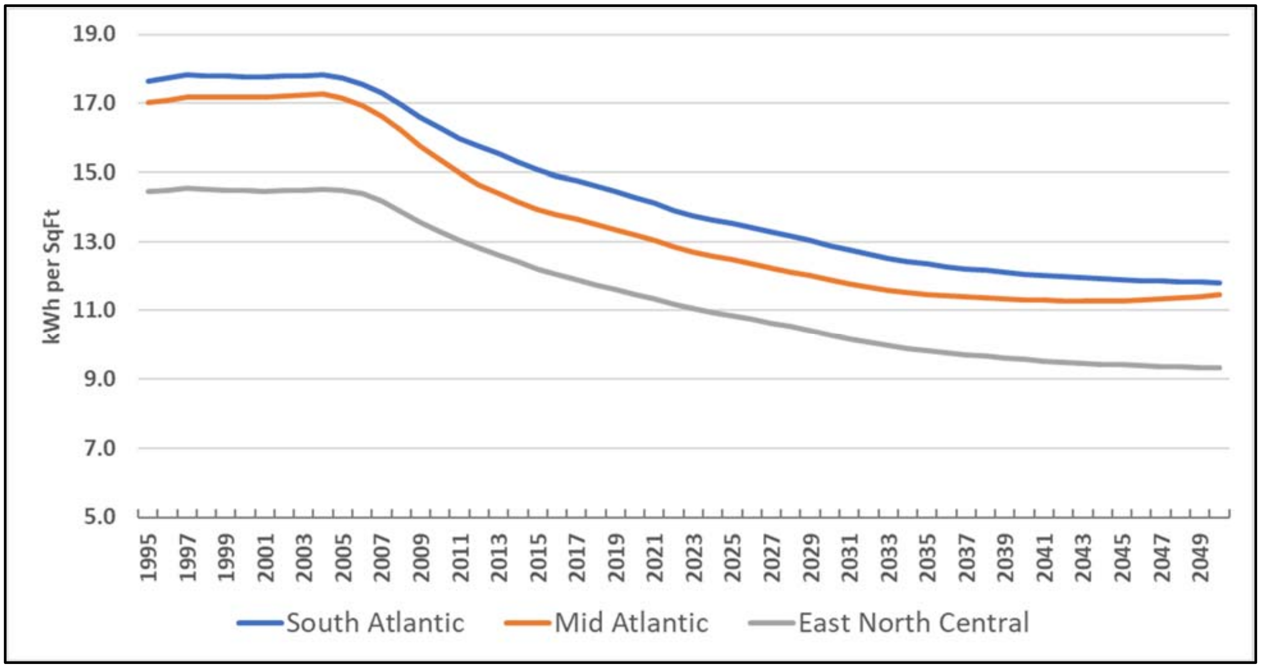
End-use intensities are also declining in the commercial sector. Figure 3-4 shows commercial end-use intensities.

FIGURE 3-4: SOUTH ATLANTIC COMMERCIAL END-USE INTENSITIES



While decline in end-use intensities are slowing across several end-uses, both lighting and ventilation are still expected to see strong overall efficiency improvements. Total commercial intensity has been declining since 2007 and is expected to continue to decline through the forecast horizon. Figure 3-5 shows total commercial intensities.

FIGURE 3-5: TOTAL COMMERCIAL INTENSITIES



TRANSITION FROM ANNUAL TO MONTHLY SECTOR MODELS

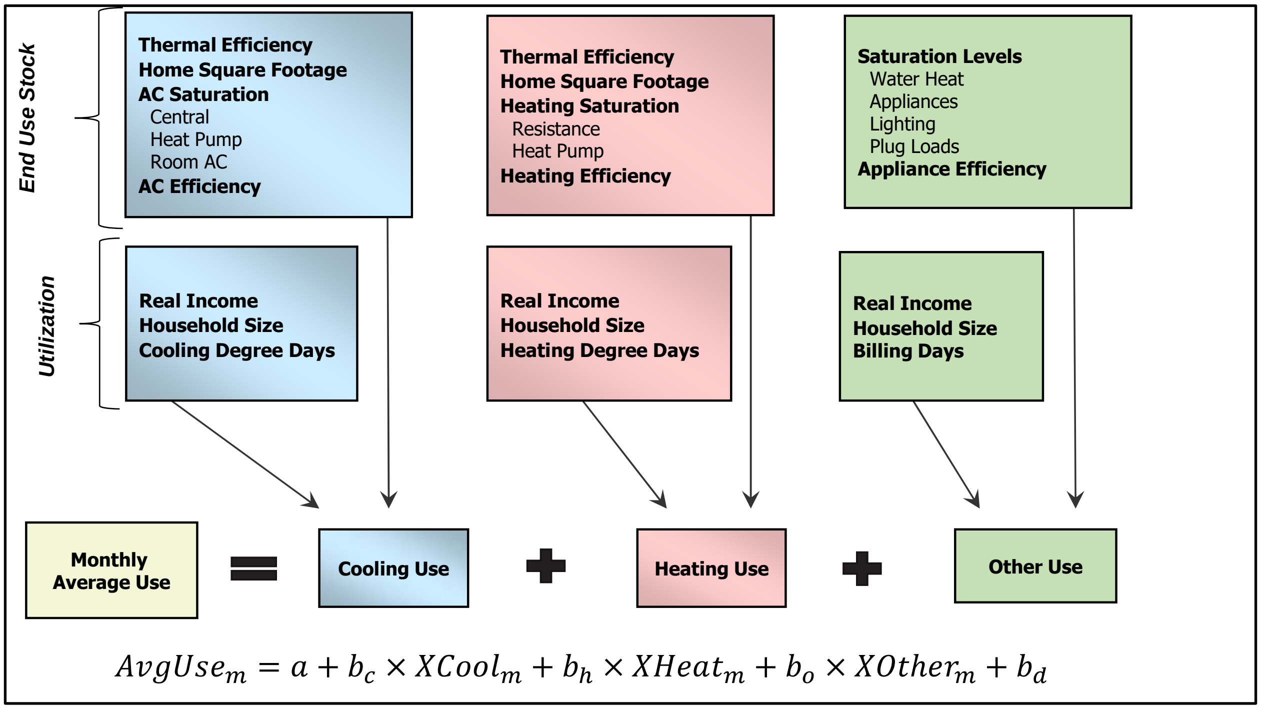
Heating Index (*HeatIdx)*, Cooling Index (*CoolIdx*), and Base Use Index (*BaseIdx*) are incorporated in the Zonal daily energy, peak, and coincident peak models. These indices are derived by combining population, economic growth, with end-use intensities allowing the indices to capture customer growth, economic activity, and current and expected gains in end-use efficiency. The construction of the indices is theoretically strong and effectively capture the impact end-use efficiency gains have had on regional sales. Resulting forecasts are consistent with EIA's long-term outlook.

In the current PJM models, quarterly end-use indices are derived from annual customer class sales models (residential, commercial, and industrial). Annual models are estimated for each zone and reflect regional population and economic growth. While we believe the current approach adequately captures efficiency improvements, estimated indices can be strengthened and calculations simplified by deriving the indices from monthly rate class sales models rather than through annual models and calculation of quarterly indices. Monthly zone-level sales and customer can be derived from the *EIA 861 and 861m* reports. EIA 861 provides annual utility sales that includes both utility and retail served energy and customers. EIA 861m provides utility-supplied energy (which excludes retail delivered sales) that is used to shape total annual sales to months. Monthly model provides more observations and greater variation in historical monthly use due to both weather and economic activity. This in turn results in stronger model coefficients both in terms of their impact (elasticity) and statistical strength. The use of monthly model also addresses Market Participants' concern as fewer years are required to estimate strong model coefficients used in constructing the model indices. Market Participants' issue was that using older annual data (which is necessary to have enough data points for modeling) may give too much weight to past years that are not reflective of current end-use characteristics. PJM sought to address this concern by shortening the estimation period to ten years but found they could not estimate reasonable models with just ten observations. Moving to monthly models addresses this issue; ten years of historical data gives 120 observations vs. 10 observations in an annual model. The shorter historical period will result in indices that are more reflective of current period end-use mix and economic activity impacts.

ESTIMATE RATE CLASS MODELS

The proposed approach is to construct end-use indices from monthly Statistically Adjusted End-Use (SAE) models for the residential and commercial sectors and more generalized model specification for the industrial sector. In the residential sector, the model is estimated for monthly average use and in the commercial sector for monthly sales. The SAE model is designed to capture economic growth as well as structural changes reflected in end-use saturation and efficiency trends and building shell improvements. Figure 3-6 shows the residential SAE average use model.

FIGURE 3-6: RESIDENTIAL SAE AVERAGE USE MODEL

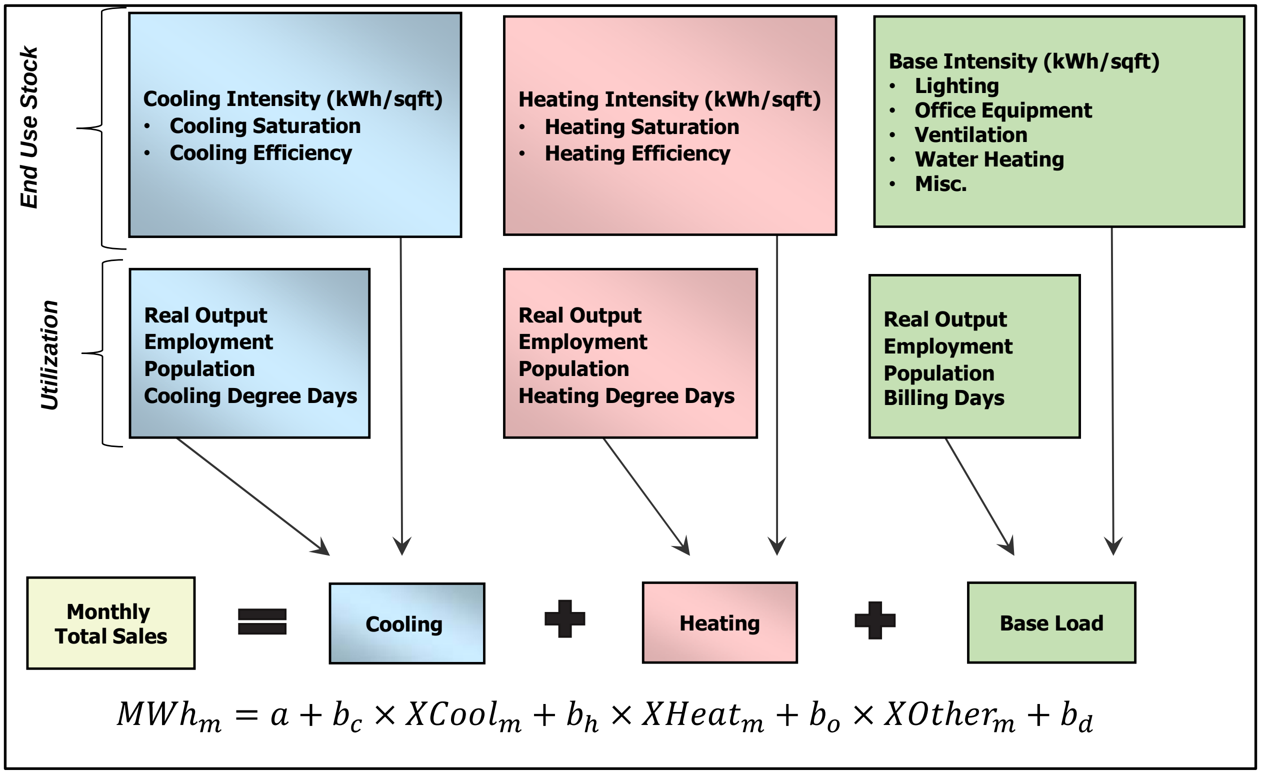


$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_d$$

The model variables *XCool*, *XHeat*, and *XOther* are initial estimates of average monthly cooling, heating, and non-weather sensitive use. The model variables are constructed by combining long-term annual saturation and efficiency trends (the end-use stock variables) with monthly weather, household income, and household size (the monthly utilization variables). The coefficients – b_c , b_h, and b_o are estimated using linear regression that relates average residential use to the constructed end-use model variable. The estimated model coefficients statistically adjust the end- use energy estimates to customer use and are used as describe below to estimate historical and projected heating, cooling, and base use loads. As parameters are estimated using an average use model, total residential heating, cooling, and baseloads are derived by multiplying per customer end-use sales by number of residential customers. Residential customer projections are based on a monthly linear regression model that relates customers to number of households.

A similar model can be estimated for the commercial sector where cooling, heating, and base-use variables are derived by combining commercial end-use energy intensity (measured in kWh per square foot) with regional economic drivers that capture both economic growth and short-term business activity. Figure 3-7 shows the commercial SAE model.

FIGURE 3-7: COMMERCIAL SAE SALES

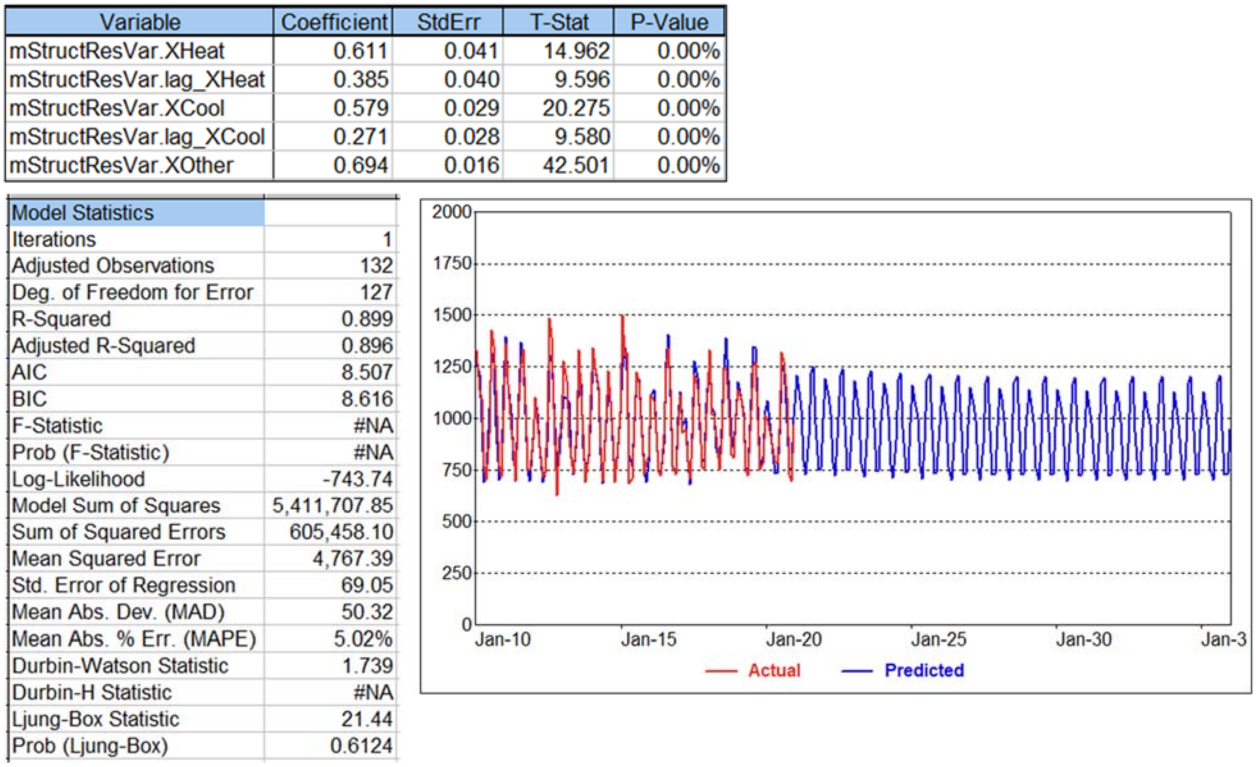


$$MWh_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_d$$

In general, commercial models are estimated at total sales level. The estimated model coefficients calibrate commercial end-use energy estimates to actual commercial sales.

The monthly SAE specification was evaluated and presented to PJM staff using DPL Zone rate class monthly sales data, economic data, and EIA Census Division residential and commercial end-use intensities. Recent data developed by the National Renewable Energy Laboratory (NREL) can potentially be used to help calibrate the census-level saturation estimates to Zones. NREL has constructed detail residential (ResStock) and commercial (ComStock) end-use data bases derived from thousands of residential and commercial building simulations. 2018 end-use saturation and consumption can be calculated for each Public Use Microdata Area (PUMA). PUMA disaggregate states into regions with no fewer than 100,000 people. Figure 3-8 shows residential actual and predicted average use and Figure 3-9 shows DPL commercial sales model.

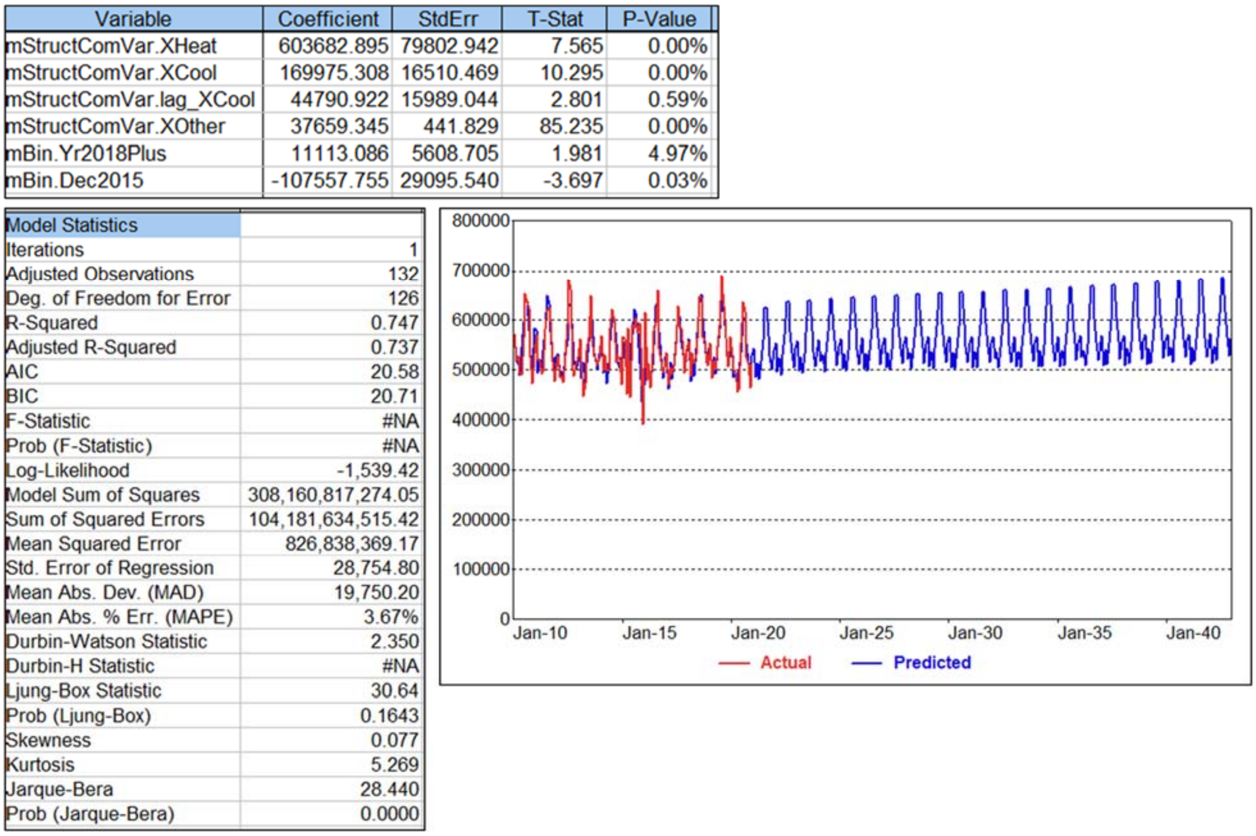
FIGURE 3-8: DPL RESIDENTIAL SAE MODEL



Variable	Coefficient	StdErr	T-Stat	P-Value
mStructResVar.XHeat	0.611	0.041	14.962	0.00%
mStructResVar.lag_XHeat	0.385	0.040	9.596	0.00%
mStructResVar.XCool	0.579	0.029	20.275	0.00%
mStructResVar.lag_XCool	0.271	0.028	9.580	0.00%
mStructResVar.XOther	0.694	0.016	42.501	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	127
R-Squared	0.899
Adjusted R-Squared	0.896
AIC	8.507
BIC	8.616
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-743.74
Model Sum of Squares	5,411,707.85
Sum of Squared Errors	605,458.10
Mean Squared Error	4,767.39
Std. Error of Regression	69.05
Mean Abs. Dev. (MAD)	50.32
Mean Abs. % Err. (MAPE)	5.02%
Durbin-Watson Statistic	1.739
Durbin-H Statistic	#NA
Ljung-Box Statistic	21.44
Prob (Ljung-Box)	0.6124

FIGURE 3-9: DPL COMMERCIAL SAE MODEL



Variable	Coefficient	StdErr	T-Stat	P-Value
mStructComVar.XHeat	603682.895	79802.942	7.565	0.00%
mStructComVar.XCool	169975.308	16510.469	10.295	0.00%
mStructComVar.lag_XCool	44790.922	15989.044	2.801	0.59%
mStructComVar.XOther	37659.345	441.829	85.235	0.00%
mBin.Yr2018Plus	11113.086	5608.705	1.981	4.97%
mBin.Dec2015	-107557.755	29095.540	-3.697	0.03%

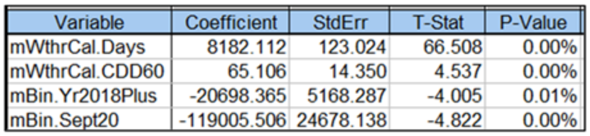
Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	126
R-Squared	0.747
Adjusted R-Squared	0.737
AIC	20.58
BIC	20.71
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,539.42
Model Sum of Squares	308,160,817,274.05
Sum of Squared Errors	104,181,634,515.42
Mean Squared Error	826,838,369.17
Std. Error of Regression	28,754.80
Mean Abs. Dev. (MAD)	19,750.20
Mean Abs. % Err. (MAPE)	3.67%
Durbin-Watson Statistic	2.350
Durbin-H Statistic	#NA
Ljung-Box Statistic	30.64
Prob (Ljung-Box)	0.1643
Skewness	0.077
Kurtosis	5.269
Jarque-Bera	28.440
Prob (Jarque-Bera)	0.0000

The models generate statistically significant end-use coefficients that can be used to generate strong estimates of cooling, heating, and base-use energy requirements. Another strength is that given the structure, the SAE model generally results in consistent estimated parameters when there are just small changes in model parameters as new data is added and older data dropped.

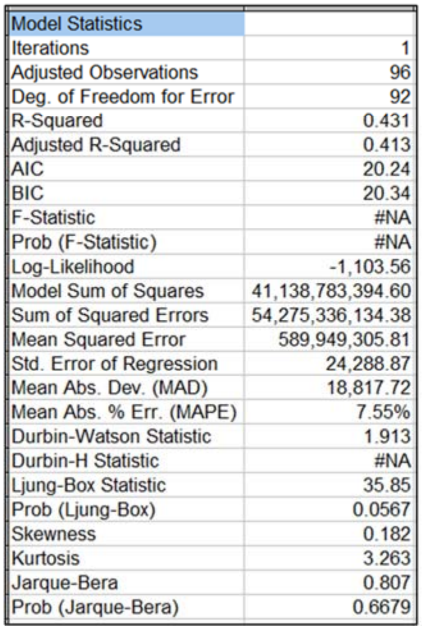
Similar structured models can be estimated for the industrial sector. To that end, PJM constructed industrial models that leverage the EIA industrial sector energy forecasts. In the industrial sector, EIA generates energy per dollar output projections by industrial sector. Using a combination of state-level output estimates and regional sector employment data, PJM constructs annual industrial indices that reflect Zonal industrial sector real output, productivity, and efficiency improvements. Itron has developed similar inputs for industrial modeling and believe that the PJM current industrial model process is theoretically strong. While structured models have worked in some regions, often they don’t as in many service areas monthly industrial sales are not “well-behaved”; in these cases, PJM will need to use reasonable judgment in constructing monthly sales models and may require exogenous adjustments based on expected activity from large industrial customers. Industrial sales are often dominated by a few large customers; there can be significant month-to-month sales variation as a result of large swings in individual customer usage and large billing adjustments.

This is illustrated in Figure 3-10 where we could not estimate a reasonable DPL industrial sales model. Not only are there large monthly sales swings that are not weather-related, but there is a drop in 2018 sales that could be the result of one or more large customer closing down part or all of their operations.

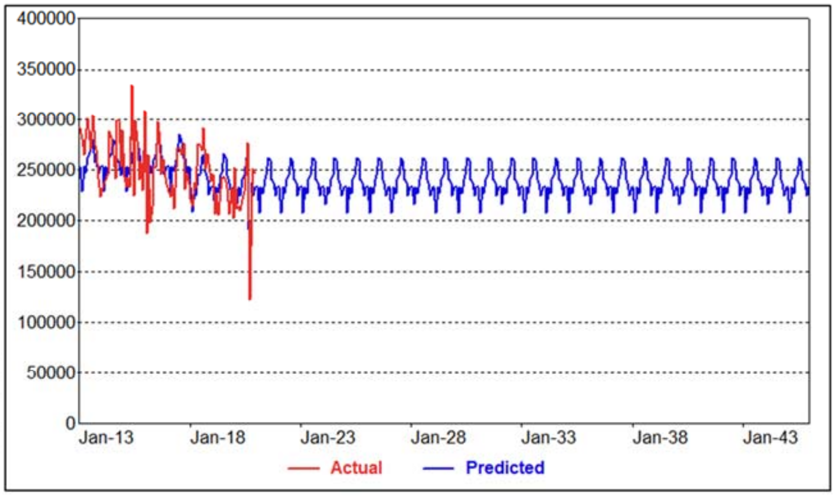
FIGURE 3-10: DPL INDUSTRIAL SALES MODEL



Variable	Coefficient	StdErr	T-Stat	P-Value
mWthrCal.Days	8182.112	123.024	66.508	0.00%
mWthrCal.CDD60	65.106	14.350	4.537	0.00%
mBin.Yr2018Plus	-20698.365	5168.287	-4.005	0.01%
mBin.Sept20	-119005.506	24678.138	-4.822	0.00%



Model Statistics	
Iterations	1
Adjusted Observations	96
Deg. of Freedom for Error	92
R-Squared	0.431
Adjusted R-Squared	0.413
AIC	20.24
BIC	20.34
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,103.56
Model Sum of Squares	41,138,783,394.60
Sum of Squared Errors	54,275,336,134.38
Mean Squared Error	589,949,305.81
Std. Error of Regression	24,288.87
Mean Abs. Dev. (MAD)	18,817.72
Mean Abs. % Err. (MAPE)	7.55%
Durbin-Watson Statistic	1.913
Durbin-H Statistic	#NA
Ljung-Box Statistic	35.85
Prob (Ljung-Box)	0.0567
Skewness	0.182
Kurtosis	3.263
Jarque-Bera	0.807
Prob (Jarque-Bera)	0.6679



Without any strong identifiable model drivers, the forecast is held constant at current levels of activity. Generally, the industrial sales forecast would then be adjusted for expected large customer load additions or load losses. While limited in terms of information, model coefficients can be still be used to isolate industrial cooling and base-use contribution to system energy requirements.

SYSTEM END-USE MODEL INPUT CONSTRUCTION

The next step is to isolate long-term system heating, cooling, and other-use energy requirements for both the historical and forecasted periods. End-use energy requirements are estimated by multiplying the end-use model coefficients with the constructed XHeat and XCool for normal weather and the XOther model variables. Normal or expected weather conditions are used in the XHeat and XCool index calculations to avoid double counting weather impacts. Weather impacts are captured in the daily or hourly zonal load weather simulations. Figure 3-11 shows the derived residential heating, cooling, and base-use loads,

Figure 3-12 the commercial and industrial monthly energy requirements, and Figure 3-13 total system cooling, heating, and baseload requirements.

FIGURE 3-11: DPL RESIDENTIAL END-USE ENERGY REQUIREMENTS (MWH)

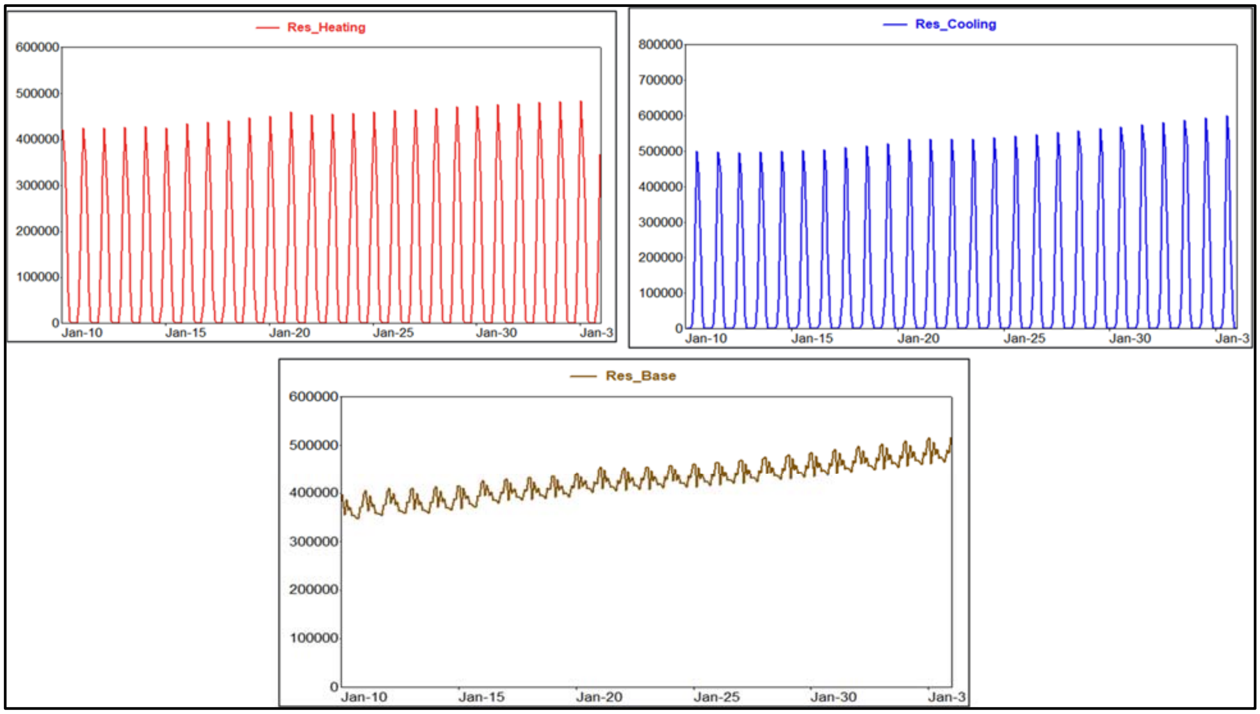


FIGURE 3-12: DPL C&I END-USE ENERGY REQUIREMENTS (MWH)

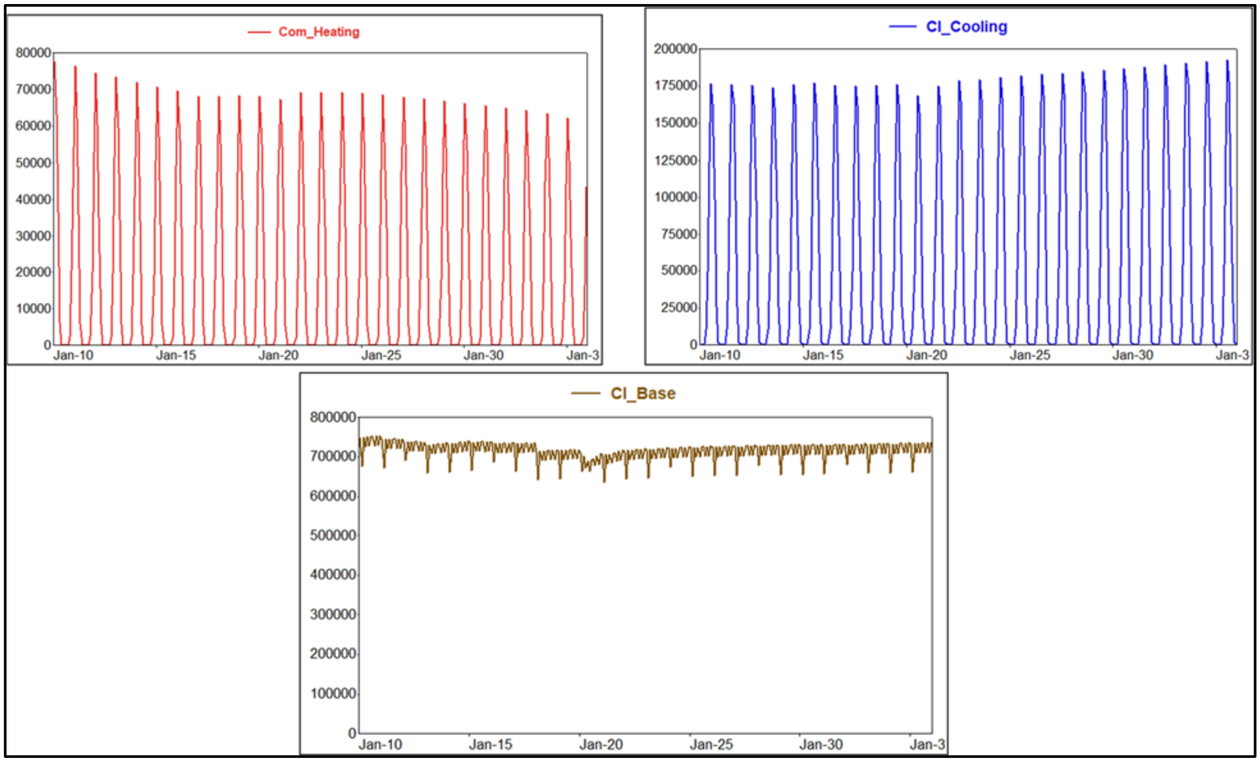
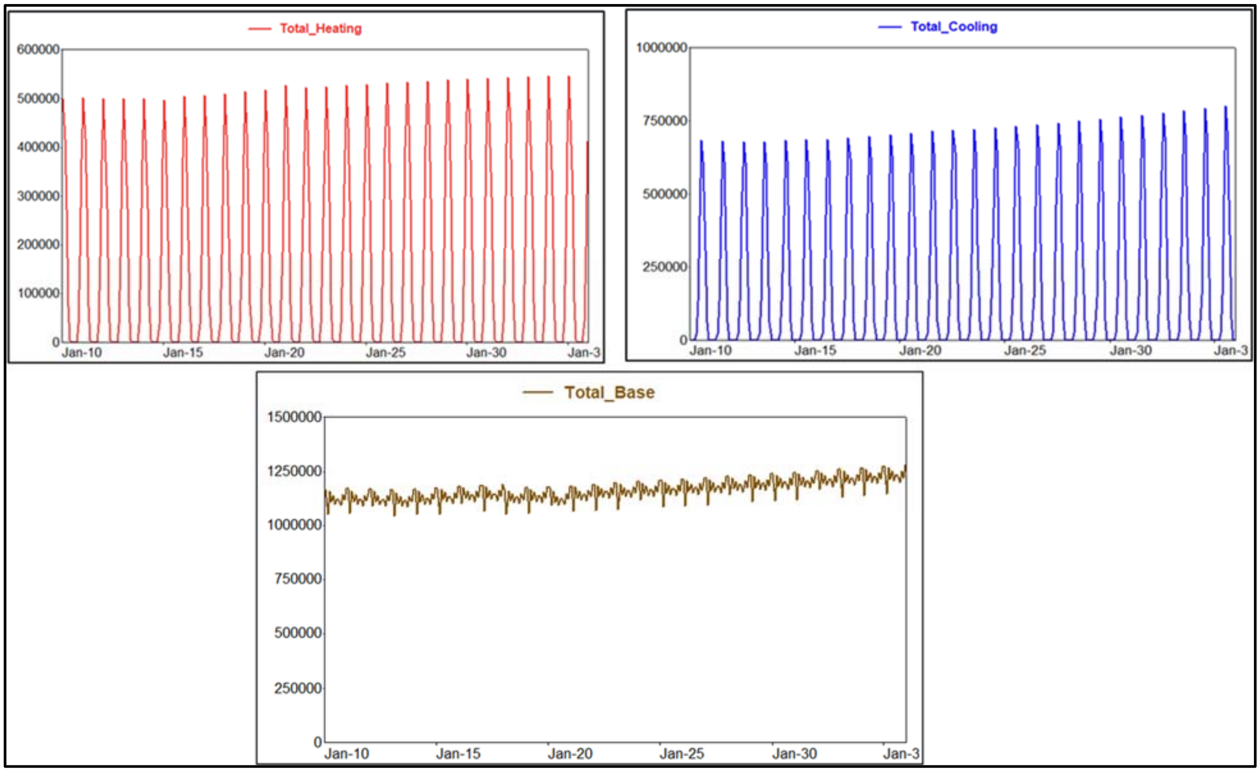
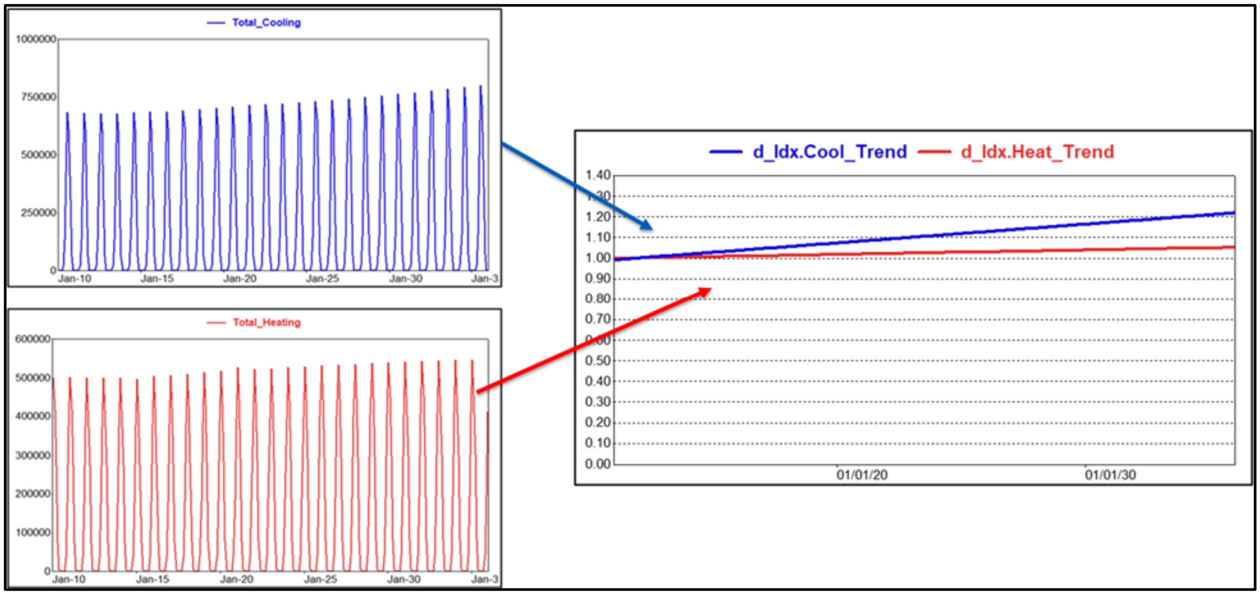


FIGURE 3-13: DPL TOTAL END-USE ENERGY REQUIREMENTS (MWH)



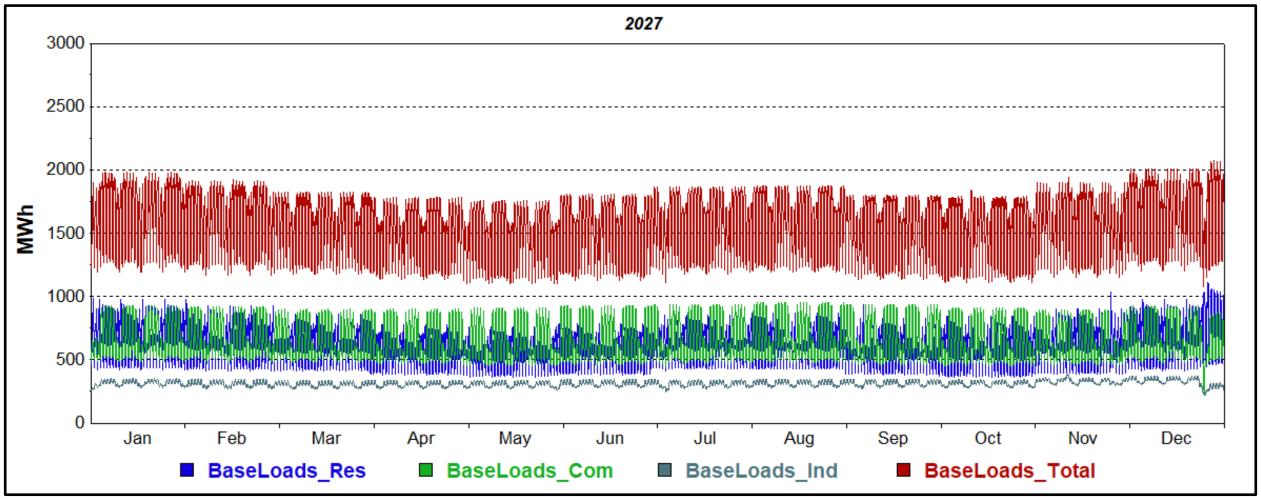
Calculated heating, cooling, and base-use energy requirements are converted to daily indices that are then incorporated into the Zonal hourly load models. *HeatIdx* is combined with the hourly model heating-related weather variables, *CoolIdx* with cooling weather variables, and *BaseIdx* with seasonal and daily binary variables. Figure 3-14 shows the conversion of monthly end-use energy requirements to *HeatIdx* and *CoolIdx*.

FIGURE 3-14: DPL DAILY INPUTS FOR HOURLY ZONAL MODELS



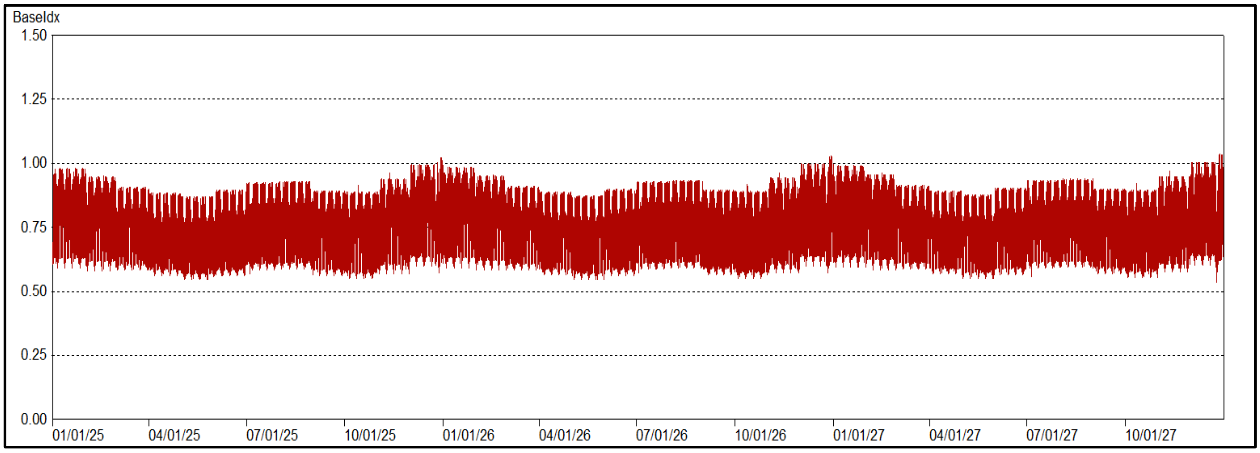
Base-use energy requirements are also converted to a daily index and interacted with hourly model binaries designed to capture non-weather sensitive load including day of the week, holiday, and seasonal daily variables. Alternatively, AMI data or end-use profiles available from NREL could be used to convert customer class base-use energy requirements to hourly load estimates. Figure 3-15 shows estimated DPL hourly base-use energy requirements by class and total for 2027.

FIGURE 3-15: DPL HOURLY BASE-USE ENERGY REQUIREMENTS (2027)



Total base-use load requirements are indexed and used in estimating the hourly Zonal models. Figure 3-16 shows the hourly BaseIdx variable for 2025 through 2027.

FIGURE 3-16: DPL BASEIDX 2025 - 2027



The integration of the end-use indices into the hourly models is discussed in the Hourly Model Analysis and Recommendations section.

4 HOURLY MODEL ANALYSIS AND RECOMMENDATIONS

The current PJM modeling process includes three sets of daily models for each zone. These are daily energy, daily noncoincident zone peak (NCP), and daily CP (zone load at the time of the daily PJM peak). For each zone, CP models are estimated for daily loads coincident with the Locational Deliverability Area (LDA) peak and coincident with the overall PJM system peak.

The application of this approach is complicated by the saturation of new technologies (PV and EV in particular) that modify the timing of system energy requirements. In particular, the penetration of behind the meter solar systems is changing both the timing of zone peaks and the coincidence factors across zones. The best way to understand the impact of these changes is through an hourly modeling process. This section shows how the hourly modeling process would work, provides an example of the level of accuracy that can be achieved, and provides recommendations about the construction of hourly weather variables.

The examples are developed using hourly load and weather data for the DPL (Delmarva) zone. As part of this project, Itron did not evaluate model performance for any other PJM zones. However, in the past we have implemented similar models and performed similar analysis for a wide variety of utilities, including many of those in the PJM footprint. Based on this experience, we believe that the conclusions presented below will generalize well to the other PJM zones.

The general conclusions of this section are:

- PJM has the data to develop accurate and robust hourly models
- Hourly models are well suited to the weather simulation approach
- Hourly models can accurately model system zone peaks (NCP) and the coincident load (CP) values.
- The conclusions include specific recommendations for construction of interactive weather variables.

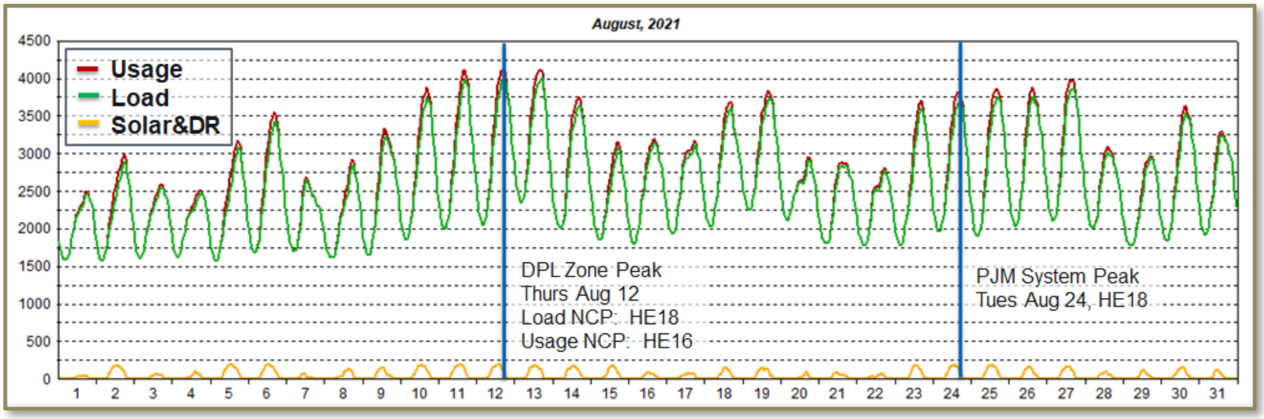
EXAMPLE OF HOURLY LOAD DATA

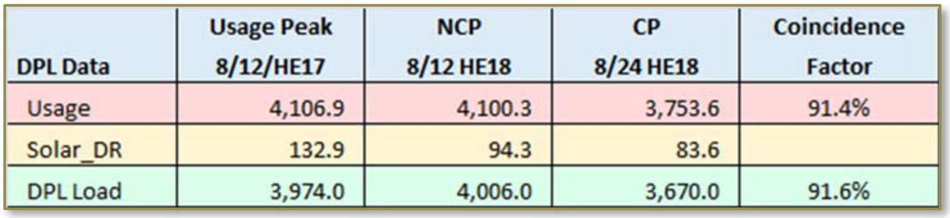
Figure 4-1 shows an example of hourly load data for the DPL (Delmarva) zone. The chart shows hourly data for one month, August 2021. The top line (Red) is labeled Usage and shows the estimate of hourly energy usage (customer end-use consumption). The Green line is labeled Load and shows the level of zone resources dispatched to meet customer energy requirements. The bottom line (Orange) shows the estimated level of behind-the-meter solar generation.

The utility load is computed as the measured hourly zone load plus estimated hourly impacts of DR programs. (Note, there were no estimated DR impacts in the DPL zone in the month displayed). The orange line (Solar) is estimated and is based on hourly solar irradiation data and installed capacity of behind-the-meter solar panels. The red Usage line is calculated as the sum of utility load (Green) and solar Generation (Orange). This is an estimate of total customer energy usage, including energy supplied by BTM solar systems and energy supplied by the zone resources.

In the chart, the two vertical blue lines represent the day and time of the DPL zone peak (on August 12) and the PJM system peak (on August 24). On the zone peak (NCP) day, customer usage peaked at HE17 (4 pm to 5 pm), but the peak utility peak load occurred in the following hour (HE18) as BTM solar production ramped downward. It was a clear day, so this is just part of the normal ramp-down process for solar generation and the resulting ramp-up process for utility loads in the late afternoon. As a point of reference, peak solar generation on this day was estimated to be 197 MW.

FIGURE 4-1: DPL HOURLY USAGE, LOAD, AND BTM SOLAR – AUGUST 2021





DPL Data	Usage Peak 8/12/HE17	NCP 8/12 HE18	CP 8/24 HE18	Coincidence Factor
Usage	4,106.9	4,100.3	3,753.6	91.4%
Solar_DR	132.9	94.3	83.6	
DPL Load	3,974.0	4,006.0	3,670.0	91.6%

The right-hand blue line on August 24th represents the PJM System peak load. Although not shown in the grid above, customer usage on this day peaked in HE16, load peaked in HE17, and the PJM peak is at HE18. Customer usage is estimated to have declined by about 73 MW over this three-hour window, but solar generation values ramped down by about the same amount (from 156 MWh to 125 MWh to 84 MWh, respectively), and as a result, net DPL load was relatively flat from the time of the customer peak to the time of the PJM peak.

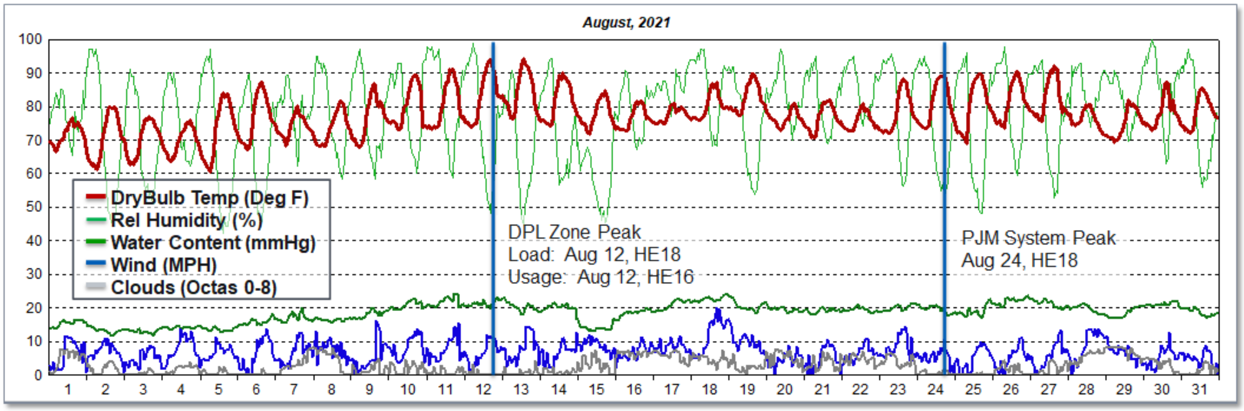
The grid below the chart pulls together the data for the hour of usage peak, the hour of DPL peak load (NCP) and the DPL load at the time of the PJM system peak (CP). The coincidence factor for usage (CP usage/Peak usage) is estimated to be 91.4%. The coincidence factor for DPL load (CP load /NCP load) is 91.6%. This is well below the typical coincidence values for the DPL area but is within the boundaries of coincidence results generated by the weather simulation approach with rotation.

EXAMPLE OF HOURLY WEATHER DATA

Figure 4-2 shows an example of weather for the DPL (Delmarva) zone. The chart shows hourly values for the same month as shown above, August of 2021. The weather data values are computed by averaging hourly data from the two weather stations, Wilmington, Newcastle (ILG) in the north and Wallops Island (WAL) in the south; based on associated population, ILG has a 70% weight and WAL a 30% weight. The red line shows data for hourly drybulb temperature. The light green line shows data for relative humidity. The dark green line shows hourly data for the moisture content of the air in millimeters of mercury (mmHg). The blue and gray lines at the bottom are for Wind speed in MPH and Cloud Cover in Octas (ranging from 0 to 8).

As with the hourly load chart, the hours for the DPL zone peak and the PJM system peak are marked with vertical blue lines. The hourly weather data for these two peak hours is displayed below the chart.

FIGURE 4-2: HOURLY WEATHER DATA FOR DPL ZONE – AUGUST 2021



Summer Peak Hour Weather Variables	DPL 2021 NCP 8/12 HE18	PJM 2021 Peak 8/24 HE18
AvgDB Temperature (Deg F)	92.7	88.8
Relative Humidity (%)	54.3	53.3
Moisture Content (mmHg)	21.3	19.1
Temp Hum Index (Deg F)	95.4	91.1
Wind Speed (MPH)	11.4	8.4
Cloud Cover (Octas)	0.12	1.6

The peak hour data show the main difference between the two days, which is that the DPL zone is four degrees warmer on the NCP day than on the peak day. The THI variable that is used in the model is 4.3 degrees higher. Estimated equations indicate that 4 additional degrees of temperature in HE18 and the preceding hours adds about 290 MWh to the load in HE18. This explains why the DPL peak on August 12 is so far above the DPL CP value on August 24.

While we are on the topic of weather, a brief comment about the THI variable and relative humidity. The normal daily cycles are clear in the weather chart. Each day, the temperature increases to a mid-day high and then decreases at night to lower values. As this cycle occurs, the amount of water that the air can hold changes significantly, since warmer air can hold much more water than colder air. Relative humidity represents ratio of the amount of moisture in the air to the amount of moisture the air can hold. The amount of moisture in the air (the numerator) remains relatively constant over most days, but as the temperature drops at night the amount of water the air can hold (the denominator) goes down, and therefore relative humidity goes up. This continues until the air temperature hits the dew point temperature, at which point relative humidity approaches 100%.

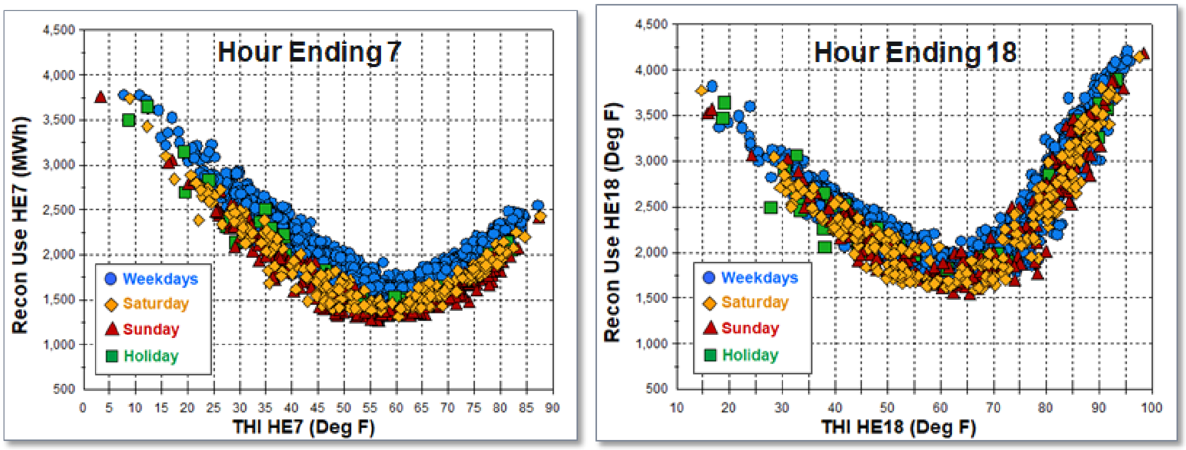
The dark green line shows a measurement that is proportional to the numerator in the relative humidity equation. It measures the absolute amount of moisture in the air in each hour. Unlike relative humidity, this water content measurement does not change much during a day. In the work below, we discuss the THI formula based on Relative Humidity. It may, however, make sense to research alternatives that utilize a more stable measurement like moisture content or dewpoint temperature.

HOURLY MODELS

This section provides an analysis of alternative approaches to constructing hourly models. Itron has studied a wide range of modeling methods including a variety of regression approaches (least squares, ridge, lasso, elastic net, quantile, support vector), decision tree regressors, and neural network models. While neural network models typically have the best estimation period accuracy, they are more complex than regressions, and can be problematic when explanatory variables move far outside their historical range, as is likely the case in a long-term forecast. We have found that least squares regression (usually called ordinary least squares or OLS) works as well as any of the alternatives in terms of out-of-sample accuracy and provide a robust approach for long-run forecasting of daily and hourly energy usage. Based on these past findings, we restrict our attention here to OLS methods.

The typical approach for long-run forecasting is to specify 24 independent structural models, with one model for each hour. The idea is illustrated in Figure 4-3 that shows scatter plots of loads at HE07 (the hour from 6 am to 7 am) and HE18 (the hour from 5 pm to 6 pm). In these charts, the height of each point represents the estimated hourly usage for the selected hour on a specific day. The position on the X axis is determined by the corresponding hourly temperature (THI in this case) on each day. The points are color coded by day of the week. Each chart shows data for mid-2017 to mid-2021, providing about 1,500 observations for each hour.

FIGURE 4-3: SCATTER PLOTS FOR HE07 AND HE18 – 2017 TO 2021



While temperature and day-of-week variables clearly explain much of the variation in loads in an hour, a variety of other factors are also important. This includes zone growth in terms of customers and economic activity, other weather variables (prior hour temperatures, humidity, wind speed, and cloud cover), seasonal factors (hours of daylight, sun angles, ground water temperatures), changes in end-use saturation and efficiency, and exogenous shocks, such as phases of the Covid pandemic.

Proper construction of explanatory variables that capture the important nonlinearities and interactions among these factors is the key to a strong and robust explanatory model. In what follows, most of the focus is on weather variable definitions and interactions since this will be central to the effectiveness of the weather simulation approach.

TRANSFORMING HOURLY WEATHER

The first analysis concerns the granularity of weather variables that are used in the hourly modeling. Data used in the analysis ranged from mid-2017 through early 2022, giving a total slightly over 1,700 observations for each hour. The hourly Y variable in this analysis is utility load (in later sections, the final model evaluations were performed using hourly usage).

Four sets of models were constructed and compared in terms of in-sample accuracy. All four sets have a common set of calendar-based variables, including the following:

- Monthly binary variables
- Monthly trend variables to capture within-month trends
- Holiday variables for individual holidays
- Long weather lags (10 day and 28-day CD and HD)
- Covid variables Phase 1 to Phase 4 to capture net covid impacts
- Time trend variable

The four sets of models differ in the way hourly weather is transformed into explanatory factors. The approaches are:

1. **Daily Average**. With this approach, hourly values are averaged for each day and the daily average variables are used to construct explanatory factors.
2. **Time-of-Day Average**. With this approach, hourly values are averaged within four time of day blocks (night, morning, afternoon, evening). The TOD averages are then used to construct explanatory factors.
3. **Rolling Hourly with Splines.** With this approach weather variables are computed for each hour as the centered moving average of the prior hour, current hour, and next hour values. The rolling hourly variables are used to construct heating degree and cooling degree variables using 5 degree temperature ranges. For example, THI degrees are computed using base values of 60, 65, 70, 75, 80 and 85. These variables are then used to construct a single heating degree spline and cooling degree spline based on temperature derivatives computed using hourly neural network models. The spline variables are then interacted with other calendar and weather variables to capture slope shifts and nonlinear interaction effects.
4. **Rolling Hourly with Two-Part Degree Days**. With this approach, two cooling degree variables and two heating degree variables are computed for each hour. For example, for HE18, cooling degrees are computed using base temperatures of 70 and 80 and heating degrees are computed using base temperatures of 60 and 50. The first heating degree variable (HD1) and the first cooling degree variable (TD1) are then interacted with other calendar and weather variables to capture slope shifts and nonlinear interaction effects.

To evaluate the relative power of these approaches, a full set of hourly models is estimated using each approach. The mean absolute percent error (MAPE) values from these models are used for the comparison. For each hour, this statistic is computed as the average of the absolute values of the estimated model errors for that hour.

Daily Average Models. For the Daily Average model, daily weather values are computed by averaging the hourly values across the hours in each day. Steps in the process are:

Hourly drybulb temperatures and hourly humidity values are used to compute hourly THI values.

Hourly values are then averaged for each day to get a daily average values (AvgDB, AvgTHI, AvgWind, AvgClouds).

- Two cooling degree variables are computed from AvgTHI using base temperatures of 60 and 70 (AvgTD1 and AvgTD2).
- Two heating degree variables are computed from AvgDB using base temperatures of 60 and 50 (AvgHD1 and AvgHD2)
- AvgTD1 and AvgHD1 are lagged one day and are also interacted with calendar and other weather variables:
    - TD1 and HD1 lagged one day
    - Cold Clouds (Clouds interacted with HD base 50)

- Warm Clouds (Clouds interacted with CD base 70)
- Cold Wind (Wind interacted with HD base 50)
- Warm Wind (Wind interacted with CD base 70)
- SpringTHI and FallTHI (Seasonal binaries interacted with TD1)
- SpringHD and Fall HD (Seasonal binaries interacted with HD1)
- WkEndTHI, WkEndHD (Weekend binary interacted with TD1 and HD1)
- TrendTD1 and TrendHD1 (Trend variable interacted with TD1 and HD1)

Time of Day (TOD) Models. For the Time-of-Day models, hourly weather values are averaged for the four quarters of the day: Night (HE01 to HE06), Morning (HE07 to HE12), Afternoon (HE13 to HE18) and Evening (HE19 to HE24).

- Hourly drybulb temperatures and hourly relative humidity values are used to compute hourly THI values.
- Hourly values are then averaged for each TOD block to get an average variable values (AvgDB), AvgTHI, AvgWind, and AvgClouds for each block.
- Two cooling degree variables are computed for each block using base temperatures that vary across blocks (60 and 70 for Night, 65 and 75 for Morning, Afternoon and Evening)
- Two heating degree variables are computed for each block using base temperatures that vary across blocks (55 and 45 for Night and Evening, 60 and 50 for Morning and Afternoon).
- Lag and interaction variables similar to those in the Daily Average model are then constructed for each TOD block.

For each hour, the TD1 and HD1 variables are included for the block the hour falls in as well as for the prior block and the following block. This surrounding block values are included to improve performance in the hours near the block boundaries.

Rolling Hourly Models. For the Rolling hourly models, weather variables are computed for each hour. Moving from one hour to the next, all calculations shift one hour to the right, including current hour variables and lagged hour variables. Steps in the process are:

For each weather variable (temperature, humidity, clouds, and wind), the hourly value is computed as a centered moving average of the values for the prior hour, the current hour, and the next hour. In test estimations, this three-hour average (MAPE = 2.29%) worked a bit better than a two-hour average (MAPE = 2.32%), which worked a bit better than the current hour reading alone (MAPE = 2.36%).

Starting with the 3-hour average for each hour, drybulb temperatures and relative humidity values are used to compute THI values for each hour.

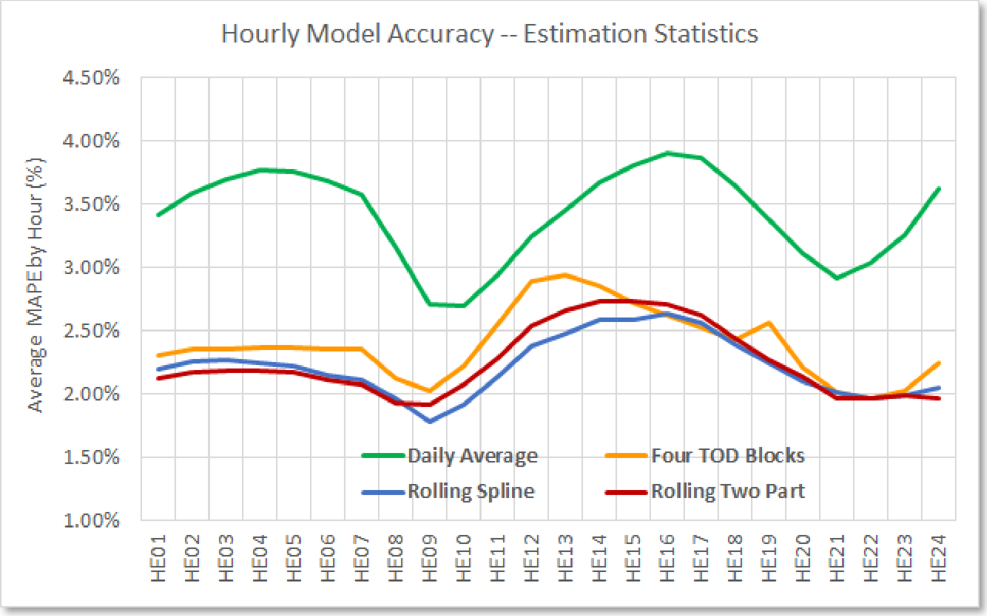
Rolling Spline Models. Starting with the 3-hour average drybulb values for heating and THI values for cooling, a full set of HD and TD variables are computed with 5 degree buckets. Base temperatures for HD are 65, 60, 55, 50, 45, 40, and 30. Base temperatures for TD are 55, 60, 65, 70, 75, 80, 85, 90.

HD and TD values in successive buckets are combined into a single HDSpline variable and a single TDSpline variable.

Rolling Two-Part Models. Starting with the 3-hour average drybulb values for heating and THI values for cooling, HD values are computed for each hour with two base temperatures (HD1 and HD2) and TD values are computed for each hour with two base temperatures (TD1 and TD2). The base temperature values are all at 5-degree points, and vary by hour, as shown in Figure 4-4.

Lag and interaction variables similar to those in the Daily Average model are then constructed for each hour of the day, using the 3-hour average weather variables.

FIGURE 4-4: ESTIMATION HOURLY MAPE STATISTICS – COMPARISON OF METHODS



Hour	DailyAvg Wthr	Four TOD Blocks	Rolling Spline	Rolling Two Part
HR00	3.42%	2.31%	2.20%	2.12%
HR01	3.59%	2.36%	2.26%	2.17%
HR02	3.69%	2.36%	2.27%	2.19%
HR03	3.77%	2.37%	2.24%	2.18%
HR04	3.76%	2.37%	2.22%	2.17%
HR05	3.68%	2.35%	2.15%	2.11%
HR06	3.57%	2.35%	2.11%	2.08%
HR07	3.16%	2.12%	1.96%	1.93%
HR08	2.71%	2.03%	1.78%	1.91%
HR09	2.69%	2.22%	1.92%	2.08%
HR10	2.94%	2.55%	2.14%	2.28%
HR11	3.24%	2.89%	2.38%	2.54%
HR12	3.45%	2.94%	2.48%	2.66%
HR13	3.67%	2.86%	2.59%	2.73%
HR14	3.81%	2.72%	2.59%	2.73%
HR15	3.90%	2.62%	2.64%	2.71%
HR16	3.86%	2.53%	2.56%	2.62%
HR17	3.65%	2.43%	2.39%	2.44%
HR18	3.38%	2.56%	2.25%	2.27%
HR19	3.11%	2.21%	2.10%	2.14%
HR20	2.92%	2.01%	2.01%	1.96%
HR21	3.04%	1.96%	1.97%	1.96%
HR22	3.26%	2.02%	1.99%	1.99%
HR23	3.62%	2.24%	2.05%	1.97%
Avg	3.41%	2.39%	2.22%	2.25%
#Coef	78	75	79-81	82

Two-part TD & HD
base temperatures

Hour	TD1	TD2	HD1	HD2
HE01	65	75	55	45
HE02	65	75	55	45
HE03	65	75	55	45
HE04	65	75	55	45
HE05	65	75	55	45
HE06	65	75	55	45
HE07	65	75	55	45
HE08	65	75	55	45
HE09	65	75	55	45
HE10	65	75	55	45
HE11	70	80	60	50
HE12	70	80	60	50
HE13	70	80	60	50
HE14	70	80	60	50
HE15	70	80	60	50
HE16	70	80	60	50
HE17	70	80	60	50
HE18	70	80	60	50
HE19	70	80	60	50
HE20	65	75	55	45
HE21	65	75	55	45
HE22	65	75	55	45
HE23	65	75	55	45
HE24	65	75	55	45

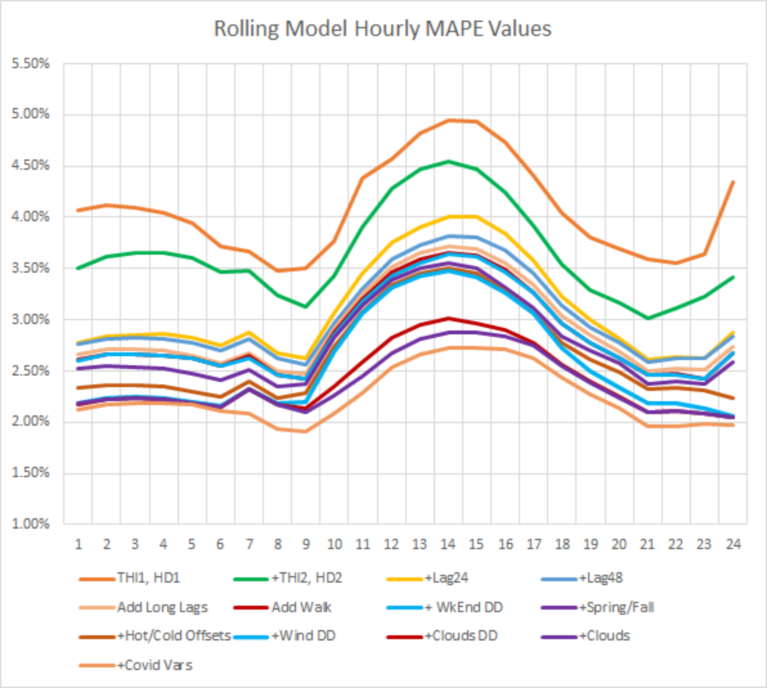
Recommendation: As shown in Figure 4-4 and the associated table, the method with TOD blocks performs much better than the Daily Average method. And the Rolling methods perform a bit better than the TOD-block method. As a result, we recommend using the rolling hourly approach. The complex rolling spline approach works slightly better than the two-part approach. Despite this slight accuracy advantage, we recommend the two-part approach because it is much simpler, it is easier to implement, and it is much easier to understand.

ROLLING TWO-PART MODEL: EXPLANATORY FACTOR CASCADE

Figure 4-5 shows a cascade of statistics for the rolling hourly Two-Part model as groups of explanatory factors are added sequentially. The chart shows the MAPE value for each hourly model and the associated table shows the average of these values across hours.

The first model which includes only the calendar-based factors and does not include any weather variables is not shown in the graph. The second model adds TD1 and HD1 variables for low powered degrees. The third model adds the TD2 and HD2 variables for higher powered degrees. Then Lag HD and TD values are added. This is followed by calendar and weather interaction variables. The last step, which adds a first order autoregressive error term is not shown in the graph.

FIGURE 4-5: ROLLING TWO-PART MODEL, EXPLANATORY FACTOR CASCADE STATISTICS



Rolling Model Components	Average MAPE
Month, DayType, Hols	10.31%
Add THI1, HD1	4.08%
Add THI2, HD2	3.64%
Add Lag24 DD	3.10%
Add Lag48 DD	3.02%
Add Long Lags	2.92%
Add Month Trends	2.87%
Add WkEnd Shift	2.86%
Add Spring/Fall Shifts	2.77%
Add Hot/Cold Lag Offsets	2.66%
Add Wind * HD,CD	2.58%
Add Clouds * HD,CD	2.41%
Add Clouds	2.37%
Add Covid Vars	2.25%
Add AR1	2.04%

This cascade reveals the accuracy gain that results as each variable group that is added. The chart shows hourly pattern of these accuracy impacts. For example, the large gap toward the bottom (from light blue to red) reflects the influence of adding the cloud interaction variables. These have the greatest impact in the day-time hours (between HE9 and HE18), reducing the mid-day MAPE values from 3.5% to 3.0%.

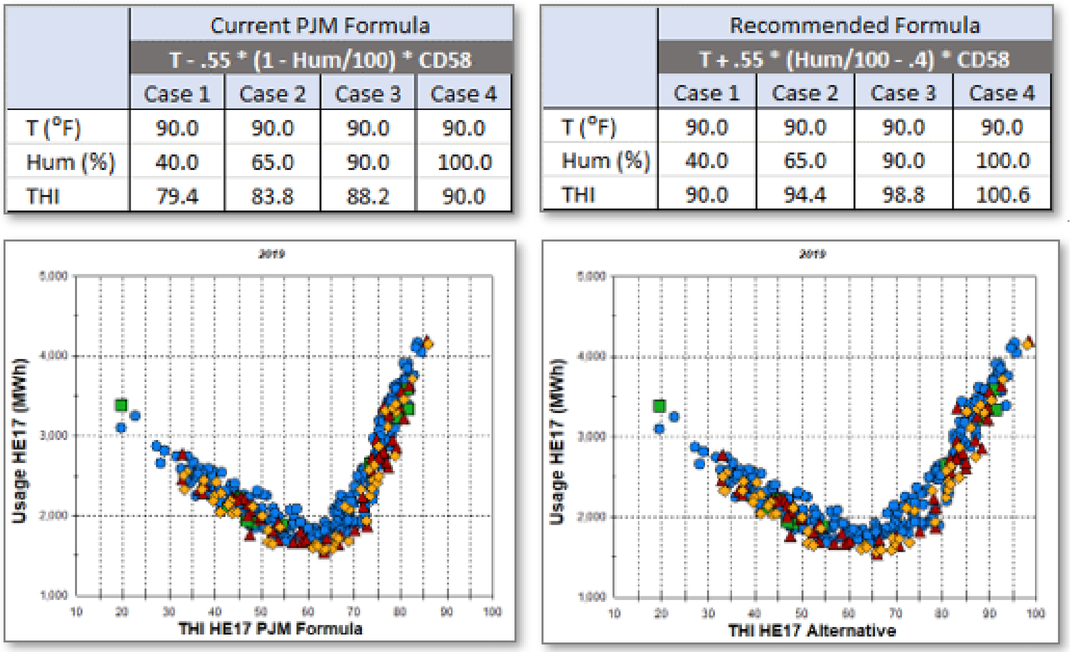
TEMPERATURE-HUMIDITY INDEX CONSTRUCTION

There are a variety of THI-type indexes that have been used over the years. There are formulas that use drybulb and wetbulb temperatures, drybulb and dewpoint temperatures, and drybulb and humidity. The index currently used by PJM falls into the third category and is shown on the left-hand side of Figure 4-6. This formula has some nice properties, in that humidity interacts with temperature. As a result, the higher the temperature, the more important an extra percent of humidity becomes.

Although it is not obvious, this formula has the unfortunate effect of compressing the temperature variable rather than creating a higher “feels-like” type of variable. This is seen in the four cases that are shown in Figure 4-6. All cases have a drybulb temperature of 90 degrees. In the first case, humidity is at 40%, which is about as low as humidity gets in the DPL zone in summer months. At 40% humidity, the PJM formula gives a THI value of 79.4. As humidity levels rise above 40%, THI values increase and hit their highest value at 100%, at which point the THI value is the same as the drybulb temperature.

The alternative formula works differently. At humidity levels rise above 40%, the THI temperature goes above 90 degrees. At the extreme of 90 degrees and 100% humidity, the THI reached a level over 100 degrees.

FIGURE 4-6: THI FORMULAS AND HE17 SCATTER PLOTS



	Current PJM Formula			
	T - .55 * (1 - Hum/100) * CD58			
	Case 1	Case 2	Case 3	Case 4
T (°F)	90.0	90.0	90.0	90.0
Hum (%)	40.0	65.0	90.0	100.0
THI	79.4	83.8	88.2	90.0

	Recommended Formula			
	T + .55 * (Hum/100 - .4) * CD58			
	Case 1	Case 2	Case 3	Case 4
T (°F)	90.0	90.0	90.0	90.0
Hum (%)	40.0	65.0	90.0	100.0
THI	90.0	94.4	98.8	100.6

The compression effect is clear in the graphs, which show scatter plots for HE17 loads against the HE17 THI value. The scatter plots show about 4 years of data from mid-2017 to mid-2021. The cold sides of the two graphs (temperatures below 58 degrees) are identical because the humidity component only impacts warmer temperatures. In the left-hand chart, which uses the current PJM formula, THI cooling impacts appear to begin a bit before 70 and the highest THI value is at 85, giving a 15-degree range. With the alternative formula, the highest values are at about 98, giving close to a 30-degree range. This makes it easier to see the difference between low powered degrees (70 to 80 using the alternative definition) and the high-powered degrees (degrees above 80).

By choosing different base temperatures for the two approaches, the two formulas can be made to work about the same in terms of accuracy. But the alternative definition makes it easier to visualize the use of multi-part TD variables on the hot side. Also, we believe that the alternative definition is easier to understand, because it is consistent with our intuition that higher levels of humidity make it feel hotter than the drybulb air temperature. As a result, the following recommendation is based more on convenience and consistency with common sense than performance improvement.

Recommendation: Use the alternative THI formula shown above. As time allows, optimize the parameters in this formula (the .55, the -.4, and the 58-degree base for the temperature interaction), noting that the best values of these parameters may vary across zones. Also, as time allows research alternatives using the same type of interactive specification with the more stable measures of humidity, like dewpoint temperature and moisture content.

WIND/TEMPERATURE INTERACTIONS

PJM currently uses a Wind-Adjusted Temperature (WWP) variable. It is defined as follows:

- WWP = T - .5 * Max (Wind – 10, 0)

This variable is used to compute heating degree values, which come into play in the winter for forecasting energy and system peaks. This variable is the only place that wind appears in the modeling. This implies:

- Wind only matters when it is cold
- Wind does not matter until it exceeds 10 MPH
- Beyond 10 MPH, each additional MPH is like a 0.5-degree temperature decline

In terms of the effect of wind on building HVAC systems, there are at least two effects. First, when it is still, there is a thin layer of air surrounding the building that acts like an insulating layer and that is heated when the sun is shining on the building surface.

When it is cold and cloudy, this layer is warmer than the surrounding air. When the wind blows, this layer of insulation is removed, which increases the heating load.

When it is warm this layer is much hotter than the surrounding air on the roof and sunny side of the building. When the wind blows, it removes this superheated layer, which reduces the cooling load.

These effects probably start to be felt by building systems well below 10 MPH.

Second, wind impacts infiltration levels. High levels of wind result in higher rates of air turnover in buildings that are not perfectly sealed. When humidity levels are high, this has the further effect of replacing dry cooler air inside with warmer humid are from outside.

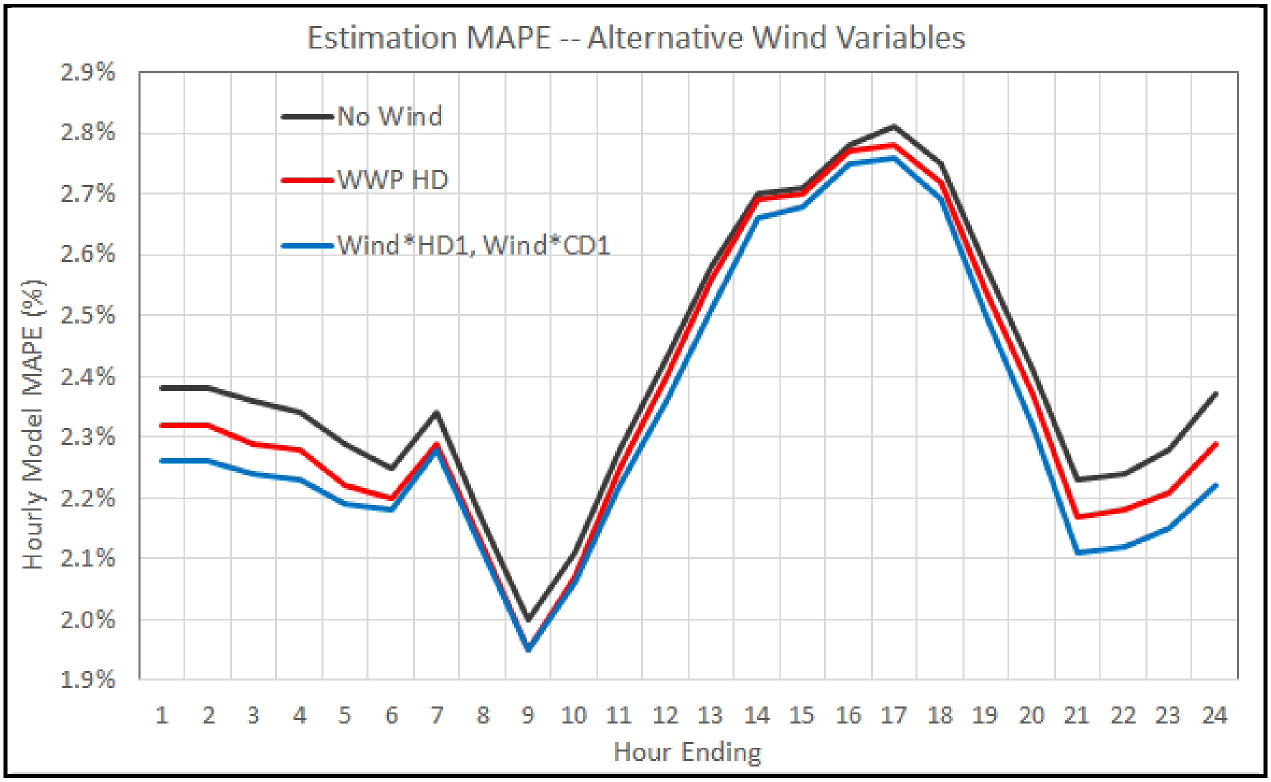
To evaluate this, we estimated models that interact wind speeds with HD and TD variables in each hour. The two variables used are:

- ColdWind = WindSpeed ×HD1
- HotWind = WindSpeed × TD1

On the heating side, the estimated coefficients are negative and significant throughout the day, implying that more wind raises the heating load in all hours when it is cold. The slopes are weaker during the mid-day hours, possibly reflecting the influence of sunlight on building surface temperatures during the day. On the cooling side, coefficients are positive and significant in the night hours and negative and significant in the mid-day hours. During the day, the wind blows the superheated air on sunny building surfaces away, lowering the cooling load. At night, wind causes higher infiltration of warm and possibly humid air, increasing the cooling load.

Figure 4-7 shows MAPE statistics without Wind (black line), with the current wind variable (red line) and the alternative hot side and cold side wind variables defined above.

FIGURE 4-7: IMPACT OF WIND VARIABLES ON MODEL ACCURACY



Inclusion of the cold-side wind variables improves model performance in all hours, with the biggest impacts in the nighttime hours. Use of the alternative variables on both the cold and hot sides result in a further accuracy improvement, with the biggest impacts in the afternoon and nighttime hours.

Recommendation: Use the alternative wind variables on both the cold and hot side. As time allows, optimize the parameters in this formula (the base temperatures in the TD and HD variables that interact with wind speed).

CLOUD COVER/TEMPERATURE INTERACTIONS

Cloud cover variables are not currently included in the PJM models. These are powerful variables, especially in the mid-day and afternoon hours. Cloud cover has three main impacts on utility loads:

On a cold day, clouds interrupt the warming effect of solar radiation on building surfaces. This will result in higher electricity use by electric heating equipment and circulating fans for central heating systems.

On a hot day, clouds interrupt the warming effect of solar radiation on building surfaces. This will result in lower electricity use by electric cooling equipment.

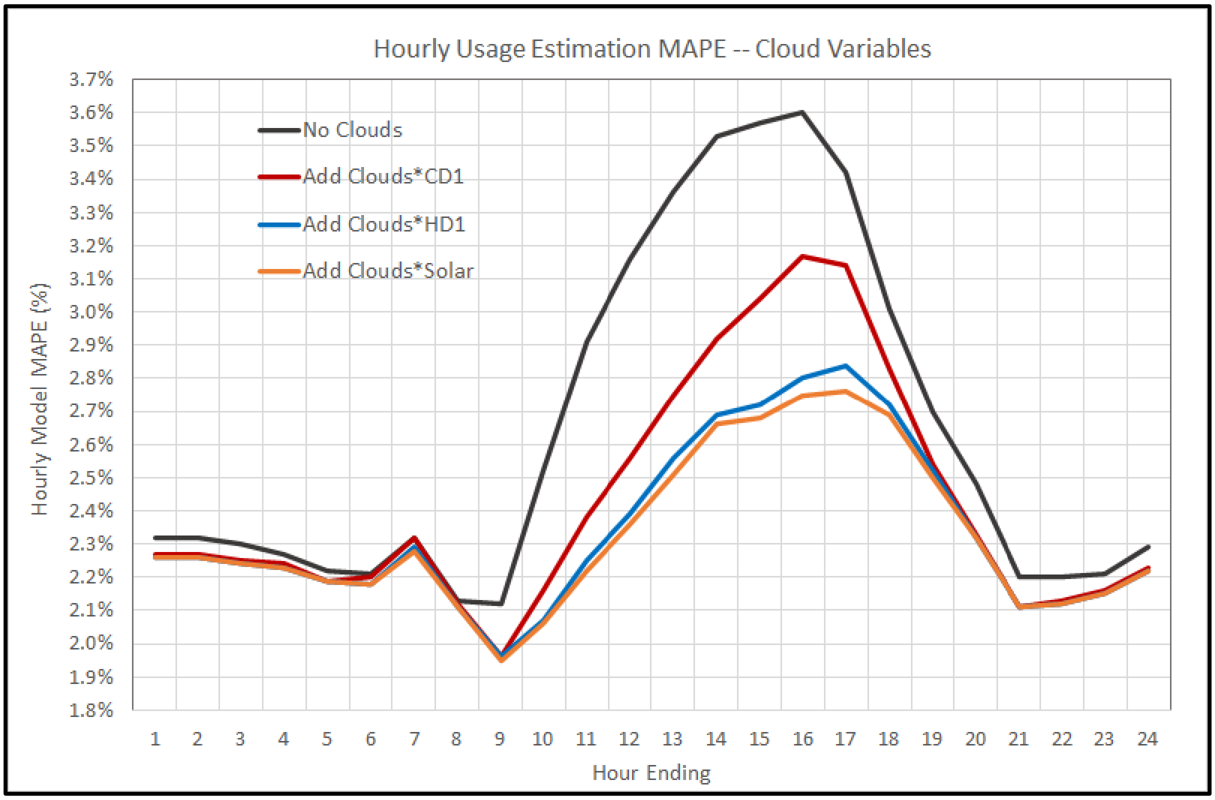
During day-time hours, clouds reduce generation levels for behind the meter solar systems, which will increase the proportion of usage supplied by utility generation sources.

In the early work on this project, we estimated models using utility load, and the third effect was large (as big as 200 MW) and significant. This is shown in the explanatory factor cascade presented above. However, as we will see below, when the explanatory variable is usage (end-use consumption) rather than utility load, the third effect is likely to be small.

Clouds have a further effect of moderating the decline in air temperature at night. But this effect is captured by the measured temperature variable.

Figure 4-8 shows MAPE statistics with usage (reconstituted load) as the variable to be explained. Hourly accuracy statistics are shown for models without Clouds (black line), models with clouds interacted with warm temperatures (red line), and models with clouds interacted with both warm and cold temperatures (blue line).

FIGURE 4-8: IMPACT OF CLOUD VARIABLES ON MODEL ACCURACY



As Figure 4-8 shows, the impact of clouds on model accuracy occurs mostly in the day-time hours, with the biggest impacts about mid-day. The improvement from the black line (average MAPE = 2.64%) to the red line (average MAPE = 2.43%) shows the impacts of clouds on warm days. The further improvement from the red line to the blue line (average MAPE = 2.34%) shows the further impact of clouds on cold days. The final step to the orange line (average MAPE = 2.33%) shows that clouds interacted with clear-sky solar irradiance have a minimal further effect, as expected.

Recommendation: Use the cloud variables interacting with cooling and heating degrees to account for the impact of clouds on hourly energy usage. As time allows, optimize the parameters in this formula (the base temperatures in the TD and HD variables that interact with cloud cover).

INTERACTING HOURLY MODEL VARIABLES WITH SAE EXPLANATORY FACTORS

The following figure shows an example of an estimated hourly model that is built to include SAE variable indexes. Three daily variables are included in the model.

Cooling Index: Accounts for changes in saturation, efficiency, and utilization of cooling equipment (room air, central air, and heat pumps). This index is interacted with the cooling degree variables

(TD1, TD2, LagTD) and the associated cooling degree interaction variables (Wind, Clouds, Weekend, Spring, Fall, etc.)

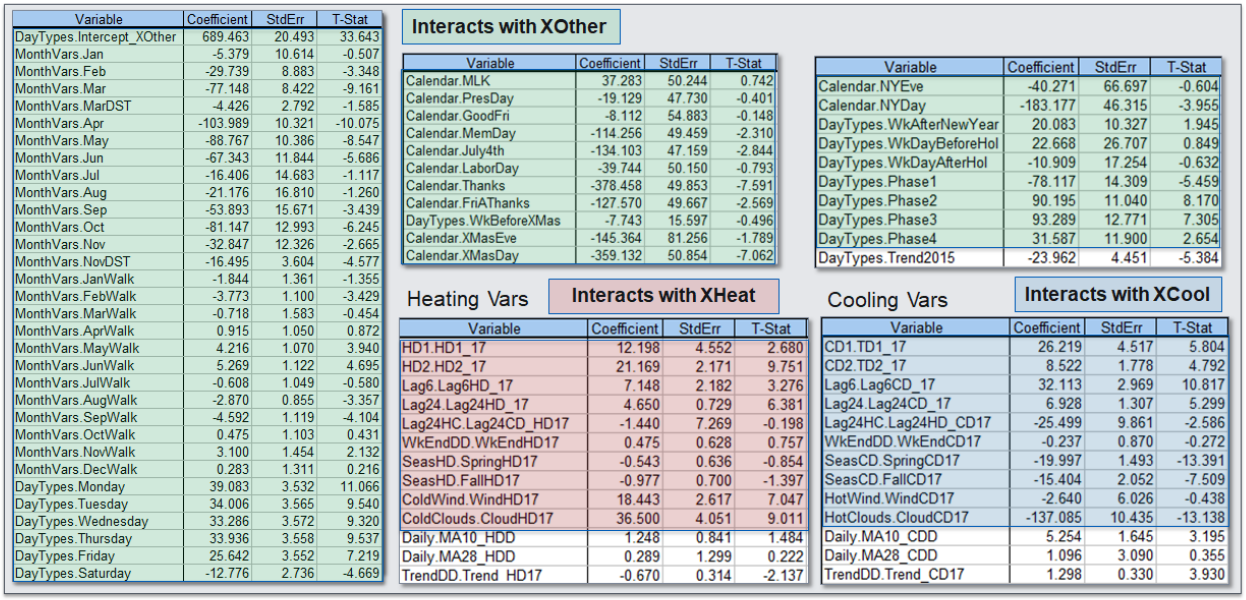
Heating Index: Accounts for changes in saturation, efficiency, and utilization of heating equipment (resistance heating and heat pumps). This index is interacted with the heating degree variables (HD1, HD2, LagHD) and the associated heating degree interaction variables (Wind, Clouds, Weekend, Spring, Fall, etc.)

Base (Other) Index: Accounts for changes in saturation, efficiency, and utilization of non_HVAC equipment (water heating, cooking, refrigeration, clothes washing and drying, dishwashers, office equipment, lighting, and miscellaneous). This index is interacted with the Constant, Monthly binary variables, day-of-week binary variables, monthly trends, holidays, and Covid phases.

Figure 4-9 provides as an example, the HE18 model (note: the rolling hourly explanatory factors in the model are labeled as hour beginning 17). The variables that are interacted with the Base Index are highlighted in green. The variables that are interacted with the Heating Index are highlighted in red. The variables that are interacted with the Cooling Index are highlighted in blue.

The variables that have clear backgrounds are not interacted with the SAE index variables. Specifically, the Trend, TrendHD, and TrendCD terms are included to allow the model to pick up any trends in the data that are not explained by the SAE variables.

FIGURE 4-9: EXAMPLE OF ESTIMATED MODEL (HE18)



Variable	Coefficient	StdErr	T-Stat
DayTypes.Intercept_XOther	689.463	20.493	33.643
MonthVars.Jan	-5.379	10.614	-0.507
MonthVars.Feb	-29.739	8.883	-3.348
MonthVars.Mar	-77.148	8.422	-9.161
MonthVars.MarDST	-4.426	2.792	-1.585
MonthVars.Apr	-103.989	10.321	-10.075
MonthVars.May	-88.767	10.386	-8.547
MonthVars.Jun	-67.343	11.844	-5.686
MonthVars.Jul	-16.406	14.683	-1.117
MonthVars.Aug	-21.176	16.810	-1.260
MonthVars.Sep	-53.893	15.671	-3.439
MonthVars.Oct	-81.147	12.993	-6.245
MonthVars.Nov	-32.847	12.326	-2.665
MonthVars.NovDST	-16.495	3.604	-4.577
MonthVars.JanWalk	-1.844	1.361	-1.355
MonthVars.FebWalk	-3.773	1.100	-3.429
MonthVars.MarWalk	-0.718	1.583	-0.454
MonthVars.AprWalk	0.915	1.050	0.872
MonthVars.MayWalk	4.216	1.070	3.940
MonthVars.JunWalk	5.269	1.122	4.695
MonthVars.JulWalk	-0.608	1.049	-0.580
MonthVars.AugWalk	-2.870	0.855	-3.357
MonthVars.SepWalk	-4.592	1.119	-4.104
MonthVars.OctWalk	0.475	1.103	0.431
MonthVars.NovWalk	3.100	1.454	2.132
MonthVars.DecWalk	0.283	1.311	0.216
DayTypes.Monday	39.083	3.532	11.066
DayTypes.Tuesday	34.006	3.565	9.540
DayTypes.Wednesday	33.286	3.572	9.320
DayTypes.Thursday	33.936	3.558	9.537
DayTypes.Friday	25.642	3.552	7.219
DayTypes.Saturday	-12.776	2.736	-4.669

Interacts with XOther

Variable	Coefficient	StdErr	T-Stat
Calendar.MLK	37.283	50.244	0.742
Calendar.PresDay	-19.129	47.730	-0.401
Calendar.GoodFri	-8.112	54.883	-0.148
Calendar.MemDay	-114.256	49.459	-2.310
Calendar.July4th	-134.103	47.159	-2.844
Calendar.LaborDay	-39.744	50.150	-0.793
Calendar.Thanks	-378.458	49.853	-7.591
Calendar.FriAThanks	-127.570	49.667	-2.569
DayTypes.WkBeforeXMas	-7.743	15.597	-0.496
Calendar.XMasEve	-145.364	81.256	-1.789
Calendar.XMasDay	-359.132	50.854	-7.062

Variable	Coefficient	StdErr	T-Stat
Calendar.NYEve	-40.271	66.697	-0.604
Calendar.NYDay	-183.177	46.315	-3.955
DayTypes.WkAfterNewYear	20.083	10.327	1.945
DayTypes.WkDayBeforeHol	22.668	26.707	0.849
DayTypes.WkDayAfterHol	-10.909	17.254	-0.632
DayTypes.Phase1	-78.117	14.309	-5.459
DayTypes.Phase2	90.195	11.040	8.170
DayTypes.Phase3	93.289	12.771	7.305
DayTypes.Phase4	31.587	11.900	2.654
DayTypes.Trend2015	-23.962	4.451	-5.384

Heating Vars

Interacts with XHeat

Variable	Coefficient	StdErr	T-Stat
HD1.HD1_17	12.198	4.552	2.680
HD2.HD2_17	21.169	2.171	9.751
Lag6.Lag6HD_17	7.148	2.182	3.276
Lag24.Lag24HD_17	4.650	0.729	6.381
Lag24HC.Lag24CD_HD17	-1.440	7.269	-0.198
WkEndDD.WkEndHD17	0.475	0.628	0.757
SeasHD.SpringHD17	-0.543	0.636	-0.854
SeasHD.FallHD17	-0.977	0.700	-1.397
ColdWind.WindHD17	18.443	2.617	7.047
ColdClouds.CloudHD17	36.500	4.051	9.011
Daily.MA10_HDD	1.248	0.841	1.484
Daily.MA28_HDD	0.289	1.299	0.222
TrendDD.Trend_HD17	-0.670	0.314	-2.137

Cooling Vars

Interacts with XCool

Variable	Coefficient	StdErr	T-Stat
CD1.TD1_17	26.219	4.517	5.804
CD2.TD2_17	8.522	1.778	4.792
Lag6.Lag6CD_17	32.113	2.969	10.817
Lag24.Lag24CD_17	6.928	1.307	5.299
Lag24HC.Lag24HD_CD17	-25.499	9.861	-2.586
WkEndDD.WkEndCD17	-0.237	0.870	-0.272
SeasCD.SpringCD17	-19.997	1.493	-13.391
SeasCD.FallCD17	-15.404	2.052	-7.509
HotWind.WindCD17	-2.640	6.026	-0.438
HotClouds.CloudCD17	-137.085	10.435	-13.138
Daily.MA10_CDD	5.254	1.645	3.195
Daily.MA28_CDD	1.096	3.090	0.355
TrendDD.Trend_CD17	1.298	0.330	3.930

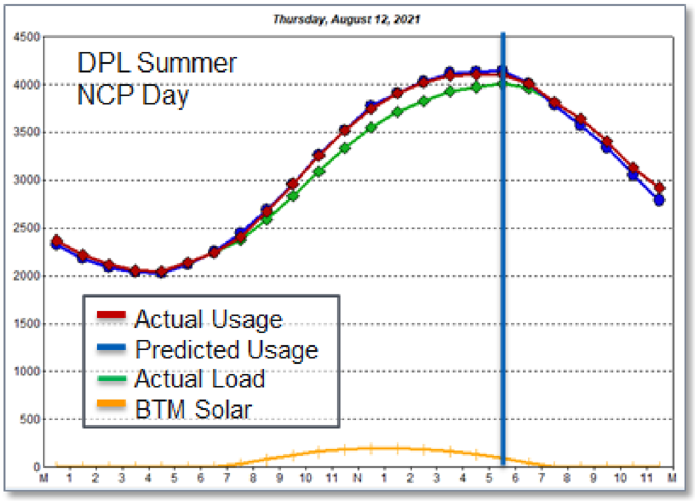
PEAK DAY PREDICTED VALUES AND POST PROCESSING

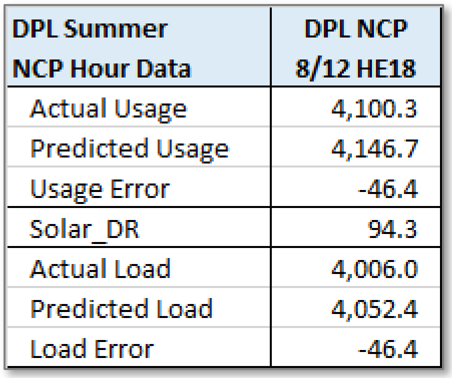
To evaluate the power of the estimated models on peak days, the following figures focus in on the actual 2021 peak days for DPL and PJM. There are three figures, and each figure shows hourly data for the following four series:

- Actual Usage: This is the estimate of actual usage (reconstituted load), which is measured utility load adjusted for estimated DR effects plus estimated behind-the-meter solar generation.
- Predicted Usage: This is the predicted value from the hourly usage models with explanatory factors interacted with SAE index variables.
- Actual Load: This is the measured DPL zone load, representing the fraction of total usage that is supplied by zone generation resources.
- Solar Generation: This is the estimate of hourly energy supplied by behind-the-meter solar generation.

Figure 4-10 shows the DPL zone peak day, August 12, 2021. Estimated usage on this day is relatively flat between HE16 and HE18. The estimated BTM solar generation, however, is ramping down from 167 MWh to 133 MWh to 94 MWh over these three hours. The hourly models correctly predict that the usage peak occurs on HE17 and that the zone peak load occurs on HE18. In the NCP hour, the model over predicts the zone load by about 46 MWh (1.2%).

FIGURE 4-10: HOURLY MODEL RESULTS – SUMMER 2021 NCP

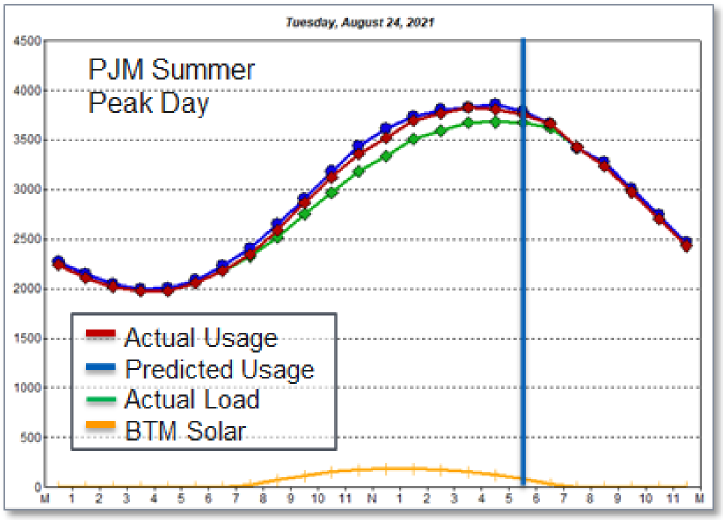




DPL Summer NCP Hour Data	DPL NCP 8/12 HE18
Actual Usage	4,100.3
Predicted Usage	4,146.7
Usage Error	-46.4
Solar_DR	94.3
Actual Load	4,006.0
Predicted Load	4,052.4
Load Error	-46.4

Figure 4-11 shows the DPL zone usage and loads on the PJM peak day, August 24, 2021. On this day, the DPL zone usage peaked in HE16, the measured zone load peaked in HE17, and the PJM peak occurred in HE18. The CP statistics provided to the right of the chart are for HE18, the hour of the annual PJM peak. In the CP hour, the hourly model overpredicts the DPL zone load by about 27 MWh (.7%).

FIGURE 4-11: HOURLY MODEL RESULTS – SUMMER 2021 CP



DPL Summer CP Hour Data	DPL CP 8/24 HE18
Actual Usage	3,753.6
Predicted Usage	3,781.0
Usage Error	-27.5
Solar_DR	83.6
Actual Load	3,670.0
Predicted Load	3,697.5
Load Error	-27.5

There is a significant difference between the DPL loads on the DPL peak day (Aug 12) and the PJM peak day (Aug 24). Weather statistics for the peak hours on these days are shown in Figure 4-12. The main factor is the difference in average drybulb temperature on these days (93 degrees on the DPL peak day and 89 degrees on the day of the PJM peak day). This difference of nearly 4 degrees persisted throughout the afternoon and evening hours on these days.

FIGURE 4-12: NCP AND CP HOUR WEATHER

Summer Peak Hour Weather Variables	DPL 2021 NCP 8/12 HE18	PJM 2021 Peak 8/24 HE18
AvgDB Temperature (Deg F)	92.7	88.8
Relative Humidity (%)	54.3	53.3
Moisture Content (mmHg)	21.3	19.1
Temp Hum Index (Deg F)	95.4	91.1
Wind Speed (MPH)	11.4	8.4
Cloud Cover (Octas)	0.12	1.6

The difference in loads and the implied coincidence factors are summarized in Figure 4-13. The table focuses on the measured loads. The coincidence factor is the ratio of the CP value to the NCP value. For the summer peak, the actual coincidence factor is 91.6% and the predicted coincidence factor is 91.2%. This are both well below the typical coincidence factor for DPL and are toward the bottom of the range generated by the multi-year weather simulations.

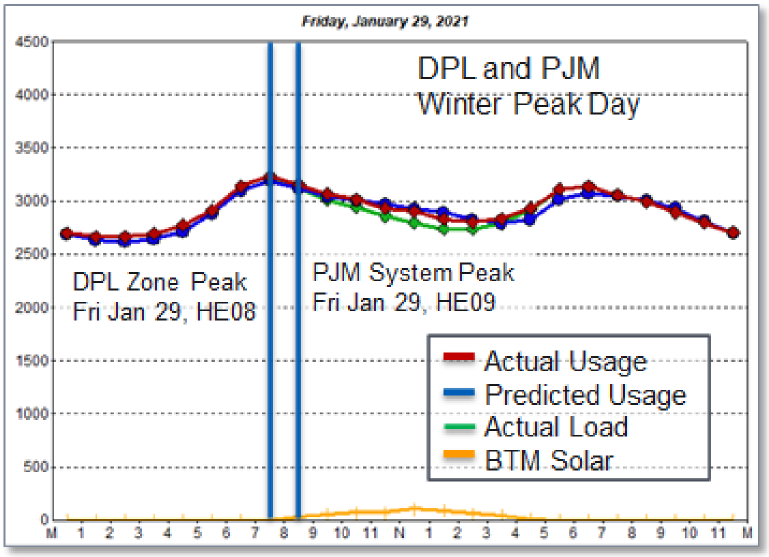
FIGURE 4-13: STATISTICS FOR 2021 SUMMER CP COINCIDENCE FACTOR

DPL Summer Peak Hour Results	Date/Time of NCP	NCP	CP 8/24 HE18	Coincidence CP/NCP
Actual Load	8/12 HE18	4,006.0	3,670.0	91.6%
Predicted Load	8/12 HE18	4,052.4	3,697.5	91.2%
Error	0	-46.4	-27.5	0.4%
Error %		-1.2%	-0.7%	

Figure 4-14 shows the DPL and PJM winter peak day (January 29, 2021). Both peaks occurred on the same day, but at different hours (HE08 and HE09, respectively). The hourly model underpredicted the load in these hours by 39 MWh (1.2%) for the NCP and 43 MWh (1.4%) for the CP. Behind-the-meter solar generation ramped up between the two hours from 2 MWh to 36 MWh.

In terms of coincidence, the hourly model correctly predicts the DPL peak to occur in the hour before the PJM Peak. The predicted winter peak coincidence factor (96.5% is within .1% of the actual measured coincidence factor (96.6%).

FIGURE 4-14: HOURLY MODEL RESULTS – WINTER 2021 NCP AND CP



	DPL NCP 1/29 HE08
Actual Usage	3,232.8
Predicted Usage	3,193.4
Usage Error	39.4
Solar_DR	1.8
Actual Load	3,231.0
Predicted Load	3,191.6
Load Error	39.4

	DPL CP 1/29 HE09
Actual Usage	3,158.0
Predicted Usage	3,115.0
Usage Error	43.0
Solar_DR	36.0
Actual Load	3,122.0
Predicted Load	3,079.0
Load Error	43.0

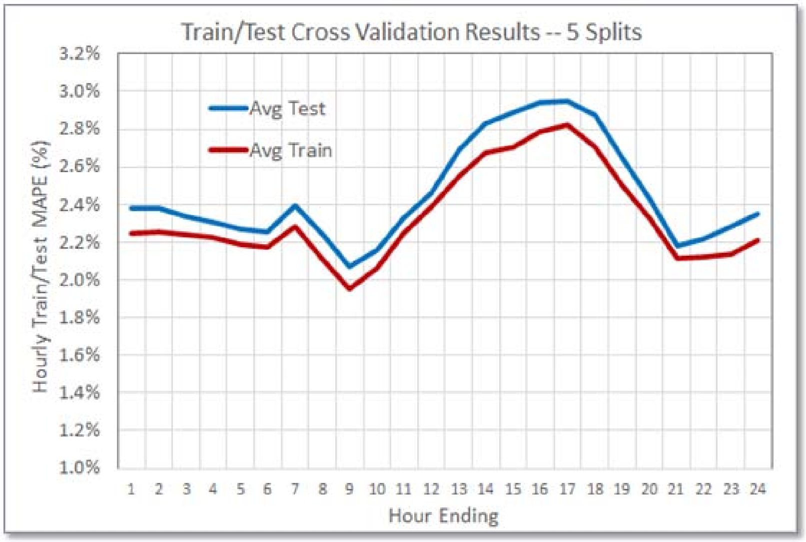
DPL Winter Peak Hour Results	Date/Time of NCP	NCP	CP 1/29 HE09	Coincidence CP/NCP
Actual Load	1/29 HE08	3,231.0	3,122.0	96.6%
Predicted Load	1/29 HE08	3,191.6	3,079.0	96.5%
Error	0	39.4	43.0	0.2%
Error %		1.2%	1.4%	

The accuracy results observed for the 2021 peak days are better than expected given that the average MAPE values for the hourly models are in the 2% to 3% range, depending on the hour. So, it is probably unrealistic to expect results this good for all years. However, the results do show that the hourly modeling approach is capable of explaining NCP, CP, and coincidence factor outcomes. By extension, simulations with alternative actual weather patterns should realistically represent the range of coincidence results that would occur under varied conditions. As part of this project, we did not estimate models for PJM zones other than DPL, nor did we analyze model accuracy for other zones in terms of peak loads and coincidence factors.

MODEL TESTING

The final step with the hourly models is out-of-sample testing. This was performed by running 5 test cases, with each case withholding about 20% of the data. Models were estimated using the training subset of the data in each case and accuracy statistics were computed using the test subset of the data in each of the cases. Figure 4-15 present the train and test statistics averaged across the 5 test cases.

FIGURE 4-15: HOURLY MODEL RESULTS – WINTER 2021 NCP AND CP



	Average	Test1	Test2	Test3	Test4	Test5
All Data Estimation	2.34%					
Average Train	2.34%	2.35%	2.35%	2.33%	2.31%	2.34%
Average Test	2.45%	2.39%	2.48%	2.46%	2.52%	2.41%

Hour	Average Train	Average Test
HR00	2.25%	2.38%
HR01	2.26%	2.38%
HR02	2.24%	2.34%
HR03	2.23%	2.30%
HR04	2.19%	2.27%
HR05	2.18%	2.26%
HR06	2.28%	2.39%
HR07	2.11%	2.24%
HR08	1.95%	2.07%
HR09	2.07%	2.16%
HR10	2.25%	2.33%
HR11	2.39%	2.46%
HR12	2.55%	2.69%
HR13	2.67%	2.83%
HR14	2.70%	2.89%
HR15	2.78%	2.94%
HR16	2.83%	2.95%
HR17	2.71%	2.88%
HR18	2.51%	2.66%
HR19	2.33%	2.43%
HR20	2.11%	2.18%
HR21	2.12%	2.22%
HR22	2.13%	2.28%
HR23	2.21%	2.35%
Average	2.34%	2.45%

As the statistics show, the accuracy for the test cases is close to the estimation (training) accuracy. Averaged across all tests and hours, the test MAPE is about .11% larger than the training MAPE. This indicates that the hourly models are robust (generalize well out of sample). This result (accuracy loss of about .10%) is what we generally expect to see in a model that is well specified in terms of nonlinearities and important interactions and that is not over specified.

5 RESHAPING DEMAND: MODELING TECHNOLOGY IMPACTS

EXTENDED WEATHER SIMULATION FRAMEWORK

The current LTFS forecast process utilizes a multi-year weather simulation framework to construct Cumulative Distribution Functions (CDF) daily energy, daily noncoincident zone peak (NCP), and daily CP (zone load at the time of the daily PJM peak). For each zone, CP models are estimated for daily loads coincident with the Locational Deliverability Area (LDA) peak and coincident with the overall PJM system peak.

The application of the CP and NCP modelling is complicated by the saturation of new technologies (PV and EV in particular) that modify the timing of system energy requirements. In particular, the penetration of behind the meter solar systems is changing both the timing of zone peaks and the coincidence factors across zones. The best way to understand the impact of these changes is by simulating the impact of new technologies on hourly loads. Summarized below are the high-level steps of the recommended Extended Weather Simulation Framework.

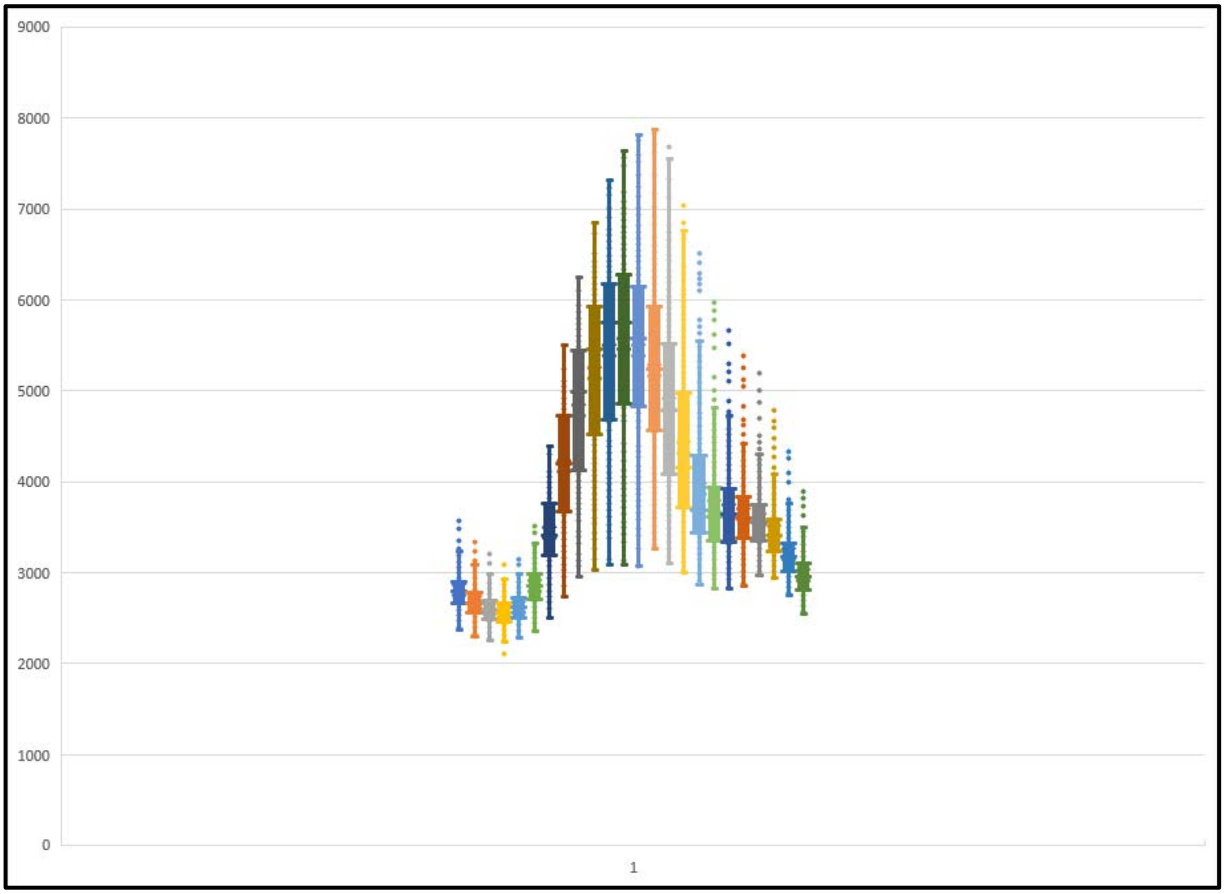
Step 1. Create Weather Forecast Simulation Traces by EDC and Forecast Year. Under this step the existing Multi-year Weather Simulation framework is extended to include hourly Solar Generation Capacity factors that are consistent with the corresponding hourly temperature, wind speed, wind direction, humidity, precipitation, and cloud cover or Global Horizontal Irradiance. The Solar Generation Capacity factors when multiplied by forecasts of embedded solar PV capacity provides an estimate of hourly embedded solar PV generation. These solar PV generation values reduce baseline forecasts of hourly reconstituted loads derived from the hourly load forecast models. The result is a forecast of PJM generation requirements net of distributed solar PV generation.

In a similar fashion, any new technologies that are weather sensitive (e.g., electric heat pumps) should have utilization or capacity factors that are consistent with the hourly weather data.

Step 2. For each EDC, Weather Trace and Forecast Year Simulate EDC-Level Hourly Reconstituted Loads using the Hourly Load models and rotated weather data. For each Weather Trace and Forecast Year Construct PJM Total & PJM Region Hourly Loads by summing across EDCs by Forecast Year, Weather Trace and EDC.

Step 2.a. For PJM Total, PJM Region and for each EDC and Forecast Year, construct hourly Probability Density Functions (PDF) and Cumulative Distribution Functions (CDF) of Reconstituted loads. An example of the PDF for a single EDC and forecast year is presented in Figure 5-1. In this figure each hourly vertical slice represents the PDF of 365 reconstituted loads in that hour.

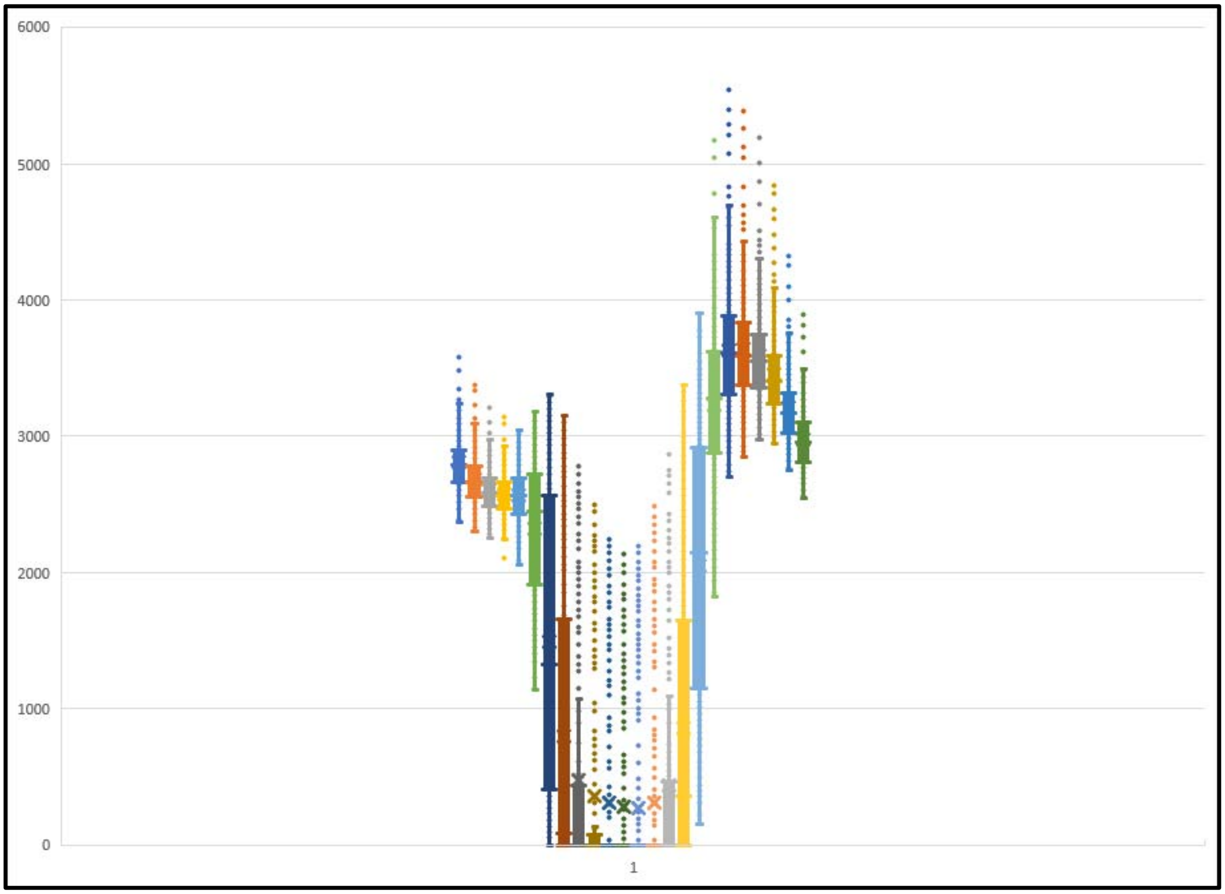
FIGURE 5-1: EXAMPLE PDF OF RECONSTITUTED LOADS FOR A SINGLE EDC AND FORECAST YEAR



Step 3. For each EDC, subtract off simulated EDC-Level embedded hourly solar PV generation Weather Trace and Forecast Year. For each Weather Trace and Forecast Year Construct PJM Total & PJM Region Hourly Loads by summing across EDCs by Forecast Year, Weather Trace and EDC.

Step 3.a. For PJM Total, PJM Region and for each EDC and Forecast Year, construct hourly PDF and CDF of Net Loads (i.e., Reconstituted loads less embedded solar PV generation). An example of the PDF for a single EDC and forecast year is presented in Figure 5-2. In this figure each hourly vertical slice represents the PDF of 365 net loads in that hour.

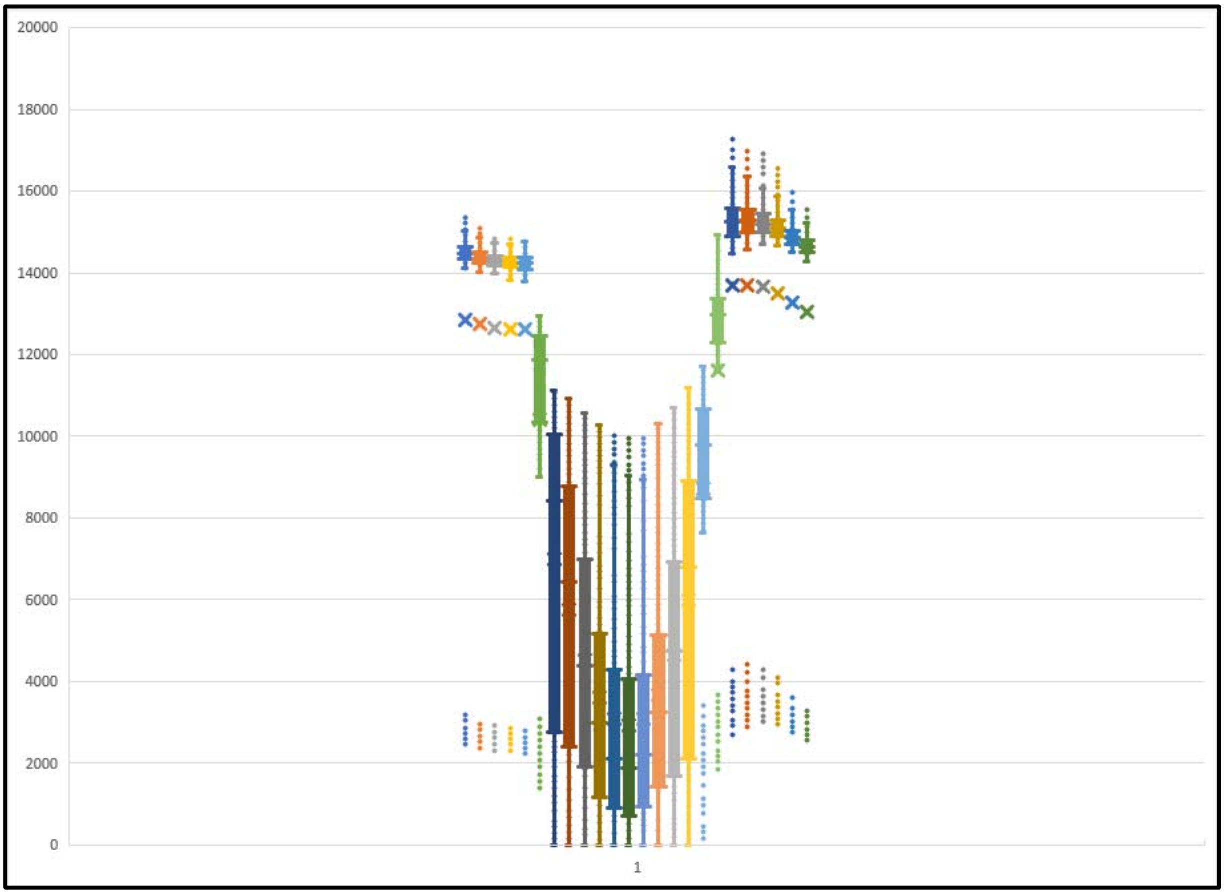
FIGURE 5-2: EXAMPLE SOLAR PV GENERATION ON NET LOADS FOR A SINGLE EDC



Step 4 – Step N. Here N represents the total number of technology impacts that are simulated. For each EDC, Layer in the hourly load impact of the remaining Weather Sensitive and Non-Weather Sensitive Technology Impact Shapes by Weather Trace and Forecast Year. For each Weather Trace and Forecast Year Construct PJM Total & PJM Region Hourly Loads by summing across EDCs by Forecast Year, Weather Trace and EDC.

Step 4.a. – Step N.a. At each step, form PDF and CDF values of the resulting hourly loads by PJM Total, PJM Region, and each EDC and Weather Forecast Year. An example of the PDF for a single EDC and forecast year is presented in Figure 5-3. In this figure each hourly vertical slice represents the PDF of 365 net loads in that hour after residential, commercial, and fleet EV Charging is added in.

FIGURE 5-3: EXAMPLE OF EV CHARGING IMPACT ON NET LOADS FOR A SINGLE EDC



6 MODELING ISSUES

The Market Participants identified several issues to be addressed as part of the study. These issues include:

- Measuring Forecast Accuracy,
- Weather Normalization,
- Capturing Impacts of Energy Efficiency Programs,
- Accounting for Temperature Trends, and
- Large Load Adjustments.

MEASURING FORECAST ACCURACY

Forecast errors for an hourly SAE model can be decomposed into three broad categories:

- Actual weather deviations from "normal"
- Economic growth deviations from forecast
- Other, including SAE saturation and efficiency forecast errors, specification errors, measurement errors, and statistical model errors.

Actual data for the first category (weather) are available on a near real time basis. Actual data for economic growth are available with varying lags and revision cycles. Updated estimates for the SAE inputs are produced annually, but the underlying research that leads to major updates take several years to develop and process, and as a result, we place these in the Other category.

The PJM zone and system forecasts are developed using the weather simulation approach, and the final forecast values for energy, NCP, and CP variables are derived by post processing these data. The best way to judge the accuracy of the underlying model that is used in the weather simulations is to substitute in the actual hourly weather that occurred and, if available, the actual economic variable values. Then compare the model predicted values to the actual values.

For energy and NCP values, this comparison is relatively straightforward. First run the hourly models with actual weather and economic data that are available. Then subtract out the estimated BTM hourly solar generation. Then compute monthly energy and NCP values for each zone and compare these results with the actual measured load values.

For the CP values, more post processing is required to compute the predicted time of the system peak and the predicted hourly zone load values at the CP times. In the end, the idea is to compare what the model would have predicts given actual weather and economics and the outcomes that actually occurred under these conditions. These comparisons are very much like the estimation error comparisons that were made toward the end of the Hourly Models section of this report, where we looked at NCP and CP errors for 2021.

WEATHER NORMALIZATION

The current LTFS forecast process utilizes a multi-year weather simulation framework to construct Cumulative Distribution Functions (CDF) daily energy, daily noncoincident zone peak (NCP), and daily CP (zone load at the time of the daily PJM peak). When this process is run over historical years the midpoint of the CDFs for each concept is taken as the *weather normalize* value.

In general, the power industry utilizes one of two broad approaches for constructing weather normalized loads where each load zone is treated independently of other load zones. In principle, the approaches are designed to provide load patterns under average or typical weather conditions.

Approach 1: Construct Normal Weather. Under this approach, a *normal* weather pattern is first constructed using historical weather data for the load zone under study. The constructed series of normal weather is then pushed through the load zone forecast model to generate a backcast of loads under normal weather conditions. There are several schemes for constructing a normal weather pattern.

- Average weather by calendar day. Under this approach, multiple years of weather are grouped by calendar date (e.g., January 1st, January 2nd, …, December 31st). The daily or hourly averages of each weather concept are then computed. The resulting time series of average data is deemed normal weather.
- An alternative to daily averages is to sort each month of historical weather data from the coldest day to the hottest day. That is, all January days across a year are sorted from the coldest day to the hottest day. The same ranking is developed for each year of available historical weather data. Once the data has been ranked, average values of the ranked data are taken. For the coldest day in January, the algorithm computes the average of the coldest day. The second rank of January data is then used to compute the average of the second coldest day. This continues until all ranked days are averaged resulting in 365 days of average data. The last step is to select a weather pattern from the historical data to allocate the ranked data. For example, if 1987 is selected as the weather pattern year, then the coldest January average is mapped to the coldest day in January 1987. The second coldest January average data is mapped to the second coldest day in January 1987. The process continues until every day in 1987 is assigned data. The resulting Rank & Average time series is then pushed through the load zone forecast model to generate a backcast of loads under normal weather conditions.
- The average approaches described above resulting in average values for all weather concepts. With the proliferation of distributed energy resources like solar PV the resulting weather normalized loads (net of solar PV generation) becomes harder to interpret. The National Renewable Energy Laboratory (NREL) has developed Typical Meteorological Year (version TMY3) weather data that is designed to support building simulations under realistic weather conditions. (See https://nsrdb.nrel.gov/data-sets/tmy). This includes solar radiation data that is consistent with temperature, humidity, wind speed, and wind direction. These data are available for most major weather stations spanning the US. The TMY3 data is constructed by selecting for each month the year that has been deemed the most typical. The actual hourly weather data for the selected year and month is then assigned as the TMY data. For example, the TMY3 data may

use for January the data from January 2010, for February the data from February 2015,…, for December the data from December 2008.

All three schemes work well when the load pattern for a single zone is considered in isolation of other load zones because the construction of normal weather is performed one weather station at a time without consideration of the weather conditions for other weather stations. Thus, it is plausible that normal weather could lead to differences in the timing of and contribution of each load zone to the PJM System and Regional Peaks that are outside historical values. If this approach is used, then of the three schemes the TMY3 data will generate the most realistic net load pattern under *normal* weather conditions.

Approach 2: Multi-year Weather Simulations. Under this approach, multiple years of observed weather data are combined with a load forecast model to backcast loads under alternative weather patterns. The resulting load backcasts are then summarized to determine *weather-normalized* loads. The LTFS constructs for each load zone CDFs of the monthly and seasonal backcast CP and NCP values. The median or 50% value from these CDFs are deemed the weather normalized values.

For multiple zones that are geographically dispersed, construction of **normal weather** patterns that yields a consistent set of "normal" loads across zones is difficult if not impossible. For multiple zones, weather simulations using historical weather patterns yield realistic distributions of loads across load zones. Weather simulations do not ensure that the weather that leads to the 50% or median value CP and NCP for a given load zone may not correspond to the same weather trace that leads to the 50% or median CP and NCP values for all other load zones. As a result, care must be taken when comparing the weather normal CP and NCP across zones.

The introduction of Distributed Energy Resources like solar PV adds complexity and begs the questions: What are "Normal" Loads? The added load volatility associated with distributed solar PV is driving a growing interest on the part of system operators and planners in quantifying hourly load uncertainty. The weather simulation process that PJM employs is well suited to quantifying hourly load uncertainty. We recommend shifting the focus away from developing "normalized" CP and NCP values toward using the weather simulation process to quantify historical and future hourly load uncertainty. The hourly load simulations can also be used to construct distributions of hourly ramp rates that are expected to evolve dramatically with deep penetration of solar PV generation and EV charging.

CAPTURING THE IMPACTS OF ENERGY EFFICIENCY PROGRAMS

Impacts of State and Utility energy efficiency (EE) programs are captured in the model end-use intensities along with new standards and natural occurring efficiency improvements as old appliances are replace with new appliance. There are two components to the end-use intensities – saturations, the share of homes or commercial floorspace that own the end-use and efficiency – the kWh or work output per kWh input. Most primary residential and commercial end-use intensities other than miscellaneous are declining or are flat as increase in end-use stock efficiency is generally increasing faster than saturation.

End-use intensities, a direct input into the SAE models, are derived from the EIA Annual Energy Outlook – saturation and efficiency projections; in the commercial sector, efficiency impacts are embedded in the intensity projections. End-use stock efficiency is derived from an end-use choice model that moves the average stock efficiency based on stock turnover, new purchases, and relative life-cycle costs of competing technology options. In this model, standards work to limit the least efficient options over time while declining costs in more efficient technologies result in greater adoption of the higher efficient technology options.

EIA captures the EE impacts in a couple of ways. First, in the last few years, EIA has made an effort to directly account for state and utility efficiency programs by mapping regional EE program expenditures to end-uses and “rebating” (lowering the cost) of the high-efficient technology options. As a result of the lower cost, more of the high-efficient technology option is adopted. Second, the underlying information on new technologies including number of units sold and associated efficiency information are updated on an on-going basis; this information is derived from annual appliance shipments data. The impact of programs that encourage adoption of more efficient technology such as the Energy Star program and utility incentive programs are partly reflected in the shipments data that in turn are used in calibrating the AEO end-use models.

The SAE estimation process itself also contributes to capturing EE program impacts as the sales and customer data used in estimating the models incorporates past EE program impacts.

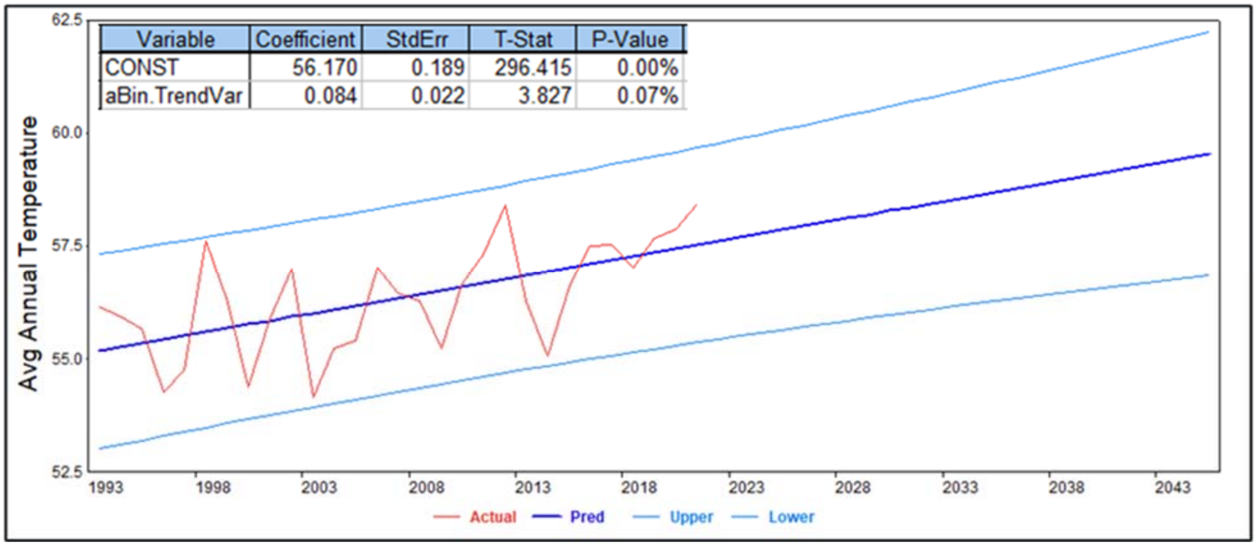
ACCOUNTING FOR TEMPERATURE TRENDS

In electric load forecasts we generally assume that current and future weather conditions will most likely look like the average of the past years. Typically, normal or expected weather is derived as an average of temperatures or degree-days for a twenty to thirty-year period; some utilities will use periods as short as ten-years. Rather than define normal weather conditions, PJM simulates with historical actual temperatures and then calculates normal as the 50% probability outcome. The outcome is approximately the same as if the average temperature profile for the PJM system could be determined.

In recent temperature trend studies, we have found that depending on location, average temperature has been increasing from 0.4 degrees to over 1.0 degree per decade. Our work has been consistent with other temperature trend studies and climate model projections. Giving increasing temperature an average based on the last 20 years would be more representative of 2011 (the mid-year) than 2022.

Figure 6-1 shows the DPL average temperature trend.

FIGURE 6-1: DPL AVERAGE TEMPERATURE TREND



Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	56.170	0.189	296.415	0.00%
aBin.TrendVar	0.084	0.022	3.827	0.07%

Since 1993, average temperature has been increasing .08 degrees per year or 0.8 degrees per decade. This translates into increasing CDD and decreasing HDD as illustrated in Figure 6-2 and Figure 6-3.

FIGURE 6-2: DPL TRENDED CDD

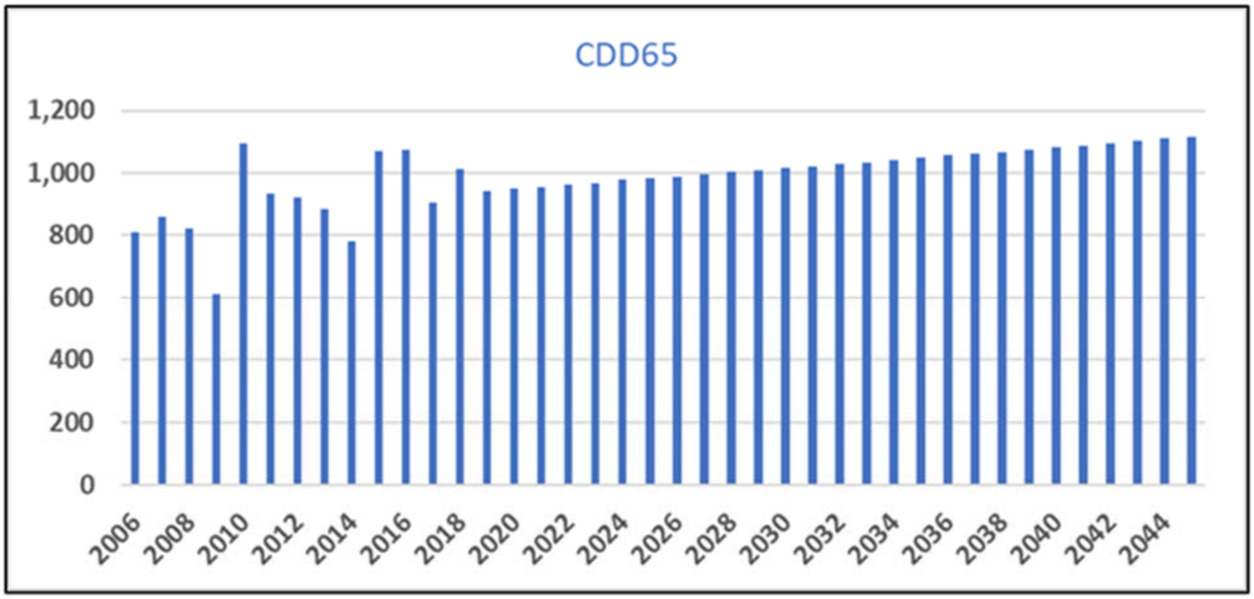
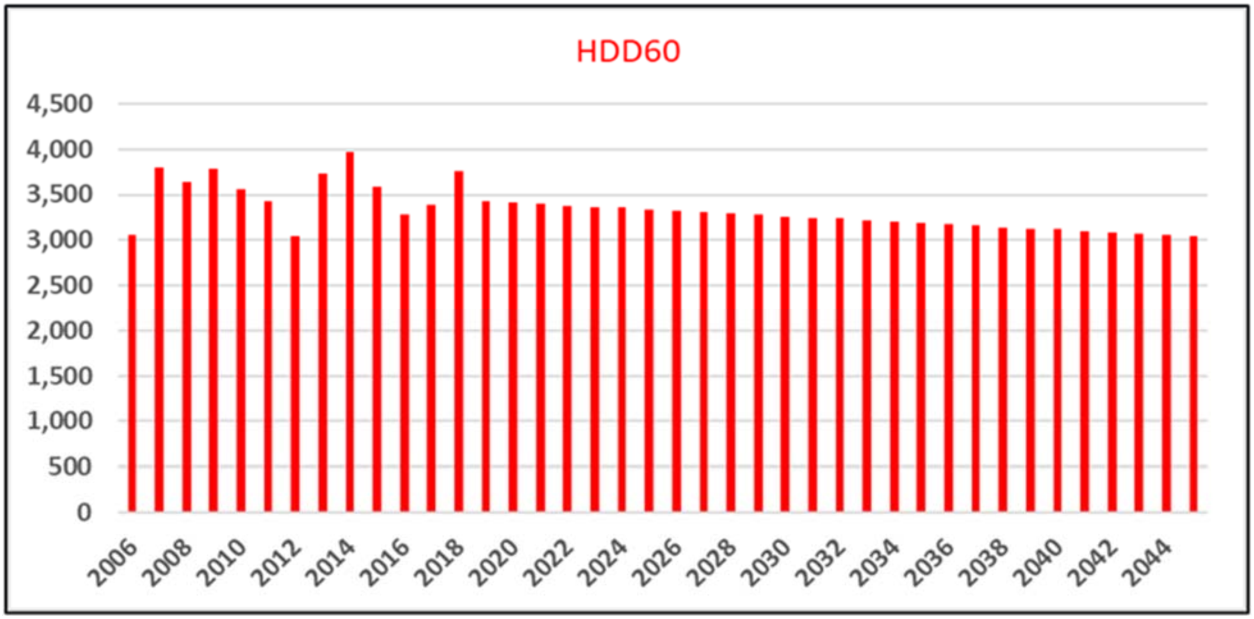


FIGURE 6-3: DPL TRENDED HDD



The weather simulation process and model complexity make it difficult to directly model the impact of increasing temperatures. The approach we recommend is less complex; that is to capture the impact of increasing temperatures with trended normal HDD and CDD in the constructed heating and cooling model indices.

LARGE LOAD ADJUSTMENTS

In the simulation framework, the impact of new technologies such as solar and EVs depends on the load/weather simulation outcome. The earlier section on reshaping loads describes the recommended approach for carrying these technology load adjustments through the forecast horizon. The load forecast may also need to be adjusted for large load additions or losses from a specific customer or group of customers; this would generally be in the industrial sector. If industrial loads adjustments are not too extreme, impacts of load loss or gain can be made to the industrial baseline energy projection that is part of the base-use model index.

One of the largest adjustments has been for data centers in Dominion Zone. Data centers load growth has been enormous – data center loads for just Dominon alone has increased from 1,250 MW at the beginning of 2020 to over 2,500 MW in June of this year. Demand is expected to continue to increase at this pace through 2026. PJM excludes the DOM Zone data center loads from the DOM Zone models and adjust the load afterwards for expected data center load growth. Given the size and growth of data center loads this is the correct approach. PJM relies on Dominion for the first five years of the load projection; this makes sense since Dominon works directly with their data center customers as Dominion plans and builds capacity for future needs.

While the DOM Zone should continue to experience strong data center load growth past the next five years, the rate of growth is likely to slow. Factors that will impact demand growth are transmission and other physical constraints, and demand for more localized data center capacity for services that require faster response time such as 5-G networks, autonomous vehicles, internet of things, and automated manufacturing processes. The long-term forecast will need to be based on historical capacity trends, continuous discussions with utility personnel that are directly involved with data center activities and transmission construction, trade and real estate publication reviews, and organizations that support regional data center development.

7 RECOMMENDATIONS

Throughout the project, we explored several modeling options, discussed issues with the current modeling approach, and ultimately through our work and meetings with PJM staff and Market Participants have developed a set of recommendations that build on the current PJM forecast model. Our recommendations are outlined below:

1. **Replace Annual/Quarterly End-Use Indices with Monthly/Daily Indices**

   Heating, cooling, and base-use load indices can be derived from monthly class SAE models. The SAE models are well documented, used by many utilities for long-term sales and energy forecasting, and are relatively robust in the sense that adding new data and dropping old data does not generally result in significant changes in the model parameters. Indices based on monthly (versus annual models) provide significantly more observations and as a result require fewer years of historical data; resulting in estimated model parameters that will be more representative of the current and forecast periods. Monthly models will also result in stronger heating and cooling coefficients because there is generally more weather variation in monthly data series than in an annual data series.

2. **Continue with Weather Simulation Approach**

   Given the diversity of weather across PJM zones, it is nearly impossible to define a normal daily or hourly weather pattern for the entire system. The current method of developing load distributions from zonal weather simulations represents the best approach for estimating expected long-term demand. Twenty-years of historical weather data with 7 rotations within in each year provides a strong basis for simulating the distribution of load outcomes.

3. **Replace Daily Models (Energy, Zone peak, and Coincident peak) with Hourly Load Models**

   The need to capture the impact of solar, EV, and other technologies that are reshaping demand requires an hourly modeling framework. Replacing the set of zonal daily models with the hourly model described in the report will meet this need. PJM should utilize the hourly rolling weather approach with two-part heating degree and cooling degree variables. PJM should interact these weather variables and other hourly model variables with heating, cooling, and base-use indices developed from the SAE models.

4. **Adjust Loads for Solar and New Technologies Through the Simulation Process**

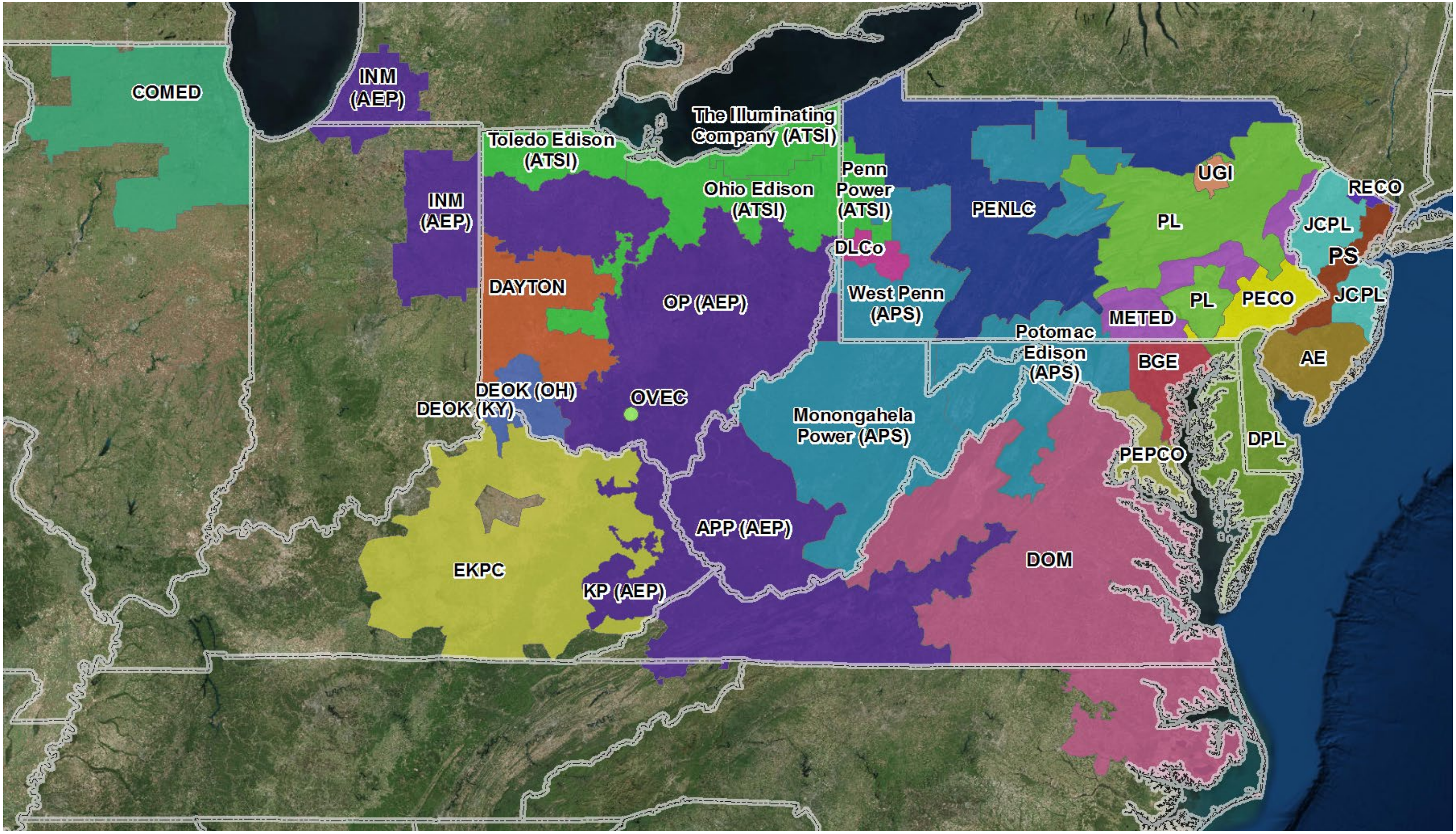
   To correctly account for solar, EVs and other load adjustments, the hourly projections for these technologies should be constructed to be consistent with the weather simulation process. Each load simulation can then be adjusted appropriately to reflect the impact of solar and other weather-sensitive technology adjustments for each simulation. The load impact of EVs and other non-weather sensitive technologies will also need to be adjusted within the simulation process, as the impact of EVs and other technologies on load depends on the net of solar simulation outcome. The adjusted hourly load simulations can then be post-process to derive zonal adjusted peak and energy and coincident peaks from the aggregation of the net zonal hourly load forecasts.

5. Capture Increasing Temperature Trends

Long-term temperature trends should be evaluated for each of the planning zones with results used to adjust cooling and heating indices that are inputs in the hourly load models. We expect to see increasing temperatures across the PJM service area that will contribute to an increase in cooling requirements and a decrease in space heating loads. Zone-level temperature trends can be used to construct trended HDD and CDD that are in turn incorporated into the heating and cooling model indices.

PJM Load Forecast Report

January 2022



Prepared by PJM Resource Adequacy Planning Department

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TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone
AEP	American Electric Power zone (incorporated 10/1/2004)
APP	Appalachian Power, sub-zone of AEP
APS	Allegheny Power zone (incorporated 4/1/2002)
ATSI	American Transmission Systems, Inc. zone (incorporated 6/1/2011)
Battery Storage	(Also Battery Energy Storage System – BESS) Devices that enable generated energy to be stored and then released at a later time
BGE	Baltimore Gas & Electric zone
CEI	Cleveland Electric Illuminating, sub-zone of ATSI
COMED	Commonwealth Edison zone (incorporated 5/1/2004)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
CSP	Columbus Southern Power, sub-zone of AEP
Direct Control	Load Management achieved directly by a signal from a control center
DAY	Dayton Power & Light zone (incorporated 10/1/2004)
DEOK	Duke Energy Ohio/Kentucky zone (incorporated 1/1/2012)
DLCO	Duquesne Lighting Company zone (incorporated 1/1/2005)
DOM	Dominion Virginia Power zone (incorporated 5/1/2005)
DPL	Delmarva Power & Light zone
EKPC	East Kentucky Power Cooperative zone (incorporated 6/1/2013)
FE-East	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)
Heating Load	The weather-sensitive portion of winter peak load
INM	Indiana Michigan Power, sub-zone of AEP
JCPL	Jersey Central Power & Light zone
KP	Kentucky Power, sub-zone of AEP

METED	Metropolitan Edison zone
MP	Monongahela Power, sub-zone of APS
NERC	North American Electric Reliability Corporation
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
OEP	Ohio Edison, sub-zone of ATSI
OP	Ohio Power, sub-zone of AEP
OVEC	Ohio Valley Electric Corporation zone (incorporated 12/1/2018)
PECO	PECO Energy zone
PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone
PL	PPL Electric Utilities, sub-zone of PLGroup
PLGroup/PLGRP	Pennsylvania Power & Light zone
PENLC	Pennsylvania Electric zone
PP	Pennsylvania Power, sub-zone of ATSI
PRD	Price Responsive Demand
PS	Public Service Electric & Gas zone
RECO	Rockland Electric (East) zone (incorporated 3/1/2002)
TOL	Toledo Edison, sub-zone of ATSI
UGI	UGI Utilities, sub-zone of PLGroup
Unrestricted Peak	Peak load prior to any reduction for load management or voltage reduction.
WP	West Penn Power, sub-zone of APS
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

2022 PJM LOAD FORECAST REPORT

EXECUTIVE SUMMARY

- This report presents an independent load forecast prepared by PJM staff.

- The report includes long-term forecasts of peak loads, net energy, load management, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area (LDA), and the total RTO.

- New to the report this year are tables for the peak load impact of battery storage (Table B-8b) and the net energy impact of plug-in electric vehicles (Table E-4).

- Since the 2021 Load Report, PJM made significant revisions to the load forecast model, to better capture granularity in the sector models and weather response in the summer and winter seasons. These enhancements are described in the supplemental report which is available with the other published materials.

- The Non-Weather Sensitive model was estimated with historical data from January 2011 through August 2021, while the Residential, Commercial, and Industrial sector models were estimated with data from 1998 through 2020. Weather scenarios were simulated with data from years 1994 through 2020, generating 351 scenarios.

- The economic forecast used was Moody's Analytics' September 2021 release.

- The 2021 update of Itron's end-use data provides the basis for appliance saturation rates, efficiency, and intensity and is consistent with the Energy Information Administration's 2021 Annual Energy Outlook. PJM obtained additional information from certain zones on Residential saturation rates based on their own load research. Details on zones providing information are presented in the supplement.

- The forecasts of the following zones have been adjusted to account for large, unanticipated load changes (see Table B-9 and the supplement for details):
  - The forecast of the APS zone has been adjusted to account for accelerating load related to natural gas processing plants;
  - The forecast of the ATSI zone has been adjusted to account for the growth in primary metals facilities;
  - The forecast of the COMED zone has been adjusted to account for the implementation of a voltage optimization program;
  - The forecast of the DOM zone has been adjusted to account for substantial on-going growth in data center construction.

- Summer peak load growth for the PJM RTO is projected to average 0.4% per year over the next 10 years, and 0.4% over the next 15 years. The PJM RTO summer peak is forecasted to be 154,381 MW in 2032, a 10-year increase of 5,443 MW, and reaches 157,689 MW in 2037, a 15-year increase of 8,751 MW. Annualized 10-year growth rates for individual zones range from -0.3% to 2.2%.

- Winter peak load growth for PJM RTO is projected to average 0.7% per year over the next 10-year period, and 0.6% over the next 15-years. The PJM RTO winter peak load in 2031/32 is forecasted to be 141,516 MW, a 10-year increase of 9,414 MW, and reaches 145,220 MW in 2036/37, a 15-year increase of 13,118 MW. Annualized 10-year growth rates for individual zones range from -0.3% to 2.6%.

- Net energy for load growth for PJM RTO is projected to average 0.8% per year over the next 10-year period, and 0.7% over the next 15-years. Total PJM RTO energy is forecasted to be 845,133 GWh in 2032, a 10-year increase of 63,815 GWh, and reaches 877,586 GWh in 2037, a 15-year increase of 96,268 GWh. Annualized 10-year growth rates for individual zones range from -0.2% to 3.4%.

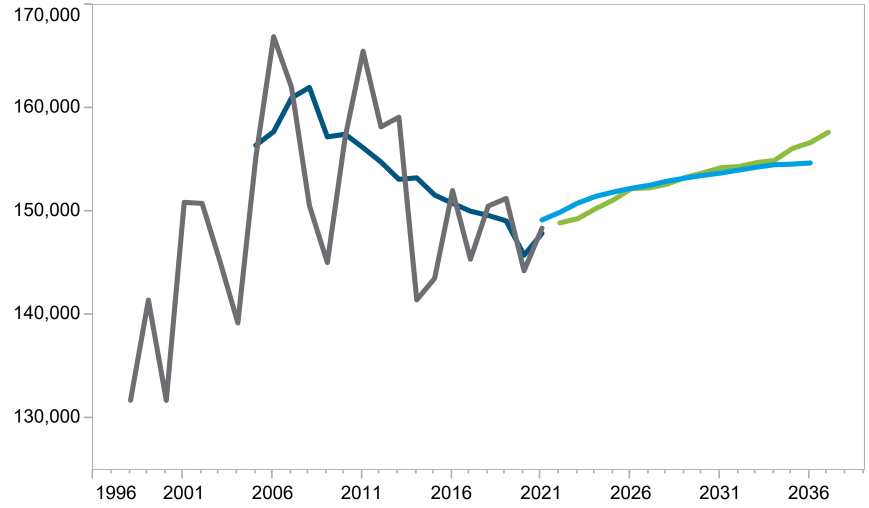
- Compared to the 2021 Load Report, the 2022 PJM RTO summer peak forecast shows the following changes for three years of interest:

○ The next delivery year – 2022	-1,028 MW (-0.7%)
○ The next RPM auction year – 2025	-763 MW (-0.5%)
○ The next RTEP study year – 2027	-249 MW (-0.2%)

NOTE:
Unless noted otherwise, all peak and energy values are non-coincident, unrestricted peaks, which represent the peak load or net energy after reductions for distributed solar generation and battery storage, additions for plug-in electric vehicles, and prior to reductions for load management impacts.
All compound growth rates are calculated from the first year of the forecast.

PJM RTO

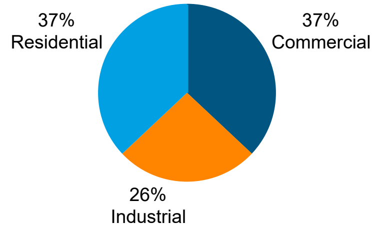
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,075*
Heating Degree Days	*3,851*
Temperature-Humidity Index	*82.7*
Wind-Adjusted Temperature	*11.7*

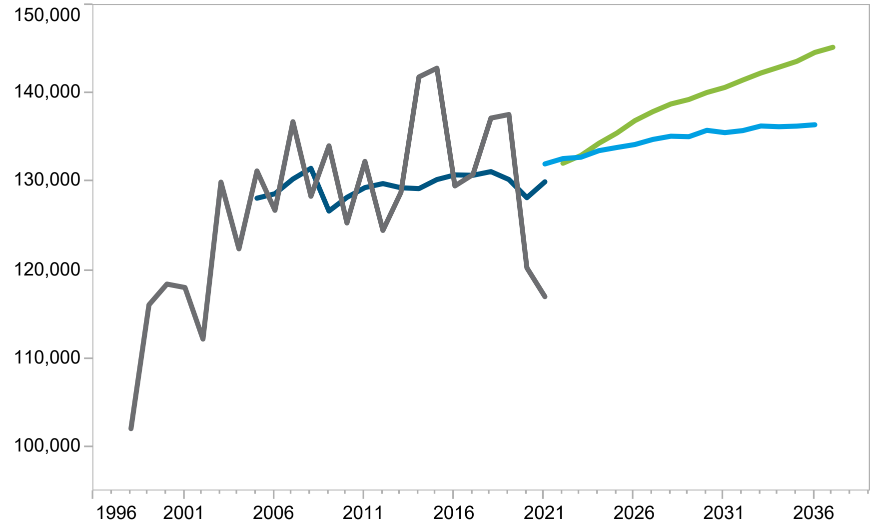
RCI Makeup



Zonal 10/15 Year Load Growth

SUMMER	0.4%	0.4%
WINTER	0.7%	0.6%

Winter Peak



LDAs

PJM Mid-Atlantic
Eastern MAAC
Southern MAAC
Central MAAC
Western MAAC
PJM West

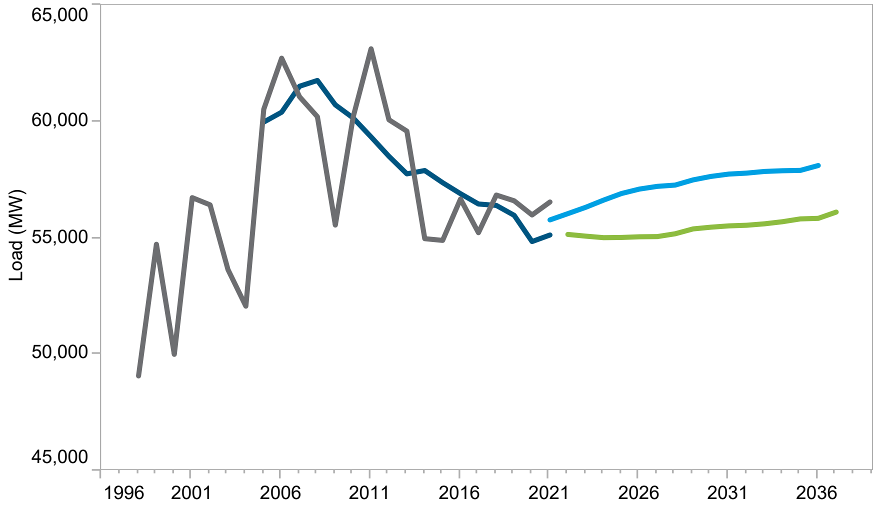
Zones

AE
AEP
APS
ATSI
BGE
COMED
DAYTON
DEOK
DLCO
DOM
DPL
EKPC
JCPL
METED
OVEC
PECO
PENLC
PEPCO
PL
PS
RECO
UGI

■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

PJM Mid-Atlantic (MAAC)

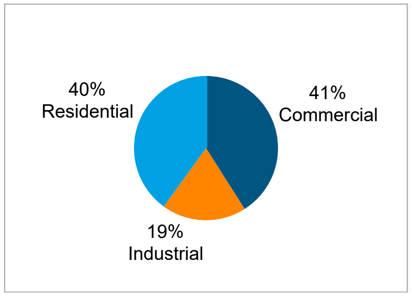
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,180*
Heating Degree Days	*3,608*
Temperature-Humidity Index	*84.3*
Wind-Adjusted Temperature	*13.2*

RCI Makeup



Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.4%	0.4%

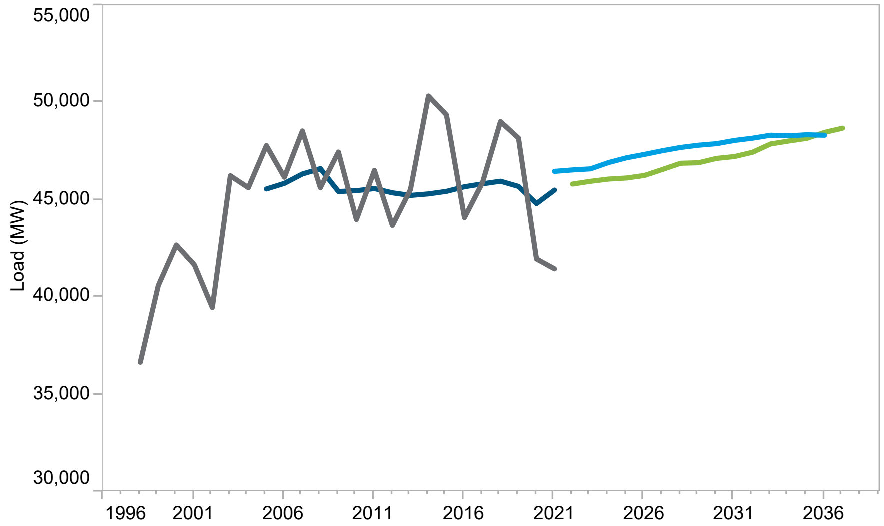
Zones

AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PSEG
RECO
UGI

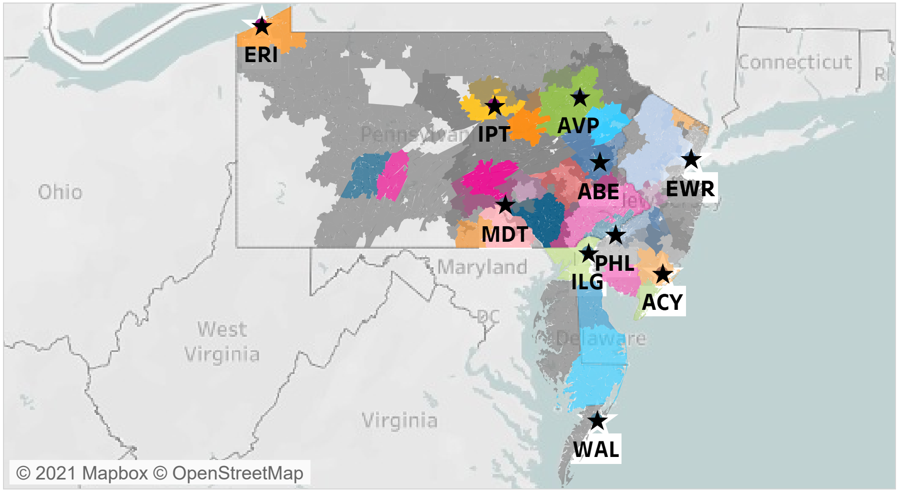
LDAs

E-MAAC
S-MAAC
C-MAAC
W-MAAC

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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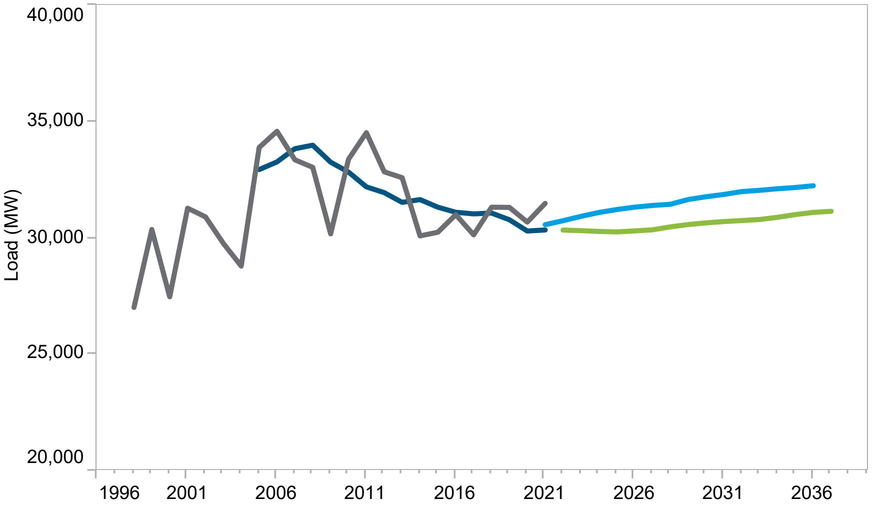
■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

PJM Eastern Mid-Atlantic (E-MAAC)

Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,233*
Heating Degree Days	*3,448*
Temperature-Humidity Index	*84.7*
Wind-Adjusted Temperature	*13.3*

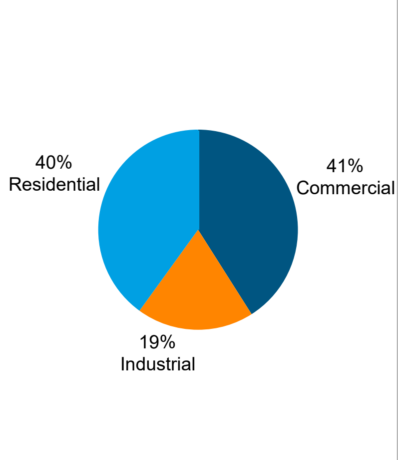
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.2%
WINTER	0.5%	0.6%

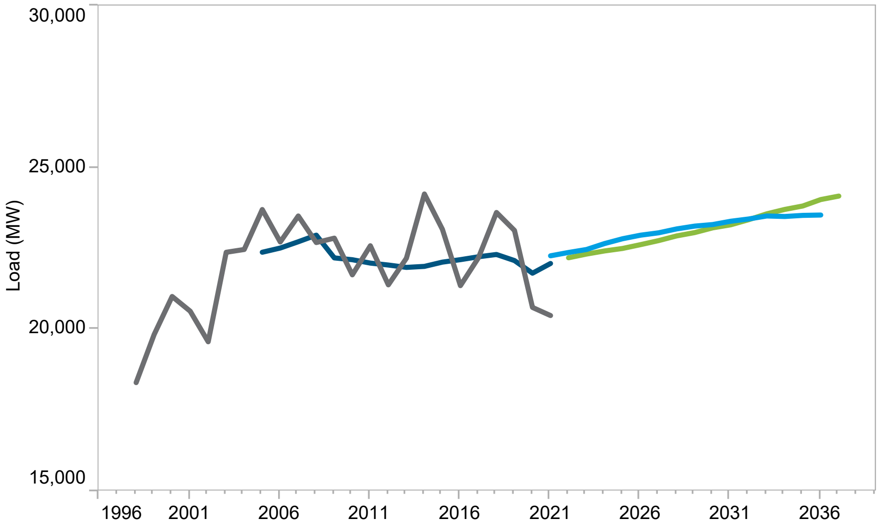
Zones

AE
DPL
JCPL
PECO
PS
RECO

RCI Makeup

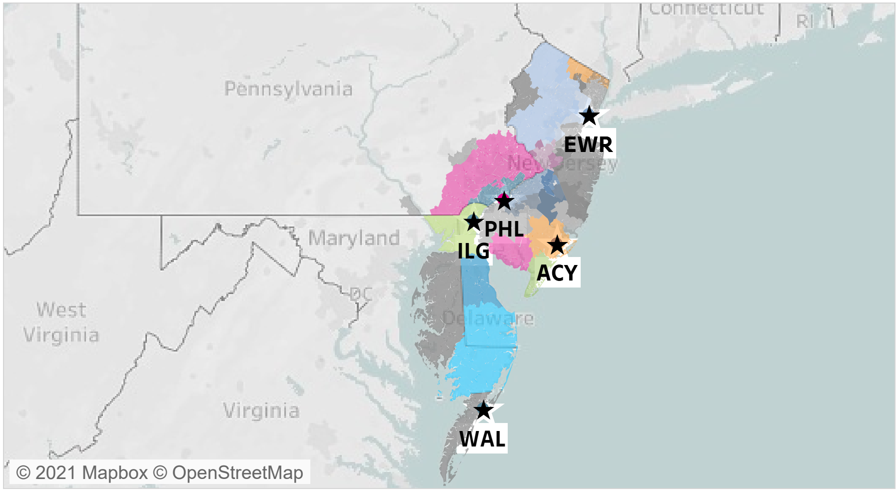


Winter Peak



■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

Metropolitan Statistical Areas and Weather Stations



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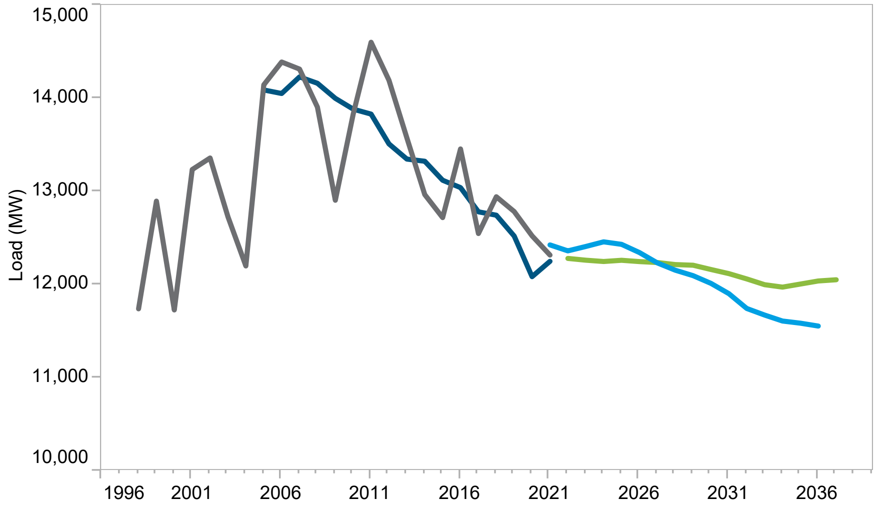
PJM Southern Mid-Atlantic (S-MAAC)

Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,390*
Heating Degree Days	*3,142*
Temperature-Humidity Index	*85.1*
Wind-Adjusted Temperature	*16.8*

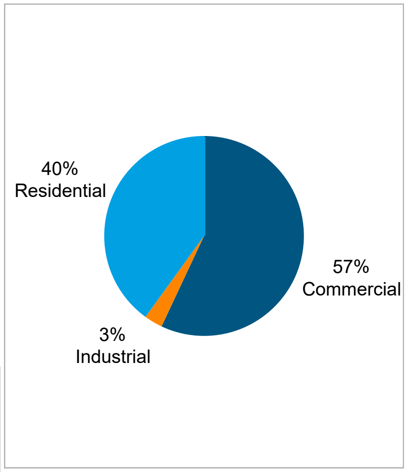
Zonal 10/15 Year Load Growth

SUMMER	-0.2%	-0.1%
WINTER	0.5%	0.5%

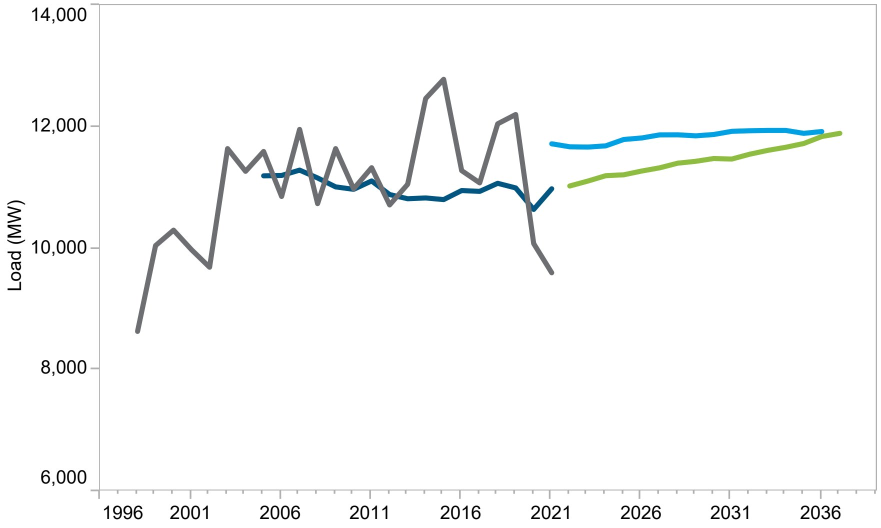
Zones

BGE PEPCO

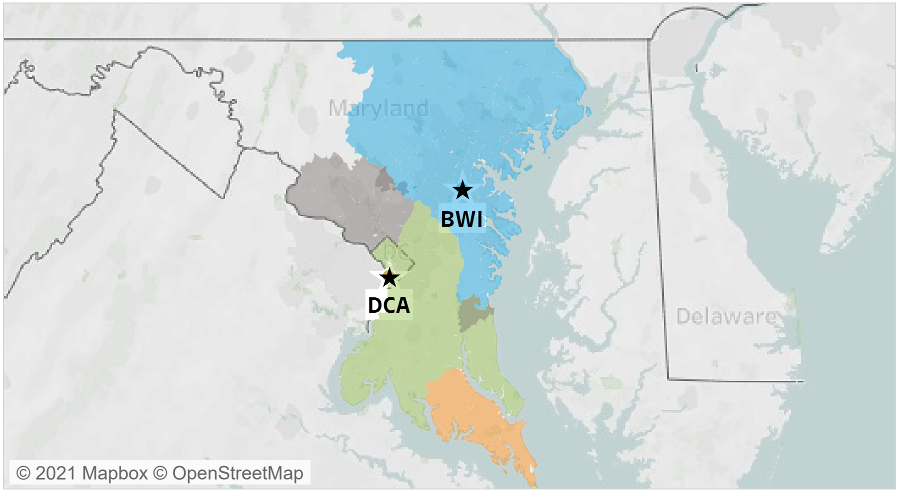
RCI Makeup



Winter Peak



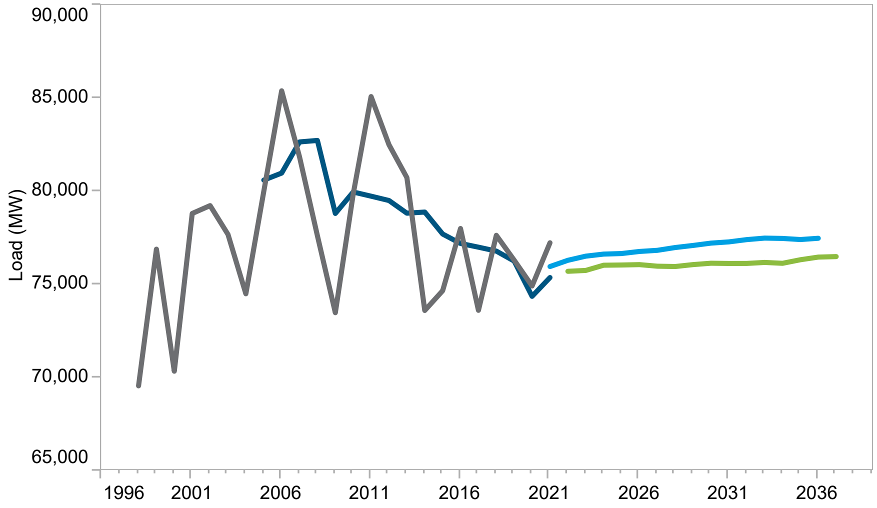
Metropolitan Statistical Areas and Weather Stations



■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

PJM Western

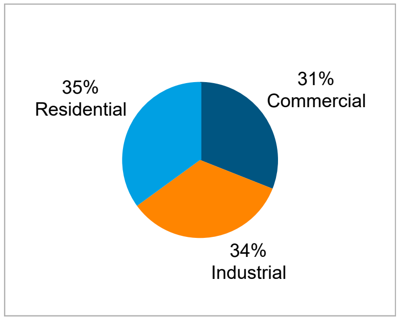
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*914*
Heating Degree Days	*4,269*
Temperature-Humidity Index	*82.8*
Wind-Adjusted Temperature	*5.8*

RCI Makeup



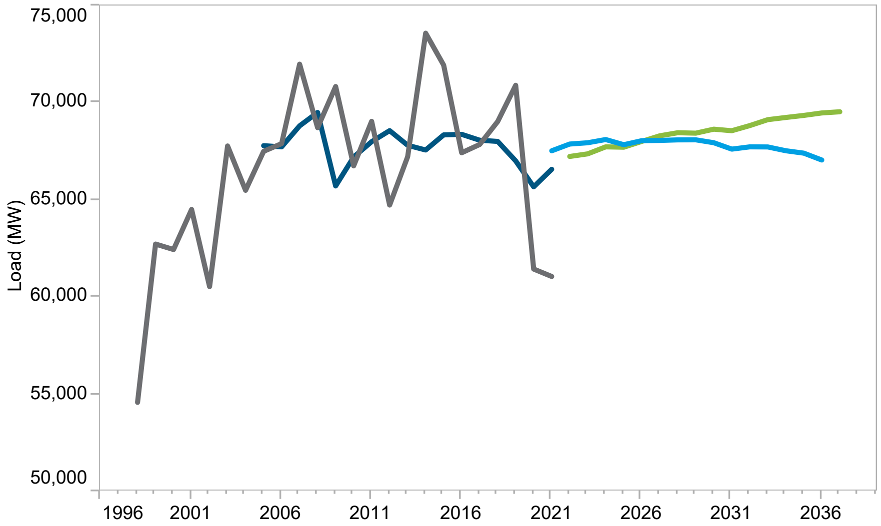
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.2%	0.2%

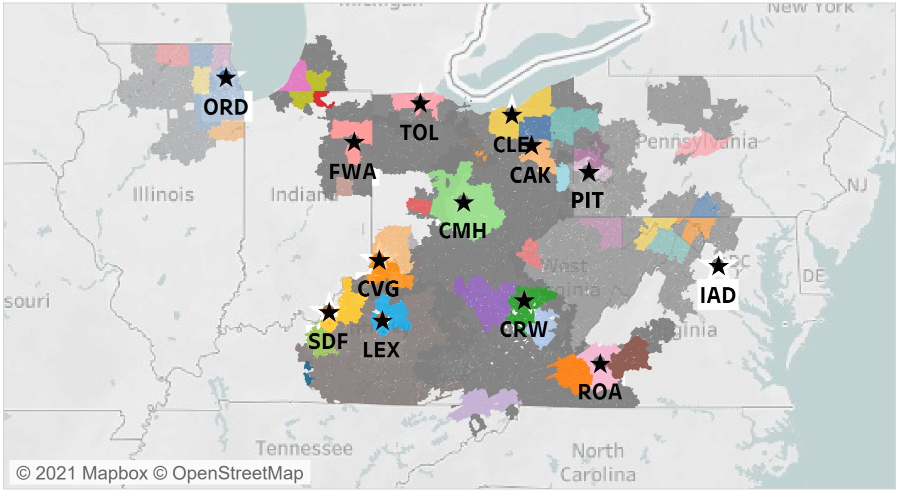
Zones

AEP
APS
ATSI
COMED
DAYTON
DEOK
DLCO
EKPC
OVEC

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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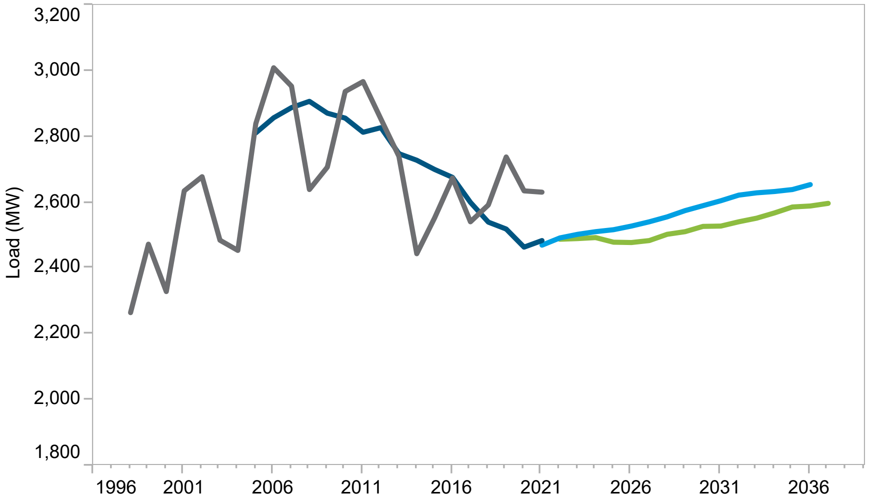
■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

Atlantic Electric (AE)

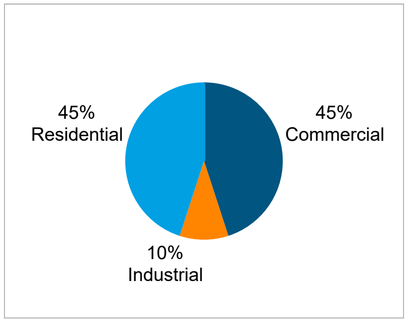
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,069*
Heating Degree Days	*3,516*
Temperature-Humidity Index	*84.8*
Wind-Adjusted Temperature	*14.7*

RCI Makeup



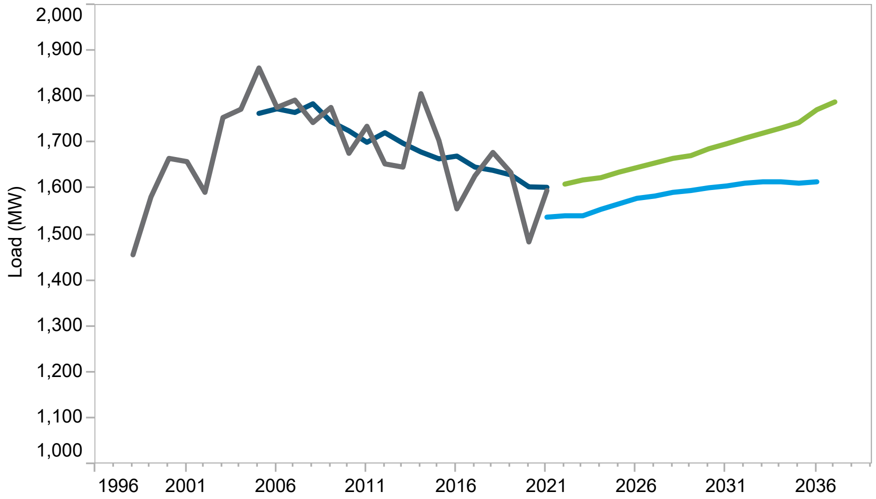
Zonal 10/15 Year Load Growth

SUMMER	0.2%	0.3%
WINTER	0.6%	0.7%

LDAs

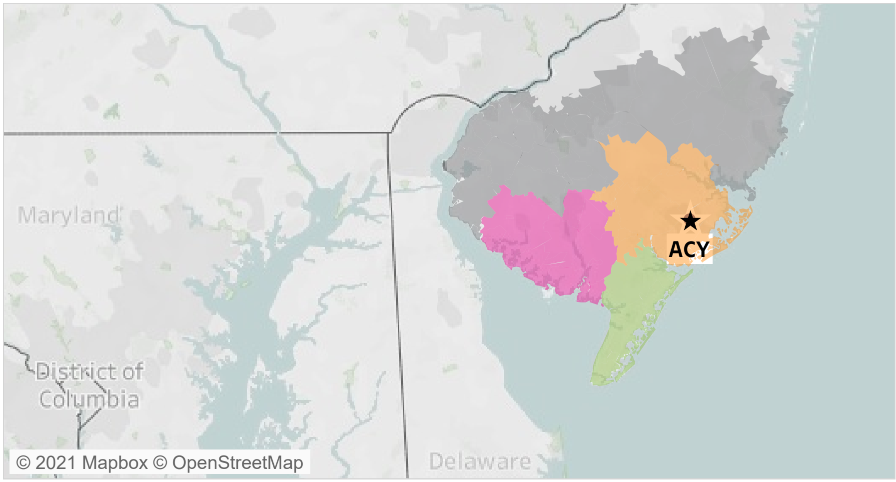
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



■ Peak
■ WN peak
■ Forecast 2021
■ Forecast 2022

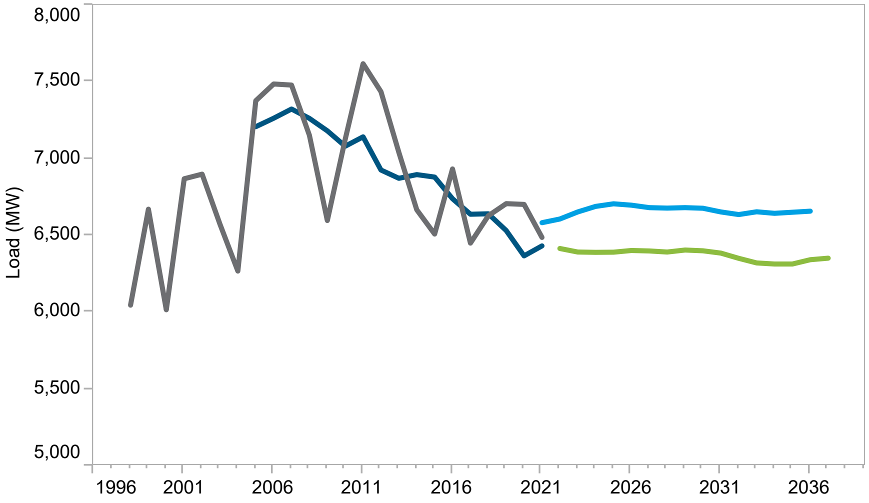
Metropolitan Statistical Areas and Weather Stations



■ AE - Non-Metro
■ Atlantic City-Hammonton, NJ
■ Ocean City, NJ
■ Vineland-Bridgeton, NJ

Baltimore Gas and Electric (BGE)

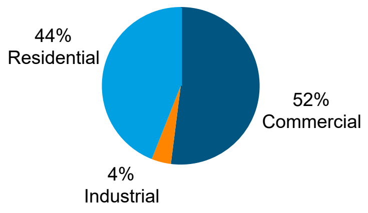
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,256*
Heating Degree Days	*3,369*
Temperature-Humidity Index	*84.8*
Wind-Adjusted Temperature	*15.9*

RCI Makeup



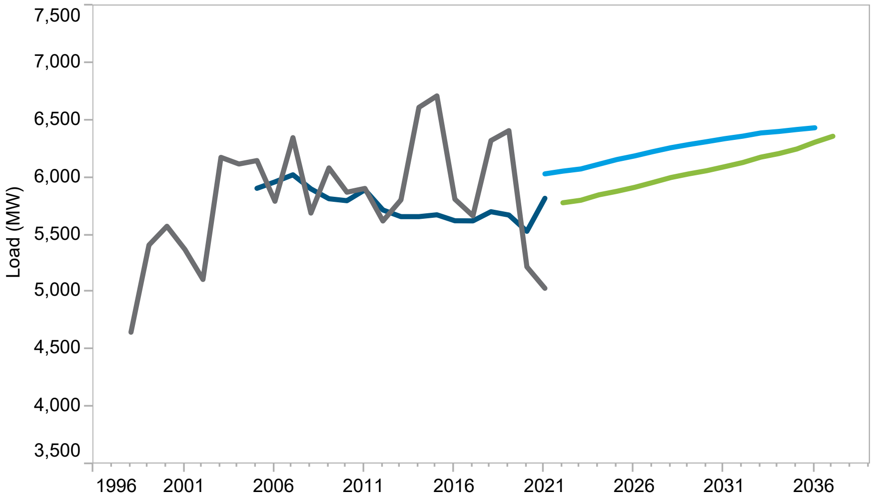
Zonal 10/15 Year Load Growth

SUMMER	-0.1%	-0.1%
WINTER	0.6%	0.6%

LDAs

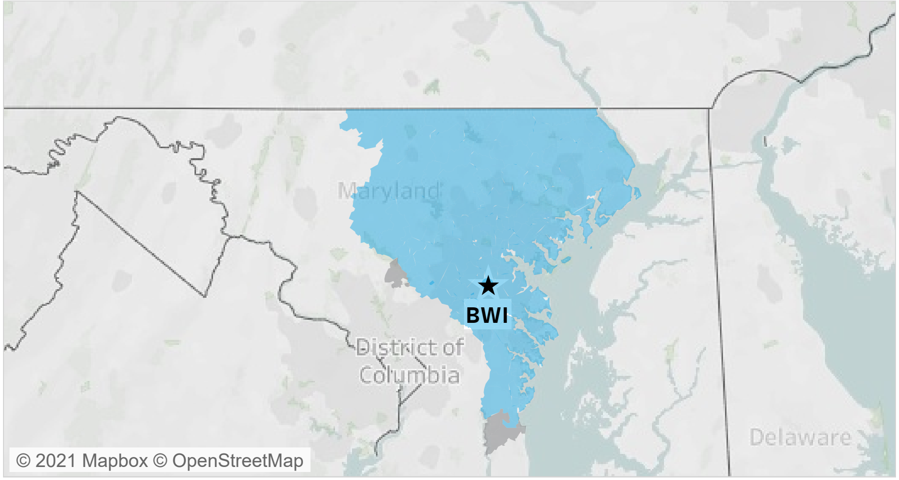
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

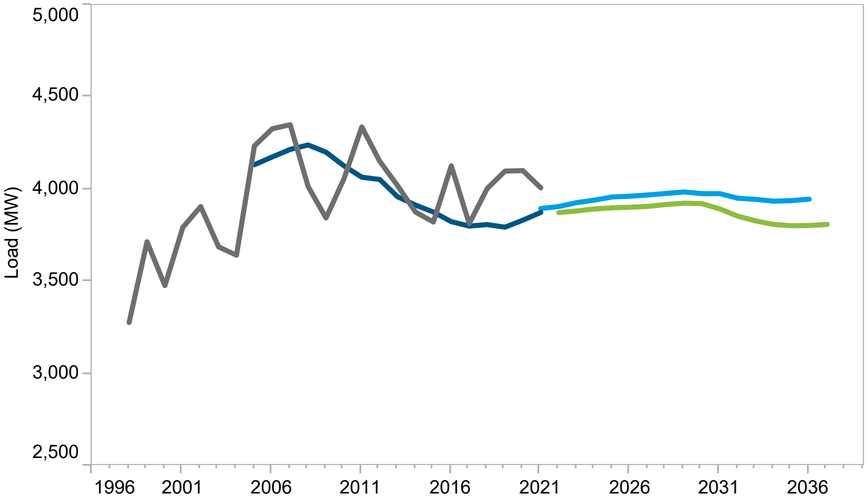
Metropolitan Statistical Areas and Weather Stations



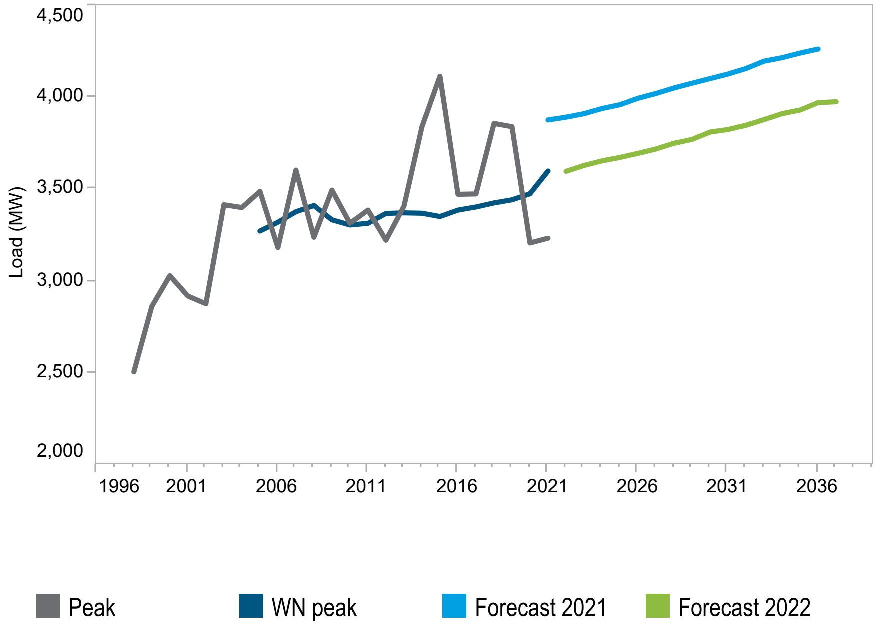
■ Baltimore-Columbia-Towson, MD
■ BGE - Non-Metro

Delmarva Power and Light (DPL)

Summer Peak



Winter Peak



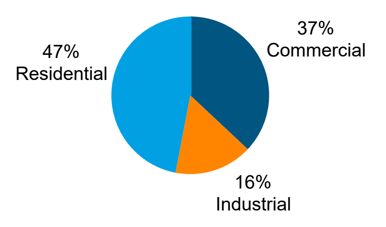
Weather - Annual Average 1994-2020

Cooling Degree Days	*1,192*
Heating Degree Days	*3,329*
Temperature-Humidity Index	*84.3*
Wind-Adjusted Temperature	*16.0*

Zonal 10/15 Year Load Growth

SUMMER	0.0%	-0.1%
WINTER	0.7%	0.7%

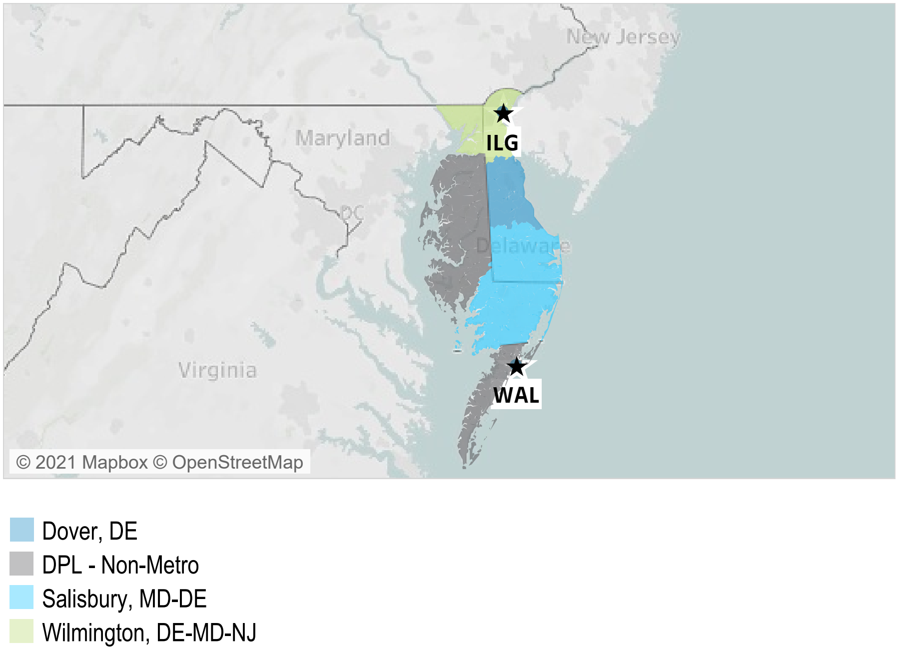
RCI Makeup



LDAs

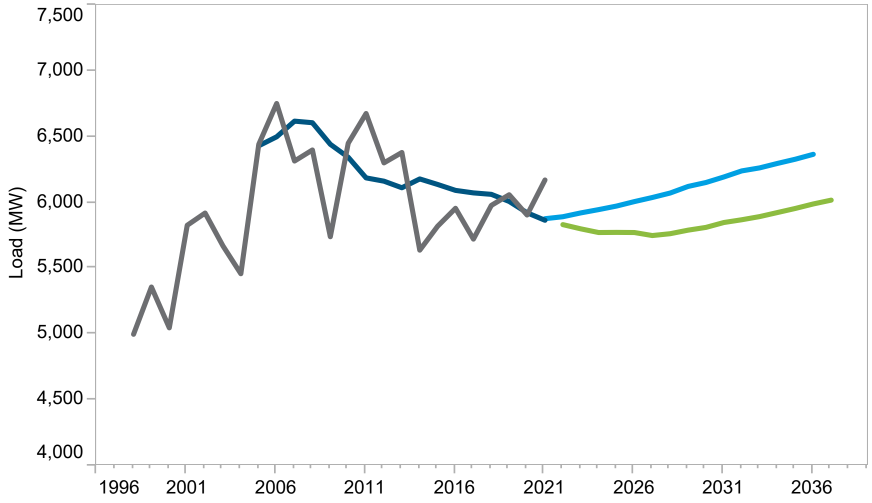
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Metropolitan Statistical Areas and Weather Stations



Jersey Central Power and Light (JCPL)

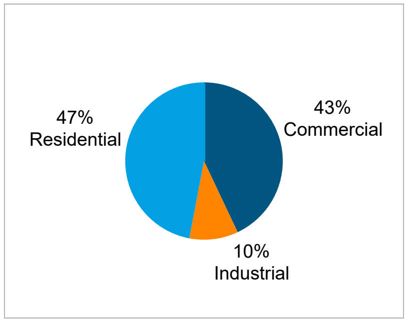
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,195*
Heating Degree Days	*3,535*
Temperature-Humidity Index	*84.5*
Wind-Adjusted Temperature	*12.4*

RCI Makeup



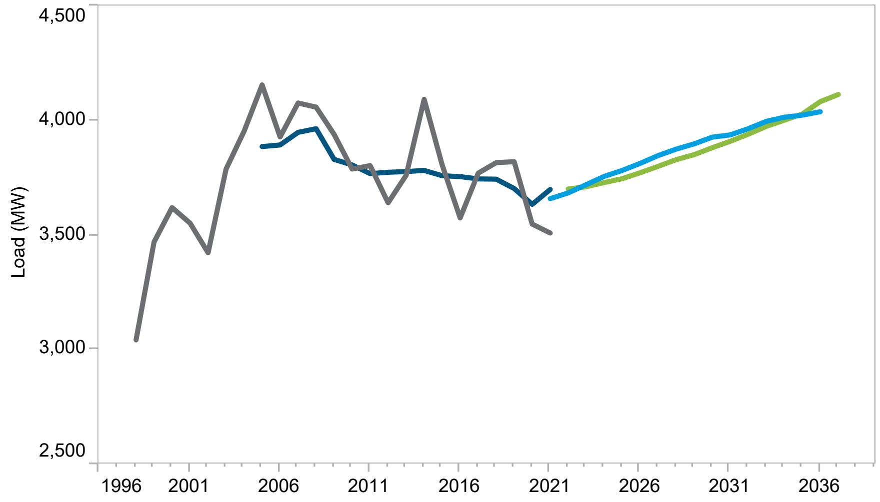
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.2%
WINTER	0.6%	0.7%

LDAs

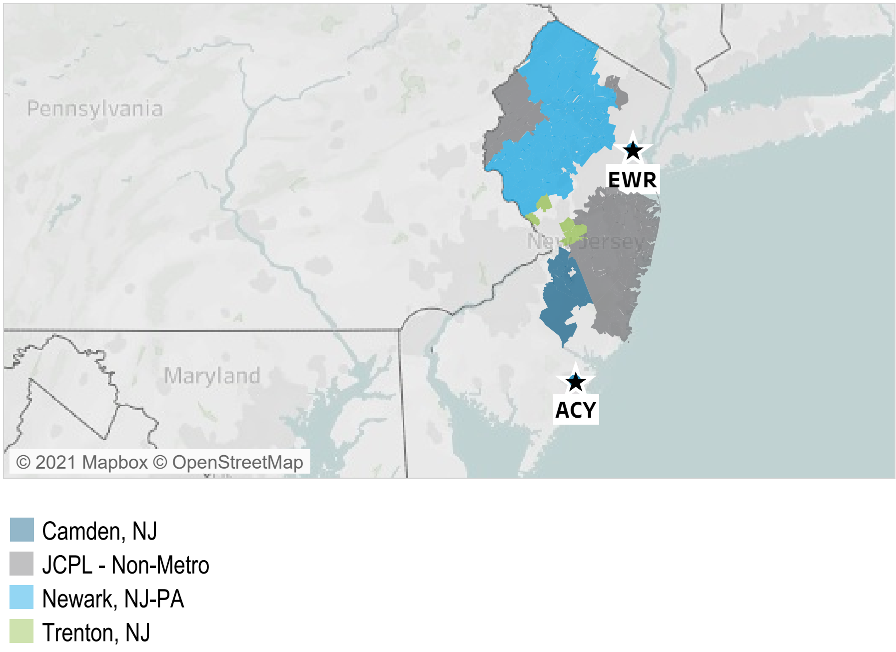
EASTERN MID-ATLANTIC FE-EAST PJM MID-ATLANTIC PJM RTO

Winter Peak



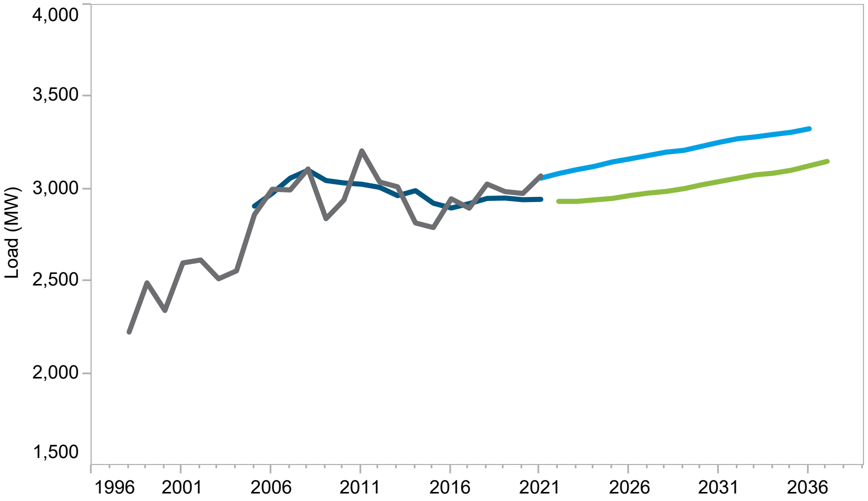
■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

Metropolitan Statistical Areas and Weather Stations



Metropolitan Edison (METED)

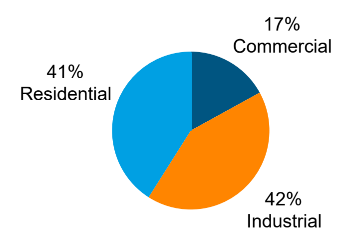
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,094*
Heating Degree Days	*3,770*
Temperature-Humidity Index	*84.0*
Wind-Adjusted Temperature	*12.5*

RCI Makeup



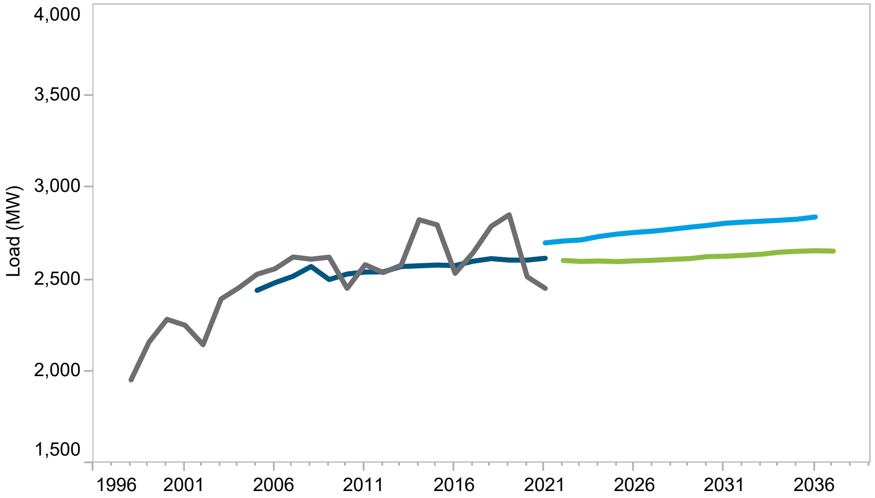
Zonal 10/15 Year Load Growth

SUMMER	0.4%	0.5%
WINTER	0.1%	0.1%

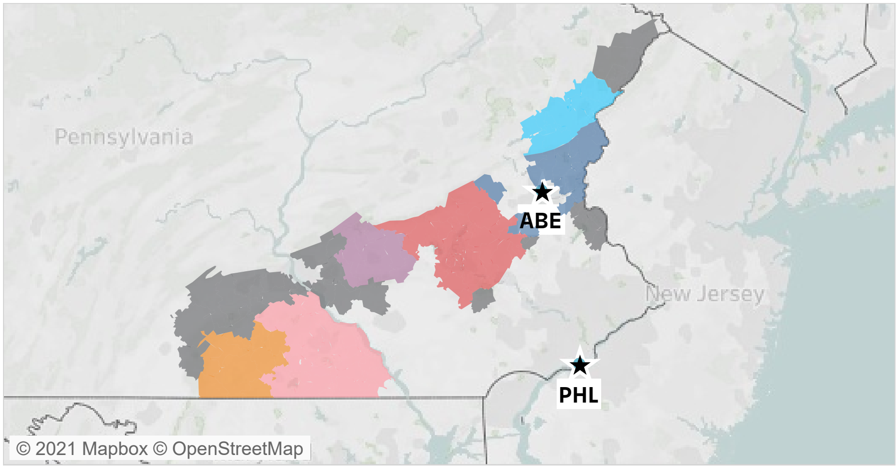
LDAs

CENTRAL MID-ATLANTIC FE-EAST PJM MID-ATLANTIC
PJM RTO WESTERN MID-ATLANTIC

Winter Peak



Metropolitan Statistical Areas and Weather Stations

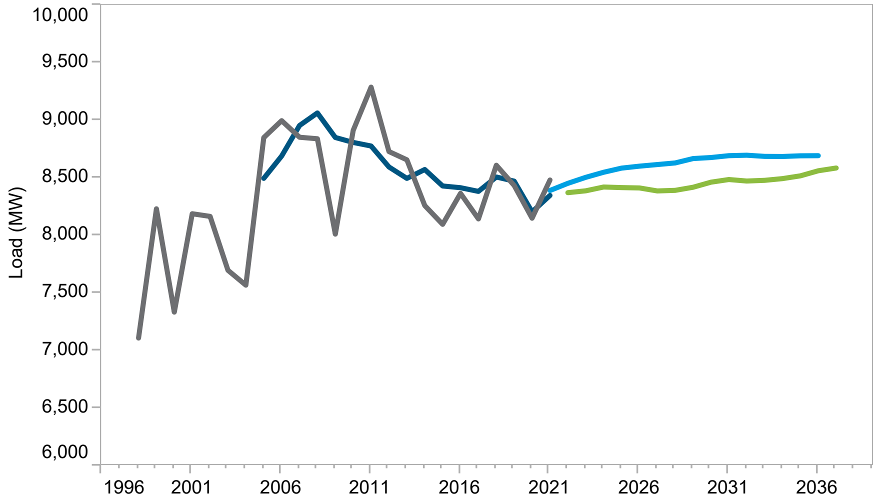


■ Allentown-Bethlehem-Easton, PA-NJ	■ METED - Non-Metro
■ East Stroudsburg, PA	■ Reading, PA
■ Gettysburg, PA	■ York-Hanover, PA
■ Lebanon, PA	

■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

PECO Energy (PECO)

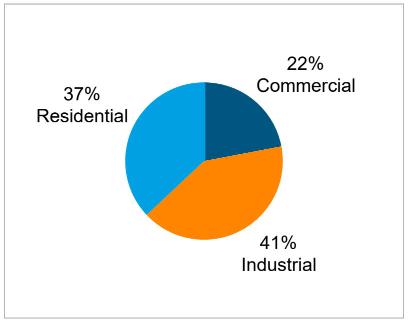
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,318*
Heating Degree Days	*3,352*
Temperature-Humidity Index	*84.9*
Wind-Adjusted Temperature	*14.2*

RCI Makeup



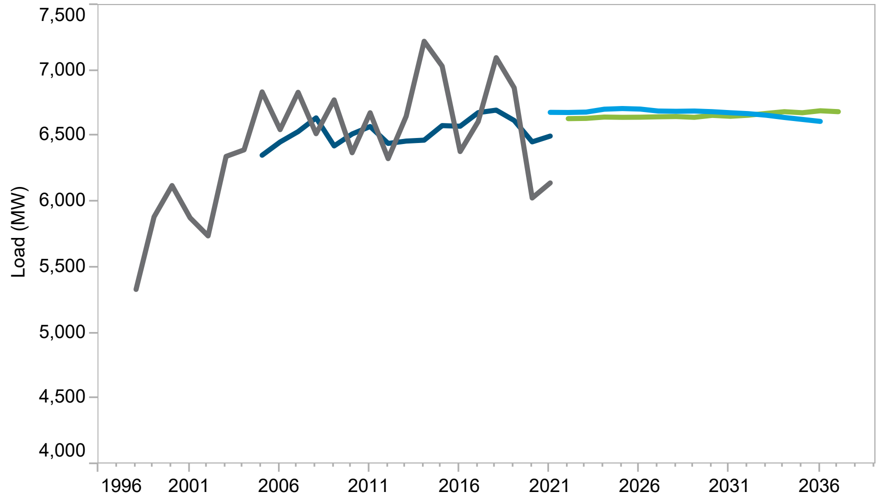
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.2%
WINTER	0.0%	0.1%

LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



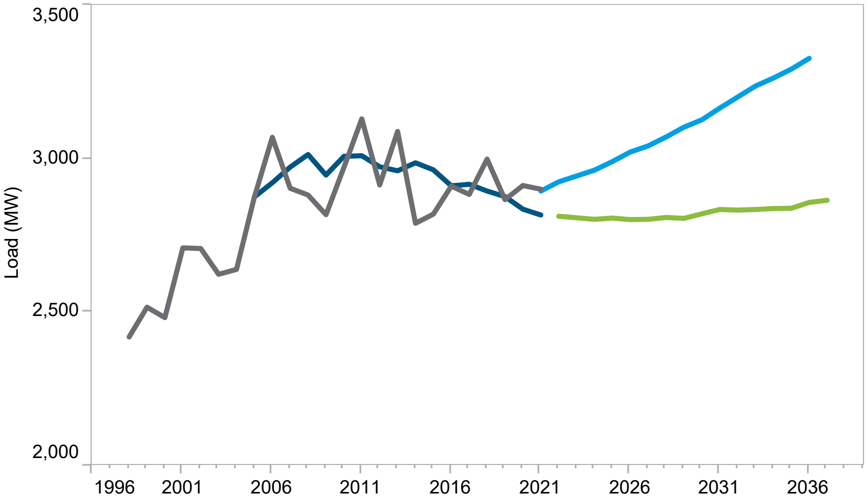
■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

Metropolitan Statistical Areas and Weather Stations

■ Montgomery County-Bucks County-Chester County, PA
■ PECO - Non-Metro
■ Philadelphia, PA

Pennsylvania Electric Company (PENLC)

Summer Peak



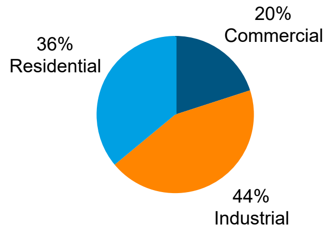
Weather - Annual Average 1994-2020

Cooling Degree Days	*698*
Heating Degree Days	*4,636*
Temperature-Humidity Index	*81.7*
Wind-Adjusted Temperature	*8.1*

Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	-0.1%	0.0%

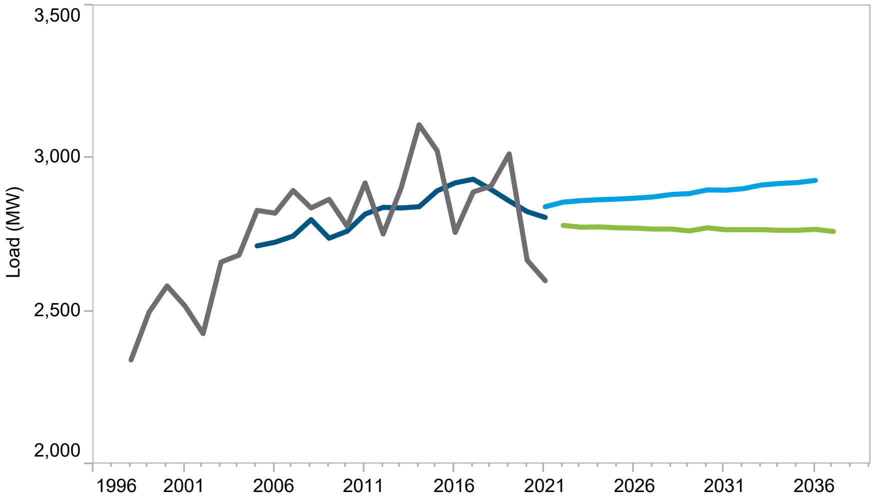
RCI Makeup



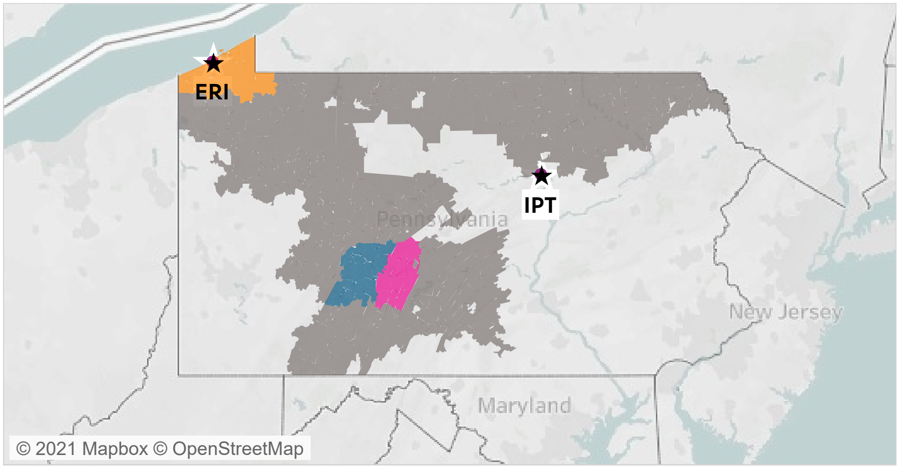
LDAs

FE-EAST PJM MID-ATLANTIC PJM RTO
WESTERN MID-ATLANTIC

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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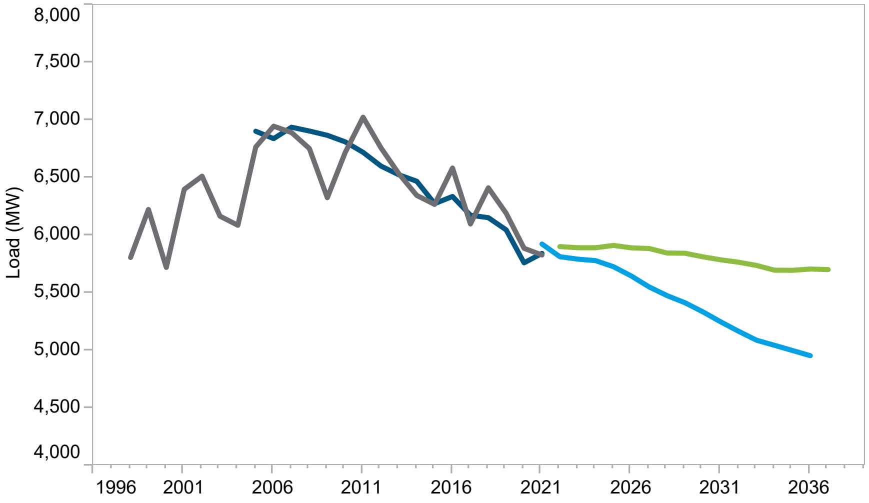
- Altoona, PA
- Erie, PA
- Johnstown, PA
- PENLC - Non-Metro

- Peak
- WN peak
- Forecast 2021
- Forecast 2022

Potomac Electric Power (PEPCO)

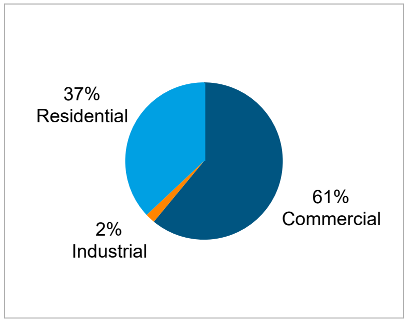
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,533*
Heating Degree Days	*2,900*
Temperature-Humidity Index	*85.3*
Wind-Adjusted Temperature	*17.7*

RCI Makeup



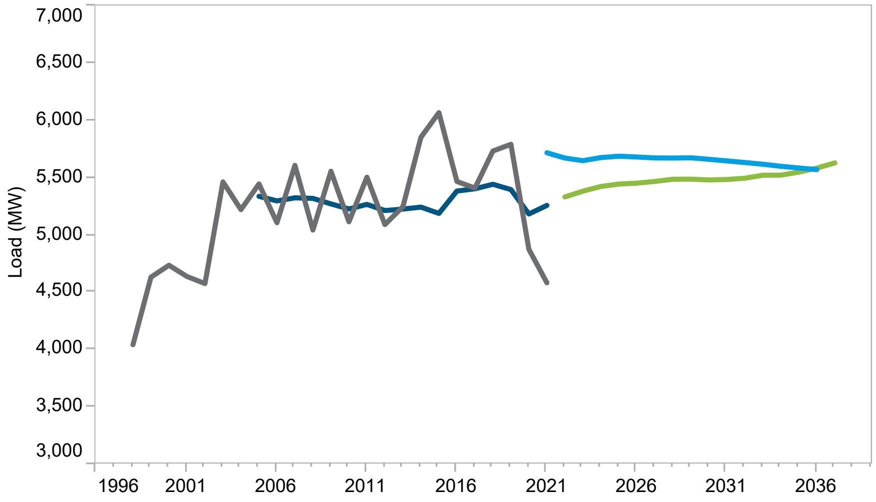
Zonal 10/15 Year Load Growth

SUMMER	-0.2%	-0.2%
WINTER	0.3%	0.4%

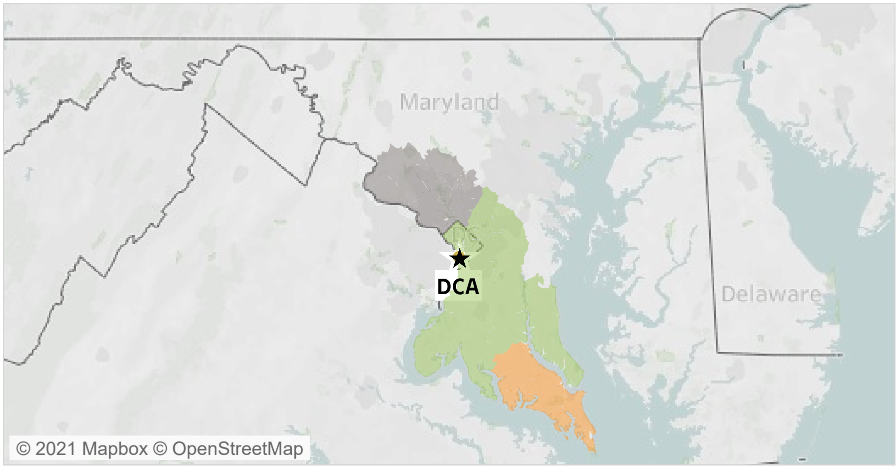
LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO SOUTHERN MID-ATLANTIC

Winter Peak



Metropolitan Statistical Areas and Weather Stations

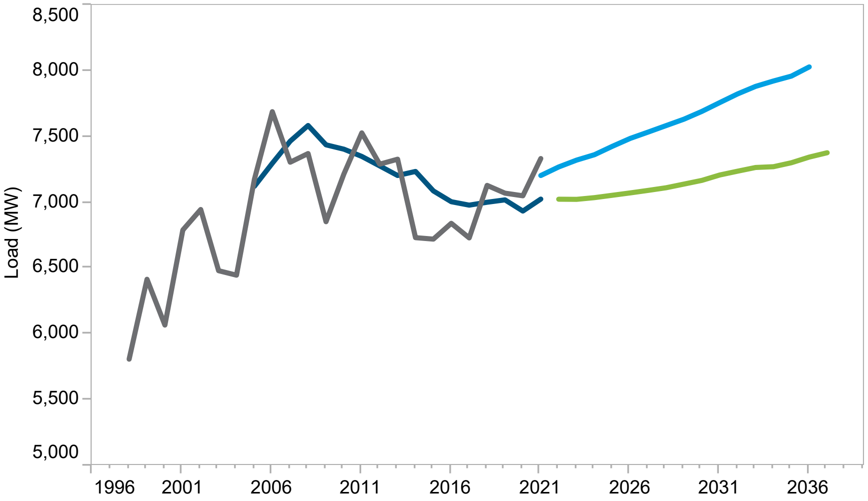


- 🟧 California-Lexington Park, MD
- ⬜ PEPCO - Non-Metro
- 🟩 Washington-Arlington-Alexandria, DC-VA-MD-WV

- ⬛ Peak
- 🟦 WN peak
- 🟦 Forecast 2021
- 🟩 Forecast 2022

PPL Electric Utilities (PL)

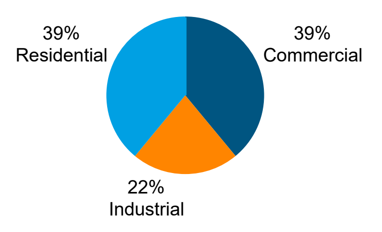
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*830*
Heating Degree Days	*4,333*
Temperature-Humidity Index	*82.9*
Wind-Adjusted Temperature	*9.8*

RCI Makeup



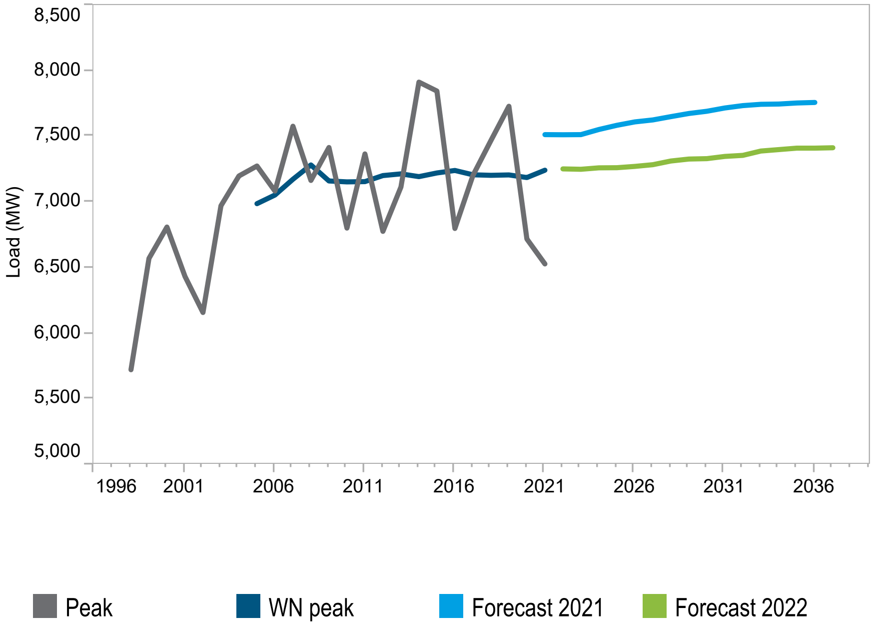
Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.3%
WINTER	0.1%	0.1%

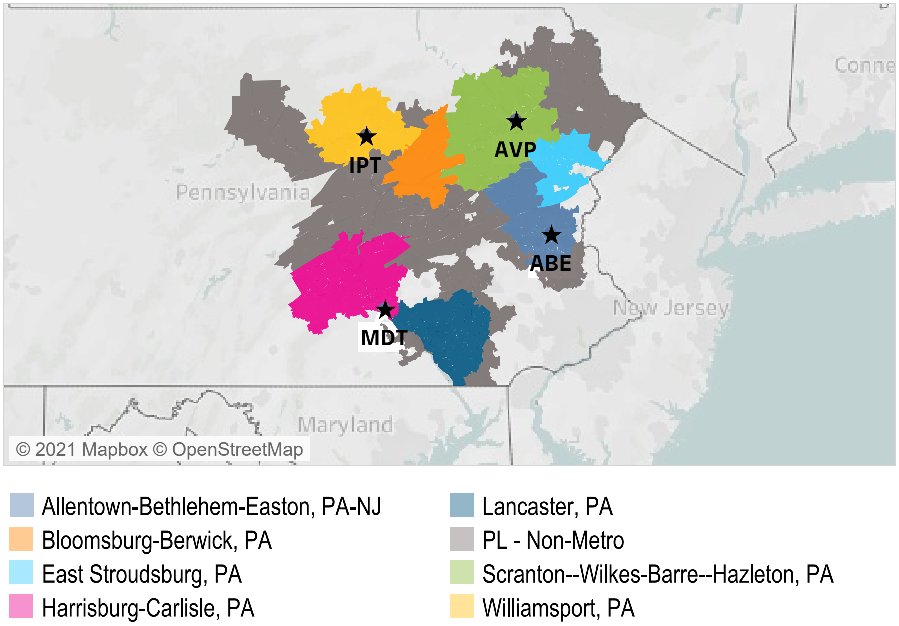
LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO PLGRP WESTERN MID-ATLANTIC

Winter Peak

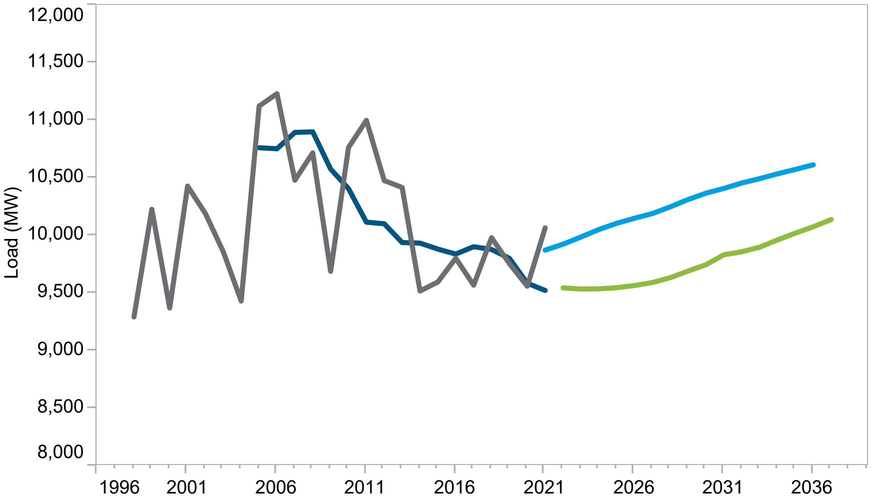


Metropolitan Statistical Areas and Weather Stations



Public Service Electric & Gas (PS)

Summer Peak



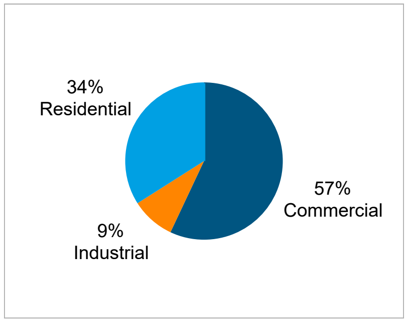
Weather - Annual Average 1994-2020

Cooling Degree Days	*1,242*
Heating Degree Days	*3,549*
Temperature-Humidity Index	*84.7*
Wind-Adjusted Temperature	*11.1*

Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.4%
WINTER	0.8%	0.9%

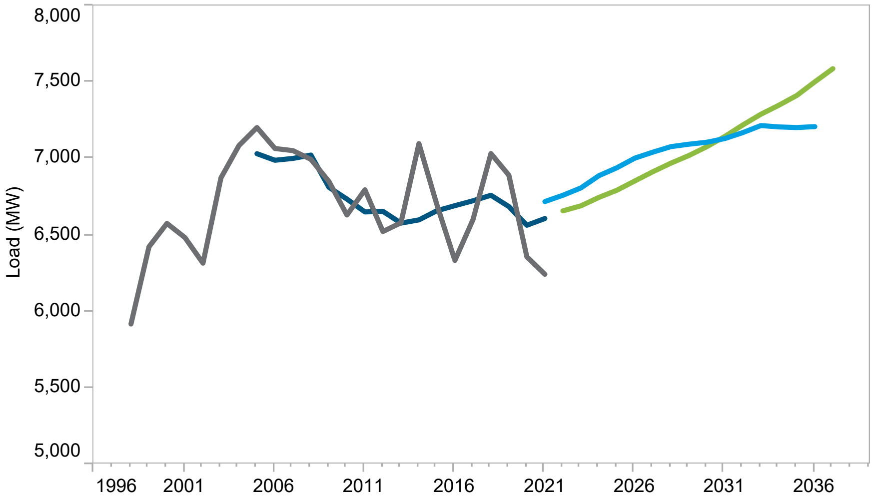
RCI Makeup



LDAs

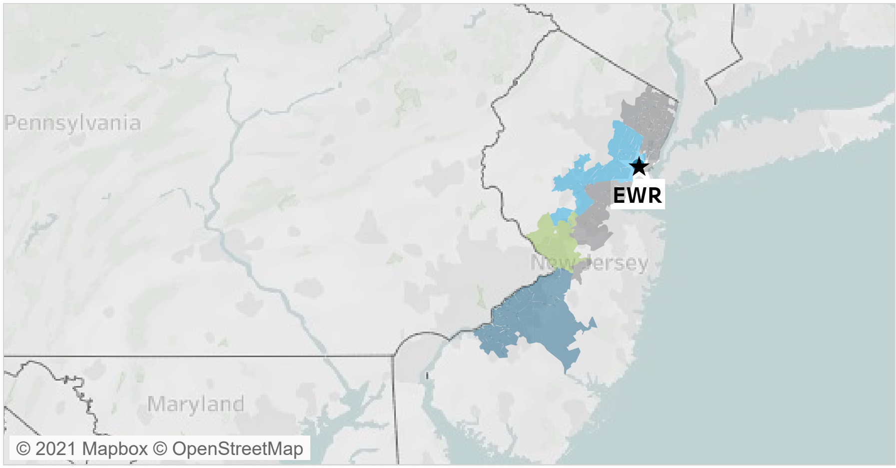
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

Metropolitan Statistical Areas and Weather Stations



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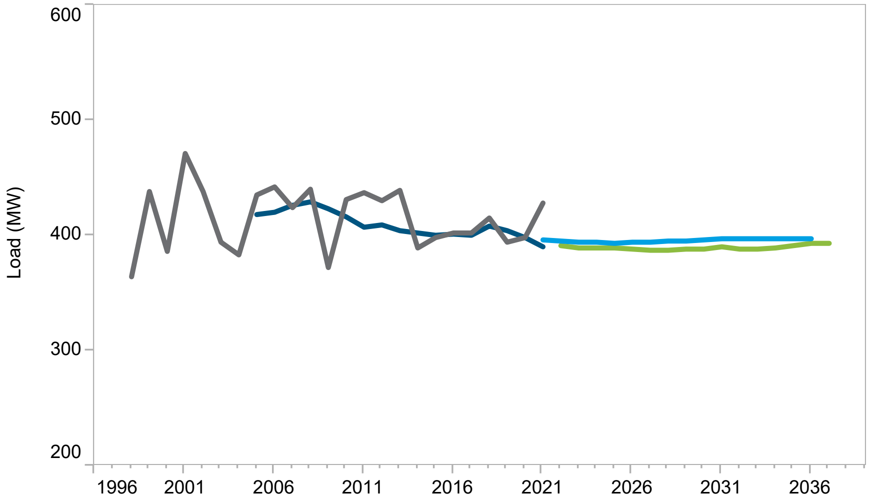
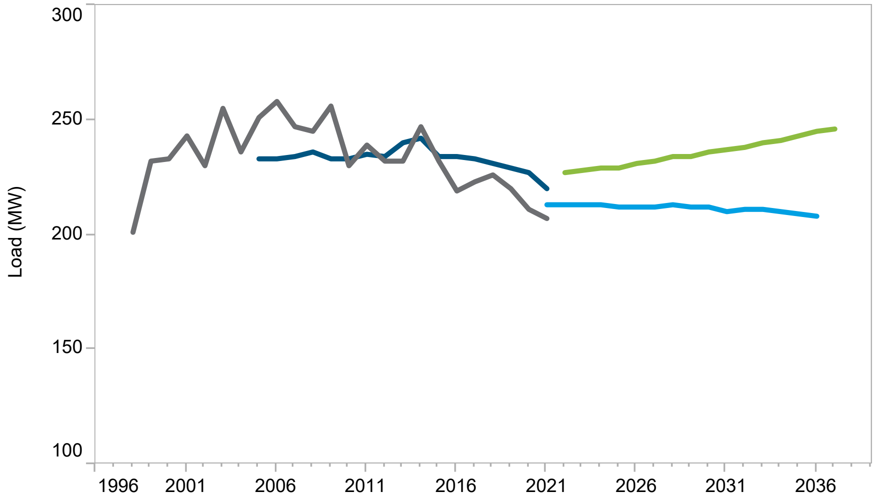
■ Camden, NJ
■ Newark, NJ-PA
■ PS - Non-Metro
■ Trenton, NJ

Rockland Electric Company (RECO)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

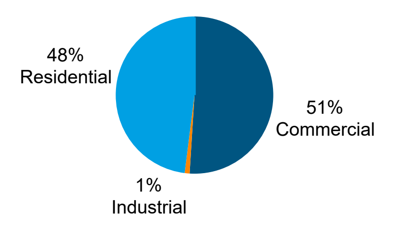
Weather - Annual Average 1994-2020

Cooling Degree Days	*1,242*
Heating Degree Days	*3,549*
Temperature-Humidity Index	*84.7*
Wind-Adjusted Temperature	*11.1*

Zonal 10/15 Year Load Growth

SUMMER	-0.1%	0.0%
WINTER	0.5%	0.5%

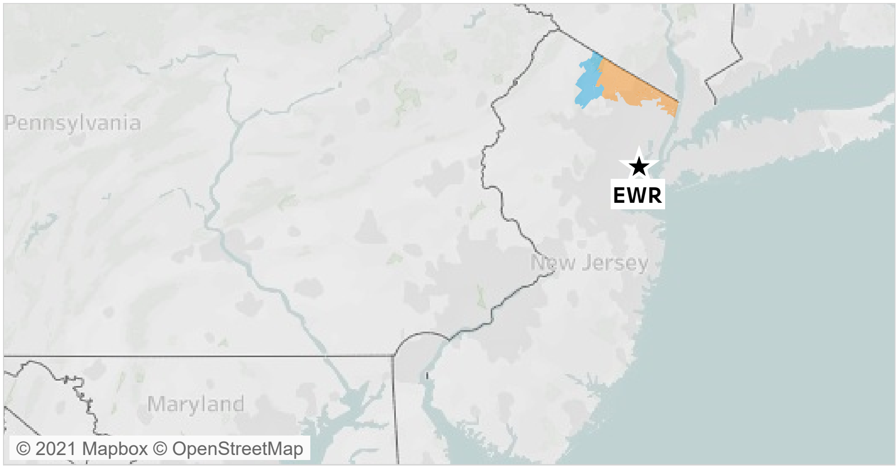
RCI Makeup



LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

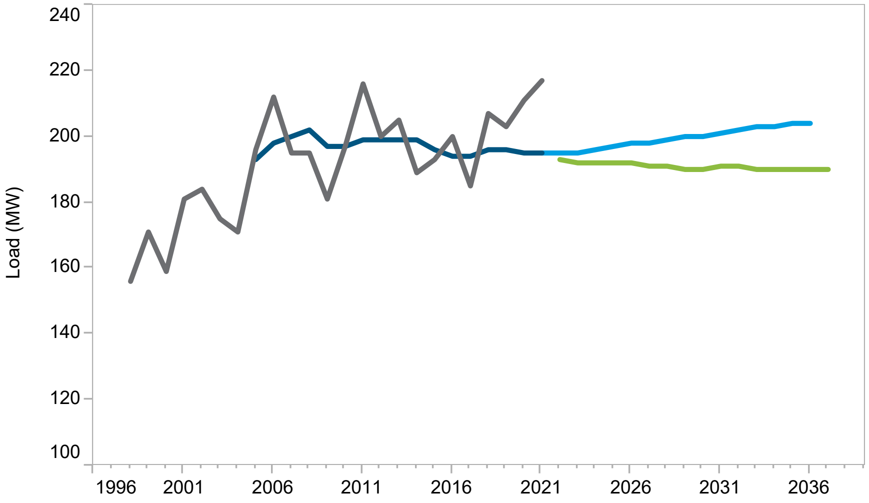
Metropolitan Statistical Areas and Weather Stations



■ New York-Jersey City-White Plains, NY-NJ
■ Newark, NJ-PA

UGI Energy Services (UGI)

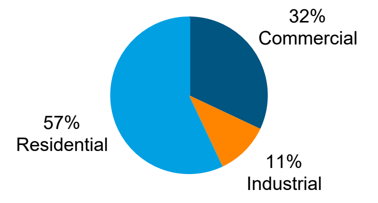
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*661*
Heating Degree Days	*4,689*
Temperature-Humidity Index	*82.2*
Wind-Adjusted Temperature	*6.4*

RCI Makeup



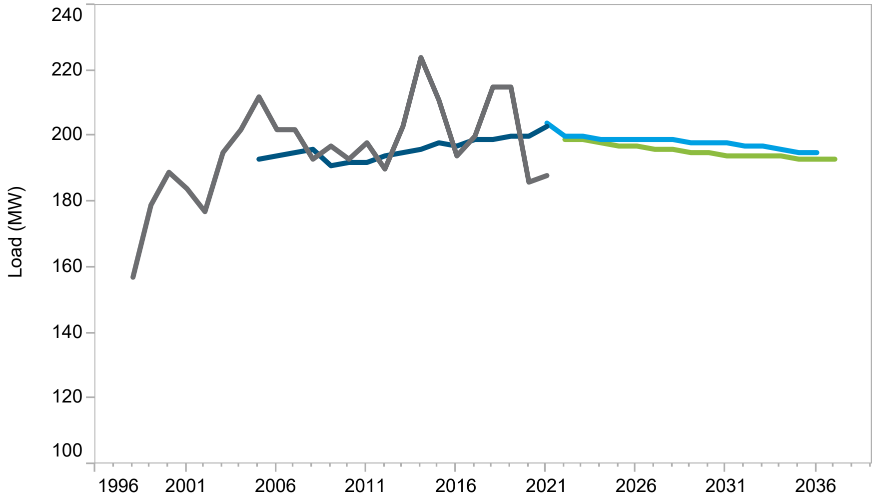
Zonal 10/15 Year Load Growth

SUMMER	-0.1%	-0.1%
WINTER	-0.3%	-0.2%

LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO PLGRP WESTERN MID-ATLANTIC

Winter Peak



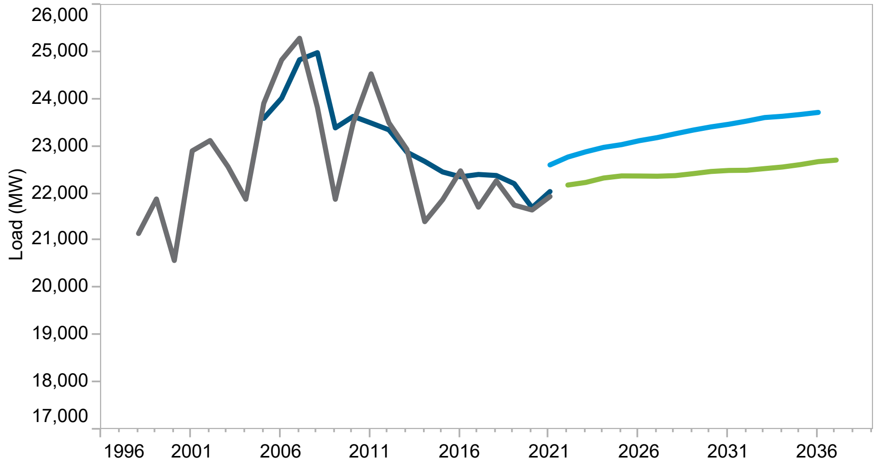
Metropolitan Statistical Areas and Weather Stations

■ Scranton--Wilkes-Barre--Hazleton, PA

■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

American Electric Power (AEP)

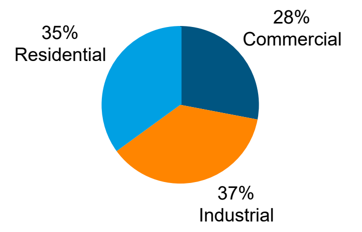
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*927*
Heating Degree Days	*3,939*
Temperature-Humidity Index	*82.2*
Wind-Adjusted Temperature	*9.2*

RCI Makeup



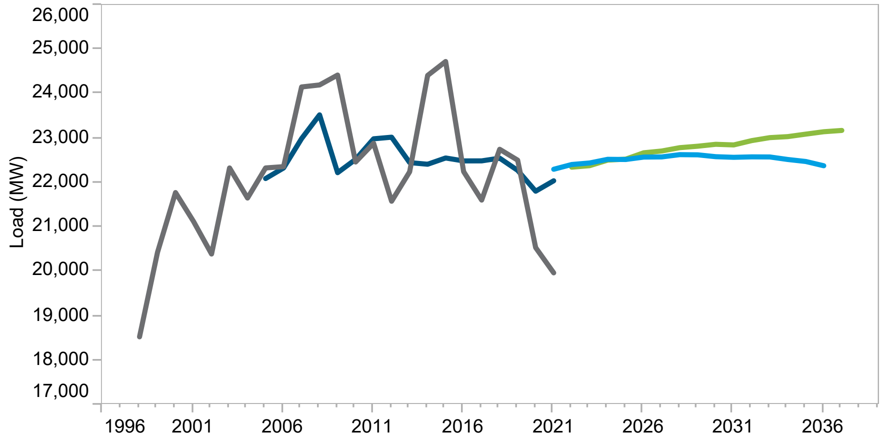
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.2%
WINTER	0.3%	0.2%

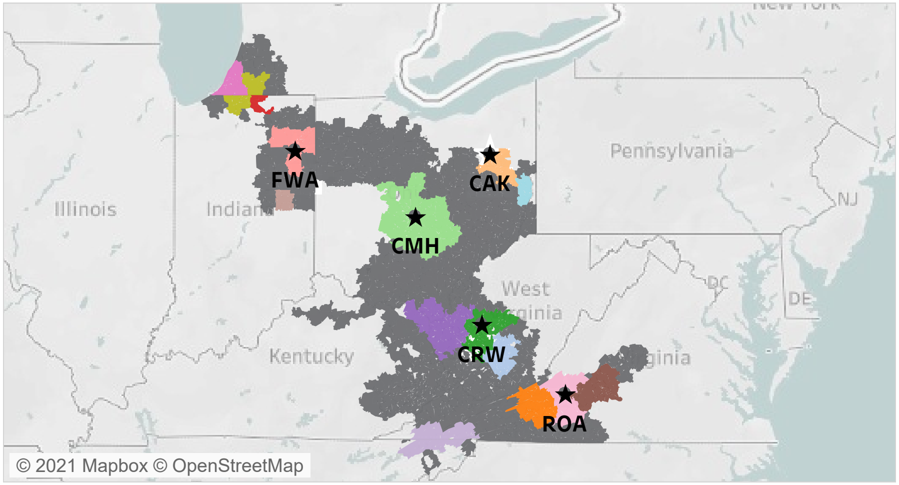
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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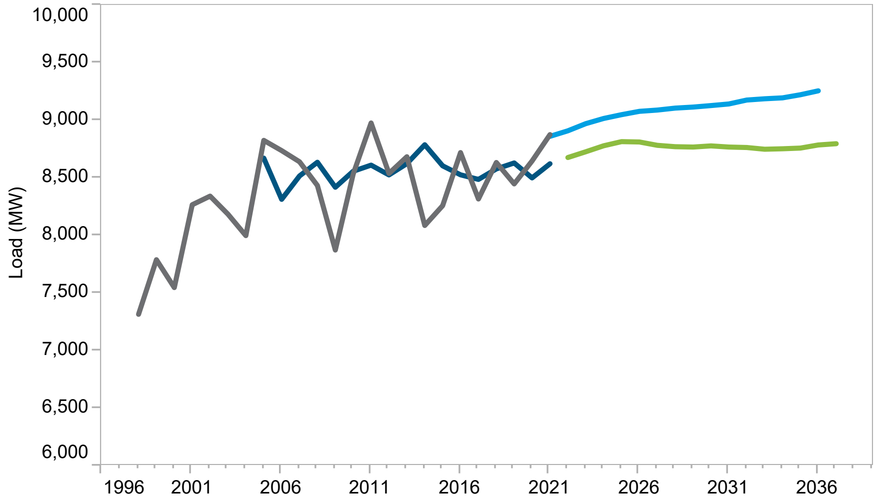
- ■ Peak
- ■ WN peak
- ■ Forecast 2021
- ■ Forecast 2022

- ■ AEP - Non-Metro
- ■ Beckley, WV
- ■ Blacksburg-Christiansburg-Radford, VA
- ■ Canton-Massillon, OH
- ■ Charleston, WV
- ■ Columbus, OH
- ■ Elkhart-Goshen, IN
- ■ Fort Wayne, IN
- ■ Huntington-Ashland, WV-KY-OH
- ■ Kingsport-Bristol-Bristol, TN-VA
- ■ Lynchburg, VA
- ■ Muncie, IN
- ■ Niles-Benton Harbor, MI
- ■ Roanoke, VA
- ■ South Bend-Mishawaka, IN-MI
- ■ Weirton-Steubenville, WV-OH

Allegheny Power Systems (APS)

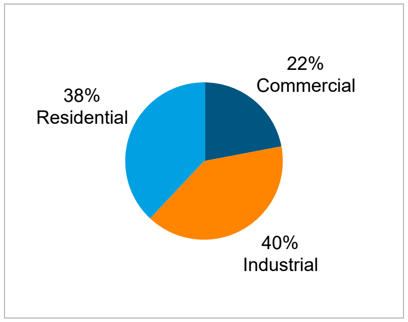
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*889*
Heating Degree Days	*4,054*
Temperature-Humidity Index	*82.2*
Wind-Adjusted Temperature	*8.8*

RCI Makeup



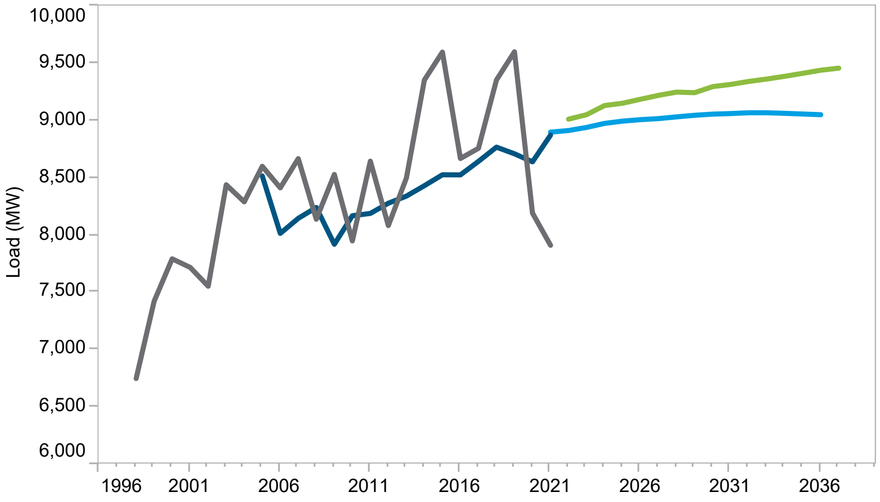
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.4%	0.3%

LDAs

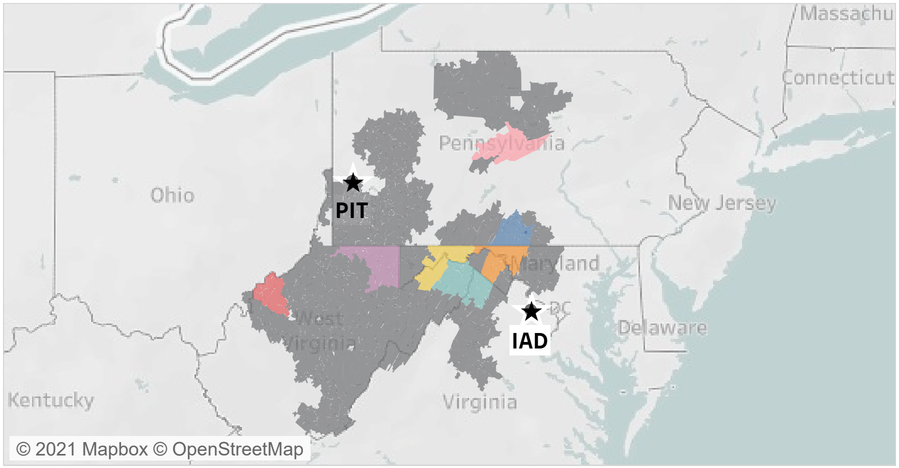
PJM RTO PJM WESTERN

Winter Peak



■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

Metropolitan Statistical Areas and Weather Stations



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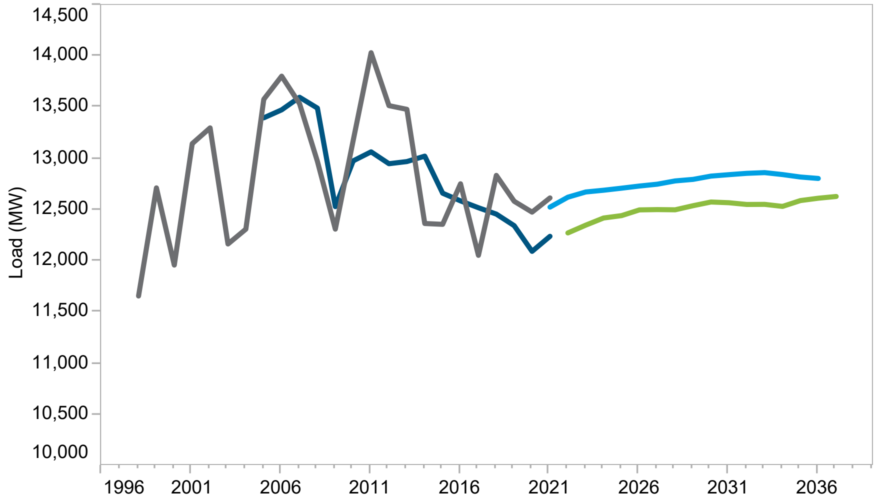
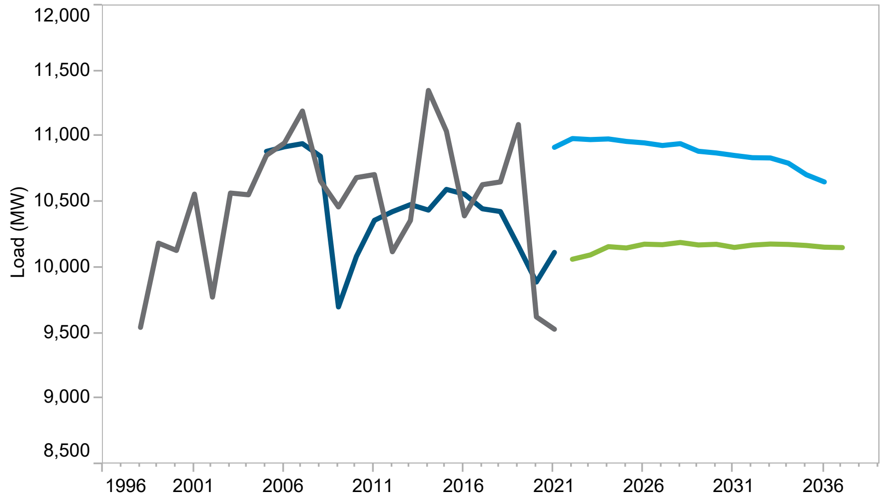
■ APS - Non-metro
■ Chambersburg-Waynesboro, PA
■ Cumberland, MD-WV
■ Hagerstown-Martinsburg, MD-WV
■ Morgantown, WV
■ Parkersburg-Vienna, WV
■ State College, PA
■ Winchester, VA-WV

American Transmission Systems, Inc. (ATSI)

Summer Peak



Winter Peak

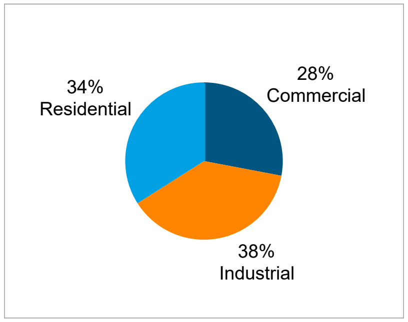


■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

Weather - Annual Average 1994-2020

Cooling Degree Days	*774*
Heating Degree Days	*4,636*
Temperature-Humidity Index	*81.9*
Wind-Adjusted Temperature	*4.3*

RCI Makeup



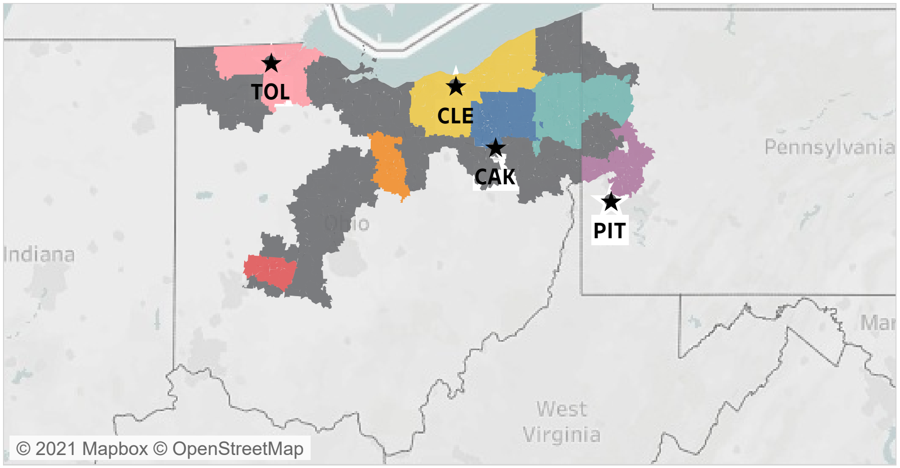
Zonal 10/15 Year Load Growth

SUMMER	0.2%	0.2%
WINTER	0.1%	0.1%

LDAs

PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations



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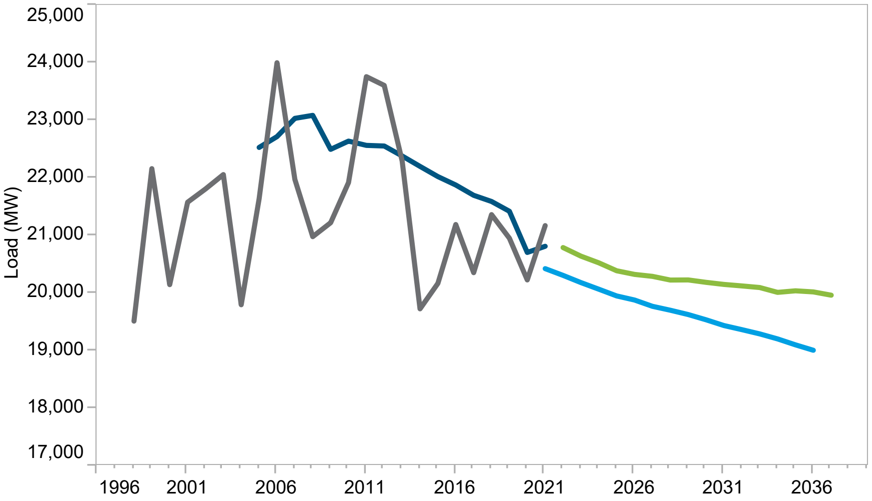
- ■ Akron, OH
- ■ ATSI - Non-Metro
- ■ Cleveland-Elyria, OH
- ■ Mansfield, OH
- ■ Pittsburgh, PA
- ■ Springfield, OH
- ■ Toledo, OH
- ■ Youngstown-Warren-Boardman, OH-PA

Commonweath Edison (COMED)

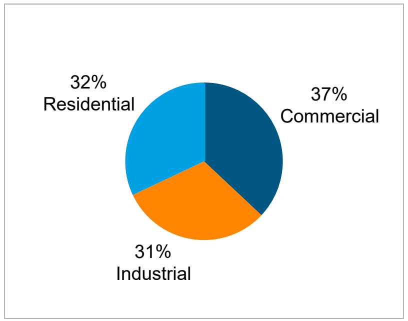
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*927*
Heating Degree Days	*4,920*
Temperature-Humidity Index	*84.0*
Wind-Adjusted Temperature	*-1.2*

RCI Makeup



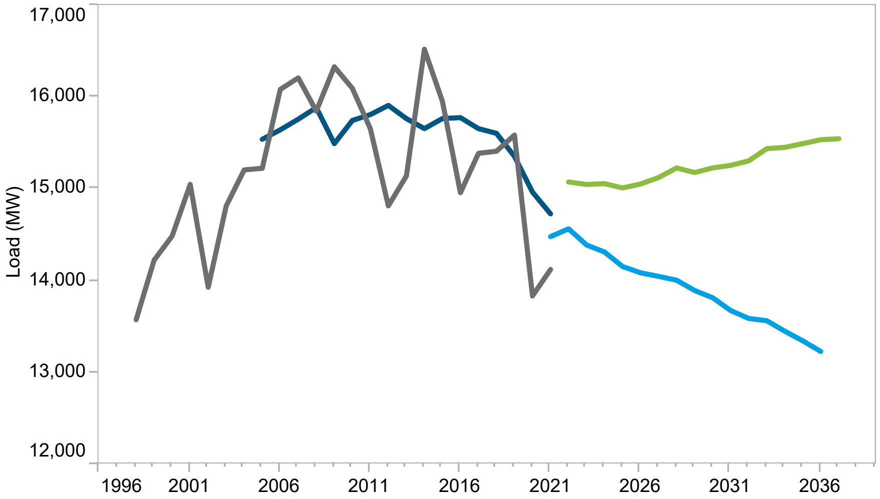
Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.3%
WINTER	0.2%	0.2%

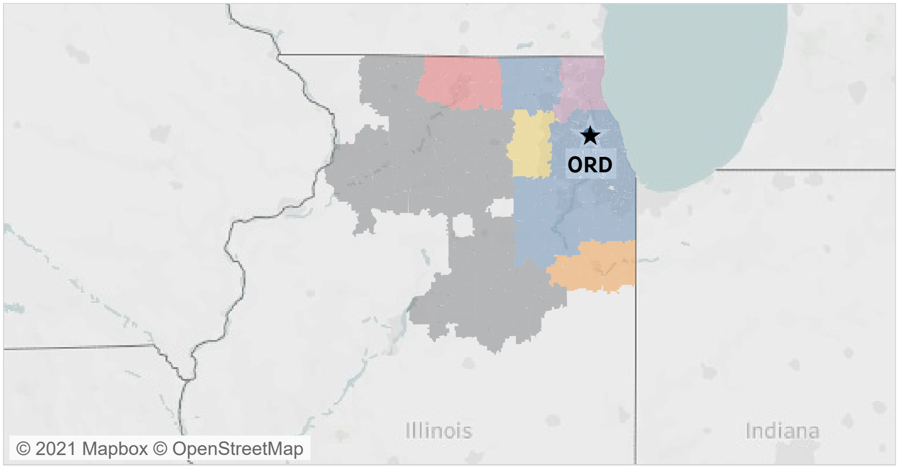
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

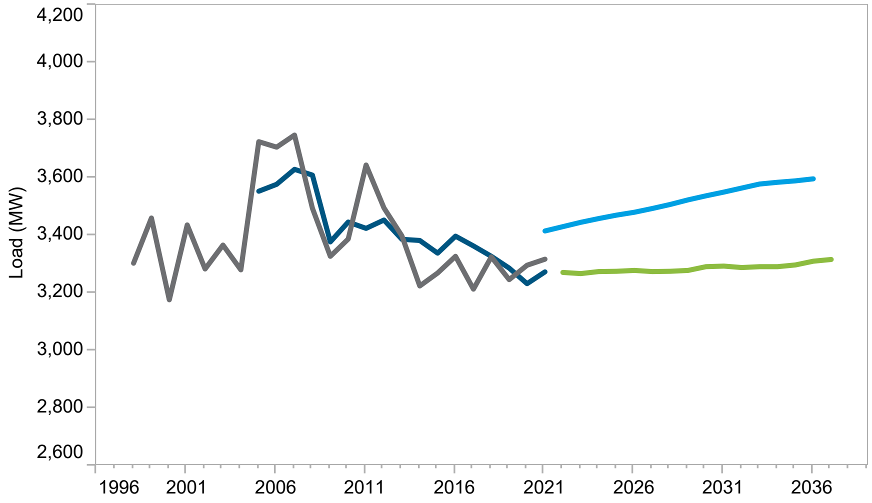


- ▨ Chicago-Naperville-Arlington Heights, IL
- ▨ Chicago-Naperville-Elgin, IL-IN-WI
- ▨ COMED - Non-Metro
- ▨ Kankakee, IL
- ▨ Lake County-Kenosha County, IL-WI
- ▨ Rockford, IL

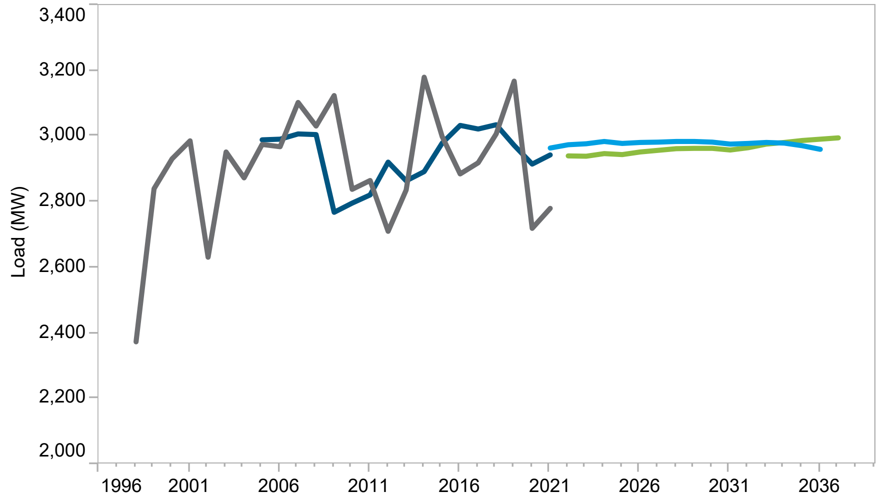
■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

Dayton Power and Light (DAYTON)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

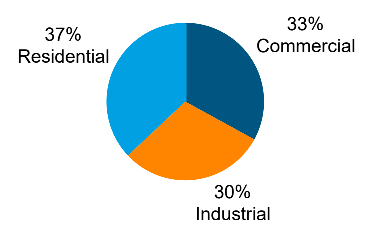
Weather - Annual Average 1994-2020

Cooling Degree Days	*951*
Heating Degree Days	*4,308*
Temperature-Humidity Index	*83.1*
Wind-Adjusted Temperature	*3.4*

Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.1%	0.1%

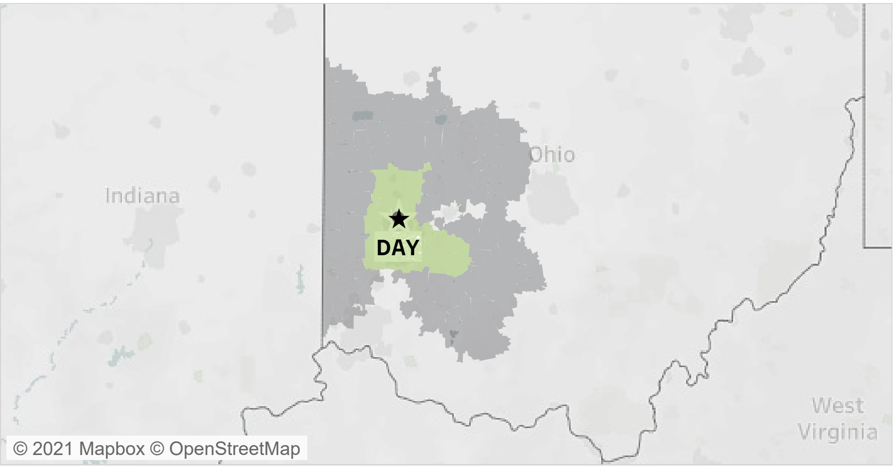
RCI Makeup



LDAs

PJM RTO PJM WESTERN

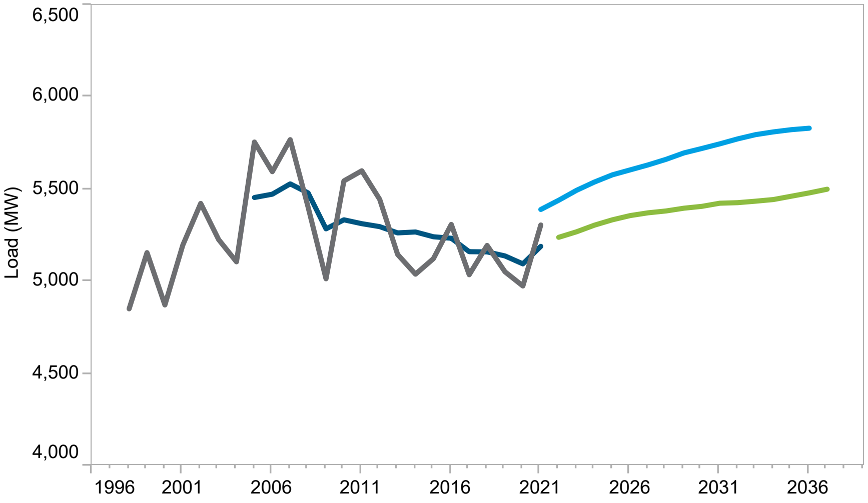
Metropolitan Statistical Areas and Weather Stations



■ DAY - Non-Metro
■ Dayton, OH

Duke Energy Ohio and Kentucky (DEOK)

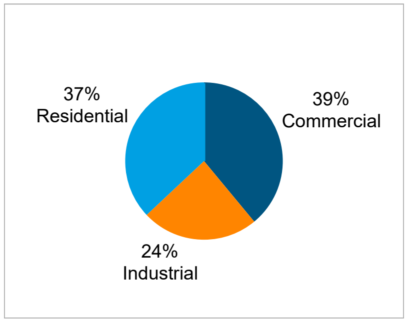
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,099*
Heating Degree Days	*3,792*
Temperature-Humidity Index	*83.8*
Wind-Adjusted Temperature	*8.2*

RCI Makeup



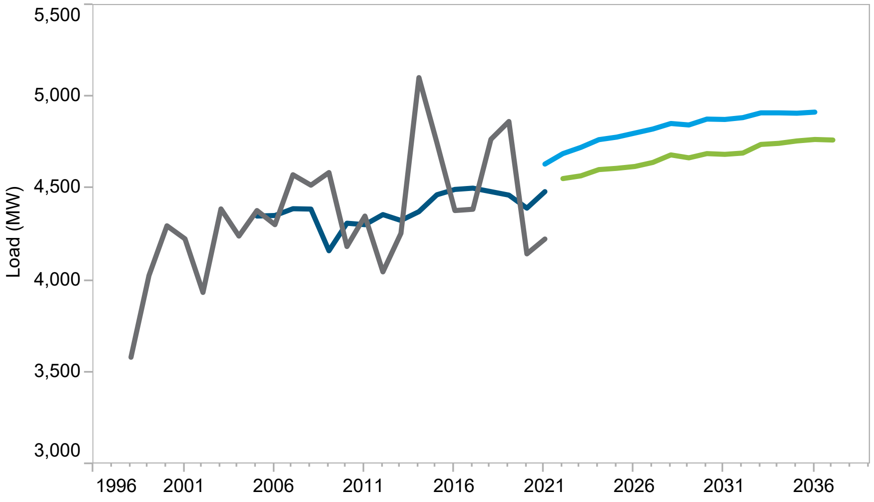
Zonal 10/15 Year Load Growth

SUMMER	0.4%	0.3%
WINTER	0.3%	0.3%

LDAs

PJM RTO PJM WESTERN

Winter Peak



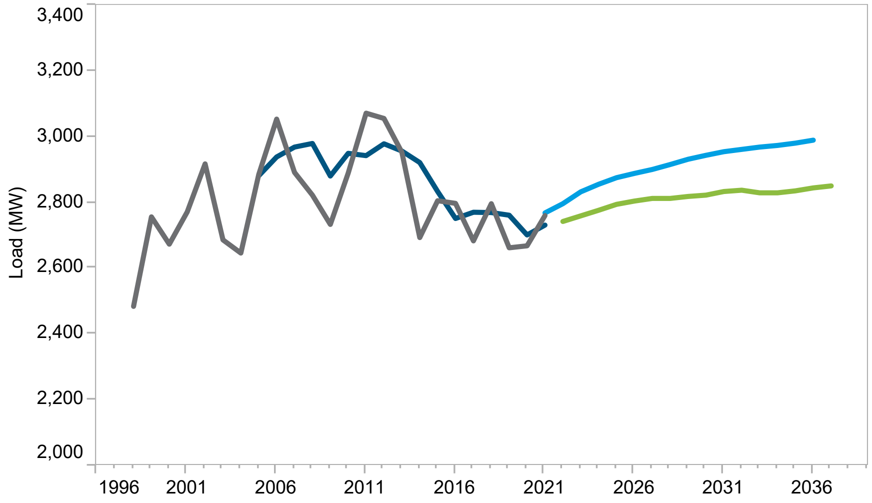
■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

Metropolitan Statistical Areas and Weather Stations

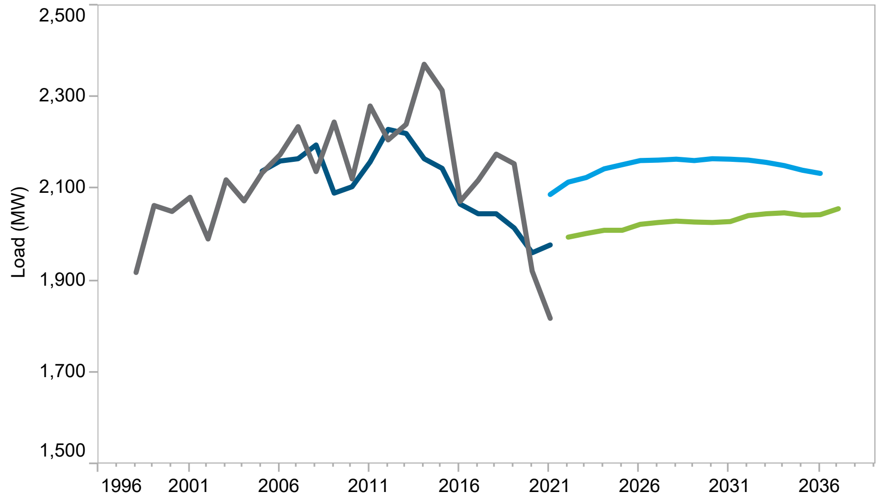
■ Cincinnati, OH-KY-IN
■ DEOK - Non-Metro

Duquesne Light Company (DLCO)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2021 ■ Forecast 2022

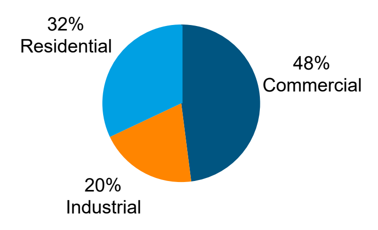
Weather - Annual Average 1994-2020

Cooling Degree Days	*787*
Heating Degree Days	*4,347*
Temperature-Humidity Index	*81.9*
Wind-Adjusted Temperature	*5.4*

Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.3%
WINTER	0.2%	0.2%

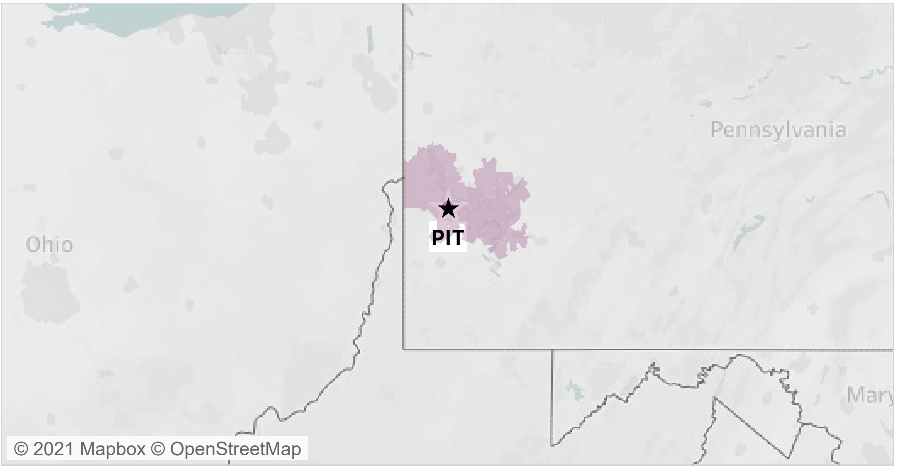
RCI Makeup



LDAs

PJM RTO PJM WESTERN

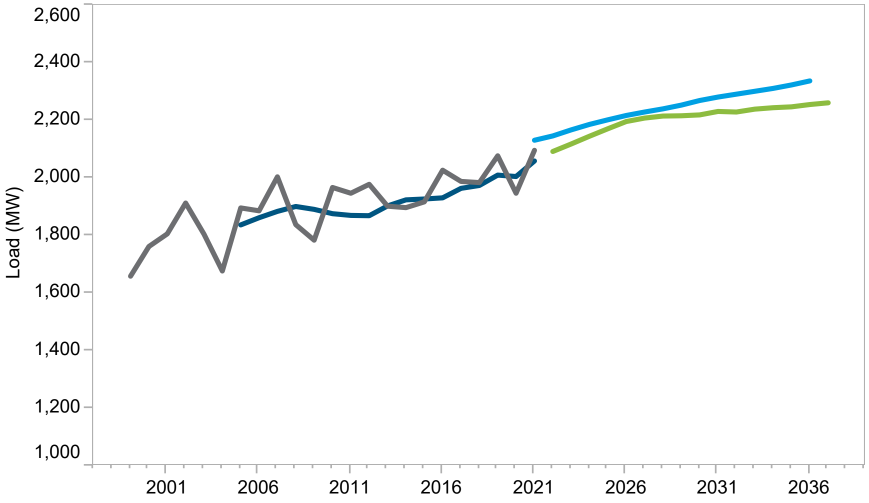
Metropolitan Statistical Areas and Weather Stations



■ Pittsburgh, PA

East Kentucky Power Cooperative (EKPC)

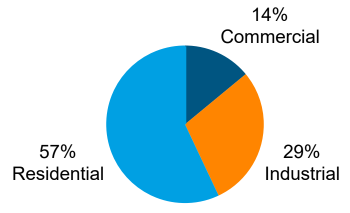
Summer Peak



Weather - Annual Average 1994-2020

Cooling Degree Days	*1,243*
Heating Degree Days	*3,433*
Temperature-Humidity Index	*83.9*
Wind-Adjusted Temperature	*11.0*

RCI Makeup



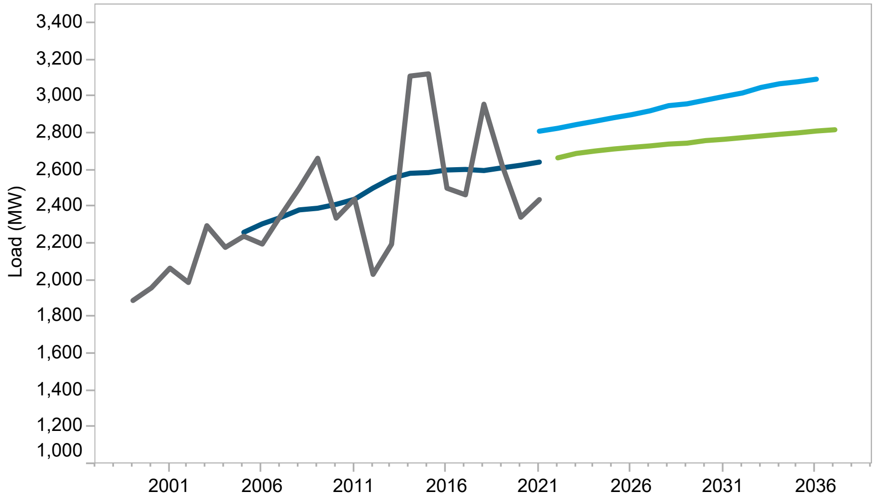
Zonal 10/15 Year Load Growth

SUMMER	0.6%	0.5%
WINTER	0.4%	0.4%

LDAs

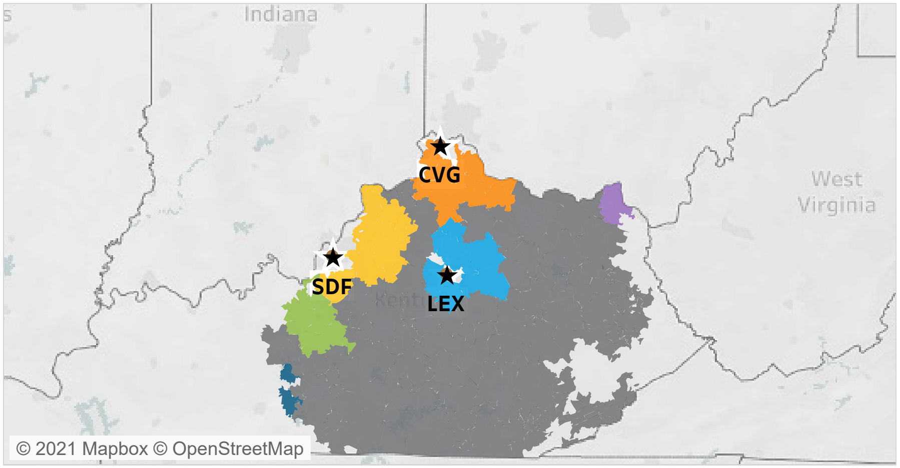
PJM RTO PJM WESTERN

Winter Peak



■ Peak
■ WN peak
■ Forecast 2021
■ Forecast 2022

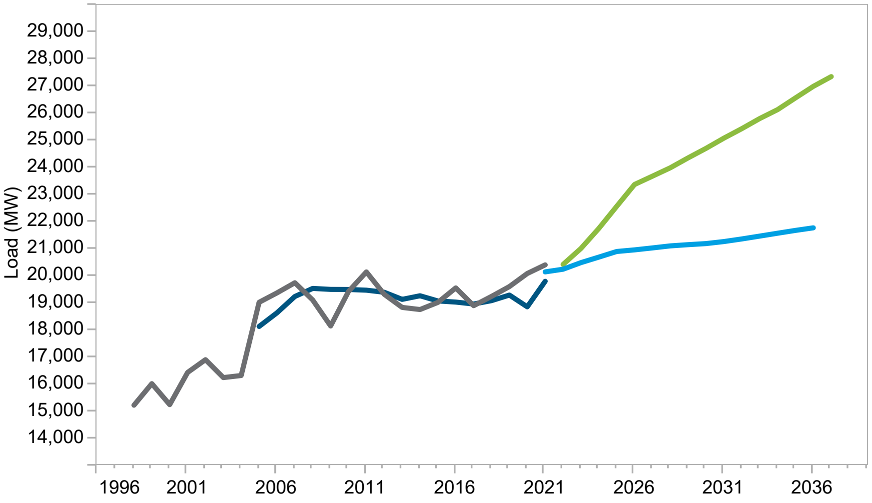
Metropolitan Statistical Areas and Weather Stations



■ Bowling Green, KY
■ Cincinnati, OH-KY-IN
■ EKPC - Non-Metro
■ Elizabethtown-Fort Knox, KY
■ Huntington-Ashland, WV-KY-OH
■ Lexington-Fayette, KY
■ Louisville/Jefferson County, KY-IN

Dominion (DOM)

Summer Peak



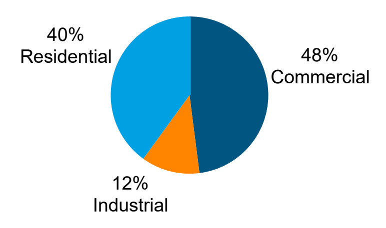
Weather - Annual Average 1994-2020

Cooling Degree Days	*1,403*
Heating Degree Days	*2,749*
Temperature-Humidity Index	*84.7*
Wind-Adjusted Temperature	*20.5*

Zonal 10/15 Year Load Growth

SUMMER	2.2%	2.0%
WINTER	2.6%	2.2%

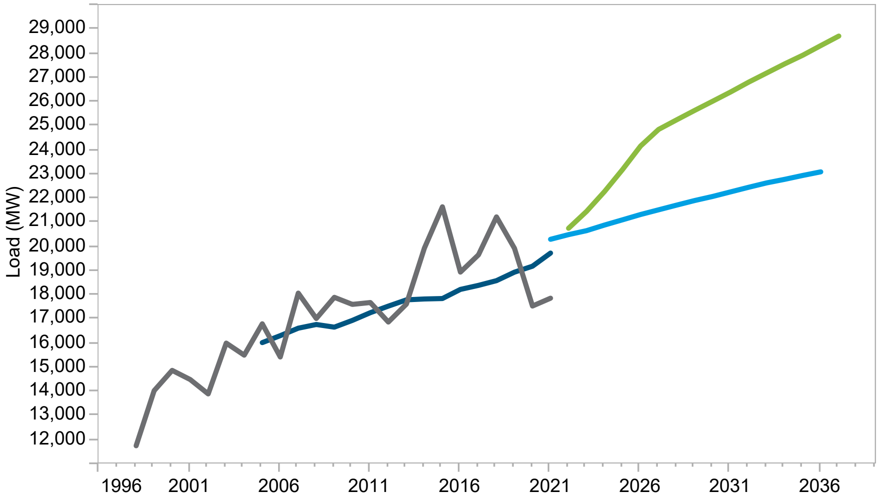
RCI Makeup



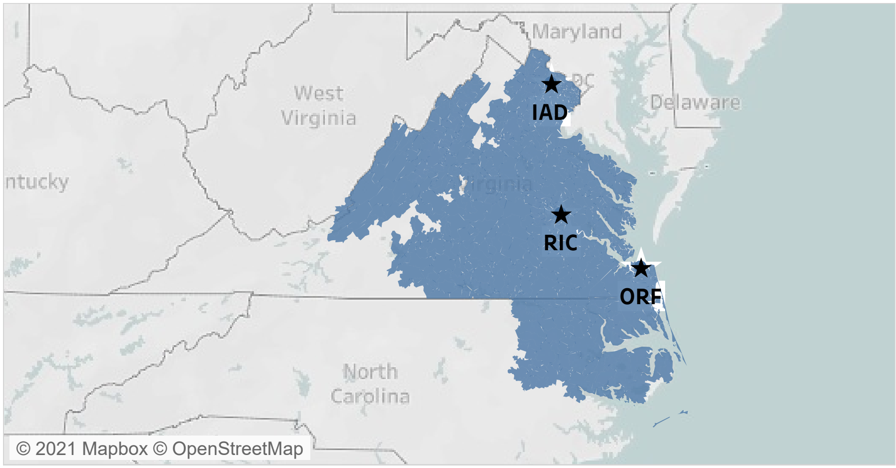
LDAs

PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



▨ Virginia Commonwealth Economics

▨ Peak ▨ WN peak ▨ Forecast 2021 ▨ Forecast 2022

Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2021 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2022		2027		2032	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	(4)	-0.2%	(57)	-2.2%	(81)	-3.1%
BGE	(192)	-2.9%	(282)	-4.2%	(285)	-4.3%
DPL	(33)	-0.8%	(62)	-1.6%	(97)	-2.5%
JCPL	(60)	-1.0%	(289)	-4.8%	(371)	-5.9%
METED	(151)	-4.9%	(204)	-6.4%	(214)	-6.5%
PECO	(81)	-1.0%	(229)	-2.7%	(224)	-2.6%
PENLC	(112)	-3.8%	(239)	-7.9%	(368)	-11.5%
PEPCO	88	1.5%	334	6.0%	600	11.6%
PL	(245)	-3.4%	(443)	-5.9%	(587)	-7.5%
PS	(380)	-3.8%	(599)	-5.9%	(597)	-5.7%
RECO	(4)	-1.0%	(7)	-1.8%	(9)	-2.3%
UGI	(2)	-1.0%	(7)	-3.5%	(11)	-5.4%
PJM MID-ATLANTIC	(893)	-1.6%	(2,156)	-3.8%	(2,238)	-3.9%
FE-EAST	(418)	-3.6%	(830)	-6.9%	(1,031)	-8.2%
PLGRP	(258)	-3.5%	(467)	-6.0%	(606)	-7.6%

Table A-1

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2021 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2022		2027		2032	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	(593)	-2.6%	(818)	-3.5%	(1,042)	-4.4%
APS	(232)	-2.6%	(306)	-3.4%	(412)	-4.5%
ATSI	(349)	-2.8%	(248)	-1.9%	(304)	-2.4%
COMED	483	2.4%	520	2.6%	759	3.9%
DAYTON	(159)	-4.6%	(219)	-6.3%	(276)	-7.7%
DEOK	(201)	-3.7%	(260)	-4.6%	(346)	-6.0%
DLCO	(54)	-1.9%	(88)	-3.0%	(124)	-4.2%
EKPC	(54)	-2.5%	(21)	-0.9%	(62)	-2.7%
OVEC	0	0.0%	0	0.0%	0	0.0%
PJM WESTERN	(590)	-0.8%	(851)	-1.1%	(1,278)	-1.7%
DOM	176	0.9%	2,647	12.6%	4,069	19.0%
PJM RTO	(1,028)	-0.7%	(249)	-0.2%	336	0.2%

Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST
TO THE JANUARY 2021 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	21/22		26/27		31/32	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	69	4.5%	72	4.5%	98	6.1%
BGE	(276)	-4.6%	(269)	-4.3%	(230)	-3.6%
DPL	(295)	-7.6%	(302)	-7.5%	(309)	-7.4%
JCPL	17	0.5%	(47)	-1.2%	(24)	-0.6%
METED	(106)	-3.9%	(159)	-5.8%	(181)	-6.4%
PECO	(47)	-0.7%	(44)	-0.7%	(12)	-0.2%
PENLC	(76)	-2.7%	(105)	-3.7%	(134)	-4.6%
PEPCO	(339)	-6.0%	(205)	-3.6%	(137)	-2.4%
PL	(260)	-3.5%	(341)	-4.5%	(379)	-4.9%
PS	(102)	-1.5%	(128)	-1.8%	50	0.7%
RECO	14	6.6%	20	9.4%	27	12.8%
UGI	(1)	-0.5%	(3)	-1.5%	(3)	-1.5%
PJM MID-ATLANTIC	(726)	-1.6%	(963)	-2.0%	(722)	-1.5%
FE-EAST	(108)	-1.2%	(240)	-2.6%	(297)	-3.1%
PLGRP	(257)	-3.3%	(339)	-4.3%	(380)	-4.8%

Table A-2

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2021 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	21/22		26/27		31/32	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	(60)	-0.3%	133	0.6%	366	1.6%
APS	99	1.1%	203	2.3%	273	3.0%
ATSI	(921)	-8.4%	(757)	-6.9%	(667)	-6.2%
COMED	510	3.5%	1,077	7.7%	1,716	12.6%
DAYTON	(34)	-1.1%	(25)	-0.8%	(13)	-0.4%
DEOK	(136)	-2.9%	(182)	-3.8%	(193)	-3.9%
DLCO	(120)	-5.7%	(136)	-6.3%	(121)	-5.6%
EKPC	(161)	-5.7%	(191)	-6.5%	(243)	-8.0%
OVEC	(5)	-4.2%	(5)	-4.2%	(5)	-4.2%
PJM WESTERN	(639)	-0.9%	238	0.3%	1,094	1.6%
DOM	263	1.3%	3,327	15.5%	4,351	19.4%
PJM RTO	(530)	-0.4%	3,144	2.3%	5,717	4.2%

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2022 - 2032

	METERED 2021	UNRESTRICTED 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Growth Rate (10 yr)
AE	2,631	2,631	2,488	2,490	2,493	2,479	2,478	2,484	2,503	2,511	2,527	2,528	2,541	0.2%
				0.1%	0.1%	-0.6%	-0.0%	0.2%	0.8%	0.3%	0.6%	0.0%	0.5%	
BGE	6,486	6,486	6,414	6,391	6,389	6,390	6,401	6,398	6,391	6,404	6,399	6,384	6,350	(0.1%)
				-0.4%	-0.0%	0.0%	0.2%	-0.0%	-0.1%	0.2%	-0.1%	-0.2%	-0.5%	
DPL	4,007	4,007	3,873	3,882	3,893	3,899	3,902	3,907	3,917	3,924	3,922	3,893	3,854	(0.0%)
				0.2%	0.3%	0.2%	0.1%	0.1%	0.3%	0.2%	-0.1%	-0.7%	-1.0%	
JCPL	6,170	6,170	5,831	5,799	5,771	5,772	5,771	5,748	5,762	5,789	5,810	5,847	5,868	0.1%
				-0.5%	-0.5%	0.0%	-0.0%	-0.4%	0.2%	0.5%	0.4%	0.6%	0.4%	
METED	3,072	3,072	2,934	2,934	2,942	2,950	2,966	2,979	2,988	3,003	3,024	3,042	3,060	0.4%
				0.0%	0.3%	0.3%	0.5%	0.4%	0.3%	0.5%	0.7%	0.6%	0.6%	
PECO	8,480	8,480	8,370	8,386	8,419	8,414	8,411	8,385	8,390	8,417	8,461	8,484	8,471	0.1%
				0.2%	0.4%	-0.1%	-0.0%	-0.3%	0.1%	0.3%	0.5%	0.3%	-0.2%	
PENLC	2,900	2,900	2,812	2,807	2,802	2,806	2,801	2,802	2,808	2,805	2,820	2,834	2,832	0.1%
				-0.2%	-0.2%	0.1%	-0.2%	0.0%	0.2%	-0.1%	0.5%	0.5%	-0.1%	
PEPCO	5,829	5,829	5,902	5,892	5,892	5,912	5,891	5,885	5,846	5,844	5,813	5,787	5,766	(0.2%)
				-0.2%	0.0%	0.3%	-0.4%	-0.1%	-0.7%	-0.0%	-0.5%	-0.4%	-0.4%	
PL	7,314	7,333	7,024	7,023	7,036	7,054	7,072	7,091	7,111	7,139	7,167	7,208	7,237	0.3%
				-0.0%	0.2%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.6%	0.4%	
PS	10,065	10,065	9,543	9,534	9,535	9,545	9,564	9,590	9,632	9,690	9,745	9,831	9,857	0.3%
				-0.1%	0.0%	0.1%	0.2%	0.3%	0.4%	0.6%	0.6%	0.9%	0.3%	
RECO	428	428	391	389	389	389	388	387	387	388	388	390	388	(0.1%)
				-0.5%	0.0%	0.0%	-0.3%	-0.3%	0.0%	0.3%	0.0%	0.5%	-0.5%	
UGI	217	217	193	192	192	192	192	191	191	190	190	191	191	(0.1%)
				-0.5%	0.0%	0.0%	0.0%	-0.5%	0.0%	-0.5%	0.0%	0.5%	0.0%	
DIVERSITY - MID-ATLANTIC(-)			629	647	746	786	792	794	752	721	809	906	875	
PJM MID-ATLANTIC	56,514	56,539	55,146	55,072	55,007	55,016	55,045	55,053	55,174	55,383	55,457	55,513	55,540	0.1%
				-0.1%	-0.1%	0.0%	0.1%	0.0%	0.2%	0.4%	0.1%	0.1%	0.0%	
FE-EAST	11,925	11,925	11,334	11,296	11,255	11,239	11,251	11,270	11,305	11,341	11,369	11,440	11,504	0.1%
				-0.3%	-0.4%	-0.1%	0.1%	0.2%	0.3%	0.3%	0.2%	0.6%	0.6%	
PLGRP	7,523	7,541	7,204	7,202	7,217	7,228	7,243	7,264	7,280	7,311	7,340	7,376	7,418	0.3%
				-0.0%	0.2%	0.2%	0.2%	0.3%	0.2%	0.4%	0.4%	0.5%	0.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022).
Summer season indicates peak from June, July, August.

Table B-1 (continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2033 - 2037

	2033	2034	2035	2036	2037	Annual Growth Rate (15 yr)
AE	2,552	2,568	2,586	2,589	2,597	0.3%
	0.4%	0.6%	0.7%	0.1%	0.3%	
BGE	6,320	6,313	6,313	6,341	6,351	(0.1%)
	-0.5%	-0.1%	0.0%	0.4%	0.2%	
DPL	3,828	3,809	3,802	3,803	3,809	(0.1%)
	-0.7%	-0.5%	-0.2%	0.0%	0.2%	
JCPL	5,892	5,923	5,954	5,988	6,017	0.2%
	0.4%	0.5%	0.5%	0.6%	0.5%	
METED	3,078	3,087	3,103	3,127	3,151	0.5%
	0.6%	0.3%	0.5%	0.8%	0.8%	
PECO	8,477	8,492	8,516	8,560	8,584	0.2%
	0.1%	0.2%	0.3%	0.5%	0.3%	
PENLC	2,834	2,837	2,838	2,857	2,864	0.1%
	0.1%	0.1%	0.0%	0.7%	0.2%	
PEPCO	5,738	5,697	5,696	5,707	5,702	(0.2%)
	-0.5%	-0.7%	-0.0%	0.2%	-0.1%	
PL	7,265	7,271	7,301	7,344	7,377	0.3%
	0.4%	0.1%	0.4%	0.6%	0.4%	
PS	9,897	9,960	10,019	10,074	10,137	0.4%
	0.4%	0.6%	0.6%	0.5%	0.6%	
RECO	388	389	391	393	393	0.0%
	0.0%	0.3%	0.5%	0.5%	0.0%	
UGI	190	190	190	190	190	(0.1%)
	-0.5%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)	857	844	896	1,137	1,067	
PJM MID-ATLANTIC	55,602	55,692	55,813	55,836	56,105	0.1%
	0.1%	0.2%	0.2%	0.0%	0.5%	
FE-EAST	11,535	11,583	11,633	11,696	11,750	0.2%
	0.3%	0.4%	0.4%	0.5%	0.5%	
PLGRP	7,432	7,447	7,472	7,504	7,557	0.3%
	0.2%	0.2%	0.3%	0.4%	0.7%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022).
Summer season indicates peak from June, July, August.

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2022 - 2032

	METERED 2021	UNRESTRICTED 2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Growth Rate (10 yr)
AEP	21,939	21,939	22,183	22,238	22,332	22,376	22,374	22,370	22,382	22,424	22,470	22,492	22,496	0.1%
				0.2%	0.4%	0.2%	-0.0%	-0.0%	0.1%	0.2%	0.2%	0.1%	0.0%	
APS	8,866	8,874	8,675	8,725	8,777	8,813	8,810	8,781	8,769	8,766	8,776	8,766	8,762	0.1%
				0.6%	0.6%	0.4%	-0.0%	-0.3%	-0.1%	-0.0%	0.1%	-0.1%	-0.0%	
ATSI	12,605	12,615	12,273	12,349	12,419	12,442	12,498	12,501	12,499	12,539	12,575	12,568	12,551	0.2%
				0.6%	0.6%	0.2%	0.5%	0.0%	-0.0%	0.3%	0.3%	-0.1%	-0.1%	
COMED	21,168	21,168	20,787	20,638	20,522	20,384	20,321	20,287	20,223	20,225	20,183	20,147	20,121	(0.3%)
				-0.7%	-0.6%	-0.7%	-0.3%	-0.2%	-0.3%	0.0%	-0.2%	-0.2%	-0.1%	
DAYTON	3,317	3,317	3,271	3,267	3,274	3,275	3,278	3,274	3,275	3,278	3,291	3,293	3,288	0.1%
				-0.1%	0.2%	0.0%	0.1%	-0.1%	0.0%	0.1%	0.4%	0.1%	-0.2%	
DEOK	5,306	5,306	5,239	5,269	5,305	5,334	5,357	5,372	5,382	5,397	5,407	5,424	5,427	0.4%
				0.6%	0.7%	0.5%	0.4%	0.3%	0.2%	0.3%	0.2%	0.3%	0.1%	
DLCO	2,760	2,760	2,742	2,759	2,776	2,794	2,804	2,812	2,812	2,818	2,822	2,833	2,837	0.3%
				0.6%	0.6%	0.6%	0.4%	0.3%	0.0%	0.2%	0.1%	0.4%	0.1%	
EKPC	2,095	2,095	2,091	2,117	2,144	2,170	2,195	2,207	2,214	2,215	2,218	2,230	2,228	0.6%
				1.2%	1.3%	1.2%	1.2%	0.5%	0.3%	0.0%	0.1%	0.5%	-0.1%	
OVEC	81	81	90	90	90	90	90	90	90	90	90	90	90	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,647	1,702	1,609	1,636	1,665	1,716	1,686	1,688	1,695	1,719	1,674	
PJM WESTERN	77,226	77,236	75,704	75,750	76,030	76,042	76,062	75,978	75,960	76,064	76,137	76,124	76,126	0.1%
				0.1%	0.4%	0.0%	0.0%	-0.1%	-0.0%	0.1%	0.1%	-0.0%	0.0%	
DOM	20,409	20,409	20,424	21,013	21,751	22,568	23,375	23,681	23,990	24,358	24,708	25,085	25,434	2.2%
				2.9%	3.5%	3.8%	3.6%	1.3%	1.3%	1.5%	1.4%	1.5%	1.4%	
DIVERSITY - TOTAL(-)			4,612	4,833	4,834	4,883	4,680	4,900	4,873	4,880	5,031	5,072	5,268	
PJM RTO	148,421	148,433	148,938	149,351	150,309	151,165	152,259	152,322	152,689	153,334	153,775	154,275	154,381	0.4%
				0.3%	0.6%	0.6%	0.7%	0.0%	0.2%	0.4%	0.3%	0.3%	0.1%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022).
Summer season indicates peak from June, July, August.

Table B-1 (continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2033 - 2037

	2033	2034	2035	2036	2037	Annual Growth Rate (15 yr)
AEP	22,531	22,565	22,616	22,679	22,711	0.2%
	0.2%	0.2%	0.2%	0.3%	0.1%	
APS	8,747	8,751	8,757	8,784	8,795	0.1%
	-0.2%	0.0%	0.1%	0.3%	0.1%	
ATSI	12,552	12,532	12,589	12,612	12,629	0.2%
	0.0%	-0.2%	0.5%	0.2%	0.1%	
COMED	20,093	20,009	20,036	20,017	19,960	(0.3%)
	-0.1%	-0.4%	0.1%	-0.1%	-0.3%	
DAYTON	3,291	3,291	3,297	3,310	3,316	0.1%
	0.1%	0.0%	0.2%	0.4%	0.2%	
DEOK	5,435	5,444	5,462	5,480	5,500	0.3%
	0.1%	0.2%	0.3%	0.3%	0.4%	
DLCO	2,829	2,829	2,835	2,844	2,850	0.3%
	-0.3%	0.0%	0.2%	0.3%	0.2%	
EKPC	2,238	2,243	2,246	2,254	2,260	0.5%
	0.4%	0.2%	0.1%	0.4%	0.3%	
OVEC	90	90	90	90	90	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,627	1,621	1,604	1,604	1,618	
PJM WESTERN	76,179	76,133	76,324	76,466	76,493	0.1%
	0.1%	-0.1%	0.3%	0.2%	0.0%	
DOM	25,807	26,136	26,568	26,994	27,354	2.0%
	1.5%	1.3%	1.7%	1.6%	1.3%	
DIVERSITY - TOTAL(-)	5,305	5,449	5,070	5,337	4,948	
PJM RTO	154,767	154,977	156,135	156,700	157,689	0.4%
	0.3%	0.1%	0.7%	0.4%	0.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022).
Summer season indicates peak from June, July, August.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2021/22 - 2031/32

	METERED 20/21	UNRESTRICTED 20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	Annual Growth Rate (10 yr)
AE	1,596	1,596	1,610	1,619	1,624	1,636	1,646	1,656	1,666	1,672	1,687	1,698	1,710	0.6%
				0.6%	0.3%	0.7%	0.6%	0.6%	0.6%	0.4%	0.9%	0.7%	0.7%	
BGE	5,034	5,034	5,780	5,802	5,849	5,880	5,915	5,957	6,000	6,032	6,060	6,095	6,131	0.6%
				0.4%	0.8%	0.5%	0.6%	0.7%	0.7%	0.5%	0.5%	0.6%	0.6%	
DPL	3,232	3,232	3,596	3,628	3,653	3,672	3,694	3,718	3,749	3,770	3,810	3,824	3,847	0.7%
				0.9%	0.7%	0.5%	0.6%	0.6%	0.8%	0.6%	1.1%	0.4%	0.6%	
JCPL	3,508	3,508	3,700	3,710	3,728	3,745	3,771	3,799	3,828	3,850	3,880	3,908	3,939	0.6%
				0.3%	0.5%	0.5%	0.7%	0.7%	0.8%	0.6%	0.8%	0.7%	0.8%	
METED	2,453	2,453	2,605	2,600	2,602	2,599	2,603	2,606	2,611	2,615	2,626	2,628	2,633	0.1%
				-0.2%	0.1%	-0.1%	0.2%	0.1%	0.2%	0.2%	0.4%	0.1%	0.2%	
PECO	6,139	6,144	6,634	6,636	6,646	6,644	6,645	6,648	6,650	6,644	6,659	6,652	6,660	0.0%
				0.0%	0.2%	-0.0%	0.0%	0.0%	0.0%	-0.1%	0.2%	-0.1%	0.1%	
PENLC	2,600	2,600	2,781	2,775	2,776	2,773	2,772	2,769	2,769	2,763	2,773	2,767	2,767	(0.1%)
				-0.2%	0.0%	-0.1%	-0.0%	-0.1%	0.0%	-0.2%	0.4%	-0.2%	0.0%	
PEPCO	4,582	4,582	5,331	5,381	5,422	5,443	5,451	5,466	5,485	5,486	5,479	5,483	5,494	0.3%
				0.9%	0.8%	0.4%	0.1%	0.3%	0.3%	0.0%	-0.1%	0.1%	0.2%	
PL	6,528	6,528	7,252	7,249	7,260	7,261	7,271	7,284	7,312	7,327	7,330	7,347	7,355	0.1%
				-0.0%	0.2%	0.0%	0.1%	0.2%	0.4%	0.2%	0.0%	0.2%	0.1%	
PS	6,242	6,242	6,657	6,690	6,745	6,792	6,853	6,913	6,969	7,019	7,077	7,144	7,219	0.8%
				0.5%	0.8%	0.7%	0.9%	0.9%	0.8%	0.7%	0.8%	0.9%	1.0%	
RECO	207	207	227	228	229	229	231	232	234	234	236	237	238	0.5%
				0.4%	0.4%	0.0%	0.9%	0.4%	0.9%	0.0%	0.9%	0.4%	0.4%	
UGI	188	188	199	199	198	197	197	196	196	195	195	194	194	(0.3%)
				0.0%	-0.5%	-0.5%	0.0%	-0.5%	0.0%	-0.5%	0.0%	-0.5%	0.0%	
DIVERSITY - MID-ATLANTIC(-)			560	563	663	747	794	681	588	700	681	751	740	
PJM MID-ATLANTIC	41,441	41,447	45,812	45,954	46,069	46,124	46,255	46,563	46,881	46,907	47,131	47,226	47,447	0.4%
				0.3%	0.3%	0.1%	0.3%	0.7%	0.7%	0.1%	0.5%	0.2%	0.5%	
FE-EAST	8,517	8,517	9,000	8,999	9,014	9,005	9,034	9,092	9,128	9,139	9,188	9,188	9,225	0.2%
				-0.0%	0.2%	-0.1%	0.3%	0.6%	0.4%	0.1%	0.5%	0.0%	0.4%	
PLGRP	6,706	6,706	7,445	7,440	7,455	7,454	7,460	7,476	7,500	7,516	7,517	7,536	7,544	0.1%
				-0.1%	0.2%	-0.0%	0.1%	0.2%	0.3%	0.2%	0.0%	0.3%	0.1%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2021/22).
Winter season indicates peak from December, January, February.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2032/33 - 2036/37

	32/33	33/34	34/35	35/36	36/37	Annual Growth Rate (15 yr)
AE	1,721	1,732	1,744	1,772	1,789	0.7%
	0.6%	0.6%	0.7%	1.6%	1.0%	
BGE	6,178	6,209	6,249	6,308	6,360	0.6%
	0.8%	0.5%	0.6%	0.9%	0.8%	
DPL	3,878	3,910	3,930	3,970	3,975	0.7%
	0.8%	0.8%	0.5%	1.0%	0.1%	
JCPL	3,973	4,000	4,027	4,081	4,112	0.7%
	0.9%	0.7%	0.7%	1.3%	0.8%	
METED	2,639	2,650	2,655	2,658	2,656	0.1%
	0.2%	0.4%	0.2%	0.1%	-0.1%	
PECO	6,674	6,687	6,679	6,694	6,687	0.1%
	0.2%	0.2%	-0.1%	0.2%	-0.1%	
PENLC	2,767	2,765	2,765	2,768	2,761	(0.0%)
	0.0%	-0.1%	0.0%	0.1%	-0.3%	
PEPCO	5,520	5,521	5,547	5,582	5,628	0.4%
	0.5%	0.0%	0.5%	0.6%	0.8%	
PL	7,388	7,399	7,410	7,410	7,413	0.1%
	0.4%	0.1%	0.1%	0.0%	0.0%	
PS	7,289	7,348	7,412	7,501	7,587	0.9%
	1.0%	0.8%	0.9%	1.2%	1.1%	
RECO	240	241	243	245	246	0.5%
	0.8%	0.4%	0.8%	0.8%	0.4%	
UGI	194	194	193	193	193	(0.2%)
	0.0%	0.0%	-0.5%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)	588	633	695	715	722	
PJM MID-ATLANTIC	47,873	48,023	48,159	48,467	48,685	0.4%
	0.9%	0.3%	0.3%	0.6%	0.4%	
FE-EAST	9,298	9,329	9,353	9,430	9,430	0.3%
	0.8%	0.3%	0.3%	0.8%	0.0%	
PLGRP	7,573	7,584	7,594	7,594	7,602	0.1%
	0.4%	0.1%	0.1%	0.0%	0.1%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2021/22).
Winter season indicates peak from December, January, February.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2021/22 - 2031/32

	METERED 20/21	UNRESTRICTED 20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	Annual Growth Rate (10 yr)
AEP	19,969	19,969	22,348	22,382	22,507	22,529	22,672	22,712	22,787	22,820	22,863	22,849	22,946	0.3%
				0.2%	0.6%	0.1%	0.6%	0.2%	0.3%	0.1%	0.2%	-0.1%	0.4%	
APS	7,909	7,909	9,009	9,048	9,128	9,148	9,183	9,217	9,245	9,240	9,293	9,312	9,338	0.4%
				0.4%	0.9%	0.2%	0.4%	0.4%	0.3%	-0.1%	0.6%	0.2%	0.3%	
ATSI	9,530	9,530	10,064	10,097	10,160	10,150	10,179	10,175	10,192	10,173	10,178	10,154	10,172	0.1%
				0.3%	0.6%	-0.1%	0.3%	-0.0%	0.2%	-0.2%	0.0%	-0.2%	0.2%	
COMED	14,120	14,120	15,073	15,046	15,055	15,008	15,051	15,122	15,226	15,176	15,226	15,254	15,303	0.2%
				-0.2%	0.1%	-0.3%	0.3%	0.5%	0.7%	-0.3%	0.3%	0.2%	0.3%	
DAYTON	2,780	2,780	2,940	2,939	2,947	2,944	2,952	2,957	2,962	2,963	2,963	2,958	2,965	0.1%
				-0.0%	0.3%	-0.1%	0.3%	0.2%	0.2%	0.0%	0.0%	-0.2%	0.2%	
DEOK	4,226	4,226	4,555	4,570	4,604	4,611	4,621	4,643	4,684	4,668	4,691	4,687	4,694	0.3%
				0.3%	0.7%	0.2%	0.2%	0.5%	0.9%	-0.3%	0.5%	-0.1%	0.1%	
DLCO	1,818	1,818	1,995	2,003	2,010	2,010	2,023	2,027	2,030	2,028	2,027	2,029	2,042	0.2%
				0.4%	0.3%	0.0%	0.6%	0.2%	0.1%	-0.1%	-0.0%	0.1%	0.6%	
EKPC	2,439	2,439	2,666	2,690	2,703	2,714	2,723	2,731	2,741	2,746	2,760	2,767	2,776	0.4%
				0.9%	0.5%	0.4%	0.3%	0.3%	0.4%	0.2%	0.5%	0.3%	0.3%	
OVEC	106	106	115	115	115	115	115	115	115	115	115	115	115	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,532	1,523	1,502	1,520	1,512	1,403	1,528	1,497	1,479	1,568	1,530	
PJM WESTERN	61,056	61,056	67,233	67,367	67,727	67,709	68,007	68,296	68,454	68,432	68,637	68,557	68,821	0.2%
				0.2%	0.5%	-0.0%	0.4%	0.4%	0.2%	-0.0%	0.3%	-0.1%	0.4%	
DOM	17,868	17,868	20,762	21,460	22,283	23,196	24,167	24,853	25,249	25,640	26,020	26,404	26,810	2.6%
				3.4%	3.8%	4.1%	4.2%	2.8%	1.6%	1.5%	1.5%	1.5%	1.5%	
DIVERSITY - TOTAL(-)			3,797	3,887	3,884	3,775	3,812	3,853	3,891	3,858	3,839	3,824	3,832	
PJM RTO	117,011	117,012	132,102	132,980	134,360	135,521	136,923	137,943	138,809	139,318	140,109	140,682	141,516	0.7%
				0.7%	1.0%	0.9%	1.0%	0.7%	0.6%	0.4%	0.6%	0.4%	0.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2021/22).
Winter season indicates peak from December, January, February.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2032/33 - 2036/37

	32/33	33/34	34/35	35/36	36/37	Annual Growth Rate (15 yr)
AEP	23,013	23,036	23,092	23,146	23,175	0.2%
	0.3%	0.1%	0.2%	0.2%	0.1%	
APS	9,359	9,383	9,409	9,436	9,454	0.3%
	0.2%	0.3%	0.3%	0.3%	0.2%	
ATSI	10,180	10,177	10,169	10,156	10,153	0.1%
	0.1%	-0.0%	-0.1%	-0.1%	-0.0%	
COMED	15,436	15,450	15,491	15,533	15,544	0.2%
	0.9%	0.1%	0.3%	0.3%	0.1%	
DAYTON	2,976	2,981	2,987	2,991	2,995	0.1%
	0.4%	0.2%	0.2%	0.1%	0.1%	
DEOK	4,741	4,747	4,760	4,768	4,765	0.3%
	1.0%	0.1%	0.3%	0.2%	-0.1%	
DLCO	2,046	2,048	2,043	2,044	2,057	0.2%
	0.2%	0.1%	-0.2%	0.0%	0.6%	
EKPC	2,785	2,794	2,802	2,812	2,819	0.4%
	0.3%	0.3%	0.3%	0.4%	0.2%	
OVEC	115	115	115	115	115	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,524	1,492	1,523	1,529	1,544	
PJM WESTERN	69,127	69,239	69,345	69,472	69,533	0.2%
	0.4%	0.2%	0.2%	0.2%	0.1%	
DOM	27,189	27,567	27,923	28,322	28,716	2.2%
	1.4%	1.4%	1.3%	1.4%	1.4%	
DIVERSITY - TOTAL(-)	3,987	3,987	4,010	3,865	3,980	
PJM RTO	142,314	142,967	143,635	144,640	145,220	0.6%
	0.6%	0.5%	0.5%	0.7%	0.4%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2021/22).
Winter season indicates peak from December, January, February.

Table B-3

SPRING PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	1,522	1,516	1,516	1,497	1,493	1,497	1,508	1,520	1,525	1,530	1,545	1,558	1,572	1,579	1,594	1,606
BGE	5,086	5,074	5,076	5,076	5,076	5,101	5,126	5,143	5,156	5,154	5,183	5,204	5,206	5,225	5,243	5,297
DPL	2,984	2,990	2,979	2,971	2,974	2,984	3,000	3,014	3,026	3,023	3,032	3,036	3,049	3,053	3,056	3,076
JCPL	3,894	3,867	3,861	3,828	3,814	3,814	3,861	3,890	3,915	3,929	3,920	3,954	3,998	4,028	4,054	4,071
METED	2,401	2,398	2,393	2,391	2,395	2,399	2,419	2,425	2,431	2,424	2,435	2,451	2,462	2,465	2,456	2,460
PECO	6,381	6,389	6,389	6,328	6,292	6,294	6,362	6,381	6,398	6,353	6,345	6,404	6,418	6,443	6,411	6,398
PENLC	2,458	2,443	2,432	2,414	2,410	2,404	2,403	2,407	2,410	2,404	2,418	2,426	2,424	2,424	2,418	2,428
PEPCO	4,665	4,660	4,676	4,638	4,632	4,628	4,643	4,637	4,611	4,573	4,590	4,605	4,602	4,611	4,615	4,635
PL	6,214	6,200	6,210	6,210	6,229	6,248	6,243	6,260	6,281	6,273	6,307	6,314	6,324	6,330	6,322	6,355
PS	6,955	6,942	6,993	6,930	6,899	6,898	6,997	7,085	7,152	7,145	7,133	7,193	7,286	7,386	7,433	7,436
RECO	271	269	268	262	258	257	261	262	263	259	258	260	263	263	262	260
UGI	169	167	166	165	165	165	164	164	163	163	163	163	163	162	161	161
DIVERSITY - MID-ATLANTIC(-)	2,355	2,379	2,386	2,256	2,283	2,297	2,286	2,305	2,362	2,235	2,284	2,309	2,370	2,454	2,380	2,421
PJM MID-ATLANTIC	40,645	40,536	40,573	40,454	40,354	40,392	40,701	40,883	40,969	40,995	41,045	41,259	41,397	41,515	41,645	41,762
FE-EAST	8,205	8,151	8,111	8,049	8,008	8,026	8,096	8,129	8,159	8,162	8,187	8,259	8,310	8,337	8,362	8,389
PLGRP	6,354	6,332	6,356	6,356	6,376	6,389	6,368	6,384	6,414	6,411	6,449	6,456	6,459	6,457	6,463	6,495

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.

Table B-3

SPRING PEAK LOAD (MW) FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AEP	19,381	19,393	19,483	19,506	19,549	19,613	19,623	19,656	19,642	19,654	19,752	19,803	19,817	19,850	19,828	19,877
APS	7,765	7,783	7,828	7,853	7,881	7,889	7,899	7,909	7,903	7,912	7,955	7,965	7,978	7,991	7,998	8,037
ATSI	9,639	9,670	9,706	9,685	9,655	9,678	9,761	9,794	9,783	9,743	9,714	9,785	9,795	9,803	9,744	9,712
COMED	14,823	14,710	14,597	14,389	14,297	14,264	14,387	14,420	14,413	14,249	14,207	14,264	14,271	14,301	14,235	14,164
DAYTON	2,627	2,616	2,614	2,607	2,605	2,604	2,627	2,631	2,628	2,617	2,615	2,639	2,643	2,647	2,636	2,642
DEOK	4,233	4,245	4,260	4,232	4,224	4,237	4,299	4,334	4,310	4,291	4,299	4,359	4,369	4,401	4,366	4,366
DLCO	2,150	2,159	2,173	2,162	2,158	2,167	2,191	2,199	2,209	2,193	2,196	2,213	2,217	2,223	2,221	2,213
EKPC	2,054	2,078	2,099	2,115	2,133	2,150	2,154	2,153	2,157	2,161	2,178	2,175	2,177	2,177	2,185	2,186
OVEC	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
DIVERSITY - WESTERN(-)	2,792	2,903	2,949	2,892	3,006	2,970	2,931	3,058	3,043	3,102	3,006	2,980	2,932	2,949	3,073	2,828
PJM WESTERN	59,995	59,866	59,926	59,772	59,611	59,747	60,125	60,153	60,117	59,833	60,025	60,338	60,450	60,559	60,255	60,484
DOM	17,634	18,262	19,000	19,829	20,697	21,193	21,521	21,859	22,211	22,576	22,931	23,284	23,636	23,996	24,354	24,757
DIVERSITY - TOTAL(-)	6,984	7,077	6,954	7,279	7,173	7,127	6,921	6,924	7,215	6,943	6,919	7,036	7,131	7,237	7,137	6,990
PJM RTO	116,437	116,869	117,880	117,924	118,778	119,472	120,643	121,334	121,487	121,798	122,372	123,134	123,654	124,236	124,570	125,262

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.

Table B-4

FALL PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2022 - 2037

	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
AE	1,884	1,878	1,869	1,863	1,859	1,864	1,877	1,883	1,893	1,905	1,919	1,932	1,943	1,954	1,975	1,990
BGE	5,423	5,417	5,422	5,436	5,446	5,459	5,471	5,486	5,512	5,523	5,532	5,533	5,551	5,575	5,610	5,652
DPL	3,169	3,182	3,187	3,192	3,194	3,204	3,225	3,244	3,242	3,255	3,239	3,248	3,246	3,243	3,264	3,276
JCPL	4,463	4,457	4,453	4,452	4,452	4,466	4,492	4,522	4,558	4,592	4,620	4,649	4,689	4,728	4,776	4,814
METED	2,452	2,449	2,449	2,452	2,454	2,463	2,469	2,479	2,502	2,519	2,533	2,546	2,556	2,569	2,594	2,611
PECO	6,892	6,900	6,895	6,895	6,891	6,896	6,892	6,903	6,928	6,960	6,964	6,981	6,984	6,997	7,048	7,071
PENLC	2,453	2,446	2,435	2,427	2,419	2,422	2,425	2,429	2,436	2,445	2,448	2,444	2,440	2,444	2,465	2,471
PEPCO	4,971	4,976	4,958	4,961	4,949	4,945	4,941	4,917	4,905	4,899	4,891	4,881	4,876	4,874	4,919	4,925
PL	6,063	6,066	6,047	6,043	6,058	6,088	6,102	6,118	6,133	6,160	6,204	6,227	6,250	6,269	6,274	6,317
PS	7,877	7,885	7,921	7,963	7,958	7,994	8,028	8,089	8,194	8,274	8,312	8,374	8,424	8,478	8,604	8,652
RECO	298	295	293	293	291	291	291	291	293	295	295	295	295	296	300	299
UGI	164	164	162	161	162	162	161	161	160	159	160	160	159	159	158	158
DIVERSITY - MID-ATLANTIC(-)	1,218	1,290	1,322	1,301	1,244	1,287	1,333	1,495	1,408	1,393	1,339	1,424	1,530	1,633	1,533	1,555
PJM MID-ATLANTIC	44,891	44,825	44,769	44,837	44,889	44,967	45,041	45,027	45,348	45,593	45,778	45,846	45,883	45,953	46,454	46,681
FE-EAST	9,094	9,026	9,010	9,036	9,036	9,048	9,035	9,073	9,150	9,236	9,280	9,290	9,322	9,366	9,497	9,548
PLGRP	6,215	6,215	6,196	6,191	6,206	6,233	6,249	6,266	6,277	6,304	6,350	6,376	6,398	6,411	6,416	6,463

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Fall season indicates peak from September, October, November.

Table B-4

FALL PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AEP	19,977	20,077	20,138	20,226	20,256	20,264	20,283	20,278	20,313	20,407	20,440	20,473	20,461	20,488	20,613	20,725
APS	7,636	7,655	7,659	7,685	7,696	7,704	7,726	7,728	7,736	7,758	7,786	7,803	7,822	7,830	7,858	7,893
ATSI	10,513	10,548	10,617	10,709	10,741	10,712	10,669	10,685	10,729	10,831	10,776	10,761	10,728	10,738	10,879	10,884
COMED	17,178	17,049	16,886	16,882	16,834	16,820	16,694	16,588	16,665	16,830	16,761	16,729	16,668	16,574	16,871	16,903
DAYTON	2,858	2,856	2,858	2,874	2,878	2,867	2,858	2,855	2,872	2,894	2,887	2,884	2,876	2,881	2,919	2,928
DEOK	4,766	4,784	4,812	4,847	4,869	4,885	4,883	4,876	4,909	4,937	4,949	4,961	4,955	4,950	5,007	5,027
DLCO	2,382	2,402	2,417	2,437	2,451	2,458	2,464	2,462	2,473	2,487	2,490	2,493	2,495	2,489	2,509	2,517
EKPC	2,004	2,026	2,043	2,066	2,096	2,102	2,106	2,109	2,110	2,118	2,126	2,130	2,134	2,138	2,143	2,153
OVEC	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
DIVERSITY - WESTERN(-)	1,624	1,619	1,625	1,692	1,518	1,660	1,594	1,692	1,619	1,602	1,424	1,671	1,519	1,571	1,377	1,488
PJM WESTERN	65,760	65,848	65,875	66,104	66,373	66,222	66,159	65,959	66,258	66,730	66,861	66,633	66,690	66,587	67,492	67,612
DOM	18,134	18,776	19,515	20,348	21,082	21,421	21,789	22,101	22,436	22,825	23,218	23,584	23,954	24,323	24,711	25,081
DIVERSITY - TOTAL(-)	6,235	6,484	6,588	6,499	6,499	6,394	6,907	7,291	6,989	6,959	6,787	7,034	7,319	7,495	7,538	7,655
PJM RTO	125,392	125,874	126,518	127,783	128,607	129,163	129,009	128,983	130,080	131,184	131,833	132,124	132,257	132,572	134,029	134,762

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Fall season indicates peak from September, October, November.

Table B-5

MONTHLY PEAK FORECAST (MW) FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC DIVERSITY	PJM MID-ATLANTIC
Jan 2022	1,610	5,780	3,596	3,700	2,605	6,634	2,781	5,331	7,252	6,657	227	199	560	45,812
Feb 2022	1,521	5,387	3,375	3,485	2,487	6,239	2,690	5,070	6,865	6,303	213	187	704	43,118
Mar 2022	1,302	4,986	2,984	3,001	2,377	5,546	2,458	4,588	6,214	5,679	178	169	843	38,639
Apr 2022	1,185	4,153	2,427	2,710	2,090	5,015	2,205	3,756	5,209	5,198	183	139	1,048	33,222
May 2022	1,522	5,086	2,881	3,894	2,401	6,381	2,247	4,665	5,503	6,955	271	144	1,305	40,645
Jun 2022	2,181	5,911	3,515	5,228	2,749	7,700	2,661	5,484	6,526	8,775	363	178	720	50,551
Jul 2022	2,488	6,414	3,873	5,831	2,934	8,370	2,812	5,902	7,024	9,543	391	193	629	55,146
Aug 2022	2,403	6,214	3,685	5,489	2,917	8,092	2,673	5,739	6,719	9,200	366	183	303	53,377
Sep 2022	1,884	5,423	3,169	4,463	2,452	6,892	2,453	4,971	6,063	7,877	298	160	1,214	44,891
Oct 2022	1,414	4,096	2,439	3,170	1,990	5,174	2,180	3,878	5,060	6,005	213	138	1,592	34,165
Nov 2022	1,311	4,454	2,675	3,043	2,174	5,216	2,354	4,073	5,866	5,619	193	164	1,046	36,096
Dec 2022	1,578	5,228	3,256	3,632	2,464	6,262	2,641	4,896	6,626	6,501	227	188	562	42,937

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2023	1,619	5,802	3,628	3,710	2,600	6,636	2,775	5,381	7,249	6,690	228	199	563	45,954
Feb 2023	1,529	5,425	3,395	3,487	2,480	6,244	2,682	5,119	6,844	6,340	214	186	732	43,213
Mar 2023	1,298	4,902	2,990	2,966	2,372	5,509	2,443	4,601	6,200	5,661	176	167	895	38,390
Apr 2023	1,180	4,113	2,419	2,665	2,075	4,971	2,184	3,722	5,112	5,169	181	137	1,022	32,906
May 2023	1,516	5,074	2,883	3,867	2,398	6,389	2,242	4,660	5,508	6,942	269	143	1,355	40,536
Jun 2023	2,183	5,878	3,513	5,164	2,736	7,751	2,656	5,466	6,519	8,715	360	177	702	50,416
Jul 2023	2,490	6,391	3,882	5,799	2,934	8,386	2,807	5,892	7,023	9,534	389	192	647	55,072
Aug 2023	2,404	6,191	3,691	5,433	2,921	8,150	2,669	5,742	6,709	9,199	363	182	245	53,409
Sep 2023	1,878	5,417	3,182	4,457	2,449	6,900	2,446	4,976	6,066	7,885	295	158	1,284	44,825
Oct 2023	1,416	4,138	2,456	3,182	2,012	5,243	2,192	3,905	5,114	6,045	211	137	1,610	34,441
Nov 2023	1,316	4,495	2,685	3,046	2,186	5,222	2,365	4,111	5,921	5,634	192	164	1,137	36,200
Dec 2023	1,576	5,266	3,276	3,649	2,463	6,269	2,641	4,931	6,632	6,528	227	187	659	42,986

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2024	1,624	5,849	3,653	3,728	2,602	6,646	2,776	5,422	7,260	6,745	229	198	663	46,069
Feb 2024	1,536	5,471	3,420	3,511	2,479	6,253	2,683	5,148	6,848	6,385	215	185	735	43,399
Mar 2024	1,292	4,873	2,979	2,941	2,361	5,464	2,432	4,613	6,210	5,658	173	166	832	38,330
Apr 2024	1,183	4,118	2,413	2,655	2,081	4,985	2,190	3,757	5,213	5,202	181	138	1,174	32,942
May 2024	1,516	5,076	2,900	3,861	2,393	6,389	2,234	4,676	5,498	6,993	268	144	1,375	40,573
Jun 2024	2,185	5,836	3,485	5,109	2,678	7,639	2,624	5,417	6,487	8,600	356	175	967	49,624
Jul 2024	2,493	6,389	3,893	5,771	2,942	8,419	2,802	5,892	7,036	9,535	389	192	746	55,007
Aug 2024	2,400	6,155	3,670	5,385	2,899	8,054	2,658	5,716	6,714	9,147	361	182	395	52,946
Sep 2024	1,869	5,422	3,187	4,453	2,449	6,895	2,435	4,958	6,047	7,921	293	159	1,319	44,769
Oct 2024	1,414	4,142	2,456	3,159	2,013	5,236	2,171	3,911	5,101	6,088	210	137	1,457	34,581
Nov 2024	1,301	4,484	2,652	3,010	2,168	5,153	2,315	4,054	5,834	5,626	189	162	1,086	35,862
Dec 2024	1,588	5,351	3,283	3,655	2,446	6,244	2,628	4,934	6,639	6,586	226	186	839	42,927

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-5

MONTHLY PEAK FORECAST (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN DIVERSITY	PJM WESTERN	DOM	TOTAL DIVERSITY	PJM RTO
Jan 2022	22,348	9,009	10,064	15,073	2,940	4,555	1,995	2,666	115	1,532	67,233	20,762	3,797	132,102
Feb 2022	21,144	8,518	9,692	14,343	2,780	4,276	1,908	2,408	115	1,677	63,507	19,432	3,273	125,165
Mar 2022	19,381	7,765	9,125	12,586	2,584	3,852	1,771	2,054	115	473	58,760	17,634	833	115,516
Apr 2022	16,438	6,536	8,127	11,506	2,222	3,489	1,679	1,607	70	627	51,047	15,297	796	100,445
May 2022	18,301	7,058	9,639	14,823	2,627	4,233	2,150	1,600	70	506	59,995	17,433	3,447	116,437
Jun 2022	20,710	8,081	11,506	18,917	3,020	4,925	2,563	1,968	70	2,069	69,691	19,270	5,228	137,073
Jul 2022	22,183	8,675	12,273	20,787	3,271	5,239	2,742	2,091	90	1,647	75,704	20,424	4,612	148,938
Aug 2022	21,858	8,443	11,822	19,971	3,192	5,113	2,638	2,054	90	2,029	73,152	20,351	5,204	144,008
Sep 2022	19,977	7,636	10,513	17,178	2,858	4,766	2,382	1,932	70	1,552	65,760	18,134	6,159	125,392
Oct 2022	15,992	6,325	8,073	12,375	2,213	3,516	1,770	1,594	70	2,055	49,873	15,440	6,394	96,731
Nov 2022	17,944	7,156	8,572	12,347	2,388	3,621	1,715	2,004	70	1,509	54,308	16,893	4,052	105,800
Dec 2022	20,601	8,306	9,709	14,623	2,742	4,259	1,925	2,383	100	1,191	63,457	19,155	4,062	123,240

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2023	22,382	9,048	10,097	15,046	2,939	4,570	2,003	2,690	115	1,523	67,367	21,460	3,887	132,980
Feb 2023	21,197	8,557	9,727	14,312	2,780	4,294	1,920	2,430	115	1,722	63,610	20,161	3,620	125,818
Mar 2023	19,393	7,783	9,168	12,528	2,582	3,861	1,781	2,078	115	513	58,776	18,262	979	115,857
Apr 2023	16,273	6,493	8,090	11,400	2,201	3,463	1,685	1,625	70	636	50,664	15,888	1,026	100,090
May 2023	18,308	7,062	9,670	14,710	2,616	4,245	2,159	1,612	70	586	59,866	18,058	3,532	116,869
Jun 2023	20,724	8,117	11,557	18,857	3,009	4,939	2,577	1,984	70	1,996	69,838	19,814	5,440	137,326
Jul 2023	22,238	8,725	12,349	20,638	3,267	5,269	2,759	2,117	90	1,702	75,750	21,013	4,833	149,351
Aug 2023	21,929	8,487	11,900	20,025	3,188	5,135	2,658	2,074	90	2,270	73,216	20,941	5,758	144,323
Sep 2023	20,077	7,655	10,548	17,049	2,856	4,784	2,402	1,956	70	1,549	65,848	18,776	6,408	125,874
Oct 2023	16,120	6,390	8,167	12,343	2,223	3,559	1,799	1,608	70	2,016	50,263	16,277	6,434	98,173
Nov 2023	18,114	7,201	8,664	12,318	2,397	3,659	1,736	2,026	70	1,501	54,684	17,692	4,129	107,085
Dec 2023	20,674	8,379	9,764	14,553	2,747	4,277	1,930	2,371	100	1,094	63,701	19,874	3,880	124,434

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2024	22,507	9,128	10,160	15,055	2,947	4,604	2,010	2,703	115	1,502	67,727	22,283	3,884	134,360
Feb 2024	21,297	8,634	9,788	14,290	2,792	4,326	1,924	2,435	115	1,639	63,962	20,941	3,623	127,053
Mar 2024	19,483	7,828	9,208	12,461	2,580	3,895	1,789	2,099	115	600	58,858	19,000	705	116,915
Apr 2024	16,634	6,600	8,159	11,376	2,204	3,544	1,705	1,654	70	769	51,177	16,665	824	101,903
May 2024	18,322	7,099	9,706	14,597	2,614	4,260	2,173	1,619	70	534	59,926	18,874	3,402	117,880
Jun 2024	20,586	8,105	11,492	18,555	2,968	4,948	2,573	1,999	70	2,247	69,049	20,454	5,676	136,665
Jul 2024	22,332	8,777	12,419	20,522	3,274	5,305	2,776	2,144	90	1,609	76,030	21,751	4,834	150,309
Aug 2024	21,904	8,507	11,855	19,669	3,153	5,148	2,661	2,096	90	2,109	72,974	21,615	5,236	144,803
Sep 2024	20,138	7,659	10,617	16,886	2,858	4,812	2,417	2,003	70	1,585	65,875	19,515	6,545	126,518
Oct 2024	16,167	6,415	8,217	12,255	2,229	3,600	1,822	1,643	70	2,123	50,295	17,101	6,093	99,464
Nov 2024	17,919	7,123	8,621	12,155	2,361	3,626	1,731	2,043	70	1,468	54,181	18,358	4,577	106,378
Dec 2024	20,672	8,363	9,712	14,501	2,720	4,276	1,926	2,379	100	1,336	63,313	20,724	3,347	125,792

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-6

MONTHLY PEAK FORECAST (MW) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2022	9,000	7,445
Feb 2022	8,519	7,039
Mar 2022	7,697	6,354
Apr 2022	6,715	5,346
May 2022	8,205	5,646
Jun 2022	10,363	6,675
Jul 2022	11,334	7,204
Aug 2022	10,885	6,880
Sep 2022	9,094	6,215
Oct 2022	6,987	5,193
Nov 2022	7,398	6,028
Dec 2022	8,618	6,805

	FE_EAST	PLGRP
Jan 2023	8,999	7,440
Feb 2023	8,518	7,019
Mar 2023	7,646	6,332
Apr 2023	6,635	5,238
May 2023	8,151	5,638
Jun 2023	10,266	6,666
Jul 2023	11,296	7,202
Aug 2023	10,842	6,864
Sep 2023	9,026	6,215
Oct 2023	7,052	5,241
Nov 2023	7,418	6,074
Dec 2023	8,623	6,817

	FE_EAST	PLGRP
Jan 2024	9,014	7,455
Feb 2024	8,526	7,010
Mar 2024	7,554	6,356
Apr 2024	6,585	5,349
May 2024	8,111	5,642
Jun 2024	10,141	6,613
Jul 2024	11,255	7,217
Aug 2024	10,786	6,872
Sep 2024	9,010	6,196
Oct 2024	7,024	5,234
Nov 2024	7,330	5,993
Dec 2024	8,564	6,808

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
FE_EAST contains JCPL, METED and PENLC zones. PLGRP contains PL and UGI zones.

Table B-7

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE																
CAPACITY PERFORMANCE	42	42	42	42	42	42	42	43	43	43	43	43	44	44	44	44
SUMMER PERIOD	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	44	44	44	44	44	44	44	45	45	45	45	45	46	46	46	46
BGE																
CAPACITY PERFORMANCE	120	120	120	120	120	120	120	120	120	120	119	119	119	119	119	119
SUMMER PERIOD	38	38	38	38	38	38	38	38	38	38	38	38	37	37	38	39
PRD	80	153	153	153	154	154	153	154	154	153	152	152	152	152	152	152
TOTAL LOAD MANAGEMENT	238	311	311	311	312	312	311	312	312	311	309	309	308	308	309	310
DPL																
CAPACITY PERFORMANCE	101	101	101	102	102	102	102	102	102	101	100	100	99	99	99	99
SUMMER PERIOD	54	55	55	55	55	55	55	55	55	55	54	54	53	53	53	53
PRD	40	57	57	57	57	58	58	58	58	57	57	56	56	56	56	56
TOTAL LOAD MANAGEMENT	195	213	213	214	214	215	215	215	215	213	211	210	208	208	208	208
JCPL																
CAPACITY PERFORMANCE	87	87	87	87	87	86	86	87	87	88	88	88	89	89	90	91
SUMMER PERIOD	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	91	91	91	91	91	90	90	91	91	93	93	93	94	94	95	96
METED																
CAPACITY PERFORMANCE	151	151	151	151	152	153	153	154	155	156	157	158	159	159	161	163
SUMMER PERIOD	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	152	152	152	152	153	154	154	155	156	157	158	159	160	160	162	164

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-7 (Continued)

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
PECO																
CAPACITY PERFORMANCE	252	252	253	253	253	252	252	253	254	255	255	255	255	256	257	258
SUMMER PERIOD	0	0	1	1	1	0	0	1	1	1	1	1	1	1	1	1
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	252	252	254	254	254	252	252	254	255	256	256	256	256	257	258	259
PENLC																
CAPACITY PERFORMANCE	219	218	218	218	218	218	218	218	219	220	220	220	221	221	222	223
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	219	218	218	218	218	218	218	218	219	220	220	220	221	221	222	223
PEPCO																
CAPACITY PERFORMANCE	105	104	104	105	104	104	104	104	103	103	102	102	101	101	101	101
SUMMER PERIOD	86	86	86	87	86	86	86	86	85	85	84	84	83	83	84	85
PRD	110	146	146	146	146	146	145	145	144	143	143	142	141	141	141	141
TOTAL LOAD MANAGEMENT	301	336	336	338	336	336	335	335	332	331	329	328	325	325	326	327
PL																
CAPACITY PERFORMANCE	408	407	408	409	410	411	412	414	415	417	420	420	421	423	424	425
SUMMER PERIOD	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	411	410	411	412	413	414	415	417	418	420	423	423	424	426	427	428
PS																
CAPACITY PERFORMANCE	186	186	186	186	187	187	188	189	190	192	192	193	194	195	197	199
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	186	186	186	186	187	187	188	189	190	192	192	193	194	195	197	199

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-7 (Continued)

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
RECO																
CAPACITY PERFORMANCE	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UGI																
CAPACITY PERFORMANCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
CAPACITY PERFORMANCE	1,673	1,670	1,672	1,675	1,677	1,677	1,679	1,686	1,690	1,697	1,698	1,700	1,704	1,708	1,716	1,724
SUMMER PERIOD	188	189	190	191	190	189	189	190	189	190	188	188	185	185	187	189
PRD	230	356	356	356	357	358	356	357	356	353	352	350	349	349	349	349
TOTAL LOAD MANAGEMENT	2,091	2,215	2,218	2,222	2,224	2,224	2,224	2,233	2,235	2,240	2,238	2,238	2,238	2,242	2,252	2,262

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AEP																
CAPACITY PERFORMANCE	1,099	1,102	1,107	1,109	1,109	1,109	1,109	1,111	1,114	1,115	1,115	1,117	1,118	1,121	1,124	1,127
SUMMER PERIOD	10	10	11	11	11	11	11	11	11	11	11	11	11	11	11	11
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,109	1,112	1,118	1,120	1,120	1,120	1,120	1,122	1,125	1,126	1,126	1,128	1,129	1,132	1,135	1,138
APS																
CAPACITY PERFORMANCE	530	533	536	538	538	536	536	535	536	535	535	534	535	535	537	539
SUMMER PERIOD	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	530	534	537	539	539	537	537	536	537	536	536	535	536	536	538	540
ATSI																
CAPACITY PERFORMANCE	698	703	707	708	711	711	711	713	716	715	714	714	713	716	718	720
SUMMER PERIOD	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	700	705	709	710	713	713	713	715	718	717	716	716	715	718	720	722
COMED																
CAPACITY PERFORMANCE	1,197	1,189	1,182	1,174	1,170	1,168	1,165	1,165	1,162	1,160	1,159	1,157	1,152	1,154	1,153	1,152
SUMMER PERIOD	110	109	109	108	108	107	107	107	107	107	106	106	106	106	106	106
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,307	1,298	1,291	1,282	1,278	1,275	1,272	1,272	1,269	1,267	1,265	1,263	1,258	1,260	1,259	1,258
DAYTON																
CAPACITY PERFORMANCE	153	152	153	153	153	153	153	153	154	154	153	154	154	154	154	154
SUMMER PERIOD	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	160	159	160	160	160	160	160	160	161	161	160	161	161	161	161	161

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
DEOK																
CAPACITY PERFORMANCE	125	126	127	128	128	128	129	129	129	130	130	130	130	131	131	131
SUMMER PERIOD	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	133	134	135	136	136	136	137	137	137	138	138	138	138	139	139	139
DLCO																
CAPACITY PERFORMANCE	75	75	76	76	76	76	76	77	77	77	77	77	77	77	77	77
SUMMER PERIOD	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	82	82	83	83	83	83	83	84	84	84	84	84	84	84	84	84
EKPC																
CAPACITY PERFORMANCE	146	148	150	152	153	154	155	155	155	156	156	157	157	157	158	159
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	146	148	150	152	153	154	155	155	155	156	156	157	157	157	158	159
PJM WESTERN																
CAPACITY PERFORMANCE	4,023	4,028	4,038	4,038	4,038	4,035	4,034	4,038	4,043	4,042	4,039	4,040	4,036	4,045	4,052	4,059
SUMMER PERIOD	144	144	145	144	144	143	143	143	143	143	142	142	142	142	142	142
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	4,167	4,172	4,183	4,182	4,182	4,178	4,177	4,181	4,186	4,185	4,181	4,182	4,178	4,187	4,194	4,201

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
DOM																
CAPACITY PERFORMANCE	657	676	700	726	752	762	772	783	795	807	818	830	841	854	868	882
SUMMER PERIOD	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	659	678	703	729	755	765	775	786	798	810	821	833	844	857	871	885
PJM RTO																
CAPACITY PERFORMANCE	6,353	6,374	6,410	6,439	6,467	6,474	6,485	6,507	6,528	6,546	6,555	6,570	6,581	6,607	6,636	6,665
SUMMER PERIOD	334	335	338	338	337	335	335	336	335	336	333	333	330	330	332	334
PRD	230	356	356	356	357	358	356	357	356	353	352	350	349	349	349	349
TOTAL LOAD MANAGEMENT	6,917	7,065	7,104	7,133	7,161	7,167	7,176	7,200	7,219	7,235	7,240	7,253	7,260	7,286	7,317	7,348

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
DR Forecast values for each DR Product Type are based on actual committed quantities for Delivery Years 2020/21, 2021/22 and actual cleared quantities in the 2022/23 RPM Base Residual Auction

Table B-8a

DISTRIBUTED SOLAR ADJUSTMENTS TO JULY PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	232	239	245	275	286	290	283	293	295	313	317	321	322	328	343	356
BGE	232	266	293	310	304	325	369	394	429	495	541	597	637	682	700	719
DPL	151	163	171	183	190	201	209	224	252	306	357	401	443	471	505	520
JCPL	346	377	409	411	426	470	488	495	510	507	525	538	553	569	576	589
METED	41	41	42	46	46	47	57	56	56	61	63	72	75	76	78	81
PECO	61	66	69	78	79	94	95	107	111	118	130	132	143	161	180	189
PENLC	10	12	18	17	22	27	24	31	35	39	46	52	55	58	64	63
PEPCO	198	227	246	246	255	257	298	309	329	366	376	410	461	478	509	524
PL	88	83	88	111	112	120	110	111	127	151	162	169	172	173	209	218
PS	520	568	641	664	694	707	731	768	777	766	806	835	845	905	919	942
RECO	13	14	15	15	15	17	18	19	19	20	22	23	23	23	23	24
UGI	0	1	1	1	1	1	1	2	2	2	2	2	3	3	3	3
AEP	103	147	189	197	221	261	324	358	407	443	447	472	503	530	576	593
APS	93	106	113	122	141	198	236	273	305	354	382	415	442	469	504	528
ATSI	68	89	126	133	132	120	145	132	153	163	160	175	207	173	194	212
COMED	362	452	551	632	687	733	793	860	938	999	1,037	1,091	1,193	1,203	1,283	1,347
DAYTON	22	29	35	41	43	47	39	42	48	51	53	49	49	52	66	67
DEOK	22	37	42	42	46	49	44	44	61	57	64	57	64	66	80	77
DLCO	14	14	21	27	24	24	30	32	35	39	35	45	48	51	59	57
EKPC	6	7	7	7	7	9	8	13	14	11	17	14	17	21	25	22
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	541	604	625	662	681	729	819	859	890	916	969	990	1,071	1,050	1,087	1,099
PJM RTO	3,150	3,498	3,821	4,034	4,224	4,647	4,865	5,148	5,642	5,974	6,703	7,109	7,609	7,400	7,856	8,072

Notes:
Adjustment values presented here are reflected in all July peak forecast values.

Table B-8b

DISTRIBUTED BATTERY STORAGE ADJUSTMENT TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO

2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	0	0	1	1	2	2	2	3	4	5	6	7	8	9	10	12
BGE	0	1	2	3	4	4	6	7	10	15	21	28	35	44	51	59
DPL	0	1	1	1	2	2	3	3	4	7	9	11	14	16	18	21
JCPL	0	1	2	3	4	4	6	7	10	12	14	16	18	21	24	28
METED	0	0	0	1	1	1	1	2	2	3	4	4	5	6	7	8
PECO	0	1	1	2	2	3	4	5	6	7	9	11	13	15	17	20
PENLC	0	0	1	1	1	1	2	2	3	3	4	5	6	7	8	9
PEPCO	0	1	2	3	4	4	5	7	9	13	16	21	25	30	34	38
PL	0	1	1	2	2	3	4	5	6	7	9	11	14	16	18	21
PS	0	2	4	6	7	9	11	14	19	23	27	31	36	41	46	53
RECO	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	2
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
AEP	1	1	3	4	5	7	9	11	15	18	22	26	32	38	45	54
APS	0	1	2	2	3	4	5	6	8	10	13	17	20	25	29	33
ATSI	0	1	1	2	3	3	4	6	7	9	11	14	16	20	24	29
COMED	1	3	5	8	10	12	16	20	25	31	39	46	53	62	74	87
DAYTON	0	0	0	0	1	1	1	1	2	2	3	3	4	5	6	8
DEOK	0	0	0	1	1	1	2	2	3	3	4	5	6	7	9	11
DLCO	0	0	0	1	1	1	1	2	2	3	3	4	5	5	6	7
EKPC	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	1	2	5	7	9	12	16	20	27	34	42	52	63	76	90	107
PJM RTO	5	17	33	47	60	76	96	125	161	206	258	314	375	445	521	610

Notes:
Adjustment values presented here are reflected in all summer peak forecast values.

Table B-8c

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO

2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	10	14	18	23	29	35	41	46	52	58	64	69	74	79	88	91
BGE	28	40	52	66	83	101	118	135	152	169	186	202	218	233	257	268
DPL	9	12	14	17	21	25	29	33	37	41	44	48	51	54	60	62
JCPL	24	34	43	54	68	82	96	109	122	136	149	162	175	187	206	215
METED	4	4	5	5	6	6	7	7	8	8	9	9	9	10	10	11
PECO	11	12	13	14	15	17	18	20	21	22	23	24	25	26	28	29
PENLC	4	4	4	5	5	6	6	7	7	8	8	8	9	9	10	10
PEPCO	23	34	44	55	70	84	99	113	127	141	156	169	183	195	216	226
PL	9	10	11	12	13	15	16	17	18	19	20	21	22	23	25	25
PS	39	56	72	90	113	136	159	181	204	226	248	270	291	311	343	357
RECO	2	2	3	4	5	5	6	7	8	9	10	11	12	12	14	14
UGI	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1
AEP	21	24	28	37	48	57	67	75	83	91	98	104	110	114	124	126
APS	13	16	19	24	30	36	42	47	53	58	63	68	73	77	84	87
ATSI	12	14	15	16	18	19	21	22	24	25	26	27	28	29	32	32
COMED	53	75	96	121	152	183	214	243	273	303	332	361	388	413	455	473
DAYTON	3	4	4	4	5	5	6	6	6	7	7	7	8	8	9	9
DEOK	5	5	6	6	7	8	8	9	9	10	10	11	11	12	13	13
DLCO	4	4	4	5	5	5	6	6	7	7	8	8	8	9	9	9
EKPC	1	1	1	2	2	2	2	2	2	3	3	3	3	3	3	3
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	32	41	56	100	147	192	234	272	309	343	374	401	426	446	482	492
PJM RTO	307	406	509	661	842	1,020	1,194	1,359	1,523	1,683	1,838	1,987	2,125	2,252	2,467	2,555

Notes:
Adjustment values presented here are reflected in all summer peak forecast values.

Table B-9

ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
METED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PENLC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PEPCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
APS	187	221	249	261	266	274	285	291	306	315	322	325	333	346	358	356
ATSI	66	109	132	148	165	174	181	186	191	191	191	191	190	192	194	192
COMED	-108	-141	-181	-220	-221	-224	-227	-231	-218	-221	-231	-220	-219	-222	-229	-219
DAYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEOK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DLCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	752	1,380	2,087	2,844	3,604	3,840	4,079	4,353	4,600	4,857	5,100	5,361	5,600	5,895	6,188	6,444
PJM RTO	897	1,643	2,344	3,061	3,885	4,166	4,441	4,624	4,834	5,118	5,505	5,754	6,002	6,297	6,588	6,798

Notes:
Adjustment values presented here are reflected in summer peak forecasts.
Adjustments are large, unanticipated changes deemed by PJM to not be captured in the load forecast model.

Table B-10

SUMMER COINCIDENT PEAK LOAD (MW) FOR EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	2,398	2,400	2,399	2,391	2,397	2,399	2,412	2,424	2,434	2,444	2,450	2,460	2,475	2,494	2,500	2,516
BGE	6,235	6,204	6,211	6,198	6,206	6,202	6,208	6,212	6,202	6,170	6,148	6,129	6,120	6,142	6,151	6,168
DPL	3,757	3,762	3,787	3,786	3,796	3,793	3,802	3,812	3,809	3,768	3,727	3,702	3,678	3,682	3,674	3,686
JCPL	5,654	5,622	5,585	5,595	5,620	5,596	5,606	5,631	5,655	5,687	5,699	5,722	5,739	5,793	5,819	5,869
METED	2,850	2,850	2,859	2,866	2,890	2,895	2,899	2,911	2,936	2,955	2,972	2,984	2,993	3,018	3,033	3,068
PECO	8,121	8,110	8,131	8,116	8,123	8,100	8,112	8,129	8,153	8,167	8,158	8,164	8,166	8,207	8,224	8,268
PENLC	2,717	2,708	2,708	2,712	2,720	2,710	2,711	2,708	2,726	2,740	2,740	2,741	2,737	2,740	2,762	2,775
PEPCO	5,744	5,726	5,734	5,741	5,735	5,721	5,692	5,683	5,650	5,629	5,594	5,562	5,517	5,526	5,528	5,544
PL	6,847	6,829	6,844	6,868	6,896	6,905	6,920	6,956	6,973	7,006	7,029	7,047	7,060	7,105	7,128	7,181
PS	9,279	9,273	9,264	9,258	9,328	9,288	9,324	9,384	9,435	9,507	9,499	9,540	9,603	9,713	9,743	9,834
RECO	377	376	374	373	373	372	372	373	373	373	373	373	373	375	376	377
UGI	187	186	186	185	186	185	185	185	184	184	184	184	183	184	183	184
AEP	21,525	21,544	21,659	21,656	21,686	21,662	21,689	21,728	21,738	21,751	21,723	21,752	21,748	21,869	21,877	21,962
APS	8,431	8,492	8,535	8,571	8,577	8,548	8,528	8,527	8,535	8,529	8,509	8,486	8,491	8,515	8,527	8,563
ATSI	11,885	11,927	12,014	12,039	12,107	12,097	12,080	12,136	12,155	12,144	12,135	12,137	12,103	12,166	12,163	12,199
COMED	20,119	19,955	19,827	19,702	19,668	19,623	19,572	19,590	19,537	19,498	19,447	19,423	19,334	19,386	19,350	19,359
DAYTON	3,145	3,140	3,149	3,149	3,159	3,150	3,152	3,153	3,159	3,161	3,153	3,153	3,152	3,166	3,175	3,187
DEOK	5,036	5,054	5,087	5,115	5,145	5,146	5,150	5,162	5,176	5,192	5,190	5,196	5,198	5,226	5,238	5,271
DLCO	2,641	2,654	2,678	2,692	2,707	2,710	2,709	2,719	2,720	2,728	2,725	2,722	2,716	2,729	2,736	2,747
EKPC	2,030	2,051	2,078	2,104	2,129	2,141	2,143	2,148	2,151	2,157	2,157	2,160	2,165	2,177	2,185	2,193
OVEC	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
DOM	19,890	20,418	21,128	21,977	22,743	23,008	23,352	23,692	24,001	24,414	24,697	25,060	25,356	25,854	26,259	26,669
PJM RTO	148,938	149,351	150,307	151,164	152,261	152,321	152,688	153,333	153,772	154,274	154,379	154,767	154,977	156,137	156,701	157,690
PJM MID-ATLANTIC	54,166	54,046	54,082	54,089	54,270	54,166	54,243	54,408	54,530	54,630	54,573	54,608	54,644	54,979	55,121	55,470
EASTERN MID-ATLANTIC	29,586	29,543	29,540	29,519	29,637	29,548	29,628	29,753	29,859	29,946	29,906	29,961	30,034	30,264	30,336	30,550
SOUTHERN MID-ATLANTIC	11,979	11,930	11,945	11,939	11,941	11,923	11,900	11,895	11,852	11,799	11,742	11,691	11,637	11,668	11,679	11,712

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Load values for Zones and Locational Deliverability Areas are coincident with the PJM RTO peak.
This table will be used for the Reliability Pricing Model.
Summer season indicates peak from June, July, August.

Table B-11

PJM CONTROL AREA - JANUARY 2022
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	127,018	126,882	127,103	127,084	127,387	127,173	127,194	127,494	127,623	127,704	127,527	0.0%
% GROWTH TOTAL		-0.1%	0.2%	-0.0%	0.2%	-0.2%	0.0%	0.2%	0.1%	0.1%	-0.1%	
CONTRACTUALLY INTERRUPTIBLE	6,112	6,239	6,251	6,252	6,253	6,248	6,246	6,259	6,266	6,269	6,263	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,112	6,239	6,251	6,252	6,253	6,248	6,246	6,259	6,266	6,269	6,263	
NET INTERNAL DEMAND	120,906	120,643	120,852	120,832	121,134	120,925	120,948	121,235	121,357	121,435	121,264	0.0%
% GROWTH NET		-0.2%	0.2%	-0.0%	0.2%	-0.2%	0.0%	0.2%	0.1%	0.1%	-0.1%	
PJM - SERC												
TOTAL INTERNAL DEMAND	21,920	22,469	23,206	24,081	24,872	25,149	25,495	25,840	26,152	26,571	26,854	2.1%
% GROWTH TOTAL		2.5%	3.3%	3.8%	3.3%	1.1%	1.4%	1.4%	1.2%	1.6%	1.1%	
CONTRACTUALLY INTERRUPTIBLE	805	826	853	881	908	919	930	941	953	966	977	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	805	826	853	881	908	919	930	941	953	966	977	
NET INTERNAL DEMAND	21,115	21,643	22,353	23,200	23,964	24,230	24,565	24,899	25,199	25,605	25,877	2.1%
% GROWTH NET		2.5%	3.3%	3.8%	3.3%	1.1%	1.4%	1.4%	1.2%	1.6%	1.1%	
PJM RTO												
TOTAL INTERNAL DEMAND	148,938	149,351	150,309	151,165	152,259	152,322	152,689	153,334	153,775	154,275	154,381	0.4%
% GROWTH TOTAL		0.3%	0.6%	0.6%	0.7%	0.0%	0.2%	0.4%	0.3%	0.3%	0.1%	
CONTRACTUALLY INTERRUPTIBLE	6,917	7,065	7,104	7,133	7,161	7,167	7,176	7,200	7,219	7,235	7,240	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,917	7,065	7,104	7,133	7,161	7,167	7,176	7,200	7,219	7,235	7,240	
NET INTERNAL DEMAND	142,021	142,286	143,205	144,032	145,098	145,155	145,513	146,134	146,556	147,040	147,141	0.4%
% GROWTH NET		0.2%	0.6%	0.6%	0.7%	0.0%	0.2%	0.4%	0.3%	0.3%	0.1%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2022).

Table B-11 (Continued)

PJM CONTROL AREA - JANUARY 2022
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2022 - 2037

	2033	2034	2035	2036	2037	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	127,547	127,456	128,104	128,256	128,827	0.1%
% GROWTH TOTAL	0.0%	-0.1%	0.5%	0.1%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	6,263	6,259	6,272	6,288	6,304	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,263	6,259	6,272	6,288	6,304	
NET INTERNAL DEMAND	121,284	121,197	121,832	121,968	122,523	0.1%
% GROWTH NET	0.0%	-0.1%	0.5%	0.1%	0.5%	
PJM - SERC						
TOTAL INTERNAL DEMAND	27,220	27,521	28,031	28,444	28,862	1.9%
% GROWTH TOTAL	1.4%	1.1%	1.9%	1.5%	1.5%	
CONTRACTUALLY INTERRUPTIBLE	990	1,001	1,014	1,029	1,044	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	990	1,001	1,014	1,029	1,044	
NET INTERNAL DEMAND	26,230	26,520	27,017	27,415	27,818	1.9%
% GROWTH NET	1.4%	1.1%	1.9%	1.5%	1.5%	
PJM RTO						
TOTAL INTERNAL DEMAND	154,767	154,977	156,135	156,700	157,689	0.4%
% GROWTH TOTAL	0.3%	0.1%	0.7%	0.4%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	7,253	7,260	7,286	7,317	7,348	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	7,253	7,260	7,286	7,317	7,348	
NET INTERNAL DEMAND	147,514	147,717	148,849	149,383	150,341	0.4%
% GROWTH NET	0.3%	0.1%	0.8%	0.4%	0.6%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2022).

Table B-12

PJM CONTROL AREA - JANUARY 2022
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2021/22 - 2031/32

	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	67,976	67,775	68,009	68,250	68,469	68,660	68,956	68,966	69,222	69,334	69,479	0.2%
% GROWTH TOTAL		-0.3%	0.3%	0.4%	0.3%	0.3%	0.4%	0.0%	0.4%	0.2%	0.2%	
CONTRACTUALLY INTERRUPTIBLE	5,550	5,550	5,560	5,561	5,562	5,558	5,558	5,569	5,578	5,583	5,581	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,550	5,550	5,560	5,561	5,562	5,558	5,558	5,569	5,578	5,583	5,581	
NET INTERNAL DEMAND	62,426	62,225	62,449	62,689	62,907	63,102	63,398	63,397	63,644	63,751	63,898	0.2%
% GROWTH NET		-0.3%	0.4%	0.4%	0.3%	0.3%	0.5%	-0.0%	0.4%	0.2%	0.2%	
PJM - SERC												
TOTAL INTERNAL DEMAND	64,126	65,205	66,351	67,271	68,454	69,283	69,853	70,352	70,887	71,348	72,037	1.2%
% GROWTH TOTAL		1.7%	1.8%	1.4%	1.8%	1.2%	0.8%	0.7%	0.8%	0.7%	1.0%	
CONTRACTUALLY INTERRUPTIBLE	803	824	850	878	905	916	927	938	950	963	974	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	803	824	850	878	905	916	927	938	950	963	974	
NET INTERNAL DEMAND	63,323	64,381	65,501	66,393	67,549	68,367	68,926	69,414	69,937	70,385	71,063	1.2%
% GROWTH NET		1.7%	1.7%	1.4%	1.7%	1.2%	0.8%	0.7%	0.8%	0.6%	1.0%	
PJM RTO												
TOTAL INTERNAL DEMAND	132,102	132,980	134,360	135,521	136,923	137,943	138,809	139,318	140,109	140,682	141,516	0.7%
% GROWTH TOTAL		0.7%	1.0%	0.9%	1.0%	0.7%	0.6%	0.4%	0.6%	0.4%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	6,353	6,374	6,410	6,439	6,467	6,474	6,485	6,507	6,528	6,546	6,555	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,353	6,374	6,410	6,439	6,467	6,474	6,485	6,507	6,528	6,546	6,555	
NET INTERNAL DEMAND	125,749	126,606	127,950	129,082	130,456	131,469	132,324	132,811	133,581	134,136	134,961	0.7%
% GROWTH NET		0.7%	1.1%	0.9%	1.1%	0.8%	0.7%	0.4%	0.6%	0.4%	0.6%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2022).

Table B-12 (Continued)

PJM CONTROL AREA - JANUARY 2022
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2021/22 - 2031/32

	32/33	33/34	34/35	35/36	36/37	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	69,834	69,934	70,089	70,486	70,612	0.3%
% GROWTH TOTAL	0.5%	0.1%	0.2%	0.6%	0.2%	
CONTRACTUALLY INTERRUPTIBLE	5,583	5,583	5,596	5,610	5,624	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,583	5,583	5,596	5,610	5,624	
NET INTERNAL DEMAND	64,251	64,351	64,493	64,876	64,988	0.3%
% GROWTH NET	0.6%	0.2%	0.2%	0.6%	0.2%	
PJM - SERC						
TOTAL INTERNAL DEMAND	72,480	73,033	73,546	74,154	74,608	1.0%
% GROWTH TOTAL	0.6%	0.8%	0.7%	0.8%	0.6%	
CONTRACTUALLY INTERRUPTIBLE	987	998	1,011	1,026	1,041	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	987	998	1,011	1,026	1,041	
NET INTERNAL DEMAND	71,493	72,035	72,535	73,128	73,567	1.0%
% GROWTH NET	0.6%	0.8%	0.7%	0.8%	0.6%	
PJM RTO						
TOTAL INTERNAL DEMAND	142,314	142,967	143,635	144,640	145,220	0.6%
% GROWTH TOTAL	0.6%	0.5%	0.5%	0.7%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	6,570	6,581	6,607	6,636	6,665	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,570	6,581	6,607	6,636	6,665	
NET INTERNAL DEMAND	135,744	136,386	137,028	138,004	138,555	0.6%
% GROWTH NET	0.6%	0.5%	0.5%	0.7%	0.4%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2022).

Table C-1

PJM LOCATIONAL DELIVERABILITY AREAS
CENTRAL MID-ATLANTIC: BGE, METED, PEPCO, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	18,220	22,261	18,658	21,101
2023	18,189	22,227	18,633	21,102
2024	18,216	22,239	18,629	21,204
2025	18,161	22,265	18,646	21,217
2026	18,179	22,283	18,683	21,259
2027	18,230	22,282	18,726	21,342
2028	18,290	22,306	18,726	21,529
2029	18,374	22,356	18,753	21,451
2030	18,383	22,345	18,778	21,615
2031	18,302	22,373	18,852	21,586
2032	18,452	22,369	18,912	21,656
2033	18,500	22,348	18,916	21,837
2034	18,531	22,314	18,923	21,877
2035	18,501	22,299	18,955	21,970
2036	18,424	22,373	19,147	22,071
2037	18,561	22,410	19,249	22,038

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	20,085	23,706	20,221	23,012
2023	20,084	23,694	20,135	23,080
2024	19,946	23,702	20,021	23,168
2025	20,097	23,710	20,098	23,209
2026	20,207	23,702	20,081	23,287
2027	20,279	23,722	20,190	23,360
2028	20,136	23,749	20,177	23,462
2029	20,179	23,780	20,095	23,505
2030	20,231	23,772	20,137	23,488
2031	20,268	23,725	20,250	23,589
2032	20,441	23,707	20,323	23,671
2033	20,426	23,711	20,331	23,779
2034	20,444	23,749	20,337	23,831
2035	20,385	23,773	20,317	23,883
2036	20,357	23,790	20,441	23,963
2037	20,603	23,873	20,510	24,054

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-2

PJM LOCATIONAL DELIVERABILITY AREAS
WESTERN MID-ATLANTIC: METED, PENLC, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	11,083	12,911	11,046	12,749
2023	11,056	12,874	11,024	12,727
2024	11,053	12,919	10,978	12,744
2025	11,029	12,965	10,981	12,726
2026	11,042	12,985	10,997	12,721
2027	11,064	13,018	11,049	12,760
2028	11,074	13,024	11,056	12,799
2029	11,095	13,072	11,081	12,820
2030	11,127	13,160	11,120	12,813
2031	11,118	13,227	11,176	12,833
2032	11,169	13,275	11,247	12,834
2033	11,183	13,308	11,265	12,896
2034	11,203	13,333	11,277	12,911
2035	11,227	13,367	11,302	12,924
2036	11,193	13,459	11,355	12,922
2037	11,236	13,518	11,411	12,918

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	12,266	13,810	11,809	13,771
2023	12,226	13,774	11,798	13,761
2024	12,067	13,876	11,725	13,760
2025	11,967	13,893	11,772	13,737
2026	12,225	13,870	11,767	13,753
2027	12,322	13,893	11,814	13,786
2028	12,213	13,952	11,845	13,813
2029	12,234	14,014	11,827	13,834
2030	12,227	14,126	11,873	13,850
2031	12,029	14,187	11,992	13,836
2032	12,378	14,210	12,045	13,857
2033	12,308	14,261	12,082	13,909
2034	12,315	14,314	12,053	13,929
2035	12,270	14,373	12,081	13,933
2036	12,213	14,444	12,204	13,941
2037	12,344	14,518	12,260	13,930

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-3

PJM LOCATIONAL DELIVERABILITY AREAS
EASTERN MID-ATLANTIC: AE, DPL, JCPL, PECO, PS and RECO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	21,524	30,333	24,325	22,211
2023	21,507	30,309	24,302	22,326
2024	21,518	30,275	24,257	22,422
2025	21,283	30,254	24,321	22,499
2026	21,159	30,298	24,337	22,617
2027	21,140	30,344	24,401	22,741
2028	21,503	30,470	24,470	22,886
2029	21,647	30,571	24,569	22,989
2030	21,746	30,642	24,734	23,135
2031	21,635	30,699	24,907	23,229
2032	21,568	30,742	25,049	23,387
2033	21,722	30,788	25,143	23,568
2034	21,925	30,881	25,254	23,704
2035	22,014	30,998	25,327	23,810
2036	22,111	31,092	25,584	24,009
2037	22,172	31,140	25,723	24,116

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	24,148	32,524	26,619	23,455
2023	24,097	32,497	27,113	23,550
2024	24,035	32,503	27,192	23,638
2025	23,937	32,514	27,181	23,744
2026	23,814	32,570	26,571	23,864
2027	23,830	32,549	26,704	23,978
2028	24,037	32,668	27,404	24,138
2029	24,119	32,811	27,031	24,233
2030	24,170	32,918	27,723	24,404
2031	24,203	33,014	27,837	24,486
2032	24,244	33,080	27,603	24,649
2033	24,306	33,153	27,797	24,825
2034	24,413	33,277	28,115	24,970
2035	24,463	33,410	28,220	25,093
2036	24,518	33,620	28,360	25,294
2037	24,578	33,776	28,321	25,429

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-4

PJM LOCATIONAL DELIVERABILITY AREAS
SOUTHERN MID-ATLANTIC: BGE and PEPCO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	9,665	12,279	10,355	11,023
2023	9,669	12,260	10,334	11,103
2024	9,709	12,246	10,323	11,192
2025	9,665	12,259	10,358	11,207
2026	9,648	12,245	10,346	11,269
2027	9,661	12,235	10,366	11,322
2028	9,682	12,213	10,366	11,398
2029	9,700	12,206	10,332	11,429
2030	9,687	12,160	10,337	11,475
2031	9,671	12,116	10,336	11,466
2032	9,701	12,059	10,354	11,546
2033	9,743	11,997	10,347	11,609
2034	9,730	11,971	10,343	11,660
2035	9,760	12,004	10,364	11,722
2036	9,795	12,037	10,415	11,837
2037	9,881	12,050	10,471	11,889

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2022	10,510	13,000	11,293	12,179
2023	10,536	12,970	11,276	12,268
2024	10,550	12,993	11,271	12,355
2025	10,524	12,973	11,275	12,414
2026	10,538	12,965	11,285	12,462
2027	10,593	12,973	11,306	12,511
2028	10,603	12,979	11,312	12,568
2029	10,630	12,973	11,188	12,612
2030	10,602	12,928	11,274	12,638
2031	10,605	12,898	11,273	12,680
2032	10,622	12,852	11,325	12,729
2033	10,616	12,826	11,316	12,783
2034	10,622	12,797	11,265	12,829
2035	10,622	12,810	11,253	12,886
2036	10,661	12,849	11,420	12,969
2037	10,773	12,868	11,461	13,035

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	2,691	2,693	2,692	2,695	2,698	2,713	2,724	2,739	2,748	2,756	2,771	2,780	2,794	2,804	2,820	2,838
BGE	6,868	6,854	6,871	6,872	6,865	6,875	6,887	6,899	6,901	6,923	6,942	6,959	6,957	6,949	6,937	6,943
DPL	4,192	4,197	4,193	4,203	4,212	4,223	4,238	4,245	4,247	4,220	4,208	4,178	4,163	4,149	4,141	4,167
JCPL	6,242	6,205	6,195	6,191	6,195	6,209	6,228	6,255	6,290	6,319	6,335	6,366	6,395	6,435	6,481	6,515
METED	3,264	3,271	3,259	3,272	3,297	3,301	3,342	3,332	3,358	3,383	3,404	3,450	3,470	3,460	3,498	3,525
PECO	9,370	9,385	9,341	9,337	9,355	9,350	9,424	9,391	9,412	9,437	9,461	9,543	9,559	9,550	9,544	9,636
PENLC	2,972	2,975	2,973	2,970	2,970	2,970	2,982	2,990	2,999	3,004	3,009	3,013	3,018	3,028	3,031	3,038
PEPCO	6,180	6,171	6,153	6,127	6,117	6,111	6,116	6,111	6,061	6,046	6,039	6,037	6,042	6,048	6,070	6,085
PL	7,499	7,511	7,557	7,556	7,561	7,570	7,608	7,644	7,699	7,732	7,729	7,800	7,798	7,835	7,909	7,930
PS	10,324	10,315	10,353	10,371	10,382	10,392	10,425	10,510	10,539	10,596	10,688	10,705	10,765	10,873	10,931	10,999
RECO	436	433	431	430	430	429	431	432	432	432	432	433	434	435	436	435
UGI	211	211	210	209	209	208	208	208	208	208	208	207	207	207	208	207
DIVERSITY - MID-ATLANTIC(-)	1,346	1,351	1,364	1,375	1,415	1,415	1,564	1,476	1,451	1,563	1,733	1,967	1,899	1,913	1,917	2,021
PJM MID-ATLANTIC	58,903	58,870	58,864	58,858	58,876	58,936	59,049	59,280	59,443	59,493	59,493	59,504	59,703	59,860	60,089	60,297
FE-EAST	12,267	12,235	12,217	12,251	12,216	12,251	12,290	12,353	12,431	12,487	12,521	12,601	12,601	12,677	12,737	12,778
PLGRP	7,709	7,712	7,752	7,752	7,768	7,769	7,803	7,845	7,903	7,939	7,929	8,000	7,993	8,036	8,109	8,125

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Summer season indicates peak from June, July, August.

Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AEP	23,286	23,342	23,387	23,413	23,413	23,422	23,439	23,438	23,427	23,444	23,479	23,517	23,561	23,606	23,652	23,692
APS	9,230	9,268	9,318	9,352	9,368	9,342	9,342	9,340	9,358	9,371	9,381	9,398	9,416	9,408	9,466	9,490
ATSI	13,294	13,366	13,415	13,437	13,471	13,501	13,522	13,552	13,559	13,555	13,560	13,577	13,570	13,587	13,595	13,600
COMED	22,287	21,909	21,958	21,797	21,711	21,589	21,569	21,546	21,511	21,444	21,354	21,309	21,263	21,204	21,194	21,133
DAYTON	3,454	3,452	3,455	3,459	3,463	3,468	3,472	3,467	3,474	3,476	3,478	3,482	3,483	3,487	3,494	3,502
DEOK	5,541	5,570	5,603	5,628	5,644	5,659	5,685	5,696	5,705	5,713	5,716	5,729	5,744	5,759	5,776	5,789
DLCO	2,908	2,931	2,950	2,965	2,981	2,990	2,998	3,003	3,010	3,015	3,020	3,014	3,025	3,031	3,038	3,046
EKPC	2,250	2,280	2,306	2,330	2,355	2,368	2,374	2,378	2,383	2,387	2,393	2,398	2,408	2,415	2,418	2,430
OVEC	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
DIVERSITY - WESTERN(-)	2,368	2,183	2,060	2,048	2,292	2,375	2,131	2,116	2,133	2,224	2,520	2,260	2,295	2,255	2,407	2,399
PJM WESTERN	79,972	80,025	80,422	80,423	80,204	80,054	80,360	80,394	80,384	80,271	79,951	80,254	80,265	80,332	80,316	80,373
DOM	21,623	22,241	22,960	23,773	24,616	24,925	25,276	25,611	25,942	26,304	26,697	27,094	27,522	27,989	28,424	28,893
DIVERSITY - TOTAL(-)	7,284	6,977	6,692	6,711	7,064	7,427	7,103	6,952	6,968	7,265	7,618	7,932	7,918	8,036	8,140	8,579
PJM RTO	156,928	157,693	158,978	159,766	160,339	160,278	161,277	161,925	162,385	162,590	162,776	163,147	163,766	164,313	165,013	165,404

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Summer season indicates peak from June, July, August.

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

2021/22 - 2036/37

	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37
AE	1,681	1,691	1,698	1,706	1,716	1,726	1,737	1,746	1,758	1,769	1,782	1,794	1,810	1,823	1,850	1,866
BGE	6,318	6,354	6,398	6,427	6,466	6,502	6,541	6,580	6,610	6,646	6,683	6,720	6,755	6,790	6,838	6,874
DPL	4,153	4,190	4,221	4,235	4,255	4,291	4,326	4,367	4,387	4,411	4,433	4,475	4,513	4,541	4,564	4,584
JCPL	3,852	3,863	3,881	3,897	3,923	3,951	3,980	4,005	4,034	4,060	4,093	4,126	4,159	4,186	4,236	4,269
METED	2,812	2,799	2,800	2,803	2,809	2,811	2,816	2,821	2,827	2,831	2,839	2,843	2,848	2,853	2,858	2,864
PECO	7,129	7,130	7,140	7,132	7,134	7,129	7,141	7,148	7,157	7,141	7,149	7,162	7,171	7,174	7,185	7,175
PENLC	2,964	2,956	2,960	2,954	2,932	2,925	2,947	2,951	2,950	2,944	2,923	2,941	2,939	2,942	2,938	2,913
PEPCO	5,870	5,918	5,962	5,987	5,997	6,009	6,037	6,035	6,029	6,034	6,046	6,073	6,074	6,098	6,139	6,162
PL	7,817	7,825	7,841	7,817	7,830	7,847	7,876	7,907	7,898	7,901	7,917	7,952	7,979	7,989	7,977	7,977
PS	6,856	6,900	6,956	7,000	7,061	7,114	7,170	7,230	7,290	7,354	7,426	7,490	7,557	7,632	7,725	7,821
RECO	234	235	235	236	237	239	240	241	243	244	245	247	249	250	253	254
UGI	211	210	210	209	208	208	207	207	206	206	205	205	205	205	204	203
DIVERSITY - MID-ATLANTIC(-)	701	725	726	787	636	661	711	731	829	811	659	733	764	794	817	783
PJM MID-ATLANTIC	49,196	49,346	49,576	49,616	49,932	50,091	50,307	50,507	50,560	50,730	51,082	51,295	51,495	51,689	51,950	52,179
FE-EAST	9,517	9,502	9,523	9,544	9,573	9,597	9,638	9,662	9,693	9,723	9,759	9,807	9,836	9,868	9,913	9,944
PLGRP	8,019	8,028	8,043	8,019	8,032	8,049	8,073	8,105	8,098	8,100	8,116	8,148	8,175	8,184	8,174	8,173

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Winter season indicates peak from December, January, February.

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2022 - 2037

	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37
AEP	24,019	24,074	24,192	24,290	24,312	24,399	24,452	24,506	24,494	24,584	24,577	24,669	24,713	24,754	24,751	24,793
APS	9,751	9,772	9,846	9,894	9,932	9,952	9,981	9,999	10,017	10,041	10,065	10,089	10,102	10,120	10,147	10,173
ATSI	10,591	10,621	10,683	10,688	10,697	10,687	10,694	10,696	10,689	10,680	10,669	10,670	10,669	10,672	10,658	10,635
COMED	15,856	15,844	15,862	15,856	15,904	15,955	16,006	16,045	16,085	16,112	16,161	16,221	16,251	16,313	16,378	16,411
DAYTON	3,119	3,113	3,124	3,121	3,132	3,135	3,142	3,143	3,133	3,136	3,147	3,157	3,157	3,166	3,162	3,178
DEOK	4,820	4,858	4,893	4,901	4,921	4,933	4,947	4,975	4,968	4,978	4,991	5,003	5,030	5,044	5,045	5,060
DLCO	2,092	2,099	2,111	2,114	2,117	2,120	2,126	2,131	2,130	2,132	2,135	2,140	2,142	2,143	2,145	2,147
EKPC	3,109	3,139	3,160	3,169	3,180	3,195	3,206	3,218	3,223	3,234	3,245	3,262	3,272	3,283	3,289	3,301
OVEC	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
DIVERSITY - WESTERN(-)	1,635	1,637	1,643	1,636	1,584	1,638	1,628	1,620	1,588	1,646	1,559	1,608	1,598	1,618	1,590	1,572
PJM WESTERN	71,837	71,998	72,343	72,512	72,726	72,853	73,041	73,208	73,266	73,366	73,546	73,718	73,853	73,992	74,100	74,241
DOM	24,007	24,745	25,594	26,524	27,498	28,215	28,635	29,040	29,443	29,860	30,272	30,720	31,133	31,584	32,044	32,432
DIVERSITY - TOTAL(-)	4,598	4,669	4,787	4,649	4,597	4,656	4,646	4,879	5,035	4,786	4,653	4,679	4,883	5,006	5,136	4,947
PJM RTO	142,778	143,782	145,095	146,426	147,779	148,802	149,676	150,227	150,651	151,627	152,465	153,395	153,960	154,671	155,365	156,260

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Winter season indicates peak from December, January, February.

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

2022 - 2032

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Growth Rate (10 yr)
AE	9,440	9,411	9,398	9,341	9,333	9,376	9,484	9,551	9,645	9,752	9,897	0.5%
		-0.3%	-0.1%	-0.6%	-0.1%	0.5%	1.2%	0.7%	1.0%	1.1%	1.5%	
BGE	30,746	30,773	30,971	30,990	31,121	31,317	31,656	31,802	31,989	32,204	32,537	0.6%
		0.1%	0.6%	0.1%	0.4%	0.6%	1.1%	0.5%	0.6%	0.7%	1.0%	
DPL	18,356	18,374	18,425	18,384	18,401	18,466	18,619	18,668	18,723	18,748	18,830	0.3%
		0.1%	0.3%	-0.2%	0.1%	0.4%	0.8%	0.3%	0.3%	0.1%	0.4%	
JCPL	21,635	21,561	21,590	21,542	21,606	21,733	21,991	22,168	22,397	22,671	23,043	0.6%
		-0.3%	0.1%	-0.2%	0.3%	0.6%	1.2%	0.8%	1.0%	1.2%	1.6%	
METED	15,409	15,379	15,416	15,393	15,423	15,465	15,545	15,562	15,595	15,659	15,775	0.2%
		-0.2%	0.2%	-0.1%	0.2%	0.3%	0.5%	0.1%	0.2%	0.4%	0.7%	
PECO	39,254	39,266	39,281	39,076	38,988	38,969	39,117	39,071	39,095	39,172	39,376	0.0%
		0.0%	0.0%	-0.5%	-0.2%	-0.0%	0.4%	-0.1%	0.1%	0.2%	0.5%	
PENLC	16,802	16,745	16,737	16,646	16,619	16,615	16,674	16,652	16,654	16,686	16,768	(0.0%)
		-0.3%	-0.0%	-0.5%	-0.2%	-0.0%	0.4%	-0.1%	0.0%	0.2%	0.5%	
PEPCO	28,020	28,076	28,185	28,107	28,063	28,081	28,189	28,134	28,049	28,055	28,208	0.1%
		0.2%	0.4%	-0.3%	-0.2%	0.1%	0.4%	-0.2%	-0.3%	0.0%	0.5%	
PL	39,554	39,540	39,683	39,611	39,673	39,774	40,014	40,055	40,163	40,329	40,630	0.3%
		-0.0%	0.4%	-0.2%	0.2%	0.3%	0.6%	0.1%	0.3%	0.4%	0.7%	
PS	42,166	42,203	42,425	42,444	42,653	42,948	43,465	43,824	44,269	44,800	45,518	0.8%
		0.1%	0.5%	0.0%	0.5%	0.7%	1.2%	0.8%	1.0%	1.2%	1.6%	
RECO	1,402	1,395	1,388	1,379	1,377	1,379	1,394	1,399	1,408	1,424	1,440	0.3%
		-0.5%	-0.5%	-0.6%	-0.1%	0.1%	1.1%	0.4%	0.6%	1.1%	1.1%	
UGI	1,024	1,020	1,018	1,009	1,007	1,004	1,007	1,000	998	997	999	(0.2%)
		-0.4%	-0.2%	-0.9%	-0.2%	-0.3%	0.3%	-0.7%	-0.2%	-0.1%	0.2%	
PJM MID-ATLANTIC	263,808	263,743	264,517	263,922	264,264	265,127	267,155	267,886	268,985	270,497	273,021	0.3%
		-0.0%	0.3%	-0.2%	0.1%	0.3%	0.8%	0.3%	0.4%	0.6%	0.9%	
FE-EAST	53,846	53,685	53,743	53,581	53,648	53,813	54,210	54,382	54,646	55,016	55,586	0.3%
		-0.3%	0.1%	-0.3%	0.1%	0.3%	0.7%	0.3%	0.5%	0.7%	1.0%	
PLGRP	40,578	40,560	40,701	40,620	40,680	40,778	41,021	41,055	41,161	41,326	41,629	0.3%
		-0.0%	0.3%	-0.2%	0.1%	0.2%	0.6%	0.1%	0.3%	0.4%	0.7%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2022).

Table E-1 (continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

2033 - 2037

	2033	2034	2035	2036	2037	Annual Growth Rate (15 yr)
AE	9,984	10,114	10,256	10,476	10,598	0.8%
	0.9%	1.3%	1.4%	2.1%	1.2%	
BGE	32,684	32,955	33,288	33,917	34,231	0.7%
	0.5%	0.8%	1.0%	1.9%	0.9%	
DPL	18,805	18,850	18,932	19,103	19,151	0.3%
	-0.1%	0.2%	0.4%	0.9%	0.3%	
JCPL	23,263	23,582	23,944	24,492	24,816	0.9%
	1.0%	1.4%	1.5%	2.3%	1.3%	
METED	15,782	15,821	15,879	15,986	16,013	0.3%
	0.0%	0.2%	0.4%	0.7%	0.2%	
PECO	39,314	39,364	39,451	39,667	39,674	0.1%
	-0.2%	0.1%	0.2%	0.5%	0.0%	
PENLC	16,732	16,734	16,758	16,824	16,804	0.0%
	-0.2%	0.0%	0.1%	0.4%	-0.1%	
PEPCO	28,226	28,374	28,595	29,085	29,329	0.3%
	0.1%	0.5%	0.8%	1.7%	0.8%	
PL	40,633	40,742	40,889	41,172	41,211	0.3%
	0.0%	0.3%	0.4%	0.7%	0.1%	
PS	45,929	46,535	47,227	48,253	48,861	1.0%
	0.9%	1.3%	1.5%	2.2%	1.3%	
RECO	1,451	1,466	1,484	1,515	1,530	0.6%
	0.8%	1.0%	1.2%	2.1%	1.0%	
UGI	995	994	993	993	990	(0.2%)
	-0.4%	-0.1%	-0.1%	0.0%	-0.3%	
PJM MID-ATLANTIC	273,798	275,531	277,696	281,483	283,208	0.5%
	0.3%	0.6%	0.8%	1.4%	0.6%	
FE-EAST	55,777	56,137	56,581	57,302	57,633	0.5%
	0.3%	0.6%	0.8%	1.3%	0.6%	
PLGRP	41,628	41,736	41,882	42,165	42,201	0.3%
	-0.0%	0.3%	0.3%	0.7%	0.1%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2022).

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2022 - 2032

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Annual Growth Rate (10 yr)
AEP	127,782	128,128	128,860	128,815	129,004	129,299	130,055	130,085	130,190	130,645	131,491	0.3%
		0.3%	0.6%	-0.0%	0.1%	0.2%	0.6%	0.0%	0.1%	0.3%	0.6%	
APS	50,310	50,569	51,056	51,112	51,191	51,316	51,639	51,658	51,708	51,906	52,265	0.4%
		0.5%	1.0%	0.1%	0.2%	0.2%	0.6%	0.0%	0.1%	0.4%	0.7%	
ATSI	64,441	64,813	65,185	65,125	65,214	65,309	65,584	65,524	65,488	65,591	65,854	0.2%
		0.6%	0.6%	-0.1%	0.1%	0.1%	0.4%	-0.1%	-0.1%	0.2%	0.4%	
COMED	93,463	92,982	92,716	92,036	91,904	92,022	92,524	92,565	92,741	93,102	93,793	0.0%
		-0.5%	-0.3%	-0.7%	-0.1%	0.1%	0.5%	0.0%	0.2%	0.4%	0.7%	
DAYTON	16,829	16,809	16,843	16,804	16,800	16,811	16,878	16,871	16,847	16,884	16,964	0.1%
		-0.1%	0.2%	-0.2%	-0.0%	0.1%	0.4%	-0.0%	-0.1%	0.2%	0.5%	
DEOK	26,679	26,827	27,060	27,102	27,186	27,291	27,473	27,510	27,553	27,654	27,832	0.4%
		0.6%	0.9%	0.2%	0.3%	0.4%	0.7%	0.1%	0.2%	0.4%	0.6%	
DLCO	13,087	13,173	13,275	13,294	13,343	13,380	13,444	13,448	13,463	13,495	13,567	0.4%
		0.7%	0.8%	0.1%	0.4%	0.3%	0.5%	0.0%	0.1%	0.2%	0.5%	
EKPC	11,384	11,483	11,591	11,643	11,727	11,780	11,844	11,846	11,860	11,896	11,968	0.5%
		0.9%	0.9%	0.4%	0.7%	0.5%	0.5%	0.0%	0.1%	0.3%	0.6%	
OVEC	375	375	375	375	375	375	375	375	375	375	375	0.0%
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	404,350	405,159	406,961	406,306	406,744	407,583	409,816	409,882	410,225	411,548	414,109	0.2%
		0.2%	0.4%	-0.2%	0.1%	0.2%	0.5%	0.0%	0.1%	0.3%	0.6%	
DOM	113,160	118,859	125,595	132,352	139,354	142,817	146,136	148,623	151,408	154,427	158,003	3.4%
		5.0%	5.7%	5.4%	5.3%	2.5%	2.3%	1.7%	1.9%	2.0%	2.3%	
PJM RTO	781,318	787,761	797,073	802,580	810,362	815,527	823,107	826,391	830,618	836,472	845,133	0.8%
		0.8%	1.2%	0.7%	1.0%	0.6%	0.9%	0.4%	0.5%	0.7%	1.0%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2022).

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2022 - 2032

	2033	2034	2035	2036	2037	Annual Growth Rate (15 yr)
AEP	131,558	131,935	132,439	133,276	133,390	0.3%
	0.1%	0.3%	0.4%	0.6%	0.1%	
APS	52,298	52,476	52,713	53,138	53,244	0.4%
	0.1%	0.3%	0.5%	0.8%	0.2%	
ATSI	65,735	65,750	65,836	66,081	65,973	0.2%
	-0.2%	0.0%	0.1%	0.4%	-0.2%	
COMED	93,977	94,424	94,998	96,078	96,431	0.2%
	0.2%	0.5%	0.6%	1.1%	0.4%	
DAYTON	16,950	16,980	17,037	17,126	17,131	0.1%
	-0.1%	0.2%	0.3%	0.5%	0.0%	
DEOK	27,860	27,962	28,091	28,289	28,339	0.4%
	0.1%	0.4%	0.5%	0.7%	0.2%	
DLCO	13,545	13,556	13,585	13,665	13,672	0.3%
	-0.2%	0.1%	0.2%	0.6%	0.1%	
EKPC	11,971	12,002	12,042	12,103	12,108	0.4%
	0.0%	0.3%	0.3%	0.5%	0.0%	
OVEC	375	375	375	375	375	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	414,269	415,460	417,116	420,131	420,663	0.3%
	0.0%	0.3%	0.4%	0.7%	0.1%	
DOM	160,628	163,762	166,999	170,984	173,715	2.9%
	1.7%	2.0%	2.0%	2.4%	1.6%	
PJM RTO	848,695	854,753	861,811	872,598	877,586	0.8%
	0.4%	0.7%	0.8%	1.3%	0.6%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2022).

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	PJM MID-ATLANTIC
Jan 2022	856	3,042	1,863	1,969	1,463	3,668	1,620	2,713	3,965	3,736	122	105	25,122
Feb 2022	741	2,606	1,593	1,711	1,293	3,192	1,445	2,349	3,482	3,264	106	94	21,876
Mar 2022	713	2,525	1,485	1,690	1,327	3,209	1,479	2,276	3,482	3,342	102	93	21,723
Apr 2022	606	2,082	1,210	1,420	1,117	2,745	1,271	1,861	2,873	2,873	93	74	18,225
May 2022	668	2,189	1,282	1,560	1,138	2,937	1,272	2,016	2,873	3,093	105	72	19,205
Jun 2022	825	2,596	1,539	1,891	1,263	3,357	1,324	2,415	3,113	3,680	132	78	22,213
Jul 2022	1,097	3,078	1,883	2,363	1,454	3,984	1,463	2,857	3,566	4,444	156	91	26,436
Aug 2022	1,012	2,889	1,752	2,184	1,426	3,837	1,434	2,714	3,421	4,277	146	85	25,177
Sep 2022	752	2,388	1,401	1,729	1,161	3,126	1,270	2,218	2,923	3,484	116	73	20,641
Oct 2022	650	2,172	1,269	1,543	1,151	2,800	1,310	1,990	2,921	3,134	100	74	19,114
Nov 2022	684	2,358	1,382	1,644	1,227	2,930	1,373	2,109	3,227	3,170	103	86	20,293
Dec 2022	836	2,821	1,697	1,931	1,389	3,469	1,541	2,502	3,708	3,669	121	99	23,783
	AE	**BGE**	**DPL**	**JCPL**	**METED**	**PECO**	**PENLC**	**PEPCO**	**PL**	**PS**	**RECO**	**UGI**	**MID-ATLANTIC**
Jan 2023	862	3,062	1,877	1,977	1,458	3,676	1,617	2,741	3,970	3,764	122	105	25,231
Feb 2023	745	2,620	1,602	1,715	1,287	3,194	1,440	2,369	3,481	3,281	106	93	21,933
Mar 2023	710	2,528	1,483	1,682	1,323	3,208	1,470	2,285	3,482	3,344	101	93	21,709
Apr 2023	600	2,072	1,202	1,401	1,107	2,731	1,256	1,851	2,853	2,852	92	74	18,091
May 2023	663	2,184	1,282	1,556	1,140	2,945	1,269	2,017	2,879	3,101	105	72	19,213
Jun 2023	820	2,582	1,537	1,871	1,258	3,350	1,317	2,408	3,106	3,662	131	77	22,119
Jul 2023	1,092	3,069	1,882	2,342	1,449	3,979	1,456	2,852	3,559	4,426	155	90	26,351
Aug 2023	1,005	2,877	1,749	2,166	1,427	3,837	1,430	2,709	3,420	4,270	145	85	25,120
Sep 2023	744	2,380	1,396	1,714	1,152	3,123	1,262	2,208	2,906	3,472	115	72	20,544
Oct 2023	648	2,185	1,274	1,546	1,160	2,815	1,318	2,004	2,939	3,158	99	74	19,220
Nov 2023	684	2,375	1,386	1,654	1,233	2,942	1,375	2,121	3,240	3,187	103	86	20,386
Dec 2023	838	2,839	1,704	1,937	1,385	3,466	1,535	2,511	3,705	3,686	121	99	23,826
	AE	**BGE**	**DPL**	**JCPL**	**METED**	**PECO**	**PENLC**	**PEPCO**	**PL**	**PS**	**RECO**	**UGI**	**MID-ATLANTIC**
Jan 2024	866	3,089	1,890	1,991	1,464	3,687	1,623	2,764	3,990	3,802	123	105	25,394
Feb 2024	775	2,733	1,668	1,785	1,334	3,314	1,493	2,465	3,616	3,427	110	96	22,816
Mar 2024	702	2,531	1,470	1,669	1,310	3,183	1,450	2,277	3,458	3,326	99	92	21,567
Apr 2024	599	2,093	1,204	1,406	1,123	2,745	1,267	1,864	2,891	2,885	92	74	18,243
May 2024	658	2,186	1,279	1,553	1,139	2,940	1,262	2,013	2,877	3,111	103	72	19,193
Jun 2024	811	2,565	1,528	1,845	1,243	3,312	1,297	2,387	3,079	3,620	128	76	21,891
Jul 2024	1,088	3,083	1,887	2,339	1,461	3,987	1,464	2,864	3,586	4,453	154	90	26,456
Aug 2024	996	2,867	1,741	2,147	1,421	3,811	1,417	2,695	3,406	4,253	143	84	24,981
Sep 2024	735	2,383	1,390	1,703	1,147	3,112	1,255	2,206	2,896	3,471	114	71	20,483
Oct 2024	646	2,202	1,278	1,552	1,167	2,811	1,322	2,013	2,957	3,184	99	74	19,305
Nov 2024	681	2,384	1,381	1,658	1,229	2,919	1,363	2,118	3,231	3,187	102	86	20,339
Dec 2024	841	2,855	1,709	1,942	1,378	3,460	1,524	2,519	3,696	3,706	121	98	23,849

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	PJM WESTERN	DOM	PJM RTO
Jan 2022	12,559	5,018	5,957	8,588	1,617	2,478	1,153	1,221	35	38,626	10,928	74,676
Feb 2022	10,831	4,389	5,299	7,502	1,402	2,139	1,023	995	35	33,615	9,302	64,793
Mar 2022	10,975	4,418	5,579	7,627	1,428	2,187	1,066	977	35	34,292	9,159	65,174
Apr 2022	9,266	3,692	4,736	6,678	1,175	1,874	937	779	25	29,162	7,944	55,331
May 2022	9,649	3,764	4,899	7,017	1,259	2,043	1,009	768	25	30,433	8,500	58,138
Jun 2022	10,362	3,981	5,361	8,075	1,411	2,315	1,147	910	25	33,587	9,440	65,240
Jul 2022	11,509	4,469	6,002	9,257	1,578	2,624	1,317	1,024	35	37,815	10,766	75,017
Aug 2022	11,369	4,382	5,870	9,006	1,564	2,548	1,246	1,001	30	37,016	10,432	72,625
Sep 2022	9,838	3,753	4,974	7,417	1,311	2,162	1,071	854	30	31,410	8,843	60,894
Oct 2022	9,505	3,698	4,912	6,892	1,247	1,927	989	792	30	29,992	8,397	57,503
Nov 2022	10,228	4,020	5,168	7,154	1,325	2,020	1,011	958	35	31,919	8,945	61,157
Dec 2022	11,691	4,726	5,684	8,250	1,512	2,362	1,118	1,105	35	36,483	10,504	70,770

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2023	12,589	5,038	5,983	8,591	1,616	2,492	1,157	1,229	35	38,730	11,443	75,404
Feb 2023	10,857	4,406	5,321	7,496	1,401	2,152	1,026	1,001	35	33,695	9,758	65,386
Mar 2023	10,999	4,436	5,616	7,601	1,427	2,199	1,072	988	35	34,373	9,635	65,717
Apr 2023	9,219	3,688	4,726	6,596	1,160	1,874	938	787	25	29,013	8,379	55,483
May 2023	9,682	3,787	4,947	6,994	1,259	2,054	1,017	773	25	30,538	8,977	58,728
Jun 2023	10,358	3,992	5,388	8,000	1,405	2,321	1,154	917	25	33,560	9,864	65,543
Jul 2023	11,517	4,486	6,022	9,159	1,574	2,636	1,325	1,034	35	37,788	11,222	75,361
Aug 2023	11,398	4,402	5,907	8,945	1,562	2,561	1,255	1,011	30	37,071	10,893	73,084
Sep 2023	9,861	3,767	4,990	7,335	1,305	2,171	1,079	862	30	31,400	9,271	61,215
Oct 2023	9,597	3,741	4,981	6,893	1,255	1,948	1,004	800	30	30,249	8,906	58,375
Nov 2023	10,315	4,055	5,228	7,148	1,333	2,042	1,024	971	35	32,151	9,460	61,997
Dec 2023	11,736	4,771	5,704	8,224	1,512	2,377	1,122	1,110	35	36,591	11,051	71,468

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2024	12,702	5,104	6,044	8,623	1,628	2,520	1,168	1,237	35	39,061	12,028	76,483
Feb 2024	11,318	4,610	5,550	7,770	1,456	2,249	1,070	1,040	35	35,098	10,649	68,563
Mar 2024	10,974	4,445	5,592	7,506	1,414	2,199	1,071	993	35	34,229	10,137	65,933
Apr 2024	9,344	3,760	4,802	6,630	1,175	1,905	951	800	25	29,392	8,933	56,568
May 2024	9,711	3,820	4,962	6,944	1,257	2,066	1,022	773	25	30,580	9,498	59,271
Jun 2024	10,283	3,981	5,342	7,850	1,387	2,315	1,150	921	25	33,254	10,319	65,464
Jul 2024	11,620	4,539	6,079	9,142	1,588	2,668	1,339	1,046	35	38,056	11,776	76,288
Aug 2024	11,383	4,409	5,893	8,837	1,552	2,567	1,257	1,018	30	36,946	11,391	73,318
Sep 2024	9,871	3,782	4,995	7,256	1,303	2,183	1,085	872	30	31,377	9,765	61,625
Oct 2024	9,651	3,776	5,026	6,886	1,260	1,966	1,015	808	30	30,418	9,465	59,188
Nov 2024	10,305	4,058	5,230	7,084	1,324	2,046	1,027	979	35	32,088	9,986	62,413
Dec 2024	11,698	4,772	5,670	8,188	1,499	2,376	1,120	1,104	35	36,462	11,648	71,959

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

Table E-3

MONTHLY NET ENERGY FORECAST (GWh) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2022	5,052	4,070
Feb 2022	4,449	3,576
Mar 2022	4,496	3,575
Apr 2022	3,808	2,947
May 2022	3,970	2,945
Jun 2022	4,478	3,191
Jul 2022	5,280	3,657
Aug 2022	5,044	3,506
Sep 2022	4,160	2,996
Oct 2022	4,004	2,995
Nov 2022	4,244	3,313
Dec 2022	4,861	3,807

	FE_EAST	PLGRP
Jan 2023	5,052	4,075
Feb 2023	4,442	3,574
Mar 2023	4,475	3,575
Apr 2023	3,764	2,927
May 2023	3,965	2,951
Jun 2023	4,446	3,183
Jul 2023	5,247	3,649
Aug 2023	5,023	3,505
Sep 2023	4,128	2,978
Oct 2023	4,024	3,013
Nov 2023	4,262	3,326
Dec 2023	4,857	3,804

	FE_EAST	PLGRP
Jan 2024	5,078	4,095
Feb 2024	4,612	3,712
Mar 2024	4,429	3,550
Apr 2024	3,796	2,965
May 2024	3,954	2,949
Jun 2024	4,385	3,155
Jul 2024	5,264	3,676
Aug 2024	4,985	3,490
Sep 2024	4,105	2,967
Oct 2024	4,041	3,031
Nov 2024	4,250	3,317
Dec 2024	4,844	3,794

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

Table E-4

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO ANNUAL ENERGY (GWh) FOR EACH PJM ZONE AND RTO

2022 - 2037

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
AE	80	116	154	199	258	322	391	462	541	628	725	825	933	1,054	1,231	1,360
BGE	223	327	438	571	745	932	1,135	1,344	1,579	1,835	2,121	2,414	2,734	3,090	3,610	3,990
DPL	71	94	119	150	190	234	280	328	382	440	504	570	641	721	839	924
JCPL	187	272	361	468	607	756	918	1,084	1,271	1,475	1,703	1,937	2,192	2,476	2,892	3,194
METED	30	34	38	43	50	57	64	71	79	87	97	106	116	128	146	158
PECO	83	94	105	119	136	155	174	193	215	238	264	290	318	349	398	431
PENLC	29	32	36	41	47	53	60	67	74	82	91	100	110	120	137	149
PEPCO	186	273	366	477	622	779	948	1,124	1,321	1,536	1,776	2,023	2,292	2,593	3,032	3,354
PL	72	81	90	102	118	133	150	167	186	206	228	250	274	302	344	372
PS	312	452	601	779	1,010	1,259	1,528	1,805	2,116	2,455	2,834	3,224	3,649	4,122	4,813	5,316
RECO	13	18	24	31	41	51	61	72	85	99	114	130	147	166	193	214
UGI	2	2	2	3	3	4	4	4	5	6	6	7	7	8	9	10
AEP	163	192	235	323	425	530	638	746	862	983	1,112	1,239	1,372	1,516	1,731	1,871
APS	98	128	162	210	270	334	402	471	548	630	721	812	911	1,020	1,182	1,296
ATSI	96	108	121	136	156	177	198	220	244	269	297	325	356	390	443	479
COMED	419	607	806	1,045	1,357	1,692	2,053	2,424	2,839	3,290	3,792	4,306	4,863	5,480	6,383	7,033
DAYTON	26	29	33	37	42	48	54	59	66	73	80	88	96	105	120	129
DEOK	38	43	48	55	62	71	79	88	97	108	119	130	142	156	177	192
DLCO	27	30	34	39	44	50	57	63	70	77	86	94	103	113	129	140
EKPC	10	11	12	14	16	18	20	22	25	28	31	34	37	41	46	50
DOM	251	332	492	886	1,329	1,783	2,251	2,715	3,209	3,720	4,259	4,782	5,325	5,903	6,754	7,300
PJM RTO	2,414	3,276	4,277	5,729	7,529	9,436	11,465	13,529	15,814	18,264	20,960	23,686	26,618	29,853	34,612	37,962

Notes:
Adjustment values presented here are reflected in all energy forecast values.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED BASE	NORMALIZED COOLING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1998				133,275	Tuesday, July 21, 1998	17:00
1999				141,491	Friday, July 30, 1999	17:00
2000				131,798	Wednesday, August 9, 2000	17:00
2001				150,924	Thursday, August 9, 2001	16:00
2002				150,826	Thursday, August 1, 2002	17:00
2003				145,227	Thursday, August 21, 2003	17:00
2004				139,279	Tuesday, August 3, 2004	17:00
2005	95,846	60,592	156,438	155,257	Tuesday, July 26, 2005	16:00
2006	95,311	62,441	157,751	166,929	Wednesday, August 2, 2006	17:00
2007	96,738	64,277	161,015	162,035	Wednesday, August 8, 2007	16:00
2008	97,213	64,812	162,025	150,622	Monday, June 9, 2008	17:00
2009	94,732	62,518	157,251	145,112	Monday, August 10, 2009	16:00
2010	93,191	64,317	157,508	157,247	Wednesday, July 7, 2010	17:00
2011	93,397	62,808	156,205	165,524	Thursday, July 21, 2011	17:00
2012	93,024	61,796	154,821	158,219	Tuesday, July 17, 2012	17:00
2013	92,558	60,591	153,149	159,149	Thursday, July 18, 2013	17:00
2014	91,934	61,359	153,293	141,509	Tuesday, June 17, 2014	18:00
2015	91,214	60,419	151,632	143,579	Tuesday, July 28, 2015	17:00
2016	89,900	60,934	150,834	152,069	Thursday, August 11, 2016	16:00
2017	88,999	61,077	150,076	145,434	Wednesday, July 19, 2017	18:00
2018	89,895	59,766	149,660	150,573	Tuesday, August 28, 2018	17:00
2019	89,624	59,511	149,135	151,302	Friday, July 19, 2019	18:00
2020	85,951	59,866	145,817	144,320	Monday, July 20, 2020	17:00
2021	85,327	62,602	147,929	148,433	Tuesday, August 24, 2021	18:00

Notes:
Normalized values for 2000 - 2021 are calculated by PJM staff using a methodology described in Manual 19.
Normalized base values are calculated by PJM staff using a two-period average of peak loads on non-heating/non-coolong days.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

WINTER

YEAR	NORMALIZED BASE	NORMALIZED HEATING	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
97/98				103,231	Wednesday, January 14, 1998	19:00
98/99				116,086	Tuesday, January 5, 1999	19:00
99/00				118,435	Thursday, January 27, 2000	20:00
00/01				118,046	Wednesday, December 20, 2000	19:00
01/02				112,217	Wednesday, January 2, 2002	19:00
02/03				129,965	Thursday, January 23, 2003	19:00
03/04				122,424	Friday, January 23, 2004	9:00
04/05			128,151	131,234	Monday, December 20, 2004	19:00
05/06	94,721	33,935	128,655	126,777	Wednesday, December 14, 2005	19:00
06/07	96,152	34,170	130,322	136,804	Monday, February 5, 2007	20:00
07/08	97,256	34,273	131,529	128,368	Wednesday, January 2, 2008	19:00
08/09	96,416	30,280	126,696	134,077	Friday, January 16, 2009	19:00
09/10	93,507	34,737	128,244	125,350	Monday, January 4, 2010	19:00
10/11	91,898	37,451	129,350	132,315	Tuesday, December 14, 2010	19:00
11/12	92,373	37,430	129,804	124,506	Tuesday, January 3, 2012	19:00
12/13	92,158	37,172	129,330	128,810	Tuesday, January 22, 2013	19:00
13/14	91,242	37,993	129,234	141,866	Tuesday, January 7, 2014	19:00
14/15	90,287	39,971	130,258	142,856	Friday, February 20, 2015	8:00
15/16	89,758	41,029	130,787	129,540	Tuesday, January 19, 2016	8:00
16/17	89,231	41,513	130,744	130,825	Thursday, December 15, 2016	19:00
17/18	89,243	41,915	131,158	137,212	Friday, January 5, 2018	19:00
18/19	88,372	41,892	130,265	137,618	Thursday, January 31, 2019	8:00
19/20	86,032	42,177	128,209	120,272	Thursday, December 19, 2019	8:00
20/21	85,341	44,664	130,005	117,012	Friday, January 29, 2021	9:00

Notes:
Normalized values for 2000 - 2021 are calculated by PJM staff using a methodology described in Manual 19.
Normalized base values are calculated by PJM staff using a two-period average of peak loads on non-heating/non-coolong days.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

Table F-2

PJM RTO HISTORICAL NET ENERGY
(GWH)

YEAR	ENERGY	GROWTH RATE
1998	718,248	2.4%
1999	740,056	3.0%
2000	756,211	2.2%
2001	754,516	-0.2%
2002	782,275	3.7%
2003	780,666	-0.2%
2004	796,702	2.1%
2005	823,342	3.3%
2006	802,984	-2.5%
2007	836,241	4.1%
2008	822,608	-1.6%
2009	781,270	-5.0%
2010	820,038	5.0%
2011	805,911	-1.7%
2012	791,768	-1.8%
2013	795,098	0.4%
2014	796,228	0.1%
2015	791,580	-0.6%
2016	791,176	-0.1%
2017	772,291	-2.4%
2018	804,917	4.2%
2019	785,209	-2.4%
2020	755,241	-3.8%

Note: All historic net energy values reflect the current membership of the PJM RTO.

Table F-3

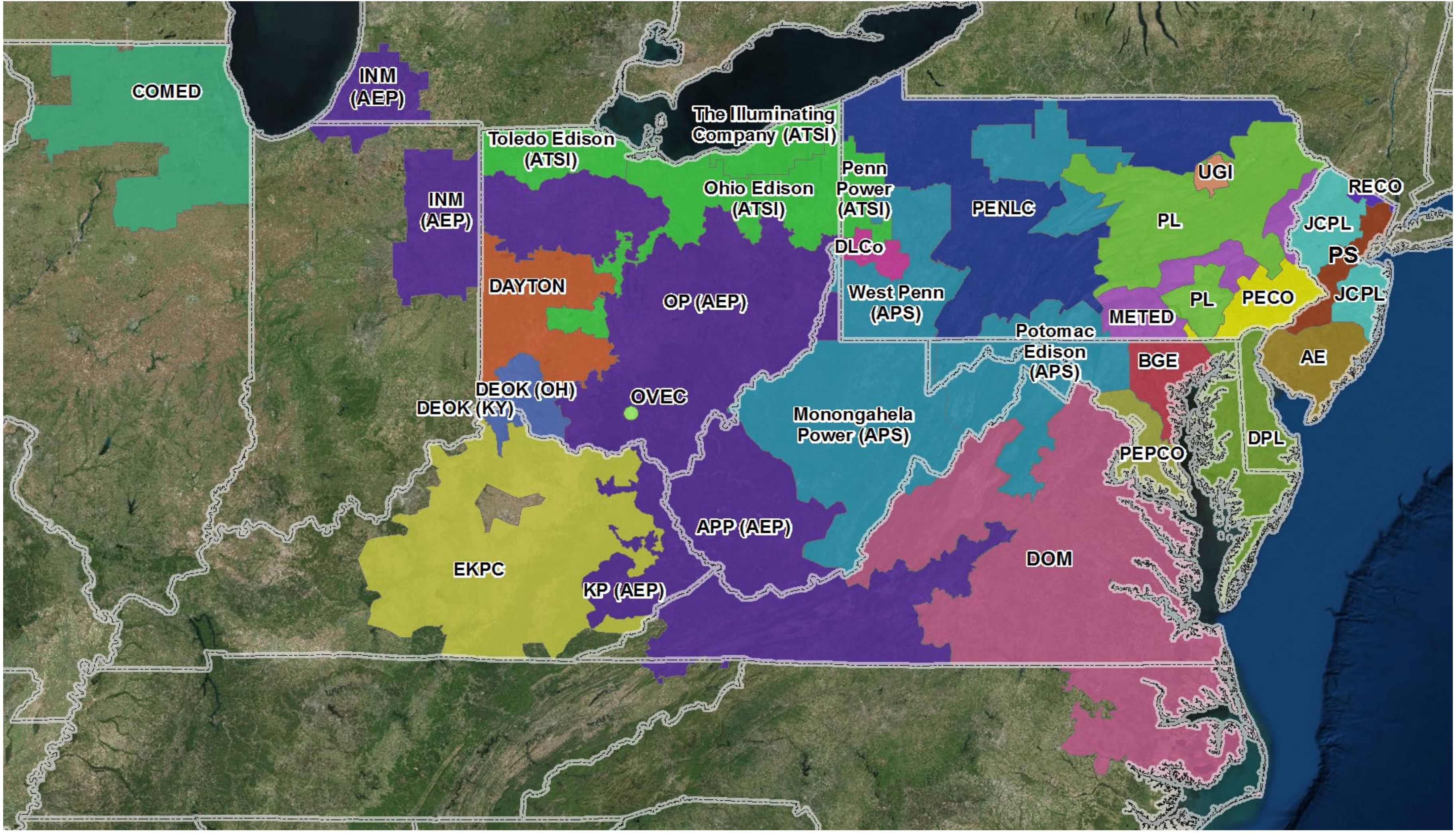
WEATHER NORMALIZED LOAD (MW) FOR EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO

	Summer 2021	Winter 2020/21
AE	2,484	1,603
BGE	6,431	5,819
DPL	3,874	3,598
JCPL	5,864	3,698
METED	2,945	2,617
PECO	8,346	6,501
PENLC	2,816	2,807
PEPCO	5,843	5,257
PL	7,025	7,242
PS	9,521	6,607
RECO	390	220
UGI	195	203
AEP	22,045	22,042
APS	8,621	8,870
ATSI	12,240	10,116
COMED	20,809	14,726
DAYTON	3,273	2,943
DEOK	5,190	4,484
DLCO	2,731	1,978
EKPC	2,058	2,643
OVEC	90	115
DOM	19,803	19,736
PJM MID-ATLANTIC	55,122	45,503
PJM WESTERN	75,369	66,572
PJM RTO	147,929	130,005

Notes:
Zonal Normal 2021 are non-coincident as estimated by PJM staff.
Locational Deliverability Area and PJM RTO Normal 2021 are coincident with their regional peak as estimated by PJM staff.

PJM Load Forecast Report

January 2023



Prepared by PJM Resource Adequacy Planning Department

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TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone
AEP	American Electric Power zone (incorporated 10/1/2004)
APP	Appalachian Power, sub-zone of AEP
APS	Allegheny Power zone (incorporated 4/1/2002)
ATSI	American Transmission Systems, Inc. zone (incorporated 6/1/2011)
Battery Storage	(Also Battery Energy Storage System – BESS) Devices that enable generated energy to be stored and then released at a later time
BGE	Baltimore Gas & Electric zone
CEI	Cleveland Electric Illuminating, sub-zone of ATSI
COMED	Commonwealth Edison zone (incorporated 5/1/2004)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
CSP	Columbus Southern Power, sub-zone of AEP
Direct Control	Load Management achieved directly by a signal from a control center
DAY	Dayton Power & Light zone (incorporated 10/1/2004)
DEOK	Duke Energy Ohio/Kentucky zone (incorporated 1/1/2012)
DLCO	Duquesne Lighting Company zone (incorporated 1/1/2005)
DOM	Dominion Virginia Power zone (incorporated 5/1/2005)
DPL	Delmarva Power & Light zone
EKPC	East Kentucky Power Cooperative zone (incorporated 6/1/2013)
FE-East	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)
Heating Load	The weather-sensitive portion of winter peak load
INM	Indiana Michigan Power, sub-zone of AEP
JCPL	Jersey Central Power & Light zone
KP	Kentucky Power, sub-zone of AEP

METED	Metropolitan Edison zone
MP	Monongahela Power, sub-zone of APS
NERC	North American Electric Reliability Corporation
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
OEP	Ohio Edison, sub-zone of ATSI
OP	Ohio Power, sub-zone of AEP
OVEC	Ohio Valley Electric Corporation zone (incorporated 12/1/2018)
PECO	PECO Energy zone
PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone
PL	PPL Electric Utilities, sub-zone of PLGroup
PLGroup/PLGRP	Pennsylvania Power & Light zone
PENLC	Pennsylvania Electric zone
PP	Pennsylvania Power, sub-zone of ATSI
PRD	Price Responsive Demand
PS	Public Service Electric & Gas zone
RECO	Rockland Electric (East) zone (incorporated 3/1/2002)
TOL	Toledo Edison, sub-zone of ATSI
UGI	UGI Utilities, sub-zone of PLGroup
Unrestricted Peak	Peak load prior to any reduction for load management or voltage reduction.
WP	West Penn Power, sub-zone of APS
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

2023 PJM LOAD FORECAST REPORT

EXECUTIVE SUMMARY

- This report presents an independent load forecast prepared by PJM staff.

- The report includes long-term forecasts of peak loads, net energy, load management, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area (LDA), and the total RTO.

- In 2022, PJM engaged with an outside consultant Itron to help with its transition to an hourly forecast model. Itron's report was shared with the Load Analysis Subcommittee and can be found here (https://www.pjm.com/-/media/committees-groups/subcommittees/las/2022/20220912/pjm-model-review-final-report-from-itron.ashx).

- Residential, Commercial, and Industrial sector models were estimated with data from 2012 through 2021. Weather scenarios were simulated with data from years 1993 through 2021, generating 377 scenarios.

- The economic forecast used was Moody's Analytics' September 2022 release.

- The 2022 update of Itron's end-use data provides the basis for appliance saturation rates, efficiency, and intensity and is consistent with the Energy Information Administration's 2022 Annual Energy Outlook. PJM obtained additional information from certain zones on Residential saturation rates based on their own load research. Details on zones providing information are presented in the supplement.

- The forecasts of the following zones have been adjusted to account for large, unanticipated load changes, market adjustments, and peak shaving adjusments(see Table B-9 and the supplement for details):
    - The AEP forecast of the AEP zone has been adjusted to account to account for growth in data center load;
    - The APS forecast has been adjusted to account to account for growth in data center load;
    - The DOM forecast has been adjusted to account for growth in data center load
    - The EKPC forecast has been adjusted to account for a peak shaving program to commence with the 2023 DY.
    - The AEP, APS, and PL forecasts have been adjusted to account for Non-Retail Behind-the-Meter Generation (NRBTMG) transitioning to participation as Demand Response in the

Reliability Pricing Model.

- Summer peak load growth for the PJM RTO is projected to average 0.8% per year over the next 10 and 15 years. The PJM RTO summer peak is forecasted to be 160,971 MW in 2033, a 10-year increase of 11,912 MW, and reaches 167,567 MW in 2038, a 15-year increase of 18,507 MW. Annualized 10-year growth rates for individual zones range from -0.7% to 5%; median of -0.1%.

- Winter peak load growth for PJM RTO is projected to average 1% per year over the next 10-year period, and 0.9% over the next 15-years. The PJM RTO winter peak load in 2032/33 is forecasted to be 144,992 MW, a 10-year increase of 14,180 MW, and reaches 150,555 MW in 2037/38, a 15-year increase of 19,744 MW. Annualized 10-year growth rates for individual zones range from -0.3% to 4.8%; median of 0.1%.

- Net energy for load growth for PJM RTO is projected to average 1.4% per year over the next 10-year period, and 1.3% over the next 15-years. Total PJM RTO energy is forecasted to be 909,622 GWh in 2033, a 10-year increase of 121,572 GWh, and reaches 960,428 GWh in 2038, a 15-year increase of 172,378 GWh. Annualized 10- year growth rates for individual zones range from -0.7% to 7%; median of 0%.

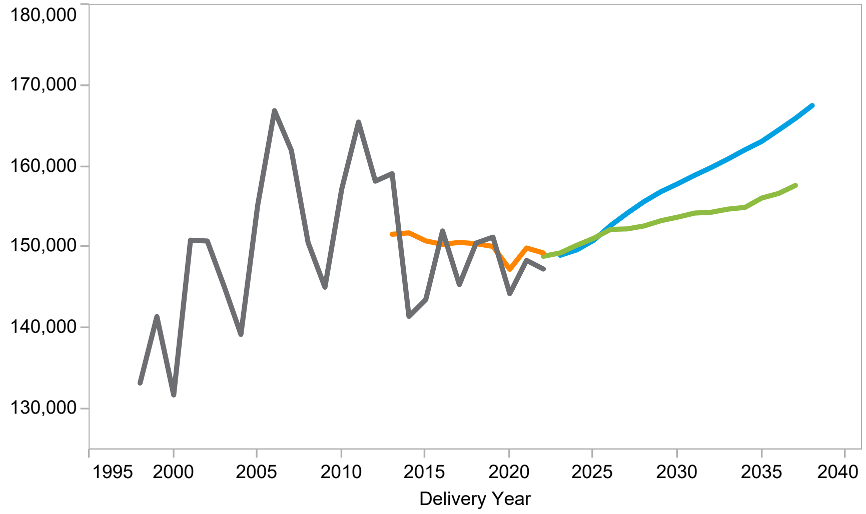
- Compared to the 2022 Load Report, the 2023 PJM RTO summer peak forecast shows the following changes for three years of interest:

○ The next delivery year – 2023	-293 MW (-0.2%)
○ The next RPM auction year – 2026	+473 MW (+0.3%)
○ The next RTEP study year – 2028	+3,015 MW (+2%)

NOTE:
Unless noted otherwise, all peak and energy values are non-coincident, unrestricted peaks, which represent the peak load or net energy after reductions for distributed solar generation and battery storage, additions for plug-in electric vehicles, and prior to reductions for load management impacts.
All compound growth rates are calculated from the first year of the forecast.

PJM RTO

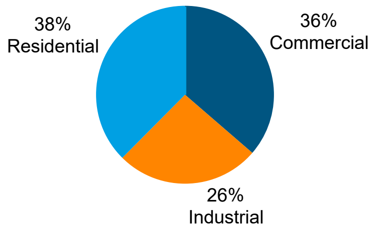
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*74.3*
Avg Summer Max Temp	*95.1*
Avg Winter Daily Temp	*34.2*
Avg Winter Min Temp	*4.0*

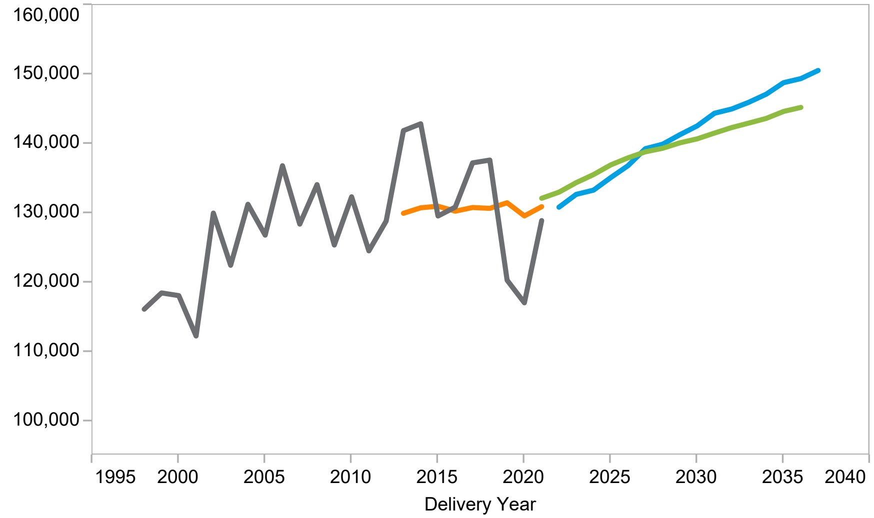
RCI Makeup



Zonal 10/15 Year Load Growth

SUMMER	0.8%	0.8%
WINTER	1.0%	0.9%

Winter Peak



LDAs

PJM Mid-Atlantic
Eastern MAAC
Southern MAAC
Central MAAC
Western MAAC
PJM West

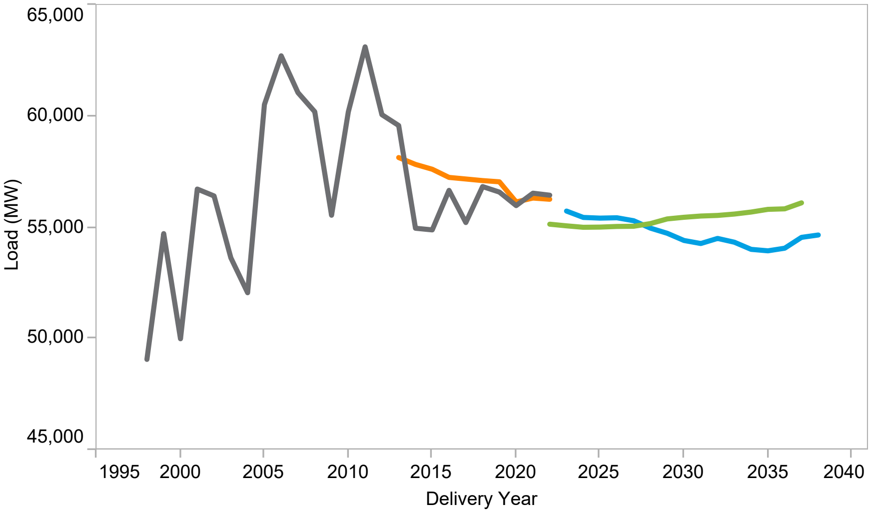
Zones

AE
AEP
APS
ATSI
BGE
COMED
DAYTON
DEOK
DLCO
DOM
DPL
EKPC
JCPL
METED
OVEC
PECO
PENLC
PEPCO
PL
PS
RECO
UGI

⬛ Peak 🟧 WN peak 🟩 Forecast 2022 🟦 Forecast 2023

PJM Mid-Atlantic (MAAC)

Summer Peak



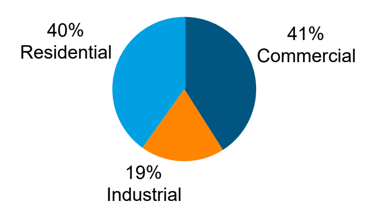
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*75.3*
Avg Summer Max Temp	*96.9*
Avg Winter Daily Temp	*35.4*
Avg Winter Min Temp	*7.4*

Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.1%
WINTER	0.1%	0.0%

RCI Makeup



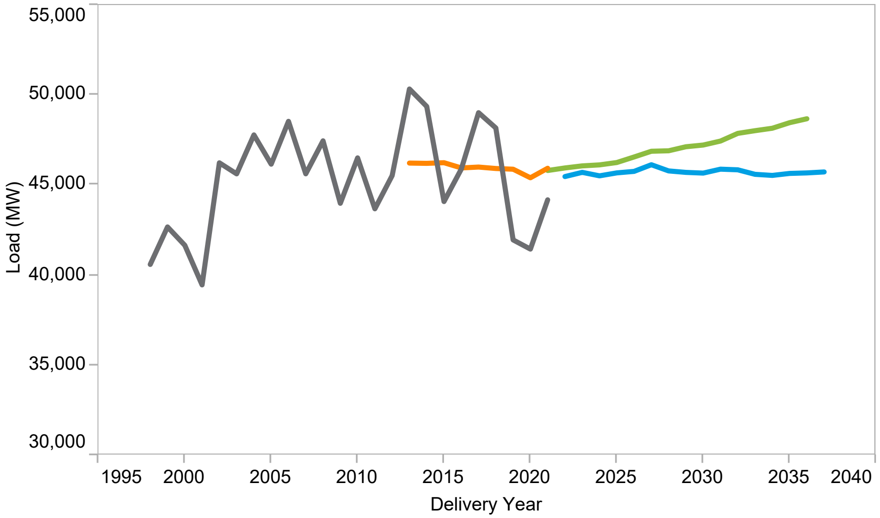
Zones

AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PSEG
RECO
UGI

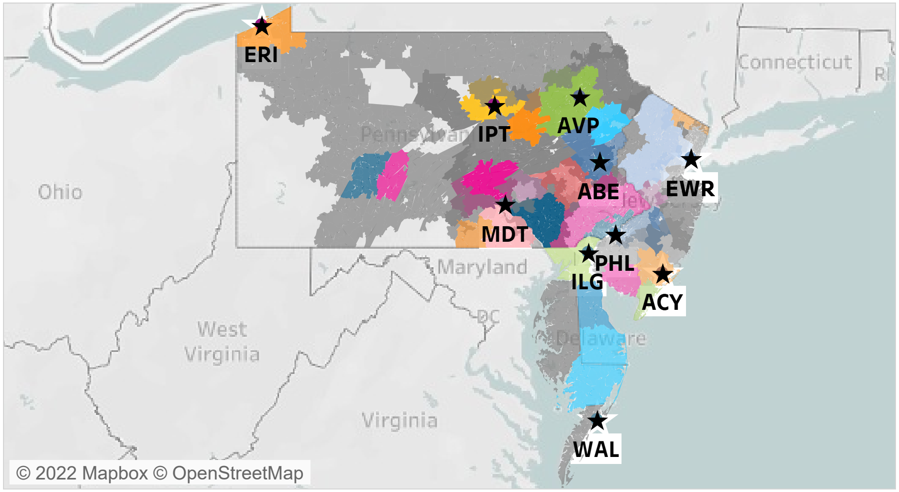
LDAs

E-MAAC
S-MAAC
C-MAAC
W-MAAC

Winter Peak



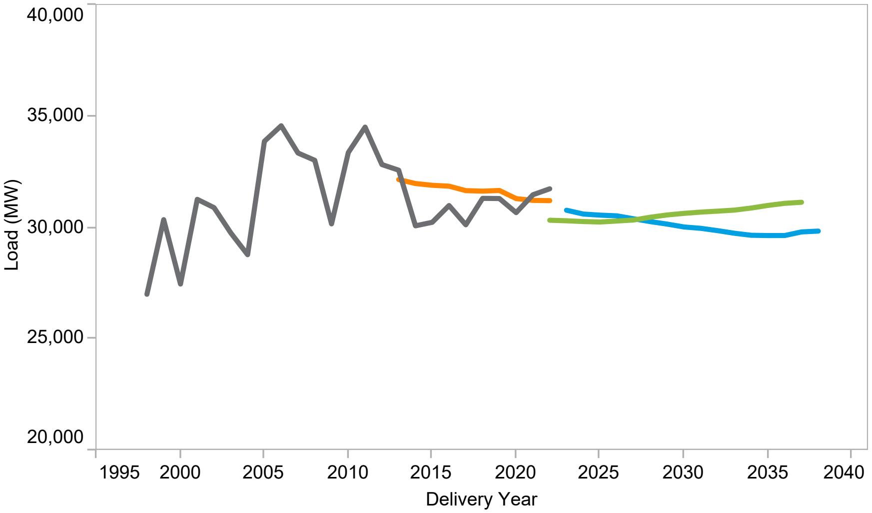
Metropolitan Statistical Areas and Weather Stations



■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

PJM Eastern Mid-Atlantic (E-MAAC)

Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*75.8*
Avg Summer Max Temp	*97.7*
Avg Winter Daily Temp	*36.2*
Avg Winter Min Temp	*8.3*

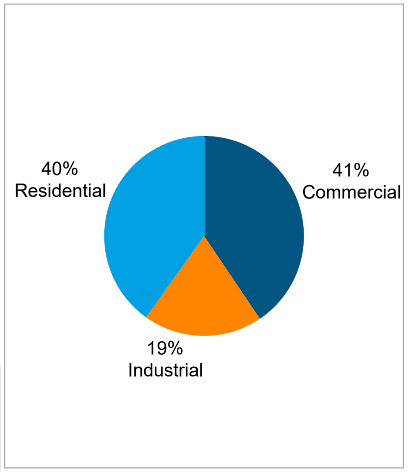
Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.2%
WINTER	0.1%	0.0%

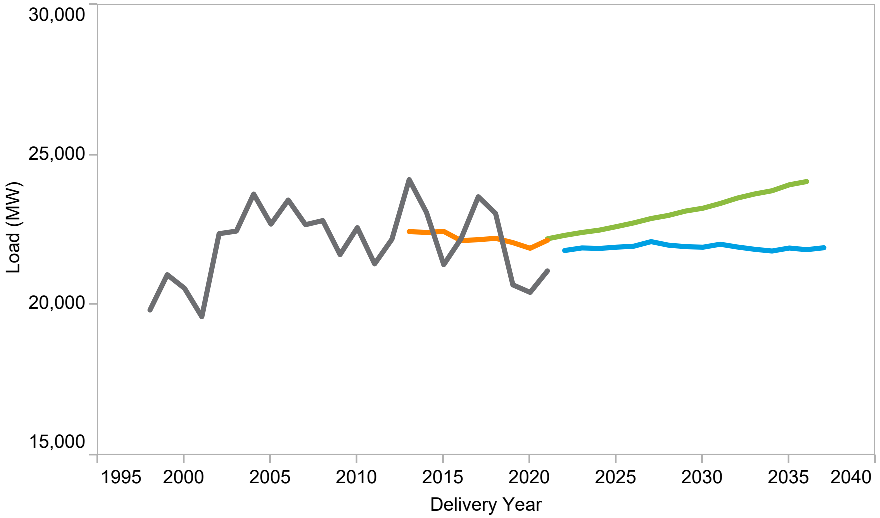
Zones

AE	PECO
DPL	PS
JCPL	RECO

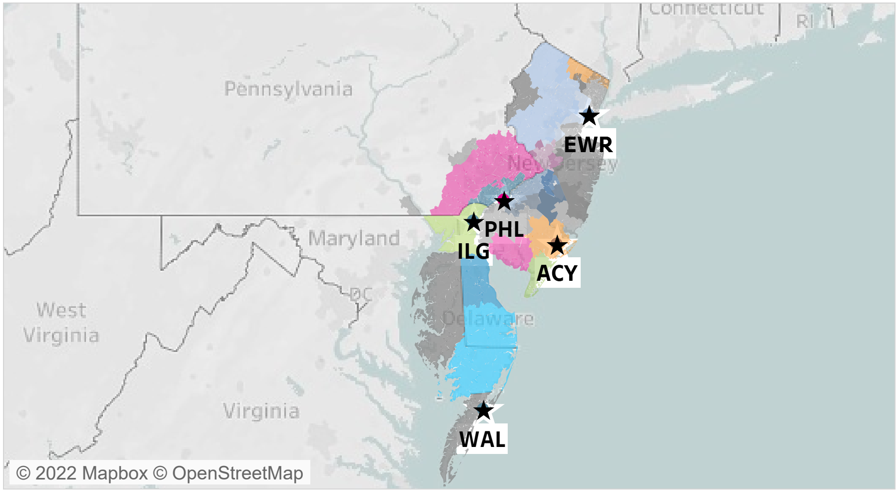
RCI Makeup



Winter Peak



Metropolitan Statistical Areas and Weather Stations



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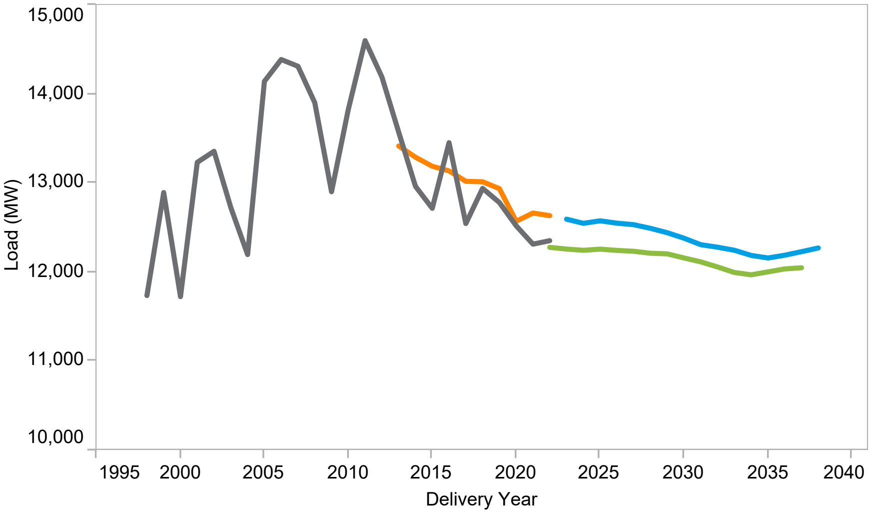
■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

PJM Southern Mid-Atlantic (S-MAAC)

Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*77.0*
Avg Summer Max Temp	*98.1*
Avg Winter Daily Temp	*37.8*
Avg Winter Min Temp	*10.2*

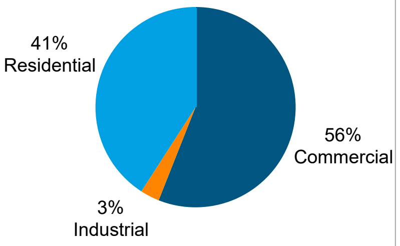
Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.2%
WINTER	0.1%	0.1%

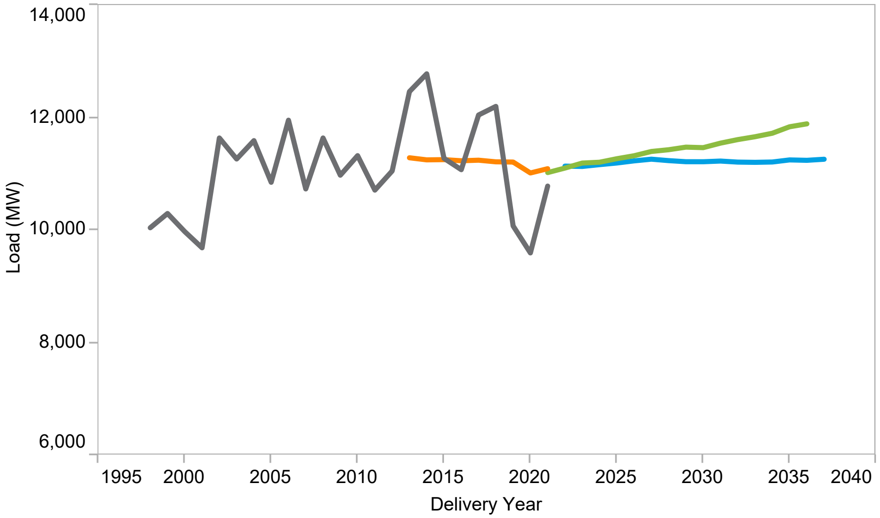
Zones

BGE PEPCO

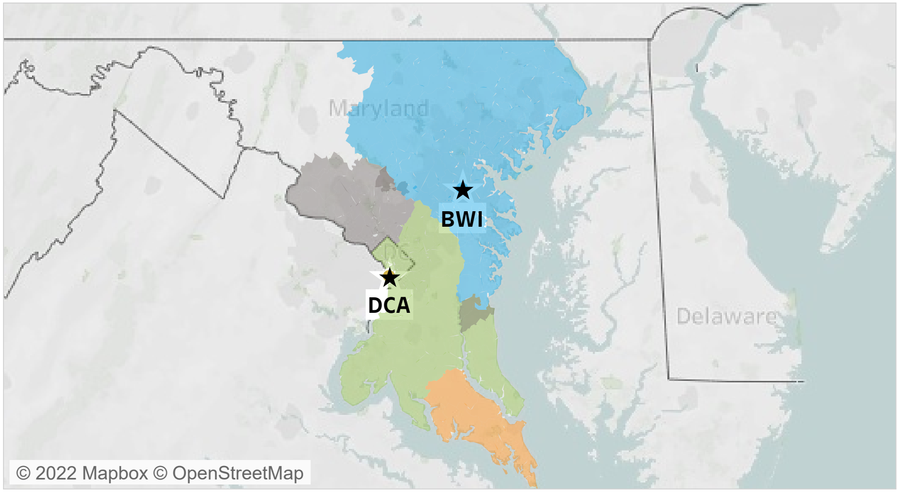
RCI Makeup



Winter Peak



Metropolitan Statistical Areas and Weather Stations



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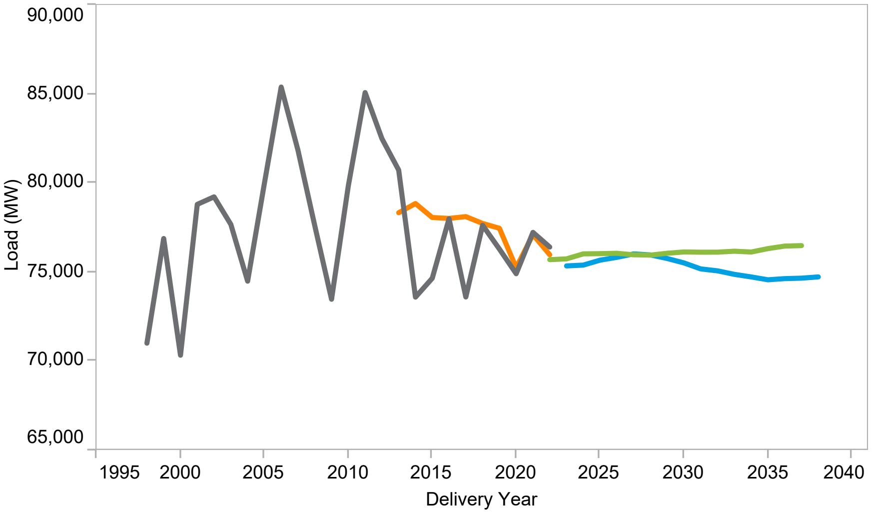
⬛ Peak 🟧 WN peak 🟩 Forecast 2022 🟦 Forecast 2023

PJM Western

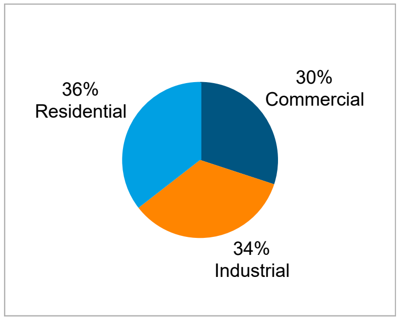
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*72.9*
Avg Summer Max Temp	*93.3*
Avg Winter Daily Temp	*31.5*
Avg Winter Min Temp	*-0.8*

RCI Makeup



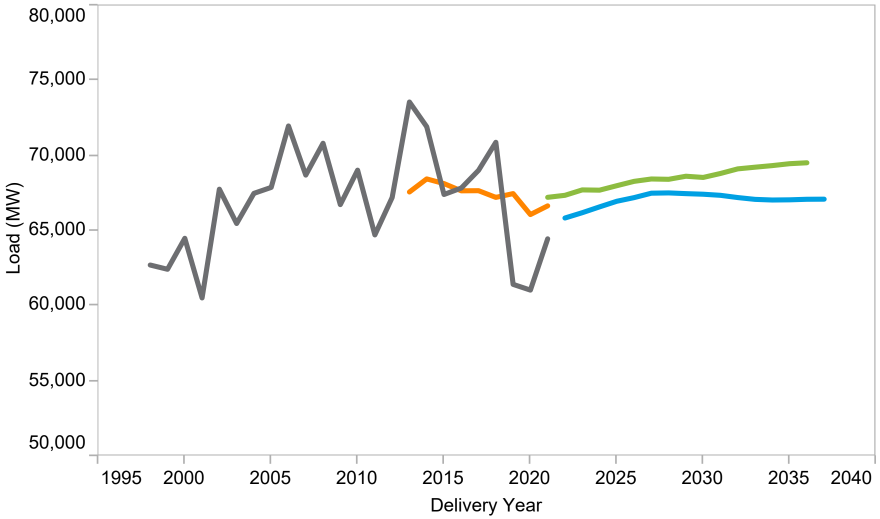
Zonal 10/15 Year Load Growth

SUMMER	-0.1%	-0.1%
WINTER	0.2%	0.1%

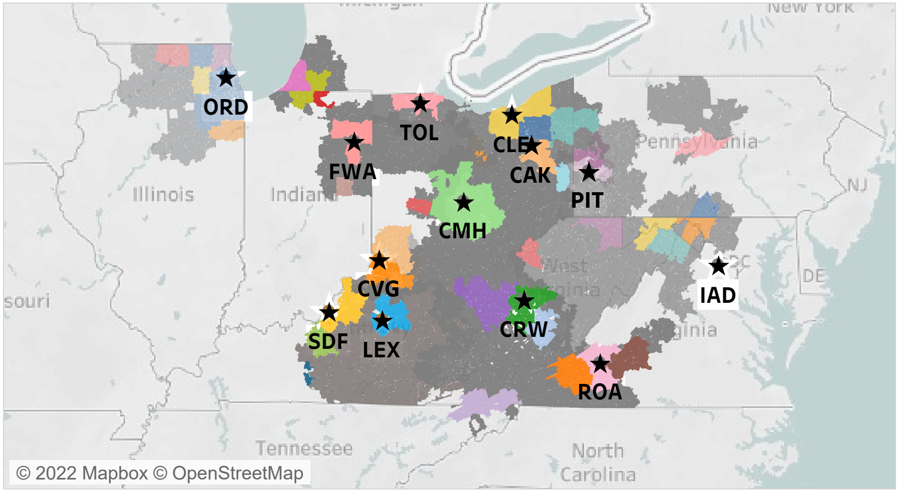
Zones

AEP
APS
ATSI
COMED
DAYTON
DEOK
DLCO
EKPC
OVEC

Winter Peak



Metropolitan Statistical Areas and Weather Stations

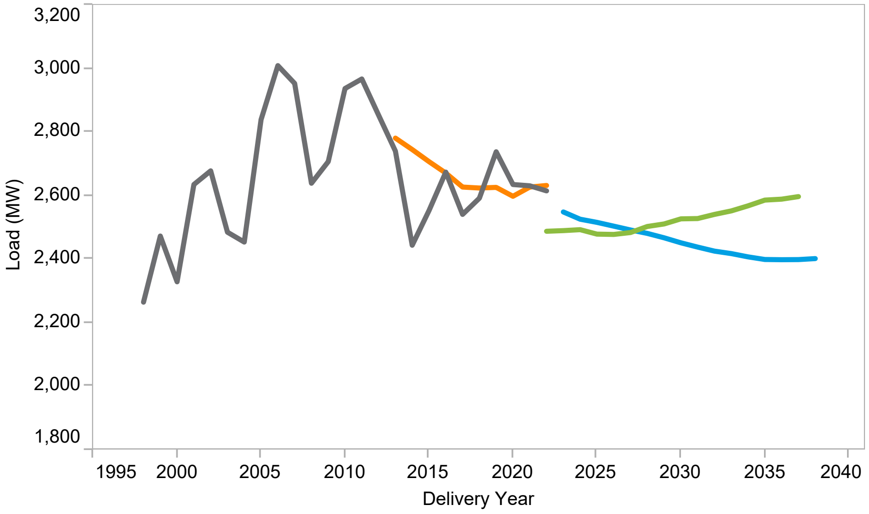


© 2022 Mapbox © OpenStreetMap

■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

Atlantic Electric (AE)

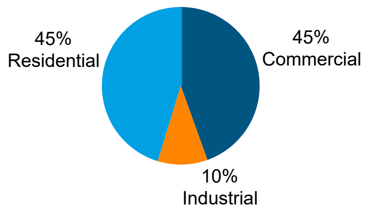
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*74.3*
Avg Summer Max Temp	*97.1*
Avg Winter Daily Temp	*36.6*
Avg Winter Min Temp	*5.9*

RCI Makeup



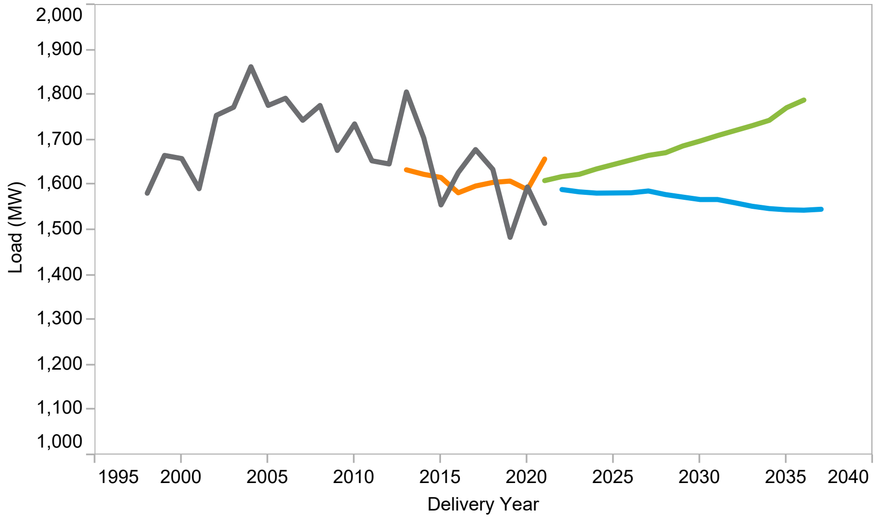
Zonal 10/15 Year Load Growth

SUMMER	-0.5%	-0.4%
WINTER	-0.2%	-0.2%

LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



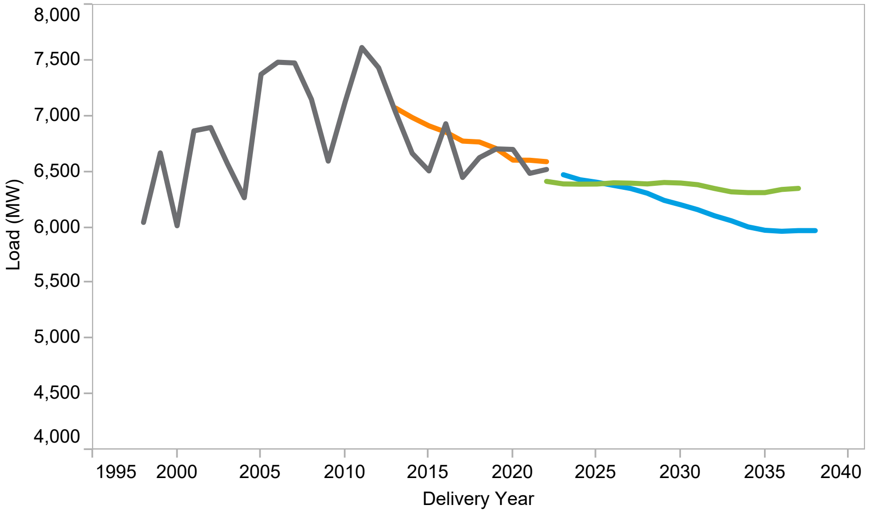
Metropolitan Statistical Areas and Weather Stations

- ■ Peak
- ■ WN peak
- ■ Forecast 2022
- ■ Forecast 2023

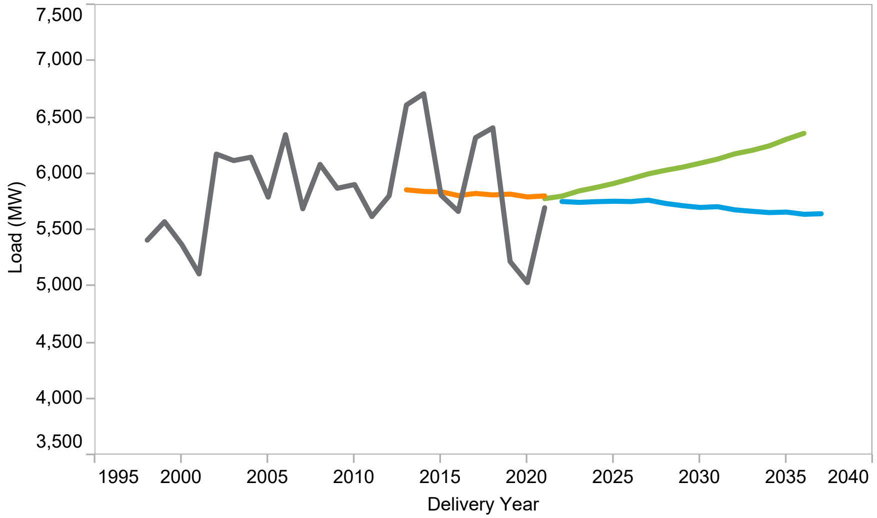
- ■ AE - Non-Metro
- ■ Atlantic City-Hammonton, NJ
- ■ Ocean City, NJ
- ■ Vineland-Bridgeton, NJ

Baltimore Gas and Electric (BGE)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

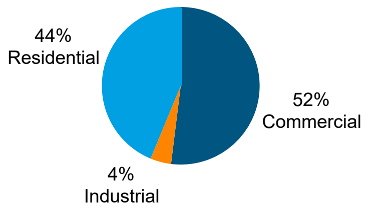
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*98.1*
Avg Winter Daily Temp	*36.7*
Avg Winter Min Temp	*7.9*

Zonal 10/15 Year Load Growth

SUMMER	-0.7%	-0.5%
WINTER	-0.1%	-0.1%

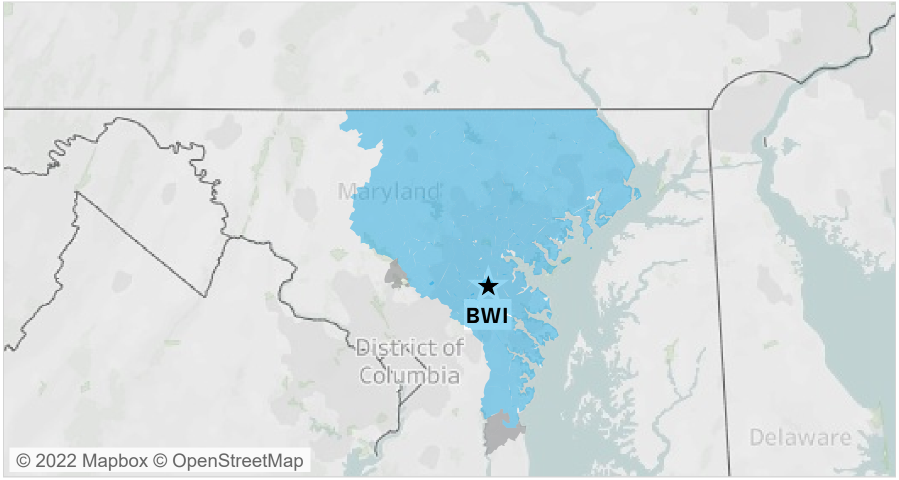
RCI Makeup



LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

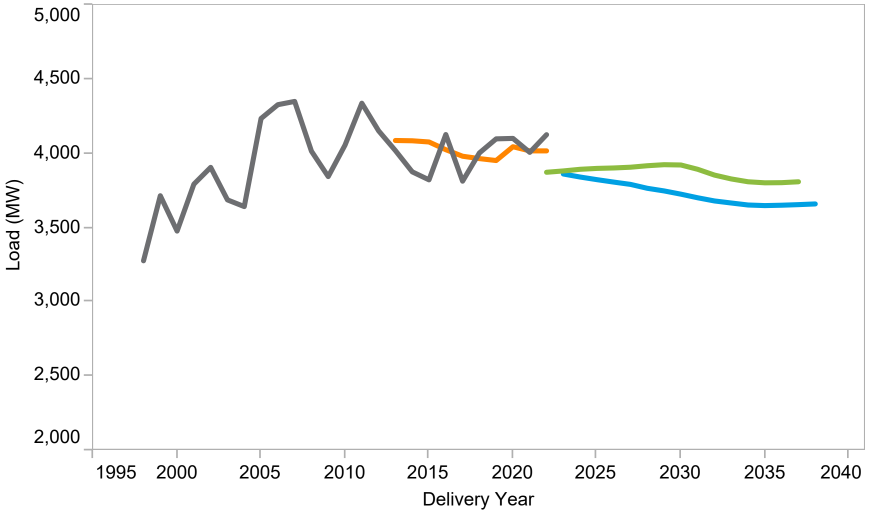
Metropolitan Statistical Areas and Weather Stations



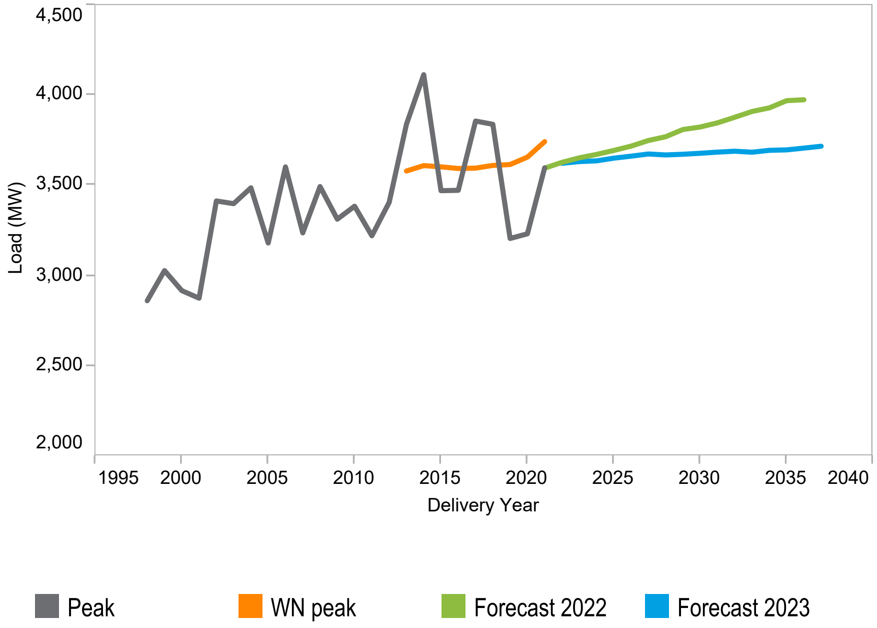
■ Baltimore-Columbia-Towson, MD
■ BGE - Non-Metro

Delmarva Power and Light (DPL)

Summer Peak



Winter Peak



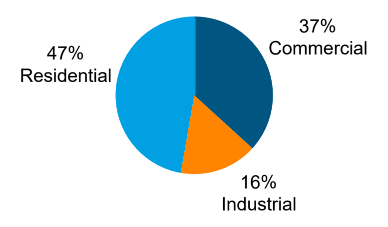
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*95.1*
Avg Winter Daily Temp	*37.0*
Avg Winter Min Temp	*9.7*

Zonal 10/15 Year Load Growth

SUMMER	-0.5%	-0.4%
WINTER	0.2%	0.2%

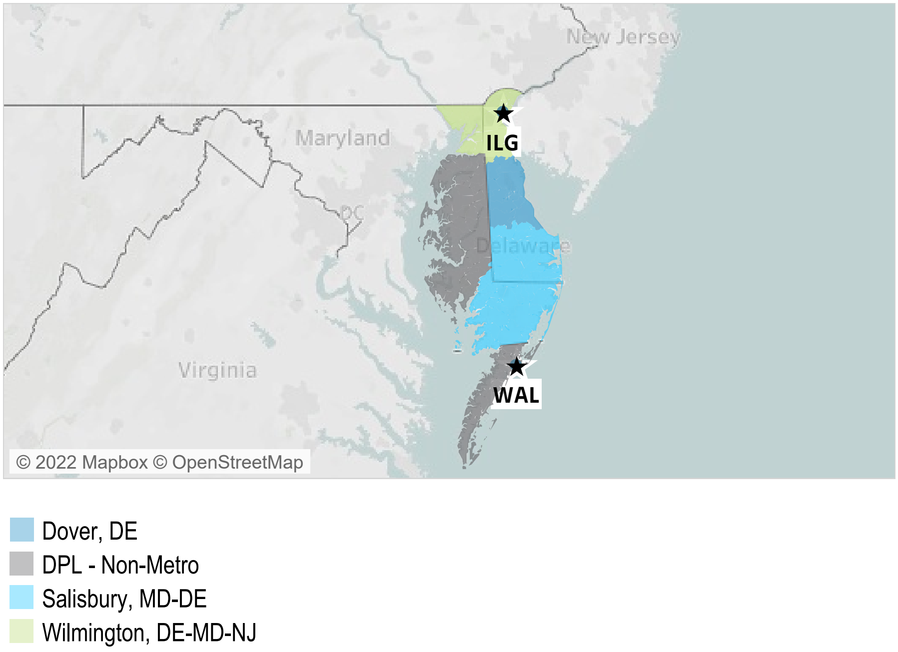
RCI Makeup



LDAs

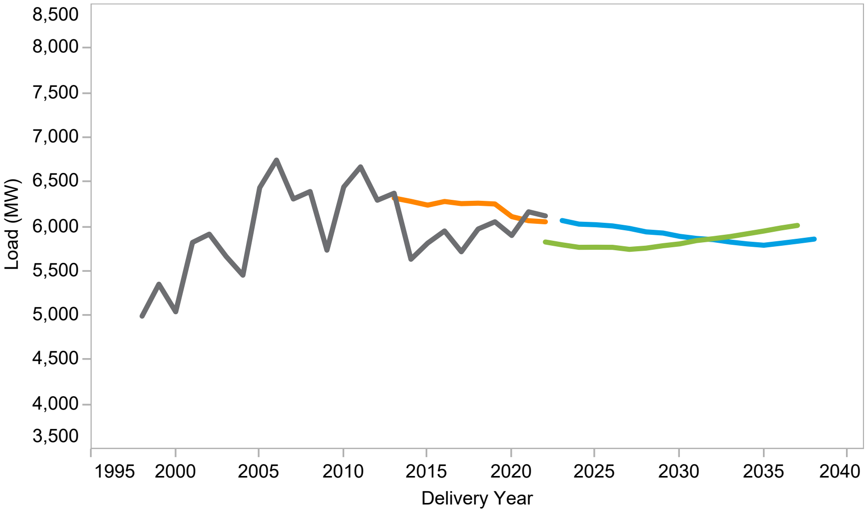
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Metropolitan Statistical Areas and Weather Stations



Jersey Central Power and Light (JCPL)

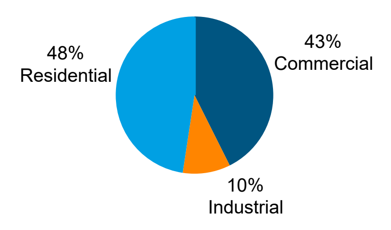
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*75.6*
Avg Summer Max Temp	*98.2*
Avg Winter Daily Temp	*35.9*
Avg Winter Min Temp	*7.6*

RCI Makeup



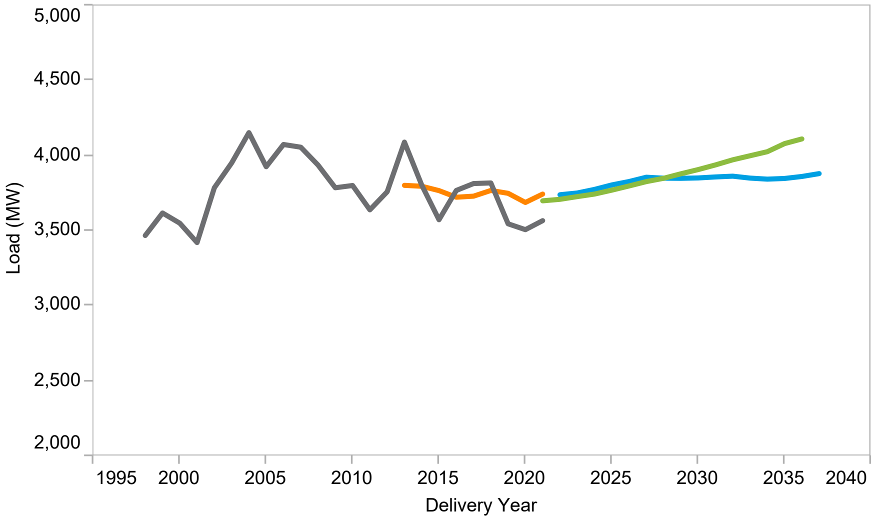
Zonal 10/15 Year Load Growth

SUMMER	-0.4%	-0.2%
WINTER	0.3%	0.2%

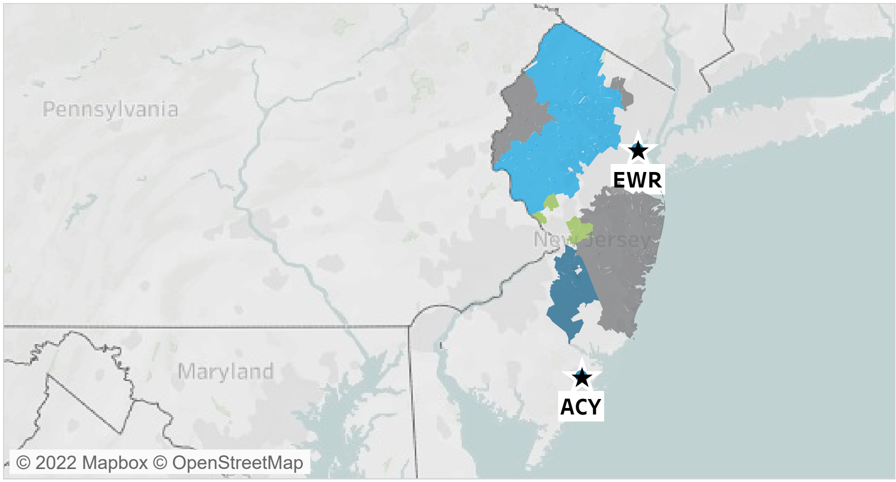
LDAs

EASTERN MID-ATLANTIC FE-EAST PJM MID-ATLANTIC PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations

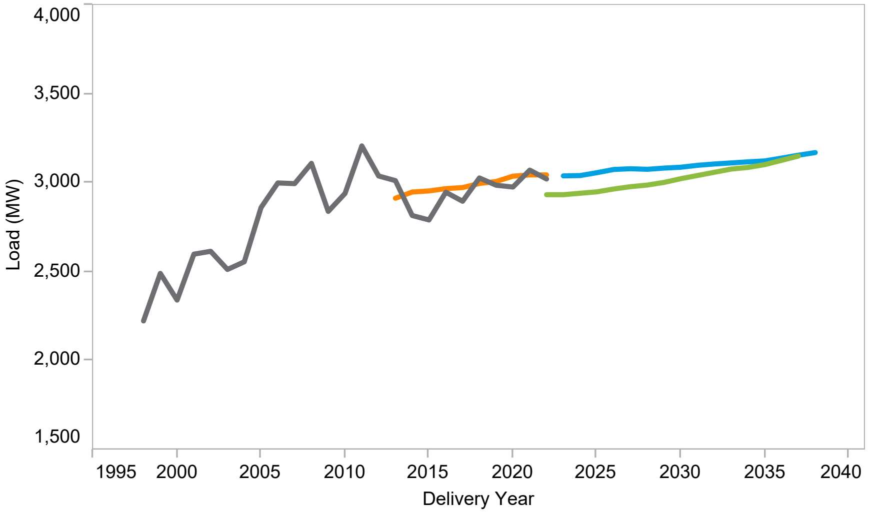


🟦 Camden, NJ
⬜ JCPL - Non-Metro
🟦 Newark, NJ-PA
🟩 Trenton, NJ

⬛ Peak 🟧 WN peak 🟩 Forecast 2022 🟦 Forecast 2023

Metropolitan Edison (METED)

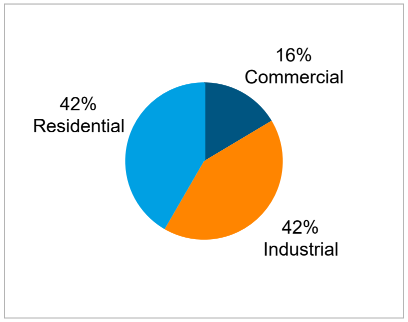
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*74.7*
Avg Summer Max Temp	*95.8*
Avg Winter Daily Temp	*34.4*
Avg Winter Min Temp	*6.6*

RCI Makeup



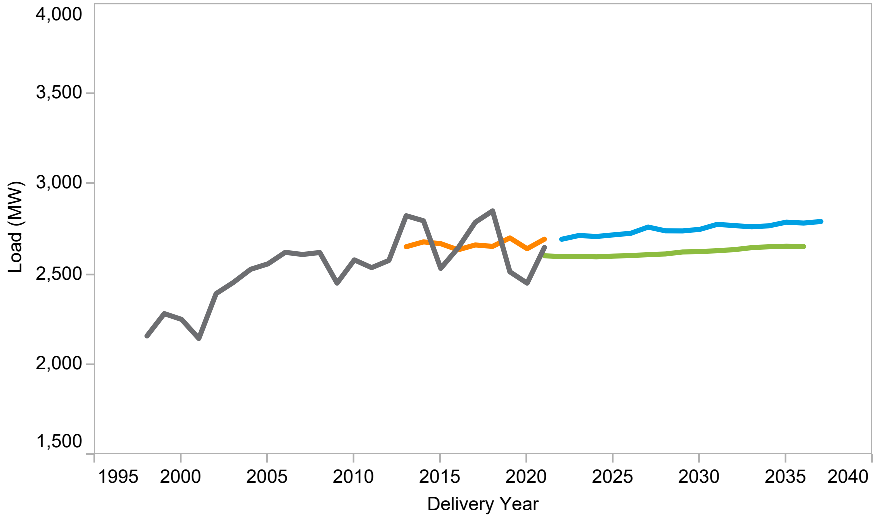
Zonal 10/15 Year Load Growth

SUMMER	0.2%	0.3%
WINTER	0.3%	0.2%

LDAs

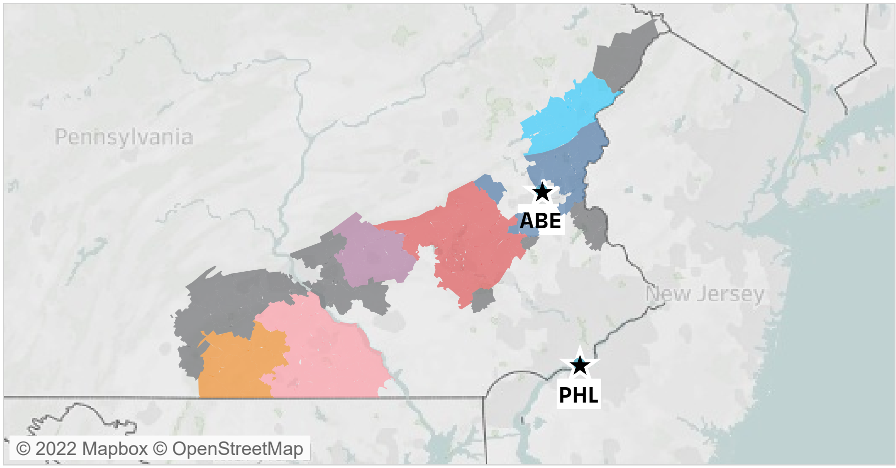
CENTRAL MID-ATLANTIC FE-EAST PJM MID-ATLANTIC
PJM RTO WESTERN MID-ATLANTIC

Winter Peak



■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

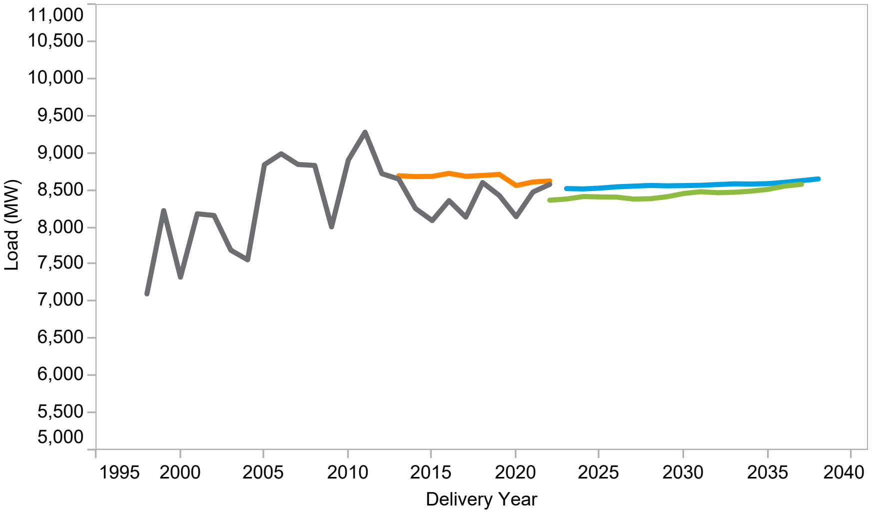
Metropolitan Statistical Areas and Weather Stations



■ Allentown-Bethlehem-Easton, PA-NJ
■ East Stroudsburg, PA
■ Gettysburg, PA
■ Lebanon, PA
■ METED - Non-Metro
■ Reading, PA
■ York-Hanover, PA

PECO Energy (PECO)

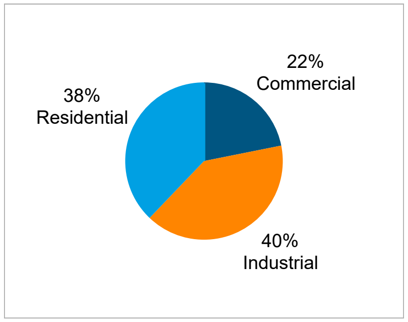
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*76.5*
Avg Summer Max Temp	*97.2*
Avg Winter Daily Temp	*36.6*
Avg Winter Min Temp	*9.3*

RCI Makeup



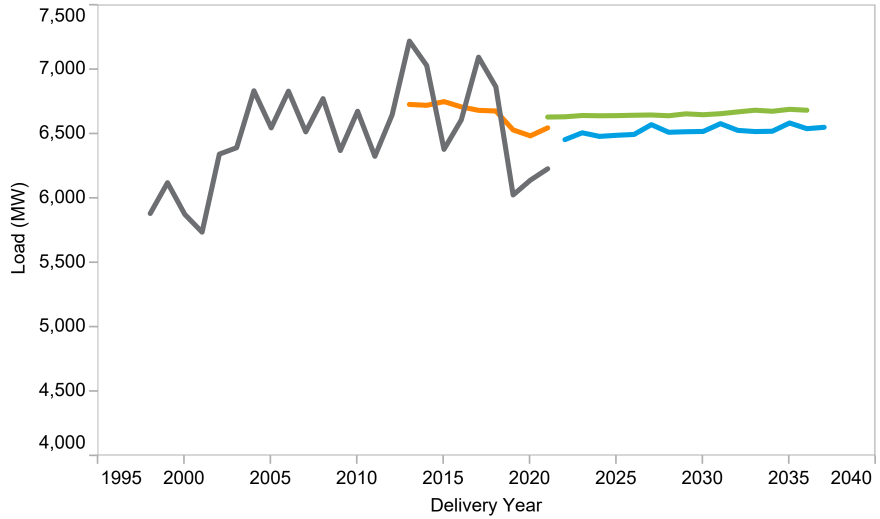
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.1%	0.1%

LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



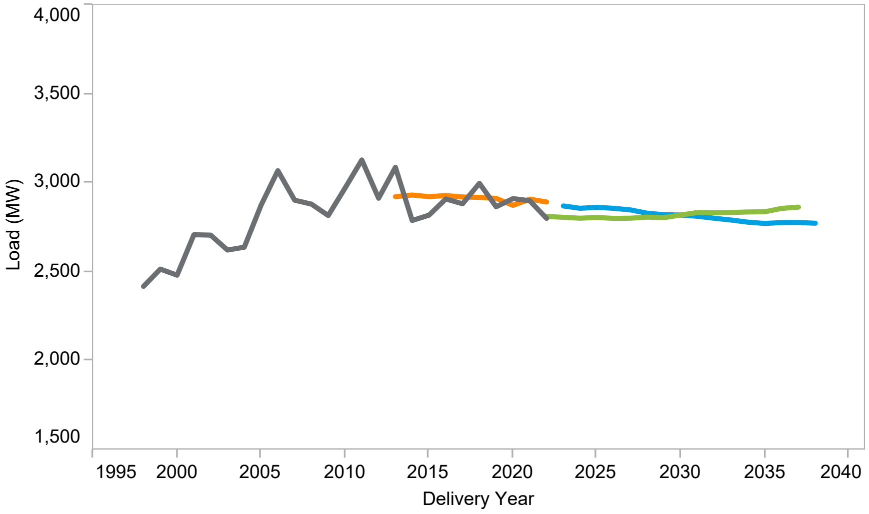
■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

Metropolitan Statistical Areas and Weather Stations

■ Montgomery County-Bucks County-Chester County, PA
■ PECO - Non-Metro
■ Philadelphia, PA

Pennsylvania Electric Company (PENLC)

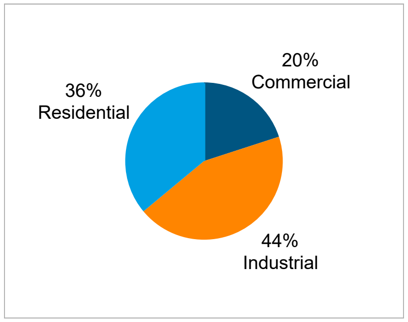
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*71.1*
Avg Summer Max Temp	*91.7*
Avg Winter Daily Temp	*30.3*
Avg Winter Min Temp	*2.0*

RCI Makeup



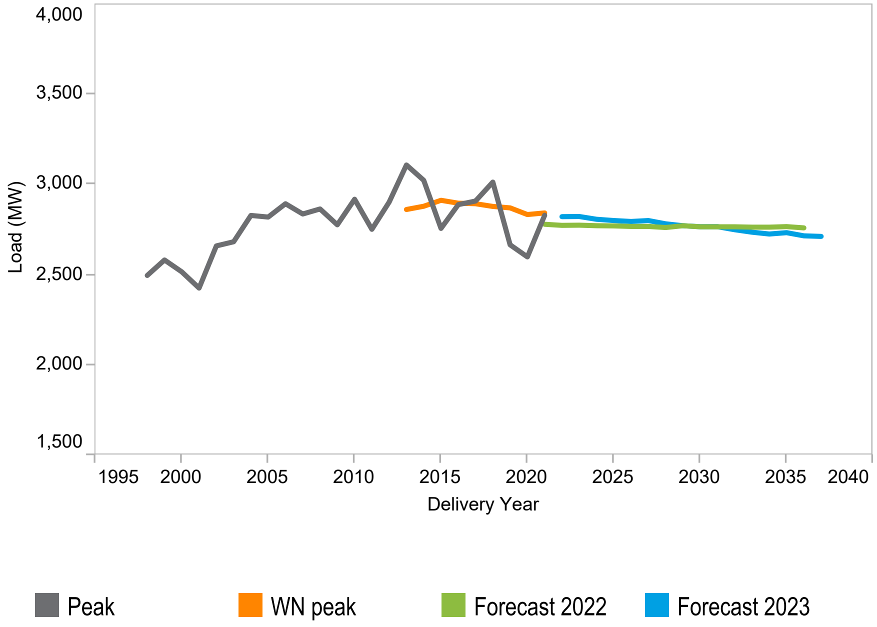
Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.2%
WINTER	-0.3%	-0.3%

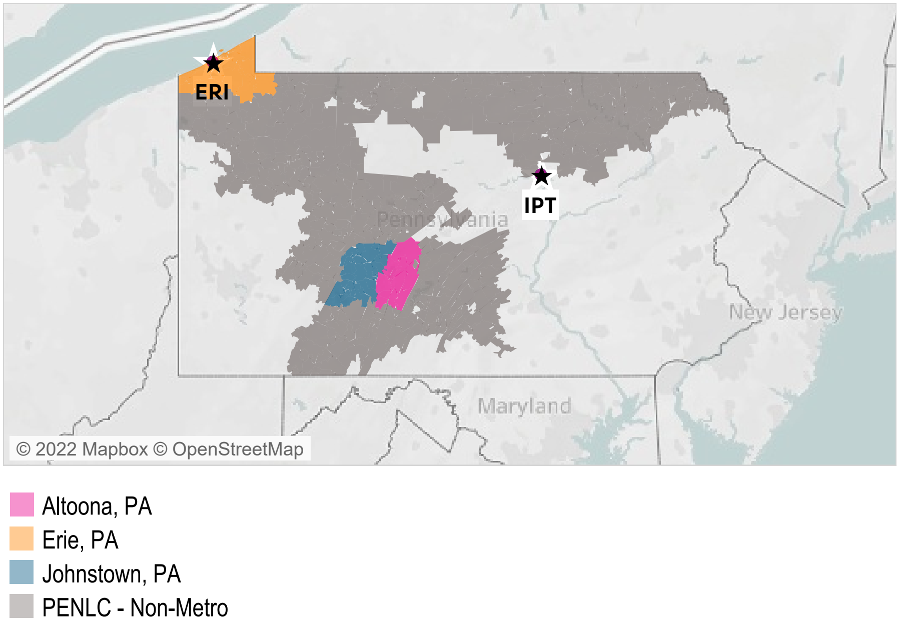
LDAs

FE-EAST PJM MID-ATLANTIC PJM RTO
WESTERN MID-ATLANTIC

Winter Peak

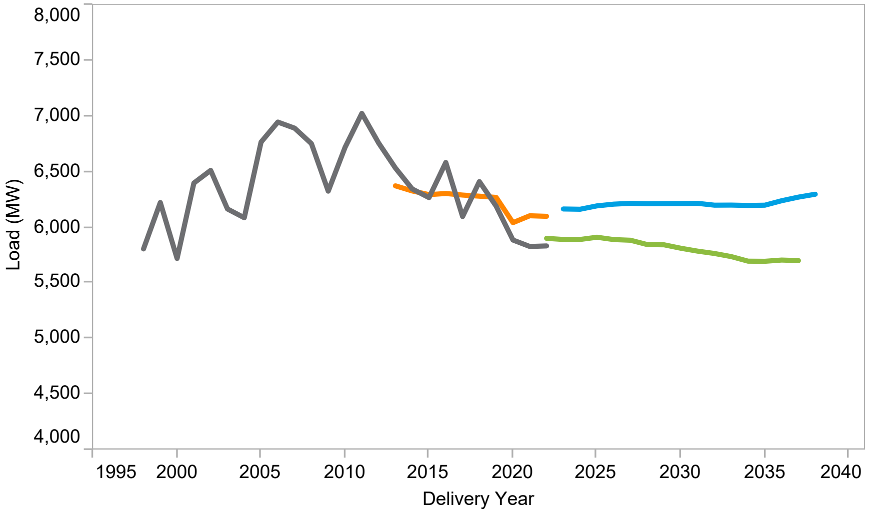


Metropolitan Statistical Areas and Weather Stations



Potomac Electric Power (PEPCO)

Summer Peak



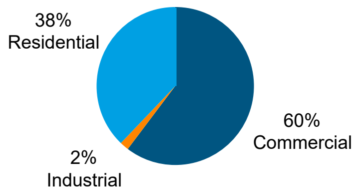
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*78.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*39.0*
Avg Winter Min Temp	*12.8*

Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.3%	0.3%

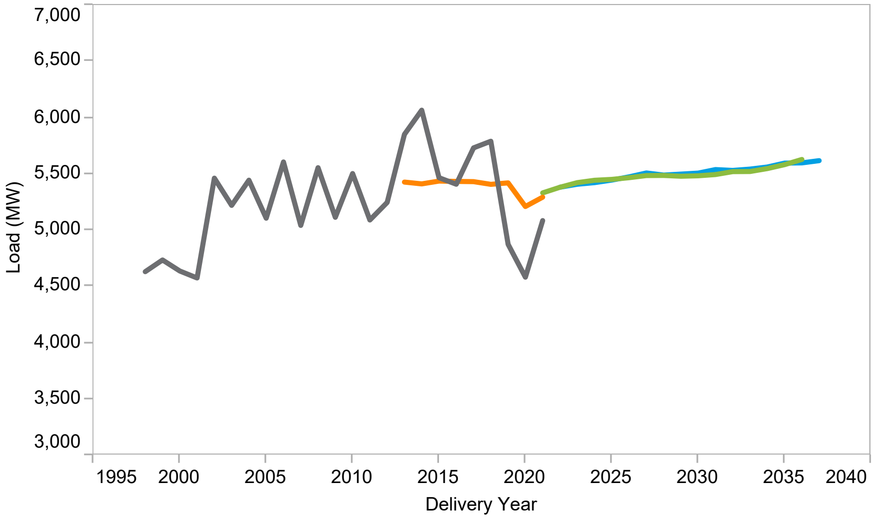
RCI Makeup



LDAs

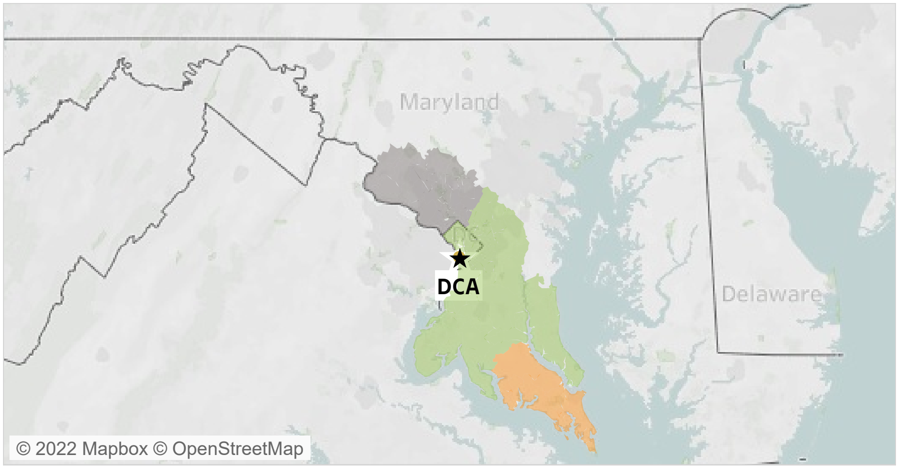
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

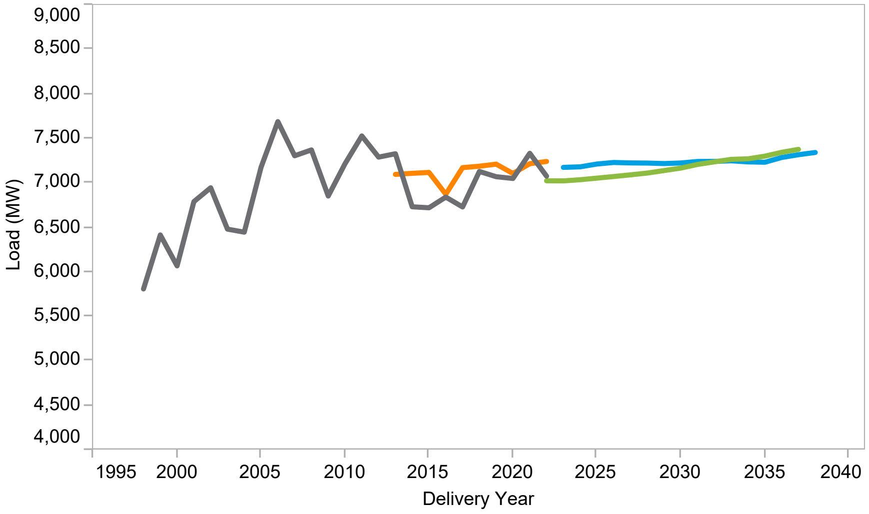
Metropolitan Statistical Areas and Weather Stations



■ California-Lexington Park, MD
■ PEPCO - Non-Metro
■ Washington-Arlington-Alexandria, DC-VA-MD-WV

PPL Electric Utilities (PL)

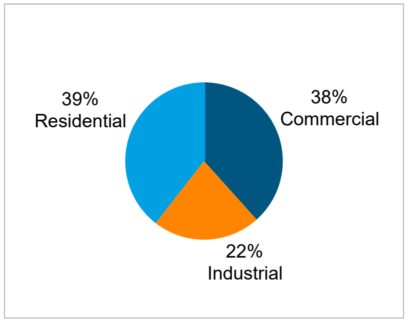
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*72.4*
Avg Summer Max Temp	*94.1*
Avg Winter Daily Temp	*31.5*
Avg Winter Min Temp	*2.8*

RCI Makeup



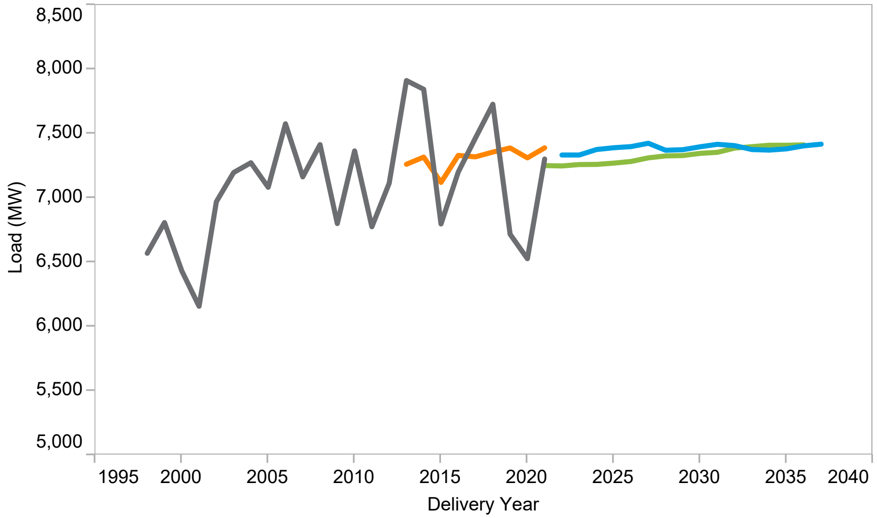
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.2%
WINTER	0.1%	0.1%

LDAs

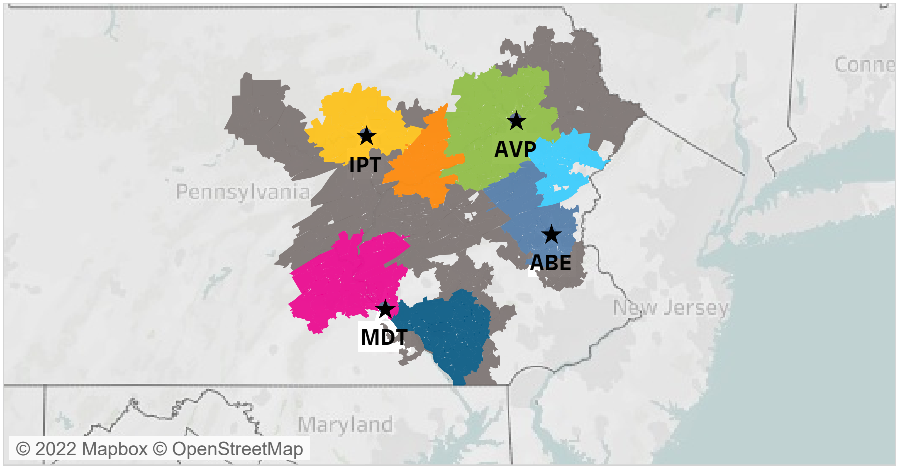
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO PLGRP WESTERN MID-ATLANTIC

Winter Peak



⬛ Peak 🟧 WN peak 🟩 Forecast 2022 🟦 Forecast 2023

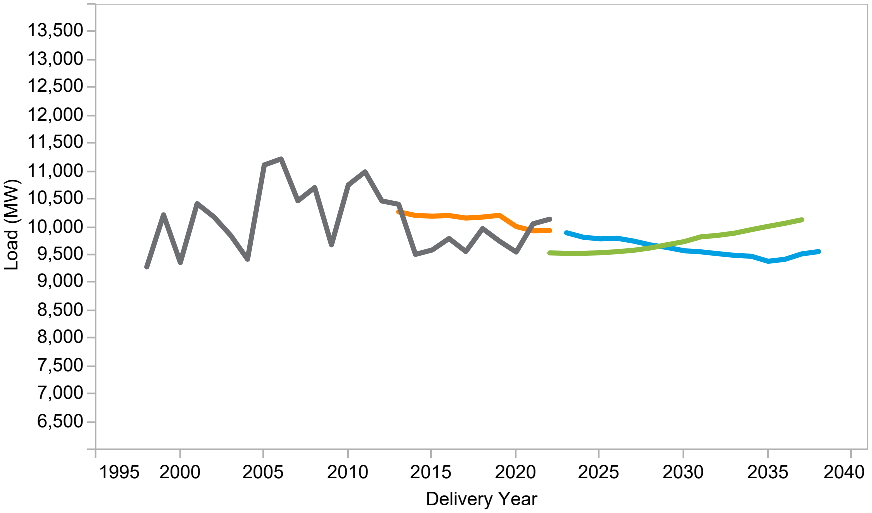
Metropolitan Statistical Areas and Weather Stations



🟦 Allentown-Bethlehem-Easton, PA-NJ	🟦 Lancaster, PA
🟧 Bloomsburg-Berwick, PA	⬜ PL - Non-Metro
🟦 East Stroudsburg, PA	🟩 Scranton--Wilkes-Barre--Hazleton, PA
🟪 Harrisburg-Carlisle, PA	🟨 Williamsport, PA

Public Service Electric & Gas (PS)

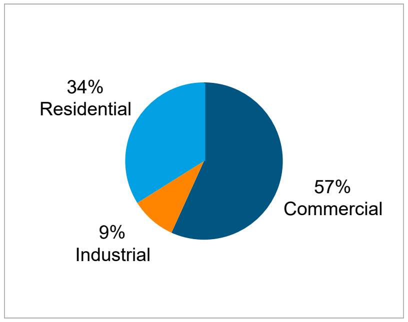
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*99.0*
Avg Winter Daily Temp	*35.6*
Avg Winter Min Temp	*7.5*

RCI Makeup



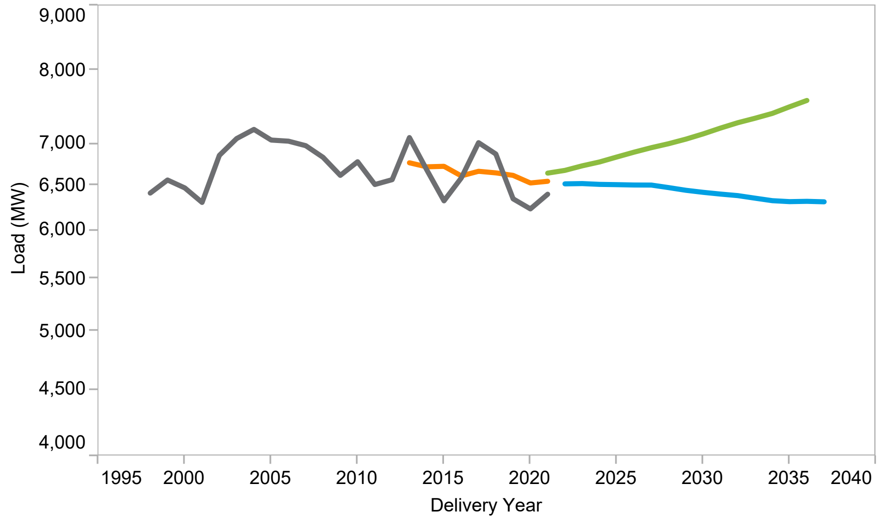
Zonal 10/15 Year Load Growth

SUMMER	-0.4%	-0.2%
WINTER	-0.2%	-0.2%

LDAs

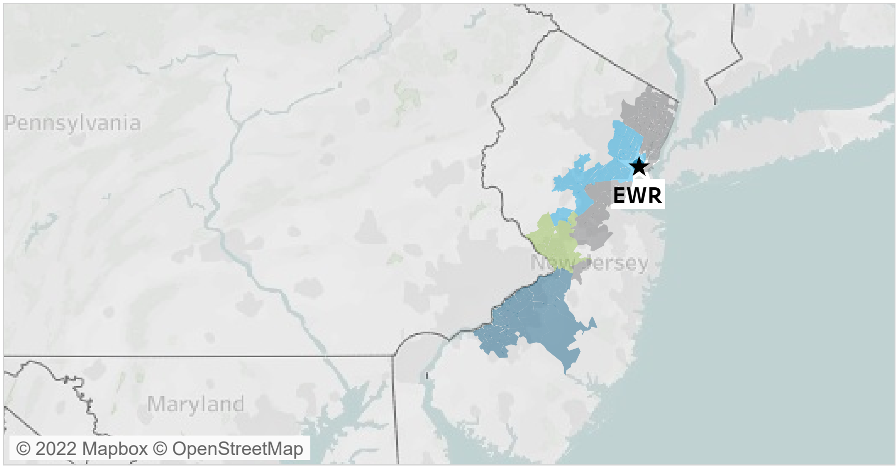
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

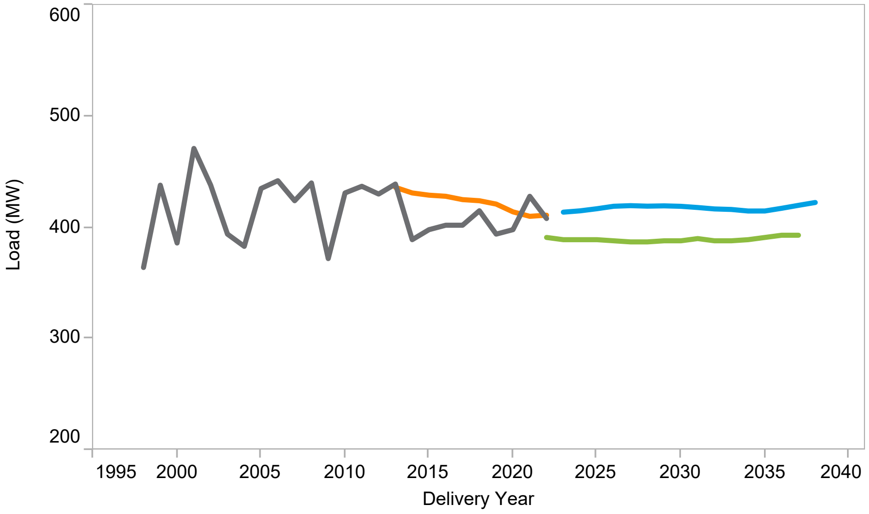
Metropolitan Statistical Areas and Weather Stations



- ■ Camden, NJ
- ■ Newark, NJ-PA
- ■ PS - Non-Metro
- ■ Trenton, NJ

Rockland Electric Company (RECO)

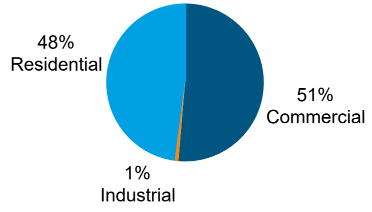
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*99.0*
Avg Winter Daily Temp	*35.6*
Avg Winter Min Temp	*7.5*

RCI Makeup



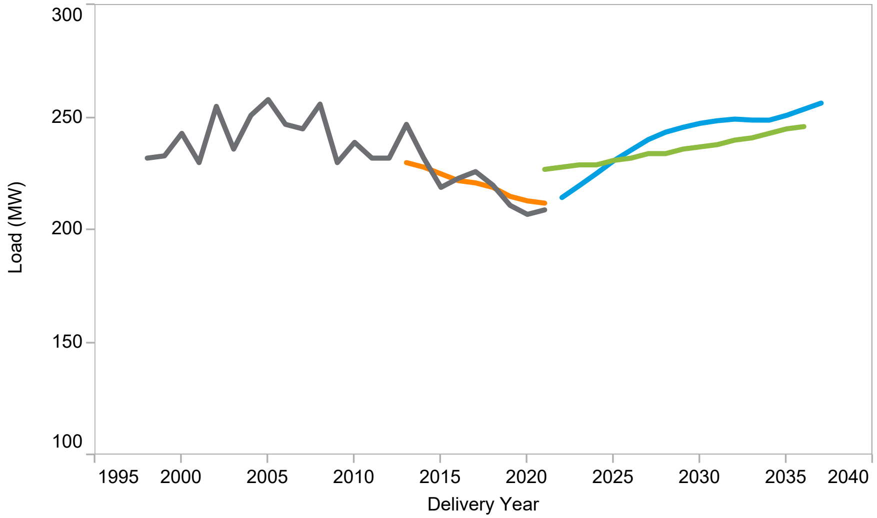
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	1.5%	1.2%

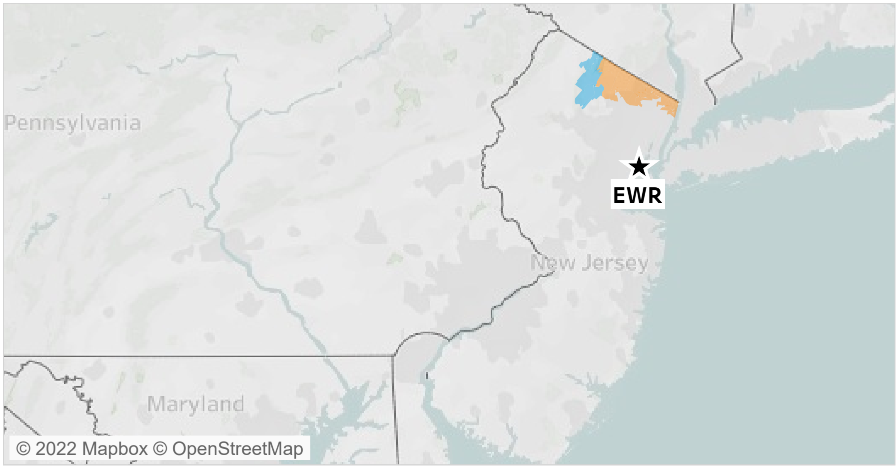
LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations

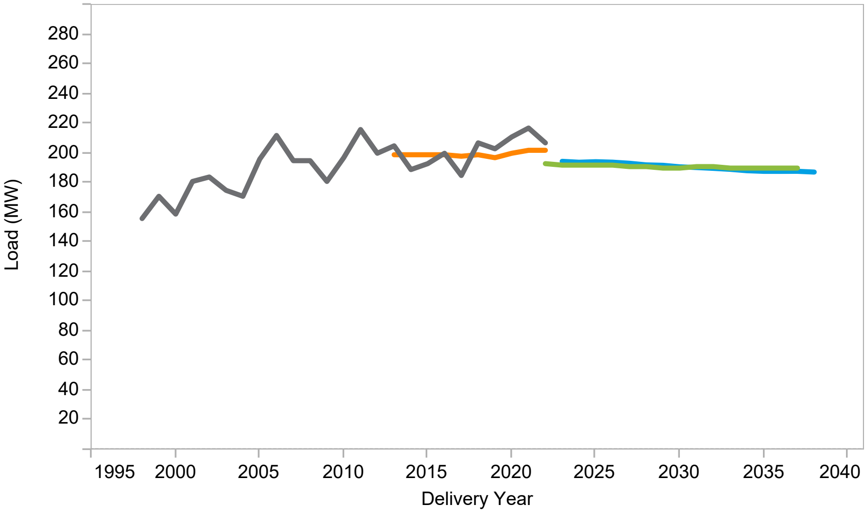


🟧 New York-Jersey City-White Plains, NY-NJ
🟦 Newark, NJ-PA

⬛ Peak 🟧 WN peak 🟩 Forecast 2022 🟦 Forecast 2023

UGI Energy Services (UGI)

Summer Peak



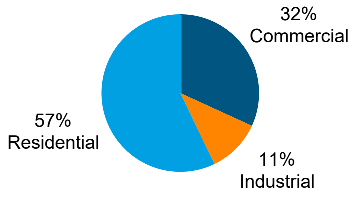
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*70.5*
Avg Summer Max Temp	*93.1*
Avg Winter Daily Temp	*30.0*
Avg Winter Min Temp	*-0.9*

Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.3%
WINTER	-0.3%	-0.3%

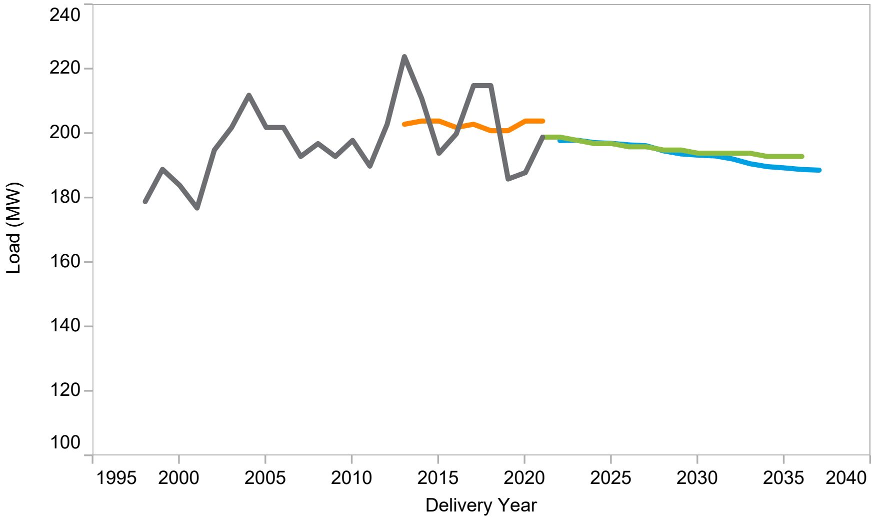
RCI Makeup



LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO PLGRP WESTERN MID-ATLANTIC

Winter Peak



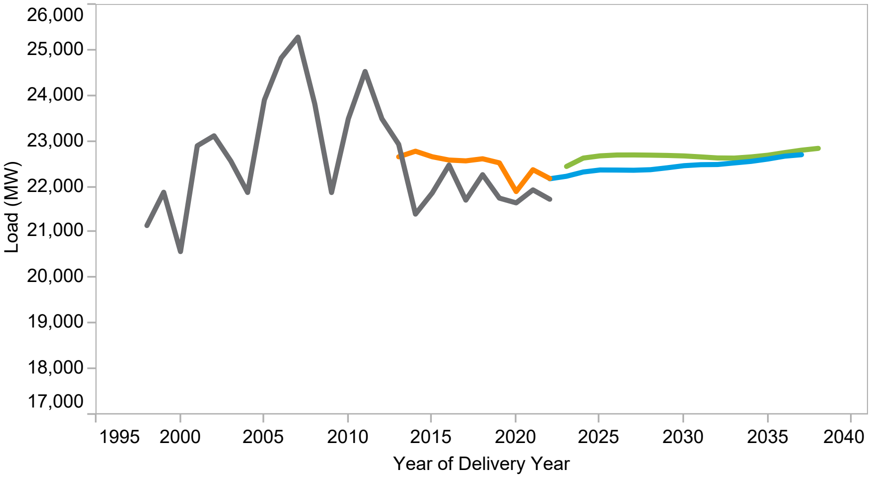
Metropolitan Statistical Areas and Weather Stations

🟩 Scranton--Wilkes-Barre--Hazleton, PA

■ Peak 🟧 WN peak 🟩 Forecast 2022 🟦 Forecast 2023

American Electric Power (AEP)

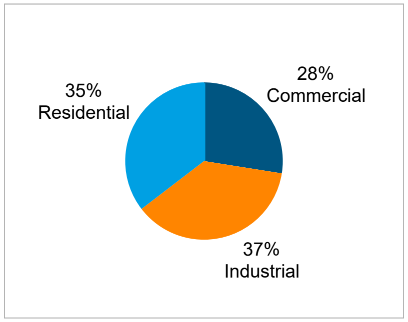
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*92.4*
Avg Winter Daily Temp	*33.2*
Avg Winter Min Temp	*2.7*

RCI Makeup



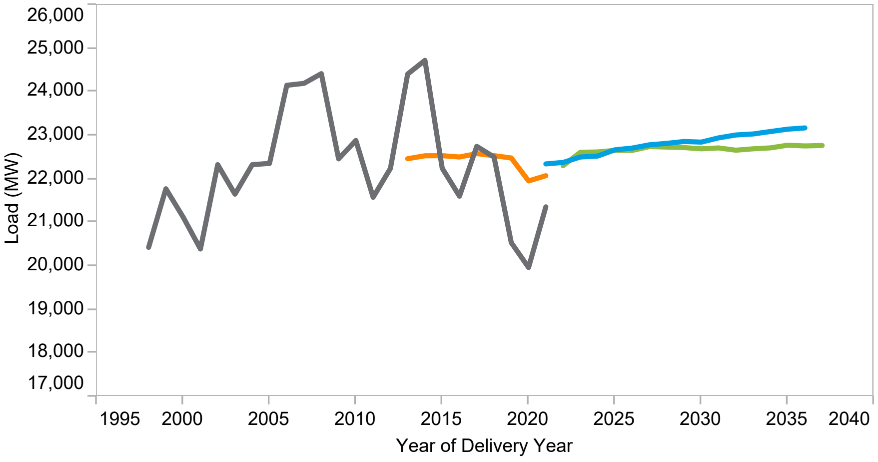
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.1%
WINTER	0.2%	0.1%

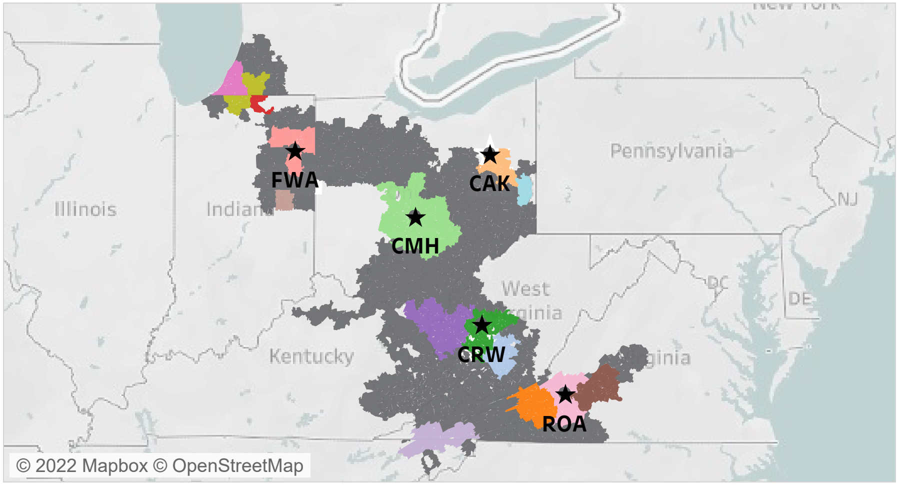
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

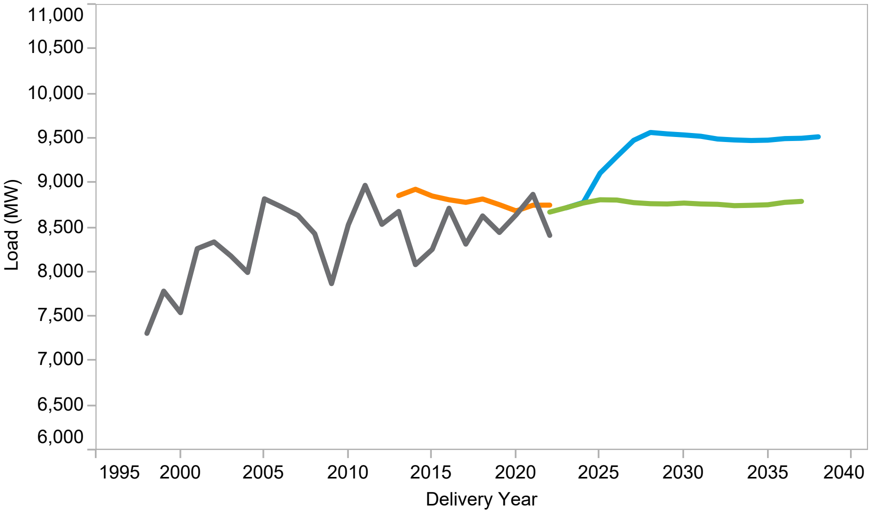


- ■ Peak
- ■ WN peak
- ■ Forecast 2022
- ■ Forecast 2023

- ■ AEP - Non-Metro
- ■ Beckley, WV
- ■ Blacksburg-Christiansburg-Radford, VA
- ■ Canton-Massillon, OH
- ■ Charleston, WV
- ■ Columbus, OH
- ■ Elkhart-Goshen, IN
- ■ Fort Wayne, IN
- ■ Huntington-Ashland, WV-KY-OH
- ■ Kingsport-Bristol-Bristol, TN-VA
- ■ Lynchburg, VA
- ■ Muncie, IN
- ■ Niles-Benton Harbor, MI
- ■ Roanoke, VA
- ■ South Bend-Mishawaka, IN-MI
- ■ Weirton-Steubenville, WV-OH

Allegheny Power Systems (APS)

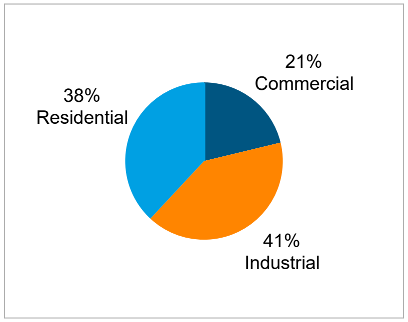
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*72.8*
Avg Summer Max Temp	*92.7*
Avg Winter Daily Temp	*32.9*
Avg Winter Min Temp	*2.3*

RCI Makeup



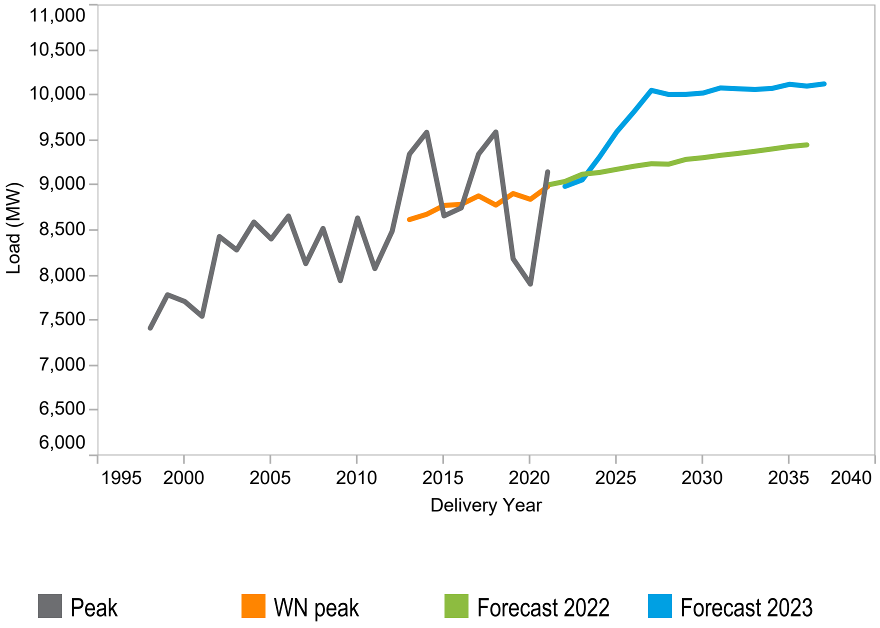
Zonal 10/15 Year Load Growth

SUMMER	0.8%	0.6%
WINTER	1.1%	0.8%

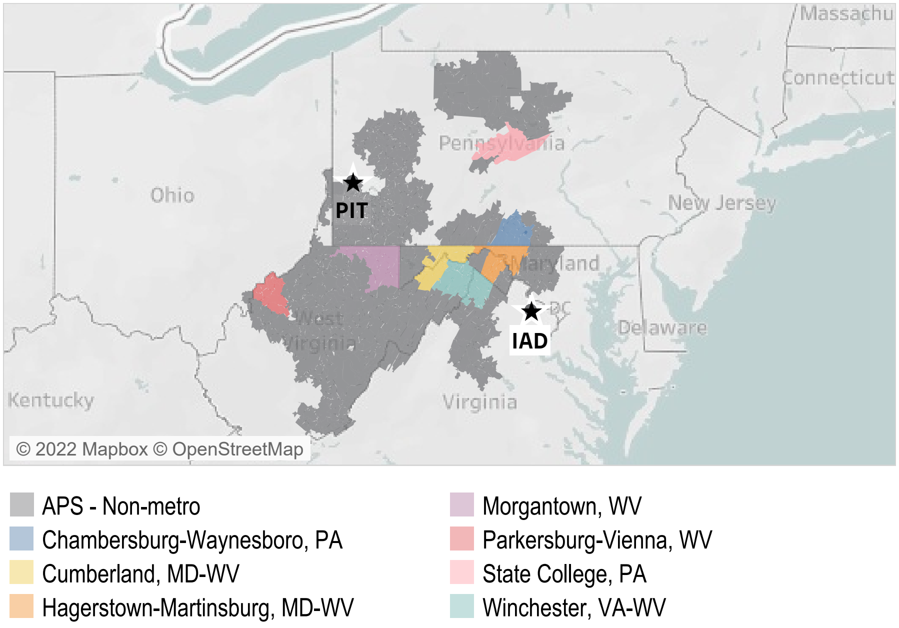
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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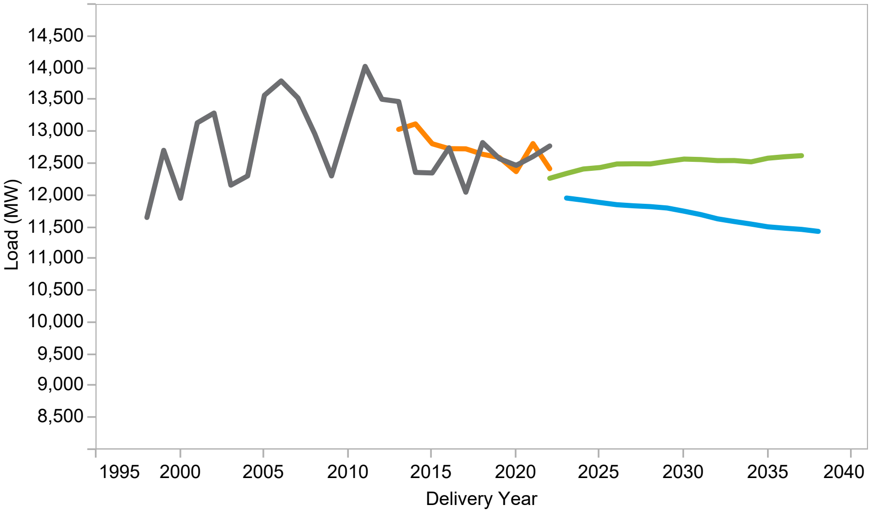
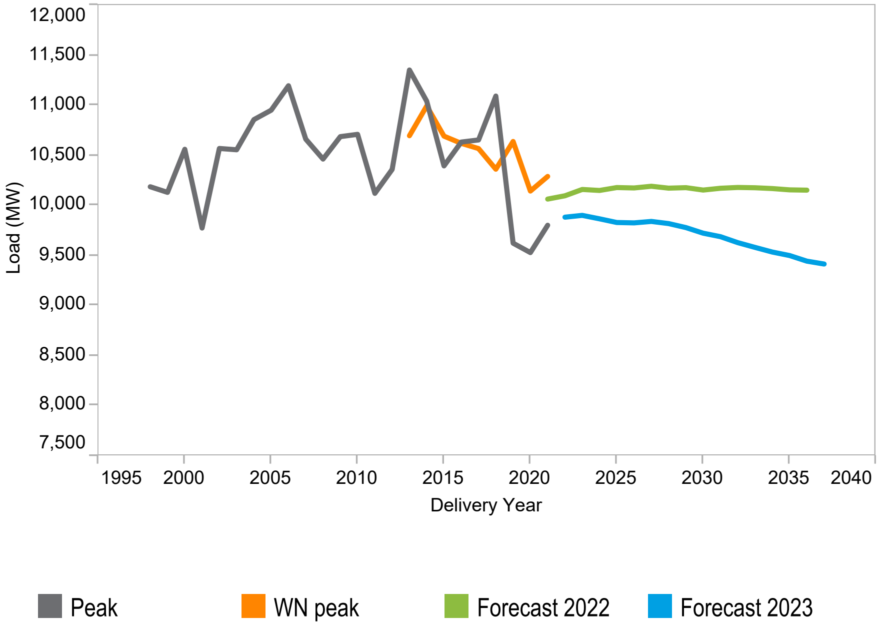
American Transmission Systems, Inc. (ATSI)

Summer Peak



Winter Peak



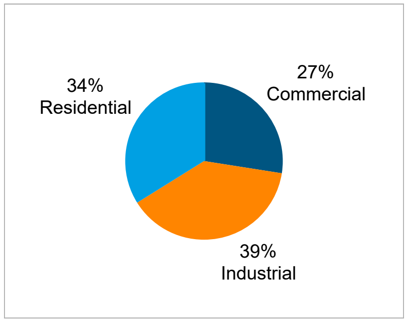
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*71.6*
Avg Summer Max Temp	*91.9*
Avg Winter Daily Temp	*29.9*
Avg Winter Min Temp	*-1.3*

Zonal 10/15 Year Load Growth

SUMMER	-0.3%	-0.3%
WINTER	-0.3%	-0.3%

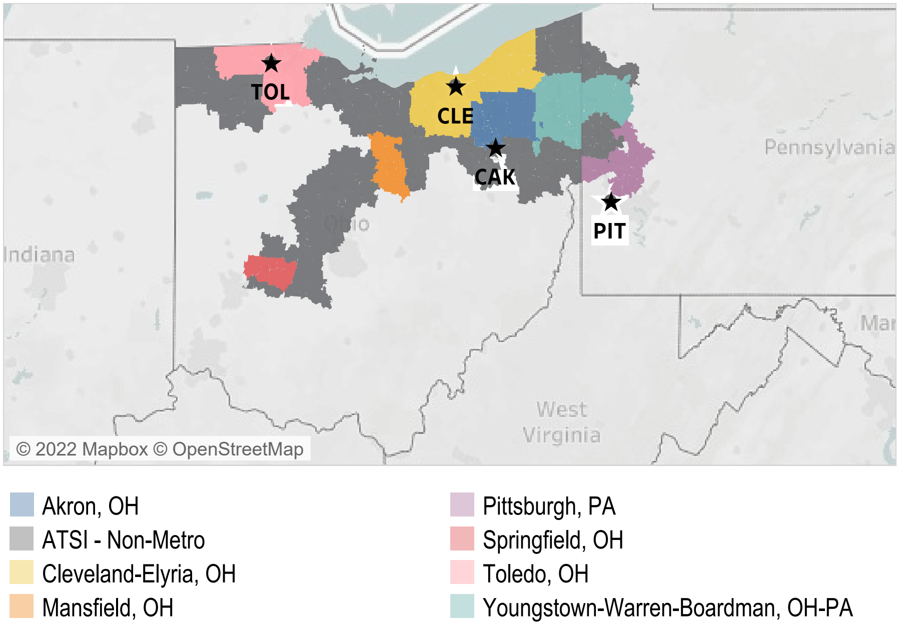
RCI Makeup



LDAs

PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations



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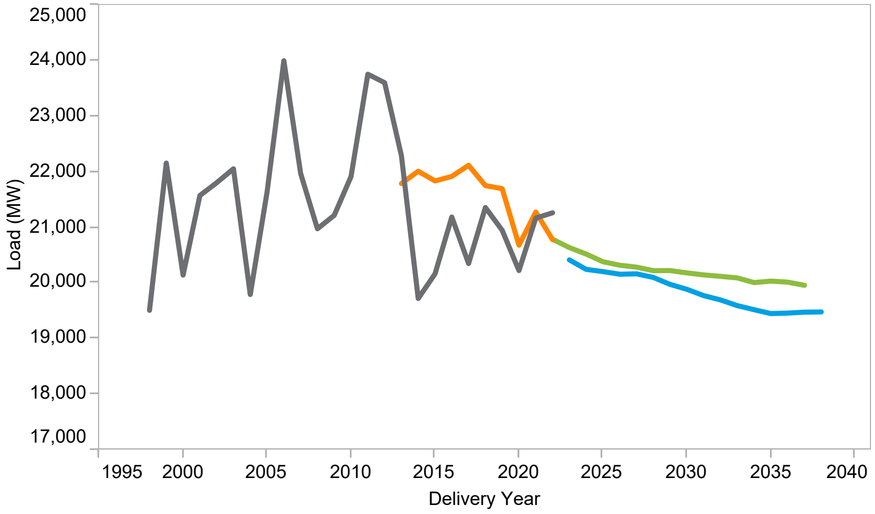
Commonwealth Edison (COMED)

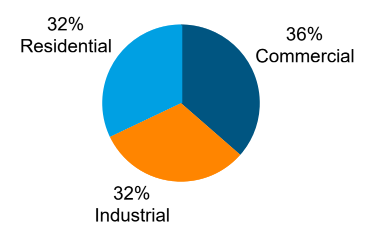
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*72.9*
Avg Summer Max Temp	*95.2*
Avg Winter Daily Temp	*27.6*
Avg Winter Min Temp	*-7.3*

RCI Makeup



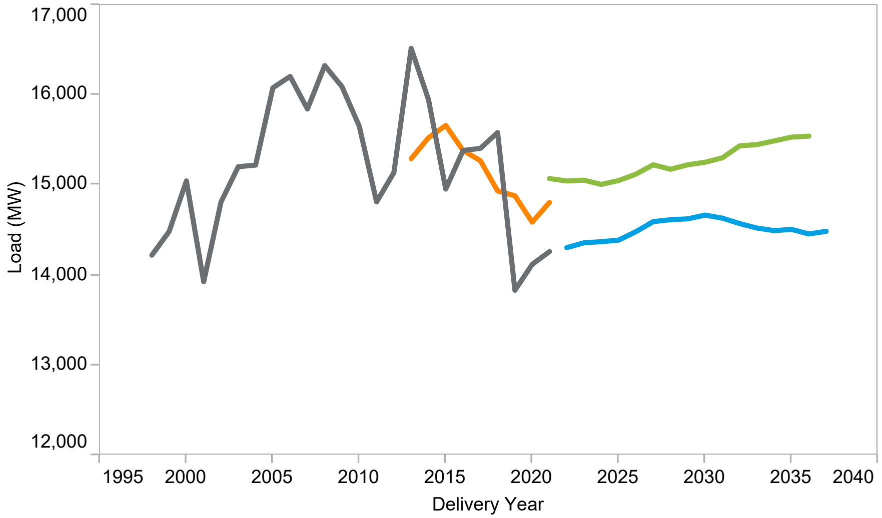
Zonal 10/15 Year Load Growth

SUMMER	-0.4%	-0.3%
WINTER	0.2%	0.1%

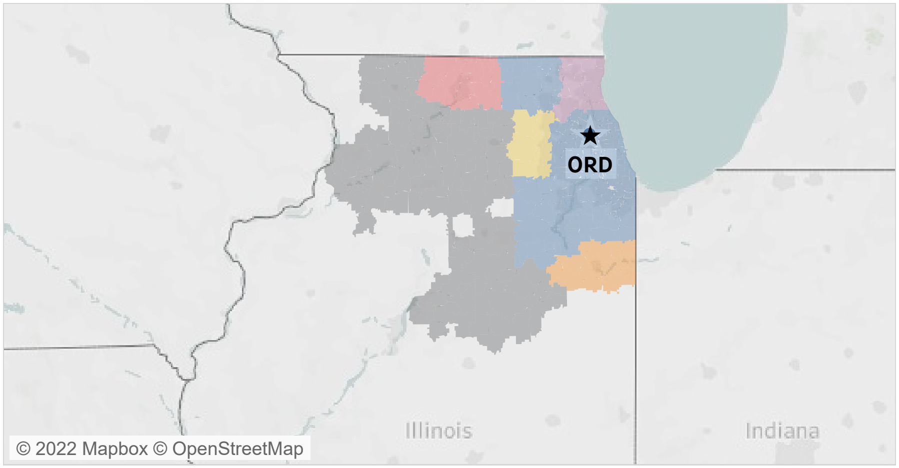
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

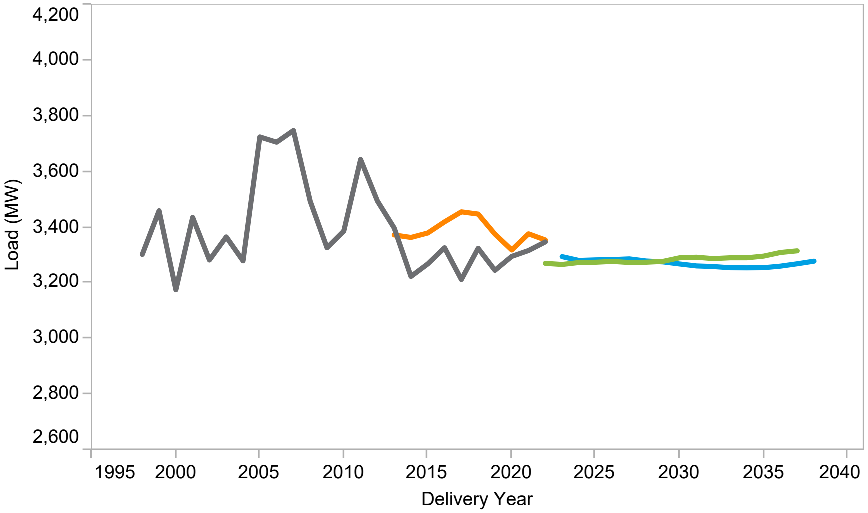


■ Chicago-Naperville-Arlington Heights, IL
■ Chicago-Naperville-Elgin, IL-IN-WI
■ COMED - Non-Metro
■ Kankakee, IL
■ Lake County-Kenosha County, IL-WI
■ Rockford, IL

■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

Dayton Power and Light (DAYTON)

Summer Peak



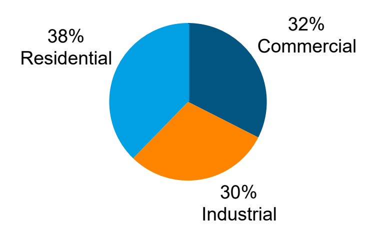
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*73.1*
Avg Summer Max Temp	*93.1*
Avg Winter Daily Temp	*31.0*
Avg Winter Min Temp	*-3.3*

Zonal 10/15 Year Load Growth

SUMMER	-0.1%	0.0%
WINTER	-0.2%	-0.2%

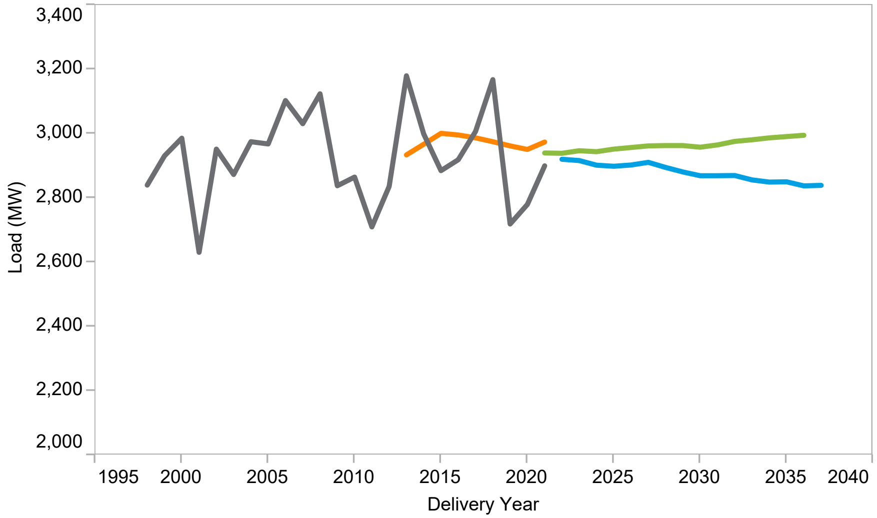
RCI Makeup



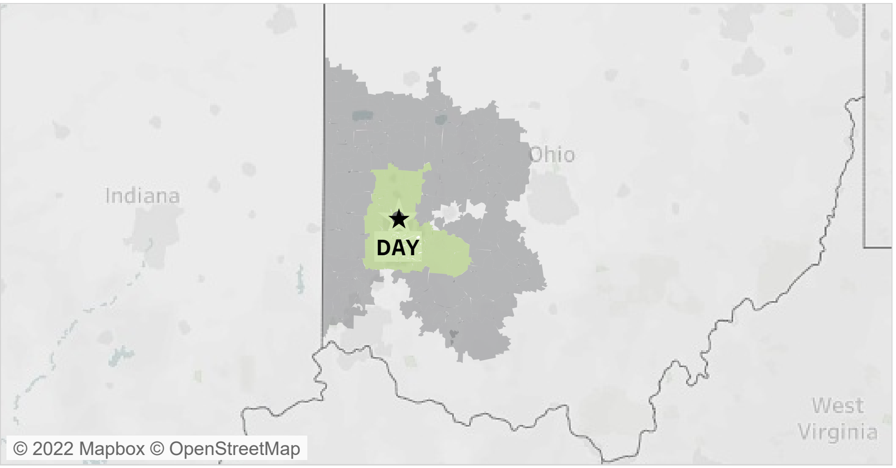
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

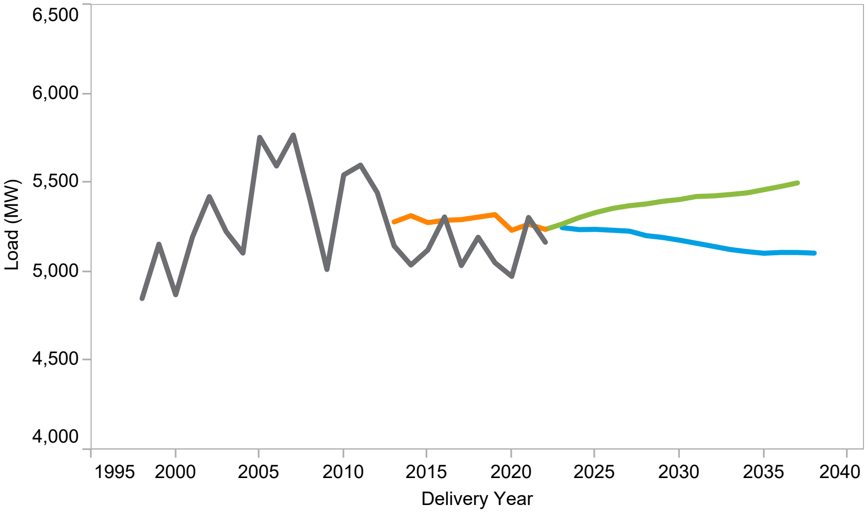


▨ DAY - Non-Metro
🟩 Dayton, OH

■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

Duke Energy Ohio and Kentucky (DEOK)

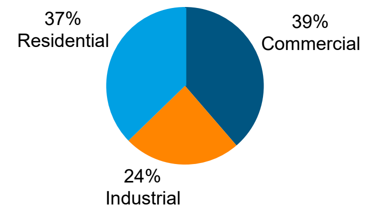
Summer Peak



Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*74.4*
Avg Summer Max Temp	*94.2*
Avg Winter Daily Temp	*33.9*
Avg Winter Min Temp	*-1.4*

RCI Makeup



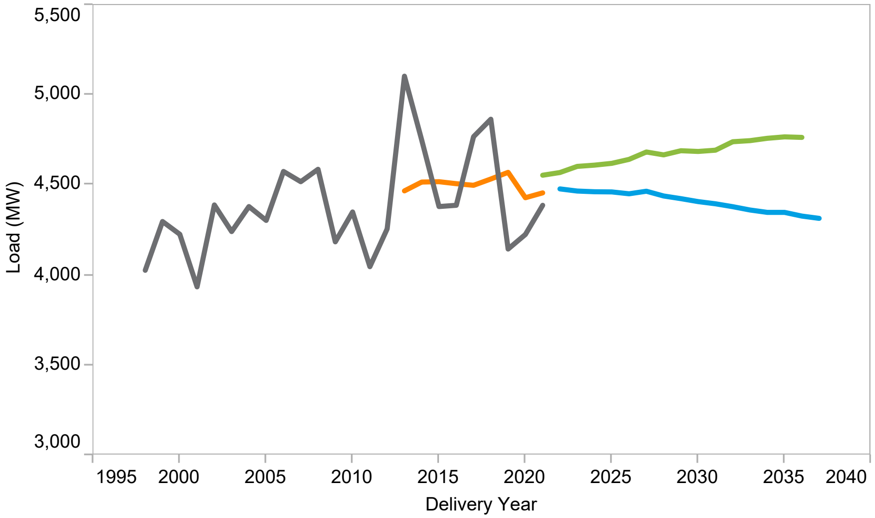
Zonal 10/15 Year Load Growth

SUMMER	-0.2%	-0.2%
WINTER	-0.2%	-0.2%

LDAs

PJM RTO PJM WESTERN

Winter Peak



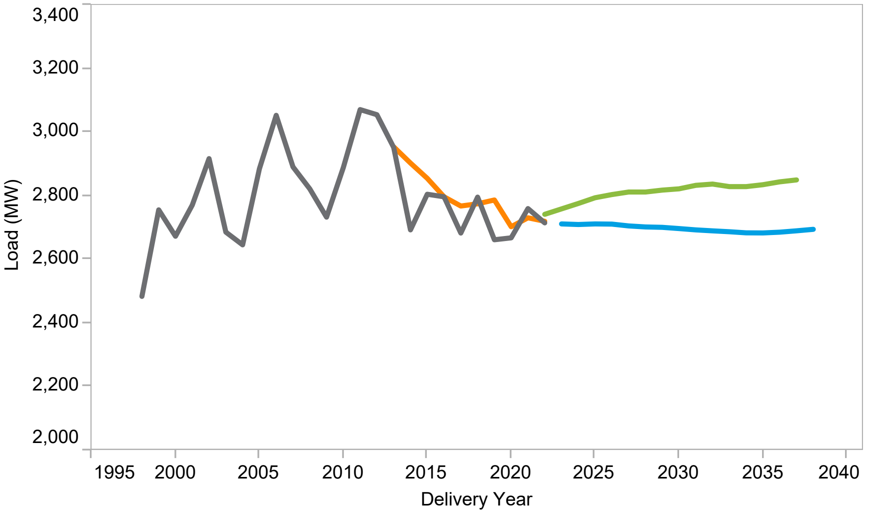
Metropolitan Statistical Areas and Weather Stations

🟧 Cincinnati, OH-KY-IN
⬜ DEOK - Non-Metro

⬛ Peak 🟧 WN peak 🟩 Forecast 2022 🟦 Forecast 2023

Duquesne Light Company (DLCO)

Summer Peak



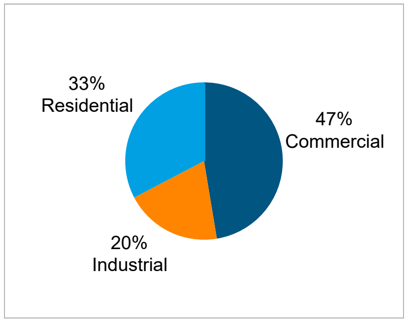
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*71.7*
Avg Summer Max Temp	*91.8*
Avg Winter Daily Temp	*31.5*
Avg Winter Min Temp	*-0.9*

Zonal 10/15 Year Load Growth

SUMMER	-0.1%	0.0%
WINTER	-0.2%	-0.2%

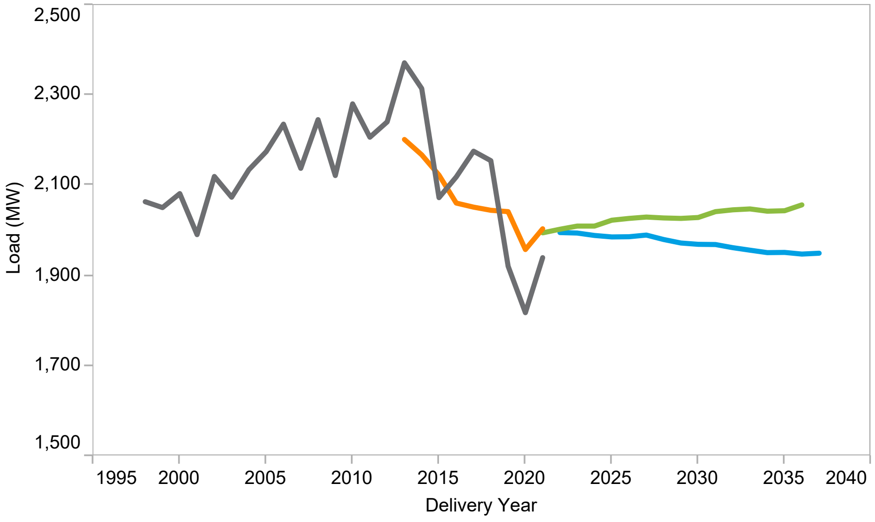
RCI Makeup



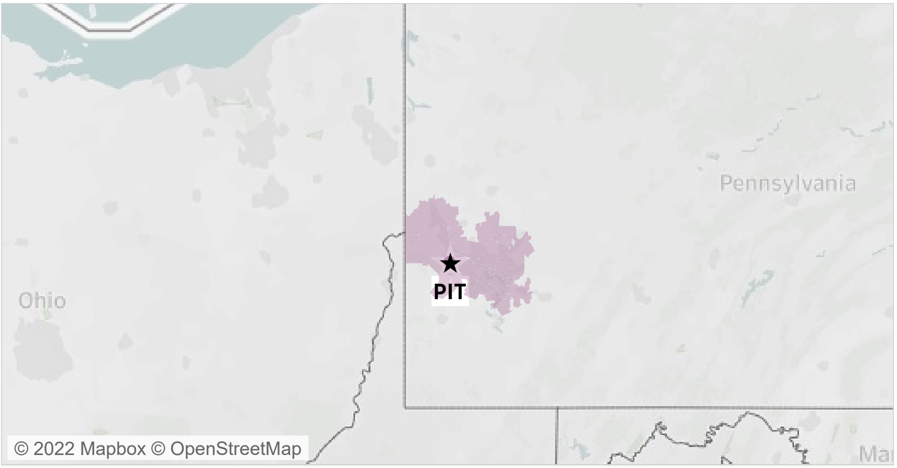
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

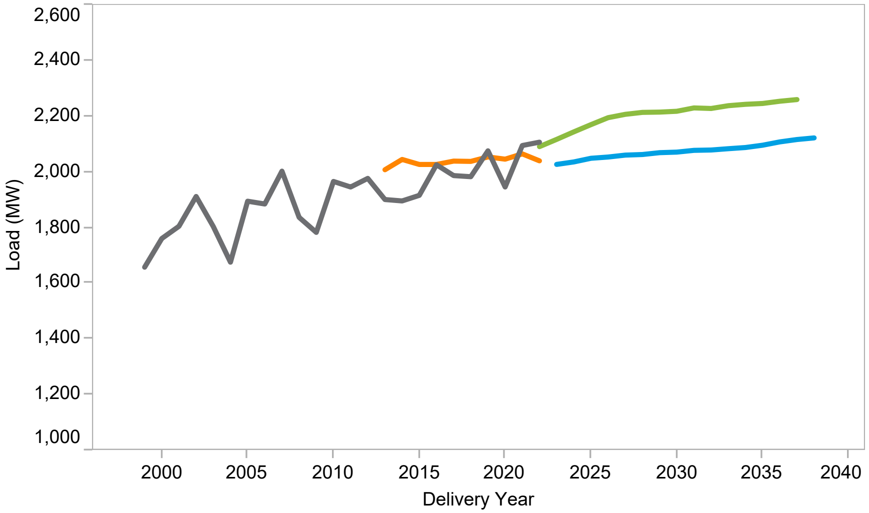


▨ Pittsburgh, PA

■ Peak ■ WN peak ■ Forecast 2022 ■ Forecast 2023

East Kentucky Power Cooperative (EKPC)

Summer Peak



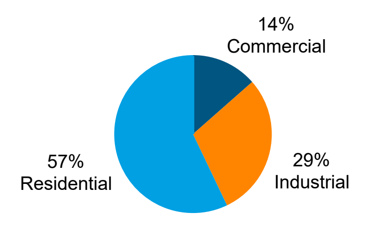
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*94.3*
Avg Winter Daily Temp	*35.9*
Avg Winter Min Temp	*2.1*

Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.3%
WINTER	0.1%	0.2%

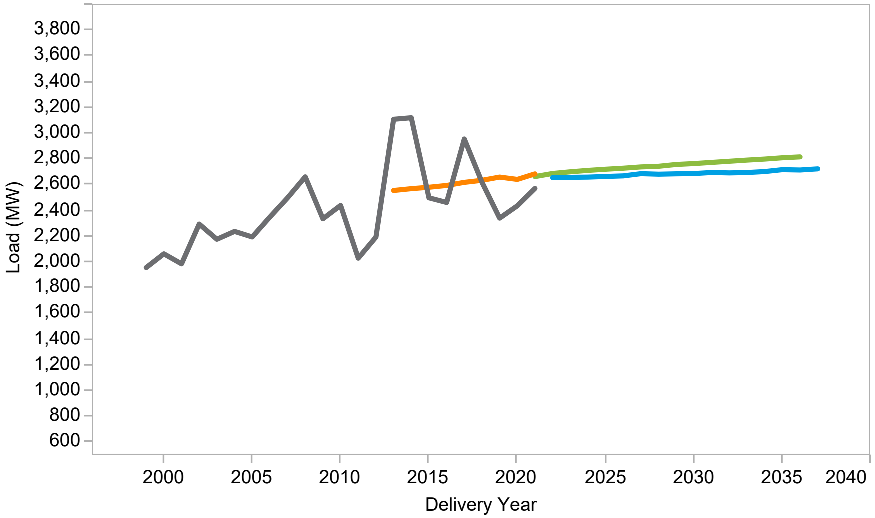
RCI Makeup



LDAs

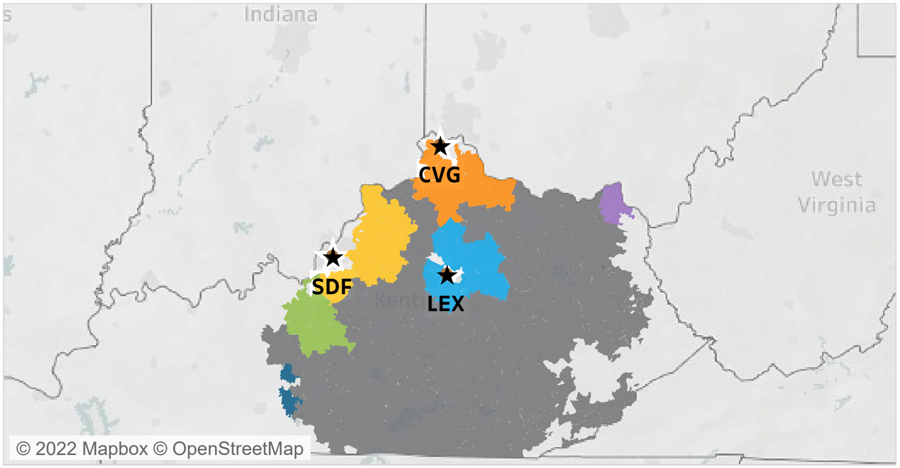
PJM RTO PJM WESTERN

Winter Peak



⬛ Peak
🟧 WN peak
🟩 Forecast 2022
🟦 Forecast 2023

Metropolitan Statistical Areas and Weather Stations



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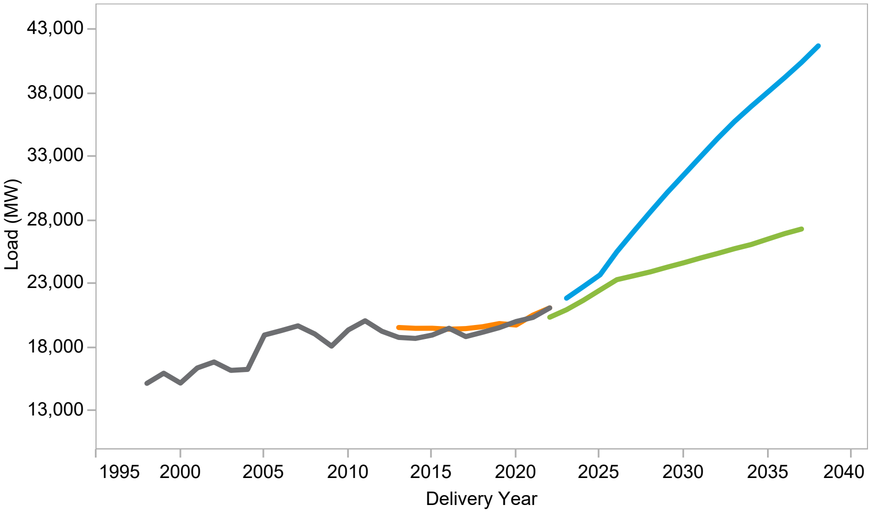
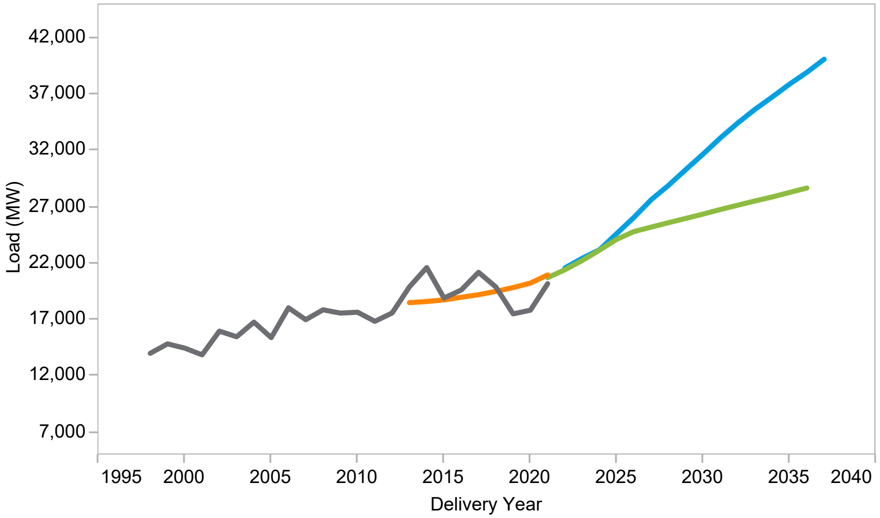
■ Bowling Green, KY
■ Cincinnati, OH-KY-IN
■ EKPC - Non-Metro
■ Elizabethtown-Fort Knox, KY
■ Huntington-Ashland, WV-KY-OH
■ Lexington-Fayette, KY
■ Louisville/Jefferson County, KY-IN

Dominion (DOM)

Summer Peak



Winter Peak



⬛ Peak 🟧 WN peak 🟩 Forecast 2022 🟦 Forecast 2023

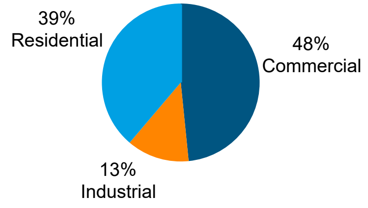
Weather - Annual Average 1993-2021

Avg Summer Daily Temp	*76.9*
Avg Summer Max Temp	*97.0*
Avg Winter Daily Temp	*40.3*
Avg Winter Min Temp	*12.3*

Zonal 10/15 Year Load Growth

SUMMER	5.0%	4.4%
WINTER	4.8%	4.2%

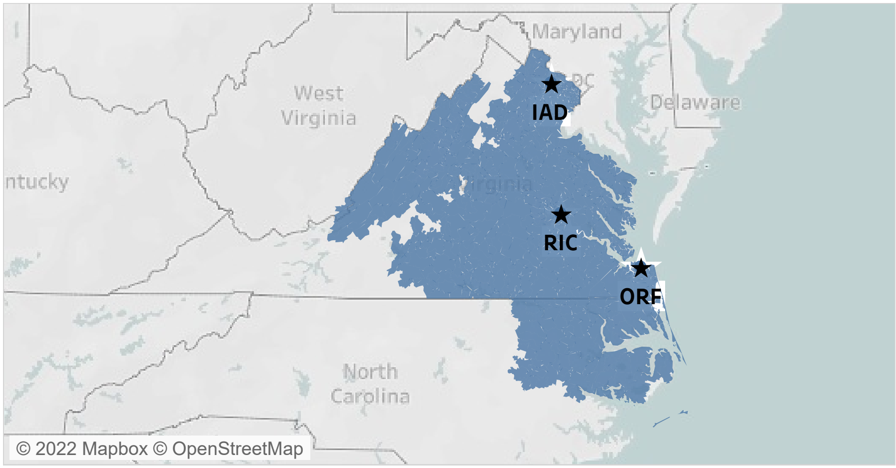
RCI Makeup



LDAs

PJM RTO

Metropolitan Statistical Areas and Weather Stations



▨ Virginia Commonwealth Economics

Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2022 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2023		2028		2033	
	MW	%	MW	%	MW	%
AE	59	2.4%	(22)	-0.9%	(134)	-5.3%
BGE	83	1.3%	(84)	-1.3%	(260)	-4.1%
DPL	(21)	-0.5%	(152)	-3.9%	(162)	-4.2%
JCPL	273	4.7%	183	3.2%	(62)	-1.1%
METED	106	3.6%	89	3.0%	34	1.1%
PECO	141	1.7%	178	2.1%	113	1.3%
PENLC	64	2.3%	22	0.8%	(42)	-1.5%
PEPCO	274	4.7%	367	6.3%	463	8.1%
PL	152	2.2%	112	1.6%	(17)	-0.2%
PS	370	3.9%	53	0.6%	(398)	-4.0%
RECO	25	6.4%	32	8.3%	28	7.2%
UGI	3	1.6%	1	0.5%	(1)	-0.5%
PJM MID-ATLANTIC	664	1.2%	(205)	-0.4%	(1,266)	-2.3%
FE-EAST	400	3.5%	312	2.8%	(53)	-0.5%
PLGRP	168	2.3%	135	1.9%	5	0.1%

Table A-1

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2022 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2023		2028		2033	
	MW	%	MW	%	MW	%
AEP	215	1.0%	320	1.4%	106	0.5%
APS	(1)	-0.0%	799	9.1%	737	8.4%
ATSI	(387)	-3.1%	(671)	-5.4%	(959)	-7.6%
COMED	(221)	-1.1%	(121)	-0.6%	(498)	-2.5%
DAYTON	28	0.9%	5	0.2%	(36)	-1.1%
DEOK	(20)	-0.4%	(178)	-3.3%	(309)	-5.7%
DLCO	(47)	-1.7%	(110)	-3.9%	(142)	-5.0%
EKPC	(90)	-4.3%	(151)	-6.8%	(154)	-6.9%
OVEC	5	5.6%	5	5.6%	5	5.6%
PJM WESTERN	(397)	-0.5%	12	0.0%	(1,299)	-1.7%
DOM	907	4.3%	4,715	19.7%	9,982	38.7%
PJM RTO	(292)	-0.2%	3,014	2.0%	6,204	4.0%

Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2022 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	22/23		27/28		32/33	
	MW	**%**	**MW**	**%**	**MW**	**%**
AE	(29)	-1.8%	(79)	-4.7%	(160)	-9.3%
BGE	(47)	-0.8%	(234)	-3.9%	(498)	-8.1%
DPL	(5)	-0.1%	(75)	-2.0%	(188)	-4.8%
JCPL	30	0.8%	29	0.8%	(109)	-2.7%
METED	96	3.7%	153	5.9%	133	5.0%
PECO	(177)	-2.7%	(75)	-1.1%	(144)	-2.2%
PENLC	48	1.7%	33	1.2%	(16)	-0.6%
PEPCO	0	0.0%	23	0.4%	11	0.2%
PL	85	1.2%	113	1.5%	19	0.3%
PS	(160)	-2.4%	(454)	-6.5%	(896)	-12.3%
RECO	(14)	-6.1%	6	2.6%	9	3.8%
UGI	(1)	-0.5%	0	0.0%	(2)	-1.0%
PJM MID-ATLANTIC	(479)	-1.0%	(749)	-1.6%	(2,022)	-4.2%
FE-EAST	181	2.0%	191	2.1%	7	0.1%
PLGRP	85	1.1%	117	1.6%	21	0.3%

Table A-2

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2022 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	22/23		27/28		32/33	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	(74)	-0.3%	(41)	-0.2%	(350)	-1.5%
APS	(55)	-0.6%	814	8.8%	718	7.7%
ATSI	(214)	-2.1%	(351)	-3.4%	(551)	-5.4%
COMED	(741)	-4.9%	(632)	-4.2%	(863)	-5.6%
DAYTON	(19)	-0.6%	(51)	-1.7%	(106)	-3.6%
DEOK	(91)	-2.0%	(218)	-4.7%	(361)	-7.6%
DLCO	(7)	-0.3%	(40)	-2.0%	(84)	-4.1%
EKPC	(32)	-1.2%	(52)	-1.9%	(91)	-3.3%
OVEC	(5)	-4.3%	(5)	-4.3%	(5)	-4.3%
PJM WESTERN	(1,512)	-2.2%	(946)	-1.4%	(1,910)	-2.8%
DOM	165	0.8%	2,440	9.7%	7,299	26.8%
PJM RTO	(2,169)	-1.6%	453	0.3%	2,678	1.9%

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2023 - 2033

	METERED 2022	UNRESTRICTED 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Annual Growth Rate (10 yr)
AE	2,615	2,615	2,549	2,526	2,516	2,504	2,492	2,481	2,467	2,452	2,438	2,426	2,418	(0.5%)
				-0.9%	-0.4%	-0.5%	-0.5%	-0.4%	-0.6%	-0.6%	-0.6%	-0.5%	-0.3%	
BGE	6,521	6,521	6,474	6,428	6,406	6,378	6,350	6,307	6,243	6,203	6,160	6,105	6,060	(0.7%)
				-0.7%	-0.3%	-0.4%	-0.4%	-0.7%	-1.0%	-0.6%	-0.7%	-0.9%	-0.7%	
DPL	4,126	4,126	3,861	3,841	3,823	3,807	3,791	3,765	3,747	3,726	3,701	3,680	3,666	(0.5%)
				-0.5%	-0.5%	-0.4%	-0.4%	-0.7%	-0.5%	-0.6%	-0.7%	-0.6%	-0.4%	
JCPL	6,124	6,124	6,072	6,032	6,025	6,011	5,984	5,945	5,932	5,894	5,871	5,857	5,830	(0.4%)
				-0.7%	-0.1%	-0.2%	-0.4%	-0.7%	-0.2%	-0.6%	-0.4%	-0.2%	-0.5%	
METED	3,022	3,022	3,040	3,041	3,058	3,076	3,080	3,077	3,083	3,088	3,099	3,106	3,112	0.2%
				0.0%	0.6%	0.6%	0.1%	-0.1%	0.2%	0.2%	0.4%	0.2%	0.2%	
PECO	8,583	8,583	8,527	8,522	8,533	8,550	8,559	8,568	8,563	8,567	8,571	8,581	8,590	0.1%
				-0.1%	0.1%	0.2%	0.1%	0.1%	-0.1%	0.0%	0.0%	0.1%	0.1%	
PENLC	2,801	2,801	2,871	2,858	2,863	2,857	2,848	2,830	2,821	2,820	2,813	2,801	2,792	(0.3%)
				-0.5%	0.2%	-0.2%	-0.3%	-0.6%	-0.3%	-0.0%	-0.2%	-0.4%	-0.3%	
PEPCO	5,834	5,834	6,166	6,164	6,194	6,209	6,217	6,213	6,214	6,215	6,217	6,200	6,201	0.1%
				-0.0%	0.5%	0.2%	0.1%	-0.1%	0.0%	0.0%	0.0%	-0.3%	0.0%	
PL	7,065	7,076	7,175	7,181	7,212	7,230	7,225	7,223	7,218	7,224	7,241	7,242	7,248	0.1%
				0.1%	0.4%	0.2%	-0.1%	-0.0%	-0.1%	0.1%	0.2%	0.0%	0.1%	
PS	10,148	10,148	9,904	9,824	9,795	9,806	9,754	9,685	9,639	9,581	9,561	9,529	9,499	(0.4%)
				-0.8%	-0.3%	0.1%	-0.5%	-0.7%	-0.5%	-0.6%	-0.2%	-0.3%	-0.3%	
RECO	408	408	414	415	417	419	420	419	419	419	418	417	416	0.0%
				0.2%	0.5%	0.5%	0.2%	-0.2%	0.0%	0.0%	-0.2%	-0.2%	-0.2%	
UGI	207	207	195	194	194	194	193	192	192	191	190	190	189	(0.3%)
				-0.5%	0.0%	0.0%	-0.5%	-0.5%	0.0%	-0.5%	-0.5%	0.0%	-0.5%	
DIVERSITY - MID-ATLANTIC(-)			1,512	1,576	1,617	1,606	1,611	1,736	1,800	1,966	2,002	1,627	1,685	
PJM MID-ATLANTIC	56,443	56,449	55,736	55,450	55,419	55,435	55,302	54,969	54,738	54,414	54,278	54,507	54,336	(0.3%)
				-0.5%	-0.1%	0.0%	-0.2%	-0.6%	-0.4%	-0.6%	-0.2%	0.4%	-0.3%	
FE-EAST	11,712	11,712	11,696	11,673	11,686	11,680	11,647	11,617	11,590	11,547	11,523	11,509	11,482	(0.2%)
				-0.2%	0.1%	-0.1%	-0.3%	-0.3%	-0.2%	-0.4%	-0.2%	-0.1%	-0.2%	
PLGRP	7,262	7,277	7,370	7,375	7,406	7,423	7,417	7,415	7,410	7,410	7,431	7,432	7,437	0.1%
				0.1%	0.4%	0.2%	-0.1%	-0.0%	-0.1%	0.0%	0.3%	0.0%	0.1%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023).
Summer season indicates peak from June, July, August.

Table B-1 (continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2034 - 2038

	2034	2035	2036	2037	2038	Annual Growth Rate (15 yr)
AE	2,407	2,399	2,399	2,399	2,402	(0.4%)
	-0.5%	-0.3%	0.0%	0.0%	0.1%	
BGE	6,005	5,975	5,966	5,972	5,972	(0.5%)
	-0.9%	-0.5%	-0.2%	0.1%	0.0%	
DPL	3,653	3,649	3,651	3,655	3,660	(0.4%)
	-0.4%	-0.1%	0.1%	0.1%	0.1%	
JCPL	5,810	5,794	5,816	5,839	5,864	(0.2%)
	-0.3%	-0.3%	0.4%	0.4%	0.4%	
METED	3,118	3,124	3,140	3,156	3,171	0.3%
	0.2%	0.2%	0.5%	0.5%	0.5%	
PECO	8,588	8,593	8,611	8,633	8,656	0.1%
	-0.0%	0.1%	0.2%	0.3%	0.3%	
PENLC	2,780	2,772	2,777	2,778	2,774	(0.2%)
	-0.4%	-0.3%	0.2%	0.0%	-0.1%	
PEPCO	6,198	6,200	6,240	6,273	6,298	0.1%
	-0.0%	0.0%	0.6%	0.5%	0.4%	
PL	7,236	7,233	7,286	7,317	7,342	0.2%
	-0.2%	-0.0%	0.7%	0.4%	0.3%	
PS	9,482	9,392	9,427	9,524	9,566	(0.2%)
	-0.2%	-0.9%	0.4%	1.0%	0.4%	
RECO	415	415	417	420	422	0.1%
	-0.2%	0.0%	0.5%	0.7%	0.5%	
UGI	188	188	188	188	187	(0.3%)
	-0.5%	0.0%	0.0%	0.0%	-0.5%	
DIVERSITY - MID-ATLANTIC(-)	1,865	1,784	1,851	1,600	1,654	
PJM MID-ATLANTIC	54,015	53,950	54,067	54,554	54,660	(0.1%)
	-0.6%	-0.1%	0.2%	0.9%	0.2%	
FE-EAST	11,448	11,445	11,471	11,497	11,523	(0.1%)
	-0.3%	-0.0%	0.2%	0.2%	0.2%	
PLGRP	7,424	7,421	7,472	7,498	7,518	0.1%
	-0.2%	-0.0%	0.7%	0.3%	0.3%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023).
Summer season indicates peak from June, July, August.

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2023 - 2033

	METERED 2022	UNRESTRICTED 2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Annual Growth Rate (10 yr)
AEP	21,733	21,733	22,453	22,637	22,686	22,705	22,706	22,702	22,695	22,684	22,663	22,640	22,637	0.1%
				0.8%	0.2%	0.1%	0.0%	-0.0%	-0.0%	-0.0%	-0.1%	-0.1%	-0.0%	
APS	8,413	8,413	8,724	8,783	9,112	9,299	9,480	9,568	9,552	9,540	9,526	9,495	9,484	0.8%
				0.7%	3.7%	2.1%	1.9%	0.9%	-0.2%	-0.1%	-0.1%	-0.3%	-0.1%	
ATSI	12,772	12,781	11,962	11,929	11,892	11,858	11,840	11,828	11,805	11,756	11,702	11,636	11,593	(0.3%)
				-0.3%	-0.3%	-0.3%	-0.2%	-0.1%	-0.2%	-0.4%	-0.5%	-0.6%	-0.4%	
COMED	21,263	21,263	20,417	20,246	20,206	20,159	20,166	20,102	19,977	19,888	19,775	19,697	19,595	(0.4%)
				-0.8%	-0.2%	-0.2%	0.0%	-0.3%	-0.6%	-0.4%	-0.6%	-0.4%	-0.5%	
DAYTON	3,348	3,348	3,295	3,281	3,284	3,285	3,287	3,280	3,276	3,269	3,262	3,260	3,255	(0.1%)
				-0.4%	0.1%	0.0%	0.1%	-0.2%	-0.1%	-0.2%	-0.2%	-0.1%	-0.2%	
DEOK	5,167	5,167	5,249	5,238	5,239	5,234	5,229	5,204	5,193	5,178	5,161	5,144	5,126	(0.2%)
				-0.2%	0.0%	-0.1%	-0.1%	-0.5%	-0.2%	-0.3%	-0.3%	-0.3%	-0.3%	
DLCO	2,715	2,715	2,712	2,710	2,712	2,711	2,705	2,702	2,701	2,697	2,693	2,690	2,687	(0.1%)
				-0.1%	0.1%	-0.0%	-0.2%	-0.1%	-0.0%	-0.1%	-0.1%	-0.1%	-0.1%	
EKPC	2,107	2,107	2,027	2,036	2,049	2,054	2,061	2,063	2,069	2,071	2,078	2,079	2,084	0.3%
				0.4%	0.6%	0.2%	0.3%	0.1%	0.3%	0.1%	0.3%	0.0%	0.2%	
OVEC	121	121	95	95	95	95	95	95	95	95	95	95	95	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,581	1,555	1,598	1,565	1,541	1,572	1,595	1,657	1,770	1,659	1,676	
PJM WESTERN	76,307	76,412	75,353	75,400	75,677	75,835	76,028	75,972	75,768	75,521	75,185	75,077	74,880	(0.1%)
				0.1%	0.4%	0.2%	0.3%	-0.1%	-0.3%	-0.3%	-0.4%	-0.1%	-0.3%	
DOM	21,157	21,157	21,920	22,828	23,758	25,568	27,157	28,705	30,216	31,633	33,055	34,465	35,789	5.0%
				4.1%	4.1%	7.6%	6.2%	5.7%	5.3%	4.7%	4.5%	4.3%	3.8%	
DIVERSITY - TOTAL(-)			7,043	7,072	7,145	7,273	7,364	7,251	7,194	7,292	7,348	7,418	7,395	
PJM RTO	147,337	147,361	149,059	149,737	150,924	152,736	154,275	155,703	156,923	157,899	158,942	159,917	160,971	0.8%
				0.5%	0.8%	1.2%	1.0%	0.9%	0.8%	0.6%	0.7%	0.6%	0.7%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023).
Summer season indicates peak from June, July, August.

Table B-1 (continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2034 - 2038

	2034	2035	2036	2037	2038	Annual Growth Rate (15 yr)
AEP	22,663	22,700	22,757	22,810	22,850	0.1%
	0.1%	0.2%	0.3%	0.2%	0.2%	
APS	9,478	9,482	9,499	9,503	9,520	0.6%
	-0.1%	0.0%	0.2%	0.0%	0.2%	
ATSI	11,553	11,510	11,488	11,469	11,438	(0.3%)
	-0.3%	-0.4%	-0.2%	-0.2%	-0.3%	
COMED	19,522	19,452	19,460	19,477	19,481	(0.3%)
	-0.4%	-0.4%	0.0%	0.1%	0.0%	
DAYTON	3,255	3,255	3,261	3,269	3,279	(0.0%)
	0.0%	0.0%	0.2%	0.2%	0.3%	
DEOK	5,114	5,105	5,110	5,109	5,106	(0.2%)
	-0.2%	-0.2%	0.1%	-0.0%	-0.1%	
DLCO	2,684	2,683	2,686	2,690	2,695	(0.0%)
	-0.1%	-0.0%	0.1%	0.1%	0.2%	
EKPC	2,088	2,096	2,108	2,117	2,122	0.3%
	0.2%	0.4%	0.6%	0.4%	0.2%	
OVEC	95	95	95	95	95	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,716	1,802	1,824	1,872	1,849	
PJM WESTERN	74,736	74,576	74,640	74,667	74,737	(0.1%)
	-0.2%	-0.2%	0.1%	0.0%	0.1%	
DOM	36,980	38,115	39,255	40,443	41,741	4.4%
	3.3%	3.1%	3.0%	3.0%	3.2%	
DIVERSITY - TOTAL(-)	7,217	7,088	7,096	7,160	7,074	
PJM RTO	162,095	163,139	164,541	165,976	167,567	0.8%
	0.7%	0.6%	0.9%	0.9%	1.0%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023).
Summer season indicates peak from June, July, August.

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Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2022/23 - 2032/33

	METERED 21/22	UNRESTRICTED 21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	Annual Growth Rate (10 yr)
AE	1,515	1,515	1,590	1,585	1,582	1,583	1,583	1,587	1,579	1,573	1,568	1,568	1,561	(0.2%)
				-0.3%	-0.2%	0.1%	0.0%	0.3%	-0.5%	-0.4%	-0.3%	0.0%	-0.4%	
BGE	5,699	5,699	5,755	5,747	5,753	5,757	5,754	5,766	5,737	5,717	5,702	5,708	5,680	(0.1%)
				-0.1%	0.1%	0.1%	-0.1%	0.2%	-0.5%	-0.3%	-0.3%	0.1%	-0.5%	
DPL	3,598	3,598	3,623	3,632	3,636	3,651	3,662	3,674	3,669	3,673	3,678	3,685	3,690	0.2%
				0.2%	0.1%	0.4%	0.3%	0.3%	-0.1%	0.1%	0.1%	0.2%	0.1%	
JCPL	3,568	3,568	3,740	3,752	3,776	3,806	3,828	3,857	3,851	3,850	3,852	3,859	3,864	0.3%
				0.3%	0.6%	0.8%	0.6%	0.8%	-0.2%	-0.0%	0.1%	0.2%	0.1%	
METED	2,651	2,651	2,696	2,718	2,712	2,721	2,730	2,764	2,743	2,743	2,752	2,779	2,772	0.3%
				0.8%	-0.2%	0.3%	0.3%	1.2%	-0.8%	0.0%	0.3%	1.0%	-0.3%	
PECO	6,232	6,232	6,459	6,512	6,484	6,492	6,499	6,575	6,516	6,520	6,522	6,583	6,530	0.1%
				0.8%	-0.4%	0.1%	0.1%	1.2%	-0.9%	0.1%	0.0%	0.9%	-0.8%	
PENLC	2,831	2,831	2,823	2,824	2,809	2,802	2,797	2,802	2,784	2,773	2,767	2,768	2,751	(0.3%)
				0.0%	-0.5%	-0.2%	-0.2%	0.2%	-0.6%	-0.4%	-0.2%	0.0%	-0.6%	
PEPCO	5,085	5,085	5,381	5,408	5,422	5,445	5,474	5,508	5,489	5,498	5,507	5,538	5,531	0.3%
				0.5%	0.3%	0.4%	0.5%	0.6%	-0.3%	0.2%	0.2%	0.6%	-0.1%	
PL	7,303	7,303	7,334	7,334	7,377	7,391	7,399	7,425	7,371	7,375	7,398	7,417	7,407	0.1%
				0.0%	0.6%	0.2%	0.1%	0.4%	-0.7%	0.1%	0.3%	0.3%	-0.1%	
PS	6,409	6,409	6,530	6,533	6,524	6,520	6,516	6,515	6,486	6,455	6,431	6,411	6,393	(0.2%)
				0.0%	-0.1%	-0.1%	-0.1%	-0.0%	-0.4%	-0.5%	-0.4%	-0.3%	-0.3%	
RECO	209	209	214	220	225	231	236	240	244	246	247	249	249	1.5%
				2.8%	2.3%	2.7%	2.2%	1.7%	1.7%	0.8%	0.4%	0.8%	0.0%	
UGI	199	199	198	198	197	197	197	196	195	194	193	193	192	(0.3%)
				0.0%	-0.5%	0.0%	0.0%	-0.5%	-0.5%	-0.5%	-0.5%	0.0%	-0.5%	
DIVERSITY - MID-ATLANTIC(-)			868	754	981	916	912	777	875	910	949	872	769	
PJM MID-ATLANTIC	44,184	44,184	45,475	45,709	45,516	45,680	45,763	46,132	45,789	45,707	45,668	45,886	45,851	0.1%
				0.5%	-0.4%	0.4%	0.2%	0.8%	-0.7%	-0.2%	-0.1%	0.5%	-0.1%	
FE-EAST	8,746	8,746	9,180	9,202	9,209	9,257	9,285	9,319	9,303	9,279	9,291	9,322	9,305	0.1%
				0.2%	0.1%	0.5%	0.3%	0.4%	-0.2%	-0.3%	0.1%	0.3%	-0.2%	
PLGRP	7,501	7,501	7,525	7,524	7,570	7,584	7,592	7,617	7,556	7,569	7,589	7,608	7,594	0.1%
				-0.0%	0.6%	0.2%	0.1%	0.3%	-0.8%	0.2%	0.3%	0.3%	-0.2%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022/23).
Winter season indicates peak from December, January, February.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2033/34 - 2037/38

	33/34	34/35	35/36	36/37	37/38	Annual Growth Rate (15 yr)
AE	1,553	1,548	1,545	1,544	1,546	(0.2%)
	-0.5%	-0.3%	-0.2%	-0.1%	0.1%	
BGE	5,667	5,656	5,660	5,641	5,646	(0.1%)
	-0.2%	-0.2%	0.1%	-0.3%	0.1%	
DPL	3,684	3,695	3,697	3,707	3,717	0.2%
	-0.2%	0.3%	0.1%	0.3%	0.3%	
JCPL	3,851	3,844	3,849	3,862	3,881	0.2%
	-0.3%	-0.2%	0.1%	0.3%	0.5%	
METED	2,766	2,771	2,791	2,786	2,795	0.2%
	-0.2%	0.2%	0.7%	-0.2%	0.3%	
PECO	6,521	6,524	6,588	6,544	6,554	0.1%
	-0.1%	0.0%	1.0%	-0.7%	0.2%	
PENLC	2,737	2,727	2,734	2,717	2,714	(0.3%)
	-0.5%	-0.4%	0.3%	-0.6%	-0.1%	
PEPCO	5,542	5,561	5,596	5,598	5,617	0.3%
	0.2%	0.3%	0.6%	0.0%	0.3%	
PL	7,376	7,372	7,382	7,405	7,418	0.1%
	-0.4%	-0.1%	0.1%	0.3%	0.2%	
PS	6,364	6,335	6,324	6,328	6,322	(0.2%)
	-0.5%	-0.5%	-0.2%	0.1%	-0.1%	
RECO	249	249	251	254	256	1.2%
	0.0%	0.0%	0.8%	1.2%	0.8%	
UGI	191	190	189	189	189	(0.3%)
	-0.5%	-0.5%	-0.5%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)	902	933	957	897	923	
PJM MID-ATLANTIC	45,599	45,539	45,649	45,678	45,732	0.0%
	-0.5%	-0.1%	0.2%	0.1%	0.1%	
FE-EAST	9,283	9,275	9,293	9,306	9,335	0.1%
	-0.2%	-0.1%	0.2%	0.1%	0.3%	
PLGRP	7,560	7,552	7,565	7,594	7,607	0.1%
	-0.4%	-0.1%	0.2%	0.4%	0.2%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022/23).
Winter season indicates peak from December, January, February.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2022/23 - 2032/33

	METERED 21/22	UNRESTRICTED 21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	Annual Growth Rate (10 yr)
AEP	21,362	21,362	22,308	22,615	22,623	22,659	22,658	22,746	22,735	22,723	22,695	22,715	22,663	0.2%
				1.4%	0.0%	0.2%	-0.0%	0.4%	-0.0%	-0.1%	-0.1%	0.1%	-0.2%	
APS	9,155	9,155	8,993	9,066	9,320	9,600	9,823	10,059	10,013	10,014	10,029	10,086	10,077	1.1%
				0.8%	2.8%	3.0%	2.3%	2.4%	-0.5%	0.0%	0.1%	0.6%	-0.1%	
ATSI	9,803	9,803	9,883	9,901	9,867	9,830	9,827	9,841	9,820	9,780	9,724	9,689	9,629	(0.3%)
				0.2%	-0.3%	-0.4%	-0.0%	0.1%	-0.2%	-0.4%	-0.6%	-0.4%	-0.6%	
COMED	14,262	14,262	14,305	14,360	14,372	14,389	14,483	14,594	14,616	14,625	14,667	14,633	14,573	0.2%
				0.4%	0.1%	0.1%	0.7%	0.8%	0.2%	0.1%	0.3%	-0.2%	-0.4%	
DAYTON	2,900	2,900	2,920	2,916	2,902	2,899	2,903	2,911	2,895	2,881	2,869	2,869	2,870	(0.2%)
				-0.1%	-0.5%	-0.1%	0.1%	0.3%	-0.5%	-0.5%	-0.4%	0.0%	0.0%	
DEOK	4,388	4,388	4,479	4,467	4,463	4,462	4,452	4,466	4,440	4,425	4,408	4,396	4,380	(0.2%)
				-0.3%	-0.1%	-0.0%	-0.2%	0.3%	-0.6%	-0.3%	-0.4%	-0.3%	-0.4%	
DLCO	1,940	1,940	1,996	1,995	1,989	1,986	1,986	1,990	1,980	1,972	1,970	1,969	1,962	(0.2%)
				-0.1%	-0.3%	-0.2%	0.0%	0.2%	-0.5%	-0.4%	-0.1%	-0.1%	-0.4%	
EKPC	2,574	2,574	2,658	2,660	2,662	2,667	2,671	2,689	2,684	2,687	2,689	2,698	2,694	0.1%
				0.1%	0.1%	0.2%	0.1%	0.7%	-0.2%	0.1%	0.1%	0.3%	-0.1%	
OVEC	106	106	110	110	110	110	110	110	110	110	110	110	110	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,797	1,881	1,712	1,631	1,700	1,898	1,766	1,738	1,722	1,799	1,741	
PJM WESTERN	64,470	64,470	65,855	66,209	66,596	66,971	67,213	67,508	67,527	67,479	67,439	67,366	67,217	0.2%
				0.5%	0.6%	0.6%	0.4%	0.4%	0.0%	-0.1%	-0.1%	-0.1%	-0.2%	
DOM	20,229	20,229	21,625	22,480	23,234	24,678	26,122	27,689	28,960	30,362	31,735	33,170	34,488	4.8%
				4.0%	3.4%	6.2%	5.9%	6.0%	4.6%	4.8%	4.5%	4.5%	4.0%	
DIVERSITY - TOTAL(-)			4,809	4,366	4,765	4,782	4,898	4,742	5,010	4,916	4,960	4,715	5,074	
PJM RTO	128,882	128,882	130,811	132,667	133,274	135,094	136,812	139,262	139,907	141,280	142,553	144,378	144,992	1.0%
				1.4%	0.5%	1.4%	1.3%	1.8%	0.5%	1.0%	0.9%	1.3%	0.4%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022/23).
Winter season indicates peak from December, January, February.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO 2033/34 - 2037/38

	33/34	34/35	35/36	36/37	37/38	Annual Growth Rate (15 yr)
AEP	22,695	22,716	22,778	22,761	22,771	0.1%
	0.1%	0.1%	0.3%	-0.1%	0.0%	
APS	10,069	10,081	10,126	10,106	10,131	0.8%
	-0.1%	0.1%	0.4%	-0.2%	0.2%	
ATSI	9,582	9,536	9,501	9,445	9,416	(0.3%)
	-0.5%	-0.5%	-0.4%	-0.6%	-0.3%	
COMED	14,523	14,495	14,509	14,458	14,487	0.1%
	-0.3%	-0.2%	0.1%	-0.4%	0.2%	
DAYTON	2,856	2,849	2,850	2,838	2,839	(0.2%)
	-0.5%	-0.2%	0.0%	-0.4%	0.0%	
DEOK	4,362	4,349	4,349	4,328	4,315	(0.2%)
	-0.4%	-0.3%	0.0%	-0.5%	-0.3%	
DLCO	1,957	1,951	1,952	1,948	1,950	(0.2%)
	-0.3%	-0.3%	0.1%	-0.2%	0.1%	
EKPC	2,697	2,705	2,720	2,717	2,726	0.2%
	0.1%	0.3%	0.6%	-0.1%	0.3%	
OVEC	110	110	110	110	110	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,754	1,738	1,828	1,608	1,635	
PJM WESTERN	67,097	67,054	67,067	67,103	67,110	0.1%
	-0.2%	-0.1%	0.0%	0.1%	0.0%	
DOM	35,702	36,800	37,938	38,983	40,145	4.2%
	3.5%	3.1%	3.1%	2.8%	3.0%	
DIVERSITY - TOTAL(-)	5,076	4,928	4,643	4,890	4,990	
PJM RTO	145,978	147,136	148,796	149,379	150,555	0.9%
	0.7%	0.8%	1.1%	0.4%	0.8%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2022/23).
Winter season indicates peak from December, January, February.

Table B-3

SPRING PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	1,670	1,658	1,649	1,636	1,628	1,632	1,635	1,628	1,614	1,601	1,598	1,594	1,595	1,590	1,587	1,593
BGE	5,154	5,113	5,095	5,087	5,071	5,051	5,039	5,007	4,964	4,943	4,942	4,923	4,927	4,912	4,917	4,911
DPL	3,059	3,047	3,042	3,042	3,045	3,037	3,035	3,034	3,023	3,027	3,033	3,029	3,031	3,002	3,034	3,055
JCPL	4,157	4,144	4,127	4,095	4,082	4,140	4,151	4,127	4,066	4,021	4,058	4,068	4,063	4,048	4,049	4,051
METED	2,464	2,467	2,469	2,479	2,484	2,495	2,504	2,505	2,501	2,508	2,520	2,520	2,527	2,522	2,534	2,543
PECO	6,326	6,344	6,322	6,293	6,281	6,351	6,361	6,369	6,342	6,253	6,340	6,358	6,368	6,362	6,329	6,314
PENLC	2,562	2,550	2,536	2,539	2,535	2,527	2,519	2,505	2,488	2,490	2,492	2,480	2,473	2,458	2,460	2,463
PEPCO	4,943	4,939	4,931	4,942	4,943	4,967	4,971	4,958	4,934	4,923	4,941	4,954	4,969	4,976	5,004	5,032
PL	6,379	6,373	6,350	6,382	6,417	6,408	6,411	6,400	6,359	6,409	6,409	6,402	6,384	6,352	6,385	6,427
PS	7,141	7,110	7,069	7,019	6,951	7,037	7,028	6,995	6,913	6,834	6,861	6,844	6,849	6,816	6,794	6,811
RECO	292	294	294	294	295	299	300	301	300	298	298	299	299	299	299	299
UGI	168	168	166	167	166	166	165	164	163	163	163	162	161	160	160	161
DIVERSITY - MID-ATLANTIC(-)	2,147	2,090	2,180	2,190	2,041	2,078	2,109	2,149	2,252	2,138	2,065	2,068	2,122	2,157	2,078	2,121
PJM MID-ATLANTIC	42,168	42,117	41,870	41,785	41,857	42,032	42,010	41,844	41,415	41,332	41,590	41,565	41,524	41,340	41,474	41,539
FE-EAST	8,661	8,670	8,672	8,670	8,683	8,725	8,729	8,698	8,668	8,634	8,697	8,685	8,674	8,635	8,673	8,701
PLGRP	6,543	6,537	6,513	6,544	6,577	6,571	6,573	6,561	6,516	6,568	6,570	6,560	6,543	6,508	6,544	6,585

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.

Table B-3

SPRING PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AEP	19,883	20,065	20,052	20,079	20,149	20,180	20,215	20,177	20,086	20,139	20,195	20,195	20,258	20,169	20,215	20,310
APS	7,854	7,859	8,212	8,455	8,696	8,810	8,818	8,820	8,792	8,840	8,839	8,835	8,844	8,793	8,836	8,885
ATSI	9,450	9,414	9,342	9,289	9,281	9,334	9,339	9,291	9,201	9,118	9,127	9,109	9,069	8,989	8,950	8,917
COMED	14,499	14,448	14,252	14,160	14,156	14,405	14,493	14,456	14,215	14,099	14,193	14,181	14,185	14,077	14,014	14,004
DAYTON	2,662	2,655	2,632	2,625	2,621	2,652	2,647	2,634	2,608	2,593	2,621	2,622	2,619	2,594	2,591	2,592
DEOK	4,255	4,239	4,201	4,184	4,164	4,217	4,202	4,180	4,133	4,092	4,125	4,123	4,113	4,081	4,072	4,043
DLCO	2,152	2,151	2,128	2,119	2,108	2,137	2,141	2,136	2,109	2,091	2,107	2,107	2,117	2,095	2,088	2,088
EKPC	2,098	2,105	2,116	2,122	2,129	2,152	2,138	2,148	2,151	2,155	2,159	2,165	2,164	2,176	2,183	2,195
OVEC	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
DIVERSITY - WESTERN(-)	2,395	2,544	2,443	2,346	2,369	2,421	2,497	2,663	2,550	2,548	2,431	2,402	2,424	2,472	2,381	2,501
PJM WESTERN	60,548	60,482	60,582	60,777	61,025	61,556	61,586	61,269	60,835	60,669	61,025	61,025	61,035	60,592	60,658	60,623
DOM	18,943	19,761	20,568	22,104	23,551	25,122	26,499	27,847	29,146	30,447	31,753	32,951	34,091	35,085	36,114	37,202
DIVERSITY - TOTAL(-)	6,817	6,820	6,673	6,521	6,508	7,028	7,046	7,031	6,751	6,794	6,771	6,925	7,026	6,880	6,845	6,752
PJM RTO	119,384	120,174	120,970	122,681	124,335	126,181	127,655	128,741	129,447	130,340	132,093	133,086	134,170	134,766	135,860	137,234

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.

Table B-4

FALL PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	1,971	1,975	1,977	1,967	1,957	1,935	1,928	1,926	1,929	1,916	1,908	1,895	1,884	1,898	1,894	1,897
BGE	5,344	5,332	5,336	5,327	5,298	5,265	5,242	5,216	5,190	5,160	5,133	5,112	5,099	5,108	5,112	5,108
DPL	3,132	3,109	3,118	3,104	3,096	3,085	3,065	3,055	3,041	3,031	3,017	2,988	2,995	3,019	3,027	3,026
JCPL	4,684	4,698	4,724	4,720	4,703	4,667	4,659	4,665	4,664	4,653	4,617	4,599	4,596	4,649	4,663	4,675
METED	2,543	2,564	2,577	2,587	2,589	2,585	2,594	2,606	2,616	2,621	2,619	2,619	2,625	2,654	2,667	2,677
PECO	6,932	6,978	7,005	7,016	7,006	6,976	6,981	7,026	7,043	7,038	7,021	7,010	7,012	7,090	7,112	7,109
PENLC	2,522	2,510	2,513	2,517	2,511	2,496	2,481	2,481	2,480	2,480	2,472	2,458	2,443	2,459	2,460	2,459
PEPCO	5,198	5,222	5,262	5,282	5,289	5,285	5,276	5,293	5,292	5,266	5,261	5,264	5,280	5,316	5,348	5,377
PL	6,205	6,207	6,240	6,268	6,266	6,251	6,247	6,253	6,267	6,284	6,275	6,266	6,253	6,294	6,342	6,363
PS	8,000	8,009	8,029	8,013	7,959	7,897	7,844	7,871	7,884	7,862	7,799	7,745	7,722	7,797	7,820	7,829
RECO	319	324	329	331	331	329	329	333	334	332	330	327	326	333	335	337
UGI	165	164	164	165	164	163	162	161	161	161	160	159	159	158	159	158
DIVERSITY - MID-ATLANTIC(-)	1,247	1,046	1,044	1,035	1,069	1,227	1,138	1,178	1,236	1,327	1,301	1,373	1,370	1,252	1,295	1,309
PJM MID-ATLANTIC	45,768	46,046	46,230	46,262	46,100	45,707	45,670	45,708	45,665	45,477	45,311	45,069	45,024	45,523	45,644	45,706
FE-EAST	9,482	9,580	9,649	9,663	9,604	9,485	9,490	9,549	9,568	9,525	9,469	9,426	9,423	9,535	9,567	9,578
PLGRP	6,365	6,369	6,401	6,428	6,423	6,409	6,407	6,411	6,423	6,438	6,432	6,419	6,410	6,448	6,496	6,515

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Fall season indicates peak from September, October, November.

Table B-4

FALL PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AEP	20,233	20,405	20,567	20,610	20,595	20,551	20,446	20,493	20,627	20,558	20,584	20,580	20,491	20,743	20,805	20,783
APS	7,676	7,839	8,171	8,388	8,589	8,607	8,592	8,592	8,606	8,609	8,604	8,598	8,575	8,609	8,641	8,653
ATSI	10,270	10,233	10,361	10,331	10,325	10,168	10,142	10,107	10,209	10,163	10,050	9,929	9,891	10,028	10,010	9,986
COMED	17,269	17,139	17,158	17,257	17,178	17,034	16,931	16,906	16,907	16,865	16,751	16,695	16,503	16,724	16,790	16,812
DAYTON	2,885	2,883	2,908	2,915	2,912	2,880	2,849	2,871	2,888	2,888	2,879	2,861	2,830	2,891	2,903	2,901
DEOK	4,689	4,677	4,704	4,697	4,682	4,656	4,617	4,620	4,629	4,601	4,588	4,565	4,541	4,585	4,577	4,567
DLCO	2,347	2,348	2,357	2,360	2,355	2,341	2,334	2,335	2,342	2,342	2,332	2,320	2,316	2,335	2,339	2,343
EKPC	1,980	1,965	1,975	1,992	2,009	2,026	2,031	2,007	2,012	2,032	2,047	2,057	2,064	2,047	2,059	2,074
OVEC	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
DIVERSITY - WESTERN(-)	1,870	2,073	2,076	1,923	2,097	1,864	2,020	2,003	2,149	2,036	2,065	2,077	2,122	2,266	2,232	2,221
PJM WESTERN	65,559	65,496	66,205	66,707	66,628	66,479	66,002	66,008	66,151	66,102	65,850	65,608	65,169	65,776	65,972	65,978
DOM	19,468	20,316	21,343	23,177	24,794	26,321	27,795	29,213	30,775	32,146	33,481	34,689	35,823	37,018	38,240	39,575
DIVERSITY - TOTAL(-)	6,155	6,193	5,992	5,945	5,758	6,089	6,397	6,364	6,262	6,073	6,401	6,680	6,758	6,674	6,612	6,561
PJM RTO	127,757	128,784	130,906	133,159	134,930	135,509	136,228	137,746	139,714	141,015	141,607	142,136	142,750	145,161	146,771	148,228

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Fall season indicates peak from September, October, November.

Table B-5

MONTHLY PEAK FORECAST SCALED to SEASONAL PEAK (MW) FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC DIVERSITY	PJM MID-ATLANTIC
Jan 2023	1,590	5,755	3,623	3,740	2,696	6,459	2,823	5,381	7,334	6,530	214	198	868	45,475
Feb 2023	1,494	5,415	3,413	3,494	2,560	6,052	2,691	4,985	7,008	6,164	201	186	552	43,111
Mar 2023	1,354	4,970	3,059	3,167	2,439	5,501	2,562	4,594	6,379	5,707	186	168	610	39,476
Apr 2023	1,246	4,151	2,426	2,883	2,152	4,946	2,309	3,909	5,414	5,234	186	142	1,011	33,987
May 2023	1,670	5,154	2,953	4,157	2,464	6,326	2,345	4,943	5,708	7,141	292	146	1,131	42,168
Jun 2023	2,283	6,088	3,581	5,724	2,901	8,171	2,743	5,717	6,771	9,391	403	181	1,691	52,263
Jul 2023	2,549	6,474	3,861	6,072	3,040	8,527	2,871	6,166	7,175	9,904	414	195	1,512	55,736
Aug 2023	2,414	6,324	3,738	5,797	2,960	8,110	2,730	6,005	6,866	9,481	395	181	1,550	53,451
Sep 2023	1,971	5,344	3,132	4,684	2,543	6,932	2,522	5,198	6,205	8,000	319	165	1,247	45,768
Oct 2023	1,419	4,068	2,385	3,216	2,084	5,131	2,285	3,981	5,298	5,891	209	143	1,194	34,916
Nov 2023	1,340	4,351	2,659	3,187	2,254	5,298	2,459	4,111	5,951	5,680	196	165	619	37,032
Dec 2023	1,532	5,177	3,240	3,654	2,567	6,105	2,675	4,856	6,767	6,324	216	188	196	43,105

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2024	1,585	5,747	3,632	3,752	2,718	6,512	2,824	5,408	7,334	6,533	220	198	754	45,709
Feb 2024	1,509	5,458	3,460	3,548	2,632	6,227	2,745	5,057	7,080	6,219	208	188	400	43,931
Mar 2024	1,347	4,948	3,047	3,178	2,434	5,473	2,550	4,556	6,373	5,701	191	168	529	39,437
Apr 2024	1,250	4,188	2,493	2,932	2,201	4,972	2,336	3,975	5,533	5,269	191	144	747	34,737
May 2024	1,658	5,113	2,934	4,144	2,467	6,344	2,337	4,939	5,750	7,110	294	146	1,119	42,117
Jun 2024	2,251	6,005	3,534	5,624	2,879	8,076	2,705	5,663	6,716	9,198	401	179	1,890	51,341
Jul 2024	2,526	6,428	3,841	6,032	3,041	8,522	2,858	6,164	7,181	9,824	415	194	1,576	55,450
Aug 2024	2,398	6,277	3,711	5,749	2,957	8,085	2,706	5,970	6,848	9,413	395	180	1,630	53,059
Sep 2024	1,975	5,332	3,109	4,698	2,564	6,978	2,510	5,222	6,207	8,009	324	164	1,046	46,046
Oct 2024	1,422	4,107	2,391	3,264	2,101	5,215	2,275	4,084	5,308	5,931	217	142	1,265	35,192
Nov 2024	1,326	4,314	2,620	3,164	2,225	5,223	2,424	4,082	5,892	5,633	199	161	607	36,656
Dec 2024	1,533	5,190	3,242	3,688	2,554	6,095	2,664	4,884	6,821	6,341	222	189	405	43,018

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2025	1,582	5,753	3,636	3,776	2,712	6,484	2,809	5,422	7,377	6,524	225	197	981	45,516
Feb 2025	1,488	5,411	3,407	3,520	2,566	6,050	2,671	5,040	6,994	6,150	211	185	693	43,000
Mar 2025	1,349	4,968	3,042	3,228	2,457	5,477	2,536	4,547	6,350	5,683	198	166	476	39,525
Apr 2025	1,250	4,208	2,482	2,984	2,230	4,987	2,325	4,003	5,535	5,264	196	143	659	34,948
May 2025	1,649	5,095	2,885	4,127	2,469	6,322	2,304	4,931	5,653	7,069	294	144	1,072	41,870
Jun 2025	2,250	5,992	3,530	5,622	2,905	8,119	2,716	5,713	6,747	9,215	404	180	1,626	51,767
Jul 2025	2,516	6,406	3,823	6,025	3,058	8,533	2,863	6,194	7,212	9,795	417	194	1,617	55,419
Aug 2025	2,395	6,244	3,682	5,725	2,967	8,085	2,705	5,998	6,845	9,396	397	180	1,643	52,976
Sep 2025	1,977	5,336	3,118	4,724	2,577	7,005	2,513	5,262	6,240	8,029	329	164	1,044	46,230
Oct 2025	1,424	4,104	2,379	3,295	2,105	5,223	2,261	4,106	5,314	5,925	219	141	1,198	35,298
Nov 2025	1,325	4,331	2,620	3,192	2,220	5,233	2,404	4,101	5,880	5,627	204	160	720	36,577
Dec 2025	1,537	5,215	3,262	3,747	2,574	6,117	2,662	4,945	6,855	6,352	229	189	435	43,249

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-5

MONTHLY PEAK FORECAST SCALED to SEASONAL PEAK (MW) FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

										WESTERN	PJM		TOTAL	
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2023	22,308	8,993	9,883	14,305	2,920	4,479	1,996	2,658	100	1,787	65,855	21,625	4,799	130,811
Feb 2023	21,218	8,541	9,446	13,582	2,753	4,190	1,895	2,424	110	1,699	62,460	20,035	4,781	123,076
Mar 2023	19,883	7,854	8,910	12,206	2,554	3,798	1,764	2,098	90	-521	59,678	18,909	968	117,184
Apr 2023	17,242	6,671	8,061	11,192	2,250	3,372	1,641	1,655	80	-176	52,340	16,189	2,224	101,127
May 2023	18,900	7,160	9,450	14,499	2,662	4,255	2,152	1,621	70	221	60,548	18,943	3,627	119,384
Jun 2023	21,421	8,360	11,577	19,756	3,152	5,016	2,611	1,916	75	2,071	71,813	20,839	8,212	140,465
Jul 2023	22,453	8,724	11,962	20,417	3,295	5,249	2,712	2,027	95	1,581	75,353	21,920	7,043	149,059
Aug 2023	22,057	8,640	11,764	20,384	3,266	5,216	2,684	2,004	75	1,984	74,106	21,365	6,227	146,229
Sep 2023	20,233	7,676	10,270	17,269	2,885	4,689	2,347	1,792	70	1,672	65,559	19,468	5,957	127,757
Oct 2023	16,839	6,545	7,990	12,344	2,268	3,611	1,737	1,595	70	2,023	50,976	16,285	5,213	100,181
Nov 2023	18,422	7,360	8,543	12,162	2,405	3,585	1,735	1,980	80	1,379	54,893	17,746	3,902	107,767
Dec 2023	20,589	8,256	9,485	13,849	2,677	4,104	1,919	2,353	90	1,870	61,452	20,154	4,459	122,318
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2024	22,615	9,066	9,901	14,360	2,916	4,467	1,995	2,660	100	1,871	66,209	22,480	4,356	132,667
Feb 2024	21,851	8,755	9,625	13,842	2,794	4,244	1,921	2,463	110	1,838	63,767	21,081	4,380	126,637
Mar 2024	20,065	7,859	8,858	12,202	2,547	3,794	1,758	2,105	90	-252	59,530	19,582	1,171	117,655
Apr 2024	17,760	6,781	8,110	11,255	2,280	3,416	1,650	1,697	80	152	52,877	17,107	2,412	103,208
May 2024	19,085	7,156	9,414	14,448	2,655	4,239	2,151	1,612	70	348	60,482	19,761	3,653	120,174
Jun 2024	21,393	8,305	11,359	19,329	3,083	4,951	2,587	1,913	75	1,938	71,057	21,705	7,598	140,333
Jul 2024	22,637	8,783	11,929	20,246	3,281	5,238	2,710	2,036	95	1,555	75,400	22,828	7,072	149,737
Aug 2024	22,137	8,665	11,684	20,179	3,217	5,183	2,670	2,006	75	1,835	73,981	22,266	7,324	145,447
Sep 2024	20,405	7,839	10,233	17,139	2,883	4,677	2,348	1,807	70	1,905	65,496	20,316	6,025	128,784
Oct 2024	17,065	6,751	8,033	12,441	2,278	3,632	1,741	1,620	70	2,113	51,518	17,195	5,222	102,061
Nov 2024	18,508	7,500	8,463	12,183	2,379	3,534	1,707	1,965	80	1,383	54,936	18,466	4,058	107,990
Dec 2024	20,749	8,491	9,509	13,918	2,668	4,108	1,921	2,361	90	1,459	62,356	21,068	4,460	123,846
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2025	22,623	9,320	9,867	14,372	2,902	4,463	1,989	2,662	100	1,702	66,596	23,234	4,755	133,274
Feb 2025	21,452	8,899	9,401	13,634	2,737	4,175	1,882	2,431	110	1,834	62,887	21,518	4,669	125,263
Mar 2025	20,052	8,212	8,852	12,249	2,536	3,777	1,755	2,116	90	-433	60,072	20,452	461	119,631
Apr 2025	17,776	7,155	8,085	11,282	2,277	3,412	1,648	1,710	80	-143	53,568	18,013	1,491	105,554
May 2025	19,014	7,475	9,342	14,252	2,632	4,201	2,128	1,617	70	149	60,582	20,568	3,271	120,970
Jun 2025	21,531	8,654	11,391	19,303	3,090	4,949	2,598	1,931	75	1,877	71,645	22,623	7,381	142,157
Jul 2025	22,686	9,112	11,892	20,206	3,284	5,239	2,712	2,049	95	1,598	75,677	23,758	7,145	150,924
Aug 2025	22,155	8,974	11,574	19,944	3,202	5,159	2,668	2,018	75	1,596	74,173	23,198	6,890	146,696
Sep 2025	20,567	8,171	10,361	17,158	2,908	4,704	2,357	1,827	70	1,918	66,205	21,343	5,834	130,906
Oct 2025	17,109	7,045	7,951	12,437	2,279	3,620	1,741	1,633	70	2,040	51,845	18,207	5,086	103,502
Nov 2025	18,555	7,769	8,371	12,147	2,376	3,522	1,705	1,975	80	1,323	55,177	19,384	4,037	109,144
Dec 2025	20,847	8,818	9,481	13,965	2,674	4,112	1,923	2,374	90	1,411	62,873	22,248	4,510	125,706

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-6

MONTHLY PEAK FORECAST SCALED to SEASONAL PEAK (MW) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2023	9,180	7,525
Feb 2023	8,645	7,188
Mar 2023	8,006	6,543
Apr 2023	7,153	5,553
May 2023	8,661	5,854
Jun 2023	11,079	6,951
Jul 2023	11,696	7,370
Aug 2023	11,243	7,047
Sep 2023	9,482	6,365
Oct 2023	7,336	5,436
Nov 2023	7,806	6,114
Dec 2023	8,822	6,946

	FE_EAST	PLGRP
Jan 2024	9,202	7,524
Feb 2024	8,823	7,275
Mar 2024	7,986	6,537
Apr 2024	7,242	5,672
May 2024	8,670	5,889
Jun 2024	10,925	6,894
Jul 2024	11,673	7,379
Aug 2024	11,202	7,030
Sep 2024	9,580	6,369
Oct 2024	7,399	5,445
Nov 2024	7,721	6,041
Dec 2024	8,859	7,007

	FE_EAST	PLGRP
Jan 2025	9,209	7,570
Feb 2025	8,685	7,174
Mar 2025	8,097	6,513
Apr 2025	7,346	5,674
May 2025	8,672	5,795
Jun 2025	10,989	6,926
Jul 2025	11,686	7,407
Aug 2025	11,198	7,024
Sep 2025	9,649	6,401
Oct 2025	7,445	5,449
Nov 2025	7,750	6,033
Dec 2025	8,917	7,044

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
FE_EAST contains JCPL, METED and PENLC zones. PLGRP contains PL and UGI zones.

Table B-7

PJM MID-ATLANTIC REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
AE																
CAPACITY PERFORMANCE	39	38	38	38	38	38	37	37	37	37	37	36	36	36	36	36
SUMMER PERIOD	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	47	46	46	46	46	46	45	45	45	45	45	44	44	44	44	44
BGE																
CAPACITY PERFORMANCE	83	82	82	81	81	80	80	79	79	78	77	77	76	76	76	76
SUMMER PERIOD	77	77	77	76	76	75	75	74	74	73	72	72	71	71	71	71
PRD	87	132	132	131	130	130	128	127	127	125	124	123	123	123	123	123
TOTAL LOAD MANAGEMENT	247	291	291	288	287	285	283	280	280	276	273	272	270	270	270	270
DPL																
CAPACITY PERFORMANCE	82	82	81	81	81	80	80	79	79	78	78	78	78	78	78	78
SUMMER PERIOD	100	99	99	98	98	97	97	96	96	95	95	94	94	94	94	94
PRD	38	50	50	50	50	49	49	49	48	48	48	48	48	48	48	48
TOTAL LOAD MANAGEMENT	220	231	230	229	229	226	226	224	223	221	221	220	220	220	220	220
JCPL																
CAPACITY PERFORMANCE	93	92	92	92	91	91	90	90	89	89	89	89	88	89	89	89
SUMMER PERIOD	8	8	8	8	8	8	8	8	8	8	8	7	7	8	8	8
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	101	100	100	100	99	99	98	98	97	97	97	96	95	97	97	97
METED																
CAPACITY PERFORMANCE	140	140	141	141	142	142	142	142	143	143	143	143	144	144	145	146
SUMMER PERIOD	26	26	26	26	26	26	26	26	26	26	26	26	26	26	27	28
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	166	166	167	167	168	168	168	168	169	169	169	169	170	170	172	174

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-7 (Continued)

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
PECO																
CAPACITY PERFORMANCE	247	246	247	247	247	248	248	248	248	248	248	248	248	249	250	251
SUMMER PERIOD	27	27	27	27	27	28	27	27	28	28	28	28	28	28	28	28
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	274	273	274	274	274	276	275	275	276	276	276	276	276	277	278	279
PENLC																
CAPACITY PERFORMANCE	149	148	149	148	148	147	146	146	146	145	145	144	144	144	144	144
SUMMER PERIOD	81	81	81	81	80	80	80	80	79	79	79	78	78	78	78	78
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	230	229	230	229	228	227	226	226	225	224	224	222	222	222	222	222
PEPCO																
CAPACITY PERFORMANCE	91	91	92	92	92	92	92	92	92	92	92	92	92	93	93	93
SUMMER PERIOD	139	139	139	140	140	140	140	140	140	139	139	139	139	140	141	142
PRD	110	140	141	141	141	141	141	141	141	141	141	141	141	142	142	142
TOTAL LOAD MANAGEMENT	340	370	372	373	373	373	373	373	373	372	372	372	372	375	376	377
PL																
CAPACITY PERFORMANCE	320	321	322	323	322	322	322	322	323	323	323	323	323	325	326	327
SUMMER PERIOD	115	115	115	116	116	116	115	115	116	116	116	116	116	116	117	118
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	435	436	437	439	438	438	437	437	439	439	439	439	439	441	443	445
PS																
CAPACITY PERFORMANCE	134	133	133	133	132	131	131	130	130	129	129	129	127	128	129	130
SUMMER PERIOD	72	72	71	71	71	71	70	70	70	69	69	69	68	69	69	69
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	206	205	204	204	203	202	201	200	200	198	198	198	195	197	198	199

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-7 (Continued)

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
RECO																
CAPACITY PERFORMANCE	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UGI																
CAPACITY PERFORMANCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
CAPACITY PERFORMANCE	1,380	1,375	1,379	1,378	1,376	1,373	1,370	1,367	1,368	1,364	1,363	1,361	1,358	1,364	1,368	1,372
SUMMER PERIOD	653	652	651	651	650	649	646	644	645	641	640	637	635	638	641	644
PRD	235	322	323	322	321	320	318	317	316	314	313	312	312	313	313	313
TOTAL LOAD MANAGEMENT	2,268	2,349	2,353	2,351	2,347	2,342	2,334	2,328	2,329	2,319	2,316	2,310	2,305	2,315	2,322	2,329

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AEP																
CAPACITY PERFORMANCE	854	861	863	864	864	864	863	863	862	861	861	862	864	866	868	870
SUMMER PERIOD	288	290	291	291	291	291	291	291	291	290	290	291	291	292	293	294
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,142	1,151	1,154	1,155	1,155	1,155	1,154	1,154	1,153	1,151	1,151	1,153	1,155	1,158	1,161	1,164
APS																
CAPACITY PERFORMANCE	418	421	436	445	454	458	457	457	456	455	454	454	454	455	455	455
SUMMER PERIOD	125	126	131	134	136	137	137	137	137	136	136	136	136	137	137	137
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	543	547	567	579	590	595	594	594	593	591	590	590	590	592	592	592
ATSI																
CAPACITY PERFORMANCE	540	538	537	535	534	534	533	531	528	525	523	521	520	519	518	517
SUMMER PERIOD	161	160	160	159	159	159	158	158	157	156	156	155	154	154	154	154
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	701	698	697	694	693	693	691	689	685	681	679	676	674	673	672	671
COMED																
CAPACITY PERFORMANCE	1,023	1,014	1,012	1,010	1,010	1,007	1,001	996	991	987	981	978	974	975	976	977
SUMMER PERIOD	328	326	325	324	324	323	321	320	318	317	315	314	313	313	313	313
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,351	1,340	1,337	1,334	1,334	1,330	1,322	1,316	1,309	1,304	1,296	1,292	1,287	1,288	1,289	1,290
DAYTON																
CAPACITY PERFORMANCE	106	106	106	106	106	106	106	106	105	105	105	105	105	105	106	107
SUMMER PERIOD	58	58	58	58	58	58	58	58	57	57	57	57	57	57	58	59
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	164	164	164	164	164	164	164	164	162	162	162	162	162	162	164	166

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
DEOK																
CAPACITY PERFORMANCE	113	113	113	113	113	112	112	112	111	111	110	110	110	110	110	110
SUMMER PERIOD	40	40	40	40	40	40	40	40	40	39	39	39	39	39	39	39
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	153	153	153	153	153	152	152	152	151	150	149	149	149	149	149	149
DLCO																
CAPACITY PERFORMANCE	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
SUMMER PERIOD	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
EKPC																
CAPACITY PERFORMANCE	94	95	96	96	96	96	96	97	97	97	97	97	98	98	99	100
SUMMER PERIOD	80	80	81	81	81	81	81	81	82	82	82	82	82	83	83	83
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	174	175	177	177	177	177	177	178	179	179	179	179	180	181	182	183
PJM WESTERN																
CAPACITY PERFORMANCE	3,208	3,208	3,223	3,229	3,237	3,237	3,228	3,222	3,210	3,201	3,191	3,187	3,185	3,188	3,192	3,196
SUMMER PERIOD	1,108	1,108	1,114	1,115	1,117	1,117	1,114	1,113	1,110	1,105	1,103	1,102	1,100	1,103	1,105	1,107
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	4,316	4,316	4,337	4,344	4,354	4,354	4,342	4,335	4,320	4,306	4,294	4,289	4,285	4,291	4,297	4,303

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
DOM																
CAPACITY PERFORMANCE	601	625	651	700	744	786	828	867	906	944	980	1,013	1,044	1,075	1,108	1,142
SUMMER PERIOD	103	107	112	120	128	135	142	149	155	162	168	174	179	185	190	195
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	704	732	763	820	872	921	970	1,016	1,061	1,106	1,148	1,187	1,223	1,260	1,298	1,337
PJM RTO																
CAPACITY PERFORMANCE	5,189	5,208	5,253	5,307	5,357	5,396	5,426	5,456	5,484	5,509	5,534	5,561	5,587	5,627	5,668	5,709
SUMMER PERIOD	1,864	1,867	1,877	1,886	1,895	1,901	1,902	1,906	1,910	1,908	1,911	1,913	1,914	1,926	1,936	1,946
PRD	235	322	323	322	321	320	318	317	316	314	313	312	312	313	313	313
TOTAL LOAD MANAGEMENT	7,288	7,397	7,453	7,515	7,573	7,617	7,646	7,679	7,710	7,731	7,758	7,786	7,813	7,866	7,917	7,968

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2020/21, 2021/22, 2022/23; forecast values for PRD are based on actual cleared quantities in the 2021/22, 2022/23 and 2023/24 RPM Base Residual Auctions

Table B-8a

DISTRIBUTED SOLAR ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO

2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	136	125	117	109	109	113	111	111	106	100	97	95	96	89	86	85
BGE	194	211	223	242	250	267	286	290	273	256	249	243	239	233	223	220
DPL	103	112	121	125	129	126	125	133	136	130	124	123	116	110	107	102
JCPL	261	271	281	289	300	305	304	308	317	329	329	328	326	332	327	318
METED	46	51	53	55	58	61	64	66	69	72	74	76	79	78	79	80
PECO	68	84	92	99	109	121	133	144	157	169	177	185	196	203	210	216
PENLC	19	28	33	37	43	49	56	62	67	73	77	81	84	85	87	88
PEPCO	214	229	249	263	280	294	304	298	289	279	282	287	289	283	278	283
PL	114	128	133	138	147	153	161	171	178	186	193	198	206	211	218	220
PS	392	408	418	423	424	404	415	406	413	372	365	364	374	360	352	338
RECO	13	14	16	18	18	19	21	22	23	24	25	25	26	26	25	24
UGI	1	1	1	1	1	2	2	2	2	3	3	3	3	3	3	3
AEP	134	180	198	214	233	253	277	297	311	332	343	355	369	370	381	390
APS	86	99	107	112	121	130	137	145	154	166	169	171	174	181	187	187
ATSI	102	133	143	151	160	171	178	185	190	197	205	212	215	217	222	229
COMED	323	412	476	531	557	603	656	701	767	813	836	869	887	899	902	917
DAYTON	26	36	38	39	42	44	47	50	52	53	55	57	59	61	62	64
DEOK	23	35	38	41	45	48	53	58	61	64	67	69	73	76	80	83
DLCO	20	25	27	29	32	36	40	44	48	51	54	56	58	59	61	63
EKPC	5	5	5	6	7	8	9	11	12	13	14	15	16	17	19	20
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	527	536	539	565	578	610	634	671	698	699	718	750	768	795	795	823
PJM RTO	2,888	3,269	3,566	3,841	4,035	4,185	4,362	4,467	4,626	4,613	4,610	4,600	4,685	4,611	4,547	4,614

Notes:
Adjustment values presented here are average summer peak distribution forecast values.

Table B-8b

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO

2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	5	10	17	24	29	32	35	37	38	39	38	37	36	38	40	42
BGE	9	21	35	49	61	72	79	85	91	94	95	93	91	97	102	108
DPL	2	4	7	9	11	13	15	16	17	17	18	18	18	19	21	22
JCPL	17	37	61	84	104	120	134	142	149	151	151	149	144	153	162	170
METED	1	2	2	3	4	4	5	5	5	6	6	6	6	7	7	8
PECO	3	6	9	11	13	15	17	19	20	21	22	22	23	25	27	29
PENLC	1	1	2	3	3	4	4	5	5	6	6	6	7	7	8	8
PEPCO	13	29	49	68	85	102	117	131	144	155	162	166	169	182	191	200
PL	1	2	3	4	5	5	6	6	7	7	8	8	8	8	9	10
PS	14	31	51	70	87	102	113	120	125	128	129	127	123	131	139	146
RECO	3	6	11	15	19	22	24	26	27	28	28	27	27	29	30	32
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	5	10	16	22	27	31	34	38	40	42	43	43	43	47	51	55
APS	3	7	12	16	20	23	26	28	29	30	30	30	29	32	34	36
ATSI	3	7	10	12	15	17	19	20	22	23	23	24	24	26	28	30
COMED	22	51	87	128	179	233	291	364	386	376	367	353	336	353	368	383
DAYTON	1	1	2	3	3	3	4	4	4	4	5	5	5	5	6	6
DEOK	1	2	3	4	5	6	6	7	7	7	7	7	7	8	9	10
DLCO	1	1	2	3	3	4	4	5	5	5	5	5	5	6	6	7
EKPC	0	1	1	2	2	2	2	3	3	3	3	3	3	3	3	4
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	26	62	107	151	191	223	252	276	291	301	304	301	295	314	333	348
PJM RTO	134	297	486	677	857	1,032	1,184	1,338	1,423	1,462	1,478	1,461	1,415	1,520	1,616	1,697

Notes:
Adjustment values presented here are average summer peak distribution forecast values.

Table B-9

ADJUSTMENTS ABOVE EMBEDDED TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
METED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PENLC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PEPCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PL	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
PS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	90	248	248	248	248	248	248	248	248	248	248	248	248	248	248	248
APS	1	85	409	597	785	856	856	856	856	856	856	856	856	856	856	856
ATSI	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
COMED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DAYTON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DEOK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DLCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EKPC	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8	-8
DOM	2,068	2,988	3,926	5,678	7,196	8,690	10,160	11,586	13,016	14,426	15,717	16,878	17,962	19,030	20,124	21,310
PJM RTO	2,231	3,393	4,654	6,594	8,300	9,866	11,336	12,762	14,192	15,602	16,893	18,054	19,139	20,206	21,300	22,486

Notes:
Adjustment values presented here are reflected in summer peak forecasts.
Adjustments due to NRBTMG (Non-Retail Behind the Meter Generation) transitioning to DR are in AEP, ATSI and PL.
Adjustments due to data center load growth are in AEP, APS, and DOM.
An adjustment due to peak shaving program is in EKPC.
Adjustment shown for DOM is reflective of data center load in addition to what is already embedded.
PJM RTO is sum of adjustments shown.

Table B-10

SUMMER COINCIDENT PEAK LOAD (MW) FOR
EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	2,296	2,268	2,262	2,253	2,241	2,231	2,221	2,210	2,201	2,198	2,194	2,191	2,186	2,186	2,193	2,191
BGE	6,232	6,191	6,179	6,149	6,111	6,065	6,026	5,973	5,930	5,878	5,846	5,818	5,800	5,787	5,778	5,766
DPL	3,637	3,601	3,578	3,559	3,532	3,514	3,497	3,468	3,442	3,418	3,400	3,390	3,394	3,402	3,412	3,410
JCPL	5,692	5,646	5,637	5,621	5,587	5,576	5,554	5,525	5,503	5,482	5,477	5,469	5,465	5,473	5,508	5,515
METED	2,918	2,923	2,932	2,941	2,944	2,948	2,955	2,959	2,963	2,965	2,971	2,979	2,993	3,002	3,017	3,031
PECO	8,037	8,034	8,047	8,047	8,035	8,023	8,015	7,995	7,974	7,945	7,938	7,941	7,969	7,968	7,988	8,009
PENLC	2,745	2,731	2,727	2,723	2,713	2,704	2,695	2,687	2,680	2,676	2,670	2,665	2,663	2,665	2,670	2,673
PEPCO	5,895	5,894	5,914	5,933	5,939	5,947	5,952	5,942	5,936	5,922	5,922	5,938	5,957	5,985	6,011	6,042
PL	6,881	6,878	6,899	6,914	6,909	6,905	6,906	6,907	6,907	6,908	6,916	6,918	6,939	6,956	6,987	7,014
PS	9,335	9,258	9,214	9,163	9,088	9,049	9,000	8,933	8,878	8,832	8,821	8,805	8,800	8,803	8,844	8,847
RECO	388	388	390	392	392	392	392	390	389	387	386	385	384	385	388	390
UGI	184	184	183	183	182	181	180	179	178	178	177	176	176	175	175	175
AEP	21,837	22,007	22,042	22,081	22,106	22,100	22,089	22,058	22,053	22,061	22,052	22,076	22,106	22,197	22,262	22,365
APS	8,531	8,602	8,927	9,124	9,305	9,382	9,374	9,355	9,338	9,332	9,326	9,325	9,324	9,324	9,335	9,360
ATSI	11,591	11,527	11,481	11,450	11,443	11,429	11,389	11,329	11,273	11,249	11,202	11,159	11,113	11,109	11,102	11,103
COMED	18,866	18,790	18,771	18,688	18,670	18,661	18,593	18,560	18,426	18,246	18,137	18,060	17,925	18,020	18,004	18,012
DAYTON	3,104	3,094	3,089	3,094	3,097	3,085	3,077	3,072	3,060	3,069	3,062	3,062	3,062	3,068	3,077	3,095
DEOK	5,001	4,982	4,973	4,968	4,971	4,960	4,946	4,919	4,893	4,886	4,869	4,864	4,859	4,854	4,857	4,871
DLCO	2,635	2,628	2,625	2,624	2,619	2,619	2,616	2,608	2,601	2,599	2,594	2,589	2,586	2,582	2,584	2,595
EKPC	1,919	1,927	1,936	1,944	1,956	1,966	1,972	1,976	1,980	1,988	1,994	2,004	2,012	2,024	2,033	2,047
OVEC	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
DOM	21,274	22,126	23,058	24,823	26,375	27,906	29,414	30,794	32,276	33,641	34,957	36,221	37,367	38,517	39,690	40,998
PJM RTO	149,058	149,739	150,924	152,734	154,275	155,703	156,923	157,899	158,941	159,920	160,971	162,095	163,140	164,542	165,975	167,569
PJM MID-ATLANTIC	54,240	53,996	53,962	53,878	53,673	53,535	53,393	53,168	52,981	52,789	52,718	52,675	52,726	52,787	52,971	53,063
EASTERN MID-ATLANTIC	29,385	29,195	29,128	29,035	28,875	28,785	28,679	28,521	28,387	28,262	28,216	28,181	28,198	28,217	28,333	28,362
SOUTHERN MID-ATLANTIC	12,127	12,085	12,093	12,082	12,050	12,012	11,978	11,915	11,866	11,800	11,768	11,756	11,757	11,772	11,789	11,808

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Load values for Zones and Locational Deliverability Areas are coincident with the PJM RTO peak.
This table will be used for the Reliability Pricing Model.
Summer season indicates peak from June, July, August.

Table B-11

PJM CONTROL AREA - JANUARY 2023
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	125,866	125,684	125,930	125,969	125,944	125,831	125,537	125,129	124,686	124,288	124,020	(0.1%)
% GROWTH TOTAL		-0.1%	0.2%	0.0%	-0.0%	-0.1%	-0.2%	-0.3%	-0.4%	-0.3%	-0.2%	
CONTRACTUALLY INTERRUPTIBLE	6,410	6,490	6,513	6,518	6,524	6,519	6,499	6,485	6,470	6,446	6,431	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,410	6,490	6,513	6,518	6,524	6,519	6,499	6,485	6,470	6,446	6,431	
NET INTERNAL DEMAND	119,456	119,194	119,417	119,451	119,420	119,312	119,038	118,644	118,216	117,842	117,589	(0.2%)
% GROWTH NET		-0.2%	0.2%	0.0%	-0.0%	-0.1%	-0.2%	-0.3%	-0.4%	-0.3%	-0.2%	
PJM - SERC												
TOTAL INTERNAL DEMAND	23,193	24,053	24,994	26,767	28,331	29,872	31,386	32,770	34,256	35,629	36,951	4.8%
% GROWTH TOTAL		3.7%	3.9%	7.1%	5.8%	5.4%	5.1%	4.4%	4.5%	4.0%	3.7%	
CONTRACTUALLY INTERRUPTIBLE	878	907	940	997	1,049	1,098	1,147	1,194	1,240	1,285	1,327	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	878	907	940	997	1,049	1,098	1,147	1,194	1,240	1,285	1,327	
NET INTERNAL DEMAND	22,315	23,146	24,054	25,770	27,282	28,774	30,239	31,576	33,016	34,344	35,624	4.8%
% GROWTH NET		3.7%	3.9%	7.1%	5.9%	5.5%	5.1%	4.4%	4.6%	4.0%	3.7%	
PJM RTO												
TOTAL INTERNAL DEMAND	149,059	149,737	150,924	152,736	154,275	155,703	156,923	157,899	158,942	159,917	160,971	0.8%
% GROWTH TOTAL		0.5%	0.8%	1.2%	1.0%	0.9%	0.8%	0.6%	0.7%	0.6%	0.7%	
CONTRACTUALLY INTERRUPTIBLE	7,288	7,397	7,453	7,515	7,573	7,617	7,646	7,679	7,710	7,731	7,758	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	7,288	7,397	7,453	7,515	7,573	7,617	7,646	7,679	7,710	7,731	7,758	
NET INTERNAL DEMAND	141,771	142,340	143,471	145,221	146,702	148,086	149,277	150,220	151,232	152,186	153,213	0.8%
% GROWTH NET		0.4%	0.8%	1.2%	1.0%	0.9%	0.8%	0.6%	0.7%	0.6%	0.7%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2023).

Table B-11 (Continued)

PJM CONTROL AREA - JANUARY 2023
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2023 - 2038

	2034	2035	2036	2037	2038	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	123,870	123,760	124,000	124,253	124,522	(0.1%)
% GROWTH TOTAL	-0.1%	-0.1%	0.2%	0.2%	0.2%	
CONTRACTUALLY INTERRUPTIBLE	6,420	6,410	6,425	6,437	6,449	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,420	6,410	6,425	6,437	6,449	
NET INTERNAL DEMAND	117,450	117,350	117,575	117,816	118,073	(0.1%)
% GROWTH NET	-0.1%	-0.1%	0.2%	0.2%	0.2%	
PJM - SERC						
TOTAL INTERNAL DEMAND	38,225	39,379	40,541	41,723	43,045	4.2%
% GROWTH TOTAL	3.4%	3.0%	3.0%	2.9%	3.2%	
CONTRACTUALLY INTERRUPTIBLE	1,366	1,403	1,441	1,480	1,520	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	1,366	1,403	1,441	1,480	1,520	
NET INTERNAL DEMAND	36,859	37,976	39,100	40,243	41,525	4.2%
% GROWTH NET	3.5%	3.0%	3.0%	2.9%	3.2%	
PJM RTO						
TOTAL INTERNAL DEMAND	162,095	163,139	164,541	165,976	167,567	0.8%
% GROWTH TOTAL	0.7%	0.6%	0.9%	0.9%	1.0%	
CONTRACTUALLY INTERRUPTIBLE	7,786	7,813	7,866	7,917	7,969	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	7,786	7,813	7,866	7,917	7,969	
NET INTERNAL DEMAND	154,309	155,326	156,675	158,059	159,598	0.8%
% GROWTH NET	0.7%	0.7%	0.9%	0.9%	1.0%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2023).

Table B-12

PJM CONTROL AREA - JANUARY 2023
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2022/23 - 2032/33

	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	125,083	125,731	126,345	128,126	129,824	132,252	132,893	134,272	135,544	137,335	137,947	1.0%
% GROWTH TOTAL		0.5%	0.5%	1.4%	1.3%	1.9%	0.5%	1.0%	0.9%	1.3%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	4,494	4,488	4,506	4,511	4,517	4,514	4,502	4,492	4,481	4,468	4,457	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	4,494	4,488	4,506	4,511	4,517	4,514	4,502	4,492	4,481	4,468	4,457	
NET INTERNAL DEMAND	120,589	121,243	121,839	123,615	125,307	127,738	128,391	129,780	131,063	132,867	133,490	1.0%
% GROWTH NET		0.5%	0.5%	1.5%	1.4%	1.9%	0.5%	1.1%	1.0%	1.4%	0.5%	
PJM - SERC												
TOTAL INTERNAL DEMAND	5,728	6,936	6,929	6,968	6,988	7,010	7,014	7,008	7,009	7,043	7,045	2.1%
% GROWTH TOTAL		21.1%	-0.1%	0.6%	0.3%	0.3%	0.1%	-0.1%	0.0%	0.5%	0.0%	
CONTRACTUALLY INTERRUPTIBLE	695	720	747	796	840	882	924	964	1,003	1,041	1,077	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	695	720	747	796	840	882	924	964	1,003	1,041	1,077	
NET INTERNAL DEMAND	5,033	6,216	6,182	6,172	6,148	6,128	6,090	6,044	6,006	6,002	5,968	1.7%
% GROWTH NET		23.5%	-0.5%	-0.2%	-0.4%	-0.3%	-0.6%	-0.8%	-0.6%	-0.1%	-0.6%	
PJM RTO												
TOTAL INTERNAL DEMAND	130,811	132,667	133,274	135,094	136,812	139,262	139,907	141,280	142,553	144,378	144,992	1.0%
% GROWTH TOTAL		1.4%	0.5%	1.4%	1.3%	1.8%	0.5%	1.0%	0.9%	1.3%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	5,189	5,208	5,253	5,307	5,357	5,396	5,426	5,456	5,484	5,509	5,534	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,189	5,208	5,253	5,307	5,357	5,396	5,426	5,456	5,484	5,509	5,534	
NET INTERNAL DEMAND	125,622	127,459	128,021	129,787	131,455	133,866	134,481	135,824	137,069	138,869	139,458	1.1%
% GROWTH NET		1.5%	0.4%	1.4%	1.3%	1.8%	0.5%	1.0%	0.9%	1.3%	0.4%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2023).

Table B-12 (Continued)

PJM CONTROL AREA - JANUARY 2023
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2022/23 - 2032/33

	33/34	34/35	35/36	36/37	37/38	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	138,920	140,068	141,716	142,273	143,423	0.9%
% GROWTH TOTAL	0.7%	0.8%	1.2%	0.4%	0.8%	
CONTRACTUALLY INTERRUPTIBLE	4,451	4,445	4,454	4,461	4,468	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	4,451	4,445	4,454	4,461	4,468	
NET INTERNAL DEMAND	134,469	135,623	137,262	137,812	138,955	0.9%
% GROWTH NET	0.7%	0.9%	1.2%	0.4%	0.8%	
PJM - SERC						
TOTAL INTERNAL DEMAND	7,058	7,068	7,080	7,106	7,132	1.5%
% GROWTH TOTAL	0.2%	0.1%	0.2%	0.4%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	1,110	1,142	1,173	1,207	1,242	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	1,110	1,142	1,173	1,207	1,242	
NET INTERNAL DEMAND	5,948	5,926	5,907	5,899	5,890	1.1%
% GROWTH NET	-0.3%	-0.4%	-0.3%	-0.1%	-0.2%	
PJM RTO						
TOTAL INTERNAL DEMAND	145,978	147,136	148,796	149,379	150,555	0.9%
% GROWTH TOTAL	0.7%	0.8%	1.1%	0.4%	0.8%	
CONTRACTUALLY INTERRUPTIBLE	5,561	5,587	5,627	5,668	5,710	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,561	5,587	5,627	5,668	5,710	
NET INTERNAL DEMAND	140,417	141,549	143,169	143,711	144,845	1.0%
% GROWTH NET	0.7%	0.8%	1.1%	0.4%	0.8%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2023).

Table C-1

PJM LOCATIONAL DELIVERABILITY AREAS
CENTRAL MID-ATLANTIC: BGE, METED, PEPCO, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	18,699	22,824	19,096	21,205
2024	18,678	22,756	19,177	21,269
2025	18,704	22,793	19,277	21,252
2026	18,739	22,811	19,345	21,322
2027	18,755	22,795	19,301	21,406
2028	18,764	22,749	19,162	21,506
2029	18,779	22,682	19,135	21,441
2030	18,745	22,616	19,205	21,393
2031	18,689	22,557	19,232	21,390
2032	18,702	22,482	19,164	21,445
2033	18,753	22,484	19,096	21,391
2034	18,740	22,438	18,988	21,311
2035	18,752	22,392	19,039	21,304
2036	18,701	22,494	19,150	21,414
2037	18,767	22,544	19,213	21,376
2038	18,819	22,615	19,265	21,492

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	20,504	24,306	21,134	22,732
2024	20,375	24,268	21,067	22,830
2025	20,373	24,388	21,145	22,742
2026	20,471	24,387	21,192	22,819
2027	20,508	24,209	21,176	22,869
2028	20,467	24,128	21,173	23,014
2029	20,446	24,276	20,972	22,877
2030	20,317	24,073	21,043	22,875
2031	20,258	24,223	21,114	22,877
2032	20,368	23,978	21,067	23,010
2033	20,351	23,991	21,056	22,921
2034	20,320	23,991	20,987	22,910
2035	20,293	24,035	20,855	22,901
2036	20,235	24,177	21,061	23,018
2037	20,319	24,230	21,119	22,971
2038	20,364	24,183	21,164	23,008

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-2

PJM LOCATIONAL DELIVERABILITY AREAS
WESTERN MID-ATLANTIC: METED, PENLC, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	11,532	13,162	11,301	12,990
2024	11,499	13,159	11,326	12,995
2025	11,458	13,209	11,373	13,024
2026	11,516	13,259	11,433	13,037
2027	11,569	13,239	11,445	13,033
2028	11,566	13,214	11,373	13,097
2029	11,551	13,218	11,331	13,043
2030	11,521	13,175	11,362	13,032
2031	11,463	13,210	11,401	13,052
2032	11,540	13,235	11,449	13,086
2033	11,548	13,232	11,450	13,049
2034	11,533	13,187	11,393	13,014
2035	11,500	13,202	11,346	13,015
2036	11,440	13,249	11,414	13,026
2037	11,488	13,324	11,523	13,036
2038	11,551	13,323	11,558	13,044

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	12,526	13,796	12,436	13,727
2024	12,497	13,785	12,437	13,720
2025	12,517	13,813	12,485	13,712
2026	12,527	13,839	12,488	13,726
2027	12,545	13,826	12,494	13,737
2028	12,525	13,843	12,481	13,763
2029	12,522	13,850	12,479	13,772
2030	12,503	13,846	12,494	13,759
2031	12,487	13,890	12,508	13,737
2032	12,491	13,859	12,528	13,743
2033	12,499	13,879	12,540	13,744
2034	12,467	13,894	12,535	13,741
2035	12,454	13,881	12,531	13,746
2036	12,445	13,968	12,619	13,749
2037	12,466	14,020	12,650	13,728
2038	12,493	13,999	12,677	13,748

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-3

PJM LOCATIONAL DELIVERABILITY AREAS
EASTERN MID-ATLANTIC: AE, DPL, JCPL, PECO, PS and RECO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	22,004	30,783	24,735	21,821
2024	21,865	30,611	24,793	21,907
2025	21,694	30,563	24,844	21,890
2026	21,474	30,531	24,814	21,932
2027	21,340	30,398	24,697	21,965
2028	21,669	30,271	24,526	22,117
2029	21,599	30,160	24,422	22,000
2030	21,497	30,031	24,450	21,950
2031	21,194	29,970	24,421	21,931
2032	21,065	29,867	24,256	22,030
2033	21,225	29,749	24,132	21,937
2034	21,314	29,659	24,067	21,861
2035	21,291	29,646	24,046	21,804
2036	21,154	29,647	24,210	21,904
2037	21,141	29,809	24,248	21,849
2038	21,211	29,846	24,302	21,914

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	25,170	33,099	27,846	22,992
2024	25,015	32,983	27,776	23,093
2025	24,716	32,952	27,832	23,070
2026	24,447	32,853	27,784	23,114
2027	24,085	32,701	27,691	23,151
2028	24,576	32,516	27,660	23,218
2029	24,631	32,323	27,479	23,162
2030	24,472	32,349	27,451	23,139
2031	24,164	32,307	27,436	23,101
2032	23,764	32,008	27,386	23,105
2033	24,180	31,854	27,323	23,025
2034	24,239	31,808	27,250	22,956
2035	24,317	31,805	27,207	22,929
2036	23,932	31,970	27,334	23,027
2037	23,972	32,030	27,444	22,982
2038	23,826	32,109	27,507	23,040

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-4

PJM LOCATIONAL DELIVERABILITY AREAS
SOUTHERN MID-ATLANTIC: BGE and PEPCO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	9,934	12,595	10,524	11,136
2024	9,881	12,549	10,546	11,132
2025	9,867	12,577	10,598	11,164
2026	9,883	12,551	10,609	11,193
2027	9,885	12,534	10,584	11,228
2028	9,891	12,492	10,517	11,261
2029	9,880	12,444	10,475	11,226
2030	9,860	12,382	10,482	11,215
2031	9,839	12,309	10,448	11,209
2032	9,825	12,281	10,404	11,228
2033	9,822	12,247	10,351	11,209
2034	9,829	12,189	10,343	11,205
2035	9,853	12,160	10,354	11,211
2036	9,857	12,191	10,424	11,248
2037	9,888	12,231	10,460	11,239
2038	9,895	12,270	10,485	11,260

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2023	10,900	13,624	11,609	12,121
2024	10,859	13,555	11,580	12,041
2025	10,841	13,583	11,624	12,048
2026	10,846	13,553	11,636	12,079
2027	10,875	13,522	11,619	12,174
2028	10,909	13,431	11,593	12,215
2029	10,870	13,425	11,540	12,170
2030	10,794	13,347	11,496	12,139
2031	10,745	13,305	11,519	12,123
2032	10,764	13,226	11,484	12,111
2033	10,773	13,200	11,465	12,208
2034	10,781	13,165	11,365	12,200
2035	10,778	13,155	11,367	12,166
2036	10,753	13,208	11,503	12,158
2037	10,760	13,214	11,453	12,147
2038	10,815	13,237	11,499	12,221

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	2,706	2,678	2,665	2,655	2,647	2,635	2,623	2,604	2,590	2,585	2,568	2,556	2,548	2,544	2,545	2,548
BGE	7,109	7,042	7,022	6,988	6,938	6,882	6,813	6,751	6,725	6,669	6,625	6,601	6,575	6,563	6,552	6,546
DPL	4,072	4,046	4,025	4,006	3,990	3,969	3,963	3,945	3,934	3,924	3,913	3,895	3,894	3,900	3,910	3,916
JCPL	6,642	6,608	6,606	6,572	6,543	6,488	6,431	6,408	6,381	6,348	6,331	6,298	6,281	6,294	6,318	6,335
METED	3,201	3,207	3,217	3,225	3,230	3,238	3,245	3,251	3,255	3,259	3,265	3,270	3,277	3,291	3,304	3,320
PECO	9,124	9,123	9,157	9,172	9,150	9,151	9,156	9,157	9,189	9,149	9,144	9,154	9,163	9,212	9,224	9,225
PENLC	2,998	2,988	2,985	2,981	2,969	2,952	2,945	2,939	2,934	2,925	2,915	2,905	2,896	2,913	2,915	2,911
PEPCO	6,588	6,581	6,613	6,621	6,625	6,615	6,632	6,614	6,617	6,600	6,598	6,588	6,619	6,699	6,704	6,731
PL	7,545	7,539	7,570	7,581	7,576	7,579	7,583	7,578	7,590	7,577	7,577	7,579	7,598	7,627	7,647	7,673
PS	10,736	10,671	10,654	10,611	10,570	10,501	10,402	10,376	10,389	10,343	10,323	10,291	10,285	10,326	10,361	10,391
RECO	466	466	468	469	470	470	471	471	471	472	472	472	473	475	477	479
UGI	210	209	209	209	208	207	206	205	205	204	203	202	202	202	201	201
DIVERSITY - MID-ATLANTIC(-)	1,466	1,331	1,335	1,311	1,320	1,248	1,198	1,237	1,407	1,389	1,321	1,261	1,280	1,105	1,118	1,262
PJM MID-ATLANTIC	59,931	59,827	59,856	59,779	59,596	59,439	59,272	59,062	58,873	58,666	58,613	58,550	58,531	58,941	59,040	59,014
FE-EAST	12,508	12,455	12,471	12,451	12,409	12,359	12,330	12,307	12,322	12,299	12,252	12,215	12,200	12,314	12,344	12,341
PLGRP	7,751	7,744	7,776	7,786	7,783	7,781	7,784	7,780	7,792	7,778	7,775	7,776	7,798	7,826	7,846	7,872

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Summer season indicates peak from June, July, August.

Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AEP	23,571	23,720	23,755	23,803	23,791	23,833	23,837	23,810	23,787	23,781	23,781	23,819	23,892	23,908	23,963	23,999
APS	9,288	9,352	9,690	9,881	10,067	10,132	10,119	10,111	10,095	10,083	10,078	10,064	10,061	10,091	10,102	10,115
ATSI	12,929	12,885	12,844	12,799	12,770	12,755	12,730	12,673	12,627	12,561	12,525	12,431	12,397	12,432	12,406	12,381
COMED	23,062	22,898	22,993	22,893	22,851	22,733	22,647	22,515	22,485	22,248	22,107	21,962	21,916	21,914	21,902	21,895
DAYTON	3,555	3,552	3,554	3,552	3,548	3,548	3,551	3,544	3,538	3,529	3,524	3,528	3,541	3,544	3,547	3,552
DEOK	5,620	5,612	5,610	5,603	5,594	5,587	5,571	5,550	5,526	5,509	5,501	5,490	5,483	5,479	5,479	5,479
DLCO	2,923	2,912	2,911	2,908	2,909	2,907	2,898	2,893	2,889	2,887	2,886	2,884	2,884	2,890	2,892	2,900
EKPC	2,152	2,159	2,166	2,171	2,180	2,188	2,194	2,196	2,195	2,197	2,204	2,211	2,219	2,225	2,233	2,236
OVEC	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
DIVERSITY - WESTERN(-)	615	597	837	910	938	916	873	880	1,046	1,017	1,032	892	970	969	944	924
PJM WESTERN	82,580	82,588	82,781	82,795	82,867	82,862	82,769	82,507	82,191	81,873	81,669	81,592	81,518	81,609	81,675	81,728
DOM	23,164	24,122	25,067	26,720	28,310	29,836	31,338	32,738	34,245	35,611	36,939	38,147	39,290	40,466	41,658	42,954
DIVERSITY - TOTAL(-)	5,090	5,275	4,713	4,505	5,763	5,708	5,667	5,797	5,641	6,270	6,390	6,422	5,955	5,908	5,326	6,687
PJM RTO	162,666	163,190	165,163	167,010	167,268	168,593	169,783	170,627	172,121	172,286	173,184	174,020	175,634	177,182	179,109	179,195

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Summer season indicates peak from June, July, August.

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

2022/23 - 2037/38

	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38
AE	1,667	1,657	1,656	1,658	1,654	1,654	1,649	1,644	1,638	1,633	1,628	1,618	1,612	1,611	1,611	1,609
BGE	6,341	6,328	6,326	6,335	6,342	6,355	6,320	6,300	6,269	6,297	6,265	6,247	6,229	6,239	6,201	6,192
DPL	3,986	4,014	3,994	4,004	4,015	4,055	4,031	4,034	4,039	4,074	4,050	4,056	4,063	4,100	4,078	4,085
JCPL	3,904	3,945	3,949	3,978	3,994	4,033	4,022	4,027	4,019	4,036	4,039	4,028	4,014	4,031	4,039	4,055
METED	2,850	2,875	2,864	2,876	2,883	2,910	2,896	2,901	2,906	2,925	2,915	2,918	2,920	2,953	2,938	2,946
PECO	6,797	6,875	6,812	6,821	6,831	6,919	6,854	6,848	6,849	6,916	6,852	6,849	6,857	6,929	6,861	6,870
PENLC	2,976	2,978	2,956	2,955	2,947	2,950	2,931	2,922	2,910	2,909	2,894	2,882	2,874	2,871	2,860	2,854
PEPCO	5,842	5,826	5,841	5,889	5,916	5,932	5,940	5,931	5,942	5,976	5,994	6,011	6,023	6,042	6,065	6,087
PL	7,763	7,763	7,775	7,783	7,797	7,803	7,808	7,807	7,802	7,797	7,802	7,802	7,802	7,809	7,809	7,823
PS	6,807	6,812	6,799	6,781	6,773	6,772	6,755	6,719	6,686	6,671	6,638	6,606	6,591	6,602	6,580	6,590
RECO	223	228	233	239	244	249	252	255	256	257	258	258	258	260	263	266
UGI	209	208	208	208	207	207	206	205	204	203	203	202	200	200	199	199
DIVERSITY - MID-ATLANTIC(-)	1,500	1,354	1,439	1,454	1,379	1,337	1,359	1,345	1,298	1,483	1,404	1,456	1,418	1,513	1,484	1,442
PJM MID-ATLANTIC	47,865	48,155	47,974	48,073	48,224	48,502	48,305	48,248	48,222	48,211	48,134	48,021	48,025	48,134	48,020	48,134
FE-EAST	9,612	9,684	9,633	9,669	9,697	9,794	9,736	9,715	9,708	9,763	9,751	9,699	9,694	9,756	9,697	9,739
PLGRP	7,966	7,964	7,976	7,985	7,997	8,002	8,004	8,000	7,999	7,993	7,994	7,992	7,991	7,999	8,001	8,013

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Winter season indicates peak from December, January, February.

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2023 - 2038

	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38
AEP	24,140	24,564	24,401	24,429	24,452	24,779	24,504	24,473	24,433	24,668	24,423	24,489	24,449	24,676	24,454	24,482
APS	9,766	9,836	10,075	10,387	10,621	10,846	10,802	10,798	10,810	10,891	10,848	10,852	10,863	10,929	10,889	10,934
ATSI	10,317	10,352	10,305	10,267	10,247	10,286	10,250	10,212	10,153	10,119	10,034	9,987	9,947	9,919	9,848	9,801
COMED	15,195	15,225	15,233	15,295	15,364	15,443	15,532	15,505	15,514	15,465	15,432	15,384	15,352	15,297	15,243	15,240
DAYTON	3,077	3,089	3,088	3,075	3,082	3,085	3,069	3,060	3,047	3,045	3,025	3,012	3,017	3,018	3,003	3,006
DEOK	4,802	4,813	4,776	4,775	4,768	4,796	4,775	4,735	4,718	4,724	4,702	4,695	4,682	4,675	4,642	4,627
DLCO	2,083	2,094	2,076	2,070	2,070	2,084	2,068	2,058	2,053	2,060	2,043	2,038	2,035	2,046	2,026	2,028
EKPC	3,070	3,047	3,033	3,059	3,071	3,071	3,072	3,055	3,050	3,072	3,076	3,082	3,080	3,068	3,091	3,105
OVEC	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
DIVERSITY - WESTERN(-)	2,303	1,989	2,261	2,399	2,454	2,175	2,394	2,404	2,452	2,267	2,354	2,369	2,289	2,108	2,356	2,387
PJM WESTERN	70,257	71,141	70,836	71,068	71,331	72,325	71,788	71,602	71,436	71,887	71,339	71,280	71,246	71,630	70,950	70,946
DOM	24,123	24,861	25,609	27,149	28,573	30,049	31,355	32,694	33,977	35,429	36,660	37,819	38,882	39,941	41,064	42,277
DIVERSITY - TOTAL(-)	5,352	6,057	5,401	5,650	5,540	5,912	5,736	5,472	5,412	6,066	5,383	5,347	5,406	5,800	5,276	5,414
PJM RTO	140,696	141,443	142,718	144,493	146,421	148,476	149,465	150,821	151,973	153,211	154,508	155,598	156,454	157,526	158,598	159,772

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Winter season indicates peak from December, January, February.

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2023 - 2033

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Annual Growth Rate (10 yr)
AE	9,644	9,621	9,545	9,494	9,433	9,403	9,311	9,239	9,165	9,125	9,020	(0.7%)
		-0.2%	-0.8%	-0.5%	-0.6%	-0.3%	-1.0%	-0.8%	-0.8%	-0.4%	-1.2%	
BGE	30,387	30,441	30,343	30,293	30,209	30,175	29,932	29,735	29,539	29,446	29,158	(0.4%)
		0.2%	-0.3%	-0.2%	-0.3%	-0.1%	-0.8%	-0.7%	-0.7%	-0.3%	-1.0%	
DPL	17,908	17,892	17,760	17,684	17,594	17,553	17,379	17,249	17,094	16,981	16,731	(0.7%)
		-0.1%	-0.7%	-0.4%	-0.5%	-0.2%	-1.0%	-0.7%	-0.9%	-0.7%	-1.5%	
JCPL	22,306	22,438	22,419	22,442	22,442	22,506	22,431	22,388	22,338	22,381	22,244	(0.0%)
		0.6%	-0.1%	0.1%	0.0%	0.3%	-0.3%	-0.2%	-0.2%	0.2%	-0.6%	
METED	15,938	16,075	16,063	16,118	16,163	16,273	16,254	16,285	16,321	16,441	16,390	0.3%
		0.9%	-0.1%	0.3%	0.3%	0.7%	-0.1%	0.2%	0.2%	0.7%	-0.3%	
PECO	38,739	38,970	38,889	38,944	38,970	39,150	39,043	39,057	39,077	39,283	39,119	0.1%
		0.6%	-0.2%	0.1%	0.1%	0.5%	-0.3%	0.0%	0.1%	0.5%	-0.4%	
PENLC	17,318	17,372	17,276	17,247	17,205	17,242	17,133	17,091	17,047	17,097	16,965	(0.2%)
		0.3%	-0.6%	-0.2%	-0.2%	0.2%	-0.6%	-0.2%	-0.3%	0.3%	-0.8%	
PEPCO	28,934	29,128	29,190	29,306	29,399	29,553	29,521	29,525	29,543	29,671	29,632	0.2%
		0.7%	0.2%	0.4%	0.3%	0.5%	-0.1%	0.0%	0.1%	0.4%	-0.1%	
PL	40,706	40,953	40,893	40,934	40,942	41,100	40,966	40,947	40,940	41,134	40,933	0.1%
		0.6%	-0.1%	0.1%	0.0%	0.4%	-0.3%	-0.0%	-0.0%	0.5%	-0.5%	
PS	41,632	41,621	41,330	41,074	40,787	40,594	40,178	39,807	39,444	39,248	38,750	(0.7%)
		-0.0%	-0.7%	-0.6%	-0.7%	-0.5%	-1.0%	-0.9%	-0.9%	-0.5%	-1.3%	
RECO	1,417	1,441	1,461	1,482	1,501	1,522	1,531	1,544	1,557	1,571	1,575	1.1%
		1.7%	1.4%	1.4%	1.3%	1.4%	0.6%	0.8%	0.8%	0.9%	0.3%	
UGI	1,038	1,041	1,035	1,031	1,028	1,028	1,022	1,019	1,014	1,015	1,006	(0.3%)
		0.3%	-0.6%	-0.4%	-0.3%	0.0%	-0.6%	-0.3%	-0.5%	0.1%	-0.9%	
PJM MID-ATLANTIC	265,967	266,993	266,204	266,049	265,673	266,099	264,701	263,886	263,079	263,393	261,523	(0.2%)
		0.4%	-0.3%	-0.1%	-0.1%	0.2%	-0.5%	-0.3%	-0.3%	0.1%	-0.7%	
FE-EAST	55,562	55,885	55,758	55,807	55,810	56,021	55,818	55,764	55,706	55,919	55,599	0.0%
		0.6%	-0.2%	0.1%	0.0%	0.4%	-0.4%	-0.1%	-0.1%	0.4%	-0.6%	
PLGRP	41,744	41,994	41,928	41,965	41,970	42,128	41,988	41,966	41,954	42,149	41,939	0.0%
		0.6%	-0.2%	0.1%	0.0%	0.4%	-0.3%	-0.1%	-0.0%	0.5%	-0.5%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2023).

Table E-1 (continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2034 - 2038

	2034	2035	2036	2037	2038	Annual Growth Rate (15 yr)
AE	8,957	8,929	8,941	8,882	8,868	(0.6%)
	-0.7%	-0.3%	0.1%	-0.7%	-0.2%	
BGE	29,006	28,891	28,913	28,708	28,644	(0.4%)
	-0.5%	-0.4%	0.1%	-0.7%	-0.2%	
DPL	16,582	16,519	16,548	16,433	16,397	(0.6%)
	-0.9%	-0.4%	0.2%	-0.7%	-0.2%	
JCPL	22,216	22,254	22,402	22,374	22,450	0.0%
	-0.1%	0.2%	0.7%	-0.1%	0.3%	
METED	16,418	16,471	16,614	16,599	16,673	0.3%
	0.2%	0.3%	0.9%	-0.1%	0.4%	
PECO	39,133	39,201	39,464	39,376	39,483	0.1%
	0.0%	0.2%	0.7%	-0.2%	0.3%	
PENLC	16,916	16,891	16,962	16,866	16,857	(0.2%)
	-0.3%	-0.1%	0.4%	-0.6%	-0.1%	
PEPCO	29,720	29,881	30,118	30,112	30,246	0.3%
	0.3%	0.5%	0.8%	-0.0%	0.4%	
PL	40,922	40,946	41,221	41,139	41,250	0.1%
	-0.0%	0.1%	0.7%	-0.2%	0.3%	
PS	38,454	38,269	38,294	38,048	37,999	(0.6%)
	-0.8%	-0.5%	0.1%	-0.6%	-0.1%	
RECO	1,586	1,599	1,621	1,627	1,646	1.0%
	0.7%	0.8%	1.4%	0.4%	1.2%	
UGI	1,002	998	1,002	996	997	(0.3%)
	-0.4%	-0.4%	0.4%	-0.6%	0.1%	
PJM MID-ATLANTIC	260,912	260,849	262,100	261,160	261,510	(0.1%)
	-0.2%	-0.0%	0.5%	-0.4%	0.1%	
FE-EAST	55,550	55,616	55,978	55,839	55,980	0.0%
	-0.1%	0.1%	0.7%	-0.2%	0.3%	
PLGRP	41,924	41,944	42,223	42,135	42,247	0.1%
	-0.0%	0.0%	0.7%	-0.2%	0.3%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2023).

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2023 - 2033

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	Annual Growth Rate (10 yr)
AEP	130,238	132,670	132,525	132,776	133,006	133,725	133,367	133,303	133,315	134,008	133,489	0.2%
		1.9%	-0.1%	0.2%	0.2%	0.5%	-0.3%	-0.0%	0.0%	0.5%	-0.4%	
APS	49,918	50,988	53,639	55,508	57,285	58,265	58,087	58,074	58,078	58,354	58,095	1.5%
		2.1%	5.2%	3.5%	3.2%	1.7%	-0.3%	-0.0%	0.0%	0.5%	-0.4%	
ATSI	62,545	62,782	62,349	62,167	62,164	62,476	62,241	61,964	61,641	61,616	61,073	(0.2%)
		0.4%	-0.7%	-0.3%	-0.0%	0.5%	-0.4%	-0.4%	-0.5%	-0.0%	-0.9%	
COMED	90,558	90,989	90,708	90,720	90,896	91,373	91,230	91,157	90,844	90,771	90,106	(0.1%)
		0.5%	-0.3%	0.0%	0.2%	0.5%	-0.2%	-0.1%	-0.3%	-0.1%	-0.7%	
DAYTON	16,944	17,016	16,964	16,960	16,947	16,994	16,911	16,858	16,823	16,876	16,775	(0.1%)
		0.4%	-0.3%	-0.0%	-0.1%	0.3%	-0.5%	-0.3%	-0.2%	0.3%	-0.6%	
DEOK	26,599	26,669	26,561	26,514	26,465	26,493	26,333	26,196	26,073	26,070	25,870	(0.3%)
		0.3%	-0.4%	-0.2%	-0.2%	0.1%	-0.6%	-0.5%	-0.5%	-0.0%	-0.8%	
DLCO	13,210	13,250	13,197	13,179	13,158	13,188	13,123	13,091	13,059	13,094	13,009	(0.2%)
		0.3%	-0.4%	-0.1%	-0.2%	0.2%	-0.5%	-0.2%	-0.2%	0.3%	-0.6%	
EKPC	11,246	11,395	11,446	11,512	11,593	11,721	11,739	11,783	11,831	11,940	11,944	0.6%
		1.3%	0.4%	0.6%	0.7%	1.1%	0.2%	0.4%	0.4%	0.9%	0.0%	
OVEC	330	330	330	330	330	330	330	330	330	330	330	0.0%
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	401,588	406,089	407,719	409,666	411,844	414,565	413,361	412,756	411,994	413,059	410,691	0.2%
		1.1%	0.4%	0.5%	0.5%	0.7%	-0.3%	-0.1%	-0.2%	0.3%	-0.6%	
DOM	120,495	128,855	136,328	150,796	163,997	177,605	189,774	201,819	214,320	226,951	237,408	7.0%
		6.9%	5.8%	10.6%	8.8%	8.3%	6.9%	6.3%	6.2%	5.9%	4.6%	
PJM RTO	788,050	801,937	810,251	826,511	841,514	858,269	867,836	878,461	889,393	903,403	909,622	1.4%
		1.8%	1.0%	2.0%	1.8%	2.0%	1.1%	1.2%	1.2%	1.6%	0.7%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2023).

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2023 - 2033

	2034	2035	2036	2037	2038	Annual Growth Rate (15 yr)
AEP	133,648	133,896	134,806	134,515	134,856	0.2%
	0.1%	0.2%	0.7%	-0.2%	0.3%	
APS	58,110	58,176	58,533	58,365	58,473	1.1%
	0.0%	0.1%	0.6%	-0.3%	0.2%	
ATSI	60,833	60,623	60,706	60,230	60,061	(0.3%)
	-0.4%	-0.3%	0.1%	-0.8%	-0.3%	
COMED	89,960	90,006	90,484	90,163	90,253	(0.0%)
	-0.2%	0.1%	0.5%	-0.4%	0.1%	
DAYTON	16,761	16,770	16,859	16,796	16,815	(0.1%)
	-0.1%	0.1%	0.5%	-0.4%	0.1%	
DEOK	25,793	25,751	25,810	25,664	25,632	(0.2%)
	-0.3%	-0.2%	0.2%	-0.6%	-0.1%	
DLCO	12,985	12,981	13,045	13,001	13,017	(0.1%)
	-0.2%	-0.0%	0.5%	-0.3%	0.1%	
EKPC	12,006	12,069	12,201	12,217	12,293	0.6%
	0.5%	0.5%	1.1%	0.1%	0.6%	
OVEC	330	330	330	330	330	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	410,426	410,602	412,774	411,281	411,730	0.2%
	-0.1%	0.0%	0.5%	-0.4%	0.1%	
DOM	247,810	257,503	267,876	276,725	287,188	6.0%
	4.4%	3.9%	4.0%	3.3%	3.8%	
PJM RTO	919,148	928,954	942,750	949,166	960,428	1.3%
	1.0%	1.1%	1.5%	0.7%	1.2%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2023).

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	PJM MID-ATLANTIC
Jan 2023	835	2,952	1,784	1,971	1,505	3,547	1,650	2,749	4,050	3,637	117	108	24,905
Feb 2023	723	2,550	1,548	1,694	1,322	3,103	1,462	2,379	3,524	3,170	101	94	21,670
Mar 2023	714	2,482	1,489	1,718	1,348	3,133	1,519	2,317	3,539	3,277	105	93	21,734
Apr 2023	623	2,067	1,198	1,499	1,149	2,703	1,312	1,966	2,959	2,859	95	74	18,504
May 2023	703	2,218	1,263	1,647	1,195	2,893	1,328	2,158	3,010	3,123	112	73	19,723
Jun 2023	865	2,606	1,494	2,007	1,325	3,370	1,388	2,521	3,243	3,724	134	80	22,757
Jul 2023	1,125	3,053	1,816	2,449	1,493	3,967	1,523	2,960	3,685	4,421	159	93	26,744
Aug 2023	1,066	2,925	1,730	2,341	1,488	3,844	1,497	2,835	3,590	4,298	152	88	25,854
Sep 2023	808	2,376	1,378	1,808	1,234	3,126	1,318	2,310	3,059	3,433	119	74	21,043
Oct 2023	682	2,153	1,236	1,605	1,198	2,798	1,360	2,073	3,037	3,077	104	76	19,399
Nov 2023	693	2,278	1,334	1,646	1,242	2,887	1,401	2,151	3,259	3,093	103	84	20,171
Dec 2023	807	2,727	1,638	1,921	1,439	3,368	1,560	2,515	3,751	3,520	116	101	23,463

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2024	832	2,953	1,785	1,982	1,518	3,563	1,653	2,762	4,068	3,642	119	108	24,985
Feb 2024	755	2,662	1,616	1,786	1,407	3,282	1,543	2,488	3,710	3,312	108	98	22,767
Mar 2024	707	2,464	1,479	1,709	1,335	3,115	1,499	2,308	3,508	3,233	106	92	21,555
Apr 2024	622	2,073	1,197	1,515	1,169	2,728	1,326	1,985	2,994	2,871	97	75	18,652
May 2024	699	2,209	1,253	1,649	1,199	2,893	1,324	2,159	3,012	3,103	113	73	19,686
Jun 2024	854	2,584	1,474	1,994	1,318	3,354	1,373	2,510	3,223	3,677	134	79	22,574
Jul 2024	1,116	3,048	1,807	2,453	1,509	3,986	1,533	2,976	3,715	4,418	161	93	26,815
Aug 2024	1,057	2,910	1,715	2,336	1,486	3,839	1,487	2,836	3,583	4,269	153	88	25,759
Sep 2024	803	2,372	1,368	1,810	1,239	3,132	1,317	2,320	3,065	3,417	120	74	21,037
Oct 2024	681	2,158	1,233	1,620	1,211	2,814	1,366	2,091	3,061	3,082	106	76	19,499
Nov 2024	689	2,274	1,326	1,650	1,240	2,883	1,392	2,157	3,252	3,076	105	84	20,128
Dec 2024	806	2,734	1,639	1,934	1,444	3,381	1,559	2,536	3,762	3,521	119	101	23,536

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2025	831	2,960	1,786	1,996	1,524	3,571	1,650	2,779	4,079	3,641	122	108	25,047
Feb 2025	718	2,551	1,544	1,707	1,331	3,113	1,455	2,398	3,535	3,155	105	94	21,706
Mar 2025	705	2,468	1,474	1,717	1,344	3,126	1,501	2,323	3,525	3,226	108	92	21,609
Apr 2025	618	2,071	1,190	1,519	1,171	2,731	1,322	1,994	2,997	2,854	99	75	18,641
May 2025	693	2,203	1,242	1,647	1,198	2,891	1,317	2,163	3,009	3,071	114	73	19,621
Jun 2025	848	2,584	1,466	1,996	1,328	3,369	1,377	2,525	3,242	3,666	136	79	22,616
Jul 2025	1,109	3,046	1,798	2,454	1,520	4,001	1,536	2,993	3,736	4,405	163	93	26,854
Aug 2025	1,050	2,902	1,703	2,329	1,484	3,836	1,478	2,843	3,576	4,235	154	87	25,677
Sep 2025	800	2,377	1,364	1,819	1,251	3,150	1,324	2,340	3,089	3,416	123	74	21,127
Oct 2025	679	2,160	1,228	1,627	1,215	2,819	1,364	2,103	3,067	3,070	108	76	19,516
Nov 2025	687	2,273	1,321	1,654	1,239	2,881	1,386	2,166	3,249	3,057	107	83	20,103
Dec 2025	807	2,748	1,644	1,954	1,458	3,401	1,566	2,563	3,789	3,534	122	101	23,687

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	PJM WESTERN	DOM	PJM RTO
Jan 2023	12,539	4,978	5,794	8,147	1,606	2,459	1,168	1,229	35	37,955	11,115	73,975
Feb 2023	10,814	4,318	5,116	7,152	1,391	2,112	1,030	1,013	30	32,976	9,555	64,201
Mar 2023	11,019	4,324	5,323	7,296	1,410	2,141	1,059	957	25	33,554	9,470	64,758
Apr 2023	9,520	3,627	4,611	6,463	1,210	1,877	948	764	25	29,045	8,383	55,932
May 2023	9,971	3,736	4,790	6,880	1,286	2,065	1,029	798	25	30,580	9,125	59,428
Jun 2023	10,793	4,011	5,299	8,076	1,439	2,346	1,177	891	25	34,057	10,208	67,022
Jul 2023	11,748	4,415	5,825	9,062	1,567	2,590	1,321	986	35	37,549	11,650	75,943
Aug 2023	11,710	4,404	5,754	8,877	1,583	2,584	1,297	973	30	37,212	11,400	74,466
Sep 2023	10,114	3,740	4,839	7,293	1,324	2,141	1,066	809	25	31,351	9,783	62,177
Oct 2023	9,926	3,724	4,767	6,760	1,287	1,970	992	792	20	30,238	9,184	58,821
Nov 2023	10,345	3,983	4,891	6,844	1,338	2,000	1,001	911	25	31,338	9,529	61,038
Dec 2023	11,739	4,658	5,536	7,708	1,503	2,314	1,122	1,123	30	35,733	11,093	70,289

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2024	12,760	5,009	5,826	8,190	1,614	2,462	1,171	1,234	35	38,301	11,770	75,056
Feb 2024	11,554	4,577	5,402	7,534	1,468	2,217	1,083	1,071	30	34,936	10,611	68,314
Mar 2024	11,085	4,304	5,258	7,219	1,391	2,119	1,049	960	25	33,410	10,081	65,046
Apr 2024	9,756	3,680	4,660	6,533	1,226	1,890	954	778	25	29,502	9,063	57,217
May 2024	10,116	3,766	4,781	6,875	1,283	2,059	1,027	806	25	30,738	9,796	60,220
Jun 2024	10,871	4,030	5,250	7,995	1,424	2,327	1,169	896	25	33,987	10,834	67,395
Jul 2024	11,961	4,501	5,855	9,100	1,578	2,597	1,325	997	35	37,949	12,329	77,093
Aug 2024	11,826	4,472	5,725	8,847	1,574	2,573	1,292	980	30	37,319	12,043	75,121
Sep 2024	10,265	3,840	4,835	7,290	1,324	2,139	1,065	819	25	31,602	10,439	63,078
Oct 2024	10,126	3,866	4,791	6,821	1,297	1,978	996	805	20	30,700	9,882	60,081
Nov 2024	10,460	4,112	4,869	6,844	1,332	1,993	997	918	25	31,550	10,180	61,858
Dec 2024	11,890	4,831	5,530	7,741	1,505	2,315	1,122	1,131	30	36,095	11,827	71,458

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2025	12,803	5,220	5,816	8,218	1,615	2,464	1,171	1,242	35	38,584	12,332	75,963
Feb 2025	10,994	4,550	5,104	7,166	1,392	2,109	1,029	1,025	30	33,399	10,653	65,758
Mar 2025	11,144	4,580	5,264	7,244	1,396	2,124	1,051	970	25	33,798	10,671	66,078
Apr 2025	9,776	3,935	4,639	6,532	1,225	1,887	953	786	25	29,758	9,654	58,053
May 2025	10,120	4,026	4,751	6,851	1,278	2,052	1,023	814	25	30,940	10,428	60,989
Jun 2025	10,934	4,292	5,252	8,013	1,432	2,331	1,171	906	25	34,356	11,489	68,461
Jul 2025	12,019	4,763	5,852	9,112	1,585	2,601	1,327	1,007	35	38,301	13,033	78,188
Aug 2025	11,812	4,701	5,677	8,798	1,567	2,563	1,288	987	30	37,423	12,734	75,834
Sep 2025	10,345	4,088	4,846	7,329	1,334	2,146	1,069	830	25	32,012	11,172	64,311
Oct 2025	10,151	4,098	4,772	6,824	1,297	1,975	995	812	20	30,944	10,619	61,079
Nov 2025	10,456	4,319	4,833	6,822	1,327	1,985	994	925	25	31,686	10,894	62,683
Dec 2025	11,971	5,067	5,543	7,799	1,516	2,324	1,126	1,142	30	36,518	12,649	72,854

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

Table E-3

MONTHLY NET ENERGY FORECAST (GWh) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2023	5,126	4,158
Feb 2023	4,478	3,618
Mar 2023	4,585	3,632
Apr 2023	3,960	3,033
May 2023	4,170	3,083
Jun 2023	4,720	3,323
Jul 2023	5,465	3,778
Aug 2023	5,326	3,678
Sep 2023	4,360	3,133
Oct 2023	4,163	3,113
Nov 2023	4,289	3,343
Dec 2023	4,920	3,852

	FE_EAST	PLGRP
Jan 2024	5,153	4,176
Feb 2024	4,736	3,808
Mar 2024	4,543	3,600
Apr 2024	4,010	3,069
May 2024	4,172	3,085
Jun 2024	4,685	3,302
Jul 2024	5,495	3,808
Aug 2024	5,309	3,671
Sep 2024	4,366	3,139
Oct 2024	4,197	3,137
Nov 2024	4,282	3,336
Dec 2024	4,937	3,863

	FE_EAST	PLGRP
Jan 2025	5,170	4,187
Feb 2025	4,493	3,629
Mar 2025	4,562	3,617
Apr 2025	4,012	3,072
May 2025	4,162	3,082
Jun 2025	4,701	3,321
Jul 2025	5,510	3,829
Aug 2025	5,291	3,663
Sep 2025	4,394	3,163
Oct 2025	4,206	3,143
Nov 2025	4,279	3,332
Dec 2025	4,978	3,890

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, reductions for distributed battery storage, and additions for plug-in electric vehicles.

Table E-4

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO ANNUAL ENERGY (GWh) FOR EACH PJM ZONE AND RTO

2023 - 2038

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
AE	22	49	82	116	148	177	204	229	252	274	293	311	328	345	358	372
BGE	48	111	190	274	351	425	491	554	613	670	719	767	811	856	893	930
DPL	10	22	36	50	64	77	90	103	116	129	141	154	166	179	191	203
JCPL	87	191	319	454	580	699	807	909	1,005	1,098	1,179	1,257	1,331	1,405	1,467	1,529
METED	5	11	17	22	28	34	39	45	50	56	62	67	73	79	84	90
PECO	19	40	61	82	103	123	143	164	184	206	227	248	269	291	311	332
PENLC	6	13	20	27	33	40	46	52	59	65	71	77	83	89	94	100
PEPCO	68	157	268	389	508	627	743	863	984	1,112	1,237	1,367	1,509	1,615	1,672	1,736
PL	7	14	22	30	37	45	52	59	66	74	81	89	96	104	111	119
PS	72	158	264	375	479	578	667	752	831	908	975	1,040	1,101	1,162	1,213	1,264
RECO	18	39	65	93	119	143	166	187	207	226	243	259	275	291	304	317
UGI	0	1	1	2	2	2	3	3	3	4	4	4	5	5	5	6
AEP	33	72	115	159	202	243	281	320	357	396	431	467	502	538	570	604
APS	20	44	72	102	129	156	181	205	228	252	273	294	314	334	352	370
ATSI	23	49	73	98	122	146	169	191	214	238	260	283	305	328	349	370
COMED	118	275	472	715	1,007	1,360	1,757	2,263	2,583	2,706	2,839	2,967	3,092	3,223	3,330	3,442
DAYTON	4	9	14	19	24	28	33	37	41	46	50	55	59	64	68	72
DEOK	7	14	21	28	35	42	49	56	63	70	77	84	91	99	105	112
DLCO	5	11	16	22	27	33	38	43	48	54	59	64	69	74	79	84
EKPC	2	5	8	10	13	16	18	21	23	26	28	31	34	37	39	42
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	143	342	594	867	1,126	1,379	1,615	1,851	2,062	2,254	2,425	2,592	2,750	2,910	3,046	3,184
PJM RTO	718	1,629	2,731	3,932	5,137	6,375	7,592	8,906	9,992	10,863	11,673	12,477	13,263	14,027	14,642	15,278

Notes:
Adjustment values presented here are reflected in all energy forecast values.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1997		130,126	Thursday, July 17, 1997	17:00
1998		133,275	Tuesday, July 21, 1998	17:00
1999		141,491	Friday, July 30, 1999	17:00
2000		131,798	Wednesday, August 9, 2000	17:00
2001		150,924	Thursday, August 9, 2001	16:00
2002		150,826	Thursday, August 1, 2002	17:00
2003		145,227	Thursday, August 21, 2003	17:00
2004		139,279	Tuesday, August 3, 2004	17:00
2005		155,257	Tuesday, July 26, 2005	16:00
2006		166,929	Wednesday, August 2, 2006	17:00
2007		162,035	Wednesday, August 8, 2007	16:00
2008		150,622	Monday, June 9, 2008	17:00
2009		145,112	Monday, August 10, 2009	16:00
2010		157,247	Wednesday, July 7, 2010	17:00
2011		165,524	Thursday, July 21, 2011	17:00
2012		158,219	Tuesday, July 17, 2012	17:00
2013	151,660	159,149	Thursday, July 18, 2013	17:00
2014	151,834	141,509	Tuesday, June 17, 2014	18:00
2015	150,837	143,579	Tuesday, July 28, 2015	17:00
2016	150,408	152,069	Thursday, August 11, 2016	16:00
2017	150,656	145,434	Wednesday, July 19, 2017	18:00
2018	150,493	150,573	Tuesday, August 28, 2018	17:00
2019	150,155	151,302	Friday, July 19, 2019	18:00
2020	147,328	144,320	Monday, July 20, 2020	17:00
2021	149,960	148,433	Tuesday, August 24, 2021	18:00
2022	149,350	147,361	Wednesday, July 20, 2022	18:00

Notes:
Normalized values for 2013 - 2022 are calculated by PJM staff using a methodology described in Manual 19.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

WINTER

YEAR	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
96/97		114,015	Friday, January 17, 1997	19:00
97/98		103,231	Wednesday, January 14, 1998	19:00
98/99		116,086	Tuesday, January 5, 1999	19:00
99/00		118,435	Thursday, January 27, 2000	20:00
00/01		118,046	Wednesday, December 20, 2000	19:00
01/02		112,217	Wednesday, January 2, 2002	19:00
02/03		129,965	Thursday, January 23, 2003	19:00
03/04		122,424	Friday, January 23, 2004	9:00
04/05		131,234	Monday, December 20, 2004	19:00
05/06		126,777	Wednesday, December 14, 2005	19:00
06/07		136,804	Monday, February 5, 2007	20:00
07/08		128,368	Wednesday, January 2, 2008	19:00
08/09		134,077	Friday, January 16, 2009	19:00
09/10		125,350	Monday, January 4, 2010	19:00
10/11		132,315	Tuesday, December 14, 2010	19:00
11/12		124,506	Tuesday, January 3, 2012	19:00
12/13		128,810	Tuesday, January 22, 2013	19:00
13/14	129,932	141,866	Tuesday, January 7, 2014	19:00
14/15	130,728	142,856	Friday, February 20, 2015	8:00
15/16	130,951	129,540	Tuesday, January 19, 2016	8:00
16/17	130,237	130,825	Thursday, December 15, 2016	19:00
17/18	130,766	137,212	Friday, January 5, 2018	19:00
18/19	130,647	137,618	Thursday, January 31, 2019	8:00
19/20	131,455	120,272	Thursday, December 19, 2019	8:00
20/21	129,550	117,012	Friday, January 29, 2021	9:00
21/22	130,888	128,882	Thursday, January 27, 2022	8:00

Notes:
Normalized values for 2013/14 - 2021/22 are calculated by PJM staff using a methodology described in Manual 19.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

Table F-2

PJM RTO HISTORICAL NET ENERGY
(GWH)

YEAR	ENERGY	GROWTH RATE
1998	718,248	2.4%
1999	740,056	3.0%
2000	756,211	2.2%
2001	754,516	-0.2%
2002	782,275	3.7%
2003	780,666	-0.2%
2004	796,702	2.1%
2005	823,342	3.3%
2006	802,984	-2.5%
2007	836,241	4.1%
2008	822,608	-1.6%
2009	781,270	-5.0%
2010	820,038	5.0%
2011	805,911	-1.7%
2012	791,768	-1.8%
2013	795,098	0.4%
2014	796,228	0.1%
2015	791,580	-0.6%
2016	791,176	-0.1%
2017	772,291	-2.4%
2018	804,917	4.2%
2019	785,209	-2.4%
2020	755,241	-3.8%
2021	780,454	3.3%

Note: All historic net energy values reflect the current membership of the PJM RTO.

Table F-3

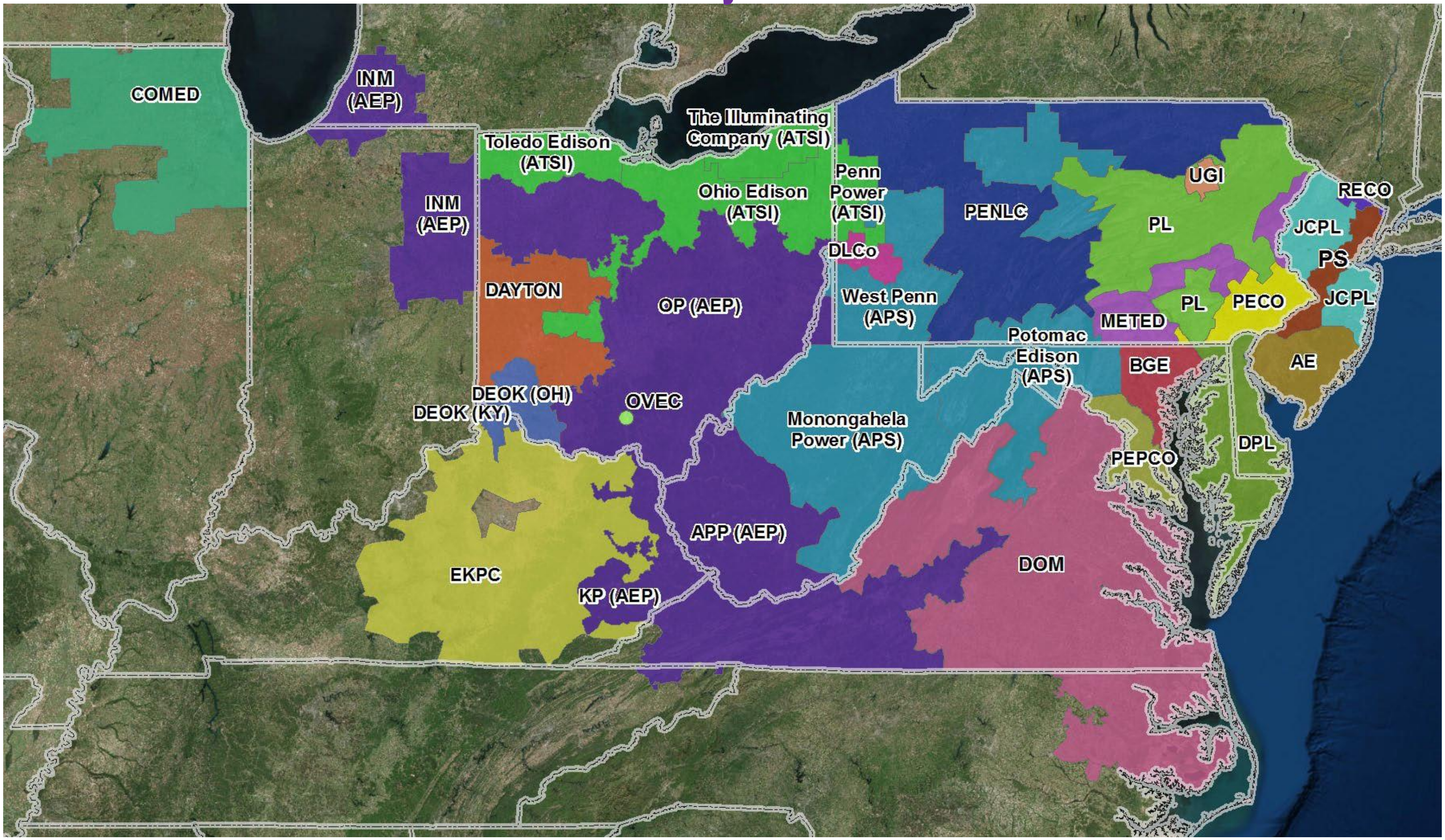
WEATHER NORMALIZED LOAD (MW) FOR EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO

	Summer 2022	Winter 2021/22
AE	2,632	1,658
BGE	6,591	5,804
DPL	4,017	3,743
JCPL	6,058	3,745
METED	3,045	2,697
PECO	8,629	6,550
PENLC	2,893	2,844
PEPCO	6,100	5,293
PL	7,241	7,390
PS	9,943	6,560
RECO	411	212
UGI	202	204
AEP	22,189	22,077
APS	8,753	8,990
ATSI	12,423	10,290
COMED	20,781	14,808
DAYTON	3,355	2,974
DEOK	5,239	4,457
DLCO	2,720	2,004
EKPC	2,040	2,687
OVEC	95	110
DOM	21,160	21,000
PJM MID-ATLANTIC	56,266	45,937
PJM WESTERN	75,980	66,664
PJM RTO	149,350	130,888

Notes:
Zonal Normal 2022 are non-coincident as estimated by PJM staff.
Locational Deliverability Area and PJM RTO Normal 2022 are coincident with their regional peak as estimated by PJM staff.

PJM Load Forecast Report

January 2024



Prepared by PJM Resource Adequacy Planning Department

Revised 2/1/2024

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TERMS AND ABBREVIATIONS USED IN THIS REPORT

AE	Atlantic Electric zone
AEP	American Electric Power zone (incorporated 10/1/2004)
APP	Appalachian Power, sub-zone of AEP
APS	Allegheny Power zone (incorporated 4/1/2002)
ATSI	American Transmission Systems, Inc. zone (incorporated 6/1/2011)
Battery Storage	(Also Battery Energy Storage System – BESS) Devices that enable generated energy to be stored and then released at a later time
BGE	Baltimore Gas & Electric zone
CEI	Cleveland Electric Illuminating, sub-zone of ATSI
COMED	Commonwealth Edison zone (incorporated 5/1/2004)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
CSP	Columbus Southern Power, sub-zone of AEP
Direct Control	Load Management achieved directly by a signal from a control center
DAY	Dayton Power & Light zone (incorporated 10/1/2004)
DEOK	Duke Energy Ohio/Kentucky zone (incorporated 1/1/2012)
DLCO	Duquesne Lighting Company zone (incorporated 1/1/2005)
DOM	Dominion Virginia Power zone (incorporated 5/1/2005)
DPL	Delmarva Power & Light zone
EKPC	East Kentucky Power Cooperative zone (incorporated 6/1/2013)
FE-East	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)
Heating Load	The weather-sensitive portion of winter peak load
INM	Indiana Michigan Power, sub-zone of AEP
JCPL	Jersey Central Power & Light zone
KP	Kentucky Power, sub-zone of AEP

METED	Metropolitan Edison zone
MP	Monongahela Power, sub-zone of APS
NERC	North American Electric Reliability Corporation
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
OEP	Ohio Edison, sub-zone of ATSI
OP	Ohio Power, sub-zone of AEP
OVEC	Ohio Valley Electric Corporation zone (incorporated 12/1/2018)
PECO	PECO Energy zone
PED	Potomac Edison, sub-zone of APS
PEPCO	Potomac Electric Power zone
PL	PPL Electric Utilities, sub-zone of PLGroup
PLGroup/PLGRP	Pennsylvania Power & Light zone
PENLC	Pennsylvania Electric zone
PP	Pennsylvania Power, sub-zone of ATSI
PRD	Price Responsive Demand
PS	Public Service Electric & Gas zone
RECO	Rockland Electric (East) zone (incorporated 3/1/2002)
TOL	Toledo Edison, sub-zone of ATSI
UGI	UGI Utilities, sub-zone of PLGroup
Unrestricted Peak	Peak load prior to any reduction for load management or voltage reduction.
WP	West Penn Power, sub-zone of APS
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

2024 PJM LOAD FORECAST REPORT

EXECUTIVE SUMMARY

- This report presents an independent load forecast prepared by PJM staff.

- The report includes long-term forecasts of peak loads, net energy, load management, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area (LDA), and the total RTO.

- Residential, Commercial, and Industrial sector models were estimated with data from 2013 through 2022. Weather scenarios were simulated with data from years 1994 through 2022, generating 377 scenarios.

- The economic forecast used was Moody's Analytics' September 2023 release.

- The 2023 update of Itron's end-use data provides the basis for appliance saturation rates, efficiency, and intensity and is consistent with the Energy Information Administration's 2023 Annual Energy Outlook. PJM obtained additional information from certain zones on Residential saturation rates based on their own load research. Details on zones providing information are presented in the supplement.

- Consultant forecasts for behind the meter solar/battery and electric vehicles including light, medium & heavy duty were provided by S&P Global.
    - The behind the meter solar/battery values were derived by PJM from a forecast obtained from SPGCI
    - The electric vehicle values were derived by PJM from a forecast obtained from SPGCI

- The forecasts of the following zones have been adjusted to account for large, unanticipated load changes, market adjustments, and peak shaving adjustments (see Table B-9 and the supplement for details):
    - The AEP zone has been adjusted to account for growth in data center load and a chip processing plant;
    - The APS zone has been adjusted to account for growth in data center load;
    - The DOM zone has been adjusted to account for growth in data center load;
    - The PS zone has been adjusted to account for growth in data center load and port electrification;

  - The EKPC forecast has been adjusted to account for a peak shaving program that commenced in the 2023 DY;
  - The AEP, ATSI, DAYTON, DEOK, PL, and PENLC forecasts have been adjusted to account for Non-Retail Behind-the-Meter Generation (NRBTMG) transitioning to participation as Demand Response in the Reliability Pricing Model.

- Summer peak load growth for the PJM RTO is projected to average 1.6% per year over the next 10-year period and 1.6% over the next 15 years. The PJM RTO summer peak is forecasted to be 176,822 MW in 2034, a 10-year increase of 25,575 MW, and reaches 190,752 MW in 2039, a 15-year increase of 39,505 MW. Annualized 10-year growth rates for individual zones range from 0% to 5.5%; median of 0.5%.

- Winter peak load growth for PJM RTO is projected to average 1.9% per year over the next 10-year period, and 1.8% over the next 15-years. The PJM RTO winter peak load in 2033/34 is forecasted to be 163,069 MW, a 10-year increase of 28,410 MW, and reaches 176,195 MW in 2038/39, a 15-year increase of 41,536 MW. Annualized 10-year growth rates for individual zones range from 0 % to 5.0%; median of 0.7%.

- Net energy for load growth for PJM RTO is projected to average 2.3% per year over the next 10-year period, and 2.2% over the next 15-years. Total PJM RTO energy is forecasted to be 1,021,955 GWh in 2034, a 10-year increase of 208,627 GWh, and reaches 1,120,928 GWh in 2039, a 15-year increase of 307,600 GWh. Annualized 10- year growth rates for individual zones range from 0.1% to 7.3%; median of 0.7%.

- Compared to the 2023 Load Report, the 2024 PJM RTO summer peak forecast shows the following changes for three years of interest:
  - The next delivery year – 2024 +1,510 MW (1.0%)
  - The next RPM auction year – 2025 +2,569 MW (1.7%)
  - The next RTEP study year – 2029 +8,758 MW (5.6%)

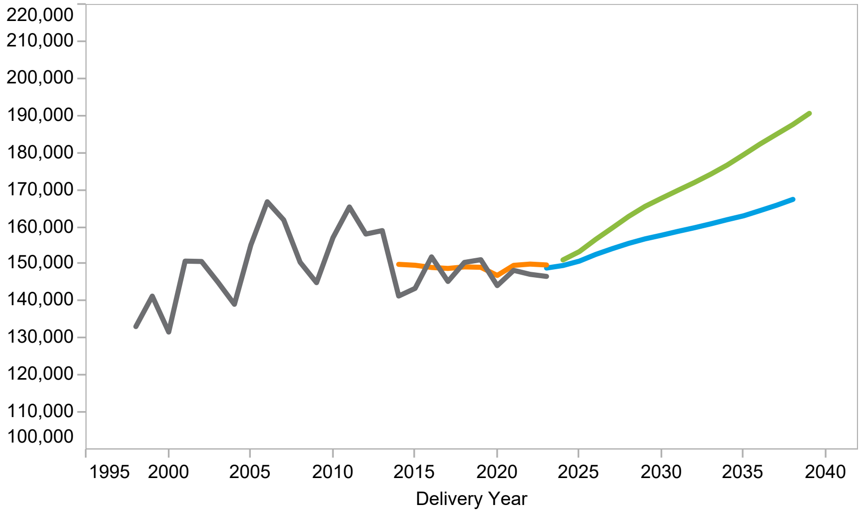
NOTE:

Unless noted otherwise, all peak and energy values are non-coincident, unrestricted peaks, which represent the peak load or net energy after reductions for distributed solar generation and battery storage (in summer peak), additions for plug-in electric vehicles, and prior to reductions for load management impacts.

All compound growth rates are calculated from the first year of the forecast.

PJM RTO

Summer Peak



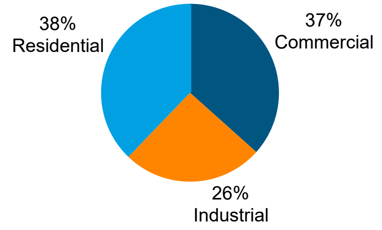
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*74.25*
Avg Summer Max Temp	*95.13*
Avg Winter Daily Temp	*34.06*
Avg Winter Min Temp	*3.93*

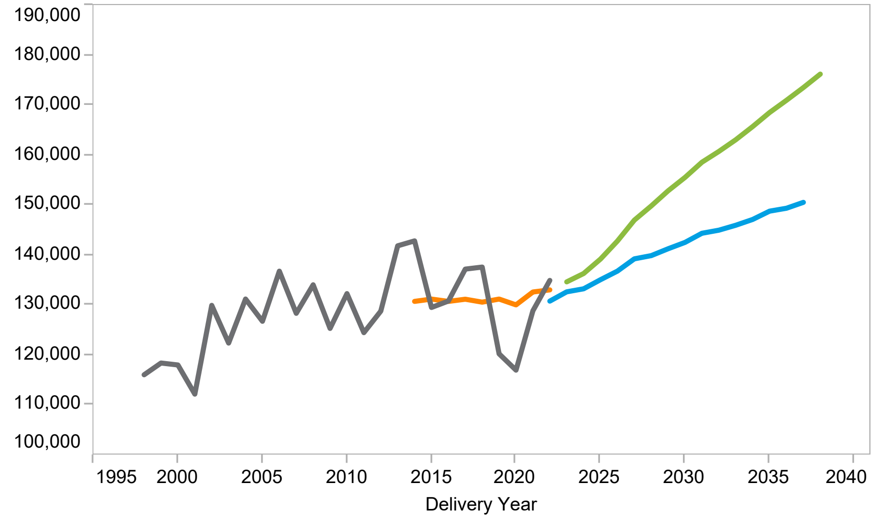
Zonal 10/15 Year Load Growth

SUMMER	1.6%	1.6%
WINTER	1.9%	1.8%

RCI Makeup



Winter Peak



LDAs

PJM Mid-Atlantic
Eastern MAAC
Southern MAAC
Central MAAC
Western MAAC
PJM West

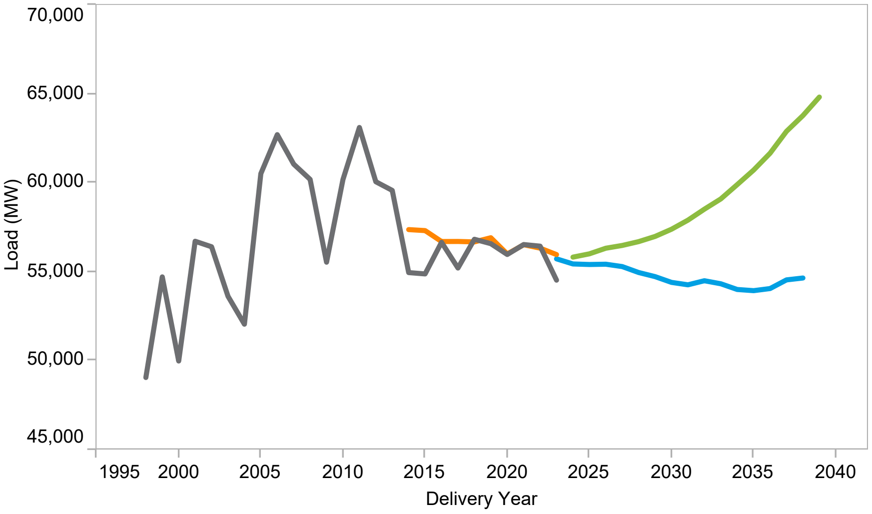
Zones

AE
AEP
APS
ATSI
BGE
COMED
DAYTON
DEOK
DLCO
DOM
DPL
EKPC
JCPL
METED
OVEC
PECO
PENLC
PEPCO
PL
PS
RECO
UGI

■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

PJM Mid-Atlantic (MAAC)

Summer Peak



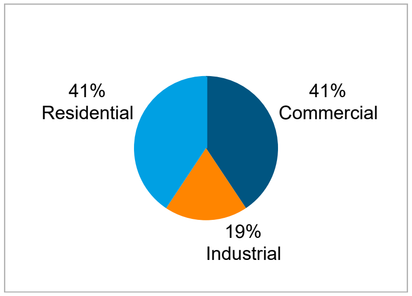
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*74.7*
Avg Summer Max Temp	*96.3*
Avg Winter Daily Temp	*34.9*
Avg Winter Min Temp	*6.5*

Zonal 10/15 Year Load Growth

SUMMER	0.7%	1.0%
WINTER	1.7%	1.7%

RCI Makeup



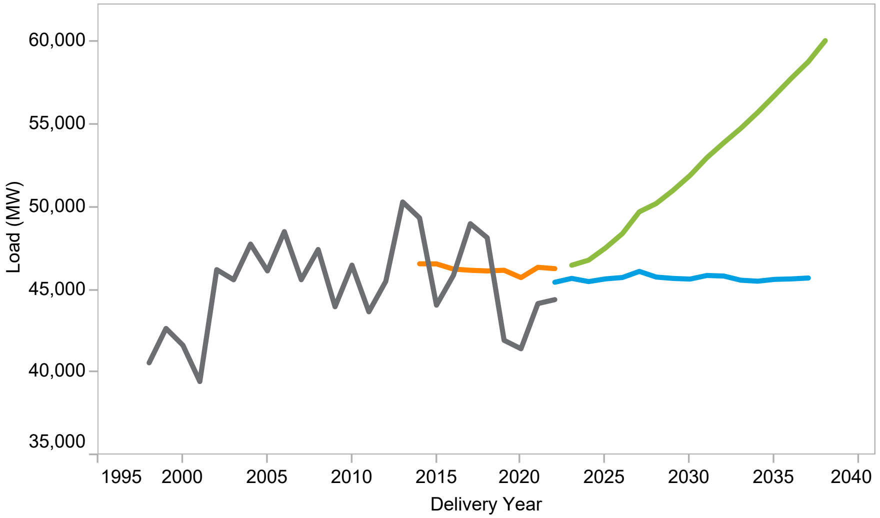
Zones

AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PSEG
RECO
UGI

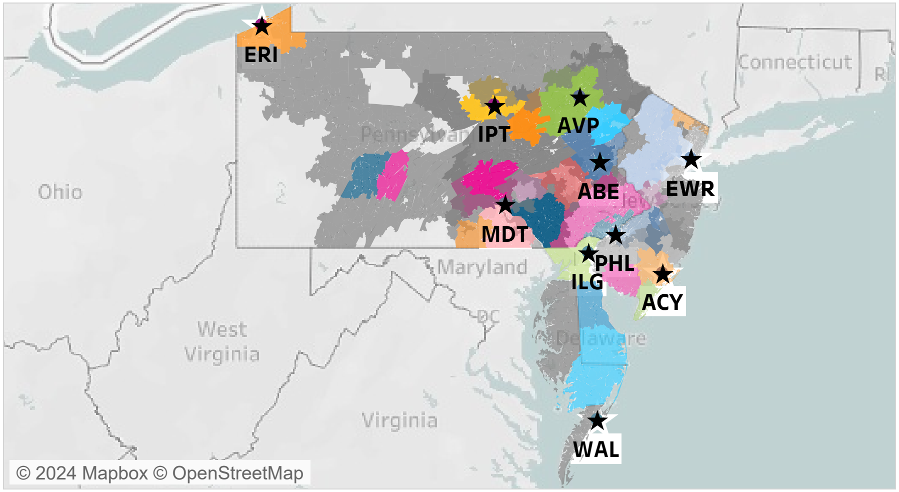
LDAs

E-MAAC
S-MAAC
C-MAAC
W-MAAC

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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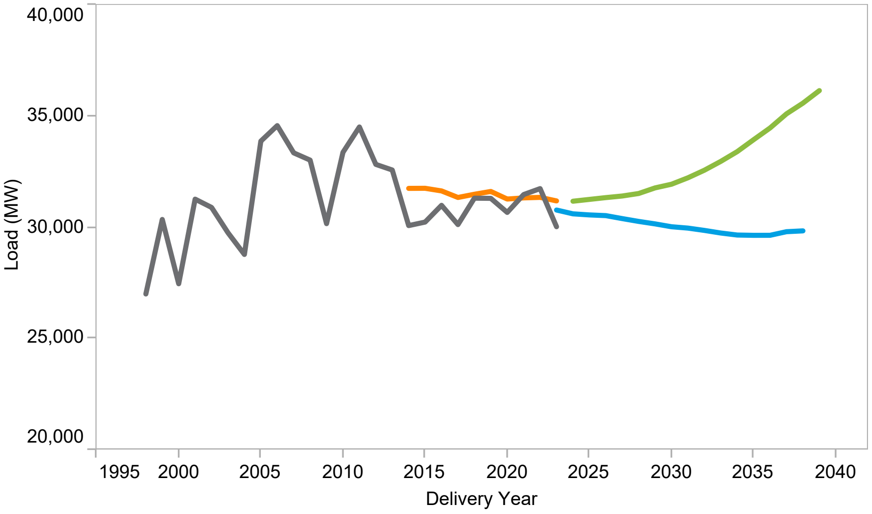
⬛ Peak 🟧 WN peak 🟦 Forecast 2023 🟩 Forecast 2024

PJM Eastern Mid-Atlantic (E-MAAC)

Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*75.7*
Avg Summer Max Temp	*97.5*
Avg Winter Daily Temp	*36.2*
Avg Winter Min Temp	*7.9*

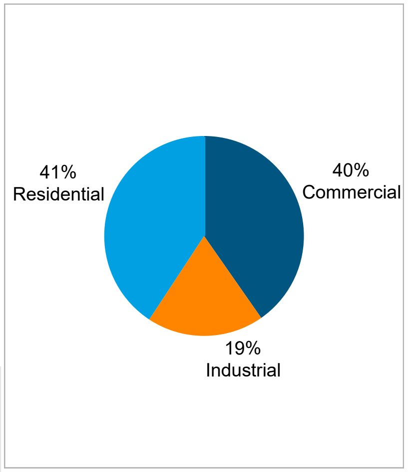
Zonal 10/15 Year Load Growth

SUMMER	0.7%	1.0%
WINTER	2.6%	2.5%

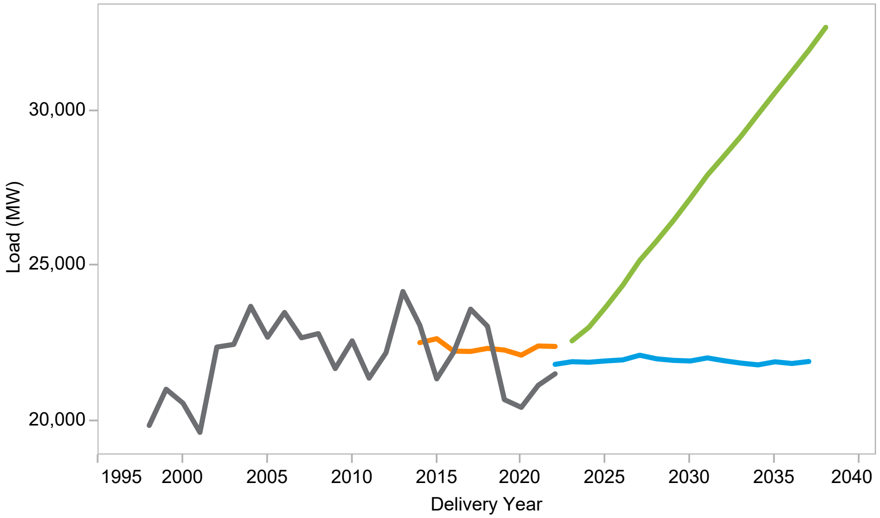
Zones

AE
DPL
JCPL
PECO
PS
RECO

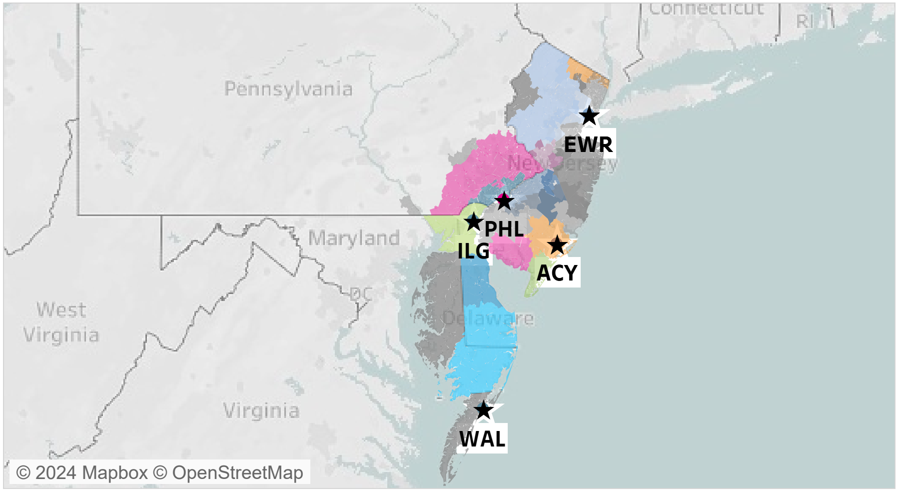
RCI Makeup



Winter Peak



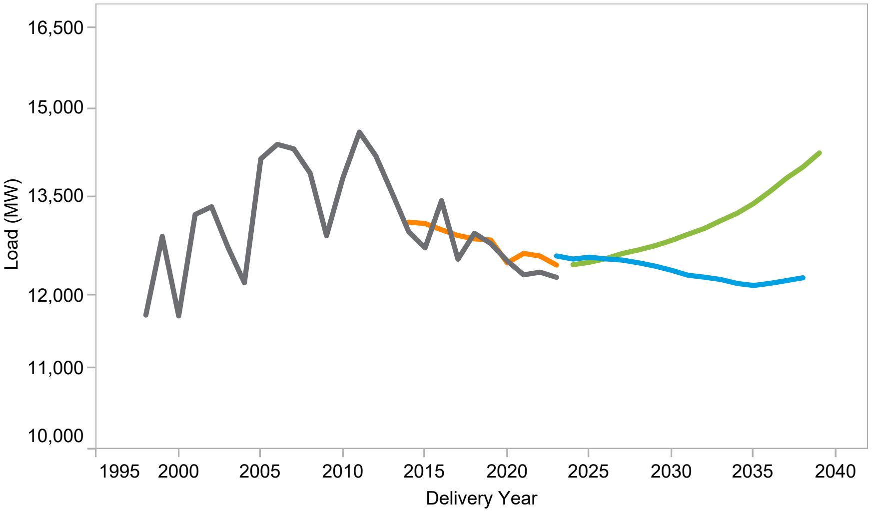
Metropolitan Statistical Areas and Weather Stations



■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

PJM Southern Mid-Atlantic (S-MAAC)

Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*77.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*37.9*
Avg Winter Min Temp	*10.3*

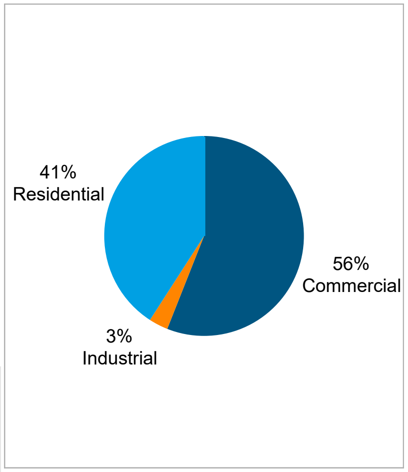
Zonal 10/15 Year Load Growth

SUMMER	0.6%	0.9%
WINTER	0.7%	0.9%

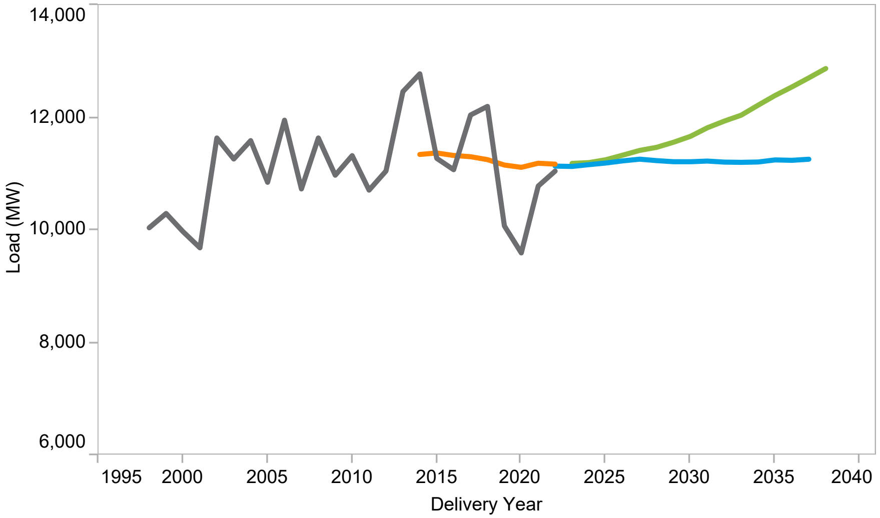
Zones

BGE PEPCO

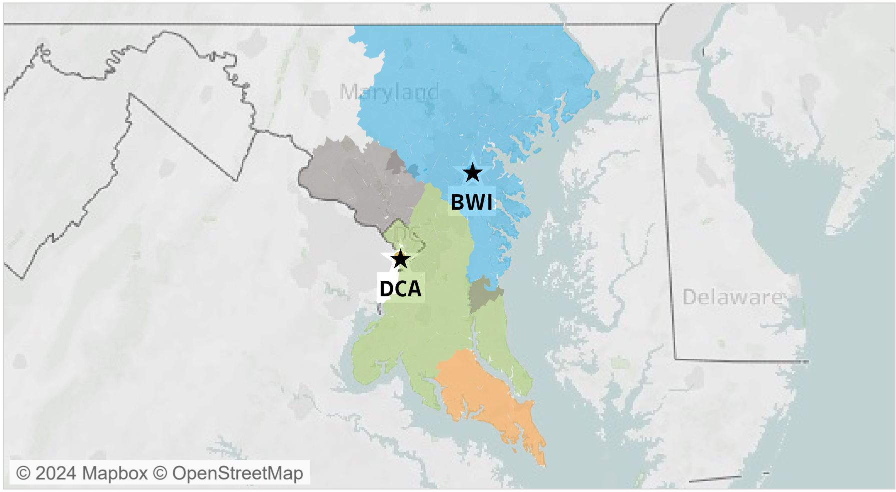
RCI Makeup



Winter Peak



Metropolitan Statistical Areas and Weather Stations



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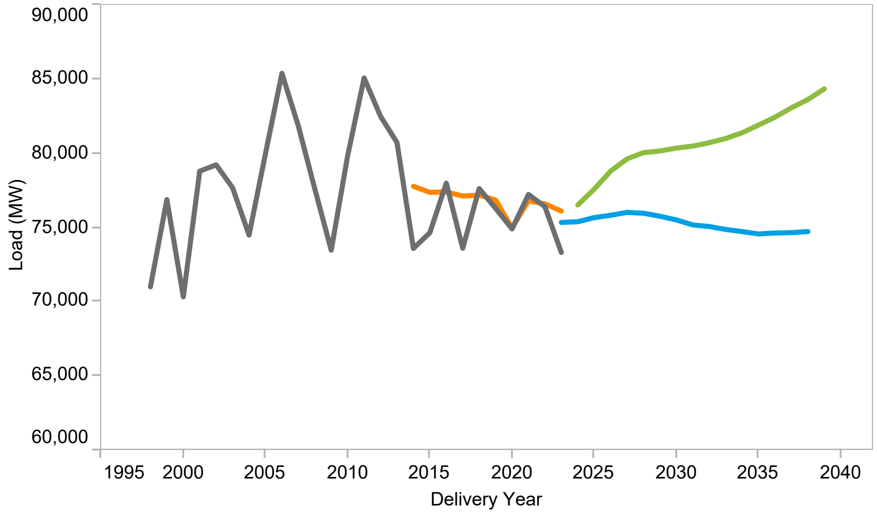
⬛ Peak 🟧 WN peak 🟦 Forecast 2023 🟩 Forecast 2024

PJM Western

Summer Peak



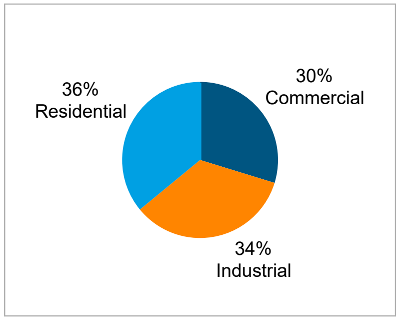
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*32.0*
Avg Winter Min Temp	*-1.0*

Zonal 10/15 Year Load Growth

SUMMER	0.6%	0.7%
WINTER	0.9%	0.8%

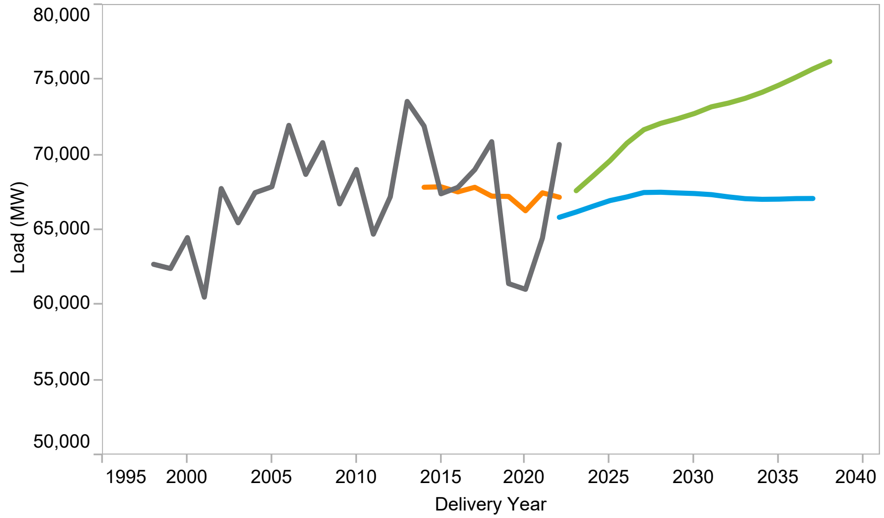
RCI Makeup



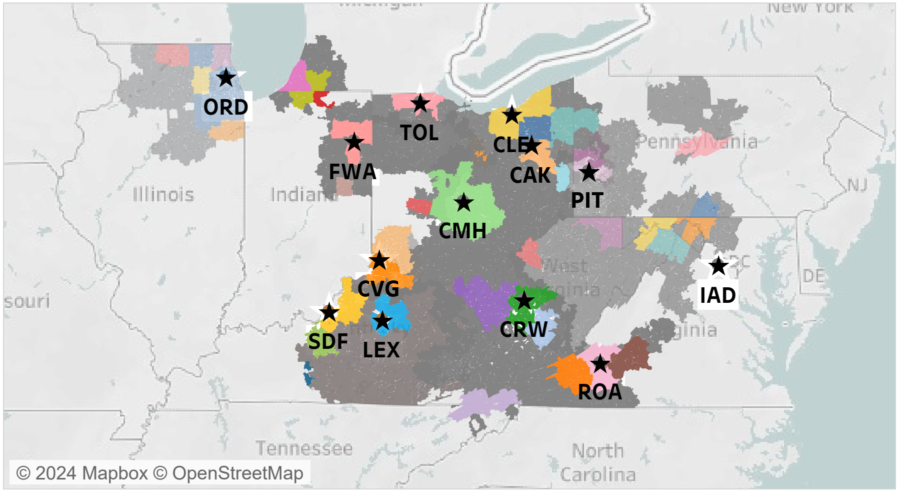
Zones

AEP
APS
ATSI
COMED
DAYTON
DEOK
DLCO
EKPC
OVEC

Winter Peak



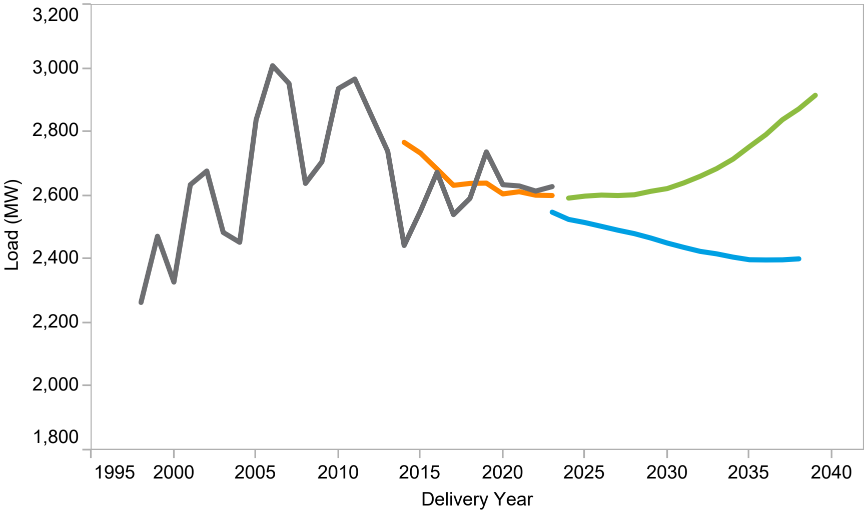
Metropolitan Statistical Areas and Weather Stations



■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

Atlantic Electric (AE)

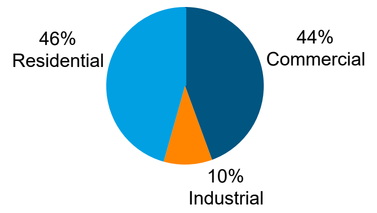
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*74.4*
Avg Summer Max Temp	*97.0*
Avg Winter Daily Temp	*36.6*
Avg Winter Min Temp	*6.0*

RCI Makeup



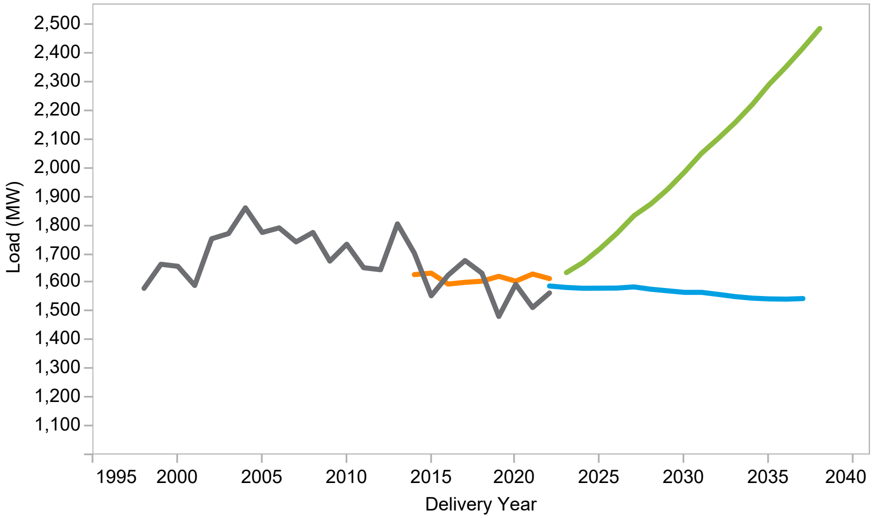
Zonal 10/15 Year Load Growth

SUMMER	0.5%	0.8%
WINTER	2.8%	2.8%

LDAs

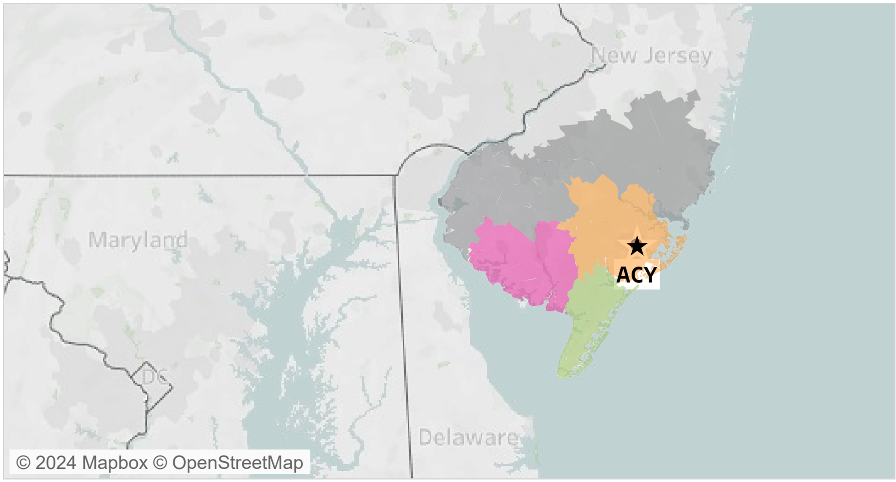
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

Metropolitan Statistical Areas and Weather Stations



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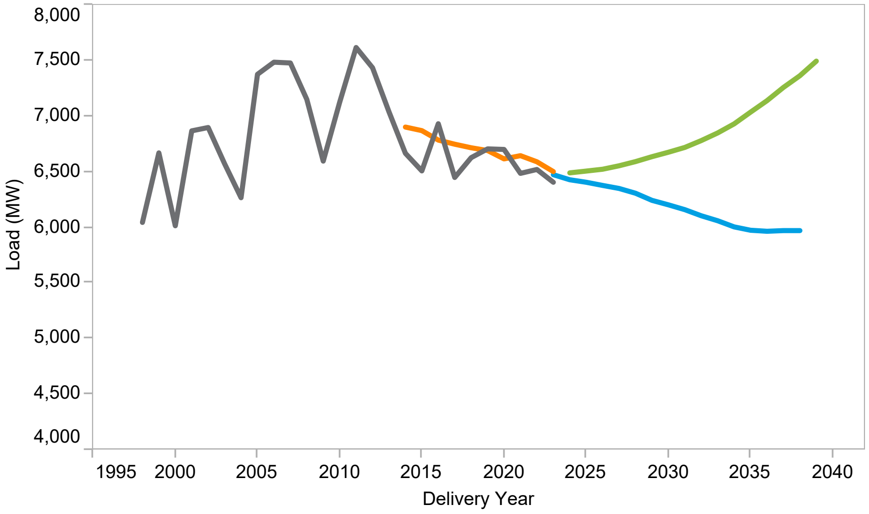
- ■ AE - Non-Metro
- ■ Atlantic City-Hammonton, NJ
- ■ Ocean City, NJ
- ■ Vineland-Bridgeton, NJ

Baltimore Gas and Electric (BGE)

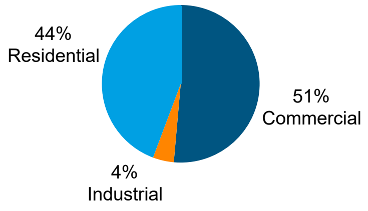
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*36.7*
Avg Winter Min Temp	*7.8*

RCI Makeup



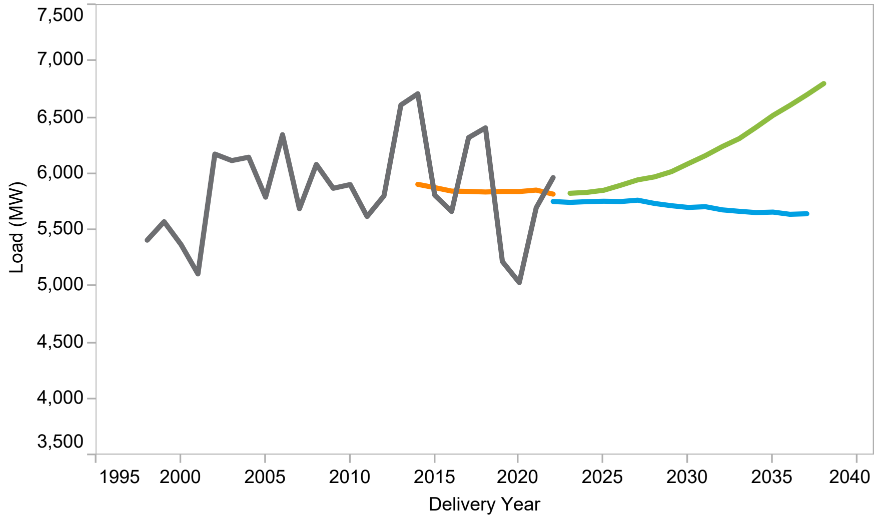
Zonal 10/15 Year Load Growth

SUMMER	0.7%	1.0%
WINTER	0.8%	1.0%

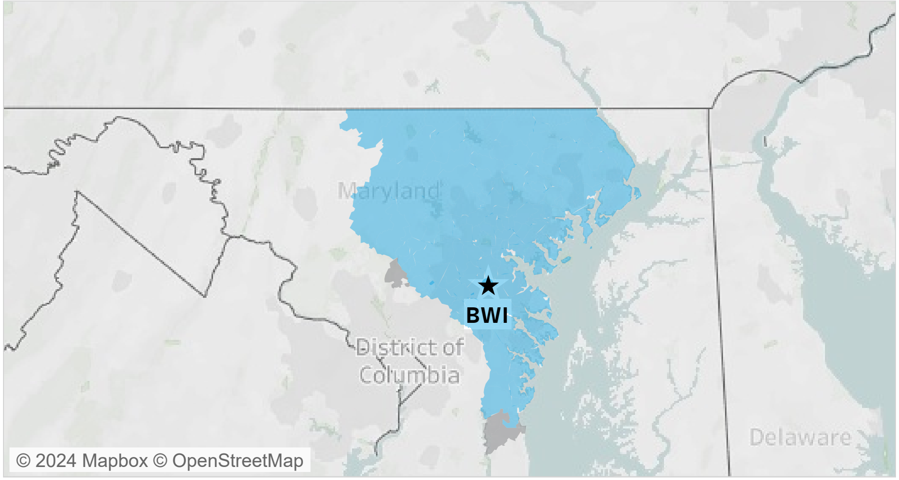
LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO SOUTHERN MID-ATLANTIC

Winter Peak



Metropolitan Statistical Areas and Weather Stations

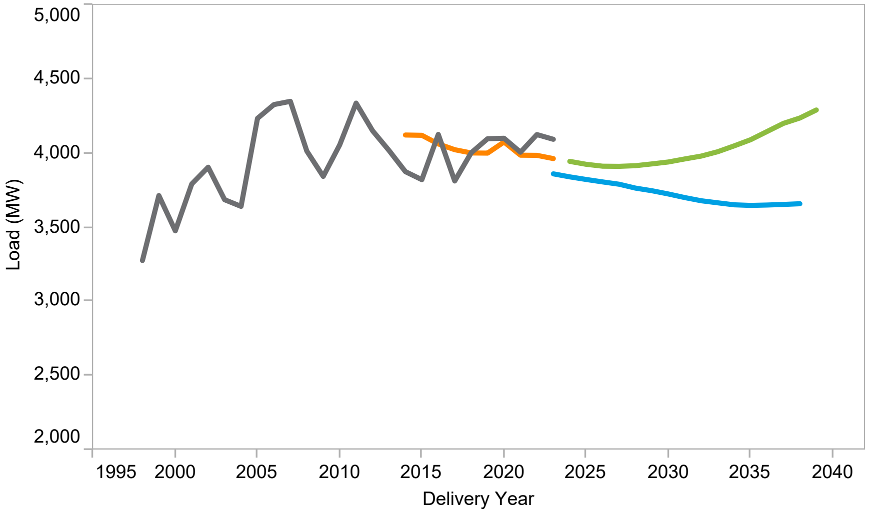


🟦 Baltimore-Columbia-Towson, MD
⬜ BGE - Non-Metro

⬛ Peak
🟧 WN peak
🟦 Forecast 2023
🟩 Forecast 2024

Delmarva Power and Light (DPL)

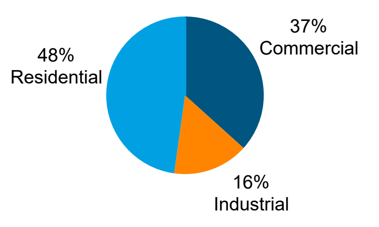
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*95.0*
Avg Winter Daily Temp	*37.0*
Avg Winter Min Temp	*9.7*

RCI Makeup



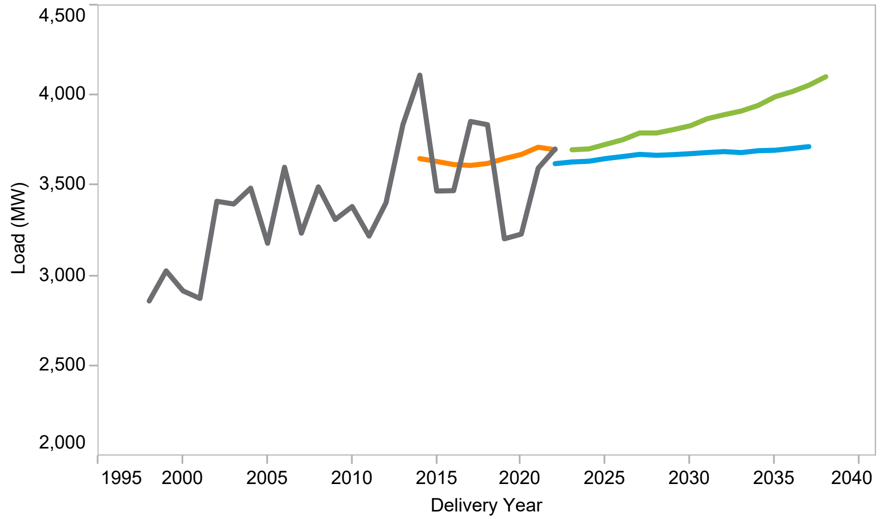
Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.6%
WINTER	0.6%	0.7%

LDAs

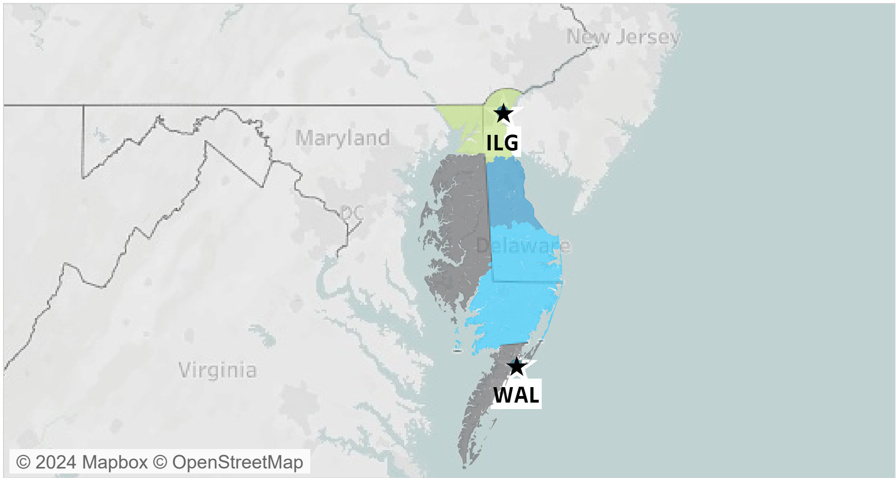
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



🟫 Peak 🟧 WN peak 🟦 Forecast 2023 🟩 Forecast 2024

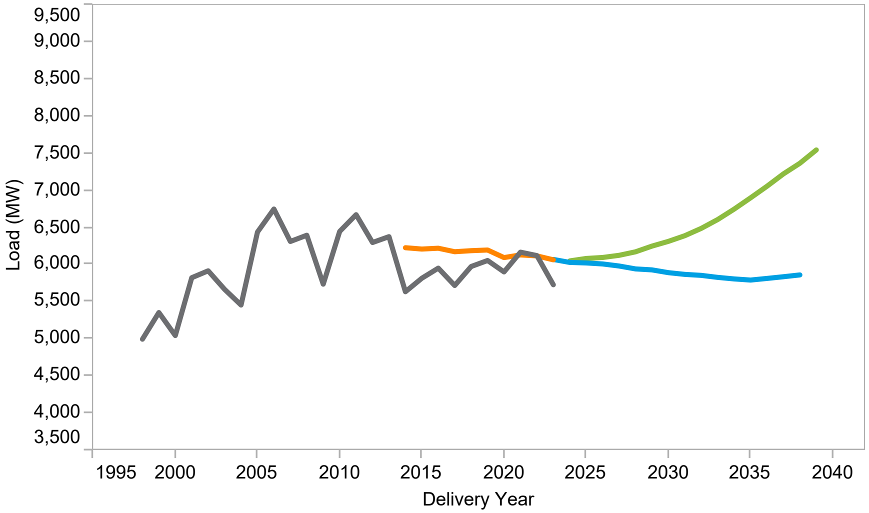
Metropolitan Statistical Areas and Weather Stations



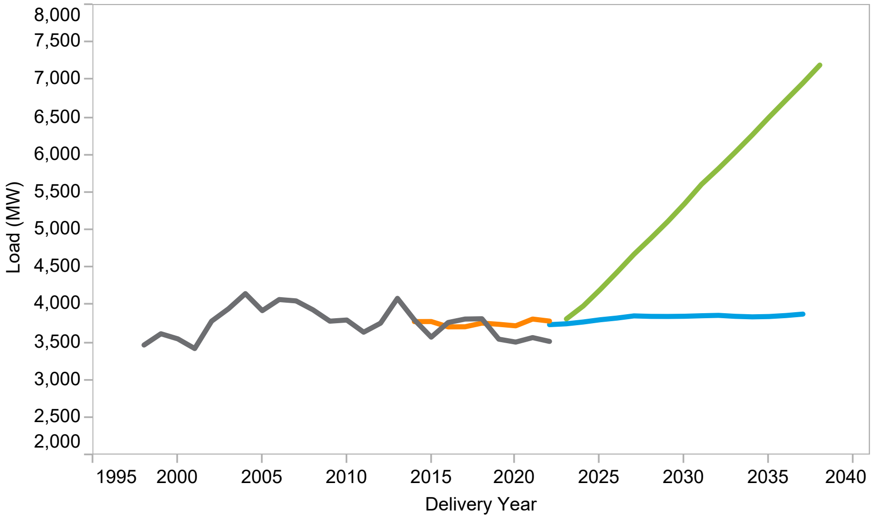
🟦 Dover, DE
⬜ DPL - Non-Metro
🟦 Salisbury, MD-DE
🟩 Wilmington, DE-MD-NJ

Jersey Central Power and Light (JCPL)

Summer Peak



Winter Peak



⬛ Peak   🟧 WN peak   🟦 Forecast 2023   🟩 Forecast 2024

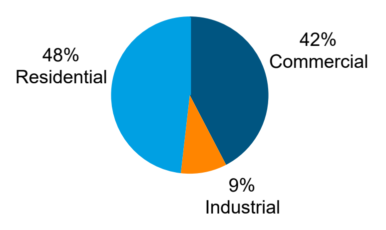
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*75.6*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*35.8*
Avg Winter Min Temp	*7.6*

Zonal 10/15 Year Load Growth

SUMMER	1.1%	1.5%
WINTER	4.7%	4.3%

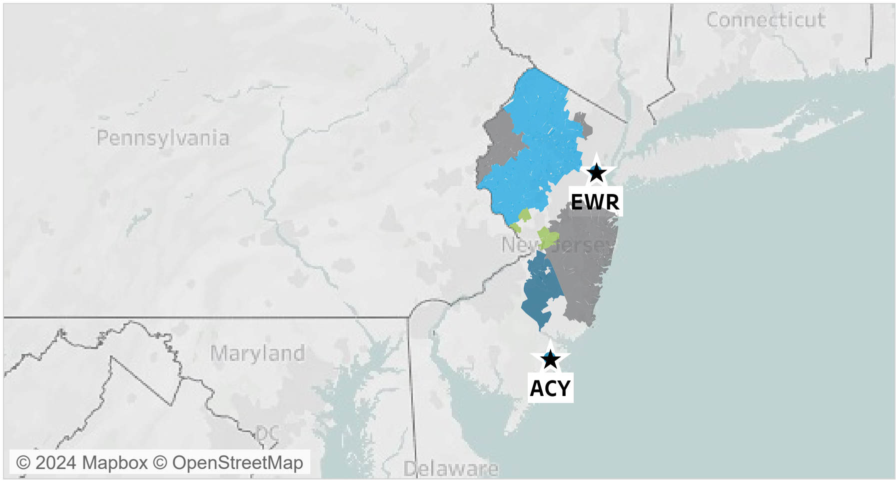
RCI Makeup



LDAs

EASTERN MID-ATLANTIC GPU PJM MID-ATLANTIC PJM RTO

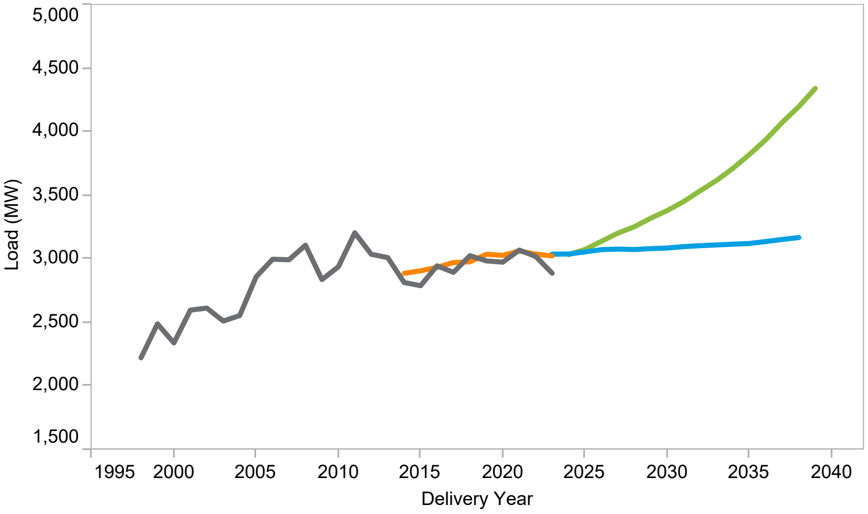
Metropolitan Statistical Areas and Weather Stations



▨ Camden, NJ
▨ JCPL - Non-Metro
▨ Newark, NJ-PA
▨ Trenton, NJ

Metropolitan Edison (METED)

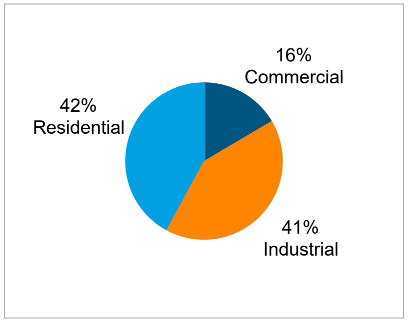
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*74.7*
Avg Summer Max Temp	*95.8*
Avg Winter Daily Temp	*34.4*
Avg Winter Min Temp	*6.6*

RCI Makeup



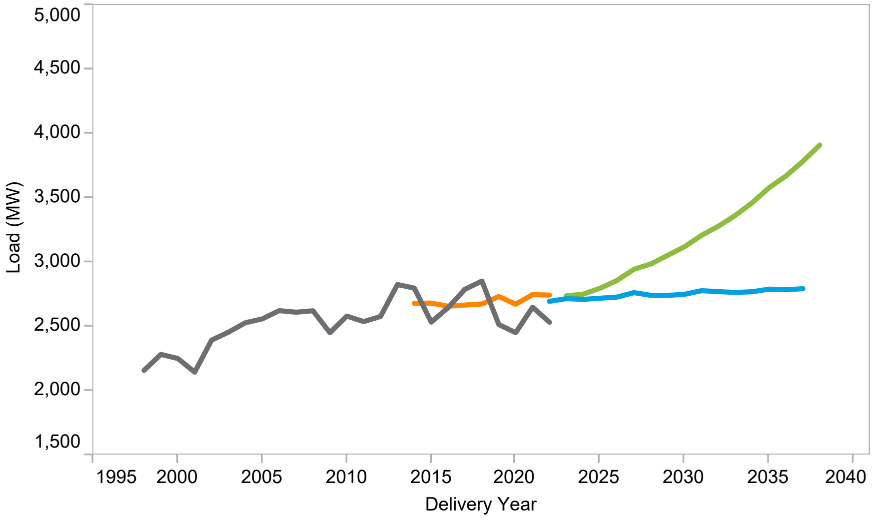
Zonal 10/15 Year Load Growth

SUMMER	2.0%	2.4%
WINTER	2.1%	2.4%

LDAs

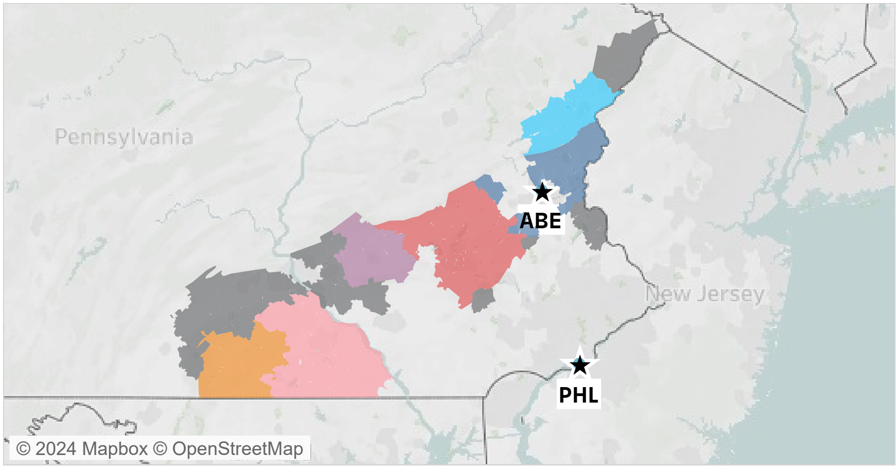
CENTRAL MID-ATLANTIC GPU PJM MID-ATLANTIC PJM RTO WESTERN MID-ATLANTIC

Winter Peak



■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

Metropolitan Statistical Areas and Weather Stations



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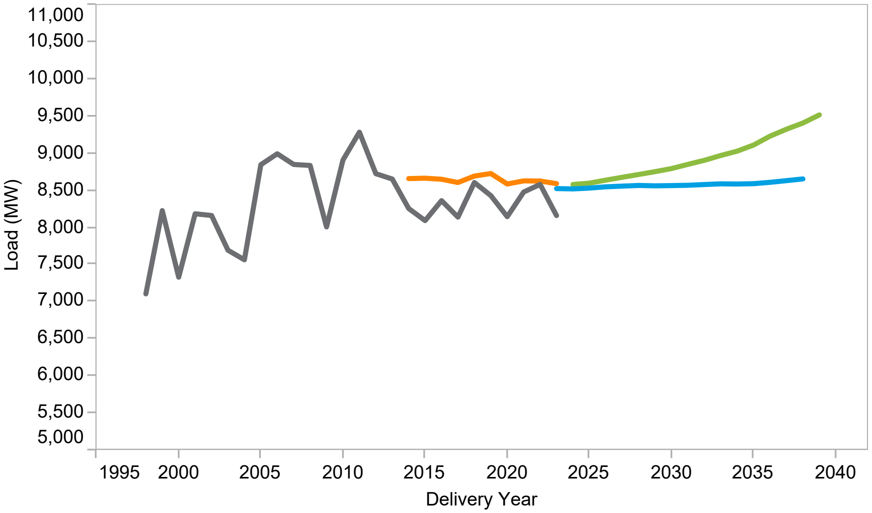
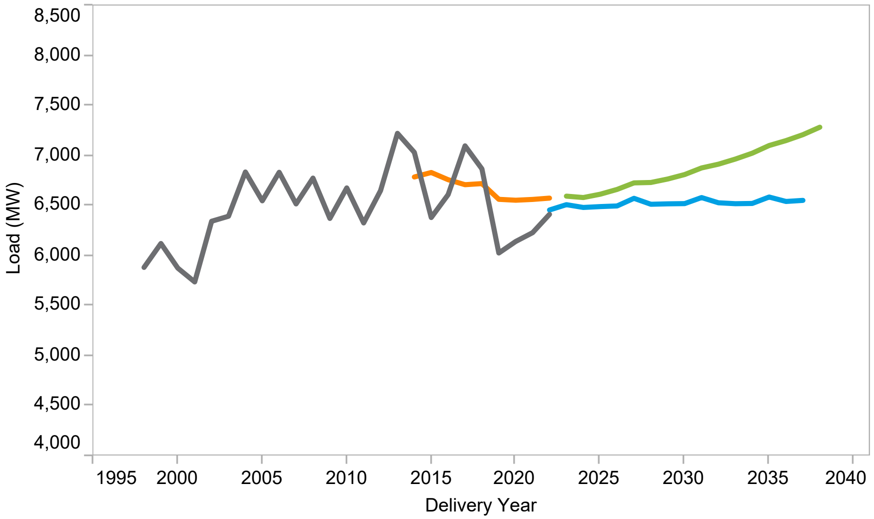
■ Allentown-Bethlehem-Easton, PA-NJ
■ East Stroudsburg, PA
■ Gettysburg, PA
■ Lebanon, PA
■ METED - Non-Metro
■ Reading, PA
■ York-Hanover, PA

PECO Energy (PECO)

Summer Peak



Winter Peak



⬛ Peak 🟧 WN peak 🟦 Forecast 2023 🟩 Forecast 2024

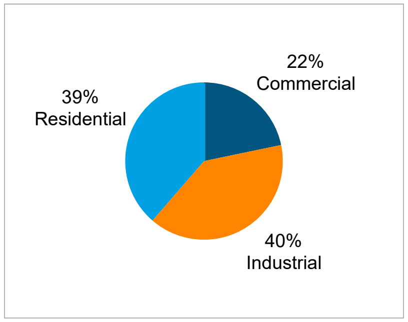
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*76.6*
Avg Summer Max Temp	*97.1*
Avg Winter Daily Temp	*36.6*
Avg Winter Min Temp	*9.2*

Zonal 10/15 Year Load Growth

SUMMER	0.5%	0.7%
WINTER	0.5%	0.7%

RCI Makeup



LDAs

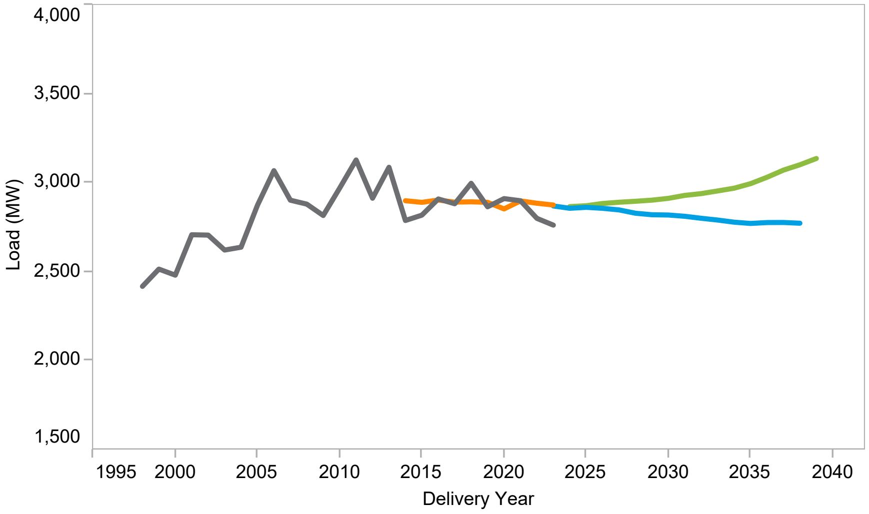
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Metropolitan Statistical Areas and Weather Stations

- 🟪 Montgomery County-Bucks County-Chester County, PA
- ⬜ PECO - Non-Metro
- 🟦 Philadelphia, PA

Pennsylvania Electric Company (PENLC)

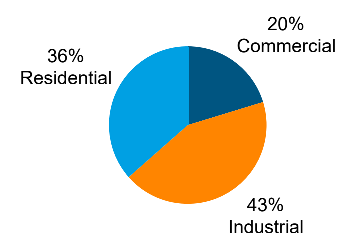
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*71.1*
Avg Summer Max Temp	*91.6*
Avg Winter Daily Temp	*30.3*
Avg Winter Min Temp	*2.0*

RCI Makeup



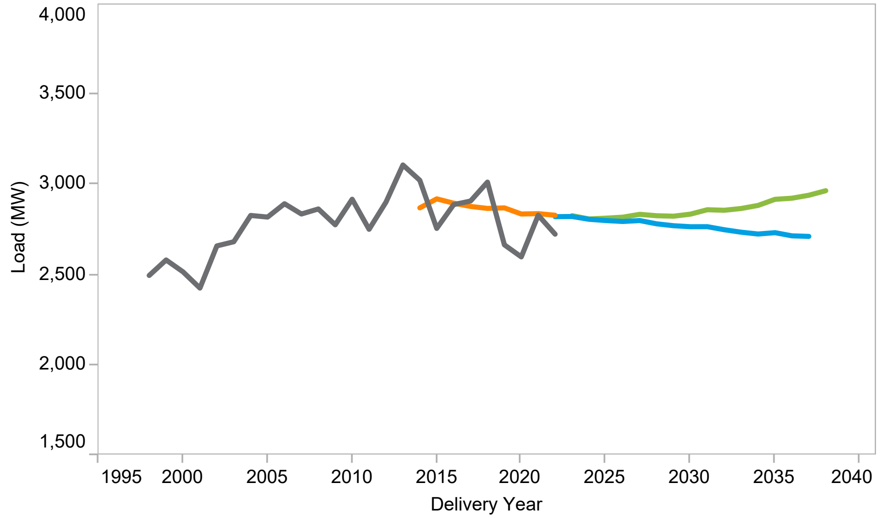
Zonal 10/15 Year Load Growth

SUMMER	0.4%	0.6%
WINTER	0.1%	0.3%

LDAs

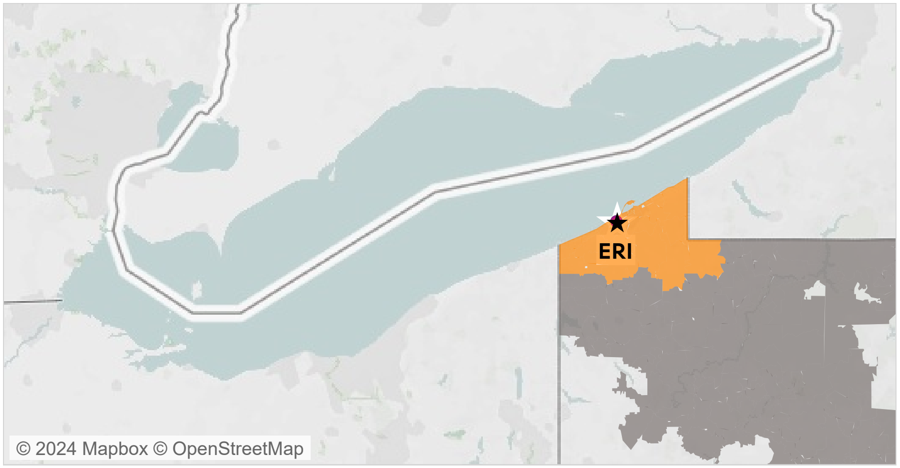
GPU PJM MID-ATLANTIC PJM RTO WESTERN MID-ATLANTIC

Winter Peak



■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

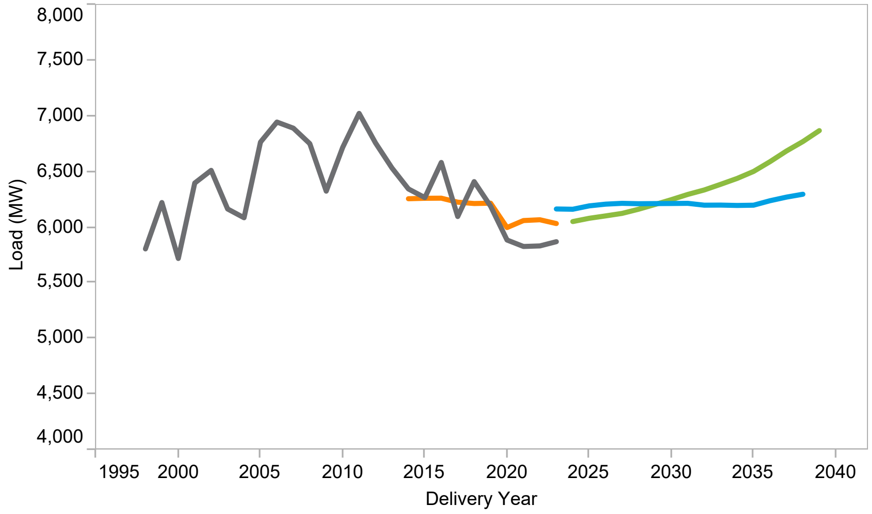
Metropolitan Statistical Areas and Weather Stations



■ Altoona, PA
■ Erie, PA
■ Johnstown, PA
■ PENLC - Non-Metro

Potomac Electric Power (PEPCO)

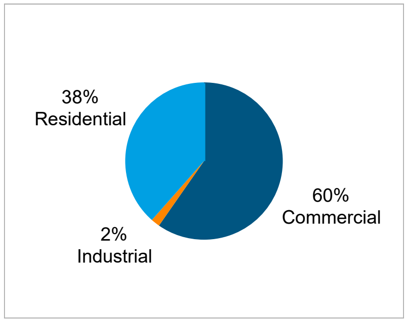
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*78.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*39.0*
Avg Winter Min Temp	*12.8*

RCI Makeup



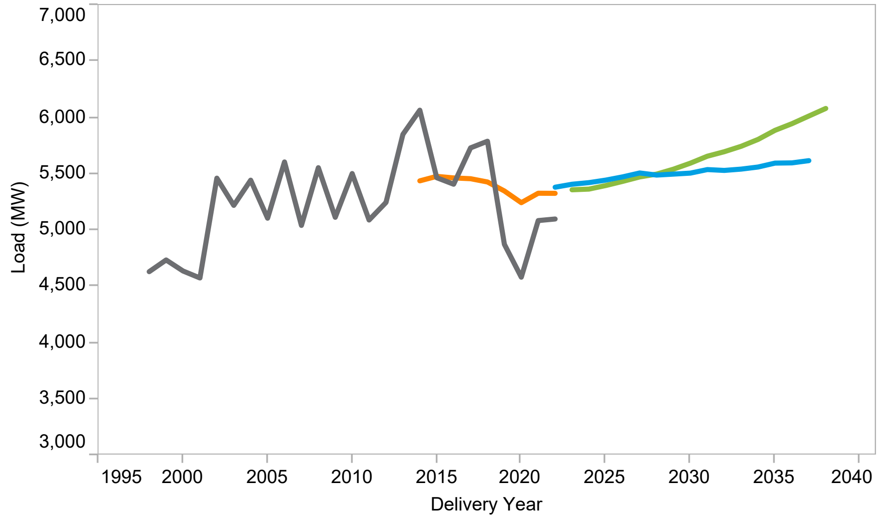
Zonal 10/15 Year Load Growth

SUMMER	0.6%	0.8%
WINTER	0.7%	0.8%

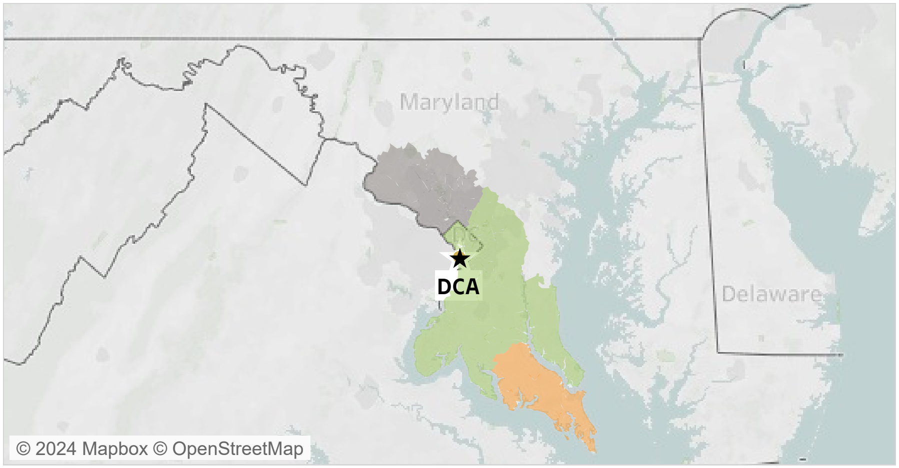
LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO SOUTHERN MID-ATLANTIC

Winter Peak



Metropolitan Statistical Areas and Weather Stations

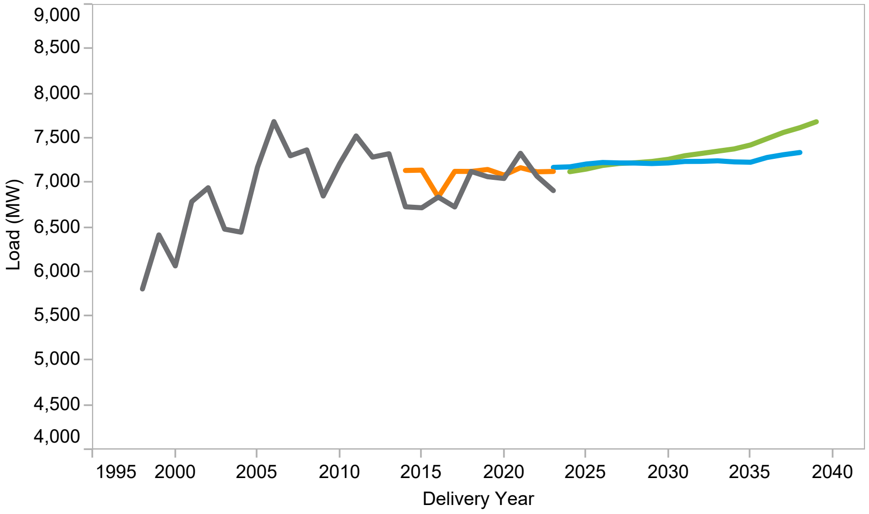


🟧 California-Lexington Park, MD
⬜ PEPCO - Non-Metro
🟩 Washington-Arlington-Alexandria, DC-VA-MD-WV

⬛ Peak   🟧 WN peak   🟦 Forecast 2023   🟩 Forecast 2024

PPL Electric Utilities (PL)

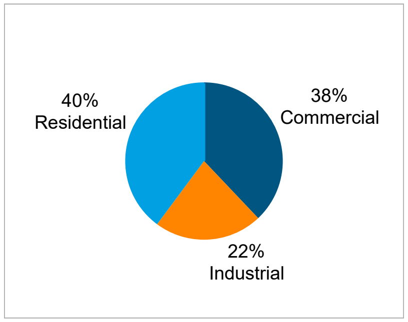
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*72.4*
Avg Summer Max Temp	*94.2*
Avg Winter Daily Temp	*31.5*
Avg Winter Min Temp	*2.8*

RCI Makeup



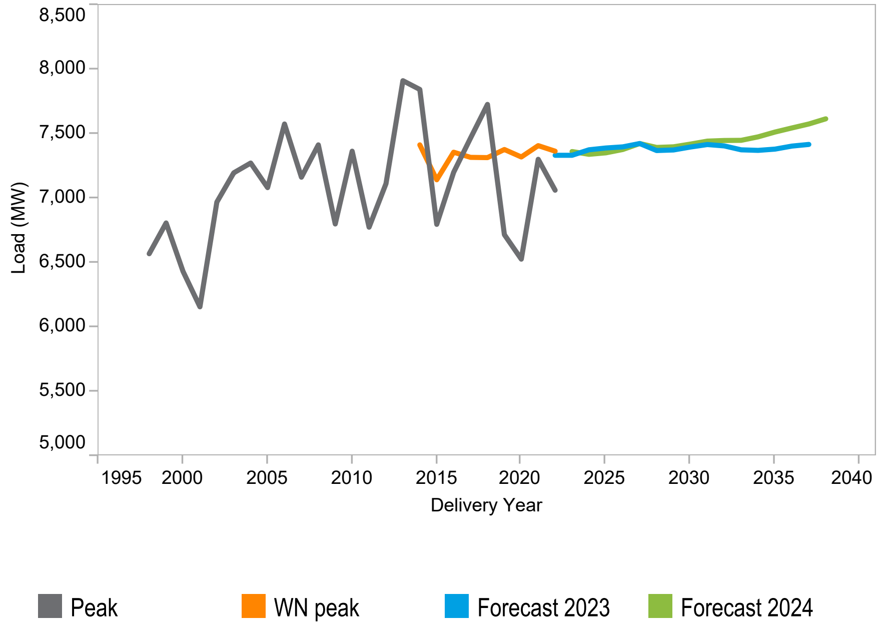
Zonal 10/15 Year Load Growth

SUMMER	0.4%	0.5%
WINTER	0.1%	0.2%

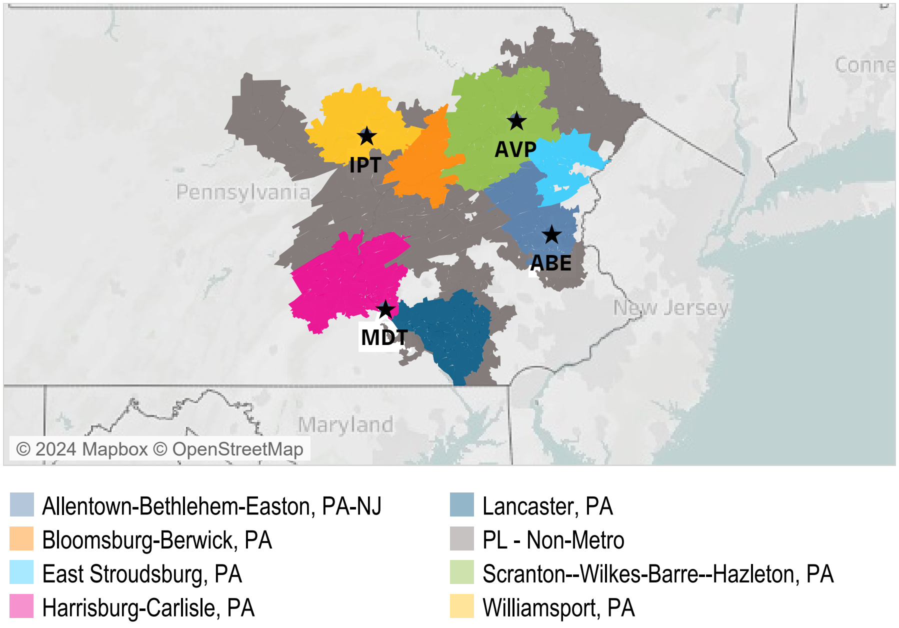
LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO PLGRP WESTERN MID-ATLANTIC

Winter Peak

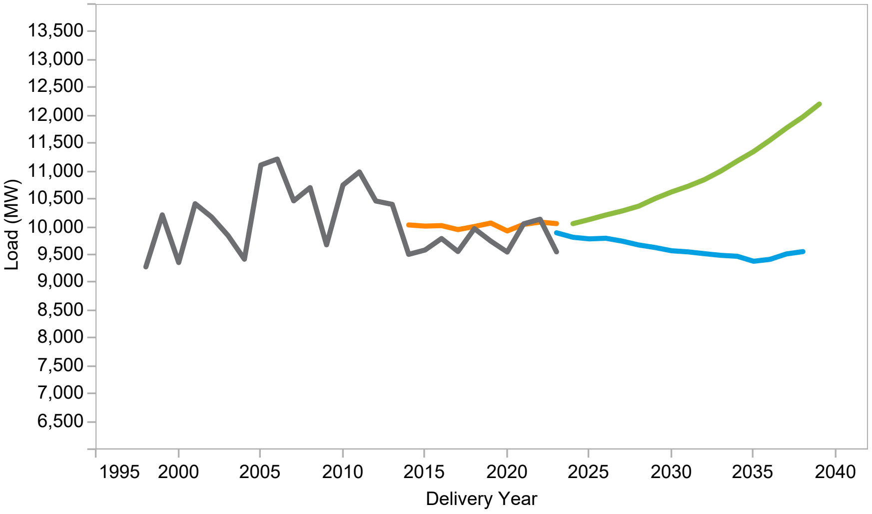


Metropolitan Statistical Areas and Weather Stations



Public Service Electric & Gas (PS)

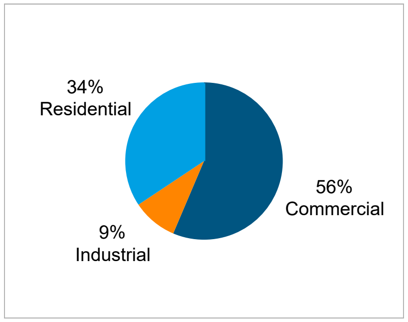
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*98.8*
Avg Winter Daily Temp	*35.6*
Avg Winter Min Temp	*7.5*

RCI Makeup



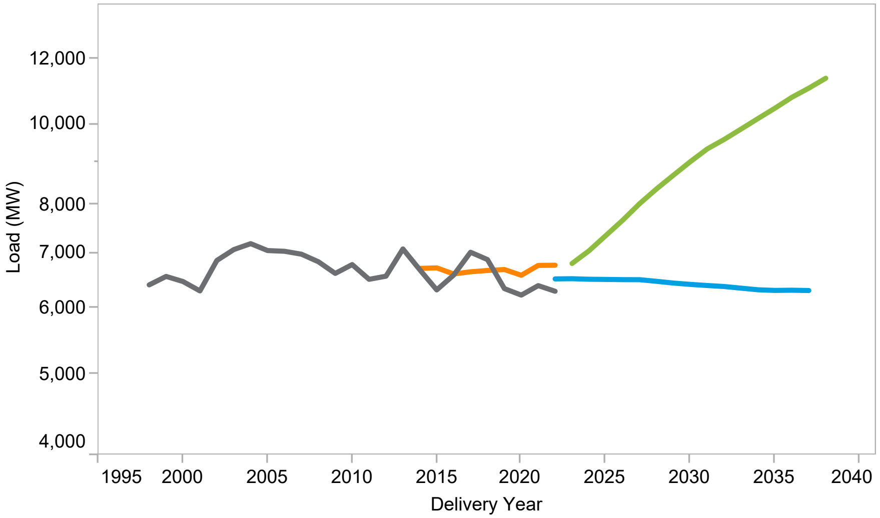
Zonal 10/15 Year Load Growth

SUMMER	1.1%	1.3%
WINTER	3.8%	3.5%

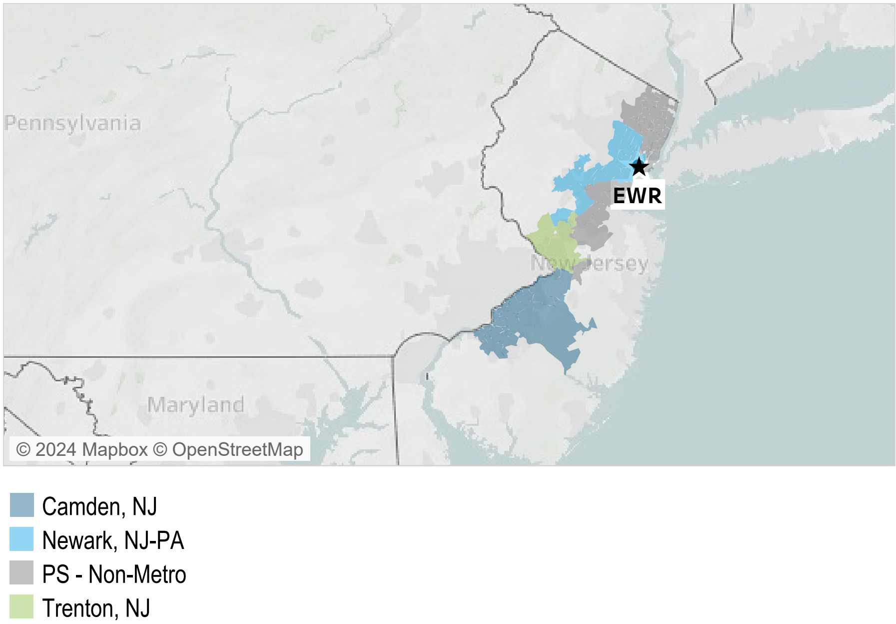
LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



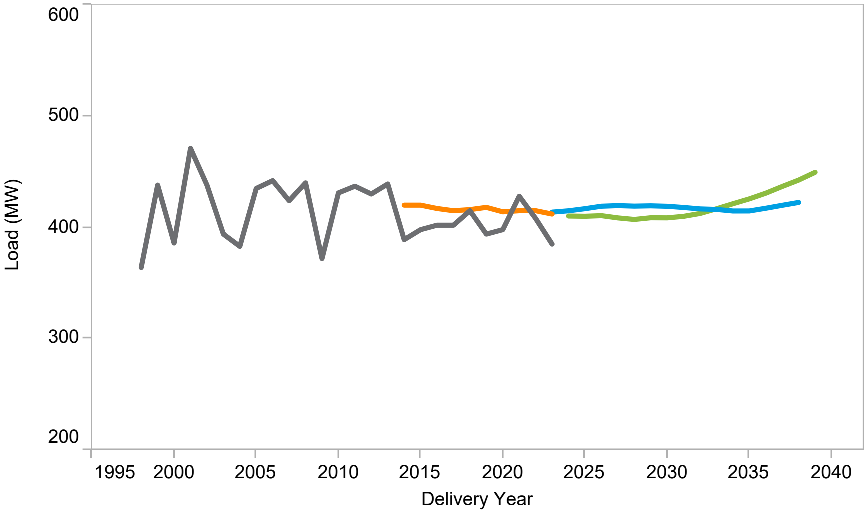
Metropolitan Statistical Areas and Weather Stations



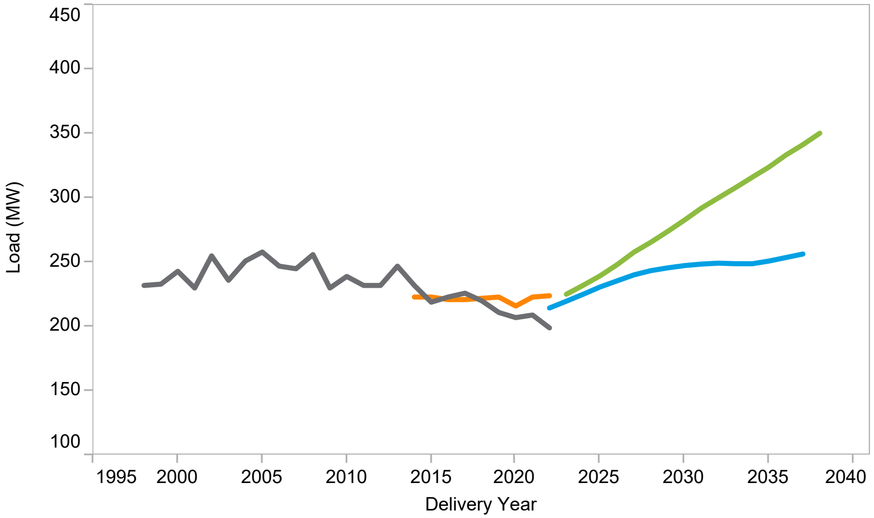
■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

Rockland Electric Company (RECO)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

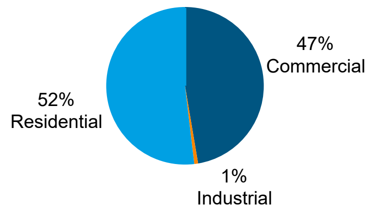
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*76.0*
Avg Summer Max Temp	*98.8*
Avg Winter Daily Temp	*35.6*
Avg Winter Min Temp	*7.5*

Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.6%
WINTER	3.2%	3.0%

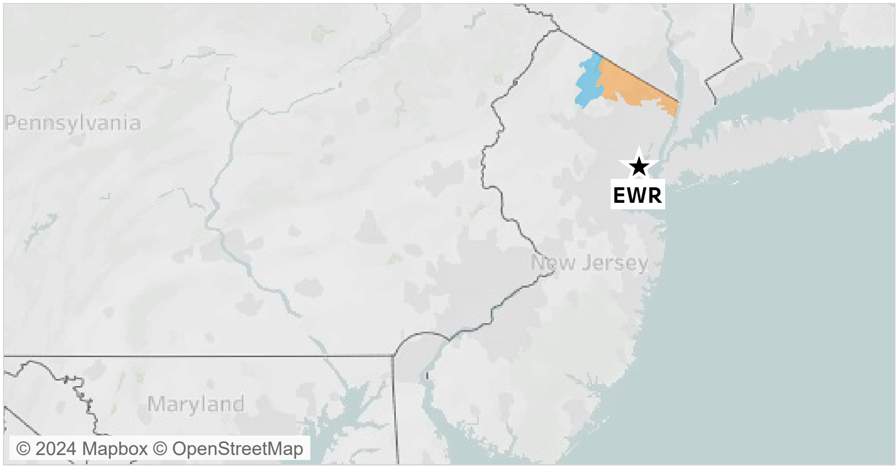
RCI Makeup



LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Metropolitan Statistical Areas and Weather Stations

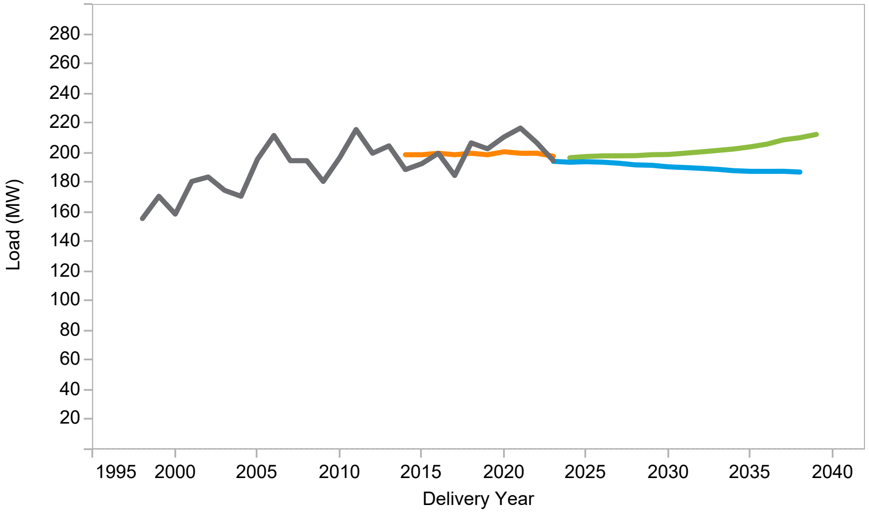


🟧 New York-Jersey City-White Plains, NY-NJ

🟦 Newark, NJ-PA

UGI Energy Services (UGI)

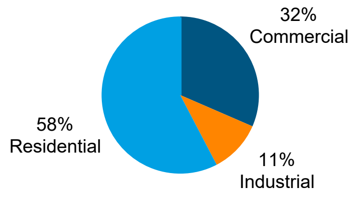
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*70.6*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*30.1*
Avg Winter Min Temp	*-1.0*

RCI Makeup



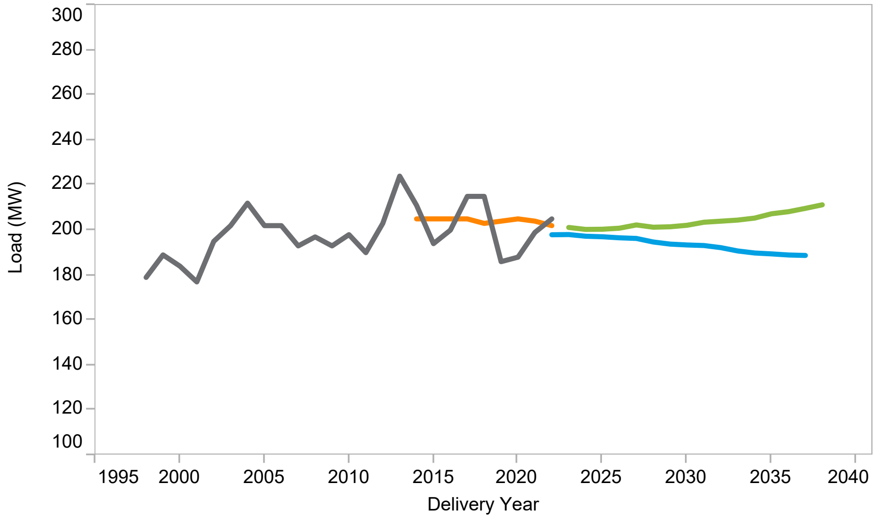
Zonal 10/15 Year Load Growth

SUMMER	0.3%	0.5%
WINTER	0.2%	0.3%

LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO PLGRP WESTERN MID-ATLANTIC

Winter Peak



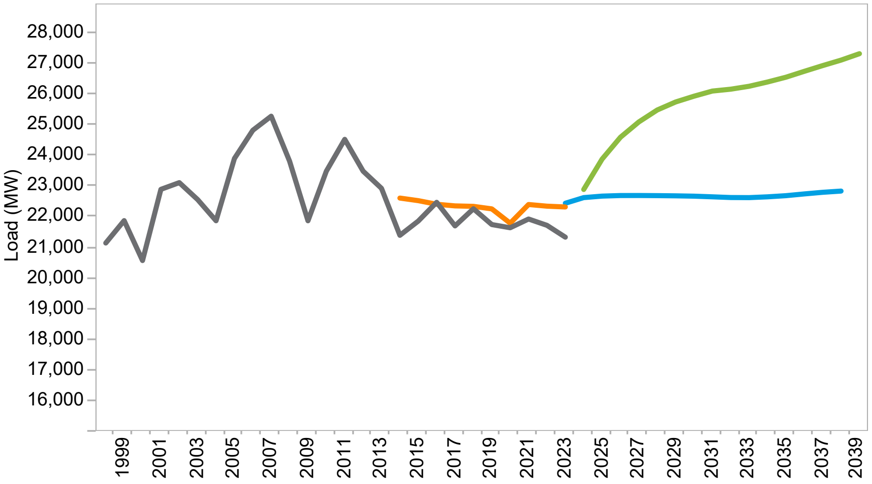
Metropolitan Statistical Areas and Weather Stations

🟩 Scranton--Wilkes-Barre--Hazleton, PA

⬛ Peak 🟧 WN peak 🟦 Forecast 2023 🟩 Forecast 2024

American Electric Power (AEP)

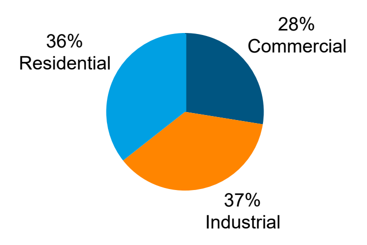
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*92.4*
Avg Winter Daily Temp	*33.2*
Avg Winter Min Temp	*2.6*

RCI Makeup



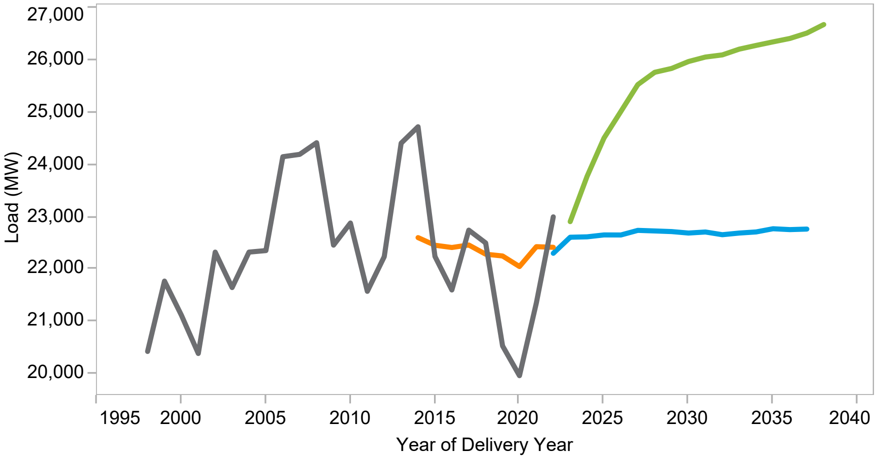
Zonal 10/15 Year Load Growth

SUMMER	1.4%	1.2%
WINTER	1.4%	1.0%

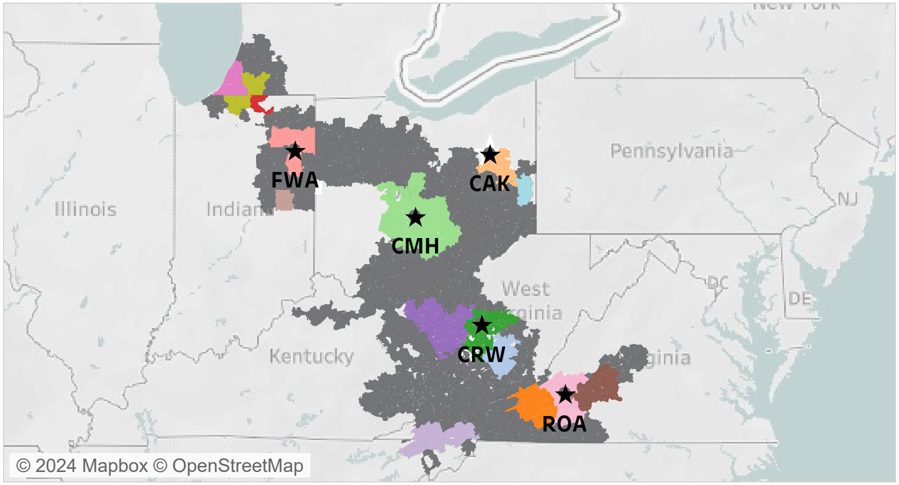
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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■ Peak
■ WN peak
■ Forecast 2023
■ Forecast 2024

■ AEP - Non-Metro
■ Beckley, WV
■ Blacksburg-Christiansburg-Radford, VA
■ Canton-Massillon, OH
■ Charleston, WV

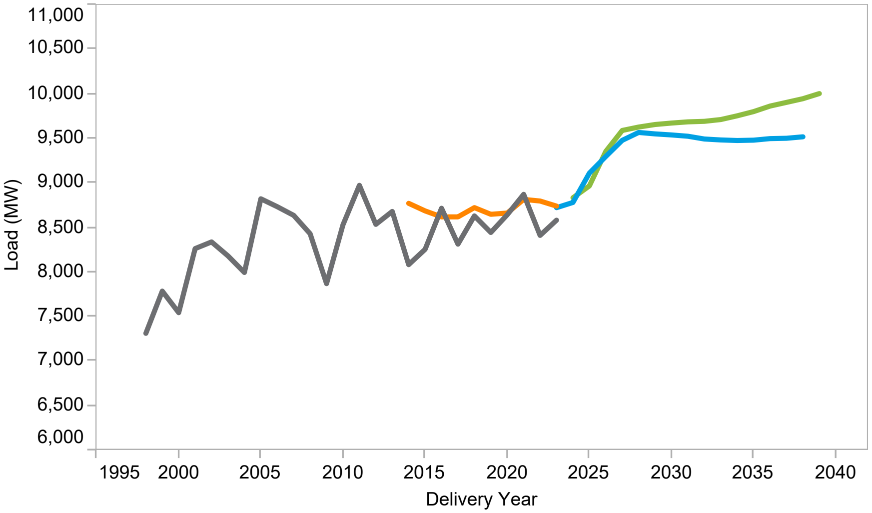
■ Columbus, OH
■ Elkhart-Goshen, IN
■ Fort Wayne, IN
■ Huntington-Ashland, WV-KY-OH
■ Kingsport-Bristol-Bristol, TN-VA

■ Lynchburg, VA
■ Muncie, IN
■ Niles-Benton Harbor, MI
■ Roanoke, VA
■ South Bend-Mishawaka, IN-MI

■ Weirton-Steubenville, WV-OH

Allegheny Power Systems (APS)

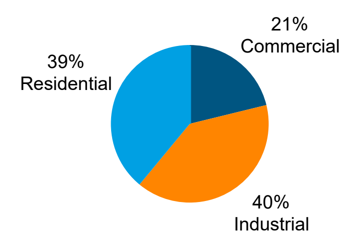
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*72.8*
Avg Summer Max Temp	*92.5*
Avg Winter Daily Temp	*32.9*
Avg Winter Min Temp	*2.2*

RCI Makeup



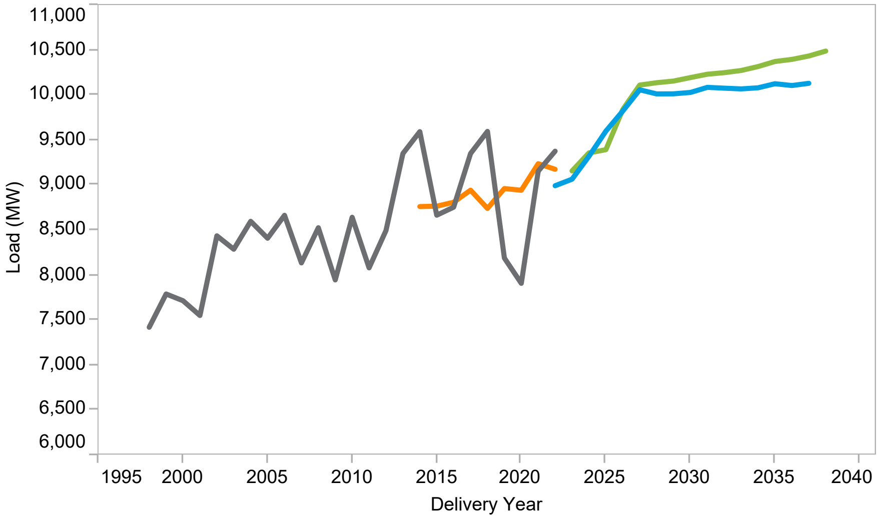
Zonal 10/15 Year Load Growth

SUMMER	1.0%	0.8%
WINTER	1.2%	0.9%

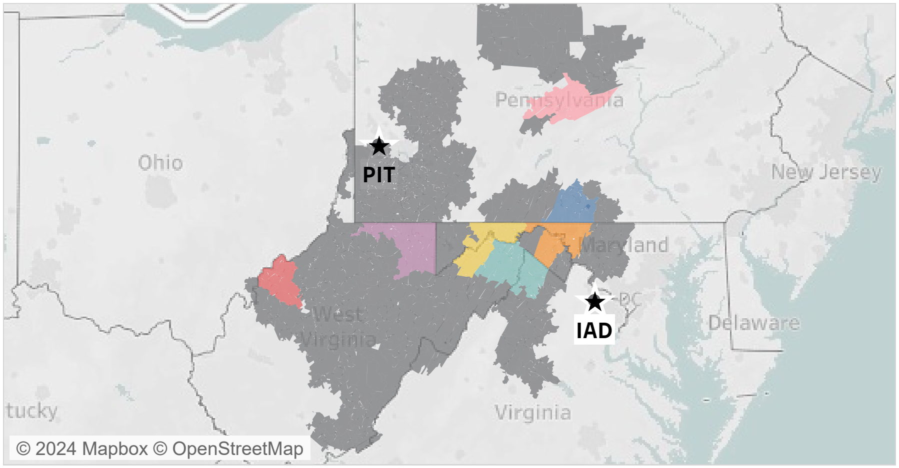
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations

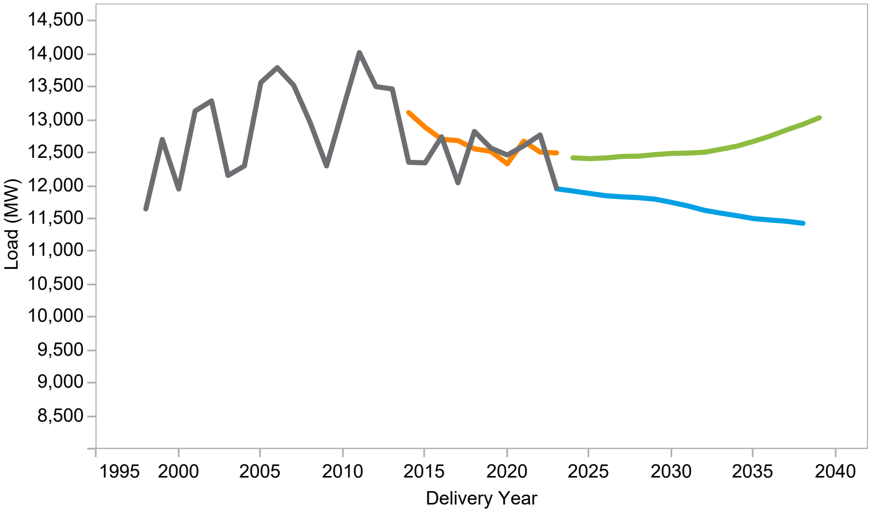


- ■ APS - Non-metro
- ■ Chambersburg-Waynesboro, PA
- ■ Cumberland, MD-WV
- ■ Hagerstown-Martinsburg, MD-WV
- ■ Morgantown, WV
- ■ Parkersburg-Vienna, WV
- ■ State College, PA
- ■ Winchester, VA-WV

■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

American Transmission Systems, Inc. (ATSI)

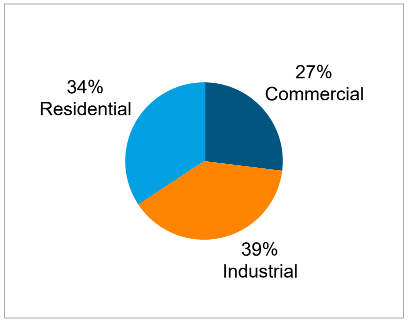
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*71.7*
Avg Summer Max Temp	*92.0*
Avg Winter Daily Temp	*29.9*
Avg Winter Min Temp	*-1.4*

RCI Makeup



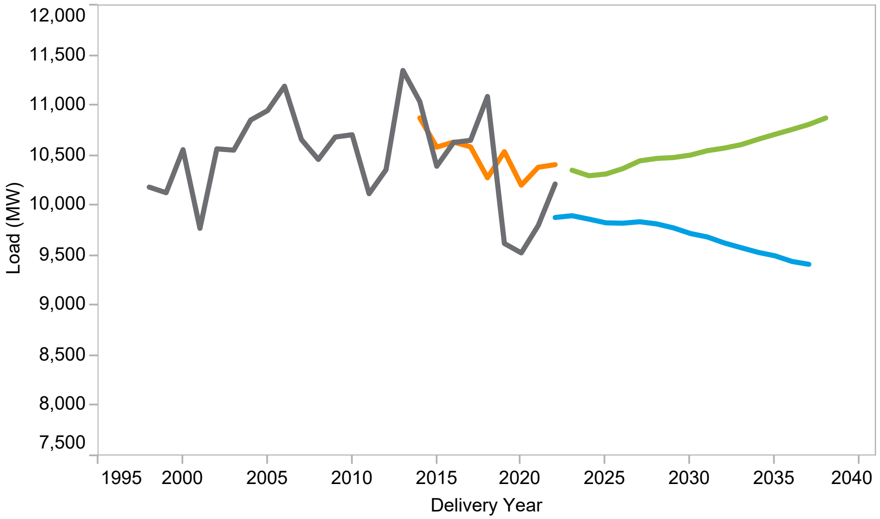
Zonal 10/15 Year Load Growth

SUMMER	0.1%	0.3%
WINTER	0.2%	0.3%

LDAs

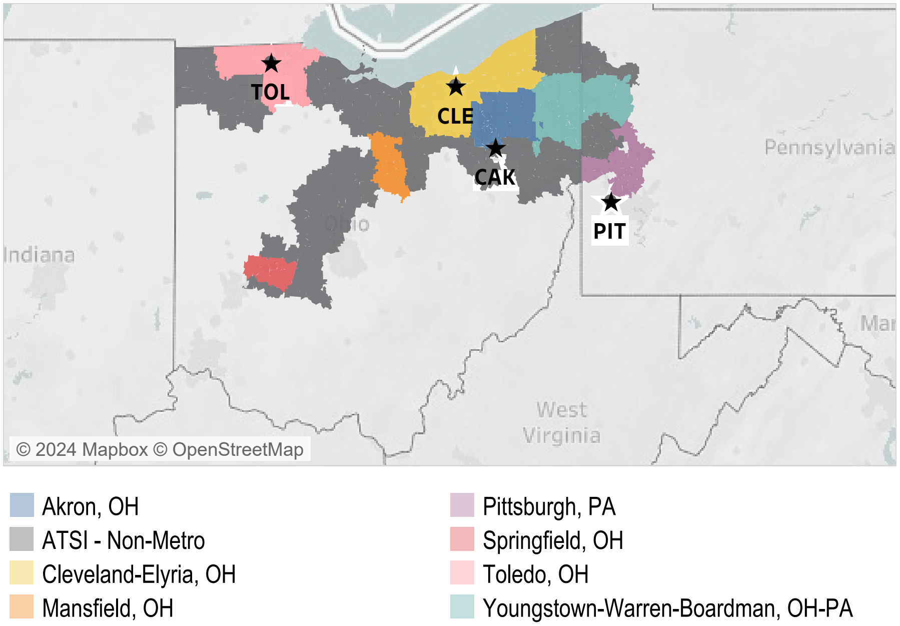
PJM RTO PJM WESTERN

Winter Peak



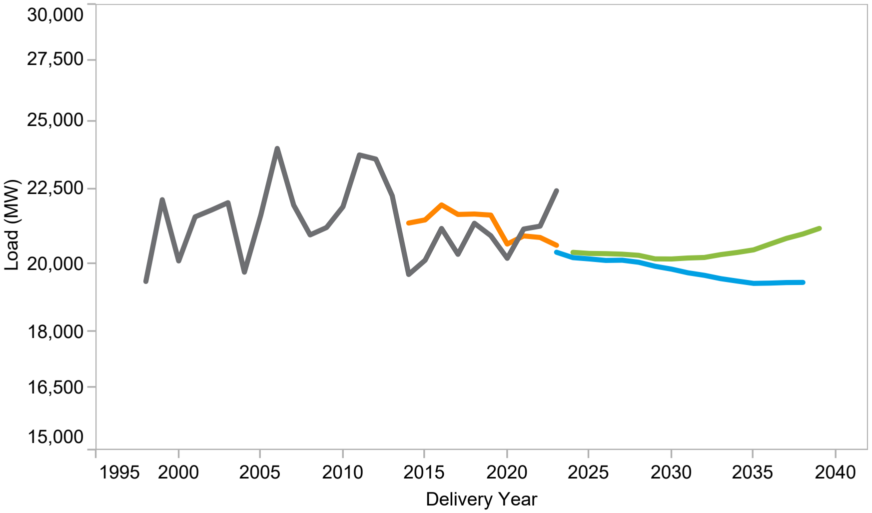
■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

Metropolitan Statistical Areas and Weather Stations



Commonweath Edison (COMED)

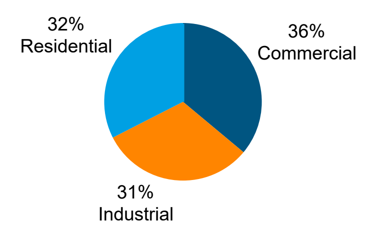
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*73.0*
Avg Summer Max Temp	*95.4*
Avg Winter Daily Temp	*27.6*
Avg Winter Min Temp	*-7.4*

RCI Makeup



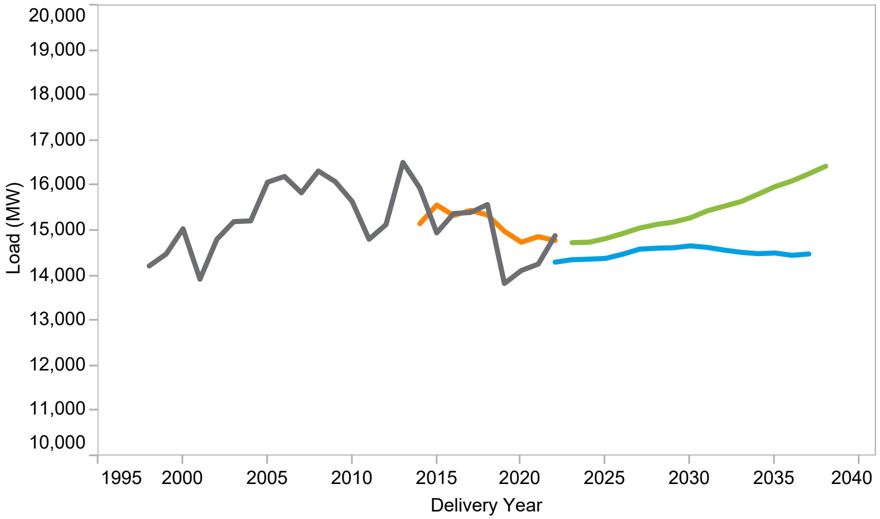
Zonal 10/15 Year Load Growth

SUMMER	0.0%	0.2%
WINTER	0.6%	0.7%

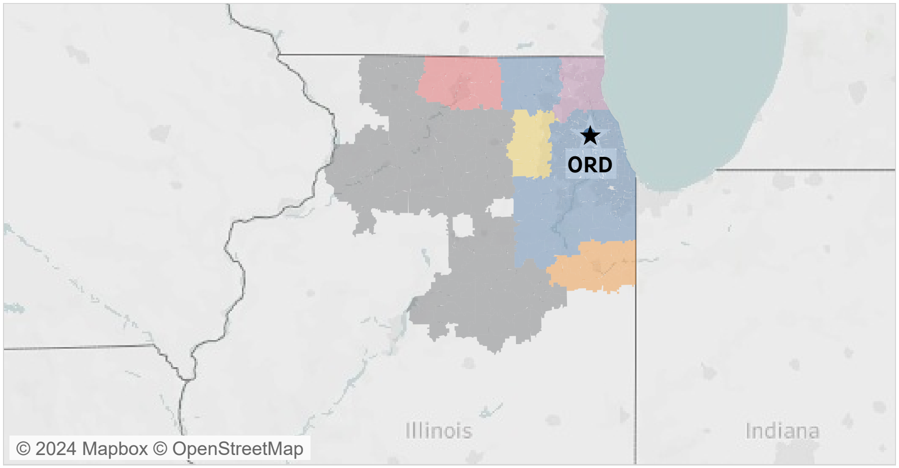
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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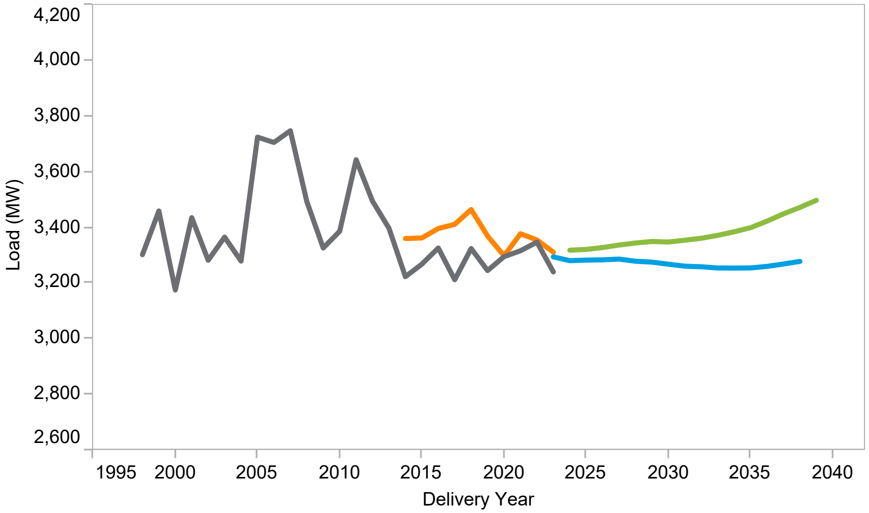
- 🟦 Chicago-Naperville-Arlington Heights, IL
- 🟨 Chicago-Naperville-Elgin, IL-IN-WI
- ⬜ COMED - Non-Metro
- 🟧 Kankakee, IL
- 🟪 Lake County-Kenosha County, IL-WI
- 🟥 Rockford, IL

- ⬛ Peak
- 🟧 WN peak
- 🟦 Forecast 2023
- 🟩 Forecast 2024

Dayton Power and Light (DAYTON)

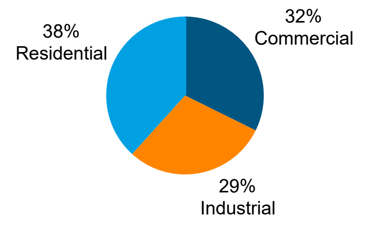
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*93.1*
Avg Winter Daily Temp	*31.0*
Avg Winter Min Temp	*-3.4*

RCI Makeup



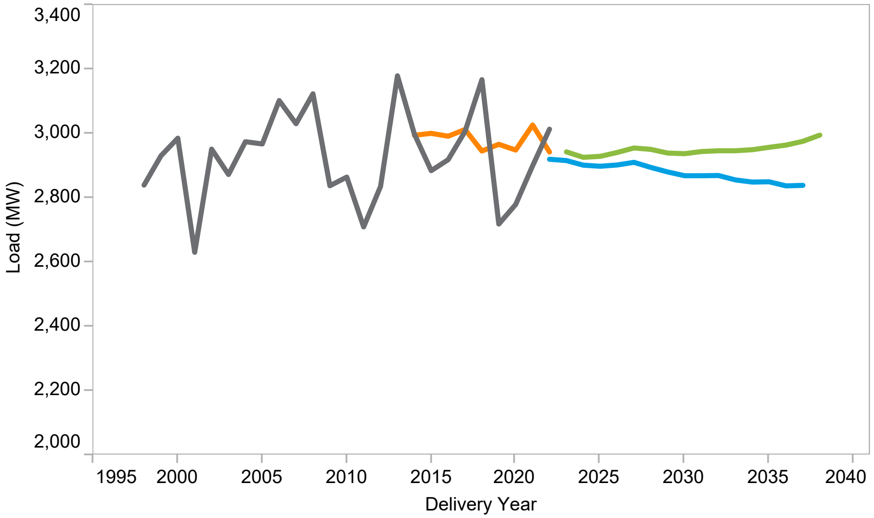
Zonal 10/15 Year Load Growth

SUMMER	0.2%	0.4%
WINTER	0.0%	0.1%

LDAs

PJM RTO PJM WESTERN

Winter Peak

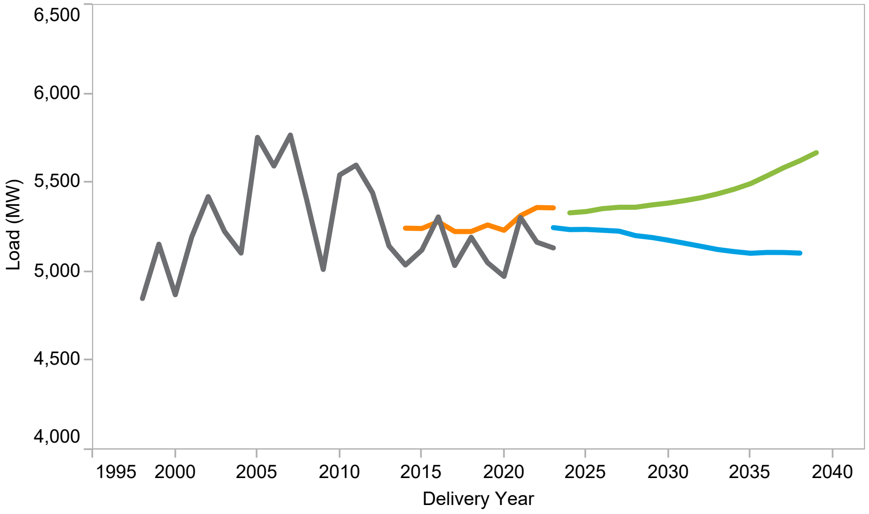


Metropolitan Statistical Areas and Weather Stations

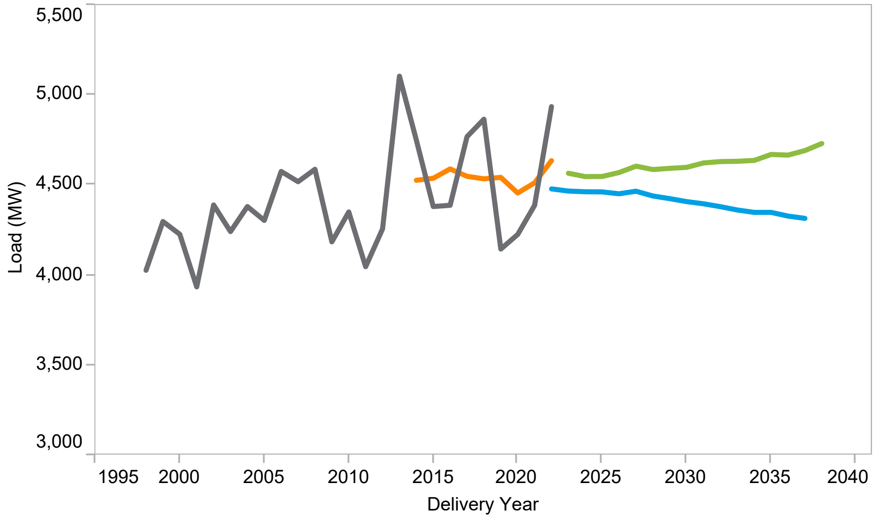
■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

Duke Energy Ohio and Kentucky (DEOK)

Summer Peak



Winter Peak



■ Peak

■ WN peak

■ Forecast 2023

■ Forecast 2024

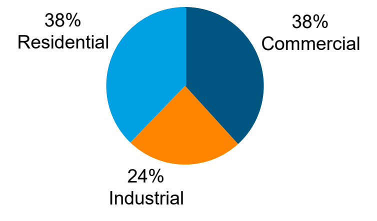
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*74.4*
Avg Summer Max Temp	*94.0*
Avg Winter Daily Temp	*33.9*
Avg Winter Min Temp	*-1.7*

Zonal 10/15 Year Load Growth

SUMMER	0.2%	0.4%
WINTER	0.1%	0.2%

RCI Makeup



LDAs

PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations

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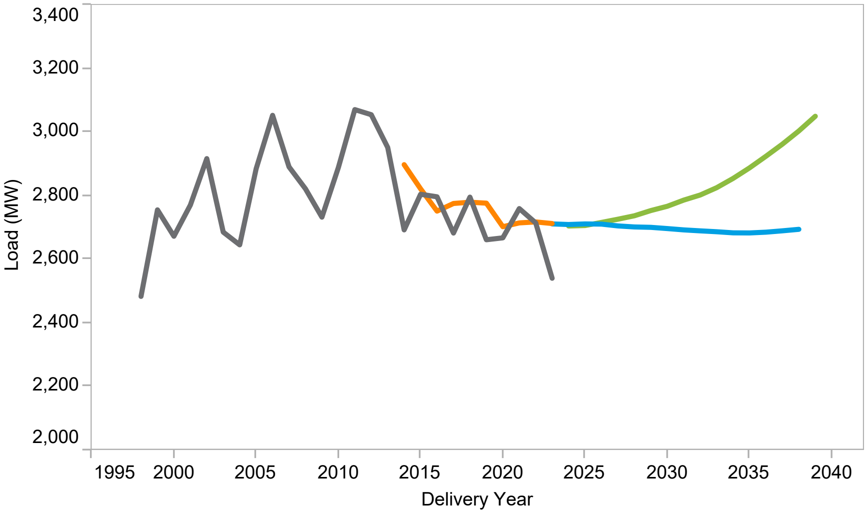
■ Cincinnati, OH-KY-IN

■ DEOK - Non-Metro

Duquesne Light Company (DLCO)

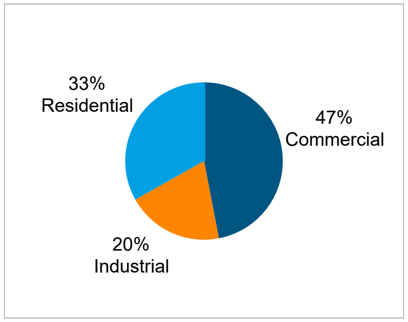
Summer Peak



Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*71.7*
Avg Summer Max Temp	*91.7*
Avg Winter Daily Temp	*31.4*
Avg Winter Min Temp	*-1.0*

RCI Makeup



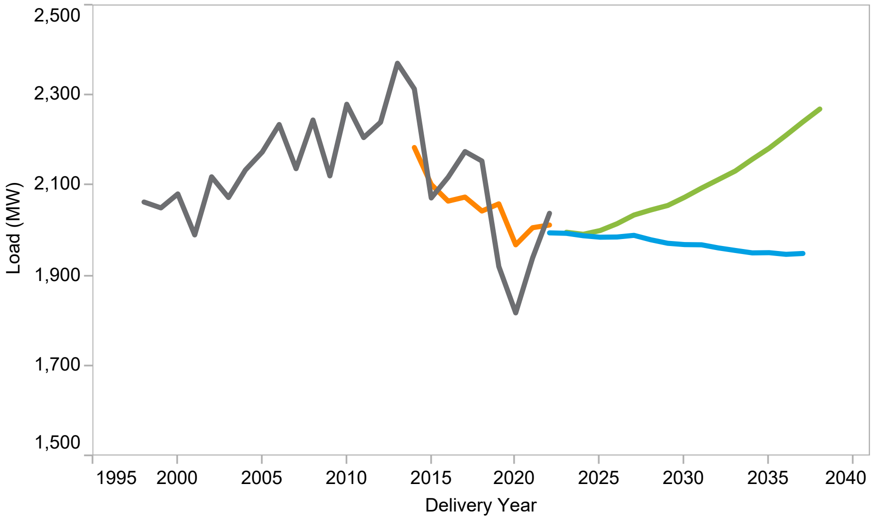
Zonal 10/15 Year Load Growth

SUMMER	0.5%	0.8%
WINTER	0.7%	0.9%

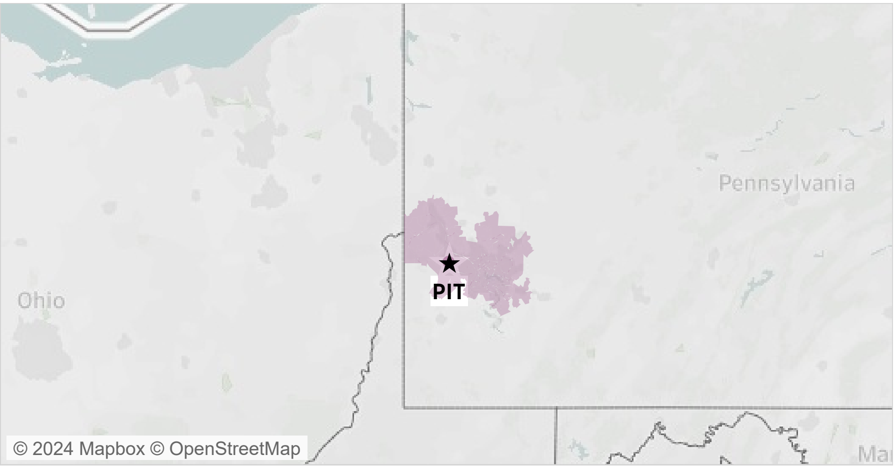
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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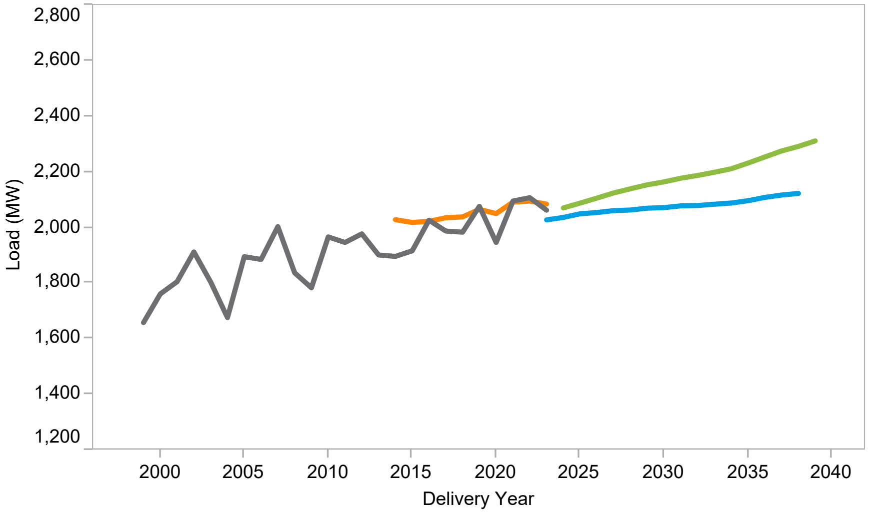
🟪 Pittsburgh, PA

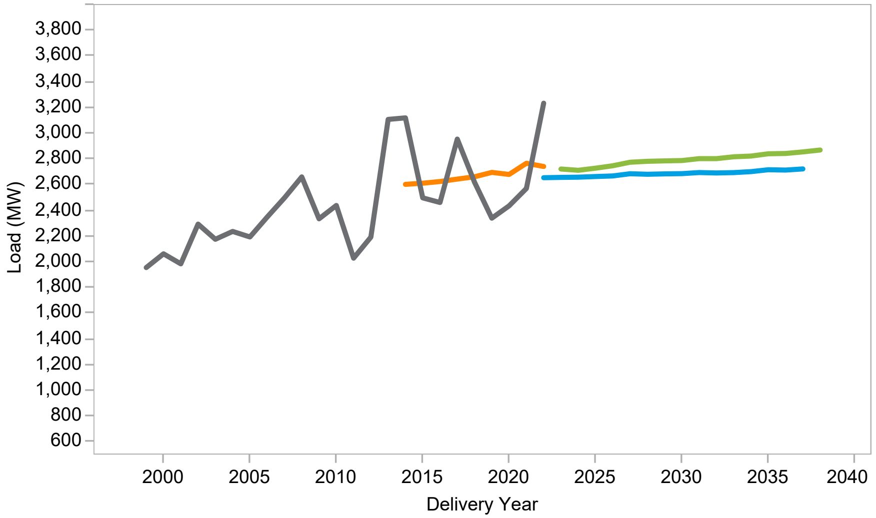
⬛ Peak 🟧 WN peak 🟦 Forecast 2023 🟩 Forecast 2024

East Kentucky Power Cooperative (EKPC)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

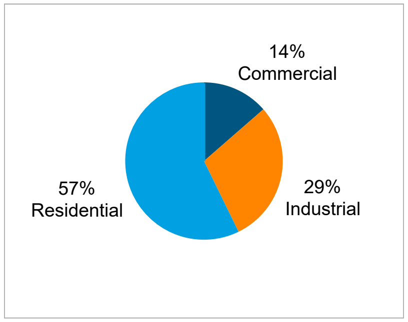
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*94.3*
Avg Winter Daily Temp	*35.9*
Avg Winter Min Temp	*1.9*

Zonal 10/15 Year Load Growth

SUMMER	0.7%	0.7%
WINTER	0.3%	0.4%

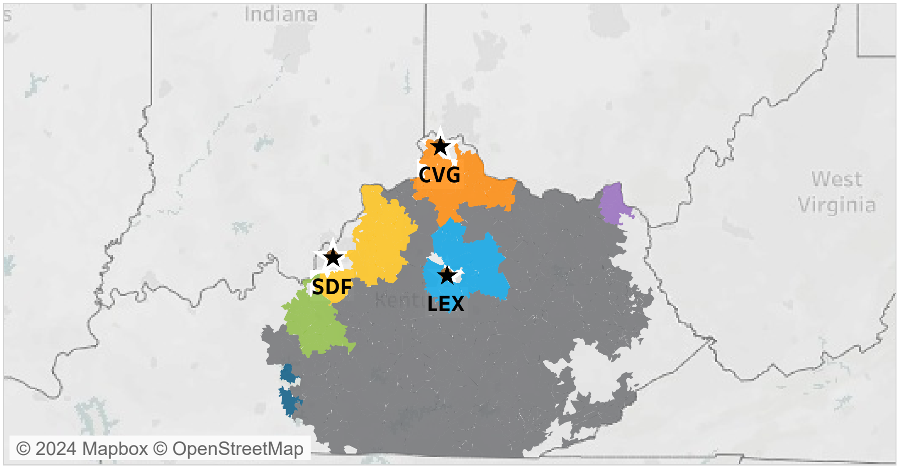
RCI Makeup



LDAs

PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations



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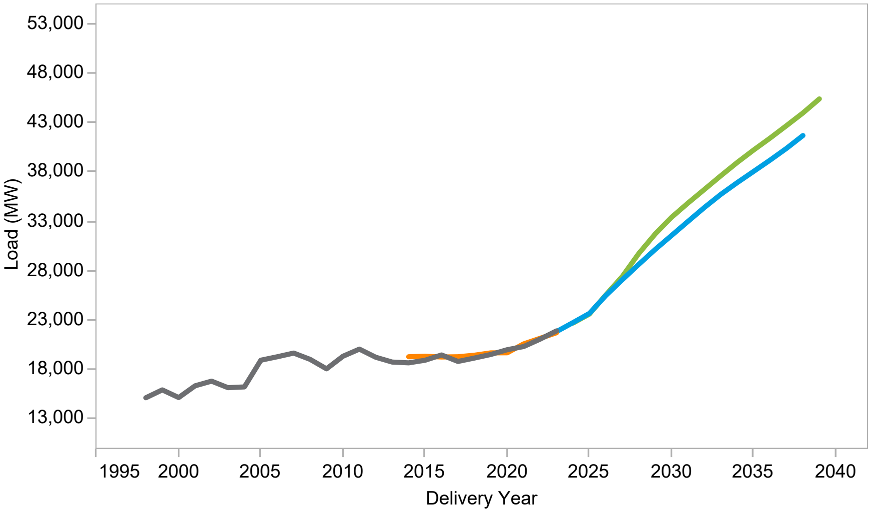
- Bowling Green, KY
- Cincinnati, OH-KY-IN
- EKPC - Non-Metro
- Elizabethtown-Fort Knox, KY
- Huntington-Ashland, WV-KY-OH
- Lexington-Fayette, KY
- Louisville/Jefferson County, KY-IN

Dominion (DOM)

Summer Peak



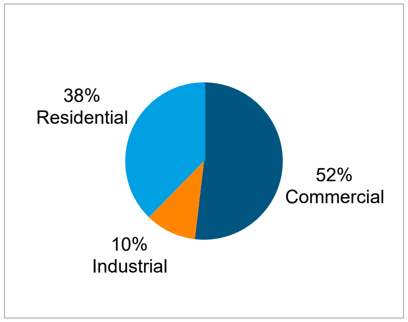
Weather - Annual Average 1994-2022

Avg Summer Daily Temp	*76.9*
Avg Summer Max Temp	*96.9*
Avg Winter Daily Temp	*40.3*
Avg Winter Min Temp	*12.3*

Zonal 10/15 Year Load Growth

SUMMER	5.5%	4.7%
WINTER	5.0%	4.3%

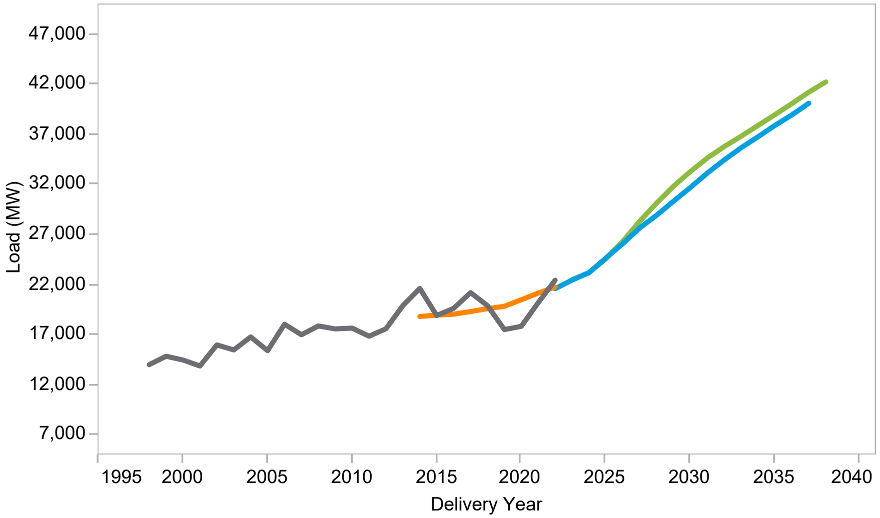
RCI Makeup



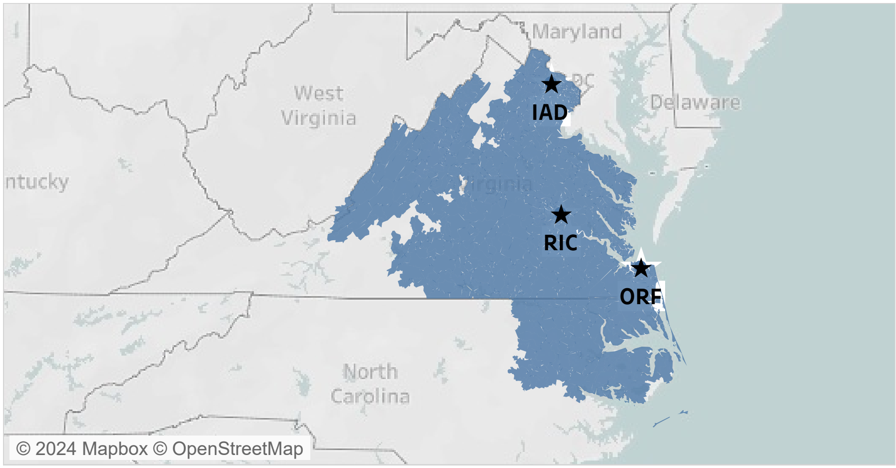
LDAs

PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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▨ Virginia Commonwealth Economics

■ Peak ■ WN peak ■ Forecast 2023 ■ Forecast 2024

Table A-1

PJM MID-ATLANTIC REGION
SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2023 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2024		2029		2034	
	MW	%	MW	%	MW	%
AE	67	2.7%	147	6.0%	308	12.8%
BGE	63	1.0%	393	6.3%	926	15.4%
DPL	104	2.7%	181	4.8%	397	10.9%
JCPL	20	0.3%	320	5.4%	940	16.2%
METED	(5)	-0.2%	240	7.8%	597	19.1%
PECO	59	0.7%	191	2.2%	443	5.2%
PENLC	9	0.3%	82	2.9%	190	6.8%
PEPCO	(111)	-1.8%	(8)	-0.1%	242	3.9%
PL	(55)	-0.8%	23	0.3%	146	2.0%
PS	244	2.5%	881	9.1%	1,711	18.0%
RECO	(5)	-1.2%	(10)	-2.4%	6	1.4%
UGI	3	1.5%	7	3.6%	15	8.0%
PJM MID-ATLANTIC	383	0.7%	2,257	4.1%	5,890	10.9%
FE-EAST	50	0.4%	597	5.2%	1,703	14.9%
PLGRP	(56)	-0.8%	25	0.3%	151	2.0%

Table A-1

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO SUMMER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2023 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	2024		2029		2034	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	265	1.2%	3,062	13.5%	3,745	16.5%
APS	52	0.6%	106	1.1%	277	2.9%
ATSI	504	4.2%	678	5.7%	1,059	9.2%
COMED	168	0.8%	231	1.2%	889	4.6%
DAYTON	38	1.2%	74	2.3%	130	4.0%
DEOK	94	1.8%	183	3.5%	351	6.9%
DLCO	(5)	-0.2%	53	2.0%	171	6.4%
EKPC	34	1.7%	84	4.1%	123	5.9%
OVEC	(5)	-5.3%	(5)	-5.3%	(5)	-5.3%
PJM WESTERN	1,129	1.5%	4,396	5.8%	6,655	8.9%
DOM	(47)	-0.2%	1,560	5.2%	2,039	5.5%
PJM RTO	1,510	1.0%	8,758	5.6%	14,727	9.1%

Table A-2

PJM MID-ATLANTIC REGION
WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2023 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	23/24		28/29		33/34	
	MW	%	MW	%	MW	%
AE	52	3.3%	297	18.8%	608	39.2%
BGE	80	1.4%	236	4.1%	646	11.4%
DPL	68	1.9%	124	3.4%	231	6.3%
JCPL	65	1.7%	1,041	27.0%	2,189	56.8%
METED	22	0.8%	244	8.9%	599	21.7%
PECO	85	1.3%	217	3.3%	446	6.8%
PENLC	5	0.2%	44	1.6%	132	4.8%
PEPCO	(49)	-0.9%	9	0.2%	203	3.7%
PL	29	0.4%	24	0.3%	74	1.0%
PS	283	4.3%	1,901	29.3%	3,542	55.7%
RECO	5	2.3%	22	9.0%	59	23.7%
UGI	3	1.5%	6	3.1%	13	6.8%
PJM MID-ATLANTIC	798	1.7%	4,456	9.7%	9,196	20.2%
FE-EAST	101	1.1%	1,340	14.4%	2,913	31.4%
PLGRP	37	0.5%	31	0.4%	87	1.2%

Table A-2

PJM WESTERN REGION, PJM SOUTHERN REGION AND PJM RTO WINTER PEAK LOAD COMPARISONS OF THE CURRENT FORECAST TO THE JANUARY 2023 LOAD FORECAST REPORT

INCREASE OR DECREASE OVER PRIOR FORECAST

	23/24		28/29		33/34	
	MW	**%**	**MW**	**%**	**MW**	**%**
AEP	298	1.3%	3,033	13.3%	3,515	15.5%
APS	92	1.0%	124	1.2%	204	2.0%
ATSI	455	4.6%	653	6.6%	1,029	10.7%
COMED	379	2.6%	526	3.6%	1,128	7.8%
DAYTON	27	0.9%	56	1.9%	91	3.2%
DEOK	99	2.2%	147	3.3%	270	6.2%
DLCO	2	0.1%	66	3.3%	176	9.0%
EKPC	65	2.4%	101	3.8%	123	4.6%
OVEC	0	0.0%	0	0.0%	0	0.0%
PJM WESTERN	1,418	2.1%	4,591	6.8%	6,688	10.0%
DOM	45	0.2%	1,216	4.2%	1,149	3.2%
PJM RTO	1,992	1.5%	9,929	7.1%	17,091	11.7%

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2024 - 2034

	METERED 2023	UNRESTRICTED 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Annual Growth Rate (10 yr)
AE	2,629	2,629	2,593	2,599	2,602	2,601	2,603	2,614	2,623	2,641	2,661	2,685	2,715	0.5%
				0.2%	0.1%	-0.0%	0.1%	0.4%	0.3%	0.7%	0.8%	0.9%	1.1%	
BGE	6,406	6,406	6,491	6,507	6,523	6,554	6,592	6,636	6,676	6,719	6,781	6,849	6,931	0.7%
				0.2%	0.2%	0.5%	0.6%	0.7%	0.6%	0.6%	0.9%	1.0%	1.2%	
DPL	4,078	4,094	3,945	3,926	3,913	3,912	3,916	3,928	3,941	3,962	3,981	4,010	4,050	0.3%
				-0.5%	-0.3%	-0.0%	0.1%	0.3%	0.3%	0.5%	0.5%	0.7%	1.0%	
JCPL	5,732	5,732	6,052	6,085	6,099	6,128	6,175	6,252	6,315	6,392	6,490	6,609	6,750	1.1%
				0.5%	0.2%	0.5%	0.8%	1.2%	1.0%	1.2%	1.5%	1.8%	2.1%	
METED	2,891	2,891	3,036	3,077	3,141	3,205	3,256	3,323	3,383	3,454	3,538	3,620	3,715	2.0%
				1.4%	2.1%	2.0%	1.6%	2.1%	1.8%	2.1%	2.4%	2.3%	2.6%	
PECO	8,163	8,163	8,581	8,599	8,640	8,679	8,716	8,754	8,796	8,852	8,907	8,972	9,031	0.5%
				0.2%	0.5%	0.5%	0.4%	0.4%	0.5%	0.6%	0.6%	0.7%	0.7%	
PENLC	2,764	2,764	2,867	2,872	2,885	2,892	2,897	2,903	2,913	2,930	2,940	2,955	2,970	0.4%
				0.2%	0.5%	0.2%	0.2%	0.2%	0.3%	0.6%	0.3%	0.5%	0.5%	
PEPCO	5,872	5,872	6,053	6,082	6,104	6,126	6,164	6,206	6,250	6,297	6,337	6,388	6,440	0.6%
				0.5%	0.4%	0.4%	0.6%	0.7%	0.7%	0.8%	0.6%	0.8%	0.8%	
PL	6,899	6,915	7,126	7,156	7,196	7,218	7,227	7,241	7,266	7,306	7,331	7,357	7,382	0.4%
				0.4%	0.6%	0.3%	0.1%	0.2%	0.3%	0.6%	0.3%	0.4%	0.3%	
PS	9,562	9,562	10,068	10,143	10,224	10,296	10,383	10,520	10,638	10,740	10,859	11,013	11,193	1.1%
				0.7%	0.8%	0.7%	0.8%	1.3%	1.1%	1.0%	1.1%	1.4%	1.6%	
RECO	385	385	410	410	411	409	407	409	409	410	413	417	421	0.3%
				0.0%	0.2%	-0.5%	-0.5%	0.5%	0.0%	0.2%	0.7%	1.0%	1.0%	
UGI	195	195	197	198	198	198	198	199	199	200	201	202	203	0.3%
				0.5%	0.0%	0.0%	0.0%	0.5%	0.0%	0.5%	0.5%	0.5%	0.5%	
DIVERSITY - MID-ATLANTIC(-)			1,586	1,636	1,603	1,729	1,830	1,990	2,009	1,993	1,913	1,975	1,896	
PJM MID-ATLANTIC	54,507	54,540	55,833	56,018	56,333	56,489	56,704	56,995	57,400	57,910	58,526	59,102	59,905	0.7%
				0.3%	0.6%	0.3%	0.4%	0.5%	0.7%	0.9%	1.1%	1.0%	1.4%	
FE-EAST	11,191	11,191	11,723	11,791	11,882	11,973	12,050	12,187	12,305	12,467	12,682	12,895	13,151	1.2%
				0.6%	0.8%	0.8%	0.6%	1.1%	1.0%	1.3%	1.7%	1.7%	2.0%	
PLGRP	7,093	7,109	7,323	7,354	7,394	7,414	7,420	7,437	7,462	7,506	7,530	7,551	7,578	0.3%
				0.4%	0.5%	0.3%	0.1%	0.2%	0.3%	0.6%	0.3%	0.3%	0.4%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2024).
Summer season indicates peak from June, July, August.

Table B-1 (continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2035 - 2039

	2035	2036	2037	2038	2039	Annual Growth Rate (15 yr)
AE	2,755	2,793	2,839	2,873	2,916	0.8%
	1.5%	1.4%	1.6%	1.2%	1.5%	
BGE	7,036	7,139	7,258	7,364	7,495	1.0%
	1.5%	1.5%	1.7%	1.5%	1.8%	
DPL	4,091	4,146	4,201	4,238	4,292	0.6%
	1.0%	1.3%	1.3%	0.9%	1.3%	
JCPL	6,902	7,058	7,224	7,367	7,547	1.5%
	2.3%	2.3%	2.4%	2.0%	2.4%	
METED	3,824	3,942	4,077	4,200	4,343	2.4%
	2.9%	3.1%	3.4%	3.0%	3.4%	
PECO	9,113	9,233	9,326	9,409	9,519	0.7%
	0.9%	1.3%	1.0%	0.9%	1.2%	
PENLC	2,996	3,032	3,072	3,102	3,137	0.6%
	0.9%	1.2%	1.3%	1.0%	1.1%	
PEPCO	6,503	6,591	6,687	6,772	6,870	0.8%
	1.0%	1.4%	1.5%	1.3%	1.4%	
PL	7,427	7,497	7,567	7,621	7,687	0.5%
	0.6%	0.9%	0.9%	0.7%	0.9%	
PS	11,365	11,570	11,787	11,987	12,218	1.3%
	1.5%	1.8%	1.9%	1.7%	1.9%	
RECO	426	431	437	443	449	0.6%
	1.2%	1.2%	1.4%	1.4%	1.4%	
UGI	204	206	209	210	213	0.5%
	0.5%	1.0%	1.5%	0.5%	1.4%	
DIVERSITY - MID-ATLANTIC(-)	1,918	1,970	1,785	1,802	1,864	
PJM MID-ATLANTIC	60,724	61,668	62,899	63,784	64,822	1.0%
	1.4%	1.6%	2.0%	1.4%	1.6%	
FE-EAST	13,432	13,738	14,074	14,381	14,746	1.5%
	2.1%	2.3%	2.4%	2.2%	2.5%	
PLGRP	7,624	7,701	7,772	7,827	7,897	0.5%
	0.6%	1.0%	0.9%	0.7%	0.9%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2024).
Summer season indicates peak from June, July, August.

Table B-1

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2024 - 2034

	METERED 2023	UNRESTRICTED 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Annual Growth Rate (10 yr)
AEP	21,348	21,348	22,902	23,893	24,607	25,106	25,495	25,757	25,945	26,113	26,174	26,269	26,408	1.4%
				4.3%	3.0%	2.0%	1.5%	1.0%	0.7%	0.6%	0.2%	0.4%	0.5%	
APS	8,584	8,585	8,835	8,968	9,356	9,591	9,629	9,658	9,674	9,687	9,693	9,713	9,755	1.0%
				1.5%	4.3%	2.5%	0.4%	0.3%	0.2%	0.1%	0.1%	0.2%	0.4%	
ATSI	11,963	11,974	12,433	12,421	12,432	12,455	12,458	12,483	12,500	12,505	12,518	12,563	12,612	0.1%
				-0.1%	0.1%	0.2%	0.0%	0.2%	0.1%	0.0%	0.1%	0.4%	0.4%	
COMED	22,468	22,468	20,414	20,380	20,372	20,356	20,320	20,208	20,204	20,236	20,252	20,343	20,411	(0.0%)
				-0.2%	-0.0%	-0.1%	-0.2%	-0.6%	-0.0%	0.2%	0.1%	0.4%	0.3%	
DAYTON	3,241	3,241	3,319	3,322	3,329	3,338	3,345	3,350	3,348	3,355	3,362	3,372	3,385	0.2%
				0.1%	0.2%	0.3%	0.2%	0.1%	-0.1%	0.2%	0.2%	0.3%	0.4%	
DEOK	5,135	5,135	5,332	5,339	5,356	5,363	5,363	5,376	5,387	5,401	5,417	5,439	5,465	0.2%
				0.1%	0.3%	0.1%	0.0%	0.2%	0.2%	0.3%	0.3%	0.4%	0.5%	
DLCO	2,535	2,541	2,705	2,707	2,716	2,727	2,737	2,754	2,767	2,787	2,803	2,826	2,855	0.5%
				0.1%	0.3%	0.4%	0.4%	0.6%	0.5%	0.7%	0.6%	0.8%	1.0%	
EKPC	2,063	2,063	2,070	2,088	2,105	2,124	2,139	2,153	2,164	2,177	2,187	2,199	2,211	0.7%
				0.9%	0.8%	0.9%	0.7%	0.7%	0.5%	0.6%	0.5%	0.5%	0.5%	
OVEC	82	82	90	90	90	90	90	90	90	90	90	90	90	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,571	1,612	1,552	1,516	1,523	1,665	1,719	1,858	1,776	1,810	1,801	
PJM WESTERN	73,321	73,330	76,529	77,596	78,811	79,634	80,053	80,164	80,360	80,493	80,720	81,004	81,391	0.6%
				1.4%	1.6%	1.0%	0.5%	0.1%	0.2%	0.2%	0.3%	0.4%	0.5%	
DOM	21,993	21,993	22,781	23,691	25,627	27,487	29,800	31,776	33,472	34,911	36,288	37,673	39,019	5.5%
				4.0%	8.2%	7.3%	8.4%	6.6%	5.3%	4.3%	3.9%	3.8%	3.6%	
DIVERSITY - TOTAL(-)			7,053	7,060	7,123	6,996	6,938	6,909	7,087	7,157	7,114	7,198	7,190	
PJM RTO	146,745	146,799	151,247	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822	1.6%
				1.5%	2.2%	1.9%	1.9%	1.7%	1.3%	1.3%	1.2%	1.3%	1.4%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2024).
Summer season indicates peak from June, July, August.

Table B-1 (continued)

SUMMER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2035 - 2039

	2035	2036	2037	2038	2039	Annual Growth Rate (15 yr)
AEP	26,564	26,756	26,944	27,122	27,331	1.2%
	0.6%	0.7%	0.7%	0.7%	0.8%	
APS	9,803	9,865	9,906	9,947	10,005	0.8%
	0.5%	0.6%	0.4%	0.4%	0.6%	
ATSI	12,684	12,763	12,857	12,942	13,043	0.3%
	0.6%	0.6%	0.7%	0.7%	0.8%	
COMED	20,494	20,679	20,864	21,005	21,188	0.2%
	0.4%	0.9%	0.9%	0.7%	0.9%	
DAYTON	3,400	3,423	3,450	3,473	3,498	0.4%
	0.4%	0.7%	0.8%	0.7%	0.7%	
DEOK	5,496	5,540	5,585	5,625	5,670	0.4%
	0.6%	0.8%	0.8%	0.7%	0.8%	
DLCO	2,888	2,924	2,962	3,004	3,050	0.8%
	1.2%	1.2%	1.3%	1.4%	1.5%	
EKPC	2,231	2,253	2,275	2,291	2,311	0.7%
	0.9%	1.0%	1.0%	0.7%	0.9%	
OVEC	90	90	90	90	90	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,740	1,853	1,862	1,872	1,842	
PJM WESTERN	81,910	82,440	83,071	83,627	84,344	0.7%
	0.6%	0.6%	0.8%	0.7%	0.9%	
DOM	40,279	41,482	42,742	44,023	45,445	4.7%
	3.2%	3.0%	3.0%	3.0%	3.2%	
DIVERSITY - TOTAL(-)	6,949	6,926	7,232	7,356	7,565	
PJM RTO	179,622	182,487	185,127	187,752	190,752	1.6%
	1.6%	1.6%	1.4%	1.4%	1.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2024).
Summer season indicates peak from June, July, August.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2023/24 - 2033/34

	METERED 22/23	UNRESTRICTED 22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	Annual Growth Rate (10 yr)
AE	1,559	1,566	1,637	1,673	1,721	1,774	1,835	1,876	1,928	1,988	2,053	2,105	2,161	2.8%
				2.2%	2.9%	3.1%	3.4%	2.2%	2.8%	3.1%	3.3%	2.5%	2.7%	
BGE	5,912	5,968	5,827	5,836	5,855	5,899	5,947	5,973	6,020	6,092	6,162	6,242	6,313	0.8%
				0.2%	0.3%	0.8%	0.8%	0.4%	0.8%	1.2%	1.1%	1.3%	1.1%	
DPL	3,659	3,705	3,700	3,705	3,730	3,756	3,793	3,793	3,812	3,833	3,872	3,894	3,915	0.6%
				0.1%	0.7%	0.7%	1.0%	0.0%	0.5%	0.6%	1.0%	0.6%	0.5%	
JCPL	3,497	3,517	3,817	3,989	4,208	4,439	4,678	4,892	5,115	5,354	5,610	5,819	6,040	4.7%
				4.5%	5.5%	5.5%	5.4%	4.6%	4.6%	4.7%	4.8%	3.7%	3.8%	
METED	2,534	2,535	2,740	2,752	2,799	2,859	2,946	2,987	3,054	3,122	3,210	3,281	3,365	2.1%
				0.4%	1.7%	2.1%	3.0%	1.4%	2.2%	2.2%	2.8%	2.2%	2.6%	
PECO	6,346	6,416	6,597	6,583	6,616	6,664	6,729	6,733	6,768	6,812	6,878	6,916	6,967	0.5%
				-0.2%	0.5%	0.7%	1.0%	0.1%	0.5%	0.7%	1.0%	0.6%	0.7%	
PENLC	2,722	2,726	2,829	2,811	2,815	2,820	2,836	2,828	2,826	2,837	2,862	2,859	2,869	0.1%
				-0.6%	0.1%	0.2%	0.6%	-0.3%	-0.1%	0.4%	0.9%	-0.1%	0.3%	
PEPCO	5,081	5,099	5,359	5,365	5,397	5,434	5,473	5,498	5,542	5,595	5,657	5,697	5,745	0.7%
				0.1%	0.6%	0.7%	0.7%	0.5%	0.8%	1.0%	1.1%	0.7%	0.8%	
PL	6,899	7,063	7,363	7,342	7,353	7,379	7,425	7,395	7,400	7,421	7,444	7,449	7,450	0.1%
				-0.3%	0.1%	0.4%	0.6%	-0.4%	0.1%	0.3%	0.3%	0.1%	0.0%	
PS	6,310	6,310	6,816	7,060	7,367	7,688	8,051	8,387	8,713	9,048	9,373	9,623	9,906	3.8%
				3.6%	4.3%	4.4%	4.7%	4.2%	3.9%	3.8%	3.6%	2.7%	2.9%	
RECO	199	199	225	232	240	248	258	266	274	283	292	300	308	3.2%
				3.1%	3.4%	3.3%	4.0%	3.1%	3.0%	3.3%	3.2%	2.7%	2.7%	
UGI	205	205	201	200	200	201	202	201	201	202	204	204	204	0.1%
				-0.5%	0.0%	0.5%	0.5%	-0.5%	0.0%	0.5%	1.0%	0.0%	0.0%	
DIVERSITY - MID-ATLANTIC(-)			604	733	747	737	431	584	608	642	593	460	448	
PJM MID-ATLANTIC	43,881	44,421	46,507	46,815	47,554	48,424	49,742	50,245	51,045	51,945	53,024	53,929	54,795	1.7%
				0.7%	1.6%	1.8%	2.7%	1.0%	1.6%	1.8%	2.1%	1.7%	1.6%	
FE-EAST	8,609	8,709	9,303	9,485	9,756	10,052	10,379	10,643	10,938	11,246	11,606	11,883	12,196	2.7%
				2.0%	2.9%	3.0%	3.3%	2.5%	2.8%	2.8%	3.2%	2.4%	2.6%	
PLGRP	7,104	7,268	7,561	7,541	7,553	7,575	7,620	7,587	7,596	7,612	7,637	7,642	7,647	0.1%
				-0.3%	0.2%	0.3%	0.6%	-0.4%	0.1%	0.2%	0.3%	0.1%	0.1%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023/24).
Winter season indicates peak from December, January, February.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2034/35 - 2038/39

	34/35	35/36	36/37	37/38	38/39	Annual Growth Rate (15 yr)
AE	2,223	2,294	2,355	2,420	2,489	2.8%
	2.9%	3.2%	2.7%	2.8%	2.9%	
BGE	6,414	6,519	6,608	6,703	6,803	1.0%
	1.6%	1.6%	1.4%	1.4%	1.5%	
DPL	3,946	3,994	4,022	4,058	4,105	0.7%
	0.8%	1.2%	0.7%	0.9%	1.2%	
JCPL	6,268	6,506	6,735	6,961	7,200	4.3%
	3.8%	3.8%	3.5%	3.4%	3.4%	
METED	3,464	3,580	3,672	3,786	3,912	2.4%
	2.9%	3.3%	2.6%	3.1%	3.3%	
PECO	7,026	7,102	7,152	7,211	7,285	0.7%
	0.8%	1.1%	0.7%	0.8%	1.0%	
PENLC	2,886	2,919	2,926	2,942	2,967	0.3%
	0.6%	1.1%	0.2%	0.5%	0.8%	
PEPCO	5,806	5,887	5,946	6,014	6,081	0.8%
	1.1%	1.4%	1.0%	1.1%	1.1%	
PL	7,477	7,514	7,546	7,577	7,617	0.2%
	0.4%	0.5%	0.4%	0.4%	0.5%	
PS	10,199	10,497	10,819	11,097	11,407	3.5%
	3.0%	2.9%	3.1%	2.6%	2.8%	
RECO	316	324	333	341	350	3.0%
	2.6%	2.5%	2.8%	2.4%	2.6%	
UGI	205	207	208	210	211	0.3%
	0.5%	1.0%	0.5%	1.0%	0.5%	
DIVERSITY - MID-ATLANTIC(-)	471	555	483	485	317	
PJM MID-ATLANTIC	55,759	56,788	57,839	58,835	60,110	1.7%
	1.8%	1.8%	1.9%	1.7%	2.2%	
FE-EAST	12,537	12,912	13,249	13,600	13,982	2.8%
	2.8%	3.0%	2.6%	2.6%	2.8%	
PLGRP	7,674	7,717	7,749	7,774	7,821	0.2%
	0.4%	0.6%	0.4%	0.3%	0.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023/24).
Winter season indicates peak from December, January, February.

Table B-2

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2023/24 - 2033/34

	METERED 22/23	UNRESTRICTED 22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	Annual Growth Rate (10 yr)
AEP	22,766	23,005	22,913	23,779	24,511	25,020	25,532	25,768	25,841	25,974	26,059	26,100	26,210	1.4%
				3.8%	3.1%	2.1%	2.0%	0.9%	0.3%	0.5%	0.3%	0.2%	0.4%	
APS	9,308	9,377	9,158	9,358	9,394	9,840	10,111	10,137	10,156	10,195	10,232	10,249	10,273	1.2%
				2.2%	0.4%	4.7%	2.8%	0.3%	0.2%	0.4%	0.4%	0.2%	0.2%	
ATSI	10,176	10,218	10,356	10,300	10,318	10,371	10,449	10,473	10,482	10,507	10,551	10,577	10,611	0.2%
				-0.5%	0.2%	0.5%	0.8%	0.2%	0.1%	0.2%	0.4%	0.2%	0.3%	
COMED	14,818	14,894	14,739	14,747	14,831	14,941	15,063	15,142	15,196	15,289	15,445	15,547	15,651	0.6%
				0.1%	0.6%	0.7%	0.8%	0.5%	0.4%	0.6%	1.0%	0.7%	0.7%	
DAYTON	3,006	3,015	2,943	2,926	2,930	2,941	2,956	2,951	2,940	2,938	2,944	2,947	2,947	0.0%
				-0.6%	0.1%	0.4%	0.5%	-0.2%	-0.4%	-0.1%	0.2%	0.1%	0.0%	
DEOK	4,933	4,936	4,566	4,547	4,548	4,570	4,605	4,587	4,593	4,599	4,623	4,631	4,632	0.1%
				-0.4%	0.0%	0.5%	0.8%	-0.4%	0.1%	0.1%	0.5%	0.2%	0.0%	
DLCO	2,033	2,039	1,997	1,992	2,001	2,016	2,035	2,046	2,056	2,075	2,095	2,114	2,133	0.7%
				-0.3%	0.5%	0.7%	0.9%	0.5%	0.5%	0.9%	1.0%	0.9%	0.9%	
EKPC	3,226	3,237	2,725	2,715	2,732	2,751	2,778	2,785	2,788	2,791	2,806	2,806	2,820	0.3%
				-0.4%	0.6%	0.7%	1.0%	0.3%	0.1%	0.1%	0.5%	0.0%	0.5%	
OVEC	89	89	110	110	110	110	110	110	110	110	110	110	110	0.0%
				0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)			1,880	1,859	1,746	1,765	1,948	1,881	1,738	1,704	1,645	1,614	1,602	
PJM WESTERN	70,188	70,708	67,627	68,615	69,629	70,795	71,691	72,118	72,424	72,774	73,220	73,467	73,785	0.9%
				1.5%	1.5%	1.7%	1.3%	0.6%	0.4%	0.5%	0.6%	0.3%	0.4%	
DOM	22,190	22,477	22,525	23,211	24,627	26,355	28,360	30,176	31,860	33,324	34,676	35,820	36,851	5.0%
				3.0%	6.1%	7.0%	7.6%	6.4%	5.6%	4.6%	4.1%	3.3%	2.9%	
DIVERSITY - TOTAL(-)			4,484	4,905	5,079	5,252	5,174	5,168	4,805	4,840	4,578	4,558	4,412	
PJM RTO	134,190	134,951	134,659	136,328	139,224	142,824	146,998	149,836	152,870	155,549	158,580	160,732	163,069	1.9%
				1.2%	2.1%	2.6%	2.9%	1.9%	2.0%	1.8%	1.9%	1.4%	1.5%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023/24).
Winter season indicates peak from December, January, February.

Table B-2 (Continued)

WINTER PEAK LOAD (MW) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2034/35 - 2038/39

	34/35	35/36	36/37	37/38	38/39	Annual Growth Rate (15 yr)
AEP	26,281	26,349	26,415	26,517	26,680	1.0%
	0.3%	0.3%	0.3%	0.4%	0.6%	
APS	10,317	10,373	10,397	10,434	10,489	0.9%
	0.4%	0.5%	0.2%	0.4%	0.5%	
ATSI	10,664	10,714	10,762	10,813	10,877	0.3%
	0.5%	0.5%	0.4%	0.5%	0.6%	
COMED	15,813	15,982	16,107	16,267	16,435	0.7%
	1.0%	1.1%	0.8%	1.0%	1.0%	
DAYTON	2,950	2,958	2,964	2,976	2,996	0.1%
	0.1%	0.3%	0.2%	0.4%	0.7%	
DEOK	4,637	4,670	4,667	4,692	4,731	0.2%
	0.1%	0.7%	-0.1%	0.5%	0.8%	
DLCO	2,159	2,183	2,212	2,242	2,270	0.9%
	1.2%	1.1%	1.3%	1.4%	1.2%	
EKPC	2,826	2,844	2,846	2,858	2,873	0.4%
	0.2%	0.6%	0.1%	0.4%	0.5%	
OVEC	110	110	110	110	110	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
DIVERSITY - WESTERN(-)	1,569	1,515	1,290	1,166	1,225	
PJM WESTERN	74,188	74,668	75,190	75,743	76,236	0.8%
	0.5%	0.6%	0.7%	0.7%	0.7%	
DOM	37,931	39,005	40,112	41,250	42,273	4.3%
	2.9%	2.8%	2.8%	2.8%	2.5%	
DIVERSITY - TOTAL(-)	4,213	4,020	3,958	3,977	3,966	
PJM RTO	165,705	168,511	170,956	173,502	176,195	1.8%
	1.6%	1.7%	1.5%	1.5%	1.6%	

Notes:
All forecast values are non-coincident as estimated by PJM staff.
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
All average growth rates are calculated from the first year of the forecast (2023/24).
Winter season indicates peak from December, January, February.

Table B-3

SPRING PEAK LOAD (MW) FOR
EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	1,742	1,743	1,739	1,746	1,775	1,797	1,816	1,846	1,888	1,927	1,971	2,023	2,045	2,094	2,151	2,202
BGE	5,179	5,177	5,193	5,213	5,258	5,304	5,339	5,385	5,446	5,527	5,617	5,724	5,800	5,897	6,017	6,129
DPL	3,133	3,117	3,119	3,130	3,147	3,161	3,173	3,185	3,208	3,248	3,271	3,316	3,330	3,375	3,430	3,465
JCPL	4,235	4,247	4,274	4,329	4,425	4,531	4,659	4,755	4,931	5,089	5,250	5,417	5,556	5,736	5,940	6,128
METED	2,471	2,495	2,546	2,606	2,682	2,746	2,800	2,857	2,932	3,036	3,121	3,222	3,311	3,427	3,540	3,689
PECO	6,466	6,437	6,450	6,455	6,554	6,613	6,656	6,640	6,645	6,755	6,818	6,923	6,944	6,993	7,047	7,199
PENLC	2,544	2,534	2,541	2,546	2,549	2,554	2,552	2,558	2,568	2,586	2,599	2,611	2,625	2,652	2,679	2,705
PEPCO	4,868	4,868	4,888	4,906	4,960	4,991	5,011	5,031	5,058	5,112	5,168	5,236	5,291	5,362	5,436	5,534
PL	6,281	6,255	6,299	6,336	6,355	6,371	6,375	6,360	6,397	6,441	6,466	6,476	6,468	6,520	6,584	6,631
PS	7,449	7,452	7,501	7,579	7,755	7,936	8,091	8,227	8,429	8,626	8,825	9,049	9,181	9,433	9,702	9,951
RECO	300	299	297	296	300	302	303	302	302	308	312	319	321	324	328	335
UGI	169	168	169	170	170	171	171	171	172	173	174	175	176	178	180	182
DIVERSITY - MID-ATLANTIC(-)	2,089	2,018	1,894	1,470	1,319	1,314	1,277	1,299	1,244	1,251	1,302	1,406	1,280	1,276	1,256	1,254
PJM MID-ATLANTIC	42,748	42,774	43,122	43,842	44,611	45,163	45,669	46,018	46,732	47,577	48,290	49,085	49,768	50,715	51,778	52,896
FE-EAST	8,790	8,871	9,008	9,233	9,440	9,628	9,824	10,020	10,245	10,576	10,833	11,115	11,324	11,641	11,999	12,383
PLGRP	6,448	6,422	6,468	6,502	6,519	6,542	6,544	6,524	6,565	6,612	6,635	6,644	6,641	6,692	6,762	6,811

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.

Table B-3

SPRING PEAK LOAD (MW) FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AEP	20,213	21,124	21,845	22,418	22,804	23,117	23,236	23,266	23,367	23,495	23,586	23,755	23,778	23,924	24,050	24,251
APS	7,891	8,072	8,199	8,577	8,814	8,859	8,881	8,848	8,929	8,985	9,004	9,084	9,012	9,118	9,221	9,258
ATSI	9,870	9,811	9,799	9,852	9,968	9,996	10,005	9,979	9,984	10,099	10,156	10,218	10,209	10,266	10,344	10,486
COMED	15,027	14,748	14,670	14,704	15,052	15,096	15,100	14,972	14,961	15,242	15,388	15,558	15,534	15,602	15,778	16,139
DAYTON	2,675	2,657	2,650	2,665	2,704	2,706	2,702	2,683	2,684	2,714	2,724	2,736	2,737	2,745	2,763	2,804
DEOK	4,357	4,321	4,324	4,328	4,375	4,393	4,400	4,382	4,381	4,434	4,463	4,492	4,489	4,517	4,540	4,632
DLCO	2,171	2,155	2,154	2,156	2,206	2,224	2,235	2,231	2,230	2,277	2,311	2,346	2,349	2,364	2,396	2,465
EKPC	2,127	2,134	2,151	2,168	2,184	2,194	2,204	2,212	2,221	2,229	2,236	2,240	2,262	2,273	2,291	2,304
OVEC	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
DIVERSITY - WESTERN(-)	2,983	2,790	2,634	2,760	2,660	2,832	2,978	2,702	2,571	2,610	2,654	2,756	2,592	2,431	2,458	2,456
PJM WESTERN	61,438	62,322	63,248	64,198	65,537	65,843	65,875	65,961	66,276	66,955	67,304	67,763	67,868	68,468	69,015	69,973
DOM	19,760	20,508	22,081	23,787	25,888	27,796	29,476	30,797	32,046	33,319	34,517	35,664	36,683	37,752	38,885	40,176
DIVERSITY - TOTAL(-)	7,312	6,937	6,700	6,666	6,757	6,994	6,883	6,464	6,507	6,322	6,131	6,360	6,254	6,197	6,243	6,259
PJM RTO	121,706	123,475	126,279	129,391	133,258	135,954	138,392	140,313	142,362	145,390	147,936	150,314	151,937	154,445	157,149	160,496

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.

Table B-4

FALL PEAK LOAD (MW) FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	2,039	2,053	2,058	2,063	2,057	2,073	2,107	2,142	2,164	2,181	2,209	2,246	2,317	2,358	2,399	2,439
BGE	5,388	5,421	5,462	5,485	5,521	5,575	5,642	5,722	5,794	5,873	5,967	6,089	6,236	6,363	6,466	6,597
DPL	3,193	3,197	3,208	3,212	3,222	3,227	3,255	3,287	3,319	3,353	3,378	3,418	3,492	3,552	3,590	3,643
JCPL	4,766	4,829	4,881	4,928	4,959	5,037	5,133	5,255	5,358	5,484	5,626	5,752	5,956	6,139	6,283	6,451
METED	2,558	2,610	2,673	2,732	2,769	2,836	2,917	2,994	3,069	3,152	3,241	3,352	3,489	3,619	3,734	3,872
PECO	6,992	7,030	7,067	7,093	7,113	7,148	7,225	7,291	7,322	7,383	7,432	7,516	7,655	7,747	7,821	7,902
PENLC	2,524	2,532	2,546	2,554	2,557	2,559	2,576	2,596	2,614	2,633	2,648	2,667	2,710	2,742	2,770	2,798
PEPCO	5,127	5,174	5,209	5,235	5,250	5,291	5,339	5,412	5,449	5,509	5,581	5,648	5,786	5,891	5,971	6,065
PL	6,147	6,175	6,227	6,243	6,239	6,247	6,276	6,332	6,380	6,407	6,414	6,446	6,539	6,622	6,670	6,711
PS	8,297	8,419	8,521	8,603	8,686	8,824	8,994	9,150	9,292	9,415	9,573	9,771	10,041	10,299	10,470	10,676
RECO	326	330	331	329	325	324	333	337	339	340	341	347	359	366	369	374
UGI	167	167	168	169	169	169	170	171	173	174	175	176	177	180	182	184
DIVERSITY - MID-ATLANTIC(-)	1,100	997	973	935	1,205	1,194	1,010	1,082	1,102	1,198	1,173	1,260	1,161	1,116	1,269	1,295
PJM MID-ATLANTIC	46,424	46,940	47,378	47,711	47,662	48,116	48,957	49,607	50,171	50,706	51,412	52,168	53,596	54,762	55,456	56,417
FE-EAST	9,616	9,779	9,925	10,016	10,037	10,179	10,389	10,655	10,856	11,052	11,287	11,542	11,947	12,298	12,574	12,907
PLGRP	6,312	6,340	6,392	6,409	6,405	6,416	6,441	6,499	6,548	6,577	6,588	6,619	6,716	6,801	6,852	6,895

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Fall season indicates peak from September, October, November.

Table B-4

FALL PEAK LOAD (MW) FOR
EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AEP	20,714	21,824	22,553	23,043	23,454	23,533	23,826	24,080	24,168	24,283	24,378	24,351	24,757	24,979	25,132	25,311
APS	7,962	8,031	8,469	8,703	8,713	8,737	8,779	8,807	8,839	8,859	8,890	8,923	8,987	9,067	9,113	9,158
ATSI	10,664	10,829	10,878	10,901	10,772	10,758	10,809	10,986	11,030	11,016	10,966	11,015	11,277	11,378	11,452	11,503
COMED	17,307	17,361	17,408	17,382	17,343	17,264	17,329	17,525	17,520	17,644	17,784	17,777	18,101	18,311	18,475	18,618
DAYTON	2,921	2,948	2,970	2,971	2,952	2,941	2,963	2,990	3,000	3,000	3,000	2,999	3,060	3,097	3,107	3,123
DEOK	4,765	4,796	4,813	4,817	4,808	4,809	4,827	4,869	4,882	4,900	4,917	4,930	5,011	5,058	5,093	5,131
DLCO	2,345	2,361	2,378	2,393	2,391	2,403	2,422	2,457	2,480	2,500	2,519	2,531	2,597	2,642	2,671	2,710
EKPC	2,001	2,014	2,036	2,061	2,077	2,090	2,088	2,099	2,118	2,132	2,144	2,160	2,167	2,194	2,213	2,233
OVEC	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
DIVERSITY - WESTERN(-)	1,951	1,916	1,925	1,836	1,726	1,824	1,900	1,937	1,798	1,773	1,818	1,991	1,927	1,955	1,886	1,898
PJM WESTERN	66,808	68,328	69,660	70,515	70,864	70,791	71,223	71,956	72,319	72,641	72,860	72,775	74,110	74,851	75,450	75,969
DOM	20,254	21,219	23,239	25,130	27,451	29,431	31,139	32,630	34,071	35,434	36,762	37,975	39,250	40,551	41,857	43,208
DIVERSITY - TOTAL(-)	6,120	5,800	5,611	5,555	5,971	6,823	6,078	5,862	5,638	5,833	6,185	6,896	6,143	6,085	6,075	5,935
PJM RTO	130,417	133,600	137,564	140,572	142,937	144,533	148,151	151,350	153,823	155,919	157,840	159,273	163,901	167,150	169,843	172,852

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Fall season indicates peak from September, October, November.

Table B-5

MONTHLY PEAK FORECAST SCALED to SEASONAL PEAK (MW) FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC DIVERSITY	PJM MID-ATLANTIC
Jan 2024	1,637	5,827	3,700	3,817	2,740	6,597	2,829	5,359	7,363	6,816	225	201	604	46,507
Feb 2024	1,558	5,517	3,481	3,618	2,628	6,261	2,735	5,040	7,037	6,509	211	190	805	43,980
Mar 2024	1,389	4,939	3,133	3,228	2,406	5,484	2,544	4,457	6,281	5,934	192	169	858	39,298
Apr 2024	1,283	4,198	2,565	2,960	2,185	5,003	2,318	3,863	5,474	5,554	197	145	933	34,812
May 2024	1,742	5,179	3,104	4,235	2,471	6,466	2,353	4,868	5,758	7,449	300	149	1,326	42,748
Jun 2024	2,327	6,066	3,637	5,603	2,857	8,122	2,709	5,626	6,658	9,403	390	181	2,011	51,568
Jul 2024	2,593	6,491	3,945	6,052	3,036	8,581	2,867	6,053	7,126	10,068	410	197	1,586	55,833
Aug 2024	2,491	6,400	3,827	5,776	2,950	8,169	2,729	5,948	6,821	9,673	394	183	1,751	53,610
Sep 2024	2,039	5,388	3,193	4,766	2,558	6,992	2,524	5,127	6,147	8,297	326	167	1,100	46,424
Oct 2024	1,464	4,121	2,441	3,295	2,106	5,226	2,260	3,993	5,224	6,153	217	142	1,135	35,507
Nov 2024	1,369	4,362	2,685	3,246	2,233	5,266	2,417	4,015	5,808	5,934	201	164	618	37,082
Dec 2024	1,606	5,254	3,317	3,832	2,574	6,188	2,650	4,811	6,730	6,738	227	191	482	43,636
	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2025	1,673	5,836	3,705	3,989	2,752	6,583	2,811	5,365	7,342	7,060	232	200	733	46,815
Feb 2025	1,566	5,453	3,432	3,709	2,593	6,129	2,656	4,976	6,878	6,641	214	187	722	43,712
Mar 2025	1,415	4,973	3,117	3,356	2,448	5,490	2,534	4,454	6,255	6,110	197	168	655	39,862
Apr 2025	1,297	4,235	2,545	3,046	2,233	5,005	2,313	3,889	5,485	5,668	200	144	906	35,154
May 2025	1,743	5,177	3,030	4,247	2,495	6,437	2,340	4,868	5,667	7,452	299	148	1,129	42,774
Jun 2025	2,336	6,080	3,606	5,631	2,906	8,171	2,725	5,665	6,709	9,500	394	183	2,116	51,790
Jul 2025	2,599	6,507	3,926	6,085	3,077	8,599	2,872	6,082	7,156	10,143	410	198	1,636	56,018
Aug 2025	2,496	6,407	3,797	5,792	2,984	8,182	2,733	5,970	6,840	9,759	393	184	1,705	53,832
Sep 2025	2,053	5,421	3,197	4,829	2,610	7,030	2,532	5,174	6,175	8,419	330	167	997	46,940
Oct 2025	1,477	4,150	2,436	3,354	2,149	5,237	2,248	4,002	5,216	6,249	219	142	1,088	35,791
Nov 2025	1,395	4,388	2,692	3,376	2,275	5,304	2,405	4,028	5,801	6,111	205	163	626	37,517
Dec 2025	1,647	5,305	3,356	4,045	2,628	6,235	2,661	4,845	6,777	7,019	234	191	287	44,656
	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	DIVERSITY	MID-ATLANTIC
Jan 2026	1,721	5,855	3,730	4,208	2,799	6,616	2,815	5,397	7,353	7,367	240	200	747	47,554
Feb 2026	1,613	5,485	3,463	3,927	2,639	6,180	2,669	5,014	6,965	6,943	222	187	558	44,749
Mar 2026	1,457	5,014	3,119	3,553	2,511	5,548	2,541	4,547	6,299	6,382	203	169	131	41,212
Apr 2026	1,321	4,253	2,524	3,180	2,287	5,025	2,305	3,924	5,472	5,811	201	143	525	35,921
May 2026	1,739	5,193	2,987	4,274	2,546	6,450	2,319	4,888	5,652	7,501	297	147	871	43,122
Jun 2026	2,338	6,111	3,593	5,654	2,969	8,192	2,736	5,681	6,758	9,590	396	183	2,024	52,177
Jul 2026	2,602	6,523	3,913	6,099	3,141	8,640	2,885	6,104	7,196	10,224	411	198	1,603	56,333
Aug 2026	2,497	6,445	3,793	5,790	3,052	8,193	2,753	5,985	6,899	9,853	393	184	1,757	54,080
Sep 2026	2,058	5,462	3,208	4,881	2,673	7,067	2,546	5,209	6,227	8,521	331	168	973	47,378
Oct 2026	1,484	4,183	2,442	3,427	2,198	5,248	2,247	4,006	5,220	6,348	221	143	1,077	36,090
Nov 2026	1,443	4,463	2,721	3,551	2,370	5,385	2,437	4,122	5,898	6,365	213	167	544	38,591
Dec 2026	1,698	5,346	3,367	4,259	2,703	6,309	2,677	4,885	6,824	7,290	243	192	240	45,553

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-5

MONTHLY PEAK FORECAST SCALED to SEASONAL PEAK (MW) FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN DIVERSITY	PJM WESTERN	DOM	TOTAL DIVERSITY	PJM RTO
Jan 2024	22,913	9,158	10,356	14,739	2,943	4,566	1,997	2,725	95	1,865	67,627	22,525	4,469	134,659
Feb 2024	22,094	8,826	10,039	14,297	2,822	4,353	1,909	2,502	110	1,773	65,179	21,125	4,107	128,755
Mar 2024	20,213	7,891	9,188	12,461	2,546	3,839	1,743	2,127	90	109	59,989	19,359	2,530	117,083
Apr 2024	17,979	6,836	8,431	11,544	2,279	3,492	1,652	1,718	75	529	53,477	16,887	4,040	102,598
May 2024	19,275	7,314	9,870	15,027	2,675	4,357	2,171	1,661	65	977	61,438	19,760	4,543	121,706
Jun 2024	21,765	8,414	12,075	19,478	3,136	5,077	2,599	1,946	75	1,864	72,701	21,709	7,655	142,198
Jul 2024	22,902	8,835	12,433	20,414	3,319	5,332	2,705	2,070	90	1,571	76,529	22,781	7,053	151,247
Aug 2024	22,447	8,694	12,285	19,888	3,251	5,253	2,652	2,031	75	1,449	75,127	22,287	6,634	147,590
Sep 2024	20,714	7,962	10,664	17,307	2,921	4,765	2,345	1,856	70	1,796	66,808	20,254	5,965	130,417
Oct 2024	17,381	6,844	8,379	12,532	2,306	3,681	1,732	1,623	70	1,874	52,674	17,134	4,985	103,339
Nov 2024	18,886	7,550	8,847	12,461	2,406	3,601	1,700	2,001	80	1,447	56,085	18,438	3,867	109,803
Dec 2024	21,018	8,527	9,867	14,172	2,707	4,196	1,905	2,414	85	1,454	63,437	21,046	4,108	125,947

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2025	23,779	9,358	10,300	14,747	2,926	4,547	1,992	2,715	95	1,844	68,615	23,211	4,890	136,328
Feb 2025	22,538	8,845	9,791	14,040	2,758	4,274	1,877	2,456	110	1,867	64,822	21,578	4,257	128,444
Mar 2025	21,124	8,072	9,179	12,525	2,541	3,829	1,740	2,134	90	34	61,200	20,107	956	120,902
Apr 2025	18,926	7,039	8,438	11,561	2,288	3,495	1,648	1,725	75	317	54,878	17,641	2,221	106,675
May 2025	20,142	7,462	9,811	14,748	2,657	4,321	2,155	1,660	65	699	62,322	20,508	3,957	123,475
Jun 2025	22,857	8,553	12,107	19,231	3,147	5,083	2,606	1,960	75	1,547	74,072	22,625	7,602	144,548
Jul 2025	23,893	8,968	12,421	20,380	3,322	5,339	2,707	2,088	90	1,612	77,596	23,691	7,060	153,493
Aug 2025	23,411	8,784	12,263	19,640	3,250	5,242	2,655	2,042	75	1,334	76,028	23,204	6,297	149,806
Sep 2025	21,824	8,031	10,829	17,361	2,948	4,796	2,361	1,877	70	1,769	68,328	21,219	5,653	133,600
Oct 2025	18,375	6,841	8,414	12,581	2,313	3,679	1,740	1,644	70	1,871	53,786	18,074	4,923	105,687
Nov 2025	19,886	7,587	8,847	12,485	2,413	3,595	1,706	2,014	80	1,500	57,113	19,310	4,126	111,940
Dec 2025	22,045	8,610	9,922	14,318	2,718	4,208	1,919	2,430	85	1,336	64,919	22,121	4,227	129,092

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	DIVERSITY	WESTERN	DOM	DIVERSITY	PJM RTO
Jan 2026	24,511	9,394	10,318	14,831	2,930	4,548	2,001	2,732	95	1,731	69,629	24,627	5,064	139,224
Feb 2026	23,303	8,914	9,832	14,195	2,762	4,278	1,891	2,474	110	1,843	65,916	23,112	4,430	131,748
Mar 2026	21,845	8,199	9,254	12,649	2,551	3,842	1,760	2,151	90	0	62,341	21,645	770	124,559
Apr 2026	19,457	7,147	8,459	11,595	2,278	3,501	1,658	1,721	75	2	55,889	19,203	1,889	109,651
May 2026	20,763	7,607	9,799	14,670	2,650	4,324	2,154	1,674	65	458	63,248	22,081	3,501	126,279
Jun 2026	23,613	8,933	12,147	19,363	3,163	5,099	2,615	1,985	75	1,539	75,454	24,473	7,621	148,046
Jul 2026	24,607	9,356	12,432	20,372	3,329	5,356	2,716	2,105	90	1,552	78,811	25,627	7,123	156,803
Aug 2026	24,148	9,234	12,236	19,737	3,261	5,263	2,666	2,069	75	1,240	77,449	25,214	6,390	153,350
Sep 2026	22,553	8,469	10,878	17,408	2,970	4,813	2,378	1,911	70	1,790	69,660	23,239	5,476	137,564
Oct 2026	19,032	7,232	8,434	12,641	2,311	3,685	1,750	1,644	70	1,802	54,997	20,081	5,412	108,635
Nov 2026	20,659	8,058	9,014	12,714	2,435	3,654	1,730	2,036	80	1,357	59,023	21,385	3,387	117,513
Dec 2026	22,807	9,066	9,978	14,452	2,729	4,236	1,941	2,447	85	1,363	66,378	24,270	4,388	133,416

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

Table B-6

MONTHLY PEAK FORECAST SCALED to SEASONAL PEAK (MW) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2024	9,303	7,561
Feb 2024	8,901	7,209
Mar 2024	7,973	6,448
Apr 2024	7,233	5,617
May 2024	8,790	5,893
Jun 2024	10,899	6,839
Jul 2024	11,723	7,323
Aug 2024	11,268	7,004
Sep 2024	9,616	6,312
Oct 2024	7,411	5,357
Nov 2024	7,788	5,969
Dec 2024	9,019	6,921

	FE_EAST	PLGRP
Jan 2025	9,485	7,541
Feb 2025	8,920	7,064
Mar 2025	8,244	6,422
Apr 2025	7,451	5,621
May 2025	8,871	5,809
Jun 2025	11,014	6,891
Jul 2025	11,791	7,354
Aug 2025	11,315	7,024
Sep 2025	9,779	6,340
Oct 2025	7,528	5,344
Nov 2025	7,959	5,950
Dec 2025	9,271	6,968

	FE_EAST	PLGRP
Jan 2026	9,756	7,553
Feb 2026	9,218	7,152
Mar 2026	8,605	6,468
Apr 2026	7,682	5,612
May 2026	9,008	5,796
Jun 2026	11,104	6,933
Jul 2026	11,882	7,394
Aug 2026	11,431	7,079
Sep 2026	9,925	6,392
Oct 2026	7,666	5,353
Nov 2026	8,298	6,053
Dec 2026	9,560	7,016

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
FE_EAST contains JCPL, METED and PENLC zones. PLGRP contains PL and UGI zones.

Table B-7

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
AE																
CAPACITY PERFORMANCE	41	41	41	41	41	41	41	42	42	42	43	43	44	45	45	45
SUMMER PERIOD	7	7	7	7	8	8	8	8	8	8	8	8	8	8	8	8
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	48	48	48	48	49	49	49	50	50	50	51	51	52	53	53	53
BGE																
CAPACITY PERFORMANCE	102	102	102	103	103	104	105	105	106	107	109	110	112	114	115	116
SUMMER PERIOD	77	78	78	78	79	79	80	80	81	82	83	84	85	87	88	89
PRD	160	110	110	111	111	112	113	113	114	116	117	119	120	122	124	126
TOTAL LOAD MANAGEMENT	339	290	290	292	293	295	298	298	301	305	309	313	317	323	327	331
DPL																
CAPACITY PERFORMANCE	89	89	88	88	88	89	89	89	90	91	91	92	94	95	96	97
SUMMER PERIOD	89	89	88	88	88	89	89	89	90	91	91	92	94	95	96	97
PRD	35	38	38	38	38	38	38	38	39	39	39	40	40	41	41	41
TOTAL LOAD MANAGEMENT	213	216	214	214	214	216	216	216	219	221	221	224	228	231	233	235
JCPL																
CAPACITY PERFORMANCE	102	103	103	104	104	106	107	108	110	112	114	117	119	122	125	128
SUMMER PERIOD	5	5	5	5	5	5	5	5	5	5	6	6	6	6	6	6
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	107	108	108	109	109	111	112	113	115	117	120	123	125	128	131	134
METED																
CAPACITY PERFORMANCE	136	138	141	144	146	149	152	155	159	162	167	171	177	183	188	193
SUMMER PERIOD	25	25	26	26	27	27	28	29	29	30	31	32	33	34	35	36
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	161	163	167	170	173	176	180	184	188	192	198	203	210	217	223	229

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-7 (Continued)

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
PECO																
CAPACITY PERFORMANCE	276	276	278	279	280	281	283	284	286	288	290	293	297	300	302	304
SUMMER PERIOD	28	28	28	28	28	28	28	28	29	29	29	29	30	30	30	30
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	304	304	306	307	308	309	311	312	315	317	319	322	327	330	332	334
PENLC																
CAPACITY PERFORMANCE	144	145	145	146	146	146	147	148	148	149	150	151	153	155	156	157
SUMMER PERIOD	86	86	87	87	87	87	87	88	88	89	89	90	91	92	93	94
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	230	231	232	233	233	233	234	236	236	238	239	241	244	247	249	251
PEPCO																
CAPACITY PERFORMANCE	96	97	97	97	98	98	99	100	101	101	102	103	105	106	107	108
SUMMER PERIOD	119	120	120	121	121	122	123	124	125	126	127	128	130	132	133	134
PRD	110	112	113	113	114	115	115	116	117	118	119	120	122	124	125	126
TOTAL LOAD MANAGEMENT	325	329	330	331	333	335	337	340	343	345	348	351	357	362	365	368
PL																
CAPACITY PERFORMANCE	322	323	325	326	326	327	328	330	331	332	333	335	339	342	344	346
SUMMER PERIOD	112	113	113	113	114	114	114	115	115	116	116	117	118	119	120	121
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	434	436	438	439	440	441	442	445	446	448	449	452	457	461	464	467
PS																
CAPACITY PERFORMANCE	153	154	156	157	158	160	162	164	165	168	170	173	176	179	183	187
SUMMER PERIOD	78	79	80	80	81	82	83	84	85	86	87	89	90	92	93	94
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	231	233	236	237	239	242	245	248	250	254	257	262	266	271	276	281

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-7 (Continued)

PJM MID-ATLANTIC REGION LOAD MANAGEMENT
PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
RECO																
CAPACITY PERFORMANCE	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UGI																
CAPACITY PERFORMANCE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUMMER PERIOD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PJM MID-ATLANTIC																
CAPACITY PERFORMANCE	1,463	1,470	1,478	1,487	1,492	1,503	1,515	1,527	1,540	1,554	1,571	1,590	1,618	1,643	1,663	1,683
SUMMER PERIOD	626	630	632	633	638	641	645	650	655	662	667	675	685	695	702	709
PRD	305	260	261	262	263	265	266	267	270	273	275	279	282	287	290	293
TOTAL LOAD MANAGEMENT	2,394	2,360	2,371	2,382	2,393	2,409	2,426	2,444	2,465	2,489	2,513	2,544	2,585	2,625	2,655	2,685

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AEP																
CAPACITY PERFORMANCE	993	1,036	1,066	1,088	1,105	1,116	1,124	1,132	1,134	1,138	1,145	1,151	1,160	1,168	1,175	1,182
SUMMER PERIOD	296	309	318	324	329	333	335	337	338	339	341	343	346	348	351	354
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,289	1,345	1,384	1,412	1,434	1,449	1,459	1,469	1,472	1,477	1,486	1,494	1,506	1,516	1,526	1,536
APS																
CAPACITY PERFORMANCE	445	452	472	483	485	487	488	488	489	490	492	494	497	499	501	503
SUMMER PERIOD	136	138	144	147	148	148	148	149	149	149	150	150	151	152	153	154
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	581	590	616	630	633	635	636	637	638	639	642	644	648	651	654	657
ATSI																
CAPACITY PERFORMANCE	609	608	609	610	610	611	612	612	613	615	617	621	625	629	634	639
SUMMER PERIOD	169	169	169	170	170	170	170	170	170	171	172	173	174	175	176	177
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	778	777	778	780	780	781	782	782	783	786	789	794	799	804	810	816
COMED																
CAPACITY PERFORMANCE	1,001	1,000	999	999	997	991	991	993	994	998	1,001	1,005	1,014	1,024	1,030	1,036
SUMMER PERIOD	374	373	373	373	372	370	370	370	371	372	374	375	378	382	384	386
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	1,375	1,373	1,372	1,372	1,369	1,361	1,361	1,363	1,365	1,370	1,375	1,380	1,392	1,406	1,414	1,422
DAYTON																
CAPACITY PERFORMANCE	109	109	109	110	110	110	110	110	110	111	111	112	112	113	114	115
SUMMER PERIOD	58	58	59	59	59	59	59	59	59	59	60	60	60	61	61	61
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	167	167	168	169	169	169	169	169	169	170	171	172	172	174	175	176

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
DEOK																
CAPACITY PERFORMANCE	128	128	129	129	129	129	129	130	130	131	131	132	133	134	135	136
SUMMER PERIOD	41	41	41	41	41	41	41	41	41	42	42	42	42	43	43	43
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	169	169	170	170	170	170	170	171	171	173	173	174	175	177	178	179
DLCO																
CAPACITY PERFORMANCE	64	64	64	64	64	65	65	66	66	66	67	68	69	70	71	72
SUMMER PERIOD	28	28	28	28	28	28	29	29	29	29	29	30	30	31	31	31
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	92	92	92	92	92	93	94	95	95	95	96	98	99	101	102	103
EKPC																
CAPACITY PERFORMANCE	120	121	122	123	124	124	125	126	126	127	128	129	130	131	132	133
SUMMER PERIOD	81	82	83	84	84	85	85	86	86	86	87	88	89	89	90	91
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	201	203	205	207	208	209	210	212	212	213	215	217	219	220	222	224
PJM WESTERN																
CAPACITY PERFORMANCE	3,469	3,518	3,570	3,606	3,624	3,633	3,644	3,657	3,662	3,676	3,692	3,712	3,740	3,768	3,792	3,816
SUMMER PERIOD	1,183	1,198	1,215	1,226	1,231	1,234	1,237	1,241	1,243	1,247	1,255	1,261	1,270	1,281	1,289	1,297
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	4,652	4,716	4,785	4,832	4,855	4,867	4,881	4,898	4,905	4,923	4,947	4,973	5,010	5,049	5,081	5,113

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-7 (Continued)

PJM WESTERN REGION AND PJM SOUTHERN REGION LOAD MANAGEMENT PLACED UNDER PJM COORDINATION - SUMMER (MW)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DOM																
CAPACITY PERFORMANCE	604	628	679	729	790	842	887	925	962	999	1,034	1,068	1,100	1,133	1,167	1,202
SUMMER PERIOD	106	110	119	127	138	147	155	162	168	174	181	187	192	198	204	210
PRD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LOAD MANAGEMENT	710	738	798	856	928	989	1,042	1,087	1,130	1,173	1,215	1,255	1,292	1,331	1,371	1,412
PJM RTO																
CAPACITY PERFORMANCE	5,536	5,616	5,727	5,822	5,906	5,978	6,046	6,109	6,164	6,229	6,297	6,370	6,458	6,544	6,622	6,701
SUMMER PERIOD	1,915	1,938	1,966	1,986	2,007	2,022	2,037	2,053	2,066	2,083	2,103	2,123	2,147	2,174	2,195	2,216
PRD	305	260	261	262	263	265	266	267	270	273	275	279	282	287	290	293
TOTAL LOAD MANAGEMENT	7,756	7,814	7,954	8,070	8,176	8,265	8,349	8,429	8,500	8,585	8,675	8,772	8,887	9,005	9,107	9,210

Notes:
Summer-Period DR refers to DR resources that aggregate with Winter-Period resources to form a year-round commitment.
Forecast values for Capacity Performance and Summer-Period DR are based on actual committed quantities for Delivery Years 2021/22, 2022/23, 2023/24; forecast values for PRD are based on actual cleared quantities in the 2022/23, 2023/24 and 2024/25 RPM Base Residual Auctions

Table B-8a

DISTRIBUTED SOLAR ADJUSTMENTS TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	130	122	115	115	118	116	112	115	117	117	121	124	122	123	126	128
BGE	211	219	239	249	259	275	286	306	300	297	299	307	319	330	335	345
DPL	120	135	137	133	135	143	142	144	145	141	141	146	149	153	156	159
JCPL	282	287	305	327	344	344	351	356	375	386	395	402	418	422	440	458
METED	51	53	54	55	57	58	57	59	62	63	66	69	72	76	82	92
PECO	68	77	86	96	107	119	129	141	155	168	182	195	206	216	225	239
PENLC	23	28	33	39	44	48	53	56	62	64	68	70	74	76	82	86
PEPCO	226	248	260	281	302	308	325	329	349	354	362	374	380	390	403	421
PL	127	133	138	146	151	157	162	173	184	195	203	207	216	224	232	239
PS	426	429	442	451	477	512	542	574	595	613	616	625	652	657	668	695
RECO	14	15	18	20	22	24	26	28	29	29	29	30	31	31	31	32
UGI	1	1	1	1	2	2	2	2	2	3	3	3	3	3	4	4
AEP	151	174	188	209	227	248	265	279	289	306	324	340	352	371	395	424
APS	94	104	113	122	130	141	152	163	173	184	197	203	213	219	223	229
ATSI	100	114	122	132	141	148	156	162	171	180	193	199	206	217	228	240
COMED	390	459	521	552	602	645	696	758	829	871	886	904	945	994	1,034	1,065
DAYTON	28	31	33	35	38	40	42	44	46	47	50	51	53	55	57	59
DEOK	21	26	29	32	35	39	43	47	51	54	58	63	67	72	77	81
DLCO	23	25	28	31	34	37	40	43	47	51	55	59	62	68	72	76
EKPC	5	5	6	7	8	9	11	12	14	15	17	18	20	22	23	24
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	581	576	596	630	666	702	741	778	805	837	877	913	960	1,000	1,088	1,172
PJM RTO	3,136	3,446	3,773	4,109	4,409	4,470	4,657	4,858	4,965	5,005	5,103	5,279	5,441	5,641	5,921	6,387

Notes:
Adjustment values presented here are average summer peak distribution forecast values.

Values are derived by PJM from a forecast obtained from SPGCI.

Table B-8b

DISTRIBUTED BATTERY STORAGE ADJUSTMENT TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	1	2	3	5	7	9	11	13	14	15	17	18	19	21	22	25
BGE	2	4	7	10	13	17	23	35	50	65	80	95	107	120	132	143
DPL	1	1	2	3	4	6	7	11	14	18	21	24	27	30	33	36
JCPL	2	4	8	12	16	21	26	30	34	37	40	43	46	50	55	61
METED	0	1	1	1	2	2	3	4	4	5	6	6	7	7	7	8
PECO	1	2	2	3	4	6	7	9	11	12	14	16	16	17	18	19
PENLC	0	1	1	1	2	2	3	4	5	5	6	7	7	7	8	8
PEPCO	2	4	7	9	12	16	21	30	41	52	63	74	84	94	103	113
PL	1	2	3	3	5	6	7	9	11	13	15	16	17	18	19	19
PS	3	7	14	22	30	39	47	54	62	67	71	76	82	89	97	107
RECO	0	0	0	1	1	1	2	2	2	3	3	3	3	3	4	4
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	2	5	7	10	13	17	21	25	30	34	39	43	47	51	55	59
APS	1	2	4	5	7	10	13	18	24	30	37	43	48	54	59	63
ATSI	1	3	5	6	8	10	12	14	16	18	20	22	23	25	26	28
COMED	4	10	17	24	32	40	49	60	72	81	87	95	102	110	117	124
DAYTON	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8
DEOK	1	1	2	2	3	4	5	5	6	7	8	8	9	10	11	11
DLCO	0	1	1	1	1	2	2	3	4	4	5	5	5	6	6	6
EKPC	0	0	0	0	0	0	1	1	1	1	2	2	3	3	4	4
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	3	8	13	18	25	35	47	61	78	92	105	115	123	131	137	143
PJM RTO	25	57	98	141	189	247	310	392	484	567	644	717	784	853	920	989

Notes:
Adjustment values presented here are reflected in all summer peak forecast values.

Values are derived by PJM from a forecast obtained from SPGCI.

Table B-8c

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2024 - 2039

	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
AE	12	30	54	80	107	137	168	204	243	284	329	375	419	466	509	561
BGE	36	79	136	198	264	342	428	530	644	759	883	1,014	1,141	1,283	1,406	1,555
DPL	12	30	53	79	105	133	164	200	239	279	323	371	418	466	509	561
JCPL	53	113	194	283	377	483	588	713	847	986	1,136	1,297	1,452	1,610	1,760	1,942
METED	15	36	66	98	133	173	215	268	328	394	468	553	641	739	840	958
PECO	24	50	84	120	158	201	246	303	367	433	505	587	668	755	837	936
PENLC	5	13	26	39	54	70	88	111	137	165	195	228	261	297	332	373
PEPCO	33	62	101	141	183	233	287	349	417	488	564	644	724	811	893	988
PL	10	22	40	58	78	101	124	153	186	221	259	301	342	387	432	484
PS	60	128	222	325	433	549	673	821	975	1,138	1,315	1,504	1,684	1,870	2,047	2,252
RECO	2	4	7	9	12	15	19	23	27	31	36	41	46	51	56	62
UGI	1	1	2	3	4	5	6	8	10	12	14	16	18	20	23	25
AEP	25	60	108	158	213	277	346	433	529	635	753	883	1,013	1,158	1,302	1,477
APS	9	22	40	60	81	104	129	161	196	234	274	317	358	403	446	496
ATSI	21	49	85	125	167	214	262	324	394	472	556	650	744	848	954	1,077
COMED	76	160	269	386	506	635	768	928	1,102	1,293	1,488	1,696	1,905	2,123	2,338	2,593
DAYTON	4	9	16	23	31	40	49	61	74	89	105	124	143	164	185	210
DEOK	11	21	36	51	66	84	103	126	152	180	211	246	280	319	357	402
DLCO	10	21	36	53	70	89	109	135	163	194	229	266	302	343	386	433
EKPC	2	6	11	16	21	28	34	43	53	63	75	88	101	115	130	146
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	67	150	259	374	498	636	779	959	1,159	1,378	1,605	1,852	2,095	2,360	2,625	2,954
PJM RTO	501	1,085	1,873	2,707	3,587	4,605	5,647	6,927	8,342	9,847	11,442	13,159	14,809	16,586	18,269	20,322

Notes:
Adjustment values presented here are average summer peak distribution forecast values.

Values are derived by PJM from a forecast obtained from SPGCI.

Table B-9

ADJUSTMENTS ABOVE EMBEDDED TO SUMMER PEAK LOAD (MW) FOR EACH PJM ZONE AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
JCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
METED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PENLC	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
PEPCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PL	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
PS	16	49	83	142	197	252	295	298	312	329	347	364	383	401	420	439
RECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AEP	767	1,738	2,419	2,871	3,218	3,432	3,544	3,638	3,626	3,627	3,634	3,621	3,641	3,647	3,638	3,624
APS	73	213	566	803	803	803	803	803	803	803	803	803	803	803	803	803
ATSI	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
COMED	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DAYTON	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
DEOK	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
DLCO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EKPC	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	1,801	2,666	4,482	6,241	8,417	10,263	11,831	13,118	14,319	15,491	16,605	17,610	18,521	19,514	20,533	21,563
PJM RTO	2,664	4,673	7,557	10,064	12,643	14,757	16,480	17,864	19,067	20,258	21,397	22,406	23,355	24,372	25,403	26,436

Notes:
Adjustment values presented here are reflected in summer peak forecasts.
Adjustments due to NRBTMG (Non-Retail Behind the Meter Generation) transitioning to DR are in AEP, ATSI, DAYTON, DEOK, PL, and PENLC.
Adjustments due to data center load growth are in AEP, APS, DOM, and PS.
Adjustments due to planned chip processing plant in AEP.
Adjustments due to Port Electrification are in PS.
An adjustment due to peak shaving program is in EKPC.

Table B-10

SUMMER COINCIDENT PEAK LOAD (MW) FOR EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	2,350	2,355	2,357	2,354	2,356	2,368	2,374	2,394	2,425	2,457	2,497	2,541	2,580	2,627	2,655	2,688
BGE	6,238	6,259	6,285	6,303	6,328	6,370	6,406	6,460	6,517	6,576	6,664	6,770	6,883	6,992	7,080	7,210
DPL	3,706	3,673	3,654	3,642	3,641	3,647	3,645	3,660	3,690	3,723	3,762	3,813	3,863	3,913	3,942	3,984
JCPL	5,693	5,719	5,742	5,760	5,808	5,854	5,912	6,009	6,119	6,250	6,398	6,558	6,722	6,891	7,023	7,202
METED	2,917	2,958	3,019	3,082	3,145	3,207	3,268	3,340	3,414	3,498	3,595	3,706	3,824	3,949	4,066	4,204
PECO	8,103	8,119	8,146	8,177	8,206	8,212	8,240	8,272	8,307	8,342	8,414	8,506	8,595	8,694	8,774	8,881
PENLC	2,742	2,745	2,755	2,766	2,775	2,783	2,793	2,811	2,825	2,844	2,868	2,897	2,930	2,964	2,994	3,029
PEPCO	5,787	5,818	5,851	5,875	5,909	5,943	5,973	6,011	6,043	6,079	6,141	6,218	6,306	6,387	6,458	6,558
PL	6,835	6,854	6,887	6,912	6,938	6,946	6,964	6,996	7,017	7,046	7,086	7,137	7,202	7,278	7,326	7,390
PS	9,521	9,584	9,638	9,699	9,802	9,909	10,019	10,129	10,265	10,433	10,625	10,828	11,048	11,277	11,443	11,668
RECO	388	388	387	385	385	383	383	385	386	390	394	398	403	409	413	420
UGI	186	186	187	187	188	187	188	188	189	190	191	193	195	197	198	201
AEP	22,306	23,296	24,038	24,595	25,015	25,275	25,425	25,574	25,660	25,752	25,863	26,049	26,260	26,391	26,589	26,782
APS	8,680	8,836	9,209	9,482	9,519	9,548	9,565	9,575	9,585	9,605	9,632	9,677	9,732	9,764	9,806	9,853
ATSI	11,980	11,978	11,998	12,043	12,066	12,082	12,071	12,086	12,119	12,161	12,193	12,253	12,336	12,394	12,485	12,564
COMED	18,835	18,839	18,807	18,851	18,781	18,822	18,806	18,805	18,792	18,861	18,930	19,094	19,244	19,347	19,488	19,624
DAYTON	3,133	3,135	3,148	3,165	3,165	3,173	3,173	3,174	3,183	3,190	3,199	3,220	3,245	3,262	3,292	3,314
DEOK	5,074	5,076	5,094	5,119	5,132	5,144	5,143	5,148	5,167	5,187	5,211	5,246	5,287	5,316	5,363	5,404
DLCO	2,619	2,622	2,634	2,650	2,668	2,685	2,698	2,713	2,733	2,755	2,778	2,809	2,841	2,872	2,910	2,951
EKPC	1,958	1,973	1,993	2,021	2,042	2,059	2,070	2,081	2,095	2,112	2,129	2,152	2,174	2,190	2,210	2,226
OVEC	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
DOM	22,134	23,021	24,915	26,731	29,044	31,023	32,700	34,139	35,520	36,856	38,194	39,498	40,756	41,953	43,175	44,538
PJM RTO	151,245	153,494	156,804	159,859	162,973	165,680	167,876	170,010	172,111	174,367	176,824	179,623	182,486	185,127	187,750	190,751
PJM MID-ATLANTIC	54,466	54,658	54,908	55,142	55,481	55,809	56,165	56,655	57,197	57,828	58,635	59,565	60,551	61,578	62,372	63,435
EASTERN MID-ATLANTIC	29,761	29,838	29,924	30,017	30,198	30,373	30,573	30,849	31,192	31,595	32,090	32,644	33,211	33,811	34,250	34,843
SOUTHERN MID-ATLANTIC	12,025	12,077	12,136	12,178	12,237	12,313	12,379	12,471	12,560	12,655	12,805	12,988	13,189	13,379	13,538	13,768

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Load values for Zones and Locational Deliverability Areas are coincident with the PJM RTO peak.
This table will be used for the Reliability Pricing Model.
Summer season indicates peak from June, July, August.

Table B-11

PJM CONTROL AREA - JANUARY 2024
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	127,155	128,499	129,895	131,107	131,886	132,599	133,103	133,788	134,494	135,398	136,499	0.7%
% GROWTH TOTAL		1.1%	1.1%	0.9%	0.6%	0.5%	0.4%	0.5%	0.5%	0.7%	0.8%	
CONTRACTUALLY INTERRUPTIBLE	6,845	6,873	6,951	7,007	7,040	7,067	7,097	7,130	7,158	7,199	7,245	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,845	6,873	6,951	7,007	7,040	7,067	7,097	7,130	7,158	7,199	7,245	
NET INTERNAL DEMAND	120,310	121,626	122,944	124,100	124,846	125,532	126,006	126,658	127,336	128,199	129,254	0.7%
% GROWTH NET		1.1%	1.1%	0.9%	0.6%	0.5%	0.4%	0.5%	0.5%	0.7%	0.8%	
PJM - SERC												
TOTAL INTERNAL DEMAND	24,092	24,994	26,908	28,752	31,086	33,082	34,770	36,220	37,615	38,968	40,323	5.3%
% GROWTH TOTAL		3.7%	7.7%	6.9%	8.1%	6.4%	5.1%	4.2%	3.9%	3.6%	3.5%	
CONTRACTUALLY INTERRUPTIBLE	911	941	1,003	1,063	1,136	1,198	1,252	1,299	1,342	1,386	1,430	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	911	941	1,003	1,063	1,136	1,198	1,252	1,299	1,342	1,386	1,430	
NET INTERNAL DEMAND	23,181	24,053	25,905	27,689	29,950	31,884	33,518	34,921	36,273	37,582	38,893	5.3%
% GROWTH NET		3.8%	7.7%	6.9%	8.2%	6.5%	5.1%	4.2%	3.9%	3.6%	3.5%	
PJM RTO												
TOTAL INTERNAL DEMAND	151,247	153,493	156,803	159,859	162,972	165,681	167,873	170,008	172,109	174,366	176,822	1.6%
% GROWTH TOTAL		1.5%	2.2%	1.9%	1.9%	1.7%	1.3%	1.3%	1.2%	1.3%	1.4%	
CONTRACTUALLY INTERRUPTIBLE	7,756	7,814	7,954	8,070	8,176	8,265	8,349	8,429	8,500	8,585	8,675	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	7,756	7,814	7,954	8,070	8,176	8,265	8,349	8,429	8,500	8,585	8,675	
NET INTERNAL DEMAND	143,491	145,679	148,849	151,789	154,796	157,416	159,524	161,579	163,609	165,781	168,147	1.6%
% GROWTH NET		1.5%	2.2%	2.0%	2.0%	1.7%	1.3%	1.3%	1.3%	1.3%	1.4%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2024).

Table B-11 (Continued)

PJM CONTROL AREA - JANUARY 2024
SUMMER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2024 - 2039

	2035	2036	2037	2038	2039	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	137,972	139,557	140,984	142,367	143,988	0.8%
% GROWTH TOTAL	1.1%	1.1%	1.0%	1.0%	1.1%	
CONTRACTUALLY INTERRUPTIBLE	7,300	7,376	7,454	7,514	7,574	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	7,300	7,376	7,454	7,514	7,574	
NET INTERNAL DEMAND	130,672	132,181	133,530	134,853	136,414	0.8%
% GROWTH NET	1.1%	1.2%	1.0%	1.0%	1.2%	
PJM - SERC						
TOTAL INTERNAL DEMAND	41,650	42,930	44,143	45,385	46,764	4.5%
% GROWTH TOTAL	3.3%	3.1%	2.8%	2.8%	3.0%	
CONTRACTUALLY INTERRUPTIBLE	1,472	1,511	1,551	1,593	1,636	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	1,472	1,511	1,551	1,593	1,636	
NET INTERNAL DEMAND	40,178	41,419	42,592	43,792	45,128	4.5%
% GROWTH NET	3.3%	3.1%	2.8%	2.8%	3.1%	
PJM RTO						
TOTAL INTERNAL DEMAND	179,622	182,487	185,127	187,752	190,752	1.6%
% GROWTH TOTAL	1.6%	1.6%	1.4%	1.4%	1.6%	
CONTRACTUALLY INTERRUPTIBLE	8,772	8,887	9,005	9,107	9,210	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	8,772	8,887	9,005	9,107	9,210	
NET INTERNAL DEMAND	170,850	173,600	176,122	178,645	181,542	1.6%
% GROWTH NET	1.6%	1.6%	1.5%	1.4%	1.6%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2024).

Table B-12

PJM CONTROL AREA - JANUARY 2024
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2023/24 - 2033/34

	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	Annual Growth Rate (10 yr)
PJM - RELIABILITY FIRST												
TOTAL INTERNAL DEMAND	128,820	129,272	132,104	135,649	139,777	142,586	145,617	148,288	151,266	153,407	155,711	1.9%
% GROWTH TOTAL		0.4%	2.2%	2.7%	3.0%	2.0%	2.1%	1.8%	2.0%	1.4%	1.5%	
CONTRACTUALLY INTERRUPTIBLE	4,812	4,867	4,926	4,970	4,992	5,012	5,034	5,058	5,076	5,103	5,135	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	4,812	4,867	4,926	4,970	4,992	5,012	5,034	5,058	5,076	5,103	5,135	
NET INTERNAL DEMAND	124,008	124,405	127,178	130,679	134,785	137,574	140,583	143,230	146,190	148,304	150,576	2.0%
% GROWTH NET		0.3%	2.2%	2.8%	3.1%	2.1%	2.2%	1.9%	2.1%	1.4%	1.5%	
PJM - SERC												
TOTAL INTERNAL DEMAND	5,839	7,056	7,120	7,175	7,221	7,250	7,253	7,261	7,314	7,325	7,358	2.3%
% GROWTH TOTAL		20.8%	0.9%	0.8%	0.6%	0.4%	0.0%	0.1%	0.7%	0.2%	0.5%	
CONTRACTUALLY INTERRUPTIBLE	724	749	801	852	914	966	1,012	1,051	1,088	1,126	1,162	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	724	749	801	852	914	966	1,012	1,051	1,088	1,126	1,162	
NET INTERNAL DEMAND	5,115	6,307	6,319	6,323	6,307	6,284	6,241	6,210	6,226	6,199	6,196	1.9%
% GROWTH NET		23.3%	0.2%	0.1%	-0.3%	-0.4%	-0.7%	-0.5%	0.3%	-0.4%	-0.0%	
PJM RTO												
TOTAL INTERNAL DEMAND	134,659	136,328	139,224	142,824	146,998	149,836	152,870	155,549	158,580	160,732	163,069	1.9%
% GROWTH TOTAL		1.2%	2.1%	2.6%	2.9%	1.9%	2.0%	1.8%	1.9%	1.4%	1.5%	
CONTRACTUALLY INTERRUPTIBLE	5,536	5,616	5,727	5,822	5,906	5,978	6,046	6,109	6,164	6,229	6,297	
DIRECT CONTROL	0	0	0	0	0	0	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,536	5,616	5,727	5,822	5,906	5,978	6,046	6,109	6,164	6,229	6,297	
NET INTERNAL DEMAND	129,123	130,712	133,497	137,002	141,092	143,858	146,824	149,440	152,416	154,503	156,772	2.0%
% GROWTH NET		1.2%	2.1%	2.6%	3.0%	2.0%	2.1%	1.8%	2.0%	1.4%	1.5%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2024).

Table B-12 (Continued)

PJM CONTROL AREA - JANUARY 2024
WINTER TOTAL INTERNAL DEMAND FORECAST (MW) FOR EACH NERC REGION
2023/24 - 2033/34

	34/35	35/36	36/37	37/38	38/39	Annual Growth Rate (15 yr)
PJM - RELIABILITY FIRST						
TOTAL INTERNAL DEMAND	158,331	161,113	163,510	166,015	168,681	1.8%
% GROWTH TOTAL	1.7%	1.8%	1.5%	1.5%	1.6%	
CONTRACTUALLY INTERRUPTIBLE	5,173	5,228	5,280	5,323	5,366	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	5,173	5,228	5,280	5,323	5,366	
NET INTERNAL DEMAND	153,158	155,885	158,230	160,692	163,315	1.9%
% GROWTH NET	1.7%	1.8%	1.5%	1.6%	1.6%	
PJM - SERC						
TOTAL INTERNAL DEMAND	7,374	7,398	7,446	7,487	7,514	1.7%
% GROWTH TOTAL	0.2%	0.3%	0.6%	0.6%	0.4%	
CONTRACTUALLY INTERRUPTIBLE	1,197	1,230	1,264	1,299	1,335	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	1,197	1,230	1,264	1,299	1,335	
NET INTERNAL DEMAND	6,177	6,168	6,182	6,188	6,179	1.3%
% GROWTH NET	-0.3%	-0.1%	0.2%	0.1%	-0.1%	
PJM RTO						
TOTAL INTERNAL DEMAND	165,705	168,511	170,956	173,502	176,195	1.8%
% GROWTH TOTAL	1.6%	1.7%	1.5%	1.5%	1.6%	
CONTRACTUALLY INTERRUPTIBLE	6,370	6,458	6,544	6,622	6,701	
DIRECT CONTROL	0	0	0	0	0	
TOTAL LOAD MANAGEMENT	6,370	6,458	6,544	6,622	6,701	
NET INTERNAL DEMAND	159,335	162,053	164,412	166,880	169,494	1.8%
% GROWTH NET	1.6%	1.7%	1.5%	1.5%	1.6%	

Notes:
SERC includes EKPC and DOM zones and Reliability First includes all other zones.
Total Internal Demand = projected PJM seasonal peak load at normal peak weather conditions in the absence of any load reductions due to load management, voltage reductions or voluntary curtailments.
Contractually Interruptible = Firm Service Level + Guaranteed Load Drop
The above forecasts incorporate all load in the PJM Control Area, including members and non-members
All average growth rates are calculated from the first year of the forecast (2024).

Table C-1

PJM LOCATIONAL DELIVERABILITY AREAS
CENTRAL MID-ATLANTIC: BGE, METED, PEPCO, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	18,425	22,639	19,025	21,298
2025	18,355	22,754	19,216	21,339
2026	18,540	22,900	19,429	21,487
2027	18,745	23,035	19,541	21,620
2028	18,908	23,159	19,572	21,830
2029	19,073	23,328	19,777	21,960
2030	19,200	23,475	20,004	22,089
2031	19,266	23,659	20,347	22,302
2032	19,537	23,858	20,614	22,573
2033	19,752	24,115	20,815	22,827
2034	20,074	24,389	21,030	22,971
2035	20,437	24,687	21,344	23,245
2036	20,610	25,043	21,916	23,567
2037	20,870	25,442	22,374	23,840
2038	21,245	25,835	22,711	24,158
2039	21,778	26,270	23,108	24,503

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	20,151	24,122	20,957	22,784
2025	20,120	24,394	21,085	22,762
2026	20,333	24,515	21,233	22,868
2027	20,525	24,473	21,380	22,985
2028	20,630	24,611	21,591	23,174
2029	20,764	24,920	21,624	23,169
2030	20,849	24,955	21,809	23,281
2031	20,894	25,163	22,083	23,389
2032	21,157	25,319	22,367	23,692
2033	21,297	25,577	22,747	23,808
2034	21,559	25,884	22,979	24,052
2035	21,859	26,204	23,225	24,335
2036	22,118	26,596	23,762	24,680
2037	22,394	26,935	24,180	24,905
2038	22,728	27,329	24,616	25,212
2039	23,172	27,767	25,080	25,518

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-2

PJM LOCATIONAL DELIVERABILITY AREAS
WESTERN MID-ATLANTIC: METED, PENLC, PL and UGI
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	11,400	13,072	11,278	13,055
2025	11,381	13,165	11,374	13,029
2026	11,487	13,278	11,515	13,092
2027	11,585	13,372	11,616	13,154
2028	11,654	13,410	11,636	13,280
2029	11,715	13,525	11,700	13,311
2030	11,768	13,585	11,843	13,391
2031	11,795	13,752	12,004	13,468
2032	11,949	13,872	12,142	13,591
2033	12,089	13,993	12,254	13,686
2034	12,221	14,107	12,382	13,797
2035	12,366	14,305	12,524	13,928
2036	12,451	14,526	12,793	14,113
2037	12,652	14,790	13,049	14,265
2038	12,875	14,982	13,243	14,445
2039	13,096	15,233	13,449	14,628

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	12,320	13,778	12,435	13,688
2025	12,357	13,838	12,509	13,686
2026	12,466	13,927	12,598	13,741
2027	12,536	14,012	12,683	13,810
2028	12,539	14,112	12,789	13,903
2029	12,587	14,203	12,878	13,968
2030	12,629	14,273	12,993	14,038
2031	12,679	14,444	13,119	14,111
2032	12,800	14,526	13,239	14,231
2033	12,915	14,655	13,384	14,307
2034	13,029	14,835	13,543	14,429
2035	13,175	15,012	13,706	14,565
2036	13,357	15,239	13,959	14,781
2037	13,538	15,454	14,172	14,882
2038	13,711	15,674	14,367	15,049
2039	13,889	15,920	14,601	15,223

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-3

PJM LOCATIONAL DELIVERABILITY AREAS
EASTERN MID-ATLANTIC: AE, DPL, JCPL, PECO, PS and RECO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	22,569	31,179	25,288	22,582
2025	22,504	31,260	25,531	23,023
2026	22,525	31,341	25,741	23,681
2027	22,740	31,413	25,878	24,382
2028	23,295	31,525	25,971	25,186
2029	23,715	31,777	26,253	25,815
2030	24,038	31,942	26,632	26,484
2031	24,317	32,231	27,030	27,201
2032	24,833	32,571	27,329	27,950
2033	25,386	32,968	27,719	28,578
2034	25,846	33,407	28,114	29,219
2035	26,317	33,944	28,631	29,926
2036	26,698	34,470	29,344	30,621
2037	27,165	35,105	29,947	31,305
2038	27,683	35,585	30,392	31,996
2039	28,416	36,148	30,981	32,738

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	25,843	33,610	28,228	23,658
2025	25,715	33,752	28,410	24,151
2026	25,629	33,853	28,548	24,817
2027	25,670	33,852	28,790	25,594
2028	26,154	34,011	29,032	26,433
2029	26,605	34,095	29,282	27,150
2030	26,651	34,562	29,621	27,851
2031	26,590	34,888	30,045	28,579
2032	26,752	35,041	30,299	29,429
2033	27,427	35,447	30,782	30,068
2034	28,032	35,909	31,312	30,700
2035	28,506	36,395	31,782	31,470
2036	28,800	37,042	32,378	32,308
2037	29,299	37,560	32,875	32,876
2038	29,965	38,073	33,371	33,644
2039	30,802	38,676	34,033	34,467

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table C-4

PJM LOCATIONAL DELIVERABILITY AREAS
SOUTHERN MID-ATLANTIC: BGE and PEPCO
SEASONAL PEAKS - MW

BASE (50/50) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	9,870	12,465	10,488	11,186
2025	9,894	12,501	10,592	11,201
2026	9,941	12,555	10,668	11,252
2027	9,995	12,632	10,709	11,333
2028	10,082	12,686	10,681	11,417
2029	10,181	12,750	10,749	11,471
2030	10,266	12,831	10,884	11,562
2031	10,314	12,925	11,134	11,666
2032	10,388	13,015	11,198	11,819
2033	10,558	13,137	11,337	11,938
2034	10,707	13,254	11,489	12,043
2035	10,866	13,408	11,648	12,220
2036	10,993	13,603	11,957	12,392
2037	11,152	13,819	12,179	12,545
2038	11,358	14,004	12,394	12,706
2039	11,594	14,241	12,597	12,872

EXTREME WEATHER (90/10) FORECAST

YEAR	SPRING	SUMMER	FALL	WINTER
2024	10,978	13,518	11,549	12,046
2025	10,961	13,585	11,613	12,050
2026	10,989	13,587	11,678	12,094
2027	11,035	13,629	11,735	12,207
2028	11,138	13,664	11,822	12,276
2029	11,212	13,730	11,914	12,295
2030	11,250	13,806	12,004	12,316
2031	11,278	13,889	12,140	12,371
2032	11,335	13,958	12,267	12,523
2033	11,528	14,079	12,427	12,620
2034	11,673	14,223	12,603	12,745
2035	11,815	14,393	12,780	12,882
2036	11,914	14,609	13,028	13,064
2037	12,035	14,823	13,253	13,123
2038	12,242	14,998	13,478	13,289
2039	12,547	15,198	13,756	13,440

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Spring season indicates peak from March, April, May.
Summer season indicates peak from June, July, August.
Fall season indicates peak from September, October, November.
Winter season indicates peak from December, January, February.

Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	2,742	2,742	2,744	2,746	2,761	2,775	2,785	2,795	2,815	2,836	2,879	2,924	2,943	2,993	3,035	3,065
BGE	7,103	7,118	7,131	7,144	7,158	7,179	7,219	7,275	7,326	7,373	7,457	7,568	7,686	7,804	7,918	8,050
DPL	4,159	4,129	4,120	4,128	4,137	4,152	4,166	4,195	4,230	4,263	4,304	4,352	4,405	4,457	4,504	4,557
JCPL	6,681	6,706	6,709	6,704	6,728	6,754	6,823	6,905	7,006	7,112	7,245	7,404	7,573	7,733	7,871	8,050
METED	3,185	3,229	3,287	3,351	3,411	3,479	3,547	3,624	3,694	3,784	3,880	3,988	4,110	4,238	4,365	4,510
PECO	9,180	9,225	9,257	9,263	9,309	9,339	9,376	9,450	9,464	9,525	9,598	9,692	9,795	9,895	9,983	10,103
PENLC	2,998	2,998	3,005	3,012	3,016	3,023	3,039	3,064	3,068	3,084	3,106	3,135	3,186	3,208	3,241	3,276
PEPCO	6,524	6,563	6,581	6,605	6,625	6,638	6,675	6,720	6,739	6,791	6,838	6,908	7,004	7,117	7,222	7,342
PL	7,505	7,527	7,548	7,568	7,591	7,609	7,604	7,654	7,654	7,693	7,720	7,775	7,834	7,887	7,952	8,025
PS	10,879	11,043	11,077	11,128	11,223	11,371	11,507	11,663	11,746	11,927	12,133	12,342	12,556	12,828	12,941	13,204
RECO	466	468	466	464	461	459	459	461	463	466	470	474	483	485	492	498
UGI	212	212	212	212	212	212	212	213	214	215	216	217	219	221	223	225
DIVERSITY - MID-ATLANTIC(-)	1,199	1,263	1,164	1,084	1,053	1,040	1,060	1,176	1,199	1,254	1,327	1,426	1,150	1,214	1,295	1,492
PJM MID-ATLANTIC	60,435	60,697	60,973	61,241	61,579	61,950	62,352	62,843	63,220	63,815	64,519	65,353	66,644	67,652	68,452	69,413
FE-EAST	12,535	12,621	12,692	12,784	12,879	12,989	13,172	13,409	13,543	13,755	14,009	14,292	14,675	15,014	15,236	15,605
PLGRP	7,716	7,736	7,757	7,777	7,801	7,819	7,813	7,865	7,868	7,907	7,933	7,989	8,052	8,107	8,173	8,248

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Summer season indicates peak from June, July, August.

Table D-1

SUMMER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AEP	24,034	24,974	25,718	26,225	26,625	26,884	27,044	27,197	27,312	27,439	27,570	27,724	27,885	28,121	28,282	28,534
APS	9,484	9,648	10,010	10,290	10,311	10,321	10,360	10,373	10,381	10,397	10,427	10,477	10,531	10,582	10,625	10,673
ATSI	13,345	13,332	13,338	13,342	13,358	13,364	13,370	13,375	13,386	13,431	13,483	13,535	13,618	13,702	13,785	13,887
COMED	22,673	22,653	22,629	22,691	22,527	22,496	22,488	22,495	22,577	22,593	22,664	22,795	22,942	23,093	23,162	23,341
DAYTON	3,582	3,586	3,592	3,602	3,604	3,620	3,623	3,625	3,625	3,637	3,658	3,679	3,697	3,719	3,741	3,768
DEOK	5,722	5,727	5,737	5,747	5,761	5,769	5,774	5,784	5,803	5,829	5,862	5,894	5,929	5,969	6,009	6,058
DLCO	2,908	2,912	2,922	2,938	2,956	2,973	2,988	3,006	3,026	3,048	3,081	3,106	3,143	3,178	3,215	3,262
EKPC	2,195	2,206	2,224	2,242	2,262	2,280	2,290	2,297	2,309	2,323	2,339	2,358	2,374	2,390	2,405	2,429
OVEC	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
DIVERSITY - WESTERN(-)	621	711	755	849	718	755	745	846	985	973	962	984	966	1,028	953	1,067
PJM WESTERN	83,412	84,417	85,505	86,318	86,776	87,042	87,282	87,396	87,524	87,814	88,212	88,674	89,243	89,816	90,361	90,975
DOM	24,144	25,057	26,829	28,695	31,033	33,042	34,758	36,211	37,586	38,949	40,274	41,540	42,780	44,030	45,311	46,647
DIVERSITY - TOTAL(-)	5,120	4,347	4,333	5,534	5,321	5,266	5,474	5,569	6,010	5,795	5,954	5,994	5,953	5,959	6,720	6,597
PJM RTO	164,691	167,798	170,893	172,653	175,838	178,563	180,723	182,903	184,504	187,010	189,340	191,983	194,830	197,781	199,652	202,997

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.
Summer season indicates peak from June, July, August.

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

2023/24 - 2038/39

	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38	38/39
AE	1,702	1,745	1,802	1,858	1,919	1,970	2,029	2,083	2,154	2,204	2,265	2,332	2,414	2,473	2,539	2,606
BGE	6,410	6,409	6,429	6,450	6,492	6,503	6,509	6,541	6,600	6,608	6,646	6,731	6,874	6,928	7,011	7,121
DPL	4,084	4,061	4,072	4,089	4,142	4,131	4,148	4,168	4,217	4,206	4,233	4,270	4,311	4,347	4,390	4,422
JCPL	4,030	4,207	4,436	4,689	4,947	5,203	5,444	5,686	5,944	6,167	6,397	6,651	6,897	7,127	7,366	7,621
METED	2,897	2,903	2,951	3,015	3,086	3,150	3,212	3,276	3,351	3,431	3,516	3,615	3,727	3,835	3,947	4,063
PECO	6,921	6,896	6,918	6,963	7,032	7,065	7,092	7,123	7,179	7,220	7,271	7,350	7,425	7,460	7,535	7,611
PENLC	2,985	2,959	2,955	2,957	2,978	2,966	2,962	2,969	2,995	2,995	3,004	3,021	3,059	3,053	3,071	3,092
PEPCO	5,803	5,807	5,838	5,866	5,916	5,910	5,934	5,973	6,026	6,059	6,110	6,171	6,259	6,294	6,339	6,395
PL	7,709	7,714	7,726	7,744	7,755	7,754	7,765	7,772	7,777	7,787	7,799	7,818	7,856	7,899	7,926	7,959
PS	7,137	7,403	7,716	8,099	8,502	8,867	9,221	9,550	9,934	10,222	10,493	10,813	11,140	11,412	11,722	12,051
RECO	236	242	251	260	270	280	288	298	307	316	324	334	342	351	359	368
UGI	212	211	211	212	212	213	213	213	214	214	215	216	217	218	220	221
DIVERSITY - MID-ATLANTIC(-)	1,389	1,315	1,237	1,239	1,189	1,178	1,026	942	927	833	774	692	724	759	735	766
PJM MID-ATLANTIC	48,737	49,242	50,068	50,963	52,062	52,834	53,791	54,710	55,771	56,596	57,499	58,630	59,797	60,638	61,690	62,764
FE-EAST	9,791	9,969	10,255	10,583	10,956	11,247	11,561	11,868	12,247	12,537	12,873	13,240	13,655	13,911	14,308	14,693
PLGRP	7,911	7,916	7,931	7,945	7,957	7,957	7,965	7,973	7,983	7,989	8,008	8,031	8,073	8,106	8,137	8,176

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Winter season indicates peak from December, January, February.

Table D-2

WINTER EXTREME WEATHER (90/10) PEAK LOAD FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2024 - 2039

	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38	38/39
AEP	24,716	25,401	26,092	26,612	27,344	27,274	27,472	27,527	27,814	27,652	27,775	27,882	28,095	28,005	28,196	28,340
APS	9,952	10,126	10,172	10,640	10,921	10,923	10,948	10,978	11,057	11,037	11,046	11,076	11,135	11,129	11,182	11,197
ATSI	10,840	10,732	10,761	10,802	10,945	10,906	10,926	10,942	11,005	10,991	11,028	11,096	11,167	11,163	11,210	11,289
COMED	15,639	15,656	15,730	15,836	15,947	15,999	16,076	16,149	16,308	16,367	16,489	16,641	16,837	16,896	17,040	17,210
DAYTON	3,108	3,099	3,098	3,100	3,119	3,113	3,110	3,103	3,106	3,104	3,104	3,110	3,123	3,133	3,142	3,150
DEOK	4,885	4,855	4,861	4,873	4,911	4,901	4,899	4,893	4,924	4,930	4,947	4,974	4,963	4,960	4,980	5,039
DLCO	2,106	2,084	2,092	2,106	2,141	2,142	2,154	2,164	2,196	2,204	2,224	2,251	2,286	2,297	2,324	2,351
EKPC	3,114	3,090	3,132	3,157	3,164	3,171	3,158	3,154	3,185	3,190	3,201	3,202	3,193	3,226	3,247	3,250
OVEC	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
DIVERSITY - WESTERN(-)	2,109	2,171	2,280	2,301	2,510	2,305	2,374	2,404	2,582	2,687	2,795	2,421	2,249	2,513	2,641	2,461
PJM WESTERN	72,361	72,982	73,768	74,935	76,092	76,234	76,479	76,616	77,123	76,898	77,129	77,921	78,660	78,406	78,790	79,475
DOM	24,826	25,476	26,999	28,667	30,641	32,461	34,136	35,584	36,823	37,974	39,053	40,165	41,240	42,094	43,246	44,353
DIVERSITY - TOTAL(-)	6,349	5,927	6,257	6,511	7,476	7,121	6,938	6,592	6,891	6,409	6,298	6,178	6,314	5,698	5,896	5,987
PJM RTO	143,073	145,259	148,095	151,594	155,018	157,891	160,868	163,664	166,335	168,579	170,952	173,651	176,356	178,712	181,206	183,832

Notes:
All forecast values represent unrestricted peaks, after reductions for distributed solar generation, additions for plug-in electric vehicles, and prior to reductions for load management.
Winter season indicates peak from December, January, February.

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION 2024 - 2034

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Annual Growth Rate (10 yr)
AE	9,956	9,970	10,026	10,077	10,170	10,228	10,321	10,438	10,621	10,759	10,972	1.0%
		0.1%	0.6%	0.5%	0.9%	0.6%	0.9%	1.1%	1.8%	1.3%	2.0%	
BGE	30,725	30,767	30,940	31,149	31,489	31,684	31,975	32,330	32,851	33,147	33,650	0.9%
		0.1%	0.6%	0.7%	1.1%	0.6%	0.9%	1.1%	1.6%	0.9%	1.5%	
DPL	18,330	18,163	18,121	18,115	18,189	18,137	18,138	18,188	18,357	18,386	18,535	0.1%
		-0.9%	-0.2%	-0.0%	0.4%	-0.3%	0.0%	0.3%	0.9%	0.2%	0.8%	
JCPL	22,673	23,004	23,443	23,894	24,451	24,935	25,514	26,176	27,017	27,708	28,609	2.4%
		1.5%	1.9%	1.9%	2.3%	2.0%	2.3%	2.6%	3.2%	2.6%	3.3%	
METED	16,123	16,338	16,755	17,211	17,729	18,132	18,585	19,093	19,744	20,252	20,946	2.7%
		1.3%	2.6%	2.7%	3.0%	2.3%	2.5%	2.7%	3.4%	2.6%	3.4%	
PECO	39,070	39,011	39,209	39,435	39,814	39,880	40,102	40,391	40,889	41,043	41,433	0.6%
		-0.2%	0.5%	0.6%	1.0%	0.2%	0.6%	0.7%	1.2%	0.4%	1.0%	
PENLC	17,334	17,250	17,287	17,336	17,449	17,421	17,463	17,532	17,695	17,703	17,812	0.3%
		-0.5%	0.2%	0.3%	0.7%	-0.2%	0.2%	0.4%	0.9%	0.0%	0.6%	
PEPCO	28,588	28,656	28,822	28,995	29,268	29,399	29,595	29,832	30,183	30,341	30,663	0.7%
		0.2%	0.6%	0.6%	0.9%	0.4%	0.7%	0.8%	1.2%	0.5%	1.1%	
PL	40,546	40,455	40,599	40,754	41,047	41,028	41,136	41,290	41,640	41,629	41,842	0.3%
		-0.2%	0.4%	0.4%	0.7%	-0.0%	0.3%	0.4%	0.8%	-0.0%	0.5%	
PS	43,445	44,025	44,717	45,483	46,395	47,172	47,995	48,716	49,776	50,545	51,645	1.7%
		1.3%	1.6%	1.7%	2.0%	1.7%	1.7%	1.5%	2.2%	1.5%	2.2%	
RECO	1,464	1,474	1,487	1,498	1,513	1,526	1,539	1,557	1,583	1,601	1,628	1.1%
		0.7%	0.9%	0.7%	1.0%	0.9%	0.9%	1.2%	1.7%	1.1%	1.7%	
UGI	1,056	1,051	1,054	1,058	1,063	1,063	1,065	1,068	1,078	1,078	1,088	0.3%
		-0.5%	0.3%	0.4%	0.5%	0.0%	0.2%	0.3%	0.9%	0.0%	0.9%	
PJM MID-ATLANTIC	269,310	270,164	272,460	275,005	278,577	280,605	283,428	286,611	291,434	294,192	298,823	1.0%
		0.3%	0.8%	0.9%	1.3%	0.7%	1.0%	1.1%	1.7%	0.9%	1.6%	
FE-EAST	56,130	56,592	57,485	58,441	59,629	60,488	61,562	62,801	64,456	65,663	67,367	1.8%
		0.8%	1.6%	1.7%	2.0%	1.4%	1.8%	2.0%	2.6%	1.9%	2.6%	
PLGRP	41,602	41,506	41,653	41,812	42,110	42,091	42,201	42,358	42,718	42,707	42,930	0.3%
		-0.2%	0.4%	0.4%	0.7%	-0.0%	0.3%	0.4%	0.8%	-0.0%	0.5%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2024).

Table E-1 (continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION
2035 - 2039

	2035	2036	2037	2038	2039	Annual Growth Rate (15 yr)
AE	11,233	11,551	11,796	12,082	12,412	1.5%
	2.4%	2.8%	2.1%	2.4%	2.7%	
BGE	34,260	35,078	35,652	36,350	37,184	1.3%
	1.8%	2.4%	1.6%	2.0%	2.3%	
DPL	18,739	19,071	19,258	19,513	19,809	0.5%
	1.1%	1.8%	1.0%	1.3%	1.5%	
JCPL	29,656	30,816	31,783	32,851	34,053	2.7%
	3.7%	3.9%	3.1%	3.4%	3.7%	
METED	21,763	22,716	23,513	24,433	25,435	3.1%
	3.9%	4.4%	3.5%	3.9%	4.1%	
PECO	41,905	42,594	42,912	43,426	43,989	0.8%
	1.1%	1.6%	0.7%	1.2%	1.3%	
PENLC	17,959	18,206	18,300	18,474	18,670	0.5%
	0.8%	1.4%	0.5%	1.0%	1.1%	
PEPCO	31,070	31,641	32,026	32,507	33,057	1.0%
	1.3%	1.8%	1.2%	1.5%	1.7%	
PL	42,089	42,597	42,758	43,094	43,453	0.5%
	0.6%	1.2%	0.4%	0.8%	0.8%	
PS	52,948	54,485	55,675	57,071	58,600	2.0%
	2.5%	2.9%	2.2%	2.5%	2.7%	
RECO	1,659	1,702	1,732	1,765	1,805	1.4%
	1.9%	2.6%	1.8%	1.9%	2.3%	
UGI	1,097	1,114	1,122	1,134	1,150	0.6%
	0.8%	1.5%	0.7%	1.1%	1.4%	
PJM MID-ATLANTIC	304,378	311,571	316,527	322,700	329,617	1.4%
	1.9%	2.4%	1.6%	2.0%	2.1%	
FE-EAST	69,378	71,738	73,596	75,758	78,158	2.2%
	3.0%	3.4%	2.6%	2.9%	3.2%	
PLGRP	43,186	43,711	43,880	44,228	44,603	0.5%
	0.6%	1.2%	0.4%	0.8%	0.8%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2024).

Table E-1

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2024 - 2034

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Annual Growth Rate (10 yr)
AEP	135,995	144,174	150,566	155,236	159,451	161,012	162,521	163,854	165,268	165,289	166,117	2.0%
		6.0%	4.4%	3.1%	2.7%	1.0%	0.9%	0.8%	0.9%	0.0%	0.5%	
APS	51,299	52,290	54,687	57,259	58,493	58,518	58,702	58,872	59,294	59,181	59,383	1.5%
		1.9%	4.6%	4.7%	2.2%	0.0%	0.3%	0.3%	0.7%	-0.2%	0.3%	
ATSI	66,125	65,898	66,102	66,403	66,955	66,947	67,092	67,284	67,821	67,755	68,088	0.3%
		-0.3%	0.3%	0.5%	0.8%	-0.0%	0.2%	0.3%	0.8%	-0.1%	0.5%	
COMED	93,350	93,118	93,408	93,740	94,361	94,331	94,557	94,965	95,889	96,098	96,887	0.4%
		-0.2%	0.3%	0.4%	0.7%	-0.0%	0.2%	0.4%	1.0%	0.2%	0.8%	
DAYTON	17,224	17,202	17,263	17,335	17,456	17,443	17,461	17,497	17,624	17,601	17,677	0.3%
		-0.1%	0.4%	0.4%	0.7%	-0.1%	0.1%	0.2%	0.7%	-0.1%	0.4%	
DEOK	27,125	27,062	27,144	27,230	27,408	27,400	27,460	27,554	27,778	27,799	27,955	0.3%
		-0.2%	0.3%	0.3%	0.7%	-0.0%	0.2%	0.3%	0.8%	0.1%	0.6%	
DLCO	13,197	13,153	13,211	13,286	13,417	13,461	13,539	13,644	13,817	13,892	14,047	0.6%
		-0.3%	0.4%	0.6%	1.0%	0.3%	0.6%	0.8%	1.3%	0.5%	1.1%	
EKPC	11,431	11,497	11,654	11,820	12,014	12,089	12,192	12,291	12,458	12,512	12,633	1.0%
		0.6%	1.4%	1.4%	1.6%	0.6%	0.9%	0.8%	1.4%	0.4%	1.0%	
OVEC	325	325	325	325	325	325	325	325	325	325	325	0.0%
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	416,071	424,719	434,360	442,634	449,880	451,526	453,849	456,286	460,274	460,452	463,112	1.1%
		2.1%	2.3%	1.9%	1.6%	0.4%	0.5%	0.5%	0.9%	0.0%	0.6%	
DOM	127,947	134,800	150,124	165,597	185,010	201,015	215,301	227,376	239,480	249,565	260,020	7.3%
		5.4%	11.4%	10.3%	11.7%	8.7%	7.1%	5.6%	5.3%	4.2%	4.2%	
PJM RTO	813,328	829,683	856,944	883,236	913,467	933,146	952,578	970,273	991,188	1,004,209	1,021,955	2.3%
		2.0%	3.3%	3.1%	3.4%	2.2%	2.1%	1.9%	2.2%	1.3%	1.8%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2024).

Table E-1 (Continued)

ANNUAL NET ENERGY (GWh) AND GROWTH RATES FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

2024 - 2034

	2035	2036	2037	2038	2039	Annual Growth Rate (15 yr)
AEP	167,252	169,070	169,532	170,725	171,991	1.6%
	0.7%	1.1%	0.3%	0.7%	0.7%	
APS	59,744	60,336	60,387	60,691	61,039	1.2%
	0.6%	1.0%	0.1%	0.5%	0.6%	
ATSI	68,563	69,359	69,552	70,096	70,668	0.4%
	0.7%	1.2%	0.3%	0.8%	0.8%	
COMED	98,043	99,584	100,336	101,528	102,896	0.7%
	1.2%	1.6%	0.8%	1.2%	1.3%	
DAYTON	17,801	18,008	18,064	18,201	18,350	0.4%
	0.7%	1.2%	0.3%	0.8%	0.8%	
DEOK	28,187	28,522	28,640	28,877	29,131	0.5%
	0.8%	1.2%	0.4%	0.8%	0.9%	
DLCO	14,240	14,502	14,665	14,878	15,119	0.9%
	1.4%	1.8%	1.1%	1.5%	1.6%	
EKPC	12,782	12,988	13,072	13,221	13,375	1.1%
	1.2%	1.6%	0.6%	1.1%	1.2%	
OVEC	325	325	325	325	325	0.0%
	0.0%	0.0%	0.0%	0.0%	0.0%	
PJM WESTERN	466,937	472,694	474,573	478,542	482,894	1.0%
	0.8%	1.2%	0.4%	0.8%	0.9%	
DOM	269,902	280,018	288,582	298,296	308,417	6.0%
	3.8%	3.7%	3.1%	3.4%	3.4%	
PJM RTO	1,041,217	1,064,283	1,079,682	1,099,538	1,120,928	2.2%
	1.9%	2.2%	1.4%	1.8%	1.9%	

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.
All average growth rates are calculated from the first year of the forecast (2024).

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR EACH PJM MID-ATLANTIC ZONE AND GEOGRAPHIC REGION

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	PJM MID-ATLANTIC
Jan 2024	862	3,005	1,850	2,013	1,537	3,603	1,657	2,749	4,055	3,799	122	109	25,361
Feb 2024	772	2,674	1,637	1,812	1,407	3,282	1,539	2,451	3,678	3,459	110	100	22,921
Mar 2024	732	2,474	1,507	1,725	1,326	3,114	1,492	2,254	3,469	3,347	107	94	21,641
Apr 2024	643	2,093	1,227	1,526	1,174	2,731	1,318	1,943	2,965	3,002	99	76	18,797
May 2024	726	2,241	1,296	1,664	1,208	2,912	1,322	2,120	2,987	3,235	115	75	19,901
Jun 2024	882	2,598	1,510	1,996	1,322	3,362	1,370	2,454	3,184	3,811	136	80	22,705
Jul 2024	1,161	3,072	1,854	2,468	1,514	3,996	1,531	2,907	3,683	4,581	163	95	27,025
Aug 2024	1,099	2,949	1,760	2,349	1,491	3,855	1,491	2,780	3,551	4,415	154	89	25,983
Sep 2024	832	2,393	1,398	1,827	1,240	3,121	1,315	2,270	3,030	3,580	123	75	21,204
Oct 2024	701	2,175	1,261	1,636	1,214	2,814	1,358	2,045	3,009	3,249	108	77	19,647
Nov 2024	711	2,288	1,353	1,669	1,242	2,887	1,383	2,112	3,203	3,238	106	84	20,276
Dec 2024	835	2,763	1,677	1,988	1,448	3,393	1,558	2,503	3,732	3,729	121	102	23,849

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2025	874	3,021	1,851	2,080	1,555	3,610	1,653	2,768	4,059	3,905	125	109	25,610
Feb 2025	744	2,571	1,557	1,779	1,346	3,107	1,450	2,366	3,498	3,382	107	94	22,001
Mar 2025	739	2,490	1,502	1,771	1,350	3,128	1,496	2,274	3,483	3,430	108	94	21,865
Apr 2025	645	2,102	1,217	1,553	1,192	2,737	1,315	1,953	2,965	3,044	100	76	18,899
May 2025	725	2,245	1,278	1,678	1,224	2,910	1,315	2,124	2,979	3,260	115	74	19,927
Jun 2025	881	2,612	1,497	2,014	1,349	3,378	1,375	2,471	3,200	3,854	137	81	22,849
Jul 2025	1,159	3,085	1,839	2,487	1,546	4,012	1,536	2,923	3,701	4,630	164	95	27,177
Aug 2025	1,097	2,954	1,745	2,361	1,509	3,855	1,484	2,786	3,543	4,444	154	89	26,021
Sep 2025	834	2,410	1,390	1,852	1,273	3,141	1,323	2,289	3,052	3,637	124	76	21,401
Oct 2025	705	2,188	1,255	1,663	1,242	2,823	1,357	2,055	3,015	3,299	109	77	19,788
Nov 2025	717	2,300	1,349	1,705	1,265	2,892	1,379	2,120	3,201	3,292	107	84	20,411
Dec 2025	850	2,789	1,683	2,061	1,487	3,418	1,567	2,527	3,759	3,848	124	102	24,215

	AE	BGE	DPL	JCPL	METED	PECO	PENLC	PEPCO	PL	PS	RECO	UGI	MID-ATLANTIC
Jan 2026	887	3,033	1,853	2,149	1,582	3,617	1,648	2,781	4,060	4,011	127	109	25,857
Feb 2026	756	2,586	1,558	1,840	1,376	3,120	1,452	2,382	3,509	3,475	109	95	22,258
Mar 2026	748	2,508	1,501	1,825	1,388	3,152	1,504	2,295	3,506	3,515	110	94	22,146
Apr 2026	648	2,113	1,208	1,581	1,224	2,750	1,317	1,962	2,975	3,084	101	76	19,039
May 2026	724	2,250	1,264	1,690	1,250	2,915	1,310	2,126	2,975	3,276	115	74	19,969
Jun 2026	880	2,625	1,487	2,029	1,390	3,401	1,384	2,486	3,223	3,892	137	81	23,015
Jul 2026	1,156	3,095	1,829	2,499	1,582	4,029	1,539	2,935	3,713	4,656	164	95	27,292
Aug 2026	1,095	2,968	1,738	2,380	1,547	3,877	1,491	2,802	3,559	4,483	155	89	26,184
Sep 2026	835	2,423	1,387	1,871	1,308	3,157	1,326	2,302	3,062	3,669	124	76	21,540
Oct 2026	707	2,199	1,250	1,688	1,273	2,832	1,355	2,061	3,015	3,333	110	77	19,900
Nov 2026	726	2,326	1,354	1,756	1,307	2,919	1,388	2,143	3,225	3,368	109	85	20,706
Dec 2026	864	2,814	1,692	2,135	1,528	3,440	1,573	2,547	3,777	3,955	126	103	24,554

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.

Table E-2

MONTHLY NET ENERGY FORECAST (GWh) FOR EACH PJM WESTERN AND PJM SOUTHERN ZONE, GEOGRAPHIC REGION AND RTO

	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	PJM WESTERN	DOM	PJM RTO
Jan 2024	13,028	5,059	6,120	8,450	1,630	2,504	1,176	1,251	30	39,248	11,771	76,380
Feb 2024	11,819	4,590	5,676	7,800	1,483	2,259	1,078	1,079	30	35,814	10,552	69,287
Mar 2024	11,265	4,277	5,520	7,437	1,400	2,138	1,044	953	25	34,059	9,986	65,686
Apr 2024	10,055	3,697	4,932	6,758	1,241	1,932	951	783	25	30,374	8,945	58,116
May 2024	10,400	3,792	5,102	7,117	1,307	2,105	1,030	813	25	31,691	9,735	61,327
Jun 2024	11,159	4,057	5,557	8,201	1,447	2,386	1,168	901	25	34,901	10,747	68,353
Jul 2024	12,263	4,530	6,159	9,346	1,600	2,653	1,324	1,002	30	38,907	12,264	78,196
Aug 2024	12,131	4,483	6,031	8,962	1,599	2,611	1,279	983	30	38,109	11,996	76,088
Sep 2024	10,562	3,905	5,133	7,492	1,350	2,182	1,062	823	25	32,534	10,358	64,096
Oct 2024	10,389	3,938	5,052	6,948	1,307	1,994	982	800	20	31,430	9,788	60,865
Nov 2024	10,721	4,125	5,097	6,957	1,341	2,020	989	911	25	32,186	10,124	62,586
Dec 2024	12,203	4,846	5,746	7,882	1,519	2,341	1,114	1,132	35	36,818	11,681	72,348
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2025	13,758	5,219	6,104	8,460	1,629	2,506	1,174	1,256	30	40,136	12,286	78,032
Feb 2025	11,873	4,490	5,346	7,397	1,404	2,150	1,022	1,030	30	34,742	10,565	67,308
Mar 2025	12,033	4,446	5,525	7,455	1,406	2,145	1,045	962	25	35,042	10,547	67,454
Apr 2025	10,758	3,842	4,923	6,757	1,241	1,932	950	791	25	31,219	9,482	59,600
May 2025	11,105	3,922	5,081	7,090	1,303	2,100	1,026	820	25	32,472	10,304	62,703
Jun 2025	11,894	4,193	5,570	8,212	1,456	2,392	1,170	911	25	35,823	11,360	70,032
Jul 2025	13,028	4,665	6,183	9,367	1,610	2,661	1,327	1,015	30	39,886	12,918	79,981
Aug 2025	12,825	4,569	6,011	8,923	1,596	2,606	1,276	992	30	38,828	12,629	77,478
Sep 2025	11,329	3,954	5,175	7,546	1,365	2,195	1,067	837	25	33,493	11,024	65,918
Oct 2025	11,135	3,938	5,075	6,981	1,314	1,998	985	812	20	32,258	10,463	62,509
Nov 2025	11,425	4,149	5,103	6,964	1,342	2,020	990	923	25	32,941	10,787	64,139
Dec 2025	13,011	4,903	5,802	7,966	1,536	2,357	1,121	1,148	35	37,879	12,435	74,529
	AEP	APS	ATSI	COMED	DAYTON	DEOK	DLCO	EKPC	OVEC	WESTERN	DOM	PJM RTO
Jan 2026	14,271	5,232	6,097	8,463	1,627	2,507	1,175	1,267	30	40,669	13,320	79,846
Feb 2026	12,364	4,510	5,358	7,423	1,408	2,157	1,025	1,042	30	35,317	11,556	69,131
Mar 2026	12,609	4,533	5,560	7,506	1,417	2,158	1,051	977	25	35,836	11,688	69,670
Apr 2026	11,278	3,933	4,938	6,778	1,246	1,938	954	804	25	31,894	10,587	61,520
May 2026	11,605	4,039	5,073	7,071	1,300	2,098	1,026	831	25	33,068	11,497	64,534
Jun 2026	12,446	4,458	5,605	8,249	1,468	2,404	1,177	926	25	36,758	12,624	72,397
Jul 2026	13,567	4,925	6,198	9,376	1,615	2,666	1,333	1,027	30	40,737	14,275	82,304
Aug 2026	13,374	4,881	6,032	8,942	1,603	2,615	1,282	1,006	30	39,765	14,040	79,989
Sep 2026	11,846	4,252	5,188	7,563	1,368	2,200	1,073	849	25	34,364	12,418	68,322
Oct 2026	11,647	4,236	5,077	6,988	1,313	1,999	988	824	20	33,092	11,896	64,888
Nov 2026	11,987	4,464	5,143	7,029	1,354	2,034	998	938	25	33,972	12,259	66,937
Dec 2026	13,572	5,224	5,833	8,020	1,544	2,368	1,129	1,163	35	38,888	13,964	77,406

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.

Table E-3

MONTHLY NET ENERGY FORECAST (GWh) FOR FE-EAST AND PLGRP

	FE_EAST	PLGRP
Jan 2024	5,207	4,164
Feb 2024	4,758	3,778
Mar 2024	4,543	3,563
Apr 2024	4,018	3,041
May 2024	4,194	3,062
Jun 2024	4,688	3,264
Jul 2024	5,513	3,778
Aug 2024	5,331	3,640
Sep 2024	4,382	3,105
Oct 2024	4,208	3,086
Nov 2024	4,294	3,287
Dec 2024	4,994	3,834

	FE_EAST	PLGRP
Jan 2025	5,288	4,168
Feb 2025	4,575	3,592
Mar 2025	4,617	3,577
Apr 2025	4,060	3,041
May 2025	4,217	3,053
Jun 2025	4,738	3,281
Jul 2025	5,569	3,796
Aug 2025	5,354	3,632
Sep 2025	4,448	3,128
Oct 2025	4,262	3,092
Nov 2025	4,349	3,285
Dec 2025	5,115	3,861

	FE_EAST	PLGRP
Jan 2026	5,379	4,169
Feb 2026	4,668	3,604
Mar 2026	4,717	3,600
Apr 2026	4,122	3,051
May 2026	4,250	3,049
Jun 2026	4,803	3,304
Jul 2026	5,620	3,808
Aug 2026	5,418	3,648
Sep 2026	4,505	3,138
Oct 2026	4,316	3,092
Nov 2026	4,451	3,310
Dec 2026	5,236	3,880

Notes:
All forecast values represent metered energy, after reductions for distributed solar generation, and additions for plug-in electric vehicles.

Table E-4

PLUG IN ELECTRIC VEHICLE ADJUSTMENT TO ANNUAL ENERGY (GWh) FOR EACH PJM ZONE AND RTO
2024 - 2039

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
AE	52	129	237	357	487	635	797	989	1,202	1,423	1,680	1,963	2,251	2,533	2,816	3,148
BGE	168	370	646	950	1,284	1,684	2,126	2,652	3,242	3,860	4,565	5,339	6,132	6,910	7,692	8,599
DPL	53	130	234	347	470	612	762	947	1,158	1,381	1,635	1,917	2,207	2,493	2,780	3,114
JCPL	238	506	876	1,289	1,730	2,228	2,750	3,374	4,088	4,829	5,671	6,588	7,512	8,413	9,315	10,376
METED	96	233	424	637	866	1,140	1,427	1,782	2,198	2,638	3,166	3,784	4,453	5,144	5,868	6,686
PECO	119	247	420	611	815	1,046	1,295	1,596	1,939	2,298	2,704	3,149	3,606	4,056	4,512	5,042
PENLC	32	84	155	232	314	406	505	627	766	912	1,081	1,270	1,466	1,661	1,859	2,087
PEPCO	124	247	410	589	784	1,011	1,262	1,561	1,897	2,249	2,648	3,084	3,533	3,992	4,443	4,962
PL	54	125	223	329	443	574	715	887	1,083	1,288	1,525	1,788	2,063	2,337	2,617	2,938
PS	266	572	997	1,473	1,981	2,562	3,199	3,951	4,785	5,652	6,644	7,731	8,836	9,918	11,007	12,281
RECO	11	21	33	47	62	79	97	119	142	167	194	224	254	283	312	346
UGI	3	7	12	17	23	30	38	47	57	68	80	94	109	123	138	155
AEP	134	331	602	900	1,223	1,605	2,028	2,547	3,140	3,770	4,508	5,352	6,250	7,157	8,093	9,154
APS	51	123	219	325	438	571	716	892	1,093	1,304	1,547	1,816	2,095	2,371	2,651	2,973
ATSI	123	284	503	742	996	1,286	1,599	1,981	2,420	2,884	3,425	4,040	4,686	5,330	5,990	6,743
COMED	362	784	1,346	1,962	2,614	3,345	4,128	5,070	6,142	7,273	8,559	9,987	11,478	12,950	14,447	16,180
DAYTON	21	53	97	144	194	251	314	390	480	576	690	824	967	1,112	1,261	1,431
DEOK	52	110	188	274	367	474	589	729	890	1,059	1,255	1,476	1,709	1,942	2,180	2,452
DLCO	48	109	192	283	379	489	606	750	916	1,090	1,290	1,513	1,744	1,973	2,207	2,475
EKPC	13	32	59	88	119	155	193	241	297	358	427	506	591	675	762	860
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOM	312	683	1,181	1,726	2,314	2,980	3,691	4,564	5,566	6,627	7,814	9,110	10,444	11,748	13,054	14,578
PJM RTO	2,333	5,179	9,056	13,324	17,903	23,163	28,836	35,695	43,503	51,709	61,108	71,555	82,382	93,120	104,003	116,579

Notes:
Adjustment values presented here are reflected in all energy forecast values.

Values are derived by PJM from a forecast obtained from SPGCI.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

SUMMER

YEAR	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
1998		133,275	Tuesday, July 21, 1998	17:00
1999		141,491	Friday, July 30, 1999	17:00
2000		131,798	Wednesday, August 9, 2000	17:00
2001		150,924	Thursday, August 9, 2001	16:00
2002		150,826	Thursday, August 1, 2002	17:00
2003		145,227	Thursday, August 21, 2003	17:00
2004		139,279	Tuesday, August 3, 2004	17:00
2005		155,257	Tuesday, July 26, 2005	16:00
2006		166,929	Wednesday, August 2, 2006	17:00
2007		162,035	Wednesday, August 8, 2007	16:00
2008		150,622	Monday, June 9, 2008	17:00
2009		145,112	Monday, August 10, 2009	16:00
2010		157,247	Wednesday, July 7, 2010	17:00
2011		165,524	Thursday, July 21, 2011	17:00
2012		158,219	Tuesday, July 17, 2012	17:00
2013		159,149	Thursday, July 18, 2013	17:00
2014	150,051	141,509	Tuesday, June 17, 2014	18:00
2015	149,806	143,579	Tuesday, July 28, 2015	17:00
2016	149,213	152,069	Thursday, August 11, 2016	16:00
2017	148,948	145,434	Wednesday, July 19, 2017	18:00
2018	149,360	150,573	Tuesday, August 28, 2018	17:00
2019	149,259	151,302	Friday, July 19, 2019	18:00
2020	147,060	144,320	Monday, July 20, 2020	17:00
2021	149,780	148,433	Tuesday, August 24, 2021	18:00
2022	150,123	147,361	Wednesday, July 20, 2022	18:00
2023	149,884	146,799	Thursday, July 27, 2023	18:00

Notes:
Normalized values for 2014 - 2023 are calculated by PJM staff using a methodology described in Manual 19.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

Table F-1

PJM RTO HISTORICAL PEAKS
(MW)

WINTER

YEAR	NORMALIZED TOTAL	UNRESTRICTED PEAK	PEAK DATE	TIME
97/98		103,231	Wednesday, January 14, 1998	19:00
98/99		116,086	Tuesday, January 5, 1999	19:00
99/00		118,435	Thursday, January 27, 2000	20:00
00/01		118,046	Wednesday, December 20, 2000	19:00
01/02		112,217	Wednesday, January 2, 2002	19:00
02/03		129,965	Thursday, January 23, 2003	19:00
03/04		122,424	Friday, January 23, 2004	9:00
04/05		131,234	Monday, December 20, 2004	19:00
05/06		126,777	Wednesday, December 14, 2005	19:00
06/07		136,804	Monday, February 5, 2007	20:00
07/08		128,368	Wednesday, January 2, 2008	19:00
08/09		134,077	Friday, January 16, 2009	19:00
09/10		125,350	Monday, January 4, 2010	19:00
10/11		132,315	Tuesday, December 14, 2010	19:00
11/12		124,506	Tuesday, January 3, 2012	19:00
12/13		128,810	Tuesday, January 22, 2013	19:00
13/14		141,866	Tuesday, January 7, 2014	19:00
14/15	130,759	142,856	Friday, February 20, 2015	8:00
15/16	131,217	129,540	Tuesday, January 19, 2016	8:00
16/17	130,755	130,825	Thursday, December 15, 2016	19:00
17/18	131,191	137,212	Friday, January 5, 2018	19:00
18/19	130,605	137,618	Thursday, January 31, 2019	8:00
19/20	131,223	120,272	Thursday, December 19, 2019	8:00
20/21	130,059	117,012	Friday, January 29, 2021	9:00
21/22	132,636	128,882	Thursday, January 27, 2022	8:00
22/23	133,059	134,951	Friday, December 23, 2022	19:00

Notes:
Normalized values for 2014/15 - 2022/23 are calculated by PJM staff using a methodology described in Manual 19.
All times are shown in hour ending Eastern Prevailing Time and historic peak values reflect current membership of the PJM RTO.

Table F-2

PJM RTO HISTORICAL NET ENERGY
(GWH)

YEAR	ENERGY	GROWTH RATE
1998	718,248	0.0%
1999	740,056	3.0%
2000	756,211	2.2%
2001	754,516	-0.2%
2002	782,275	3.7%
2003	780,666	-0.2%
2004	796,702	2.1%
2005	823,342	3.3%
2006	802,984	-2.5%
2007	836,241	4.1%
2008	822,608	-1.6%
2009	781,270	-5.0%
2010	820,038	5.0%
2011	805,911	-1.7%
2012	791,768	-1.8%
2013	795,098	0.4%
2014	796,228	0.1%
2015	791,580	-0.6%
2016	791,176	-0.1%
2017	772,291	-2.4%
2018	804,917	4.2%
2019	785,209	-2.4%
2020	755,241	-3.8%
2021	780,454	3.3%
2022	792,832	1.6%

Note: All historic net energy values reflect the current membership of the PJM RTO.

Table F-3

WEATHER NORMALIZED LOAD (MW) FOR EACH PJM ZONE, LOCATIONAL DELIVERABILITY AREA AND RTO

	Summer 2023	**Winter 2022/23**
AE	2,601	1,616
BGE	6,502	5,820
DPL	3,964	3,700
JCPL	6,067	3,788
METED	3,026	2,745
PECO	8,593	6,577
PENLC	2,876	2,831
PEPCO	6,035	5,327
PL	7,129	7,366
PS	10,069	6,783
RECO	412	224
UGI	198	202
AEP	22,332	22,423
APS	8,742	9,176
ATSI	12,508	10,411
COMED	20,639	14,787
DAYTON	3,312	2,943
DEOK	5,360	4,636
DLCO	2,713	2,013
EKPC	2,084	2,745
OVEC	90	110
DOM	21,804	21,791
PJM MID-ATLANTIC	55,976	46,300
PJM WESTERN	76,115	67,192
PJM RTO	149,884	133,059

Notes:
Zonal Normal 2023 are non-coincident as estimated by PJM staff.
Locational Deliverability Area and PJM RTO Normal 2023 are coincident with their regional peak as estimated by PJM staff.

2025

PJM Long-Term Load Forecast Report

Posted Date: January 24, 2025

Prepared by PJM Resource Adequacy Planning Department

For Public Use

Contents

TO Zones and Subzones

Abbreviation	Zone Name	Date Incorporated
AE	Atlantic Electric zone	
AEP	American Electric Power zone	Oct. 1, 2004
APP	Appalachian Power, sub-zone of AEP	
APS	Allegheny Power zone	April 1, 2002
ATSI	American Transmission Systems, Inc. zone	June 1, 2011
BGE	Baltimore Gas & Electric zone	
CEI	Cleveland Electric Illuminating, sub-zone of ATSI	
COMED	Commonwealth Edison zone	May 1, 2004
CSP	Columbus Southern Power, sub-zone of AEP	
DAY	Dayton Power & Light zone	Oct. 1, 2004
DEOK	Duke Energy Ohio/Kentucky zone	January 1, 2012
DLCO	Duquesne Lighting Company zone	January 1, 2005
DOM	Dominion Virginia Power zone	May 1, 2005
DPL	Delmarva Power & Light zone	
EKPC	East Kentucky Power Cooperative zone	June 1, 2013
FE-East	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)	
INM	Indiana Michigan Power, sub-zone of AEP	
JCP&L	Jersey Central Power & Light zone	
KP	Kentucky Power, sub-zone of AEP	

Abbreviation	Zone Name	Date Incorporated
METED	Metropolitan Edison zone	
MP	Monongahela Power, sub-zone of APS	
OEP	Ohio Edison, sub-zone of ATSI	
OP	Ohio Power, sub-zone of AEP	
OVEC	Ohio Valley Electric Corporation zone	December 1, 2018
PECO	PECO Energy zone	
PED	Potomac Edison, sub-zone of APS	
PEPCO	Potomac Electric Power zone	
PL	PPL Electric Utilities, sub-zone of PLGroup	
PLGroup/PLGRP	Pennsylvania Power & Light zone	
PENLC	Pennsylvania Electric zone	
PP	Pennsylvania Power, sub-zone of ATSI	
PS	Public Service Electric & Gas zone	
RECO	Rockland Electric (East) zone	March 1, 2002
TOL	Toledo Edison, sub-zone of ATSI	
UGI	UGI Utilities, sub-zone of PLGroup	
WP	West Penn Power, sub-zone of APS	

Glossary

Term / Abbreviation	Definition
Battery Storage	Devices that enable generated energy to be stored and then released at a later time. (Also Battery Energy Storage System – BESS)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
Direct Control	Load Management achieved directly by a signal from a control center
Heating Load	The weather-sensitive portion of winter peak load
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
PRD	Price Responsive Demand
Unrestricted Peak	Peak load prior to any reduction for load management or voltage reduction.
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

Executive Summary

This report presents an independent load forecast prepared by PJM staff.

- The report includes a 20 year long-term forecasts of peak loads, net energy, load management, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area (LDA), and the total RTO.

- New to the report this year is a table for the total load associated with adjustments to summer peak loads (Table B-9b available on the PJM Website). All tables are now provided in excel format for ease of use.

- Residential, Commercial, and Industrial sector models were estimated with data from 2014 through 2023. Hourly models were estimated with data from 2015 to August 2024. Weather scenarios were simulated with data from years 1993 through 2023, generating 403 scenarios.

- The economic forecast used was Moody’s Analytics’ September 2024 release.

Energy Information Administration & Vendor Data

The Energy Information Administration (EIA) did not publish an Annual Energy Outlook (AEO) update in 2024 as they revamp models and make improvements to capture emerging technologies. Therefore, the 2023 update of Itron's end-use data provides the basis for appliance saturation rates, efficiency, and intensity and is consistent with the EIA's 2023 AEO. PJM obtained additional information from certain zones on Residential saturation rates based on their own load research. Details on zones providing information are presented in the supplement.

Consultant forecasts for behind the meter solar/battery and electric vehicles including light, medium & heavy duty were provided by S&P Global.

- The behind the meter solar/battery values were derived by PJM from a forecast obtained from SPGCI
- The electric vehicle values were derived by PJM from a forecast obtained from SPGCI

Compared to the 2024 Load Report, the 2025 PJM RTO summer peak forecast shows the following changes for three years of interest:

Next Year:		
Delivery	RPM Auction	RTEP Study
2025 **+651** MW *(0.4%)*	**2026** **+2,134** MW *(1.4%)*	**2030** **+16,010**MW *(9.5%)*

Load Adjustments

The forecasts of the following zones have been adjusted to account for large, unanticipated load changes, market adjustments, and peak shaving adjustments (see **Tables B-9** and **B-9b** and the supplement for details available on the PJM Website):

Zones	Adjusted to account for:
AEP	growth in data center load and a chip processing plant
APS, ATSI, BGE, DAYTON, PECO, and PL	growth in data center load
COMED	growth in data center load and an electric vehicle battery plant
DEOK	adjusted to account for growth in a steel facility
DOM	growth in data center load and a voltage optimization program
PS	growth in data center load and port electrification
EKPC	a peak shaving program that commenced in the 2023 DY
ATSI and DOM	Non-Retail Behind-the-Meter Generation (NRBTMG) transitioning to participation as Demand Response in the Reliability Pricing Model

Summer & Winter Summary

Summer peak load growth for the PJM RTO

- Projected to average 3.1% per year over the next 10-year period and 2.0% over the next 20 years.
- Summer peak is forecasted to be 209,923 MW in 2035, a 10-year increase of 55,779 MW, and reaches 228,544 MW in 2045, a 20-year increase of 74,400 MW.
- Annualized 10-year growth rates for individual zones range from 0.1% to 6.3%; median of 0.7%.

Winter Peak Load Growth – PJM RTO

- Projected to average 3.8% per year over the next 10-year period, and 2.4% over the next 20 years.
- The PJM RTO winter peak load in 2034/35 is forecasted to be 198,175 MW, a 10-year increase of 62,048 MW, and reaches 218,760 MW in 2044/45, a 20-year increase of 82,633 MW.
- Annualized 10-year growth rates for individual zones range from 0.1% to 6.0%; median of 1.6%.

Net Energy Load Growth – PJM RTO

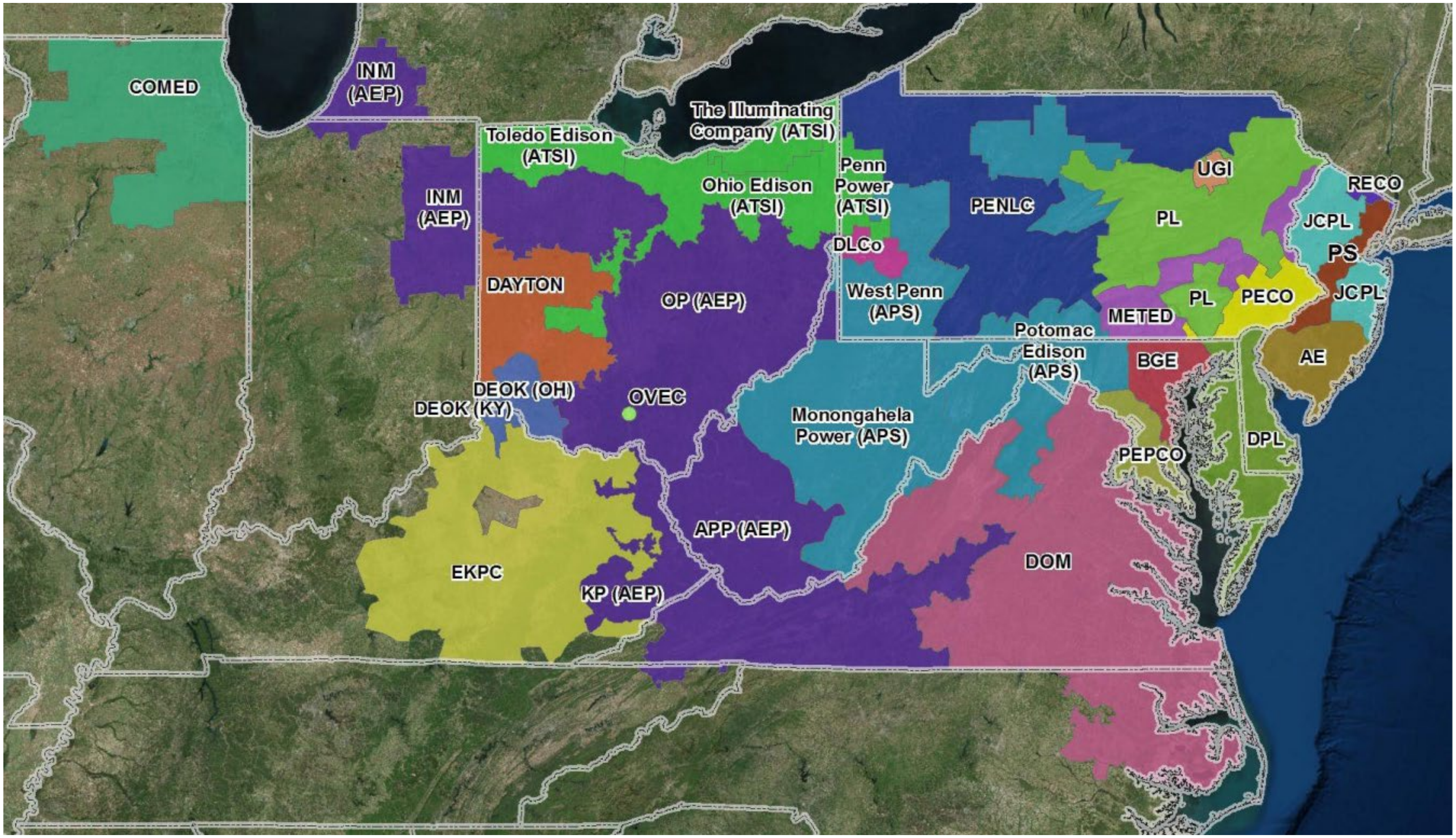
- Projected to average 4.8% per year over the next 10-year period, and 2.9% over the next 20-years.
- Total PJM RTO energy is forecasted to be 1,328,045 GWh in 2035, a 10-year increase of 495,264 GWh, and reaches 1,482,068 GWh in 2045, a 20-year increase of 649,287 GWh.
- Annualized 10- year growth rates for individual zones range from 0.2% to 8.4%; median of 1.6%.

NOTE:

Unless noted otherwise, all peak and energy values are non-coincident, unrestricted peaks, which represent the peak load or net energy after reductions for distributed solar generation and battery storage (in summer peak), additions for plug-in electric vehicles, and prior to reductions for load management impacts.

All compound growth rates are calculated from the first year of the forecast.

PJM Map


COMED
INM (AEP)
The Illuminating Company (ATSI)
Toledo Edison (ATSI)
Penn Power (ATSI)
UGI
RECO
INM (AEP)
Ohio Edison (ATSI)
PENLC
PL
JCPL
DLCo
PS
DAYTON
OP (AEP)
West Penn (APS)
PL
PECO
JCPL
METED
Potomac Edison (APS)
BGE
AE
DEOK (OH)
DEOK (KY)
OVEC
Monongahela Power (APS)
PEPCO
DPL
APP (AEP)
DOM
EKPC
KP (AEP)

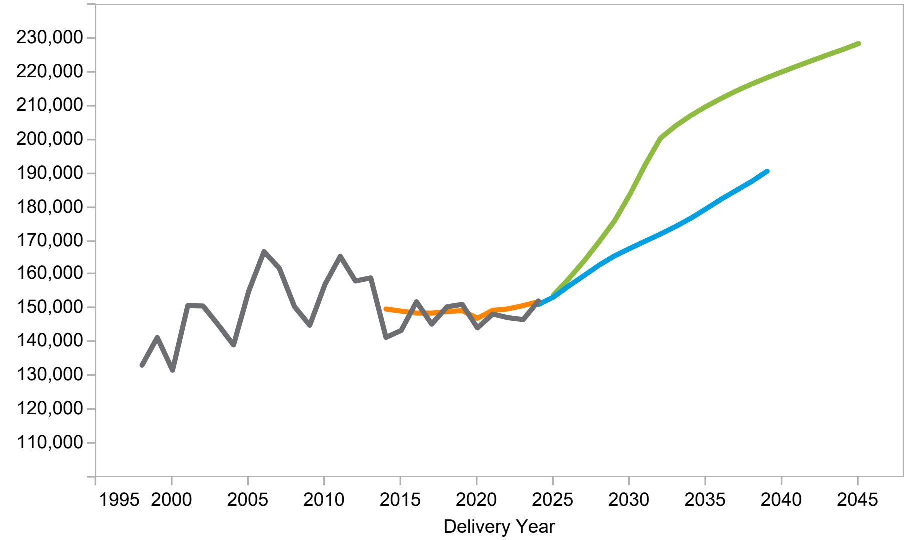
PJM RTO, LDA, and Zonal Dashboards

Click below to jump to an LDA or PJM Zone's data page

PJM RTO	MAAC	E-MAAC	S-MAAC	PJM Western
AE	BGE	DPL	JCPL	METED
PECO	PENLC	PEPCO	PL	PS
RECO	UGI	AEP	APS	ATSI
COMED	DAYTON	DEOK	DLCO	EKPC
DOM				

PJM RTO

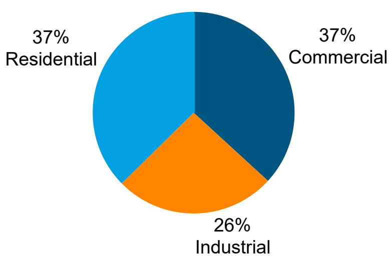
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*74.3*
Avg Summer Max Temp	*95.2*
Avg Winter Daily Temp	*34.3*
Avg Winter Min Temp	*4.1*

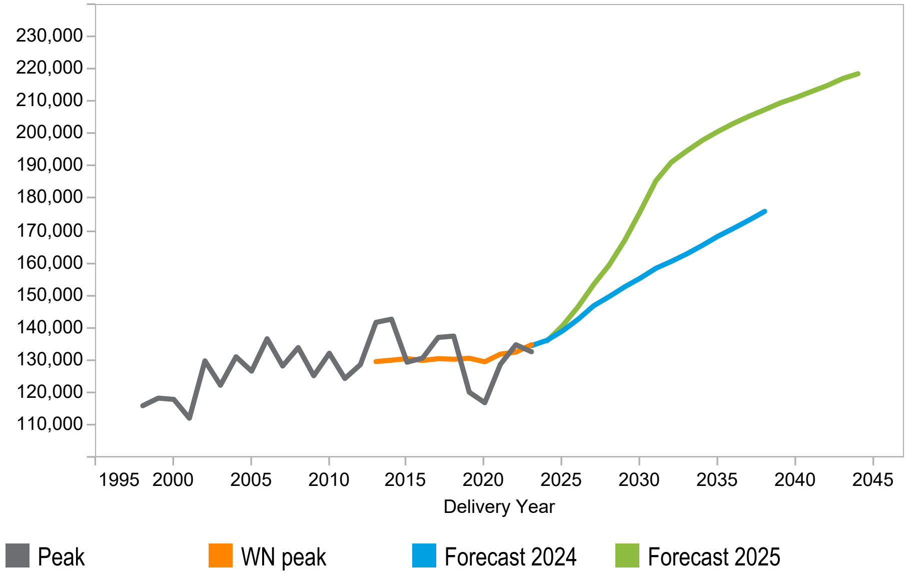
RCI Makeup



Zonal 10/15/20 Year Load Growth

SUMMER	3.1%	2.4%	2.0%
WINTER	3.8%	2.9%	2.4%

Winter Peak



LDAs

PJM Mid-Atlantic
Eastern MAAC
Southern MAAC

Central MAAC
Western MAAC
PJM West

Zones

AE
AEP
APS
ATSI
BGE
COMED

DAYTON
DEOK
DLCO
DOM
DPL
EKPC

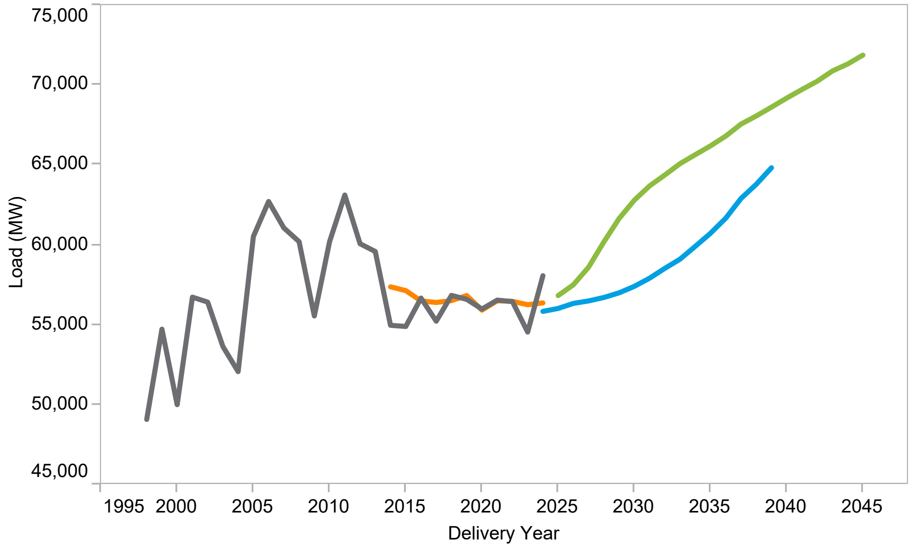
JCPL
METED
OVEC
PECO
PENLC

PEPCO
PL
PS
RECO
UGI

Back to Top

PJM Mid-Atlantic (MAAC)

Summer Peak



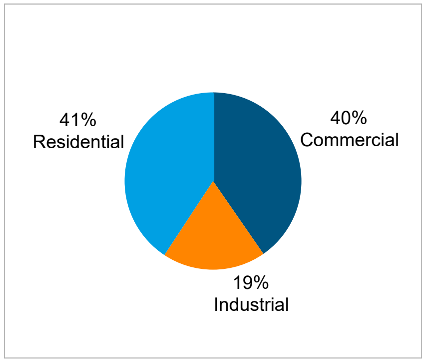
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*74.8*
Avg Summer Max Temp	*96.3*
Avg Winter Daily Temp	*35.1*
Avg Winter Min Temp	*6.6*

Zonal 10/15/20 Year Load Growth

SUMMER	1.5%	1.3%	1.2%
WINTER	2.7%	2.2%	1.9%

RCI Makeup



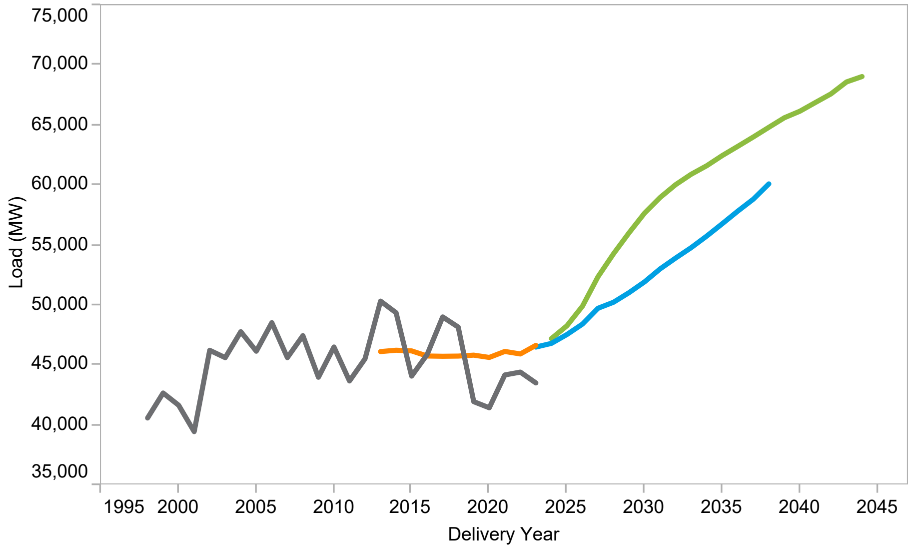
Zones

AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PSEG
RECO
UGI

LDAs

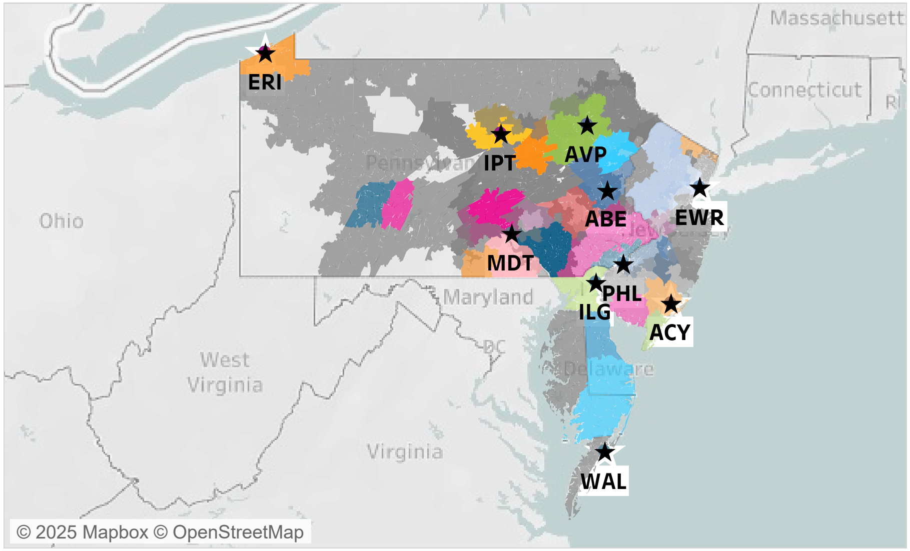
E-MAAC
S-MAAC
C-MAAC
W-MAAC

Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Metropolitan Statistical Areas and Weather Stations



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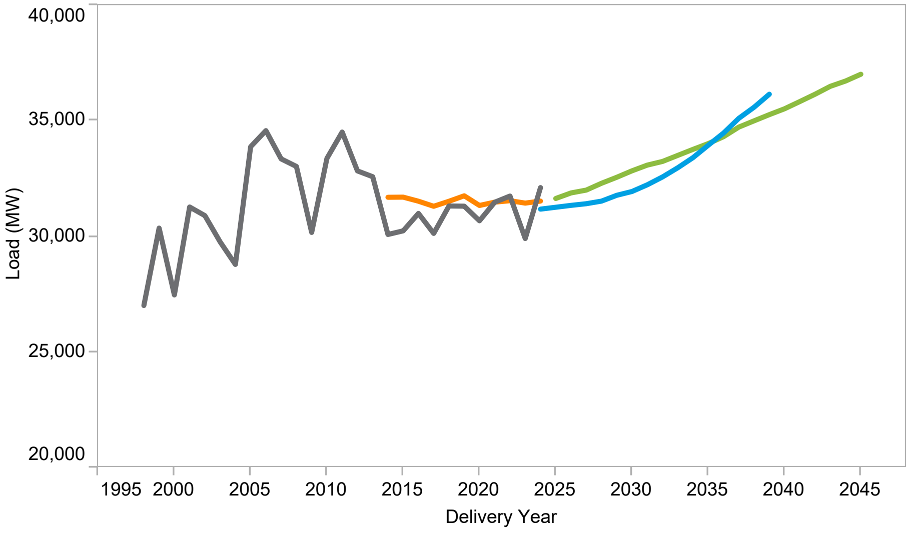
PJM Eastern Mid-Atlantic (E-MAAC)

Summer Peak



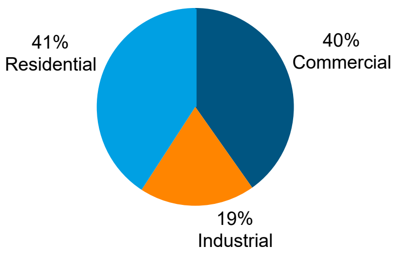
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*75.7*
Avg Summer Max Temp	*97.5*
Avg Winter Daily Temp	*36.4*
Avg Winter Min Temp	*7.9*

Zonal 10/15/20 Year Load Growth

SUMMER	0.7%	0.8%	0.8%
WINTER	2.7%	2.3%	2.1%

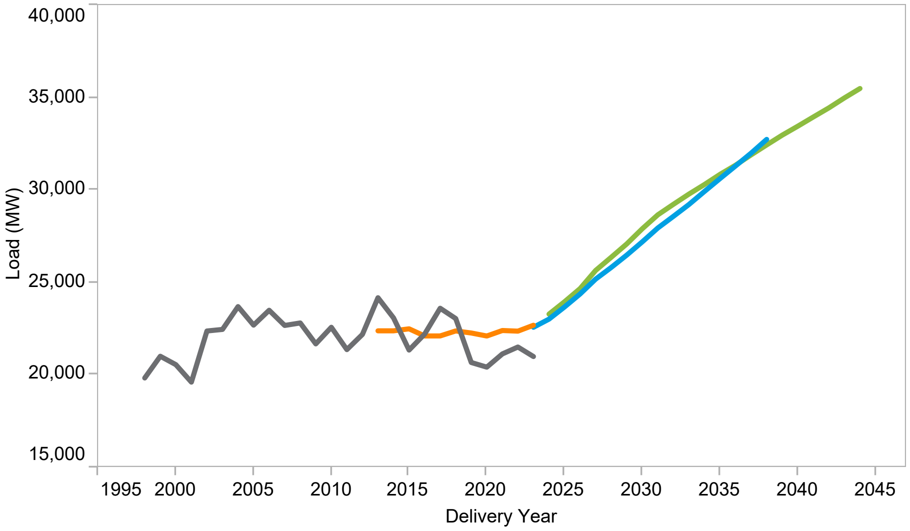
RCI Makeup



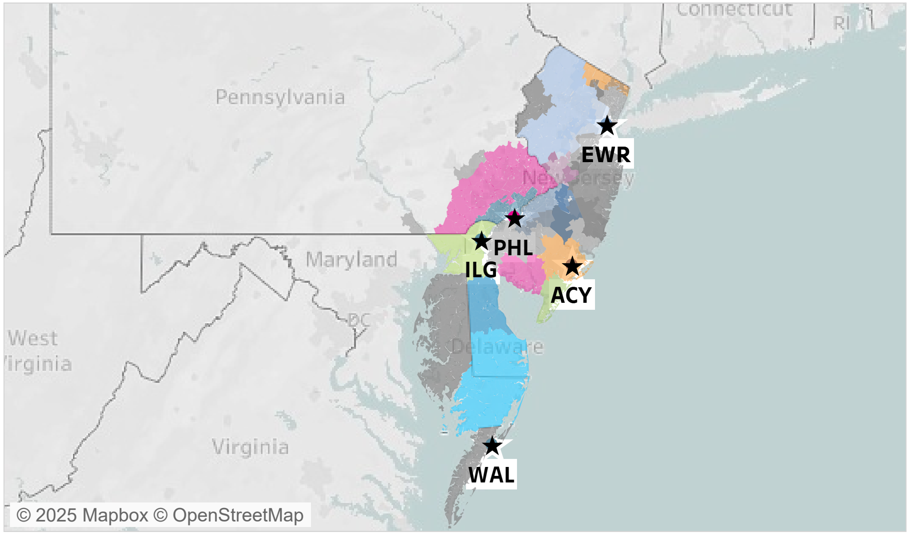
Zones

AE DPL JCPL PECO PS RECO

Winter Peak



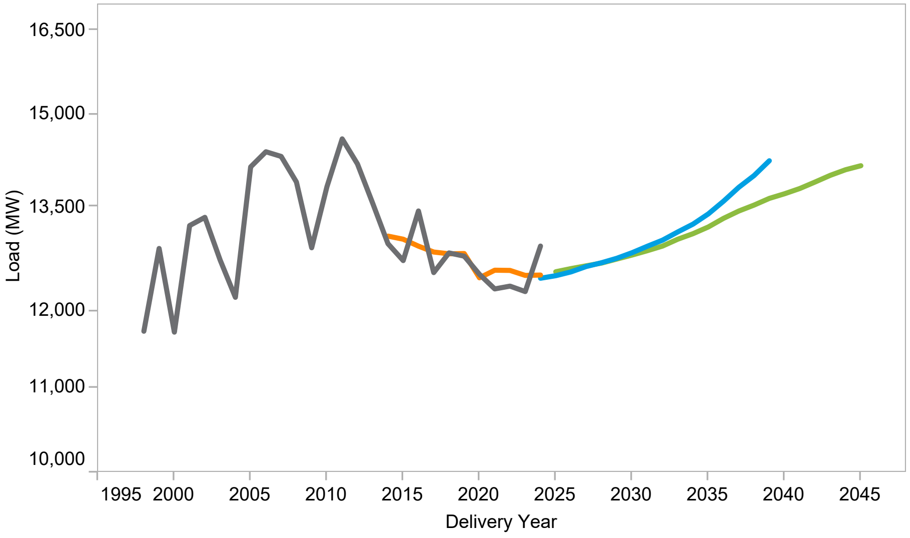
Metropolitan Statistical Areas and Weather Stations



■ Peak 🟧 WN peak 🟦 Forecast 2024 🟩 Forecast 2025

PJM Southern Mid-Atlantic (S-MAAC)

Summer Peak



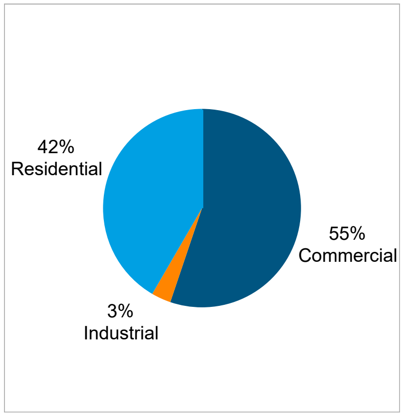
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*77.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*38.1*
Avg Winter Min Temp	*10.4*

Zonal 10/15/20 Year Load Growth

SUMMER	0.5%	0.6%	0.6%
WINTER	0.8%	0.8%	0.7%

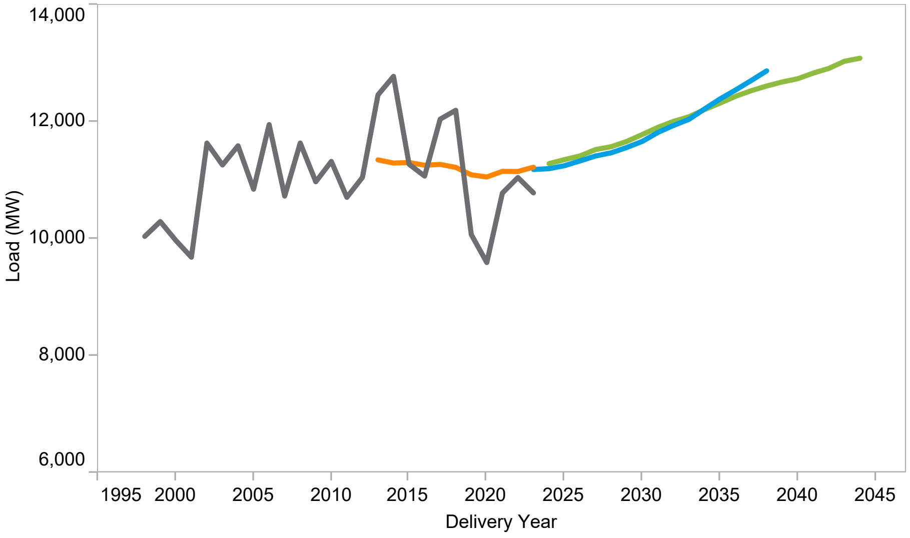
RCI Makeup



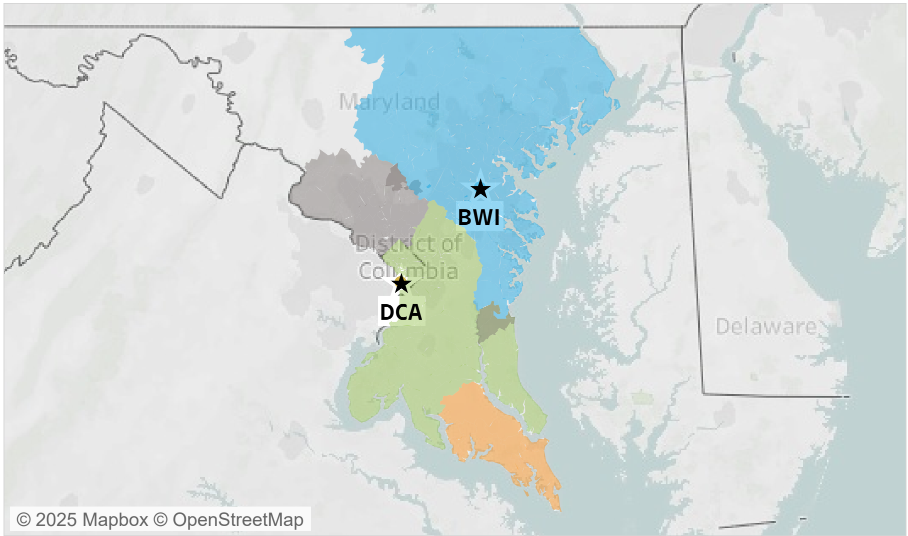
Zones

BGE PEPCO

Winter Peak



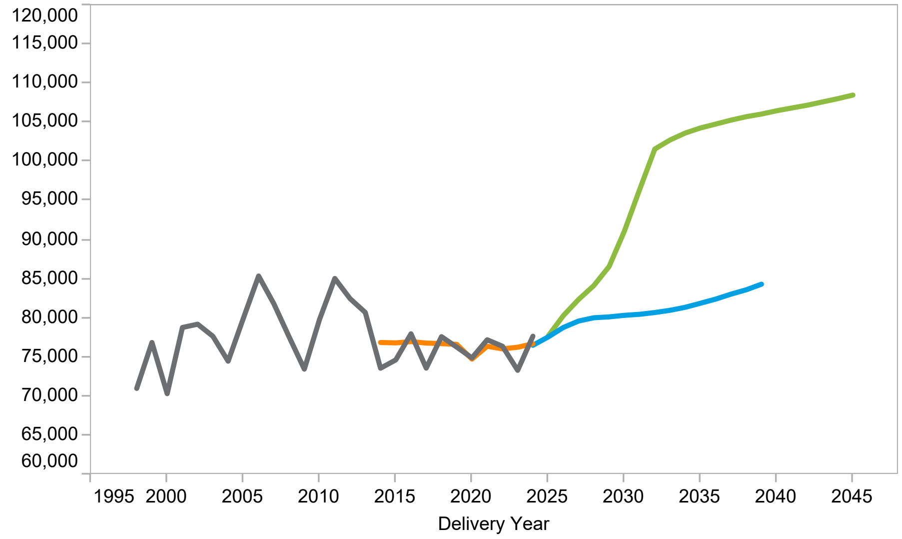
Metropolitan Statistical Areas and Weather Stations



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

PJM Western

Summer Peak



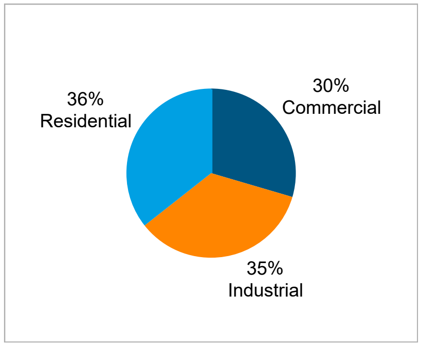
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*32.2*
Avg Winter Min Temp	*-0.7*

Zonal 10/15/20 Year Load Growth

SUMMER	3.0%	2.1%	1.7%
WINTER	3.7%	2.6%	2.1%

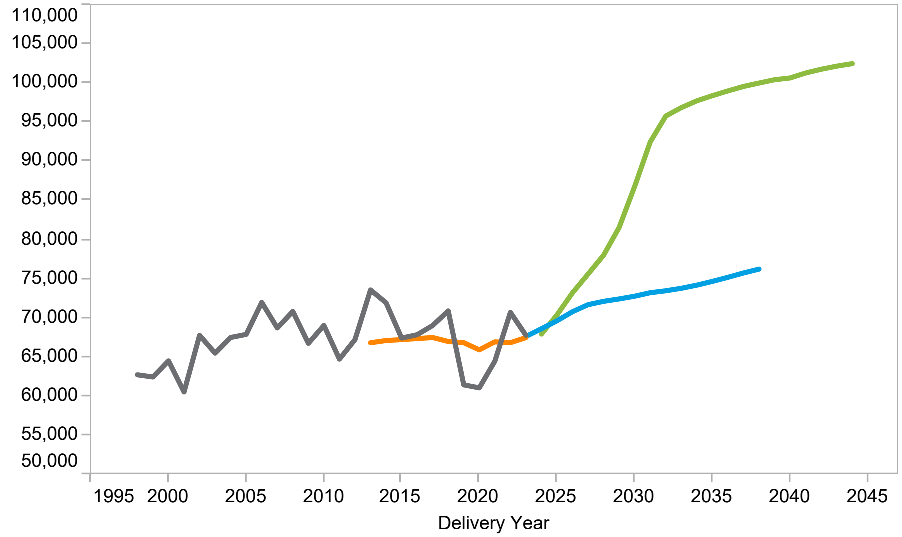
RCI Makeup



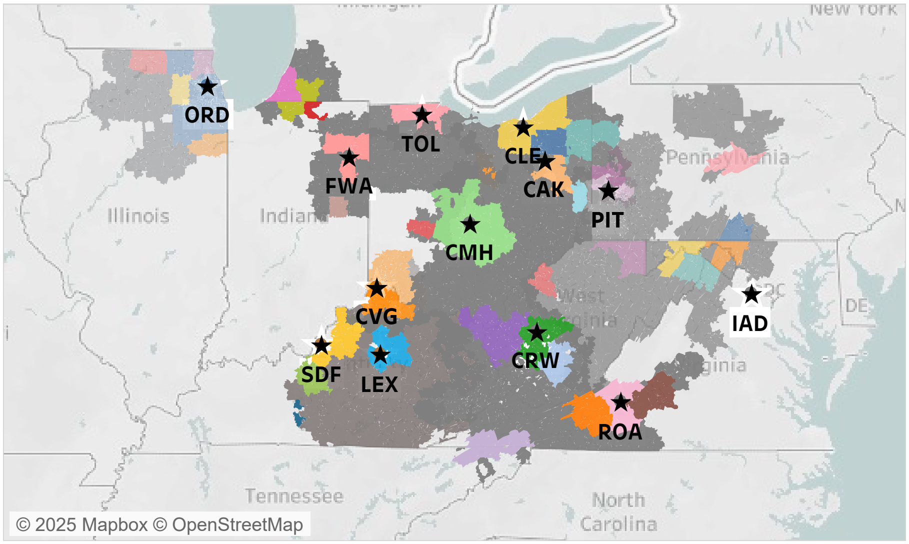
Zones

AEP	COMED	DLCO
APS	DAYTON	EKPC
ATSI	DEOK	OVEC

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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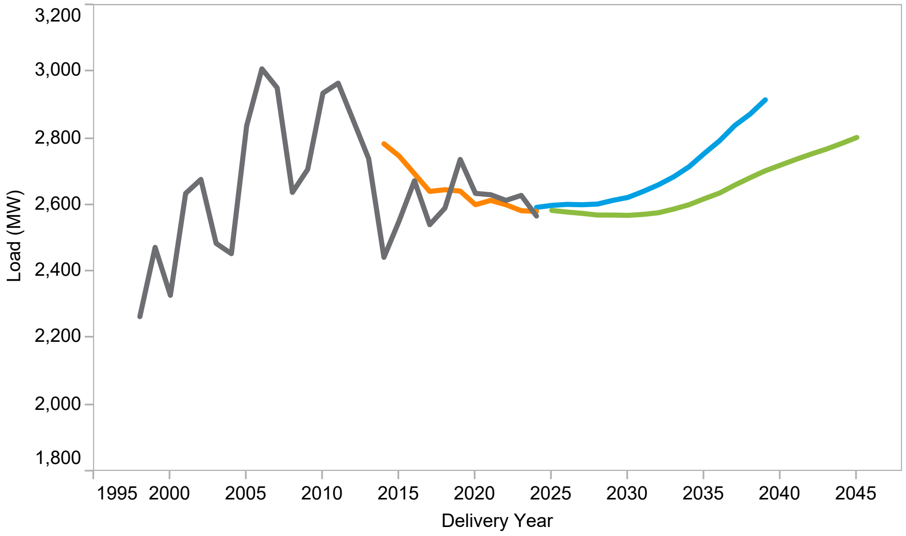
■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Atlantic Electric (AE)

Summer Peak



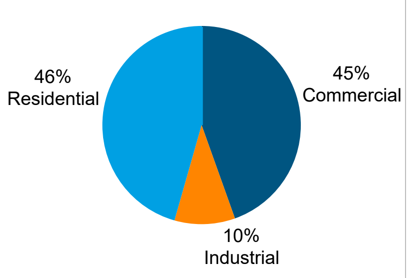
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*74.3*
Avg Summer Max Temp	*97.0*
Avg Winter Daily Temp	*36.8*
Avg Winter Min Temp	*6.1*

Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.3%	0.4%
WINTER	2.4%	2.3%	2.2%

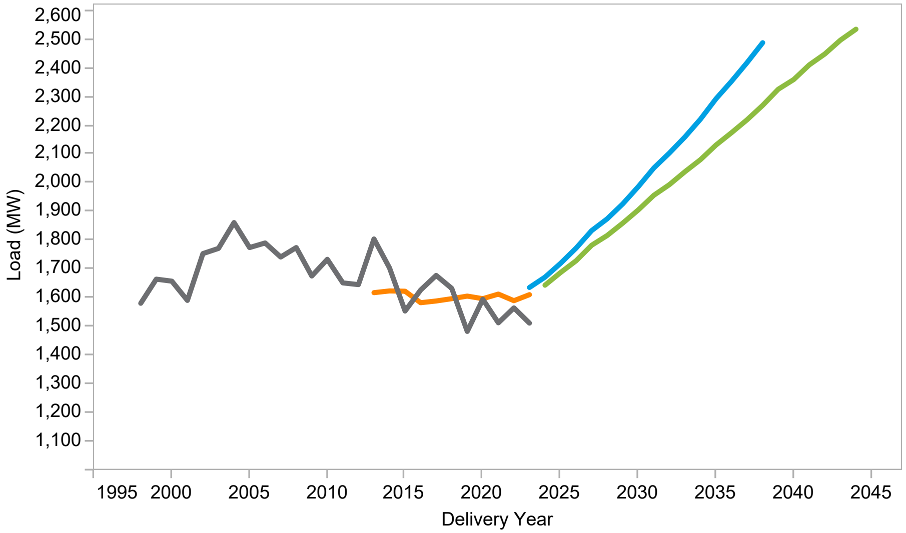
RCI Makeup



LDAs

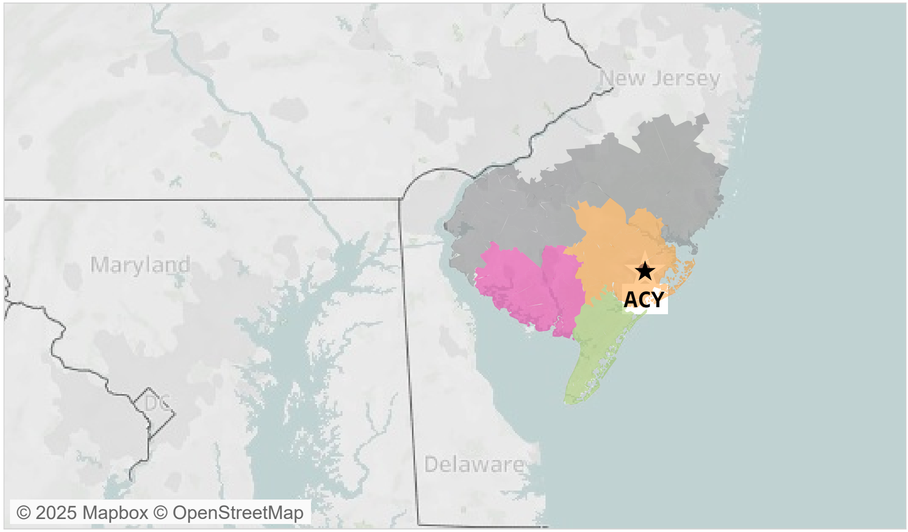
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Metropolitan Statistical Areas and Weather Stations

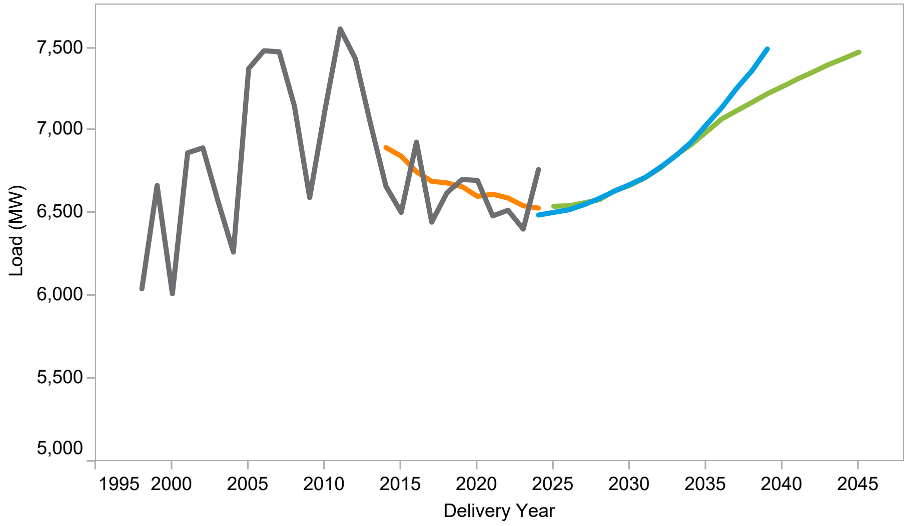


MSA

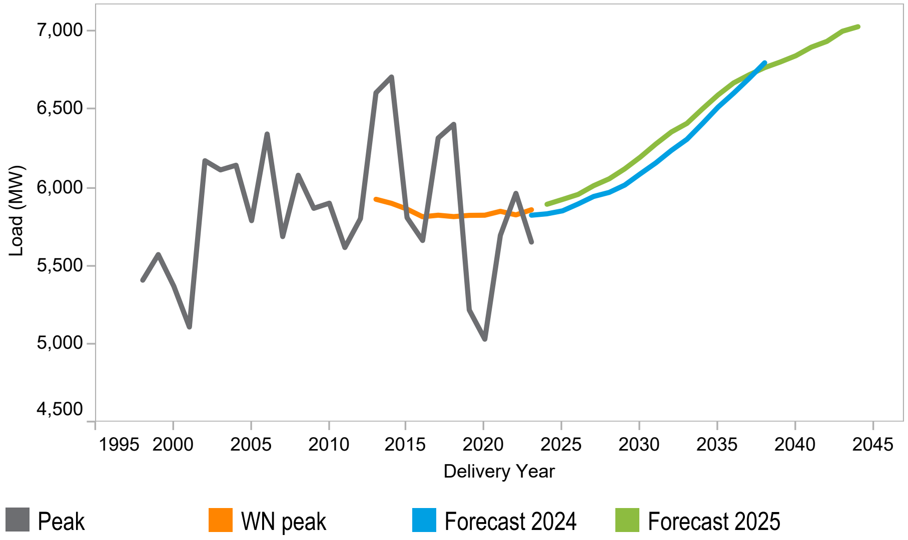
■ AE - Non-Metro
■ Atlantic City-Hammonton, NJ
■ Ocean City, NJ
■ Vineland-Bridgeton, NJ

Baltimore Gas & Electric (BGE)

Summer Peak



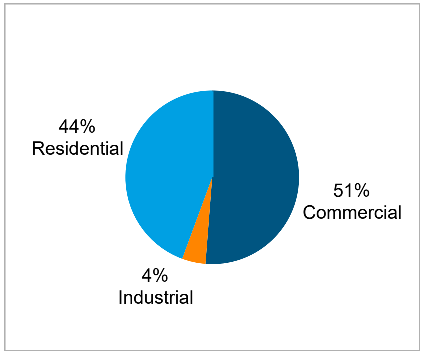
Winter Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*76.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*36.9*
Avg Winter Min Temp	*8.0*

RCI Makeup



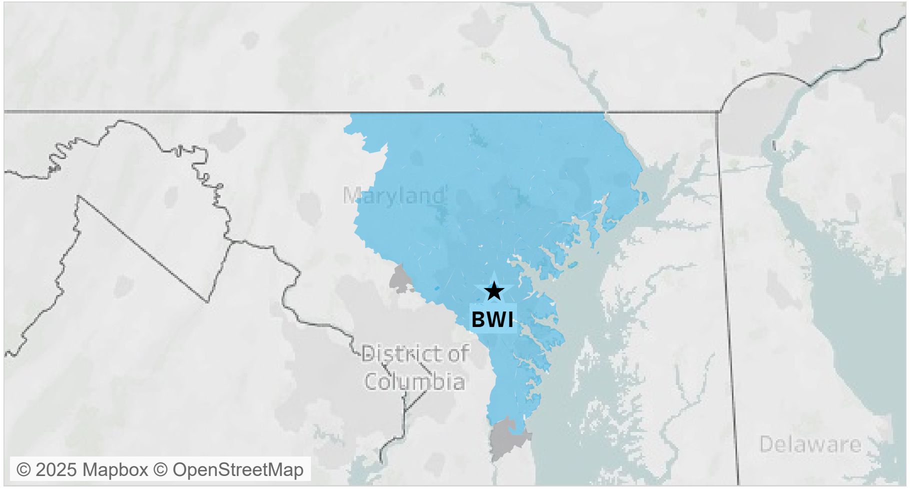
Zonal 10/15/20 Year Load Growth

SUMMER	0.7%	0.7%	0.7%
WINTER	1.0%	1.0%	0.9%

LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO SOUTHERN MID-ATLANTIC

Metropolitan Statistical Areas and Weather Stations



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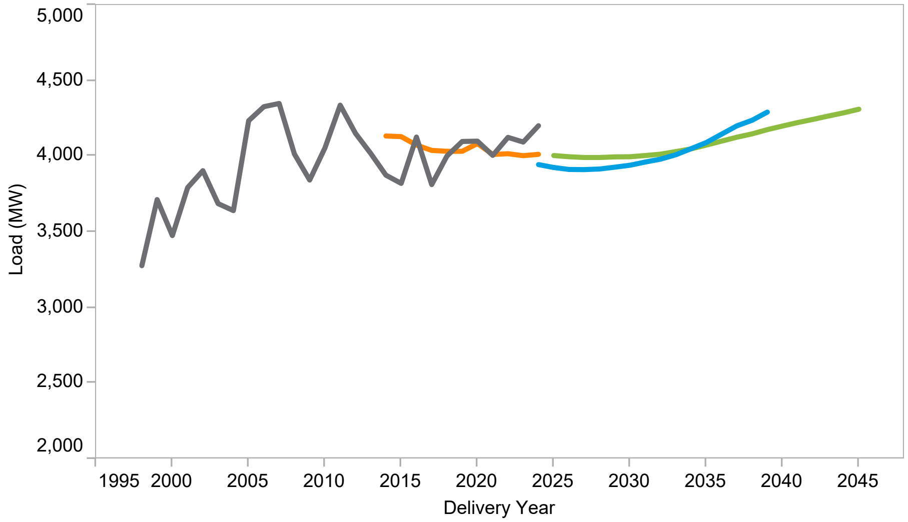
MSA
- Baltimore-Columbia-Towson, MD
- BGE - Non-Metro

Delmarva Power and Light (DPL)

Summer Peak



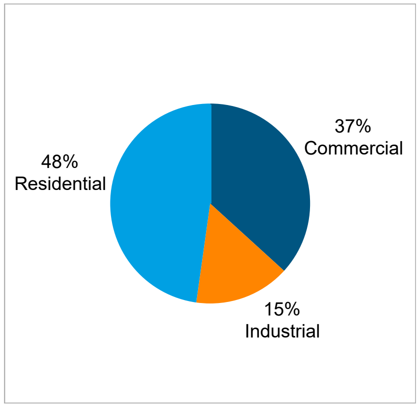
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*95.1*
Avg Winter Daily Temp	*37.2*
Avg Winter Min Temp	*9.7*

Zonal 10/15/20 Year Load Growth

SUMMER	0.2%	0.3%	0.4%
WINTER	0.6%	0.6%	0.6%

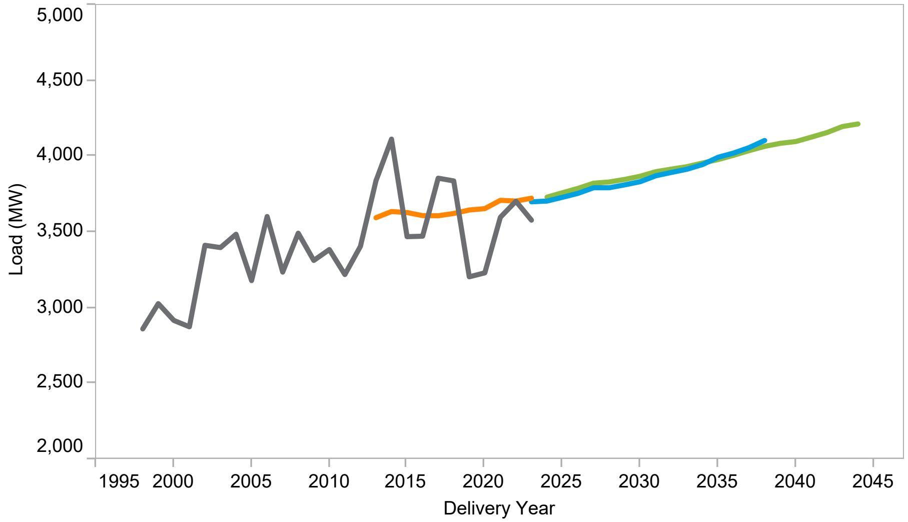
RCI Makeup



LDAs

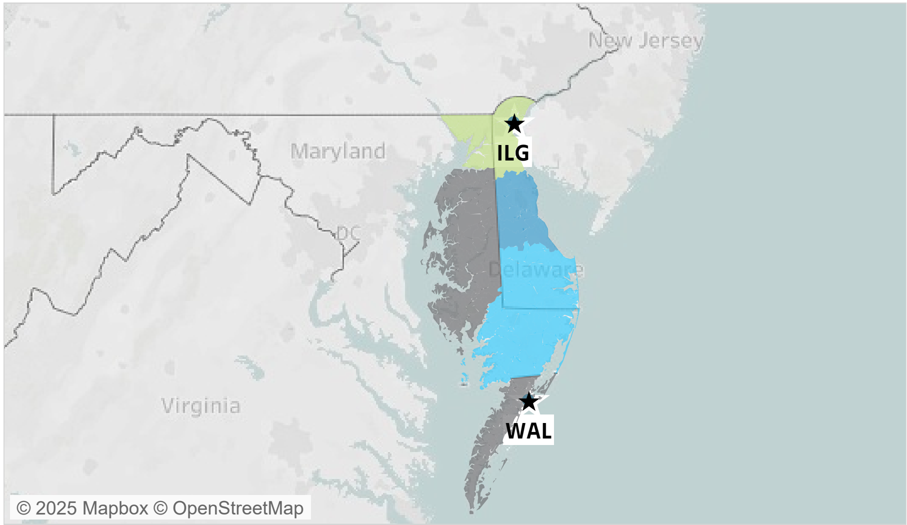
EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Metropolitan Statistical Areas and Weather Stations



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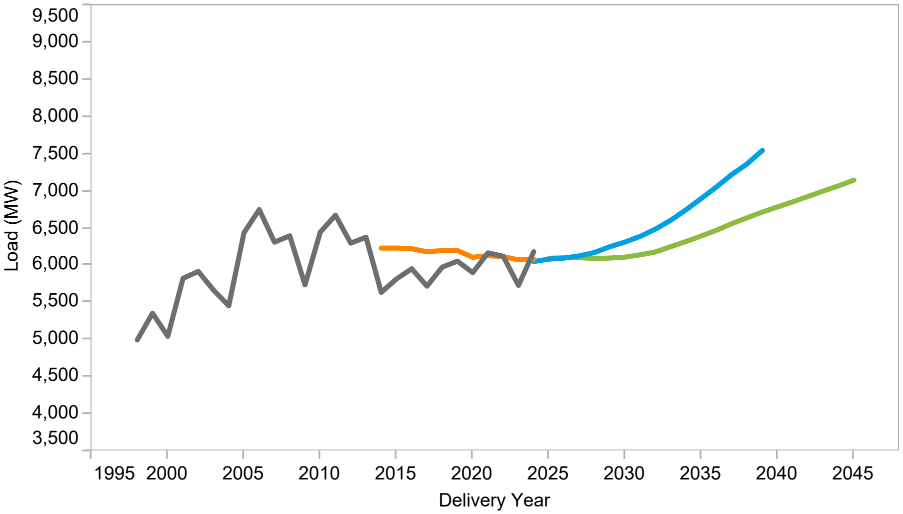
MSA

- ■ Dover, DE
- ■ DPL - Non-Metro
- ■ Salisbury, MD-DE
- ■ Wilmington, DE-MD-NJ

Jersey Central Power and Light (JCPL)

Summer Peak



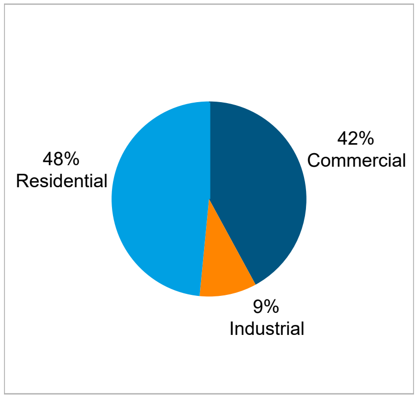
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*75.7*
Avg Summer Max Temp	*98.1*
Avg Winter Daily Temp	*36.1*
Avg Winter Min Temp	*7.5*

Zonal 10/15/20 Year Load Growth

SUMMER	0.5%	0.7%	0.8%
WINTER	3.9%	3.6%	3.3%

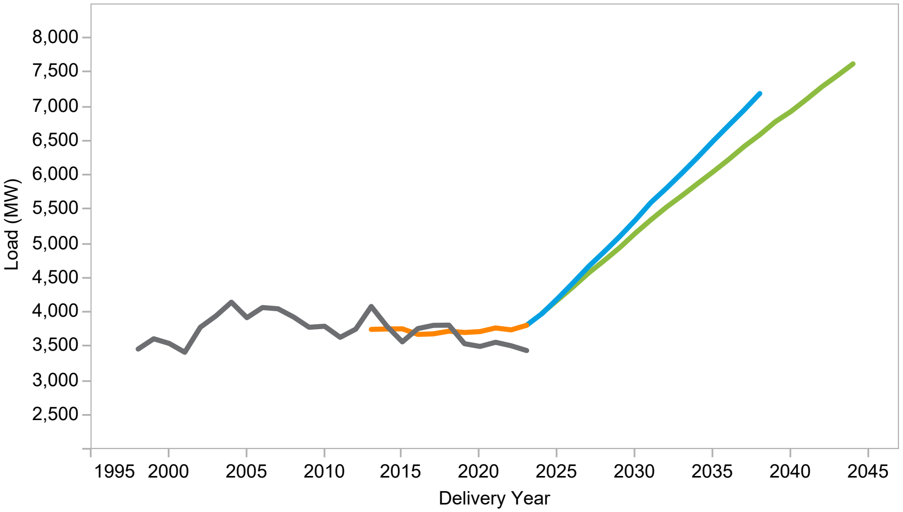
RCI Makeup



LDAs

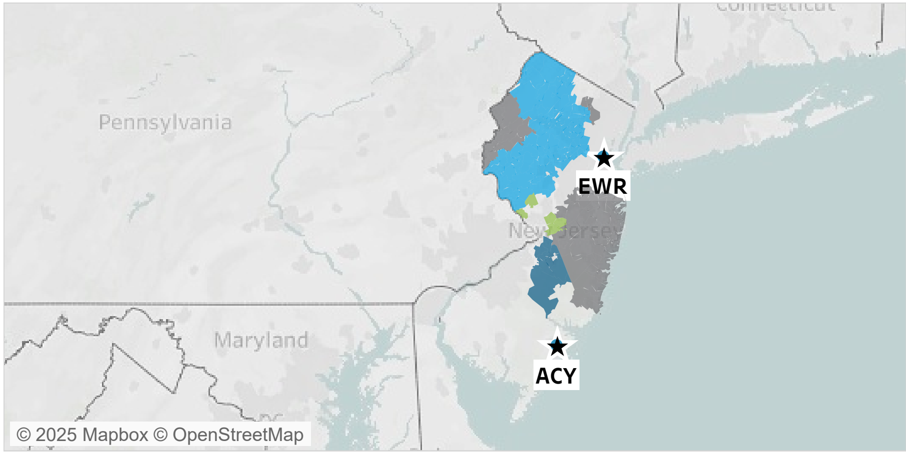
EASTERN MID-ATLANTIC GPU PJM MID-ATLANTIC PJM RTO

Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Metropolitan Statistical Areas and Weather Stations



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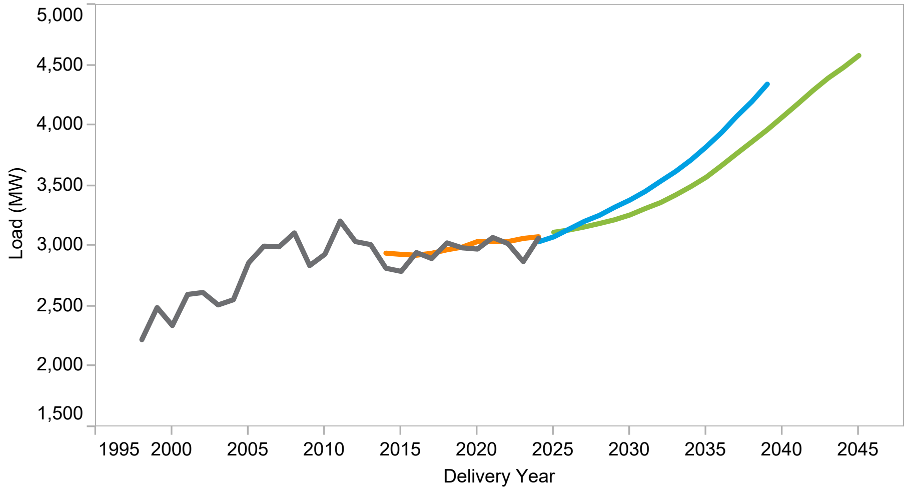
MSA
- ■ Camden, NJ
- ■ JCPL - Non-Metro
- ■ Newark, NJ-PA
- ■ Trenton, NJ

Metropolitan Edison (METED)

Summer Peak



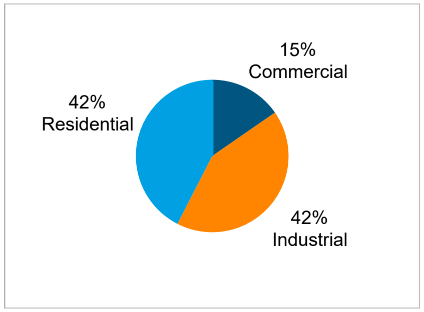
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*74.7*
Avg Summer Max Temp	*95.8*
Avg Winter Daily Temp	*34.6*
Avg Winter Min Temp	*6.7*

Zonal 10/15/20 Year Load Growth

SUMMER	1.4%	1.8%	1.9%
WINTER	1.6%	2.0%	2.1%

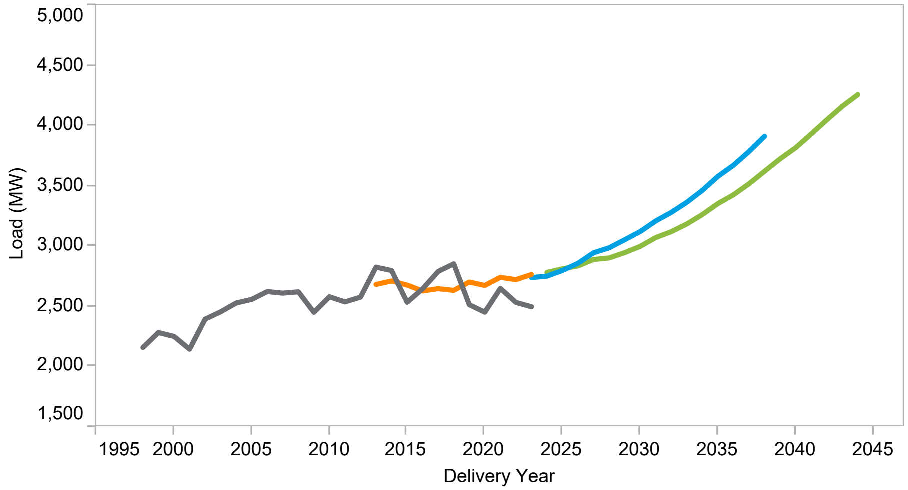
RCI Makeup



LDAs

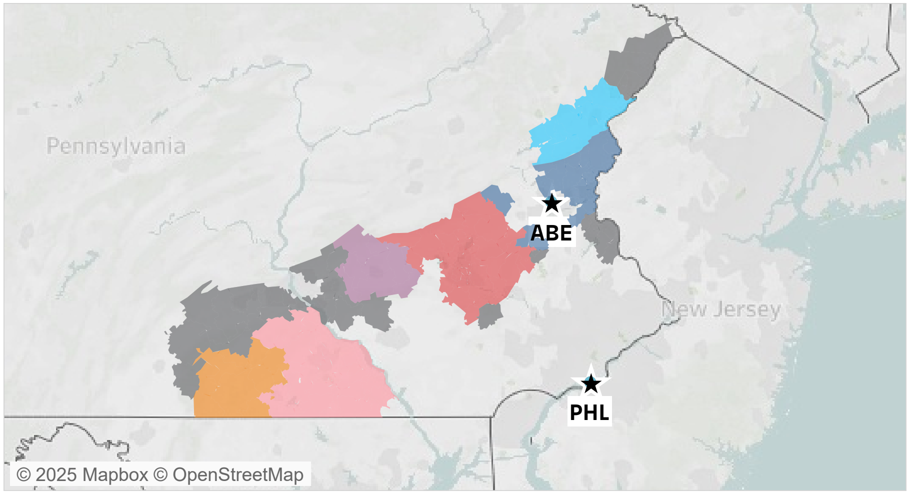
CENTRAL MID-ATLANTIC GPU PJM MID-ATLANTIC PJM RTO WESTERN MID-ATLANTIC

Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Metropolitan Statistical Areas and Weather Stations

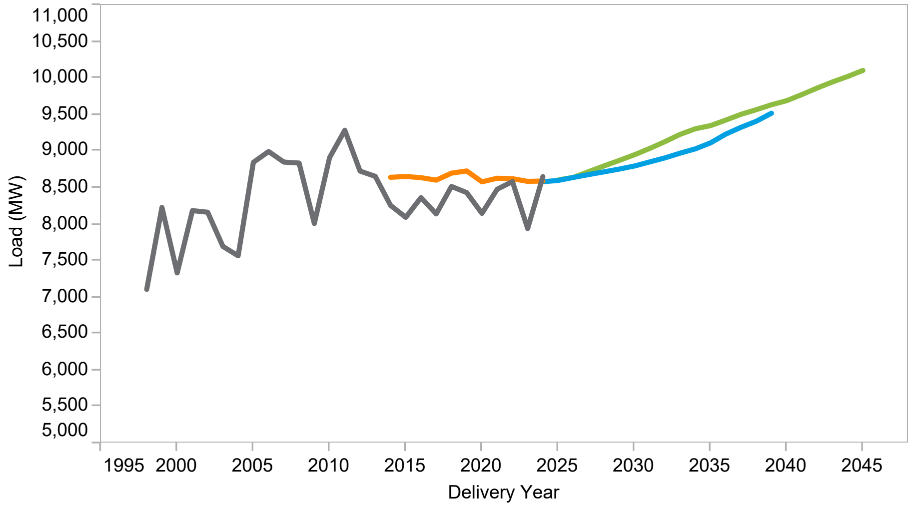


MSA

- ■ Allentown-Bethlehem-Easton, PA-NJ
- ■ East Stroudsburg, PA
- ■ Gettysburg, PA
- ■ Lebanon, PA
- ■ METED - Non-Metro
- ■ Reading, PA
- ■ York-Hanover, PA

PECO Energy (PECO)

Summer Peak



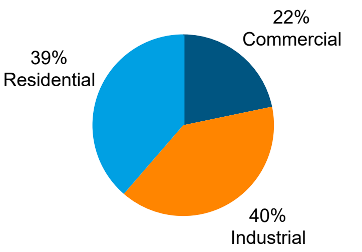
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*76.6*
Avg Summer Max Temp	*97.1*
Avg Winter Daily Temp	*36.8*
Avg Winter Min Temp	*9.4*

Zonal 10/15/20 Year Load Growth

SUMMER	0.8%	0.8%	0.8%
WINTER	1.3%	1.1%	1.0%

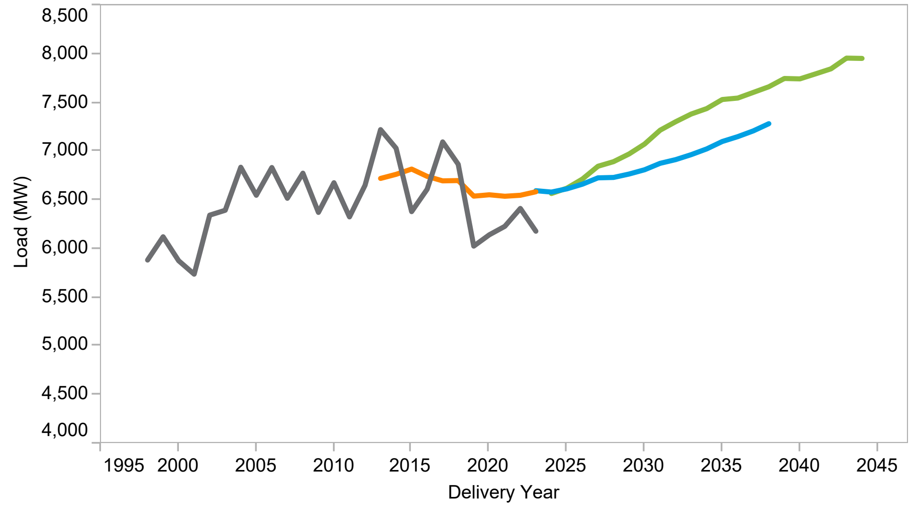
RCI Makeup



LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

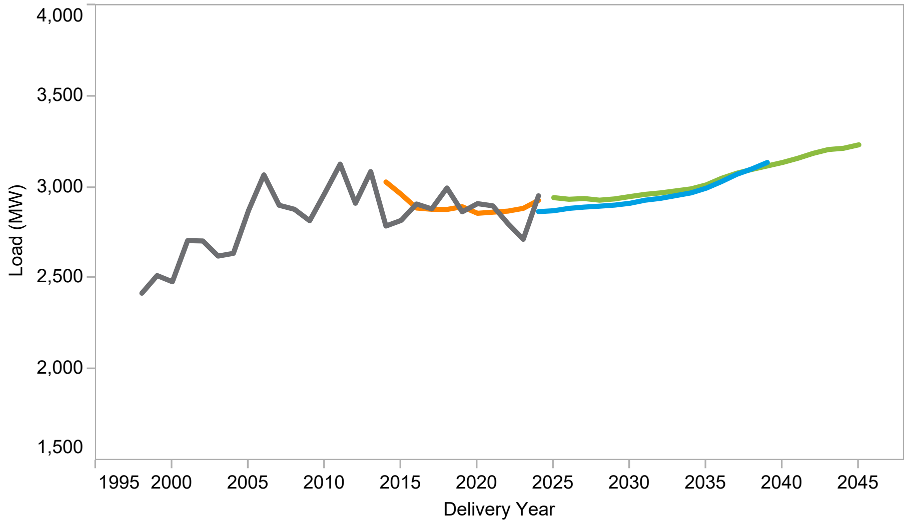
Metropolitan Statistical Areas and Weather Stations

MSA

- ■ Montgomery County-Bucks County-Chester County, PA
- ■ PECO - Non-Metro
- ■ Philadelphia, PA

Pennsylvania Electric Company (PENLC)

Summer Peak



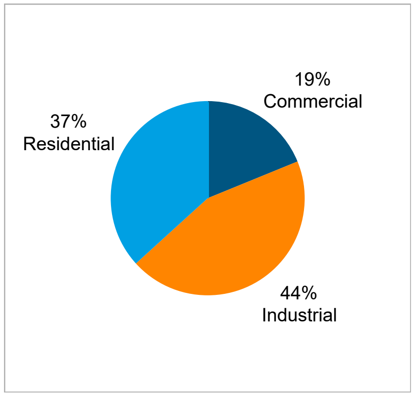
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*71.1*
Avg Summer Max Temp	*91.7*
Avg Winter Daily Temp	*30.5*
Avg Winter Min Temp	*2.1*

Zonal 10/15/20 Year Load Growth

SUMMER	0.2%	0.4%	0.5%
WINTER	0.3%	0.4%	0.4%

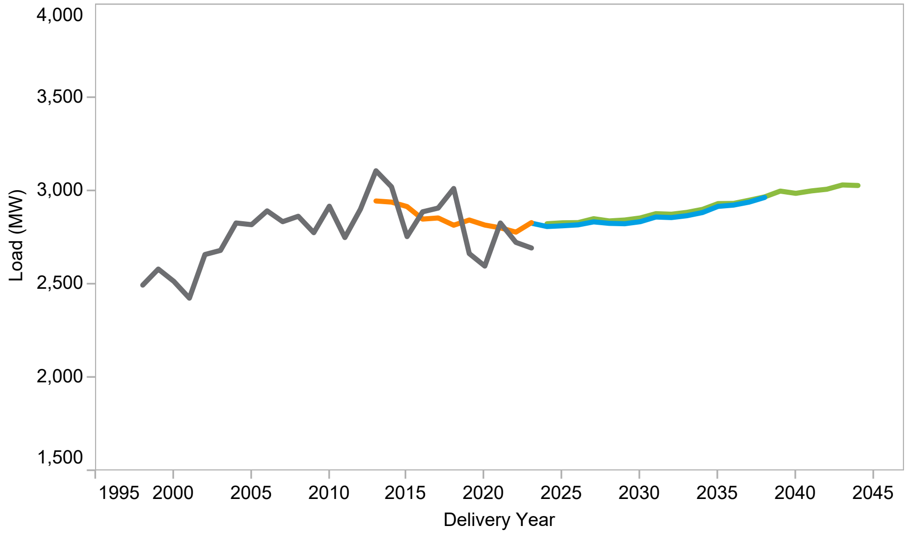
RCI Makeup



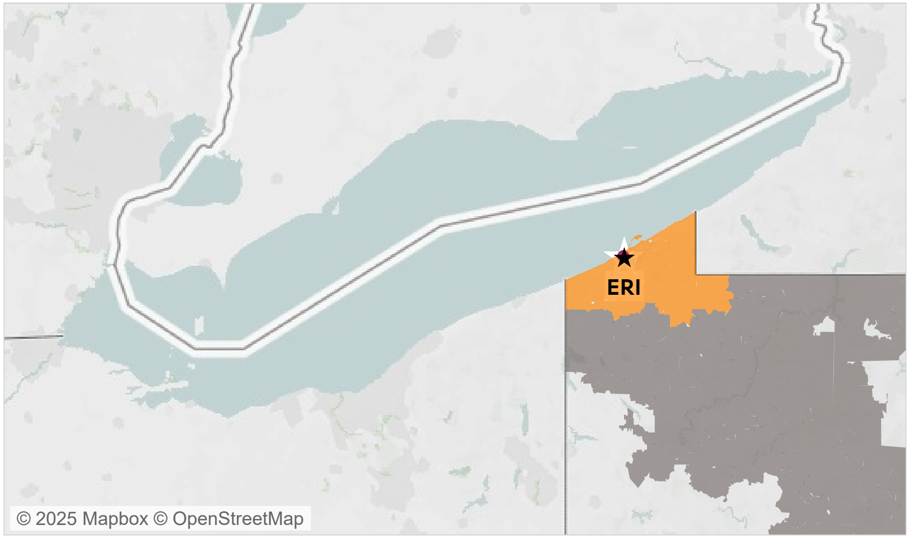
LDAs

GPU PJM MID-ATLANTIC PJM RTO WESTERN MID-ATLANTIC

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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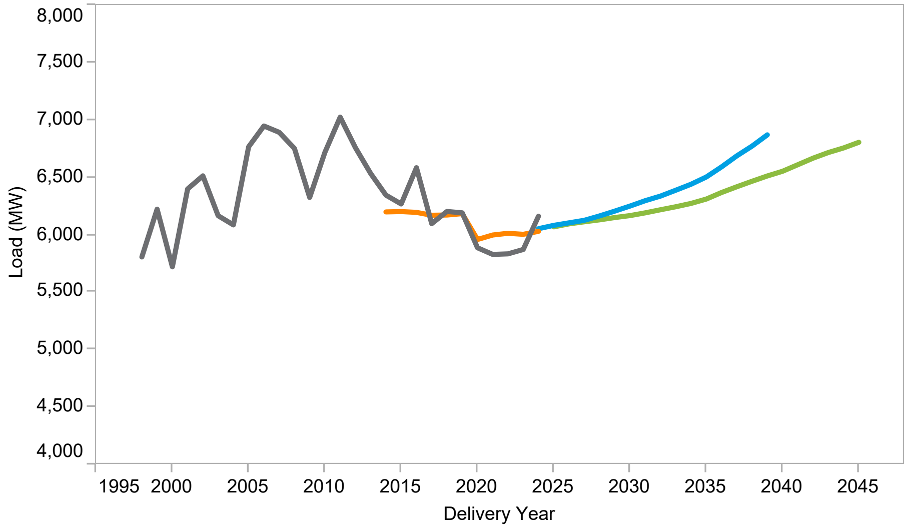
■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

MSA

■ Altoona, PA	■ Johnstown, PA
■ Erie, PA	■ PENLC - Non-Metro

Potomac Electric Power (PEPCO)

Summer Peak



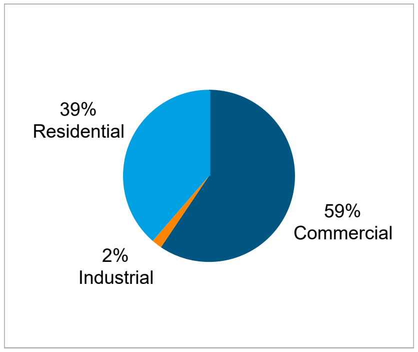
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*78.1*
Avg Summer Max Temp	*98.0*
Avg Winter Daily Temp	*39.2*
Avg Winter Min Temp	*12.8*

Zonal 10/15/20 Year Load Growth

SUMMER	0.4%	0.5%	0.6%
WINTER	0.6%	0.6%	0.6%

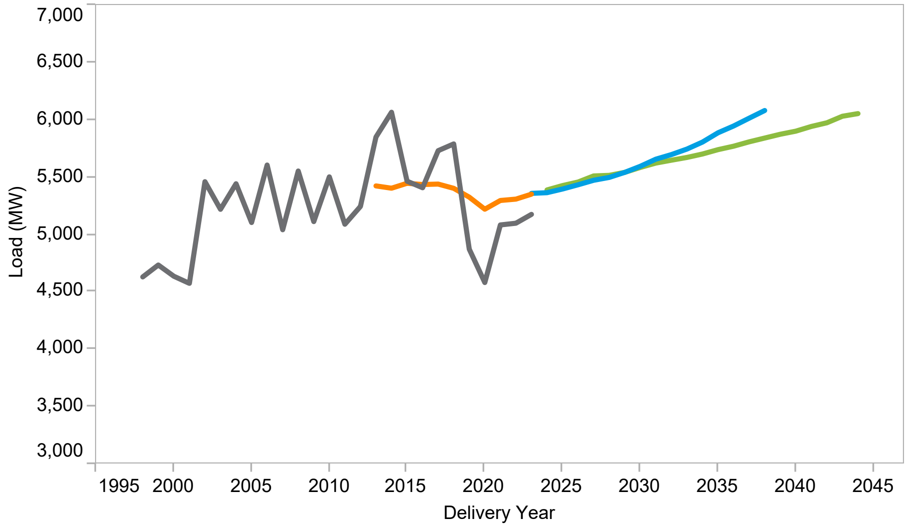
RCI Makeup



LDAs

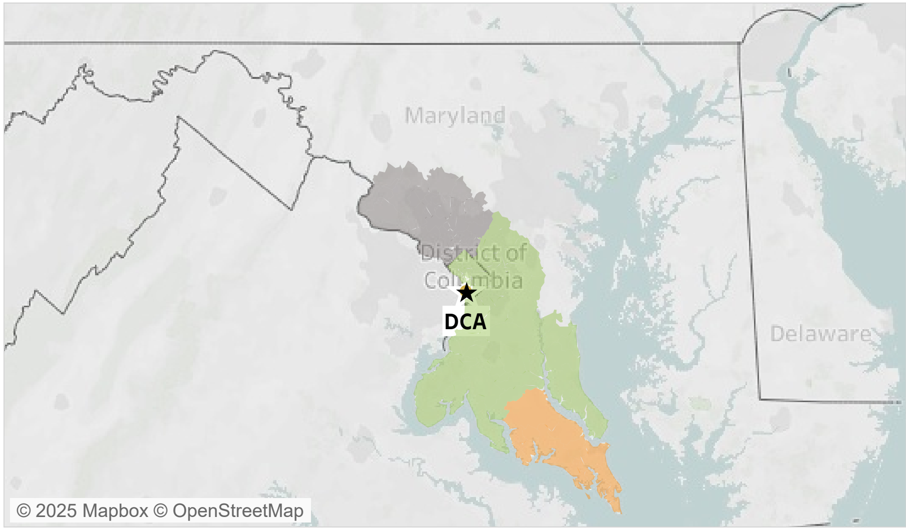
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Metropolitan Statistical Areas and Weather Stations



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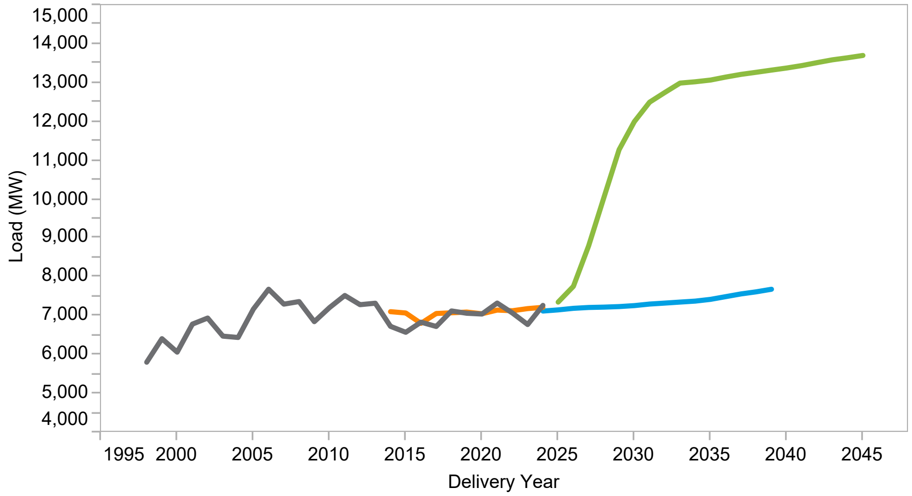
MSA

■ California-Lexington Park, MD
■ Washington-Arlington-Alexandria, DC-VA-..
■ PEPCO - Non-Metro

PPL Electric Utilities (PL)

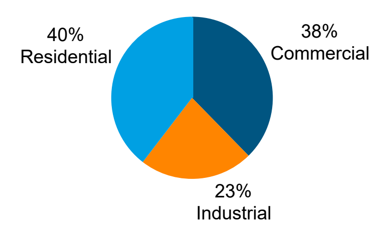
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*72.4*
Avg Summer Max Temp	*94.2*
Avg Winter Daily Temp	*31.7*
Avg Winter Min Temp	*2.9*

RCI Makeup



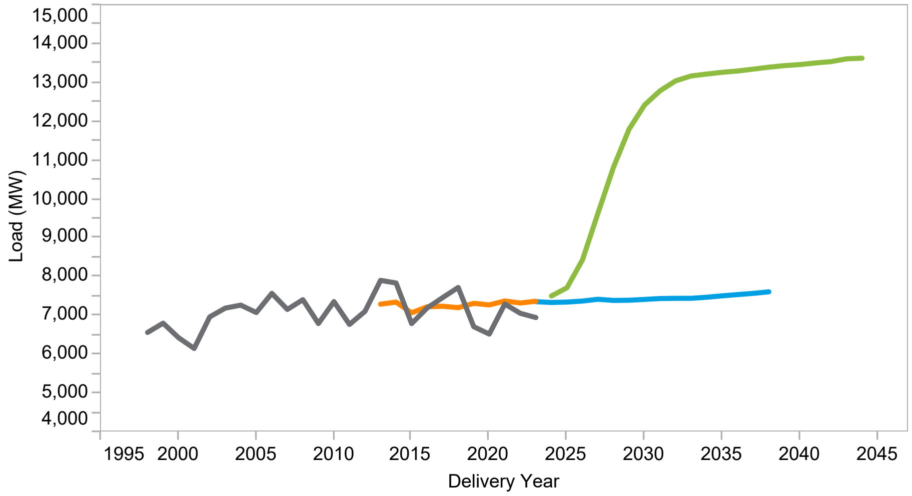
Zonal 10/15/20 Year Load Growth

SUMMER	5.9%	4.1%	3.2%
WINTER	5.8%	4.0%	3.0%

LDAs

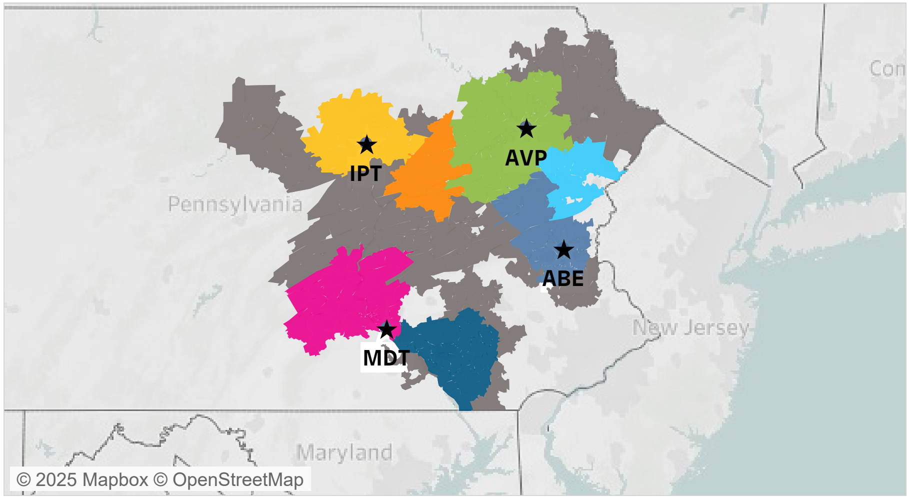
CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Winter Peak



⬛ Peak 🟧 WN peak 🟦 Forecast 2024 🟩 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



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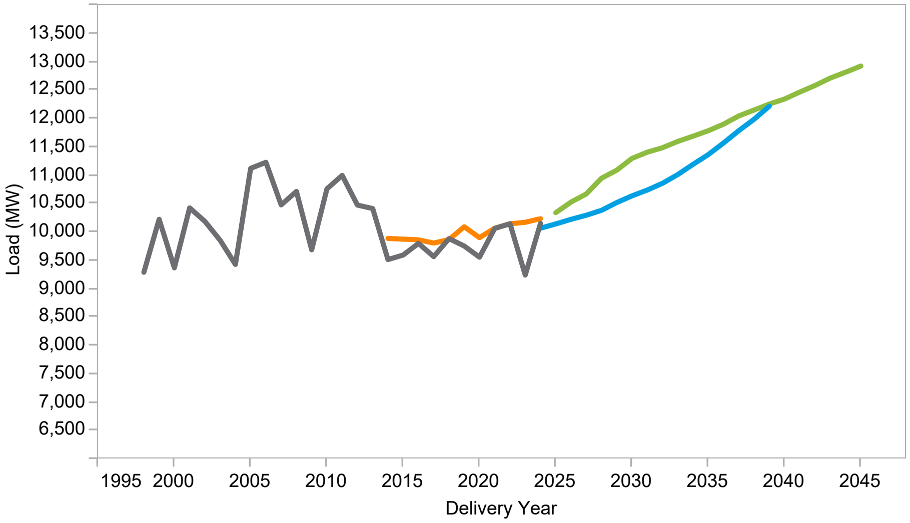
MSA

- ■ Allentown-Bethlehem-Easton, PA-NJ
- ■ Bloomsburg-Berwick, PA
- ■ East Stroudsburg, PA
- ■ Harrisburg-Carlisle, PA
- ■ Lancaster, PA
- ■ PL - Non-Metro
- ■ Scranton--Wilkes-Barre--Hazleton, PA
- ■ Williamsport, PA

Public Service Electric & Gas (PS)

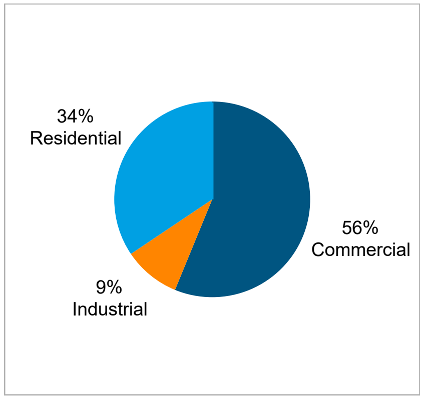
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*76.1*
Avg Summer Max Temp	*98.9*
Avg Winter Daily Temp	*35.8*
Avg Winter Min Temp	*7.4*

RCI Makeup



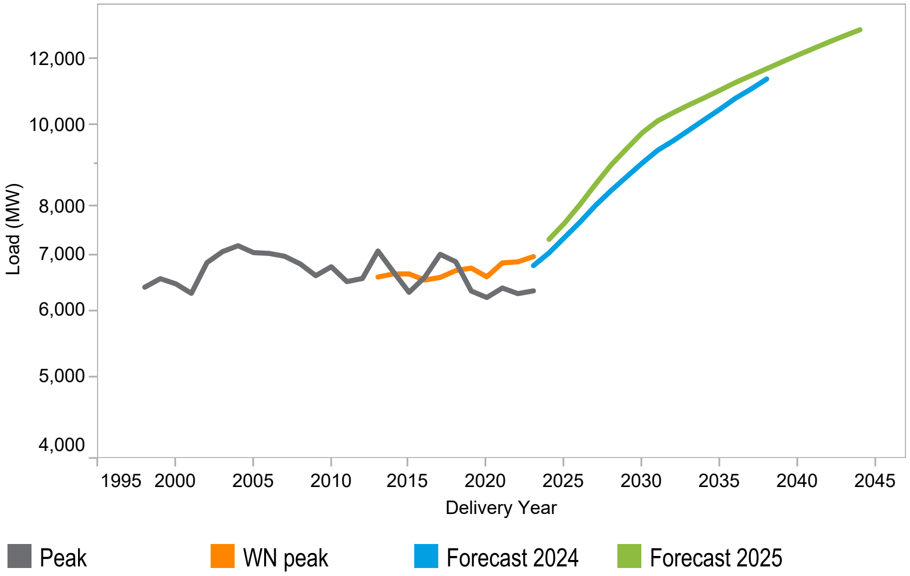
Zonal 10/15/20 Year Load Growth

SUMMER	1.3%	1.2%	1.1%
WINTER	4.0%	3.3%	2.9%

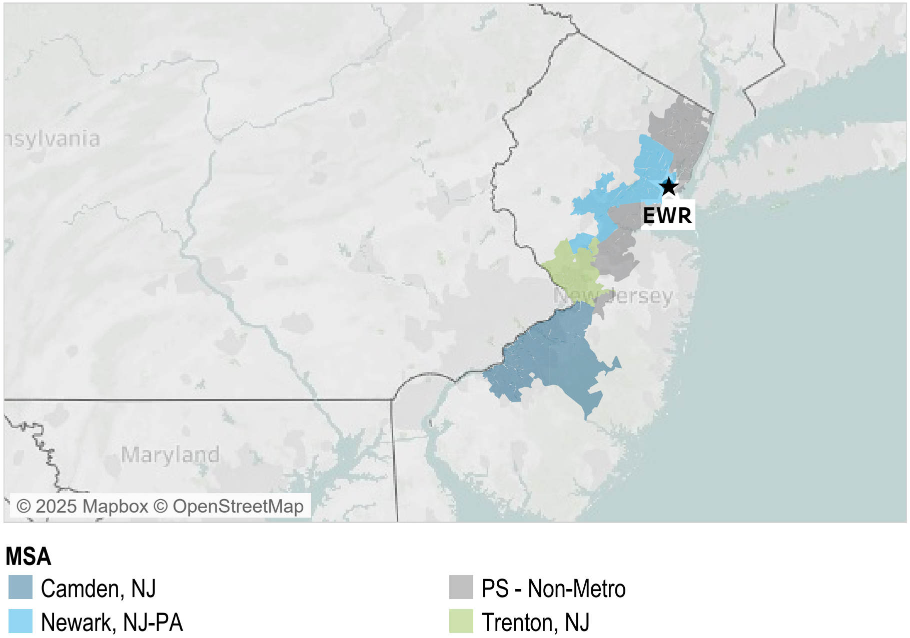
LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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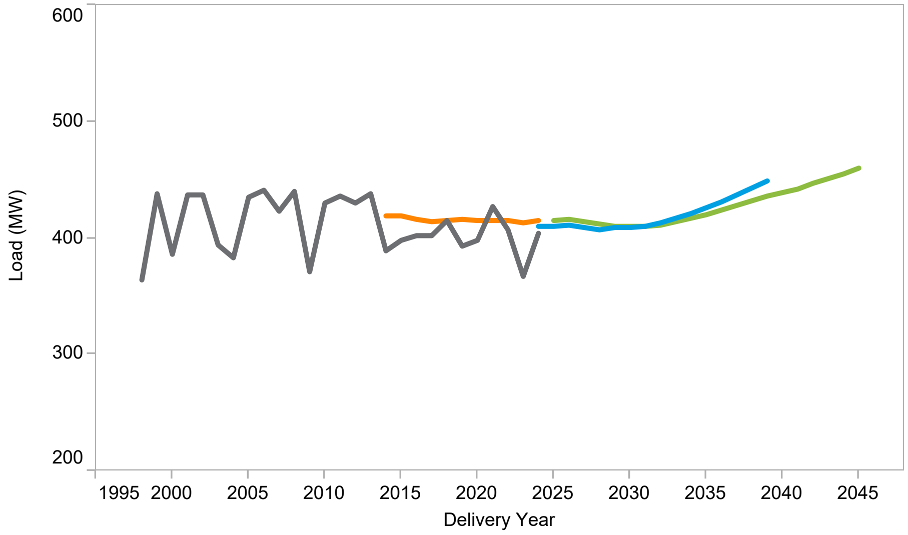
Rockland Electric Company (RECO)

Summer Peak



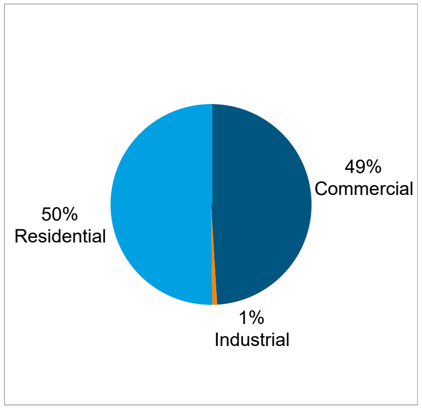
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*76.1*
Avg Summer Max Temp	*98.9*
Avg Winter Daily Temp	*35.8*
Avg Winter Min Temp	*7.4*

Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.4%	0.5%
WINTER	2.6%	2.5%	2.3%

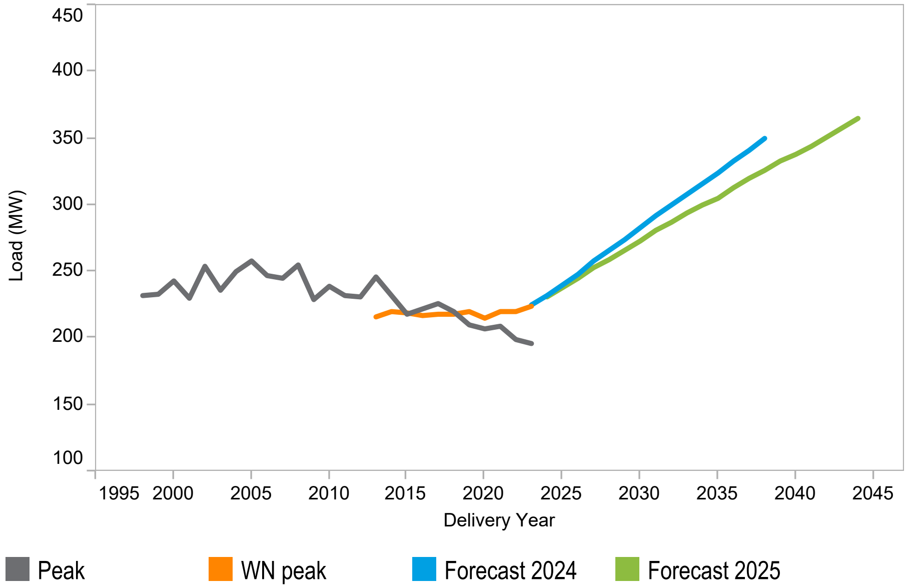
RCI Makeup



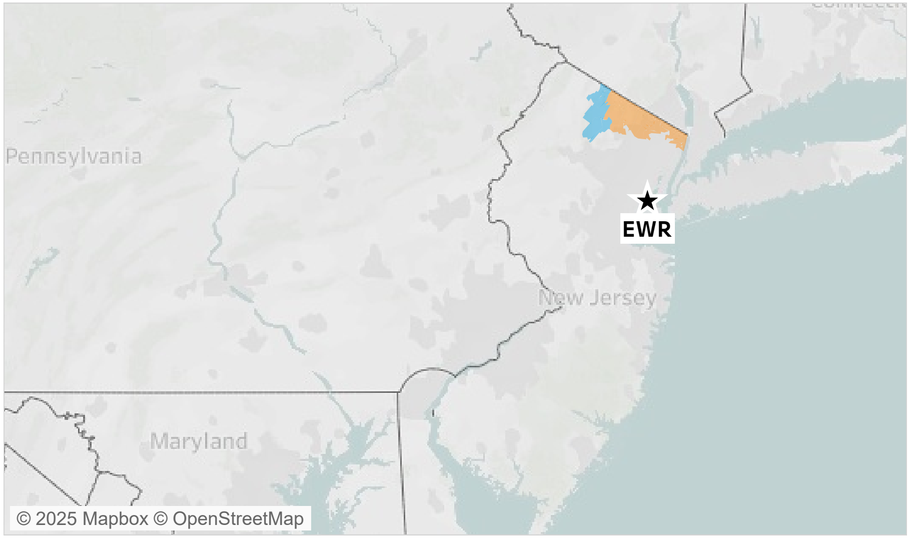
LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations

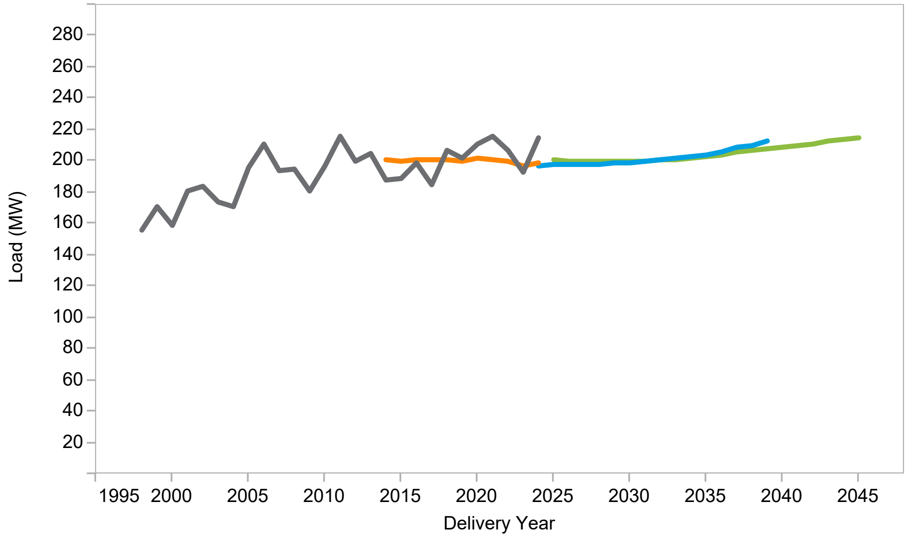


MSA

- 🟧 New York-Jersey City-White Plains, NY-NJ
- 🟦 Newark, NJ-PA

UGI Energy Services (UGI)

Summer Peak



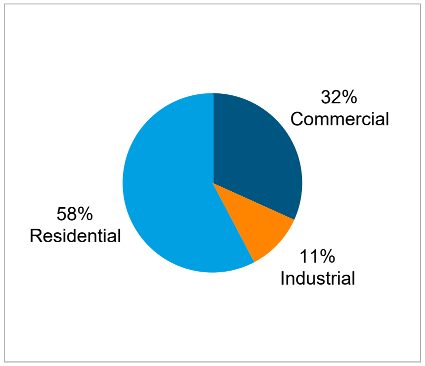
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*70.6*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*30.1*
Avg Winter Min Temp	*-1.0*

Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.3%	0.3%
WINTER	0.1%	0.3%	0.3%

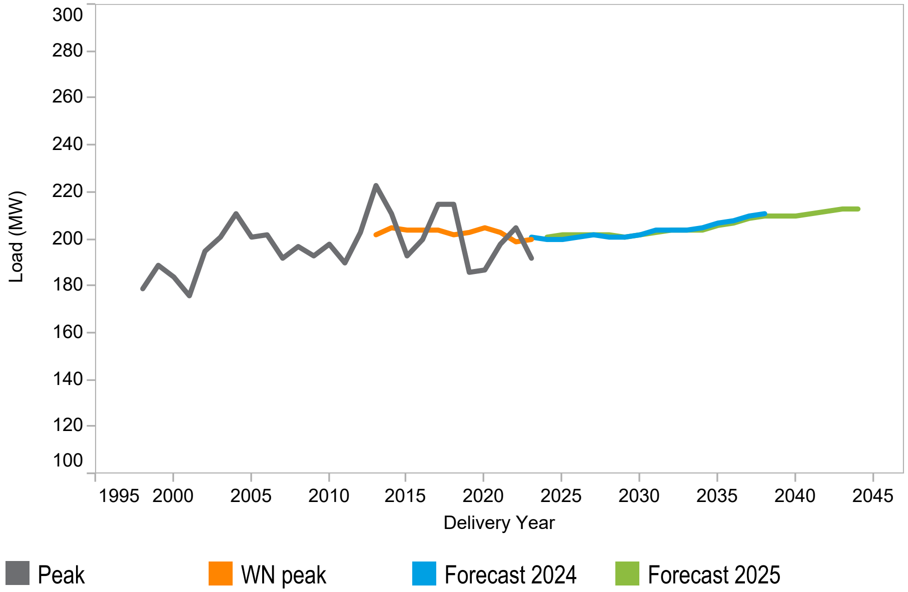
RCI Makeup



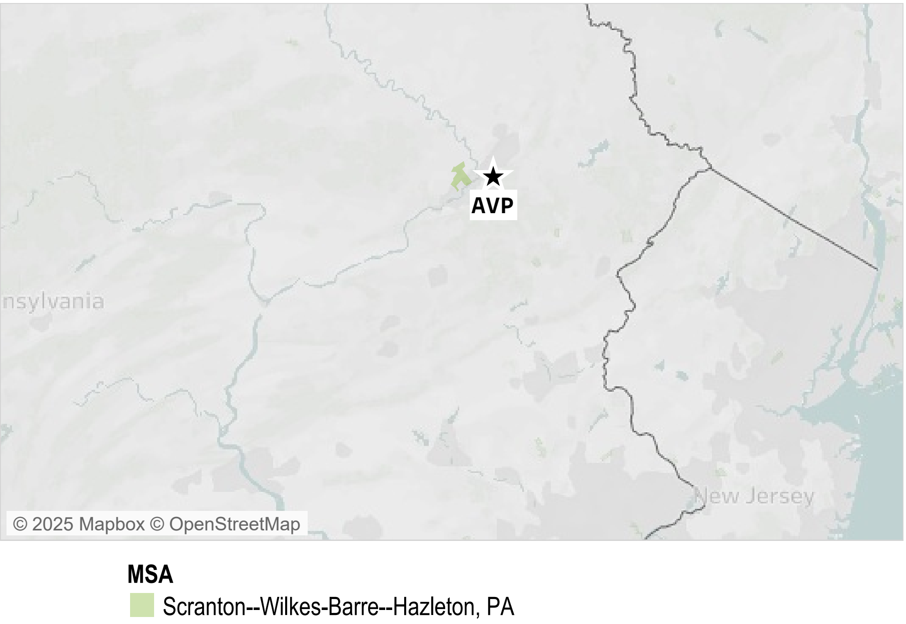
LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Winter Peak

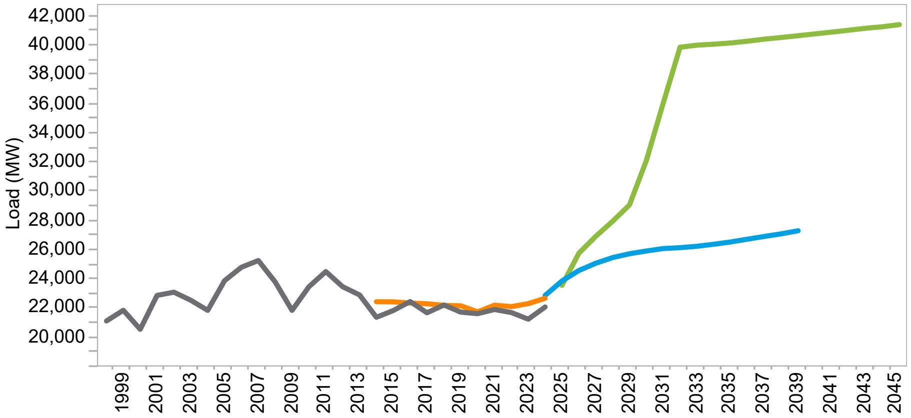


Metropolitan Statistical Areas and Weather Stations



American Electric Power (AEP)

Summer Peak



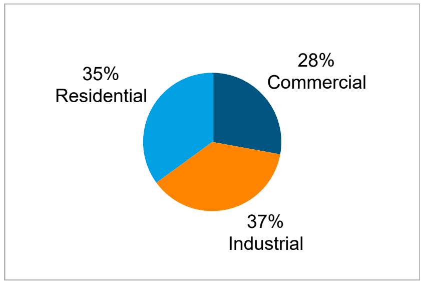
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*92.3*
Avg Winter Daily Temp	*33.4*
Avg Winter Min Temp	*2.9*

Zonal 10/15/20 Year Load Growth

SUMMER	5.5%	3.7%	2.9%
WINTER	5.9%	4.0%	3.1%

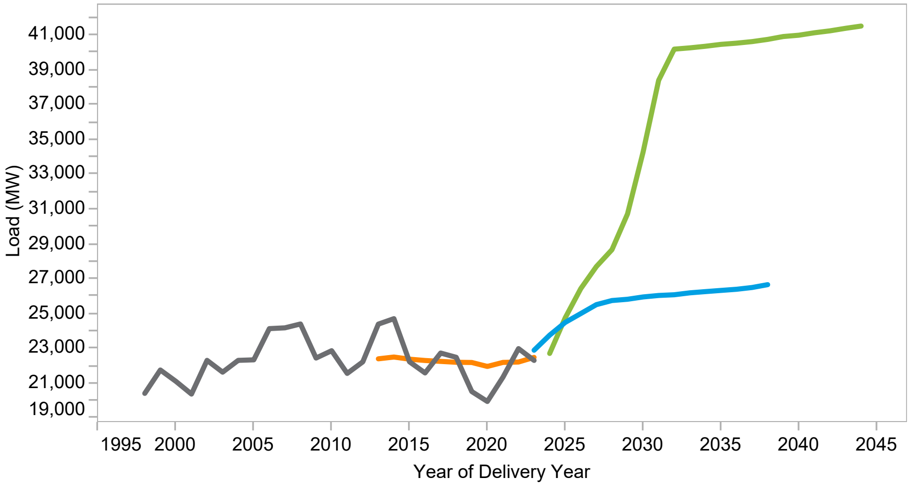
RCI Makeup



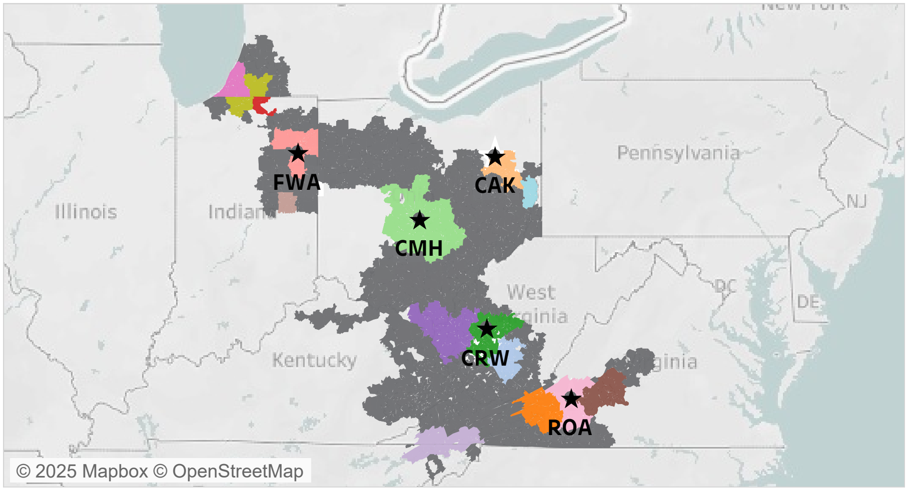
LDAs

PJM RTO PJM WESTERN

Winter Peak



Metropolitan Statistical Areas and Weather Stations



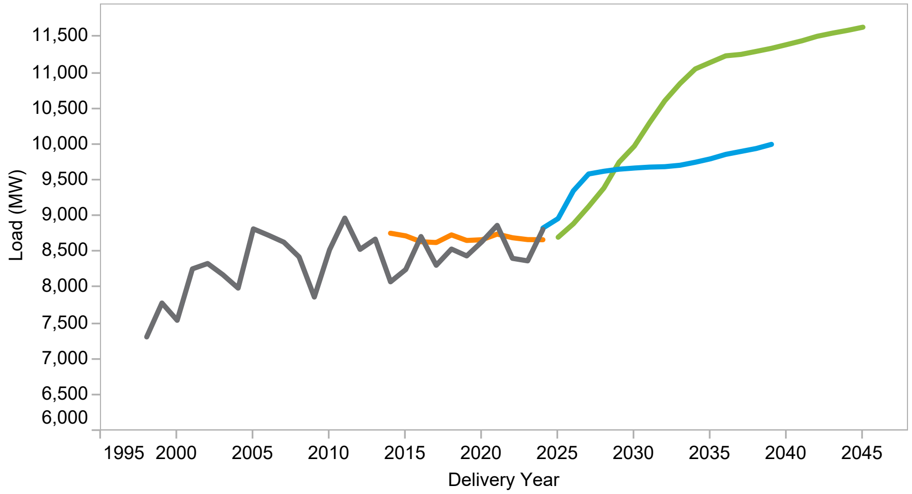
- ■ Peak
- ■ WN peak
- ■ Forecast 2024
- ■ Forecast 2025

MSA

- ■ AEP - Non-Metro
- ■ Beckley, WV
- ■ Blacksburg-Christiansburg-Radford, VA
- ■ Canton-Massillon, OH
- ■ Charleston, WV
- ■ Columbus, OH
- ■ Elkhart-Goshen, IN
- ■ Fort Wayne, IN
- ■ Huntington-Ashland, WV-KY-OH
- ■ Kingsport-Bristol-Bristol, TN-VA
- ■ Lynchburg, VA
- ■ Muncie, IN
- ■ Niles-Benton Harbor, MI
- ■ Roanoke, VA
- ■ South Bend-Mishawaka, IN-MI
- ■ Weirton-Steubenville, WV-OH

Allegheny Power Systems (APS)

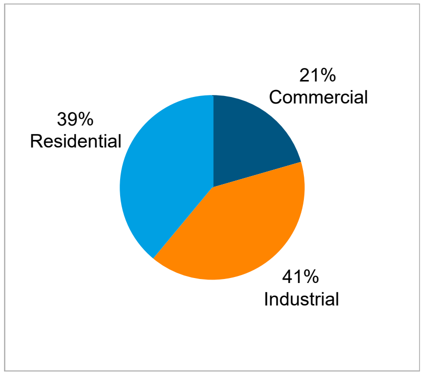
Summer Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*72.8*
Avg Summer Max Temp	*92.6*
Avg Winter Daily Temp	*33.1*
Avg Winter Min Temp	*2.4*

RCI Makeup



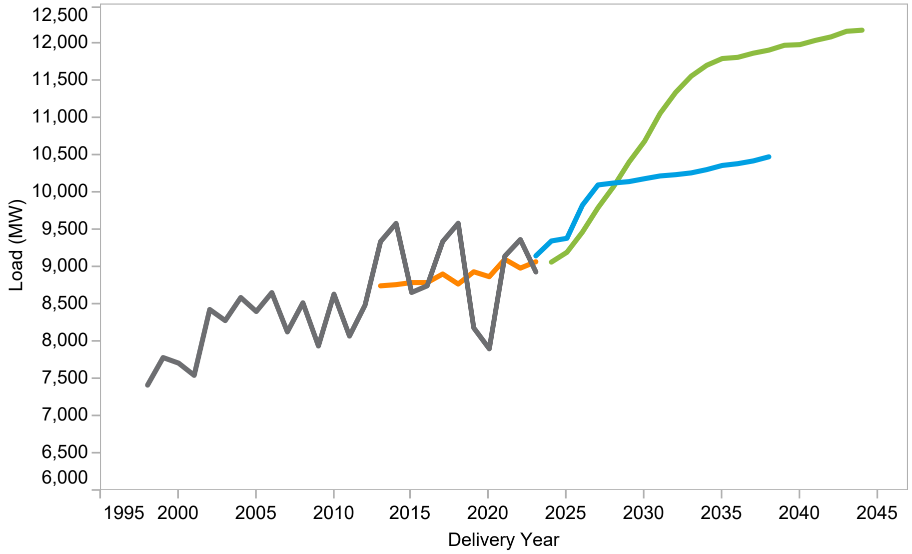
Zonal 10/15/20 Year Load Growth

SUMMER	2.5%	1.8%	1.5%
WINTER	2.6%	1.9%	1.5%

LDAs

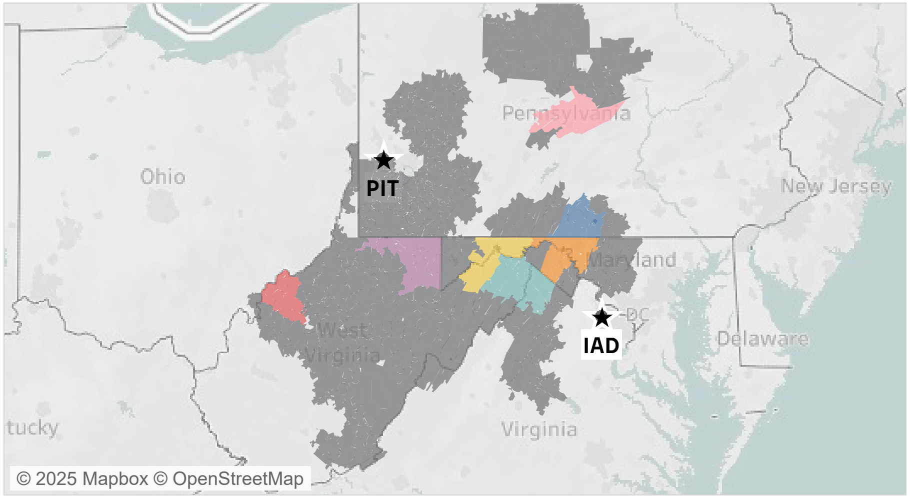
PJM RTO PJM WESTERN

Winter Peak



⬛ Peak 🟧 WN peak 🟦 Forecast 2024 🟩 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



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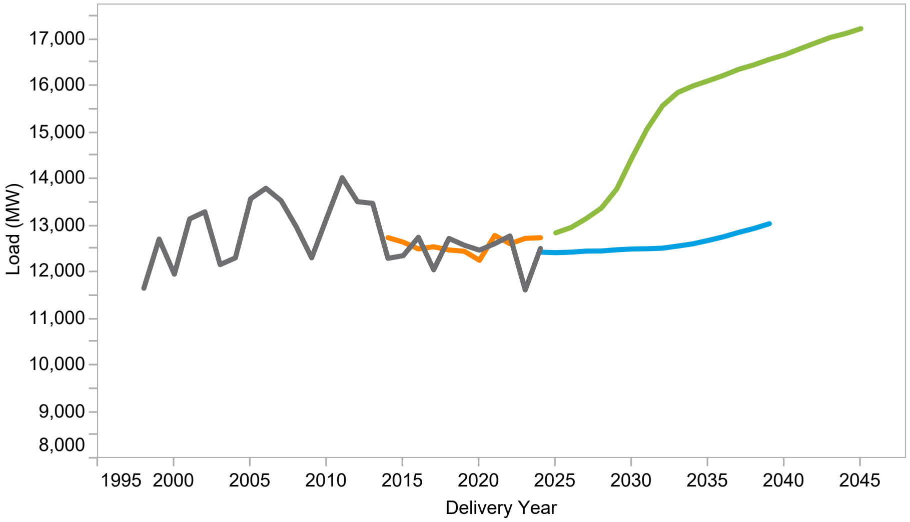
MSA

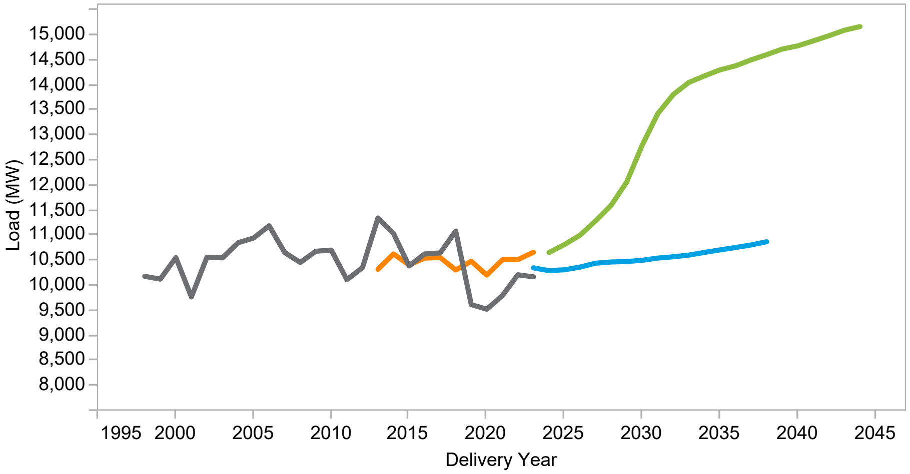
- APS - Non-metro
- Chambersburg-Waynesboro, PA
- Cumberland, MD-WV
- Hagerstown-Martinsburg, MD-WV
- Morgantown, WV
- Parkersburg-Vienna, WV
- State College, PA
- Winchester, VA-WV

American Transmission Systems, Inc (ATSI)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

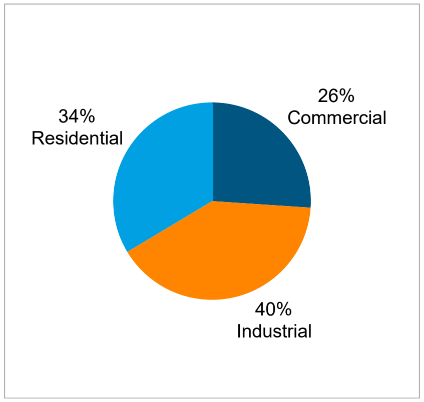
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*71.6*
Avg Summer Max Temp	*91.9*
Avg Winter Daily Temp	*30.2*
Avg Winter Min Temp	*-1.0*

Zonal 10/15/20 Year Load Growth

SUMMER	2.3%	1.8%	1.5%
WINTER	2.9%	2.2%	1.8%

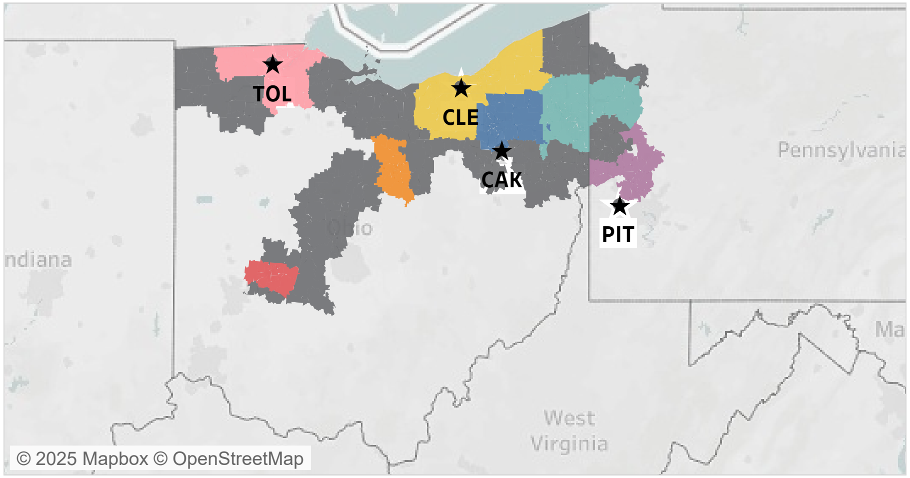
RCI Makeup



LDAs

PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations



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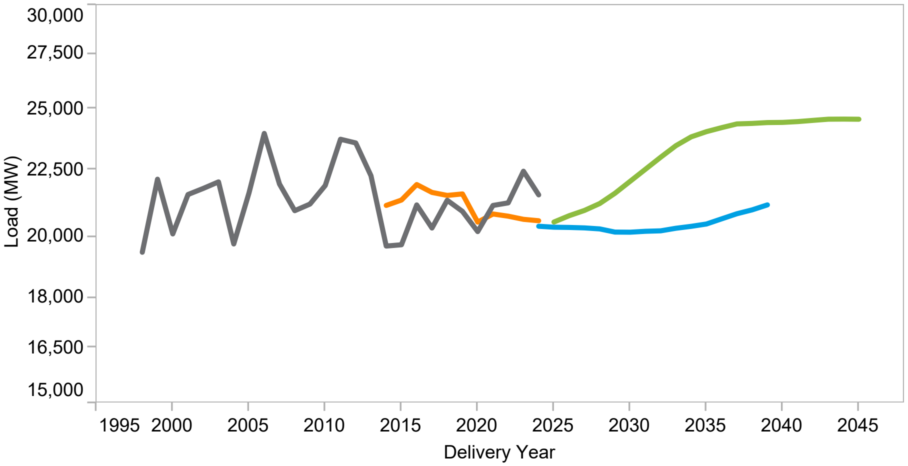
MSA

- Akron, OH
- ATSI - Non-Metro
- Cleveland-Elyria, OH
- Mansfield, OH
- Pittsburgh, PA
- Springfield, OH
- Toledo, OH
- Youngstown-Warren-Boardman, OH-PA

Commonwealth Edison (COMED)

Summer Peak



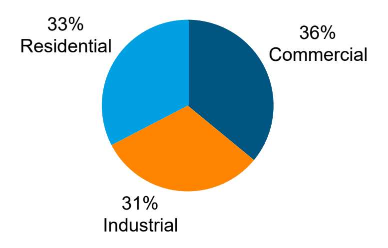
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*73.0*
Avg Summer Max Temp	*95.5*
Avg Winter Daily Temp	*27.8*
Avg Winter Min Temp	*-7.1*

Zonal 10/15/20 Year Load Growth

SUMMER	1.6%	1.2%	0.9%
WINTER	2.9%	2.2%	1.8%

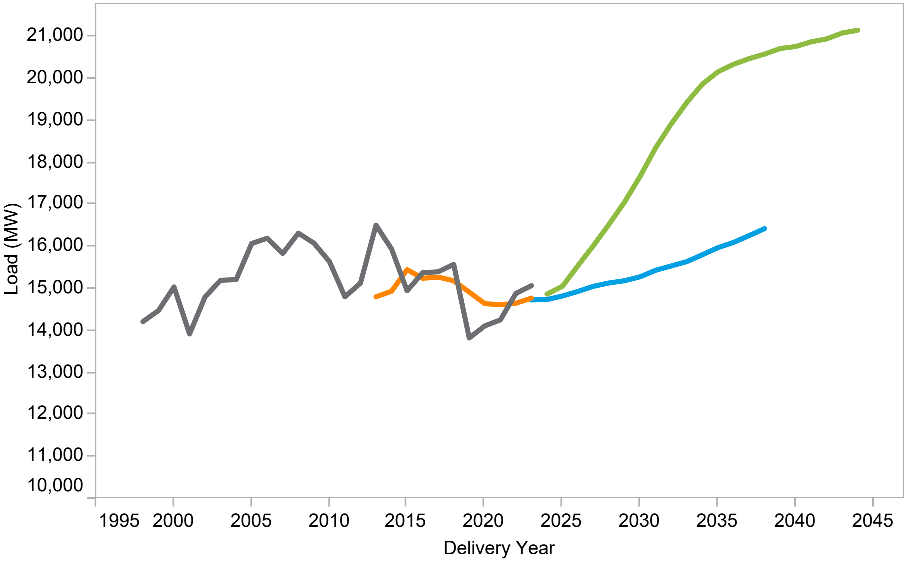
RCI Makeup



LDAs

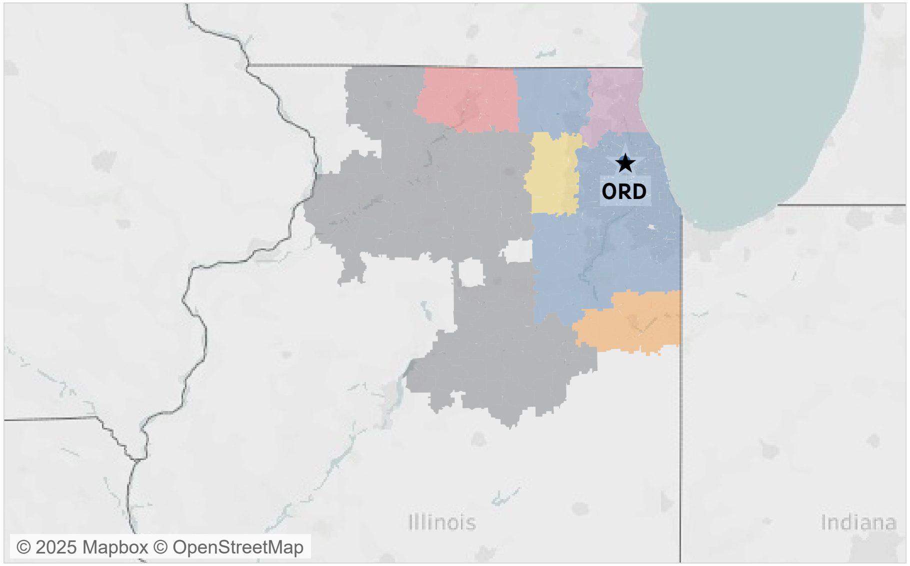
PJM RTO PJM WESTERN

Winter Peak



⬛ Peak 🟧 WN peak 🟦 Forecast 2024 🟩 Forecast 2025

Metropolitan Statistical Areas and Weather Stations



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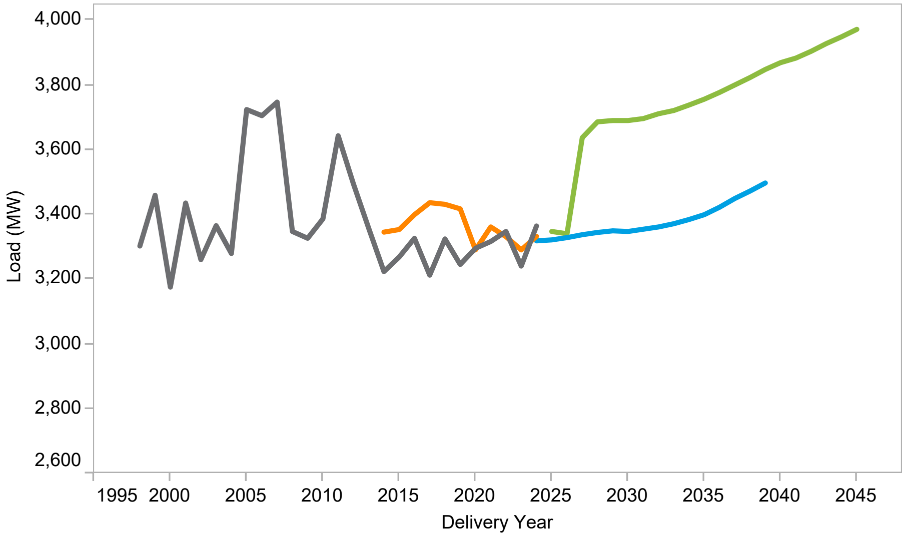
MSA

- Chicago-Naperville-Arlington Heights, IL
- Chicago-Naperville-Elgin, IL-IN-WI
- COMED - Non-Metro
- Kankakee, IL
- Lake County-Kenosha County, IL-WI
- Rockford, IL

Dayton Power and Light (DAYTON)

Summer Peak



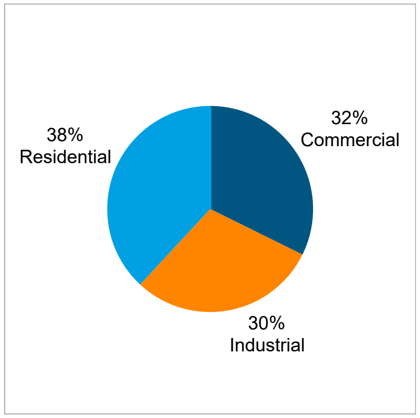
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*31.3*
Avg Winter Min Temp	*-3.0*

Zonal 10/15/20 Year Load Growth

SUMMER	1.2%	1.0%	0.9%
WINTER	1.3%	1.0%	0.9%

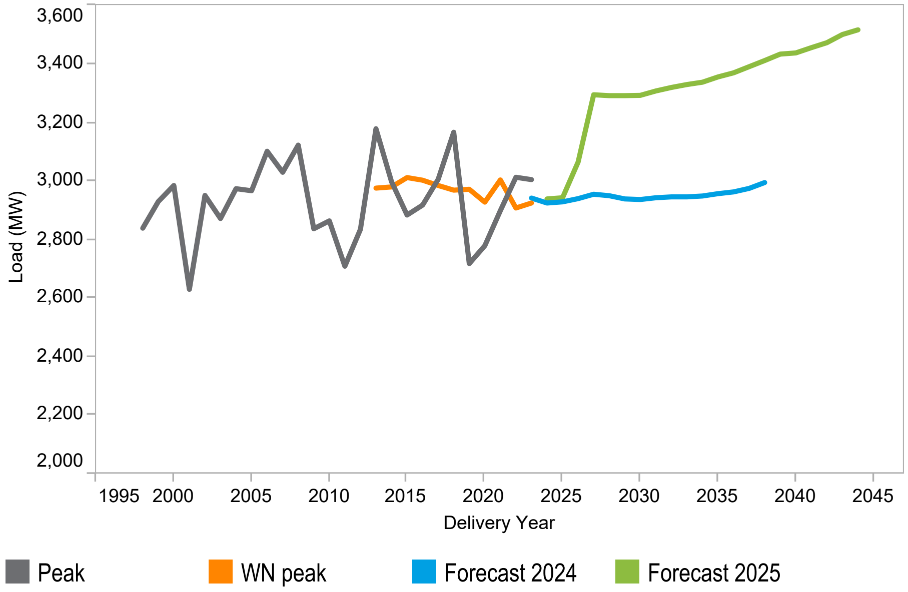
RCI Makeup



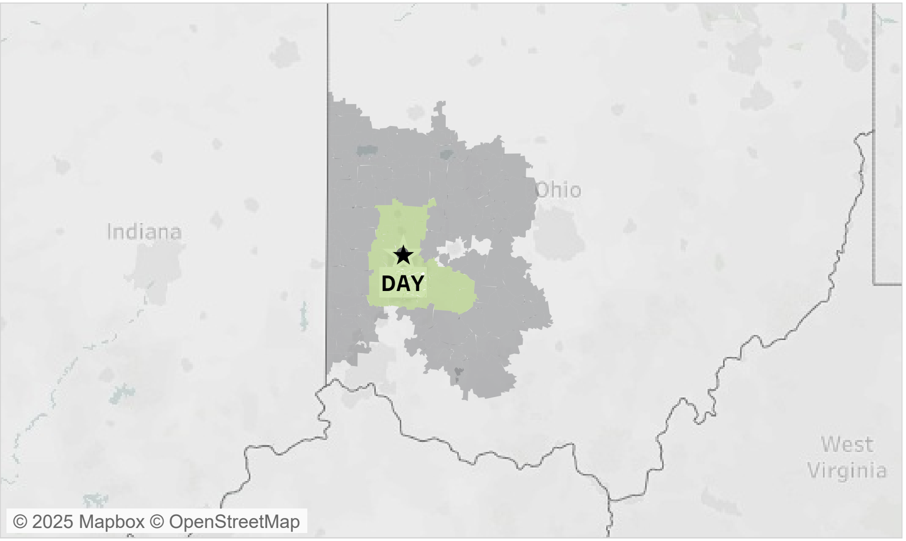
LDAs

PJM RTO PJM WESTERN

Winter Peak



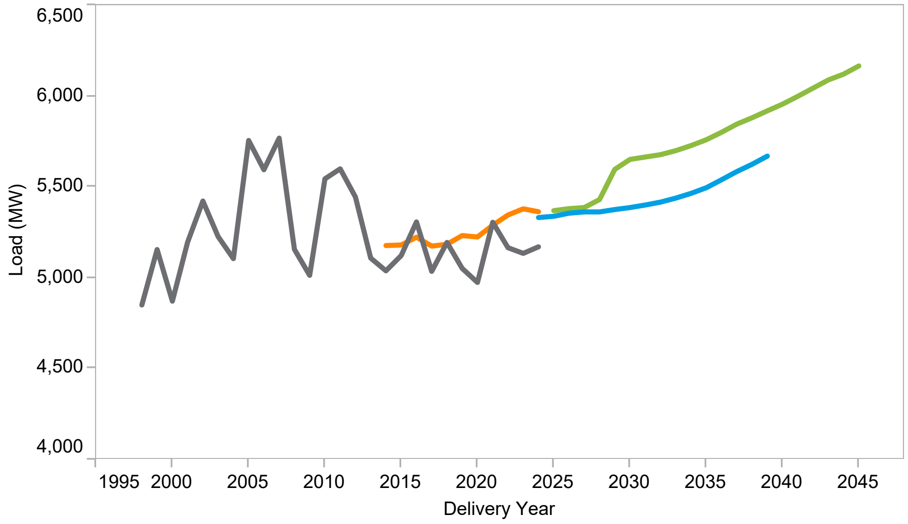
Metropolitan Statistical Areas and Weather Stations



MSA
- DAY - Non-Metro
- Dayton, OH

Duke Energy Ohio and Kentucky (DEOK)

Summer Peak



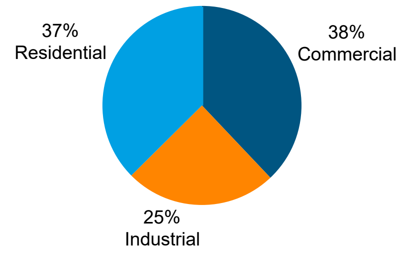
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*74.4*
Avg Summer Max Temp	*94.2*
Avg Winter Daily Temp	*34.1*
Avg Winter Min Temp	*-1.1*

Zonal 10/15/20 Year Load Growth

SUMMER	0.7%	0.7%	0.7%
WINTER	0.9%	0.8%	0.8%

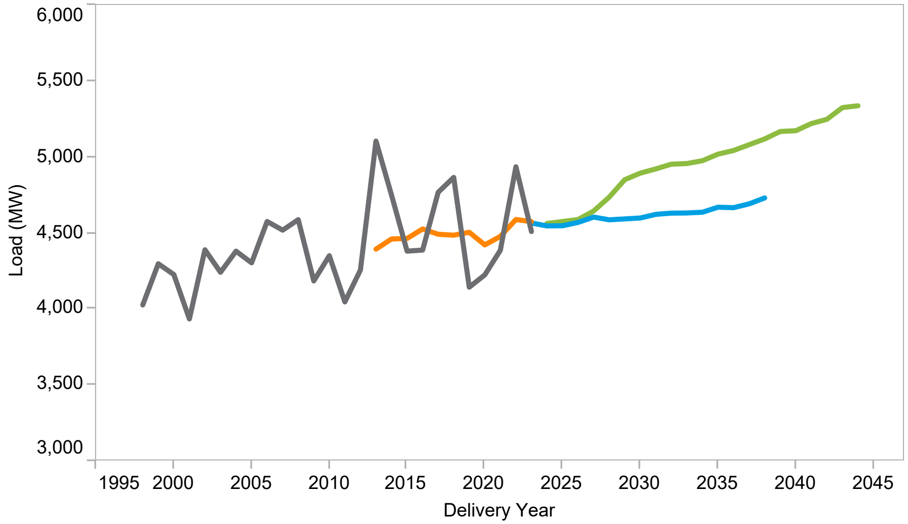
RCI Makeup



LDAs

PJM RTO PJM WESTERN

Winter Peak



■ Peak 🟧 WN peak 🟦 Forecast 2024 🟩 Forecast 2025

Metropolitan Statistical Areas and Weather Stations

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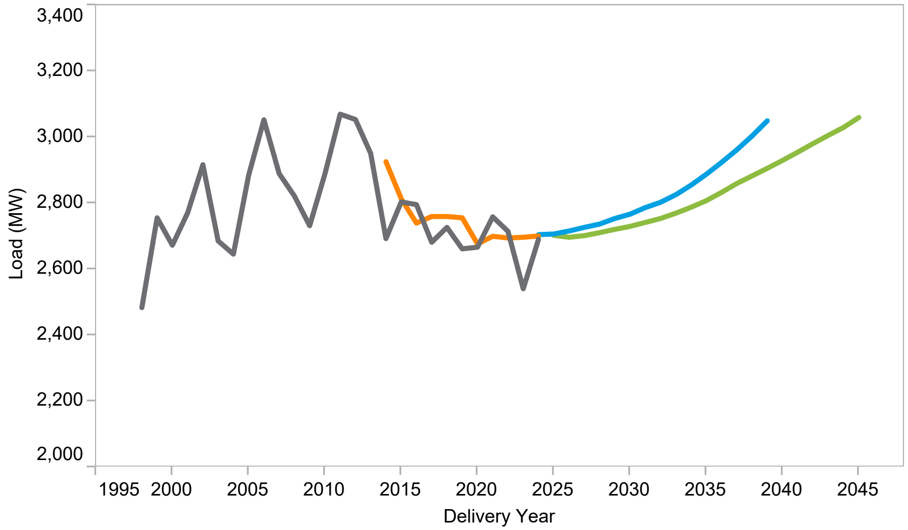
MSA

🟧 Cincinnati, OH-KY-IN

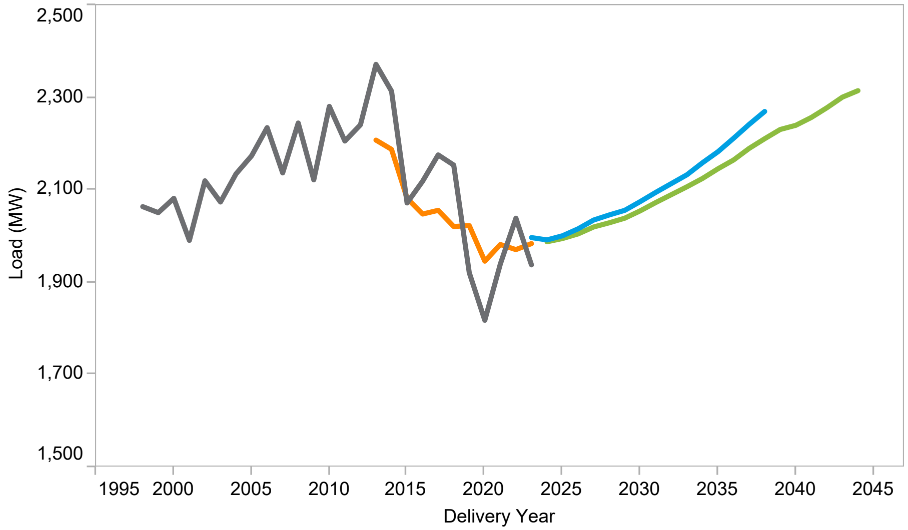
■ DEOK - Non-Metro

Duquesne Light Company (DLCO)

Summer Peak



Winter Peak



- ■ Peak
- ■ WN peak
- ■ Forecast 2024
- ■ Forecast 2025

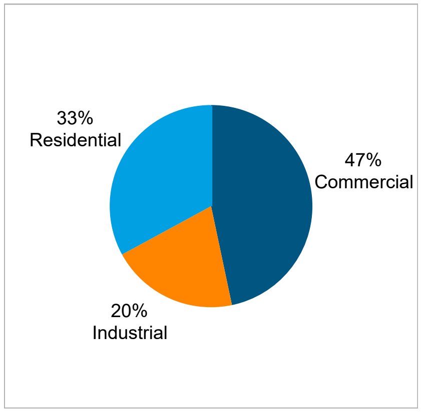
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*71.7*
Avg Summer Max Temp	*91.8*
Avg Winter Daily Temp	*31.7*
Avg Winter Min Temp	*-0.8*

Zonal 10/15/20 Year Load Growth

SUMMER	0.4%	0.5%	0.6%
WINTER	0.7%	0.8%	0.8%

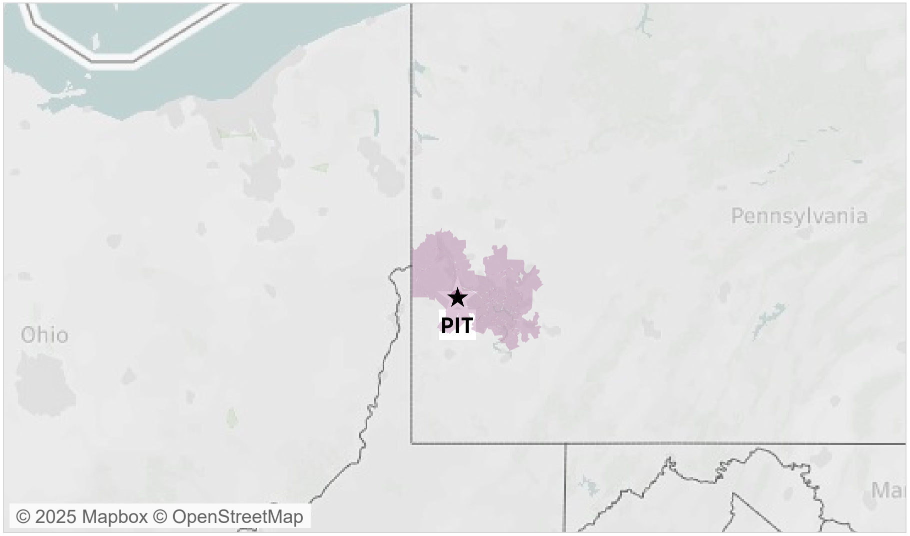
RCI Makeup



LDAs

PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations



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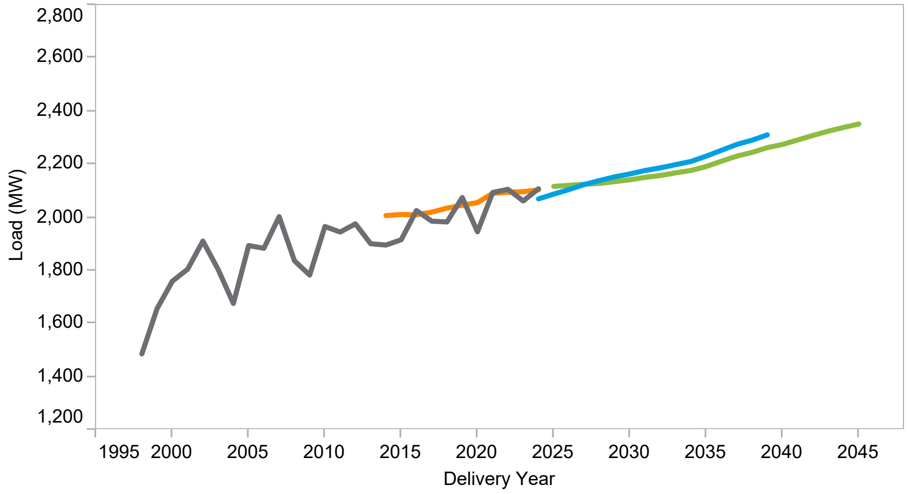
MSA

- ■ Pittsburgh, PA

East Kentucky Power Cooperative (EKPC)

Summer Peak



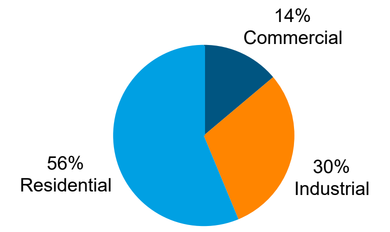
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*94.4*
Avg Winter Daily Temp	*36.1*
Avg Winter Min Temp	*2.4*

Zonal 10/15/20 Year Load Growth

SUMMER	0.3%	0.5%	0.5%
WINTER	0.3%	0.4%	0.4%

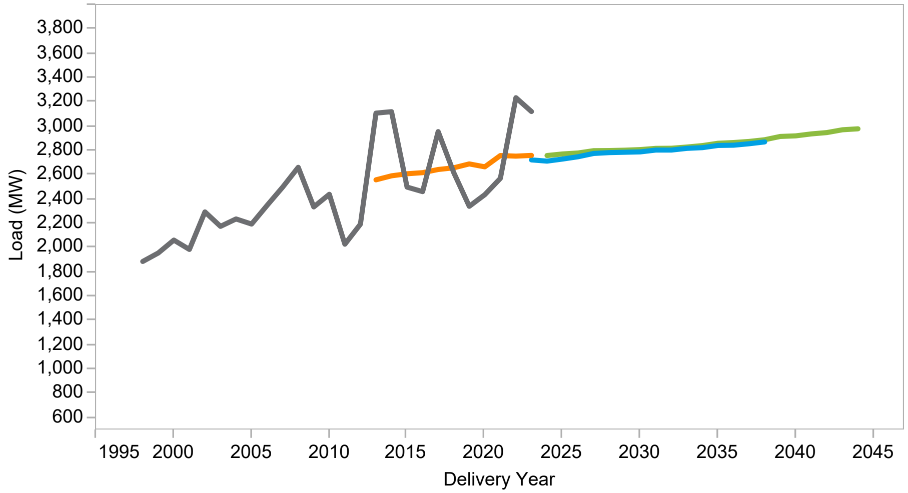
RCI Makeup



LDAs

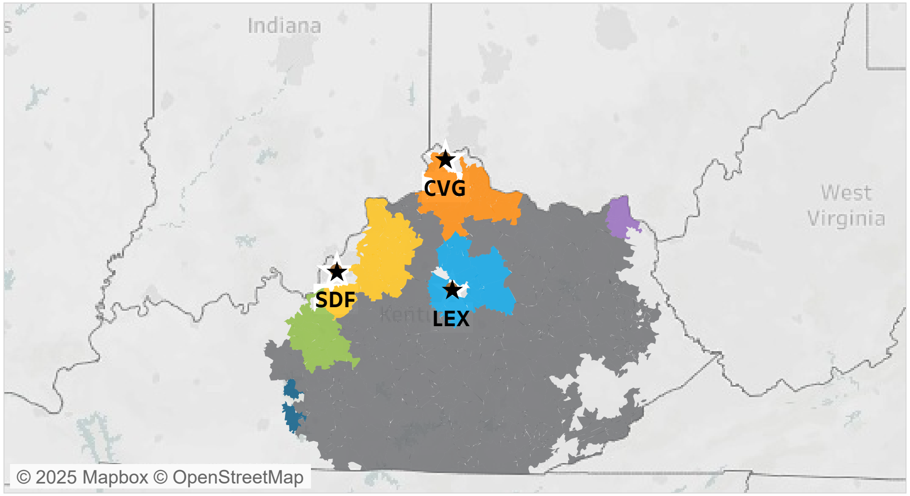
PJM RTO PJM WESTERN

Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Metropolitan Statistical Areas and Weather Stations

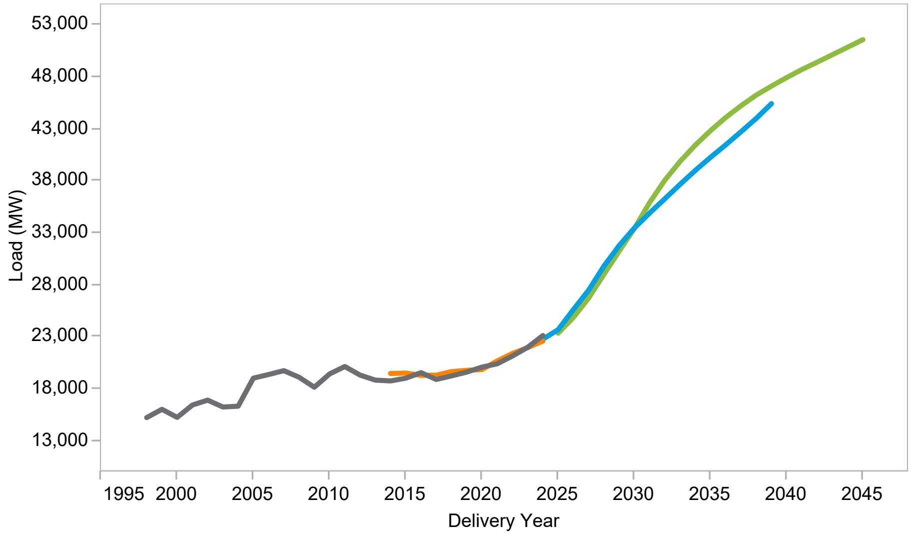


MSA

■ Bowling Green, KY
■ Cincinnati, OH-KY-IN
■ EKPC - Non-Metro
■ Elizabethtown-Fort Knox, KY
■ Huntington-Ashland, WV-KY-OH
■ Lexington-Fayette, KY
■ Louisville/Jefferson County, KY-IN

Dominion (DOM)

Summer Peak



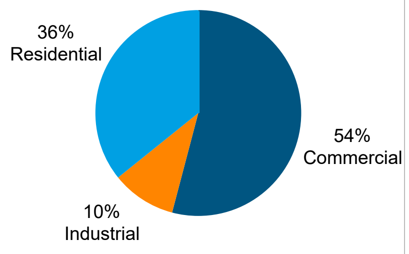
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	*77.0*
Avg Summer Max Temp	*97.0*
Avg Winter Daily Temp	*40.5*
Avg Winter Min Temp	*12.4*

Zonal 10/15/20 Year Load Growth

SUMMER	6.3%	4.9%	4.0%
WINTER	6.0%	4.7%	3.9%

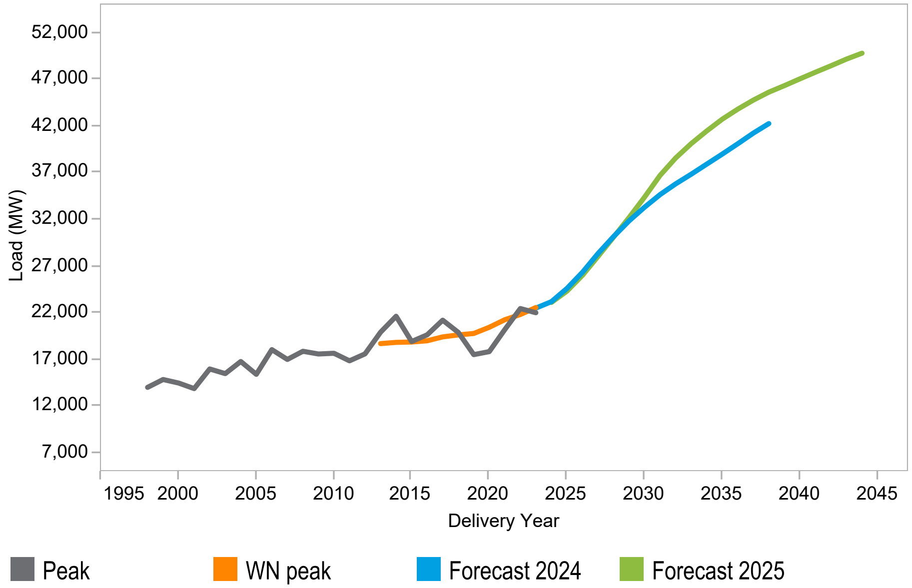
RCI Makeup



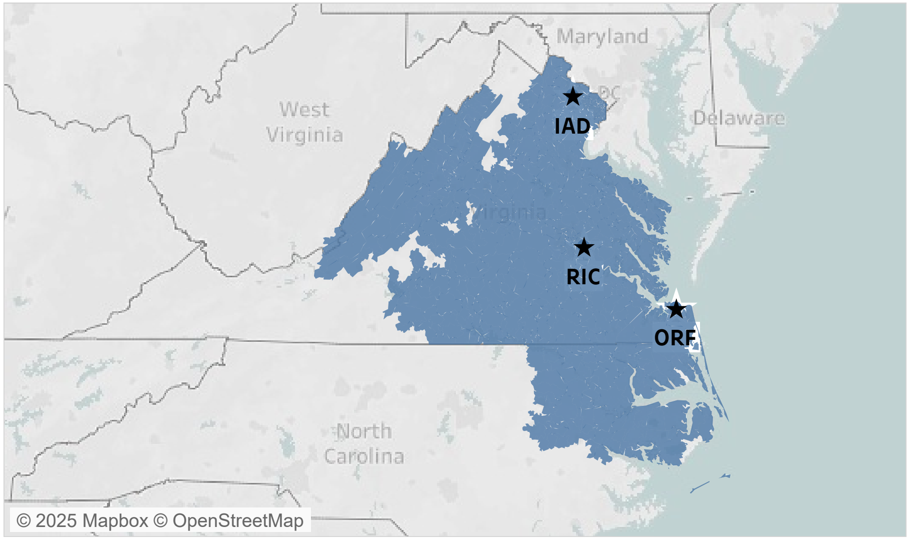
LDAs

PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



MSA

▨ Virginia Commonwealth Economics

2026

PJM Load Forecast Report

Posted Date: January 14, 2026

Prepared by PJM Resource Adequacy Planning Department

For Public Use

Contents

TO Zones and Sub-Zones

Abbreviation	Zone Name	Date Incorporated
AE	Atlantic Electric zone	
AEP	American Electric Power zone	Oct. 1, 2004
APP	Appalachian Power, sub-zone of AEP	
APS	Allegheny Power zone	April 1, 2002
ATSI	American Transmission Systems, Inc. zone	June 1, 2011
BGE	Baltimore Gas & Electric zone	
CEI	Cleveland Electric Illuminating, sub-zone of ATSI	
COMED	Commonwealth Edison zone	May 1, 2004
CSP	Columbus Southern Power, sub-zone of AEP	
DAYTON	Dayton Power & Light zone	Oct. 1, 2004
DEOK	Duke Energy Ohio/Kentucky zone	January 1, 2012
DLCO	Duquesne Lighting Company zone	January 1, 2005
DOM	Dominion Virginia Power zone	May 1, 2005
DPL	Delmarva Power & Light zone	
EKPC	East Kentucky Power Cooperative zone	June 1, 2013
FE-East	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)	
INM	Indiana Michigan Power, sub-zone of AEP	
JCPL	Jersey Central Power & Light zone	
KP	Kentucky Power, sub-zone of AEP	

Abbreviation	Zone Name	Date Incorporated
METED	Metropolitan Edison zone	
MP	Monongahela Power, sub-zone of APS	
OEP	Ohio Edison, sub-zone of ATSI	
OP	Ohio Power, sub-zone of AEP	
OVEC	Ohio Valley Electric Corporation zone	December 1, 2018
PECO	PECO Energy zone	
PED	Potomac Edison, sub-zone of APS	
PEPCO	Potomac Electric Power zone	
PL	PPL Electric Utilities, sub-zone of PLGroup	
PLGroup/PLGRP	Pennsylvania Power & Light zone	
PENLC	Pennsylvania Electric zone	
PP	Pennsylvania Power, sub-zone of ATSI	
PS	Public Service Electric & Gas zone	
RECO	Rockland Electric (East) zone	March 1, 2002
TOL	Toledo Edison, sub-zone of ATSI	
UGI	UGI Utilities, sub-zone of PLGroup	
WP	West Penn Power, sub-zone of APS	

Glossary

Term / Abbreviation	Definition
Battery Storage	Devices that enable generated energy to be stored and then released at a later time (Also Battery Energy Storage System – BESS)
Contractually Interruptible	Load management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
Direct Control	Load management achieved directly by a signal from a control center
Heating Load	The weather-sensitive portion of winter peak load
Net Energy	Net energy for load, measured as net generation of main generating units plus energy receipts minus energy deliveries
PRD	Price Responsive Demand
RCI Makeup	Residential, commercial and industrial breakdown of load
Unrestricted Peak	Peak load prior to any reduction for load management or voltage reduction
WN	Weather-normalized load produced by model run showing median historical seasonal peaks
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

Executive Summary

This report presents an independent load forecast prepared by PJM staff.

- The report includes a 20-year long-term forecast of peak loads, net energy, load management, distributed solar generation, plug-in electric vehicles and battery storage for each PJM zone, region, locational deliverability area (LDA) and the total RTO.

- All tables are now provided in Excel format for ease of use.

- Residential, commercial and industrial-sector models were estimated with data from 2015 through 2024. Hourly models were estimated with data from January 2016 to August 2025. Weather scenarios were simulated with data from years 1994 through 2024, generating 403 scenarios.

- The economic forecast used was Moody's Analytics' September 2025 release.

- The 2026 Long-Term Load Forecast is lower than the 2025 Long-Term Load Forecast in the near term through 2032 due to updates to the electric vehicle forecast, economics and large load adjustments. PJM, in collaboration with stakeholders, created and published a Load Adjustment Request Implementation (PDF) document to provide transparency in how PJM evaluates large load adjustment requests in the 2026 Long-Term Load Forecast. Near-term forecast years need "firm" commitments, such as Electric Service Obligation (ESO)/Construction Commitments (CC), while longer-term projects will be considered "non-firm" and will be derated because of their greater uncertainty. This distinction has brought large load adjustments down in the near-term forecast years compared to the 2025 Long-Term Load Forecast, as outlined in the Load Adjustment Requests Summary (PDF).

Energy Information Administration & Vendor Data

The Energy Information Administration (EIA) published an Annual Energy Outlook (AEO) update in 2025 based on revamped models and improvements to capture emerging technologies. The update of Itron's end-use data provides the basis for appliance saturation rates, efficiency and intensity and is consistent with the EIA's 2025 AEO. PJM obtained additional information from certain zones on residential saturation rates based on their own load research. Details on zones providing information are presented in the Supplement.

Consultant forecasts for behind-the-meter solar/battery and electric vehicles, including light, medium and heavy duty, were provided by S&P Global.

- The behind-the-meter solar/battery values were derived by PJM from a forecast obtained from SPGCI (PDF).
- The electric vehicle values were derived by PJM from a forecast obtained from SPGCI (PDF).

Compared to the 2025 Load Report, the 2026 PJM RTO summer peak forecast shows the following changes for three years of interest:

3rd IA	RPM Auction	RTEP Study
2026	**2028**	**2031**
-2,564 MW	**-4,414** MW	**-1,630** MW
-1.6%	*-2.6%*	*-0.8%*

Load Adjustments

The forecasts of the following zones have been adjusted to account for large, unanticipated load changes, market adjustments and peak shaving adjustments (see **Tables B-9** and **B-9b** and the Supplement for details):

Zones	Adjusted to account for:
AEP, ATSI, APS, BGE, COMED, DAYTON, DLCO, JCPL, METED, PECO, PEPCO, PL	Growth in data center load
DOM	Growth in data center load and a voltage optimization program
PS	Growth in data center load and port electrification
EKPC	A peak shaving program that commenced in the 2023 DY

Summer & Winter Summary

Summer Peak Load Growth for the PJM RTO

- Summer peak load growth is projected to average 3.6% per year over the next 10-year period and 2.4% over the next 20 years.
- Summer peak is forecasted to be 222,106 MW in 2036, a 10-year increase of 65,733 MW, and reaches 253,077 MW in 2046, a 20-year increase of 96,704 MW.
- Annualized 10-year growth rates for individual zones range from -0.2% to 6.4%, with a median of 1.6%.

Winter Peak Load Growth – PJM RTO

- Winter peak load growth is projected to average 4.0% per year over the next 10-year period and 2.7% over the next 20 years.
- The PJM RTO winter peak load in 2035/2036 is forecasted to be 204,650 MW, a 10-year increase of 66,980 MW, and reaches 236,693 MW in 2045/2046, a 20-year increase of 99,023 MW.
- Annualized 10-year growth rates for individual zones range from 0.0% to 6.5%, with a median of 2.1%.

Net Energy Load Growth – PJM RTO

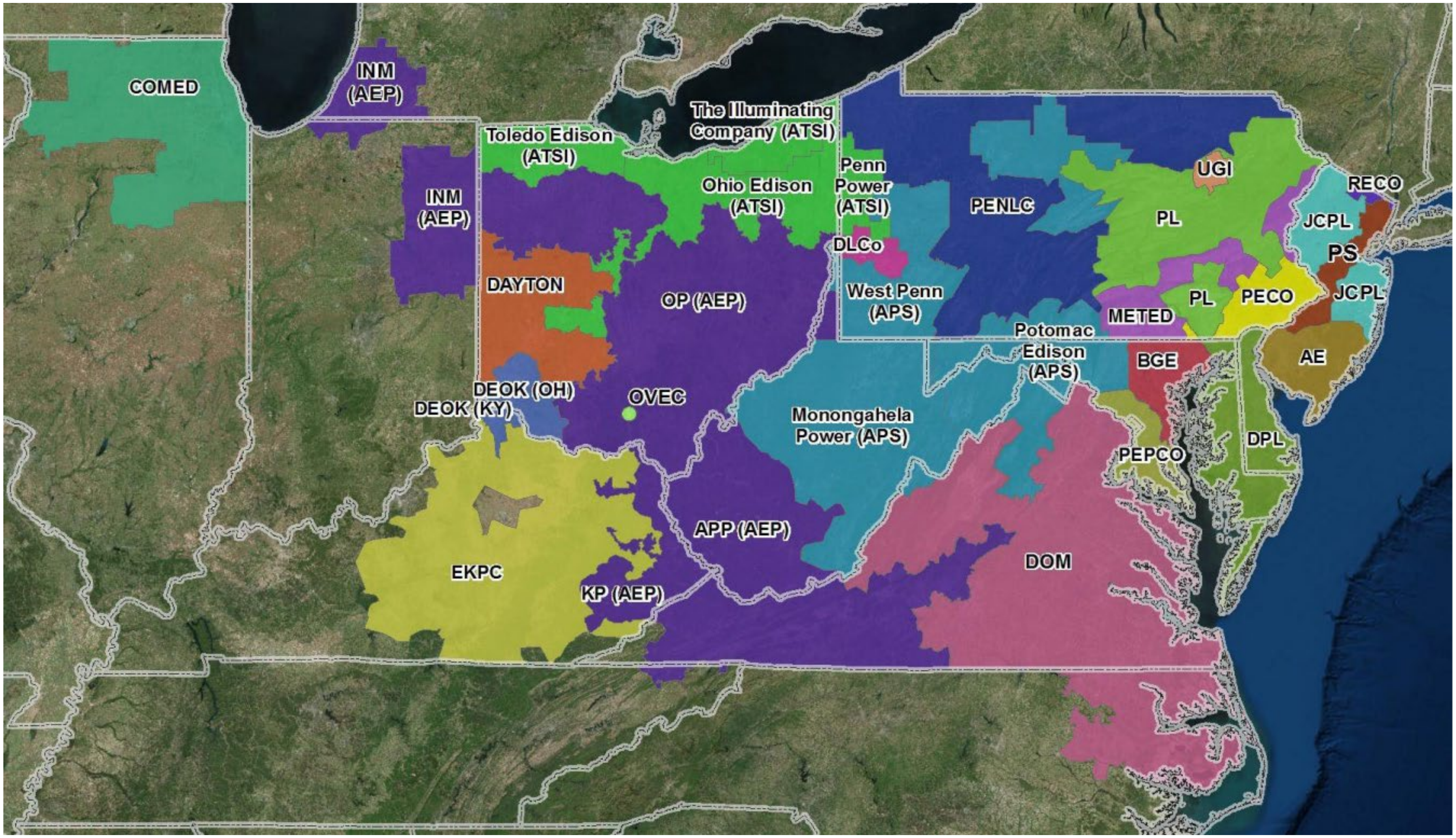
- Net energy load growth is projected to average 5.3% per year over the next 10-year period and 3.4% over the next 20 years.
- Total PJM RTO energy is forecasted to be 1,437,629 GWh in 2036, a 10-year increase of 581,554 GWh, and reaches 1,667,075 GWh in 2046, a 20-year increase of 811,000 GWh.
- Annualized 10-year growth rates for individual zones range from 0.1% to 8.8%, with a median of 2.5%.

NOTE:

Unless noted otherwise, all peak and energy values are non-coincident, unrestricted peaks, which represent the peak load or net energy after reductions for distributed solar generation and battery storage (in summer peak), after additions for plug-in electric vehicles and before reductions for load management impacts.

All compound growth rates are calculated from the first year of the forecast.

PJM Map


COMED
INM (AEP)
Toledo Edison (ATSI)
The Illuminating Company (ATSI)
INM (AEP)
Ohio Edison (ATSI)
Penn Power (ATSI)
UGI
RECO
PENLC
PL
JCPL
DLCo
PS
DAYTON
OP (AEP)
West Penn (APS)
PL
PECO
JCPL
METED
Potomac Edison (APS)
BGE
AE
DEOK (OH)
DEOK (KY)
OVEC
Monongahela Power (APS)
DPL
PEPCO
APP (AEP)
DOM
EKPC
KP (AEP)

NEET MA Exhibit AG-8

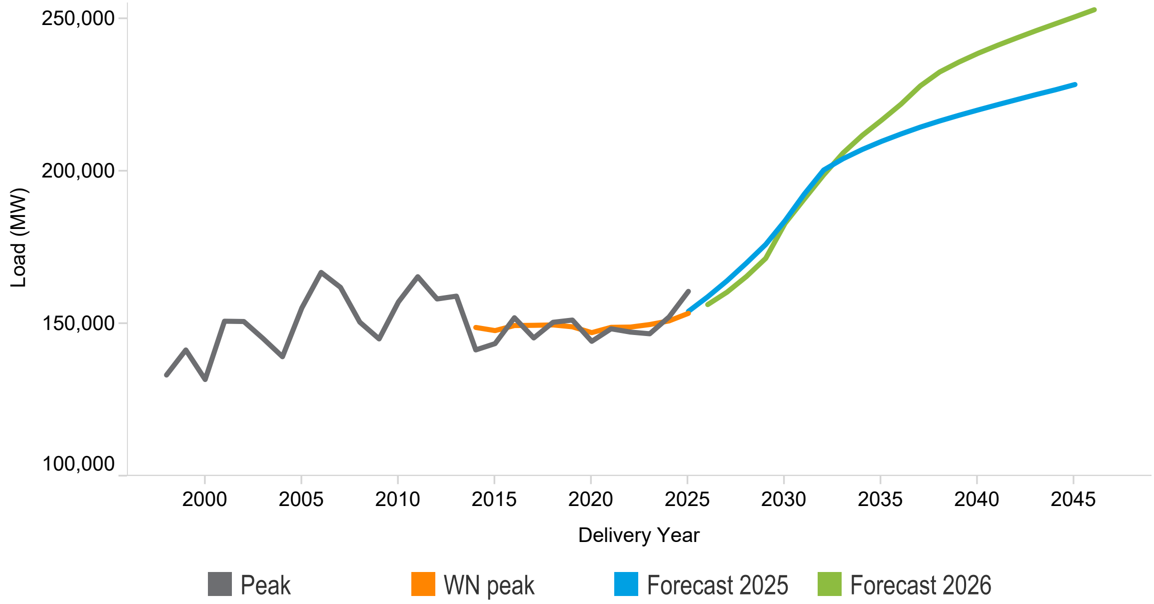
PJM RTO, LDA and Zonal Dashboards

Click below to jump to an LDA's or PJM Zone's data page.

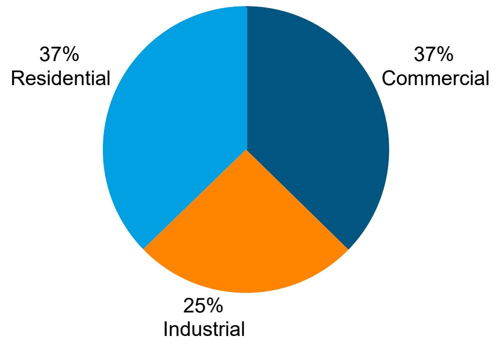
PJM RTO
MAAC
E-MAAC
S-MAAC
PJM Western
AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PS
RECO
UGI
AEP
APS
ATSI
COMED
DAYTON
DEOK
DLCO
EKPC
DOM

PJM RTO

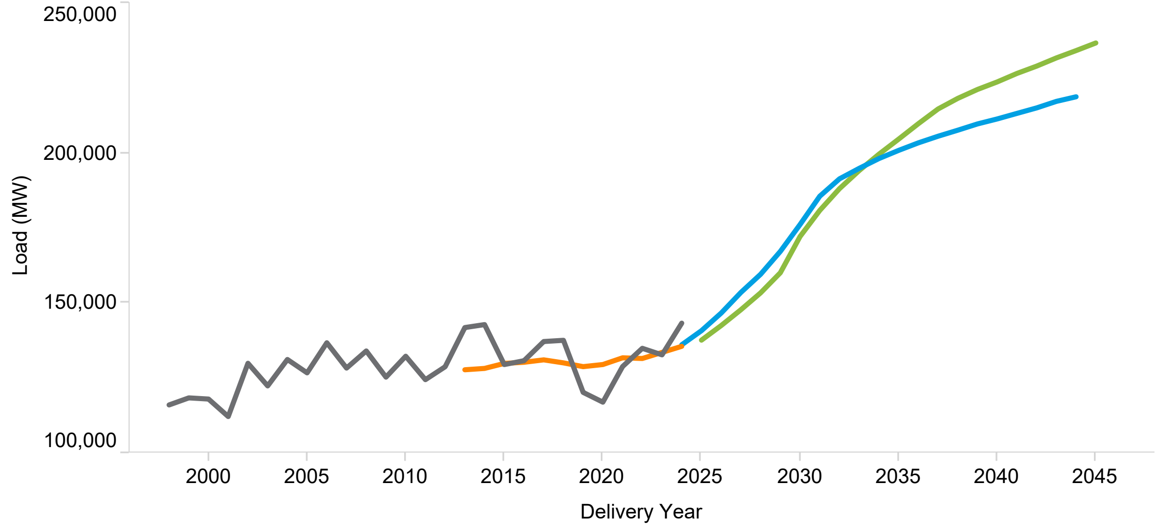
Summer Peak



RCI Makeup



Winter Peak



Weather - Annual Average 1994-2024

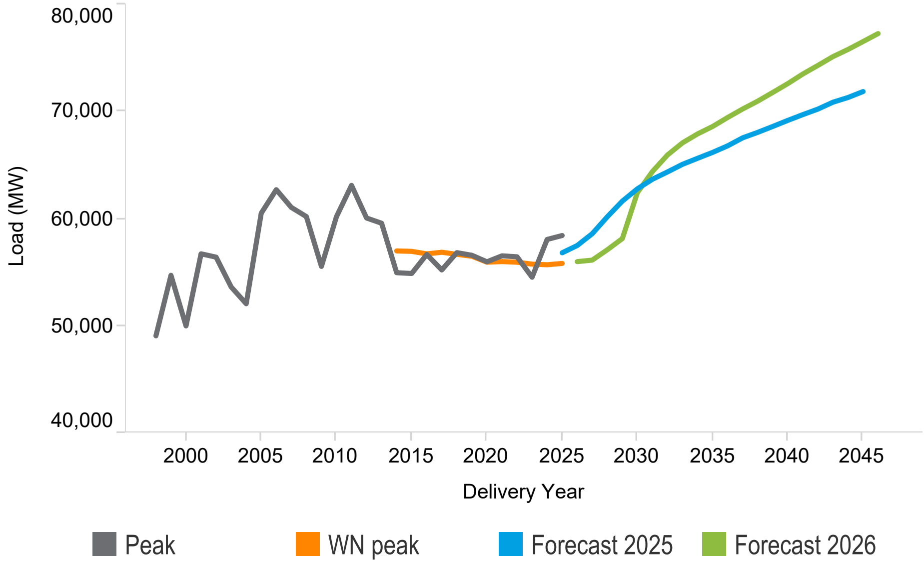
Avg Summer Daily Temp	*74.3*
Avg Summer Max Temp	*95.2*
Avg Winter Daily Temp	*34.4*
Avg Winter Min Temp	*4.2*

Zonal 10/15/20 Year Load Growth

SUMMER	3.6%	2.9%	2.4%
WINTER	4.0%	3.3%	2.7%

PJM Mid-Atlantic (MAAC)

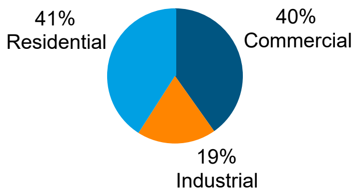
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*74.8*
Avg Summer Max Temp	*96.3*
Avg Winter Daily Temp	*35.2*
Avg Winter Min Temp	*6.7*

RCI Makeup



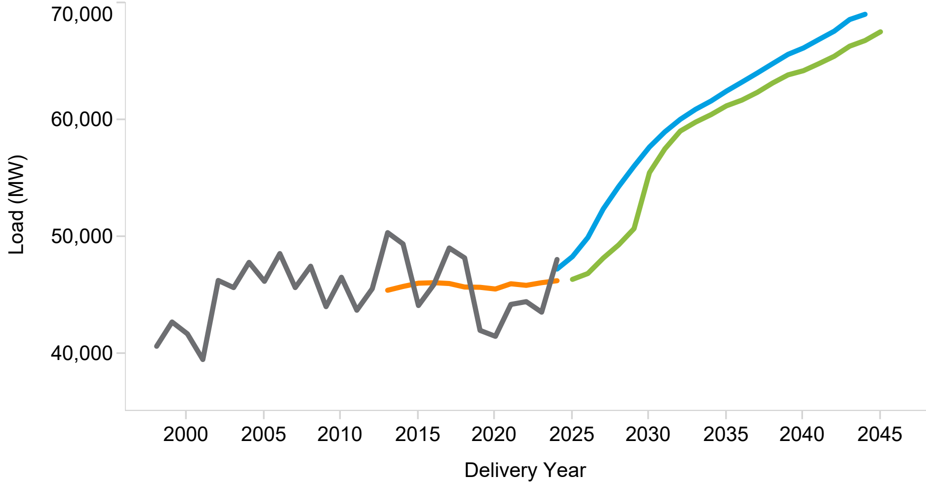
Zonal 10/15/20 Year Load Growth

SUMMER	2.2%	1.8%	1.6%
WINTER	2.8%	2.2%	1.9%

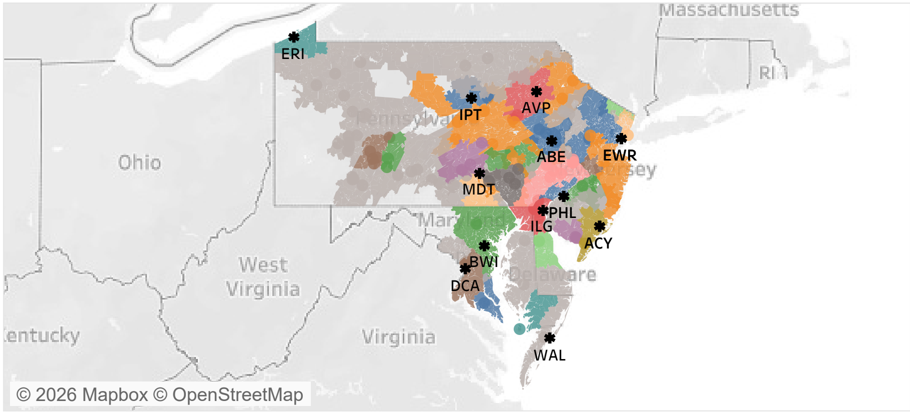
Zones

AE BGE DPL JCPL METED PECO PENLC PEPCO PL PS RECO UGI

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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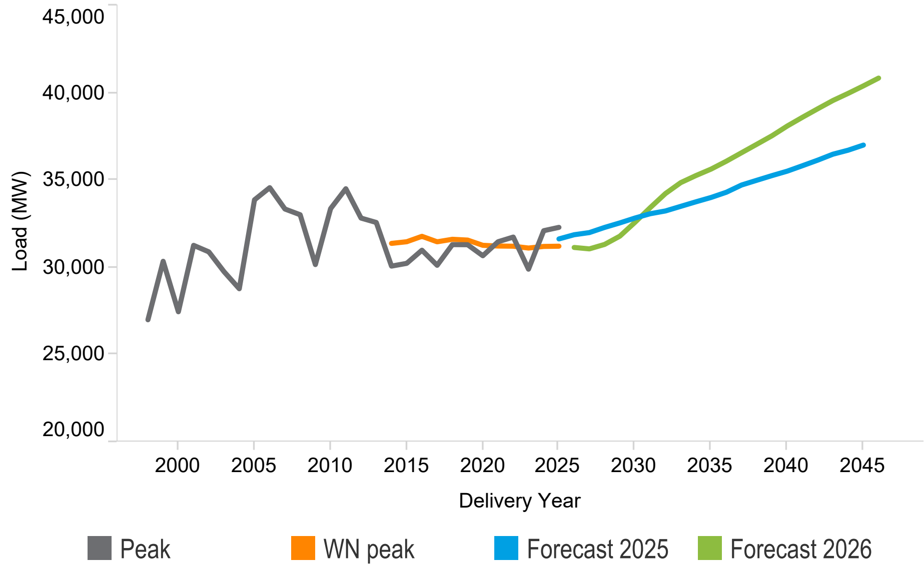
LDAs

CENTRAL MID-ATLANTIC EASTERN MID-ATLANTIC SOUTHERN MID-ATLANTIC WESTERN MID-ATLANTIC

PJM Eastern Mid-Atlantic (E-MAAC)

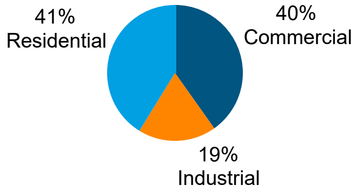
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*75.7*
Avg Summer Max Temp	*97.4*
Avg Winter Daily Temp	*36.5*
Avg Winter Min Temp	*8.0*

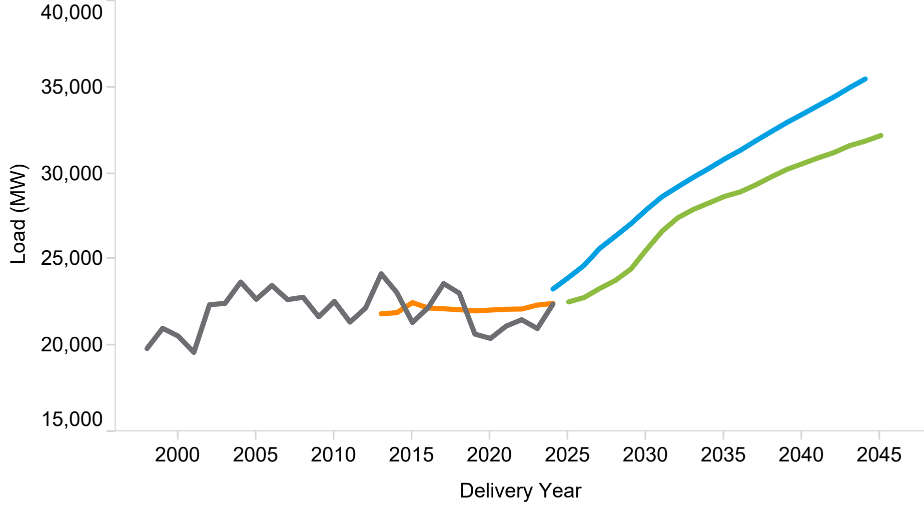
RCI Makeup



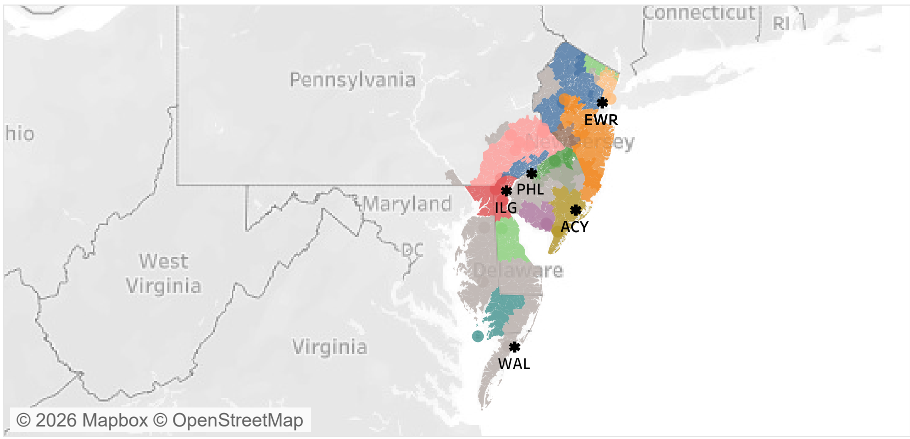
Zonal 10/15/20 Year Load Growth

SUMMER	1.5%	1.4%	1.4%
WINTER	2.4%	2.1%	1.8%

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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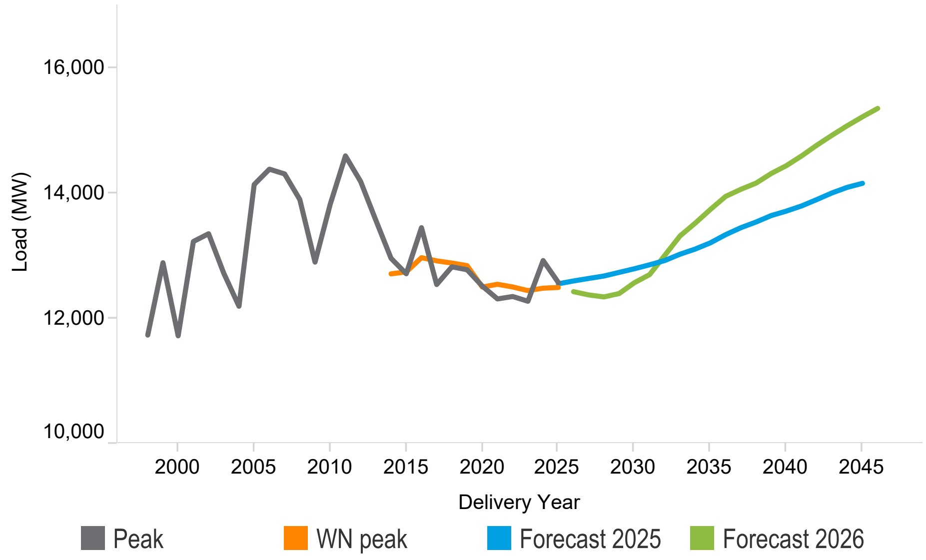
Zones

AE DPL JCPL PECO PS RECO

PJM Southern Mid-Atlantic (S-MAAC)

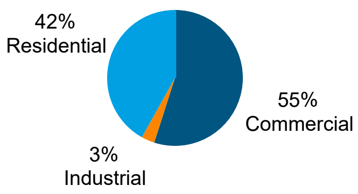
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*77.1*
Avg Summer Max Temp	*98.1*
Avg Winter Daily Temp	*38.2*
Avg Winter Min Temp	*10.6*

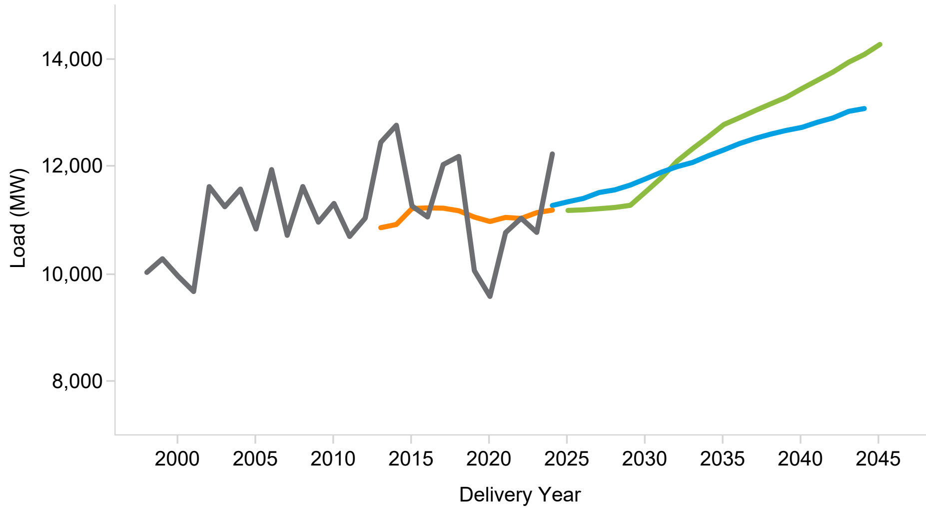
RCI Makeup



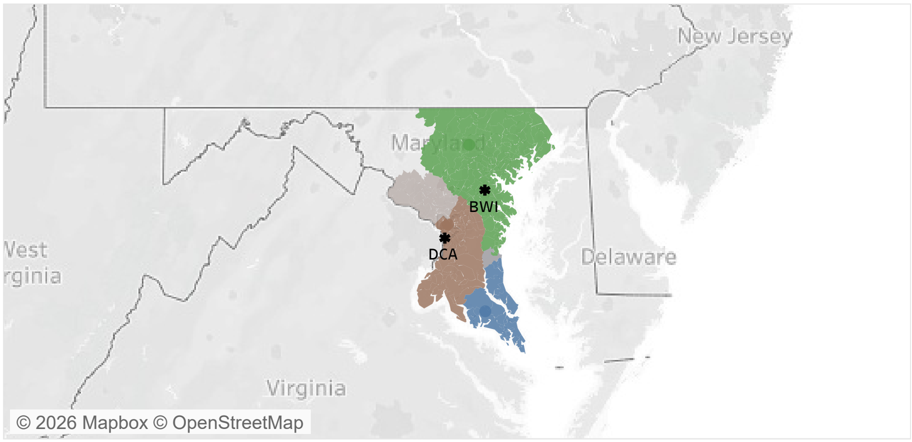
Zonal 10/15/20 Year Load Growth

SUMMER	1.2%	1.1%	1.1%
WINTER	1.3%	1.2%	1.2%

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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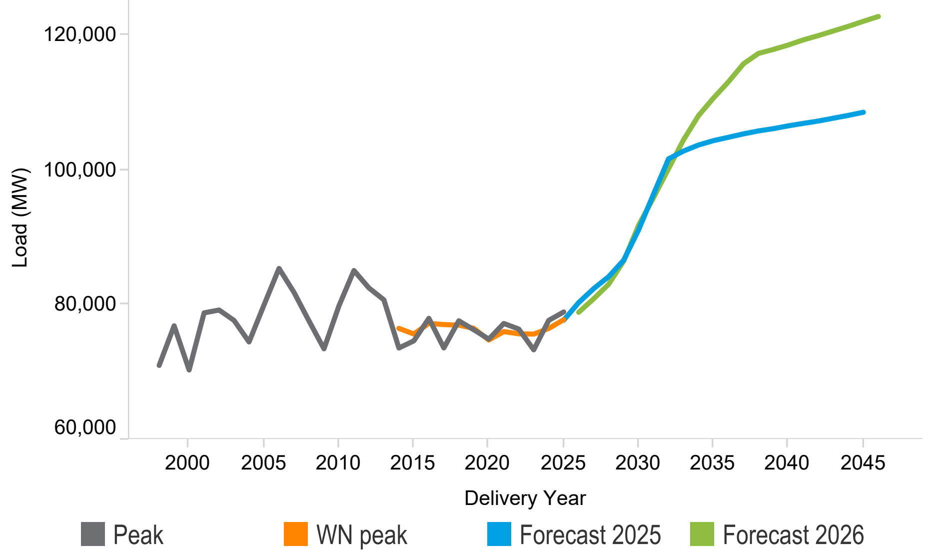
Zones

BGE PEPCO

PJM Western

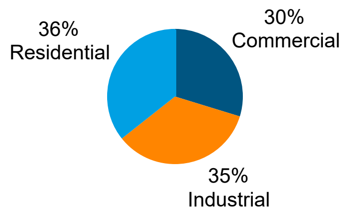
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*93.3*
Avg Winter Daily Temp	*32.4*
Avg Winter Min Temp	*-0.6*

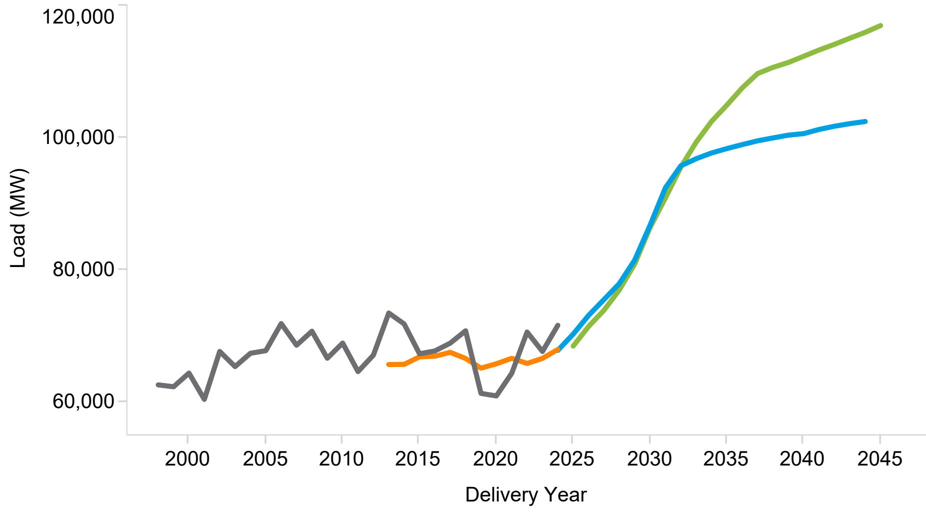
RCI Makeup



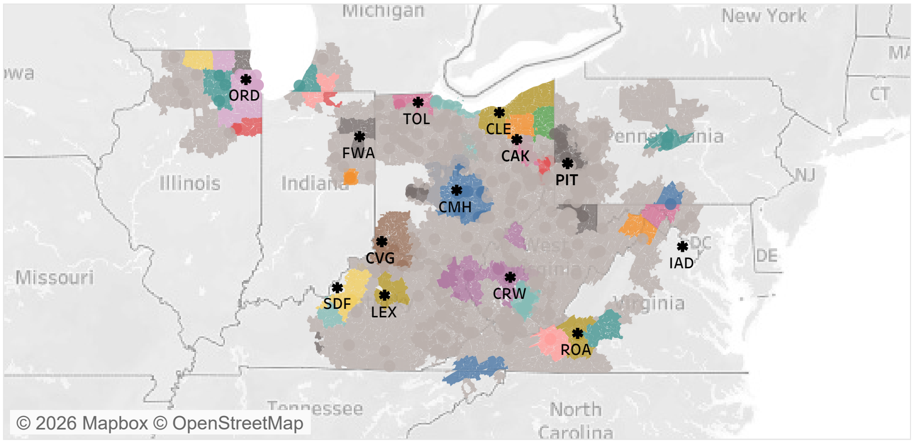
Zonal 10/15/20 Year Load Growth

SUMMER	3.7%	2.8%	2.2%
WINTER	4.3%	3.3%	2.7%

Winter Peak



Metropolitan Statistical Areas and Weather Stations

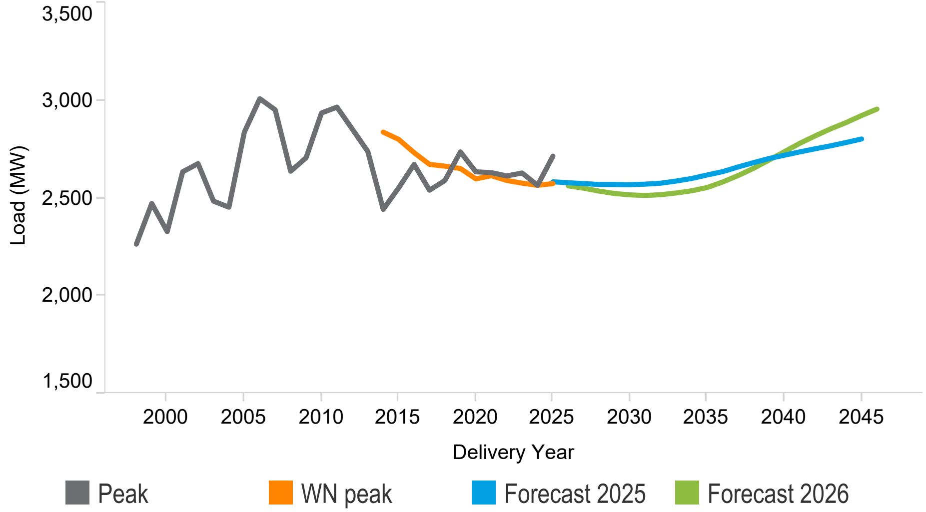


Zones

AEP APS ATSI COMED DAYTON DEOK DLCO EKPC OVEC

Atlantic Electric (AE)

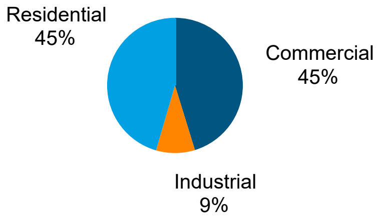
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*74.4*
Avg Summer Max Temp	*97.0*
Avg Winter Daily Temp	*36.8*
Avg Winter Min Temp	*6.3*

RCI Makeup



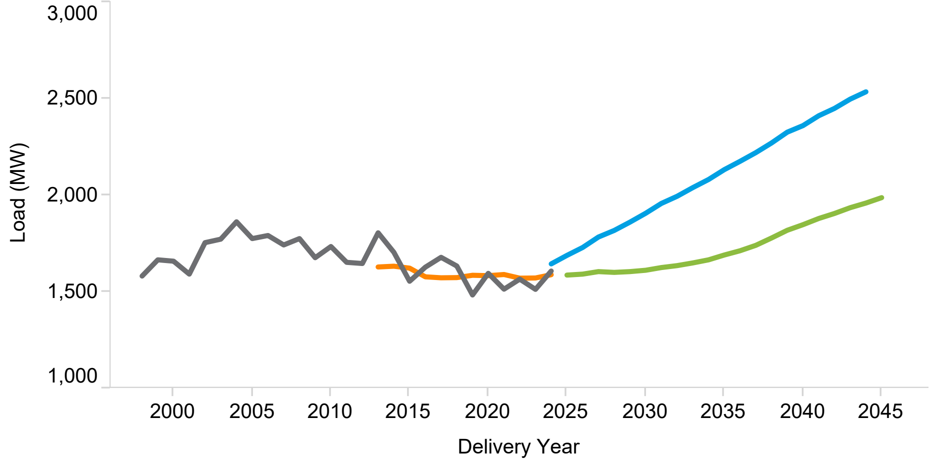
Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.5%	0.7%
WINTER	0.6%	1.0%	1.1%

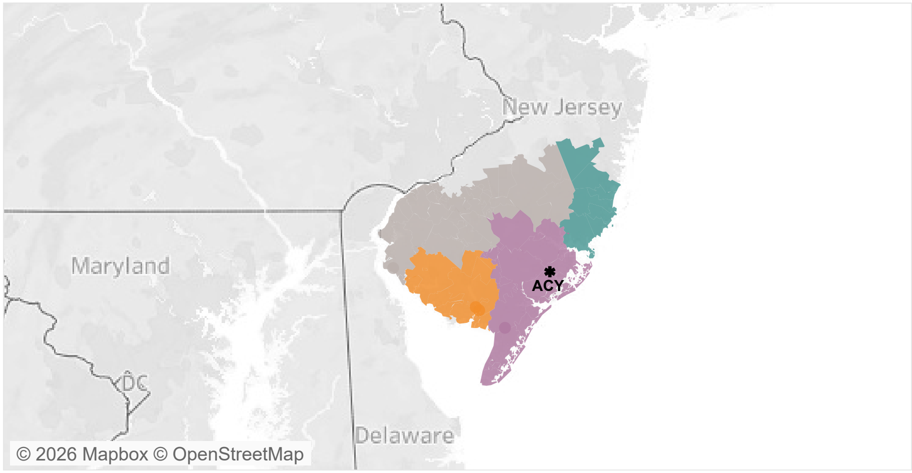
LDAs

PJM MID-ATLANTIC
EASTERN MID-ATLANTIC
PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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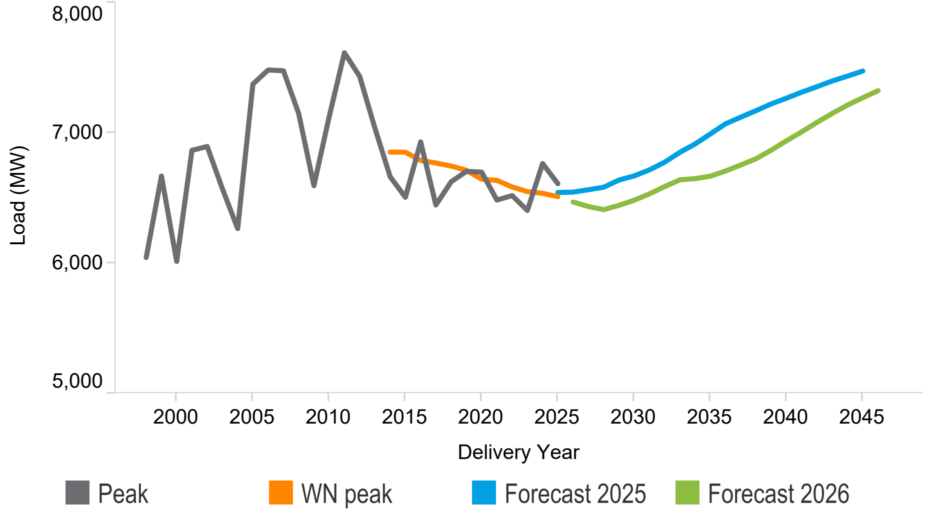
MSA

AE - Non-Metro	Vineland-Bridgeton, NJ
Atlantic City-Hammonton, NJ	Lakewood-New Brunswick, NJ

Baltimore Gas & Electric (BGE)

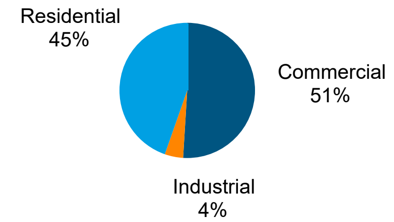
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*76.1*
Avg Summer Max Temp	*98.2*
Avg Winter Daily Temp	*37.0*
Avg Winter Min Temp	*8.2*

RCI Makeup



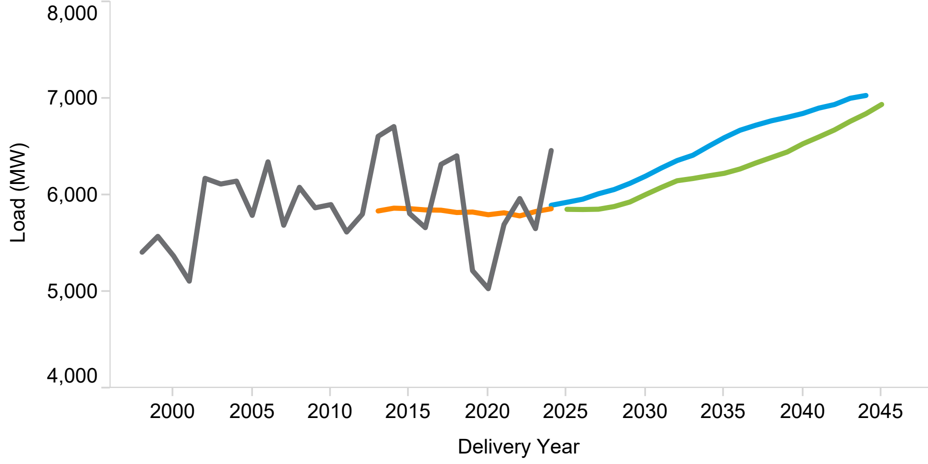
Zonal 10/15/20 Year Load Growth

SUMMER	0.4%	0.5%	0.6%
WINTER	0.6%	0.7%	0.9%

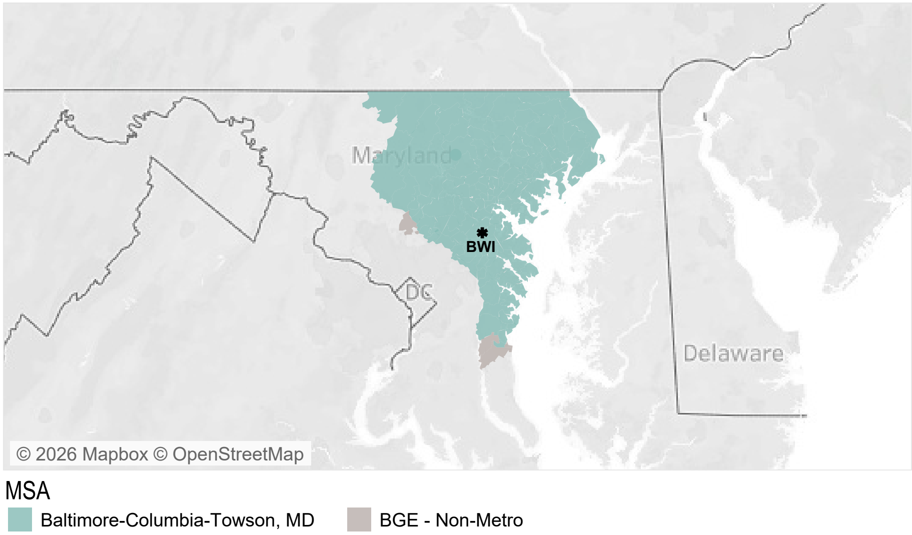
LDAs

PJM MID-ATLANTIC
CENTRAL MID-ATLANTIC
SOUTHERN MID-ATLANTIC
PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



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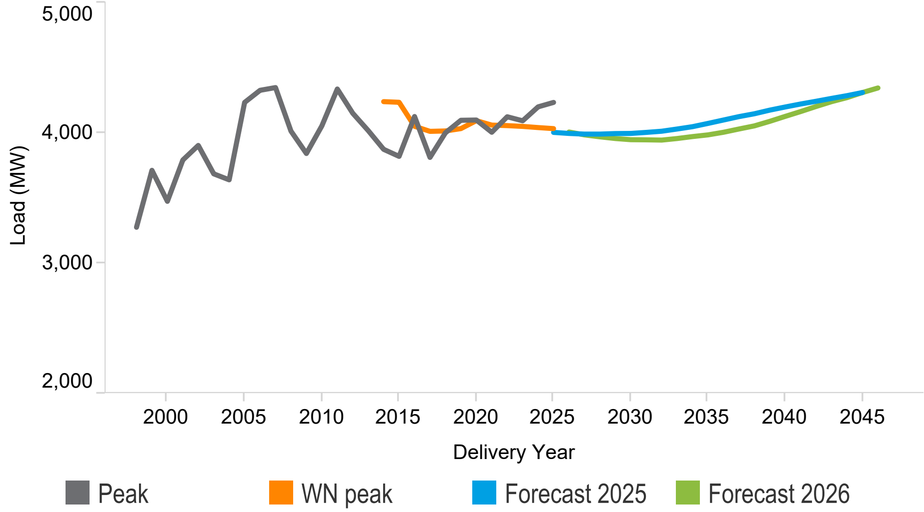
Delmarva Power & Light (DPL)

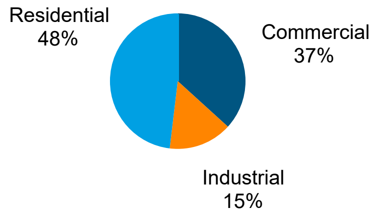
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*75.5*
Avg Summer Max Temp	*95.0*
Avg Winter Daily Temp	*37.3*
Avg Winter Min Temp	*9.7*

RCI Makeup



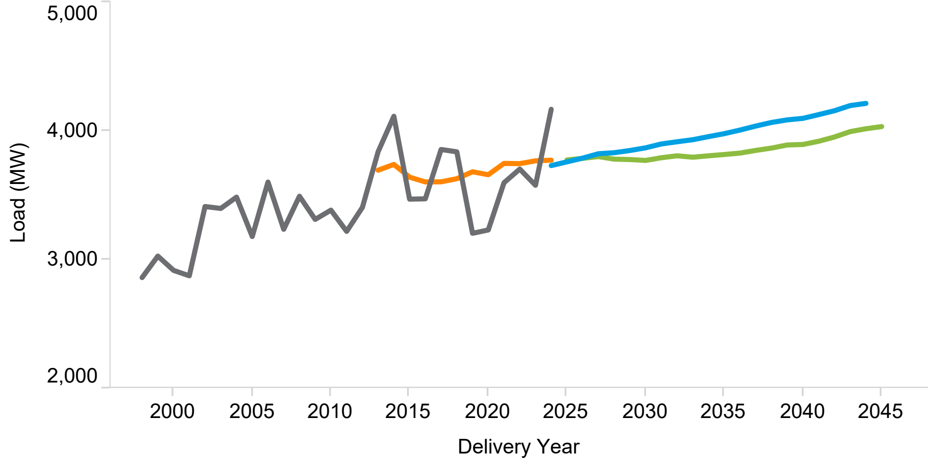
Zonal 10/15/20 Year Load Growth

SUMMER	0.0%	0.3%	0.4%
WINTER	0.1%	0.2%	0.3%

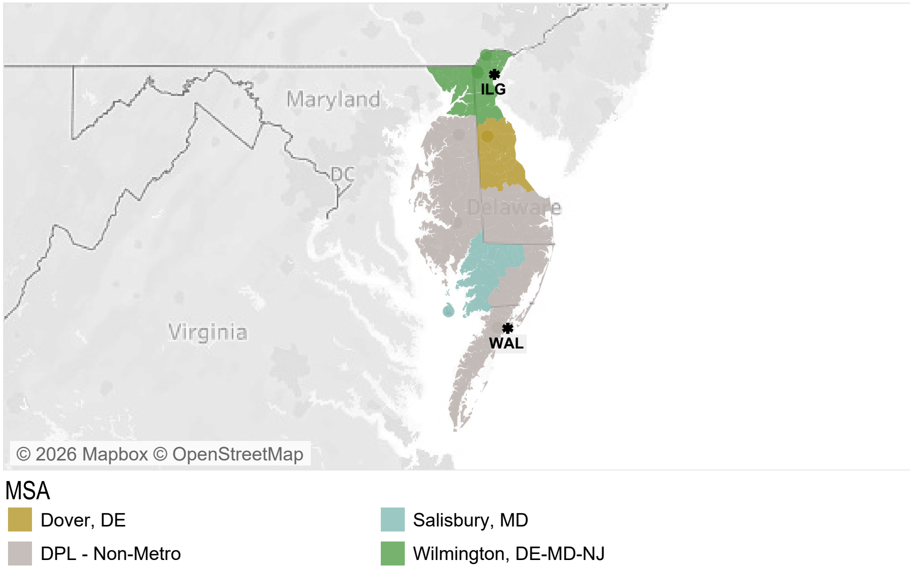
LDAs

PJM MID-ATLANTIC
EASTERN MID-ATLANTIC
PJM RTO

Winter Peak

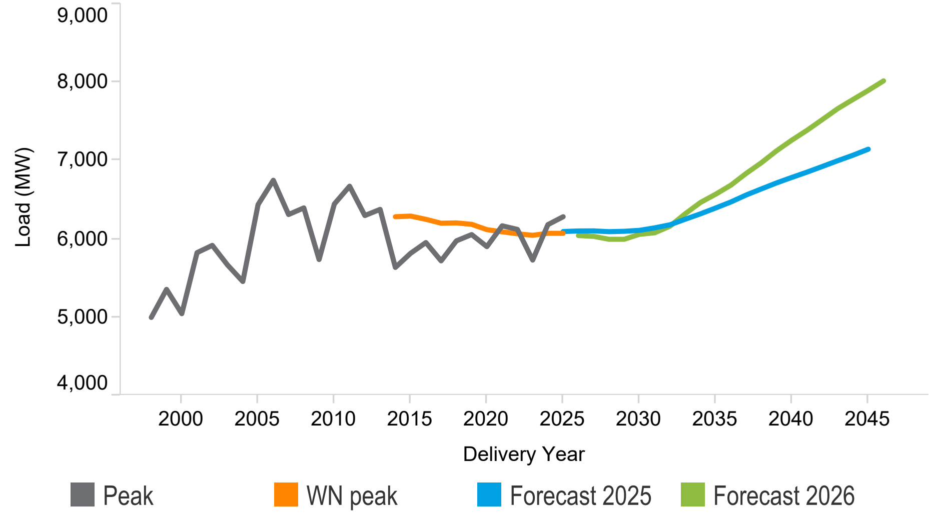


Metropolitan Statistical Areas and Weather Stations



Jersey Central Power & Light (JCPL)

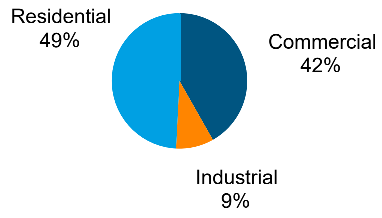
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*75.7*
Avg Summer Max Temp	*97.9*
Avg Winter Daily Temp	*36.2*
Avg Winter Min Temp	*7.7*

RCI Makeup



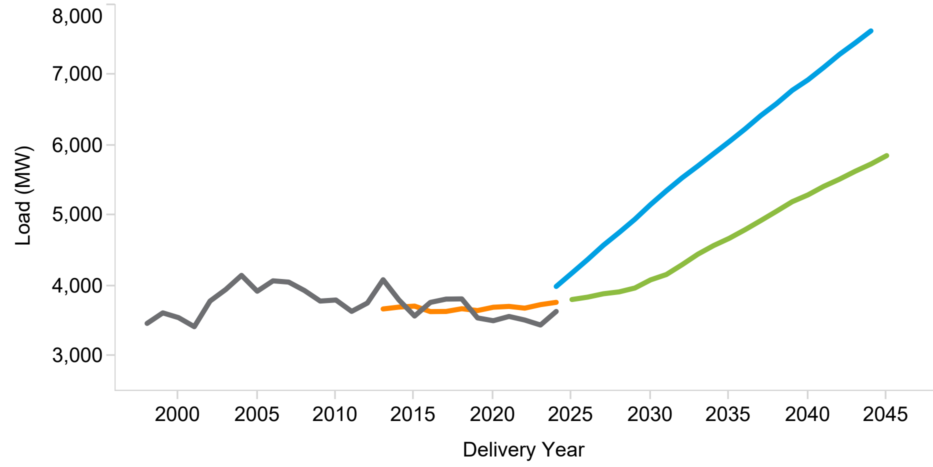
Zonal 10/15/20 Year Load Growth

SUMMER	1.0%	1.4%	1.4%
WINTER	2.1%	2.2%	2.2%

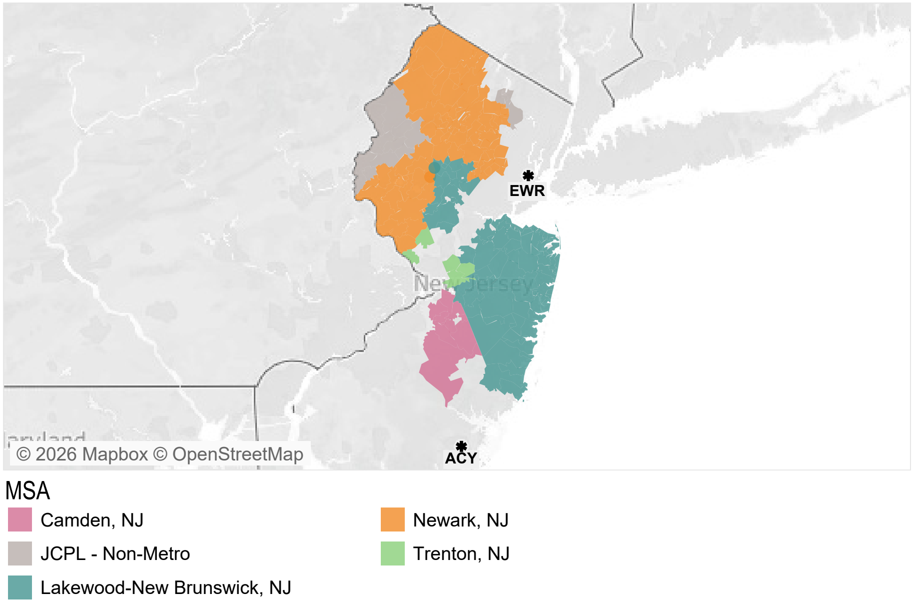
LDAs

PJM MID-ATLANTIC
EASTERN MID-ATLANTIC
GPU
PJM RTO

Winter Peak

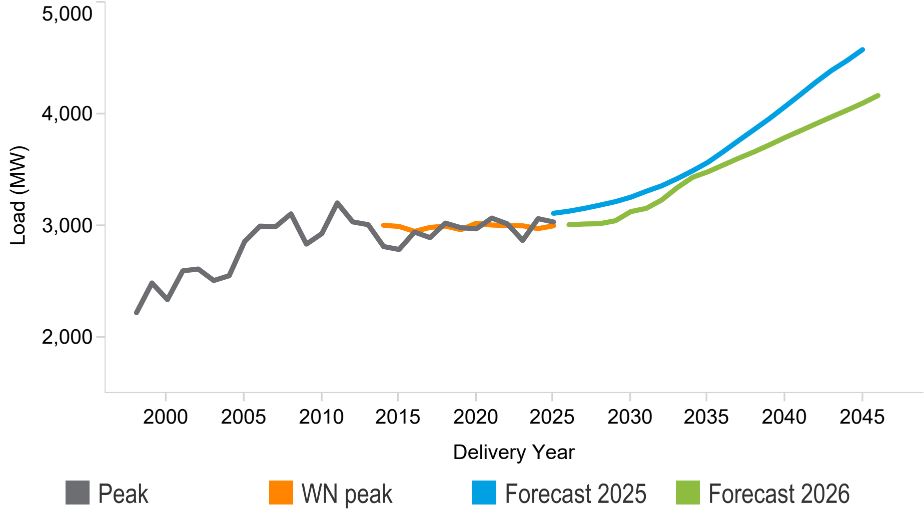


Metropolitan Statistical Areas and Weather Stations



Metropolitan Edison (METED)

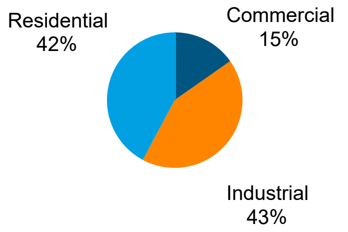
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*74.7*
Avg Summer Max Temp	*95.7*
Avg Winter Daily Temp	*34.6*
Avg Winter Min Temp	*6.7*

RCI Makeup



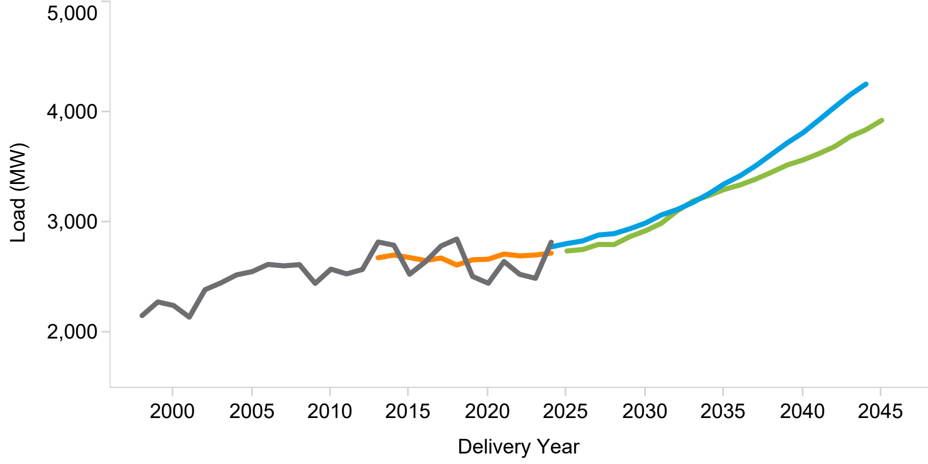
Zonal 10/15/20 Year Load Growth

SUMMER	1.6%	1.7%	1.6%
WINTER	1.9%	1.8%	1.8%

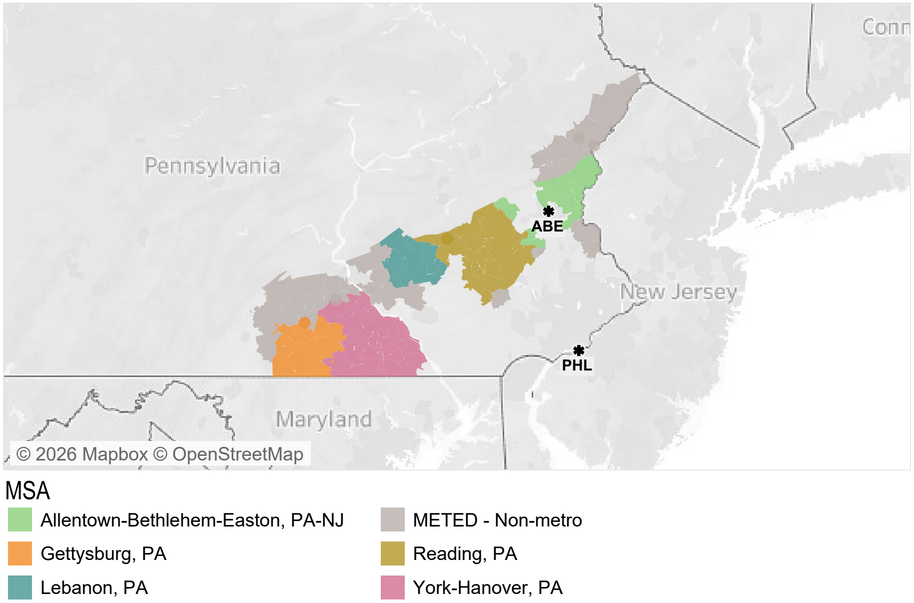
LDAs

PJM MID-ATLANTIC
CENTRAL MID-ATLANTIC
WESTERN MID-ATLANTIC
GPU
PJM RTO

Winter Peak

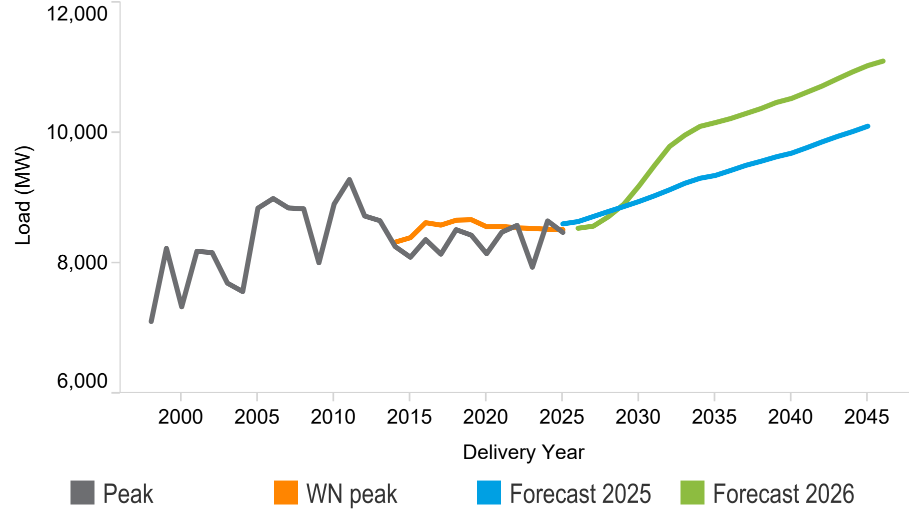


Metropolitan Statistical Areas and Weather Stations



PECO Energy (PECO)

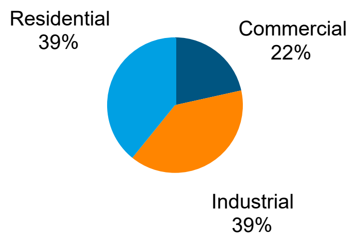
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*76.6*
Avg Summer Max Temp	*97.0*
Avg Winter Daily Temp	*36.9*
Avg Winter Min Temp	*9.5*

RCI Makeup



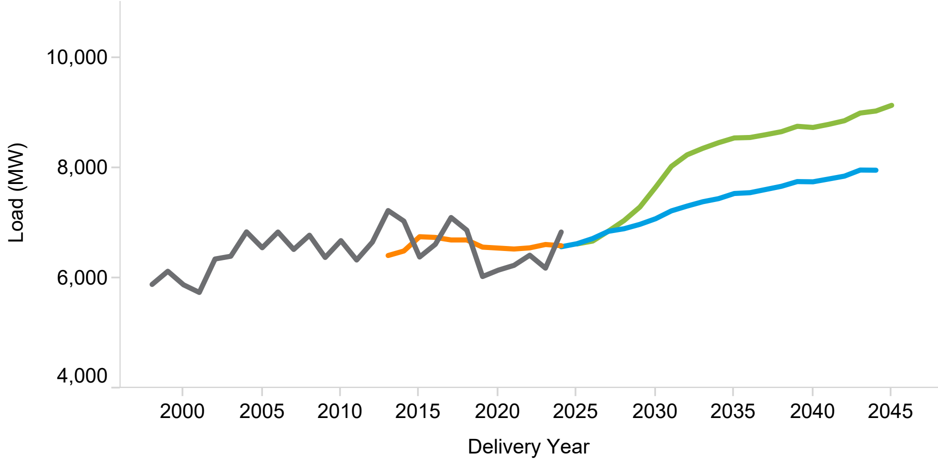
Zonal 10/15/20 Year Load Growth

SUMMER	1.8%	1.5%	1.3%
WINTER	2.6%	1.9%	1.6%

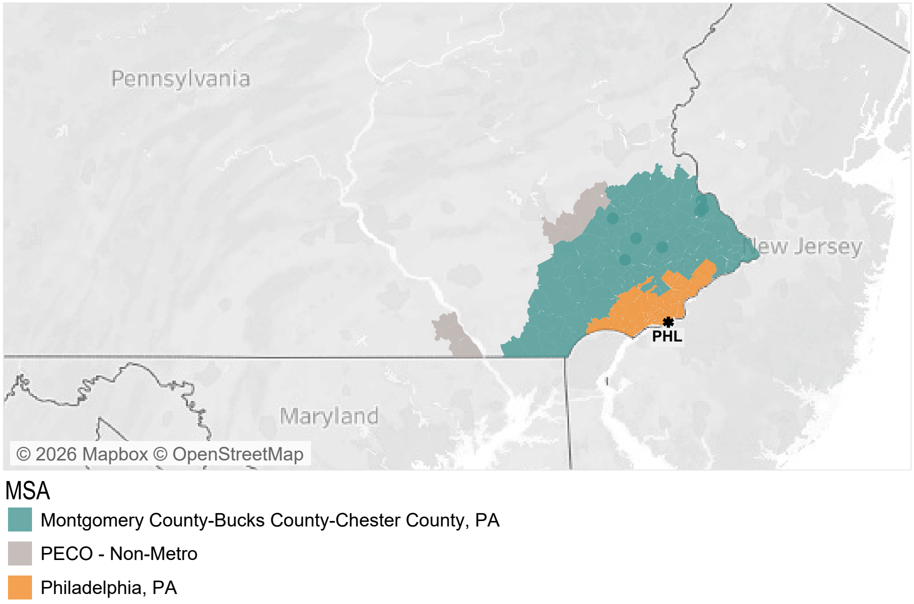
LDAs

PJM MID-ATLANTIC
EASTERN MID-ATLANTIC
PJM RTO

Winter Peak

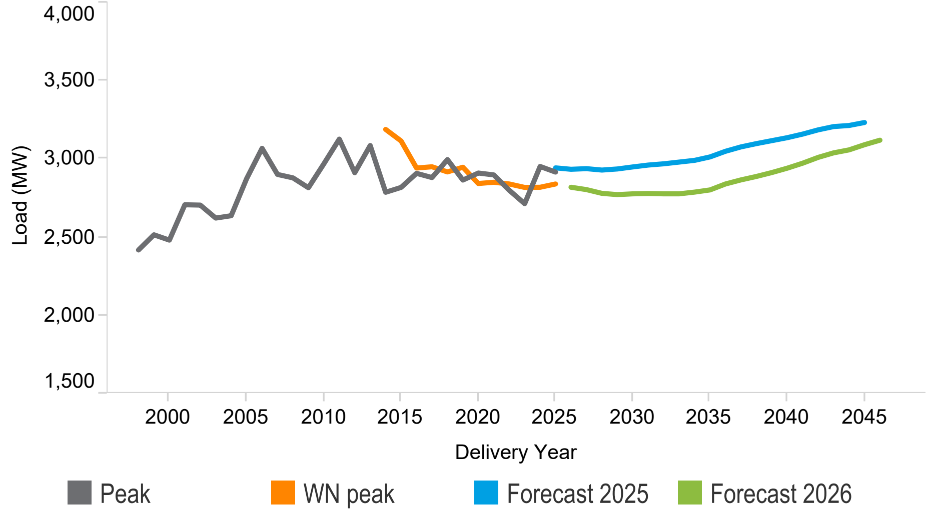


Metropolitan Statistical Areas and Weather Stations



Pennsylvania Electric Company (PENLC)

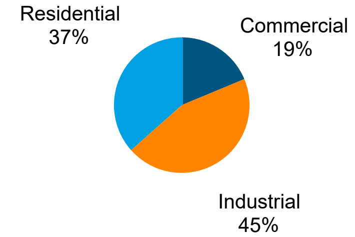
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*71.1*
Avg Summer Max Temp	*91.7*
Avg Winter Daily Temp	*30.6*
Avg Winter Min Temp	*2.3*

RCI Makeup



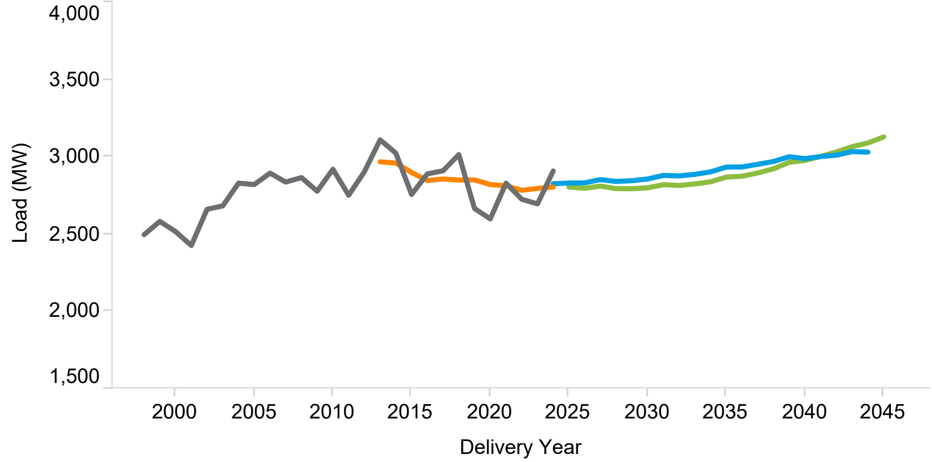
Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.4%	0.5%
WINTER	0.2%	0.4%	0.5%

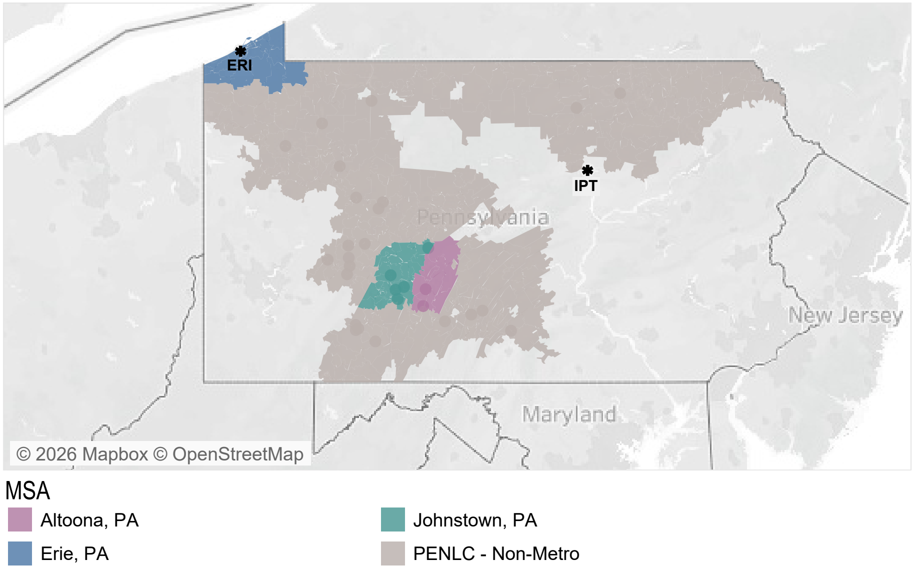
LDAs

PJM MID-ATLANTIC
WESTERN MID-ATLANTIC
GPU
PJM RTO

Winter Peak

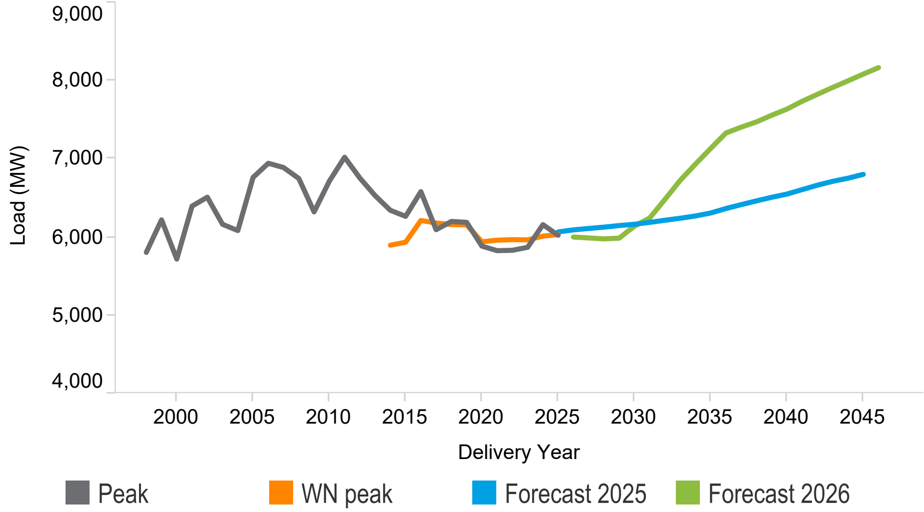


Metropolitan Statistical Areas and Weather Stations



Potomac Electric Power (PEPCO)

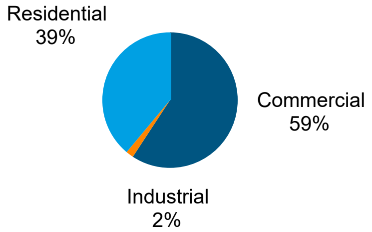
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*78.1*
Avg Summer Max Temp	*98.1*
Avg Winter Daily Temp	*39.4*
Avg Winter Min Temp	*13.0*

RCI Makeup



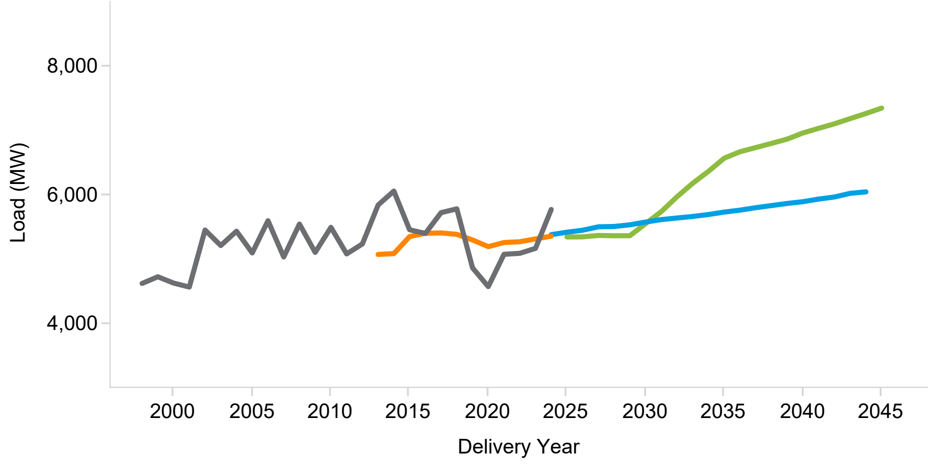
Zonal 10/15/20 Year Load Growth

SUMMER	2.0%	1.7%	1.6%
WINTER	2.1%	1.8%	1.6%

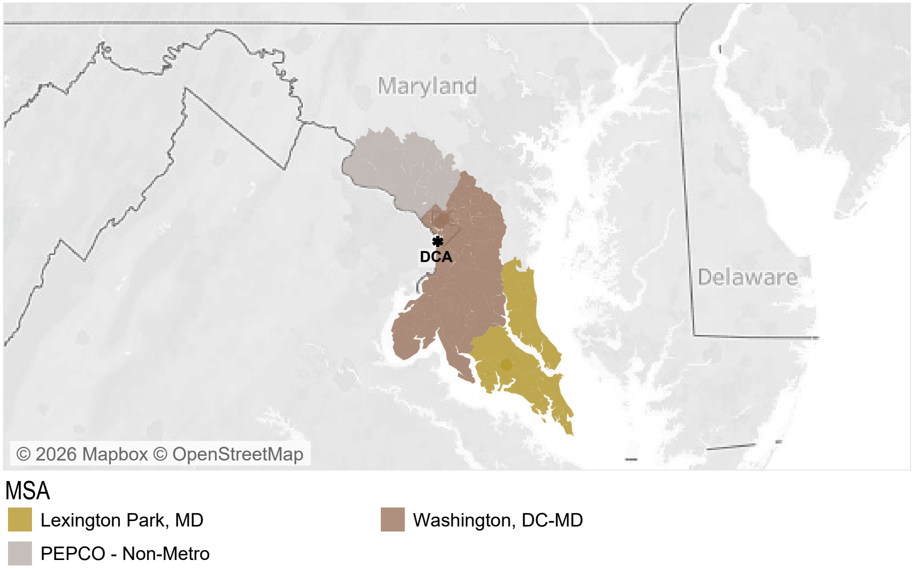
LDAs

PJM MID-ATLANTIC
CENTRAL MID-ATLANTIC
SOUTHERN MID-ATLANTIC
PJM RTO

Winter Peak

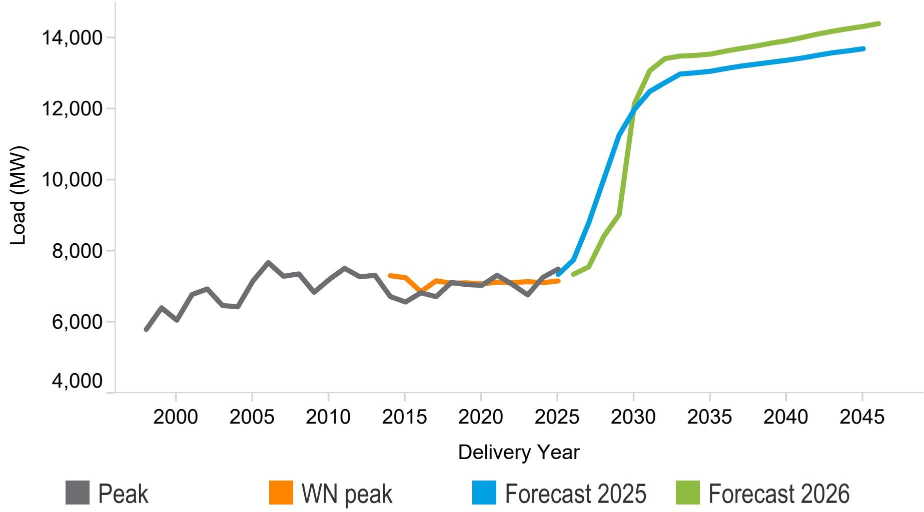


Metropolitan Statistical Areas and Weather Stations



PPL Electric Utilities (PL)

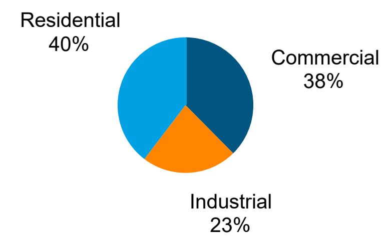
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*72.4*
Avg Summer Max Temp	*94.2*
Avg Winter Daily Temp	*31.8*
Avg Winter Min Temp	*2.9*

RCI Makeup



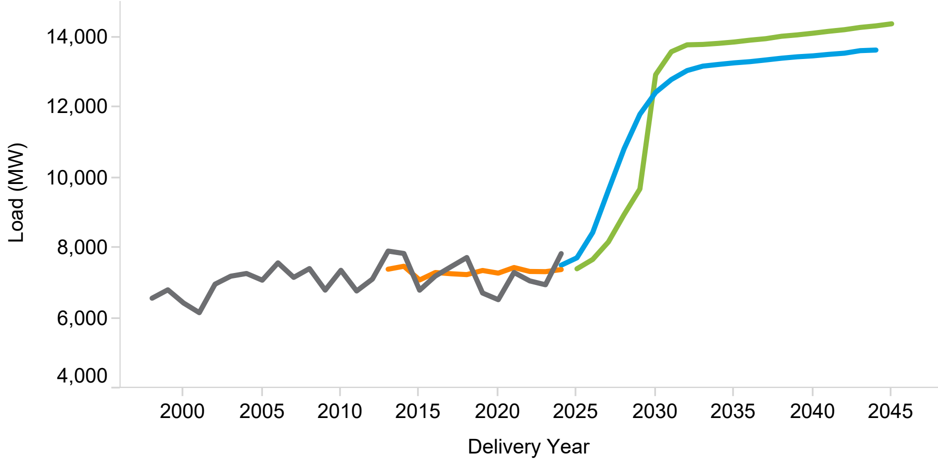
Zonal 10/15/20 Year Load Growth

SUMMER	6.4%	4.4%	3.4%
WINTER	6.5%	4.4%	3.4%

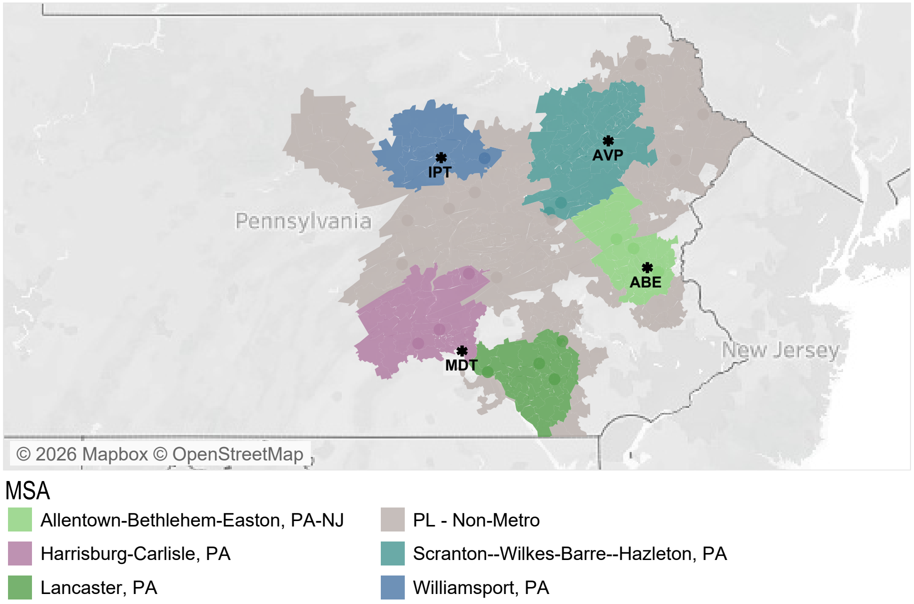
LDAs

PJM MID-ATLANTIC
CENTRAL MID-ATLANTIC
WESTERN MID-ATLANTIC
PLGRP
PJM RTO

Winter Peak

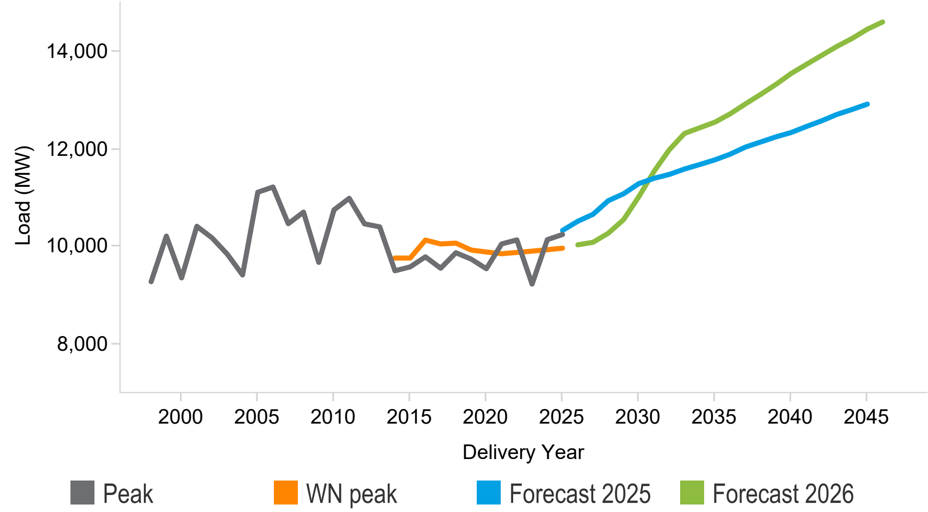


Metropolitan Statistical Areas and Weather Stations



Public Service Electric & Gas (PS)

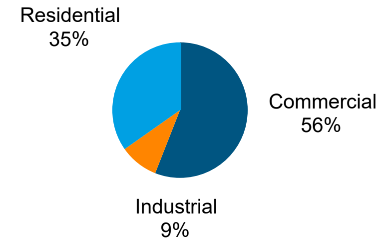
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*76.1*
Avg Summer Max Temp	*98.7*
Avg Winter Daily Temp	*35.9*
Avg Winter Min Temp	*7.6*

RCI Makeup



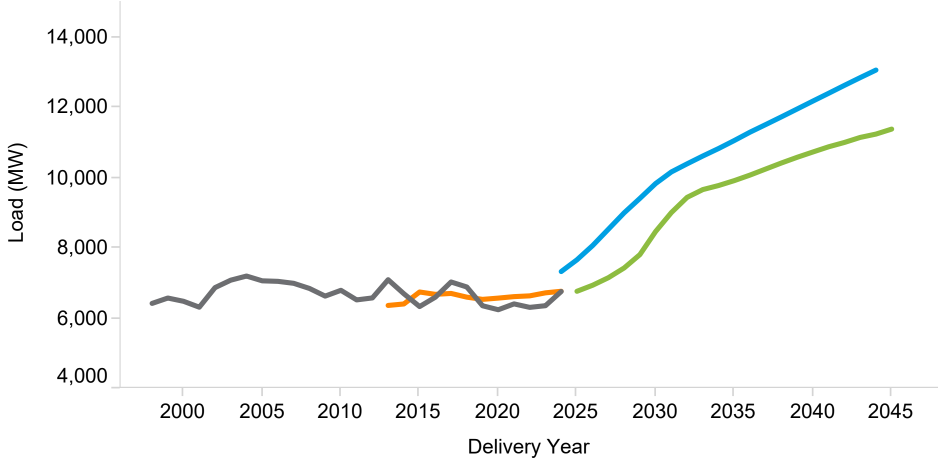
Zonal 10/15/20 Year Load Growth

SUMMER	2.4%	2.1%	1.9%
WINTER	3.9%	3.1%	2.6%

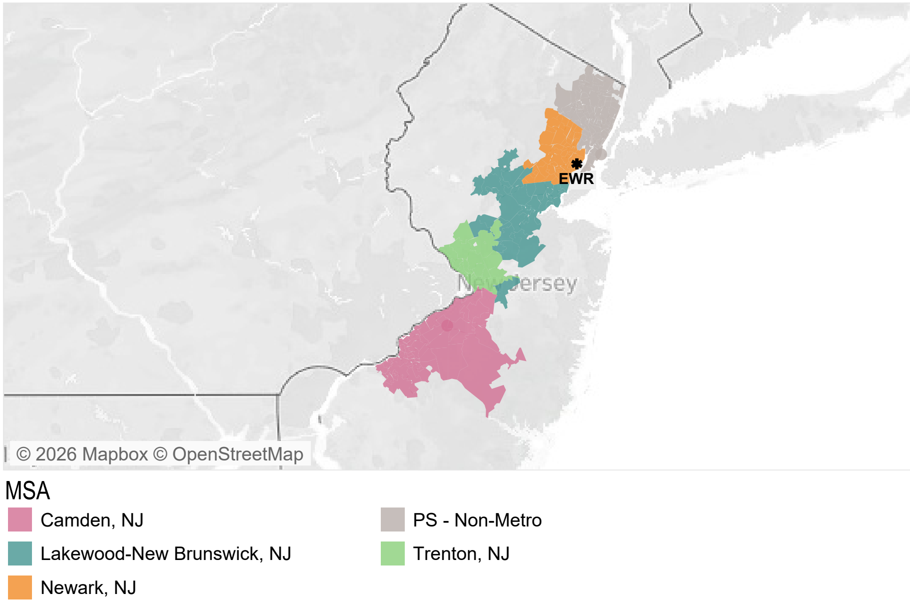
LDAs

PJM MID-ATLANTIC
EASTERN MID-ATLANTIC
PJM RTO

Winter Peak

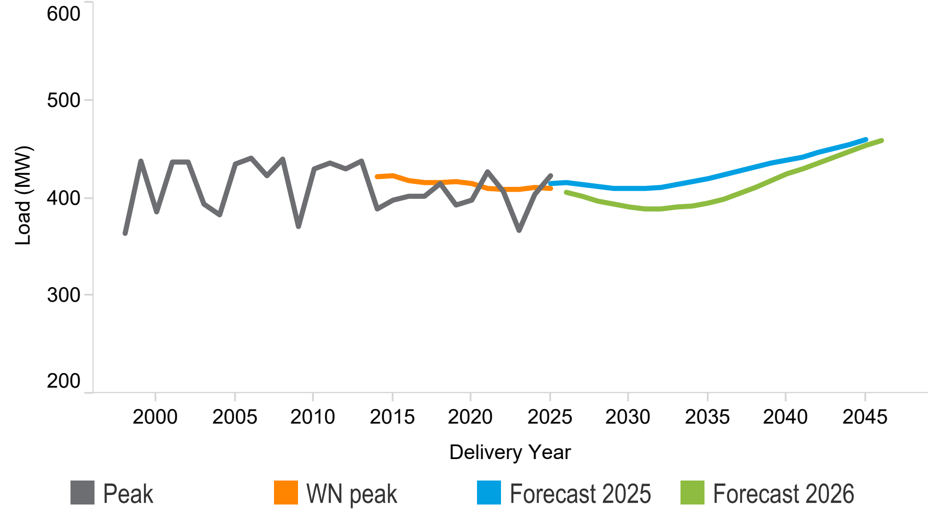


Metropolitan Statistical Areas and Weather Stations



Rockland Electric Company (RECO)

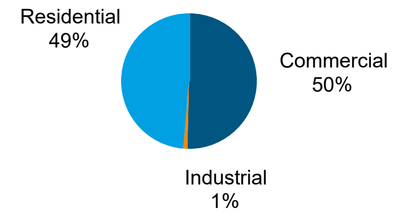
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*76.1*
Avg Summer Max Temp	*98.7*
Avg Winter Daily Temp	*35.9*
Avg Winter Min Temp	*7.6*

RCI Makeup



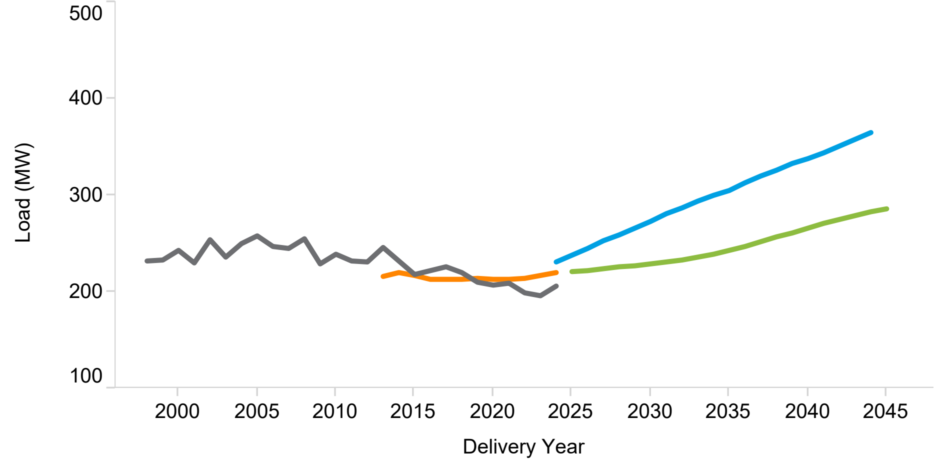
Zonal 10/15/20 Year Load Growth

SUMMER	-0.2%	0.4%	0.6%
WINTER	1.0%	1.2%	1.3%

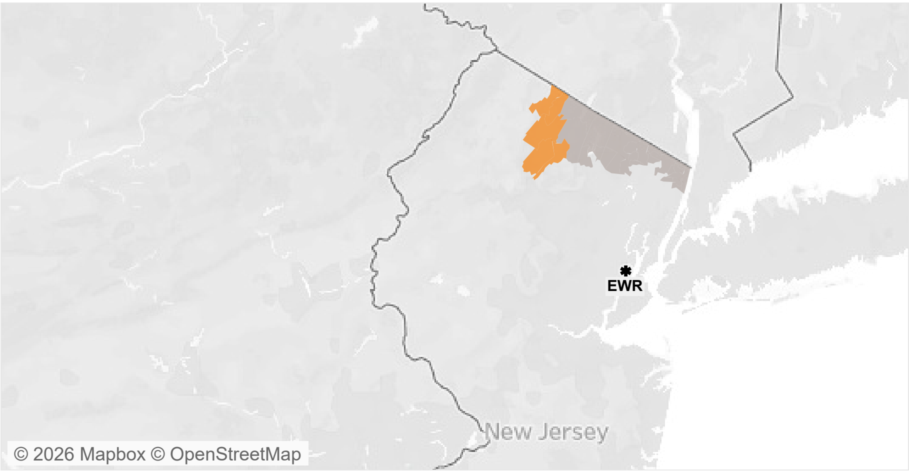
LDAs

PJM MID-ATLANTIC
EASTERN MID-ATLANTIC
PJM RTO

Winter Peak



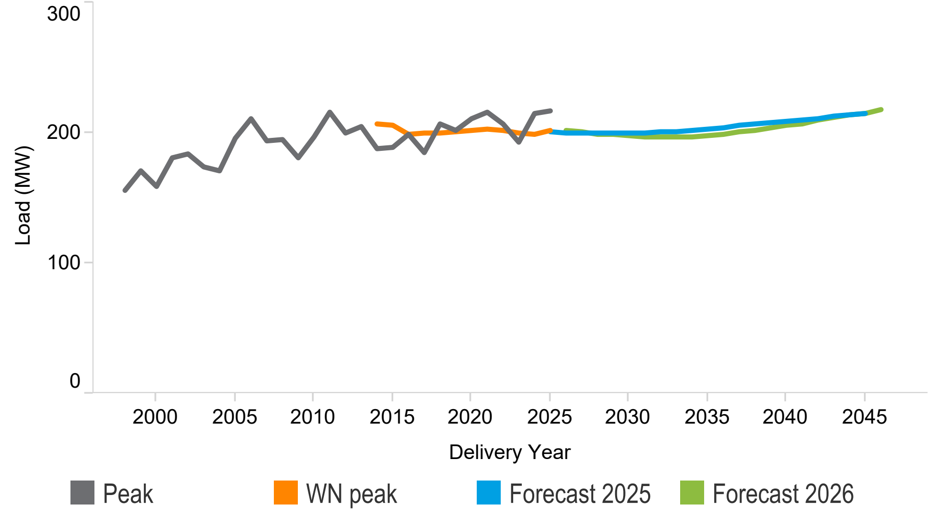
Metropolitan Statistical Areas and Weather Stations



MSA
🟧 Newark, NJ
⬜ RECO - Non-Metro

UGI Energy Services (UGI)

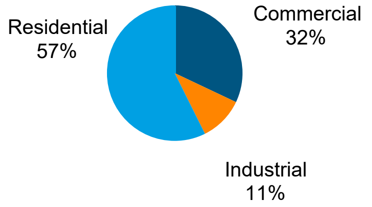
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*70.6*
Avg Summer Max Temp	*93.3*
Avg Winter Daily Temp	*30.4*
Avg Winter Min Temp	*-1.0*

RCI Makeup



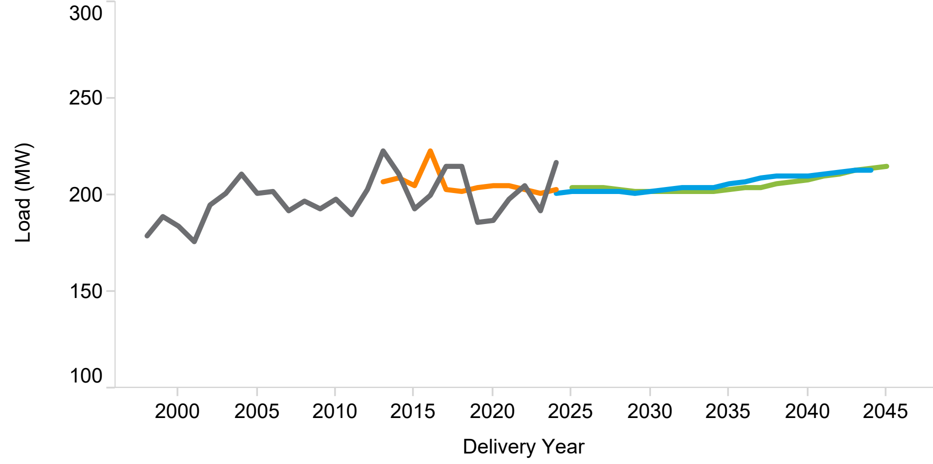
Zonal 10/15/20 Year Load Growth

SUMMER	-0.1%	0.2%	0.4%
WINTER	0.0%	0.1%	0.3%

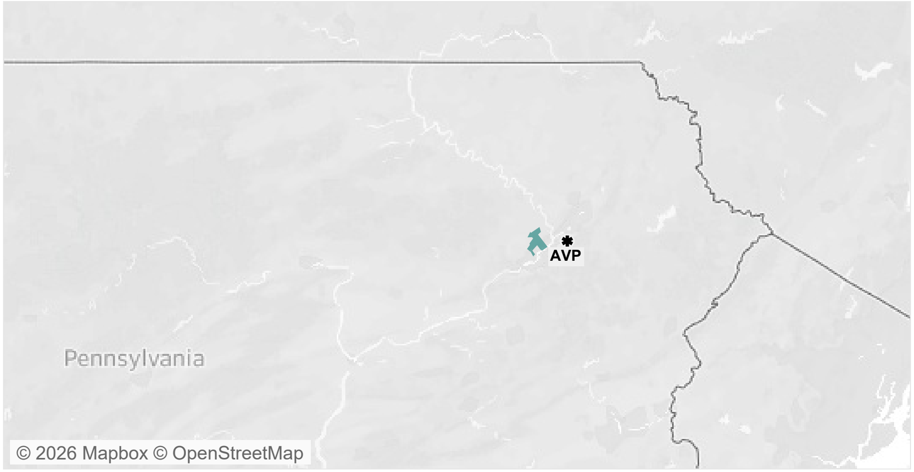
LDAs

PJM MID-ATLANTIC
CENTRAL MID-ATLANTIC
WESTERN MID-ATLANTIC
PLGRP
PJM RTO

Winter Peak



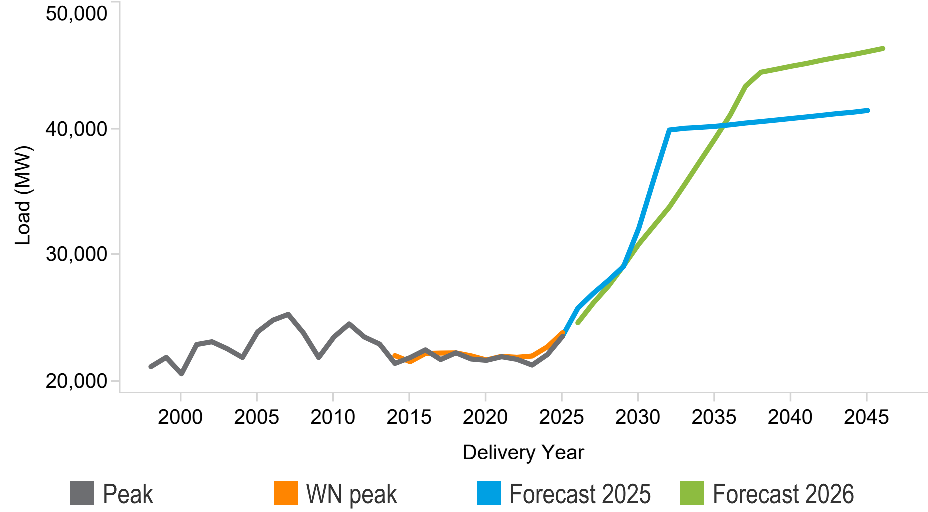
Metropolitan Statistical Areas and Weather Stations



MSA
🟩 Scranton--Wilkes-Barre--Hazleton, PA

American Electric Power (AEP)

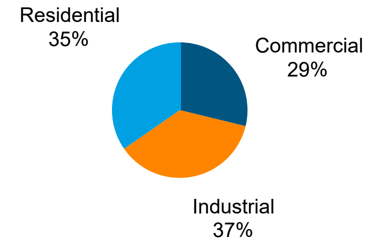
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*92.3*
Avg Winter Daily Temp	*33.6*
Avg Winter Min Temp	*3.0*

RCI Makeup



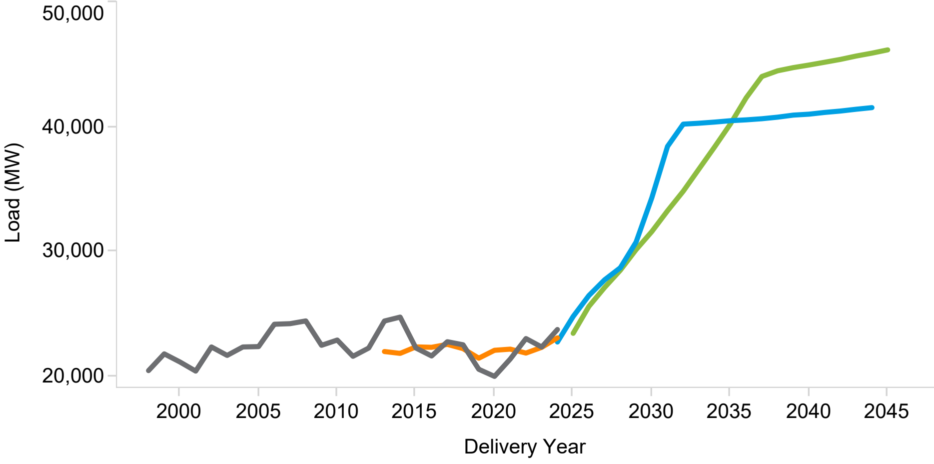
Zonal 10/15/20 Year Load Growth

SUMMER	5.3%	4.1%	3.2%
WINTER	5.6%	4.4%	3.5%

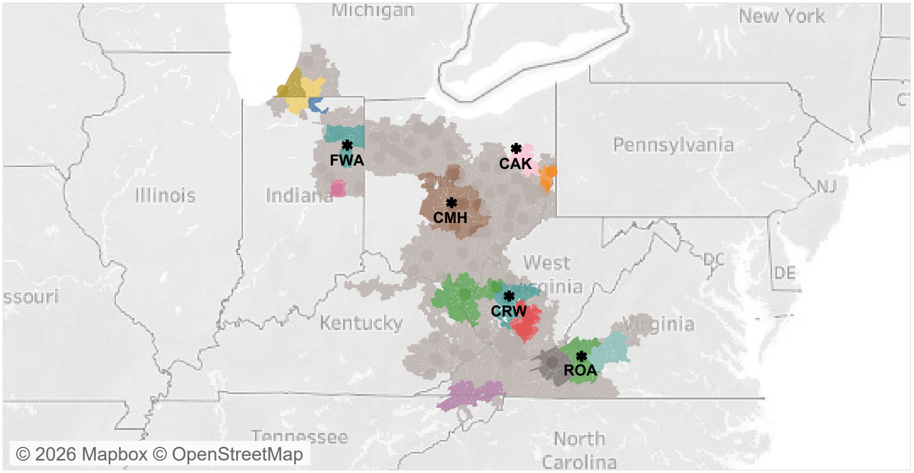
LDAs

PJM WESTERN
PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations

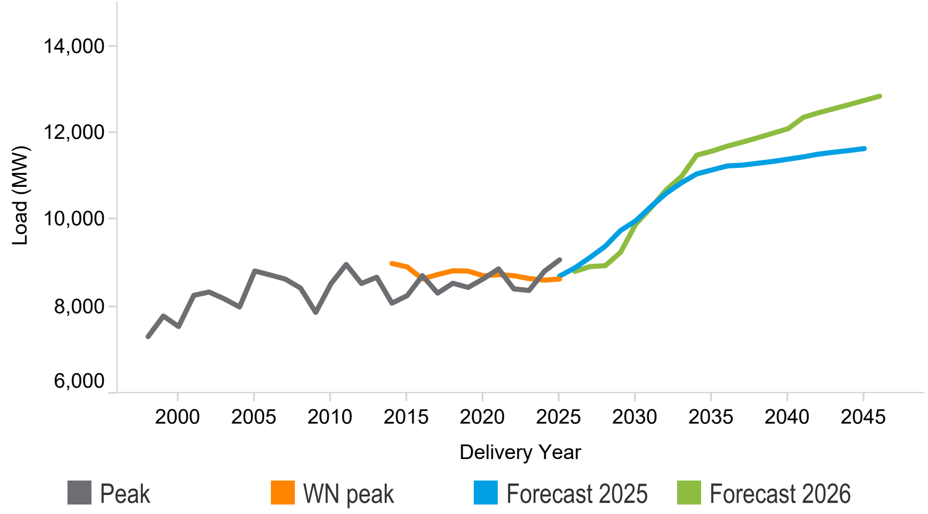


MSA

AEP - Non-Metro	Charleston, WV	Huntington-Ashland, WV-KY-OH	Niles-Benton Harbor, MI
Beckley, WV	Columbus, OH	Kingsport-Bristol-Bristol, TN-VA	Roanoke, VA
Blacksburg-Christiansburg-Radford, VA	Elkhart-Goshen, IN	Lynchburg, VA	South Bend-Mishawaka, IN-MI
Canton-Massillon, OH	Fort Wayne, IN	Muncie, IN	Weirton-Steubenville, WV-OH

Allegheny Power Systems (APS)

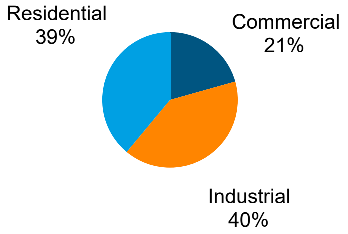
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*72.8*
Avg Summer Max Temp	*92.6*
Avg Winter Daily Temp	*33.3*
Avg Winter Min Temp	*2.6*

RCI Makeup



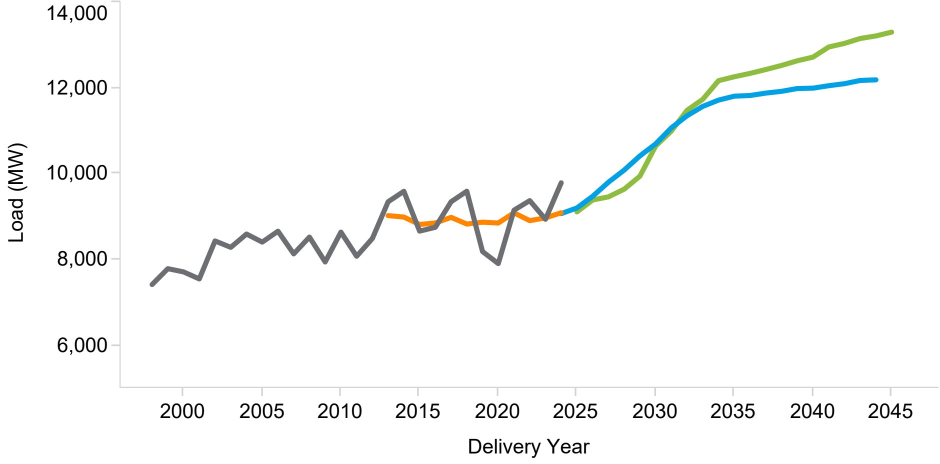
Zonal 10/15/20 Year Load Growth

SUMMER	2.9%	2.3%	1.9%
WINTER	3.0%	2.2%	1.9%

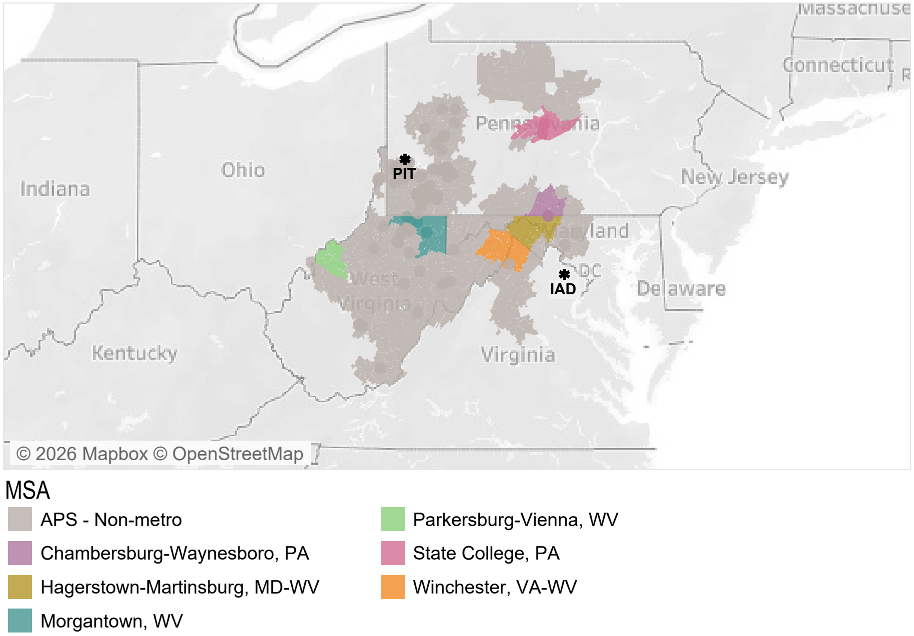
LDAs

PJM WESTERN
PJM RTO

Winter Peak

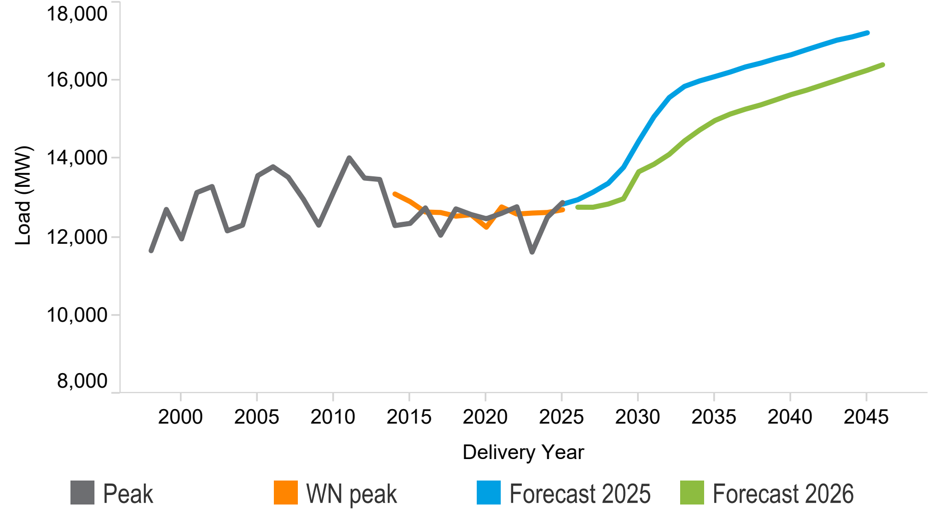


Metropolitan Statistical Areas and Weather Stations



American Transmission Systems, Inc. (ATSI)

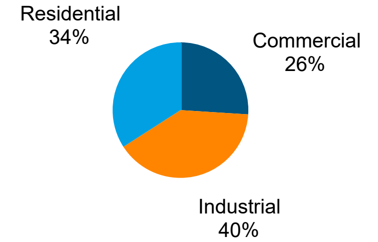
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*71.7*
Avg Summer Max Temp	*91.9*
Avg Winter Daily Temp	*30.3*
Avg Winter Min Temp	*-0.9*

RCI Makeup



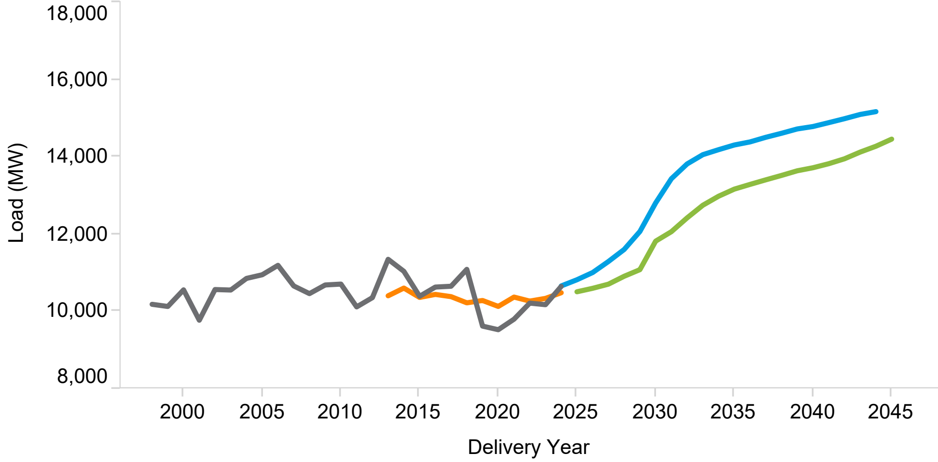
Zonal 10/15/20 Year Load Growth

SUMMER	1.7%	1.4%	1.3%
WINTER	2.3%	1.8%	1.6%

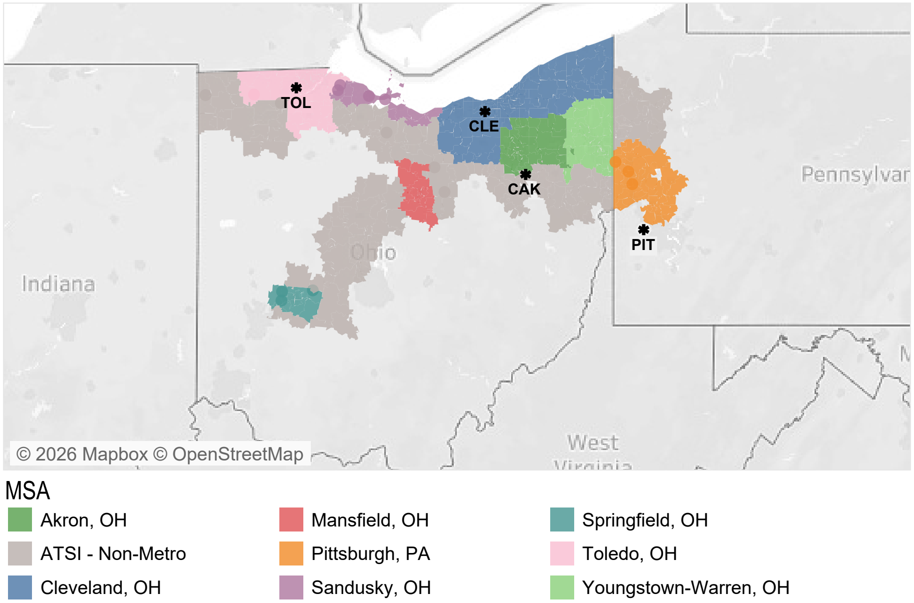
LDAs

PJM WESTERN
PJM RTO

Winter Peak

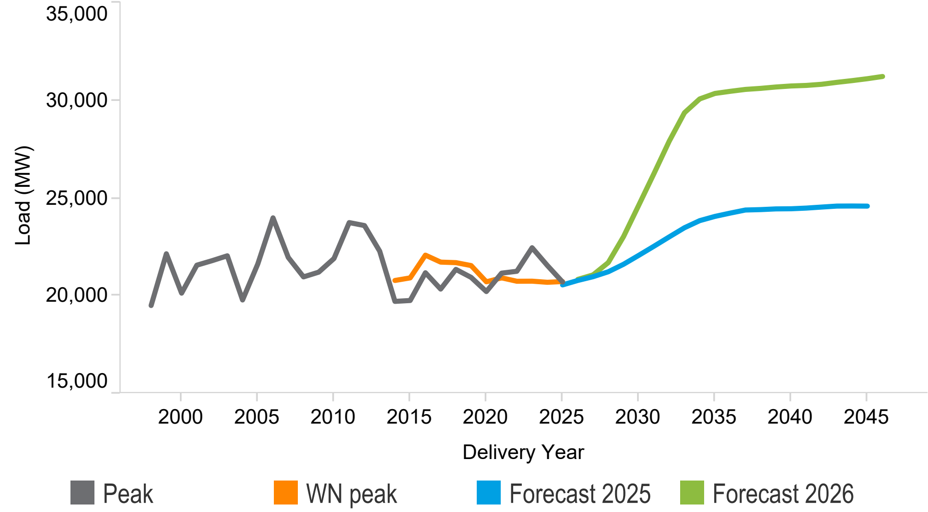


Metropolitan Statistical Areas and Weather Stations



Commonwealth Edison (COMED)

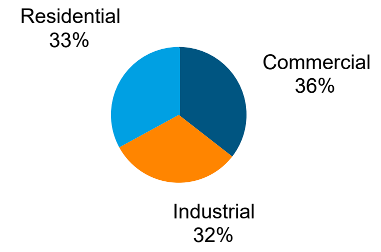
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*73.1*
Avg Summer Max Temp	*95.7*
Avg Winter Daily Temp	*28.0*
Avg Winter Min Temp	*-7.3*

RCI Makeup



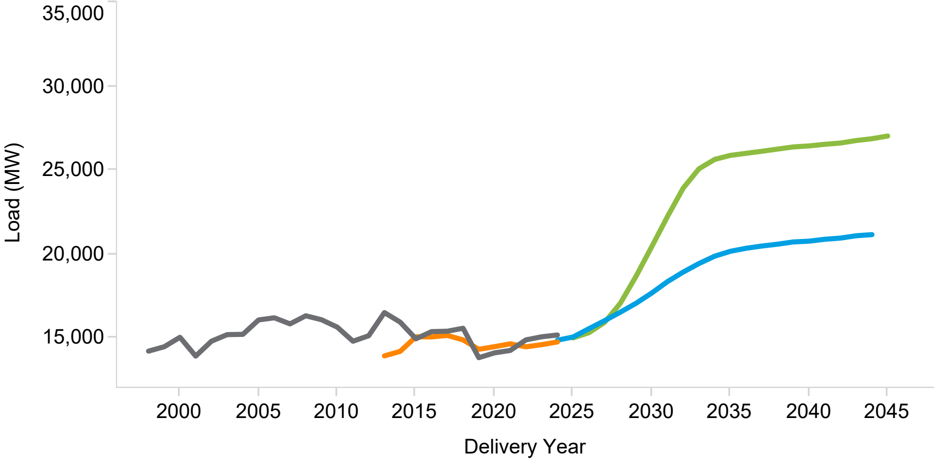
Zonal 10/15/20 Year Load Growth

SUMMER	3.9%	2.6%	2.0%
WINTER	5.6%	3.8%	3.0%

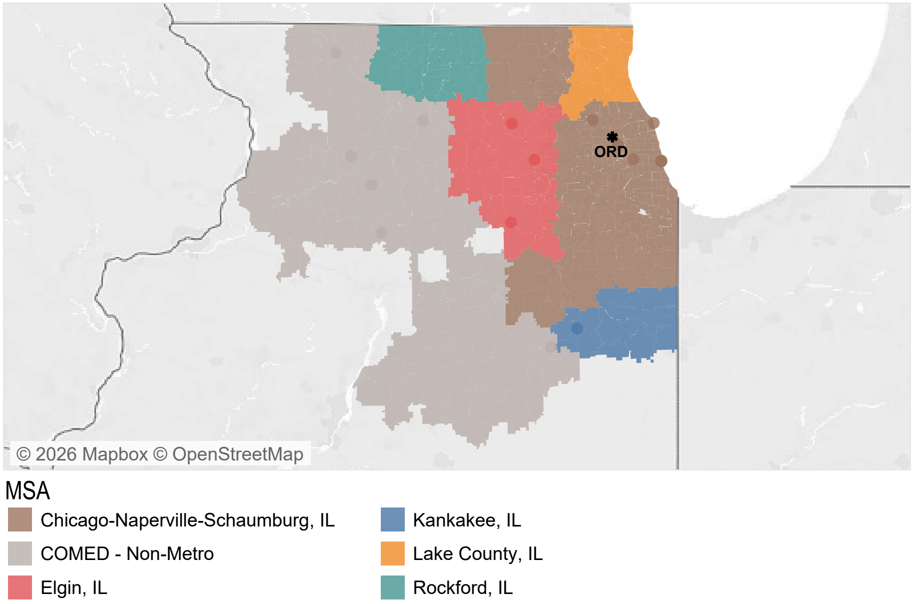
LDAs

PJM WESTERN
PJM RTO

Winter Peak

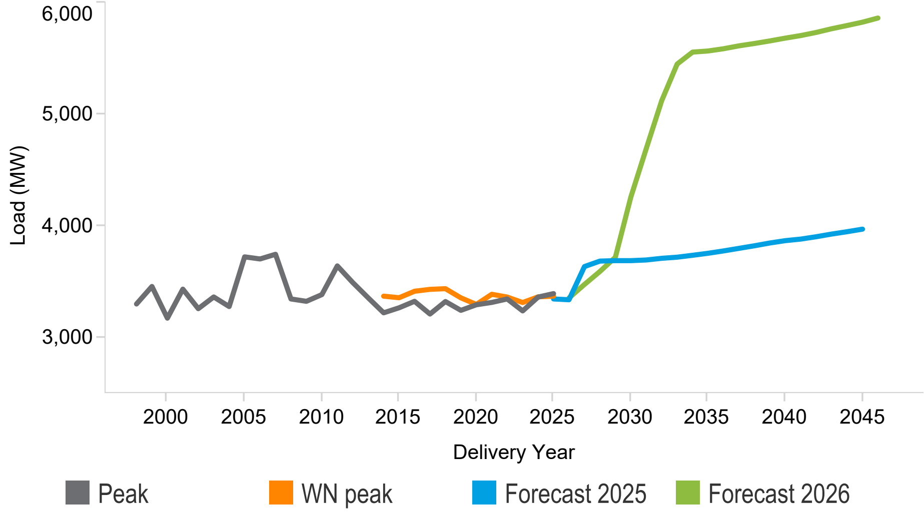


Metropolitan Statistical Areas and Weather Stations



Dayton Power & Light (DAYTON)

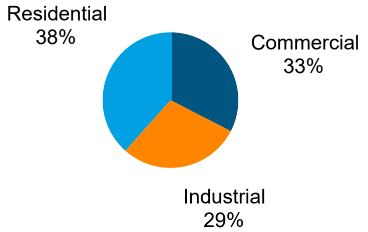
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*73.2*
Avg Summer Max Temp	*93.2*
Avg Winter Daily Temp	*31.5*
Avg Winter Min Temp	*-2.8*

RCI Makeup



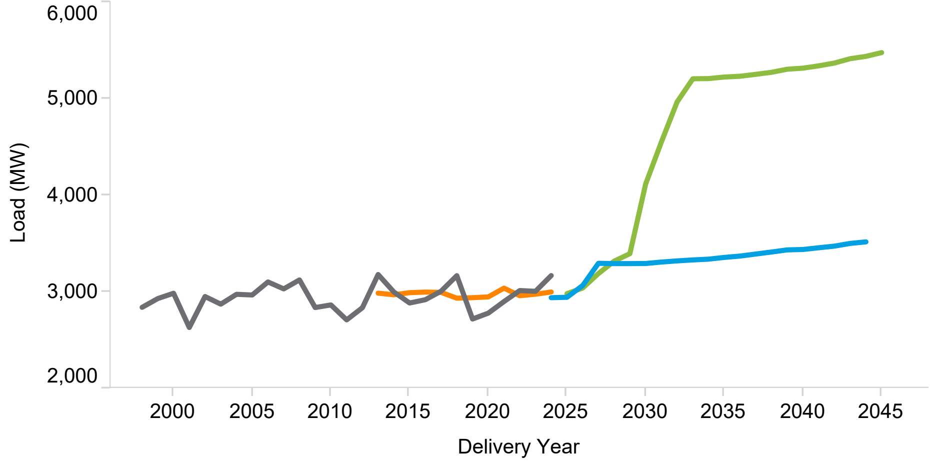
Zonal 10/15/20 Year Load Growth

SUMMER	5.2%	3.6%	2.8%
WINTER	5.8%	3.9%	3.1%

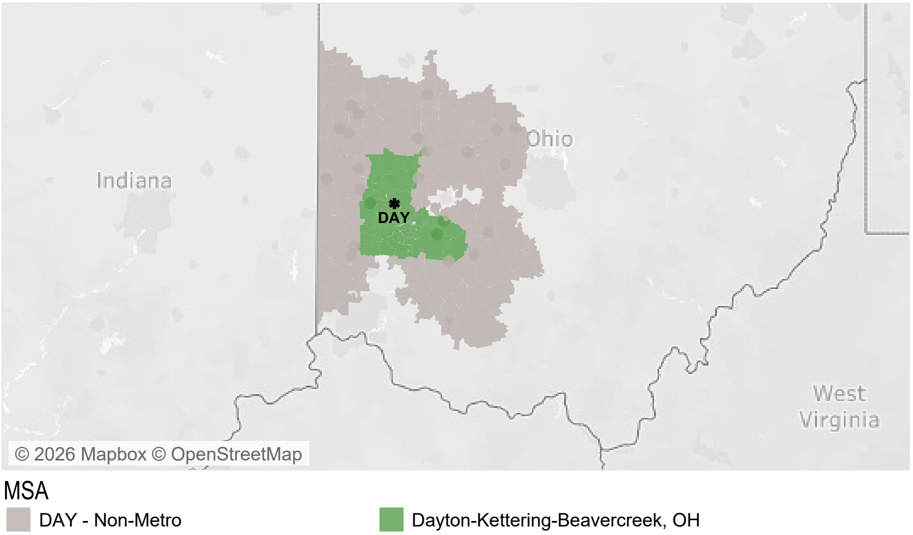
LDAs

PJM WESTERN
PJM RTO

Winter Peak

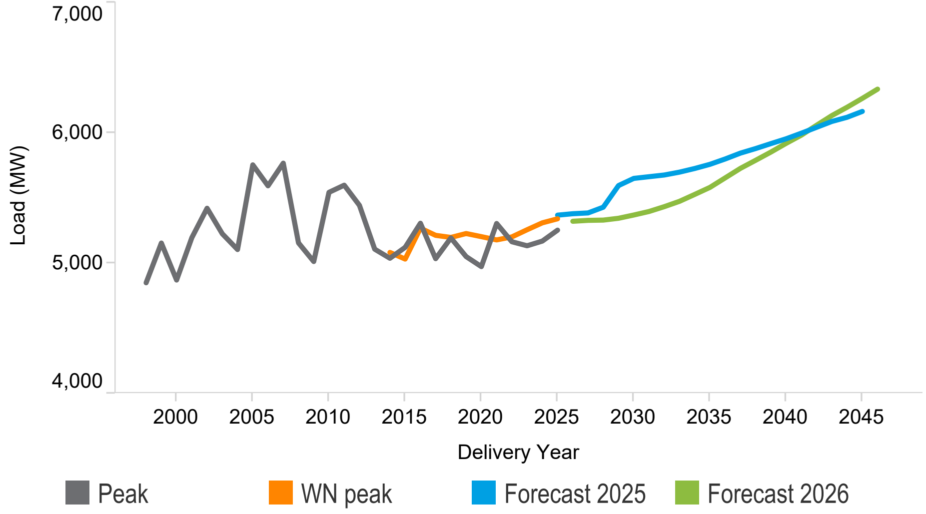


Metropolitan Statistical Areas and Weather Stations



Duke Energy Ohio & Kentucky (DEOK)

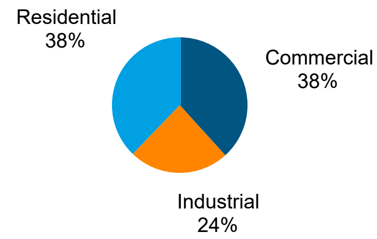
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*74.4*
Avg Summer Max Temp	*94.1*
Avg Winter Daily Temp	*34.2*
Avg Winter Min Temp	*-1.1*

RCI Makeup



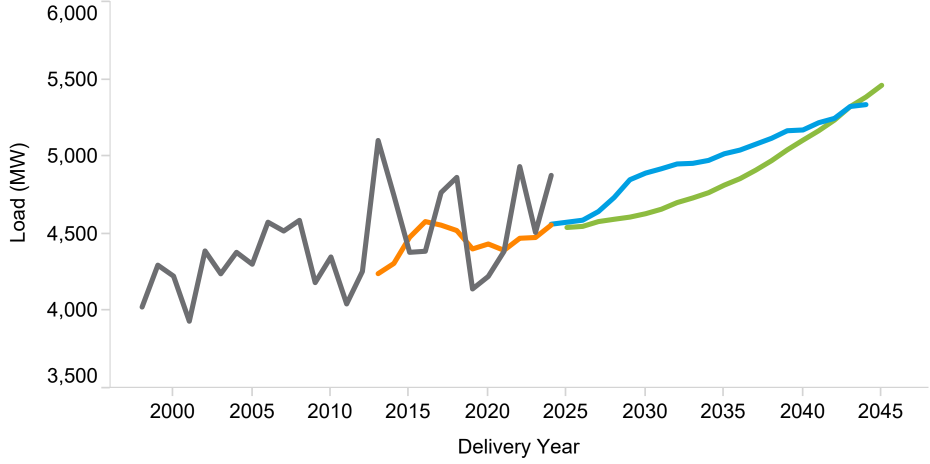
Zonal 10/15/20 Year Load Growth

SUMMER	0.6%	0.8%	0.9%
WINTER	0.6%	0.8%	0.9%

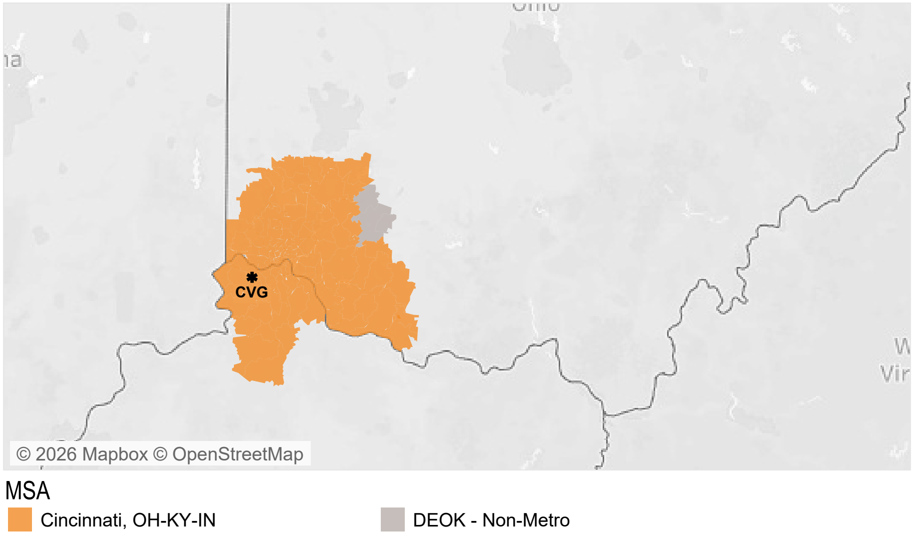
LDAs

PJM WESTERN
PJM RTO

Winter Peak

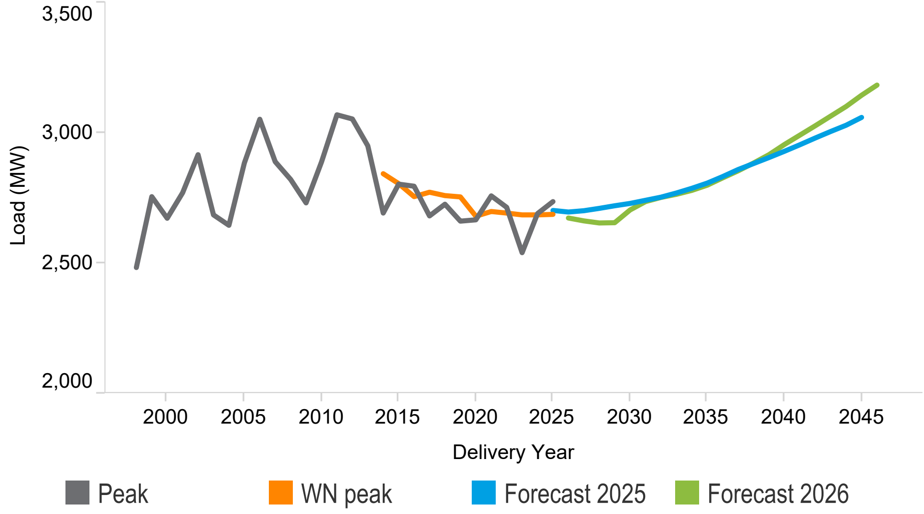


Metropolitan Statistical Areas and Weather Stations



Duquesne Light Company (DLCO)

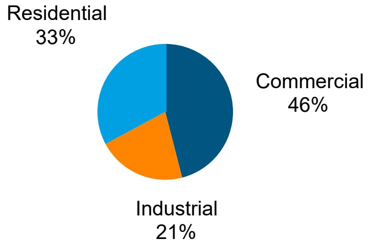
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*71.7*
Avg Summer Max Temp	*91.7*
Avg Winter Daily Temp	*31.8*
Avg Winter Min Temp	*-0.6*

RCI Makeup



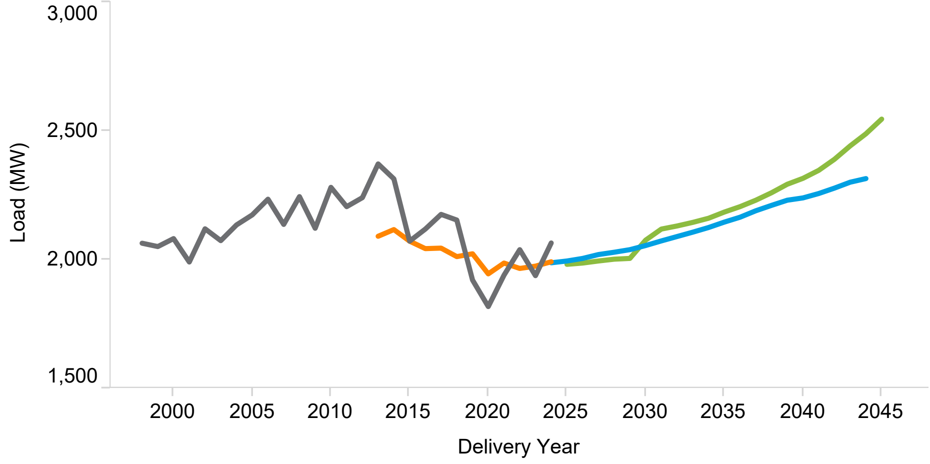
Zonal 10/15/20 Year Load Growth

SUMMER	0.6%	0.8%	0.9%
WINTER	1.0%	1.0%	1.3%

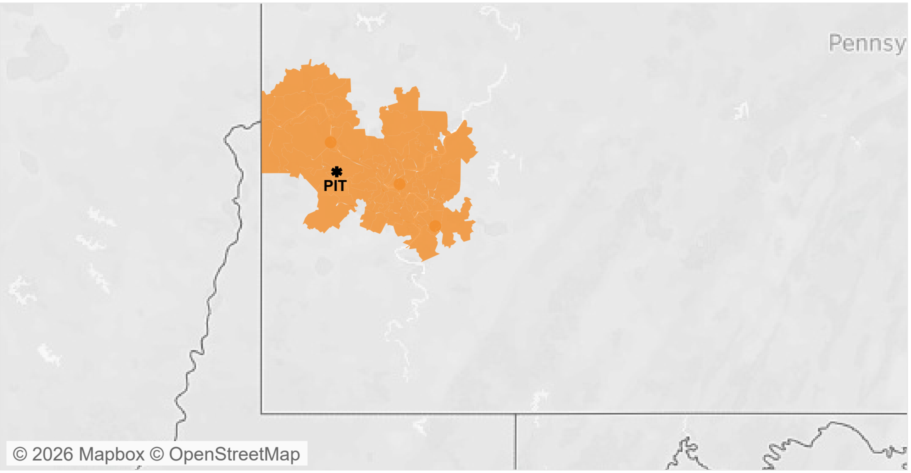
LDAs

PJM WESTERN
PJM RTO

Winter Peak



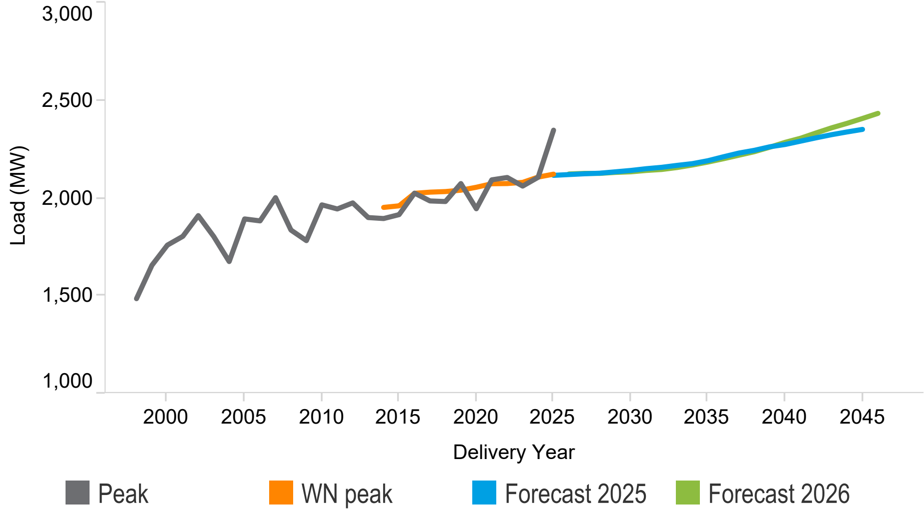
Metropolitan Statistical Areas and Weather Stations



MSA
🟧 Pittsburgh, PA

East Kentucky Power Cooperative (EKPC)

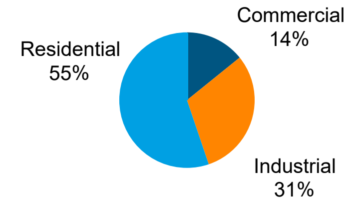
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*75.6*
Avg Summer Max Temp	*94.5*
Avg Winter Daily Temp	*36.3*
Avg Winter Min Temp	*2.3*

RCI Makeup



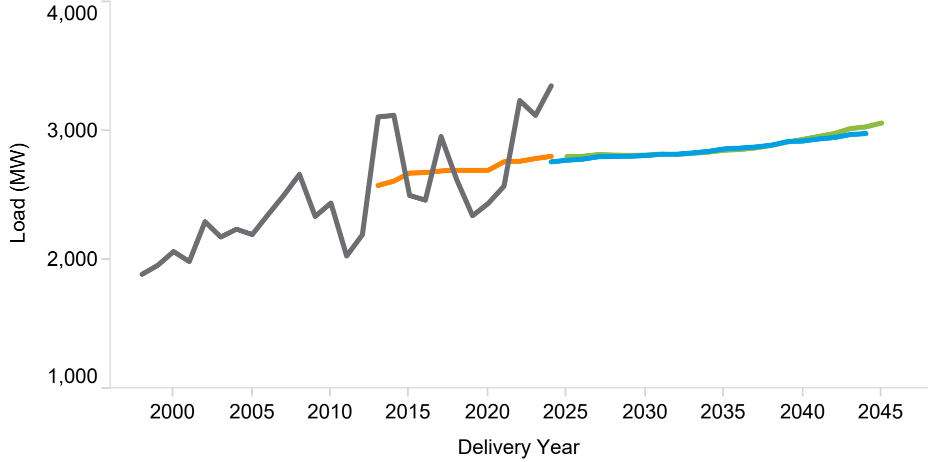
Zonal 10/15/20 Year Load Growth

SUMMER	0.4%	0.6%	0.7%
WINTER	0.2%	0.3%	0.4%

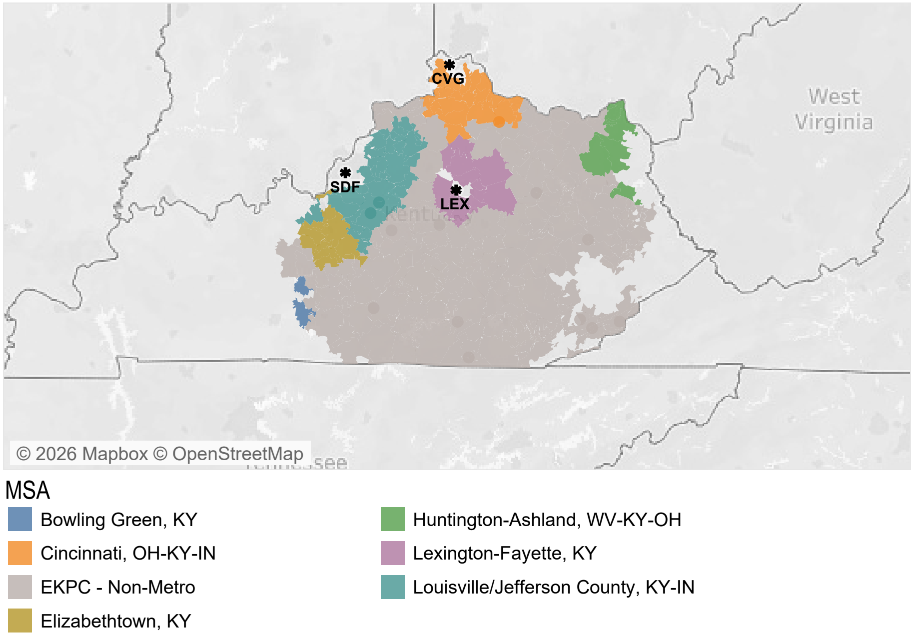
LDAs

PJM WESTERN
PJM RTO

Winter Peak



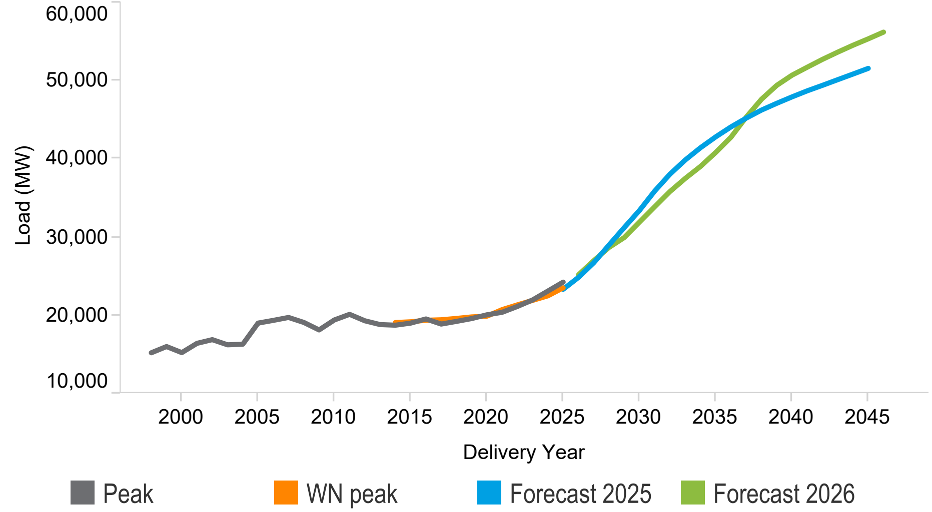
Metropolitan Statistical Areas and Weather Stations



NEET MA Exhibit AG-8

Dominion (DOM)

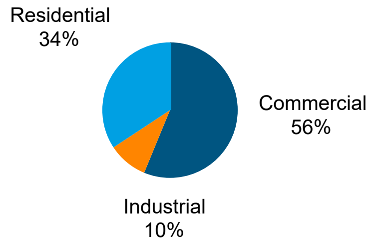
Summer Peak



Weather - Annual Average 1994-2024

Avg Summer Daily Temp	*77.0*
Avg Summer Max Temp	*96.9*
Avg Winter Daily Temp	*40.6*
Avg Winter Min Temp	*12.6*

RCI Makeup



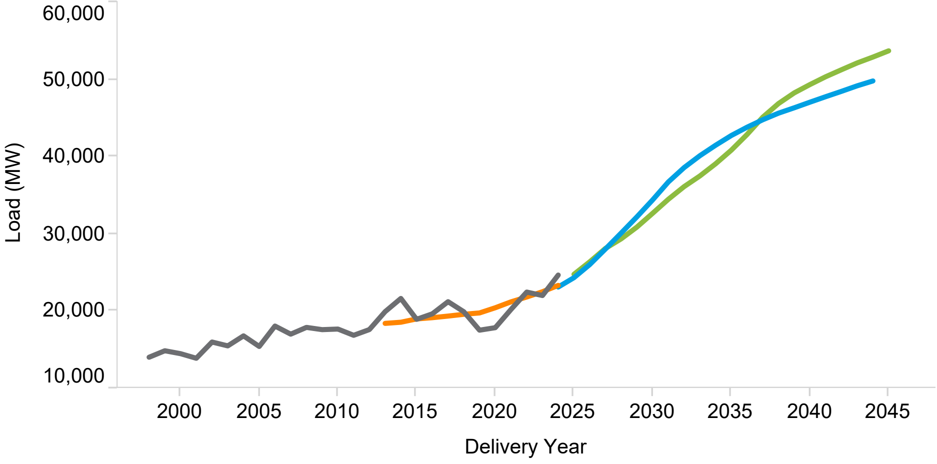
Zonal 10/15/20 Year Load Growth

SUMMER	5.4%	4.9%	4.1%
WINTER	5.1%	4.7%	3.9%

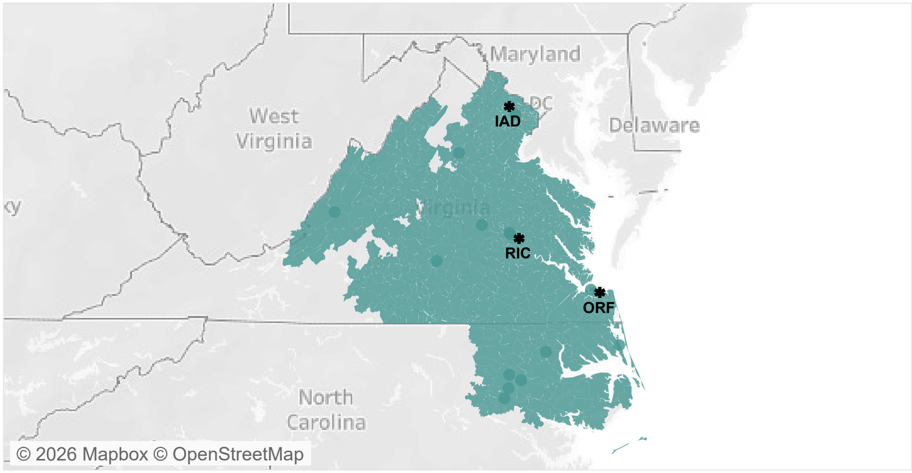
LDAs

PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



MSA
🟩 Virginia Commonwealth Economics