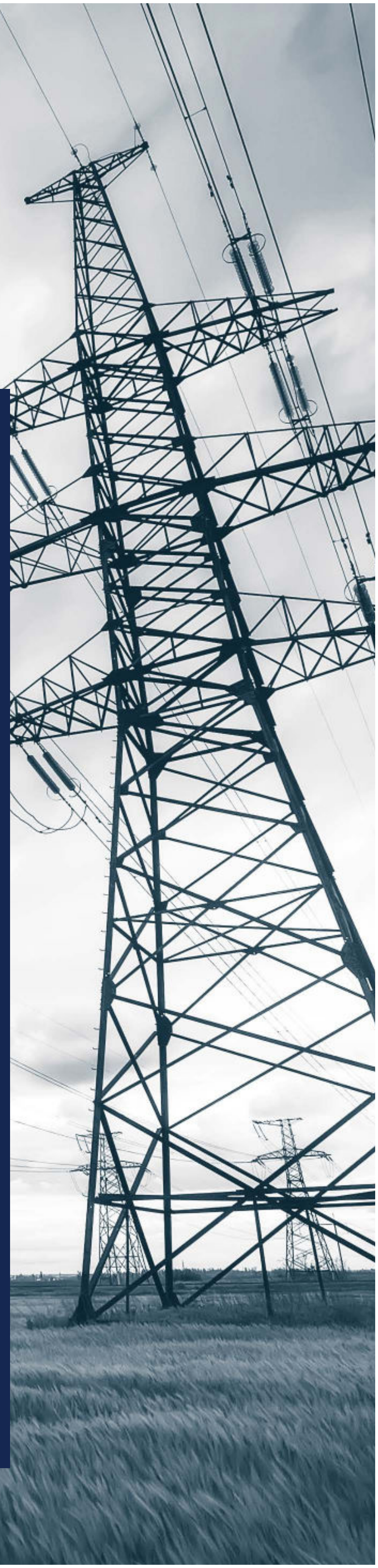


Transmission Planning for PJM's Future Load and Generation Version 1

May 2024

Authors | Zach Zimmerman, Dinos Gonatas, Anjali Patel, and Rob Gramlich

GridStrategies

D|G/A David Gardiner and Associates

Americans for a Clean Energy Grid

This report was sponsored by Americans for a Clean Energy Grid (ACEG). ACEG is a non-profit broad-based public interest advocacy coalition focused on the need to expand, integrate, and modernize the North American high-capacity grid.

CONTENTS

1 | EXECUTIVE SUMMARY

The United States needs to expand electricity transmission capacity to meet growing demand, facilitate new generation interconnection and retirements, provide resilience against extreme weather, and reduce cap constraints hindering access to low-cost energy sources. However, building new high-capacity transmission is challenging, and currently not enough high-capacity lines are being planned or developed.

A key barrier to transmission development is a lack of proactive transmission planning. Opponents and skeptics of proactive planning often raise the specter of uncertainty and speculation as a roadblock to achieving robust and reliable results. But these concerns will not be resolved by ignoring the massive changes impacting the energy industry and continuing to plan reactively. Rather, uncertainty is best addressed by incorporating best available data on the future resource mix to conduct scenario analyses in which different futures are tested to determine the optimum set of transmission solutions, all of which is now required for regional transmission planning by FERC Order No. 1920.[1]

Proactive, scenario-based long-term regional planning is especially critical for PJM because many states have deregulated utilities and rely on PJM's interconnection queue and regional capacity market. This paradigm necessitates greater regional planning and coordination to ensure the transmission needed is planned and developed to provide ratepayers with reliable and affordable power given the reality of the future generation mix.

While there is no singular right way to plan, there are better and worse ways. We developed this report to demonstrate that there is better data available to inform a more robust planning process. We focus here on the initial inputs on which PJM transmission plans should be based–load, retirements, and new generation needs. The information presented herein is not intended to set the boundaries on how PJM's assumptions and planning processes should evolve, but rather should serve as a platform to encourage a broader discussion on needed improvements.

1 Order No. 1920, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, FERC Stats. & Regs. at 61,068 (May 13, 2024) ("Order No. 1920").

To address uncertainty and ensure results are verifiable, this report is based on two futures scenarios developed using publicly available data on estimates of load growth, modeled retirements, new generation, and clean energy demand from states, utilities, and large energy buyers in 2040.

- The Expected scenario represents the most likely estimate of future needs given consideration of all the inputs.
- The High scenario represents a future with greater energy needs due to accelerated electrification, more generator retirements, and additional clean energy demand.

Results

By 2040, we estimate PJM's demand for energy will increase above the 2024 load forecast by approximately 8 percent for the Expected scenario and 18 percent for the High scenario. The Expected Scenario forecast may still be conservative given continued announcements of new manufacturing facilities and data centers. Along with load growth, PJM has an aging thermal generation fleet that we anticipate will lead to generator retirements equivalent to approximately 25 percent of PJM's 2023 load. The combination of load growth and retirements will require PJM to plan and build new lines to meet this projected resource gap.

We find PJM will need an additional 623 terawatt-hours (TWh) of annual energy generation by 2040 to meet this resource gap under our Expected scenario–equivalent to 76 percent of PJM's 2023 generation. Under the High scenario PJM faces a larger resource gap in 2040 and will need to nearly double current energy generation by adding 798 TWh. The increase is driven by higher electrification estimates leading to larger load growth and higher amounts of generation retirements due to shorter plant lifespan assumptions. In both scenarios we find states' RPS laws, large energy buyers' commitments, and utilities' goals all increase demand for new clean energy generation. In the Expected scenario, state RPS laws cover a minimum of 29 percent of the load in 2040.

PJM has taken steps to advance load forecasts and the inputs to its long-term transmission planning, including updates to the operation of the Independent State Agencies Committee (ISAC) and the Long-Term Regional Transmission Planning workshops, which proposed a scenario-based framework for long-term transmission planning. This report highlights several recommendations of best practices PJM can adopt to further progress its long-term transmission planning:

- PJM should continue to improve estimates of electrification within its footprint.
    - The RTO could survey its transmission owners, states, and large customers to better understand how the potential developments of large or novel loads, corporate goals, and customer demand for electrification may impact future load profiles and growth.
    - PJM should continue to survey states and local governments about relevant policies, including both demand- and supply-side policies, and fully incorporate the results into a lo. The solicitation of relevant state policies by PJM through the Independent State Agencies Committee (ISAC) is a good first step that can be built upon.

  - PJM could also develop its own high electrification estimates for end-use electrification or have an independent group conduct an analysis just as it engaged S&P Global for an electric vehicle forecast.

- PJM must plan more proactively for retirements across the entire long-term planning horizon. Understanding the impact of potential retirement on overall system reliability and clearly communicating the results to interested parties is a critical part of a proactive long-term planning process. It can also reduce overall costs for consumers by avoiding costly reliability must run (RMR) agreements for plants that would otherwise retire.
- PJM should run economic capacity expansion models along with production cost modeling to ensure the optimal buildout of new generation and transmission while delivering the lowest system cost. This is particularly necessary given the low cost of renewable energy and battery storage resources and new federal tax incentives affecting a variety of sources.
- Other scenarios with differing retirement assumptions, new loads, electrification, and other relevant inputs could also be created by PJM.
- The development of any new methodologies, best practices, or results should be done in clear communication with interested parties and allow ample opportunity for input from interested parties.

2 | BACKGROUND

A. National need to expand transmission capacity

The high-capacity transmission grid in the United States is not equipped to meet the needs of a changing system. In 2023, the U.S. Department of Energy (DOE) released the National Transmission Needs Study (Needs Study), which found the U.S. will need to more than double intra-regional transmission capacity and quadruple interregional transmission capacity by 2035.[2] The Needs Study found that transmission capacity expansion is necessary in order to connect a changing resource mix to maintain overall grid reliability, particularly as extreme weather events continue to increase.[3] The Needs Study also found that almost all regions across the country need to increase transmission deployment to meet demand growth, with a 2023 study of load growth finding that the 5-year nationwide forecast nearly doubled when comparing 2022 to 2023 forecasts.[4] The need to expand transmission capacity is a consistent finding across many independent studies.[5]

Moreover, developing high-capacity transmission is challenging as recent historical trends illustrate. Over the past decade, the average miles of new high-capacity transmission lines constructed in the U.S. has dropped by almost one third from 1,700 miles in the early 2010s to less than 650 miles per year in the last half of the decade.[6] A 2023 study by Grid Strategies and Americans for a Clean Energy Grid (ACEG) found that large transmission projects can take 20 years to complete.[7]

---

2 U.S. Department of Energy, National Transmission Needs Study, iii-xi (October 2023) ("Needs Study"), https://www.energy.gov/sites/default/files/2023-10/National_Transmission_Needs_Study_2023.pdf.

3 *Id,* ii-xi; *See also* NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2024); https://www.ncei.noaa.gov/access/billions/.

4 *Needs Study*, xi. *See also* John D. Wilson and Zach Zimmerman, Grid Strategies, The Era of Flat Power Demand is Over, at 3 (December 2023) ("Era of Flat Power Demand is Over"), https://gridstrategiesllc.com/wpcontent/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

5 This finding of expanding transmission capacity is consistent across many independent studies, including ones from Princeton, MIT, and Vibrant Clean Energy, all finding that the U.S. needs to double or triple transmission capacity in the coming decades.

6 J. Caspary, M. Goggin, R. Gramlich, and J Selker, "Fewer New Miles: The US Transmission Grid in the 2010s," Grid Strategies, August 2022, https://gridprogress.files.wordpress.com/2022/08/grid-strategies_fewer-new-miles.pdf.

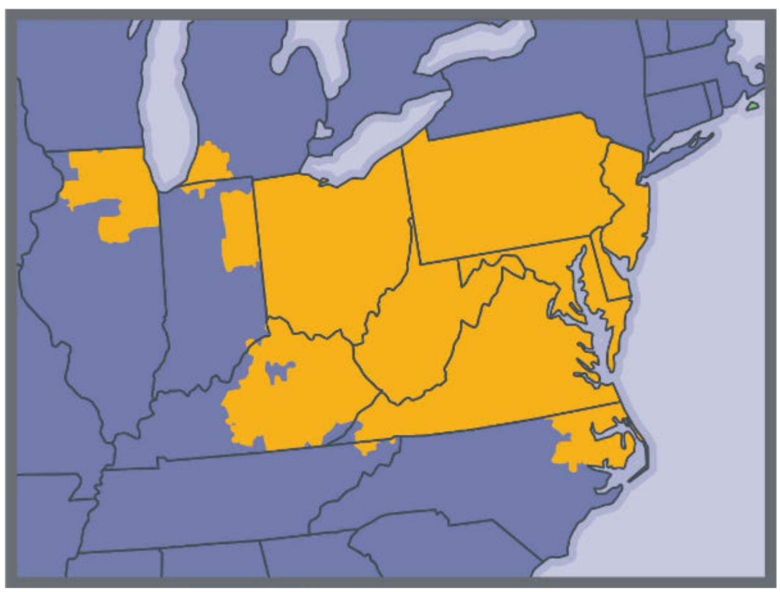
7 Z. Zimmerman, M. Goggin, R. Gramlich, *Ready-to-Go Transmission Projects 2023 Progress and Status since 2021* (September 2023), https://cleanenergygrid.org/wp-content/uploads/2023/09/ACEG_Transmission-Projects-Ready-To-Go_September-2023.pdf.

In addition, there are increasing supply chain constraints for components of high-capacity transmission. For example, in many cases high-voltage direct current (HVDC) systems ordered now have delivery times in the early 2030s.[8]

B. PJM's need to expand transmission capacity

PJM, North America's largest Regional Transmission Organization, spanning 13 states and the District of Columbia, has historically had one of the most robust transmission networks due to a strong 500 and 765 kV backbone. But PJM, like the rest of the country, will need to expand transmission capacity to meet the needs of a changing system. In its National Transmission Needs Study, DOE estimated that in the high load and high clean energy growth scenario, which is most closely match with the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA) as well as current trends in load growth,[9] PJM needs to expand within-region transmission capacity by 61% and interregional capacity with MISO, one of its neighboring RTOs, by almost 500%.[10] The main drivers of transmission needed according to the DOE study are increasing resilience and reliability, reducing interregional transfer capacity limits, and delivering economic generation to meet demand.[11]

FIGURE 1 | Map of PJM[12]



Delays and rising upgrades costs in interconnection queues can also be an indicator of the need to expand transmission capacity. Over the past decade, interconnection queues across the country, and in PJM, have grown as renewable generation and storage have become more cost

8 Cornelis Plet, "2023 was a pivotal year for HVDC. What can we expect next?," DNV (March 2024), https://www.dnv.com/article/2023-was-a-pivotal-year-for-HVDC/.

9 *See* "Era of Flat Power Demand is Over."

10 *Needs Study*, ix-x.

11 *Id.*, xi.

12 PJM Interconnection, "Territory Served," accessed May 1, 2024, https://www.pjm.com/about-pjm/who-we-are/territory-served.

effective. This shift has led to longer times and rising upgrade costs to connect new generation to the grid. PJM has seen interconnection time increase to 40 months and costs rise from tens of dollars per kW to $185 per kW on average today.[13] PJM has reformed its interconnection process and updated its generator deliverability test in the RTEP process, which will hopefully improve interconnection outcomes.[14] But according to a customer surveyed by Brattle and Grid Strategies for Advanced Energy United (AEU) on interconnection queues, "PJM's historically robust transmission system is at the point of hitting saturation and the planning process is unprepared to respond."[15]

In December 2023, just two months after DOE published the National Transmission Needs Study, the PJM Board of Managers approved approximately $5 billion in transmission upgrades that were identified through the 2022 RTEP process.[16] PJM highlighted that the need for these transmission upgrades was driven by generator retirements and load growth (primarily data centers).[17]

C. Current planning practices are limiting high-capacity transmission development

To meet foreseeable transmission needs, PJM must consider projects beyond system reliability needs only, with a planning horizon covering long lead times for new projects.

In a 2023 ACEG report comparing regional practices to best practice transmission planning, the Mid-Atlantic region received a below-average grade. PJM's transmission planning occurs through the Regional Transmission Expansion Planning (RTEP) process. Planning thereby siloes via reliability, economic, and public policy categories so that each project must meet a need stipulated entirely by one category. Instead of pursuing a more integrated, multi-value approach that incorporates the best available data about the region's future load and generation resource mix, PJM's current RTEP process does not include scenario planning or conduct proactive analysis of retirements or new generation.[18]

PJM's RTEP process includes a short term reliability process which is conducted on a five-year planning horizon and the long-term reliability planning process uses a 15-year horizon. Both processes begin with the development of a base-case which is put into a power flow model. The

13 J. Seel, J. Rand, et al., "Interconnection Cost Analysis in the PJM Territory," Lawrence Berkeley National Laboratory (January 2023) https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_2023.1.12-_pjm_interconnection_costs.pdf; J. Wilson, R. Seide, R. Gramlich, and J.M. Hagerty, *Generator Interconnection Scorecard,* Grid Strategies and Brattle Group, 33 (February 2024), https://gridstrategiesllc.com/wp-content/uploads/2024/03/AEI-2024-Generation-Interconnection-Scorecard.pdf.

14 PJM Interconnection, *2022 Regional Transmission Expansion Plan,* 11 (March 14, 2023), https://www.pjm.com/-/media/library/reports-notices/2022-rtep/2022-rtep-report.ashx.

15 *Id.,* 66.

16 PJM Inside Lines, "PJM Board of Managers Approves Critical Grid Upgrades," PJM Interconnection (December 2023), https://insidelines.pjm.com/pjm-board-of-managers-approves-critical-grid-upgrades/.

17 *Id.*

18 Grid Strategies and Americans for a Clean Energy Grid, *Transmission Planning and Development Regional Report Card*, 29-31 (June 2023) ("*Transmission Planning Report Card*"), https://www.cleanenergygrid.org/ wp-content/uploads/2023/06/ACEG_Transmission_Planning_and_Development_Report_Card.pdf; *See also* Pfeifenberger, J., R. Gramlich, et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, Brattle Group and Grid Strategies, (October 2021) ("*Transmission Planning for the 21st Century*"), https://gridprogress.files.wordpress.com/2021/10/transmissionplanning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf.

base case incorporates assumptions around load, new generation, retirements and transmission. The load forecast is done across a 15-year horizon and is independently developed by PJM and includes estimates of electrification, energy efficiency, demand response, and some policies. Any new generation included in the base case are resources that cleared PJM's capacity auction, while only announced generator deactivations, which only require 90 days advance notice, are included in the base case assumptions.[19]

Since 2014, transmission spending in PJM has increasingly focused on lower-voltage projects, outside the purview of the current RTEP process.[20] These supplemental projects have dominated planning while less than 100 miles of high-capacity (345 kV+) transmission lines have been built since 2020.[21]

There is interest in more proactive long-term planning in PJM, including from the RTO itself. The Organization of PJM States (OPSI, the public utility commissioners from PJM's states), requested PJM develop more holistic and proactive transmission planning.[22] PJM has recognized this need, and in response initiated the Long-Term Regional Transmission Planning (LTRTP) process. Through LTRTP, PJM has advanced transmission planning including convening interested parties for workshops late 2023 and proposing transmission planning manual changes.[23] However, the process is still early and it is not yet clear how reforms will be implemented once the new LTRTP process is underway. PJM will also need to make further changes to its current RTEP process or its proposed LTRTP process to align with the requirements in FERC Order No. 1920 described in further detail in the next section.

D. Planning and Development Begins with Robust Assessment of the Future Resource Mix

The Federal Energy Regulatory Commission (FERC) has recognized the need to expand national transmission capacity and improve transmission planning processes.[24] In May 2024, FERC finalized a rule requiring many of the transmission planning best practices identified by ACEG[25] and others[26]:

---

19 *See* PJM, "PJM Manual 14B: PJM Region Transmission Planning Process," 2023, https://www.pjm.com/-/media/documents/manuals/m14b.ashx. *See* David Gardiner and Associates, "Consumer Advocates of the PJM States' Transmission Handbook" (February 2024) ("PJM Transmission Handbook"), https://www.dgardiner.com/pjm-transmission-handbook/.

20 *See* "PJM Transmission Handbook;" *See also* C. Wayner, "Increased Spending on Transmission in PJM — Is It the Right Type of Line?," RMI (March 2023), https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/.

21 *Id.,* 58.

22 Chandler, Kent A., President, Organization of PJM States, Inc. Letter to Mr. Mark Takahashi, Chair, PJM Board of Managers and Mr. Manu Asthana, PJM President, and CEO, November 28, 2023, https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20231128-opsi-letter-re-grid-reliability.ashx

23 PJM Interconnection, "Long-Term Regional Transmission Planning Workshop," accessed May 1, 2024, https://www.pjm.com/committees-and-groups/workshops/ltrtp.

24 Order No. 1920. at P 85-111.

25 *See Transmission Planning Report Card.*

26 *See* Pfeifenberger, J., R. Gramlich, et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, Brattle Group and Grid Strategies, (October 2021) ("*Transmission Planning for the 21st Century*"), https://gridprogress.files.wordpress.com/2021/10/transmissionplanning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf.

> “[W]e require transmission providers to satisfy specific requirements in implementing Long-Term Regional Transmission Planning, including requirements to: (1) use a transmission planning horizon of no less than 20 years into the future in developing Long-Term Scenarios; (2) reassess and revise those scenarios at least once every five years; (3) incorporate into the Long-Term Scenarios a set of Commission-identified categories of factors that give rise to Long-Term Transmission Needs; (4) develop a plausible and diverse set of at least three Long-Term Scenarios; (5) perform sensitivity analyses of uncertain operational outcomes during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area; and (6) use “best available data” in developing Long-Term Scenarios.”[27]

ACEG’s Transmission Planning and Development Report Card evaluated transmission planning best practices across ten regions.[28] The best practices include:

1. Proactive planning for future generation and load;
2. Accounting for the full range of transmission projects’ benefits and using multi-value planning;
3. Addressing uncertainties and high-stress grid conditions explicitly through scenario-based planning;
4. Using comprehensive transmission network portfolios (as opposed to only line-specific assessments); and
5. Joint planning across neighboring interregional systems.

The ACEG report card also evaluated three additional best practices that contribute to successful planning and development:

1. Early, meaningful engagement and input with interested parties;
2. Considering all business models;
3. Balanced governance for regional planning.[29]

The additional best practices were reinforced by a 2024 Grid Strategies study which highlighted that effective collaboration between transmission owners, operators, planners, and other interested parties is a critical element to successfully planning needed regional and interregional transmission across all regions in the U.S.[30]

Without proactive planning for all known needs, numerous incremental transmission upgrades may be built to compensate. Incremental upgrades often overlook the most cost-effective long-term solutions from a system-wide perspective. Proactive planning also helps guide the market towards the optimal mix of generation and transmission and can identify needs where an integrated network solution is most efficient.

---

27 Order No. 1920 at P 248.

28 *See Transmission Planning for the 21st Century.*

29 *See Transmission Planning Report Card.*

30 *See* R. Gramlich, R. Doying, and Z. Zimmerman, *Fostering Collaboration Would Help Build Needed Transmission,* Grid Strategies (February 2024), https://gridstrategiesllc.com/wp-content/uploads/2024/02/GS_WIRES-Collaborative-Planning.pdf

For example, the MISO Multi-Value Projects (MVP) were a portfolio of transmission lines that connected 11 GW of new resources. The MVP portfolio grew out of a proactive study and planning process called the Regional Generation Outlet Study (RGOS). In 2017, when MISO reevaluated the portfolio, it found the MVP portfolio provided $12-$53 billion in benefits to the region, an increase of 21-36 percent over what was initially calculated when the lines were approved in 2011.

CAISO,[31] ERCOT,[32] SPP,[33] and NYISO[34] have shown that when comprehensive transmission planning is in place, the resulting transmission development delivers benefits to consumers and lowers overall system costs. PJM has also quantified the benefits of optimzing transmission and interconnection of new generation in multiple studies.[35]

Proactive transmission planning and development can also help alleviate interconnection queue backlogs and reduce interconnection upgrade costs. For example, PJM found that proactive holistic regional transmission planning for offshore wind reduces the cost of interconnection by 55 percent from $400 per kW to $188 per kW compared to incremental upgrades needed to interconnect new offshore wind through the queue.[36] The MISO MVP projects discussed above, also show the value of holistic planning, reducing interconnection costs compared to some current generator upgrade costs in In Western MISO from $750 kW to $400 kW.[37]

Anticipating generation retirements is critical for proactive transmission planning. If these are unpredicted it can lead to higher costs. The unanticipated retirement of the Baltimore MD Brandon Shores Generating Plant led to a reliability impact. When the plant owner, Talen Energy, announced in 2023 that it would close Brandon Shores in 2025, PJM determined it needed $785 million in upgrades to mitigate the system impact of the shutdown.[38] But the planned upgrades are not expected to be completed until 2028, 3.5 years after the planned closing.[39] In the interim, PJM will require Brandon Shores to run for 3.5 years under a reliability must-run (RMR) agreement, potentially costing consumers $250 million for every year of

---

31 *See* Armie Perez, *Memorandum to California Independent System Operator Board of Directors re Decision on Tehachapi Projects* (January 2007), https:// www.caiso.com/Documents/DecisiononTehachapiProject-Memo.pdf.

32 *See* ERCOT, "The Texas Competitive Renewable Energy Zone Process," Clean Energy Solutions Center (September 2017), https://www.youtube.com/watch?v=I7Jwd0G_ruY.

33 *See* Southwest Power Pool, *The Value of Transmission* (January 2016), https://spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf.

34 *See* NYISO, *AC Transmission Public Policy Transmission Plan*, (April 2019), https://www.nyiso.com/documents/20142/5990681/AC-Transmission-Public-Policy-Transmission-Plan-2019-04-08.pdf/23cbba74-a65e-66c2-708e-eaa0afc9f789; *See also* Potomac Economic, *NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects* (February 2019), https://www.nyiso.com/documents/20142/5172540/04d%20AC%20Transmission%20ApnxE%20MMU%20Report.pdf/113062e4-4ae4-9b7d-46a5-3eec40ad739d

35 *See* PJM Interconnection, *The Benefits of the PJM Transmission System* (April 2019) https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf; *See also* PJM Interconnection, *Offshore Wind Transmission Study: Phase 1 Results* (October 2021), https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

36 *Transmission Planning for the 21st Century,* 10; *See also* B. Burke, M. Goggin, and R. Gramlich, *Offshore Wind Transmission White Paper,* Business Network for Offshore Wind and Grid Strategies, 10 (November 2020), https://gridprogress.files.wordpress.com/2020/11/business-network-osw-transmission-white-paper-final.pdf.

37 *Transmission Planning for the 21st Century,* 12.

38 E. Howland, "2024 PJM Outlook: Tough choices loom on capacity market, plant retirements, transmission planning," Utility Dive (February 2024), https://www.utilitydive.com/news/pjm-outlook-2024-capacity-market-reform-rmr-transmission-planning/708811/.

39 Federal Energy Regulatory Commission, *Commissioner Clements' Concurrence in ER23-2612-000*, November 2023, https://www.ferc.gov/news-events/news/commissioner-clements-concurrence-er23-2612-000#_ftn2.

operation.[40] If PJM had anticipated the plant closing earlier, some of the RMR costs could have been avoided.

E. Inputs and assumptions for scenario development

This report focuses on initial assumptions (load, retirements, and new generation needs)–the input data necessary for effective planning. Planners should include best available information for the following factors:

- Electrification
- Energy efficiency adoption
- Demand response
- Economic growth
- Demand growth from manufacturing, data centers, and other large loads
- Generation costs
- Generation type and location
- Potential generation retirements and location
- Resource adequacy and reserve needs
- Hydrogen production
- Technology costs & availability
- Future weather/climate conditions, including extreme weather events and frequency
- Customer preferences
- Utility plans and goals
- State and federal laws and goals[41]

FERC, in Order No. 1920, now requires transmission planners to include seven factors in development of scenarios for long-term regional planning including:

> "(1) federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand; (2) federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved integrated resource plans and expected supply obligations for load-serving entities; (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs."[42]

40 Telos Energy and GridLab, "Brandon Shores Retirement Analysis Project Update," (January 2024), https://www.sierraclub.org/sites/default/files/2024-02/2024-01-30%20Brandon%20Shores%20Maryland%20Presentation.pdf.

41 *Transmission Planning for the 21st Century,* 59.

42 Order No. 1920 at P 387.

Between the six requirements for long-term planning discussed in Section 1.d. and the seven factors required for scenario planning, FERC has generally incorporated the initial inputs recommended above. However, monitoring and participating in the regional implementation of the six planning considerations and seven factors now required by Order No. 1920 by interested parties will be critical to ensure regions are incorporating the best available data for each of these inputs.

Our report broadly incorporates the seven factors required by Order No. 1920. However, we did not run a capacity expansion model for this report, and several of the factors more closely related to capacity expansion modeling, such as generation cost, generation type, and location, which could be contained within Order No. 1920 Factors 1, 2, 4, or 6, were included in our recommendations for improvements to PJM's current long-term planning process.

As noted above, planning must be over time horizons far enough in the future to accurately assess the benefits of building the projects identified. FERC's Order No. 1920 requires planners to use a 20-year planning horizon, which is often the timeline for utility Integrated Resource Planning (IRP).[43] For the report, we aligned our analysis with PJM's current 15-year long-term planning horizon. We used the 15-year planning horizon for better comparison with PJM's current planning process and published reports. Nevertheless, there will be a need for PJM to update its planning to match FERC's required 20-year planning horizon.

43 Order No. 1920 at P 225; *Transmission Planning Report Card,* 18.

3 SCENARIO RESULTS AND IMPLICATIONS FOR PJM'S PLANNING PROCESS

In this section, we summarize the analysis and results from our scenario development for PJM's future needs and resource mix in 2040. The subsequent sections provide in-depth discussion of our assumptions and findings for each component of our scenarios including load, retirements, generation additions, and demand for clean energy.

Using publicly available data, we developed two future scenarios for PJM – Expected and High – based on estimates of load growth, retirements, new generation, and demand for clean energy in 2040. The Expected scenario represents the most likely estimate of future needs given consideration of all the inputs, while the High scenario represents a future with greater energy needs due to accelerated electrification, more generator retirements, and clean energy demand. If PJM finds the same transmission need under both scenarios, this is a strong indication that the RTO should plan for and develop that line.

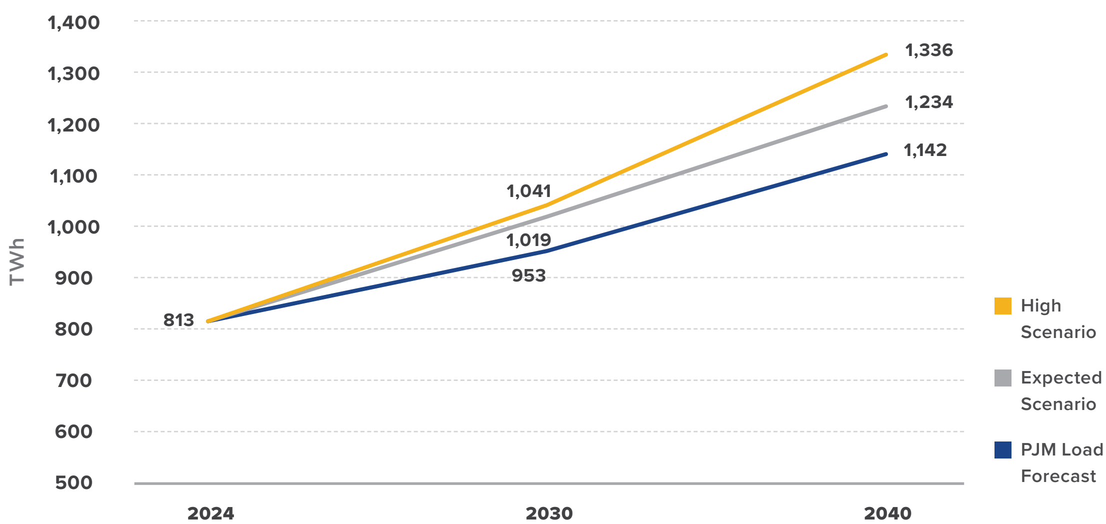
TABLE 1 | Summary of Scenario Assumptions

	Expected	**High**
Load Scenario	NREL Electrification Futures Medium-moderate + Data Centers	NREL Electrification Futures High-moderate + Data Centers
Retirement Assumptions	Model considering efficiency and age of thermal plant. Peaker plants remain for resource adequacy.	Age-based retirement assumptions ▸ Coal (30 years) ▸ NG - cc (35 years) ▸ NG - other (No retirements) ▸ Nuclear (If Announced) ▸ Solar (25 years) ▸ Wind (25 years)
Generation Additions	Additional new energy generation needed to meet the resource gap between load and existing generation minus retirements.	Additional new energy generation needed to meet the resource gap between load and existing generation minus retirements.
Demand for Clean Energy	Demand from states and large energy buyers for additional clean energy, providing a backstop and market certainty.	Demand from states, utilities, and large energy buyers for additional clean energy, providing a backstop and market certainty.

A. Load

Based on NREL's Electrification Futures Scenarios for the Expected Scenario, PJM's load could increase by almost 50 percent over the next 15 years, or an additional 421 TWh. This adds approximately 90 TWh beyond PJM's 2024 load forecast, which estimates demand for electricity will increase almost 40 percent over 2024 levels, or 329 TWh, by 2040. In our High scenario, load grows 523 TWh representing an almost 20 percent increase in forecasted load in 2040 compared to PJM's 2024 load forecast.

FIGURE 2 | Comparison of load Forecasts



The main driver of difference between PJM and NREL's load forecasts is different assumptions about the pace of adoption and technology development for end-use electrification. For the 2024 load forecast, PJM included an independent analysis of electric vehicle adoption as well as individual utility adjustments for new data center and manufacturing load. These changes should be built upon to develop more robust estimates of new industrial and data center load as well as all potential sources of electrification.

B. Retirements

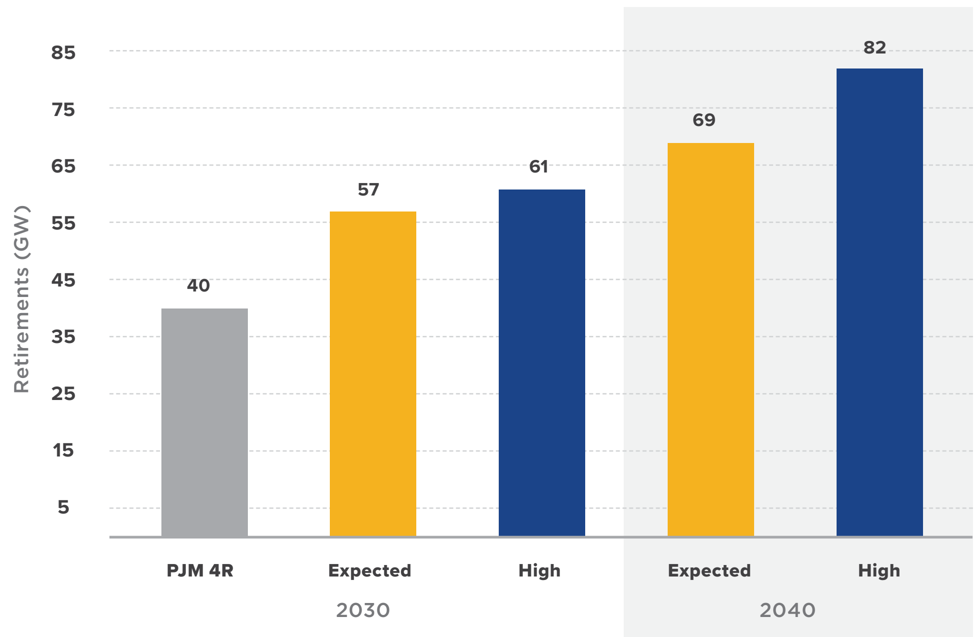
We estimate that by 2040 PJM could face retirements of thermal generation that currently provide as much as 285 TWh in 2040, using plant age assumptions for the High scenario.[44] This represents about 35 percent of PJM's current energy supply. Within our Expected scenario, we developed our own model for thermal generation retirements based on plant heat rates and

44 The results in this report are generally reported on an energy rather than capacity basis. We focused on energy rather than capacity because, among other things, our load forecast and RPS standards are based on energy needs not capacity.

age.[45] Using this model we find that resources providing almost 26 percent of PJM's current energy generation or 213 TWh would retire over the next 15 years.

In 2023, PJM modeled resource retirements out to 2030, finding that approximately 40 GW are at risk of retirement.[46] This is lower than our estimated retirements of 57 GW in 2030 for the Expected Scenario, which rises to almost 70 GW in 2040. However, in its 2023 Annual State of the Market Report, PJM's market monitor estimated that up to 58 GW of thermal generation are at risk of retirement by 2030.[47] The market monitor also noted the retirement estimates are similar to the 54 GW that retired in PJM over the last seven years from 2011 to 2023.[48]

FIGURE 3 | Comparison of Retirements



C. Generation additions

The load growth and retirement estimates create a resource gap in our Expected and High scenarios which requires new generation additions over 15 years. In our High scenario, the PJM region must nearly double current generation to meet the projected resource gap in 2040, while the Expected scenario requires adding resources that will provide equivalent to 76 percent of current generation by 2040. These estimates of new energy needs do not include the additional generation needed to meet PJM's reserve margin.

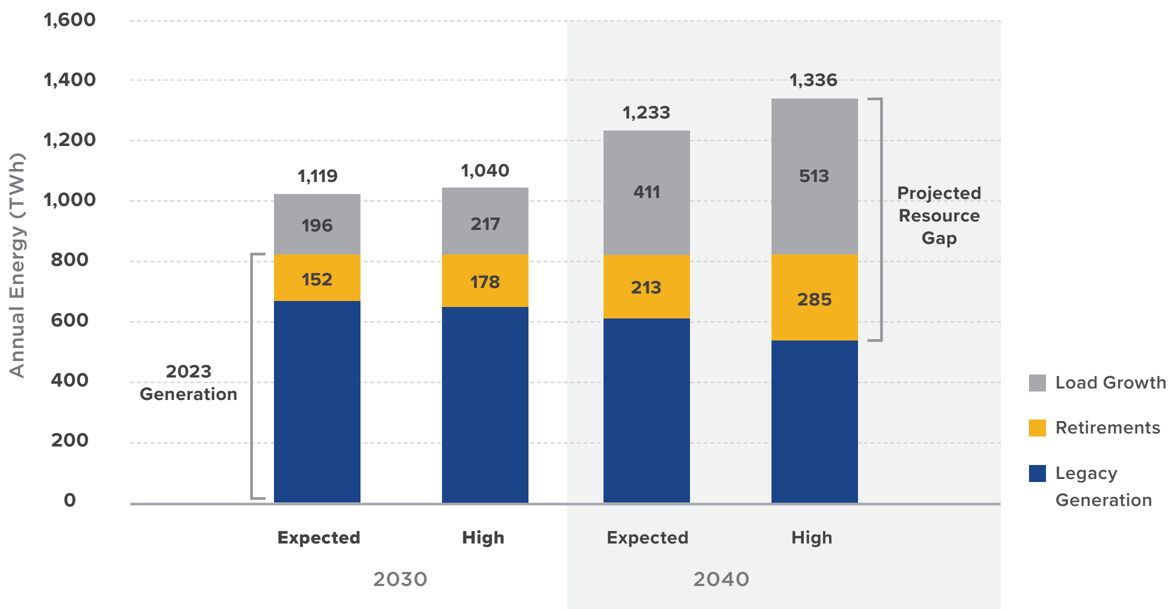
45 Further explanation of the model and assumptions can be found in Section 5.b.ii.

46 PJM Interconnection, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, 2 (February 2023) ("PJM 4R Report"), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx

47 Monitoring Analytics, *2023 Annual State of the Market Report for PJM*, 1 (March 2024) (2023 State of the Market), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023-som-pjm-sec1.pdf.

48 *Id.*, 2.

FIGURE 4 | Summary of Load Growth, Retirements, and New Generation Additions

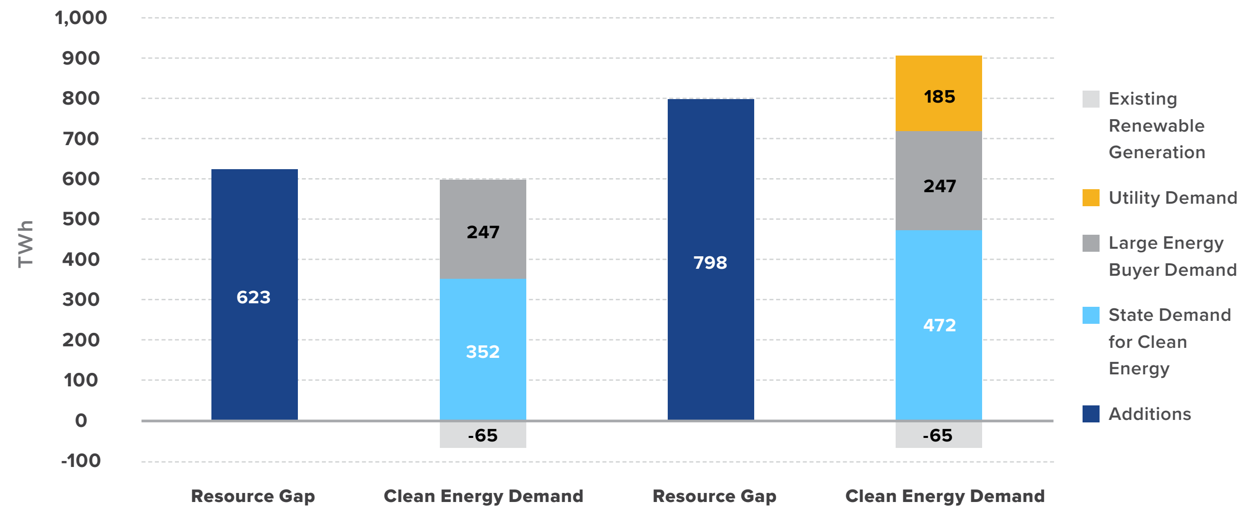


D. Clean energy demand

We show that state laws, large energy buyers, and utility goals all serve to provide a backstop or assurance of the need for clean energy generation. State laws would only require approximately 29 percent of the energy in PJM in 2040 to come from renewable generation. This would be a five-fold increase over PJM's current renewable generation, but it would require only 46 percent of the additional energy needed to meet the resource gap to come from renewable sources after accounting for existing generation. Given that over 95 percent of the active projects in PJM's interconnection queue are renewable or storage projects, and the fact that renewable resources make up the vast majority of resource additions in nearly every region of the country, state laws are unlikely to be binding constraints on PJM's resource mix.

Large energy buyers could add 247 TWh of clean energy demand in addition to state RPSs. And in the High Scenario, when utility goals are considered PJM would need to decrease emissions by 67 percent in 2040 compared to a 2005 baseline, requiring an additional 185 TWh of clean energy beyond state demand.

FIGURE 5 | Summary of Clean Energy Demand Compared to New Generation Additions



PJM should develop and run their own capacity expansion model as a part of their long-term transmission planning that models the most economic generation expansion, with and without state laws. An economic capacity expansion model would likely deploy new renewable generation at a higher rate than current state RPSs would require. As a result, the total renewable penetration is likely to be roughly the same between the cases that are run with and without state policies, indicating that economics and not state policy is the factor driving renewable additions. This is the case for MISO, where its economic modeling for their LRTP process deployed renewables at a rate that exceeded the levels called for under utility and state plans and goals within the region.[49]

The state laws that may drive resource additions that differ from economic modeling results are resource specific targets or carve-outs within state laws for generation that may not be the lowest cost, like offshore wind.

TABLE 2 | State Policy Resource Carve-outs

Resource Specific Carve-outs	2030 (MWh)	2040 (MWh)
Offshore Wind	7,849,486	95,357,856

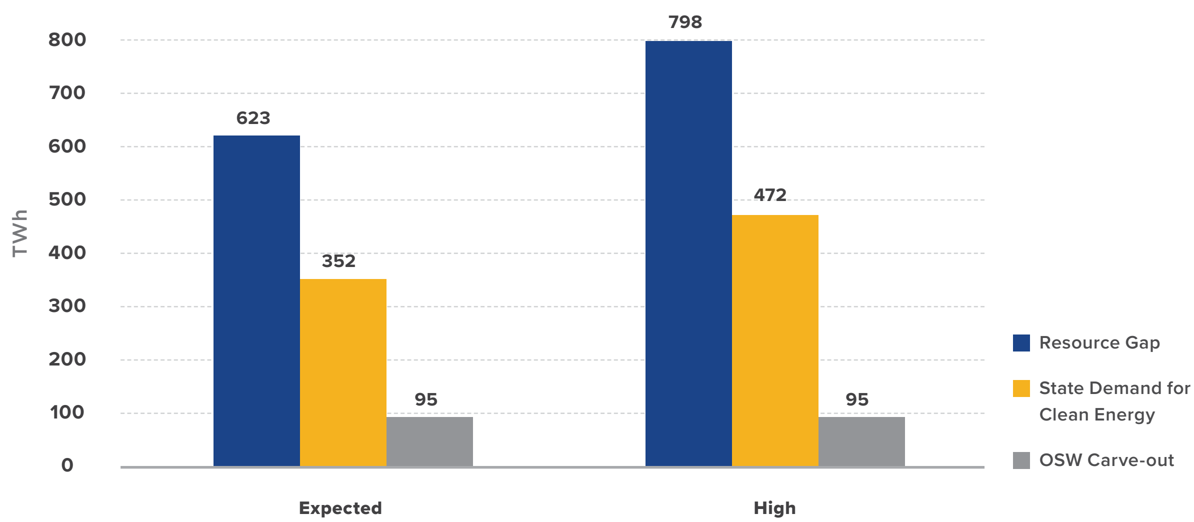
TABLE 3 | State Offshore Wind Requirements by 2040

State	Offshore Wind
Maryland	8,500 MW
New Jersey	11,000 MW
North Carolina	8,000 MW
Virginia	5,200 MW
Total	32,700 MW

49 Midcontinent Independent System Operator, *MISO Futures Report: Series 1A*, 4, 7 (November 2023) (*MISO Futures Report*), https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

The tables above summarize current state offshore wind targets and potential energy carve-outs for offshore wind in 2040. The offshore wind goals and state carve-outs represent approximately 15 percent of the new energy needed in the Expected scenario to meet the 2040 projected resource gap.

FIGURE 6 | Comparison of Projected Resource Gap in 2040 to State Demand for Clean Energy



Based on state laws, including wind and solar resources, Figure 6 above shows the relative proportion of demand for new clean energy from states compared with the estimated resource gap in the Expected and High scenarios along with carve-outs for new generation from offshore wind. In the Expected scenario demand for offshore wind is only 15 percent, while In the High scenario it is 12 percent. In turn, these resources drive specific transmission needs — either for offshore transmission together with on-shore infrastructure upgrades at points of interconnection (POI), or for long-distance high-capacity backbone transmission lines for land-based generation resources.

E. Implications for PJM transmission planning

Our scenarios demonstrate that PJM will need to add substantial new generation over the next 15 years. In this report, we focused on the inputs driving PJM's future energy needs rather than capacity needs. Addressing future capacity needs would require capacity expansion and production cost modeling to understand the optimal future resource mix, which is outside the scope of this report but is a critical part of PJM's transmission planning.

TABLE 4 | 2040 Futures Scenario Results

	Expected	High
Load Scenario	1,234 TWh (2.37% CAGR)	1,336 TWh (2.86% CAGR)
Retirements[50]	213 TWh ▶ Coal and Gas Steam Plants: 139 TWh ▶ NG - cc: 73 TWh ▶ NG - other: 0 TWh ▶ Nuclear: No announcements ▶ Solar: 0.8 TWh ▶ Wind: 15 TWh	285 TWh ▶ Coal and Gas Steam Plants: 174 TWh ▶ NG - cc: 111 TWh ▶ NG - other: 0 TWh ▶ Nuclear: No announcements ▶ Solar: 0.8 TWh ▶ Wind: 15 TWh
Generation Additions	Additional Energy Needed: 623 TWh	Additional Energy Needed: 798 TWh
Clean Energy Demand	State demand for clean energy: 352 TWh Large energy buyers demand for clean energy: 247 TWh 2023 renewable generation: 65 TWh Total new demand: 534 TWh	State demand for clean energy: 472 TWh Large energy buyers demand for clean energy: 247 TWh Utility demand for clean energy: 185 TWh 2023 renewable generation: 65 TWh Total new demand: 839 TWh

To better understand and plan for how the resource mix will evolve to meet the estimated future energy and capacity needs while maintaining system reliability, PJM should iteratively run an economic capacity expansion model alongside a production cost model to ensure both energy and capacity needs are being met and co-optimize generation and transmission buildout.

Capacity expansion models evaluate many potential resource mixes to determine the optimal generation retirements and additions. However, capacity expansion models do not typically model transmission constraints and have limited representation of the hourly dispatch of generation resources, because of the complexity of evaluating so many combinations of resources. Therefore, running a production cost model run iteratively with the capacity expansion model ensures the hourly reliability and optimal economics of the generation mix

50 Wind and solar retirements do not contribute to generation addition needs. Similar to the MISO LRTP Futures Scenario development, wind, and in our case, solar generation, was assumed to be repowered the year following retirement. *MISO Futures Report,* 21.

from the capacity expansion model and identifies potential transmission constraints. This modeling process is what MISO uses to determine the optimal portfolio of generation and transmission expansion.

This iterative process would incorporate resource adequacy needs and will likely find the optimal solution is for some older generators to remain online primarily to meet capacity needs, operating at very low capacity factors. PJM's energy and capacity markets will help ensure an optimal mix of capacity and energy resources is assembled from existing and new resources. In our report, we account for this outcome and the likelihood of increasing capacity prices and needs by not retiring natural gas "peaker" plants. Maintaining the operational capacity of the natural gas peaker fleet through 2040 provides reliability and resource adequacy benefits. Preventing the retirement of the gas peaker fleet also has minimal impact on overall energy and emissions contributions in 2040. Our estimate of the avoided retirements by keeping peaker plants online in 2040 is 15.5 TWh for the Expected scenario and 21.5 TWh in the High scenario.

4 ASSUMPTIONS AND INPUTS TO FUTURE RESOURCE MIX SCENARIOS

A. 2040 Load Forecasts

PJM produces an annual 15-year load forecast. The forecast includes estimates of "peak loads, net energy, load management, distributed solar generation, plug-in electric vehicles, and battery storage."[51] The forecast can include sub-regional or utility adjustments if needed to account for "large, unanticipated load changes, market adjustments, and peak shaving adjustments."[52] In comparison to the 2023 load forecast, PJM's 2024 load forecast, summer, and winter peaks all increased significantly. PJM's 2024 load forecast adds an additional 25,000 MW to the 15-year winter peak compared to the 2023 forecast and almost 200,000 GWh of additional load growth.[53]

In 2023, PJM's load forecast had a 15-year annualized energy growth rate of 1.3 percent, while the 2024 load forecast increased by nearly 1 percent to a 2.2 percent 15-year annualized energy growth rate. PJM is expecting a nearly 40 percent increase in total annual energy usage from about 800 TWh in 2024 to 1,100 TWh in 2039.[54] For the 2024 load forecast, PJM worked with S&P Global to develop an electric vehicle forecast. S&P Global estimated light-duty electric vehicles (EVs) to grow at a rate just under 30 percent annually reaching approximately 23 million EVs by 2039. A similar growth rate was forecasted for medium- and heavy-duty EVs meaning PJM will reach about 1.45 million medium- and heavy-duty EVs by 2039.

However, PJM's load forecast still contains limited projections for electrification driven by state electrification policies and industrial or commercial electrification goals or Scope 1 targets. For this and other reasons, PJM's base estimates of electrification are likely too conservative. The

51 PJM Resource Adequacy Planning Department, *PJM Load Forecast Report January 2024,* PJM Interconnection, 1 (January 2024) (*PJM 2024 Load Report*), https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx.

52 *Id.,* 1.

53 *Id.,* 1-2; PJM Resource Adequacy Planning Department, *PJM Load Forecast Report January 2023,* PJM Interconnection, 1-2 (January 2023) (*PJM 2023 Load Report*), https://www.pjm.com/-/media/library/reports-notices/load-forecast/2023-load-report.ashx.

54 *PJM 2024 Load Report*, 71; *PJM 2023 Load Report,* 72.

load forecast relies on data from Itron to forecast residential electrification. PJM notes these estimates are "consistent with the Energy Information Administration's Annual Energy Outlook." However, it is very likely EIA's forecasts are too conservative and do not reflect the potential rate of adoption of various electrification technologies.[55]

As an example, the only state electrification policies included in the load forecast was New Jersey. The inclusion of these policies resulted in a significant additional load increase for the state by 2040.[56] Moreover, federal electrification incentives now apply across all states and should be accounted for in development of the load forecast.

PJM also included specific load adjustments from distribution companies.[57] For 2024, this included additions for new data and manufacturing loads in Ohio, Maryland, New Jersey, and Virginia.[58] While most of PJM's load adjustments in 2024 were for data centers, new manufacturing and hydrogen investments have the potential to add significant new loads in PJM as well. Since 2021, there has been around $630 billion in near-term investment commitments nationally, related to new manufacturing, industrial, and data centers, with over 200 new manufacturing facilities being announced nationwide in 2023 alone.[59]

Load Scenarios

For our PJM Future Scenarios, we drew from the National Renewable Energy Laboratory's (NREL) Electrification Futures Study load scenarios. The Electrification Futures provide a diverse range of possible outcomes across nine different future load scenarios that model different adoption rates and technology progress for new electrification technologies.[60]

After selecting the NREL Electrification Futures study, we compared their estimates to PJM's current 2024 Load Forecast as a method of validation and to determine which future load scenarios to use. For the Expected scenario, we selected NREL's Medium Electrification and Moderate End-Use Technology Advancement scenario (Medium-Moderate) and for the High scenario, we selected NREL's High Electrification and Moderate End-Use Technology Advancement scenario (High-Moderate). We discuss the comparison of the NREL Electrification Futures with PJM's load forecast further below.

We found that NREL's reference scenarios were likely too conservative. For example, the Reference case estimates light-duty electric vehicles (EV) will make up 22 percent of light-

55 K. Stark, "EIA Outlook 2019: The 'Extremely Conservative' Case for Renewables Growth," GreenTech Media (February 2019), https://www.greentechmedia.com/articles/read/eia-outlook-conservative-renewables; *See also* M. Mahajan and R. Orvis, "Comparing Inflation Reduction Act Modeling to the Annual Energy Outlook," Energy Innovation (March 2023), https://energyinnovation.org/wp-content/uploads/2023/03/Inflation-Reduction-Act-Annual-Energy-Outlook-Comparison.pdf.

56 PJM Inside Lines, "PJM Publishes 2024 Long-Term Load Forecast," PJM Interconnection (January 2024) ("PJM Publishes 2024 Long-Term Load Forecast"), https://insidelines.pjm.com/pjm-publishes-2024-long-term-load-forecast/.

57 PJM Resource Adequacy Planning Department, *2024 Load Forecast Supplement,* PJM Interconnection, 16-18 (January 2024) (*2024 Load Forecast Supplement*), https://www.pjm.com/-/media/planning/res-adeq/load-forecast/load-forecast-supplement.ashx.

58 *PJM 2024 Load Report,* 1-2.

59 "Era of Flat Power Demand is Over," 3-12.

60 T. Mai, P. Jadun, et al., *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States,* National Renewable Energy Laboratory, 43-48 (2018) (*Electrification Futures Study*), https://www.nrel.gov/docs/fy18osti/71500.pdf.

duty fleet sales by 2050.[61] But current light-duty EV sales are already 7.6 percent of sales in 2023, and Kelley Blue Book predicts they will be more than 10 percent in 2024.[62] Carmaker electrification goals are also significantly higher than NREL's reference case.[63] For building electrification, the Reference case is similarly conservative, as shown in Table 7 below.[64]

FIGURE 7 | NREL Electrification Futures Demand-Side Adoption Results for 2050

Select Metrics to Characterize the Electrification Levels Explored in this Analysis[a]

Electrification Metric	2018	Demand-Side Adoption Scenario Results for 2050: Reference Electrification	Medium Electrification	High Electrification
Electricity's share of space heating services	12%	17%	38%	61%
Electricity's share of water heating services	26%	26%	39%	52%
Share of transport miles from electric vehicle miles traveled	< 1%	8%	52%	76%
Light-duty plug-in electric vehicles (number and % of fleet)	~1 million (< 1%)	30 million (11%)	186 million (66%)	242 million (84%)
Electricity"s share of industrial curing needs	0%	0%	15%	63%

a Results are based on the demand-side adoption scenarios in Mai et al. (2018). These metrics do not vary with the assumed level of end-use technology advancement.

NREL's Medium-Moderate scenario estimates about 60 percent of light-duty sales will be some form of EV by 2050. This comes to about 186 million EVs on the road nationally by 2050 or roughly 35 million EVs within the PJM footprint in 2050.[65] This forecast is in line with PJM's 2024 EV forecast. For the 2024 load forecast, S&P Global estimated EVs would have a 30 percent annual growth rate through 2039, culminating in around 23 million total light-duty EVs.[66] PJM could achieve 35 million EVs by 2050 even with a significant slowdown in growth rate, to an under 5 percent annual growth rate. The Medium-Moderate case estimates electrification reaches approximately 50 percent by 2040.[67] While this might be a more aggressive estimate, it is possible given the more conservative penetration in commercial and industrial segments as well as new federal policies incentivizing residential adoption.

61 *Id.*, 43-48.

62 S. Tucker, "Americans Bought Nearly 1.2 Million EVs Last Year," Kelly Blue Book (January 2024) https://www.kbb.com/car-news/americans-bought-nearly-1-2-million-evs-last-year/.

63 International Energy Agency, *Global Energy EV Outlook 2023: Corporate Strategy* (2023), https://www.iea.org/reports/global-ev-outlook-2023/corporate-strategy

64 C. Murphy, T. Mai, et al., *Electrification Futures Study: Scenarios of Power System Evolution and Infrastructure Development for the United States*, National Renewable Energy Laboratory, 5 (January 2021) (*Electrification Futures Study: Scenarios of Power System Evolution*), https://www.nrel.gov/docs/fy21osti/72330.pdf.

65 *Id.*

66 *2024 Load Forecast Supplement,* 16-18.

67 *Electrification Futures Study,* 50-59.

NREL's High-Moderate scenario has a more optimistic estimate of vehicle electrification of nearly 100 percent adoption by 2050. The High-Moderate scenario also contains significant electrification of industrial processes, near total residential electrification by 2035, and 60 percent commercial electrification for space heating by 2035.[68] These are all likely ambitious electrification targets, even given current trends and federal legislation. However, we used NREL's high electrification scenarios to represent the high-end of possible future load demand. **PJM should develop its own high electrification estimates or have an independent group conduct an analysis similar to S&P Global's electric vehicle forecast for the 2024 Load Forecast.**

The NREL Electrification Futures Study is now several years old and does not fully capture recent electrification developments. To account for more recent acute load growth trends from data centers, we added into both the Expected and High future load estimate the data center load adjustments reported by utilities to PJM.[69] However, because only some utilities reported estimates of future data center load growth and the Electrification Futures are a few years old, it is likely the Medium-Moderate scenario used could still underestimate future load. The High-Moderate scenario used in our High scenario was chosen for its more aggressive electrification adoption and more closely estimates the upper bound of future load growth from electrification.

Scenario Results

The table below shows the different load estimates in PJM in 2040 for our Expected and High scenarios. PJM's 2024 load forecast estimates demand for electricity will increase almost 40 percent, or approximately 330 TWh, by 2040. Based on our analysis of NREL's Electrification Futures Scenarios, in our Expected scenario, PJM's load would add an additional 90 TWh above PJM's load forecast in 2040. In the High scenario load could be increasing by almost 65 percent over the next 15 years or an additional 523 TWh. The High scenario's load growth represents an almost 20 percent increase in forecasted load in 2040 compared to PJM's 2024 load forecast.

TABLE 5 | PJM 2040 Load Scenarios

	PJM Forecast	Expected	High
Load Assumptions	PJM's Forecasted Load in 2024	NREL Medium-Moderate + Data Centers	NREL High-Moderate + Data Centers
Load Scenario	813 TWh	1,234 TWh (2.37% CAGR)	1,336 TWh (2.86% CAGR)

The NREL Electrification Futures scenarios provide a more robust estimate of electrification — combined with projected data center load – demonstrate there is potential for load growth beyond PJM's 2024 load forecast. At a minimum, PJM should work to improve estimates of

68 *Id.*

69 *2024 Load Forecast Supplement,* 16-18.

end-use electrification within its footprint, survey its transmission owners, states, and large customers to better understand how the potential developments of large loads and corporate goals or customer demand for electrification may impact future load profiles and growth. PJM's tariff established the role of Independent State Agency Committee to provide input on PJM's transmission planning process. To date that role has been limited, but in 2023 PJM and ISAC began a process to compile relevant state policies that may be incorporated in the RTEP process.[70] This is a first step that can be built upon to more fully incorporate state policies in the transmission planning process.[71]

B. Generation Retirements

PJM does not currently estimate future generation retirements as a part of its long-term planning. Instead, PJM relies on announced retirements, despite having an aging thermal generation fleet.[72] However, this will likely change as PJM has proposed to proactively model retirements as a part of its LTRTP reforms and Order No. 1920 requires planners to account for likely retirements beyond announcements.[73] For the report, we modeled potential retirements based on the age and efficiency of the thermal generation as one possible methodology for estimating potential retirements within PJM's footprint.

At the end of 2023, PJM's total installed thermal capacity was 151 GW.[74] Many plants will retire between 2030 and 2040 based simply from obsolescence. For simplicity, here we focus on historical retirement patterns, not taking into account economics going forward such as future capacity market revenue, nor the recent EPA section 111 rulemaking.[75] Estimating retirements based on historical data are thus lower limits for possible future retirements.

PJM's Thermal Generation Fleet is Aging

For the report, we conducted an analysis on the age of the thermal generation fleet to better understand potential retirements within PJM's footprint.

First, we analyzed the age of the 58.9 GW fleet of fossil steam plants still operating in PJM, many of which are coal powered, and the vast majority of which have turbine units built prior

70 PJM Interconnection, "Independent State Agencies Committee," accessed May 1, 2024, https://www.pjm.com/committees-and-groups/state-commissions/isac.

71 "PJM Publishes 2024 Long-Term Load Forecast."

72 For our analysis we classified fossil retirements by Prime Mover, which included steam turbines (either coal, oil, or gas-powered), simple cycle gas turbines, and combined cycle plants. EIA defines Prime Mover as "the engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cells)." U.S. Energy Information Agency, "Glossary: Prime Mover," accessed May 1, 2024, https://www.eia.gov/tools/glossary/index.php?id=Prime%20mover#:~:text=Prime%20mover%3A%20The%20engine%2C%20turbine,photovoltaic%20solar%20and%20fuel%20cells.

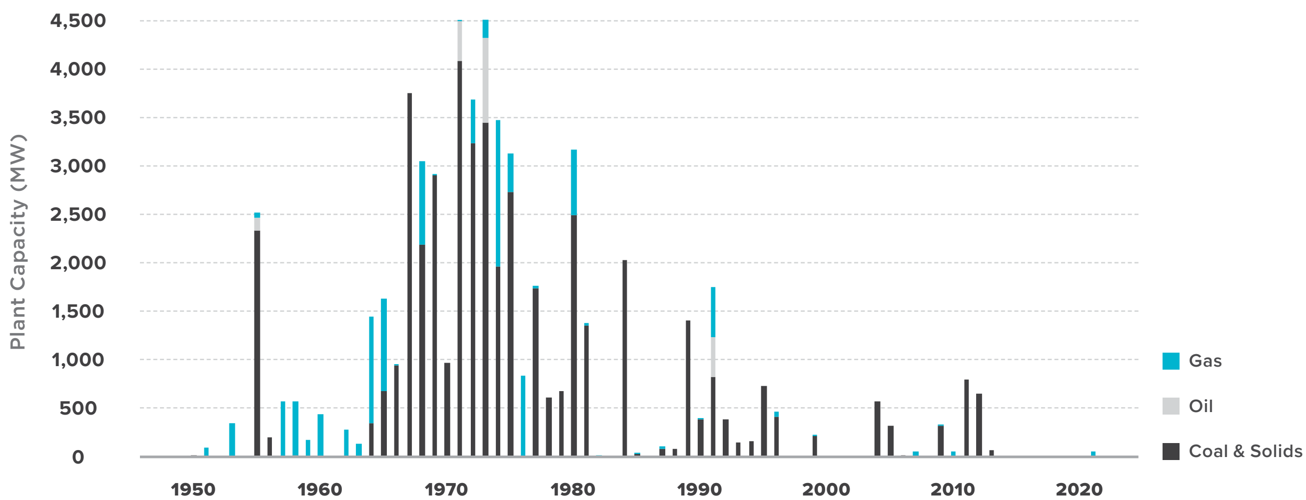
73 Order No. 1920 at P 463.

74 Data used in the Generation Retirements section is sourced from EIA forms 860 and 923.

75 U.S. Environmental Protection Agency, *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule,* EPA-HQ-OAR-2023-0072, (April 2024) ("EPA Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants"), https://www.regulations.gov/docket/EPA-HQ-OAR-2023-0072.

to 1980 as shown in Figure 8 below. These plants tend to be inefficient and are therefore uncompetitive with newer natural gas combined cycle plants. The average capacity factor for these plants is 33 percent, which reflects their relatively higher marginal costs. Looking to historical retirements for an indication of future longevity, nationally the average life of a boiler-powered steam turbine plant has been 53.3 plus or minus 9.1 years.[76] Thus, we project nearly all of this fleet will be retired by 2040 if not by 2030, though some plants could be repowered with more efficient turbine units. The remaining steam units, 7.7 GW total, entered service on average in 1996, more recent than the bulk of the fleet.

FIGURE 8 | PJM Fossil Steam Turbine Unit Age

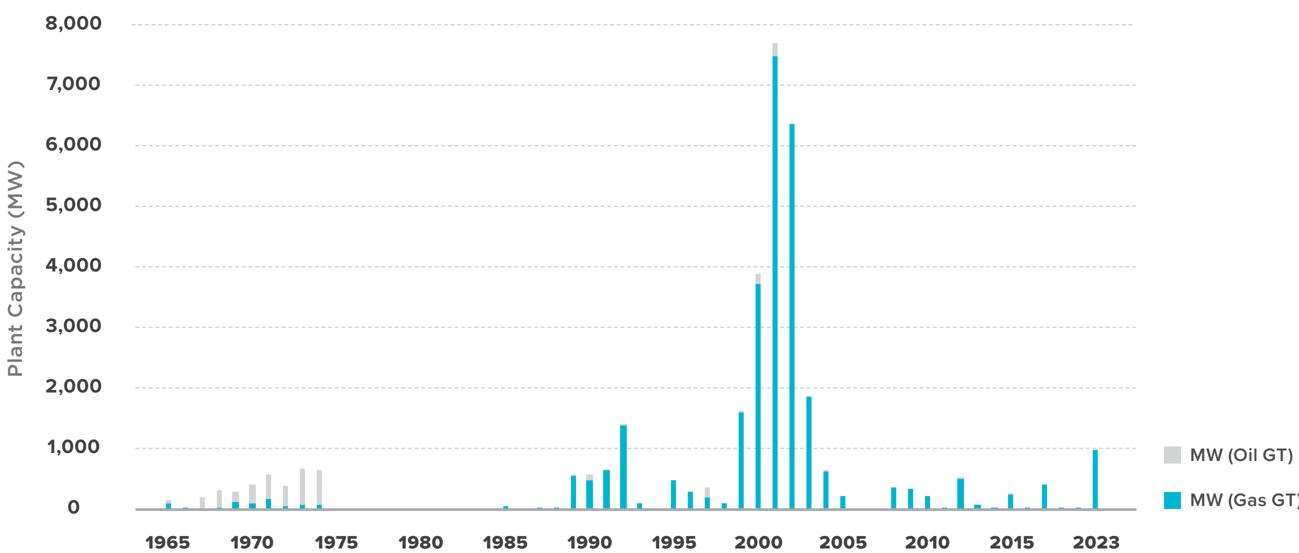


Next, we reviewed the 33.8 GW fleet of simple cycle combustion turbines ("peaker plants"). These plants have a very low average capacity factor of 8 percent but play a critical role in resource adequacy by providing power during peak hours of demand. Within PJM's territory, peaker plants tend to be a more recent vintage than steam-powered boilers.

Historical national retirement data for combustion turbine plants shows these plants last an average 39.8 plus or minus 11.3 years. Their vintage shows a big set of additions around the turn of the century. Just based on age, we can reasonably expect these plants to remain online through 2030, with potential for significant retirements setting in by 2040. However, this will likely be impacted by resource adequacy considerations which we discuss further at the end of this section.

76 We used a national data set for the analysis, but we excluded steam powered plants in California from this sample as coal plants were phased out by regulation. Age-based retirement analysis for Western power plants has been studied by Grubert et al. (2020), Environmental Research Letters 15 1040a4, https://emilygrubert.org/wp-content/uploads/2022/10/Grubert-2020-Fossil-electricity-retirement-deadlines-for-a-just.pdf.

FIGURE 9 | Combustion Turbine Age

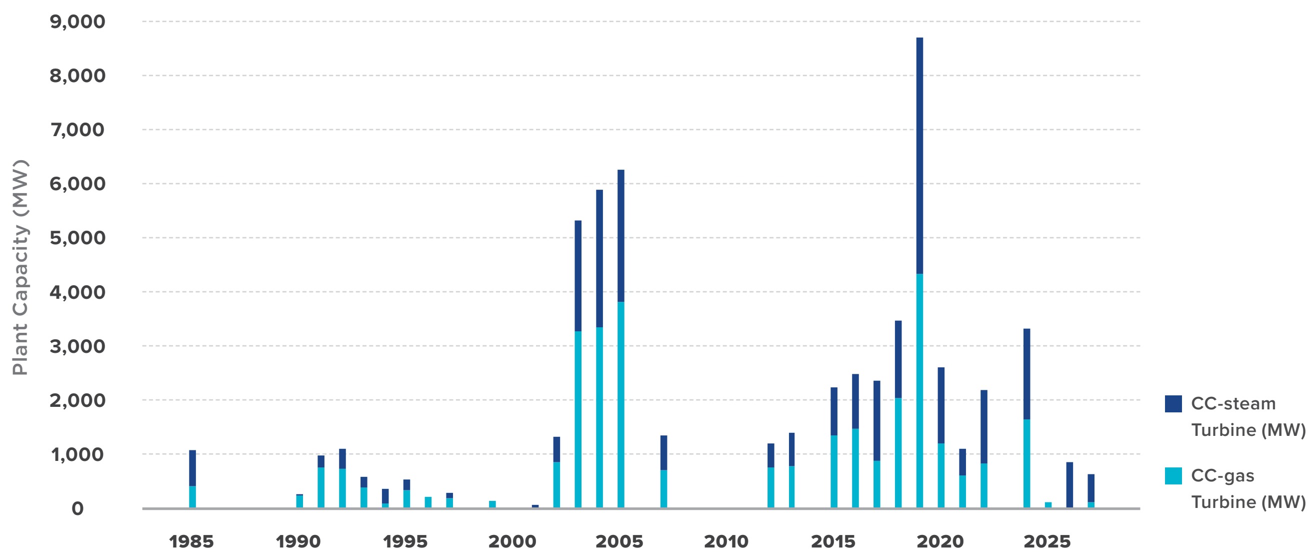


Lastly, we reviewed the combined cycle units. These plants have a capacity of 58.8 GW and are currently the workhorse of the PJM thermal generation fleet, with an average capacity factor of 56 percent, nearly double that of steam turbines. Historical national retirement data show these plants last an average of 35.2 plus or minus 17.1 years. Their vintage shows large additions after 2000. For simplicity, we excluded the impact of repowering combined cycle plants with new gas turbine units but assumed that on average, a combined cycle plant would be derated in proportion to retirements of its components and because repowering adds new capacity which comes with investment uncertainty.

Thus, there will likely be few retirements prior to 2030, with potential for substantial retirements between 2030 and 2040 for additions made prior to 2005. Additions following 2015 can be expected to continue to operate past 2040 assuming no major technological or other external constraints, such as anticipated EPA regulations of greenhouse gas emissions from existing gas generators.[77]

77 *See* "EPA Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants."

FIGURE 10 | Combined Cycle Plant Age by First Year of Full Operation



Scenario Approach

We adopted two different approaches for modeling retirements under our Expect and High scenarios. The High scenario utilizes an age-based sensitivity case derived from retirement assumptions MISO uses for their Long Range Transmission Planning (LRTP).[78]

FIGURE 11 | MISO LRTP Futures Scenarios Generator Retirement Age Assumptions

	Future 1A	Future 2A	Future 3A
Coa	46	36	30
Natural Gas - CC	50	45	35
Natural Gas - Other	46	36	30
Oil	45	40	35
Nuclear & Hydro	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
Solar - Utility-Scale	25	25	25
Wind - Utility-Scale	25	25	25

78 *MISO Futures Report*, 21.

For the High scenario, we use the short-lived plant assumptions from MISO's Future 3A to provide a more accelerated but still reasonable scenario with a significant number of retirements.

For the Expected scenario, we trained a machine learning model on historical national retirement data considering the plant size and heat rate as independent variables.[79] In the table below, we compare the prediction error on a validation set in the machine learning (ML) regression model to the standard deviation from the age-based retirement distribution. Particularly for gas turbines and combined cycle units, the prediction errors were far smaller than the plant life variance in the dataset of retired plants.[80]

TABLE 6 | Comparison of Prediction Error

Prediction error (years)	Steam Turbines	Gas turbines	Combined Cycle
Age-based distribution	9.1	11.3	17.1
Machine learning model	8.2	5.1	9.2

TABLE 7 | Summary of Modeled Generation Retirements

	Steam	Gas Turbines[81]	Combined Cycle	Wind	Solar	Total
PJM Current Capacity (MW)	58,931	33,841	58,667	10,647	6,415	168,501
Current Generation (GWh/yr)	168,983	23,546	288,069	27,452	9,793	517,843
Net capacity factor	0.33	0.08	0.56	0.294	0.174	-
Capacity Retirements						
2030 Retirements (MW)	49,565	13,450	7,070	264.3	0	70,349
2040 Retirements (MW)	51,257	24,918	18,201	6172.9	613.3	101,162
Energy Retirements						
2030 Retirements (GWh/yr)	135,578	7,927	16,210	543	0	160,258
2040 Retirements (GWh/yr)	139,003	15,482	73,497	14749	798	243,529

79 Python scikit-learn random forest regression model. Here we considered steam turbine and gas turbine components separately in combined cycle plants. We also considered combined heat and power generation status but adding this variable did not reduce prediction error. Our code and source data: https://github.com/dinosg/PJM_plant_retirements

80 Data source was EIA Forms 860 and 923 from 2007 through 2023. The analysis began in 2007 because prior to 2007, the EIA did not post data on plant fuel consumption, from which we calculated heat rate.

81 We modeled gas turbine plant retirements and included the results within this section on generation retirements as informational but did not include these retirements as a part of the final scenarios, given the resource adequacy contribution of these resources.

In the model nearly all of the steam plants will have retired by 2030 due to their age. Gas combustion turbines phase out to some extent by 2030 and more so by 2040, reflecting the bulk of their installs occurred in the early 2000's but very few after 2010. Combined cycle generation retirement is minimal considering most of the capacity has been installed since 2010.

Table 7 above includes modeled gas turbine plant retirements for informational purposes, but within our final Future Scenarios, we assume the plants do not retire and remain online due to potential for rising capacity prices and for their contributions towards resource adequacy. Given the plants limited energy contributions, their emissions impact is minimal and is unlikely to impact any state or utility goals.

We compared the results of our model in the Expected scenario to age-based sensitivity cases using the plant retirement age assumptions from the MISO LRTP process. The table below summarizes those results.

TABLE 8 | Age-based Sensitivity cases for PJM Thermal Fleet

	Combined Cycle		Steam Turbine	
Retirement Sensitivity Age Assumption	MISO 3A Future (35 years)	MISO 1A Future (50 years)	MISO 3A Future (30 years)	MISO 1A Future (46 years)
Capacity Retirements				
2030 Retirements (MW)	4,955	1,077	56,003	48,540
2040 Retirements (MW)	24,526	1,347	57,380	54,372
Energy Retirements				
2030 Retirements (GWh/yr)	10,357	627	167,309	147,300
2040 Retirements (GWh/yr)	110,666	1,097	174,200	162,873

For our modeling of retirements for future scenarios, we do not consider plant economics or environmental regulations, such as the EPA power plant emission rules.[82] The modeling and assumptions for whether a plant should retire were based on plant age and efficiency. While not perfect, plant age and efficiency do capture some economic factors, since aging plants have higher fixed operations and maintenance costs, making the plants less economic over time. However, while our model used for the Expected scenario was trained on historic data, which captures plant economics of the time as a secondary factor, it does not explicitly include energy or capacity market revenue or other variables such as the decrease in natural gas prices enabled by shale gas production as inputs. As we discuss throughout the report, **modeling retirements as a part of a capacity expansion model would help PJM capture these dynamics on a forward-going basis and better understand when a plant might retire.**

82 "EPA Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants."

While we do not explicitly include environmental and economic factors within our model, our Expected scenario results for steam and combined cycle retirements in 2030 are roughly in line with the high end of PJM's Market Monitor's estimated generations retirements by 2030, which are based on economics and state and federal regulation.[83] In the next section, we also compared our model with two states' regulations and found our model results roughly align with the expected retirements based on state goals.

Policy Impact of State Legal and Regulatory Mandates

Illinois and New Jersey have enacted laws and regulations respectively mandating some power plants retire by certain dates depending on their carbon emissions per MWh in New Jersey, or heat rates and proximity to Environmental Justice communities in Illinois.[84]

We determined which fossil plants are required to retire in these states based on policies and compared those plants to our analysis of retirements due to age, in the absence of regulatory mandates.

TABLE 9 | Illinois Generation Plants with Mandatory Retirement Dates

Plants Retiring under Illinois Regulation						Modeled Expected Illinois Plant Retirements and Age Sensitivities		
Facility Name	First Year of Operation	Plant Type	Heat Rate (mmBtu/kWh)	Capacity Factor (%)	Nameplate Capacity (MW)	Expected Retirements (GS Model)	MISO Future 1A	MISO Future 3A
Aurora Generating Station	2001	CT	9,954	7.7	723.2	2041	2047	2031
Calumet	2002	CT	8579		312.8	2037	2048	2032
Cordova Energy Company	2001	CC	6825	37.7	611.2	Gas turbine (420 MW) retires in 2029; Steam turbine (191 MW) steam turbine does not retire by 2040	2051	2036
Crete Energy Park	2002	CT	13,162	1.2	356.0	2041	2048	2032
Dynegy Kendall Energy Facility	2002	CC	7668	65.7	1175	One unit retires in 2030 and the other in 2037	2052	2037
Elgin Energy Center, LLC	2002	CT	11,500	8.6	540.0	2021	2048	2032

83 *2023 State of the Market,* 1.

84 R. Kettig and K. Ratzman, "Clean Energy Compliance Options for EGU's," New Jersey Department of Environmental Protection (March 2023), https://dep.nj.gov/wp-content/uploads/njpact/docs/njpact-cec-slides-20230322.pdf; S. Bennett and C. Pilong, "Illinois Clean Energy Jobs Act Fossil Fuel Generation Phaseout," PJM Interconnection (December 2021) https://www.pjm.com/-/media/committees-groups/committees/oc/2021/20211202/20211202-item-16-update-on-illinois-clean-energy-jobs-act.ashx; Illinois Commerce Commission, *Illinois Renewable Access Plan*, Second Draft Plan, Figure 7 (December 2022) https://www.icc.illinois.gov/informal-processes/Renewable-Energy-Access-Plan.

						Modeled Expected Illinois Plant Retirements and Age Sensitivities		
	Plants Retiring under Illinois Regulation							
Facility Name	First Year of Operation	Plant Type	Heat Rate (mmBtu/kWh)	Capacity Factor (%)	Nameplate Capacity (MW)	Expected Retirements (GS Model)	MISO Future 1A	MISO Future 3A
Elwood Energy Facility	2001	CT	11,500	2.5	1,728.0	2022	2047	2031
Joliet 29	1966	Steam	10,200	11.4	1,320.0	2008	2012	1996
Joliet 9	1959	Steam	12,634	0	360	1991	2005	1989
Lee County Generating Station, LLC	2001	CT	13,565	4	692.0	2037	2047	2031
LSP University Park, LLC	2002	CT	12,155	17.4	726	2022	2048	2032
Morris Cogeneration, LLC	2000	CC	7076	35.4	83	2029	2050	2035
Nelson Energy Center	2015	CC	7542	71	627.5	Gas turbine (361 MW) retires in 2043; Steam turbine (266 MW) retires in 2050	2065	2050
Rockford Energy Center	2000	CT	10,457	3.8	316.0	2039	2046	2030
Rockford Energy Center II	2002	CT	10,457	3.8	168	2041	2048	2032
Rocky Road Power, LLC	2000	CT	11,951	2.2	374.0	2012	2046	2030
University Park Energy	2001	CT	12,921	13.7	353	2036	2047	2031
Zion Energy Center	2002	CT	11,135	11.5	596.7	2042	2048	2032

For Illinois, under our age-based retirement assumptions, the only plant that would have remained open in its entirety in the absence of regulatory requirements is the 628 MW Nelson Energy Center combined cycle unit, completed in 2015. Therefore, plant age has a similar impact as policy in what PJM should be planning for in its long-term transmission planning for 2040.

In addition, according to our model, the Aurora Generating Station combustion turbine would retire due to obsolescence in 2040, except for a portion that retires in 2041, thus regulatory mandates should not have a material impact on what PJM should be planning for either.

For New Jersey a similar picture emerges.

TABLE 10 | New Jersey Retirement Analysis (Grid Strategies Model)

Retirement Scenario		**Total**
Current NJ thermal plant capacity (MW)		10,477
Modeled expected retirements (based on plant age and efficiency)		
2030 Retirements (MW)		3,431
2040 Retirements (MW)		5,686
Retirements under proposed regulations		
2030 Retirements (MW)		1,655
2040 Retirements (MW)		3,215
Retirements due to regulation only	**Combined Cycle**	**Gas Turbine**
2030 Retirements (MW)	0	1,228
2040 Retirements (MW)	26.8	498

Here, the MW retired due to obsolescence by 2030 and 2040 exceed the MW of power plants retired by regulatory mandate, as shown in the table above. When we performed a plant-by-plant comparison of generators in New Jersey, we did find that certain power plants may be retired by regulatory mandate before the end of their useful life: for simple cycle gas turbines, 1228 MW would be required to retire by 2030 by mandate and by 2040, 298 MW single cycle gas turbines would be required to retire by mandate that would otherwise continue to operate if age was the only retirement consideration. For combined cycle units, only 26.8 MW of capacity would still have continued to operate past 2040 absent a regulatory mandate. For 2030, there is no impact.

Role of Gas Peaker Plants

Studies show that adding significant amounts of renewable generation greatly reduces energy prices, but has less impact on ancillary services and capacity prices. This is because variable renewable resources provide more energy than capacity, and the long run marginal cost of capacity needs to be high enough to keep sufficient generating capacity online as resources retire due to lower energy market prices.[85] Capacity prices are likely to keep some gas generation from retiring, but only operating a limited number of hours during the year due to lower energy prices.

Because our analysis does not account for increasing capacity prices and needs, we did not include retirements of gas turbine "peaker" plants within our final Expected and High scenario

85 J. Seel, A. Mills, and R. Wiserhttps, *Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making,* Lawrence Berkeley National Laboratory (May 2018), https://emp.lbl.gov/publications/impacts-high-variable-renewable.

results. Maintaining the operational capacity of the natural gas peaker fleet provides reliability and resource adequacy benefits, while minimally impacting overall energy and emissions contributions in 2040 because these plants seldom operate.

For the Expected scenario, we estimate that approximately 15.5 TWh would remain online and 21.5 TWh in the High scenario. These energy contributions from peaker plants represent just over 2 percent of the total projected load for both the Expected and High scenarios in 2040.

PJM's assessment of the future resource mix for transmission planning purposes will need to incorporate resource adequacy needs. Understanding the impacts the potential retirement or need to maintain operations of its gas peaker fleet have on overall system reliability in 2040, and clearly communicating that information to interested parties, is part of a long-term planning process.

C. Generation Additions

Using the future load growth and estimated retirements outlined in the sections, we find that there will be a resource gap between current energy generation and estimated future energy needs within the PJM footprint. The table below shows our estimate of the resource gap and future energy generation needs.

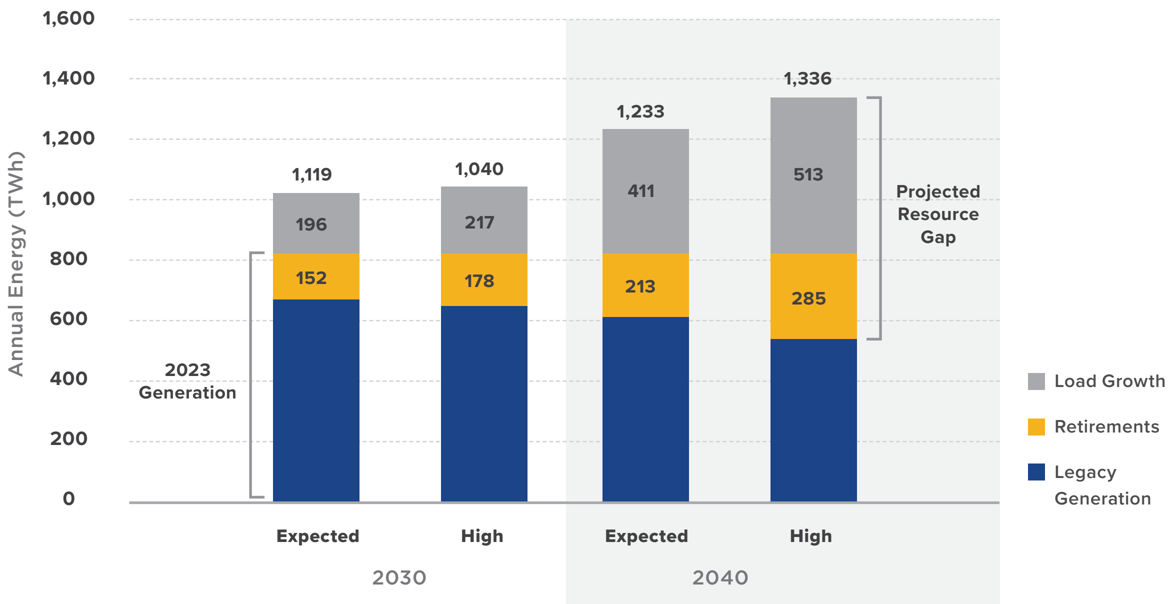
TABLE 11 | Additional Energy Generation Needed by 2040 in PJM

	Expected	High
Generation Additions	Additional Energy Needed: 623 TWh	Additional Energy Needed: 798 TWh

According to U.S. Energy Information Agency (EIA) data, PJM generation for 2023 was just under 825 TWh.[86] To meet the resource gap in 2040 in our Expected scenario, PJM will need to add approximately 75 percent more energy compared to its 2023 energy generation, and in the High scenario, PJM will need to almost double its current energy generation by adding an additional 798 TWh of new generation. The figure below shows the projected resource gap across both scenarios, represented as the sum of projected Load Growth and Retirements.

86 U.S. Energy Information Administration, "Hourly Electric Grid Monitor," accessed May 1, 2024, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

FIGURE 12 | Summary of Load Growth, Retirements, and New Generation Additions



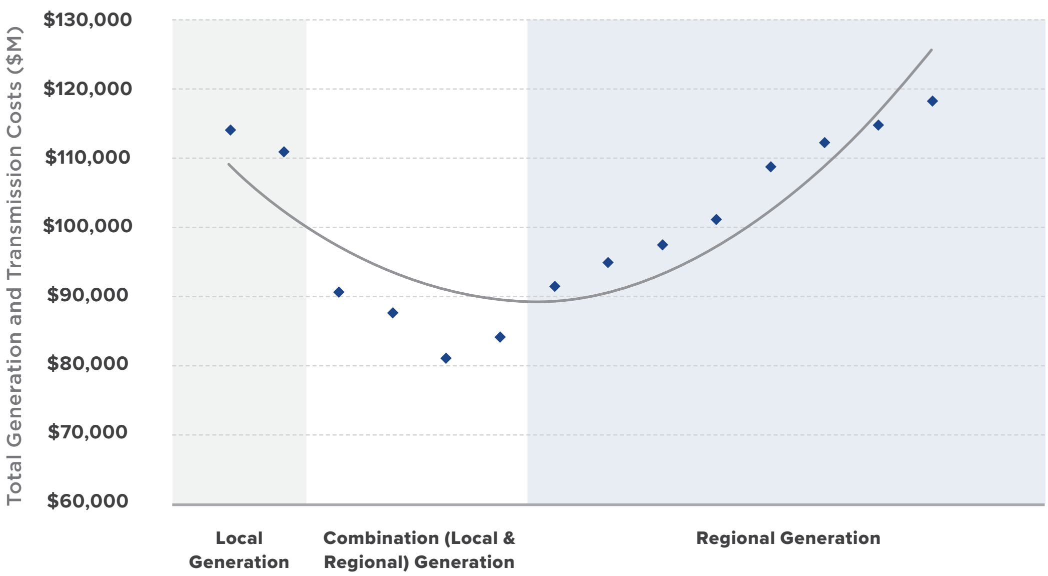
Economic Capacity Expansion Models

For PJM to plan transmission to meet this energy gap, it should use economic capacity expansion modeling.

In its Renewable Generator Outlet Study (RGOS) conducted over ten years ago, MISO demonstrated that the most cost-effective way to plan its energy system was to co-optimize generation and transmission.[87] As the figure below depicts, too much investment in local generation leads to higher system costs which are passed on to consumers. Whereas proactive planning that optimizes both generation and transmission lowers overall systems costs and provides the most benefit to consumers. The same reasoning applies in PJM.

87 *See* MISO, *Regional Generation Outlet Study*, (November 2010) (*RGOS Study*), https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf.

FIGURE 13 | RGOS Generator and Transmission Cost Comparison (MISO "Bathtub Curve")[88]



Indeed, PJM has performed similar analyses in the past optimizing generation and transmission but only with respect to a limited issue. In 2021, PJM conducted its Offshore Wind Transmission Study, a proactive study that holistically evaluated the regional onshore transmission needs to connect new offshore wind to the system. The study found that it would only require $3.2 billion in network upgrades to connect 75 GW of clean energy including 17 GW of offshore wind generation to meet the needs of PJM states' offshore wind plans. Additional, PJM identified through the study that the, "$3.2 billion in onshore network upgrades result in substantial additional regional benefits in the form of congestion relief, customer load LMP reduction, and reduced renewable generation curtailments."[89]

In contrast, connecting the offshore wind projects in PJM through single interconnection requests would double interconnection costs. One study found connecting 15.5 GW of offshore wind incrementally would cost $6.4 billion in network upgrades (over $400/kW).[90] Conversely, proactive transmission planning reduces interconnection costs to $188/kW for 17 GW of offshore wind, a 55 percent reduction.[91] These cost savings are achieved because economies of scale accrue from fewer, high-capacity transmission lines being developed at the beginning of offshore wind deployment compared to numerous smaller lines added incrementally. Fewer lines also optimize the use of limited corridors for offshore transmission landing points where there are constraints from narrow channels and harbors just as fewer larger lines optimize scarce, land-based rights-of-way.

---

88 *Id.*, 33.

89 *Transmission Planning for the 21st Century,* 10.

90 *Id.; See also* B. Burke, M. Goggin, and R. Gramlich, *Offshore Wind Transmission White Paper,* Business Network for Offshore Wind and Grid Strategies, 10 (November 2020), https://gridprogress.files.wordpress.com/2020/11/business-network-osw-transmission-white-paper-final.pdf.

91 *Transmission Planning for the 21st Century,* 10.

MISO's Capacity Expansion Modeling

For its Long-Range Transmission Planning (LRTP), MISO conducts an economic capacity expansion model for its transmission planning to meet resources needs on a 20-year time horizon.

MISO has stated this process is critical for allowing its members to reliability and affordably serve customers by minimizing the total cost of generation and transmission. As a part of its modeling, MISO includes generation from state policies, and utility goals and IRPs. However, these plans often do not include enough resources to meet needs across the full 20-year planning horizon, creating a "resource gap." MISO uses capacity expansion modeling to make sure all resource needs are met.

MISO makes it clear it is not a resource planner, nor does it have the authority to make decisions around new generation or resource development. But MISO does need to conduct resource expansion analysis to meet the resource gap between state and utility policies and plans and 20-year future needs. Within the resource expansion analysis, the modeling is performed on multiple planning scenarios called the MISO Futures, designed "to hedge uncertainty and 'bookend' a range of economic, political, and technological possibilities over the 20-year study period."[92] The capacity expansion modeling MISO conducts is designed to "find the optimal resource buildout that minimizes the overall system cost while meeting reliability and policy requirements."[93]

Moreover, economic capacity expansion analysis can help inform which system needs are based on load additions and generation retirements — issues that are the cornerstones of effective system planning – and which system needs are incremental to those issues and arise only as a result of a particular state resource directive. For example, the Future 2A results used for MISO's LRTP Tranche 2 transmission plan showed that under all three scenarios new renewables would be added at a rate greater than the amount needed to meet state laws and utility IRPs and goals:

Summary of Future 2A results

- In MISO's middle scenario, which is the basis for MISO's LRTP Tranche 2 transmission plan, state and utility policies were not binding for resource deployment.
- The model deployed 288 GW of new renewables and storage, which is estimated to deliver 83 percent of the energy in the optimal energy mix or approximately 930 TWh of energy.[94]
- This optimal generation mix results in a 96 percent reduction in carbon dioxide emission, which is much higher than the 76 percent decarbonization that was required to meet "100% of utility IRPs and announced state and utility goals."[95]

92 *MISO Futures Report*, 2.
93 *Id.*
94 *Id.*, 7.
95 *Id.*, 4.

Renewable additions still greatly outpaced state policy requirements in the conservative Future 1A:

Summary of Future 1A results

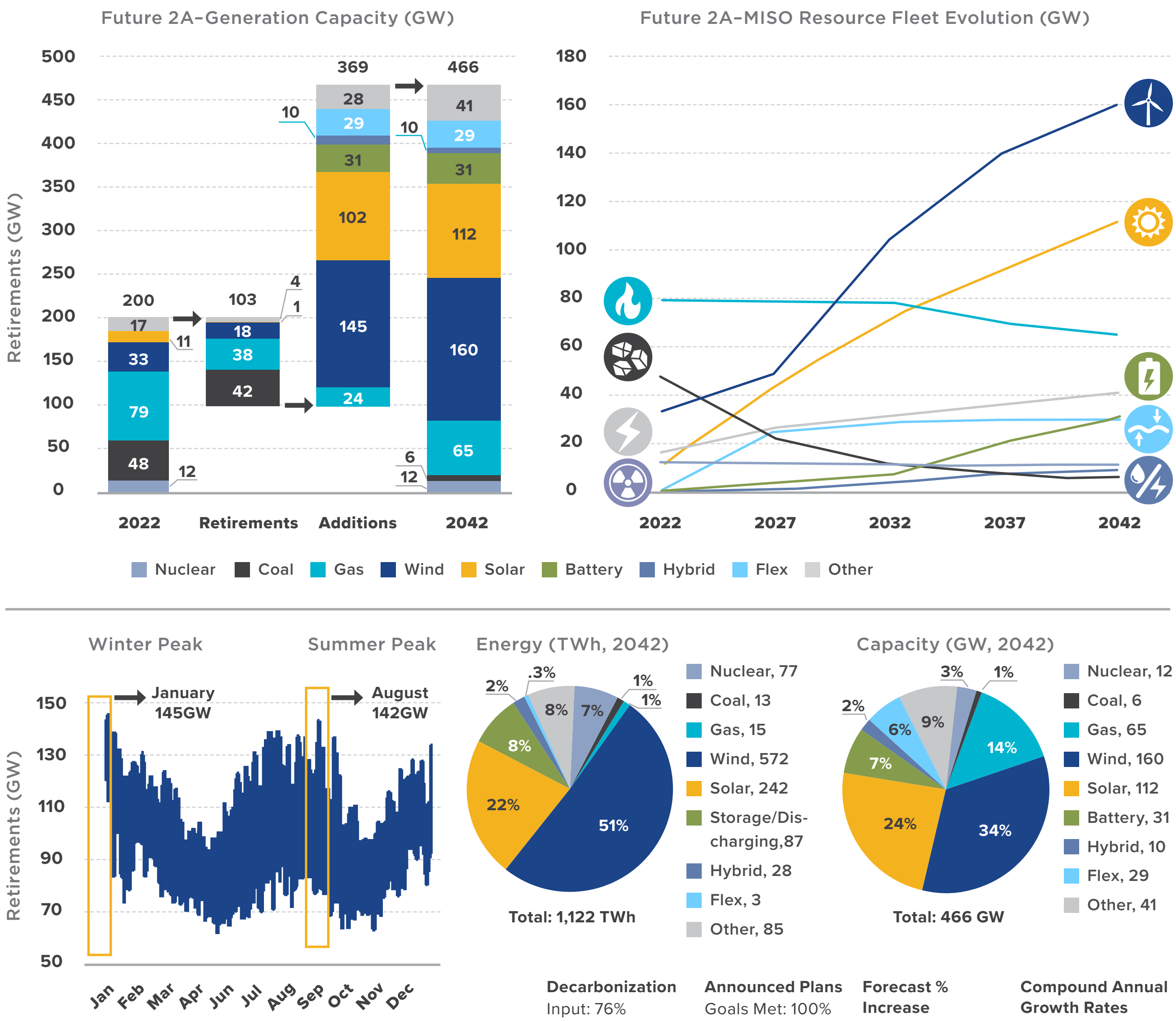
- Future 1A contained the most conservative assumptions and still deployed more renewables than was required by state or utility policy and plans.
- MISO states included a 71% carbon reduction trajectory to meet utility and state plans and requirements, but the model resulted in 83% carbon reduction."[96]
- 214 GW of new resources were deployed and 57% of the energy comes from wind, solar, or hybrid resources.[97]

The figure below shows the results of the capacity expansion modeling for Future 2A, as well as the energy and capacity contributions of each resource type.

---

96 *Id.*, 4.
97 *Id.*, 3.

FIGURE 14 | Modeling Results for MISO Future 2A[98]

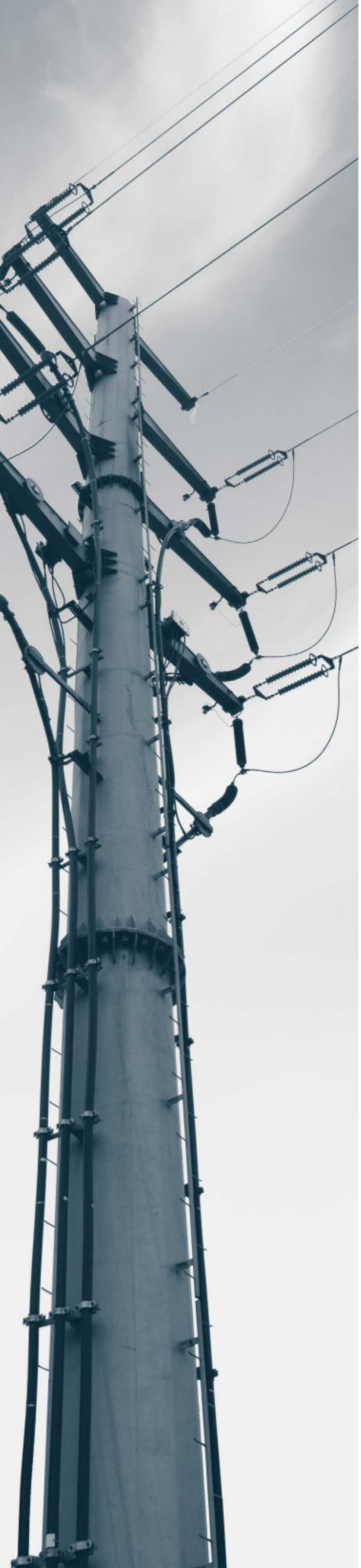


Decarbonization	Announced Plans	Forecast % Increase	Compound Annual Growth Rates
Input: 76%	Goals Met: 100%	Energy: 17.3%	Energy: 0.80%
Input: 96%	IPS: 100%	Demand: 7.6%	Demand: 0.82%

Load and growth values are net of load-modifying resources. Gross forecast values are unchanged except for extrapolation to 2042. Energy TWh value includes energy required for storage-charging

As shown in the figure above, MISO clean energy development is not restricted by state laws or utility goals because the economically optimal deployment of renewable and storage generation is greater than those requirements. As a result, if MISO were to run the model only based on the underlying economics without any of the state or utility plans or policy constraints, it would result in a similar deployment of clean energy.

98 *Id.*, 7.



PJM's Queue for Capacity Expansion

PJM relies more on its interconnection queue to plan for new resources than MISO, in part because of the number of deregulated utilities that do not rely on an IRP process in PJM. **Since most states in PJM no longer require their utilities to conduct IRPs, it is even more important that PJM conduct regional economic modeling of generation additions and retirements as a starting point for ensuring the region has the transmission needed to provide ratepayers with reliable and affordable power given the reality of the future generation mix.**

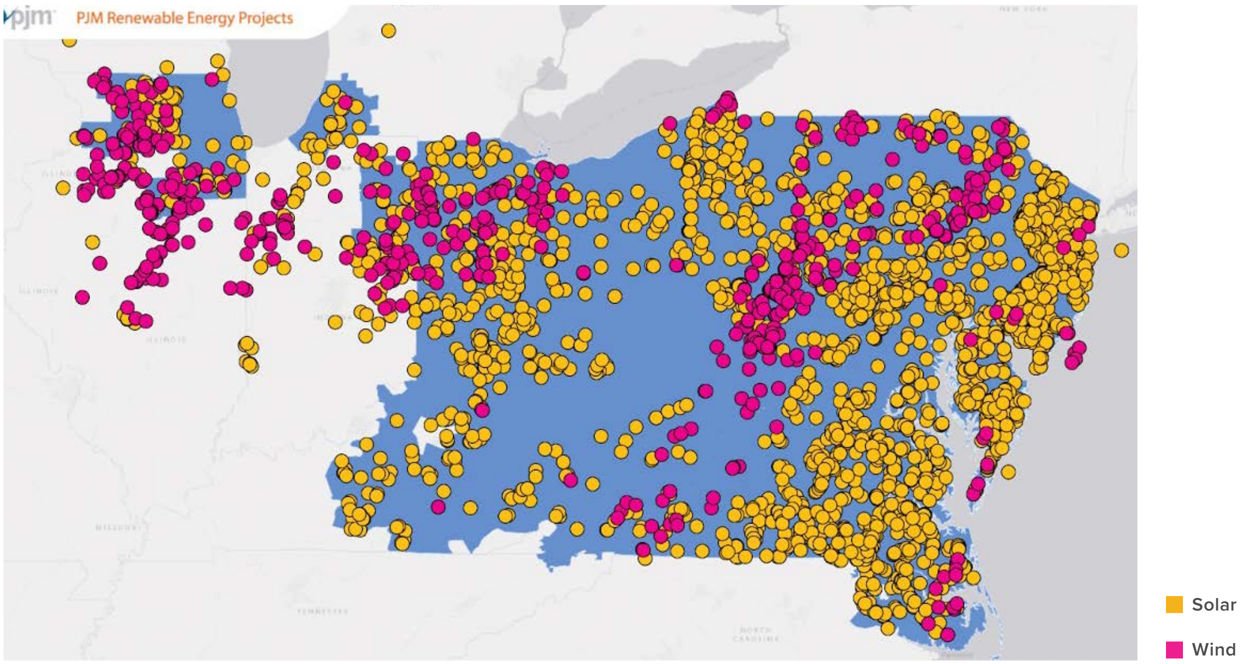
Like MISO, ERCOT, and SPP, PJM has relatively concentrated areas of strong wind resources, primarily in the western part of the footprint. There is also significant wind potential along the Allegheny Mountains in the eastern part of PJM. The vast majority of proposed wind projects in PJM's interconnection queue are concentrated in these areas, as shown in Figure 15 below. The map indicates that areas of solar developer interest are more dispersed across the region, but show some concentration in the eastern and western parts of the footprint. Generator capacity expansion modeling co-optimized with transmission expansion would allow PJM to identify expansion plans that minimize consumer costs while spreading net benefits across the entire region, as MISO has done in its modeling.

The resource mix in PJM's interconnection queue is consistent with MISO's modeling results. At the end of 2023, PJM had 230 GW of active projects of which only 2 percent were natural gas generation and 97 percent were new wind, solar, storage, or hybrid projects.[99] The queue composition reflects the current low cost of clean energy resources. Even if many of the renewable and storage projects are speculative, applying NREL's lowest capacity-weighted completion success rate of 10 percent for solar across all active renewable and storage projects in PJM's queue and assuming natural gas generation has a 100 percent success rate still means renewables and storage projects would be installed at nearly 5 times the rate

99 A. Haque, "PJM Introduction and Ensuring a Reliable Energy Transition," PJM Interconnection, 12 (January 2024), https://www.pjm.com/-/media/library/reports-notices/testimony/2024/20240111-haque-maryland-senate-energy-education-environment-committee-presentation.ashx.

of natural gas projects.[100] Further, analyzing 2023 generation capacity installations nationally showed that solar and wind accounted for nearly two-thirds of the deployment, with natural gas accounting for just under 20 percent of capacity additions, consistent with national additions from 2020 to 2023, which had similar deployment ratios.[101]

FIGURE 15 | Solar and Wind Sites in PJM Interconnection Queue[102]



D. Clean Energy Demand

State renewable portfolio standards, utility goals, and demand from large energy buyers and other consumers indicate future clean energy needs. We summarize clean energy demand across PJM by the above categories.

State Laws & Regulations

PJM is the grid operator for 13 states including Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee Virginia, West Virginia plus the District of Columbia. We compiled renewable portfolio standards (RPS) or clean energy laws that have been enacted into law or issued by a state authority, such as through an executive order. Many PJM states have had an RPS law in effect for almost 20 years.

100 J. Rand, R. Strauss, W. Gorman, et al., *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022,* Lawrence Berkeley National Laboratory, 20 (April 2024), https://emp.lbl.gov/sites/default/files/emp-files/queued_up_2022_04-06-2023.pdf.

101 L. Jenkins, "Four charts that capture U.S. solar deployment in 2023," Latitude Media (March 2024), https://www.latitudemedia.com/news/four-charts-that-capture-u-s-solar-installation-in-2023.

102 PJM Interconnection, "PJM Renewable Energy Projects," accessed May 2, 2024, https://mapservices.pjm.com/renewables/.

Many states have also adopted more ambitious targets since the initial passage of an RPS. Ten of the eleven states in PJM plus DC with clean energy laws have updated their goals in the last five years. Five states plus DC have greenhouse gas reduction targets. Only four states lack goals or renewable portfolio standards, and of those Indiana has a voluntary RPS. Over 80 percent of PJM's load is subject to some form of state clean energy law or goal.

TABLE 12 | Summary of State Clean Energy Laws[103]

State	RPS or CES	Resource Carve Outs
Delaware	25% by 2026; 40% by 2035; Reduce statewide emissions 50% from 2005 levels by 2030 and 100% by 2050.	5% solar in 2030 and 10% by 2035
Illinois[104]	40% by 2030; 50% by 2040; 100% by 2050	45% is required to be procured from wind and hydropower projects and 55% from photovoltaic projects
Indiana[105]	10% by 2025	N/A
Kentucky	N/A	N/A
Maryland	50% by 2030; 100% by 2045; Reduce statewide emissions by 60% from 2006 levels by 2031 and reach statewide net-zero emissions by 2045.	14.5% from solar and 1,200 MW (2,022.5 MW already procured) OSW by 2030, 8,500 MW OSW by 2031.
Michigan	15% by 2029; 50% by 2034; 60% by 2035; 80% by 2039; 100% by 2040	N/A
New Jersey[106]	35% by 2025; 50% by 2030; Executive Order sets goal of 100% clean energy by 2035.	1.1% solar in 2031, 3500 MW of OSW and 11,000 MW by 2040. 2000 MW of storage by 2030.
North Carolina	12.5% by 2021; Utilities reduce emissions by 70% from 2005 levels by 2030 net-zero by 2050.	0.20% from solar, 2.8 GW of OSW by 2030 and 8.0 GW by 2040.
Ohio[107]	8.5% by 2026	N/A
Pennsylvania[108]	8% by 2021	0.5% solar
Tennessee	N/A	N/A
Virginia[109]	100% by 2045 for Phase II utilities and 2050 for Phase I utilities	5,200 MW of OSW by December 31, 2034.
West Virginia	N/A	N/A
DC	100% by 2032	5% solar in 2030 and 10% in 2040

103 Definitions of renewable resources vary by state. For example, Pennsylvania's statute includes waste coal and Maryland includes waste to energy. All these sources are included in our quantification of State demand for clean energy, though by 2040 we expect a large portion of this demand to come from solar, wind, and storage projects.

104 Applies to IOUs only.

105 Voluntary RPS.

106 RPS applies to IOUs only.

107 RPS only applies through 2026.

108 Applies to IOUs only.

109 Applies to IOUs only.

We used state laws and goals above to quantify the minimum clean energy demand in 2040. Applying State laws to load in 2040, we estimate that in the Expected scenario state RPSs will only cover 29 percent of PJM energy generation, while in the High scenario minimum clean energy demand rises to 35 percent. New renewable generation would need to increase 5-7-fold from 65 TWh in 2023 to 352 or 472 TWh in 2040 under our Expected and High scenarios. This equals approximately 7.5 GW of new wind and solar resources added annually.

As shown in Table 13 below, state policy requirements account for just over half of PJM's energy needs in the Expected and High Scenarios. Economic deployment of renewable resources is likely to greatly exceed the quantity required under state policies, as indicated by the results of MISO's Future Scenarios,[110] PJM's queue, and other factors, as discussed above. As a result, the total deployment of renewable resources is likely to be the same with or without state policies, though as more in detail in Section IV.iv. state policies may shift some deployment to higher-cost resources like offshore wind. PJM could confirm this finding by running an economic capacity expansion model to determine the lowest-cost generation mix with and without state policy requirements.

TABLE 13 | PJM Energy Needs are Much Greater than State Policy Clean Energy Demand

	Expected	High
Generation Additions	Additional Energy Needed: 623 TWh	Additional Energy Needed: 798 TWh
Demand for Clean Energy	State demand for clean energy: 352 TWh	State demand for clean energy: 472 TWh

Given these results and discussion, MISO's example of modeling generation additions, and the low cost of renewables combined with federal tax incentives, renewable portfolio standards may not significantly constrain the economic expansion of resources. As discussed in previous sections, PJM should conduct its own capacity expansion modeling as a part of its long-term transmission planning to better understand the optimal resource mix.

Large Energy Buyer Demand

Some of the biggest companies in the U.S. have clean energy goals, driving demand with deals for over 60 GW of clean energy. In 2022 alone, U.S. corporations signed contracts for nearly 17 GW of new clean energy, including McDonald's, U.S. Steel Corporation, Comcast, BASF Corporation, Nestle, and Walmart.

In PJM's territory, a significant amount of load growth and demand for clean energy is driven by new data centers. Google, Meta, Microsoft, Amazon, and Iron Mountain are some of the largest data center operators in PJM, and all have goals to supply their centers with 100 percent clean

110 *MISO Futures Report,* 4, 8.

energy.[111] Many of these companies are also planning expansions of their operations in PJM. For example, Amazon Web Services (AWS) has plans to invest over $40 billion in new data centers in Virginia and Ohio.[112] AEP has also said 15 GW of new load, mostly from data centers, is looking to connect by 2030. Google plans to invest $2 billion in a new data center campus near Fort Wayne and AWS has announced $11 billion in investment in Northern Indiana. Indiana Michigan Power (AEP) has committed to bring on clean resources for Google's data center and AWS has said they will enable 600 MW of new solar and wind resources.[113]

In their 2024 load forecast, PJM included subregional adjustments based on significant load additions. AEP, FirstEnergy, PSE&G, Dominion, and Northern Virginia Electric Cooperative (NOVEC) submitted adjustments to their load forecast based on data center additions, with a significant portion coming from Dominion and NOVEC.[114] While most of the adjustments made in PJM's Load Forecast Supplement were for data centers, AEP also included an adjustment for a chip manufacturing facility.[115] Given the recent focus and investment in new industrial capabilities in the U.S. discussed in the load section, it is very likely PJM will need to account for other large loads such as manufacturing facilities or hydrogen plants, which will also likely have clean energy goals or regulations, in future load forecasts.

Using the information provided in PJM's Load Forecast Supplement, we estimated the additional energy needs required to meet the load. Given that many companies operating data centers have committed to purchasing 100 percent clean energy for their data centers, we assumed that all the estimated additional energy required by these data centers in 2040 would be met with clean energy.

TABLE 14 | Large Buyer Clean Energy Demand

	Expected	**High**
Generation Additions	Additional Energy Needed: 623 TWh	Additional Energy Needed: 798 TWh
Demand for Clean Energy	Large energy buyers demand for clean energy: 247 TWh	Large energy buyers demand for clean energy: 247 TWh

111 J. Harkness, "Tracking the Transition to Renewable Energy Across Data Centers," Cedara (January 2023), https://www.cedara.io/post/tracking-the-transition-to-renewable-energy-in-the-data-center-industry#:~:text=Google%20Cloud%2C%20Microsoft%20Azure%2C%20and,energy%20between%202025%20and%202030.; Iron Mountain, "Iron Mountain commits to the RE100 and science-based targets," (June 2018), https://www.ironmountain.com/about-us/sustainability/stories/i/iron-mountain-commits-to-the-re100-and-science-based-targets.

112 M. Barakat, "Virginia, Amazon announce $35 billion data center plan," AP News, January 2023, https://apnews.com/article/technology-data-management-and-storage-amazoncom-inc-virginia-business-c75df1f34069b09549fe15c99335b8fb; M. Vincent, "AWS Readies $3.5B for 5 More Ohio Data Centers in Booming Columbus Suburb New Albany," Data Center Frontier (September 2023), https://www.datacenterfrontier.com/site-selection/article/33011941/aws-readies-35b-for-5-more-ohio-data-centers-in-booming-columbus-suburb-new-albany.

113 Amazon Web Services, "AWS plans to invest $11 billion in Indiana, the largest capital investment in the state's history," (April 2024), https://www.aboutamazon.com/news/aws/aws-indiana-investment-11-billion; E. Howland, "AEP faces 15 GW of new load, driven by Amazon, Google, other data centers: interim CEO Fowke," Utility Dive (May 2024), https://www.utilitydive.com/news/aep-data-centers-amazon-google-load-growth-epa/714806/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202024-05-01%20Utility%20Dive%20Newsletter%20%5Bissue:61623%5D&utm_term=Utility%20Dive.

114 "PJM Publishes 2024 Long-Term Load Forecast."

115 *2024 Load Forecast Supplement,* 19-20.

This estimate is not inclusive of state demand for clean energy as both state RPS requirements and large buyer demand will need to retire separate RECs to satisfy the goals. In addition, this estimate of large buyer demand for clean energy is conservative, given that not all subregions or utilities within PJM included adjustments for potential load growth due to data centers and new manufacturing loads.[116] In the 2024 load report, PJM even noted some utilities expect to see further demand from data centers and manufacturing.[117]

Utility Demand

We reviewed the clean energy goals for PJM's Investor-Owned Utilities (IOUs). Of the 43 IOUs reviewed, only six do not have a clean energy goal. In some cases, the utility goals align with the state law, but in others, utilities have outlined more aggressive goals than state law or set a goal even if there is no state law. In the six states with no, comparatively low, or voluntary RPSs (Indiana, Kentucky, Ohio, Pennsylvania, Tennessee and West Virginia) the majority of the Investor Owned Utilities have set much higher climate goals.

In PJM, most of the transmission owners are deregulated utilities that no longer own generation. Some of these transmission owners are owned by a handful of parent corporations, which have significant climate goals as shown in the table below.

TABLE 15 | Summary of Utility Goals

State	Utility	Goal
Delaware	Delmarva	50% by 2030 and achieve net-zero operations by 2050
Illinois	ComEd	50% by 2030 and achieve net-zero operations by 2050
Indiana	Indiana Michigan Power	80% by 2030 and net zero by 2045.
Kentucky	Duke Energy Ohio and Kentucky	50% by 2030 and net-zero by 2050.
	Kentucky Power	80% by 2030 and net zero by 2045.
	East Kentucky Power Cooperative	N/A
Maryland	Baltimore Gas and Electric	50% by 2030 and achieve net-zero operations by 2050
	Delmarva Power and Light Company	50% by 2030 and achieve net-zero operations by 2050
	Potomac Edison	Carbon neutrality by 2050
	Potomac Electric Power Company (PEPCO)	50% by 2030 and achieve net-zero operations by 2050
Michigan	Indiana Michigan Power	80% by 2030 and net zero by 2045.
New Jersey	Atlantic City Energy	50% by 2030 and achieve net-zero operations by 2050
	Jersey Central Power & Light	Carbon neutrality by 2050
	Orange & Rockland	100% clean energy by 2050
	PSE&G	100% net-zero by 2030.
North Carolina	Dominion Energy NC	Net-zero by 2050.

116 The Columbus Region, "Project Announcements," accessed May 1, 2024, https://columbusregion.com/economy/project-announcements/.

117 *2024 Load Forecast Supplement,* 20.

State	Utility	Goal
Ohio	AES Ohio (Dayton Power and Light)	Net zero carbon emissions from electricity sales by 2040 and net zero carbon emissions for entire business portfolio by 2050
	Duke Energy Ohio and Kentucky	50% by 2030 and net-zero by 2050.
Pennsylvania	The Illuminating Company (Ohio Edison)	Carbon neutrality by 2050
	The Illuminating Company (Toledo Edison)	Carbon neutrality by 2050
	The Cleveland Illuminating Company	Carbon neutrality by 2050
	Columbus Southern Power/Ohio Power	80% by 2030 and net zero by 2045.
	Ohio Valley Electric Company	N/A
	Duquesne Light Company	N/A
	Pennsylvania Power Company	Carbon neutrality by 2050
	Metropolitan Edison Company (MetEd)	Carbon neutrality by 2050
	Pennsylvania Electric Company (Penelec)	Carbon neutrality by 2050
	PPL Electric Company	70% reduction from 2010 levels by 2035, 80% by 2040, and net-zero carbon emissions by 2050.
	PECO Energy Company	50% by 2030 and achieve net-zero operations by 2050
	West Penn Power	Carbon neutrality by 2050
	UGI	N/A
Tennessee	Appalachian Power (AEP)	80% by 2030 and net zero by 2045.
Virginia	Appalachian Power (AEP)	80% by 2030 and net zero by 2045.
	Allegheny Power (First Energy)	Carbon neutrality by 2050
	Dominion Energy Virginia	Net-zero by 2050.
	Delmarva	50% by 2030 and achieve net-zero operations by 2050
West Virginia	Appalachian Power (AEP)	80% by 2030 and net zero by 2045.
	Monongahela Power Company (Mon Power)	Carbon neutrality by 2050
	The Potomac Edison Company	Carbon neutrality by 2050
	Wheeling Power Company	80% by 2030 and net zero by 2045.

Using the goals summarized above we calculated the demand for clean energy from PJM Investor-Owned Utilities to meet their publicly stated emissions reduction goals.

TABLE 16 | Utility Demand for Clean Energy

	Expected	High
Generation Additions	Additional Energy Needed: 623 TWh	Additional Energy Needed: 798 TWh
Demand for Clean Energy		State demand for clean energy: 472 TWh Utility demand for clean energy: 657 TWh **Additional demand from utility goals: 185 TWh**

The estimated clean energy demand from utility goals was only included in the High scenario, given the non-binding nature of their commitments. Many of the utilities do not include interim goals, making them harder to quantify.

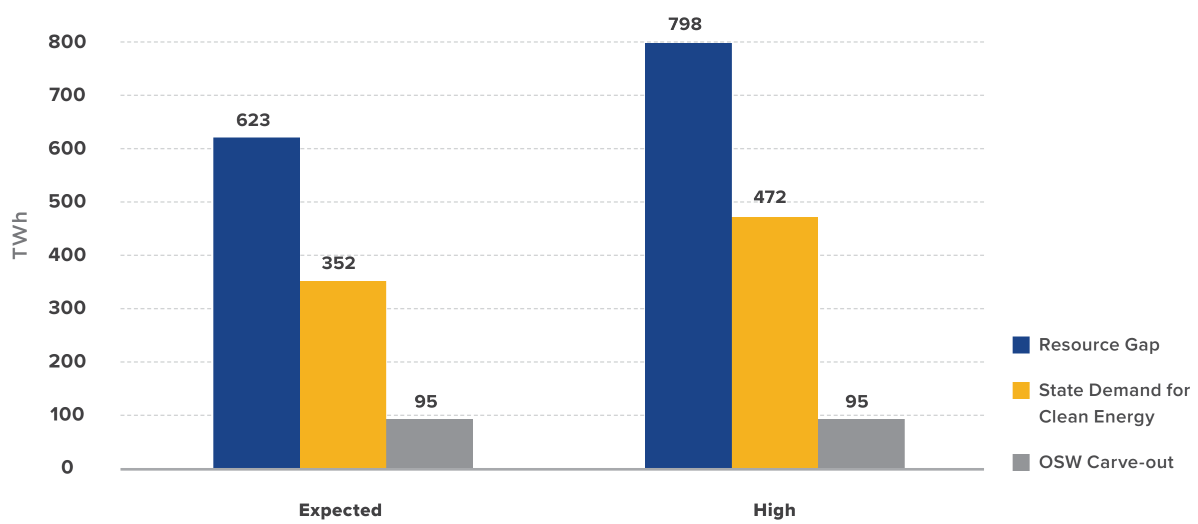
But when the utility goals are applied to the High Scenario, PJM would need a 67 percent decrease in emissions compared to a 2005 baseline, requiring an additional 185 TWh of clean energy beyond state demand. Even if 100 percent of the utility goals are not met, these commitments should still be viewed as indicative that utilities and shareholders are aligned on the goal of adding additional clean energy to the grid.

Resource Carve-outs

State policymakers will often include resource carve-outs that require the development of a specific or minimum amount of generation from a particular resource, often because the resource might not compete within a pure technology-neutral economic deployment of resources. Policymakers may create these carve-outs for other reasons as well, such as local economic development, job creation, or to incentivize investment in an industry.

In PJM, many coastal states have minimum goals for offshore wind. This is most likely to be the resource required by state law that is not deployed under an economic capacity expansion model due to the currently higher costs for offshore wind compared to other generation resources deployed in PJM.

FIGURE 16 | Comparison of Projected Resource Gap in 2040 to State Demand for Clean Energy



Currently, PJM states have set goals to develop more than 32 GW of offshore wind by 2040, which is roughly 100 TWh. These carve-outs, as summarized in the tables below, are approximately 25 percent of the energy needed to meet state clean energy laws.

TABLE 17 | State Policy Resource Carve-outs

Resource Specific Carve-outs	2030 (MWh)	2040 (MWh)
Offshore Wind	7,849,486	95,357,856

TABLE 18 | State Offshore Wind Requirements by 2040

State	Offshore Wind
Maryland	8,500 MW
New Jersey	11,000 MW
North Carolina	8,000 MW
Virginia	5,200 MW
Total	32,700 MW

Economic capacity expansion modeling can help determine if these carve-outs are economic or should be treated as incremental additions. Offshore wind requirements may at least partially displace deployment of other renewable resources, so in some cases the requirements may not significantly change the total renewable deployment.

Regardless, proactive transmission planning for offshore wind resources can yield benefits for ratepayers. In New Jersey, the state proactively planned transmission upgrades for 6,400 MW of new offshore wind, reducing costs by two-thirds compared to costs identified for incremental transmission upgrades in queue studies, saving approximately $1 billion.[118] Even when incremental upgrades are made to interconnect new offshore wind generation, it is still likely these transmission upgrades will lead to some regional benefits, and a share of the transmission investment cost should be allocated to reflect the regional economic and reliability benefits of those upgrades.

118 Brattle Group, *New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report,* prepared for New Jersey Board of Public Utilitie, 92 (2022), https://www.brattle.com/wp-content/uploads/2022/10/New-Jersey-State-Agreement-Approach-for-Offshore-Wind-Transmission-Evaluation-Report.pdf.

5 | CONCLUSION

We find PJM will have significant future energy needs that transmission planning should consider. PJM's proposed LTRTP process and FERC Order No. 1920 provide PJM with the perfect opportunity to begin planning now to better understand where new generation will be located, as well as anticipate potential impacts from retirements and load growth. Delaying or failing to plan for these foreseeable changes in the generation mix poses economic and reliability risks to consumers.

Some clear gaps, outside the scope of this report, remain in PJM's overall long-term transmission planning process including the need for improved interregional planning and consideration of interregional transmission within the long-term planning process. In the DOE National Transmission Needs Study's high load and high clean energy growth scenario, PJM needs to expand interregional transmission by over 400 percent to both MISO and New York.[119] One study found expanding interregional transmission capacity between MISO and PJM could provide over $1 billion in annual energy market savings.[120]

Proactive long-term planning of inter- and intra-regional transmission can help achieve the lowest delivered cost of energy, a requirement to achieve just and reasonable rates. To identify these opportunities, PJM should follow best practice transmission planning methods.

119 *Needs Study,* X.

120 *See* M. Goggin and Z. Zimmerman, *Billions in Benefits: A Path for Expanding Transmission Between MISO and PJM,* Grid Strategies and ACORE (October 2023), https://acore.org/wp-content/uploads/2023/11/ACORE-Billions-in-Benefits-A-Path-for-Expanding-Transmission-Between-MISO-and-PJM.pdf.

Grid Strategies

gridstrategiesllc.com
info@gridstrategiesllc.com

Grid Strategies LLC is a power sector consulting firm helping clients understand the opportunities and barriers to integrating clean energy into the electric grid. Drawing on extensive experience in transmission and wholesale markets, Grid Strategies analyzes and helps advance grid integration solutions.

Based in the Washington DC area, the firm is actively engaged with the Federal Energy Regulatory Commission, Department of Energy, state Public Utility Commissions, Regional Transmission Organizations, the North American Electric Reliability Corporation, Congressional committees, the administration, and various stakeholders.

Americans for a Clean Energy Grid

cleanenergygrid.org
info@cleanenergygrid.org

Americans for a Clean Energy Grid (ACEG) is a non-profit broad-based public interest advocacy coalition focused on the need to expand, integrate, and modernize the North American high-voltage grid.

Expanded high-voltage transmission will make America's electric grid more affordable, reliable, and sustainable and allow America to tap all economic energy resources, overcome system management challenges, and create thousands of well-compensated jobs. But an insular, outdated and often short-sighted regional transmission planning and permitting system stands in the way of achieving those goals.