RTEP 2022

Regional Transmission Expansion Plan

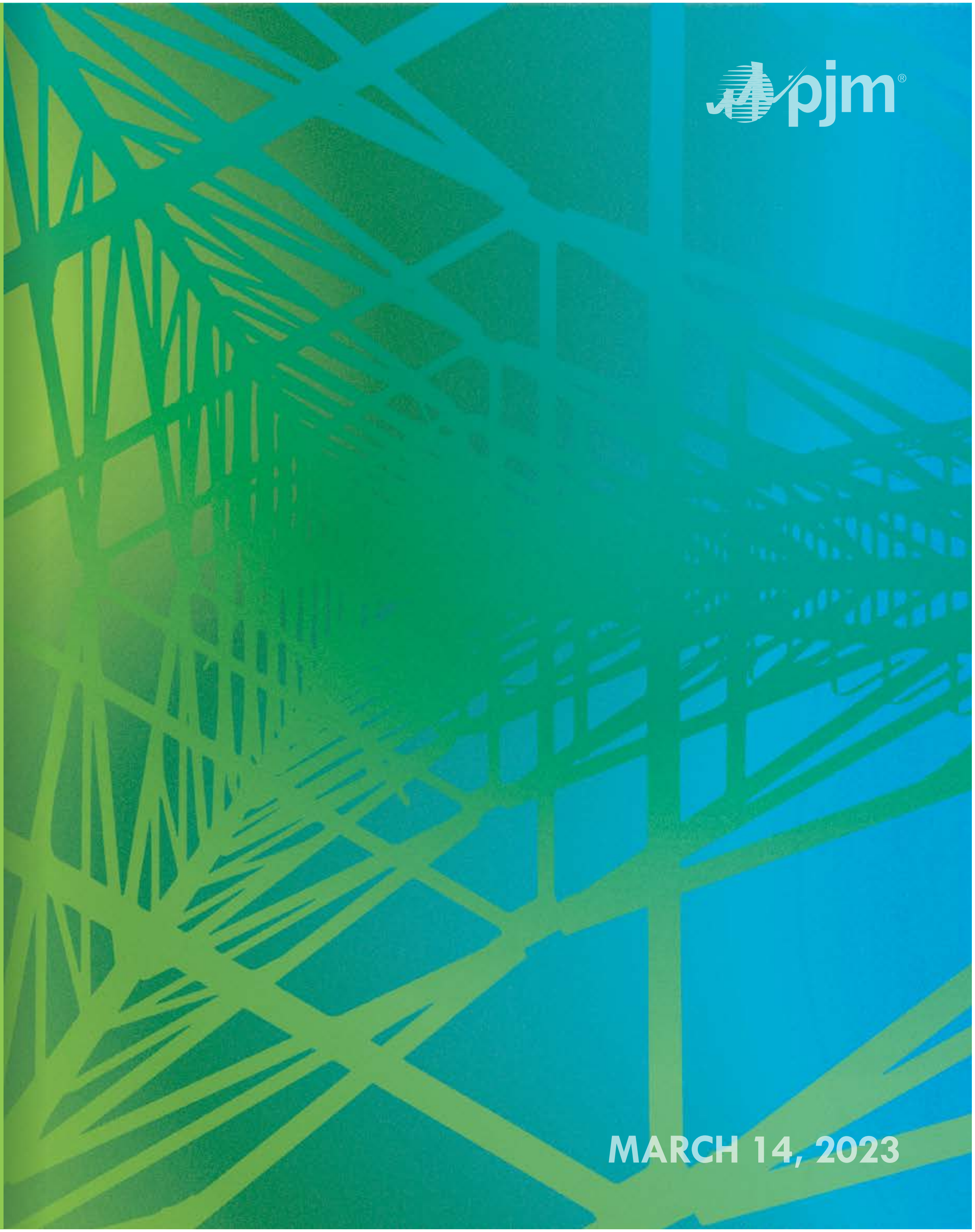
How will interconnection process reforms improve queue efficiency for generation developers?

How will PJM's grid of the future initiatives enable states' decarbonization public policy goals?

What transmission is needed for offshore wind power to reach customers?

How are electric vehicles, behind-the-meter solar, and storage impacting PJM's load forecast?

What was the reliability impact of generator deactivations in 2022?



MARCH 14, 2023

Table of Contents

1.0: Preface

The PJM Regional Transmission Expansion Plan (RTEP) Report is published annually to convey planning study results throughout the year and to explain the rationale behind transmission system enhancement needs.

In 2022, PJM observed several ongoing trends, which are discussed throughout this report. These include the continuing shift in PJM's generation fuel mix, driven by new renewables and natural gas-fired plants and deactivation of coal-fired plants.

- **Section 1** is a high-level summary of 2022 RTEP activities, including process improvements and a summary of projects organized by driver.
- **Section 2** includes an overview and detailed data from PJM's 2022 Load Forecast Report.
- **Section 3** provides highlights of RTEP system enhancements approved by the PJM Board in 2022, including those driven by generator deactivations, and summarizes the reevaluation of previously approved projects.
- **Section 4** summarizes 2022 RTEP market efficiency process activity, including input assumptions, analysis and the outcome of related competitive windows.
- **Section 5** provides an overview of PJM's new service queue requests as well as interconnection process improvements.
- **Section 6** provides state summaries, including a detailed breakdown of interconnection requests within each state, as well as transmission system enhancements identified as part of the RTEP analysis.

Planning Community

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PJM's online communities create an easily accessible venue for stakeholders to collaborate with PJM staff and each other.

The Planning Community allows stakeholders to collaborate and find information on planning initiatives, proposal windows and processes. It includes similar features to the Member Community, along with:

- Access to PJM subject matter experts
- Moderated discussions between generation owners, transmission owners and PJM staff

- **Appendix 1** – Transmission Owner Zones and Locational Deliverability Areas
- **Glossary**
- **Topical Index**
- **Key Maps, Tables and Figures**
- **RTEP Project Statistics**

Close X

Use this button to jump to the next section.

Use the menu button to return to the Table of Contents.

Click the arrows to page forward and backward.

KEY 2022 HIGHLIGHTS

PJM's RTEP process identified 172 new baseline projects during 2022 at an estimated cost of $2.4 billion to ensure fundamental system reliability across the grid. Two hundred and sixty-seven new network transmission projects at an estimated cost of $225 million are required to ensure the reliable delivery of generation seeking interconnection to PJM markets.

PJM's interconnection queue continues to take in a record number of requests. In 2022, PJM received 610 new service requests.

PJM has implemented the State Agreement Approach for the first time as part of the 2022 RTEP. PJM and the New Jersey Board of Public Utilities worked together to develop public policy-driven transmission to satisfy state offshore wind power objectives.

+ In 2022, PJM's queue included a total of 254,781 MW of energy seeking to interconnect into PJM's system. The magnitude of these requests nearly equals PJM's all-time peak.
+ PJM has issued agreements allowing construction activities to begin for 548 interconnection requests representing 38.2 GW.
+ PJM processed 610 requests to interconnect new generation totaling nearly 106,000 MW nameplate capability. PJM studied 20 deactivation notifications totaling 5,119 MW.

+ Public policy projects in 2022 driven by the New Jersey State Agreement Approach made up 45% ($1,064 million) of approved baseline projects.
+ 12.4% of baseline projects were driven by transmission owner (TO) criteria. The remaining 42.6% were driven by NERC, TO and PJM baseline criteria as well as generator deactivation and operational performance.
+ PJM facilitated four competitive windows in 2022 to address 200 unique flowgate reliability criteria violations and four clusters of market efficiency congestion needs.

+ PJM's 2022 forecast load growth rate remained flat at a 10-year RTO summer, normalized peak growth rate of 0.4%, up from 0.3% last year.
+ Resource adequacy improvements focusing on Effective Load Carrying Capability (ELCC), which estimates the resource adequacy value of generating resources, were approved in early 2023 based on work completed in 2022.
+ Load forecast process improvements in 2022 included changes to better align the forecast's non-weather-sensitive model with underlying drivers and historical trends.

Section 1: 2022 Year in Review

1.0: Executive Summary

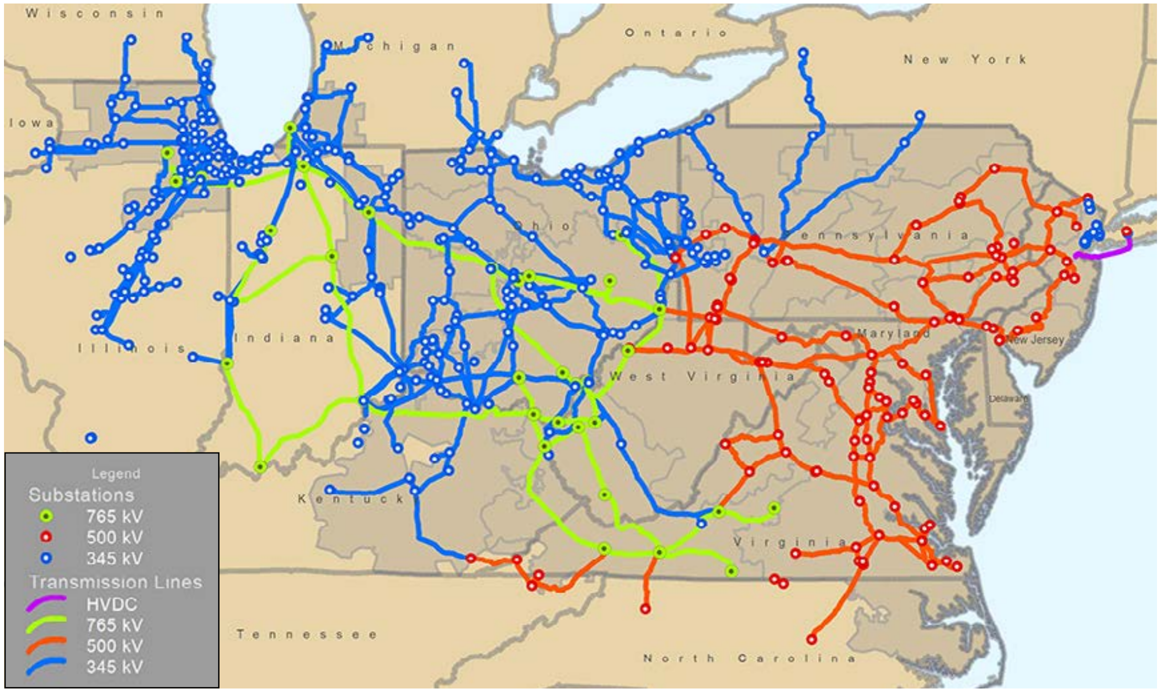
The PJM Regional Transmission Expansion Plan (RTEP) Report is published annually to convey planning study results throughout the year and to explain the rationale behind transmission system enhancement needs. The report also examines trends that continued throughout 2022 and will drive PJM's grid of the future, including the ongoing shift from fossil fuels to renewables and the impact of public policy.

1.0.1 — Regional Planning

PJM, a FERC-approved regional transmission organization (RTO), coordinates the movement of wholesale electricity across a high-voltage transmission system in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia, as shown on **Map 1.1**. PJM's footprint encompasses major U.S. load centers from the Atlantic Coast to the western border of Illinois, including the metropolitan areas in and around Baltimore, Chicago, Columbus, Cleveland, Dayton, Newark, Norfolk, Philadelphia, Pittsburgh, Richmond, Toledo and Washington, D.C.

PJM's RTEP process identifies transmission system additions and improvements needed to serve more than 65 million people throughout 13 states and the District of Columbia. The PJM system includes key U.S. Eastern Interconnection transmission arteries, providing members with access to PJM's regional power markets as well as those of adjoining systems. Collaborating with more than 1,000 members, PJM dispatches more than 185,000 MW of generation capacity over 85,000 miles of transmission lines.

Map 1.1: PJM Backbone Transmission System



RTO Perspective

PJM's RTEP process spans state boundaries shown in **Map 1.1** and is a key RTO function, as shown in **Figure 1.1**. A regional perspective gives PJM the ability to identify one optimal, comprehensive set of solutions to solve reliability criteria violations, operational performance issues and market efficiency constraints. Specific system enhancements are identified and planned to meet local reliability requirements and deliver needed power to load centers across the region PJM serves. When the PJM Board of Managers approves recommended system enhancements, new facilities and upgrades to existing ones, they formally become part of PJM's RTEP. PJM recommendations can also include the removal of, or change in scope to, previously approved projects. Forecast system conditions can change such that justification for a project no longer exists or requires modification to capture system changes.

System Enhancement Drivers

A 15-year, long-term planning horizon allows PJM to consider the aggregate effects of many drivers, shown in **Figure 1.2.** Initially, with its inception in 1997, PJM's RTEP consisted of system enhancements mainly driven by load growth and generating resource interconnection requests. Today, PJM's RTEP process studies the interaction and impact of many drivers, including those arising out of reliability, aging infrastructure, operational performance, market efficiency, public policy and demand-side trends. Importantly, as **Figure 1.2** shows, RTEP development considers all drivers through a reliability criteria, market efficiency and resilience lens. PJM's RTEP process encompasses a comprehensive assessment of system compliance with the thermal, reactive, stability and short-circuit North American Electric Reliability Corporation (NERC) Standard TPL-001-4 as described in **Section 1.2**.

Highlights of projects identified and approved by the PJM Board during 2022 appear in **Section 3**. Details of specific large-scale projects are presented in **Section 6**.

Figure 1.1: RTEP Process – RTO Perspective

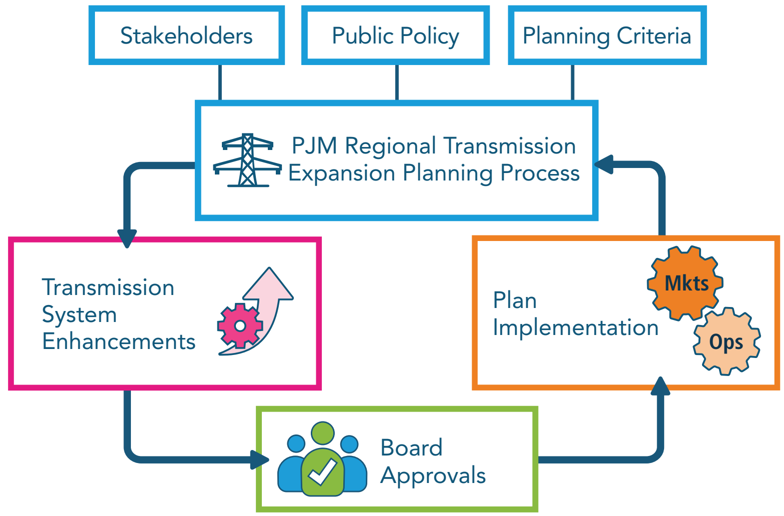
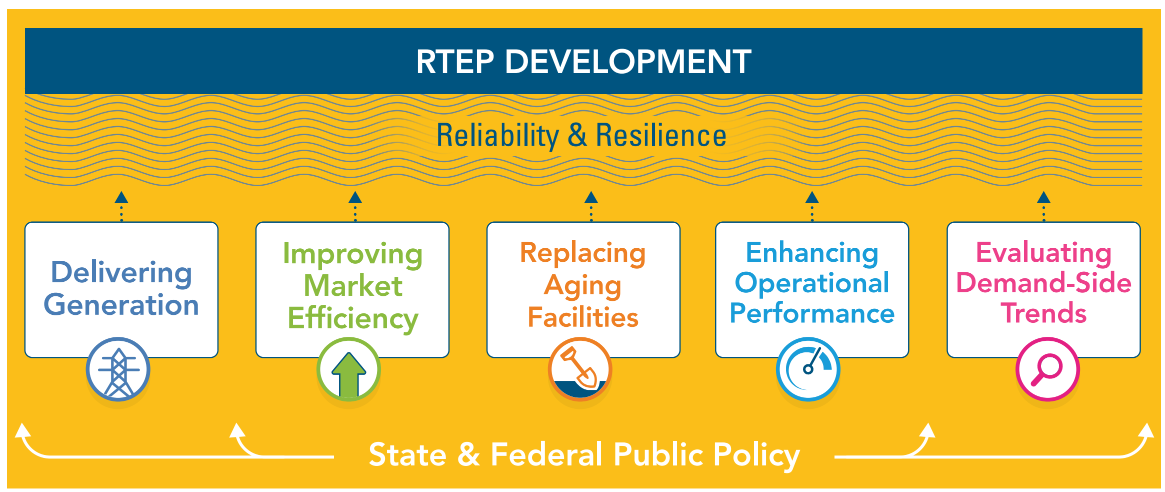


Figure 1.2: System Enhancement Drivers

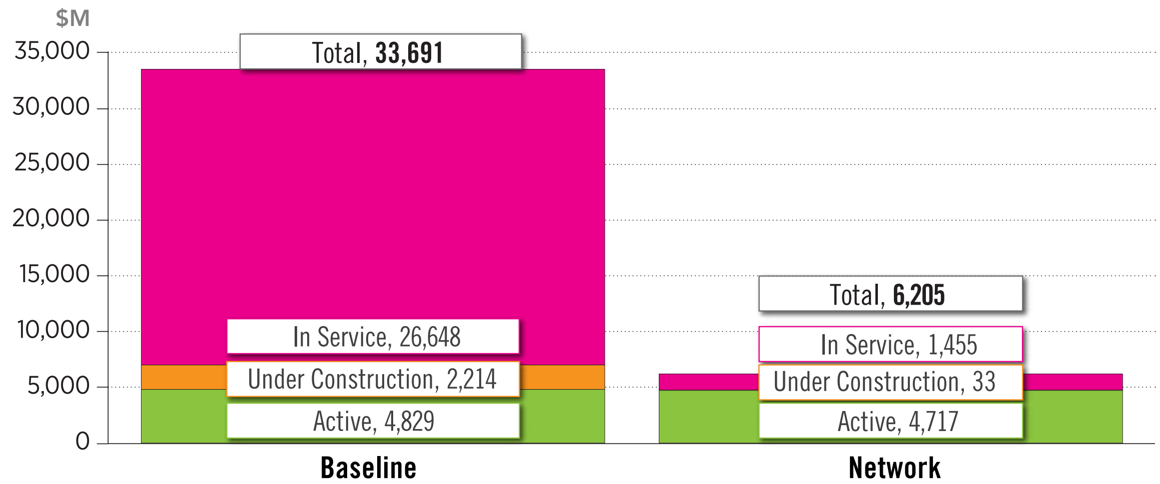


2022 Outcomes and Conclusions

The PJM transmission system ensures that electricity can be delivered reliably across the grid to customers the instant it is needed. PJM's 2022 RTEP process continued to yield grid enhancements to ensure delivery under a historic and unprecedented generation shift driven increasingly by public policy and fuel economics.

- The PJM Board approved 172 new baseline projects during 2022 at an estimated $2,392 million to ensure that fundamental system reliability criteria across the grid are met.
- The Board also approved the inclusion of 267 new network transmission projects at an estimated $225 million into the RTEP.

Figure 1.3: Board-Approved RTEP Projects as of Dec. 31, 2022



Since the RTEP process was implemented in 1997, the PJM Board has approved transmission system enhancements totaling approximately $39.9 billion. Of this, approximately $33.7 billion represents baseline projects to ensure compliance with NERC, regional and local transmission owner planning criteria and to address market efficiency congestion relief. An additional $6.2 billion represents network facilities to enable the reliable interconnection of over 90,000 MW of new generation. A summary of projects by status as of Dec. 31, 2022, appears in **Figure 1.3**. Active projects include those that are actively under study in PJM's interconnection process. Projects listed as under construction have completed the interconnection process, and construction activities have commenced. The numbers provide a snapshot of one point in time, as with an end-of-year balance sheet. The 2022 totals, and likewise those in **Figure 1.3**, reflect revised cost-estimate changes and project cancellations for previously approved RTEP elements. For example, PJM can recommend canceling a network system enhancement from the RTEP when a queued project driving the need for the network project withdraws from the queue. Withdrawals at this point in the interconnection process are typically driven by developer business decisions, including PJM Reliability Pricing Model (RPM) Auction activity, siting challenges, financing challenges or other business model factors.

Supplemental projects are identified and developed by transmission owners to address local reliability needs, including customer service; equipment material condition, performance and risk; operational flexibility and efficiency; and infrastructure resilience. And, while supplemental projects are not subject to Board approval, PJM conducts do-no-harm studies to ensure that they do not introduce reliability criteria violations on the regional transmission system. A discussion of supplemental projects, including summaries by driver, is included in **Section 3.2**. The topology of models changes from year to year as projects are approved. A major assumption included in 2022 RTEP analyses was the exclusion of the Transource IEC "9A" project. In September 2021, the PJM Board endorsed PJM's recommendation to suspend the Transource IEC (9A) project due to permitting risks, in order to remove it from the models pending future updates.

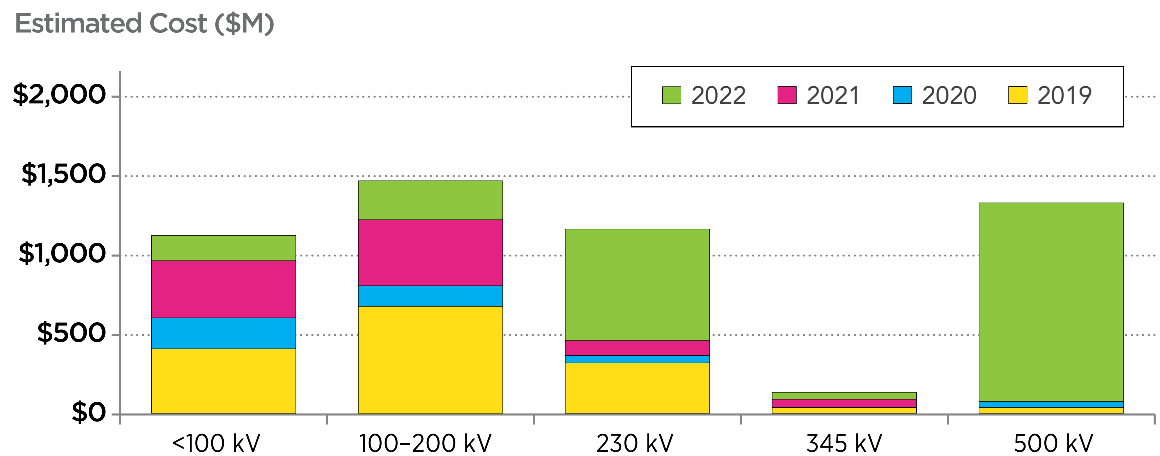
Shifting RTEP Dynamics

The $2,392 million of baseline transmission investment approved during 2022 continues to reflect the shifting dynamics driving transmission expansion. As **Figure 1.4** shows, new large-scale transmission projects (345 kV and above) have become more uncommon as RTO load growth has fallen below 1%. Aging infrastructure, grid resilience, a shifting generation mix and more localized reliability needs are now more frequently driving new system enhancements.

RTO Annual Load Growth

PJM's 2022 RTEP baseline power flow model for study year 2027 was based on the 2022 PJM Load Forecast Report, summarized in **Section 2**, and shows a 10-year RTO summer, normalized peak growth rate of 0.4% per year. Average 10-year-annualized summer growth rates for individual PJM zones ranged from -0.3% to 2.2%. Load forecasts from the past five years reflect broader trends in the U.S. economy and PJM model refinements to capture evolving customer behaviors. These include more efficient manufacturing equipment and home appliances and distributed energy resources, such as behind-the-meter, rooftop solar installations. However, in 2022, PJM also identified trends of large load increases in specific areas driven by new data centers, as discussed in **Section 3**.

Figure 1.4: Approved Baseline Projects by Voltage 2019–2022



Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

As of Dec. 31, 2022, interconnection requests comprising renewable resources continue to represent a significant portion of PJM's interconnection queue, as discussed in **Section 1.1**.

Solar-powered resources total nearly 108,000 MW of capacity interconnection rights (CIRs), or around 43%, of the over 250,000 MW of CIRs resources in PJM's queue, as shown in **Figure 1.6**. Solar generation has overtaken natural gas in PJM's queue, tripling on a megawatt basis over the past two years. Natural gas plants total nearly 8,000 MW and constitute 9.3% of queued generation.

On the deactivation side, more than 36,000 MW of coal-fired generation has retired since 2011. Market factors as well as the economic impacts of environmental public policy, coupled with the age of these plants – many more than 40 years old – make ongoing operation prohibitively expensive. Throughout 2022, PJM continued to receive deactivation notifications (20 units totaling 5,119 MW), the impacts of which are discussed in **Section 3.3.**

1.1: Generation in Transition

PJM's 184,833 MW of RPM-eligible existing installed capacity reflects a fuel mix comprising 47% natural gas, 24% coal and 18% nuclear, as shown in **Figure 1.5**. Hydro, wind, solar, oil and waste fuels constitute the remaining 11%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility.

Totaling over 78,000 MW of Capacity Interconnection Rights (CIRs), renewable fuels are changing the landscape of PJM's interconnection queue. Solar energy makes up 66% of the generation in PJM's interconnection queue, shown in **Figure 1.6**. An increase in solar generation interconnection requests is attributable to state policies encouraging renewable generation. **Figure 1.6** shows PJM's fuel mix based on requested CIRs for generation that was active, under construction or suspended as of Dec. 31, 2022.

Interconnection requests by fuel type and status for renewable and non-renewable fuels are summarized in **Table 1.1**.

Figure 1.5: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2022)

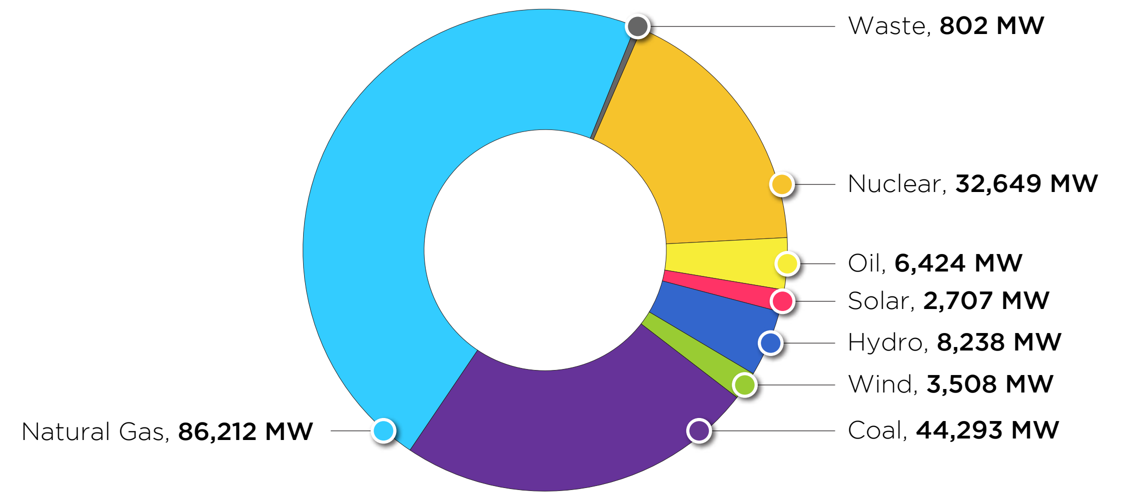
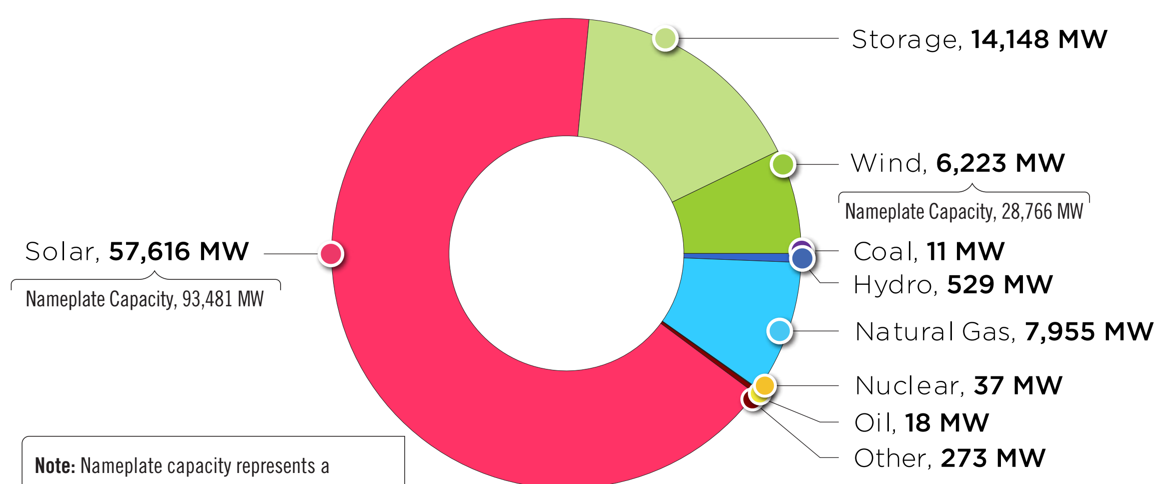


Figure 1.6: Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Table 1.1: Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2022)

		In Queue				Complete					
		Active		Under Construction		In Service		Withdrawn		Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	3	65.0	52	2,137.9	70	33,577.6	125	35,780.5
	Diesel	1	0.0	0	0.0	10	68.5	17	76.7	28	145.2
	Natural Gas	38	5,531.5	40	8,537.9	369	53,583.1	689	249,555.5	1,136	317,208.0
	Nuclear	0	0.0	4	81.4	43	3,902.8	24	9,038.0	71	13,022.2
	Oil	0	0.0	7	9.0	17	534.8	25	2,318.0	49	2,861.8
	Other	7	327.6	0	0.0	6	332.8	77	858.8	90	1,519.2
	Storage	646	50,118.7	27	503.9	24	9.8	303	9,507.4	1,000	60,139.7
Renewable	Biomass	0	0.0	0	0.0	9	162.8	40	896.9	49	1,059.7
	Hydro	8	549.30	3	35.0	32	1,155.90	52	2,190.9	95	3,931.0
	Methane	1	6.0	0	0.0	77	368.5	95	490.1	173	864.6
	Solar	1,856	96,772.4	340	8,875.9	252	2,913.5	1,756	37,549.5	4,204	146,111.2
	Wind	107	9,819.3	15	621.7	113	2,073.8	508	16,852.2	743	29,367.0
	Wood	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
	Grand Total	**2,664**	**163,124.80**	**439**	**18,729.80**	**1,006**	**67,298.20**	**3,660**	**363,064.60**	**7,769**	**612,217.40**

Renewables

PJM's interconnection queue process continues to see renewable generation growth. As **Figure 1.6** and **Table 1.1** show, queued requests as of Dec. 31, 2022, for CIRs totaled 10,441 MW of wind-powered generators that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 28,768 MW. Queued solar-powered generator requests for CIRs totaled 57,616 MW that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 93,481 MW.

Nameplate Capacity vs. Capacity Interconnection Rights

Nameplate capacity represents a generator's rated full power output capability. As **Figure 1.6** shows, nameplate capacity is typically much greater than CIRs for wind- and solar-powered generators. This arises from the fact that while some resources can operate continuously like conventional fossil-fueled power plants, renewable resources, such as wind and solar, operate intermittently.

A wind turbine can generate electricity only when wind speed is within a range consistent with the turbine's physical specifications. This requires a special set of rules with respect to real-time operational dispatch and capacity rights. To address the latter concern, PJM has established a set of business rules unique to intermittent resources for determining capacity rights. This value is used to ensure resource adequacy based on the amount of power output PJM can expect from each unit over peak summer hours. PJM business rules permit these values to change as annual operating performance data for individual units are analyzed. Until such time, class averages, or specific data provided by the developer, establish the amount of CIRs that a unit may initially request, as discussed in **Section 1.4.6**.

Generators powered by intermittent resources, such as wind, frequently require analytical studies unique to their particular characteristics. For example, wind-powered generator requests are clustered in areas that are most suitable to their operating characteristics and economics, but they have less access to robust transmission infrastructure. Such an injection of power increases system stress in areas already limited by real-time operating restrictions. Consequently, RTEP studies include complex power-system stability and low-voltage, ride-through analyses.

PJM's interconnection study process is described in PJM Manual 14A: New Services Request Process, available on the PJM website.

Table 1.2: Queued Study Requests (Dec. 31, 2022)

	Projects	Energy (MW)	Capacity (MW)
Active	2,664	254,781	163,125
In Service	1,006	80,681	67,298
Under Construction	439	26,467	18,730
Withdrawn	3,660	469,993	363,065
Total	**7,769**	**831,921**	**612,218**

1.1.1 — New Services Queue Requests

Interconnection Activity

The generation interconnection process has three study phases: feasibility, system impact and facilities studies, to ensure that new resources interconnect without violating established NERC, PJM, transmission owner and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to interconnect and to participate in PJM capacity and energy markets.

Generation Queue Activity

Through 2022, PJM markets have attracted generation proposals totaling 831,921 MW, as shown in **Table 1.2**. Over 254,781 MW of interconnection requests were actively under study, and over 26,000 MW were under construction or suspended as of Dec. 31, 2022. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. While withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy as well as regulatory, industry, economic and other competitive factors.

Queue Progression History

PJM reviews generation queue progression to understand overall developer trends more fully and their impact on the interconnection process. **Figure 1.7** shows that for all generation – both new resources and existing plant uprates – submitted in Queue A (1999) through Dec. 31, 2022, 69,997 MW (or 15.5%) reached commercial operation. As **Figure 1.7** also shows, 29,663 MW (or 7%) of that accounts for withdrawals from the queue after Interconnection Service Agreement (ISA) execution, and 1,385 MW (or 0.3%) represents withdrawals after wholesale market participant agreement (WMPA) execution, but before construction. Overall, 20.5% of projects that requested uprates to existing capacity reached commercial operation.

Figure 1.7: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2022)

Percentage of planned capacity and projects that have reached commercial operation

15.5% Requested capacity megawatts

20.5% Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	203	Interconnection Service Agreements	29,663 MW	38,580 MW
	338	Wholesale Market Participation Agreements	1,385 MW	2,781 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

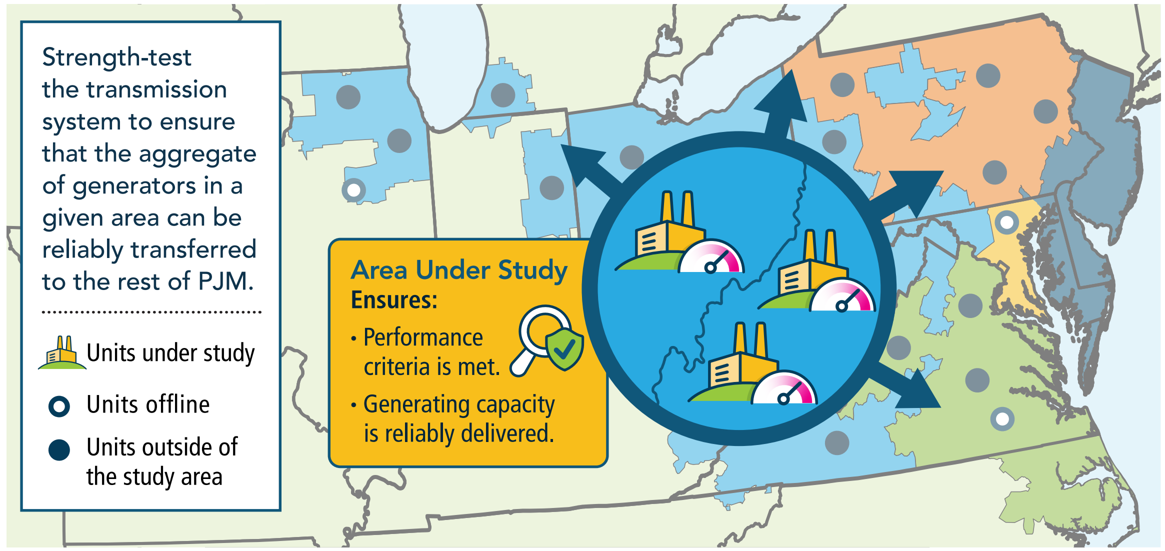
NOTE:
Figure 1.7 reflects requested capacity interconnection rights, which are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants.

Interconnecting Reliably

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. The PJM Board has approved network facility reinforcements totaling over $6.5 billion since the inception of the RTEP process in 1997. These facilities have allowed more than 90,000 MW of new generating resources and other new service requests (e.g., merchant transmission interconnection) to be approved for participation in PJM operations and markets. The PJM Board approved the incorporation of 267 new network system enhancements totaling over $225 million into the RTEP in 2022 alone.

As described in **Section 1.2**, PJM tests for compliance with all reliability criteria imposed by the NERC and PJM regional reliability criteria as well as TO criteria. Specifically, NERC reliability standards require that PJM identifies the system conditions to be evaluated that sufficiently stress the transmission system to ensure that it meets the performance criteria specified in the standards. PJM's generator deliverability test ensures that sufficient transmission capability exists to deliver generating capacity reliably from a defined generator or area to the rest of PJM load, as illustrated in **Figure 1.8**.

Figure 1.8: Generator Deliverability Concept



Generator Deliverability Process

In 2022, PJM continued its effort in pursuing modifications to the RTEP process generator deliverability methodology, as initiated in 2021 with PJM stakeholders in the Planning Committee, to improve variable resource modeling and consistency with operations. PJM is pursuing such modifications in order to more accurately reflect the emerging resource mix under summer, light load and winter operating conditions.

PJM's existing generator deliverability test does not dispatch generation in the same way as PJM's real-time operations, and therefore does not accurately reflect the behavior of PJM's rapidly evolving resource mix. Instead of dispatching generation in merit order (by least cost), the existing test relies on historic capacity factors to derate all generation.

PJM's updated testing methodology, implemented starting in 2023, will include a new dispatch approach that better aligns with how operations dispatches units based on economic conditions. With this new approach, Locational Deliverability Area imports will be limited to their Capacity Emergency Transfer Objective in the base case. Additionally, only firm interchange will be modeled in the base case, with separate, simplified procedures for performing historical interchange sensitivity analysis.

In addition to modifying the generator deliverability test, PJM will redefine the light-load period for planning studies to more accurately model solar generation by focusing the test on daytime hours that exhibit load levels between 40–60%. Existing light-load power flow cases are modeled at 50% annual peak load, reflect nighttime hours and utilize summer ratings, which are viewed as too conservative given the system conditions under study. Proposed changes would generally establish a new light-load temperature rating set of 59 degrees Fahrenheit and align ramping procedures more closely with respective seasonal operating conditions.

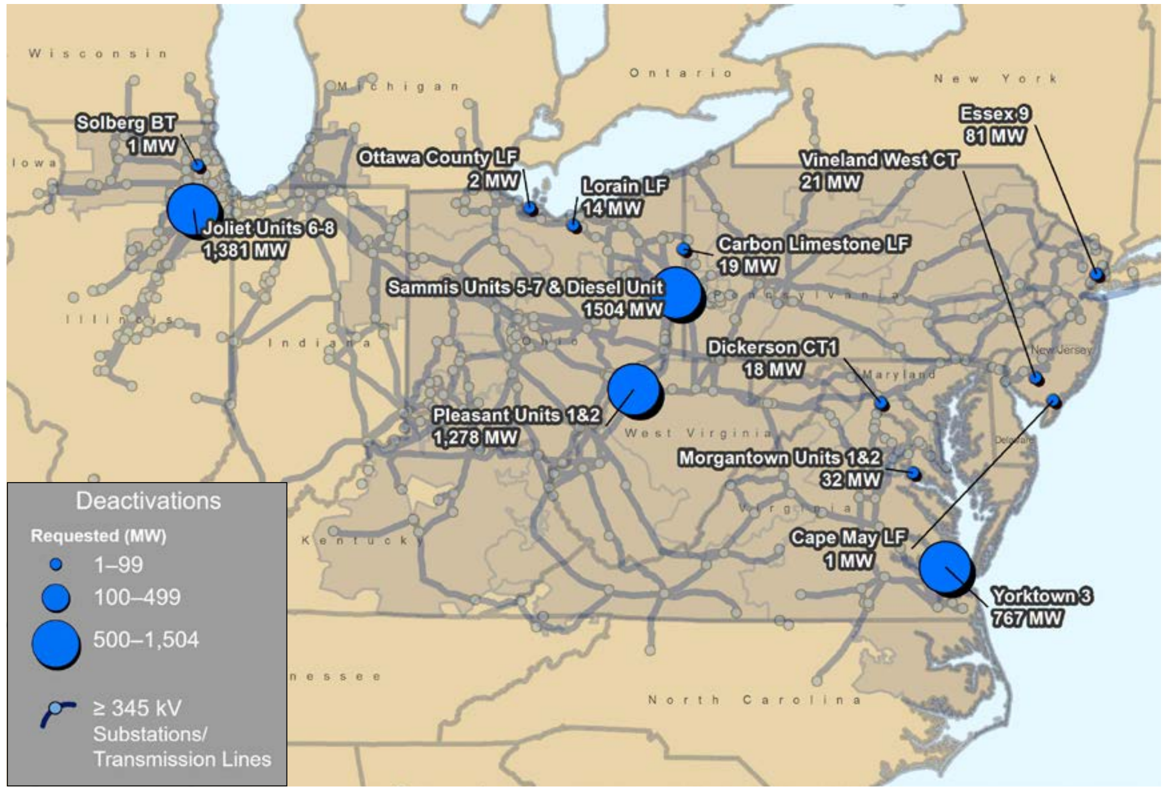
Deactivations

PJM received 20 deactivation notifications in 2022 totaling 5,119 MW. **Map 1.2** shows the deactivation request locations received between Jan. 1, 2022, and Dec. 31, 2022.

Generator owners requested the deactivation of these units take place between May 2022 and June 2023. PJM maintains a list of formally submitted deactivation requests, which is available on the PJM website.

PJM has 30 days in which to respond to a generator owner with deactivation study results. Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can reduce voltage support. Deactivation reliability studies include thermal and voltage analysis, such as generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, reliability criteria violations caused by a unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board. In 2022, PJM received approval for changes to its generation deactivation process, as described in **Section 1.4**.

Map 1.2: Deactivation Notifications Received in 2022



1.2: Baseline Project Drivers

NERC Criteria – RTEP Perspective

PJM's RTEP process rigorously applies NERC's Planning Standard TPL-001-4 through a wide range of reliability analyses, including load and generation deliverability tests, over a 15-year planning horizon. PJM documents all instances where the system does not meet applicable reliability standards and develops system reinforcements to ensure compliance. NERC penalties for violation of a standard can be as high as $1 million per violation, per day.

PJM addresses transmission expansion planning from a regional perspective, spanning transmission owner zonal boundaries and state boundaries, to address the comprehensive impact of many system enhancement drivers, including NERC reliability criteria violations. Reliability criteria violations may occur locally, in a given transmission owner zone, driven by an issue in that same zone. Violations may also be driven by some combination of regional factors.

Bulk Electric System Facilities

NERC's planning standards apply to all bulk electric system (BES) facilities, defined by ReliabilityFirst Corporation and the SERC Reliability Corporation, to include all of the following power system elements:

1. Individual generation resources larger than 20 MVA, or a generation plant with aggregate capacity greater than 75 MVA, that is connected via step-up transformer(s) to facilities operated at voltages of 100 kV or higher
2. Lines operated at voltages of 100 kV or higher
3. Associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment)

The ReliabilityFirst definition of BES facilities excludes the following:

1. Radial facilities connected to load-serving facilities, or individual generation resources smaller than 20 MVA, or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher
2. The balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and its associated step-up transformer), include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions
3. All other facilities operated at voltages below 100 kV

Given this BES definition, PJM conducts reliability analyses on PJM Tariff facilities, which may include facilities below 100 kV, in coordination with PJM markets, to ensure system compliance with NERC Standard TPL001- 4. If PJM identifies violations, it develops transmission expansion solutions to resolve them, as part of its RTEP window process.

NERC Reliability Standard TPL-001-4

Under NERC Reliability Standard TPL-001-4, "planning events," as NERC refers to them, are categorized as P0 through P7 and defined in the context of system contingency. PJM studies each event as part of one or more steady-state analyses as described in PJM Manual 14B: PJM Region Transmission Planning Process, available on the PJM website.

- P0 – No Contingency
- P1 – Single Contingency
- P2 – Single Contingency (bus section)
- P3 – Multiple Contingency
- P4 – Multiple Contingency (fault plus stuck breaker)
- P5 – Multiple Contingency (fault plus relay failure to operate)
- P6 – Multiple Contingency (two overlapping singles)
- P7 – Multiple Contingency (common structure)

Consistent with NERC definitions, if an event comprises an equipment fault such that the physical design of connections or breaker arrangements also take additional facilities out of service, then they are taken out of service in the study as well for simulating the event. For example, if a transformer is tapped off a line without a breaker, both the line and transformer are removed from service as a single contingency event.

PJM N-0 analysis, shown in **Table 1.3** as a NERC planning event and mapped to planning event P0, examines the BES as is, with all facilities in service. PJM identifies facilities that have pre-contingency loadings that exceed applicable normal thermal ratings. Additionally, bus voltages that violate established limits are specified in [PJM Manual 3: Transmission Operations](), available on the PJM website.

Similarly, N-1 analysis, mapped to planning event P1, requires that BES facilities be tested for the loss of a single generator, transmission line or transformer. Likewise, bus voltages that exceed limits specified by PJM Manual 3 are also identified. Generator and load deliverability tests are also applied to event P1.

PJM N-1-1 analysis, mapped to planning events P3 and P6, examines the impact of two successive N-1 events with re-dispatch and system adjustment prior to the second event. Monitored facilities must remain within normal thermal and voltage limits after the first N-1 contingency and re-dispatch within applicable emergency thermal ratings and voltage limits after the second contingency as specified in PJM Manual 3.

PJM's N-2 multiple contingency and common mode analyses evaluate planning events P2, P4, P5 and P7 to look at the loss of multiple facilities that share a common element or system protection arrangement. These include bus faults, breaker failures, double circuit tower line outages and stuck breaker events. N-2 analysis is conducted on the base case itself. Common mode analysis is conducted within the context of PJM's deliverability testing methods, discussed in PJM Manual 14B, available on the PJM website. NERC Standard TPL-001-4 includes extreme events as well. PJM studies system conditions following a number of extreme events, also known as maximum credible disturbances, judged to be critical from an operational perspective for risk and consequences to the system.

Table 1.3: Mapping RTEP Analysis to NERC Planning Events

Steady-State Analysis	NERC Planning Events
Base case N-0 – No Contingency Analysis	P0
Base case N-1 – Single Contingency Analysis	P1
Base case N-2 – Multiple Contingency Analysis	P2, P4, P5, P7
N-1-1 Analysis	P3, P6
Generator Deliverability	P0, P1
Common Mode Outage Procedure	P2, P4, P5, P7
Load Deliverability	P0, P1
Light-Load Reliability Criteria	P1, P2, P4, P5, P7

Stability Requirements

PJM conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operations throughout PJM's planning horizon. NERC criteria disturbances are those required by the NERC planning criteria applicable to system-normal, single-element outage and common-mode, multiple-element outage conditions.

A key aspect of NERC Reliability Standard TPL-001-4 also calls for modeling the dynamic behavior of loads as part of stability analysis at peak load levels. Prior to TPL-001-4 standard implementation, stability analyses were conducted on static load models that may not necessarily have captured the dynamic nature of real and reactive components of system loads and energy-efficient loads. From an analytical perspective, this requirement enhances analysis of fault-induced, delayed voltage recovery or changes in load characteristics like that of more energy-efficient loads.

Transmission Owner Criteria

The PJM Operating Agreement specifies that individual transmission owner (TO) planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions, such as in urban areas. TOs are required to include their individual criteria as part of their respective FERC Form 715 filings. TO criteria can be found on the PJM website.

As part of its RTEP process, PJM applies TO criteria to the respective facilities that are included in the PJM Open Access Transmission Tariff (OATT) facility list. Transmission enhancements driven by TO criteria are considered RTEP baseline projects and are eligible for proposal window consideration, as shown in **Figure 1.9**. Under the terms of the OATT, the costs of such projects are allocated 100% to the TO zone (as of Jan. 1, 2020, TO criteria projects are included in PJM's competitive proposal process).

2022 Transmission Owner Criteria-Driven Projects

TO criteria are increasingly driving the need for baseline projects. Spare 500/230 kV transformers, aging 500 kV line rebuilds and other equipment enhancements approved in prior years are already part of the RTEP.

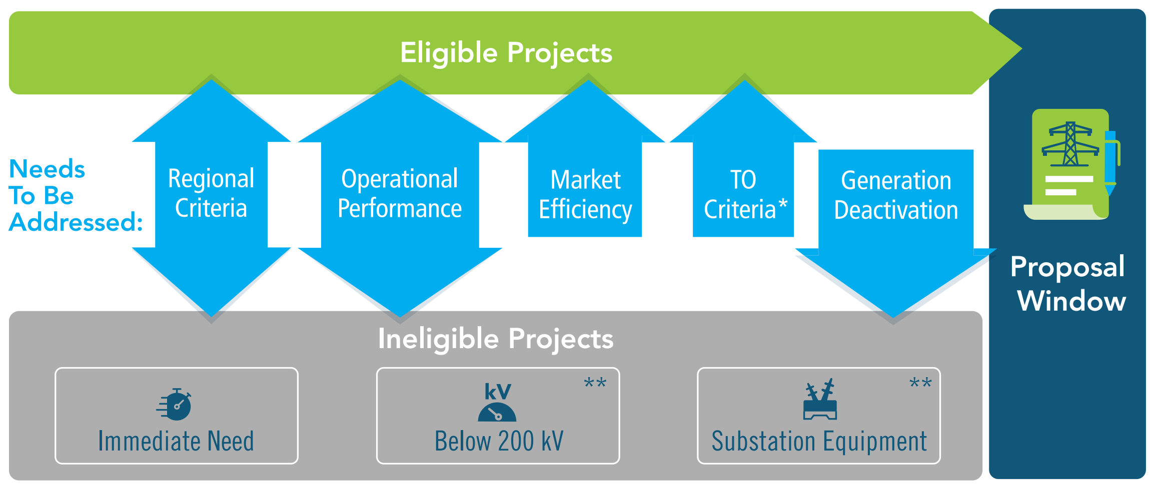
In other instances, TO criteria encompass local loss-of-load thresholds, particularly on radial facilities. The threshold for some is on a megawatt-mile basis, others on a megawatt-magnitude basis, to reduce the extent of load impacted under contingency or outage conditions.

Section 3.1 summarizes TO criteria-driven transmission projects with cost estimates greater than or equal to $10 million, as approved by the PJM Board in 2022.

Developing Transmission Solutions

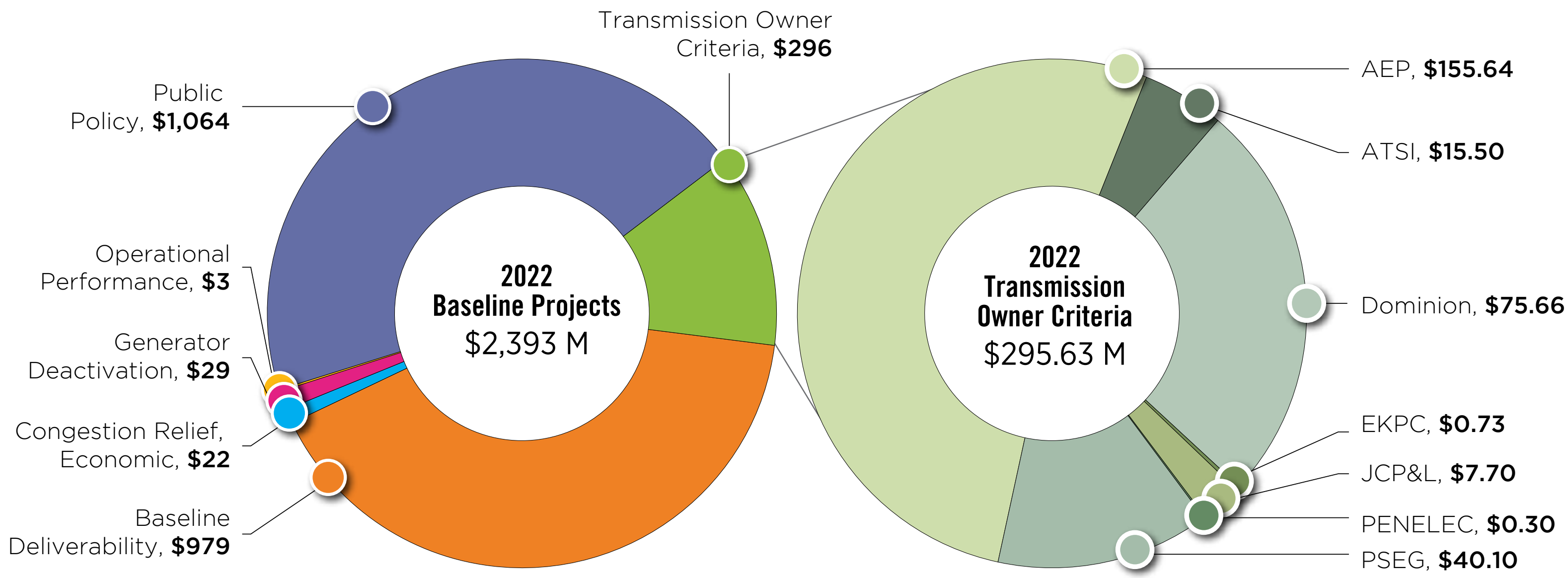
After PJM identifies a baseline transmission need, including needs arising out of market efficiency studies, PJM may open a competitive proposal window, depending on the required in-service date, voltage level and likely project scope. Window eligibility for project driver types is shown in **Figure 1.9**. Throughout each RTEP window, developers can submit project proposals to address one or more needs. When a window closes, PJM evaluates each proposal to determine if any meet all specified project requirements. If so, PJM then recommends a proposal to the PJM Board. Once the Board approves a proposal, the designated developer becomes responsible for financing, project construction, ownership, operation and maintenance.

Figure 1.9: RTEP Proposal Window Eligibility



*__Note:__ *TO criteria-driven violations are eligible for proposal windows as of Jan. 1, 2020.*
***Projects below 200 kV and substation equipment projects could become eligible for competition if multiple needs share common geography/contingency or if the project has multi-zonal cost allocation.*

Figure 1.10: 2022 RTEP Baseline Project Drivers ($ Million)



2022 Baseline Project Drivers

PJM RTEP baseline analysis identifies the need for transmission enhancement projects that span a range of drivers. Those projects identified by PJM and approved by the PJM Board in 2022 were no different, as discussed in later sections of this report and summarized in **Figure 1.10**. As the figure shows, baseline transmission investment, once primarily made up of projects driven by deliverability, now also includes projects driven by other factors, like public policy via the New Jersey State Agreement Approach.

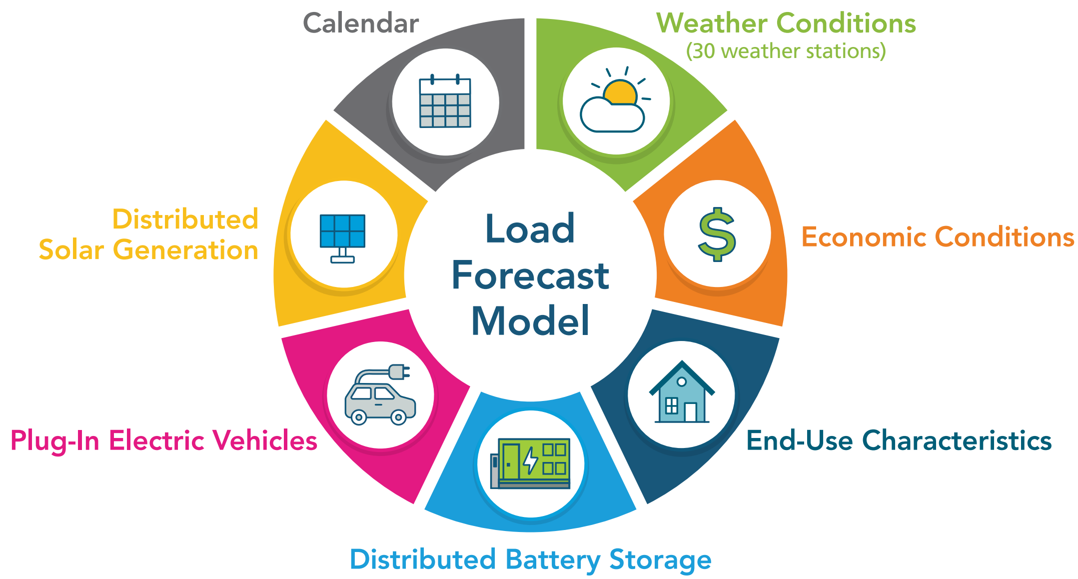
Market Efficiency

PJM's RTEP process includes market efficiency analysis to accomplish the following goals:

- Determine which reliability-based enhancements have economic benefit if accelerated
- Identify new transmission enhancements that may realize economic benefit
- Identify the economic benefits associated with reliability-based enhancements already included in the RTEP that, if modified, would relieve one or more congestion constraints, providing additional economic benefit

PJM identifies the economic benefit of proposed transmission projects by conducting production cost simulations accounting for the concepts in **Figure 1.11**. These simulations show the extent to which congestion is mitigated by a project for specific study-year transmission and generation dispatch scenarios. Economic benefit is determined by comparing future-year simulations both with and without the proposed transmission enhancement. The metrics and methods used to determine economic benefit are described in **Section 4.3**.

Figure 1.11: Market Efficiency Analysis Parameters



1.3: Grid of the Future

1.3.1 — Regional Planning Perspective

Over the past decade, an increasing focus by federal and state governments on climate change, energy independence and other public policy areas has highlighted the critical role of a reliable and resilient transmission system. Ongoing PJM initiatives continue to examine current industry trends and drivers and how they could impact PJM's transmission planning process in order to best develop the "grid of the future."

PJM's RTEP process continues to evolve, bringing into clearer focus a future grid driven by decarbonization, renewables, public policy, resource mix changes, increasing electrification and technology enhancements. Achieving this future means enhancing operational flexibility and ensuring that reliability and resilience remain paramount.

To that end, PJM System Planning – in collaboration with markets and operations teams – developed a grid of the future road map, introduced in Section 1.3 of PJM's 2021 RTEP Report and described more fully in a May 10, 2022, paper entitled Grid of the Future: PJM's Regional Planning Perspective. This road map outlines a multiyear effort to implement PJM's corporate strategy, approved by the PJM Board, to enable grid transition in a changing industry:

1. *Transmission build-out scenario studies began in 2022* based on power flow case alignment with PJM's energy transition studies and by leveraging analytical work of the Offshore Wind Scenario Study Phase 1. This major planning effort has considered both offshore wind injection as well as renewable resources necessary to achieve states' Renewable Portfolio Standard (RPS) objectives for a 2035 study year under both base level and accelerated scenarios.
2. *Targeted reliability studies will build on 2022 scenario study results* to evaluate generation and transmission reliability attributes, such as reactive control, stability, system inertia and frequency control, and short-circuit impacts to ensure reliable operations.
3. *RTEP process enhancements continue to evolve,* including interconnection process reform, generator deliverability methodology improvement, Effective Load Carrying Capability methodology development, and implementation of future probabilistic planning techniques.

These road map elements will continue to unfold against a backdrop of anticipated final rules in FERC Docket No. RM21-17-000, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection ("Transmission NOPR") and FERC Docket No. RM22-14-000, Interconnection Process Reform, which is discussed in **Section 5.3**.

NOTE:

On August 17, 2022, PJM submitted comments in response to the FERC Transmission NOPR.

On October 13, 2022, PJM submitted comments in response to the FERC Interconnection Process Reform NOPR.

1.3.2 — Grid of the Future Scenario Studies

Studying and understanding future grid scenarios are foundational elements of PJM's multiyear, PJM Board-approved corporate strategy to enable grid planning, operations and markets transition in an industry pursuing decarbonization public policy goals. To that end, the scenario studies currently underway leverage recently completed offshore wind reliability studies and markets-focused energy transition studies as part of examining that transition. The 2035 Policy Scenario will model plausible, realistic future grid conditions based on known state and federal decarbonization public policies currently in effect. The 2035 Accelerated Scenario will model renewable and deactivation parameters that are more representative of what might be expected over the next 25–30 years, out to year 2050.

More specifically, initial scenario studies are focusing on the reliability-driven need for RTO-wide transmission build-out in a decarbonized future and marks the latest in a series of related PJM informational thought leadership publications:

1. **Reliability impact of integrating offshore wind-powered generation:** PJM's Offshore Wind Transmission Study: Phase 1 examined grid reinforcements needed to reliably deliver: (1) over 17,000 MW of announced offshore wind in the PJM region; and (2) all state Renewable Portfolio Standard (RPS) targets, based on the necessary renewable capacity by resource type and location to achieve them. Based on the study's phase 1 results, states have requested additional scenarios for PJM to model. To that end, phase 2 of the Offshore Wind Transmission Study is currently under development in parallel with the future grid scenario studies discussed here.

   Scenario Study Alignment: The Offshore Wind Transmission Study provided significant input to the grid of the future scenario studies conducted in 2022. Like with the offshore wind study, the scenario development for the 2022 studies was based on power flow case alignment with offshore wind injection totals at specific points of interconnection (POIs); generator deactivations; and state RPS requirements through utility-scale and behind-the-meter solar, onshore wind and battery storage; as well as incorporated electric vehicle and energy efficiency policy targets captured as part of the PJM load forecast.

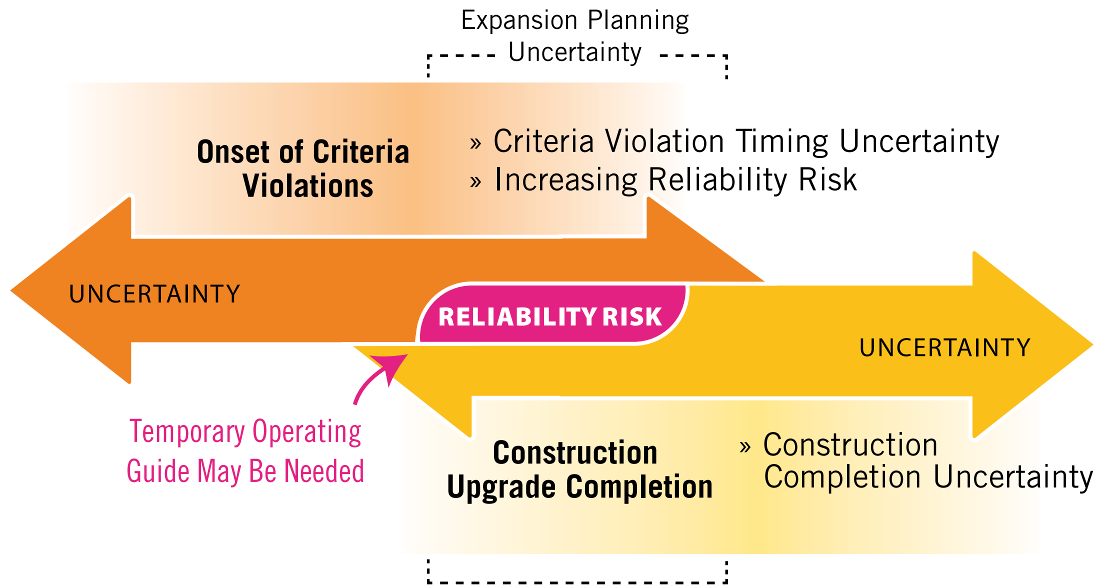
2. **Market and operational impacts of integrating renewables:** This initiative comprises a multi-phase, multiyear effort to study the potential impacts associated with PJM's evolving resource mix. The first phase of this study culminated in the Energy Transition in PJM: Frameworks for Analysis report published Dec. 15, 2021. The report showed that as the penetration of renewable resources increases, the risk profile shifts toward later hours in the evening, as peak net demand (load minus renewable generation) shifts toward the sunset. The second phase of this study culminated in the Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid report, published May 17, 2022, which studied the impacts of refined assumptions regarding solar, storage, electrification, interchange and reserves.

   Scenario Study Alignment: The scenario development methodology used in the ongoing Energy Transition in PJM study has provided study year 2035 Policy and Accelerated scenario parameters to be modeled as part of both this planning analysis and the third phase of the Energy Transition in PJM study:

   - Assumptions for state and federal policies and regulations that are driving the changing resource mix
   - Amounts and locations of resource expansion and deactivation
   - Demand inputs, consistent with the 2022 PJM Load Forecast
   - The assumption for Loss of Load Expectation (LOLE) risk level to be set at one day in 10 years

As with the Energy Transition in PJM and Offshore Wind Transmission studies, the Grid of the Future Scenario Study will be studied under PJM's long-term RTEP framework. Findings can then inform federal and state regulatory bodies and the broader PJM stakeholder community as they continue to engage in decarbonized grid public policy discussions, pursue decision-making, and develop the long-term regional transmission infrastructure needed to enable that future.

Figure 1.12: Transmission Expansion Uncertainty



1.3.3 — Grid of the Future Initial Scenario Study Observations

Holistically speaking, for both the Policy and Accelerated 2035 scenarios, the tightly networked nature of the PJM grid suggests that renewables will not be locating long distances from load centers. Nonetheless, the locations of new generation will likely be different from where current generation exists. That trend, coupled with the deactivation of coal- and natural gas-powered generation, has significant implications for future grid planning, insofar as the need for major long-distance, possible multistate, backbone transmission lines to deliver RPS-mandated power may not necessarily be the most efficient first-choice grid solution. Rather, an enhanced mesh grid expansion would be required under each scenario, which will be best understood by considering the role of transmission at different voltage levels.

- *Highways* – These are today's backbone transmission facilities at 345 kV, 500 kV and 765 kV. Thermal overloads will require both increasing the transfer capability on existing transmission infrastructure as well as new transmission lines on new (or existing) rights of way. Notably, however, the grid expansion that will be required at these voltage levels will not likely entail implementation of long-distance trunk lines to access remote swaths of new renewables. Rather, PJM grid enhancements to backbone facilities will likely be more localized and likely will require extensive rebuilding or upgrading of existing facilities. Where new lines are required to continue to deliver bulk power transfers across transmission owner and state boundaries to load centers, it is anticipated to be at distances generally under 100 miles.
- *Byways* – New and/or enhanced transmission infrastructure "byways" from 69 kV through 230 kV will ensure that new renewable generation power can be delivered out of bottled areas, which could be referred to as generation pockets, to access the backbone transmission capability in order to reach load centers.

Results from these initial scenario studies will provide an indication of the scope of transmission grid enhancements that will be needed as older thermal generation retires, new renewable generation connects to the grid and electrification of load increases.

1.3.4 — 2035 Generation Outlook

Across the PJM footprint, as in other areas of the country, the generation fleet fuel mix continues to shift. Driven by public policy (including RPS mandates and environmental regulations) and abundant shale gas in the PJM footprint, coal-fired generation is retiring and being replaced by renewable generation.

PJM's diverse installed capacity resource profile today includes generation powered by natural gas, coal, nuclear, wind and solar, coupled with demand response and storage. However, increasing public demand for cleaner sources of electricity, combined with public policy standards and goals, is driving unprecedented growth in renewable resources. PJM generation interconnection queue activity reflects a shift from interconnection requests by natural gas generation to solar, wind and storage.

Renewable Power

While PJM state renewable goals differ in scope, timing, resource specificity, means of implementation and mandatory versus voluntary, most state jurisdictions in the region PJM serves have some level of renewable resource or clean energy targets. Meeting these targets will include terrestrial wind, offshore wind and solar resource development as well as storage. In PJM's interconnection queue, renewables and storage account for over 90% of requests. Most of the recent queued requests for grid interconnection throughout the PJM service area are from inverter-based solar generation resources. And while solar projects were once small in size and limited to a handful of areas, today, individual projects can be on the order of hundreds of megawatts, in-part driven by states' RPS goals, and are locating in every PJM transmission zone.

Onshore wind continues to interconnect to the grid, but current trends show it to be more concentrated in western areas of the PJM footprint. Offshore wind is also emerging as a major source of power, seeking to interconnect to the grid along PJM coastal states. The potential for development is substantial. PJM must address the challenges that these locationally constrained resources present.

Renewable Portfolio Standards

PJM's grid of the future will enable customer access to renewable power at much greater levels than today, driven by states' RPS mandates. Ten states in the PJM footprint, plus the District of Columbia, have enacted them as shown in **Table 1.4** and **Map 1.3**, below. These mandated state RPS targets require that a certain percentage of a state's load is served by qualified renewable energy resources. RPS policies have functioned as a significant driver of renewable resource development. Across the nation, and in the PJM region, many states have increased their RPS targets in recent years in pursuit of accelerated decarbonization objectives. Since 2018, Delaware, the District of Columbia, Illinois, Maryland, New Jersey and Virginia have all established new RPS targets.

State RPS policies also vary by eligible resource technology, in-state resource carve-out requirements, and required qualified resource location. Whether characterized as a goal or target, the majority of PJM states are moving toward a decarbonized grid over the course of the next 20–30 years. In addition, some in-state resource carve-outs are crafted as a percentage of energy, while others specify the minimum renewable capacity to be developed in-state. The variability in policies has not been a hindrance to building new renewable generation and, in fact, has provided developers both direction and flexibility in siting planned renewable generators. As a result, renewable generation is now the most prominent resource type in PJM's interconnection queue in each state, including those that have historically been more fossil fuel intensive.

Table 1.4: PJM State RPS Targets

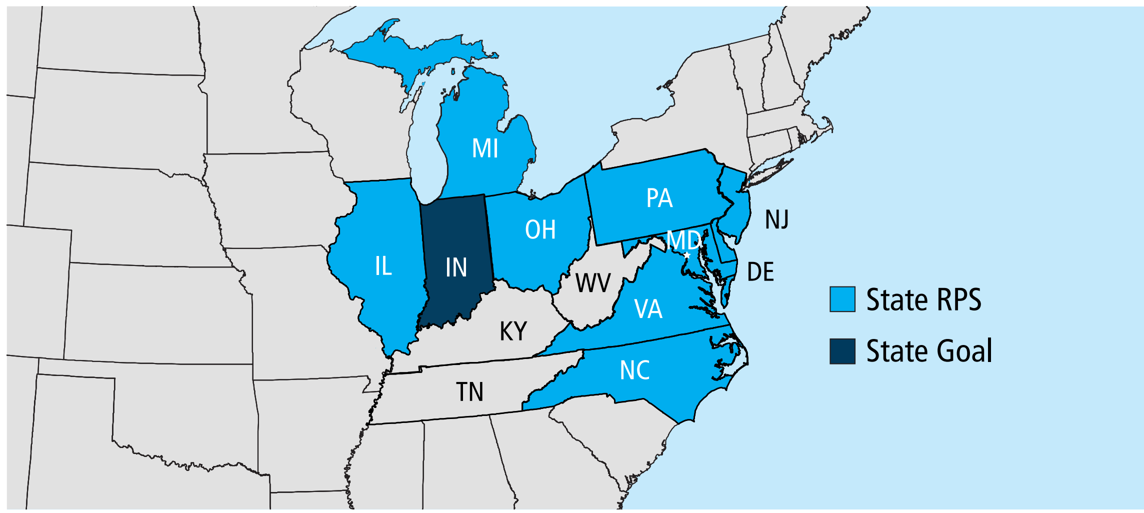
State RPS Targets*

☼	**NJ:** 50% by 2030**	☼	**PA:** 18% by 2021***		**OH:** 8.5% by 2026
☼	**MD:** 50% by 2030**	☼	**IL:** 50% by 2040		**MI:** 15% by 2021
☼	**DE:** 40% by 2035	☼	**VA:** 100% by 2045/2050 (IOUs)		**IN:** 10% by 2025***
☼	**DC:** 100% by 2032	☼	**NC:** 12.5% by 2021 (IOUs)		

☼ Minimum solar requirement

* Targets may change over time; these are recent representative snapshot values
** Includes an additional 2.5% of Class II resources each year
*** Includes non-renewable "alternative" energy resources

Map 1.3: PJM State RPS Targets and Goals



For additional background discussion on RPS standards, see Section 2.1. of PJM's May 10, 2022, Grid of the Future: PJM's Regional Planning Perspective Report.

Onshore Wind

Renewables growth is not emerging uniformly across PJM's footprint. Growth is occurring fastest in areas with favorable wind speed and sustained duration in order to achieve energy production levels that generate profit-making revenue streams. PJM continues to see developer interest in constructing wind-powered generating facilities throughout its footprint with clusters emerging in PJM's western subregion (including Illinois, Indiana and Ohio) and along the Allegheny Mountains in Pennsylvania and West Virginia.

For additional background discussion regarding onshore wind, see Section 2.1.5 of PJM's May 10, 2022, Grid of the Future: PJM's Regional Planning Perspective Report.

Offshore Wind

The area off the U.S. Atlantic coast encompasses a major wind-energy resource that could potentially yield thousands of megawatts of power. Efficiently harnessing that energy through the construction of offshore wind farms will require extending the existing transmission grid to deliver power ashore to users, particularly to load centers along the East Coast.

The injection of thousands of megawatts from offshore wind will fundamentally change how power flows over the transmission grid in the Northeast and Mid-Atlantic. Generation will now be located closer to load centers along the I-95 corridor. Historically, this area of the grid was served mainly by west-to-east power flow from large mine-mouth coal generating stations in western Pennsylvania and beyond and, later, shale natural gas-fired plants in central Pennsylvania. This unfolding scenario will drive the need for new transmission assets and system configurations to maximize power delivery to onshore load.

For additional background discussion regarding offshore wind, see Section 2.1.6 of PJM's May 10, 2022, Grid of the Future: PJM's Regional Planning Perspective Report.

Solar

States rely on solar power as one of the main resources to meet their RPS requirements. Eight of the 10 PJM states with mandatory RPS targets include solar-specific requirements, the details of which vary by state. Some include in-state solar carve-outs as a percentage of total state energy demand. Others permit their solar carve-outs to be met by solar resources located anywhere within the PJM footprint. Still others, particularly those located along PJM's seams, allow solar commitments from resources located outside the PJM footprint to meet RPS targets and goals.

For additional background discussion regarding solar, see Section 2.1.7 of PJM's May 10, 2022, Grid of the Future: PJM's Regional Planning Perspective Report.

Storage

Energy storage development continues to grow in PJM as in other RTOs. As solar generation increases across the PJM footprint, storage growth is expected to follow, particularly as part of co-located projects. Efficient grid operations in an era of rapid renewable energy resource growth will require increased electric system flexibility. Energy storage can help grid operators maintain stable power supply under varying wind and solar power output, driven by weather conditions and unit outages, and improve utilization levels of existing transmission facilities. PJM has worked with various companies and national laboratories to study storage use and to ensure that the PJM wholesale market can permit all forms of energy storage to participate.

PJM recognizes that storage paired with renewables and transmission can optimize the delivery of power. To address the limited-duration issue, some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

For additional background discussion regarding storage, see Section 2.1.8 and Section 5.4 of PJM's May 10, 2022, Grid of the Future: PJM's Regional Planning Perspective Report.

Public Policy Factors: Storage development is also being driven by both explicit and implicit state policy objectives. Explicit state targets include Virginia's 3,100 MW of storage by 2035 and New Jersey's 2,000 MW target by 2030, as outlined in its 2019 Energy Master Plan. Maryland also has an energy storage pilot program that was implemented in 2019 to develop storage capacity within the state. Implicitly, storage is being developed to complement the influx of renewable resources driven by state RPS targets.

Generator Deactivations

Generator deactivations alter power flows that can cause transmission line overloads and, given the loss of reactive power control capability from large-scale coal-fired and nuclear-powered generators, can undermine voltage control. When PJM receives a formal generator deactivation request, it conducts thermal and reactive studies to ensure that remaining generation continues to be deliverable to load. If criteria violations are identified, PJM develops a solution in coordination with affected transmission owners.

Many factors can lead units to deactivate. Plant age and economic impacts of increasing operating costs are often key drivers. Other significant factors include environmental public policy, particularly with regard to carbon emissions. Generator deactivations are both driven by and directly impact PJM capacity auction activity. For example, 10 coal-fired units did not clear the 2022/2023 Base Residual Auction conducted in May 2021. Nine of these units submitted notifications of deactivation in June 2021. The 10th unit that did not request deactivation exhibited strong energy and ancillary service revenue supported by expected strong operating periods.

A major factor putting a generator at risk is its inability to clear a capacity auction given its costs compared to other resources offered into the auction:

1. New entrants with more efficient performance, including those powered by Marcellus and Utica shale natural gas
2. Wind- and solar-powered renewable energy resources with no marginal fuel cost
3. Demand resources
4. Energy efficiency programs

Such factors drove the business decisions by owners to retire 47,340 MW of generation between 2012 and 2022, for example. By 2035, that number could reach 87,482 MW.

Coal-Fired Plants

For perspective, coal-fired power plants account for 80% (nearly 37,000 MW) of total deactivations between 2012 and 2022, driven by one or more factors. Some larger coal units were located on or near now-depleted coal mines in order to reduce fuel transportation costs. To remain in operation, these plants sought more cost-effective sources for coal, increasing the fuel transportation component of their unit operating costs. Environmental compliance has been another factor, linked to overall age when refit of facilities was considered.

Public Policy Factors: For many coal plants, environmental regulations – including those to reduce mercury emissions under EPA's Mercury and Air Toxics Standard rule (MATS) of 2011, NO_x emissions under EPA's ozone transport rules, CO_2 under the Regional Greenhouse Gas Initiative, wastewater discharges under EPA's Effluent Guidelines, and coal ash disposal under the EPA's coal combustion residuals rule – have increased unit costs driven by the need to install new emission control equipment, upgrade facilities or acquire emissions allowances. Some states are also facilitating the eventual retirement of their coal facilities through policies in pursuit of a decarbonized grid. For example, the Illinois Climate and Equitable Jobs Act is mandating a scheduled phase-out of Illinois' coal units over the next two decades.

For additional background discussion regarding coal unit deactivation, see Section 2.2.2 of PJM's May 10, 2022, Grid of the Future: PJM's Regional Planning Perspective Report.

Nuclear Power Plants – Public Policy Factors: Unlike coal-fired generating plants, nuclear plants do not emit carbon dioxide. This operational characteristic has resulted in some states providing financial assistance to their nuclear facilities, such as through zero emission credit (ZEC) programs. ZECs are subject to periodic review and renewal and, like other public policy action, can have an impact on deactivation decisions. At the federal level, the 2021 Infrastructure Investment and Jobs Act also established a $6 billion Civil Nuclear Credit Program for at-risk nuclear facilities. Nuclear plants have rising operating costs but are kept in the market to ensure reliability and to satisfy decarbonization and other environmental public policy objectives. To the extent that nuclear plant operators can reap positive revenue streams, they will likely pursue relicensing. The Nuclear Regulatory Commission (NRC) staff has defined subsequent license renewal (SLR) to be an operating extension from 60 years to 80 years. In the scenarios included in this study, PJM assumes that existing nuclear generation resources complete the SLR process to remain operational. No new-build nuclear generation is included. PJM notes that new nuclear technologies are being explored in the industry, though no such new nuclear facilities have yet been proposed within the PJM footprint.

For additional background discussion regarding nuclear plant deactivation, see Section 2.2.2 of PJM's May 10, 2022, Grid of the Future: PJM's Regional Planning Perspective Report.

1.3.5 — 2035 Load Level Outlook

Electrification is the process of converting an end-use load that uses fossil fuels (or other non-electric energy sources) to electricity. This most commonly refers to vehicles, but can also refer to home and business uses for ambient heating, water heating, cooking and other activities. Transportation and heating could have the greatest impact on load forecast and load shape.

Transportation Electrification

Transportation electrification will be a significant contributor to future demand. Electric vehicle (EV) purchases have been growing at an exponential rate yet still amount to less than 1% of light-duty vehicles in the PJM service area. As with any emerging technology, a significant degree of adoption-rate uncertainty always exists. Forecasts for EV sales range widely from 4% of total vehicle sales by 2030 and 8% by 2040, to the recent White House EV target to reach 50% by 2030. Ultimately, the pace of EV sales will fundamentally be driven by battery prices and government incentives.

PJM continues to pay close attention to U.S. transportation sector electrification and, in particular, the impact of EVs on transmission system needs. The Edison Electric Institute (EEI) estimates that EVs will grow from 1 million today to 7 million across the country by 2025. EEI goes on to cite the Northeast as one of the regions of the country "with higher concentrations of first adopters of electric vehicles and more immediate, more ambitious policy targets."

For additional background discussion on transportation electrification, see Section 4.1.1 of PJM's May 10, 2022, Grid of the Future: PJM's Regional Planning Perspective Report.

Building Heating Electrification

The outlook for building heating is more uncertain than that for EVs. General consensus holds that future EV penetration levels will be significantly higher than today, but the uncertainty centers on quantifying the magnitude of that growth. This is not the case with electric heating.

In PJM's 2021 Load Forecast, which used input from the 2020 Energy Information Administration Annual Energy Outlook, electric heating does not gain traction. Given current policy and costs, the direction tends to be more toward natural gas heating in much of the PJM service area. Some areas in PJM's southern subregion already rely on electricity to some degree for heating (e.g., Virginia). However, northern Midwest and Mid-Atlantic areas of the PJM region predominately use non-electric fuels (mostly natural gas and some propane and fuel oil).

For additional background discussion on building heating electrification, see Section 4.1.2 of PJM's May 10, 2022, [Grid of the Future: PJM's Regional Planning Perspective Report](https://www.pjm.com).

Distributed Energy Resources

Distributed energy resources (DER) are not new to PJM, nor to regional grid planning. Since its New Services Queue process began in the late 1990s, PJM has integrated DER that have included hydro, natural gas, landfill gas (methane), diesel, oil, waste, wood byproducts, storage, wind, solar and hybrid facilities. But, while PJM has integrated DER into its wholesale market, DER can also operate outside PJM's service territory and PJM's New Services Queue process. For additional background discussion on DER, see Section 3 of PJM's May 10, 2022, Grid of the Future: PJM's Regional Planning Perspective Report.

1.3.6 — Emerging Technologies

Emerging technologies will likely play a growing role in managing congestion and solving reliability criteria violations associated with integrating significant amounts of renewable resources. Such technologies may reduce the need for, or mitigate impacts of, new greenfield transmission lines and the attendant siting approval and permitting challenges. Both reliability and market efficiency studies are already identifying the need for additional transmission capability to make the transition to a more decarbonized grid.

The needs of the future grid in the PJM region will likely require a range of solutions. While new transmission lines on new rights-of-way continue to be an option for developers, the attendant siting and permitting, time to construct, and cost to build can be formidable challenges. For these and other reasons, PJM anticipates that innovative solutions that maximize the use of existing facilities and existing transmission corridors will play a role in meeting the future grid's needs. Among the technologies under active PJM and industry discussion are dynamic line ratings (DLRs), specialized conductor designs, compact tower construction, power-flow control devices and grid-forming Flexible AC Transmission System (FACTS) devices.

1. **DLR technology** can identify additional capacity on transmission lines, potentially relieving congestion and creating economic efficiencies. Such technology can also enhance system resilience by providing enhanced real-time monitoring of transmission assets.

2. **Advanced conductor designs** can provide a means of achieving a higher ampacity transmission line capability on existing corridors, mitigating the need for new lines or significant rebuild. Developers that build new transmission lines, or rebuild existing ones, often encounter siting and permitting challenges that can cause lengthy delays or even prevent project construction altogether. Other advanced conductor design incorporates the use of special conductor coatings that have a higher emissivity and lower absorptivity, which leads to cooler conductors and, thus, higher ampacity ratings.

3. **Advanced transmission tower configuration technology** can provide a means to enhance the utilization of existing and new transmission line corridors as part of future grid expansion. Such designs, coupled with low-impedance bundled conductors, reduce line losses and significantly increase power delivery capability while avoiding the complexities and costs of series compensation.

4. **Flexible Alternating Current Transmission Systems (FACTS)** are power system devices that take more conventional power system components (e.g., capacitors and reactors) and integrate them in various configurations with intelligent power electronics, high-speed thyristor valve technology and voltage-sourced converter (VSC) technology. FACTS devices can directly support additional transmission line power flow with reactive power injections at their point of interconnection and can indirectly control power flow by modulating transmission line impedances. The most common FACTS devices include static VAR compensators (SVCs) and static synchronous compensators (STATCOMs).

5. **SVC hybrids** are a new type of FACTS device that combine the reactive support of a traditional STATCOM with the real power support of energy storage. The purpose of an SVC hybrid is to level-out power fluctuations from variable generating resources, such as wind and solar, by employing the SVC hybrid's grid-forming inverter enabled by the active power control of its energy storage. A grid-forming inverter functions to "go first, not follow" existing grid conditions to try to establish desired power levels and quality.

PJM remains neutral with respect to grid-enhancing technologies that are part of proposals submitted in RTEP windows or as part of transmission owner supplemental projects. To the extent submitted as part of a competitive RTEP window, PJM evaluates qualifying grid-enhancing technology proposals in a manner that is not materially different than the way it evaluates other project proposals. PJM examines the impact of a technology's characteristics on solving identified reliability and market efficiency needs efficiently or cost-effectively. Further, PJM evaluates whether a proposal that includes the deployment of a grid-enhancing technology requires any changes to telemetry, modeling and other operating tools or protocols to support and accommodate integration from a PJM markets and operations standpoint.

1.3.7 — Resilience

A resilient grid must be able to withstand larger-scale system disturbances, to which it is difficult to attach probabilities and that can exceed conventional NERC planning N-1-1 and operations N-1 criteria. Generation and transmission low-probability, high-impact contingencies can significantly impact PJM's ability to serve load reliably. Heavy reliance on intermittent variable resource types raises resilience concerns.

A number of emerging system conditions already present challenges to reliable system operations:

- Extreme weather
- Cyber and physical attacks
- Generation fleet shift driven by natural gas and increased deployment of renewable resources

Such challenges will continue to stress future grid resilience, which enhanced reliability criteria must address. For decades, planning criteria have been developed and applied to power systems across the country (and around the world) to ascertain the need for grid enhancement, so that system operators can meet the operating conditions they encounter on any given day. Planners test the system under simulated stressed conditions, such as extreme weather, to understand where reinforcements may be warranted to make the grid reliable.

Clear and focused resilience reliability criteria are needed to address more extreme system events. These warrant greater attention for a transmission grid with: (1) higher penetration of variable and duration-limited resources reliant on sun and wind to operate; and (2) an end-use sector with growing reliance on electrification.

Reliability and Resilience

While resilience and reliability both define what it means for PJM to keep the lights on under a broad range of conditions, the concepts are not identical. PJM already complies with established NERC, regional and transmission owner reliability standards. To that end, PJM conducts its planning studies under critical, stressed conditions, so that system dispatchers can manage the actual system conditions on any given day in real time. Resilience takes this to another level, addressing challenges and emerging risks that existing reliability standards do not fully capture, such as:

1. Maintaining reliability in the face of significant events beyond typical planning criteria
2. Evaluating threats as part of the transmission planning process
3. Slowing disruptive events, mitigating their impacts and quickly recovering essential functions
4. Protecting essential systems based on assessed risks and hazards
5. Improving grid flexibility and control to adapt efficiently and quickly to post-event conditions
6. Addressing heavy reliance on one resource type

Planning for the grid of the future must consider all of these dimensions of resilience.

NOTE:
In light of Winter Storm Elliott in December 2022, PJM will be investigating the causes and possible mitigation of forced generator outages to ensure system resilience on an ongoing basis.

Beyond NERC Transmission Standards

Existing NERC planning criteria are structured around likely events, requiring that the bulk power system be tested for such contingencies as the loss of a transmission line (a high-probability, low-impact event) under the assumption that all other transmission facilities are in service. Yet in reality, dozens of facilities are out of service on any given day. PJM also simulates more severe, lower-probability N-1-1 events, like the loss of two circuits on a common tower line or a fault on a circuit followed by a breaker failure.

NERC standards address resilience to a degree. Existing planning standards require examination of the impact of extreme events, such as the loss of an entire substation or the loss of an entire right-of-way – caused by a landslide, tornado, hurricane or fire, for example – that would take out multiple transmission lines at one time. Although an assessment of the impact of these events is required, reinforcement for these high-impact, low frequency events is not required under current NERC criteria. Planners must now also assess whether the transmission system is sufficiently reinforced to address extreme events like these as well those caused by physical and cyberattacks.

Reliability Criteria for Extreme Events

PJM's ongoing efforts are taking a forward-looking, holistic and proactive approach to plan for future transmission needs with respect to extreme events, which may become a more significant grid expansion driver under higher levels of renewable penetration. The scope of planning studies will support efforts to assess how extreme events can be analytically evaluated and how consequential impacts to system reliability are identified. This may lead to new reliability criteria and planning tests. To that end, PJM continues to work with stakeholders to consider planning process policy changes that may be needed to enable it to identify and plan needed transmission to address extreme events. PJM, in its NOPR comments noted earlier in **Section 1.0**, has urged FERC to adopt a common definition of resilience and a specific resilience planning driver for grid enhancements, applicable to all planning entities.

Fuel Assurance

Resilience also encompasses fuel assurance – the ability of PJM to withstand disruptions to power output caused by the availability of fuel, ranging from natural gas pipeline delivery to weather-based restrictions on renewable resources. The 2014 Polar Vortex event demonstrated the exposure of gas-fired generation to pipeline delivery constraints as did the impacts of the February 2021 arctic event on ERCOT, SPP and MISO.

Solar and wind generator availability is characterized as variable insofar as output is impacted by both weather and time of day. Wind generation may be forced to shut down during periods of high winds to protect equipment. Such generators are designed with cut-out speeds of approximately 55 mph. The opposite conditions also present fuel-assurance concerns, including loss of wind-powered generation under severe, windless heat spells.

Loss of Transmission

Extreme weather, such as hurricanes and derechos, can force out portions of the transmission system, and the generation connected to it, for days. This could also happen under a geomagnetic disturbance, which is a space-weather phenomenon during which the grid can be exposed to quasi-DC-induced currents. These currents cause grid elements like transformers to overheat, necessitating their preemptive removal from service.

Additionally, NERC's CIP-014 standard requires transmission owner assessments to identify critical facilities that, if rendered inoperable, would cause instability, uncontrolled separation or cascading outages. Concerns across the industry about grid security and resilience under the outage of such facilities continues to grow. PJM's future planning must include efforts to eliminate current vulnerabilities for CIP-014 critical infrastructure, while also working to develop RTEP process criteria to avoid and mitigate the same risk for future critical infrastructure.

1.3.8 — FERC Transmission NOPR

As indicated earlier in **Section 1.3.1**, PJM's Grid of the Future road map continues to unfold against a backdrop of anticipated final rules in FERC Docket No. RM21-17-000, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection (Transmission NOPR), summarized here, and FERC Docket No. RM22-14-000, Interconnection Process Reform, discussed in **Section 5.3**.

Over the past decade, increasing focus by federal and state governments, corporations and other organizations regarding climate change, energy independence and other policy areas continues to make clear the critical role of the transmission system. In its initial comments, PJM generally supported the Commission's proposed reforms aimed at requiring forward-looking, long-term scenario planning to meet transmission needs driven by changes in the resource mix and demand.

- PJM agreed with the fundamental premises underlying the NOPR, i.e., that facilitation of transmission investment will help enhance reliability, reduce power costs, and address our nation's changing resource mix.
- PJM agreed that a longer-term, forward-looking approach to transmission planning can help to achieve these goals.
- PJM strongly supported the need to allow the present short-term reliability and market efficiency planning processes to proceed in their current form so as to ensure that the vital day-to-day work of maintaining a reliable and efficient grid can continue.

Among other factors, PJM stated that the final rule should address enhanced reliability insofar as any endeavor to tackle the transmission needs of the electric grid of the future would be incomplete without factoring resilience into revisions to intermediate-term and long-term regional transmission planning processes. PJM believes the Commission should modify its list of seven factors by directing transmission providers to include enhanced reliability planning and interregional transfer capability as two additional factors to consider when developing the long-term scenarios.

More specifically, PJM urged FERC to adopt the following:

(i) Maintain existing short-term planning processes to address reliability and market efficiency needs, consistent with the Commission's commitment in the NOPR.

(ii) Include enhanced reliability as a specific factor to be considered in both the intermediate-term and the long-term regional transmission planning processes.

(iii) Harmonize the Commission's various transmission planning NOPRs so as to avoid the topic of enhanced reliability planning being "piecemealed" as between new proposed NERC processes and long-term regional transmission planning processes as it relates to intermediate-term planning (between the five-year and the planning horizon associated with the long-term regional transmission planning process).

Importantly, for grid of the future initiatives, PJM requested that the Commission reinforce the need for short-term five-year processes to be able to respond quickly to address imminent reliability violations and short-term market efficiency needs. PJM understands that the Commission proposes to establish the new long-term regional transmission planning process that is not intended to modify the existing short-term reliability and market efficiency processes presently in existence. PJM strongly supports that approach to maintain the current portions of the planning process focused on promptly addressing identified reliability violations and short-term market efficiency issues identified within a five-year period. Being able to respond quickly to address these imminent needs is critical to ensuring the reliability and efficiency of the power grid. Grid topology can change dramatically in the short-term as a result of:

- Major load additions or losses as large customers such as data centers are expanded within a zone or industrial customers close facilities and leave the zone
- Generation retirements that are announced on short notice to PJM as a result of a particular unit failing to clear a capacity auction or facing other external events that precipitate closure
- Reliability violations that are identified in the short term due to equipment failures and other needs to reinforce the system

For these reasons, PJM urged the Commission to reaffirm in the final rule its intention to not disturb the short-term five-year planning that addresses reliability and market efficiency. Although the long-term planning horizon that the Commission contemplates as part of the long-term regional transmission planning process can and will certainly inform the short-term process, it is imperative that the short-term five-year-out process continues to be able to respond to short-term needs quickly and nimbly.

1.4: RTEP Process Milestones

2022 Activities

PJM's RTEP process continues to evolve as the scope of system enhancement drivers shifts. In addition to the efforts undertaken by PJM to bring the grid of the future into clearer focus, as discussed in **Section 1.3**, other related process improvement milestones were achieved throughout 2022, as discussed below.

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to renewable resource grid interconnection. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process New Service Requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

State Agreement Approach

In 2022, PJM continued working with the state of New Jersey on the first implementation of PJM's State Agreement Approach, leading to the NJBPU's selection of a transmission project that it will sponsor to achieve the stated public policy goals of injecting 7,500 MW of offshore wind into New Jersey by 2035, as discussed in **Section 5.2**.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant, Itron, to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak and non-coincident peak demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted EDCs.

Deactivation Improvements

In 2022, PJM revised Part V of the Open Access Transmission Tariff (OATT) regarding deactivation study timing. Prior to the change, PJM had 30 days from each deactivation notice to complete its studies. This included receiving transmission owner input for mitigation of any overloads or voltage concerns identified. During that same period, the Independent Market Monitor had to identify whether the deactivation would result in undue market power. While these assessments are achievable in the 30-day window when deactivation requests are received sequentially, one at a time, receiving many deactivations close in time has made the existing Tariff requirement unworkable. PJM's deactivation Tariff timing is significantly more restrictive than MISO and NYISO.

The PJM Planning Committee reviewed the problem statement and issue charge addressing the Tariff revisions in February 2022. The proposal sought to transition PJM's deactivation process more in line with MISO and NYISO. PJM's proposal sought a rolling quarterly process in which the following steps would take place:

1. Generation owners would submit their formal deactivation notice during a "notification quarter."
2. PJM would study those deactivations in the subsequent and sequential rolling second quarter.
3. PJM would alert stakeholders of study results in the subsequent and sequential rolling third quarter.

Owners of deactivating generators would be required to provide six months minimum advance notice if at the beginning of a quarter, and three months plus a day if submitting at the end of the notification quarter.

Stakeholders were receptive to the advance notification and additional study time changes. PJM filed Tariff changes with FERC on July 12, 2022. PJM manual changes were also approved pending FERC approval. In September 2022, PJM received FERC's approval to implement the changes effective in the final quarter of 2022. In October 2022, the deactivation notice and analyses were implemented under the new process.

Generator Deliverability Improvements

In December 2022, PJM's Markets and Reliability Committee approved enhancements to the generator deliverability test, described in **Section 1.3**.

Distributed Energy Resources

Distributed energy resources (DER) are not new to PJM, nor to regional grid planning. Since its New Services Queue process began in the late 1990s, PJM has integrated DER that have included hydro, natural gas, landfill gas (methane), diesel, oil, waste, wood byproducts, storage, wind, solar and hybrid facilities. As defined by FERC in 2016, DER are "a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment."

DER trends, currently consisting primarily of rooftop solar, have been steadily growing in recent years and may continue to grow as a result of FERC Order 2222. The intent of the order is to reduce barriers to DER participation in wholesale markets by incorporating processes to permit aggregation of smaller-sized resources.

Research shows an increasing trend toward the installation of resources behind the meter, incentivized by state customer-focused programs or required for local reliability. Such resources clearly impact the operation of local distribution grids but can also impact bulk power system operations, including load levels, transmission facility loading patterns and voltage profiles. The continued penetration of DER will require close and effective coordination between PJM and distribution operators to ensure reliable and efficient operations.

Queue Activity

Today, storage resources comprise pumped hydro totaling nearly 4,000 MW and battery and flywheel energy storage totaling 300 MW. Pumped storage can participate in the PJM capacity, Energy, Regulation and reserves markets. Queued storage resources total over 34,000 MW of interconnection requests for CIRs.

DER RTEP Process Impact

DER interconnections have been growing steadily since 2009 and are expected to continue to grow over the next two decades. Currently, over 6,300 MW of distributed solar capacity is connected at the distribution level based on Generation Attribute Tracking System (GATS) data reporting. DER growth in PJM is driven by local, state and federal policies as well as environmental considerations, customer desire for self-supply and the declining costs for acquiring DER technologies. PJM's Resource Adequacy Planning Department has published projections for further DER growth. By 2035, the current 2,300 MW of load reduction, due to non-wholesale DER, is projected to grow to an estimated 8,000 MW, more than tripling the level of DER penetration.

Currently, PJM planning studies account for retail DER by netting the forecast amount from the load forecast. This approach may be adequate at lower DER levels but could be problematic at substantially higher levels, at which point PJM may not be accounting for the full load that must otherwise be served absent DER. Nonetheless, DER can provide system benefits given their proximity to load, reducing the burden on transmission facilities if load were otherwise served by more distant sources.

Public Policy Drivers

State Policy

State policies are a significant driver of the clean energy transition and renewable resource development and, therefore, a significant driver of transmission infrastructure.

In the PJM region, ten states have mandatory Renewable Portfolio Standards (RPS). These mandated state RPS targets require that a certain percentage of a state's load be served by qualified renewable energy resources.

Across the nation, and in PJM, many states have increased their RPS targets in recent years in pursuit of accelerated decarbonization objectives. Since 2018, Delaware, the District of Columbia, Illinois, Maryland, New Jersey and Virginia have all established new RPS targets.

One outcome of state policies requiring that more electricity come from renewable resources has been an increase in the amount of renewable generation entering the PJM interconnection queue. Renewable generation (wind, solar, storage or a combination thereof) is now the most prominent resource type in PJM's interconnection queue in each state, including those that have historically been more fossil fuel intensive.

With PJM's revamped interconnection process, PJM will be able to move all new projects and uprates through the queue in a timely manner. This will enable more renewables to reach commercial operation, thereby helping states meet their clean energy public policy goals.

Maintaining reliability is paramount as the grid transitions to more intermittent renewable resources. PJM continues to plan for the grid of the future, and through scenario studies like PJM's Grid of the Future Study and the Offshore Wind Transmission Study, PJM and industry stakeholders are able to ascertain the scope and scale of how the grid is likely to evolve. States are also beginning to proactively plan for their renewable integration objectives. For example, New Jersey utilized PJM's State Agreement Approach to solicit transmission solutions that support the state's offshore wind development, as described in **Section 5.2**.

Retirement Studies

Preparing for more renewables coming onto the system is one part of planning for the future grid. Another aspect is planning for the replacement of dispatchable, thermal facilities. To move toward a decarbonized grid, some states are beginning to encourage, facilitate or mandate through policy the eventual retirement of carbon-emitting resources. Recent examples of state policies that facilitate decarbonization and may result in resource mix changes include Virginia's Clean Economy Act (2020), Illinois' 2021 Climate and Equitable Jobs Act (CEJA), Maryland's Climate Solutions Now Act (2022), and the New Jersey Department of Environmental Protection's recently issued Control and Prohibition of Carbon Dioxide Emissions rule (2022).

PJM studies policies such as these to assess their potential impacts to grid reliability. One example of this is the Illinois Generation Retirement Study (August 2022) that PJM performed to determine impacts to the transmission system resulting from anticipated generation retirements driven by CEJA. The transmission upgrades identified in such studies are a function of the transmission system at the time of the deactivations, and the eventual results can differ as the study horizon gets closer to reality. It is also important that as states continue to advance decarbonization objectives, these retirement policies must be afforded enough flexibility to allow system reliability to be maintained.

Federal-State Coordination on Transmission Planning

In June 2021, FERC established the Joint Federal-State Task Force on Electric Transmission to explore transmission-related topics with state regulators. The task force began meeting in November 2021 and met an additional four times in 2022. These meetings are open to the public, and stakeholders are able to submit post-meeting comments on the issues raised during each session. Through its post-meeting comments submitted to FERC, PJM continues to offer its expertise as the regional planner to federal and state regulators participating in the task force on transmission-related issues.

FERC also issued several NOPRs in 2022 aimed at transmission planning. One of these NOPRs (RM21-17) is entitled Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, and it focuses on forward-looking scenarios to plan for a new class of long-term regional transmission facilities. The NOPR is also proposing that PJM (and other regional planners) collaborates with relevant state entities within the planning region as part of the process in selecting these new transmission facilities.

Section 2: Resource Adequacy Modeling

2.0: Power Flow Model Load

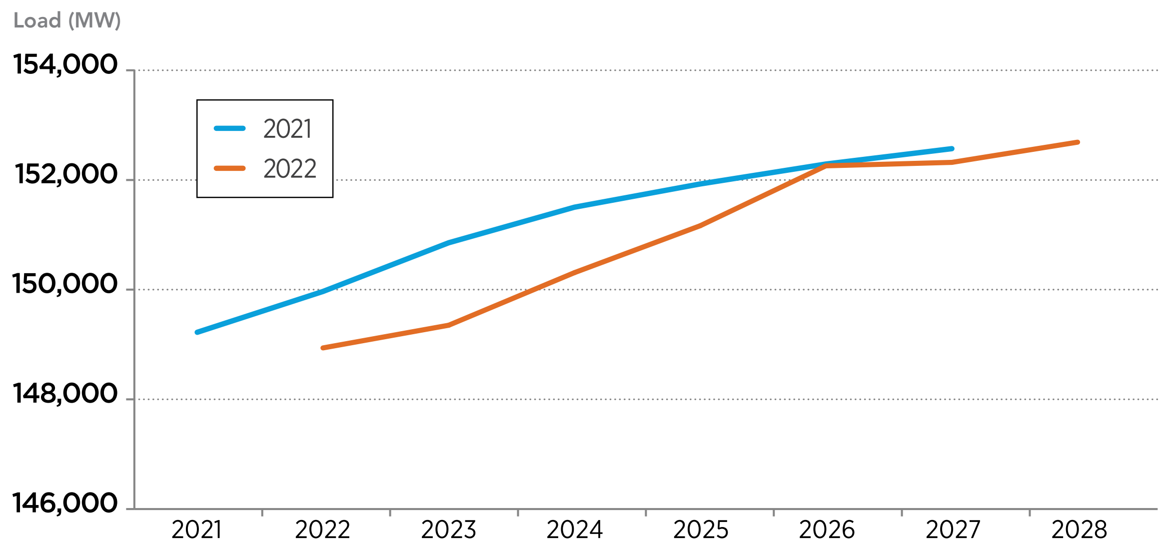
Fundamentally, PJM's planning process identifies future system transmission needs based on power flow studies that reveal reliability criteria violations. Power flow study models incorporate the effect of many system expansion drivers. Zonal load forecasts are the basis for power flow case bus loads. Modeling load this way is essential if transmission expansion studies are to yield plans that will continue to ensure reliable and economic system operations.

In order to develop a power flow base case model, PJM first assigns zonal load from its January forecast to individual zonal buses according to ratios of each bus load to total zonal load. Ratios are supplied by each transmission owner. Given that loads in different geographical areas peak at different times, for load deliverability studies, zonal load is studied at its non-coincident level (i.e., at the time of the zone's peak).

2022 RTEP Process Context

PJM's 2022 RTEP baseline power flow model for study year 2027 was based on an overall RTO summer peak load of 152,322 MW from the [2022 PJM Load Forecast Report](). Summarized in the sections that follow, PJM's January 2022 load forecast covered the 2022 through 2037 planning horizon. Using this figure reflects that PJM now projects its RTO summer-normalized peak to grow 0.4% annually over the next 10 years, shown in **Figure 2.1**, which is up 0.1 percentage points from the 2021 forecast.

Figure 2.1: Summer Peak Load Forecast 2022 vs. 2021



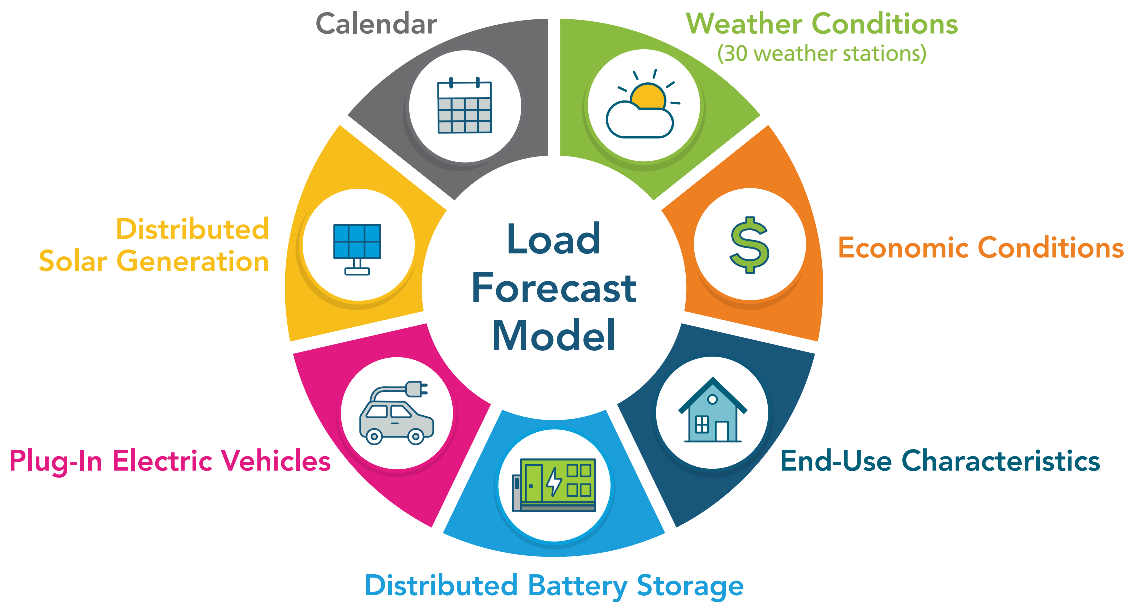
Significant load growth due to new construction of data centers is driving the need for additional sensitivity studies to assess the potential impacts of large localized load increases on transmission adequacy. PJM will continue to work closely with local transmission owner planners to ensure these load additions are properly captured in future forecasts.

Load Forecasting Process

PJM's load forecast model produces a 15-year forecast for each PJM zone, Locational Deliverability Area and the RTO. The model estimates the historical relationship between load (peak and energy) and a range of different drivers, including weather variables, economics, calendar effects, end-use characteristics (equipment/appliance saturation and efficiency), distributed solar and battery storage generation, and plug-in electric vehicles. The model then leverages those relationships to derive forecast load, shown in **Figure 2.2.**

PJM instituted changes in the 2022 load forecast methodology to provide greater alignment with ongoing load trends and enhance forecast accuracy. Specifically, PJM made model changes in the 2022 load forecast to better capture granularity in the sector models and weather response in the summer and winter seasons. These changes were implemented through stakeholder engagement at the Load Analysis Subcommittee and Planning Committee meetings.

Figure 2.2: Load Forecast Model



Calibration

The model takes advantage of publicly available sector data to calibrate the independent variables used to forecast load, such as end-use and economic trends. Load data used in the PJM load forecast is at the transmission zone level, but unseen are the customers that contribute to that load. These customers broadly come from three sectors: residential, commercial and industrial. Understanding trends in each of these categories is valuable to understanding their holistic impact at zonal and RTO levels. PJM leverages data from the Energy Information Administration's (EIA) Form 861, the Annual Electric Power Industry Report, in order to better inform this understanding.

Weather Conditions

The impact on load driven by weather conditions across the RTO is accounted for through concepts such as temperature, humidity and wind speed. PJM obtains weather data from over 30 identified weather stations across the PJM footprint.

Calendar

Calendar effects are variables that represent the day of the week, month and holidays.

Economic Conditions

The impact of economic conditions on load forecasting is accounted for by employing such factors as measures of households, real personal income, population, working-age population and real output. This allows for localized treatment of economic effects within a zone. PJM has contracted with an outside economic services vendor to provide economic forecasts for all areas within the PJM footprint.

End-Use Characteristics

End-use characteristics are captured through three distinct variables designed to capture the various ways in which electricity is used: both weather-sensitive heating and cooling and non-weather-sensitive use. Each variable addresses a specific set of equipment types, accounting over time for both the saturation of that equipment type, as well as its respective efficiency. For instance, the cooling variable captures increasing central air conditioning unit efficiency.

Plug-In Electric Vehicles

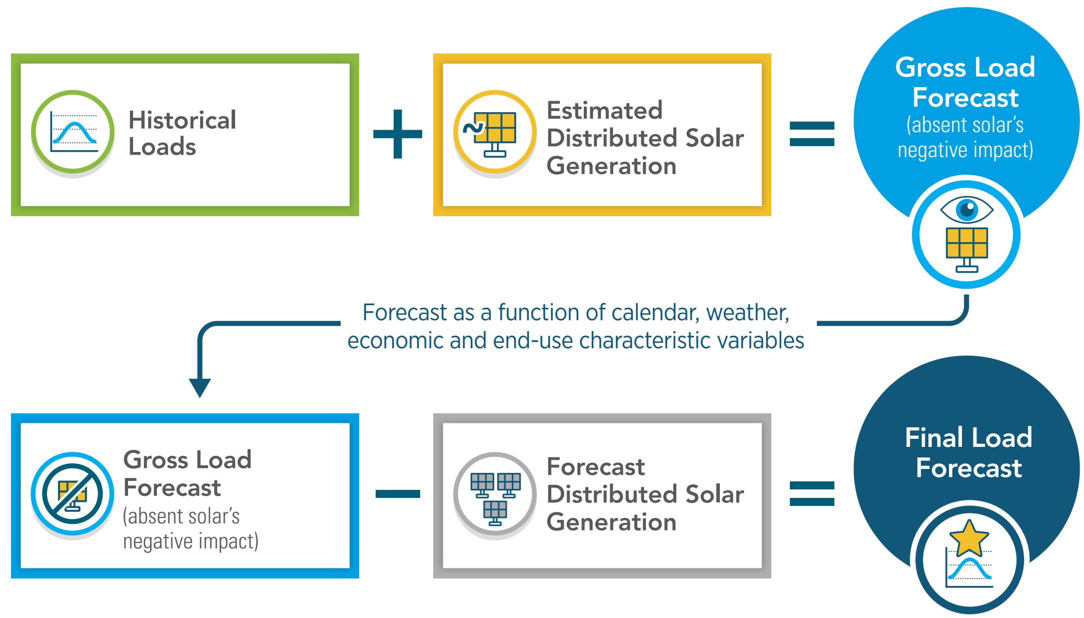
PJM's load forecast now also incorporates an explicit adjustment for plug-in electric vehicle (PEV) charging in peak megawatt demand and energy forecasts. Doing so ensures that PJM is accounting for their impact on reliability, as the share of them on the road continues to grow.

Distributed Solar and Battery Storage Generation

PJM has adopted a more granular approach to modeling behind-the-meter solar load forecast impacts. PJM has adopted an approach to modeling behind-the-meter solar load forecast impacts by varying solar output tied to the historical weather scenario that is run through the model. The 2022 load forecast was the first to include impacts from distributed battery storage facilities co-located with solar facilities. Notably, the 2022 load forecast was the first to also include impacts from distributed battery storage facilities co-located with solar facilities.

Distributed solar and battery storage generation acts to lower load from what it otherwise would be. Recent years have witnessed a significant ramp-up in behind-the-meter distributed solar resources:

Figure 2.3: Accounting for Distributed Solar Generation



more than 6,500 MW since 1998, with more than 95% of installations since 2010. Though not a large amount from an RTO perspective, the level of distributed solar is significant in certain areas of the PJM region and is expected to increase more in the years ahead. Under PJM's model update, distributed solar generation impacts are reflected in its load forecast using the approach shown in **Figure 2.3** to determine a final load forecast.

PJM first adds back estimated distributed solar generation to its historical loads to obtain a hypothetical history of loads as if solar did not exist. PJM uses a vendor-supplied historical estimate of hourly distributed solar generation, based on the installation date and location of resources.

Having obtained a load forecast as if solar did not exist, PJM then subtracts existing and forecast distributed solar and battery storage generation to obtain a final load forecast for each zone and for the RTO. Forecast distributed solar and battery storage generation is based on vendor-supplied, forecast distributed solar and battery capacity additions over the ensuing 15 years. The vendor forecast takes into consideration assumptions for federal and state policy, net energy metering policy, energy growth, solar photovoltaic capital costs, power prices and other factors. This forecast is discounted for: (1) expected panel degradation over time; and (2) solar energy production that does not align with the timing of PJM's peak load.

2.1: January 2022 Forecast

The January 2022 PJM Load Forecast Report, used in 2022 RTEP studies, includes forecast data for the 2022 through 2037 planning horizon, highlights of which are summarized in this section. The complete January 2022 PJM Load Forecast Report is accessible on the PJM website. As that report states, PJM's 2027 RTO summer peak is forecast to be 152,322 MW.

Forecasting Trends

Table 2.1 summarizes the seasonal transmission owner zonal summer and winter 10-year forecasts and load growth rates for 2022 through 2032. All load forecasts in the table reflect adjustments for distributed solar and battery storage generation and PEVs. Adjustments to the summer 10-year forecast are summarized in **Table 2.2**. Adjustments to the winter forecast for distributed solar are approximately zero.

Table 2.3 compares 10-year load growth rates for each PJM transmission owner zone and for the overall RTO over the past five years. Lower load forecast trends over that period reflect broader trends in the U.S. economy and PJM model refinements to capture energy efficiency. These trends are subsequently reflected in RTEP process power flow models.

Table 2.1: 2022 Load Forecast Report

	Summer Peak (MW)			Winter Peak (MW)		
Transmission Owner	2022	2032	Growth Rate	2021/22	2031/32	Growth Rate
Atlantic City Electric	2,488	2,541	0.2%	1,610	1,710	0.6%
Baltimore Gas & Electric	6,414	6,350	-0.1%	5,780	6,131	0.6%
Delmarva Power	3,873	3,854	0.0%	3,596	3,847	0.7%
Jersey Central Power & Light	5,831	5,868	0.1%	3,700	3,939	0.6%
Metropolitan Edison (Met-Ed)	2,934	3,060	0.4%	2,605	2,633	0.1%
PECO	8,370	8,471	0.1%	6,634	6,660	0.0%
Pennsylvania Electric Company (Penelec)	2,812	2,832	0.1%	2,781	2,767	-0.1%
PPL Electric Utilities Corporation	7,024	7,237	0.3%	7,252	7,355	0.1%
Potomac Electric Power Company (Pepco)	5,902	5,766	-0.2%	5,331	5,494	0.3%
Public Service Electric & Gas Company (PSE&G)	9,543	9,857	0.3%	6,657	7,219	0.8%
Rockland Electric Company	391	388	-0.1%	227	238	0.5%
UGI Utilities	193	191	-0.1%	199	194	-0.3%
Diversity – Mid-Atlantic	-629	-875		-560	-740	
Mid-Atlantic	**55,146**	**55,540**	**0.1%**	**45,812**	**47,447**	**0.4%**
American Electric Power	22,183	22,496	0.1%	22,348	22,946	0.3%
Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)	8,675	8,762	0.1%	9,009	9,338	0.4%
American Transmission Systems, Inc. (FirstEnergy)	12,273	12,551	0.2%	10,064	10,172	0.1%
Commonwealth Edison (ComEd)	20,787	20,121	-0.3%	15,073	15,303	0.2%
AES Ohio (formerly Dayton Power & Light)	3,271	3,288	0.1%	2,940	2,965	0.1%
Duke Energy Ohio and Kentucky	5,239	5,427	0.4%	4,555	4,694	0.3%
Duquesne Light Company	2,742	2,837	0.3%	1,995	2,042	0.2%
East Kentucky Power Cooperative	2,091	2,228	0.6%	2,666	2,776	0.4%
Ohio Valley Electric Corporation	90	90	0.0%	115	115	0.0%
Diversity – Western	-1,647	-1,674		-1,532	-1,530	
Western	**75,704**	**76,126**	**0.1%**	**67,233**	**68,821**	**0.2%**
Dominion Energy Virginia and North Carolina	20,424	25,434	2.2%	20,762	26,810	2.6%
Southern	**20,424**	**25,434**	**2.2%**	**20,762**	**26,810**	**2.6%**
Diversity – Total	-4,612	-5,268		-3,797	-3,832	
PJM RTO	**148,938**	**154,381**	**0.4%**	**132,102**	**141,516**	**0.7%**

Table 2.2: Distributed Solar Generation and PEV Adjusted to Summer Peak

Transmission Owner	Adjustment to Summer Peak (MW) — Distributed Solar Generation 2022	Distributed Solar Generation 2032	Plug-In Electric Vehicle 2022	Plug-In Electric Vehicle 2032	Distributed Battery Storage 2022	Distributed Battery Storage 2032
Atlantic City Electric	232	317	10	64	0	6
Baltimore Gas & Electric	232	541	28	186	0	21
Delmarva Power	151	357	9	44	0	9
Jersey Central Power & Light	346	525	24	149	0	14
Metropolitan Edison (Met-Ed)	41	63	4	9	0	4
PECO	61	130	11	23	0	9
Pennsylvania Electric Company (Penelec)	10	46	4	8	0	4
PPL Electric Utilities Corporation	88	162	9	20	0	9
Potomac Electric Power Company (Pepco)	198	376	23	156	0	16
Public Service Electric & Gas Company (PSE&G)	520	806	39	248	0	27
Rockland Electric Company	13	22	2	10	0	1
UGI Utilities	0	2	0	1	0	0
American Electric Power	103	447	21	98	1	22
Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)	93	382	13	63	0	13
American Transmission Systems, Inc. (FirstEnergy)	68	160	12	26	0	11
Commonwealth Edison (ComEd)	362	1,037	53	332	1	39
AES Ohio (formerly Dayton Power & Light)	22	53	3	7	0	3
Duke Energy Ohio and Kentucky	22	64	5	10	0	4
Duquesne Light Company	14	35	4	8	0	3
East Kentucky Power Cooperative	6	17	1	3	0	1
Ohio Valley Electric Corporation	0	0	0	0	0	0
Dominion Energy Virginia and North Carolina	541	969	32	374	1	42
PJM RTO	**3,150**	**6,703**	**307**	**1,838**	**5**	**258**

Table 2.3: Comparison of 10-Year Summer Peak Load Growth Rates

Load Forecast Report Summer Peak (MW)

	2018			2019			2020			2021			2022		
Transmission Owner	**2018**	**2028**	**Growth Rate**	**2019**	**2029**	**Growth Rate**	**2020**	**2030**	**Growth Rate**	**2021**	**2031**	**Growth Rate**	**2022**	**2032**	**Growth Rate**
Atlantic City Electric	2,460	2,409	-0.2%	2,450	2,388	-0.3%	2,542	2,773	0.9%	2,470	2,605	0.5%	2,488	2,541	0.2%
Baltimore Gas & Electric	6,848	6,744	-0.2%	6,697	6,663	-0.1%	6,447	6,558	0.2%	6,582	6,652	0.1%	6,414	6,350	-0.1%
Delmarva Power	3,937	4,018	0.2%	3,933	3,962	0.1%	3,979	4,327	0.8%	3,895	3,976	0.2%	3,873	3,854	0.0%
Jersey Central Power & Light	5,942	5,943	0.0%	5,914	5,912	0.0%	5,842	6,122	0.5%	5,876	6,193	0.5%	5,831	5,868	0.1%
Metropolitan Edison (Met-Ed)	2,974	3,115	0.5%	2,986	3,157	0.6%	3,003	3,287	0.9%	3,060	3,255	0.6%	2,934	3,060	0.4%
PECO	8,642	8,979	0.4%	8,711	9,082	0.4%	8,415	8,677	0.3%	8,389	8,691	0.4%	8,370	8,471	0.1%
Pennsylvania Electric Company (Penelec)	2,895	2,922	0.1%	2,897	2,908	0.0%	2,849	2,957	0.4%	2,894	3,164	0.9%	2,812	2,832	0.1%
PPL Electric Utilities Corporation	7,140	7,350	0.3%	7,148	7,347	0.3%	7,069	7,792	1.0%	7,204	7,758	0.7%	7,024	7,237	0.3%
Potomac Electric Power Company (Pepco)	6,493	6,466	0.0%	6,466	6,413	-0.1%	6,109	5,794	-0.5%	5,924	5,248	-1.2%	5,902	5,766	-0.2%
Public Service Electric & Gas Company (PSE&G)	9,903	9,876	0.0%	9,904	9,753	-0.2%	9,792	10,597	0.8%	9,871	10,407	0.5%	9,543	9,857	0.3%
Rockland Electric Company	402	402	0.0%	404	402	0.0%	395	420	0.6%	396	397	0.0%	391	388	-0.1%
UGI Utilities	190	188	-0.1%	189	188	-0.1%	191	184	-0.4%	195	201	0.3%	193	191	-0.1%
Diversity – Mid-Atlantic	-1,225	-1,086		-1,213	-1,135	0.0%	-781	-948		-986	-810		-629	-875	
Mid-Atlantic	**56,601**	**57,326**	**0.1%**	**56,486**	**57,040**	**0.1%**	**55,852**	**58,540**	**0.5%**	**55,770**	**57,737**	**0.3%**	**55,146**	**55,540**	**0.1%**
American Electric Power	22,876	24,018	0.5%	22,945	24,072	0.5%	21,945	24,113	0.9%	22,609	23,471	0.4%	22,183	22,496	0.1%
Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)	8,825	9,447	0.7%	8,707	9,305	0.7%	8,685	9,373	0.8%	8,859	9,140	0.3%	8,675	8,762	0.1%
American Transmission Systems, Inc. (FirstEnergy)	12,952	13,309	0.3%	12,872	13,134	0.2%	12,378	12,428	0.0%	12,525	12,842	0.3%	12,273	12,551	0.2%
Commonwealth Edison (ComEd)	22,121	23,207	0.5%	21,890	22,514	0.3%	20,635	20,876	0.1%	20,421	19,433	-0.5%	20,787	20,121	-0.3%
AES Ohio (formerly Dayton Power & Light)	3,459	3,508	0.1%	3,408	3,525	0.3%	3,236	3,228	0.0%	3,415	3,550	0.4%	3,271	3,288	0.1%
Duke Energy Ohio and Kentucky	5,523	5,860	0.6%	5,480	5,742	0.5%	5,280	5,650	0.7%	5,390	5,746	0.6%	5,239	5,427	0.4%
Duquesne Light Company	2,872	2,924	0.2%	2,862	2,887	0.1%	2,759	2,855	0.3%	2,768	2,954	0.7%	2,742	2,837	0.3%
East Kentucky Power Cooperative	1,960	2,033	0.4%	1,989	2,072	0.4%	2,004	2,334	1.5%	2,130	2,280	0.7%	2,091	2,228	0.6%
Ohio Valley Electric Corporation				95	95	0.0%	95	95	0.0%	90	90	0.0%	90	90	0.0%
Diversity – Western	-1,540	-1,522		-1,612	-1,369		-1,377	-1,311		-2,248	-2,224		-1,647	-1,674	
Western	**79,048**	**82,784**	**0.5%**	**78,636**	**81,977**	**0.4%**	**75,640**	**79,641**	**0.5%**	**75,959**	**77,282**	**0.2%**	**75,704**	**76,126**	**0.1%**
Dominion Energy Virginia and North Carolina	19,596	21,161	0.8%	19,391	21,238	0.9%	19,813	22,336	1.2%	20,150	21,269	0.5%	20,424	25,434	2.2%
Southern	**19,596**	**21,161**	**0.8%**	**19,391**	**21,238**	**0.9%**	**19,813**	**22,336**	**1.2%**	**20,150**	**21,269**	**0.5%**	**20,424**	**25,434**	**2.2%**
Diversity – RTO	-3,137	-3,636		-5,980	-6,070		-5,371	-5,644		-5,889	-5,563		-4,612	-5,268	
PJM RTO	**152,108**	**157,635**	**0.4%**	**151,358**	**156,689**	**0.3%**	**148,092**	**157,132**	**0.6%**	**149,224**	**153,759**	**0.3%**	**148,938**	**154,381**	**0.4%**

2022 Forecast Summer Zonal Load Growth Rates

The PJM RTO weather-normalized summer peak is forecast to grow at an average rate of 0.4% per year for the next 10 years. The PJM RTO summer peak is forecast to be 154,381 MW in 2032, an increase of 5,443 MW over the 2022 peak of 148,938 MW. Individual geographic zone growth rates vary from -0.3% to 2.2%, as shown in **Figure 2.4** and **Figure 2.5**.

Figure 2.4: PJM Mid-Atlantic Summer Peak Load Growth 2022–2032

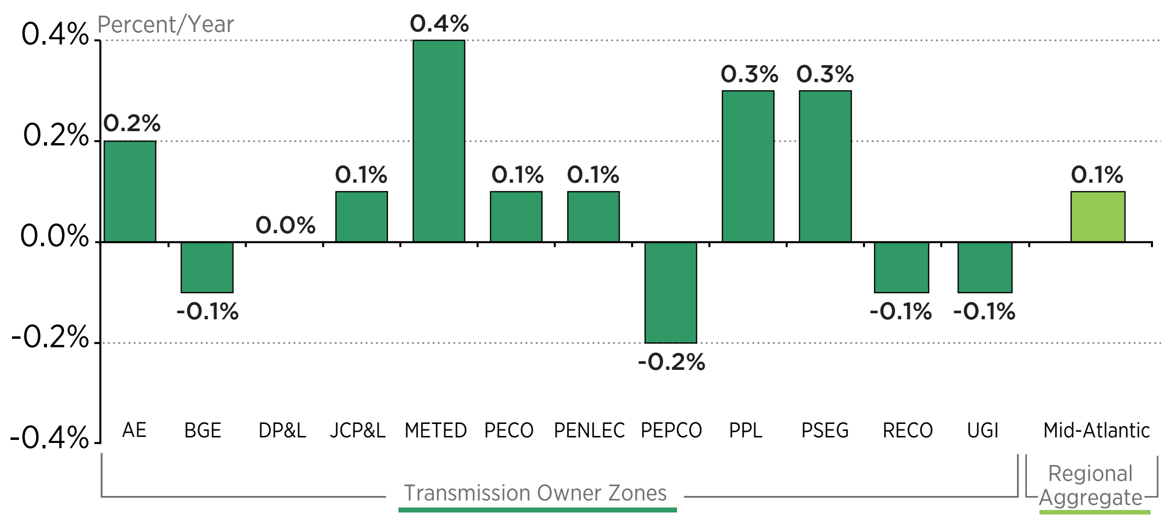
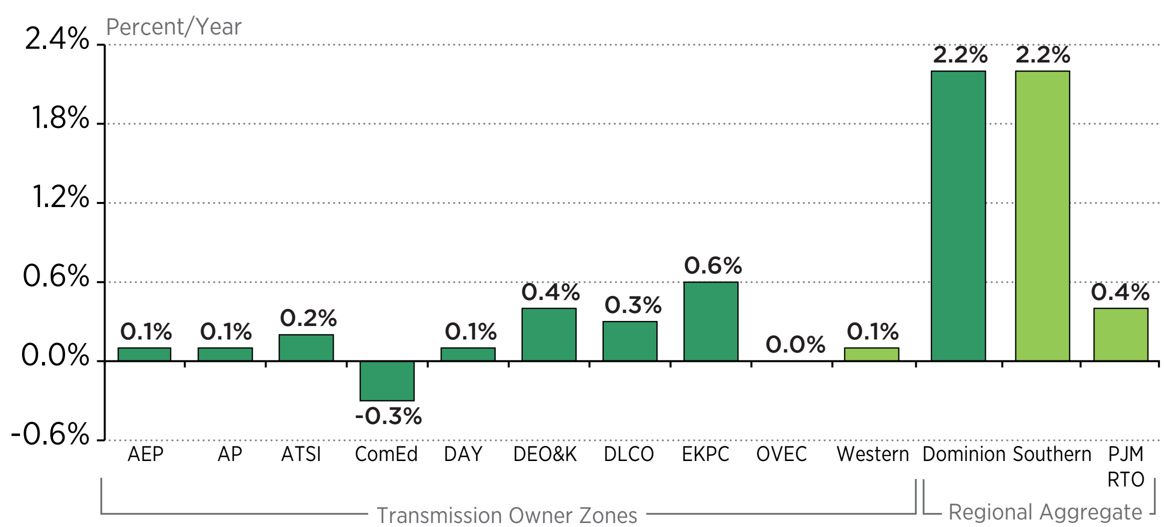


Figure 2.5: PJM Western and Southern Summer Peak Load Growth 2022–2032



2022 Forecast Winter Zonal Load Growth Rates

The PJM RTO weather-normalized winter peak is forecast to grow at an average rate of 0.7% per year for the next 10 years. The PJM RTO winter peak is forecast to be 141,516 MW in 2031/2032, an increase of 9,414 MW over the 2021/2022 peak of 132,102 MW. Individual geographic zone growth rates vary from -0.3% to 2.6%, as shown in **Figure 2.6** and **Figure 2.7**.

Figure 2.6: PJM Mid-Atlantic Winter Peak Load Growth 2022–2032

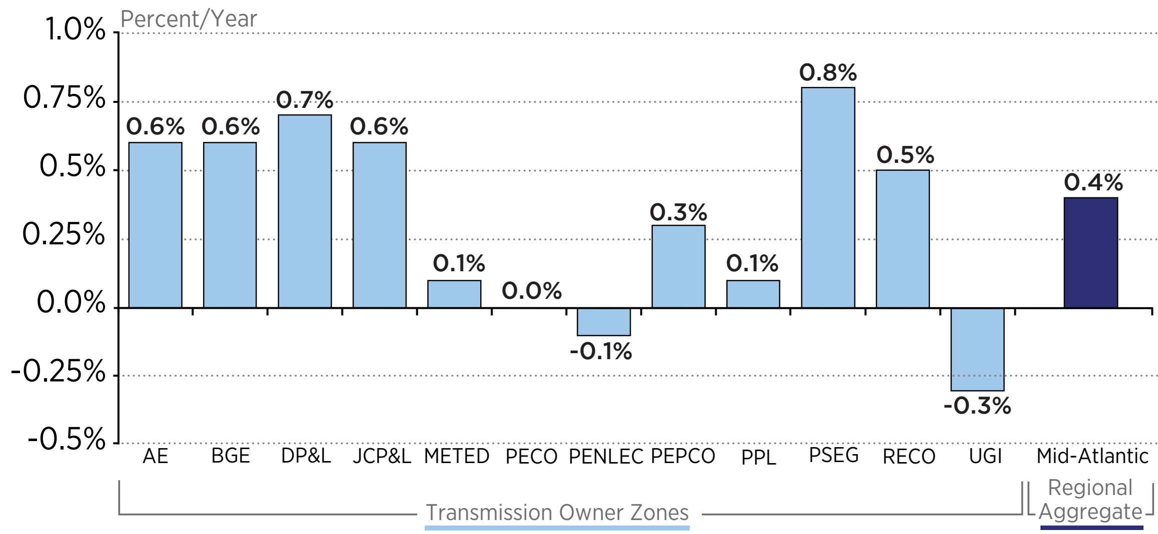
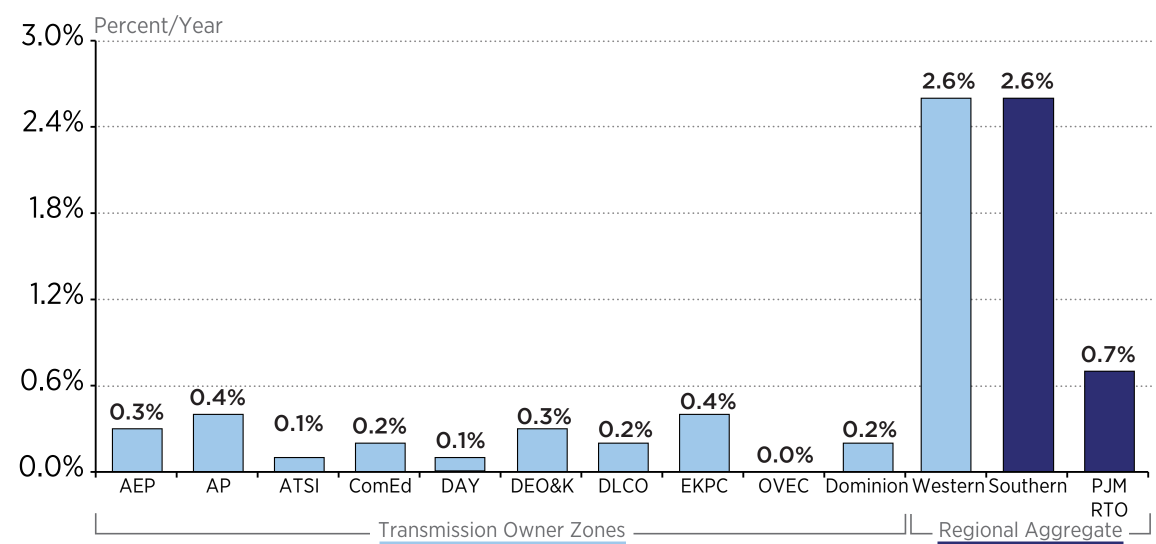


Figure 2.7: PJM Western and Southern Winter Peak Load Growth 2022–2032

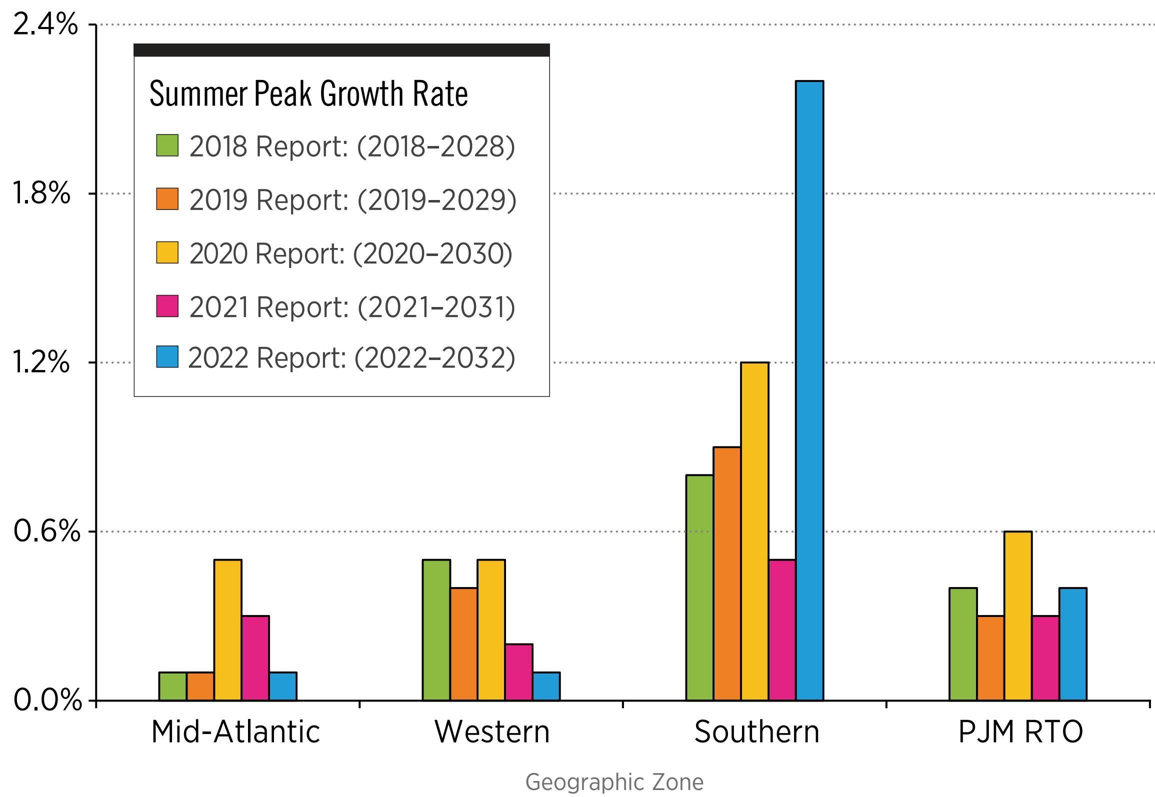


Subregional Forecast Trends

Figure 2.8 provides a summary based on load growth rate trends from the respective January load forecast over each of the last five years, from 2018 through 2022, for the ensuing 10 years on a subregional basis. The trend reflects changes in the broader U.S. economic outlook and the growing impact of energy efficiency, solar and PEVs looking forward in each of the five forecasts. Load forecasts for the Southern region of PJM are growing at an increasing rate due to the large volume of data center activity in this area, as described in **Section 2.3.4**.

In particular, the 2022 report forecast that the load growth rate for the RTO increased by 0.1 percentage points when compared to the 2021 report.

Figure 2.8: PJM 10-Year Summer Peak Load Growth Rate Comparison 2018–2022 Load Forecast Reports



Data Center Load Growth

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

In the PJM 2022 Load Forecast Report, Dominion requested that PJM consider a forecast adjustment to account for the growth of data centers in northern Virginia. This adjustment has been in place in some form since the 2014 Load Forecast Report. The rationale for making an adjustment for data centers is that these centers have a load impact that is disproportionate with their economic impact. Data centers generally require minimum staffing and thus would not have a significant impact on economic variables, but do have a considerable impact on energy demand. Dominion has provided PJM with energy and peak information historical data for such facilities as well as expectations for new facilities through 2026. For years beyond 2026, PJM used a linear trend constructed on data through 2021.

2.2: Demand Resources and Peak Shaving

PJM accounts for demand resources by adjusting its base, unrestricted, peak load forecast by a forecast amount, which is calculated based on committed quantities in previous Reliability Pricing Model (RPM) auctions. Those amounts, as reflected in the 2022 Load Forecast Report, are shown in **Table 2.4** for each transmission owner zone. The adjusted forecast is then used in RTEP power flow model studies that focus on summer peak capacity emergency conditions, during which demand resources are assumed to be implemented. Consequently, demand resources can have a measurable impact on future system conditions and the potential need for transmission system enhancements to serve load. Forecast values for each zone are determined based on the following steps:

- Compute the final amount of committed demand resources for each of the three most recent delivery years. Express the committed demand resource amount as a percentage of the zone's 50/50 forecast summer peak from the January load forecast report immediately preceding the respective delivery year.
- Compute the most recent three-year average committed demand resources percentage for each zone.
- Multiply each zone's 50/50 forecast summer peak by the results from step two to obtain the demand resource forecast for each zone.

Alternatively, load management can directly impact the unrestricted peak load forecast through a peak shaving program. Peak shaving program administrators provide PJM with information on curtailment behavior (e.g., temperature/humidity trigger), which PJM then uses to adjust the load forecast accordingly. No peak shaving programs are included in this year's forecast used for the RTEP.

Capacity Performance Impacts

PJM's RPM transition to Capacity Performance in 2016 has required a transition in the treatment of demand resources as well. **Table 2.4** assumes the following:

- Annual demand resources are assumed to be Capacity Performance demand resources and are based on actual committed quantities of demand resource products in the 2020/2021, 2021/2022 and actual cleared quantities in the 2022/2023 RPM Base Residual Auctions.
- Summer period demand resources refer to demand resources that aggregate with winter-period resources to form a year-round commitment.

Both existing and planned demand resources may participate in auctions, provided the resource resides in a party's portfolio for the duration of the delivery year. Further details can be found in PJM Manual 19, Load Forecasting and Analysis, available on the PJM website.

Table 2.4: 2022 Load Forecast Report Demand Resources

Transmission Owner	Total Load Management 2022	Total Load Management 2032
Atlantic City Electric	44	45
Baltimore Gas & Electric	238	309
Delmarva Power	195	211
Jersey Central Power & Light	91	93
Metropolitan Edison (Met-Ed)	152	158
PECO	252	256
Pennsylvania Electric Company (Penelec)	219	220
PPL Electric Utilities Corporation	411	423
Potomac Electric Power Company (Pepco)	301	329
Public Service Electric & Gas Company (PSE&G)	186	192
Rockland Electric Company	2	2
UGI Utilities	0	0
Mid-Atlantic	**2,091**	**2,238**
American Electric Power	1,109	1,126
Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)	530	536
American Transmission Systems, Inc. (FirstEnergy)	700	716
Commonwealth Edison (ComEd)	1,307	1,265
AES Ohio (formerly Dayton Power & Light)	160	160
Duke Energy Ohio and Kentucky	133	138
Duquesne Light Company	82	84
East Kentucky Power Cooperative	146	156
Ohio Valley Electric Corporation	0	0
Western	**4,167**	**4,181**
Dominion Energy Virginia and North Carolina	659	821
Southern	**659**	**821**
PJM RTO	**6,917**	**7,240**

2.3: Effective Load Carrying Capability

Overview

PJM uses an Effective Load Carrying Capability (ELCC) methodology to evaluate the contribution that intermittent and energy storage resources provide to PJM's resource adequacy. The ELCC study is run annually producing ELCC Class Ratings that serve as inputs to determine the accreditation that an intermittent or energy storage resource receives to participate in the RPM.

2.3.1 — 2022 Study Results

As part of its annual RPM auction input parameters development, PJM develops ELCC Class Ratings. Completed in December 2022, those ratings for each class of ELCC generation enumerated in **Table 2.5** were calculated for each delivery year in the period 2023/2024–2032/2033. However, only 2023/2024, 2025/2026 and 2026/2027 values are binding and applicable to the 2023/2024 Third Incremental Auction, 2025/2026 Base Residual Auction and 2026/2027 Base Residual Auction, respectively. Full study results can be found on the PJM website.

Table 2.5: ELCC Class Ratings for 2023/2024 Third Incremental Auction, 2025/2026 BRA and 2026/2027 BRA

ELCC Class	ELCC Class Rating for: 2023/2024 3IA	2025/2026 BRA	2026/2027 BRA
	(% of Nameplate)		
Onshore Wind	15%	15%	13%
Offshore Wind	42%	40%	31%
Solar Fixed Panel	50%	37%	33%
Solar Tracking Panel	61%	51%	45%
4-Hr Storage	94%	77%	77%
6-Hr Storage	100%	96%	94%
8-Hr Storage	100%	100%	100%
10-Hr Storage	100%	100%	100%
Solar Hybrid Open Loop – Storage Component	93%	74%	83%
Solar Hybrid Closed Loop – Storage Component	93%	74%	83%
Hydro Intermittent	37%	37%	37%
Landfill Gas Intermittent	63%	63%	64%
Hydro With Non-Pumped Storage*	98%	94%	93%

* PJM performs an ELCC analysis for each individual unit in this class. The values shown in the table are provided for informational purposes.

NOTE:
PJM members endorsed a consensus package of reforms designed to more closely integrate CIRs into PJM's capacity accreditation process for ELCC resources on Jan. 25, 2023.

2.3.2 — Capacity Interconnection Rights for ELCC Resources

The PJM Planning Committee also initiated a separate stakeholder process in 2021 to review and modify existing Capacity Interconnection Rights (CIRs) request and retention policies, with an emphasis on ELCC resources, including the application of CIRs to the ELCC methodology and UCAP valuation. A number of special sessions of the Planning Committee took place in 2022 leading to PJM stakeholder approval, with implementation scheduled for the 2025/2026 Base Residual Auction.

2.3.3 — Resource Adequacy Senior Task Force (RASTF)

In late 2021, the Resource Adequacy Senior Task Force was formed to investigate issues related to the PJM capacity market. One of these issues was to investigate potential load forecasting improvements through the Load Analysis Subcommittee. Following a request for proposal, PJM hired a consultant in early 2022 to provide a comprehensive independent review of the long-term load forecast methodology as well as recommendations on implementing an hourly forecast methodology. PJM reviewed their recommendations and implementation plan with stakeholders, and subsequently implemented the necessary methodology changes as part of the 2023 load forecast.

NOTE:

PJM continues to monitor the rapid growth of data center load especially in light of its emergence beyond northern Virginia (both the Allegheny Power and AEP transmission zones now include data center adjustments in PJM's 2023 Load Forecast Report). To better account for this growth, PJM requested longer-term load-shift projections from EDCs for its 2023 Load Forecast Report and will continually assess the situation. Continued coordination with EDCs and TOs is critical to ensuring accurate projections and system reliability.

Section 3: Transmission Enhancements

3.0: 2022 RTEP Proposal Windows

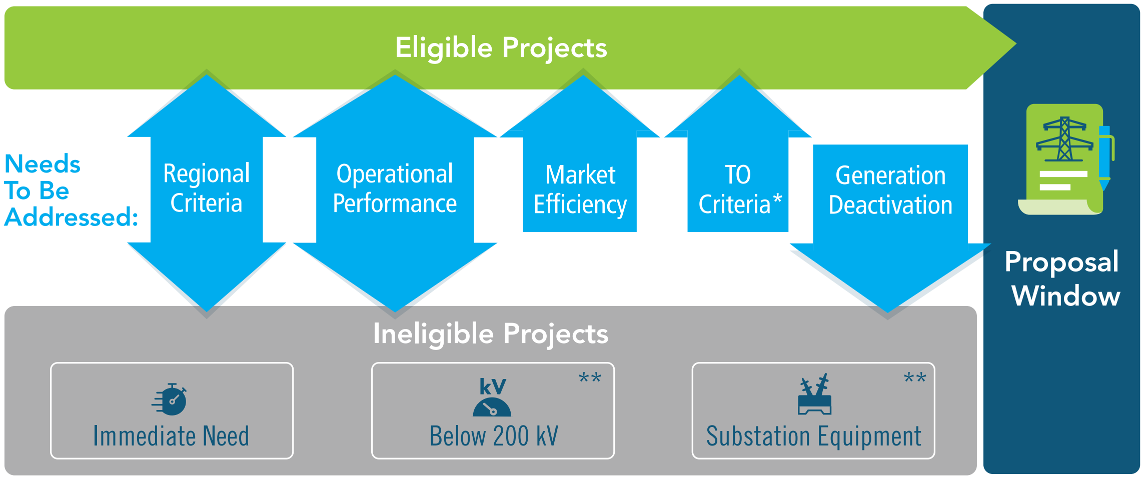
RTEP Process Context

PJM seeks transmission proposals during each RTEP window to address one or more identified needs – reliability, market efficiency, operational performance and public policy. RTEP windows provide an opportunity for both incumbent and non-incumbent transmission developers to submit project proposals to PJM for consideration. When a window closes, PJM proceeds with analytical, constructability and financial evaluations to assess proposals for possible recommendation to the PJM Board. If selected, designated developers become responsible for project construction, ownership, operation, maintenance and financing. PJM's Manual 14 series addresses the rules governing the RTEP process. In particular, Manual 14F describes PJM's competitive transmission process, including all aspects of analysis and evaluation pertaining to proposal windows.

Proposal Window Exemptions

Certain flowgate violations are exempted from PJM's competitive planning process and are designated to the incumbent transmission owner (TO), as described in the PJM Operating Agreement, Schedule 6, Section 1.5.8. These FERC-approved exemptions, as seen in **Figure 3.1**, were developed with collaborative input from PJM stakeholders:

Figure 3.1: RTEP Proposal Window Eligibility



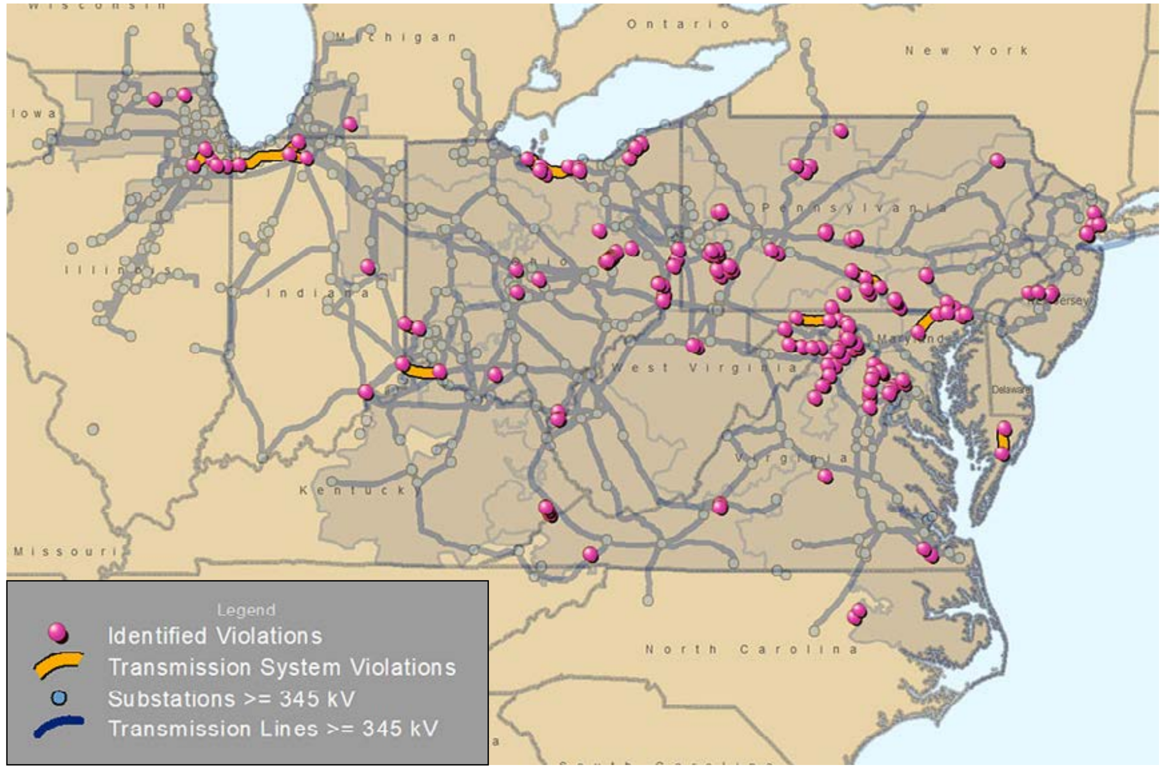
*Note: *TO criteria-driven violations are eligible for proposal windows as of Jan. 1, 2020.*
***Projects below 200 kV and substation equipment projects could become eligible for competition if multiple needs share common geography/contingency or if the project has multi-zonal cost allocation.*

- *Immediate-Need Exemption:* The required in-service date drives these projects, and they may be exempted from the competitive process to ensure they can be completed before the required in-service date.
- *Below 200 kV:* Solutions below 200 kV are exempted from the competitive process. Experience has demonstrated that the selected solutions at these voltage levels have, by and large, ultimately been those proposed by the incumbent TOs themselves.
- *Substation Equipment:* In situations where the limiting element causing a reliability criteria violation is a piece of substation equipment, then such solutions are designated to the incumbent TO.

Proposal Window Baseline Reliability Analysis Results

PJM's analysis of 2027 summer, winter and light load conditions identified 852 flowgates that were thermal and voltage criteria violations. Two hundred sixty-nine of those were included in competitive windows, while 583 were excluded from competition. A summary of the 852 violations is shown in **Map 3.1**. These flowgate violations were addressed as part of RTEP Proposal Window No. 1, as discussed below.

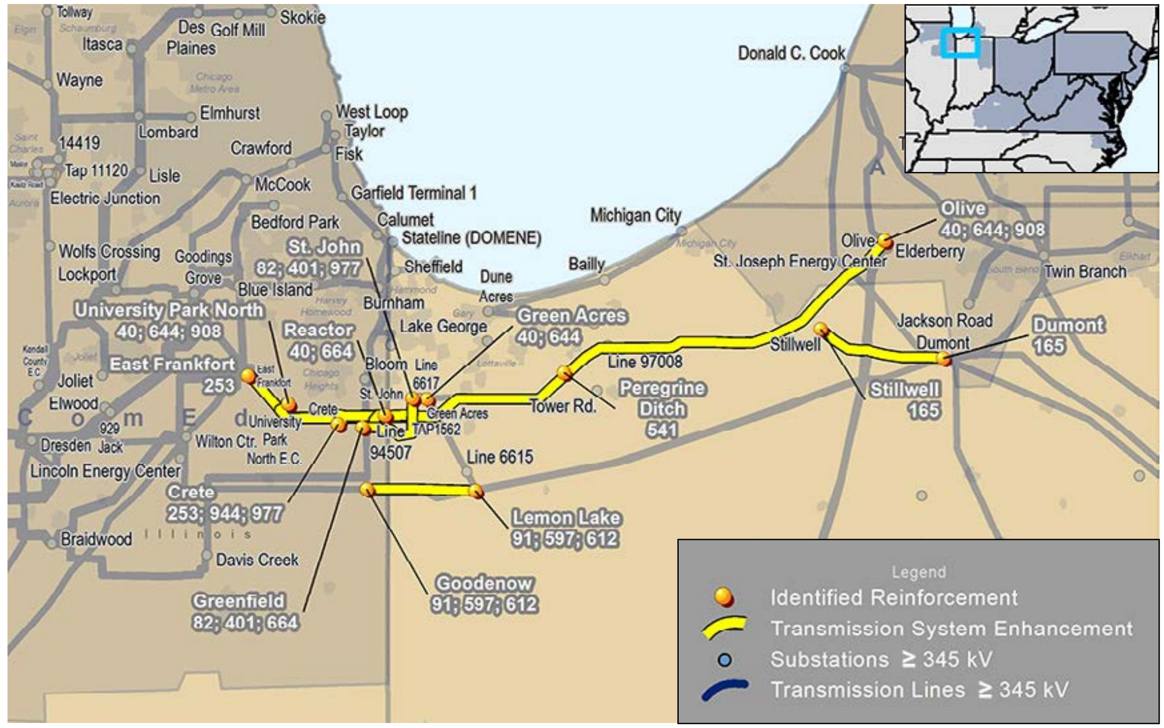
Map 3.1: 2022 RTEP Baseline Thermal and Voltage Criteria Violations



Multi-Driver Proposal Window

The first multi-driver proposal window, which contained 17 flowgate violations that were open to reliability and market efficiency solutions, opened on June 7, 2022, and closed on Aug. 8, 2022. PJM received 11 proposals from two entities and included three proposals that shared an overlap in flowgates from the 2021 RTEP Proposal Window No. 2 from one entity for a total of 14 proposals. Six proposals comprised upgrades to existing transmission infrastructure, while eight proposals comprised greenfield projects. Four projects included cost containment provisions. This is the first multi-driver window that PJM has held and was studied with a five-year-out RTEP base case. The congestion drivers were related to the Dumont-Stillwell line, the Olive-University Park North line, and the East Frankfort-Crete-St. John lines. The proposals are shown in **Map 3.2** and **Table 3.1**. The solutions that were submitted aimed to address both the congestion and reliability issues in the area.

Map 3.2: 2022 RTEP Multi-Driver Submittals



NOTE:

The PJM Board approved a modified version of proposal No. 664 February Board meeting for a total cost of $73.88 M.

Table 3.1: 2022 RTEP Multi-Driver Window Submittals

Proposal ID	Target Zone	kV	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
165	AEP/NIPSCO	345	AEP	Upgrade	No	$0.21	Perform a sag study on the Dumont-Stillwell line.
908	AEP/ComEd	345	AEP	Upgrade	No	$1.49	Perform a sag study on the Olive-University Park line.
541	AEP/ComEd	345	AEP	Greenfield	Yes	$14.79	Peregrine Ditch
401	AEP/ComEd	345	Nextera	Greenfield	No	$51.22	Add a new 345 kV double circuit to reconfigure existing lines.
82	AEP/ComEd	345	Nextera	Greenfield	No	$61.52	Add a new 345 kV double circuit to tap existing lines and connect to an existing sub, and reconfigure existing lines at the sub.

Table 3.1: 2022 RTEP Multi-Driver Window Submittals (Cont.)

Proposal ID	Target Zone	kV	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
664	ComEd	345	Nextera	Greenfield	No	$73.96	Add a new 345 kV double circuit line looping the existing line into a new substation.
40	ComEd	345	Nextera	Greenfield	No	$83.44	Swap 345 kV transmission line at Green Acres, rebuild University Park to Olive 345 kV lines and add a reactor along Crete-St John 345 kV line.
612	ComEd	345	AEP	Greenfield	Yes	$98.12	Build Goodenow-Lemon Lake 345 kV Greenfield line and stations.
644	ComEd	345	Nextera	Upgrade	No	$98.75	Swap 345 kV transmission line at Green Acres; rebuild University Park to Olive 345 kV lines.
91	ComEd	345	AEP	Greenfield	Yes	$101.76	Build enhanced Goodenow-Lemon Lake 345 kV Greenfield line and stations.
597	ComEd	345	AEP	Greenfield	Yes	$127.12	Build robust Goodenow-Lemon Lake 345 kV Greenfield line and stations.
253	ComEd	345	Nextera	Upgrade	No	$62.67	Rebuild 345 kV lines 6607/6608 East Frankfort-Crete and 94507/97008 Crete-St. John.
977	ComEd	345	Nextera	Upgrade	No	$12.01	Install series inductor on line 94507 Crete-St. John.
994	ComEd	345	Nextera	Upgrade	No	$17.13	Rebuild 345 kV double circuit lines 94507 and 97008 Crete-Indiana.

2022 RTEP Proposal Window No. 1

RTEP Proposal Window No. 1, which contained 852 flowgate violations with 269 flowgates open for competition, opened on July 1, 2022, and closed on Aug. 30, 2022. This window seeks to address thermal and voltage violations identified as part of the 2022 RTEP. PJM received 17 proposals from seven entities. Seven of the proposals included cost containment provisions, and six of the proposals included greenfield construction. The proposals are shown in **Map 3.3** and **Table 3.2**. Six baseline projects were approved by the PJM Board totaling $126 million to address the reliability criteria violations associated with this window.

Map 3.3: 2022 RTEP Proposal Window No. 1 Submittals

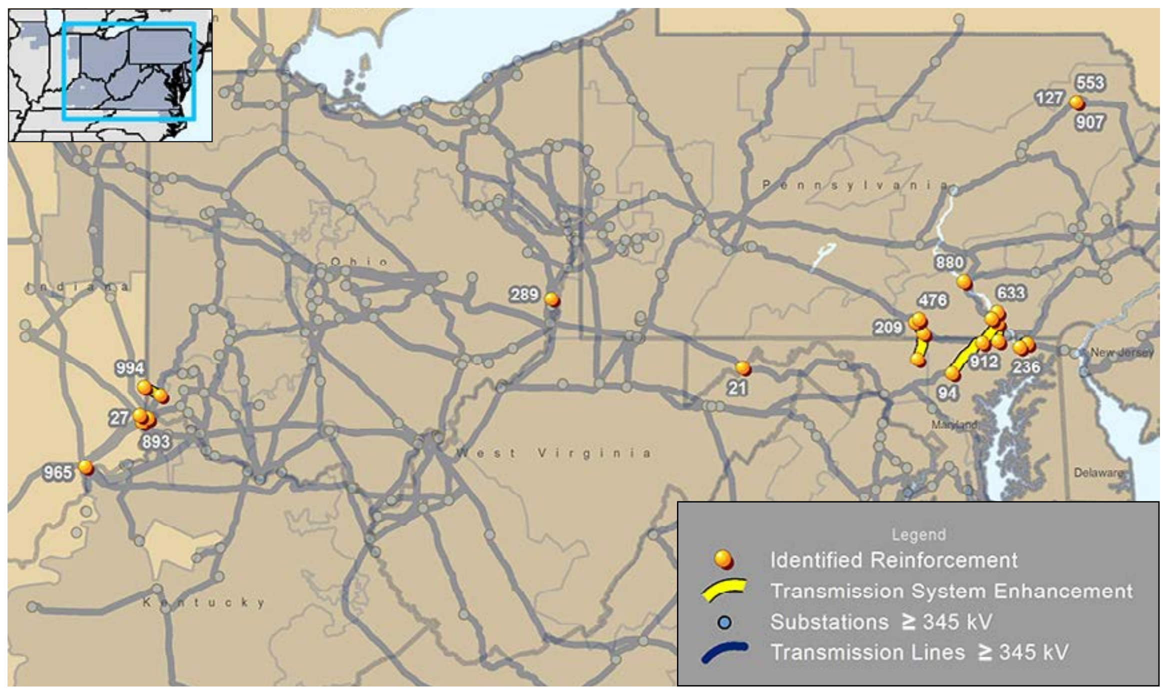


Table 3.2: 2022 RTEP Proposal Window No. 1 Submittals

Proposal ID	Target Zone	kV	Project Type	Cost ($M)	Cost Containment	Incumbent TO	Project Description
476	METED	230	Greenfield	$148.83	No	MAIT	Hunterstown-Carroll 230 kV double circuit
236	PECO/DPL	230	Upgrade	$0.26	No	DP&L	Increase rating of Conowingo/Colora 230 kV line.
21	AP	500	Upgrade	$17.37	No	AP	Install new bay position for SVC and install transformer high-side breaker at Black Oak 500 kV substation.
209	METED	115	Upgrade	$17.36	No	MAIT	Reconductor Germantown-Lincoln 115 kV line.
94	BGE	230	Upgrade	$37.76	No	BGE	Reconductor Conastone to Northwest No. 2.
633	APS/BGE/PENELEC/METED/PECO/PPL	230	Greenfield	$386.73	Yes	AEP	Upgrade Furnace Run area regional transmission.
880	METED	500/230	Upgrade	$30.19	No	MAIT	Add TMI 500/230 kV transformer.
912	PPL/BGE	230	Upgrade	$8.40	No	PPL	Rebuild Graceton to PPL tie line.
994	AEP/DEO&K	138	Greenfield	$25.52	Yes	AEP	Johnson Fork-Willey 138 kV
446	AEP/DEO&K	138	Greenfield	$39.70	Yes	AEP	Pribble Station
893	AEP/DEO&K	138	Greenfield	$58.11	Yes	AEP	Tanners Creek-Miami Fort 345 kV
965	AEP/OVEC	345	Upgrade	$0.85	No	AEP	Replace Clifty Creek switches.
289	AEP	345	Upgrade	$2.53	No	AEP	Reconfigure West Bellaire.
27	AEP/DEO&K	345	Upgrade	$3.07	No	AEP	Reconfigure Tanners Creek.
127	PPL	230	Upgrade	$10.65	Yes	PPL	Upgrade Lackawanna T3 and T4 transformer 230 kV retermination.
553	PPL	500/230	Upgrade	$55.97	Yes	PPL	Upgrade Lackawanna 500/230 kV T3 and T4 transformer replacement.
907	PPL	500	Greenfield	$51.48	Yes	PPL	Upgrade Lackawanna Energy POI 500 kV retermination.

2022 RTEP Proposal Window No. 2

RTEP Proposal Window No. 2, which contained six flowgate violations open for competition, opened on Nov. 1, 2022, and closed on Dec. 1, 2022. This window sought to address thermal and voltage reliability criteria violations identified as part of the 2022 RTEP, which were not addressed as part of the 2022 RTEP Proposal Window No. 1. PJM received three proposals from one entity. None included cost containment provisions, and all three were upgrades to existing transmission infrastructure. The proposals are shown in **Map 3.4** and **Table 3.3**. Analysis and selection of a proposal to address these violations continues into early 2023.

Map 3.4: 2022 RTEP Proposal Window No. 2 Submittals

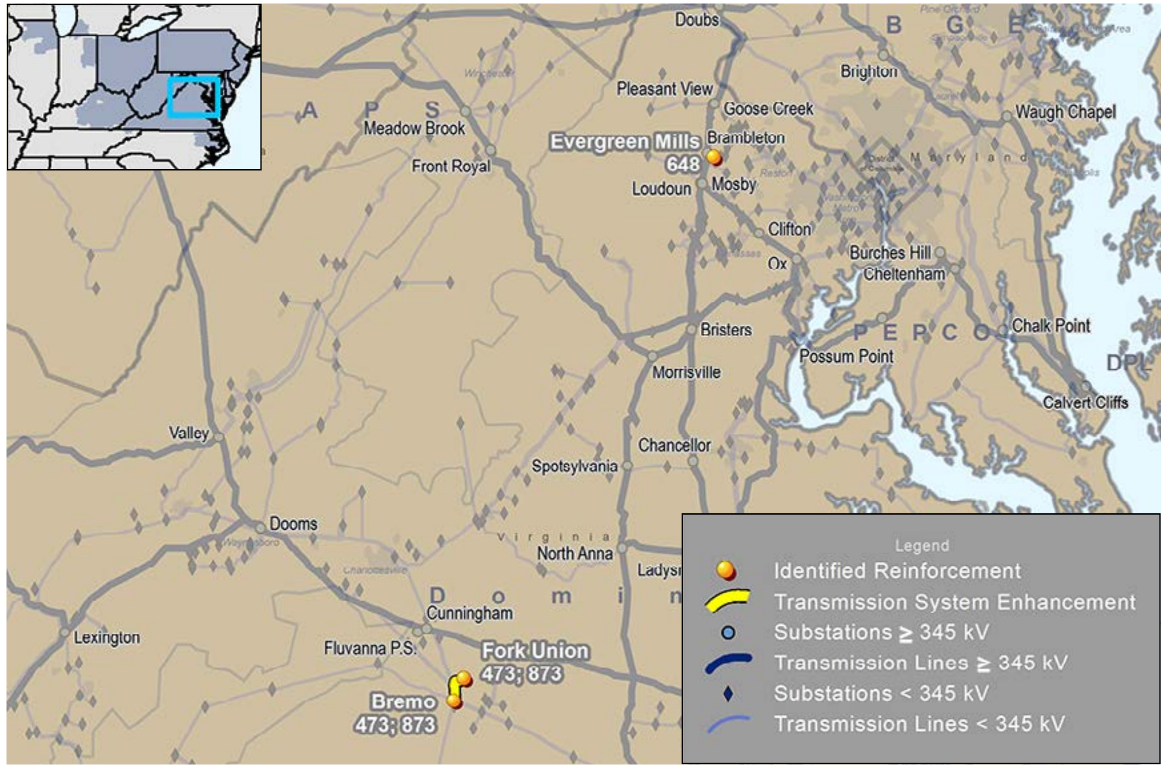


Table 3.3: 2022 RTEP Proposal Window No. 2 Submittals

Proposal ID	Target Zone	kV	Incumbent TO	Project Type	Cost Containment	Cost ($M)	Description
473	Dominion	230	VEPCO	Upgrade	No	$10.09	Bremo transformer No. 9 Load Relief Alternative 1: Bear Garden to Fork Union Connection
648						$7.70	300 MW load drop violation at Evergreen Mills
873						$35.17	Relocate Bremo transformer No. 9 to Fork Union substation.

3.1: New Jersey Offshore Wind

Background

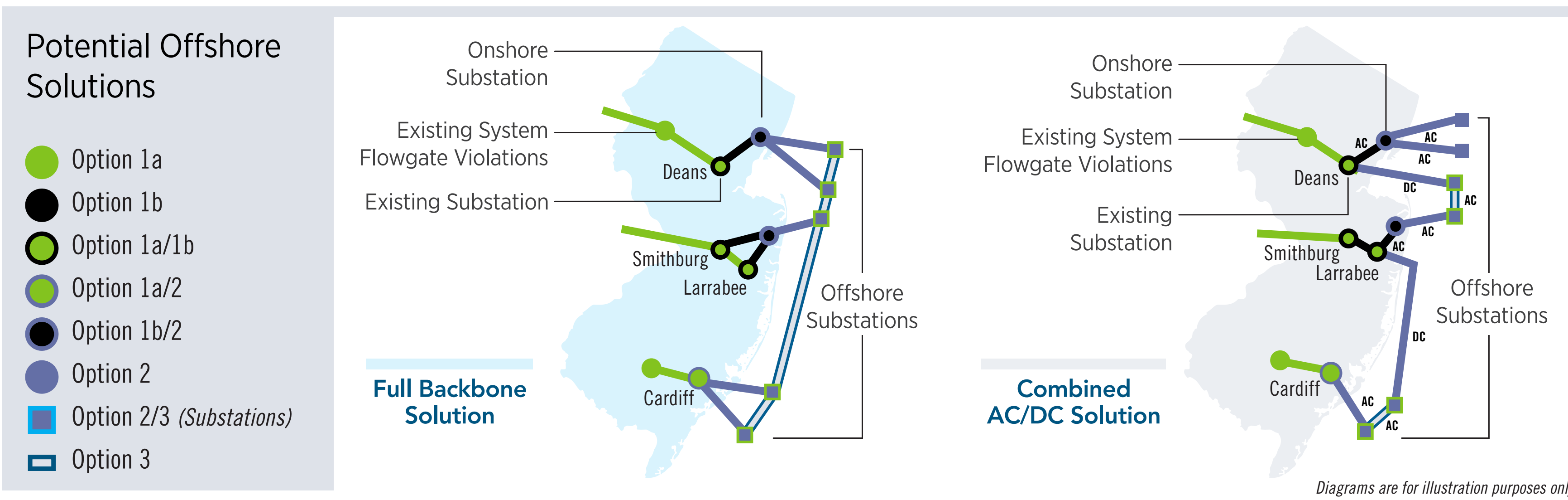
On Nov. 18, 2020, the New Jersey Board of Public Utilities (NJBPU) issued an order formally requesting that PJM open a competitive proposal window to solicit project proposals to identify a transmission project to meet the state's public policy goals for 7,500 MW of offshore wind (OSW) by 2035.

Working with the NJBPU, PJM opened its first public policy window for six months ending Sept. 17, 2021. The proposals were categorized into four options according to the function and location of the proposal as shown in **Figure 3.2**.

Altogether, PJM received a diverse set of 80 proposals from 13 different entities for onshore upgrades to existing facilities, onshore new greenfield facilities to extend the grid to the shore, offshore transmission proposals to extend the grid to access OSW lease areas, and offshore backbone transmission to intertie future OSW platforms.

- **Option 1a proposals:** Onshore transmission upgrades to resolve potential reliability criteria violations on existing PJM facilities in accordance with all applicable PJM, regional and transmission owner planning criteria
- **Option 1b proposals:** Onshore new transmission facilities required for OSW connection from existing substations to the shoreline
- **Option 2 proposals:** Offshore new transmission connection facilities required for OSW connection from the shoreline out to OSW platforms
- **Option 3 proposals:** Offshore new transmission network facilities for OSW platform-to-platform connection

Figure 3.2: Potential Options for the New Jersey Offshore Wind Transmission Solution



Diagrams are for illustration purposes only.

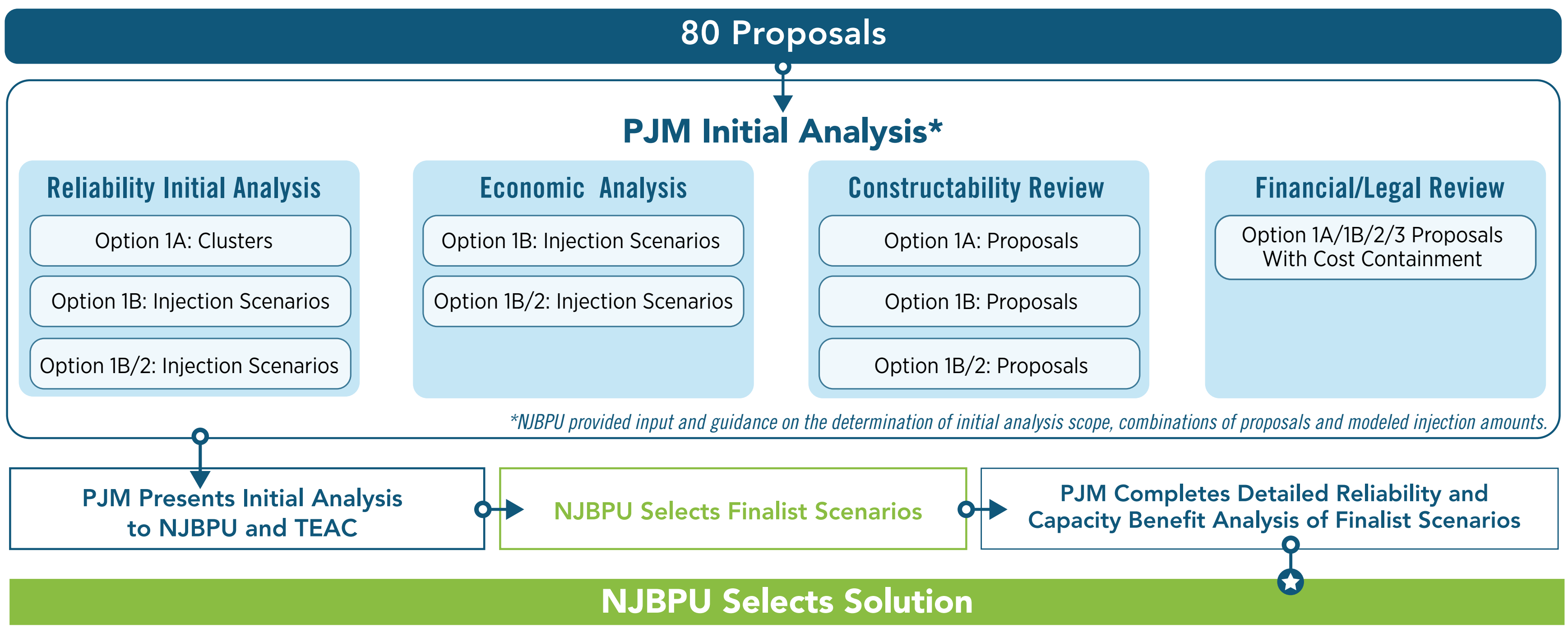
In 2022, PJM conducted the following four-part evaluation, as summarized in **Figure 3.3**: Reliability Initial Analysis, Economic Analysis, Constructability Review, Financial Review and Legal Review.

The findings of each body of analysis were provided to the NJBPU for its consideration as input to its independent evaluation of the proposals and decision on which project, if any, it would select.

PJM and the NJBPU jointly determined the analysis that PJM would perform to assess the performance of the proposals. The technical analysis involves an initial screening of all proposals followed by a more detailed analysis phase of proposals that passed the screening, which may be required to evaluate solutions in a window with multiple competitive proposals and/or complex system needs.

The NJBPU provided its input and guidance to the initial analysis scope, which informed the combinations of proposals and modeled injection amounts. Additionally, the NJBPU separately convened several public meetings for stakeholder input on various topics concerning the development of transmission for offshore wind. This information was also made available to PJM in its analysis.

Figure 3.3: New Jersey SAA Offshore Wind Evaluation Process Overview



Reliability Analysis

The initial reliability screening analysis of the proposals was performed for the purpose of determining what upgrades would be needed to the existing system in combination with Option 1b/2 proposals to satisfy both reliability criteria and the OSW requirements. The analysis consisted of a range of injection scenarios to consider the various proposed POIs (points of interconnection) and concepts offered by each of the proposing entities. Each injection scenario incorporated the consideration of NJBPU solicitation No. 2 projects. Given the number of proposals and associated scenarios, it was impractical to perform the full complement of reliability tests for all of the scenarios. For this initial reliability analysis, the scope of the technical studies was limited to those tests that were deemed mostly likely to stress the system and provide a reasonable test of proposed Option 1a onshore system upgrades. The balance of complete reliability analysis was conducted for the four finalist scenarios selected by the NJBPU.

Details of the reliability analysis are documented in the PJM Reliability Analysis Report.

Economic Analysis

Similar to the reliability analysis, economic analysis was performed for the injection scenarios that included projections of energy market and capacity market benefits. The scope of the economic analysis was developed jointly with the NJBPU for the purpose of identifying potential economic benefits that might differentiate the performance of the transmission proposals.

The energy market simulations were performed in conjunction with the initial reliability analysis. Simulation results included estimated load locational marginal prices (LMPs) and gross load payments for selected load zones, generation LMPs and energy market value of New Jersey's OSW generation, simulated OSW unit energy output and curtailments of New Jersey's OSW generation, and the state's estimated emissions.

The capacity market benefits simulations were conducted for the three finalists' scenarios (scenarios 18 and 18a are equivalent for market analysis simulations) and consisted of simulating capacity market prices for the four New Jersey load zones (Atlantic City Electric, Jersey Central Power and Light, Public Service Electric and Gas Company, Rockland Electric) and adjacent load zones (Baltimore Gas and Electric, PECO).

Details of the economic analysis are documented in the PJM Economic Analysis Report.

Constructability Evaluation

Detailed constructability evaluation of all Option 1a, 1b and 2/3 proposals was performed in parallel with the initial screening analysis to assess the feasibility of constructing the proposed solutions. The detailed constructability analysis consisted of an in-depth review of the project scope, project cost, project complexity and constructability factors that could impact the cost and/or schedule, including ability to acquire rights-of-way and land, ability to site and permit the project, equipment technical feasibility, and the overall project schedule.

Details of the constructability evaluation are documented in three PJM reports:

- Constructability Report: Option 1a Proposals
- Constructability Report: Option 1b Proposals
- Constructability Report: Option 2 & 3 Proposals

Financial Analysis

Detailed financial analysis of the proposals that included a cost commitment was performed during the initial analysis. The financial analysis consisted of simulating the cost of the project over the lifetime under a base scenario as well as several stress scenarios. The lifetime cost was calculated as the net present value revenue requirement (NPVRR) for the projects based on the proposed financial parameters and a representative cost of service revenue model. The NPVRR was then calculated for several scenarios that included variations of return on equity, capital cost, debt cost, equity percentage, and operation and maintenance costs. The purpose of the scenario simulations was to test the overall effectiveness of the proposed cost commitments.

Details of the financial analysis are documented in the PJM Financial Analysis Report.

Legal Review

In conjunction with the financial analysis, PJM performed a legal review of the cost commitment language that consisted of a qualitative assessment of the risks associated with the cost commitment provisions. The assessment considered such factors that might lead to delays in finalizing the Designated Entity Agreement (DEA) or potential risks to acceptance of filed DEA and subsequent rate filing.

Details of the legal review are documented in Appendix C of the PJM Financial Analysis Report.

NJBPU Project Selection

After completion of the initial analysis work, PJM presented its findings to the NJBPU and to PJM's Transmission Expansion Advisory Committee (TEAC) on July 18, 2022.

The NJBPU selected four finalist scenarios for comprehensive reliability analysis by PJM. Based on those results, the NJBPU completed its independent evaluation of the proposals, and on Oct. 26, 2022, the NJBPU issued an order notifying PJM of its selection of the transmission project, inclusive of all components, that it will sponsor to achieve its stated public policy goals of injecting 7,500 MW of offshore wind into New Jersey by 2035.

The NJBPU selected the "Larrabee Tri-Collector Solution" or "MAOD-JCP&L Option 1b Solution," which includes elements of the Jersey Central Power & Light (JCP&L) Option 1b proposal, as well as scaled-down elements of Mid-Atlantic Offshore Development's (MAOD's) Option 2 proposal, and the necessary Option 1a upgrades to create the SAA Capability associated with the scenario evaluating the Larrabee Tri-Collector Solution. This solution was studied by PJM as Scenario 18a.

The primary component of the MAOD portion of Larrabee Tri-Collector Solution is a Larrabee Collector Station (LCS) to be constructed adjacent to the existing JCP&L Larrabee 230 kV substation. MAOD will construct the alternating current portion of the station that will enable the interconnection of three future high-voltage direct current (HVDC) circuits, which would be constructed by the future OSW generator developers. The proposal also includes sufficient land for the future installation of up to a total of four direct current converter stations.

The JCP&L Option 1b (proposal No. 453) portion of the Larrabee Tri-Collector Solution includes transmission upgrades to create three paths from the LCS to the three points of injection: Larrabee 230 kV, Atlantic 230 kV and Smithburg 500 kV. The primary components include:

- Smithburg substation 500 kV expansion to a four-breaker ring
- Atlantic 230 kV substation conversion to double-breaker double-bus
- New Larrabee Collector station-Smithburg No. 1 500 kV line
- G1021 Atlantic-Smithburg 230 kV line rebuild between the Larrabee and Smithburg substations as a double circuit 500 kV/ 230 kV line
- D2004 Larrabee-Smithburg 230 kV rebuild to 1590 ACSS
- New Larrabee Collector station-Atlantic 230 kV line
- New Larrabee Collector station-Larrabee 230 kV line

NOTE:

SAA Capability has the meaning set forth in Paragraph 1 of the State Agreement Approach Agreement by and among PJM Interconnection, L.L.C. and New Jersey Board of Public Utilities, designated as Rate Schedule FERC No. 49, as filed at and accepted by FERC in Docket No. ER22-902-000. See PJM Interconnection, L.L.C., 179 FERC ¶ 61,024 (2022), reh'g denied 179 FERC ¶ 62,131 (2022). Specifically, SAA Capability is defined to include:

all transmission capability created by a SAA Project(s), including but not limited to the capability to integrate resources injecting energy up to the Maximum Facility Output ("MFO"), capability which may become CIRs through the PJM interconnection process, and any other capability or rights under the PJM Tariff, and consistent with the reliability study criteria applied to the evaluation of a SAA Project(s) as set forth in Paragraph 6 below. For the avoidance of doubt, SAA Capability shall also include any incremental transmission capability that is created by a SAA Project(s) and is determined to provide Incremental Auction Revenue Rights ("IARRs") or Incremental Capacity Transfer Rights ("ICTRs") associated with Incremental Rights-Eligible Required Transmission Enhancements, pursuant to Tariff, Schedule 12-A.

The selected solution also requires a number of Option 1a upgrades to reinforce the existing grid to accommodate the OSW injections. The primary components include:

- Rebuild the underground portion of Richmond-Waneeta 230 kV.
- Rebuild Clarksville-Lawrence 230 kV.
- Reconductor Kilmer I-Lake Nelson I 230 kV.
- Rebuild Larrabee-Smithburg No. 1 230 kV.
- Reconductor Red Oak A-Raritan River 230 kV.
- Reconductor Red Oak B-Raritan River 230 kV.
- Reconductor small section of Raritan River-Kilmer I 230 kV.
- Add a third set of submarine cables for the Silver Run-Hope Creek 230 kV line.
- Linden subproject: Install a new 345/230 kV transformer at the Linden 345 kV switching station and relocate the Linden-Tosco 230 kV line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV.
- Build a new greenfield North Delta station with two 500/230 kV 1500 MVA transformers and nine 63 kA breakers.
- Build a new North Delta-Graceton 230 kV line by rebuilding 6.07 miles of the existing Cooper-Graceton 230 kV line. Upgrade to Graceton-Cooper 230 kV.

The complete list of components that make up the Larrabee Tri-Collector Solution are provided in Appendix A of the PJM document Summary Report for the NJBPU Selected Project, 2021 SAA Proposal Window to Support NJ OSW.

PJM baseline project B3737 includes the Option 1a, 1b and 2 system upgrade components required to support the selected Scenario 18a, Larrabee Tri-Collector Solution. Baseline B3737 was approved at the December 2022 PJM Board Meeting.

3.2: Transmission Owner Criteria

Transmission Owner FERC Form 715 Planning Criteria

The PJM Operating Agreement specifies that individual TO planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions. TOs are required to include their individual criteria as part of their respective FERC Form 715 filings. TO criteria can be found on the PJM website. PJM applies TO criteria to all facilities included in the PJM Open Access Transmission Tariff (OATT) facility list.

Transmission enhancements driven by TO criteria are considered RTEP baseline projects. Projects may be eligible for proposal window consideration as shown in **Figure 3.1**. Under the terms of the OATT, the costs of such projects follow existing baseline reliability cost allocation rules. The 2022 RTEP included 25 TO criteria projects for a total cost of over $200 million. The description and location of those projects are shown in **Table 3.4** and **Map 3.5**. More detailed descriptions of these projects can be found in TEAC PJM Board White Papers.

Map 3.5: 2022 Transmission Owner Criteria Driven Projects

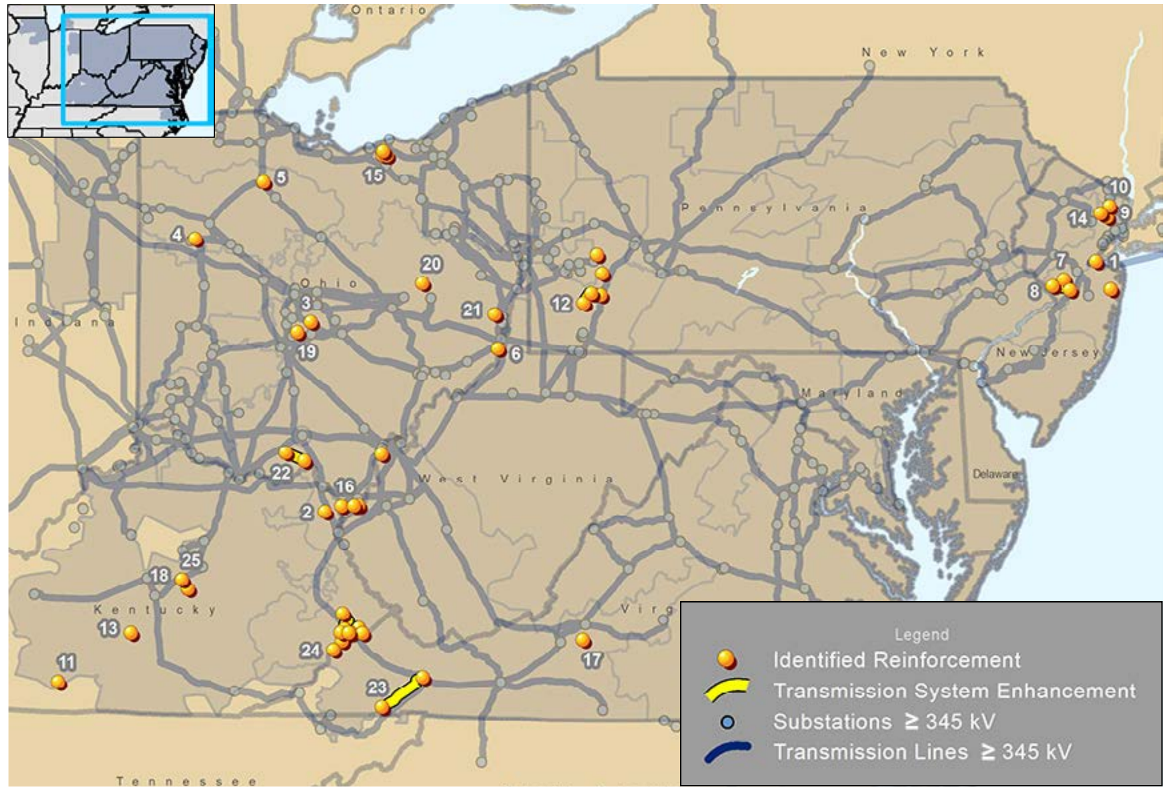


Table 3.4: 2022 Transmission Owner Criteria Driven Projects

Map ID	Upgrade ID	Description	TO Zone	Cost Estimate ($M)	Required In-Service	Projected In-Service
1	B3130.11	Replace four Atlantic 34.5 kV breakers (BK1A, BK1B, BK3A and BK3B) with 63 kA rated breakers and associated equipment.	JCP&L	$3.5	9/30/2023	9/30/2023
	B3130.12	Replace six Werner 34.5 kV breakers (E31A_Prelim, E31B_Prelim, V48 future, W101, M39 and U99) with 40 kA rated breakers and associated equipment.		$4.2	6/1/2024	6/1/2024
2	B3350.1	Replace overdutied 69 kV breakers C, G, I, Z, AB and JJ in place. The new 69 kV breakers to be rated at 3000A 40 kA breakers.	AEP	$2	6/1/2023	6/1/2023
	B3350.2	Upgrade remote end relaying at Point Pleasant, Coalton and South Point 69 kV substations.		$0	6/1/2023	6/1/2023

Table 3.4: Transmission Owner Criteria Projects (Cont.)

Map ID	Upgrade ID	Description	TO Zone	Cost Estimate ($M)	Required In-Service	Projected In-Service
3	B3354	Replace circuit breakers 42 and 43 at Bexley station with 3000 A, 40 kA 69 kV breakers (operated at 40 kV), slab, control cables and jumpers.	AEP	$1	6/1/2023	6/1/2023
4	B3355	Replace circuit breakers A and B at South Side Lima station with 34.5 kV, 1200A 25 kA breakers, slab, control cables and jumpers.		$0.75	6/1/2023	10/31/2022
5	B3356	Replace circuit breaker H at West End Fostoria station with 69 kV, 3000A 40 kA breaker, slab, control cables and jumpers.		$0.5	6/1/2023	6/1/2022
6	B3357	Replace circuit breakers C, E, and L at Natrium station with 69 kV, 3000A 40 kA breakers, slab, control cables and jumpers.		$1.5	6/1/2023	6/1/2022
7	B3703	Construct a third 69 kV supply line from Penns Neck substation to the West Windsor substation.	PSEG	$1.05	1/1/2023	1/1/2023
8	B3704	Replace the Lawrence switching station 230/69 kV transformer No. 220-4 and its associated circuit switchers with a new larger capacity transformer with load tap changer (LTC) and new dead tank circuit breaker. Install a new 230 kV gas insulated breaker, associated disconnects, overhead bus and other necessary equipment to complete the bay within the Lawrence 230 kV switchyard.		$13.36	6/1/2026	6/1/2026
9	B3705	Replace existing 230/138 kV Athenia No. 220-1 transformer.		$13.04	6/1/2026	6/1/2026
10	B3706	Replace Fair Lawn 230/138 kV transformer No. 220-1 with an existing O&M system spare at Burlington.		$4.454	6/1/2026	6/1/2026
11	B3709	Rebuild the Summer Shade-West Columbia 69 kV 0.19 miles of 266 conductor double circuit to 556 conductor.	EKPC	$0.191	12/1/2025	12/1/2025
12	B3710	Expand the future AA2-161 138 kV six-breaker ring bus into an eleven-breaker substation with a breaker-and-a-half layout by constructing five additional breakers and expanding the bus. Loop the Yukon-Charleroi No. 2 138 kV line into the future AA2-161 substation. Relocate terminals as necessary at AA2-161. Upgrade terminal equipment (wavetrap, substation conductor) and relays at Yukon, Huntingdon, Springdale, Charleroi and the AA2-161 substation.	AP	$10.64	6/1/2026	6/1/2026
13	B3712	Install a 28 MVAR cap bank at Liberty Junction 69 kV.	EKPC	$0.542	12/1/2022	12/1/2023
14	B3716	Construct a third 69 kV supply line from Totowa substation to the customer's substation.	PSEG	$8.2	1/1/2025	1/1/2025
15	B3720	Rebuild the Abbe-Johnson No. 2 69 kV line (approx. 4.9 miles) with 556 kcmil ACSR conductor. Replace three disconnect switches (A17, D15 & D16) and line drops and revise relay settings at Abbe. Replace one disconnect switch (A159) and line drops and revise relay settings at Johnson. Replace two MOAB disconnect switches (A4 & A5), one disconnect switch (D9), and line drops at Redman.	ATSI	$10.9	6/1/2027	6/1/2026
16	B3722	Rebuild the existing Darrah-Barnett 69 kV line, approximately 2.8 miles and replace a riser at Darrah station.	AEP	$6.98	12/1/2027	12/1/2027
17	B3724	Install 138 kV circuit switcher on the high side of transformer No. 2 at Roanoke station (previously proposed as a portion of S2469.7, posted in 2021 AEP local plan).	AEP	$0.1	6/1/2027	6/1/2027
18	B3727	Rebuild EKPC's Fawkes-Duncannon Lane tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR.	EKPC	$8.5	12/1/2026	12/31/2024
19	B3731	Replace 40 kV breaker J at McComb station with a new 3000A 40 kA breaker.	AEP	$0.5	6/1/2027	6/1/2025
20	B3732	Install a 6 MVAR, 34.5 kV cap bank at Morgan Run station.		$0.37	6/1/2027	6/1/2027
21	B3733	Rebuild the 1.8 mile 69 kV T-line between Summerhill and Willow Grove switch. Replace 4/0 ACSR conductor with 556 ACSR.		$5.1	6/1/2027	6/1/2027
22	B3734	Install a 7.7 MVAR, 69 kV cap bank at both Otway station and Rosemount station.		$1.73	6/1/2027	6/15/2026
23	B3735	Terminate the existing Broadford-Wolf Hills No. 1 138 kV line into Abingdon 138 kV station. This line currently bypasses the existing Abingdon 138 kV station. Install two new 138 kV circuit breakers on each new line exit towards Broadford and toward Wolf Hills No. 1. Install one new 138 kV circuit breaker on line exit toward South Abingdon for standard bus sectionalizing.		$8.48	6/1/2027	6/1/2027
24	B3736.1	Establish 69 kV bus and new 69 kV line circuit breaker at Dorton substation.		$1.13	12/1/2027	7/31/2027
	B3736.10	Retire Henry Clay substation.		$0.3	12/1/2027	7/31/2027

Table 3.4: Transmission Owner Criteria Projects (Cont.)

Map ID	Upgrade ID	Description	TO Zone	Cost Estimate ($M)	Required In-Service	Projected In-Service
24	B3736.11	Work at Cedar Creek substation.	AEP	$0.44	12/1/2027	7/31/2027
	B3736.12	Retire Breaks substation 46 kV equipment.		$0.25	12/1/2027	7/31/2027
	B3736.13	Retire Pike 29 substation and Rob Fork substation.		$0.42	12/1/2027	7/31/2027
	B3736.14	Serve Pike 29 and Rob Fork customers from nearby 34 kV distribution sources.		$0	12/1/2027	7/31/2027
	B3736.15	Construct Poor Bottom substation		$0	12/1/2027	7/31/2027
	B3736.16	Retire Henry Clay 46 kV substation.		$0	12/1/2027	7/31/2027
	B3736.17	Install new Draffin 69 kV substation.		$0	12/1/2027	7/31/2027
	B3736.18	Retire Draffin 46 kV substation.		$0	12/1/2027	7/31/2027
	B3736.2	Reuse 72 kV breaker A as the new 69 kV line breaker at Breaks substation.		$0.71	12/1/2027	7/31/2027
	B3736.3	Rebuild ~16.7 mile Dorton-Breaks 46 kV line to 69 kV.		$58.52	12/1/2027	7/31/2027
	B3736.4	Retire ~17.2 mile Cedar Creek-Elwood 46 kV circuit.		$11.15	12/1/2027	7/31/2027
	B3736.5	Retire ~6.2 mile Henry Clay-Elwood 46 kV line section.		$4.3	12/1/2027	7/31/2027
	B3736.6	Retire Henry Clay 46 kV substation and replace with Poor Bottom 69 kV station. Install a new 0.7 mile double circuit extension to Poor Bottom 69 kV.		$3.42	12/1/2027	7/31/2027
	B3736.7	Retire Draffin substation and replace with a new substation. Install a new 0.25 mile double circuit extension to New Draffin substation.		$2.01	12/1/2027	7/31/2027
	B3736.8	Perform remote end work at Jenkins substation.		$0.03	12/1/2027	7/31/2027
	B3736.9	Provide transition fiber to Dorton, Breaks, Poor Bottom, Jenkins and New Draffin substations.		$0.41	12/1/2027	7/31/2027
25	B3762	Rebuild EKPC's Fawkes-Duncannon lane tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR.	EKPC	$8.5	12/1/2026	12/31/2024

In situations where the TO is not able to complete construction by the required in-service date, PJM works to establish operating procedures to ensure that the system remains reliable until the reinforcement is in service.

3.3: Supplemental Projects

Supplemental projects are not required for compliance with system reliability, operational performance or market efficiency economic criteria. They are put forward by TOs as transmission expansions or enhancements that enable the continued reliable operation of the transmission system by meeting customer service needs, enhancing grid resilience and security, promoting operational flexibility, addressing transmission asset health, and ensuring public safety, among other drivers.

Supplemental projects may also address reliability issues for transmission facilities that are on non-bulk electric system (BES) facilities or not considered under NERC requirements or other PJM criteria. Maintenance work and emergency work (e.g., work that is unplanned, including necessary work resulting from an unanticipated customer request, repair of equipment or facilities damaged by storms or other causes, or replacement of failing or failed equipment) do not constitute supplemental projects.

Figure 3.4 reflects the primary drivers of supplemental projects. Transmission expansions or enhancements that replace facilities that are near or at the end of their useful lives are a primary focus of equipment material condition, performance and risk. TOs develop and apply their own factors and considerations for addressing facilities at or near the end of their useful lives. Each TO explains the criteria, assumptions and models it uses to identify project drivers at the annual assumptions meeting provided under the Attachment M3 process.

While not subject to PJM Board approval, supplemental projects are included in PJM's RTEP models. Attachment M3 of the PJM Tariff describes the FERC-approved process that PJM and TOs must follow.

PJM, in its role as a facilitator in the Attachment M3 process, is responsible for the following:

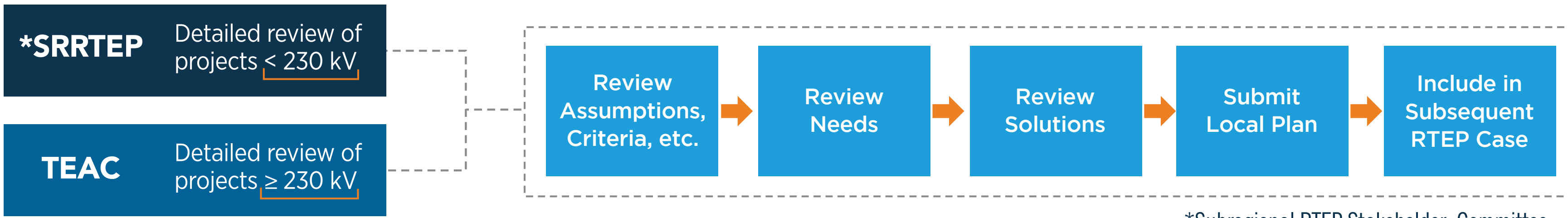
- Provide necessary facilitation and logistical support so that supplemental project planning meetings can be conducted as outlined in Attachment M3 of the PJM Tariff.
- Provide the applicable TO with modeling information so that TOs can determine if a stakeholder-proposed project can address a supplemental project need.
- Perform do-no-harm analysis to ensure that a supplemental project that a TO elects for inclusion in its local plan does not cause additional reliability violations.
- Work with TOs and stakeholders to improve Attachment M3 transparency.

The Attachment M3 process provides stakeholders – via the PJM Transmission Expansion Advisory Committee (TEAC) and subregional RTEP committees – the meaningful opportunity to review supplemental projects and provide feedback, including written comments, as shown in **Figure 3.5**. Stakeholders interested in providing feedback can do so via PJM's Planning Community.

Figure 3.4: Primary Supplemental Project Drivers

Customer Service	Provide service to new and existing customers; interconnect new customer load; address distribution load growth, customer outage exposure, equipment loading, etc.
Equipment Material Condition, Performance and Risk	Address degraded equipment performance, material condition, obsolescence; end of the useful life of equipment or a facility; equipment failure; employee and public safety; environmental impact.
Operational Flexibility and Efficiency	Optimize system configuration, equipment duty cycles and restoration capability; minimize outages.
Infrastructure Resilience	Improve system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather or geomagnetic disturbances.
Other	Meet objectives not included in other definitions such as, but not limited to, technological pilots, industry recommendations, environmental and safety impacts, etc.

Figure 3.5: Attachment M3 Process for Supplemental Projects

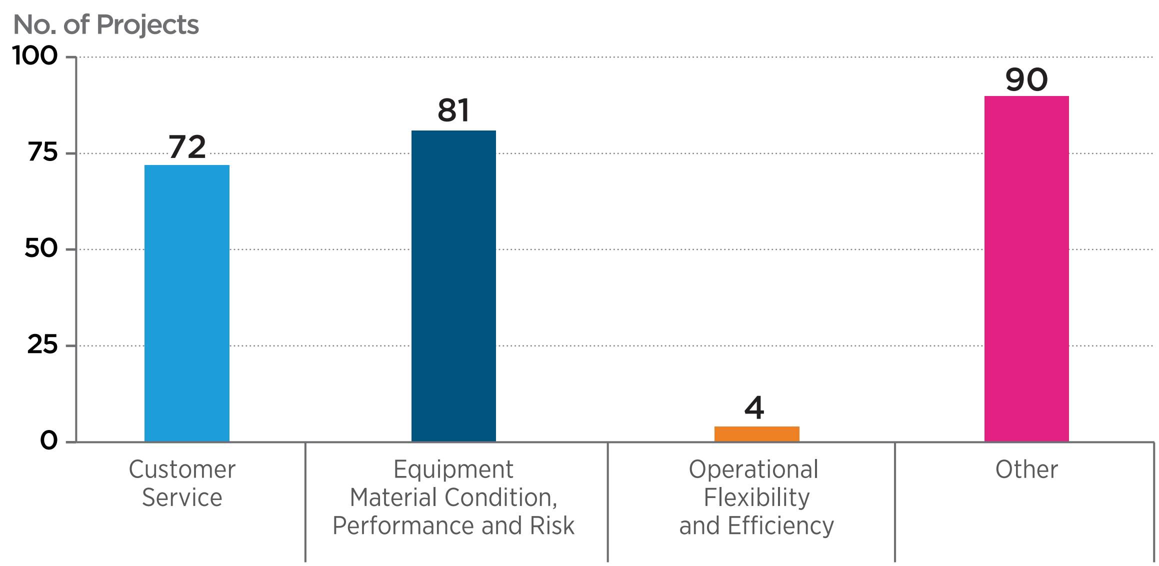


*Subregional RTEP Stakeholder Committee

2022 Supplemental Projects

PJM evaluated approximately $3.6 billion of TO supplemental projects in 2022. **Figure 3.6** shows a breakdown of supplemental solutions by driver, presented at TEAC and subregional RTEP committees over the past year. It suggests that the largest driver is equipment material condition, performance and risk, and totals approximately $951.7 million. Projects driven by customer service requests and operational flexibility and efficiency totaled approximately $465.3 million and $26.4 million, respectively. The remaining $632.8 million are required by projects classified as "Other" or with more than one driver.

Figure 3.6: 2022 Supplemental Projects by Driver



3.4: Generator Deactivations

PJM received 20 deactivation notices, including new requests and revisions to existing requests, totaling 5,119 MW during 2022. **Map 3.6** and **Table 3.5** show these 20 generators' deactivation notifications.

Map 3.6: Deactivation Notifications Received in 2022

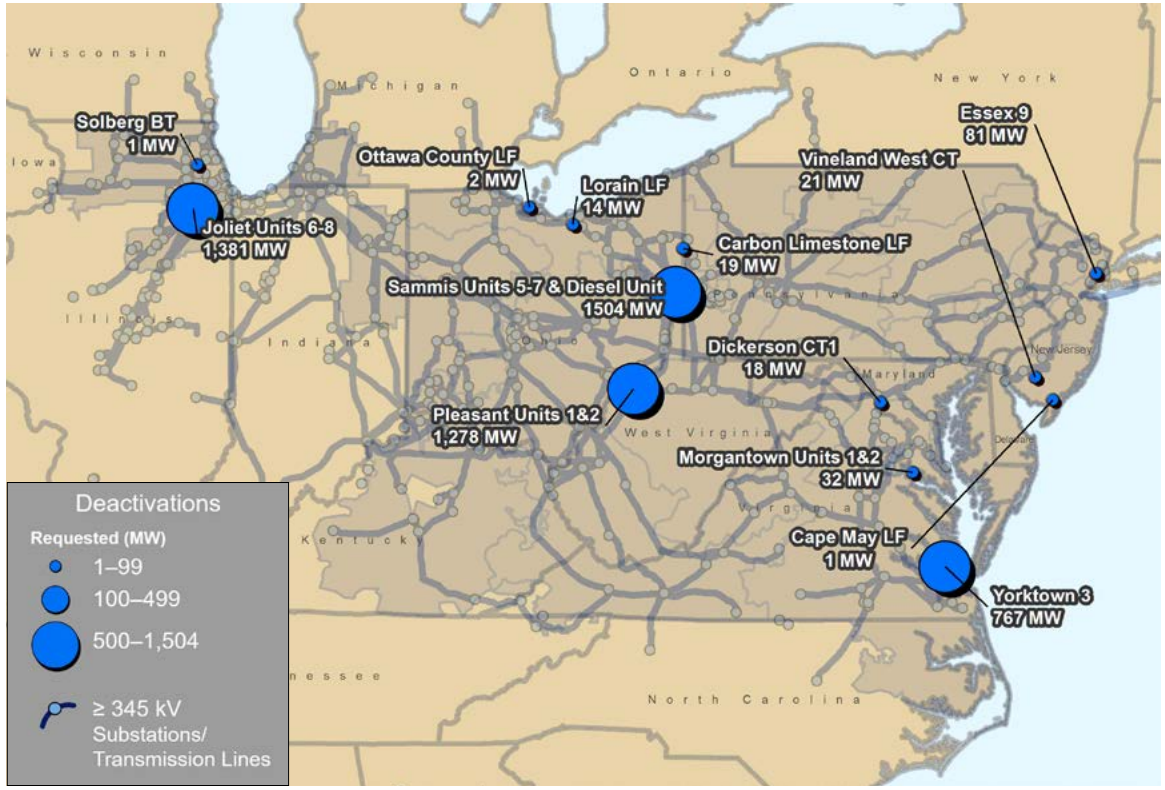


Table 3.5: Deactivation Notifications Received in 2022

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Requested Deactivation Date	Projected Deactivation Date
Yorktown 3	767.1	Dominion	48	Oil	5/31/2023	5/31/2023
Solberg 1	1	ComEd	4	Battery	4/1/2023	4/1/2023
Oberlin Lorain County 2 LF	14	ATSI	21	Methane	4/1/2023	4/1/2023
Dickerson CT 1	18	PEPCO	55	Oil	10/23/2022	10/23/2022
Joliet 8	550	ComEd	56	Natural Gas	6/1/2023	6/1/2023
Joliet 7	550	ComEd	57	Natural Gas	6/1/2023	6/1/2023
Joliet 6	281	ComEd	63	Natural Gas	6/1/2023	6/1/2023
Vineland CT	21.1	AE	50	Oil	10/14/2022	10/14/2022
Capy May County MUA LF	0.6	AE	9	Methane	3/1/2022	3/1/2022
Carbon Limestone LF	19.3	ATSI	21	Methane	11/15/2022	11/15/2022
Morgantown CT 2	16	PEPCO	51	Oil	10/1/2022	10/1/2022
Morgantown CT 1	16	PEPCO	52	Oil	10/1/2022	10/1/2022
Pleasants 2	639	AP	42	Coal	6/1/2023	6/1/2023
Pleasants 1	639	AP	42	Coal	6/1/2023	6/1/2023
Sammis Diesel	13	ATSI	50	Coal	6/1/2023	6/1/2023
Sammis 7	600	ATSI	51	Coal	6/1/2023	6/1/2023
Sammis 6	600	ATSI	53	Coal	6/1/2023	6/1/2023
Sammis 5	291.3	ATSI	55	Coal	6/1/2023	6/1/2023
Essex 9	81	PSEG	32	Natural Gas	6/1/2022	6/1/2022
Ottawa County LF	1.7	ATSI	21	Methane	5/31/2022	5/31/2022

Forty-one generators totaling 6,104 MW deactivated in the PJM region during 2022, as shown in **Map 3.7** and **Table 3.6**.

PJM completed the required analysis to identify reliability criteria violations caused by deactivations. Four baseline transmission enhancements totaling $30 million are required to solve the reliability criteria violations caused by these deactivations. Several deactivations required completion of existing baseline enhancements, and others had no reliability impacts identified.

Map 3.7: Actual Generator Deactivations in 2022

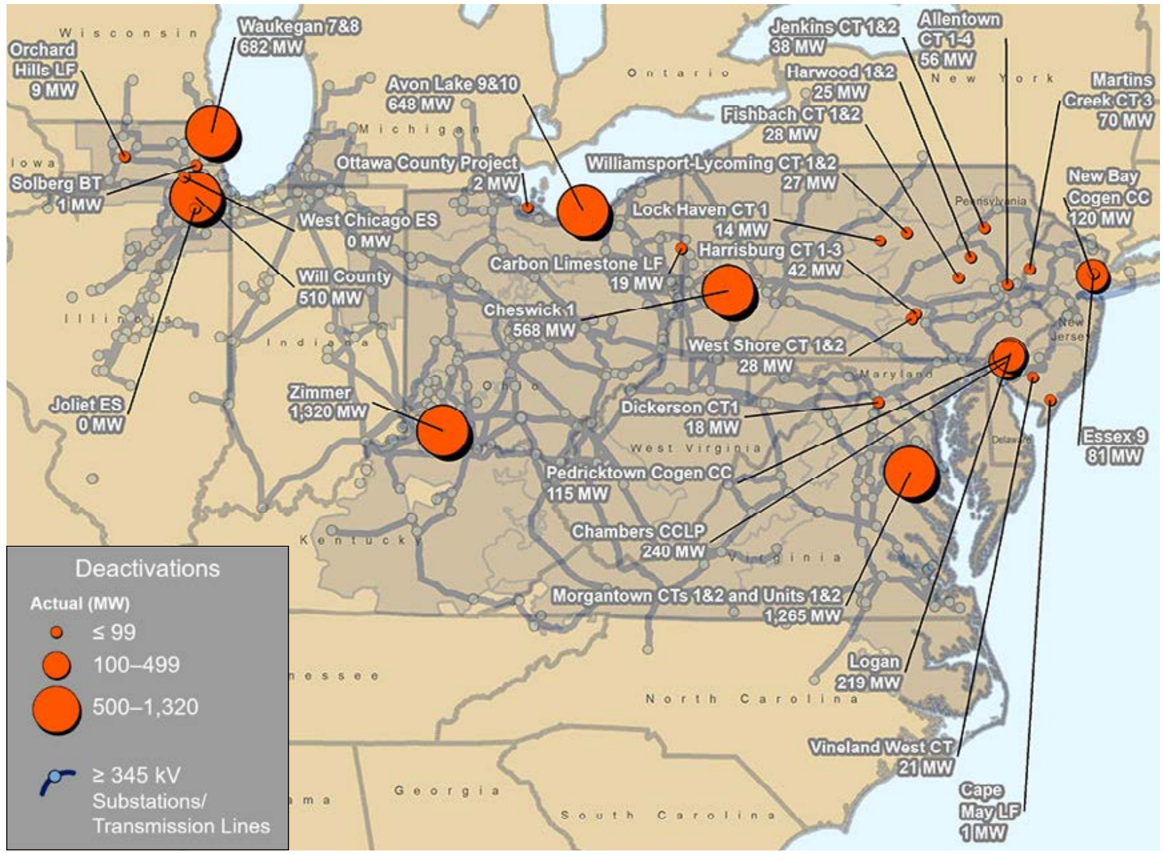


Table 3.6: Actual Deactivations in 2022

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Requested Deactivation Date	Projected Deactivation Date
Solberg 1	1	ComEd	4	Battery	4/1/2023	12/20/2022
Dickerson CT 1	18	PEPCO	55	Oil	10/23/2022	10/23/2022
Vineland West CT	21.1	AE	50	Oil	10/14/2022	10/14/2022
Cape May County LF	0.6	AE	9	Methane	3/1/2022	3/1/2022

Table 3.6: Actual Deactivations in 2022 (Cont.)

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Requested Deactivation Date	Projected Deactivation Date
Carbon Limestone LF	19.3	ATSI	21	Methane	11/15/2022	11/15/2022
Morgantown CT 2	16	PEPCO	51	Oil	10/1/2022	10/1/2022
Morgantown CT 1	16	PEPCO	52	Oil	10/1/2022	10/1/2022
Essex 9	81	PSEG	32	Natural Gas	6/1/2022	6/1/2022
Ottawa County LF	1.7	ATSI	21	Methane	5/31/2022	5/31/2022
Logan	219	AE	27	Coal	5/31/2022	5/31/2022
Chambers CCLP	240	AE	27	Coal	6/7/2022	6/7/2022
Orchard Hills LF	9.3	ComEd	5	Methane	3/31/2022	3/31/2022
Joliet 1	0	ComEd	6	Battery	4/29/2022	4/29/2022
West Chicago 3	0	ComEd	6	Battery	4/29/2022	4/29/2022
Williamsport 2	13.4	PPL	54	Oil	4/1/2022	4/1/2022
Williamsport 1	13.2	PPL	54	Oil	4/1/2022	4/1/2022
West Shore 2	14	PPL	52	Oil	4/1/2022	4/1/2022
West Shore 1	14	PPL	52	Oil	4/1/2022	4/1/2022
Martins Creek CT 3	18	PPL	50	Oil	6/1/2022	6/1/2022
Lockhaven 1	14	PPL	52	Oil	4/1/2022	4/1/2022
Jenkins 2	13.8	PPL	52	Oil	4/1/2022	4/1/2022
Jenkins 1	13.8	PPL	52	Oil	4/1/2022	4/1/2022
Harrisburg 3	13.8	PPL	54	Oil	6/1/2022	6/1/2022
Harrisburg 2	13.9	PPL	54	Oil	6/1/2022	6/1/2022
Harrisburg 1	13.4	PPL	54	Oil	6/1/2022	6/1/2022
Fishbach 2	14	PPL	52	Oil	4/1/2022	4/1/2022
Fishbach 1	14	PPL	52	Oil	4/1/2022	4/1/2022
Allentown 4	14	PPL	54	Oil	6/1/2022	6/1/2022
Allentown 3	14	PPL	54	Oil	6/1/2022	6/1/2022
Allentown 2	14	PPL	54	Oil	6/1/2022	6/1/2022
Allentown 1	14	PPL	54	Oil	6/1/2022	6/1/2022
Zimmer 1	1320	DEO&K	30	Coal	5/31/2022	5/31/2022
NewBay Cogen CC	120.2	PSEG	28	Natural Gas	6/1/2022	6/1/2022
Pedricktown Cogen CC	115.3	AE	29	Natural Gas	6/1/2022	6/1/2022

Table 3.6: Actual Deactivations in 2022 (Cont.)

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Requested Deactivation Date	Projected Deactivation Date
Will County 4	510	ComEd	58	Coal	6/30/2022	6/30/2022
Waukegan 8	354.4	ComEd	59	Coal	5/31/2022	5/31/2022
Waukegan 7	328	ComEd	63	Coal	5/31/2022	5/31/2022
Cheswick 1	567.5	DLCO	51	Coal	4/1/2022	3/31/2022
Avon Lake 9	627	ATSI	51	Coal	4/1/2022	3/31/2022
Avon Lake 10	21	ATSI	53	Oil	4/1/2022	3/31/2022
Morgantown 2	619.4	PEPCO	50	Coal	5/31/2022	5/31/2022
Morgantown 1	613.3	PEPCO	51	Coal	5/31/2022	5/31/2022
Harwood 2	12.3	PPL	53	Oil	5/31/2022	5/31/2022
Harwood 1	12.9	PPL	53	Oil	5/31/2022	5/31/2022

3.5: 2022 Retool Impacts

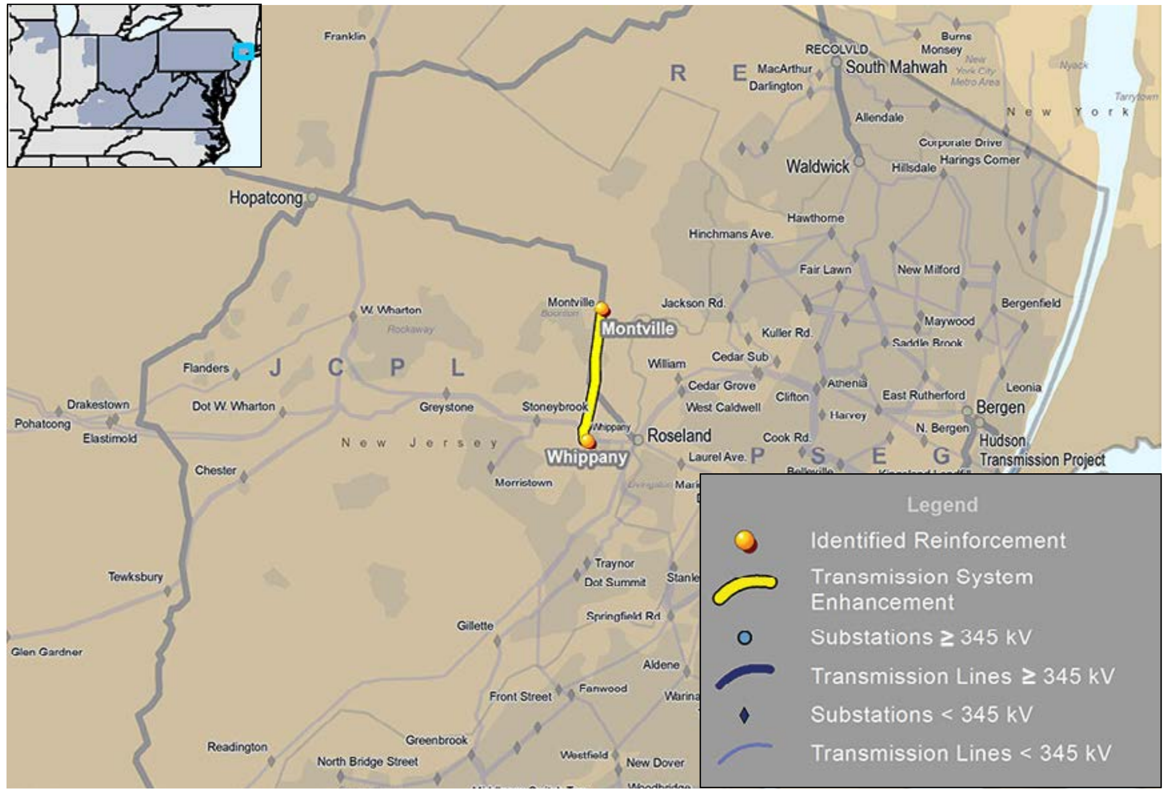
As part of each RTEP cycle, PJM evaluates how specific input assumptions impact the results of analysis from prior RTEP cycles. Individual generator or load modeling changes are studied as a sensitivity to understand their impact on the transmission system. But, when a large set of input assumptions change, a full reevaluation, known as a retool, allows for assumptions to be updated in the model used for analysis and reanalyzed to understand their impacts.

During 2022, PJM performed a retool for the 2027 RTEP considering the generation changes for new in-service agreements, withdrawn projects, as well as deactivations.

Additionally, PJM performed a retool study in the JCP&L area. The retool was performed to see if violations would still exist without baseline upgrade B2003, which will rebuild the Montville to Whippany 230 kV line. The conclusion was that without the project, the violation was still present. Therefore the baseline upgrade was needed.

In addition to retool analysis, PJM also performs scenario analysis to understand the impacts that changing assumptions have on the grid. In 2022, PJM performed a scenario analysis to understand the impacts of high load growth scenarios that are driving the need for transmission enhancements. PJM continues to study the impact of high load growth scenarios into 2023.

Map 3.8: RTEP Baseline Project B2003



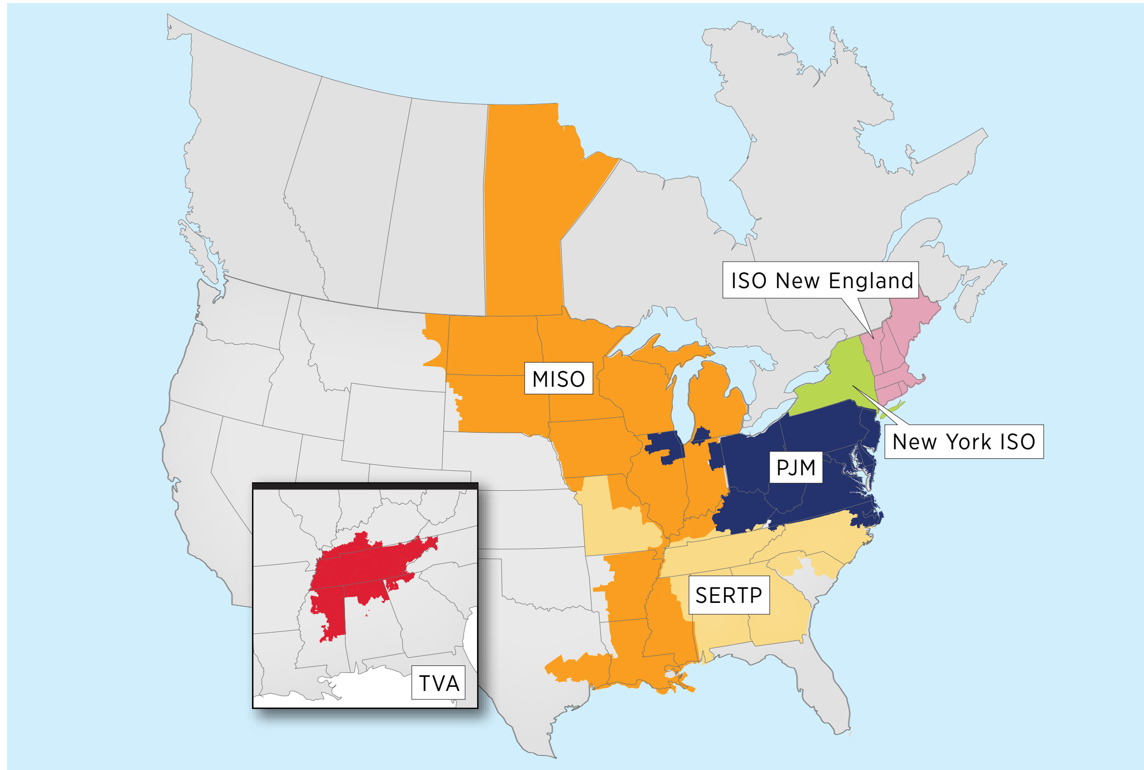
3.6: Interregional Planning

3.6.1 — Adjoining Systems

PJM's interregional planning activities continue to foster increased interregional coordination. The nature of these activities includes structured, Tariff-driven analyses, as well as sensitivity evaluations to target specific issues that may arise each year. PJM currently has interregional planning arrangements with the New York Independent System Operator (NYISO), the Independent System Operator of New England (ISO-NE), the Mid-Continent Independent System Operator (MISO), the Tennessee Valley Authority (TVA), and to the south through the Southeastern Regional Transmission Planning process (SERTP), shown on **Map 3.9**.

In addition, PJM actively participates in the Eastern Interconnection Planning Collaborative.

Map 3.9: PJM Interregional Planning



Interregional Agreements

Under each interregional agreement, provisions governing coordinated planning ensure that critical cross-border operational and planning issues are identified and addressed before they impact system reliability or adversely impact efficient market administration. The planning processes applicable to each of PJM's three external transmission interfaces include provisions to address issues of mutual concern, including:

- Interregional impacts of regional transmission plans
- Impacts of queued generator interconnection requests and deactivation requests
- Opportunities for improved market efficiencies at interregional interfaces
- Solutions to reliability and congestion constraints
- Interregional planning impacts of national and state public policy objectives
- Enhanced modeling accuracy within individual planning processes due to periodic exchange of power system modeling data and information

Each study is conducted in accordance with the PJM Tariff and respective interregional agreement. Studies may include cross-border analyses that examine reliability, market efficiency or public policy needs. Reliability studies may assess power transfers, stability, short circuit, generation, merchant transmission interconnection analyses and generator deactivation. Taken together, these coordinated planning activities enhance the reliability, efficiency and cost effectiveness of regional transmission plans.

3.6.2 — MISO

The 2022 planning efforts under Article IX of the MISO/PJM joint operating agreement continued to ensure the coordination of regional reliability, market efficiency, interconnection requests and deactivation notifications. Interconnection-driven network transmission enhancements are summarized in **Section 5**. Deactivation-driven baseline analyses are summarized in **Section 3.3**.

Annually, stakeholder input and feedback to the interregional planning process are coordinated through the MISO/PJM Interregional Planning Stakeholder Advisory Committee (IPSAC).

TMEP 2022 Activities

TMEP interregional projects address historical congestion on market-to-market flowgates – a set of specific flowgates subject to joint and common market (JCM) congestion management. The JCM congestion management process is described in the MISO/PJM Joint Operating Agreement. Congestion arising from joint market operations creates significant financial consequences for market participants. PJM and MISO agree that there is a need to remedy historical congestion on the seam.

2022 Targeted Market Efficiency Project Study

As part of the 2022 CSP, PJM and MISO initiated a TMEP study. TMEP interregional projects address historical, persistent congestion on market-to-market flowgates. Those flowgates are subject to JCM congestion management as described in the MISO/PJM Joint Operating Agreement.

The Joint RTO Planning Committee (JRPC), in consultation with IPSAC, initiated a TMEP study in April that concluded in December, culminating in one JRPC-recommended project. The 2022 study evaluated the 23 most congested market-to-market flowgates in 2020 and 2021. Cumulative PJM and MISO congestion on these facilities was approximately $328 million.

Twenty-two of 23 of the flowgates were eliminated from consideration based because of the following criteria:

- Whether or not previously planned projects (RTEP, MISO Transmission Expansion Plan, or interregional TMEPs) are expected to address specific flowgate congestion
- Whether the congestion identified with a particular flowgate was driven by specific transmission outages that are not expected to persist

Then, for remaining congestion, potential TMEP projects were identified and evaluated.

NOTE:
The "Powerton Sub 138 kV Wave Trap" project to address the congestion identified in the 2022 TMEP study was approved by the PJM Board in February 2023.

During the 2022 study, this process yielded the one project shown in **Table 3.7** and **Map 3.10**: the "Powerton 138 kV Substation Wave Trap" project. Doing so is expected to yield $1.8 million of congestion benefit per year based on two-year average historical congestion data and $7.3 million of congestion relief over a four-year period.

3.6.3 — New York ISO and ISO New England

In 2022, PJM, the New York ISO and ISO New England reviewed the status of their ongoing work plan and anticipated 2023 activities. The 2022 work included continued coordination, a review of transmission needs and solutions proposed by neighboring systems, coordination of the interconnection queue, long-term firm transmission service, and transmission projects that potentially impact interregional system performance. The group continues discussion on potential coordination/collaboration of an interregional offshore wind study. The group continues to seek opportunities for interregional transmission. The next Northeast Coordinated System Plan is anticipated by the second quarter of 2023.

3.6.4 — Adjoining Systems South of PJM

Interregional planning activities with entities south of PJM are conducted mainly under the auspices of the Southeastern Regional Transmission Planning (SERTP) process and SERC Reliability Corp.

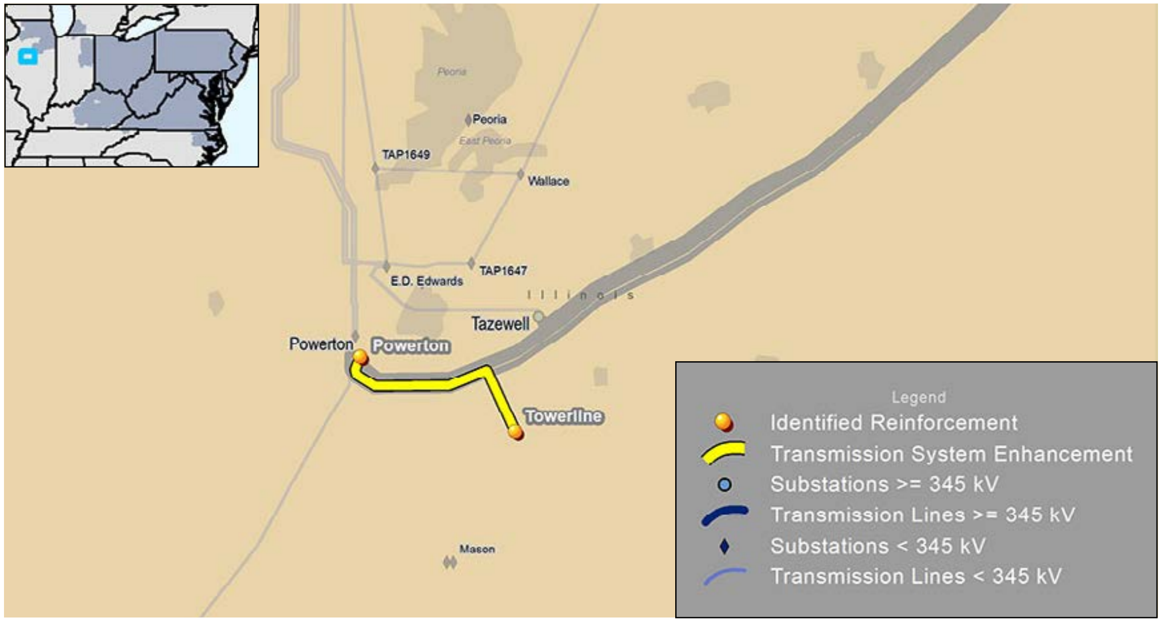
Southeastern Regional Transmission Planning

PJM and the SERTP, shown earlier on **Map 3.9**, continued interregional data exchange and interregional coordination during 2022. SERTP membership includes several entities under FERC jurisdiction and voluntary participation among six non-jurisdictional entities. The jurisdictional

Table 3.7: JRPC Recommended 2022 Targeted Market Efficiency Project

Market-to-Market Facility	Upgrade	Transmission Owner	Benefit ($M)	Cost ($M)	Interregional Benefit Allocation	MTEP Project No.	RTEP Project No.
Powerton-Towerline 138 kV Line	Terminal Equipment (wave trap)	ComEd (IL)	$7.31	$0.2	PJM 71.62% MISO 28.38%	M24573	B3760

Map 3.10: JRPC Recommended 2022 Targeted Market Efficiency Project



entities include Southern Co., Duke Energy (including Duke Energy Carolinas and Duke Energy Progress), and Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E and KU). Duke Energy and LG&E and KU are directly connected to PJM. Of the non-jurisdictional entities, only TVA is directly connected to PJM. The remaining five SERTP participants are planning areas south and west of Duke Energy and TVA.

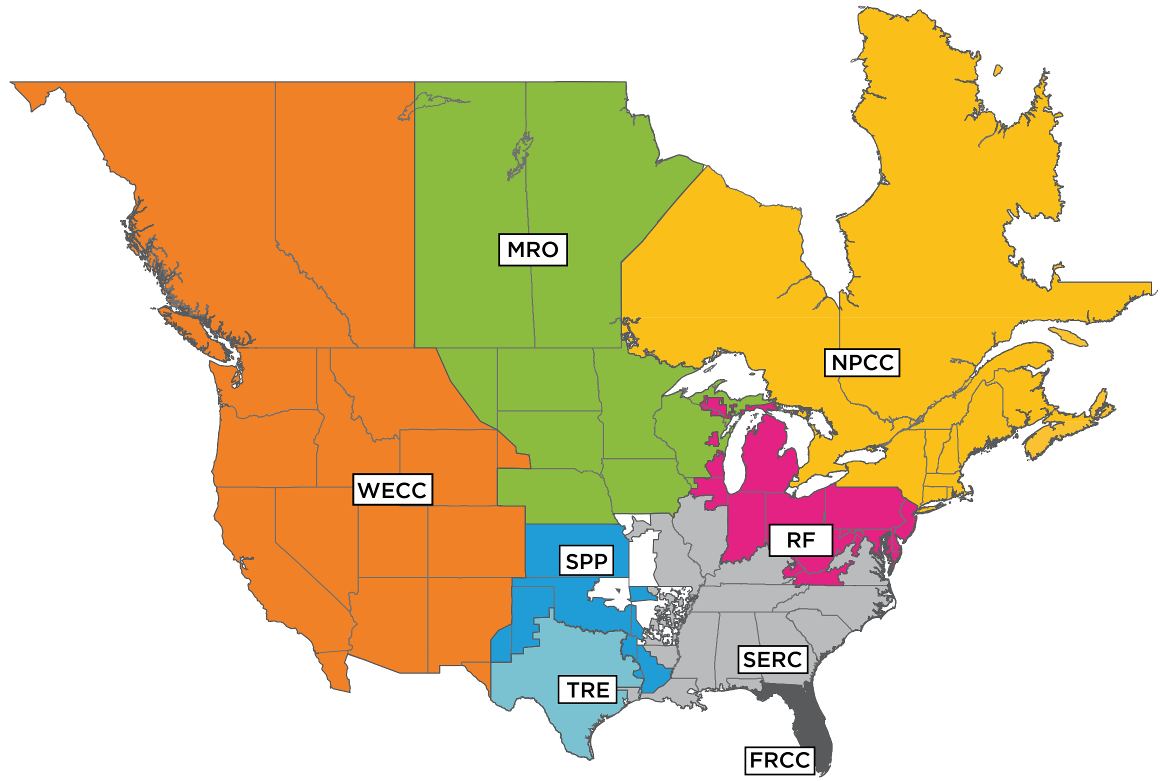
SERTP input occurs through each region's respective planning process stakeholder forums. Stakeholders who have reviewed their respective region's needs and transmission plans may provide input regarding any potential interregional opportunities that may be more efficient or cost-effective than individual regional plans. Successful interregional project proposals can displace the respective regional plans. PJM discussions of SERTP planning, as well as reports on other interregional planning, occur at the TEAC. The SERTP regional process itself can be followed at www.southeasternrtp.com.

SERC Activities

PJM continues to support its members that are located within SERC, Dominion and East Kentucky Power Cooperative (EKPC), as shown on **Map 3.11**. That support includes active participation in the Engineering Committee, Planning Coordination Subcommittee, the Long-Term Working Group, Dynamics Working Group, Short-Circuit Database Working Group, Resource Adequacy Working Group, and the Near-Term Working Group.

PJM actively contributed to SERC committee and working group activities to coordinate 2022 model development and study activities.

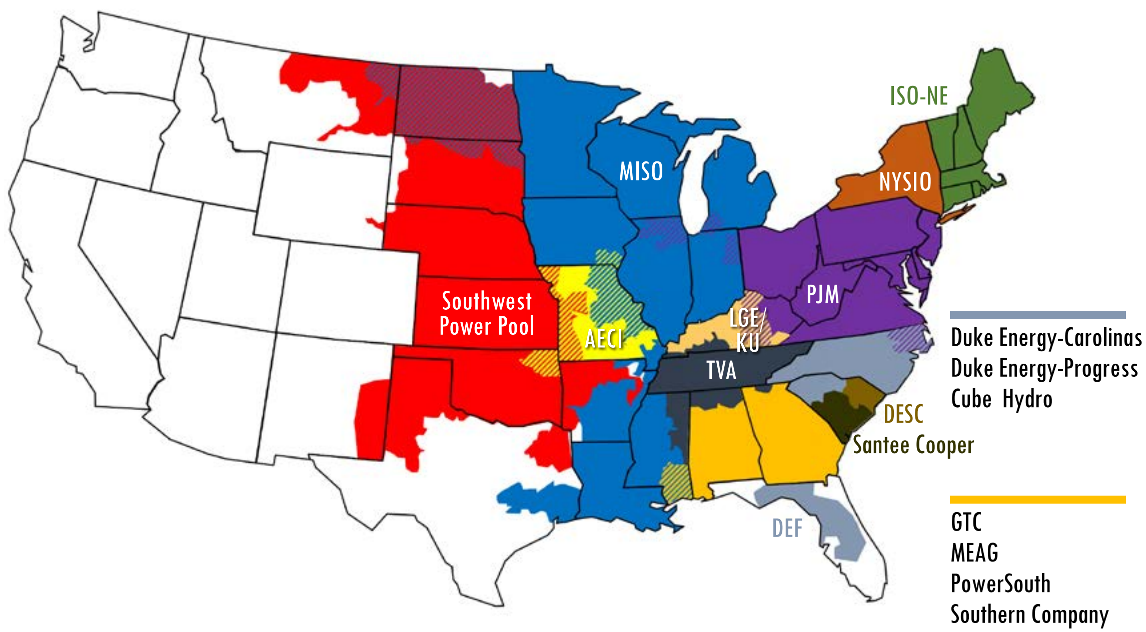
Map 3.11: NERC Areas



3.6.5 — Eastern Interconnection Planning Collaborative

The Eastern Interconnection Planning Collaborative (EIPC) is an interconnection-wide transmission planning coordination effort among NERC planning authorities in the Eastern Interconnection, shown on **Map 3.12**. EIPC consists of 19 planning coordinators representing over 90% of the Eastern Interconnection load. EIPC coordinates analysis of regional transmission plans to ensure their coordination and provides resources to conduct analysis of emerging issues impacting the transmission grid. EIPC's work builds on, rather than replaces, existing regional and interregional transmission planning processes of participating planning authorities. EIPC's efforts are intended to inform regional planning processes.

Map 3.12: Eastern Interconnection Planning Collaborative



EIPC Activities

During 2022, EIPC continued to engage power system planning analysis activities including the following:

- EIPC provided advisory and technical support for the Department of Energy National Transmission Planning Study.
- EIPC participated in the Dec. 5, 2022, FERC Interregional Transfer Workshop, providing testimony in advance primarily addressing the technical requirements for the development of a methodology (including the criteria, metrics and models) that can be used by transmission planners, the Commission and others to identify the appropriate interregional transfer capability across various interfaces of the bulk electric system during extreme conditions.
- The EIPC Modeling Coordination Working Group (MCWG) continued to provide coordination between EIPC and the Multiregional Modeling Working Group (MMWG) in order to facilitate and enhance the Eastern Interconnection model building process.

3.7: Stage 1A ARR 10-Year Analysis

RTEP Context

Auction Revenue Rights (ARRs) are the mechanisms by which the proceeds from the annual FTR Auction are allocated. ARRs entitle the holder to receive an allocation of the revenues from the annual FTR Auction. Incremental ARRs (IARRs) are additional ARRs created by new transmission expansion projects. The PJM Operating Agreement, Section 7.8, Schedule 1 sets forth provisions permitting any party to request IARRs by agreeing to fund transmission expansions necessary to support the requested financial rights. Requests must specify a source, sink and megawatt amount. PJM conducts annual studies to determine if transmission system expansions are required to accommodate the requested IARRs so that all are simultaneously feasible for a 10-year period.

Scope

Each year, PJM conducts an analysis to test the transmission system's ability to support the simultaneous feasibility of all Stage 1A ARRs for base load plus the projected 10-year load growth. If needed, PJM will recommend expansion projects to be included in the RTEP with required in-service dates based on results of the 10-year analysis itself. As with all other RTEP expansion recommendations, those for ARRs will include the driver, cost, cost allocation and analysis of project benefits, provided that such projects will not otherwise be subject to a market efficiency cost/benefit analysis. Project costs are allocated across transmission zones based on each zone's Stage 1A eligible ARR flow contribution to the total Stage 1A eligible ARR flow on the facility that limits feasibility.

Results: 2022/2023 Stage 1A ARR 10-Year Analysis

During 2022, PJM staff completed a 10-year simultaneous feasibility analysis for 2022/2023 Stage 1A ARR selections. The power flow case used in the 10-year feasibility analysis is the same one used in the 2022/2023 annual ARR allocation, but without any modeled maintenance transmission outages. The results of the 10-year analysis identified a violation on a PJM internal facility. That facility is identified in **Table 3.8**. A solution to the address the violation has been analyzed as part of the 2022 RTEP process.

Table 3.8: 2022/23 Stage 1A ARR 10-Year Infeasible Facilities

Facility Name	Facility Type	Upgrade Expected To Fix Infeasibility
TMI 500 kV No. 1 transformer	Internal	Determination as part of 2022 RTEP development

NOTE:
PJM will recommend to the PJM Board a second 500/230 kV transformer at Three Mile Island that addresses the ARR violation.

Section 4: Market Efficiency

4.0: Scope

RTEP Process Context

PJM performs market efficiency analysis as part of the overall Regional Transmission Expansion Plan (RTEP) process to accomplish the following objectives:

- Identify new transmission enhancements or expansions that could relieve transmission constraints that have an economic impact
- Review costs and benefits of economic market efficiency-driven transmission projects previously included in the RTEP to assure that they continue to be cost beneficial
- Determine which reliability-driven transmission projects, if any, provide an economic market efficiency benefit if accelerated or modified
- Identify reliability-driven transmission projects already included in the RTEP that could be designed in a more robust manner in order to relieve one or more economic constraints or provide additional economic benefits

PJM identifies the economic benefit of proposed transmission projects by conducting production-cost simulations. These simulations show the extent to which congestion is mitigated by a project for specific study year transmission and generation dispatch scenarios. Economic benefits are determined by comparing future-year simulations both with and without the proposed transmission enhancement. The metrics and methods used to determine economic benefits are described in:

- PJM Manual 14B, Section 2.6
- PJM Operating Agreement, Schedule 6, Section 1.5.7

Market Simulation Analysis

To conduct a market efficiency analysis, PJM uses market simulation software that models forecast PJM market conditions. The results, from an hourly security-constrained generation commitment and economic dispatch algorithm, provide the basis for the specific project evaluation. Several evaluation cases are developed. The primary difference between these cases is the transmission topology to which the simulation data corresponds:

- An "as-planned" power flow case that models PJM Board-approved RTEP system enhancements in a five-year-out topology
- A power flow case that models the specific project under study

PJM determines a transmission project's economic value by comparing the results of these simulations across a set of study years and the associated transmission and generation modeled with each. These collective results are then utilized as part of benefit-to-cost ratio development to determine if a project does provide economic benefit. PJM also conducts input parameter sensitivity studies that provide additional information regarding the robustness of a project.

The input parameters for market efficiency studies are broadly described in **Section 4.1**. Importantly, the simulated transmission congestion results and published base case database provide key system information and fundamental trends to PJM stakeholders.

24-Month Cycle

PJM's 2022/2023 24-month market efficiency timeline is shown in **Figure 4.1**. The 2022 market efficiency body of analysis is represented by the first year of the 24-month cycle and focused on the following:

- Creating and reviewing with stakeholders base case models and results
- Reevaluating previously approved economic transmission projects
- Performing analysis that considers the benefits of accelerating baseline projects previously approved for reliability not yet built
- Identifying the congestion drivers associated with the 2022/2023 long-term window

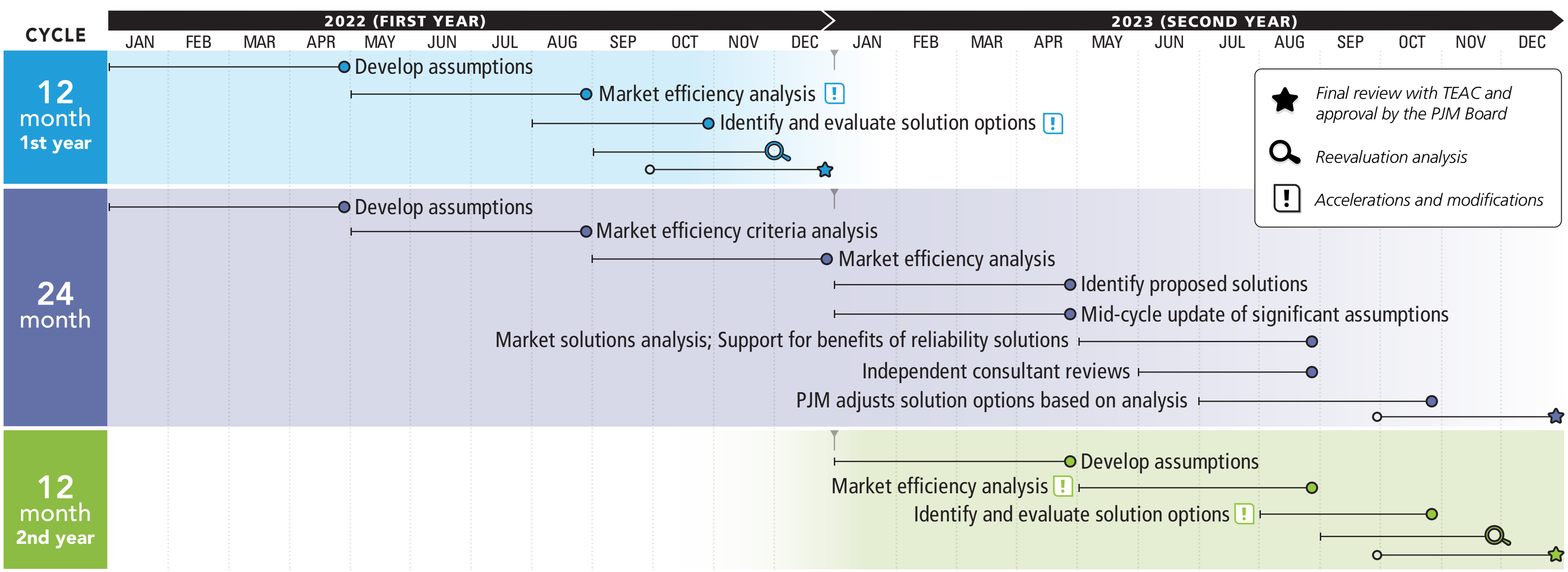
Long-Term Window Simulations

In order to quantify future longer-range transmission system market efficiency needs, PJM develops a simulation database for use as part of the 24-month long-term window study process. This database is mapped to the five-year-out RTEP case (i.e., "as-planned" topology).

The following future simulation years are included in the database used for the 2022/2023 24-month cycle: 2023, 2027, 2030 and 2033.

Congestion drivers will be identified using the cases developed during 2022 and will be posted before opening the 2022/2023 long-term proposal window, currently scheduled for 2023. PJM also develops updated market efficiency cases that incorporate significant RTEP modeling changes. The update case may include potentially significant forecast changes in topology, generation, load and fuel costs. The purpose for the update is to ensure that potential projects are evaluated using the best available case at the time.

Figure 4.1: 2022/2023 Market Efficiency 24-Month Cycle



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PJM calculates a benefit-to-cost ratio to determine if sufficient market efficiency justification exists for a particular transmission enhancement. The benefit-to-cost ratio is calculated by comparing the net present value of annual benefits for a 15-year period starting with the RTEP year compared to the net present value of the project's revenue requirement for the same 15-year period. Market efficiency transmission proposals that meet or exceed a 1.25 benefit-to-cost ratio threshold are further assessed to examine their economic, system reliability and constructibility impacts. PJM's Operating Agreement requires that projects with a total cost exceeding $50 million also undergo an independent third-party cost review.

For the majority of proposed projects, PJM determines market efficiency benefits based on energy market simulations. Transmission projects that may impact PJM Reliability Pricing Model auction activities derive additional economic benefit as determined through capacity market simulations.

Section 4.4 describes the 2022/2023 RTEP long-term proposal window progress. Training material is available on PJM's website.

Project Acceleration Analysis

PJM compares simulations of near-term topologies (i.e., "as-is" case) with those of planned topologies (i.e., "as-planned" case) to assess the individual and collective congestion benefits of RTEP transmission enhancements not yet in-service. For example, if a constraint causes significant congestion in the 2023 "as-is" simulation but not in the 2027 "as-planned" simulation, then the project that eliminates this congestion may be a candidate for acceleration. The acceleration cost is considered against the benefit of accelerating a project before any recommendation is made to the PJM Board.

This process allows PJM to perform the following:

- Quantify the transmission congestion reduction due to the collection of recently planned RTEP enhancements
- Reveal if specific, already-planned transmission enhancements may eliminate or relieve congestion so that the constraint is no longer an economic concern
- Identify if a project may provide benefits that would make it a candidate for acceleration or modification

During 2022, PJM quantified the transmission congestion reduction due to recently planned RTEP enhancements by comparing the simulation differences between the "as-is" topology and the "as-planned" topology for the 2023 and 2027 study years. **Section 4.2** describes results from this 2022 Project Acceleration Analysis.

Reevaluation of Previously Approved Market Efficiency Projects

Annual RTEP analysis includes a reevaluation of approved market efficiency projects from previous long-term window processes. The reevaluation criteria include the following:

- Projects that are under construction or that have a Certificate of Public Necessity (CPCN):
  - Are not required to be reevaluated
- Projects not under construction or without a CPCN with capital costs less than $20 million:
  - Will have projected costs updated while maintaining previously determined benefits
  - Should maintain a benefit-to-cost ratio greater than 1.25
- Projects not under construction or without a CPCN with capital costs greater than $20 million:
  - Will have projected costs updated and benefits reevaluated
  - Should maintain a benefit-to-cost ratio greater than 1.25

Section 4.3 describes the 2022 reevaluation of previously approved market efficiency transmission projects.

4.1: Input Parameters – 2022 Analysis

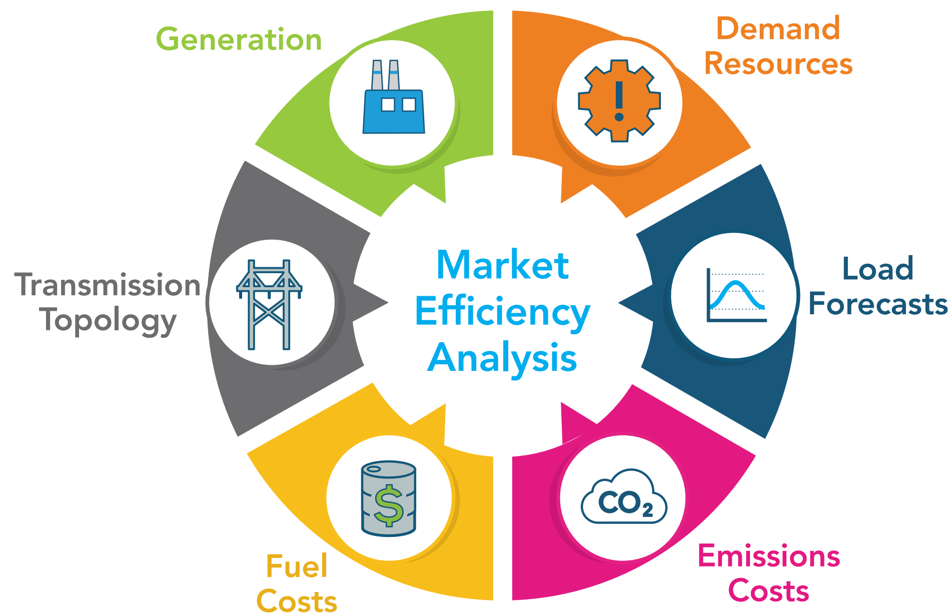
Overview
PJM licenses a commercially available database containing the necessary data elements to perform detailed PJM market simulations. This database is periodically updated with the most recent representation of the Eastern Interconnection, and in particular, PJM. The PJM Transmission Expansion Advisory Committee (TEAC) reviews the key analysis input parameters shown in **Figure 4.2**. These parameters include fuel costs, emissions costs, load forecasts, demand resource projections, generation projections, expected future transmission topology and several financial valuation assumptions.

Transmission Topology
Market efficiency power flow models were developed to represent:

- 2023 "as-is" transmission system topology
- 2027 "as-planned" system topology for the five-year-out RTEP year

PJM derived the "as-is" system topology from its review of the Eastern Interconnection Reliability Assessment Group's Series 2022 Multi-Regional Modeling Working Group 2023 summer peak case. It included transmission enhancements expected to be in service by the summer of 2023. PJM derived system topologies for 2027 market efficiency simulations from the 2027 RTEP baseline reliability power flow case and included significant RTEP projects approved during the 2022 RTEP cycle.

Figure 4.2: Market Efficiency Analysis Parameters



Monitored Constraints
Specific thermal and reactive interface transmission limits are modeled for each base topology. Monitored thermal constraints are based on actual PJM market activity, historical PJM congestion events, PJM planning studies or studies compiled by NERC.

PJM reactive interface limits are modeled as thermal values that correlate to power flows beyond which voltage violations may occur. The modeled interface limits are based on voltage stability analysis and a review of historical values. Modeled values of future-year reactive interface limits incorporate the impact of approved RTEP enhancements on the reactive interfaces.

Generation Modeled

Market efficiency simulations model existing in-service generation plus active, queued generation with at least an executed Interconnection Service Agreement (ISA). Planned generator deactivations that have given formal notification are removed from the model. The modeled generation provides enough capacity to meet PJM's installed reserve requirement through all study years, as shown in **Figure 4.3**.

Fuel Price Assumptions

PJM uses a commercially available database tool that includes generator fuel price forecasts. Forecasts for short-term gas and oil prices are derived from New York Mercantile Exchange future prices. Long-term forecasts for gas and oil are obtained from commercially available databases, as are all coal price forecasts. Vendor-provided basis adders are applied as well to account for commodity transportation cost to each PJM zone. The fuel price forecasts used in PJM's 2022 Market Efficiency Analysis are represented in **Figure 4.4.**

Figure 4.3: PJM Market Efficiency Reserve Margin

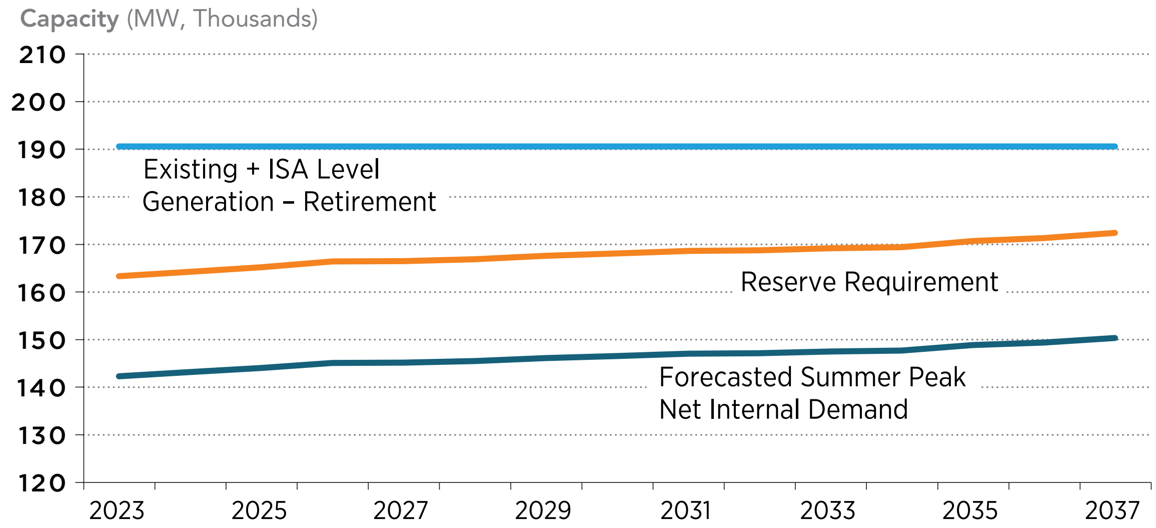
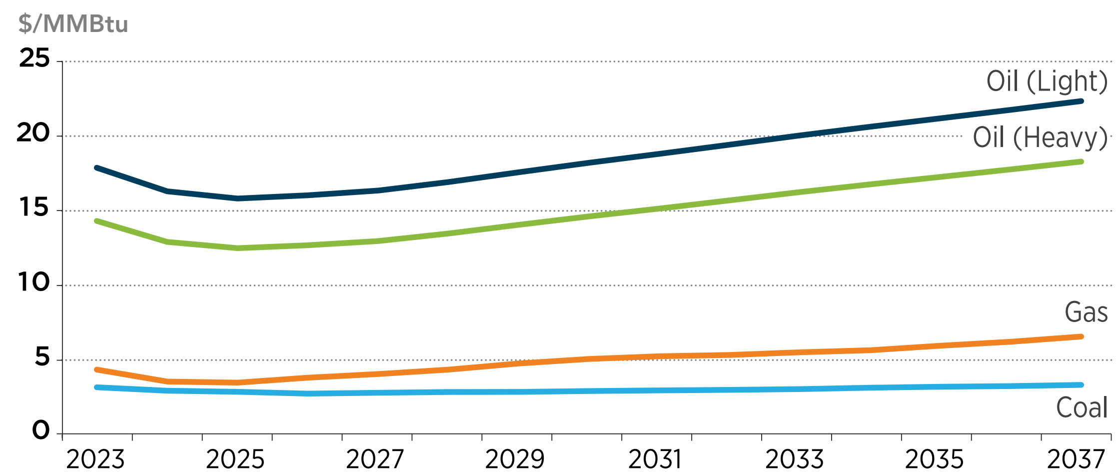


Figure 4.4: Fuel Price Assumptions



Load and Energy Forecasts

PJM's 2022 Load Forecast Report provided the transmission zone peak load and energy data modeled in market efficiency simulations. **Table 4.1** summarizes the PJM peak load and energy values used in the 2022 market efficiency cases.

Demand Resources

The amount of demand resources modeled in each transmission zone was based on the 2022 PJM Load Forecast Report. **Table 4.2** summarizes PJM demand resource totals by year.

Emission Allowance Price Assumptions

PJM currently models three major effluents – SO_2, NO_x and CO_2 – in its market efficiency simulations. SO_2 and NO_x emission price forecasts reflect implementation of the Cross-State Air Pollution Rule (CSAPR) and are shown in **Figure 4.5** and **Figure 4.6**, respectively. PJM unit CO_2 emissions are modeled as either part of the national CO_2 program or the Regional Greenhouse Gas Initiative (RGGI) program. Currently, Maryland, Delaware, New Jersey, Virginia and Pennsylvania participate in the RGGI.

Table 4.1: 2022 PJM Peak Load and Energy Forecast

Load	2023	2027	2030	2033	2037
Peak (MW)	149,351	152,322	153,775	154,767	157,689
Energy (GWh)	787,761	815,527	830,618	848,695	877,586

Table 4.2: Demand Resource Forecast

Demand Resource	2023	2027	2030	2033	2037
Demand Resource (MW)	7,065	7,167	7,219	7,253	7,348

Figure 4.5: SO_2 Emission Price Assumption

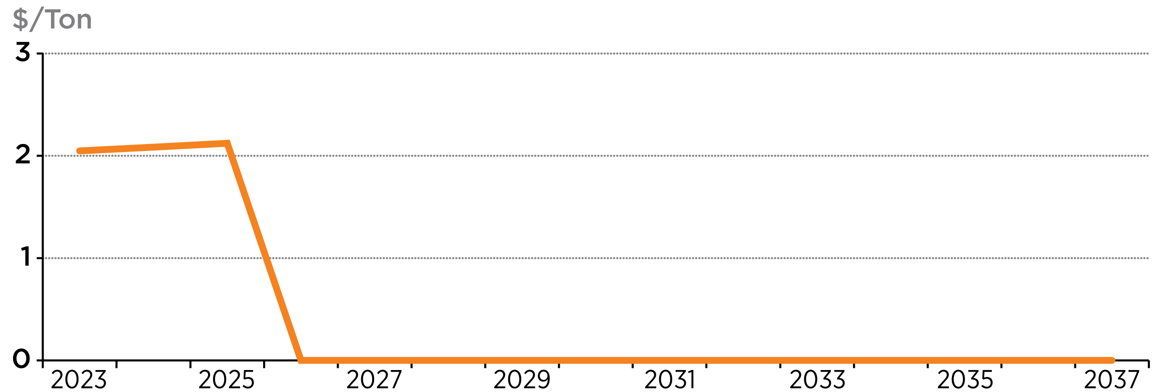
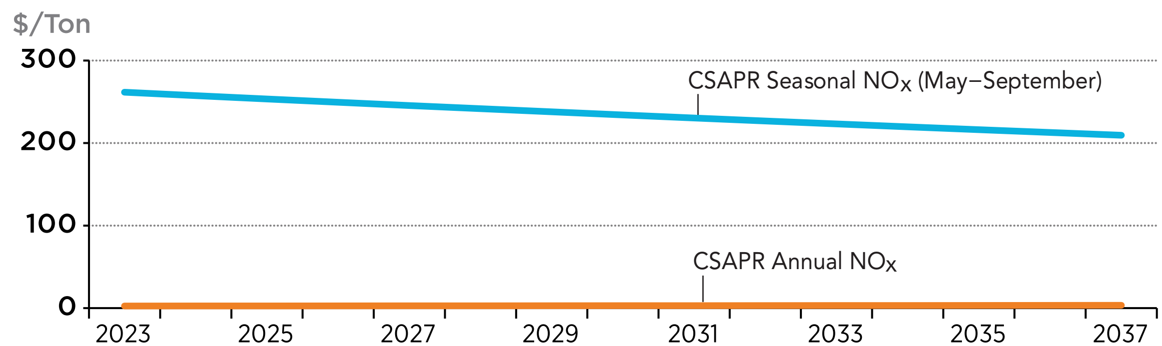


Figure 4.6: NO_x Emission Price Assumption

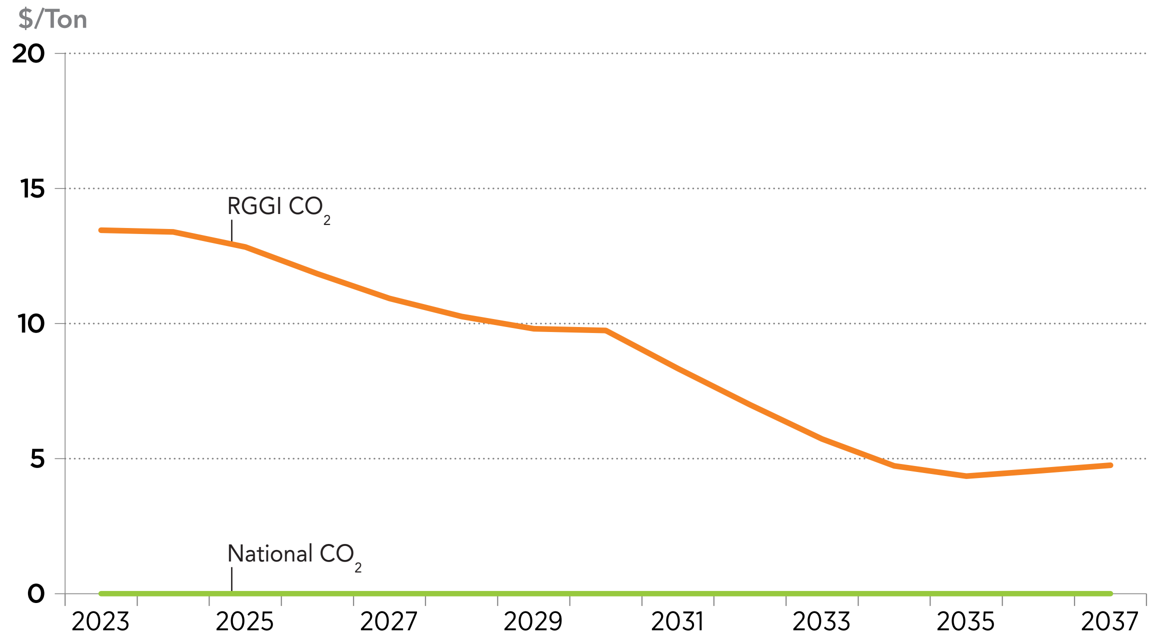


The base emission price assumption for both the national CO_2 and RGGI CO_2 program are shown in **Figure 4.7**.

Carrying Charge Rate and Discount Rate

The evaluation of proposed market efficiency projects requires a benefit-to-cost analysis. As part of this evaluation, the present value of annual benefits projected for a 15-year period starting with the RTEP year is compared to the present value of the annual cost for the same period. If the benefit-to-cost ratio exceeds a threshold of 1.25:1, then the project can be recommended for inclusion in the PJM RTEP. The annual cost of the upgrade will be based on the total capital cost of the project, multiplied by a levelized annual carrying charge rate. A discount rate will be used to determine the present value of the project's annual costs and annual benefits. The annual carrying charge rate and discount rate are developed using information contained in the transmission owners' formula rate sheets and incorporated in the Transmission Cost Information Center (TCIC) available on PJM's website. The annual carrying charge rate and discount rate for this 2022 market efficiency analysis are 11.59% and 7.26%, respectively.

Figure 4.7: CO_2 Emission Price Assumption



4.2: 2022 Results From Project Acceleration Analysis

PJM's 2022 cycle of analysis included near-term simulations for study years 2023 and 2027. They identified collective and constraint-specific transmission system congestion due to the impacts of previously approved RTEP projects not yet in service. PJM conducted the simulations under two different transmission topologies:

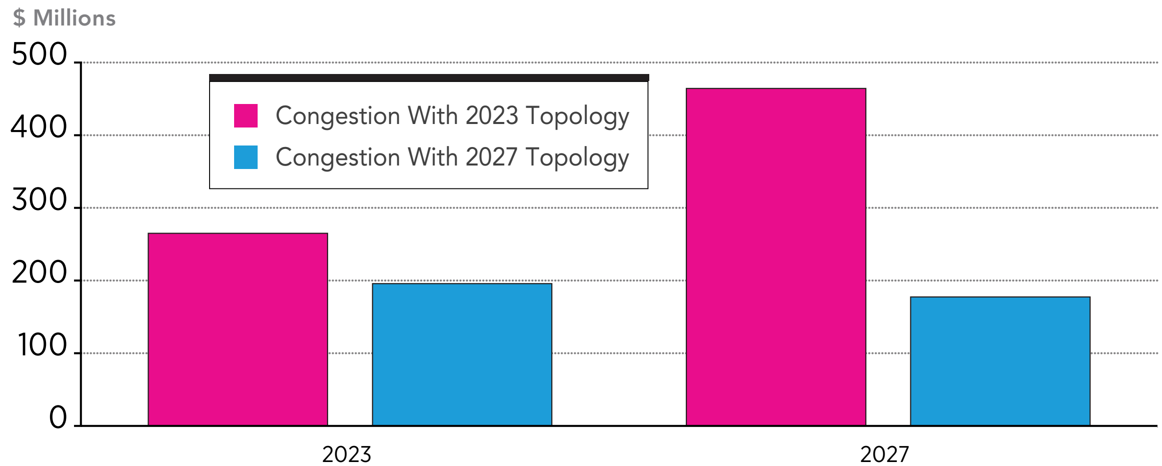
1. 2023 "as-is" PJM transmission system topology
2. 2027 "as-planned" RTEP PJM transmission system topology

By comparing results of multiple simulations with the same fundamental supply, demand, and operating constraints but with differing transmission topologies, the economic value of a transmission enhancement can be determined. This technique allows PJM to perform the following:

1. Value collectively the congestion benefits of approved RTEP upgrades
2. Evaluate the congestion benefits of accelerating or modifying specific RTEP projects

PJM congestion costs from market simulations for study years 2023 and 2027 are shown in **Figure 4.8**. Results identified annual congestion cost reductions of more than $69 million (26%) for 2023 and more than $286 million (61%) for 2027 using the 2027 RTEP topology. RTEP enhancements that are approved but not yet in service account for the reduction in congestion.

Figure 4.8: Simulated PJM Congestion Costs – 2023, 2027



Project-Specific Acceleration Analysis

PJM identified and evaluated specific RTEP enhancements that were most responsible for the congestion reductions identified in the acceleration simulations. The majority of identified baseline reliability enhancements, viewed within the context of the short-term analysis, will not be recommended for acceleration. These projects provide neither significant congestion benefits in the acceleration analysis, nor are they practical to accelerate, because they have a near-term in-service date or because their scope prevents them from being completed earlier.

Two related baseline reliability-driven projects did satisfy PJM criteria to be accelerated for market efficiency gains. As summarized in **Table 4.3** baseline project B3694 – parts 10 through 13 – involves reconductoring the Hopewell-Chesterfield 230 kV lines ‘A’ and ‘B’ with related upgrades to station equipment. At no additional cost, the projects will be advanced from June 2026 to June 2025 in order to alleviate projected congestion costs.

Table 4.3: RTEP Projects Reducing Specific Congestion Drivers: 2023 Analysis

				2023 Study Year		
				2023 Topology	2027 Topology	
Constraint Name	Upgrade Associated With Congestion Reduction	Area	Type	2023 Congestion ($M)	2023 Congestion ($M)	Congestion Savings ($M)
Hopewell-Chesterfield A 230 kV	**B3694 (10-13):** Reconductor ~2.9 miles of 230 kV line. Upgrade station equipment at Chesterfield and Hopewell.	Dominion	LINE	$7.7	$0.0	$7.7
Hopewell-Chesterfield B 230 kV	**B3694 (10-13):** Reconductor ~2.9 miles of 230 kV line. Upgrade station equipment at Chesterfield and Hopewell.	Dominion	LINE	$1.9	$0.0	$1.9

Note: The congestion savings for the 2023 study year are calculated as the difference in simulated congestion between with as-is topology and the RTEP topology.

4.3: Reevaluation of Previously Approved Market Efficiency Projects

PJM's 2022 analysis included a reevaluation of approved market efficiency projects from previous long-term windows. The reevaluation criteria include the following:

- Projects that are under construction or that have a Certificate of Public Necessity (CPCN):
  - Are not required to be reevaluated
- Projects not under construction or without a CPCN with capital costs less than $20 million:
  - Will have projected costs updated while maintaining previously determined benefits
  - Should maintain a benefit-to-cost ratio greater than 1.25
- Projects not under construction or without a CPCN with capital costs greater than $20 million:
  - Will have projected costs updated and benefits reevaluated
  - Should maintain a benefit-to-cost ratio greater than 1.25

In accordance with the second reevaluation criterion, PJM analyzed three previously approved market efficiency projects. All were in the engineering phase and have not yet begun construction. Cost estimates for these projects have not changed. Reevaluation results, shown in **Table 4.4,** revealed that the benefit-to-cost ratios are in excess of the 1.25 threshold and continue to justify market efficiency need for all three projects.

Table 4.4: Market Efficiency Projects Not Under Construction With Cost Less Than $20 Million

Project ID	Baseline	Type	Area	Constraint	Status	In-Service Date	Cost ($M)	Benefit-to-Cost Ratio	Description
202021_1-704	B3697	Upgrade	PECO	Plymouth-Whitpain 230 kV	Engineering and Procurement Status	6/1/2025	$0.62	75.3	Replace station equipment at Whitpain and Plymouth 230 kV.
202021_1-218	B3698	Upgrade	PPL	Juniata-Cumberland 230 kV		12/31/2023	$8.99	11.28	Reconductor 14.2 miles of Juniata-Cumberland 230 kV.
202021_1-651	B3702	Upgrade	Dominion	Charlottesville-Proffit 230 kV		11/1/2023	$11.38	16.05	Install series reactor on Charlottesville-Proffit 230 kV.

Likewise, in accordance with the third reevaluation criterion, PJM analyzed one previously approved project with a capital cost greater than $20 million that has not yet begun construction nor has received full CPCN certification.

This specific RTEP transmission enhancement, known as Project 9A, comprises baseline elements B2742 and B2752 as shown on **Map 4.1**.

In September 2021, the PJM Board endorsed PJM's recommendation to suspend the project, due to siting risks, in order to remove it from RTEP power flow models, pending any future developments in the regulatory process.

Table 4.5 summarizes the 2022 market efficiency reevaluation showing project 9A with a benefit-to-cost ratio of 2.48.

Map 4.1: Project 9A – RTEP Baseline Project B2743 and B2752

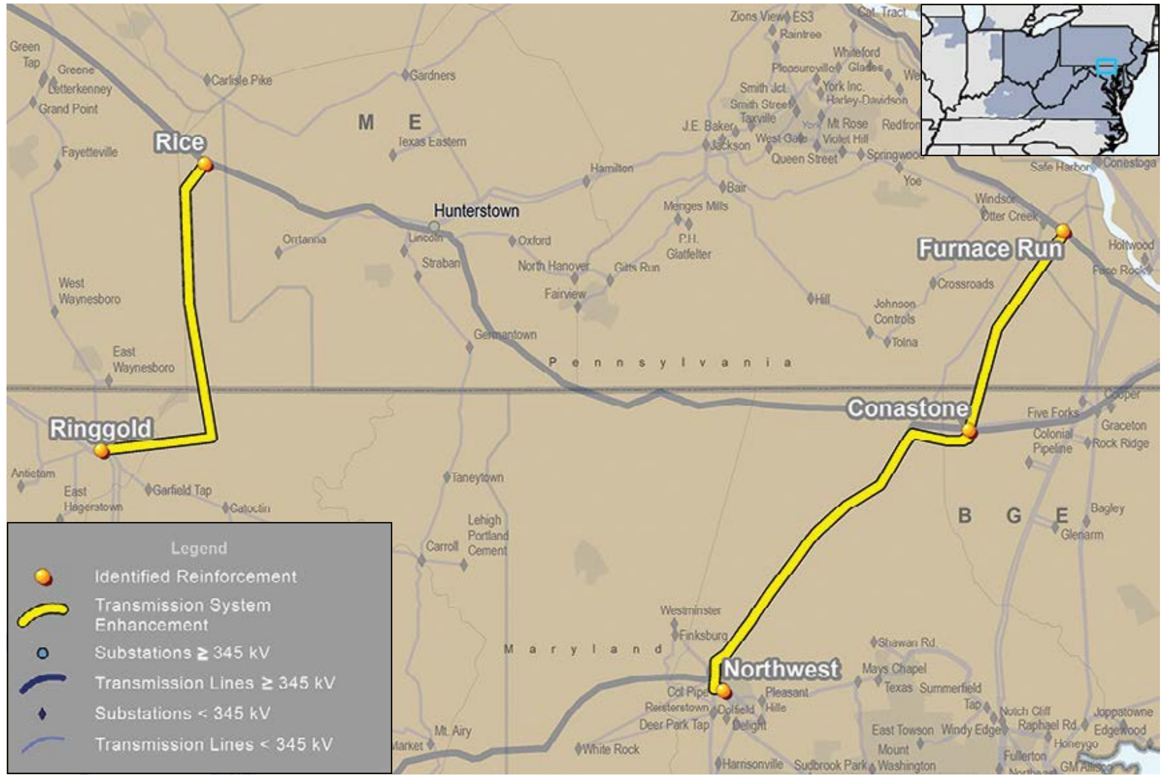


Table 4.5: 2022 Reevaluation of Project 9A

Reevaluation	Benefit-to-Cost Ratio November 2022 (In-Service Project Cost)	Notes
Project 9A Base Case Analysis	2.48	Benefit-to-Cost Ratio (Sunk Costs Excluded*) = 3.47
		In-Service Cost: $428.76 Million
		Sunk Cost: $136.27 Million

* Sunk costs represent unavoidable costs.

4.4: 2022/2023 RTEP Long-Term Proposal Window

During 2022, PJM conducted market simulations for study years 2023, 2027, 2030 and 2033 to identify and quantify long-term transmission system congestion. These simulations used the 2027 RTEP "as-planned" transmission system topology and included RTEP projects approved through the 2022 RTEP cycle.

Overall, these long-term congestion studies have identified growing levels of congestion when compared to recent RTEP cycles. This is due, in part, to:

- Higher gas-price assumptions coupled with generation portfolio shifts that include increased high-efficiency, gas-fired generation
- Higher forecast load growth, primarily in the Dominion Zone, increasing power flow levels into the area

Table 4.6: Preliminary 2022 Base Case Congestion for 2027

Constraint	Area	Type	2027 Congestion ($M)
Black Oak-Bedington Interface	AP	Interface	$36.19
BC-PEPCO Interface	BGE-PEPCO	Interface	$34.43
AP South Interface	AP	Interface	$13.81
AEP-Dominion Interface	AEP-Dominion	Interface	$9.73
Yorkana-Brunner Island 230 kV	METED-PPL	Line	$11.99
Five Forks-Rock Ridge 115 kV	BGE	Line	$4.76
Graceton-Bagley 230 kV	BGE	Line	$4.30
Face Rock 115/69 kV	PPL	Transformer	$3.46
Hunterstown-Lincoln 115 kV	METED	Line	$1.55
Smith Mountain-Museville 138 kV	AEP	Line	$1.02

1) Preliminary results, not final congestion drivers. List of constraints and congested areas may change in the final base case.
2) Included only flowgates with binding hours > 25 hours and annual simulated congestion > $1 million.

PJM will solicit stakeholder proposals for market efficiency projects as part of an RTEP proposal window focusing on congestion identified in the 2022 long-term analysis. The 2022/2023 RTEP long-term proposal window is scheduled to open in 2023. It will seek solution alternatives to resolve or alleviate market efficiency congestion identified in the long-term simulations.

Market efficiency evaluation criteria include the following, which are further described in PJM Manual 14F: Competitive Planning Process. Projects must address a specified congestion driver and produce a benefit-to-cost ratio greater than 1.25. Proposals with costs in excess of $50 million are subject to an independent cost review. Other factors considered in selecting a successful project include risk assessment, model sensitivity evaluation, reliability impact and outage impact.

Table 4.6 shows congested facilities and their respective congestion levels from PJM's preliminary 2022 base case for 2027. PJM is currently evaluating the impact of the 2023 PJM load forecast on potential congestion drivers, before opening the proposal window. The market efficiency base case and the associated congestion drivers will be communicated before the start of 2022/2023 long-term window.

NOTE:
The opening of the 2022/2023 RTEP long-term window will be delayed until the reliability violations for the 2022 window No. 3 are addressed. Updated information on this and other RTEP proposal windows is available on Competitive Planning Process page of the PJM website.

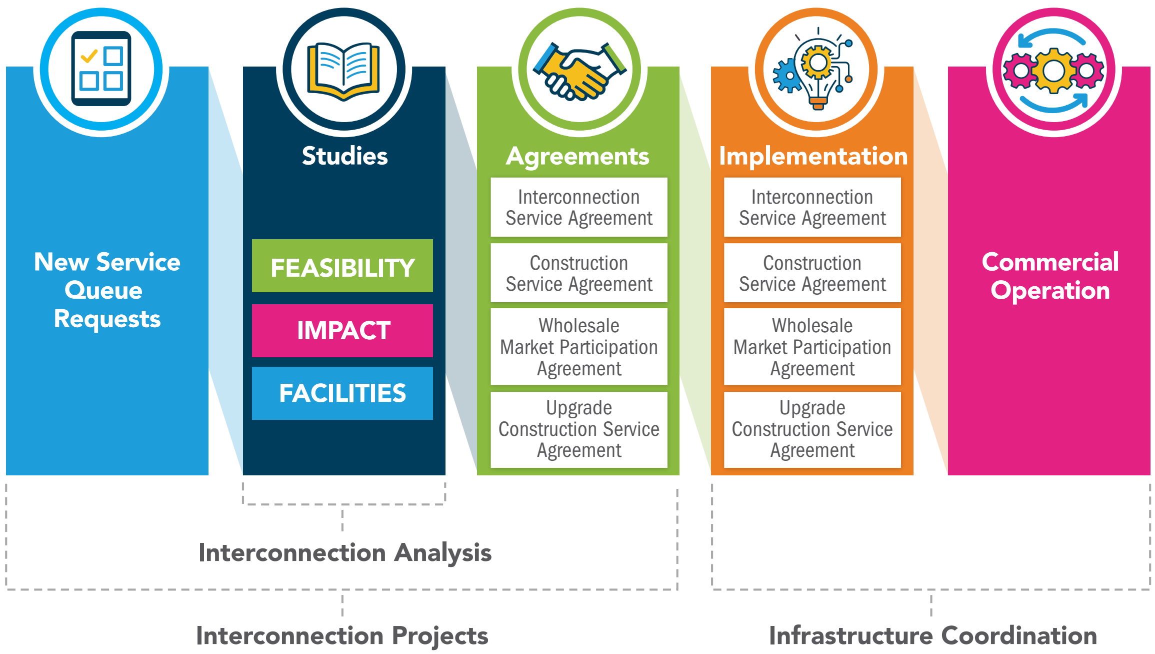
Section 5: Facilitating Interconnection

5.0: Interconnection Reliability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. The PJM Board has approved network transmission projects totaling $6.2 billion since the inception of the RTEP process in 1999. Approved network projects in 2022 have totaled $224.98 million. As described in **Section 1.2**, PJM tests for compliance with NERC and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

PJM's generator deliverability test prescribes the test conditions for ensuring that sufficient transmission capability exists to deliver generating capacity reliably from a defined generator or area to PJM load. In addition to generator interconnection requests, PJM conducts this power flow test as part of a baseline analysis under summer and winter peak load conditions, when capacity is most needed to serve load, as well as under light load conditions to ensure that a range of resource combinations and conditions is examined.

Figure 5.1: New Services Queue Process Overview



Queue Process Overview

During 2022, queue activity was impacted by the ongoing queue reform activities. PJM's queue process was frozen for over one year in order to clean up backlog and prepare for interconnection queue reform, as described later in this section. PJM's interconnection queue process consists of five phases shown in **Figure 5.1**. Requests for generation interconnection can be submitted during one of two six-month queue windows: April through September and October through March.

During the feasibility study phase, PJM performs initial, high-level power flow analysis at the point of interconnection specified by the developer, who can also designate a secondary, optional point of interconnection to be evaluated as well. PJM targets feasibility study completion within 120 days after each window closes.

During the system impact study phase, the project developer elects one of the two points of interconnection it has requested. The study is targeted to be completed within 120 days after the start of the system impact study phase for the queue – or 120 days after the study agreement is signed – whichever is later. During this phase, PJM also coordinates with neighboring entities to conduct an affected system study, if applicable. The facilities study phase is targeted to be completed approximately six months after the Facilities Study Agreement has been executed. This study is conducted by the transmission owner.

During the feasibility study phase, the project is evaluated at a primary and a secondary (optional) point of interconnection for power flow and short-circuit analysis. During the impact study phase, PJM performs power flow and short-circuit analyses and coordinates with neighboring entities to conduct an affected system study, if applicable. During the facilities study phase, PJM performs power flow, short-circuit and stability analyses to ensure the project's reliable interconnection to PJM's system. When the study phases have been completed, the project developer signs an Interconnection Service Agreement (ISA) and the Construction Service Agreement, which describe the milestones, point of interconnection, system upgrades and construction responsibilities that are associated with the project. The ISA also confers the rights associated with the interconnection of a generator as a capacity resource, including Capacity Interconnection Rights. **Section 5.3** discusses interconnection queue process initiatives in 2022 and beyond, including those arising out of the Interconnection Process Request Task Force stakeholder process and in compliance with FERC's recent Generation Interconnection Process NOPR.

5.1: Interconnection Queue Initiatives

Interconnection Process Reform

In 2021, the Interconnection Process Reform Task Force (IPRTF) was charged with developing improvements to the existing interconnection process in order to reduce queue backlog and increase efficiency. After months of stakeholder engagement through the IPRTF, PJM's new interconnection process package and proposal to transition to the new interconnection process were endorsed by the Planning Committee in January and February 2022, respectively. The final vote by the PJM Members Committee occurred during the April 27, 2022, meeting with the proposed reforms, as amended during the May 17, 2022, Members Committee meeting, garnering the overwhelming support of PJM stakeholders.

FERC Filing

On June 14, 2022, PJM filed Tariff revisions for interconnection process reform with FERC. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process New Service Requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach utilized by other regional transmission organizations and stand-alone transmission providers. The reforms detailed in the filing represent the culmination of an eighteen-month stakeholder effort through the IPRTF.

The filing's reforms include:

- Moving from a serial queue process to a clustered cycle process for both studies and cost allocation
- Implementation of multiple decision points at which project developers and other parties seeking interconnection-related services will need to provide readiness deposits and meet other threshold requirements to move forward, thus permitting projects that are ready to progress to do so while incentivizing projects that are not ready to proceed to exit the interconnection process
- A transition mechanism to ensure a timely transition to the new "first-ready, first-served" cycle approach while providing an expedited process for projects in the existing interconnection queue that are close to completing that process (the "Expedited Process")
- Consolidation of PJM's interconnection-related service agreements and forms that will be used for the Part VII transition process and the Part VIII New Rules set forth in new Part IX of the Tariff.

The interconnection reforms are set forth in their entirety in FERC Docket No. ER22-2110.

FERC Approval

On Nov. 29, 2022, FERC issued an order conditionally approving PJM's interconnection reform filing, subject to two compliance filings, one of which has already been submitted by PJM. Pursuant to the Commission's order, PJM's new Tariff Parts VII and IX have an effective date of Jan. 3, 2023; these Tariff provisions have already been merged into PJM's Tariff. The transition to the new interconnection process will occur when all AD2 and prior queue window ISAs or WMPAs have been executed or filed unexecuted.

Interconnection Planning Subcommittee

The Interconnection Planning Subcommittee (IPS) was established by the Planning Committee in April 2022 to continue the work of the IPRTF. The purpose of the IPS is to provide a stakeholder forum to investigate and resolve specific issues related to the interconnection process and associated agreements, governing documents and manuals. Moving forward, the IPS will be the main environment for communicating details of the implementation of the new interconnection process, as well as for discussing further improvements to the interconnection process in the future.

FERC Interconnection Process NOPR

The interconnection reform and the interconnection NOPR agree philosophically on many issues, including the transition to a first-ready, first-served model. However, the details of implementation are different and were consolidated in PJM's comments on the NOPR detailed in FERC Docket RM22-14.

5.2: New Services Queue Requests

Interconnection Activity

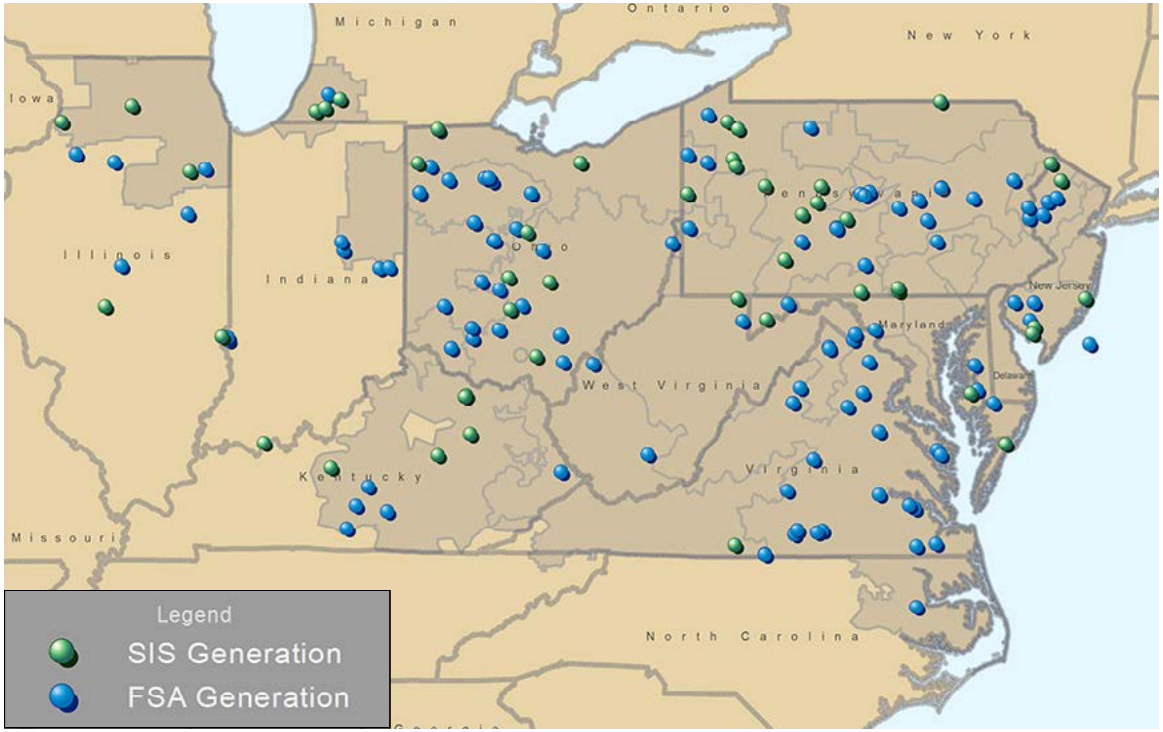
The generation interconnection process encompasses three sequential study phases – feasibility, system impact and facilities studies – to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets.

Generation Queue Activity

PJM markets have attracted generation proposals totaling 831,921 MW, as shown in **Table 5.1**. 254,781 MW of interconnection requests were actively under study during 2022. PJM analyzed and issued study reports for 52 system impact studies and 135 facilities studies, as shown on **Map 5.1**.

Over 26,000 MW of new generation was under construction as of Dec. 31, 2022, across all fuel types. While withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, regulatory, industry, economic and other competitive factors. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities.

Map 5.1: Feasibility and System Impact Studies Performed in 2022



In 2022:

PJM received 610 new service requests representing 77,267 MW (energy) of generation and 42,333 MW of Capacity Interconnection Rights.

PJM issued agreements allowing construction activities to begin for 548 interconnection requests representing 38.2 GW.

PJM issued a total of 204 system impact and facilities studies for a total of 17.6 GW.

Note: No feasibility studies were issued in 2022 due to PJM's queue process reform.

Go to Next Section >

Queue Progression History

PJM reviews generation queue progression annually to understand overall developer trends more fully and their impact on PJM's interconnection process. **Figure 5.2** shows that for generation submitted in Queue A (1999) through Dec. 31, 2022, only 69,997 MW – 15.5% – reached commercial operation. Note that **Figure 5.2** reflects requested Capacity Interconnection Rights, which are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants.

Following the execution of an ISA or wholesale market participant agreement (WMPA), 29,663 MW of capacity with ISAs and 1,385 MW of capacity with WMPAs withdrew from PJM's interconnection process.

Table 5.1: Queued Study Requests (Dec. 31, 2022)

	Projects	Energy (MW)	Capacity (MW)
Active	2,664	254,781	163,125
In Service	1,006	80,681	67,298
Under Construction	439	26,467	18,730
Withdrawn	3,660	469,993	363,065
Total	**7,769**	**831,922**	**612,218**

Overall, 53.4% of projects that requested uprates to existing capacity reached commercial operation. Only 12.7% of new generator requests, by megawatt, reached commercial operation.

NOTE:
Figure 5.2 reflects requested capacity interconnection rights, which are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants.

Figure 5.2: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2022)

			Capacity	Nameplate
Projects withdrawn after final agreement	203	Interconnection Service Agreements	29,663 MW	38,580 MW
	338	Wholesale Market Participation Agreements	1,385 MW	2,781 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.0: Delaware RTEP Summary

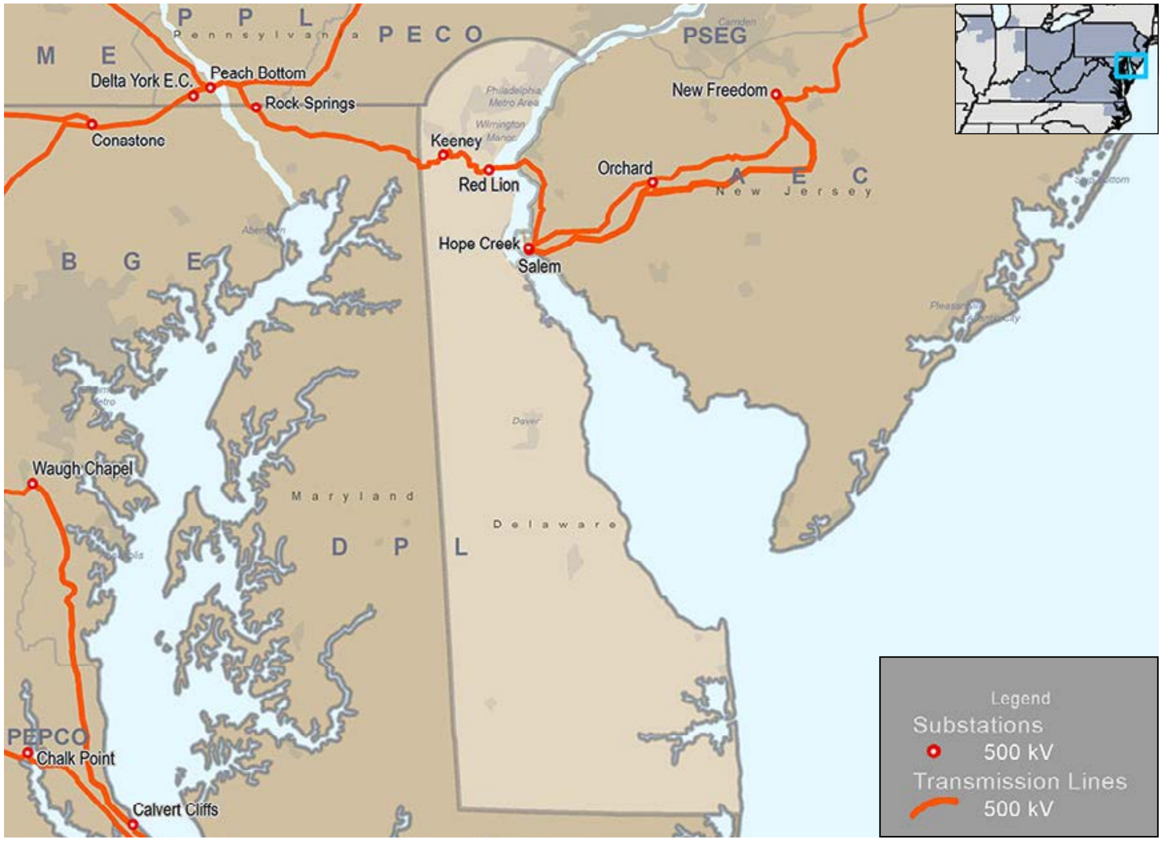
6.0.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Delaware, including facilities owned and operated by Delaware Municipal Electric Corporation (DEMEC), Delmarva Power & Light (DP&L) and Old Dominion Electric Cooperative (ODEC) as shown on **Map 6.1**. Delaware's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside PJM.

Renewable Portfolio Standards

Delaware has a mandatory renewable portfolio standard (RPS) of 40% by 2035. This target includes a minimum solar carve-out of 10% by 2035 as well.

Map 6.1: PJM Service Area in Delaware



6.0.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.1** summarizes the expected loads within the state of Delaware and across the PJM region.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

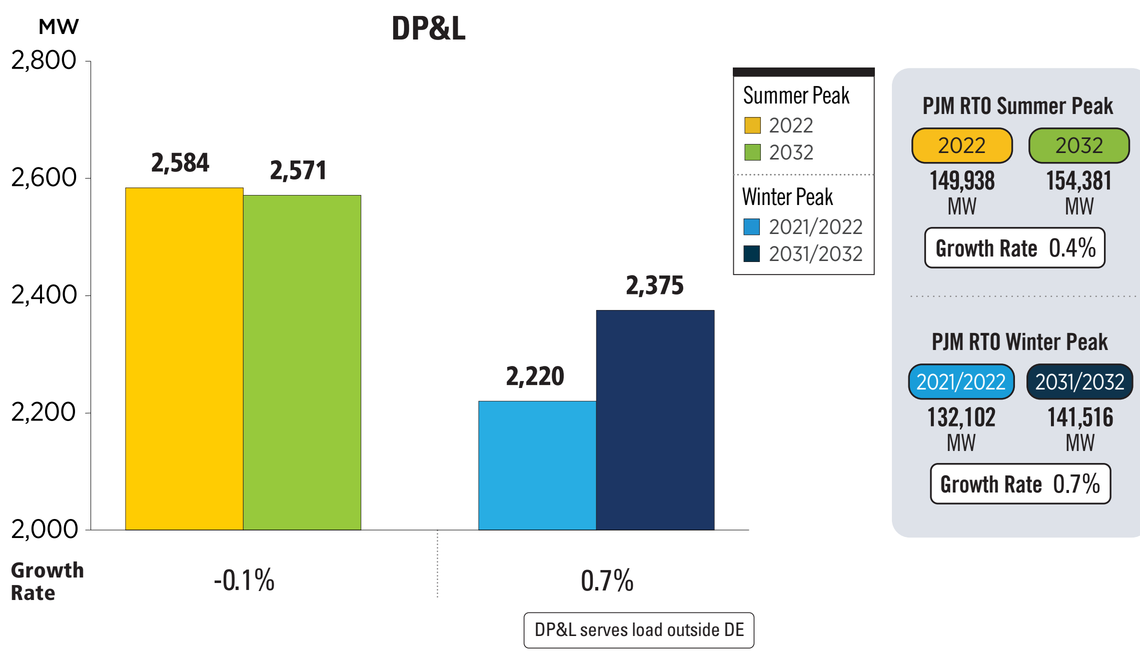
The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

Figure 6.1: Delaware – 2022 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.0.3 — Existing Generation

Existing generation in Delaware as of Dec. 31, 2022, is shown by fuel type in **Figure 6.2**.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

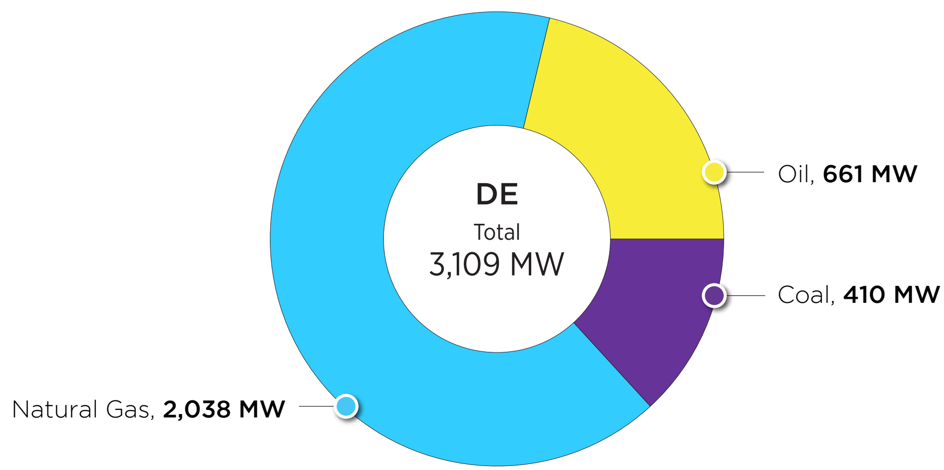
- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in Delaware as of Dec. 31, 2022, are discussed next, in **Section 6.0.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

Figure 6.2: Delaware – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



6.0.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Delaware, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Delaware, as of Dec. 31, 2022, 32 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.1, Table 6.2, Figure 6.3, Figure 6.4** and **Figure 6.5**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.1: Delaware – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	Delaware Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	0	0.00%	529	0.61%
Natural Gas	0	0.00%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	0	0.00%	273	0.31%
Solar	297	21.22%	57,616	66.37%
Storage	40	2.87%	14,148	16.30%
Wind	1,061	75.90%	6,223	7.17%
Grand Total	**1,398**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.2: Delaware – Interconnection Requests (Dec. 31, 2022)

		In Queue				Complete				Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	2	23.0	1	630.0	3	653.0
	Natural Gas	0	0.0	1	451.0	18	1,281.1	19	5,556.4	38	7,288.5
	Oil	0	0.0	0	0.0	5	168.2	1	1.0	6	169.2
	Other	0	0.0	0	0.0	2	26.3	1	0.0	3	26.3
	Storage	2	40.2	1	0.0	0	0.0	4	45.0	7	85.2
Renewable	Biomass	0	0.0	0	0.0	1	0.0	4	24.0	5	24.0
	Methane	0	0.0	0	0.0	4	9.0	3	28.8	7	37.8
	Solar	6	296.8	10	99.9	0	0.0	24	263.8	40	660.4
	Wind	11	1,061.4	1	64.4	0	0.0	5	396.9	17	1,522.7
	Grand Total	**19**	**1,398.4**	**13**	**615.3**	**32**	**1,507.6**	**62**	**6,945.9**	**126**	**10,467.1**

Figure 6.3: Delaware – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

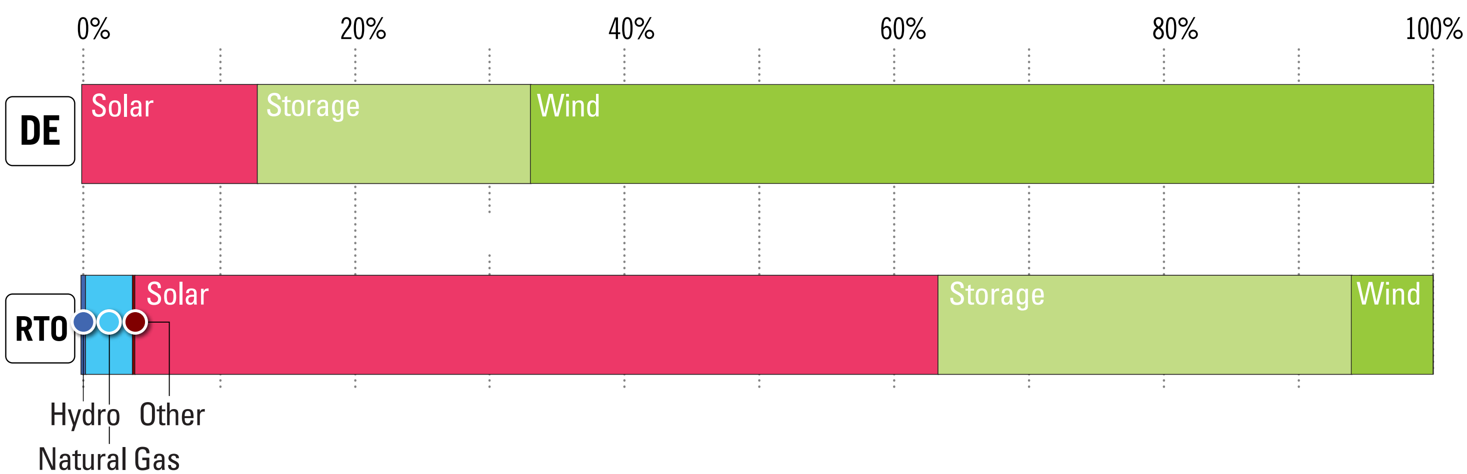
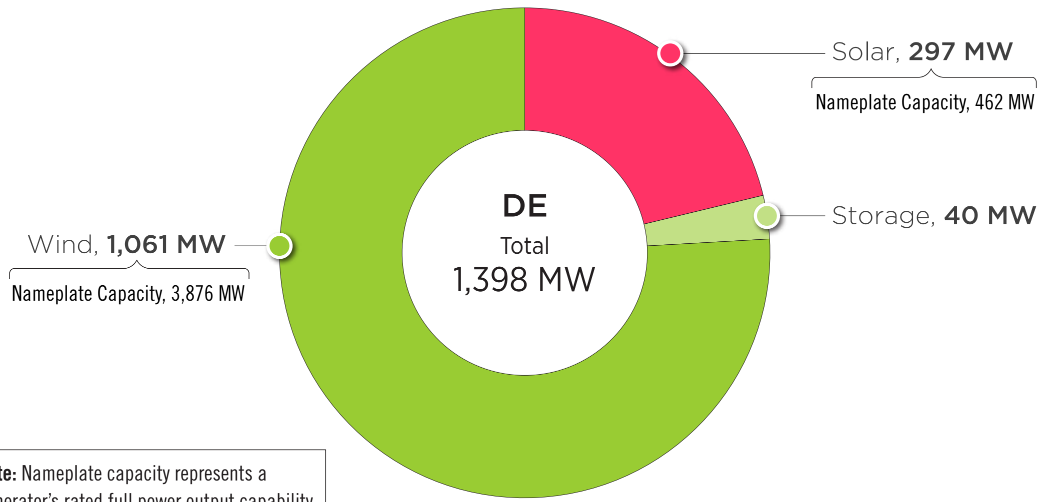


Figure 6.4: Delaware – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.5: Delaware Progression History of Queue – Interconnection Requests (Dec. 31, 2022)

Percentage of planned capacity and projects that have reached commercial operation

- 16.2% Requested capacity megawatts
- 26.7% Requested projects

Projects withdrawn after final agreement			Capacity	Nameplate
	3	Interconnection Service Agreements	420 MW	780 MW
	6	Wholesale Market Participation Agreements	17 MW	54 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.0.5 — Generation Deactivation

There were no generating unit deactivation requests in Delaware between Jan. 1, 2022, and Dec. 31, 2022, as part of the 2022 RTEP.

6.0.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in Delaware are summarized in **Map 6.2** and **Table 6.3**.

6.0.7 — Network Projects

No network projects in Delaware were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.0.8 — Supplemental Projects

There were no supplemental projects in Delaware between Jan. 1, 2022, and Dec. 31, 2022, as part of the 2022 RTEP.

6.0.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Delaware were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.2: Delaware Baseline Projects (Dec. 31, 2022)

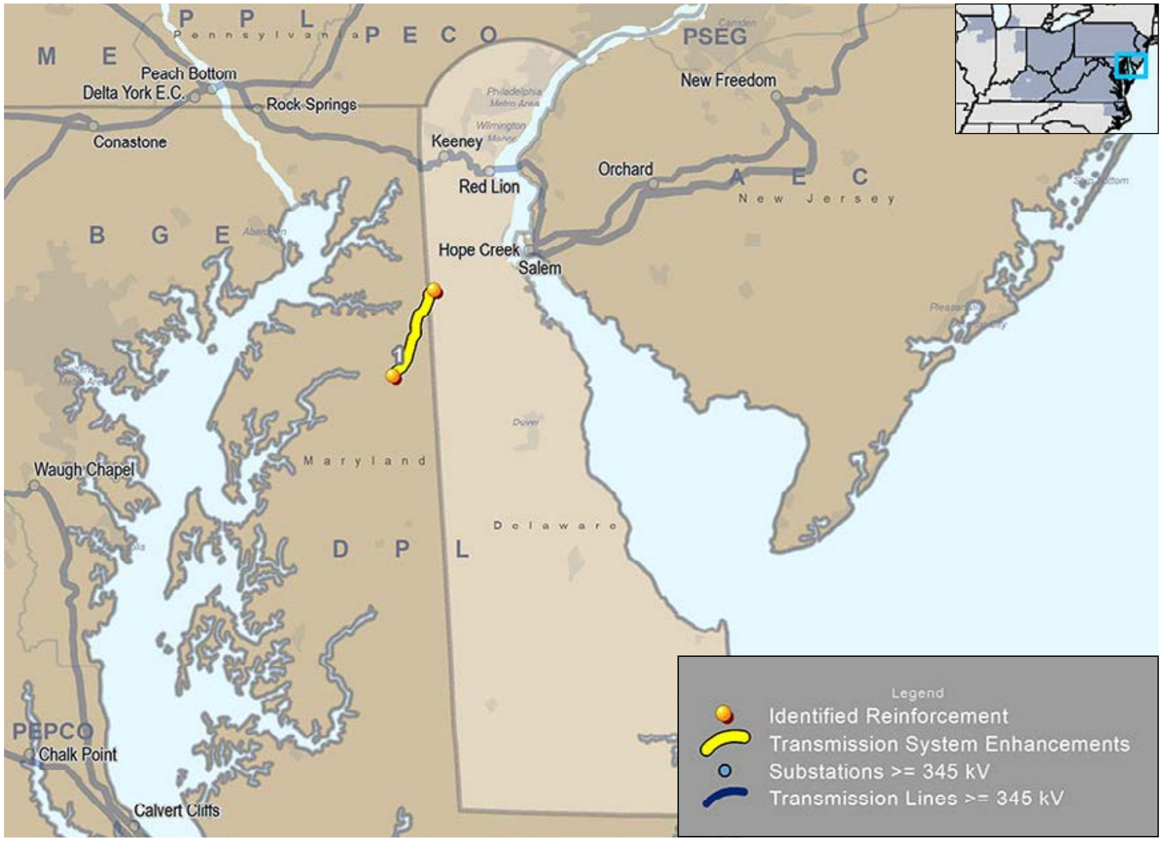


Table 6.3: Delaware Baseline Projects (Dec. 31, 2022)

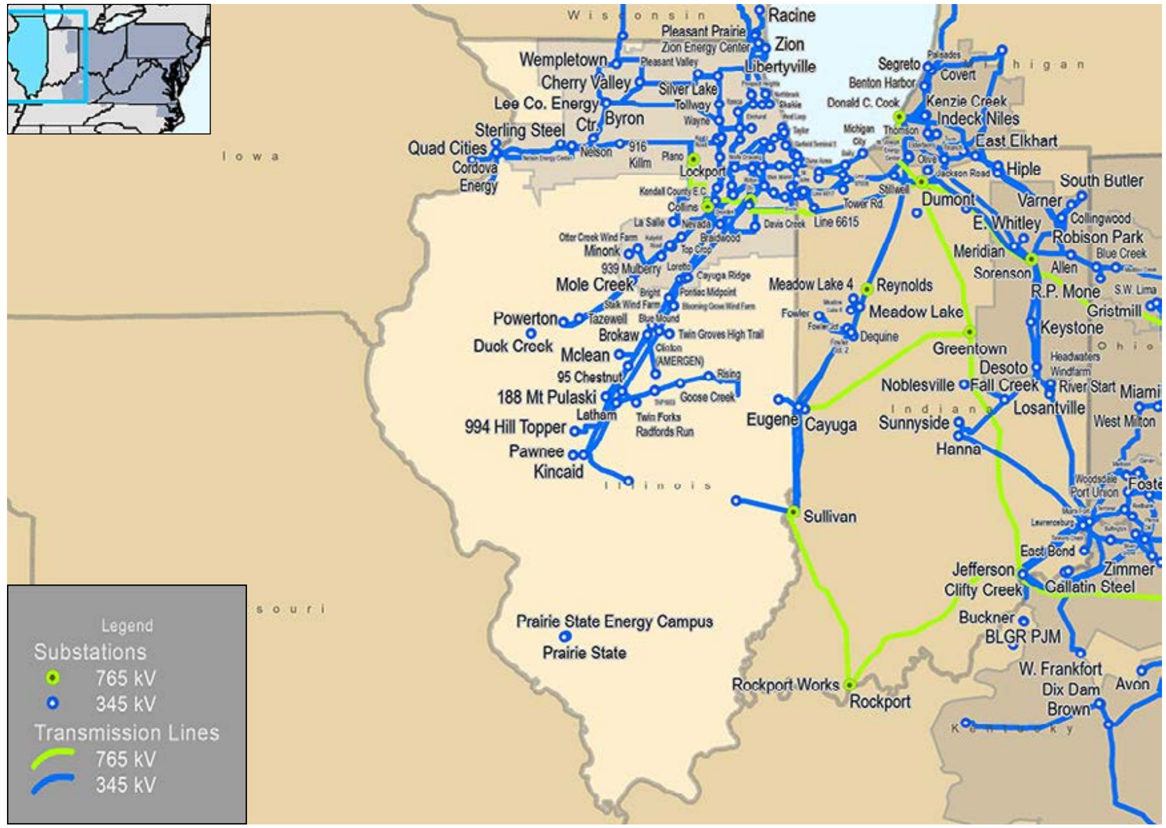
Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3669	.2	Replace terminal equipment (circuit breaker) at Townsend substation (Townsend-Church 138 kV).	12/1/2026	$0.45	DP&L	11/18/2021

6.1: Northern Illinois RTEP Summary

6.1.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in northern Illinois, including facilities owned and operated by Commonwealth Edison (ComEd) and the City of Rochelle as shown on **Map 6.3**. The transmission system in northern Illinois delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Map 6.3: PJM Service Area in Northern Illinois



Renewable Portfolio Standards

Illinois has a mandatory renewable portfolio standard (RPS) of 40% renewable energy by 2030 and 50% renewables by 2040. The RPS target was established by the Climate and Equitable Jobs Act (CEJA), which was enacted in 2021 and contains specific carve-outs for wind and solar. CEJA also established a clean electricity goal of 100% for Illinois by 2050.

CEJA contains a number of provisions to advance Illinois' decarbonization efforts. It requires all privately owned facilities that use coal or oil to reduce their carbon emissions to zero by 2030. Publicly owned coal facilities must reduce CO_2 emissions 45% by 2035 and be zero-carbon by 2045. Privately owned natural gas facilities must reduce their carbon emissions to zero on a tiered schedule ranging from 2030 to 2045 depending on proximity to designated environmental justice communities as well as operating parameters and emission intensity. In certain cases, these facilities also have interim emission reduction targets. CEJA also provides funding for electric vehicle infrastructure and deployment.

The Illinois Commerce Commission (ICC) is required by CEJA to develop an actionable plan to achieve CEJA's interim and long-term policy objectives of transitioning the state to a clean electricity system. In December 2022, the ICC opened an investigation to develop and review its draft Renewable Energy Access Plan (REAP). This plan will be published following the conclusion of the investigation. No later than Dec. 31, 2025, and every other year thereafter, the ICC must open a new investigation to develop and adopt an updated REAP.

6.1.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.6** summarizes the expected loads within the state of Illinois and across the PJM region.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

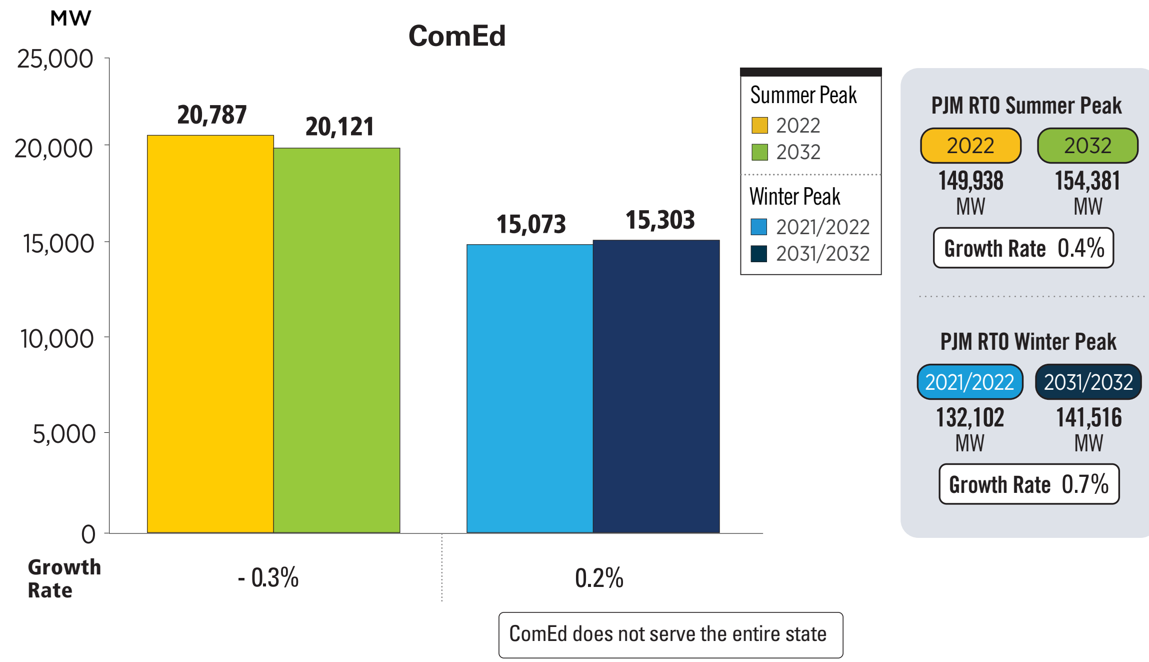
The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

Figure 6.6: Northern Illinois – 2022 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.1.3 — Existing Generation

Existing generation in Illinois as of Dec. 31, 2022, is shown by fuel type in **Figure 6.7**.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

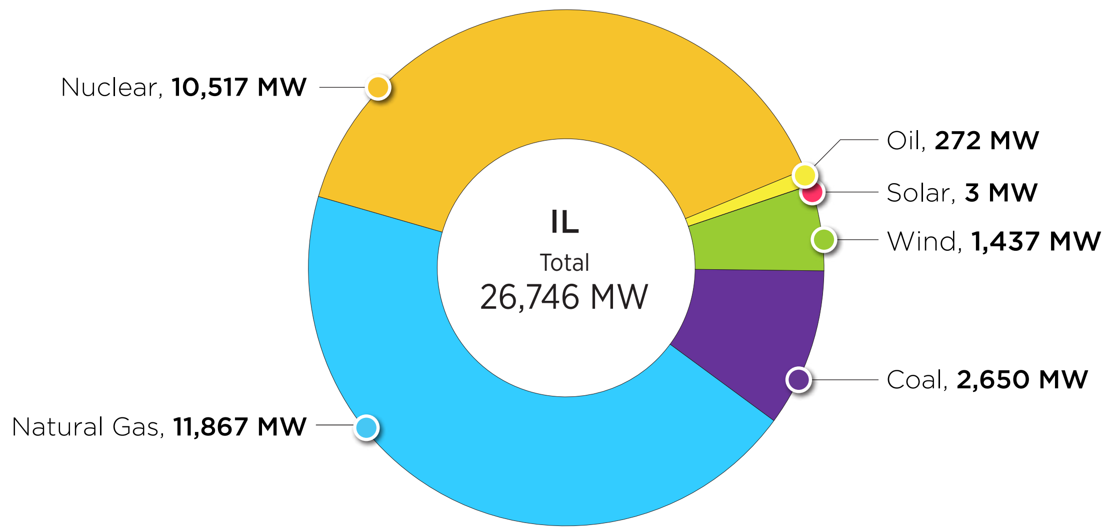
- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in Illinois as of Dec. 31, 2022, are discussed next, in **Section 6.1.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

Figure 6.7: Northern Illinois – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



6.1.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Illinois, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Illinois, as of Dec. 31, 2022, 148 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.4, Table 6.5, Figure 6.8, Figure 6.9** and **Figure 6.10.** These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.4: Northern Illinois – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	Illinois Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	0	0.00%	529	0.61%
Natural Gas	940	9.46%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	0	0.00%	273	0.31%
Solar	5,729	57.67%	57,616	66.37%
Storage	1,895	19.07%	14,148	16.30%
Wind	1,371	13.80%	6,223	7.17%
Grand Total	**9,935**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.5: Northern Illinois – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue				Complete				Total	
		Active		Under Construction		In-Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	6	3,652.0	6	3,652.0
	Diesel	0	0.0	0	0.0	2	22.0	0	0.0	2	22.0
	Natural Gas	7	939.6	5	1,540.0	27	2,926.5	23	9,358.3	62	14,764.4
	Nuclear	0	0.0	0	0.0	10	385.8	5	782.0	15	1,167.8
	Other	0	0.0	0	0.0	0	0.0	3	0.0	3	0.0
	Storage	32	1,894.7	0	0.0	6	0.0	28	1,116.6	66	3,011.2
Renewable	Biomass	0	0.0	0	0.0	0	0.0	3	90.0	3	90.0
	Hydro	0	0.0	0	0.0	0	0.0	5	27.0	5	27.0
	Methane	0	0.0	0	0.0	2	19.7	14	63.9	16	83.6
	Solar	62	5,729.0	2	42.0	1	3.4	62	2,431.3	127	8,205.7
	Wind	37	1,371.4	3	42.5	31	847.7	112	2,908.5	183	5,170.1
	Grand Total	**138**	**9,934.7**	**10**	**1,624.5**	**79**	**4,205.1**	**261**	**20,429.6**	**488**	**36,193.8**

Figure 6.8: Northern Illinois – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

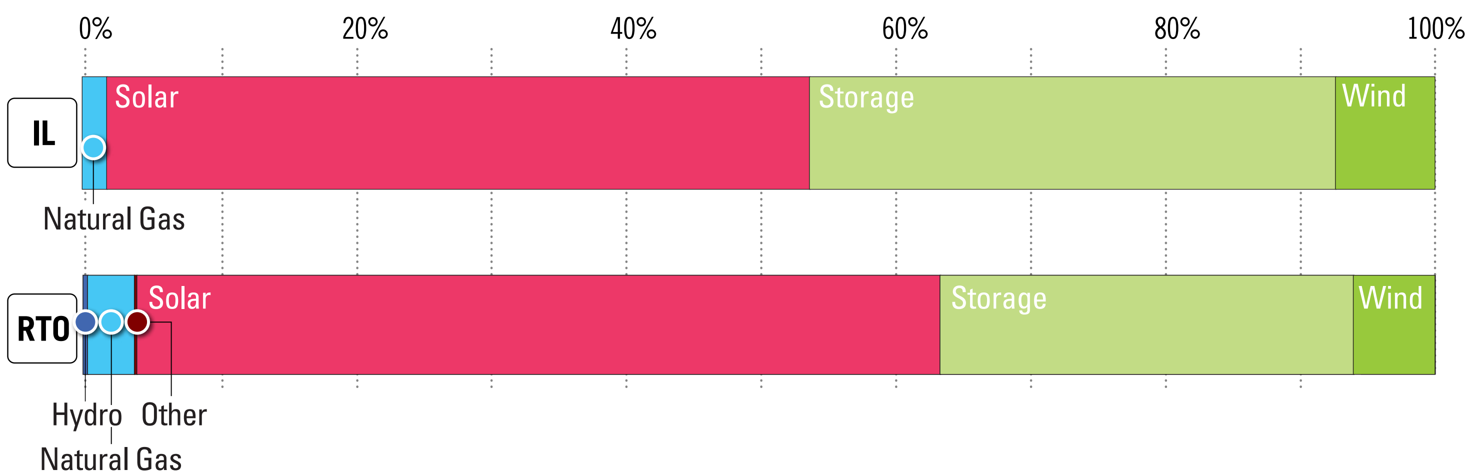
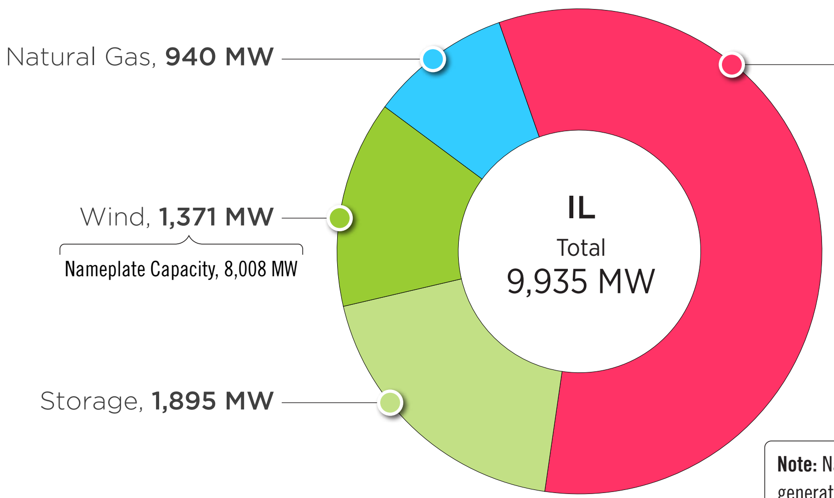


Figure 6.9: Northern Illinois – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.10: Northern Illinois Progression History of Queue – Interconnection Requests (Dec. 31, 2022)

Percentage of planned capacity and projects that have reached commercial operation

14.8%	Requested capacity megawatts
21.7%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	11	Interconnection Service Agreements	836 MW	2,207 MW
	6	Wholesale Market Participation Agreements	27 MW	37 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.1.5 — Generation Deactivation

Formal generator deactivation requests received by PJM in Illinois between Jan. 1, 2022, and Dec. 31, 2022, are summarized in **Map 6.4** and **Table 6.6**.

Deactivation Reliability Studies

PJM has 30 days in which to respond to a generator owner with deactivation study results. Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can reduce voltage support.

Deactivation reliability studies comprise thermal and voltage analysis, including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, reliability criteria violations caused by unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board.

Map 6.4: Northern Illinois Generation Deactivations (Dec. 31, 2022)

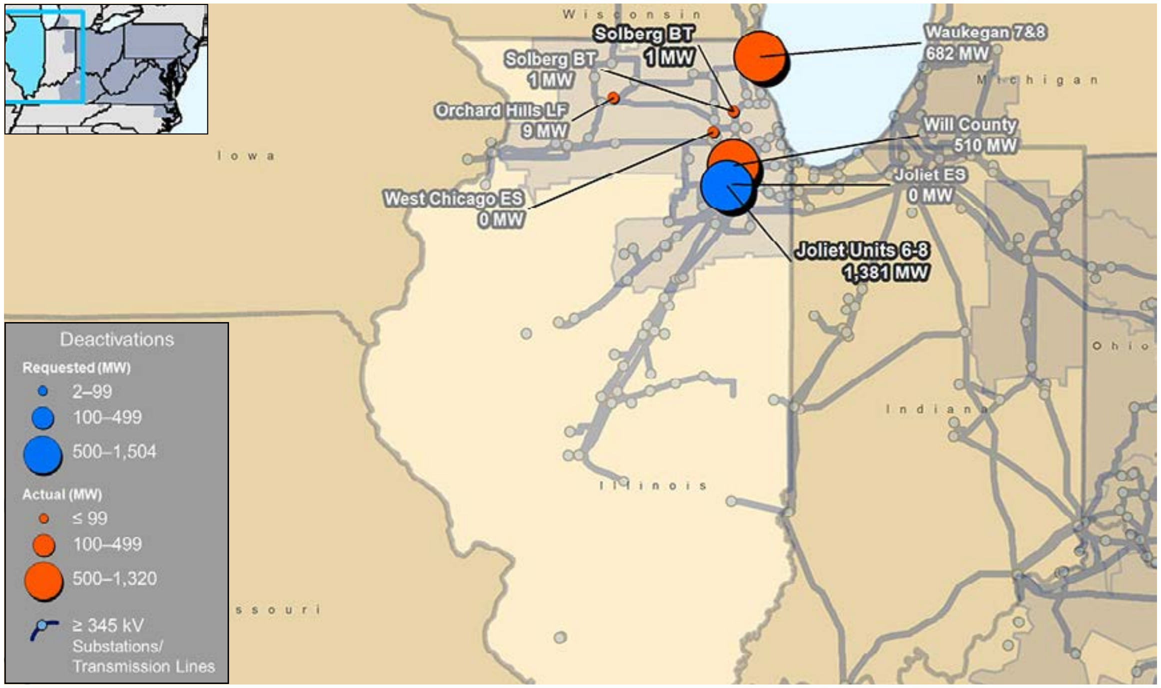


Table 6.6: Northern Illinois Generation Deactivations (Dec. 31, 2022)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Joliet 8	ComEd	Natural Gas	7/25/2022	6/1/2023	56	550.0
Joliet 7	ComEd	Natural Gas	7/25/2022	6/1/2023	57	550.0
Joliet 6	ComEd	Natural Gas	7/25/2022	6/1/2023	63	281.0
Solberg 1 BT	ComEd	Battery	11/8/2022	12/20/2022	4	1.0
Orchard Hills LF	ComEd	Methane	12/30/2021	3/31/2022	5	9.3
Joliet Energy Storage	ComEd	Battery	11/9/2021	4/29/2022	6	0.0
West Chicago Energy Storage	ComEd	Battery	11/9/2021	4/29/2022	6	0.0
Will County 4	ComEd	Coal	6/30/2021	6/30/2022	58	510.0
Waukegan 8	ComEd	Coal	6/30/2021	5/31/2022	59	354.4
Waukegan 7	ComEd	Coal	6/30/2021	5/31/2022	63	328.0

6.1.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in northern Illinois are summarized in **Map 6.5** and **Table 6.7**.

Map 6.5: Northern Illinois Baseline Projects (Dec. 31, 2022)

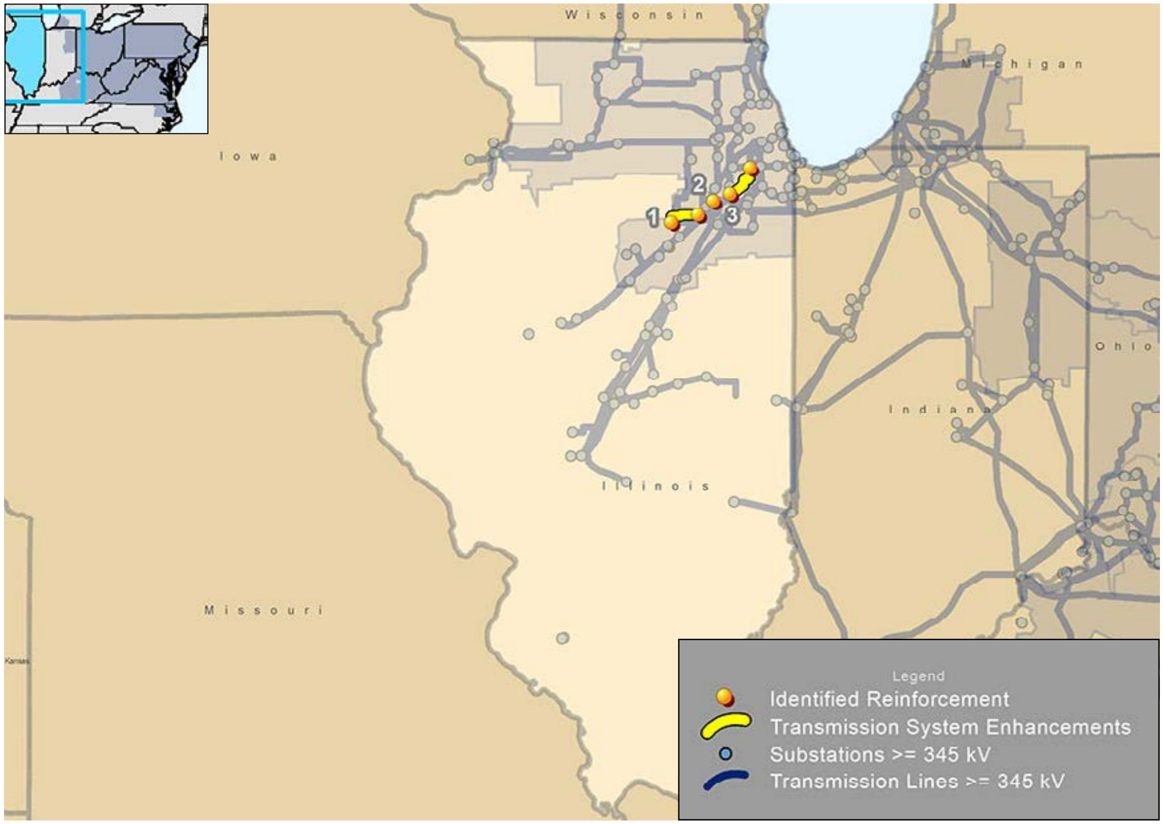


Table 6.7: Northern Illinois Baseline Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3677		Rebuild a 13-mile section of 138 kV line 0108 between LaSalle and Mazon with 1113 ACSR or higher rated conductor. The 13-mile portion of line 7713 from Oglesby (future Corbin) to Mazon that shares double circuit towers with line 0108 will also be reconductored due to the rebuild.	11/1/2026	$42.06	ComEd	11/19/2021
2	B3711		Install 345 kV bus tie 5-20 circuit breaker in the ring at Dresden station in series with existing bus tie 5-6.	12/1/2026	$4.26		4/12/2022
3	B3725		Replace the 1600A bus disconnect switch at Goodings Grove on L11622 Elwood-Goodings Grove 345 kV.	12/1/2027	$0.50		10/4/2022

6.1.7 — Network Projects

2022 RTEP network projects in northern Illinois are summarized in **Map 6.6** and **Table 6.8**.

Map 6.6: Northern Illinois Network Projects (Dec. 31, 2022)

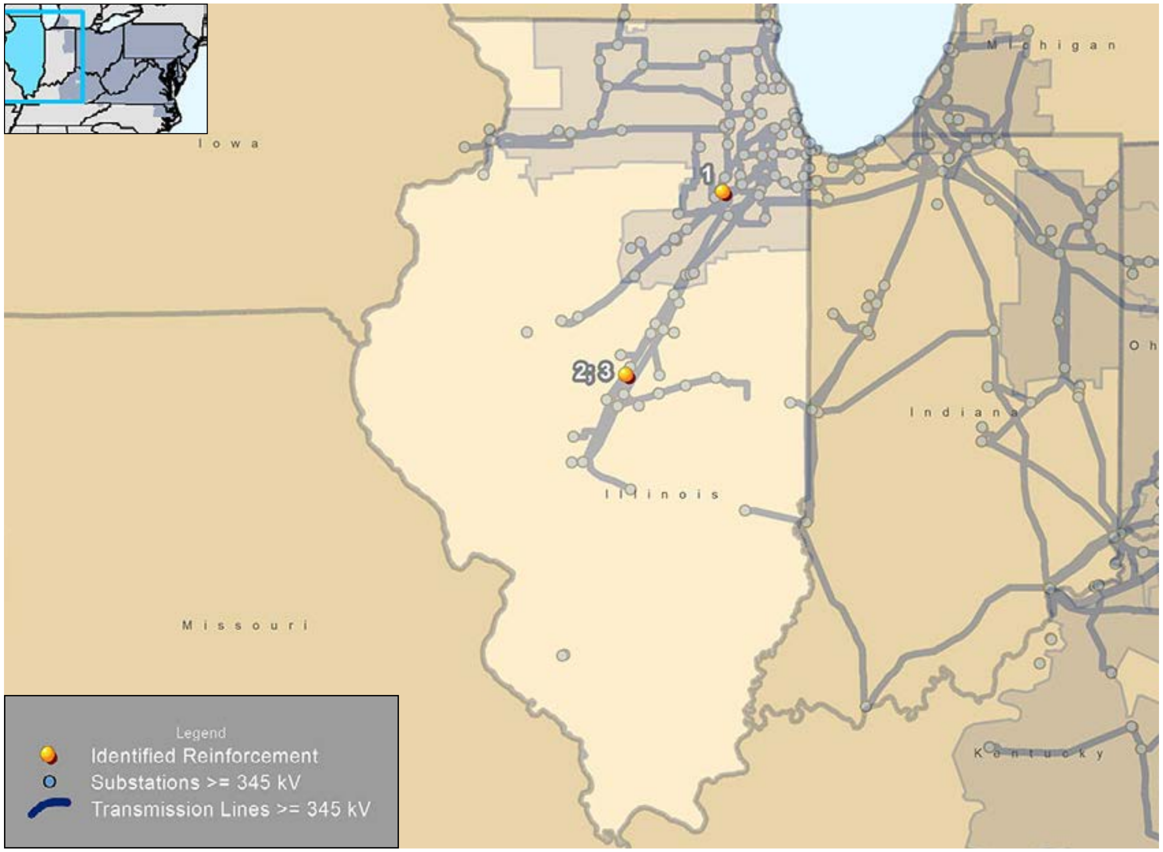


Table 6.8: Northern Illinois Network Projects (Dec. 31, 2022)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	**N5756**	Mitigate sag limitation on the AB1-122 Tap-Dresden; R 345 kV line.	AB1-122	6/1/2021	$1.49	ComEd	11/1/2022
2	**N6804**	Engineering Oversight for TSS 909 Deer Creek	AB2-070	12/30/2021	$1.92		
3	**N6807**	Loop 18806 into TSS 909 Deer Creek.			$2.88		

6.1.8 — Supplemental Projects

Supplemental projects received by PJM in 2022 in northern Illinois are summarized in **Map 6.7** and **Table 6.9**.

Map 6.7: Northern Illinois Supplemental Projects (Dec. 31, 2022)

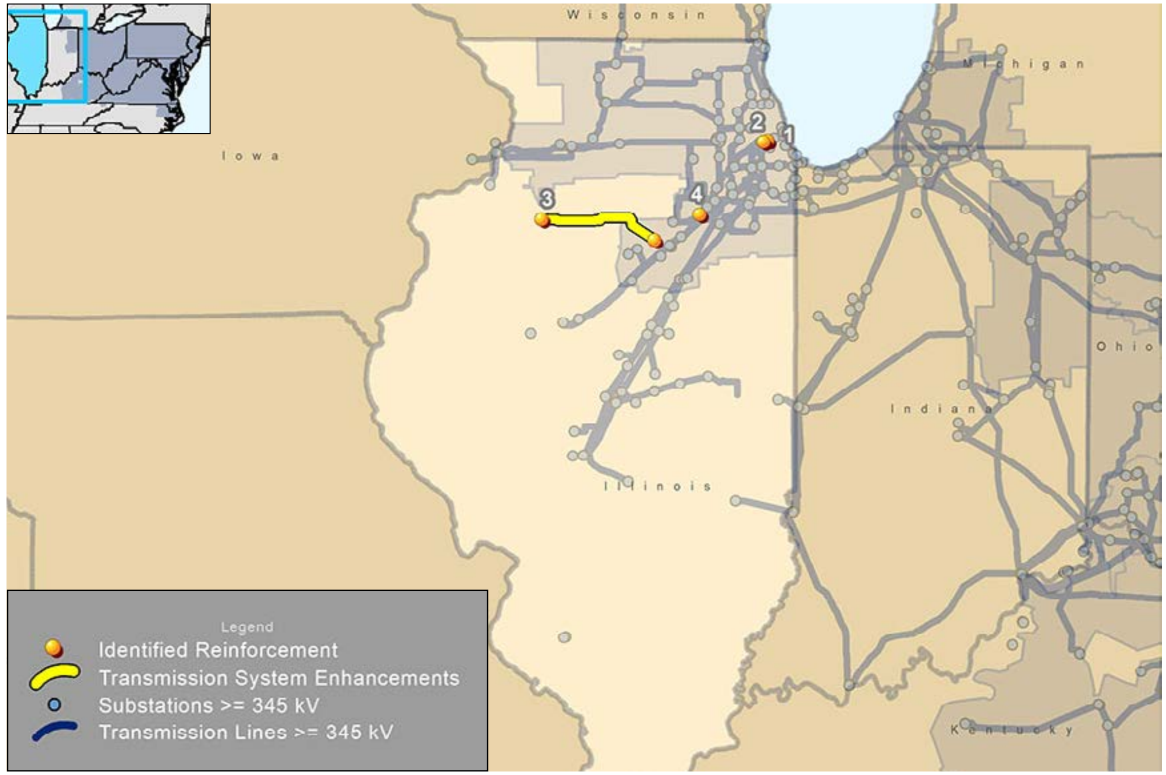


Table 6.9: Northern Illinois Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	**S2668**	Rebuild McCook 138 kV with breaker and a half GIS.	12/31/2025	$68.00	ComEd	10/15/2021
2	**S2669**	Install two new 345/138/34.5 kV autotransformers at McCook (TR 81 and TR 83), replace reblocked TR 84, and reconductor two miles out of 2.5 miles on 138 kV McCook-Ridgeland to obtain a minimum rating of 351/449/459/498 MVA (SN/SLTE/SSTE/SLD).		$36.00		11/2/2021
3	**S2725**	New Ameren station Putnam will be a 138 kV breaker and a half design. The station will be cut into the ComEd Kewanee to Streator line. The existing ComEd connection to Ameren's Hennepin station will be removed, eliminating the three-terminal line.	12/1/2023	$5.20		4/22/2022
4	**S2768**	Replace 138 kV circuit breaker 7713/7719 at Mazon substation and associated equipment fault interrupting capability: Old: 17 kA New: 63 kA	12/31/2023	$2.50		5/19/2022

6.1.9 — Merchant Transmission Project Requests

As of Dec. 31, 2022, PJM's queue contained two merchant transmission project requests with a terminal in Illinois, as shown in **Map 6.8** and **Table 6.10**.

Map 6.8: Northern Illinois Merchant Transmission Project Requests (Dec. 31, 2022)

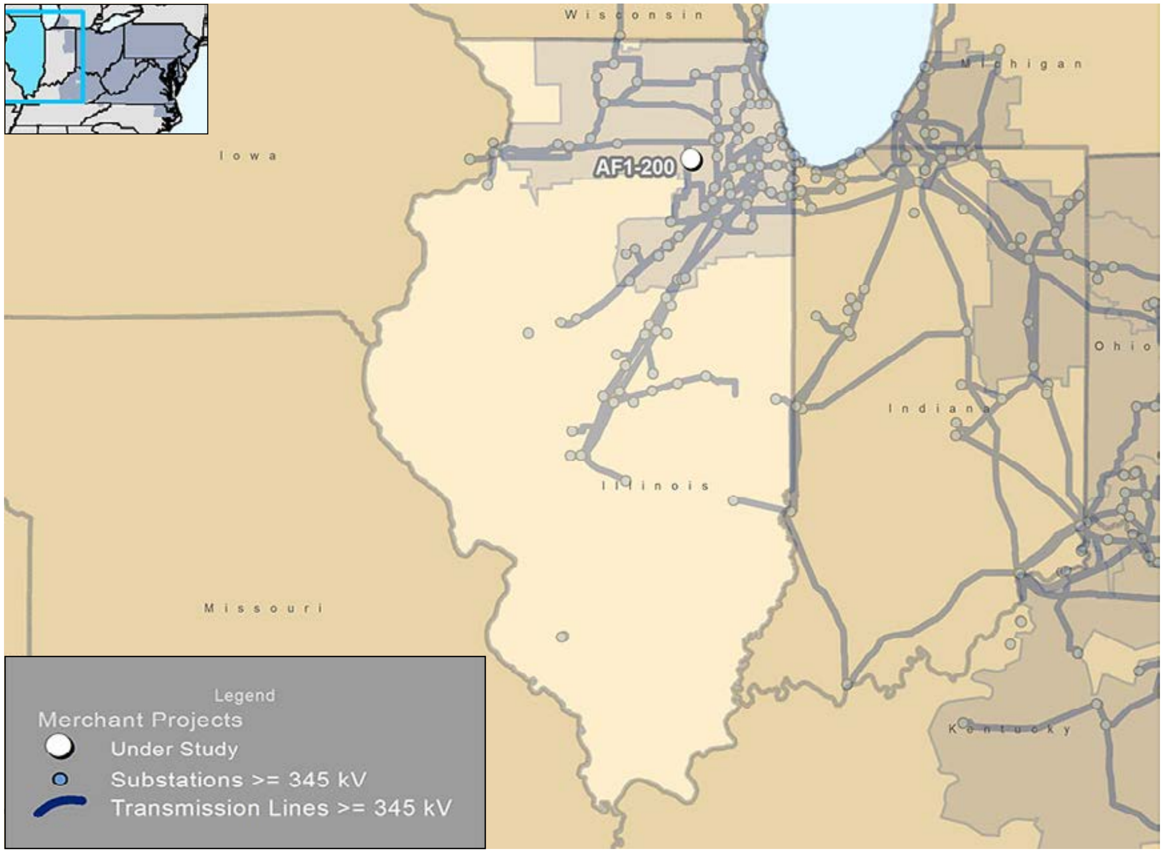


Table 6.10: Northern Illinois Merchant Transmission Project Requests (Dec. 31, 2022)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AF1-200	Plano 345 kV	ComEd	Active	1/31/2025	2,100

6.2: Indiana RTEP Summary

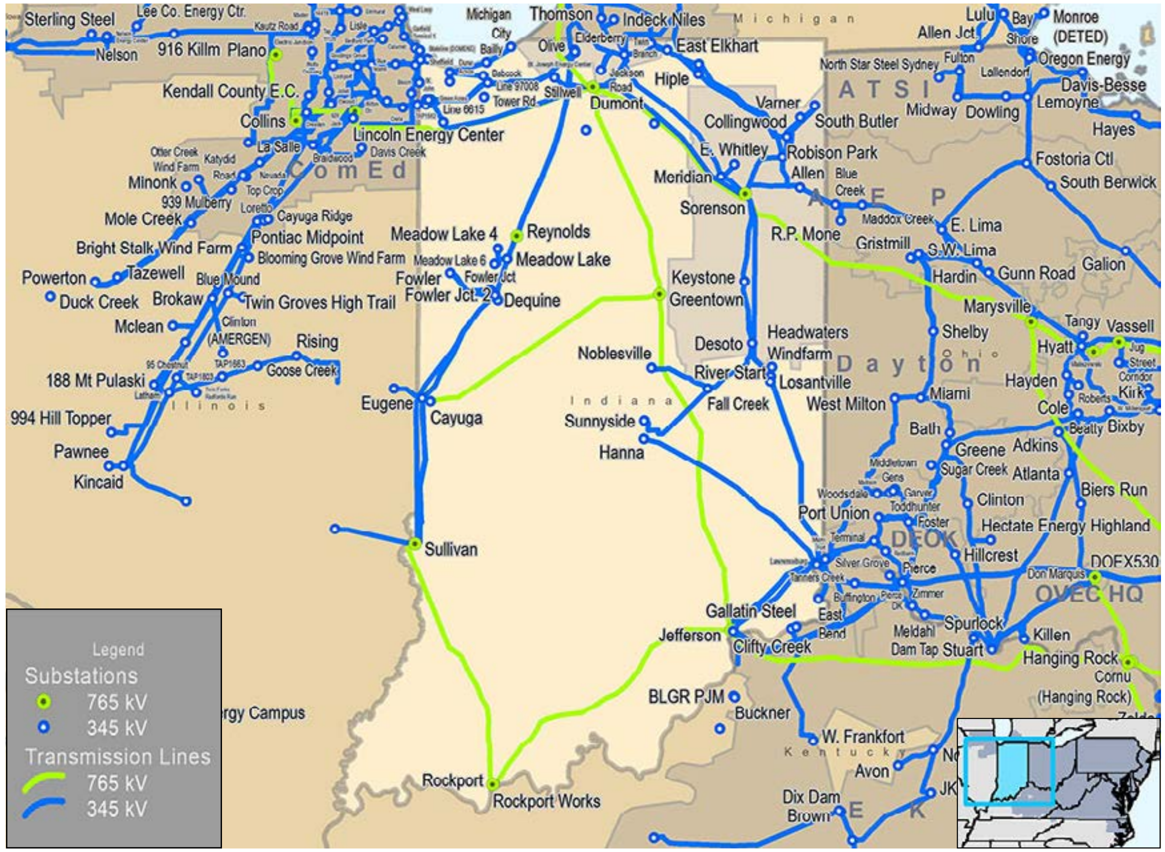
6.2.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Indiana, including facilities owned and operated by American Electric Power (AEP) as shown on **Map 6.9**. Indiana's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

Indiana has a voluntary clean energy portfolio standard of 10% by 2025. This target can be met with eligible clean energy technologies, and 50% of the qualifying energy must come from within Indiana.

Map 6.9: PJM Service Area in Indiana



6.2.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.11** summarizes the expected loads within the state of Indiana and across the PJM region.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

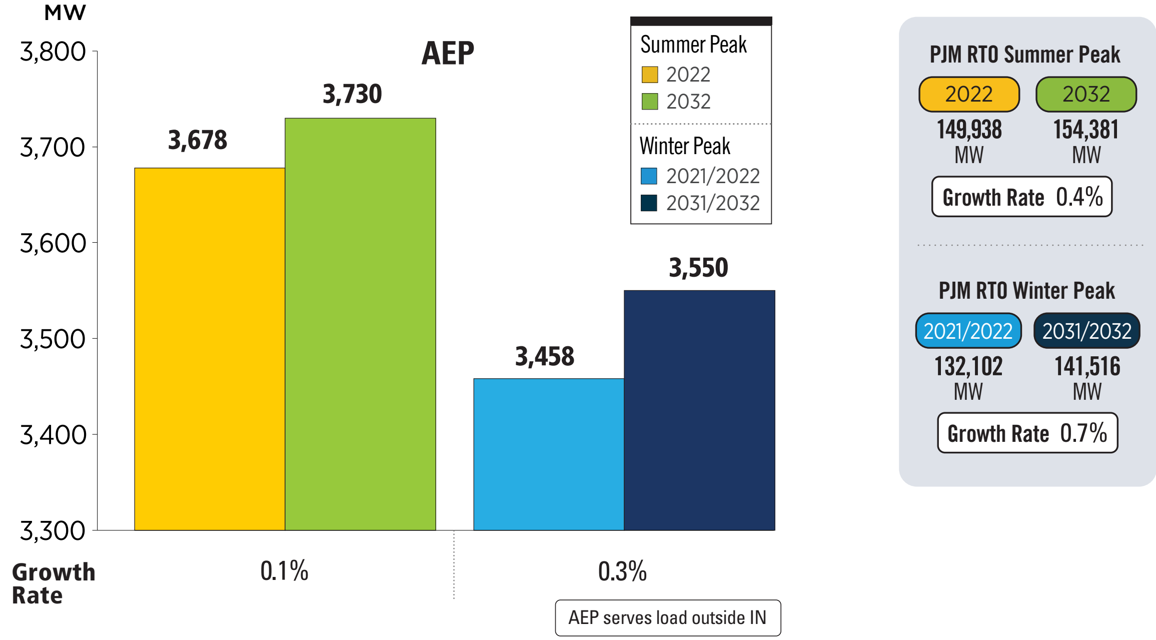
The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

Figure 6.11: Indiana – 2022 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.2.3 — Existing Generation

Existing generation in Indiana as of Dec. 31, 2022, is shown by fuel type in **Figure 6.12**.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

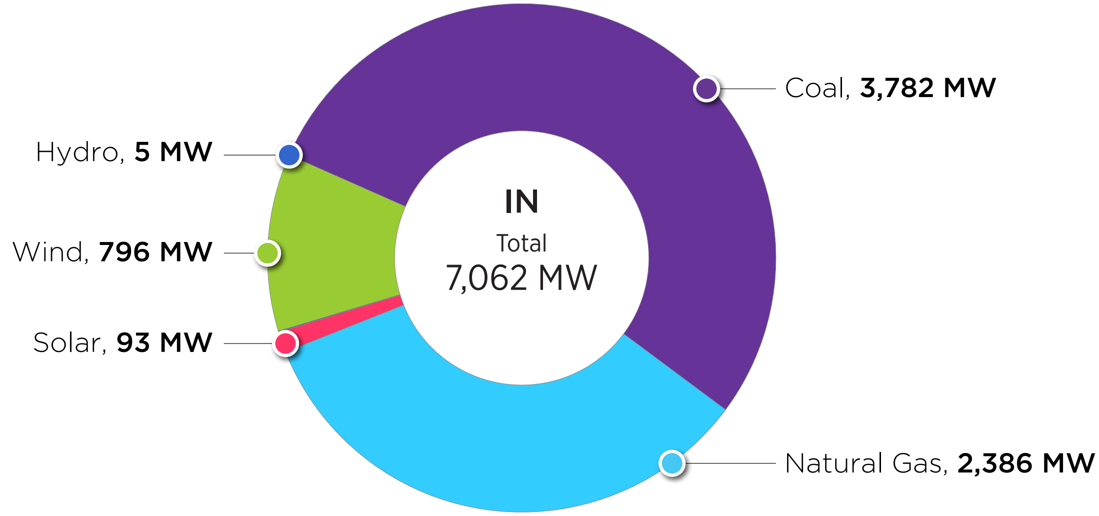
- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in Indiana as of Dec. 31, 2022, are discussed next, in **Section 6.2.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

Figure 6.12: Indiana – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



6.2.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Indiana, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Indiana, as of Dec. 31, 2022, 117 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.11, Table 6.12, Figure 6.13, Figure 6.14** and **Figure 6.15**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.11: Indiana – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	Indiana Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	0	0.00%	529	0.61%
Natural Gas	735	6.80%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	253	2.34%	273	0.31%
Solar	8,526	78.85%	57,616	66.37%
Storage	1,001	9.26%	14,148	16.30%
Wind	298	2.76%	6,223	7.17%
Grand Total	**10,814**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.12: Indiana – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue				Complete				Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	4	66.0	2	901.0	6	967.0
	Natural Gas	2	735.0	1	50.0	5	811.0	2	1,747.0	10	3,343.0
	Other	1	253.4	0	0.0	0	0.0	0	0.0	1	253.4
	Storage	15	1,001.3	0	0.0	0	0.0	13	614.1	28	1,615.5
Renewable	Methane	0	0.0	0	0.0	2	8.0	1	3.6	3	11.6
	Solar	87	8,526.4	0	0.0	7	184.6	28	3,729.6	122	12,440.6
	Wind	11	298.0	0	0.0	11	414.9	50	1,835.6	72	2,548.5
	Grand Total	**116**	**10,814.1**	**1**	**50.0**	**29**	**1,484.5**	**96**	**8,830.9**	**242**	**21,179.6**

Figure 6.13: Indiana – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

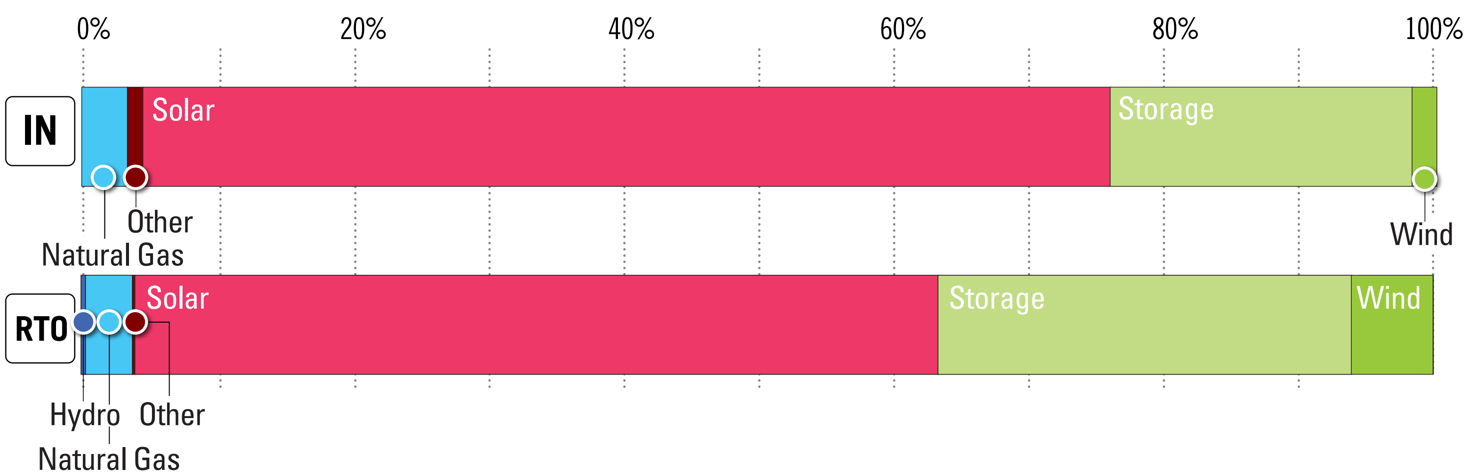
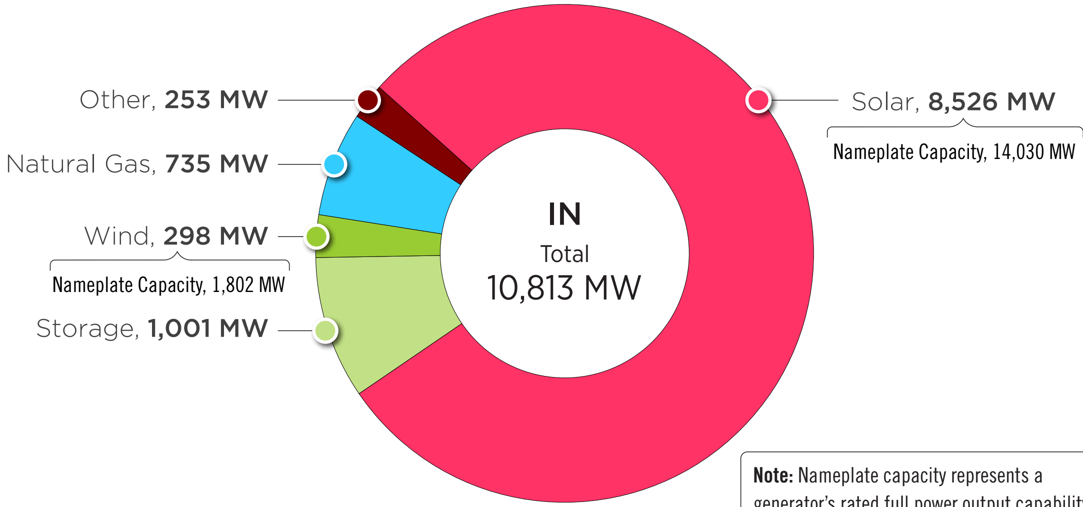


Figure 6.14: Indiana – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.15: Indiana Progression History of Queue – Interconnection Requests (Dec. 31, 2022)

Percentage of planned capacity and projects that have reached commercial operation

12.8%	Requested capacity megawatts
22.1%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	3	Interconnection Service Agreements	71 MW	420 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.2.5 — Generation Deactivation

There were no generating unit deactivation requests in Indiana between Jan. 1, 2022, and Dec. 31, 2022, as part of the 2022 RTEP.

6.2.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in Indiana are summarized in **Map 6.10** and **Table 6.13**.

Map 6.10: Indiana Baseline Projects (Dec. 31, 2022)

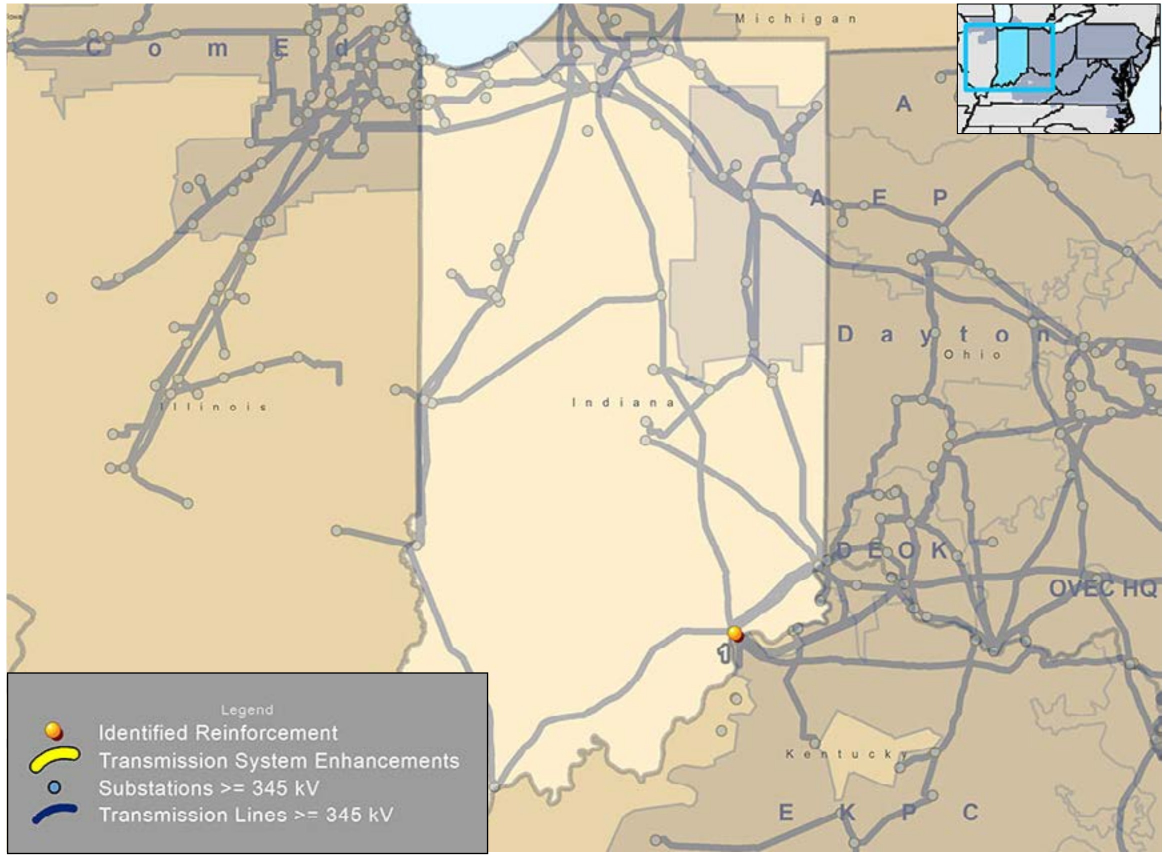


Table 6.13: Indiana Baseline Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3748		Replace four Clifty Creek 345 kV 3000A switches with 5000A 345 kV switches.	6/1/2027	$0.85	AEP	11/1/2022

6.2.7 — Network Projects

2022 RTEP network projects in Indiana are summarized in **Map 6.11** and **Table 6.14**.

Map 6.11: Indiana Network Projects (Dec. 31, 2022)

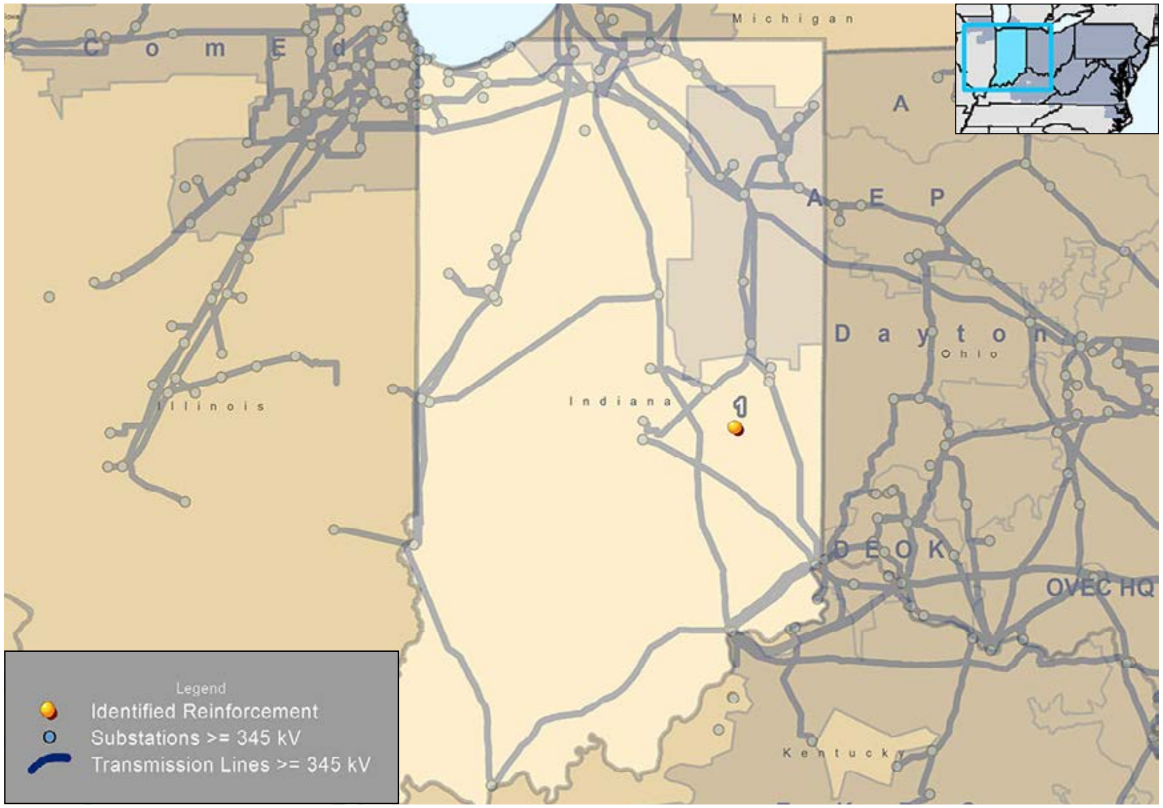


Table 6.14: Indiana Network Projects (Dec. 31, 2022)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N7881	Perform a sag study. OVECs cost estimate for performing the sag study is $125K. Sag study results (from AE2-297 Fac Study) show the need to replace 16 tangent structures, three dead-end structures, and conductor over one Ohio river crossing. Cost estimate is $11.383 M. New SE rating to be 1165 MVA.	AE2-297	12/31/2021	$11.38	OVEC	11/1/2022

6.2.8 — Supplemental Projects

Supplemental projects received by PJM in 2022 in Indiana are summarized in **Map 6.12** and **Table 6.15.**

Map 6.12: Indiana Supplemental Projects (Dec. 31, 2022)

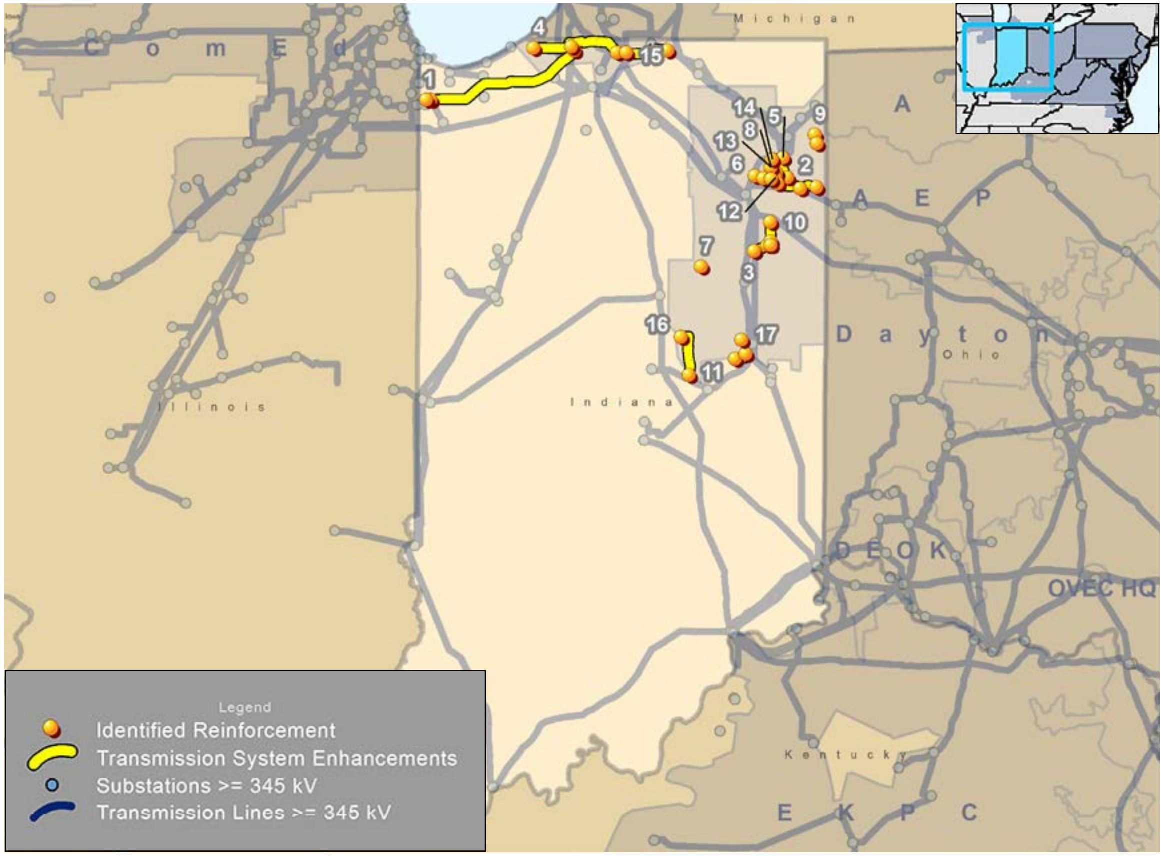


Table 6.15: Indiana Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2631		Reconductor circuit 1 of the ~13-mile double-circuit lines from St. Johns-Green Acres-Olive (L6617, L6615) with 2 x 1033.5 ACSS ACSR conductor.	6/1/2023	$9.50	NEET	8/10/2021
2	S2632	.1	Retire ~11 miles of the Lincoln-Tillman 34.5 kV line.	10/31/2024	$17.30	AEP	9/17/2021
		.2	Remove Lincoln circuit breaker “P” at 'Lincoln 138/69/34.5 kV substation.				

Table 6.15: Indiana Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2 Cont.	S2632 Cont.	.3	Remove circuit breaker “A” and “B” as well as the 138/34.5 kV transformer and all 34.5 kV equipment at Tillman 138/34.5 kV substation.	10/31/2024	$17.30	AEP	9/17/2021
		4	Remove St Rd. 14 34.5 kV Sw.				
		.5	Rebuild a portion of the Lincoln-Tillman line as a new ~2.5-mile 138 kV double circuit extension from the Allen-Milan 138 kV line to Huguenard 138/34.5 kV substation at Huguenard 138 kV extension.				
		.6	At Huguenard 138/34.5 kV station, build the new 138/34.5 kV substation to feed the St Rd 14 load. This station will have two 138 kV circuit breaker’s, one 138 kV circuit switcher, one 34.5 kV circuit breaker and a 138/34.5 kV 30 MVA transformer. The transformer, 34.5 kV circuit breaker and high side switcher will be reused from Tillman substation.				
		.7	At Huguenard-ST Rd 14 34.5 kV, rebuild the radial 34.5 kV line to connect to the new Huguenard substation.				
3	S2633	.1	Install a new switch pole to feed the new Decker 69 kV transformer. Install a motor on the switch toward Liberty Center.	3/31/2022	$0.50		9/17/2021
		.2	Cut the new pole at Decker Switch into the Liberty Center-Bluffton 69 kV line.				
4	S2654	.1	Rebuild ~0.95 miles of 138 kV single circuit line with 1590 ACSR 45/7 Lapwing to match the NIPSCO owned conductor size at New Carlisle-Maple 138 kV.	10/28/2024	$4.69		10/15/2021
		.2	Rebuild ~0.95 miles of 138 kV double circuit line with 1590 ACSR 45/7 Lapwing to match the NIPSCO-owned conductor size and transition fiber installation for NIPSCO connectivity at New Carlisle-Bosserman 138 kV.				
		.3	Remove ~0.86 mile of the existing 138 kV line at New Carlisle-South Bend 138 kV.				
		.4	Relay settings changes at Bosserman 138 kV station.				
		.5	Perform remote end relaying upgrades and settings changes at New Carlise 138 kV station.				
5	S2655	.1	Retire the ~3.65-mile 138 kV Lincoln extension and reconnect the existing line between Robison Park and Allen. The extension can be retired due to previous upgrades strengthening the underlying sub-transmission system through connections to other sources and a rebuild of the existing Robison Park-Allen and Lincoln-Robison Park lines, which increased the 138 kV capacity. This extension does not impact the larger 138 kV network as Lincoln station will keep three 138 kV sources to serve the Fort Wayne area.	3/25/2025	$4.80		9/17/2021
		.2	At Lincoln station, retire 138 kV circuit breaker “B” and “C,” replace 138 kV circuit breaker “I” and relocate 138 kV circuit breaker “A” to the old circuit breaker “C” position.				
6	S2656	.1	On the Colony Bay-Illinois Rd 69 kV line, rebuild ~2.7 miles and reconductor ~3.6 miles with 556.5 ACSR. The 3.6 miles to be reconductored has newer structures that do not need replaced due to various INDOT and Fort Wayne road widening projects that have replaced structures more recently but kept the original conductor in place.	10/1/2025	$11.50		10/15/2021
		.2	Replace Aboite 69 kV switch due to the line structure replacements.				
7	S2664		Rebuild ~4.5 miles of 34.5 kV line with the conductor size 556.5 ACSR 26/7 Dove to 69 kV standards at Hummel Creek-Marion 34.5 kV. The following cost includes the line rebuild, line removal and right of way.	10/15/2026	$11.30		11/19/2021
8	S2682	.1	Rebuild the Spy Run-McKinley 34.5 kV line as the ~2.2-mile Spy Run-Melita 69 kV line and retire the remaining 2.8 miles.	5/1/2023	$47.90		1/21/2022
		.2	Melita station: Add a 69 kV circuit breaker to Melita station.				

Table 6.15: Indiana Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
8 Cont.	S2682 Cont.	.3	Rebuild the through-path of Fulton 34.5/12 kV station at 69 kV and replace the transformer with a 69/12 kV unit.	5/1/2023	$47.90	AEP	1/21/2022
		.4	Spy Run Station: Replace transformer No. 3 with a 138/69/34.5 kV unit. Move the Fulton exit from 34.5 kV to 69 kV.				
		.5	Retire circuit breaker "G" at McKinley station.				
		.6	Retire the 34.5 kV voltage class equipment at Wallen station.				
		.7	At Industrial Park, retire the entire 34.5 kV voltage class, install a new 138/12 kV load delivery to replace the 34.5/12 kV delivery. Replace 69 kV circuit breaker "G," Replace the 138/69 kV transformer 1 and add a high side switcher to transformer 1.				
		.8	Retire the ~3.3-mile Wallen-Industrial Park 34.5 kV line.				
		.9	Retire Glenbrook 34.5/12 kV substation.				
		.10	Retire the ~4.2-mile 34.5 kV Industrial Park-Spy Run 34.5 kV line.				
		.11	Install a new 138/12kV Beckwith substation to take the place of Glenbrook with two 25 MVA transformer's and a 138 kV bus tie circuit breaker.				
		.12	Cut in the Industrial Park-Spy Run 138 kV to Beckwith station.				
9	S2685	.1	At Robison Park-Sowers 138 kV line, rebuild the 13.6 miles of wood construction with double circuit capable 138 kV with one side strung. Reconductor 4.3 miles of the steel lattice section with 795 Drake ACSR. This 4.3 mile section is already constructed as double circuit capable.	11/1/2025	$43.30		1/21/2022
		.2	Replace switches and risers at Grabill switch to accommodate the line rebuild.				
10	S2690	.1	Install a new switchpole to feed the new North Bluffton 69 kV transformer.	2/21/2022	$0.60		2/28/2022
		.2	Cut the new pole at North Bluffton into the 69 kV line.				
11	S2747	.1	At Cowan 138 kV, install a new 138 kV four circuit breaker ring bus, two 138 kV revenue metering, fiber and relaying.	9/22/2022	$9.07		3/18/2022
		.2	At Cowan 138 kV North Extension and right of way, install ~0.1 mi of 138 kV single circuit with the conductor size 795 ACSR 26/7 Drake.				
		.3	Cowan 138 kV South Extension and right of way: Install ~0.1 mi of 138 kV single circuit with the conductor size 795 ACSR 26/7 Drake.				
		.4	Replace two structures with dead end structures on the Fuson-23rd Street 138 kV circuit to connect the Cowan North Extension and Cowan South Extension.				
		.5	Upgrade 23rd Street relay.				
		.6	Upgrade Fuson relay.				

Table 6.15: Indiana Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
12	S2772		Rebuild the Pettit Ave-Melita 69 kV 1.84 mile section on centerline utilizing 556.5 ACSR. Construction includes a high percentage of custom self-supporting running corners and dead ends due to line angles created by route adjustments. Constrained corridors are not suitable for guy wire installation. There are also an increased number of structures per mile due to configuration of existing underbuild and existing distribution service connections to residential and commercial customers along the existing line route. The line also passes through a heavily developed urban area of Fort Wayne, requiring new easements along the route and short span construction, which all lead to higher than normal costs.	2/14/2025	$12.00	AEP	4/22/2022
13	S2776		Industrial Park-McKinley 138 kV line: Rebuild the ~1-mile section that is double circuit with McKinley-Melita 69 kV, and rebuild the ~0.9 mile section that is double circuit with Melita-Hadley 69 kV in place. The remaining ~1.3 miles will be rebuilt as single circuit. All new line conductor will be 795 Drake ACSR. The total rebuild length is 1.9 miles double circuit and 1.3 miles single circuit for a total of 3.2 miles.	11/1/2026	$9.30		
14	S2777		Robison Park-Wallen 69 kV line: Reconductor the ~2.96 miles of 300,000 CU with 556.5 ACSR, and replace 21 structures outlined in the need with steel monopole structures.	11/1/2025	$6.30		
15	S2787	.1	Install a new 138 kV straight bus with two 138 kV MOAB switches, fiber and relaying at RV Capital 138 kV.	3/28/2023	$5.77		
		.2	At East Elkhart-RV Capital 138 kV, install ~1.44 mi of 138 kV single circuit from structure 1 to RV Capital on the East Elkhart-Mottville Hydro 138 kV circuit with the conductor size 795 ACSR 26/7 Drake.				
		.3	Relocate East Elkhart Stateline Metering to Mottville Hydro.				
16	S2797	.1	Rebuild ~15 miles of 138 kV line with the conductor size 795 ACSR at Pendleton-Makahoy 138 kV. The following cost includes the line rebuild, line removal and right of way.	9/30/2026	$28.40		6/15/2022
		.2	Replace the Pendleton 138/34.5 kV transformer with a 138/34.5 kV 75 MVA transformer. The following cost includes the transformer install and removal.				
17	S2798		Replace 34.5 kV Moab switches “A” and “B” with 2000 A switches, and install a 2000 A bus tie switch for operational and transformer maintenance flexibility at McGalliard Road.	9/6/2024	$0.40		

6.2.9 — Merchant Transmission Project Requests

As of Dec. 31, 2022, PJM's queue contained two merchant transmission project requests with a terminal in Indiana, as shown in **Map 6.13** and **Table 6.16**.

Map 6.13: Indiana Merchant Transmission Project Requests (Dec. 31, 2022)

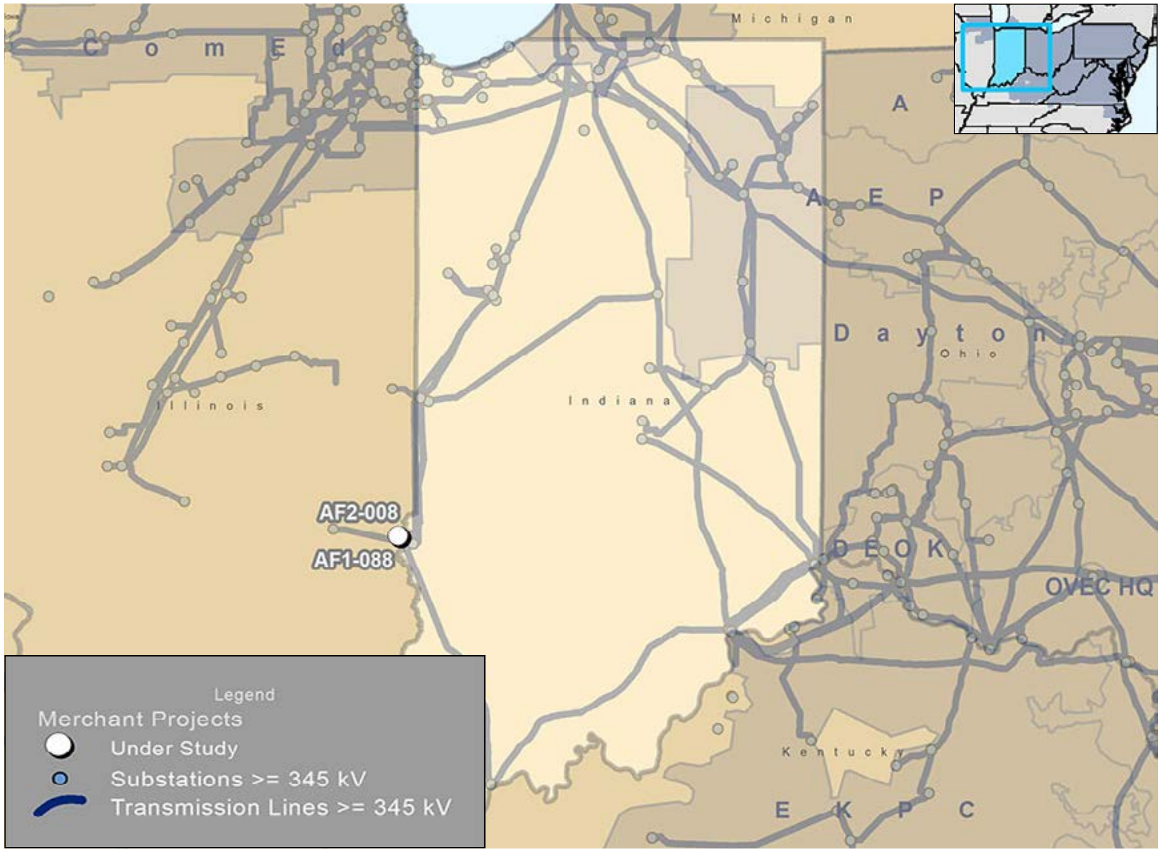


Table 6.16: Indiana Merchant Transmission Project Requests (Dec. 31, 2022)

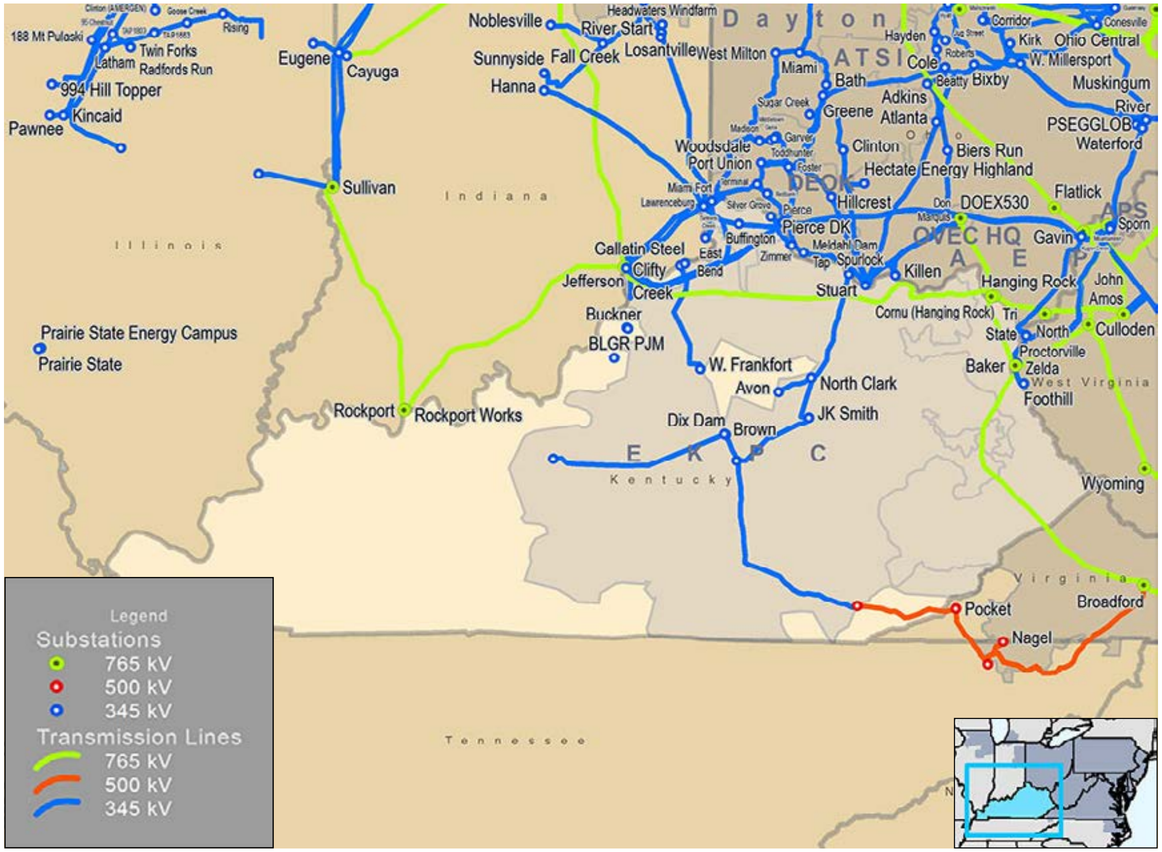
Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AF1-088	Sullivan 345 kV	AEP	Active	12/31/2025	1,000
AF2-008	Sullivan 345 kV	AEP	Active	12/31/2025	2,000

6.3: Kentucky RTEP Summary

6.3.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Kentucky, including facilities owned and operated by American Electric Power (AEP), Duke Energy Ohio and Kentucky (DEO&K) and East Kentucky Power Cooperative (EKPC) as shown on **Map 6.14**. Duke Energy Ohio and Kentucky owns the Duke transmission delivery facilities in Kentucky rated over 69 kV. Kentucky's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Map 6.14: PJM Service Area in Kentucky



6.3.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.16** summarizes the expected loads within the state of Kentucky and across the PJM region.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

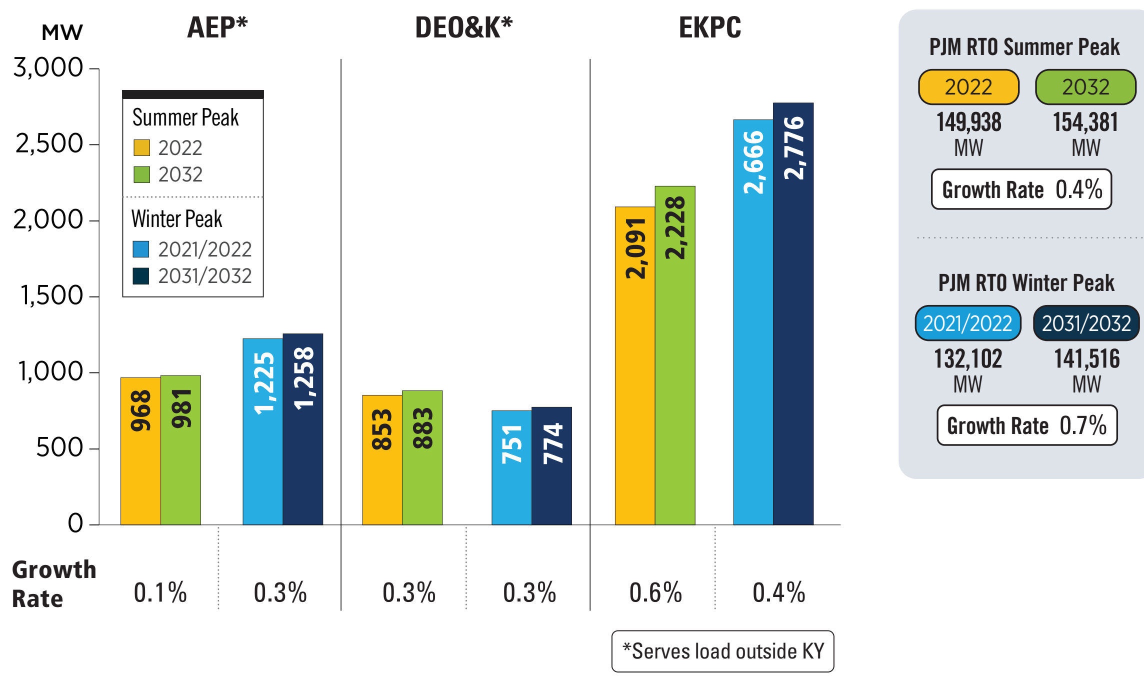
The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

Figure 6.16: Kentucky – 2022 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.3.3 — Existing Generation

Existing generation in Kentucky as of Dec. 31, 2022, is shown by fuel type in **Figure 6.17**.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

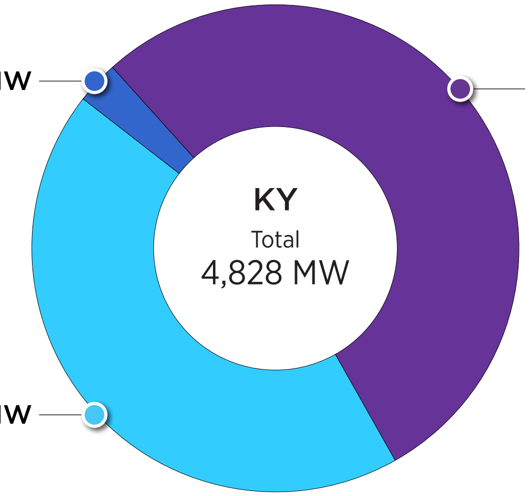
- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in Kentucky as of Dec. 31, 2022, are discussed next, in **Section 6.3.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

Figure 6.17: Kentucky – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



6.3.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Kentucky, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Kentucky, as of Dec. 31, 2022, 77 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.17, Table 6.18, Figure 6.18, Figure 6.19** and **Figure 6.20**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.17: Kentucky – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	Kentucky Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	0	0.00%	529	0.61%
Natural Gas	0	0.00%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	0	0.00%	273	0.31%
Solar	3,993	96.24%	57,616	66.37%
Storage	156	3.76%	14,148	16.30%
Wind	0	0.00%	6,223	7.17%
Grand Total	**4,149**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.18: Kentucky – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue				Complete				Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	6	2,969.0	6	2,969.0
	Natural Gas	0	0.0	0	0.0	6	71.0	6	2,804.7	12	2,875.7
	Storage	6	156.0	0	0.0	0	0.0	3	106.2	9	262.2
Renewable	Biomass	0	0.0	0	0.0	0	0.0	5	198.5	5	198.5
	Hydro	0	0.0	0	0.0	0	0.0	1	70.0	1	70.0
	Solar	67	3,992.6	4	180.2	1	30.0	33	1,630.6	105	5,833.3
	Wind	0	0.0	0	0.0	0	0.0	2	27.3	2	27.3
	Grand Total	**73**	**4,148.6**	**4**	**180.2**	**7**	**101.0**	**56**	**7,806.3**	**140**	**12,236.0**

Figure 6.18: Kentucky – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

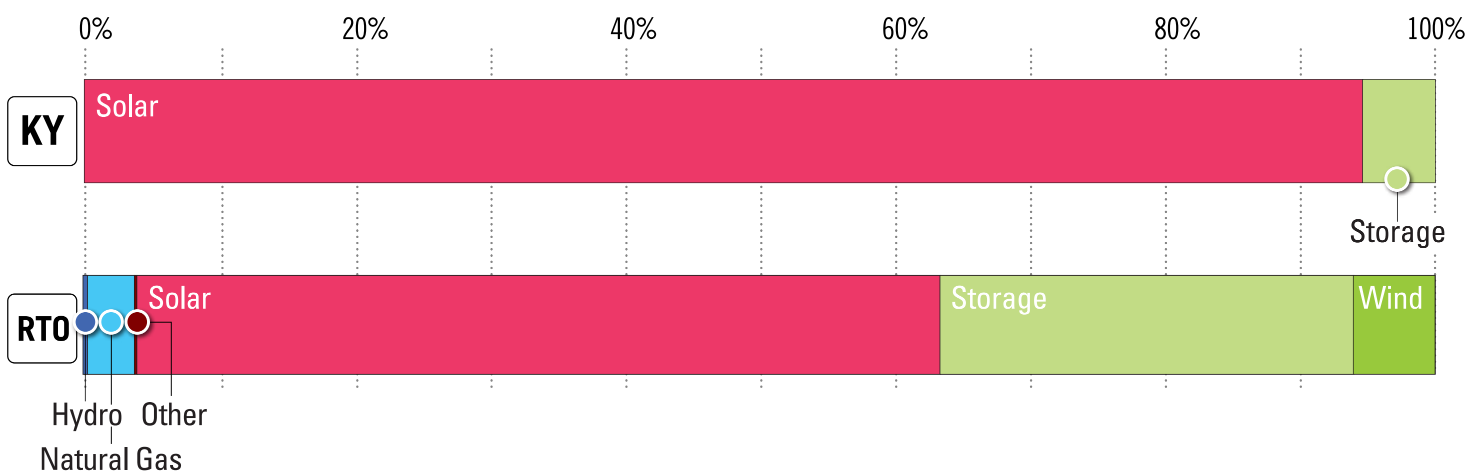
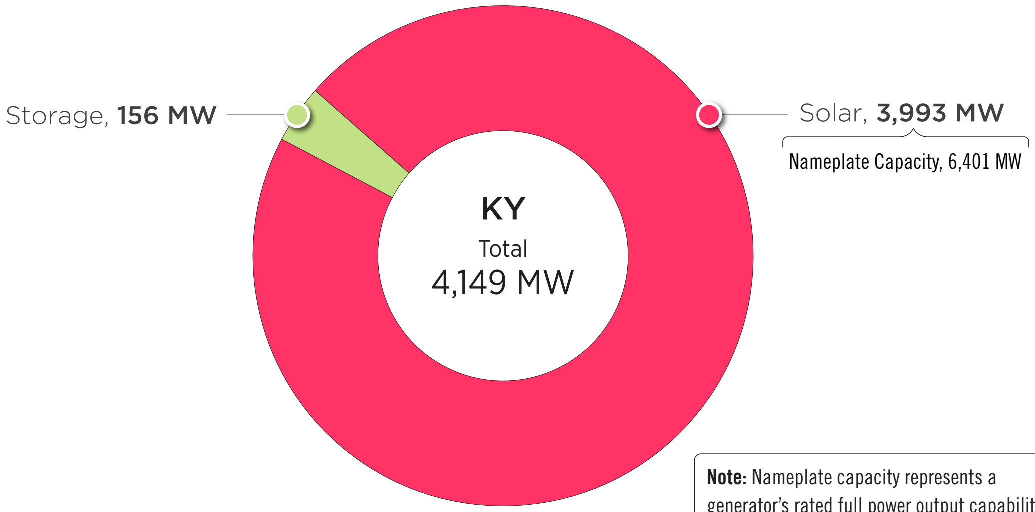
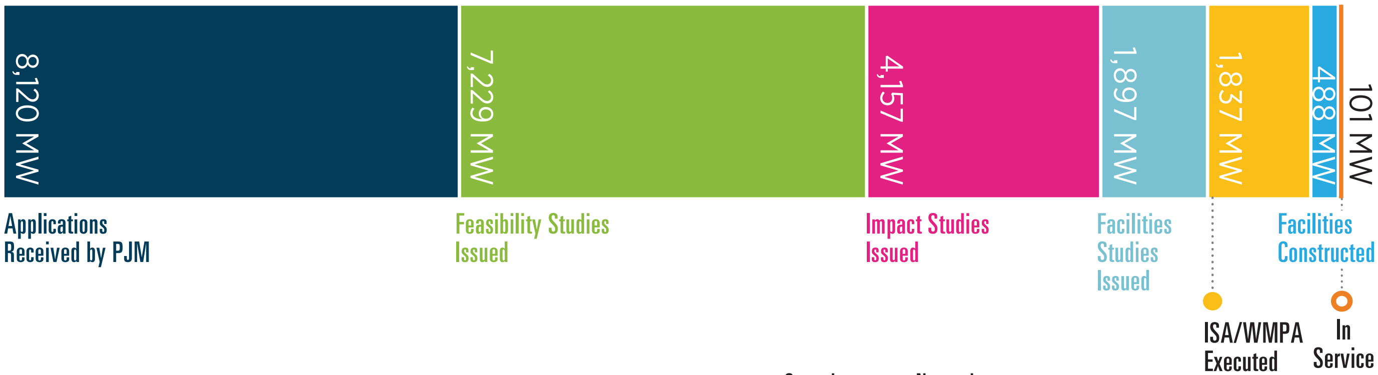


Figure 6.19: Kentucky – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.20: Kentucky Progression History of Queue – Interconnection Requests (Dec. 31, 2022)



Percentage of planned capacity and projects that have reached commercial operation

1.2%	Requested capacity megawatts
9.6%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	2	Interconnection Service Agreements	1,180 MW	1,230 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.3.5 — Generation Deactivation

There were no generating unit deactivation requests in Kentucky between Jan. 1, 2022, and Dec. 31, 2022, as part of the 2022 RTEP.

6.3.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in Kentucky are summarized in **Map 6.15** and **Table 6.19**.

Map 6.15: Kentucky Baseline Projects (Dec. 31, 2022)

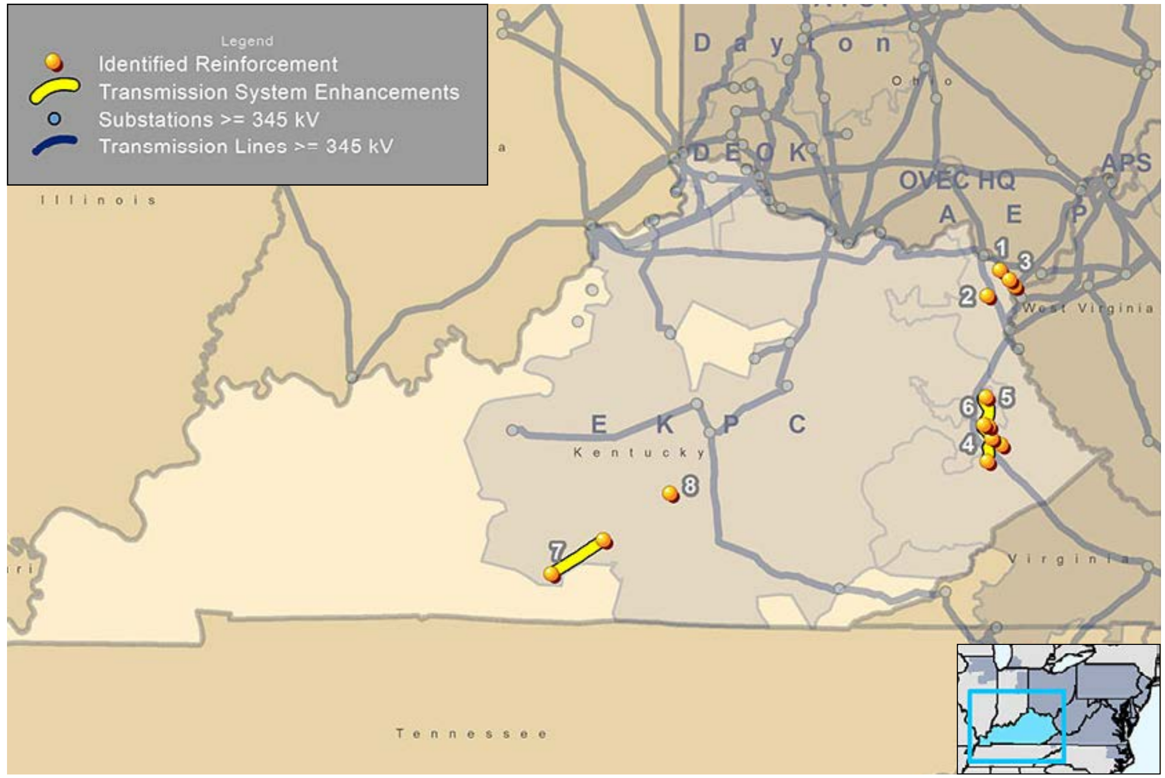


Table 6.19: Kentucky Baseline Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3349		Replace Bellefonte 69 kV risers on the section between Bellefonte transformer No. 3 and 69 kV bus No. 2.	6/1/2026	$0.54	AEP	11/19/2021
2	B3350	.1	Replace overdutied 69 kV breakers C, G, I, Z, AB and JJ in place. The new 69 kV breakers to be rated at 3000A 40 kA breakers.	6/1/2023	$2.00		1/21/2022
		.2	Upgrade remote end relaying at Point Pleasant, Coalton and South Point 69 kV substations.				
3	B3352		Replace MOAB W, MOAB Y, line and bus side jumpers of both W and Y at 47th Street 69 kV station. Upgrade the 69 kV strain bus between MOABs W and Y to 795 KCM AAC. Change the connectors on the tap to MOAB X1 to accommodate the larger 795 KCM AAC.	6/1/2026	$0.00		11/19/2021

Table 6.19: Kentucky Baseline Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	B3353	.1	Rebuild Allen station to the northwest of its current footprint utilizing a standard air-insulated substation with equipment raised by 7' concrete platforms and control house raised by a 10' platform to mitigate flooding concerns at Allen substation. Install five 69 kV, 3000A 40 kA circuit breakers in a ring bus (operated at 46 kV) configuration with a 13.2 MVAR capacitor bank. Existing Allen station will be retired (does not include the distribution cost). Distribution scope of work: Install 69/46 kV-12 kV 20 MVA transformer along with 2-12 kV breakers on 7' concrete platforms (conversion of S2405.1).	12/1/2026	$16.00	AEP	11/19/2021
4	B3353	.2	A 0.20-mile segment of the Allen-East Prestonburg 46 kV line will be relocated to the new station (SN/SE/WN/WE: 53/61/67/73MVA). (Conversion of S2405.2)	12/1/2026	$16.00	AEP	11/19/2021
4	B3353	.3	The new line extension of the McKinney-Allen line will walk around the south and east sides of the existing Allen station to the new Allen station being built in the clear. A short segment of new single circuit 69 kV line and a short segment of new double circuit 69 kV line (both operated at 46 kV) will be added to the line to tie into the new Allen station bays. (Conversion of S2405.3)	12/1/2026	$16.00	AEP	11/19/2021
4	B3353	.4	A segment of the Stanville-Allen line will have to be relocated to the new station (SN/SE/WN/WE: 50/50/63/63MVA). (Conversion of S2405.4)	12/1/2026	$16.00	AEP	11/19/2021
4	B3353	.5	0.25-mile segment of the Allen-Prestonburg existing single circuit will be relocated. The relocated line segment will require construction of one custom self-supporting double circuit dead-end structure and single circuit suspension structure. A short segment of new double circuit 69 kV line (energized at 46 kV) will be added to tie into the new Allen station bays, which will carry Allen-Prestonsburg 46 kV and Allen-East Prestonsburg 46 kV lines. A temporary 0.15-mile section double circuit line will be constructed to keep Allen-Prestonsburg and Allen-East Prestonsburg 46 kV lines energized during construction. (Conversion of S2405.5)	12/1/2026	$16.00	AEP	11/19/2021
4	B3353	.6	Perform required remote end work at Prestonsburg, Stanville and McKinney stations. (Conversion of S2405.6)	12/1/2026	$16.00	AEP	11/19/2021
5	B3360		Replace Thelma Transformer No. 1 with a 138/69/46 kV 130/130/90 MVA transformer and replace 46 kV risers and relaying toward Kenwood substation. Existing transformer No. 1 to be used as spare.	12/1/2026	$3.54	AEP	11/19/2021
6	B3361		Rebuild Prestonsburg-Thelma 46 kV circuit, ~14 miles. Retire Jenny Wiley substation.	12/1/2026	$33.01	AEP	11/19/2021
7	B3709		Rebuild the Summer Shade-West Columbia 69 kV 0.19 miles of 266 conductor double circuit to 556 conductor.	12/1/2025	$0.19	EKPC	3/18/2022
8	B3712		Install a 28 MVAR cap bank at Liberty Junction 69 kV.	12/1/2022	$0.54	EKPC	4/22/2022

6.3.7 — Network Projects

2022 RTEP network projects in Kentucky are summarized in **Map 6.16** and **Table 6.20**.

Map 6.16: Kentucky Network Projects (Dec. 31, 2022)

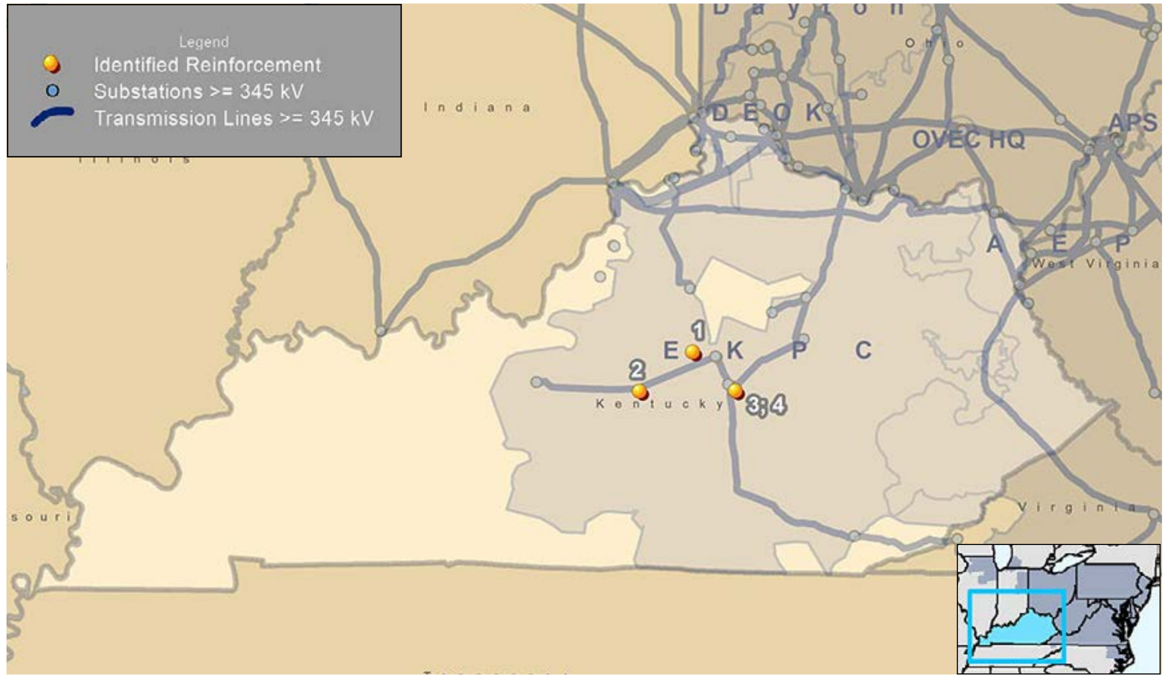


Table 6.20: Kentucky Network Projects (Dec. 31, 2022)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5861	Build 69 kV switching station along the Van Arsdell-Mercer Industrial 69 kV line.	AD2-072	12/1/2021	$2.00	EKPC	11/1/2022
2	N6732	Install necessary equipment (a 161 kV isolation switch structure and associated switch, plus interconnection metering, fiber-optic connection and telecommunications equipment, circuit breaker and associated switches, and relay panel) at Marion County 161 kV substation to accept the IC's generator lead line/bus.	AE1-143	11/30/2022	$1.19		
3	N6913	EKPC to install necessary equipment (a 69 kV isolation switch structure and associated switch, plus interconnection metering, fiber-optic connection and telecommunications equipment, circuit breaker and associated switches, and relay panel) at the new South Lancaster Switching station to accept the IC generator lead line/bus.	AE2-254	12/31/2022	$1.14		
4	N6914	EKPC to construct a new 69 kV switching station (South Lancaster Switching) to facilitate connection of the Turkey Creek Solar generation project.	AE2-254	12/31/2022	$3.41		

6.3.8 — Supplemental Projects

Supplemental projects received by PJM in 2022 in Kentucky are summarized in **Map 6.17** and **Table 6.21**.

6.3.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Kentucky were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.17: Kentucky Supplemental Projects (Dec. 31, 2022)

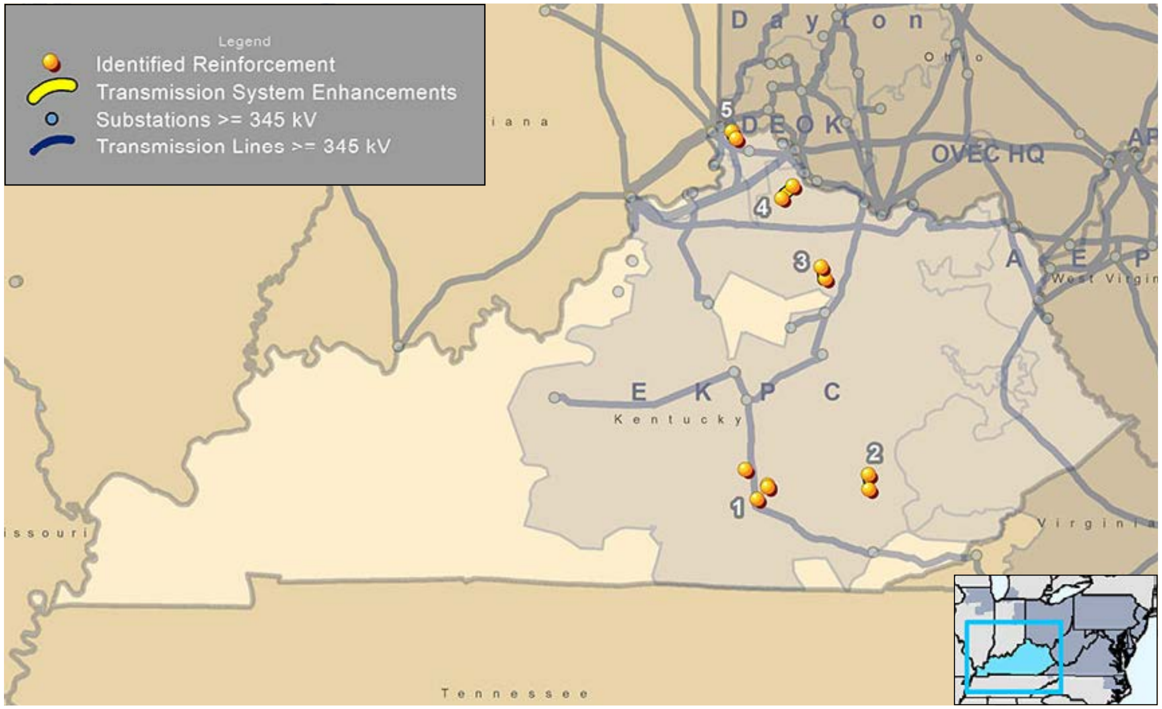


Table 6.21: Kentucky Supplemental Projects (Dec. 31, 2022)

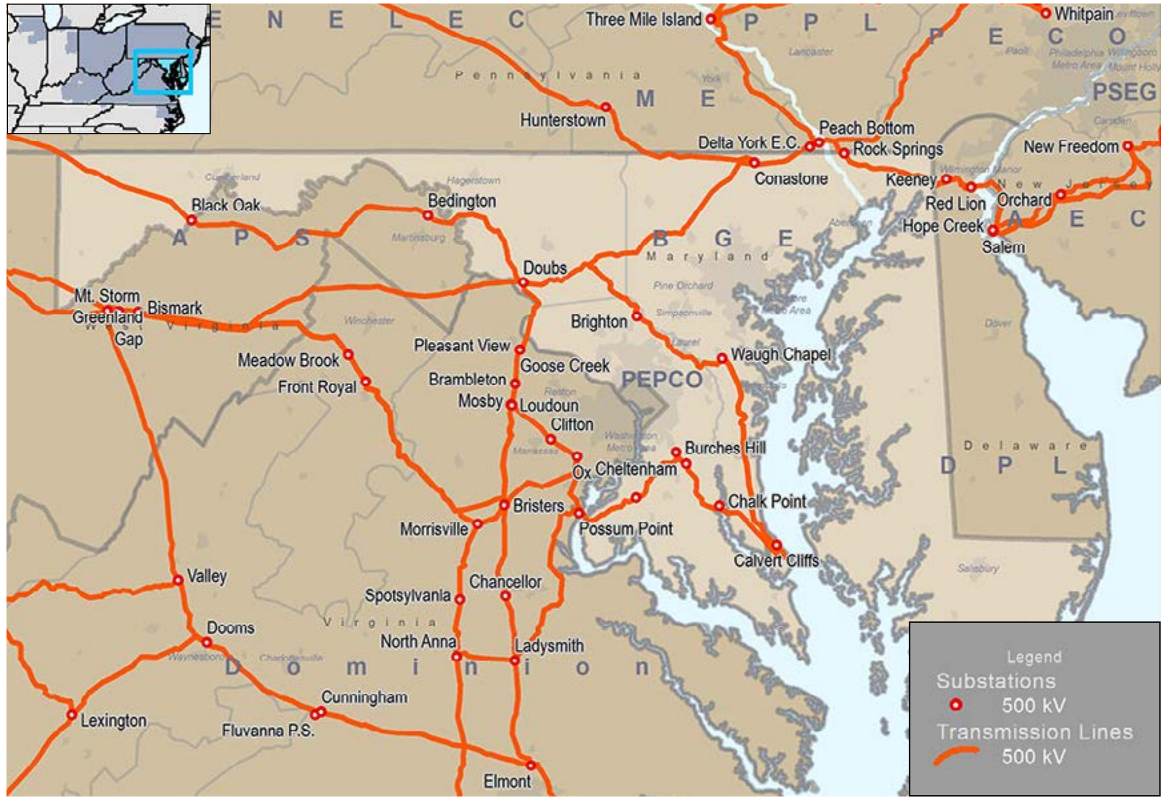
Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2670	Construct new 69 kV-12.5 kV 12/16/20 MVA Dahl Road distribution substation and associated 0.10 mile tap line. Station will be served from the EKPC Shopville-Asahi Motor Wheel transmission line. Build new 7.0-mile 69 kV Floyd-Woodstock transmission line using 556 ACSR conductor. Construct a new four line exit 69 kV breaker station at Norwood Junction.	12/1/2023	$12.70	EKPC	11/19/2021
2	S2765	Rebuild the Fall Rock-Manchester 5.83 mile 69 kV transmission line using 556.5 ACSR conductor.	12/31/2024	$4.40		6/15/2022
3	S2766	Rebuild the 5.12-mile Headquarters-Millersburg Tap 69 kV line section using 556.5 ACSR conductor.	12/31/2025	$3.80		6/15/2022
4	S2767	Build a new 6.4-mile Griffin Junction-Griffin 69 kV line section using 266.8 ACSR conductor parallel to the existing line section. Retire the existing 6.4 mile-line section upon completion of new line.	12/31/2023	$0.00		6/15/2022
5	S2681	Install a new substation, Litton, with two take-off structures, bus work, eight motorized bus disconnects, two motorized line disconnects and two CCVTs for use in an ATO scheme. Loop the 69 kV feeder from Hebron to Limaburg through the substation. Retire eight wooden poles. Install 12 light duty steel poles with 750 feet of 954 ACSR and OPGW. Transfer the static from the wooden poles to the new steel poles.	6/1/2024	$4.80	DEO&K	1/21/2022

6.4: Maryland/District of Columbia RTEP Summary

6.4.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Maryland and the District of Columbia, including facilities owned and operated by Allegheny Power (AP), Baltimore Gas and Electric (BGE), Delmarva Power & Light (DP&L), Potomac Electric Power Company (PEPCO) and Southern Maryland Electric Cooperative (SMECO) as shown on **Map 6.18**. Maryland and the District of Columbia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside PJM.

Map 6.18: PJM Service Area in Maryland/District of Columbia



Renewable Portfolio Standards

Maryland has a mandatory renewable portfolio standard (RPS) target of 50% Tier 1 renewable resources by 2030. This includes a solar carve-out target of at least 14.5% by 2030, which must come from in-state solar resources. The state also requires 2.5% Tier 2 renewable resources each year.

Maryland is also advancing offshore wind to support its clean energy policies. Maryland's Clean Energy Jobs Act of 2019 called for a minimum of 1,200 MW of offshore wind constructed and operational by the year 2030, which is in addition to the 348 MW the state procured in an award issued in 2017.

In 2021, the Maryland Public Service Commission awarded offshore wind renewable energy credits (ORECs) to two more offshore wind projects in order to meet their 2030 target: the 808.5 MW Momentum Wind project and the 846 MW Skipjack 2.1 project. With these additional ORECs being awarded, Maryland is now advancing a total of 2,022.5 MW of offshore wind by 2030.

Maryland also enacted the Climate Solutions Now Act of 2022. The act calls for Maryland to reduce statewide greenhouse gas emissions by 60% from 2006 levels by 2031 and reach statewide net-zero emissions by 2045.

The District of Columbia has a mandatory RPS target of 100% by 2032. The district's RPS target is one of two in the PJM region set at 100%, with the other being Virginia's RPS. The resources serving D.C.'s RPS target must be located within the PJM region. The RPS target also includes a solar carve-out target of 5.5% by 2032 and 10% by 2041.

6.4.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.21** summarizes the expected loads within the state of Maryland and the District of Columbia, and across the PJM region.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

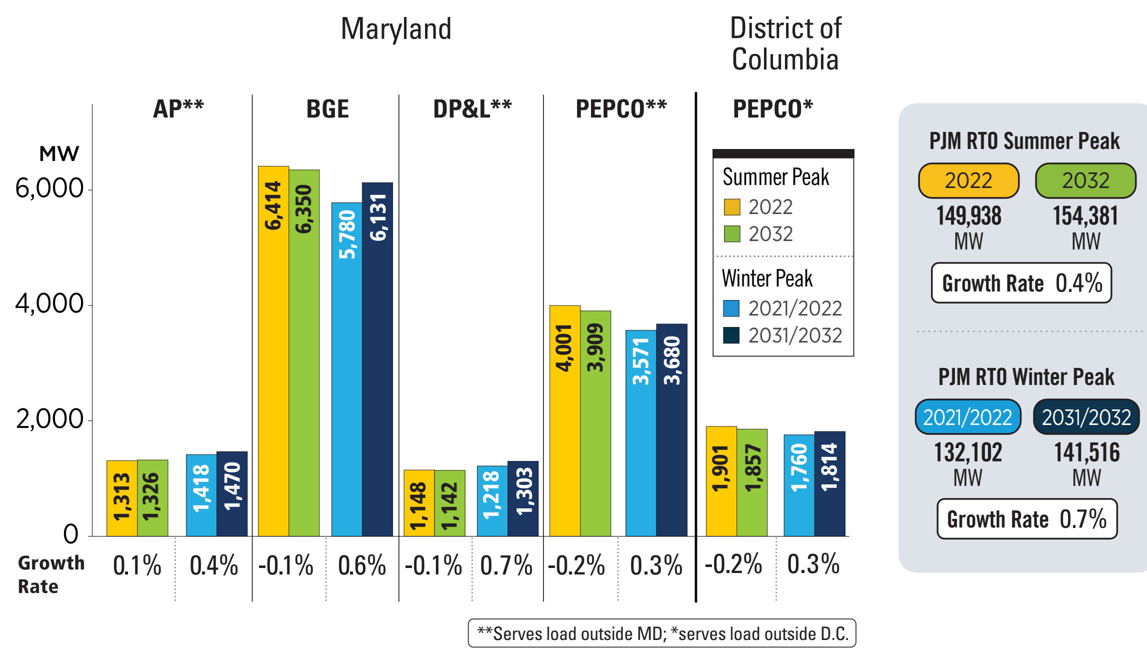
The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

Figure 6.21: Maryland/District of Columbia – 2022 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.4.3 — Existing Generation

Existing generation in Maryland and the District of Columbia as of Dec. 31, 2022, is shown by fuel type in **Figure 6.22**.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

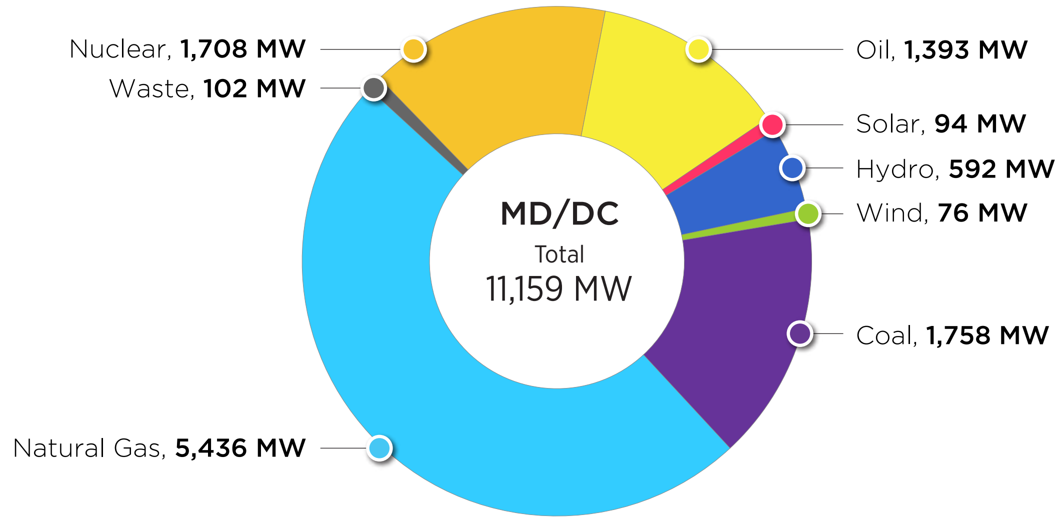
- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in Maryland and the District of Columbia as of Dec. 31, 2022, are discussed next, in **Section 6.4.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

Figure 6.22: Maryland/District of Columbia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



6.4.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Maryland and the District of Columbia, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Maryland and the District of Columbia, as of Dec. 31, 2022, 88 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.22, Table 6.23, Figure 6.23, Figure 6.24** and **Figure 6.25**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.22: Maryland/District of Columbia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	Maryland/District of Columbia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	0	0.00%	529	0.61%
Natural Gas	173	8.03%	7,955	9.16%
Nuclear	37	1.74%	37	0.04%
Oil	18	0.84%	18	0.02%
Other	0	0.00%	273	0.31%
Solar	1,291	60.10%	57,616	66.37%
Storage	629	29.29%	14,148	16.30%
Wind	0	0.00%	6,223	7.17%
Grand Total	**2,149**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.23: Maryland/District of Columbia – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue				Complete				Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	1	10.0	0	0.0	1	10.0
	Diesel	0	0.0	0	0.0	1	0.0	1	5.0	2	5.0
	Natural Gas	8	172.6	0	0.0	34	3,827.2	65	32,860.5	107	36,860.3
	Nuclear	3	37.4	0	0.0	1	0.0	4	4,955.0	8	4,992.4
	Oil	3	18.0	0	0.0	1	0.0	1	2.0	5	20.0
	Other	0	0.0	0	0.0	0	0.0	4	132.0	4	132.0
	Storage	11	629.3	5	17.9	0	0.0	39	454.2	55	1,101.4
Renewable	Biomass	0	0.0	0	0.0	0	0.0	12	227.6	12	227.6
	Hydro	0	0.0	0	0.0	3	60.0	4	88.4	7	148.4
	Methane	0	0.0	0	0.0	5	14.5	6	18.3	11	32.8
	Solar	26	1,291.2	32	397.4	18	57.3	194	1,564.3	270	3,310.2
	Wind	0	0.0	0	0.0	5	40.3	10	265.6	15	305.9
	Grand Total	**51**	**2,148.5**	**37**	**415.3**	**69**	**4,009.3**	**340**	**40,572.9**	**497**	**47,146.0**

Figure 6.23: Maryland/District of Columbia – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

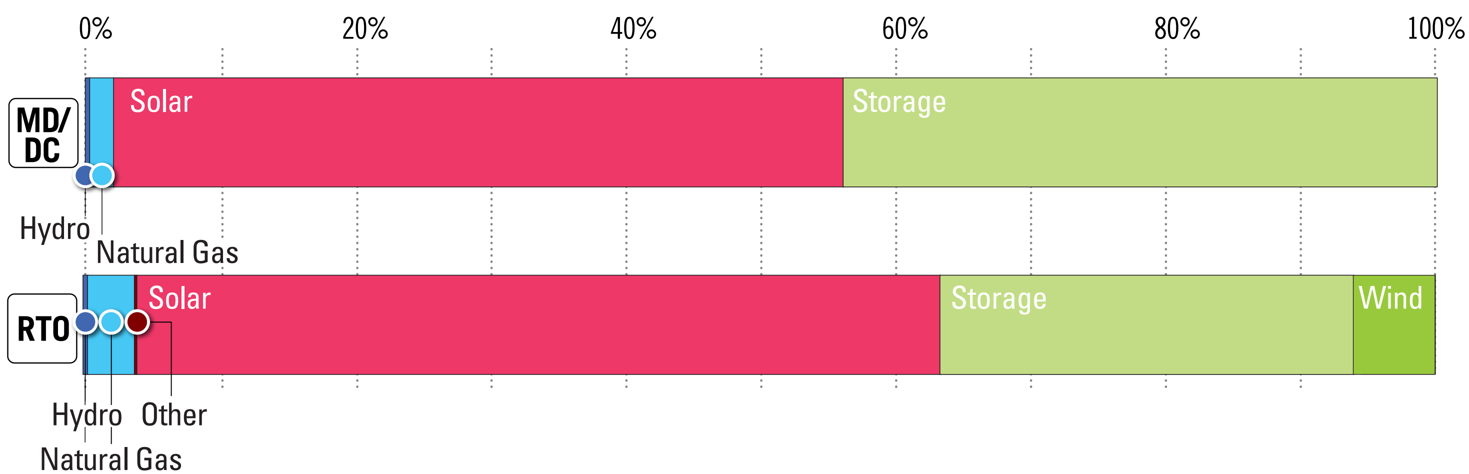


Figure 6.24: Maryland/District of Columbia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)

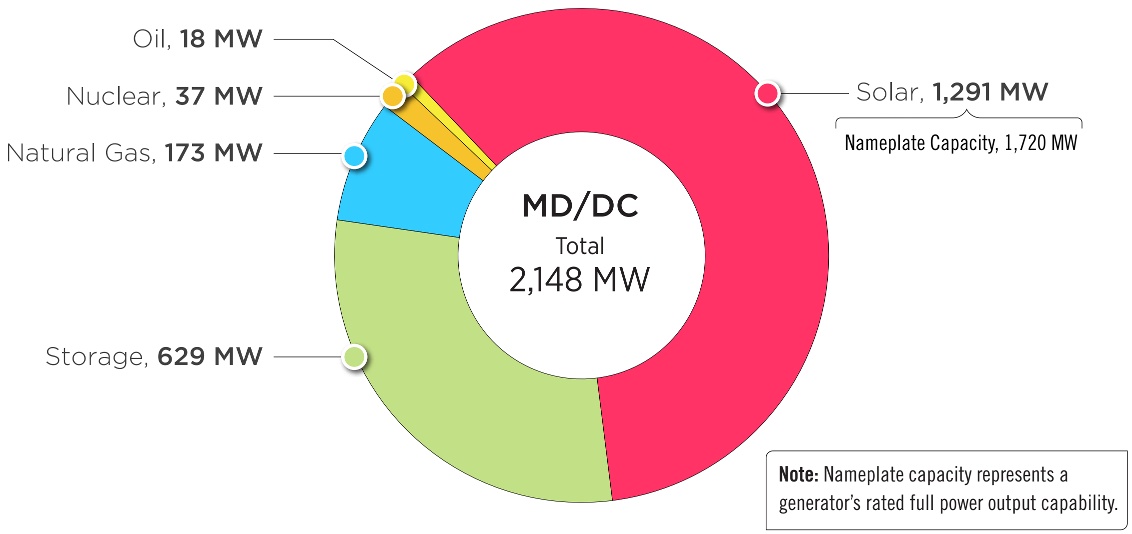


Figure 6.25: Maryland/District of Columbia Progression History of Queue – Interconnection Requests (Dec. 31, 2022)

Percentage of planned capacity and projects that have reached commercial operation

9% Requested capacity megawatts

15.6% Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	28	Interconnection Service Agreements	5,668 MW	6,164 MW
	52	Wholesale Market Participation Agreements	136 MW	271 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.4.5 — Generation Deactivation

Formal generator deactivation requests received by PJM in Maryland and the District of Columbia between Jan. 1, 2022, and Dec. 31, 2022, are summarized in **Map 6.19** and **Table 6.24**.

Deactivation Reliability Studies

PJM has 30 days in which to respond to a generator owner with deactivation study results. Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can reduce voltage support.

Deactivation reliability studies comprise thermal and voltage analysis, including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, reliability criteria violations caused by unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board.

Map 6.19: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2022)

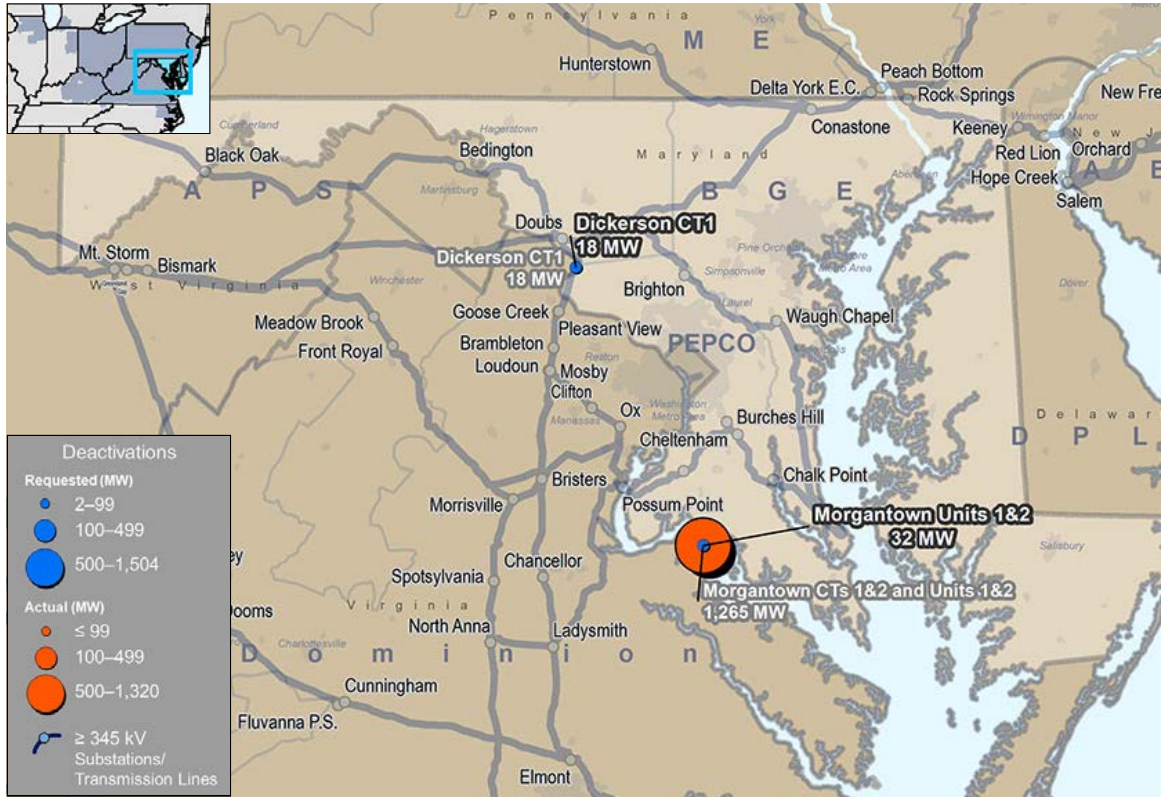


Table 6.24: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2022)

<table>
<tr><th>Unit</th><th>TO Zone</th><th>Fuel Type</th><th>Request Received to Deactivate</th><th>Actual or Projected Deactivation Date</th><th>Age (Years)</th><th>Capacity (MW)</th></tr>
<tr><td>Dickerson CT1</td><td rowspan="5">PEPCO</td><td rowspan="3">Oil</td><td>7/25/2022</td><td>10/23/2022</td><td>55</td><td>18.0</td></tr>
<tr><td>Morgantown CT2</td><td rowspan="2">4/12/2022</td><td rowspan="2">10/1/2022</td><td>51</td><td>16.0</td></tr>
<tr><td>Morgantown CT1</td><td>52</td><td>16.0</td></tr>
<tr><td>Morgantown Unit 2</td><td rowspan="2">Coal</td><td rowspan="2">6/9/2021</td><td rowspan="2">5/31/2022</td><td>50</td><td>619.4</td></tr>
<tr><td>Morgantown Unit 1</td><td>51</td><td>613.3</td></tr>
</table>

6.4.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in Maryland and the District of Columbia are summarized in **Map 6.20** and **Table 6.25**.

6.4.7 — Network Projects

No network projects in Maryland and the District of Columbia were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.20: Maryland/District of Columbia Baseline Projects (Dec. 31, 2022)

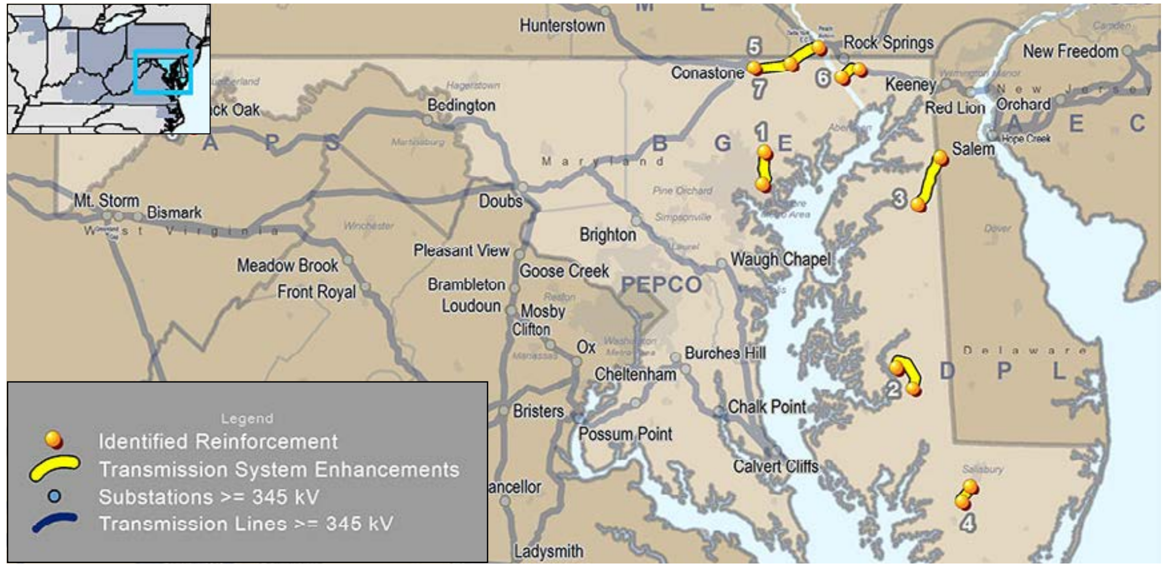


Table 6.25: Maryland/District of Columbia Baseline Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3668		Upgrade Windy Edge 115 kV substation conductor to increase ratings of the Windy Edge-Chesco Park 110501 circuit.	6/1/2026	$0.50	BGE	11/18/2021
2	B3688		Replace the 4/0 SDCU stranded bus with 954 ACSR and a 600A disconnect switch with a 1200A disconnect switch on the 6716 line terminal inside Todd substation (on the Preston-Todd 69 kV circuit).	6/1/2026	$0.75	DP&L	12/20/2021
3	B3669	.1	Replace terminal equipment (stranded bus, disconnect switch and circuit breaker) at Church substation (Townsend-Church 138 kV).	12/1/2026	$1.00	DP&L	11/18/2021
4	B3670		Upgrade terminal equipment on the Loretto-Fruitland 69 kV circuit: Replace the 477 ACSR stranded bus on the 6711 line terminal inside Loretto substation and the 500 SDCU stranded bus on the 6711 line terminal inside Fruitland substation with 954 ACSR conductor.	6/1/2026	$0.80	DP&L	11/18/2021
5	B3728	.1	Upgrade two breaker bushings on the 500 kV line 5012 (Conastone-Peach Bottom) at Conastone substation.	12/1/2027	$2.00	BGE	10/4/2022
6	B3729		Install cable shunts on each phase, on each side of four dead-end structures and replace existing insulator bells to increase maximum operating temperature of DP&L circuit 22088 (Colora-Conowingo 230 kV).	6/1/2027	$0.26	DP&L	10/4/2022
7	B3737	.46	Install a new breaker at Graceton 230 kV substation to terminate a new 230 kV line from the new greenfield North Delta station.	6/1/2029	$2.85	BGE	11/4/2022
		.52	Replace one 63 kA circuit breaker "B4" at Conastone 230 kV with 80 kA.				

6.4.8 — Supplemental Projects

Supplemental projects received by PJM in 2022 in Maryland and the District of Columbia are summarized in **Map 6.21** and **Table 6.26**.

6.4.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Maryland and the District of Columbia were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.21: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2022)

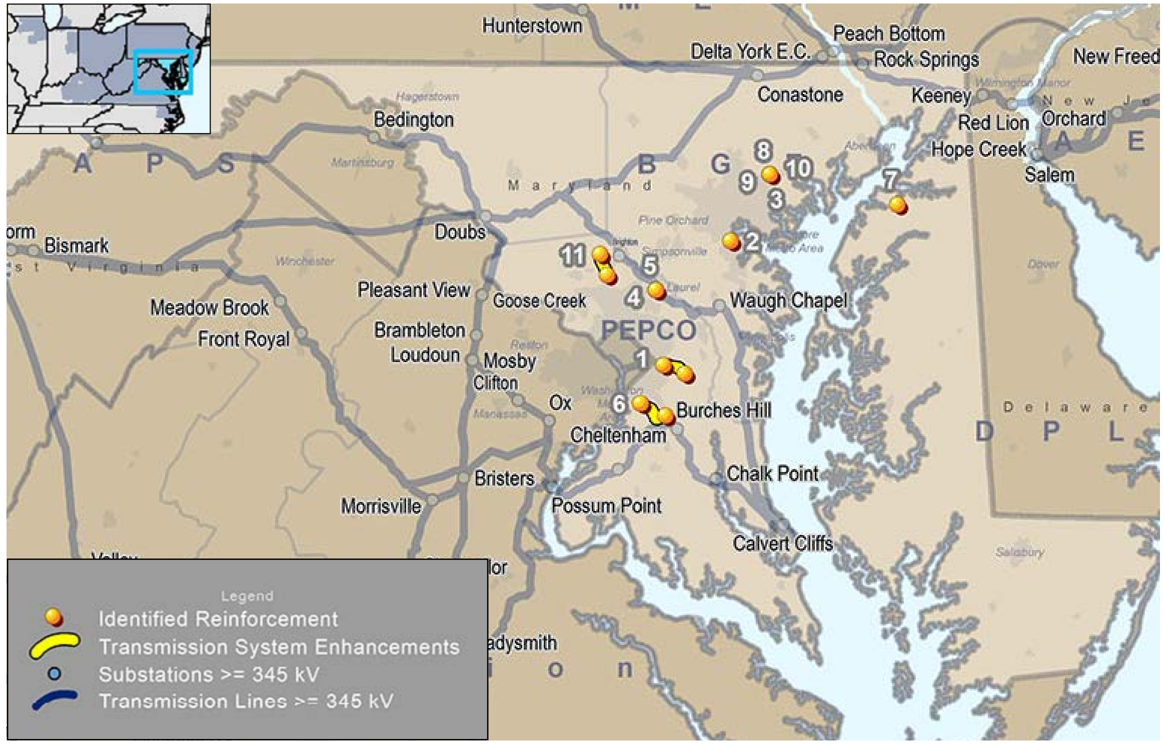


Table 6.26: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2751	Upgrade a line relay on 230 kV Circuit 23058 (Ritchie-Oak Grove) at Oak Grove substation.	12/1/2023	$0.42	PEPCO	8/9/2022
2	S2589	Replace Pumphrey circuit breakers No. B22, B28, B29.	11/30/2021	$5.20	BGE	8/13/2021
3	S2590	Replace Windy Edge circuit breaker No. B27.	9/30/2021	$1.00	BGE	8/13/2021
4	S2717	Replace 230 kV circuit breaker No. 3A at Burtonsville, associated disconnect switches and strain bus.	12/1/2022	$1.07	PEPCO	3/8/2022
5	S2718	Replace 230 kV circuit breaker No. 4A at Burtonsville, associated disconnect switches and strain bus.	6/1/2022	$1.07	PEPCO	3/8/2022
6	S2719	Upgrade relays and metering on 230 kV circuit 23090 (Burches Hill-Palmers Corner).	12/1/2022	$0.25	PEPCO	3/8/2022
7	S2721	Reconfigure and expand the Chestertown 69 kV bus to six-breaker ring bus to prevent a stuck breaker from causing an outage on either both transmission lines or both transformers simultaneously.	3/30/2023	$6.30	DP&L	3/17/2022
8	S2722	Replace Windy Edge circuit breaker No. B6.	4/7/2022	$1.30	BGE	3/17/2022
9	S2723	Replace Windy Edge circuit breaker No. B32.	5/6/2022	$1.30	BGE	3/17/2022
10	S2724	Replace Windy Edge circuit breaker No. B26.	6/3/2022	$13.00	BGE	3/17/2022
11	S2727	Upgrade relays and metering on 230 kV circuit 23008 (Mt. Zion-Norbeck) at Norbeck substation.	7/31/2022	$0.40	PEPCO	4/12/2022

6.5: Southwestern Michigan RTEP Summary

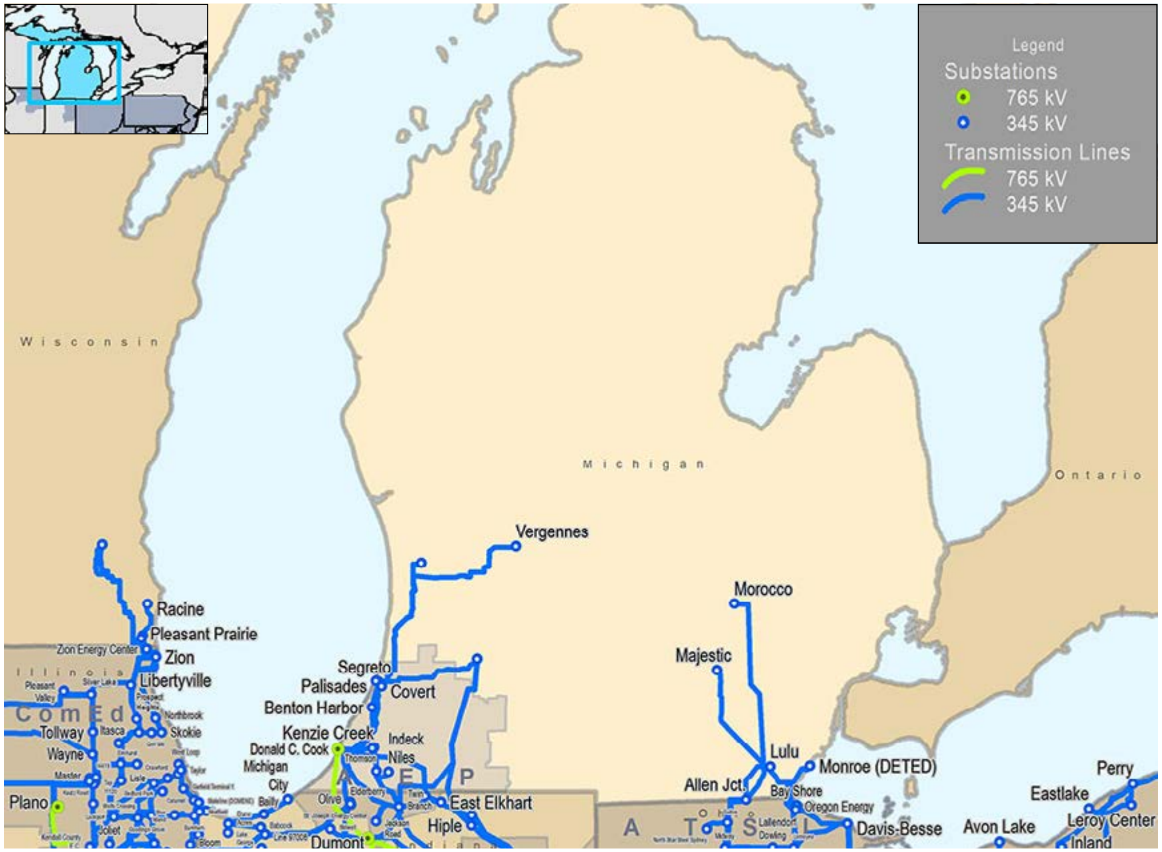
6.5.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in southwestern Michigan, including facilities owned and operated by American Electric Power (AEP) and ITC Interconnection (ITCI) as shown on **Map 6.22**. The transmission system in southwestern Michigan delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, Michigan has a mandatory renewable portfolio standard (RPS) target of 15% by 2022.

Map 6.22: PJM Service Area in Southwestern Michigan



6.5.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.26** summarizes the expected loads within southwestern Michigan and across the PJM region.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

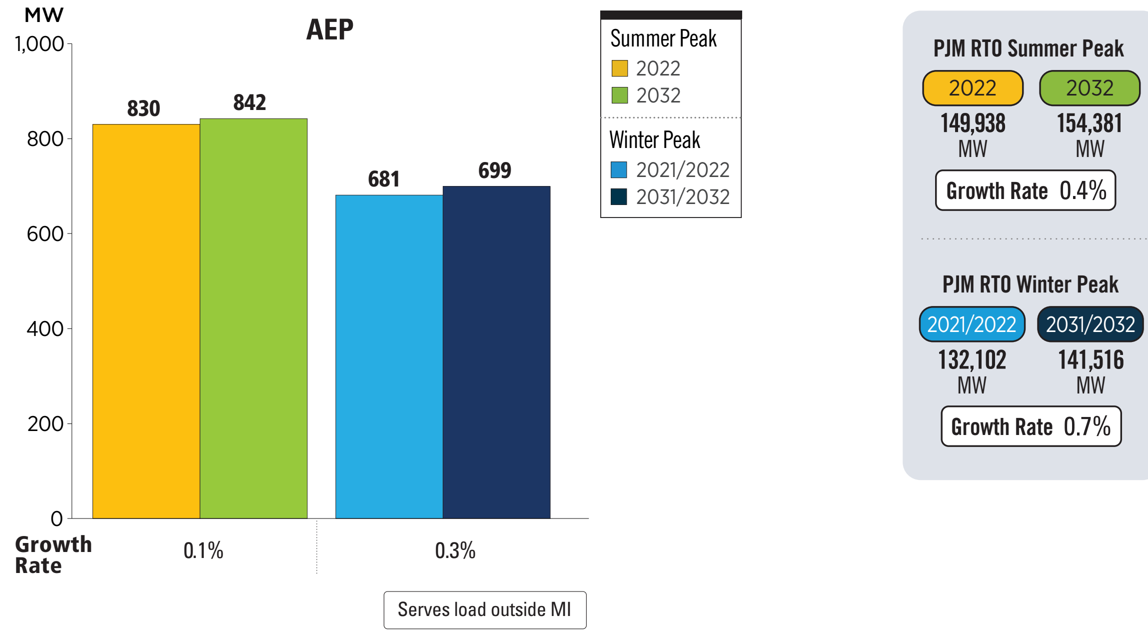
The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

Figure 6.26: Southwestern Michigan – 2022 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.5.3 — Existing Generation

Existing generation in southwestern Michigan as of Dec. 31, 2022, is shown by fuel type in **Figure 6.27**.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

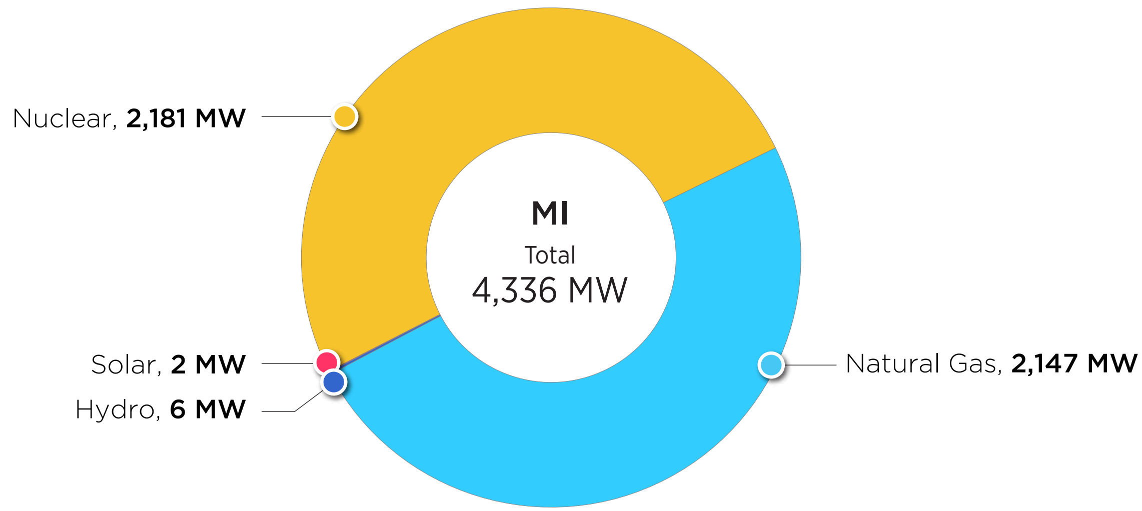
- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in southwestern Michigan as of Dec. 31, 2022, are discussed next, in **Section 6.5.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

Figure 6.27: Southwestern Michigan – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



6.5.4 — Interconnection Requests

PJM markets continue to attract generation proposals in southwestern Michigan, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in southwestern Michigan, as of Dec. 31, 2022, 15 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.27, Table 6.28, Figure 6.28, Figure 6.29** and **Figure 6.30**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.27: Southwestern Michigan – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	New Jersey Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0%	0	0%
Hydro	0	0%	0	0%
Natural Gas	145	13.87%	7,955	9.16%
Nuclear	0	0%	0	0%
Oil	0	0%	0	0%
Other	0	0%	0	0%
Solar	820	78.36%	57,616	66.37%
Storage	81	7.78%	14,148	16.30%
Wind	0	0%	0	0%
Grand Total	**1,046**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.28: Southwestern Michigan – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue		Complete				Total	
		Active		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Natural Gas	1	145.0	4	2,140.0	1	1,120.0	6	3,405.0
	Nuclear	0	0.0	3	205.0	0	0.0	3	205.0
	Other	0	0.0	0	0.0	1	0.0	1	0.0
	Storage	3	81.3	0	0.0	1	75.0	4	156.3
Renewable	Methane	0	0.0	3	10.4	0	0.0	3	10.4
	Solar	11	819.5	1	2.3	5	237.8	17	1,059.5
	Wind	0	0.0	0	0.0	1	26.0	1	26.0
	Grand Total	**15**	**1,045.8**	**11**	**2,357.7**	**9**	**1,458.8**	**35**	**4,862.2**

Figure 6.28: Southwestern Michigan – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

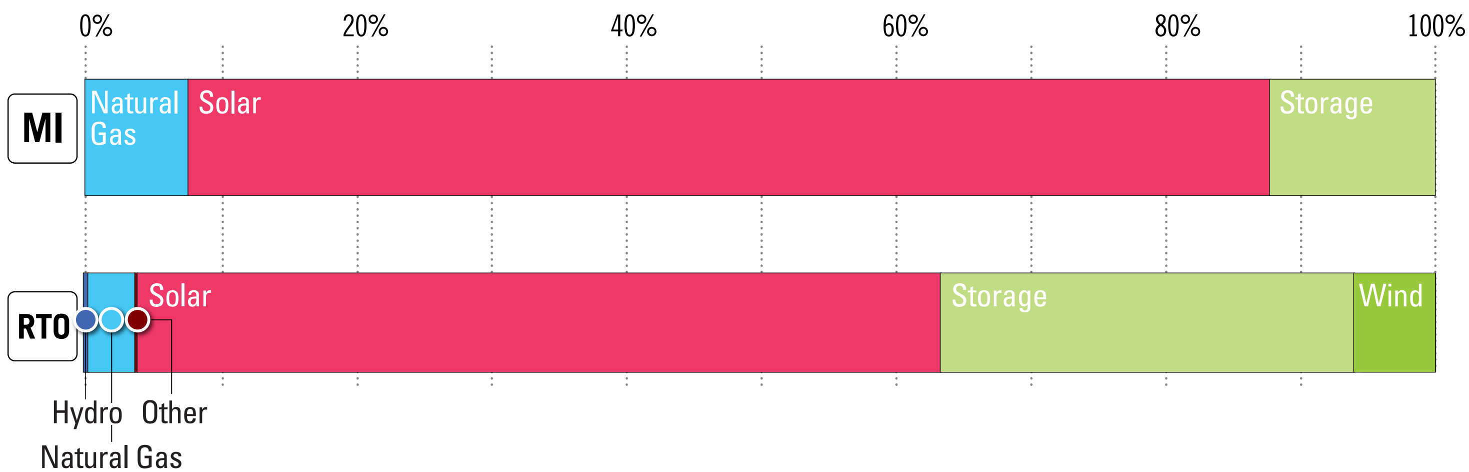
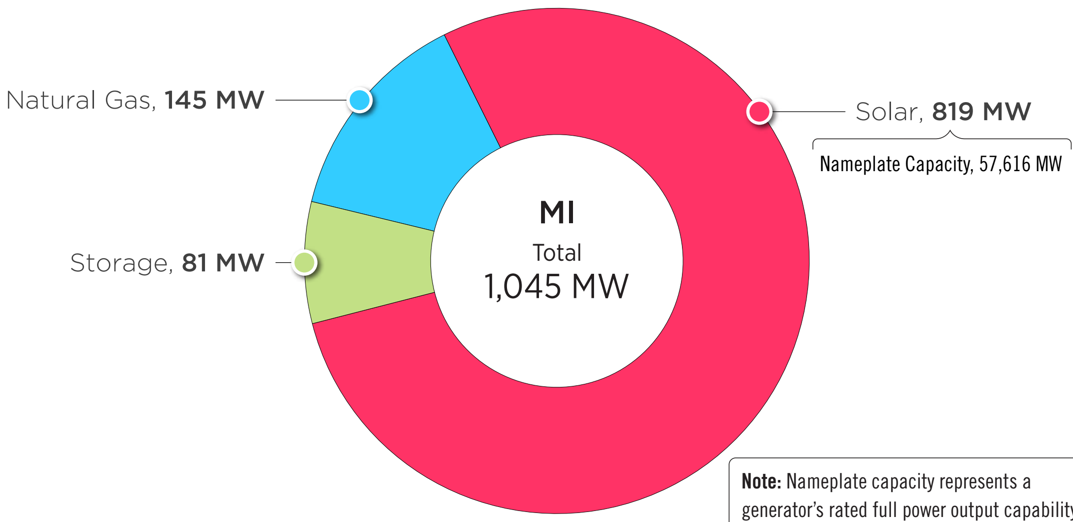
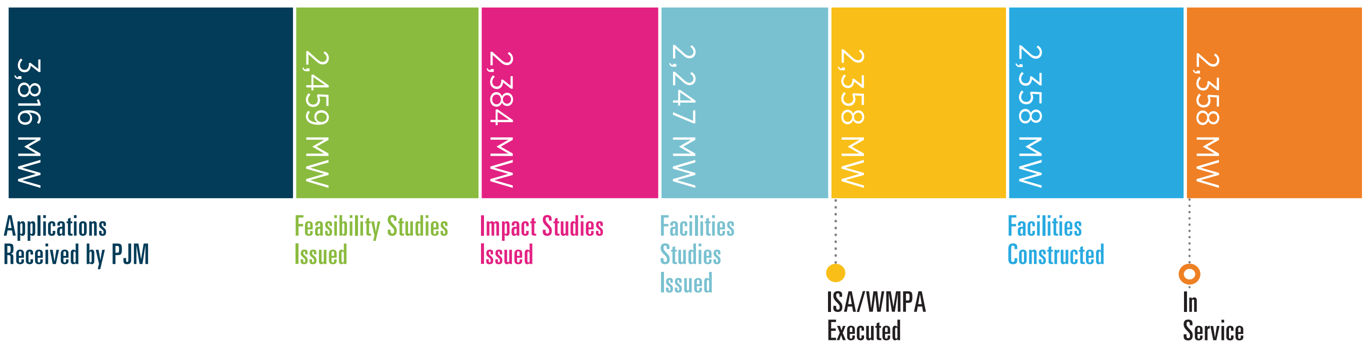


Figure 6.29: Southwestern Michigan – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.30: Southwestern Michigan Progression History of Queue – Interconnection Requests (Dec. 31, 2022)



Percentage of planned capacity and projects that have reached commercial operation

61.8% Requested capacity megawatts

55% Requested projects

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.5.5 — Generation Deactivation

There were no generating unit deactivation requests in southwestern Michigan between Jan. 1, 2022, and Dec. 31, 2022, as part of the 2022 RTEP.

6.5.6 — Baseline Projects

No baseline projects in southwestern Michigan were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.5.7 — Network Projects

No network project requests in southwestern Michigan were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.23: Southwestern Michigan Network Projects (Dec. 31, 2022)

Table 6.29: Southwestern Michigan Network Projects (Dec. 31, 2022)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N7508	Install a new 345-138 kV 450 MVA transformer, 138 kV circuit breaker, 345 kV circuit breaker, two three-pole turning structures, monopole transition structure, 345 kV rigid bus conductor, and Discontinuous Inductor Current Mode (DICM) expansion.	MISO - J793	3/1/2023	$7.91	AEP	11/1/2022

6.5.8 — Supplemental Projects

2022 RTEP supplemental projects in southwestern Michigan are summarized in **Map 6.24** and **Table 6.30**.

6.5.9 — Merchant Transmission Project Requests

No merchant transmission project requests in southwestern Michigan were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.24: Southwestern Michigan Supplemental Projects (Dec. 31, 2022)

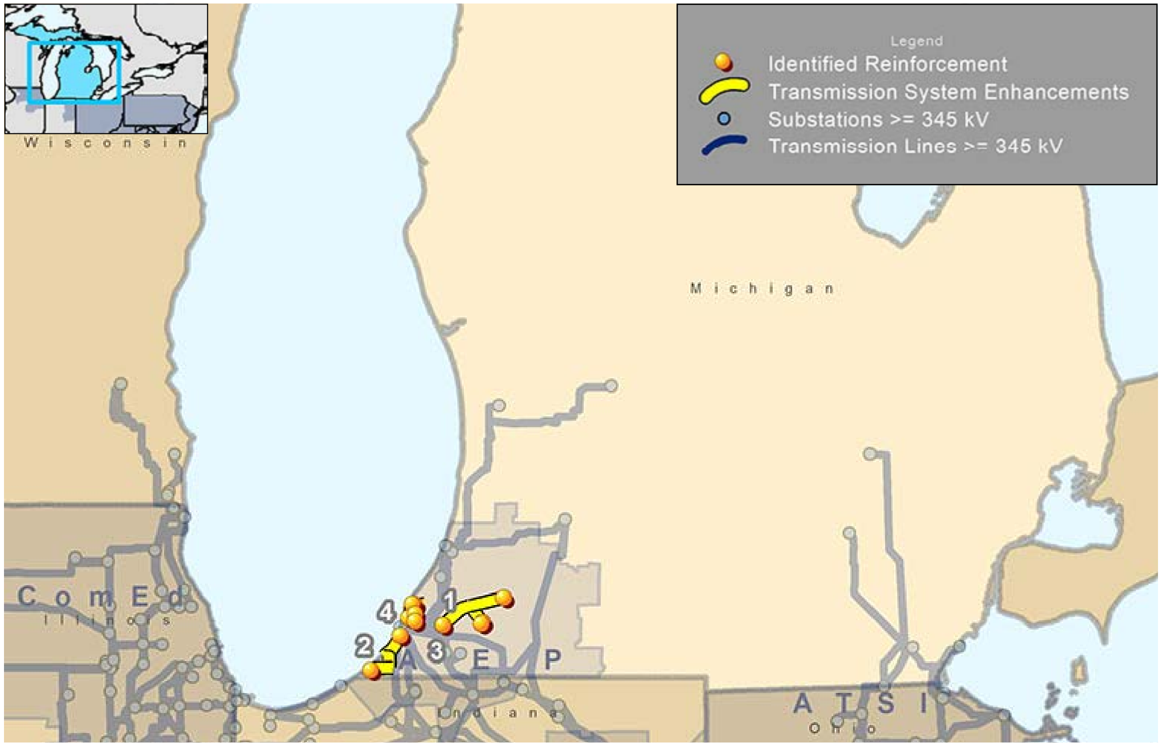


Table 6.30: Southwestern Michigan Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2657	.1	Retire the ~10.2 miles of Blossom Trail-Colby 34.5 kV line between Blossom Trail-Dowagiac Tap.	6/13/2024	$21.60	AEP	10/15/2021
		.2	Replace the failed Rudy Tap switch at Ruby tap 34.5 kV.				
		.3	Reterminate the Valley 138 kV line into Colby with a .1-mile new extension at Colby North Ext. 138 kV.				
		.4	Reterminate the Kenzie Creek 138 kV line into Colby with a .25-mile new extension at Colby South Ext. 138 kV.				
		.5	Reterminate the Rothedew 34.5 kV line into Colby.				
		.6	Reterminate the Dowagiac 34.5 kV feed back into Colby station.				
		.7	Reterminate the Rudy Tap 34.5 kV feed back into Colby station.				

Table 6.30: Southwestern Michigan Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	S2657 Cont.	.8	Reterminate the Kenzie Creek 69 kV feed back into Colby station.	6/13/2024	$21.60	AEP	10/15/2021
		.9	Retire the Colby 138 kV switch.				
		.10	Build a new 138 kV yard with four circuit breakers built in a ring configuration at Colby 138/69/34.5 kV on the existing property. Install a new 138/34.5 50 MVA transformer with a low-side circuit breaker protecting the single-line exit toward Rudy tap to replace the source previously served by the retired line to Blossom Trail. Install three 34.5 kV circuit breakers on a new 34.5 kV bus that will be connected to the existing 138/69/34.5 kV transformer, and the Rothedew and Dowagiac exits. Install a new 69 kV circuit breaker toward Kenzie Creek.				
		.11	Remove circuit breaker “M” and reuse it at Colby station at Blossom Trail 138/69/34.5 kV.				
2	S2658		Rebuild the 22.1 mile New Buffalo-Bridgman 69 kV line with 556.5 ACSR Dove.	10/1/2025	$55.50		10/15/2021
3	S2686		Replace 138kV Circuit Breakers “F,” “F1,” “F2,” “G” and “G1” with 40 kA circuit breakers at Kenzie Creek 345/138/69 kV station.	3/3/2024	$1.80		1/21/2022
4	S2796	.1	Rebuild the remaining ~6.2 miles of the Derby-Hickory Creek 69 kV line utilizing 795 ACSR, which will match the ~2.5 miles built in 2013.	11/1/2025	$24.10		6/15/2022
		.2	Retire the ~6.16 mile Derby-Hickory Creek 34.5 kV line.				
		.3	Retire the ~1.73 mile Bendix Lakeshore 34.5 kV Tap.				
		.4	At Hawthorne SS 69 kV/Bendix Sw 34. 5 kV, remove the switch from Bendix Sw and reuse it at Hawthorne SS.				
		.5	Rework the through-path to accommodate the new line entrances at Stevensville 69kV.				
		.6	Install Trafalgar station to serve the Bendix 34.5 kV customer. This station will include a new 69 kV switcher and a new 69/34.5 kV transformer. Two Circuit Breakers will be reused from Derby and Hickory Creek.				
		.7	At Scottdale 69 kV, re-energize to 69 kV.				
		.8	At Derby 138/69/34.5 kV, retire the 34.5 kV voltage class				
		.9	Re-energize at Boxer-Blossom Trail 34.5 kV.				
		.10	Re-energize at Boxer-Hickory Cr 69 kV.				
		.11	At Trafalgar-Bendix 34.5 kV, build a 0.15 mile radial line from Trafalgar to Bendix Lakeshore.				

6.6: New Jersey RTEP Summary

6.6.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in New Jersey, including facilities owned and operated by Atlantic City Electric (AE), Jersey Central Power & Light (JCP&L), Linden VFT (VFT), Neptune Regional Transmission System (Neptune RTS), Public Service Electric & Gas Company (PSEG) and Rockland Electric Company (RECO) as shown on **Map 6.25**. New Jersey's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

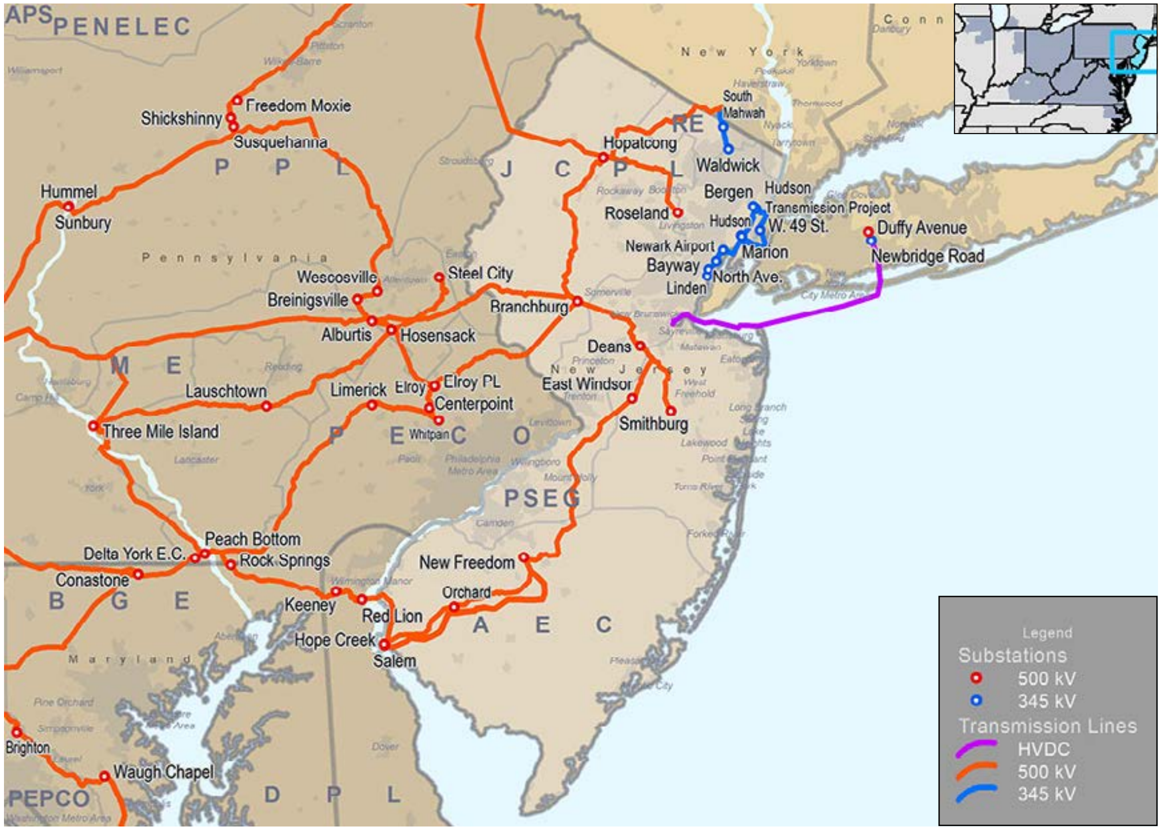
Renewable Portfolio Standards

New Jersey has a mandatory renewable portfolio standard (RPS) target of 50% Class I renewable resources by 2030. The state also requires 2.5% Class II renewable resources each year.

In 2021, New Jersey implemented a new solar incentive program that seeks up to 3,750 MW of new solar generation by 2026.

New Jersey is advancing offshore wind to support its clean energy policies. The Clean Energy Act of 2018 requires New Jersey to procure at least 3,500 MW of offshore wind. In 2019, the state's offshore wind target was increased to 7,500 MW by 2035 through Gov. Phil Murphy's Executive Order No. 92. In 2022, that target was increased to 11,000 MW by 2040 through Gov. Murphy's Executive Order No. 307.

Map 6.25: PJM Service Area in New Jersey



In 2019, New Jersey awarded offshore wind renewable energy credits (ORECs) to the 1,100 MW Ocean Wind 1 project. For its next solicitation, the state sought between 1,200 MW to 2,400 MW of offshore wind. In 2021, New Jersey awarded ORECs to two more offshore wind projects – the 1,148 MW Ocean Wind 2 project and the 1,509.6 MW Atlantic Shores project. New Jersey has now awarded ORECs to 3,757.6 MW of offshore wind. In October 2022, the New Jersey Board of Public Utilities issued an order to approve transmission solutions that support the state's offshore wind development as part of the State Agreement Approach.

6.6.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.31** summarizes the expected loads within the state of New Jersey and across the PJM region.

Load Forecast Accuracy Model Improvements

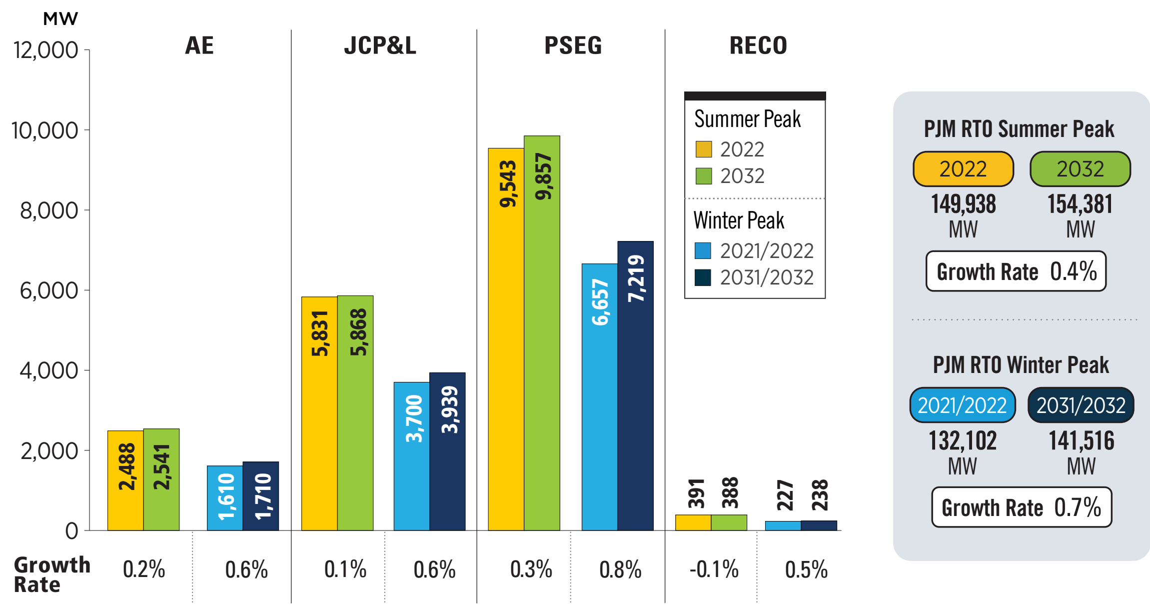
During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).

Figure 6.31: New Jersey – 2022 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

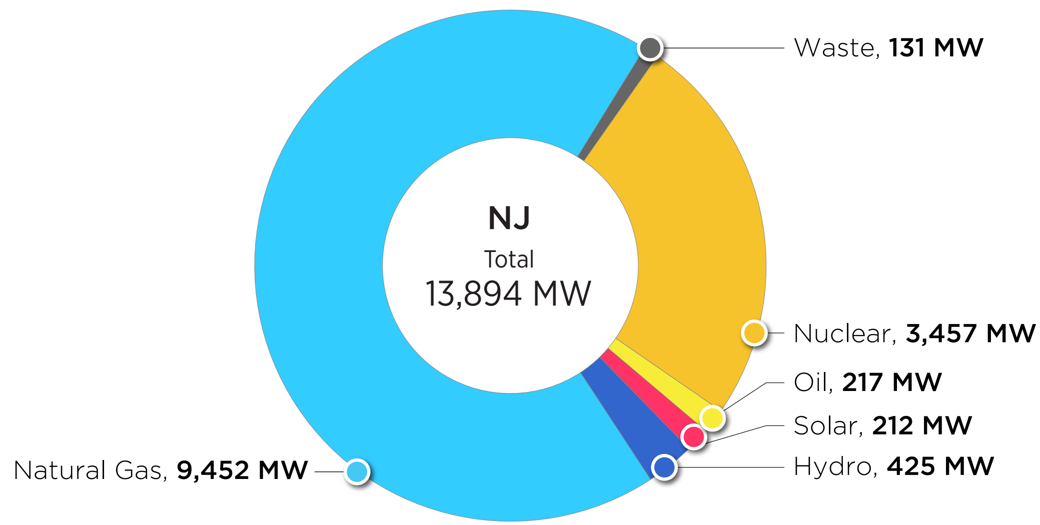
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

6.6.3 — Existing Generation

Existing generation in New Jersey as of Dec. 31, 2022, is shown by fuel type in **Figure 6.32**.

Figure 6.32: New Jersey – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in New Jersey as of Dec. 31, 2022, are discussed next, in **Section 6.6.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

6.6.4 — Interconnection Requests

PJM markets continue to attract generation proposals in New Jersey, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in New Jersey, as of Dec. 31, 2022, 129 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.31, Table 6.32, Figure 6.33, Figure 6.34** and **Figure 6.35**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.31: New Jersey – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	New Jersey Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	30	0.70%	529	0.61%
Natural Gas	53	1.25%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	0	0.00%	273	0.31%
Solar	749	17.57%	57,616	66.37%
Storage	1,535	36.00%	14,148	16.30%
Wind	1,897	44.48%	6,223	7.17%
Grand Total	**4,264**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.32: New Jersey – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue				Complete				Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0	0	0.0	0	0.0	1	15.0	1	15.0
	Natural Gas	3	53.1	3	51.1	78	7,830.0	181	51,838.5	265	59,772.7
	Nuclear	0	0.0	0	0.0	6	381.0	0	0	6	381.0
	Oil	0	0.0	0	0.0	2	35.0	8	945.0	10	980.0
	Other	0	0.0	0	0.0	0	0.0	6	45.5	6	45.5
	Storage	41	1,535.2	8	4.8	6	4.0	53	283.4	108	1,827.3
Renewable	Biomass	0	0.0	0	0.0	0	0.0	3	17.3	3	17.3
	Hydro	1	30.0	0	0.0	2	20.5	2	1,001.1	5	1,051.6
	Methane	0	0.0	0	0.0	12	30.9	9	40.6	21	71.5
	Solar	41	749.4	20	44.4	122	266.4	510	1,845.4	693	2,905.6
	Wind	11	1,896.7	1	121.4	1	0.0	24	1,710.5	37	3,728.6
	Grand Total	**97**	**4,264.4**	**32**	**221.7**	**229**	**8,567.8**	**797**	**57,742.4**	**1,155**	**70,796.2**

Figure 6.33: New Jersey – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

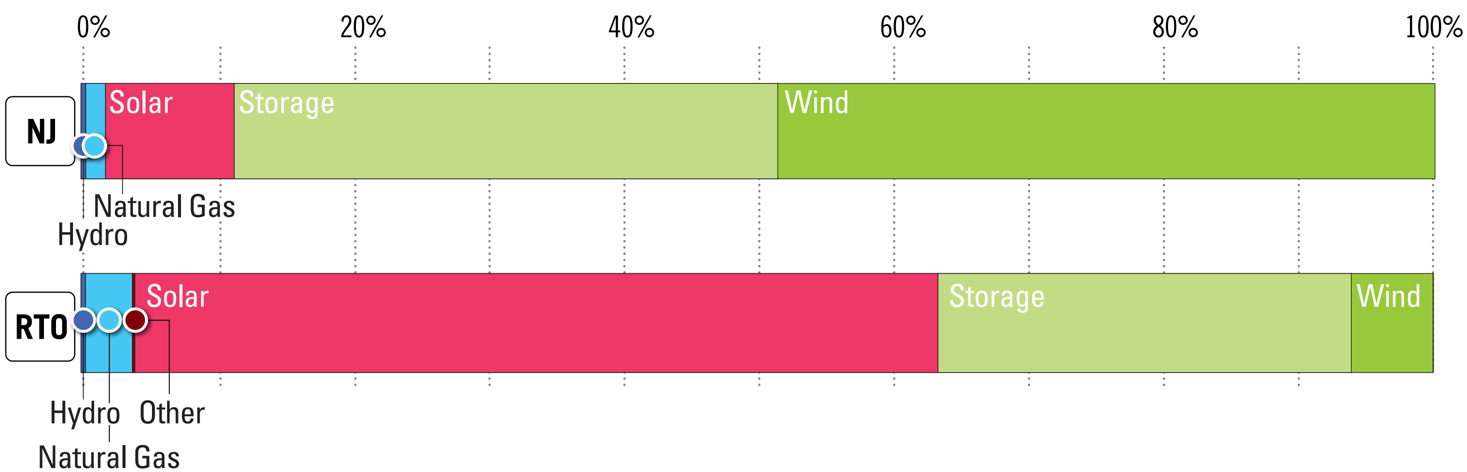
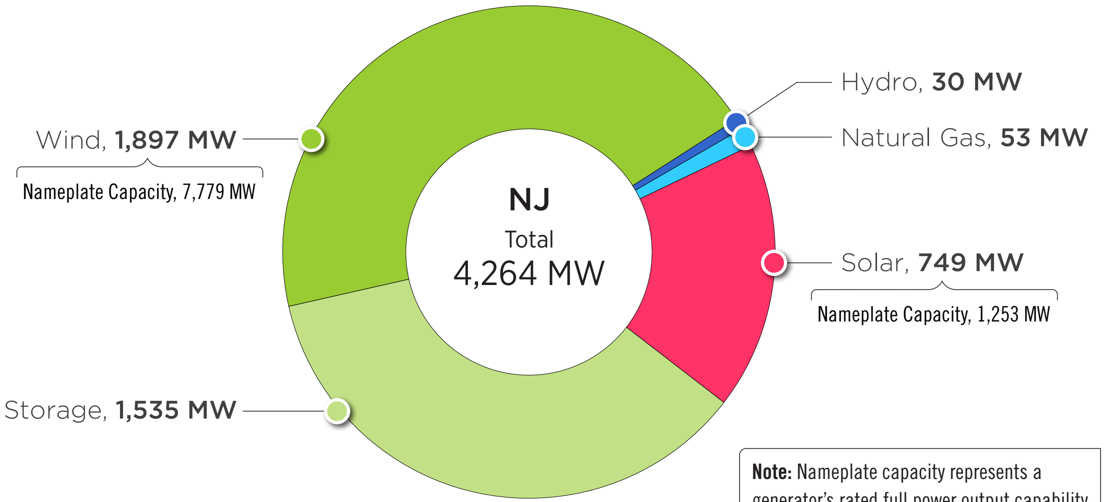


Figure 6.34: New Jersey – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.35: New Jersey Progression History of Queue – Interconnection Requests (Dec. 31, 2022)

			Capacity	Nameplate
Projects withdrawn after final agreement	25	Interconnection Service Agreements	2,670 MW	3,102 MW
	153	Wholesale Market Participation Agreements	383 MW	1,092 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.6.5 — Generation Deactivation

Formal generator deactivation requests received by PJM in New Jersey between Jan. 1, 2022, and Dec. 31, 2022, are summarized in **Map 6.26** and **Table 6.33**.

Deactivation Reliability Studies

PJM has 30 days in which to respond to a generator owner with deactivation study results. Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can reduce voltage support.

Deactivation reliability studies comprise thermal and voltage analysis, including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, reliability criteria violations caused by unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board.

Map 6.26: New Jersey Generation Deativations (Dec. 31, 2022)

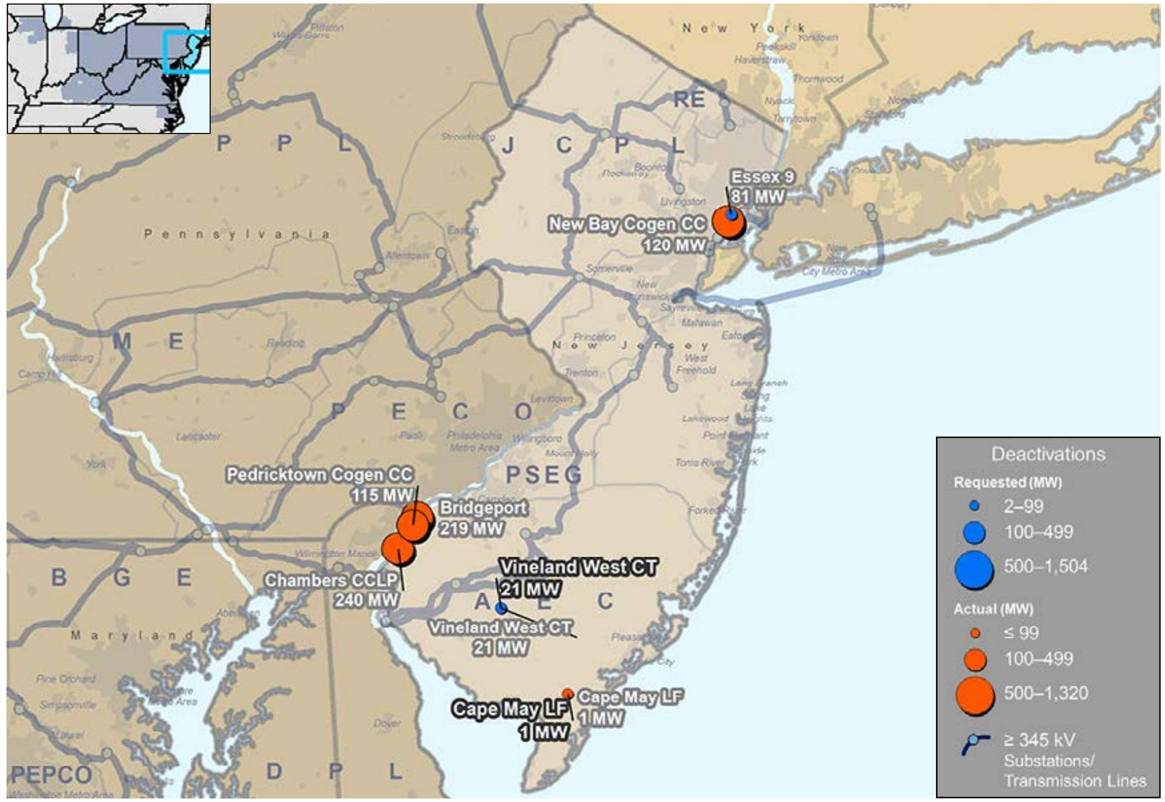


Table 6.33: New Jersey Generation Deactivations (Dec. 31, 2022)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Vineland West CT	AE	Oil	7/6/2022	10/14/2022	50	21.1
Cape May County Municipal LF		Methane	5/5/2022	3/1/2022	9	0.6
Essex 9	PSEG	Natural Gas	3/3/2022	6/1/2022	32	81.0
Logan	AE	Coal	3/9/2022	5/31/2022	27	219.0
Chambers CCLP				6/7/2022	27	240.0
New Bay Cogen CC	PSEG	Natural Gas	7/15/2021	6/1/2022	28	120.2
Pedricktown Cogen CC	AE				29	115.3

6.6.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in New Jersey are summarized in **Map 6.27** and **Table 6.34**.

6.6.7 — Network Projects

No network projects in New Jersey were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.27: New Jersey Baseline Projects (Dec. 31, 2022)

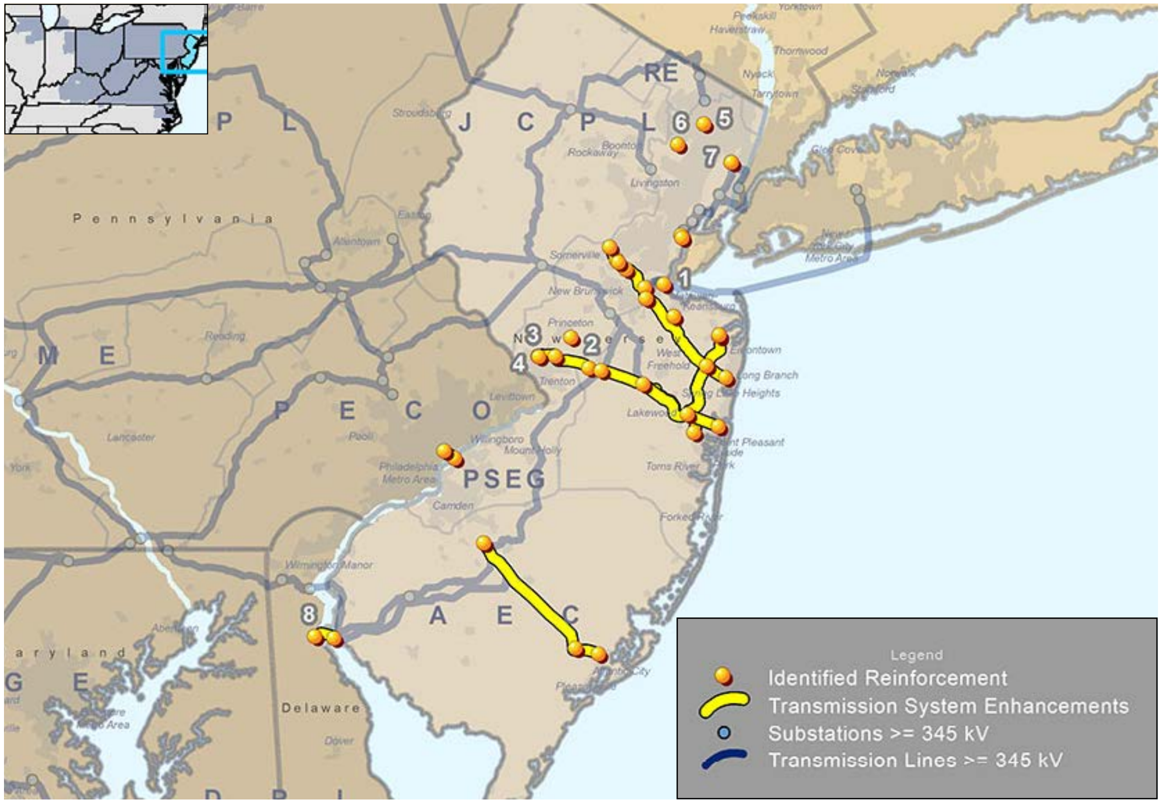


Table 6.34: New Jersey Baseline Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3130	.11	Replace four Atlantic 34.5 kV breakers (BK1A, BK1B, BK3A and BK3B) with 63 kA rated breakers and associated equipment.	9/30/2023	$7.70	JCP&L	5/16/2022
		.12	Replace six Werner 34.5 kV breakers (E31A_Prelim, E31B_Prelim, V48 future, W101, M39 and U99) with 40 kA rated breakers and associated equipment.	6/1/2024			
2	B3703		Construct a third 69 kV supply line from Penns Neck substation to the West Windsor substation.	1/1/2023	$1.05	PSEG	1/20/2022

Table 6.34: New Jersey Baseline Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	B3704		Replace the Lawrence switching station 230/69 kV transformer No. 220-4 and its associated circuit switchers with a new larger capacity transformer with load tap changer (LTC) and new dead tank circuit breaker. Install a new 230 kV gas insulated breaker, associated disconnects, overhead bus and other necessary equipment to complete the bay within the Lawrence 230 kV switchyard.	6/1/2026	$13.36	PSEG	2/8/2022
4	B3705		Replace existing 230/138 kV Athenia No. 220-1 transformer.	6/1/2026	$13.04	PSEG	2/8/2022
5	B3706		Replace Fair Lawn 230/138 kV transformer No. 220-1 with an existing O&M system spare at Burlington.	6/1/2026	$4.45	PSEG	2/8/2022
6	B3716		Construct a third 69 kV supply line from Totowa substation to the customer's substation.	1/1/2025	$8.20	PSEG	6/13/2022
7	B3719		Replace the two existing 1200A Bergen 138 kV circuit switchers with two 138 kV disconnect switches to achieve a minimum summer normal device rating of 298 MVA and a minimum summer emergency rating of 454 MVA.	12/31/2022	$1.20	PSEG	9/15/2022
8	B3737	.1	Reconfigure Larrabee substation.	6/1/2029	$947.40	JCP&L	11/4/2022
		.2	Install direct connection equipment at Larrabee 230 kV substation.				
		.3	Update relay settings on the Larrabee 230 kV line at Lakewood generator substation.				
		.4	Install Larrabee to South Lockwood 34.5 kV line transfer equipment.				
		.5	Build new Larrabee Collector station-Larrabee 230 kV line.				
		.6	Build new Larrabee Collector station-Smithburg No. 1 500 kV line built to 'double circuit' to accommodate a 500 kV line and a 230 kV line.	12/31/2027			
		.7	Rebuild G1021 Atlantic-Smithburg 230 kV line between the Larrabee and Smithburg substations as a double circuit 500 kV/230 kV line.				
		.8	Expand Smithburg substation 500 kV four-breaker ring.				
		.9	Upgrade Larrabee substation.	6/1/2030			
		.10	Convert Atlantic 230 kV substation to double-breaker double-bus.				
		.11	Update relay settings on the Atlantic 230 kV line at Freneau substation.				
		.12	Update relay settings on the Atlantic 230 kV line at Smithburg substation.				
		.13	Update relay settings on the Atlantic 230 kV lines at Oceanview substation.				
		.14	Update relay settings on the Atlantic 230 kV lines at Redbank substation.				
		.15	Update relay settings on the Atlantic 230 kV line at South River substation.				
		.16	Update relay settings on the Atlantic 230 kV line at Larrabee substation.				
		.17	Construct a new 230 kV line terminal position to accept the generator lead line from the offshore wind Larrabee Collector station at Atlantic substation.				
		.18	Upgrade G1021 (Atlantic-Smithburg) 230 kV.				
		.19	Updgrade R1032 (Atlantic-Larrabee) 230 kV.				
		.20	Build new Larrabee Collector station-Atlantic 230 kV line.				
		.21	Upgrade Larrabee-Oceanview 230 kV line.				

Table 6.34: New Jersey Baseline Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
8 Cont.	B3737 Cont.	.22	Construct the Larrabee Collector station AC switchyard, composed of a 230 kV 3 x breaker-and-a-half substation with a nominal current rating of 4000A and four single-phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. Procure land adjacent to the AC switchyard and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV.	12/31/2027	$947.40	MAOD	11/4/2022
		.23	Rebuild the underground portion of Richmond-Waneeta 230 kV.	6/1/2029		AE	
		.24	Upgrade Cardiff-Lewis 138 kV by replacing 1590 kcmil strand bus inside Lewis substation.	4/30/2028		AE	
		.25	Upgrade Lewis No. 2-Lewis No. 1 138 kV by replacing its bus tie with 2000A circuit breaker.				
		.26	Upgrade Cardiff-New Freedom 230 kV by modifying existing relay setting to increase relay limit.				
		.27	Rebuild ~0.8 miles of the D1018 (Clarksville-Lawrence 230 kV) line between Lawrence substation (PSEG) and structure No. 63.	6/1/2029		JCP&L	
		.28	Reconductor Kilmer I-Lake Nelson I 230 kV.				
		.29	Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits; one a 500 kV line and the other a 230 kV line.				
		.30	Add third Smithburg 500/230 kV transformer.	12/31/2027			
		.31	Reconductor Lake Nelson I-Middlesex 230 kV.	6/1/2029			
		.32	Rebuild Larrabee-Smithburg No. 1 230 kV.	12/31/2027			
		.33	Reconductor Red Oak A-Raritan River 230 kV.	6/1/2029			
		.34	Reconductor Red Oak B-Raritan River 230 kV.				
		.35	Reconductor small section of Raritan River-Kilmer I 230 kV.				
		.36	Replace substation conductor at Kilmer and reconductor Raritan River-Kilmer W 230 kV.				
		.37	Add a third set of submarine cables, rerate the overhead segment, and upgrade terminal equipment to achieve a higher rating for the Silver Run-Hope Creek 230 kV line.	6/1/2029		LS POWER	
		.38	Install a new 345/230 kV transformer at the Linden 345 kV switching station, and relocate the Linden-Tosco 230 kV (B-2254) line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV for Linden subproject.	12/31/2027		PSEG	
		.39	Upgrade the Bergen 138 kV ring bus by installing a 80 kA breaker along with the foundation, piles and relays to the existing ring bus; install breaker isolation switches on existing foundations and modify and extend bus work for the Bergen subproject.				
		.40	Create a paired conductor path between Clarksville 230 kV and JCP&L Windsor Switch 230 kV for the Windsor to Clarksville subproject.	6/1/2029		JCP&L	
		.41	Upgrade all terminal equipment at Windsor 230 kV and Clarksville 230 kV to create a paired conductor path between Clarksville and JCP&L East Windsor 230 kV.	6/1/2029		PSEG	
		.42	Upgrade inside plant equipment at Lake Nelson I 230 kV.				
		.43	Upgrade Kilmer W-Lake Nelson W 230 kV line drop and strain bus connections at Lake Nelson 230 kV.				
		.44	Upgrade Lake Nelson-Middlesex-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV.				

6.6.8 — Supplemental Projects

Supplemental projects received by PJM in 2022 in New Jersey are summarized in **Map 6.28** and **Table 6.35**.

Map 6.28: New Jersey Supplemental Projects (Dec. 31, 2022)

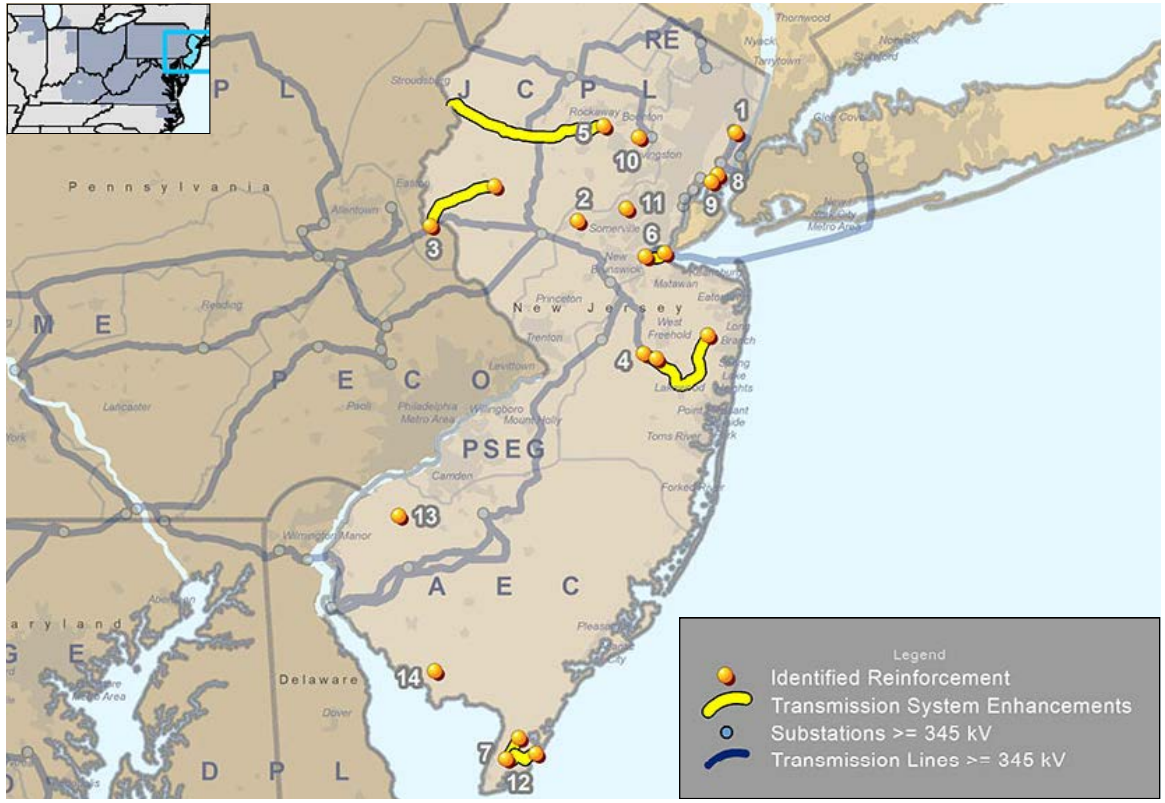


Table 6.35: New Jersey Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2588		Construct second half of 230-13 kV Class H station at existing North Bergen station. Install two additional new 230-13 kV transformers and associated equipment. Transfer load from heavily loaded Homestead and Penhorn to the new second half North Bergen 230 kV station.	12/31/2021	$28.90	PSEG	8/31/2021
2	S2644		Install third 69-13 kV transformer and associated equipment to increase capacity at North Bridge Street. Transfer load from heavily loaded Somerville and Polhemus stations.	5/1/2024	$35.10		9/14/2021
3	S2677		Gilbert-Glen Gardner 230 kV line	12/17/2021	$1.90	JCP&L	11/30/2021
		.1	Replace line relaying, disconnect switch, CT, line metering, circuit breakers, wave trap, and substation conductor at Gilbert 230 kV substation.				

Table 6.35: New Jersey Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	S2678		Atlantic-Smithburg 230 kV line	12/30/2021	$3.50	JCP&L	11/30/2021
		.1	Replace line relaying, CT, and substation conductor at Atlantic 230 kV substation.				
		.2	Replace PLC, and substation conductor at New Prospect Road 230 kV substation.				
		.3	Replace line relaying and substation conductor at Smithburg 230 kV substation.				
5	S2679		Greystone-Portland 230 kV line	3/22/2022	$1.40		
		.1	Replace circuit breaker, disconnect switch and wave trap at Greystone 230 kV substation.				
		.2	Replace circuit breaker, disconnect switch and wave trap at Portland 230 kV substation.				
6	S2680		Raritan River-Werner 230 kV line	4/30/2022	$1.90		
		.1	Replace line relaying, disconnect switch, wave trap, and substation conductor at Raritan River 230 kV substation.				
		.2	Replace line relaying, line metering, wave trap, and substation conductor EH Werner 230 kV substation.				
7	S2712		Replace the T4 transformer bank with a 138/69 kV, 225 MVA three-phase autotransformer with tap changer at Middle substation.	12/31/2025	$8.70	AE	3/17/2022
8	S2715		Construct new (Garfield Ave) 69-13-4 kV station on existing property.	5/31/2027	$84.20	PSEG	3/17/2022
9	S2720		Retire the Bayonne to Bayonne Cogen 138 kV circuit (A-1353) assets.	12/31/2022	$8.00		1/20/2022
10	S2728		Remove ~100 feet of 34.5 kV line to the customer facilities at Chapin Road-Whippany 34.5 kV line. Remove metering and associated facilities from the customer substation.	4/30/2022	$0.10	JCP&L	4/19/2022
11	S2729		Upgrade South Plainfield area.	5/31/2027	$96.60	PSEG	4/19/2022
12	S2752	.1	Install two new circuit breakers to reconfigure Lake Ave substation as a seven-breaker ring bus.	12/31/2024	$21.00	AE	5/16/2022
		.2	Rebuild the existing 0798 Court-Middle-Lake 69 kV line as two circuits. After rebuild, 0798 line will be from Court to Middle and the new line will be from Middle-Lake Ave.				
		.3	For better reliability, a second tie breaker will be installed in Middle substation to prevent an event from deenergizing the entire 69 kV bus.				
13	S2754		Install new 69 kV terminal position at High Street substation, and install new 1.7-mile 69 kV line to service the customer.	1/31/2023	$0.00		6/13/2022
14	S2755		Reconfigure 69 kV section of Newport substation to accommodate three new breakers, a new 69/12 kV 28 MVA transformer, and a mobile unit transformer tie-in to operate as a four-breaker ring bus.	5/31/2023	$14.00		6/3/2022

6.6.9 — Merchant Transmission Project Requests

As of Dec. 31, 2022, PJM's queue contained two merchant transmission project requests with a terminal in New Jersey, as shown in **Map 6.29** and **Table 6.36**.

Map 6.29: New Jersey Merchant Transmission Project Requests (Dec. 31, 2022)

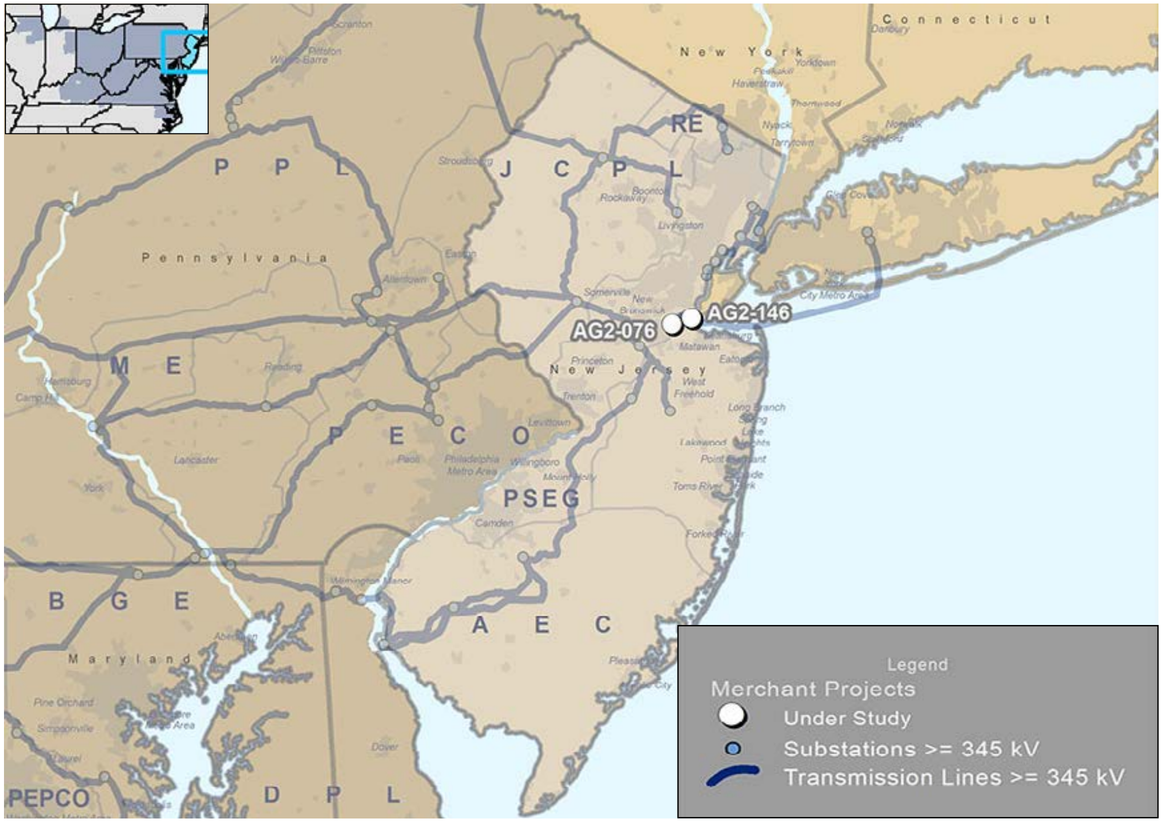


Table 6.36: New Jersey Merchant Transmission Project Requests (Dec. 31, 2022)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AG2-076	Raritan River 230 kV	JCP&L	Active	1/1/2024	0
AG2-146	Werner 230 kV-Ravenwood 345 kV	JCP&L	Active	12/1/2026	0

6.7: North Carolina RTEP Summary

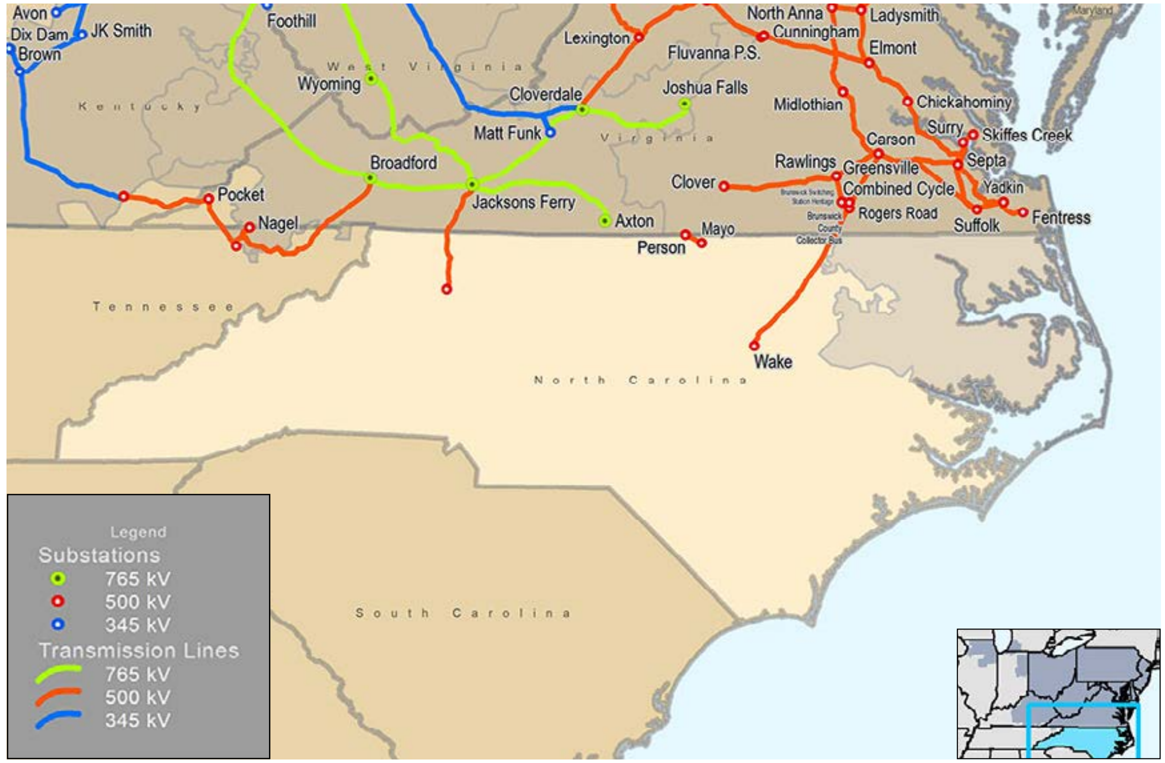
6.7.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in North Carolina, including facilities owned and operated by Dominion as shown on **Map 6.30**. North Carolina's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

North Carolina has a mandatory renewable portfolio standard (RPS) target of 12.5% for investor-owned utilities. The target is 10% for the state's electric cooperatives and municipalities.

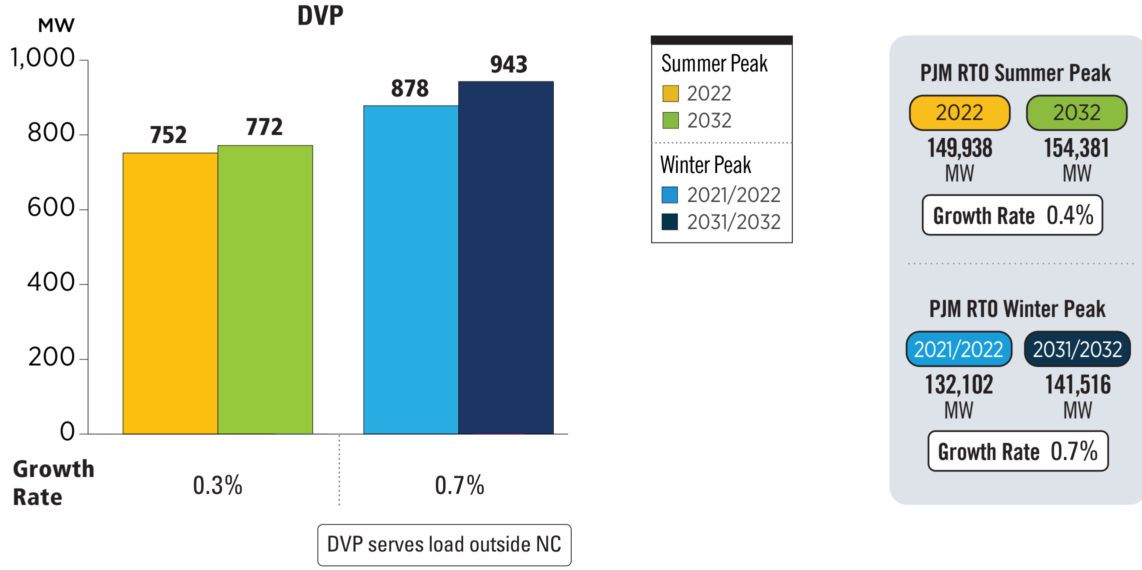
Map 6.30: PJM Service Area in North Carolina



6.7.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.36** summarizes the expected loads within the state of North Carolina and across the PJM region.

Figure 6.36: North Carolina – 2022 Load Forecast Report



PJM notes that Dominion Virginia Power serves load other than in North Carolina. The summer and winter peak MW values in this table each reflect the estimated amount of forecast load to be served by Dominion Virginia Power solely in North Carolina and excludes impacts of datacenter loads. Estimated amounts were calculated based on the average share of Dominion Virginia Power's real-time summer and winter peak load located in North Carolina over the past five years excluding datacenter load estimates.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

6.7.3 — Existing Generation

Existing generation in North Carolina as of Dec. 31, 2022, is shown by fuel type in **Figure 6.37**.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

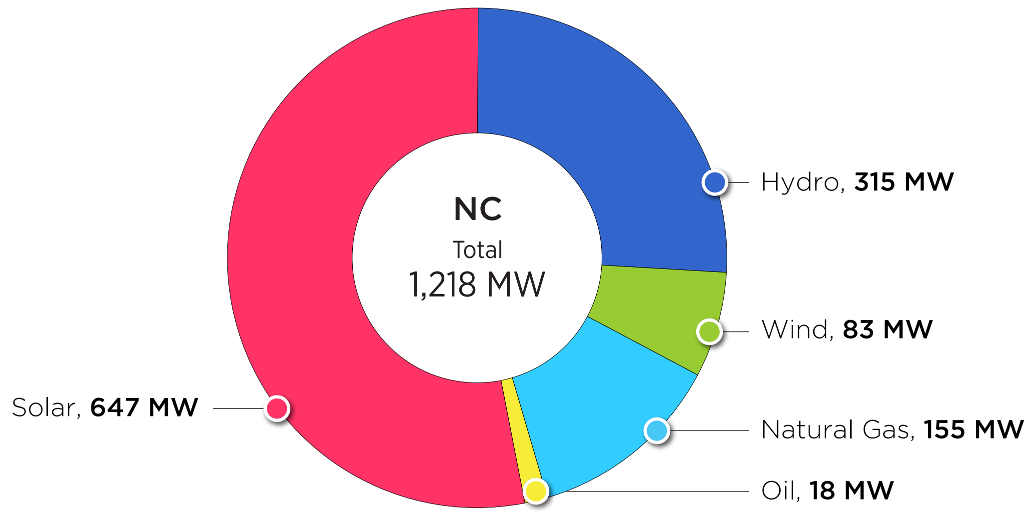
- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in North Carolina as of Dec. 31, 2022, are discussed next, in **Section 6.7.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

Figure 6.37: North Carolina – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



6.7.4 — Interconnection Requests

PJM markets continue to attract generation proposals in North Carolina, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in North Carolina, as of Dec. 31, 2022, 58 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.37, Table 6.38, Figure 6.38, Figure 6.39** and **Figure 6.40**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.37: North Carolina – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	North Carolina Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	0	0.00%	529	0.61%
Natural Gas	0	0.00%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	0	0.00%	273	0.31%
Solar	2,631	87.73%	57,616	66.37%
Storage	368	12.27%	14,148	16.30%
Wind	0	0.00%	6,223	7.17%
Grand Total	**2,999**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.38: North Carolina – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue				Complete					
		Active		Under Construction		In Service		Withdrawn		Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Storage	9	368.0	0	0.0	0	0.0	5	130.5	14	498.5
Renewable	Methane	0	0.0	0	0.0	0	0.0	1	12.0	1	12.0
	Solar	38	2,630.6	10	351.8	23	697.0	87	3,490.3	158	7,169.7
	Wind	0	0.0	1	24.5	1	27.0	9	195.3	11	246.8
	Wood	0	0.0	0	0.0	1	50.0	1	80.0	2	130.0
	Grand Total	**47**	**2,998.6**	**11**	**376.3**	**25**	**774.0**	**103**	**3,908.1**	**186**	**8,057.0**

Figure 6.38: North Carolina – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

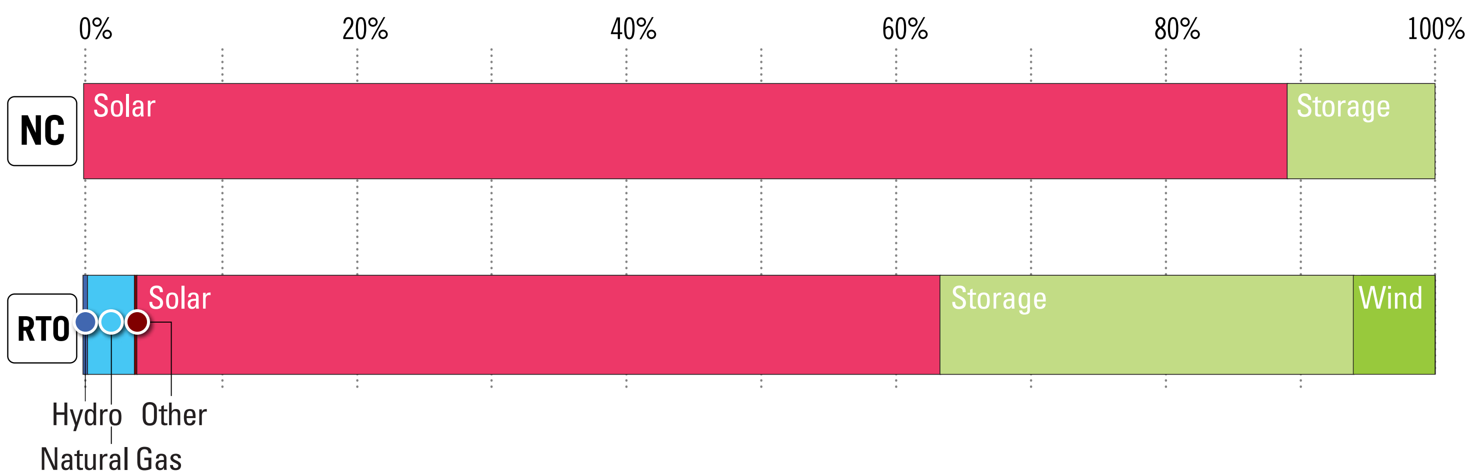
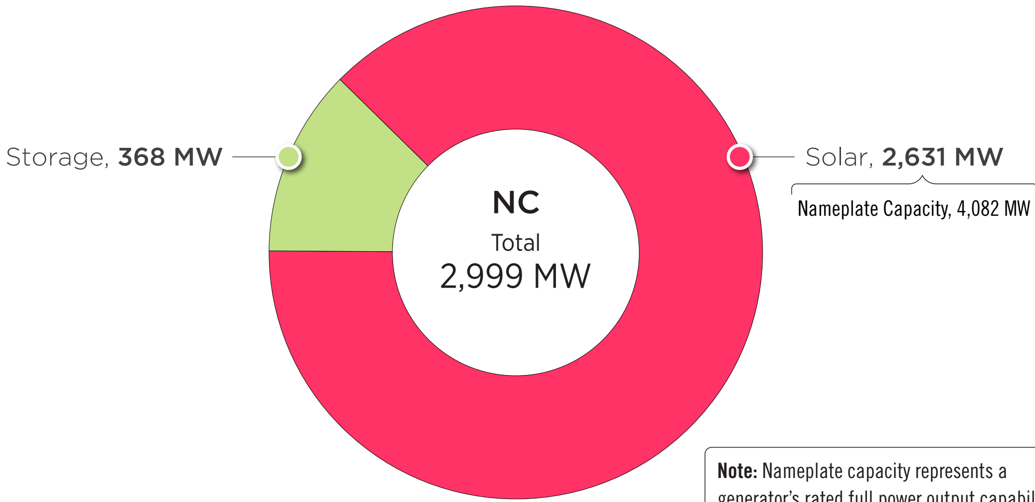


Figure 6.39: North Carolina – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.40: North Carolina Progression History of Queue – Interconnection Requests (Dec. 31, 2022)

Percentage of planned capacity and projects that have reached commercial operation

12.2%	Requested capacity megawatts
16.8%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	7	Interconnection Service Agreements	234 MW	743 MW
	5	Wholesale Market Participation Agreements	44 MW	65 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.7.5 — Generation Deactivation

There were no generating unit deactivation requests in North Carolina between Jan. 1, 2022, and Dec. 31, 2022, as part of the 2022 RTEP.

6.7.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in North Carolina are summarized in **Map 6.31** and **Table 6.39**.

Map 6.31: North Carolina Baseline Projects (Dec. 31, 2022)

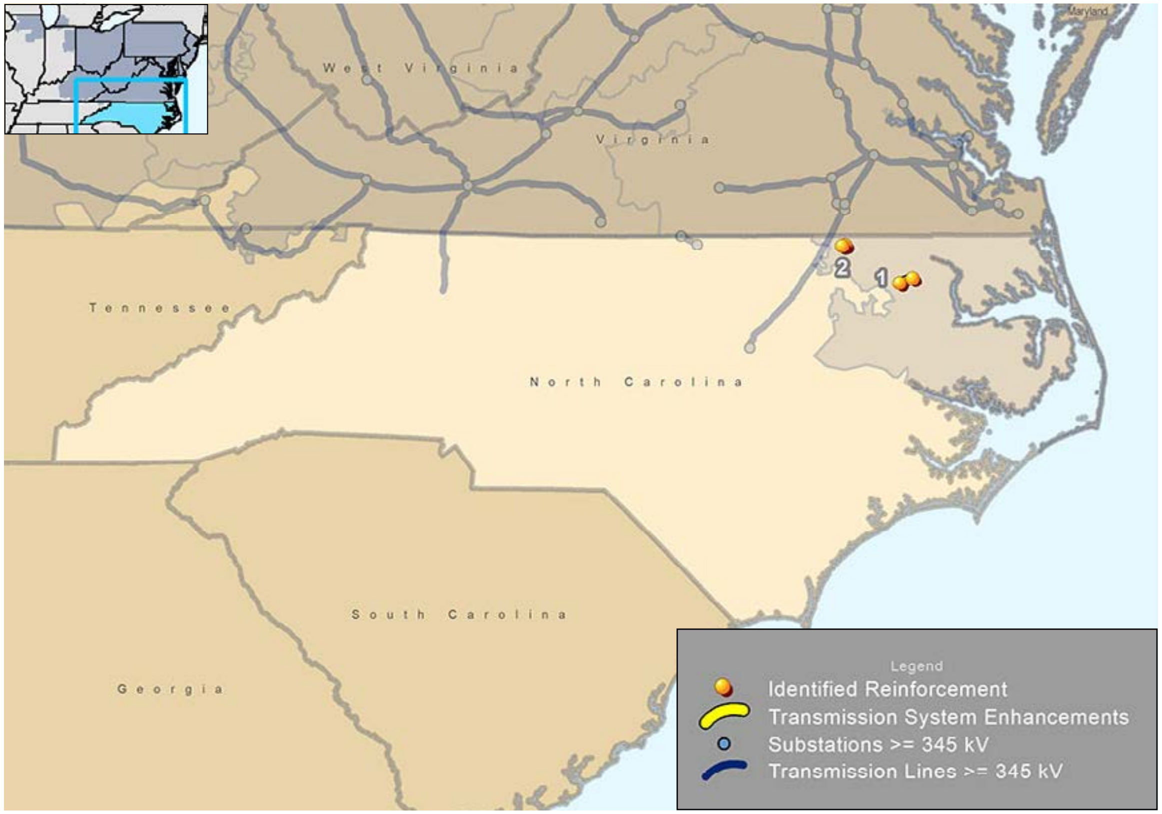


Table 6.39: North Carolina Baseline Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3684		Rebuild 12.4 miles of 115 line No. 126 segment from Earleys to Kelford with a summer emergency rating of 262 MVA. Replace structures as needed to support the new conductor. Upgrade breaker switch 13668 at Earleys from 1200A to 2000A.	6/1/2026	$18.75	Dominion	11/18/2021
2	B3691		Reconductor ~1.4 miles of 230 kV line No. 2141 from Lakeview-Carolina to achieve a summer rating of 1047 MVA.	6/1/2026	$1.19	Dominion	11/30/2021

6.7.7 — Network Projects

2022 RTEP network projects in North Carolina are summarized in **Map 6.32** and **Table 6.40**.

Map 6.32: North Carolina Network Projects (Dec. 31, 2022)

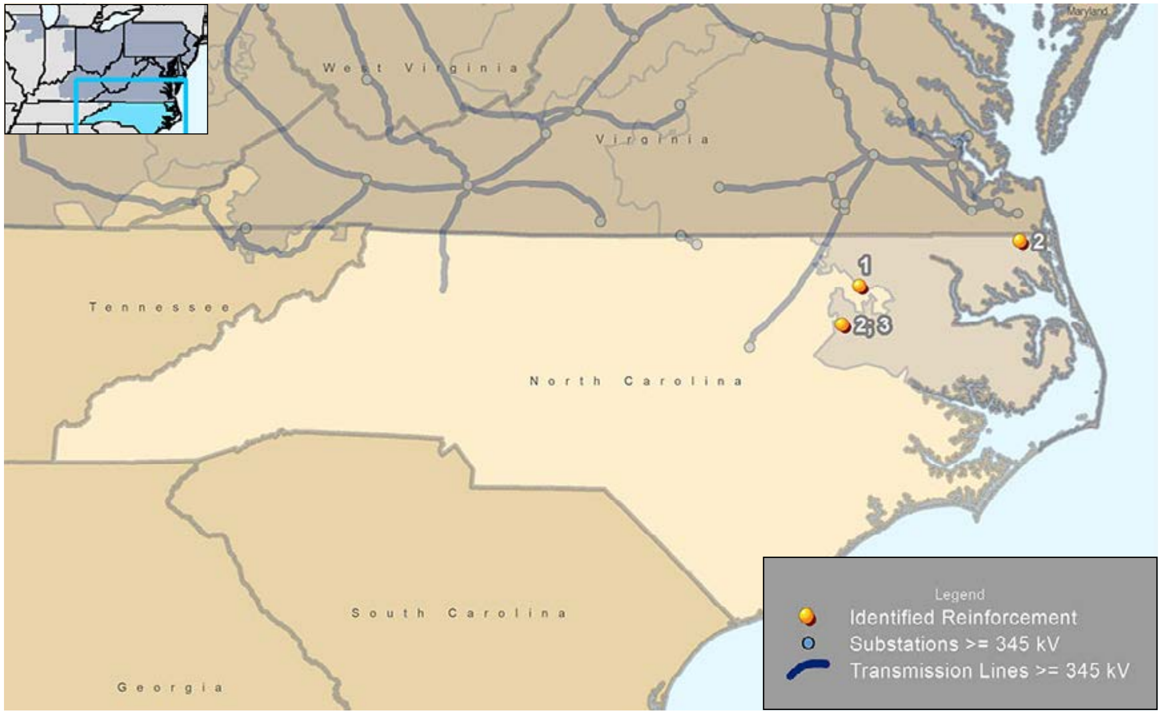


Table 6.40: North Carolina Network Projects (Dec. 31, 2022)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N6282	Construct new substation connection on Transmission Line 1015 between South Justice Branch and Scotland Neck Substation into the new AC1-098_099 three-breaker ring bus.	AC1-098	6/1/2019	$1.13	Dominion	11/1/2022
2	N6644	Three-breaker	AC1-034	12/15/2020	$5.30		
3	N6645	Build new structures to cut and loop the line into AC1-034 switching station.			$1.29		
4	N6753	Build a three-breaker 230 kV substation at the AD2-160 facility.	AD2-160	12/31/2020	$6.20		

6.7.8 — Supplemental Projects

Supplemental projects received by PJM in 2022 in North Carolina are summarized in **Map 6.33** and **Table 6.41**.

6.7.9 — Merchant Transmission Project Requests

No merchant transmission project requests in North Carolina were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.33: North Carolina Supplemental Projects (Dec. 31, 2022)

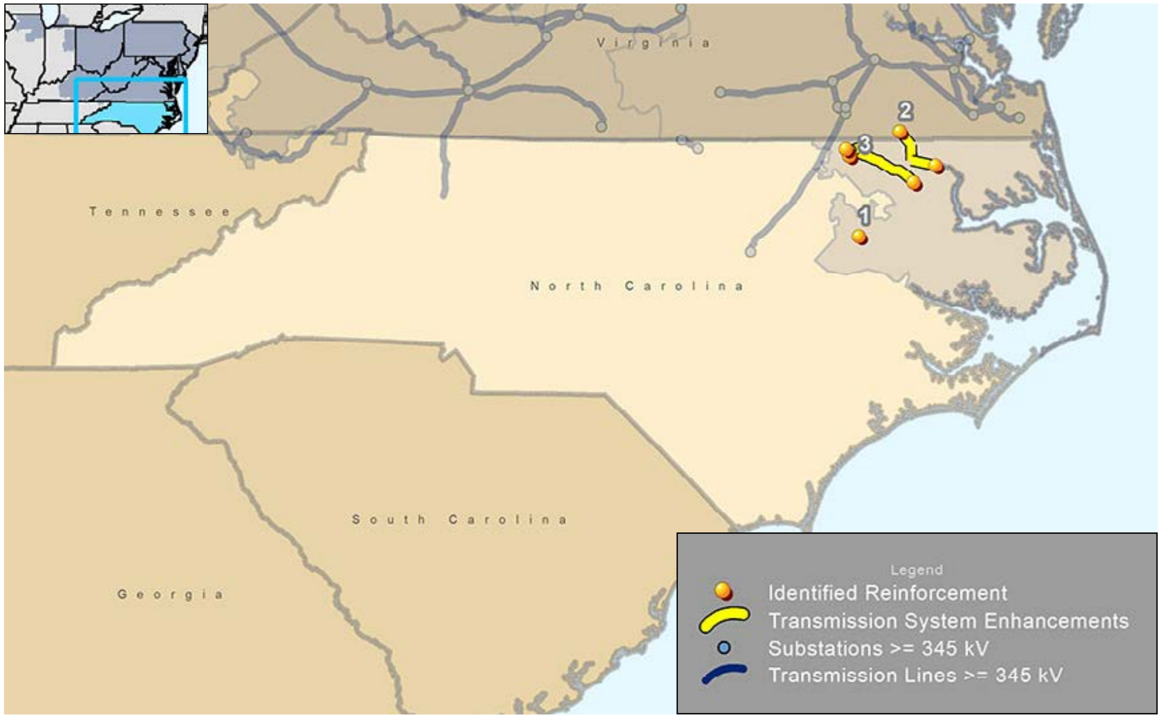


Table 6.41: North Carolina Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2701	Rebuild ~15.7 miles of 115 kV Line No. 105 Tarboro to normally open switch 96T105 with current 115 kV standard construction practices. This includes replacing four COR-TEN® double circuit towers and excludes the double circuit tap to Shiloh DP. The new conductor will have a minimum normal summer rating of 393 MVA. Terminal equipment will be upgraded as needed.	7/31/2025	$24.50	Dominion	12/20/2021
2	S2702	Rebuild the entire 115 kV line No. 108 from Boykins to Tunis, ~26.5 miles, using current 115 kV standard construction practices. The new conductor will have a minimum normal summer rating of 393 MVA. Terminal equipment will be upgraded as needed.	12/31/2024	$46.00		
3	S2707	Retire Roanoke Valley NUG (RVN) substation, and remove the four structures between RVN Sub and structure 2012/1D,2060/27. Connect 230 kV Line No. 2012 with 230 kV line No. 2060 at the junction point (structure 2012/13A,2060/13A) creating line No. 2012 from Earleys to Carolina. The remaining portion of double circuit Line No. 2012/2060 will be kept as idle line.	9/26/2025	$1.20		10/5/2021

6.8: Ohio RTEP Summary

6.8.1 — RTEP Context

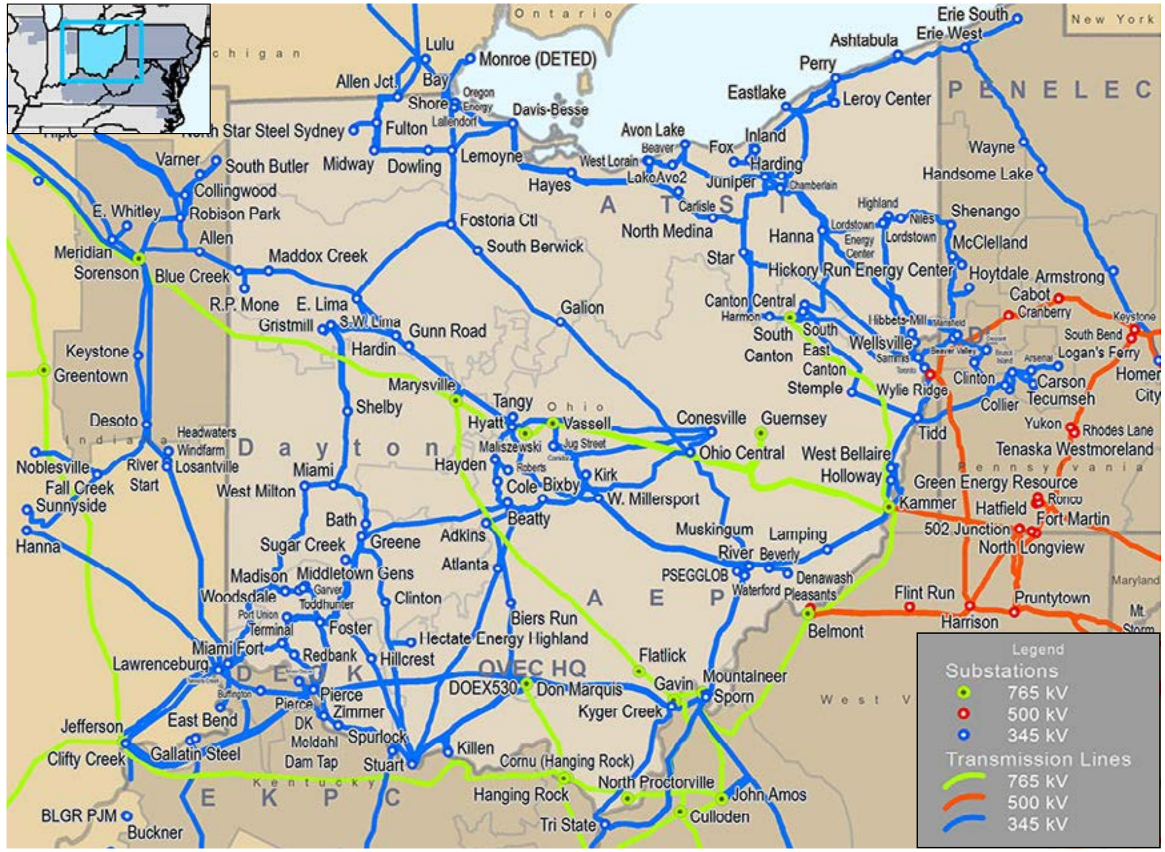
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Ohio, including facilities owned and operated by American Electric Power (AEP), AES Ohio – formerly Dayton Power & Light Company (DAY), American Transmission Systems, Inc. (ATSI), Duke Energy Ohio and Kentucky (DEO&K), the City of Cleveland and the City of Hamilton as shown on **Map 6.34**.

Ohio's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

Ohio has a mandatory renewable portfolio standard (RPS) target of 8.5% by 2026.

Map 6.34: PJM Service Area in Ohio



Next Section >
View state summaries: DC DE IL IN KY MD MI NJ NC OH PA TN VA WV
TOC

6.8.2 — Load Growth

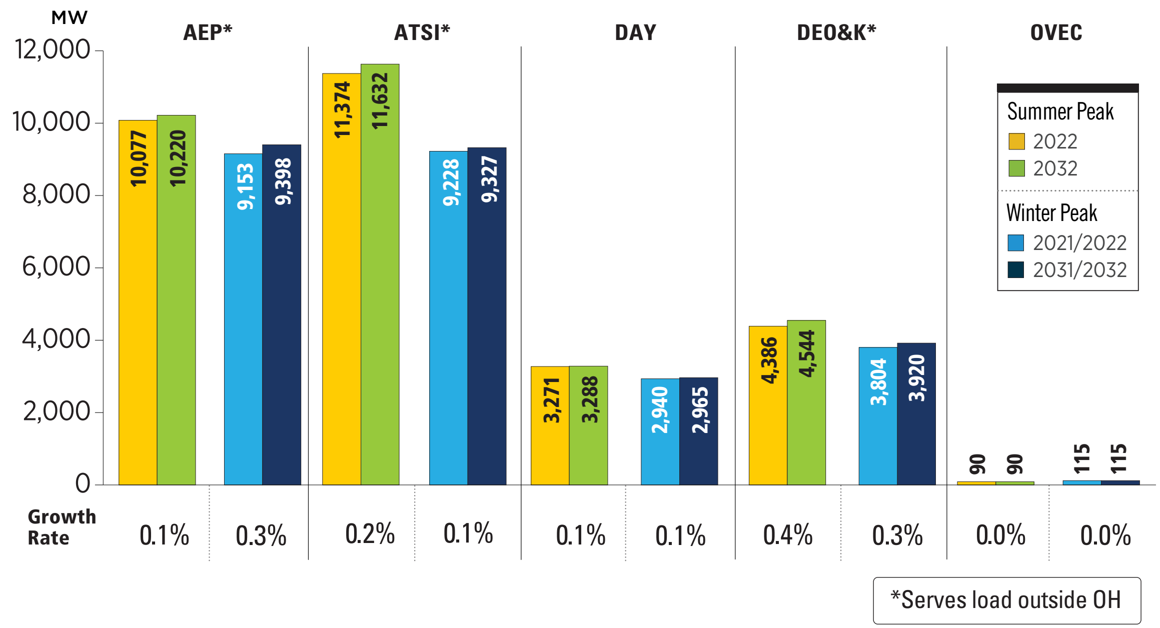
PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.41** summarizes the expected loads within the state of Ohio and across PJM.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

Figure 6.41: Ohio – 2022 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2022	2032	2021/2022	2031/2032
149,938 MW	154,381 MW	132,102 MW	141,516 MW
Growth Rate 0.4%		Growth Rate 0.7%	

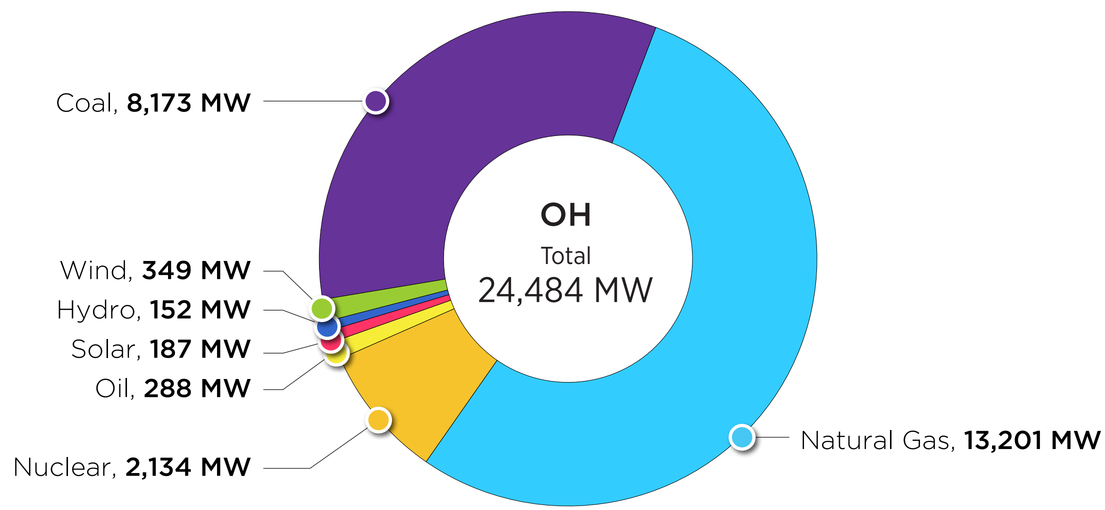
The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

Figure 6.42: Ohio – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



6.8.3 — Existing Generation

Existing generation in Ohio as of Dec. 31, 2022, is shown by fuel type in **Figure 6.42**.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in Ohio as of Dec. 31, 2022, are discussed next, in **Section 6.8.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

6.8.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Ohio, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Ohio, as of Dec. 31, 2022, 248 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.42, Table 6.43, Figure 6.43, Figure 6.44** and **Figure 6.45**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.42: Ohio – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	Ohio Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	11	0.08%	11	0.01%
Hydro	0	0.00%	529	0.61%
Natural Gas	1,096	7.79%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	0	0.00%	273	0.31%
Solar	10,636	75.61%	57,616	66.37%
Storage	2,154	15.32%	14,148	16.30%
Wind	169	1.20%	6,223	7.17%
Grand Total	**14,066**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.43: Ohio – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue				Complete				Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	1	11.0	1	18.0	11	230.0	16	8,923.0	29	9,182.0
	Diesel	0	0.0	0	0.0	1	7.0	0	0.0	1	7.0
	Natural Gas	7	1,096.1	4	2,686.0	32	5,626.7	36	14,245.4	79	23,654.2
	Nuclear	0	0.0	0	0.0	1	16.0	0	0.0	1	16.0
	Oil	0	0.0	1	1.5	0	0.0	1	5.0	2	6.5
	Other	0	0.0	0	0.0	0	0.0	2	135.0	2	135.0
	Storage	27	2,154.4	0	0.0	5	0.0	28	1,048.5	60	3,203.0
Renewable	Biomass	0	0.0	0	0.0	1	0.0	3	185.0	4	185.0
	Hydro	0	0.0	0	0.0	1	112.0	8	76.2	9	188.2
	Methane	0	0.0	0	0.0	7	37.7	10	26.1	17	63.8
	Solar	168	10,635.5	33	1,465.9	6	178.0	138	4,643.7	345	16,923.0
	Wind	5	168.5	1	38.7	8	197.4	74	1,832.9	88	2,237.5
	Grand Total	**208**	**14,065.6**	**40**	**4,210.0**	**73**	**6,404.7**	**316**	**31,120.9**	**637**	**55,801.2**

Figure 6.43: Ohio – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

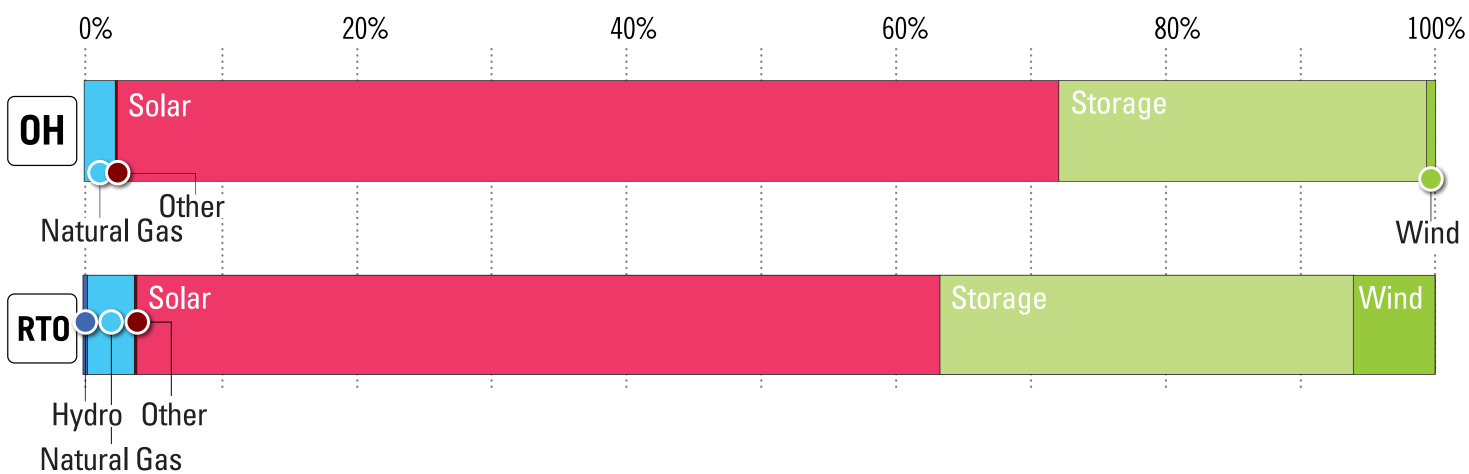


Figure 6.44: Ohio – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)

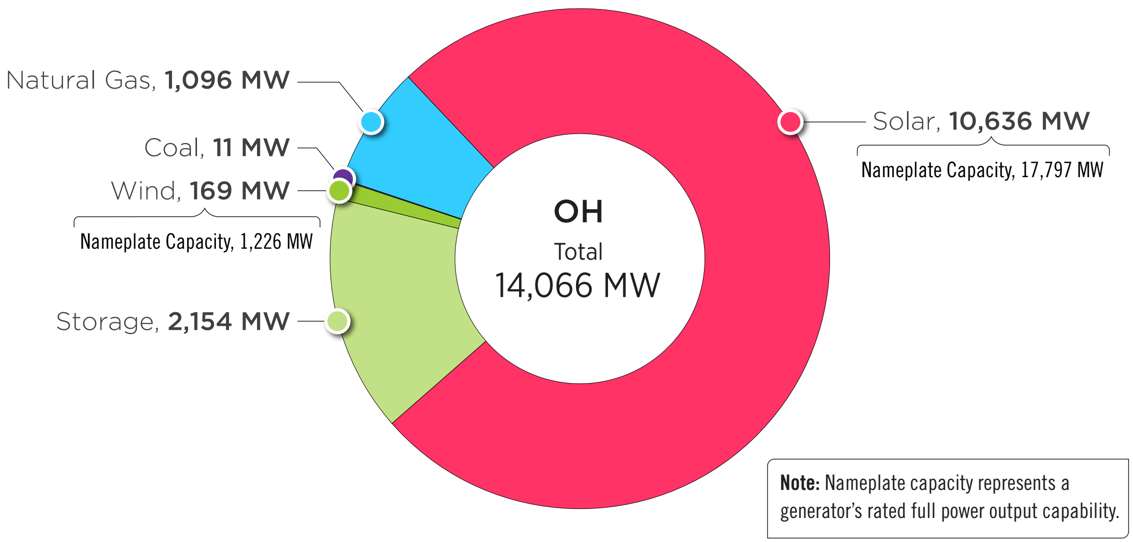


Figure 6.45: Ohio Progression History of Queue – Interconnection Requests (Dec. 31, 2022)

Percentage of planned capacity and projects that have reached commercial operation

- **18.5%** Requested capacity megawatts
- **15.0%** Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	**29**	Interconnection Service Agreements	4,817 MW	7,185 MW
	13	Wholesale Market Participation Agreements	22 MW	82 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.8.5 — Generation Deactivation

Formal generator deactivation requests received by PJM in Ohio between Jan. 1, 2022, and Dec. 31, 2022, are summarized in **Map 6.35** and **Table 6.44**.

Deactivation Reliability Studies

PJM has 30 days in which to respond to a generator owner with deactivation study results. Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can reduce voltage support.

Deactivation reliability studies comprise thermal and voltage analysis, including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, reliability criteria violations caused by unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board.

Map 6.35: Ohio Generation Deactivations (Dec. 31, 2022)

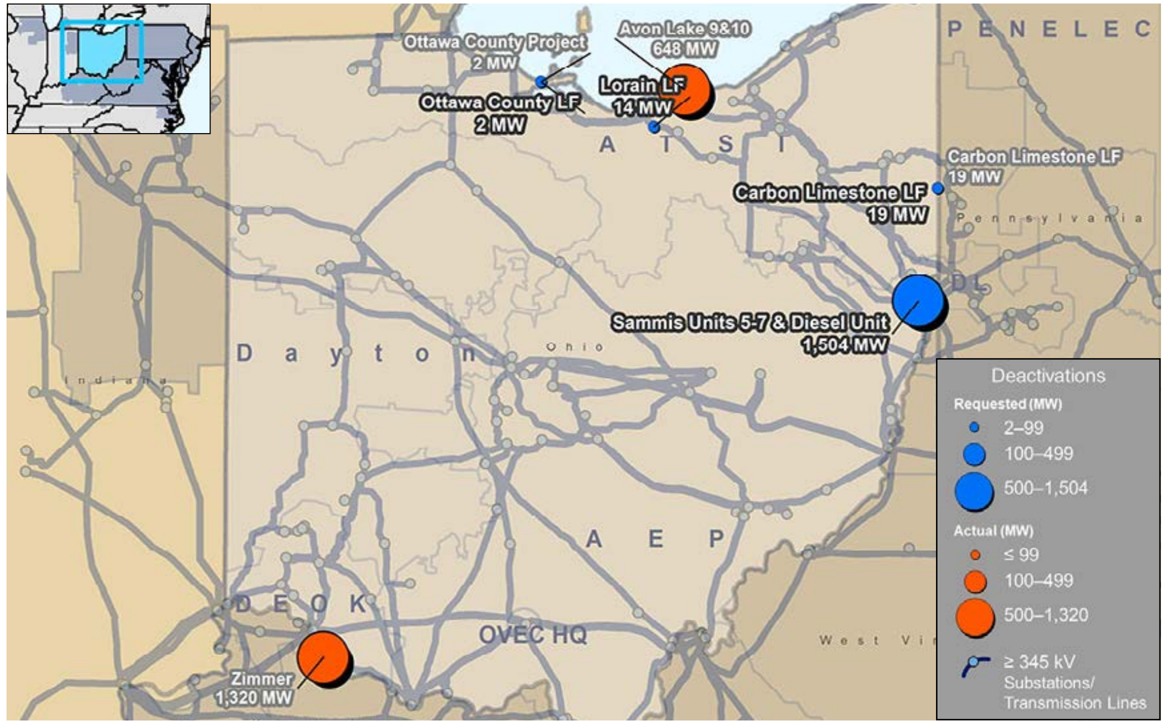


Table 6.44: Ohio Generation Deactivations (Dec. 31, 2022)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Lorain 1 LF	ATSI	Methane	10/14/2022	4/1/2023	21	14.0
Sammis Diesel Units	ATSI	Coal	3/14/2022	6/1/2023	50	13.0
Sammis Unit 7	ATSI	Coal	3/14/2022	6/1/2023	51	600.0
Sammis Unit 6	ATSI	Coal	3/14/2022	6/1/2023	53	600.0
Sammis Unit 5	ATSI	Coal	3/14/2022	6/1/2023	55	291.3
Carbon Limestone LF	ATSI	Methane	5/2/2022	11/15/2022	21	19.3
Ottawa County Project	ATSI	Methane	2/18/2022	5/31/2022	21	1.7
Zimmer 1	DEO&K	Coal	7/19/2021	5/31/2022	30	1,320.0
Avon Lake 9	ATSI	Coal	7/14/2021	3/31/2022	51	627.0
Avon Lake 10	ATSI	Oil	7/14/2021	3/31/2022	53	21.0

6.8.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in Ohio are summarized in **Map 6.36** and **Table 6.45**.

Map 6.36: Ohio Baseline Projects (Dec. 31, 2022)

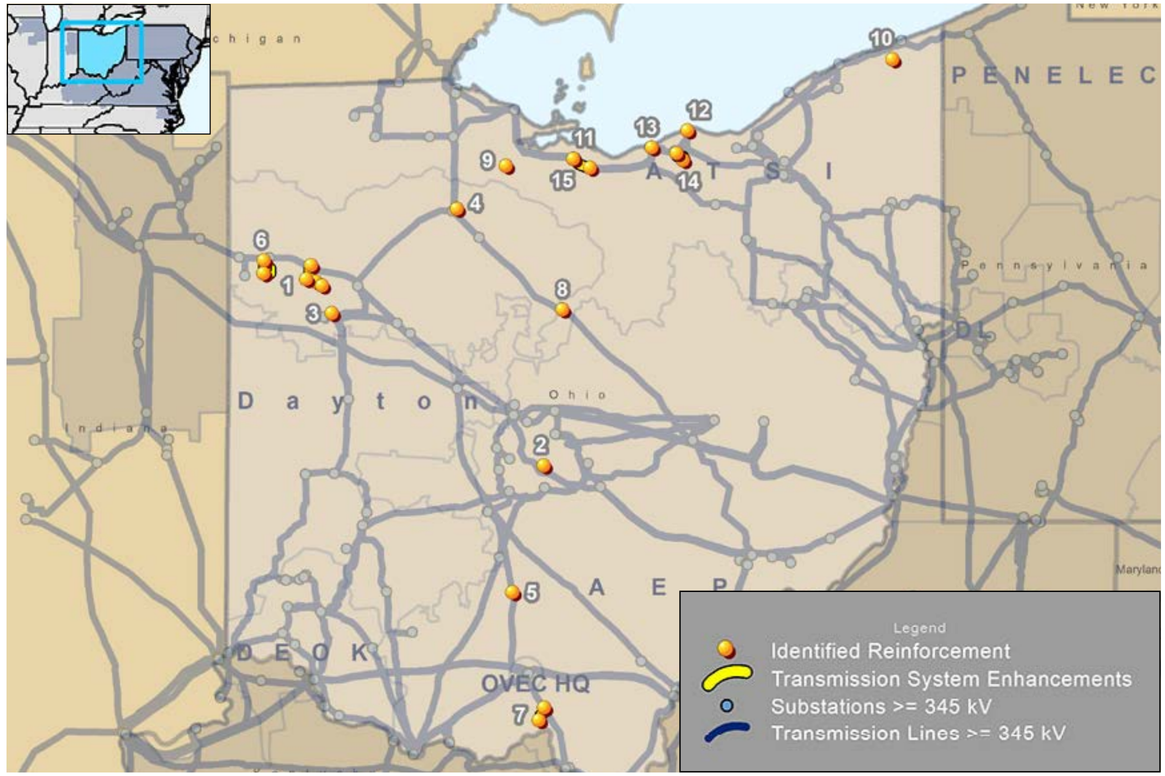


Table 6.45: Ohio Baseline Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3346	.1	Rebuild ~3.5 miles of overloaded 69 kV line between North Delphos-East Delphos-Elida Road switch. This includes ~1.1 miles of double circuit line that makes up a portion of the North Delphos-South Delphos 69 kV line and the North Delphos-East Delphos 69 kV line. ~2.4 miles of single circuit line will also be rebuilt between the double circuit portion to East Delphos station and from East Delphos to Elida Road switch.	6/1/2026	$8.87	AEP	11/30/2021
		.2	Replace the line entrance spans at South Delphos to eliminate the overloaded 4/0 Copper and 4/0 ACSR conductor.				
2	B3354		Replace circuit breakers '42' and '43' at Bexley station with 69 kV, 3000A 40 kA breakers (operated at 40 kV), slab, control cables and jumpers.	6/1/2023	$1.00	AEP	1/21/2022

Table 6.45: Ohio Baseline Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	B3355		Replace circuit breakers 'A' and 'B' at South Side Lima station with 34.5 kV, 1200A 25 kA breakers, slab, control cables and jumpers.	6/1/2023	$0.75	AEP	1/21/2022
4	B3356		Replace circuit breaker 'H' at West End Fostoria station with 69 kV, 3000A 40 kA breaker, slab, control cables and jumpers.		$0.50		
5	B3358		Install a 69 kV 11.5 MVAR capacitor at Biers Run station.	6/1/2026	$0.85		11/19/2021
6	B3359		Rebuild ~2.3 miles of the existing North Van Wert Sw-Van Wert 69 kV line utilizing 556 ACSR conductor.		$6.20		
7	B3362		Rebuild ~3.1 miles of the overloaded conductor on the existing Oertels Corner-North Portsmouth 69 kV line utilizing 556 ACSR.		$8.00		
8	B3678		Expand Galion 138 kV substation; Install 100 MVAR reactor, associated breaker and relaying.	11/1/2026	$1.70	ATSI	11/19/2021
9	B3679		Replace West Fremont 138/69 kV TR2 with a transformer having additional high-side taps.	11/1/2026	$2.90		
10	B3680		Replace limiting substation conductors on Ashtabula 138 kV exit to make transmission line conductor the limiting element at Sanborn.	6/1/2026	$0.30		
11	B3682		Install a second 345/138 kV transformer at Hayes, 448 MVA nameplate rating. Add one 345 kV circuit breaker (3000A) to provide transformer high-side connection between breaker B-18 and the new breaker. Connect the new transformer low side to the 138 kV bus. Add one 138 kV circuit breaker (3000A) at Hayes 138 kV substation between B-42 and the new breaker. Relocate the existing 138 kV No. 1 capacitor bank between B-42 and the new breaker. Protection per FE standard.	6/1/2026	$7.59		11/30/2021
12	B3713		- Disconnect and remove five 138 kV bus tie lines and associated equipment from the Avon Lake substation to the plant (800-B Bank, 8-AV-T Generator, 5-AV-T, 6-AV-T, and 7-AV-T). - Disconnect and remove one 345 kV bus tie line and associated equipment from the Avon substation to the plant (Unit 9). - Adjust relay settings at Avon Lake, Avon and Avondale substations. - Removal/rerouting of fiber to the plant and install new fiber between the 345 kV and 138 kV yards for the Q4-AV-BUS relaying. - Remove SCADA RTU, communications and associated equipment from plant.	4/28/2023	$2.50		6/7/2022
13	B3714		- Replace four 345 kV disconnect switches (D74, D92, D93, & D116) with 3000A disconnect switches at Beaver. - Replace dual 954 45/7 ACSR SCCIR conductors between 5" pipe and WT with new, which meets or exceeds ratings of SN: 1542 MVA, SSTE: 1878 MVA at Beaver. - Replace 3000 SAC TL drop and 3000 SAC SCCIR between 954 ACSR and 5" bus with new, which meets or exceeds ratings of SN: 1542 MVA, SSTE: 1878 MVA at Beaver. - Upgrade BDD relays at breaker B-88 and B-115 at Beaver. - Relay settings changes at Hayes.	6/1/2023	$2.10		6/7/2022
14	B3720		Rebuild the Abbe-Johnson No. 2 69 kV line (~4.9 miles) with 556 kcmil ACSR conductor. Replace three disconnect switches (A17, D15 & D16) and line drops and revise relay settings at Abbe. Replace one disconnect switch (A159) and line drops and revise relay settings at Johnson. Replace two MOAB disconnect switches (A4 & A5), one disconnect switch (D9), and line drops at Redman.	6/1/2027	$10.90		10/14/2022
15	B3721		Rebuild and reconductor the Avery-Hayes 138 kV line (~6.5 miles) with 795 kcmil 26/7 ACSR.	6/1/2027	$10.40		10/14/2022

6.8.7 — Network Projects

2022 RTEP network projects in Ohio are summarized in **Map 6.37** and **Table 6.46**.

Map 6.37: Ohio Network Projects (Dec. 31, 2022)

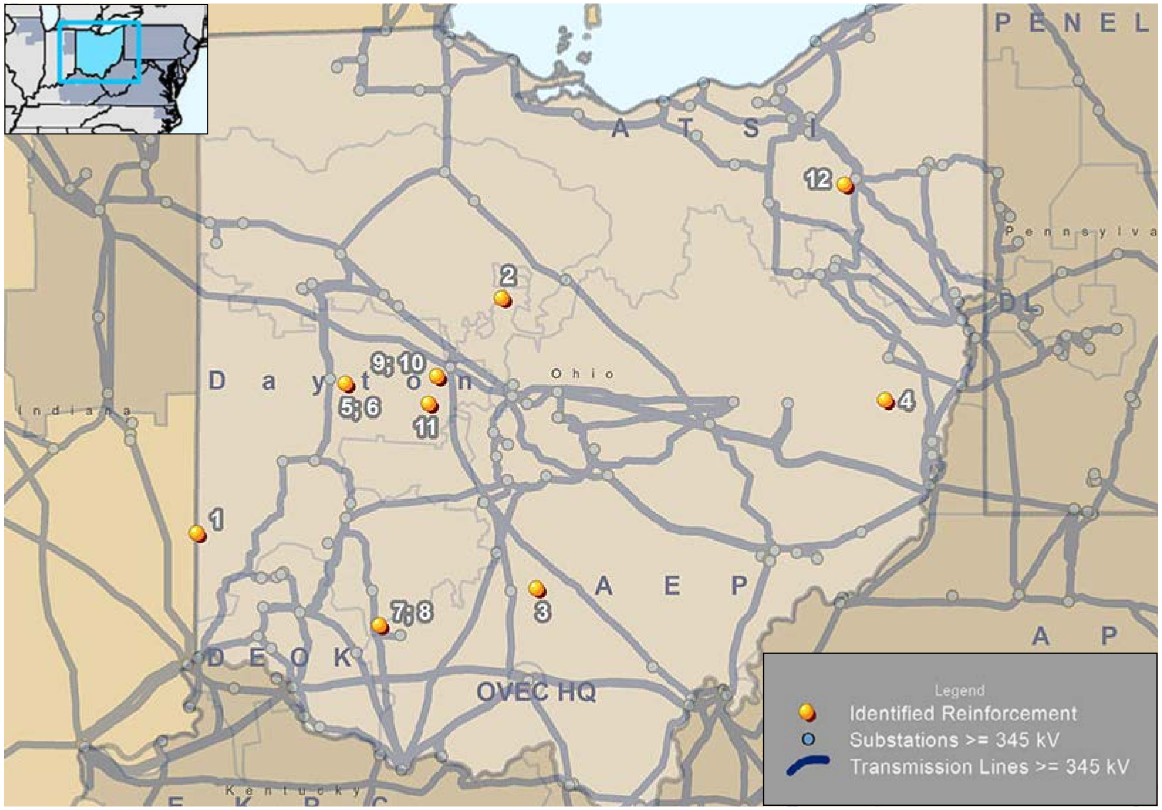


Table 6.46: Ohio Network Projects (Dec. 31, 2022)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N6034	Expand College Corner 138 kV substation and installation of associated protection and control equipment.	AC2-111	7/1/2019	$3.00	AEP	11/1/2022
2	N6707	AC2-195 Interconnection Switchyard including SCADA, metering and Project Management	AC2-195	10/1/2022	$7.31	ATSI	11/1/2022
3	N7269	To accommodate the interconnection at AEP's existing Delano 138 kV station, the station will have to be expanded by adding two 138 kV circuit breakers, extending the 138 kV bus No. 1 and No. 2, and adding a new circuit breaker string.	AC1-001	6/1/2022	$3.18	AEP	11/1/2022
4	N7453	Expand Nottinham 138 kV station, including the addition of two 138 kV circuit breakers, installation of associated protection and control equipment, 138 kV line risers, and supervisory control and data acquisition (SCADA) equipment.	AE2-290	12/31/2023	$1.24	AEP	11/1/2022

Table 6.46: Ohio Network Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5	N7471	Construct a new AE2-206 138 kV interconnection switching station to interconnect the Customer Facility.	AE2-206	11/30/2021	$4.01	DAY	11/1/2022
6	N7472	Construct a new loop-in tap line from Dayton's existing East Sidney-Quincy 138 kV line to the new AE2-206 138 kV interconnection switching station.			$1.10		
7	N7476	Construct a new 345 kV switching station to interconnect the Customer Facility.	AE2-221	12/31/2021	$6.88		
8	N7477	Construct a new loop-in tap line from Dayton's existing Clinton-Stuart 345 kV line to the new AE2-221 345 kV interconnection switching station.			$1.99		
9	N7482	Construct a new four-breaker ring bus 69 kV switching station to interconnect the Customer Facility.	AE2-303	6/1/2023	$3.93		
10	N7483	Construct a new loop-in tap line from Dayton's existing Honda East Liberty-East Liberty Union REA-Honda Marysville Union REA 69 kV line to the new AE2-303 69 kV interconnection switching station.			$2.15		
11	N7487	Construct a four-circuit breaker ring bus 69 kV substation. This includes the installation of all physical structures, protection and control equipment, communications equipment and associated facilities at the Woodstock 69 kV substation.	AE2-342	12/1/2022	$3.28		
12	N7490	Expand Continental 69 kV station, including the addition of one 69 kV circuit breaker, installation of associated protection and control equipment, 69 kV line risers, switches, jumpers, and supervisory control and data acquisition (SCADA) equipment.	AD1-101	10/31/2022	$1.00	AEP	

6.8.8 — Supplemental Projects

Supplemental projects received by PJM in 2022 in Ohio are summarized in **Map 6.38** and **Table 6.47**.

Map 6.38: Ohio Supplemental Projects (Dec. 31, 2022)

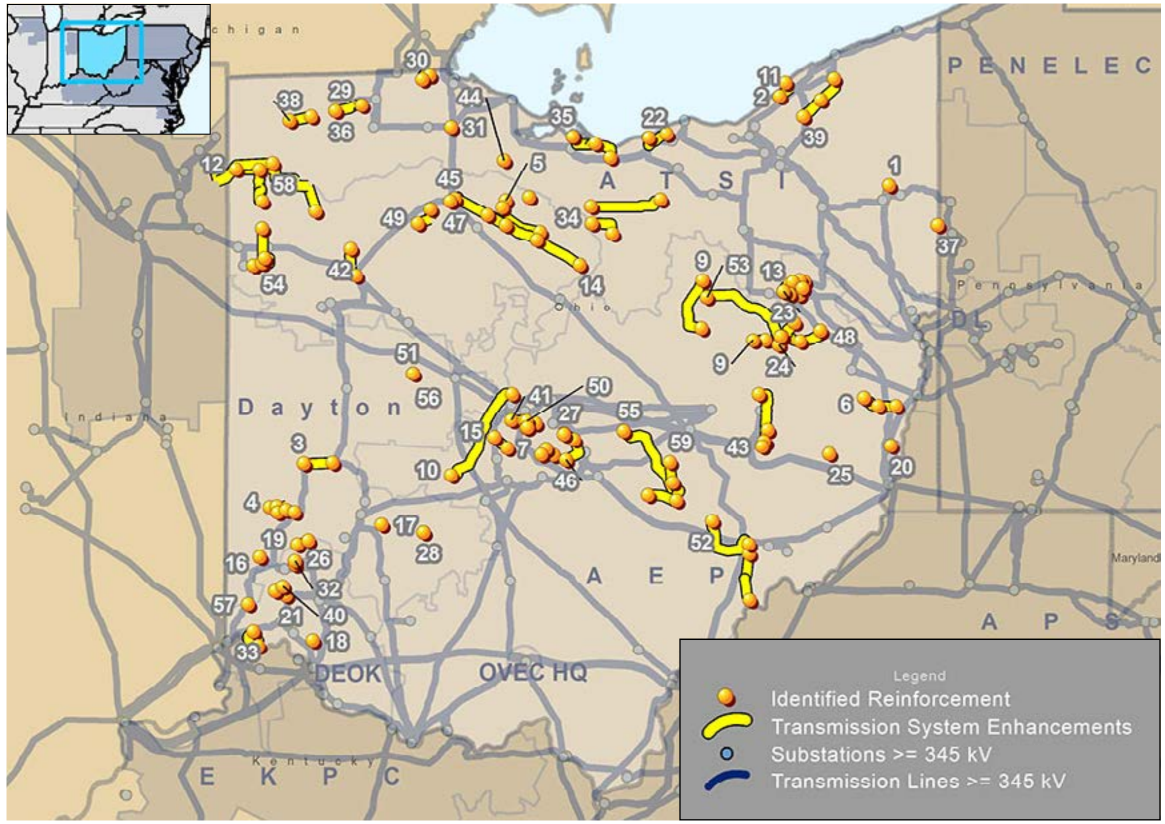


Table 6.47: Ohio Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1954		Upgrade Evergreen 138 kV relay. Replace bus protection scheme with dual differential protection. Replace bus PTs due to condition. Replace three breakers (B23, B24 and B27 bus transfer) due to condition and insufficient lack of sufficient CTs for proper system to support standard, redundant bus protection.	12/8/2023	$4.20	ATSI	3/25/2019
2	S2228		Retire Toms Fork-Westerly 46 kV and Toms Fork-Str. 364-13 46 kV (~24 miles total).	3/3/2023	$1.10		11/22/2019

Table 6.47: Ohio Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S2422		This project will tap the existing West Milton to Miami 138 kV line and build a two new 138 kV circuits, each extending ~1 mile from the tap point to the new substation. There will be a single 138/12 kV 30 MVA distribution transformer, a 138 kV delivery to Pioneer REC, and four new 138 kV breakers arranged in a ring bus configuration. The new substation will be in proximity to the growing load center near the Dayton airport and will provide critical distribution sources for AES Ohio's distribution load and Pioneer Electric distribution load in this area.	12/31/2022	$12.90	DAY	2/28/2022
4	S2585	.1	For the new Westville substation replacement, establish a new 138 kV three-breaker ring bus substation that will tie into AEP's Hodgin, connect back to AES Ohio's West Manchester substation, and serve AES Ohio distribution in the New Westville area. Once the new substation is online, the existing New Westville 33 kV substation will be retired. This will help improve reliability to customers served via New Westville and eliminate vintage 33kV system. The new substation will upgrade the obsolete and nonstandard equipment at New Westville.	12/31/2025	$22.90	DAY	8/16/2021
		.5	New Orphan Road POI (Darke REA): Install a new three-way phase over phase MOAB to serve a new 138 kV delivery point for the Darke REA Electric Co-operative.	12/31/2026			
		.6	Rebuild West Manchester-West Senora Tap double circuit. Retire the existing single circuit section of the 6639 line tap to Sonora up to West Manchester and rebuild as a four-mile double circuit 69 kV line. One circuit will connect West Manchester to Lewisburg, and the other circuit will connect back to West Manchester to Wolfcreek.	12/1/2026			
		.7	The Lewisburg 69 kV substation will be converted to a new four breaker 69 kV ring station and will serve the 7 MVA additional customer load that is being added in Lewisburg. Also, this conversion will allow AES Ohio to close in the normally open feed at Lewisburg when complete.	12/1/2025			
		.8	At West Sonora (Darke REA), install a new three-way phase over phase MOAB to serve the Sonora Darke REA delivery point that is currently served via a one-way switch. Retire the existing switch.				
		.9	Replace the existing two-way switch with a new three-way phase-over-phase MOAB switch at Mid-Valley Pipeline Tap. This will provide greater flexibility to switch during outages on the portion of the tap down to the customer.	12/1/2026			
		.10	Modify the bus arrangement at Brookville substation to install two new 69 kV line circuit breakers. This will improve reliability at Brookville substation by removing tapped transformers from the transmission lines.				
5	S2637	.1	Install a new 69 kV three-way phase-over-phase switch (Kilbourne Sw) and 69 kV metering to serve North Central's Republic station.	9/1/2024	$20.93	AEP	9/17/2021
		.2	Construct a new three-breaker 69 kV station in a ring configuration named Founders.				
		.3	Construct ~8 miles of new 69 kV line between Tiffin Center and the new Kilbourne switch delivery point using 556 ACSR conductor.				
		.4	Install a new 69 kV, 3000A 40 kA breaker and associated terminal equipment at Tiffin Center on the line toward Kilbourne switch.				
		.5	Remove the existing Honey Creek 69 kV switch currently used to radially serve the Republic delivery point.				
		.6	Construct ~0.83 miles of new 69 kV double circuit line between structure 103 on the Carrothers-Greenlawn circuit to the new Founders delivery point using 556 ACSR conductor.				
6	S2638	.1	Construct a new 69-12 kV station ("Ruby") 0.2-mile to the east of Robyville, on new property. The station will have a four-breaker 69 kV ring bus, with three 69 kV circuit connections and serving one AEP Ohio distribution transformer.	11/1/2023	$10.54	AEP	9/17/2021

Table 6.47: Ohio Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
6 Cont.	S2638 Cont.	.2	At the 69 kV remote end of South Cadiz, replace 69 kV circuit breaker D, line relays to Ruby, and 69 kV bus protection. Expand control building.	11/1/2023	$10.54	AEP	9/17/2021
		.3	At the 69 kV remote end of Dillonvale, replace 69 kV circuit breaker B, line relays to Ruby, and 69 kV bus protection.				
		.4	Reroute the three 69 kV transmission lines near Robyville to extend to the new Ruby station.				
		.5	Remove the former DTE Coal 69 kV switch just south of South Cadiz station.				
		.6	Retire the existing Robyville station, and remove all equipment.				
7	S2639	.1	Construct a greenfield station 138 kV ring bus with four 138 kV, 3000A 63 kA breakers and two 138/13 kV transformers to replace the existing 40 kV station at Poth 138 kV station.	12/18/2023	$8.11	AEP	9/17/2021
		.2	At East Broad 138 kV station, replace circuit breaker 3 and circuit breaker 7 and 4 disconnect switches with 138 kV, 3000A 63 kA breakers and four 3000A disconnect switches and install new relaying to coordinate with the new relays at Poth station.				
		.3	Perform remote end relay settings at Yearling 138 kV station.				
		.4	At Poth Extension 138 kV, tap the existing East Broad-Bexley 138 kV line into Poth station by constructing ~0.5 miles of greenfield lines from the line taps. Extend telecom ADSS for relaying and communication from Bexley to Poth and East Broad to Poth.				
8	S2640	.1	At West Dover station, install four 138 kV breakers in a ring bus arrangement. Install one 69 kV breaker on the low-side of the 138-69 kV transformer. Remove the existing control building and install a new prefabricated drop-in-control-module (DICM). Upgrade the 69 kV circuit protection to Sugarcreek, replacing electromechanical relays with new fiber-based protection. Various improvements to the station site, including new fencing, grading and station service.	12/1/2023	$8.31	AEP	9/17/2021
		.2	Reterminate the three 138 kV transmission lines at West Dover to connect to the new ring bus layout. The Sugarcreek 138 kV tap will be rerouted slightly.				
		.3	Remote end 69 kV protection upgrades at Sugarcreek station, to coordinate with the West Dover upgrades.				
9	S2641	.1	Reconfigure the existing West Millersburg-Wooster 138 kV circuit to add in Salt Creek switch.	7/31/2023	$2.48	AEP	9/17/2021
		.2	Install a new 138 kV three-way phase over phase switch named Salt Fork switch.				
		.3	Construct ~0.75 miles of new 138 kV line between Salt Fork switch and Holmesville delivery point using 556 ACSR conductor.				
		.4	Install new customer metering at Holmesville for Holmes Wayne Cooperative.				
10	S2648		Construct a 138 kV tap (~1-2 spans) off the London-Tangy 138 kV line. Tap location is ~15 miles from the Tangy substation. Add two SCADA control switches at transmission line tap location and one tap switch. Adjust relay settings at London and Tangy substations.	4/30/2022	$1.40	ATSI	8/16/2021
11	S2649		Move the existing No. 3 transformer from Nathan substation to the open bay position at Lloyd substation in order to feed the distribution load. Retire the failed No. 2 Lloyd transformer in place.	12/31/2021	$0.00		
12	S2650	.1	Rebuild Mark Center station in the clear as Platter Creek station. Install 4 new 69 kV, 3000A 40 kA breakers at the new Platter Creek ring bus and add a DICM. Upgrade NW Coop 69 kV metering.	3/31/2023	$9.00	AEP	10/15/2021
		.2	Retire existing Mark Center station. Relocate circuit switcher AA to Platter Creek.				

Table 6.47: Ohio Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
12 Cont.	S2650 Cont.	.3	Perform remote end work at South Hicksville station.	3/31/2023	$9.00	AEP	10/15/2021
		.4	Relocate Mark Center-Continental to terminate at Platter Creek.				
		.5	Relocate Mark Center-Paulding to terminate at Platter Creek.				
		.6	Relocate Mark Center-South Hicksville to terminate at Platter Creek.				
		.7	Relocate Mark Center-NW Co-op to terminate at Platter Creek.				
13	S2651	.1	Rebuild the Philo-Torrey 138 kV transmission line between South Canton and Torrey (3.5 miles). The circuits affected are South Canton-Timken Richville and Timken Richville-Timken 138 kV.	11/1/2025	$22.71		
		.2	Rebuild the Philo-Canton 138 kV transmission line between South Canton and Sunnyside (5.5 miles). The circuits affected are South Canton-Southeast Canton and Southeast Canton-Sunnyside 138 kV.				
		.3	Replace the 138 kV switches at Faircrest Street station to accommodate the new line structures.				
		.4	At Sunnyside, upgrade the relays on the 138 kV circuit to Southeast Canton. The control building needs expanded to accommodate the new relay panels.				
14	S2652		Install a new 69 kV, 3000A 40 kA breaker to replace breaker K at Howard station.	5/1/2025	$1.10		
15	S2653	.1	Cosgray 345 kV station: Greenfield 345 kV ring bus station laid out as a six-breaker ring bus for future expansion that includes four 345 kV 63 kA breakers initially. 345 kV revenue metering equipment will be installed.	5/1/2023	$18.02		
		.2	Cut into the Hayden–Roberts No. 1 345 kV circuit with two dead-end monopoles that will then tie directly in to the new Cosgray station. Fiber extension and termination into new Cosgray station. Remote end relay settings updates.				
		.3	Install tie lines between Cosgray and the customer's station at Cosgray-Customer Tie line 1 and 2.				
16	S2659		Expand the Collinsville substation. Install three 138 kV breakers to form a ring bus. Install a new 138/69 kV 150 MVA transformer. Relocate the 138 kV feeder terminals. Install three 69 kV breakers to form a ring bus. Relocate the 69 kV feeder terminals. Install a control building with relaying and communications equipment.	7/5/2023	$12.70	DEO&K	
17	S2660		A new 69/12 kV transformer will be installed at Jasper substation and terminated into a new 69 kV breaker position. This will expand Jasper substation from a four breaker 69 kV ring bus to a five breaker 69 kV ring bus. This transformer will increase capacity to serve the new customer load addition coming online and will also support growth in the nearby industrial parks. Further, this will enhance operational flexibility via adding new switching capability between Jasper and Xenia substations to perform maintenance and help reduce extended outage times due to enhanced switching between the substations.	12/31/2023	$0.31	DAY	
18	S2661		Summerside 69 kV substation: Remove existing structures, bus work, the capacitor, transformer and foundations. Expand and rebuild the 69 kV section of Summerside. Install new foundations, ttwo new box structures and bus work. Reuse the existing circuit breakers, and install a new zero-crossing circuit breaker connecting a new 43.2 MVAR capacitor. Install a new 69/34 kV 22.4 MVA transformer. Install a control house for relaying and communications equipment.	12/31/2023	$10.30	DEO&K	11/19/2021
19	S2662		Rebuild the section of 69 kV feeder between Carlisle and Poasttown with steel poles, new hardware and conductor. Remove two switches and a tap to an industrial customer. The capacity of the line will increase from 77 MVA to 93 MVA.	12/31/2024	$15.10		
20	S2665		Replace the failed West Bellaire 138/69 kV transformer No. 2 with a spare transformer (130 MVA nameplate, 2016 vintage).	12/16/2021	$0.50	AEP	11/19/2021
21	S2666		Install a new box structure. Move the Seward-Port Union feeder termination from a monopole to the new box structure. Install CCVTs and a line disconnect for the new feeder connection. Install two new switches and 138 kV bus work to form a ring bus. Install a 138/13 kV, 22 MVA transformer with a bus disconnect, circuit switcher and wave trap on the high side of the transformer. Install protection and controls for the new equipment in the existing control enclosure.	12/31/2022	$2.40	DEO&K	12/17/2021

Table 6.47: Ohio Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
22	S2671		Construct a greenfield 0.3-mile 138 kV double circuit line tapping the Beaver-Black River (ATSI) 138 kV line. Install five monopole 138 kV double circuit steel structures with concrete foundations and string 1590 ACSR conductor. Expand the Amherst No.2 substation with the installation of three 138 kV circuit breakers; one 138/69/12 kV 130 MVA transformers; two (2) 69 kV circuit breaker. Install one 69 kV breaker towards Nordson.	12/31/2023	$14.05	AMPT	11/19/2021
		.1	Design and construct tap structure(s) at tap location. Upgrade line relaying with new panel at Black River. Upgrade line relaying with new panel at Beaver. Install/complete fiber connection to Beaver and Black River substations. Provide/install four 69 kV revenue metering equipment packages at Amherst Muni substations.			ATSI	
23	S2683	.1	At Timken Richville, install two 138 kV circuit breakers on the two line exits to Timken and South Canton. Retire the old control house and install a new prefabricated building with new relaying. Remote end settings updates only required at South Canton.	8/1/2023	$4.69	AEP	1/21/2022
		.2	Upgrade the 138 kV line relays to coordinate with Timken Richville and Southeast Canton. Retire the pilot-wire and electromechanical relays. Install new three-phase CCVTs.				
		.3	Upgrade the 138 kV line relays to Timken 'At Southeast Canton. Retire the pilot-wire and electromechanical relays.				
24	S2687		Tap the Beartown-West New Philadelphia 69 kV circuit and install a three-way switch (“stout switch”). Extend two spans of radial 69 kV T-line to reach the customer’s substation.	7/1/2022	$1.41		
25	S2688	.1	Install a new distribution station (“Pumpkin”) adjacent to the 69 kV transmission through-path south of Barnesville. Retire Barnesville station.	12/1/2023	$2.67		
		.2	Retire the 0.4-mile 69 kV transmission line tap into Barnesville station.				
		.3	Loop the Speidel-Summerfield 69 kV transmission line into Pumpkin station.				
26	S2689		At Dicks Creek Gas 69 kV substation, retire the one wood pole between the tap and substation. Retire two spans of conductor. Install post insulators for jumper support at the former tap.	7/1/2022	$0.08	DEO&K	2/28/2022
27	S2691		Install one 138 kV 4000A 63 kA circuit breaker and breaker control relays to accommodate the installation of a new 138/34.5 kV distribution bank at Babbitt 138 kV station.	9/1/2023	$0.70	AEP	
28	S2695		A new 69/12 kV transformer will be installed at Octa substation and terminated into a new 69 kV breaker position. This will expand Octa substation from a three-breaker 69 kV ring bus to a four-breaker 69 kV ring bus. This transformer will create a new delivery point for AES Ohio distribution. This delivery point will provide capacity and switching flexibility, particularly at the Washington Courthouse and Jeffersonville substations, ensuring load can be restored under contingency conditions.	12/31/2023	$0.31	DAY	
29	S2696		Construct a 138 kV tap off the Delta-Wauseon 138 kV line to thenew 138 kV Customer substation. The customer substation tap location is ~0.9-mile extension from the existing structures to the new customer substation. Add MOAB and SCADA to two new switches on the Delta-Wauseon 138 kV line. Upgrade 336 ACSR TL Drop at Lemoyne substation (Dowling line Exit).	6/1/2022	$2.10	ATSI	3/18/2022
30	S2697		Replace Jackman-Westgate line relaying with primary and backup line relays. Replace 138 kV breakers at Westgate and Jackman substations with associated disconnect switches. Replace line traps, CCVTs. Replace substation conductor to exceed transmission line ratings.	4/1/2022	$2.50		2/18/2022
31	S2698		Replace 2000A breaker with 3000A. Replace live parts of disconnect switches to increase amperage rating to 3000A. Replace substation conductor to exceed transmission line ratings.	3/20/2022	$1.80	ATSI	2/18/2022
32	S2744		Replace the wooden structure with embedded steel structures at Meadow-Meadow tap 69 kV. Reconductor with 954ACSR. The summer rating will increase to 97/97 MVA SN/SE.	7/1/2022	$1.63	DEO&K	3/18/2022
33	S2745		Build a new substation named Linneman. Loop the nearby Ebenezer-Ferguson-Delhi 69 kV feeder through Linneman switch connecting the feeder to the bus. Install a 69 kV circuit switcher to connect a 69/13 kV 22 MVA distribution transformer. Install a control enclosure to house relaying and communications equipment.	12/31/2025	$2.86		

Table 6.47: Ohio Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
34	S2748	.1	Install a new three-way phase-over-phase switch (Boughtonville Sw) and 69 kV metering to address the hard tap to Firelands' Boughtonville station.	9/3/2025	$33.50	AEP	3/18/2022
		.2	Install a new three-way phase-over-phase switch (Lake Park Sw) and 69 kV metering to address the hard tap to Lake Park Industries.				
		.3	Install a new three-way phase-over-phase switch (Greenwich Sw) to address the hard tap to the Village of Greenwich's Greenwich station.				
		.4	Remove North Greenwich switch.				
		.5	Construct ~10.4 miles of new 69 kV line between South Greenwich and ATSI's New London delivery point using 556 ACSR conductor to give the existing radial line looped transmission service.				
		.6	Install a box bay and two new 69 kV, 3000A 40kA breaker at South Greenwich to accommodate the new line to New London (ATSI).				
		.7	Remove the existing 69 kV bypass line at Willard station.				
		.8	Build a new four-breaker 69 kV ring bus substation adjacent to the Fireland's New London distribution substation. Acquire the Fireland 69 kV tap (~2 miles) and rebuild as a double circuit into the new ring bus and loop in/out the Hanville-Wellington 69 kV line. Serve the Firelands New London distribution substation from the new ring bus substation. Transfer the existing Firelands New London revenue metering from the existing location (line) into the Firelands New London distribution substation at the transformer high side within the zone of protection. Install new 69 kV tie line revenue metering equipment at the new ring bus substation exit to South Greenwich (AEP). Upgrade/adjust relaying at Hanville and Wellington. Upgrade terminal equipment at Wellington.			ATSI	
35	S2749	.1	At Rye Beach Road (Huron Muni) 69/12 kV substation, expand the current 69 kV station to a four-circuit breaker ring bus arrangement to accommodate a second 69 kV circuit (toward Shinrock). Build the new 69 kV ring bus to 2000A ratings. Install four 69 kV circuit breakers. Install one 69 kV circuit switcher. Install ten 69 kV bus disconnect switches (2000A). Relocate existing FE revenue metering at the substation as a result of the system reconfiguration.	6/1/2025	$8.50	AMPT	5/21/2021
		.2	Build ~0.2 miles 69 kV line into AMPT's Rye Beach Road substation in a separate right of way using 556 kcmil ACSR conductor. Loop in/out the Greenfield-Shinrock 69 kV line into AMPT's Rye Beach Road substation. FE will install two dead-end structures just outside of the AMPT's substation. For the new and existing line, this structure will be the point of interconnection (POI). The FE facilities/lines will terminate at the dead-end structure. FE will install two 1200A motor-operated switches on the new and existing line at the dead-end structures. Adjust relay settings at Shinrock substation. Replace existing Greenfield (Shinrock line) relay with a standard line relaying panel.			ATSI	
36	S2756		Construct a new 138 kV four-breaker (expandable to six) ring bus. Install two 345/138 kV transformers. Loop in the Delta-Wauseon 138 kV line into the New 138 kV ring bus. Install two new 138 kV line switches. One switch will be installed for the Lear tap. One switch will be installed for the Worthington tap.	12/1/2025	$25.10	ATSI	7/12/2022
37	S2757		Install 69 kV revenue metering package at new customer-owned metering station, Intall one SCADA controlled transmission switch, adjust relay settings at Lowellville substation.	9/2/2022	$0.10		
38	S2758		Construction of a new 69 kV tap along the East Archbold-Stryker 69 kV line. This new tap will feed a new customer with ~6 MVA of load.	12/1/2022	$1.70		
39	S2759		Reconductor the 15.8-mile Q2 line section from Leroy Center-Pawnee Tap and Pawnee Tap-Mayfield with 336 ACSS. Updated rating for Leroy Center-Mayfield Q2.	6/1/2026	$14.90		

Table 6.47: Ohio Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
40	S2769		Construct a new 69 kV ring bus substation named Kennel. Install six circuit breakers and one 69/13 kV, 22 MVA transformer. Loop the 69 kV feeders currently feeding adjacent Miller substation through Kennel. Refeed Miller from Kennel. Distribution will feed the relocating customer from this new substation.	12/31/2023	$6.67	DEO&K	4/22/2022
41	S2770	.1	Lazelle 69 kV station: Replace 69 kV circuit breakers 61 and 62 with 3000A 40 kA breakers and associated equipment and relaying.	6/1/2025	$1.78	AEP	
		.2	Replace 69 kV circuit breaker B with 3000A 40 kA breaker and associated controls at Sawmill 138 kV station.				
		.3	Replace 69 kV circuit breakers 62 and 63 with 3000A 40 kA breakers and associated equipment and relaying at Westerville 69 kV station.				
		.4	Replace 69 kV circuit breaker 64 with 3000A 40 kA breaker at Genoa 138 kV station.				
		.5	Install Telecom site with CES SFP to communicate with Lazelle station at Hyatt Telecom site.				
42	S2773	.1	Rebuild 9.3 miles of the East Lima-Columbus Grove line between Columbus Grove and structure 38. Construct ~1 mile of greenfield 69 kV line between structure 38 and the existing Bluelick Sw. Rebuild 1.65 miles of the 34.5 kV line section between Bluelick and East Lima to 69 kV to provide looped service to the new 69 kV delivery at Bluelick. Retire 1.7 miles of the Columbus Grove-East Lima line from structure 38 into East Lima.	5/15/2024	$28.36		
		.2	Install Slabtown SW with 1200A phase-over-phase switches. Install Auto-sectionalizing on the through path. Upgrade Bluelick delivery point metering.				
		.3	Retire 34.5 kV Bluelick SW.				
		.4	Replace Cairo switch with 1200A phase-over-phase switches. Install SCADA control on the through-path.				
		.5	Upgrade telecom equipment at East Lima station.				
		.6	In order to accommodate the line rebuild, work will be performed on the existing Columbus Grove switch. Install a box bay with two 69 kV, 1200A line witch automated MOABs, at Columbus Gove station.				
43	S2778	.1	Rebuild ~4.6 mile of the Newcomerstown- Cambridge 69 kV line that wasn't addressed under b3274 and b3345 utilizing 556 ACSR conductor.	6/1/2025	$11.91		
		.2	Rebuild the 0.6 mile Leatherwood Sw-North Cambridge with double circuit 556 ACSR conductor to provide loop service to North Cambridge station.				
		.3	Add line MOABs for each of the double circuit lines coming into North Cambridge station				
		.4	Remove the Leatherwood switch that currently radially serves North Cambridge station.				
		.5	Replace Salt Fork switch with a new 1200A phase-over-phase switch.				

Table 6.47: Ohio Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
44	S2779		Rebuild the existing 69 kV yard to a breaker and a half arrangement at Fremont Center. Install 11 new 69 kV, 3000A 40 kA breakers and relocate one existing breaker into the new strings.	12/15/2026	$10.35	AEP	4/22/2022
45	S2780	.1	Rebuild the 15.7 mile 138 kV line between Howard and Chatfield stations with new 1033 ACSR conductor.	5/1/2025	$85.12		4/22/2022
		.2	Rebuild the 6.1-mile 138 kV line between Melmore and South Tiffin stations with new 1033 ACSR conductor.				
		.3	Rebuild the 11.7-mile 138 kV line between South Tiffin and West End Fostoria stations with new 1033 ACSR conductor.				
46	S2781	.1	Relocate the Anguin extension No. 4 into strings C and D at Anguin 138 kV station installing two circuit breakers in each string to complete the strings. The new double circuit line to Brie station will be installed in strings A and B. Expand DICM to accommodate additional relays.	6/1/2023	$21.09		4/22/2022
		.2	Re-terminate the existing 138 kV Anguin Extension lines into strings C and D at Anguin-Penguin DP1 138 kV.				
		.3	Establish the greenfield 138 kV Brie 138 kV station. Two full breaker and a half strings and two partial strings will be initially installed for a total of ten 138 kV breakers.				
		.4	At Anguin-Brie 138 kV, build ~1.5 miles of greenfield 138 kV double circuit line between Anguin and Brie station with two Bundle ACSS 1033.5 Curlew. Extend the telecom fiber into Brie station for relaying/communication. Short span construction and larger than normal foundations are required in this area to maintain clearances and paths for future development from the customers in the area, leading to higher than normal costs for this line.				
		.5	At Brie-Customer Why 1 138 kV, tie lines No. 1-4 to the customer's facility.				
47	S2782	.1	At Iron Triangle switch 138 kV, establish a new three-way phase-over-phase switch on the Fostoria Central-Melmore circuit to serve new North Central delivery point. The through-path will include auto-sectionalizing switches.	7/1/2023	$11.42		4/22/2022
		.2	At Iron Triangle-Loudon 138 kV, construct ~3.85 miles of single circuit 138 kV line utilizing 795 ACSR conductor between the proposed Iron Triangle switch and the new NCEC Loudon delivery point.				
		.3	At West End Fostoria-Melmore 138 kV, cut in work will be required on the Fostoria-Melmore circuit for the Iron Triangle switch.				
		.4	At Ohio Central-Fostoria Central 345kV, modify Fostoria Central-South Berwick 345 kV for the Iron Triangle-Loudon 138 kV line crossing.				
48	S2784	.1	Rebuild the existing 8.8 mile-69 kV line section between Merrick switch and Atwood switch, using 477 ACSR conductor.	5/1/2025	$38.71		5/19/2022
		.2	Build 7.0 mile greenfield 69 kV line between Merrick switch and Zoarville, using 477 ACSR conductor.				
		.3	Retire 6.5 miles of 69 kV line between Merrick switch and East Dover.				
		.4	Remove 69 kV breaker K and associated equipment. Connect the modified Carrollton 69 kV circuit to breaker H; upgrade a small amount of risers at East Dover.				
		.5	Install 69 kV switch and conductor to connect to new T-line entrance at Zoarville. Relay settings updates at Carrollton.				
49	S2785	.1	At Invision switch, install a new switch on the Ebersole-Findlay center 138 kV line to serve the new Buckeye Co-Op Cass substation.	8/15/2023	$2.09		5/19/2022
		.2	At Invision-Cas, at: install ~0.1 miles of new 138 kV line from Invision switch to the Buckeye Co-op Cass substation.				

Table 6.47: Ohio Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
50	S2789	.1	Install a new 2000 A three-way phase-over-phase switch with SCADA automation on the Huntley-Greif through path and install a bypass for maintenance at Scherers switch 138 kV.	4/1/2024	$2.71	AEP	4/22/2022
		.2	Tap the existing Greif-Huntley 138 kV circuit by installing structures to carry the 69 kV underbuild Lazelle-Busch circuit and maintain separation from the new Scherers switch as well as install dead end poles and centerline poles on each direction of the new switch.				
		.3	At Cologix Extension 138 kV, construct ~0.24 miles of single circuit 138 kV radial transmission line from Scherers switch to the new Cologix Customer station.				
51	S2790		Install two new supervisory controlled automatic sectionalizing switches on each side of the East Logan tap.	12/31/2025	$0.55	DAY	6/15/2022
52	S2791	.1	Construct a greenfield 138/69 kV West Watertown station off the existing Corner-Wolf Creek 138 kV circuit. Install four-138 kV 3000A 40 kA breakers configured in a ring arrangement. Install 90 MVA 138/69/13.09 kV transformer along with a 3000A 40 kA 69 kV low side breaker towards WEC's Bartlett delivery.	9/1/2024	$38.90	AEP	6/15/2022
		.2	Cut-in on the line to install the new West Watertown station at Wolf Creek-Corner 138 kV line cut-in.				
		.3	At West Watertown-Watertown (WEC) 138 kV circuit, construct ~4.3 miles of single circuit 138 kV line between the newly proposed West Watertown station and WEC's new 138 kV delivery at Watertown.				
		.4	At West Watertown-Patten Mills 69 kV circuit, construct ~5.8 miles of single circuit 69 kV line between the newly proposed West Watertown station and a proposed phase over phase switch (Patten Mills switch) near WEC's delivery at Bartlett.				
		.5	Install a new 69 kV 2000A phase-over-phase (Patten Mills switch) to serve the Bartlett delivery point.				
		.6	At South Stockport-Washington Co-op 69 kV line cut-in, cut-in on the line to install the new Patten Mills switch.				
		.7	Retire ~9 miles of existing 69 kV line between Grace and Muskingum River stations at Muskingum River-South Rokeby 69 kV line removal.				
		.8	At Muskingum River 138 kV yard, retire the 138/69 kV XF No. C, circuit breaker-HM and HW.				
		.9	Retire Grace-Muskingum River circuit, upgrade protection and fiber work at Grace station 69 kV.				
		.10	At Grace-Watertown Fiber, install fiber between Grace and Watertown stations.				
		.11	Perform remote end protection upgrade at Wolf Creek and Corner stations.				
		.12	Install 12 kV revenue metering at WEC's new Watertown station.				
53	S2792	.1	Eliminate the Moreland area 69 kV hard tap and install a new three-way, motor-operated switch with SCADA functionality ("Rufener switch").	12/1/2023	$1.50	AEP	6/15/2022
		.2	Modify the Beartown-Moreland 69 kV through-path T-line and ROW in order to install the new switch structure.				
		.3	Modify the Rufener-Co-op 69 kV radial T-line and ROW in order to install the new switch structure.				
54	S2793	.1	Rebuild the 8.9 mile West Van Wert-Ohio City 34.5 kV circuit to operate at 69 kV utilizing 556 ACSR conductor.	6/1/2025	$21.75	AEP	6/15/2022
		.2	In order to address the three terminal point created by closing in the interconnection at Rockford and address existing dissimilar zones of protection, four new 3000A 40 kA breakers will be installed at West Van Wert station in a ring configuration.				
		.3	Relocate Haviland-West Van Wert 69 kV to accommodate work at West Van Wert station.				

Table 6.47: Ohio Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
54 Cont.	S2793 Cont.	.4	Relocate West Van Wert-South Van Wert to accommodate work at West Van Wert station.	6/1/2025	$21.75	AEP	6/15/2022
		.5	Install new 69/12 kV Roller Creek station to replace Ohio City 34.5/12 kV station. Install a box bay with a 1200A 69 kV auto-sectionalizing MOAB and a 69 kV, 3000A 40 kA breaker on the West Van Wert-Rockford through path. Install 69 kV metering.				
		.6	Retire West Ohio City switch 34 kV.				
		.7	Retire Southwest Van Wert switch 34 kV.				
55	S2794	.1	Install a new three-way phase-over-phase MOAB switch (Mount Perry switch) tapping the Crooksville-North Newark 138 kV circuit to SCP's new Mount Perry station.	7/19/2024	$2.44	AEP	6/15/2022
		.2	Construct ~0.08 miles of greenfield 138 kV transmission line from the greenfield three-way phase-over-phase MOAB switch to SCP's new Mount Perry station.				
		.3	Install 12 kV metering at SCP's new Mount Perry station.				
		.4	Perform work to cut-in the Crooksville-North Newark 138 kV line to install the new phase-over-phase MOAB switch.				
		.5	Perform remote end protection upgrade for Crooksville.				
56	S2799		Install two new supervisory controlled automatic sectionalizing switches on each side of the East Logan tap.	6/1/2024	$13.50	DAY	7/22/2022
57	S2800		Install a new, second 138/34 kV, 60MVA transformer to feed a new, second 34 kV bus at Willey substation. Install a new 138 kV circuit breaker to connect the new transformer. Move two of the four existing 34 kV feeders to the new 34 kV bus to distribute load between transformers.	8/10/2023	$0.00	DEO&K	7/22/2022
58	S2801	.1	Retire the existing box bay and breaker bypass switch at Lockwood Rd 138 kV. Install two 138 kV 40 kA breakers in coordination with an active IPP AF1-063 project that will be installing an additional two breakers in a ring bus arrangement at the station. Install a DICM. Install a new 23MVAR capacitor bank with breaker.	6/20/2023	$5.58	AEP	7/22/2022
		.2	For Sowers-Lockwood Rd-Richlands 138 kV, relocate Lockwood Road-Sowers and Lockwood Road-Richland lines line to accommodate work at Lockwood Road station.				
		.3	Relocate Lockwood Road-City of Bryan line to accommodate work at Lockwood Road station.				
59	S2802	.1	Replace 69 kV oil filled FK type breaker circuit breaker-W with a 3000A 40 kA breaker at Crooksville station, 69 kV.	1/2/2026	$50.30	AEP	7/22/2022
		.2	Retire circuit breaker-B at South Fultonham, 69 kV.				
		.3	Retire Saltillo switch.				
		.4	Rebuild ~7.4 miles of single circuit 69 kV line between the Crooksville and South Fultonham stations.				
		.5	Rebuild ~8.8 miles of single circuit and 1.6 miles of double circuit 69 kV line between the Crooksville and Somerset stations.				
		.6	Rebuild ~7.2 miles of single circuit 69 kV line between the South Fultonham and Mount Sterling stations.				
		.7	Retire ~5.9 miles of single circuit 69 kV line between the South Fultonham station and Saltillo switch.				

6.8.9 — Merchant Transmission Project Requests

As of Dec. 31, 2022, PJM's queue contained two merchant transmission project requests with a terminal in Ohio, as shown in **Map 6.39** and **Table 6.48**.

Map 6.39: Ohio Merchant Transmission Project Requests (Dec. 31, 2022)

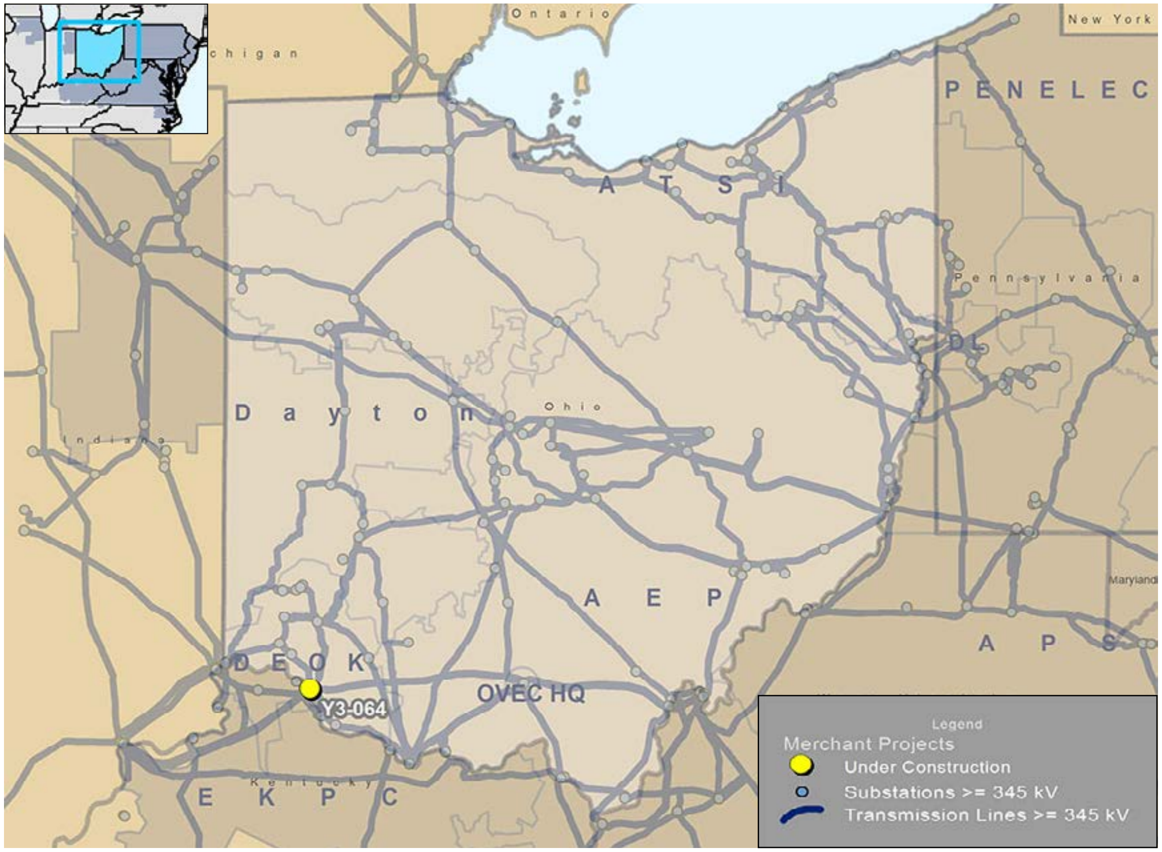


Table 6.48: Ohio Merchant Transmission Project Requests (Dec. 31, 2022)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
Y3-064	Pierce-Beckjord 138 kV	DEO&K	Under Construction	12/20/2020	160

6.9: Pennsylvania RTEP Summary

6.9.1 — RTEP Context

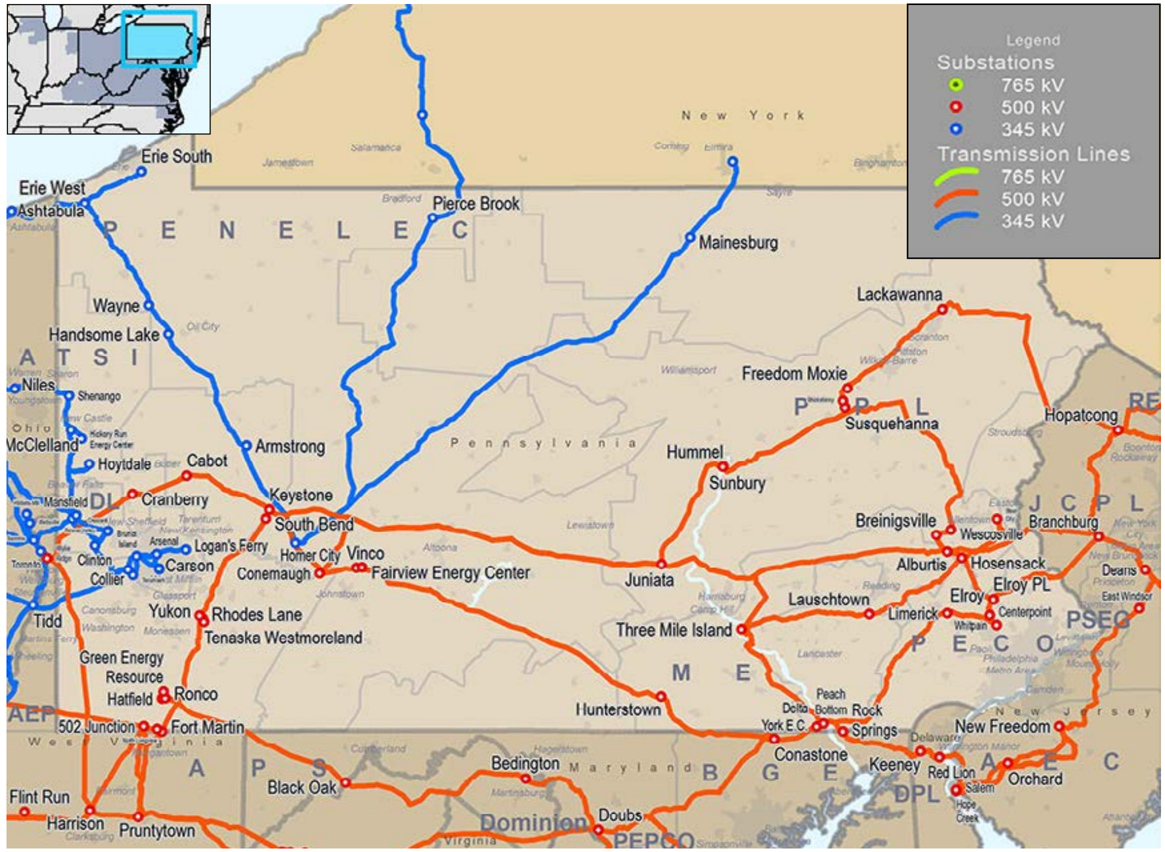
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Pennsylvania, including facilities owned and operated by Allegheny Power (AP), Duquesne Light Company (DLCO), Metropolitan Edison, Pennsylvania Electric Company (PENELEC), PECO Energy Company (PECO), PPL Electric Utilities (PPL), UGI Utilities (UGI), Rock Springs and American Transmission Systems, Inc. (ATSI) as shown on **Map 6.40**.

Pennsylvania's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, Pennsylvania has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with the percentage of generation expected to be fueled by renewable fuels in coming years. Pennsylvania has a mandatory alternative energy portfolio standard (AEPS) target of 8% Tier 1 resources and 10% Tier 2 resources. The AEPS includes a solar carve-out of 0.5%, and solar resources counting toward the AEPS must be located within Pennsylvania.

Map 6.40: PJM Service Area in Pennsylvania



6.9.2 — Load Growth

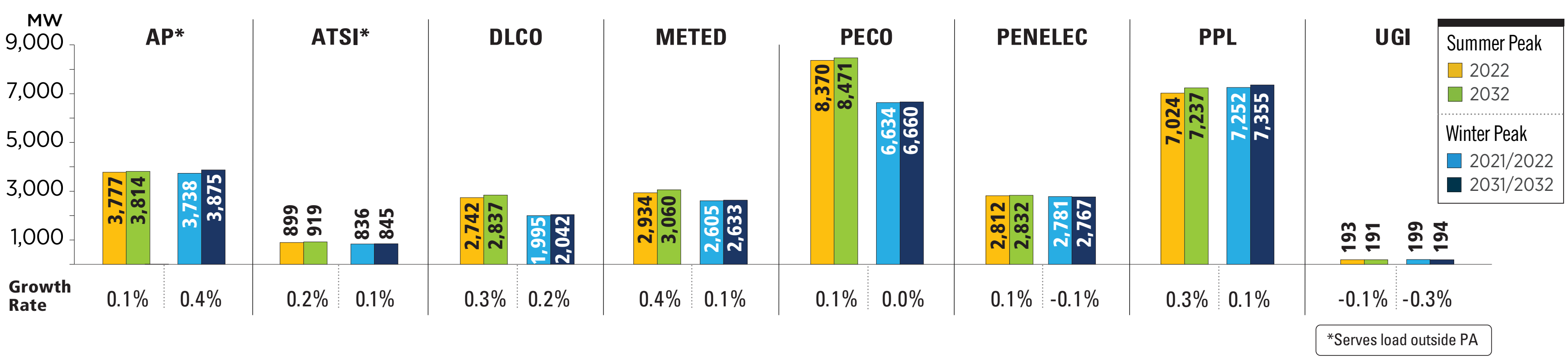
PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.46** summarizes the expected loads within the state of Pennsylvania and across the PJM region.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

Figure 6.46: Pennsylvania – 2022 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2022	2032	2021/2022	2031/2032
149,938 MW	154,381 MW	132,102 MW	141,516 MW
Growth Rate 0.4%		Growth Rate 0.7%	

The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

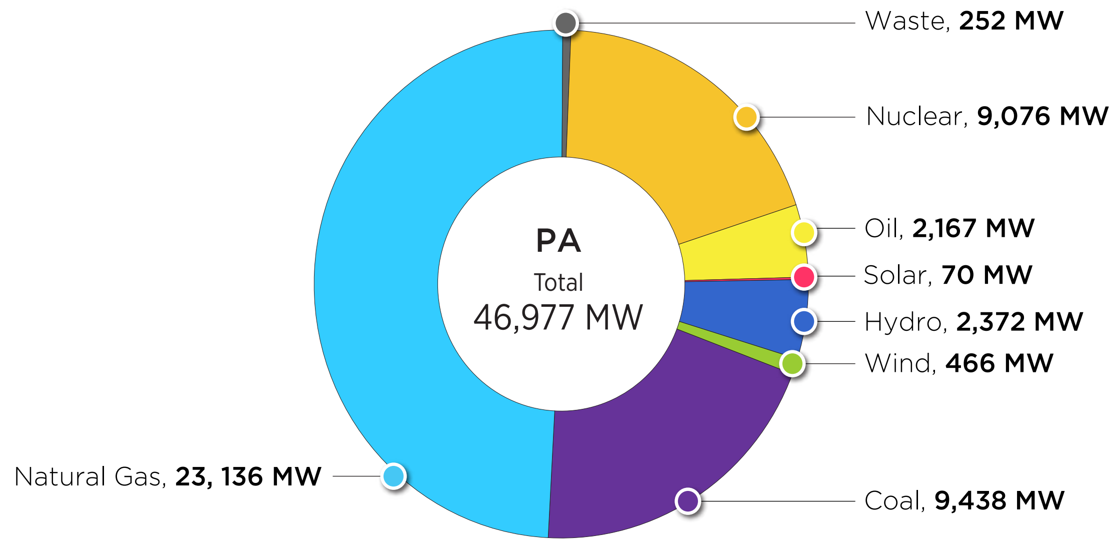
- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

6.9.3 — Existing Generation

Existing generation in Pennsylvania as of Dec. 31, 2022, is shown by fuel type in **Figure 6.47**.

Figure 6.47: Pennsylvania – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in Pennsylvania as of Dec. 31, 2022, are discussed next, in **Section 6.9.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

6.9.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Pennsylvania, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Pennsylvania, as of Dec. 31, 2022, 435 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.49, Table 6.50, Figure 6.48, Figure 6.49** and **Figure 6.50**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.49: Pennsylvania – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	Pennsylvania Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	469	6.09%	529	0.61%
Natural Gas	291	3.78%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	0	0.00%	273	0.31%
Solar	5,839	75.90%	57,616	66.37%
Storage	1,011	13.14%	14,148	16.30%
Wind	84	1.09%	6,223	7.17%
Grand Total	**7,693**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.50: Pennsylvania – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue				Complete					
		Active		Under Construction		In Service		Withdrawn		Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	16	229.0	28	14,354.6	44	14,583.6
	Diesel	0	0.0	0	0.0	4	37.4	12	51.5	16	88.9
	Natural Gas	5	290.5	14	276.8	110	21,371.5	252	91,301.0	381	113,239.8
	Nuclear	2	0.0	1	44.0	14	2,565.0	12	1,731.0	29	4,340.0
	Oil	0	0.0	6	7.5	3	9.4	9	1,307.0	18	1,323.9
	Other	0	0.0	0	0.0	2	306.5	6	344.0	8	650.5
	Storage	34	1,010.9	0	0.0	5	0.0	47	798.4	86	1,809.3
Renewable	Biomass	0	0.0	0	0.0	2	15.4	4	36.5	6	51.9
	Hydro	4	468.8	2	21.5	12	480.8	18	465.4	36	1,436.4
	Methane	0	0.0	0	0.0	23	125.9	37	201.3	60	327.2
	Solar	287	5,839.5	74	772.0	15	65.3	252	4,271.2	628	10,948.1
	Wind	4	83.7	2	32.0	42	295.9	138	1,757.5	186	2,169.1
	Wood	0	0.0	0	0.0	0	0.0	1	16.0	1	16.0
	Grand Total	336	7,693.3	99	1,153.8	248	25,502.1	816	116,635.3	1,499	150,984.5

Figure 6.48: Pennsylvania – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

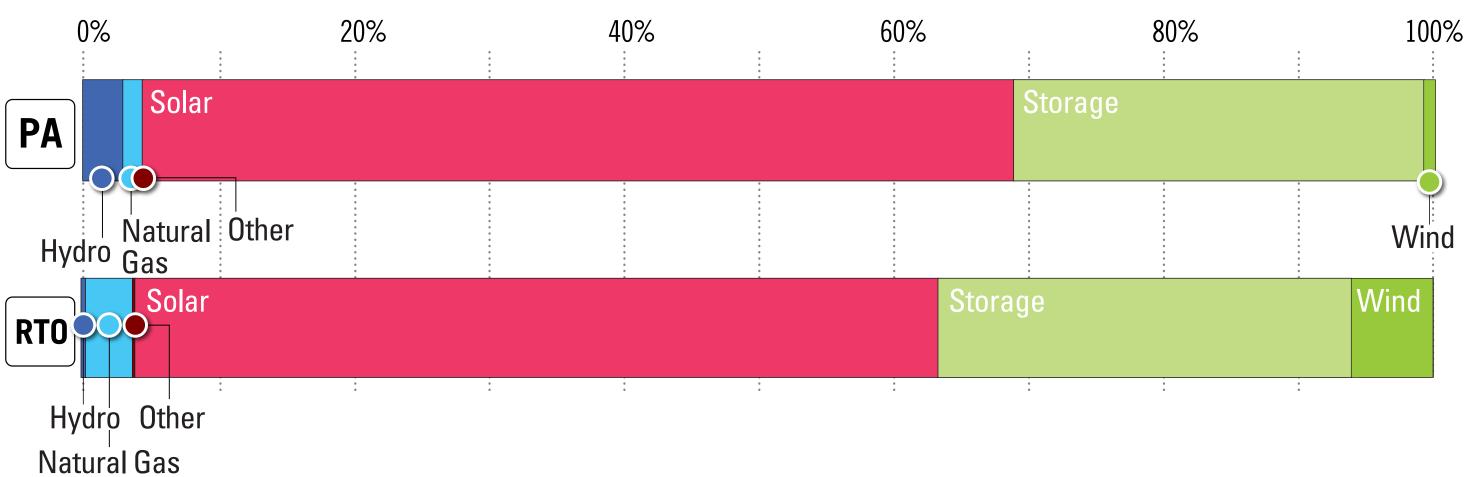


Figure 6.49: Pennsylvania – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)

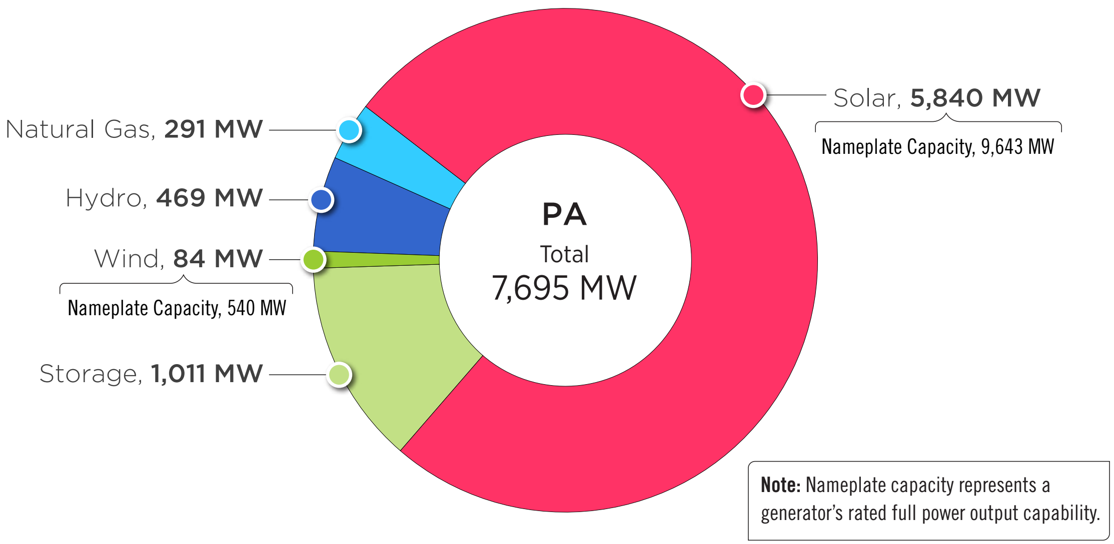


Figure 6.50: Pennsylvania Progression History of Queue – Interconnection Requests (Dec. 31, 2022)

Percentage of planned capacity and projects that have reached commercial operation

17.8%	Requested capacity megawatts
21.7%	Requested projects

Projects withdrawn after final agreement			Capacity	Nameplate
	62	Interconnection Service Agreements	7,581 MW	9,629 MW
	56	Wholesale Market Participation Agreements	332 MW	467 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.9.5 — Generation Deactivation

Formal generator deactivation requests received by PJM in Pennsylvania between Jan. 1, 2022, and Dec. 31, 2022, are summarized in **Map 6.41** and **Table 6.51**.

Deactivation Reliability Studies

PJM has 30 days in which to respond to a generator owner with deactivation study results. Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can reduce voltage support.

Deactivation reliability studies comprise thermal and voltage analysis, including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, reliability criteria violations caused by unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board.

Map 6.41: Pennsylvania Generation Deactivations (Dec. 31, 2022)

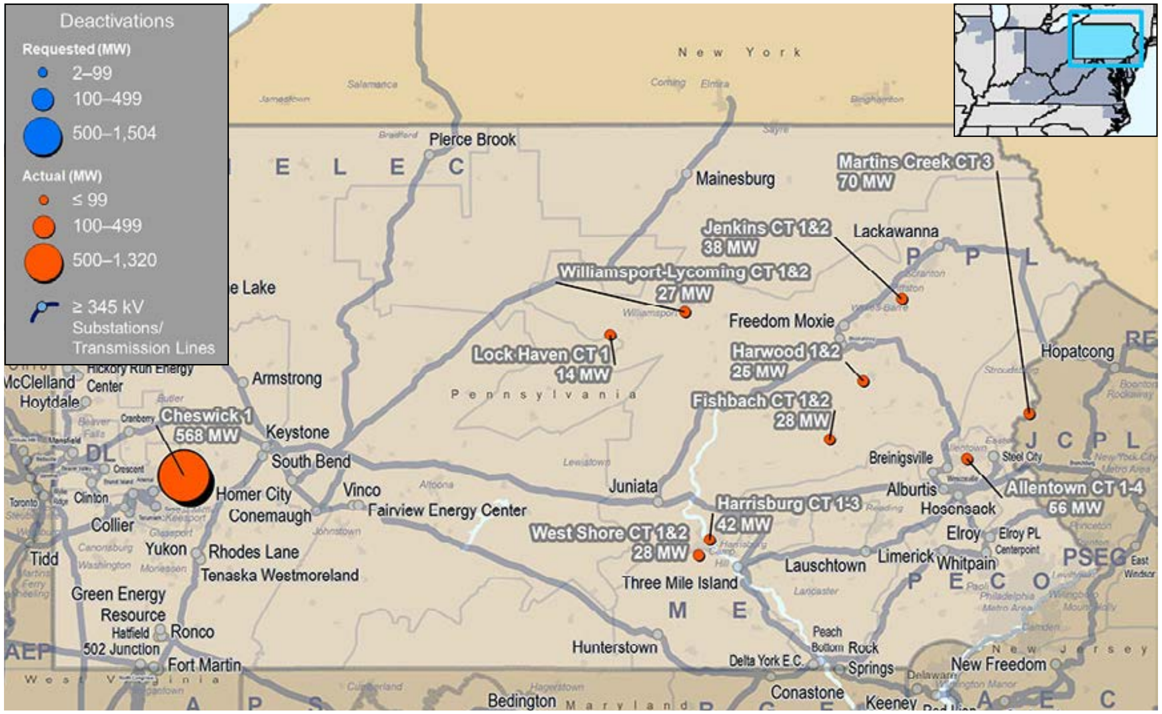


Table 6.51: Pennsylvania Generation Deactivations (Dec. 31, 2022)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Williamsport-Lycoming CT 2	PPL	Oil	9/30/2021	4/1/2022	54	13.4
Williamsport-Lycoming CT 1						13.2
West Shore CT 2					52	14.0
West Shore CT 1						14.0
Martins Creek CT 3				6/1/2022	50	18.0
Lock Haven CT 1				4/1/2022	52	14.0
Jenkins CT 2						13.8
Jenkins CT 1						13.8
Harrisburg CT 3	PPL	Oil	9/30/2021	6/1/2022	54	13.8
Harrisburg CT 2						13.9
Harrisburg CT 1						13.4
Fishbach CT 2					52	14.0
Fishbach CT 1						14.0
Allentown CT 4					54	14.0
Allentown CT 3						14.0
Allentown CT 2						14.0
Allentown CT 1	PPL					14.0
Cheswick 1	DLCO	Coal	7/14/2021	3/31/2022	51	567.5
Harwood 2	PPL	Oil	4/27/2021	5/31/2022	53	12.3
Harwood 1			10/29/2020			12.9

6.9.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in Pennsylvania are summarized in **Map 6.42** and **Table 6.52**.

Map 6.42: Pennsylvania Baseline Projects (Dec. 31, 2022)

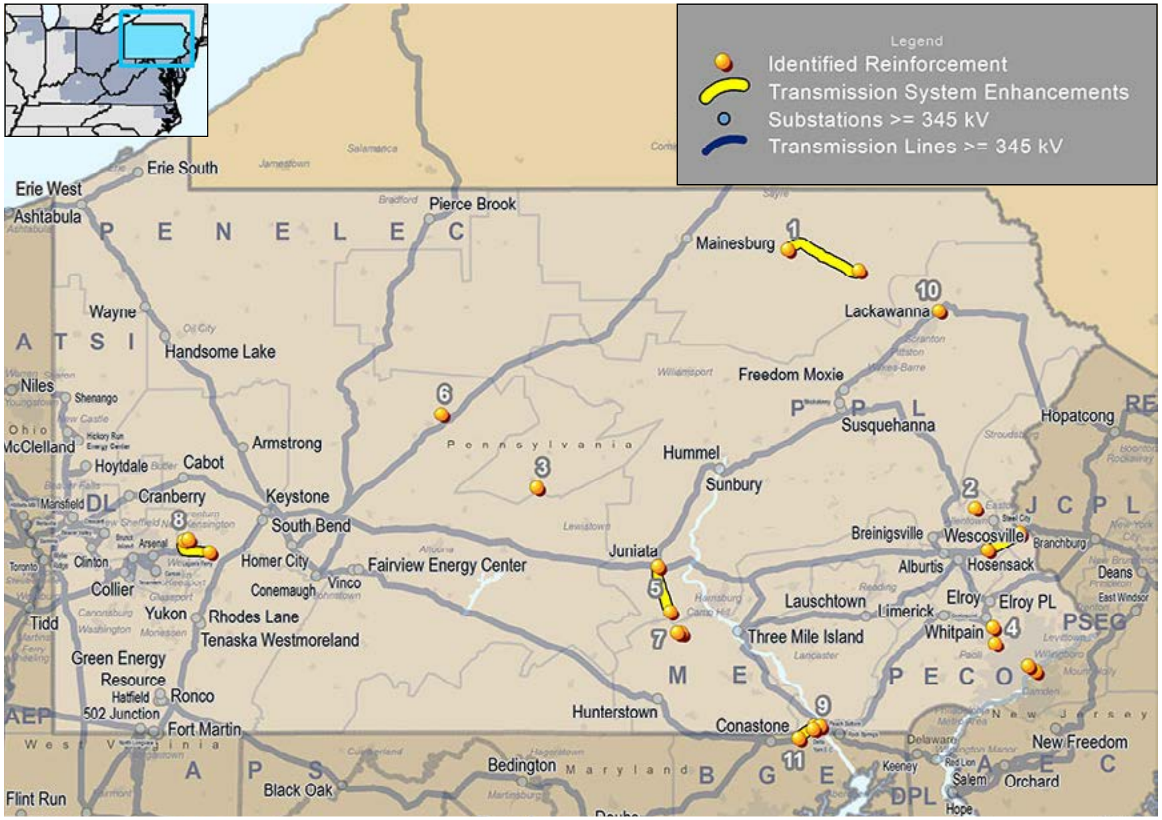


Table 6.52: Pennsylvania Baseline Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3672		Rebuild 2.5 miles of 636 ACSR with 1113 ACSS conductor using single circuit construction at East Towanda-North Meshoppen 115 kV line. Upgrade all terminal equipment to the rating of 1113 ACSS.	6/1/2026	$6.66	PENELEC	11/18/2021
2	B3673		Replace the relay panels at Bethlehem 33 46 kV substation on the Cambria Prison line.		$0.30		

Table 6.52: Pennsylvania Baseline Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	B3681		Upgrade the Shingletown No. 82 230-46 kV transformer circuit by installing a 230 kV breaker and disconnect switches, removing existing 230 kV switches, replacing 46 kV disconnect switches, replacing limiting substation conductor, and installing/replacing relays.	6/1/2026	$1.66	AP	11/30/2021
4	B3697		Replace station conductor and metering inside Whitpain and Plymouth substations to increase the ratings of the 220-13/220-14 Whitpain-Plymouth 230 kV line facilities.	6/1/2025	$0.62	PECO	
5	B3698		Reconductor the 14.2 miles of the existing Juniata-Cumberland 230 kV line with 1272 ACSS/TW HS285 “Pheasant” conductor.	12/31/2023	$9.00	PPL	
6	B3708		Replace the Shawville 230/115/17.2 kV transformer with a new Shawville 230/115 kV transformer and associated facilities. Replace the plant’s No. 2B 115/17.2 kV transformer with a larger 230/17.2 kV transformer.	6/1/2026	$8.78	PENELEC	3/8/2022
7	B3715	.1	Install a new 300 MVA 230/115 kV transformer at the existing PPL Williams Grove substation.	6/1/2026	$17.82	PPL	5/10/2022
		.2	Construct a new ~3.4 mile 115 kV single circuit transmission line from Williams Grove to Allen substation.				
		.3	Install a new Allen four-breaker ring bus switchyard near the existing MetEd Allen substation on adjacent property presently owned by FirstEnergy. Terminate the Round Top-Allen and the Allen-PPGI (PPG Industries) 115 kV lines into the new switchyard.			METED	
8	B3717	.1	Install a series reactor on Cheswick-Springdale 138 kV line.	12/31/2024	$33.00	DLCO	9/6/2022
		.2	Replace four structures and reconductor DLCO portion of Plum-Springdale 138 kV line. Install associated communication equipment and relay setting changes at Plum and Cheswick.				
9	B3728	.2	Replace four meters and bus work inside Peach Bottom substation on the 500 kV line 5012 (Conastone-Peach Bottom).	12/1/2027	$3.80	PECO	10/4/2022
10	B3730		Reterminate the Lackawanna T3 and T4 500/230 kV transformers on the 230 kV side to remove them from the 230 kV buses and bring them into dedicated bay positions that are not adjacent to one another.	6/1/2027	$10.70	PPL	10/4/2022
11	B3737	.23	Rebuild the underground portion of Richmond-Waneeta 230 kV.	6/1/2029	$114.11	AE	11/4/2022
		.45	Reconductor 0.33 miles of PPL’s portion of the Gilbert-Springfield 230 kV line.	6/1/2030		PPL	
		.47	Build a new greenfield North Delta station with two 500/230 kV 1500 MVA transformers and nine 63 kA breakers (four high-side and five low-side breakers in ring bus configuration).	6/1/2029		Transource	
		.48	Build a new North Delta-Graceton 230 kV line by rebuilding 6.07 miles of the existing Cooper-Graceton 230 kV line to double circuit.	6/1/2029		PECO	
		.49	Bring the Cooper-Graceton 230 kV line “in and out” of North Delta by constructing a new double circuit North Delta-Graceton 230 kV (0.3 miles) and a new North Delta-Cooper 230 kV (0.4 miles) cut-in lines.				
		.50	Bring the Peach Bottom-Delta Power Plant 500 kV line “in and out” of North Delta by constructing a new Peach Bottom-North Delta 500 kV (0.3 miles) cut-in and cut-out lines.				
		.51	Replace four 63 kA circuit breakers “205,” “235,” “225” and “255” at Peach Bottom 500 kV with 80 kA.				

6.9.7 — Network Projects

2022 RTEP network projects in Pennsylvania are summarized in **Map 6.43** and **Table 6.53**.

Map 6.43: Pennsylvania Network Projects (Dec. 31, 2022)

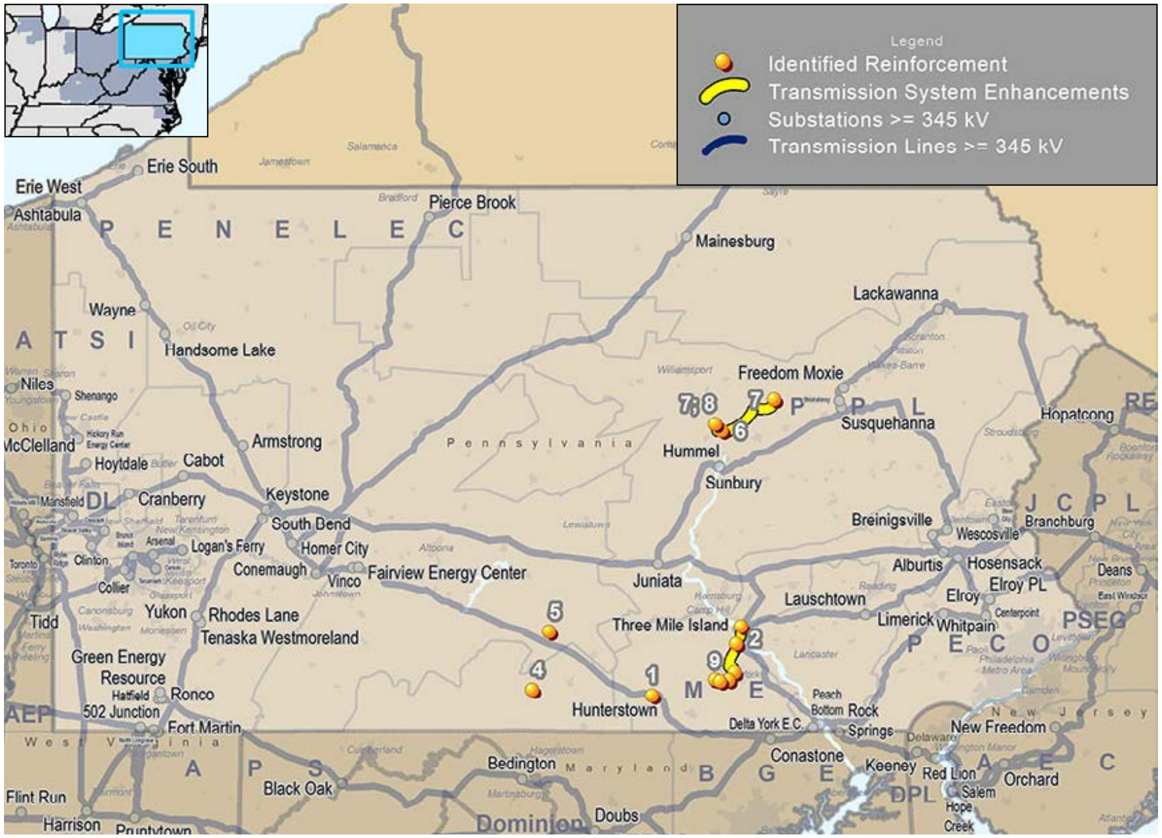


Table 6.53: Pennsylvania Network Projects (Dec. 31, 2022)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N6255	Install 115 kV six-breaker ring bus interconnection station for new customer generation addition (new AD1-020 switchyard). Includes Project Management and Construction Management.	AD1-020	10/31/2020	$4.30	METED	11/1/2022
2	N7002	Construct a new three-breaker ring bus on the 115 kV (977) line between Middletown Junction and Zions View.	AE1-129	9/30/2021	$5.89	MAIT	
3	N7003	Loop the Middletown Junction-Smith Street (977) 115 kV line into new AE1-129 ring bus approximately 6.4 miles from Middletown Junction.			$1.05		
4	N7010	Construct a new three-breaker ring bus on the 138 kV line between Guilford and McConnellsburg.	AE1-101	10/1/2022	$6.12	AP	

Table 6.53: Pennsylvania Network Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5	N7085	Construct a new three-breaker ring bus on the 115 kV line between Roxbury and Shade Gap.	AE1-071	9/30/2019	$6.65	MAIT	11/1/2022
6	N7242	Construct attachment facilities, including: - 69 kV circuit from the Milton-AE2-042 69kV line to the point of interconnection - One motor operated load break air break switch - Associated poles, structures and foundations	AE2-042	11/30/2022	$1.27	PPL	11/1/2022
7	N7242	Add a second circuit (Milton-AE2-042 69 kV line), to the existing Milton-Millville line structures, and modify the new Milton-AE2-042 69kV circuit to tie in the Attachment Facilities.	AE2-042	11/30/2022	$1.27	PPL	11/1/2022
8	N7242	Modify the Milton 69 kV substation relays.	AE2-042	11/30/2022	$1.27	PPL	11/1/2022
9	N7261	AE1-185 Supervisory Control and Data Acquisition (SCADA)/Fiber Communication. Estimated installation of 700 MHz radio system (70% penetration of FE territory) to support the SCADA switch installations.	AE1-185	12/31/2022	$1.56	MAIT	11/1/2022
10	N7261	Tap the Hokes-Jackson (79) 69 kV line to the new developer substation (AE1-185 generator lead termination).	AE1-185	12/31/2022	$1.56	MAIT	11/1/2022
11	N7261	Update relay settings for Hokes 69 kV substation.	AE1-185	12/31/2022	$1.56	MAIT	11/1/2022
12	N7261	Update relay settings for Jackson 69 kV substation.	AE1-185	12/31/2022	$1.56	MAIT	11/1/2022

6.9.8 — Supplemental Projects

Supplemental projects received by PJM in 2022 in Pennsylvania are summarized in **Map 6.44** and **Table 6.54**.

6.9.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Pennsylvania were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.44: Pennsylvania Supplemental Projects (Dec. 31, 2022)

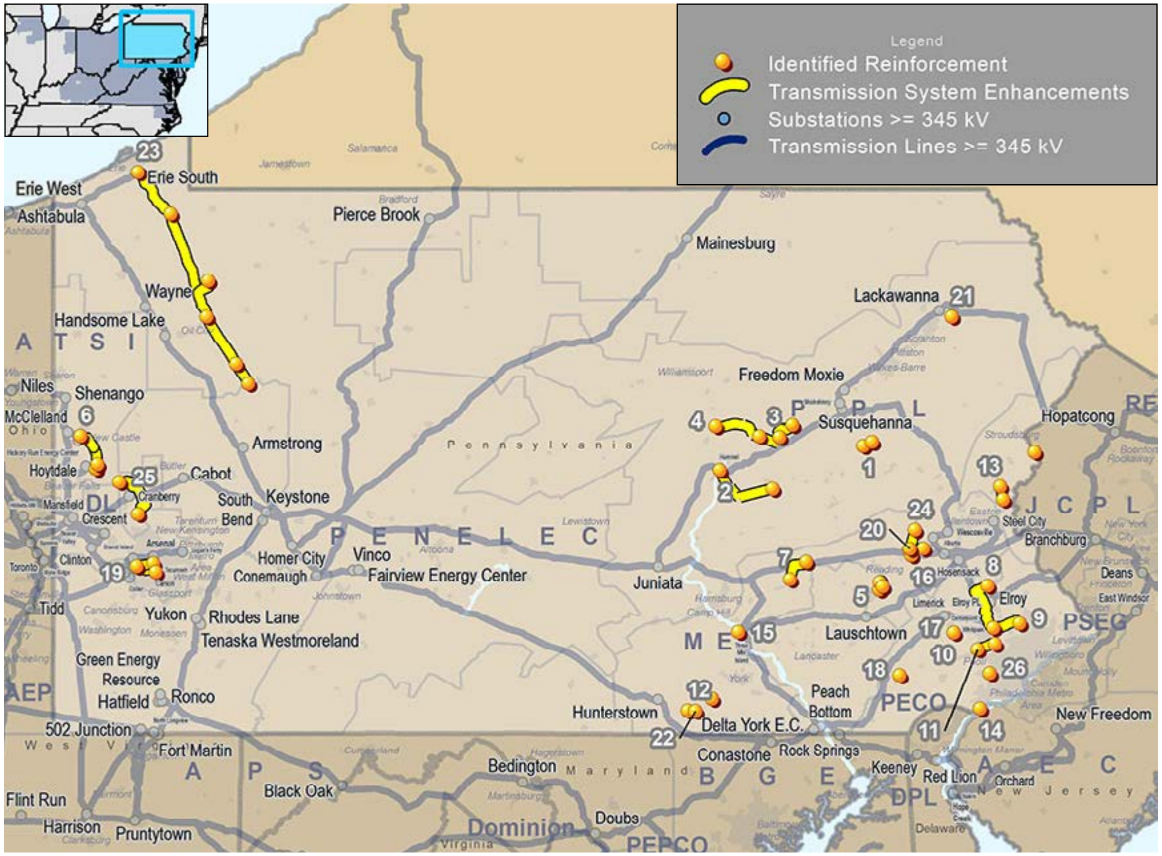


Table 6.54: Pennsylvania Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2591		Extend a second circuit to Freeland substation from the HARW-EHAZ No. 1 69 kV line (0.75 miles).	10/30/2024	$0.60	PPL	8/13/2021
2	S2592		Retire Toms Fork-Westerly 46 kV and Toms Fork-Str. 364-13 46 kV (~24 miles total).	10/30/2024	$0.50		
3	S2593		Install one 19.8 MVAR switched cap bank on the Columbia-Scott 69 kV line near the Scott 69/12 kV substation.	11/30/2022	$1.30		

Table 6.54: Pennsylvania Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	S2594		Extend a new double circuit 69 kV tap from the existing Danville-Milton and Columbia-Danville No. 1 69 kV lines to interconnect a new customer 69-12.47kV substation. Build 0.2 miles of new 69 kV double circuit line using 556 ACSR conductor.	2/28/2022	$1.30	PPL	8/13/2021
5	S2645	.1	Replace circuit breaker, and line relaying (Carpenter Technology-West Shore Tap-West Reading 25 69 kV line) at Carpenter Technology.	6/8/2021	$2.10	METED	9/14/2021
		.2	Replace circuit breaker, and line relaying (Carpenter Technology-West Shore Tap-West Reading 25 69 kV line) at West Reading.				
6	S2647		Tap the Cedar St-Frisco No. 1 69 kV line between Cedar St and Inmetco. Install two network 69 kV disconnect switches. Install one 69 kV tap switch. Construct ~1 span of 69 kV into new substation and adjust relaying at Cedar St and Frisco substations.	5/1/2022	$1.40	ATSI	8/16/2021
7	S2672		Tap the North Lebanon Tap-Frystown 69 kV line. Install 69 kV switches and construct ~2 span of 69 kV to customer substation.	11/1/2021	$0.80	METED	10/14/2021
8	S2673		Upgrade relays, communication, metering and replace station conductor on 220-10 (Whitpain-Buxmont) 230 kV line.	11/2/2021	$0.50	PECO	11/2/2021
9	S2674		Upgrade relays, communication, metering and replace station conductor on 220-52 (Whitpain-Jarrett) 230 kV line.	12/22/2021	$1.04	PECO	11/2/2021
10	S2675		Replace a piece of station cable on the 69 kV side of the Cromby No. 5 230/69 kV transformer facility.	10/17/2021	$0.10	PECO	11/2/2021
11	S2676		Upgrade relays, communication, metering and removal of wave trap on 220-69 (Plymouth Meeting-Upper Merion) 230 kV line.	10/7/2021	$1.90	PECO	11/30/2021
12	S2708	.1	Replace line relaying, disconnect switches, substation conductor, line trap, and circuit breaker at North Hanover 115 kV substation.	12/31/2022	$2.70	METED	1/20/2022
		.2	Replace line relaying, disconnect switches, substation conductor, line trap, and circuit breaker at PH Glatfelter 115 kV substation.				
13	S2709		Tap the Northwood-Belfast 115 kV line, install 115 kV switches and construct ~1 span of 115 kV to customer substation.	9/30/2022	$2.20	METED	1/20/2022
14	S2710		Replace Chester 69 kV circuit breaker No. 60.	12/23/2022	$0.65	PECO	1/20/2022
15	S2711		Replace the TMI No. 1 500/230 kV transformer and associated equipment with a 450/600/750 MVA transformer.	12/31/2023	$25.20	METED	2/8/2022
16	S2713	.1	Replace line relaying, disconnect switches, substation conductor, and circuit breaker on the Baldy-Kutztown Tap 69 kV line.	4/15/2022	$3.30	METED	3/17/2022
		.2	For Lyons 69 kV substation, replace line relaying, and circuit breaker on the Kutztown Tap-Lyons				
17	S2714		Replace circuit breaker No. 370 and associated wire drops at the Cromby 138 kV substation.	9/23/2022	$0.65	PECO	3/17/2022
18	S2716		Replace Newlinville 230 kV circuit breaker No. 260.	4/1/2022	$0.78	PECO	3/8/2022
19	S2726		Establish a new 138-23 kV Watson substation with a 138 kV, 3000A GIS ring bus. New substation will provide additional distribution feeds to DLC's downtown area, which will increase capacity and provide increased resiliency. The existing Oakland–Forbes (Z-48) and Carson-Forbes (Z-86) 138 kV circuits will be looped through the new Watson 138 kV substation to act as its transmission source. Four new 138 kV circuits will be created: Oakland-Watson (Z-48), Forbes-Watson (Z-85), Forbes-Watson (Z-86) and Carson-Watson (Z-89). The Watson substation will provide load relief, increased service reliability, and resiliency to the distribution lines, which provide service to Pittsburgh's downtown area and nearby communities.	6/1/2025	$34.00	DLCO	4/22/2022
20	S2750	.1	For Baldy 69 kV substation, replace line relaying, and substation conductor on the Baldy-Kutztown Tap 69 kV line.	5/27/2022	$1.90	METED	5/16/2022
		.2	For East Topton 69 kV substation, replace line relaying, substation conductor and circuit breaker on Kutztown Tap-East Topton.				
21	S2762		Extend a second circuit to Jessup substation from the LACK-POCO 69 kV line (0.05 miles).	10/30/2023	$0.25	PPL	5/16/2022
22	S2763		Construct six-breaker ring bus at Gitts Run 115 kV substation. Remove line trap at North Hanover 115 kV substation.	12/22/2023	$14.40	METED	7/21/2022

Table 6.54: Pennsylvania Supplemental Projects (Dec. 31, 2022) (Cont.)

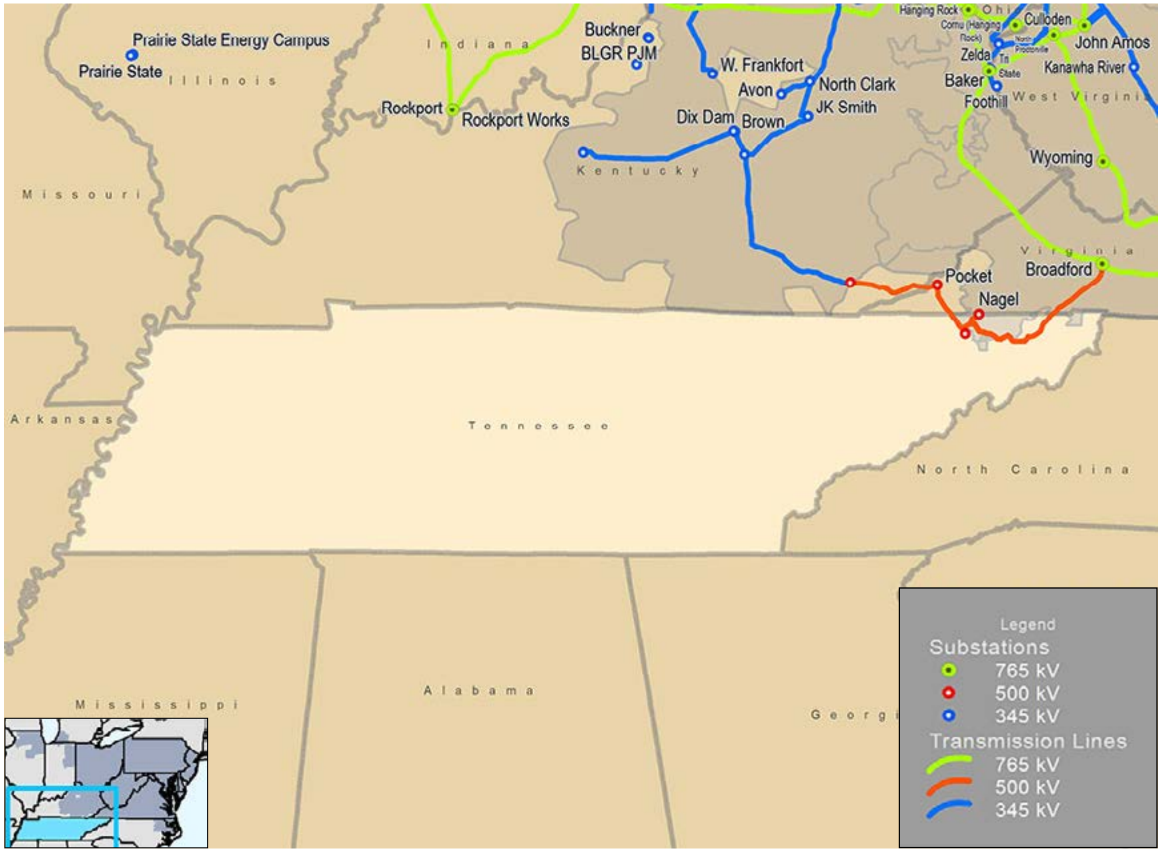
Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
23	S2764		Rebuild the Piney-Grandview-Titusville-Union City-Erie South 115 kV line using double circuit 115 kV construction adjacent to the existing 115 kV corridor (~82 miles). Energize the line in a six-wire configuration. Rebuild the Piney-Grandview-Titusville-Union City-Erie South 115 kV line using double circuit 115 kV construction adjacent to the existing 115 kV corridor (~82 miles). Energize the line in a six-wire configuration. Upgrade all substation terminals such that the new transmission line is the most limiting element.	6/1/2034	$443.00	PENELEC	7/21/2022
		.1	Rebuild the Piney-Haynie 115 kV line using double circuit 115 kV construction adjacent to the existing 115 kV.				
		.2	Rebuild the Haynie-Grandview115 kV line using double circuit 115 kV construction adjacent to the existing 115 kV.				
		.3	Rebuild the Grandview-Titusville 115 kV line using double circuit 115 kV construction adjacent to the existing 115 kV.				
		.4	Rebuild the Titusville-Union City 115 kV line using double circuit 115 kV construction adjacent to the existing 115 kV.				
		.5	Rebuild the Union City-Erie South 115 kV line using double circuit 115 kV construction adjacent to the existing 115 kV.				
24	S2803		Tap the Baldy-Weisenberg 69 kV line. Install 69 kV switches and Construct ~1 span of 69 kV to customer substation.	8/3/2023	$0.80	METED	7/21/2022
25	S2804		Tap the Maple-Pine Y-192 69 kV line between Callery and Concast Metals. Install one network 69 kV disconnect switch with SCADA. Construct ~1 span of 69 kV into new substation.	6/30/2022	$0.80	ATSI	11/19/2021
26	S2805		Install third Bryn Mawr 138/13 kV 62 MVA transformer with high side breaker. Install two 3000A 63 kA 138 kV breakers on the Bryn Mawr straight bus to create two double breaker bus ties. Install two 138 kV, 3000A 63kA line breakers on 130-35 (Bryn Mawr-Plymouth) and 130-36 (Bryn Mawr-Llanerch) lines at Bryn Mawr end.	6/1/2025	$3.00	PECO	4/19/2022

6.10: Tennessee RTEP Summary

6.10.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Tennessee, including facilities owned and operated by American Electric Power (AEP) as shown on **Map 6.45**. Tennessee's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

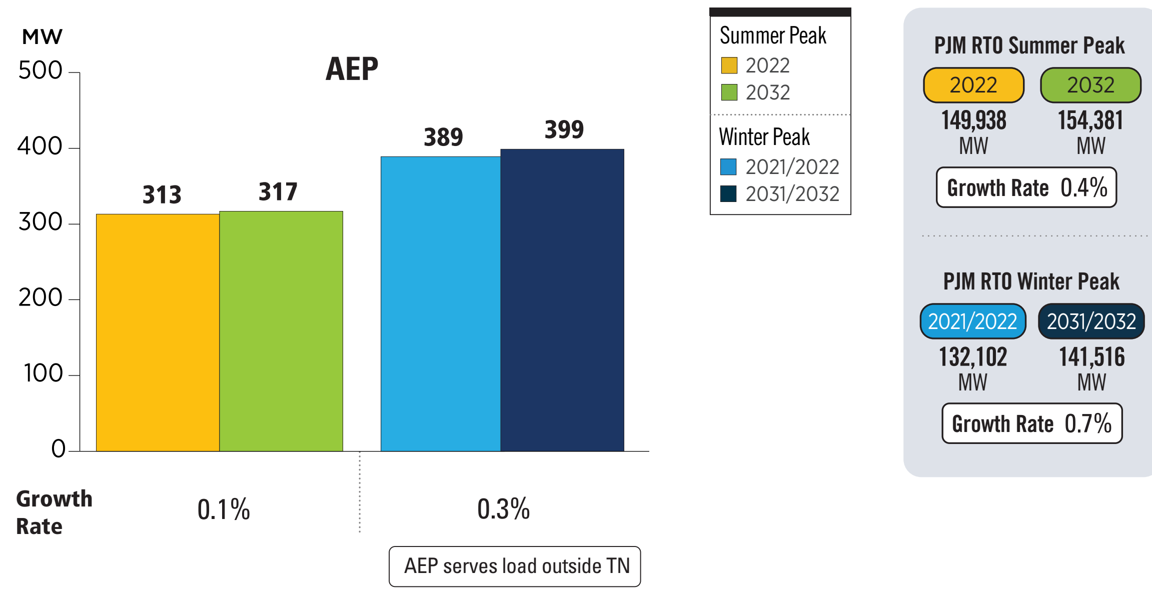
Map 6.45: PJM Service Area in Tennessee



6.10.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.51** summarizes the expected loads within the state of Tennessee and across the PJM region.

Figure 6.51: Tennessee – 2022 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

6.10.3 — Existing Generation

There is no existing generation in PJM's portion of Tennessee as of Dec. 31, 2022.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in Tennessee as of Dec. 31, 2022, are discussed next, in **Section 6.10.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

6.10.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Tennessee, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Tennessee, as of Dec. 31, 2022, one queued project was actively under study or under construction as shown in the summaries presented in **Table 6.55, Table 6.56, Figure 6.52** and **Figure 6.53**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.55: Tennessee – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	Tennessee Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	0	0.00%	529	0.61%
Natural Gas	0	0.00%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	0	0.00%	273	0.31%
Solar	0	0.00%	57,616	66.37%
Storage	0	0.00%	14,148	16.30%
Wind	0	0.00%	6,223	7.17%
Grand Total	**0**	**0.00%**	**86,810**	**100.00%**

Table 6.56: Tennessee – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		Complete			
		Withdrawn		Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	1.00	75.0	1.00	75.0
	Grand Total	**1.00**	**75.0**	**1.00**	**75.0**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

6.10.5 — Generation Deactivation

There were no generating unit deactivation requests in Tennessee between Jan. 1, 2022, and Dec. 31, 2022, as part of the 2022 RTEP.

6.10.6 — Baseline Projects

No baseline projects in Tennessee were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.10.7 — Network Projects

No network projects in Tennessee were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.10.8 — Supplemental Projects

There were no supplemental projects in Tennessee between Jan. 1, 2022, and Dec. 31, 2022, as part of the 2022 RTEP.

6.10.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Tennessee were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Figure 6.52: Tennessee – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

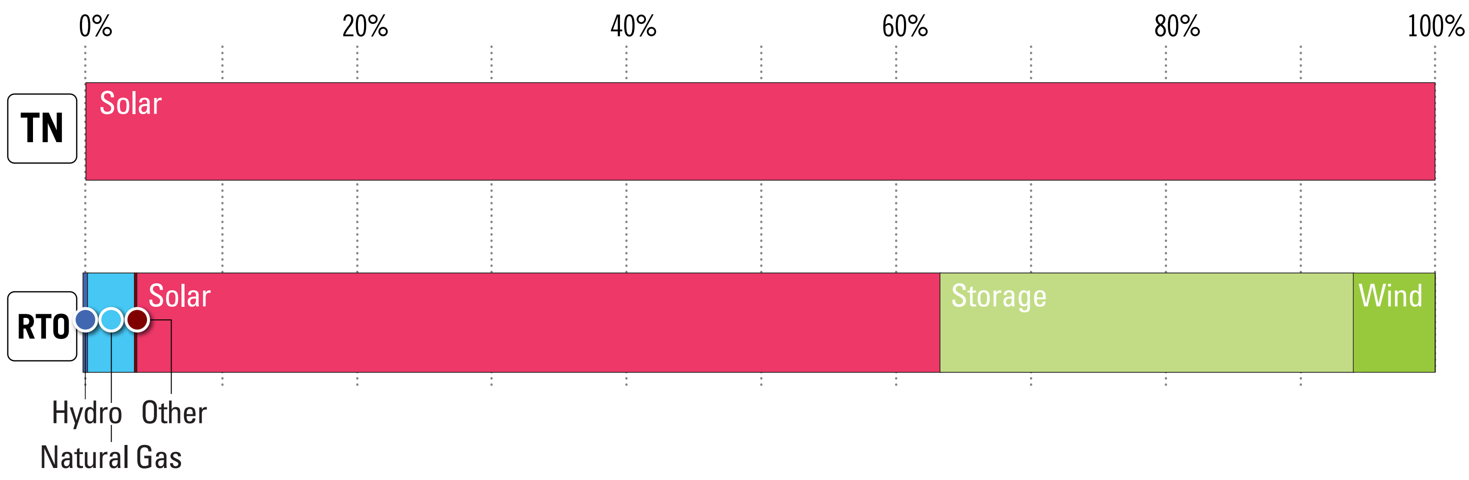
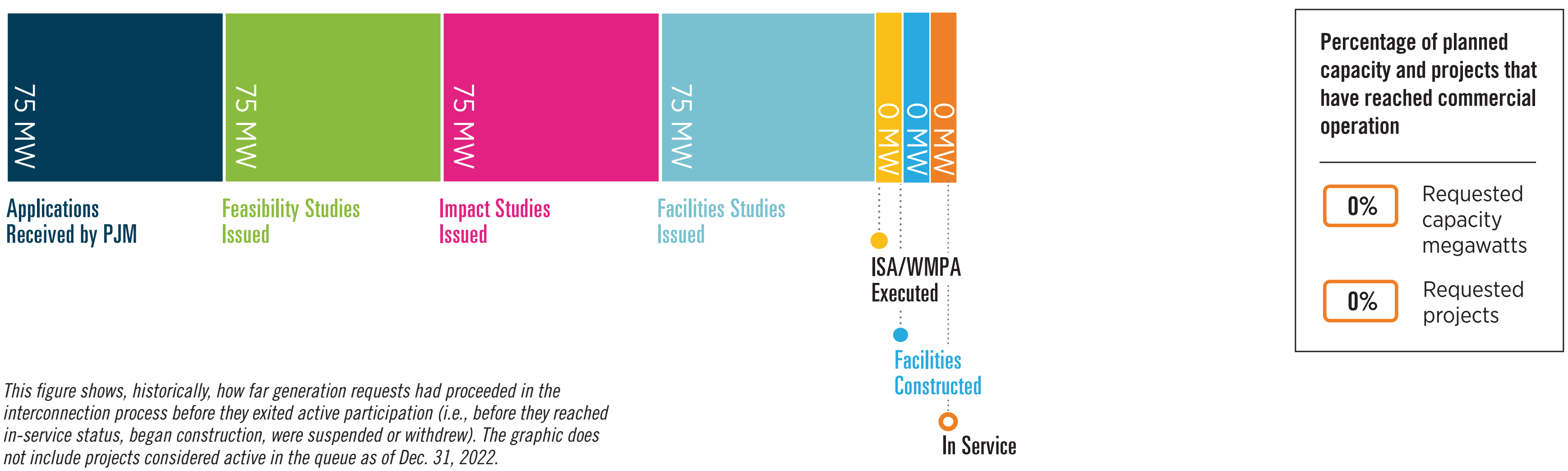


Figure 6.53: Tennessee Progression History of Queue – Interconnection Requests (Dec. 31, 2022)



This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.11: Virginia RTEP Summary

6.11.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Virginia, including facilities owned and operated by Allegheny Power (AP), American Electric Power (AEP), Delmarva Power & Light (DP&L) and Dominion as shown on **Map 6.46**. Virginia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

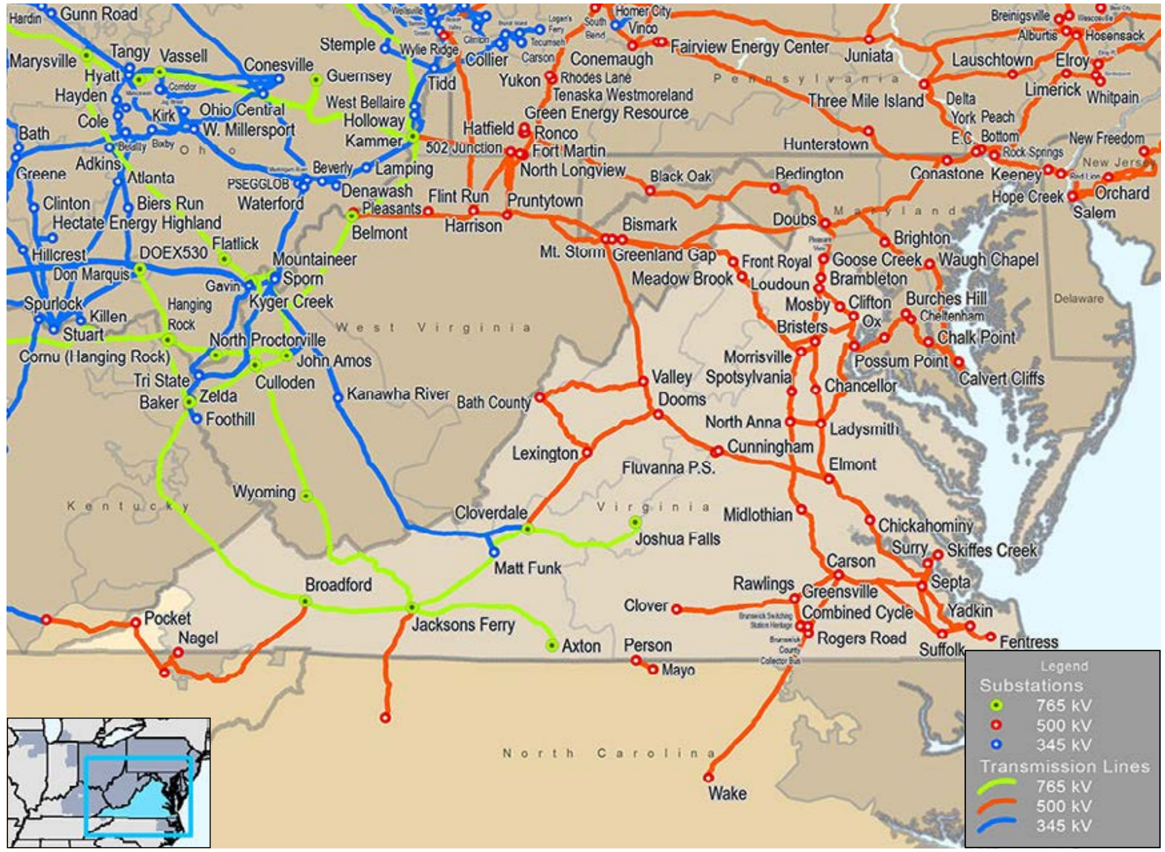
Renewable Portfolio Standards

Virginia has a mandatory renewable portfolio standard (RPS) target of 100% by 2045 or 2050, depending on the utility service territory. Virginia's RPS target is one of two in the PJM region set at 100%, with the other being the District of Columbia's.

The Virginia Clean Economy Act (VCEA) was enacted in 2020. In addition to mandating the 100% clean electricity target, the VCEA also called for renewable resource carve-outs to be developed within the commonwealth. For offshore wind, the VCEA specifically ordered the development of up to 5,200 MW by 2034. In 2020, the 12 MW Coastal Virginia Offshore Wind project became the first operational offshore wind facility in the PJM region.

The VCEA also directs Virginia utilities to develop, acquire or enter into agreements with 16,700 MW of solar or onshore wind capacity by 2035. Through the VCEA, Virginia is also looking to develop 3,100 MW of energy storage by 2035.

Map 6.46: PJM Service Area in Virginia



6.11.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.54** summarizes the expected loads within the state of Virginia and across the PJM region.

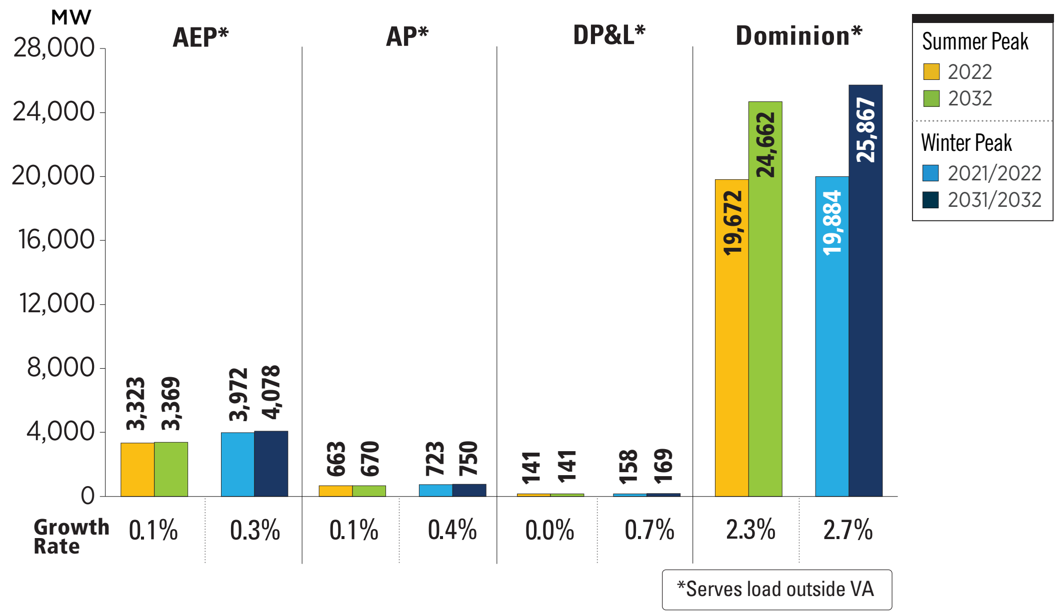
As part of the 2022 RTEP, PJM continues work to address an increase of 7.5 GW of load in an area known as "Data Center Alley" in the Loudon County area of Virginia. The PJM Board approved a $627 million project to construct a new substation called Wishing Star, interconnecting into existing Brambleton-Mosby 500 kV lines. Analysis will continue into 2023 as PJM opens a competitive proposal window seeking solutions to reliability criteria violations that were not addressed by the Wishing Star project.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar,

Figure 6.54: Virginia – 2022 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2022	2032	2021/2022	2031/2032
149,938 MW	154,381 MW	132,102 MW	141,516 MW
Growth Rate 0.4%		Growth Rate 0.7%	

PJM notes that American Electric Power Company, Delmarva Power and Light, Allegheny Power and Dominion Virginia Power serve load other than in Virginia. The summer and winter peak MW values in this table each reflect the estimated amount of forecast load to be served by each of those transmission owners solely in Virginia. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Virginia over the past five years.

expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

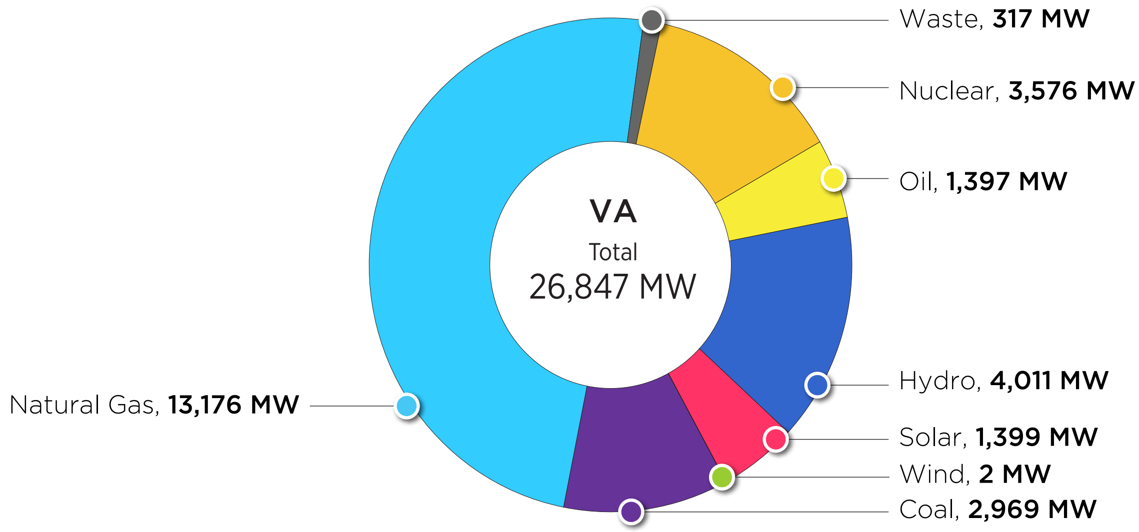
- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

6.11.3 — Existing Generation

Existing generation in Virginia as of Dec. 31, 2022, is shown by fuel type in **Figure 6.55**.

Figure 6.55: Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in Virginia as of Dec. 31, 2022, are discussed next, in **Section 6.11.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

6.11.4 — Interconnection Requests

PJM markets continue to attract generation proposals in Virginia, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in Virginia, as of Dec. 31, 2022, 442 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.57, Table 6.58, Figure 6.56, Figure 6.57** and **Figure 6.58**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.57: Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	0	0.00%	529	0.61%
Natural Gas	1,138	5.03%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	20	0.09%	273	0.31%
Solar	15,005	66.39%	57,616	66.37%
Storage	5,118	22.64%	14,148	16.30%
Wind	1,321	5.85%	6,223	7.17%
Grand Total	**22,602**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.58: Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue				Complete				Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	8	718.9	2	35.0	10	753.9
	Diesel	0	0.0	0	0.0	2	2.1	2	20.2	4	22.3
	Natural Gas	3	1,138.0	0	0.0	48	7,288.4	46	20,389.8	97	28,816.2
	Nuclear	0	0.0	0	0.0	8	350.0	1	1,570.0	9	1,920.0
	Oil	0	0.0	0	0.0	6	322.2	2	40.0	8	362.2
	Other	1	20.0	0	0.0	1	0.0	2	136.3	4	156.3
	Storage	94	5,118.0	5	60.0	1	0.0	23	703.7	123	5,881.7
Renewable	Biomass	0	0.0	0	0.0	5	147.4	4	70.0	9	217.4
	Hydro	0	0.0	0	0.0	9	423.4	2	254.0	11	677.4
	Methane	0	0.0	0	0.0	16	106.8	11	81.8	27	188.6
	Solar	256	15,004.5	73	1,864.0	53	1,342.9	232	7,683.2	614	25,894.7
	Wind	9	1,321.4	1	10.1	1	1.5	32	895.5	43	2,228.5
	Wood	0	0.0	0	0.0	1	4.0	2	57.0	3	61.0
	Grand Total	**363**	**22,602.0**	**79**	**1,934.1**	**159**	**10,707.6**	**361**	**31,936.4**	**962**	**67,180.1**

Figure 6.56: Virginia – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

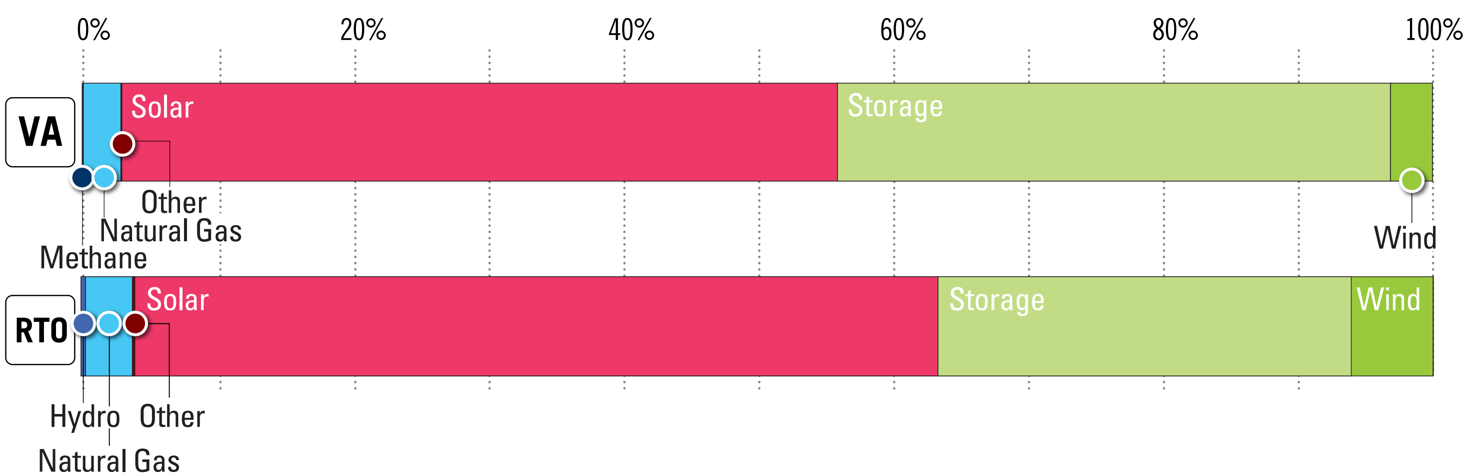
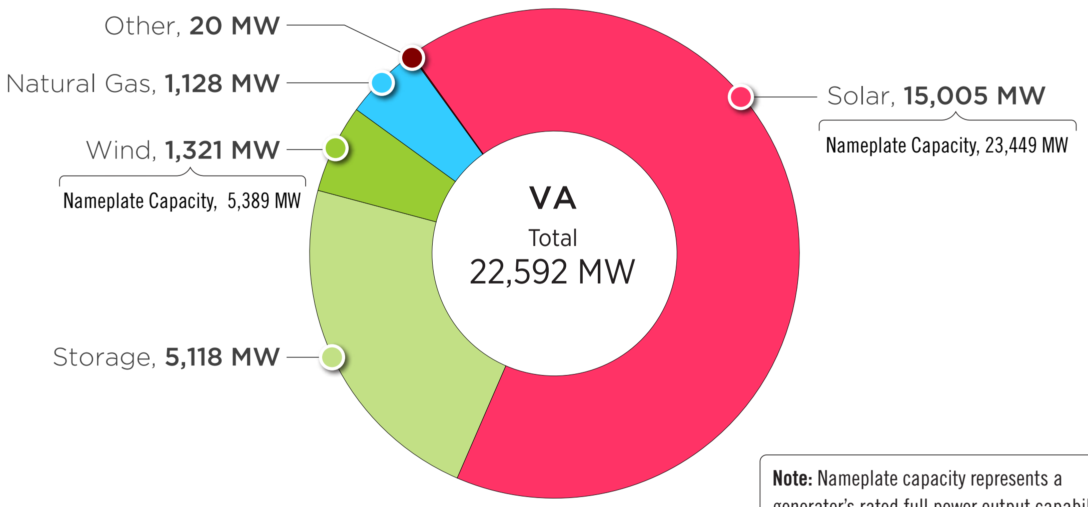


Figure 6.57: Virginia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.58: Virginia Progression History of Queue – Interconnection Requests (Dec. 31, 2022)

Percentage of planned capacity and projects that have reached commercial operation

- **22.5%** Requested capacity megawatts
- **23.7%** Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	20	Interconnection Service Agreements	4,676 MW	5,150 MW
	45	Wholesale Market Participation Agreements	417 MW	700 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.11.5 — Generation Deactivation

Formal generator deactivation requests received by PJM in Virginia between Jan. 1, 2022, and Dec. 31, 2022, are summarized in **Map 6.47** and **Table 6.59**.

Deactivation Reliability Studies

PJM has 30 days in which to respond to a generator owner with deactivation study results. Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can reduce voltage support.

Deactivation reliability studies comprise thermal and voltage analysis, including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, reliability criteria violations caused by unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board.

Map 6.47: Virginia Generation Deactivations (Dec. 31, 2022)

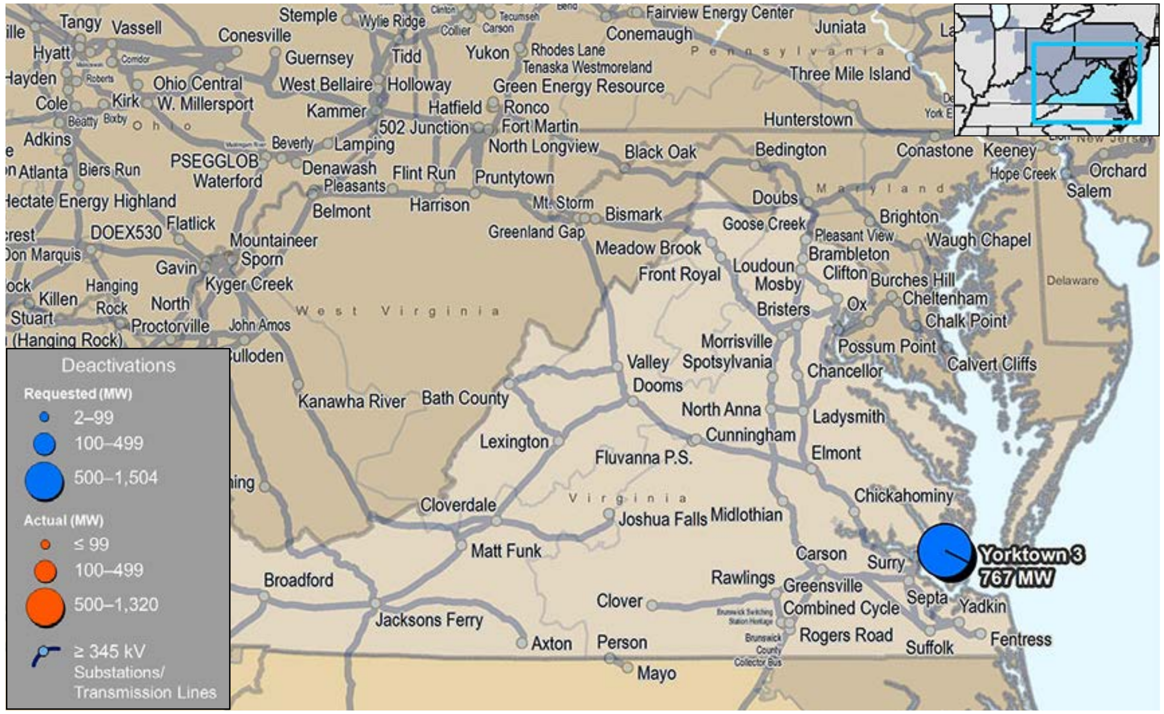


Table 6.59: Virginia Generation Deactivations (Dec. 31, 2022)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Yorktown 3	Dominion	Oil	12/20/2022	5/31/2023	48	767.1

6.11.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in Virginia are summarized in **Map 6.48** and **Table 6.60**.

Map 6.48: Virginia Baseline Projects (Dec. 31, 2022)

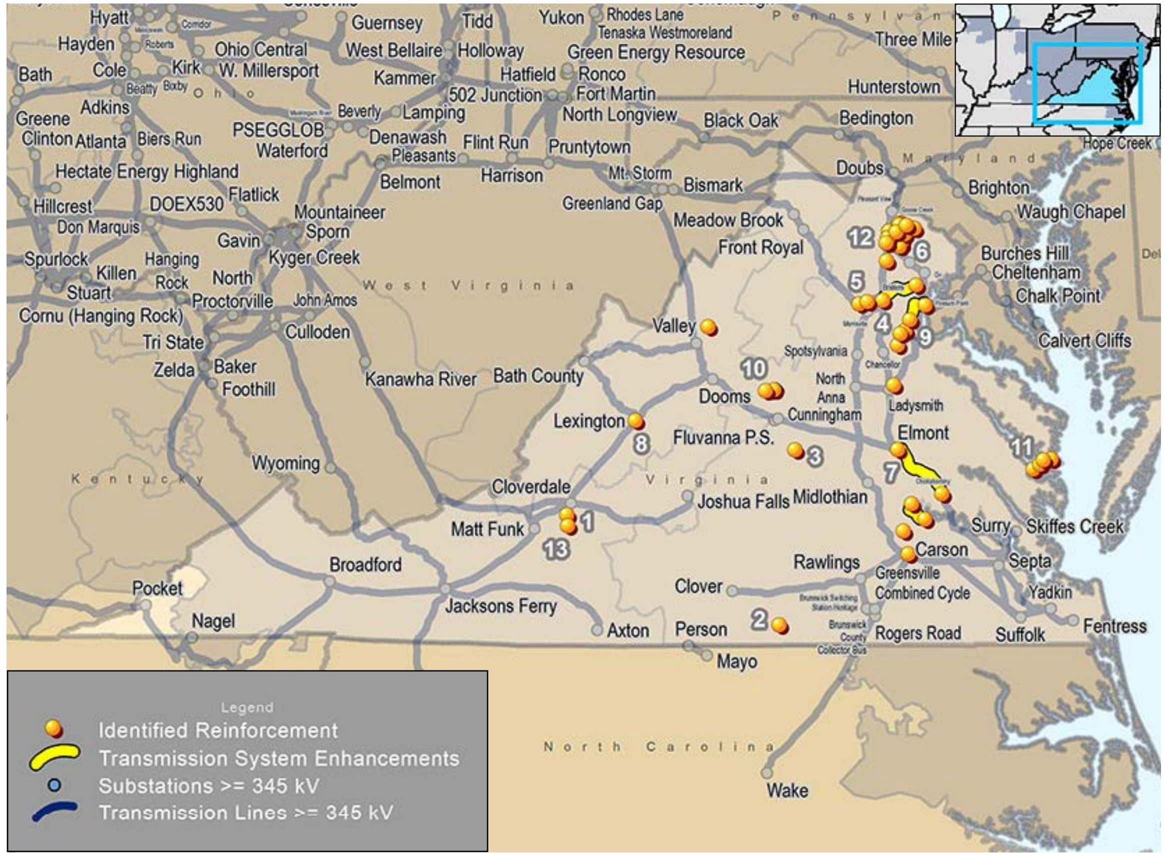


Table 6.60: Virginia Baseline Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3351		Replace the 69 kV in-line switches at Monterey 69 kV substation.	6/1/2026	$0.00	AEP	11/19/2021
2	B3685		Install a 33 MVAR cap bank at Cloud 115 kV bus along with a 115 kV breaker. Add 115 kV circuit breaker for 115 kV line No. 38.	6/1/2026	$1.50	Dominion	11/18/2021
3	B3686		Purchase land close to the bifurcation point of 115 kV line No. 4 (where the line is split into two sections) and build a new 115 kV switching station called Duncan Store. The new switching station will require space for an ultimate transmission interconnection consisting of a 115 kV six-breaker ring bus (with three breakers installed initially).	12/1/2026	$16.00		

Table 6.60: Virginia Baseline Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	B3687		Rebuild ~15.1-mile-long line segment between 115 kV line No. 183 Bristers and Minnieville D.P. with 2-768 ACSS and 4000A supporting equipment from Bristers to Ox to allow for future 230 kV capability of 115 kV line No. 183. The continuous summer normal rating will be 523 MVA from Ox-Minnieville. The continuous summer normal rating will be 786 MVA from Minnieville-Bristers.	6/1/2026	$30.00	Dominion	11/18/2021
5	B3689	.1	Reconductor ~24.42 miles of 230 kV line No. 2114 Remington CT-Elk Run-Gainesville to achieve a summer rating of 1574 MVA by fully reconductoring the line and upgrading the wave trap and substation conductor at Remington CT and Gainesville.	6/1/2026	$30.68	Dominion	11/30/2021
		.2	Replace 230 kV breakers SC102, H302, H402 and 218302 at Brambleton substation with 4000A 80 kA breakers and associated equipment including breaker leads as necessary to address breaker duty issues identified in short circuit analysis.				
6	B3690		Reconductor ~1.07 miles of 230 kV line No. 2008 segment from Cub Run-Walney to achieve a summer rating of 1574 MVA. Replace line switch 200826 with a 4000A switch.	6/1/2026	$1.93	Dominion	11/30/2021
7	B3692		Rebuild ~27.7 miles of 500 kV transmission line from Elmont to Chickahominy with current 500 kV standards construction practices to achieve a summer rating of 4330 MVA.	6/1/2026	$58.16	Dominion	11/30/2021
8	B3693		Expand substation and install ~294 MVAR cap bank at 500 kV Lexington substation along with a 500 kV breaker. Adjust the tap positions associated with the two 230/69 kV transformers at Harrisonburg to neutral position and lock them.	11/1/2026	$5.86	Dominion	11/30/2021
9	B3694	.1	Convert line No. 29 Aquia Harbor to Possum Point to 230 kV (Extended line No. 2104) and swap line No. 2104 and converted line No. 29 at Aquia Harbor backbone termination. Upgrade terminal equipment at Possum Point to terminate converted line 29 (now extended line No. 2104). (Line No. 29 from Fredericksburg to Aquia Harbor is being rebuilt under baseline b2981 to 230 kV standards.)	6/1/2026	$93.42	Dominion	11/30/2021
		.2	Upgrade Aquia Harbor terminal equipment to not limit 230 kV line No. 9281 conductor rating.				
		.3	Upgrade Fredericksburg terminal equipment by rearranging 230 kV bus configuration to terminate converted line 29 (now becoming 9281). The project will add a new breaker at the 230 kV bay and reconfigure line termination of 230 kV lines No. 2157, No. 2090 and No. 2083.				
		.4	Reconductor/rebuild ~7.6 miles of 230 kV line No. 2104 Cranes Corner-Stafford to achieve a summer rating of 1047 MVA(1). Reconductor/rebuild ~0.34 miles of 230 kV line No. 2104 Stafford-Aquia Harbor to achieve a summer rating of 1047 MVA. Upgrade terminal equipment at Cranes Corner to not limit the new conductor rating.				
		.5	Upgrade wave trap and line leads at 230 kV line No. 2090 Ladysmith CT terminal to achieve 4000A rating.				
		.6	Upgrade Fuller Road substation to feed Quantico substation via 115 kV radial line. Install four-breaker ring and break 230 kV line No. 252 into two new lines: 1) No. 252 between Aquia Harbor to Fuller Road, and 2) No. 9282 between Fuller Road and Possum Point. Install a 230/115 kV transformer, which will serve Quantico substation.				
		.7	Energize in-service spare 500/230 kV Carson transformer No. 1.				
		.8	Partial wreck and rebuild 10.34 miles of 230 kV line No. 249 Carson-Locks to achieve a minimum summer emergency rating of 1047 MVA. Upgrade terminal equipment at Carson and Locks to not limit the new conductor rating.				
		.9	Wreck and rebuild 5.4 miles of 115 kV line No. 100 Locks-Harrowgate to achieve a minimum summer emergency rating of 393 MVA. Upgrade terminal equipment at Locks and Harrowgate to not limit the new conductor rating and perform line No.100 Chesterfield terminal relay work.				
		.10	Reconductor ~2.9 miles of 230 kV line No. 211 Chesterfield-Hopewell to achieve a minimum summer emergency rating of 1046 MVA.				

Table 6.60: Virginia Baseline Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
9 Cont.	B3694 Cont.	.11	Reconductor ~2.9 miles of 230 kV line No. 228 Chesterfield-Hopewell to achieve a minimum summer emergency rating of 1046 MVA.	6/1/2026	$93.42	Dominion	11/30/2021
		.12	Upgrade equipment at Chesterfield substation to not limit ratings on lines 211 and 228.				
		.13	Upgrade equipment at Hopewell substation to not limit ratings on lines 211 and 228.				
10	B3702		Install one 13.5 Ohm series reactor to control the power flow on the 230 kV line No. 2054 from Charlottesville substation to Proffit Rd. 230 kV line.	6/1/2023	$11.38		
11	B3707	.1	Reconductor ~0.57 miles of 115 kV line No. 1021 from Harmony Village to Greys Point with 768 ACSS to achieve a summer emergency rating of 237 MVA. The current conductor is 477 ACSR.	6/1/2022	$3.00		2/8/2022
		.2	Reconductor ~0.97 miles of 115 kV line No. 65 from Rappahanock to White Stone with 768 ACSS to achieve a summer emergency rating of 237 MVA. The current conductor is 477 ACSR.				
12	B3718	.1	Install one 500/230 kV 1440 MVA transformer at a new substation called Wishing Star. Cut and extend 500 kV line No. 546 (Brambleton-Mosby) and 500 kV line No. 590 (Brambleton-Mosby) to the proposed Wishing Star substation. Lines to terminate in a 500 kV breaker-and-a-half configuration.	6/1/2025	$627.62		9/6/2022
		.2	Install one 500/230 kV 1440 MVA transformer at a new substation called Mars near Dulles International Airport.				
		.3	Construct a new 500 kV transmission line for ~3.5 miles along with substation upgrades at Wishing Star and Mars. New right of way will be needed and will share same structures with the line. New conductor to have a minimum summer normal rating of 4357 MVA.				
		.4	Reconductor ~0.62 miles of 230 kV line No. 2214 (Buttermilk-Roundtable) to achieve a summer rating of 1574 MVA.				
		.5	Reconductor ~1.52 miles of 230 kV line No. 2031 (Enterprise-Greenway-Roundtable) to achieve a summer rating of 1574 MVA.				
		.6	Reconductor ~0.64 miles of 230 kV line No. 2186 (Enterprise-Shellhorn) to achieve a summer rating of 1574 MVA.				
		.7	Reconductor ~2.17 miles of 230 kV line No. 2188 (Lockridge-Greenway-Shellhorn) to achieve a summer rating of 1574 MVA.				
		.8	Reconductor ~0.84 miles of 230 kV line No. 2223 (Lockridge-Roundtable) to achieve a summer rating of 1574 MVA.				
		.9	Reconductor ~3.98 miles of 230 kV line No. 2218 (Sojourner-Runway-Shellhorn) to achieve a summer rating of 1574 MVA.				
		.10	Reconductor ~1.61 miles of 230 kV line No. 9349 (Sojourner-Mars) to achieve a summer rating of 1574 MVA.				
		.11	Upgrade 4-500 kV breakers (total) to 63 kA on either end of 500 kV line No. 502 (Loudoun-Mosby).				
		.12	Upgrade 4-500 kV breakers (total) to 63 kA on either end of 500 kV line No. 584 (Loudoun-Mosby).				
		.13	Cut and loop 230 kV line No. 2079 (Sterling Park-Dranesville) into Davis Drive substation and install two GIS 230 kV breakers.				
		.14	Construct a new 230 kV transmission line for ~3.5 miles along with substation upgrades at Wishing Star and Mars. New right of way will be needed and will share same structures with the 500 kV line. New conductor to have a minimum summer normal rating of 1573 MVA.				
13	B3724		Install 138 kV circuit switcher on the high side of transformer No. 2 at Roanoke station (previously proposed as a portion of s2469.7, posted in 2021 AEP local plan).	6/1/2027	$0.10	AEP	10/14/2022

6.11.7 — Network Projects

2022 RTEP network projects in Virginia are summarized in **Map 6.49** and **Table 6.61**.

Map 6.49: Virginia Network Projects (Dec. 31, 2022)

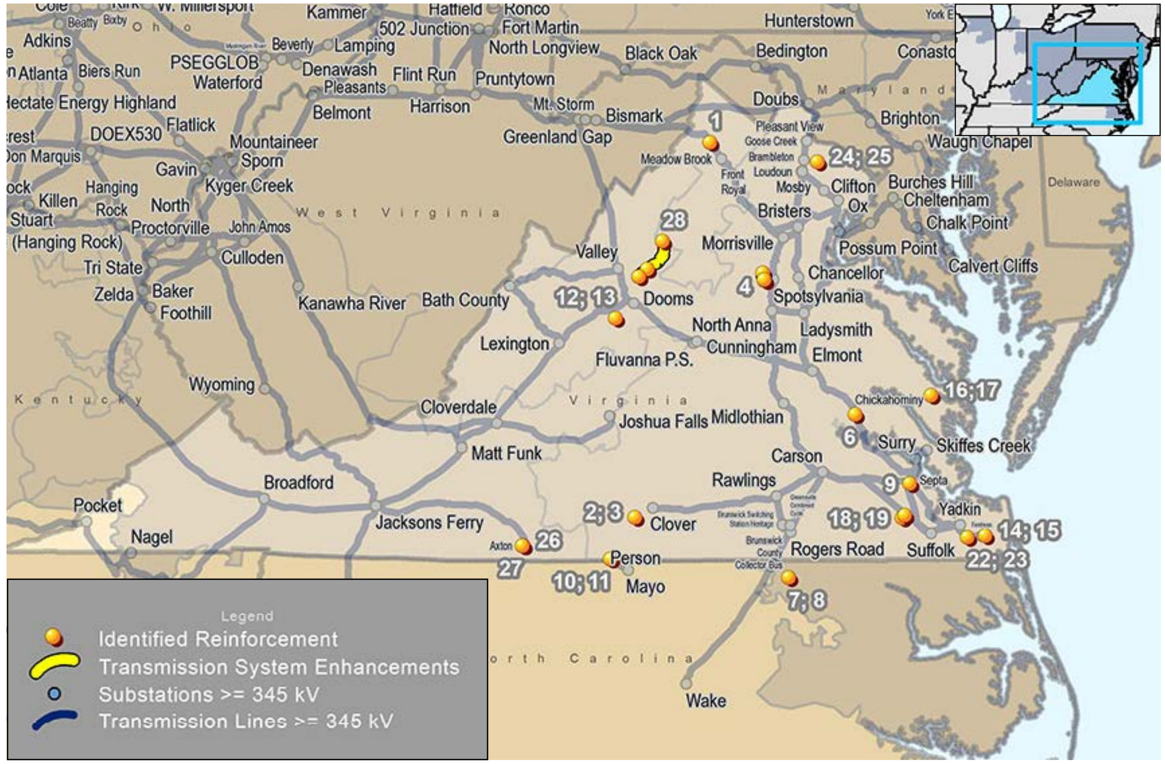


Table 6.61: Virginia Network Projects (Dec. 31, 2022)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5794	Construct a 138 kV three-breaker ring bus interconnection substation.	AD1-155	12/31/2018	$4.67	AP	11/1/2022
2	N6072	Build a three-breaker ring bus at the new AC1-105 substation.	AC1-105	7/31/2018	$5.23	Dominion	
3	N6073	Build new structures to cut and loop the line into AC1-105 115 kV switching station.			$1.19		
4	N6083	Construct a three-breaker ring bus for AC1-076 interconnection substation.	AC1-076	12/31/2021	$5.12		

Table 6.61: Virginia Network Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5	N6084	Line 115 kV modifications for Locust Grove-Paytes 115 kV line.	AC1-076	12/31/2021	$2.02	Dominion	11/1/2022
6	N6252	Expand the Chickahominy 230 kV subtation with a new bay.	AC1-164	10/1/2019	$5.00		
7	N6469	Build new structures to cut and loop the line No. 81 into AC1-208 115 kV substation.	AC1-208	12/1/2019	$1.80		
8	N6470	Build a three-breaker 115 kV substation at the AC1-208 facility.			$5.30		
9	N6647	Create a new bay position at the Septa 500 kV substation for the interconnection of the AC1-161 project.	AC1-161	10/1/2019	$1.50		
10	N6651	Build a three-breaker 230 kV substation at the AC2-100 facility.	AC2-100	3/7/2019	$6.25		
11	N6652	Build new structures to cut and loop the transmission line into AC2-100 115 kV substation.			$1.10		
12	N6655	Build a three-breaker 115 kV substation at the AC2-112 facility.	AC2-112	10/31/2018	$6.25		
13	N6656	Build new structures to cut and loop the transmission line into AC2-112 115 kV substation.			$1.10		
14	N6695	Build a three-breaker 230 kV substation at the AD1-033 facility.	AD1-033	12/31/2020	$6.80		
15	N6696	Build new structures to cut and loop the transmission line into AD1-033 230 kV substation.			$1.80		
16	N6704	Build a three-breaker 115 kV substation at the AD1-041 facility.	AD1-041	12/23/2019	$5.90		
17	N6705	Build new structures to cut and loop the transmission line into AD1-041 115 kV substation.			$1.60		
18	N6749	Build a three-breaker 115 kV substation at the AC2-079 facility.	AC2-079	12/31/2019	$5.24		
19	N6750	Build new structures to cut and loop the transmission line into AC2-079 115 kV substation.			$2.00		
20	N6900	Build a three-breaker 115 kV substation at the AD2-085 facility.	AD2-085	11/30/2021	$5.40		
21	N6901	Build new structures to cut and loop the transmission line into AD2-085 115 kV substation.			$1.10		
22	N6903	Build a three-breaker 115 kV substation at the AC2-012 facility.	AC2-012	12/31/2019	$5.60		
23	N6904	Build new structures to cut and loop the transmission line into AC2-012 115 kV substation.			$1.90		
24	N7437	Rearrange line No. 2137 to loop into and out of the new three-breaker AF1-147 230 kV switching station.	AF1-147	6/1/2023	$2.42		
25	N7438	Build a three-breaker AF1-147 230kV switching station.			$7.73		
26	N7671	Install 138 kV metering at the Axton 138 kV station. Construct generator lead transmission line from the Axton 138 kV station to the point of interconnection. Install dual fiber telecommunications from the Axton 138 kV station to the Customer Facility collector station.	AE1-100	12/31/2022	$6.75	AEP	

Table 6.61: Virginia Network Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
27	N7671	Expand Axton 138 kV station, including the addition of two 138 kV circuit breakers, extending the south 138 kV bus No. 1, installation of associated protection and control equipment, 138 kV line risers, switches, jumpers and supervisory control and data acquisition (SCADA) equipment.	AE1-100	12/31/2022	$6.75	AEP	11/1/2022
28	N7873	Build a new three-breaker ring substation AE2-029. The facilities identified provide for the initial construction of a new 115 kV three-breaker ring substation near Transmission Structure 119/413 in Rockingham County, Virginia. The objective of this project is to build a 115 kV, three-breaker ring bus to support the new 50 MW Solar Farm built by Blue Ridge Solar, LLC. The site is located along Dominion Energy's existing 115kV, 119 Line from Grottoes substation to Merck No. 5 substation. The cut line will consume two of the positions in the ring bus. The third position will be for the 115kV feed from Blue Ridge Solar, LLC Collector station for the new 50 MW Solar Farm.	AE2-029	12/30/2022	$5.63	Dominion	
29	N7874	Rearrange line No. 119 to loop into and out of the new three-breaker AE2-029 115 kV switching station. This project will connect line number 119 to a new 115 kV switching station located off the main line 119 between structures 119/412 and 119/414. This project is located in Rockingham County, Virginia.	AE2-029	12/30/2022	$2.45		

6.11.8 — Supplemental Projects

Supplemental projects received by PJM in 2022 in Virginia are summarized in **Map 6.50** and **Table 6.62**.

6.11.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Virginia were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.50: Virginia Supplemental Projects (Dec. 31, 2022)

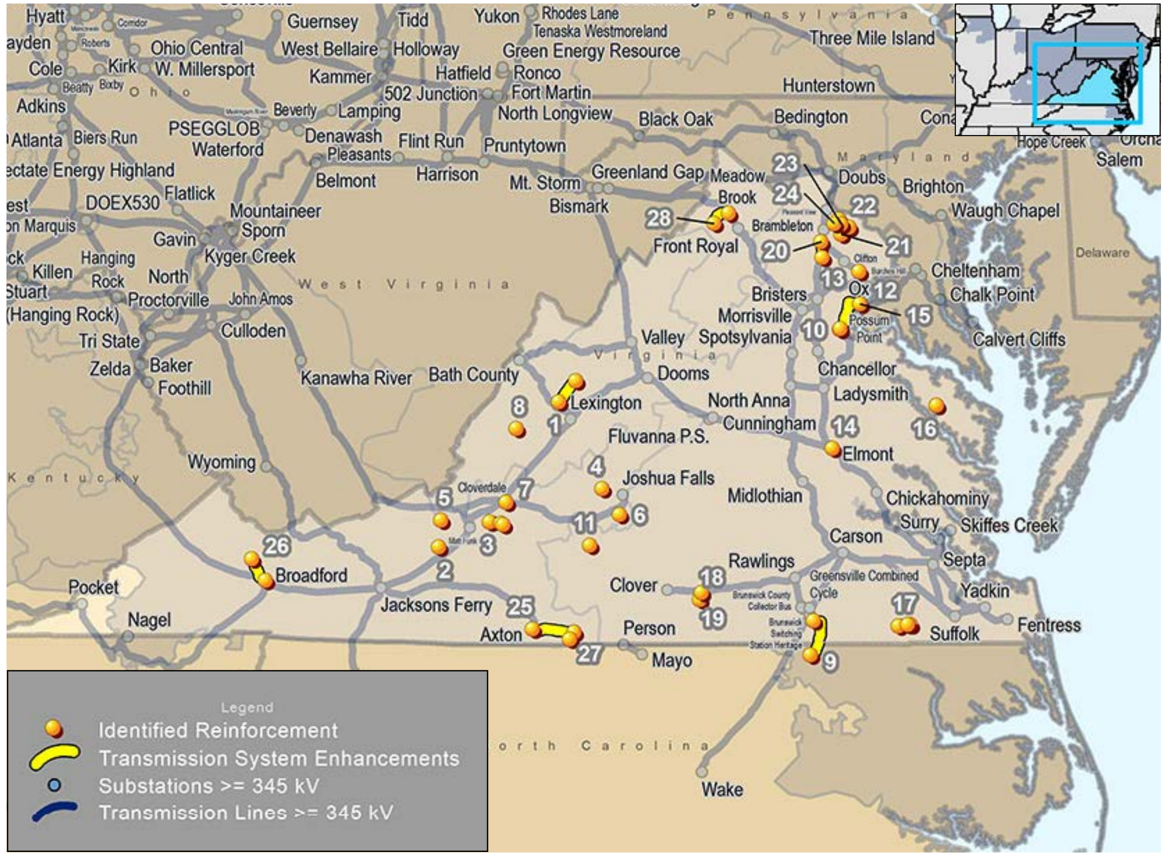


Table 6.62: Virginia Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2730		Replace ~11 miles of 115 kV line No. 10 from Craigsville to Goshen with appropriate structures. New conductor with a minimum normal summer rating of 393 MVA will be used. Terminal equipment will be upgraded as needed.	12/31/2027	$29.60	Dominion	5/16/2022
2	S2636		The 13.2 Mvar 69 kV capacitor bank and circuit switcher at South Christiansburg station will be replaced with a circuit switcher and a 17.2 Mvar 69 kV capacitor bank at Hans Meadow Station. The placement of the capacitor bank at Hans Meadow will provide better support to the 69 kV network and place the capacitor bank closer to the load centers on the 69 kV circuit.	11/19/2021	$1.10	AEP	9/17/2021

Table 6.62: Virginia Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S2663	.1	Extend a 0.37-mile double circuit 69 kV line to the new station location by tapping the existing Hancock-Walnut Ave 69 kV circuit using 556 ACSR 26/7 overhead conductor.	12/1/2023	$4.83	AEP	11/19/2021
		.2	Establish new 69 kV station (Winston Avenue) in a straight bus configuration with two 69 kV circuit breakers, 69/12 kV, 25 MVA transformer with high-side circuit switcher and three 12 kV feeder breakers.				
		.3	Update relay settings at Walnut Ave and Hancock stations.				
		.4	At Winston Ave install a second 69/12 kV, 25 MVA transformer with high-side circuit switcher and 12 kV feeders.	12/1/2026			
		.5	Install a second 138/12 kV Distribution transformer with high-side circuit switcher and 12 kV feeders at Roanoke.				
		.6	Retire Distribution from Walnut Ave. station.				
4	S2667		Expand Reusens Station and install 138/12kV, 20 MVA transformer connected to 138 kV bus No. 2, 12 kV bus regulators and two 12 kV breakers.	3/31/2022	$3.07		12/17/2021
5	S2684		At North Blacksburg Station, replace existing transformer No. 1 with a 130 MVA 138/69-12 kV transformer. Replace existing transformer No. 2 with a 25 MVA 138/12 kV transformer and add bus regulators. Add a 69 kV circuit breaker on the low side of transformer No. 1.	11/1/2021	$4.06		1/21/2022
6	S2692		Rebuild ~0.63 miles of 4/0 copper between Expressway and Perkins Park Tap 69 kV (Str.443-43 to Str. 443-49).	10/31/2022	$1.71		2/28/2022
7	S2694		At Cloverdale station, replace 345/138 kV Transformer 11A and 11B with new 345/138 kV, 675 MVA transformer 11 and reconnect to the 138 kV structure via a new 138 kV tie-line with three custom single-pole structures outside of the station in order to keep age/driving space within the station. Install two new 345 kV, 5000A 63 kA breakers to connect the new transformer and existing transformer 3 into a string position in the 345 kV yard. Replace all 69 kV hook-stick switches new 2000 A GOAB switches.	10/31/2025	$12.33		2/9/2022
8	S2703		Replace Clifton Forge TX No. 2 with a new three-phase, 230/138/13.2 kV, 250 MVA unit. Include other ancillary equipment (arresters, switches, relays, etc.) as needed.	5/31/2023	$3.00	Dominion	10/5/2021
9	S2704		Tap 115 kV line No. 130 (Skippers - Carolina) near structure 154 and install three line switches and other associated transmission equipment to connect to the proposed new substation called Sockman. The new section of line will have a minimum rating of 261 MVA. The developer will bear the full cost of the project.	10/28/2022	$3.60		10/14/2021
10	S2705		Using current 230 kV standards and a minimum summer emergency rating of 1047 MVA, wreck and rebuild ~ 12 miles of double circuit 230 kV line No. 252 and 115 kV line No. 29 from Aquia Harbour Switching Station to Possum Point. At Possum Point, upgrade the wave trap on 230 kV line No. 252 to 3000A. At Aquia Substation, upgrade the 230 kV line No. 252 switches and leads to 3000A. At Aquia Harbour Switching Station, upgrade the 230 kV line No. 252 wave trap and a circuit breaker switch to 3000A.	6/1/2026	$38.00		10/5/2021
11	S2706		Replace Altavista TX#4 with a new three-phase, 138/115/13.2 kV, 112 MVA unit. Include other ancillary equipment (arresters, switches, relays, etc.) as needed.	3/17/2022	$3.80		11/18/2021
12	S2731		The following substation equipment will be replaced at Possum Point: Four 500 kV breakers (560T571, 568T571, H1T568 & H1T560) with 5000A, 50kA breakers and breaker failure protection. Eight 500 kV breaker disconnect switches (56075, 56078, H178, H175, 56875, 56878, 57178 & 57175) with 5000A switches and associated leads. Bus No. 1 differential protection from electromechanical to digital relays. Install three 500 kV line arresters on line No. 560 station terminations.	6/8/2023	$6.80		3/8/2022
13	S2732		Replace 500 kV breaker 561T571 with a 5000A 50 kA breaker at Ox substation.	2/27/2023	$1.40		
14	S2733		Replace the following substation equipment at Elmont: Breaker H1T553 with 5000A 50 kA breaker. Two 500 kV breaker disconnect switches (H198 & 55397) with 5000A switches and associated leads.	12/1/2022	$1.80		

Table 6.62: Virginia Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
15	S2734		Install a four-breaker ring bus arrangement to create a Possum Point-EPG line and an EPG-Hayfield line to add the second and third distribution transformers at EPG substation in Fairfax County. The new transformers are being driven by continued load growth in the area.	3/31/2023	$1.50	Dominion	4/12/2022
16	S2735		Install two 230 kV, 1200 Amp, 40 kA circuit switchers on the high-side of Northern Neck GSU TX#2 and GSU TX#3, including any associated equipment (bus, relaying, etc.) determined necessary by the project team.	9/30/2022	$0.45	Dominion	4/19/2022
17	S2736		Build a single circuit 115 kV tap line for ~200 feet, connecting the City of Franklin P&L's proposed Pretlow DP to 115 kV line No. 93 from Southampton to Union Camp. Install required switch structures and switches in accordance with Dominion Facilities Interconnection Requirements.	6/1/2024	$1.30	Dominion	5/16/2022
18	S2737		Interconnect new substation La Crosse by cutting and extending 115 kV line No. 40 from Chase City to Broadnax. Add 33 MVAR 115 kV cap bank at La Crosse Sub for voltage support. The data center customer will bear the full cost of the project.	4/28/2023	$9.00	Dominion	5/16/2022
19	S2738		Obtain land and build a new 500/230 kV Finneywood switching station at the intersection of 500 kV line No. 556 (Clover-Rawlings) and 230 kV line No. 235 (Cloud-Farmville). Cut and terminate 500 kV line No. 556 into Finneywood 500/230 kV switching station. Cut and terminate 230 kV line No. 235 into Finneywood 500/230 kV switching station. In the new Finneywood switching station, install two 840 MVA 500/230 kV transformers, a 230 kV breaker and half bus with 12 breakers and a 500 kV ring bus with six breakers. Construct Butler Farm 230 kV substation with four 230 kV breaker ring bus to terminate two 230 kV lines. Construct one new 230 kV transmission line for ~20 miles from Clover Sub to Butler Farm Substation. Construct one new 230 kV transmission line for ~10 miles from Finneywood Sub to Butler Farm Substation. New right-of-way will be needed for both transmission lines. New conductor to have a minimum summer normal rating of 1573 MVA.	7/1/2025	$180.00	Dominion	6/7/2022
20	S2739		Cut and extend 230 kV line No. 2140 Heathcote-Loudoun to the proposed Youngs Branch Substation. Terminate both ends into a four-breaker ring arrangement to create a Heathcote-Youngs Branch line and a Loudoun-Youngs Branch line.	6/30/2023	$10.00	Dominion	7/13/2021
21	S2740		Install a 2x1200 Amp, 63 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the two new transformers at Takeoff.	6/15/2024	$1.00	Dominion	5/11/2021
22	S2741		Install a 1200 Amp, 50 kAIC circuit switcher and associated equipment (bus, relaying, etc.) to feed the new transformer at BECO.	6/1/2022	$0.50	Dominion	6/8/2021
23	S2742	.1	Install a 2x1200 Amp, 50 kAIC circuit switcher and associated equipment (bus, relaying, etc.) to feed the new transformers at Davis Drive.	10/1/2022	$16.00	Dominion	5/11/2021
23	S2742	.2	Cut and Loop 230 kV line No. 2079 Sterling Park-Dranesville into Davis Drive substation and install two GIS 230 kV breakers.	6/15/2026	$16.00	Dominion	8/31/2021
24	S2743		Install a 1200 Amp, 50 kAIC circuit switcher and associated equipment (bus, relaying, etc.) to feed the new transformer at Shellhorn.	6/23/2023	$0.50	Dominion	8/10/2021
25	S2746	.1	Establish new 138 kV Brosville station consisting of two 138 kV, 3000 A 40 kA circuit breakers and 138 kV revenue metering.	9/1/2023	$12.31	AEP	3/18/2022
25	S2746	.2	Install 1.66 miles of greenfield double circuit 138 kV transmission line that will run from the new Brosville Station to the new tap structure being installed on the Axton-Danville No. 2 138 kV transmission line. Acquire associated right of way for new double circuit 138 kV line.	9/1/2023	$12.31	AEP	3/18/2022
25	S2746	.3	Install a tap structure to accommodate the new greenfield transmission line on the Axton-Danville No. 2 circuit. Acquire associated right of way for new structure as needed.	9/1/2023	$12.31	AEP	3/18/2022
25	S2746	.4	Berry Hill and Danville remote end relay setting changes and fiber extension to Brosville.	9/1/2023	$12.31	AEP	3/18/2022

Table 6.62: Virginia Supplemental Projects (Dec. 31, 2022) (Cont.)

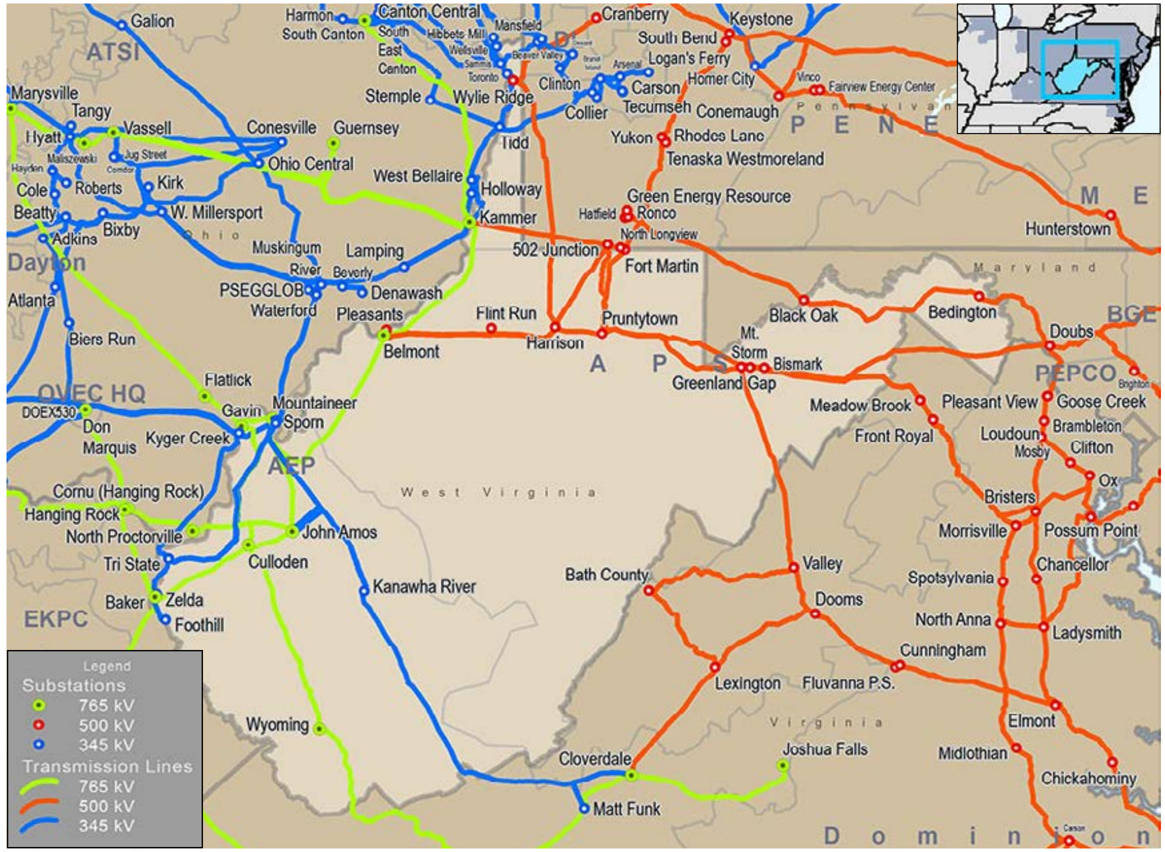
Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
26	S2774	.1	Construct a greenfield station (Salmon) with a 138/12 kV 25 MVA transformer with high side circuit switcher. There will be two 12 kV feeders from the station. The 138 kV side will be a straight bus with two 138 kV circuit breakers.	9/1/2024	$9.30	AEP	4/22/2022
		.2	Tap the Broadford-Claypool Hill 138 kV line and construct an in and out line to the greenfield Salmon station by building 2.3 miles of greenfield double circuit 138 kV line. The higher estimated cost is due to environmental surveying and a large amount of new access roads required for this greenfield line that is in hilly terrain.				
		.3	Build 4.1 miles of 96 ADSS Telecom underbuilt cable to connect Salmon station to the existing fiber network.				
27	S2783	.1	Ballou station was recently abandoned due to a previous customer no longer being served there. This project will remove all steel and cut all foundations down to 6" below grade. The only existing equipment that will be reused are two H-frames, and the control house AEP will not have any relaying equipment inside this building). Two 138 kV MOABs and high-side 69 kV, three-element metering and associated CTs and PTs will be installed.	11/1/2023	$0.88	AEP	5/19/2022
		.2	Remove the temporary span between structure 290-58 and 289-1C, replace structure 289-1C, and then reinstall the span into Ballou Station using 795 kcmil 26/7 Drake ACSR with a 7#10 Alumoweld Shield Wire at Ballou-State line 69 kV line asset.				
		.3	Remove the temporary span between structure 290-58 and 289-1C, replace structure 290-58, and then reinstall the span into Ballou Station using 795 kcmil 26/7 Drake ACSR with a 7#10 Alumoweld Shield Wire at Ballou-Danville 69 kV line asset.				
28	S2699		For Meadow Brook-Strasburg 138 kV line, replace wave trap at Meadow Brook 138 kV substation. Strasburg 138 kV substation-Replace line relaying, CT, and wave trap	3/31/2022	$1.10	AP	11/19/2021

6.12: West Virginia RTEP Summary

6.12.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in West Virginia, including facilities owned and operated by Allegheny Power (AP) and American Electric Power (AEP) as shown on **Map 6.51**. West Virginia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Map 6.51: PJM Service Area in West Virginia



6.12.2 — Load Growth

PJM's 2022 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2022 analyses. **Figure 6.59** summarizes the expected loads within the state of West Virginia and across the PJM region.

Load Forecast Accuracy Model Improvements

During calendar year 2022, PJM worked with a consultant to review the long-term load forecast model and assist PJM with its transition to an hourly forecasting framework. Over the years, the PJM forecast has evolved to address the challenges of long-term forecasting across a geographically diverse region with demand driven by large variations in weather conditions and economic activity, as well as technological changes (e.g., end-use efficiency improvements, distributed resources).

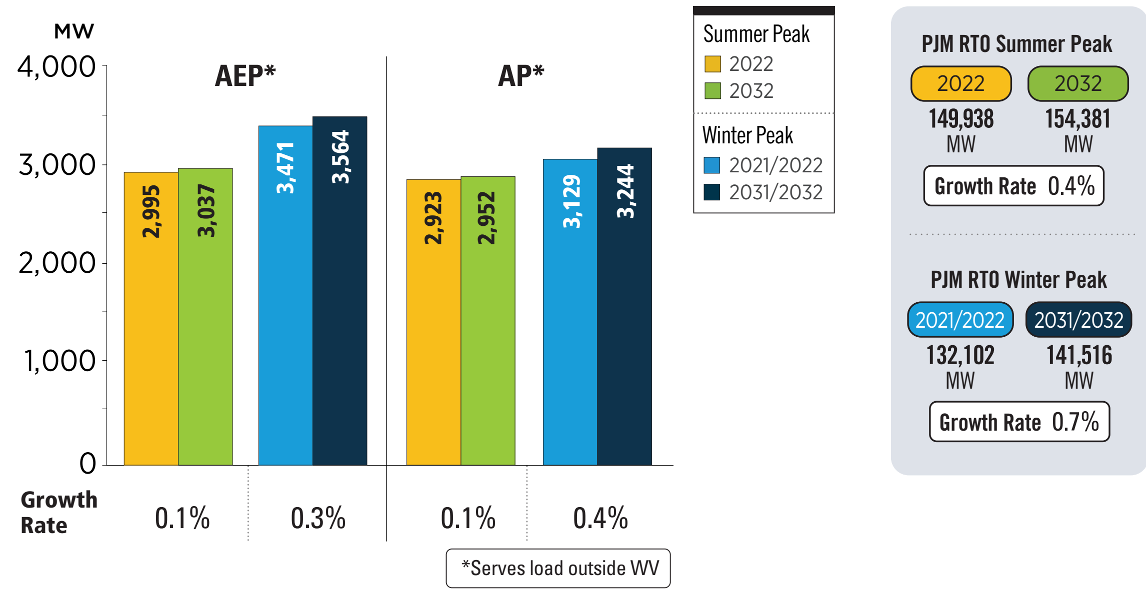
The next challenge is addressing the onset of further new technologies that are reshaping system hourly loads, and as a result, the level and timing of coincident peak (CP) and non-coincident peak (NCP) demands across the PJM service area. The marked penetration of solar, expected impacts of electric vehicles, state electrification programs, home battery storage and a significant increase in data center loads are complicating the load forecasting process.

PJM implemented a number of changes to the 2023 load forecast to improve model accuracy, including:

- *More granular data* – Switching from an annual to monthly end-use model for PJM's residential, commercial and industrial models provides more detailed data for determining heat, cool and other (non-weather-sensitive load).
- *Moving to an hourly framework* – Switching to an hourly model allows PJM to better capture new technologies and peak shifting.
- *Longer-range load adjustment forecasts* – Higher expectations for data center loads now incorporate 15-year forecasts from impacted Electric Distribution Companies.

These are discussed further in **Section 1.3.5** and **Section 2.0**.

Figure 6.59: West Virginia – 2022 Load Forecast Report



The summer and winter peak megawatt values reflect the estimated amount of forecast load to be served by each transmission owner in the noted state/district. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in those areas over the past five years.

6.12.3 — Existing Generation

Existing generation in West Virginia as of Dec. 31, 2022, is shown by fuel type in **Figure 6.60**.

Changing Capacity Mix

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. This shift is characterized by:

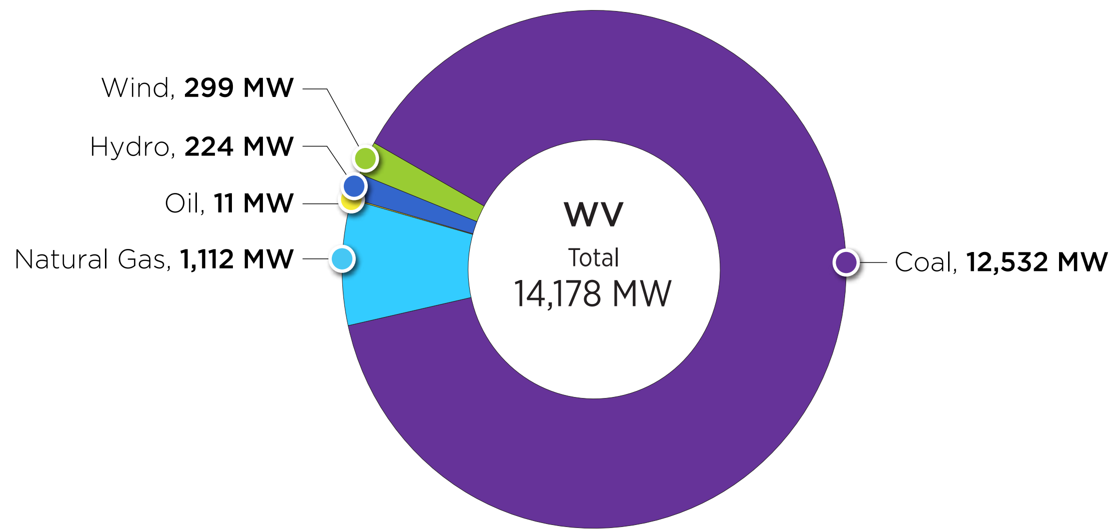
- New generating plants powered by Marcellus and Utica shale natural gas
- New wind and solar generating units driven by federal and state renewable incentives
- Generating plant deactivations
- Market impacts introduced by demand response and energy efficiency programs

Interconnection requests in West Virginia as of Dec. 31, 2022, are discussed next, in **Section 6.12.4**.

Deliverability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. As described in **Section 1.2**, PJM tests for compliance with North American Electric Reliability Corporation (NERC) and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

Figure 6.60: West Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2022)



6.12.4 — Interconnection Requests

PJM markets continue to attract generation proposals in West Virginia, as shown in the graphics that follow. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. The generation interconnection process has three study phases: feasibility, system impact and facilities studies to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets. And, while withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, and regulatory, industry, economic and other competitive factors at each step in the interconnection process. PJM's interconnection process is described in Manual 14A.

Specifically, in West Virginia, as of Dec. 31, 2022, 42 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.63, Table 6.64, Figure 6.61, Figure 6.62** and **Figure 6.63**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.63: West Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2022)

	West Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	11	0.01%
Hydro	30	0.53%	529	0.61%
Natural Gas	3,385	59.43%	7,955	9.16%
Nuclear	0	0.00%	37	0.04%
Oil	0	0.00%	18	0.02%
Other	0	0.00%	273	0.31%
Solar	2,101	36.89%	57,616	66.37%
Storage	158	2.78%	14,148	16.30%
Wind	22	0.38%	6,223	7.17%
Grand Total	**5,696**	**100.00%**	**86,810**	**100.00%**

Interconnection Process Enhancements

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process is also a critical step in integrating renewable generation into the grid as part of federal and state policy goals. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing.

PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), reforms have been developed to remove process barriers to the increasing volume of renewable resources. In November 2022, FERC conditionally approved PJM's interconnection process reform filing. The filing constitutes a comprehensive reform of the PJM interconnection process designed to more efficiently and timely process new service requests by transitioning from a serial "first-come, first-served" queue approach to a "first-ready, first-served" cycle approach. These concepts are discussed further in **Section 5.3**.

Table 6.64: West Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2022)

		In Queue				Complete				Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	1	36.0	10	861.0	7	2,023.0	18	2,920.0
	Natural Gas	3	3,385.0	0	0.0	6	409.7	43	16,140.8	52	19,935.5
	Other	0	0.0	0	0.0	0	0.0	2	66.0	2	66.0
	Storage	4	158.2	1	0.0	2	5.8	5	38.0	12	202.0
Renewable	Biomass	0	0.0	0	0.0	0	0.0	2	48.0	2	48.0
	Hydro	1	30.0	0	0.0	5	59.2	12	208.8	18	298.0
	Methane	0	0.0	0	0.0	3	5.6	3	13.8	6	19.4
	Solar	29	2,101.3	1	8.7	0	0.0	5	74.2	35	2,184.2
	Wind	1	21.6	1	11.8	11	212.6	27	426.5	40	672.5
	Grand Total	**38**	**5,696.1**	**4**	**56.5**	**37**	**1,553.9**	**106**	**19,039.2**	**185**	**26,345.6**

Figure 6.61: West Virginia – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2022)

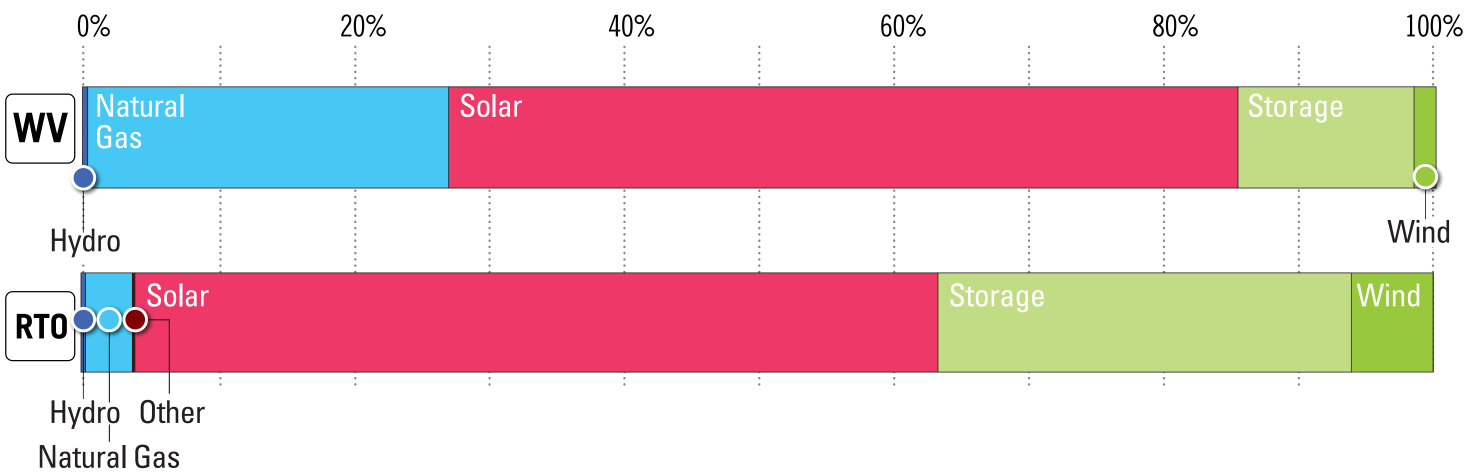
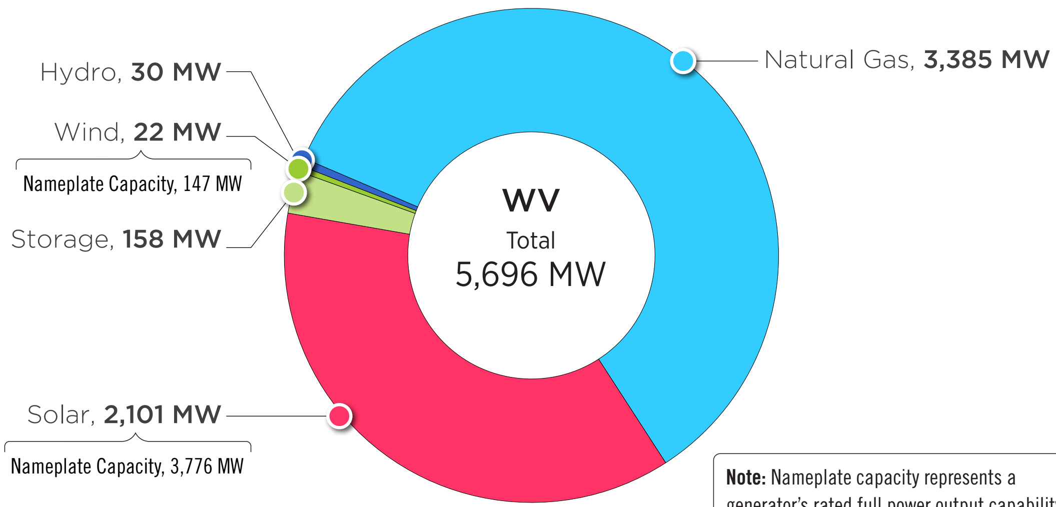


Figure 6.62: West Virginia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Figure 6.63: West Virginia Progression History of Queue – Interconnection Requests (Dec. 31, 2022)

Percentage of planned capacity and projects that have reached commercial operation

- **6.9%** Requested capacity megawatts
- **23.5%** Requested projects

Projects withdrawn after final agreement			Capacity	Nameplate
	14	Interconnection Service Agreements	1,509 MW	1,971 MW
	2	Wholesale Market Participation Agreements	6 MW	11 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

6.12.5 — Generation Deactivation

Formal generator deactivation requests received by PJM in West Virginia between Jan. 1, 2022, and Dec. 31, 2022, are summarized in **Map 6.52** and **Table 6.65**.

Deactivation Reliability Studies

PJM has 30 days in which to respond to a generator owner with deactivation study results. Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can reduce voltage support.

Deactivation reliability studies comprise thermal and voltage analysis, including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, reliability criteria violations caused by unit deactivation have been resolved by RTEP enhancements already approved by the PJM Board.

Map 6.52: West Virginia Generation Deactivations (Dec. 31, 2022)

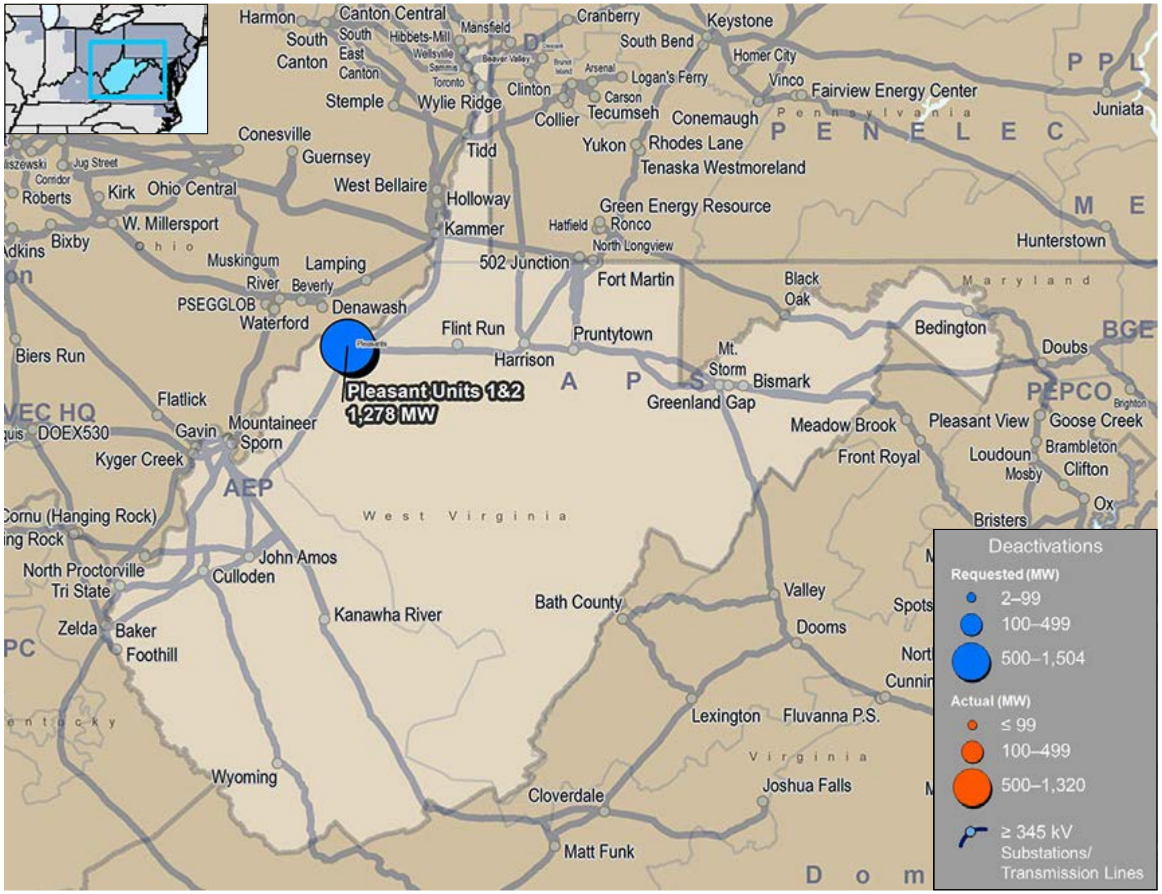


Table 6.65: West Virginia Generation Deactivations (Dec. 31, 2022)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Pleasant Unit2	AP	Coal	3/14/2022	6/1/2023	42	639.0
Pleasant Unit 1						639.0

6.12.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board in 2022 in West Virginia are summarized in **Map 6.53** and **Table 6.66**.

Map 6.53: West Virginia Baseline Projects (Dec. 31, 2022)

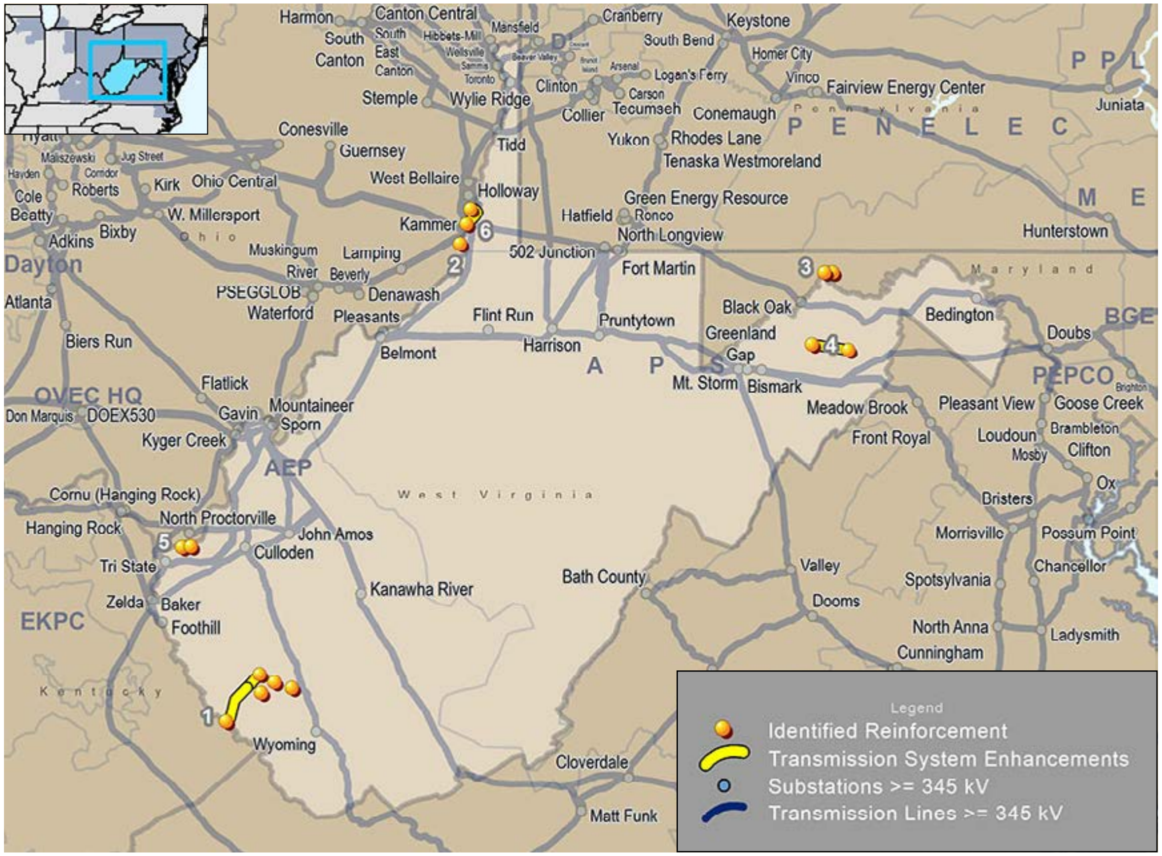


Table 6.66: West Virginia Baseline Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3348	.1	Construct a 138 kV single bus station (Tin Branch) consisting of a 138 kV box bay with a distribution transformer and 12 kV distribution bay. Two 138 kV lines will feed this station (from Logan and Sprigg stations), and distribution will have one 12 kV feed. Install two 138 kV circuit breakers on the line exits. Install 138 kV circuit switcher for the new transformer.	11/1/2026	$65.80	AEP	11/30/2021

Table 6.66: West Virginia Baseline Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	B3348 Cont.	.2	Construct a new 138/46/12 kV Argyle station to replace Dehue station. Install a 138 kV ring bus using a breaker-and-a-half configuration, with an autotransformer with a 46 kV feed and a distribution transformer with a 12 kV distribution bay. Two 138 kV lines will feed this station (from Logan and Wyoming stations). There will also be a 46 kV feed from this station to Becco station. Distribution will have two 12 kV feeds. Retire Dehue station in its entirety.	11/1/2026	$65.80	AEP	11/30/2021
		.3	Bring the Logan-Sprigg No. 2 138 kV circuit in and out of Tin Branch station by constructing approximately 1.75 miles of new overhead double circuit 138 kV line. Double circuit T3 series lattice towers will be used along with 795,000 cm. ACSR 26/7 conductor. One shield wire will be conventional 7 #8 ALUMOWELD, and one shield wire will be OPGW.				
		.4	Construct the Logan-Wyoming No. 1 circuit in and out of the proposed Argyle station utilizing double circuit lattice towers and ACSR 26/7 conductor. One shield wire will be conventional 7 #8 ALUMOWELD, and one shield wire will be OPGW.				
		.5	Rebuild approximately 10 miles of 46 kV line between Becco and the new Argyle substation. Retire approximately 16 miles of 46 kV line between the new Argyle substation and Chauncey station.				
		.6	Adjust relay settings due to new line terminations and retirements at Logan, Wyoming, Sprigg, Becco and Chauncey stations.				
2	B3357		Replace circuit breakers 'C', 'E,' and 'L' at Natrium station with 69 kV, 3000A 40 kA breakers, slab, control cables and jumpers.	6/1/2023	$1.50	AEP	1/21/2022
3	B3683		Reconductor the existing 556.5 ACSR line segments (3.49 miles) on the Messick Road-Ridgeley WC4 138 kV line with 954 45/7 ACSR to achieve 308/376 MVA SN/SE and 349/445 MVA WN/WE ratings. Replace the remote end equipment for the Messick Road-Ridgeley WC4 138 kV line. The total length of the line is 5.02 miles.	6/1/2026	$11.20	AP	12/17/2021
4	B3701		Replace terminal equipment on the French's Mill-Junction JST1 138 kV line.	11/1/2022	$0.77	AP	1/11/2022
5	B3722		Rebuild the existing Darrah-Barnett 69 kV line, approximately 2.8 miles, and replace a riser at Darrah station.	12/1/2027	$6.98	AEP	10/14/2022
6	B3723		Rebuild the George Washington-Kammer 138 kV circuit, except for 0.1 miles of previously upgraded T-line outside each terminal station (6.7 miles of total upgrade scope). Remove the existing 6-wired steel lattice towers and supplement the right of way as needed.	6/1/2027	$18.30	AEP	10/14/2022
7	B3726		Install two new 500 kV breakers on the existing open SVC string to create a new bay position. Relocate & Reterminate facilities as necessary to move the 500 kV SVC into the new bay position and Install a 500 kV breaker on the 500/138 kV No. 3 transformer. Upgrade relaying at Black Oak substation.	6/1/2027	$17.37	AP	11/1/2022

6.12.7 — Network Projects

2022 RTEP network projects in West Virginia are summarized in **Map 6.54** and **Table 6.67**.

Map 6.54: West Virginia Network Projects (Dec. 31, 2022)

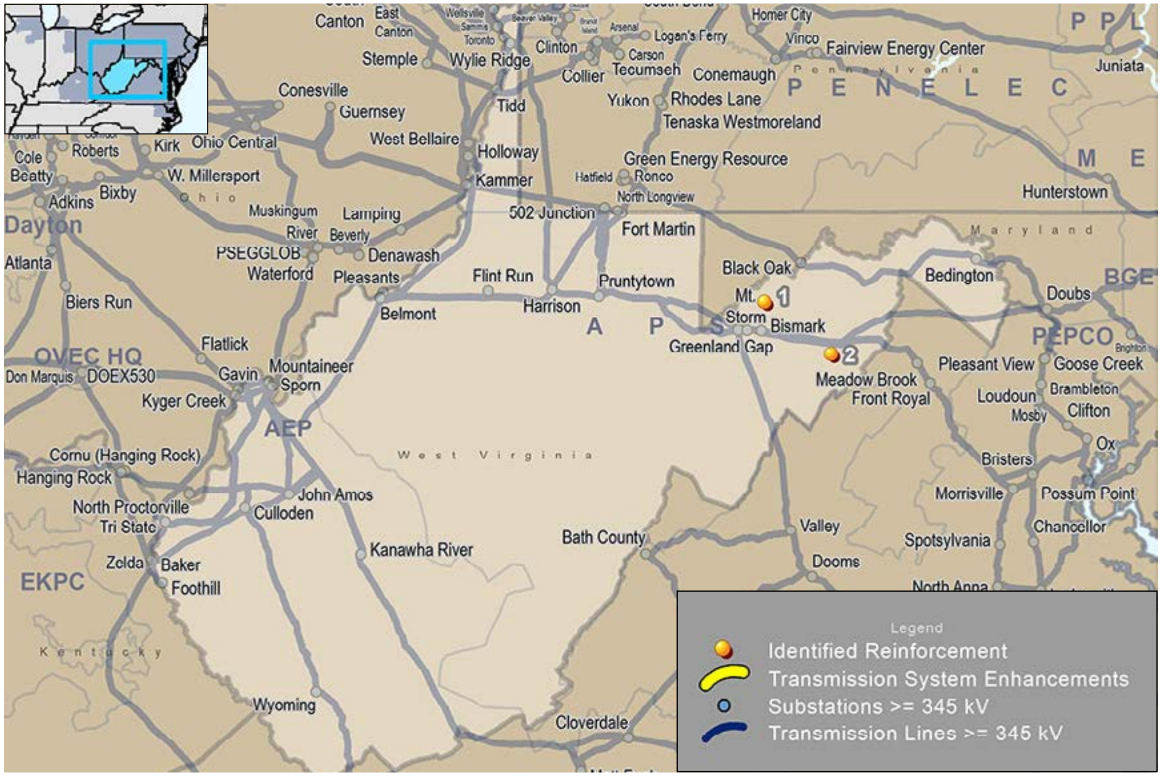


Table 6.67: West Virginia Network Projects (Dec. 31, 2022)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N6895	Kelso Gap-Parr Run 138 kV line loop to new Sulphur city 138 kV interconnection substation, including project management, environmental, forestry, real estate and right-of-way.	AD2-180	12/31/2021	$1.66	AP	11/1/2022
2	N7251	Reconfigure Baker substation into a 138 kV three-breaker ring bus configuration. Reterminate the existing 138/34.5 kV Transformer 1 and add new AD1-125 generation interconnection line at Baker.	AD1-125	12/31/2023	$3.55		

6.12.8 — Supplemental Projects

Supplemental projects received by PJM in 2022 in West Virginia are summarized in **Map 6.55** and **Table 6.68**.

6.12.9 — Merchant Transmission Project Requests

No merchant transmission project requests in West Virginia were identified as part of the 2022 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.55: West Virginia Supplemental Projects (Dec. 31, 2022)

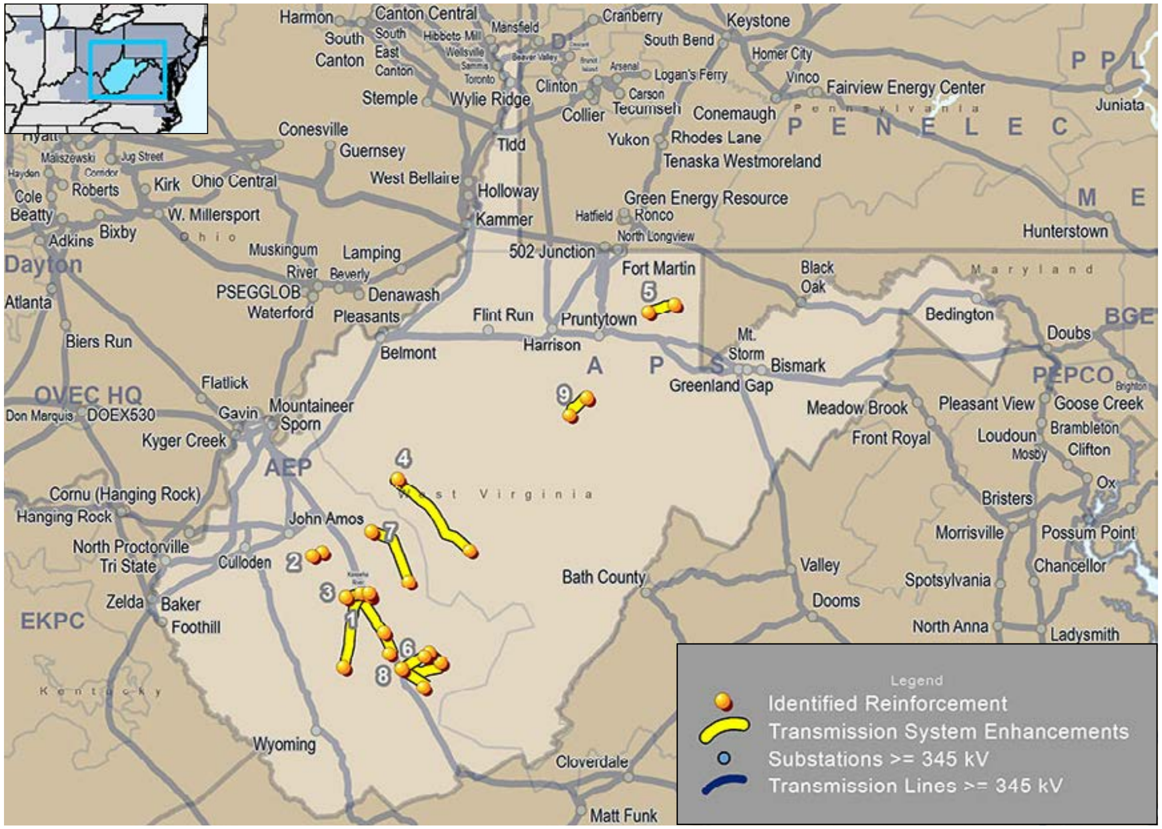


Table 6.68: West Virginia Supplemental Projects (Dec. 31, 2022)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2634	.1	Construct ~three miles of new 46 kV line from Kincaid to Westerly. Rebuild 5.4 miles of the existing Westerly-Pax Branch 46 kV line. New line to be constructed at 69 kV, operated at 46 kV. Install fiber on the new line construction for upgraded relaying communication.	10/7/2024	$44.80	AEP	9/17/2021
		.2	Retire Toms Fork-Westerly 46 kV and Toms Fork-Str. 364-13 46 kV (~24 miles total).				
		.3	Six wire the existing double circuit 46 kV line from Cabin Creek to Str. 364-13 to maintain the feed to Rhoda station.				

Table 6.68: West Virginia Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	S2364 Cont.	.4	Construct a new 138 kV double circuit in/out (~two miles) from Kanawha-Sundial No. 1 138 kV circuit to Toms Fork Station. Because of the very rugged terrain in the area, large angles and long span construction is required. These heavy angles and long spans mean minimal tangent structures could be utilized and required dead end towers for nearly every structure instead. These dead end towers are very heavy, resulting in larger equipment and steel costs, and require large foundations resulting in higher costs.	10/7/2024	$44.80	AEP	9/17/2021
		.5	Convert Toms Fork Station to 138 kV by installing a new 138/12 kV transformer, circuit switcher and two 138 kV line switches.				
		.6	Replace existing switches at Westerly Station with two new 1200A switches.				
		.7	Replace existing switches at Fork Ridge/Mossy Creek with two new 1200A switches, renamed Haystack Station.				
		.8	Perform remote end work at Kincaid.				
		.9	Perform remote end work at Pax Branch.				
2	S2635	.1	Replace existing hard tap at SCSM with a new 1200A three-way SCADA-controlled MOAB switch.	10/7/2022	$2.90		
		.2	Replace existing hard tap at CMS with a new 1200A three-way switch.				
		.3	Reconfigure 0.13 mile of the Chemical-Ward Hollow line to accommodate the new switches being installed.				
3	S2693	.1	Rebuild ~4.5 miles of 46 kV line on the Cabin Creek-London 46 kV circuit (total length ~eight miles) in an area where there's larger than standard right-of-way requirements due to long spans from ridge-ridge and more angle/dead ends required to mitigate landslide risk in rugged terrain. Long access roads due to terrain.	5/1/2025	$37.20		2/28/2022
		.2	Remove/retire existing Cabin Creek-London (4.5 miles). Helicopter removal will be utilized for existing line to avoid avoiding landslide prone areas.				
		.3	Retire the existing Hugheston Station.				
		.4	Rebuild London Station in the clear due to space constraints and access concerns. Install four 46 kV circuit breakers in a single bus configuration, DICM and appropriate metering equipment for the adjacent Hydro Plant.				
		.5	Rebuild ~one mile of double circuit line from the existing London Hydro station to the new London station. Due to terrain dead-end structures will be used to construct this section of line.				
		.6	Rebuild ~one mile of single circuit line on the Carbondale-London 46 kV to accommodate the new London station location.				
4	S2760		Replace Transmission line switches on Powell Mt-Linden Rd 138 kV.	11/1/2022	$0.50	AP	7/22/2022
5	S2761		Rebuild 138 kV line and upgrade terminal equipment at Albright-Kingwood.	12/31/2023	$8.00		
6	S2771	.1	Retire the existing Bradley-Layland 69 kV line (~14.3 miles).	5/1/2025	$20.70	AEP	4/22/2022
		.2	Construct a new double circuit 138 kV in/out line from the existing Bradley-Grandview 138 kV line (~2.6 miles).				
		.3	Retire existing Prince station.				
		.4	Install new 138 kV station including two 138 kV switches, circuit switcher and 138/12 kV 20 MVA transformer at Chessie station.				
		.5	Install a new 138/12 kV transformer, Grand station, to accommodate the retirement of Prince station.				
		.6	Remove existing 69 kV breaker due to line retirement at Bradley station.				

Table 6.68: West Virginia Supplemental Projects (Dec. 31, 2022) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
6 Cont.	**S2771 Cont.**	.7	Remove existing 69 kV breaker due to line retirement at Layland station.	5/1/2025	$20.70	AEP	4/22/2022
7	**S2775**	.1	Rebuild the existing Belva-Clendenin 46 kV line to 138 kV standards (~27 miles).	9/1/2026	$89.20		
		.2	Belva Station: Replace existing Gr. Sw. MOAB with a new 138 kV, 3000 A 40 kA circuit breaker. Install a new 138 kV, 3000 A 40 kA circuit breaker on the Belva-Gilboa 138 kV line at Belva Station. Install 9.6 MVAR cap bank.				
		.3	Replace existing MOABs W and Y with two new switches at Harland station. Retire/Remove existing circuit switcher AA and cap bank.				
8	**S2795**	.1	Rebuild ~4 miles of line from Layland-Mollys Creek (Str. 1183-229).	9/1/2025	$26.80		6/15/2022
		.2	Install a new 138 kV phase-over-phase switch on the Bradley-Mollys Creek 138 kV line and associated line work on the existing Bradley-Mollys Creek 138 kV line to accommodate switch.				
		.3	Construct a new 138 kV extension from the new 138 kV phase-over-phase switch to the existing Claremont Station (to be renamed Dun Glen) (~0.6 mile).				
		.4	Convert existing Claremont station from 69 kV to 138 kV. Station to be renamed Dun Glen.				
		.5	Retire existing Claremont-Mollys Creek 69 kV line (~3.1 miles). Retire existing Thurmond S.S.-Brooklyn S.S. 69 kV line (~3.2 miles).				
		.6	Install two new 138 kV breakers at Mollys Creek station.				
9	**S2700**		For Buckhannon-Volga Tap 138 kV line, replace disconnect switch, substation conductor, and wave trap at Pruntytown 138 kV substation. For Leer South-Pruntytown 139 kV line, meter Pruntytown 138 kV substation.	11/23/2022	$1.60	AP	11/19/2021

Appendix 1: TO Zones and Locational Deliverability Areas

1.0: TO Zones and Locational Deliverability Areas

The terms transmission owner zone and Locational Deliverability Area, as used in this report, are defined below and shown on **Map 1.1**. They are provided for the convenience of the reader based on definitions from other sources.

A transmission owner (TO) is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a TO. Schedule 15 of the Reliability Assurance Agreement defines the distinct zones that the PJM control area comprises and is available on the PJM website.

A Locational Deliverability Area (LDA) is an electrically cohesive area defined by transmission zones, parts of zones or combination of zones. LDAs are used as part of PJM's RTEP process load deliverability test. They are restated in **Table 1.1** below for ease of reference.

Map 1.1: Locational Deliverability Areas

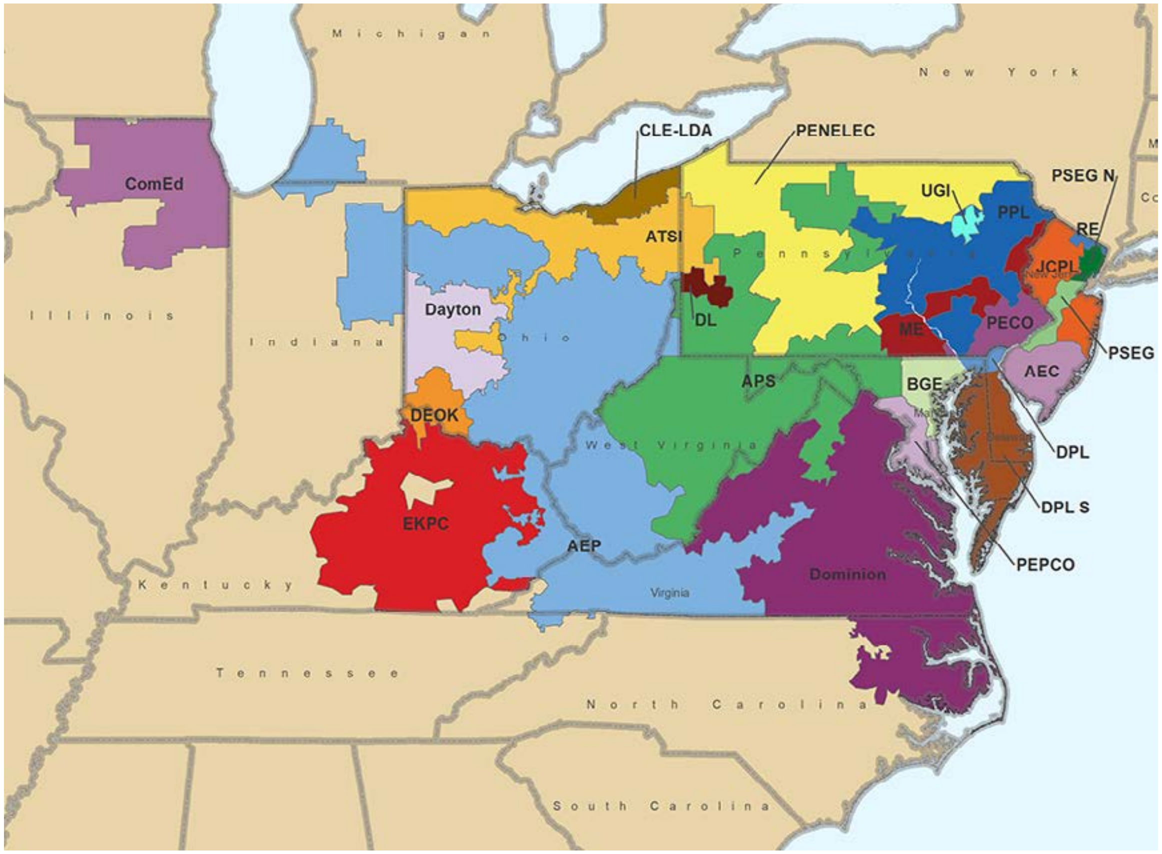


Table 1.1: Locational Deliverability Areas

Entity Name	TO Zone	LDA	Description
AE	▲	▲	Atlantic City Electric
AEP	▲	▲	American Electric Power
AP	▲	▲	Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)
ATSI	▲	▲	American Transmission Systems, Inc. (FirstEnergy)
BGE	▲	▲	Baltimore Gas & Electric
Cleveland	n/a	▲	Cleveland Area
ComEd	▲	▲	Commonwealth Edison (ComEd)
DAY	▲	▲	AES Ohio (formerly Dayton Power & Light)
DEO&K	▲	▲	Duke Energy Ohio and Kentucky
DLCO	▲	▲	Duquesne Light Company
Dominion	▲	▲	Dominion Energy Virginia and North Carolina
DP&L	▲	▲	Delmarva Power
Delmarva South	n/a	▲	Southern portion of Delmarva Power
Eastern Mid-Atlantic	n/a	▲	Global area: JCP&L, PECO, PSE&G, AE, DPL, RECO
EKPC	▲	▲	East Kentucky Power Cooperative
JCP&L	▲	▲	Jersey Central Power & Light
METED	▲	▲	Metropolitan Edison (Met-Ed)
Mid-Atlantic	n/a	▲	Global area: PENELEC, METED, JCP&L, PPL, PECO, PSE&G, BGE, PEPCO, AE, DPL, RECO
PECO	▲	▲	PECO
PENELEC	▲	▲	Pennsylvania Electric Company (Penelec)
PEPCO	▲	▲	Potomac Electric Power Company (Pepco)
PPL	▲	▲	PPL Electric Utilities Corporation, UGI Utilities
PSEG	▲	▲	Public Service Electric & Gas Company (PSE&G)
PSEG North	n/a	▲	Northern portion of PSE&G
Southern Mid-Atlantic	n/a	▲	Global area: BGE and PEPCO
Western Mid-Atlantic	n/a	▲	Global area: PENELEC, METED, PPL
Western PJM	n/a	▲	Global area: AP, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC, OVEC

Topical Index

E

F

G

I

K

L

M

N

O

P

Q

R

S

T

V

W

Glossary

The terms and concepts in this glossary are provided for the convenience of the reader and are in large part based on definitions from other sources, as indicated in the "Reference" column for each term.

These references include the following:

- **Mxx:** PJM Manual
- **NERC:** North American Electric Reliability Corporation
- **OA:** PJM Operating Agreement
- **OATT:** PJM Open Access Transmission Tariff
- **RAA:** Reliability Assurance Agreement

Term	Reference	Acronym	Definition
Adequacy	NERC		Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency. "Resources" refers to a combination of electricity generation and transmission facilities, which produce and deliver electricity, and "demand response" programs, which reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
Aluminum Conductor Steel Reinforced		ACSR	This high-capacity, stranded conductor type is typically made with a core of steel (for its strength properties), surrounded by concentric layers of aluminum (for its conductive properties).
Aluminum Conductor Steel Supported		ACSS	This high capacity, stranded conductor type is made from annealed aluminum.
Ancillary Service	OATT		Ancillary services are those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Annual Demand Resources			Demand resources can be called on an unlimited number of times any day of the delivery year, unless on an approved maintenance outage. Product type ceases to exist following the commencement of Capacity Performance rules.
Attachment Facilities	OATT		Attachment facilities are necessary to physically connect a customer facility to the transmission system or interconnected distribution facilities.
Auction Revenue Right	OA	ARR	An Auction Revenue Right is a financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the annual FTR Auction.
Available Transfer Capability	NERC	ATC	The available transfer capability is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Base Capacity Resource	M18		Base capacity resources are capacity resources that are not capable of sustained, predictable operation throughout the entire delivery year. These resources were only procured through the 2019/2020 Delivery Year. Starting with the 2020/2021 Delivery Year, all resources are Capacity Performance Resources. See "Capacity Performance."
Baseline Upgrades	M14B		In developing the RTEP, PJM tests the baseline adequacy of the transmission system to deliver energy and capacity resources to each load in the PJM region. The system (as planned to accommodate forecast demand, committed resources and commitments for firm transmission service for a specified time frame) is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, nuclear plant licensee requirements, PJM reliability standards and PJM design standards. Areas not in compliance with the standards are identified, and enhancement plans to achieve compliance are developed. Baseline expansion plans serve as the base system for conducting feasibility studies and system impact studies for all proposed requests for generation and merchant transmission interconnection, and for long-term firm transmission service.
Behind-the-Meter Generation	OATT	BTM	Behind-the-meter generation delivers energy to load without using the transmission system or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of PJM), provided, however, that behind-the-meter generation does not include: (1) at any time, any portion of such generating unit's capacity that is designated as a capacity resource, or (2) in an hour, any portion of the output of such generating unit(s) sold to another entity for consumption at another electrical location or in to the PJM Interchange Energy Market.
Bilateral Transaction	OA		A bilateral transaction is a contractual arrangement between two entities (one or both being PJM members) for the sale and delivery of a service.

Go to Next Section >

Term	Reference	Acronym	Definition
Breaker-and-a-Half		BAAH	This substation configuration type is typically composed of two main sections connected by element strings. Each element string is composed of circuit breakers, transformers or line elements.
Bulk Electric System	NERC, M14B	BES	ReliabilityFirst defines the bulk electric system as all individual generation resources larger than 20 MVA, or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher, lines operated at voltages of 100 kV or higher, associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment). The ReliabilityFirst BES definition excludes: (1) radial facilities connected to load-serving facilities or individual generation resources smaller than 20 MVA, or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher; (2) the balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and step-up transformer), which would include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions; and (3) all other facilities operated at voltages below 100 kV.
Capacitor Voltage Transformer		CCVT	This type of transformer is used to step down high voltage signals and provide a low voltage signal for metering or protection devices.
Capacity Emergency	M13		A capacity emergency is a system condition where operating capacity plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet the total of its demand, firm sales and regulating requirements.
Capacity Emergency Transfer Limit	RAA, M14B, M18	CETL	The capacity emergency transfer limit is part of load deliverability analysis used to determine the maximum limit, expressed in megawatts, of a study area's import capability, under the conditions specified in the load deliverability criteria.
Capacity Emergency Transfer Objective	RAA, M14B, M18, M20	CETO	The CETO is the emergency import capability, expressed in megawatts, required of a PJM subregion area to satisfy established reliability criteria.
Capacity Interconnection Rights	OATT	CIRs	Capacity Interconnection Rights are rights to input generation as a capacity resource into the transmission system at the point of interconnection, where the generating facilities connect to the transmission system.
Capacity Performance			Capacity Performance is a set of rules governing resource participation in the Reliability Pricing Model (RPM). Following a series of transition auctions, Capacity Performance rules were fully in place starting with the 2020/2021 Delivery Year. See "Base Capacity Resource" and "Capacity Performance Resource."
Capacity Performance Resource	M18		Capacity Performance Resources are capable of sustained, predictable operation throughout the entire delivery year. Starting with the 2020/2021 Delivery Year, all resources are Capacity Performance Resources. See "Capacity Performance."
Capacity Resource	RAA, M14A, M14B		Capacity resources are megawatts of net capacity from existing or planned generation resources or load reduction capability provided by demand resources or interruptible load for reliability (ILR) in the region PJM serves.
Circuit Breaker		CB	This automatic device is used to stop the flow of current in an electric circuit as a safety measure.
Clean Air Interstate Rule		CAIR	The Clean Air Interstate Rule is an Environmental Protection Agency (EPA) rule regarding the interstate transport of soot and smog.
Clean Power Plan		CPP	The Clean Power Plan is an EPA rule regarding carbon pollution from power plants.
Coincident Peak	M19		The coincident peak is a zone's contribution to the RTO or higher level locational deliverability area (LDA) peak load.
Combined Cycle (Turbine)		CC/CCT	This type of turbine is a generating unit facility that generally consists of a gas-fired turbine and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion Turbine		CT	A combustion turbine is a generating unit in which a combustion turbine engine is the prime mover.
Consolidated Transmission Owners Agreement	PJM.com	CTOA	The Consolidated Transmission Owners Agreement is an agreement between transmission owners, which PJM is a signatory to, establishing the rights and commitments of all parties involved.
Contingency			A contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Coordinated System Plan		CSP	A Coordinated System Plan (CSP) contains the results of coordinated PJM/MISO studies required to assure the reliable, efficient and effective operation of the transmission system. The CSP also includes the study results for interconnection requests and long-term firm transmission service requests. Further description of CSP development can be found in the PJM/MISO Joint Operating Agreement.
Cost of New Entry	M18	CONE	The Cost of New Entry is a Reliability Pricing Model (RPM) capacity market parameter defined as the levelized annual cost in installed capacity $/MW-day of a reference combustion turbine to be built in a specific locational deliverability area.

Term	Reference	Acronym	Definition
Cross-Linked Polyethylene		XLPE	A type of plastic used to insulate power lines; the benefits of cross-linked polyethylene include resistance to temperature fluctuations and other environmental factors.
Cross-State Air Pollution Rule		CSAPR	The Cross-State Air Pollution Rule is an EPA rule regarding reduction in air pollution related to power plant emissions.
Current Transformer		CT	This type of transformer is used to measure electrical flows for purposes of telemetry.
Deactivation	M14D		Deactivation encompasses retiring or mothballing a generating unit governed by the PJM Open Access Transmission Tariff. Any generator owner, or designated agent, who wishes to retire a unit from PJM operations must initiate a deactivation request in writing no less than 90 days in advance of the planned deactivation date.
Deliverability	RAA, M14B, M18		Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver energy from generation facilities to wherever it is needed to ensure only that the transmission system is adequate for delivery of energy to load under prescribed conditions. The testing procedure includes two components: (1) generation deliverability, and (2) load deliverability.
Demand Resource	M18	DR	See “Load Management.”
Designated Entity			A designated entity can be an existing transmission owner or non-incumbent transmission developer designated by PJM with the responsibility to construct, own, operate, maintain and finance immediate-need reliability projects, short-term projects, long-lead projects, or economic-based enhancements or expansions.
Designated Entity Agreement	OATT	DEA	When a project is designated as a greenfield project that is not reserved for the transmission owner, execution of a Designated Entity Agreement (DEA) is required. The DEA defines the terms, duties, accountabilities and obligations of each party, and relevant project information, including project milestones. Once construction is complete and the designated entity has met all DEA requirements, the agreement is no longer needed. The designated entity must execute the Consolidated Transmission Owners Agreement as a requirement for DEA termination. Once a project is energized, a designated entity that is not already a transmission owner must become a transmission owner, subject to the Consolidated Transmission Owners Agreement.
Distributed Solar Generation			Distributed solar generation is not connected to PJM and does not participate in PJM markets. These resources do not go through the full interconnection queue process. The output of these resources is netted directly with the load. PJM does not receive metered production data from any of these resources.
Distribution Factor		DFAX	A distribution factor is the portion of an imposed power transfer that flows across a specified transmission facility or interface.
Diversity	M18		Diversity is the number of megawatts that account for the difference between a transmission owner zone’s forecast peak load at the time of its own peak and its coincident load at the time of the PJM peak.
Eastern Interconnection Planning Collaborative		EIPC	The Eastern Interconnection Planning Collaborative (EIPC) represents an interconnection-wide transmission planning coordination effort among planning authorities in the Eastern Interconnection. EIPC consists of 20 planning coordinators comprising approximately 95% of the Eastern Interconnection electricity demand. EIPC coordinates analysis of regional transmission plans to ensure their coordination and also provides the resources to conduct analysis of emerging issues affecting the grid.
Eastern Interconnection Reliability Assessment Group		ERAG	The ERAG is a group whose purpose is to further augment the reliability of the bulk power system in the Eastern Interconnection through periodic studies of seasonal and longer-term transmission system conditions.
Eastern MAAC	M14B	EMAAC	Eastern MAAC is a term used in PJM deliverability analysis to refer to the portion of PJM that includes AE, DP&L, JCP&L, PECO, PSEG and Rockland.
Effective Forced Outage Rate on Demand	M22	EFORd	EFORd is a measure of the probability that a generating unit will not be available due to forced outages or forced de-ratings when there is a demand on the unit to generate. See Manual 22: Generator Resource Performance Indices for the equation.
Electrical Distribution Company		EDC	An electrical distribution company owns and/or operates electrical distribution facilities for the delivery of electrical energy to end-use customers.
End-Use Characteristics	M19		End-use characteristics are the measures of electrical equipment and appliance efficiency used in residential and commercial settings. These are represented in forecast models as part of heating, cooling and other applications.
Energy Efficiency Programs		EE	Energy efficiency programs are incentives or requirements at the state or federal level, which promote energy conservation and wise use of energy resources.
Energy Resource	M14A, M14B		An energy resource is a generating facility that is not a capacity resource.
Extended Summer Demand Resources			Extended summer demand resources can be called on as many times as needed from 10 a.m. to 10 p.m., any day from June through October and during the following May of that delivery year. Product ceases to exist following the commencement of Capacity Performance rules.
Extra High Voltage		EHV	Extra high voltage transmission equipment operates at 230 kV and above.

Go to Next Section >

Term	Reference	Acronym	Definition
Facilities Study Agreement	M14A	FSA	A facilities study agreement is an agreement made between the interconnection customer/developer and PJM to identify the scope of facility additions and upgrades to be included in the interconnection study.
Fault			A fault is a physical condition that results in the failure of a component or facility within the transmission system to transmit electrical power in the manner for which it was designed.
Federal Energy Regulatory Commission		FERC	FERC is an independent federal agency that regulates the interstate transmission of electricity, natural gas and oil.
Financial Transmission Right	M6	FTR	A Financial Transmission Right is a financial instrument entitling the holder to receive revenues based on transmission congestion, measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm Transmission Service	OATT		Firm transmission service is intended to be available at all times to the maximum extent practical. Service availability is subject to system emergency conditions, unanticipated facility failure, or other unanticipated events and is governed by Part II of the OATT.
Fixed Series Capacitor		FSC	A fixed series capacitor is a grouping of capacitors used to reduce transfer reactances on bulk transmission corridors.
Flexible Alternating Current Transmission System		FACTS	FACTS is a system composed of static equipment used for the AC transmission of electrical energy, meant to enhance controllability and increase power transfer capability of the network. It is generally a power electronics-based system.
Flowgate			A flowgate is a specific combination of a monitored facility and a contingency that impacts that monitored facility.
Gas Insulated Substation		GIS	This is a high voltage substation in which the major electrical components are contained within a sealed environment with sulfur hexafluoride gas as the insulating medium.
Generation Deliverability	M14B		Generation deliverability is the ability of the transmission system to export capacity resources from one electrical area to the remainder of PJM. The generator deliverability test for reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the transmission system is capable of delivering the aggregate system generating capacity at peak load with all firm transmission uses modeled.
Generator Step-up Transformer		GSU	A GSU transformer “steps-up” generator power output voltage level to the suitable grid-level voltage for transmission of electricity to load centers.
Geomagnetically Induced Current		GIC	This is a manifestation at ground level of space weather; these currents impact the normal operation of electrical conductor systems.
Good Utility Practice	OATT		Good Utility Practice is any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be practices, methods or acts generally accepted in the region.
Group/Gang Operated Air Break		GOAB	A group/gang operated air break is the portion of a circuit breaker that opens and closes to allow or block current to flow through or not. This particular type of break uses air as a dielectric medium, as opposed to others that use gas, oil or air contained within a vacuum. “Gang operated” refers to a mechanical linkage that opens and closes the disconnect.
Horizontal Directional Drilling		HDD	Horizontal directional drilling technology for laying transmission cable employs a long, flexible drill bit to bore horizontally underground. This is a trenchless method in which no surface excavation is required except for drill entry and exit points, which minimizes surface restoration, ecological disturbances and environmental impacts. By contrast, jet-plowing techniques affect the riverbed over the length of the installation.
Independent State Agencies Committee	PJM.com	ISAC	The ISAC is a voluntary, stand-alone committee that consists of members from regulatory and other state agencies representing all of the states and the District of Columbia within the service territory of PJM. The ISAC is an independent committee that is not controlled or directed by PJM, the PJM Board or PJM members. The purpose of the ISAC is to provide PJM with input and scenarios for transmission planning studies.
Independent System Operator		ISO	An independent system operator is an entity that is authorized to operate an electric transmission system and is independent of any influence from the owner(s) of that electric transmission system. See also “RTO.”
Installed Capacity		ICAP	Installed capacity is valued based on the summer net dependable rating of the unit as determined in accordance with PJM rules and procedures relating to the determination of generating capacity.
Interconnected Reliability Operating Limit	M14B	IROL	The interconnected reliability operating limit is a system operating limit that, if violated, could lead to instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk electric system.

Term	Reference	Acronym	Definition
Interconnection Construction Service Agreement	M14C	ICSA	The ICSA is a companion agreement to the ISA and is necessary for projects that require the construction of interconnection facilities as defined in the ISA. The ICSA details the project scope, construction responsibilities of the involved parties, ownership of transmission and customer interconnection facilities, and the schedule of major construction work.
Interconnection Coordination Agreement	OATT	ICA	An interconnection coordination agreement is made between transmission owners and/or transmission developers outlining the schedules and responsibilities of each party involved.
Interconnection Process Reform Task Force		IPRTF	A task force within PJM's stakeholder process seeking to make improvements to the interconnection process.
Interconnection Service Agreement	M14A	ISA	An Interconnection Service Agreement is made among the transmission provider, an interconnection customer and an interconnected transmission owner regarding interconnection under Part IV and Part VI of the Tariff.
Interregional Market Efficiency Project		IMEP	Interregional proposals are designed to address congestion and its associated costs along the MISO/PJM border within the context of the MISO/PJM JOA as identified in long-term market efficiency simulation results.
Joint RTO Planning Committee		JRPC	The JRPC is the decision-making body for MISO/PJM coordinated system planning as governed by the MISO/PJM Joint Operating Agreement.
Light Load Reliability Analysis	M14B		Light load reliability analysis ensures that the transmission system is capable of delivering the system generating capacity during a light load situation (50% of 50/50 summer peak demand level).
Limited Demand Resources			Limited demand resources can be called on up to 10 times from noon to 8 p.m. on weekdays, other than NERC holidays, from June through September. Product type ceases to exist following the commencement of Capacity Performance rules.
Load			Load refers to demand for electricity at a given time, expressed in megawatts.
Load Analysis Subcommittee	M19	LAS	The Load Analysis Subcommittee is responsible for technical analysis and coordination of information related to the electric peak demand and energy forecasts, interruptible load resources for capacity, credit and weather, and peak load studies. The LAS reports to the Planning Committee.
Load Deliverability	M14B		Load deliverability is the ability of the transmission system to deliver energy from the aggregate of available capacity resources in one PJM electrical area and adjacent non-PJM areas to another PJM electrical area that is experiencing a capacity deficiency.
Load Management	M18	LM	Load management is the ability to interrupt retail customer load at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. Load management derives a demand resource or interruptible-load-for-reliability credit in RPM.
Load Serving Entity	RAA, OATT	LSE	Load serving entities (LSE) provide electricity to retail customers. LSEs include traditional distribution utilities.
Local Distribution Company		LDC	A local distribution company (LDC) is a regulated utility involved in the delivery of natural gas to consumers within a specific geographic area. While some large industrial, commercial and electric generation customers receive natural gas directly from high-capacity pipelines, most other users receive natural gas from their LDCs.
Locational Deliverability Area	M14B	LDA	Locational deliverability areas are electrically cohesive load areas, historically defined by transmission owner service territories and larger geographical zones comprising a number of those service areas.
Locational Marginal Price		LMP	The locational marginal price is the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.
Loss-of-Load Expectation	M14B	LOLE	Loss-of-load expectation defines the adequacy of capacity for the entire PJM footprint based on load exceeding available capacity, on average, during only one day in 10 years.
Market Participant			A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met credit requirements as established by PJM. Market buyers are able to make purchases and market sellers are able to make sales in PJM energy and capacity markets.
Maximum Facility Output	M14A, M14G	MFO	This term refers to the maximum amount of power a generator is capable of producing.
Megavolt-Ampere Reactive	OA	MVAR	See "Reactive Power."
Merchant Transmission Facility	OATT		Merchant transmission facilities are AC or DC transmission facilities that are interconnected with, or added to, the transmission system in accordance with the PJM Open Access Transmission Tariff. These facilities are not existing facilities within the transmission system, transmission facilities included in the rate base of a public utility on which a regulated return is earned, or transmission facilities included in previous RTEPs or customer interconnection facilities.
Mercury and Air Toxins Standards		MATS	MATS is an EPA rule limiting the emissions of toxic air pollutants like mercury, arsenic and metals from power plant emissions.

Term	Reference	Acronym	Definition
Mid-Atlantic Subregion	M14B	MAAC	The PJM Mid-Atlantic Subregion encompasses 12 transmission owner zones: Atlantic City Electric (ACE), Baltimore Gas and Electric (BGE), Delmarva Power (DPL), Jersey Central Power and Light (JCPL), Metropolitan Edison (MetEd), Neptune, PECO, Pennsylvania Electric Company (PENELEC), Potomac Electric Power Company (PEPCO), PPL Electric Utilities (PPL), Public Service Electric & Gas (PSEG) and Rockland Electric (REKO). The Neptune Regional Transmission System interconnects with the Mid-Atlantic PJM transmission system at Sayreville substation in Northern New Jersey.
MISO Transmission Expansion Planning		MTEP	MTEP is the Midcontinent Independent System Operator (MISO) plan for enhancing the future of the power grid in their area.
Motor-Operated Air Break		MOAB	A motor-operated air break is the portion of a circuit breaker that opens and closes to allow or block current. This particular type of break uses air as a dielectric medium, as opposed to others that use gas, oil or air contained within a vacuum. “Motor operated” refers to a remote-controlled motorized linkage that opens and closes the disconnect.
Multiregional Model Working Group		MMWG	The Multiregional Model Working Group reports to the ERAG and is responsible for developing all Eastern Interconnection power flow and dynamic base case models, including seasonal updates to summer and winter power flow study cases.
National Renewable Energy Laboratory		NREL	The NREL, part of the Department of Energy, is a federal laboratory dedicated to the research, development, commercialization, and deployment of renewable energy and energy efficiency technologies.
Network Reinforcements	OATT		Network reinforcements are modifications or additions to transmission-related facilities that are integrated with and support the transmission provider’s overall transmission system for the general benefit of all users of such transmission system.
Non-Coincident Peak	M19	NCP	The non-coincident peak is a zone’s individual peak load.
North American Electric Reliability Corporation	NERC	NERC	NERC is a FERC-appointed body whose mission is to ensure the reliability of the bulk power system.
Open Access Same-Time Information System		OASIS	The Open Access Same-Time Information System (OASIS) provides information by electronic means about available transmission capability for point-to-point service and a process for requesting transmission service on a non-discriminatory basis. OASIS enables transmission providers and transmission customers to communicate requests and responses to buy and sell available transmission capacity offered under the PJM Open Access Transmission Tariff.
Open Access Transmission Tariff	OATT	OATT	The OATT is a FERC-filed tariff specifying the terms and conditions under which PJM provides transmission service and carries out its generation and merchant transmission interconnection process.
Optical Grounding Wire Communications		OPGW	This is a type of fiber optic cable that is used in the construction of electric power transmission and distribution lines and that combines the functions of grounding and communications.
Optimal Power Flow		OPF	Optimal power flow is a tool used to determine optimal dispatch, subject to transmission constraints. Optimal often means most economical but may also mean “minimum control change.”
Organization of PJM States, Inc.		OPSI	OPSI refers to an organization of statutory regulatory agencies in the 13 states and the District of Columbia within which PJM Interconnection operates. OPSI Member Regulatory Agencies’ activities include, but are not limited to, coordinating activities such as data collection, issues analyses and policy formulation related to PJM, its operations, its market monitor and matters related to the FERC, as well as their individual roles as statutory regulators within their respective state boundaries.
PJM Manuals			PJM Manuals contain the instructions, rules, procedures and guidelines established by PJM for the operation, planning and accounting requirements of the region PJM serves and the PJM Interchange Energy Market.
PJM Member	OA, M33		A PJM member is any entity that has satisfied PJM requirements to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
Planning Committee	OA	PC	The Planning Committee was established under the Operating Agreement to review and recommend system planning strategies and policies, as well as planning and engineering designs for the PJM bulk power supply system.
Planning Cycle	M14B		The planning cycle is the annual RTEP process, including a series of studies, analysis, assessments and related supporting functions.
Planning Horizon	M14B		The planning horizon is the future time period over which system transmission expansion plans are developed based on forecast conditions.
Probabilistic Risk Assessment	M14B	PRA	PJM assesses risk exposure using a Probabilistic Risk Assessment (PRA) risk management tool. The goal of the PRA model is to minimize asset service cost. PJM’s PRA method integrates the economics of facility loss with the likelihood of that loss occurring.

Term	Reference	Acronym	Definition
Reactive Power (expressed in MVAR)	M14A		Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers or electrostatic equipment such as capacitors and directly influences electric system voltage. Reactive power is usually expressed as megavolt-ampere reactive (MVAR).
Regional Greenhouse Gas Initiative		RGGI	States and provinces in the northeastern United States and eastern Canada adopted the Regional Greenhouse Gas Initiative to reduce greenhouse gas emissions.
Regional RTEP Project	M14B, OA		A regional RTEP project is a transmission expansion or enhancement at a voltage level of 100 kV or higher.
Regional Transmission Expansion Plan	M14B	RTEP	The Regional Transmission Expansion Plan (RTEP) is prepared by PJM pursuant to Schedule 6 of the PJM Operating Agreement for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the region PJM serves.
Regional Transmission Organization	FERC	RTO	A regional transmission organization is an independent, FERC-approved organization of sufficient regional scope, which coordinates the interstate movement of electricity under FERC-approved tariffs by operating the transmission system and competitive wholesale electricity markets, and ensures reliability and efficiency through expansion planning and interregional coordination.
Reliability	NERC		A reliable bulk power system is one that is able to meet the electricity needs of end-use customers, even when unexpected equipment failures or other factors reduce the amount of available electricity.
Reliability Assurance Agreement	RAA	RAA	The Reliability Assurance Agreement (RAA) among load-serving entities in the region PJM serves is intended to ensure that adequate capacity resources will be planned and made available to provide reliable service to loads within PJM, to assist other parties during emergencies and to coordinate planning of capacity resources consistent with the reliability principles and standards.
Reliability Must Run		RMR	A reliability must run (RMR) generating unit is one slated to be retired by its owners but is needed to be available to maintain reliability. Typically, it is requested to remain operational beyond its proposed retirement date until required transmission enhancements are completed.
Reliability Pricing Model		RPM	The Reliability Pricing Model (RPM) is PJM's resource adequacy construct. The purpose of RPM is to develop a long-term pricing signal for capacity resources and load serving entity obligations that is consistent with the PJM RTEP process. RPM adds stability and a locational nature to the pricing signal for capacity.
ReliabilityFirst Corporation		RFC	ReliabilityFirst is a not-for-profit company incorporated in the state of Delaware, whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. ReliabilityFirst was approved by the North American Electric Reliability Corporation (NERC) to become one of eight Regional Reliability Councils in North America and began operations on Jan. 1, 2006. ReliabilityFirst is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council, the East Central Area Coordination Agreement and the Mid-American Interconnected Network.
Renewable Portfolio Standard		RPS	The Renewable Portfolio Standard is a set of guidelines or requirements at the state or federal level requiring energy suppliers to provide specified amounts of electric energy from eligible renewable energy resources.
Right of First Refusal		ROFR or RFR	The right of first refusal is a contractual right that gives the holder the option to enter a business transaction with the owner of an asset, according to specified terms, before the owner is entitled to enter into that transaction with a third party.
Right-of-Way		ROW	A right-of-way is a corridor of land on which electric lines may be located. The transmission owner may own the land in fee; own an easement; or have certain franchise, prescription or license rights to construct and maintain lines.
Security	NERC		The ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by physical or cyberattacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.
Security Constrained Optimal Power Flow		SCOPF	The optimal power flow determines the ideal dispatch, subject to transmission constraints. Optimal usually means "least cost" (or most economical), but may also mean "minimum control change." Security-constrained OPF, or SCOPF, adds contingencies. The SCOPF will seek a single dispatch that does not cause any overloads in the base case, nor any overloads during any of the contingencies.
Southern Subregion	M14B		The PJM Southern Subregion comprises one transmission owner zone – Dominion Energy Virginia and North Carolina.
Special Protection System	M03	SPS	A Special Protection System (SPS), also known as a remedial action scheme, includes an assembly of protection devices designed to detect and initiate automatic action in response to abnormal or predefined system conditions. The intent of these schemes is generally to protect equipment from thermal overload or to protect against system instability following subsequent contingencies on the electric system. Redundant assemblies may be applied for the above functions on an individual facility – in such cases, each assembly is considered a separate protection system. An SPS consists of protection devices such as relays, current transformers, potential transformers, communication interface equipment, communication links, breaker trip and close coils, switch gear auxiliary switches and all associated connections.

Term	Reference	Acronym	Definition
Static Synchronous Compensator		STATCOM	This is a shunt device of the Flexible AC Transmission System (FACTS) family that uses power electronics to control power flow and improve transient stability on power grids.
Static Var Compensation		SVC	An SVC device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system transmission and distribution performance.
Storage as a Transmission Asset		SATA	This a storage device that can be utilized on the transmission system to address reliability issues.
Subregional RTEP Committee	M14B, OA		This PJM committee that facilitates the development and review of the subregional RTEP projects. The Subregional RTEP Committee is responsible for the initial review of the subregional RTEP projects and for providing recommendations to the Transmission Expansion Advisory Committee concerning the subregional RTEP projects.
Subregional RTEP Project	M14B, OA		A subregional RTEP project is defined in the PJM Operating Agreement as a transmission expansion or enhancement rated below 230 kV.
Sub-Synchronous Resonance		SSR	Power system sub-synchronous resonance (SSR) is the buildup of mechanical oscillations in a turbine shaft arising from the electro-mechanical interaction between the turbine generator and the rest of the power system. This can lead to turbine shaft damage, or even catastrophic loss. The term "sub-synchronous" refers to the fact that the oscillations a shaft can experience occur at levels below 60 Hz (cycles per second).
Supplemental Project	M14B, OA		"Supplemental Project" replaces the term "Transmission Owner Initiated or TOI Project" and refers to a regional RTEP project or a subregional RTEP project that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.
Surge Impedance Loading		SIL	This is the megawatt loading of a transmission line at which a natural reactive power balance occurs. A line loaded below its SIL supplies reactive power to the system; a line above its SIL absorbs reactive power.
System Operating Limit	M14B	SOL	This is the value (such as MW, MVAR, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System operating limits are based upon certain operating criteria.
System Stability			Stability studies examine the grid's ability to return to a stable operating point following a system fault or similar disturbance. Such contingencies can cause a nearby generator's rotor position to change in relation to the stator's magnetic field, affecting the generator's ability to maintain synchronism with the grid. Power system engineers measure this stability in terms of generator bus voltage and maximum observed angular displacement between a generator's rotor axis and the stator magnetic field. Stability in actual operations is affected by machine megawatt, system voltage, machine voltage, duration of the disturbance and system impedance. Transient stability examines this phenomenon over the first several seconds following a system disturbance.
Targeted Market Efficiency Project		TMEP	TMEP interregional projects address historical congestion on reciprocal coordinated flowgates – a set of specific flowgates subject to joint and common market congestion management.
Temperature-Humidity Index	M19	THI	The temperature-humidity index (THI) gives a single numerical value in the general range of 70 to 80, reflecting the outdoor atmospheric conditions of temperature and humidity during warm weather. The THI is defined as follows: THI = Td – (0.55 – 0.55RH) * (Td - 58), where Td is the dry-bulb temperature and RH is the percentage of relative humidity, when Td is greater than or equal to 58.
Thyristor Controlled Series Compensator		TCSC	A thyristor controlled series compensator is a series capacitor bank that is shunted by a thyristor controlled reactor.
Topology	M14B		Topology is a geographically based or other diagrammatic representation of the physical features of an electrical system or portion of an electrical system – including transmission lines, transformers, substations, capacitors and other power system elements – that in aggregate constitute a transmission system model for power flow and economic analysis.
Transmission Customer	M14A, M14B, M2, OATT		A transmission customer is any eligible customer, or its designated agent, that: (1) executes a service agreement, or (2) requests in writing that PJM file with FERC, a proposed, unexecuted service agreement to receive transmission service under Part II of the PJM OATT.
Transmission Expansion Advisory Committee	M14B	TEAC	The Transmission Expansion Advisory Committee was established by PJM to provide advice and recommendations to aid in the development of the RTEP.
Transmission Loading Relief	M03	TLR	Transmission loading relief is a NERC procedure developed for the Eastern Interconnection to mitigate overloads on the transmission system by allowing reliability coordinators to request the curtailment of transactions that are causing parallel flows through their system.
Transmission Owner	M14B, OATT	TO	A transmission owner is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a transmission owner.
Transmission Owner Initiated		TOI	See "Supplemental Project."

Term	Reference	Acronym	Definition
Transmission Owner Upgrade	OA		A transmission owner upgrade is an improvement to, addition to, or replacement of part of a transmission owner's existing facility and is not an entirely new transmission facility.
Transmission Provider	M14B, OATT		The transmission provider is PJM for all purposes in accordance with the PJM OATT.
Transmission Service Request	M02	TSR	A transmission service request is a request submitted by a PJM market participant for transmission service over PJM-designated facilities. Typically, the request is for either short-term or long-term service, over a specific path for a specific megawatt amount. PJM evaluates each request and determines if it can be accommodated and, if the requestor so chooses, pursues needed upgrades to accommodate the request.
Transmission System	OATT		The transmission system comprises the transmission facilities operated by PJM used to provide transmission services. These facilities that transmit electricity are within the PJM footprint, meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities, and have been demonstrated to the satisfaction of PJM to be integrated with the transmission system of PJM and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.
Unforced Capacity	RAA	UCAP	Unforced capacity is an entitlement to a specified number of summer-rated MW of capacity from a specific resource, on average, not experiencing a forced outage or de-rating, for the purpose of satisfying capacity obligations imposed under the RAA.
Upgrade	OA		See "Transmission Owner Upgrade."
Upgrade Construction Service Agreement		UCSA	The terms and conditions of a UCSA govern the construction activities associated with the upgrade of capability along an existing PJM bulk electric system circuit in order to accommodate a merchant transmission interconnection request. Facilities constructed under a UCSA are not owned by a developer. All ownership rights of the physical facilities are retained by the respective transmission owner following the completion of construction. PJM and the developer execute a separate UCSA with each impacted transmission owner. A developer retains the right, but not the obligation (option to build), to design, procure, construct and install all or any portion of the direct assignment facilities and/or customer-funded upgrades.
Violation	M14B		A violation is a PJM planning study result that shows a specific system condition that is not in compliance with established NERC, ReliabilityFirst, SERC or PJM reliability criteria.
Weather Normalized Peak	M19		The weather normalized peak is an estimate of the seasonal peak load at normal peak-day weather conditions.
Western Subregion	M14B, OA		The PJM Western Subregion comprises five transmission owner zones: Allegheny Power (AP), American Electric Power (AEP), American Transmission Systems, Inc. (ATSI), Commonwealth Edison (ComEd), AES Ohio – formerly Dayton Power & Light (DAY), Duke Energy Ohio and Kentucky (DEO&K), Duquesne Light Company (DLCO) and Eastern Kentucky Power Cooperative (EKPC).
Wheel			A wheel is the contracted, third-party use of electrical facilities to transmit power whose origin and destination are outside the entity transmitting the power.
Wholesale Market Participation Agreement	M14C	WMPA	This is a contractual agreement required for generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM's market.
X-Effective Forced Outage Rate on Demand		XEFORd	XEFORd is a statistic that results from excluding events outside management control (outages deemed not to be preventable by the operator) from the EFORd calculation. See "Effective Forced Outage Rate on Demand (EFORd)."
Zone/Control Zone	M14B		A zone/control zone is an area within the PJM control area, as set forth in the PJM OATT and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

Map 1.1: PJM Backbone Transmission System

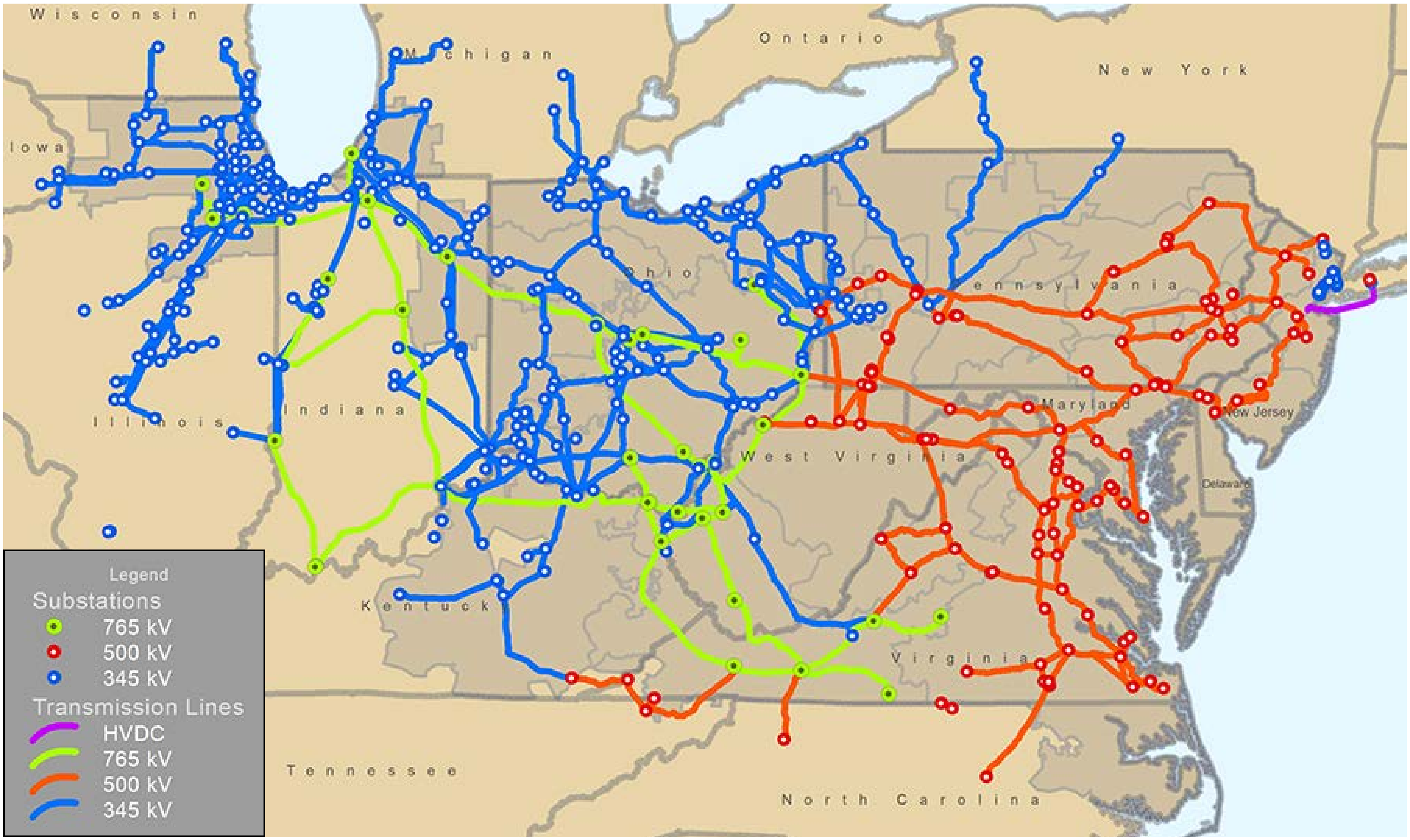


Figure 1.1: Board-Approved RTEP Projects as of Dec. 31, 2022

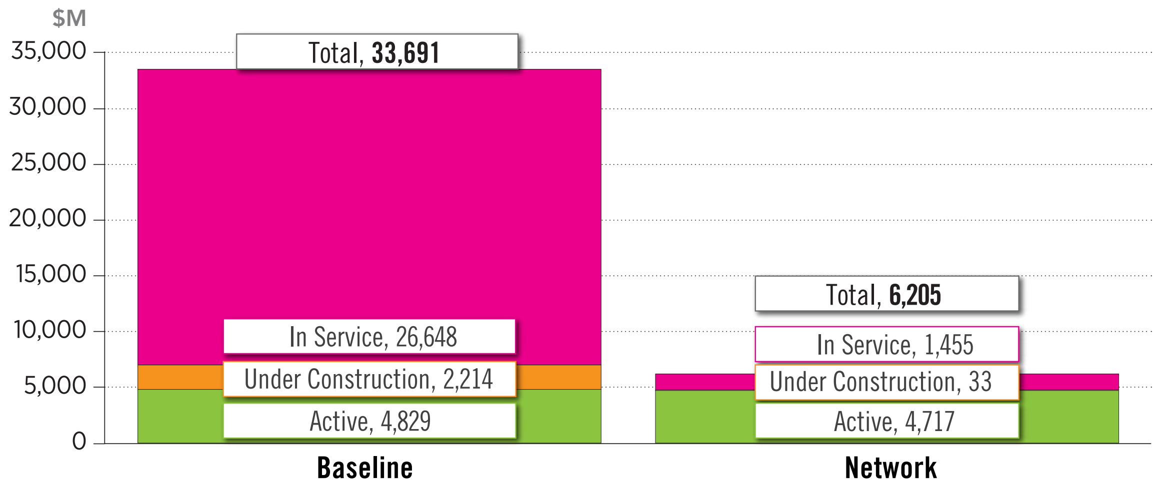


Figure 1.2: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2022)

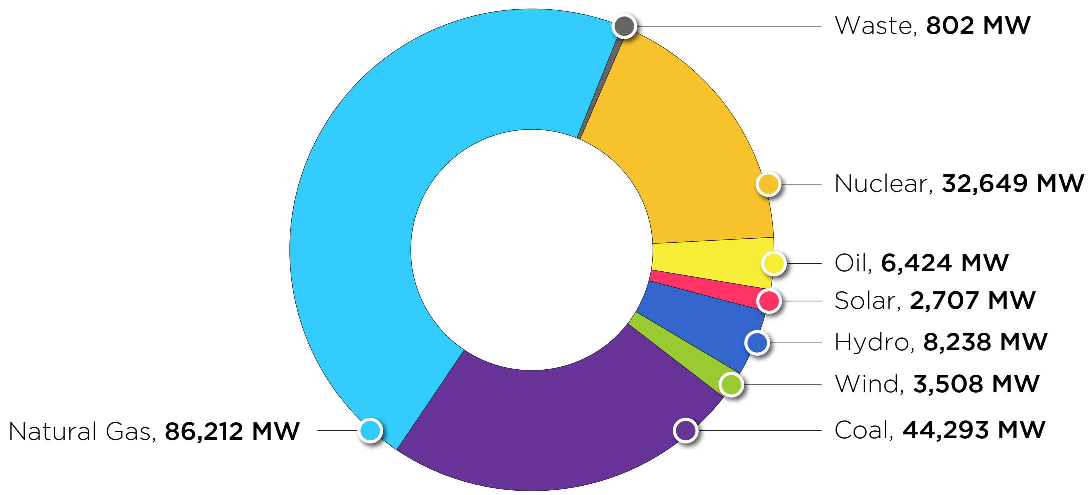
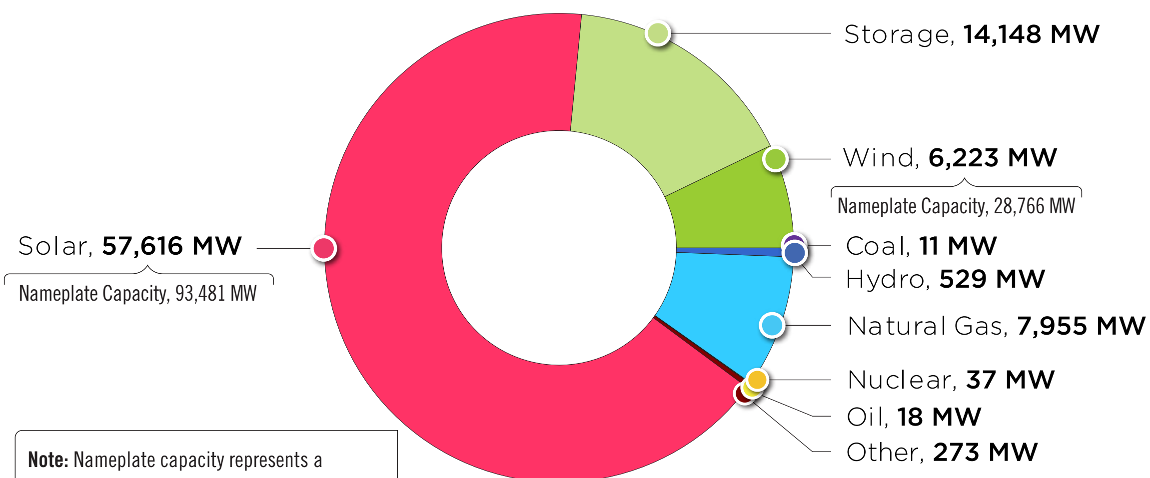


Figure 1.3: Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2022)



Note: Nameplate capacity represents a generator's rated full power output capability.

Table 1.1: Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2022)

		In Queue				Complete					
		Active		Under Construction		In Service		Withdrawn		Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	3	65.0	52	2,137.9	70	33,577.6	125	35,780.5
	Diesel	1	0.0	0	0.0	10	68.5	17	76.7	28	145.2
	Natural Gas	38	5,531.5	40	8,537.9	369	53,583.1	689	249,555.5	1,136	317,208.0
	Nuclear	0	0.0	4	81.4	43	3,902.8	24	9,038.0	71	13,022.2
	Oil	0	0.0	7	9.0	17	534.8	25	2,318.0	49	2,861.8
	Other	7	327.6	0	0.0	6	332.8	77	858.8	90	1,519.2
	Storage	646	50,118.7	27	503.9	24	9.8	303	9,507.4	1,000	60,139.7
Renewable	Biomass	0	0.0	0	0.0	9	162.8	40	896.9	49	1,059.7
	Hydro	8	549.30	3	35.0	32	1,155.90	52	2,190.9	95	3,931.0
	Methane	1	6.0	0	0.0	77	368.5	95	490.1	173	864.6
	Solar	1,856	96,772.4	340	8,875.9	252	2,913.5	1,756	37,549.5	4,204	146,111.2
	Wind	107	9,819.3	15	621.7	113	2,073.8	508	16,852.2	743	29,367.0
	Wood	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
	Grand Total	**2,664**	**163,124.8**	**439**	**18,729.8**	**1,006**	**67,298.2**	**3,660**	**363,064.6**	**7,769**	**612,217.4**

Figure 1.4: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2022)

			Capacity	Nameplate
Projects withdrawn after final agreement	203	Interconnection Service Agreements	29,663 MW	38,580 MW
	338	Wholesale Market Participation Agreements	1,385 MW	2,781 MW

This figure shows, historically, how far generation requests had proceeded in the interconnection process before they exited active participation (i.e., before they reached in-service status, began construction, were suspended or withdrew). The graphic does not include projects considered active in the queue as of Dec. 31, 2022.

Map 1.2: Deactivation Notifications Received in 2022

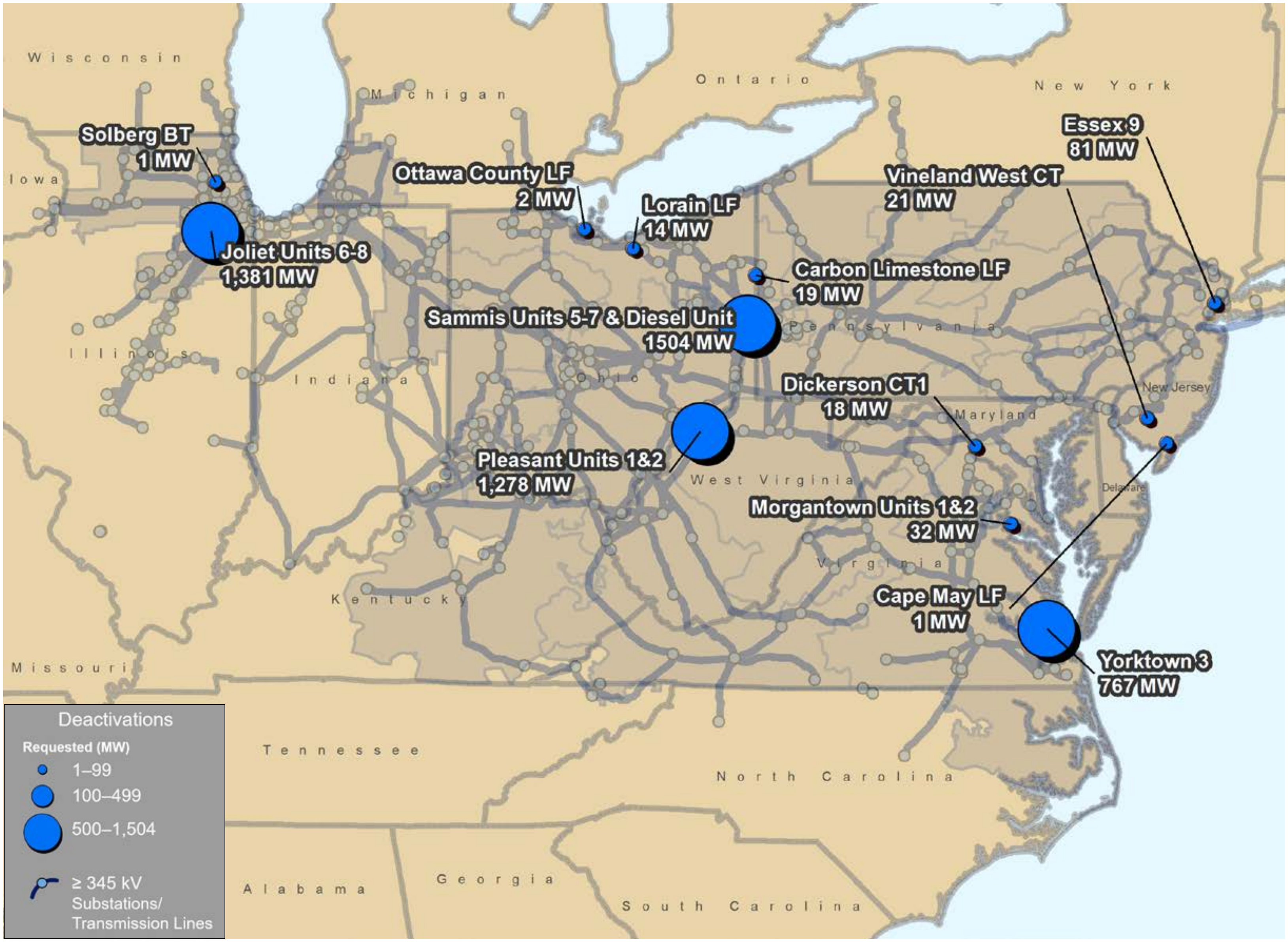


Figure 1.5: 2022 RTEP Baseline Project Drivers ($ Million)

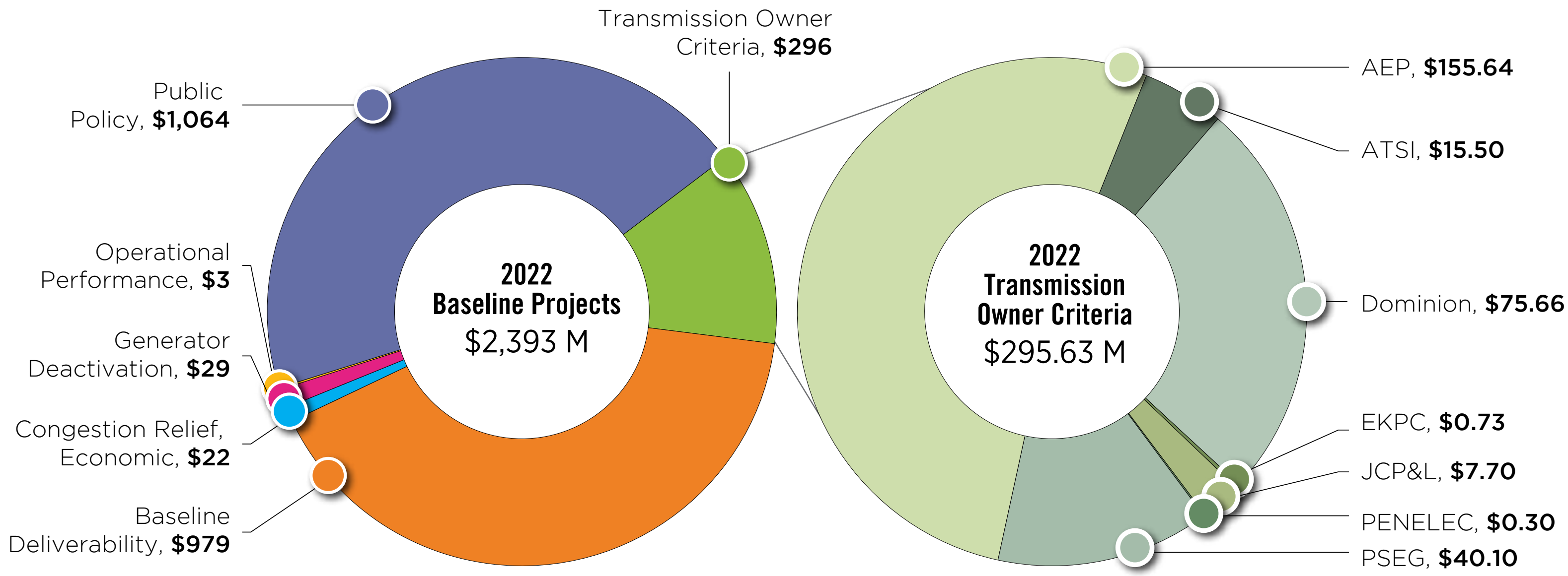


Figure 1.6: Transmission Expansion Uncertainty

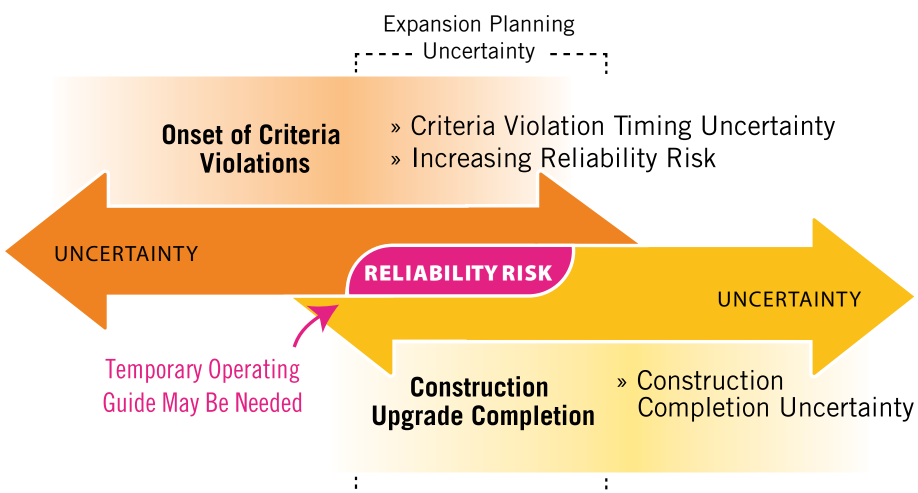


Table 1.2: PJM State RPS Targets

State RPS Targets*

☼	**NJ:** 50% by 2030**	☼	**PA:** 18% by 2021***		**OH:** 8.5% by 2026
☼	**MD:** 50% by 2030**	☼	**IL:** 50% by 2040		**MI:** 15% by 2021
☼	**DE:** 40% by 2035	☼	**VA:** 100% by 2045/2050 (IOUs)		**IN:** 10% by 2025***
☼	**DC:** 100% by 2032	☼	**NC:** 12.5% by 2021 (IOUs)		

☼ Minimum solar requirement

* Targets may change over time; these are recent representative snapshot values
** Includes an additional 2.5% of Class II resources each year
*** Includes non-renewable "alternative" energy resources

Map 1.3: PJM State RPS Targets and Goals

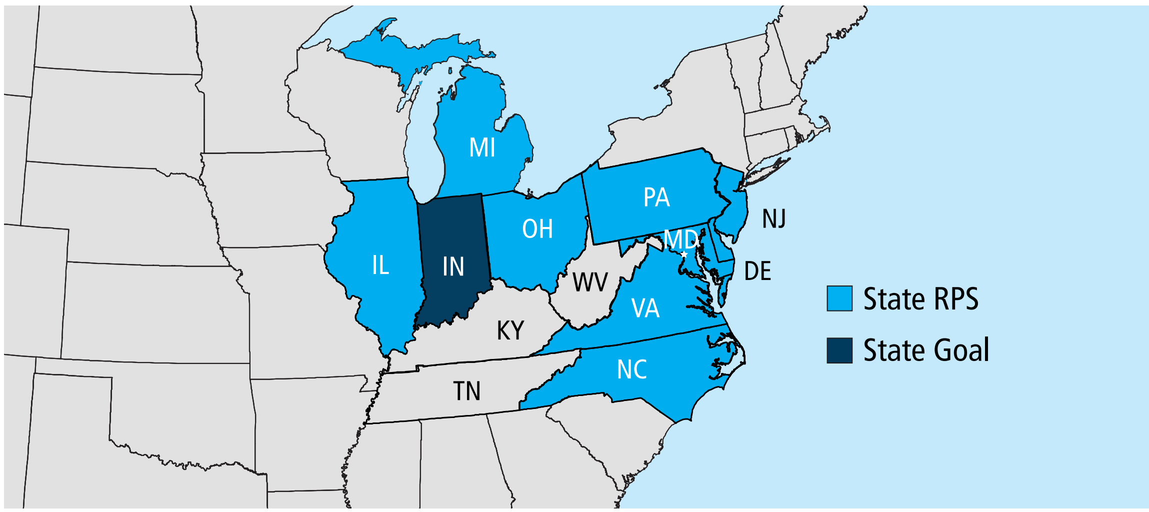


Figure 1.7: Load Forecast Model

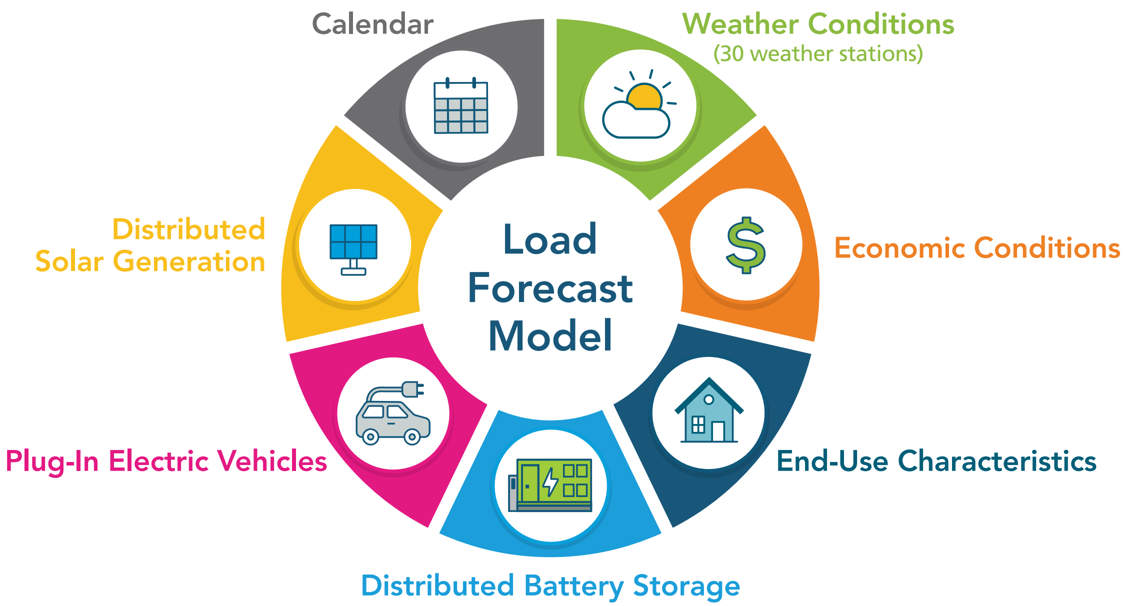


Table 1.3: 2022 Load Forecast Report

Transmission Owner	Summer Peak (MW) 2022	Summer Peak (MW) 2032	Summer Peak (MW) Growth Rate	Winter Peak (MW) 2021/22	Winter Peak (MW) 2031/32	Winter Peak (MW) Growth Rate
Atlantic City Electric	2,488	2,541	0.2%	1,610	1,710	0.6%
Baltimore Gas & Electric	6,414	6,350	-0.1%	5,780	6,131	0.6%
Delmarva Power	3,873	3,854	0.0%	3,596	3,847	0.7%
Jersey Central Power & Light	5,831	5,868	0.1%	3,700	3,939	0.6%
Metropolitan Edison (Met-Ed)	2,934	3,060	0.4%	2,605	2,633	0.1%
PECO	8,370	8,471	0.1%	6,634	6,660	0.0%
Pennsylvania Electric Company (Penelec)	2,812	2,832	0.1%	2,781	2,767	-0.1%
PPL Electric Utilities Corporation	7,024	7,237	0.3%	7,252	7,355	0.1%
Potomac Electric Power Company (Pepco)	5,902	5,766	-0.2%	5,331	5,494	0.3%
Public Service Electric & Gas Company (PSE&G)	9,543	9,857	0.3%	6,657	7,219	0.8%
Rockland Electric Company	391	388	-0.1%	227	238	0.5%
UGI Utilities	193	191	-0.1%	199	194	-0.3%
Diversity – Mid-Atlantic	-629	-875		-560	-740	
Mid-Atlantic	**55,146**	**55,540**	**0.1%**	**45,812**	**47,447**	**0.4%**
American Electric Power	22,183	22,496	0.1%	22,348	22,946	0.3%
Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)	8,675	8,762	0.1%	9,009	9,338	0.4%
American Transmission Systems, Inc. (FirstEnergy)	12,273	12,551	0.2%	10,064	10,172	0.1%
Commonwealth Edison (ComEd)	20,787	20,121	-0.3%	15,073	15,303	0.2%
AES Ohio (formerly Dayton Power & Light)	3,271	3,288	0.1%	2,940	2,965	0.1%
Duke Energy Ohio and Kentucky	5,239	5,427	0.4%	4,555	4,694	0.3%
Duquesne Light Company	2,742	2,837	0.3%	1,995	2,042	0.2%
East Kentucky Power Cooperative	2,091	2,228	0.6%	2,666	2,776	0.4%
Ohio Valley Electric Corporation	90	90	0.0%	115	115	0.0%
Diversity – Western	-1,647	-1,674		-1,532	-1,530	
Western	**75,704**	**76,126**	**0.1%**	**67,233**	**68,821**	**0.2%**
Dominion Energy Virginia and North Carolina	20,424	25,434	2.2%	20,762	26,810	2.6%
Southern	**20,424**	**25,434**	**2.2%**	**20,762**	**26,810**	**2.6%**
Diversity – Total	-4,612	-5,268		-3,797	-3,832	
PJM RTO	**148,938**	**154,381**	**0.4%**	**132,102**	**141,516**	**0.7%**

Figure 1.8: PJM 10-Year Summer Peak Load Growth Rate Comparison 2018–2022 Load Forecast Reports

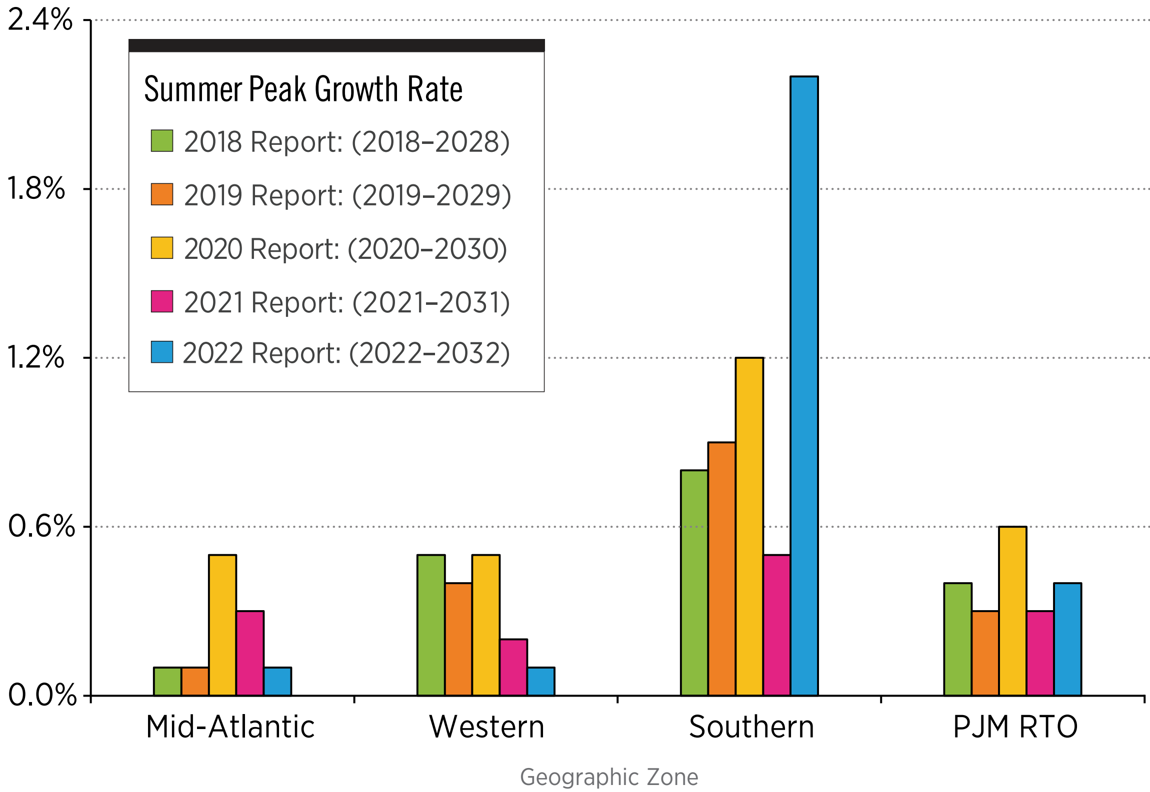


Figure 1.9: Primary Supplemental Project Drivers

Customer Service	Provide service to new and existing customers; interconnect new customer load; address distribution load growth, customer outage exposure, equipment loading, etc.
Equipment Material Condition, Performance and Risk	Address degraded equipment performance, material condition, obsolescence; end of the useful life of equipment or a facility; equipment failure; employee and public safety; environmental impact.
Operational Flexibility and Efficiency	Optimize system configuration, equipment duty cycles and restoration capability; minimize outages.
Infrastructure Resilience	Improve system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather or geomagnetic disturbances.
Other	Meet objectives not included in other definitions such as, but not limited to, technological pilots, industry recommendations, environmental and safety impacts, etc.

Map 1.4: Actual Generator Deactivations in 2022

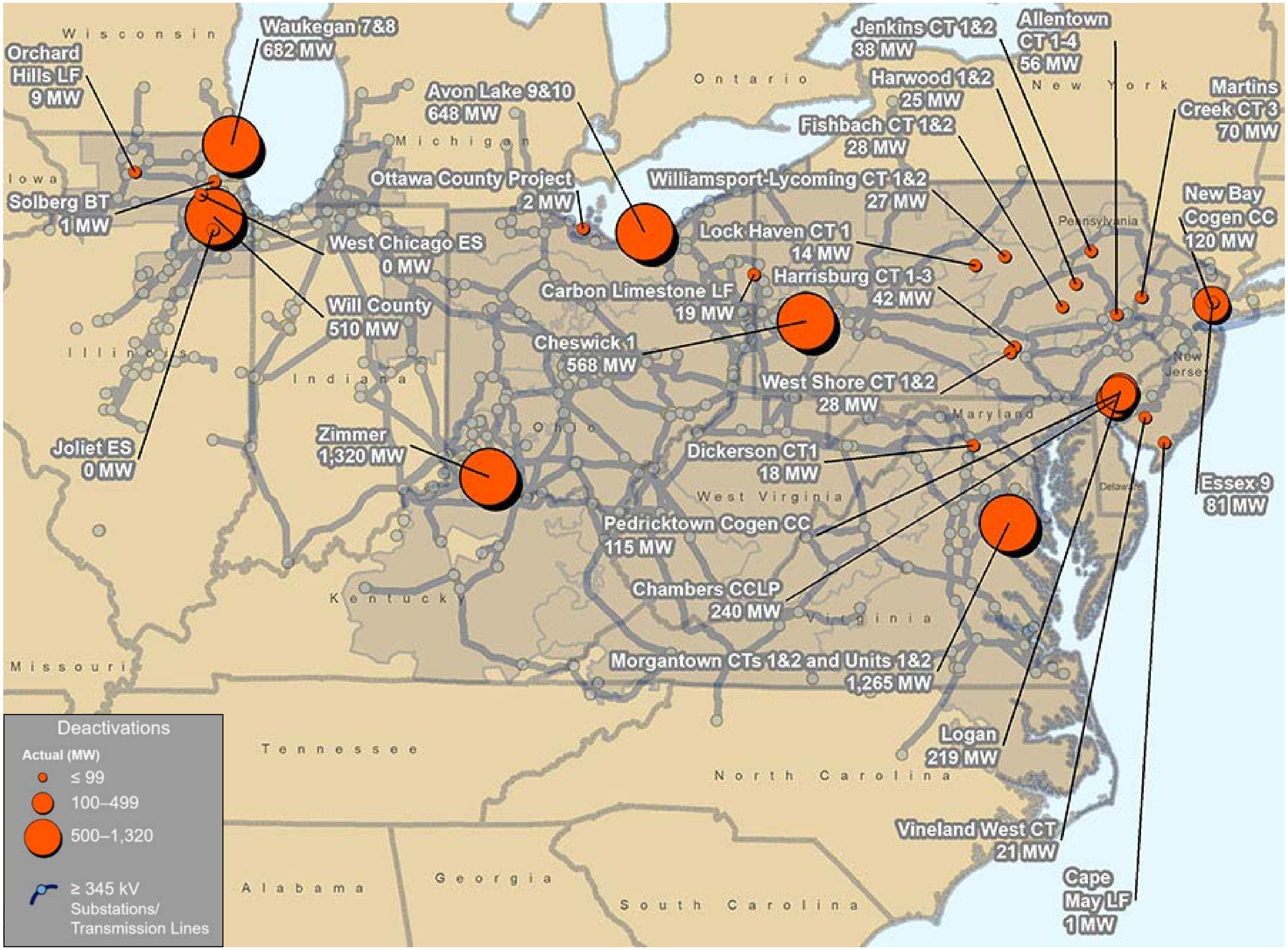


Figure 1.10: 2022/2023 Market Efficiency 24-Month Cycle

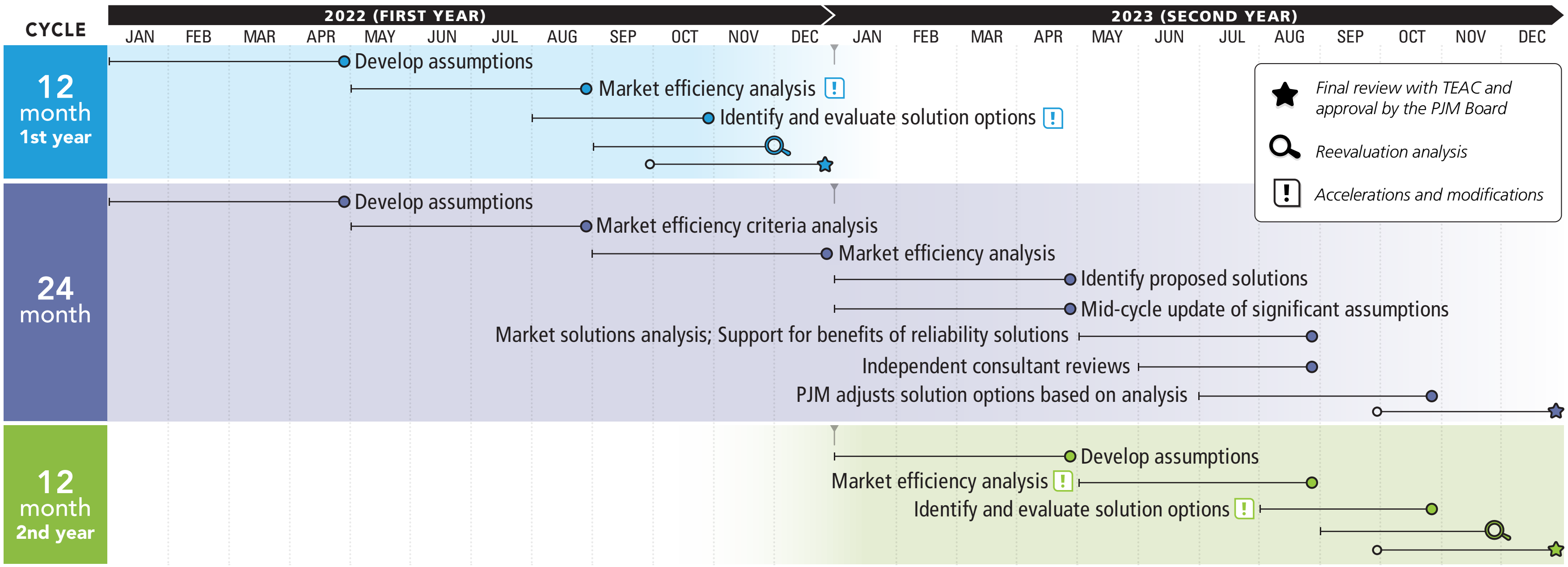


Figure 1.11: Market Efficiency Analysis Parameters

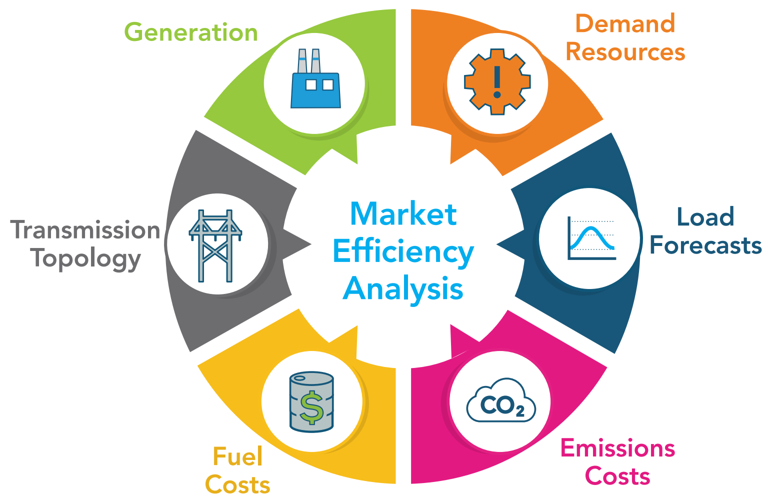
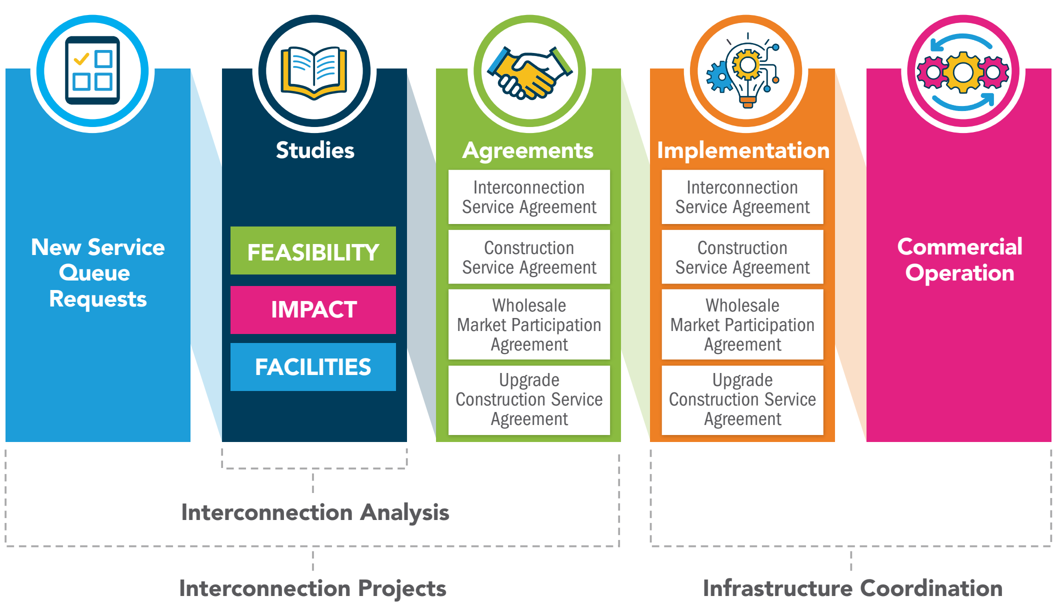


Figure 1.12: New Services Queue Process Request



Map 1.5: Feasibility and System Impact Studies Performed in 2022

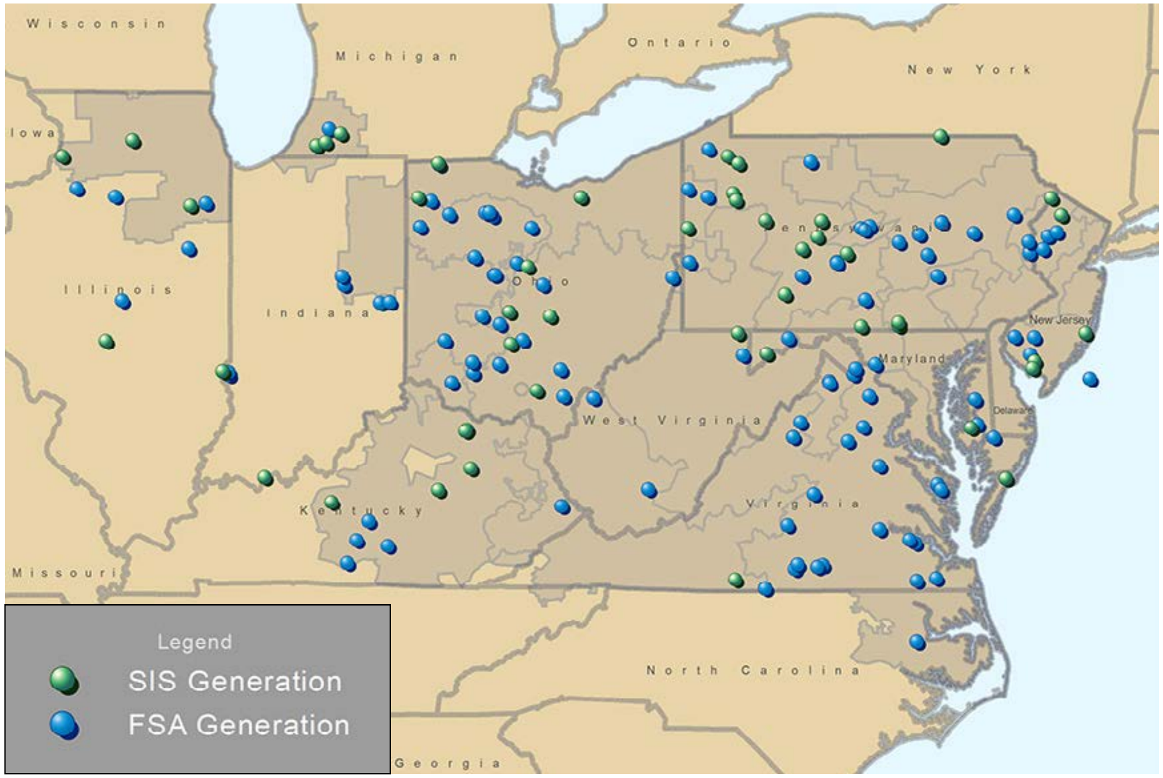


Figure 1.13: Potential Options for the New Jersey Offshore Wind Transmission Solution

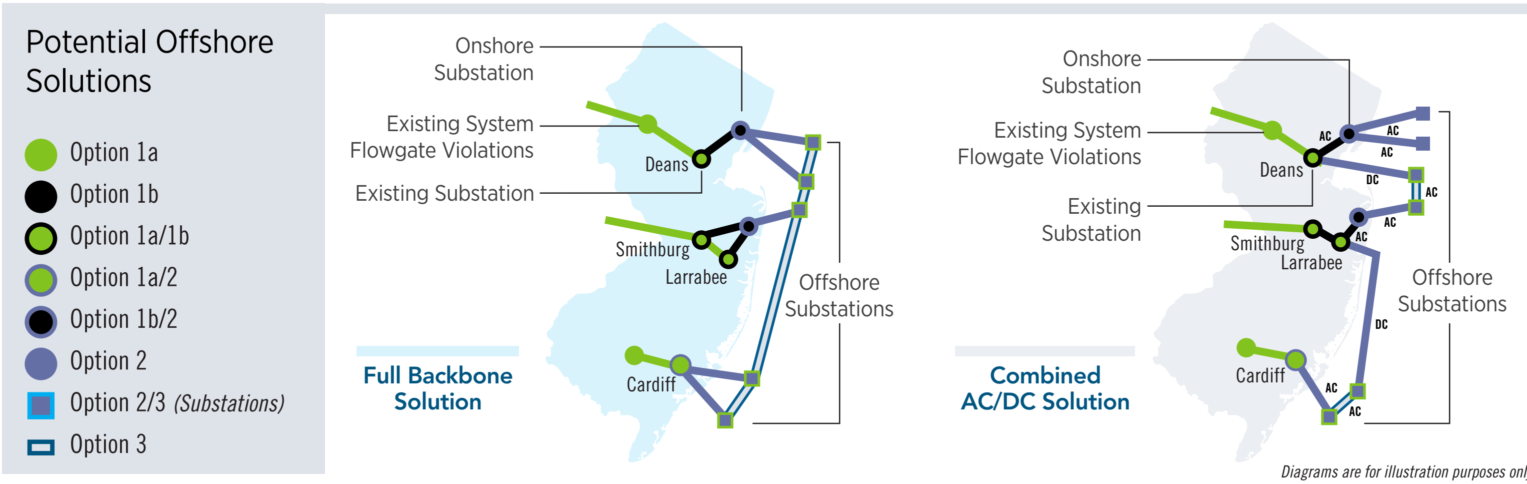
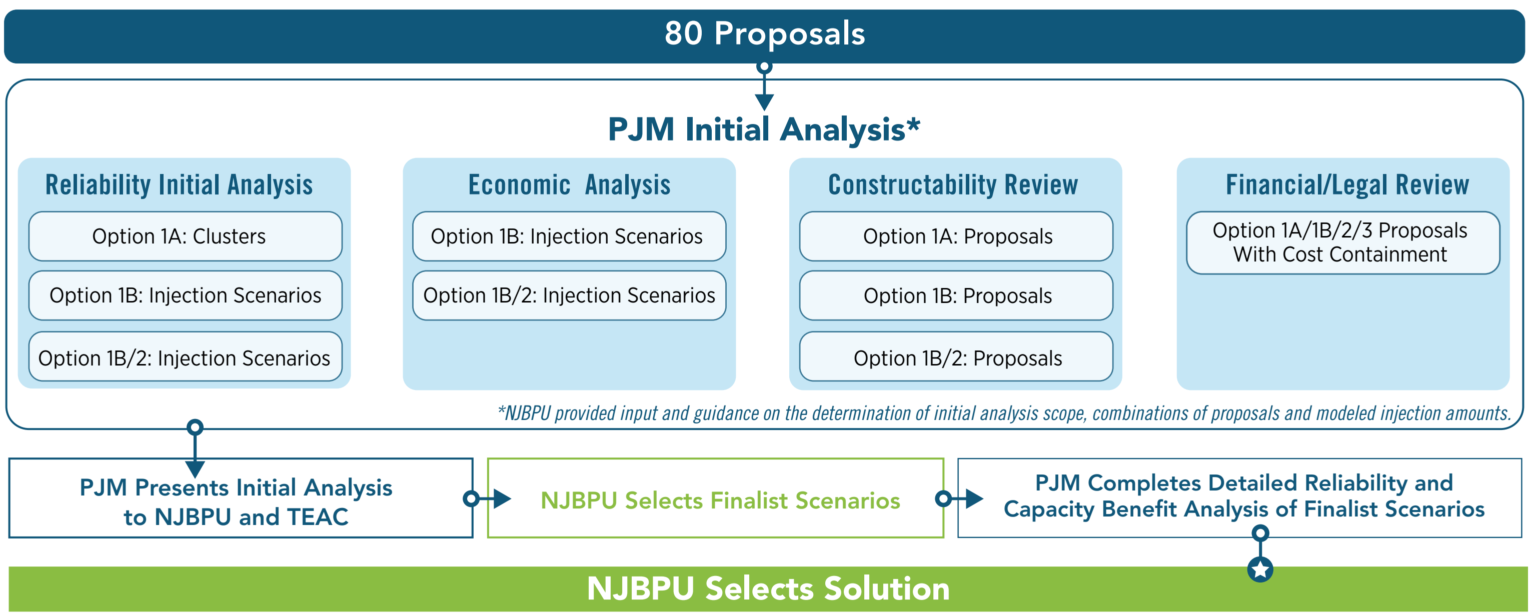


Figure 1.14: New Jersey SAA Offshore Wind Evaluation Process Overview



5.0: RTEP Project Statistics

This set of figures and tables summarizes the estimated costs for projects presented at the Transmission Expansion Advisory Committee or Subregional TEAC meetings. It is intended to provide a visual representation of and consolidate materials presented elsewhere in this report to allow stakeholders to view trends in the identification of violations over time, and by voltage class. Where historical costs are used in the comparison of a graph, the costs have been adjusted for inflation to have a common representation of 2022 dollars, as discussed below.

1. Baseline project was approved by the PJM Board.
2. Supplemental project was presented at the TEAC or Subregional TEAC meetings.
3. Costs are provided by the designated entity or transmission owners. Cost estimation methods may vary by company. Estimated costs in this document may include cost caps or cost containment, even though it is not specifically noted.
4. Cost estimates may change over time as new information is incorporated into the estimate by the project sponsor. This document reflects the current estimates that are provided to PJM.
5. Estimated project costs are adjusted by average inflation rate from 2012 to 2021 (1.88%).
6. Transmission line mileage is based on FERC Form 1 filed in 2019 or EIA-411 Schedule 6A for 2023.
7. TO peak load is the average of forecast summer peak load from 2023 to 2027.

Figure 5.1: Project Status as of Dec. 31, 2022

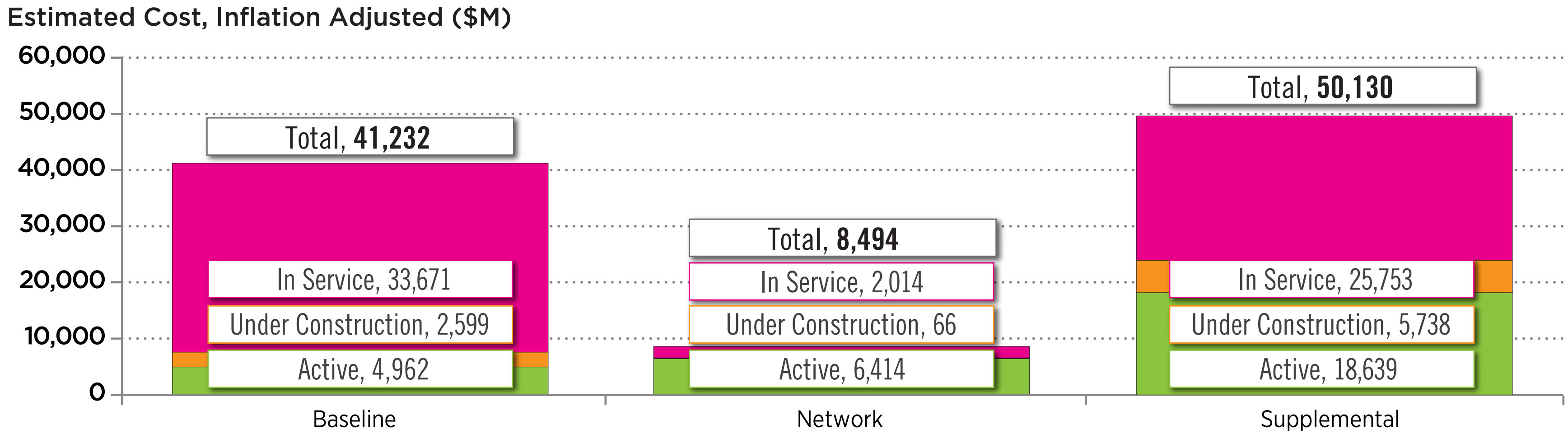


Figure 5.2: Baseline and Supplemental Projects by Year

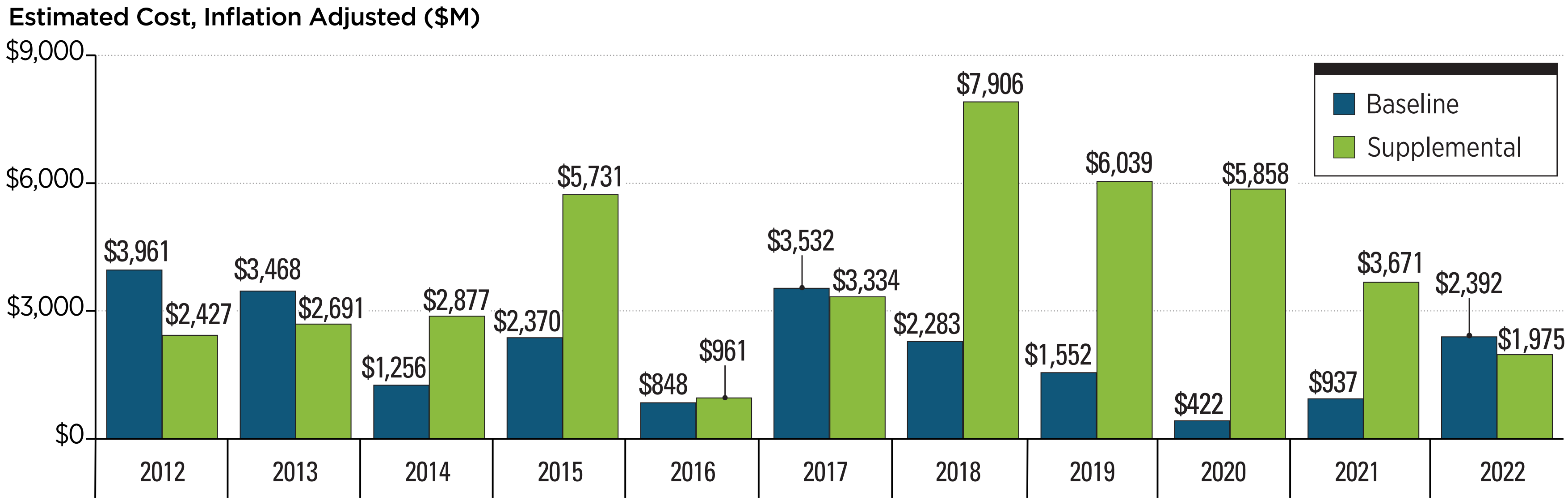


Figure 5.3: PJM Baseline Projects by Criteria

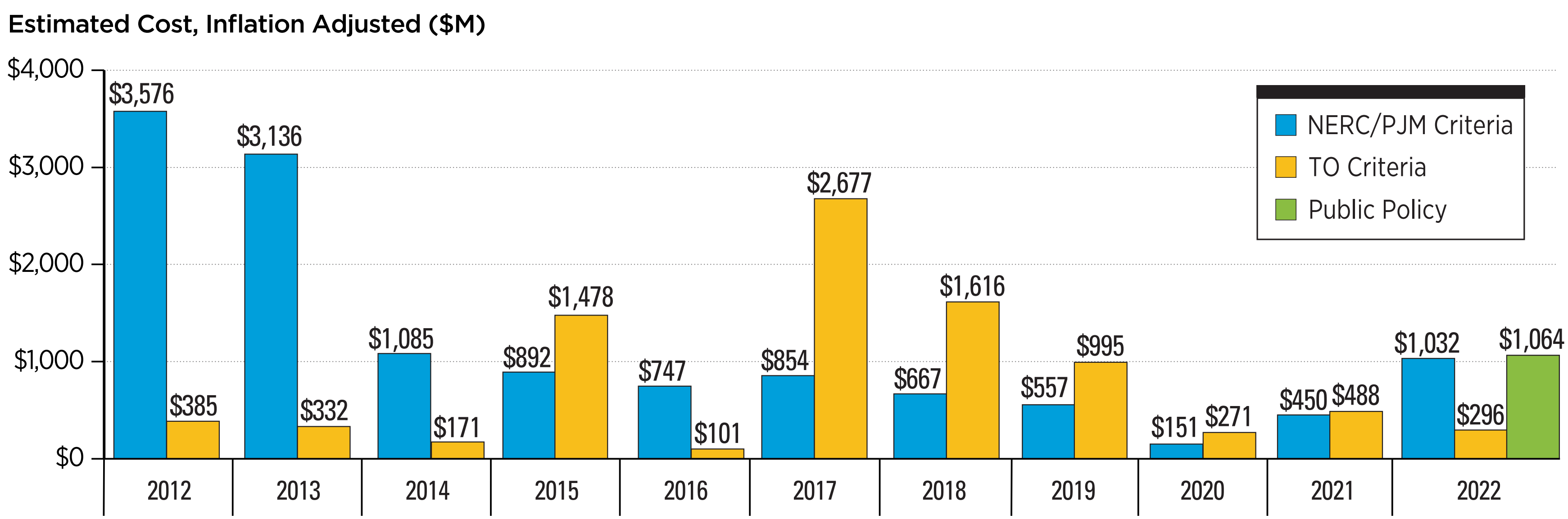


Figure 5.4: Baseline Projects by Voltage

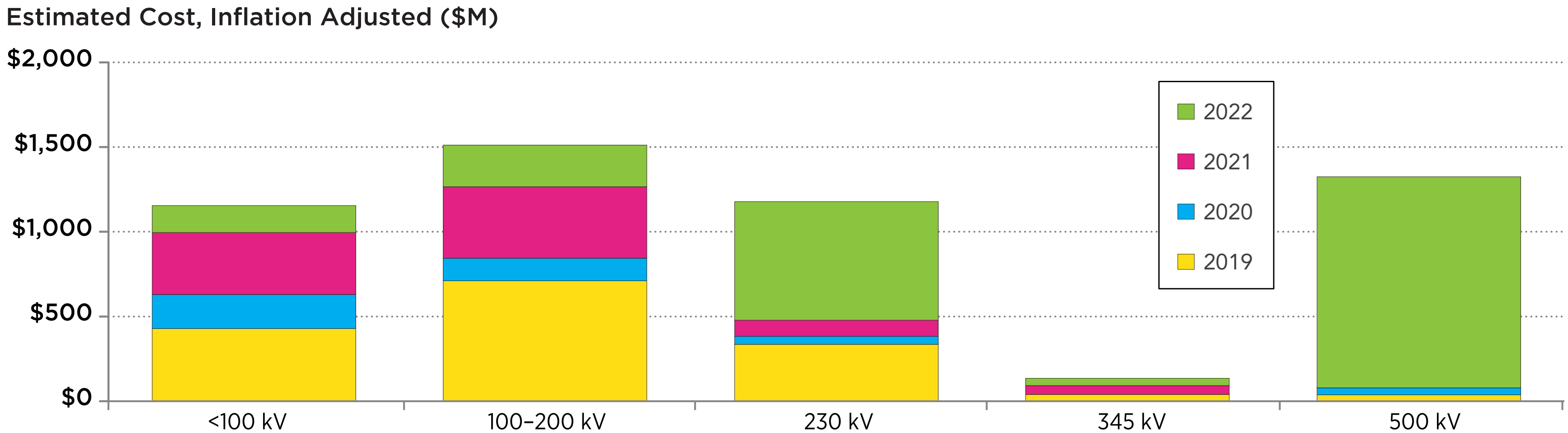


Figure 5.5: Supplemental Projects by Voltage

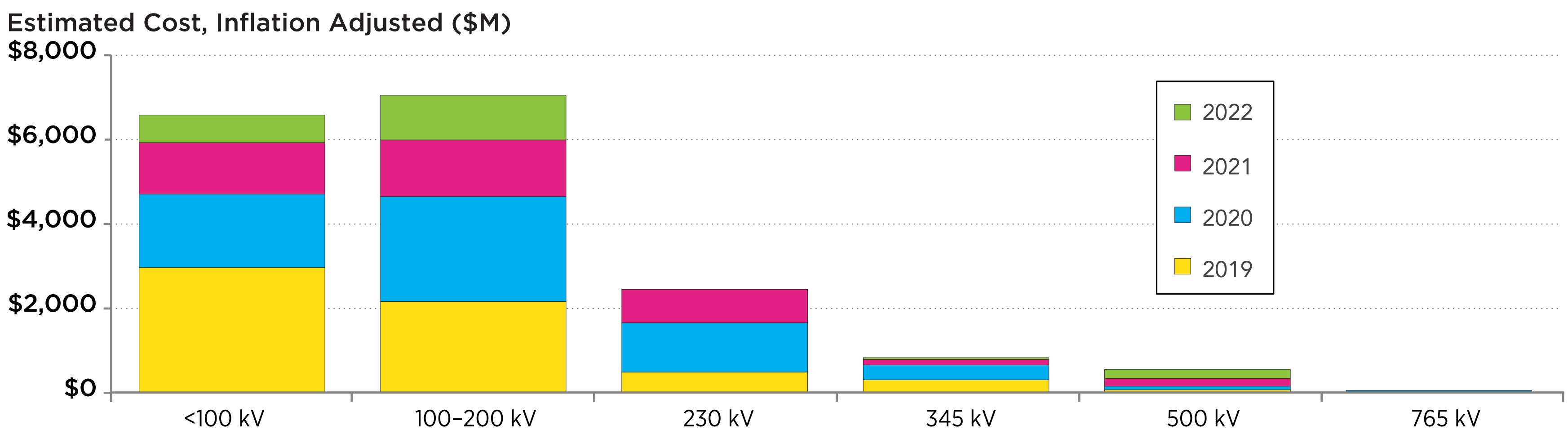


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2012

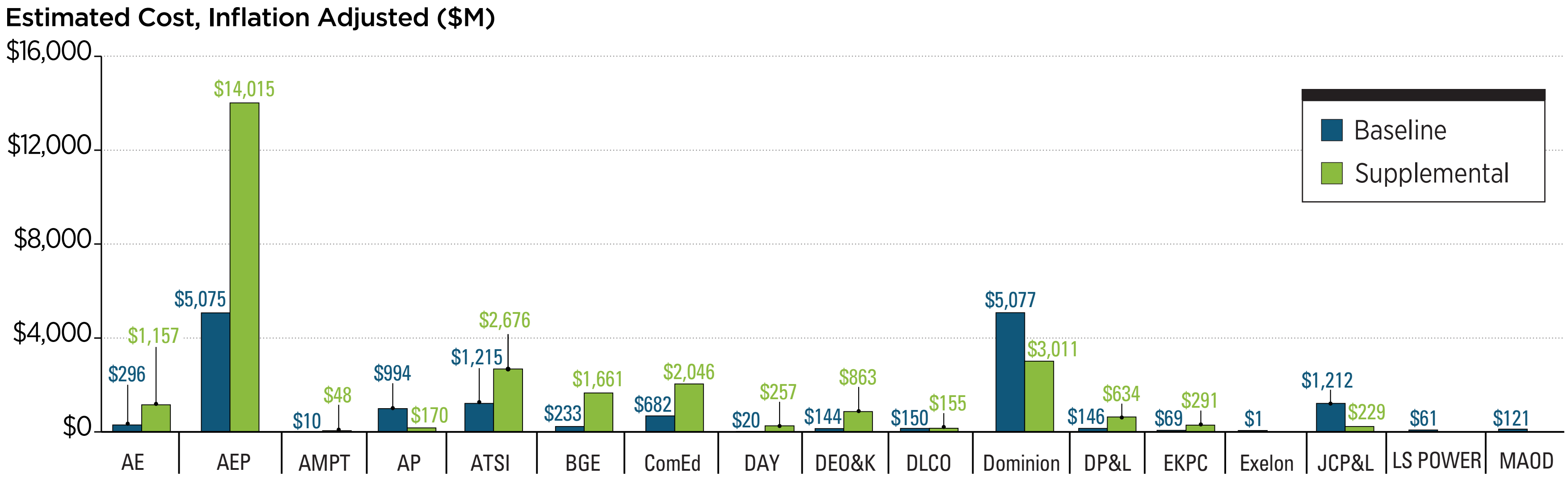


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2012 (Cont.)

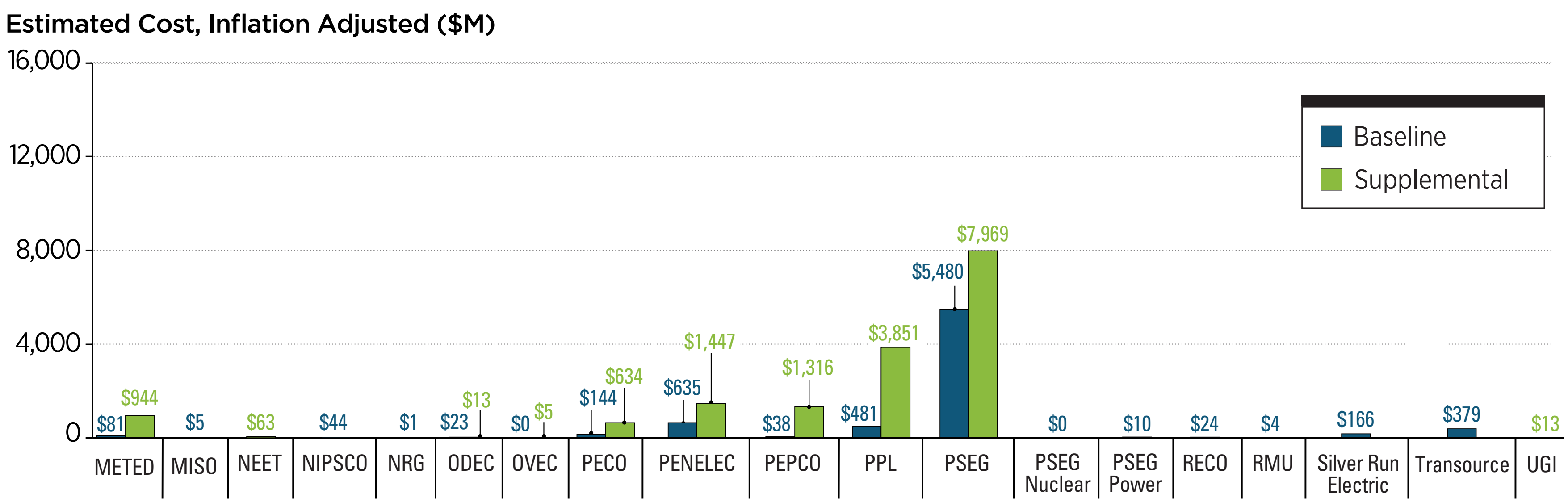


Figure 5.7: 2022 Baseline and Supplemental Projects by Designated Entity

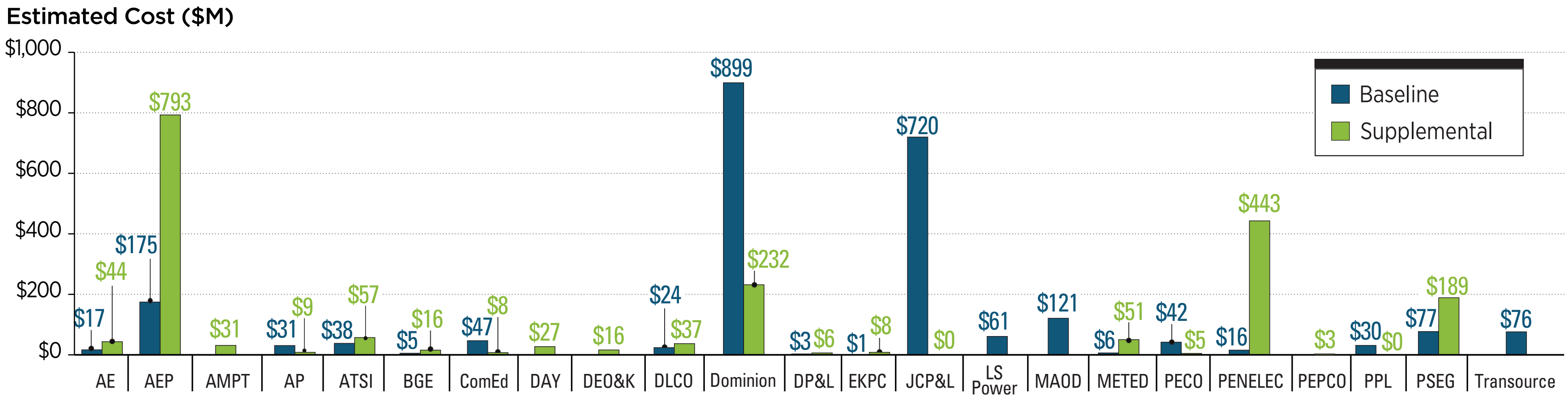


Figure 5.8: Baseline and Supplemental Projects Adjusted by Peak Load Since 2012

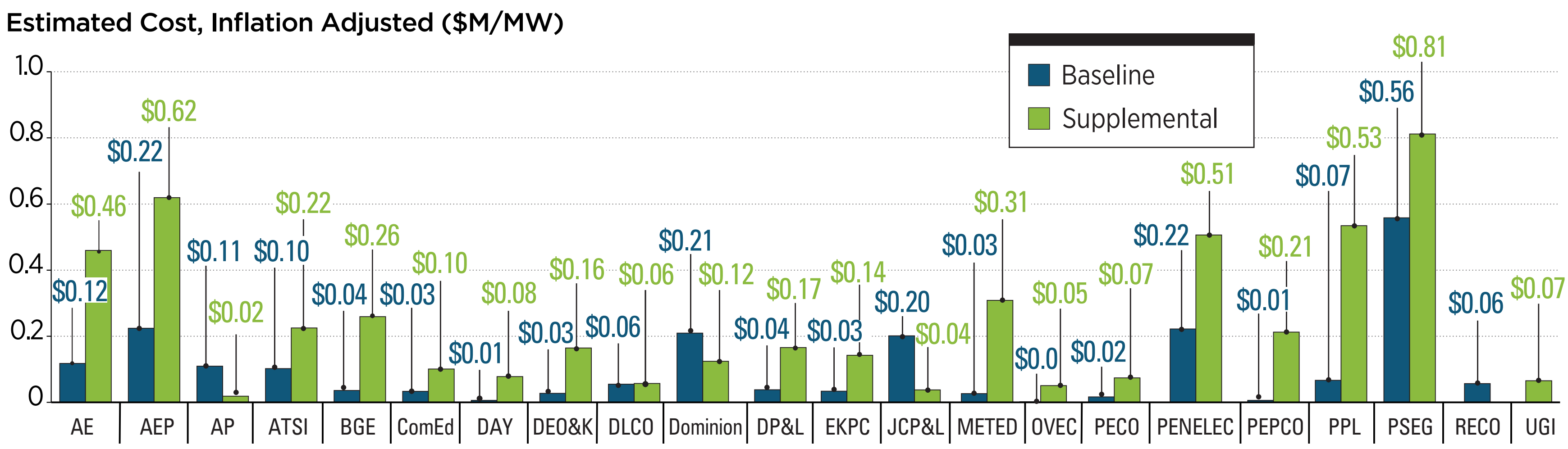


Figure 5.9: 2022 Baseline and Supplemental Projects Adjusted by Peak Load

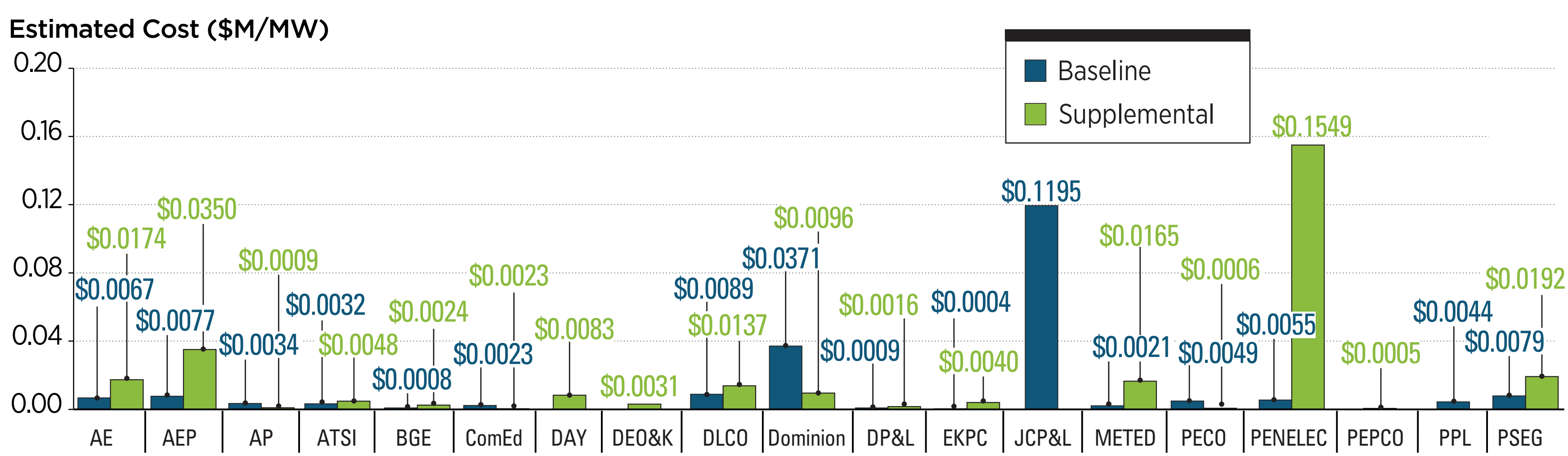


Figure 5.10: Baseline and Supplemental Projects Adjusted by Circuit Miles Since 2012

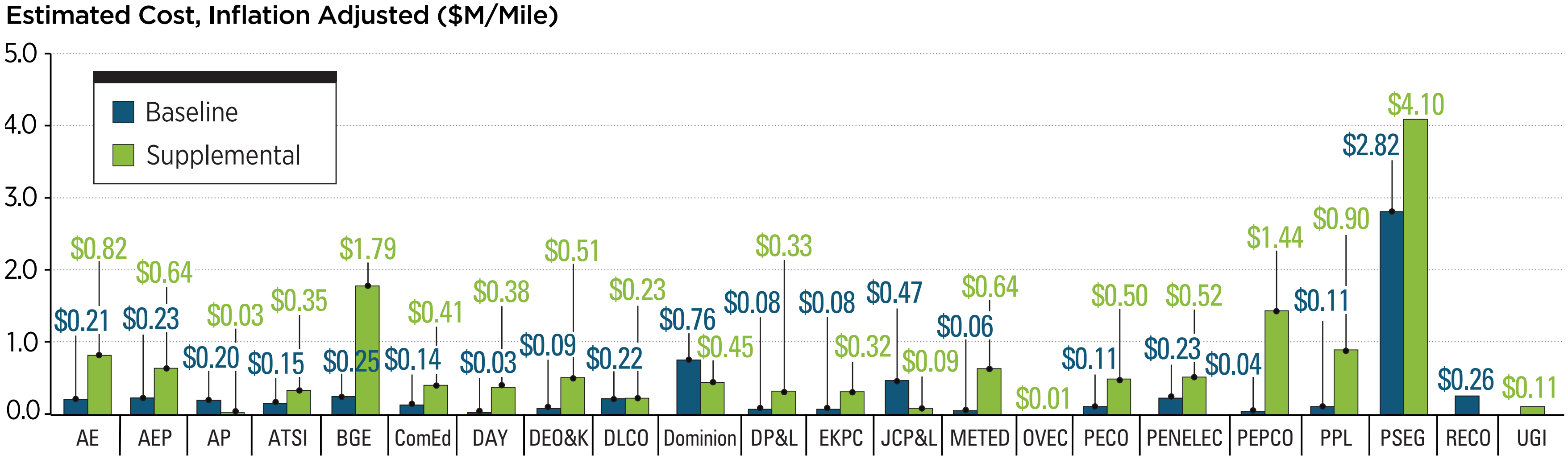


Figure 5.11: 2022 Baseline and Supplemental Projects Adjusted by Circuit Miles