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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 2024, PJM observed several ongoing trends, which are discussed throughout this report.

- **Section 1** is a high-level summary of the 2024 RTEP process, activities and milestones, and includes a look toward the future of regional transmission planning.
- **Section 2** includes an overview and detailed data from PJM's 2024 Long-Term Load Forecast Report.
- **Section 3** provides highlights of 2024 RTEP system enhancements approved by the PJM Board, including those driven by generator deactivations, and summarizes the reevaluation of previously approved projects.
- **Section 4** summarizes 2024 market efficiency process activity, including input parameters, acceleration analysis results, reevaluation of previously approved market efficiency projects and the window progress.
- **Section 5** provides an overview of PJM's interconnection process and related initiatives.
- **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.

Request access at
https://pjm.force.com/planning/s/

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**
- **Appendix 5** – RTEP Project Statistics

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KEY 2024 HIGHLIGHTS

PJM's RTEP process continues to identify transmission system additions and improvements needed to serve more than 67 million people throughout 13 states and the District of Columbia as the grid continues to undergo a historic energy transition.

PJM and its stakeholders continued to work throughout 2024 to identify challenges and craft solutions toward maintaining a reliable grid and enhancing markets.

+ PJM's RTEP process identified 63 new baseline projects in 2024 at an estimated cost of $5.9 billion to maintain fundamental grid reliability in the face of markedly changing regional power flows.
+ 201 new network transmission projects at an estimated cost of $1.7 billion are required to enable the reliable delivery of generation seeking to connect to the PJM system.

Load growth continues to increase, driven by the proliferation of data centers, electrification of buildings and vehicles, as well as manufacturing.

+ PJM now projects its RTO-wide summer normalized peak to grow 1.6% annually over the next 10 years, which is up 0.8% from its 2023 forecast.

Accelerated retirements, driven by unit age and environmental public policy, of generators that provide necessary attributes needed to maintain reliability are outpacing new, mainly inverter-based resource additions.

+ PJM received over 30 deactivation notifications totaling over 2 GW in 2024.
+ Approximately 40% of new interconnection requests to the PJM grid are solar resources.

Additional Milestones:

PJM faces an extreme and rapid tightening of supply and demand for capacity resources and needs additional resources to address near-term reliability challenges. Throughout 2024, PJM reached key process improvement milestones.

+ Interconnection reforms that encompass a "first-ready, first-served" cycle-based approach for new generators are allowing generator projects that are ready to proceed to do so while incentivizing those that are not ready to exit the interconnection process. In 2024, PJM issued 307 Phase I System Impact Studies and 206 Phase II System Impact Studies as part of its reformed interconnection process.
+ PJM's Reliability Resource Initiative (RRI) has created a reliability on-ramp to Transition Cycle 2 under PJM's interconnection process reform. RRI itself comprises a one-time procedure that will expand the eligibility criteria for Transition Cycle 2 so that additional resources may submit Generation Interconnection Requests into that transition cycle.
+ PJM has implemented Surplus Interconnection Service (SIS) to expedite the unused portion of energy delivery at a given point of interconnection by a generator that cannot or does not operate continuously, every hour of every day, year-round. The expedited SIS process will allow installation of alternate generation resources to provide energy when the original generator is not otherwise doing so.

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Section 1: 2024 Year in Review

1.0: Executive Summary

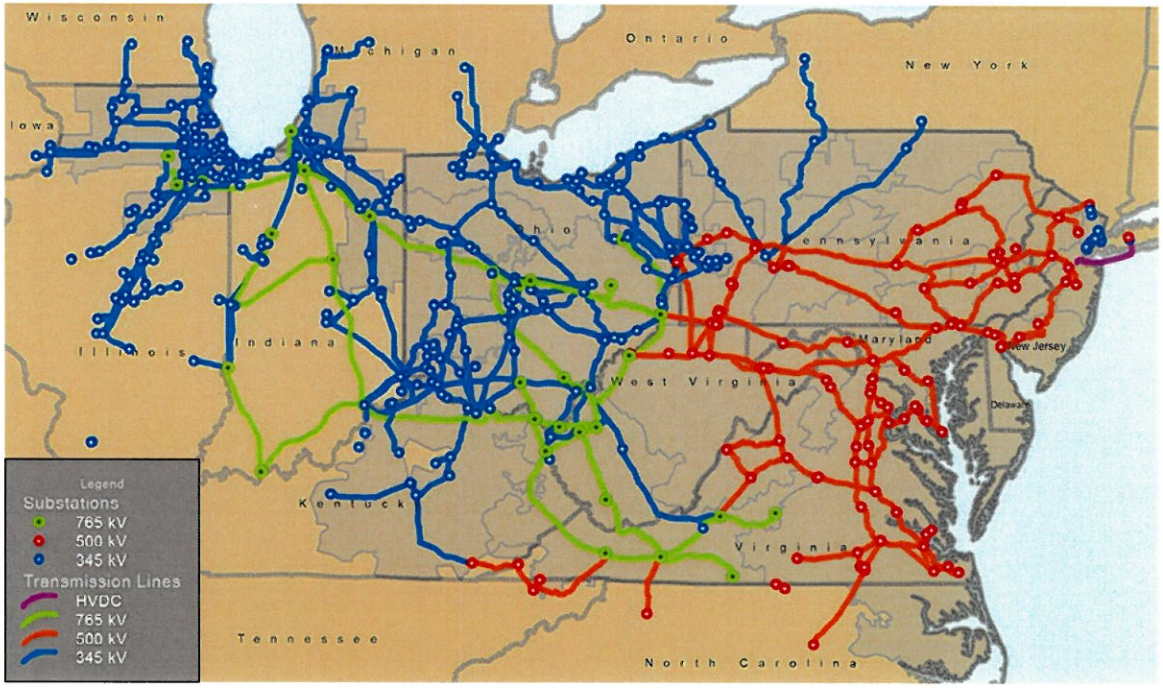
The PJM Regional Transmission Expansion Plan (RTEP) Report is published annually to convey planning study results throughout the year and to explain the rationale behind transmission system enhancement needs. The report also examines trends that continued throughout 2024 and will drive PJM's grid of 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 67 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 183,000 MW of generation capacity over 88,000 miles of transmission lines.

Map 1.1: PJM Backbone Transmission System



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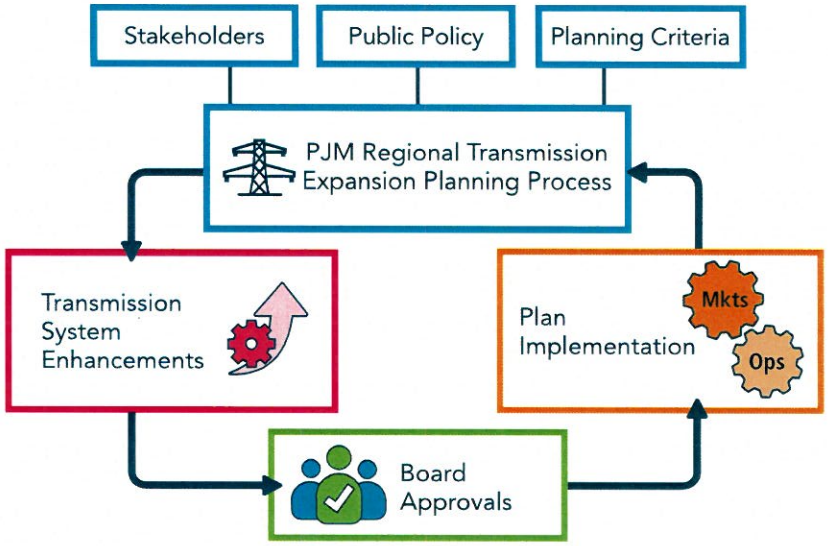
RTO Perspective

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. Forecasted system conditions can change such that justification for a project no longer exists or requires modification to capture system changes.

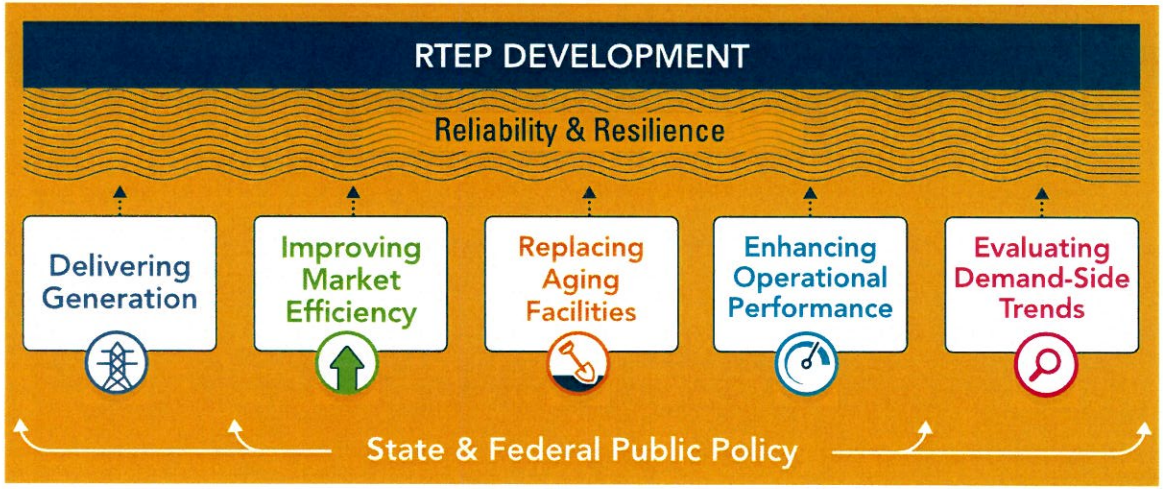
Figure 1.1: RTEP Process – RTO Perspective



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

Figure 1.2: System Enhancement Drivers



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system compliance with the thermal, reactive, stability and short-circuit requirements of the North American Electric Reliability Corporation (NERC) Standard TPL-001-5 as described in **Section 1.2**. Highlights of projects identified and approved by the PJM Board during 2024 appear in **Section 3**. Details of specific large-scale projects are presented in **Section 6**.

1.0.2 — 2024 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 2024 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 63 new baseline projects for the 2024 RTEP at an estimated $5.9 billion to ensure that fundamental system reliability criteria across the grid are met.
- The Board also approved the inclusion of 201 new network transmission projects at an estimated $1.7 billion into the RTEP.

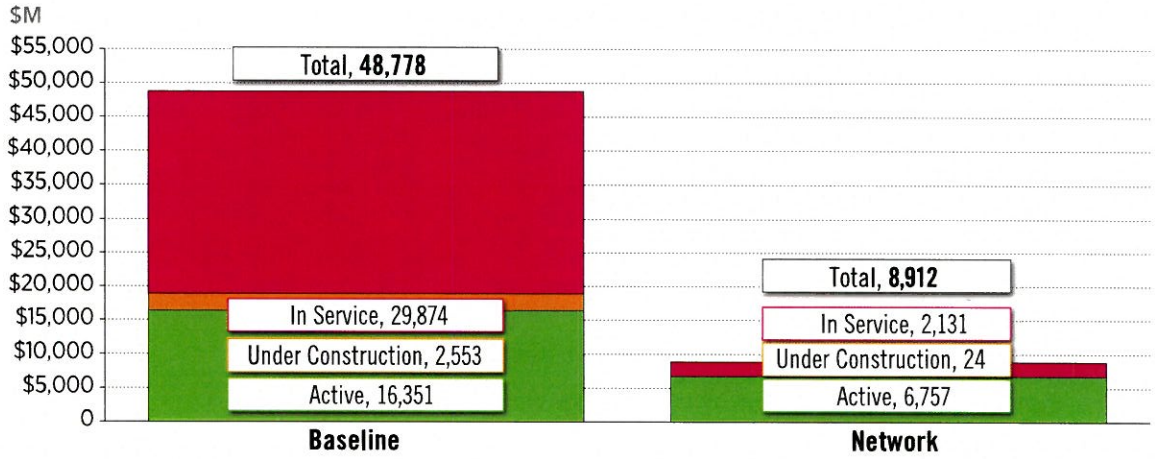
Since the RTEP process was implemented in 1997, the PJM Board has approved transmission system enhancements totaling approximately $57.8 billion. Of this, approximately $48.8 billion represents baseline projects to ensure compliance with NERC, regional and local transmission owner planning criteria and to address market efficiency congestion relief. An additional $8.9 billion represents network facilities to enable the reliable interconnection of new generation on the PJM system. A summary of projects by status as of the 2024 RTEP Board approval appears in **Figure 1.3**. Active Network Upgrades include those that are actively under study in PJM's interconnection process. Active baseline projects include those that have been recommended at the Transmission Expansion Advisory Committee or Subregional RTEP Committees, on hold and PJM Board-approved projects. 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 2024 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 valid New Service Request driving the need for the network project withdraws from the interconnection process. 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
- Infrastructure resilience

Figure 1.3: Board-Approved RTEP Projects as of Dec. 31, 2024



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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**. RTEP power flow models are updated for projects accepted by PJM following do-no-harm studies and any necessary TO follow up.

RTO Annual Load Growth

PJM's 2024 RTEP baseline power flow models for study years 2029 and 2032 were based on the 2024 PJM Long-Term Load Forecast Report, summarized in **Section 2**, and show a 10-year RTO summer, normalized peak growth rate of 1.6% per year. Average 10-year-annualized summer growth rates for individual PJM zones ranged from 0% to 5.5%. 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 2024, PJM also identified trends of large load increases in specific areas driven primarily by new data centers, as discussed in **Section 3**.

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, 2024, renewable resources continue to represent a significant portion of PJM's New Service Requests, as discussed in **Section 1.1**.

Solar-powered resources total nearly 58,474 MW of Capacity Interconnection Rights (CIRs), or around 40%, of the nearly 145,850 MW of CIRs resources in PJM's New Service Requests, as shown in **Figure 1.5**. Solar generation has overtaken natural gas in PJM's New Service Requests. Natural gas plants total nearly 9,762 MW of CIRs and constitute around 6.7% of requested generation interconnections.

With respect to resource deactivation, i.e., supply exit, more than 42,180 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 2024, PJM continued to receive deactivation notifications (30 units totaling 2,091.1 MW), the impacts of which are discussed in **Section 3.3**.

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1.1: Generation Landscape

PJM's 181,533 MW of RPM-eligible existing installed capacity reflects a fuel mix of 48.7% natural gas, 20.9% coal and 17.9% nuclear, as shown in **Figure 1.4.** Hydro, wind, solar, oil, diesel and waste fuels constitute the remaining 12.5%. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility.

Totaling nearly 96,445 MW of CIRs, renewable and hybrid fuels are changing the landscape of PJM's interconnection process. Solar energy makes up 40% of the generation in PJM's interconnection New Service Requests, shown in **Figure 1.5**. An increase in solar Generation Interconnection Requests is attributable to state policies encouraging renewable generation. **Figure 1.5** shows PJM's fuel mix based on requested CIRs for generation that was active or under construction as of Dec. 31, 2024.

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

Renewables

PJM's interconnection process continues to see renewable generation growth. As **Figure 1.5** and **Table 1.1** show, New Service Requests as of Dec. 31, 2024, for CIRs totaled around 17,890 MW of wind-powered generators that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 29,566 MW. Solar-powered generator requests for CIRs totaled 58,474 MW that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 84,128 MW.

Figure 1.4: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2024)

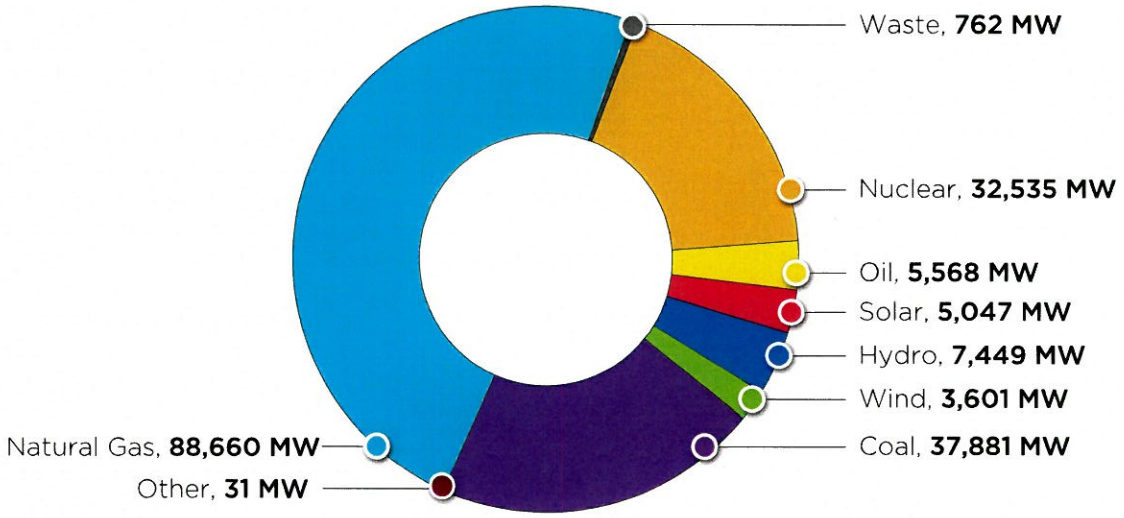
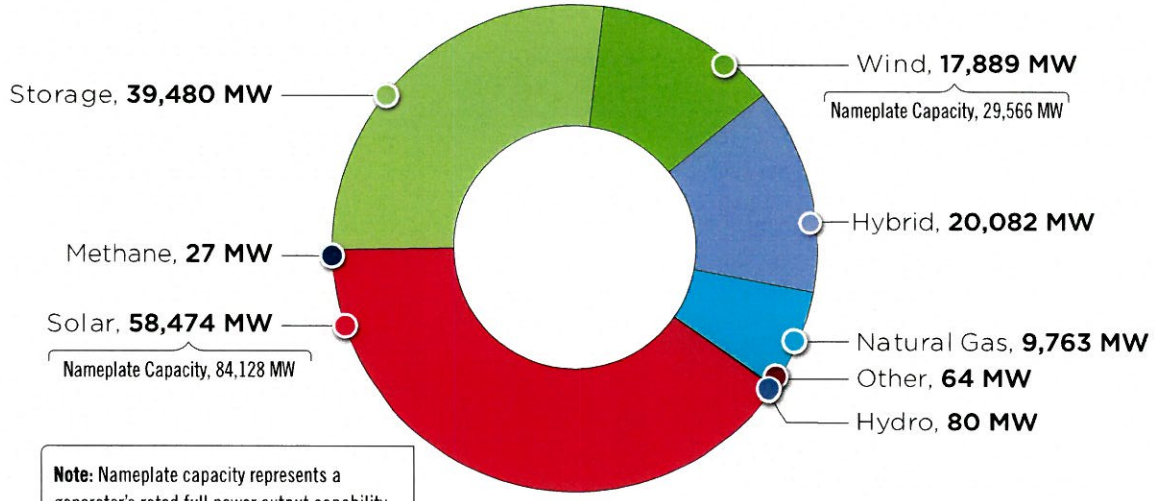


Figure 1.5: Interconnection Service Request Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2024)



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

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Table 1.1: Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2024)

		In Queue				Complete				Grand 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	53	2,140.4	70	33,577.6	123	35,718.0
	Diesel	1	0.0	0	0.0	10	68.5	16	56.5	27	125.0
	Natural Gas	30	4,808.8	1	850.0	399	57,501.9	713	253,670.7	1,143	316,831.4
	Nuclear	0	0.0	0	0.0	46	3,940.2	25	9,038.0	71	12,978.2
	Oil	0	0.0	0	0.0	24	543.8	25	2,318.0	49	2,861.8
	Other	5	52.6	1	11.0	6	330.3	14	1,112.2	26	1,506.1
	Storage	398	37,861.3	2	0.3	32	24.7	598	26,922.7	1,030	64,809.0
Renewable	Biomass	0	0.0	0	0.0	8	153.8	39	889.6	47	1,043.4
	Hydro	2	45.0	1	12.0	32	1,155.9	59	2,695.1	94	3,908.0
	Methane	2	27.1	0	0.0	76	359.3	96	496.1	174	882.5
	Solar	1,215	65,672.4	50	1,413.4	363	6,479.2	2,659	72,033.4	4,287	145,598.3
	Wind	131	16,662.6	5	236.9	120	2,167.6	552	23,977.2	808	43,044.3
	Wood	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
	Grand Total	**1,784**	**125,129.8**	**60**	**2,523.6**	**1,171**	**74,919.4**	**4,870**	**426,940.1**	**7,885**	**629,512.9**

Nameplate Capacity vs. Capacity Interconnection Rights

Nameplate capacity represents a generator's rated full power output capability. As **Figure 1.5** 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.

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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 previous interconnection study process is described in Manual 14A: New Service Request Process, and the newly reformed process is described in Manual 14H: New Service Requests Cycle Process, available on the PJM website.

1.1.1 — New Service Requests

Interconnection Activity

As part of the interconnection process, PJM performs System Impact 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.

New Service Request Activity

Through 2024, PJM markets have attracted generation proposals totaling 648,907 MW (CIRs), as shown in **Table 1.2**. Over 125,130 MW of capacity of New Service Requests were actively under study, and over 20,729 MW of capacity were under construction or suspended as of Dec. 31, 2024. PJM's 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.

Table 1.2: Interconnection Service Study Requests (Dec. 31, 2024)

	Count of Queue Number	Nameplate Capability (MW)	Capacity (MW)
Active	1,825	159,198	129,165
In Service	1,207	93,370	75,569
Under Construction	60	4,795	2,524
Withdrawn	5,529	607,357	429,307
Grand Total	**8,621**	**864,720**	**636,565**

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Figure 1.6: Interconnection Service Study Requests (Dec. 31, 2024)

			Capacity	Nameplate
Projects withdrawn after final agreement	244	Interconnection Service Agreements	33,666 MW	43,849 MW
	423	Wholesale Market Participation Agreements	1,748 MW	3,487 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, 2024.

Interconnection Progression History

PJM reviews the progression of generation interconnection to understand overall developer trends more fully and their impact on the interconnection process. **Figure 1.6** shows that for all generation (both new resources and existing plant uprates) submitted in Queue A (1999) through Dec. 31, 2024, 76,107 MW (or 15.2%) reached commercial operation. As **Figure 1.6** also shows, 33,666 MW (or 6.7%) of that account for withdrawals from the interconnection process after Interconnection Service Agreement (ISA) execution, and 1,748 MW (or 0.3%) represent withdrawals after wholesale market participant agreement (WMPA) execution, but before construction. Overall, 29.1% of projects that requested uprates to existing capacity reached commercial operation.

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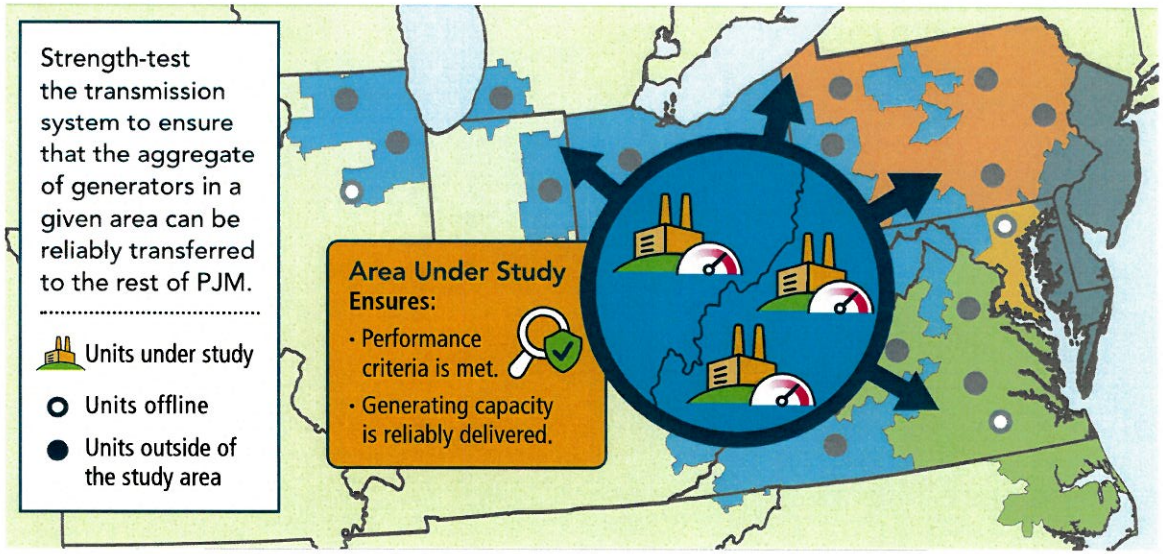
Interconnecting Reliably

A key component of PJM's RTEP process is the assessment of New Service 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 $9 billion since the inception of the RTEP process in 1997. The PJM Board approved the incorporation of 201 new network system enhancements totaling approximately $1.7 billion into the RTEP in 2024 alone.

As described in **Section 1.2**, PJM tests for compliance with all reliability criteria imposed by NERC and PJM regional reliability criteria as well as transmission owner 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 1.7.**

Figure 1.7: Generator Deliverability Concept



1.1.2 — Deactivations

PJM received 30 deactivation notifications in 2024 totaling 2,091.1 MW. **Map 1.2** shows the deactivation request locations received between Jan. 1, 2024, and Dec. 31, 2024.

Generator owners requested that the deactivation of these units takes place between June 2024 and June 2026. PJM maintains a list of formally submitted deactivation requests, which is available on the PJM website.

PJM has 60 days after the end of the quarter in which the notice was received 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.

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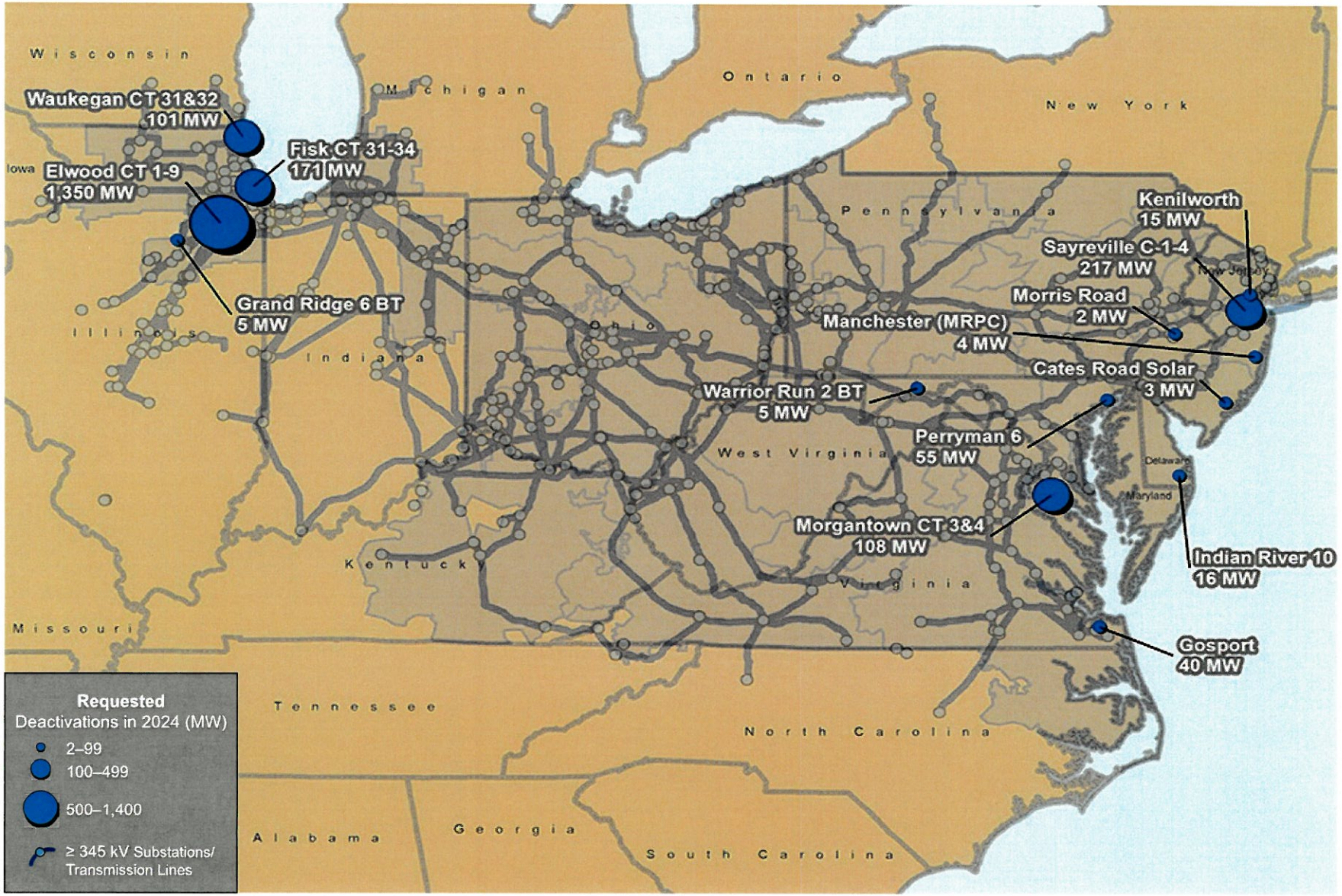
Map 1.2: Deactivation Notifications Received in 2024



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1.2: Baseline Project Drivers

1.2.1 — NERC Criteria – RTEP Perspective

PJM's RTEP process rigorously applies NERC's Planning Standard TPL-001-5 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); these facilities would 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 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 TPL-001-5. If PJM identifies violations, it develops transmission expansion solutions to resolve them as part of its RTEP window process.

NERC Reliability Standard TPL-001-5

Under NERC Reliability Standard TPL-001-5, "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 single contingencies)
- 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.

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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 events P1 and P2, requires that BES facilities be tested for the loss of a single generator, transmission line, transformer, shunt device, bus section fault or an internal breaker fault. Likewise, bus voltages that exceed limits specified by PJM Manual 3 are also identified. While the generator deliverability test is applied to events P1 and P2, the load deliverability test is only applied to event P1 (loss of a single generator, transmission line, transformer or shunt device).

PJM N-1-1 analysis, mapped to planning events P3 and P6, examines the impact of two successive N-1 events with redispatch 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 redispatch 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 P4, P5 and P7 to look at the loss of multiple facilities that share a common element or system protection arrangement. These include stuck breaker events, delayed fault clearing due to failure of non-redundant component of a protection system or double circuit tower line outages. N-2 analysis is conducted on the base case itself.

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, P2
Base case N-2 – Multiple Contingency Analysis	P4, P5, P7
N-1-1 Analysis	P3, P6
Generator Deliverability	P0, P1, P2
Common Mode Outage Procedure	P4, P5, P7
Load Deliverability	P0, P1
Light-Load Reliability Criteria	P1, P2, P4, P5, P7

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-001-5 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.

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.

One of the new aspects of NERC Reliability Standard TPL-001-5 (compared to the previous TPL-001-4) is that it calls for evaluating the failure of a non-redundant component of a protection system, which significantly increases the scope of Category P5 planning events. Non-redundant components of a protection system to consider include:

1. A single protective relay
2. A single communication system associated with protective functions
3. A single-station dc supply associated with protective functions
4. A single-control circuitry associated with protective functions

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Another new aspect of NERC Reliability Standard TPL-001-5 requires the planning coordinator or transmission planner to assess the stability impact of:

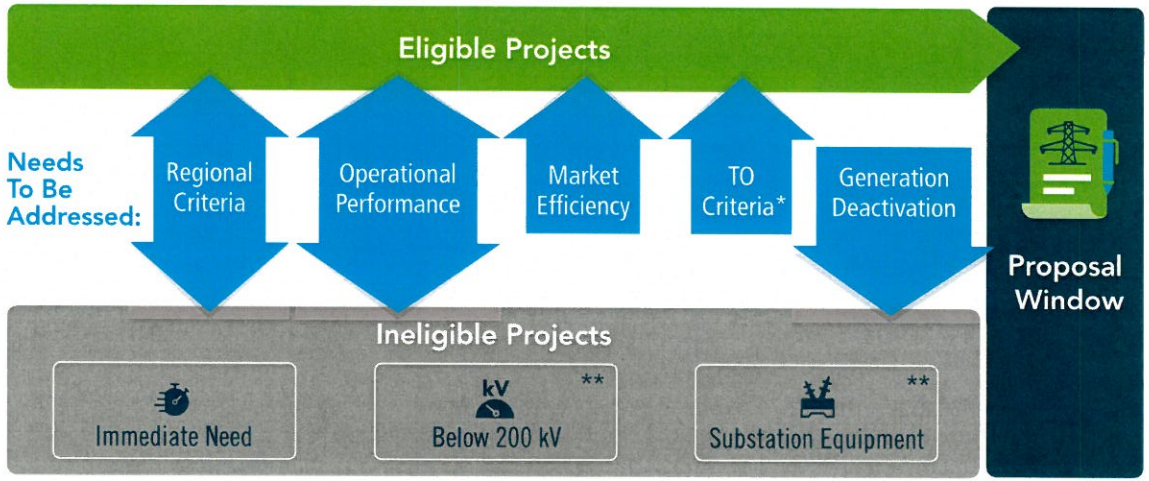
1. Selected known outage(s) of transmission facility(ies) or generation
2. The unavailability of major transmission equipment that has a lead time of one year or more in the near-term planning horizon

1.2.2 — 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 1.8.** 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).

Figure 1.8: 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.*

2024 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 2024.

1.2.3 — 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 1.8.** 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.

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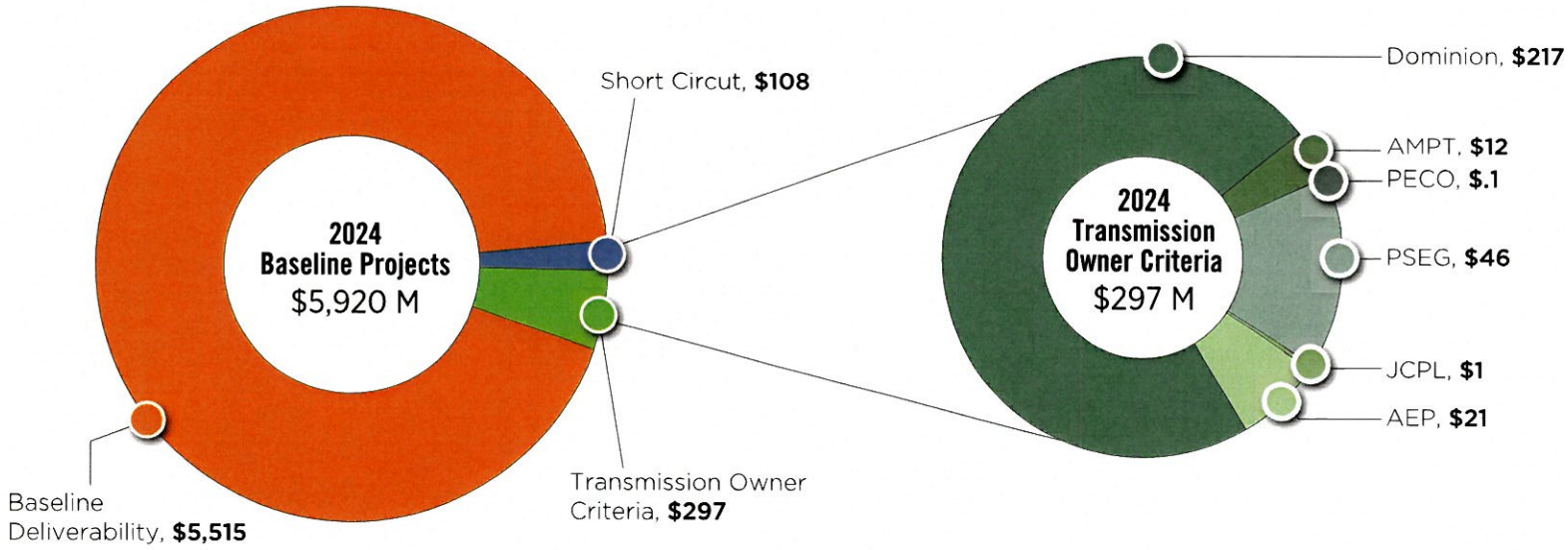
Figure 1.9: 2024 RTEP Baseline Project Drivers ($ Million)



2024 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 2024 were no different, as discussed in later sections of this report and summarized in **Figure 1.9.**

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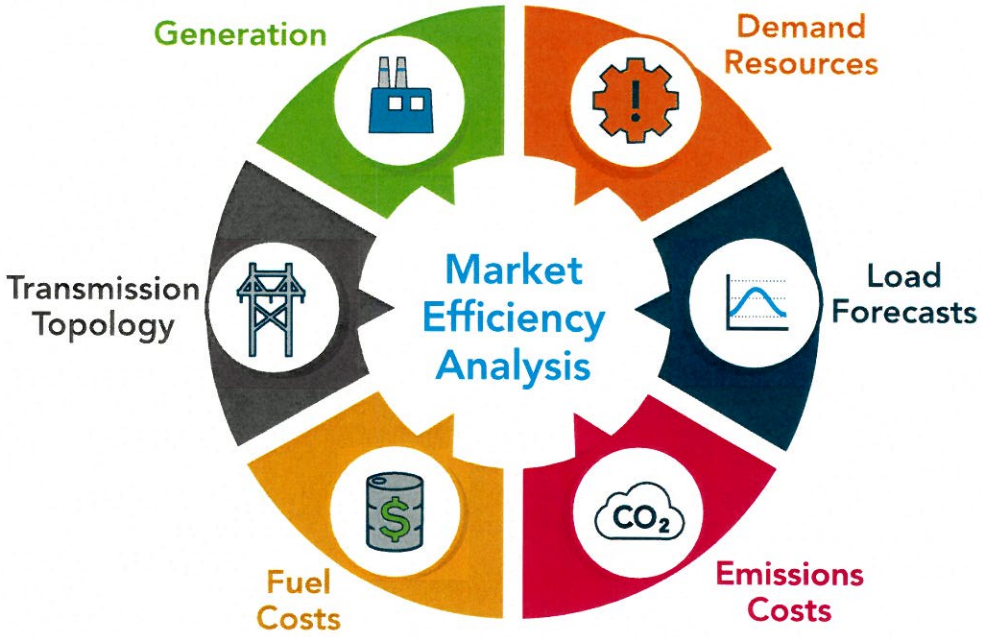
Market Efficiency

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 1.10.** 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 1.10: Market Efficiency Analysis Parameters



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1.3: Energy Transition in PJM – 2024 RTEP Process Improvement

As indicated in the Energy Transition in PJM: Flexibility for the Future report, published in June 2024, there is a potential shortfall in supply by 2030 as demand growth and thermal resource retirements accelerate and new resource development and deployment lag. It is critical to accelerate the pace of new entry to maintain reliability.

- *Load Growth* – PJM is experiencing significant load growth driven primarily from the proliferation of data centers, electrification of buildings and vehicles, and manufacturing. Looking forward, the PJM 2024 Long-Term Load Forecast Report predicts significant growth in electricity demand. As discussed in Section 2, PJM expects its summer peak to increase by 25,575 MW to 176,822 MW by 2034. This represents an annual average growth rate of 1.6% over the next 10 years.
- *Supply Exit* – Accelerated generator retirements continue, driven by unit age and environmental public policy. Notably, thermal generators – which provide dispatchable generation and other attributes needed to maintain reliability – are retiring at a rapid pace. For perspective, PJM's Energy Transition in PJM: Flexibility for the Future studies modeled, in its Policy scenario, retirements totaling 41 GW of generators fueled by coal, natural gas and oil by 2030.
- *Replacement Capacity* – New resource additions are reaching commercial operation more slowly than anticipated, a result of supply chain, permitting, financing and other issues. In short, generator retirements are outpacing new generator additions.

All generating resources do not have the same physical attributes, differing in their ability to provide installed capacity resource adequacy value and such NERC-defined essential reliability services (ERS) as ramping, voltage support, short-circuit current and frequency control, among others.

If current trends continue, PJM will continue to see more inverter-based resources (IBRs), including wind and solar generation, as shown in **Figure 1.5** earlier in **Section 1.1**, showing the breakdown of queued interconnection requests by fuel type as of Dec. 31, 2024. By contrast, fewer conventional synchronous generators, primarily driven by coal and oil deactivations, will be available to provide essential NERC-defined reliability functions. In their place, increasing amounts of variable, intermittent non-synchronous IBRs are connecting to the grid via inverters that utilize power-electronic devices to interconnect to the grid.

NOTE:
On June 24, 2024, PJM published the Energy Transition in PJM: Flexibility for the Future report.

On August 8, 2024, an addendum to the report was published.

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Resource Adequacy

Growing levels of intermittent and limited-duration IBRs, such as wind, solar and battery storage, do not replace conventional large-scale generation installations megawatt for megawatt. Rather, they require multiple megawatts to replace one megawatt of dispatchable generation due to their limited availability in certain hours of the day and seasons of the year. Many megawatts from a range of generation technologies, available at different times, are required to replace a megawatt of thermal generating capacity.

Essential Reliability Services

As PJM and other RTOs have identified, IBRs currently do not supply the full range of reliability attributes (inertia, voltage control, stability, ramping and short-circuit current) that conventional, directly synchronized generators provide. Planners and operators must consider these factors as older conventional generators – coal-fired ones in particular – continue to retire. Maintaining an adequate level of generation resources with the right operational and physical characteristics is essential for PJM's ability to serve consumer demand through the energy transition. The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. Today, thermal resources supply essential reliability services. Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability.

RTEP Process Changes To Enhance Reliability

To mitigate the risk of resource adequacy capacity shortage and ERS decline, PJM's Board of Managers has recently directed a number of planning process initiatives intended to enable capacity interconnection more expeditiously:

1. Interconnection Process Reform
2. Reliability Resource Initiative (RRI)
3. Surplus Interconnection Service (SIS)
4. Capacity Interconnection Rights (CIR) Transfer Reforms

These initiatives are part of a broader set of actions, described in **Section 1.3**, that PJM has undertaken to ensure that reliability remains paramount throughout its energy transition.

NOTE:

Generator attributes and essential reliability services are described in detail in the following reports:

- Energy Transition in PJM: Frameworks for Analysis, Dec. 15, 2021.
- Reliability in PJM: Today and Tomorrow, March 11, 2021.

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1.3.1 — Forecasting Increasing Demand for Electricity

Load forecasting fundamentally drives how PJM plans and operates the bulk electric system and related markets. The growth in electricity demand, or load, is now primarily being driven by the development of energy-intensive data centers and the electrification of vehicles and building heating systems as shown in **Figure 1.11**.

Beginning in 2023, PJM began to identify trends encompassing large load increases in specific areas, driven primarily by the construction of new data centers, and these were incorporated in PJM's 2024 RTEP cycle analyses for five-year (2029) and eight-year (2032) study year models. The large load increases are driving heavier, increased regional transfers and consequent need for significant system reinforcement, as discussed further in **Section 3**. PJM's load forecasting process incorporates methods by which it solicits and applies large load adjustments by transmission zone.

Electrification itself is the process of converting conventional end-use load that uses fossil fuels (e.g., gas stoves and oil-burning furnaces) to use electricity instead, as well as the increased use of electric vehicles (EVs). This is having a significant impact on the magnitude of the load forecast and load shape. Notably, additional electric heating will narrow the gap between summer and winter peaks.

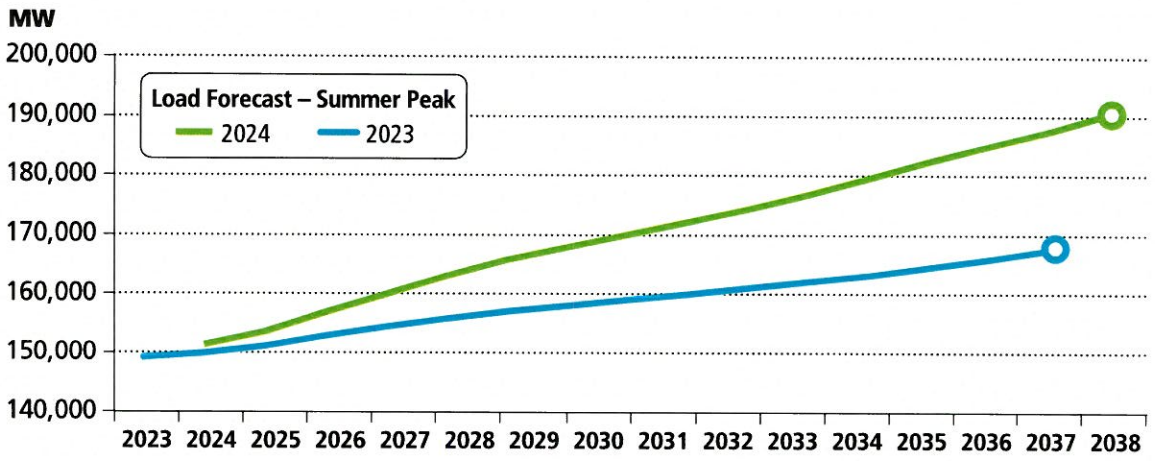
Looking Ahead

As part of compliance with FERC Order 1920, PJM will be extending its planning horizon from 15 to 20 years. The 20-year annualized growth rate in PJM's 2025 Long-Term Load Forecast for the summer peak is 2%, compared with the 2024 Long-Term Load Forecast, which saw a comparable growth rate of 1.6% through 2039. Similarly, PJM's winter peak growth rate is now up to 2.4%, compared with 1.8% for the previous 15-year forecast.

According to the forecast released in January 2025, PJM expects its summer peak to climb about 70,000 MW, to 220,000 MW, over the next 15 years. For perspective, the record summer peak for the PJM footprint occurred in 2006 at 165,563 MW.

While winter peaks will remain slightly lower, the 2025 Long-Term Load Forecast shows winter closing the gap in peak electricity use, estimated at 210,000 MW by 2039. PJM's record-high winter peak occurred on the morning of Jan. 22, 2025, when PJM served an estimated load of approximately 145,000 MW.

Figure 1.11: Impact of Electrification and Data Center Load on Forecasts



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2024 MILESTONE: Increasing Demand for Electricity

Load Large Forecast Adjustment Process

Electric distribution companies (EDCs) are encouraged to provide PJM with information about large changes that may not be captured in the forecast process. This enables PJM to review requests to determine if the request is significant and remove the risk of double counting based on trends that may already be captured in the economic forecast and/or may need to be removed from historical data.

Beginning in 2024, PJM now formally requests information from EDCs on potential load adjustments. In September of each year, PJM receives and begins to evaluate that information. Results are presented to the Load Analysis Subcommittee (LAS) in October.

PJM planners continue to evaluate and present preliminary accepted adjustments to the LAS. The final accepted adjustments are posted as part of the official PJM Long-Term Load Forecast in January.

Notably, load adjustment requests for data centers, manufacturing and voltage optimization programs (which conserve energy) have been identified in several PJM TO zones, some of which are impacted by multiple entities' requests for adjustment. The Dominion TO zone, for example, includes requests from Old Dominion Electric Cooperative (ODEC), Northern Virginia Electric Cooperative (NOVEC) and Dominion Energy.

In light of this, PJM planners have created a standardized template for the yearly requests PJM receives from EDCs for large load adjustments to help with the anticipated broadening in large load trends, such as data centers. That template and additional process information can be found on PJM's LAS web page.

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2024 MILESTONE: Increasing Demand for Electricity

Electrification Impacts From Specific Public Policy

Starting with the 2024 Long-Term Load Forecast process, PJM has initiated discussions with states and cities to provide public policy impacts to electrification. To that end, PJM now incorporates these impacts in its residential and commercial sector load forecast models, including the impact of New Jersey Executive Order 316 with respect to water heaters and heat pumps.

2024 MILESTONE: Increasing Demand for Electricity

EVs and Winter Weather Variables

PJM implemented the following improvements to its load forecasting methodology to enhance forecasting accuracy:

1. PJM incorporated vendor-supplied, TO zone-based forecasts for light-, medium- and heavy-duty electric vehicle classes over the recently implemented LTRTP 20-year forecast horizon.
2. PJM added an "HD3" variable to its forecasting process to capture temperature impacts from extreme winter weather more accurately. This change was implemented as an outgrowth of reviewing PJM Winter Storm Elliott operations in which PJM experienced "under-fit" in some TO zones.

Increasing the accuracy of load forecasts increases the accuracy of capacity markets and power flow modeling upon which RTEP process reliability studies are conducted.

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1.3.2 — Interconnection Process Reform

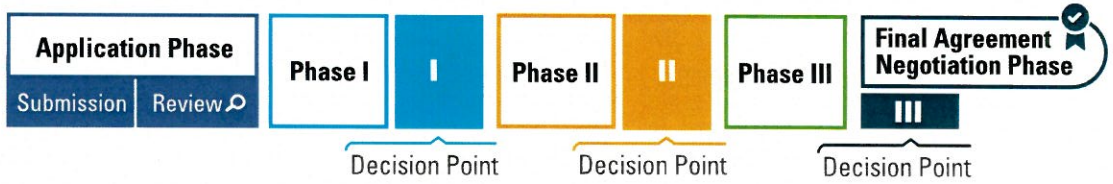
PJM's interconnection process reform continued in 2024, yielding results described in **Section 5.3**. PJM conducted interconnection requests for projects that were not eligible under the Expedited Process under a new cluster study approach. Transition Cycle 1 and Transition Cycle 2, which began in June 2024, included a Decision Point after each of three study phases.

New Generation Interconnection Requests now proceed under PJM's reformed interconnection process that includes three study phases and three decision points before interconnection agreements are executed, as shown in **Figure 1.12**.

New Service Request Study Phases

Phase I of each study cycle includes peak analysis and light load generator deliverability power flow analysis, and TO Interconnection Facilities desk-side estimates. Phase II includes completion of short circuit analysis, stability analysis, voltage analysis, Facilities Study, Affected System Operator's Affected System Study where necessary (i.e., MISO, NYISO, Duke, LGEE and/or TVA), and any additional special studies specific to merchant transmission requests or storage requests. During Phase III, PJM conducts power flow retool load flow, short circuit and stability studies based on decisions made by developers at Decision Point II and coordinates required studies with Affected System Operators.

Figure 1.12: Reformed Interconnection Process



New Service Request Decision Points

At Decision Point I, the developers must provide the following in order to stay in the Transition Cycle, among other items as described in PJM Manual 14H:

- Second readiness deposit
- Demonstration of Site Control as a way of showing readiness
- Valid corresponding interconnection request with any required adjacent control areas
- Evidence of air and water permits

At Decision Point II, developers must submit the following, among other items as described in PJM Manual 14H:

- Third readiness deposit
- Evidence of executed Affected System Study Agreement

At Decision Point III, developers must submit the following:

- Sufficient security to cover Network Upgrade costs
- Evidence of 100% Site Control
- Evidence of fuel delivery agreement or water agreement (if necessary) and control of right-of-way for fuel and water interconnections
- Evidence of any necessary local, county and state site permits
- A signed memorandum of understanding (MOU) for acquisition of major equipment

NOTE:
A full description of the New Service Requests Cycle Process can be found in PJM Manual 14H.

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Implementing Innovative Tools

As part of a comprehensive modernization effort, PJM continues to enhance its suite of innovative interconnection tools: Queue Scope, QueueDestination, NextGen, DocuTrack and InfraTrack. Together, they provide streamlined, transparent and efficient processing at each interconnection request stage: from initial exploration through construction and commercial operation.

1. *Queue Scope* is an interconnection screening tool that empowers project developers to evaluate potential points of interconnection (POI) even before formally entering the PJM interconnection process. By leveraging the most up-to-date system data, Queue Scope allows developers to assess grid impacts, estimate facility loading and analyze megawatt injection or withdrawal scenarios. This user-friendly tool provides a platform for developers to receive preliminary system loading conditions, enabling informed decision-making early in the process and reducing business decision uncertainty.

2. *QueueDestination* complements Queue Scope by addressing the technical coordination of the interconnection process for projects accepted into a Cycle. It automates critical tasks, such as model creation, technical study management, result consolidation, cost allocation and report generation. By streamlining collaboration with TOs and facilitating cost estimates, QueueDestination ensures timely and accurate technical evaluations, establishing a solid foundation for each project Cycle. Results from QueueDestination are provided to developers at the conclusion of each Cycle phase, enabling them to review overloaded facilities and estimated reinforcement costs.

3. *NextGen* is a generation lifecycle management tool that is being implemented in two phases over the next three years. The first phase of the tool was launched in March 2025. NextGen is designed to replace elements of Queue Point in order to provide a "one-stop shop" for Generation Interconnection Requests, Transmission Interconnection Requests and Long-Term Firm Transmission Service Requests. The tool provides developers with more visibility on project studies, status and requirements. This improvement will increase the efficiency of the study process by automating manual tasks, interconnection process cycle management, task management and integration with other critical PJM tools.

4. *DocuTrack* is a document management system that streamlines PJM workflow that encompasses drafting, negotiating, finalizing and executing Interconnection Service Agreements. DocuTrack has been a valuable aid given the volume of agreements that PJM's planning engineers and legal staff must process and track.

2024 MILESTONE: Enabling PJM's Energy Transition

InfraTrack Project Management Tool

The fifth tool in the suite, InfraTrack, was launched in November 2024. It focuses on efficiently managing projects after interconnection agreement execution. Designed as an internal project management tool, InfraTrack supports PJM engineers who oversee generation interconnection projects that are under agreement. The tool helps maintain project files, document meeting minutes and action items; track agreement milestones; and maintain project completion evidence. InfraTrack ensures clear roles and responsibilities within PJM, highlights priorities at each phase of construction, and enables the team to focus efforts to bring needed generation online as efficiently as possible.

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1.3.3 — Reliability Resource Initiative

PJM's Reliability Resource Initiative (RRI) creates a reliability on-ramp to Transition Cycle 2 under PJM's interconnection process reform discussed in **Section 5.1**. The RRI is a one-time procedure that expands the eligibility criteria for Transition Cycle 2 so that additional resources may submit Generation Interconnection Requests into the cycle.

The RRI is intended – along with recent reforms to the capacity market, Surplus Interconnection Service and Capacity Interconnection Rights transfer provisions – to address serious resource adequacy concerns discussed earlier:

- Load growth
- Accelerated generator retirements
- Slow pace of new generator additions
- The scope of intermittent and limited-duration resources in the interconnection queue

The multiyear, multi-phase energy transition study PJM published, Energy Transition in PJM: Resource Retirements, Replacements & Risks, examines these trends that pose increasing reliability risks through 2030.

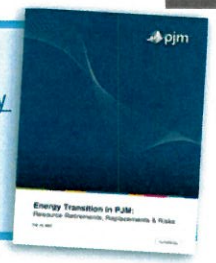
Recent Capacity Markets Point to Growing Supply and Demand Mismatch

Recent PJM capacity auctions are already revealing a growing mismatch between electricity supply and demand. The capacity auction for the 2025/2026 Delivery Year held in July 2024 yielded results that showed almost all available capacity participating in the auction clearing. That auction revealed that only 514 MW of annual Unforced Capacity was offered above the PJM region's reliability requirement. Moreover, the auction for the 2025/2026 Delivery Year resulted in much higher prices than the last several prior capacity auctions.

Load Growth Trends

The 10-year annualized growth rate in PJM's 2024 Long-Term Load Forecast for the summer peak is 1.6%. This amounts to an increase of over 25,000 MW by 2034. PJM's 2025 Long-Term Load Forecast Report, released in January 2025, notes a projected average RTO summer peak load growth rate of 3.1% over the next 10 years (by 2035). PJM could not have anticipated this growth during the 2020–2022 time frame in which PJM was developing its comprehensive interconnection queue reform and attendant implementation of Transition Cycle 1 and Transition Cycle 2.

NOTE:
The February 2023 paper titled Energy Transition in PJM: Resource Retirements, Replacements & Risks can be found on PJM's website.



NOTE:
Resource or capacity adequacy of the PJM system is assessed using loss-of-load expectation (LOLE). LOLE is a measure of how often, on average, the available capacity is expected to fall short of demand. LOLE is a statistical measure of the frequency of firm load loss and does not quantify the magnitude or duration of firm load loss. The use of LOLE to assess resource adequacy is an internationally accepted practice. PJM resource adequacy studies are computed using the LOLE criterion of one day in 10 years (translated as 0.1 days per year for annual analyses).

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2024 Generation Additions

As noted in **Section 1.3**, PJM faces an extreme and rapid tightening of supply and demand for capacity resources and needs additional resources to rapidly address PJM's near-term reliability challenge. Generator retirements, load growth, the pace of new entry, and the operating characteristics of intermittent and limited-duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030 and drive the need for the RRI's implementation.

This RRI process is designed to accelerate the interconnection of "shovel-ready" reliability resources, i.e., resources that are able to reach commercial operation within one to three years of executing a Generation Interconnection Agreement (GIA), and to offer at least 10 MW of Unforced Capacity with higher ELCC ratings, into future capacity auctions.

Solving a Potential Capacity Shortfall

Projects in Cycle 1, under the reformed interconnection process rules, will not have effective interconnection-related service agreements until approximately mid-2028 at the earliest. Therefore, they likely will not be constructed and reach commercial operation until 2031. That will be too late to support identified resource adequacy needs for the 2030/2031 Delivery Year of the PJM capacity market, when load growth and generator retirements are expected to outstrip installed capacity in PJM.

PJM currently projects a 10 GW capacity gap in the 2030/2031 Delivery Year. This projection assumes that 40% of eligible generation projects that submit an interconnection request will achieve commercial operation; an optimistic assumption that outpaces historical averages. This projected capacity shortfall could swell further as annual load forecasts are updated.

In contrast to Transition Cycle 1, projects in Transition Cycle 2 (the second and final cycle during the transition period) can be expected to have effective interconnection-related service agreements by approximately mid-2027 and reach commercial operation by the 2029/2030 Delivery Year. PJM estimates that adding projects via the RRI process to Transition Cycle 2 could advance these shovel-ready projects' commercial operation dates by at least 18 months. This 18-month head start is key to bringing significant amounts of Unforced Capacity to the PJM markets before 2028, when PJM anticipates the resource adequacy issues will become more severe, and in advance of the 2030/2031 Delivery Year when PJM anticipates that demand could begin to outgrow supply.

NOTE:

Effective Load Carrying Capability (ELCC) is a means of assessing resource reliability value (also referred to as capacity value) tied to the concepts of resource adequacy and probabilistic evaluation. For traditional resources, such as a thermal generator, ELCC will be approximately equal to its **unforced capacity** (UCAP) value (where UCAP value is determined based on the resource's forced outage rate). For variable or energy-limited resources, such as wind, solar and energy storage, ELCC methodology can be applied to derive a UCAP-equivalent value. ELCC results are driven by those hours with high risk or high loss-of-load probability (i.e., hours experiencing shortage or near-shortage conditions).

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RRI FERC Filing

PJM submitted a FERC filing on Dec. 13, 2024, containing Open Access Transmission Tariff (OATT) revisions in Docket No. ER25-712-000 to implement RRI terms and conditions. Rather than opening Transition Cycle 2 to an unlimited number of New Service Requests, the Tariff reforms permit only a limited number of resources that meet detailed individual scoring based on reliability, viability and availability criteria. FERC accepted PJM's RRI filing on Feb. 11, 2025, with a Dec. 14, 2024, effective date, as requested. The application window for RRI projects opened Feb. 28, 2025, and closed March 14, 2025.

RRI Process Summary

PJM has chosen to cap, at 50, the number of RRI projects that may enter Transition Cycle 2 to limit the RRI projects' potential impact on legacy Transition Cycle 2 projects, but to allow nearly unrestricted applications to be considered for a spot among those 50. PJM will implement certain minimum requirements for applicants for the RRI process, summarized here.

First, projects applying for the RRI process must represent a minimum of 10 MW of Unforced Capacity to be considered. Second, a project must provide a critical path construction schedule and a signed attestation verifying the accuracy of the information, including all dates, and certify that the developer will exercise commercially reasonable best efforts to meet these dates. Third, a developer must provide an RRI deposit in the amount of $4,000 per megawatt of energy or capacity, whichever is greater. These requirements, and certain post-construction commitments, will further enable the ability of Unforced Capacity to reach commercial operation more quickly.

Top 50 RRI Projects – Scoring and Weighting

PJM has developed seven RRI scoring categories, broken into two groups of criteria: 1. Market impact 2. Commercial operation date viability

Market impact criteria categories include the following:

- Amount of Unforced Capacity a project will provide, factoring in its ELCC rating. More megawatts at a higher ELCC rating means more impact per megawatt and per project.
- RRI ELCC class rating, indicative of a project's reliability profile. The higher the ELCC rating, the more likely the resource will be available to operate when it is needed for system reliability.
- Location, given that certain LDAs experienced much higher prices than other LDAs in the capacity auction for the 2025/2026 Delivery Year due to a scarcity of capacity.

Commercial operation date viability criteria categories include the following:

- Commercial operation date. This date must be supported by an attestation of an officer, rather than having a cutoff in-service date after which a project would not be eligible for the RRI process.
- Project support. Scoring for this category would be demonstrated by the following: (1) permits; (2) an engineering, procurement and construction agreement; (3) major equipment; and (4) financing, if necessary.
- RRI uprate to a base project already in commercial operation that has an effective interconnection-related service agreement or is being studied already. These projects generally can be brought online quickly.
- Headroom based on PJM power flowgate power flow analyses. PJM will use the project's point of interconnection (POI) to determine what reliability violations a prospective RRI project may cause and determine a project's violation points based on how many violations it triggers and at what voltage levels.

PJM crafted the scoring criteria and categories, and the weightings they were given, to ensure that its evaluation of RRI project applications would be as transparent as possible, objective and resource neutral. The RRI scoring and weighting also will allow smaller projects to compete against larger projects and intermittent or limited-duration projects to compete against larger-scale, conventional thermal generation projects.

NOTE:

- A full description of the RRI process, including Transition Cycle 2 integration, as well as project scoring and weighting, can be found in PJM's RRI FERC filing on PJM's website.
- FERC's February 11, 2025, order approving the RRI process is available on PJM's website

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1.3.4 — Surplus Interconnection Service

Surplus Interconnection Service (SIS) refers to the unused portion of energy delivery at a given point of interconnection by a generator that cannot or does not operate continuously, every hour of every day, year-round. The expedited SIS process discussed here allows the installation of alternate generation resources to provide energy when the original generator is not otherwise doing so. SIS is implemented outside of PJM's existing generation interconnection process given that it does not require Network Upgrades. PJM's existing SIS is not permitted in circumstances where it would:

- Require new Network Upgrades.
- Impact determination of necessary Network Upgrades required for interconnection requests already in PJM's queue.
- Impact short-circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response.

The details of these limitations are provided in Section 12 of PJM Manual 14H.

Easing Reliability Issues

PJM faces extreme and rapid tightening of supply and demand, driving the need for new capacity resources to meet emerging reliability challenges. PJM's Tariff changes will encourage and facilitate the use of SIS from existing and planned generating units, such as pairing a renewable resource with battery storage. By taking a less restrictive approach to SIS, PJM is in a better position to maximize existing system use, enhancing resource adequacy without the need for additional Network Upgrades. Removing SIS limitations also allows requests for its use to be submitted earlier in a project's development cycle.

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Streamlined Surplus Interconnection Service

On Dec. 20, 2024, PJM submitted a filing at FERC, Docket ER25-778-000, to change existing SIS Tariff provisions to remove existing limitations to SIS. FERC accepted PJM's filing on Feb. 11, 2025, with a March 7, 2025, effective date, as requested. PJM and stakeholders continue to work on the necessary changes to Manual 14H to conform that manual to these Tariff revisions.

Physical Interconnection Facilities

Language has been added to PJM's Tariff to explicitly allow the construction of additional physical interconnection facilities where developers need them to accommodate requested SIS. This would allow parallel operation of a surplus generating unit and an existing or planned generator, an important factor for solar facilities seeking to add a closed loop for storage resources.

Existing Versus New Network Upgrades

PJM has eliminated the current restrictions on SIS in instances where the service:

1. Affects the determination of Network Upgrades for projects already in the interconnection process
2. Results in material adverse impacts on short-circuit capability limits, steady-state thermal and voltage limits, or dynamic system stability and response

This change will bring PJM's Tariff more in line with other RTOs that allow for SIS except when it requires new Network Upgrades. Importantly, this ensures that granting SIS has no additional impacts affecting the determination of upgrades for Generation Interconnection Requests already in the queue.

Planned Generation

PJM is expanding SIS availability to projects that have an Interconnection Service Agreement or Generation Interconnection Agreement, but have not reached commercial operation. Former Tariff provisions only permitted SIS requests from existing, operational generators. This reform enables interconnection customers with unused interconnection service to let other generating facilities use that interconnection service earlier than is currently allowed.

Energy Storage

PJM Tariff provisions now also allow SIS from resources that receive energy from the grid and store it for later grid injection, such as electric storage resources. Doing so provides this subset of facilities the same SIS opportunities as generating resources.

NOTE:

"Surplus Project Developer" is defined in the Tariff as "a Project Developer whose Generating Facility is already interconnected to or has executed (or requested to file unexecuted) an Interconnection Service Agreement or Generation Interconnection Agreement to interconnect to the PJM Transmission System or one of its affiliates, or an unaffiliated entity that submits a Surplus Interconnection Request to utilize Surplus Interconnection Service within the Transmission System in the PJM Region."

1.3.5 — Capacity Interconnection Rights Transfer

Capacity Interconnection Rights (CIRs) permit generation seeking capacity resource status to inject power at a defined point of interconnection on the transmission system. Once a developer's generating facility is accredited as deliverable through the applicable Tariff procedures, the developer receives CIRs commensurate with the megawatts identified in its Generation Interconnection Agreement (GIA). CIRs continue to exist for one year following the actual unit deactivation date and can be transferred to another generating facility by the owner at the same point of interconnection. Once transferred, CIRs continue to exist so long as the new resource continues to meet deliverability testing requirements.

PJM stakeholders and Planning staff have recognized the need for an expedited interconnection process for a replacement resource seeking to use the CIRs of a deactivating resource. Doing so will enable much-needed replacement generation as part of the energy transition in PJM.

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CIR Transfer Efficiency Enhancements

Stakeholder efforts with PJM since May 2023 culminated in the endorsement of a CIR Transfer Efficiency proposal at the respective Nov. 21, 2024, meetings of the Markets and Reliability Committee and Members Committee. As endorsed, the proposed revisions will expedite the replacement of capacity from deactivating resources. The proposed Tariff revisions will expedite and enhance the transfer of CIRs from deactivating generation resources to replacement generation resources by providing a process for Replacement Generation Interconnection Requests that is separate from but parallel to PJM's three-phase, clustered Cycle Process.

On Jan. 31, 2025, PJM submitted a FERC filing in Docket No. ER25-1128 to make the necessary revisions to the PJM Open Access Transmission Tariff provisions and the Reliability Assurance Agreement (RAA). The revised Tariff:

- Clarifies that all types of resources are eligible to receive CIRs transferred from deactivating facilities, e.g., a deactivating thermal generation resource can be replaced by a battery storage facility, which expands the types of capacity resources that can utilize this faster process at a time when more capacity is needed.
- Implements an efficient and timely process to minimize diverting PJM organizational resources away from clustered cycle studies
- Applies "first-ready, first-served" principles to Replacement Generation Interconnection Requests in a transparent and nondiscriminatory manner
- Ensures that system capability is utilized to a greater extent and on a nondiscriminatory basis
- Clarifies the reliability analyses to be applied to Replacement Generation Interconnection Requests while ensuring that PJM system reliability and the scope of the necessary reliability studies are not degraded

The proposed changes do not apply to the current process of transferring CIRs when the replacement resource does not interconnect to the same substation (at same or different breaker position in that substation) as the deactivating generator.

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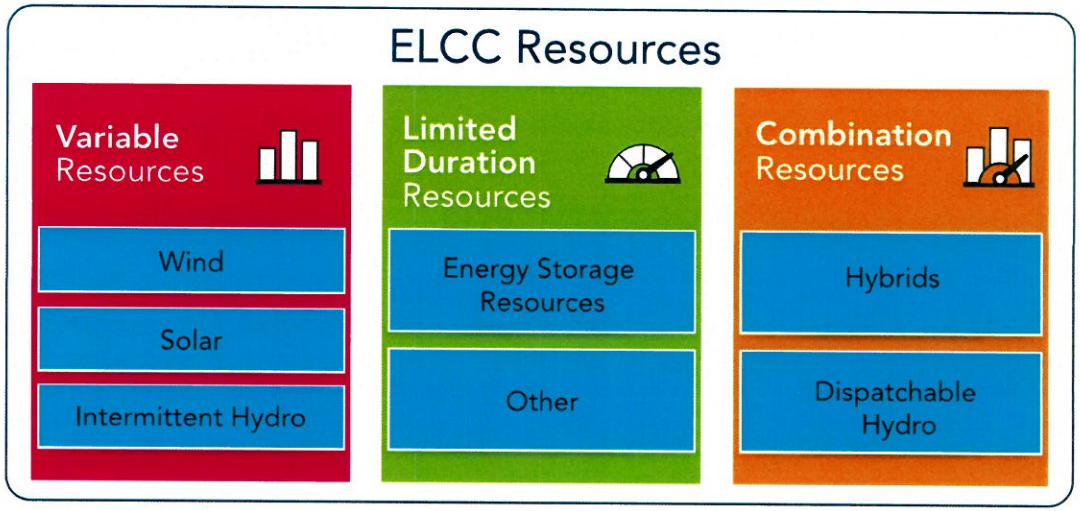
1.3.6 — ELCC Capacity Accreditation Impact on Capacity Emergency Transfer Limits

As discussed in Section 1.3.2 of the 2023 RTEP Report, PJM proposed, and FERC approved in Docket ER24-99, a new methodology to accredit resources' capacity capabilities using an Effective Load Carrying Capability (ELCC) approach. The types of generators that have been designated ELCC resources are shown in **Figure 1.13**. An important change manifested by implementing the ELCC methodology is a shifting of the calculation of risk to those periods throughout the year where a combination of temperature/load scenarios and generation performance scenarios reveal that most loss of load risk has shifted from the summer peak period to winter periods.

Figure 1.13: ELCC Resources



2024 MILESTONE: Enabling PJM's Energy Transition

CETL Methodology Improvement

Stakeholders have identified a disconnect between:

1. The Expected Unserved Energy (EUE) used in the ELCC methodology to determine the annual accreditation
2. PJM's continued use of the summer peak to determine the Capacity Emergency Transfer Limit (CETL) for the Locational Delivery Areas (LDAs)

Under the previous capacity accreditation methodology, capacity market risk was focused on the summer peak period. Under that previous methodology, it made sense to calculate the summer peak CETL such that power flow reliability study results reflected transfer limits at the riskiest periods modeled for the year.

Having switched to a model that assesses risk throughout the year, using a summer peak-based CETL calculation without reference to EUE distribution, creates a misalignment between the periods when capacity is most valuable and the transfer limits for LDAs during those periods. Such a misalignment will impact the relative pricing of capacity among LDAs, potentially leading to incorrect capacity prices and investment signals at a time when those price signals must be clear and precise enough to incentivize new capacity investment.

Next Steps

At its meeting on Nov. 6, 2024, the PC approved an issue charge to look at this issue including development of a methodology to align the CETL with the shift in risk from the summer peak to the winter period. In addition to education and analysis, proposed methodology solutions will drive the need for corresponding revisions to PJM's governing documents and manuals.

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1.3.7 — State Agreement Approach – Enabling Offshore Wind

As part of the RTEP's baseline planning process, PJM works with states to implement their public policy goals through various means, including through the State Agreement Approach (SAA). Under this approach, states that wish to build out the transmission system to meet public policy initiatives, such as offshore wind goals, can utilize the PJM planning process to efficiently develop and implement needed grid expansions.

2024 MILESTONE: Enabling PJM's Energy Transition

Enabling Offshore Wind in New Jersey

As described in Section 1.3.5 of the 2023 RTEP Report, the New Jersey Board of Public Utilities (NJBPU) initiated an SAA request with PJM to study the transmission needs to locate wind-powered generation off the New Jersey coast. Initially in November 2020, the NJBPU request entailed 7,500 MW by 2035, which was also known as "SAA 1.0." In October 2022, the NJBPU increased the amount to 11,000 MW by 2040, which became known as "SAA 2.0." From 2020 through 2024, PJM initiated required RTEP process power flow and other reliability studies based on the respective, requisite SAA study agreements executed between the NJBPU and PJM, as also described in the 2023 RTEP Report.

- *SAA 1.0:* PJM analysis of the NJBPU's SAA 1.0 request continued in 2024, including expansion of work at the Larrabee Collector substation to include certain pre-build provisions encompassing civil work to minimize disturbance to the shoreline and in the vicinity of the Larrabee substation.
- *SAA 2.0:* On May 28, 2024, the NJBPU announced: "...it will pause on moving forward with the Second State Agreement Approach (SAA) for coordinated offshore wind transmission planning with regional grid operator, PJM Interconnection (PJM). The decision to pause follows the Federal Energy Regulatory Commission's (FERC) release of Order 1920, which addresses long-term regional transmission planning and PJM's ongoing interconnection queue reform process, each of which impacts planning and costs. Pausing at this time affords Board staff the opportunity to fully evaluate the implications of the new FERC rule and participate in PJM's process to ensure the best outcome to meet New Jersey's transmission needs at the least cost to ratepayers."

At the June 2024 meeting of the PJM Transmission Expansion Advisory Committee, PJM announced that it was pausing further New Jersey SSA 2.0 work.

NOTE:
The May 28, 2024 , press release from New Jersey regarding developments in offshore wind activity is available online

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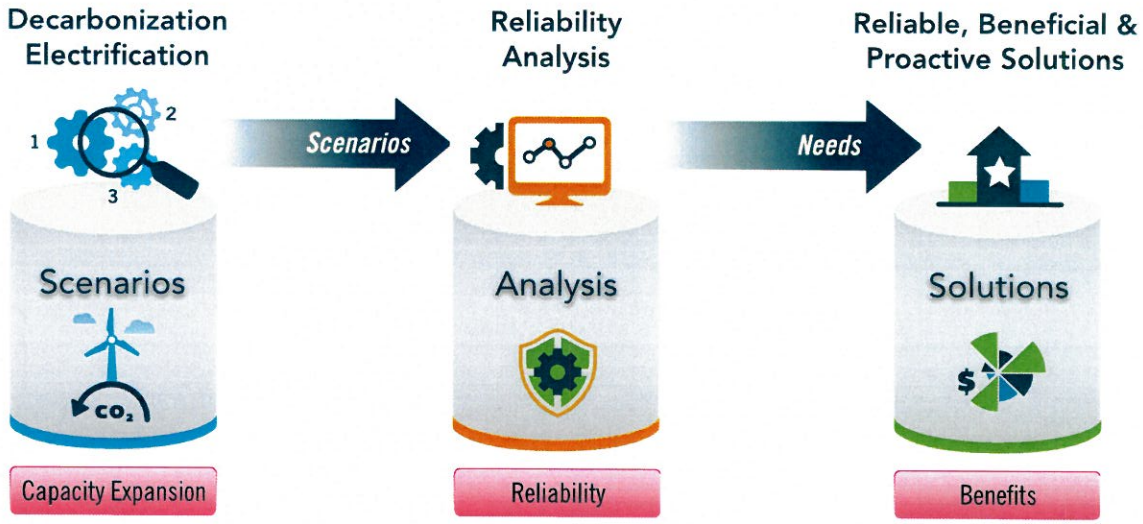
1.3.8 — Long-Term Regional Transmission Planning

Throughout 2024, PJM continued to implement long-term regional transmission planning (LTRTP) protocols in anticipation of FERC rulemaking action in Docket No. RM21-17-000, Building for the Future through Electric Regional Planning. The protocol encompasses analysis of longer-term system needs under multiple future scenarios, as depicted in the framework shown in **Figure 1.14**. Indeed, PJM's focus on LTRTP reflects FERC's own recognition of similar growing national need as expressed in the following orders:

- May 13, 2024: FERC Order 1920 in Docket No. RM21-17-000
- Nov 21, 2024: FERC Order 1920-A in Docket No. RM21-17-001

These orders specify that transmission providers must develop at least three distinct long-term scenarios that utilize enumerated factor categories and a planning horizon of not less than 20 years. Long-term scenarios must be reviewed and updated at least once every five years. The orders also call for an enhanced role of relevant state entities and better transparency with local transmission planning processes.

Figure 1.14: Long-Term Regional Transmission Planning Framework



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2024 MILESTONE: Long-Term Regional Transmission Planning

Order 1920 Implementation

In anticipation of an LTRTP order from FERC, PJM continued to work with stakeholders during 2024 on the following RTEP process-related initiatives:

- Developing and filing requisite compliance filing for Order 1920 implementation, the deadline for which was extended by Order 1920-A to June 12, 2027
- Revising applicable PJM Manuals to incorporate the following: number and types of scenarios; extreme weather sensitivities; 20-year planning horizon; categories of planning factors; scenario planning approach; and ultimate identification of transmission based on drivers of transmission needs, reliability and economic analysis, and generation interconnection process
- Engaging relevant state entities in long-term regional transmission planning, especially their role in shaping scenario development and cost allocation
- Revising existing interregional transmission coordination procedures
- Supporting transmission owners as necessary as they develop needed changes to make a FERC filing that implements one or more ex ante cost allocation methodologies to apply to selected LTRTP processes

These efforts will continue in 2025.

1.3.9 — Facilitating States' Decarbonization Policies

The scale of the PJM system provides tremendous value for grid reliability. Electrons do not know state boundaries and travel across a vast network of interstate transmission. PJM plans for and operates this system in a manner that is both reliable and cost-effective. PJM has a diverse portfolio of resources and a footprint that spans multiple states and time zones. Operating the PJM region as one cohesive system gives operators the flexibility to rely on resources throughout the footprint and also allows the grid to better absorb abrupt system disturbances. Further, using competitive processes for the construction of transmission and competitive markets for the procurement of power, PJM is able to derive significant cost savings for consumers.

As with the entire U.S. electric grid, and as discussed previously, PJM is experiencing an accelerating transition toward intermittent, renewable generation. State and federal policies, economics and consumer choices are shifting the grid away from dispatchable, emitting generation resources toward intermittent generation with little-to-no carbon emissions. The pace of retirements is being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generation to comply or retire.

More than ever, federal and state policies are contributing to the energy transition. PJM has been engaging with states on how their policies can be advanced reliably and is working with federal officials to help inform their policies as well.

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:** 60% 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

**** Eliminated after 2026

Renewable Portfolio Standards

Table 1.4 summarizes the Renewable Portfolio Standards utilized in the 2024 Energy Transition study. These mandated state RPS targets require that a certain percentage of a state's load is served by qualified renewable energy resources. State RPS policies also vary by eligible resource technology, in-state resource carve-out requirements and required qualified resource location. 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.

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.

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Offshore Wind Targets

Table 1.5 summarizes current offshore wind procurement targets for states in PJM utilized in this study, per respective state policies.

Energy Storage Targets

Storage development is also being driven by both explicit and implicit state policy objectives. Explicit state targets include Virginia's 3,100 MW by 2035, Maryland's 3,000 MW by 2033, Michigan's 2,500 MW by 2029 and New Jersey's 2,000 MW target by 2030. Implicitly, storage is being developed to complement the influx of renewable resources driven by state RPS targets.

Table 1.5: PJM States' Policy Targets for Offshore Wind*

	Offshore Wind Target (MW)	Policy Target Date
Maryland	8,500	2031
New Jersey	11,000	2040, per Gov. Murphy's September 2022 Executive Order
Virginia	5,200	2034

**North Carolina also has an offshore wind target of 8,000 MW by 2040 per Executive Order No. 218, which was issued in 2021. It is to be determined how much of North Carolina's offshore wind may interconnect into the PJM region.*

NOTE:
Michigan's 2,500 MW storage target applies to the entire state, including the portion of Michigan outside the PJM footprint.

2024 MILESTONE: States: Facilitating Decarbonization Policies

State-by-State Engagement

FERC Orders 1920 and 1920-A, discussed in **Section 1.3.8**, contain provisions espousing enhanced PJM engagement with relevant state entities in long-term regional transmission planning, especially the states' role in shaping scenario development and cost allocation. See **Section 6.0** for a current state-by-state summary of public policy impacts on regional transmission planning.

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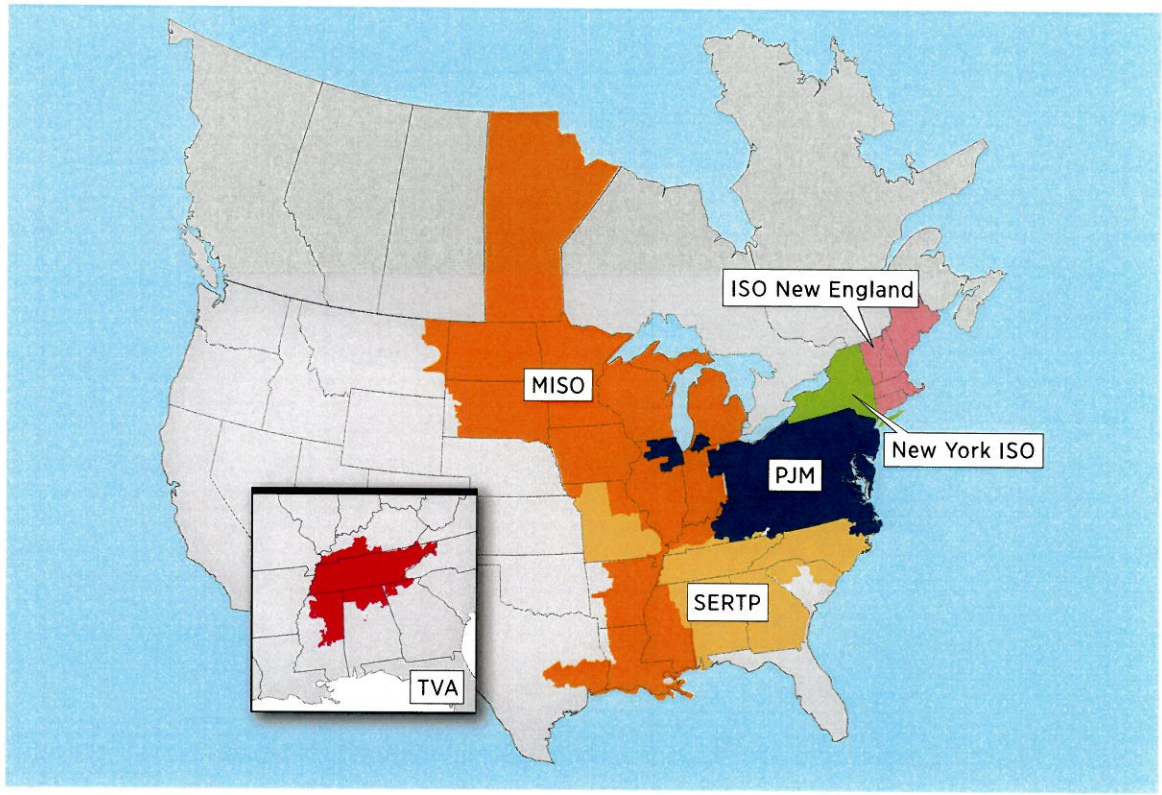
1.3.10 — Interregional Transfer Capability

As discussed in **Section 3.5**, PJM has interregional planning agreements, some dating to the 1970s and earlier, 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 (SERTP) process, shown on **Map 1.3**. 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.

As PJM's June 2024 report Energy Transition in PJM: Flexibility for the Future discusses, resource diversity across the Eastern Interconnection has allowed PJM and its neighbors to coordinate day-to-day power transfers to leverage economic opportunities and ensure reliability and resilience during periods of system stress. As part of this energy transition, increasing amounts of intermittent wind power, solar power and energy storage coupled with the retirement of large-scale thermal generation raises new concerns about the ability of systems to lean on each other during periods of system stress and support greater interchange variability.

Map 1.3: PJM Interregional Planning



NOTE:
The June 24, 2024, Energy Transition in PJM: Flexibility for the Future report can be found on PJM's website.

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2024 MILESTONE: Interregional Transfer Capability

NERC Interregional Transfer Capability Study (ITCS)

Congress ordered an Interregional Transfer Capability Study (ITCS) to examine the potential need for additional transmission between regions to ensure reliability. Signed into law in June 2023, this congressional directive falls within the scope of NERC's obligation under Section 215 of the Federal Power Act to "conduct periodic assessments of the reliability and adequacy of the bulk power system in North America." The three-part study was conducted under the auspices of NERC and its Regional Entities, including extensive PJM input and participation, and completed the following:

1. Determined existing total transfer capability (TTC) between each pair of neighboring transmission planning regions
2. Developed a recommendation of how much additional, prudent level of TTC between neighboring transmission regions would demonstrably strengthen reliability within and between them. This included an energy margin analysis to identify whether a particular region would be at risk for energy inadequacy considering the calculated TTCs and extreme weather events.

This NERC ITCS effort has paralleled and informs PJM's own energy transition interregional initiatives – with MISO in particular – as an outgrowth of FERC Order 1920.

NOTE:
Total Transfer Capability (TTC) is calculated as the sum of the Base Transfer Level (BTL) and First Contingency Incremental Transfer Capability (FCITC): TTC = BTL + FCITC. This enables a consistent calculation method. BTL for each interface was derived, where available, from the scheduled interchange tables provided by each region for each study case. FCITC involves simulating an incremental increase in transfers from source subregion to sink subregion while applying relevant contingencies and monitoring criteria.

NERC ITCS Study Part 1: Transfer Capability Analysis

The Transfer Capability Analysis Report, published in August 2024, presented interregional TTC results, for subsequent use in Part 2 and Part 3, based on two different base cases: summer 2024 and winter 2024/2025. Given the unprecedented scope of the study, TTC calculations were limited in Part 1 to steady-state power flow analysis using P-0 (no contingency) and P-1 (single contingency) scenarios as defined in NERC Reliability Standard TPL-001-5.1. In particular, Chapter 5 of Part 1 provides TTC values for each pair of subregions in the Eastern Interconnection results, including those between PJM's three subregions (East, West and South) and with each adjoining system (NYISO, MISO and SERC), respectively.

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2024 MILESTONE: Interregional Transfer Capability

NERC ITCS Study Part 2: Additions To Strengthen Reliability

Part 2 of the ITCS evaluated the future energy adequacy based on past weather conditions occurring again in 2033. Specifically, the study applied 12 past weather years to the 2033 load and resource mix using the TTCs calculated in Part 1. The year 2033 was chosen because those transmission projects – particularly interregional ones – can require at least 10 years to be built. The energy margin analysis in Part 2 quantified the frequency, magnitude and duration of energy deficiency for each region.

Not surprisingly, findings in Part 2 note that the North American grid is vulnerable to extreme weather. Transmission limitations and the potential for energy inadequacy were identified in all 12 years studied. Enhancing specific transmission interfaces could reduce the likelihood of energy deficits during extreme conditions. Reliability risks are highly dependent on regional conditions. The import capability needed during extreme conditions varied significantly across the country, indicating that a one-size-fits-all requirement may be ineffective. An additional 35 GW of transfer capability is recommended across the United States as a vehicle to strengthen energy adequacy under extreme conditions.

The study report notes that MISO East and the PJM Southern Region among others (including New York) each have significant vulnerability to extreme weather, such as requiring more than 1,000 MW to mitigate an energy deficiency. **Table 1.6**, excerpted from Table ES-1 of Part 2/Part 3, shows the amount of transfer capability needed to mitigate energy deficiencies, as studied.

NOTE:
NERC Interregional Transfer Capability Study (ITCS) Strengthening Reliability Through the Energy Transformation:

Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3) November 2024

NOTE:
The Part 2/Part 3 report defines an "energy deficiency" as an instance where available resources, including energy transfers from neighbors, are insufficient to meet the projected demand plus a minimum margin level (set at an agreed-upon 3% of regional load).

Table 1.6: Selected ITCS Energy Deficiency Results

Transmission Planning Region	Weather Years (WY)/Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
MISO-E	WY2020 heat wave and two other events	58	5,715	3,000	MISO-W (2,000) PJM-W (1,000)
New York	WY2023 heat wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec (1,900)
PJM-S	Winter Storm Elliott (WY2022)	20	4,147	2,800	PJM-E (2,800)
SERC-E	Winter Storm Elliott (WY2022)	9	5,489	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)

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2024 MILESTONE: Interregional Transfer Capability

NERC ITCS Study Part 3: Meeting and Maintaining Transfer Capability

Part 3 of the ITCS Study, per Chapter 5 of the combined Part 2/Part 3 report cited above, recommends approaches to achieve and maintain adequate levels of transfer capability based on the results in Part 2. However, the ITCS intentionally did not specify a particular set of projects or approach given the multiple options available to planners for mitigating identified energy adequacy risks:

- Increase transfer capability to neighbors with surplus resources.
- Construct local generation.
- Increase demand response resources.
- Accept the identified risks during extreme events (assuming other reliability thresholds are met).

If planners elect to increase transfer capability, multiple options exist, including:

- Upgraded transmission infrastructure
- Remedial action schemes (RAS)
- Dynamic line ratings (DLR)
- Power flow control devices

The last two of these, along with advanced conductors, are frequently referred to as Grid Enhancing Technologies. Grid Enhancing Technology projects are typically less expensive and require less lead time than building new transmission lines.

Next Steps

On Nov. 19, 2024, NERC submitted the ITCS to FERC. On Nov. 25, 2024, FERC issued a Notice of Request for comments from interested parties by Feb. 24, 2025.

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2024 MILESTONE: Interregional Transfer Capability

PJM/MISO Interregional Transfer Capability Study (ITCS)

On May 9, 2024, PJM and MISO announced they were embarking on a study to identify near-term upgrades that incrementally enhance transfer capability between the two RTOs. Increasing transfer capability between regions may help to support greater grid resilience, particularly following extreme weather events and the influx of renewable generation resources with intermittent output. The study effort is being driven by input received by each organization from the Organization of PJM States (OPSI), the Organization of MISO States (OMS) and the Midwestern Governors Association (MGA). The study will identify potential opportunities for near-term transmission enhancements along the seam shared by PJM and MISO.

The study includes reliability, economic and transfer analyses using forward-looking models and assumptions for a 2032 model year. Potential solutions will address needs using existing rights-of-way and upgrading terminal equipment or transformers. This study, along with FERC Order 1920, will pave the way for future efforts focused on longer-term needs and greenfield solutions. Following the study, MISO and PJM will partner with states and stakeholders to identify and pursue Joint Operating Agreement/Tariff adjustments as needed to bring solutions forward for implementation. Results are expected to be shared with stakeholders in the first half of 2025.

This study is complementary to the NERC Interregional Transfer Capability Study. The NERC study is intended to identify and maintain an interregional transfer baseline objective. The goal of the PJM and MISO ITCS is to identify opportunities to enhance transfer capability on an incremental basis.

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1.4: Optimizing Regional Transmission Infrastructure Investment

PJM's RTEP process identifies transmission projects needed to serve customers by ensuring compliance with national and regional reliability criteria to prevent overloaded facilities and potential blackouts. Today, PJM's RTEP process studies the interaction and impact of many system need drivers: load growth, generation retirement, new services like Generation Interconnection Requests, aging infrastructure, operational performance, market efficiency, public policy, electrification and other demand-side trends. Fundamentally, in order to conduct these studies, PJM's RTEP process employs analytical deliverability tests that simulate stressed, emergency grid conditions as described in **Section 1.2**. This ensures power can be delivered when it is most needed, i.e., when local generation cannot meet customer demand. The outcome of these RTEP analyses yields three types of transmission projects.

1. **Baseline Projects.** 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 PJM transmission system provides the means for delivering the output of interconnected generators to the load centers in the PJM energy and capacity markets. Baseline reliability analyses ensure the security and adequacy of the transmission system to serve all existing and projected long-term firm transmission use including existing and projected native load growth as well as market efficiency and long-term firm transmission service.

2. **Customer-Funded Projects.** These encompass Network Upgrades, local upgrades or merchant Network Upgrades, the cost of which are paid for by a New Service Customer. All entities requesting interconnection of a Generating Facility (including increases to the capacity of an existing generating unit) or requesting interconnection of a Merchant Transmission Facility within the PJM region must do so through PJM's interconnection process. PJM studies the interconnection and deliverability of generation or Transmission Interconnection Requests or Upgrade Requests in the local area at the point of interconnection to determine whether customer-funded upgrades are required to either interconnect to the system or upgrade existing transmission facilities.

3. **Supplemental Projects.** These arise out of transmission owner-identified needs associated with a transmission expansion or enhancement not required to comply with PJM reliability, operational performance, FERC Form No. 715 or economic criteria. Transmission owners in PJM plan supplemental projects in accordance with the OATT Attachment M-3 Process. Projects planned through the OATT Attachment M-3 Process could include those that:

   - Expand or enhance the transmission system.
   - Address local reliability issues.
   - Maintain the existing transmission system.
   - Comply with regulatory requirements.
   - Implement transmission owner asset management activities including needs related to transmission facilities approaching the end of their useful life.

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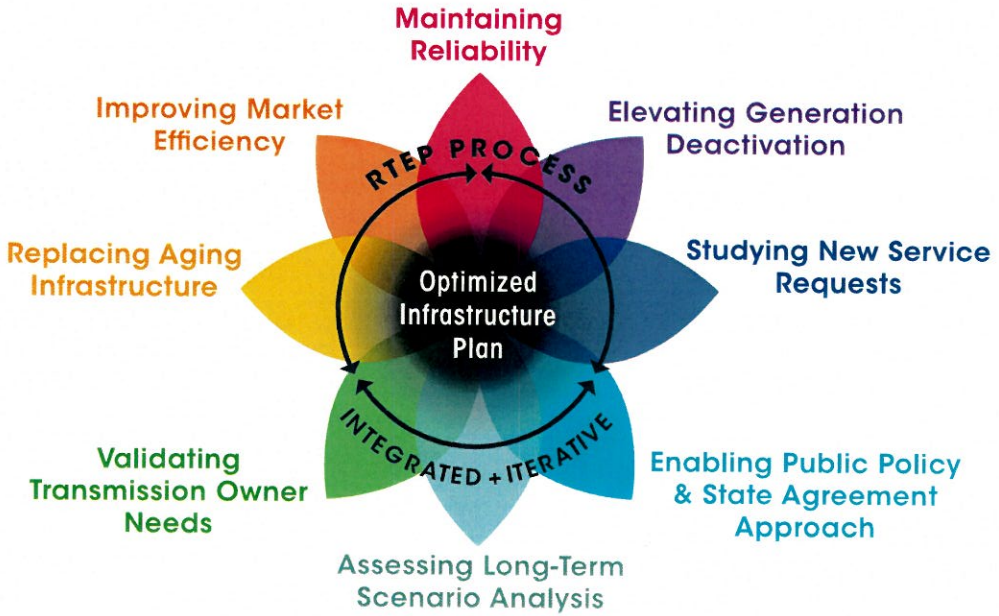
As **Figure 1.15** shows, PJM's comprehensive, regional transmission plan is the outcome of overlapping and interacting analytical processes, not siloed ones. PJM leverages opportunities to optimize regional transmission infrastructure investment under one plan by developing efficient solutions across all three types of transmission: baseline, customer-funded and supplemental.

1.4.1 — Baseline Market Efficiency Opportunities

As discussed in **Section 4**, PJM performs market efficiency analysis as part of the RTEP process baseline analysis in pursuit of the following opportunities:

- Identify new transmission enhancements or expansions that could relieve transmission constraints (i.e., congestion) that have an economic impact on customers.
- 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.

Figure 1.15: Optimizing Regional Transmission Infrastructure Investment



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.

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1.4.2 — Optimizing Baseline Enhancements and Interconnection Upgrades

When PJM identifies instances where increasing the capability of an RTEP project would obviate the need for a separate Network Upgrade driven by a Generation Interconnection Request, the interconnection customer's incremental need(s) are factored into the RTEP project, and the customer is responsible for the incremental cost of the project. This coordination across processes permits PJM to plan grid enhancements that benefit both load and interconnection customers.

Importantly, PJM has implemented common process controls and assumption alignment for generation interconnection and cases by leveraging a common system modeling approach to ensure consistent annual power flow base case use for baseline reliability and market efficiency analyses that is then updated for interconnection analysis. This integrated approach ensures:

- Consideration of common load forecast assumptions (based on latest load forecast)
- Inclusion of RTEP baseline and supplemental projects
- Inclusion of previously identified customer-funded upgrades, including those for generation projects that have executed interconnection service agreements (ISAs)
- Alignment of base case assumptions with the model of the Eastern Interconnection
- Recently deactivated generators
- Accurate Capacity Interconnection Rights, or CIRs

PJM's RTEP process incorporates procedures that require the baseline studies to be completed annually in order to "lock down" the annual base case prior to commencing interconnection studies. This process provides a New Service Customer with a complete system model by which to make informed business decisions based on new system capabilities using the most recent Board-approved RTEP grid enhancements.

Notably, PJM Board-approved baseline projects, together with supplemental projects, are included in the RTEP and reflected in power flow base case models, so interconnection customers can take advantage of remaining system capability, i.e., "headroom," available on the transmission system before the need for customer-funded Network Upgrades are identified.

1.4.3 — Baseline, Supplemental and Customer-Funded Investment

PJM works with stakeholders to identify any transmission projects that interact electrically. By doing so, PJM is able to develop more efficient or cost-effective solutions:

- Between an OATT Attachment M-3 Process supplemental project and an existing baseline project
- After a supplemental project is included in the Local Plan but not yet included in the RTEP base case
- After an RTEP project is included in the base case (in a prior RTEP cycle) and an identified supplemental project or customer-funded upgrade interacts with the RTEP project

PJM's process provides the opportunity to discuss these interactions with stakeholders at the TEAC and Subregional RTEP Committee meetings.

Achieving Baseline and OATT Attachment M-3 Process Supplemental Project Efficiencies

The OATT Attachment M-3 Process allows PJM transmission owners to plan supplemental projects. Instances arise in which projects driven by Operating Agreement, Schedule 6 (i.e., baseline projects), and the OATT Attachment M-3 Process (i.e., supplemental projects) require changes or upgrades to be made to the same transmission facilities on the system. PJM's RTEP process examines overlaps between baseline projects and TO supplemental projects.

During a review of the RTEP analysis, it may become apparent that a supplemental need identified in the OATT Attachment M-3 Process may interact with an identified violation, system condition, economic constraint or public policy requirement posted on the PJM website. In this case, PJM will provide notice of the potential interaction associated with the posted system condition by posting the newly available information to the PJM website and provide notification to stakeholders.

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PJM may determine whether to lengthen an open proposal window in order to permit project proposers additional time to consider the availability of new or changed information. PJM can consider proposals, including proposals in its open proposal window, that more efficiently and cost-effectively address both the identified baseline need(s) and any related needs identified in the OATT Attachment M-3 Process.

After PJM has had an opportunity for stakeholder review and comment, PJM determines the action to take depending on the point in the RTEP process in which the electrical interaction has been identified, as described in Section 1.4 of PJM Manual 14B, PJM Region Transmission Planning Process.

Recent Examples

The following examples show how PJM leverages opportunities to develop cost-effective transmission solutions that address overlapping transmission needs.

1 Line A 138 kV Overloads – Optimized Interstate Solution To Address Baseline and Supplemental Needs

In this recent example, PJM received four proposals to solve baseline overloads on an interstate 138 kV transmission line. As part of its review and analysis of the four window proposals, PJM identified its own solution based on converting six elements of an existing transmission owner supplemental project into a new PJM RTEP baseline project. PJM determined that doing so more cost-effectively addressed both the identified RTEP baseline reliability criteria violations and supplemental project drivers associated with aging infrastructure, operational performance and local power delivery needs. Notably, the cost estimate for the new baseline project was millions of dollars less than two of the original four transmission developer-submitted baseline proposals.

2 Local Area 69 kV Thermal Overloads – Optimized Area Solution To Address Baseline and Supplemental Needs

In this recent example, PJM received three proposals to solve 30 identified baseline thermal overloads on three local 69 kV transmission lines. PJM's review and technical analysis identified the first proposal, which encompassed rebuilds of the three lines as the more cost-effective solution. The project solves all 30 thermal violations and obviates the need to pursue and also solves emerging OATT Attachment M-3 Process local supplemental projects to address identified aging infrastructure issues on including two transmission lines dating to 1939 with deteriorating wood-pole structures.

NOTE:

After PJM has had an opportunity for stakeholder review and comment, PJM determines the action to take depending on the point in the RTEP process in which the electrical interaction has been identified, as described in Section 1.4 of PJM Manual 14B, PJM Region Transmission Planning Process.

Section 2: Resource Adequacy Modeling

2.0: Power Flow Model Load

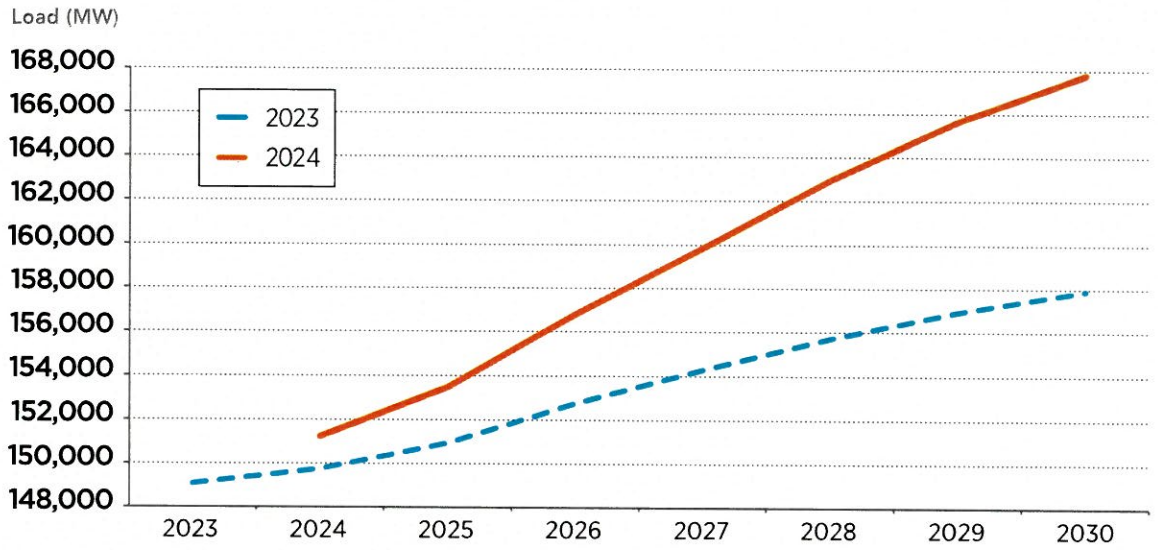
Fundamentally, PJM's planning process identifies future system transmission needs based on power flow studies that reveal reliability criteria violations. Power flow study models incorporate the effect of many system expansion drivers. Zonal load forecasts are the basis for power flow case bus loads. 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 yearly 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).

2024 RTEP Process Context

PJM's 2024 RTEP baseline power flow model for study year 2029 was based on an overall RTO summer peak load of 165,681 MW as published in the 2024 PJM Long-Term Load Forecast Report. The Long-Term Load Forecast Report, which covers the 2024 through 2039 planning horizon, states that PJM now projects its RTO-wide summer-normalized peak to grow 1.6% annually over the next 10 years, shown in **Figure 2.1**, which is up 0.8% from the 2023 forecast.

Figure 2.1: Summer Peak Load Forecast 2024 vs. 2023



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.

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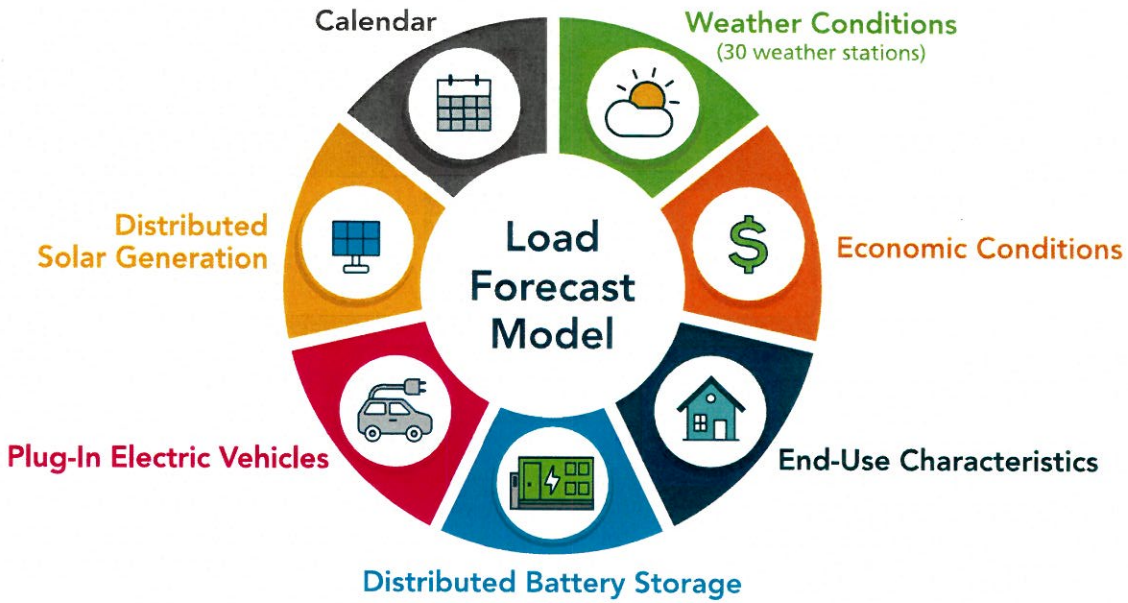
Load Forecasting Process

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 forecasted load, shown in **Figure 2.2**.

Figure 2.2: Load Forecast Model



Hourly Forecast Model Implementation

In 2022, based on guidance provided by an independent consultant's report, PJM implemented changes to its hourly forecast model through stakeholder engagement at its Load Analysis Subcommittee and Planning Committee meetings.

Beginning with the 2023 Load Forecast Report, PJM implemented 24 hourly models in each zone. This granularity allows PJM to incorporate the impacts of new technologies on the grid more accurately, including distributed solar and electric vehicles. The forecast also uses monthly data to model residential, commercial and industrial sectors.

Calibration

The forecast 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 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 increases PJM's understanding of 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

PJM accounts for the impact on load driven by weather conditions through metrics including temperature, humidity and wind speed. PJM obtains weather data from over 30 weather stations across the PJM footprint.

Calendar

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

Economic Conditions

PJM accounts for the impact of economic conditions on load forecasting by including such factors as real personal income, population and real gross domestic product. This allows for localized treatment of economic effects within a zone. PJM has contracted with an outside economic services vendor to provide forecasts for metropolitan areas within PJM.

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End-Use Characteristics

Residential, commercial and industrial end-use characteristics are captured through three distinct variables: weather-sensitive heating, weather-sensitive 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.

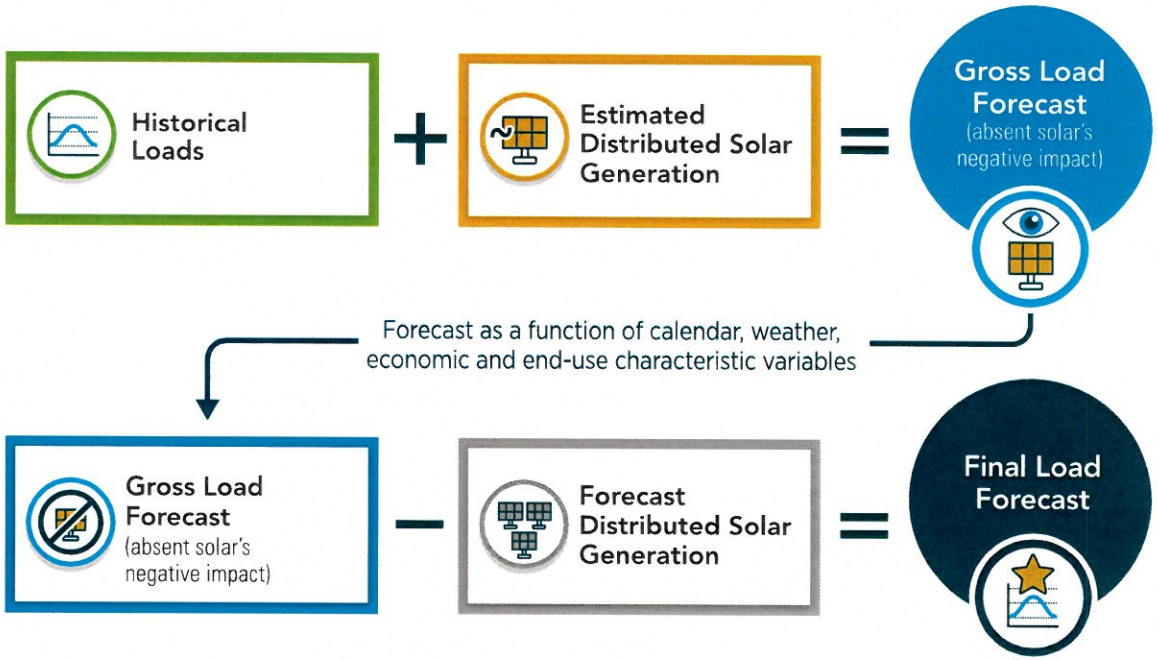
Plug-In Electric Vehicles

PJM's load forecast incorporates an explicit adjustment for plug-in electric vehicle (PEV) charging in peak megawatt demand and energy forecasts. Starting with the 2024 Long-Term Load Forecast Report, PJM uses a vendor-supplied electric vehicle forecast for light-, medium- and heavy-duty vehicle charging impacts on a zonal basis.

Distributed Solar and Battery Storage Generation

Distributed solar and battery storage generation lowers load from what it otherwise would be. Recent years have shown a significant ramp-up in behind-the-meter distributed solar resources. 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, distributed hourly solar generation impacts are reflected in its load forecast using the approach shown in **Figure 2.3** to determine a final load forecast.

Figure 2.3: Accounting for Distributed Solar Generation



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 forecasted distributed solar and battery storage generation to obtain a final load forecast for each zone and for the RTO. Forecasted distributed solar and battery storage generation is based on vendor-supplied 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.

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2.1: 2024 Long-Term Load Forecast Report

The 2024 PJM Long-Term Load Forecast Report, used in 2024 RTEP studies, includes forecasted data for the 2024 through 2039 planning horizon. The PJM 2029 RTO-wide summer peak is forecasted to be 165,681 MW. Additional highlights from the forecast are summarized in this section.

Forecasting Trends

Table 2.1 summarizes the seasonal transmission owner zonal summer and winter 10-year forecasts and load growth rates for 2024 through 2034. All load forecasts in the table reflect adjustments for distributed solar and battery storage generation as well as 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. PJM zones show higher load growth trends tied to electric vehicle charging and data center load. These trends are subsequently reflected in RTEP process power flow models.

Table 2.1: 2024 Long-Term Load Forecast Report: Summer and Winter Peaks

	Summer Peak (MW)			Winter Peak (MW)		
Transmission Owner	2024	2034	Growth Rate	2023/24	2033/34	Growth Rate
Atlantic City Electric	2,593	2,715	0.5%	1,637	2,161	2.8%
Baltimore Gas and Electric	6,491	6,931	0.7%	5,827	6,313	0.8%
Delmarva Power	3,945	4,050	0.3%	3,700	3,915	0.6%
Jersey Central Power & Light	6,052	6,750	1.1%	3,817	6,040	4.7%
Met-Ed	3,036	3,715	2.0%	2,740	3,365	2.1%
PECO Energy Company	8,581	9,031	0.5%	6,597	6,967	0.5%
Pennsylvania Electric Company (Penelec)	2,867	2,970	0.4%	2,829	2,869	0.1%
PPL Electric Utilities	7,126	7,382	0.4%	7,363	7,450	0.1%
Potomac Electric Power Company (Pepco)	6,053	6,440	0.6%	5,359	5,745	0.7%
Public Service Electric & Gas Company (PSE&G)	10,068	11,193	1.1%	6,816	9,906	3.8%
Rockland Electric Company	410	421	0.3%	225	308	3.2%
UGI Utilities	197	203	0.3%	201	204	0.1%
Diversity – Mid-Atlantic	-1,586	-1,896		-604	-448	
Mid-Atlantic	**55,833**	**59,905**	**0.7%**	**46,507**	**54,795**	**1.7%**
American Electric Power	22,902	26,408	1.4%	22,913	26,210	1.4%
Allegheny Power (FirstEnergy)	8,835	9,755	1.0%	9,158	10,273	1.2%
American Transmission Systems, Inc. (FirstEnergy)	12,433	12,612	0.1%	10,356	10,611	0.2%
Commonwealth Edison	20,414	20,411	0.0%	14,739	15,651	0.6%
AES Ohio	3,319	3,385	0.2%	2,943	2,947	0.0%
Duke Energy Ohio and Kentucky	5,332	5,465	0.2%	4,566	4,632	0.1%
Duquesne Light Company	2,705	2,855	0.5%	1,997	2,133	0.7%
East Kentucky Power Cooperative	2,070	2,211	0.7%	2,725	2,820	0.3%
Ohio Valley Electric Corporation	90	90	0.0%	110	110	0.0%
Diversity – Western	-1,571	-1,801		-1,880	-1,602	
Western	**76,529**	**81,391**	**0.6%**	**67,627**	**73,785**	**0.9%**
Dominion Energy	22,781	39,019	5.5%	22,525	36,851	5.0%
Southern	**22,781**	**39,019**	**5.5%**	**22,525**	**36,851**	**5.0%**
Diversity – Total	-7,053	-7,190		-4,484	-4,412	
PJM RTO	**151,247**	**176,822**	**1.6%**	**134,659**	**163,069**	**1.9%**

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Table 2.2: 2024 Long-Term Load Forecast Report: Distributed Solar Generation and PEV Adjusted to Summer Peak

Transmission Owner	Adjustment to Summer Peak (MW)					
	Distributed Solar Generation		Plug-In Electric Vehicle		Distributed Battery Storage	
	2024	2034	2024	2034	2024	2034
Atlantic City Electric	130	121	12	329	1	17
Baltimore Gas and Electric	211	299	36	883	2	80
Delmarva Power	120	141	12	323	1	21
Jersey Central Power & Light	282	395	53	1,136	2	40
Met-Ed	51	66	15	468	0	6
PECO Energy Company	68	182	24	505	1	14
Pennsylvania Electric Company (Penelec)	23	68	5	195	0	6
PPL Electric Utilities	127	203	10	259	1	15
Potomac Electric Power Company (Pepco)	226	362	33	564	2	63
Public Service Electric & Gas Company (PSE&G)	426	616	60	1,315	3	71
Rockland Electric Company	14	29	2	36	0	3
UGI Utilities	1	3	1	14	0	0
American Electric Power	151	324	25	753	2	39
Allegheny Power (FirstEnergy)	94	197	9	274	1	37
American Transmission Systems, Inc. (FirstEnergy)	100	193	21	556	1	20
Commonwealth Edison	390	886	76	1,488	4	87
AES Ohio	28	50	4	105	0	5
Duke Energy Ohio and Kentucky	21	58	11	211	1	8
Duquesne Light Company	23	55	10	229	0	5
East Kentucky Power Cooperative	5	17	2	75	0	2
Ohio Valley Electric Corporation	0	0	0	0	0	0
Dominion Energy	581	877	67	1,605	3	105
PJM RTO	**3,136**	**5,103**	**501**	**11,442**	**25**	**644**

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Table 2.3: 2024 Long-Term Load Forecast Report: Comparison of 10-Year Summer Peak Load Growth Rates

	Load Forecast Report Summer Peak (MW)														
	2020			2021			2022			2023			2024		
Transmission Owner	2020	2030	Growth Rate	2021	2031	Growth Rate	2022	2032	Growth Rate	2023	2033	Growth Rate	2024	2034	Growth Rate
Atlantic City Electric	2,542	2,773	0.9%	2,470	2,605	0.5%	2,488	2,541	0.2%	2,549	2,418	-0.5%	2,593	2,715	0.5%
Baltimore Gas and Electric	6,447	6,558	0.2%	6,582	6,652	0.1%	6,414	6,350	-0.1%	6,474	6,060	-0.7%	6,491	6,931	0.7%
Delmarva Power	3,979	4,327	0.8%	3,895	3,976	0.2%	3,873	3,854	0.0%	3,861	3,666	-0.5%	3,945	4,050	0.3%
Jersey Central Power & Light	5,842	6,122	0.5%	5,876	6,193	0.5%	5,831	5,868	0.1%	6,072	5,830	-0.4%	6,052	6,750	1.1%
Met-Ed	3,003	3,287	0.9%	3,060	3,255	0.6%	2,934	3,060	0.4%	3,040	3,112	0.2%	3,036	3,715	2.0%
PECO Energy Company	8,415	8,677	0.3%	8,389	8,691	0.4%	8,370	8,471	0.1%	8,527	8,590	0.1%	8,581	9,031	0.5%
Pennsylvania Electric Company (Penelec)	2,849	2,957	0.4%	2,894	3,164	0.9%	2,812	2,832	0.1%	2,871	2,792	-0.3%	2,867	2,970	0.4%
PPL Electric Utilities	7,069	7,792	1.0%	7,204	7,758	0.7%	7,024	7,237	0.3%	7,175	7,248	0.1%	7,126	7,382	0.4%
Potomac Electric Power Company (Pepco)	6,109	5,794	-0.5%	5,924	5,248	-1.2%	5,902	5,766	-0.2%	6,166	6,201	0.1%	6,053	6,440	0.6%
Public Service Electric & Gas Company (PSE&G)	9,792	10,597	0.8%	9,871	10,407	0.5%	9,543	9,857	0.3%	9,904	9,499	-0.4%	10,068	11,193	1.1%
Rockland Electric Company	395	420	0.6%	396	397	0.0%	391	388	-0.1%	414	416	0.0%	410	421	0.3%
UGI Utilities	191	184	-0.4%	195	201	0.3%	193	191	-0.1%	195	189	-0.3%	197	203	0.3%
Diversity – Mid-Atlantic	-781	-948		-986	-810		-629	-875		-1,512	-1,685		-1,586	-1,896	
Mid-Atlantic	**55,852**	**58,540**	**0.5%**	**55,770**	**57,737**	**0.3%**	**55,146**	**55,540**	**0.1%**	**55,736**	**54,336**	**-0.3%**	**55,833**	**59,905**	**0.7%**
American Electric Power	21,945	24,113	0.9%	22,609	23,471	0.4%	22,183	22,496	0.1%	22,453	22,637	0.1%	22,902	26,408	1.4%
Allegheny Power (FirstEnergy)	8,685	9,373	0.8%	8,859	9,140	0.3%	8,675	8,762	0.1%	8,724	9,484	0.8%	8,835	9,755	1.0%
American Transmission Systems, Inc. (FirstEnergy)	12,378	12,428	0.0%	12,525	12,842	0.3%	12,273	12,551	0.2%	11,962	11,593	-0.3%	12,433	12,612	0.1%
Commonwealth Edison	20,635	20,876	0.1%	20,421	19,433	-0.5%	20,787	20,121	-0.3%	20,417	19,595	-0.4%	20,414	20,411	0.0%
AES Ohio	3,236	3,228	0.0%	3,415	3,550	0.4%	3,271	3,288	0.1%	3,295	3,255	-0.1%	3,319	3,385	0.2%
Duke Energy Ohio and Kentucky	5,280	5,650	0.7%	5,390	5,746	0.6%	5,239	5,427	0.4%	5,249	5,126	-0.2%	5,332	5,465	0.2%
Duquesne Light Company	2,759	2,855	0.3%	2,768	2,954	0.7%	2,742	2,837	0.3%	2,712	2,687	-0.1%	2,705	2,855	0.5%
East Kentucky Power Cooperative	2,004	2,334	1.5%	2,130	2,280	0.7%	2,091	2,228	0.6%	2,027	2,084	0.3%	2,070	2,211	0.7%
Ohio Valley Electric Corporation	95	95	0.0%	90	90	0.0%	90	90	0.0%	95	95	0.0%	90	90	0.0%
Diversity – Western	-1,377	-1,311		-2,248	-2,224		-1,647	-1,674		-1,581	-1,676		-1,571	-1,801	
Western	**75,640**	**79,641**	**0.5%**	**75,959**	**77,282**	**0.2%**	**75,704**	**76,126**	**0.1%**	**75,353**	**74,880**	**-0.1%**	**76,529**	**81,391**	**0.6%**
Dominion Energy	19,813	22,336	1.2%	20,150	21,269	0.5%	20,424	25,434	2.2%	21,920	35,789	5.0%	22,781	39,019	5.5%
Southern	**19,813**	**22,336**	**1.2%**	**20,150**	**21,269**	**0.5%**	**20,424**	**25,434**	**2.2%**	**21,920**	**35,789**	**5.0%**	**22,781**	**39,019**	**5.5%**
Diversity – RTO	-5,371	-5,644		-5,889	-5,563		-4,612	-5,268		-7,043	-7,395		-7,053	-7,190	
PJM RTO	**148,092**	**157,132**	**0.6%**	**149,224**	**153,759**	**0.3%**	**148,938**	**154,381**	**0.4%**	**149,059**	**160,971**	**0.8%**	**151,247**	**176,822**	**1.6%**

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2024 Forecasted Summer Zonal Load Growth Rates

The PJM RTO weather-normalized summer peak is forecasted to grow at an average rate of 1.6% per year for the next 10 years. The PJM RTO summer peak is forecasted to be 176,822 MW in 2034, an increase of 25,575 MW over the 2024 peak of 151,247 MW. Individual geographic zone growth rates vary from 0.0% to 5.5%, as shown in **Figure 2.4** and **Figure 2.5**.

Figure 2.4: PJM Mid-Atlantic Summer Peak Load Growth 2024–2034

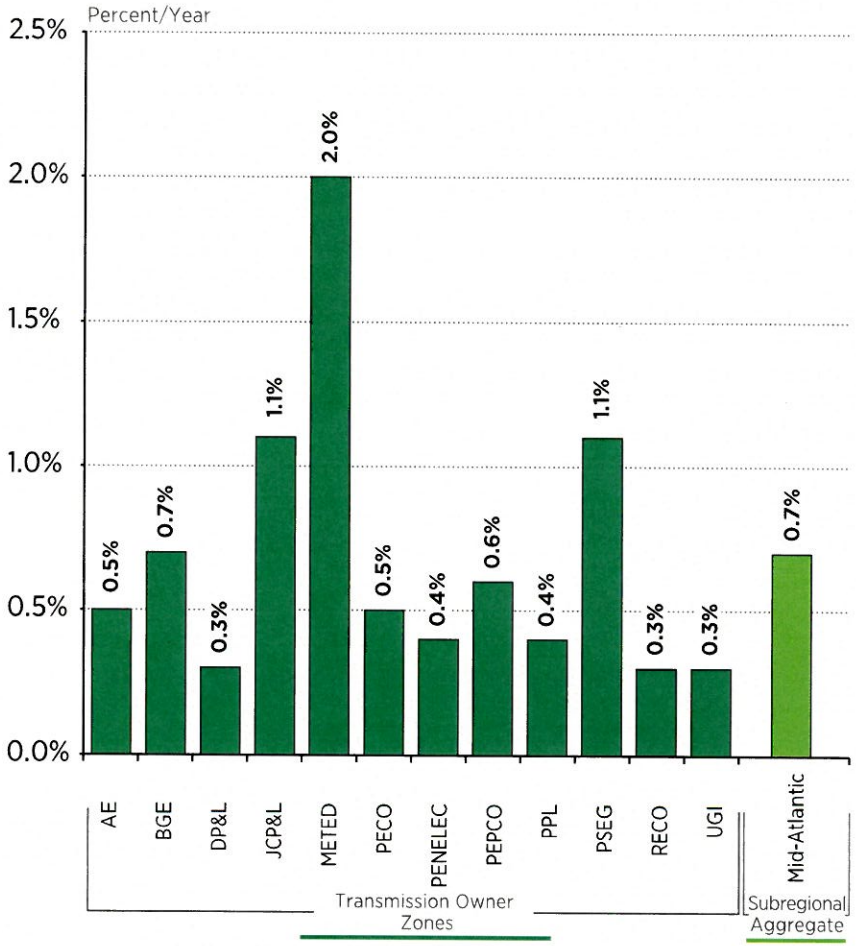
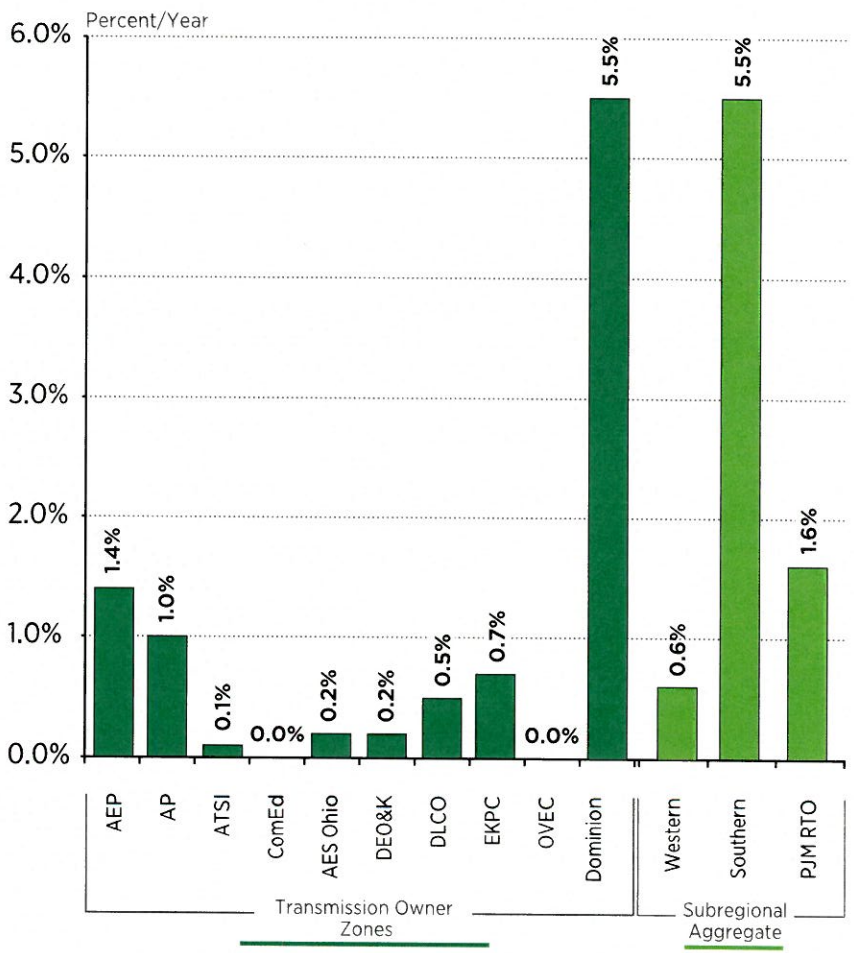


Figure 2.5: PJM Western and Southern Summer Peak Load Growth 2024–2034



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2024 Forecasted Winter Zonal Load Growth Rates

The PJM RTO weather-normalized winter peak is forecasted to grow at an average rate of 1.9% per year for the next 10 years. The PJM RTO winter peak is forecasted to be 163,069 MW in 2033/2034, an increase of 28,410 MW over the 2023/2024 peak of 134,659 MW. Individual geographic zone growth rates vary from 0.0% to 5.0%, as shown in **Figure 2.6** and **Figure 2.7**.

Figure 2.6: PJM Mid-Atlantic Winter Peak Load Growth 2024–2034

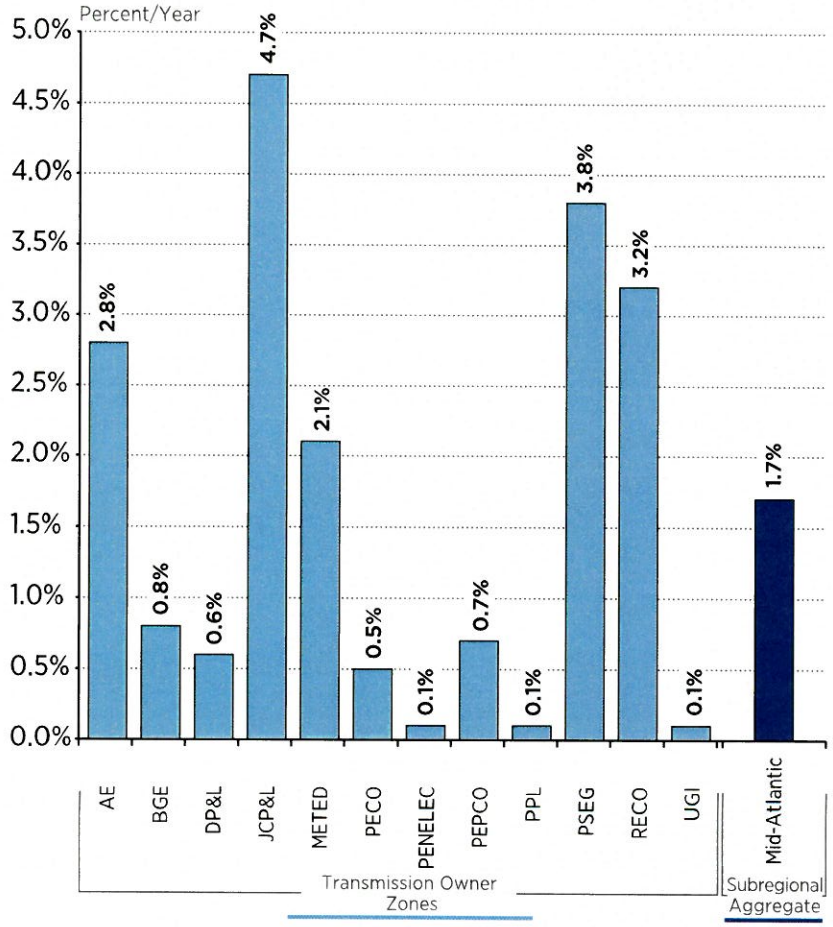
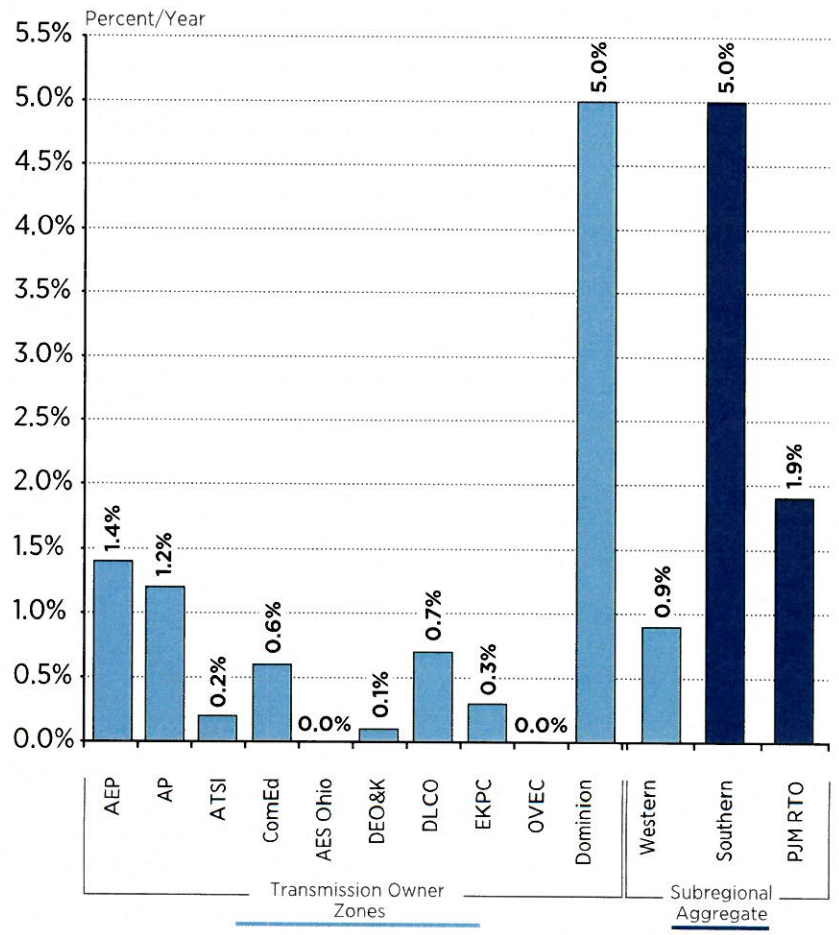


Figure 2.7: PJM Western and Southern Winter Peak Load Growth 2024–2034



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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 2020 through 2024, for the ensuing 10 years on a subregional basis. The growth trend reflects impacts from electric vehicle charging and data center growth, particularly in the Southern Region of PJM, which is growing at an increasing rate due to the large volume of data center activity in this area.

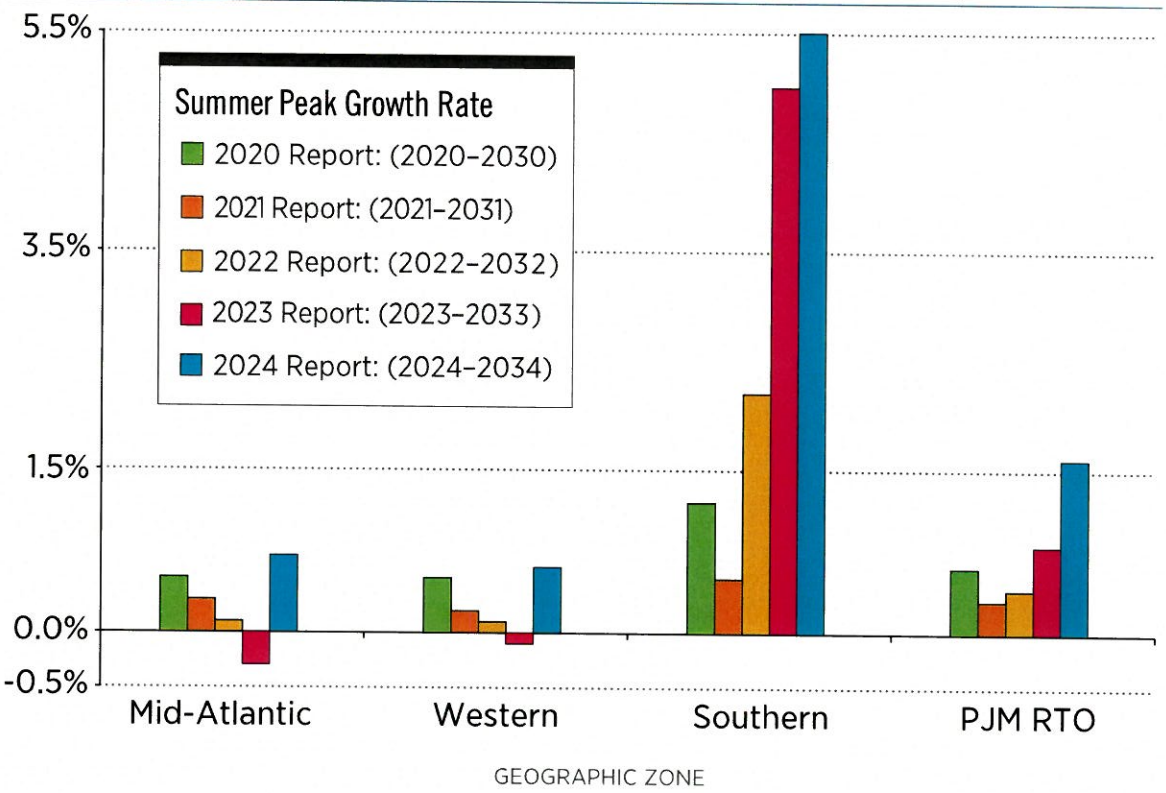
In particular, the 2024 report forecasted that the load growth rate for the RTO increased by 0.8% (from 0.8% to 1.6%) when compared to the 2023 report.

Data Center Load Growth

PJM annually solicits information from its member electric distribution companies (EDCs) and Load Serving Entities (LSEs) for known large load shifts (either positive or negative). 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 2024 Long-Term Load Forecast Report, Dominion Energy 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.

Figure 2.8: PJM 10-Year Summer Peak Load Growth Rate Comparison 2020–2024 Long-Term Load Forecast Reports



Dominion Energy has provided PJM with energy and peak information historical data for such facilities as well as expectations for new facilities through 2039. In addition to Dominion Energy, American Electric Power (AEP), Allegheny Power (AP) [FirstEnergy] and Public Service Electric & Gas (PSEG) have forecasted adjustments to account for data center load.

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2.2: Demand Resources and Peak Shaving

PJM forecasts the amount of demand response (DR) resources based on committed quantities in previous Reliability Pricing Model (RPM) auctions. Those amounts, as reflected in the 2024 Long-Term Load Forecast Report, are shown in **Table 2.4** for each transmission zone. An adjusted forecast (peak load forecast less forecasted DR) 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, DR can have a measurable impact on future system conditions and the potential need for transmission system enhancements to serve load. Forecasted values for each zone are determined based on the following steps:

1. Compute the final amount of committed DR for each of the three most recent delivery years. Express the committed DR amount as a percentage of the zone's 50/50 forecasted summer peak from the January load forecast report immediately preceding the respective delivery year.
2. Compute the most recent three-year-average committed DR percentage for each zone.
3. Multiply each zone's 50/50 forecasted summer peak by the results from step two to obtain the DR 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. East Kentucky Power Cooperative (EKPC) included a peak shaving program starting with the 2023 Delivery Year that was included in the 2023 and 2024 load forecasts.

Capacity Performance Impacts

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

- Annual DR resources are assumed to be Capacity Performance DR and are based on actual committed quantities of DR products in the 2021/2022, 2022/2023, 2023/2024 and actual cleared quantities in the 2022/2023, 2023/2024 and 2024/2025 RPM Base Residual Auctions for Price Responsive Demand.
- Summer period DR resources refer to DR that aggregates with winter-period resources to form a year-round commitment.

Both existing and planned DR 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.

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Table 2.4: 2024 Long-Term Load Forecast Report: Demand Resources

Transmission Owner	Total Load Management	
	2024	2034
Atlantic City Electric	48	51
Baltimore Gas and Electric	339	309
Delmarva Power	213	221
Jersey Central Power & Light	107	120
Met-Ed	161	198
PECO Energy Company	304	319
Pennsylvania Electric Company (Penelec)	230	239
PPL Electric Utilities	434	449
Potomac Electric Power Company (Pepco)	325	348
Public Service Electric & Gas Company (PSE&G)	231	257
Rockland Electric Company	2	2
UGI Utilities	0	0
Mid-Atlantic	**2,394**	**2,513**
American Electric Power	1,289	1,486
Allegheny Power (FirstEnergy)	581	642
American Transmission Systems, Inc. (FirstEnergy)	778	789
Commonwealth Edison	1,375	1,375
AES Ohio	167	171
Duke Energy Ohio and Kentucky	169	173
Duquesne Light Company	92	96
East Kentucky Power Cooperative	201	215
Ohio Valley Electric Corporation	0	0
Western	**4,652**	**4,947**
Dominion Energy	710	1,215
Southern	**710**	**1,215**
PJM RTO	**7,756**	**8,675**

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Section 3: Transmission Enhancements

3.0: 2024 RTEP Proposal Windows

3.0.1 — RTEP Process Context

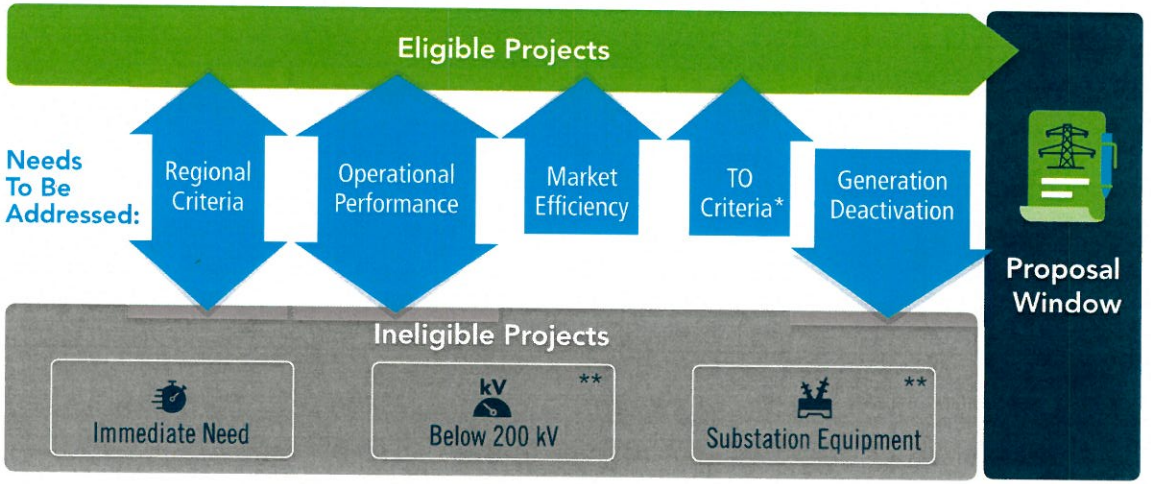
PJM seeks transmission proposals during each RTEP window to address one or more identified needs: reliability, market efficiency, operational performance and public policy. RTEP windows provide an opportunity for both incumbent and non-incumbent transmission developers to submit project proposals to 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.

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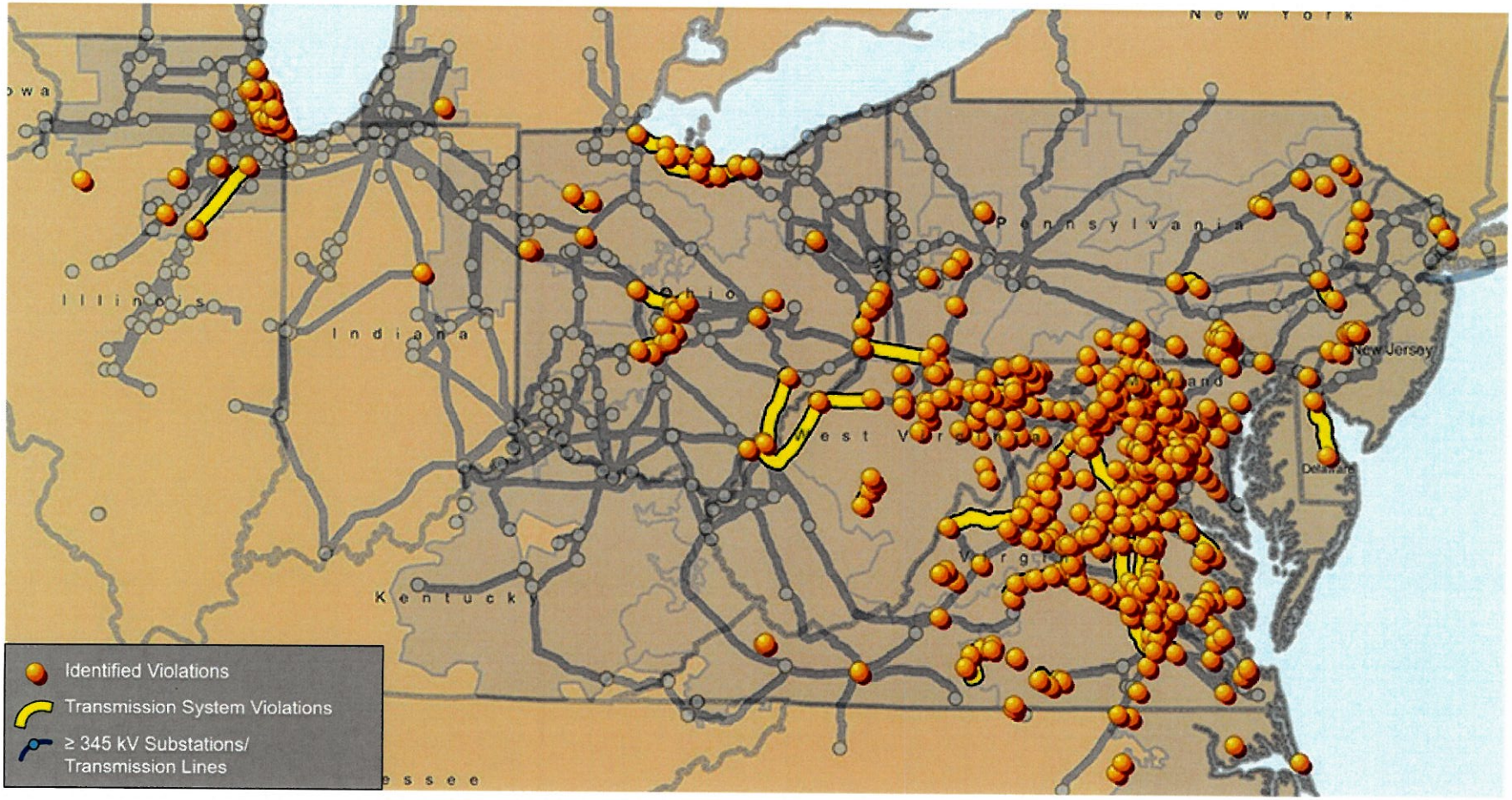
3.0.2 — 2024 RTEP Cycle

Baseline Analysis Results

PJM's analysis of 2029 and 2032 summer, winter and light load conditions identified 8,520 thermal and voltage criteria flowgate violations across PJM, as shown in **Map 3.1**, of which 1,609 were ineligible from competitive windows, as defined in **Section 3.0.1**. The 6,911 remaining violations were addressed in 2024 RTEP Proposal Window No.1, as discussed in **Section 3.0.3**. Subsequent **Map 3.2**, **Map 3.3** and **Map 3.4** show the flowgate violations by PJM subregions.

Map 3.1: 2024 RTEP Baseline Thermal and Voltage Criteria Violations



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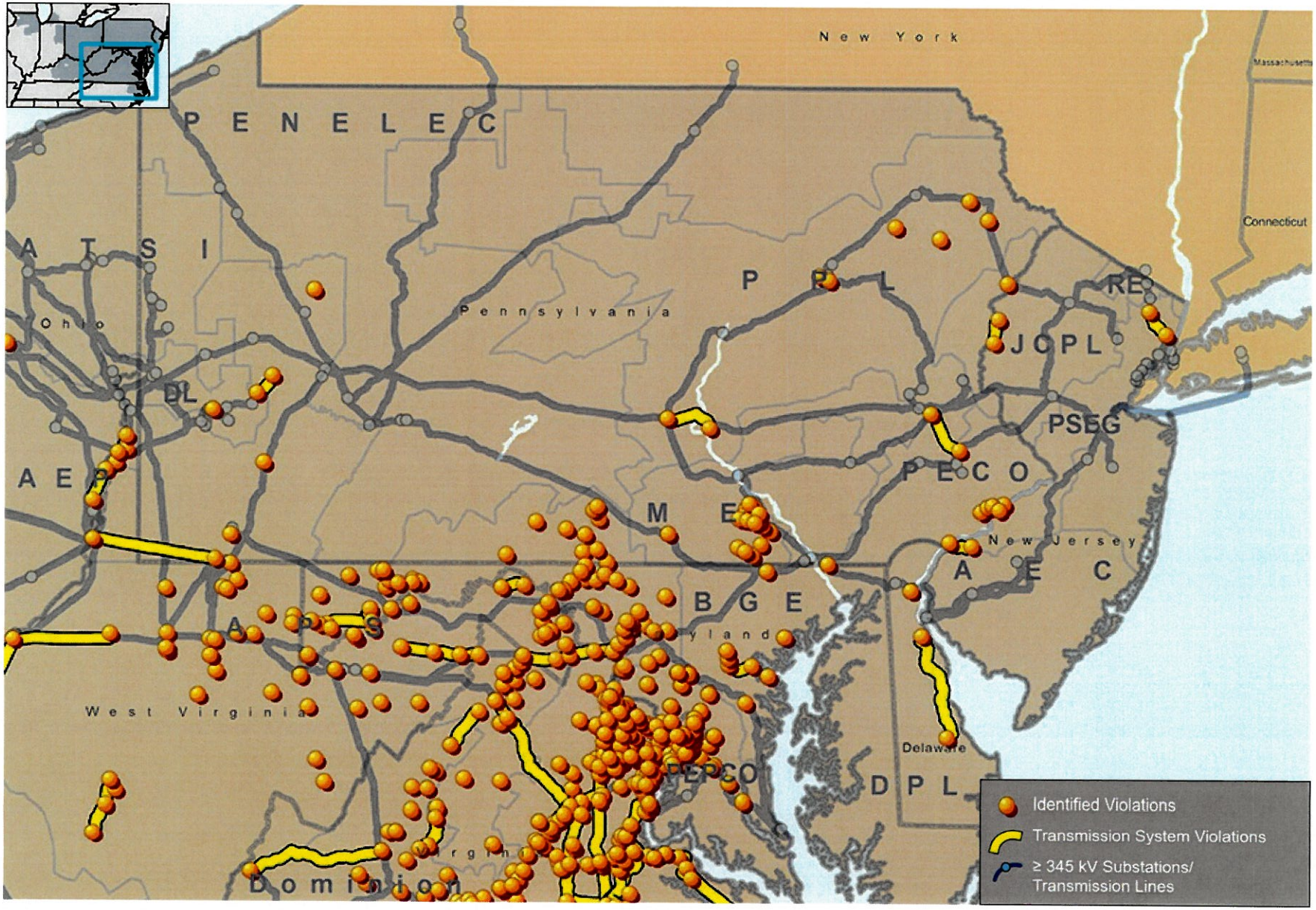
Map 3.2: 2024 RTEP Baseline Thermal and Voltage Criteria Violations – Mid-Atlantic



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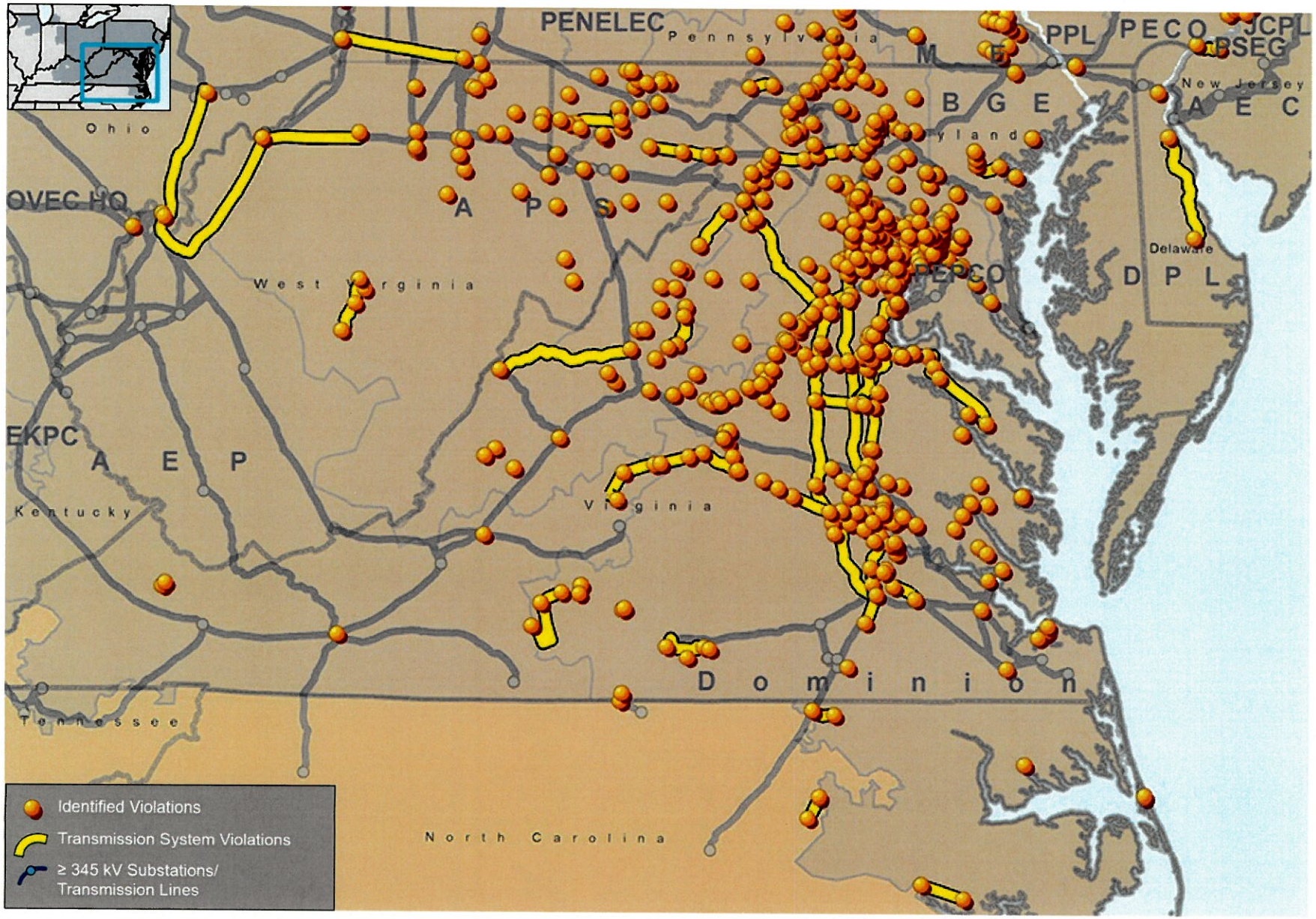
Map 3.3: 2024 RTEP Baseline Thermal and Voltage Criteria Violations – South



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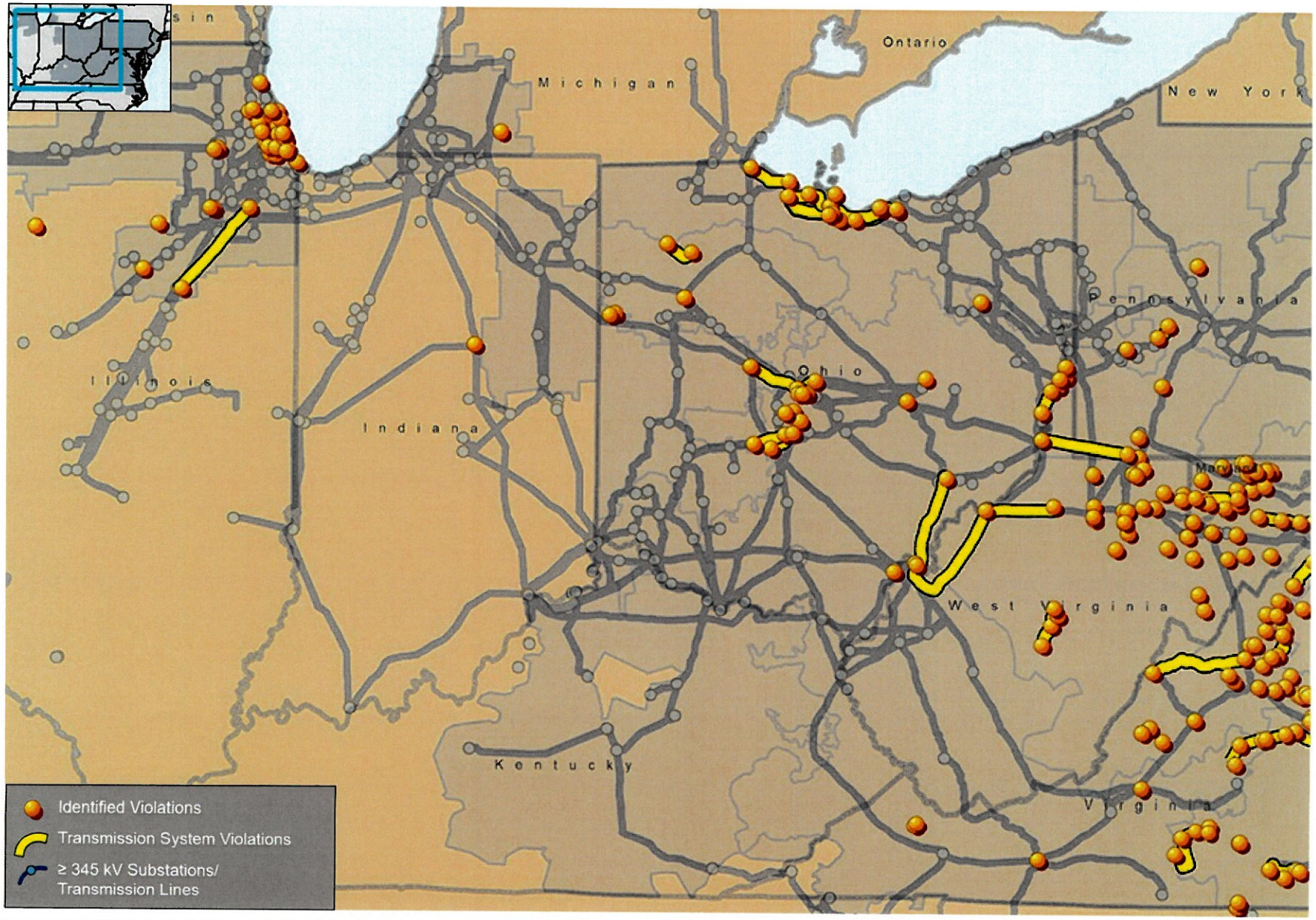
Map 3.4: 2024 RTEP Baseline Thermal and Voltage Criteria Violations – West



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The large number of violations observed in the 2024 RTEP were driven by heavy west-to-east transmission interface flows caused by large load increases in the Dominion zone and in eastern PJM: 10 GW and 15 GW load increase for 2029 and 2032 between the load forecasts used for the 2022 and 2024 RTEP study cycles, respectively. The significant load growth is attributed primarily to data centers, electrification and electric vehicle developments.

And, while the proposed reinforcements recommended through the 2022 RTEP Window 3 and the 2023 RTEP Windows 1 and 2 are indeed solving the NERC reliability criteria violations, which justified their need, additional load pockets in the American Electric Power (AEP), American Transmission Systems, Inc. (ATSI) [FirstEnergy], Dominion, PECO, Baltimore Gas and Electric (BGE) and PPL transmission zones have shifted power transfers, amplified by generator deactivations totaling over 2 GW.

3.0.3 — 2024 RTEP Proposal Window No. 1

PJM opened 2024 RTEP Proposal Window No. 1 on July 15, 2024, to solve 6,911 NERC reliability criteria violations identified in the RTEP 2029 model year analysis as well as those identified in the 2032 model year requiring long-lead-time transmission solutions. The objective is to develop holistic and robust solutions to address the identified criteria violations.

2024 RTEP Proposal Window No. 1 closed on Sept. 17, 2024, out of which PJM received 94 competitive proposals from 16 entities as shown in **Table 3.1**. Of these, 46 proposals were greenfield projects. The remaining 48 were upgrades to existing transmission infrastructure. Cost containment provisions were included in 48 of the proposals. On the following pages:

- 2024 RTEP Proposal Window No. 1 proposed solution submittals to resolve competitive regional violations are shown in **Map 3.5**.
- 2024 RTEP Proposal Window No. 1 proposed solution submittals to resolve competitive local violations in the Southern Region of PJM are shown in **Map 3.6**.
- 2024 RTEP Proposal Window No. 1 proposed solution submittals to resolve competitive local violations in the Mid-Atlantic Region of PJM are shown in **Map 3.7**.
- 2024 RTEP Proposal Window No. 1 proposed solution submittals to resolve competitive local violations in the Western Region of PJM are shown in **Map 3.8**.

Baseline Solutions

The PJM Board approved competitive regional baseline solutions totaling $4.65 billion, along with $1.27 billion worth of competitive local solutions and noncompetitive projects for the 2024 RTEP, to address the reliability criteria violations posted with this window. After 2024 RTEP Proposal Window No. 1 closed, PJM evaluated the submitted proposals to develop and recommend solutions that meet all reliability and constructability requirements as detailed in the Reliability Analysis Report and Constructability & Financial Analysis Report, accessible on the Transmission Expansion Advisory Committee web page.

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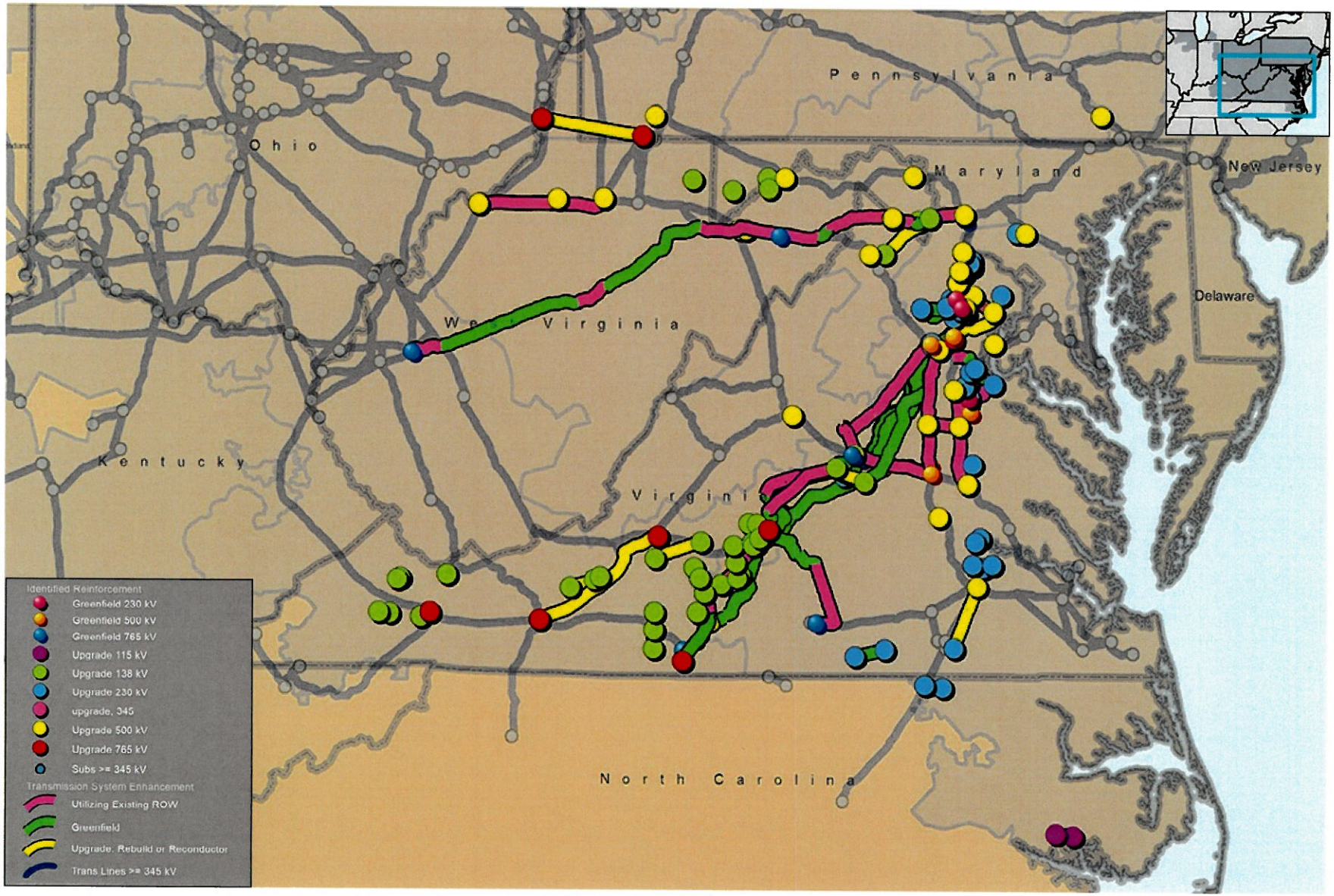
Map 3.5: 2024 RTEP Proposal Window No. 1 Submittals – Regional



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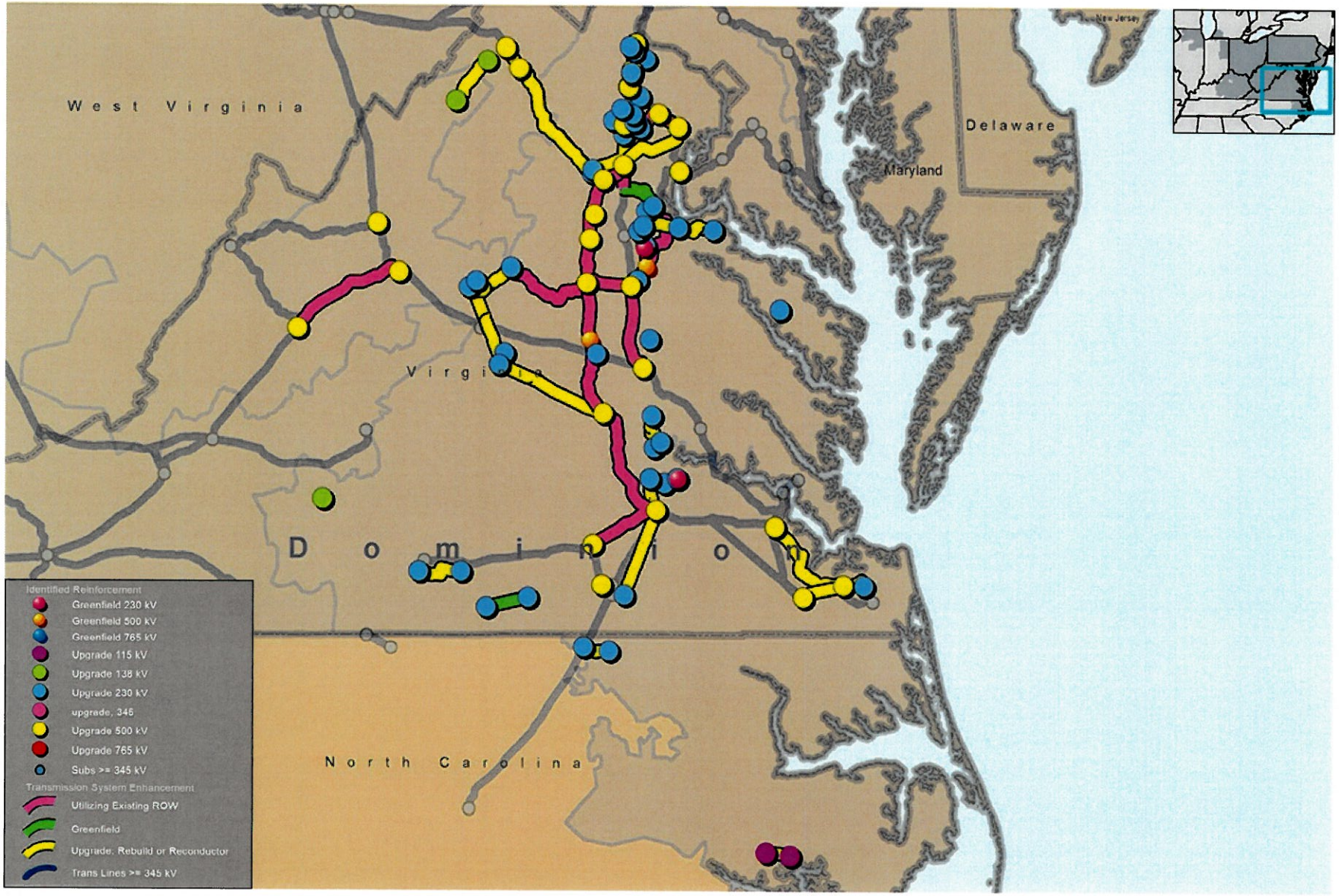
Map 3.6: 2024 RTEP Proposal Window No. 1 Submittals – South



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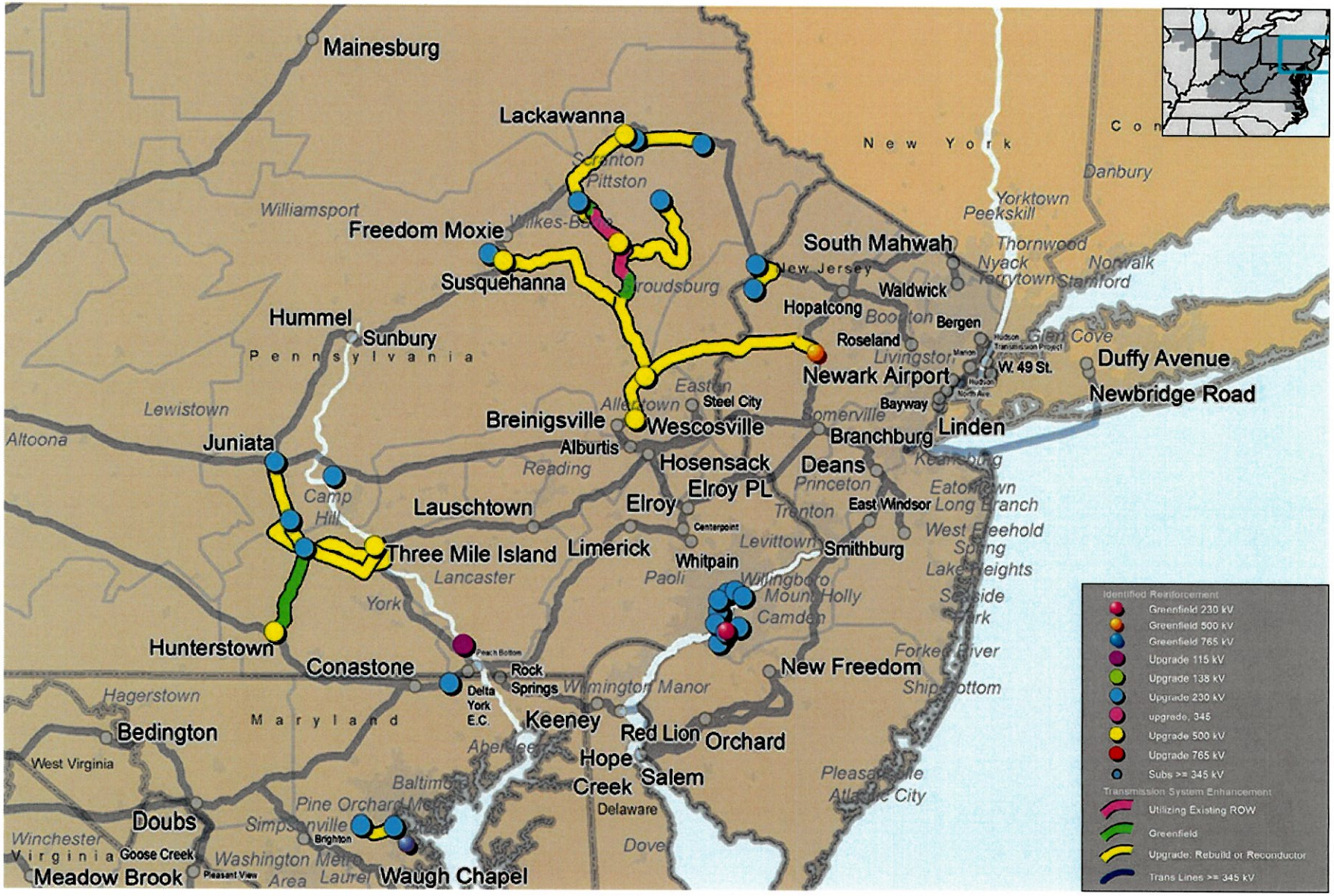
Map 3.7: 2024 RTEP Proposal Window No. 1 Submittals – Mid-Atlantic



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Map 3.8: 2024 RTEP Proposal Window No. 1 Submittals – West

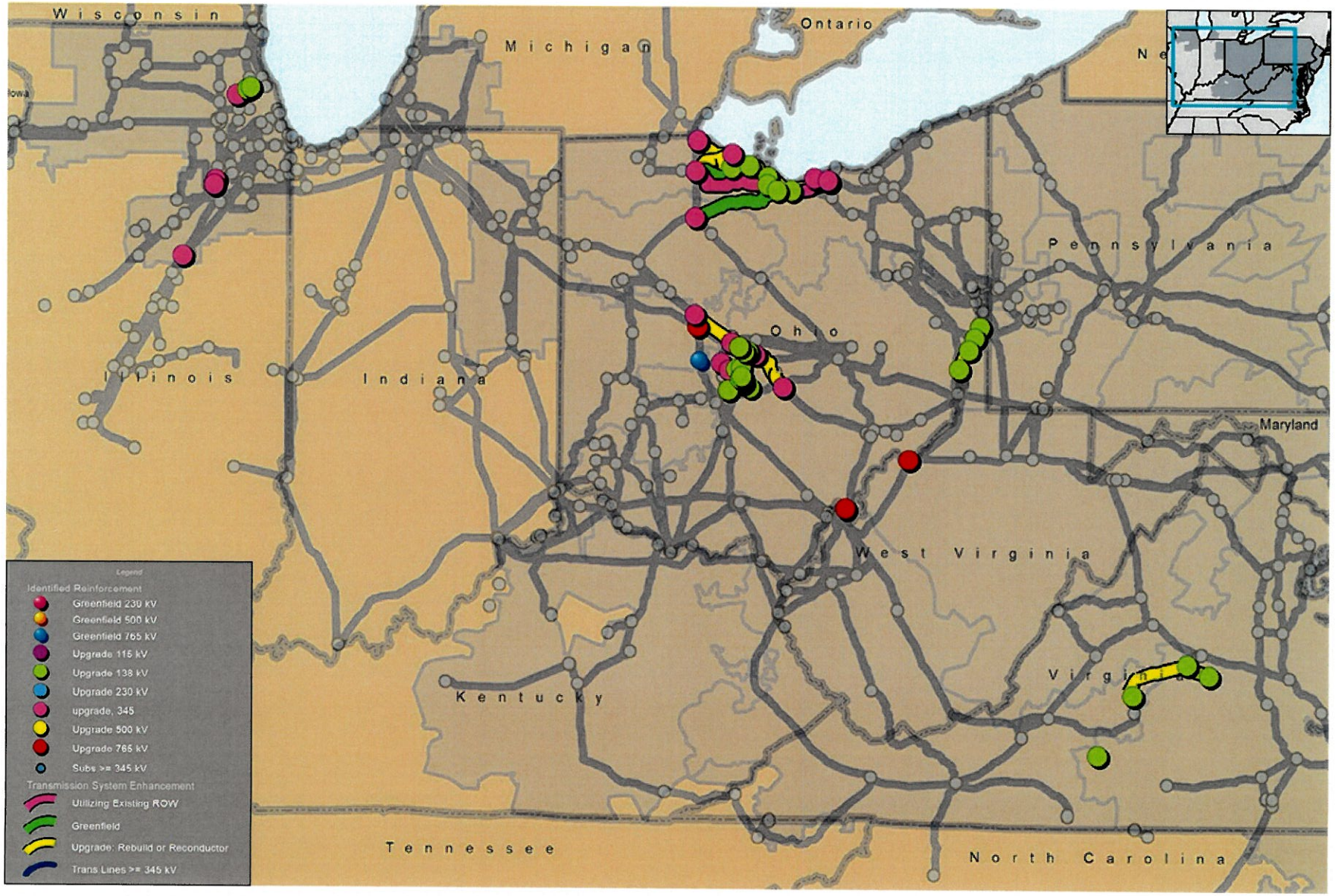

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Table 3.1: 2024 RTEP Proposal Window No. 1 Submittals

Proposal ID	Cluster	Proposing Entity	Project Type	Cost Containment	Cost Estimate ($M)	Project Title
738	AEP Local 1	AEPSCT	UPGRADE	No	$140.36	Boxwood-Bremo 138 kV rebuild
873		VEPCO			$42.10	Line 8 Rebuild-Bremo to Scottsville Interconnection (APCO)
949		AEPSCT			$10.58	Boxwood-Bremo 138 kV sag study and partial rebuild
276	AEP Local 2		GREENFIELD		$4.08	Bixby-Buckeye Steel 138 kV reconfiguration
856			UPGRADE		$31.09	Canal-Mound Street 138 kV rebuild
350	AEP Local 3 & 4	TRNSRC	GREENFIELD	Yes	$229.41	Jester-Hayden
863		AEPSCT	UPGRADE	No	$2.33	Maliszewski series reactor upgrades
408	AEP Local 3, 4 & 5		GREENFIELD		$145.49	Maliszewski 765/345 kV upgrades
744	AEP Local 4		UPGRADE		$8.88	Maliszewski-Polaris rebuild
756	AEP Local 6				$1.75	Cyprus station reconfiguration
769					$33.11	Rebuild Beatty-Cyprus 138 kV line
338	AEPL Local 3				$8.79	Genoa-Westar rebuild
464					$2.81	Genoa-Westar sag remediation
294	ATSI	NEETMH	GREENFIELD	Yes	$257.30	Bay Shore-Davis-Besse-Lake Ave
357					$344.12	Bay Shore-Davis-Besse-Lake Ave + Lemoyne-Lake Ave 345 kV
533					$202.08	Lemoyne-Lake Ave 345 kV
605		ATSI	UPGRADE	No	$265.16	ATSI 138 kV rebuild + substation terminal upgrades
694		TRNSRC	GREENFIELD	Yes	$328.37	Fostoria Central-Lake Ave. 345 kV DC
843		ATSI	UPGRADE	No	$455.04	Lemoyne-Lake Ave 345 kV line
295	BGE	PEPCO			$107.62	Marley Neck 115 kV substation
470					$71.96	BGE local mitigation alternative
135	COMED Local 1	COMED			$16.27	Reconductor 345 kV lines 1202 & 1227 Dresden to Mulberry
447			GREENFIELD		$23.59	Cut 345 kV L8014 Pontiac to Dresden into Mulberry
532			UPGRADE		$28.23	345 kV shunt inductor at Mulberry
816	COMED Local 2				$14.31	Autotransformer at Itasca
888					$7.21	Reconductor Des Plaines to Busse
24	DOM Local	VEPCO	GREENFIELD		$861.74	230 kV and 115 kV solutions for portfolios
261			UPGRADE		$70.78	Overdutied breaker replacement
390			GREENFIELD		$1,008.58	230 kV safety solutions (Optional reinforcements depending on selected proposals)
527			UPGRADE		$322.00	500 kV and 230 kV cap bank and STATCOM installation (Required/discretionary depending on selected proposals)

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Table 3.1: 2024 RTEP Proposal Window No. 1 Submittals (Cont.)

Proposal ID	Cluster	Proposing Entity	Project Type	Cost Containment	Cost Estimate ($M)	Project Title
761	DOM Local	VEPCO	UPGRADE	No	$104.07	138/115 kV safety solutions (Optional reinforcements depending on selected proposals)
781					$161.68	500 kV solutions for portfolios
967			GREENFIELD	Yes	$1,189.78	DVP central area improvement for portfolios
980			UPGRADE	No	$216.78	500 kV line No. 579 EOL rebuild Septa-Yadkin
983			GREENFIELD		$2,839.36	500 kV safety solutions (Optional reinforcements depending on selected proposals)
502	METED	MATLIT	UPGRADE		$43.09	Hunterstown No. 2 500/230 kV transformer
117	No Cluster	AEPSCT			$15.05	Tidd-Mahans Lane 138 kV rebuild
132		PEPCO			$12.42	Dickerson H 230 kV caps
167		AEPSCT			$0.12	Leesville station conductor replacement
232		POTOED			$97.47	FirstEnergy upgrades to support portfolio proposals
459		AEPSCT			$10.52	Mountaineer and Belmont station upgades
574					$28.57	Tiltonsville-West Bellaire 138 kV rebuild
940					$15.59	Canal-Gay 138 kV rebuild
944		NEETMH			$69.14	Upgrades to AEP 138 kV and Dominion 230 kV transmission lines
955	PECO	PSEGRT	GREENFIELD		$390.99	230 kV Eagle Point-Penrose
12		PE	UPGRADE		$43.22	PECO competitive window upgrades
546	PPL Local 1	TRNSLK	GREENFIELD	Yes	$246.05	Pennsylvania Border-Drakestown 500 kV line (greenfield route)
900					$277.00	Pennsylvania Border-Drakestown 500 kV line (brownfield route)
17	PPL Local 2	PPLTO	UPGRADE		$35.00	Bushkill-Kittatinny 230 kV line reconductor
72					$78.59	Juniata-Cumberland-Williams Grove 230 kV upgrade project
312			GREENFIELD		$116.33	Acahela 500/230 kV substation expansion project
330					$356.70	Juniata-Hunterstown 500 kV line
386			UPGRADE		$353.71	Juniata-TMIS 500 kV DCT line
479					$47.70	Lackawanna-Paupack 230 kV line reconductor
526					$60.03	Jenkins-Pocono 230 kV line
549					$9.50	Susquehanna T10 station line reconfiguration
850					$4.93	Pocono 80 MVAR 230 kV capacitor bank
860					$9.51	Face Rock T1 and T2 transformer replacement
876					$106.93	Siegfried 500/230 kV substation expansion project
922			GREENFIELD		$618.38	Lackawanna-Siegfried-Drakestown 500 kV line project

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Table 3.1: 2024 RTEP Proposal Window No. 1 Submittals (Cont.)

Proposal ID	Cluster	Proposing Entity	Project Type	Cost Containment	Cost Estimate ($M)	Project Title
926	PPL Local 2	PPLTO	UPGRADE	Yes	$36.83	Wescosville 2nd 500/138 kV transformer
935					$22.24	Juniata 500 kV substation yard reconfiguration
994					$2.26	Juniata-Dauphin 230 kV line reconductor
81	Regional	TRNSRC		No	$137.02	AEP incumbent upgrades for Portfolio #1, 2 & 3
286			GREENFIELD	Yes	$350.25	Joshua Falls-Durandal
300					$381.73	Yeat-Vontay
551		POTOED		No	$13.97	Woodside/Chanceford/Rocky Point termination swap
617		TRNSRC			$167.35	AEP incumbent upgrades for Portfolio #4
665				Yes	$1,188.51	Joshua Falls-Vontay-Morrisville South
708		TRAIL			$1,944.99	John Amos-Welton Spring-Rocky Point 765 kV line
727		KEYATC	UPGRADE	No	$292.46	Kammer-502 Junction 765 kV line
820		TRNSRC	GREENFIELD	Yes	$1,016.90	765 kV Joshua Falls-Yeat
883		TRAIL			$1,274.42	John Amos-Welton Spring 765 kV line
885			UPGRADE	No	$52.67	FirstEnergy components for proposals 2024-W1-636, 610, 279 and 114
907			GREENFIELD	Yes	$2,838.90	500 kV expansion plan
977					$277.41	Belmont-Harrison 500 kV line
78	Regional & Dominion Local	CNTLTM			$1,897.05	F5 Solution
114		TRNSRC		No	~$3,300.00	Portfolio #4B
124		CNTLTM		Yes	$1,810.83	F4 Solution
146		NEETMH			$2,263.76	Axton-Joshua Falls 765 kV + Joshua Falls-Mt Ida 500 kV
200		CNTLTM			$439.75	Common Components
262		TRNSRC		No	$5,497.68	Portfolio #1A
279					~$2,400.00	Portfolio #4A
317		CNTLTM		Yes	$1,896.76	F7 Solution
506					$1,732.11	F6 Solution
610		TRNSRC		No	~$3,700.00	Portfolio #3
622		CNTLTM		Yes	$1,848.14	F2 Solution
636		TRNSRC		No	~$3,900.00	Portfolio #2
759					$4,827.12	Portfolio #1B
768		NEETMH		Yes	$2,191.01	Axton-Joshua Falls-Mt Ida

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Table 3.1: 2024 RTEP Proposal Window No. 1 Submittals (Cont.)

Proposal ID	Cluster	Proposing Entity	Project Type	Cost Containment	Cost Estimate ($M)	Project Title
839	Regional & Dominion Local	CNTLTM	GREENFIELD	Yes	$1,808.09	F8 Solution
898					$2,015.63	F3 Solution
904					$1,864.62	F1 Solution
992		NEETMH			$2,256.23	Axton-Joshua Falls-Mt Ida 765 kV transmission lines + Link 500/230 kV substation

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3.1: Transmission Owner Criteria

3.1.1 — 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.

As part of its RTEP process, PJM applies TO criteria to the respective facilities included in the transmission facilities list maintained by PJM. Transmission enhancements driven by TO criteria are considered RTEP baseline projects. Projects may be eligible for proposal window consideration as shown earlier in **Figure 3.1**. Under the terms of the PJM Open Access Transmission Tariff (OATT), the costs of such projects follow existing baseline reliability cost allocation rules.

3.1.2 — 2024 RTEP TO Criteria-Driven Projects

The 2024 RTEP included 18 TO criteria-driven projects for a total cost of approximately $297 million. The description and location of those projects are shown in **Table 3.2** and **Map 3.9**. More detailed descriptions of these projects can be found in TEAC PJM Board White Papers.

Map 3.9: 2024 Transmission Owner Criteria-Driven Projects

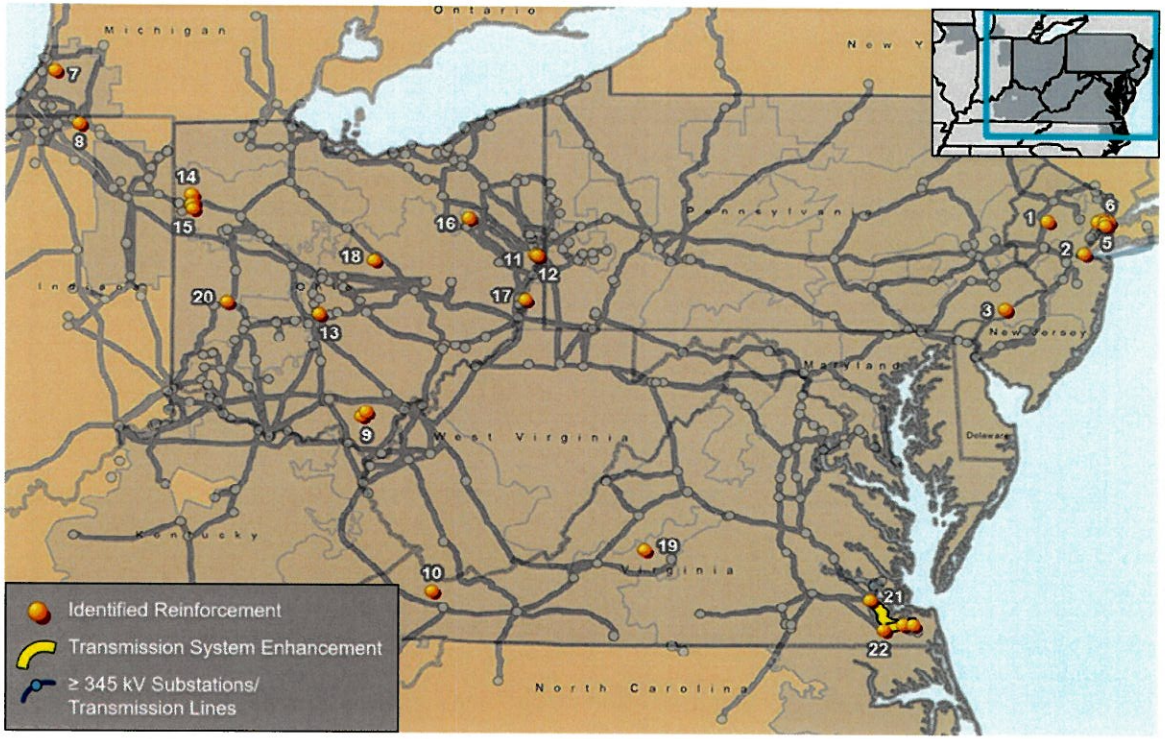

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Table 3.2: 2024 Transmission Owner Criteria-Driven Projects

Map ID	Sub ID	Description	TO Zone	TEAC Cost ($M)	Required In-Service Date	Projected In-Service Date
1	B3860.1	Replace the 34.5 kV bus tie breaker at Chester substation with a new 34.5 kV breaker that has an interruption capability of 40 kA.	JCP&L	$0.54	6/1/2029	6/1/2029
2	B3861.1	Replace the W101 34.5 kV breaker at Werner substation with a new 34.5 kV breaker that has an interruption capability of 40 kA.		$0.54		
3	B3863.1	Change tap ratios on two CTs at Schuylkill 230 kV substation.	PECO	$0.10	12/1/2029	12/1/2029
4	B3868.1	Cut existing Carlstadt to River Road 69 kV line and extend Carlstadt line side to Penhorn 69 kV. Extend the other end of the line by constructing a new portion and connecting it to Kingsland 69 kV switch.	PSEG	$14.62	6/1/2029	6/1/2029
5	B3868.2	Extend the other end of L-636 to Kingsland switch by constructing new 5.5 miles portion utilizing existing I-2314 transmission towers from H-A 5/4 to H-A 2/3. New 69 kV line to be routed along County Ave pass Secaucus Rd in Secaucus NJ.		$30.87		
6	B3868.3	Reconfigure former River Road to Carlstadt 69 kV and Tonnelle Ave to Union City 69 kV lines at the intersection Tonnelle Ave and Granton Ave in North Bergen, NJ by connecting Union City to River Road and Tonnelle Ave to Kingsland.		$0.51		
7	B3872.1	Adjust the tertiary tap on the Hartford 138/69/34.5 kV transformer 1 and on Hartford 138/69/12 kV transformer 4 to eliminate the high voltage issues and avoid circulating current.	AEP	$0.10	4/15/2029	6/1/2026
8	B3873.1	Install 12 MVAR 34.5 kV cap bank at Greenleaf.		$1.31	6/1/2029	6/1/2029
9	B3875.1	Reconductor ~3.95 miles of ACSR 6/1 Penguin (4/0) on the Firebrick-Jefferson switch 69 kV branch with ACSR 556.6 26/7. Remote end (line setting) would need to be updated at Firebrick and Lick. Replace 600A switches at Jefferson and replace 477 AA 19 sub conductor at Firebrick.		$8.50		4/1/2029
10	B3876.1	Install a 69 kV 11.5 MVAR capacitor bank at Richlands station with a circuit switcher.		$1.00	12/1/2029	12/1/2029
11	B3879.1	Replace line conductor, ~0.11 miles of 4/0 ACSR 6/1 conductor with 556.5 26/7 between South Toronto and the South Toronto Tap.		$0.50	6/1/2029	4/1/2029
12	B3879.2	Upgrade the wave trap, CCVTs, switches, and station conductor at South Toronto station currently limiting the line to South Toronto Tap.		$0.60		6/1/2029
13	B3880.1	At Beatty Road substation, install a 69 kV 23 MVAR capacitor bank along with the 69 kV cap bank breaker.		$2.25		
14	B3883.1	69 kV station equipment, including relays, conductor, and switches, will be replaced at Haviland station in order to address identified overloads on the lines to North Van Wert and Cavett.		$0.80	12/1/2029	4/1/2029
15	B3884.1	Replace the 69 kV circuit breaker D at Van Wert with a 40 kA breaker.		$1.00	6/1/2026	6/1/2026
16	B3885.1	Replace 69 kV circuit breakers N and M at Schroyer Avenue station with higher fault current capable counterparts.		$2.00		
17	B3886.1	Replace 69 kV circuit breaker A along with disconnect switches at Benwood substation with a 40 kA circuit breaker.		$1.00		
18	B3892.1	Replace 69 kV circuit breakers A and S at Mount Vernon station with 40 kA breakers.		$2.00		
19	B3896.1	Adjust the capacitor bank voltage settings to allow the cap bank to operate as needed under N-1-1 scenarios.		$0.10	12/1/2029	6/1/2029
20	B3918.1	Add one additional breaker, a 2nd 138/69kV transformer, replace five 69 kV breakers & four 138 kV breakers.	AMPT	$12.00	6/1/2029	6/30/2028
21	B3929.1	Rebuild ~33.09 miles of 500 kV line No. 579 from structure 579/1 inside Septa substation to structure 579/193 inside Yadkin substation.	Dominion	$191.25		6/1/2029
	B3929.2	At Septa substation, upgrade CB (579T586), breaker switches (56288, 57985, 58688 & 57988), and line leads to 5000A rating to support line No. 579 rebuild.		$3.84		
	B3929.3	At Yadkin substation, upgrade line leads to 5000A rating to support line No. 579 rebuild.		$0.44		
22	B3929.4	Rebuild ~7.7 miles of 230 kV line No. 2110 Suffolk – Thrasher that share the double circuit towers under line No. 579.		$21.25		

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3.2: Supplemental Projects

3.2.1 — Project Drivers

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 3.2 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 OATT Attachment M-3 process.

3.2.2 — OATT Attachment M-3 Process

While not subject to PJM Board approval, supplemental projects are included in PJM's RTEP models. The OATT Attachment M-3 process of the PJM Tariff describes the FERC-approved process that PJM and TOs must follow.

PJM, in its role as a facilitator in the OATT Attachment M-3 process, is responsible for the following:

- Provide necessary facilitation and logistical support so that supplemental project planning meetings can be conducted as outlined in the OATT Attachment M-3 process 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.
- Collaborate with TOs and stakeholders to improve OATT Attachment M-3 process transparency.

Figure 3.2: Primary Supplemental Project Drivers

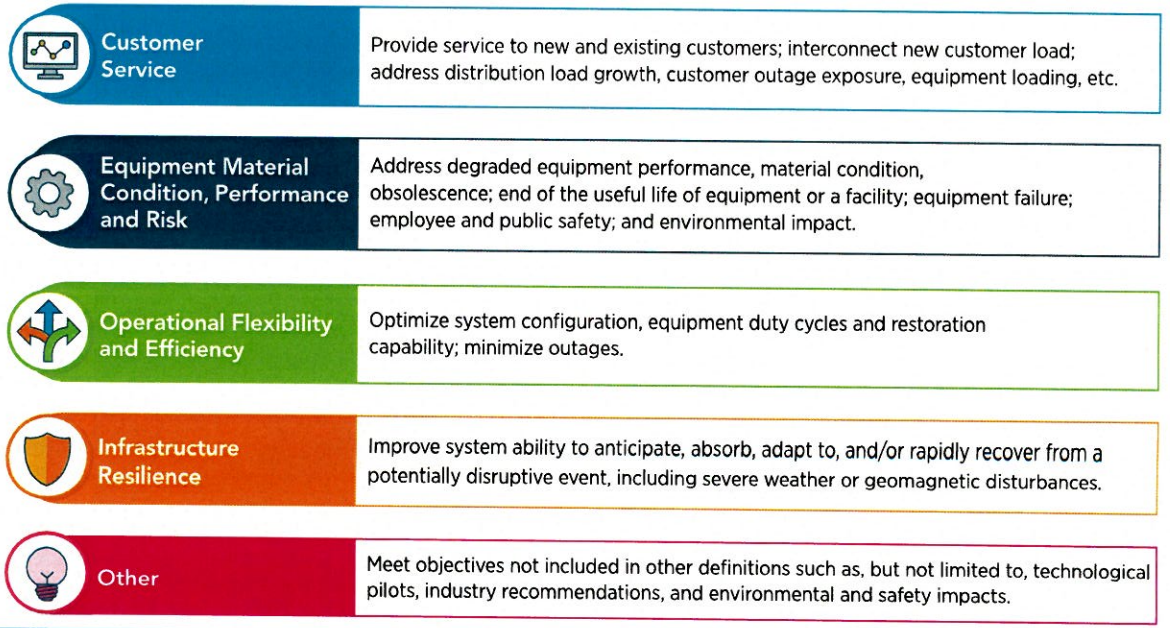

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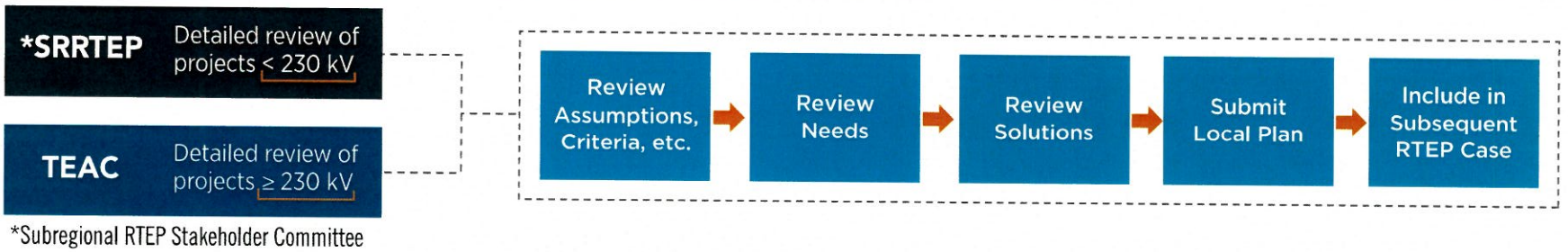
Figure 3.3: OATT Attachment M-3 Process for Supplemental Projects



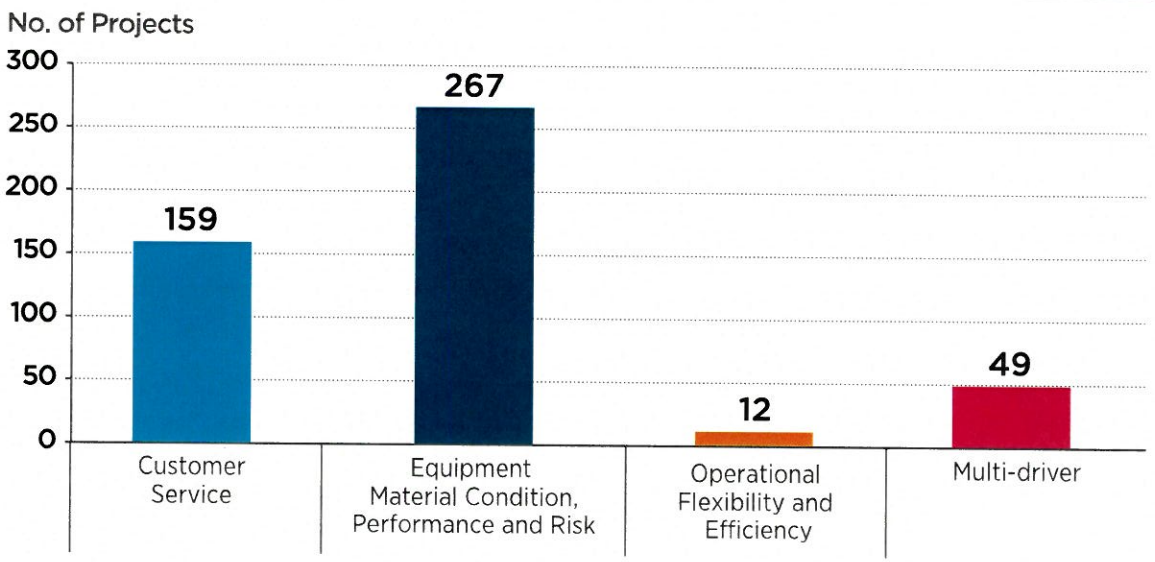
*Subregional RTEP Stakeholder Committee

The OATT Attachment M-3 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 3.3**. Stakeholders interested in providing feedback can do so via PJM's Planning Community.

3.2.3 — 2024 Supplemental Projects

PJM evaluated over $9 billion of TO supplemental projects for the 2024 Local Plan. **Figure 3.4** 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 customer service, which totals approximately $4.49 billion. Projects driven by equipment material condition, performance and risk, and operational flexibility and efficiency total $3.3 billion and $110 million, respectively. The remaining $1.17 billion are required by projects with more than one driver.

Figure 3.4: 2024 Supplemental Projects by Driver



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3.3: Generator Deactivations

PJM received 30 deactivation notices totaling 2,091.1 MW of generation deactivation in 2024. **Map 3.10** and **Table 3.3** show these generators' deactivation notifications.

Map 3.10: Deactivation Notifications Received in 2024

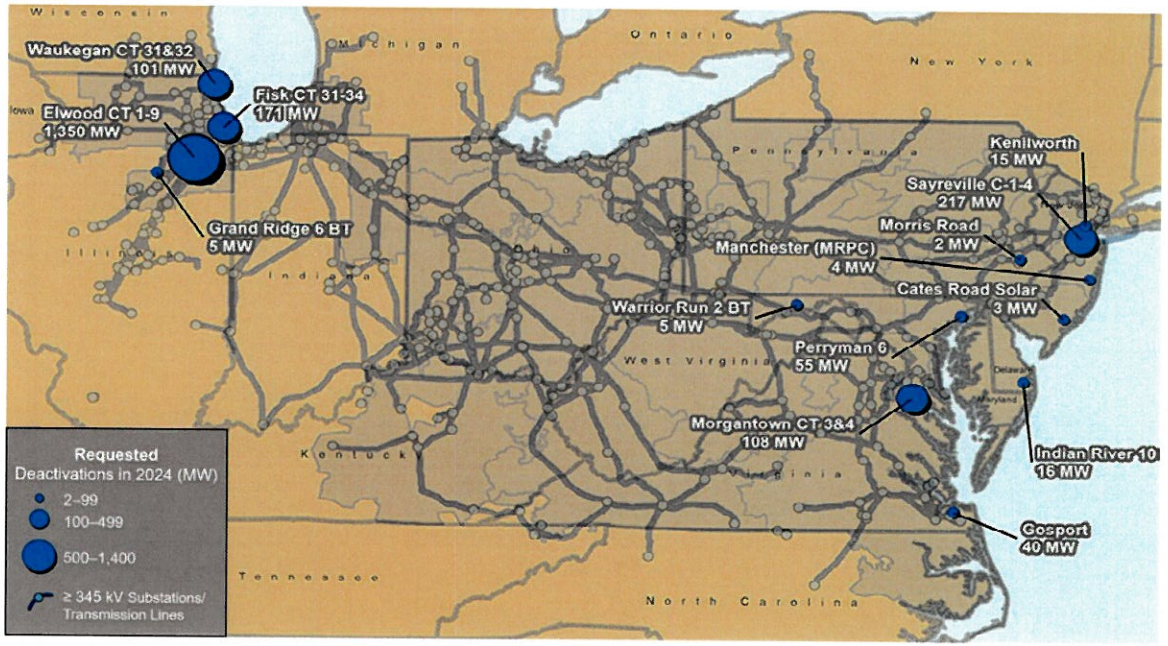

Table 3.3: Deactivation Notifications Received in 2024

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Owner Request Date	Requested Deactivation Date	Projected Deactivation Date
Cates Road Solar	2.6	ACE	10	Solar	12/30/2024	4/1/2025	4/1/2025
Manchester (MRPC) Nug	4	JCP&L	36	Methane	11/14/2024	5/1/2025	5/1/2025
Kenilworth Nug	15	PSEG	35	Natural Gas	9/13/2024	6/1/2026	6/1/2026
Fisk CT 31	49.1	ComEd	56	Oil	7/22/2024		
Fisk CT 32	50.8						
Fisk CT 33	47.9						
Fisk CT 34	22.9						
Indian River 10	16.1	DP&L	4				

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Table 3.3 Deactivation Notifications Received in 2024 (Cont.)

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Owner Request Date	Requested Deactivation Date	Projected Deactivation Date
Waukegan CT 32	48.9	ComEd	56	Oil	7/22/2024	6/1/2026	6/1/2026
Waukegan CT 31	52.5						
Perryman 6	54.9	BGE	9	Natural Gas	7/20/2024	5/31/2025	5/31/2025
Morgantown CT 4	54	PEPCO	51	Oil	7/19/2024	6/1/2026	6/1/2026
Morgantown CT 3	54						
Morris Road 1 D	2	PECO	14		7/17/2024	5/31/2025	5/31/2025
VP Gosport 1 F	40	Dominion	36	Biomass	7/11/2024	7/15/2024	7/15/2024
Grand Ridge 6 BT	4.5	ComEd	12	Storage	6/28/2024	10/1/2024	10/1/2024
Warrior Run 2 BT	5	AP	22	Battery	5/31/2024		
Elwood CT 9	150	ComEd	25	Natural Gas	5/29/2024	6/1/2025	6/1/2025
Elwood CT 8	150						
Elwood CT 7	150						
Elwood CT 6	150						
Elwood CT 5	150						
Elwood CT 4	150						
Elwood CT 3	150						
Elwood CT 2	150						
Elwood CT 1	150						
Sayreville C-4	48.5	JCP&L	51		5/12/2024	6/1/2024	6/1/2024
Sayreville C-3	54.6						
Sayreville C-2	56.7						
Sayreville C-1	57.1						

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Fifteen generators totaling 701.1 MW deactivated in the PJM region during 2024, as shown in **Map 3.11** and **Table 3.4**. PJM conducted the required reliability analyses to evaluate the system impact of these deactivations. No NERC reliability criteria violations were identified. Consequently, no additional RTEP baseline enhancements are required.

Map 3.11: Actual Generator Deactivations in 2024

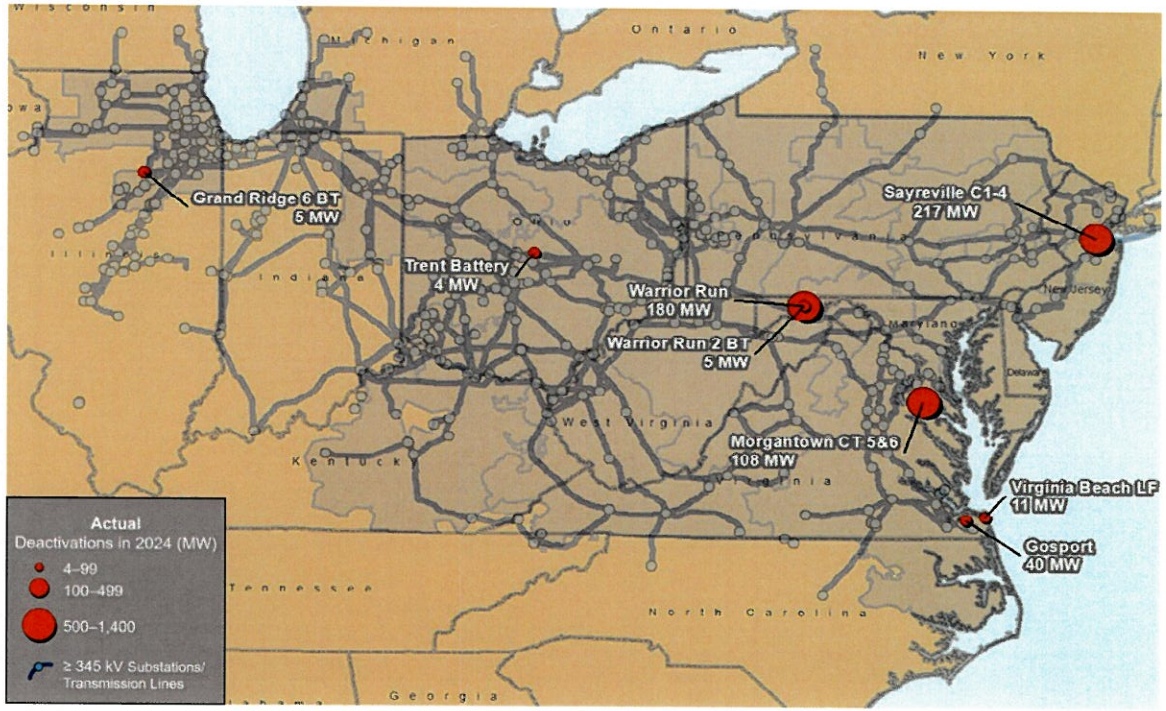

Table 3.4: Actual Deactivations in 2024

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Owner Request Date	Requested Deactivation Date	Projected Deactivation Date	Actual Deactivation Date	Mothball Return Date
Trent 1 BT#	4	AEP	10	Battery	9/22/2023	1/1/2024	1/1/2024	1/1/2024	
Virginia Beach Landfill	11	Dominion	18	Methane	12/8/2023	4/1/2024	4/1/2024	4/1/2024	
Sayreville C-4	48.5	JCP&L	51	Natural Gas	5/12/2024	6/1/2024	6/1/2024	6/1/2024	6/1/2027
Sayreville C-3	54.6								
Sayreville C-2	56.7								

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Table 3.4: Actual Deactivations in 2024 (Cont.)

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Owner Request Date	Requested Deactivation Date	Projected Deactivation Date	Actual Deactivation Date	Mothball Return Date
Sayreville C-1	57.1	JCP&L	51	Natural Gas	5/12/2024	6/1/2024	6/1/2024	6/1/2024	6/1/2027
Morgantown CT 6	54	PEPCO	50	Oil	12/22/2023				
Morgantown CT 5	54		50						
Warrior GEN1	180	AP	21	Coal	9/29/2023				
VP Gosport 1 F	40	Dominion	36	Biomass	7/11/2024	7/15/2024	7/15/2024	7/15/2024	
Grand Ridge 6 BT	4.5	ComEd	12	Storage	6/28/2024	10/1/2024	10/1/2024	10/1/2024	
Warrior Run 2 BT	5	AP	22	Battery	5/31/2024				

** A "mothball outage" refers to a deliberate situation where a power generating unit is taken out of service for an extended period, but is still considered potentially available to be brought back online in the future if needed, essentially being "stored" and preserved until required.*

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3.4: 2024 Retool Impacts

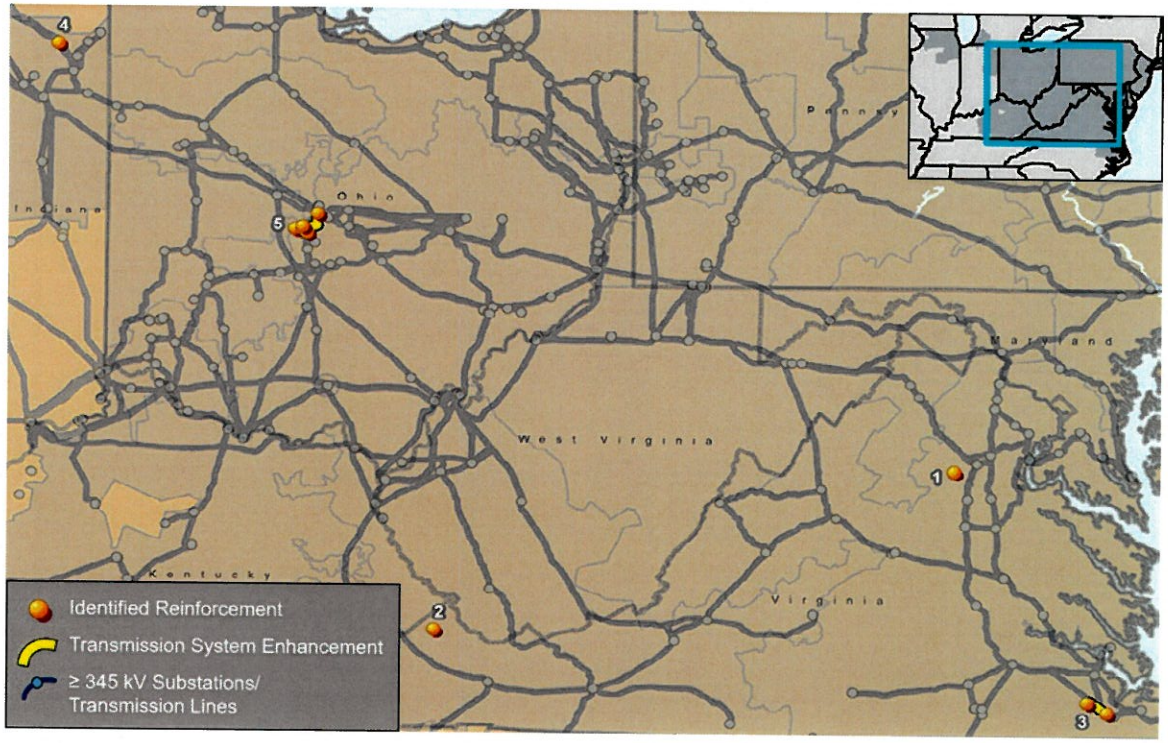
As part of each RTEP cycle, PJM conducts retool studies to evaluate how changes to input assumptions impact study results from prior RTEP cycles. Sensitivity studies evaluate the impacts of changes to generator models, load models, project configurations and scope, and other power flow input parameters. Retool studies conducted during 2024 for several projects are shown on **Map 3.12** and **Table 3.5**.

A Dominion zone retool study assessed the impact of the cancellation of baseline project b3162. This project involved building a new 230 kV switching station (Stevensburg/Batna) with a 224 MVA, 230/115 kV transformer. However, revised load allocations relieved reliability violations in the area within the study horizon. The retool study results revealed no additional reliability criteria violations. As a result, the baseline project was canceled.

Another Dominion zone retool study assessed the impact of additional required scope of baseline project b3759. This project originally reconductored approximately 10.5 miles of line No. 23 (Oak Ridge-Windsor 115 kV). During the conceptual review of this original project scope, a number of transmission tower issues were encountered:

- The towers were unable to maintain adequate clearance using the new conductor.
- Approximately 80% of the towers would need grillage foundation modifications.
- Approximately 50% of the structures experienced failures in two of the steel angle members located in the arms when subjected to the region's specified ice and wind parameters. Upgrading these structures by replacing the angles in the arms would necessitate full access to the structures. This would include the access roads, as well as equipment and labor costs to hold the wire in the air during arm modifications.

Map 3.12: 2024 RTEP Cycle Retool Studies



The new required scope of work includes the wreck and rebuild of the line (structures to be rebuilt to current 115 kV standards). The 115 kV line No. 44 segment from Oak Ridge to Windsor, which shares the same structures as line No. 23, will be reconductored. The retool study results revealed no additional reliability criteria violations. As a result, the baseline project could move forward.

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Table 3.5: 2024 RTEP Cycle Retool Study Impacts

Map ID	Project	Description
1	B3162	Acquire land and build a new 230 kV switching station (Stevensburg) with a 224 MVA, 230/115 kV transformer. Gordonsville-Remington 230 kV (line No. 2199) will be cut and connected to the new station. Remington-Mt. Run 115 kV (line No. 70) and Mt. Run-Oak Green 115 kV (line No. 2) will also be cut and connected to the new station.
2	B3295	Grundy 34.5 kV: Install a 34.5 kV 9.6 MVAR cap bank.
3	B3759	Wreck and rebuild ~10.5 miles of 115 kV line No. 23 segment from Oak Ridge to AC2-079 Tap to minimum emergency ratings of 393 MVA Summer/412 MVA Winter. Structures to be rebuilt to current 115 kV standards. Transmission Estimated Cost: $37.1M * Reconductor 115 kV line No. 44 segment from Oak Ridge to AC2-079 Tap which also shares the same structures to minimum emergency ratings of 393 MVA Summer/412 MVA Winter. Existing conductor is about 70 years old.
4	S2831	Noble Station: Retire 69 kV Noble station. Reterminate 69 kV Auburn-Kendallville 69 kV line outside of Noble station.
	S2831	Virtue 138 kV/12 kV station: Install 138 kV bus, 15.4 MVAR Capacitor with 138 kV circuit breaker, 2x 138 kV MOAB to serve new distribution station. Install telecom at Virtue station and remote ends.
5	S3441.1	Jerome 138 kV: Construct a greenfield Jerome station with (10 11) 138 kV 63 kA 4000A circuit breakers in breaker-and-a-half bus configuration. Construct ~2.5 miles of double circuit 138 kV transmission line extending from Celtic & Kileville station to Jerome utilizing 2-bundled ACSS Cardinal 954 (45/7) conductor, SE rating 1061 MVA. Construct ~1.6 miles of double circuit 138 kV transmission line extending from Jerome to cut-in back to Hyatt – Amlin line utilizing 2-bundled ACSS Cardinal 954 (45/7) conductor, SE rating 1061 MVA. Construct four 138 kV tie lines to the customers dead-end structures ~0.05 miles utilizing ACSR Dove 556.5 (26/7) conductor SE 284 MVA. Customers will be directly connected at this station.
	S3441.4	Celtic 345/138 kV: Originally, Kileville is the station that was envisioned (S2855) to serve 461 MW of demand with room for 345 kV expansion based on LOAs with the customer. However, land in the area of the proposed Kileville station was not available for expansion to install 345/138 kV transformation. Therefore, a new station site called Celtic is being proposed to serve as the 345 kV source for the 461 MW of load to be served in this area. Cut into the Hayden-Hyatt 345 kV circuit, reroute ~0.8 miles of the circuit and extend ~1.1 miles of new double circuit line, utilizing two-bundled ACSR Pheasant 1272 (54/19) conductor, SE rating 2413 MVA, to the greenfield Celtic 345/138 kV station with four 345 kV, 63 kA, 5000 A breakers laid out as ring bus configuration on high side. Install two 675 MVA-345/138 kV power transformers. Install (8 6) 138 kV, 63 kA, 138 kV 63 kA 4000A breakers and two 69.1 MVAR 138 kV cap bank on low side configured as breaker-and-a-half ring bus with provisions for future expansion breaker and half configuration. The proposed Kileville-Jerome 138 kV line will be brought in and out of the station creating two 138 kV Celtic-Jerome circuits and a single Celtic-Kileville 138 kV circuit.

An AEP zone retool study assessed the impact of baseline project B3295 cancellation. This project involved the installation of a 9.6 MVAR capacitor bank at the Grundy 34.5 kV substation. However, since the approval of the baseline project, a portion of the load in the area was retired and is no longer served from the local transmission system. The retool study results revealed no additional reliability criteria violations. As a result, the baseline project was canceled.

Another AEP zone retool study assessed the scope change for supplemental project S2831. This project originally involved rebuilding the Noble 69/12 kV distribution station on neighboring property with a bus tie breaker and line motor-operated air-breaker switch. The Auburn-Kendallville 69 kV line would reconnect to the new Noble station. However, the land option chosen for the rebuild is neighboring a 138 kV line, and due to its proximity, the project is moving forward with the alternate option of rebuilding the station to 138 kV. The retool study results revealed no reliability criteria violations. As a result, the supplemental project can move forward.

Another AEP zone retool study assessed the scope change for supplemental project S3441. This project originally involved the construction of a greenfield Jerome 138 kV substation, building double-circuit 138 kV transmission lines to extend to existing Celtic and Kileville substations, and cutting into the Hayatt-Amlin 138 kV line. After beginning project outreach and right-of-way activities, and given the amount of development in the area, building the initially proposed 138 kV line between Jerome and the existing Hyatt-Amlin circuit on a route northeast of Kileville station was going to be extremely challenging from a property acquisition standpoint and would have a significant impact on initial conceptual cost estimates. Therefore, in working with the customers in the area, the decision was made to pivot to an alternative line route that involved ultimately serving the Jerome site out of a double-circuit 138 kV line connected into Celtic station. The retool study results revealed no reliability criteria violations. As a result, the supplemental project can move forward.

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3.5: Interregional Planning

3.5.1 — 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 (SERTP) process, shown on **Map 3.13**. PJM interactions with its neighbors are also frequently part of NERC activity under neighboring Regional Reliability Organizations (RROs) shown in **Map 3.14**.

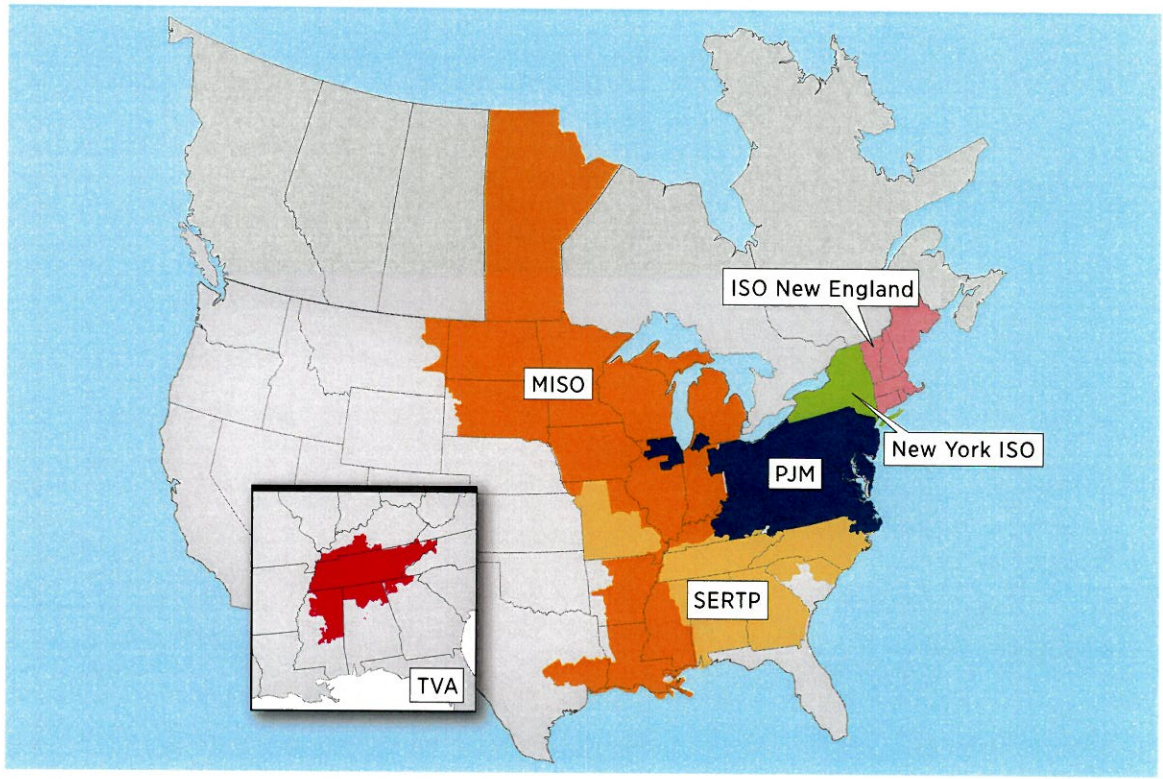
In addition, PJM actively participates in the Eastern Interconnection Planning Collaborative.

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 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 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 from periodic exchange of power system modeling data and information

Map 3.13: PJM Interregional Planning



Each study is conducted in accordance with the PJM Tariff and respective interregional agreements. 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.

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3.5.2 — MISO

The 2024 planning efforts under Article IX of the MISO/PJM Joint Operating Agreement continued to ensure the coordination of regional reliability, market efficiency, generator 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).

MISO Long-Range Transmission Planning Process

As part of its own long-range transmission planning (LRTP) process, MISO has reached out to PJM to discuss long-range studies that have identified the need for MISO system expansion to support greater system transfers to solve thermal and voltage violations, resolve wide area congestion, and enable significant amounts of new generation. MISO LRTP studies completed in 2024 examined "Tranche 2.1," which encompasses a portfolio of 24 new 765 kV and 345 kV projects, seven of which would terminate in PJM's western subregion, as summarized in the MISO/PJM presentation at the Nov. 22, 2024, IPSAC meeting.

While PJM's own RTEP analyses have not identified the need for MISO's LRTP Tranche 2.1 transmission, PJM continues to work with MISO and impacted PJM transmission owners via the M-3 process. PJM has performed initial reliability "no-harm" analysis with impacted transmission owners. Preliminary results indicate that upgrades to the PJM system would be needed to accommodate Tranche 2.1 MISO facilities. Such upgrades, if they were to go forward, would be funded by MISO, as further discussed in the IPSAC proposal, per the link above.

Joint Interregional Transfer Capability Study (ITCS)

On May 9, 2024, PJM and MISO announced that the organizations will collaborate on an interregional transfer capability study, set to be performed during the second half of 2024 and first half of 2025. Specifically, the ITCS will explore opportunities to:

- Engage in joint transmission analysis and coordinated modeling.
- Identify transfer, reliability and economic needs along the seam.
- Pursue solutions through existing processes as appropriate.
- Identify and pursue JOA/Tariff adjustments to implement additional solutions and further improve joint planning processes.

PJM and MISO presented an ITCS progress status and timeline at the Nov. 22, 2024, IPSAC meeting and preliminary results at the March 7, 2025, IPSAC meeting. The ITCS is discussed in the context of broader PJM energy transition issues in Section 1.3.10.

2024 Coordinated System Plan Activities

As part of annual issues review process under Section 9.3.7.2 of the MISO/PJM Joint Operating Agreement, PJM and MISO reviewed:

- Newly approved projects near the seam
- New regional issues
- Market-to-market historical congestion
- Third-party issues

After rigorous review and analysis, and considering the initiation of the ITCS, the Joint Reliability Planning Committee (JRPC) determined that a CSP study would not be performed in 2024.

3.5.3 — New York ISO and ISO New England

Northeast Coordinated System Plan

In 2023, PJM, NYISO and ISO-NE reviewed the status of their ongoing work plan and anticipated 2024 activities under the auspices of the Joint ISO/RTO Planning Committee (JIPC). The 2023 work included continued coordination, a review of transmission needs and solutions proposed by neighboring systems, coordination of interconnection requests, long-term firm transmission service, and transmission projects that potentially impact interregional system performance. This work culminated in the 2023 Northeast Coordinated System Plan (NCSP23), published on May 28, 2024. The report summarized the interregional needs and plans for PJM, NYISO and ISO-NE. The report did not identify the need for new interregional transmission projects that would be more efficient or cost-effective in meeting the transmission system needs of multiple regions than proposed regional system improvements.

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JIPC Loss of Source Study

In March 2023, ISO-NE formally requested, via letter, that the JIPC conduct a study to determine the feasibility of raising the minimum loss of source value for New England from its existing 1,200 MW level to a proposed 2,000 MW level. In August 2023, the JIPC posted a response accepting to collaboratively participate in the study. Study activities commenced in Q4 2023 and continued throughout 2024. The study is targeted to be completed by mid-2025.

DOE Atlantic Offshore Wind Transmission Study

JIPC has been actively participating in the DOE Atlantic Offshore Wind Transmission Study (AOSWTS) for more than two years, culminating in a March 2024 report. The AOSWTS was driven by needs to explore transmission expansion needs driven by offshore wind generation totaling 110 GW or more by 2050. The study included in Table 28 a list of 20 studied points of interconnection (POIs) and their potential maximum injection capability. As the report states, "The study provides guidance for policymakers and transmission stakeholders on possible outcomes resulting from a proactive, coordinated, and interregional approach to transmission planning for offshore wind energy development in the Atlantic." JIPC will again consider this issue as informed by the DOE study.

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3.5.4 — Adjoining Systems South of PJM

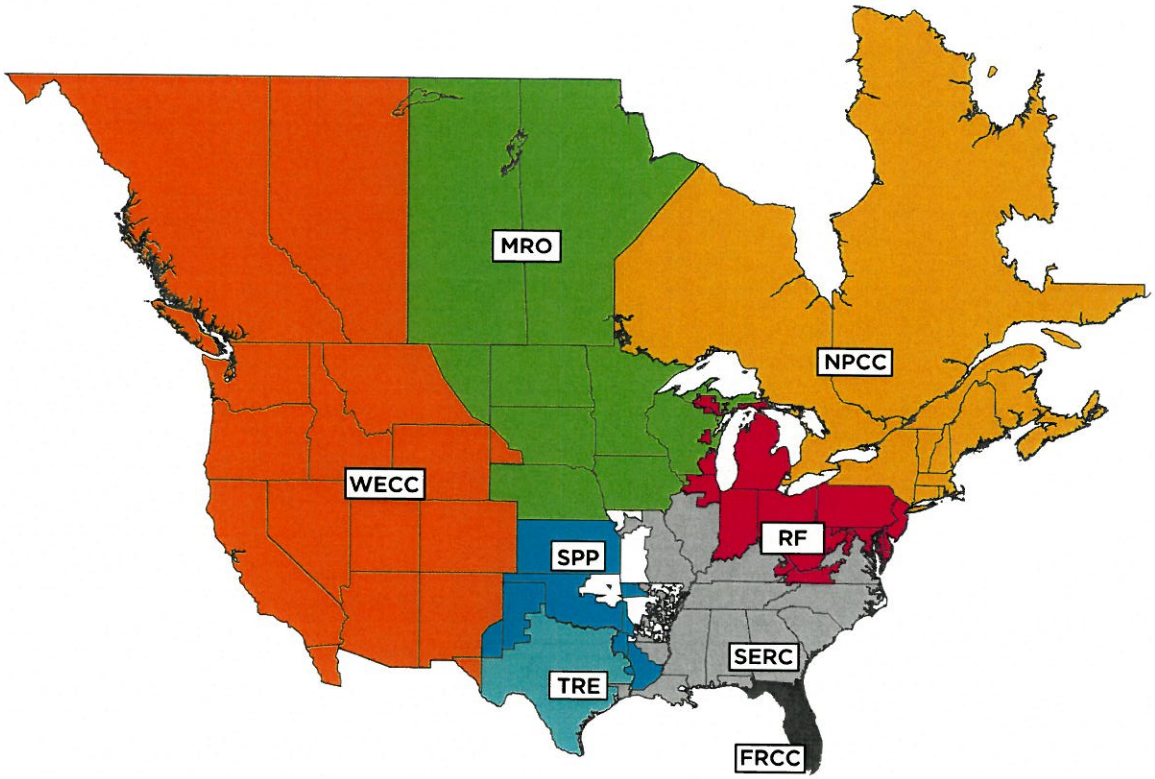
Interregional planning activities with entities south of PJM are conducted mainly under the auspices of the Southeastern Regional Transmission Planning (SERTP) process and SERC Reliability Corp.

Southeastern Regional Transmission Planning

PJM and the SERTP, shown earlier on **Map 3.13**, continued interregional data exchange and interregional coordination during 2024. SERTP membership includes several entities under FERC jurisdiction and voluntary participation among six non-jurisdictional entities. The jurisdictional 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, 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.

Map 3.14: NERC Regional Reliability Organizations



SERC Activities

PJM continues to support its members that are located within SERC, Dominion Energy and East Kentucky Power Cooperative (EKPC), as shown on **Map 3.14**. This support includes active participation in various committees and working groups such as the Engineering Committee, Planning Coordination Subcommittee, the Long-Term Working Group, Reliability Risk Working Group, Dynamics Working Group, Short-Circuit Database Working Group, Resource Adequacy Working Group and the Near-Term Working Group.

In 2024, PJM actively contributed to SERC committee and working group activities to coordinate model development, perform study activities, review results, and collaborate on industry risk identification and mitigation.

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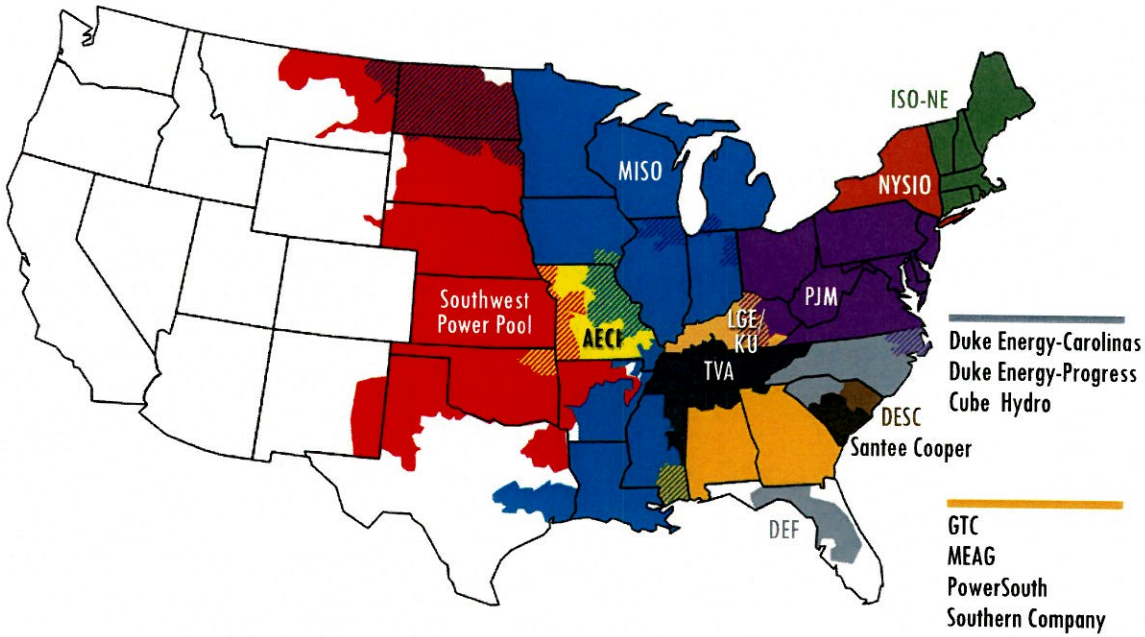
3.5.5 — Eastern Interconnection Planning Collaborative

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 3.15**. 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 3.15: Eastern Interconnection Planning Collaborative



EIPC Activities

During 2024, EIPC continued to engage power system planning analysis activities including the following:

- The EIPC released its EIPC Interregional Transfer Capability white paper in December 2023, providing its perspective on the technical considerations for large power transfers between regions.
- The EIPC conducted an analysis that improved the models of system response to frequency events and assessed the 2025 system. The results, published on Feb. 10, 2024, showed acceptable system performance after fully considering the anticipated retirements of older high-inertia synchronous generators and additions of planned nonsynchronous resources within the Eastern Interconnection.
- 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.

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3.6: Stage 1A ARR 10-Year Analysis

RTEP Context

Auction Revenue Rights (ARRs) comprise the mechanism by which annual FTR auction revenue is allocated. Incremental ARRs (IARRs) are 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 incremental ARRs 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 up to 60% of Network Service Peak 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.

Table 3.6: 2024/2025 Stage 1A ARR 10-Year Infeasible Facilities

Facility Name	Upgrade Expected To Fix Infeasibility	Expected In-Service Date
Cooper-Graceton 230 kV	2022 RTEP Reliability Window 3 (B3780, B3800)	2027-2028
Cooper-Peach Bottom Tap 230 kV		
Nottingham 1-3 Bus Tie 230 kV		
Nottingham 2-3 Bus Tie 230 kV		
Nottingham-Peach Bottom Tap 230 kV		
Kilmer-Lake Nelson I 230 KV	Reconductor Kilmer-Lake Nelson I 230 kV (B3737.28)	2029
Lake Nelson-Middlesex 230 kV		

Results: 2024/2025 Stage 1A ARR 10-Year Analysis

During 2024, PJM completed a 10-year simultaneous feasibility analysis for 2024/2025 Stage 1A ARR. The power flow case used in the 10-year feasibility analysis is the same one used in the 2024/2025 annual ARR allocation, but without any modeled maintenance transmission outages. The results of the 10-year analysis identified violations on several PJM transmission facilities. **Table 3.6** lists the facilities of concern and the solutions expected to address the violations identified in the analysis.

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Section 4: Market Efficiency Analysis

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-based transmission projects previously included in the RTEP to assure that they continue to be cost beneficial.
- Determine which reliability-based transmission projects, if any, have an economic benefit if accelerated or modified.
- Identify economic benefits associated with changes to reliability-based transmission projects already included in the RTEP that, when modified, would relieve one or more economic constraints. Such projects, originally identified to solve reliability criteria violations, may be designed in a more robust manner to provide economic benefit as well.

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 the 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 a market simulation tool that models forecasted PJM market conditions. The analytical solution, developed from an hourly security-constrained generation commitment and economic dispatch algorithm, provides the basis for the specific evaluations. Several evaluation base cases are developed. The primary difference between these cases is the transmission topology to which the simulation data corresponds:

- An "as-planned" base case power flow models PJM Board-approved RTEP projects included in the five-year-out study year.
- An "as-is" base case power flow models a one-year-out study year transmission topology.
- Project analysis includes topology for specific projects under study.

PJM can determine a transmission project's economic value by comparing the results of these multiple simulations with the same input assumptions and operating constraints but different transmission topologies. Combining the comparisons with benefit analysis allows PJM to evaluate if specific proposed transmission enhancements or expansions are economically beneficial.

System modeling characteristics included in these databases are broadly described in **Section 4.1**. Importantly, the simulated transmission congestion results and published database provide key system information and trends to PJM stakeholders.

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24-Month Cycle

PJM's 2024/2025 24-month market efficiency timeline is shown in **Figure 4.1**. The 2024 market efficiency body of analysis is represented by the first year of the 24-month cycle and focused on the following:

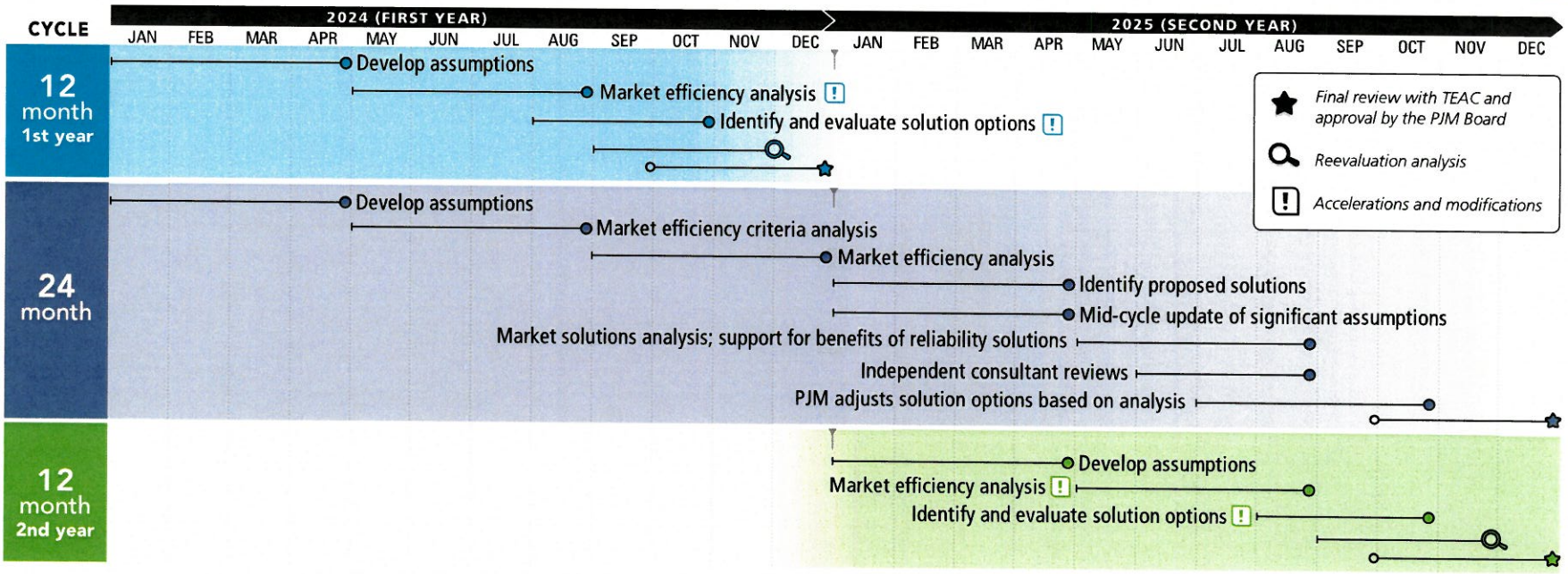
- Creating and reviewing with stakeholders base case models and results
- Reevaluating previously approved economic transmission projects
- Performing analysis considering the benefits of accelerating baseline projects previously approved for reliability not yet built
- Identifying the congestion drivers associated with the 2024/2025 Market Efficiency Window

Market Efficiency Window Simulations

In order to quantify future transmission system market efficiency needs, PJM develops a simulation database for use as part of the 24-month market efficiency study process. The database is mapped to the five-year-out RTEP power flow case (i.e., "as-planned" base case).

Market efficiency projects identified during the 2024/2025 market efficiency window will be evaluated using the database initially developed during 2024. However, during the project evaluation phase, PJM develops a mid-cycle update case that incorporates significant RTEP modeling assumption changes. The mid-cycle update case includes potentially significant forecast changes in topology, generation, load and fuel costs. The purpose for the mid-cycle update case is to ensure that potential projects are evaluated using an updated forecast of future conditions.

Figure 4.1: 2024/2025 Market Efficiency 24-Month Cycle



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PJM calculates a benefit-to-cost ratio to determine if there is market efficiency justification 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 constructability 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 may derive additional economic benefit as determined through capacity market simulations.

Market efficiency training material is available on PJM's website.

Project Acceleration Analysis

PJM compares simulations of near-term topologies (i.e., "as-is" base case) with those of planned topologies (i.e., "as-planned" base 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 2025 "as-is" simulation but not in the 2029 "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:

- Quantify the transmission congestion reduction driven by 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 2024, PJM quantified the transmission congestion reduction due to recently planned RTEP enhancements by comparing the simulation differences between the "as-is" base case and the "as-planned" base case for the 2025 and 2029 study years.

Reevaluation of Previously Approved Market Efficiency Projects

PJM's annual analysis includes a reevaluation of approved projects from previous market efficiency 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 and using 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

During 2024, PJM reevaluated a previously approved market efficiency transmission project.

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4.1: Input Parameters – 2024 Base Case

Overview

PJM licenses a commercially available database containing the necessary data elements to perform detailed PJM market simulations. This database is periodically updated for any changes in 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.

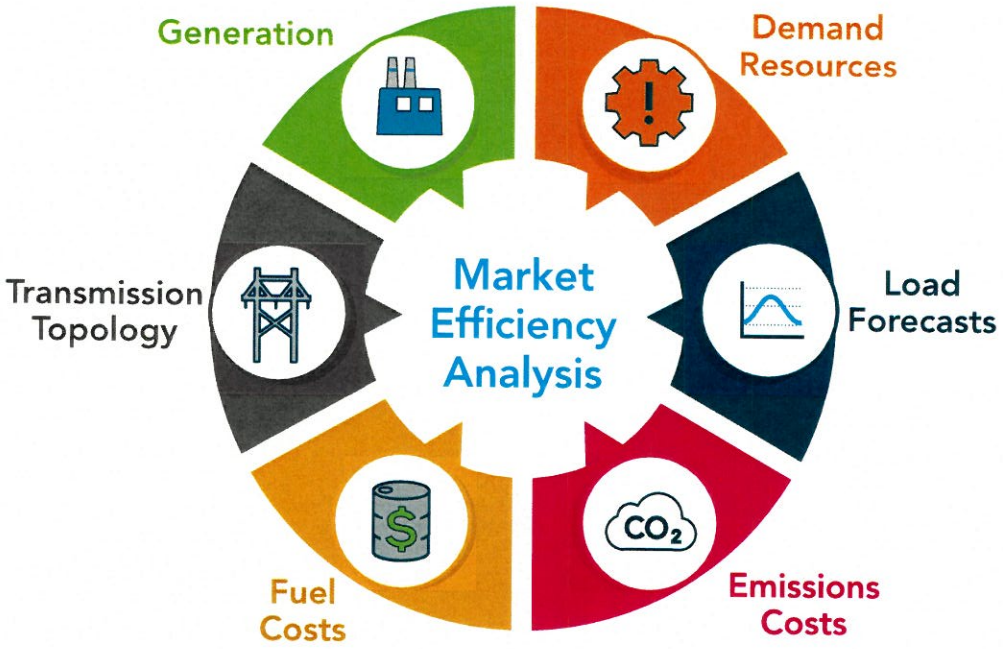
Transmission Topology

Market efficiency power flow models were developed to represent:

- The 2025 "as-is" transmission system topology
- The expected 2029 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 2023 Multi-Regional Modeling Working Group 2024 summer peak case. It included transmission enhancements expected to be in service by the summer of 2025. PJM derived system topologies for 2029 from the 2029 RTEP power flow case and included several significant RTEP projects approved during the 2023 RTEP cycle.

Figure 4.2: Market Efficiency Analysis Parameters



Monitored Constraints

Specific thermal and reactive interface transmission constraints 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.

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Generation Modeled

Market efficiency simulations model existing in-service generation plus actively queued generation, less planned generator deactivations that have given formal notification. Recent market efficiency cycles have had sufficient generation with at least an executed Interconnection Service Agreement (ISA) to meet PJM's reserve requirement. The 2024/2025 base case required additional suspended ISA and Facility Service Agreement (FSA) level units to meet the reserve requirement for the entire study period. **Figure 4.3** shows a comparison of the modeled generation capacity within PJM's footprint to the projected peak net internal demand with reserve requirement used for the market efficiency base case.

Fuel Price Assumptions

PJM uses a commercially available generator fuel price forecast database. 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 2024 market efficiency analysis are represented in **Figure 4.4**.

Figure 4.3: 2024/2025 PJM Market Efficiency Reserve Margin

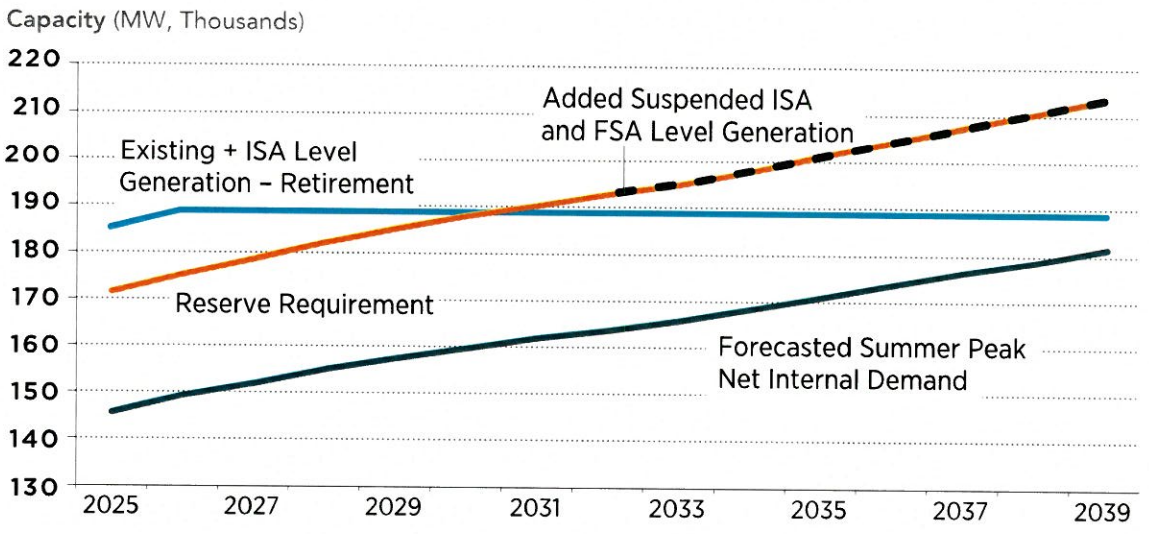
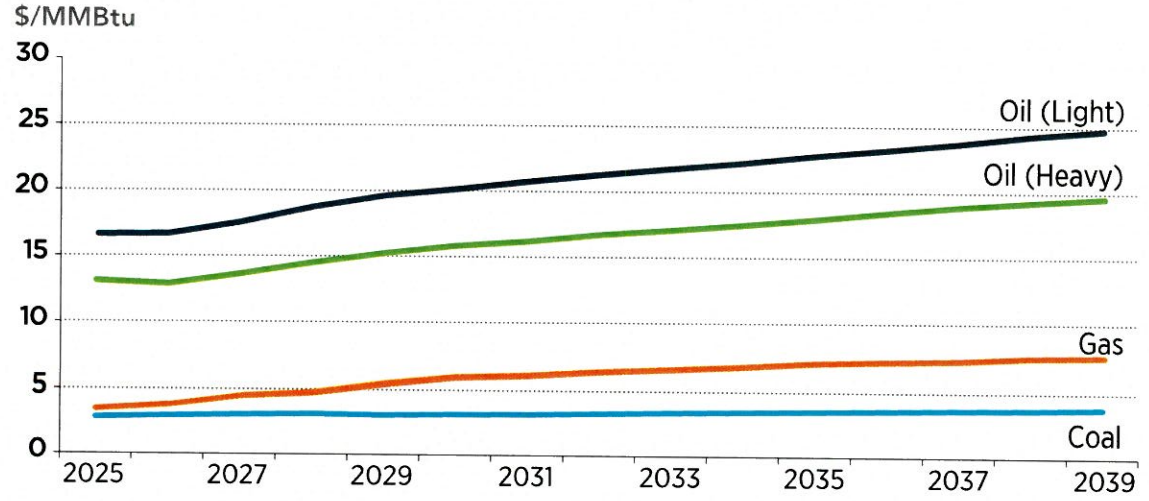


Figure 4.4: 2024/2025 Market Efficiency Fuel Price Assumptions



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Load and Energy Forecasts

PJM's 2024 Load Forecast Report provides the transmission zone peak load and energy data to be modeled in market efficiency simulations. **Table 4.1** summarizes the PJM peak load and energy values to be used in the 2024 market efficiency cases.

Demand Resources

The amount of demand resource modeled in each transmission zone is based on the 2024 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 – within 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. The spring 2024 emissions forecast includes units located in Maryland, Delaware and New Jersey participating in the RGGI. The emission price assumption for both the national CO_2 and RGGI CO_2 program are shown in **Figure 4.7**.

Table 4.1: 2024/2025 Market Efficiency PJM Peak Load and Energy Forecast

Load	2025	2029	2032	2035	2039
Peak (MW)	153,493	165,681	172,109	179,622	190,752
Energy (GWh)	829,683	933,146	991,188	1,041,217	1,120,928

Table 4.2: 2024/25 Market Efficiency Demand Resource Forecast

Demand Resource	2025	2029	2032	2035	2039
Demand Resource (MW)	7,814	8,265	8,500	8,772	9,210

Figure 4.5: 2024/2025 Market Efficiency SO_2 Emission Price Assumption

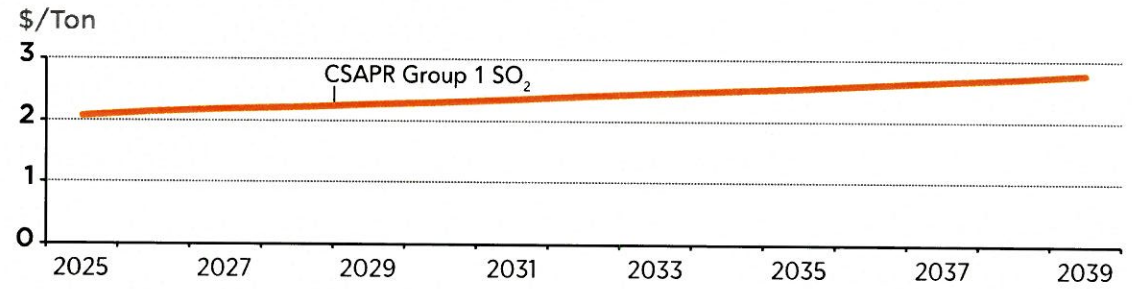
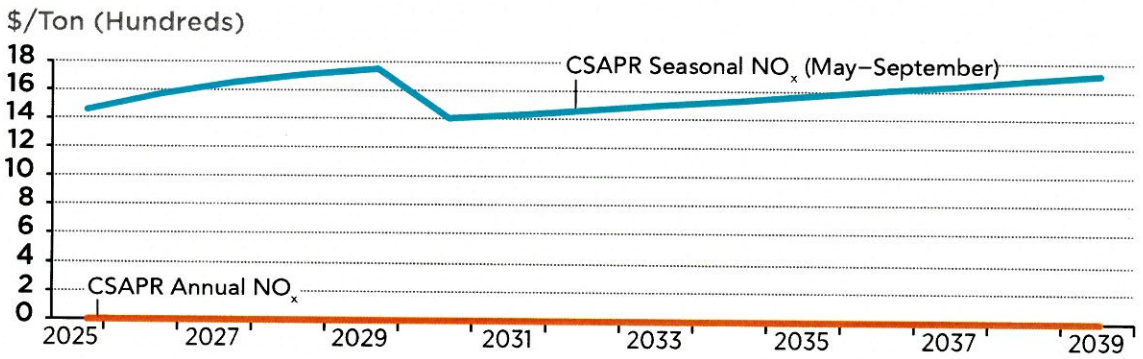


Figure 4.6: 2024/2025 Market Efficiency NO_x Emission Price Assumption



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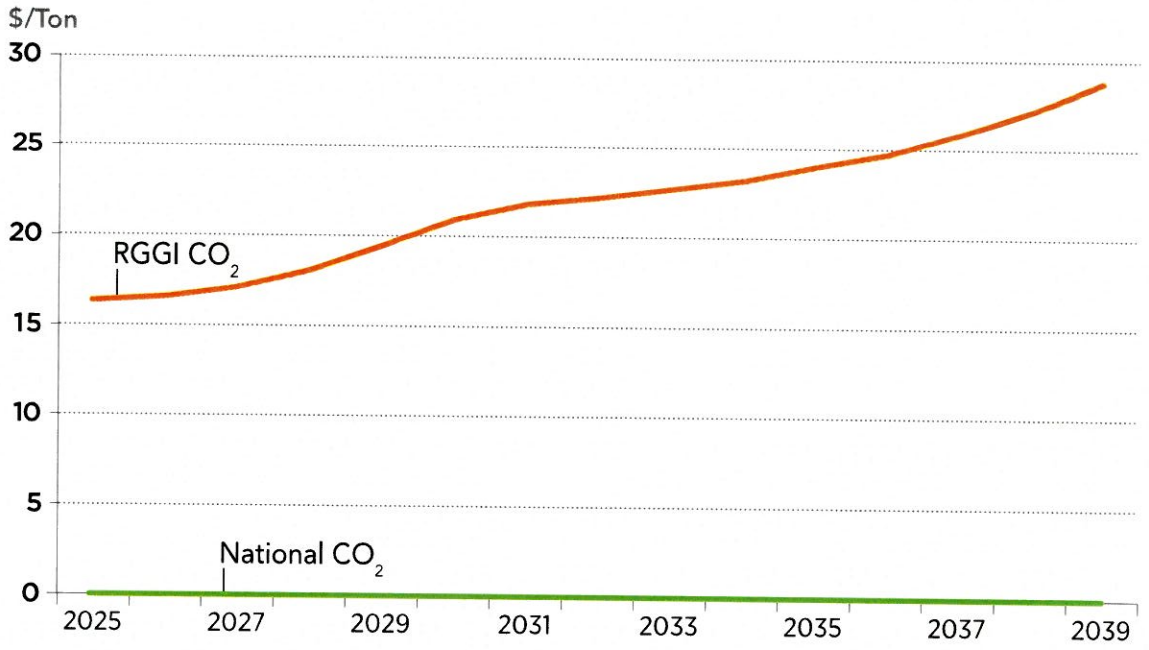
Carrying Charge Rate and Discount Rate

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 at least 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 these analyses are 11.94% and 7.11%, respectively.

Figure 4.7: 2024/2025 Market Efficiency CO_2 Emission Price Assumption



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4.2: 2024 Results From Project Acceleration Analysis

PJM's 2024 cycle of analysis included near-term simulations for study years 2025 and 2029. They identified collective and constraint-specific transmission system congestion due to the impacts of previously approved RTEP projects not yet in service. PJM conducted these simulations under two different transmission topologies:

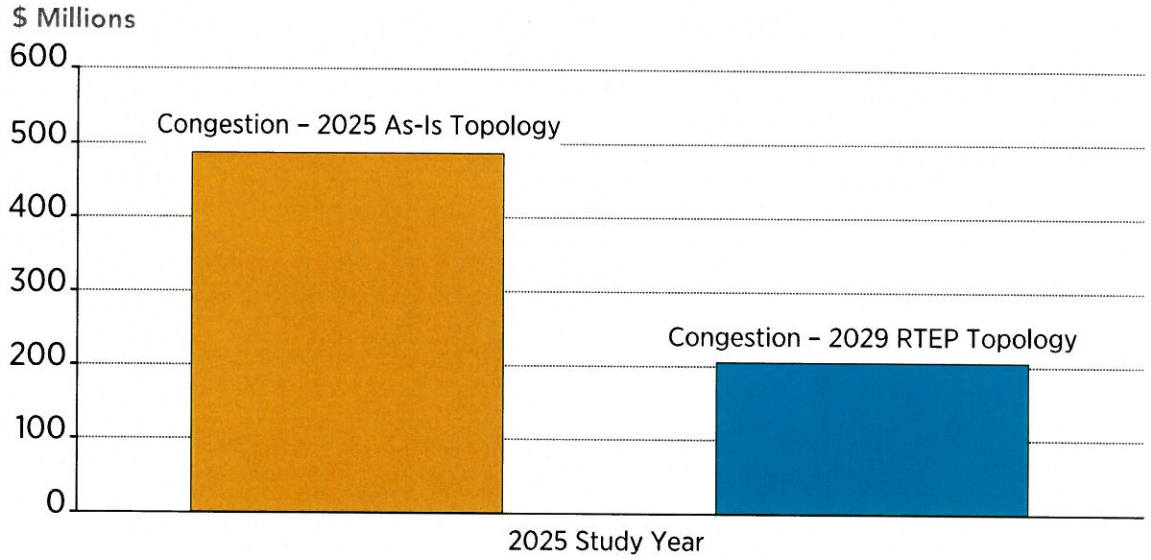
1. 2025 "as-is" PJM transmission system topology
2. 2029 "as-planned" RTEP PJM transmission system topology

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 cost net reductions comparing the 2025 "as-is" topology with the 2029 RTEP topology from market simulations for study year 2025 are shown in **Figure 4.8**. Annual congestion cost reductions of more than $282 million for the 2025 simulation are shown. RTEP enhancements that are approved but not yet in service account for the reduction in congestion.

Figure 4.8: 2025 Simulated PJM Congestion Cost Net Reduction: RTEP Topology Compared to "As-Is" Topology



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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 identified baseline reliability enhancements, viewed within the context of the short-term analysis, will not be recommended for acceleration. These projects are not practical to accelerate, because they have been identified with one or more of the following:

- The project has a near-term in-service date.
- The project is currently in the siting and permitting process, and schedules are not final.
- The cost of acceleration is greater than the simulated market efficiency benefits.
- PJM and the transmission owners are working to coordinate the implementation of the project work to meet the current expected in-service dates.
- An analysis of the outage schedule shows no ability to accelerate.

Table 4.3 identifies specific RTEP reliability projects and related congestion reductions considered as part of the 2025 study year acceleration analysis.

Table 4.3: RTEP Projects Reducing Specific Congestion Drivers: 2025 Study Year Analysis

Constraint	RTEP Upgrade	Area	Simulated 2025 Annual Congestion Savings ($M)	Upgrade In-Service Date
Lincoln-Straban 115 kV	**B3800:** Build new Hunterstown-Carroll 230 kV circuit	METED	$153.1	6/1/2028
Juniata No. 2 500/230 kV transformer	**B3664:** Replace station equipment at Juniata 230 kV	PPL	$22.77	5/1/2026
Haumesser Road-W DeKalb 138 kV	**B3811:** Rebuild Haumesser Road to H-452 138 kV	NIPSCO-COMED	$19.11	12/1/2028
Nottingham Reactor 230 kV	**B3800:** Eastern Cluster	PECO	$18.26	12/1/2030
Powerton-Towerline 138 kV	**B3760:** Replace wave trap at Powerton 138 kV	COMED-AMIL	$16.87	9/30/2024
Dumont-Stillwell 345 kV	**B3775:** Dumont-Stillwell 345 kV sag study	AEP-NIPSCO	$15.97	12/1/2026
Northwest-Conastone 230 kV	**B3771:** Reconductor Northwest-Conastone 230 kV circuits	BGE	$13.72	6/1/2027
St John-Crete 345 kV	**B3775:** Reconductor/Rebuild Crete-St John 345 kV	NIPSCO-COMED	$10.68	12/1/2026
Roxbury-Shade Gap 115 kV	**B3751, B3752:** Rebuild Roxbury-Shade Gap 115 kV	PENELEC	$8.63	6/1/2027
Olive-University Park 345 kV	**B3775:** Olive-University Park 345 kV sag study	AEP-COMED	$7.72	12/1/2026
Face Rock No. 2 115/69 kV transformer	**B3800:** Eastern Cluster	PPL	$7.42	12/1/2030
Maliszewski 765/138 kV transformer	**B3852:** Install second 765/345 kV bank at Vassell	AEP	$6.35	6/1/2027
Charlottesville-Proffit 230 kV	**B3800:** Rebuild 230 kV line #2054	Dominion	$5.1	12/29/2027
Plymouth Meeting-Whitpain 230 kV	**B3697:** Replace station equipment at Whitpain and Plymouth	PECO	$3.35	6/1/2025

Note: The 2025 study year congestion savings are calculated as the difference in simulated congestion between the RTEP and the as-is topology.

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4.3: 2024 Reevaluation of Previously Approved Market Efficiency Projects

PJM's 2024 analysis included a reevaluation of an approved project from previous market efficiency window processes.

One previously approved project with capital costs greater than $20 million has yet to begin construction or receive full CPCN certification. This project, identified as Project 9A, includes RTEP baseline projects B2742 and B2752. On Sept. 22, 2021, the PJM Board endorsed PJM's recommendation to suspend the project due to siting risks in order to remove it from the models pending any future developments in the regulatory process.

On Nov. 21, 2023, PJM filed a request with FERC for a waiver of the timing requirement associated with the 2023 reevaluation analysis of Project 9A. This would allow PJM time to update the market efficiency model to include the Board-approved 2022 RTEP Window 3 projects associated with future reliability. PJM's waiver request was granted on Dec. 21, 2023, and it directed PJM to complete the 2023 reevaluation analysis of Project 9A by June 30, 2024.

Consistent with the Commission's grant of a waiver, the 2023 reevaluation was completed in May 2024. Results of this reevaluation are shown in **Table 4.4.** It was noted that due to issues related to the potential reliability violations in the base case, impacts of approved RTEP projects, constructability concerns and regulatory uncertainties, further review of Project 9A was needed.

Table 4.4: 2023 Reevaluation and 2024 Reevaluation

Reevaluation	Base Case Ratio (May 2024)	Notes
Project 9A Base Case Analysis	0.81	**Base Case Ratio (Sunk Costs Excluded)** = 1.09
		In-Service Cost: $420.94 million
		Sunk Cost: $107.96 million

PJM also completed its 2024 reevaluation analysis in December 2024. The results from this analysis were the same as the results from the 2023 reevaluation. This was because the model used for the 2023 reevaluation was the latest available model despite known changed system conditions. Significant impacts of the project may be masked by reliability and other issues solved by RTEP projects expected to be approved in the first quarter of 2025.

PJM continues to recommend retention of Project 9A in suspended status in the RTEP for reasons including:

- Changed system conditions including substantially increased load forecasts and generation deactivations
- Newly approved transmission system enhancements and any not-yet-addressed needs identified in the planning process
- The uncertainty facing approved transmission projects due to ongoing regulatory proceedings that may impact the development and timing of a number of proposed PJM transmission projects
- The designated entity's investment in the project
- Maryland approval of the project
- A federal court finding that Pennsylvania violated the United States Constitution in denying approval of the project

An updated reevaluation for 2025 will be performed after a model is available that includes RTEP projects anticipated to be approved in 2025.

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4.4: 2024/2025 RTEP Market Efficiency Window Progress

The 2024/2025 RTEP market efficiency window process uses study years 2025, 2029, 2032 and 2035 to identify and quantify transmission system congestion. These simulations will use the 2029 RTEP "as-planned" transmission system topology and include RTEP projects approved through the 2024 RTEP cycle.

Overall, congestion levels in PJM's market efficiency analysis have been increasing, particularly for the 5-, 7- and 10-year-out cases compared to recent RTEP cycles. This is due, in part, to increasing forecasted load growth, particularly for zones with expected data center additions coupled with generator deactivations that are driving increased simulated regional power flows.

PJM solicits stakeholder proposals for projects as part of an RTEP proposal window focusing on congestion identified in the market efficiency analysis. It seeks solution alternatives to resolve or alleviate market efficiency congestion identified in the simulations. Market efficiency evaluation criteria are 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. Factors considered in selecting a successful project include risk assessment, model sensitivity evaluation, reliability impact and outage impact.

PJM is currently evaluating and updating the market efficiency cases to address the impact of continued forecasted load growth and the 2024 RTEP Window 1 solutions on potential congestion drivers. The market efficiency base case and the associated congestion drivers will be communicated to stakeholders before the start of the 2024/2025 long-term window.

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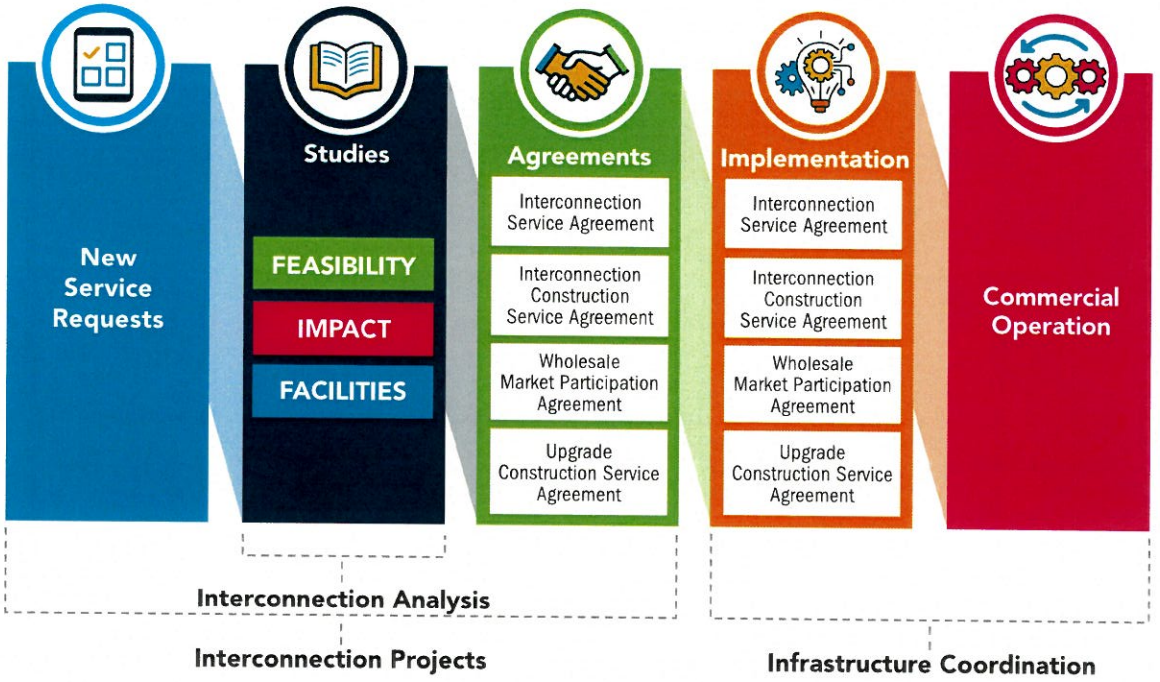
Section 5: Facilitating Interconnection

5.0: Interconnection Reliability

A key component of PJM's RTEP process is the assessment of 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 approximately $9 billion since the inception of the RTEP process in 1999. Approved network projects in 2024 have totaled approximately $1.7 billion. 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 point of interconnection to PJM load. PJM also conducts this power flow test as part of 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: Interconnection Process Prior to July 10, 2023



Interconnection Process Overview

PJM's interconnection process, as it existed prior to July 2023 reforms, consisted of five phases as shown in **Figure 5.1** and is described in Section 5 of the 2023 RTEP Report. Requests for generation interconnection could be submitted during one of two six-month queue windows: April through September and October through March.

Section 5.2 discusses interconnection process initiatives in 2023 and beyond, including those arising out of the Interconnection Process Reform Task Force (IPRTF) stakeholder process and in compliance with FERC's recent Generation Interconnection Process NOPR.

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5.1: Interconnection Process Reforms

5.1.1 — Energy Transition in PJM

As indicated in the Energy Transition in PJM: Flexibility for the Future report, published in June 2024, there is a potential shortfall in supply by 2030 as the demand growth and thermal resource retirements accelerate and new resource development and deployment lag. It is critical to accelerate the pace of new entry to maintain reliability.

To mitigate the risk of capacity shortages and the decline of essential reliability services, the PJM Board directed PJM to engage in a number of targeted planning process initiatives, discussed previously in **Section 1.3**, which are intended to expedite the interconnection of capacity resources. These targeted initiatives are in addition to the interconnection process reforms that are discussed throughout the remainder of Section 5.

5.1.2 — First-Ready, First-Served

On June 14, 2022, PJM filed Tariff revisions with FERC for interconnection process reform. The filing constituted PJM's reforms designed to more efficiently process New Service Requests. PJM's transition from a serial "first-come, first-served" queue approach to a "first-ready, first-served" Cycle approach is shown in **Figure 5.2**. This new approach, described in **Section 5.2**, is utilized by other regional transmission organizations and stand-alone transmission providers. The reforms detailed in the Tariff filing represent the culmination of an 18-month stakeholder effort through the IPRTF.

The Tariff reforms include:

- Moving from a serial queue process to a clustered Cycle process for interconnection studies and cost allocation
- Implementing multiple Decision Points at which those seeking interconnection-related services must provide readiness deposits and meet other threshold requirements to move forward, thus allowing projects that are ready to proceed to do so while incentivizing those that are not ready to exit the interconnection process
- Implementing 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
- Consolidating PJM's interconnection-related service agreements and forms

The interconnection reforms are set forth in their entirety in FERC Docket No. ER22-2110 and are described in PJM Manual 14H.

FERC Approval and Next Steps

On Nov. 29, 2022, FERC issued an order conditionally approving PJM's interconnection reform filing, subject to two compliance filings. PJM's new Tariff Parts VII and IX were integrated into PJM's Tariff with an effective date of Jan. 3, 2023. The transition to the new interconnection process started on July 10, 2023. In 2023, PJM completed its Transition Sorting Analysis to determine which AE1-AG1 projects were eligible for the Expedited Process and which will be re-prioritized into Transition Cycle 1.

NOTE:
On June 24, 2024, PJM published the Energy Transition in PJM: Flexibility for the Future report.

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Figure 5.2: Interconnection Process Reform Timeline *(as of Feb. 18, 2025, 2:11 p.m. EPT)*

Phase	Transition Cycle 1			Transition Cycle 2			Cycle 1		
	Start Date	End Date	Duration	Start Date	End Date	Duration	Start Date	End Date	Duration
Fast Lane End Date *executed by Developer & TO **or** filed unexecuted*	12/15/2023	4/18/2025							
Application Deadline	N/A	N/A	N/A	12/17/2024	12/17/2024	0	4/24/2026	4/24/2026	0
Application Review	N/A	N/A	N/A	12/18/2024	5/27/2025	161	4/27/2026	7/25/2026	90
Model Posting	2/1/2024	2/1/2024	0	4/28/2025	4/28/2025	0	6/27/2026	6/27/2026	0
Phase I	1/22/2024	5/21/2024	120	5/28/2025	9/24/2025	120	7/27/2026	11/23/2026	120
Decision Point I	5/22/2024	6/20/2024	30	9/25/2025	10/24/2025	30	11/24/2026	12/23/2026	30
Phase II	6/21/2024	12/20/2024	182	10/27/2025	4/24/2026	180	12/24/2026	6/21/2027	180
Decision Point II	12/23/2024	1/21/2025	30	4/27/2026	5/26/2026	30	6/22/2027	7/21/2027	30
Phase III	4/21/2025	8/31/2025	133	5/27/2026	11/22/2026	180	7/22/2027	1/17/2028	180
Decision Point III	9/2/2025	10/1/2025	30	11/23/2026	12/22/2026	30	1/18/2028	2/16/2028	30
Final Agreement	9/2/2025	10/31/2025	60	11/23/2026	1/21/2027	60	1/18/2028	3/17/2028	60

Notes:

- ***Transition Cycle 1 Phase III*** *cannot formally start until Fast Lane is officially closed out. PJM will begin prepatory work activities for Phase III SIS in March 2025.*
- ***Transition Cycle 2 Phase I*** *start date is dependent on Transition Cycle 1 Decision Point II close, Transition Cycle 2 Review completion and Transition Cycle 2 Model being posted for 30 days.*
- ***Transition Cycle 2 Phase II*** *start date is dependent on Transition Cycle 1 Decision Point III close.*
- ***Transition Cycle 2 Phase III*** *start date is dependent on Transition Cycle 1 GIAs executed or filed unexecuted.*
- ***Cycle 1 Phase I*** *start date is dependent on Transition Cycle 2 Decision Point II close, Cycle 1 Review completion and Cycle 1 Model being posted for 30 days.*
- ***Cycle 1 Phase II*** *start date is dependent on Transition Cycle 2 Decision Point III close.*
- ***Cycle 1 Phase III*** *start date is dependent on Transition Cycle 2 GIAs executed or filed unexecuted.*

Legend
Actual date
Projected date

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As shown in **Figure 5.2**, the initial study phase of Transition Cycle 1 began on Jan. 22, 2024. Phase I System Impact Study reports were posted to PJM.com on May 20, 2024, followed by the Decision Point I period, which closed June 20, 2024. Transition Cycle 1 projects that elected to proceed to the next phase of study were studied in Phase II, which concluded on Dec. 20, 2024. The Application Phase for Transition Cycle 2 opened June 21, 2024, for AG2 and AH1 projects that chose to reapply under the new interconnection process rules. The Transition Cycle 2 application phase closed Dec. 17, 2024. Applications are currently being reviewed for inclusion in the initial study phase. The transition will continue to progress over the coming years, culminating in Cycle 1 of the new process, which is currently expected to occur in the second quarter of 2026.

Stakeholder Engagement

The Interconnection Planning Subcommittee (IPS) was established by the Planning Committee in April 2022 to continue the work of the IPRTF. The IPS provides a stakeholder forum to resolve specific issues related to the interconnection process and associated agreements, governing documents and manuals.

Since its inception, the IPS has been the main environment for communicating details of the implementation of the new interconnection process, as well as for discussing future improvements.

5.1.3 — FERC Interconnection Process NOPR

On July 28, 2023, FERC issued Order 2023, a Final Rule adopting reforms to address interconnection queue backlogs and promote new technologies through generation interconnection procedures and agreements. The Final Rule encompasses several reforms, including:

- The adoption of a first-ready, first-served cluster study process with greater financial commitments for interconnection customers
- The imposition of firm deadlines and penalties in the event transmission providers fail to complete their interconnection studies on time
- The incorporation of technological advancements study into the interconnection process
- An update of modeling and performance requirements for inverter-based resources to ensure continued system reliability

On Aug. 28, 2023, PJM filed a Request for Clarification and Rehearing of Order 2023 stating that PJM has already developed a reformed interconnection process and received FERC approval in November 2022 that meets the Commission's intent and substantially satisfies the requirements of the Final Rule. On Sept. 28, 2023, FERC essentially denied PJM's rehearing motion by operation of law and would issue a future order providing more detail related to the rehearing request.

FERC Order 2023-A, issued on March 21, 2024, reaffirmed and clarified the reforms introduced in Order 2023 to streamline the generation interconnection process. PJM submitted its Order 2023 and Order 2023-A compliance filing with FERC on May 16, 2024. The filing demonstrates that PJM's Tariff already substantially complies with the Final Rule, paralleling many reforms PJM has already implemented.

On July 31, 2024, FERC requested additional information concerning PJM's compliance filing regarding deviations from the Final Rule and explanations as to how the compliance filing satisfies the independent entity standard. PJM submitted a response to FERC's data request on Oct. 29, 2024, and is awaiting FERC's final ruling.

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5.2: Cycle-Based Process

5.2.1 — New Service Requests

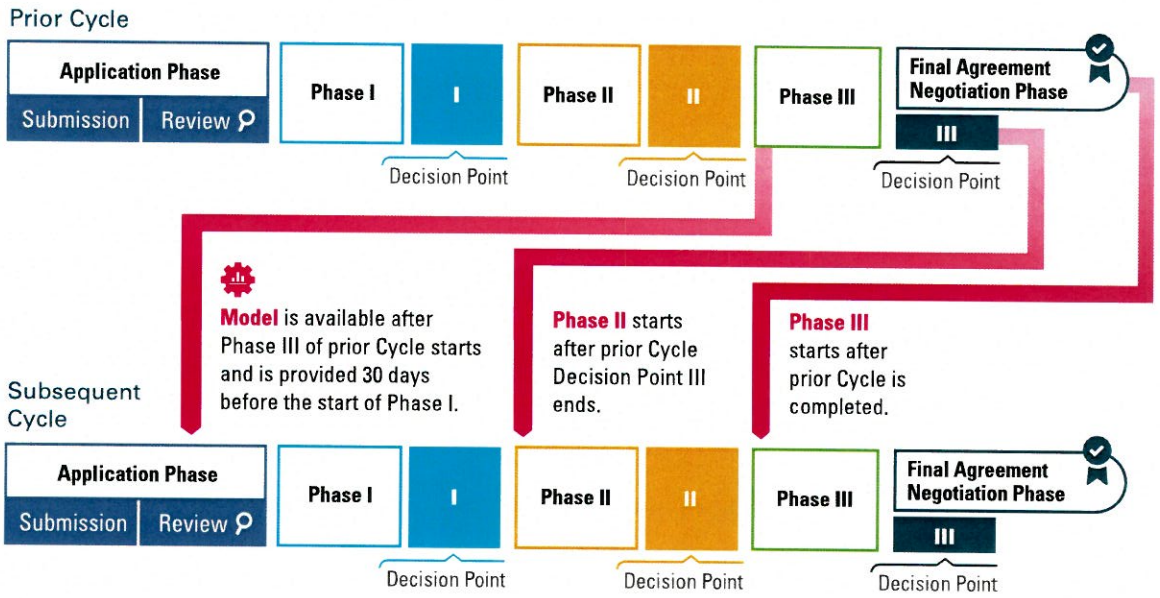
PJM has transitioned to a "first-ready, first-served" Cycle-based interconnection study approach for New Service Requests as outlined in the new PJM Manual 14H. Project Developers with a Generation or Transmission Interconnection Request as well as Eligible Customers with Long-Term Firm Transmission Service Requests will now follow the new Cycle Process. Additional types of requests are also studied under a parallel process outside of the Cycle Process. These include Upgrade Requests, Surplus Interconnection Requests, Affected System Study Requests, and requests to convert an existing two-party Interconnection Agreement to a PJM three-party Generation Interconnection Agreement (GIA), as also described in Manual 14H.

5.2.2 — Cycle Process Phases

A Cycle is the period of time between the start of an Application Phase and the conclusion of the corresponding Final Agreement Negotiation Phase. As shown in Figure 5.3, each Cycle consists of the following:

- Application Phase
- Phase I System Impact Study
- Decision Point I
- Phase II System Impact Study
- Decision Point II
- Phase III System Impact Study
- Decision Point III
- Final Agreement Negotiation Phase

Figure 5.3: New Interconnection Request Cycles



The Application Phase includes the submission of New Service Requests by the Project Developer or Eligible Customer and review and validation by PJM.

During Phases I, II and III, PJM performs System Impact Studies. All three phases include load flow analysis. Stability and short circuit analyses are performed during Phases II and III.

Decision Points I, II and III are each a period of 30 days commencing on the first business day immediately following the prior phase of the Cycle. At each Decision Point, the Project Developer or Eligible Customer decides to proceed to the next phase or withdraw. During the Decision Point periods, the customer provides required data, evidence (such as permits, Site Control, etc.) and deposits, as specified in the PJM Tariff and as described in Manual 14H. The customer can also submit any modification as permitted by the PJM Tariff, and, if eligible, may accelerate to the Final Agreement. PJM reviews the provided information, validates the customer's submission and advances the customer to the subsequent phase.

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After the third study phase and prior to the start of the Final Agreement Negotiation Phase, PJM will provide the Project Developers in the Cycle with drafts of the applicable interconnection-related agreements. These agreements will be prepared based upon the most recently completed studies. If any New Service Requests are withdrawn during Decision Point III, PJM will conduct a restudy and reissue updated agreements to any Project Developers with New Service Requests remaining in the Cycle if their required Network Upgrades and/or cost allocation are impacted by the retooled results.

Once Phase III is complete, the Final Agreement Negotiation Phase begins, typically lasting around 60 days. During this phase, draft agreements are prepared; negotiated; and either executed, filed unexecuted with FERC, or withdrawn if the project exits during Decision Point III, which runs in parallel. After an agreement becomes effective and has been accepted by FERC, a construction kickoff call is scheduled, generally within a few weeks of execution, allowing construction activities to commence.

A subsequent Cycle Process does not begin until certain milestones in the prior Cycle have been achieved, as described in Manual 14H, Section 1.3.2, "Cycle Process Overview."

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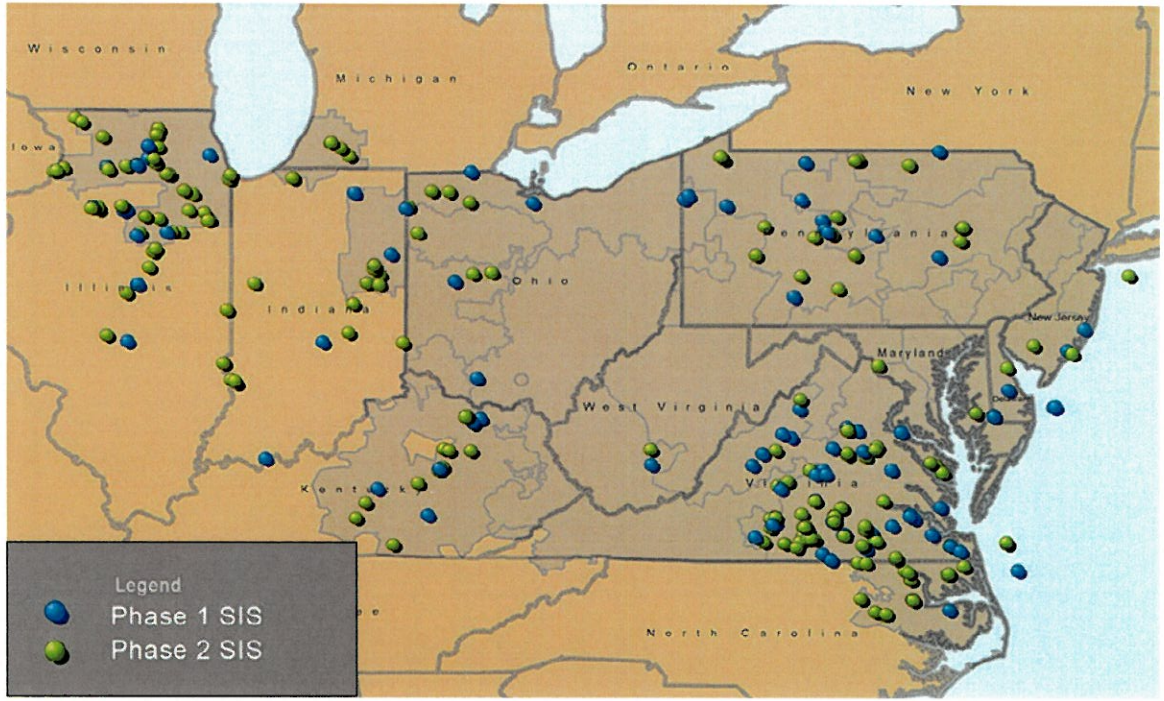
5.3: New Service Request Activity

PJM markets have attracted generation proposals totaling 648,907 MW of capacity, as shown in **Table 5.1**. Over 125,130 MW of capacity of New Service Requests were actively under study during 2024. PJM analyzed and issued 307 Phase I System Impact Studies and 206 Phase II System Impact Studies in Transition Cycle 1, the locations of which throughout PJM are shown on **Map 5.1**.

Over 20,729 MW of capacity of new generation was under construction as of Dec. 31, 2024, 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 and regulatory, industry, economic and other competitive factors.

Map 5.1: System Impact Studies Performed in 2024



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Interconnection Progression History

PJM reviews the progression of generation interconnection annually to understand overall developer trends more fully and their impact on PJM's interconnection process. **Figure 5.4** shows that for generation submitted in Queue A in 1999 through Dec. 31, 2024, only 76,107 MW, or 15.2%, reached commercial operation. Note that **Figure 5.4** reflects requested Capacity Interconnection Rights, which are lower than nameplate capability given the intermittent operational nature of wind- and solar-powered plants.

Following execution of an ISA or WMPA, 33,666 MW of capacity with ISAs and 1,748 MW of capacity with WMPAs withdrew from PJM's interconnection process.

Table 5.1: Interconnection Requests Studied in 2024

	Projects	Nameplate Capability (MW)	Capacity (MW)
Active	1,784	152,603	125,130
In-Service	1,196	93,336	76,107
Under Construction	434	36,854	20,729
Withdrawn	4,870	568,151	426,940
Total	**8,284**	**850,944**	**648,906**

Overall, 38% of projects that requested uprates to existing capacity reached commercial operation. Only 14% of new generation requests reached commercial operation.

Figure 5.4: New Service Request Progression

Percentage of planned capacity and projects that have reached commercial operation

- **15.2%** Requested capacity megawatts
- **18.6%** Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	**244**	Interconnection Service Agreements	33,666 MW	43,849 MW
	423	Wholesale Market Participation Agreements	1,748 MW	3,487 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, 2024.

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Section 6: State Summaries

This section contains state-specific information on the following topics:

- Load forecast
- Existing generation mix
- Interconnection requests
- Generation deactivations
- Baseline projects
- Network projects
- Supplemental projects
- Merchant transmission project requests

If a topic is absent from a state summary, it means that no deactivations occurred during the 2024 calendar year or no projects were approved for the 2024 RTEP for that state.

6.0: 2024 Development and Milestones

Load Growth

Load Forecast Accuracy Model Improvements

The 2024 Long-Term Load Forecast model uses 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., energy efficiency improvements, distributed resources).

A continuing 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 the following changes to the 2024 Long-Term Load Forecast to improve model accuracy, including:

- More comprehensive electric vehicle data – PJM contracted with S&P Global to provide an electric vehicle forecast that includes zonal vehicle counts and hourly charging impacts for light-, medium-, and heavy-duty electric vehicles.
- Adding an additional cold variable – PJM added a third heating variable to the forecast model that acts like a spline when weather gets very cold. This variable is meant to capture different relationships of load to weather under different conditions. The additional cold weather variable was added in response to testing after Winter Storm Elliott.

These are discussed further in **Section 1.3.5** and **Section 5**.

Use the navigation bar at the bottom of the page to quickly jump between state summaries.

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Existing Generation

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

Evaluating Interconnection Requests

A key component of PJM's RTEP process is the assessment of 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. PJM's generation 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.

Interconnection Process Reform

PJM interconnection process reform continued through 2024. As discussed earlier in this report, Transition Cycle 1, encompassing three phases, began in January 2024. PJM conducted interconnection studies for projects that were not eligible under the Expedited Process under a new cluster approach. Transition Cycle 1 and Transition Cycle 2, which began in June 2024, included a Decision Point after each of three study phases as described in **Section 5**.

Use the navigation bar
at the bottom of the page to quickly jump between state summaries.

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Generation Deactivation

Deactivation Reliability Studies

PJM Planning performs deactivation analyses four times per year,commencing 30 days after the end of the previous quarter. 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 generation 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.

This topic will only appear in states with generating unit **deactivations and requests** received between Jan. 1, 2024, and Dec. 31, 2024, as part of the 2024 RTEP.

The following states include information about **deactivation requests**:						
DE	IL	MD&DC	NJ	OH	PA	VA

Baseline Projects

PJM tests the baseline adequacy of the transmission system to deliver energy and capacity resources to each load in the PJM region. The system is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst Corporation or SERC Reliability Corporation) 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 generation, merchant transmission and long-term firm transmission service interconnection studies. This subsection will only appear in states with RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP.

This subsection will only appear in states with RTEP **baseline system enhancements** approved by the PJM Board in 2024.

The following states include information about **baseline projects**:					
DE	IL	IN	KY	MD&DC	MI
NJ	NC	OH	PA	VA	WV

Network Projects

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.

This topic will only appear in states with RTEP **network projects** approved by the PJM Board in 2024. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

The following states include information about **network projects**:					
DE	IL	KY	MD&DC	MI	NJ
NC	OH	PA	VA	WV	

Use the navigation bar at the bottom of the page to quickly jump between state summaries.

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Supplemental Projects

A supplemental project 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.

This topic will only appear in states with **supplemental projects** included in the 2024 Local Plan.

The following states include information about **supplemental projects**:					
DE	**IL**	**IN**	**KY**	**MD&DC**	**MI**
NJ	**NC**	**OH**	**VA**	**WV**	

Merchant Transmission Project Requests

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.

This topic will only appear in states with **merchant transmission project requests** identified as part of the 2024 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

The following state includes information about merchant transmission requests:
IN

Use the navigation bar at the bottom of the page to quickly jump between state summaries.

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6.1: Delaware RTEP Summary

6.1.1 — RTEP Context

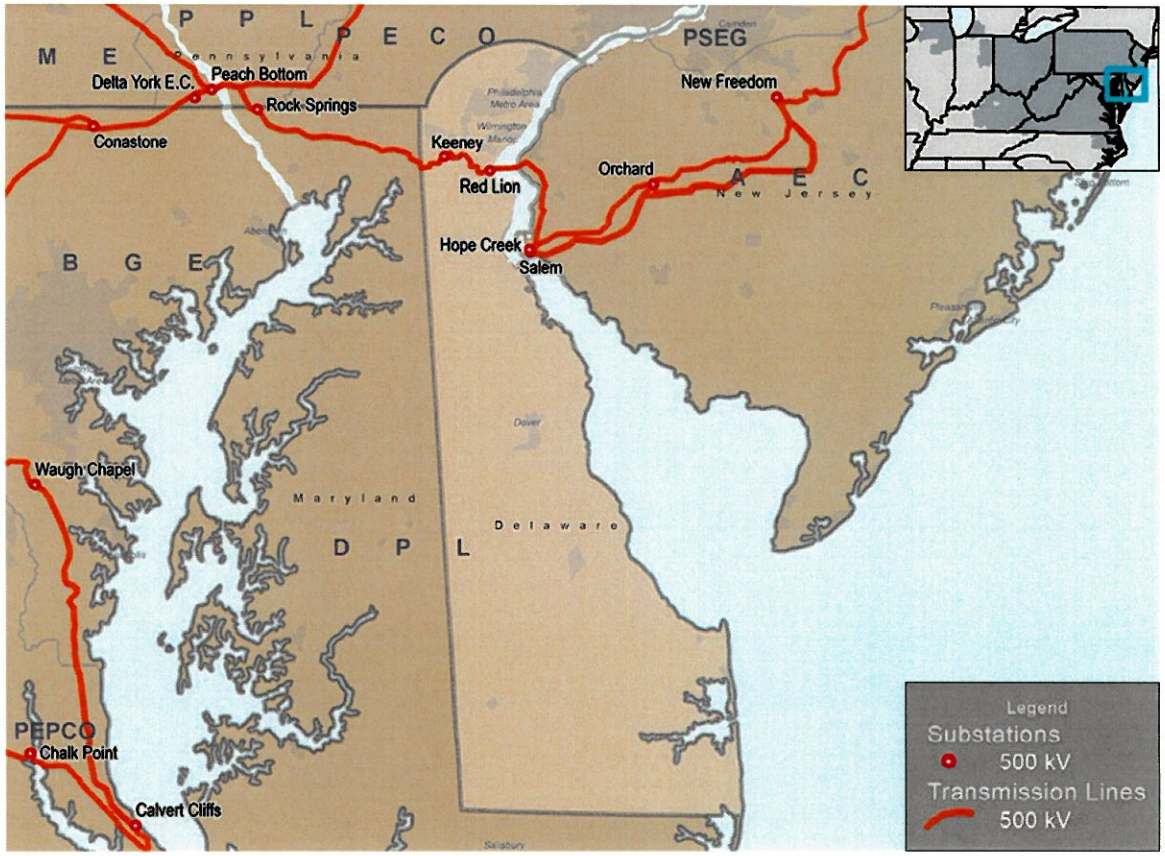
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Delaware, including facilities owned and operated by Delaware Municipal Electric Corporation (DEMEC), Delmarva Power (DP&L) and Old Dominion Electric Cooperative (ODEC) as shown on **Map 6.1**. Delaware's transmission system 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 of the PJM service area.

Renewable Portfolio Standards

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

Delaware is also pursuing decarbonization through additional efforts. In 2023, Delaware enacted the Climate Change Solutions Act, which calls for Delaware to reduce statewide greenhouse gas emissions by at least 50% from 2005 levels by 2030 and reach statewide net-zero emissions by 2050.

Map 6.1: PJM Service Area in Delaware



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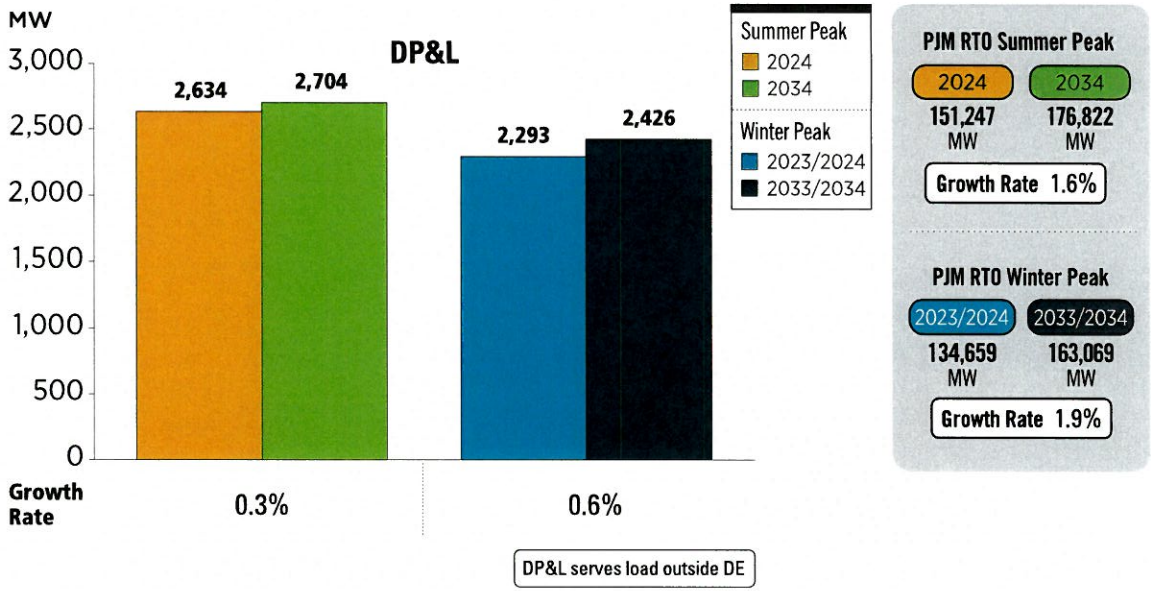
6.1.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.1** summarizes the expected loads within the state of Delaware and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.1: Delaware – 2024 Long-Term Load Forecast



PJM notes that Delmarva Power serves load other than in Delaware. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by Delmarva Power solely in Delaware. Estimated amounts were calculated based on the average share of Delmarva Power's real-time summer and winter peak load located in Delaware over the past five years.

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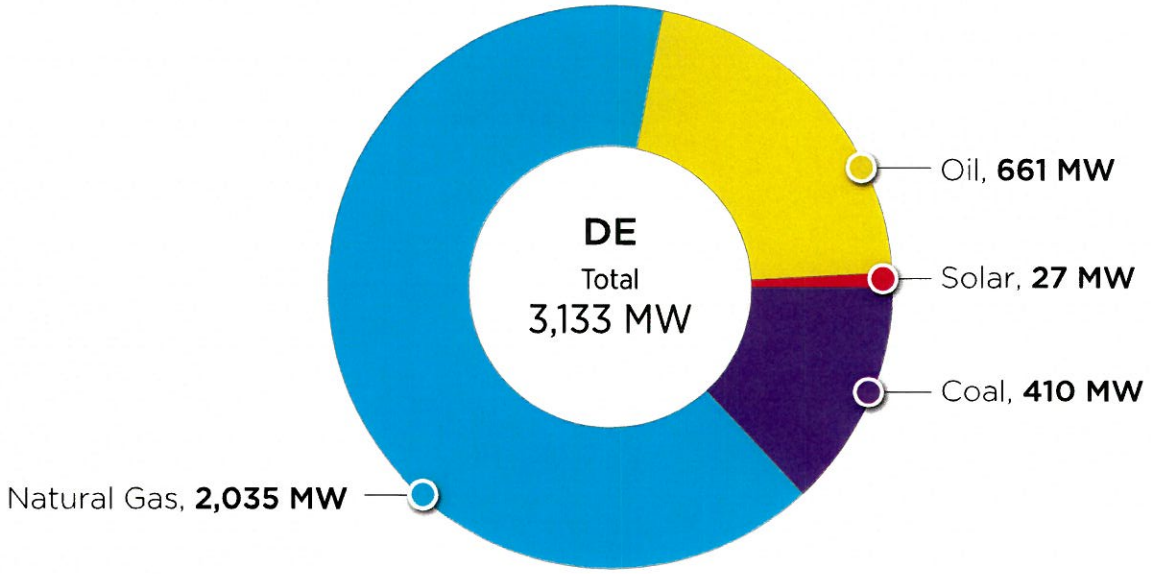
6.1.3 — Existing Generation

Existing generation in Delaware as of Dec. 31, 2024, is shown by fuel type in **Figure 6.2**.

Figure 6.2: Delaware – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



Read More
Changing Capacity Mix and Deliverability

6.1.4 — Interconnection Requests

In Delaware, as of Dec. 31, 2024, 25 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**.

NOTE:
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.

Read More
Interconnection Requests

Table 6.1: Delaware – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	Delaware Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	84	7.07%	20,162	14.38%
Hydro	0	0.00%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	0	0.00%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	10	0.84%	64	0.05%
Solar	251	21.16%	55,040	39.25%
Storage	395	33.25%	39,064	27.86%
Wind	448	37.67%	17,455	12.45%
Grand Total	1,188	100%	140,231	100%

Table 6.2: Delaware – Interconnection Requests (Dec. 31, 2024)

		In Queue				Complete				Grand 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
	Natural Gas	0	0.0	0	0.0	18	1,281.1	20	6,007.4	38	7,288.5
	Oil	0	0.0	0	0.0	5	168.2	1	1.0	6	169.2
	Other	1	10.0	0	0.0	2	26.3	1	0.0	4	36.3
	Storage	3	395.0	0	0.0	0	0.0	10	269.7	13	664.7
Renewable	Hybrid	1	84.0	0	0.0	0	0.0	1	20.7	2	104.7
	Biomass	0	0.0	0	0.0	1	0.0	4	24	5	24
	Methane	0	0.0	0	0.0	4	9.0	3	28.8	7	37.8
	Solar	12	232.3	3	19.0	1	37.6	40	556.7	56	845.6
	Wind	5	447.5	0	0.0	0	0.0	16	2,031.6	21	2,479.1
	Grand Total	**22**	**1,168.8**	**3**	**19.0**	**33**	**1,545.2**	**97**	**9,569.9**	**155**	**12,302.9**

Figure 6.3: Delaware – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

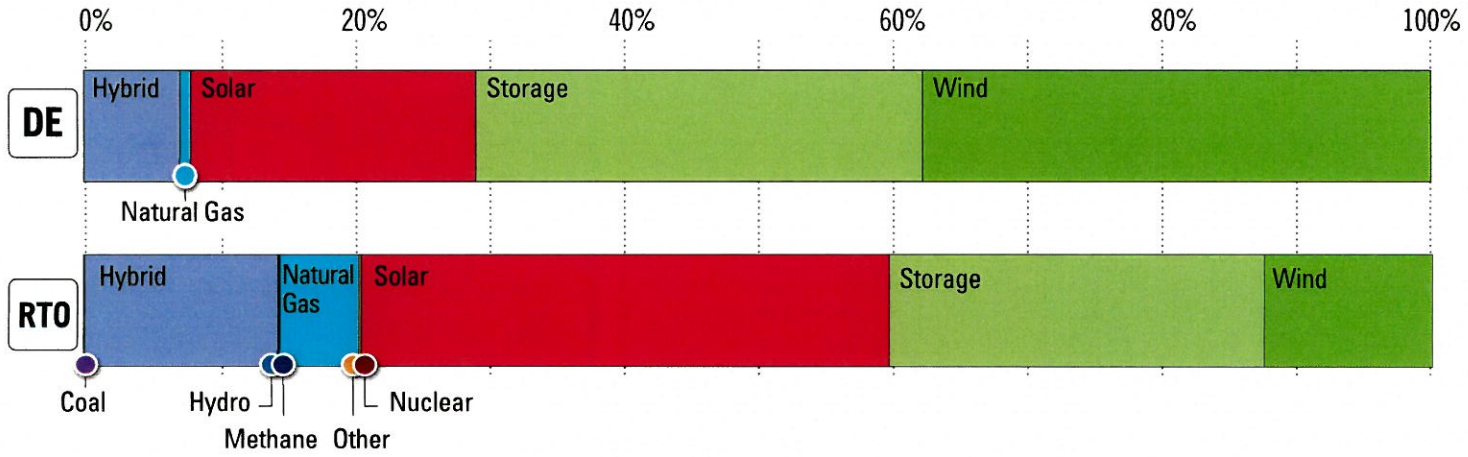


Figure 6.4: Delaware Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

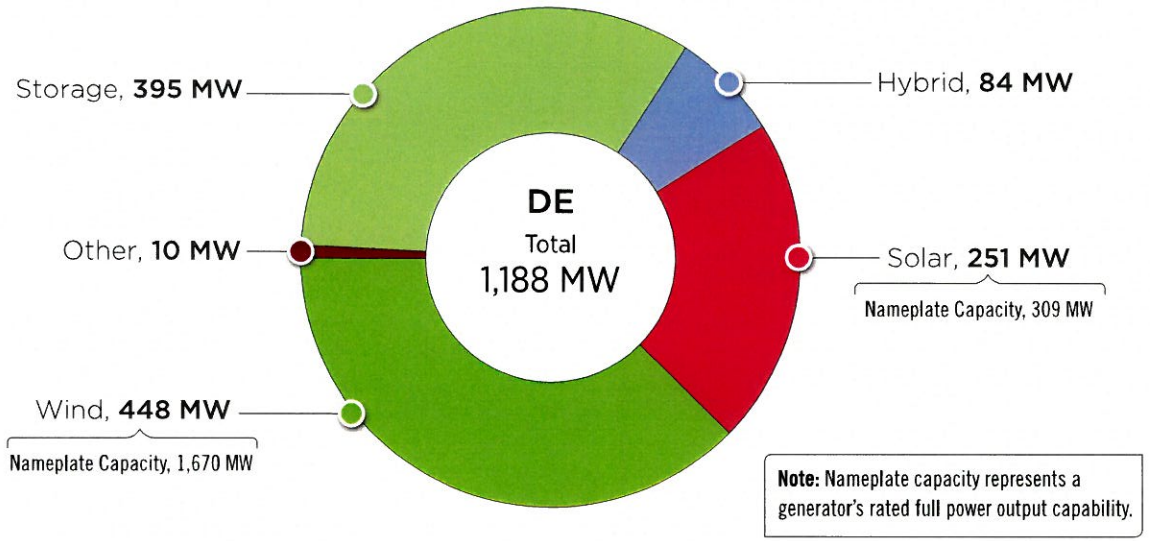
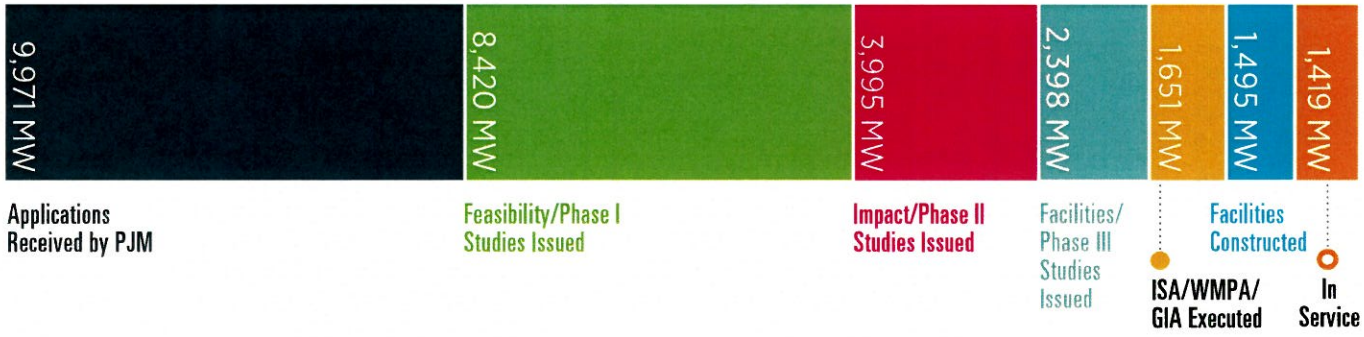


Figure 6.5: Delaware Progression of Interconnection Requests (Dec. 31, 2024)



			Capacity	Nameplate
Projects withdrawn after final agreement	4	Interconnection Service Agreements	871 MW	1,231 MW
	7	Wholesale Market Participation Agreements	18 MW	55 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, 2024.

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6.1.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Delaware between Jan. 1, 2024, and Dec. 31, 2024, are summarized in **Map 6.2** and **Table 6.3**.

Read More
Baseline Projects

Map 6.2: Delaware Generation Deactivations (Dec. 31, 2024)

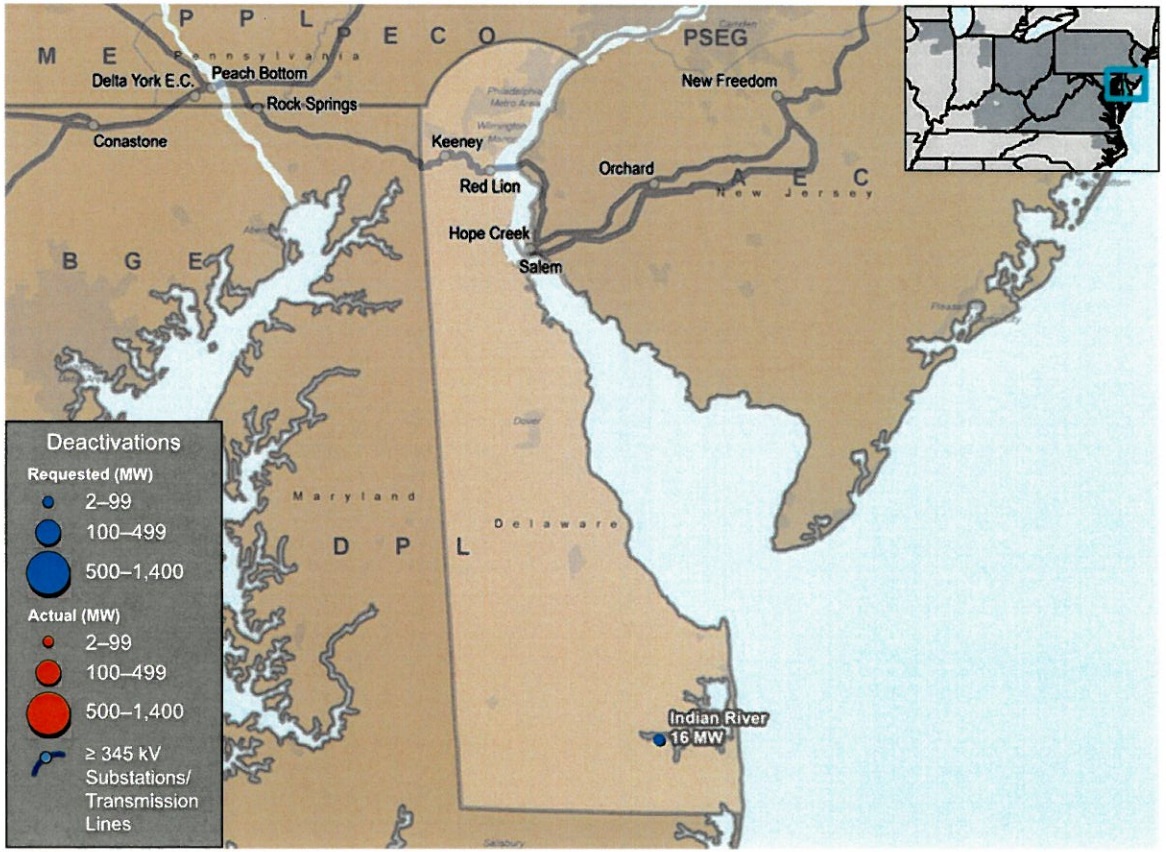

Table 6.3: Delaware Generation Deactivations (Dec. 31, 2024)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Indian River 10	DP&L	Oil	7/23/2024	6/1/2026	4	16.1

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6.1.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in Delaware are summarized in **Map 6.3** and **Table 6.4**.

Read More
Baseline Projects

Map 6.3: Delaware Baseline Projects (Dec. 31, 2024)

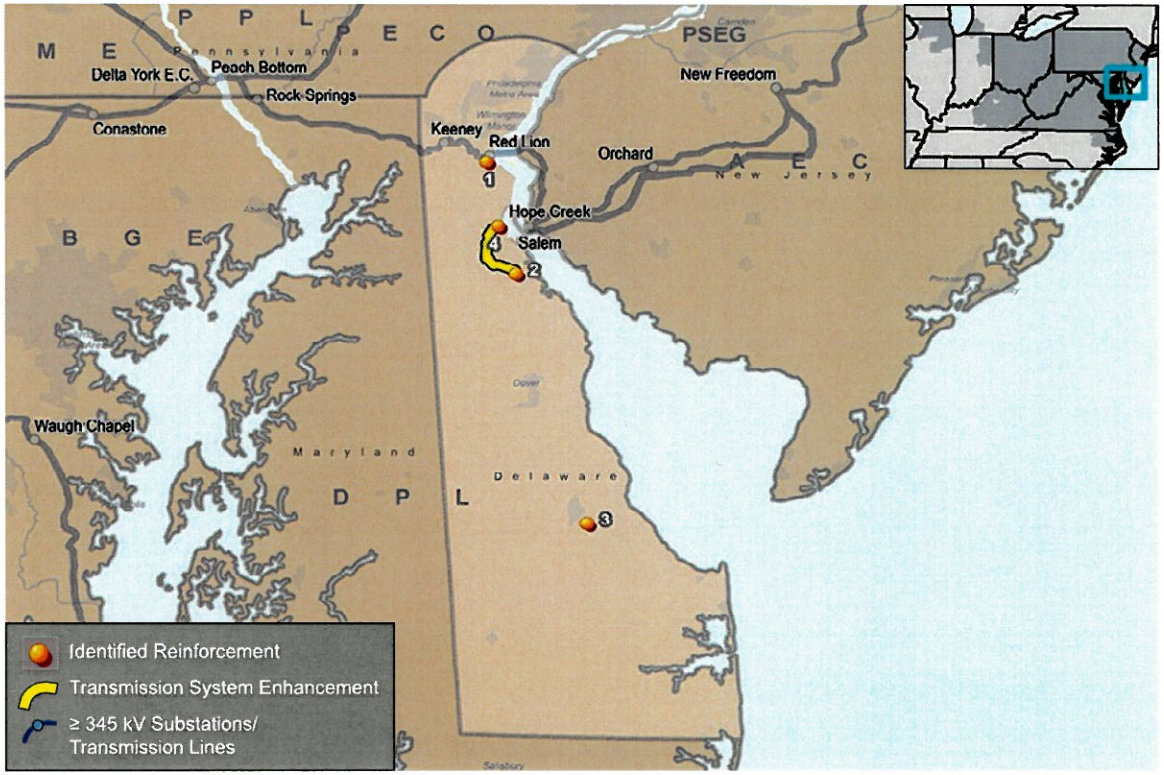

Table 6.4: Delaware Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3865.1	Upgrade 138/69 kV autotransformer, a 69 kV breaker, two disconnects and move a takeoff structure at Reybold substation. These upgrades will require a substation expansion to move the takeoff structure and a control house expansion to move the 69 kV breaker relays from the Delaware City control house to the Reybold control house.	12/1/2029	$9.48	DP&L	11/14/2024
2	B3866.1	Adjust relay setting at Cedar Creek 230 kV substation.	12/31/2029	$0.10		12/3/2024
	B3793.2	Replace three standalone CTs, disconnect switch, stranded bus and rigid bus to achieve higher rating at Cedar Creek.	6/1/2028	$0.45		10/31/2023
3	B3866.2	Change relay setting at Milford 230 kV substation.	12/31/2029	$0.10		12/3/2024
4	B3793.1	Reconductor Silver Run-Cedar Creek 230 kV line. Reconductor 8.8 miles of 230 kV circuit with 1594-T11/ACCR "Lapwing" conductor and replace all insulators with high-temp. hardware.	6/1/2028	$7.68		10/31/2023
	B3793.3	Replace three 1-1590 ACSR jumpers and one air disconnect switch at Silver Run.		$0.58		

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6.1.7 — Network Projects

Network projects in Delaware for 2024 are summarized in **Map 6.4** and **Table 6.5**.

Read More
Network Projects

Map 6.4: Delaware Network Projects (Dec. 31, 2024)

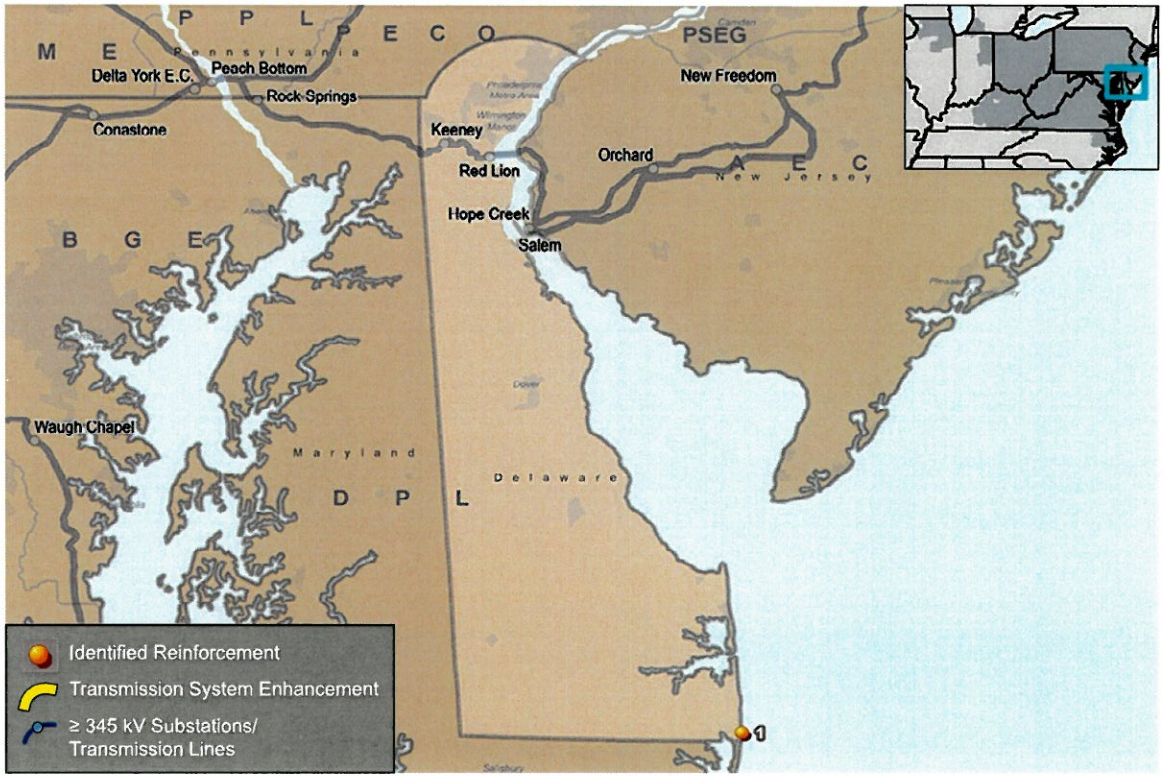

Table 6.5: Delaware Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N8342	Install harmonic measurement equipment and collect data for a harmonic study. Provide data and report to interconnection customer and PJM.	AF1-007	12/31/2024	$0.40	DP&L	1/9/2024

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6.2: Northern Illinois RTEP Summary

6.2.1 — RTEP Context

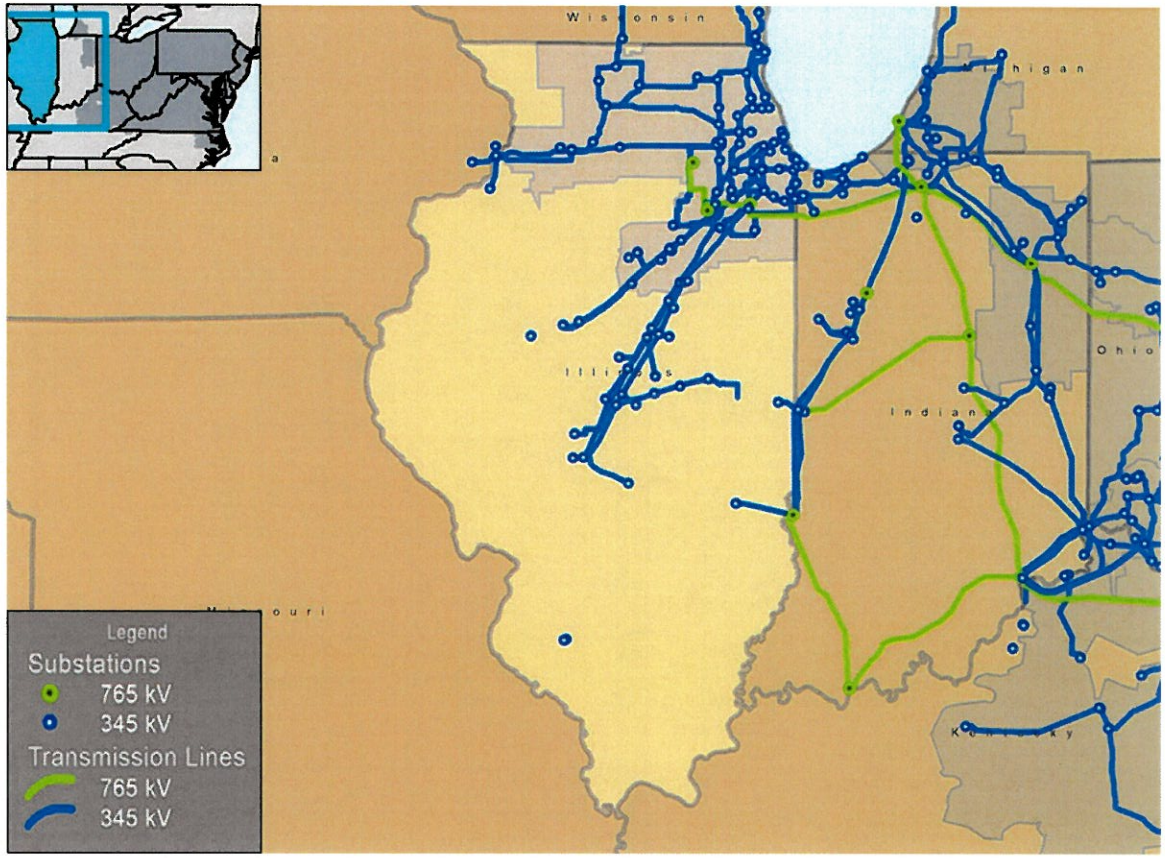
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in northern Illinois, including facilities owned and operated by Commonwealth Edison (ComEd) and the city of Rochelle as shown on **Map 6.5**. The transmission system in northern Illinois delivers power to customers from native 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 the PJM service area.

Renewable Portfolio Standards

Illinois has a mandatory renewable portfolio standard (RPS) of 40% renewable energy by 2030 and 50% 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 solar, wind and hydro. CEJA also established a clean electricity target of 100% for Illinois by 2050.

CEJA includes 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 carbon-free 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.

Map 6.5: PJM Service Area in Northern Illinois



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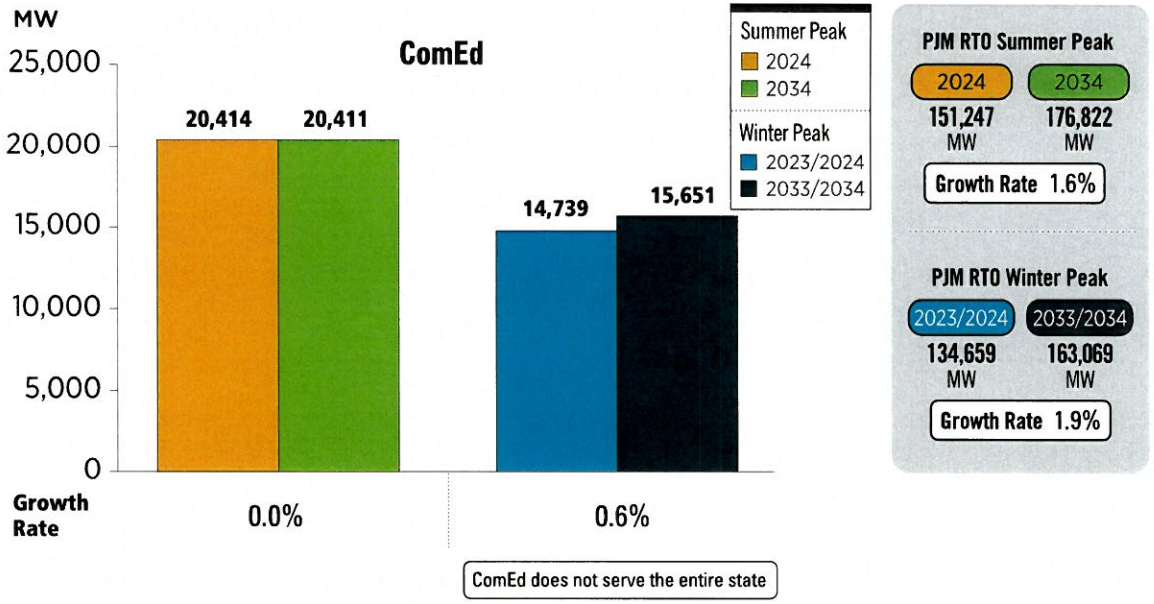
6.2.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.6** summarizes the expected loads within the state of Illinois and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.6: Northern Illinois – 2024 Long-Term Load Forecast



The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by ComEd in northern Illinois. Estimated amounts were calculated based on the average share of ComEd's real-time summer and winter peak load in northern Illinois over the past five years.

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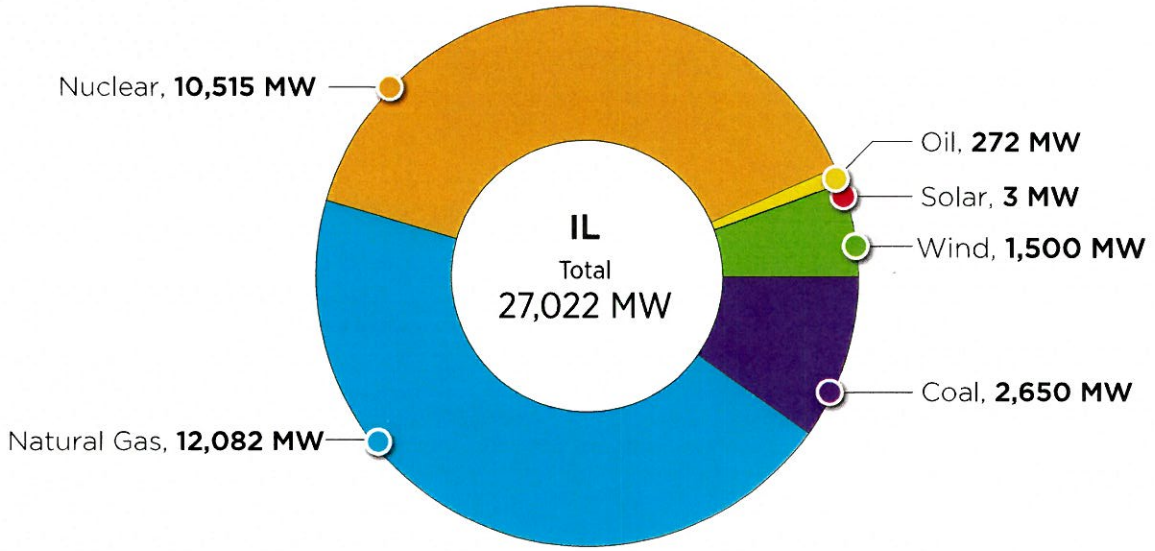
6.2.3 — Existing Generation

Existing generation in Illinois as of Dec. 31, 2024, is shown by fuel type in **Figure 6.7**.

Figure 6.7: Northern Illinois – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



Read More
Changing Capacity Mix and Deliverability

6.2.4 — Interconnection Requests

In Illinois, as of Dec. 31, 2024, 243 projects were actively under study or under construction as shown in the summaries presented in **Table 6.6**, **Table 6.7**, **Figure 6.8**, **Figure 6.9** and **Figure 6.10**.

NOTE:
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 6.6: Northern Illinois – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	Illinois Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	1,435	7.04%	20,162	14.38%
Hydro	0	0.00%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	353	1.73%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	0	0.00%	64	0.05%
Solar	6,954	34.07%	55,040	39.25%
Storage	8,552	41.91%	39,064	27.86%
Wind	3,112	15.25%	17,455	12.45%
Grand Total	**20,409**	**100%**	**140,231**	**100%**

Read More
Interconnection Requests

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Table 6.7: Northern Illinois – Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

		In Queue				Complete				Grand 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
	Natural Gas	2	140.0	2	213.0	33	4,490.9	26	10,221.5	63	15,065.4
	Diesel	0	0.0	0	0.0	2	22.0	0	0.0	2	22.0
	Nuclear	0	0.0	0	0.0	10	385.8	5	782.0	15	1,167.8
	Storage	74	8,552.3	0	0.0	5	0.0	51	3,140.8	130	11,693.1
Renewable	Hybrid	16	1,437.5	0	0.0	1	2.2	11	685.3	28	2,125.0
	Hydro	0	0.0	0	0.0	0	0.0	5	27.0	5	27.0
	Biomass	0	0.0	0	0.0	0	0.0	3	90.0	3	90.0
	Methane	0	0.0	0	0.0	2	19.7	14	63.9	16	83.6
	Solar	92	6,954.1	0	0.0	3	45.4	99	4,644.7	194	11,644.2
	Wind	53	2,888.2	4	223.6	37	955.3	129	3,508.9	223	7,576.1
	Grand Total	**237**	**19,972.2**	**6**	**436.6**	**93**	**5,921.3**	**349**	**26,816.1**	**685**	**53,146.2**

Figure 6.8: Northern Illinois – Percentage of Total Capacity in Queue by Fuel Type (Dec. 31, 2024)

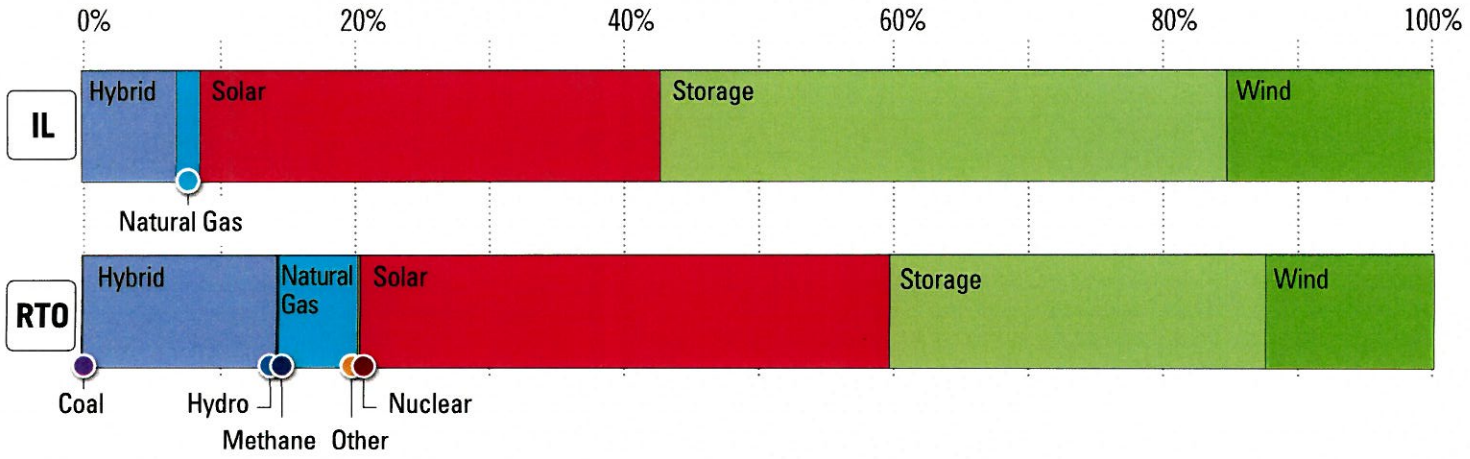

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Figure 6.9: Northern Illinois Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

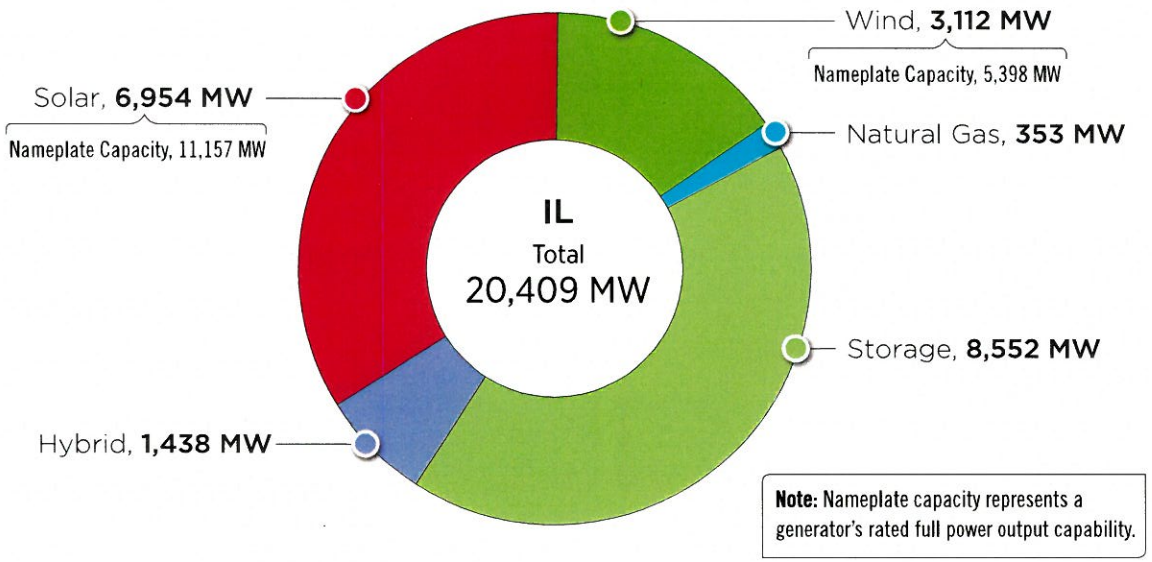
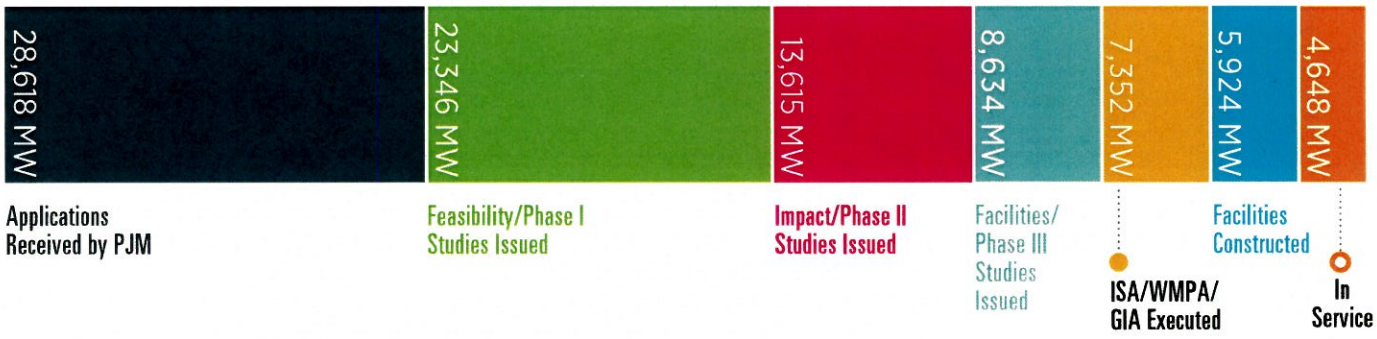


Figure 6.10: Northern Illinois Progression of Interconnection Requests (Dec. 31, 2024)



Percentage of planned capacity and projects that have reached commercial operation

16.2%	Requested capacity megawatts
14.2%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	13	Interconnection Service Agreements	1,687 MW	3,078 MW
	9	Wholesale Market Participation Agreements	42 MW	71 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, 2024.

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6.2.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Illinois between Jan. 1, 2024, and Dec. 31, 2024, are summarized in **Map 6.6** and **Table 6.8**.

Read More
Baseline Projects

Map 6.6: Northern Illinois Generation Deactivations (Dec. 31, 2024)

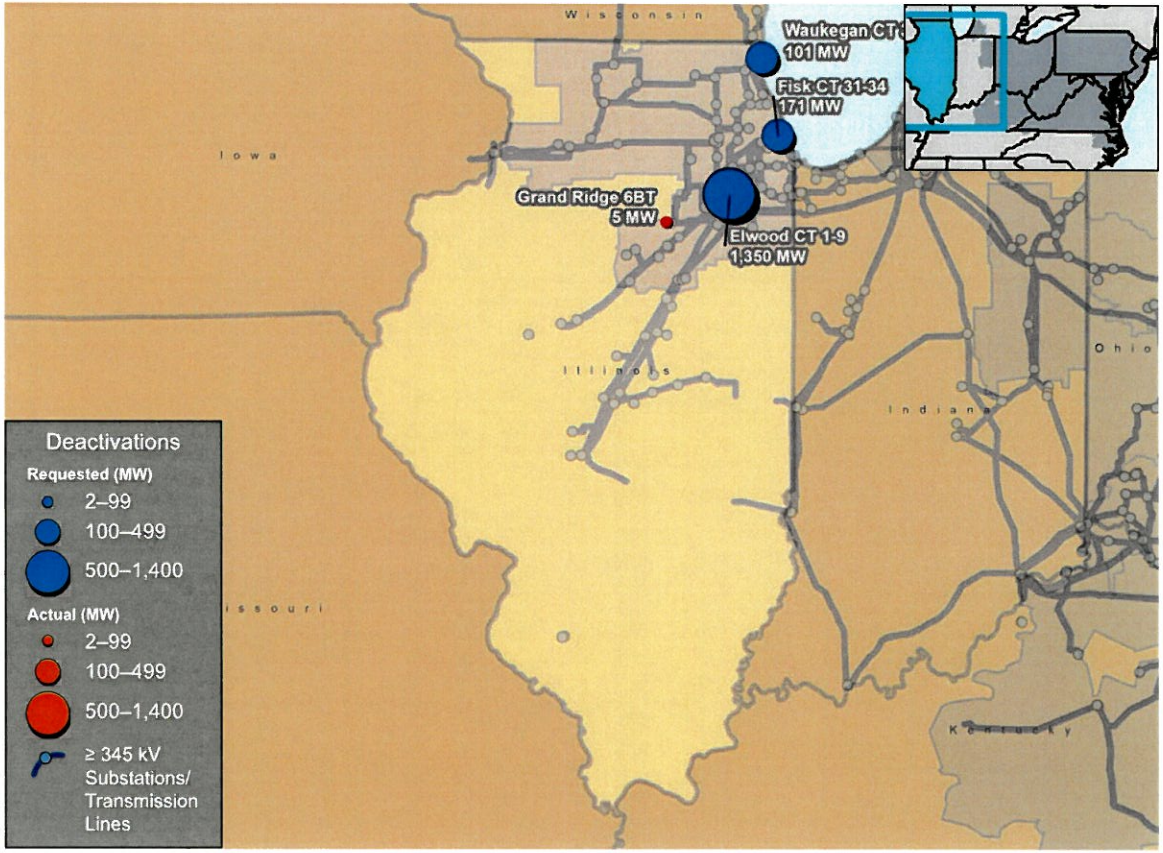

Table 6.8: Northern Illinois Generation Deactivations (Dec. 31, 2024)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Grand Ridge 6 BT	ComEd	Storage	6/28/2024	10/1/2024	12	4.5
Fisk CT 31		Oil	7/23/2024	6/1/2026	56	49.1
Fisk CT 32						50.8
Fisk CT 33						47.9
Fisk CT 34						22.9

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Table 6.8: Northern Illinois Generation Deactivations (Dec. 31, 2024) (Cont.)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Waukegan CT 32	ComEd	Oil	7/23/2024	6/1/2026	56	48.9
Waukegan CT 31						52.5
Elwood CT 9		Natural Gas	5/29/2024	6/1/2025	25	150
Elwood CT 8						150
Elwood CT 7						150
Elwood CT 6						150
Elwood CT 5						150
Elwood CT 4						150
Elwood CT 3						150
Elwood CT 2						150
Elwood CT 1						150

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6.2.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in northern Illinois are summarized in **Map 6.7** and **Table 6.9**.

Read More
Baseline Projects

Map 6.7: Northern Illinois Baseline Projects (Dec. 31, 2024)

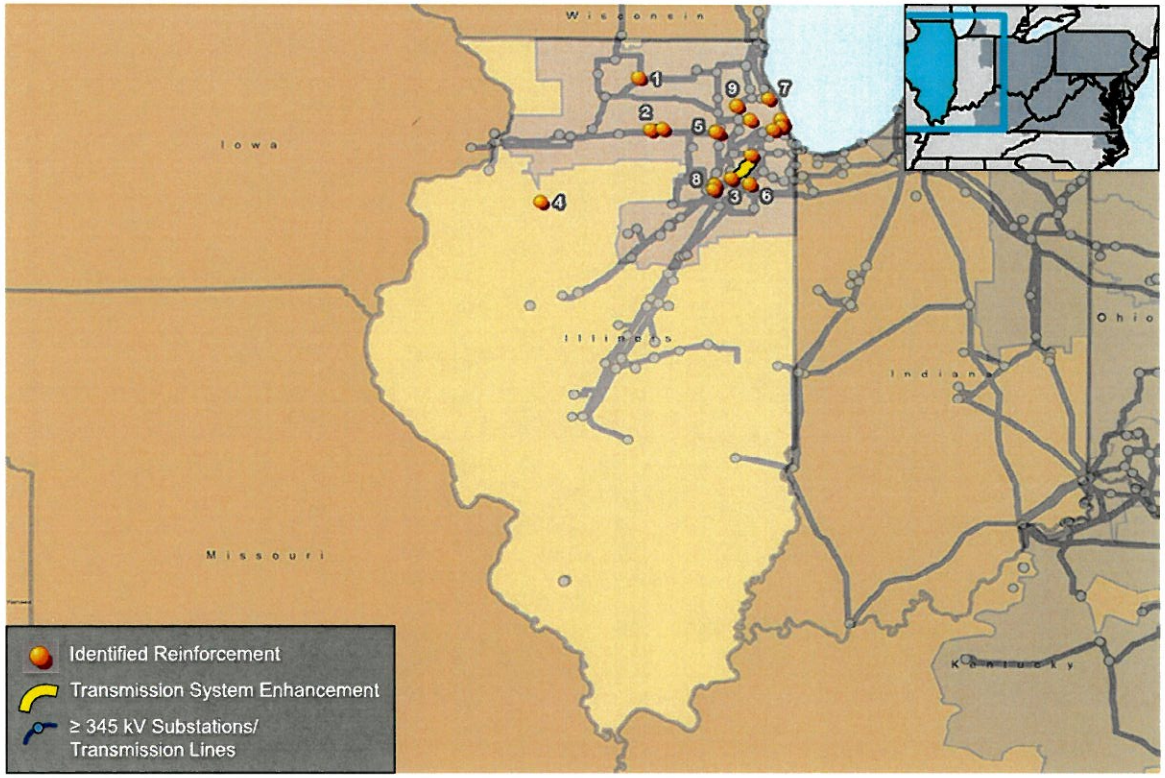

Table 6.9: Northern Illinois Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3810.0	Add three 345 kV circuit breakers to Cherry Valley substation.	6/1/2028	$7.75	ComEd	1/9/2024
2	B3811.1	Expand Haumesser Road 138 kV substation as a four-circuit breaker ring bus.	12/1/2028	$15.91	ComEd	2/6/2024
	B3811.2	Add one 138 kV circuit breaker at H-452 to complete a three-circuit breaker ring bus.		$1.98		
	B3811.3	Rebuild 3 miles of 138 kV line 11323 from Haumesser Road to the H-452 tap with double circuit towers. Cut the H-452 tap over to the second circuit from Haumesser Road. Both circuits to use twisted pair 556 ACSR Parakeet conductor.		$10.22		

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Table 6.9: Northern Illinois Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	B3812.1	Reconductor 345 kV lines 11620 and 11622 from Elwood to Goodings Grove.	6/1/2028	$56.18	ComEd	3/5/2024
	B3812.2	Upgrade Goodings Grove 345 kV circuit breakers, disconnects and associated equipment.		$5.16		
	B3812.3	Upgrade station conductor at Elwood 345 kV.		$0.50		
	B3812.4	Adjust reclosing cycle on for Goodings Grove 345 kV circuit breaker "116 9806" to eliminate the reclosing derating.		$0.00		
4	B3900.1	Replace 300 copper conductor with 1113 kcmil ACSR conductor on Kewanee 138 kV Bus No. 1.	4/1/2029	$0.20		11/15/2024
	B3903.1	Replace the Kewannee 138 kV L7411 circuit breaker with a SF6 63 kA circuit breaker.	6/1/2026	$1.10		
5	B3901.1	Reconductor 138 kV line from Electric Junction to W541.	6/1/2029	$1.38		
	B3901.2	Replace 2" tubular bus, 2-500 KCMIL Cu and 1113 KCMIL ACSR/AA on bus 2 and line terminal of 138 kV L11106 at TSS 111 Electric Junction with bus that meets or exceeds a minimum thermal capability of 2036/2236/2690A (487/534/643MVA) SN/SE/SLD.		$0.28		
6	B3902.1	Replace the Wilton Center 345 kV BT 4-5 circuit breaker.	12/1/2029	$2.70		12/3/2024
7	B3914.1	Change no-load tap of two autotransformers at Fisk from 338.25 kV to 346.5 kV.	4/15/2029	$0.03		12/13/2024
	B3914.2	Change no-load tap of four autotransformers at Crawford from 338.25 kV to 3456.5 kV.		$0.07		
	B3914.3	Change no-load tap of three autotransformers at Elmhurst from 338.25 kV to 346.5 kV.		$0.05		
	B3914.4	Change no-load tap of two autotransformers at West Loop from 338.25 kV to 346.5 kV.		$0.03		
	B3914.5	Change no-load tap of two autotransformers at Taylor from 338.25 kV to 346.5 kV.		$0.03		
	B3914.6	Change no-load tap of four autotransformers at Skokie from 338.25 kV to 3456.5 kV.		$0.07		
8	B3915.1	Reconductor 1.5 miles of 345 kV lines 1202 and 1227 from Dresden to Mulberry with two conductor bundled 1033.5 ACSS conductor. Modify and replace towers as necessary to accommodate the higher mechanical loads of the bundled conductor.	6/1/2029	$12.33		12/3/2024
	B3915.2	Install 345 kV circuit breaker on line 1202 (Dresden-Mulberry 345 kV) and upgrade sisconnects and associated equipment at Dresden 345 kV substation.		$3.77		
	B3915.3	Upgrade disconnects and associated equipment at Mulberry 345 kV substation.		$0.17		
9	B3916.1	Install a new 420 MVA 345/138 kV autotransformer and associated 345 kV and 138 kV circuit breakers at Itasca substation.		$14.31		

6.2.7 — Network Projects

Network projects in northern Illinois for 2024 are summarized in **Map 6.8** and **Table 6.10**.

Read More
Network Projects

Map 6.8: Northern Illinois Network Projects (Dec. 31, 2024)

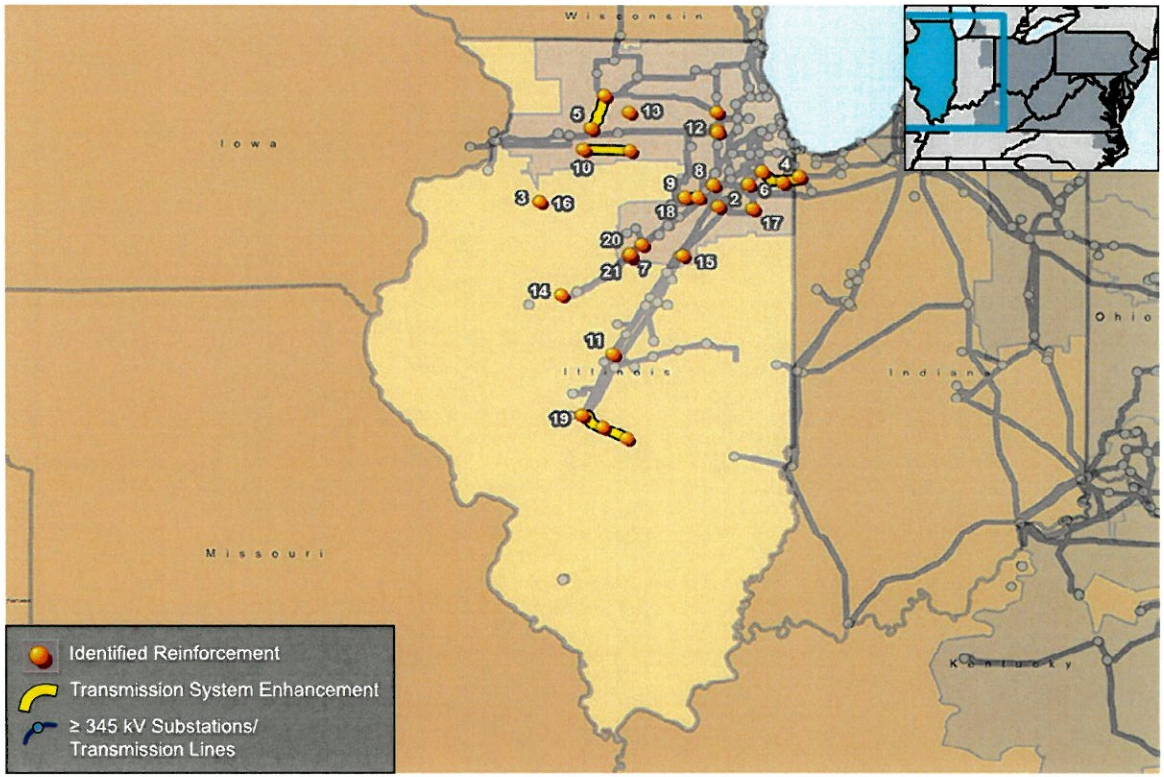

Table 6.10: Northern Illinois Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N4790	Replace Dumont 345 kV substation 2500A wavetrap.	AB1-122	6/1/2019	$0.20	AEP	10/8/2024
2	N5145	Reconfigure Wilton 765 kV bus thereby allowing for 765 kV L11216 (currently on bus 6) to be relocated to bus 8. Along with this line relocation, installation of two 765 kV bus tie circuit breakers (6-8 & 8-2).	AD1-100	10/31/2026	$55.23	ComEd	

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Table 6.10: Northern Illinois Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	N5171.1	Upgrade all existing 138 kV circuit breakers at Kewanee to three-cycle devices with achievable clearing time of 6/11 cycles. Relay upgrade on line L6101 will be required to support this clearing time.	U4-027	12/31/2018	$0.14	ComEd	10/8/2024
	N5171.2	Upgrade all existing 138 kV circuit breakers at Kewanee to three-cycle devices with achievable clearing time of 6/11 cycles. Relay upgrade on line L7411 will be required to support this clearing time.			$0.14		
	N5171.3	Upgrade all existing 138 kV circuit breakers at Kewanee to three-cycle devices with achievable clearing time of 6/11 cycles. Relay upgrade on line L7421 will be required to support this clearing time.			$0.14		
	N5171.4	Upgrade all existing 138 kV circuit breakers at Kewanee to three-cycle devices with achievable clearing time of 6/11 cycles. Relay upgrade on line L7423 will be required to support this clearing time.			$0.14		
	N5171.5	Upgrade, all existing 138 kV circuit breakers at Kewanee to three-cycle devices with achievable clearing time of 6/11 cycles. Relay upgrade on line L94301 will be required to support this clearing time.			$0.14		
	N5171.6	Upgrade all existing 138 kV circuit breakers at Kewanee to three-cycle devices with achievable clearing time of 6/11 cycles. Relay upgrade on line segment of L15508 from Kewanee to U4-027 (new line number 7408).			$0.14		
	N5173	Add high-speed backup relaying and associated communications to 138 kV line Kewanee to U4-027 (7408).			$2.80		
4	N5253	Reconductor the ComEd portion of Crete-St John 345 kV line.	AD1-100	6/1/2020	$14.90		
5	N5254	Reconductor the Lee County-Byron 345 kV line.	AF2-199	10/1/2017	$17.20		
	N5254.1	Mitigate sag on the Lee County-Byron 345 kV line.	AF2-393	9/1/2024	$10.00		
6	N5917	Reconductor the E Frankfort-Crete 345 kV line.	AE1-198	6/1/2022	$10.30		
7	N6280	Upgrade will be to mitigate sag on ComEd portion of line. A preliminary estimate is $4.5 M with a estimated construction timeline of 24 months.	AE1-163	11/30/2021	$2.47		1/9/2024
8	N6840	ComEd 345 kV L11212 SSTE rating is 1846 MVA. The upgrade will be to install a new 345 kV bus tie circuit breaker at station 12 Dresden. The new 345 kV breaker will be installed as bus tie circuit breaker 12-13. Initial review of this proposal is that the existing contingency will be reduced and potentially reducing the post-contingency flow. PJM to confirm this proposal in study. The ratings for L11212 will not change rather the contingency as stated above will be revised.	AD2-100	11/24/2026	$3.44		10/8/2024
9	N7033	Reconductor the AD2-066 Tap-Mazon 138 kV line.	AD2-066	9/1/2020	$32.20		1/9/2024
10	N7383	Relaying upgrades at TSS 100 Shady Oaks 138 kV substation including: Install a SEL-411L as current differential line protection on L94701, and make the existing primary relay, SEL-311L, the secondary relay. Modify L16901 circuit breaker and L13901 circuit breaker tripping to accommodate new topology. Install load rejection logic such that transfer trip is initiated on both primary and secondary relaying to TSS 946 GSG-6 wind farm if L94701 circuit breakers are open at TSS 100 Shady Oaks.	AD2-134	12/31/2020	$0.41		10/8/2024
11	N8010	ComEd will be responsible to perform design, procurement and construction to revise remote terminal.	AC1-053		$0.32		1/9/2024
	N8011	ComEd will be responsible to perform design, procurement and construction to revise remote terminal to TSS 987 Beason instead of TSS 188 Mount Pulaski.			$0.31		
	N8012	ComEd will be responsible for performing design, procurement and construction to build L18806 and L98704 from the cut-in location to TSS 987 Beason. New conductor will match existing conductor rating.			$5.56		
	N8013	Engineering and construction oversight for TSS 987 Beason performed by IC.			$1.32		

Table 6.10: Northern Illinois Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
12	N8133.1	Relay settings need to be updated at TSS 951 Aurora Energy Center L95102. Connect new meters into the SCADA system at TSS 951 Aurora Energy Center.	AG1-513	6/1/2024	$0.29	ComEd	1/9/2024
	N8133.2	Relay settings need to be updated at TSS 144 Wayne L14403.			$0.23		
	N8133.3	Relay settings need to be updated at TSS 111 electric junction L11103.			$0.22		
13	N8143	Perform design, procurement and construction to expand 138 kV ESS H-445 Twombly Road substation.	AD1-013	12/15/2018	$12.30		
14	N8189.1	Construct the new 345 kV TSS 918 Dana substation with three 345 kV circuit breakers arranged in breaker-and-a-half configuration.	AD2-038	12/31/2021	$31.27		
	N8189.2	Upgrade existing System 1 and System 2 line protection for 345 kV L0303.			$0.59		
	N8189.3	Upgrade existing System 1 and System 2 line protection for 345 kV L91815, formerly L0303.			$0.38		
	N8189.4	Transmission line cut-in: Install new line facilities required to connect 345 kV L0303 and 345 kV L91815 into TSS 918 Dana substation.			$9.79		
	N8189.5	Install diverse fiber paths from TSS 918 Dana to TSS 908 Mole Creek and from TSS 918 Dana to TSS 98 Nevada.			$4.55		
	N8189.6	Install one fiber cable to station 3 Powerton.			$30.58		
	N8189.7	Replace and/or modify remote relay communication devices and SCADA equipment at Powerton-Nevada 345 kV line to reliably interconnect the customer facility with the transmission system at the applicable remote end stations. Remove microwave equipment at remote end stations.		4/6/2026	$0.81		10/8/2024
15	N8195.1	Oversight for self-build of TSS 905 Essex construction	AD1-100	9/30/2020	$3.46		1/9/2024
	N8195.2	Transmission line (L2002, L11212) cut-in tap into TSS 905 Essex			$20.14		
	N8195.3	Design, procurement and construction to upgrade existing System 1 and System two-line protection for 345 kV L90505			$0.83		
	N8195.4	Design, procurement and construction to upgrade existing System 1 and System two-line protection for 345 kV L2002			$0.83		
	N8195.5	Design, procurement and construction to upgrade existing System 1 and System two-line protection for 345 kV L90506			$0.83		
	N8195.6	Design, procurement and construction to install a new fiber path between TSS 905 Essex and station 20 Braidwood			$3.14		
	N8195.7	Design, procurement and construction to install a new fiber path between TSS 905 Essex and TSS 86 Davis Creek			$8.83		
	N8195.8	Design, procurement and construction to install a new fiber path between TSS 905 Essex and TSS 93 Loretto			$10.81		

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Table 6.10: Northern Illinois Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
16	N6679	AC1-033 new line section for interconnection at Kewanee	AC1-033	12/1/2021	$4.00	ComEd	1/9/2024
	N8214.1	The L7423 138 kV line will be cut and looped into the new TSS 922 Kentville Rd interconnection substation.	AD1-031	12/31/2019	$1.91		
	N8214.2	Install dual 87L/SEL-411L current differential scheme via direct fiber. Upgrade L7423 circuit breaker from 25/SEL-279H and 50/2BF SEL-251C to 50BF/25/79 SEL-451. Install SEL-3350 RTAC with redundant RST-2228 switch architecture (Master, Master Aux A/B, Aux A/B switches). Install SEL-3620 port servers as needed for IED that must be connected serially over the available 3350 RTAC ports. Remove any PLC equipment on L7423 including wave trap, line tuner etc.			$1.91		
	N8214.3	A new breaker-and-a-half substation, 138 kV TSS 922 Kentville Rd, will be constructed an ~0.13 miles south of existing TSS74 Kewanee, which will interconnect via existing 138 kV L7423.			$20.33		
	N8214.4	Relaying coordination and oversight			$0.03		
	N8214.5	138 kV L. 7423 will require two single-mode fiber paths from TSS 74 Kewanee to TSS 922 Kentville Rd, an ~0.4 miles. These will be used for 138 kV L7423 System 1 and System 2 relay scheme using direct-on-fiber connections. At least one of these two fiber paths will need to be built per ESP 5.8.1 and 5.8.2 to determine the fiber count and construction. The second single-mode fiber path will require a minimum of 48 fibers. Both of these cables will be owned and maintained by ComEd. These fibers must be built in physically diverse paths from each other. Fiber paths are assumed to be installed underground for an approximate distance of 1,000' per fiber path. Fiber count and construction for this fiber path will be determined by ComEd standards.			$1.10		
17	N8223	Expansion of existing TSS 86 Davis Creek substation	AD2-047	9/30/2020	$0.68		
18	N8329.1	Build a new ring bus three breaker-and-a-half configuration.	AD2-066	9/1/2020	$20.68		
	N8329.2	Cut and loop L7713 138 kV line to new sub.			$4.07		
	N8329.3	Relay settings shall be modified based on the new line topology.			$0.03		
	N8329.4	Relay settings shall be modified based on the new line topology.			$0.49		
	N8329.5	Installation of fiber cable in existing right-of-way.			$2.65		
19	N8362.1	New 345 kV, TSS 964 Clear Creek substation to accommodate AD2-100 and AD2-131.	AD2-100	12/31/2021	$32.00		
	N8362.2	Modify the Kincaid-Pana 345 kV transmission line to tie in the interconnection substation.			$6.50		
	N8362.3	Relay and fiber upgrades to station 21 Kincaid.			$0.80		
	N8362.4	ComEd coordination with Ameren for relay and fiber upgrades to Ameren's Pana substation.			$0.70		
	N8362.5	Install two physically diverse 48-count single-mode fiber cables per ComEd standards from TSS 964 Clear Creek substation to STA 21 Kincaid.			$107.80		
	N8362.6	Install two physically diverse 48-count single-mode fiber cables per ComEd standards from TSS 964 Clear Creek substation to Ameren's Pana substation.			$41.30		

Table 6.10: Northern Illinois Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
20	N8372.1	Transmission line (L0303) cut-in tap into TSS 915 Dee Mac Road	AE1-163	11/30/2021	$11.12	ComEd	1/9/2024
	N8372.2	Upgrade existing System 1 and System 2 line protection for existing L9150.			$0.38		
	N8372.3	Install one 48-count single-mode fiber cable and upgrade existing System 1 and System 2 line protection for existing L0303.			$0.61		
	N8372.4	Fiber Installation between TSS915 Dee Mac Rd and existing ComEd facilities.			$0.17		
21	N8436.1	Reroute existing L93913 to the new termination at the new 345 kV bus 4 at TSS 908 Mole Creek 345 kV.	AE1-113	12/31/2021	$3.57		10/8/2024
	N8436.2	Expand TSS 908 Mole Creek 345 kV to a six-breaker ring bus.			$17.66		

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6.2.8 — Supplemental Projects

Supplemental projects included in the 2024 Local Plan in northern Illinois are summarized in **Map 6.9** and **Table 6.11**.

Read More
Supplemental Projects

Map 6.9: Northern Illinois Supplemental Projects (Dec. 31, 2024)

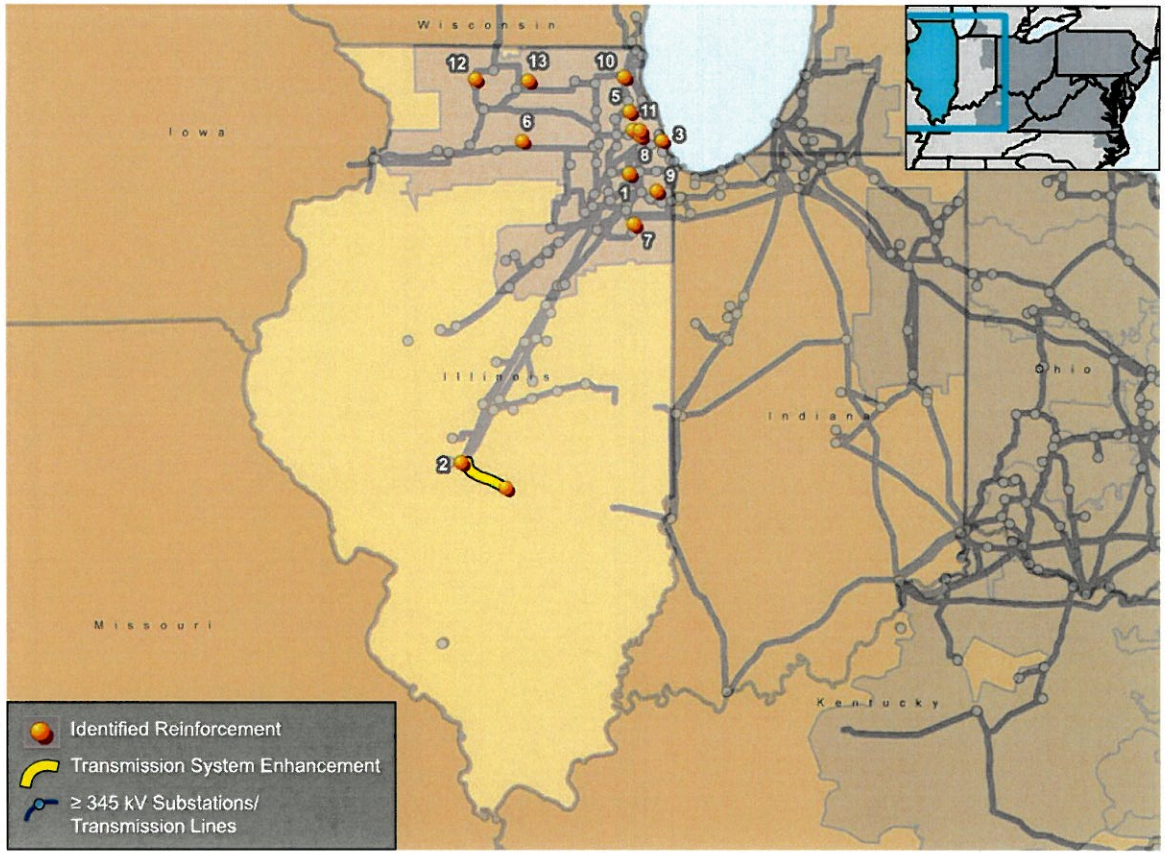

Table 6.11: Northern Illinois Supplemental Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S3011	Replace 345 kV open air straight bus with GIS in a breaker-and-a-half configuration (34 Circuit Breakers) at Goodings Grove with 80 kA capability.	12/31/2028	$264.00	ComEd	10/3/2023
2	S3012	Rebuild ~ 26.4 miles of Kincaid-Pana(Ameren) 345 kV line with new structures, OPGW and 2-1277 ACAR conductor.	12/31/2026	$149.00		
3	S3155	Install a new 50 MVA 138-12 kV distribution transformer and 138 kV BT 4-5 circuit breaker at State substation.	12/31/2024	$2.00		9/15/2023

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Table 6.11: Northern Illinois Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	S3156	Replace existing 345 kV oil BT2-3, BT3-4, BT4-5, BT5-6, BT6-7 circuit breakers at Wilton Center substation with new 345 kV SF6 circuit breakers.	12/31/2024	$11.00	ComEd	10/31/2023
5	S3157	Replace the 345/138 kV autotransformer 83 with a new standard autotransformer at Des Plaines substation. Replace tertiary capacitor bank with a new 138 kV capacitor bank on new 138 kV bus. Replace 138 kV TR 83 oil circuit breaker with a new 138 kV SF6 circuit breaker.	12/31/2025	$24.10		
6	S3341.0	Replace the Franklin Park L3705 138 kV phase shifting transformer. Install a new 138 kV BT1-8 circuit breaker.		$11.80		4/19/2024
	S3342.1	Cut into existing 345 kV line 15502 (Nelson-Electric Junction 345 kV) and extend two lines, 6 miles each to a new Keslinger substation 345 kV breaker-and-a-half bus. Provide four radial 345 kV leads to customer-owned transformers.	12/31/2026	$105.00		2/6/2024
	S3342.2	Cut into existing 138 kV lines 8309 (Glidden-Crego Rd) and 11307 (Waterman-Crego Rd) and extend four lines 0.7 miles to a new Keslinger substation 138 kV breaker-and-a-half bus. Connect two new 138/34 kV distribution transformers at Keslinger. Install two new 345/138 kV transformers at Keslinger.	12/31/2027	$70.00		
7	S3343.1	Tap existing 138 kV line 0901 (Davis Creek-East Frankfort-Joliet) and extend a new 1.1-mile line to a new 138/13.2 kV transformer.	12/31/2024	$0.00		3/15/2024
	S3343.2	Cut into existing 138 kV 0901 and 0902 lines (Davis Creek-East Frankfort-Joliet) and extend two 1.1-mile circuits and two 0.7 mile circuits to a new 138 kV breaker-and-a-half substation. New substation will have eleven 138 kV circuit breakers and supply four 138/12.5 kV distribution transformers.	12/31/2027	$64.00		
8	S3344.0	Replace the existing oil BT circuit breaker, install three new SF6 BT circuit breakers to create a ring bus, and swap bus position of L19209 and distribution TR72 at Oak Park 138 kV.	12/31/2026	$24.00		4/19/2024
9	S3345.0	Replace 138 kV line 17904 disconnect at TDC 457 Park Forest.	12/31/2025	$0.50		
10	S3346.0	Replace the 345 kV oil BT 1-2 and BT 2-3 circuit breakers with new SF6 circuit breakers, install five new 345 kV BT circuit breakers and extend bus to create a double ring bus configuration, and install two new 345 kV circuit breakers on the high side of the 345/138 kV transformers at Libertyville 345 kV.	12/31/2027	$35.00		4/30/2024
11	S3347.0	Replace 138 kV BT1-2, BT1-212, BT1-9, BT4-5, BT8-9 oil circuit breakers with new SF6 circuit breakers, install a new BT circuit breaker 729 between bus 280 and bus 278, and move 138/12 kV transformer from bus 2 to bus 3 at Natoma substation.	12/31/2025	$22.00		5/17/2024
12	S3348.0	Cut 138 kV L19414 Sabrooke-Lancaster into a new 138 kV, three-breaker ring.	12/31/2026	$38.50		
13	S3392.1	Install 138 kV service from overhead high-voltage distribution lines L15623 and L15624 (Belvidere-ESS B465 138 kV double circuit). Four wood double-circuit poles will be replaced with steel poles, and three new poles will be installed. Customer substation will be double ring bus configuration with six 138 kV circuit breakers and two 60 MVA, 138/34 kV transformers.		$0.00		6/14/2024

6.3: Indiana RTEP Summary

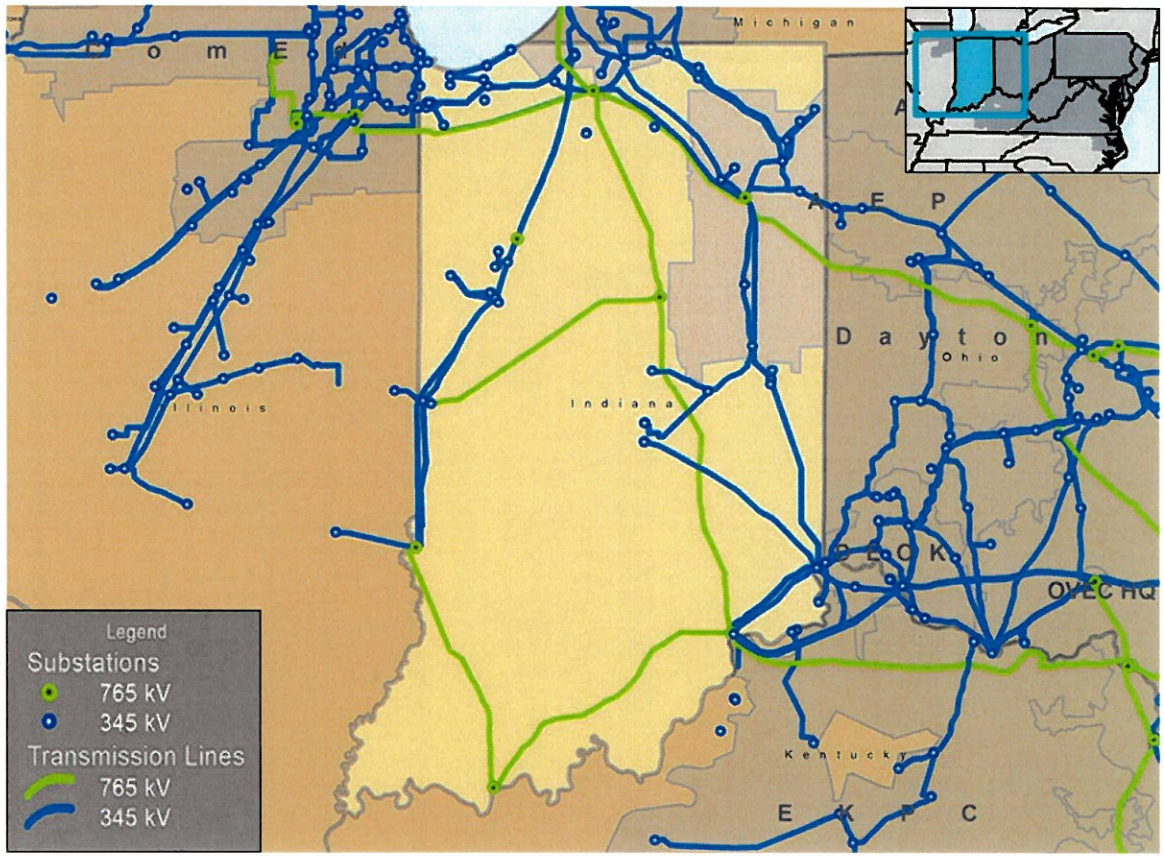
6.3.1 — RTEP Context

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 6.10**. 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 the PJM service area.

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 6.10: PJM Service Area in Indiana



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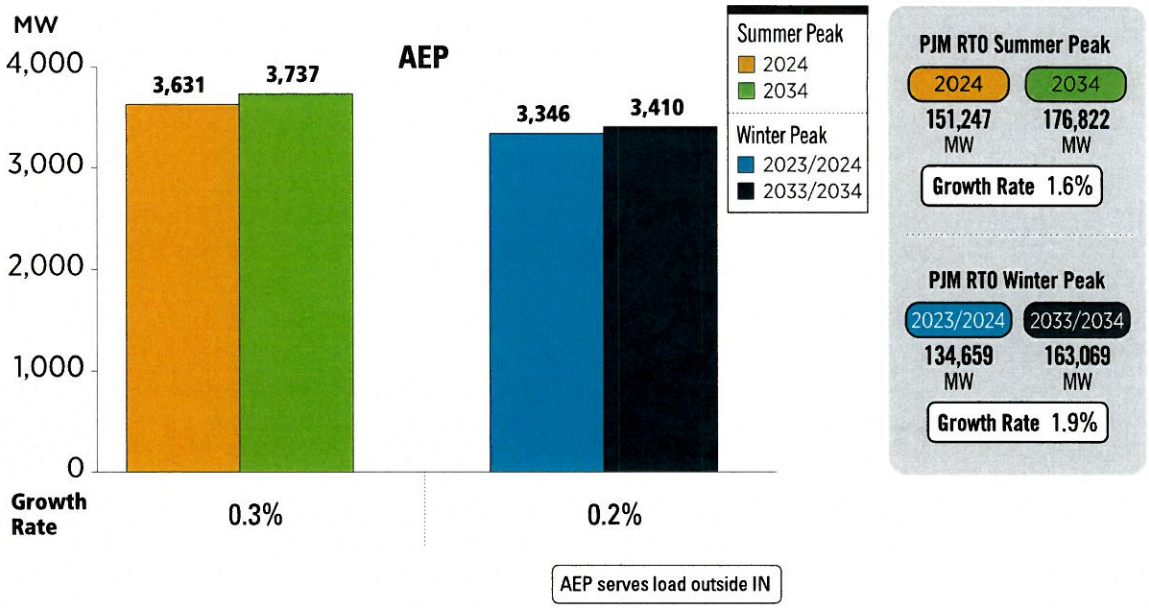
6.3.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.11** summarizes the expected loads within the state of Indiana and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.11: Indiana – 2024 Long-Term Load Forecast



PJM notes that AEP serves load other than in Indiana. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by AEP solely in Indiana. Estimated amounts were calculated based on the average share of AEP's real-time summer and winter peak load located in Indiana over the past five years.

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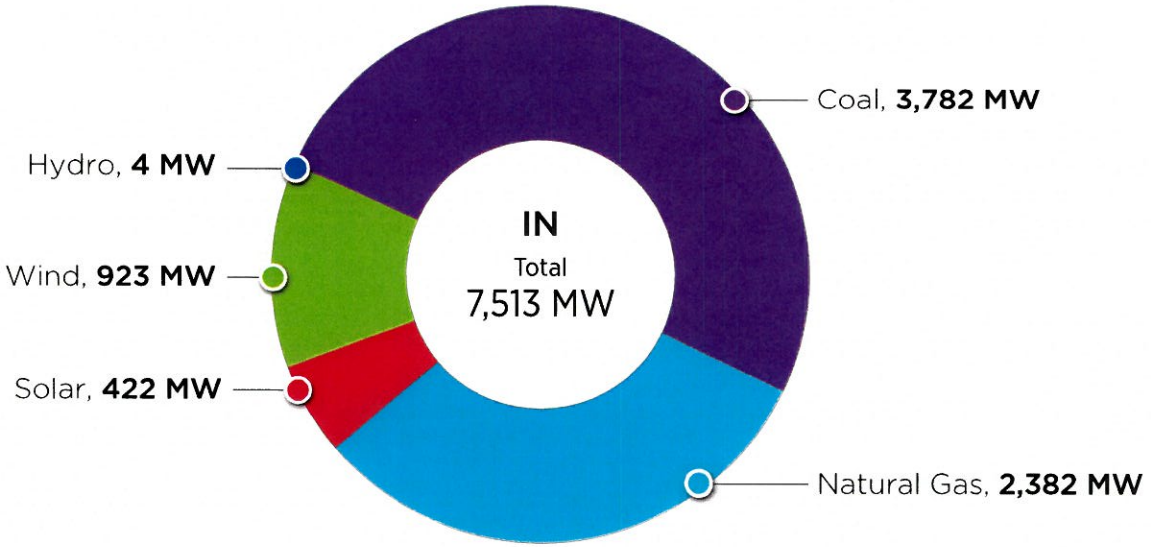
6.3.3 — Existing Generation

Existing generation in Indiana as of Dec. 31, 2024, is shown by fuel type in **Figure 6.12.**

Figure 6.12: Indiana – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



Read More
Changing Capacity Mix and Deliverability

6.3.4 — Interconnection Requests

In Indiana, as of Dec. 31, 2024, 211 projects were actively under study or under construction as shown in the summaries presented in **Table 6.12**, **Table 6.13**, **Figure 6.13**, **Figure 6.14** and **Figure 6.15.**

NOTE:
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 6.12: Indiana – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	Indiana Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	3,985	19.97%	20,162	14.38%
Hydro	0	0.00%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	1,835	9.19%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	0	0.00%	64	0.05%
Solar	9,422	47.21%	55,040	39.25%
Storage	3,424	17.16%	39,064	27.86%
Wind	1,290	6.47%	17,455	12.45%
Grand Total	19,957	100%	140,231	100%

Read More
Interconnection Requests

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Table 6.13: Indiana – Interconnection Requests by Fuel Type (Dec. 31, 2024)

		In Queue				Complete				Grand 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	4	1,835	0	0.0	6	861.0	2	1,747.0	12	4,443.0
	Other	0	0.0	0	0.0	0	0.0	1	253.4	1	253.4
	Storage	34	3,424.0	0	0.0	0	0.0	32	2,238.5	66	5,662.5
Renewable	Hybrid	31	3,894.9	1	90.0	0	0.0	11	2,881.4	43	6,866.3
	Methane	0	0.0	0	0.0	2	8.0	1	3.6	3	11.6
	Solar	118	9,422.4	0	0.0	10	462.6	58	4,761.3	186	14,646.2
	Wind	23	1,290.4	0	0.0	11	414.9	53	2,053.9	87	3,759.2
	Grand Total	**210**	**19,866.7**	**1**	**90.0**	**33**	**1,812.5**	**160**	**14,840.0**	**404**	**36,609.2**

Figure 6.13: Indiana – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

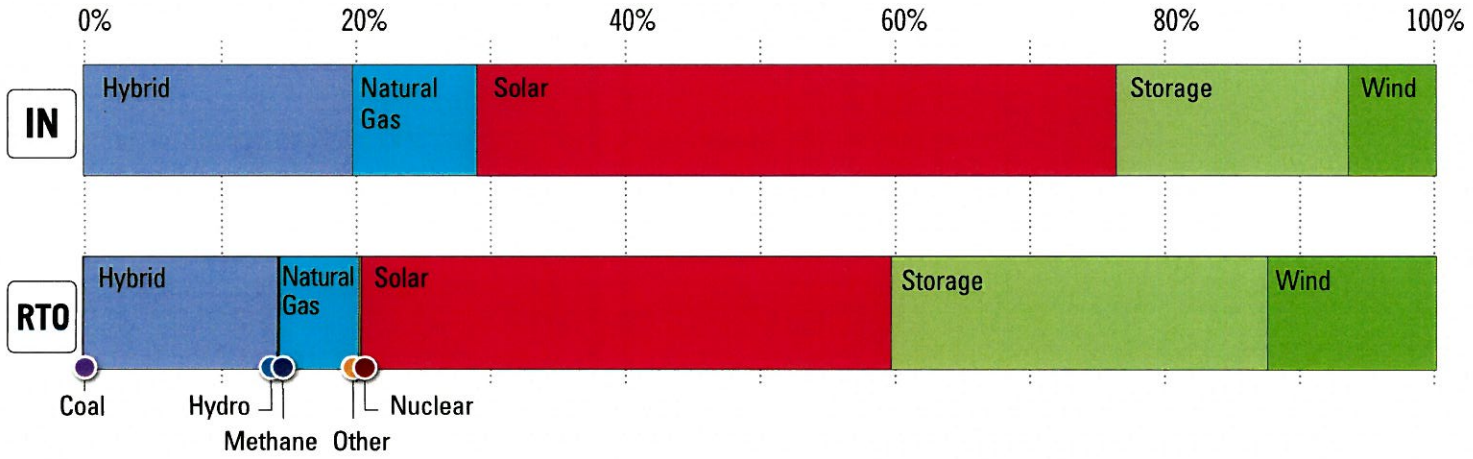

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Figure 6.14: Indiana Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

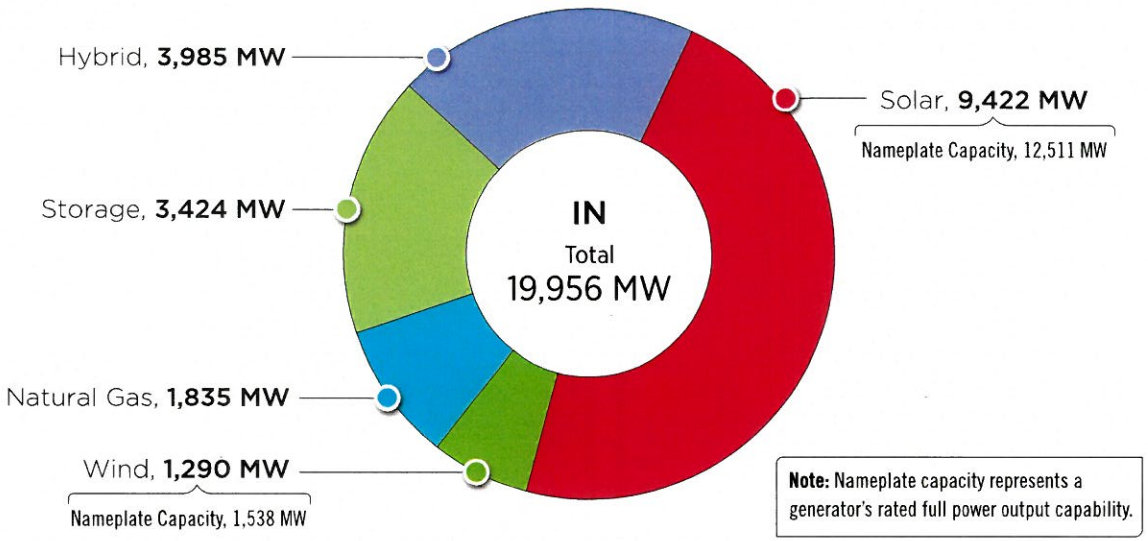

Figure 6.15: Indiana Progression of Interconnection Requests (Dec. 31, 2024)

Percentage of planned capacity and projects that have reached commercial operation

9.5%	Requested capacity megawatts
15.1%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	4	Interconnection Service Agreements	110 MW	720 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, 2024.

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6.3.5 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in Indiana are summarized in **Map 6.11** and **Table 6.14**.

Read More
Baseline Projects

Map 6.11: Indiana Baseline Projects (Dec. 31, 2024)

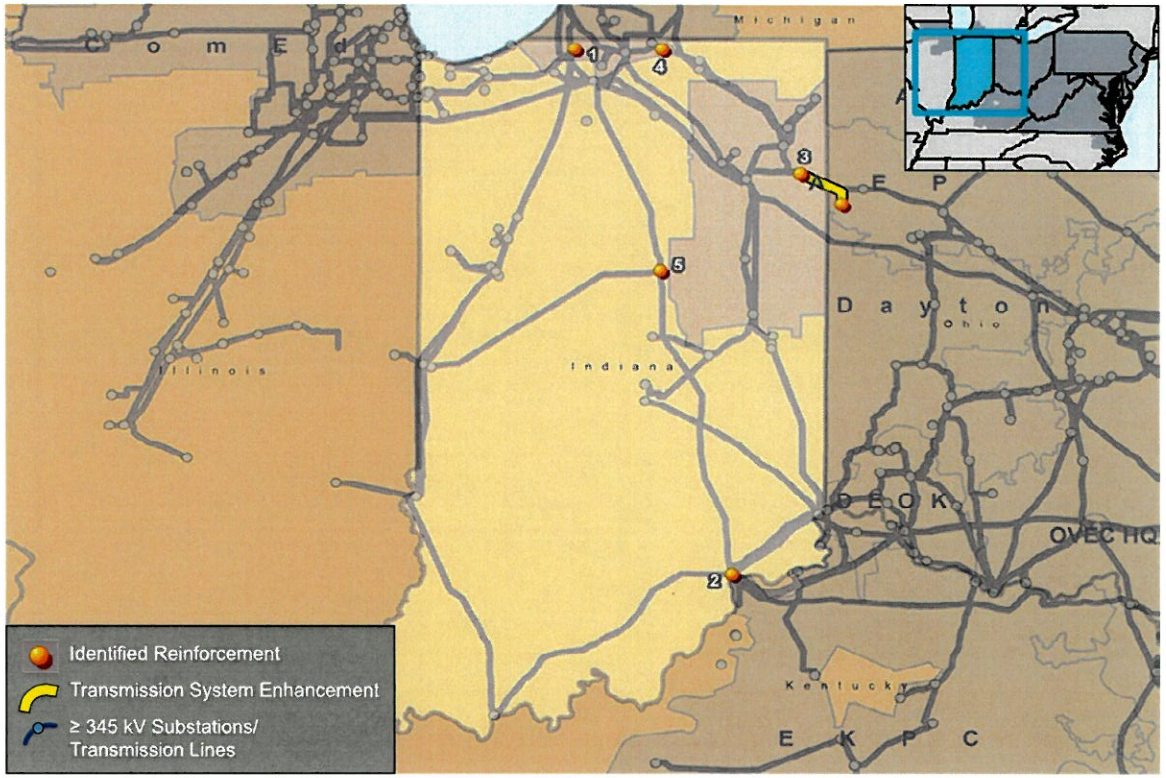

Table 6.14: Indiana Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3790.0	Replace the overdutied Olive 345 kV circuit breaker "D" with a 5000A 63 kA circuit breaker. Reuse existing cables and a splice box to support the circuit breaker install.	6/1/2028	$1.08	AEP	12/5/2023
2	B3847.3	Add a 765 kV breaker to the reactor at Jefferson station on the Greentown 765 kV line.	6/1/2024	$8.53		6/5/2024
3	B3851.1	Rebuild Allen-R.P. Mone 345 kV line (18.6 miles).	6/1/2027	$49.88		7/10/2024
4	B3873.1	Install 12 MVAR 34.5 kV cap bank at Greenleaf.	6/1/2029	$1.31		11/15/2024
5	B3887.1	Replace Greentown 138 kV circuit switcher for transformer No. 5 with a 138 kV 63 kA circuit breaker.	6/1/2026	$1.00		

6.3.6 — Network Projects

Network projects in Indiana for 2024 are summarized in **Map 6.12** and **Table 6.15**.

Read More
Network Projects

Map 6.12: Indiana Network Projects (Dec. 31, 2024)

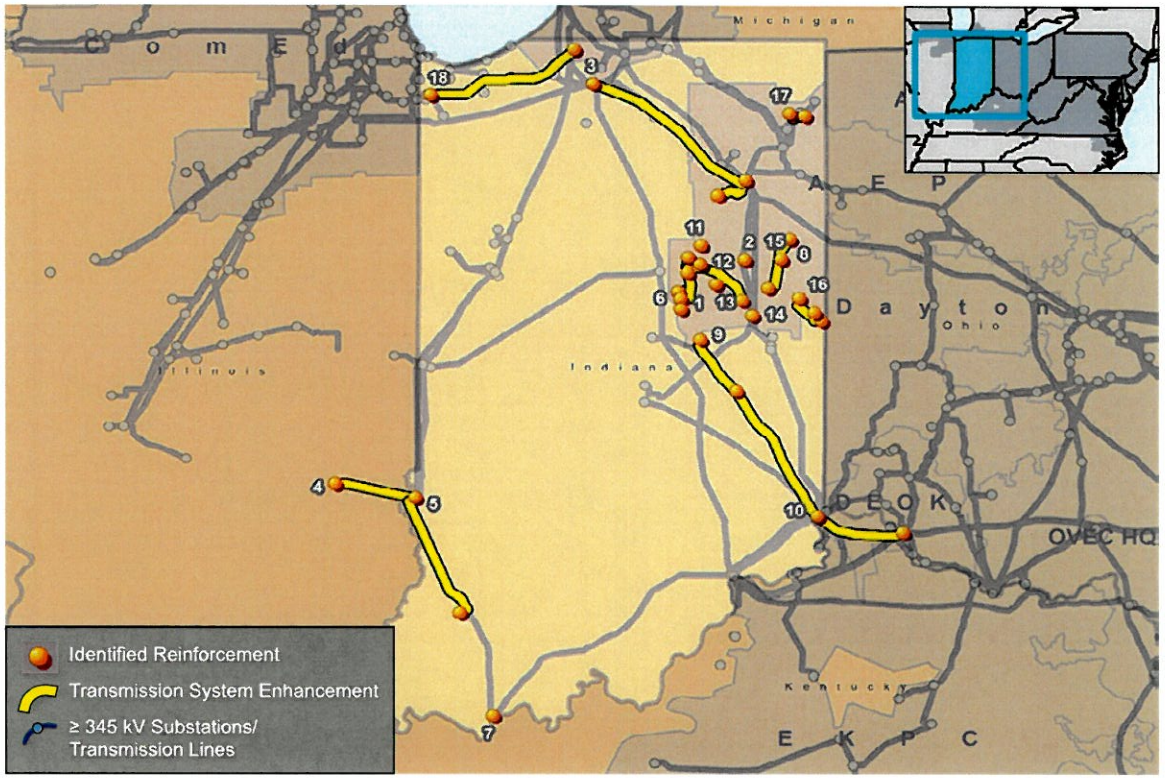

Table 6.15: Indiana Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N104.1	A new three-circuit breaker 138 kV station, Snowhill, physically configured in a breaker-and-half bus arrangement but operated as a ring bus	AD2-071	12/1/2021	$6.54	AEP	1/9/2024
	N104.2	Connect Snowhill 138 kV station to existing transmission circuit; update remote end work protective relay settings.			$0.81		
	N104.3	Replace protective relays at Strawton 138 kV station.			$0.20		
	N104.4	Install two fiber-optic paths to facilitate relaying between Snowhill, Deer Creek and Strawton 138 kV stations.			$0.24		
	N104.5	Replace three structures, six spans of conductor along the Deer Creek-Makahoy 138 kV circuit.			$0.63		

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Table 6.15: Indiana Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	N3069	Install metering at the Keystone 345 kV substation for V3-015 project.	V3-015	8/1/2012	$0.07	AEP	10/8/2024
3	N4323	Loop the Dumont-Sorenson 345 kV line into the new Eldeberry substation pending the results of the AEP sag study.	X2-052	10/1/2014	$5.00		
4	N6037	Expansion of Sullivan 345 kV substation and installation of associated protection and control equipment	AB1-087	6/1/2019	$1.75		
	N6037.1	Install breakers, physical structures, protection and control equipment, and associated facilities at Sullivan 345 kV switching station.			$3.57		
	N6037.2	Install custom dead-end transmission line structure to raise Sullivan-West Casey 345 kV line.			$0.61		
	N6037.3	Install custom dead-end transmission line structure to raise Sullivan-Petersburg 345 kV line.			$0.61		
	N6038	Install 345 kV revenue metering at Sullivan 345 kV switching station.			$0.35		
5	N6039	Expansion of Sullivan 345 kV substation and installation of associated protection and control equipment.	AB1-088		$1.75		
	N6039.1	Install breakers, physical structures, protection and control equipment, and associated facilities at Sullivan 345 kV switching station.			$1.68		
	N6040	Install 345 kV revenue metering at Sullivan 345 kV switching station.			$0.35		
	N6049	Expand existing bay and install one 345 kV circuit breaker, physical structures, protection and control equipment, communications equipment, and associated facilities at the Sullivan 345 kV switching station.	AC2-157	12/31/2020	$2.22		1/9/2024
6	N6329	Perform a sag study on the Pipe Creek-05GRNTTA 138 kV line.	AD2-071	12/1/2021	$0.02		
	N6330	Perform a sag study on the AD2-071 Tap-Pipe Creek 138 kV line.			$0.03		
7	N6497.2	Replace six 3000A Rockport CTs on the Rockport-Jefferson 765 kV line.	AE2-130	12/1/2022	$4.80		10/8/2024
8	N6593	Replace Adam substation conductor on the AE2-089 Tap-Adam 138 kV line.	AE2-089	12/31/2022	$0.30		
9	N7243.1	Install 138 kV revenue metering.	AE2-297	12/31/2021	$0.25		1/9/2024
	N7243.2	Construct a new three-circuit breaker 138 kV switching station.			$6.00		
	N7243.3	Construct facilities to loop the existing Madison-Tanners Creek 138 kV line into the proposed 138 kV interconnection switching station.			$1.00		
	N7243.4	Modify relays and/or settings at the Madison 138 kV substation.			$0.25		
	N7243.5	Modify relays and/or settings at the Tanners Creek 138 kV substation.			$0.25		
10	N7881	Perform a sag study on the Dearborn-Pierce 345 kV line transmission line. OVEC's cost estimate for performing the sag study is $125,000. 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.			$11.38	OVEC	
11	N8089.1	Expand Huntington junction switching station into a four-breaker ring bus.	AF1-092	6/1/2022	$4.23	AEP	10/8/2024
	N8089.2	Sorenson-Delaware 138 kV reroute; Sorenson and Hummel Creek 138 kV line reterminations			$0.38		
	N8089.3	Install transition fiber cable at Huntington junction 138 kV substation.			$0.15		
	N8089.4	Sorenson and Hummel Creek 138 kV remote end work			$0.05		

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Table 6.15: Indiana Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
12	N8104.1	A new three-circuit breaker 138 kV station, Snowhill, physically configured in a breaker-and-a-half bus arrangement but operated as a ring bus.	AD2-071	12/1/2021	$6.54	AEP	1/9/2024
	N8104.2	Connect Snowhill 138 kV station to existing transmission circuit. Update remote end work protective relay settings.	AD2-071		$0.81		
	N8104.3	Replace protective relays at Strawton 138 kV station.	AD2-071		$0.20		
	N8104.4	Install two fiber-optic paths to facilitate relaying between Snowhill, Deer Creek and Strawton 138 kV stations.	AD2-071		$0.24		
13	N8170.1	Construct Fritts 138 kV three-breaker station, associated line protection and control equipment, line risers, switches, jumpers and SCADA at the proposed Fritts 138 kV station.	AE1-207	12/31/2022	$5.53		
	N8170.2	Install two structures, two spans of conductor; connect Fritts 138 kV station to existing transmission circuit. Update remote end work protective relay settings at Deer Creek 138 kV station.	AE1-207		$0.64		
	N8170.3	Install two fiber-optic paths to facilitate ICON relaying between Fritts and Gaston 138 kV stations.	AE1-207		$0.29		
	N8170.4	Replace protective relays at Gaston 138 kV station.	AE1-207		$0.28		
	N8186	Update protective relay settings at Fritts 138 kV station.	AE2-172		$0.05		
14	N8176.1	Install one new 345 kV circuit breaker and associated equipment; update protective relay settings and install jumpers for Sorenson and Tanners Creek 345 kV line reterminations.	AE1-209	10/31/2021	$2.18		
	N8176.2	Reterminate the Desoto-Tanners Creek and Desoto-Sorenson 345 kV circuits in the Desoto 345 kV "B" string.	AE1-209		$0.50		
15	N8208.1	Construct a new three-circuit breaker 138 kV station, Atalla 138 kV station, physically designed as a breaker-and-a-half bus station but operated as a three-breaker ring bus.	AE2-089	12/31/2022	$5.92		10/8/2024
	N8208.2	Install two structures, two spans of conductor and OPGW shield wire. Connect Atalla 138 kV station to existing transmission circuit.	AE2-089		$0.77		
	N8208.3	Install two fiber-optic paths to facilitate SCADA/CES connectivity. Includes CES ICON upgrade work at Adams and Jay stations 138 kV.	AE2-089		$0.20		
16	N8215.1	Construct new three-breaker 138 kV station in a breaker-and-a-half configuration.	AE2-219	10/31/2022	$6.47		1/9/2024
	N8215.2	Install two structures, two spans of conductor. Connect proposed 138 kV station to existing transmission circuit. Update remote end work protective relay settings at Bluff Point 138 kV station.	AE2-219		$0.88		
	N8215.3	Install two fiber-optic paths to facilitate relaying between the randolph and proposed 138 kV stations.	AE2-219		$1.20		
	N8215.4	Replace protective relays. Install ICON at Randolph 138 kV station.	AE2-219		$0.19		
17	N8534	Relocation of Auburn-Varner 138 kV structure	AF1-141	5/31/2022	$0.15		10/8/2024
18	N6288	A preliminary estimate for sag mitigation between Green Acres, T and Olive 345 kV is $13.9 M with an estimated construction timeline of 30 months.	AE1-193	9/1/2021	$13.90	ComEd	

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6.3.7 — Supplemental Projects

Supplemental projects included in the 2024 Local Plan in Indiana are summarized in **Map 6.13** and **Table 6.16**.

Read More
Supplemental Projects

Map 6.13: Indiana Supplemental Projects (Dec. 31, 2024)

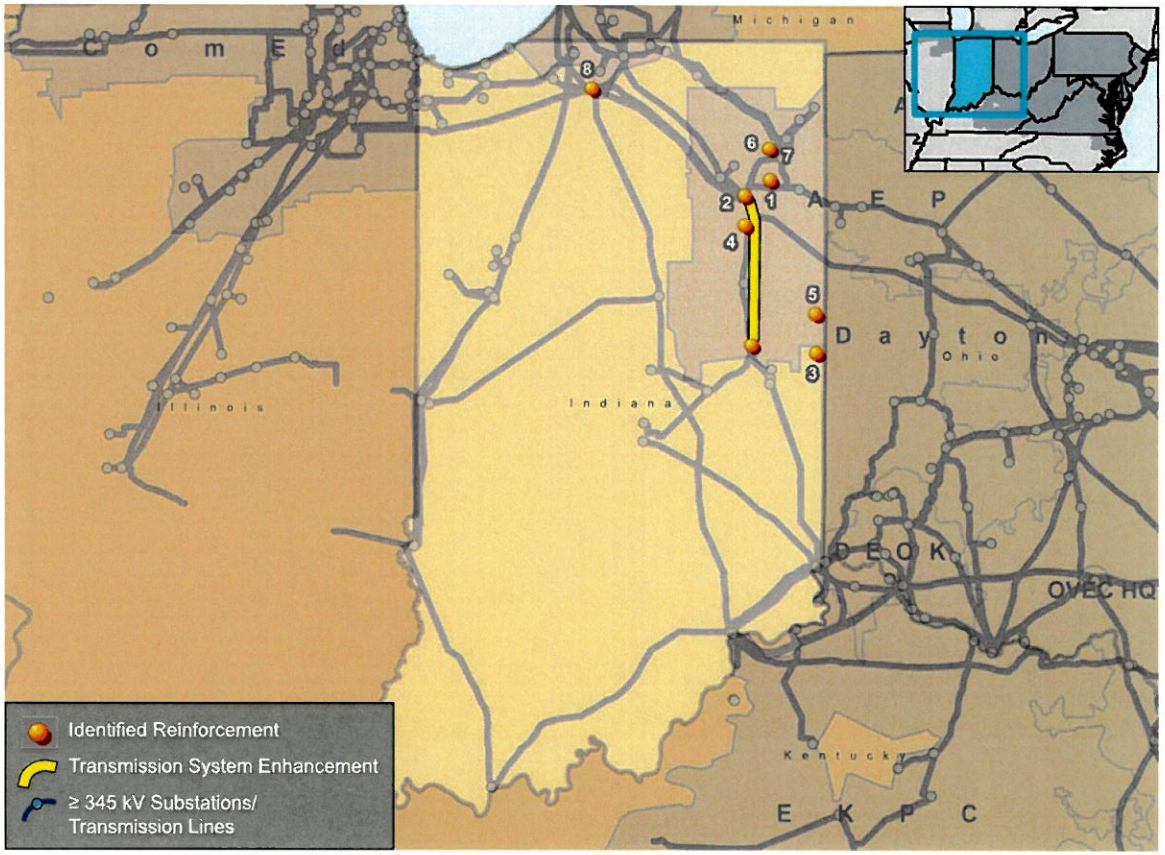

Table 6.16: Indiana Supplemental Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S3144.1	Install a 138 kV/12 kV distribution station named Kekionga on the Mckinley-Ellison Road 138 kV line. Install 138 kV line extension from Mckinley-Ellison 138 kV line with fiber (~0.15 miles from the 138 kV line). Install 138 kV bus with two 138 kV switches and 138 kV MOAB.	11/12/2025	$4.40	AEP	8/18/2023
2	S3148.1	Rebuild the ~51.5-mile line as is using double-circuit 345 kV construction on the Sorenson-Desoto 345 kV. Replace jumpers at Sorenson and Desoto to accommodate the new structure entrances at the stations.	6/10/2027	$202.40		8/8/2023

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Table 6.16: Indiana Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S3302.1	Install a 69 kV 23 MVAR capacitor bank at Price station and a 69 kV circuit breaker.	11/25/2024	$1.50	AEP	2/16/2024
	S3302.2	Install a temporary, mobile 69 kV 14.4 MVAR capacitor bank at Winchester station to mitigate low-voltage violations in the Winchester area. The mobile capacitor bank at Winchester will be removed when project s2273 Randolph upgrades are completed.		$0.02		
	S3302.3	Install a 69/4 kV 12.5 MVA transformer and a 69 kV high-side circuit switcher.		$0.00		
4	S3304.1	Install a three-way phase-over-phase switch on the Sorenson-Van Buren 138 kV circuit. From the new switch, install an ~2.5-mile 138 kV line to the customer delivery point. Low-side metering will be installed in the customer-owned station.	10/1/2026	$9.40	AEP	3/15/2024
5	S3309.1	Construct a new 69/12 kV Mt Zion substation with a three-position 69 kV ring to serve new member load.	9/1/2025	$8.00	WVPA	
	S3309.2	Construct an ~6.5 miles of new 69 kV from Trinity to Mt Zion using 954 ACSS/TW; conductor rating: 196 MVA/212 MVA SN/SE.	6/1/2025	$14.00		
	S3309.3	Construct an ~2.5 miles of 69 kV at Mt Zion-Macedon (AES) from Mt Zion to the IN-OH border where AES will assume ownership and construct the remaining 69 kV to the AES-Marathon substation; conductor rating: 196 MVA/212 MVA SN/SE.	12/31/2026	$5.00	AES Ohio	
	S3309.4	Rebuild 3.2 miles of 69 kV from AEP-Marathon to Trinity with 954ACSS/TW. AEP to build Burr Oak 3 terminal 69 kV ring. This tie will provide improved reliability for WVPA's Trinity and Mt Zion stations as well as to AES-Marathon that is currently served on a long radial. Conductor rating: 196 MVA/212 MVA SN/SE.	12/31/2027	$6.50	AEP	
	S3309.5	Build a new 4-69 kV circuit breaker ring bus to help facilitate a new network connection from AEP to WVPA to AES Ohio. The following cost includes the new station construction, property purchase, metering, remote-end relay upgrades, the Portland-Marathon 69 kV line connection, Marathon-Berne 69 kV line connection and Trinity radial line AEP removal.		$8.70		
6	S3389.1	Install a three-way switch, with SCADA, on Albion-Robison Park 138 kV circuit. From the new switch, install an ~0.01-mile 138 kV line radial to customer station at 138 kV. Low-side metering will be installed in the customer-owned station.	6/19/2025	$3.20		7/19/2024
7	S3390.1	Install a three-way switch, with SCADA, on Albion-Robison Park 138 kV circuit. From the new switch install an ~0.2-mile 138 kV line radial to customer delivery 138 kV. Low-side metering will be installed in the customer-owned station.	3/31/2027	$4.50		
8	S3442.26	Dumont 765 kV: Replace 3000A circuit breaker at Dumont to address a generation deliverability violation on the Dumont-Sorenson 765 kV branch related to the new customer interconnections in the area.	12/1/2026	$4.00		12/5/2023

NOTE:
Wabash Valley Power Alliance (WVPA) is a generation and transmission electric cooperative serving 23 distribution electric cooperatives in Indiana, Illinois and Missouri.

6.3.8 — Merchant Transmission Project Requests

As of Dec. 31, 2024, PJM's queue contained two merchant transmission project requests with a terminal in Indiana as shown in **Map 6.14** and **Table 6.17**.

Read More
Merchant Transmission Projects

Map 6.14: Indiana Merchant Transmission Project Requests (Dec. 31, 2024)

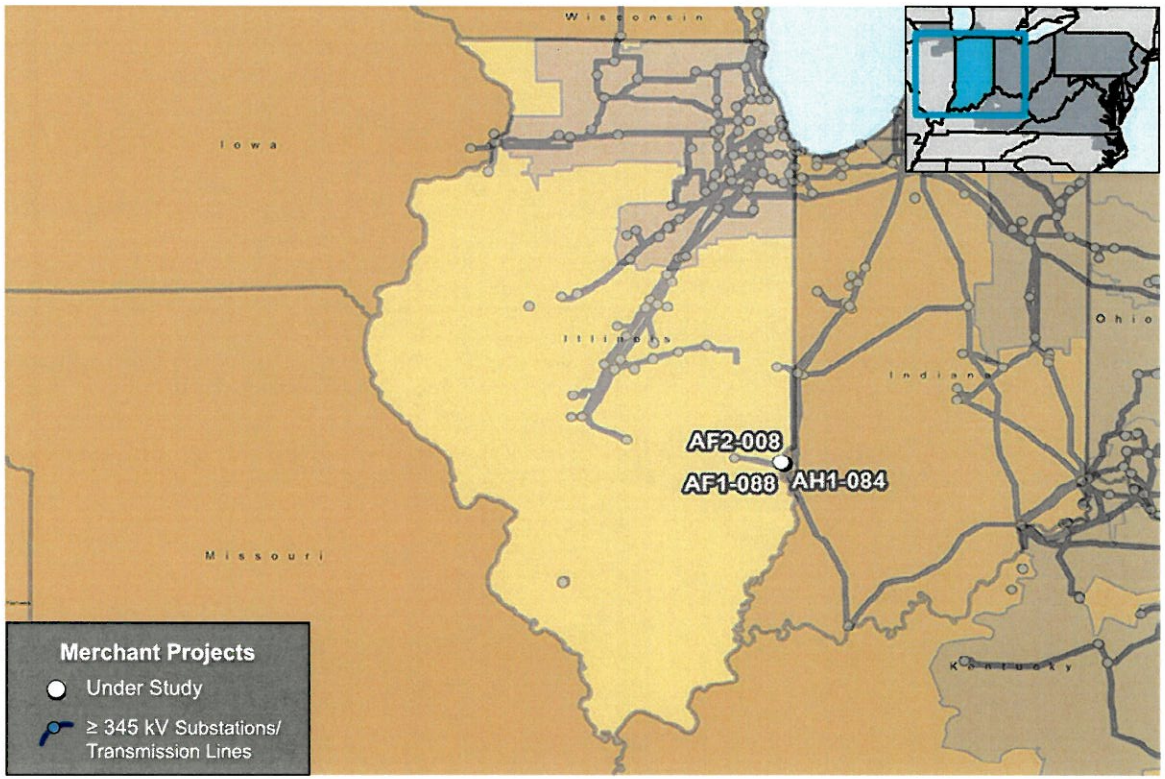

Table 6.17: Indiana Merchant Transmission Project Requests (Dec. 31, 2024)

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					2,000
AH1-084					500

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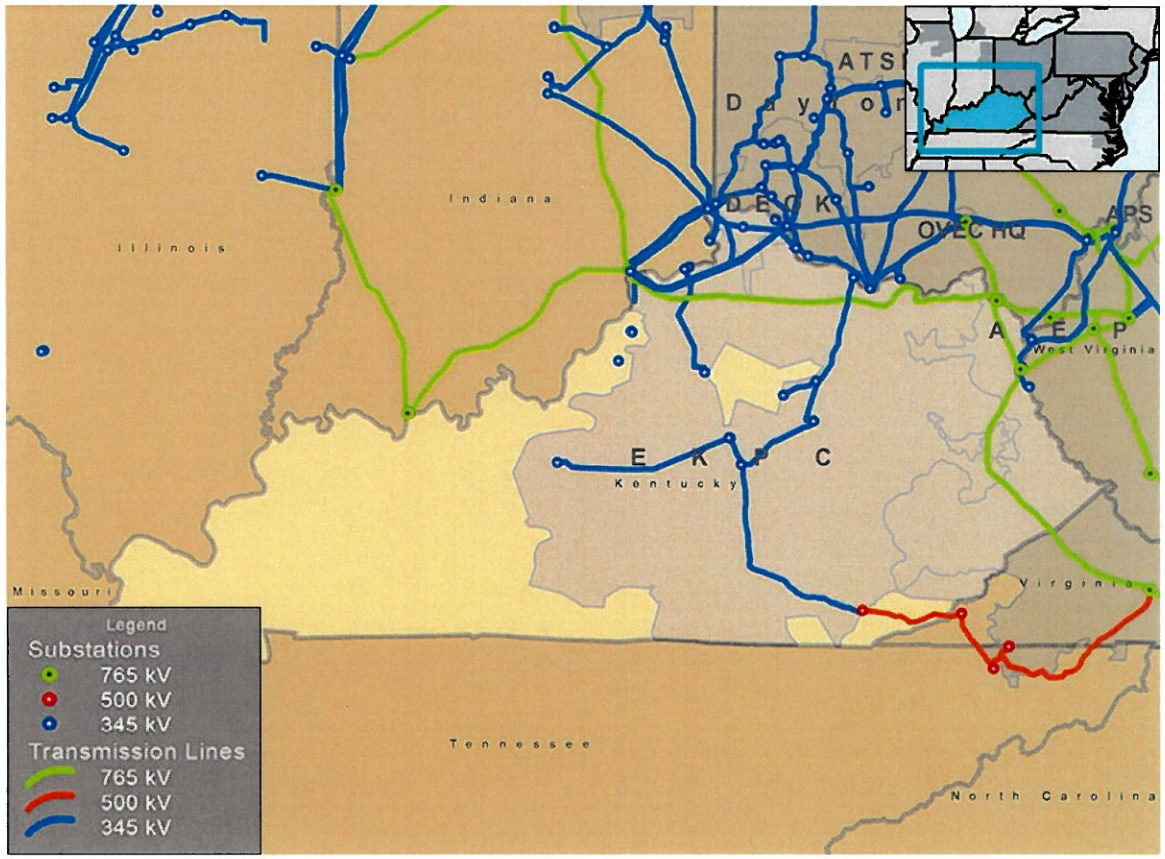
6.4: Kentucky RTEP Summary

6.4.1 — 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 6.15**. 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 the PJM service area.

Map 6.15: PJM Service Area in Kentucky



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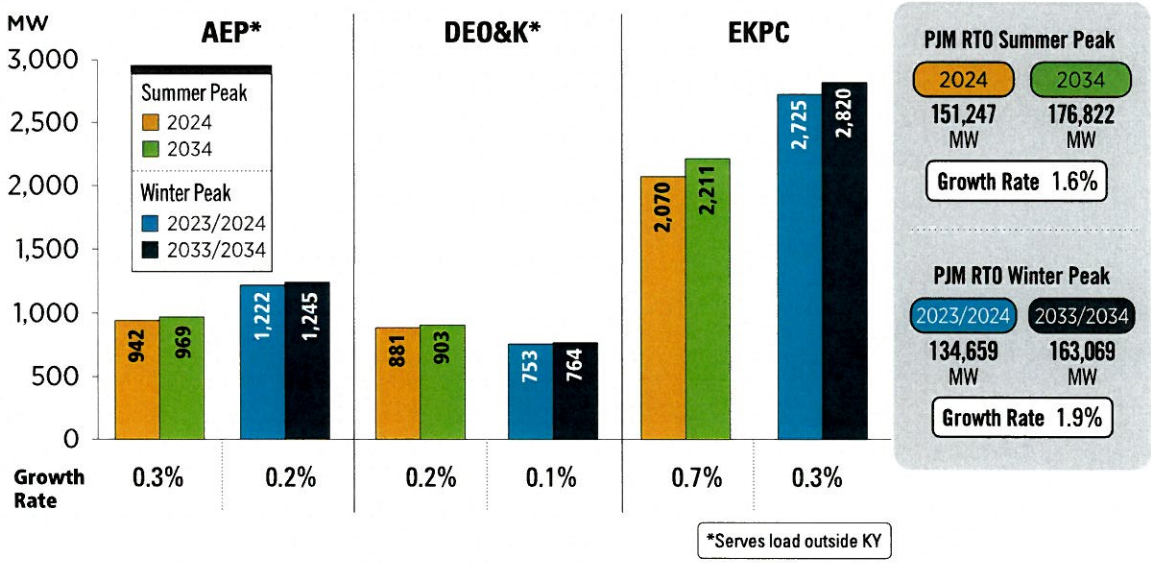
6.4.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.16** summarizes the expected loads within the state of Kentucky and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.16: Kentucky – 2024 Long-Term Load Forecast

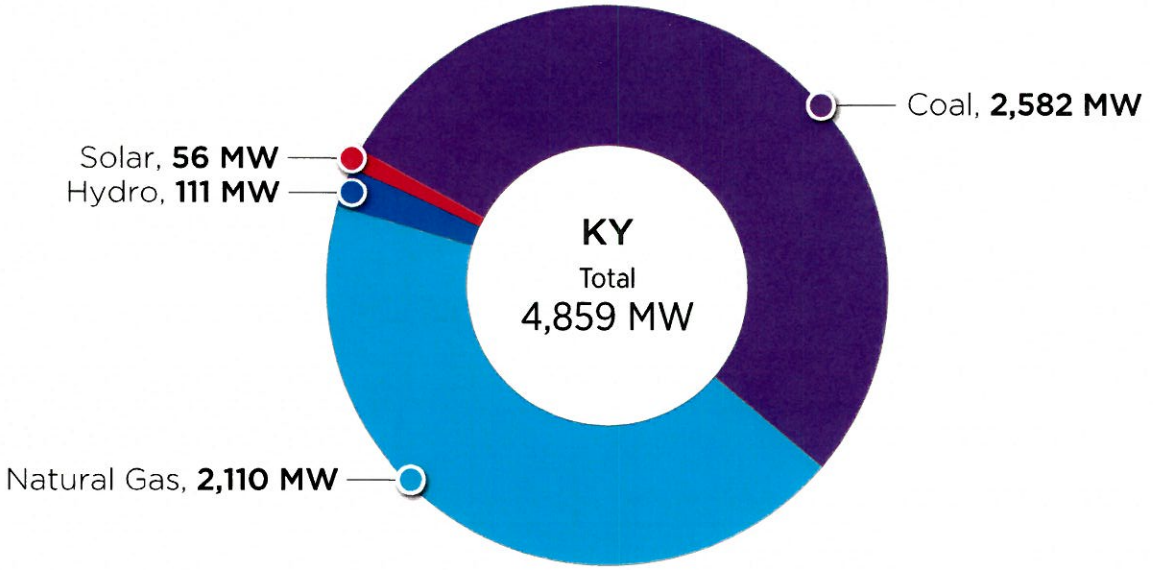


PJM notes that AEP and Duke Energy Ohio and Kentucky serve load other than in Kentucky. The summer and winter peak megawatt values in this figure each reflect an estimated amount of forecasted load to be served by each of those transmission owners solely in Kentucky. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Kentucky over the past five years.

6.4.3 — Existing Generation

Existing generation in Kentucky as of Dec. 31, 2024, is shown by fuel type in **Figure 6.17**.

Figure 6.17: Kentucky – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



Read More
Changing Capacity Mix and Deliverability

6.4.4 — Interconnection Requests

In Kentucky, as of Dec. 31, 2024, 103 projects were actively under study or under construction as shown in the summaries presented in **Table 6.18**, **Table 6.19**, **Figure 6.18**, **Figure 6.19** and **Figure 6.20**.

NOTE:
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 6.18: Kentucky – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	Kentucky Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	954	14.42%	20,162	14.38%
Hydro	0	0.00%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	0	0.00%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	0	0.00%	64	0.05%
Solar	5,274	79.72%	55,040	39.25%
Storage	388	5.86%	39,064	27.86%
Wind	0	0.00%	17,455	12.45%
Grand Total	**6,616**	**100%**	**140,231**	**100%**

Read More
Interconnection Requests

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Table 6.19: Kentucky – Interconnection Requests by Fuel Type (Dec. 31, 2024)

		In Queue				Complete				Grand 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	7	388.0	0	0.0	0	0.0	7	220.2	14	608.2
Renewable	Hybrid	19	954.1	0	0.0	0	0.0	20	1,299.6	39	2,253.7
	Hydro	0	0.0	0	0.0	0	0.0	1	70.0	1	70.0
	Biomass	0	0.0	0	0.0	0	0.0	5	198.5	5	198.5
	Solar	73	5,024.3	4	249.9	3	63.0	66	3,402.1	146	8,739.3
	Wind	0	0.0	0	0.0	0	0.0	2	27.3	2	27.3
	Grand Total	**99**	**6,366.4**	**4**	**249.9**	**9**	**134.0**	**113**	**10,991.4**	**225**	**17,741.8**

Figure 6.18: Kentucky – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

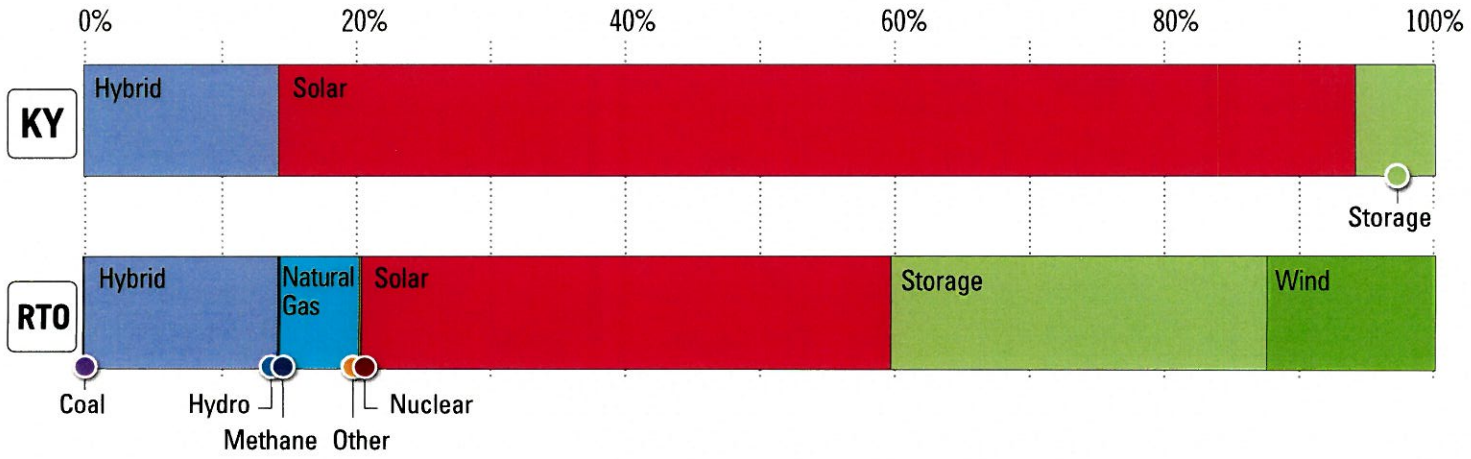

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Figure 6.19: Kentucky Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

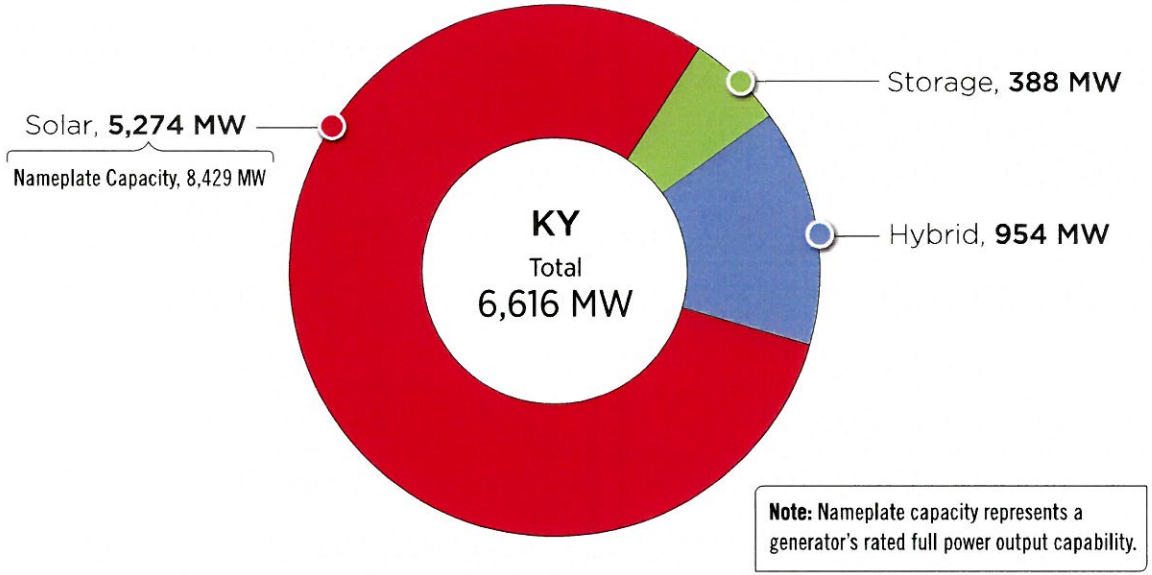
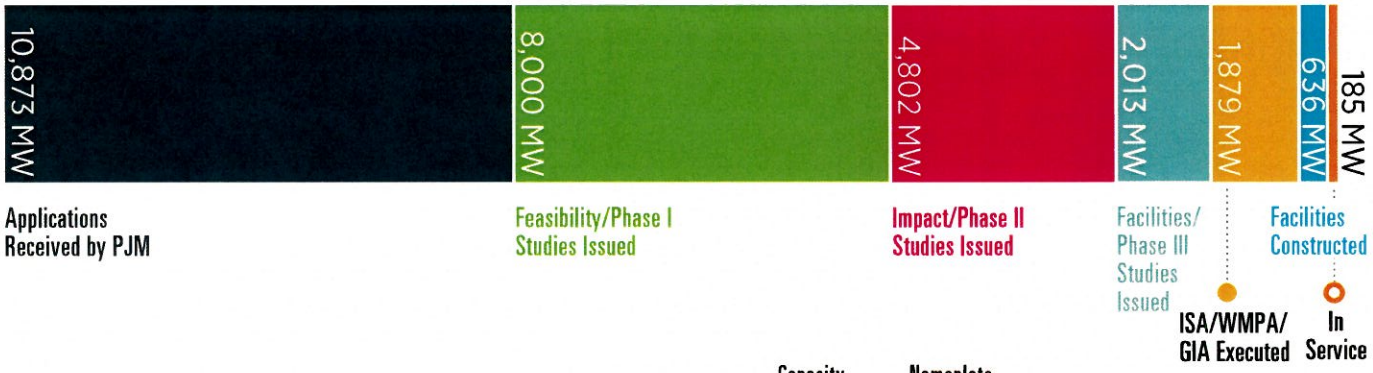


Figure 6.20: Kentucky Progression of Interconnection Requests (Dec. 31, 2024)



Percentage of planned capacity and projects that have reached commercial operation

1.7%	Requested capacity megawatts
3.6%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	3	Interconnection Service Agreements	1,244 MW	1,325 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, 2024.

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6.4.5 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in Kentucky are summarized in **Map 6.16** and **Table 6.20**.

Read More
Baseline Projects

Map 6.16: Kentucky Baseline Projects (Dec. 31, 2024)

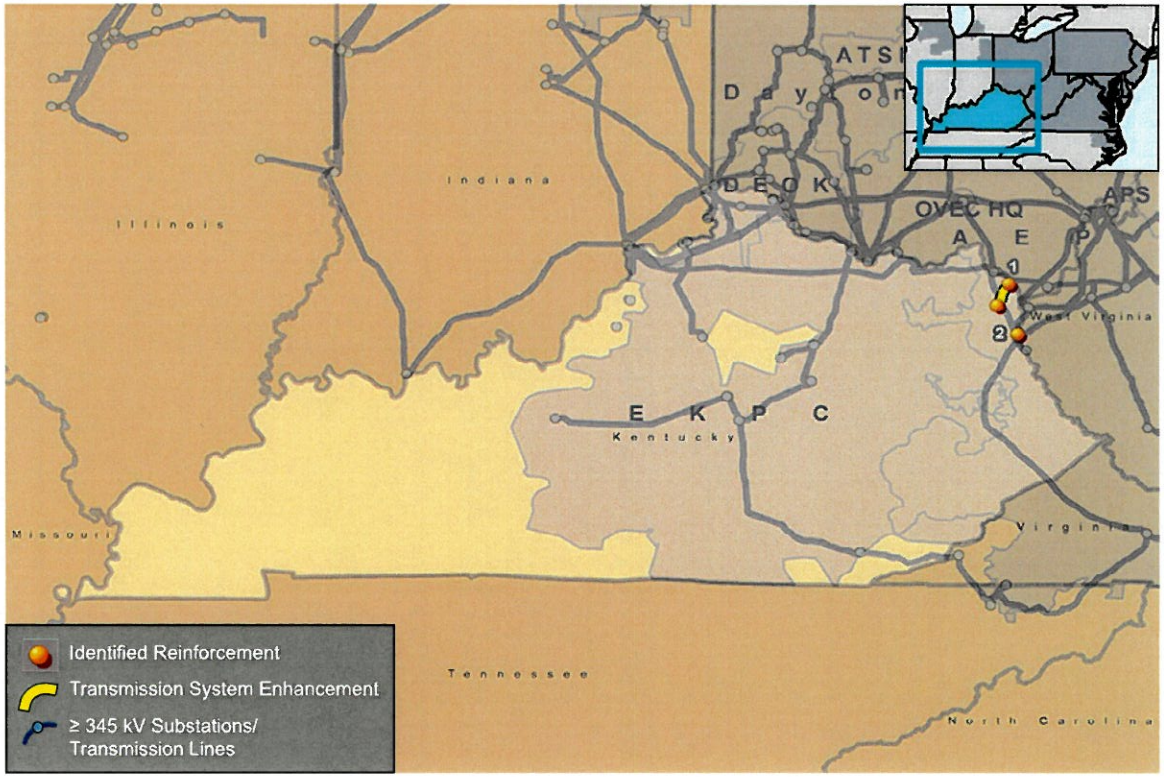

Table 6.20: Kentucky Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3787.1	Install a CCVT on three-phase stand and remove the single-phase existing CCVT on the 69 kV Coalton to Bellefonte line exit. The existing CCVT is mounted to lattice on a single-phase CCVT stand, which will be replaced with the three-phase CCVT stand. The line riser between line disconnect and line takeoff is being replaced. This remote end work changes the MLSE of the line section between Coalton-Princess 69 kV line section.	12/1/2028	$0.00	AEP	11/17/2023
2	B3847.1	Add a 765 kV breaker at Baker station for the reactor on the Broadford 765 kV line.	6/1/2024	$23.36		6/5/2024

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6.4.6 — Network Projects

Network projects in Kentucky for 2024 are summarized in **Map 6.17** and **Table 6.21**.

Read More
Network Projects

Map 6.17: Kentucky Network Projects (Dec. 31, 2024)

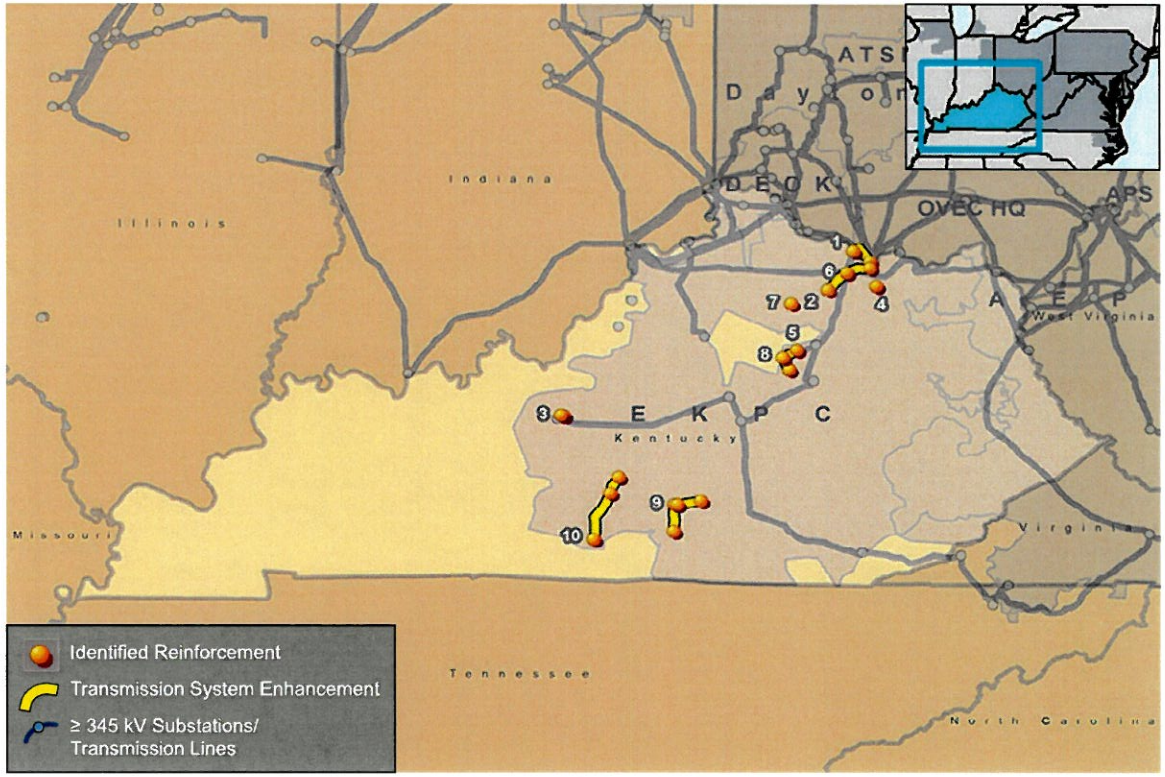

Table 6.21: Kentucky Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5780	Reconductor Stuart-Spurlock 345 kV line with twin bundle 1033 Curlew ACCR conductor.	AE1-144	7/1/2022	$17.00	EKPC	10/8/2024
2	N5858	Increase MOT on Headquarters-Snow Hill 69 kV line.	AD2-048	6/1/2020	$0.25		
	N5859	Increase MOT on Snow Hill-Murphysville 69 kV line.			$1.10		

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Table 6.21: Kentucky Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	N6238	Increase the operating temperature of the 556.5 MCM ACSR/TW conductor from 212 degrees Fahrenheit to 302 degrees Fahrenheit at Central Haridn 69 kV substation.	AF1-050	12/31/2024	$0.04	EKPC	10/8/2024
	N6238.4	Replace the 750 MCM copper jumpers at the Central Hardin 69 kV substation using bundled 500 MCM copper or equivalent.			$0.01		
	N6238.5	Replace the 1200A disconnect switches W124-623 and W124-625 at Central Hardin 69 kV substation and W80-605 at the Kargle tap location.			$0.31		
4	N6461	Perform sag study on AEP's portion of Wildcat-Kenton (Kenton-Emerss) 138 kV circuit; 23.5 miles 477 ACSR 26/7 Hawk conductor.	AE2-038	6/1/2022	$0.09	AEP	
5	N6463.1	Increase MOT of Boone-Longbranch 138 kV line section 954 MCM conductor to 275F (~2.25 miles).	AE2-138		$0.20	EKPC	
6	N6480	Increase the maximum operating temperature of the 266 MCM ACSR conductor in the Murphysville-Plumville 69 kV line section to 266 degrees Fahrenheit (9.9 miles).	AE2-038		$0.65		
7	N6676.1	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 East Harrison 69 kV switching station to accept the IC generator lead line/bus.	AD2-048		$0.73		
	N6676.2	EKPC to construct a new 69 kV switching station (East Harrison switching) to facilitate connection of the Blue Moon Solar generation project (AD2-048).			$2.77		
	N6676.4	EKPC to modify relay settings at Renaker 69 kV substation for existing line to East Harrison 69 kV switching station.			$0.01		
	N6676.5	EKPC to upgrade relays and modify relay settings at headquarters 69 kV substation for existing line to East Harrison 69 kV switching substation.			$0.01		
8	N6954	Install a 138 kV steel isolation switch structure and associated 138 kV isolation switch, conductor from the terminal structure to the point of interconnection, interconnection metering, fiber-optic connection, line differential relay panel, and telecommunications equipment to accept the IC generator lead line at Avon 138 kV substation.	AE2-339	12/1/2022	$0.70		
	N6955	Modify Avon 138 kV substation by installing two circuit breakers, A-frame structure and associated terminal switches, bus conductor, PTs, foundations, breaker relay panel for new bus position; a new steel structure (for repositioned Dale line); transfer existing conductor, OPGW fiber optic, and existing relay panel on Avon-Dale line at Avon substation.			$1.76		
	N8504	Expand existing Avon 138 kV substation.		4/30/2027	$5.01		
9	N8076.1	Install a 69 kV switch structure, associated switch and 69 kV breaker; disconnect switches, interconnect metering, relaying and fiber at new AF1-038 switching station to accept the IC's generator line.	AF1-038	6/6/2019	$1.55		
	N8076.2	AF1-038 69 kV interconnect switching station (North Russell County Switching) – Construct a new 69 kV switching station to connect the Queue #AF1-038 solar generating facility.			$6.11		
	N8076.3	Sewellton Junction-Windsor 69 kV – Construct a new loop-in tap line (~500 ft.) from EKPC's existing Sewellton Junction-Windsor 69 kV line to the new AF1-038 69 kV interconnection switching station.			$0.99		
	N8076.4	Sewellton Junction 69 kV substation – Upgrade relays and modify relay settings.			$0.35		
	N8076.5	Windsor 69 kV substation – Upgrade relays and modify relay settings.			$0.35		
	N8076.6	Install OPGW fiber on the 69 kV line from Sewellton junction to the new North Russell County switching station, an ~1 mile in length.			$0.57		
	N8201	Increase the maximum operating temperature of the 266 MCM ACSR conductor in the 2Webb CR R T line section to 266 degrees Fahrenheit.			$0.14		

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Table 6.21: Kentucky Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
10	N8077.1	New switching station (South Green County switching station) to interconnect customer facility	AF1-050	12/31/2022	$4.10	EKPC	10/8/2024
	N8077.2	Loop in tap line to new AF1-050 switching station from Summer Shade-Green County 161 kV line.			$0.28		
	N8077.3	Replace existing and modify relay settings at Summer Shade 161 kV substation.			$0.01		
	N8077.4	Upgrade relays and modify relay settings at Green County 161 kV substation.			$0.01		
	N8077.5	Install OPGW between Green County-South Green County 161 kV switching stations.			$0.73		

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6.4.7 — Supplemental Projects

Supplemental projects included in the 2024 Local Plan in Kentucky are summarized in **Map 6.18** and **Table 6.22**.

Read More
Supplemental Projects

Map 6.18: Kentucky Supplemental Projects (Dec. 31, 2024)

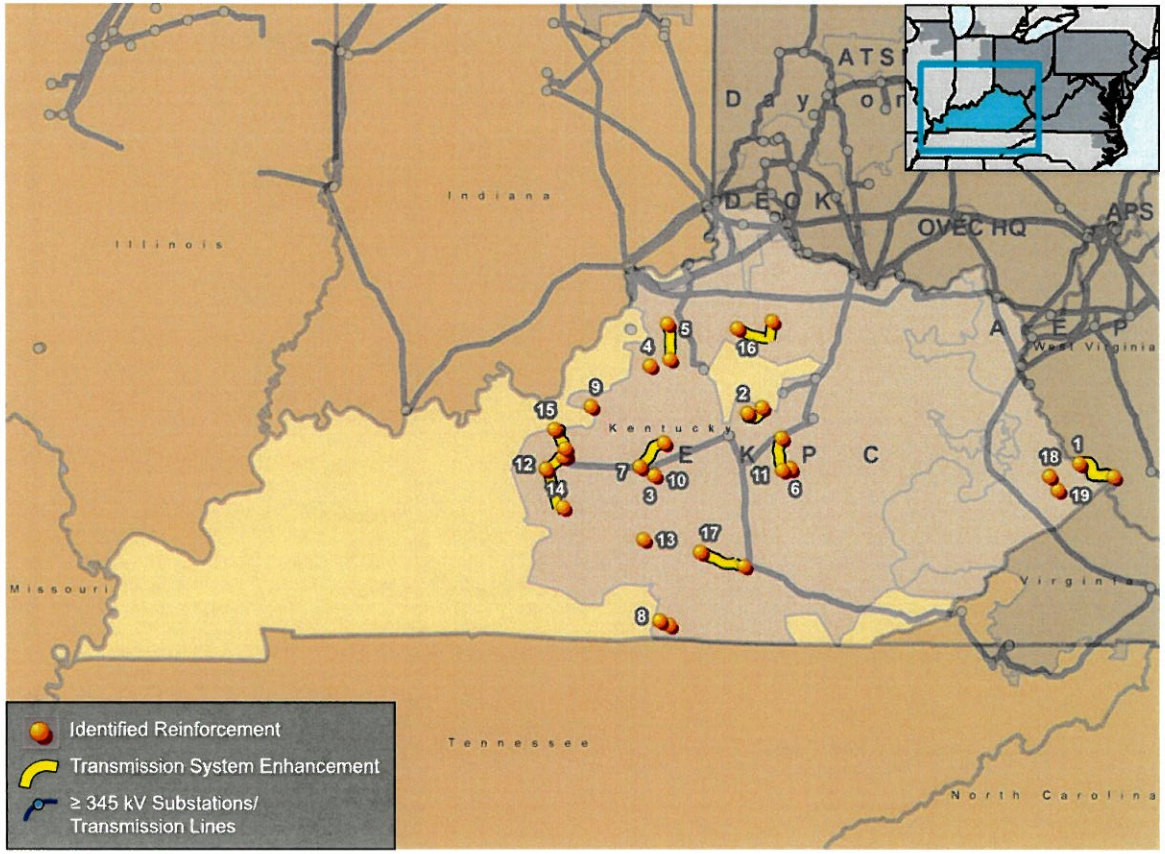

Table 6.22: Kentucky Supplemental Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S3147.18	Remove an ~1.29 miles of Sprigg-Wharncliffe 46 kV line in KY.	6/1/2030	$1.10	AEP	8/18/2023
2	S3164.0	Rebuild the 12-mile Fayette-Baker Lane 69 kV circuit using 556.5 conductor and steel pole construction. Expand the scope of a current project to rebuild the Nicholasville distribution substation to include a new 69 kV double-bay switching station and control building.	12/1/2029	$17.50	EKPC	10/20/2023

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Table 6.22: Kentucky Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S3165.0	Construct a new 161/13.8 kV distribution substation and associated 0.25-mile 161 kV double-circuit tap line. This new delivery point will tap the existing EKPC Marion County-Green County 161 kV transmission circuit an ~2 miles southwest of the Marion County substation.	4/1/2024	$0.01	EKPC	10/20/2023
4	S3166.0	Construct a new 69/26.4 kV, 18/24/30 MVA distribution substation and associated 1.4-mile 69 kV tap line. The tap line will be constructed using 556.5 conductor and steel pole construction. This new station will be served from the EKPC Shelby County substation.	4/1/2026	$0.00		
5	S3167.0	Rebuild the 14.29-mile Clay Village-New Castle 69 kV line using 556.5 conductor and steel pole construction.	6/9/2025	$8.48		
6	S3168.0	Build a new 69/13.2 kV, 12/16/20 MVA distribution substation (Big Hill), and install a 9 MVAR capacitor bank and 8.6-mile 69 kV tap line using 266.8 conductor. Tap point will be 1.2 miles from Three Link toward Sand gap, tapping the Three Link-Sand Gap 69 kV line section.	2/26/2026	$3.10		11/17/2023
7	S3169.0	Rebuild the 14.11-mile North Springfield-Loretto 69 kV line using 556.5 conductor and steel pole construction.	8/1/2025	$10.61		
8	S3170.0	Rebuild the 4.4-mile Snow Tap-North Albany 69 kV line using 556.5 conductor and steel pole construction.	7/1/2026	$4.60		
9	S3171.0	Construct a new West Shepherdsville 69/13.2 kV, 12/16/20 MVA substation with an associated 4-mile 69 kV tap line from the existing Shepherdsville substation tap.	6/1/2025	$0.00		
10	S3172.0	Construct a new Metts Drive 161/25 kV, 12/16/20 MVA distribution substation. New substation will be served by extending the Marion County Industrial Park 161 kV tap line by 0.9 miles. Construct a new 2.28-mile parallel 161 kV line section extending from the existing Marion County Industrial tap point to the South Marion County Industrial distribution substation. Install normally open switch at the existing Marion County Industrial tap point.	6/1/2027	$2.95		
11	S3173.0	Rebuild the 16.3-mile Duncannon Lane tap-West Berea 69 kV line sections using 795 conductor and steel pole construction. Construct a new Madison County 69 kV switching station near the Duncannon Lane tap point. This project will also include a new section of 69 kV double-circuit line between the Crooksville tap point and the Madison County switching station (an ~1.3 miles) to serve Crooksville and Speedwell radially from the new Madison County switching station. Additionally, Duncannon Lane will be served radially from the new switching station.	7/1/2026	$15.50		
12	S3174.0	Rebuild the 16.42-mile Stephensburg-Bonnieville 69 kV line using 556.5 conductor and steel pole construction.	3/1/2027	$12.40		12/15/2023
13	S3175.0	Establish a new free-flowing interconnection with LG&E/KU by constructing a new 10-mile Coburg-Heartland 69 kV line using 556 conductor and steel pole construction. Construct a new LG&E/KU-owned ring bus configuration substation near Campbellsville and a new breaker station at Coburg junction. Additionally, increase the Coburg capacitor bank to 17 MVAR and the Green River Plaza capacitor bank to 27 MVAR.	12/31/2026	$20.10		
14	S3176.0	Rebuild the 11.7-mile Elizabethtown-Central Hardin-Stephensburg 69 kV line sections using existing conductor size and steel pole construction.	8/1/2027	$10.70		
15	S3177.0	Rebuild the 7.45-mile Elizabethtown-Patriot Parkway-Vine Grove 69 kV line sections using existing conductor size and steel pole construction.	12/1/2027	$5.20		
16	S3178.0	Rebuild the 20.79-mile Renaker-Penn 69 kV line sections using 556 conductor and steel pole construction.		$16.40		
17	S3179.0	Rebuild the 18.97-mile Windsor-Somerset 69 kV line sections using existing conductor size and steel pole construction.		$17.00		
18	S3303.1	Install new revenue metering for a 20 MW customer load connection at Gund Metering Point. Install a new 69 kV manual switch on the customer side of the hard tap.	11/15/2024	$1.15	AEP	3/15/2024
19	S3303.2	Motorize the existing switch at Bevins toward Gund at Bevins Metering Point to facilitate the connection of a 7 MW customer load to existing delivery point.		$0.59		

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6.5: Maryland/District of Columbia RTEP Summary

6.5.1 — RTEP Context

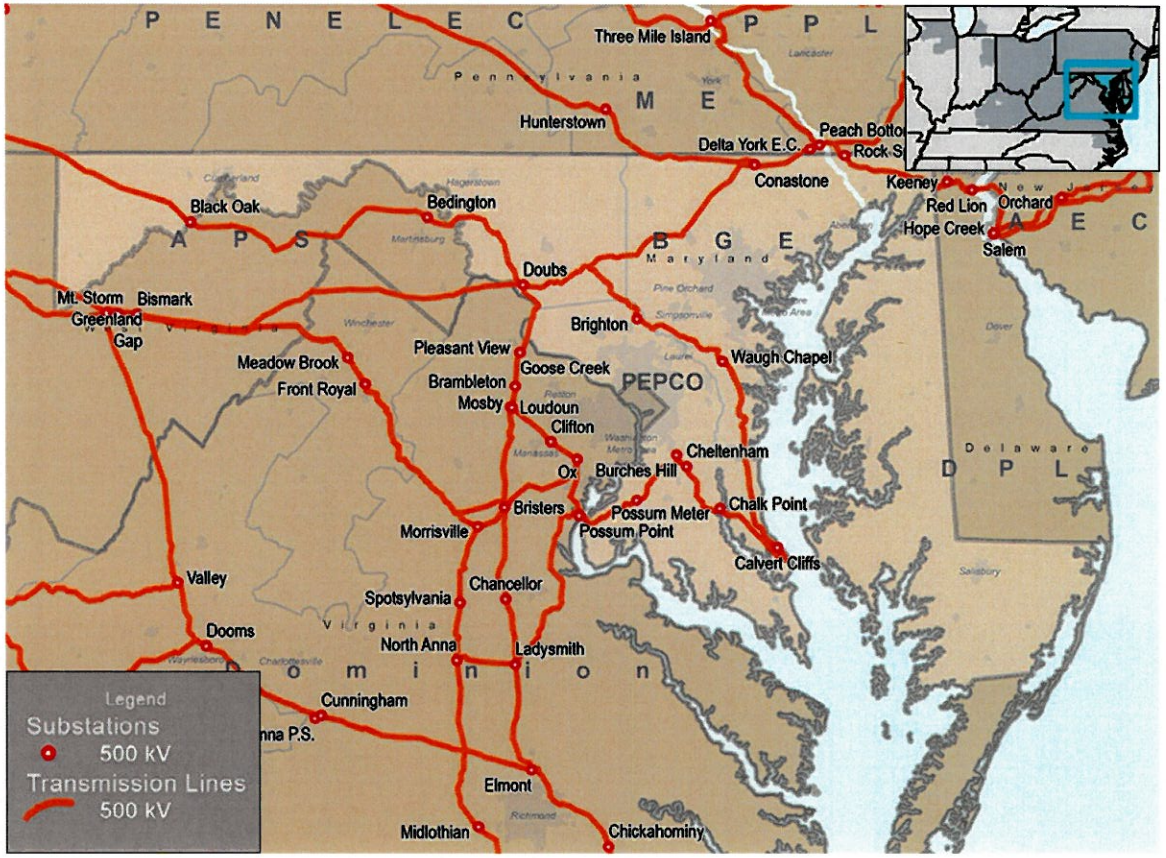
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Maryland and the District of Columbia, including facilities owned and operated by Allegheny Power (AP) [FirstEnergy], Baltimore Gas and Electric (BGE), Delmarva Power (DP&L), Potomac Electric Power Company (PEPCO) and Southern Maryland Electric Cooperative (SMECO) as shown on **Map 6.19**. 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 of the PJM service area.

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 advancing offshore wind to support its clean energy policies and has awarded offshore wind renewable energy credits (ORECs) to projects totaling 2,022.5 MW. In 2023, Maryland enacted the Maryland POWER Act. The POWER Act increased the state's offshore wind target to 8,500 MW by 2031. The POWER Act also directs the Maryland Public Service Commission and Maryland Energy Administration to work with PJM in exploring competitive transmission solutions that support the state's offshore wind facilities.

Map 6.19: PJM Service Area in Maryland/District of Columbia



Maryland is also pursuing decarbonization through additional efforts. In 2022, Maryland enacted the Climate Solutions Now Act, which calls for Maryland to reduce statewide greenhouse gas emissions 60% from 2006 levels by 2031 and reach statewide net-zero emissions by 2045. In 2023, Maryland enacted H.B. 910 that established an energy storage target of 3,000 MW by 2033.

The District of Columbia has a mandatory renewable portfolio standard (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.

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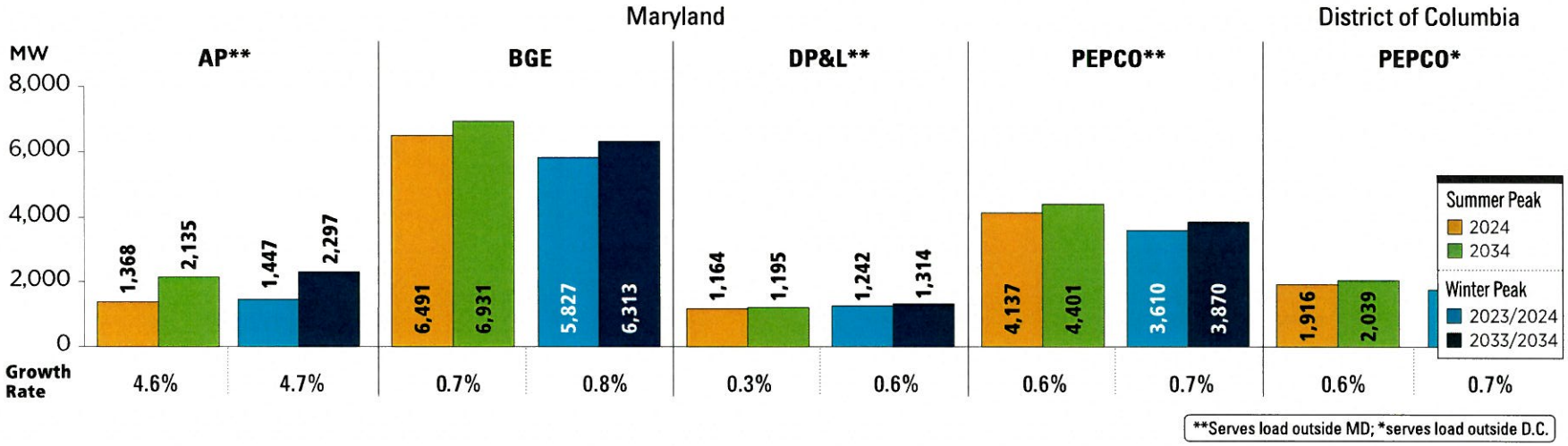
6.5.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.21** summarizes the expected loads within the state of Maryland and the District of Columbia, and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.21: Maryland/District of Columbia – 2024 Long-Term Load Forecast



PJM RTO Summer Peak		PJM RTO Winter Peak	
2024	2034	2023/2024	2033/2034
151,247 MW	176,822 MW	134,659 MW	163,069 MW
Growth Rate 1.6%		Growth Rate 1.9%	

PJM notes that Allegheny Power (FirstEnergy), Delmarva Power and Pepco serve load other than in Maryland, and Pepco serves load other than in the District of Columbia. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by each of those transmission owners solely in Maryland, as well as for Pepco solely in the District of Columbia. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Maryland the District of Columbia over the past five years.

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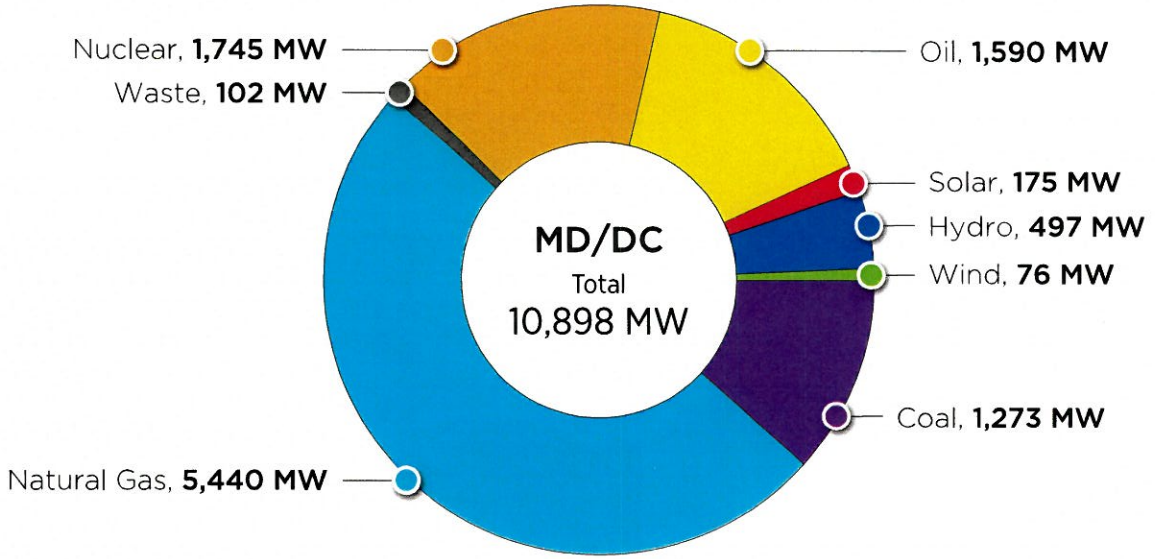
6.5.3 — Existing Generation

Existing generation in Maryland and the District of Columbia as of Dec. 31, 2024, is shown by fuel type in **Figure 6.22**.

Figure 6.22: Maryland/District of Columbia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



Read More
Changing Capacity Mix and Deliverability

6.5.4 — Interconnection Requests

In Maryland and the District of Columbia, as of Dec. 31, 2024, 86 projects were actively under study or under construction as shown in the summaries presented in **Table 6.23**, **Table 6.24**, **Figure 6.23**, **Figure 6.24** and **Figure 6.25**.

NOTE:
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 6.23: Maryland/District of Columbia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	Maryland/District of Columbia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	1,031	17.76%	20,162	14.38%
Hydro	15	0.26%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	45	0.78%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	0	0.00%	64	0.05%
Solar	1,263	21.78%	55,040	39.25%
Storage	3,388	58.40%	39,064	27.86%
Wind	60	1.03%	17,455	12.45%
Grand Total	5,801	100%	140,231	100%

Read More
Interconnection Requests

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Table 6.24: Maryland/District of Columbia – Interconnection Requests by Fuel Type (Dec. 31, 2024)

		In Queue				Complete				Grand 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
	Natural Gas	1	45.0	0	0.0	36	3,834.2	72	33,060.4	109	36,939.6
	Oil	0	0.0	0	0.0	1	0.0	4	20.0	5	20.0
	Diesel	0	0.0	0	0.0	1	0.0	1	5.0	2	5.0
	Nuclear	0	0.0	0	0.0	4	37.4	4	4,955.0	8	4,992.4
	Other	0	0.0	0	0.0	0	0.0	1	132.0	1	132.0
	Storage	21	3,387.5	1	0.3	2	0.7	52	1,261.4	76	4,649.9
Renewable	Hybrid	8	1,028.9	1	1.6	0	0.0	9	332.7	18	1,363.2
	Hydro	1	15.0	0	0.0	3	60.0	4	88.4	8	163.4
	Biomass	0	0.0	0	0.0	0	0.0	12	227.6	12	227.6
	Methane	0	0.0	0	0.0	5	14.5	5	8.0	10	22.5
	Solar	43	1,023.1	7	240.2	28	147.0	224	1,967.0	302	3,377.3
	Wind	3	59.7	0	0.0	6	43.2	10	265.6	19	368.5
	Grand Total	**77**	**5,559.1**	**9**	**242.1**	**87**	**4,147.0**	**398**	**42,323.1**	**571**	**52,271.4**

Figure 6.23: Maryland/District of Columbia – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

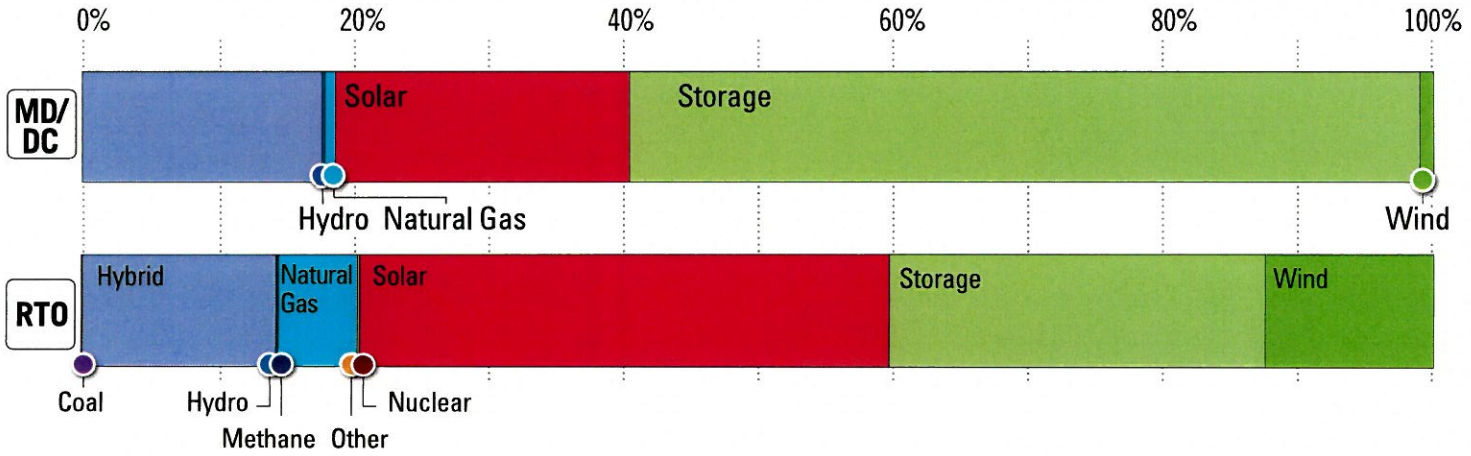

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Figure 6.24: Maryland/District of Columbia Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

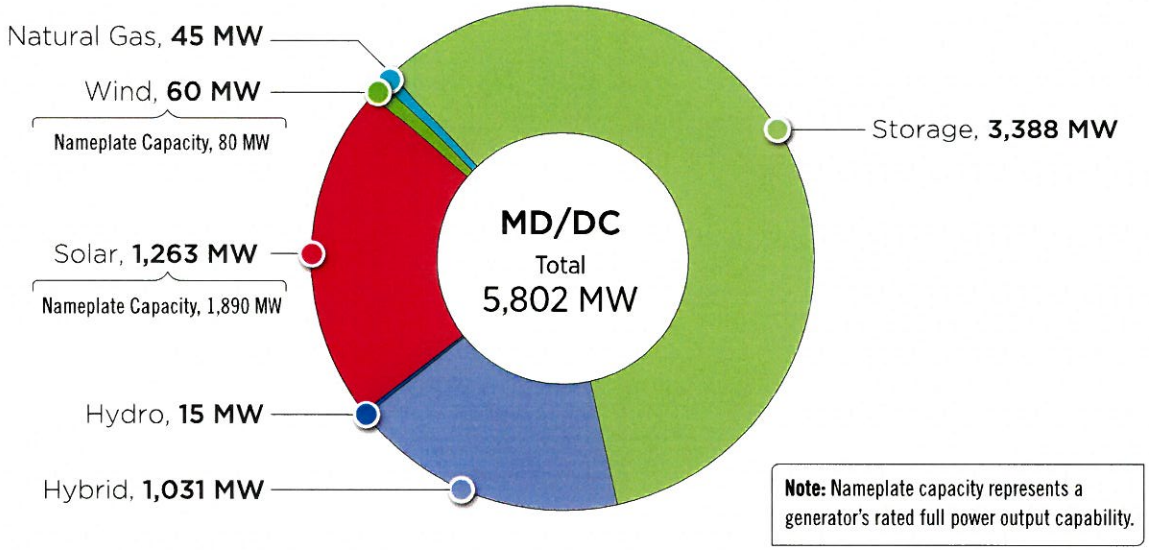
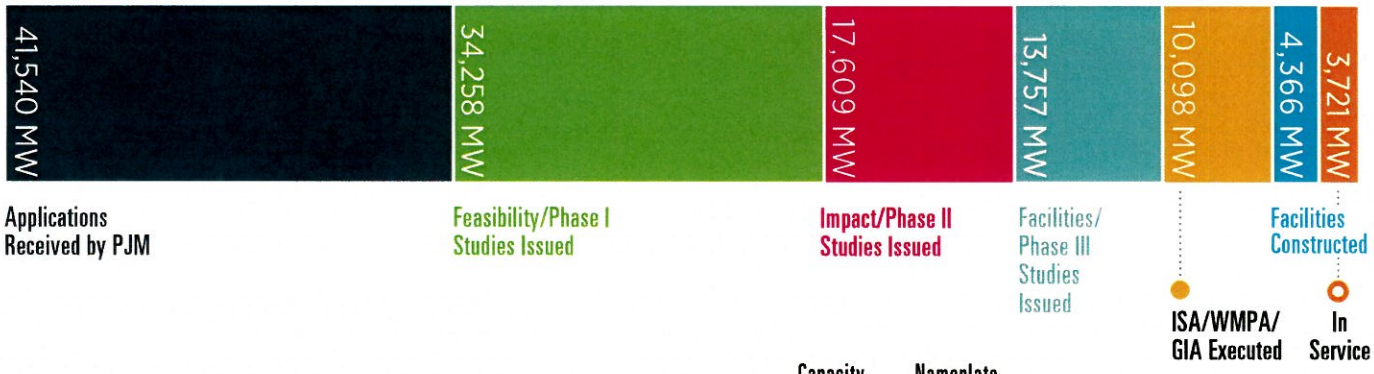


Figure 6.25: Maryland/District of Columbia Progression of Interconnection Requests (Dec. 31, 2024)



Percentage of planned capacity and projects that have reached commercial operation

9.0%	Requested capacity megawatts
14.5%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	30	Interconnection Service Agreements	5,692 MW	6,196 MW
	58	Wholesale Market Participation Agreements	166 MW	309 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, 2024.

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6.5.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Maryland between Jan. 1, 2024, and Dec. 31, 2024, are summarized in **Map 6.20** and **Table 6.25**.

Read More
Baseline Projects

Map 6.20: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2024)

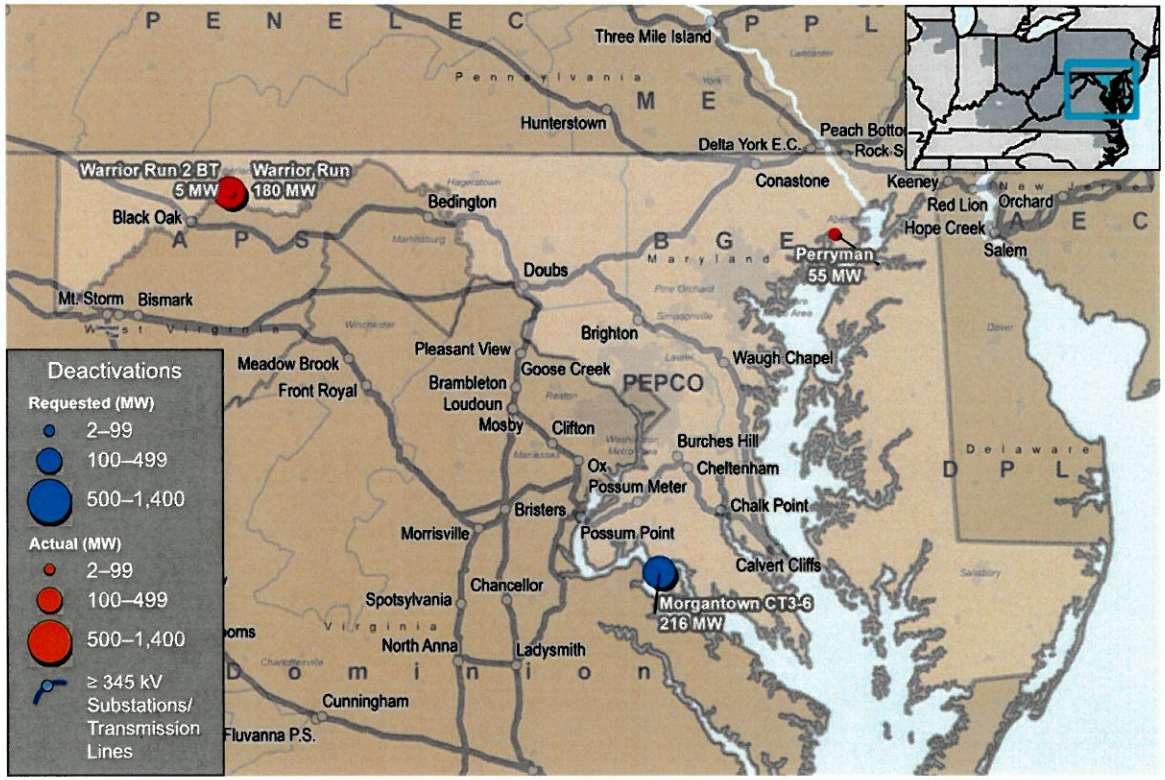

Table 6.25: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2024)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Warrior Run 2 BT	AP	Battery	5/31/2024	10/1/2024	22	5
Morgantown CT 6	PEPCO	Oil	12/22/2023	6/1/2024	50	54
Morgantown CT 5						
Warrior Gen1	AP	Coal	9/29/2023		21	180
Perryman 6	BGE	Natural Gas	7/22/2024	5/31/2025	9	54.9
Morgantown CT 4	PEPCO	Oil		6/1/2026	51	54
Morgantown CT 3						

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6.5.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in Maryland and the District of Columbia are summarized in **Map 6.21** and **Table 6.26**.

Read More
Baseline Projects

Map 6.21: Maryland/District of Columbia Baseline Projects (Dec. 31, 2024)

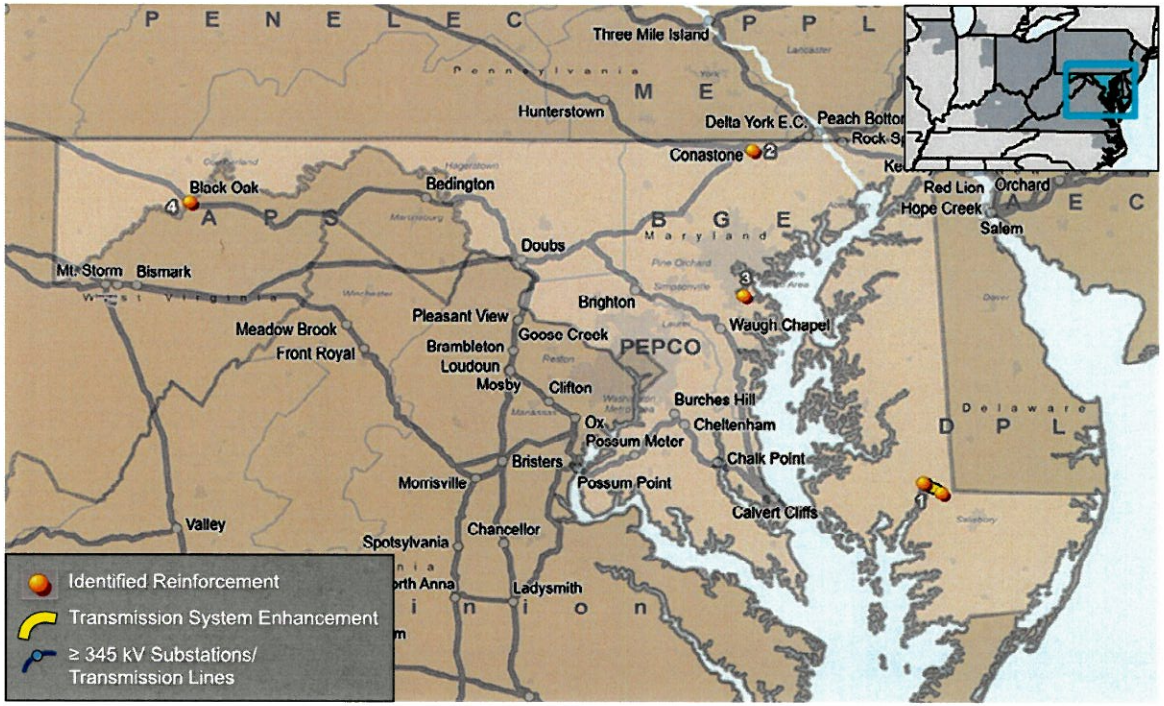

Table 6.26: Maryland/District of Columbia Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3846.1	Rebuild 6.25 miles of 69 kV circuit 6708 (Vienna-Mardela) with new single-pole steel structures and with 954.0 45/7 "Rail" conductor. This new rebuild will be from the dead-end structure on the east side of the Nanticoke River to the Mardela tap.	6/1/2028	$18.63	DP&L	11/16/2023
	B3846.2	Upgrade disconnect switch at Vienna to increase ratings of existing Vienna-Mardela transmission facility.		$1.00		
	B3846.3	Upgrade three disconnect switches at Mardela to increase ratings of existing Vienna-Mardela transmission facility.		$1.75		
2	B3857.1	Replace Conastone 230 kV breaker No. 5.	6/1/2029	$1.92	BGE	11/6/2024
3	B3906.1	Construct new Marley Neck 115 kV substation. Marley Neck 115 kV portion will accommodate 10 breaker-and-a-half bays, with only six bays planned for initial service while accommodating four future bays. Two standard 230/115 kV transformers will be connected between the 230 and 115 kV equipment with appropriate isolation methods.		$107.62		12/3/2024
4	B4000.11	Expand Black Oak substation to accommodate the connection of the 502 Jct-Woodside 500 kV line and loop the 502 Jct-Woodside 500 kV line into the Black Oak substation by constructing ~0.85 miles of new 500 kV line into and out of Black Oak 500 kV substation.		$19.23	AP	1/7/2025

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6.5.7 — Network Projects

Network projects in Maryland and the District of Columbia for 2024 are summarized in **Map 6.22** and **Table 6.27**.

Read More
Network Projects

Map 6.22: Maryland/District of Columbia Network Projects (Dec. 31, 2024)

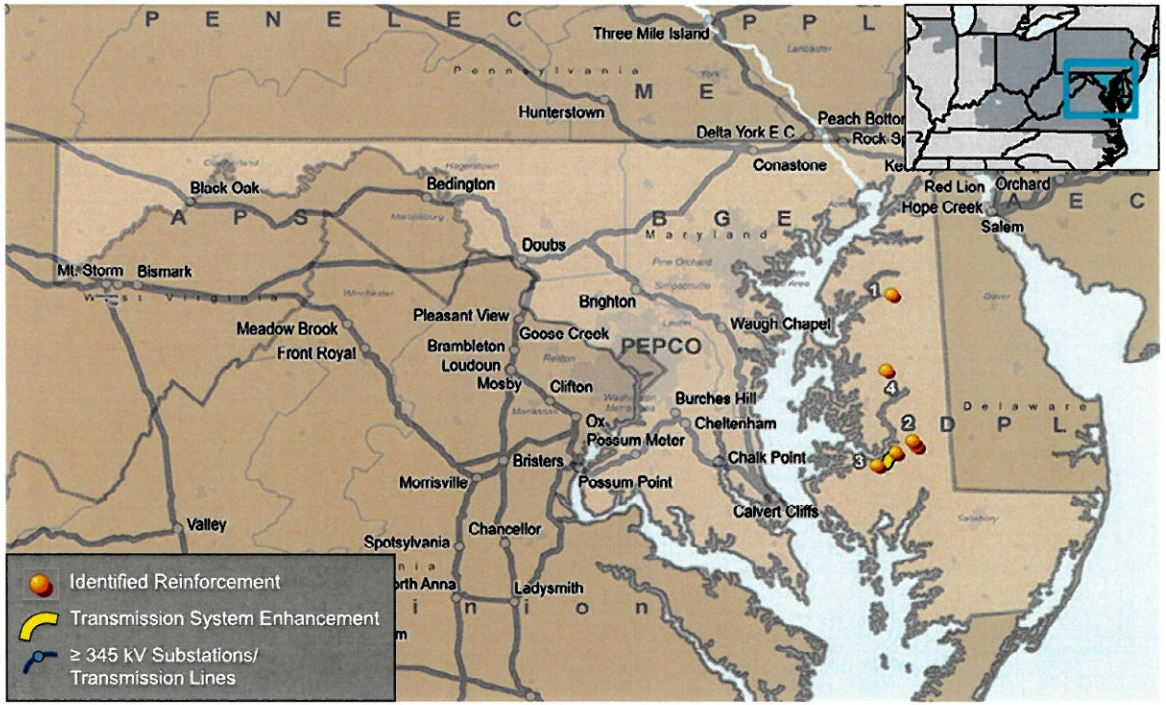

Table 6.27: Maryland/District of Columbia Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5119	Build a new 138 kV substation with a three-position ring bus (with provisions to add a fourth position for PJM Queue Project AB2-032) off of the right-of-way for circuit 13723 in Queen Anne's County, Maryland. Two of the positions on the ring bus will be transmission line terminals for the tie in of circuit 13723 to the substation. The third position will be a terminal configured for the interconnection of a generator.	AB1-141	11/1/2017	$7.60	DP&L	10/8/2024
2	N5788	Substation reinforcements at Preston substation and at Todd 69 kV substations. The estimate to perform this work is $67,000 and will take an ~one year to complete. The new emergency rating would be 173 MVA.	AE1-087	12/14/2018	$0.10		
3	N8042.1	Convert the East New Market 69 kV substation from a four-position line bus to a six-position ring bus.	AC1-190	7/15/2026	$11.34		1/9/2024
	N8042.2	Modify lines 6715 and 6719 to align with their new takeoff positions at East New Market 69 kV substation.			$1.26		
4	N8051	Cut and loop in 13712 transmission line to the AE2-093, 138 kV three-position ring bus substation, occupying two of those positions.	AE2-093	12/31/2025	$6.22		

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6.5.8 — Supplemental Projects

Supplemental projects included in the 2024 Local Plan in Maryland and the District of Columbia are summarized in **Map 6.23** and **Table 6.28**.

Read More
Supplemental Projects

Map 6.23: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2024)

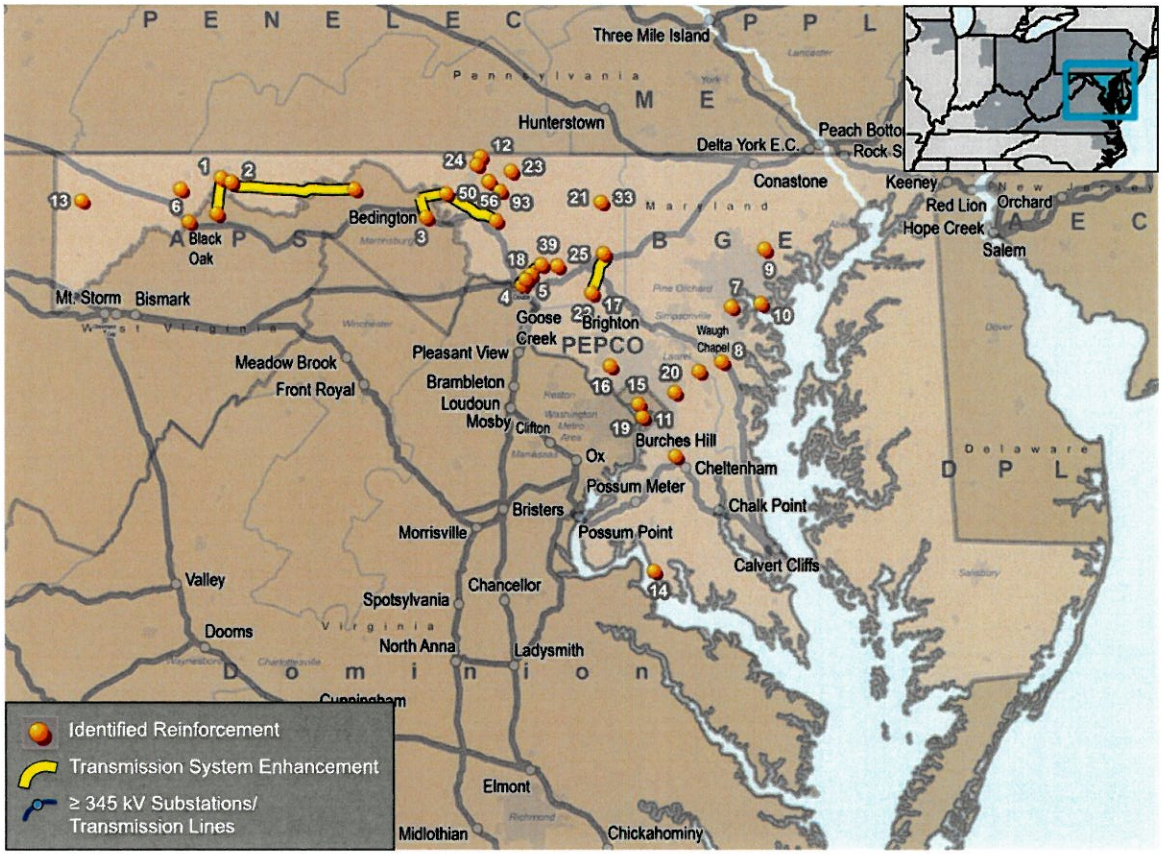

Table 6.28: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S3116.1	Replace conductor and disconnect switches on Short Gap 138 kV line terminal at Cumberland substation.	4/11/2025	$0.40	AP	11/17/2023
2	S3128.1	Install three-way 138 kV transmission line tap using three 2000A SCADA switches. Construct 0.1 miles of 556 ACSR 26/7 from tap location to new substation.	6/1/2025	$1.80		7/21/2023
3	S3131.1	Replace 1200A manual disconnect switches with two 2000A motor-operated disconnect switches on the Boonsboro 138 kV line exit at Marlowe substation; limiting substation conductor. Replace 1200A manual disconnect switches with two 2000A motor-operated disconnect switches on the Bedington BMA 138 kV line exit; limiting substation conductor.	10/27/2023	$0.30		8/18/2023

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Table 6.28: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	S3150.1	230 kV transmission substation (Quantum 400). Expand Quantum 400 station to a nine-breaker, breaker-and-a-half substation. Loop the Doubs-Sage No. 206 230 kV line in and out of the new substation. Modify line relay settings at Doubs and Sage substations.	12/31/2027	$14.60	AP	2/6/2024
	S3150.2	Build a six-breaker, two-bay (expandable to four bays) breaker-and-a-half substation (Quantum 400). Loop the Doubs-Lime Kiln No. 231 230 kV line in and out of the new substation. Modify line relay settings at Doubs and Lime Kiln substations. Provide two feeds to the customer facility.	10/31/2025	$20.80		
5	S3152.1	Proposed Solution 1 of 3: Expand the existing three-breaker ring bus into a six-breaker, breaker-and-a-half substation by installing three new 230 kV circuit breakers. Install two 230-34.5 kV transformers. Construct two 34.5 kV buses on the low side of transformers. 230 kV transmission substation expansion.	3/6/2026	$1.50		
	S3152.2	Proposed Solution 2 of 3: Expand the six-breaker, breaker-and-a-half substation to 15 breakers by adding nine 230 kV circuit breakers. Terminate the Doubs-Eastalco 206 230 kV line into the Sage substation. Loop in the Doubs-Lime Kiln 207 230 kV line into the Sage substation.	12/31/2027	$25.00		
6	S3153.1	230 kV transmission substation – Build a new 11-breaker (future 15), breaker-and-a-half 230 kV substation. Cut and loop the Doubs-Lime Kiln 230 kV No. 231 and No. 207 230 kV lines in and out of the new substation. Modify relay settings in Doubs and Lime Kiln substations. Provide three 230 kV feeds to customer facility.	12/31/2025	$28.70		9/5/2023
7	S3223.1	Replace Pumphrey circuit breaker B4.	4/5/2024	$0.94	BGE	11/16/2023
	S3224.1	Replace Pumphrey circuit breaker B5.	5/10/2024	$0.94		
	S3225.1	Replace Pumphrey circuit breaker B6.	6/13/2024	$0.70		
	S3226.1	Replace Pumphrey circuit breaker B7.	11/28/2024	$0.70		
	S3227.1	Replace Pumphrey circuit breaker B9.	10/18/2024	$0.70		
8	S3228.1	Replace Waugh Chapel circuit breaker B6.	10/17/2024	$0.70		
	S3229.1	Replace Waugh Chapel circuit breaker B9.	6/6/2024	$0.70		
9	S3230.1	Replace Windy Edge circuit breaker B19.	11/4/2024	$0.70		
	S3231.1	Replace Windy Edge circuit breaker B20.	10/10/2024	$0.70		
10	S3279.1	Rebuild Riverside 115 kV station as 12-position GIS breaker-and-a-half substation on existing BGE-owned property. Install 115 kV, 4000A 63 kA interrupting current equipment. Install relay and control panels. Reterminate existing transmission lines and transformer connections into new GIS equipment.	12/31/2028	$84.30		2/15/2024
11	S3312.1	Replace the existing 138 kV oil circuit breakers 13B & 14B at Buzzard Point. Total estimated cost: $300,000. Existing rating: 2000A 40 kA. Proposed rating: 3000A 63kA.	12/31/2024	$0.30	PEPCO	4/18/2024
12	S3529.1	The breakers are in deteriorating condition, have a lack of replacement parts and have elevated maintenance cost. Replace the existing 230 kV oil circuit breakers 1A.	12/31/2028	$0.81		12/5/2023
	S3530.1	The breakers are in deteriorating condition, have a lack of replacement parts and have elevated maintenance cost. Replace the existing 23 kV oil circuit breakers 2A.		$0.81		
	S3531.1	The breakers are in deteriorating condition, have a lack of replacement parts and have elevated maintenance cost. Replace the existing 230 kV oil circuit breakers 3A.		$0.81		
13	S3532.1	Replace the existing 230 kV oil circuit breakers 3A at Burches Hill.		$0.81		
	S3533.1	Replace the existing 230 kV oil circuit breakers 3B at Burches Hill.		$0.81		

Table 6.28: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
14	S3534.1	Replace the existing 230 kV oil circuit breakers 6B at Morgantown.	12/31/2028	$0.81	PEPCO	12/5/2023
	S3535.1	Replace the existing 230 kV oil circuit breakers 6C at Morgantown.		$0.81		
15	S3536.1	Replace the existing 138 kV O street circuit breaker 1B.		$0.68		12/13/2023
	S3537.1	Replace the existing 138 kV O street circuit breaker 3B.		$0.68		
	S3538.1	Replace the existing 138 kV O street circuit breaker 4B.		$0.68		
16	S3539.1	Replace the existing 138 kV oil circuit breaker 8BT at Bells Mill.		$0.68		
17	S3091.1	Replace circuit switcher and limiting substation conductor at Damascus. Replace wave trap, disconnect switches and limiting substation conductor at Mount Airy.	12/22/2023	$2.20	AP	9/5/2023
18	S3093.1	Replace 230/138 kV No. 5 transformer at Doubs with a 225 MVA unit. Upgrade transformer relaying.	11/8/2024	$5.43		10/31/2023
19	S3203.1	Replace the existing 138 kV oil circuit breaker 7TS at Buzzard Point.	12/1/2025	$0.68	PEPCO	10/19/2023
20	S3208.1	Replace the existing 115 kV oil circuit breaker 2A at Lanham.	10/23/2025	$0.68		11/16/2023
	S3209.1	Replace the existing 115 kV oil circuit breaker 3A at Lanham.		$0.68		
21	S3190.1	Replace 200 MVA 230/138 kV transformer No. 4 with a new 224 MVA 230/138 kV transformer. Replace limiting transformer conductor and relaying.	12/31/2026	$4.13	AP	1/9/2024
22	S3451.1	At Damascus substation: Replace circuit breakers, disconnect switches, line trap, substation conductor and relaying. At Montgomery substation: Replace disconnect switches, line trap, substation conductor and relaying.	11/10/2028	$2.80		4/2/2024
23	S3488.1	At East Hagerstown, replace circuit breaker, line trap, disconnect switches, substation conductor and relaying. At Ringgold, replace circuit breaker, line trap, disconnect switches, substation conductor and relaying.	12/1/2028	$5.00		6/14/2024
24	S3490.1	At Paramount, replace circuit breaker, disconnect switches, line trap and relaying. At Reid, replace substation conductor and relaying.	10/31/2026	$4.00		
25	S3526.1	At Monocacy, replace circuit breaker, disconnect switches, substation conductor and relaying. At Doubs, replace relaying.	4/6/2029	$4.00		7/9/2024

6.6: Southwestern Michigan RTEP Summary

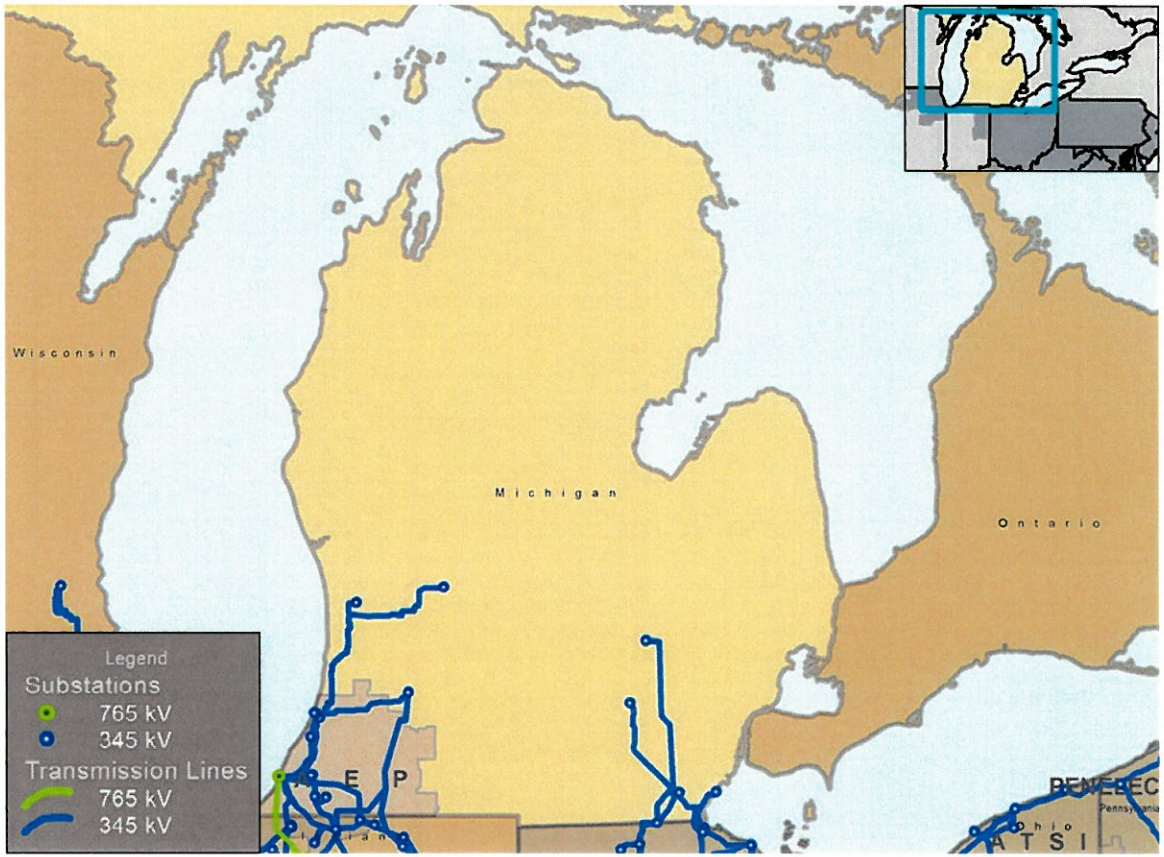
6.6.1 — RTEP Context

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 6.24**. 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 the PJM service area.

Renewable Portfolio Standards

Michigan has a mandatory renewable portfolio standard (RPS) target of 15% annually until 2029, 50% from 2030 through 2034, and the target increases to 60% for 2035 and each year thereafter. This new RPS target was established in 2023 when Michigan enacted S.B. 271. Through S.B. 271, Michigan also established a clean energy standard for its regulated utilities. The clean energy targets are 80% from 2035 through 2039 and a 100% target beginning in 2040. The legislation also set an energy storage target of 2,500 MW by 2029.

Map 6.24: PJM Service Area in Southwestern Michigan



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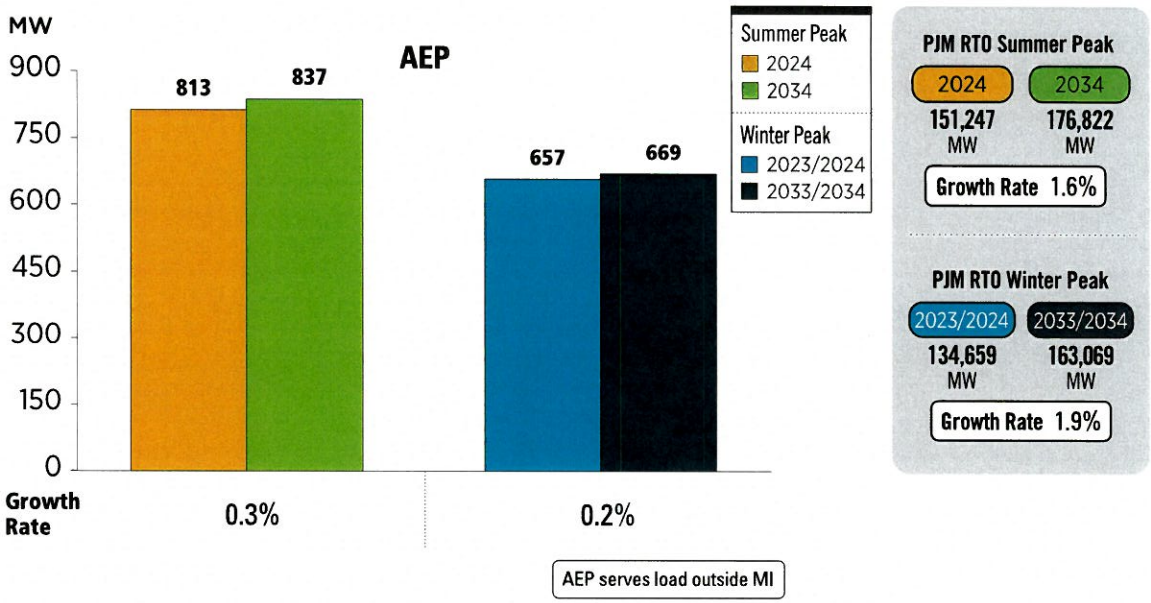
6.6.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.26** summarizes the expected loads within southwestern Michigan and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.26: Southwestern Michigan – 2024 Long-Term Load Forecast



PJM notes that AEP serves load other than in Michigan. The summer and winter peak megawatt values in this table each reflect the estimated amount of forecasted load to be served by AEP solely in Michigan. Estimated amounts were calculated based on the average share of AEP's real-time summer and winter peak load located in Michigan over the past five years.

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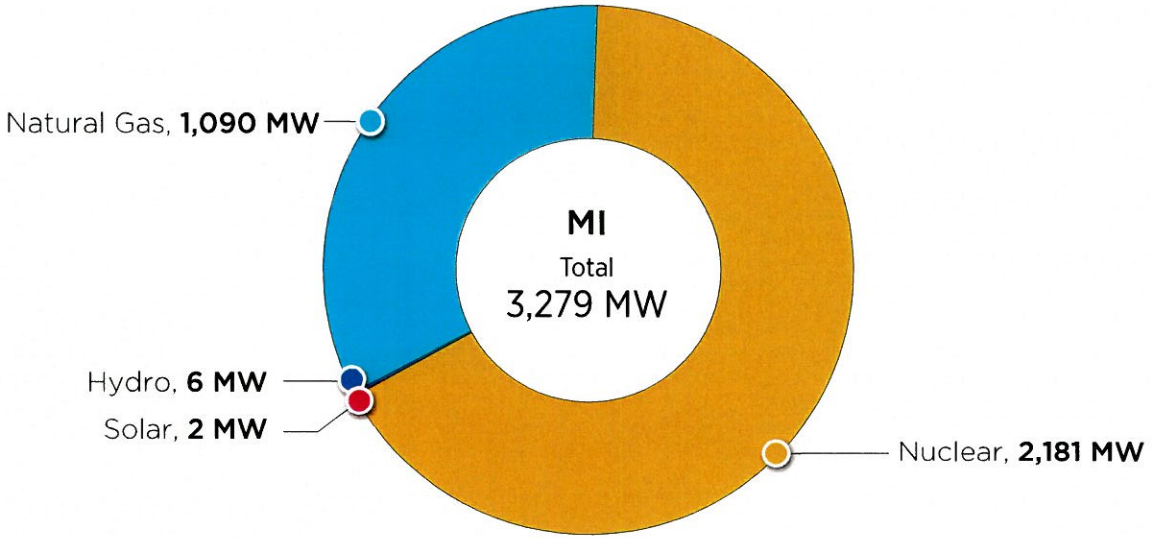
6.6.3 — Existing Generation

Existing generation in southwestern Michigan as of Dec. 31, 2024, is shown by fuel type in **Figure 6.27**.

Read More
Changing Capacity Mix and Deliverability

Figure 6.27: Southwestern Michigan – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



6.6.4 — Interconnection Requests

In southwestern Michigan, as of Dec. 31, 2024, 25 projects were actively under study or under construction as shown in the summaries presented in **Table 6.29**, **Table 6.30**, **Figure 6.28**, **Figure 6.29** and **Figure 6.30**.

NOTE:
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.

Read More
Interconnection Requests

Table 6.29: Southwestern Michigan – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	Michigan Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	728	44.09%	20,162	14.38%
Hydro	0	0.00%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	0	0.00%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	0	0.00%	64	0.05%
Solar	691	41.89%	55,040	39.25%
Storage	231	14.02%	39,064	27.86%
Wind	0	0.00%	17,455	12.45%
Grand Total	**1,650**	**100%**	**140,231**	**100%**

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Table 6.30: Southwestern Michigan – Interconnection Requests by Fuel Type (Dec. 31, 2024)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-renewable	Natural Gas	0	0.0	0	0.0	4	2,140.0	2	1,265.0	6	3,405.0
	Nuclear	0	0.0	0	0.0	3	205.0	0	0.0	3	205.0
	Storage	4	231.3	0	0.0	0	0.0	1	75.0	5	306.3
Renewable	Hybrid	6	727.7	0	0.0	0	0.0	2	112.0	8	839.7
	Methane	0	0.0	0	0.0	3	10.4		0.0	3	10.4
	Solar	15	691.4	0	0.0	1	2.3	6	335.8	22	1,029.5
	Wind	0	0.0	0	0.0	0	0.0	1	26.0	1	26.0
	Grand Total	**25**	**1,650.4**	**0**	**0.0**	**11**	**2,357.7**	**12**	**1,813.8**	**48**	**5,821.9**

Figure 6.28: Southwestern Michigan – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

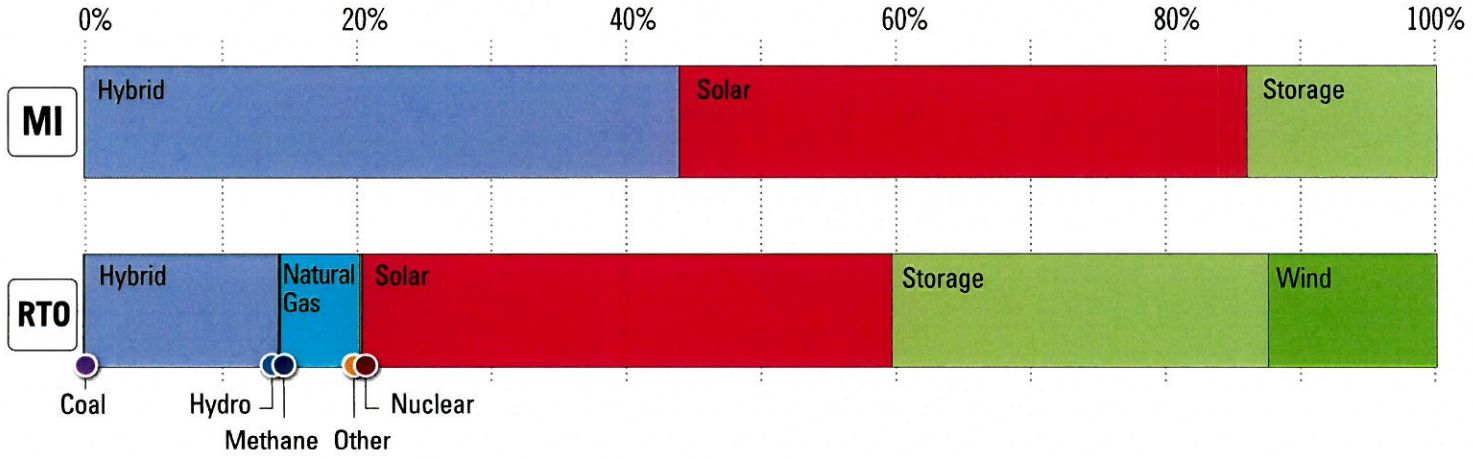

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Figure 6.29: Southwestern Michigan Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

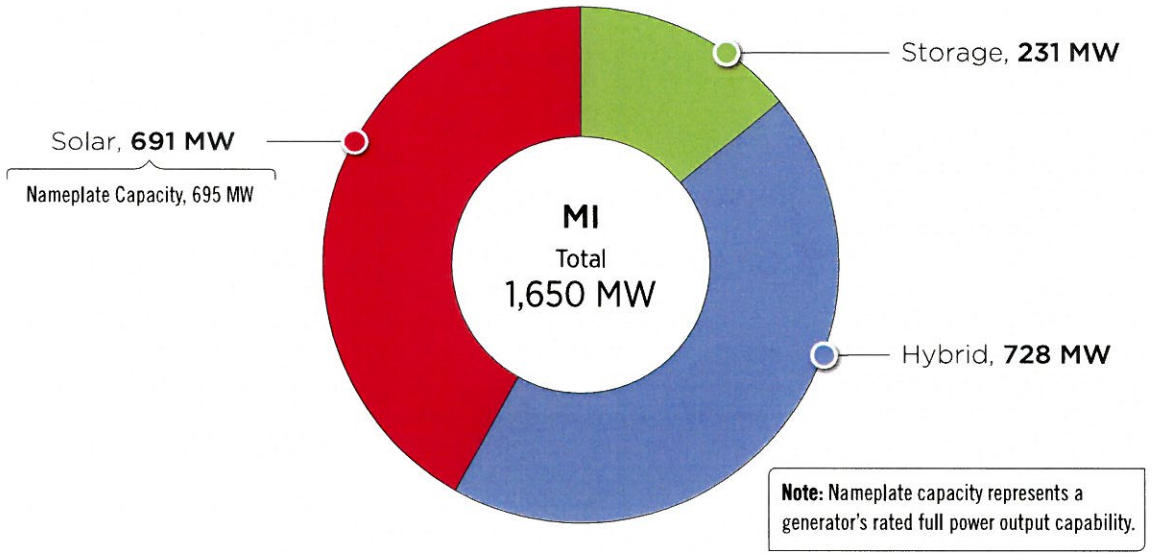

Figure 6.30: Southwestern Michigan Progression of Interconnection Requests (Dec. 31, 2024)

Percentage of planned capacity and projects that have reached commercial operation

54%	Requested capacity megawatts
31.6%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	1	Interconnection Service Agreements	145 MW	285 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, 2024.

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6.6.5 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in southwestern Michigan are summarized in **Map 6.25** and **Table 6.31**.

Read More
Baseline Projects

Map 6.25: Southwestern Michigan Baseline Projects (Dec. 31, 2024)

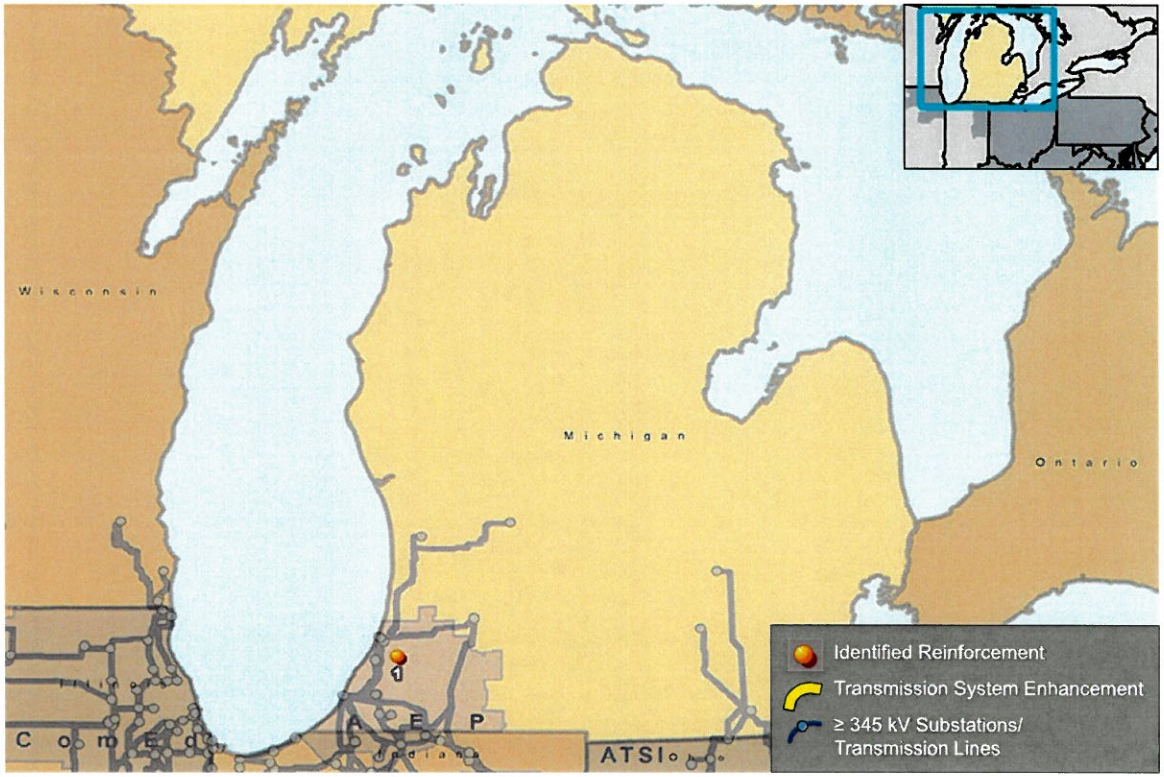

Table 6.31: Southwestern Michigan Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3872.1	Adjust the tertiary tap on the Hartford 138/69/34.5 kV transformer 1 and on Hartford 138/69/12 kV transformer 4 to eliminate the high voltage issues and avoid circulating current.	4/15/2029	$0.10	AEP	11/15/2024

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6.6.6 — Network Projects

Network projects in southwestern Michigan for 2024 are summarized in **Map 6.26** and **Table 6.32**.

Read More
Network Projects

Map 6.26: Southwestern Michigan Network Projects (Dec. 31, 2024)

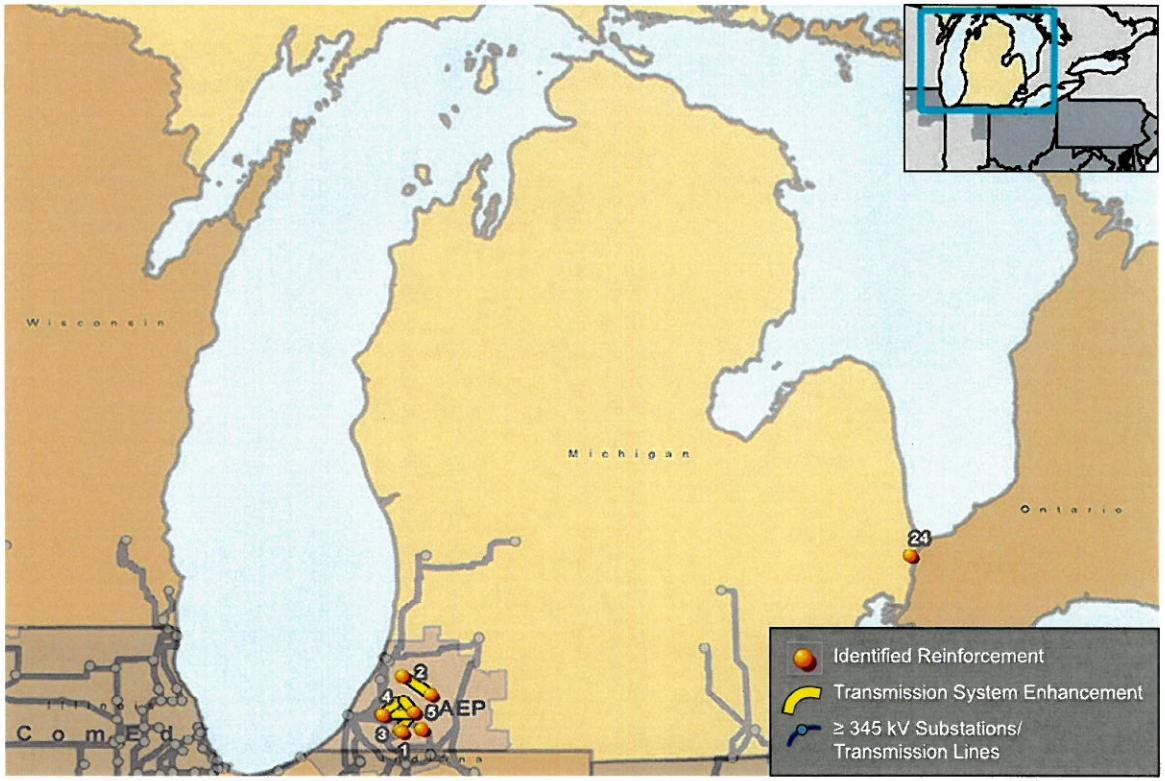

Table 6.32: Southwestern Michigan Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N8071.1	Construct a new 69 kV ring bus station, initially populated with three circuit breakers, expandable to four breakers.	AF2-083	10/21/2022	$2.09	AEP	10/8/2024
	N8071.2	Installation of two new steel, 85' single circuit, single-pole dead-end structures on concrete piers with anchor bolt cages and two spans of ACSR 1033.5 (Curlew) transmission line conductor with 7#8 Alumoweld shield wire.			$0.34		
	N8071.3	Install two new fiber-optic cable paths.			$0.05		
	N8071.4	Replace all 447 all aluminum conductors and replace the bus differential panel.			$0.04		
	N8071.5	Rebuild 0.6 miles of the Pokagon-Colby 69 kV circuit.			$0.87		

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Table 6.32: Southwestern Michigan Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	N8090.1	Install one new 138 kV circuit breaker, one new box bay, one new line connection. Update remote end protective relay settings at the Valley 138 kV station.	AD2-020	12/1/2022	$0.91	AEP	1/9/2024
	N8090.2	Install six structures, seven spans of conductor in the existing Hartford-Valley 138 kV right-of-way.			$1.11		
	N8090.3	Expand the Valley 138 kV station yard, fence and control house.			$0.47		
3	N8169.1	Construct Millikan 138 kV station, associated line protection and control equipment, line risers, switches, jumpers and SCADA at the Millikan 138 kV station.	AE1-170	12/31/2022	$6.49		
	N8169.2	Install two structures, two spans of conductor. Connect Millikan 138 kV station to existing transmission circuit. Update remote end protective relay settings.			$0.76		
	N8169.3	Install two fiber-optic paths to facilitate relaying between Millikan, Kenzie Creek and Colby tap 138 kV stations.			$0.20		
4	N8598.0	Removal of equipment at Pokagon-Colby 69 kV circuit.	AF2-083	12/31/2027	$0.37		10/8/2024

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6.6.7 — Supplemental Projects

Supplemental projects included in the 2024 Local Plan in southwestern Michigan are summarized in **Map 6.27** and **Table 6.33**.

Read More
Supplemental Projects

Map 6.27: Southwestern Michigan Supplemental Projects (Dec. 31, 2024)

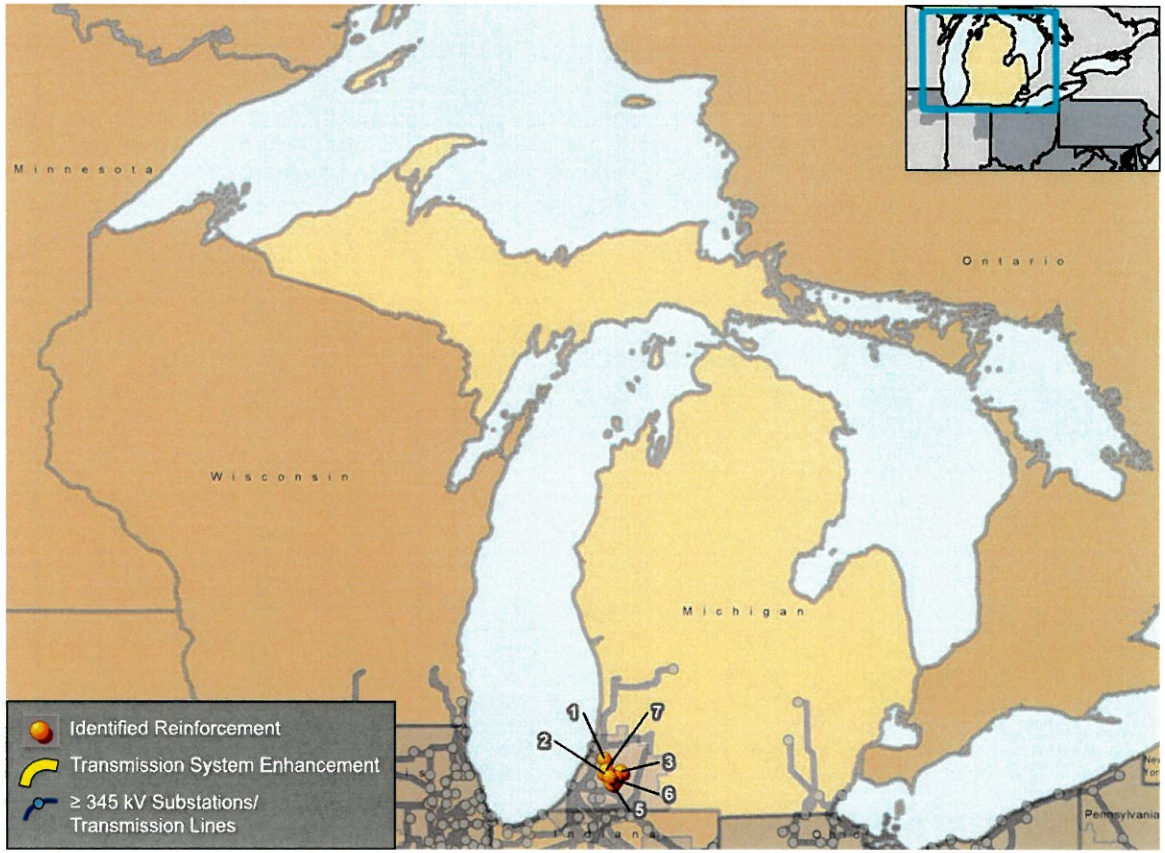

Table 6.33: Southwestern Michigan Supplemental Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S3136.1	Hartford Station: Install a 69 kV breaker and remove the 34.5 kV equipment. Station service will be relocated closer to the transformer.	7/27/2027	$0.59	AEP	11/17/2023
2	S3136.2	Sister Lakes: Replace both transformers with 9.375 MVA 69/12 kV units and install a high-side switcher on transformer 1.		$0.00		
3	S3136.3	Dewey Lake Street: Install a new 7.5 MVA 69/34.5 kV transformer with low-side breaker and high-side fuse. This will be located close to Gearcon switch.		$1.72		

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Table 6.33: Southwestern Michigan Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	S3136.4	Valley: Install a 69/34.5 kV 12.5 MVA transformer and retermniate the Rothadew line to the 69 kV bus.	7/27/2027	$3.63	AEP	11/17/2023
5	S3136.5	Colby: Move the Rothadew line to the 69 kV bus.		$0.11		
6	S3136.6	Twin Lakes Sw.: Replace switch.		$0.83		
7	S3136.7	Keelette, Sister Lakes, Gearcon Sw., Rothadew: Energize to 69 kV.		$1.01		

6.7: New Jersey RTEP Summary

6.7.1 — RTEP Context

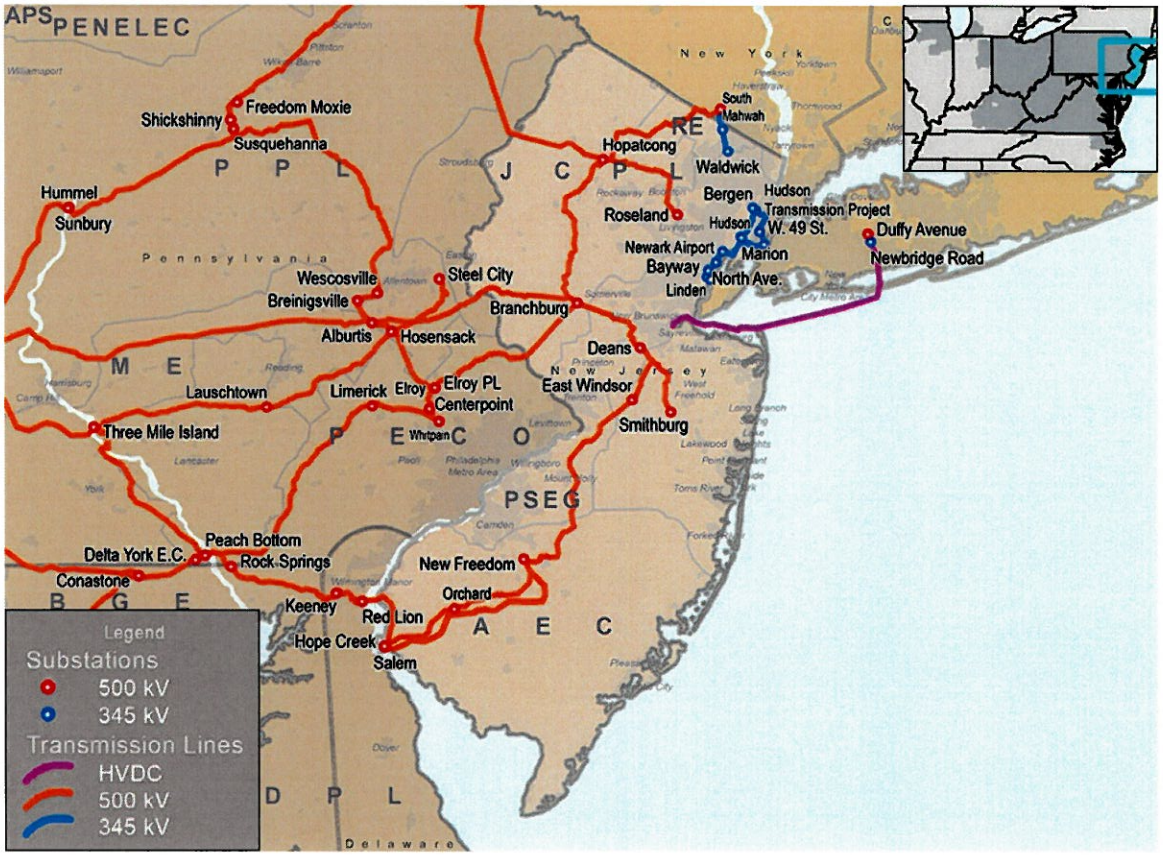
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in New Jersey, including facilities owned and operated by Atlantic City Electric (AE), Jersey Central Power & Light (JCP&L), Linden VFT (VFT), Neptune Regional Transmission System (Neptune RTS), Public Service Electric & Gas Company (PSE&G), and Rockland Electric Company (RECO) as shown on **Map 6.28**. 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 the PJM service area.

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 objectives. The Clean Energy Act of 2018 required 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 Executive Order No. 92. In 2022, that target was again increased to 11,000 MW by 2040 through Executive Order No. 307.

Map 6.28: PJM Service Area in New Jersey



New Jersey is supporting the development of its offshore wind projects by proactively planning for the transmission needed to interconnect its overall target of 11,000 MW by 2040. In October 2022, the New Jersey Board of Public Utilities (NJBPU) issued an Order approving transmission solutions as part of the State Agreement Approach (SAA) to support the interconnection of the first 7,500 MW target.

New Jersey is also pursuing decarbonization through additional efforts. In 2023, the New Jersey Department of Environmental Protection implemented CO_2 regulations for existing and proposed fossil fuel resources. New Jersey is also pursuing an energy storage target of 2,000 MW by 2030.

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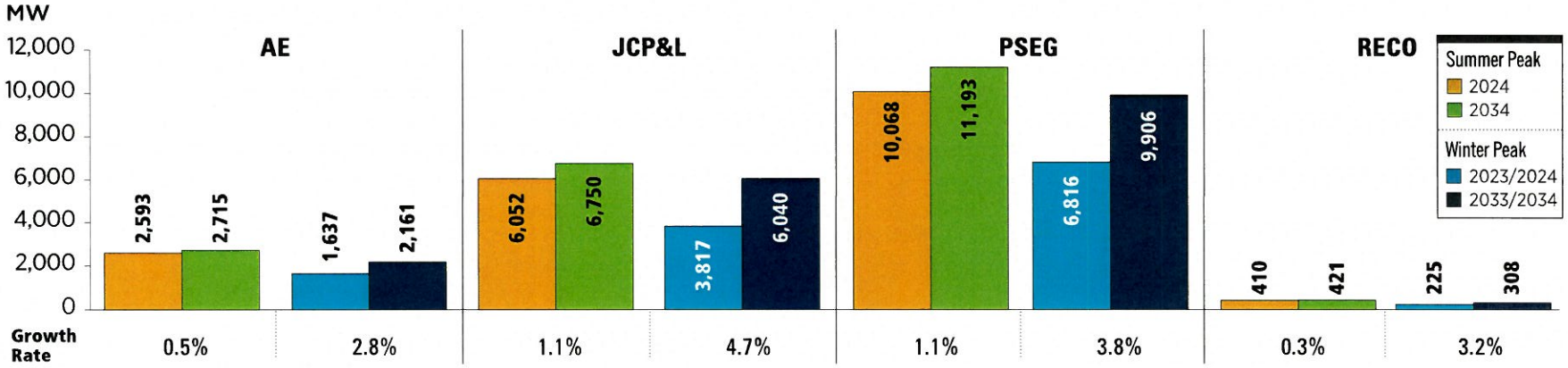
6.7.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.31** summarizes the expected loads within the state of New Jersey and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.31: New Jersey – 2024 Long-Term Load Forecast



PJM RTO Summer Peak		PJM RTO Winter Peak	
2024	2034	2023/2024	2033/2034
151,247 MW	176,822 MW	134,659 MW	163,069 MW
Growth Rate 1.6%		Growth Rate 1.9%	

The summer and winter peak megawatt values reflect the estimated amount of forecasted load to be served by each transmission owner in New Jersey. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load in New Jersey over the past five years.

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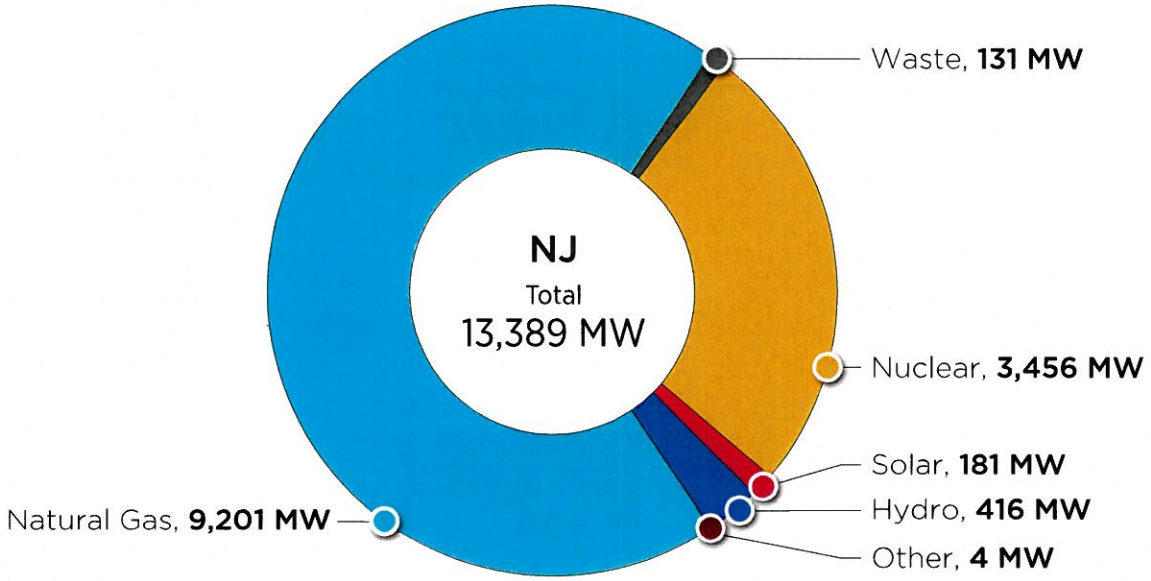
6.7.3 — Existing Generation

Existing generation in New Jersey as of Dec. 31, 2024, is shown by fuel type in **Figure 6.32**.

Figure 6.32: New Jersey – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



Read More
Changing Capacity Mix and Deliverability

6.7.4 — Interconnection Requests

In New Jersey, as of Dec. 31, 2024, 121 projects were actively under study or under construction as shown in the summaries presented in **Table 6.34**, **Table 6.35**, **Figure 6.33**, **Figure 6.34** and **Figure 6.35**.

NOTE:
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.

Read More
Interconnection Requests

Table 6.34: New Jersey – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	New Jersey Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	186	1.28%	20,162	14.38%
Hydro	0	0.00%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	71	0.49%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	0	0.00%	64	0.05%
Solar	629	4.31%	55,040	39.25%
Storage	3,636	24.93%	39,064	27.86%
Wind	10,060	68.99%	17,455	12.45%
Grand Total	14,583	100%	140,231	100%

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Table 6.35: New Jersey – Interconnection Requests by Fuel Type (Dec. 31, 2024)

		In Queue				Complete				Grand 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	1.0	15.0	1	15.0
	Natural Gas	1	20.0	1	51.1	77	7,289.0	184	52,599.3	263	59,959.4
	Oil	0	0.0	0	0.0	2	35.0	8	945.0	10	980.0
	Nuclear	0	0.0	0	0.0	6	381.0	0	0.0	6	381.0
	Other	0	0.0	0	0.0	1	0.0	2	45.5	3	45.5
	Storage	38	3,636.2	1	0.0	12	4.0	83	1,655.3	134	5,295.5
Renewable	Hybrid	6	186.3	0	0.0	7	541.9	28	516.3	41	1,244.5
	Hydro	0	0.0	0	0.0	2	20.5	3	1,031.1	5	1,051.6
	Biomass	0	0.0	0	0.0	0	0.0	2	10.0	2	10.0
	Methane	0	0.0	0	0.0	12	30.9	9	40.6	21	71.5
	Solar	49	606.3	7	22.9	127	276.9	529	2,016.5	712	2,922.6
	Wind	18	10,060.1	0	0.0	1	0.0	41	7,564.8	60	17,624.9
	Grand Total	**112**	**14,508.8**	**9**	**74.0**	**247**	**8,579.2**	**890**	**66,439.6**	**1,258**	**89,601.6**

Figure 6.33: New Jersey – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

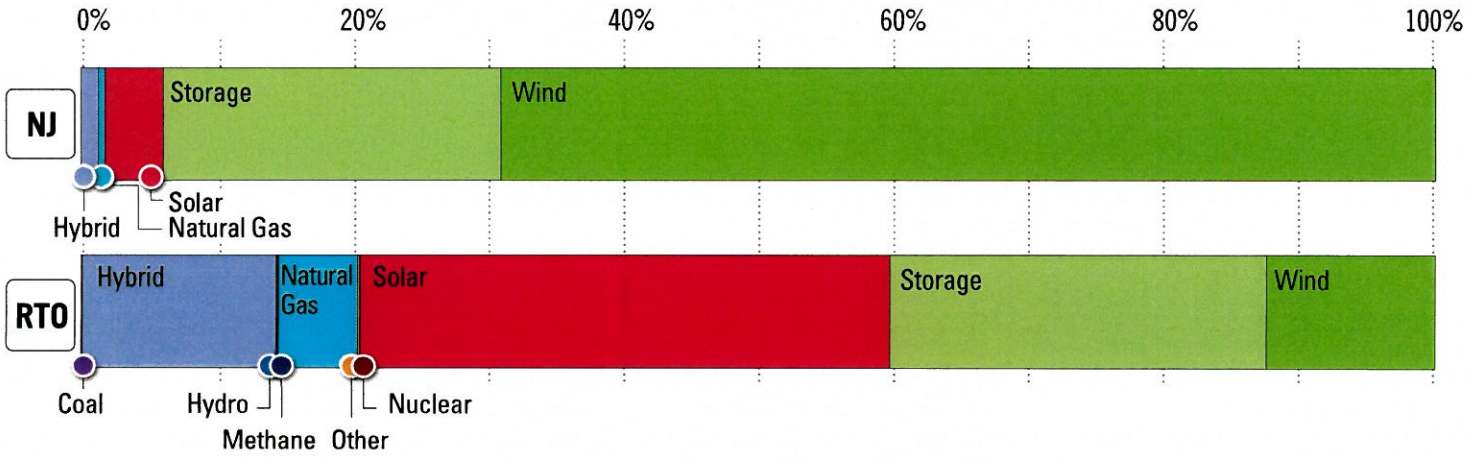

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Figure 6.34: New Jersey Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

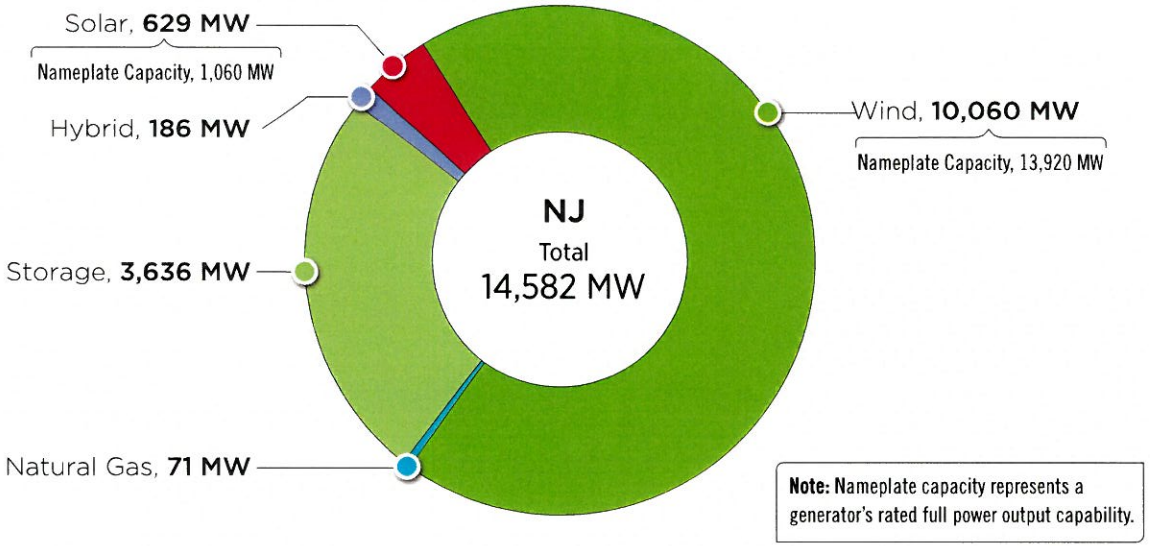

Figure 6.35: New Jersey Progression of Interconnection Requests (Dec. 31, 2024)

Percentage of planned capacity and projects that have reached commercial operation

11.0%	Requested capacity megawatts
18.4%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	29	Interconnection Service Agreements	3,594 MW	4,040 MW
	148	Wholesale Market Participation Agreements	396 MW	1,126 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, 2024.

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6.7.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in New Jersey between Jan. 1, 2024, and Dec. 31, 2024, are summarized in **Map 6.29** and **Table 6.36**.

Read More
Baseline Projects

Map 6.29: New Jersey Generation Deativations (Dec. 31, 2024)

Table 6.36: New Jersey Generation Deactivations (Dec. 31, 2024)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Sayreville C-4	JCP&L	Natural Gas	12/29/2023	6/1/2024	51	48.5
Sayreville C-3						54.6
Sayreville C-2						56.7
Sayreville C-1						57.1

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Table 6.36: New Jersey Generation Deactivations (Dec. 31, 2024) (Cont.)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Mickleton 1 CT	AE	Natural Gas	1/30/2023	6/1/2024	49	57.2
Carlls Corner CT 2					50	38.2
Carlls Corner CT 1						36.3
Cates Road Solar		Solar	12/30/2024	4/1/2025	10	2.6
Manchester (MRPC) NUG	JCP&L	Methane	11/14/2024	5/1/2025	36	4
Kenilworth NUG	PSEG	Natural Gas	9/13/2024	6/1/2026	35	15

6.7.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in New Jersey are summarized in **Map 6.30** and **Table 6.37**.

Read More
Baseline Projects

Map 6.30: New Jersey Baseline Projects (Dec. 31, 2024)

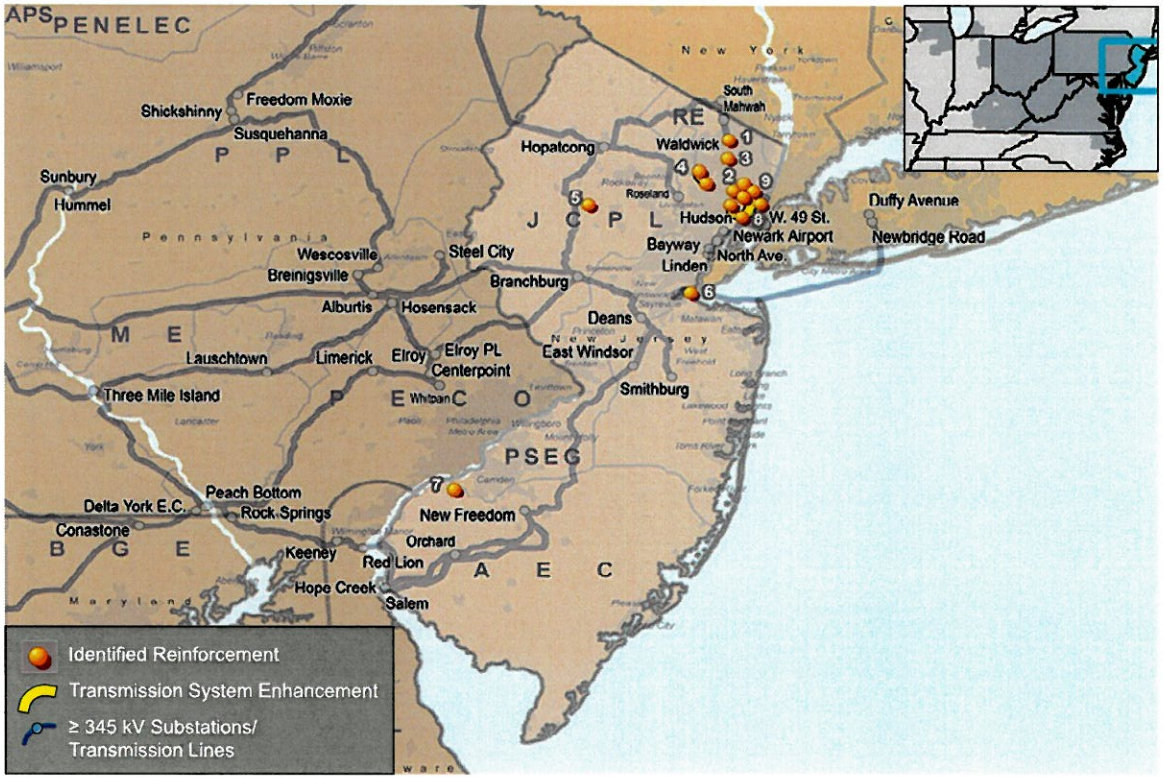

Table 6.37: New Jersey Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3794.1	Replace existing Waldwick 230 kV 50 MVAR fixed shunt reactor with a 230 kV 150 MVAR variable shunt reactor.	6/1/2028	$13.60	PSEG	10/31/2023
	B3794.2	Replace existing Waldwick 345 kV 100 MVAR fixed shunt reactor with a 345 kV 150 MVAR variable shunt reactor.		$16.00		
2	B3848.1	Open East Rutherford 69 kV tie breaker (26K).		$0.00		6/13/2024
	B3848.2	Move line U-775 (East Rutherford to Hasbrouck Heights) currently on section 2 to section 7 of the ring bus.		$2.14		

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Table 6.37: New Jersey Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	B3849.1	Perform all necessary engineering design and evaluation to increase Fairlawn 69 kV GIS from 50 kA to 55 kA.	6/1/2028	$1.49	PSEG	6/13/2024
4	B3855.1	Build 4 miles of new 230 kV XLPE circuit using (345 kV rated 5000 kcmil cable) from Jackson Road 230 kV station to Cedar Grove 230 kV station.		$77.15		7/9/2024
	B3855.2	Expand a new 230 kV bay at the existing Cedar Grove station with one line position by adding two 230 kV circuit breakers and associated disconnect switches.		$6.61		
	B3855.3	Replace the existing HPFF termination structure with a new XLPE termination structure to connect to spare GIS bay position at Jackson 230 kV.		$0.82		
5	B3860.1	Replace the 34.5 kV bus tie breaker at Chester substation with a new 34.5 kV breaker that has an interruption capability of 40 kA.	6/1/2029	$0.54	JCP&L	11/14/2024
6	B3861.1	Replace the W101 34.5 kV breaker at Werner substation with a new 34.5 kV breaker that has an interruption capability of 40 kA.		$0.54		
7	B3867.1	Upgrade a circuit switcher at Mickleton substation.		$1.03	AE	12/3/2024
8	B3868.1	Cut existing Carlstadt to River Road 69 kV line and extend Carlstadt line side to Penhorn 69 kV. Extend the other end of the line by constructing a new portion and connecting it to Kingsland 69 kV switch.		$14.62	PSEG	11/14/2024
	B3868.2	Extend the other end of L-636 to Kingsland switch by constructing new 5.5 miles portion utilizing existing I-2314 transmission towers from H-A 5/4 to H-A 2/3. New 69 kV line to be routed along County Ave pass Secaucus Rd in Secaucus, NJ.		$30.87		
	B3868.3	Reconfigure former River Road to Carlstadt 69 kV and Tonnelle Ave to Union City 69 kV lines at the intersection Tonnelle Ave. and Granton Ave. in North Bergen, NJ by connecting Union City to River Road and Tonnelle Ave to Kingsland.		$0.51		
9	B3869.1	Relocate the Bergen Gen No. 1 point of interconnection from Bergen 138 kV to Bergen 345 kV GIS through the existing 345/138 kV transformer.	12/1/2029	$6.80		
	B3869.2	Remove and retire the two existing Bergen 138 kV series reactors and associated ancillary equipment.		$5.70		

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6.7.7 — Network Projects

Network projects in New Jersey for 2024 are summarized in **Map 6.31** and **Table 6.38**.

Read More
Network Projects

Map 6.31: New Jersey Network Projects (Dec. 31, 2024)

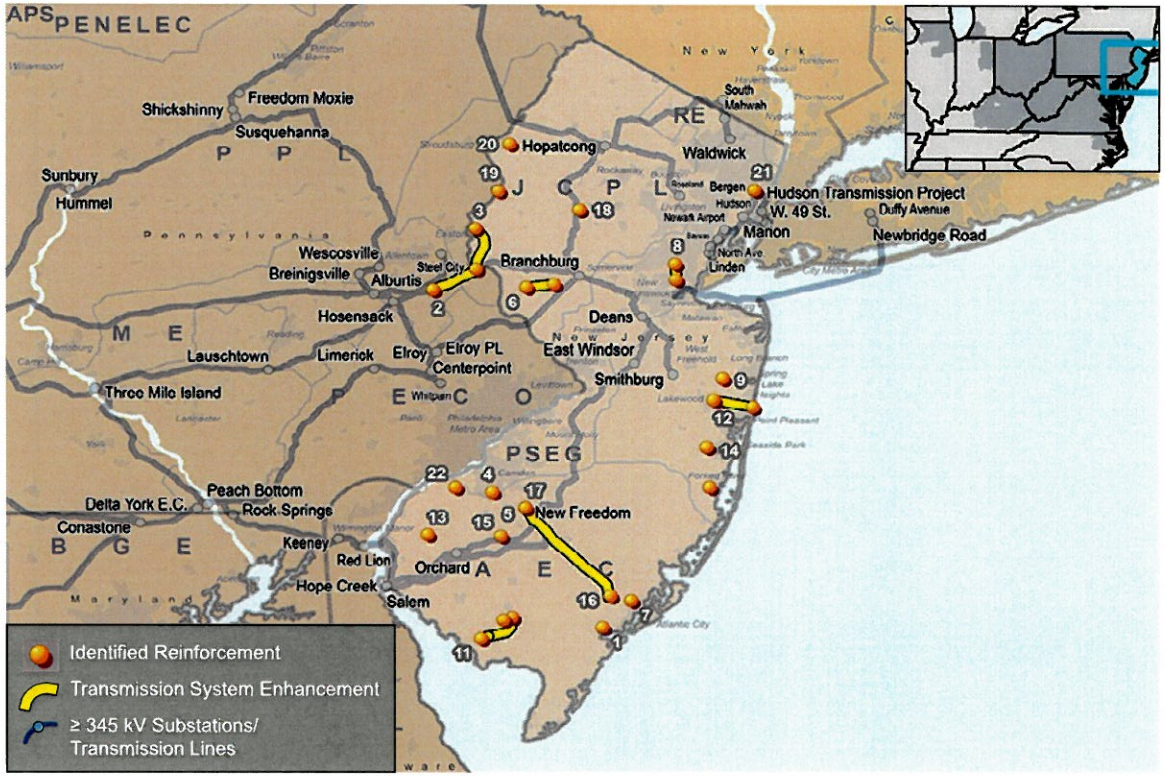

Table 6.38: New Jersey Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N4296	The SCULL No. 2 to MILL No. 2 138 kV line: In order to mitigate the overloads, the relay settings should be adjusted at Mill 138 kV bus. The new emergency rating will be 270 MVA.	Y1-077	6/1/2015	$0.01	AEC	10/8/2024
2	N5146	Gilbert 230 kV substation – Construct the new 230 kV line terminal at the new Gilbert 230 kV substation for the new AB1-154 interconnection.	AB1-154	6/1/2020	$0.81	JCP&L	
	N5165	Reconductor 0.4 miles of Gilbert-Springfield 230 kV circuit replacing 1590 ACSR with 1590 ACSS.			$0.81		
	N5264	TOSCO_2-VFT 2 230 kV line rebuild with paired 1033 ACSS	AB2-055	6/1/2021	$5.01	PSEG	

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Table 6.38: New Jersey Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	N6145	Construct a 34.5 line tap/connection and 2-34.5 kV load-break switches with SCADA control at tap location, including one span of 34.5 kV line to the point of interconnection at Gilbert-Morris Park (A27) 34.5 kV generation interconnection. (One 34.5 kV switch on the generator lead line and the span of 34.5 kV circuit are considered attachment facilities.)	AE1-243	12/1/2019	$0.07	JCP&L	1/9/2024
	N6146	Construct a 34.5 line tap/connection and 2-34.5kV load-break air switches with SCADA control at tap location, including 1 span of 34.5kV line to the point of interconnection at Gilbert-Morris Park (A27) 34.5kV Generation Interconnection. (The one (1) switch on the main circuit next to the tap is considered a Non-Direct Connection cost) Estimated installation of 700 MHz radio system (70% penetration of FE territory) to support the (3) SCADA switch replacements. Assumed SCADA work is included in this cost. Provide and install 34.5 kV instrument transformer package and bi-directional 4G cell meter at AE1-243 site (new battery facility.)			$0.82		
	N6147	Gilbert Substation – Revise remote relay and metering settings on the Morris Park 34.5 kV terminal.			$0.04		
	N6148	Morris Park Substation – Revise remote relay and metering settings on the Gilbert 34.5 kV terminal.			$0.04		
4	N6233	Replacement of two poles and associated PSE&G standard conductor Installation of two new poles as H-frame for STATCOM equipment Installation and commissioning of STATCOM equipment Relocation of branch recloser to new poles	AE2-064	12/10/2019	$0.40	PSEG	
5	N6342	To mitigate the (ACE) Cardiff-New Freedom 230 kV line (from bus 227900 to bus 219100 ckt 1) overload, it will require increasing the emergency rating of the Cardiff to New Freedom 230 kV line by rebuilding the circuit. The rebuild will include the installation of new poles, foundations, insulators and conductor. New Ratings: 796/932/932	AE2-022	6/1/2022	$105.00	AEC	
6	N6865	Construct a tap and install 3-34.5 kV load-break air switches on the West Flemington tap-Frenchtown Solar 2 portion of the East Flemington-Frenchtown (A729) 34.5 kV line.	AF2-192	4/17/2020	$0.40	JCP&L	10/8/2024
	N6866	Install FE-owned 34.5 kV metering in the interconnection customer's substation for AF2-192.			$0.27		
	N6867	Upgrade relaying at East Flemington 34.5 kV.			$0.40		
	N6868	Upgrade relaying at Frenchtown 34.5 kV.			$0.40		
7	N7051	To mitigate the Lewis 138 kV bus tie overload, breaker 'JN' will be replaced with a 3000 amp breaker.	AF2-016	5/31/2023	$0.24	AEC	
8	N7137	Reconductor METUCHEN-NEWDOVR_H 230 kV transmission line to 1080 MVA SER.	AF2-415	6/1/2022	$12.88	PSEG	
9	N7262	At Farmingdale 34.5 kV: Appropriate terminal equipment upgrades required to accommodate higher generation output.	AG1-563	6/1/2023	$0.01	JCP&L	1/9/2024
	N7263	At Bennett 34.5 kV: Appropriate terminal equipment upgrades required to accommodate higher generation output.			$0.01		
	N7264	Review of relay settings/protection settings at X4-031 34.5 kV required.			$0.02		
10	N7599	Reconductor one section of 4/0 CU sub conductor circular at Drakes town 115 kV with a conductor able to meet or exceed 254 MVA STE. Reconductor 14.18 miles of 556.5 ACSR 26/7 115 kV transmission line from Belvedere tap to Drakes town with 795 ACSR or a conductor able to meet or exceed 254 MVA STE. Replace one 5 A thermal relay at Pequest River.	AG1-348	12/17/2021	$49.63		10/8/2024
	N7600	Replace one 800 A Generic wave trap at Whippany 115 kV.			$0.13		

Table 6.38: New Jersey Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
11	N8023	Upgrade relays at remote ends.	AE1-179	11/1/2021	$0.20	AEC	1/9/2024
	N8024	Modify line No. 0762.			$1.80		
	N8025	Install new communication equipment at new ring bus substation.			$0.20		
	N8026	Install new underground fiber between IC switching station and ring bus substations control enclosure at AE1-179 South Millville-Newport 69 kV line.			$0.20		10/8/2024
12	N8032.1	Tap the Larrabee-Point Pleasant No. 1 34.5 kV line an ~1.9 miles from Larrabee and 3.9 miles from Allaire to the customer facility and build a single span to point of interconnection with customer.	AG1-223	2/18/2022	$2.26	JCP&L	
	N8032.2	Review relay settings at Point Pleasant 34.5 kV.			$0.04		
	N8032.3	Review relay settings at Larrabee 34.5 kV.			$0.04		
	N8514.1	Install two 34.5 kV load-break air switches with SCADA control on the Larrabee-Point Pleasant B106 34.5 kV line an ~1.9 miles from Larrabee and 3.9 miles from Allaire.		12/31/2026	$0.80		
	N8514.2	Revise relay settings at Larrabee 34.5 kV.			$0.07		
	N8514.3	Revise relay settings at Point Pleasant 34.5 kV.			$0.07		
13	N8040.1	Construct a new 138 kV three-position ring bus substation.	AE1-229	9/30/2021	$8.71	AEC	1/9/2024
	N8040.2	Cut and loop in 1405 transmission line to the new 138 kV three-position ring bus substation, occupying two of those positions. The third position will accommodate the interconnection of the customer facility.			$0.25		
	N8040.3	Install a new lead line (no longer than 500 feet) from the point of interconnection to the new 138 kV ring bus substation.			$0.25		
14	N8043.1	Oyster Creek substation: Install two new 230 kV breakers at Oyster Creek 230 kV substation for one new point of interconnection to AE1-020 (AE2-000).	AE1-020	6/1/2023	$5.77	JCP&L	
	N8043.2	Manitou substation: Relay settings changes			$0.12		
15	N8044.1	Construct a new 69 kV ring bus.	AE2-334	6/30/2022	$8.71	AEC	
	N8044.2	Cut in transmission line 0716 to the new 69 kV three-position ring bus substation, occupying two of those positions. The third position will accommodate interconnection of the customer facility.			$0.25		
	N8044.3	Install protective relaying at the new 69 kV three-position ring bus substation.			$0.25		
16	N8222.1	Build new control house and all associated communications and relaying for reconfiguration at Cardiff 230 kV substation.	AE2-020	12/1/2029	$25.00		
17	N8310	Replacement of the equipment for the 2310 line termination at New Freedom switching station including A-frame structure, line disconnect switch, relays and associated equipment.	AE2-022	6/1/2029	$2.73	PSEG	
	N8315	Install harmonic measurement equipment and collect data for a harmonic study. Provide data and report to interconnection customer and PJM.			$0.30	AC	
18	N8442.3	Review relay settings.	AG1-191	12/17/2021	$0.08	JCP&L	
	N8442.4	Review relay settings.			$0.08		

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Table 6.38: New Jersey Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
19	N8483.1	Tap the Pequest River-Washington 34.5 kV line, an ~2.2 miles from Pequest River and 5.6 miles from Washington. Install two line switches with SCADA control. Provide 120 V power to the new switch structures.	AG1-348	12/17/2021	$0.79	JCP&L	10/8/2024
	N8483.2	Upgrade relay settings at Pequest River 34.5 kV substation.			$0.08		
	N8483.3	Upgrade relay settings Washington 34.5 kV substation.			$0.08		
20	N8499	Install an adjacent structure on the existing E707 Kittatinny-Newton 34.5 kV line in order to accommodate the new tap installed on the M715 Kittatinny-Newton 34.5 kV line. Install two SCADA-controlled in-line switches and extend distribution circuit to provide power to the switches.	AG1-510	8/30/2027	$2.71		
21	N8511	Install new relays at Bergen 138 kV to accommodate the AF2-415 generator lead line.	AF2-415	12/31/2026	$0.08	PSEG	
22	N6070	Reinforcements to increase the emergency rating of the Delco tap to Mickleton 230 kV line require the replacement of substation equipment, including substation bus at Mickleton substation. The estimate to perform this work is $905,000 and will take 18 months to complete.	AB2-153	11/1/2017	$0.91	AEC	1/9/2024

6.7.8 — Supplemental Projects

Supplemental projects included in the 2024 Local Plan in New Jersey are summarized in **Map 6.32** and **Table 6.39**.

Read More
Supplemental Projects

Map 6.32: New Jersey Supplemental Projects (Dec. 31, 2024)

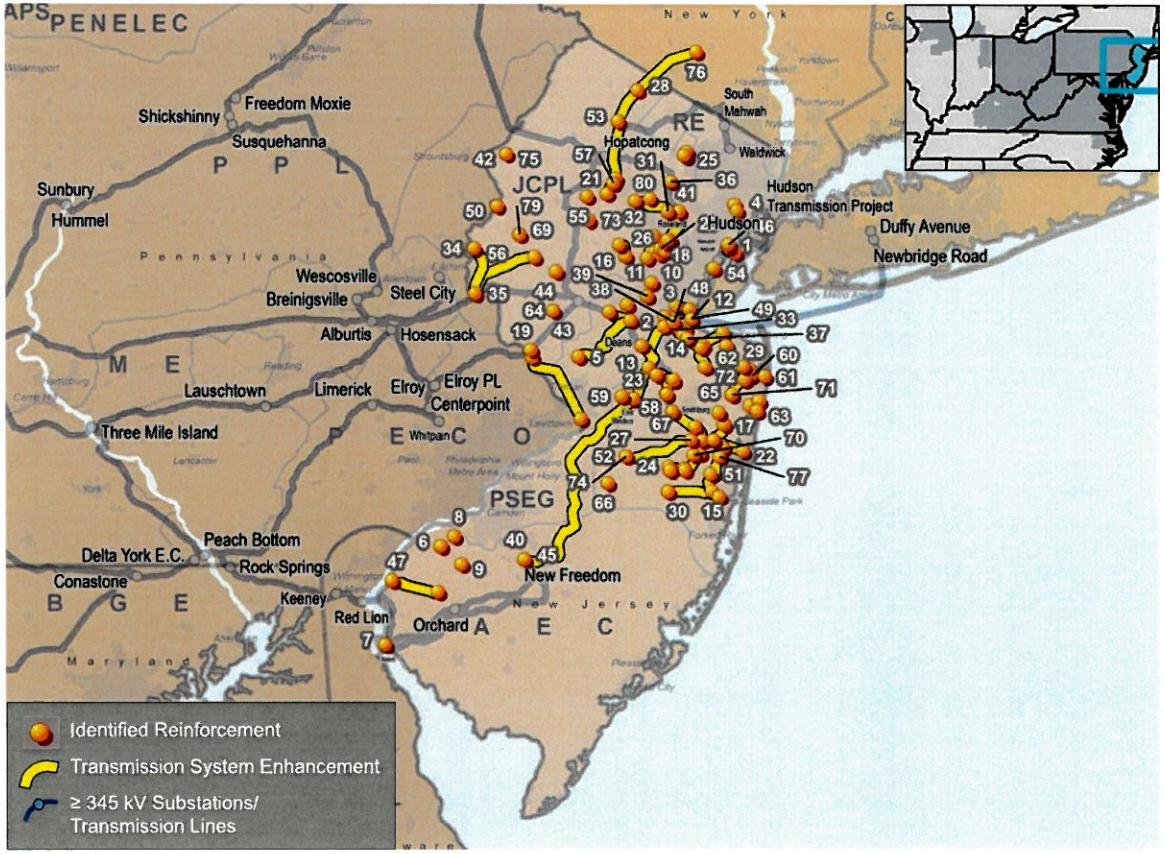

Table 6.39: New Jersey Supplemental Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S3007.1	Replace the G-709 High Pressure Fluid Filled (HPFF) cable with Extruded Pipe (EP) cable. Replace 2.3 miles of HPFF cable with EP cable. Reuse the existing G-709 pipe and route for the cable replacement. Modify terminal equipment at PVSC and Bayonne stations to accommodate the EP cables. At Bayonne station, decommission and remove the oil pumping equipment, including pumping plant, tank, controls and piping associated with the cable.	6/1/2028	$46.80	PSEG	7/20/2023
2	S3008.1	Construct a 230-13 kV substation at PSEG property adjacent to Meadow Road substation. Construct a 230 kV substation. Install two 230-13 kV transformers. Resolves contingency overload at Meadow Road substation.	11/30/2028	$79.70		9/5/2023

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Table 6.39: New Jersey Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S3009.1	Construct a new 69/13 kV station on PSE&G-owned adjacent property to Keasbey station. Build a new 69 kV line to Rahway station. Build a new 69 kV line to Blair Rd. Install one 230/69 kV transformer at South Edison. Build a new 69 kV line to South Edison.	12/1/2028	$220.68	PSEG	9/5/2023
4	S3010.1	Upgrade Van Winkle to a 69-13 kV substation. To ensure continuity of service, the project requires a temporary 69 kV contingency during the construction sequence. Remove existing transformers and associated equipment at Van Winkle. Install two 69-13 kV transformers and associated equipment.	12/30/2028	$22.30		8/17/2023
5	S3090.1	Construct a new 69-13 kV substation in the Harlingen area. Construct new 69-13 kV station on new property. Install two 69-13 kV transformers. Cut and loop the Bennetts Lane-Montgomery 69 kV line into the new substation. Cut and loop the Montgomery-Customer sub 69 kV line into the new substation.	12/31/2029	$67.00		10/31/2023
	S3090.2	Construct a second 230-69 transformer at the Bennetts Lane substation. Install one 230-69 transformer. Modify 230 kV bus at Bennetts Lane. Modify 69 kV bus at Bennetts Lane.		$38.10		
6	S3149.1	Construct new six-breaker 69 kV ring bus substation by cutting into Paulsboro-Beckett line. Install a 30 MVAR cap bank at Woolwich substation. Install two new 69/12 kV 40 MVA transformers to address the growing distribution load in the area.	12/15/2027	$25.00	AE	9/14/2023
7	S3154.1	Install a new 69 kV terminal position at Quinton substation. Install new 11-mile 69 kV line to provide service to the customer.	10/30/2024	$2.00		
8	S3180.1	At Mickleton substation, replace the existing transformer with a new 230/69 kV three-phase autotransformer.	5/31/2025	$5.90		1/9/2024
9	S3181.1	Install a new 69 kV tie breaker at Lamb substation to provide an additional terminal for distribution resources.	4/30/2027	$2.50		1/18/2024
10	S3184.1	Construct a third transformer at existing South Second St. station. Install one 69/13 kV transformer.	12/1/2027	$11.20	PSEG	
11	S3232.1	Rebuild the Gillette-Green Village 34.5 kV E5 and J114 circuit (shared structures). Replace an ~134 damaged poles. Install 5.7 miles of new conductor. Gillette substation: Replace line relaying, limiting substation conductor. Green Village substation: Replace line relaying, line side disconnect switch transmission line ratings.	2/23/2024	$24.20	JCP&L	11/16/2023
12	S3233.1	115 kV breaker addition: Install one 115 kV breaker to create a 115 kV five-breaker ring bus and create a terminal for customer connection. Modify relay settings/scheme to accommodate breaker addition.	12/31/2025	$1.50		12/13/2023
13	S3234.1	At Monroe, replace relaying: Citgo D tap-Monroe D82 34.5 kV, Hoffman Solar Tap-Monroe H34 34.5 kV.		$1.89		11/16/2023
14	S3235.1	At Freneau, replace relaying: Freneau-Hillsdale tap F32 34.5 kV, Freneau-Pennwalt tap V100 34.5 kV, Freneau-Hazlet S45 34.5, Freneau-Ernston tap W101 34.5 kV.	6/1/2028	$3.78		
15	S3236.1	At Manitou, replace relaying: Manitou-Toms River Tap V126 34.5 kV, Manitou-Pine Beach Tap X50 34.5 kV.	11/16/2024	$1.92		
16	S3237.1	At Bernardsville, replace relaying.	6/1/2025	$1.28		
17	S3238.1	At Allenhurst, replace relaying: Allenhurst-Oceanview H216 34.5 kV.	12/31/2024	$1.28		
18	S3239.1	At Murray Hill, replace relaying: Air Reduction-Murray Hill D108 34.5 kV.	12/1/2026	$0.64		
19	S3240.1	At Rocktown Road, replace relaying: Rocktown Road-Mercer tap N716 34.5 kV, Alexauken tap-Rocktown Road Y727 34.5 kV.	6/1/2028	$1.28		
20	S3241.1	At New Providence, replace relaying: Air Reduction Tap-New Providence D108 34.5 kV.	10/31/2025	$0.64		
21	S3242.1	At West Wharton, replace relaying: West Wharton-Route 15 switch point T254 34.5 kV, West Wharton-Kenvil Tap Z728 34.5 kV.	10/15/2025	$1.92		
22	S3243.1	At Point Pleasant, replace relaying: Lanes Mill Tap-Point Pleasant T146 34.5 kV, Brielle-Point Pleasant B106 34.5 kV.	12/31/2026	$1.92		
23	S3244.1	At Englishtown, replace relaying: Englishtown-Hoffman Solar Tap H34 34.5 kV, Englishtown-Route 33 switch point I87 34.5 kV, Englishtown-Gordons Corner A209 34.5 kV.	6/1/2027	$2.56		

Table 6.39: New Jersey Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
24	S3245.1	At Lakehurst, replace relaying: Lakehurst-Ship Test E109 34.5 kV, Lakehurst-Lakehurst Solar Tap N140 34.5 kV, Lakehurst-South Lakewood W777 34.5 kV Lakehurst-TRC O Tap O41 34.5 kV.	12/31/2027	$2.56	JCP&L	11/16/2023
25	S3246.1	At Riverdale, replace relaying: Pompton Plains Tap-Riverdale M117 34.5 kV, Riverdale Quarry Tap-Riverdale I9 34.5 kV.	12/20/2024	$1.28		
26	S3247.1	At Traynor, replace relaying: Traynor-Canoe Brook T72 34.5 kV, Traynor-ELRR Summit Q Tap Q17 34.5 kV, Canoe Brook Tap-Traynor C81 34.5 kV.	12/31/2028	$1.92		
27	S3248.1	At Larrabee, replace relaying: Larrabee-Laurelton Tap Q43 34.5 kV, Hyson-Larrabee K219 34.5 kV, Larrabee-Metedeconk Tap E213 34.5 kV, Larrabee-Allaire Tap B106 34.5 kV.	5/7/2025	$2.56		
28	S3249.1	Replace the 115-34.5 kV No. 1 transformer at Vernon substation. Replace 115 kV circuit switcher with a circuit breaker. Upgrade transformer relaying.	12/14/2026	$4.70		3/15/2024
29	S3250.1	At Red Bank, replace relaying: Red Bank-Little Silver Z78 34.5 kV.	12/31/2027	$1.28		11/16/2023
30	S3251.1	At Whitings, replace relaying: Manitou-Whitings L138 34.5 kV.	12/31/2026	$1.28		
31	S3253.1	Replace relaying and limiting substation conductor: Traynor and Whippany substations, Traynor-Whippany Z1040 230 kV line.	11/15/2025	$3.25		12/5/2023
32	S3254.1	Replace relaying and limiting substation conductor: Traynor and Whippany substations, Greystone-Whippany J1024 230 kV line.	5/31/2025	$2.75		
33	S3255.1	Replace relaying and limiting substation conductor at Freneau, Williams Gas and Parlin substations, Freneau-Williams Gas-Parlin K1025 230 kV line.	5/30/2025	$4.10		
34	S3256.1	Replace limiting substation equipment to meet or exceed the line (P2016) conductor rating at Gilbert substation: circuit breakers, disconnect switches, substation conductor.	5/30/2024	$2.40		
35	S3257.1	Replace limiting substation equipment at Gilbert and Glen Gardner substations to meet or exceed the line (V1036) conductor rating: circuit breakers, disconnect switches, substation conductor.	4/4/2025	$5.20		
36	S3258.1	Replace the 230-34.5 kV No. 3A and 3B transformers at Montville substation with a single 168 MVA unit.	12/31/2026	$8.55		2/6/2024
37	S3259.1	Install one SCADA-controlled line switch toward Freneau substation and build an ~one to two spans toward Cheesequake substation and install one SCADA-controlled tap switch. Install 34.5 kV revenue metering equipment. Modify relay schemes/settings at terminal stations.	6/1/2025	$1.30		1/18/2024
38	S3260.1	Replace the 230-115 kV No. 13 transformer at Raritan River substation with a 224 MVA unit. Replace high-side switch with a circuit breaker. Upgrade transformer relaying.	6/30/2026	$5.40		1/9/2024
39	S3261.1	Convert the existing Middlesex 230 kV switching station to a three-breaker ring bus. Upgrade limiting switches and TL drops at the Middlesex 230 kV switching station.	6/1/2026	$8.85		2/6/2024
40	S3262.1	Upgrade communication equipment from PLC to fiber at East Windsor substation on the 5022 and 5038 500 kV lines. Retire line traps, tuners and carrier equipment. Replace static wire. Replace line relays transmission line ratings.	6/1/2027	$2.00		
41	S3272.1	Replace relaying and limiting substation conductor at Traynor and Whippany substations.	5/30/2026	$2.33		1/9/2024
42	S3273.1	Replace the 230-34.5 kV No. 1 transformer at Kittatinny substation with a 90 MVA unit. Replace high-side switch with a circuit breaker. Upgrade transformer relaying.	12/31/2025	$7.00		
43	S3274.1	Replace the 230-34.5 kV No. 3 transformer at East Flemington substation with a 125 MVA unit. Install a 34.5 kV breaker with SCADA control. Upgrade transformer relaying.	12/31/2026	$7.18		
44	S3275.1	Replace the 230-34.5 kV No. 4 transformer at East Flemington substation with a 125 MVA unit. Install a 34.5 kV breaker with SCADA control. Upgrade transformer relaying.	12/31/2027	$7.18		

Table 6.39: New Jersey Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
45	S3276.1	Construct new fiber path between New Freedom-E Windsor-Deans. Replace 53 miles of static wire on 5038 (New Freedom-E Windsor) and 15 miles of static wire on 5022 (E Windsor-Deans). Upgrade line relay equipment and remove Power Line Carrier (PLC) equipment. This project will replace Project s0473 and will be coordinated with JCP&L-2023-064.	6/1/2027	$18.30	PSEG	2/6/2024
46	S3277.1	Retire the Essex Switch to Newark Bay Cogen circuit (J-2210) assets o Remove circuit assets (i.e., cable, fluid and station equipment). Abandon pipe/conduit and manhole system.	10/1/2024	$3.74		3/5/2024
47	S3278.1	Rebuild 0725 and 0726 Churchtown-Woodstown 69 kV lines using 795 ACSR and replacing the existing shield wire with new OPGW.	12/31/2028	$31.00	AE	2/15/2024
48	S3280.1	Raritan River-Werner (D30) 115 kV line: Construct an ~1.5 miles of new 115 kV transmission line from the tap point to the customer's substation. Install two main-line switches and one tap switch. Switches to be SCADA controlled. Modify relay settings at Raritan River substation and Werner substation.	10/30/2025	$5.80	JCP&L	
49	S3281.1	Replace the 115-34.5 kV No. 12 transformer at EH Werner substation with a 125 MVA unit. Upgrade transformer relaying.	12/31/2025	$6.40		
50	S3283.1	Replace the 115-34.5 kV No. 2 transformer at Pequest River with a 90 MVA unit. Upgrade transformer relaying.		$4.23		
51	S3284.1	Install a new 34.5 kV breaker, disconnect switch and relaying to connect to the existing 34.5 kV bus at Vermont Ave substation. Modify relay schemes/settings on the Leisure Village-South Lakewood 34.5 kV F214 line. Modify relay schemes/settings on the Larrabee-Metedeconk 34.5 kV E213 line.	2/15/2027	$0.30		
52	S3298.1	Expand Cookstown substation from a four-breaker ring bus to a five-breaker ring bus.	12/31/2026	$2.50		12/5/2023
	S3298.2	Construct a new 230 kV circuit from Cookstown substation to the Van Hiseville junction on existing vacant circuit position, creating two new 230 kV lines: Cookstown-Larrabee 230 kV Cookstown-Whitings 230 kV.		$46.20		
	S3298.3	At Cookstown substation – Replace circuit switcher, line trap and relaying. Install 230 kV circuit breaker, disconnect switches and line trap		$0.90		
	S3298.4	At Larrabee substation – Replace line trap, substation conductor and relaying.		$0.40		
	S3298.5	At Whitings substation – Replace line trap, substation conductor and relaying.		$0.40		
53	S3299.1	At Franklin substation: Construct an 11-breaker 115 kV breaker-and-a-half substation.	12/31/2025	$20.30		11/16/2023
	S3299.2	Cut the existing Vernon-West Wharton 115 kV D931 & J932 lines and terminate them at Franklin substation. This will create the following 115 kV lines:Franklin-West Wharton No. 1 115 kV, Franklin-West Wharton No. 2 115 kV, Franklin-Vernon No. 1 115 kV Franklin-Vernon No. 2 115 kV.		$2.80		
	S3299.3	Install a new 90 MVA 115-34.5 kV transformer. Replace the existing 115-34.5 kV No. 2 transformer with a 90 MVA unit.		$8.10		
	S3299.4	Replace relaying at Franklin, Vernon and West Wharton substations.		$0.80		
54	S3310.1	Construct new 69-13 kV substation at PSEG-owned property in Elizabeth, NJ. Install two 69/13 kV transformers. Cut and loop Roselle-Elizabeth 69 kV line into the new 69 kV bus. Build new 69 kV circuit to Port Street. Estimated Cost: $222.7 M.	6/1/2029	$222.70	PSEG	4/18/2024
55	S3325.1	Replace the 115-34.5 kV No. 1 transformer at Flanders substation. Replace the 115 kV circuit switcher with a circuit breaker. Upgrade the transformer relaying. Install new control enclosure.	12/31/2025	$8.10	JCP&L	
	S3326.1	Replace the 115-34.5 kV No. 2 transformer at Flanders substation. Replace the 115 kV circuit switcher with a circuit breaker. Upgrade the transformer relaying.	5/29/2026	$8.10		
56	S3327.1	Replace relaying and limiting substation conductor at Gilbert substation. Replace circuit breakers and disconnect switches at Flanders substation.	12/17/2026	$3.27		
57	S3328.1	Install a new control building at West Wharton substation to provide adequate space needed for relay panel upgrades. Replace relaying and limiting substation conductor at West Wharton substation.	12/9/2025	$13.28		

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Table 6.39: New Jersey Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
58	S3329.1	Rebuild the existing Smithburg 230 kV gas-insulated substation bus as an open-air, 230 kV breaker-and-a-half station with 10 230 kV breakers. Upgrade terminal equipment and reterminate the existing 230 kV transmission lines and transformers. Retire the Smithburg-Larrabee No. 2 230 kV line. Revise relay settings at Larrabee, East Windsor, New Prospect Rd and Manalapan substations.	6/1/2027	$30.20	JCP&L	4/30/2024
59	S3394.1	Replace the 230-34.5 kV No. 1 transformer at Windsor with a 168 MVA unit.	11/2/2023	$6.30		9/5/2023
60	S3397.1	Install two main-line and one tap-line SCADA-controlled switches. Construct one span of 34.5 kV line between tap point and customer substation. Review/modify relay settings on the Eaton Crest-Woodbine (R226) 34.5 kV line.	9/1/2025	$1.40		10/19/2023
61	S3398.1	At Long Branch substation, replace relaying.	12/5/2024	$0.64		
62	S3399.1	At Taylor Lane substation, replace relaying.	5/31/2026	$0.64		
63	S3400.1	At Bradley Beach substation, replace relaying.	6/1/2026	$0.64		
64	S3401.1	At East Flemington substation, replace relaying.	12/31/2025	$0.64		
65	S3402.1	At Farmingdale substation, replace relaying.		$1.28		
66	S3403.1	At McGuire substation, replace relaying.	12/31/2024	$0.64		
67	S3404.1	At Smithburg substation, replace relaying.	12/31/2027	$0.64		
68	S3405.1	At Lebanon substation, replace relaying.	5/31/2028	$1.28		
69	S3406.1	At Washington substation, replace relaying.	6/1/2028	$1.28		
70	S3407.1	At Whitesville substation, replace relaying.		$1.92		
71	S3411.1	Replace relaying and limiting substation conductor at Atlantic and Red Bank 230 kV substations.	12/31/2026	$2.00		10/31/2023
72	S3412.1	Replace limiting substation conductor at Eaton Crest 230 kV. Replace relaying at Atlantic and Red Bank 230 kV substations.		$2.00		
73	S3413.1	Replace relaying and limiting substation conductor at Chester and West Wharton 230 kV substations.	4/25/2025	$2.00		
74	S3414.1	Replace the 230-34.5 kV No. 2 transformer at Cookstown with a 168 MVA unit. Upgrade transformer relaying.	6/2/2025	$7.95		
75	S3415.1	Replace relaying, limiting substation conductor and line disconnect switches at Kittatinny substation.	12/3/2022	$1.30		
	S3432.1	Replace the Kittatinny No. 4 230-34.5 kV transformer with a 125 MVA unit. Replace the transformer relaying.	5/1/2028	$5.00		6/4/2024
76	S3421.1	Remove the normally open interconnections between Vernon (FE) and Sugarloaf (Central Hudson) by removing the line jumper loops on Structure 161 for the 115 kV Sugarloaf CH-West Wharton No 1 D931 and No. 2 J932 lines.	7/25/2023	$0.05		8/17/2023
77	S3433.1	Replace the Lakewood Gen No. 6 230-34.5 kV transformer with a 125 MVA unit. Replace the transformer relaying	6/30/2028	$6.00		6/4/2024
78	S3437.1	Branchville-Franklin 34.5 kV Q745 line 34.5 kV line tap. Install one in-line and one tap-line SCADA-controlled switches. Construct an ~0.2-mile 34.5 kV line extension to the customer. Review/modify relay settings on the Branchville-Franklin 34.5 kV Q745 line.	6/2/2025	$0.80		6/13/2024
79	S3438.1	Replace Washington 34.5 kV C705, P718, Q719, W23A, W23B, U723A and U723B circuit breakers. Replace bus and line disconnect switches. Install line disconnect switches for C705 and Q719 breakers.	8/27/2027	$5.40		7/18/2024
80	S3336.1	Tap the Montville-Whippany 34.5 kV D4 line. Extend tap line an ~one span to customer. Add SCADA-controlled switches. Modify relay settings on the Montville-Whippany 34.5 kV D4 line.	1/24/2025	$1.40		5/16/2024

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6.8: North Carolina RTEP Summary

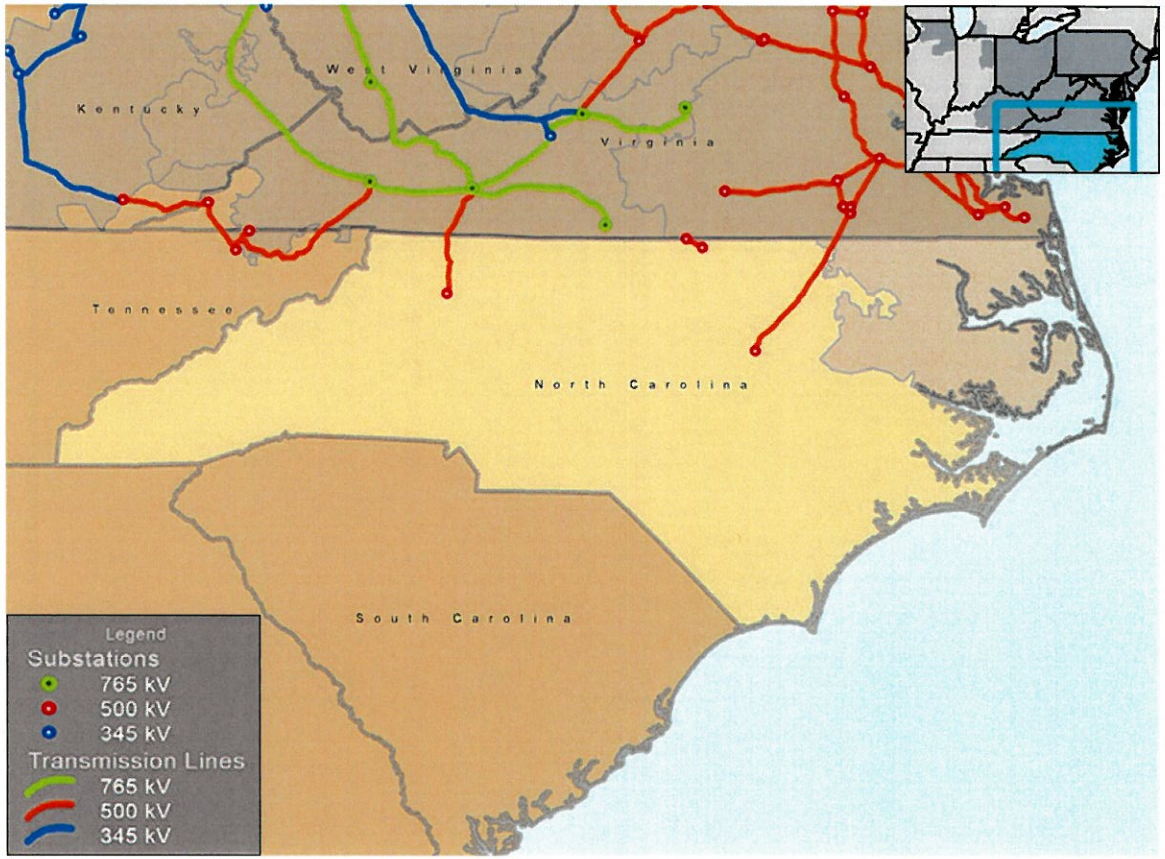
6.8.1 — RTEP Context

PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in North Carolina, including facilities owned and operated by Dominion Energy as shown on **Map 6.33**. 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 the PJM service area.

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 6.33: PJM Service Area in North Carolina

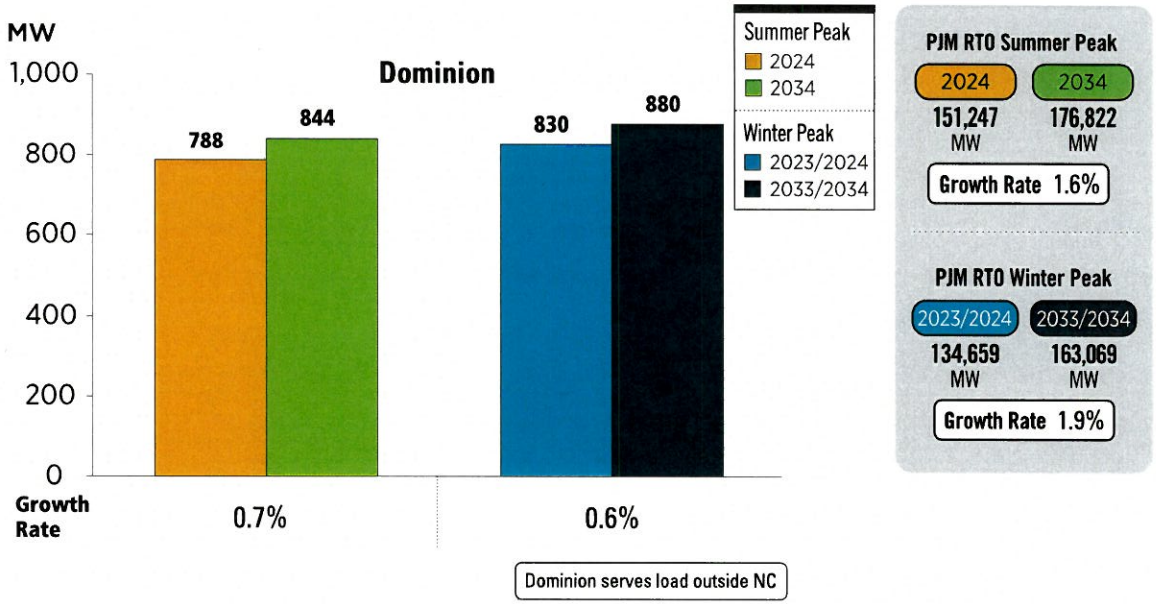


6.8.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.36** summarizes the expected loads within the state of North Carolina and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.36: North Carolina – 2024 Long-Term Load Forecast



PJM notes that Dominion Energy serves load other than in North Carolina. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by Dominion solely in North Carolina. Estimated amounts were calculated based on the average share of Dominion's real-time summer and winter peak load located in North Carolina over the past five years.

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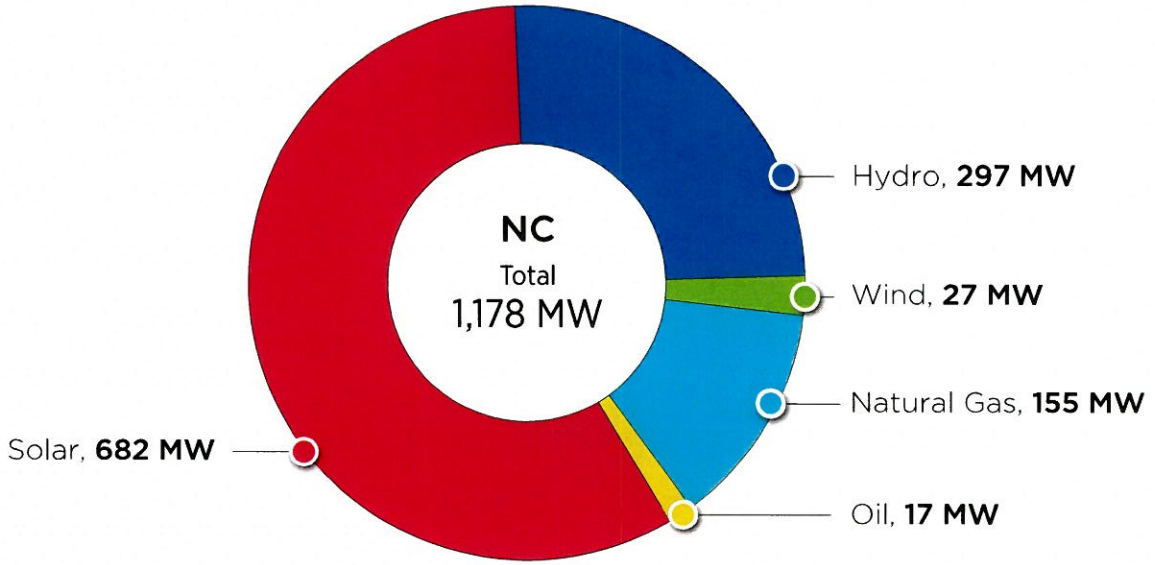
6.8.3 — Existing Generation

Existing generation in North Carolina as of Dec. 31, 2024, is shown by fuel type in **Figure 6.37**.

Figure 6.37: North Carolina – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



Read More
Changing Capacity Mix and Deliverability

6.8.4 — Interconnection Requests

In North Carolina, as of Dec. 31, 2024, 59 projects were actively under study or under construction as shown in the summaries presented in **Table 6.40**, **Table 6.41**, **Figure 6.38**, **Figure 6.39** and **Figure 6.40**.

NOTE:
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.

Read More
Interconnection Requests

Table 6.40: North Carolina – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	North Carolina Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	160	6.75%	20,162	14.38%
Hydro	0	0.00%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	0	0.00%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	0	0.00%	64	0.05%
Solar	2,011	84.57%	55,040	39.25%
Storage	150	6.31%	39,064	27.86%
Wind	56	2.37%	17,455	12.45%
Grand Total	2,378	100%	140,231	100%

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Table 6.41: North Carolina – Interconnection Requests by Fuel Type (Dec. 31, 2024)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-renewable	Wood	0	0.0	0	0.0	1	50.0	1	80.0	2	130.0
	Storage	9	150.0	0	0.0	0	0.0	10	438.5	19	588.5
Renewable	Hybrid	6	160.4	0	0.0	0	0.0	13	853.2	19	1,013.6
	Methane	0	0.0	0	0.0	0	0.0	1	12.0	1	12.0
	Solar	39	1,878.5	4	132.4	28	860.2	87	4,065.1	158	6,936.2
	Wind	1	56.4	0	0.0	2	51.5	9	195.3	12	303.2
	Grand Total	**55**	**2,245.3**	**4**	**132.4**	**31**	**961.7**	**121**	**5,644.1**	**211**	**8,983.5**

Figure 6.38: North Carolina – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

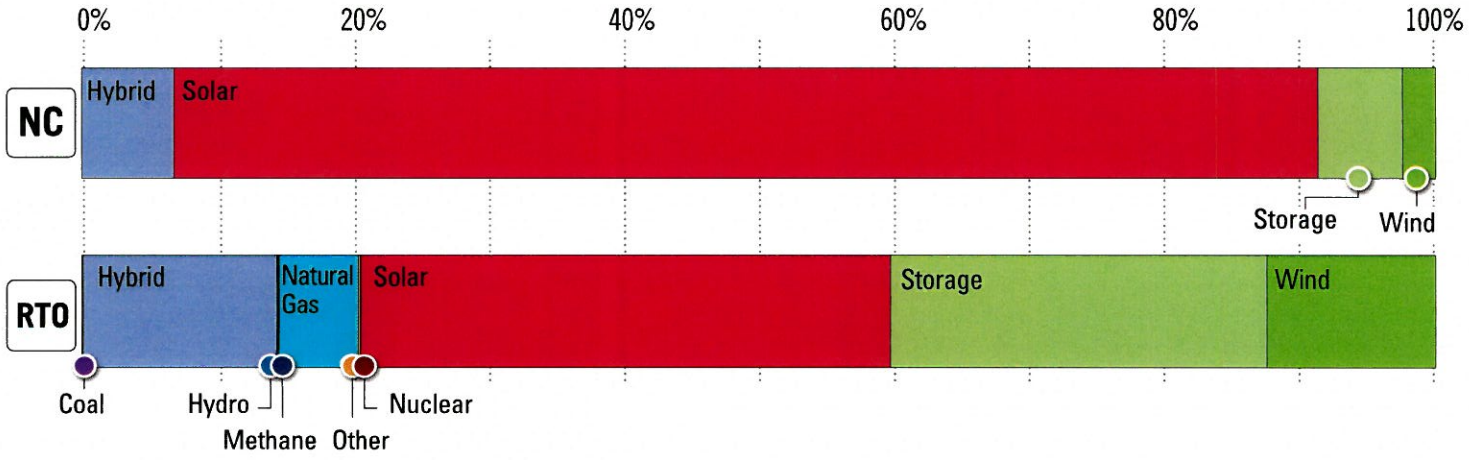

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Figure 6.39: North Carolina Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

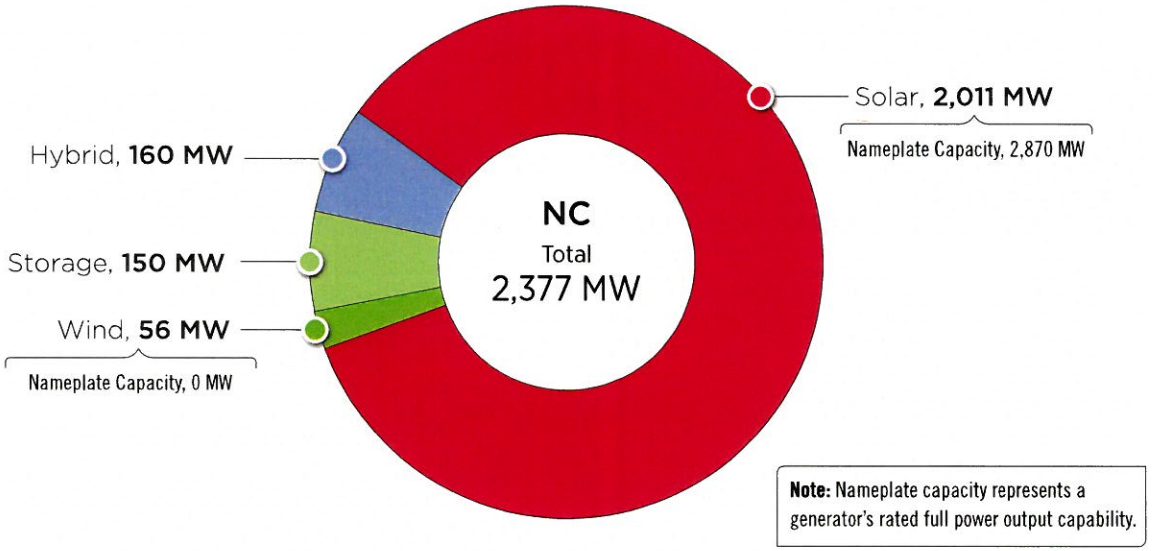

Figure 6.40: North Carolina Progression of Interconnection Requests (Dec. 31, 2024)

Percentage of planned capacity and projects that have reached commercial operation

13.3%	Requested capacity megawatts
16.7%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	7	Interconnection Service Agreements	234 MW	744 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, 2024.

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6.8.5 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in North Carolina are summarized in **Map 6.34** and **Table 6.42**.

Read More
Baseline Projects

Map 6.34: North Carolina Baseline Projects (Dec. 31, 2024)

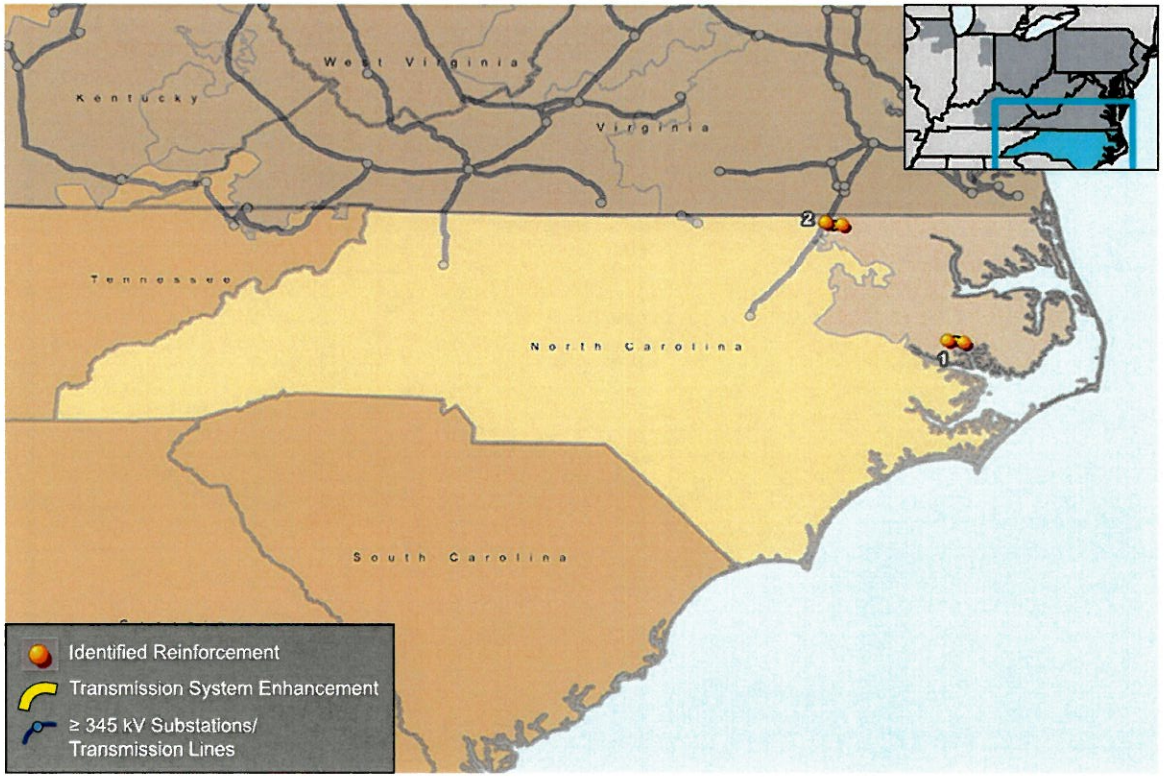

Table 6.42: North Carolina Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3922.1	This project serves to wreck and rebuild 115 kV line 1031 from structure 1031/220 to structure 1031/329. The existing structures to be removed are primarily single circuit wood, steel or concrete monopoles. The existing structures to be removed were primarily constructed in 1993 with the weathering steel structures being constructed in 2011. The existing structures shall be replaced one for one within the existing right-of-way using single circuit steel monopoles on foundations. The line will be rebuilt with single circuit 3-phase 768.2 ACSS/TW/HS (20/7) "Maumee" conductor and single DNO-11410 OPGW, respectively.	6/1/2029	$29.37	Dominion	12/12/2024
2	B4000.311	Rebuild 230 kV line No. 213 and No. 225 from Thelma-Lakeview. New conductor has a summer rating of 1573 MVA.		$44.69		1/7/2025
	B4000.312	At Thelma subsation, upgrade line lead, wave traps (213WT & 225WT), circuit breaker leads to 4000A. Circuit breaker switches 22535, 23235, 23238 and 21335 will also be upgraded to 4000A DEB switches. CCVTs 213P1, 213P2 and 213P3 will be replaced due to aging.		$2.30		
	B4000.313	At Lakeview substation, upgrade wave traps 213WT and 225WT, line leads and circuit breaker leads to 4000A. Upgrade circuit breader switches 22565 and 22564 to 4000A double-end break switches. Replace CCVTs 225P1, 225P2 and 225P3 due to aging.		$1.72		

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6.8.6 — Network Projects

Network projects in North Carolina for 2024 are summarized in **Map 6.35** and **Table 6.43**.

Read More
Network Projects

Map 6.35: North Carolina Network Projects (Dec. 31, 2024)

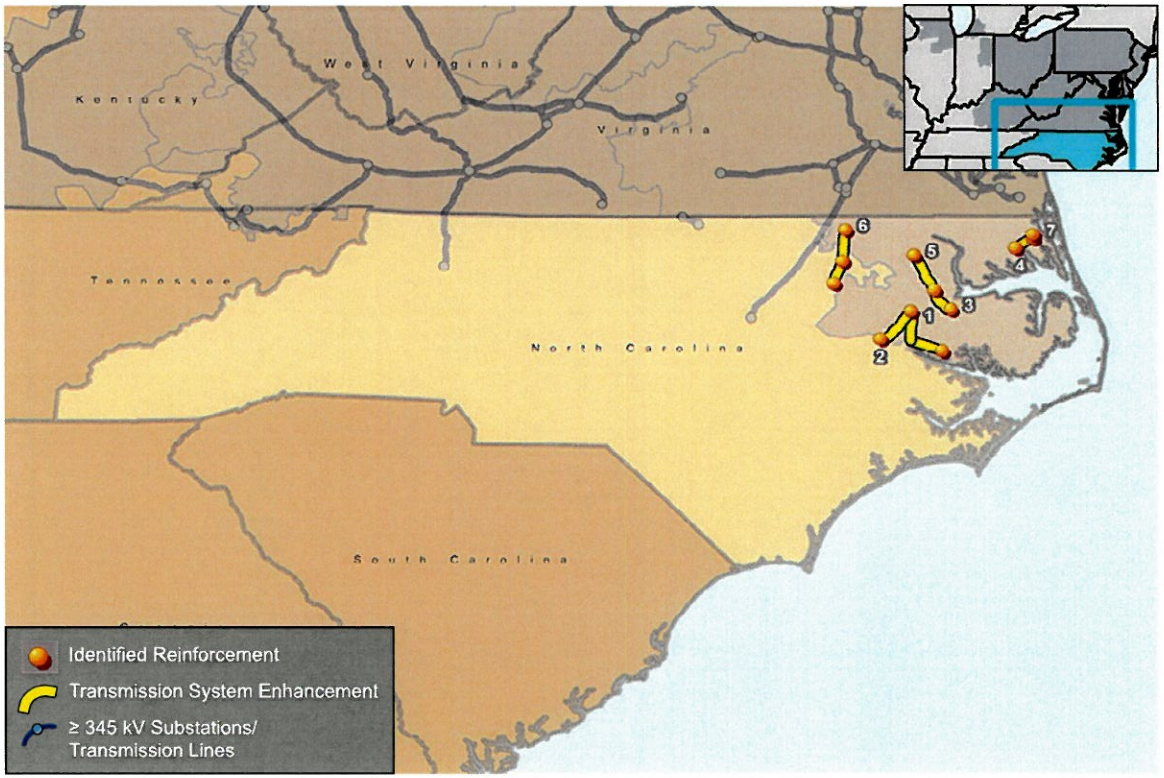

Table 6.43: North Carolina Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N6141	Replace relay at Everetts 115 kV; rating after the upgrade: 300/300/345.	AD1-076	6/1/2021	$0.50	Dominion	10/8/2024
	N6142	Rebuild 5.14 miles 636 ACSR between AB2-169 tap 115 kV and 3FIVE PT 115 kV circuit 1; rating after the upgrade: 261/261/301.			$6.68		
2	N6144	Rebuild DEV portion 20.5 miles 2-636 ACSR and rebuild 17.5 miles 2-636 ACSR between 6GREENVILE T-6EVERETS 230 kV substations. Rating after the upgrade: 1047/1047/1204.	AD1-023	6/1/2019	$39.92		

Table 6.43: North Carolina Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	N6287	Trowbridge 230/115 kV substation reconfiguration. 230 kV yard changes: Expand 230 kV yard to accommodate additional rung of 230 kV breakers. This will require relocation of existing 115 kV equipment. Relocate transformer No. 1 to accommodate new rung of 230 kV breakers. Install one new 230 kV breaker and two new 230 kV backbones. Reterminate line 2126 on new rung; will require T-line reconfiguration outside of station. Terminate new AD1-074/75/76 line on new rung. Will require T-line reconfiguration outside of the station to utilize existing 115 kV line 25 station entrance infrastructure. 115 kV yard changes: Expand station to the north and rebuild entire 115 kV yard (eight breakers, four backbones). Reterminate all four existing 115 kV lines. Line 1020 and line 25 will require significant T-Line reconfigurations outside of the station.	AD1-074	6/1/2021	$8.10	Dominion	10/8/2024
	N6287.1	Add additional 230 kV breaker at Trowbridge to prevent loss of transformer No. 1 upon fault on 230 kV line 2034 in stuck breaker scenario.		6/21/2021	$0.62		
	N6287.2	Add two breakers in the Trowbridge 230 kV substation to accommodate AD1-074/75/76.		6/1/2020	$4.00		1/9/2024
	N8190	Rearrange lines 167, 168 and 2126 and reroute lines 25 and 1020 at Trowbridge substation and route developer transmission line into Trowbridge substation.			$3.17		
4	N6314	Shawboro-Elizabeth City 230 kV line No. 2021	AD1-057		$15.42		
5	N8070.1	Rearrange line No. 2034 to loop into and out of the new three-breaker AD1-022/023 230 kV switching station.	AD1-022	6/1/2019	$1.42		
	N8070.2	Remote protection and communication work: Additional protection and communication work to be required at Cashie, Earleys and Trowbridge 230 kV substations.			$3.38		
	N8070.3	This project provides for the initial construction of a new 230 kV three-breaker ring substation between transmission structures 2034/220 and 2034/221. The objective of this project is to build a 230 kV, three-breaker ring bus to support the new 120 MW solar farm built by Sumac Solar, LLC. The site is located along Dominion Energy's existing 230 kV, 2034 line from Earleys to Trowbridge. The cut line will consume two of the positions in the ring bus. The third position will be for the 230 kV feed from Sumac Solar, LLC collector station for the new 120 MW solar farm.			$6.43		10/8/2024
6	N8167.1	Rearrange line No. 2056 to loop into and out of the new three-breaker AD1-056/AD1-057 230 kV switching station.	AD1-057	8/14/2017	$1.71		
	N8167.2	Build a three-breaker AD1-056/AD1-057 230 kV switching station.			$7.19		
	N8167.3	Remote protection and communication work at Hathaway 230 kV and Hornertown 230 kV substations			$0.07		
7	N8432.1	Rearrange line No. 269 to loop into and out of the new three breaker AE1-072 230 kV switching station.	AE1-072	6/1/2026	$3.89		
	N8432.2	Remote protection and communication work			$0.43		
	N8432.3	Build a three-breaker AE1-072 230 kV switching station.			$1.06		

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6.8.7 — Supplemental Projects

Supplemental projects included in the 2024 Local Plan in North Carolina are summarized in **Map 6.36** and **Table 6.44**.

Read More
Supplemental Projects

Map 6.36: North Carolina Supplemental Projects (Dec. 31, 2024)

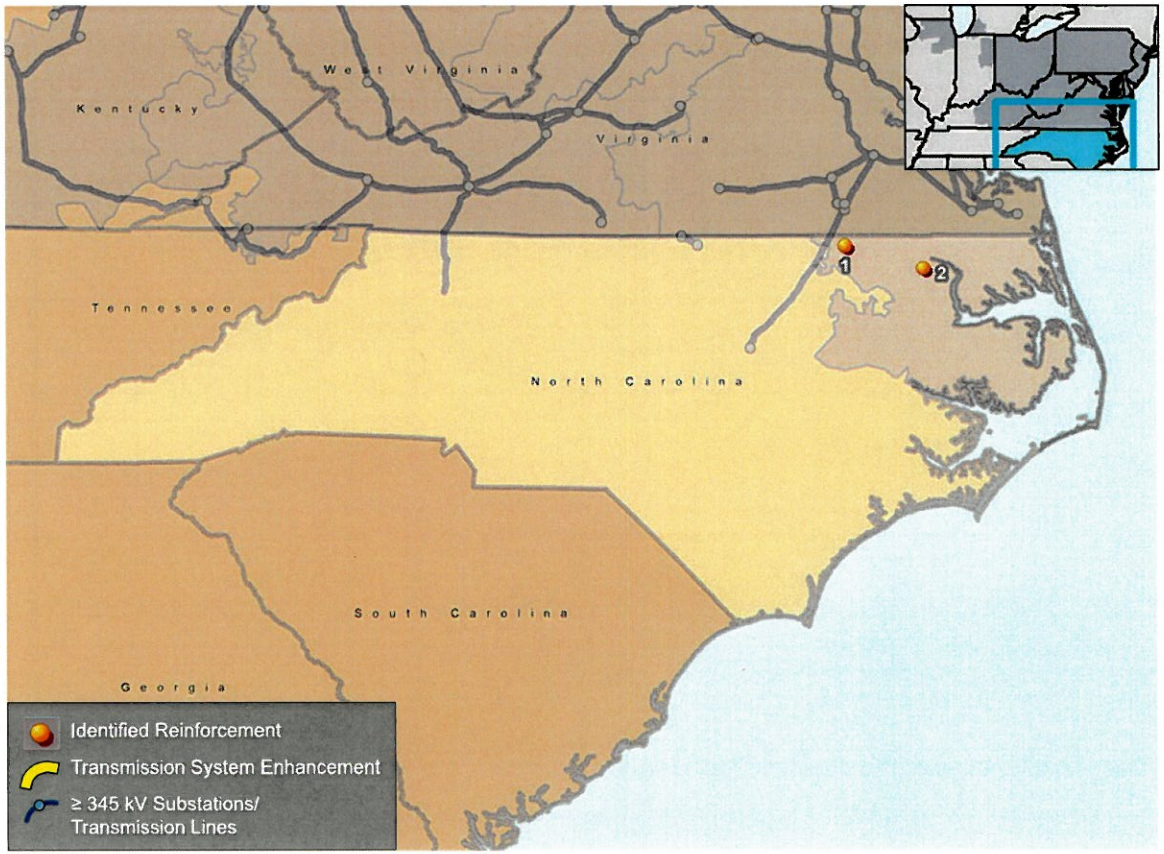

Table 6.44: North Carolina Supplemental Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S3038	Rebuild an ~1.8 miles of single-circuit 115 kV line No. 77 from Carolina to Roanoke Rapids hydro to current 115 kV standards, and with a conductor minimum summer normal rating of 262 MVA. The terminal ends should be upgraded as needed.	12/31/2023	$7.40	Dominion	8/18/2022
2	S3063	Tap 230 kV line No. 246 (Earleys-Suffolk) near structure 246/290 and extend a single-circuit 230 kV line to Firetower Road sub.		$5.00		4/11/2023

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6.9: Ohio RTEP Summary

6.9.1 — RTEP Context

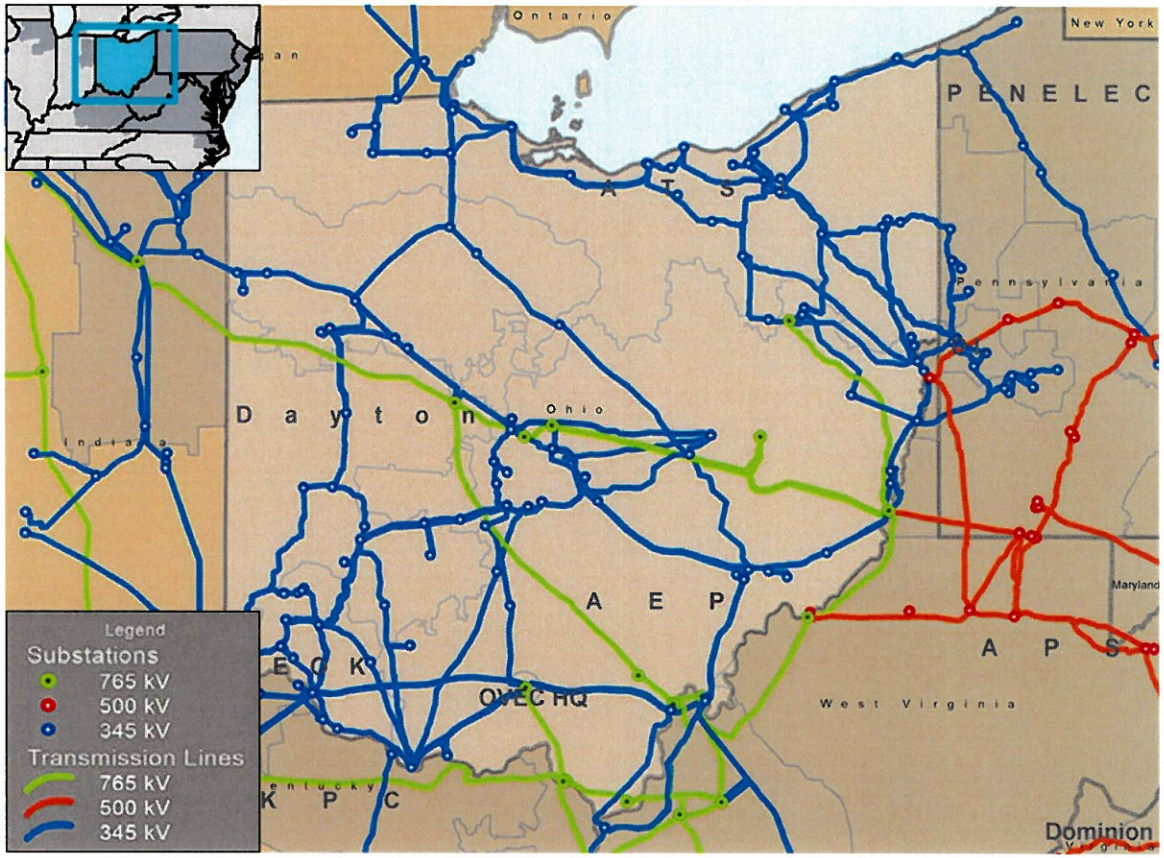
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Ohio, including facilities owned and operated by American Electric Power (AEP), AES Ohio, American Transmission Systems, Inc. (ATSI) [FirstEnergy], Duke Energy Ohio and Kentucky (DEO&K), the city of Cleveland and the city of Hamilton as shown on **Map 6.37**.

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 the PJM service area.

Renewable Portfolio Standards

Ohio has a mandatory renewable portfolio standard (RPS) target of 8.5% by 2026.

Map 6.37: PJM Service Area in Ohio



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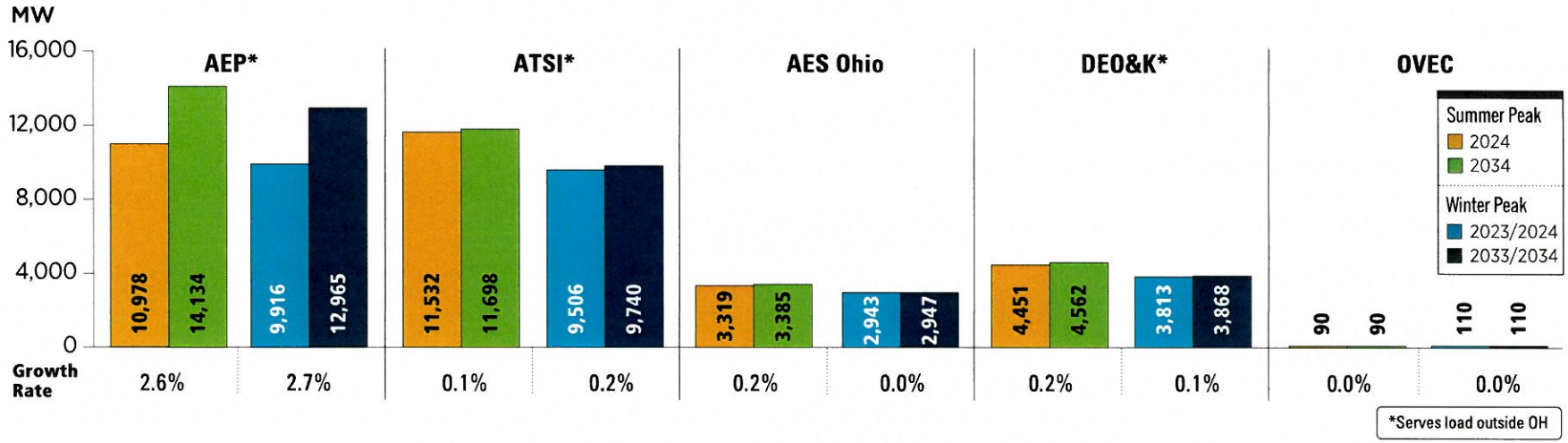
6.9.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.41** summarizes the expected loads within the state of Ohio and across PJM.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.41: Ohio – 2024 Long-Term Load Forecast



PJM RTO Summer Peak		PJM RTO Winter Peak	
2024	2034	2023/2024	2033/2034
151,247 MW	176,822 MW	134,659 MW	163,069 MW
Growth Rate 1.6%		Growth Rate 1.9%	

PJM notes that AEP, ATSI (FirstEnergy) and Duke Energy Ohio and Kentucky serve load other than in Ohio. The summer and winter peak megawatt values in this figure each reflect an estimated amount of forecasted load to be served by each of those transmission owners solely in Ohio. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Ohio over the past five years.

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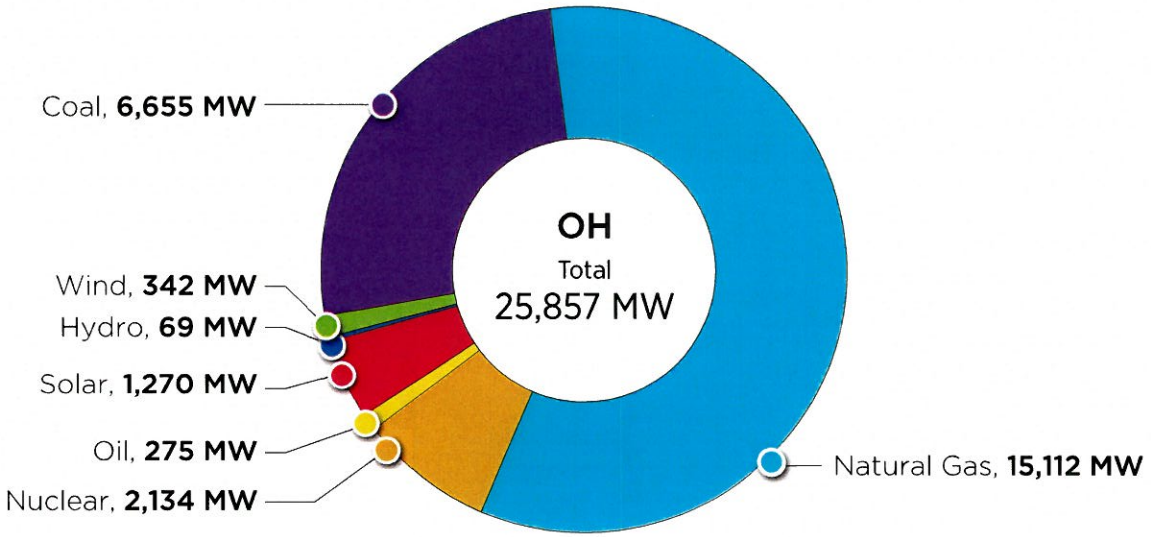
6.9.3 — Existing Generation

Existing generation in Ohio as of Dec. 31, 2024, is shown by fuel type in **Figure 6.42**.

Figure 6.42: Ohio – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



6.9.4 — Interconnection Requests

In Ohio, as of Dec. 31, 2024, 301 projects were actively under study or under construction as shown in the summaries presented in **Table 6.45**, **Table 6.46**, **Figure 6.43**, **Figure 6.44** and **Figure 6.45**.

NOTE:
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 6.45: Ohio – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	Ohio Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	18	0.09%	54	0.04%
Hybrid	2,721	13.53%	20,162	14.38%
Hydro	0	0.00%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	1,446	7.19%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	51	0.25%	64	0.05%
Solar	11,868	59.02%	55,040	39.25%
Storage	3,512	17.47%	39,064	27.86%
Wind	493	2.45%	17,455	12.45%
Grand Total	20,109	100%	140,231	100%

Table 6.46: Ohio – Interconnection Requests by Fuel Type (Dec. 31, 2024)

		In Queue				Complete				Grand 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	18.0	11	230.0	16	8,923.0	28	9,171.0
	Natural Gas	7	595.5	1	850.0	36	7,552.3	38	15,095.4	82	24,093.2
	Oil	0	0.0	0	0.0	1	1.5	1	5.0	2	6.5
	Diesel	0	0.0	0	0.0	1	7.0	0	0.0	1	7.0
	Nuclear	0	0.0	0	0.0	1	16.0	0	0.0	1	16.0
	Other	3	39.7	1	11.0	0	0.0	1	135.0	5	185.7
	Storage	33	3,512.4	0	0.0	5	0.0	62	4,395.3	100	7,907.7
Renewable	Hybrid	31	2,664.1	2	57.3	0	0.0	30	2,291.1	63	5,012.5
	Hydro	0	0.0	0	0.0	1	112.0	8	76.2	9	188.2
	Biomass	0	0.0	0	0.0	1	0.0	3	185.0	4	185.0
	Methane	0	0.0	0	0.0	7	37.7	10	26.1	17	63.8
	Solar	194	11,014.6	18	853.8	25	1,617.1	265	10,191.3	502	23,676.8
	Wind	10	492.5	0	0.0	8	197.4	80	2,069.9	98	2,759.8
	Grand Total	**278**	**18,318.9**	**23.0**	**1,790.1**	**97**	**9,771**	**514.0**	**43,393.3**	**912**	**73,273.3**

Figure 6.43: Ohio – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

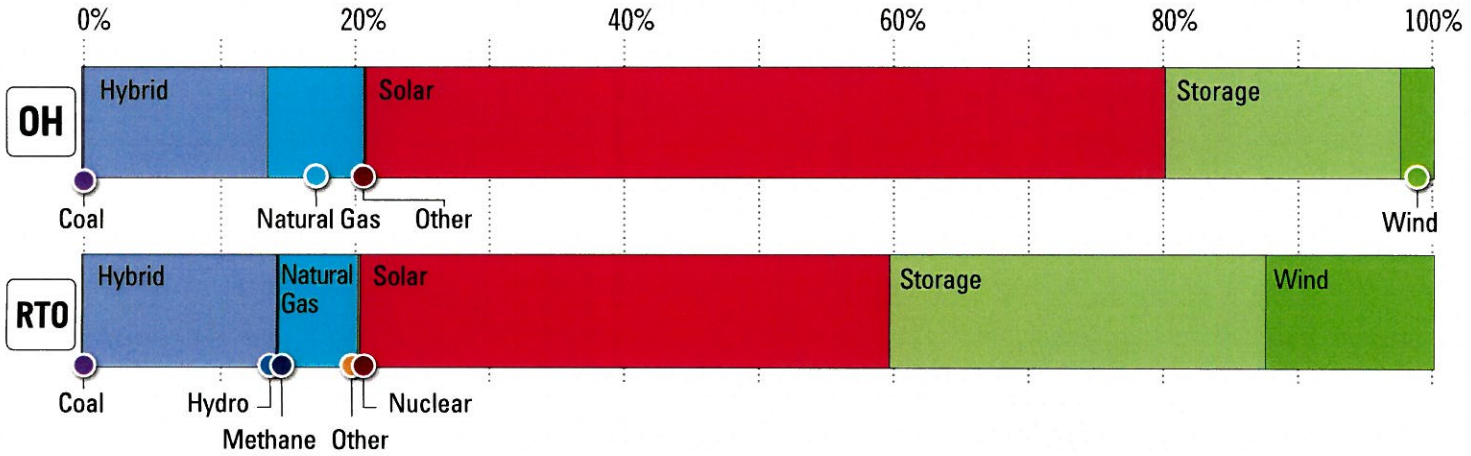


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Figure 6.44: Ohio Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

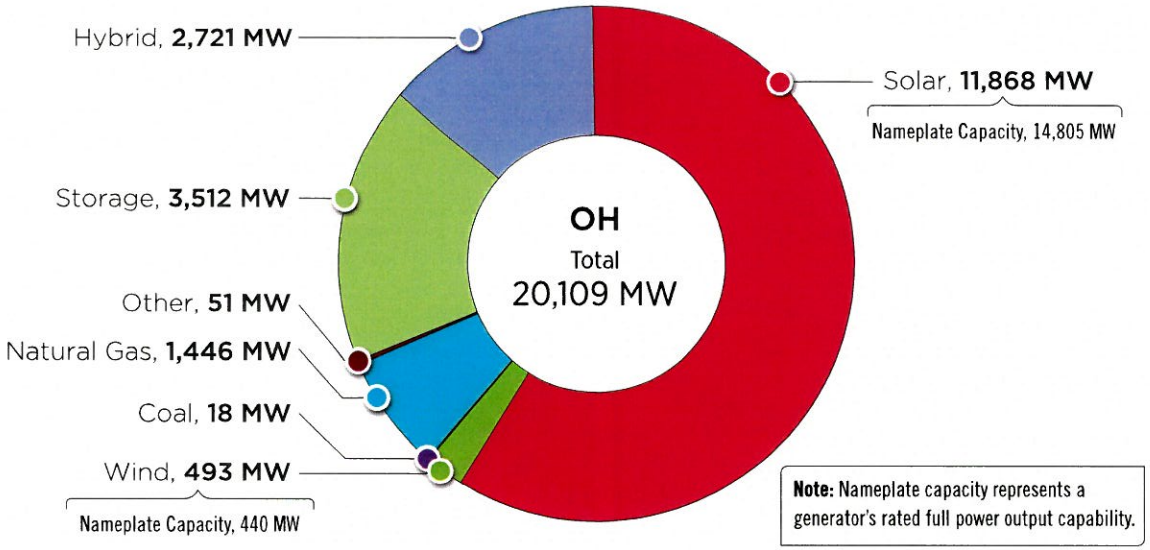

Figure 6.45: Ohio Progression of Interconnection Requests (Dec. 31, 2024)

Percentage of planned capacity and projects that have reached commercial operation

16.6%	Requested capacity megawatts
13.4%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	33	Interconnection Service Agreements	5,849 MW	8,360 MW
	16	Wholesale Market Participation Agreements	22 MW	91 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, 2024.

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6.9.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Ohio between Jan. 1, 2024, and Dec. 31, 2024, are summarized in **Map 6.38** and **Table 6.47**.

Read More
Baseline Projects

Map 6.38: Ohio Generation Deactivations (Dec. 31, 2024)

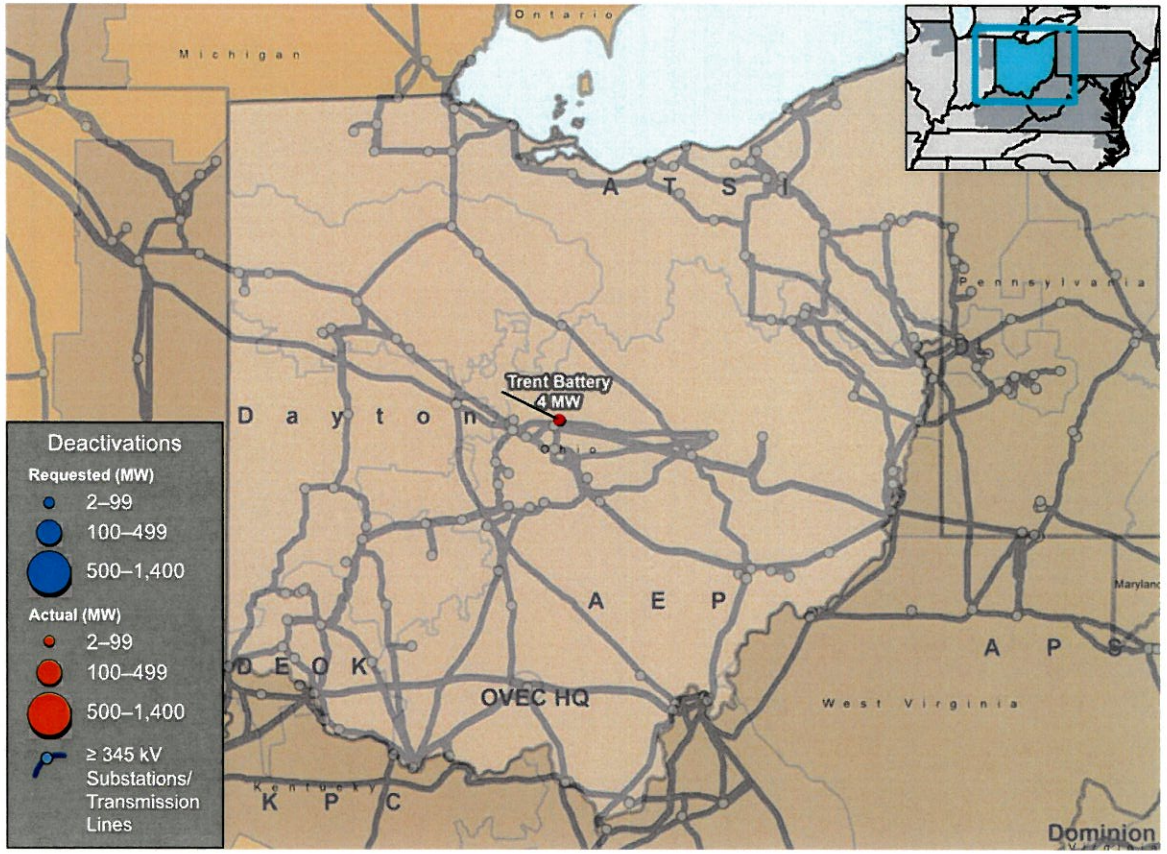

Table 6.47: Ohio Generation Deactivations (Dec. 31, 2024)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Trent Battery	AEP	Battery	9/22/2023	1/1/2024	10	4

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6.9.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in Ohio are summarized in **Map 6.39** and **Table 6.48**.

Read More
Baseline Projects

Map 6.39: Ohio Baseline Projects (Dec. 31, 2024)

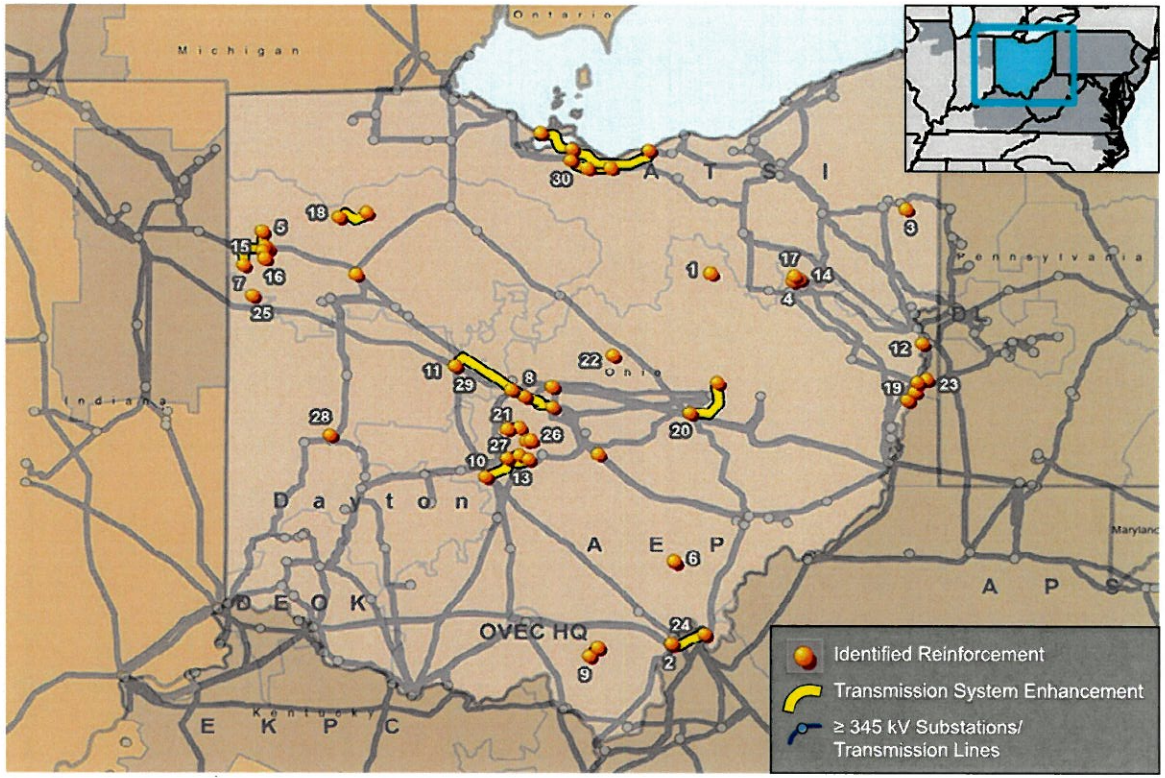

Table 6.48: Ohio Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3784.1	Replace 138 kV breaker 5 at Canal St. station with a new 3000A 63 kA breaker.	6/1/2028	$0.50	AEP	11/17/2023
2	B3788.1	Replace AEP-owned station takeoff riser and breaker BB risers at OVEC-owned Kyger Creek station.		$0.41		12/5/2023
3	B3789.0	A 69 kV, 60 MVAR shunt reactor will be installed at the Salt Springs substation. The reactor terminal will be connected to the existing 69 kV bus, and an independent-pole operation, 1200A circuit breaker will be installed for reactor switching.		$5.45	ATSI	11/17/2023
4	B3838.1	Replace breaker A and B at Timken station with 40 kA breakers.		$1.20	AEP	
5	B3839.1	Replace 69 kV breaker C at Haviland station with a new 3000A 40 kA breaker.		$0.40		

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Table 6.48: Ohio Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
6	B3843.1	Rebuild the underground portion of the Ohio University-West Clark 69 kV line, an ~0.65 miles.	6/1/2028	$4.60	AEP	11/17/2023
7	B3851.2	Rebuild R.P. Mone-Maddox Creek 345 kV line (9.4 miles).	6/1/2027	$39.03		7/9/2024
	B3851.3	Replace breakers 'B1' and 'B' at Maddox Creek.		$1.80		
	B3851.4	Replace two 345 kV breakers 'M' and 'M2' at East Lima station.		$1.76		
8	B3852.1	Connect and energize a second 765/345 kV bank at Vassell station.		$30.83		
	B3852.2	Replace 765 kV breaker D at Maliszewski station.		$2.90		
9	B3875.1	Reconductor ~3.95 miles of ACSR 6/1 Penguin (4/0) on the Firebrick-Jefferson switch 69 kV branch with ACSR 556.6 26/7. The remote end (line setting) would need to be updated at Firebrick and Lick. Replace 600A switches at Jefferson and replace 477 AA 19 substation conductor at Firebrick.	6/1/2029	$8.50		11/15/2024
10	B3877.1	Project will replace station conductor and switches in the 345 kV yard at Beatty that are currently limiting the 345 kV lines to Adkins and Chenoweth		$0.50		12/3/2024
	B3877.2	Project will upgrade 345 kV circuit breakers 'A' and 'A1' to 4000A 63 kA breakers at Adkins station along with some station conductor that is currently limiting the 345 kV line to Beatty.		$4.50		
11	B3878.1	Proposal will upgrade 765 kV circuit breakers 'B' and 'B2' 'to 5000A 50 kA breakers at Marysville station. In addition, the project will upgrade the existing wavetrap towards Sorenson.		$10.00		1/7/2025
12	B3879.1	Replace line conductor, ~0.11 miles of 4/0 ACSR 6/1 conductor with 556.5 26/7 between South Toronto and the South Toronto tap.		$0.50		11/15/2024
	B3879.2	Upgrade the wave trap, CCVTs, switches and station conductor at South Toronto station currently limiting the line to South Toronto tap.		$0.60		
13	B3880.1	At Beatty Road substation, install a 69 kV 23 MVAR capacitor bank along with the 69 kV Cap bank breaker.		$2.25		
14	B3882.1	Replace 138 kV circuit breaker BB with higher fault current-capable counterpart.	6/1/2026	$1.00		
15	B3883.1	69 kV station equipment, including relays, conductor and switches, will be replaced at Haviland station in order to address identified overloads on the lines to North Van Wert and Cavett.	12/1/2029	$0.80		
16	B3884.1	Replace the 69 kV circuit breaker D at Van Wert with a 40 kA breaker.	6/1/2026	$1.00		
17	B3885.1	Replace 69 kV circuit breakers N and M at Schroyer Avenue station with higher fault current capable counterparts.		$2.00		
18	B3888.1	Preform sag study and complete mitigations on the 138 kV line between East Leipsic and the AE2-072 tap (Lammer) to allow line's conductor to operate to its maximum operating temperature (MOT).	6/1/2029	$2.50		
19	B3889.1	Project will replace limiting station equipment at Tiltonsville station to increase the rating on the branch to Windsor.		$0.80		
20	B3890.1	Replace station conductor at South Coshocton station currently limiting the branch to Ohio Central.		$0.20		
21	B3891.1	Project will perform relay upgrades at Kenny 138 kV to raise the CT and relay thermal limits that are currently limiting the line to Roberts.		$0.40		
22	B3892.1	Replace 69 kV circuit breakers A and S at Mount Vernon station with 40 kA breakers.	6/1/2026	$2.00		
23	B3894.1	Replace limiting station conductor at Tidd on the line to Carnegie (FE).	6/1/2029	$0.50		
24	B3899.1	Replace OVEC-owned station equipment at Kyger Creek to raise the rating of the Kyger Creek-Sporn 345 kV line. Equipment to be replaced includes station conductor and a wave trap at Kyger Creek.		$0.80	OVEC	1/7/2025
25	B3904.1	Rebuild and reconductor 7.7 miles of 69 kV line with our standard 1351 AAC conductor from Rockford substation to the point of interconnection.	4/15/2029	$25.00	AES Ohio	1/17/2025

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Table 6.48: Ohio Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
26	B3911.1	Rebuild the existing 1.1-mile Canal-Gay 138 kV oil-filled pipe-type underground line to address overloads on the existing cable utilizing 5000 MCM XLPE cable.	6/1/2029	$15.60	AEP	12/3/2024
	B3912.1	Rebuild the existing 2.2-mile Canal-Mound St 138 kV oil-filled pipe-type underground line to address overloads on the existing cable utilizing 5000 MCM XLPE cable.		$31.09		
27	B3913.1	Rebuild 138 kV line section between Beatty and White Road stations (an ~4.5 miles). Update remote end relay settings as needed.		$18.80		
	B3913.2	Rebuild 138 kV line section between White Road and Cyprus stations (an ~3.34 miles). Update remote end relay settings as needed.		$14.31		
28	B3918.1	Add one additional breaker, a 2nd 138/69 kV transformer; replace five 69 kV breakers & four 138 kV breakers.		$12.00	AMP	1/17/2025
29	B3919.1	Reconfigure Maliszewski 765 kV station from two breakers to a six-breaker ring bus. Install a new 765/345 kV transformer. Establish new 345 kV breaker yard with three-string breaker and a half to include a line exit to Hyatt and a line exit to Corridor. Loop the existing Hyatt-West Millersport 345 kV line into the newly established 345 kV yard at the Maliszewski station.		$79.74	AEP	12/3/2024
	B3919.2	Establish a 0.18-mile double circuit 345 kV line extension to cut the existing Hyatt-West Millersport 345 kV line in and out of Corridor station.		$3.10		
	B3919.3	Install three new 345 kV breakers at Corridor station in order to accommodate the cut in of the Hyatt-West Millersport 345 kV line.		$5.52		
	B3919.4	Reconductor 10.2-mile of Maliszewski-Corridor 345 kV line.		$18.30		
	B3919.5	Reconductor 4.75 miles of the existing Bokes Creek-Marysville 345 kV circuit. Update the associated relay settings.		$6.67		
	B3919.6	Rebuild 4.4 miles of the existing Marysville-Hyatt 345 kV double circuit line where it extends into Marysville station.		$26.26		
	B3919.7	Upgrade 345 kV breakers K & K1 along with associated switches and conductor to 5000A at Hyatt station.		$2.94		
	B3919.8	Upgrade the relaying and associated equipment at West Millersport station to coordinate with the cut-in work to Corridor station.		$0.41		
	B3919.9	Upgrade 3000A, 345 kV breaker 'L2' along with associated terminal elements to 5000A at Marysville.		$2.56		
	B3919.10	Rebuild ~19 miles of Hyatt-Marysville 345 kV line using four-bundled 795 ACSR conductor bold construction (EOL rebuild).		$116.70		1/7/2025
30	B3925.1	Rebuild the 7.46 miles of Avery-Shinrock 138 kV line with 795 kcmil 26/7 ACSS (7.46 miles).		$15.20	ATSI	
	B3925.2	Rebuild the 13.45 miles of Greenfield-Lakeview 138 kV line from 2 x 336.4 kcmil 26/7 ACSR to 1 x 795 kcmil 26/7 ACSS.		$59.68		
	B3925.3	Rebuild the 6.5 miles of Avery-Hayes 138 kV line with 795 kcmil 26/7 ACSS conductor.	6/1/2027	$11.01		
	B3925.4	Rebuild the Greenfield-Beaver 138 kV corridor (32 miles) with 795 kcmil 26/7 ACSS. This corridor encompasses multiple 138 kV lines that are constructed on common towers.	6/1/2029	$131.43		

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6.9.7 — Network Projects

Network projects in Ohio for 2024 are summarized in **Map 6.40** and **Table 6.49**.

Read More
Network Projects

Map 6.40: Ohio Network Projects (Dec. 31, 2024)

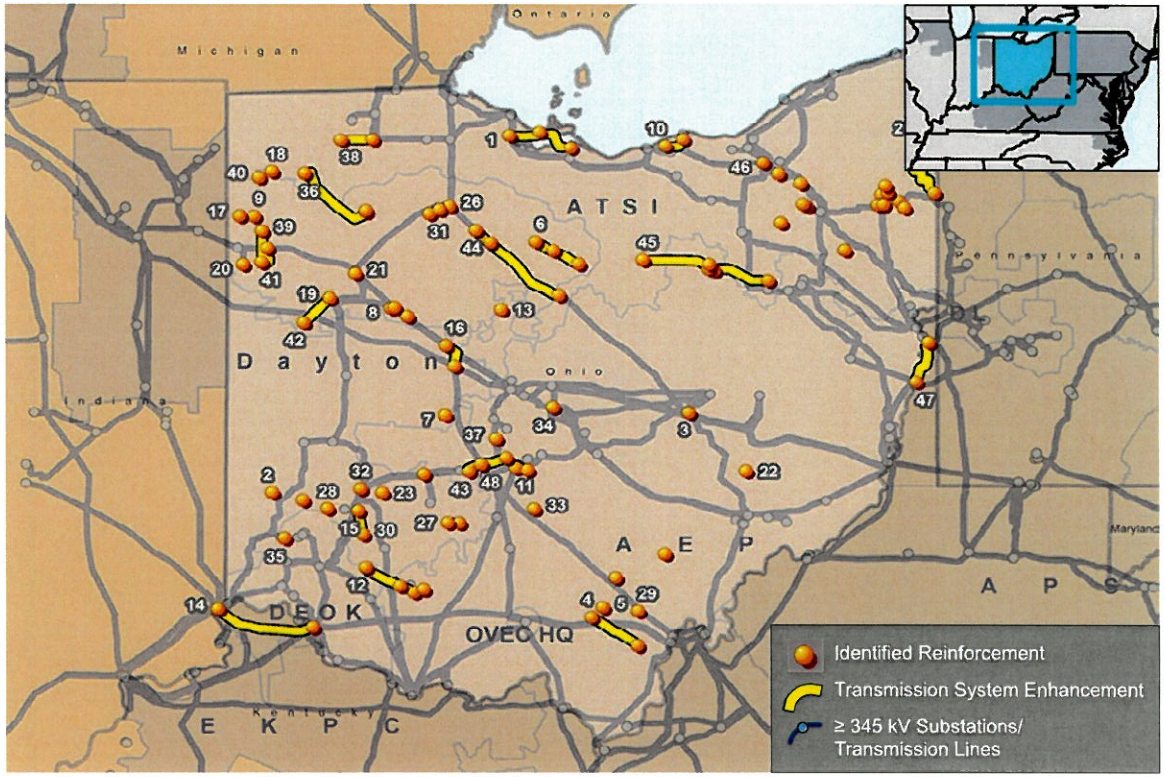

Table 6.49: Ohio Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N4173	Un-six wire the existing Lakeview-Ottawa and Lakeview-Greenfield 138 kV lines, creating a new third line in the process, Ottawa-Greenfield 138 kV.	AB1-107	6/1/2015	$3.52	ATSI	10/8/2024
2	N5520	Protection system changes at Crystal 69 kV substation	AC2-067	7/1/2019	$0.12	AES Ohio	
	N5521	Protection system changes at Hutchings 69 kV substation			$0.50		
3	N5583	Install 138 kV revenue metering at the Ohio Central substation.	AC1-100	11/1/2017	$0.25	AEP	1/9/2024

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Table 6.49: Ohio Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	N5669	Modify Rio to Lick 138 kV transmission line cut-in.	AC1-188	10/31/2016	$1.07	AEP	10/8/2024
	N5670	Install 138 kV revenue meter, generator lead transmission line span from the new Terrapin 138 kV station to the point of interconnection, and install two diverse fiber-optic paths from the point of interconnection to the Terrapin 138 kV station control house.			$0.83		
5	N5674	Rebuild and expand the existing Elk 138 kV station by removing the two existing 138 kV box bays and associated equipment and installing a new five-breaker 138 kV station, physically designed as a six-position breaker-and-a-half station but operated as a five-breaker ring bus. The two existing 138 kV circuit breakers will be reused, and three new 138 kV circuit breakers will be installed. A 16' x 12' DICM expansion will be added to existing Elk 138 kV station control house. Install other associated line protection and control equipment, 138 kV line risers, switches, jumpers, and supervisory control and data acquisition (SCADA) equipment. Review and update remote end protection relay settings at the Corwin and Lemaster 138 kV stations.	AC1-194		$6.72		
	N5675	Reroute and reterminate the Corwin-Elk and Elk-Lemaster 138 kV circuits to a new bay position in the rebuilt Elk 138 kV station.			$0.70		
	N5676	Install a portion of 138 kV generator lead line from the Elk 138 kV station to the point of change of ownership with interconnection customer, 138 kV revenue meter, and dual fiber-optic cable from the Elk 138 kV station control house to interconnection customer's fiber connection/transition.			$0.95		
	N8456	Review the protection and control settings at the Elk 138 kV station and adjust as needed. Review the Elk 138 kV station relay settings.	AE1-093	12/31/2021	$0.05		
6	N5699	Install 138 kV revenue meter, generator lead transmission line span from the new Red Run 138 kV station to the point of interconnection, and install two diverse fiber-optic paths from the point of interconnection to the Red Run 138 kV station control house.	AC2-015	3/21/2019	$0.61		
	N5700	Install new 138 kV three-breaker ring bus station along the Chatfield-Howard 138 kV line; installation of associated protection and control equipment, line risers, switches, jumpers, and supervisory control and data acquisition (SCADA) equpment.			$5.44		
	N5701	Chatfield-Crawford 138 kV T-line cut-in			$1.10		
	N5702	Install new SFP transceivers and update protective relay settings at Chatfield and Howard 138 kV stations.			$0.08		
	N5703	Install one fiber-optic path to the AEP network to facilitate relaying between Red Run, Howard and Melmore 138 kV stations.			$0.56		
7	N5865	Install attachment facility line, line disconnect switch and associated hardware to accept the interconnection customer generator lead line terminating at the AD2-163 interconnection switching station. Install customer-owned revenue metering at the AD2-163 facility.	AD2-163	12/1/2021	$0.50	ATSI	1/9/2024
	N5866	138 kV three-breaker ring bus generation interconnection @ AD2-163 interconnection SS			$11.16		
8	N5986	Settings changes will need to be reviewed; the estimated cost for relay setting review/revision for AD1-130 is $25,000.	AD1-130	12/31/2019	$0.03	AEP	
9	N6032	AC1-173 relay settings – Convert two-terminal gen lead to three-terminal gen lead (n5648).	AC1-173	10/31/2019	$0.06		
	N6033	AC1-173 fiber system modifications (n5474)			$0.01		
10	N6185	Build a new 138 kV line from Black River to Astor substation.	AE1-119	6/1/2022	$18.67	ATSI	10/8/2024
11	N6263.2	Replace 600 amp Sw at Harrison to upgrade the Harrison-Zuber 138 kV line.	AE1-093	12/31/2020	$0.20	AEP	

Table 6.49: Ohio Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
12	N6634.1	New 138 kV switching station – Construct a new three-circuit breaker 138 kV switching station physically configured in a breaker-and-a-half bus arrangement but operated as a ring bus for AC2-061 interconnection.	AC2-061	7/1/2020	$6.00	AEP	10/8/2024
	N6634.2	Install 138 kV revenue metering at Hillsboro-Clinton County 138 kV.			$0.25		
	N6634.3	Install Hillsboro-Clinton County 138 kV transmission line cut-in.			$1.00		
	N6634.4	Upgrade line protection and controls at the Hillsboro 138 kV substation to coordinate with the new AC2-061 138 kV switching station.			$0.25		
	N6634.5	Re-tune wave traps at two (Hillsboro and Clinton County 138 kV) substations and adjust relay settings at one.			$0.00		
13	N6712	Install AC2-195 ADSS fiber from the new AC2-195 interconnection substation to the anticipated ADSS cable near the intersection of Marion Williamsport Road and N Main Street proposed for PJM queue position AB2-131. The assumed route is a combination of aerial ADSS (0.87 miles) and underground bore (0.14 miles).	AC2-195	12/31/2020	$0.17	ATSI	
14	N6759.2	Replace two 1600A switches at Dearborn and four switches at Pierce on the Dearborn-Pierce 345 kV line.	AF1-202	12/31/2022	$9.00	OVEC	
15	N6950	Tap the Martinsville-Wilmington 69 kV line and install a three-way phase switch to interconnect the AD2-031 project. (One switch covering the generator lead line is considered an attachment facility.)	AD2-031	9/1/2019	$0.22	AES Ohio	1/9/2024
	N6951	Tap the Martinsville-Wilmington 69 kV line and install a three-way phase switch to interconnect the AD2-031 project. (Two network switches of the three-way switch are considered direct connection facilities.)			$0.45		
	N6952	Install a new 69 kV breaker at Martinsville substation. This will include the installation of all physical structures, P&C equipment, communications equipment, metering equipment and associated facilities.			$1.61		
	N6953	Protection system changes at Wilmington substation			$0.01		
	N7375	Tap the Martinsville-Wilmington 69 kV line and install a three-way phase switch to interconnect the AD2-031 project (two network switches of the three-way switch are considered direct connection facilities).			$0.45		
	N7376	Install a new 69 kV breaker at Martinsville substation. This will include the installation of all physical structures, P&C equipment, communications equipment, metering equipment and associated facilities.			$1.61		
	N7377	Protection system changes at Wilmington substation			$0.01		
16	N7245.1	345 kV revenue metering	AF1-227	9/30/2023	$0.43	AEP	
	N7245.2	Generator lead first span exiting the point of interconnection station, including the first structure outside the fence			$0.69		
	N7245.3	A three-circuit breaker 345 kV station physically configured and operated as a ring bus including associated protection and control equipment, 345 kV line risers and SCADA			$12.47		
	N7245.4	Install two structures, two spans of conductor; connect Bokes Creek 345 station to existing transmission circuit; update remote end protective relay settings.			$1.90		
	N7245.6	Install two fiber-optic paths to the AEP telecom network to facilitate SCADA connectivity at the Boke Creek station. Includes Telecom upgrades at the Marysville 345 kV substation.			$0.18		
17	N7287	Installation of gen tie line connecting Payne station to the IPP generator	AD1-119	9/28/2017	$0.11		
	N7288	Dual fiber telecom from Payne to the IPP station			$1.73		

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Table 6.49: Ohio Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
18	N7290	Construct generator lead first span exiting the point of interconnection station, including the first structure outside the fence at Lockwood Road 138 kV.	AF1-063	9/28/2017	$0.40	AEP	10/8/2024
	N7291	Install 138 kV revenue metering at Lockwood Road 138 kV substation.			$0.39		
	N7292	Upgrade line protections & controls at the Lockwood Road 138 kV substation.			$0.05		
19	N7293	Expand the Southwest Lima 345 kV substation: Install one additional 345 kV circuit breaker and extend the 345 kV bus. Install associated protection and control equipment, 345 kV line risers and SCADA.	AF1-164	9/20/2019	$1.76		
	N7294	Construct generator lead first span exiting the point of interconnection station, including the first structure outside the fence at South West Lima 345 kV.			$1.03		
	N7295	Install 345 kV revenue metering at South West Lima 345 kV substation.			$0.43		
20	N7355	Protection setting changes at East Lima, RP Mone and Maddox Creek	AC2-044	9/28/2017	$0.05		1/9/2024
21	N7364	Modify line settings at Hardin switch.	AD1-130		$0.08		
	N7365	Modify remote end settings at Gunn Road.			$0.02		
	N7366	Modify remote end settings at East Lima.			$0.02		
	N8060.1	Replace existing revenue meter CTs at Hardin switch 345 kV station.	AD2-086	3/20/2018	$0.24		
	N8060.2	Update protective relay settings at the Hardin, East Lima and Gunn Road 345 kV station.			$0.12		
	N8067.1	Update protective relay settings at the Hardin, East Lima and Gunn Road 345 kV station.	AD2-091		$0.12		
	N8068.1	Update protective relay settings at the Hardin, East Lima and Gunn Road 345 kV station.	AE2-216	3/21/2019	$0.12		
22	N7832	69 kV revenue meter, generator lead transmission line span from the South Cumberland 69 kV station to the point of interconnection, including the first structure outside the South Cumberland 69 kV station; extend dual fiber-optic from the point of interconnection to the South Cumberland 69 kV station control house.	AE1-227	9/28/2018	$0.77		
	N7833	Expand the South Cumberland 69 kV station, including the addition of one one 69 kV circuit breaker, installation of associated protection and control equipment, 69 kV line risers, and supervisory control and data acquisition (SCADA) equpment.			$0.79		
23	N7842	Revenue metering installation oversight	AE2-318	3/30/2019	$0.19	DEO&K	
	N7843	New 138 kV station oversight			$0.21		
	N7844	Ford-Cedarville 138 kV T-line loop in/out			$1.17		
	N7845	Perform remote protection and communication work at Ford and Cedarville substations to accommodate the interconnection switching substation.			$0.72		
	N7846	Distribution line extension for station power			$0.19		
24	N7879	Marysville 345 kV protection settings change	AD2-092	3/20/2018	$0.02	AEP	
25	N7929	Update relay settings at Masury 69 kV substation.	AE1-079	6/1/2020	$0.09	ATSI	10/8/2024
	N7932	Update relay settings at Dilworth 69 kV substation.			$0.09		

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Table 6.49: Ohio Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
26	N7962	138 kV revenue meter, generator lead transmission line span from the Fostoria Central 138 kV station to the point of interconnection, including the first four structures outside the Fostoria Central 138 kV station, and extend dual fiber optic from the point of interconnection to the Fostoria Central 138 kV station control house.	AD1-070	8/1/2017	$1.49	AEP	
	N7963	Expand the Fostoria Central 138 kV station, including the addition of one one 138 kV circuit breaker, installation of associated protection and control equipment, 138 kV line risers, and supervisory control and data acquisition (SCADA) equpment.			$0.85		
27	N8048.1	Robinson relaying: Upgrade the line relaying equipment at Robinson substation to prevent islanding.	AC1-068	12/31/2021	$0.64	AES Ohio	
	N8048.2	Washington C.H. relaying: Upgrade the line relaying equipment at Washington Courthouse substation to prevent islanding.			$0.40		
28	N8058	Modify relay settings.	AE2-315	6/1/2020	$0.02		
29	N8064.1	Review protection relay settings at the Flatlick 765 kV station.	AF2-395	3/31/2020	$0.05	AEP	
30	N8092	Replace protective relays, wave trap & CCVT at Highland 69 kV station.	AD2-031	9/1/2019	$0.53	AEP	
	N8099	Fiber installation to Wilmington and Martinsville tap			$0.85	AES Ohio	1/9/2024
31	N8130.1	138 kV revenue meter, generator lead transmission line span from the new Rocky Ford 138 kV station to the point of interconnection, and extend dual fiber optic from the point of interconnection to the new 138 kV station control house.	AE1-146	9/24/2018	$0.98	AEP	
	N8130.2	Install new 138 kV three-breaker ring bus station along the Ebersole-Fostoria Central No. 2 138 kV line; installation of associated protection and control equipment, line risers, switches, jumpers, and supervisory control and data acquisition (SCADA) equipment.			$6.16		
	N8130.3	Ebersole-Fostoria Central No. 2 138 kV T-Line cut-in	AE1-146		$0.84		
	N8130.4	Replace protective relays at Ebersole and Fostoria Central 138 kV stations.			$0.38		
	N8130.5	Install two fiber-optic paths to facilitate relaying between Rocky Ford, Ebersole and Fostoria Central 138 kV stations.			$0.24		
32	N8135	Review relay settings and change the carrier frequency at the Greene 345 kV station.	AE2-148	6/1/2022	$0.02	AES Ohio	
	N8136	Review relay settings and change the carrier frequency at the Madison 345 kV station.			$0.02		
33	N8150	Expand the Circleville 138 kV station, including the addition of one 138 kV circuit breaker, installation of associated protection and control equipment, line risers, switches, jumpers, a 16' x 12' expansion DICM, and supervisory control and data acquisition (SCADA) equipment.	AC2-029	1/31/2017	$1.55	AEP	
34	N8158	Expand the Jug Street 138 kV station, including the addition of one 138 kV circuit breaker, installation of associated protection and control equipment, line risers, switches, jumpers and supervisory control and data acquisition (SCADA) equipment.	AF1-062	7/31/2019	$0.94		
	N8420	Install one new 138 kV circuit breaker, associated equipment, and update protective relay settings at the Jug Street 138 kV station.		8/22/2022	$0.94		10/8/2024
35	N8177	Install one dual SEL-311L relay protection package, fiber connected to the customer end, for primary and backup protection of the interconnect line at the Woodsdale 345 kV substation.	AE2-267	3/28/2019	$0.04	DEO&K	

Table 6.49: Ohio Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
36	N8177.1	Install new 138 kV three-breaker ring bus station along the East Leipsic-Richland 138 kV line. Install a Drop-In Control Module (DICM) and other associated line protection and control equipment, line risers, switches, jumpers, and supervisory control and data acquisition (SCADA) equipment.	AE2-072	12/31/2021	$5.90	AEP	1/9/2024
	N8177.2	Perform final connection of the East Leipsic-Richland 138 kV to the Lammer 138 kV station, and update protective relay settings at East Leipsic 138 kV station.			$0.70		
	N8177.3	Install one fiber-optic path to facilitate relaying between Lammer, East Leipsic and Yellow Creek 138 kV stations.			$0.77		
	N8177.4	Update protective relays settings at Richland 138 kV station.			$0.00	ATSI	
37	N8179	Install one new 138 kV circuit breaker & associated equipment, and update protective relay settings at the Cole 345 kV station.	AE2-214		$1.56	AEP	
38	N8409	For the Napoleon Muni-Midway 138 kV line, reconductor the section of 336 ACSR 30/7 of the transmission line with 556.5 ACSR. Change the relay settings of the SEL relay for the ZR component to meet or exceed 262 MVA for summer emergency.	AF2-127	3/31/2022	$23.10	ATSI	10/8/2024
39	N8434.2	Install one new bay box, expand the control house and reterminate the existing 138/12 kV transformer. Install associated line protection and control equipment, line risers, switches, jumpers and SCADA.	AE1-245	6/30/2021	$0.77	AEP	1/9/2024
40	N8435	Update protective relay settings at the Platter Creek 69 kV station.	AE2-322	12/1/2021	$0.05		10/8/2024
41	N8448.1	Install two structures, two spans of conductor; connect ITO 69 station to existing transmission circuit.	AE2-298	12/31/2021	$0.68		
	N8448.2	Install two fiber-optic paths to facilitate relaying between ITO, Haviland and South Van Wert 69 kV stations.			$0.26		
	N8448.3	Replace protective relays, other equipment at Haviland and South Van Wert 69 kV stations.			$0.74		
	N8448.4	Review/update protective relay settings at the proposed AE2-298 69 kV station.			$0.45		
	N8505.1	Install two new fiber-optic cable paths consisting of 3 miles of 144-count all-dielectric self-supporting (ADSS) cable installed on existing AEP structures, 0.2 miles of 144 count ADLT cable installed in new underground right of way, and associated terminating equipment and devices between the proposed AE2-298 switching station, Haviland and South Van Wert 69 kV stations.		12/30/2026	$0.39		
	N8505.2	Install two new steel, 75' single circuit, single-pole dead-end structures on concrete piers with anchor bolt cages and two spans of drake transmission line conductor with 7#10 alumoweld shield wire on the Cavett Switch-West Van Wert 69 kV line.			$1.01		
	N8505.3	Replace the protective relays and circuit breaker controls; replace the existing coupling capacitor voltage transformer (CCVT) with a new three-phase CCVT and install a new surge arrester at Haviland 69 kV.			$0.47		
	N8505.4	Replace the protective relays and circuit breaker controls; replace the existing coupling capacitor voltage transformer (CCVT) with a new three-phase CCVT and install a new surge arrester at South Van Wert 69 kV.			$0.52		
42	N8454	Lower the Southwest Lima-West Moulton 138 kV circuit.	AF1-164	9/20/2019	$0.26		
	N8540	Expansion of existing substation at Southwest Lima 345 kV		6/30/2022	$1.79		
	N8541	Replace two existing 85' single-pole, single circuit tangent structures on the Southwest Lima to West Moulton 138 kV line.			$0.31		

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Table 6.49: Ohio Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
43	N8474.1	Install four structures, four spans of conductor; connect the proposed 345 kV AF1-228 station to existing Beatty-Greenek 345 kV transmission circuit (AEP).	AF1-228	10/31/2022	$2.78	AEP	10/8/2024
	N8474.2	Update protective relay settings at the Beatty and proposed AE2-148 345 kV (AEP) substations.			$0.07		
	N8474.3	Review and revise (as needed) the Greene 345 kV station remote end line protection relay settings depending on the relative timing of completion of AE2-148 and AF1-228 (AES Ohio-AES Ohio).			$0.25	AES Ohio	
44	N8475.1	Install three structures, three spans of conductor with shield wire; connect proposed 345 kV station to existing Galion to South Berwick 345 kV line.	AF1-229		$1.88	AEP	
	N8475.2	Replace protective relays at South Berwick 345 kV station, install SFP transceiver, remove wave trap.			$0.32		
	N8475.3	Install one 6-mile fiber-optic cable path to facilitate direct fiber relaying and SCADA connectivity between the proposed AF1-229 345 kV station and Berwick station.			$0.46		
	N8475.4	Review and revise (as needed) the Galion 345 kV station remote end line protection relay settings.			$0.25	ATSI	
45	N8498.1	AF2-187 interconnection substation: Install physical security and camera system.	AF2-187	9/30/2027	$0.39		
	N8498.2	Cloverdale-East Wooster 138 kV line: Install tangent structure to support the Cloverdale-East Wooster 138 kV circuit parallel to the Brookside-Cloverdale 138 kV loop location.			$0.23		
	N8498.3	Brookside-Cloverdale 138 kV loop: Loop the Brookside-Cloverdale 138 kV an ~18.3 miles from the Cloverdale 138 kV substation near structure #487 into the new AF2-187 interconnection substation.			$0.83		
	N8498.4	Ross substation 138 kV: Install in-sub fiber run and SEL-2506.			$0.43		
	N8498.5	Brookside substation 138 kV: Install new wave trap, line tuning unit and revise relay settings.			$0.78		
	N8498.6	Cloverdale substation 138 kV: Install new wave trap, line tuning unit and revise relay settings.			$0.75		
	N8498.7	AF2-187 138 kV interconnection substation: Design, installation and testing/commissioning for MPLS equipment for SCADA transport at AF2-187 interconnection substation			$0.33		
	N8498.8	AF2-187 138 kV interconnection substation: New ADSS fiber installation between AF2-187 interconnection substation and fiber backbone.			$0.27		
46	N8515	Modify relay settings at GM Lordstown, Niles, Magellan, Newton Falls, Evergreen, Mahoningside, Bluebell, Darrow, Shalersville, Lordstown, Salt Springs, Bruce Mansfield, Juniper, Brady, Beaver Valley, Chamberlin, Ravenna and East Akron 345 kV substations and integrate customer protection and controls to the FirstEnergy transmission system.	AB1-105	8/12/2025	$1.03		
47	N6137	Perform a sag study & mitigation on the AEP-owned portion of the Tidd-Wylie Ridge 345 kV tie-line circuit (8.6 miles). This will raise the operating temperature & ratings to the standard value.	AE1-080	2/1/2022	$0.04	AEP	
48	N6769.1	Upgrade/replace 3-345 kV 1600A switches at Beatty station.	AF1-228	10/31/2022	$1.50		

6.9.8 — Supplemental Projects

Supplemental projects included in the 2024 Local Plan in Ohio are summarized in **Map 6.41** and **Table 6.50.**

Read More
Supplemental Projects

Map 6.41: Ohio Supplemental Projects (Dec. 31, 2024)

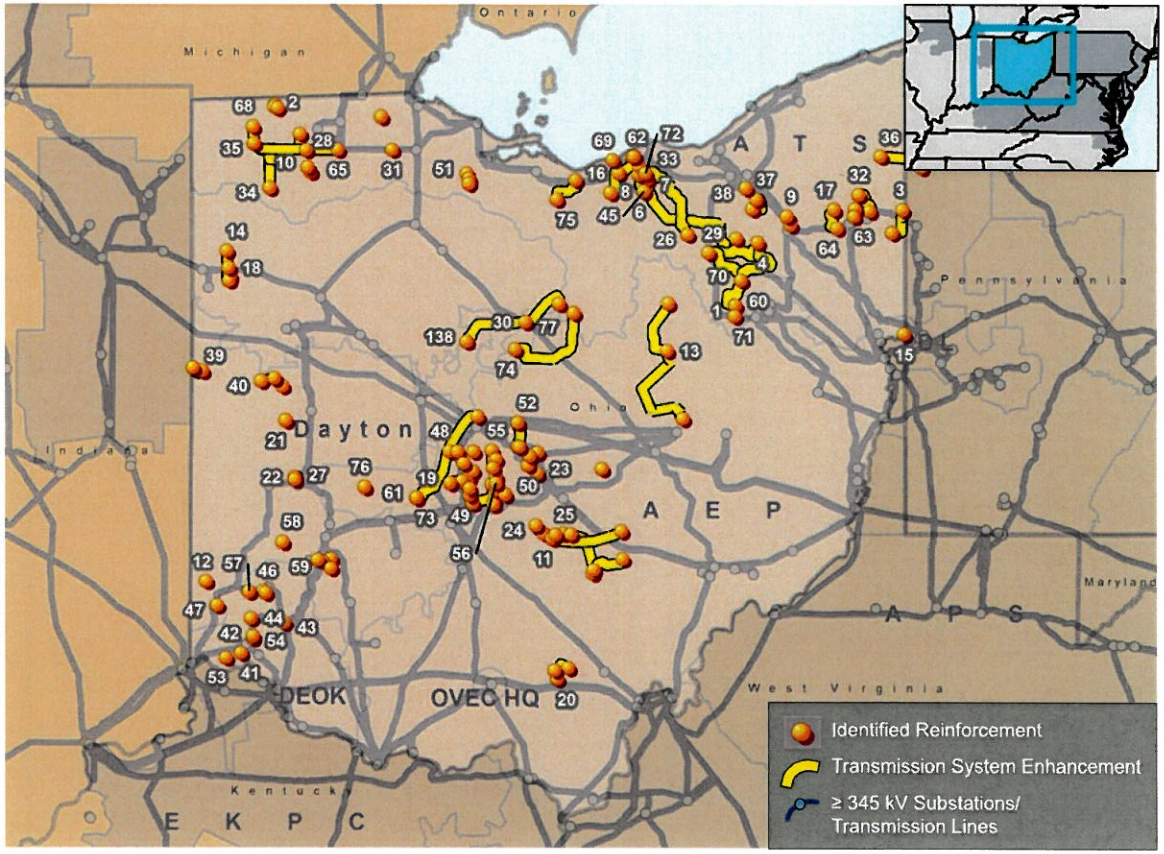

Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S3106.1	Install a 138 kV circuit breaker at the Cloverdale 138 kV North bus. Construct an ~0.1 miles of transmission line from the Cloverdale substation to the customer substation. Install one SCADA-controlled transmission line switch.	8/1/2025	$0.00	ATSI	10/20/2023

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Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S3117.1	At Kexon substation: Install two additional 69 kV circuit breakers and associated substation disconnect switches. These additional breakers will be used to terminate the new Kexon-Snyder No. 1 and Kexon-East Fayette 69 kV lines. ($2.1 M)	7/31/2027	$2.10	AMP	11/17/2023
	S3117.2	Build an ~2.5 miles of new double circuit 69 kV line using 795 ACSR Drake conductor from Kexon station to a point on the existing AMP owned Kidston tap. Rebuild an ~1 mile of the existing Kidston tap to a double-circuit 69 kV line using 795 ACSR Drake conductor from a point on the existing Kidston tap to a point on the FE owned East Fayette-Snyder 69 kV line. ($9.2 M)		$9.20		
	S3117.3	Extend the existing normally open circuit out of AMP's Kidston station to connect into FE's Snyder 69 kV station. This will require the construction of an ~1 mile of greenfield single-circuit 69 kV line using 795 ACSR Drake conductor. ($2.6 M)		$2.60		
	S3117.4	Snyder 69 kV substation: Expand the Snyder substation from five-breaker to a six-breaker ring bus by adding one 69 kV circuit breaker to accommodate the Kexon-Bruce R. Kidston-Snyder 69 kV line terminal (i.e., KexonSnyder No. 2) and install a dead-end structure just outside Snyder substation to provide a termination point for the new line. Revise line relay settings to Kexon (formerly E Fayette exit). Install standard BES line relay panel with on the new line exit for the Kexon-Snyder No. 2 69 kV line.	5/31/2027	$5.40	ATSI	
	S3117.5	Stryker: Install 2nd 138/69 kV transformer, adjust all 69 & 138 kV relays as required, integrate the new transformer protection to the system. Install one 138 kV bus tie breaker.		$6.40		
	S3117.6	East Fayette-Snyder 69 kV line: Split the E Fayette-Snyder 69 kV line between structure No. 191 & 192 to loop in the AMP Kexon substation. Revise relay settings at E Fayette and Snyder substations. Install a jumper between the new E. Fayette-Kexon & Snyder-Kexon No. 1 69 kV line with inline normally open SCADA-controlled switch.		$0.80		
3	S3118.1	Masury substation: Replace relaying on Lincoln Park line terminal with microprocessor relays. Replace two 138 kV breakers for Lincoln Park and Shenango lines. Replace two associated disconnect switches. Lincoln Park substation: Replace relaying on Masury line terminal with microprocessor relays. Replace two 138 kV breakers for Masury line. Replace four associated disconnect switches.	6/8/2026	$3.40		
4	S3119.1	Gilchrist substation: Replace one circuit breaker, associated disconnect switches and relaying for Hartville line terminal. Hartville substation: Replace one circuit breaker, associated disconnect switches and relaying for Gilchrist line terminal.	6/1/2026	$1.60		
5	S3120.1	Vulcan 138/69 kV transformer terminal upgrades. Replace substation conductor including the breaker leads and transformer leads.	3/28/2024	$1.00		
6	S3121.1	At Carlisle substation, replace one 138 kV oil circuit breaker. Replace three 138 kV disconnect switches. Replace associated relaying with microprocessor relays. Remove wave trap and replace power line carrier communications with fiber communications. At Fieldstone substation, remove wave trap. At Johnson substation, replace one 138 kV disconnect switch. Remove wave trap and replace power line carrier communications with fiber communications. Connect fiber to existing microprocessor relays.	9/5/2025	$2.20		
7	S3122.1	At Firestone substation, replace associated relaying with microprocessor relays. Replace wave trap and power line carrier equipment. At Urban substation, replace one 138 kV oil circuit breaker. Replace three 138 kV disconnect switches. Replace associated relaying with microprocessor relays. Replace wave trap and power line carrier equipment.	5/15/2026	$2.50		
8	S3129.1	Install two main-line SCADA-controlled switches. Install one tap-line SCADA-controlled switch.	11/1/2024	$1.30		7/21/2023
9	S3130.1	69 kV transmission line tap: Install three SCADA-controlled load-break switches. Construct an ~0.4 miles of transmission line using 477 kcmil ACSR 26/7 conductor from tap point to customer substation. Relay settings revised at Ravenna and Campbellsport.	4/28/2024	$0.80		
10	S3132.1	69 kV transmission line tap: Install one SCADA-controlled transmission line switch. Construct an ~1–2 spans of transmission line using 336.4 26/7 ACSR from tap point to the customer substation. Retire and remove all distribution owned assets from Campbell Soup No. 1 substation along with transmission line portion from new interconnection to existing substation.	5/26/2025	$0.00		8/18/2023

Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
11	S3133.1	Ralston-North Logan 69 kV line: Retire the line section between North Logan-Geneva switch (~9.0 miles) between Str. 70–147 and rebuild a portion as double circuit from Geneva Sw up to Str. 70/71 (~1.15 miles).	3/1/2029	$9.67	AEP	11/17/2023
	S3133.2	East Logan-Shawnee 69 kV line: Six-wire the 69 kV line between N. Logan-E. Logan (Str. 2-43) and terminate the E. Logan-New Lexington 69 kV circuit into the now vacated Ralston-N. Logan 69 kV line position at N. Logan station at/near structure 44 to form the new N. Logan-New Lex. 69 kV circuit. Remove sections between Str. 43–44 and Str. 2–E. Logan (circuit breaker-L).		$1.28		
	S3133.3	Clouse-West Lancaster 138 kV: Rebuild ~23 miles of 138 kV line between West Lancaster and Clouse stations. The existing double-circuit line will be rebuilt as double circuit between West Lancaster and just east of South Lancaster station along with the section between structure 96 and Clouse station. The remaining ~5.6 miles of the line will be rebuilt as single circuit. The section between structure 96 and Clouse will have one circuit of the double circuit operated at 69 kV to form the South Lancaster-Clouse circuit to allow for the retirement of the Ralston-North Logan line south. 69 kV and 138 kV line extensions will be installed into Clouse station, using 795 ACSR conductor SE 360 MVA.		$65.81		
	S3133.4	East Logan-South Lancaster 69 kV line: Reterminate this line at East Logan to utilize circuit breaker-P, which is a newer vintage breaker in better health than existing breaker M.		$0.72		
	S3133.5	East Logan 69 kV: Retire 69 kV circuit breaker-M and repurpose circuit breaker-P for re-terminating the South Lancaster circuit.		$0.77		
	S3133.6	Clouse 138 kV & 69 kV: Add a 138 kV, 3000A 63 kA breaker to accommodate the new 138 kV line from Crooksville. Add a 69 kV, 3000A 40 kA breaker to accommodate the new 69 kV line from South Lancaster (thru Geneva Sw). Install all associated attachment facilities. DICM expansion will likely be required.		$1.67		
	S3133.7	Geneva Sw 69 kV: Replace & relocate the existing phase-over-phase switch with a three-way 1200A phase-over-phase switch.		$0.95		
	S3133.8	Junction City 138 kV: Replace the existing two-way phase-over-phase with a three-way 2000A phase-over-phase.		$1.15		
	S3133.9	West Lancaster 138 kV & 69 kV: Replace T2 with a 90 MVA bank. Replace 138 kV circuit breaker-D with one 138 kV, 3000A 40 kA circuit breaker, 69 kV circuit breaker-C & circuit breaker-J with two 69 kV, 3000A 40 kA circuit breakers, 69 kV CS-BB with one 69 kV, 2000A 31.5 kA circuit breaker and the control building with DICM & new relays. Retire 138 kV circuit breaker-E. Replace 69 kV Bbus 1 PTs. Note: Work will be coordinated with previously proposed upgrades at station captured under S2857.9.		$10.83		
	S3133.10	South Lancaster 138 kV & 69 kV: Add two 69 kV, 3000A 40 kA and two 138 kV, 3000A 40 kA circuit breakers to the low and high sides of T1 and T2. Upgrade transformers' protection.		$3.22		
	S3133.11	Lancaster-E. Lancaster-S. Lancaster 69 kV: In order to mitigate the three-terminal line, 0.2 miles of 69 kV double circuit line, including several dead-end and turning structures, will be constructed to loop the circuit into East Lancaster station.		$2.39		
	S3133.12	East Lancaster 69 kV: Extend the bus to accommodate a new line. Install one new 69 kV, 3000A 40 kA breaker and all associated attachment facilities (relays, bus work, risers and switches). Retire the 69 kV cap bank.		$1.04		
	S3133.13	Lancaster Jct-E. Lancaster-Ralson 69 kV: In order to mitigate the three-terminal line, 0.2 miles of 69 kV double circuit line will be constructed to loop the circuit into Lancaster Junction station. There will be associated telecom work performed as well.		$1.65		
	S3133.14	Lancaster Junction 69 kV: Add three 69 kV, 3000A 40 kA line breakers at Lancaster junction and all associated attachment facilities (relays, bus work, risers and switches). Expand the station to include two box bays. Retire 69 kV line & bus tie switches.		$5.03		
	S3133.15	Anchor Hocking, Lancaster, North Logan, New Lexington 69 kV: Remote end PCE work will be performed to accommodate project in area.		$0.69		
12	S3138.1	At Taylor station, install one 138 kV, 40 kA 3000A bus tie circuit breaker and one138 kV, 3000A 40 kA GOAB beaker disconnect switch to accommodate a new distribution transformer.	12/31/2024	$1.26		

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Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
13	S3140.1	Wooster-South Coshocton: The 37.7-mile line will be rebuilt using 795 ACSR DRAKE to alleviate identified asset renewal conditions. This includes the 15.2-mile West Millersburg-Wooster 138 kV circuit as well a portion of the 30.9-mile single circuit Ohio Central-West Millersburg 138 kV circuit up to structure 13 outside Ohio Central station.	10/31/2026	$96.50	AEP	10/20/2023
	S3140.2	Perform remote end work at Wooster.		$0.50		
	S3140.3	Perform remote end work at West Millersburg.		$0.50		
14	S3142.1	Haviland-Van Wert: Rebuild the line to double-circuit 138 kV design using 1033 Curlew ACSR conductor. The line will be six wired and operated at 69 kV. The rebuild will include a 2.6-mile greenfield section to route the line near several new industrial sites. The overall line length will be 10.8 miles. Newer installed poles will be reused elsewhere.	1/1/2026	$27.80		
	S3142.2	Modify the b3359 scope from single-circuit 69 kV construction to double-circuit 1033 Curlew at 138 kV design.		$2.89		
	S3142.3	Perform remote end work at Haviland.		$1.03		
	S3142.4	Perform remote end work at Van Wert.		$0.64		
	S3142.5	Upgrade telecom equipment at South Van Wert, Logtown, Maddox Creek, Timber Switch and North Delphos stations.		$0.19		
15	S3145.1	At East Liverpool station, replace the 138 kV MOAB/ground switch system with a circuit breaker and new relays. Install a 69 kV breaker on the low side of the 138-69 kV transformer. Upgrade tie-line metering, relays and expand SCADA functionality at the station. Replace the control house with a new prefabricated control building.	5/1/2025	$3.00		8/18/2023
	S3145.2	At the 69 kV remote end station of Second Street, replace the electromechanical relays and pilot wire communications with microprocessor-based relays to coordinate with East Liverpool. Install new 69 kV CCVTs.		$0.30		
16	S3192.1	Henrietta-Johnson 69 kV line: Replace wood structures and rebuild 12.1 miles of line with new conductor. Reconductor 1 mile of line on steel structures. Replace two 600A switches with 1200 switches at South Amherst. Replace limiting substation conductor at Henrietta.	5/31/2025	$18.00	ATSI	1/19/2024
17	S3193.1	At Newton Falls substation for Garrettsville South 69 kV line, replace circuit breaker B30. Replace two associated disconnect switches. Replace associated relaying with microprocessor relays.	2/2/2024	$1.00		
18	S3212.1	A new 69/12 kV distribution station (Vision) will be constructed. The station will be an in-and-out design utilizing in line MOABs.	12/31/2024	$1.12	AEP	3/17/2023
	S3212.2	Work will be performed on the West Van Wert-Cavett 69 kV circuit to cut in the newly proposed Vision station.		$2.99		
19	S3213.1	Construct a greenfield station "Milepost," utilizing three 138 kV, 3000A 63 kA circuit breakers configured in a ring to serve new customer loads.	4/15/2024	$4.54		
	S3213.2	Cut into the Roberts-Trabue 138 kV circuit and construct a new 0.14-mile double-circuit 138 kV in and out line to the new Milepost station utilizing 795 ACSR conductor SE: 360 MVA.		$2.79		
	S3213.3	Remote end work to accommodate the above work at Cole, Roberts & Trabue.		$0.17		
	S3213.4	Retire 3.3 miles of the Bethel Rd-Hilliard 69 kV line from Bethel Rd to the structure adjacent to Davidson 69 kV. Build a 0.3-mile extension connecting the line from Hilliard to Davidson using 795 ACSR conductor creating the Hilliard-Davidson 69 kV circuit.		$2.92		
	S3213.5	Retire Bethel Road 138/69/13.8 kV transformer No. 3 and associated breakers. Install a new 138/69 kV transformer at Davidson station with a high-side MOAB and a single 69 kV, 3000A 40 kA breaker on the low side connecting to the reconfigured Davidson-Hilliard 69 kV circuit.		$1.58		
	S3213.6	Upgrade Sub Cond 477 AAC 19 Str. at Blaire 69 kV.		$0.05		

Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
20	S3214.1	Install new 138 kV phase-over-phase switch on the Corwin-Lick 138 kV circuit. Install metering toward Veterans.	12/31/2024	$0.67	AEP	7/21/2023
	S3214.2	Install ~0.3 miles of line from Pattonsville switch to Veterans.		$0.45		
	S3214.3	Modify existing line to accommodate switch installation.		$0.32		
	S3214.4	Heppner-Lick 138 kV: Remove span of line from City of Jackson's Lick station toward Veterans.		$0.10		
21	S3216.1	Hardin 69 kV substation: Build a new 69/12 kV substation with two 69 kV breakers with line terminals looking toward AES new station and Piqua Sub 5 and accommodate one 69/12 kV transformer for the City of Piqua. The 69/12 kV transformer and associated 12 kV equipment costs are distribution costs not included as part of the transmission costs. Piqua Sub 5 69 kV substation: Upgrade line panel at Piqua Sub 5 looking toward the new Hardin sub.	12/1/2027	$5.60	AMP	1/19/2024
	S3216.2	New AES Piqua Sub 69 kV substation: Replace the existing line tap to the Piqua No. 5 substation with a new 69 kV three-breaker ring.		$9.90	AES Ohio	
22	S3217.1	Tipp City Identified Scope: Tipp City to build new distribution station and new 69 kV line to connect to AMP Tower sub. *The Tipp City identified scope is not included in the cost. Tower 69 kV substation: Install new line relays, RTU and CCVTs for the new 69 kV line terminal. Perform necessary work to terminate new 69 kV line to Tower station.	3/1/2026	$1.24	AMP	
23	S3301.1	At Mink station, install two 138 kV, 3000A 63 kA breakers in the breaker-and-a-half configuration and associated work to terminate two new distribution transformers.	3/28/2025	$2.70	AEP	7/21/2023
24	S3305.1	Sifford Station: Sifford station will be built out to accomodate two new 138 kV feeds to the customer. This will include the installation of four 138 kV, 3000A 40 kA circuit breakers and associated equipment.	9/30/2024	$6.37		3/15/2024
	S3305.2	Sifford-Ruble No. 2 138 kV Feed A: Install 138 kV line extension from AEP's Sifford station to serve the customer's station located just south of the Sifford station.		$2.95		
	S3305.3	Sifford-Ruble No. 2 138 kV Feed B: Install a second 138 kV line from AEP's Sifford station to serve the customer's station located just south of the Sifford station to meet customer's redundancy requirements at the site.		$0.00		
25	S3308.1	West Lancaster-South Baltimore-West Millersport 138 kV: Rebuild ~14.4 miles of the line between West Lancaster and West Millersport stations using 1033 ACSS 54/7 conductor.	10/31/2026	$38.70		
	S3308.2	West Lancaster Station: Replace existing bus and line risers at the station; upgrade line relays.		$1.00		
	S3308.3	South Baltimore Station: Replace existing bus and line risers at the station; upgrade line relays. While at the station some additional site concerns such as the existing fence will be addressed.		$0.70		
26	S3320.1	Install one SCADA-controlled transmission line switch on existing tap from the Abbe-Medina 69 kV line. Construct an ~100 ft. of transmission line from tap point to the customer substation.	6/1/2024	$0.00	ATSI	2/16/2024
27	S3351.1	Construct New Kessler-AES Tipp City line ($ 12.1 M) – Build an ~4.5 miles of new single-circuit 69 kV line using 795 ACSR Drake conductor from the future Tipp City Kessler station to AES's Tipp City station. Canal 69 kV substation ($ 1.44 M) – Install new line relays and CCVTs for both 69 kV line terminals. Tower 69 kV substation ($ 1.24 M) – Install new line relays and CCVTs for line Tower-Canal line terminal. Kessler 69 kV substation ($ .45 M) – Install new RTU, security system, and update relay settings.	6/3/2028	$15.30	AMP	2/15/2024
	S3351.2	AES Ohio Tipp City 69 kV ring bus: Upgrade AES Tipp City sub to four-breaker ring bus and enable interconnection with the new Kessler-Tipp City (AMP T) 69 kV line. Construct new Miami-Canal 69 kV T-line: Rebuild 2 miles of the existing 6692 line from AES Ohio Miami sub to AMP-Ts Canal tap, from single-circuit line to double-circuit Miami-Canal. Demo existing line tap. Miami substation upgrades: Add one additional breaker, a second 138/69 kV transformer, replace five 69 kV breakers & four 138 kV breakers.	6/30/2028	$24.30	AES Ohio	3/15/2024

Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
28	S3352.1	Reconstruct Enterprise sub from the existing single-breaker/single-bus design to a five-breaker ring bus design. Install five 2000A, 69 kV circuit breakers with associated circuit breaker disconnects. Change the status of the Enterprise-FE Napoleon 69 kV line to normally closed and network operation. Update (remote terminal) relay settings at Sullivan substation. Napoleon Power & Light (NPL) will also rebuild their distribution sub; The 69-12 kV transformer and associated 12 kV work are distribution costs and not included as part of overall project costs.	8/1/2026	$11.50	AMP	3/15/2024
	S3352.2	Convert the FE Napoleon 69 kV straight bus into a four-breaker ring bus. Provide a line termination point for the AMP 69 kV line (Enterprise substation exit). Upgrade the existing revenue metering equipment, including the CTs and PTs. Revise relay settings at Napoleon, Richland and Midway substations.	10/2/2026	$7.10	ATSI	
29	S3359.1	Gilchrist-Star 69 kV line: Rebuild the Gilchrist-Star 69 kV line with new conductor. Replace A-42, A-87, A-86, A-38 switches with new switches equipped with SCADA control & motor operation. Dale-Star 69 kV line: Rebuild the 3.3-mile Dale-Star 69 kV line section that is double circuited with the Gilchrist-Star 69 kV line with new conductor. This includes the Star-Martin 69 kV line and part of the Martin-Marathon tap 69 kV line section. Gilchrist: Replace 69 kV breaker B23.	12/1/2027	$62.50		2/16/2024
30	S3360.1	At Galion: Replace 138 kV breakers B-52, B-55, B-58, B-59 and B-60 as well as circuit switchers CS-136 and CS-137. Replace and install associated disconnect switches and protective relaying. Replace limiting substation conductor.	6/1/2027	$5.80		
31	S3361.1	Expand the existing Dowling substation to a 12-breaker, breaker-and-a-half substation. Build two 138 kV lines, an ~0.5 miles, from Dowling substation to the customer substation.	11/30/2025	$10.30		
32	S3362.1	Rebuild the Niles Central-Packard 138 kV line with new conductor, an ~8.9 miles.	11/1/2030	$12.60		
33	S3363.1	Install one SCADA-controlled transmission line switch on existing tap from the Abbe-Medina 69 kV line. Construct an ~100 ft. of transmission line from tap point to the customer substation.	11/22/2024	$0.00		
34	S3370.1	Midway-Richland-Wauseon 138 kV line reconductor: Project scope assumes completion of Midway-Richland-Wauseon 138 kV line – Eliminate three-terminal line project is complete (s1698) (projected ISD: 4/12/2023). Reconductor the Richland-Wauseon 138 kV line from Richland substation to structure 215, an ~21.2 miles. Reconductor the Midway-Richland-Wauseon 138 kV line from the Midway substation to structure 215, an ~12.2 miles. Install OPGW from the Midway substation to the Richland substation, an ~21.2 miles. Upgrade substation conductor at Midway substation and Wauseon substation.	12/31/2026	$44.00		3/15/2024
35	S3371.1	Napolean-Richland-Stryker 138 kV line reconductor: Reconductor the Napoleon Muni Northside-Stryker 138 kV line from Napoleon substation to the Stryker substation, an ~17.1 miles. Reconductor the Richland-Stryker 138 kV line from Richland substation to Structure 265, an ~11.8 miles. Replace one 138 kV breaker at Richland substation. At AMP (Napoleon) Sullivan station: Revise remote end relay settings to accommodate new conductor.		$12.00		
36	S3372.1	Rebuild an ~11.4-mile section of the Dilworth-Maysville 69 kV line from Dilworth substation to Andover substation. Replace the obsolete normally open line switch.	12/31/2025	$25.20		
37	S3373.1	Replace limiting substation conductor, line trap and relaying at Hudson East substation.	5/15/2026	$1.90		
38	S3374.1	At Chamberlin substation, replace 69 kV circuit breakers B-31, B-39 and B-74, associated disconnect switches, limiting conductor and protective relaying for Plastic Materials, Verizon and No. 2 138/69 kV transformer circuit. At Plastic Materials tap, replace switch A-189.	1/10/2025	$4.20		2/16/2024
39	S3375.1	Macedon-Mt. Zion 69 kV line: Acquire and rebuild a 69 kV line between the new Macedon 69 kV ring bus and the Marathon Delivery Point with 795 ACSR. Establish a new tap for the existing Marathon customer with auto sectionalizing motor-operated air brake switches. Construct a new 5-mile 69 kV single circuit from the new Marathon tap point to the Ohio-Indiana border and the new interconnection point with Wabash Valley Power Authority (WVPA).	6/30/2027	$30.10	AES Ohio	3/15/2024
	S3375.2	Macedon 69 kV ring bus: Install a new three-breaker ring bus near the existing Macedon Delivery Point.		$9.00		
	S3375.3	Ft. Recovery-Macedon 69 kV rebuild: Rebuild the ~4.8-mile Ft-Recovery-Macedon line from 1/0 AAAC to 795 ACSR and OPGW.	6/30/2028	$11.50		

Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
40	S3376.1	Roberts Road Delivery Point: Construct a new 1.3-mile double-circuit extension off the Amsterdam-McCartyville 69 kV line and install MOAB sectionalizing at the proposed Roberts POI. The new line should be constructed with 1351 conductor and OPGW.	12/31/2025	$4.80	AES Ohio	3/15/2024
	S3376.2	New Kettlersville substation: Install a four-breaker ring bus on the Amsterdam-Franklin 138 kV line.	1/31/2027	$9.50		
	S3376.3	McCartyville Legacy substation: Retire the existing legacy McCartyville substation.	12/31/2028	$1.40		
41	S3377.1	Relocate 138/69 kV TB 4 to make room for a second 22 MVA distribution transformer, TB 6. Install a circuit breaker on the high side of TB 4 to reconnect it to 138 kV bus 4. Install a circuit switcher on the high side of TB 6 to connect it to 138 kV bus 4. Rework distribution feeders transferring some load from the existing distribution transformer to TB 6.	12/26/2025	$5.50	DEO&K	5/17/2024
42	S3378.1	Retire the existing Merrel substation. Expand the substation area to allow for new equipment installation meeting adequate safety clearances. Install new 69 kV bus, switch separated into two sections. Reconnect the 69 kV feeders to the bus with motorized switches and transmission line sectionalizing. Install two 69/13 kV, 22 MVA transformers, each connected to the 69 kV bus with circuit switchers. Install two new open air breaker sections of 13 kV bus to reconnect distribution feeders.	4/23/2027	$0.00		
43	S3379.1	Replace circuit breaker 961 with a new gas-filled circuit breaker, the circuit breaker 961 disconnects and bus conductor. Replace circuit breaker 962 with a new gas-filled circuit breaker, the circuit breaker 962 disconnects and bus conductor. Replace the disconnects and bus conductor for circuit breakers 964 and 967. While scoping the project, these were found to be the same vintage and condition as those for circuit breakers 961 and 962.	4/28/2025	$4.98		4/19/2024
44	S3380.1	Rebuild the 69 kV section of Port Union, expanding the substation to allow adequate room for minimum approach distances. Add tie breakers to split each of the buses into two sections. Redistribute the feeders among all four bus sections to increase operational flexibility.	5/30/2028	$37.22		3/15/2024
45	S3381.1	Carlisle substation: Disconnect the 13 kV tertiary winding on TB2. Install a new 138/13 kV, 22.4 MVA transformer to feed the distribution buses. Carlisle substation: Replace 69 kV breakers 619, 621, 622 and 623 with 2000A breakers. Replace Capacitor 2 with a non-fused, rack style 36.9 MVAR capacitor. Install two new 138 kV breakers to form a ring bus with the one existing breaker.	5/22/2029	$10.24		10/20/2023
46	S3382.1	Tap into the 69 kV Todhunter-Monroe feeder. Replace a 600A switch between Todhunter and the new tap with a 2000A switch to increase the capacity of the feeder. Install 0.9 miles of feeder from the new tap to AES Ohio Technologies using 17 steel poles with 954 ACSR conductor. Install a tap with a switch and drop to connect Worthington Steel. This configuration allows Worthington Steel and AES Ohio Technologies to be fed from either direction and the isolation of both individually.	8/28/2026	$5.70		
47	S3386.1	From Layhigh to the tap to Millville, replace wooden structures with steel pole structures, reconductor the line with 954ACSR, retire a switch between Layhigh and the tap. The new ratings increase to 150/150/174 MVA summer, 189/189/206 MVA winter.	4/2/2026	$8.50		5/17/2024

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Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
48	S3440.1	Cyprus 345/138 kV: Cyprus is the station that was originally developed (s2526) to serve 675 MW of demand with room for 345 kV expansion based on LOA with the customer. Cut into the Beatty-Bixby 345 kV circuit and construct ~1.6 miles of double-circuit line, utilizing 2-bundled ACSR Bittern 1272 conductor, SE rating 2278 MVA, to a new 345 kV ring bus at Cyprus station with four 5000A 63 kA circuit breakers; two 345/138/34.5 kV, 675 MVA transformers; 12 138 kV, 4000A 63 kA circuit breakers; one 69.1 MVAR 138 kV cap bank. Construct two 138 kV single-circuit ~0.4-mile tie lines and two double-circuit ~0.9-mile tie lines to the customers dead-end structures utilizing ACSR Drake 795 (26/7) conductor SE 360 MVA. Modify the existing Cyprus 138 kV Extension & Parsons 138 kV circuits No. 1 & 2 structures to accommodate a fence relocation. Remote end relay upgrades are required at Beatty & Bixby 345 kV stations.	11/13/2024	$46.90	AEP	12/5/2023
	S3440.2	Parsons 138 kV: Install one 69.1 MVAR cap bank to resolve N-1-1 voltage issues.	7/24/2025	$2.00		
	S3440.3	Beatty-Canal 138 kV line sag rerate: The Beatty-Canal 138 kV line flagged as overloading under N-1-1 scenarios after the addition of the new load at Cyprus. The line will be flown to address sag issues that are limiting its current rating. It is anticipated that several structures will need to be replaced in order to raise the rating of the line.		$5.50		
	S3440.4	Waverly Reactor 138 kV: Install a 4% series reactor toward Rozelle at Waverly station to address a N-1-0 scenario related to the loss of a nearby 345 kV line.	12/1/2026	$3.00		
	S3440.5	Saint Clair Avenue Reactor 138 kV: Adjust tap settings on reactors toward Mound and Clinton stations to 3%.		$0.00		
	S3440.6	Marion Station: Replace switch and line riser at Marion station toward Obetz to address loading concern under certain N-1-1 scenario related to customer interconnections in the area.	12/1/2027	$0.10		
49	S3441.1	Construct a greenfield Jerome station with 10 138 kV, 4000A 63 kA circuit breakers in breaker-and-a-half bus configuration. Construct ~ 2.5 miles of double-circuit 138 kV transmission line extending from Kileville station to Jerome utilizing 2-bundled ACSS Cardinal 954 (45/7) conductor, SE rating 1061 MVA. Construct four 138 kV tie lines to the customers dead-end structures, ~0.05 miles, utilizing ACSR Dove 556.5 (26/7) conductor SE 284 MVA. Customers will be directly connected at this station.	1/30/2025	$30.00		
	S3441.2	Beacon 345 kV: Construct a greenfield station with eight 345 kV, 5000A 63 kA circuit breakers & one 158.4 MVAR 345 kV cap bank in a breaker-and-a-half configuration. Cut into the 345 kV Hayden-Roberts No. 2 circuit with two single-circuit 345 kV lines, ~0.2 miles, terminating into Beacon station utilizing 2-bundle ACSR Rail 954 (45/7) conductor SE 1887 MVA. A structure will need be installed to raise the Hayden-Roberts No. 1 circuit. Construct three single-circuit lines ~0.1 miles, between Beacon and the customer utilizing 2-bundle ACSR Drake 795 (26/7) conductor SE 1800 MVA.	11/21/2024	$40.00		
	S3441.3	Cosgray 345 kV: Expand the existing Cosgray ring bus (originally proposed under s2653) station by installing two 345 kV, 5000A 63 kA circuit breakers. Construct two ~0.06-mile single-circuit lines to connect the new customer deliveries to Cosgray.	6/14/2024	$5.10		
	S3441.4	Originally, Kileville is the station that was envisioned (s2855) to serve 461 MW of demand with room for 345 kV expansion based on LOAs with the customer. However, land in the area of the proposed Kileville station was not available for expansion to install 345/138 kV transformation. Therefore, a new station site called Celtic is being proposed to serve as the 345 kV source for the 461 MW of load to be served in this area. Cut into the Hayden-Hyatt 345 kV circuit, reroute ~0.8 miles of the circuit and extend ~1.1 miles of new double-circuit line, utilizing 2-bundled ACSR Pheasant 1272 (54/19) conductor, SE rating 2413 MVA, to the greenfield Celtic 345/138 kV station with four 345 kV, 5000A 63 kA breakers laid out as ring bus configuration on high side. Install two 675 MVA-345/138 kV power transformers. Install eight 138 kV, 4000A 63 kA breakers & two 69.1 MVAR 138 kV cap bank on low side configured as breaker-and-a-half bus with provisions for future expansion. The proposed Kileville-Jerome 138 kV line will be brought in and out of the station creating two 138 kV Celtic-Jerome circuits and a single Celtic-Kileville 138 kV circuit.	11/13/2025	$60.00		
	S3441.5	Kileville 138 kV: Expand Kileville station (originally proposed under s2855) with four additional 4000A 63 kA circuit breakers in breaker-and-a-half bus configuration. Construct two 138 kV tie lines to the customers dead-end structures, ~0.05 miles, utilizing ACSR Dove 556.5 (26/7) conductor SE 284 MVA. Customers will be directly connected at this station.	4/1/2024	$4.10		
	S3441.6	Beatty-Wilson 138 kV line sag rerate: Due to new customer interconnections in the area the Beatty-Wilson, Beatty-Bolton, Bolton-Hall and Hall-Wilson 138 kV, circuits will overload for certain N-1-1 scenarios. Structures will be replaced on the line to address distribution clearance issue in order to allow the lines to operate to their conductor's designed maximum operating temperature.	12/1/2026	$1.50		
	S3441.7	Dublin Reactor 138 kV: Install a 4% series reactor toward Sawmill at Dublin station to address a N-1-1 scenario as a result of the new load interconnections in the area.		$3.00		

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Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
50	S3442.1	Badger 138 kV: Cut into the Green Chapel-Jug 138 kV circuit and extend ~0.1 miles of new double-circuit line, utilizing 2-bundled ACSR Falcon 1590 (54/19) conductor, SE rating 1118 MVA, to the greenfield Badger station with 10 4000A 80 kA breakers & one 69.1 MVAR 138 kV cap bank, laid out as breaker-and-a-half for future expansion to six strings. Construct four 138 kV tie lines to the customers dead-end structures, ~.05 miles, utilizing ACSR Dove 556.5 (26/7) conductor SE 284 MVA.	11/24/2024	$18.43	AEP	12/5/2023
	S3442.2	QTS North 138 kV: Construct ~0.3 miles of double-circuit & a single-circuit radial 138 kV tie line from Anguin station to QTS customer's site dead-end structures serving transformers No. 1, No. 2, No. 3, each utilizing ACSR Dove 556.5 (26/7) conductor SE 284 MVA.	3/25/2024	$1.80		
	S3442.3	Innovation 345/138 kV: Cut into the Corridor-Conesville 345 kV circuit and construct ~0.1 miles of double-circuit line, utilizing 2-bundled ACSR Bittern 1272 conductor, SE rating 2278 MVA, to a new 345 kV ring bus at Innovation station (s2578) with four 5000A 63 kA circuit breakers, two 345/138/34.5 kV, 675 MVA transformers, 15 138 kV, 4000A 80 kA circuit breakers, two 69.1 MVAR, 138 kV cap banks. Upgrade the line protection relays at Conesville & Corridor 345 kV. Construct two 138 kV tie lines to the customers dead-end structures, ~0.04 miles, utilizing ACSR Dove 556.5 (26/7) conductor SE 284 MVA.	6/24/2026	$53.70		
	S3442.4	Horizon 138 kV: Construct a greenfield station with eight 4000A 80 kA circuit breakers in breaker-and-a-half bus configuration. Construct ~0.05 miles of double-circuit 138 kV transmission line extending from the Jug St.- Green Chapel 138 kV circuit to Horizon station utilizing 2-bundled ACSR Falcon 1590 (54/19) conductor, SE rating 1118 MVA.	6/1/2025	$10.81		
	S3442.5	Jorden 138 kV: Cut into the Innovation-Kirk 138 kV circuit with two single-circuit 138 kV lines, ~0.35 miles, terminating into Jorden station, utilizing 2-bundled ACSS Curlew 1033.5 (54/7) conductor, SE rating 1123 MVA, to construct a greenfield 138 kV four-circuit breaker ring bus station, configurable to 4-strings breaker-and-a-half station in future, with four 4000A 80 kA circuit breakers. Construct two single-circuit 138 kV lines, ~0.1 miles, between Jorden and the customer.	7/10/2026	$12.50		
	S3442.6	QTS South 138 kV: Cut into one of the circuits of Anguin-Brie 138 kV line and extend ~0.1 miles of two single-circuit lines, utilizing 2-bundled ACSS Curlew 1033.5 (54/7) conductor, SE rating 1123 MVA, to the greenfield Macy station with four 4000A 80 kA breakers laid out as four-circuit breaker ring bus. Construct two 138 kV tie lines to the customer's dead-end structures, ~0.04 miles, utilizing ACSR Dove 556.5 (26/7) conductor SE 284 MVA.	7/31/2024	$9.54		
	S3442.7	Brie-Innovation 138 kV tie: Construct a greenfield ~1.75-mile double-circuit line, utilizing 2-bundled ACSS Curlew 1033.5 (54/7) conductor, connecting Brie and Innovation stations as well as reestablish the Babbitt-Kirk 138 kV circuit. At Brie 138 kV station, will install four 138 kV circuit breakers in two partial strings breaker-and-a-half configuration along with a 69.1 MVAR capacitor. Perform remote end work at Innovation, Babbitt and Kirk 138 kV stations. This project addresses a consequential (for a N-1-1 contingency) load-drop event of more than 300 MW for the loads served out of AEP's Anguin and Brie stations while also addressing an overload on the Babbitt-innovation 138 kV circuit in relation to new customer interconnections in the area.	7/31/2025	$10.80		
	S3442.8	Curleys 345 kV: Cut into the rerouted Corridor-Innovation 345 kV circuit, utilizing 2-bundled ACSR Falcon 1590 (54/19) conductor, SE rating 2278 MVA, to a new 345 kV Curleys station with 14 5000A 63 kA circuit breakers & two 158.4 MVAR 345 kV cap banks, laid out as breaker-and-a-half for future expansion to 3 strings with future configurations to build up to total 10 breaker-and-a-half strings. Construct four single-circuit lines, ~0.1 miles, between Curleys station and the customer, utilizing 2-bundle ACSR Drake 795 (26/7) conductor SE 1800 MVA. The rerouted line, built as double circuit, will establish two 345 kV ties between Bermuda and Curleys stations. Reason for update: As part of further engineering reviews, it was determined that the previously proposed capacitor bank at Bermuda would be more efficiently accommodated at Curleys station. The scope update adds the 2nd capacitor at Curleys and removes it from the scope at Bermuda	12/1/2027	$57.20		
	S3442.9	Souder 138 kV: Cut into the Corridor-Green Chapel 138 kV circuit and extend ~1 mile of new double-circuit line, utilizing 2-bundled ACSR Falcon 1590 (54/19) conductor, SE rating 1118 MVA, to the greenfield Souder station with five 4000A 80 kA breakers laid out as five-circuit breaker ring bus for future expansion to six-circuit breaker ring.	10/22/2025	$14.31		

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Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
50 (Cont.)	S3442.10	Bermuda 345 kV: Reroute the Corridor-Innovation 345 kV circuit across the customer's site utilizing 2-bundled ACSR Falcon 1590 (54/19) conductor, built with double-circuit structures, SE rating 2278 MVA, to a new 345 kV Bermuda station with 11 5000A 63 kA circuit breakers & one 158.4 MVAR 345 kV cap bank, laid out as breaker-and-a-half configuration. Construct four single-circuit lines ~0.1 miles, between Bermuda station and the customer, utilizing 2-bundle ACSR Drake 795 (26/7) conductor SE 1800 MVA. Reason for update: As part of further engineering reviews, it was determined that the previously proposed capacitor bank at Bermuda would be more efficiently accommodated at Curleys station. The scope update adds the 2nd capacitor at Curleys and removes it from the scope at Bermuda.	9/12/2025	$58.30	AEP	12/5/2023
	S3442.11	Fiesta 138 kV: Cut into the Corridor-Green Chapel 138 kV circuit and extend ~0.75 miles of new double-circuit line, utilizing 2-bundled ACSR Falcon 1590 (54/19) conductor, SE rating 1118 MVA, to the greenfield Fiesta station with 10 4000A 80 kA breakers laid out as breaker-and-a-half for future expansion to six strings. Construct four 138 kV tie lines to the customers dead end structures ~0.05 miles utilizing ACSR Drake 795 (26/7) conductor SE 360 MVA.	1/2/2026	$22.30		
	S3442.12	Anguin-Rockhopper 138 kV: Reconfigure existing Anguin station and install 10 138 kV, 4000A 80 kA circuit breakers to feed customer stations at Penguin and QTS North. Build out strings G & H and construct a new greenfield ~0.6 miles double-circuit line to customer's Rockhopper station. Install two 69.1 MVAR cap banks at Anguin station.	2/20/2024	$13.20		
	S3442.13	Tasjan 138 kV: Cut into the Innovation-Green Chapel 138 kV circuit No. 1 and extend ~0.75 miles of new double-circuit line, utilizing 2-bundled ACSS Curlew 1033.5 (54/7) conductor, SE rating 1123 MVA, to the greenfield Tasjan station with four 4000A 80 kA breakers laid out four-circuit breaker ring bus. Construct two 138 kV tie lines to the customers dead-end structures ~0.05 miles utilizing ACSR Drake 795 (26/7) conductor SE 360 MVA.	11/19/2025	$18.95		
	S3442.14	Anguin-Chinstrap 138 kV: Extend the 138 kV double-circuit line to Rockhopper by ~0.22 miles to the new Chinstrap (customer) station.	4/4/2024	$1.01		
	S3442.15	Anguin-NBY-6A 138 kV: Install three 138 kV, 4000A 80 kA circuit breakers and construct a new greenfield ~0.9 miles double circuit line to customer's new NBY-6A station.	1/31/2025	$6.92		
	S3442.16	Corridor-Vassell 345 kV No. 1 & No. 2 circuits sag rerate: Replace two structures to mitigate sag issues on the line in order to allow the line to operate to its conductor's designed maximum operating temperature.	10/14/2025	$1.88		
	S3442.17	Kiber Station 138 kV: Cut into Green Chapel-Corridor 138 kV circuit to a new Kiber station with eight 80 kA, 138 kV circuit breakers laid out in a breaker-and-a-half arrangement to install a 2x150 MVAR STATCOM to support the significant amount of load added to the area. Reason for update: As part of further engineering analysis, it was determined that in order to be able to physically accommodate the line exits along with two feeds to the STATCOM when taking into account future needs at the station that a total of eight 138 kV breakers would need to be installed initially.	5/2/2027	$35.00		
	S3442.18	Green Chapel cap banks 138 kV: Upgrade proposed cap banks at Green Chapel station from two 69.1 MVAR to two 115.2 MVAR.	10/2/2026	$3.60		
	S3442.19	Corridor 138 kV: Replace 12 63 kA circuit breakers & cap breakers with 80 kA circuit breakers to improve interrupting capabilities as a result of the new sources in the area.	6/1/2025	$12.60		
	S3442.20	Babbitt 138 kV: Replace two 63 kA bus-tie circuit breakers with 80 kA circuit breakers to improve interrupting capabilities as a result of the new sources in the area.	2/17/2026	$2.15		
	S3442.21	Jug Street: Replace circuit breaker-C, which is an existing 40 kA breaker with a 138 kV, 4000A 80 kA breaker to address interrupting capability concerns related to the introduction of the new 345 kV source at Innovation.	4/8/2025	$0.80		
	S3442.22	Anchor Hocking-Lancaster 69 kV line: Rebuild ~1.16 miles of 69 kV line utilizing ACSR Dove 556.5 (26/7) conductor, SE 142 MVA. As a result of the new customer interconnections in the area, this line will overload under certain N-1-1 scenarios.	6/29/2026	$2.50		
	S3442.23	Newark Center 138 kV: Install high- and low-side sectionalizing on the 138/69 kV transformer to address overloading of 69 kV lines in the area related to the new customer interconnections under certain N-1-1 scenarios.	5/3/2027	$2.50		

Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
51	S3442.24	Fremont-West Fremont 138 kV: Sag rerate the 138 kV circuit & upgrade 1200A switches at Fremont to address a Generation deliverability violation related to the new customer interconnections in the area.	12/1/2026	$2.00	AEP	12/5/2023
	S3442.25	Fremont-Fremont Center 138 kV: Sag rerate the 138 kV circuit to address a generation deliverability violation related to the new customer interconnections in the area.		$1.50		
52	S3442.27	Vassell-Green Chapel 345 kV line: Install an ~12.5-mile long 345 kV transmission between Vassell and Green Chapel stations to mitigate overloading on multiple transmission facilities including other 345 kV transmission lines and 345-138 kV transformers.	4/1/2026	$75.00		
	S3442.28	Vassell-Curleys 345 kV line: Install an ~12.5-mile long 345 kV transmission between Vassell and Curleys stations to mitigate overloading on multiple transmission facilities including other 345 kV transmission lines and 345-138 kV transformers.	12/1/2026	$75.00		
	S3442.29	Vassell 765 & 345 kV stations: Add three 345 kV breakers to connect new lines to Curleys and Green Chapel.	4/1/2026	$10.00		
	S3442.30	Green Chapel 345/138 kV station: Install two 675 MVA, 345/138 kV transformers to connect the new Vassell-Green Chapel 345 kV line to 138 kV system and to mitigate overloading on the other 345/138 kV transformers in the system.		$39.20		
53	S3443.1	Tap the existing feeder adjacent to customer's new substation. Install three steel poles: one at the tap, one to support a line switch, and one to support two spans to the customer's substation. Install a motorized line switch with SCADA control. Connect all with 954 ACSR conductor. Install revenue metering in the customer's new substation.	2/23/2026	$0.50	DEO&K	7/19/2024
54	S3444.1	At Evendale, disconnect circuit breaker 930 and save it for reuse. In an open, adjacent bay, install a new 3000A gas circuit breaker in series with circuit breaker 929 creating a double-bus, double-breaker connection for the feeder that connects Evendale through Kemper to Port Union. Install new line and bus disconnects and connecting bus conductors. This double-breaker configuration removes the total interruption of service contingency and acts as a bus tie. At Port Union, replace circuit breaker 835 with a new 3000A gas circuit breaker, its line and bus disconnects, and connecting bus conductors. Circuit-limiting CTs are being replaced with circuit breaker 835. The new ratings for the circuit from Port Union to Kemper are 394/394 MVA summer and 487/487 MVA winter.	12/18/2026	$3.06		
55	S3445.1	Giles station 138 kV: Establish a new three-breaker ring bus station named Giles using 3000A 40 kA circuit breakers.	10/1/2025	$3.88	AEP	2/16/2024
	S3445.2	Clinton-Huntley-Karl 138 kV circuit: Cut into the existing Clinton-Huntley-Karl 138 kV for the Giles extension line to tap into.		$0.79		
	S3445.3	Giles 138 kV Extension: Construct a new 0.1-mile double circuit in-and-out line from the Clinton-Huntley-Karl 138 kV circuit to the new Giles station.		$0.56		
	S3445.4	Giles 138 kV Extension: Remote end relay upgrades at Scherers Switch, Huntley and Blendon stations.		$0.07		
56	S3446.1	Rebuild on the existing site with nine 138 kV, 3000A 63 kA breakers and utilizing one of the original breakers that is in good health to create a ten-breaker ring bus. Add a 28.8 MVAR 138 kV cap bank. Construct a greenfield 40 kV yard with two new 50 MVA 138/40 kV transformers to support the three 40 kV customers served from the station. Use existing breaker 16 and 22 on the low side of the transformers. Replace breakers 17 and 10 with existing breakers 15 and 21, which are in good health. Install a new DICM and remove the existing control house.	3/31/2027	$35.38		1/19/2024
	S3446.2	As part of the station reconfiguration, the double-circuit 138 kV line from Marion to LSII and Harrison will be rerouted into the new 138 kV yard with a new 0.15-mile extension using ACSR Drake 795 (26/7) conductor (SE 360 MVA).		$1.14		
	S3446.3	Reroute the existing 40 kV service (Royal Building Products) T-line into the new 40 kV yard with a new 0.24-mile extension using ACSR Dove 556.5 (26/7) conductor (SE 142 MVA).		$0.90		
	S3446.4	Reroute the existing 40 kV service (ITC Manufacturing) T line into the new 40 kV yard with a new 0.19-mile extension using ACSR Dove 556.5 (26/7) conductor (SE 142 MVA).		$0.93		
	S3446.5	Construct a greenfield ~0.15-mile single-circuit line to Columbus Auto Shredding POI using ACSR Dove 556.5 (26/7) conductor (SE 142 MVA).		$0.92		
	S3446.6	Remote end work will be performed at Mound, Harrison and LSII stations to coordinate with the work at Marion Road.		$0.89		

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Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
57	S3447.1	Replace the circuit breakers with 3000A, gas-filled circuit breakers. Replace 17 disconnect switches with 3000A switches. Replace all bus conductors with dual 1590 kcmil conductor.	11/12/2027	$7.77	DEO&K	6/4/2024
58	S3448.1	Midtown substation: Install a new four-breaker ring bus substation in downtown AES Ohio. The solution will allow us to serve the load increase near the Montgomery County Fairgrounds and create shorter, more reliable feeds to local critical facilities.	12/31/2028	$8.30	AES Ohio	3/15/2024
	S3448.2	Midtown-6651 69 kV line: Cut in/out of the existing Tait-Eaker 1 circuit (6651) and build ~1.44-mile double-circuit line looping in and out of the new Midtown substation using 1351 AAC conductor with OPGW.		$4.60		
	S3448.3	Eaker substation: AES will install a new 69 kV, 2000A circuit breaker at the Eaker substation to sectionalize the existing transmission. AES will also install transmission lines relays for 6650 and the new 69 kV from Eaker to the Midtown sub.		$4.00		
59	S3450.1	Columbus Street substation: Retire the existing Columbus Street 69/12 kV substation. Construct a new replacement Columbus Street substation. Install four 69 kV circuit breakers arranged in a four-breaker ring configuration. Estimated Cost: $11.2 M, ISD 12/31/2027.	12/31/2027	$11.20		
	S3450.2	Columbus Street-Webb Road 69 kV line: Construct a new 7.1-mile 69 kV line with 1351 AAC and OPGW from Webb Road station to the newly established Columbus Street replacement substation. Estimated Cost: $17.2 M, ISD 12/31/2027.		$17.20		
	S3450.3	Wilmington-Columbus Street 69 kV line: Rebuild the 2.6-mile Columbus Street-Wilmington 69 kV line with 1351 AAC and OPGW. Construct a new 0.9-mile 69 kV line extension into the newly relocated Columbus Street substation. Upgrade relaying at both remote ends. Estimated Cost: $8.8 M, ISD 12/31/2028.	12/31/2028	$8.80		
	S3450.4	Webb Road substation: Expand the Webb Road 69 kV substation and construct a new 69 kV four-breaker ring. Estimated Cost: $9 M, ISD 12/31/2028.		$9.00		
	S3450.5	Washington CH-Wilmington 69 kV line (6637): Rebuild with OPWG fiber: AES will rebuild ~23.0-mile 69 kV line from Washington CH to Wilmington substation utilizing 1351 AAC conductor with OPGW fiber, including remote-end upgrades at Wilmington and Washington CH substations. Estimated Cost: $60.1 M, ISD 12/1/2030.	12/1/2030	$60.10		
	S3450.6	Sabina 69 kV substation: AES will install a new four-breaker ring bus configuration between the two 69/12 kV banks, replace four switches, replace the existing wood structures with steel. Estimated transmission cost: $9 M, ISD 12/1/2030.		$9.00		
	S3450.7	Air Park 69 kV substation: AES will install two new 69 kV, 2000A circuit breakers to establish three-breaker ring bus at the existing Air Park substation. Estimated Cost: $5.2 M, ISD 12/1/2029.	12/1/2029	$5.20		
60	S3453.1	Install two main-line SCADA-controlled switches. Install one tap-line SCADA controlled switch. Construct an ~150 feet of 69 kV line to the customer substation. Revise relay settings at Cloverdale and Dale substations.	2/7/2025	$0.63	ATSI	4/19/2024
61	S3454.1	Install two main-line switches. Construct an ~0.1 miles of 138 kV line to the customer substation. Adjust relay settings at London and Tangy substations.	5/24/2024	$0.00		
62	S3455.1	Cut open the Republic Arc-Republic Vine 138 kV line and install a normally open switch. Adjust protection setting at Black River, Republic Arc and Republic Vine substations.	8/25/2025	$0.40		
63	S3456.1	Install one main-line SCADA-controlled switch. Install one tap-line SCADA-controlled switch. Construct an ~0.2 miles of 138 kV line to the customer substation. Revise relay settings at Evergreen and Highland substations.	6/1/2026	$1.40		
64	S3467.1	Milton-Newton Falls 69 kV line: Rebuild an ~27.3 miles of Milton-Newton Falls 69 kV line.	12/29/2028	$45.92		5/17/2024
65	S3468.1	Angola: Replace circuit switcher with a new circuit breaker. Replace line trap, limiting substation conductor and line relaying. Midway: Replace circuit breaker and associated disconnect switches. Replace line trap and line relaying.	4/1/2029	$3.42		
66	S3469.1	Galion-Roberts North 138 kV line and Galion-Roberts South 138 kV line: Rebuild the double-circuit Galion-Roberts North 138 kV line and Galion-Roberts South 138 kV line on shared structures. Galion: Replace circuit breakers and associated disconnect switches. Roberts: Replace substation conductor.	8/27/2026	$66.50		

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Table 6.50: Ohio Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
68	S3496.1	Rebuild the West Unity (Stryker) 69 kV line (total rebuild length an ~11.6 miles).	12/31/2026	$18.10	ATSI	6/14/2024
69	S3497.1	Install 138 kV tie line breaker and associated relaying at West Lorain. Install revenue metering equipment on the 138 kV tie line at Beaver. Remove breaker B-23 and associated relaying. Upgrade revenue metering equipment for West Lorain units 2–6. Transfer ownership of the 345 kV motor-operated disconnect switch D-177 at Beaver substation to ATSI.	12/18/2026	$3.56		
70	S3498.1	Convert Tiger substation into a four-breaker ring bus.	6/19/2028	$5.40		
71	S3499.1	Install one tap-line SCADA-controlled switch. Install SCADA-controlled on existing main-line switch. Construct 0.6 miles of 138 kV line extension. Adjust relay settings at Cloverdale and Harmon substations. Install revenue metering.	5/26/2028	$0.70		
72	S3500.1	Install one tap-line SCADA-controlled switch. Construct 0.1 miles of 69 kV line extension. Adjust relay settings at Abbe and Medina substations. Install revenue metering.	8/29/2025	$0.20		
73	S3521.1	Install two main-line SCADA-controlled switches. Install one tap-line SCADA-controlled switch. Construct 0.1 miles of 138 kV line extension. Adjust relay settings at London and Tangy substations. Install revenue metering.	6/3/2026	$1.60		7/19/2024
74	S3522.1	Install two main-line SCADA-controlled switches. Install one tap-line SCADA-controlled switch. Construct 0.1 miles of 69 kV line extension. Adjust relay settings at Bingham and Cook substations. Install revenue metering.	12/27/2027	$1.21		
75	S3523.1	Install one tap-line SCADA-controlled switch. Construct a span of 69 kV line extension. Adjust relay settings at Adams and Shinrock substations. Install revenue metering.	5/9/2025	$0.15		
76	S3524.1	Phase 1: 138 kV transmission line tap: Install two main-line SCADA-controlled switches. Install one tap-line SCADA-controlled switch. Construct an ~0.1 miles of 138 kV line extension. Adjust relay settings at East Springfield and North Titus substations. Install revenue metering.	6/1/2027	$2.47		
	S3524.2	Phase 2: 138 kV switching station: Build a new 11-breaker, breaker-and-a-half 138 kV substation. Loop the East Springfield-London 138 kV line in and out of the new substation. Remove the tap on the East Springfield-North Titus 138 kV line and loop the line in and out of the new substation. Install three 30 MVAR capacitor banks at the new 138 kV substation. Build an additional span of 138 kV line from the new substation to the POI with the customer. Install a second set of revenue metering. Adjust relay settings at London, North Titus and East Springfield substations.	11/1/2028	$23.60		
77	S3525.1	Install two main-line SCADA-controlled switches. Install one tap-line SCADA-controlled switch. Construct 0.1 miles of 138 kV line extension. Adjust relay settings at Galion and Ontario substations. Install revenue metering.	7/14/2025	$1.04		

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6.10: Pennsylvania RTEP Summary

6.10.1 — RTEP Context

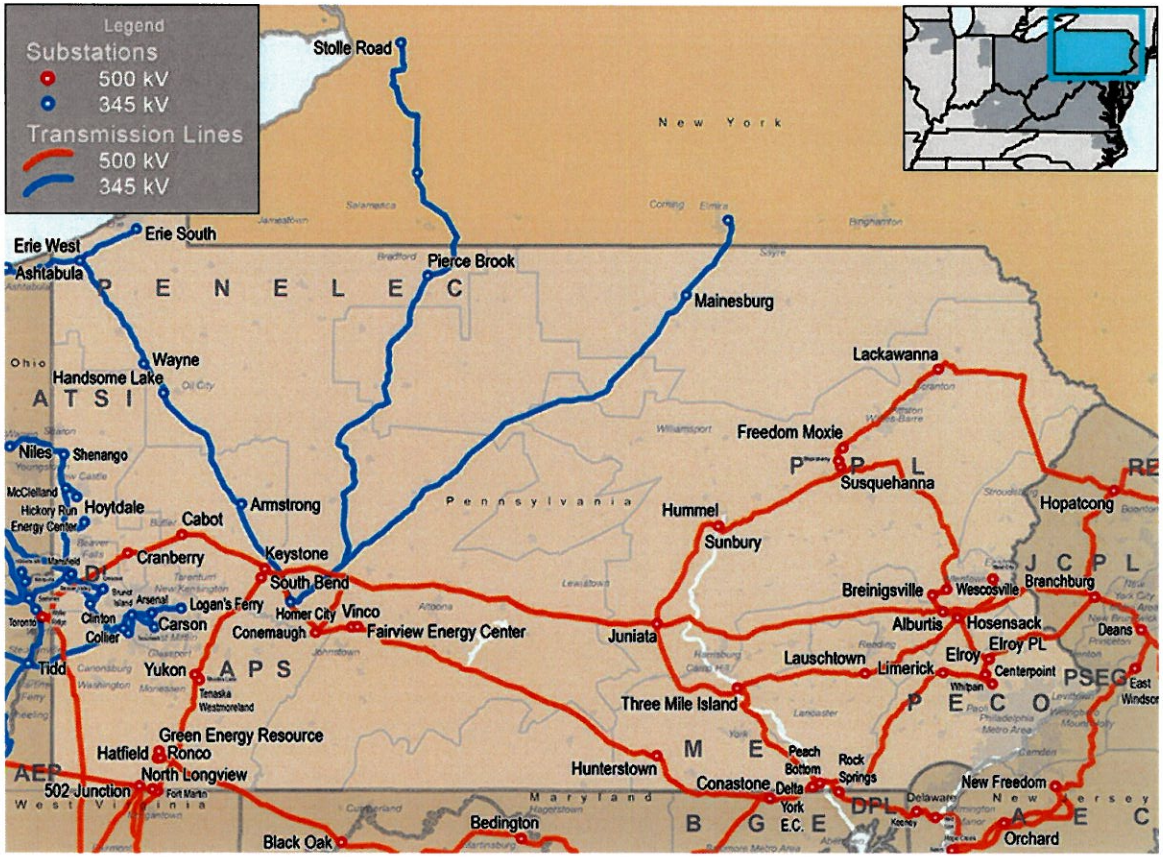
PJM, a FERC-approved RTO, operates and plans the bulk electric system (BES) in Pennsylvania, including facilities owned and operated by Allegheny Power (AP) [FirstEnergy], Duquesne Light Company (DLCO), Met-Ed (METED), Pennsylvania Electric Company (Penelec), PECO Energy Company (PECO), PPL Electric Utilities (PPL), UGI Utilities (UGI), Rock Springs and American Transmission Systems, Inc. (ATSI) [FirstEnergy] as shown on **Map 6.42**.

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 the PJM service area.

Renewable Portfolio Standards

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 applying toward the AEPS must be located within Pennsylvania.

Map 6.42: PJM Service Area in Pennsylvania



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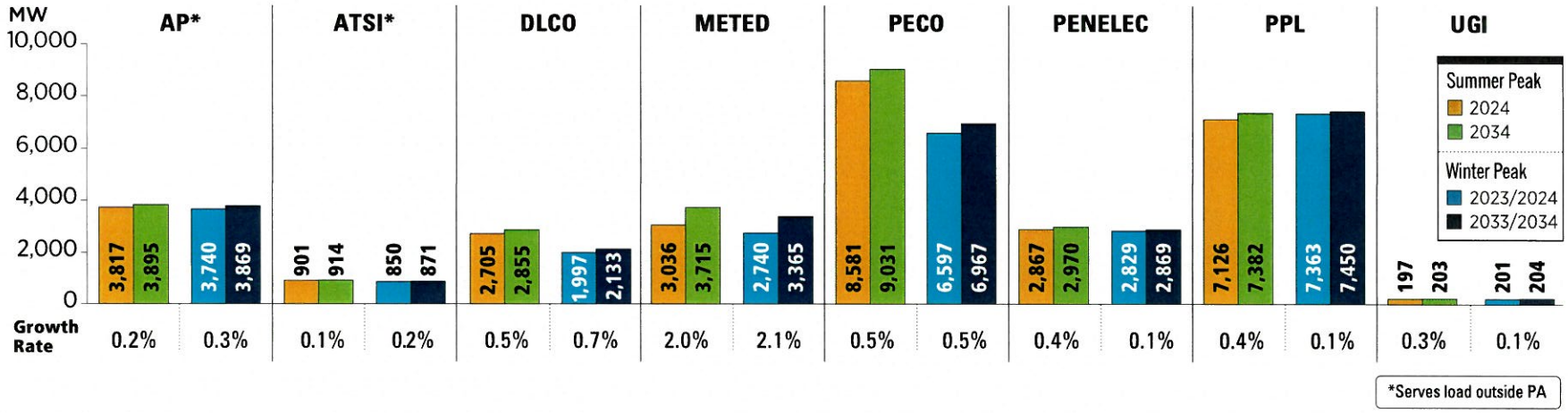
6.10.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.46** summarizes the expected loads within the state of Pennsylvania and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.46: Pennsylvania – 2024 Long-Term Load Forecast



PJM RTO Summer Peak

2024	2034
151,247 MW	176,822 MW

Growth Rate 1.6%

PJM RTO Winter Peak

2023/2024	2033/2034
134,659 MW	163,069 MW

Growth Rate 1.9%

PJM notes that Allegheny Power (FirstEnergy) and ATSI (FirstEnergy) serve load other than in Pennsylvania. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by each of those transmission owners solely in Pennsylvania. Estimated amounts were calculated based on the average share of each transmission owner's real-time summer and winter peak load located in Pennsylvania over the past five years.

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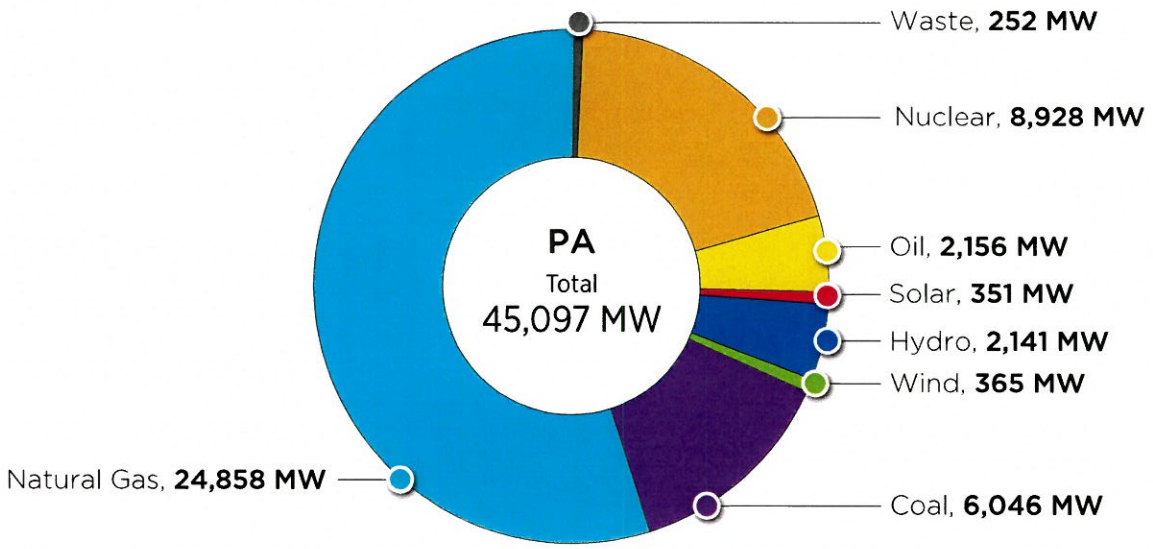
6.10.3 — Existing Generation

Existing generation in Pennsylvania as of Dec. 31, 2024, is shown by fuel type in **Figure 6.47**.

Figure 6.47: Pennsylvania – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



Read More
Changing Capacity Mix and Deliverability

6.10.4 — Interconnection Requests

In Pennsylvania, as of Dec. 31, 2024, 394 projects were actively under study or under construction as shown in the summaries presented in **Table 6.51**, **Table 6.52**, **Figure 6.48**, **Figure 6.49** and **Figure 6.50**.

NOTE:
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.

Read More
Interconnection Requests

Table 6.51: Pennsylvania – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	Pennsylvania Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	3,092	26.30%	20,162	14.38%
Hydro	35	0.30%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	60	0.51%	8,242	5.88%
Nuclear	44	0.37%	44	0.03%
Other	3	0.02%	64	0.05%
Solar	4,694	39.92%	55,040	39.25%
Storage	3,414	29.04%	39,064	27.86%
Wind	415	3.53%	17,455	12.45%
Grand Total	11,757	100%	140,231	100%

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Table 6.52: Pennsylvania – Interconnection Requests by Fuel Type (Dec. 31, 2024)

		In Queue				Complete				Grand 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	17	2,31.5	28	14,354.6	45	14,586.1
	Natural Gas	1	60.0	0	0.0	126	21,743.3	261	92,559.5	388	114,362.8
	Oil	0	0.0	0	0.0	9	16.9	9	1,307.0	18	1,323.9
	Diesel	0	0.0	0	0.0	4	37.4	13	51.5	17	88.9
	Nuclear	0	0.0	1	44.0	14	2,565	15	1,731.0	30	4,340.0
	Wood	0	0.0	0	0.0	0	0.0	1	16.0	1	16.0
	Other	1	2.9	0	0.0	1	304.0	4	344.0	6	650.9
	Storage	46	3,414	0	0.0	5	0.0	89	2,292.4	140	5,706.3
Renewable	Hybrid	73	3,092.4	0	0.0	0	0.0	77	1,628.0	150	4,720.3
	Hydro	2	23.0	1	12.0	12	480.8	23	939.6	38	1,455.4
	Biomass	0	0.0	0	0.0	1	6.4	4	36.5	5	42.9
	Methane	0	0.0	0	0.0	22	120.2	37	201.3	59	321.5
	Solar	247	4,508	8	185.7	37	495.9	542	7,726.6	834	12,916.1
	Wind	12	380.4	2	34.5	40	289.0	141	1,799.3	195	2,503.1
	Grand Total	**382**	**11,480.6**	**12**	**276.2**	**288**	**26,290.3**	**1,244**	**124,987.2**	**1,926**	**163,034.2**

Figure 6.48: Pennsylvania – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

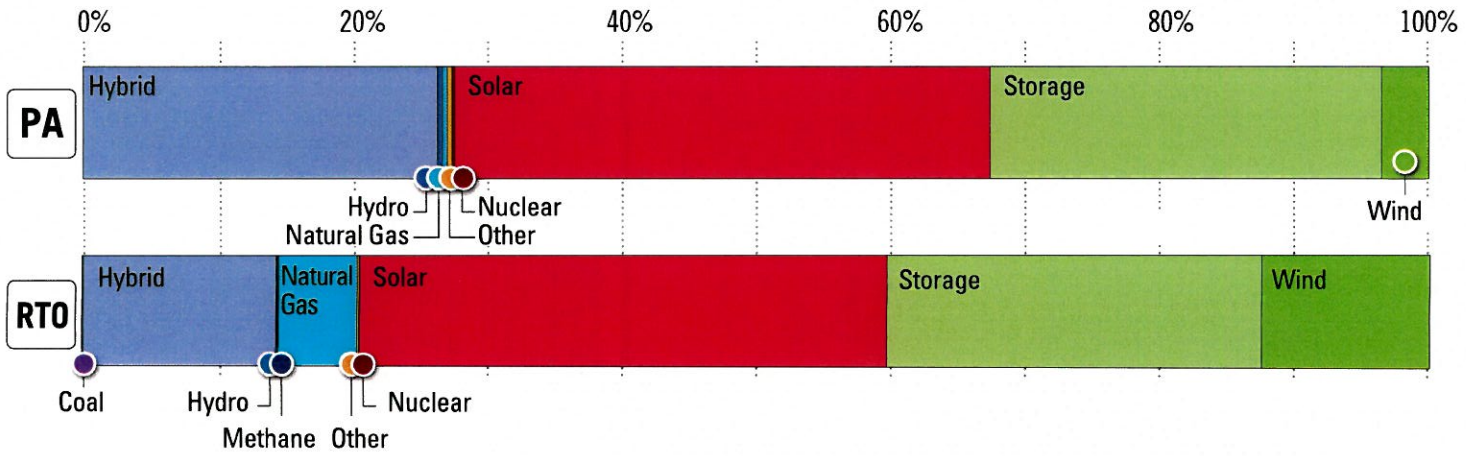

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Figure 6.49: Pennsylvania Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

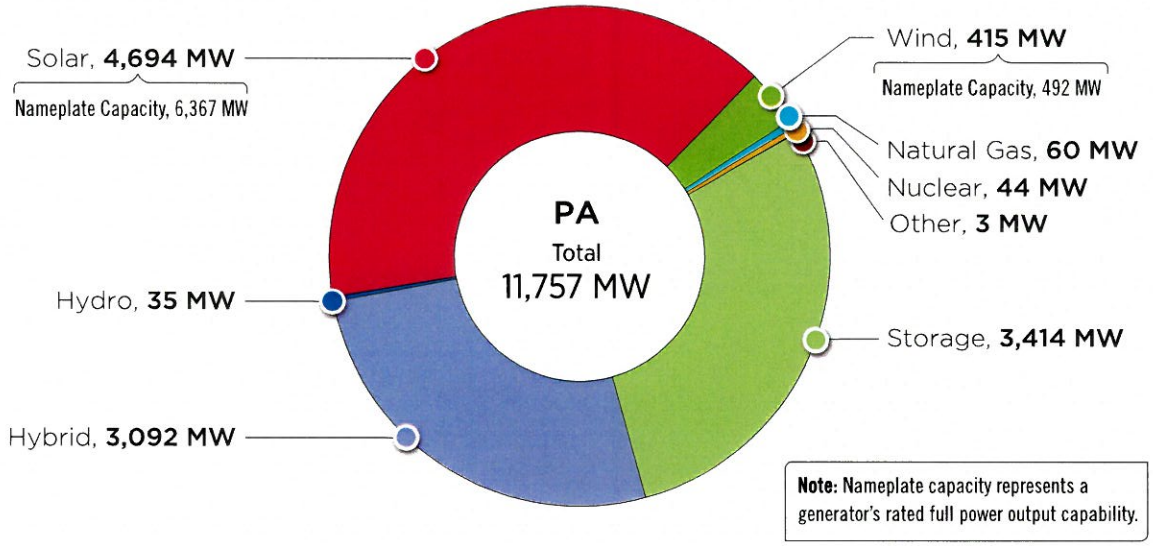

Figure 6.50: Pennsylvania Progression of Interconnection Requests (Dec. 31, 2024)

Percentage of planned capacity and projects that have reached commercial operation

16.0%	Requested capacity megawatts
13.5%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	79	Interconnection Service Agreements	7,743 MW	10,216 MW
	118	Wholesale Market Participation Agreements	510 MW	835 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, 2024.

6.10.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Pennsylvania between Jan. 1, 2024, and Dec. 31, 2024, are summarized in **Map 6.43** and **Table 6.53**.

Read More
Baseline Projects

Map 6.43: Pennsylvania Generation Deactivations (Dec. 31, 2024)

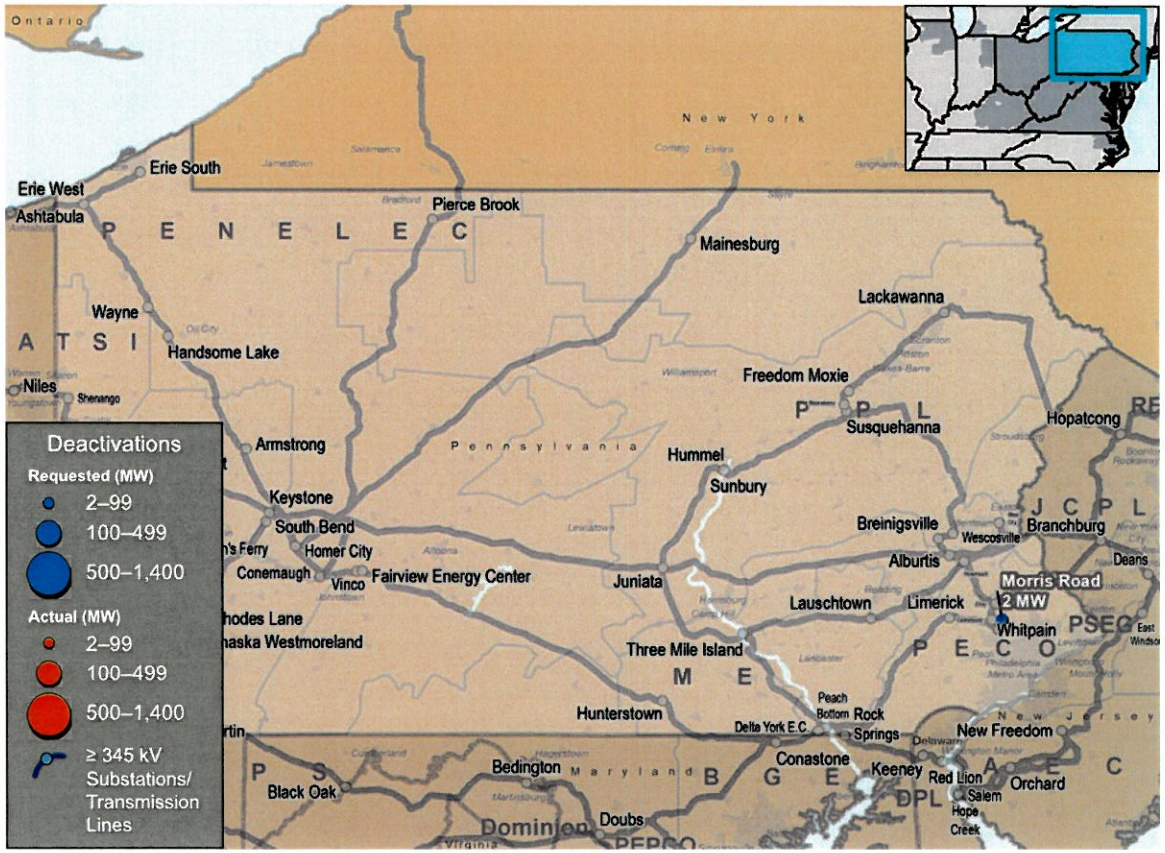

Table 6.53: Pennsylvania Generation Deactivations (Dec. 31, 2024)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Morris Road	PECO	Oil	7/17/2024	5/31/2025	14	2

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6.10.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in Pennsylvania are summarized in **Map 6.44** and **Table 6.54**.

Read More
Baseline Projects

Map 6.44: Pennsylvania Baseline Projects (Dec. 31, 2024)

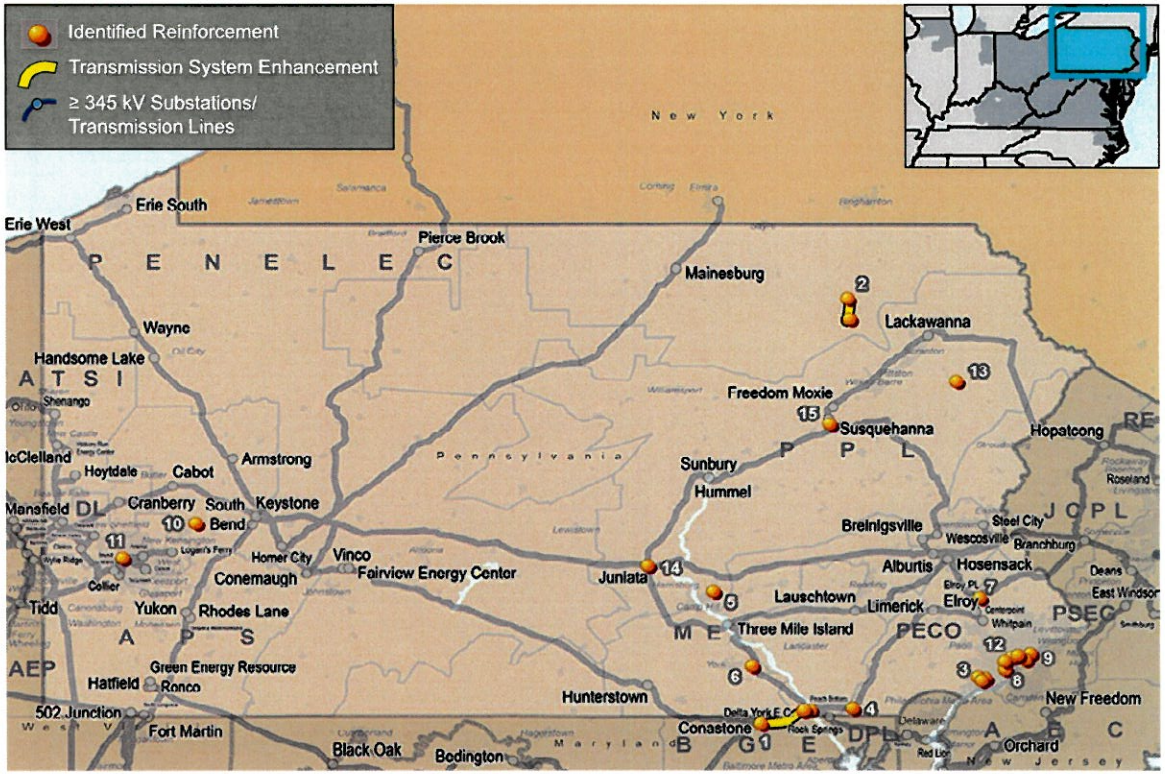

Table 6.54: Pennsylvania Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3780.14	Reconfigure Cooper transmission feeds by establishing new Cooper-North Delta 230 kV line and rerouting existing transmissions lines by Cooper.	6/1/2025	$6.73	PECO	12/5/2023
	B3780.15	Cut in 5012 Peach Bottom-Conastone 500 kV line into North Delta 500/230 kV substation by rebuilding 5012 between new terminal at Peach Bottom South and North Delta on single circuit structures and terminating at North Delta.		$7.29		
	B3780.16	Terminate new Cooper-North Delta 230 kV line (Transource Scope) at North Delta 230 kV.		$0.47	Transource	
	B3780.17	Cut in 5012 Peach Bottom-Conastone 500 kV line into North Delta 500/230 kV substation by rebuilding 5012 between new terminal at Peach Bottom South and North Delta on single circuit structures and terminating at North Delta (Transource Scope).		$1.10		
	B3800.52	Reconfigure Peach Bottom North and South yards to allow for termination of 500 kV lines from Peach Bottom to North Delta. North Delta 500 kV termination for the new Peach Bottom-North Delta 500 kV line.	6/1/2027	$7.86	PECO	10/31/2023
	B3800.53	Construct a double circuit 500 kV line from the existing TMI-Peach Bottom 500 kV right-of-way to the proposed Chanceford switchyard ~1.0 miles in length.		$12.59	PP&L	5/1/2024
2	B3791.0	Rebuild the North Meshoppen-Mehoopany No. 1 115 kV line with 795 ACSR 26/7 STR conductor. Upgrade terminal equipment to exceed transmission line ratings.	6/1/2028	$17.40	PENELEC	10/19/2023
	B3792.0	Rebuild the North Meshoppen-Mehoopany No. 2 115 kV line using 795 ACSR 26/7 STR conductor, and upgrade terminal equipment to exceed the transmission line rating.		$17.70		
3	B3844.1	Replacement of relays at Macdade, Printz and Morton to increase rating limits of transmission relay equipment. Line protection relays will be upgraded with latest standard relays used across the PECO system.	12/31/2026	$1.40	PECO	12/5/2023
4	B3845.1	Add a second breaker next to Nottingham 895 circuit breaker to eliminate stuck breaker contingency.	5/31/2028	$1.28		11/16/2023
5	B3858.1	Rebuild the Windsor substation 115 kV yard to convert from a straight bus configuration into a six-breaker ring bus configuration. Install two 21.62 MVAR, 115 kV capacitor banks. The substation fence will need to be expanded and an ~one acre of land will need to be purchased. No wetlands or environmental risks were identified at this time. The Tolna and Yorkana 115 kV line exits will need to be relocated. Below Grade: Install foundation, trench, conduit and grounding for new equipment. Install fencing, stoning, grading and ground grid for expansion area. Install conduit for fiber. Above Grade: Install four 115 kV, 3000A 40 kAIC circuit breakers. Relocate two 115 kV circuit breakers (B4 & B98932). Install 12 115 kV, 1200A GOAB disconnect switches. Install four 115 kV, 1200A MOAB disconnect switches. Install six 115 kV CVTs. Install six 115 kV surge arresters. Install four 115 kV H-frame dead ends. Install one 115 kV wave trap. Install two 115 kV, 21.62 MVAR cap banks. Install one 115 kV SSVT. Install one lot of cables, grounding, rigid bus and fittings for new equipment. Install one lot of fencing. Relaying and Control: Install six-breaker control panels with one SEL-451. Install two standard line relay panels with one SEL-421 and one SEL-411L. Install one carrier panel. Install two standard cap bank panels with two SEL-487Vs. Install one lot of control cables, SEL cables and fiber. Additional equipment to be removed: Existing foundations, conduit, steel structures, one 115 kV circuit breaker, six 115 kV disconnect switches 115 kV relay panels, one 115 kV wave trap, line tuner and coax.	6/1/2028	$12.36	METED	11/14/2024

Table 6.54: Pennsylvania Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
6	B3858.2	Rebuild the Yorkana Substation 115 kV yard converting from a straight bus configuration to a nine breaker, breaker-and-a-half configuration. The substation fence will need to be expanded but no land acquisition will be required. The Glades, Windsor, and Redfront 115 kV line exits will need to be relocated. Below Grade: Install one lot of foundations, conduit and grounding for new equipment. Install one lot of cable trench in 115 kV area of the yard. Install one lot of stoning, grading, and ground grid for the substation yard expansion. Above Grade: Install one prefabricated control building with battery system, AC & DC aux power panels, security cabinet, and MPLS network equipment. Install one lot of fencing for substation yard expansion. Install three 115 kV A-frame dead ends. Install three 115 kV H-Frame dead ends. Install two 115 kV monopole structures. Install nine 115 kV circuit breakers. Install 18 115 kV GOAB disconnect switches. Install six 115 kV MOAB disconnect switches. Install 18 115 kV surge arresters. Install 18 115 kV CVTs. Install two 115 kV SSVTs. Install one lot of rigid bus, insulators, fittings, conductor, connectors, and support structures. Relaying and Control: Install three Standard FE line relay panels, consisting of one SEL-421, one SEL-411L, over fiber. Install nine standard FE breaker panels, consisting of one SEL-451. Install three standard FE transformer panels. Install two standard FE bus diff panels. Install one standard FE cap bank panels. Install one SCADA RTU. Install one HMI panel with GPS clock and RTAC. Install one ATS. Install one lot of control cables and SEL cables. Additional equipment to be removed: Remove existing 115 kV rigid bus, steel, seven circuit breakers, 12 disconnect switches, 10 CVTs, 12 surge arresters and five A-frame dead ends. Remove all existing 115 kV relaying and controls: Three transformer panels, two bus panels, one cap bank panel, three line panels and seven breaker panels.	6/1/2028	$20.80	METED	11/14/2024
7	B3862.1	Upgrade two 500 kV free standing CTs, one disconnect switch and four sections of tube bus at Elroy 500 kV substation.	6/1/2029	$1.50	PECO	12/3/2024
8	B3863.1	Change tap ratios on two CTs at Schuylkill 230 kV substation.	12/1/2029	$0.10	PECO	11/14/2024
9	B3864.1	Replace station cable at Tacony 69 kV station.	6/1/2029	$0.18	PECO	11/14/2024
	B3864.2	Replace station cable at Richmond 230 kV station.		$0.18	PECO	11/14/2024
10	B3870.1	At Federal Street substation: Install three 138 kV CCVTs on the 138 kV bus. Remove the transformer 1 CO-6 138 kV Phase relay overcurrent relays. Install one SEL-421 relay on the high side of transformer 1. Install foundations, conduit and grounding for new CCVTs. Install cables between CCVTs and relay.	6/1/2028	$0.69	AP	11/15/2024
11	B3871.1	Replace two 138 kV disconnect switches with 3000 amp disconnect switches and replace a portion of the stranded conductor on the No. 2 138 kV bus with aluminum pipe bus.	6/1/2029	$8.00	DL	11/15/2024
12	B3907.1	Reconductor entire 2.5 miles of North Philadelphia to master 230 kV line.	6/1/2029	$6.49	PECO	12/3/2024
	B3907.2	Richmond to Waneeta 230 kV line: Rebuild entire 0.95 miles of existing UGT and rebuild entire 2.23 miles of existing OHT.	6/1/2028	$29.40	PECO	12/3/2024
	B3907.3	Reconductor 2.12 miles of North Philadelphia to Waneeta 230 kV line.	6/1/2028	$7.33	PECO	12/3/2024
13	B3908.1	Install one 80 MVAR 230 kV capacitor bank at Pocono 230 kV substation.	6/1/2029	$4.93	PP&L	12/3/2024
14	B3909.1	Juniata 500 kV yard expansion/reconfiguration to include one new bay and eliminate the line fault stuck breaker.	6/1/2028	$22.20	PP&L	12/3/2024
15	B3910.1	Susquehanna T10 230 kV station reconfiguration: Break the existing Susquehanna-Glen Brook 230 kV line and loop it 0.2 miles in and out of the Susquehanna T10 230 kV station.	6/1/2029	$9.50	PP&L	12/3/2024

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6.10.7 — Network Projects

Network projects in Pennsylvania for 2024 are summarized in **Map 6.45** and **Table 6.55**.

Read More
Network Projects

Map 6.45: Pennsylvania Network Projects (Dec. 31, 2024)

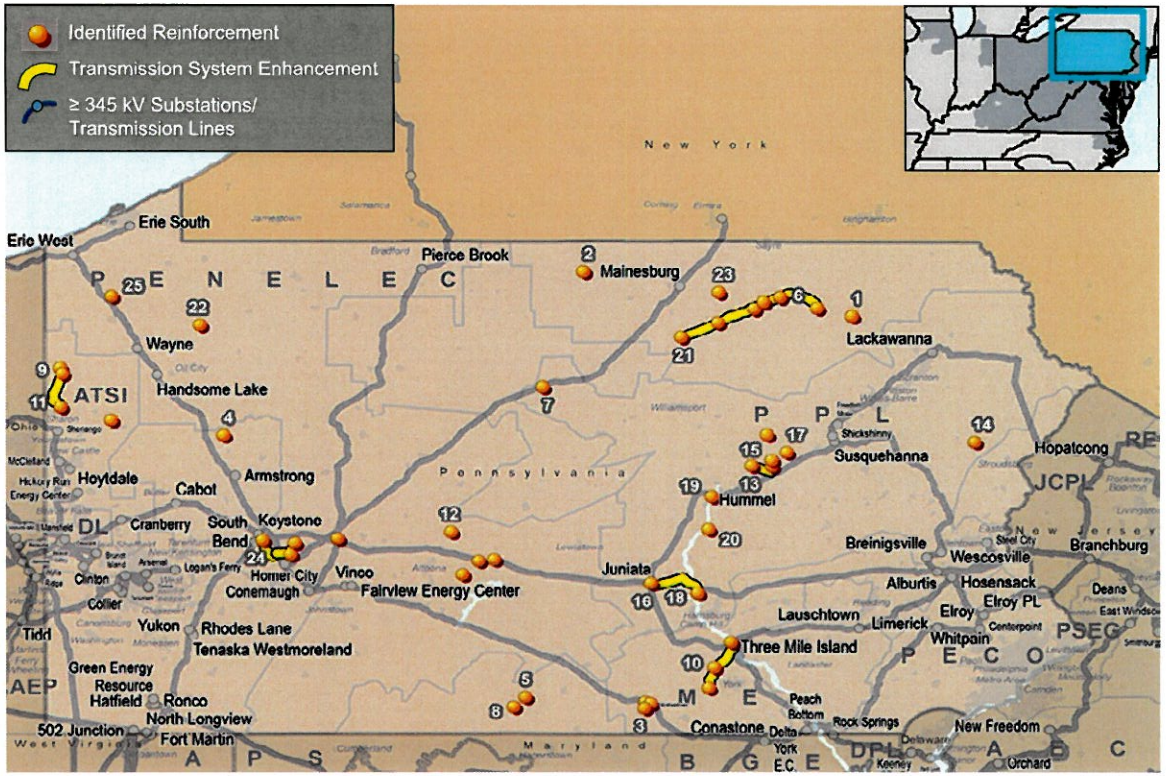

Table 6.55: Pennsylvania Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N4287	Install 34.5 kV tap, radio-controlled switch and associated equipment at North Meshoppen 34.5 kV and Tunkahannock 34.5 kV substations.	Z1-038	12/31/2015	$0.10	PENELEC	10/8/2024
2	N4997	Replace the disconnect switch at the Sabinsville 115 kV substation.	AA2-081	6/1/2017	$0.09	PENELEC	10/8/2024

Table 6.55: Pennsylvania Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	N5987	Install new 115 kV three-breaker ring bus substation.	AD1-020	9/30/2019	$3.88	AP	1/9/2024
	N5988	Loop the 962 (Hunterstown-Lincoln) 115 kV circuit into substation.			$0.47		
	N5989	Revenue metering – engineering oversight of specification and design of new revenue metering that will be installed by power producer (interconnection customer) at their location (AD1-020) and connected to the new ring bus station on the Hunterstown-Lincoln line. Coordinate FE MV90 access to the new meter.			$0.00		
	N5990	Replace one existing shield wire with optical ground wire (OPGW) on the Hunterstown-Lincoln 115 kV circuit between the proposed AD1-020 ring bus and Lincoln substation, an ~1.6 miles.			$0.50		
	N5991	Replace one existing shield wire with OPGW on the Hunterstown-Lincoln 115 kV circuit between the proposed AD1-020 ring bus and Hunterstown substation, an ~1.0 miles.			$0.32		
	N5992	Install new line relaying and capacitor-voltage transformers (CVT) for the AD1-020 interconnection at Hunterstown substation.			$0.26		
	N5993	Install new line relaying and capacitor-voltage transformers (CVT) for the AD1-020 interconnection at Lincoln substation.			$0.26		
	N5994	Estimated MPLS router at new AD1-020 interconnection substation to support new RTU			$0.15		
4	N6680	Construct one span 25 kV tap to customer's substation on Young junction to Sligo 25 kV line.	AF1-210	6/1/2023	$0.03		10/8/2024
	N6681	Install 25 kV metering in the customer's substation at Young junction to Sligo 25 kV line.			$0.04		
	N6682	Construct 25 kV line tap with two 25 kV switches on the at Young junction to Sligo 25 kV line for the interconnection of AF1-210.			$0.06		
	N6683	Update relay settings at Burma 23 kV.			$0.01		
	N6684	Update relay settings at Templeton 23 kV.			$0.01		
5	N7009	At new AE1-101 138 kV switchyard: Install line exit take-off structure, foundations, disconnect switch and associated equipment at ring bus substation.	AE1-101	10/1/2022	$0.64		1/9/2024
	N7028	Garrett: Replace wave trap and line tuner. Add anti-islanding & replace line relaying. Change carrier frequency and adjust relay settings.			$0.39		
6	N7127.2	Reconductor 13.01 miles of line East Towanda to Canyon 230 kV line. Replace transmission line drop at East Towanda.	AE2-139	5/30/2022	$89.22	PENELEC	10/8/2024
	N7127.3	Replace disconnect switch at Canyon 230 kV substation.			$1.06		
	N7127.4	Replace line trap at East Towanda 230 kV substation.			$0.23		
	N7127.5	Adjust/replace metering and line relaying at East Towanda 230 kV substation.			$0.50		
7	N7202	Reconductor 0.1 miles of the Chapman to AA2-000 tap 230 kV line.			$0.45		
8	N7272	Install a 600A gang-operated switch on a new pole to tap the McConnellsburg-Mercersburg 34.5 kV line.	AD1-061	12/31/2021	$0.04	AP	1/9/2024
	N7273	Provide 34.5 kV meter package at LSBP solar facility connection.			$0.01		
	N7278	Project management, environmental, forestry, real estate and right-of-way			$0.06		

Table 6.55: Pennsylvania Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
9	N7310	AE2-285 generator lead termination: installation of foundations, disconnect switch and associated equipment to accommodate the termination of the 69 kV generator lead line at the new AE2-285 substation	AE2-285	6/30/2022	$0.09	ATSI	10/8/2024
	N7311	Metering: Install customer-owned revenue metering at the new AE2-285 substation.			$0.00		
10	N7359	Loop the Jackson-TMI 230 kV line into the new AE2-211 ring bus substation.	AE2-211		$0.78	METED	1/9/2024
	N7360	Modify relay settings at Jackson.	AE2-212		$0.06		
	N7361	Modify relay settings at Three Mile Island.			$0.06		
11	N7926	Tap the Maysville-Sharon 69 kV (Y-301) line near structure 62 and install disconnect switches on either side of the tap at the new AE1-079 substation. Includes project management, environmental, forestry, real estate and right of way.	AE1-079	6/1/2020	$1.19	ATSI	10/8/2024
	N7927	Update relay settings at Marysville 69 kV substation.			$0.09		
	N7928	Update relay settings at Sharon 69 kV substation.			$0.09		
	N7930	Update relay settings at Cedar street 69 kV substation.			$0.09		
	N7931	Update relay settings at McDowell Street 69 kV substation.			$0.09		
	N7933	SCADA/fiber communication: Estimated installation of 700 MHz radio system (70% penetration of FE territory) to support the SCADA switch replacements at the new AE1-079 substation			$0.10		
	N7934	Tap the Dilworth-Andover (Maysville) 69 kV (Y-78) line at structure 145 and install disconnect switches on either side of the tap. Includes project management, environmental, forestry, real estate and right of way.	AE1-237		$0.88		
	N7935	Update relay settings at Marysville 69 kV substation.			$0.09		
	N7936	Update relay settings at Sharon 69 kV substation.			$0.09		
	N7937	SCADA/fiber communication: estimated installation of 700 MHz radio system (70% penetration of FE territory) to support the SCADA switch replacements at AE1-237 substation. Assumed SCADA work is included in this cost.			$0.05		
	N8087.1	McDowell 69 kV: Replace Maysville Y-80/107 line relay & control panel with a standard line relaying panel.	AF1-093	1/6/2026	$0.72		
	N8087.2	Masury 69 kV: Relay settings will be revised.			$0.04		
	N8087.3	AF1-093: Tap the Maysville-McDowell 69 kV line roughly 8.2 miles from McDowell substation, near structure 108. Install two 69 kV line switches with SCADA. Install one span of 795 ACSR Drake toward the customer substation.			$0.77		
	N8087.4	Maysville 69 kV: Relay settings will be revised.			$0.04		
	N8087.5	Cedar Street 69 kV: Relay settings will be revised.			$0.04		
	N8087.6	Sharon 69 kV: Relay settings will be revised.			$0.04		
	N8087.7	Campbell 69 kV: Relay settings will be revised.			$0.04		

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Table 6.55: Pennsylvania Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
12	N7995	AE2-117: Tap the Warrior Ridge-Williamsburg 46kV line to provide interconnection facilities to the customer substation, an ~2.5 miles from the Alexandria substation. Install SCADA-controlled MOAB switches on either side of tap location.	AE2-117	10/2/2021	$1.00	PENELEC	10/8/2024
	N7996	Williamsburg 46 kV: Replace existing line relaying and control panel for Tyrone North-Warrior Ridge line exit with one standard prewired relaying panel.			$0.25		
	N7997	Warrior Ridge 46 kV: Replace existing line relaying and control panel for Tyrone North-Williamsburg line exit with one standard prewired relaying panel.			$0.25		
	N7998	Tyrone North 46 kV: Replace existing line relaying and control panel for Warrior Ridge-Williamsburg line exit with one standard prewired relaying panel.			$0.25		
13	N8131.1	Complete DANV-COLU 2 line modifications to tie in the new AE2-110 attachment facilities. This includes connecting the conductors and OPGW from the MILT-MVIL line to the new tap structure. Install one MOLBAB just north of the AE2-110 tap point.	AE2-110	12/31/2021	$0.28	PP&L	1/9/2024
	N8131.2	Relay modifications scope of work at Columbia substation			$0.14		
14	N8165.1	Modifications to the Acahela-Jackson 69 kV line to tie in the AE2-175 attachment facilities	AE2-175	10/31/2021	$0.10		
	N8165.2	Relay modifications and remote end work			$0.14		
	N8165.3	Relay modifications and remote end work			$0.14		
15	N8181.1	Complete COLU-SCOT line modifications to tie in the new AE2-241 attachment facilities. This includes replacing existing structure (grid # 34537N30614) with a new high pole of a high-low tap structure with a foundation, and reframe/modify existing structures on each side of the new tap structure if required.	AE2-241	3/5/2021	$0.05		
	N8181.2	Relay modifications and remote end work			$0.11		
16	N8341.1	Modifications to the Mifflintown rap 69 kV line to tie in the AF2-361 attachment facilities	AF2-361	12/31/2022	$0.10		
	N8341.2	Relay modifications scope of work at Juniata substation			$0.24		
	N8341.3	Relay modifications scope of work at Dauphin substation			$0.24		
17	N8351.1	Modifications to the Millville tap 69 kV line to tie in the AF1-226 attachment facilities	AF1-226	3/5/2021	$0.28		
	N8351.2	Relay modification work for IC and remote end			$0.14		
18	N8446.1	Modify relays at Dauphin 69 kV substation.	AF2-082	12/31/2027	$0.14		10/8/2024
19	N8446.2	Modify relays at Sunbury 69 kV substation.	AF2-083		$0.14		
20	N8446.4	Install a new single circuit, custom foundation, custom steel pole, full terminal dead-end structure (PCO) between Sunbury-Dauphin 69 kV line. The PCO structure must be outside of the Project Developer's substation fenced area.	AF2-084		$0.01		

Table 6.55: Pennsylvania Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
21	N8486.1	Install physical security devices and other construction work by FirstEnergy at new AE2-139 interconnection substation by developer.	AE2-139	5/31/2027	$1.14	PENELEC	10/8/2024
	N8486.2	Estimated design, installation and testing/commissioning for MPLS equipment for SCADA transport at AE2-139 230 kV interconnect substation		5/31/2027	$0.24		
	N8486.3	Install ADSS from East Towanda 230 kV substation to the new AE2-139 230 kV interconnection substation.		5/31/2027	$0.44		
	N8486.4	East Towanda-Marshall 230 kV: Cut the existing East Towanda-Marshall 230 kV line an ~4 miles from the Scotch Hollow tap to create a loop into the new three-breaker ring bus for AE2-139 interconnection.		5/31/2027	$1.56		
	N8486.5	Marshall 230 kV substation: Modify relay settings, drawings review and nameplate.		5/31/2027	$0.07		
	N8486.6	East Towanda 230 kV substation: Modify relay settings, drawings review and nameplate.		5/31/2027	$0.07		
	N8486.7	Scotch Hollow 230 kV substation: Modify relay settings, drawings review and nameplate.		5/31/2027	$0.07		
	N8486.8	Grover 230 kV substation: Relay settings, drawings review and nameplate		5/31/2027	$0.07		
22	N8488	Install 34.5 kV potential transformer and replace Oil Creek phase and RC relays with SEL-351S at Titusville 34.5 kV substation.	AF2-235	7/31/2027	$0.65		
23	N8489.1	Replace 34.5 kV South Troy line relaying and controls and install one 34.5kV PT.	AF2-238	7/31/2027	$0.55		
	N8489.2	Revise relay settings at South Troy 34.5 kV substation.		7/31/2027	$0.06		
24	N8496.1	Lucerne 115 kV substation: Convert Lucerne substation to a four-breaker (future six-breaker) bus.	AF1-272	5/31/2027	$10.50		
	N8496.2	Lucerne-Shelocta 115 kV line: Reterminate the Lucerne-Shelocta 115 kV line to accommodate the new Lucerne 115 kV substation layout.		5/31/2027	$0.64		
	N8496.3	East Pike-Lucerne 115 kV line: Reterminate the East Pike-Lucerne 115 kV line to accommodate the new Lucerne 115 kV substation layout.		5/31/2027	$1.03		
	N8496.4	East Pike 115 kV substation: Replace one 115 kV line trap and line tuner with one wideband line trap and line tuner for the Glory line terminal.		5/31/2027	$0.63		
	N8496.5	Glory 115 kV substation: Replace one 115 kV line trap and line tuner with one wideband line trap and tuner.		5/31/2027	$0.64		
	N8496.6	Shelocta 115 kV: Install one PCM 5350 for the Lucerne 115 kV line.		5/31/2027	$0.46		
25	N8497	Revise relay settings as needed on 34.5 kV Turner St line.	AG1-100	8/29/2027	$0.08		

6.10.8 — Supplemental Projects

Supplemental projects included in the 2024 Local Plan in Pennsylvania are summarized in **Map 6.46** and **Table 6.56**.

Read More
Supplemental Projects

Map 6.46: Pennsylvania Supplemental Projects (Dec. 31, 2024)

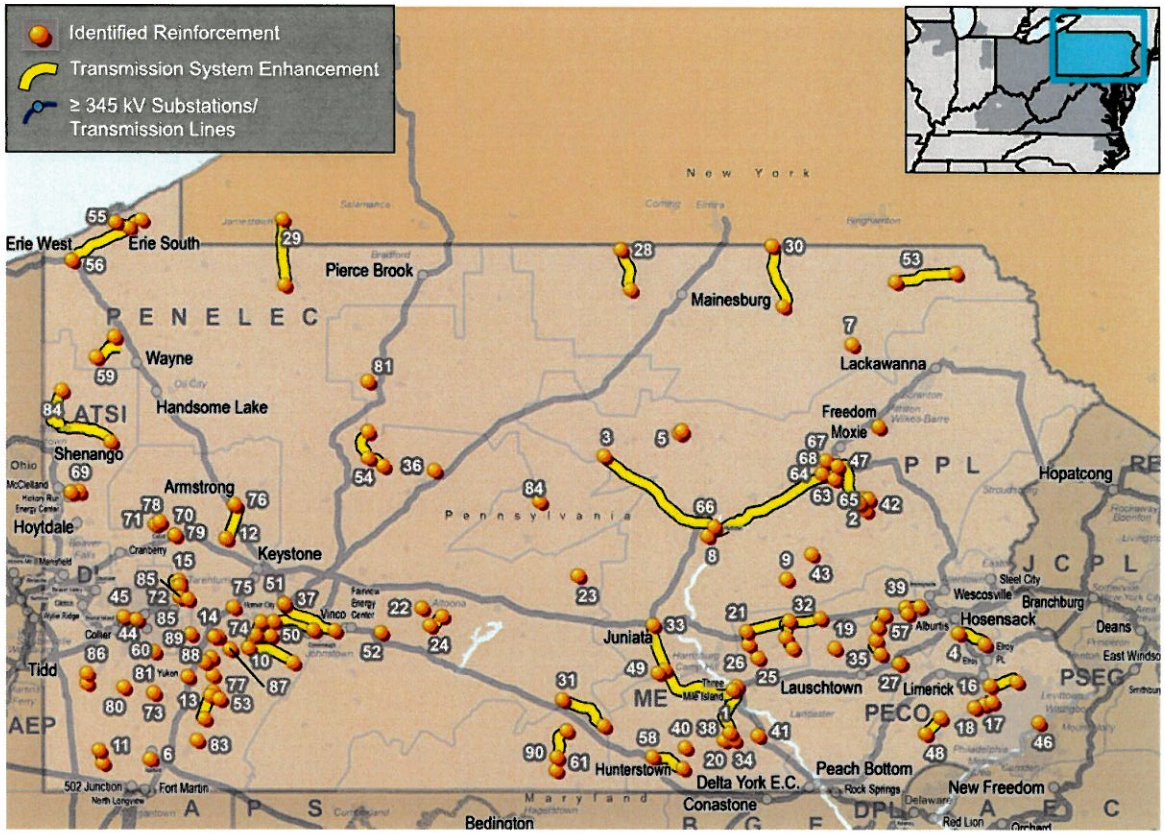

Table 6.56: Pennsylvania Supplemental Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S3017	Install three SCADA-controlled transmission line switches. Construct an ~0.2 miles of transmission line using 556 ACSR 26/7 from tap point to customer substation. Install one 115 kV revenue metering package at customer substation. Modify relay settings at Middletown junction and Smith Street substations.	7/3/2026	$4.90	METED	7/20/2023
2	S3082.1	Extend a new double-circuit 69 kV tap from the existing Harwood-East Hazelton 1 and 2 69 kV lines line to interconnect a PP&L distribution owned 69-12.47 kV substation (McAdoo).	6/9/2025	$2.00	PP&L	
	S3082.2	Harwood-Freeland No. 1 and No. 2: Add a second circuit from Harwood substation to Cando tap (1.3 miles), reconfigure existing circuits from Cando and Harleigh, and install 3.6 miles of new double-circuit 69 kV from Harleigh to East Hazelton.	12/31/2027	$16.20		

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Table 6.56: Pennsylvania Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S3083.1	Rebuild the Sunbury-Lock Haven 69 kV line (~39 miles) to double-circuit 69 kV operation with 795 ACSR conductor. Install new line terminals at Sunbury and Lock Haven substations to accommodate the new circuit.	12/30/2028	$103.00	PP&L	7/20/2023
4	S3084.1	Rebuild the Buxmont 2-Upper Hanover tap 69 kV line (~9.14 miles) to single circuit, future double-circuit 69 kV operation with 556 ACSR conductor.	5/31/2026	$18.00		9/14/2023
5	S3085.1	Rebuild the Lycoming-Williamsport No. 2 69 kV line (2.1 miles) to double-circuit 69 kV operation with 556 ACSR conductor. Remove 1.2 miles of the Lycoming-Williamsport No. 1 69 kV line.	12/30/2027	$6.00		10/19/2023
6	S3086.1	Extend a second circuit to New Kingston substation from the Cumberland-Carlisle No. 2 69 kV line (0.06 miles).	11/30/2025	$0.90		
7	S3087.1	Rebuild the PP&L section of the Hunlock-Glen Brook 69 kV line (3.5 miles) to single-circuit 69 kV operation with 556 ACSR conductor.	12/30/2028	$7.00		
8	S3088.1	Rebuild the Selinsgrove 69 kV taps (1.45 miles) to double-circuit 69 kV operation with 556 ACSR conductor.	12/30/2026	$3.00		
9	S3089.1	Extend a single-circuit 69 kV tap to the new customer substation from the Eldred-Pine Grove 69 kV line (0.15 miles).	6/30/2025	$1.00		
10	S3096.1	Construct a new 8-mile 138 kV line between Ethel Springs and Bethlen substations using 954 ACSR conductor. The following work will be performed at neighboring substations: At Social Hall, replace substation conductor, wave trap and circuit breaker. At Vasco, construct a four-breaker 138 kV ring bus. At Edgewater tap, install three SCADA-controlled switches. At Loyalhanna, replace substation conductor on the Bethlen 138 kV line terminal. At Ethel Springs, convert the 138 kV yard into a four-breaker ring bus. At Bethlen, convert the 138 kV yard into a three-breaker ring bus new line ratings: Vasco Tap-Social Hall 138 kV: 297 / 365 MVA (SN / SE), Bethlen-Loyalhanna 138 kV: 309 / 376 MVA (SN / SE), Bethlen-Ethel Springs: 308 / 376 MVA (SN / SE).	12/31/2025	$59.60	AP	10/20/2023
11	S3107.1	At Franklin substation, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying. At Pursely substation, replace substation conductor and relaying.	5/23/2026	$2.20		11/17/2023
12	S3109.1	At Armstrong substation, replace disconnect switches, substation conductor and relaying.	5/26/2023	$2.50		
13	S3123.1	Rebuild/rehab the Connellsville-Stoner Junction 138 kV line. Replace existing transmission line conductor with larger size. Rebuild/rehab the Stoner Junction-King Farm 138 kV line. Rebuild/rehab the Stoner Junction-Iron Bridge 138 kV line. Replace existing transmission line conductor with larger size.	6/15/2026	$31.50		7/21/2023
14	S3125.1	138 kV transmission line tap: Install three SCADA-controlled transmission line switches. Construct an ~0.75 miles of transmission line using 1590 ACSR 45/7 from tap point to customer substation. Install one 138 kV revenue metering package at customer substation.	3/28/2025	$5.40		
15	S3161.1	At Fawn substation, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying. At Gobain substation, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying.	10/31/2025	$3.50		12/15/2023
16	S3183.1	Replace existing 1590 ACSR station cable adjacent to breaker 875 within Warrington bus tie 7-8 facility with new 2-2000 AAC station cable.	3/8/2024	$0.20	PECO	1/9/2024
17	S3185.1	Rebuild ~2.5 miles with new dual circuit, weathering steel monopole structures and 959.6 kcmil ACSS conductor. Replace various substation equipment at Plymouth Meeting and Flint substations to make the conductor the limiting element.	12/31/2025	$18.20		10/31/2023
18	S3186.1	Rebuild ~4.5 miles with new dual circuit, weathering steel monopole structures and 959.6 kcmil ACSS conductor. Replace various substation equipment at Plymouth Meeting and Upper Merion substations to make the conductor the limiting element.	12/31/2026	$29.20		
19	S3210.1	Extend a second circuit to Lavino substation from the Berks-Lavino No. 2 69 kV line (0.05 miles).	12/1/2026	$0.90	PP&L	1/18/2024
20	S3263.1	Convert Hokes substation into a six-breaker ring bus. Upgrade terminal equipment to transmission line ratings and adjust relay settings transmission line ratings.	6/1/2026	$24.10	METED	11/16/2023
21	S3264.1	Rebuild North Lebanon-Fredericksburg 73 69 kV line as double circuit. At North Lebanon substation, add 69 kV breaker. Replace limiting terminal equipment at Fredericksburg substation.	12/31/2026	$13.60		

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Table 6.56: Pennsylvania Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
22	S3268.1	Westfall 115 kV substation: Replace the existing control building with a new package control enclosure that can accommodate all relaying and equipment.	10/30/2026	$6.70	PENELEC	12/13/2023
23	S3269.1	At Yeagertown substation: Replace the Yeagertown No. 1 230-46 kV transformer. Replace transformer relaying.	10/17/2025	$3.50		3/5/2024
	S3270.1	At Yeagertown substation: Replace the Yeagertown No. 2 230-46 kV transformer. Replace transformer relaying.	9/30/2025	$4.00		
24	S3271.1	Replace relaying at Altoona and Hollidaysburg substations. Replace disconnect switches and substation conductor at Altoona and Hollidaysburg substations.	12/31/2026	$1.50		3/14/2024
25	S3287.1	Convert Campbelltown into a five-breaker 69 kV ring bus. At Campbelltown substation: Replace two 69 kV circuit breakers and associated disconnect switches. Install two new 69 kV circuit breakers and associated disconnect switches. Relocate one existing 69 kV circuit breaker and associated disconnect switches. Install new bus conductor. Install four standard transmission line relay panels. Replace substation conductor. At North Lebanon substation: Replace one 69 kV circuit breaker. Replace one 69 kV disconnect switch. Install one standard transmission line relay panel. Replace substation conductor. At Middletown substation: Replace one 69 kV circuit breaker. Replace one 69 kV disconnect switch. Install one standard transmission line relay panel. Replace substation conductor.	6/1/2026	$10.00	METED	2/15/2024
26	S3288.1	Rebuild an ~5.9 miles of the Carpenter Technology-South Reading 69 kV line. At South Reading substation: Replace 69 kV breaker, line-side disconnect and line relaying. Install surge arresters. At Carpenter Technology substation: Replace 69 kV line-side disconnect and line relaying. At Glenside substation: Replace 69 kV motor-operated airbreak switches, disconnects and CCVTs.	5/29/2026	$15.20		
27	S3289.1	Rebuild and reconductor an ~0.5 miles of the Birdsboro-Birdsboro Extrusions 69 kV line. At Birdsboro substation: Replace 69 kV circuit breaker. Replace four 69 kV disconnect switches. Replace existing line drop and bus conductor. Replace existing line and breaker relaying. At South Reading substation: Adjust relay settings.	12/10/2025	$2.10		
28	S3290.1	At Niles Valley substation: Construct a 115 kV, six-breaker ring bus. Remove Niles Valley No. 1 115-34.5 kV transformer. Remove the 115 kV bypass switch between the Wellsboro and Mansfield line exits (s2835) upon ring bus completion. Adjust relay settings.	11/4/2028	$16.00	PENELEC	
29	S3291.1	Provide 115 kV service from the Warren-Falconer 115 kV line: Tap the Warren-Falconer 115 kV line, install switches and build an ~190 ft. of transmission line from the tap point to customer substation. Install one 115 kV revenue metering package at customer substation. Adjust relay settings at Warren substation. Operate disconnect switch toward Falconer substation as normally open.	4/28/2028	$1.50		
30	S3292.1	Provide 115 kV service from the East Sayre-East Towanda 115 kV line: Tap the East Sayre-East Towanda115 kV line, install switches and build an ~250 feet of transmission line to the customer substation. Install three 115 kV motor-operated disconnects with SCADA. Install one wave trap.	10/31/2025	$1.67		
31	S3293.1	Provide 115 kV service from the Carlisle Pike-Roxbury 115 kV line: Tap the Carlisle Pike-Roxbury 115 kV line, install switches and build an ~1.76 miles of transmission line to the customer substation. Install one new 115 kV breaker at Carlisle Pike substation. Install one new 115 kV revenue metering package at the customer substation. Adjust relaying at Carlisle Pike substation and Roxbury substation.	12/31/2027	$8.00		
32	S3300.1	Construct new 69 kV line from structure No. 37 on the S. Lebanon-Frystown/Rehrersburg 83 69 kV line to the Northkill substation (an ~8.9 miles).	12/1/2026	$19.60	METED	11/16/2023
	S3300.2	Create a new line terminal and add a fourth 69 kV breaker at Northkill substation. Install two sets of 69 kV disconnect switches with SCADA control and auto-transfer scheme. Install one set of 69 kV disconnect switches with SCADA control on the tap to Rehrersburg substation.		$0.80		
	S3300.3	Rebuild the Bernville-Northkill 845 69 kV line (0.84 mi) to double-circuit construction. New line will share ~0.94 miles of common structure with newly rebuilt 825 line tranmission line ratings.		$3.73		

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Table 6.56: Pennsylvania Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
33	S3311.1	Break the existing Juniata (JUNI)-Three Mile Island (TMIS) 500 kV line and extend the lines 0.1 miles into a new four bay Bernheisel (BERN) 500 kV breaker-and-a-half yard.	6/30/2026	$40.00	PP&L	4/2/2024
	S3311.2	Rebuild the existing JUNI-TMIS 500 kV line to double-circuit for 13.3 miles from Juniata substation to Bernheisel substation. PP&L's standard is to have three sources into a BES substation.		$117.00		
	S3311.3	Install four 500-138 kV transformers.		$62.00		
	S3311.4	Install a six-bay 138 kV yard.		$15.00		
	S3311.5	Install two 138 kV capacitor banks.		$7.00		
	S3311.6	Extend six 138 kV lines to customer facility.		$3.00		
34	S3330.1	Replace the No. 6 115-69 kV 75 MVA transformer with a 125 MVA transformer. Replace 69 kV circuit breaker and associate disconnect switches. Replace strain bus conductor and transformer relaying.	12/31/2027	$6.10	METED	4/18/2024
35	S3331.1	Replace the existing 230 kV bus conductor. Install eight 230 kV circuit breakers and associated disconnect switches. Reterminate the existing transmission lines and transformers. Install new control house and relay panels.		$35.00		4/30/2024
	S3332.1	Replace the existing South Reading 230-69 kV No. 7 transformer. Replace limiting conductor and disconnect switches. Replace relaying at South Reading substation.	6/30/2027	$8.80		
	S3333.1	Replace the existing South Reading 230-69 kV No. 8 transformer. Replace limiting conductor and disconnect switches. Replace relaying at South Reading substation.		$8.80		
36	S3334.1	Replace the existing Shawville 1A transformer with a three-winding, 230/115- 17.2 kV, 180/240/300 MVA transformer. Install a 17.2 kV circuit breaker. Replace disconnect switches, bus conductor, insulators, surge arresters and the 230 kV breaker.	12/31/2025	$8.80	PENELEC	
37	S3335.1	Replace Homer City South 345/230/23 kV transformer. Replace the South 345/230-23kV transformer and associated equipment with: One 345/230 kV transformer with three single-phase units. Replace 345 kV circuit switcher, disconnects, circuit breaker, and substation conductor.	6/1/2027	$8.80		
38	S3337.1	At Willis Road substation (refer to ME-2023-002): Install a new No. 1 115-69 kV 125 MVA transformer and associated relaying. At Smith Street: Retire No. 1 and No. 3A 115-69 kV transformers.	6/1/2026	$6.60	METED	5/16/2024
39	S3338.1	Install a 69 kV, 19.8 MVAR effective cap bank at Baldy 69 kV substation.	5/30/2025	$1.00		10/19/2023
40	S3339.1	Convert Hamilton substation into a 115 kV five-breaker ring bus. Remove all 115 kV equipment and structures, excluding: three transformer disconnect switches. Hamilton-Jackson 115 kV dead-end structure: Install four 115 kV breakers and associated disconnect switches and CVTs. Relocate one existing breaker and two 115 kV line disconnect switches. Upgrade relaying.	12/31/2026	$7.70		
41	S3340.1	Yorkana 230 kV substation: Expand 230 kV ring bus to a five-breaker ring bus. Install one new 230 kV circuit breaker. Relocate the Brunner Island 230 kV terminal.	6/1/2025	$3.70		10/31/2023
42	S3349.1	Rebuild 2.6 miles of the existing Harwood-East Hazelton 1 and 2 69 kV lines from Harwood substation to the MCCI tap with 795 ACSR conductor.	12/1/2026	$6.00	PP&L	12/13/2023
43	S3350.1	Rebuild the 0.1-mile Cass tap from the FRACAUBU 69 kV line. Remove 69 kV tap from FRACFISH No. 3.	5/31/2026	$0.90		
44	S3356.1	Establish a new substation, Veterans Bridge substation, in the North Shore neighborhood of Pittsburgh by tapping the existing Brunot Island-Forbes 138 kV underground HPFF transmission line. Veterans Bridge substation will supply the customer for the duration of the customer's construction project. Veterans Bridge substation will contain a single 138 kV breaker and 138/23 kV transformer to serve the customer's load. Establishing Veterans Bridge substation will require extending the Brunot Island-Forbes 138 kV underground HPFF transmission line by an ~50 ft.	1/31/2026	$0.00	DL	2/16/2024

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Table 6.56: Pennsylvania Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
45	S3367.1	Replace the four aged 138 kV breakers and their associated equipment with modern breakers and equipment. Install redundant, secondary microprocessor protection schemes for the ten 138 kV buses and one 69 kV bus that lack redundancy. Replace the aged, existing electromechanical relaying schemes on five 138 kV buses and one 69 kV bus. Note the aged, existing electromechanical relaying schemes on the other five 138 kV buses are not capable of being replaced at this time due to CT limitations on distribution transformers.	6/1/2025	$8.00	DL	3/15/2024
46	S3383.1	Rebuild Tacony 69 kV substation to 230 kV standards by cutting into the 220-56 Eddington/Holmesburg/Richmond 230 kV line in and out of the substation.	12/31/2027	$11.00	PECO	6/4/2024
	S3383.2	Replace the existing 69-13 kV 40 MVA transformers with two new 230-13kV 62MVA units.		$6.00		
47	S3528.4	Susquehanna T10 230 kV switchyard: Install a new BAAH bay at the Susquehanna T10 230 kV yard. Install two dead ends, three 230 kV breakers and associated equipment.	6/1/2027	$6.00	PP&L	8/6/2024
48	S3384.1	Rebuild an ~6.24 miles of the 220-31 Planebrook-Bradford 230 kV line with new dual circuit, weathering steel monopole structures and 959.6 kcmil ACSS/TW conductor. Replace various substation equipment at Planebrook and Bradford substations.	12/31/2027	$36.00	PECO	6/4/2024
	S3385.1	Rebuild an ~4.5 miles of the 220-02 Planebrook-Bradford 230 kV line with new dual circuit, weathering steel monopole structures and 959.6 kcmil ACSS/TW conductor. Replace various substation equipment at Planebrook and Bradford substations	12/31/2028	$36.00		
49	S3391.1	Extend a new double-circuit 69 kV tap from the existing Cumberland-Carlisle No. 1 and No. 2 69 kV lines to interconnect the new Stonehouse 69-12.47 kV substation. Build 0.1 miles of new 69 kV double-circuit line using 556 ACSR conductor. Initial loading of ~18 MVA.	6/1/2026	$1.40	PP&L	7/18/2024
50	S3395.1	Install three SCADA-controlled transmission line switches. Construct an ~2000 ft. of transmission line from tap point to customer substation. Install one 115 kV revenue metering package at customer substation.	3/14/2025	$3.50	PENELEC	9/14/2023
51	S3396.1	At Johnstown substation, replace the following: 230 kV bus tie breaker No. 1 and No. 2 disconnect switches, 230 kV Johnstown line switches on the Fiddler's Green terminal, 115 kV bus tie switches and bus, line trap on the Homer City terminal, substation conductor on the Homer City terminal, substation conductor on the Fiddler's Green terminal. At Homer City substation, replace the following: CCVT on the Johnstown terminal.	12/30/2023	$1.12		10/3/2023
52	S3408.1	At Portage substation, replace the 46 kV structure, including 46 kV line switches.	10/30/2026	$3.70		10/19/2023
53	S3409.1	Replace relays, breakers, disconnect switches and substation conductor at Tiffany 115 kV substation.	11/7/2022	$0.47		
54	S3410.1	Replace substation conductor, wave trap, line tuners, disconnect switch, breaker and relaying at Dubois 115 kV substation. Replace substation conductor at Harvey Run 115 kV substation. Replace wave trap, CCVT, line tuners, arresters and relaying at Whetstone 115 kV substation.	11/29/2023	$2.10		
55	S3422.1	At Erie South, replace relaying and line trap (Erie South-Erie West 345 kV).	6/3/2028	$10.70		12/5/2023
	S3422.2	At Erie West, replace relaying and line trap (Erie South-Erie West 345 kV).		$10.70		
56	S3423.1	At Erie South, replace relaying and line trap (Erie South-Warren 230 kV).		$10.70		
57	S3434.1	North Temple-Allentown Cement 69 kV line. Install three SCADA-controlled transmission line switches. Construct an ~one to two spans of transmission line from tap point to customer substation. Install one 69 kV revenue metering package at customer substation. Modify relay settings at North Temple and Allentown Cement substations.	6/1/2025	$0.70	METED	6/13/2024
58	S3435.1	Hunterstown-North Hanover 115 kV line. Install three SCADA-controlled transmission line switches. Construct an ~ont to two spans of transmission line from tap point to customer substation. Install one 115 kV revenue metering package at customer substation. Modify relay settings at North Hanover and Hunterstown substations.	12/1/2027	$1.70		
59	S3436.1	Geneva-Morgan Street 115 kV line transmission line tap: Install three SCADA-controlled transmission line switches. Construct an ~one to two spans of transmission line from tap point to customer substation. Install one 115 kV revenue metering package at customer substation. Modify relay settings at Geneva and Morgan Street substations.	5/2/2025	$1.60	PENELEC	

Table 6.56: Pennsylvania Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
60	S3466.1	Eliminate the 69 kV voltage level from Dravosburg substation by replacing the two aged 138-69 kV autotransformers and the station's existing 69-23 kV transformers with two new 138-23 kV transformers. This elimination will require an extension of the 138 kV bus, the addition of three new 138 kV breakers, and the removal of the 69 kV bus and associated breakers.	12/1/2027	$8.50	DL	5/17/2024
61	S3481.1	Tap the Grandpoint-Guilford 138 kV and install two SCADA-controlled switches. Construct 500 ft. of 138 kV line extension from the tap location to the customer's substation. Install one SCADA-controlled switch at POI between FE and customer. Install 138 kV revenue metering in customer's substation. Modify line relay settings in Grandpoint and Guilford substations.	10/31/2025	$1.75	AP	
62	S3494.1	Maysville-McDowell 69 kV line: Rebuild the Maysville-McDowell 69 kV line, excluding the line section from Werner substation to Hartstown substation (total rebuild length an ~35 miles). Replace three obsolete line switches. Replace the 69 kV circuit breaker B26 and associated disconnect switches at McDowell substation. Replace the substation conductor at Greenville substation. Upgrade line relaying at McDowell substation.	7/25/2028	$55.30	ATSI	6/14/2024
63	S3528.1	Tomhicken 230 kV switchyard: Install a six-bay BAAH 230 kV switchyard with a 125 MVAR capacitor bank.	6/1/2027	$45.00	PP&L	8/6/2024
64	S3528.2	Nescopeck 230 kV switchyard: Install a new three-bay BAAH 230 kV switchyard.		$29.50		
65	S3528.3	Susquehanna 230 kV switchyard: Install a new line terminal at Susquehanna 230 kV yard by installing new dead end, 230 kV breaker, and associated equipment.		$2.00		
	S3528.5	Harwood 230 kV substation: Install new line terminal in the Harwood 230 kV switchyard. Install one dead end, two breakers and associated equipment. New bay to be DBDB initial and future BAAH.		$4.00		
	S3528.6	SUSQ-HARW No. 1 and No. 2 230 kV lines: Bifurcate the Susquehanna-Harwood No. 1 and No. 2 230 kV and terminate at the new Tomhicken 230 kV switchyard. Extend lines an ~0.25 into the new Tomhicken 230 kV switchyard.		$3.70		
66	S3528.7	Sunbury-Susquehanna No. 1 230 kV line: Bifurcate the Sunbury-Susquehanna No. 1 230 kV into the new Nescopeck 230 kV switchyard. Extend lines an ~0.2 into the new Nescopeck 230 kV switchyard.		$1.85		
	S3528.8	Sunbury-Susquehanna No. 1 230 kV line partial rebuild: Rebuild the Sunbury-Susquehanna No. 1 230 kV line to double-circuit 230 kV for 3.9 miles from the Susquehanna 230 kV yard to the new Nescopeck 230 kV switchyard.		$17.20		
67	S3528.9	Glen Brook-Susquehanna 230 kV line: Bifurcate the Glen Brook-Susquehanna 230 kV line into the Susquehanna T10 yard. Extend lines an ~0.25 into the existing Susquehanna T10 230 kV switchyard.		$3.00		
68	S3528.10	Extend a double-circuit 230 kV (built for 500 kV) for ~9 miles from Nescopeck to Tomhicken on existing PP&L ROW. Extend single-circuit 230 kV (built for 500 kV DlbCir) for 2.7 miles from Tomhicken to Harwood and terminate at Harwood. This will create the Nescopeck-Tomhicken 230 kV and Nescopeck-Harwood 230 kV lines.		$80.50		
	S3528.11	Tomhicken Customer taps 230 kV lines: Install four 230 kV lead lines for an ~0.1 miles from Tomhicken 230 kV switchyard to the customer facility.		$3.80		
69	S3495.1	Reconductor the Cascade (Cedar Street) 69 kV line, an ~18.3 miles.	3/31/2028	$34.70	ATSI	6/14/2024
70	S3114.1	At Cabot substation, replace circuit breakers, disconnect switches, substation conductor and relaying. At Houseville substation, replace circuit breaker, disconnect switches, substation conductor and relaying. At McCalmont substation, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying.	12/15/2023	$5.30	AP	11/17/2023
71	S3194.1	At Bredinville, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying. At Butler, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying. At Cabot, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying.	12/31/2026	$4.90		1/19/2024
72	S3195.1	At Springdale, replace relaying.	7/31/2026	$0.80		
73	S3196.1	At Charleroi, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying. At Allenport, replace circuit breaker, disconnect switches, line trap, line turner and coax, substation conductor and relaying.	12/8/2028	$3.40		

Table 6.56: Pennsylvania Supplemental Projects (Dec. 31, 2024) (Cont.)

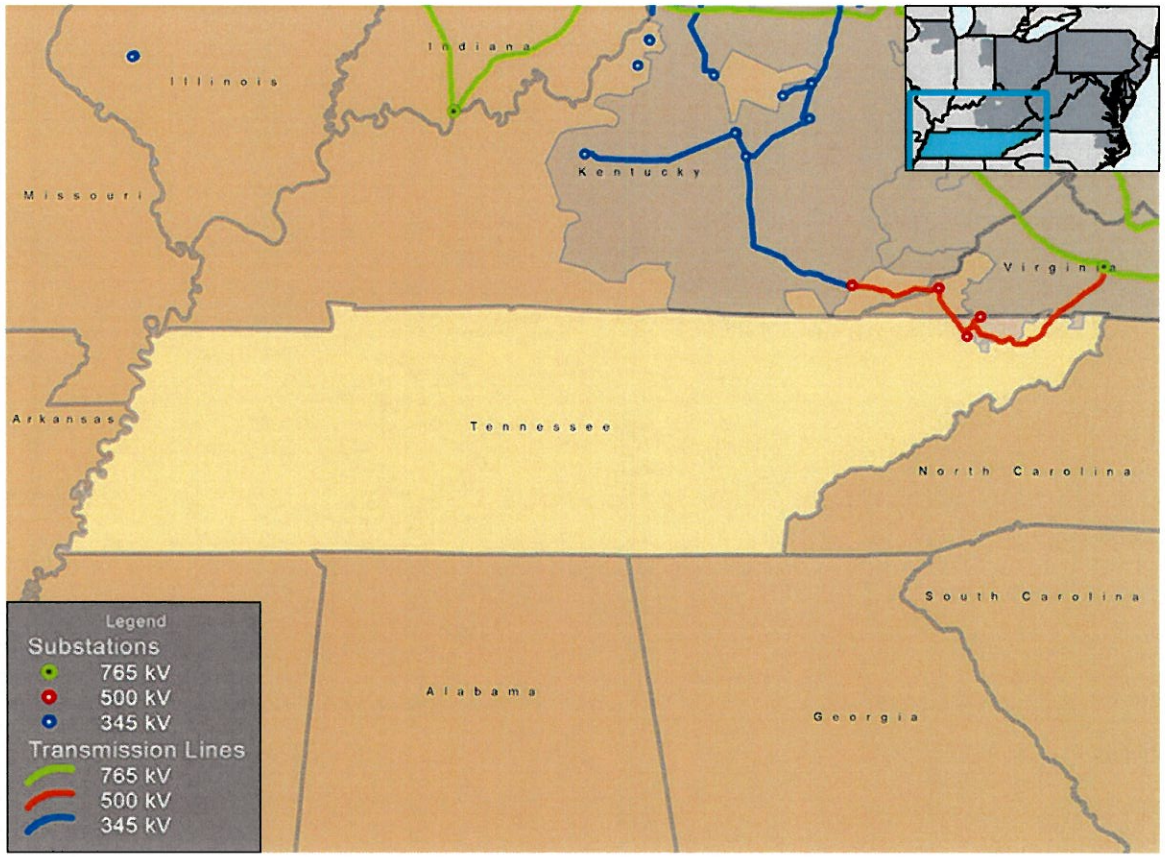
Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
74	S3197.1	At Loyalhanna, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying. At Luxor, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying. At Youngwood, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying.	5/15/2026	$4.00		
75	S3198.1	At Saltsburg, replace disconnect switches, line trap, and relaying. At Vandergrift, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying.	5/14/2027	$2.90		1/19/2024
76	S3199.1	At Armstrong, replace disconnect switches, line trap, substation conductor and relaying. At Burma, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying.	6/1/2026	$3.00		
77	S3200.1	At Youngwood, replace circuit breaker, line trap, substation conductor and relaying. At Yukon, replace line trap and relaying.	3/28/2026	$2.10		
78	S3368.1	At Butler substation, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying. At Cabot substation, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying.	6/30/2028	$3.60		3/15/2024
79	S3457.1	At Cabot substation, replace disconnect switches, line trap, substation conductor and relaying. At Kiski Valley substation, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying. At Northpointe substation, replace disconnect switches relaying.	12/31/2029	$2.45		4/19/2024
80	S3459.1	Install automatic sectionalizing switches outside Vanceville substation. Replace limiting substation conductor and remove line trap at Charleroi substation. Replace limiting substation conductor and remove line trap at Washington substation.	4/29/2027	$1.60		
	S3460.1	Install automatic sectionalizing switches outside Vanceville substation. Replace limiting substation conductor and remove line trap at Charleroi substation. Replace limiting substation conductor and remove line trap at Washington substation.	5/23/2025	$2.80		
81	S3470.1	At Charleroi, replace relaying. At Yukon, replace relaying.	11/30/2025	$1.00	AP	
82	S3471.1	At Ridgway, replace circuit breaker, disconnect switches, line trap and relaying. At Paper City, replace circuit breaker, disconnect switches, line trap and relaying.	5/1/2026	$4.40		5/17/2024
83	S3472.1	At Bethelboro, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying. At Yukon, replace line trap and relaying.	10/29/2027	$2.50		
84	S3483.1	Convert milesburg substation into a four-breaker 230 kV ring bus.	12/17/2027	$9.80		6/4/2024
85	S3484.1	At Springdale, replace line trap, substation conductor and relaying. At Shaffers Corners, replace circuit breaker, disconnect switches, line trap, substation conductor and relaying.	11/12/2027	$4.00		6/14/2024
86	S3514.1	At Gordon, replace circuit breaker, disconnect switches, substation conductor and relaying. At Nyswaner, replace substation conductor and relaying.	5/30/2027	$4.00		
87	S3516.1	At Loyalhanna, replace circuit breaker, disconnect switches, substation conductor, line trap and relaying. At Luxor, replace circuit breaker, disconnect switches, line trap and relaying.	11/30/2026	$5.00		
88	S3517.1	At Hempfield, replace circuit breaker, disconnect switches, substation conductor, line trap and relaying. At Sewickley, replace disconnect switches. At Yukon, replace line trap and relaying.	4/30/2027	$4.00		7/19/2024
89	S3518.1	At Huntingdon, replace circuit breaker, disconnect switches, substation conductor, line trap and relaying. At Yukon, replace disconnect switches, substation conductor, line trap and relaying.	2/28/2027	$4.00		
90	S3519.1	At Grand Point, replace circuit breaker, disconnect switches, substation conductor, line trap and relaying. At Guilford, replace circuit breaker, disconnect switches, substation conductor, line trap and relaying.	8/30/2026	$5.00		

6.11: Tennessee RTEP Summary

6.11.1 — 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 6.47**. 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 the PJM service area.

Map 6.47: PJM Service Area in Tennessee



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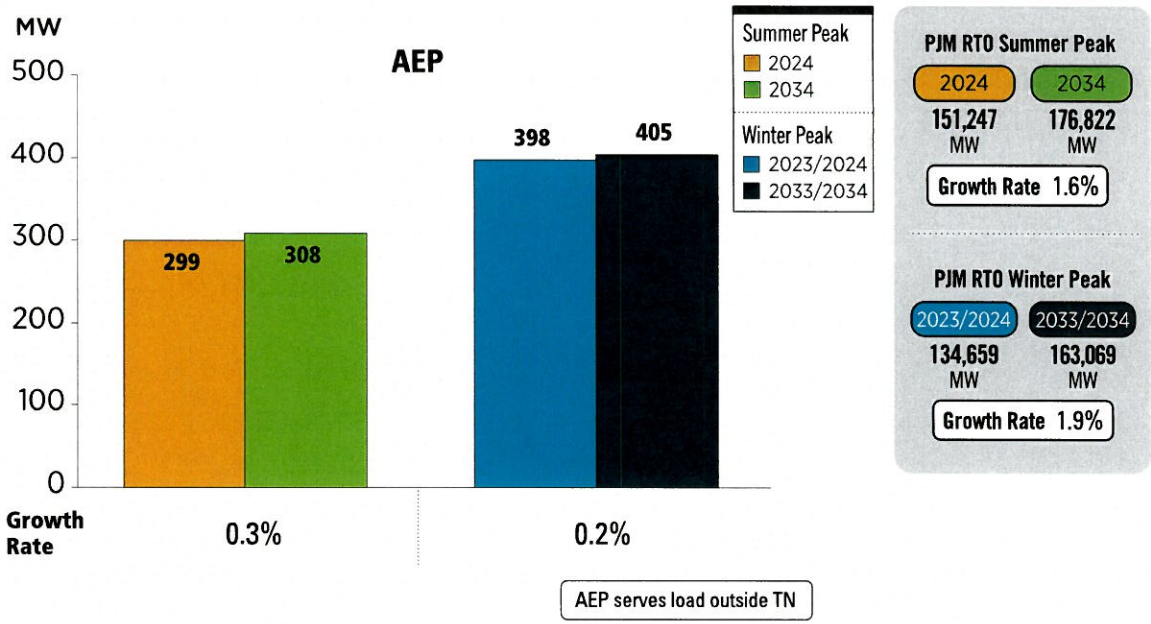
6.11.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.51** summarizes the expected loads within the state of Tennessee and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.51: Tennessee – 2024 Long-Term Load Forecast



PJM notes that AEP serves load other than in Tennessee. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted load to be served by AEP solely in Tennessee. Estimated amounts were calculated based on the average share of AEP's real-time summer and winter peak load located in Tennessee over the past five years.

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6.11.3 — Existing Generation

There is no existing generation in PJM's portion of Tennessee as of Dec. 31, 2024.

6.11.4 — Interconnection Requests

In Tennessee, as of Dec. 31, 2024, one project was actively under study or under construction as shown in the summaries presented in **Table 6.57**, **Table 6.58**, **Figure 6.52**, **Figure 6.53** and **Figure 6.54**.

Table 6.57: Tennessee – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	Tennessee Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	0	0.00%	20,162	14.38%
Hydro	0	0.00%	80	0.06%
Methane	0	0.00%	27	0.02%
Natural Gas	0	0.00%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	0	0.00%	64	0.05%
Solar	80	100.00%	55,040	39.25%
Storage	0	0.00%	39,064	27.86%
Wind	0	0.00%	17,455	12.45%
Grand Total	**80**	**100%**	**140,231**	**100%**

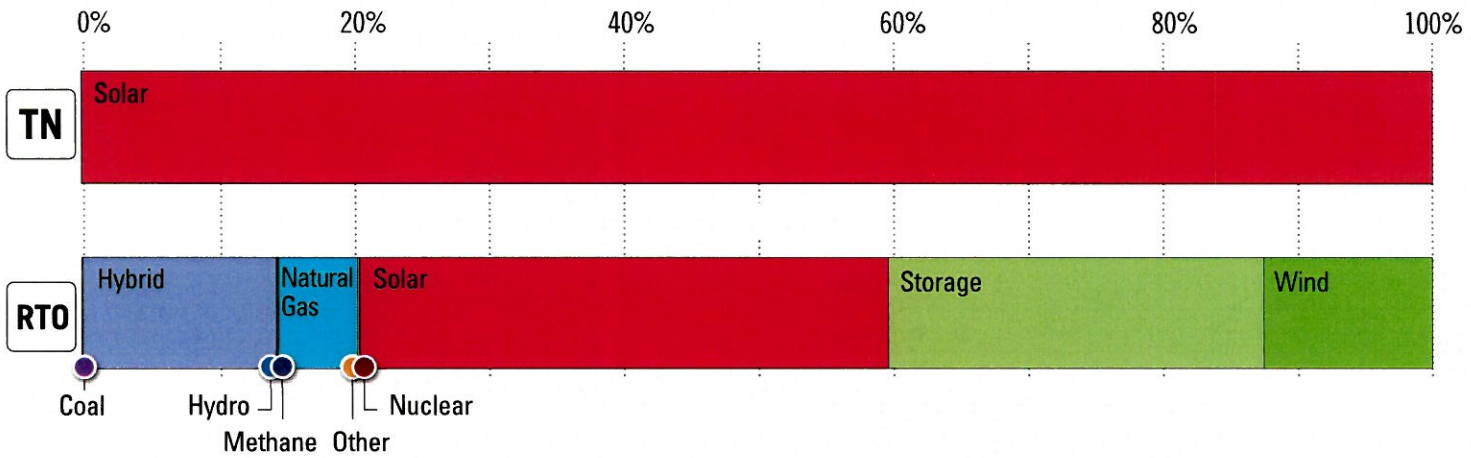
NOTE:
These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Read More
Interconnection Requests

Table 6.58: Tennessee – Interconnection Requests by Fuel Type (Dec. 31, 2024)

		In Queue		Complete			
		Active		Withdrawn		Grand Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-renewable	Coal	0	0.0	1	75.0	1	75.0
Renewable	Solar	1	80.2	1	13.6	2	93.8
	Grand Total	**1**	**80.2**	**2**	**88.6**	**3**	**168.8**

Figure 6.52: Tennessee – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)



PJM © 2025

Figure 6.53: Tennessee Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

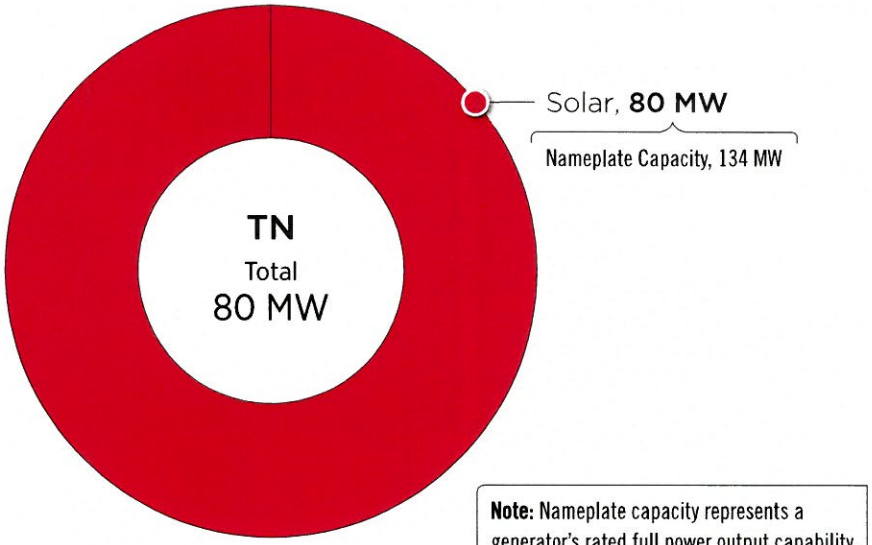
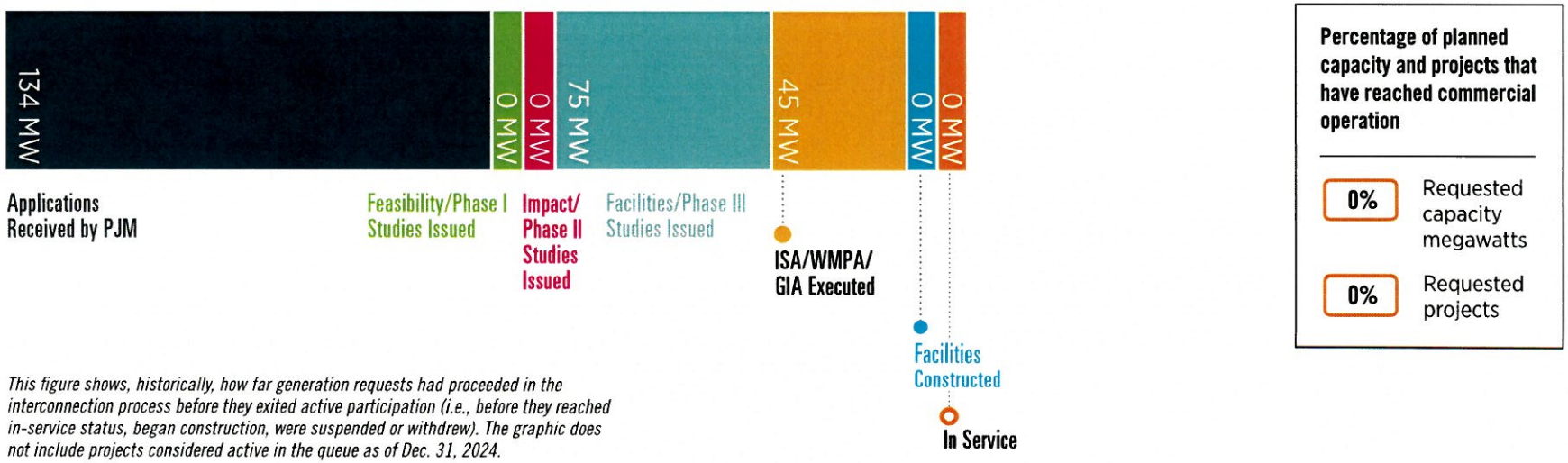


Figure 6.54: Tennessee Progression of Interconnection Requests (Dec. 31, 2024)



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, 2024.

6.12: Virginia RTEP Summary

6.12.1 — 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) [FirstEnergy], American Electric Power (AEP), Delmarva Power (DP&L) and Dominion Energy as shown on **Map 6.48**. 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 the PJM service area.

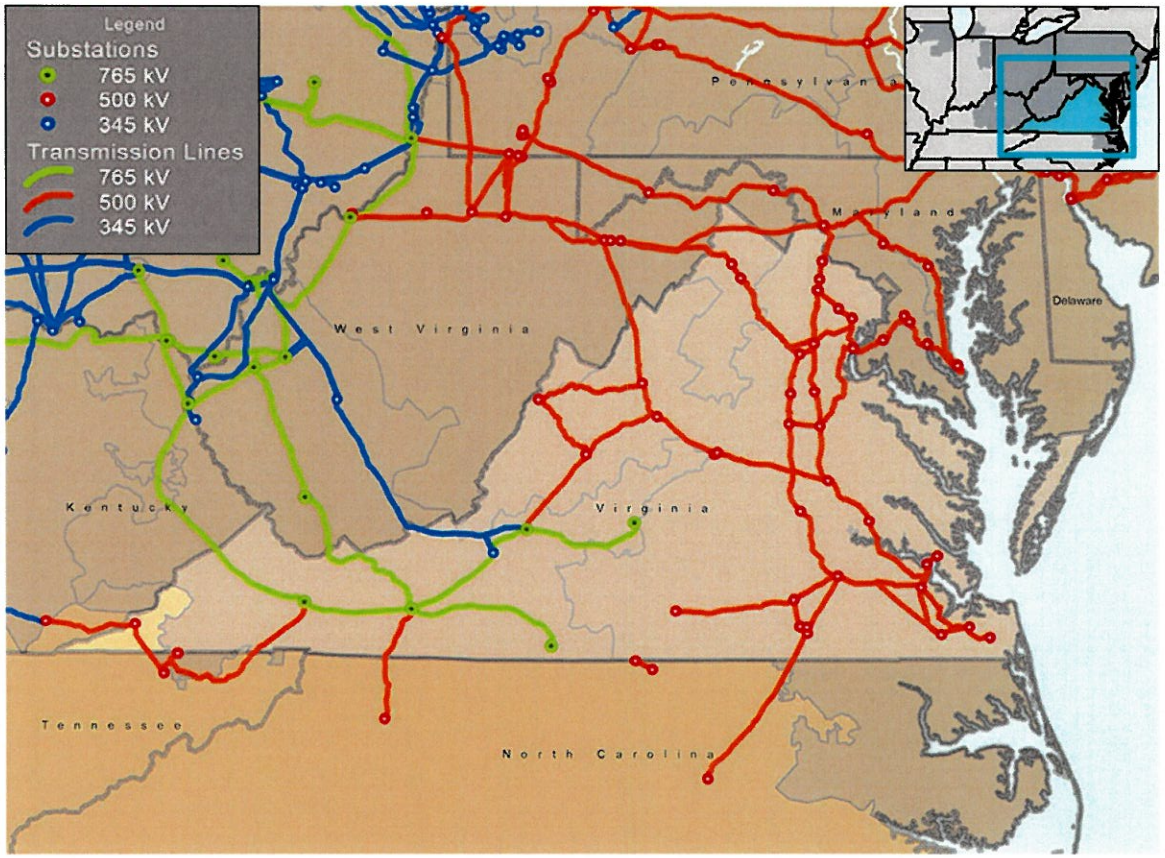
Renewable Portfolio Standards

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 PJM.

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 6.48: PJM Service Area in Virginia



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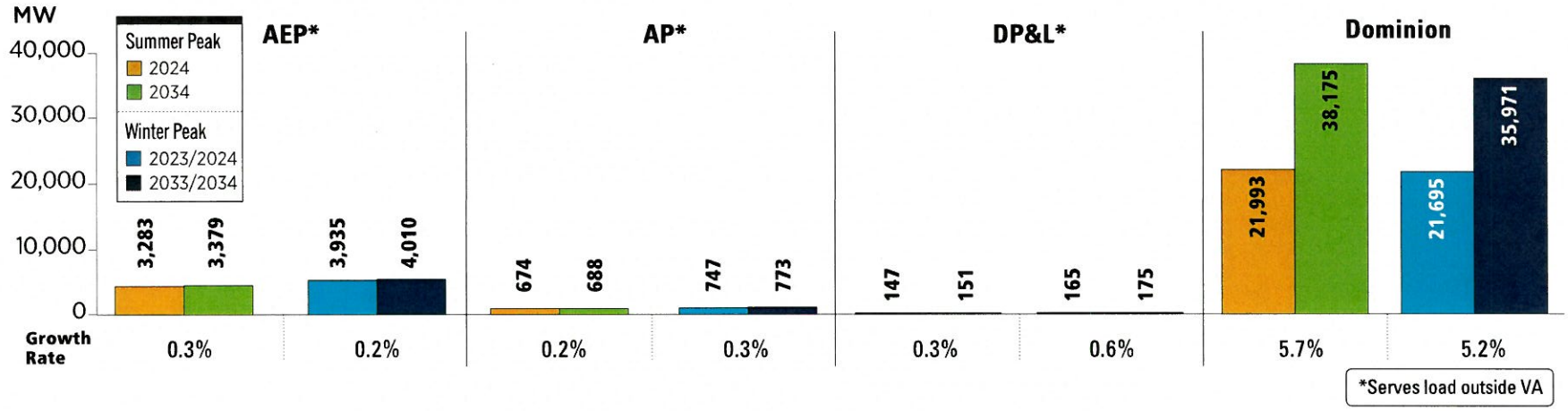
6.12.2 — Load Growth

PJM's 2024 Long-Term Load Forecast provided the basis for the loads modeled in power flow studies used in PJM's 2024 analyses. **Figure 6.55** summarizes the expected loads within the state of Virginia and across the PJM region.

Read More
Load Forecast Accuracy Model Improvements

Figure 6.55: Virginia – 2024 Long-Term Load Forecast



PJM RTO Summer Peak

2024	2034
151,247 MW	176,822 MW

Growth Rate 1.6%

PJM RTO Winter Peak

2023/2024	2033/2034
134,659 MW	163,069 MW

Growth Rate 1.9%

PJM notes that AEP, Allegheny Power (FirstEnergy) and Delmarva Power serve load other than in Virginia. The summer and winter peak megawatt values in this figure each reflect the estimated amount of forecasted 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.

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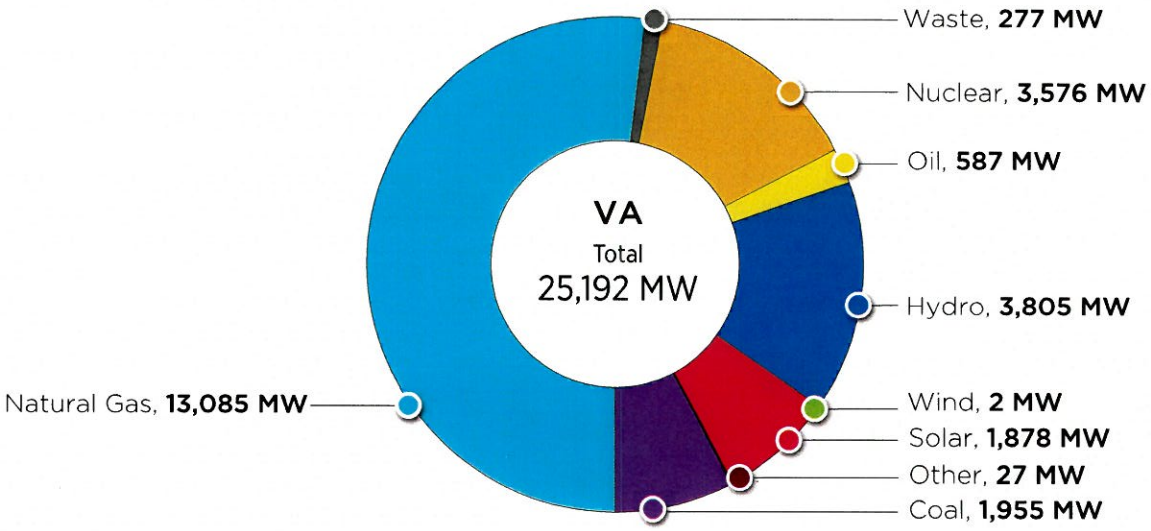
6.12.3 — Existing Generation

Existing generation in Virginia as of Dec. 31, 2024, is shown by fuel type in **Figure 6.56**.

Figure 6.56: Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2024)



Read More
Changing Capacity Mix and Deliverability

6.12.4 — Interconnection Requests

In Virginia, as of Dec. 31, 2024, 443 projects were actively under study or under construction as shown in the summaries presented in **Table 6.59**, **Table 6.60**, **Figure 6.57**, **Figure 6.58** and **Figure 6.59**.

NOTE:
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.

Read More
Interconnection Requests

Table 6.59: Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2024)

	Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	54	0.04%
Hybrid	2,534	9.54%	20,162	14.38%
Hydro	0	0.00%	80	0.06%
Methane	27	0.10%	27	0.02%
Natural Gas	1,342	5.05%	8,242	5.88%
Nuclear	0	0.00%	44	0.03%
Other	0	0.00%	64	0.05%
Solar	10,188	38.38%	55,040	39.25%
Storage	11,421	43.02%	39,064	27.86%
Wind	1,034	3.89%	17,455	12.45%
Grand Total	26,545	100%	140,231	100%

Table 6.60: Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2024)

		In Queue				Complete				Grand 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
	Natural Gas	14	1,341.5	0	0.0	49	7,288.4	49	20,428.2	112	29,058.1
	Oil	0	0.0	0	0.0	6	322.2	2	40.0	8	362.2
	Diesel	0	0.0	0	0.0	0	0.0	1	0.0	1	0.0
	Nuclear	0	0.0	0	0.0	8	350.0	1	1,570.0	9	1,920.0
	Wood	0	0.0	0	0.0	1	4.0	2	57.0	3	61.0
	Other	0	0.0	0	0.0	1	0.0	2	136.3	3	136.3
	Storage	146	11,420.9	0	0.0	2	20.0	176	10,088.5	324	21,529.4
Renewable	Hybrid	44	2,533.6	0	0.0	3	12.3	76	5,188.0	123	7,733.9
	Hydro	0	0.0	0	0.0	9	423.4	2	254.0	11	677.4
	Biomass	0	0.0	0	0.0	5	147.4	4	70.0	9	217.4
	Methane	2	27.1	0	0.0	16	103.3	12	87.8	30	218.2
	Solar	218	9,876.2	12	311.8	92	2,410.9	435	16,372.8	757	28,971.7
	Wind	7	1,033.8	0	0.0	1	1.5	36	1,246.2	44	2,281.5
	Grand Total	**431**	**26,233.1**	**12**	**311.8**	**201**	**11,802.4**	**800**	**55,573.8**	**1,444**	**93,921.1**

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Figure 6.57: Virginia – Percentage of Total Interconnection Request Capacity by Fuel Type (Dec. 31, 2024)

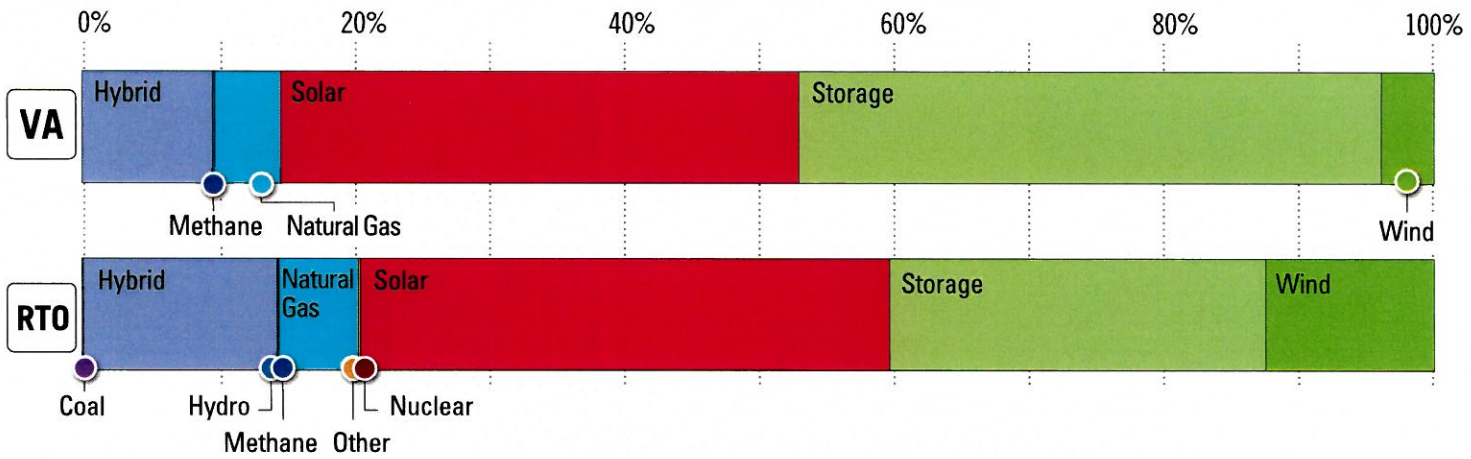

Figure 6.58: Virginia Interconnection Request Capacity (MW) by Fuel Type (Dec. 31, 2024)

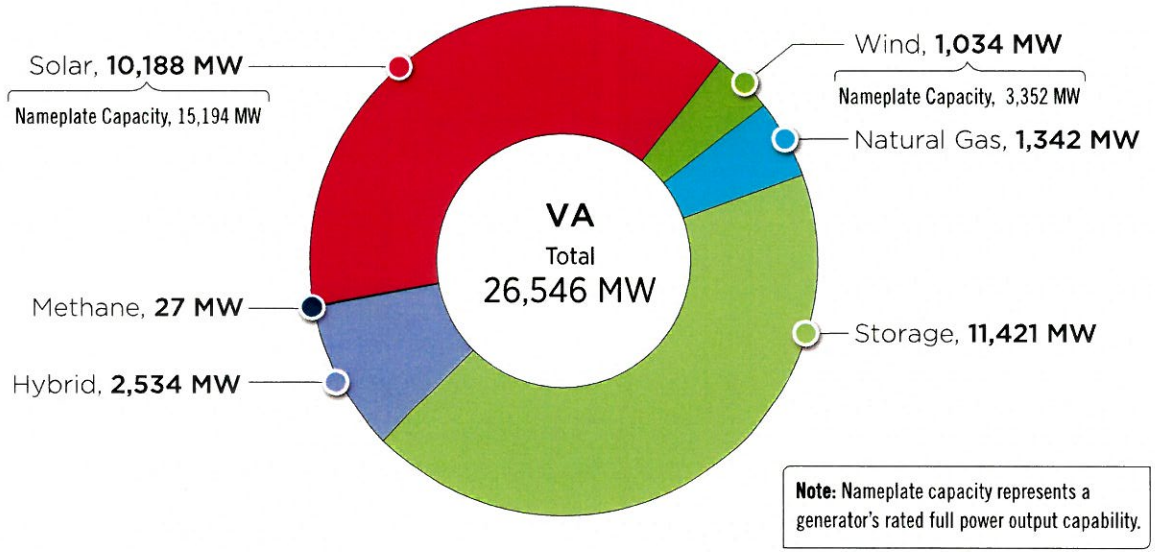

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Figure 6.59: Virginia Progression of Interconnection Requests (Dec. 31, 2024)

Percentage of planned capacity and projects that have reached commercial operation

16.2%	Requested capacity megawatts
14.1%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	**26**	Interconnection Service Agreements	4,941 MW	5,605 MW
	59	Wholesale Market Participation Agreements	531 MW	894 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, 2024.

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6.12.5 — Generation Deactivation

Formal generator deactivations and requests received by PJM in Virginia between Jan. 1, 2024, and Dec. 31, 2024, are summarized in **Map 6.49** and **Table 6.61**.

Read More
Baseline Projects

Map 6.49: Virginia Generation Deactivations (Dec. 31, 2024)

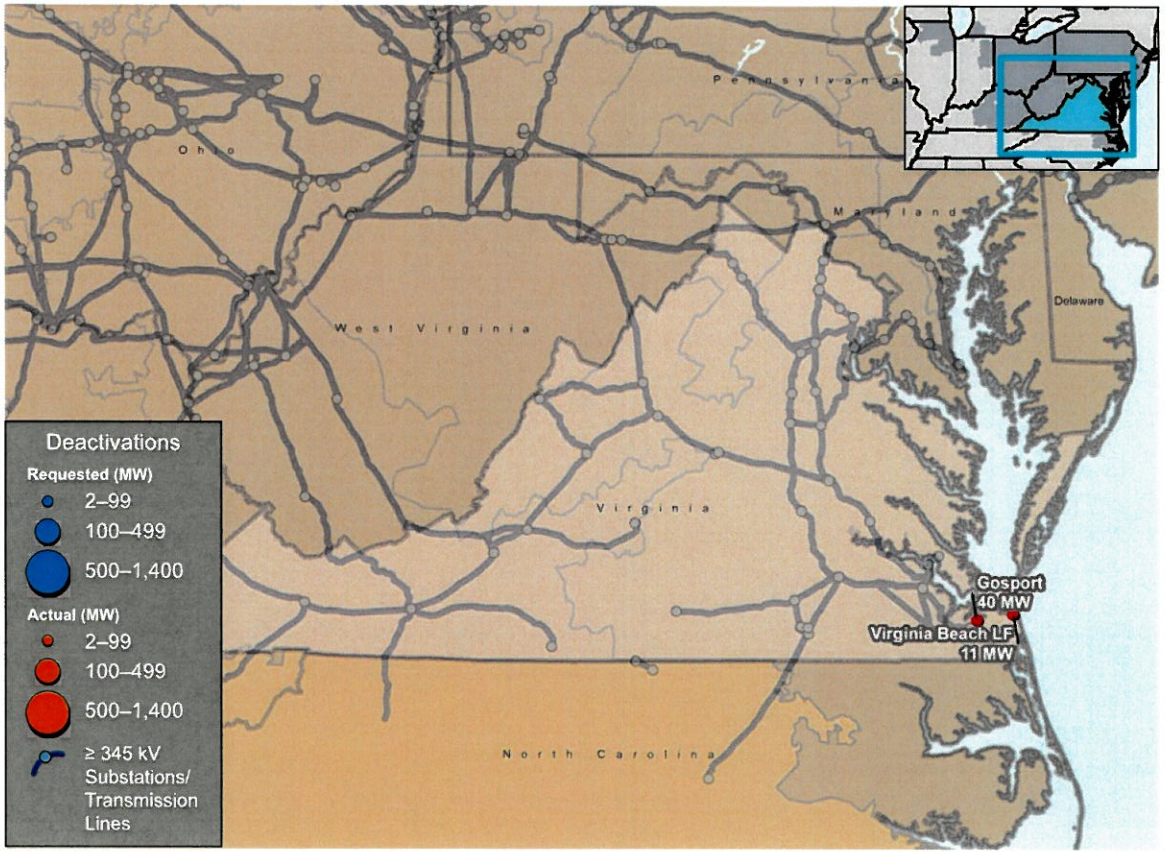

Table 6.61: Virginia Generation Deactivations (Dec. 31, 2024)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
VP Gosport 1 F	Dominion	Biomass	7/11/2024	7/15/2024	36	40
Virginia Beach Landfill		Methane	12/8/2023	4/1/2024	18	11

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6.12.6 — Baseline Projects

RTEP baseline system enhancements approved by the PJM Board for the 2024 RTEP in Virginia are summarized in **Map 6.50** and **Table 6.62**.

Read More
Baseline Projects

Map 6.50: Virginia Baseline Projects (Dec. 31, 2024)

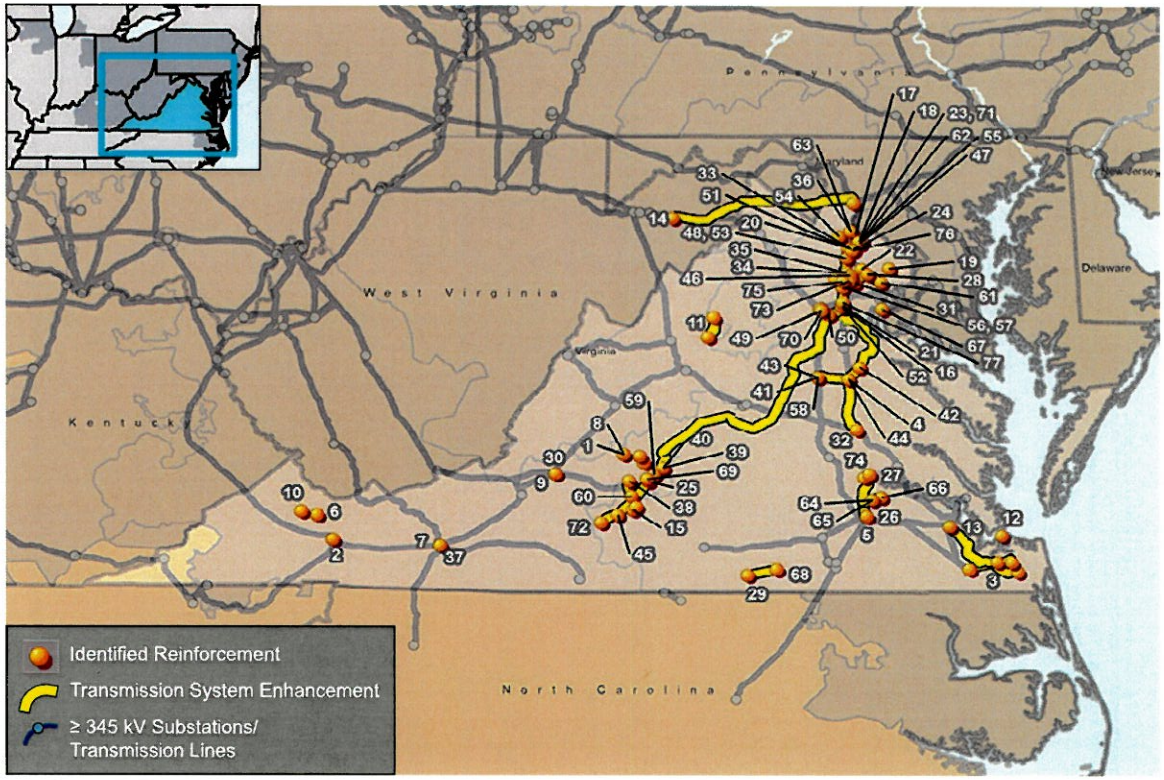

Table 6.62: Virginia Baseline Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3786.1	Rebuild ~4.5 miles of 69 kV line between Abert and Reusens substations. Update line settings at Reusens and Skimmer.	6/1/2028	$14.40	AEP	11/17/2023
2	B3847.2	Add two 765 kV breakers to the reactors at Broadford station on the Baker and Jacksons Ferry 765 kV lines.	6/1/2024	$29.05		6/5/2024

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Table 6.62: Virginia Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	B3850.1	Rebuild an ~13.51 miles of 500 kV line No. 588 from structure 588/184 inside Yadkin substation to structure 588/254 outside of Fentress substation.	6/1/2028	$78.60	Dominion	6/4/2024
	B3850.2	Line No. 588 terminal equipment at Yadkin substation will be upgraded to a rating of 5000A. Since the new 500 kV line will be using fiber, the wave trap will be removed and the line protection scheme will be updated.		$0.96		
	B3850.3	At Fentress substation, since the new 500 kV line will be using fiber, the wave trap will be removed and the line protection scheme will be updated.		$0.14		
4	B3853.1	Replace over-duty Ladysmith CT 230 kV circuit breakers SX1272 and SX3472 with an interrupting rating of 63 kA.	6/1/2025	$1.25		7/9/2024
5	B3854.1	Replace over-duty Carson 230 kV circuit breakers 200272 and 24972-3 with an interrupting rating of 63 kA.		$1.25		
6	B3876.1	Install a 69 kV 11.5 MVAR capacitor bank at Richlands station with a circuit switcher.	12/1/2029	$1.00	AEP	11/15/2024
7	B3895.1	Replace existing 138 kV, 40 kA circuit switcher L at Jacksons Ferry station with new 138 kV, 63 kA circuit breaker.	6/1/2026	$1.00		
8	B3896.1	Adjust the capacitor bank voltage settings to allow the cap bank to operate as needed under N-1-1 scenarios.	12/1/2029	$0.10		
9	B3897.1	Replace the 138 kV 40 kA circuit switcher XT8 with a 63 kA circuit breaker.	6/1/2026	$1.00		
10	B3898.1	Upgrade the CT thermal limit at Buchanan station on the Buchanan-Keen Mountain 138 kV line.	12/1/2029	$0.10		
11	B3921.1	Wreck and rebuild 115 kV line No. 119 from structure 119/305 (Merck No. 5 substation) to 119/411A (Port Republic Substation). The existing structures shall be replaced one for one within the existing right of way using primarily custom engineered double circuit 115 kV steel structures on concrete foundations. The line will be rebuilt with three-phase 1-768.2 ACSS/TW/HS (20/7) 250 MOT "Maumee" conductor and two DNO-11410 OPGW. The rebuild includes the installation of double circuit structures but assumes the second circuit will not be installed as part of this project, and that the vacant conductor arms should not be utilized without acquiring additional right of way. This scope assumes project GITAE2029C will be completed prior to the construction of this project. Project GITAE2029C serves to install Port Republic substation, which will split line No. 119 in between existing structures 119/411 and 119/412.	6/1/2029	$41.87	Dominion	12/12/2024
	B3921.2	Uprate the 397.5 ACSR jumpers and associated equipment to meet the line conductor rating of 393 MVA.		$0.46		
12	B3928.1	Install one 230 kV, 50 MVAR shunt capacitor bank & associated equipment including breaker at Navy North substation.		$3.00		1/7/2025
13	B3929.1	Rebuild an ~33.09 miles of 500 kV line No. 579 from structure 579/1 inside Septa substation to structure 579/193 inside Yadkin substation.		$191.25		
	B3929.2	At Septa substation, upgrade circuit breaker (579T586), breaker switches (56288, 57985, 58688 & 57988), and line leads to 5000A rating to support line No. 579 rebuild.		$3.84		
	B3929.3	At Yadkin substation, upgrade line leads to 5000A rating to support line No. 579 rebuild.		$0.44		
	B3929.4	Rebuild an ~7.7 miles of 230 kV line No. 2110 Suffolk-Thrasher that share the double circuit towers under line No. 579.		$21.25		

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Table 6.62: Virginia Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
14	B4000.7	Construct a new 86-mile Welton Spring to Rocky Point 765 kV line (in DVP local area/Millville to Lovettsville section, roughly 10.5 miles).	6/1/2029	$52.50	AP	1/7/2025
	B4000.8	Construct a new 86-mile Welton Spring to Rocky Point 765 kV line (DVP local area to Rocky Point, roughly 4.8 miles).		$24.00		
	B4000.9	Construct a new substation called Rocky Point with a 765 kV and a 500 kV yard. Loop in the Doubs-Goose Creek 500 kV line, the Doubs-Aspen 500 kV line and the Woodside-Goose Creek 500 kV line. Install two 765/500 kV transformer at Rocky Point substation.		$254.70		
	B4000.10	Install four 250 MVAR cap banks (two on 765 and two on 500 kV side) and a +/-500 MVAR STATCOM on the 765 kV Rocky Point yard.		$121.00		
	B4000.12	Upgrade the terminal equipment on the Doubs No. 1 500/230 kV transformer.		$0.43		
	B4000.13	Terminate the Woodside-Goose Creek 500 kV line into Doubs substation, creating the Woodside-Doubs No. 2 500 kV line. Remove the Chanceford-Doubs and Rocky Point-Doubs line terminations at the Doubs substation and connect the two lines through a 0.6-mile 500 kV bypass line around the Doubs substation.	6/1/2032	$13.97		
	B3800.128	Construct new Woodside-Goose Creek 500 kV line for ~15 miles on single circuit monopole structures within the Doubs-Goose Creek Corridor (FE portion).	6/1/2027	$115.30		7/10/2024
	B3800.129	Construct 500 kV line from existing structure MVF1-101 on the Doubs-Millville 138 kV line around Doubs substation and into the entrance of the Doubs-Goose Creek corridor (~2 miles).		$13.20		
	B3800.375	Construct new Woodside-Goose Creek 500 kV line for ~3 miles on single circuit monopole structures within the Doubs-Goose Creek Corridor (DOM portion).	6/1/2028	$15.60	Dominion	
	B4000.110	Doubs substation 500 kV: Replace 50 kA breaker DL-59 No. 2CAP with 63 kA.	6/1/2029	$11.50	AP	1/7/2025
15	B4000.209	Reconductor 14.4 miles of Altavista-Otter 138 kV line.		$1.20	AEP	
16	B4000.339	At Anderson Branch substation, install/upgrade substation terminal equipment to 4000A.		$0.95	Dominion	
17	B4000.100	Ashburn substation 230 kV: Replace 50 kA breaker SC332 with 63 kA.		$0.50		
18	B4000.101	Beaumeade substation 230 kV: Replace 63 kA breaker 274T2206 with 80 kA.		$0.66		
19	B4000.102	Braddock substation 230 kV: Replace 40 kA breakers 207T294, 237T294, 237T297, 281T297 with 63 kA.		$2.00		
20	B4000.103	Brambleton substation 230 kV: Replace 63 kA breakers 217202, 2172T2183, L102, L202 with 80 kA.		$2.64		
	B4000.343	Uprate bus at Brambleton to support 500 kV line No. 558 (Aspen to Brambleton) uprate.		$0.00		
21	B4000.104	Bristers substation 230 kV: Replace 40 kA and 50 kA breakers H1TH2, H2TH3, L1T2101 with 63 kA.		$1.50		
22	B4000.105	Bull Run substation 230 kV: Replace 50 kA breaker H362 with 63 kA.		$0.50		
23	B4000.106	Buttermilk substation 230 kV: Replace 63 kA breakers 215212, 217012, 220312, 221412, 2152T2203 with 80 kA.		$3.30		
24	B4000.107	Cabin Run substation 230 kV: Replace 63 kA breakers 209512, 221312, T122 with 80 kA.		$1.98		
25	B4000.205	Candler's Mountain 138 kV: Replace 1590 KCM AAC, 61-stranded Replace MOAB "Y" SMITH MTN LINE.		$0.20	AEP	
	B4000.204	Reconductor 34 miles of Candler's Mountain-Opossum Creek 138 kV line.		$4.90		
26	B4000.108	Carson substation 230 kV: Replace 40 kA breaker 23872 with 63 kA.		$0.50	Dominion	
	B4000.320	At Carson substation, upgrade all line No. 2002 terminal equipment at Carson to 4000A. CCVTs will also be replaced due to aging.		$0.89		
27	B4000.318	Revise relay settings at Chesterfield substation.		$0.02		
28	B4000.109	Clifton substation 230 kV: Replace 63 kA breakers 201182, SR182, XT2011 with 80 kA.		$1.98		

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Table 6.62: Virginia Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
29	B4000.332	At Cloud substation, upgrade substation terminal equipment to 4000A.	6/1/2029	$1.43	Dominion	1/7/2025
	B4000.331	Construct a new 230 kV single circuit line from Raines substation to Cloud substation to solve electrical violations cause by the significant load growth in South Hill, Virginia. The scope also includes an idle 230 kV circuit being installed between these stations.		$77.50		
30	B4000.251	Replace the wave trap and upgrade the relay at Cloverdale 765 kV substation.		$1.00	AEP	
31	B4000.330	At Cloverhill substation, install the necessary associated equipment to accomdate the new line between Cloverhill-Ox. This project also includes demolishing and reconstructing the existing bus system and roadway.		$2.27	Dominion	
	B4000.329	At Ox substation, install the necessary associated equipment to accomdate the new line between Cloverhill-Ox. This project also includes expanding the substation with associated security level 1 fencing and super post structure needed.		$6.37		
	B4000.328	Construct a new 24.5-mile 230 kV line from Cloverhill substation to Ox substation.		$287.54		
32	B4000.326	At Elmont substation, install/upgrade associated equipment to accommodate a 4000A line rating for the new 230 kV line between Elmont-Ladysmith.		$2.19		
	B4000.353	Upgrade 500 kV terminal equipment at Elmont substation.		$8.90		
	B4000.325	Build a new 26.38-mile 230 kV line from Elmont-Ladysmith on the existing 5-2 structures between the two stations. New conductor has a summer rating of 1573 MVA.		$26.09		
33	B4000.111	Evergreen Mills substation 230 kV: Replace 63 kA breakers H132, H232 with 80 kA.		$1.32		
34	B4000.308	Upgrade all line No. 2161 terminal equipment at Gainesville to 4000A. A CCVT will also be replaced due to aging.		$1.78		
35	B4000.304	Partial reconductor/partial wreck & rebuild of 230 kV line No. 2161 Gainesville-Wheeler. New conductor has a summer rating of 1573 MVA (Wheeler-Linton tap segment).		$17.72		
	B4000.305	Partial reconductor/partial wreck & rebuild of 230 kV line No. 2161 Gainesville-Wheeler. New conductor has a summer rating of 1573 MVA (Linton tap-Atlantic segment).		$3.49		
	B4000.306	Partial reconductor/partial wreck & rebuild of 230 kV line No. 2161 Gainesville-Wheeler. New conductor has a summer rating of 1573 MVA (Atlantic-Trident segment).		$1.72		
	B4000.307	Partial reconductor/partial wreck & rebuild of 230 kV line No. 2161 Gainesville-Wheeler. New conductor has a summer rating of 1573 MVA (Trident-Gainesville segment).		$6.16		
	B4000.309	Upgrade all line No. 2161 terminal equipment Wheeler substation to 4000A.		$2.25		
36	B4000.112	Goose Creek substation 230 kV: Replace 63 kA breaker L1T227 with 80 kA.		$0.66		
	B4000.113	Goose Creek substation 500 kV: Replace 50 kA breaker SC182 with 63 kA.		$1.02		
	B4000.340	Uprate existing Goose Creek 500/230 kV transformer to 1440 MVA.		$34.01		
37	B4000.200	Broadford 765 kV Upgrade: Replace Jackson's Ferry circuit breaker Q2.		$4.50	AEP	
38	B4000.211	Reconductor 14.4 miles of Johnson Mountain-New London 138 kV line.		$7.68		
39	B4000.252	Replace the wave trap and upgrade the relay at Joshua Falls 765 kV substation.		$1.00		
	B4000.359	Add two 765 kV breakers at Joshua Falls substation. Substation expansion is required to add the additional breakers.		$99.19		
40	B4000.355	Build a new 156-mile 765 kV line from Joshua Falls-Yeat (roughly 69.3 miles in AEP section).		$341.17		
	B4000.356	Build a new 156-mile 765 kV line from Joshua Falls-Yeat (roughly 86.7 miles in Dominion section).		$426.83	Dominion	

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Table 6.62: Virginia Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
41	B4000.344	Build a 500 kV line from North Anna substation (bypassing Ladysmith substation) to a new substation called Kraken. New conductor to have a minimum summer normal rating of 4357 MVA.	6/1/2029	$186.67	Dominion	1/7/2025
42	B4000.346	Cut in 500 kV line from Kraken substation into Yeat substation.		$5.00		
	B4000.345	Build a 500 kV line from a new substation called Kraken to a new substation called Yeat. New conductor to have a minimum summer normal rating of 4357 MVA.		$394.71		
43	B4000.351	Cut in line No. 568 Ladysmith-Possum Point into Kraken, creating line No. 568 Ladysmith to Kraken.		$3.60		
	B4000.352	Cut in line No. 568 Ladysmith-Possum Point into Kraken, creating new line from Kraken to Possum Point.		$3.60		
	B4000.348	Build a new 500/230 kV substation called Kraken. The 500 kV, 5000A ring bus will be set up for a redundant breaker configuration. Install two 1400MVA 500/230 kV transformers. A new redundant breaker ring will be added at Kraken to accommodate the new 500 kV line from North Anna to Kraken.		$84.41		
44	B4000.114	Ladysmith S1 substation 230 kV: Replace 40 kA breakers 25672, 209072, 256T2090, GT172, GT272, GT372, GT472, GT572 with 63 kA.		$4.00		
	B4000.115	Ladysmith substation 500 kV: Replace 40 kA breaker 574T581 with 63 kA.		$1.02		
	B4000.327	Upgrade/install equipment at Ladysmith substation to 4000A. Expansion will be required to accommodate a total of three new 230 kV strings of breaker-and-a-half scheme.		$8.72		
	B4000.349	Update relay settings at Ladysmith to change the destination of 500 kV line No. 568 from Possum Point to Kraken.		$0.04		
	B4000.354	Expand Ladysmith substation to a add redundant circuit breakers to the middle breakers on both 500 kV strings (574T575 and 568T581). The equipment including switches 57518, 57515, H115 will be replaced with 5000A equipment.		$8.24		
45	B4000.207	Leesville Station Upgrade 138 kV: Replace 795 KCM AAC, 37-stranded IPS Sch. 40 1272 KCM AAC, 61-stranded 1272 KCM AAC, 61-stranded PH A,B,C ALTA VISTA CB-A BUS DISC ALTA VISTA CB-A LINE DISC Wavetrap (1200A) Relay Thermal Limit 1356 Amps		$0.60	AEP	
46	B4000.116	Liberty substation 230 kV: Replace 50 kA breaker SC112 with 63 kA.		$0.50	Dominion	
47	B4000.117	Lockridge substation 230 kV: Replace 63 kA breakers 218872, H12T2188, 222372, H12T2223 with 80 kA.		$2.64		
48	B4000.118	Loudoun substation 230 kV: Replace 63 kA breakers 209452, L152, L252 with 80 kA.		$1.98		
	B4000.119	Loudoun Cap substation 230 kV: Replace 50 kA breaker SC352 with 63 kA.		$0.50		
	B4000.120	Loudoun substation 500 kV: Replace 50 kA breakers 502T535, 569T584, H1T569, H2T502, H2T584, SC152 with 63 kA.		$6.09		
49	B4000.121	Marsh Run substation 230 kV: Replace 50 kA breaker 28002, 29902, 280T2039, 299T2040, 203902, 204002 with 63 kA.		$3.00		
	B4000.302	Uprate line No. 299 terminal equipment, line leads, and bus at Marsh Run substation to be rated to 4000A.		$2.53		
	B4000.300	Rebuild an ~1.71 miles of 230 kV line 299 from the Marsh Run substation to the Remington CT substation. New conductor has a summer rating of 1573 MVA.		$5.35		
50	B4000.122	Morrisville substation 230 kV: Replace 50 kA breaker L1T2039, L1T2040, L2T2039, L2T2040 with 63 kA.		$2.00		
	B4000.123	Morrisville substation 500 kV: Replace 50 kA breakers H1T541, H1T594, H2T545, H2T569, SC122 with 63 kA.		$5.08		
	B4000.338	At Morrisville substation, install/upgrade substation terminal equipment to 4000A.		$0.95		
51	B4000.342	Remove the terminal equipment and substation work required for the termination of the Morrisville-Wishing Star 500 kV line into Vint Hill.		$0.00		

Table 6.62: Virginia Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
52	B4000.337	Extend a new 230 kV line an ~7.85 miles between the existing Morrisville and Anderson Branch substations. The existing tower structures currently supporting the Bristers to Morrisville 500 kV line No. 545 will be used to support this new line as shared tower structures.	6/1/2029	$5.26	Dominion	1/7/2025
53	B4000.124	Mosby substation 500 kV: Replace 50 kA breakers 50272, 54672, 55972, 58472, 59072, 502T546, 559T584, SC172, SV172, SV272, XT590 with 63 kA		$11.17		
54	B4000.126	Nimbus substation 230 kV: Replace 63 kA breakers 215282, 225532-5, 225532-6, 226034 with 80 kA.		$2.64		
55	B4000.127	NIVO 1 substation 230 kV: Replace 63 kA breaker 2116T2130 with 80 kA (4-breaker ring bus).		$0.66		
56	B4000.323	Upgrade terminal equipment at Nokesville substation. The project adds one more line to Nokesville, including the installation of one 230 kV breaker and two 230 kV switches.		$1.43		
57	B4000.324	Upgrade terminal equipment at Hornbaker substation. This project provides for installing a new 230 kV, 4000A rated line terminal at Hornbaker to accommodate the new line to Nokesville.		$1.43		
	B4000.322	Build a new 230 kV line from Nokesville-Hornbaker using the vacant arms of the double circuit monopole structures installed as part of previous project 993027. New conductor has a summer rating of 1573 MVA.		$15.28		
58	B4000.128	North Anna substation 500 kV: Replace 40 kA breakers 57502, G102-1, G102-2, G202, G2T575, XT573 with 63 kA		$6.09		
	B4000.347	Upgrade/install equipment at North Anna substation to 5000A to support the new conductor rating.		$9.12		
59	B4000.206	Opposum Creek 138 kV: Replace Opossum Creek switch.		$0.10	AEP	
60	B4000.208	Otter 138 kV station upgrade: Replace 795 KCM AAC, 37-stranded.		$0.10		
	B4000.210	Reconductor 14.4 miles of Otter-Johnson Mountain 138 kV line.		$8.40		
61	B4000.129	Ox substation 230 kV: Replace 50 kA and 63 kA breakers 201342, 209742, 206342, SC242 with 80 kA.		$2.64	Dominion	
	B4000.130	Ox substation 500 kV: Replace 40 kA breakers 56142, H1T539, H2T539 with 63 kA.		$3.05		
62	B4000.131	Paragon Park substation 230 kV: Replace 63 kA breakers 220632, 220732 with 80 kA.		$1.32		
63	B4000.132	Pleasantview substation 230 kV: Replace 63 kA breakers 203T274, 274T2098 with 80 kA.		$1.32		
	B4000.133	Pleasantview substation 500 kV: Replace 40 kA breaker H322 with 63 kA.		$1.02		
64	B4000.316	At Poe substation, uprate all line No. 2003 terminal equipment, line leads and bus to be rated to 4000A.		$1.79		
	B4000.321	At Poe substation, upgrade all line No. 2002 terminal equipment at Carson to 4000A. CCVTs will also be replaced due to aging.		$0.81		
	B4000.335	At Poe substation, install a new 230 kV six-breaker ultimate ring bus, which will fit the station to current 230 kV standards. The substation scope includes the installation of 230 kV breaker-and-a-half GIS bus. Work at Poe subsation is associated with line No. 121 reconductor.		$38.28		
65	B4000.319	Reconductor 230 kV line No. 2002 Carson-Poe. New conductor has a summer rating of 1573 MVA.		$30.29		
66	B4000.334	Reconductor 115 kV line No. 121 from Poe-Prince George. Specifically, line No. 121 will be reconductored and converted to 230 kV from Poe substation to Prince George substation.		$14.62		
	B4000.336	Build a new 230-115 kV Prince George substation along the existing 115 or 230 kV corridor. The substation scope includes the installation of 230 kV breakers and one 115 kV breaker along with its associated terminal equipment initially but will have provision for making it a six-breaker ring (both 230 and 115 kV) in future. The existing 230-115 kV transformer at Prince George will be relocated to serve this new substation.		$26.62		

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Table 6.62: Virginia Baseline Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
67	B4000.350	Update relay settings at Possum Point to change the destination of 500 kV line No. 568 from Ladysmith to Kraken.	6/1/2029	$0.04	Dominion	1/7/2025
68	B4000.333	At Raines substation, upgrade substation terminal equipment to 4000A.		$1.32		
69	B4000.203	Reconductor 34 miles of Redeye-Candler's Mountain 138 kV line.		$21.00	AEP	
70	B4000.134	Remington substation 230 kV: Replace 40 kA and 50 kA breakers 211462, GT162, GT262, GT362, GT462, 2077T2086, 208662, H962, H9T299 with 63 kA.		$4.50	Dominion	
	B4000.303	Uprate line No. 299 terminal equipment, line leads and bus at Remington CT substation to be rated to 4000A.		$2.44		
	B4000.301	Reconductor an ~1.24 miles of 230 kV line 280 from Remington-the Marsh Run CT substation to the Remington substation. New conductor has a summer rating of 1573 MVA.		$3.89		
71	B4000.135	Roundtable substation 230 kV: Replace 63 kA breakers 203102, 214902, 221402, 222302, 2031T2223, 2149T2214 with 80 kA.		$3.96		
72	B4000.201	Smith Mountain 138 kV upgrade: Replace 795 KCM AAC, 37-stranded 795 KCM AAC, 37-stranded PH A B2S1 B2S2 BS1 BS2.		$0.40	AEP	
	B4000.202	Reconductor 34 miles of Smith Mountain-Redeye 138 kV line.		$14.90		
73	B4000.310	Revise relay settings at Trident substation.		$0.03	Dominion	
74	B4000.317	At Tyler substation, upgrade the necessary line terminal equipment to maintain 4000A at Tyler substation.		$0.54		
	B4000.314	Reconductor 230 kV line No. 2003 Chesterfield-Tyler segment. New conductor has a summer rating of 1573 MVA.		$3.16		
	B4000.315	Reconductor 230 kV line No. 2003 Tyler-Poe segment. New conductor has a summer rating of 1573 MVA.		$20.61		
75	B4000.136	Vint Hill substation 230 kV: Replace 63 kA breakers 2101T2174, 2163T2174, 2101T2163 with 80 kA.		$1.98		
	B4000.341	Remove the 500 kV conductor previously planned to terminate into the Vint Hill 500 kV substation and extend an ~0.2 miles of conductor to fly-over the site.		$0.00		
76	B4000.137	Yardley substation 230 kV: Replace 63 kA breakers WT2209, WT2213, XT2209, XT2213 with 80 kA.		$2.64		
77	B4000.358	Build a new 765/500/230 kV substation called Yeat. Install one 500/230 kV transformer. Cut in 230 kV line Vint Hill-Elk Run into Yeat substation.		$45.60		
	B4000.357	Build a new 765/500/230 kV substation called Yeat. Install two 765/500 kV transformers. Cut in 500 kV line Bristers-Ox and 500 kV line Meadowbrook-Vint Hill into Yeat.		$197.10		

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6.12.7 — Network Projects

Network projects in Virginia for 2024 are summarized in **Map 6.51** and **Table 6.63**.

Read More
Network Projects

Map 6.51: Virginia Network Projects (Dec. 31, 2024)

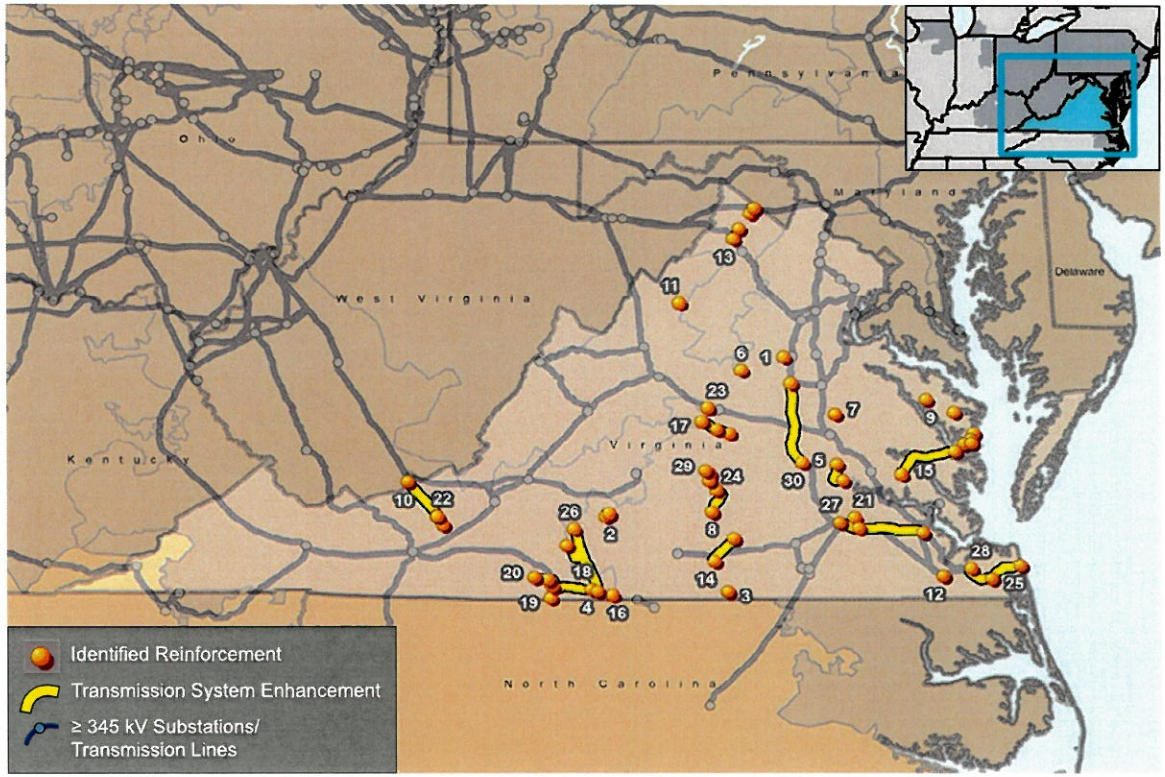

Table 6.63: Virginia Network Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5612	Rebuild 2.8 miles 768 ACSS with a rating of A: 393, B: 393, C: 452 at AC1-076 Tap-Paytes DP 115 kV line.	AD1-115	6/30/2019	$3.65	Dominion	10/8/2024
2	N5613	Rebuild or reconductor 0.9 miles of overhead conductor (ACSR ~ 397.5 ~ 30/7 ~ LARK) between ALTVSTA and 050TTER 138 kV line.	AE1-250	10/1/2019	$2.74	AEP	10/8/2024
	N5613.1	Replace 795 AAC station conductors at Altavista 138 kV substation.			$0.10	Dominion	10/8/2024
3	N6115	For DEV portion, rebuild 4.7 miles of 115 kV line 45 from Kerr Dam to GW King Tap with 768 ACSS.	AD2-033	10/31/2020	$11.35		10/8/2024

Table 6.63: Virginia Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	N6124	Increasing the Danville-East Danville 138 kV circuit summer rating to 337/482 MVA will still require AEP to rebuild the line.	AD1-152	6/1/2021	$8.25	AEP	10/8/2024
	N6124.1	Reconductor/rebuild 2.78 miles of ACSR ~ 336/556 six-wire conductor on the 05EDAN 1-05DANVL2 138 kV line.	AD1-076		$4.28		1/9/2024
	N6124.2	Reconductor/rebuild 0.03 miles of ACSR ~ 1351.5 ~ 45/7 ~ DIPPER-Conductor Section 3 on the 05EDAN 1-05DANVL2 138 kV line.			$0.04		
	N6124.3	Reconductor/rebuild 0.03 miles of ACSR ~ 1351.5 ~ 45/7 ~ DIPPER-Conductor Section 1 on the 05EDAN 1-05DANVL2 138 kV line.			$0.04		
	N7554.1	Replace 5 substation conductor 2000 AAC 91 stranded at Danville2 138 kV station.	AE1-250	12/31/2024	$0.00		10/8/2024
	N7554.2	Replace 3 substation conductor 2000 AAC 91 stranded at East Danville 138 kV station.			$0.00		
	N7754.3	The Danville-East Danville 138 kV circuit will require higher capacity conductor to obtain a rating higher than the 482 MVA achieved by the initial rebuild. As such, APCo will instead install 1272 ACSS conductor during the initial rebuild project under n6124.	AG1-030	6/1/2024	$0.46		
5	N6130	Rebuild 12.4 miles 2-636 ACSR between Chesterfield-Basin 230 kV; ratings after the upgrade: 1047/1047/1204.	AE1-069	12/1/2021	$31.00	Dominion	
6	N6236	Build new strandeductures to cut and loop the line into AC1-043 115 kV switching station.	AC1-043	10/2/2019	$1.43		1/9/2024
7	N6786	Build a three-breaker 115 kV substation at the existing Kings Dominion DP substation.	AD1-105	12/31/2019	$5.30		
	N6787	Build new strandeductures to cut and loop the transmission line into the new Kings Dominion 115 kV ring bus sustation.		12/31/2020	$0.50		
	N6788	Modify protection and communication work to support interconnection of the new Kings Dominion DP three-breaker ring bus substation.			$0.20		
8	N7180	Rebuild 7.2 miles of 230 kV line 235 from Prince EDW to Farmville with two 768.2 ACSS/TW (20/7) "MAUMEE" at 250 C.	AF1-042	12/31/2022	$20.70		10/8/2024
	N7181	Rebuild 5.7 miles of 230 kV line 235 from Briery to Prince EDW with 2-636 ACSR.		12/31/2023	$8.55		1/9/2024
9	N7854.3	Remote protection and communication work: Additional work is required at Northern Neck, Rappahannock and Harmony Village 115 kV substations. Drawing work, relay resets and field support necessary to change the line 65 destinations at Garner DP, Lancaster, Ocran and White Stone substations will also be completed.	AE1-155	9/15/2022	$0.32		10/8/2024
	N7972	Split line No. 65 between Northern Neck substation and Rappahannock substation. Rappahannock substation: The AD2-074/AF1-042 substation will be built in line with line 65 approximately halfway between existing strandeductures 65/541 and 65/542. This location is approximately 5.4 miles to the southeast of Garner DP. The final location of the substation is subject to change but shall remain within the same vicinity. The portion of the 65 line between the Northern Neck substation and the AD2-074/AF1-042 substation will be assigned a new line number and the strandeductures will be renumbered accordingly.	AF1-042	5/31/2025	$0.97		1/9/2024
	N7973	Build a three-breaker AD2-074/AF1-042 115 kV switching station. The objective of this project is to build a 115 kV, three-breaker ring bus to support the new solar farm built by Waller Solar I, LLC. The site is located along Dominion Energy's existing 115 kV, 65 line from Northern Neck substation to Rappahannock substation. The cut line will consume two of the positions in the ring bus. The third position will be for the 115 kV feed from Waller Solar I, LLC collector station for the new solar farm.			$5.44		
	N7974	Remote protection and communication work. Additional work to be required at Harmony Village, Rappahannock, Northern Neck and Garner DP, Lancaster, Ocran & White Stone substations.			$0.32		

Table 6.63: Virginia Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
10	N7904	Constrandeduct a new three-circuit breaker AD2-179 138 kV station.	AD2-179	11/1/2020	$4.37	AEP	1/9/2024
	N7905	138 kV revenue meter, generator lead transmisison line first span exiting the point of interconnection station, including the first strandeducture outside the fence		3/28/2018	$1.78		
	N7906	Claytor-Glen Lyn 138 kV No. 2 Ckt T-line new station cut-in OPGW to Morgans Cut		11/1/2020	$1.50		
	N7907	Upgrade line protections and controls at the Glen Lyn 138 kV station.		3/28/2018	$0.50		
	N7908	Replace the Claytor 138 kV station remote end circuit breaker "A" line relays with a dual carrier system and implement required settings. Install breaker controls and a second line trap.		11/1/2020	$0.42		
11	N7954	Install a new 115 kV overhead transmission line from Endless Caverns substation.	AF1-028	10/31/2023	$1.42	Dominion	
	N7955	Additional work to be required at Endless Caverns includes adding a new 115 kV bay, relocating bus No. 3 cap bank, relocating 115 kV line 118 and relocating transformer No. 5 tap position. Control enclosure CE1 will be expanded to the North by 10' to allow room for new relaying panels to be installed with project and battery and charger replaced as well.			$3.38		
12	N8049	Build a new 115 kV solar farm to interconnect into the Suffolk station. Project AE2-104 provides for the constrandeduction of one new 115 kV interconnect into Suffolk substation. The objective of this project is to add one new line position and one new 115 kV breaker installed at Suffolk substation to support the new 49 MW solar farm built by Switchgrass Solar I, LLC. Additional modifications will be required to accommodate this additional infrastrandeducture.	AE2-104	12/30/2024	$3.35		
13	N8061.1	Install fiber from Bartonville substation to backbone for relaying communications transport.	AE2-230	11/15/2022	$0.25	AP	
	N8061.2	Loop the Bartonville-Meadow Brook 138 kV into the new Long Creek substation.			$1.21		
	N8061.3	New strandeducture installation per the Bartonville-Meadow Brook 138 kV Line estimate.			$0.52		
	N8061.4	Retune single frequency line trap and replace line tuner on Stephenson line.			$0.23		
	N8061.5	Retune single frequency line trap and replace line tuner for Bartonville and Stonewall lines.			$0.49		
	N8061.6	Replace line relaying, modify nameplates and drawings for line name change.			$0.36		
	N8061.7	Replace line relying, retune single frequency line trap and replace line tuner on Stephenson line.			$0.53		
	N8061.8	Interconnection customer will constrandeduct a new three-breaker ring bus substation along the Bartonville-Meadow Brook 138 kV transmission line, to electrically interconnect the customer facility with the transmission system.			$0.67		
14	N8109.1	Build a three-breaker 115 kV switching station.	AD2-033	10/31/2020	$5.46	Dominion	
	N8109.2	Rearrange line No. 98 to loop into and out of the new three-breaker 115 kV switching station.			$1.80		
	N8109.3	Remote station work – Lunenburg 115 kV substation			$0.14		
	N8109.4	Remote station work – Butcher Creek 115 kV substation.			$0.02		
15	N8116.1	Install one new 230 kV interconnect at Harmony Village station.	AE2-041	4/1/2025	$3.83		
	N8116.2	Relocate existing 230 kV Lanexa line 2016.			$2.61		
	N8116.3	Remote station work – Lanexa 230 kV substation			$0.09		

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Table 6.63: Virginia Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
16	N8120.1	A new three-circuit breaker 230 kV station, Firefly 230 kV station, physically configured and operated as a ring bus	AD2-022	6/1/2020	$7.10	AEP	1/9/2024
	N8120.2	T-line cut-in and dead-end strandeducture installation			$1.51		
	N8120.3	Remote end tie line metering removal.			$0.04		
	N8120.4	230 kV Duke tie line meter installation.			$0.40		
	N8120.5	Roxboro (DEP) 230 kV station – Update relay settings, engineering drawings, equipment labels.			$0.12		
17	N8127.1	Oversight of proposed Riverstone 138 kV station	AE1-108	9/12/2018	$0.47		
	N8127.2	Bremo-Scottsville 138 kV T-line cut-in and fiber installation			$0.55		
	N8127.3	Upgrade line protection and controls at the Scottsville 138 kV station.			$0.04		
	N8127.4	138 kV extension line from Bremo-Scottsville 138 kV circuit tap to the proposed Riverstone 138 kV station.			$1.25		
18	N8178.1	Install new 138 kV three-breaker ring bus station along the Axton-Danville No. 1 138 kV line. Install a drop-in control module (DICM) and other associated line protection and control equipment, line risers, switches, jumpers, and supervisory control and data acquisition (SCADA) equipment.	AE2-140	5/31/2022	$4.70		
	N8178.2	Perform final connection of the Axton-Danville No. 1 138 kV line to the Lendlease 138 kV station, update remote end protective relay settings.		12/31/2021	$1.26		
	N8178.3	Install one fiber-optic path to facilitate relaying between Lendlease and Axton 138 kV stations.			$0.76		
	N8178.4	Replace protective relays.			$0.24		
	N8178.5	Extend two new fiber-optic connections from the AE2-140 proposed Lendlease 138 kV station into AEP's existing fiber-optic network to facilitate SCADA network connectivity.			$0.18		
19	N8200.1	Constrandeduct a new three-circuit breaker 69 kV station physically configured and operated as a ring bus.	AE2-047	12/15/2021	$3.78		
	N8200.2	Install three dead-end strandeductures, four spans of conductor; connect point of interconnection station to existing transmission circuit; update remote end relay settings.			$1.29		
20	N8212.1	Expand the Stockton 138 kV station into a four-breaker ring-bus arrangement.	AE2-166	12/31/2022	$7.14		
	N8212.2	Axton-Martinsville transmission line work; Martinsville remote end settings			$0.45		
	N8212.3	Install a new ICON at the Axton 138 kV station with connectivity to the Stockton 138 kV station. Replace the existing relays at the Axton 138 kV station.			$0.25		
	N8212.4	Install Stockton circuit switcher.			$0.20		
21	N8226.1	Rearrange line No. 15 to loop into and out of the new three-breaker AE1-149 115 kV switching station.	AE1-149	12/1/2021	$1.38	Dominion	
	N8226.2	Build a three-breaker AE1-149 115 kV switching station.			$7.04		
	N8226.3	Remote protection and communication work			$0.64		
22	N8232	Install diverse UG/ADSS fiber-optic cable path.	AD2-179	11/1/2020	$0.37	AEP	
	N8233	Morgans Cut station circuit breaker addition and associated work			$1.26		

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Table 6.63: Virginia Network Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
23	N8258.1	Rearrange line No. 91 to loop into and out of the new three-breaker AE2-092 230 kV switching station.	AE2-092	3/1/2022	$2.51	Dominion	1/9/2024
	N8258.2	Remote protection and communication work			$0.59		
	N8258.3	Build a three-breaker AE2-092 230 kV switching station.			$1.06		
24	N8311.1	Install line 149 tap to AE2-259 switching station.	AE2-259	9/15/2021	$6.07		10/8/2024
	N8311.2	Remote protection and communication work at Curdsville 115 kV substation			$0.15		
25	N8317.1	Expand Fentress 500 kV and 230 kV substations to terminate three new 230 kV lines from Harpers Road substation and connect them to Fentress 500 kV.	AF1-123	12/31/2025	$157.58		
	N8317.2	Constrandeduct three overhead 230 kV transmission lines that will start at the existing Fentress substation and terminate at the new Harpers Road substation, located an ~14.3 miles away.			$150.64		
	N8317.3	Build new 230 kV Harpers Road switching station to terminate nine offshore wind export cables for AF1-123/124/125 and consolidate to three overhead 230 kV transmission lines to go to Fentress substation.			$274.95		
26	N8459.1	Install custom steel double circuit tap strandeducture, two conductor spans for in-and-out from the new 138 kV station to existing Smith Mountain-East Danville 138 kV circuit.	AE1-250	9/30/2021	$1.28	AEP	
	N8459.2	Remote protection and relay work at Museville 138 kV			$0.42		
	N8459.3	Remote protection and relay work at East Danville 138 kV			$0.42		
	N8459.4	Build a three-breaker at AE1-250 138 kV switching station.			$4.29		
27	N8485.1	Build a three-breaker AE2-051 500 kV switching substation.	AE2-051	6/30/2027	$19.50	Dominion	
	N8485.2	Rearrange line No. 562 to loop into and out of the new three-breaker AE2-051 500 kV switching station.			$3.85		
	N8485.3	Remote protection and communications work at Septa and Carson 500 kV substations			$0.20		
28	N8492	Constrandeduct one overhead 500 kV transmission line that will start at the existing Fentress 500 kV substation and terminate at the existing Yadkin 500 kV substation, located an ~13.7 miles away.	AF1-123	12/31/2025	$73.72		
	N8492.1	Install two 5000 amp GIS breakers at Fentress substation; time: 30–36 months.			$99.58		
	N8492.2	Expansion of Yadkins 500 kV switchyard to accommodate the new 500 kV line, which includes addition of 5000 amp GIS breakers and relocation of the existing Suffolk-Yadkin 500 kV line No. 565; time: 30–36 months.			$15.45		
29	N8506	Tap Line 149 into AE2-259 switching station	AE2-259	8/12/2025	$6.07		
	N8507	Remote protection and communication work at Willis Mountain 115 kV substation		3/1/2030	$0.22		
30	N5609	Rebuild 41.13 miles of 500 kV Line 576 from Midlothian to North Anna with 3-1351.5 125C ACSR with the following ratings: Rate A: 4816, Rate B: 4816 and Rate C: 5539.	AC2-141	12/1/2021	$234.44		

6.12.8 — Supplemental Projects

Supplemental projects included in the 2024 Local Plan in Virginia are summarized in **Map 6.52** and **Table 6.64**.

Read More
Supplemental Projects

Map 6.52: Virginia Supplemental Projects (Dec. 31, 2024)

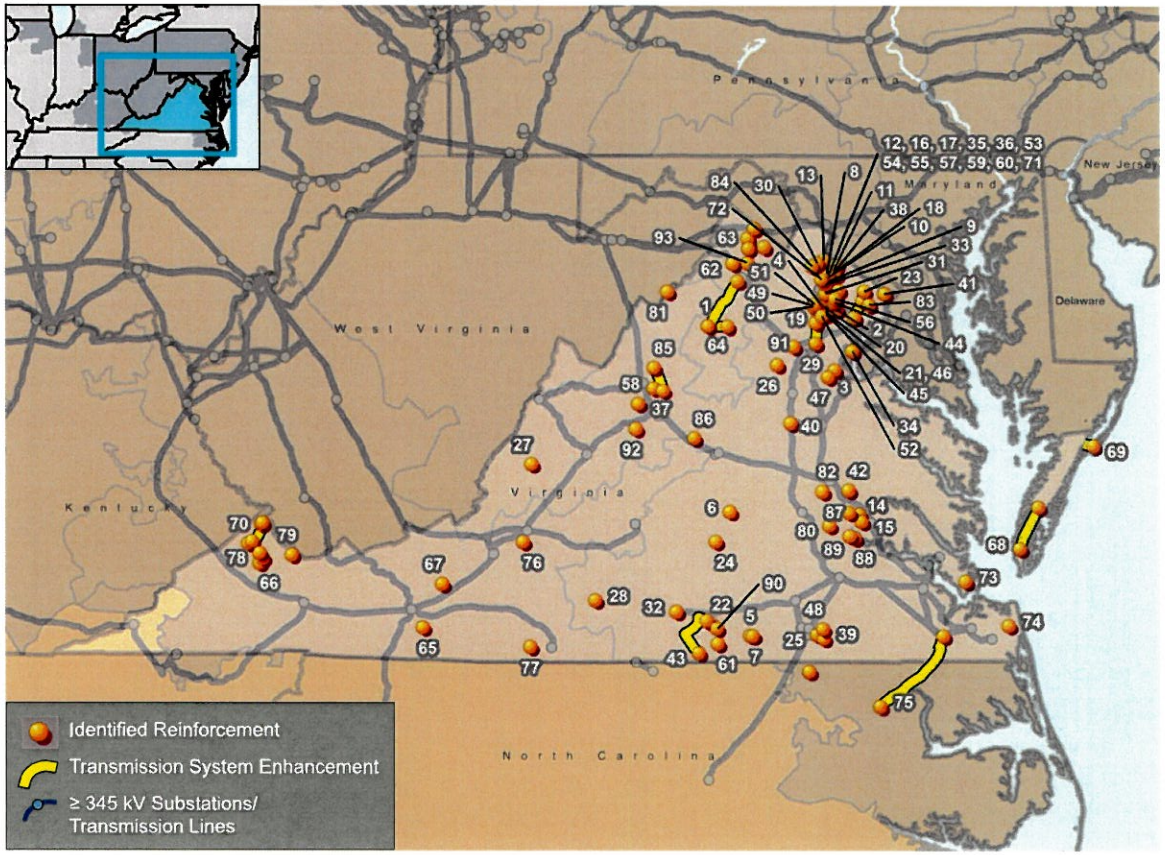

Table 6.64: Virginia Supplemental Projects (Dec. 31, 2024)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2935	Rebuild the Page-Sperryville 138 kV line, an ~21.5 miles, with wood pole equivalent steel structures. Replace limiting substation conductor, wave trap, circuit breaker and relaying at Page 138 kV substation. Replace limiting substation conductor, wave trap, and circuit switcher at Hardy 138 kV substation.	6/1/2026	$45.80	AP	4/21/2023
2	S3018	Interconnect the new Dawkins Branch substation by cutting and extending 230 kV line No. 2163 (Vint Hill-Liberty). Terminate both ends into a four-breaker ring arrangement to create a Vint Hill-Dawkins Branch line and a Dawkins Branch-Liberty line.	7/1/2023	$16.00	Dominion	7/12/2022

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Table 6.64: Virginia Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S3019	Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (bus, relaying, etc.) to feed the second distribution transformer at Garrisonville.	7/17/2024	$0.75	Dominion	7/12/2022
4	S3020	Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (bus, relaying, etc.) to feed the second distribution transformer at Youngs Branch.	9/30/2024	$0.75		
5	S3021	Construct Evans Creek 230 kV substation with a four-breaker 230 kV breaker ring bus to terminate two 230 kV lines. Construct one new 230 kV transmission line for an ~5 miles from Tunstall substation to Evans Creek substation. Construct one new 230 kV transmission line for an ~3 miles from Raines sub to Evans Creek substation. New right-of-way will be needed for both transmission lines. New conductor to have a minimum summer normal rating of 1573 MVA.	8/1/2025	$30.00		
6	S3022	Obtain land and build a new 500/230 kV Unity switching station near the intersection of 500 kV line No. 593 (Finneywood-Rawlings) and Route 138. Cut and terminate line No. 593 into Unity 500/230 kV switching station. In the new Unity switching station, install two 840 MVA 500/230 kV transformers, a 230 kV ring bus with 6 breakers and a 500 kV ring bus with 6 breakers. Construct Tunstall 230 kV substation with four rows of 230 kV breaker-and-a-half bus to terminate four 230 kV lines. Construct two new 230 kV single circuit transmission lines for an ~11 miles from Unity Substation to Tunstall substation. New right-of-way will be needed for both transmission lines. New conductor to have a minimum summer normal rating of 1573 MVA.		$140.00		
7	S3023	Construct Raines 230 kV substation with four-breaker 230 kV breaker ring bus to terminate two 230 kV lines. Construct one new 230 kV transmission line for an ~8 miles from Tunstall substation to Raines substation. New right-of-way will be needed for the transmission line. New conductor to have a minimum summer normal rating of 1573 MVA. Due to the total load requested less than 100 MW, the data center customer will be required to pay excess facilities for all equipment required for the ring bus configuration above a T-tap.		$20.00		
8	S3024	Interconnect the new Northstar substation by cutting and extending 230 kV line No. 2045 Brambleton-Loudoun. Lines to terminate in a 230 kV four-breaker ring arrangement with an ultimate arrangement of a six-breaker ring.	12/20/2024	$42.00		
9	S3025	Interconnect the new Thunderball substation by cutting and extending 230 kV line No. 206 Stonewater-Brambleton. Lines to terminate in a 230 kV four-breaker ring arrangement with an ultimate arrangement of a six-breaker ring.	10/31/2024	$15.40		
10	S3026	Interconnect the new Trappe Rock substation by cutting and extending 230 kV line No. 201 Belmont-Altair. Lines to terminate in a 230 kV four-breaker ring arrangement with an ultimate arrangement of a six-breaker ring.	12/13/2024	$19.80		
11	S3027	Interconnect the new Barrister substation by cutting and extending 230 kV line from Roundtable to Stratus and line from Lockridge to Stratus. Terminate both ends into a six-breaker ring bus arrangement to create Roundtable-Barrister, Lockridge-Barrister lines as well as two Stratus-Barrister lines.	6/30/2028	$24.00		8/9/2022
12	S3028	Cut and extend 230 kV line No. 2231 Global Plaza-Pacific to the proposed Ocean Court substation. Terminate lines in a four-breaker 230 kV ring bus with an ultimate arrangement of six-breaker ring.	10/22/2025	$12.70		
13	S3029	Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (bus, relaying, etc.) to feed the 4th distribution transformer at Pleasant View.	12/31/2025	$1.00		
14	S3030.1	Install equipment and bus work to support the installation of 2-56 MVA distribution transformers at White Oak substation.	3/31/2023	$1.00		
	S3030.2	Cut 230 kV line No. 2075 and extend double circuit 230 kV lines into White Oak substation. Install two 1200 amp switches and upgrade bus work and existing equipment at the White Oak substation. Add three additional 230 kV breakers to terminate 230 kV lines.	11/26/2026	$42.20		
15	S3031	Cut 230 kV line No. 286 Darbytown-White Oak and 230 kV line No. 2198 Portugee-White Oak and terminate at the new Techpark Place (TPP) substation in a 6-breaker 230 kV ring bus. Include associated equipment (bus, switches, relays, etc.) as required.	1/31/2024	$23.70		
16	S3032	Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (bus, relaying, etc.) to feed the fourth distribution transformer at Farmwell.	8/1/2023	$0.50		

Table 6.64: Virginia Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
17	S3033	Interconnect the new Stratus substation by cutting and extending 230 kV line No. 2188 Lockridge-Shellhorn and 230 kV line No. 2031 Roundtable-Enterprise. Terminate both ends into a six-breaker ring bus arrangement to create Roundtable-Stratus, Stratus-Shellhorn, Enterprise-Stratus and Lockridge-Stratus lines.	12/8/2025	$24.00	Dominion	8/9/2022
18	S3034	Install three 1200 amp, 50 kAIC circuit switchers and associated equipment (bus, relaying, etc.) to feed three new distribution transformers at Lockridge.	2/28/2025	$1.50		
19	S3035.1	Interconnect the new Hornbaker substation by cutting and extending 230 kV line No. 2187 Liberty-Pioneer. Lines to terminate into a 230 kV four-breaker ring arrangement with an ultimate arrangement of a six-breaker ring.	10/19/2027	$45.00		
	S3035.2	Construct one new 230 kV transmission line for an ~7.5 miles from Hornbaker to Nokesville substation with a minimum summer normal conductor rating of 1573 MVA. New right-of-way and expansion of existing right-of-way will be required. Install a 230 kV ring bus and associated 230 kV equipment (breakers, switches, leads) at the existing Nokesville substation. Reconfigure the existing terminations of 230 kV line No. 2101 Bristers-Vint Hill into Nokesville substation to accommodate the new 230 kV line.	11/1/2028	$139.00		
20	S3036	Interconnect the new Mint Springs substation by cutting and extending 230 kV line No. 2030 Loudoun-Gainesville. Lines to terminate into a 230 kV four-breaker ring arrangement with an ultimate arrangement of a six-breaker ring.	11/13/2026	$16.00		
21	S3037	Interconnect the new Rixlew substation by cutting and extending 230 kV line No. 2228 Liberty-Pioneer. Lines to terminate into a 230 kV four-breaker ring arrangement with an ultimate arrangement of a six-breaker ring.	6/20/2025	$10.00		
22	S3039	Tap 115 kV line No. 171 Chase City-Herbert near structure 171/51 and extend a single circuit 115 kV tap to Cemetery Road substation.	10/15/2024	$6.30		8/18/2022
23	S3040	Rebuild ~7.9 miles of double-circuit line from Ox to Braddock and partial line No. 2097 (Ox-Idylwood) to current 230 kV standards. The normal summer rating of the line conductor will be 1573 MVA.	6/30/2027	$43.50		9/6/2022
24	S3041	Replace Farmville transformer No. 5 with a new three-phase, 230/115/13.2 kV, 168 MVA unit. Include other ancillary equipment (high-side breaker, arresters, switches, relays, etc.) as needed.	1/31/2025	$6.40		
25	S3042	Replace Clubhouse transformer No. 1 with a new three-phase, 230/115/13.2 kV, 224 MVA unit. Include other ancillary equipment (arresters, switches, relays, etc.) as needed.	5/30/2025	$6.60		
26	S3044	Build new Kyser switching station to feed REC's existing Mountain Run DP. The initial build will include four 230 kV breakers, associated bus, switches, etc. Build new Cirrus switching station to feed REC's new DP. The initial build will include four 230 kV breakers, associated bus, switches, etc. Wreck and rebuild an ~five miles of existing double-circuit 115 kV line No. 2 and line No. 70, using 230 kV construction, from Mountain Run Junction to the new Kyser/Cirrus switching stations. Cut 230 kV line No. 2199 at Mountain Run Junction and feed the rebuilt double-circuit line to Kyser/Cirrus switching stations. Reconnect the remaining sections of 115 kV lines No. 2 and line No. 70 at Mountain Run Junction. REC to convert their existing Mountain Run DP to 230 kV. Install a 230/115 kV – 168 MVA transformer and spare at Cirrus switching station to maintain the 115 kV feed to Culpeper and Culpeper DP.	11/15/2027	$60.00		
27	S3045	Create a tee-tap on 138 kV line No. 133 Clifton Forge – Low Moor between structures 22 and 23 to source the customer substation located an ~100' away from the line. Install switch structures and switches on both sides of the tap point and an H-frame backbone structure inside Alleghany substation, along with a wave trap, MOAB switch, circuit switcher and other ancillary work as needed.	12/31/2023	$2.90		9/15/2022
28	S3046	Install a 69 kV circuit switcher, high-side switch and associated equipment (bus, switches, relaying, etc.) to feed the second distribution transformer at Gretna.	6/30/2025	$0.50		

Table 6.64: Virginia Supplemental Projects (Dec. 31, 2024) (Cont.)

Map ID	Upgrade ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
29	S3047.1	Reconductor an ~9.2 miles of 230 kV line No. 2101 Nokesville-Bristers using a higher capacity conductor as well as terminal equipment upgrades to achieve a minimum normal summer conductor rating of 1573 MVA.	12/31/2027	$23.00	Dominion	2/7/2023
	S3047.2	Install two 1400 MVA 500-230 kV transformers and associated 500 kV and 230 kV equipment (breakers, switches, leads) at Vint Hill substation to supply the area with a 500 kV source cut and loop 500 kV line No. 535 Loudoun-Meadowbrook and No. 569 Loudoun-Morrisville as the 500 kV sources into the proposed 500 kV ring bus Vint Hill substation will be expanded to the north of the existing site to accommodate the 500 kV ring required for the addition of the new transformers. Existing terminations for 230 kV line No. 2174 Wheeler-Vint Hill, line No. 2101 Bristers-Vint Hill, and line No. 2163 Liberty-Vint Hill will be rearranged to terminate into the expanded Vint Hill substation 230 kV line No. 2114 Remington CT-Rollins Ford will also be cut and looped into the expanded Vint Hill substation due to spatial constraints along the existing right-of-way.	6/30/2029	$269.00		
30	S3048	Interconnect the new Sycolin Creek substation by cnstructing two 230 kV lines an ~1.0 mile from Twin Creeks substation. Lines to terminate in a 230 kV six-breaker ring arrangement.	9/30/2026	$20.00		6/6/2023
31	S3049	Interconnect the new Twin Creeks substation by cutting and extending line No. 203 Pleasant View – Edwards Ferry. Lines to terminate in a 230 kV six-breaker ring arrangement.	10/4/2027	$56.00		
32	S3050	Replace the following 230 kV breakers and switches at Clover substation – Two breakers (L912 and 206812) with 3000 amp 50 kA breakers, three breakers (SX1212, SX12T235 and 23512) with 4000 amp 63 kA breakers and six disconnect switches (SX1214, SX1215, SX1218, 23518, 23514, and 23515) with 4000 amp switches.	6/1/2023	$2.75		11/1/2022
33	S3051	Install an ~2.2 ohm series reactor at Evergreen Mills station on terminal of line No. 2172.		$3.00		2/7/2023
34	S3052	Remove ground switches and install circuit switchers at five substations – Quantico transformer No. 1 and 2, Deep Creek transformer No. 1 and 2, Alexander Corner transformer No. 1, Tunis transformer No. 2 and Brown Boveri transformer No. 1.	12/31/2026	$2.50		3/16/2023
35	S3053	Install two 1200 amp, 50 kAIC circuit switchers and associated equipment (bus, relaying, etc.) to feed the third and fourth transformers at roundtable.	2/27/2025	$1.00		7/11/2023
36	S3054	Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the fifth transformer at Cumulus.	6/1/2025	$0.50		
37	S3055	Replace the 65A fuse H111 on high-side of Verona transformer No. 1 with a 1200A, 25kA circuit switcher and upgrade 600A switch H114 with a motor operated switch.	12/31/2025	$0.52		7/20/2023
38	S3056	Interconnect the new Prentice Drive substation by cutting and extending line No. 2188 Lockridge-Shellhorn. Lines to terminate in a 230 kV six-breaker ring arrangement.	10/31/2025	$20.00		8/8/2023
39	S3057	Replace the fuse on the high side with a 1200A, 25 kAIC circuit switcher, install any high side equipment to accommodate the installation of the new transformer.	4/30/2025	$0.62		8/17/2023
40	S3058	Replace the following 230 kV equipment at North Anna substation-Breaker 25502 with a 3000 amp 63 kA breaker, center breaker switches H304, H305, 25504 and 25505 with 3000 amp switches, 230 kV line No. 255 wave trap with a 3000 amp wave trap and transformer No. 3 high-side circuit switcher H302 with a 1200 amp 40 kAIC circuit switcher.	8/30/2023	$2.36		11/1/2022
41	S3059	Replace Davis transformer No. 2 with a new three-phase, 230/69/13.2 kV, 168 MVA unit. Include other ancillary equipment (arresters, switches, relays, etc.) as needed.	6/30/2023	$4.50		
42	S3060	Replace 230 kV switches 207576 and 207579 at Pearsons substation with 3000A switches on the existing backbone. The Pearsons to Elmont segment of line No. 2075 normal, emergency and load dump ratings will increase as follows: Summer – From (876, 956, 1163) to (1047, 1047, 1204) MVA and Winter – From (1068, 1123, 1334) to (1160, 1160, 1334) MVA.	4/18/2023	$0.47		2/7/2023