2021 REGIONAL TRANSMISSION EXPANSION PLAN

RTEP

How is PJM preparing for the grid of the future?

How will offshore wind connect to the grid?

What is the status of coal deactivations?

What interconnection process reforms are coming?

MARCH 7, 2022

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 2021, PJM observed several ongoing trends, which are discussed throughout this report. These include the continuing shift in PJM's generation fuel mix, driven by new natural gas-fired plants and deactivation of coal-fired plants.

- **Section 1** is a high-level summary of 2021 RTEP activities, including process improvements and a summary of projects organized by driver.
- **Section 2** includes an overview and detailed data from PJM's 2021 Load Forecast Report.
- **Section 3** provides 2021 RTEP project highlights, generator deactivations and reevaluation of previously approved projects.
- **Section 4** summarizes the market efficiency process, including input assumptions, analysis and competitive windows.
- **Section 5** provides an overview of PJM's new service queue requests.
- **Section 6** includes state summaries, including a detailed breakdown of interconnection requests within each individual state in PJM, as well as transmission system enhancements identified as part of the RTEP analysis.

Planning Community

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**
- **RTEP Project Statistics**

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KEY 2021 HIGHLIGHTS

One hundred and eighteen new baseline projects were planned during 2021 at an estimated cost of $920 million to ensure fundamental system reliability across the grid. Thirty-four new network transmission projects at an estimated cost of $48 million are required to ensure the reliable delivery of generation seeking interconnection to PJM markets.

PJM's interconnection queue continues to receive record numbers of requests. In 2021, PJM received 1,351 new service requests. This value has nearly tripled since 2018.

PJM has implemented the State Agreement Approach for the first time as part of the 2021 RTEP. PJM and the New Jersey Board of Public Utilities are working together to develop public-policy-driven transmission to satisfy state offshore wind power objectives.

- 139,937 MW of interconnection requests were actively under study in 2021. The magnitude of these requests nearly equals PJM's all-time winter peak.
- Solar requests now total over 128,000 MW in PJM's interconnection queue. Solar has nearly tripled over 2019, now comprising 58% of PJM's queue.
- PJM processed 1,351 requests to interconnect new generation totaling 104,316 MW nameplate capability. PJM studied 52 deactivation notifications totaling 10,607 MW.

- Baseline projects in 2021 driven by TO criteria violations comprised 52% ($479 million) of approved baseline projects.
- 23% of baseline projects were driven by generator deactivations. The remaining 52% were driven by NERC, TO and PJM baseline criteria.
- PJM facilitated six proposal windows in 2022 including over 170 unique reliability flowgates that were open to competition and four clusters of market efficiency congestion.

- PJM 2021 forecasted load growth rate remained flat at a 10-year RTO summer, normalized peak growth rate of 0.3%, which is down from 0.6% last year.
- Resource adequacy improvements continued in 2021, focusing on Effective Load Carrying Capability (ELCC), which estimates the reliability value/capacity capabilities of generating resources.
- Load forecast process improvements in 2021 include changes to better align the non-weather-sensitive model with underlying drivers and historical trends.

Section 1: 2021 Year in Review

1.0: Executive Summary

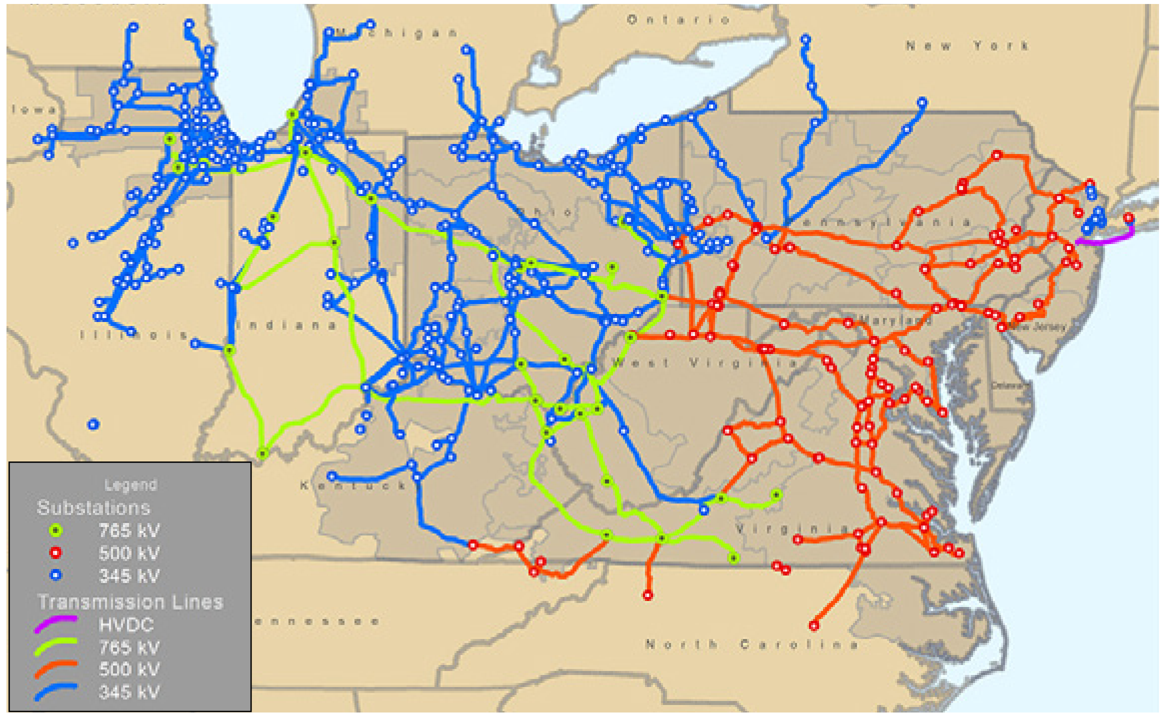
The PJM Regional Transmission Expansion Plan (RTEP) Report is published annually to convey planning study results throughout the year and to explain the rationale behind transmission system enhancement needs. The report also examines trends that continued throughout 2021 and will drive PJM's grid of 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 and northern New Jersey, Norfolk, Philadelphia, Pittsburgh, Richmond, Toledo and Washington, D.C.

PJM's Regional Transmission Expansion Plan (RTEP) process identifies transmission system additions and improvements needed to serve more than 65 million people throughout 13 states and the District of Columbia. The PJM system includes key U.S. Eastern Interconnection transmission arteries, providing members with

Map 1.1: PJM Backbone Transmission System



access to PJM's regional power markets as well as those of adjoining systems. Collaborating with more than 1,000 members, PJM dispatches more than 185,000 MW of generation capacity over 85,000 miles of transmission lines.

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 PJM. 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 scope changes.

System Enhancement Drivers

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

Highlights of projects identified and approved by the PJM Board during 2021 appear in **Section 3**. Details of specific large-scale projects are presented in **Section 6**.

Figure 1.1: RTEP Process – RTO Perspective

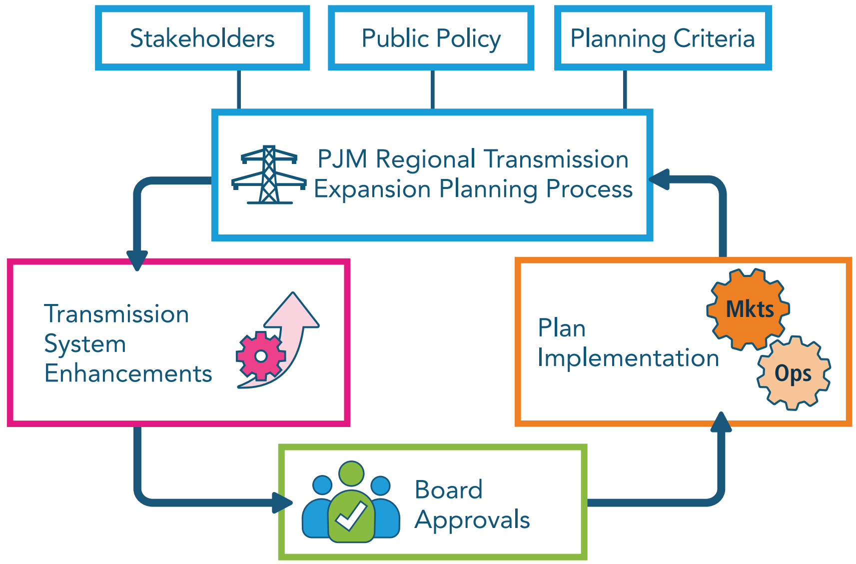
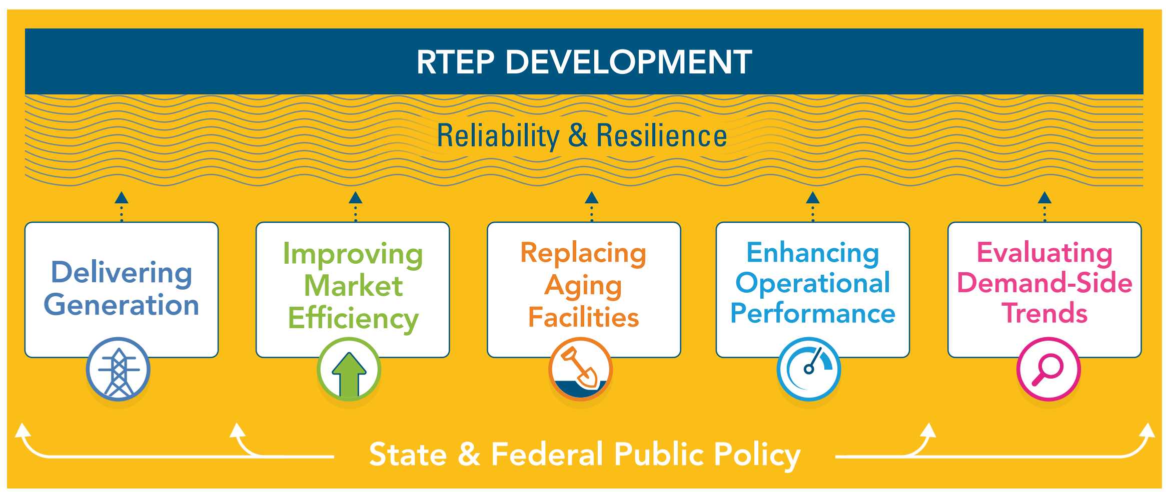


Figure 1.2: System Enhancement Drivers



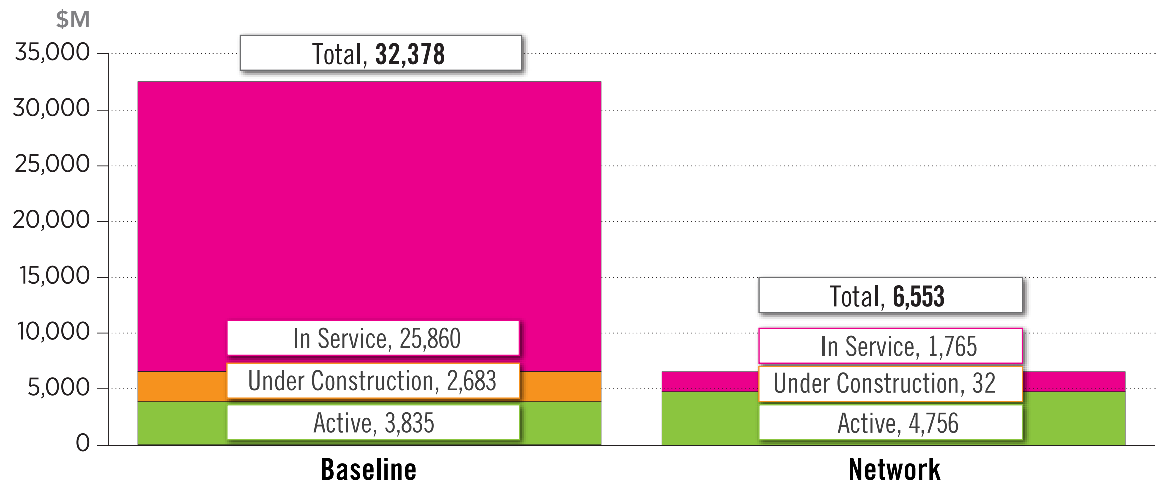
2021 Outcomes and Conclusions

At its most fundamental, the PJM transmission system ensures that electricity can be delivered reliably across the grid to customers the instant it is needed. PJM's 2021 RTEP process continued to yield grid enhancements to ensure that delivery under a historic and unprecedented generation shift driven increasingly by public policy and fuel economics.

- The PJM Board approved 118 new baseline projects during 2021 at an estimated $920 million to ensure that fundamental system reliability criteria across the grid are met. Projects driven by TO criteria violations comprised 52% ($478 million) of approved baseline projects. Generator deactivations drove 23% and the remaining 25% were driven by other NERC and PJM reliability criteria.
- The Board also approved 34 new network transmission projects at an estimated $48 million.

Since the RTEP process was implemented in 1997, the PJM Board has approved transmission system enhancements totaling approximately $38.9 billion. Of this, approximately $32.4 billion represents baseline projects to ensure compliance with NERC, regional and local transmission owner planning criteria and to address market efficiency congestion relief. An additional $6.5 billion represents network facilities to enable over 90,000 MW of new generation to interconnect reliably. A summary of projects by status as of Dec. 31, 2021, appears in **Figure 1.3**. The numbers provide a snapshot of one point in time, as with an end-of-year balance sheet. The 2021 totals, and likewise those in **Figure 1.3**, reflect revised cost-estimate changes and project cancellations for previously approved RTEP elements. For example, PJM can recommend canceling a network system enhancement from the RTEP when a queued project driving the need for the network project withdraws from the queue. Withdrawals at this point in the interconnection process are typically driven by developer business decisions, including PJM Reliability Pricing Model (RPM) auction activity, siting challenges, financing challenges or other business model factors.

Figure 1.3: Board-Approved RTEP Projects as of Dec. 31, 2021



Supplemental projects are identified and developed by transmission owners to address local reliability needs, including customer service; equipment material condition, performance and risk; operational flexibility and efficiency; and infrastructure resilience. And, while supplemental projects are not subject to Board approval, PJM reviews them to evaluate their impact on the regional transmission system. A discussion of supplemental projects, including summaries by driver, is included in **Section 3.2**.

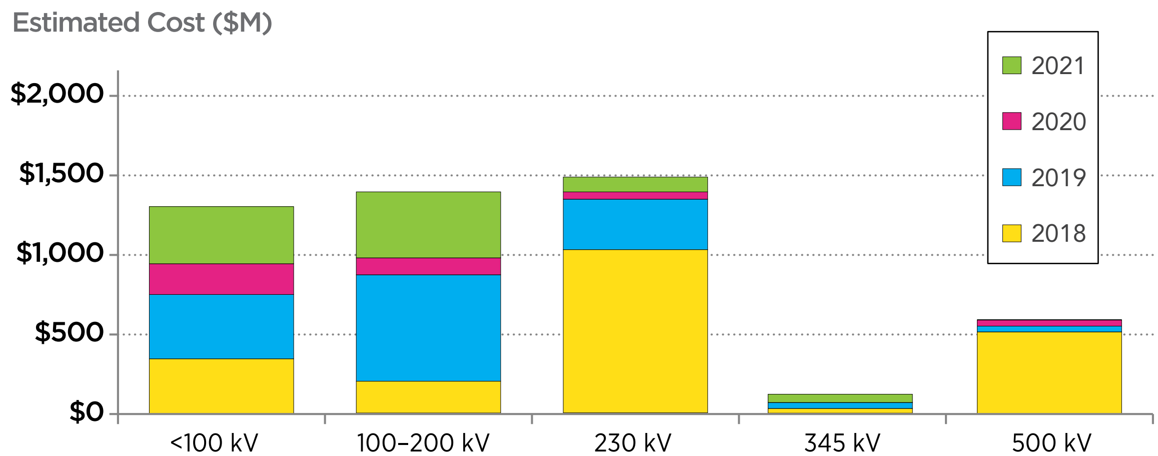
Shifting RTEP Dynamics

The $920 million of baseline transmission investment approved during 2021 continues to reflect the shifting dynamics driving transmission expansion. As **Figure 1.4** shows, new large-scale transmission projects (345 kV and above) have become more uncommon as RTO load growth has fallen below 1%. Aging infrastructure, grid resilience, a shifting generation mix and more localized reliability needs are now more frequently driving new system enhancements. Much of the new investment that is occurring at 500 kV is to address existing, aging transmission lines, many of which were constructed in the 1960s.

Flat Load Growth

PJM's 2021 RTEP baseline power flow model for study year 2026 was based on the 2021 PJM Load Forecast Report, summarized in **Section 2**, showing a 10-year RTO summer, normalized peak growth rate of 0.6%. Average 10-year-annualized summer growth rates for individual PJM zones ranged from -0.5–1.5%. 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.

Figure 1.4: Approved Baseline Project by Voltage 2018–2021



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

As of Dec. 31, 2021, interconnection requests comprising renewable resources continue to represent a significant portion of PJM's interconnection queue, as discussed in **Section 1.1**.

Solar-powered resources total nearly 94,000 MW, or around 58% of the approximately 160,000 MW resources in PJMs queue, as shown in **Figure 1.6**. Solar generation has overtaken natural gas in PJM's queue, tripling on a megawatt basis over the past two years. Natural gas plants total nearly 24,000 MW and constitute 14.8% of queued generation. Utility-scale storage facilities and wind-powered generation account for another 21.1% and 5.4%, respectively.

On the deactivation side, more than 31,000 MW of coal-fired generation has retired since 2011. 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 2021, PJM continued to receive deactivation notifications – 52 units totaling 10,607 MW – the impacts of which are discussed in **Section 3.3.**

1.0.2 — Report Structure

The body of this report examines results and outcomes of PJM's 2021 RTEP process as well as continuing efforts to develop the grid of the future and enable public policy goals.

- **Section 2** includes an overview and detailed data from PJM's 2021 Load Forecast Report.
- **Section 3** provides 2021 RTEP project highlights, generator deactivations and reevaluation of previously approved projects.
- **Section 4** summarizes the market efficiency process, including input assumptions, analysis and competitive windows.
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1.1: Generation in Transition

PJM's 186,868 MW of RPM-eligible existing installed capacity reflects a fuel mix comprising 44% natural gas, 27% coal and 17% nuclear, as shown in **Figure 1.5**. Hydro, wind, solar, oil and waste fuels constitute the remaining 12%. Nameplate capacity values represent the full power output of the generators. These values are not limited to RPM-eligible installed capacity. A diverse generation portfolio reduces the system risk associated with fuel availability and reduces dispatch price volatility.

Totaling over 137,000 MW of Capacity Interconnection Rights (CIRs), renewable fuels are changing the landscape of PJM's interconnection queue. Solar energy comprises 58% of the generation in PJM's interconnection queue, shown in **Figure 1.6**. An increase in solar generation interconnection requests is attributable to state policies encouraging renewable generation. **Figure 1.6** shows PJM's fuel mix based on requested CIRs for generation that was active, under construction or suspended as of Dec. 31, 2021.

Figure 1.5: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2021)

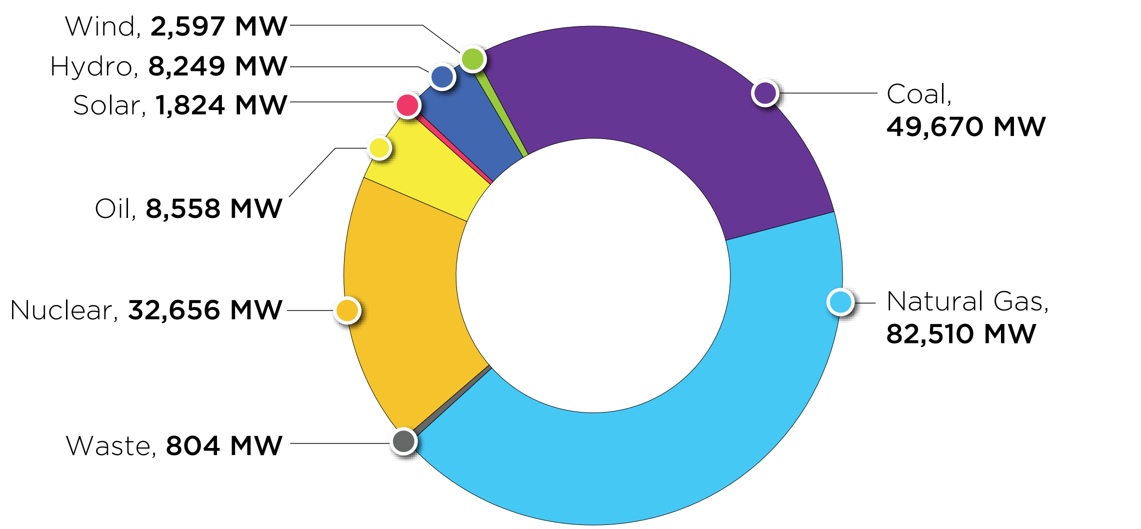
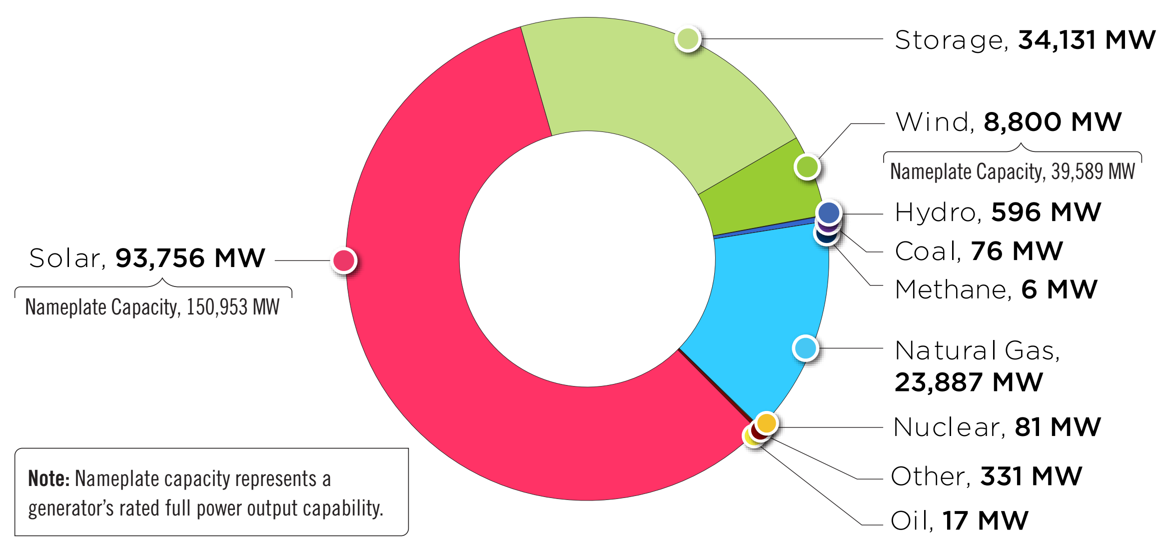


Figure 1.6: Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2021)



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

Table 1.1: Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2021)

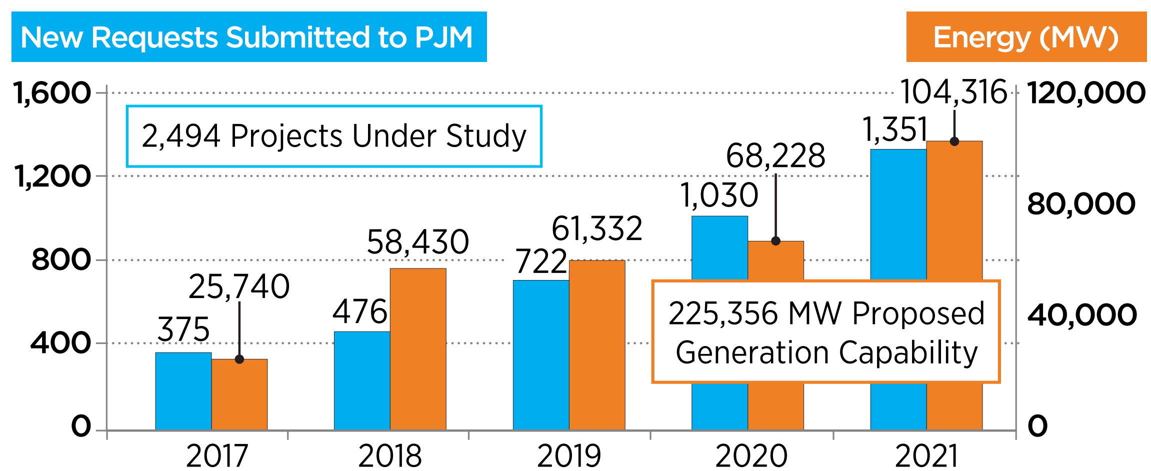
		In Queue						Complete					
		Active		Suspended		Under Construction		In Service		Withdrawn		Grand Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	1	11.0	0	0.0	3	65.0	53	2,146.9	70	33,577.6	127	35,800.5
	Diesel	0	0.0	0	0.0	0	0.0	10	68.5	16	76.7	26	145.2
	Natural Gas	52	9,634.5	16	6,695.0	41	7,557.5	355	50,733.0	672	245,831.0	1,136	320,451.0
	Nuclear	5	37.4	0	0.0	1	44.0	43	3,902.8	22	9,038.0	71	13,022.2
	Oil	2	4.0	0	0.0	8	13.0	18	539.8	23	2,314.0	51	2,870.8
	Other	19	331.3	0	0.0	2	0.0	6	336.5	100	858.8	127	1,526.6
	Storage	534	34,033.5	6	17.6	18	79.3	26	4.0	258	6,000.7	842	40,135.2
Renewable	Biomass	0	0.0	0	0.0	0	0.0	11	252.8	40	896.9	51	1,149.7
	Hydro	9	562.8	0	0.0	3	33.6	32	1,155.9	51	2,178.8	95	3,931.0
	Methane	1	6.0	0	0.0	0	0.0	83	404.2	95	490.1	179	900.3
	Solar	1,712	86,883.6	48	875.2	268	5,997.2	221	1,897.3	1,596	33,265.0	3,845	128,918.4
	Wind	110	8,433.2	2	47.7	9	319.2	112	2,022.2	490	14,817.3	723	25,639.6
	Wood	0	0.0	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
	Grand Total	**2,445**	**139,937.3**	**72**	**7,635.6**	**353**	**14,108.8**	**972**	**63,517.9**	**3,437**	**349,497.9**	**7,279**	**574,697.5**

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

Renewables

PJM's interconnection queue process continues to see renewable generation growth. As **Figure 1.6**, **Figure 1.7** and **Table 1.1** show, queued requests as of Dec. 31, 2021, for CIRs totaled 8,800 MW of wind-powered generators that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 39,589 MW. Queued solar-powered generator requests for CIRs totaled 93,756 MW that were actively under study, suspended or

Figure 1.7: Growth of Renewables in PJM Queue



under construction. Those CIRs correspond to nameplate capacity totaling 150,953 MW.

Nameplate Capacity vs. Capacity Interconnection Rights

Nameplate capacity represents a generator's rated full power output capability. As **Table 1.2** 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 operate intermittently, such as wind and solar.

Wind turbines can generate electricity only when wind speed is within a range consistent with turbine physical specifications. This requies 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 is analyzed. Until such time, class averages or specific data provided by the developer establish the amount of CIRs that a unit may initially request, as discussed in **Section 1.4.6**.

Generators powered by intermittent resources such as wind frequently require analytical studies unique to their particular characteristics. For example, wind-powered generator requests have clustered in remote 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.

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

Table 1.2: Queued Study Requests (Dec. 31, 2021)

	Projects	Nameplate Capacity (MW)	Capacity (MW)
Active	2,445	139,937.30	225,348
In Service	972	63,517.90	76,075
Suspended	72	7,635.60	9,121
Under Construction	353	14,108.80	20,616
Withdrawn	3,437	349,497.90	448,037
Grand Total	**7,279**	**574,697.50**	**779,197**

1.1.1 — New Services Queue Requests

Interconnection Activity

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

Generation Queue Activity

Through 2021, PJM markets have attracted generation proposals totaling 574,698 MW, as shown in **Table 1.2**. Over 139,937 MW of interconnection requests were actively under study, and over 14,000 MW were under construction or suspended as of Dec. 31, 2021. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities. While withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy as well as regulatory, industry, economic, and other competitive factors.

Queue Progression History

PJM reviews generation queue progression annually to understand overall developer trends more fully and their impact on the interconnection process. **Figure 1.8** shows that for all generation – both new resources and existing plant uprates – submitted in Queue A (1999) through Dec. 31, 2021, 65,734 MW – or 21% – reached commercial operation. As **Figure 1.8** also shows, 26,351 MW – or 6% – of that accounts for withdrawals from the queue after interconnection service agreement (ISA) execution and 1,271 – or 0.2% – represents withdraws after the wholesale market participant agreement (WMPA) execution, but before construction. Overall, 15% of projects that requested uprates to existing capacity reached commercial operation.

Figure 1.8: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

21% Requested capacity megawatts

15% Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	189	Interconnection Service Agreements	26,351 MW	34,892 MW
	315	Wholesale Market Participation Agreements	1,271 MW	2,577 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

NOTE

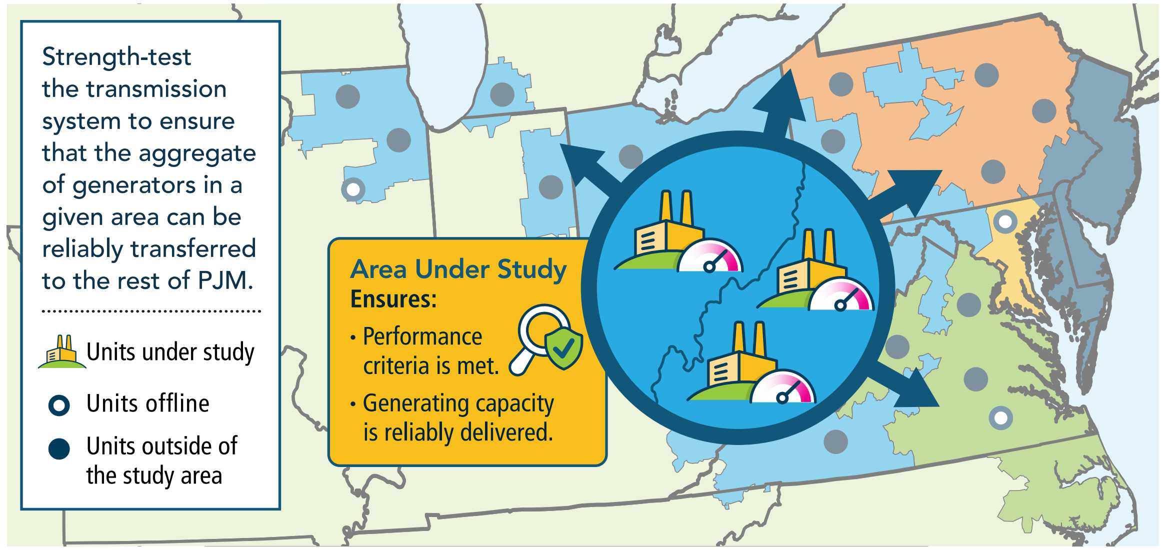
Figure 1.8 reflects requested capacity interconnection rights, which are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants.

Interconnecting Reliably

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. The PJM Board has approved network facility reinforcements totaling over $6.5 billion since the inception of the RTEP process in 1997. These facilities allow more than 90,000 MW of new generating resources and other new service requests – merchant transmission interconnection, for example – to be approved for participation in PJM operations and markets. The PJM Board approved the incorporation of 34 new network system enhancements totaling over $47 million into the RTEP in 2021 alone.

As described in **Section 1.2**, PJM tests for compliance with all reliability criteria imposed by the NERC and PJM regional reliability 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 1.9**.

Figure 1.9: Generator Deliverability Concept



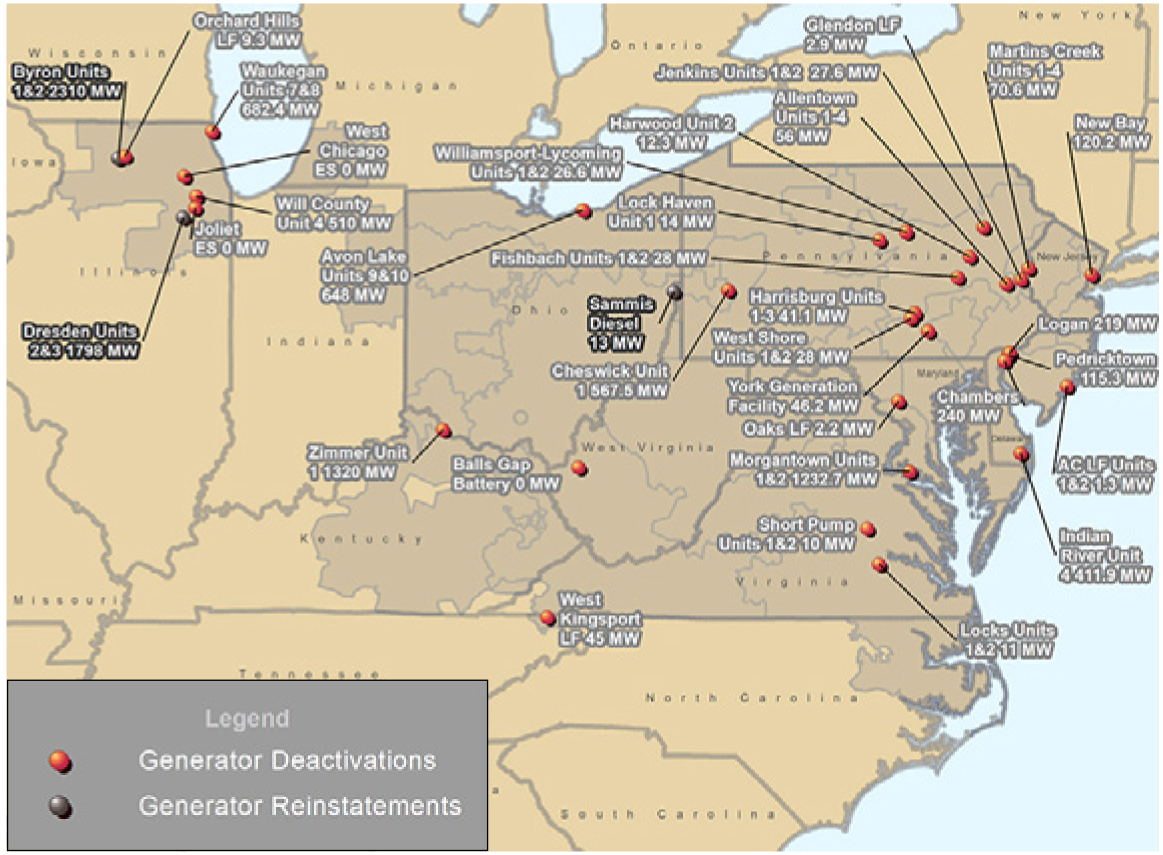
Deactivations

PJM received 52 deactivation notifications in 2021 totaling 10,607 MW. This was up from the previous eight years. **Map 1.2** shows the deactivation request locations received between Jan. 1, 2021, and Dec. 31, 2021.

Generator owners requested the deactivation of these units to take place between April 2021 and June 2023. PJM maintains a list of formally submitted deactivation requests, available on the PJM website.

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

Map 1.2: PJM Generator Deactivation Notifications Received Jan. 1, 2021, Through Dec. 31, 2021



NOTE

At the January 2022 PJM Planning Committee, PJM introduced a set of proposed changes to deactivation analysis process timing. These changes seek to establish a batch study approach to address deactivation process timing concerns.

1.2: Baseline Project Drivers

NERC Criteria – RTEP Perspective

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

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

Bulk Electric System Facilities

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

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

The ReliabilityFirst definition of BES facilities excludes the following:

1. Radial facilities connected to load-serving facilities, or individual generation resources smaller than 20 MVA, or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher
2. The balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and its associated step-up transformer), which 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 BES definition, PJM conducts reliability analyses on PJM Tariff facilities, which may included facilities below 100 kV, to ensure system compliance with NERC Standard TPL-001-4. If PJM identifies violations, it develops transmission expansion solutions to resolve them, as part of its RTEP window process.

NERC Reliability Standard TPL-001-4

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

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

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

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

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

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

PJM's N-2 multiple contingency and common mode analyses evaluate planning events P2, P4, P5 and P7 to look at the loss of multiple facilities that share a common element or system protection arrangement. These include bus faults, breaker failures, double circuit tower line outages and stuck breaker events. N-2 analysis is conducted on the base case itself.

Table 1.3: Mapping RTEP Analysis to NERC Planning Events

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

Common mode analysis is conducted within the context of PJM's deliverability testing methods, discussed in PJM Manual 14B, available on the PJM website.

NERC Standard TPL-001-4 includes extreme events as well. PJM studies system conditions following a number of extreme events, also known as maximum credible disturbances, judged to be critical from an operational perspective for risk and consequences to the system.

Stability Requirements

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

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

Transmission Owner Criteria

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

As part of its RTEP process, PJM applies TO criteria to the respective facilities that are included in the PJM Open Access Transmission Tariff (OATT) facility list. While transmission enhancements driven by TO criteria are considered RTEP baseline projects, they are assigned to the incumbent TO and are not eligible for proposal window consideration, as shown in **Figure 1.10**. 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).

2021 Transmission Owner Criteria-Driven Projects

PJM has observed that TO aging infrastructure criteria are increasingly driving the need for baseline projects. Review of facilities built in the 1960s and earlier have revealed significant deterioration. Planning for aging infrastructure is not new to PJM. Spare 500/230 kV transformers, aging 500 kV line rebuilds and other equipment enhancements approved in prior years are already part of the RTEP.

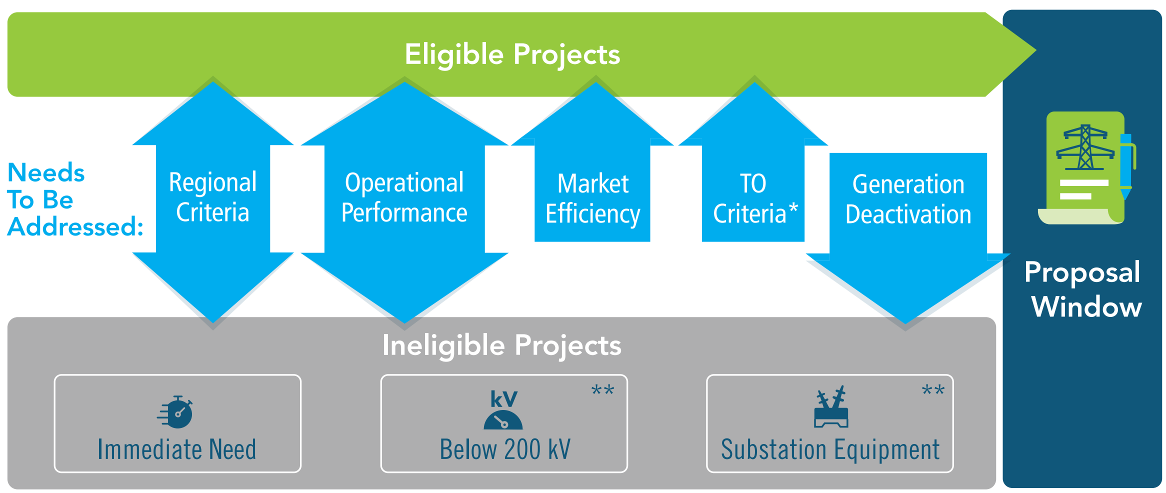
In other instances, TO criteria encompass local loss-of-load thresholds, particularly on radial facilities. The threshold for some is on a megawatt-mile basis, others on a megawatt-magnitude basis, to reduce the extent of load impacted under contingency or outage conditions.

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 2020.

Developing Transmission Solutions

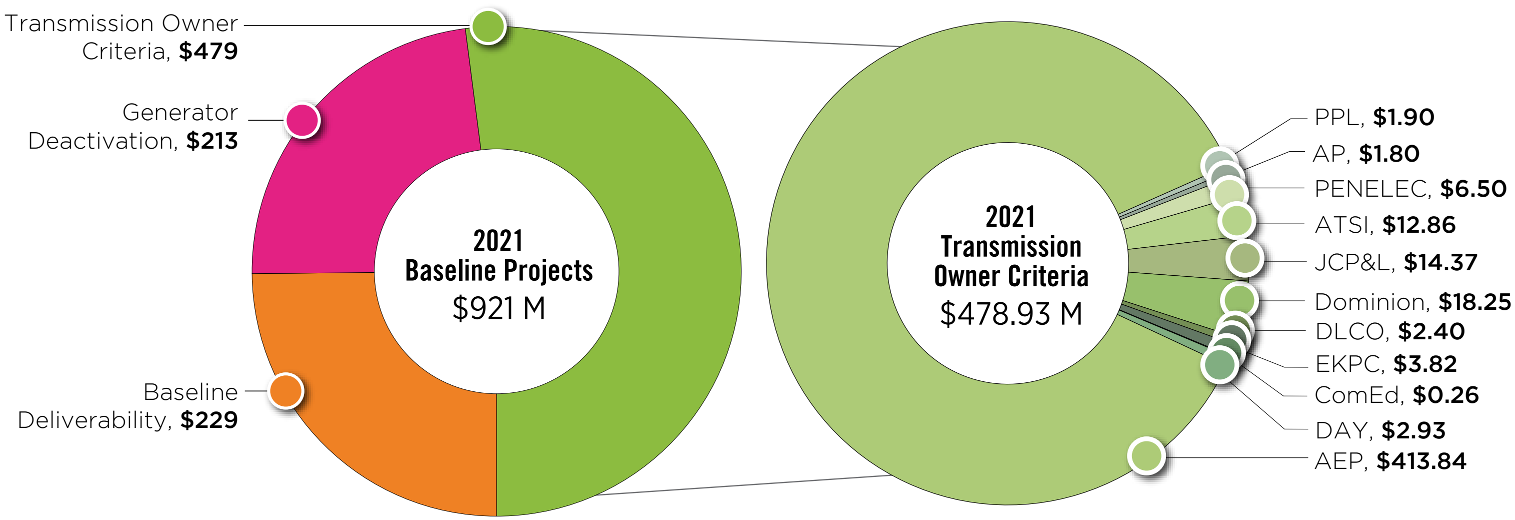
After PJM identifies a baseline transmission need, including market efficiency driven needs, PJM may open a competitive proposal window, depending on the required in-service date, voltage level and scope of projects. Window eligibility for project driver types is shown in **Figure 1.10**. Throughout 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 of our project requirements. If so, PJM then recommends a proposal to the PJM Board. Once the Board approves a proposal, the designated developer becomes responsible for financing, project construction, ownership, operation and maintenance.

Figure 1.10: RTEP Proposal Window Eligibility



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

Figure 1.11: 2021 RTEP Baseline Project Driver ($ Million)



2021 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 2021 were no different, as discussed in later sections of this report and summarized in **Figure 1.11**. As the figure shows, baseline transmission investment, once primarily comprising projects driven by deliverability, now also comprises projects driven by other factors, including transmission owner criteria.

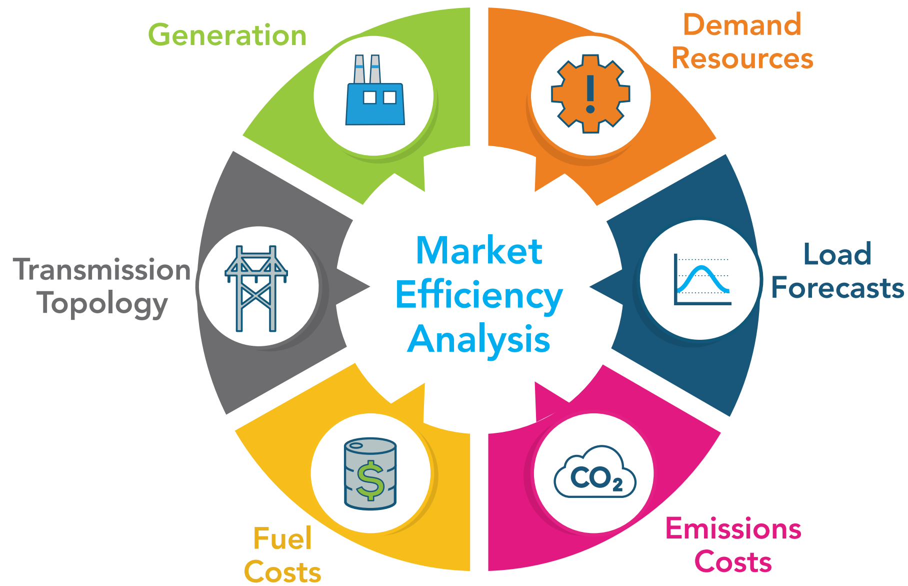
Market Efficiency

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 1.12**. 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 1.12: Market Efficiency Analysis Parameters



1.3: Grid of the Future

1.3.1 — Context

PJM's RTEP process continues to evolve, bringing into clearer focus the grid of the future (GOTF), one driven by decarbonization, renewables, public policy, resource mix and new infrastructure technologies. Such change, though, will not move forward in a vacuum. Reliability will remain paramount with a growing focus on integrating greater resilience into PJM's existing reliability standards, by which the grid of the future is planned and operated.

The GOTF is not some far-distant idea but is here now. PJM, like other RTOs across the U.S., has before it a robust, reliable transmission grid, but one upon which enhanced operational flexibility must continue to grow to ensure reliable power delivery 24/7 year-round. Key milestones and insights out of PJM's 2021 GOTF initiatives are summarized below.

1.3.2 — Fuel Mix Shift to Renewables

PJM's diverse installed capacity resource profile today includes generation powered by natural gas, coal, nuclear, wind and solar, coupled with demand response and storage. However, increasing public demand for cleaner sources of electricity, combined with public policy reflecting this demand in state Renewable Portfolio Standards (RPS), is driving unprecedented growth in renewable generation resources. As discussed below, PJM generation interconnection queue activity reflects a shift from interconnection requests by natural gas generation to solar, wind and storage.

While they differ in scope, timing, resource specificity, mechanism, and mandatory-versus–voluntary status, most state jurisdictions in PJM have enacted some level of renewable resource or clean energy targets. Fulfillment of these targets will encompass variable resources such as terrestrial wind, offshore wind, solar and storage, as evidenced by PJM queue activity in which they currently account for over 90% of interconnection requests.

State Renewable Portfolio Standards

PJM's GOTF will enable customer access to renewable power at much greater levels than today, driven by states' RPS mandates. Ten states in the PJM footprint, plus the District of Columbia, have enacted them as shown in **Table 1.4** and **Map 1.3**, below.

These mandated state RPS targets require that a certain percentage of a state's load are

Table 1.4: PJM State RPS Targets

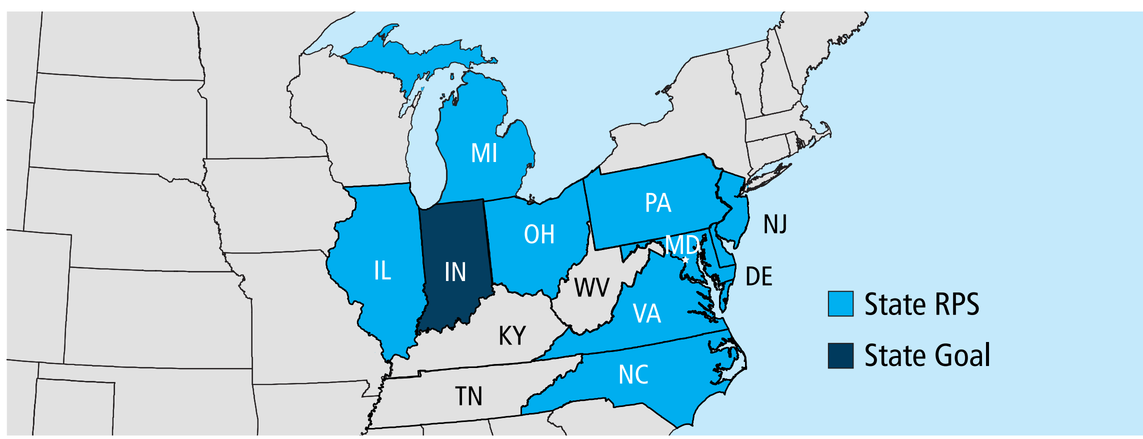
State RPS Targets*

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

☼ Minimum solar requirement

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

Map 1.3: PJM State RPS Targets and Goals



served by qualified renewable energy resources. RPS policies have functioned as a significant driver of renewable resource development. Across the nation, and in PJM, many states have increased their RPS targets in recent years in pursuit of accelerated decarbonization objectives. Since 2018, Delaware, the District of Columbia, Illinois, Maryland, New Jersey and Virginia have all established new RPS targets.

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

Geography

PJM's footprint draws attention to the two locational dimensions of wind-powered generation:

1. Onshore, mainly along the Appalachian Mountains' ridge and PJM's western subregion
2. Offshore, along the coast of New Jersey, Maryland, Delaware, Virginia and North Carolina

Through careful GOTF scenario analyses, PJM will be able to evaluate the holistic impact on the need for grid expansion. Notably, unlike other areas of the country, renewable-powered generation developers in the PJM footprint are not seeking interconnection far from load centers. This trend has significant implications for GOTF planning insofar as the need for major long-distance, possible multi-state, backbone transmission lines to deliver RPS-mandated power may not necessarily be the most efficient first-choice grid solution.

Reliability Attributes

Most queue requests for grid interconnection across the PJM footprint are from inverter-based solar generation resources. Previously, solar projects were smaller in size and limited to a handful of areas. Now, individual projects can reach hundreds of megawatts, driven by states' RPS goals, and are seeking interconnection in every PJM transmission zone. In contrast, deactivations across PJM continue to be mostly made up of coal-fired generating units driven by economics, age and public policy.

Across the country, states' decarbonization and other environmentally focused public policies are primary drivers in the evolution of the grid. Implementing these policies requires a transmission grid that will give system operators greater flexibility to ensure reliability. Operators increasingly face grid conditions in which new, variable generating resources of intermittent power from inverter-based resources (IBR) serve customer load. As PJM and other RTOs have identified, IBR resources 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.

PJM's GOTF studies will evaluate how to maintain – or even increase – the level of NERC-defined essential reliability services necessary to ensure system reliability.

1.3.3 — Offshore Wind Trends

Offshore wind is emerging as a major source of power, seeking grid interconnection along coastal states in the PJM region. Although offshore wind is on a longer planning horizon, the potential for development is substantial. Future system enhancements will solve the challenges that these locationally constrained resources present. Moreover, they will also address the interregional implications associated with wind lease areas that can also serve adjoining systems north and south of PJM's RTO borders.

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

Offshore Wind Public Policy Drivers

The current offshore wind targets within the PJM footprint were all recently implemented. Maryland and New Jersey established their current goals in 2019, and Virginia's 5,200 MW objective stems from legislation enacted in 2020.

However, that does not mean that just because these targets were recently crafted that states will not increase them in the coming years.

The possibility always exists for new political leadership to bring with it more ambitious offshore wind targets. This is currently playing out at the federal level with the Biden administration now making offshore wind a national priority. The new federal emphasis on offshore wind development is likely to impact PJM. The Biden administration has specifically named the New York Bight as an area of focus with high offshore wind potential. The added emphasis on the New York Bight, coupled with greater support for the Bureau of Ocean Energy Management (BOEM) to issue leases to developers, is likely to help both New Jersey and New York advance their offshore wind initiatives and encourage greater interregional transmission planning collaboration. Joint offshore wind transmission planning with NYISO and New England received growing attention at the Inter-Regional Planning Stakeholder Advisory Committee (IPSAC) Q4 2021.

Within the PJM region, Maryland, New Jersey and Virginia have all established offshore wind targets that together total 14,723 MW, with planned in-service dates by 2035. North Carolina recently announced an 8,000 MW target by 2040 via June 2021 executive order. New Jersey's goal is driven by a combination of legislation and executive order.

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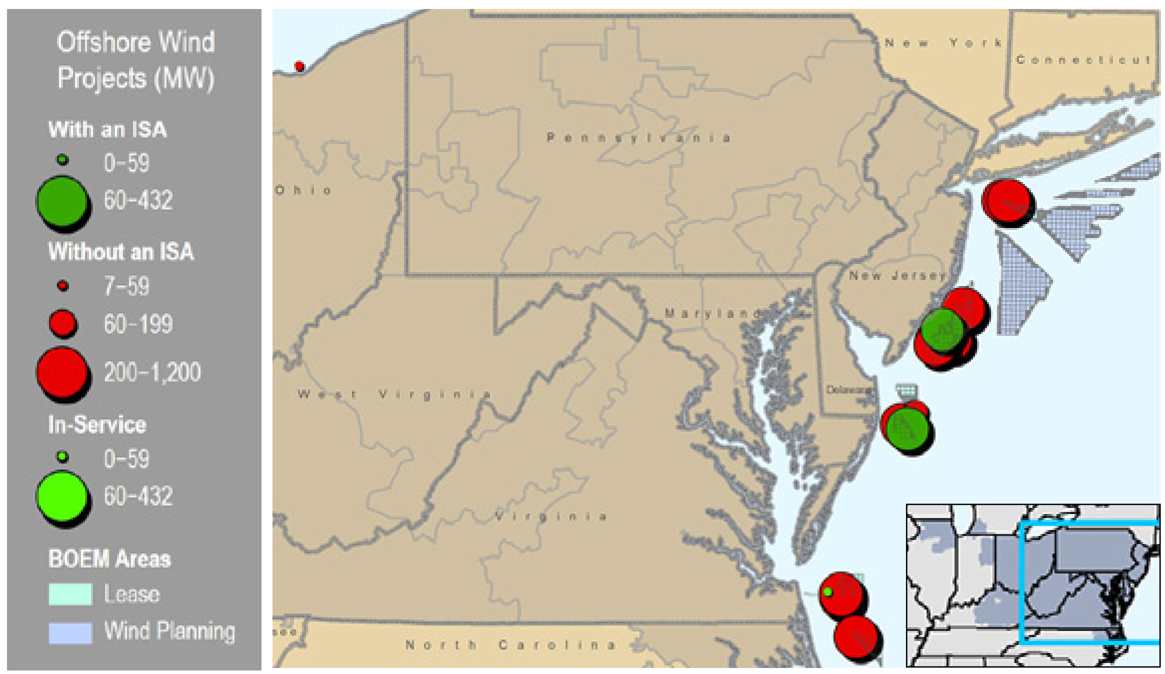
[What is a "bight"?]

Several projects have already been selected. New Jersey has conducted two solicitations to date to award Offshore Wind Renewable Energy Certificates (ORECs) to three projects totaling 3,758 MW. New Jersey's first solicitation was awarded to Ørsted's 1,100 MW Ocean Wind 1 project. The second solicitation was awarded to Ørsted's 1,148 MW Ocean Wind 2 project and the 1,509.6 MW Atlantic Shores project (a joint venture between EDF Renewables North America and Shell New Energies).

Maryland has awarded ORECs to four projects totaling 2,023 MW, the most recent of which was awarded in 2021. Maryland's first two offshore wind solicitations were awarded to Ørsted's 120 MW Skipjack project and US Wind's 248 MW MarWin project. Maryland's third offshore wind solicitation awarded ORECs to Ørsted's 846 MW Skipjack 2.1 project and US Wind's 808.5 MW MarWin 2 project.

Within Virginia, Dominion Energy has proposed 2,640 MW of offshore wind capacity to be constructed via three phases of 880 MW each. In addition to these announced projects, Avangrid Renewables is advancing a 2,500 MW merchant offshore wind project off the coast of North Carolina. **Map 1.4** shows PJM Offshore Wind Generation Locations through the close of Queue AG2.

Map 1.4: PJM Offshore Wind Generation Locations (Through Queue AG2)



While offshore wind development in the United States has largely been led by individual state initiatives, the Biden administration introduced a federal offshore wind policy target in March 2021. Through a shared goal between the departments of the Interior, Energy and Commerce, the United States is now pursuing 30 GW of operational offshore wind by 2030. As part of its plan to reach this milestone, the Biden administration plans to support the BOEM in issuing new lease sales and reviewing at least 16 construction and operations plans by 2025. The national 30 GW target is also believed to be a starting point for an eventual offshore wind goal of 110 GW by 2050.

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

Offshore Wind Study 1.0

As discussed in **Section 3.6**, during 2021, PJM conducted an initial scenario study of the transmission needed to interconnect the anticipated growth in renewable generation. That Offshore Wind Transmission (OSW) Scenario Study Phase 1 study report can be found on PJM's website.

The study consisted of multiple scenarios that integrated between 30,000 MW and 80,000 MW of renewable generation and identified the need for as much as $3 billion in transmission upgrades to meet the RPS goals in the next 10–15 years. While the study was limited to the bulk electric system, the analysis provides a vision of the magnitude of transmission expansion that will be needed to integrate the growing number of renewable resources.

As PJM continues its initiatives to enable a decarbonized grid, additional analysis beyond the OSW scenario studies will examine an accelerated renewable penetration case, including a more in-depth assessment of the impacts from higher levels of building and transportation electrification.

OSW Study – State Focus

PJM's significant growth in planned renewable generation, including offshore wind resources, is driven by states' renewable energy policies. PJM has affirmatively committed, through its five-year strategic plan and advancement of its new State Policy Solutions team, to leverage its expertise to maintain reliability and cost-effectively facilitate state decarbonization policies. This OSW study represents another tangible part of that ongoing PJM-state dynamic.

The study was initiated in response to a request from the Organization of PJM States (OPSI) to identify potential transmission solutions that present a more efficient and economic path for states to advance their offshore wind policy objectives than if each coastal state decided to independently integrate their offshore wind generation. Phase 1 provides an important starting point for future scenario studies that consider the integration of offshore wind and other renewable resources into the PJM system. It also presents a framework for how future collaborative transmission planning studies between PJM and states can be achieved.

The Offshore Transmission Study does not commit any PJM state to any transmission grid enhancement. Rather, it serves as an opportunity to identify the potential scope of coordinated transmission solutions to help inform state policymakers as they advance their offshore wind policy objectives. States can incorporate study findings into future offshore wind solicitations and related State Agreement Approach (SAA)-derived transmission solutions. The study has also provided valuable experience with developing the holistic GOTF planning process analysis and modeling needed for evaluating future renewable integration.

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BOEM information

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The OPSI request can be found on the PJM website.

1.3.4 — New Jersey State Agreement Approach

The SAA is a PJM Operating Agreement provision that allows one or more states to pursue public policy requirements as part of PJM RTEP process study planning parameters. States, in collaboration with PJM, voluntarily agree to develop identified transmission solutions identified in RTEP process studies. States are subsequently responsible for 100% of the cost allocation of each such SAA-derived RTEP projects for which they elect to move forward.

The New Jersey Board of Public Utilities (NJBPU) initiated PJM's SAA by soliciting transmission proposals to accommodate full integration of 7,500 MW of planned offshore wind-powered generation by 2035. New Jersey's initiation of the SAA is the first time a state in the PJM region has elected to pursue achieving public policy requirements through PJM's competitive RTEP process. In this instance, doing so will enable the construction of large-scale, offshore wind-powered generation. This joint New Jersey-PJM SAA experience provides an effective planning blueprint going forward for states to pursue their own respective renewable portfolio standards and other public policy goals as part of effective, coordinated planning within PJM for the grid of the future.

1.3.5 — Grid-Enhancing Technologies

Applying grid-enhancing technologies in new ways will play a growing role in realizing PJM's evolving power grid. The grid expansion technology needed to deliver power will not be limited to conventional greenfield (and often multi-state) transmission lines, which are increasingly more difficult to site and permit. Emerging technologies like dynamic line ratings, special conductors, tower configurations and other technologies are discussed below.

To the extent submitted as part of PJM's competitive proposal process set forth in Operating Agreement, Schedule 6, or as an SAA project, PJM evaluates qualifying grid-enhancing technologies proposals in a manner that is not materially different than the way it evaluates other project proposals.

PJM remains agnostic with respect to grid-enhancing technologies that are part of proposals submitted in RTEP windows or as part of transmission owner supplemental projects. PJM nonetheless evaluates the impact of a technology's characteristics on solving identified reliability and market efficiency needs efficiently or cost effectively. Further, PJM evaluates whether a proposal that includes the deployment of a grid-enhancing technology requires any changes to PJM's telemetry, modeling and other operating tools or protocols to support and accommodate integration from a markets and operations standpoint.

NOTE

PJM and the New Jersey Board of Public Utilities filed an SAA joint agreement with FERC on Jan. 27, 2022, outlining how New Jersey will put PJM's competitive planning process to work in pursuit of its ambitious offshore wind goals. The agreement details the contractual commitments and responsibilities of the NJBPU and PJM regarding the competitive selection of transmission solutions.

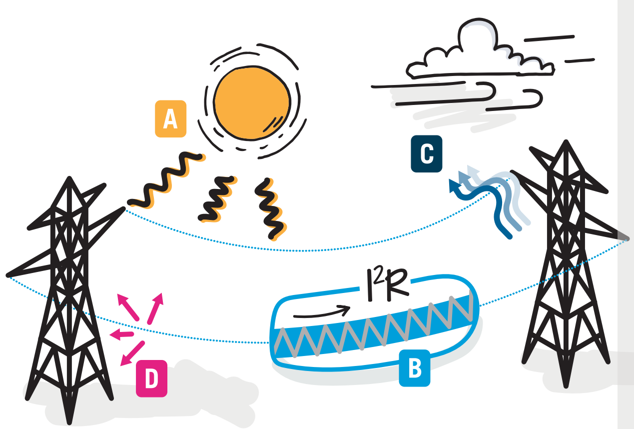
Dynamic Line Ratings

Dynamic line rating (DLR) technology can identify additional capacity on transmission lines that could potentially relieve congestion and create economic efficiencies in real-time operations. Such technology can also enhance system resilience by providing enhanced monitoring of the real-time capabilities of transmission assets. Shown conceptually in **Figure 1.13**, DLR uses advanced sensors and software to monitor real-time conductor temperature along a transmission line. It then uses this data to calculate real-time ratings for the line based on environmental conditions versus a pre-established set of static ratings based on conservatively assumed ambient temperatures. Introducing DLR technology could allow a more dynamic update of transmission line ratings (e.g., hourly, daily, monthly or seasonally) that would improve the reliability and economic efficiency of system operations.

In October 2020, PJM and one of its transmission owners, PPL Electric Utilities (PPL), began to pilot the use of DLR sensors on two transmission lines. PJM and PPL sought to determine if the DLR devices could alleviate congestion and provide PJM with real-time information to optimize the performance and increase actual power flow (not just static ratings). The results to date suggest that PPL's installation of DLR sensors are likely to mitigate significant congestion, warranting PJM's removal of a posted market efficiency driver from a competitive proposal window. Although work remains to be done, this is an example of a situation where a proposed transmission technology can introduce efficient and cost-effective solutions instead of new or rebuilt transmission lines.

As part of the ongoing pilot, PJM and PPL are performing a full impact analysis, evaluating the technical, market efficiency and reliability benefits; integration requirements (such as communication, system, operating protocols and governing documents); and a functional area impact assessment (including analyses of markets, operations, and planning and risk management impacts). PJM is also continuing to assess necessary data requirements, associated data volume, rating methodologies and reliability compliance associated with DLR implementation. PJM is further assessing the interplay between NERC standards and DLR implementation and the impact DLR might have on the standards for establishing, monitoring and controlling system operating limits.

Figure 1.13: Dynamic Line Rating (DLR) Technology



A **Solar Heating –** Just as the sun warms the air and the Earth's surface, heat from the sun's rays will raise the temperature at the conductor's surface.

B **Resistive Heating –** As current passes through the conductor, heat is generated inside the conductor by electrical losses.

C **Convective Cooling –** Nearby wind carries away warm air surrounding the conductor and can cause a dramatic cooling effect along the transmission line.

D **Radiative Cooling –** Even with no wind, transmission lines lose a portion of their heat to cooler ambient air.

Flexible AC Transmission Systems

A Flexible Alternating Current Transmission System (FACTS) is a power system device that takes more conventional power system components – capacitors and reactors – and integrates them in various configurations with intelligent power electronics, high-speed thyristor valve technology and voltage sourced converter (VSC) technology. FACTS devices can directly support additional transmission line power flow with reactive power injections at their point of interconnection and can indirectly control power flow by modulating transmission line impedances. The most common FACTS devices include static VAR compensators (SVCs) and static compensators (STATCOMs).

Available since the 1980s, FACTS devices have been deployed in PJM to help regulate voltage power factor, harmonics and system stability. PJM's RTEP planning model includes SVC devices totaling more than 6,100 MVAR. These devices provide system operators with additional operational flexibility to control voltages, particularly during high-voltage conditions overnight when transmission lines are lightly loaded. Additionally, the model includes over 800 MVAR of STATCOM technology. A STATCOM includes a unique design that incorporates voltage-sourced converters and thyristor valves to yield additional performance, in terms of speed and dynamic range, as compared to SVC devices.

Grid-Forming Inverters

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

Conventional inverter technology currently found on solar and wind generation does not have grid-forming capabilities, but uses a voltage-following process to adapt to the existing grid AC conditions and hence is incapable of counteracting power fluctuations. If a grid disturbance occurs that creates a large power fluctuation, the conventional inverter could trip off, causing a loss of generation as collateral impact to the initial grid disturbance. Furthermore, as the nation's fleet of conventional plants shrinks and is replaced by inverter-based renewables, the grid could experience more acute power fluctuations. As such, the industry will likely see a proliferation of grid-stabilizing devices like the SVC Hybrid in proportion to the increase in renewable generation.

The need for standardization in grid-forming inverters is recognized as a national goal. An EnergyWire article reported on Sept. 9, 2021: *"Late last month, the Department of Energy awarded $25 million to a research consortium to create a standard grid-forming inverter. Separately, the Biden administration has released its Solar Futures Study calling for doubling and then redoubling 2020's record solar power installations between now and 2035."* (EnergyWire, Sept. 16, 2021)

Industry manufacturers continue to expand the scope of grid-forming technologies, particularly with respect to SVC installations. The concept of "SVC light," for example, pairs a grid-forming inverter with super capacitors – as energy storage – for grid applications at transmission-level voltages. Currently, these devices are typically rated in the range of 20 MW for about 15 to 45 minutes. However, this technology can be scaled up to hundreds of megawatts for up to eight-hours duration.

Special Conductors

Advanced conductor designs can provide a means of achieving higher transmission line capability on existing corridors and transmission structures, mitigating the need for new lines or significant rebuild. Building new transmission lines, or rebuilding existing ones, often encounters siting and permitting challenges that can cause lengthy delays or prevent project construction altogether.

One approach uses high-temperature low-sag (HTLS) conductors such as aluminum conductor composite core (ACCC) and aluminum conductor composite reinforced (ACCR). These conductors also use aluminum wires surrounding the composite core that are either annealed or are heat-resistant during high-temperature operation. This type of conductor with a composite-core construction reduces the conductor sag compared to that for conventional overhead conductor designs. This allows conductors to operate at higher temperatures and achieve a higher capability without significant new line construction. In 2010, rating tables for these conductors were added to the PJM Transmission & Substation Design Guidelines.

Advanced conductor design also incorporates the use of special coatings that have a higher emissivity and lower absorptivity. The result is cooler conductors and, thus, higher ampacity rating – i.e., greater current-carrying capability. In PJM, a recent project in PEPCO to reconductor the Mount Zion to Norbeck line (4.5 miles) employed this technology.

Transmission Tower Configuration Technology

Transmission towers continue to advance technologically and can provide a means to enhance the utilization of existing and new transmission line corridors as part of GOTF expansion. For example, AEP's Sorenson-Robison Park 345 kV/138 kV line, which was energized in November 2016, employs a new tubular steel tower configuration that has yielded shorter tower heights and increased capacity within an existing 138 kV right of way.

This design, coupled with low-impedance bundled conductors, reduces line losses and significantly increases power delivery capability while avoiding the complexities and costs of series compensation. Overall, the design increases line capacity by 50%, reduces system losses and maximizes transmission efficiency. Similarly, lines made from composite-core conductors can lower line losses by 25–40% compared to traditional aluminum-conductor steel-reinforced cable. PJM expects that it will continue to see more transmission tower technology innovations in the future.

Electric Vehicles

PJM continues to pay close attention to U.S. transportation sector electrification and, in particular, the impact of electric vehicles (EVs) on transmission system needs. EEI estimates that EVs will grow from 1 million today to 7 million across the country by 2025. From a GOTF perspective, PJM load forecasting processes must ensure that EVs are accounted for in charging mode, and transmission planning studies account for the bus loads associated with charging stations. EVs may also be in a position to provide grid reliability services like regulation vis-à-vis their on-board battery storage capability if public policy economic incentives can drive desired customer behaviors.

Microgrids

Microgrid control technology coupled with distributed energy assets have the real capability to improve grid resilience, security, reliability and efficiency. Microgrids are small clusters of energy assets and loads that are controlled to achieve a variety of benefits for the owner/operator. One of the primary benefits of building a microgrid is the ability to provide reliable electric power during significant electric grid disturbances, such as storm outages. PJM continues to work with industry partners, universities and states to better understand how microgrids can impact the grid in a positive way and how they can derive value from the PJM wholesale markets.

1.3.6 — Probabilistic Transmission Planning

Since the implementation of the RTEP process in 1999, PJM has continued to add reliability planning criteria. These now include winter peak conditions, low load system conditions, and natural gas pipeline contingencies in addition to summer peak load planning conditions. While existing transmission planning relies on a set of models, assumptions and scenarios using deterministic analytical tools, more powerful techniques can be used for longer-range scenario development to better understand the full range of grid of the future system conditions. This is particularly true given the added complexity associated with renewable generation variable output profiles.

Evaluating Resilience

As discussed further in **Section 1.3.7,** PJM currently incorporates probabilistic methods into its planning process to analyze high-impact, low-frequency (HILF) events and to identify areas of risk and potential resilience enhancements to the grid. Since the attacks of 9/11, the power industry has taken a closer look at system contingencies not only driven by naturally occurring events but additional man-made threats as well, including: (1) cyberattacks; (2) loss of interdependent systems; (3) earthquakes; (4) physical attacks; (5) severe terrestrial weather; (6) geomagnetic disturbances; and (7) electromagnetic pulses.

PJM uses cascading tree analysis to assess the probability and consequence of cascading outages in electric systems. PJM is currently developing a metric of resilience to complement and enhance a planning process that traditionally has been focused on reliability and market efficiency. The cascading trees methodology could be used in decision-making and as a driver for new projects. For example, transmission corridors that appear frequently across multiple cascading paths are good candidates for system reinforcements significantly lowering the probability of a severe cascading outage.

Grid of the Future Scenario Analysis

A larger shift to stochastic models could become an effective transmission planning tool. One application could involve renewable generation output profiles. These techniques may require a shift away from a deterministic elimination of violations to the identification of an optimal hedge against probable scenarios. These models, however, raise a number of complex issues that will require further thought and resolution:

1. How to assign a proper probability to a scenario
2. Resolving disagreement over assigned probabilities
3. What constitutes an optimal hedge in all scenarios (e.g., eliminate or minimize violations for 99% of cases)
4. Compatibility with other analytical tools (e.g., AC power flow, transient stability, electromagnetic transient, etc.)

PJM believes that probabilistic methods can be a valuable planning tool and will continue to study the application and effectiveness of probabilistic approaches.

1.3.7 — Resilience

A resilient grid must be able to withstand large-scale system disturbances, to which it is difficult to attach probabilities and that can exceed conventional NERC planning N-1-1 and N-1 planning criteria. High-impact, low-frequency contingencies – encompassing generation, transmission or both – can significantly impact PJM's ability to serve load reliably and maintain overall system integrity. Growing reliance on greater levels of variable resources raises resilience concerns, as the winter weather impacts of February 2021 on ERCOT, SPP and MISO demonstrated.

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

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

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

Reliability and Resilience

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

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

GOTF planning must consider all of these dimensions of resilience.

Beyond NERC Transmission Standards

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

NERC standards address resilience to a degree. Existing planning standards require examination of the impact of extreme events such as the loss of an entire substation or the loss of an entire right-of-way – caused by a landslide, tornado, hurricane or fire, for example – that would take out

multiple transmission lines at one time. Although an assessment of the impact of these events is required, reinforcement for these high-impact, low frequency events is not required under current NERC criteria. Planners must now also assess whether the transmission system is sufficiently reinforced to address extreme events like these as well those caused by physical and cyberattacks.

Reliability Criteria for Extreme Events

PJM's ongoing efforts are taking a forward-looking, holistic and proactive approach to plan for future transmission needs with respect to extreme events, which may become a more significant grid expansion driver under higher levels of renewable penetration. The scope of planning studies will support efforts to assess how extreme events can be analytically evaluated and how consequential impacts to system reliability are identified. This may lead to new reliability criteria and planning tests. To that end, PJM continues to work with stakeholders to consider planning process policy changes that may be needed to enable it to identify and plan needed transmission to address extreme events.

PJM, in its ANOPR comments, has urged FERC to adopt a common definition of resilience and a specific resilience planning driver for grid enhancements, applicable to all planning regions. See also **Section 1.4.10** of this report.

Fuel Assurance

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

Solar and wind generator availability is characterized as variable insofar as output is impacted by both weather and time of day. Wind generation may be forced to shut down during periods of high winds to protect equipment. Such generators are designed with cut-out speeds of approximately 55 mph. The opposite conditions also present fuel-assurance concerns. California is cited as an example test case for ensuring grid reliability under growing levels of power from fluctuating wind and solar resources, including loss of wind-powered generation under severe, windless heat spells.

Loss of Transmission

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

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

1.3.8 — Grid of the Future Road Map

Moving forward, PJM has identified four planning process areas of focus to achieve the grid of the future.

1. **Transmission build-out scenario studies** will be conducted in 2022 based on power-flow case alignment with PJM's Energy Transition Analysis and renewable integration studies and leveraging analysis work of the OSW Scenario Study Phase 1. This OSW study phase considered multiple offshore wind injection scenarios as well as the renewable resources needed to meet state RPS onshore wind objectives. As PJM continues its initiatives to enable a decarbonized grid, additional analysis beyond the OSW scenario studies will examine an accelerated renewable penetration case, including a more in-depth assessment of the impacts from higher levels of building and transportation electrification.

   The heart of RTEP GOTF scenario studies to be conducted in 2022 will focus on identifying reliability impacts in terms of both transmission planning and resource adequacy. These scenario studies are not starting from scratch. To the contrary, as discussed above, they are building on foundational studies that have preceded them, including Energy Transition Analysis and OSW study efforts.

   Scenario studies will examine the need for additional grid expansion driven by the location of retiring capacity (primarily coal and nuclear) relative to capacity replacement (natural gas and renewables), and the load centers they serve. These studies will employ generator deliverability methodologies to identify NERC and regional reliability criteria violations under test conditions that include summer peak, winter peak and light-load system conditions, as well as time-of-day conditions given the intermittency of renewables. The studies will focus on impacts to the BES where the impacts might lead to the rebuild of existing or construction of new grid infrastructure.

2. **Targeted reliability studies** will build on 2022 scenario study results in order to evaluate generation and transmission reliability attributes, such as reactive control, stability, system inertia and frequency control, and short-circuit impacts, to ensure grid reliability.

   The scenario studies described above comprise just one area of GOTF reliability evaluation. PJM's generation shift from large coal and nuclear plants to utility-scale renewables at new locations more numerous than those of the generators they replace, will necessarily drive grid development. The ability of new, natural gas-fired generating units to replace reliability attributes (inertia, voltage support, frequency response, short-circuit current, etc.) lost by coal and nuclear unit deactivations will depend significantly on their location. Operability issues can arise in areas where sufficient levels of those attributes are not readily accessible. As a result, targeted reliability studies that examine them are also a necessary component of PJM's GOTF road map.

3. **RTEP process enhancements** will continue. Two key enhancements are already underway: (1) modeling wind and solar impacts as part of generator deliverability analysis and Effective Load Carrying Capability (ELCC) methodology development; and (2) planning for resilience.

4. **Additional regulatory action** is expected on a number of issues, including reliability criteria for resilience and extreme events, transportation and building electrification, interconnection process reform, DER expansion, and regional transmission planning reforms per FERC's recent ANOPR. PJM engagement with policymakers will be critical on these issues that impact how PJM plans the transmission grid.

PJM intends to follow this road map in 2022 and beyond to ensure grid of the future reliability and enable public policy goals.

PJM expects to publish a white paper in the first quarter of 2022, which will lay out its GOTF road map in detail.

Go to Next Section >

1.4: RTEP Process Milestones

1.4.1 — 2021 Activities

PJM's RTEP process continues to evolve as the scope of system enhancement drivers shifts. In addition to the efforts undertaken by PJM to bring the grid of the future into clearer focus, as discussed in **Section 1.3**, other related process improvement milestones were achieved throughout 2021, as discussed below.

1.4.2 — Load Forecast Accuracy

PJM annually reviews its load forecast methodology and implements changes when improvements to accuracy are identified. For the 2022 Load Forecast, PJM revised the load forecast model to capture with greater granularity: (1) sector models; and (2) summer and winter seasonal weather response. PJM also implemented a behind-the-meter battery storage forecast for the first time. These resources are used in conjunction with the distributed solar forecast.

Each year, PJM measures model accuracy of the long-term load forecast model by running the forecast model with up-to-date inputs, solving with actual weather and comparing to actual load. This measure of accuracy is meant to show how well the model would have performed with the most recent forecast inputs. PJM reviews model accuracy results on the 10 highest coincident peak days for each season for a number of forecast horizons with the Load Analysis Subcommittee. PJM's most recent report on model accuracy is available on the PJM website.

1.4.3 — Generator Deliverability Process

In 2021, PJM initiated discussions with PC stakeholders to improve variable resource modeling. PJM is pursuing modifications to the RTEP process generator deliverability methodology to more accurately reflect emerging resource mix under light load and winter operating conditions. The existing generator deliverability procedure is overly complex and has remained relatively unchanged for many years. PJM's discussions with the PC will continue in 2022.

In order to model operations more realistically, a new block dispatch approach will be implemented that seeks to simulate economic conditions and matches historical regional dispatch patterns. The existing dispatch procedure relies on historic capacity factors and does not accurately reflect PJM's rapidly evolving resource mix. Locational deliverability area imports will be limited to their Capacity Emergency Transfer Objective in the base case. Only firm interchange will be modeled in the base case, with separate, simplified procedures for performing historical interchange sensitivity analysis.

In addition to the generator deliverability test modification, the light-load period for planning studies may be redefined to include any nighttime and daytime hours that exhibit load levels between 40–60% of annual peak. Doing so will allow solar generation to be more accurately modeled. Existing light-load power flow cases are modeled at 50% annual peak load and utilize summer ratings, which are viewed as too conservative given the system conditions under study. The proposed changes would establish a new light-load temperature default rating set of 59 degrees Fahrenheit and align ramping procedures more closely with respective seasonal operating conditions.

1.4.4 — Storage as Transmission Asset

Energy storage development continues to grow in PJM and other RTOs. As solar generation increases in PJM, growth of storage is expected to follow. Storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility.

Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, DOE national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

Queue Activity

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

State Public Policy Drivers

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

Grid Opportunities for Energy Storage Resources

PJM, like other RTOs, recognizes that storage paired with renewables and transmission can optimize the delivery of power. To address the limited-duration issue, some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or the pairing is hybrid (in which the storage facility and generator share a common connection to the grid). Whether co-located or hybrid, the net result with respect to solar power, for example, smooths minute-by-minute load fluctuations, flattens peak load while storage devices are charging, and discharges power back into the grid at later hours, as shown in **Figure 1.14**. PJM continues to research how storage impacts load shape and reliability. Storage technologies can solve geographic diversity-driven reliability issues that arise out of growing levels of wind and solar and can mitigate IBR reliability attribute risks like frequency response and other aspects of system stability.

LEARN MORE

2019 New Jersey Master Plan: Pathway to 2050 report

Status

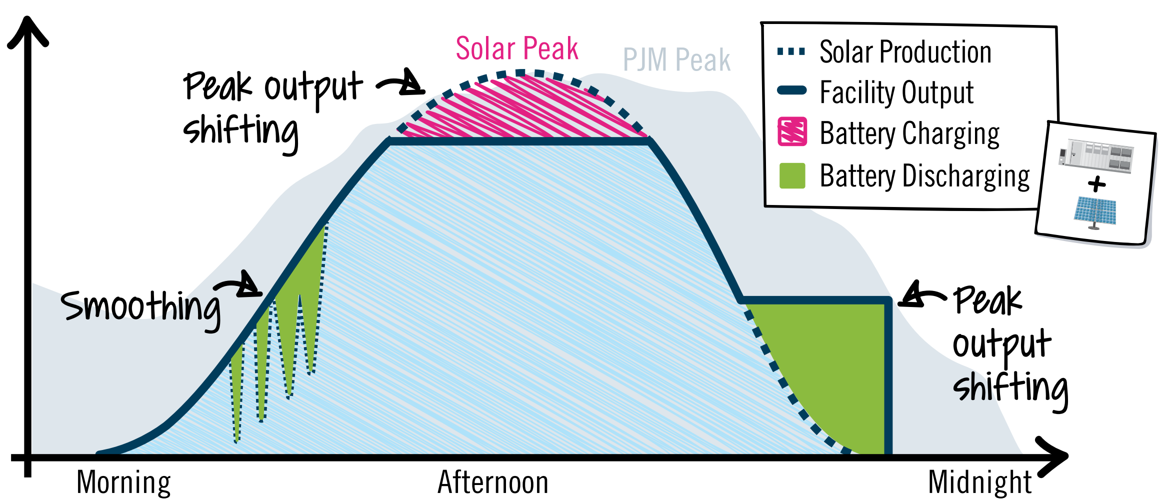
Interconnection requests for grid-scale storage resources – both stand-alone and as part of hybrid renewable resources – are an increasing trend in PJM's interconnection queue. These resources are anticipated to provide significant grid benefits given their ability to "firm-up" otherwise variable resources by charging and discharging to serve load at any given point in time.

1.4.5 — Critical Infrastructure Stakeholder Oversight

NERC CIP-014 Standard

The NERC CIP-014 standard requires TO assessments to identify critical facilities that, if rendered inoperable, would cause instability, uncontrolled separation or cascading outages. Concerns across the industry about grid security and resilience continue to grow. Throughout 2021, PJM continued to pursue stakeholder support to embed testing and other strategies in its RTEP process to ensure those concerns are addressed. Specifically, PJM continues to support efforts to eliminate current vulnerabilities for CIP-014 critical infrastructure, while also working to develop RTEP process criteria to avoid the risk of potential future CIP-014 critical infrastructures facilities.

Figure 1.14: Impact of Storage on Peak Solar Production



Attachment M4 Process

On March 17, 2020, FERC approved Attachment M4 of the PJM Tariff, which will govern the planning of CIP-014 Mitigation Projects (CMPs). These CMP projects are designed to address existing identified CIP-014 facilities and are limited, based on the filing, to only those facilities that were identified as of Sept. 30, 2018. The locations of these facilities are confidential, but have been publicly identified as not to exceed 20.

Avoidance

As part of PJM's CBIR process, stakeholders evaluated and developed a planning process to avoid or reduce the aggravation of conditions associated with identified critical facilities. The process would also seek to avoid or minimize the creation of new critical facilities in the PJM region. Stakeholder endorsement of these concepts and corresponding documentation were approved at the May 2021 meeting of the Markets and Reliability Committee.

1.4.6 — Federal Legislation

In 2021, the Infrastructure Investment and Jobs Act ("the Act") included $1.2 trillion in infrastructure-related funding provisions for the energy sector, including additional funding for electric vehicle infrastructure, $6 billion in relief to economically distressed nuclear facilities through fiscal year 2026, and funds for grid reliability and resilience.

Notably, from a PJM perspective, the Act incorporates a more expanded role for the Department of Energy (DOE) in:

- Using the DOE national laboratories more proactively to potentially undertake transmission planning analyses that would normally be done through RTO and interregional planning processes
- Utilizing new Congressional authority to fund up to 50% of specific transmission projects and to market newly created capacity from such projects
- Establishing national transmission corridors that would serve as a condition precedent to FERC exercising "backstop" siting authority
- Providing significant funding for states to participate in planning processes and funding for the development of grid-enhancing technologies

How the DOE will exercise this new authority remains unclear. The Act included a directive from Congress to the DOE to coordinate directly with planning authorities to avoid duplication and to ensure that DOE actions lead to reasonable, non-discriminatory outcomes. Many unknowns remain. PJM on its own and through the Eastern Interconnection Planning Collaborative are looking to work with the DOE to ensure outcomes that complement the existing PJM RTEP process.

1.4.7 — Interconnection Process Reform

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process has been key to helping states achieve renewable targets. PJM recognizes, though, that changes may be warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing. In 2021, for example, PJM received 1,351 new service requests, more than triple the 470 new service requests received just three years prior and the highest number since implementation of the interconnection queue 25 years ago in 1997.

PJM's interconnection process is a critical step in integrating renewable generation into the grid as part of federal and state policy goals. To that end, PJM and stakeholders continue to improve the process and reduce study backlogs. Through the activities of the Interconnection Process Reform Task Force (IPRTF), commissioned in April 2021, reforms are under development to remove process barriers to increasing volume of renewable resources. These concepts are discussed further in **Section 5.3**.

1.4.8 — Interconnection Pricing Policies and Cost Allocation

Recognizing ongoing grid evolution, and in parallel with the IPRTF discussed above, PJM undertook a series of Interconnection Policy Workshops, beginning in May 2021, to encourage stakeholder discussions regarding cost-allocation methodologies and whether any changes or enhancements to the current participant funding approach are warranted.

Through the workshops, PJM and its stakeholders have discussed six potential alternative interconnection cost responsibility options. Implementing one of the six could replace the present "cost causer pays" rule out of FERC Order 2003 and provide a more efficient and fairer way to allocate interconnection-related costs. Each option offers an approach that can address more than a single queue project, in anticipation of greater penetration of renewables and attendant volume of grid interconnection requests.

1 **Option 1:** State Underwriting for Transmission to Particular Renewable-Rich Areas as Identified by Queue Requests

2 **Option 2:** Enhancing Baseline Upgrades for Transmission to Particular Renewable-Rich Areas as Identified by Queue Requests

3 **Option 3:** Option for Transmission Owners to Treat Upgrades as Supplemental Projects

4 **Option 4:** Baseline Upgrades for DOE-Identified Transmission Corridors per the Energy Policy Act of 2005 (EPAct 2005)

5 **Option 5:** Enhanced Merchant Funding for New Transmission to Renewable-Rich Areas

6 **Option 6:** Subscription Option for Generators

Each of the six options provides a potential path to planning for future generation, including renewable resources, in a way that does not rely solely on the interconnection queue process. Rather, these options provide an approach that can address more than a single queue project and would allow for long-term planning for future generation that would be anticipated to meet state renewable goals. All of these options would impact the current cost allocation construct of participant funding for transmission upgrades in that load serving entities, and ultimately their customers, would assume some degree of cost responsibility.

LEARN MORE

The six interconnection policy options were presented at a workshop on July 22, 2021.

1.4.9 — Distributed Energy Resources

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

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

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

RTEP Process Impact

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

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

Public Policy Drivers

Federal and state policies are driving rapid growth of DER in PJM, as evidenced by the interconnection queue. PJM states have also adopted EV growth policies and battery storage pilots, which could drive additional future DER growth. Moreover, the Biden administration has set even more aggressive goals than PJM states to achieve a "carbon-free power sector" by 2035. In addition to the clean electricity standard, administration goals would expand the EV market from 2.5% of cars in 2021 to 50% by 2030. This volume could impact transmission planning and operations, especially in densely populated and highly networked areas like in the eastern PJM region.

Existing and newly proposed financial incentives could accelerate this target-driven growth. The federal government offers tax credits for renewables and some EVs, with more proposals – including possible Clean Energy Program Payments – winding their way through Congress. When combined with possible state and local incentives for both EVs and renewables, including tax abatement, grants, net metering, RECs and even state tax credits, the market could surpass target-driven growth projections in certain locations, especially where project capital and unused space are available.

Taken together, these policy drivers could lead to multiple possible future DER penetration scenarios, ranging from 10–50% by 2030. While quantitative analysis for predicting DER penetration by location may still be somewhat primitive, anecdotal data could contribute to qualitative analysis of a high-penetration DER future.

Impact of FERC Order 2222

FERC Order 2222 enables DER, including non-wholesale DER, to participate in wholesale markets. PJM will need to implement changes in its planning process modeling and dispatch methods to consider future DER growth anticipated with the implementation of Order 2222 and similar orders. These enhancements to the RTEP process will enable greater DER visibility and allow better alignment with operations and markets studies.

PJM is advocating for greater visibility of non-wholesale DER, particularly as part of FERC Order 2222 proceedings and internal implementation discussions. The order allows aggregated non-wholesale DER to participate in wholesale markets. Overall, PJM will need to track three types:

1. Wholesale DER
2. Non-wholesale DER still being netted
3. Non-wholesale DER participating in wholesale aggregation (The need to explicitly model loads and DER generation will require careful tracking to avoid double counting.)

PJM currently relies heavily on economic modeling of rooftop solar development, and then nets out the load in the load forecast, which effectively masks the actual total load being served

NOTE

PJM filed a comprehensive proposal Feb. 1 with FERC outlining how it will comply with Order 2222. PJM's approach balances both the needs of distributed energy resource (DER) aggregators to participate in PJM's markets on a level playing field with other resource types, and the rights of relevant electric retail regulatory authorities and distribution utilities to ensure safe and reliable operations on the distribution system. DER aggregation participation in PJM charters new territory in several areas, including interactions between distribution and transmission systems, emerging technology integration, grid modernization, and operational flexibility. PJM's filing is available online.

in the PJM region. While netting lower levels of DER relative to gross load may be adequate, this modeling approach may be inadequate to reliably plan the system under certain solar conditions as DER grows. For example, the issue is illustrated by an operational event that occurred in 2017 in the Dominion transmission zone in North Carolina. A combination of switching moves and maintenance outages caused line overloads when the setting sun reduced BTM solar output, and load exceeded the capability of certain 115 kV lines to deliver power.

1.4.10 — FERC Transmission Planning ANOPR

PJM engagement with federal and state policymakers is critical to successful GOTF planning initiatives focused on renewable integration coupled with impacts of current trends in generation, transmission and load. Indeed, GOTF trends associated with decarbonization are significantly driven by public policy, including FERC's July 15, 2021, Advance Notice of Proposed Rulemaking (ANOPR), entitled, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection.* PJM replied with *Initial Comments* on Oct. 12, 2021, and *Reply Comments* on Nov. 30, 2021. Details of these filings can be found:

1. Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection. Advance Notice of Proposed Rulemaking (ANOPR). July 15, 2021. [Docket No. RM21-17-000]
2. PJM Initial Comments. Oct. 12, 2021
3. PJM Reply Comments. Nov. 30, 2021

PJM's Initial Comments in response to the ANOPR identified four "Guiding Principles" that PJM believes should govern planning reforms, including those enunciated in the ANOPR itself.

- ***Accommodating the Nation's Move Toward a More Decarbonized Future***: Planning processes should ensure a reliable and resilient transmission grid that incorporates and enables effective implementation of policy choices made by local, state and federal governments, as well as the desires of customers, for reduced carbon electricity. Accommodating states' goals by implementing policy choices while ensuring just, reasonable and nondiscriminatory outcomes need not be an "either/or" choice. By carefully crafting policy choices that do not favor one resource type over another, both goals can be achieved, consistent with applicable law.
- ***Grid Resilience***: Resilience is too important to be excluded from any forward-looking holistic approach to proactively plan for transmission needs of the electricity grid of the future. To that end, PJM believes it is imperative for FERC to put in place a common working definition of resilience, as well as resilience-based industry planning drivers to ensure the grid is prepared to withstand or quickly recover from events that pose operational risks, including but not limited to, climate change and extreme weather events, as well as threats of physical and cyberattacks.
- ***Protecting Consumers***: PJM's currently effective rules create a balance, in that interconnecting generators pay their "but for" costs to interconnect to the existing transmission system, while load thereafter bears the costs of ensuring continued deliverability of those generators once interconnected. Other pricing policy models can and should be considered, but any change to the Order No. 2003 pricing policy should account for a reasonable allocation of risk and reward to ensure that the change in policy choice does not result in an unreasonable shift of costs or risks to load.
- ***Equitable Treatment Between RTO/Independent System Operator (ISO) and Non-RTO/ISO Regions***: Changes to the energy mix and customer demands are not limited to RTO/ISO regions. FERC should ensure that its proposed reforms are implemented in a manner that does not create disincentives for transmission owner participation in RTOs/ISOs.

Then, within the parameters of these guidelines, PJM set forth a number of specific recommendations in its Initial Comments to be considered by both stakeholders and FERC as the process moves forward to any future Notice of Proposed Rulemaking. In short, PJM divided its recommendations among: (1) recommendations that are appropriate for inclusion in a national rule; (2) recommendations that PJM will be undertaking with its stakeholders as potential initiatives to enhance its existing planning processes; (3) areas where the Commission should avoid a national rule and instead defer to individual regions; and (4) areas where PJM believes reforms are not necessary. PJM, and the industry, await FERC's proposed rule, expected in 2022.

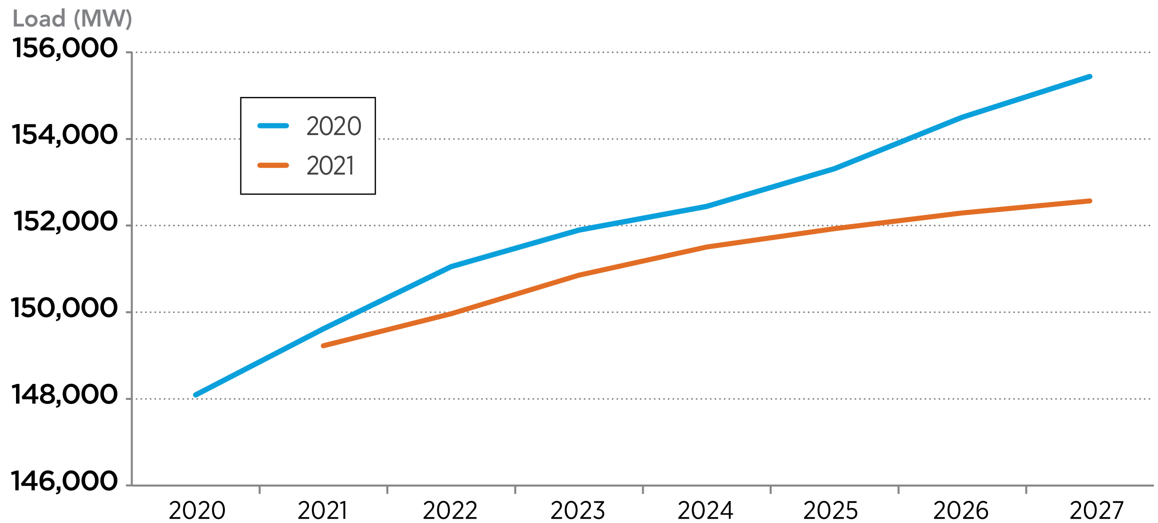
Section 2: Resource Adequacy Modeling

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 economically efficient system operations.

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

Figure 2.1: Summer Peak Load Forecast 2021 vs. 2020



2021 RTEP Process Context

PJM's 2021 RTEP baseline power flow model for study year 2026 is based on the [2021 PJM Load Forecast Report](). Summarized in the sections that follow, PJM's January 2021 load forecast covered the 2021 through 2036 planning horizon. From a power flow modeling perspective, the 2026 summer peak from that January 2021 forecast at an overall RTO demand of 152,290 MW was the basis for developing PJM's 2026 base case power flow model. Doing so will reflect that PJM now projects its RTO summer-normalized peak to grow 0.3% annually over the next 10 years, shown in **Figure 2.1**, which is down 0.3 percentage points from the 2020 forecast.

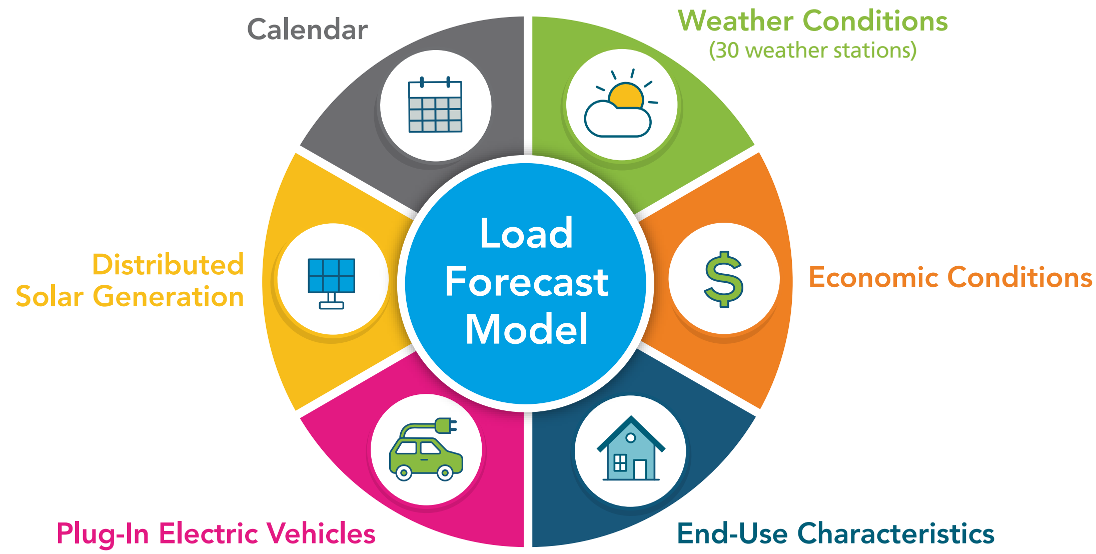
Significant load growth due to new construction of data centers in historically low load areas drives the need for additional sensitivity studies to assess the potential impacts of large load increases. PJM will continue to work closely with local utility planners to ensure these load additions are properly captured in future forecasts.

Load Forecasting Process

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

PJM instituted changes in the 2021 load forecast, aimed at providing a more accurate forecast that better aligns with ongoing load trends. For the 2021 load forecast, PJM made model changes to better align the non-weather-sensitive model with underlying drivers and historical trends. The commercial sector model was updated to include service sector employment as a driver. These changes were implemented through significant stakeholder engagement at the Load Analysis Subcommittee and Planning Committee meetings.

Figure 2.2: Load Forecast Model



Calibration

The model takes advantage of publicly available sector data to calibrate the independent variables used to forecast load, such as end-use and economic trends. Load data used in the PJM load forecast is at the transmission zone level, but unseen are the customers that contribute to that load. These customers broadly come from three sectors: residential, commercial and industrial. Understanding trends in each of these categories is valuable to understanding the whole picture. 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.

Distributed Solar Generation

PJM is taking a more granular approach to modeling behind-the-meter solar load forecast impacts. The solar output by weather scenario varies in the same way that the weather related to the historical weather scenario in the weather simulation varies.

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

Plug-In Electric Vehicles

PJM is incorporating an explicit adjustment for plug-in electric vehicle (PEV) charging in its peak and energy forecasts. PJM wants to be sure to account for PEVs to maintain reliability, as the share of them on the road continues to grow.

Weather Conditions

Weather conditions across the RTO are accounted for by calculating a load-weighted average of temperature, humidity, wind speed and cooling degree days. PJM obtains weather data from over 30 identified weather stations across the PJM footprint.

Calendar

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

Economic Conditions

The economic dimension used in the calibration includes economic measures of households, real personal income, population, working-age population and goods-producing output. This allows for localized treatment of economic effects within a zone. PJM has contracted with an outside economic services vendor to provide economic forecasts for all areas within the PJM footprint.

End-Use Characteristics

End-use characteristics are captured through three distinct variables designed to capture the various ways in which electricity is used: both weather-sensitive heating and cooling and non-weather-sensitive use. Each variable addresses a collection of different 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.

PJM has updated its load forecast model in a way that reflects the continued evolution toward a more service-driven, less manufacturing-based, less energy-intensive economy. This trend is further driven by the accelerated proliferation of energy-efficient electric appliances and equipment.

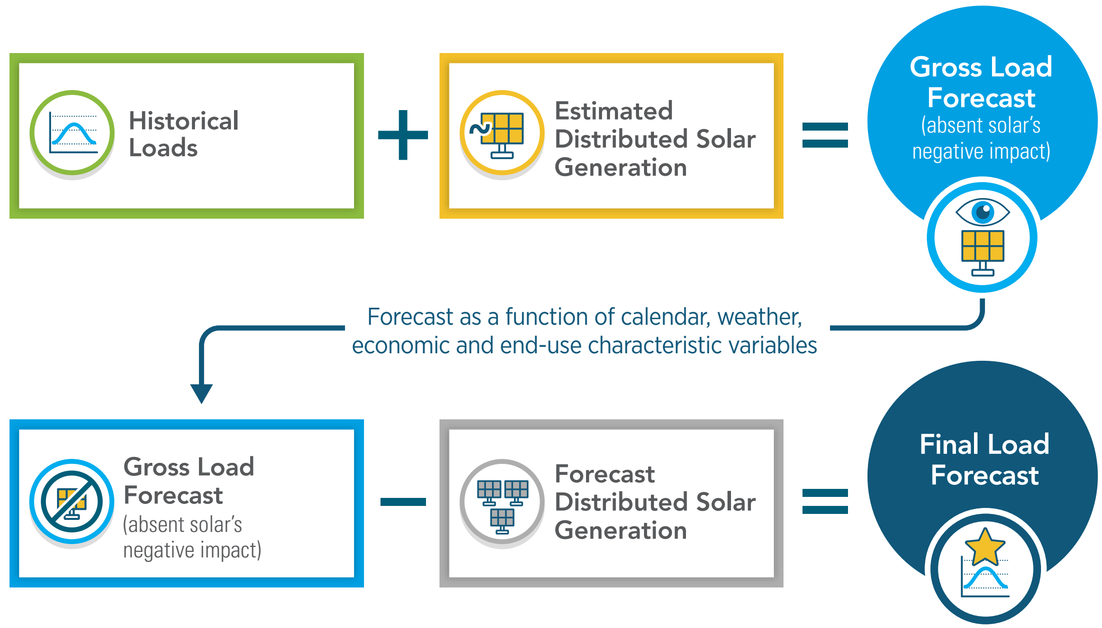
Distributed Solar Generation

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

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

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

Figure 2.3: Accounting for Distributed Solar Generation



2.1: January 2021 Forecast

PJM's January 2021 load forecast used in 2021 RTEP studies covered the 2021 through 2036 planning horizon, highlights of which are summarized in this section. The complete January 2021 PJM Load Forecast Report is accessible on the PJM website. As that report states, PJM's 2026 RTO summer peak is forecasted to be 152,290 MW.

Forecasting Trends

Table 2.1 summarizes the seasonal transmission owner zonal summer and winter 10-year forecasts and load growth rates for 2021 through 2031. All load forecasts in the table reflect adjustments for distributed solar generation and PEVs. Adjustments to the summer 10-year forecast are summarized in **Table 2.2**. Adjustments to the winter forecast for distributed solar are approximately zero.

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

Table 2.1: 2021 Load Forecast Report

Transmission Owner	Summer Peak (MW)			Winter Peak (MW)		
	2021	2031	Growth Rate	2020/21	2030/31	Growth Rate
Atlantic City Electric	2,470	2,605	0.5%	1,538	1,606	0.4%
Baltimore Gas & Electric	6,582	6,652	0.1%	6,032	6,339	0.5%
Delmarva Power	3,895	3,976	0.2%	3,876	4,126	0.6%
Jersey Central Power & Light	5,876	6,193	0.5%	3,658	3,936	0.7%
Metropolitan Edison (Met-Ed)	3,060	3,255	0.6%	2,701	2,808	0.4%
PECO	8,389	8,691	0.4%	6,682	6,679	-0.0%
Pennsylvania Electric Company (Penelec)	2,894	3,164	0.9%	2,842	2,896	0.2%
PPL Electric Utilities Corporation	7,204	7,758	0.7%	7,513	7,716	0.3%
Potomac Electric Power Company (Pepco)	5,924	5,248	-1.2%	5,716	5,645	-0.1%
Public Service Electric & Gas Company (PSE&G)	9,871	10,407	0.5%	6,718	7,130	0.6%
Rockland Electric Company	396	397	0.0%	213	210	-0.1%
UGI Utilities	195	201	0.3%	204	198	-0.3%
Diversity – Mid-Atlantic	-986	-810		-1,228	-1,235	
Mid-Atlantic	**55,770**	**57,737**	**0.3%**	**46,465**	**48,054**	**0.3%**
American Electric Power	22,609	23,471	0.4%	22,301	22,570	0.1%
Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)	8,859	9,140	0.3%	8,896	9,058	0.2%
American Transmission Systems, Inc. (FirstEnergy)	12,525	12,842	0.3%	10,918	10,856	-0.1%
Commonwealth Edison (ComEd)	20,421	19,433	-0.5%	14,478	13,673	-0.6%
AES Ohio (formerly Dayton Power & Light)	3,415	3,550	0.4%	2,964	2,976	0.0%
Duke Energy Ohio and Kentucky	5,390	5,746	0.6%	4,634	4,877	0.5%
Duquesne Light Company	2,768	2,954	0.7%	2,088	2,165	0.4%
East Kentucky Power Cooperative	2,130	2,280	0.7%	2,811	3,000	0.7%
Ohio Valley Electric Corporation	90	90	0.0%	120	120	0.0%
Diversity – Western	-2,248	-2,224		-1,686	-1,685	
Western	**75,959**	**77,282**	**0.2%**	**67,524**	**67,610**	**0.0%**
Dominion Energy Virginia and North Carolina	20,150	21,269	0.5%	20,306	22,269	0.9%
Southern	**20,150**	**21,269**	**0.5%**	**20,306**	**22,269**	**0.9%**
Diversity – Total	-5,889	-5,563		-5,182	-5,285	
PJM RTO	**149,224**	**153,759**	**0.3%**	**132,027**	**135,568**	**0.3%**

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

Transmission Owner	Adjustment to Summer Peak (MW)			
	Distributed Solar Generation		Plug-In Electric Vehicle	
	2021	2031	2021	2031
Atlantic City Electric	225	284	8	39
Baltimore Gas & Electric	168	680	17	87
Delmarva Power	133	362	7	36
Jersey Central Power & Light	288	460	18	89
Metropolitan Edison (Met-Ed)	27	52	4	23
PECO	56	104	12	64
Pennsylvania Electric Company (Penelec)	6	36	4	22
PPL Electric Utilities Corporation	72	135	10	54
Potomac Electric Power Company (Pepco)	203	680	15	77
Public Service Electric & Gas Company (PSE&G)	435	726	30	150
Rockland Electric Company	14	22	1	6
UGI Utilities	0	2	0	1
American Electric Power	76	311	23	124
Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)	98	311	11	56
American Transmission Systems, Inc. (FirstEnergy)	57	120	15	80
Commonwealth Edison (ComEd)	162	718	41	217
AES Ohio (formerly Dayton Power & Light)	26	43	4	20
Duke Energy Ohio and Kentucky	15	50	6	31
Duquesne Light Company	12	32	4	21
East Kentucky Power Cooperative	6	14	1	8
Ohio Valley Electric Corporation	0	0	0	0
Dominion Energy Virginia and North Carolina	530	1,229	28	140
PJM RTO	**2,331**	**5,828**	**261**	**1,344**

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

	Load Forecast Report Summer Peak (MW)														
	2017			2018			2019			2020			2021		
Transmission Owner	2017	2027	Growth Rate	2018	2028	Growth Rate	2019	2029	Growth Rate	2020	2030	Growth Rate	2021	2031	Growth Rate
Atlantic City Electric	2,495	2,445	-0.2%	2,460	2,409	-0.2%	2,450	2,388	-0.3%	2,542	2,773	0.9%	2,470	2,605	0.5%
Baltimore Gas & Electric	6,889	6,911	0.0%	6,848	6,744	-0.2%	6,697	6,663	-0.1%	6,447	6,558	0.2%	6,582	6,652	0.1%
Delmarva Power	4,028	3,983	-0.1%	3,937	4,018	0.2%	3,933	3,962	0.1%	3,979	4,327	0.8%	3,895	3,976	0.2%
Jersey Central Power & Light	6,056	6,108	0.1%	5,942	5,943	0.0%	5,914	5,912	0.0%	5,842	6,122	0.5%	5,876	6,193	0.5%
Metropolitan Edison (Met-Ed)	2,940	3,028	0.3%	2,974	3,115	0.5%	2,986	3,157	0.6%	3,003	3,287	0.9%	3,060	3,255	0.6%
PECO	8,547	8,693	0.2%	8,642	8,979	0.4%	8,711	9,082	0.4%	8,415	8,677	0.3%	8,389	8,691	0.4%
Pennsylvania Electric Company (Penelec)	2,891	2,847	-0.2%	2,895	2,922	0.1%	2,897	2,908	0.0%	2,849	2,957	0.4%	2,894	3,164	0.9%
PPL Electric Utilities Corporation	7,132	7,186	0.1%	7,140	7,350	0.3%	7,148	7,347	0.3%	7,069	7,792	1.0%	7,204	7,758	0.7%
Potomac Electric Power Company (Pepco)	6,614	6,543	-0.1%	6,493	6,466	0.0%	6,466	6,413	-0.1%	6,109	5,794	-0.5%	5,924	5,248	-1.2%
Public Service Electric & Gas Company (PSE&G)	10,057	10,012	0.0%	9,903	9,876	0.0%	9,904	9,753	-0.2%	9,792	10,597	0.8%	9,871	10,407	0.5%
Rockland Electric Company	404	404	0.0%	402	402	0.0%	404	402	0.0%	395	420	0.6%	396	397	0.0%
UGI Utilities	191	185	-0.3%	190	188	-0.1%	189	188	-0.1%	191	184	-0.4%	195	201	0.3%
Diversity – Mid-Atlantic	-1,080	-1,161		-1,225	-1,086		-1,213	-1,135	0.0%	-781	-948		-986	-810	
Mid-Atlantic	**57,164**	**57,184**	**0.0%**	**56,601**	**57,326**	**0.1%**	**56,486**	**57,040**	**0.1%**	**55,852**	**58,540**	**0.5%**	**55,770**	**57,737**	**0.3%**
American Electric Power	22,945	23,888	0.4%	22,876	24,018	0.5%	22,945	24,072	0.5%	21,945	24,113	0.9%	22,609	23,471	0.4%
Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)	8,802	9,087	0.3%	8,825	9,447	0.7%	8,707	9,305	0.7%	8,685	9,373	0.8%	8,859	9,140	0.3%
American Transmission Systems, Inc. (FirstEnergy)	12,994	13,177	0.1%	12,952	13,309	0.3%	12,872	13,134	0.2%	12,378	12,428	0.0%	12,525	12,842	0.3%
Commonwealth Edison (ComEd)	22,296	22,872	0.3%	22,121	23,207	0.5%	21,890	22,514	0.3%	20,635	20,876	0.1%	20,421	19,433	-0.5%
AES Ohio (formerly Dayton Power & Light)	3,479	3,503	0.1%	3,459	3,508	0.1%	3,408	3,525	0.3%	3,236	3,228	0.0%	3,415	3,550	0.4%
Duke Energy Ohio and Kentucky	5,497	5,741	0.4%	5,523	5,860	0.6%	5,480	5,742	0.5%	5,280	5,650	0.7%	5,390	5,746	0.6%
Duquesne Light Company	2,884	2,882	0.0%	2,872	2,924	0.2%	2,862	2,887	0.1%	2,759	2,855	0.3%	2,768	2,954	0.7%
East Kentucky Power Cooperative	1,948	2,010	0.3%	1,960	2,033	0.4%	1,989	2,072	0.4%	2,004	2,334	1.5%	2,130	2,280	0.7%
Ohio Valley Electric Corporation							95	95	0.0%	95	95	0.0%	90	90	0.0%
Diversity – Western	-1,529	-1,468		-1,540	-1,522		-1,612	-1,369		-1,377	-1,311		-2,248	-2,224	
Western	**79,316**	**81,692**	**0.3%**	**79,048**	**82,784**	**0.5%**	**78,636**	**81,977**	**0.4%**	**75,640**	**79,641**	**0.5%**	**75,959**	**77,282**	**0.2%**
Dominion Energy Virginia and North Carolina	19,729	20,501	0.4%	19,596	21,161	0.8%	19,391	21,238	0.9%	19,813	22,336	1.2%	20,150	21,269	0.5%
Southern	**19,729**	**20,501**	**0.4%**	**19,596**	**21,161**	**0.8%**	**19,391**	**21,238**	**0.9%**	**19,813**	**22,336**	**1.2%**	**20,150**	**21,269**	**0.5%**
Diversity – RTO	-3,210	-3,604		-3,137	-3,636		-5,980	-6,070		-5,371	-5,644		-5,889	-5,563	
PJM RTO	**152,999**	**155,773**	**0.2%**	**152,108**	**157,635**	**0.4%**	**151,358**	**156,689**	**0.3%**	**148,092**	**157,132**	**0.6%**	**149,224**	**153,759**	**0.3%**

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2021 Forecast Summer Zonal Load Growth Rates

The PJM RTO weather-normalized summer peak is forecasted to grow at an average rate of 0.3% per year for the next 10 years. The PJM RTO summer peak is forecasted to be 153,759 MW in 2031, an increase of 4,535 MW over the 2021 peak of 149,224 MW. Individual geographic zone growth rates vary from -1.2% to 0.9%, as shown in **Figure 2.4** and **Figure 2.5**.

Figure 2.4: PJM Mid-Atlantic Summer Peak Load Growth 2021–2031

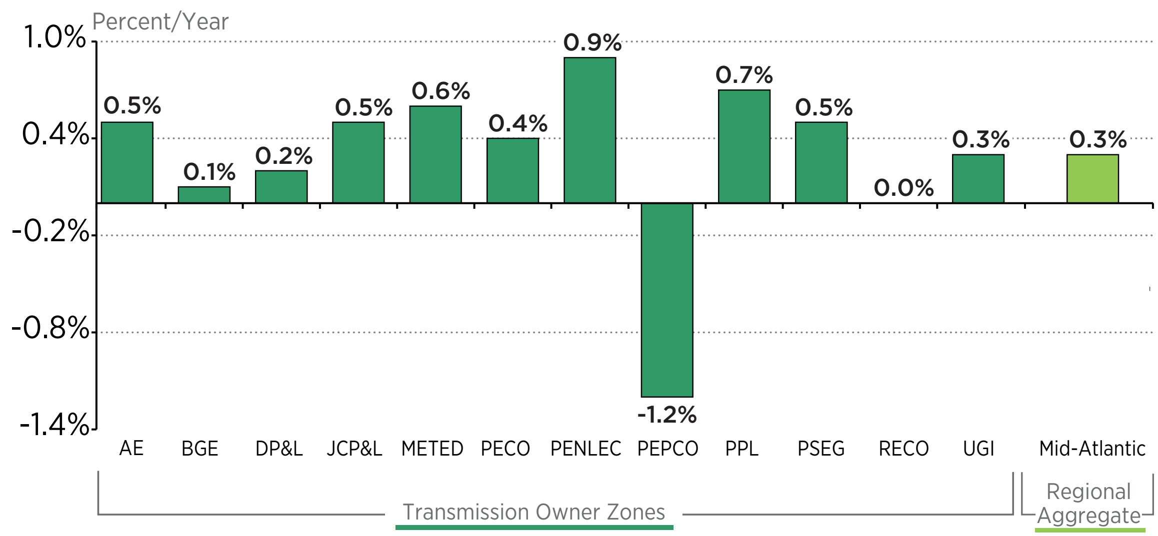
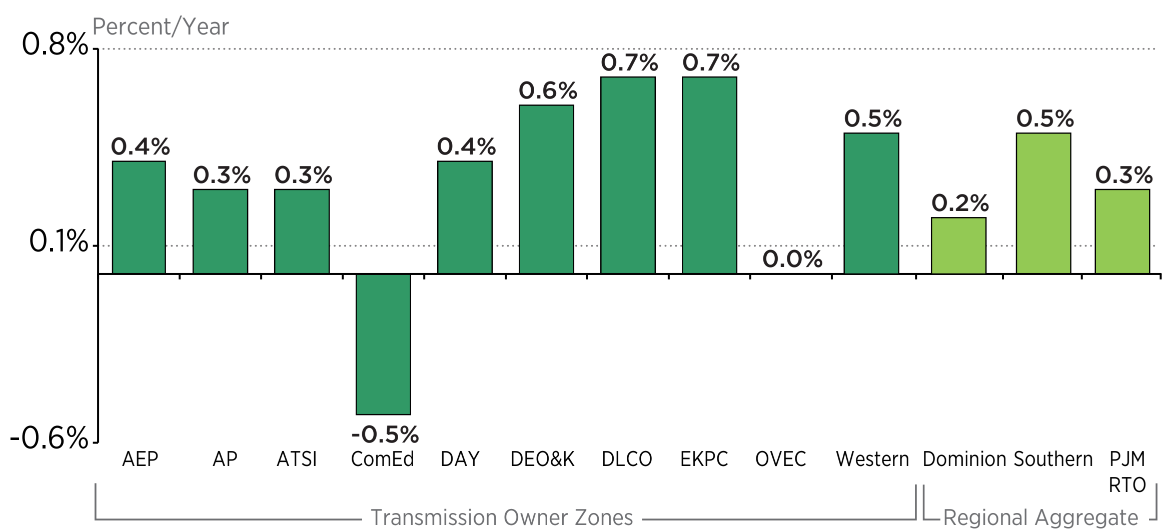


Figure 2.5: PJM Western and Southern Summer Peak Load Growth 2021–2031



2021 Forecast Winter Zonal Load Growth Rates

The PJM RTO weather-normalized winter peak is forecasted to grow at an average rate of 0.3% per year for the next 10 years. The PJM RTO winter peak is forecasted to be 135,568 MW in 2030/2031, an increase of 3,541 MW over the 2020/2021 peak of 132,027 MW. Individual geographic zone growth rates vary from -0.6% to 0.9%, as shown in **Figure 2.6** and **Figure 2.7**.

Figure 2.6: PJM Mid-Atlantic Winter Peak Load Growth 2021–2031

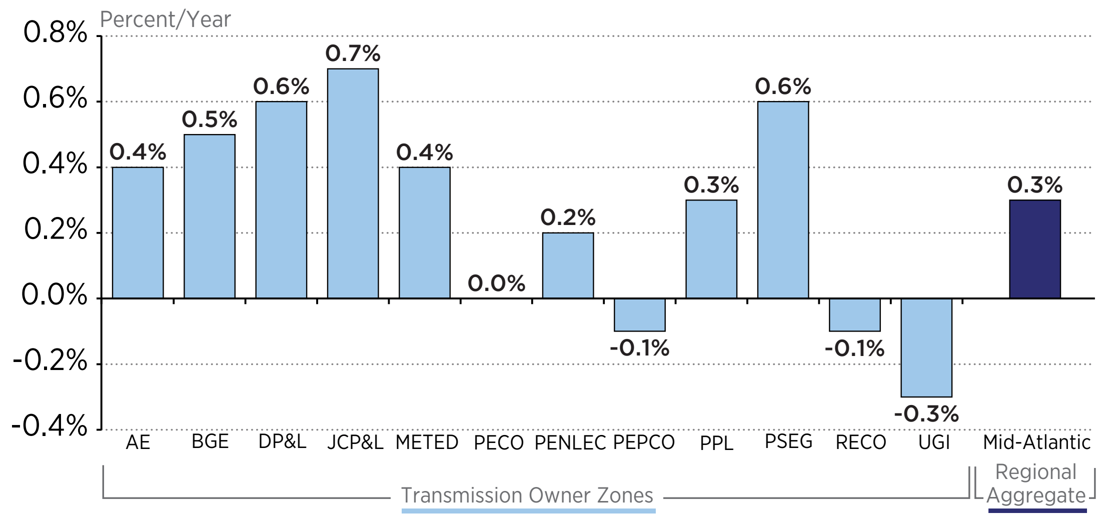
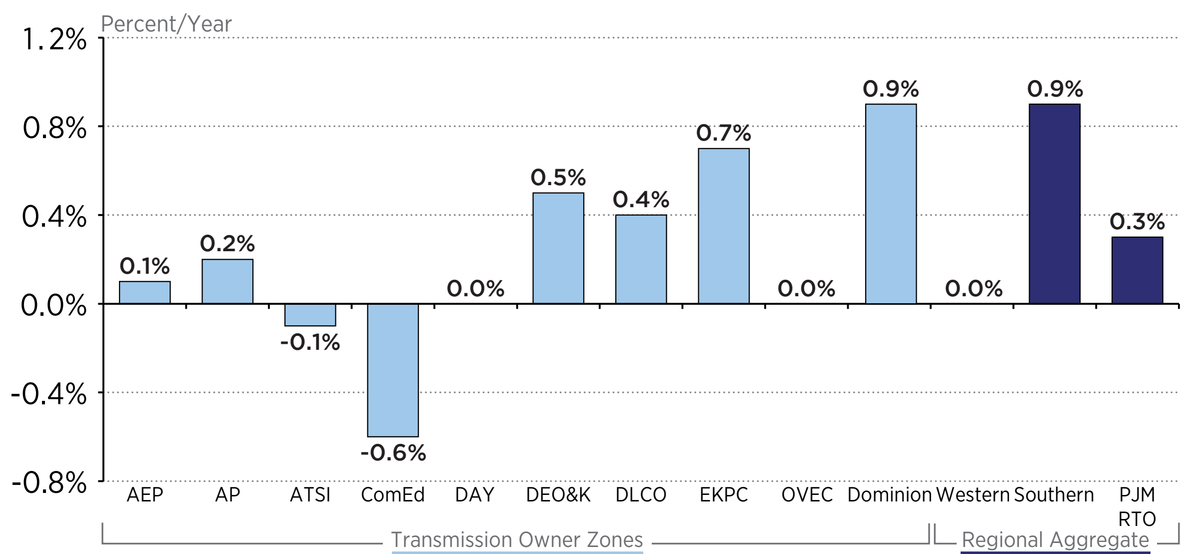


Figure 2.7: PJM Western and Southern Winter Peak Load Growth 2021–2031



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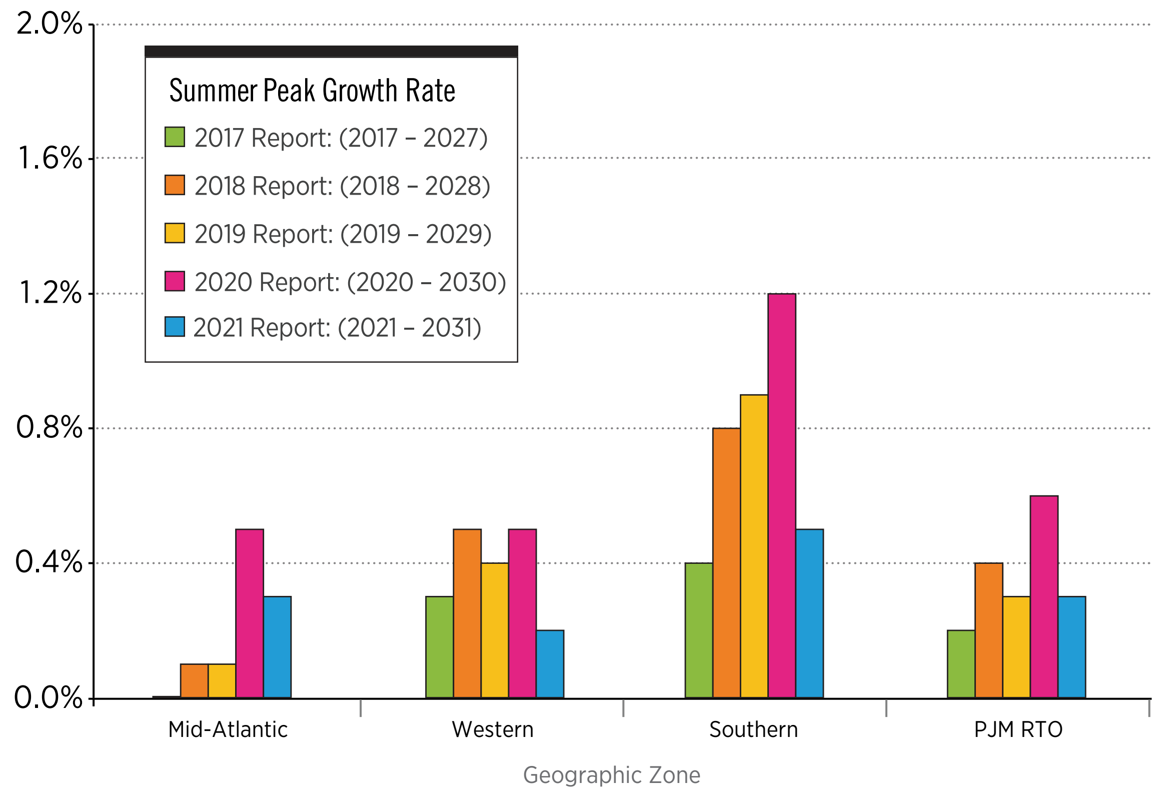
Subregional Forecast Trends

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 2017 through 2021, for the ensuing 10 years on a subregional basis. The trend reflects changes in the broader U.S. economic outlook and the growing impact of energy efficiency, solar and PEVs looking forward in each of the five forecasts.

In particular, the 2021 report forecasted that the load growth rate for the RTO decreased by 0.3 percentage points when compared to the 2020 report.

Figure 2.8: PJM 10-Year Summer Peak Load Growth Rate Comparison 2017–2021 Load Forecast Reports



2.2: Demand Resources and Peak Shaving

PJM accounts for demand resources by adjusting its base, unrestricted, peak load forecast by a forecasted amount, which is calculated based on committed quantities in previous Reliability Pricing Model (RPM) auctions. Those amounts, as reflected in the 2021 Load Forecast Report, are shown in **Table 2.4** for each transmission owner zone. The adjusted forecast is then used in RTEP power flow model studies that focus on summer peak capacity emergency conditions, during which demand resources are assumed to be implemented. Consequently, demand resources can have a measurable impact on future system conditions and 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 demand resources for each of the three most recent delivery years. Express the committed demand resource amount as a percentage of the zone's 50/50 forecast summer peak from the January load forecast report immediately preceding the respective delivery year.
2. Compute the most recent three-year average committed demand resources percentage for each zone.
3. Multiply each zone's 50/50 forecast summer peak by the results from step two to obtain the demand resource forecast for each zone.

Table 2.4: 2021 Load Forecast Report Demand Resources

	Total Load Management	
Transmission Owner	2021	2031
Atlantic City Electric	62	65
Baltimore Gas & Electric	425	478
Delmarva Power	272	268
Jersey Central Power & Light	127	135
Metropolitan Edison (Met-Ed)	253	269
PECO	324	335
Pennsylvania Electric Company (Penelec)	280	306
PPL Electric Utilities Corporation	528	568
Potomac Electric Power Company (Pepco)	424	356
Public Service Electric & Gas Company (PSE&G)	284	299
Rockland Electric Company	3	3
UGI Utilities	0	0
Mid-Atlantic	**2,982**	**3,082**
American Electric Power	1,255	1,303
Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)	737	760
American Transmission Systems, Inc. (FirstEnergy)	893	915
Commonwealth Edison (ComEd)	1,453	1,382
AES Ohio (formerly Dayton Power & Light)	189	196
Duke Energy Ohio and Kentucky	171	181
Duquesne Light Company	104	111
East Kentucky Power Cooperative	149	159
Ohio Valley Electric Corporation	0	0
Western	**4,951**	**5,007**
Dominion Energy Virginia and North Carolina	846	893
Southern	**846**	**893**
PJM RTO	**8,779**	**8,982**

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 inform the load forecast. No peak shaving programs are included in this year's forecast used for the RTEP.

Capacity Performance Impacts

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

- *Delivery years 2021 and beyond:* Annual demand resources are assumed to become Capacity Performance demand resources and are based on actual cleared quantities of demand resource products in the 2020/2021 and 2021/2022 RPM Base Residual Auctions.
- *Summer period demand resources:* Refers to demand resources that aggregate with winter-period resources to form a year-round commitment.

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

2.3: Effective Load Carrying Capability

2.3.1 — 2021 Study Results

As part of annual Base Residual Auction input parameters development, PJM now develops Effective Load Carrying Capability (ELCC) Class Ratings. Completed in December 2021, those ratings for each class of ELCC generation enumerated in **Table 2.5** were calculated for each delivery year in the period 2024/2025 through 2032/2033. However, only 2024/2025 values – also shown in **Table 2.5** and compared to July 2021 preliminary ELCC results for 2023/2024 – are binding and applicable to the 2024/2025 Base Residual Auction. Full study results can be found on the PJM website.

2.3.2 — ELCC Concept Development

PJM continues to witness extraordinary growth in energy storage and intermittent generating resources such as wind, solar and other renewable resources. As a result, the manner in which PJM evaluates the contribution of such resources toward resource capacity value has also evolved. Prior to 2021, PJM calculated the resource capacity value of an intermittent resource, and that which historically has been labeled as "limited duration," by a methodology independent of changes to the overall resource mix. This meant that a resource's capacity capability and its contribution toward meeting PJM's resource adequacy requirements would not have been impacted by the amount of renewables and energy storage within the RTO as a whole. This began to draw PJM attention and concern in 2018, given that increasing amounts of intermittent and limited-duration resources impact hourly loss-of-load probability

Table 2.5: ELCC Class Ratings

ELCC Class	ELCC Class Rating for: 2024/2025 BRA (% of Effective Nameplate)	ELCC Class Rating for: 2023/2024 BRA (% of Effective Nameplate)
Onshore Wind	16%	15%
Offshore Wind	37%	40%
Solar Fixed Panel	36%	38%
Solar Tracking Panel	54%	54%
4-Hr Storage	82%	83%
6-Hr Storage	97%	98%
8-Hr Storage	100%	100%
10-Hr Storage	100%	100%
Solar Hybrid Open Loop – Storage Component	82%	82%
Solar Hybrid Closed Loop – Storage Component	82%	82%
Hydro Intermittent	46%	42%
Landfill Gas Intermittent	60%	59%
Hydro With Non-Pumped Storage*	96%	96%

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

(LOLP) risk profile. Without recognizing this dynamic, PJM may be over or under valuing intermittent and limited-duration resource contribution to resource adequacy over time.

Prior to 2021, wind- and solar-powered capacity value was set at each resource's average output over a defined number of summer peak load hours. This approach has two limitations:

1. Output is weighted over all hours equally, regardless of an individual hour's actual contribution to the annual loss-of-load risk.
2. Saturation effect as the amount of intermittent resources in PJM increases is not recognized.

To address these two limitations, PJM performed analysis to assess the reliability value of intermittent resources by using an ELCC methodology that:

1. Measures the performance of each resource over all 8,760 hours of the year
2. Recognizes the performance of the resource over the critical high-load, high-risk hours
3. Recognizes the declining reliability value of wind, solar and storage resources as their penetration level increases

The PJM Capacity Capability Senior Task Force (CCSTF) – created by the Markets and Reliability Committee (MRC) in March 2020 – developed an ELCC methodology suitable to PJM to determine the capacity capability of renewables and storage. The results of the studies that were the outcome of that effort became effective in the second half of 2021, as discussed above in **Section 2.3.1**. PJM filed Tariff and Reliability Assurance Agreement (RAA) changes with FERC on Oct. 30, 2020, based on a member-endorsed solution package. On July 30, 2021, FERC approved PJM's ELCC proposal, requiring the implementation of performing stakeholder-approved revisions to the following PJM Manuals:

1. PJM Manual 20: Resource Adequacy Analysis
2. PJM Manual 21: Rules & Procedures for Determination of Generating Capability
3. PJM Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis

These manuals define ELCC in more detail, the process by which ELCC values are calculated, and how they are used as part of Base Residual Auction capacity market activity.

2.3.3 — Capacity Interconnection Rights for ELCC Resources

The PJM Planning Committee (PC) also initiated a separate stakeholder process in 2021 to review and modify existing CIR request and retention policies, with an emphasis on ELCC resources, including the application of CIRs to the ELCC methodology and UCAP valuation. The PC currently anticipates completing these efforts in time for the 2025/2026 Base Residual Auction in order to provide certainty around ELCC resource CIR values.

Section 3: Transmission Enhancements

3.0: 2021 RTEP Proposal Windows

RTEP Process Context

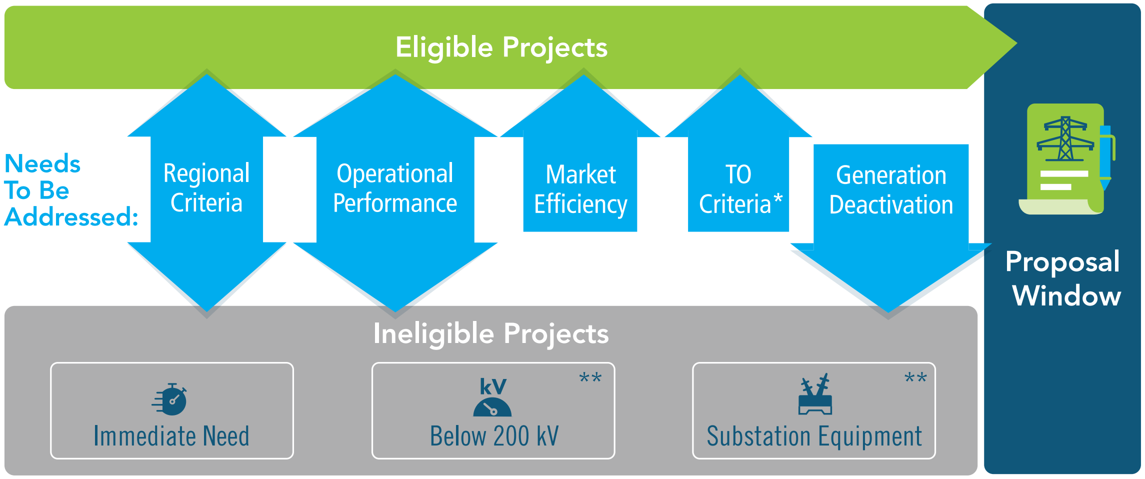
PJM seeks transmission proposals during each RTEP window to address one or more identified needs – reliability, market efficiency, operational performance and public policy. RTEP windows provide an opportunity for both incumbent and non-incumbent transmission developers to submit project proposals to PJM for consideration. When a window closes, PJM proceeds with analytical, constructability and financial evaluations to assess proposals for possible recommendation to the PJM Board. If selected, designated developers become responsible for project construction, ownership, operation, maintenance and financing.

PJM's Manual 14 series addresses the rules governing the RTEP process. In particular, Manual 14F describes PJM's competitive transmission process, including all aspects of analysis and evaluation pertaining to proposal windows. The manual provides one centralized source of business rules for stakeholders and PJM and is available on the PJM website.

Proposal Window Exemptions

The following definitions explain the basis for excluding flowgates (a combination of an overloaded facility and the event that caused the overload) and/or projects from the competitive planning process. Exemptions are designated to the incumbent transmission owner (TO), as described in the PJM Operating Agreement, Schedule 6, Section 1.5.8.

Figure 3.1: RTEP Proposal Window Eligibility



*Note: *TO Criteria is 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.*

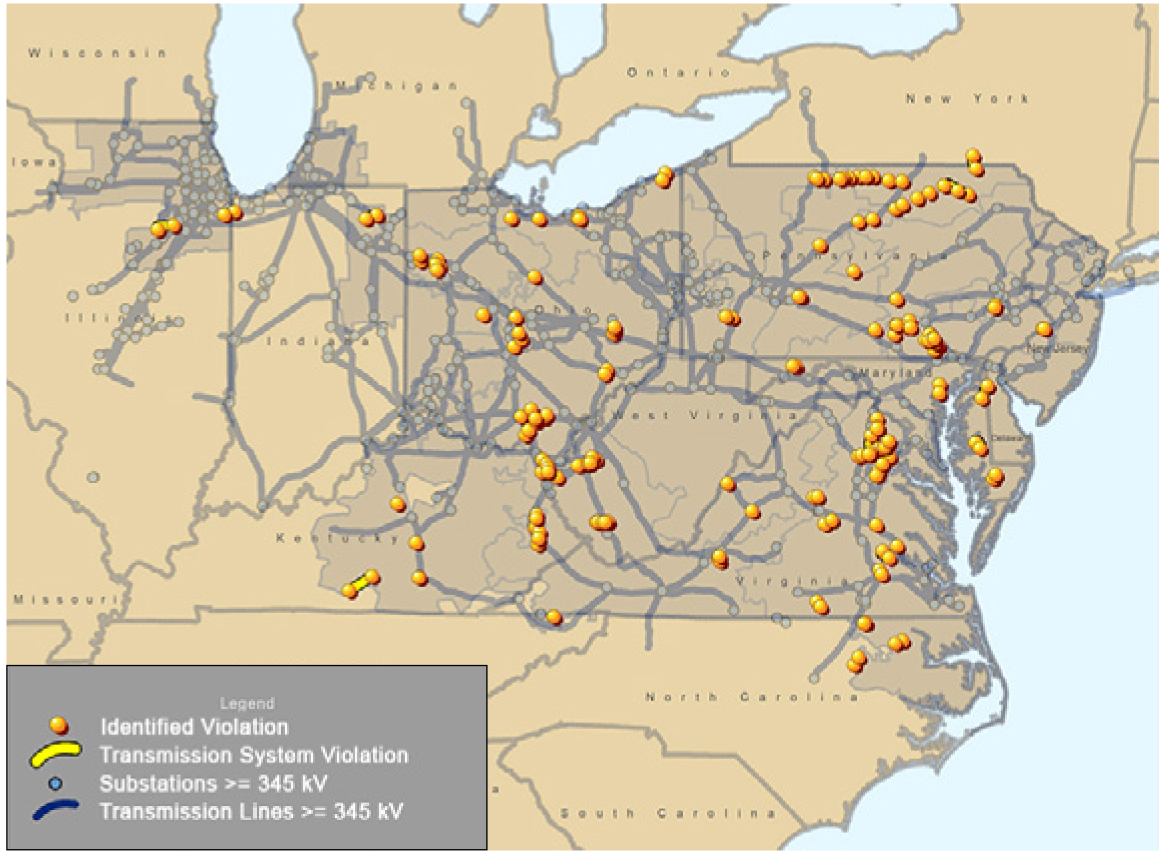
These exemptions, as seen in **Figure 3.1** were developed with input from PJM stakeholders and have been approved by FERC:

- *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 in advance of the required in-service date.
- *Below 200 kV:* Given the high likelihood that the selected solution will be designated to the incumbent TO, solutions below 200 kV are exempted from the competitive process.
- *Substation Equipment:* Due to identification of the limiting element(s) as substation equipment, these projects are designated to the incumbent TO and therefore exempted.

Proposal Window Baseline Reliability Analysis Results

PJM's analysis of 2026 summer, winter and light load conditions identified 405 flowgates, thermal and voltage criteria violations and one end-of-life criteria violation. A summary of the 405 violations is shown in **Map 3.1**.

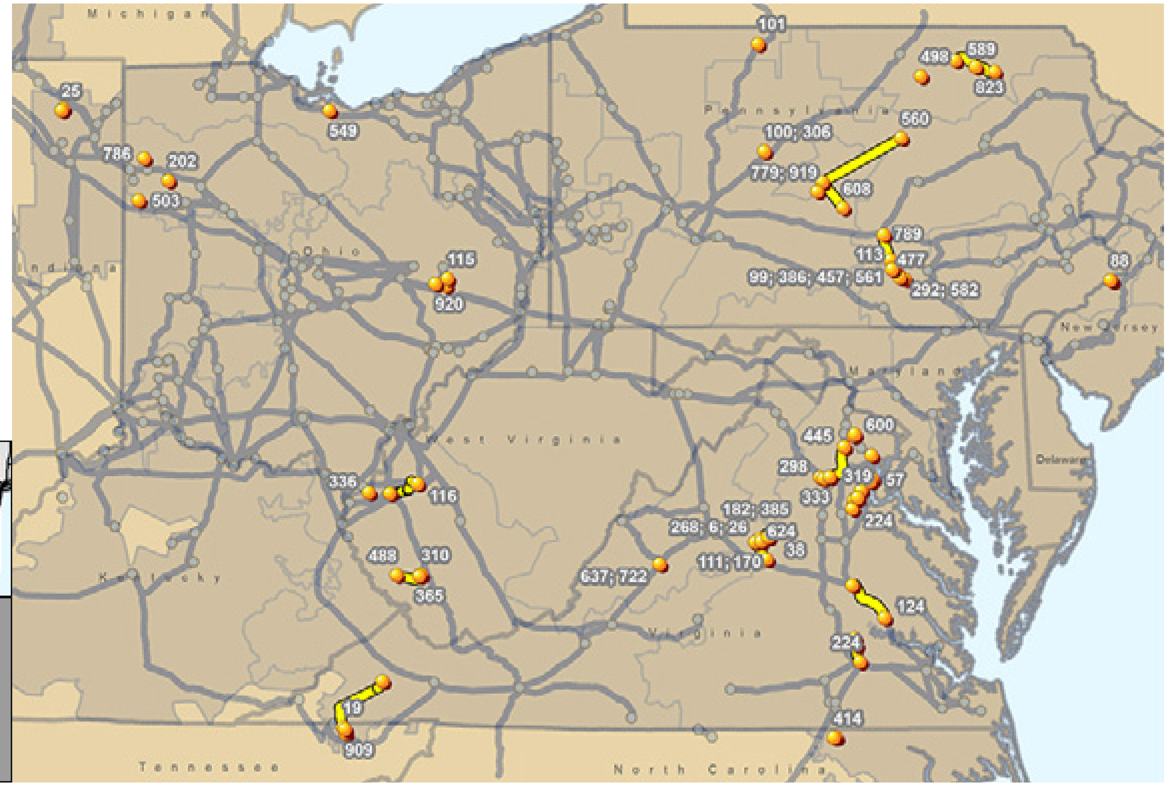
Map 3.1: 2021 RTEP Baseline Thermal and Voltage Criteria Violations



RTEP Proposal Window No. 1 Proposals

RTEP Proposal Window No. 1, which contained 405 flowgate violations, with 161 flowgates open for competition, opened on July 2, 2021, and closed on Aug. 31, 2021. PJM received 57 proposals from 10 entities. Fifteen of the proposals included cost containment provisions, and 21 of the proposals included greenfield construction. The proposals are shown in **Map 3.2** and **Table 3.1**.

Map 3.2: 2021 RTEP Proposal Window No. 1 Submittals



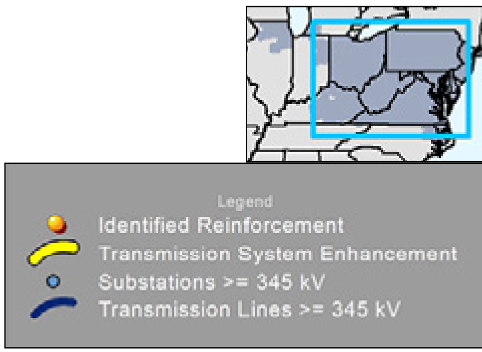


Table 3.1: 2021 RTEP Proposal Window No. 1 Submittals

Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
6	Dominion	230	Thermal, Gen Deliv	VEPCO	Upgrade	No	$16.124	Rebuild line No. 2054 Charlottesville to Hollymeade Tap, 2-636 option.
19	AEP	138	Thermal, Gen Deliv	AEPSCT	Upgrade	No	$2.096	Cut in West Kingsport line.
25	AEP	69	Thermal, Gen Deliv	AEPSCT	Upgrade	No	$0.609	Rebuild Albion-Kendallville.
26	Dominion	230	Thermal, Gen Deliv	VEPCO	Upgrade	No	$35.157	Add 16 MW-64 MWh Battery Energy Storage System (BESS) at Hollymeade substation.
38	Dominion	230	Thermal, Gen Deliv	CNTLTM	Greenfield	Yes	$35.549	Install Sleepy Hollow-Gordonsville 230 kV transmission project.
57	Dominion	115	Thermal, Gen Deliv	VEPCO	Upgrade	No	$24.538	Upgrade Possum Point second 500-230 kV transformers.
88	PECO/PSEG	230	Thermal, Gen Deliv	PE	Upgrade	No	$0.794	Replace a portion of Croydon-Burlington line conductor.

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Table 3.1: 2021 RTEP Proposal Window No. 1 Submittals (Cont.)

Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
99	METED	230	Thermal, Gen Deliv	PPLTO	Greenfield	Yes	$17.822	Upgrade Williams Grove-Allen 115 kV line sourced from Williams Grove 230 kV bus (FE-Allen switchyard).
100	PENELEC			MATLIT	Upgrade	No	$8.775	Shawville 230/115-17.2 kV transformer – Replace 2A transformer with standalone 230/115 kV transformer and install a new 2B transformer for the plant.
101	AP/ PENELEC						$5.067	Pierce Brook substation – Install second 230/115 kV transformer.
111	Dominion			NEETMH	Greenfield	Yes	$23.708	Install Charlottesville to Proffit 230 kV greenfield project.
113	METED			TRNSRC			$12.026	Install Allen-Williams Grove greenfield line.
115	AEP	69		AEPSCT	Upgrade	No	$9.100	Rebuild Salt Fork-Leatherwood.
116				AEPSCT			$56.729	Rebuild Bancroft-Milton.
124	Dominion	500		VEPCO			$58.155	Rebuild line No. 557 Elmont-Chickahominy 500 kV line.
170		230		VEPCO			$10.621	Add a 4.35 ohm series reactor at Hollymeade station on the terminal of line 2054.
182				NEETMH	Greenfield	Yes	$41.922	Install Charlottesville to Gordonsville 230 kV greenfield project.
202	AEP	69		AEPSCT	Upgrade	No	$8.870	Rebuild Delphos area lines.
224	Dominion	230		VEPCO			$93.412	Make improvements to Fredericksburg/Carson/Hopewell area.
268				VEPCO	Greenfield		$33.551	Build a new 230 kV substation at Hollymeade Tap, rebuild 8.72 miles of line No. 2054 and 7.1 miles of line No. 2135.
292	METED	115		CNTLTM		Yes	$15.098	Install Dogwood Run 115/230 kV transmission project.
298	Dominion	230		TRNSRC			$72.876	Install Greenfield Lee district station.
306	PENELEC			MATLIT	Upgrade	No	$5.376	Shawville 230/115-17.2 kV transformer – Purchase a new higher-rated 2A transformer.
310	AEP	69		AEPSCT			$50.191	Rebuild Becco-Pine Gap.
319	Dominion	500		VEPCO			$63.767	Replace two transformers at Ox 500-230 kV.
333		230		VEPCO			$39.692	Line No. 2114 – Reconductor Remington CT to Gainesville-Full and upgrade terminal equipment at Remington CT and Gainesville.
336	AEP	138		AEPSCT	Greenfield		$13.684	Install Cabell station expansion and cut in.
365		69		AEPSCT			$13.048	Install Accoville-Becco 69 kV.
385	Dominion	230		TRNSRC			$65.430	Multi-Driver Project – Install Charlottesville rebuild and greenfield Cismont station.
386	METED	115		TRNSRC		Yes	$20.253	Multi-Driver Project – Install Allen-Williams Grove greenfield line & reconductor.
414	Dominion	230		VEPCO	Upgrade	No	$1.184	Rebuild line No. 2141 Lakeview to Carolina 230 kV.
445				VEPCO			$30.680	Upgrade line No. 2114; Reconductor Remington CT to Gainesville-Full.
457	METED	115		PPLTO	Greenfield	Yes	$15.270	Williams Grove-Allen 115 kV – Upgrade line sourced from Williams Grove 69 kV bus (FE-Allen switchyard).

Table 3.1: 2021 RTEP Proposal Window No. 1 Submittals (Cont.)

Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
477	METED	230	Thermal, Gen Deliv	MATLIT	Upgrade	No	$32.158	Upgrade Northern Loop STATCOM.
488	AEP	69		AEPSCT	Greenfield		$68.798	Install Dehue expansion and line rebuilds.
498	PENELEC	230		MATLIT	Upgrade		$5.311	Grover substation – Install two reactors and install line breakers.
503	AEP	69		CNTLTM	Greenfield	Yes	$14.414	Install LS Rockford-LS West Van Wert 69 kV transmission project.
549	ATSI	345		ATSI	Upgrade	No	$7.595	Construct Hayes second transformer addition.
560	AP	230		CNTLTM	Greenfield	Yes	$135.548	Build Persia-Elimsport 230 kV transmission project.
561	METED	115		PPLTO			$15.617	Install Williams Grove-Allen 115 kV line upgrade sourced from Williams Grove 69 kV bus (PPL-Allen switchyard).
582		500		CNTLTM			$21.583	Install Dogwood Sprint 115/500 kV Transmission Project.
589	PENELEC	115		MATLIT	Upgrade	No	$6.661	Upgrade East Towanda-North Meshoppen 115 kV.
600	Dominion	230		VEPCO			$1.934	Upgrade line 2008 Uprate-Cub Run to Walney.
608	AP			CNTLTM	Greenfield	Yes	$77.592	Build Persia-Yeagertown 230 kV Transmission Project.
624	Dominion			VEPCO	Upgrade	No	$16.503	Rebuild line No. 2054 – Charlottesville to Hollymeade Tap, 2-768.2 option.
637		500					$85.800	Upgrade Occoquan 500-230 kV transformer (OX transformer overload).
722							$5.860	Install an approx. 294 MVAR cap bank at Lexington substation.
779	AP	230		WPenn			$11.926	Create a 230 kV ring bus at Shingletown 230 kV substation.
786	AEP	69		AEPSCT			$1.309	Build Haviland sectionalizing addition.
789	METED	230		MATLIT	Greenfield		$28.543	Install New Allen 115 kV source.
823	PENELEC				Upgrade		$35.274	Upgrade East Towanda-Canyon 230 kV.
909	AEP	138		AEPSCT			$7.424	Perform West Kingsport transformer replacement and line rebuilds.
919	AP	345		WPenn			$1.668	Shingletown 230 kV – Upgrade No. 82 transformer circuit.
920	AEP	69		AEPSCT			$4.952	Perform West Cambridge transformer addition.

RTEP Proposal Window No. 2 Proposals

RTEP Proposal Window No. 2, which contained four flowgate violations for competition, opened on Nov. 3, 2020, and closed on Jan. 12, 2022. The four flowgates were a result of ComEd's recent deactivation updates including Waukegan 7 and 8 and Will County 4 deactivation requests, and the reinstatement of Byron 1 and 2 and Dresden 2 and 3. PJM received 10 proposals from three entities. The proposals are shown in **Map 3.3** and **Table 3.2**. PJM will continue to evaluate these proposals during 2022. This evaluation will also include coordination with MISO.

Map 3.3: 2021 RTEP Proposal Window No. 2 Submittals

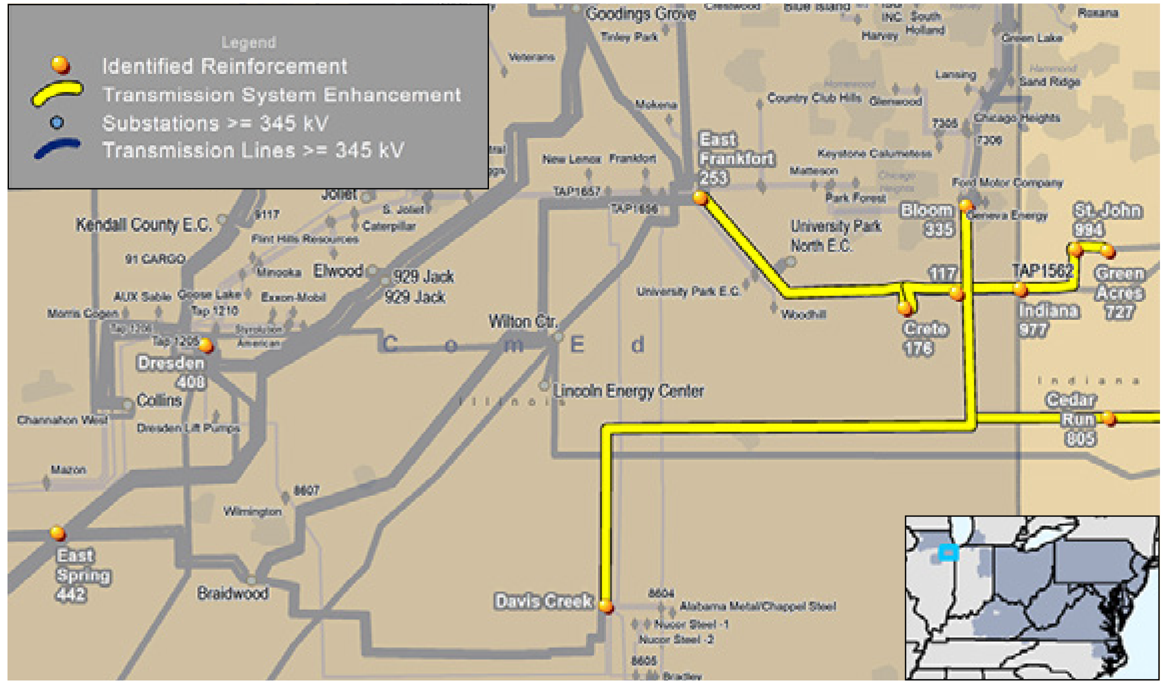

Table 3.2: 2021 RTEP Proposal Window No. 2 Submittals

Proposal ID	Target Zone	kV	Analysis Type	Project Type	Cost ($M)	Project Description
176	ComEd	345	Winter Gen Deliv	Upgrade	$35.70	Reconductor 345 kV E. Frankfort to Crete to St. John transmission line.
805				Greenfield	$16.70	Build Cedar Run 345 kV transmission project.
253				Upgrade	$62.60	Rebuild 345 kV lines 6607/6608 East Frankfort-Crete and 94507/97008 Crete-St. John.
994					$12.00	Install series inductor on line 94507 Crete-St. John.
408					$4.26	Install 345 kV bus tie circuit breaker at Dresden station.
442				Greenfield	$10.40	Construct East Spring 345 kV transmission project.
977				Upgrade	$17.10	Rebuild 345 kV double circuit lines 94507 and 97008 Crete-Indiana.
727					$22.03	Swap 345 kV transmission line at Green Acres and reconductor Crete to St. John 345 kV line.
117				Greenfield	$27.08	Build series reactor along Crete-St John 345 kV line and reconductor Crete to St. John 345 kV line.
335					$47.12	Loop in Bloom-Davis 345 kV line at new NEET-proposed Illinois substation; loop in NEET-owned Crete-St. John 345 kV line at new NEET proposed state line 345 kV substation.

RTEP Proposal Window No. 3 Proposals

RTEP Proposal Window No. 3, which contained three flowgate violations for competition, opened on Nov. 3, 2021, and closed on Dec. 8, 2021. The flowgates were in relation to Public Service Electric and Gas Company's (PSEG) FERC 715 thermal criteria violations. PJM received three proposals from the incumbent TO. The proposals are shown in **Map 3.4** and **Table 3.3**.

NJOSW SAA Proposal Window

The New Jersey Offshore Wind State Agreement Apprach (NJOSW SAA) Proposal Window, which contained 67 flowgate violations for competition opened on April 15, 2021, and closed on Sept. 17, 2021. PJM sought project proposals to build the necessary transmission to meet New Jersey's goal of facilitating the delivery of a total of 7,500 MW of offshore wind by 2035. PJM received 80 proposals from various entities. Evaluation of these proposals continues into 2022.

Map 3.4: 2021 RTEP Proposal Window No. 3 Submittals

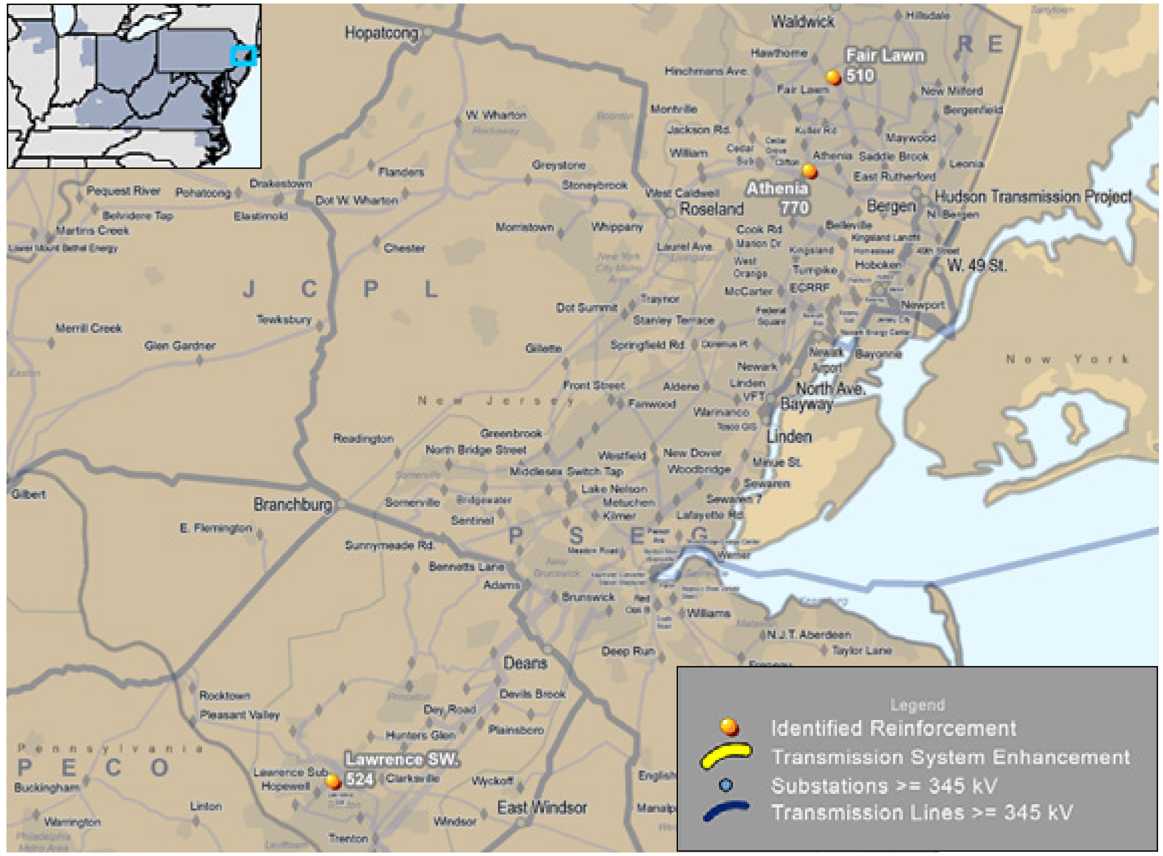

Table 3.3: 2021 RTEP Proposal Window No. 3 Submittals

Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
510	PSEG	230/138	FERC 715 Other	PSEG	Upgrade	No	$4.28	Replace Fair Lawn 230-138 kV transformer 220-1.
524		230/69					$12.95	Replace Lawrence switching station 230-69 kV transformer 220-4 and its associated circuit switchers with a new larger capacity transformer with load tap changer (LTC) and new dead tank circuit breaker. Install a new 230 kV gas insulated breaker, associated disconnects, overhead bus, and other necessary equipment to complete the bay within the Lawrence 230 kV switchyard.
770		230/138					$12.59	Replace Athenia 230-138 kV transformer 220-1.

3.1: Transmission Owner Criteria

Transmission Owner FERC Form 715 Planning Criteria

The PJM Operating Agreement specifies that individual TO planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions 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. PJM applies TO criteria to all facilities included in the PJM Open Access Transmission Tariff (OATT) facility list.

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

Map 3.5: Transmission Owner Criteria Projects

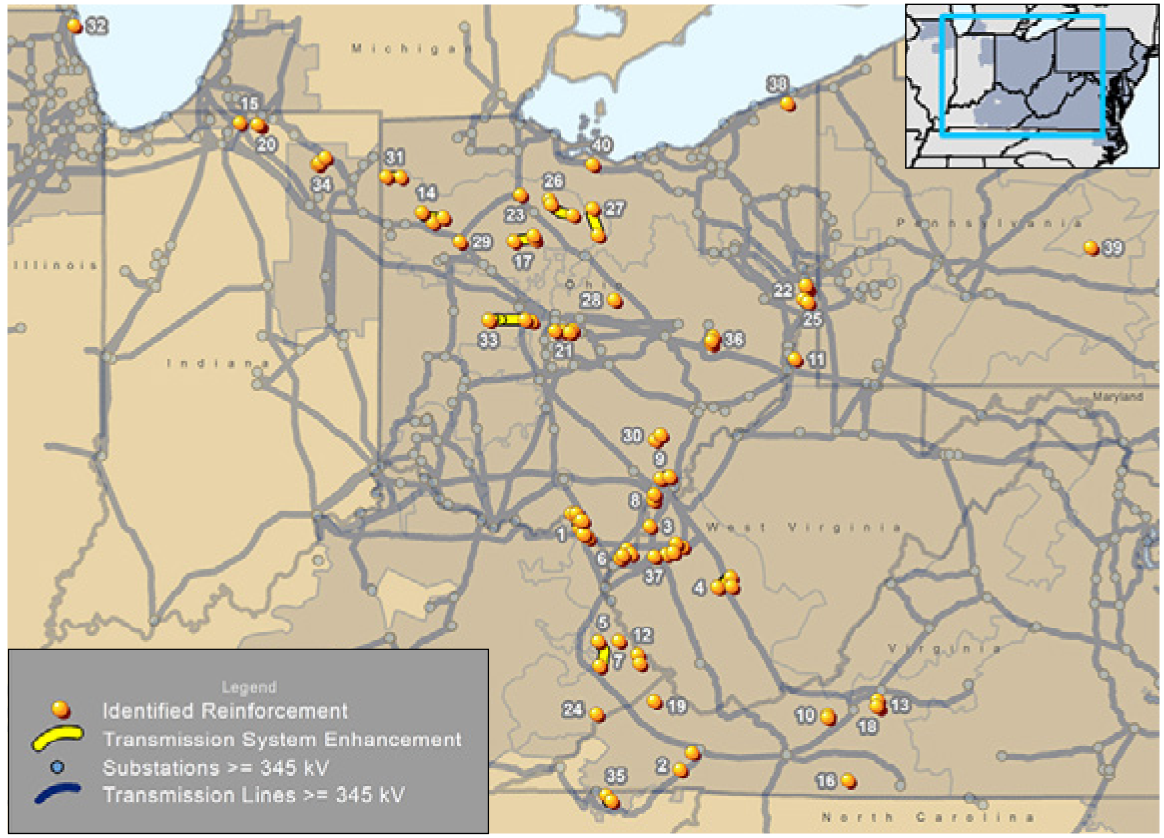

Table 3.4: Transmission Owner Criteria Projects

Map ID	Upgrade ID	Description	TO Zone	Cost Estimate ($M)	Required In-Service	Projected In-Service
1	B2604.1	Remove ~11.32 miles of the 69 kV line between Millbrook Park and Franklin Furnace.	AEP	$1.13	6/1/2019	4/15/2025
	B2604.10	Build a new station (Althea) with a 138/69 kV, 90 MVA transformer. The 138 kV side will have a single 2000A 40 kA circuit breaker, and the 69 kV side will be a 2000A 40 kA three-breaker ring bus.		$11.07		
	B2604.11	Perform remote end work at Hanging Rock, East Wheelersburg and North Haverhill 138 kV.		$0.06		
	B2604.2	At Millbrook Park station, add a new 138/69 kV transformer No. 2 (90 MVA) with 3000A 40 kA breakers on the high and low side. Replace the 600A MOAB switch and add a 3000A circuit switcher on the high side of transformer No. 1.		$3.05		

Table 3.4: Transmission Owner Criteria Projects (Cont.)

Map ID	Upgrade ID	Description	TO Zone	Cost Estimate ($M)	Required In-Service	Projected In-Service
1 Cont.	B2604.3	Replace Sciotoville 69 kV station with a new 138/12 kV in-out station (Cottrell) with 2000A line MOABs facing Millbrook Park and East Wheelersburg 138 kV.	AEP	$1.40	6/1/2019	4/15/2025
	B2604.4	Tie Cottrell switch into the Millbrook Park-East Wheelersburg 138 kV circuit by constructing 0.50 miles of line using 795 ACSR 26/7 Drake (SE 359 MVA).		$1.96		
	B2604.5	Install a new 2000A three-way phase-over-phase switch outside of Texas Eastern 138 kV substation (Sadiq switch).		$1.08		
	B2604.6	Replace the Wheelersburg 69 kV station with a new 138/12 kV in-out station (Sweetgum) with a 3000A 40 kA breaker facing Sadiq switch and a 2000A, 138 kV MOAB facing Althea.		$2.16		
	B2604.7	Build ~1.4 miles of new 138 kV line using 795 ACSR 26/7 Drake (SE 359 MVA) between the new Sadiq switch and the new Sweetgum 138 kV stations.		$3.41		
	B2604.8	Remove the existing 69 kV Hayport Road switch.		$0.10		
	B2604.9	Rebuild ~2.3 miles along existing right of way from Sweetgum to the Hayport Rd. switch 69 kV location as 138 kV single circuit and rebuild ~2 miles from the Hayport Road switch to Althea 69 kV with double circuit 138 kV construction, one side operated at 69 kV to continue service to K.O. Wheelersburg, using 795 ACSR 26/7 Drake (SE 359 MVA).		$10.76		
2	B3278.1	Saltville station – Replace high side MOAB switches on the high side of the 138/69/34.5 kV T1 with a high side circuit switcher.		$0.72	12/1/2025	12/1/2025
	B3278.2	Meadowview station – Replace existing 138/69/34.5 kV transformer T2 with a new 130 MVA, 138/69/13 kV transformer.		$3.14		
	B3278.3	Saltville station – Install two 138 kV breakers and bus diff protection.		$0.36		
3	B3279	Install a new 138 kV, 21.6 MVAR cap bank and circuit switcher at Apple Grove station.		$1.00	6/1/2025	6/1/2025
4	B3280	Rebuild the existing Cabin Creek-Kelly Creek 46 kV line (to structure 366-44), ~4.4 miles. This section is double circuit with the existing Cabin Creek-London 46 kV line, so a double circuit rebuild would be required.		$17.90		
5	B3281	Install 138 kV circuit switcher on the 138/69 kV transformer No. 1 and 138/34.5 kV transformer No. 2 at Dewey. Install 138 kV, 2000A 40 kA breaker on Stanville line at Dewey 138 kV substation.		$1.40	12/1/2025	12/1/2025
6	B3282.1	Install a second 138 kV circuit utilizing 795 ACSR conductor on the open position of the existing double circuit towers from East Huntington-North Proctorville. Remove the existing 34.5 kV line from East Huntington-North Chesapeake and rebuild this section to 138 kV served from a new phase-over-phase switch off the new East Huntington-North Proctorville 138 kV No. 2 line.		$7.10	6/1/2025	6/1/2025
	B3282.2	Install a 138 kV, 40 kA circuit breaker at North Proctorville.		$1.40		
	B3282.3	Install a 138 kV, 40 kA circuit breaker at East Huntington.		$1.10		
	B3282.4	Convert the existing 34/12 kV North Chesapeake to a 138/12 kV station.		$0.80		
7	B3283	Replace the existing Inez 138/69 kV, 50 MVA autotransformer with a 138/69 kV 90 MVA autotransformer.		$2.96	12/1/2025	12/1/2025
8	B3284	Rebuild ~5.44 miles of 69 kV line from Lock Lane to Point Pleasant.		$13.50	6/1/2025	6/1/2025
9	B3285	Replace the Meigs 69 kV, 4/0 copper station riser toward Gavin and rebuild the section of the Meigs-Hemlock 69 kV circuit from Meigs to approximately structure No. 40 (~4 miles) replacing the line conductor 4/0 ACSR with the line conductor size 556.5 ACSR.		$12.14		9/15/2024
10	B3286	Reconductor the first three spans from Merrimac station to Str. 464-3 of 3/0 ACSR conductor utilizing 336 ACSR on the existing Merrimac-Midway 69 kV circuit.		$0.45		6/1/2025
11	B3287	Upgrade 69 kV risers at Moundsville station toward George Washington.		$0.05		9/1/2024

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Table 3.4: Transmission Owner Criteria Projects (Cont.)

Map ID	Upgrade ID	Description	TO Zone	Cost Estimate ($M)	Required In-Service	Projected In-Service
12	B3288.1	Construct ~2.75 miles Orinoco-Stone 69 kV transmission line in the clear between Orinoco station and Stone station.	AEP	$9.23	12/1/2025	12/1/2025
	B3288.2	Construct ~3.25 miles Orinoco-New Camp 69 kV transmission line in the clear between Orinoco station and New Camp station.		$9.95		
	B3288.3	Stone substation – circuit breaker A to remain in place and be utilized as T1 low-side breaker. Circuit breaker B to remain in place and be utilized as new Hatfield (via Orinoco and New Camp) 69 kV line breaker. Add new 69 kV circuit breaker E for Coleman line exit.		$0.66		
	B3288.4	Reconfigure the New Camp 69 kV tap, which includes access road improvements/installation, temporary wire and permanent wire work along with dead-end structures installation.		$0.45		
	B3288.5	New Camp substation – Rebuild the 69 kV bus, add 69 kV MOAB W and replace the 69 kV ground switch Z1 with a 69 kV circuit switcher on the New Camp transformer.		$1.18		
13	B3289.1	Roanoke Station – Install high-side circuit switcher on 138/69/12 kV T5.		$1.10	6/1/2025	6/1/2025
	B3289.2	Huntington Court Station – Install high-side circuit switcher on 138/69/34.5 kV T1.		$1.42		
14	B3290.1	Build 9.4 miles of single circuit 69 kV line from Roselms to near East Ottoville 69 kV switch.		$13.70		10/25/2024
	B3290.2	Rebuild 7.5 miles of double circuit 69 kV line between East Ottoville switch and Kalida station (combining with the new Roselms to Kalida 69 kV circuit).		$23.60		
	B3290.3	Roselms switch – Install a new three-way 69 kV, 1200A phase-over-phase switch, with sectionalizing capability.		$0.60		
	B3290.4	Kalida 69 kV station – Terminate the new line from Roselms switch. Move the CS XT2 from high side of T2 to the high side of T1. Remove existing T2 transformer.		$1.00		
15	B3291	Replace the Russ St. 34.5 kV switch.		$1.50		12/1/2022
16	B3292	Replace existing 69 kV capacitor bank at Stuart station with a 17.2 MVAR capacitor bank.		$0.00	12/1/2025	
17	B3293	Replace 2/0 copper entrance span conductor on the South Upper Sandusky 69 kV line and 4/0 copper Risers/Bus conductors on the Forest line at Upper Sandusky 69 kV station.		$0.54	6/1/2025	6/1/2025
18	B3294	Replace existing 69 kV disconnect switches for circuit breaker "C" at Walnut Avenue station.		$0.00		
19	B3295	Grundy 34.5 kV – Install a 34.5 kV 9.6 MVAR cap bank.		$0.80		
20	B3296	Rebuild the overloaded portion of the Concord-Whitaker 34.5 kV line (1.13 miles). Rebuild is double circuit and will utilize 795 ACSR conductor.		$2.80		3/17/2024
21	B3297.1	Rebuild 4.23 miles of 69 kV line between Sawmill and Lazelle station, using 795 ACSR 26/7 conductor.		$12.00		6/1/2025
	B3297.2	Rebuild 1.94 miles of 69 kV line between Westerville and Genoa stations, using 795 ACSR 26/7 conductor.		$5.90		
	B3297.3	Replace risers and switchers at Lazelle, Westerville and Genoa 69 kV stations. Upgrade associated relaying accordingly.		$1.90		
22	B3298	Rebuild 0.8 miles of double circuit 69 kV line between South Toronto and West Toronto. Replace 219 kcmil ACSR with 556 ACSR.		$2.83		
	B3298.1	Replace the 69 kV breaker D at South Toronto station with 40 kA breaker.		$0.70		
23	B3299	Rebuild 0.2 miles of the West End Fostoria-Lumberjack switch 69 kV line with 556 ACSR (Dove) conductors. Replace jumpers on West End Fostoria line at Lumberjack switch.		$0.47		
24	B3307	Rebuild Fleming station in the clear; Replace 138/69 kV Fleming transformer No.1 with 138/69 kV, 130 MVA transformer with high-side 138 kV circuit breaker; Install a five-breaker 69 kV ring bus on the low side of the transformer, replace 69 kV circuit switcher AA, replace 69/12 kV transformer No. 3 with 69/12 kV, 30 MVA transformer, replace 12 kV circuit breaker A and D. Retire existing Fleming substation.		$21.10	12/1/2025	12/1/2025

Table 3.4: Transmission Owner Criteria Projects (Cont.)

Map ID	Upgrade ID	Description	TO Zone	Cost Estimate ($M)	Required In-Service	Projected In-Service
25	B3308	Reconductor and rebuild one span of T-line on the Fort Steuben-Sunset Blvd. 69 kV branch with 556 ACSR.	AEP	$0.73	6/1/2025	6/1/2025
26	B3309	Rebuild 1.75 miles of the Greenlawn-East Tiffin line section of the Carrothers-Greenlawn 69 kV circuit containing 133 ACSR conductor with 556 ACSR conductor. Upgrade relaying as required.	AEP	$3.45	6/1/2025	6/1/2025
27	B3310.1	Rebuild 10.5 miles of the Howard-Willard 69 kV line utilizing 556 ACSR conductor.	AEP	$19.00	6/1/2025	6/1/2025
27	B3310.2	Upgrade relaying at Howard 69 kV station.	AEP	$0.23	6/1/2025	6/1/2025
27	B3310.3	Upgrade relaying at Willard 69 kV station.	AEP	$0.23	6/1/2025	6/1/2025
28	B3312	Rebuild ~4 miles of existing 69 kV line between West Mount Vernon and Mount Vernon stations. Replace the existing 138/69 kV transformer at West Mount Vernon with a larger 90 MVA unit along with existing 69 kV breaker ‘C.’	AEP	$12.93	6/1/2025	6/1/2025
29	B3313	Add 40 kA circuit breakers on the low and high side of East Lima 138/69 kV transformer.	AEP	$1.20	6/1/2025	6/1/2025
30	B3314.1	Install a new 138/69 kV, 130 MVA transformer and associated protection at Elliot station.	AEP	$3.00	6/1/2025	10/25/2024
30	B3314.2	Perform work at Strouds Run station to retire 138/69/13 kV, 33.6 MVA transformer No. 1 and install a dedicated 138/13 kV distribution transformer.	AEP	$0.00	6/1/2025	10/25/2024
31	B3315	Upgrade Relaying on Mark Center-South Hicksville 69 kV line and replace Mark Center cap bank with a 7.7 MVAR unit.	AEP	$1.25	6/1/2025	6/1/2025
32	B3317	Modify backup relay clearing times at the 138 kV STA16 Waukegan station.	ComEd	$0.26	6/1/2023	6/1/2023
33	B3341.1	Marysville Substation – Install two 69 kV, 16.6 MVAR cap banks; Install five 69 kV circuit breakers; Upgrade station relaying; Replace 600A wave trap on the Marysville-Kings Creek 69 kV (6660) circuit.	DAY	$2.43	6/1/2026	3/1/2026
33	B3341.2	Darby substation – Upgrade remote end relaying at Darby 69 kV substation.	DAY	$0.25	6/1/2026	3/1/2026
33	B3341.3	Kings Creek – Upgrade remote end relaying at Kings Creek 69 kV substation.	DAY	$0.25	6/1/2026	3/1/2026
34	B3343	Rebuild ~0.3 miles of overloaded 69 kV line between Albion-Philips switch and Philips Switch-Brimfield switch with 556 ACSR conductor.	AEP	$0.61	6/1/2026	6/1/2026
25	B3344.1	Install two 138 kV circuit breakers in the M and N strings in the breaker-and-a half configuration in West Kingsport station 138 kV yard to allow the Clinch River-Moreland Dr. 138 kV to cut in the West Kingsport station.	AEP	$1.85	11/1/2026	11/1/2026
25	B3344.2	Upgrade remote end relaying at Riverport 138 kV station due to the line cut in at West Kingsport station.	AEP	$0.25	11/1/2026	11/1/2026
36	B3345.1	Rebuild ~4.2 miles of overloaded sections of the 69 kV line between Salt Fork switch and Leatherwood switch with 556 ACSR.	AEP	$9.06	6/1/2026	6/1/2026
36	B3345.2	Update relay settings at Broom Road station.	AEP	$0.04	6/1/2026	6/1/2026
37	B3347.1	Rebuild approximately 20 miles of line between Bancroft and Milton stations with 556 ACSR conductor.	AEP	$56.55	11/1/2026	6/30/2026
37	B3347.2	Replace the jumpers around Hurrican switch with 556 ACSR.	AEP	$0.01	11/1/2026	6/30/2026
37	B3347.3	Replace the jumpers around Teays switch with 556 ACSR.	AEP	$0.01	11/1/2026	6/30/2026
37	B3347.4	Winfield station – Update relay settings to coordinate with remote ends on line rebuild.	AEP	$0.05	11/1/2026	6/30/2026
37	B3347.5	Bancroft station – Update relay settings to coordinate with remote ends on line rebuild.	AEP	$0.03	11/1/2026	6/30/2026
37	B3347.6	Milton Station – Update relay settings to coordinate with remote ends on line rebuild.	AEP	$0.03	11/1/2026	6/30/2026
37	B3347.7	Putnam Village station – Update relay settings to coordinate with remote ends on line rebuild.	AEP	$0.03	11/1/2026	6/30/2026

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Table 3.4: Transmission Owner Criteria Projects (Cont.)

Map ID	Upgrade ID	Description	TO Zone	Cost Estimate ($M)	Required In-Service	Projected In-Service
38	B3680	At Sanborn – Replace limiting substation conductors on Ashtabula 138 kV exit to make transmission line conductor the limiting element.	ATSI	$0.30	6/1/2026	6/1/2026
39	B3681	Upgrade the Shingletown No. 82 230-46 kV transformer circuit by installing a 230 kV breaker and disconnect switches, removing existing 230 kV switches, replacing 46 kV disconnect switches, replacing limiting substation conductor, and installing/replacing relays.	AP	$1.66		6/1/2025
40	B3682	Install a second 345/138 kV transformer at Hayes, 448 MVA nameplate rating. Add one 345 kV circuit breaker (3000A) to provide transformer high-side connection between breaker B-18 and the new breaker. Connect the new transformer low side to the 138 kV bus. Add one 138 kV circuit breaker (3000A) at Hayes 138 kV substation between B-42 and the new breaker. Relocate the existing 138 kV No. 1 capacitor bank between B-42 and the new breaker. Protection per FirstEnergy standard.	ATSI	$7.59	6/1/2026	6/1/2026

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

3.2: Supplemental Projects

Supplemental projects are not required for compliance with system reliability, operational performance or market efficiency economic criteria, as determined by PJM. They are 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 non-Bulk Electric System (BES) facilities, 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.

While not subject to PJM Board approval, supplemental projects are included in PJM's RTEP models. FERC-approved and TO owned, Attachment M3 of the PJM Tariff provides additional procedures that PJM and TOs follow for supplemental projects. PJM, in its role as a facilitator in the Attachment M3 process, is responsible for the following:

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

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 Attachment M3 process.

Figure 3.2: Primary Supplemental Project Drivers

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

Figure 3.3: Attachment M3 Process for Supplemental Projects

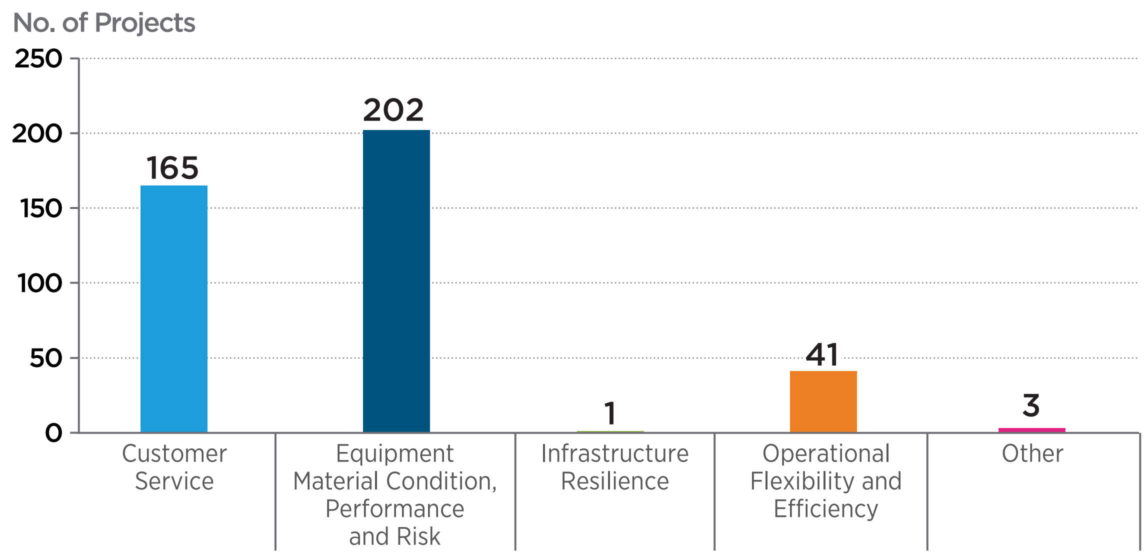
*Subregional RTEP Stakeholder Committee

The Attachment M3 process leverages PJM's Transmission Expansion Advisory Committee (TEAC) and subregional RTEP committees, which provides stakeholders a meaningful opportunity to participate and provide feedback, including written comments, throughout the transmission planning process for supplemental projects, as shown in **Figure 3.3**. Stakeholders interested in providing feedback can do so via PJM's Planning Community.

2021 Supplemental Projects

PJM evaluated approximately $3.3 billion of TO supplemental projects in 2021. **Figure 3.4** shows a breakdown of supplemental solutions by driver, presented at TEAC and subregional RTEP committees over the past year, and suggests that the largest driver is equipment material condition, performance and risk. In 2021, projects driven solely by equipment material condition, performance and risk add up to a total of approximately $1.6 billion, while projects driven by customer service requests and operational flexibility and efficiency totaled approximately $615 million and $154 million, respectively. The remaining $931 million are required by projects with more than one driver.

Figure 3.4: 2021 Supplemental Projects by Driver



The 2021 RTEP supplemental analysis included an evaluation of potential overlap between supplemental projects and a confidential set of "end-of-life" facilities, identified by the TOs. This process was approved by FERC in December 2020 as part of updates to the Attachment M-3 process, documented in PJM's Operating Agreement.

3.3: Generator Deactivations

PJM received 52 deactivation notices, including new requests and revisions to existing requests, totaling 10,607 MW during 2021. **Map 3.6** and **Table 3.5** show the 13 generators being deactivated with a capacity greater than or equal to 100 MW. The remaining included 35 generators under 100 MW with a combined capacity of 453 MW, and four generators that rescinded their deactivation notices. Deactivation notifications in 2021 included 11 coal unit deactivations for a total of 5,811 MW. PJM completed the required analysis to identify reliability criteria violations caused by deactivations. A number of new baseline upgrades were identified for the deactivation notifications in 2021. Several deactivations required completion of existing baseline enhancements, and others had no reliability impacts identified.

PJM requested the Indian River No. 4 unit to remain operational beyond the requested generation deactivation date to allow time for completion of required transmission upgrades. All other units studied in 2021 can retire as requested; operational flexibility will allow PJM to bridge any delays with the completion of required transmission enhancements. On Sept. 15, 2021, PJM received reinstatement notifications from Exelon for the Byron 1 and 2, and Dresden 2 and 3 units, totaling 4,108 MW. These units will not be deactivating.

Map 3.6: Deactivation Notifications in 2021 Greater Than or Equal to 100 MW

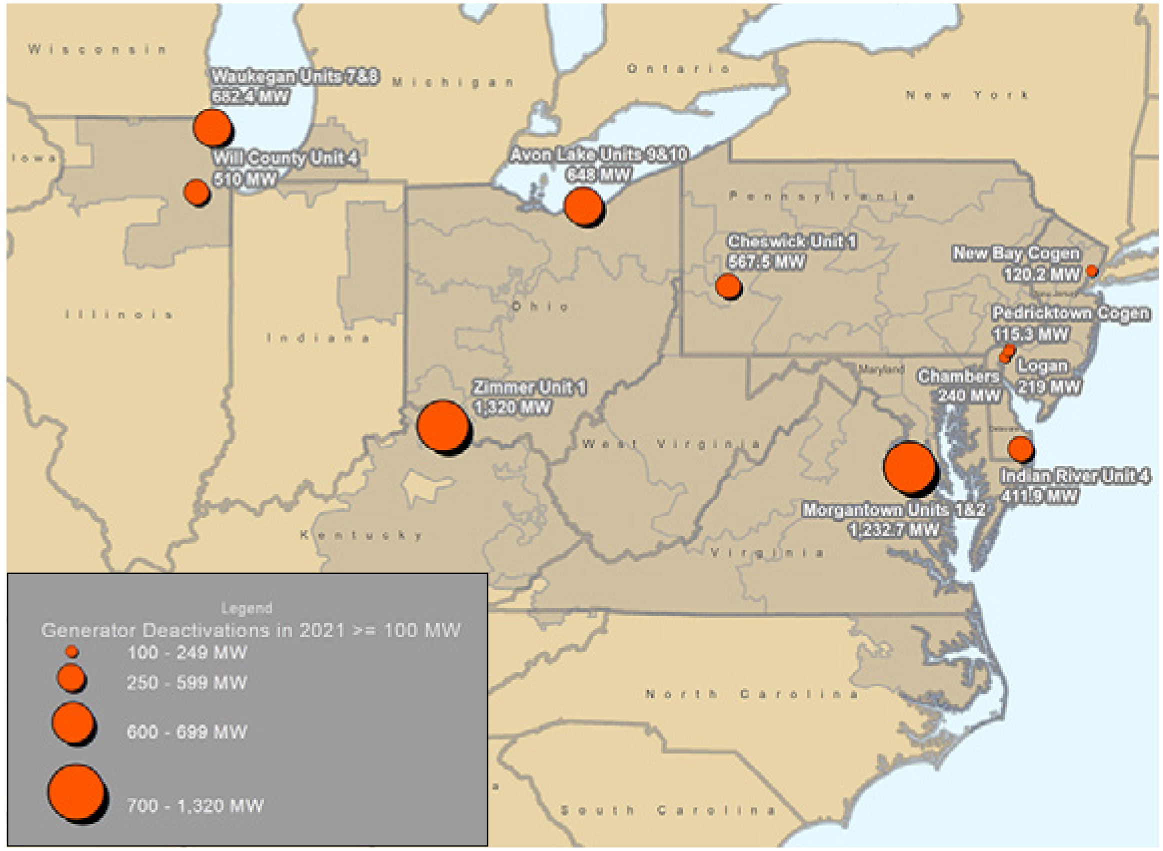


Table 3.5: Deactivation Notifications in 2021 Greater Than or Equal to 100 MW

<table>
<tr><th>Unit</th><th>Capacity (MW)</th><th>TO Zone</th><th>Age (Years)</th><th>Fuel Type</th><th>Request Submittal Date</th><th>Actual/Projected Deactivation Date</th></tr>
<tr><td>Logan</td><td>219</td><td rowspan="2">AE</td><td>27</td><td rowspan="3">Coal</td><td rowspan="2">12/29/2021</td><td rowspan="2">4/1/2022</td></tr>
<tr><td>Chambers CCLP</td><td>240</td><td>27</td></tr>
<tr><td>Zimmer 1</td><td>1,320</td><td>DEO&K</td><td>30</td><td>7/19/2021</td><td rowspan="7">5/31/2022</td></tr>
<tr><td>New Bay Cogen CC</td><td>120</td><td>PSEG</td><td>28</td><td rowspan="2">Natural Gas</td><td rowspan="2">7/15/2021</td></tr>
<tr><td>Pedricktown Cogen CC</td><td>115</td><td>AE</td><td>29</td></tr>
<tr><td>Will County 4</td><td>510</td><td rowspan="3">ComEd</td><td>58</td><td rowspan="8">Coal</td><td rowspan="4">6/30/2021</td></tr>
<tr><td>Waukegan 8</td><td>354</td><td>59</td></tr>
<tr><td>Waukegan 7</td><td>328</td><td>63</td></tr>
<tr><td>Indian River 4</td><td>412</td><td>DP&L</td><td>41</td></tr>
<tr><td>Cheswick 1</td><td>568</td><td>DLCO</td><td>51</td><td rowspan="4">6/9/2021</td><td rowspan="2">4/1/2022</td></tr>
<tr><td>Avon Lake 9</td><td>627</td><td>ATSI</td><td>51</td></tr>
<tr><td>Morgantown Unit 2</td><td>619</td><td rowspan="2">PEPCO</td><td>50</td><td rowspan="2">5/31/2022</td></tr>
<tr><td>Morgantown Unit 1</td><td>613</td><td>51</td></tr>
</table>

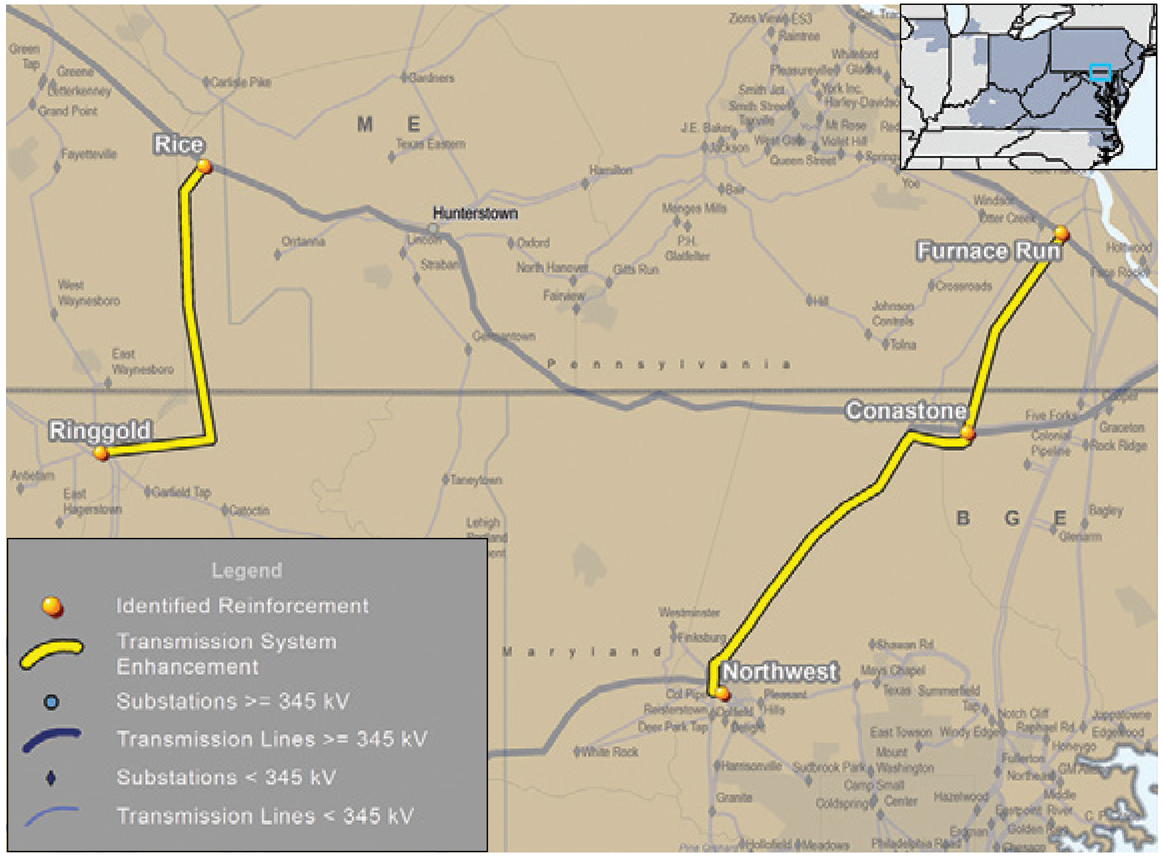
3.4: 2021 Re-Evaluations

As part of each RTEP cycle, PJM evaluates how changing input assumptions impact the results of analysis. Individual generator or load modeling changes are studied as a sensitivity to understand their impact to the transmission system. But, when a large set of input assumptions change, a full re-evaluation of these changing impact assumptions is required. This re-evaluation, known as a retool, allows for assumptions to be updated in the model used for analysis and re-analyzed to understand their impacts.

As part of the 2021 RTEP, PJM performed a sensitivity study to determine reliability impacts associated with the removal of the 9A project, shown on **Map 3.7,** due to permitting risks. The study was performed on the 2026 RTEP case. The 9A project was proposed to address a congestion identified in the 2014/2015 long-term Market Efficiency window. The evaluation resulted in multiple criteria violations.

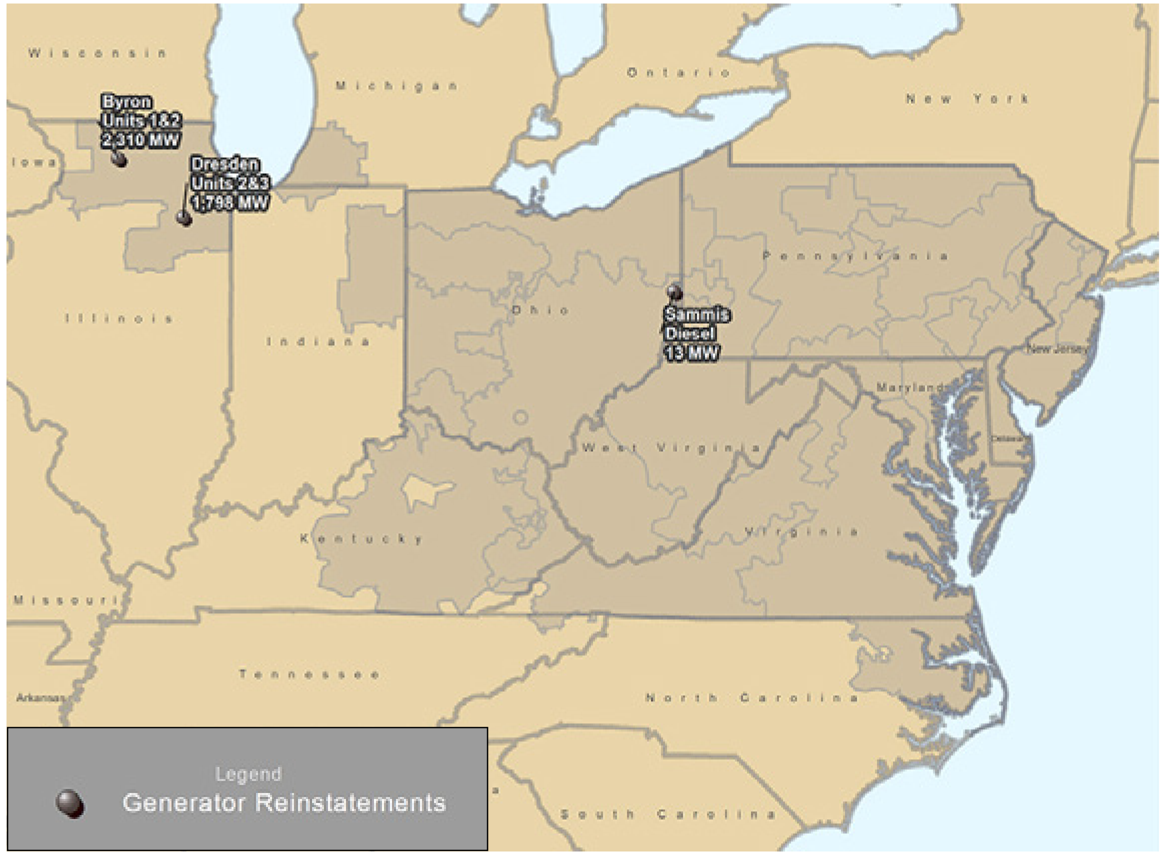
On Sept. 22, 2021, the PJM Board endorsed PJM's recommendation to suspend Project 9A due to permitting risks. PJM will remove Project 9A from the 2022 RTEP model to determine the need for any reliability reinforcements.

Map 3.7: Project 9A – RTEP Baseline Projects B2743 and B2752



Additionally, PJM performed a retool of the 2026 RTEP analysis, driven by the withdrawn deactivation of the Dresden units 2 and 3, the Byron units 1 and 2 and Sammis Diesel shown in **Map 3.8**, which had previously announced their intent to deactivate. This retool led to the cancellation of baseline upgrades, previously identified for these units to deactivate without creating reliability criteria violations.

Map 3.8: Withdrawn Deactivations



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 process (SERTP), shown on **Map 3.9**.

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

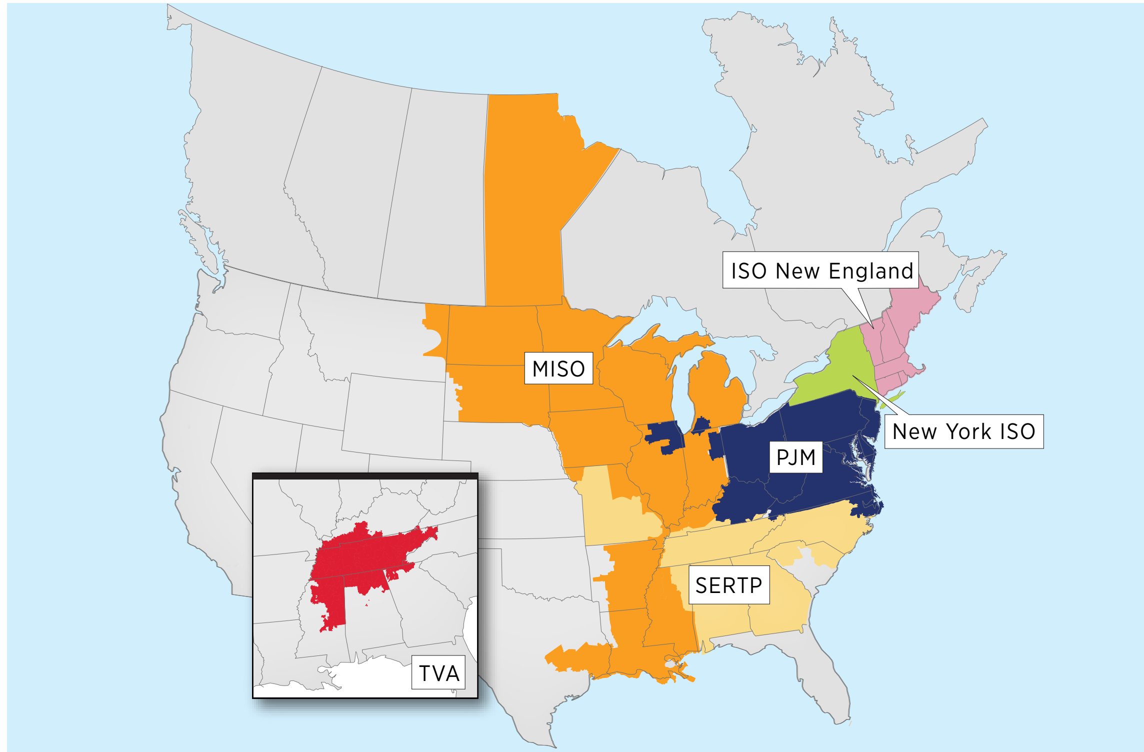
Interregional Agreements

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 adversely impact efficient market administration. The planning processes applicable to each of PJM's three external transmission interfaces include provisions to address issues of mutual concern, including:

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

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

Map 3.9: PJM Interregional Planning



3.5.2 — MISO

The 2021 planning efforts under Article IX of the MISO/PJM joint operating agreement ensure the coordination of regional reliability, market efficiency, interconnection requests and deactivation notifications. Interconnection-driven network transmission enhancements are summarized in **Section 4.** Deactivation-driven baseline analyses are summarized in **Section 3.3.** Annually, stakeholder input and feedback to the interregional planning process is coordinated through the MISO/PJM Interregional Planning Stakeholder Advisory Committee (IPSAC).

Following the annual issues review in the first quarter of 2021, PJM and MISO confirmed their commitment to identify market efficiency issues in the fourth quarter.

In 2020, PJM identified two Market-to-Market congestion drivers as candidates for potential interregional market efficiency projects: Duff to Francisco 345 kV line and Gibson to Francisco 345 kV line, both in the Duke Energy Indiana area. However, upon further study in 2021, and in consideration of MISO approved upgrades, the congestion for both drivers was found to be mitigated, as announced at the March 9, 2021, TEAC meeting.

Additionally, the interregional planning process sought to identify interregional reliability projects that were more efficient or cost effective than the alternative regional plans. No drivers for a potential interregional reliability project were identified in 2021.

Based on the annual issues review and stakeholder feedback, no significant drivers for other interregional studies were identified. No other interregional studies were conducted under the Coordinated System Plan (CSP) in 2021.

3.5.3 — New York ISO and ISO New England

In 2021, PJM, the New York ISO and ISO New England reviewed the status of the ongoing work plan and anticipated 2022 activities. The 2021 work included continued coordination, a review of transmission needs and solutions proposed by neighboring systems, coordination of the interconnection queue, long-term firm transmission service, and transmission projects that potentially impact interregional system performance. The group continues discussion on potential coordination/collaboration for an interregional offshore wind study. The group continues to seek opportunities for interregional transmission. The compiliation of the next Northeast Coordinated System Plan is anticipated by the second quarter of 2022.

3.5.4 — Adjoining Systems South of PJM

Interregional planning activities with entities south of PJM are conducted mainly under the auspices of the SERTP process and SERC Reliability Corp.

Southeastern Regional Transmission Planning

PJM and the SERTP, shown earlier on **Map 3.9**, continued interregional data exchange and interregional coordination during 2021. 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 LG&E and KU Energy. Duke Energy and LG&E and KU Energy are directly connected to PJM. Of the non-jurisdictional entities, only TVA is directly connected to PJM. The remaining five SERTP participants are planning areas south and west of Duke Energy and TVA.

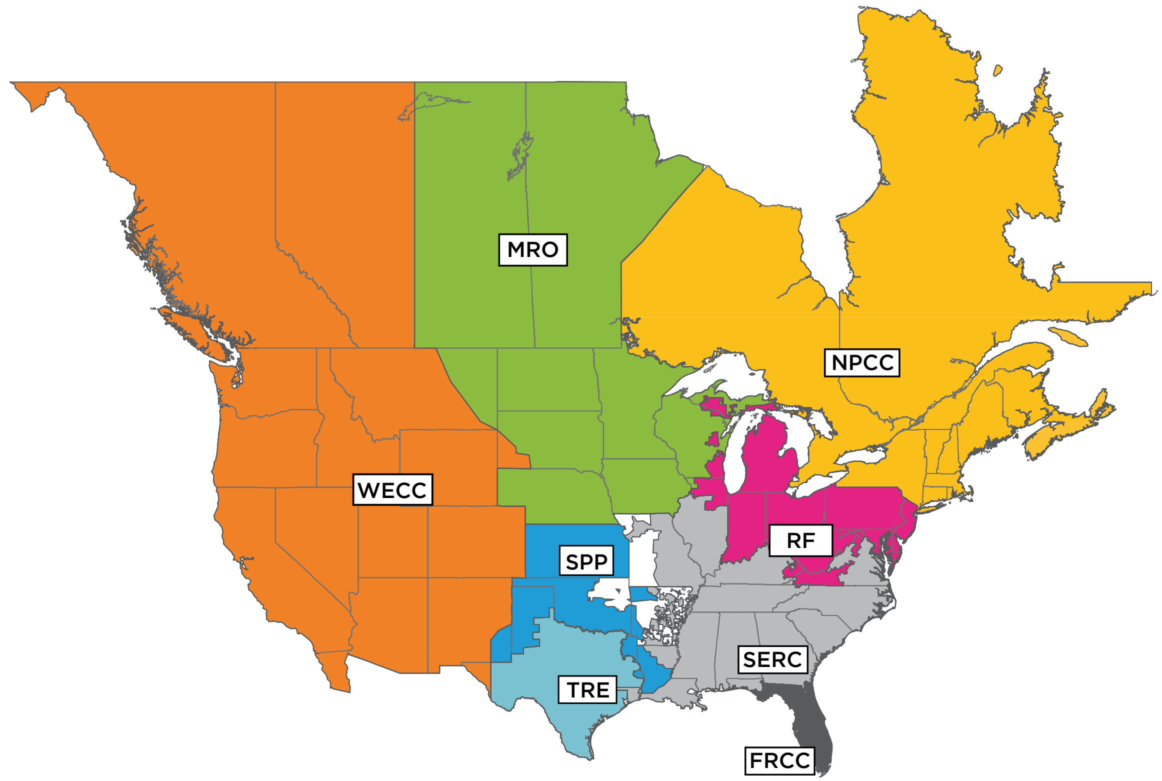
SERTP input occurs through each region's respective planning process stakeholder forums. Stakeholders who have reviewed their respective region's needs and transmission plans may provide input regarding any potential interregional opportunities that may be more efficient or cost effective than individual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

SERC Activities

PJM continues to support its members that are located within SERC, which are Dominion and East Kentucky Power Cooperative (EKPC), as shown on **Map 3.10**. That support includes active participation in the Engineering Committee, Planning Coordination Subcommittee, the Long-Term Working Group, Dynamics Working Group, Short-Circuit Database Working Group, Resource Adequacy Working Group, and the Near-Term Working Group.

PJM actively contributed to SERC committee and working group activities to coordinate 2021 model development and study activities.

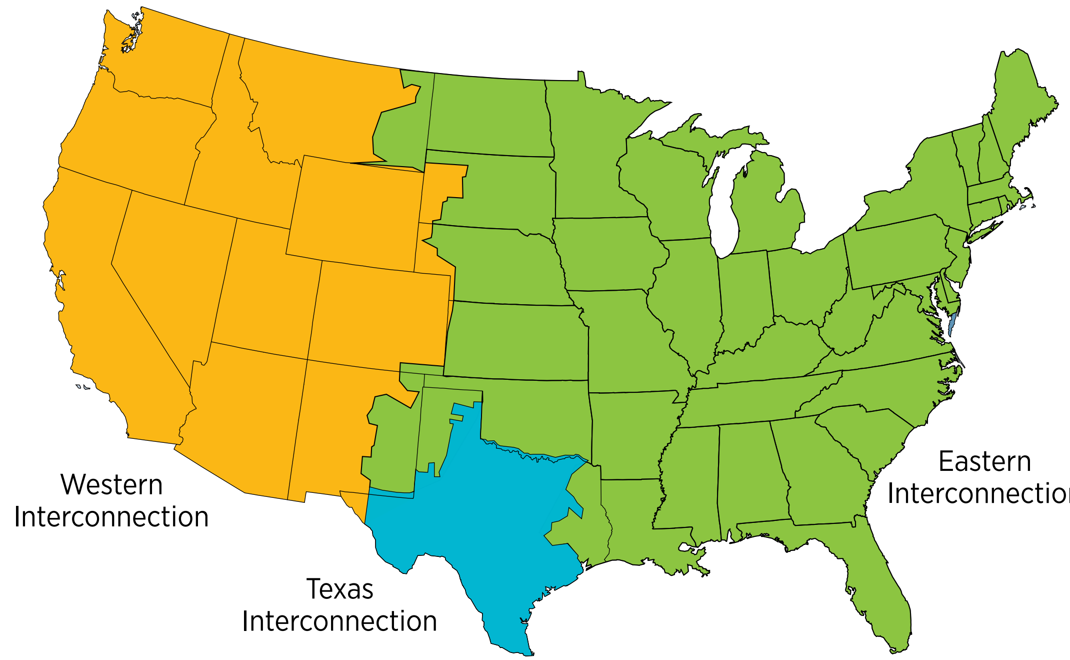
Map 3.10: NERC Areas



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 3.11**. EIPC consists of 20 planning coordinators representing approximately 95% 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 3.11: U.S. Interconnections



EIPC Activities

During 2021, EIPC continued to engage power system planning analysis activities including the following:

- EIPC published a white paper titled Planning the Grid for a Renewable Future on Oct. 5, 2021. The white paper was based on EIPC and member regions analyses, included a compendium of lessons learned and provides recommendations for regulators and policymakers.
- EIPC published a State-of-the-Grid report on Dec. 7, 2021. The report describes the coordinated planning undertaken to maintain the reliability of the bulk power system, highlighting current and future EIPC initiatives.
- EIPC submitted a draft paper to IEEE entitled Eastern Interconnection Frequency Response in System Low Inertia Condition on Nov. 21, 2021. The paper presented a frequency response study to demonstrate that the Eastern Interconnection will have sufficient system inertia over the next five years with the generation resource mix, load and interchange levels, and governor participation anticipated. In addition, the paper discusses the impact of system inertia reduction and governor participation on system frequency response.
- EIPC formed the Modeling Coordination Working Group (MCWG) to provide coordination between EIPC and the Multiregional Modeling Working Group (MMWG) in order to facilitate and enhance the Eastern Interconnection model building process.

3.6: Scenario Studies

PJM may conduct scenario studies in a given year in response to public policy and regulatory action, operational performance incidents, market economics, and/or technical industry trends and advancements. The studies, which are not required for reliability compliance, can provide valuable long-term expansion planning insights beyond conventional RTEP studies. In 2021, PJM investigated the incorporation of offshore wind into PJM's transmission system.

Offshore Wind Transmission Study

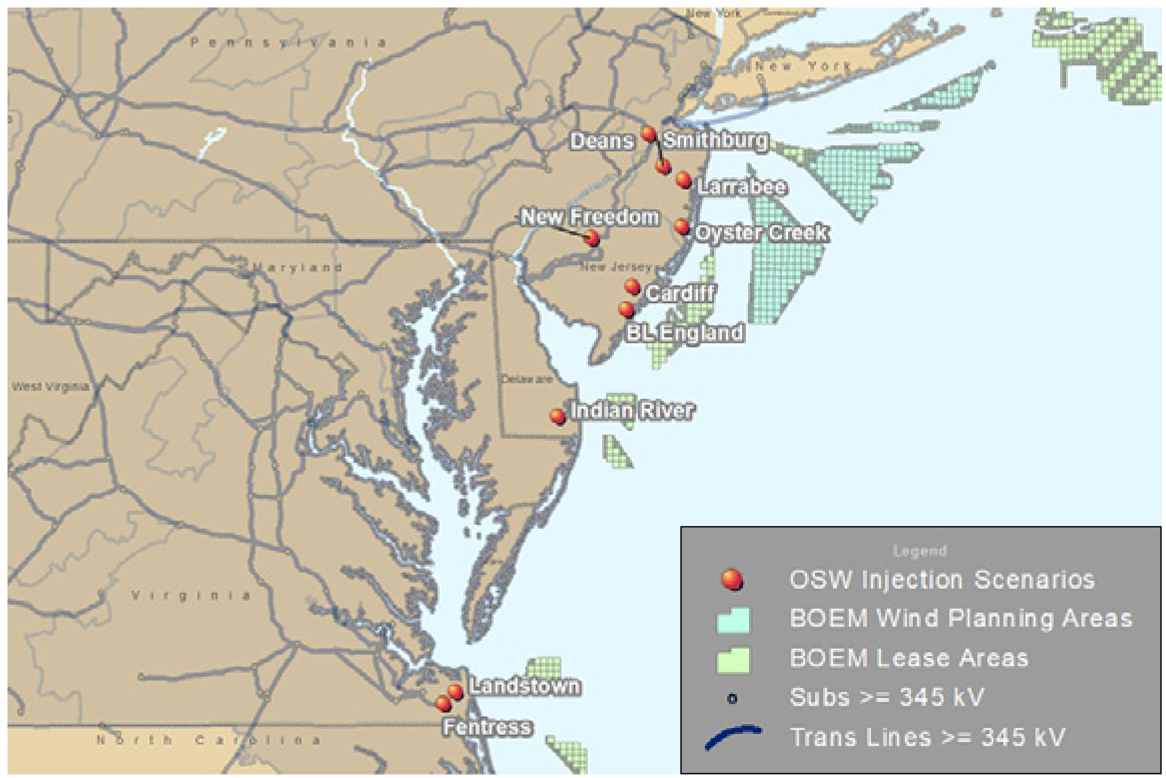
The PJM region is experiencing significant growth in planned renewable generation, including offshore wind resources being driven by states' renewable energy policies. To date, the transmission solutions needed to integrate renewable resources have primarily been advanced through PJM's generation interconnection queue. This avenue provides the ability to identify requisite transmission upgrades on a resource-by-resource basis. While such an approach does allow interconnecting resources to achieve commercial operation and maintain system reliability, efficiencies in transmission planning can be achieved through the holistic and regional assessment of interconnecting multiple, and in the case of offshore wind, large-scale resources.

In December 2019, the Organization of PJM States, Inc. (OPSI) requested that PJM engage the states in conducting analysis on integrating renewable resources and offshore wind planning. From this request, the Offshore Transmission Study Group (OTSG) was formed. The OTSG is an independent effort between PJM and the state agencies within the PJM footprint, created to assess the impact of the coastal states' planned offshore wind generation and to identify regional transmission solutions.

The collaborative discussions between PJM and the coastal states participating in the OTSG resulted in a scenario-based study called the Offshore Wind Transmission Study. The study is purely advisory in nature and is meant to help inform the coastal states as they advance their offshore wind endeavors. In addition to offshore wind, the study also incorporates the Renewable Portfolio Standards (RPS) targets of every PJM state with an RPS policy. The reason for including the RPS component is the recognition that offshore wind is not developing in isolation, and the integration of other renewable resources will also impact the transmission system as it is planned into the future.

The study's first phase, shown in **Map 3.12** below was developed and modeled in 2021. In Phase 1, PJM analyzed offshore wind injection totals ranging from 6,416 MW to 17,016 MW, in

Map 3.12: Points of Interconnection Used in Phase 1 Scenario



addition to modeling all state RPS targets, across short-term and long-term scenarios. Of the agreed-upon five scenarios, one scenario was short term, modeling out to 2027, while the remaining four scenarios were long term, modeling out to 2035.

The Phase 1 study focused on enhancements to the existing infrastructure required to reliably integrate the megawatts being injected by offshore wind generation. It did not address transmission infrastructure from sea-to-shore, offshore transmission networks, greenfield transmission solutions or offshore transmission facilities. These considerations may be incorporated within a future Phase 2 of the study. A high-level market efficiency analysis was also performed for the short-term scenario as an example of what could be provided in later study phases.

For the five scenarios, the cost estimates to upgrade the existing onshore transmission system were identified to be $627.34 million in the short-term scenario and between $2.16 billion and $3.21 billion for the long-term scenarios. Although this study did identify the locations and costs of transmission upgrades, the results are not indicative of cost allocation to any ratepayer.

The first phase of this study provides an important starting point for future scenarios that consider the integration of offshore wind and other renewable resources into the PJM system. It also presents a framework for how future collaborative transmission planning studies between PJM and the states can be achieved. The Phase 1 report, Offshore Wind Transmission Study: Phase 1 Results, details the results of the first phase of the study is available on the PJM website.

3.7: Stage 1A ARR 10-Year Analysis

RTEP Context

Auction Revenue Rights (ARRs) are the mechanisms by which the proceeds from the annual FTR auction are allocated. ARRs entitle the holder to receive an allocation of the revenues from the annual FTR auction. Incremental ARRs (IARRs) are additional ARRs created by new transmission expansion projects. The PJM Operating Agreement, Section 7.8, Schedule 1, sets forth provisions permitting any party to request Incremental ARRs 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 for base load plus the projected 10-year load growth. If needed, PJM will recommend expansion projects to be included in the RTEP with required in-service dates based on results of the 10-year analysis itself. As with all other RTEP expansion recommendations, those for ARRs will include the driver, cost, cost allocation and analysis of project benefits, provided that such projects will not otherwise be subject to a market efficiency cost/benefit analysis. Project costs are allocated across transmission zones based on each zone's Stage 1A eligible ARR flow contribution to the total Stage 1A eligible ARR flow on the facility that limits feasibility.

Results: 2021/2022 Stage 1A ARR 10-Year Analysis

During 2021, PJM staff completed a 10-year simultaneous feasibility analysis for 2021/2022 Stage 1A ARR selections. The power flow case used in the 10-year feasibility analysis is the same one used in the 2021/2022 annual ARR allocation, but without any modeled maintenance transmission outages. The results of the 10-year analysis identified a violation on a PJM internal facility. That facility is identified in **Table 3.6**. PJM anticipates that a solution to the violation will be addressed and incorporated in the 2022 RTEP process.

Table 3.6: 2021/2022 Stage 1A ARR 10-Year Infeasible Facilities

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

Section 4: Market Efficiency

4.0: Scope

RTEP Process Context

PJM performs market efficiency analysis as part of the overall Regional Transmission Planning process (RTEP) 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 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:

- 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 to model hourly security-constrained generation commitment and economic dispatch. Several 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 of the five-year-out study year
- A project case that 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 resulting comparisons with benefit analysis allows PJM to evaluate if specific proposed transmission enhancements or expansions are economically beneficial.

Project Acceleration Analysis

Also, as part of the annual acceleration analysis, PJM creates an "as-is" base case power flow that models a one-year-out study-year transmission topology. This allows PJM to perform the following:

- Identify economic benefits associated with acceleration or modification of reliability-based transmission projects already included in the RTEP
- Collectively value the congestion impact of approved RTEP portfolio of enhancements

Importantly, the simulated transmission congestion results provide important system information and trends to PJM stakeholders.

24-Month Cycle

PJM's 2020/2021 24-month market efficiency timeline is shown in **Figure 4.1**. The 2021 market efficiency body of work is represented by the second year of the 24-month cycle and focused on the following:

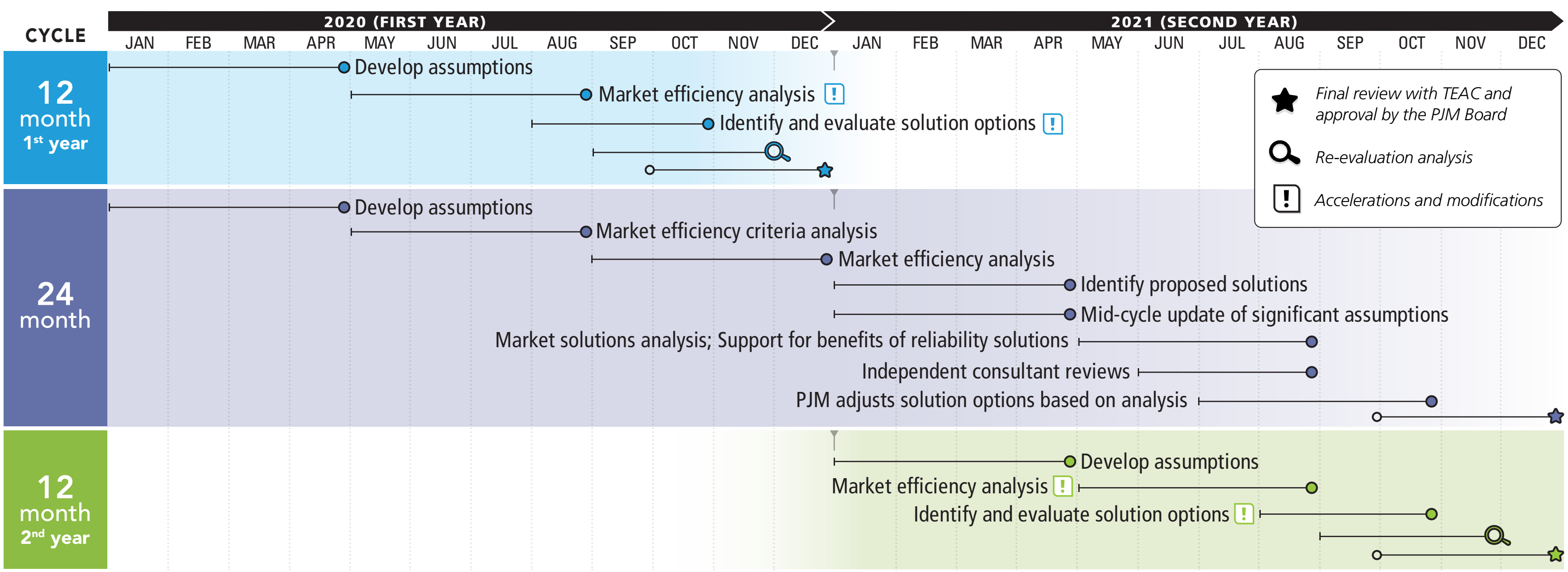
- Updating mid-cycle base case models and results
- Re-evaluating previously approved economic transmission projects
- Performing analysis to consider benefits of accelerating baseline projects previously approved for reliability
- Evaluating proposals submitted in the 2020/2021 long-term window

RTEP Project Acceleration Analysis: 2022 and 2026 Study Years

PJM compared simulations of near-term topologies with those of planned topologies to assess the individual and collective congestion benefits of RTEP transmission enhancements not yet in service. 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 2022 and 2026 study years. Simulation comparisons help PJM to:

- Quantify the transmission congestion reduction due to the collection of recently planned RTEP enhancements
- Reveal if specific, already-planned reliability-based 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

Figure 4.1: 2020/2021 Market Efficiency 24-Month Cycle



For example, if a constraint causes significant congestion in the 2022 "as-is" simulation but not in the 2026 "as-planned" simulation, then a 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.

Long-Term Window Simulations: 2021, 2025, 2028 and 2031 Study Years

In order to quantify future longer-range transmission system market efficiency needs, PJM develops a simulation database for use as part of the long-term window study process. System modeling characteristics included in this database are broadly described in **Section 4.1**.

Market efficiency projects for the 2020/2021 long-term proposal window described in **Section 4.3** are identified using the cases developed during the first nine months of 2020. However, during the 2021 project evaluation phase, PJM developed a 2021 mid-cycle update case that incorporates significant RTEP modeling changes approved through the 2020 RTEP cycle. The mid-cycle update case includes potentially significant changes in topology, generation, load and fuel costs. The purpose for the 2021 mid-cycle update case is to ensure that potential projects are evaluated using the best available forecast of future conditions.

Benefit-to-Cost Threshold Test

PJM calculates a benefit-to-cost threshold 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 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 cost review.

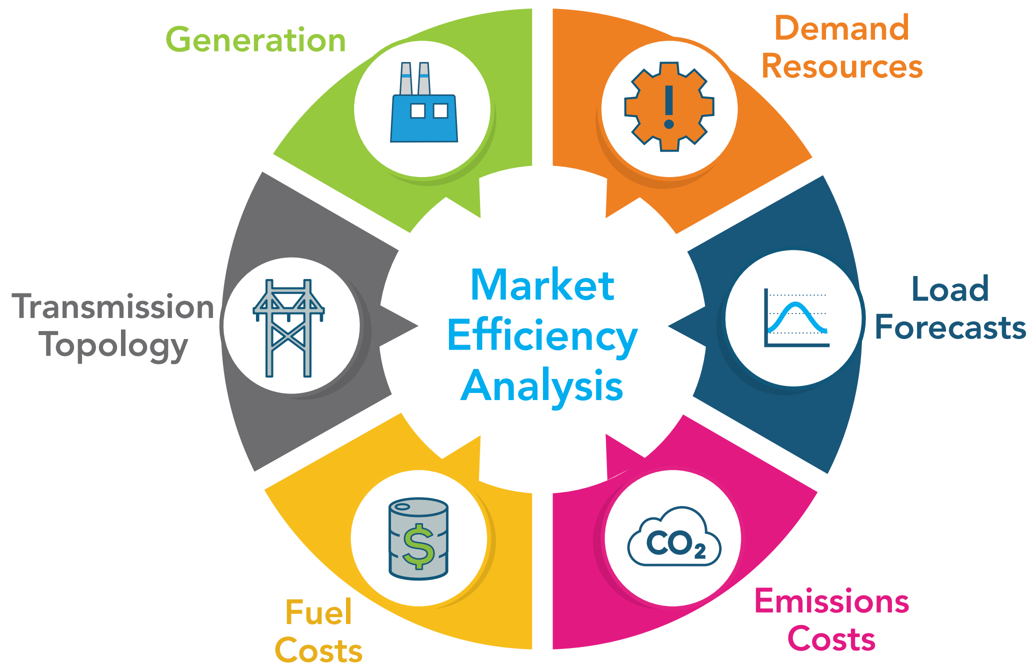
For the majority of proposed projects, PJM determines market efficiency benefits based on energy market simulations. Transmission projects that may impact PJM Reliability Pricing Market auction activities may derive additional economic benefit as determined through capacity market simulations. Market efficiency study process training material is available on PJM's website.

4.1: Input Parameters – 2021 Mid-Cycle Update

Overview

PJM licenses a commercially available database containing the necessary data elements to perform detailed PJM market simulations. This database is periodically updated permitting up-to-date 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.

Figure 4.2: Market Efficiency Analysis Parameters



Transmission Topology

Market efficiency power flow models were developed to represent:

- The 2022 "as-is" transmission system topology
- The expected 2026 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 2020 Multi-Regional Modeling Working Group 2022 summer peak case. It included transmission enhancements expected to be in service by the summer of 2022. PJM derived system topologies for 2026 from the 2026 RTEP case and included significant RTEP projects approved during the 2020 RTEP cycle.

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.

Generation Modeled

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

Fuel Price Assumptions

PJM uses a commercially available database tool that includes generator fuel price forecasts. Forecasts for short-term gas and oil prices are derived from New York Mercantile Exchange future prices. Long-term forecasts for gas and oil are obtained from commercially available databases, as are all coal price forecasts. Vendor-provided basis adders are applied as well to account for commodity transportation cost to each PJM zone. The fuel price forecasts used in PJM's 2021 market efficiency analysis are represented in **Figure 4.4**.

Figure 4.3: PJM Market Efficiency Reserve Margin

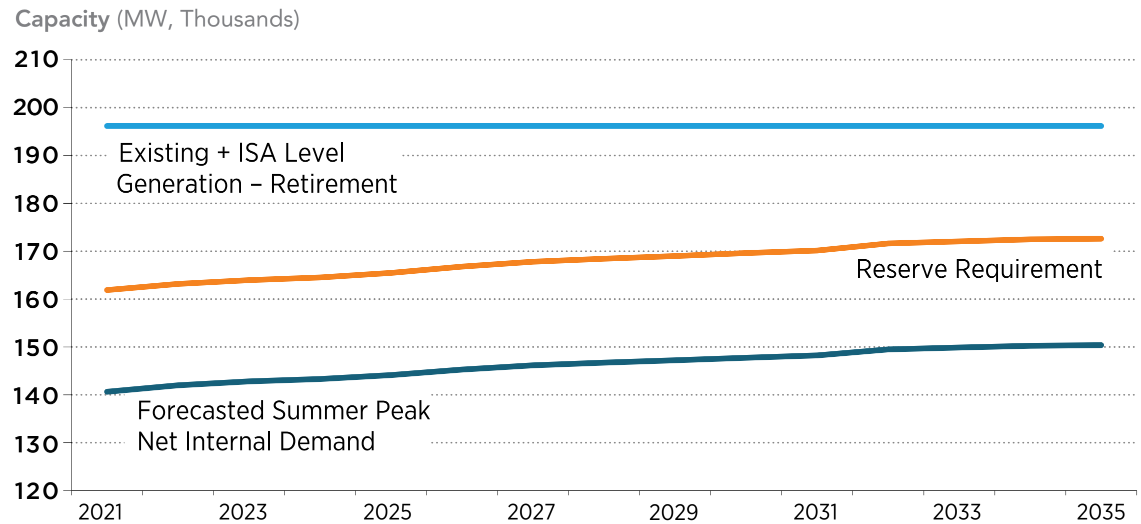
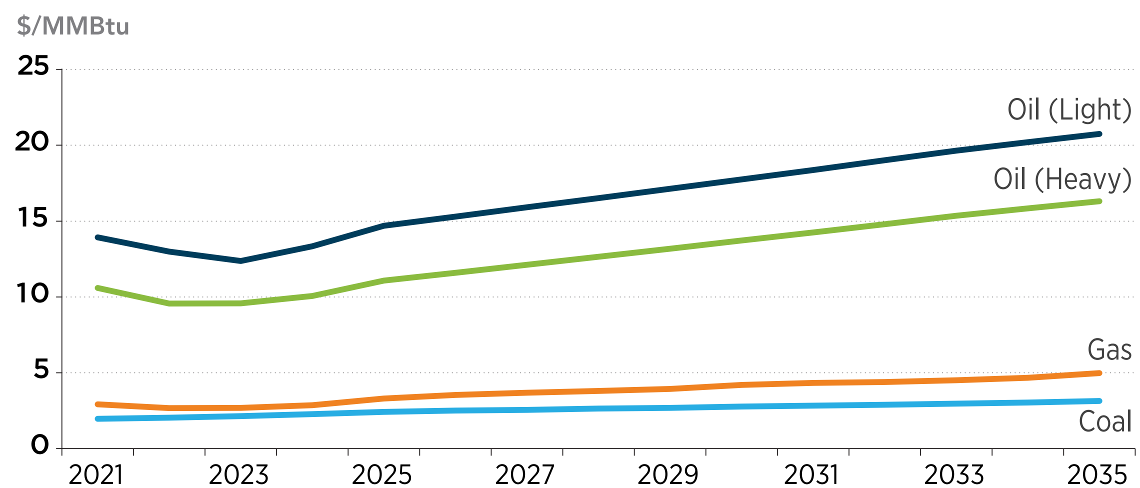


Figure 4.4: Fuel Price Assumptions



Load and Energy Forecasts

PJM's 2021 Load Forecast Report provides the transmission zone peak load and energy data modeled in market efficiency simulations. **Table 4.1** summarizes the PJM peak load and energy values used in the 2021 market efficiency analysis.

Demand Resources

The amount of demand resource modeled in each transmission zone is based on the 2021 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 Initiative (RGGI) program. Currently, Maryland, Delaware, New Jersey and Virginia participate in the RGGI.

Table 4.1: 2021 PJM Peak Load and Energy Forecast

Load	2021	2025	2028	2031	2035
Peak (MW)	149,224	151,928	152,971	153,759	154,620
Energy (GWh)	780,068	794,760	802,993	806,729	815,394

Table 4.2: Demand Resource Forecast

Demand Resource	2021	2025	2028	2031	2035
Demand Resource (MW)	8,779	8,910	8,947	8,982	9,022

Figure 4.5: SO_2 Emission Price Assumption

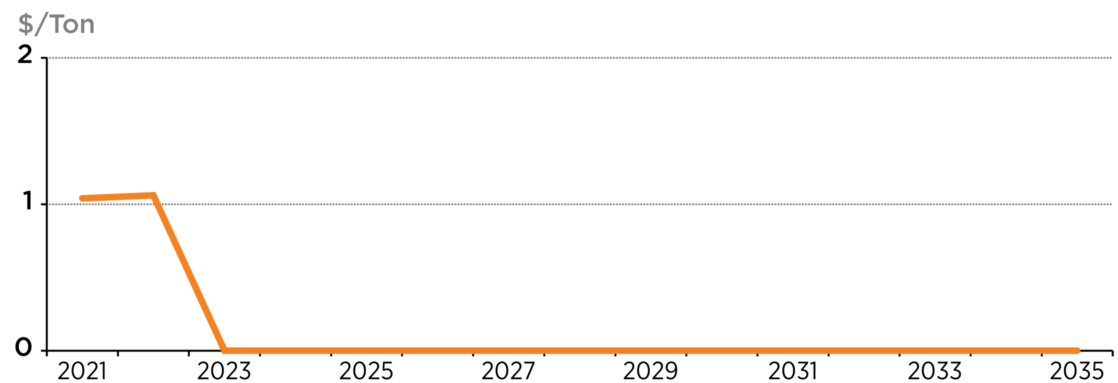
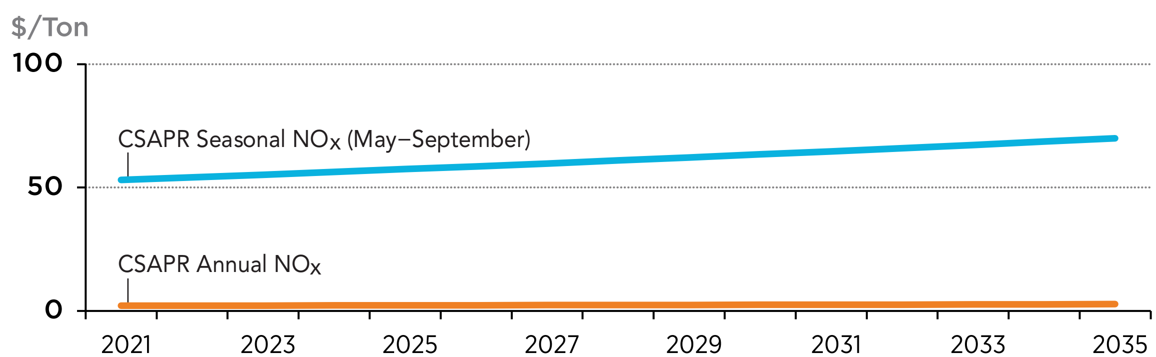


Figure 4.6: NO_x Emission Price Assumption

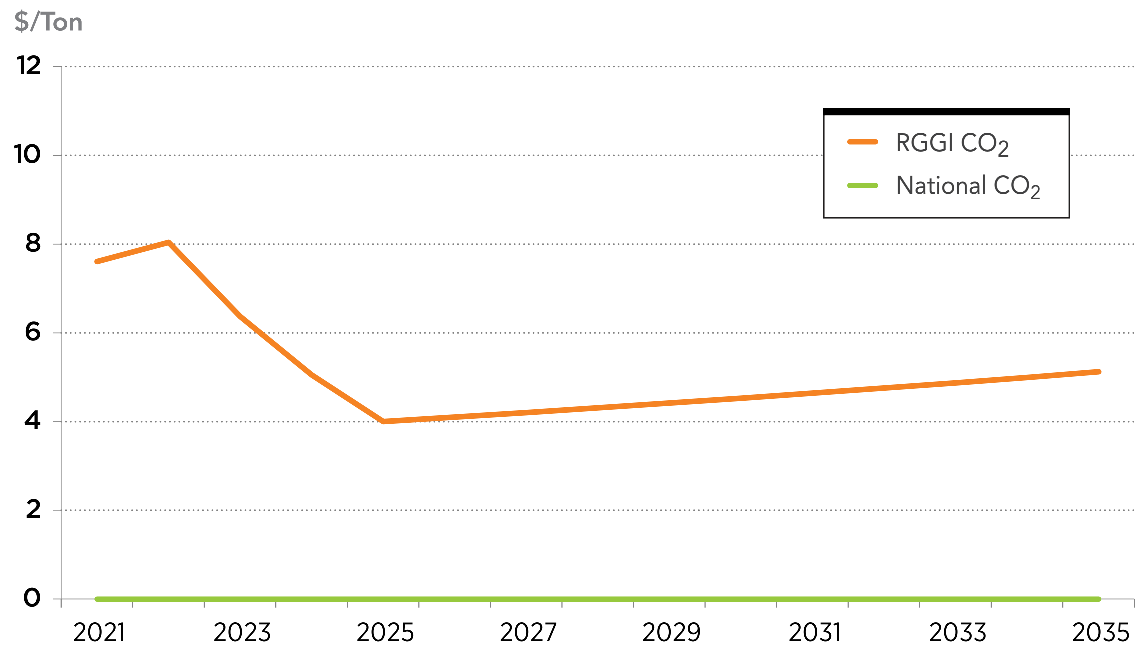


The base emission price assumptions for both the national CO_2 and RGGI CO_2 programs are shown in **Figure 4.7**.

Carrying Charge Rate and Discount Rate

The evaluation of proposed market efficiency projects requires a benefit-to-cost analysis. As part of this evaluation, the present value of annual benefits projected for a 15-year period starting with the RTEP year, is compared to the present value of the annual cost for the same period. If the benefit-to-cost ratio exceeds a threshold of 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 this analysis are 11.81% and 7.26%, respectively.

Figure 4.7: CO_2 Emission Price Assumption



4.2: Acceleration Results From 2021 Analysis

PJM's 2021 cycle of analysis included near-term simulations for study years 2022 and 2026. They identified collective and constraint-specific transmission system congestion due to the impacts of previously approved RTEP projects not yet in service. PJM conducted the simulations under two different transmission topologies:

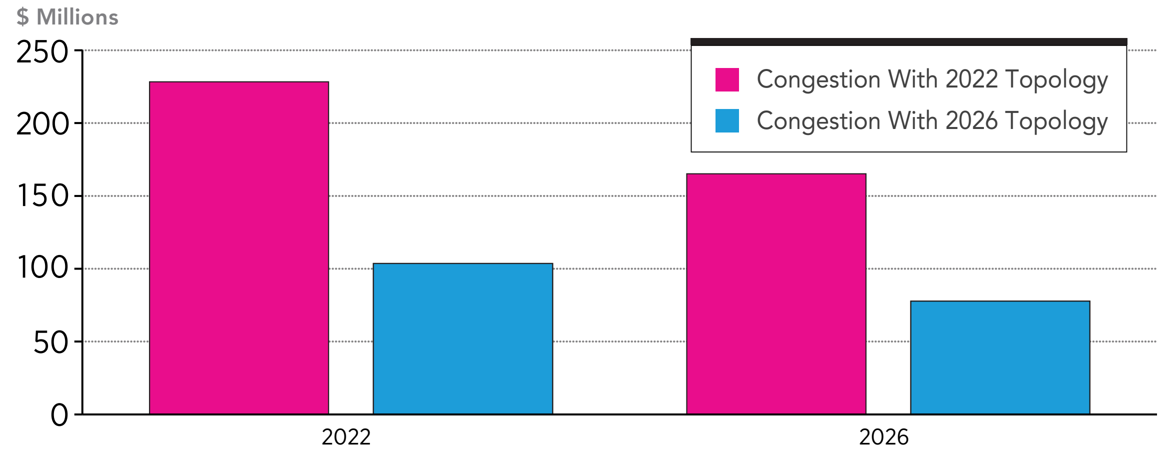
1. 2022 "as-is" PJM transmission system topology
2. 2026 "as-planned" RTEP PJM transmission system topology

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

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

PJM congestion costs from market simulations for study years 2022 and 2026 are shown in **Figure 4.8.** Annual congestion cost reductions of more than $103 million (54%) for 2022 and more than $87 million (52%) for 2026 resulted using the 2026 RTEP topology. RTEP enhancements that are approved but not yet in service account for the reduction in congestion.

Figure 4.8: 2021 Analysis of Simulated PJM Congestion Costs – 2022, 2026



Project-Specific Acceleration Analysis

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

Table 4.3 identifies specific RTEP reliability projects and related congestion reductions considered as part of the 2026 study-year acceleration analysis.

Baseline project B3240, a $0.23 million upgrade of terminal equipment on Morgan-Cherry Run 138 kV, will be accelerated to June 2024 at no additional cost. Project B3242, a $13.3 million reconfiguration of the Stonewall 138 kV substation, cannot be accelerated at this time.

Table 4.3: RTEP Projects Reducing Specific Congestion Drivers: 2026 Analysis

				2026 Study Year		
				2022 Topology	2026 Topology	
Constraint Name	Upgrade Associated With Congestion Reduction	Area	Type	2026 Congestion ($M)	2026 Congestion ($M)	Congestion Savings ($M)
Morgan-Cherry Run 138 kV	B3240: Upgrade Cherry Run and Morgan terminals.	AP	LINE	$6.6	$0.0	$6.6
Gore-Stonewall 138 kV	B3242: Reconfigure Stonewall 138 kV substation.	AP	LINE	$51.3	$0.0	$51.3

Note: The congestion savings for the 2026 study year are calculated as the difference in simulated congestion between with as-is topology and the RTEP topology.

4.3: 2020/2021 RTEP Long-Term Proposal Window – Market Efficiency Proposals

To identify and quantify long-term transmission system congestion, market simulations were conducted for study years 2021, 2025, 2028 and 2031. These simulations used the 2026 RTEP “as-planned” transmission system topology and included RTEP projects approved through the 2020 RTEP cycle.

Overall, simulated congestion levels in PJM’s 2021 market efficiency analyses remain relatively low compared to previous RTEP cycles. This is due, in part, to:

- Generation portfolio shifts that include increased high-efficiency, gas-fired generation and renewable resources
- Continued high generation reserves (Projected reserves are based on PJM’s load forecast, generation queue composition, and planned generator deactivations that have given formal notification. While the queue composition is influenced by state environmental legislation, it is not currently an objective of the market efficiency studies to meet state environmental legislation.)
- Continued lower load forecast levels compared to previous forecasts
- RTEP transmission enhancements, which are improving or eliminating potential congestion-causing constraints

Table 4.4: 2020/2021 Long-Term Window Congestion Drivers

			Market Efficiency Base Case			
			Annual Congestion ($M)		Hours Binding	
			Simulated Year			
Constraint	From Area	To Area	2025	2028	2025	2028
Junction to French’s Mill 138 kV	AP	AP	$15.24	$15.72	342	317
Charlottesville to Proffit Rd. Del Pt 230 kV	DOMINION	DOMINION	$7.34	$10.25	164	169
Plymouth Meeting to Whitpain 230 kV	PECO	PECO	$4.03	$2.76	78	89
Cumberland to Juniata 230 kV	PPL	PPL	$9.30	$10.10	209	217

PJM solicited stakeholder proposals for market efficiency projects as part of an RTEP proposal window focusing on long-term analysis. The 2020/2021 RTEP long-term proposal window opened on January 11, 2021, and closed on May 11, 2021. It sought solution alternatives to resolve or alleviate market efficiency congestion identified in the long-term simulations.

PJM posted a list of identified congestion drivers – facilities and their simulated congestion levels – as part of soliciting proposals during the 2020/2021 long-term proposal window, as shown in **Table 4.4**.

Seven qualified entities submitted 24 proposals during the 2020/2021 RTEP long-term proposal window that closed in May of 2021. Proposals ranged in cost from $0.6 million to $128.8 million and included transmission upgrades from transmission owners and greenfield projects from both incumbent and non-incumbent transmission entities.

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

4.4: 2020/2021 Long-Term Window Results

Seven qualified entities submitted 24 proposals during the 2020/2021 RTEP long-term proposal window that closed in May of 2021. Proposals ranged in cost from $0.6 million to $128.8 million and included transmission upgrades and greenfield projects from both incumbent and non-incumbent transmission entities. The proposals were grouped and evaluated by cluster according to the constraint being addressed.

Cluster No. 1: Junction to French's Mill 138 kV Constraint

Five proposals, submitted through PJM's Competitive Planner Tool, were evaluated for this cluster. The proposals are summarized in **Table 4.5**. Publicly available redacted versions of the proposals can be found on the PJM website.

PJM evaluated each of the proposals to determine which projects address the congestion driver and satisfy the market efficiency criteria of having a benefit-to-cost ratio greater than 1.25. Of the five proposed solutions, three fully addressed the congestion driver. The three proposals included:

1. French's Mill-Junction 138 kV terminal upgrades
2. French's Mill-Junction 138 kV terminal upgrades with a reconductoring of the Messick Rd-Ridgeley 138 kV line
3. A new Black Oak-Bismark 500 kV line

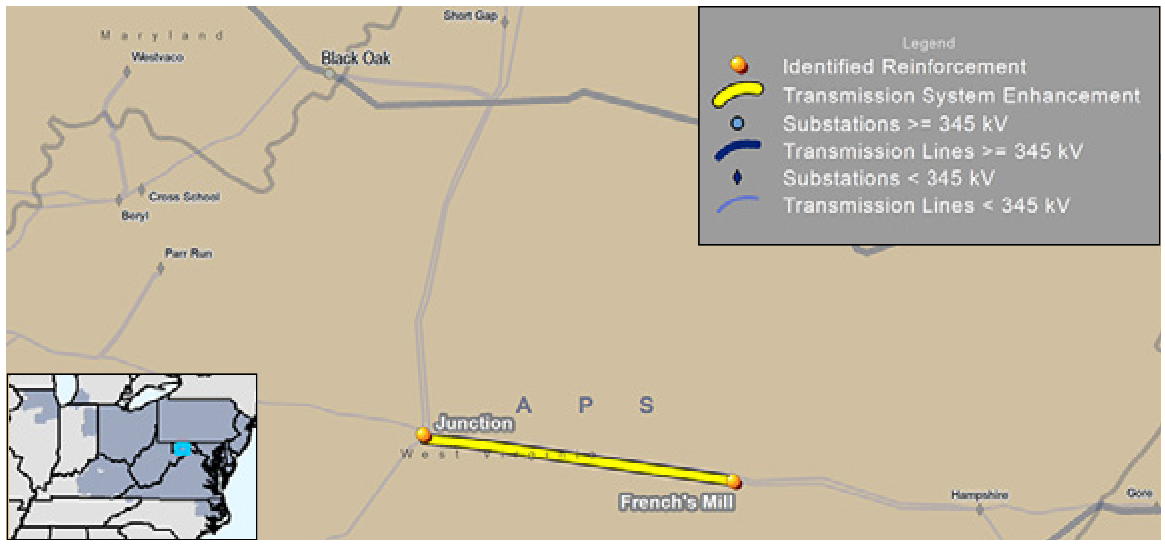
Determination of which project addressed the identified congestion in the most cost effective manner while considering cost and constructability risk of the proposals was made. Based on the analysis performed, PJM selected Proposal ID No. 756 – terminal equipment upgrades at the French's Mill and Junction 138 kV substations. RTEP baseline project B3701 is shown on **Map 4.1.** The project:

- Has a benefit-to-cost ratio of 119.03, the highest across the evaluated proposals
- Fully addresses the target congestion driver
- Is an upgrade and has lower constructibility risk compared to the other proposals

Table 4.5: 2020/2021 Long-Term Window: Cluster No. 1 List of Proposals

Proposal ID	Project Type	Project Description	Estimated Total In-Service Construction Cost ($M)	Cost Capping Provisions (Yes/No)
102		Install Reston 230 kV capacitor.	$1.89	
425	Upgrade	Perform terminal upgrades at French's Mill 138 kV and Junction 138 kV. Reconductor Messick Rd.-Ridgeley 138 kV line.	$11.99	No
540		Install Bull Run 230 kV capacitor.	$5.73	
547	Greenfield	Install Black Oak-Bismark 500 kV line.	$128.75	Yes
756	Upgrade	Perform terminal upgrades at French's Mill 138 kV and Junction 138 kV.	$0.77	No

Map 4.1: Baseline Project B3701: French's Mill-Junction 138 kV Terminal Upgrades



In addition to the market efficiency base case analysis for the recommended proposal, PJM also performed sensitivity analyses on key input variables: natural gas price, PJM load forecast and generation expansion. A reliability analysis of the project did not identify any reliability criteria violations.

The project has an estimated cost of $0.77 million with a 2022 in-service date.

Cluster No. 2: Plymouth Meeting to Whitpain 230 kV Constraint

Four proposals, submitted through PJM's Competitive Planner Tool, were evaluated for this cluster. The proposals are summarized in **Table 4.6**. Publicly available redacted versions of the proposals can be found on the PJM website.

PJM evaluated each of the proposals to determine which projects address the congestion driver and satisfy the market efficiency criteria of having a benefit-to-cost ratio greater than 1.25. Each of the four proposed solutions addressed the congestion driver. These proposals included:

1. Plymouth Meeting-Whitpain 230 kV terminal upgrades
2. Plymouth Meeting-Whitpain 230 kV terminal upgrades in conjunction with a SmartWire installation
3. Plymouth Meeting-Whitpain 230 kV reconductor
4. A new 500/230 kV solution (Old Lime Stone-Doe Run Project)

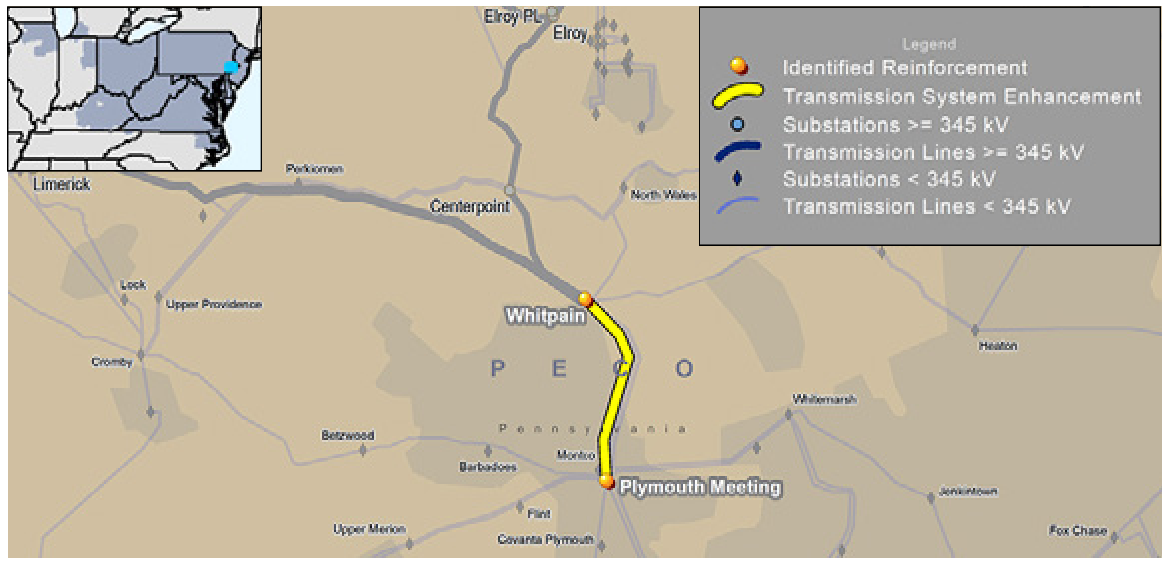
Determination of which project addressed the identified congestion in the most cost-effective manner while considering cost and constructability risk of the proposals was made. Based on the analysis performed, PJM selected Proposal ID No. 704 – terminal equipment upgrades at the Plymouth Meeting-Whitpain 230 kV substations. RTEP baseline project B3697 is shown on **Map 4.2**. The project:

- Has a benefit-to-cost ratio of 75.30, the highest across the evaluated proposals
- Fully addresses the target congestion driver
- Is an upgrade and has lower constructability risk compared to the other proposals

Table 4.6: 2020/2021 Long-Term Window: Cluster No. 2 List of Proposals

Proposal ID	Project Type	Project Description	Estimated Total In-Service Construction Cost ($M)	Cost Capping Provisions (Yes/No)
227	Greenfield	Construct Old Limestone-Doe Run 500/230 kV project.	$73.51	Yes
399	Upgrade	Perform Plymouth Meeting-Whitpain 230 kV terminal upgrade including SmartWires.	$8.42	No
704	Upgrade	Perform Plymouth Meeting-Whitpain 230 kV terminal upgrade.	$0.62	No
735	Upgrade	Reconductor Plymouth Meeting-Whitpain 230 kV line.	$14.98	No

Map 4.2: Baseline Project B3697: Plymouth Meeting-Whitpain 230 kV Terminal Upgrades



In addition to the market efficiency base case analysis for the recommended proposal, PJM also performed sensitivity analyses on key input variables: natural gas price, PJM load forecast and generation expansion. A reliability analysis of the project did not identify any reliability criteria violations.

The project has an estimated cost of $0.62 million with a 2025 in-service date.

Cluster No. 3: Cumberland to Juniata 230 kV Constraint

Five proposals, submitted through PJM's Competitive Planner Tool, were evaluated for this cluster. The proposals are summarized in **Table 4.7**. Publicly available redacted versions of the proposals can be found on the PJM website.

PJM evaluated each of the proposals to determine which projects address the congestion driver and satisfy the market efficiency criteria of having a benefit-to-cost ratio greater than 1.25. Of the five proposed solutions, three fully addressed the congestion driver. These proposals included:

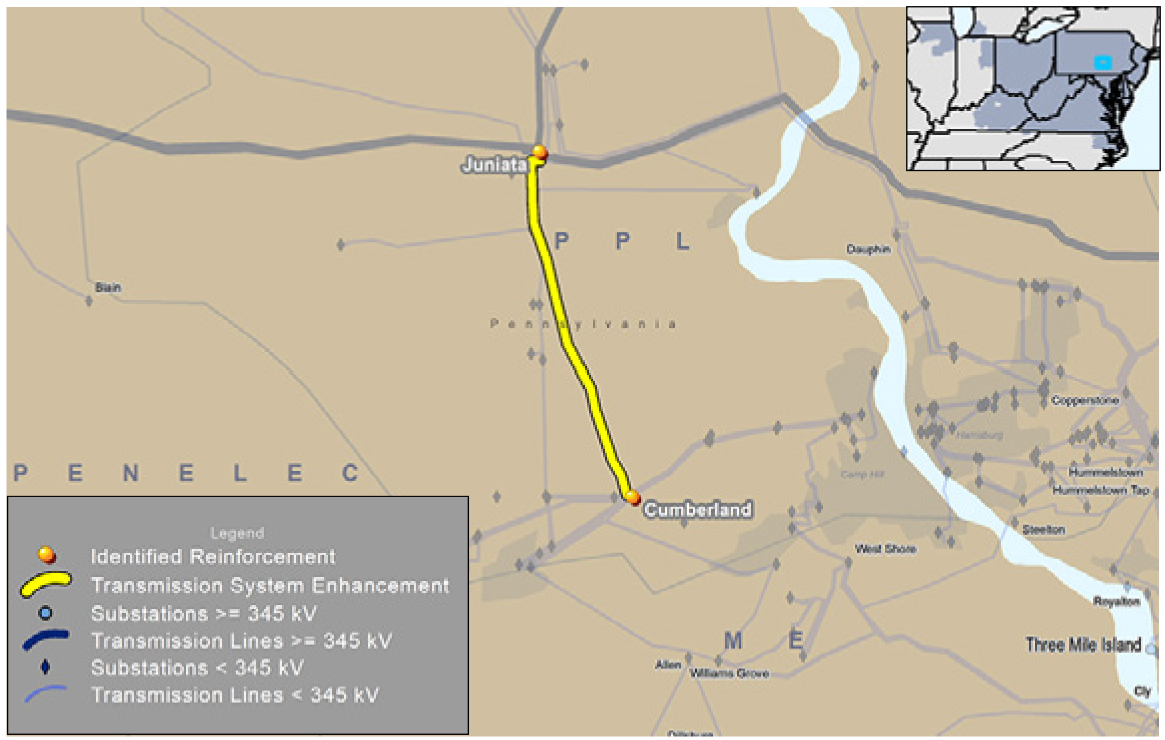
1. Juniata-Cumberland 230 kV reconductor
2. Juniata-Cumberland 230kV line rebuild to double circuit and Cumberland-Williams Grove 230 kV
3. A new 500/230 kV solution (Bow Creek Project)

Determination of which project addressed the identified congestion in the most cost effective manner while considering cost and constructability risk of the proposals was made. Based on the analysis performed, PJM selected

Table 4.7: 2020/2021 Long-Term Window: Cluster No. 3 List of Proposals

Proposal ID	Project Type	Project Description	Estimated Total In-Service Construction Cost ($M)	Cost Capping Provisions (Yes/No)
102	Upgrade	Install Reston 230 kV capacitor.	$1.89	No
218		Reconductor Juniata-Cumberland 230 kV line.	$9.00	Yes
251		Rebuild Juniata-Cumberland 230 kV line to double circuit and reconductor Cumberland-Williams Grove 230 kV line.	$49.05	No
540		Install Bull Run 230 kV capacitor.	$5.73	No
738	Greenfield	Install Bow Creek 500/230 kV project.	$55.05	Yes

Map 4.3: Baseline Project B3698: Juniata-Cumberland 230 kV Line Reconductor



Proposal ID No. 218 – Juniata-Cumberland 230 kV line reconductor. RTEP baseline project B3698 is shown on **Map 4.3.** The project:

- Has a benefit-to-cost ratio of 11.28, the highest across the evaluated proposals
- Fully addresses the target congestion driver
- Is an upgrade and has lower constructability risk compared to the other proposals

In addition to the market efficiency base case analysis for the recommended proposal, PJM also performed sensitivity analyses on key input variables: natural gas price, PJM load forecast and generation expansion. A reliability analysis of the project did not identify any reliability criteria violations.

The project has an estimated cost of $9 million with a 2023 in-service date.

Cluster No. 4: Charlottesville to Proffit Rd Del Pt 230 kV Constraint

Twelve proposals, submitted through PJM's Competitive Planner Tool, were evaluated for this cluster. Additionally, during the 2021 Window No. 1, PJM received ten proposals for a reliability violation on Charlottesville to Proffit 230 kV. One of the reliability proposals, Proposal No. 38, addressed the market efficiency congestion driver and was therefore included in this evaluation. The proposals are summarized in **Table 4.8**. Publicly available redacted versions of the proposals can be found on the PJM website.

PJM evaluated each of the proposals to determine which projects address the congestion driver and satisfy the market efficiency criteria of having a benefit-to-cost ratio greater than 1.25. Of the proposed solutions, five fully addressed the congestion driver. These proposals included:

1. Charlottesville-Gordonsville 230 kV Greenfield line
2. New Hollymeade Tap 230 kV substation with Charlottesville-Hollymeade tap-Cash's Corner-Gordonsville 230 kV line rebuild
3. Charlottesville-Proffit 230 kV line series reactor
4. New Cismont 230 kV Substation with Charlottesville-Hollymeade tap-Cash's Corner-Gordonsville 230 kV line rebuild
5. Sleepy Hollow-Gordonsville 230 kV greenfield project

Table 4.8: 2020/2021 Long-Term Window: Cluster No. 4 List of Proposals

<table>
<tr><th>Proposal ID</th><th>Project Type</th><th>Project Description</th><th>Estimated Total In-Service Construction Cost ($M)</th><th>Cost Capping Provisions (Yes/No)</th></tr>
<tr><td>196</td><td>Upgrade</td><td>Rebuild Charlottesville-Proffit 230 kV line.</td><td>$19.49</td><td>No</td></tr>
<tr><td>238</td><td>Greenfield</td><td>Install Charlottesville-Gordonsville 230 kV greenfield line.</td><td>$45.83</td><td>Yes</td></tr>
<tr><td>309</td><td>Upgrade</td><td>Install 5 MW Battery Energy Storage System at Louisa CT substation.</td><td>$25.97</td><td rowspan="4">No</td></tr>
<tr><td>327</td><td>Greenfield</td><td>New Hollymeade Tap 230 kV substation – Rebuild Charlottesville-Hollymeade Tap-Cash's Corner-Gordonsville 230 kV line.</td><td>$35.93</td></tr>
<tr><td>533</td><td>Upgrade</td><td>Install 10 MW Battery Energy Storage System at Hollymeade substation.</td><td>$40.45</td></tr>
<tr><td>578</td><td rowspan="2">Greenfield</td><td>Construct new Hollymeade Tap 230 kV substation.</td><td>$10.02</td></tr>
<tr><td>589</td><td>Build second Charlottesville-Gordonsville 230 kV line. Upgrade terminal equipment from Hollymeade to Gordonsville 230 kV.</td><td>$25.97</td><td>Yes</td></tr>
<tr><td>632</td><td rowspan="3">Upgrade</td><td>Install 5 MW Battery Energy Storage System at Gordonsville substation.</td><td>$29.15</td><td rowspan="3">No</td></tr>
<tr><td>651</td><td>Install Charlottesville-Proffit 230 kV line series reactor.</td><td>$11.38</td></tr>
<tr><td>669</td><td>Install 5 MW Battery Energy Storage System at Hollymeade substation.</td><td>$25.95</td></tr>
<tr><td>692</td><td rowspan="3">Greenfield</td><td>Install Sleepy Hollow-Stoney Point 230 kV greenfield project.</td><td>$36.07</td><td>Yes</td></tr>
<tr><td>813</td><td>Install Sleepy Hollow-Stoney Point 230 kV greenfield project.</td><td>$73.64</td><td>No</td></tr>
<tr><td>38</td><td>Install Sleepy Hollow-Gordonsville 230 kV greenfield project.</td><td>$40.17</td><td>Yes</td></tr>
</table>

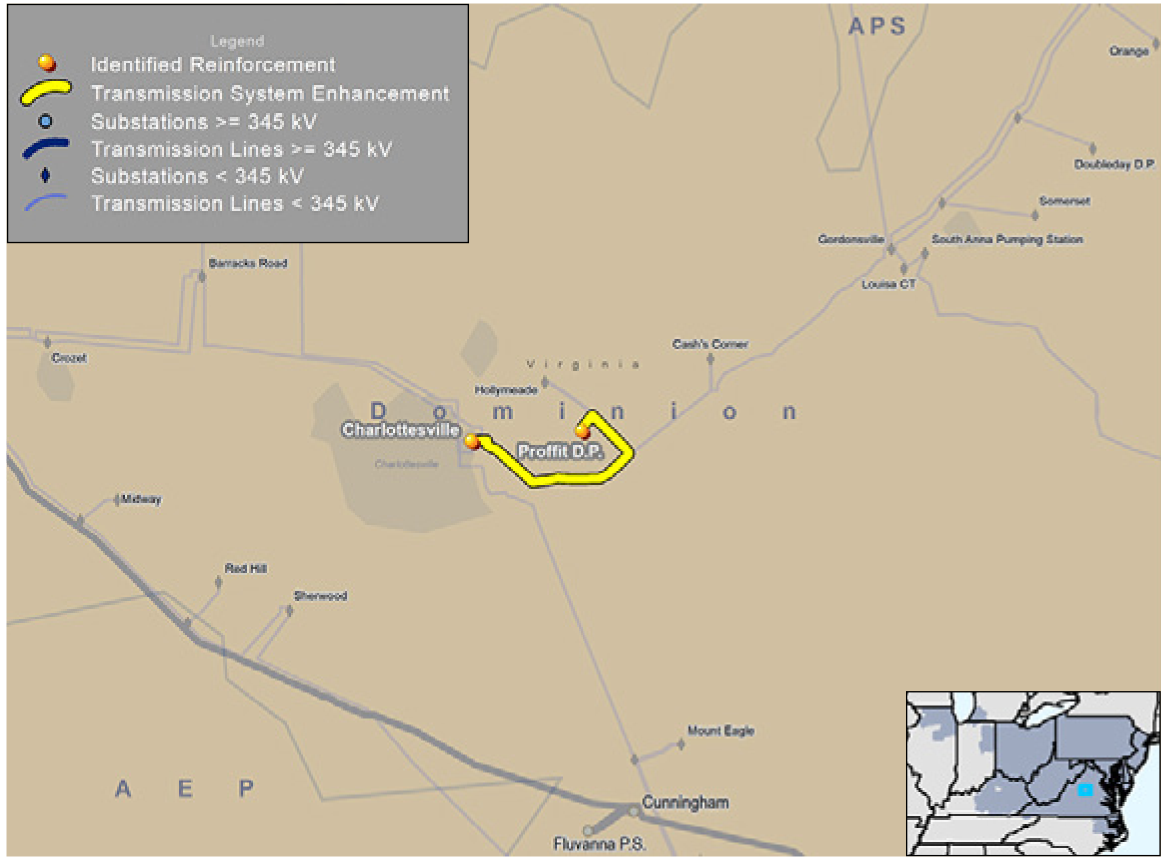
Determination of which project addressed the identified congestion in the most cost effective manner while considering cost and constructability risk of the proposals was made. Based on the analysis performed, PJM selected Proposal ID No. 651 – Charlottesville-Proffit 230 kV line series reactor. RTEP baseline project B3702 is shown on **Map 4.4.** The project:

- Has a benefit-to-cost ratio of 16.05, the highest across the evaluated proposals
- Fully addresses the target congestion driver
- Is an upgrade and has lower constructability risk compared to the other proposals

In addition to the market efficiency base case analysis for the recommended proposal, PJM also performed sensitivity analyses on key input variables: natural gas price, PJM load forecast and generation expansion. A reliability analysis of the project did not identify any reliability criteria violations.

The project has an estimated cost of $11.38 million with a 2023 in-service date.

Map 4.4: Baseline Project B3702: Charlottesville-Proffit 230 kV Line Series Reactor



2021 Re-Evaluation of Previously Approved Market Efficiency Projects

PJM's 2021 analysis included a re-evaluation of approved market efficiency projects from previous long-term window processes. The re-evaluation criteria include the following:

- Projects that are under construction or that have a Certificate of Public Necessity (CPCN) are not required to be re-evaluated.
- Projects not under construction or without a CPCN with capital costs less than $20 million will have projected costs updated. 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 re-evaluated. The project should maintain a benefit-to-cost ratio greater than 1.25.

Go to Next Section >

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, which includes RTEP Baseline Projects B2743 and B2752, is shown on **Map 4.5**. **Table 4.9** shows the 2021 re-evaluation results for Project 9A.

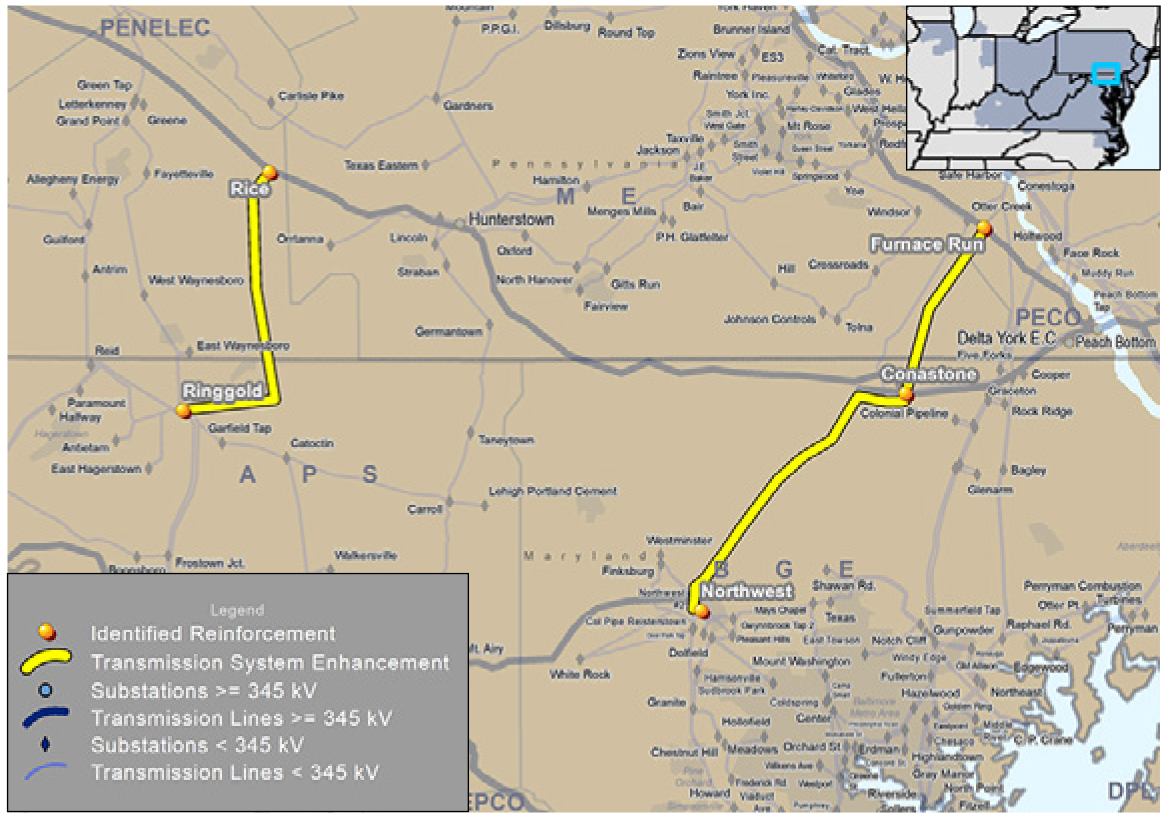
On September 22, 2021, the PJM Board endorsed PJM's recommendation to suspend Project 9A due to permitting risks. PJM will remove Project 9A from the 2022 RTEP model to determine the need for any reliability reinforcements.

Table 4.9: 2021 Re-Evaluation of Project 9A

Re-Evaluation	Benefit-to-Cost Ratio (Sunk Costs Excluded*)	Benefit-to-Cost Ratio (In-Service Cost*)
Project 9A Base Case Analysis	1.44	1.00
Sensitivity Scenario With Higher Load Growth	2.08	1.44
Sensitivity Scenario With Additional Coal Retirements	2.00	1.39

*Note: Sunk Costs represent costs already incurred. In-Service Cost represents total cost estimate.

Map 4.5: Project 9A – RTEP Baseline Project B2743 and B2752



Section 5: Facilitating Interconnection

5.0: Interconnection Reliability

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. The PJM Board has approved network facility reinforcements totaling $6.5 billion. The PJM Board approved 34 new network system enhancements totaling $47.6 million in 2021 alone. As described in **Section 1.2**, PJM tests for compliance with NERC and regional reliability criteria. Specifically, NERC reliability standards require that PJM identifies system conditions that sufficiently stress the transmission system as part of evaluating criteria compliance.

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

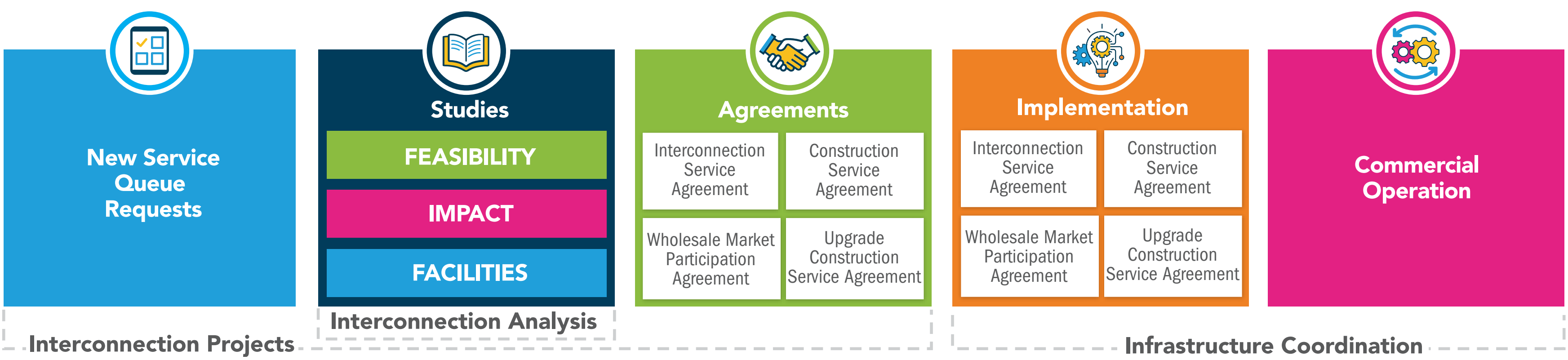
Queue Process Overview

PJM's interconnection queue process consists of five phases as shown in **Figure 5.1**. A new service queue request is submitted during one of the two queue windows: April through September and October through March. During the feasibility study phase, PJM conducts initial, high-level evaluations at a primary and a secondary (optional) point of interconnection. PJM targets to complete the feasibility study within 120 days after each window closes.

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

During the study phases, PJM performs power flow, short circuit and stability analyses to ensure the project's reliable interconnection to PJM's system. When the study phases have been completed, the project developer signs agreements that grant it the rights to interconnect to the PJM system. The Interconnection Service Agreement and the Construction Service Agreement describe the milestones, point of interconnection, system upgrades and construction responsibilities that are associated with the project.

Figure 5.1: New Services Queue Process Overview



5.1: New Services Queue Requests

Interconnection Activity

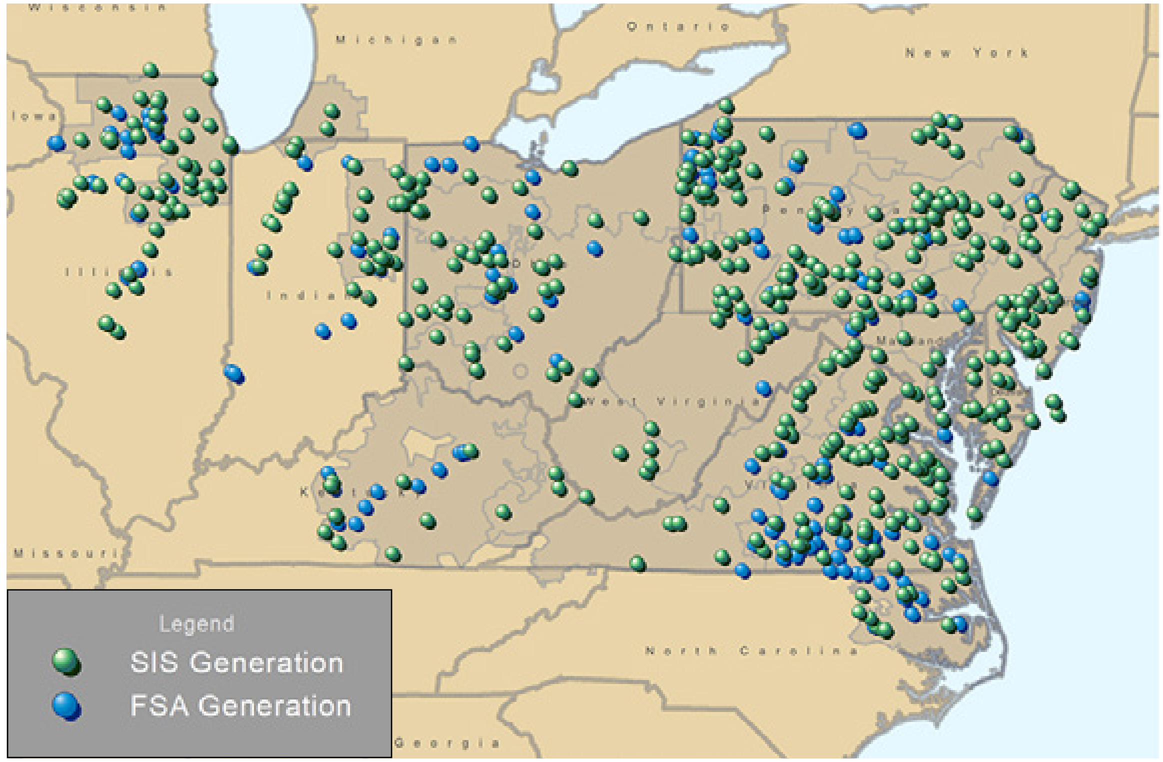
As described in **Section 5.0**, the generation interconnection process has three study phases – feasibility, system impact and facilities studies – to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible to participate in PJM capacity and energy markets.

Generation Queue Activity

PJM's markets have attracted generation proposals totaling 567,062 MW, as shown in **Table 5.1**. Over 139,937 MW of interconnection requests were actively under study during 2021. PJM analyzed and issued study reports for 523 feasibility studies and 604 system impact studies for generator interconnection requests across the RTO, as shown on **Map 5.1**. This unprecedented queue volume, as of Dec. 31, 2021, was largely composed of renewable fuel types – notably, solar – as described later in this section.

Over 14,109 MW of new generation was under construction as of Dec. 31, 2021, across all fuel types. While withdrawn projects make up a significant portion of total interconnection request activity, the numbers simply reflect ongoing business decisions by developers in response to changing public policy, regulatory, industry, economic and other competitive factors. PJM's queue-based interconnection process offers developers the flexibility to consider and explore cost-effective interconnection opportunities.

Map 5.1: Feasibility and System Impact Studies Performed in 2021



In 2021 PJM received **1,351 new service requests** representing 106,944 MW (energy) of generation and 73,556 MW of CIRs.

During calendar year 2021, PJM issued a total of **1,213 feasibility, impact and facilities studies.**

Queue Progression History

PJM reviews generation queue progression annually to understand overall developer trends more fully and their impact on the interconnection process. **Figure 5.2** shows that for all generation – both new resources and existing plant uprates – submitted in Queue A (1999) through Dec. 31, 2021, 65,734 MW – or 21% – reached commercial operation. As **Figure 5.2** also shows, 26,351 MW – or 6% – of that accounts for withdrawals from the queue after interconnection service agreement (ISA) execution and 1,271 – or 0.2% – represents withdraws after the wholesale market participant agreement (WMPA) execution, but before construction. Overall, 15% of projects that requested uprates to existing capacity reached commercial operation.

Table 5.1: Queued Study Requests (Dec. 31, 2021)

	Projects	Energy (MW)	Capacity (MW)
Active	2,445	225,348	139,937
In Service	972	76,075	63,518
Under Construction	353	20,616	14,109
Withdrawn	3,437	448,037	349,498
Grand Total	**7,207**	**770,076**	**567,062**

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

Figure 5.2: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2021)

			Capacity	Nameplate
Projects withdrawn after final agreement	189	Interconnection Service Agreements	26,351 MW	34,892 MW
	315	Wholesale Market Participation Agreements	1,271 MW	2,577 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

5.2: New Jersey State Agreement Approach

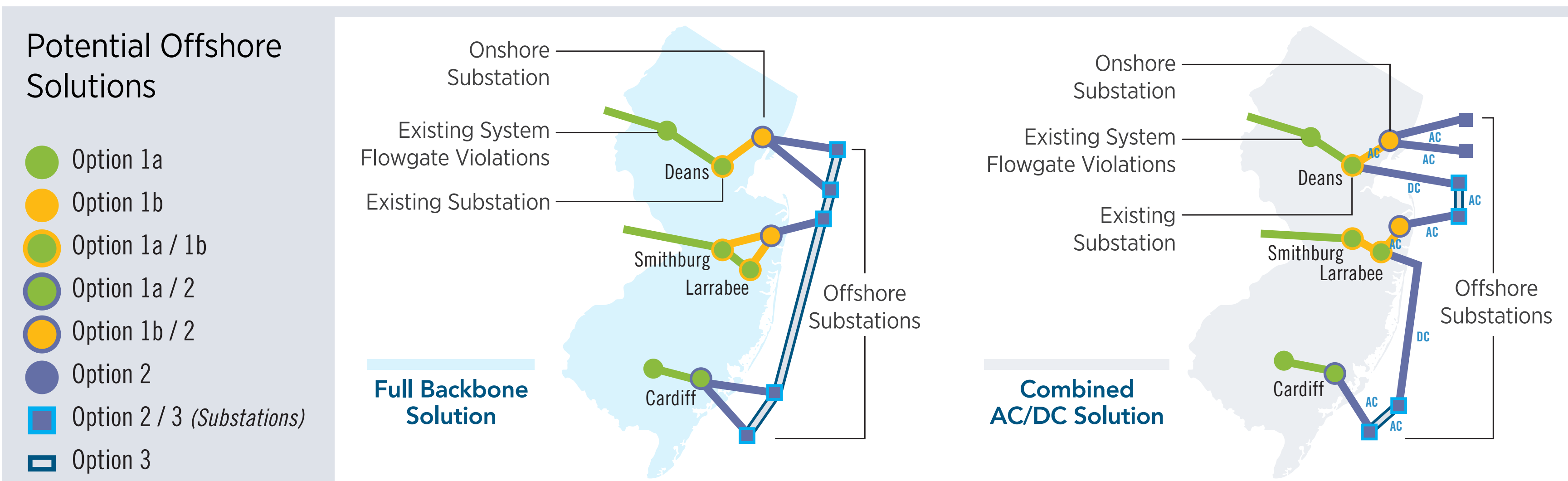
New Jersey State Agreement Approach

In November 2020, the New Jersey Board of Public Utilities (NJBPU) initiated PJM's State Agreement Approach (SAA) by soliciting transmission proposals to accommodate full integration of New Jersey's 7,500 MW of planned offshore wind-powered generation. Potential hypothetical examples of offshore solution configurations, as presented to stakeholders, are shown in **Figure 5.3**. PJM opened a long-term competitive window in April 2021 and received 80 competitive bids from 13 different entities by close of the window on Sept. 17, 2021. Potential developers were asked to submit proposals that address both onshore and offshore transmission needs. These proposals are discussed further in **Section 3.0**.

In 2022, PJM will evaluate each proposal and make a recommendation to the NJBPU on which project or projects best address the objectives specified within the solicitation request. Ultimately, the NJBPU has the final say on which projects will move forward, if any. If New Jersey moves forward with any of the proposed projects, the costs will be allocated solely to the state's ratepayers.

New Jersey's initiation of the SAA is the first time a state in the PJM region has elected to achieve its public policy goals through PJM's competitive RTEP process. In this instance, doing so will enable the construction of large-scale, offshore wind-powered generation. This joint New Jersey-PJM SAA experience provides an effective planning blueprint going forward for states to pursue their own respective renewable portfolio standards and other public policy goals as part of effective, coordinated planning within PJM for the grid of the future.

Figure 5.3: New Jersey Offshore Wind Potential Solutions



Diagrams are for illustration purposes only.

5.3: Interconnection Queue Initiatives

PJM/Stakeholder Initiative

Based on related workshop feedback, the Planning Committee (PC) at its April 2021 meeting approved an issue charge creating an Interconnection Process Reform Task Force (IPRTF). The task force was charged with developing improvements to the existing interconnection process in order to reduce queue backlog and increase efficiency. The sixteen meetings – beginning in April 2021 – yielded substantive discussion leading to:

1. A proposal accepted by the PC in January 2022
2. Transition plan proposals upon which the PC is expected to vote at its February 2022 meeting

Process Reforms

Throughout the task force meetings, numerous ideas and proposals were put forward. Out of these discussions emerged general consensus on PJM's proposal to change the current "first come, first served" approach to a "first ready, first served" approach. The proposal reforms the interconnection process, breaking it up into three phases. At the end of each, the interconnection customer (IC) must decide whether to continue or withdraw from the process. ICs will be required to submit readiness deposits based on the size of the project in order to progress through successive process phases. The interconnection request queue itself will be modified from the current two, six-month windows each year to a rolling window, each open until cycle application deadline posted at the beginning of Phase No. 2 of the previous cycle (180 days in advance).

The opening of each successive rolling window will be based on the completion of the prior one. Additionally, the IC will only be able to select a single point of interconnection for each application.

Transition Process Proposals

In parallel with process package development, the IPRTF also developed transition plans by which PJM will implement the process reform changeover. Three main transition packages emerged over the course of the sixteen IPRTF meeting discussions. All three proposals maintain the interconnection queues up to and through AD2 under the existing interconnection process. For queues AE1 through AG1, IC requests will fall under an expedited process. The three transition proposals differ in terms of the network upgrade cost allocation criteria to be considered for the expedited process. The packages are expected to be voted on at the February 2022 Planning Committee meeting.

NOTE:

- **Jan. 11, 2022:** The PJM Planning Committee vote endorsed a process package developed by PJM with nearly 100% support. Nearly 100% also agreed that the proposed solution was preferable to the status quo. A description of the package can be found on PJM's website.
- **Feb. 8, 2022:** The PJM Planning Committee endorsed the PJM transition package with 91% approval. A description of the transition package can be found on PJM's website.

PJM anticipates an MRC first read of both the process package and transition package in March with MRC and MC vote in April.

Section 6: State Summaries

6.0: Delaware RTEP Summary

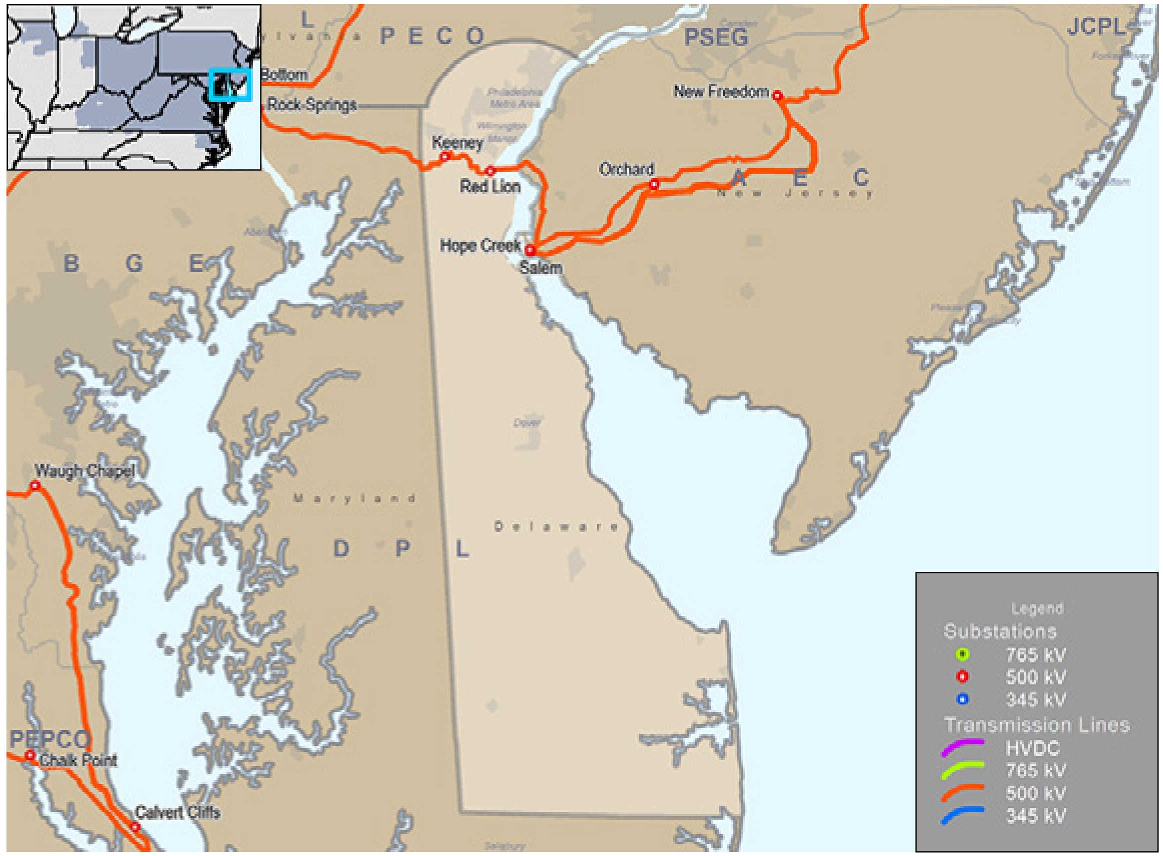
6.0.1 — RTEP Context

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

Renewable Portfolio Standards

From an energy policy perspective, Delaware has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years. In 2021, Delaware increased its mandatory RPS to 40% by 2035. This new target includes a minimum solar carve-out of 10% by 2035 as well.

Map 6.1: PJM Service Area in Delaware



Close X

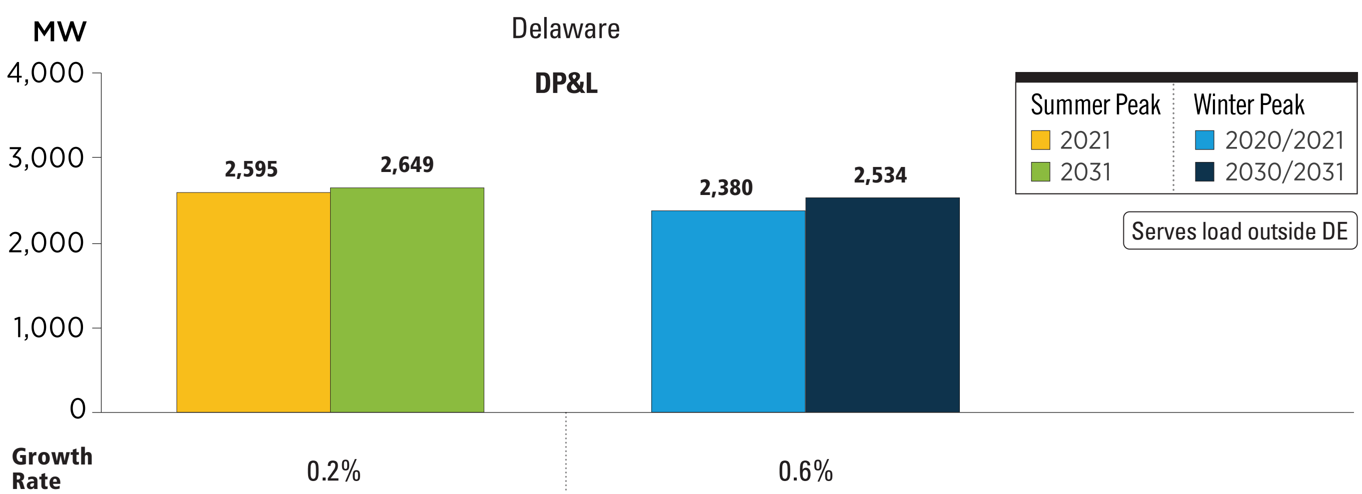
Use this button to jump to the next section.

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

6.0.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.1** summarizes the expected loads within the state of Delaware and across PJM.

Figure 6.1: Delaware – 2021 Load Forecast Report



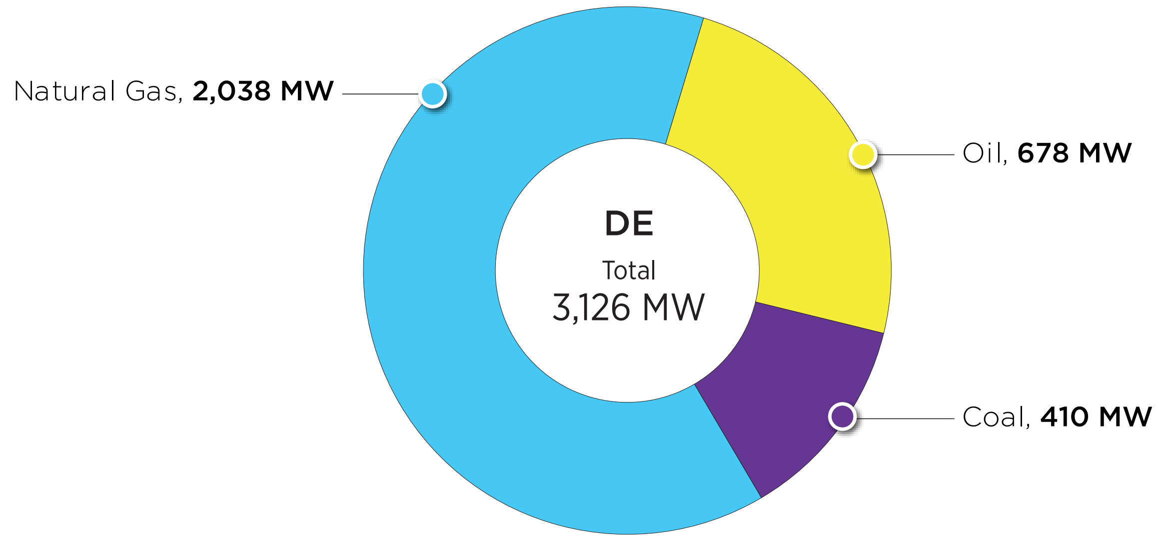
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.0.3 — Existing Generation

Existing generation in Delaware as of Dec. 31, 2021, is shown by fuel type in **Figure 6.2**.

Figure 6.2: Delaware – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.0.4 — Interconnection Requests

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

Specifically, in Delaware, as of Dec. 31, 2021, 48 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.1**, **Table 6.2**, **Figure 6.3**, **Figure 6.4** and **Figure 6.5**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.1: Delaware – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	Delaware Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	0	0.00%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	451	13.86%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	0	0.00%	17	0.01%
Other	0	0.00%	331	0.20%
Solar	486	14.93%	93,756	57.99%
Storage	235	7.23%	34,130	21.11%
Wind	2,082	63.98%	8,800	5.44%
Grand Total	**3,254**	**100.00%**	**161,682**	**100.00%**

Table 6.2: Delaware – Interconnection Requests (Dec. 31, 2021)

		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	653.0
	Natural Gas	0	0.0	1	451.0	18	1,281.1	19	5,556.4	38	7,288.5
	Oil	0	0.0	0	0.0	5	168.2	1	1.0	6	169.2
	Other	0	0.0	0	0.0	2	30.0	0	0.0	2	30.0
	Storage	6	235.2	0	0.0	0	0.0	4	45.0	10	280.2
Renewable	Biomass	0	0.0	0	0.0	1	0.0	4	24.0	5	24.0
	Methane	0	0.0	0	0.0	4	9.0	3	28.8	7	37.8
	Solar	15	386.1	10	99.9	0	0.0	30	341.6	55	827.6
	Wind	15	2,017.8	1	64.4	0	0.0	5	396.9	21	2,479.1
	Grand Total	**36**	**2,639.1**	**12**	**615.3**	**32**	**1,511.3**	**67**	**7,023.7**	**147**	**11,789.4**

Figure 6.3: Delaware – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

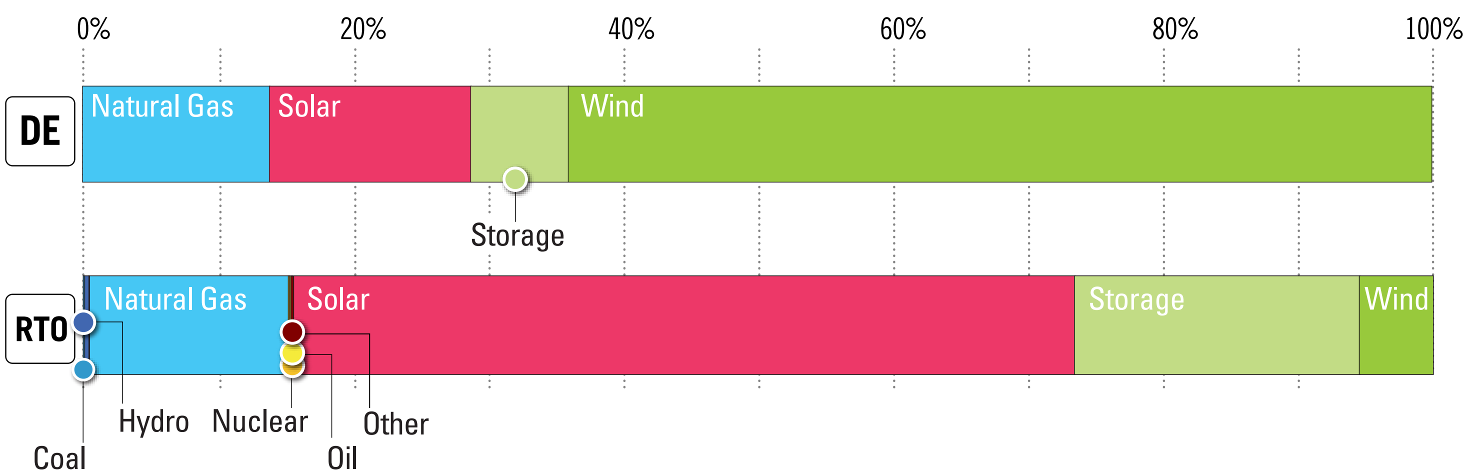
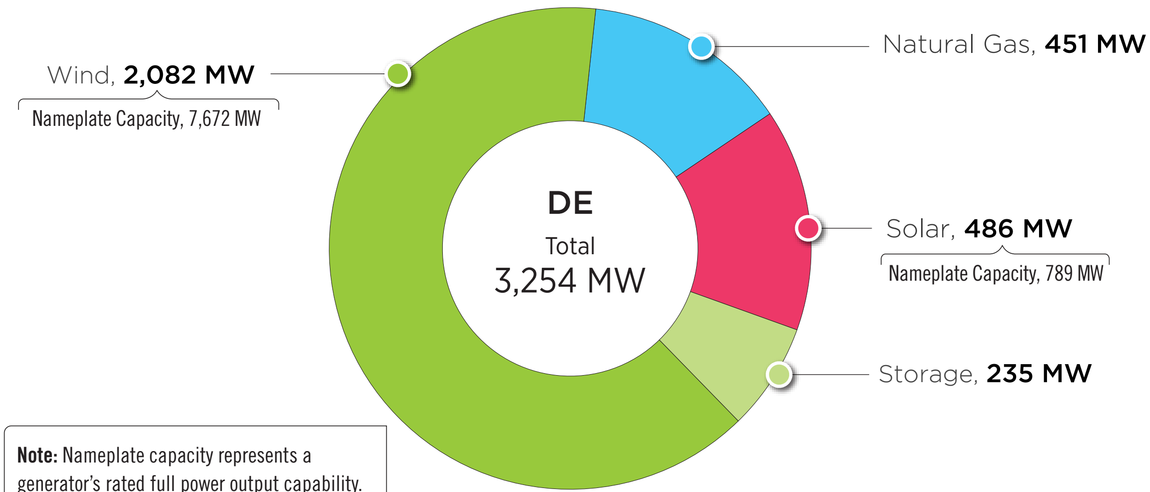


Figure 6.4: Delaware – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.5: Delaware Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

16.5%	Requested capacity megawatts
28.8%	Requested projects

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

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.0.5 — Generation Deactivation

Known generating unit deactivation requests in Delaware between Jan. 1, 2021, and Dec. 31, 2021, are summarized in **Map 6.2** and **Table 6.3**.

Map 6.2: Delaware Generation Deactivations (Dec. 31, 2021)

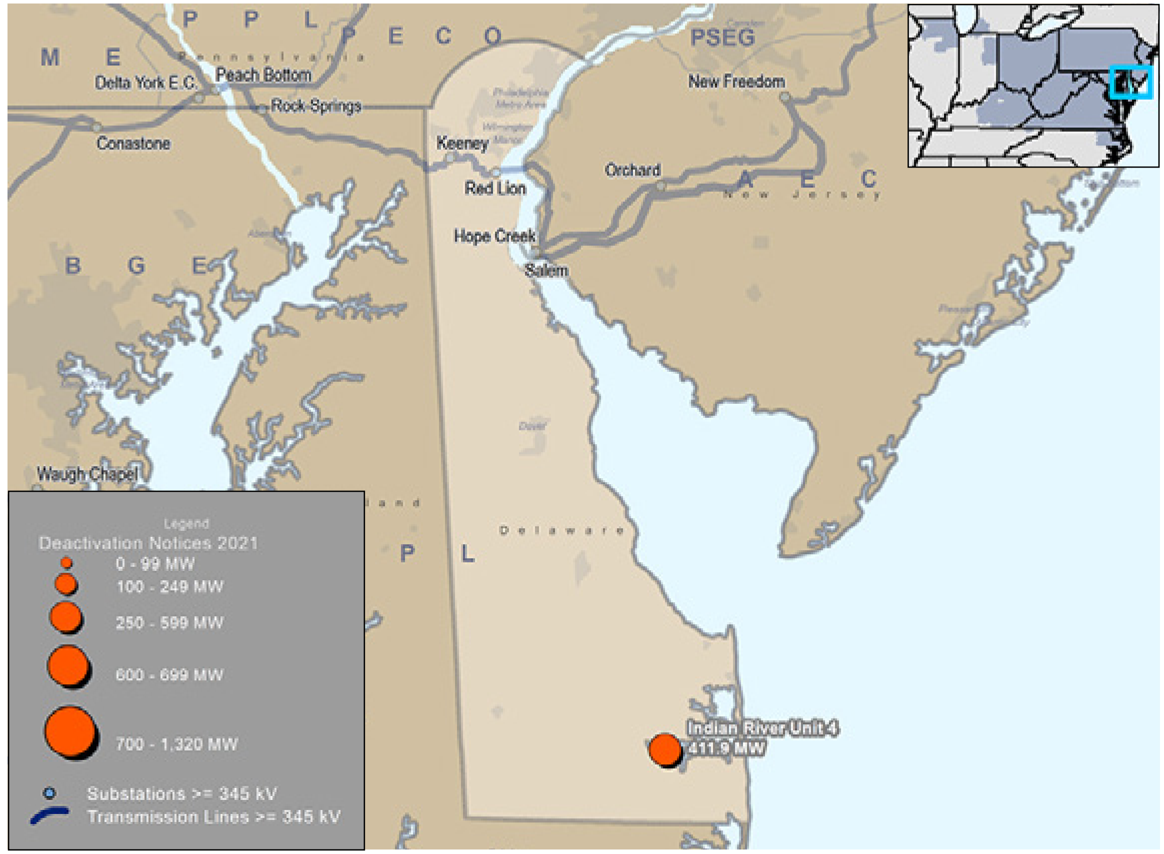


Table 6.3: Delaware Generation Deactivations (Dec. 31, 2021)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Indian River 4	DP&L	Coal	6/30/2021	5/31/2022	41	411.9

6.0.6 — Baseline Projects

2021 RTEP baseline projects in Delaware are summarized in **Map 6.3** and **Table 6.4**.

Map 6.3: Delaware Baseline Projects (Dec. 31, 2021)

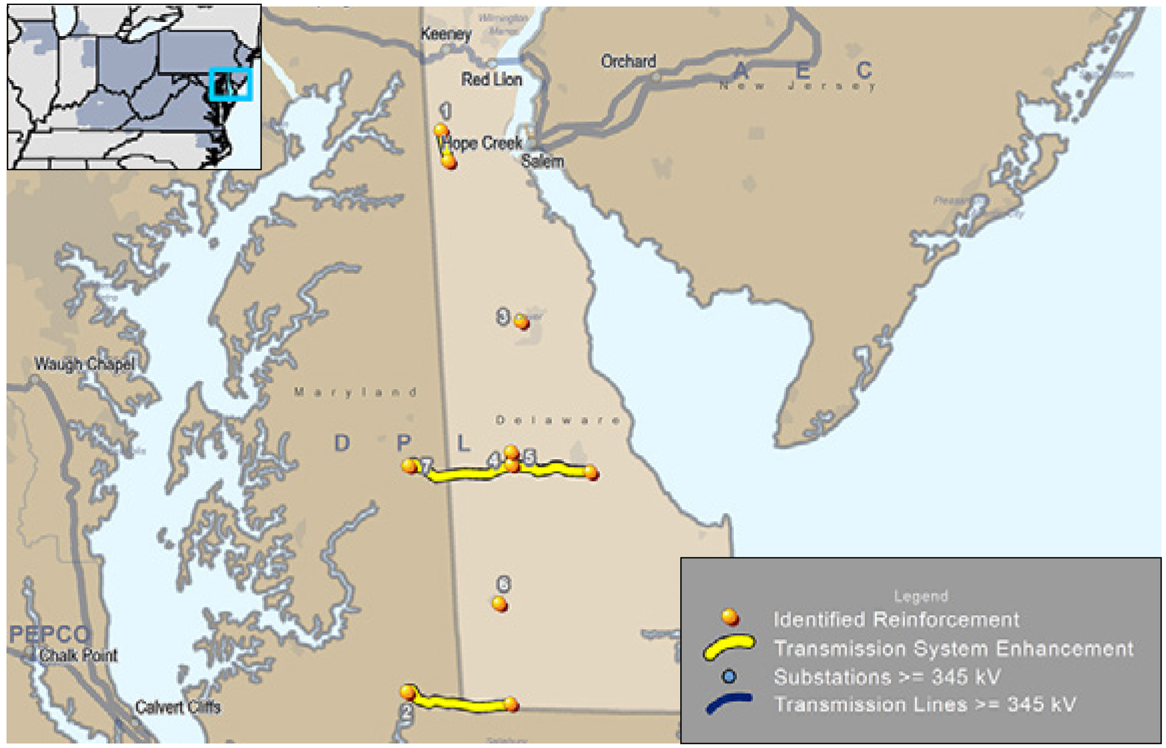


Table 6.4: Delaware Baseline Projects (Dec. 31, 2021)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3224	Replace a disconnect switch and reconductor a short span of Mt. Pleasant-Middletown tap line.	6/1/2025	$0.43	DP&L	11/18/2020
2	B3326	Rebuild the 13707 Vienna-Nelson 138 kV line.	6/1/2022	$38.50		8/10/2021
3	B3327	Upgrade the disconnect switch (6784-L1) at Kent.		$0.25		8/31/2021
4	B3329	Rerate the 13773 Farmview-Milford 138 kV line.		$0.30		
5	B3330	Rerate the 13774 Farmview-S. Harrington 138 kV line.		$0.25		
6	B3331	Upgrade bus conductor and relay at Seaford 138 kV.		$0.50		
7	B3332	Rerate the 23076 Steel-Milford 230 kV line.		$0.60		

6.0.7 — Network Projects

2021 RTEP network projects in Delaware are summarized in **Map 6.4** and **Table 6.5**.

Map 6.4: Delaware Network Projects (Dec. 31, 2021)

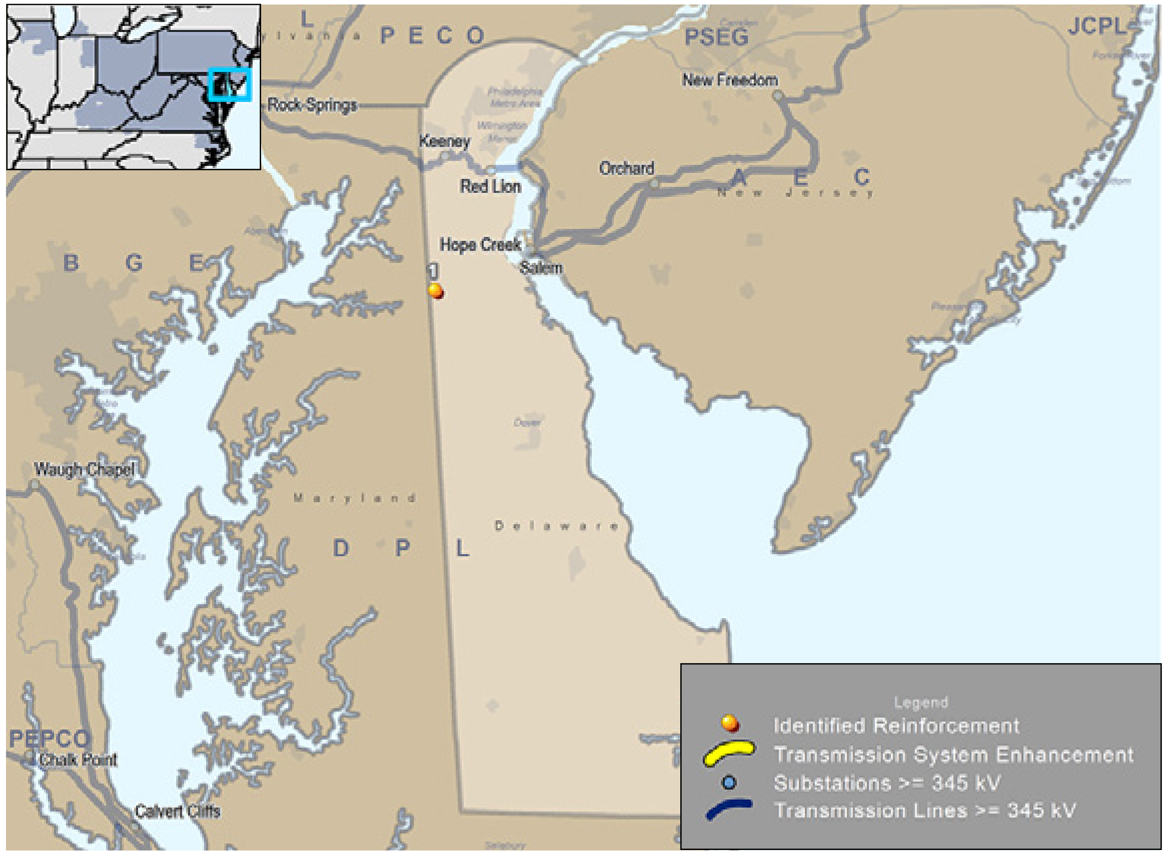


Table 6.5: Delaware Network Projects (Dec. 31, 2021)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N6974	Construct a new seventh breaker position onto the 138 kV, six-breaker position ring bus at Townsend substation. Install metering control cable and meter cabinets, secondary wiring connections at the metering enclosure, primary and backup. Solid state multifunction meters for the new metering position, protective relays and perform relay setting changes as required.	AC1-203	10/1/2022	$1.94	DP&L	11/30/2021

6.0.8 — Supplemental Projects

2021 RTEP supplemental projects in Delaware are summarized in **Map 6.5** and **Table 6.6**.

6.0.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Delaware were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.5: Delaware Supplemental Projects (Dec. 31, 2021)

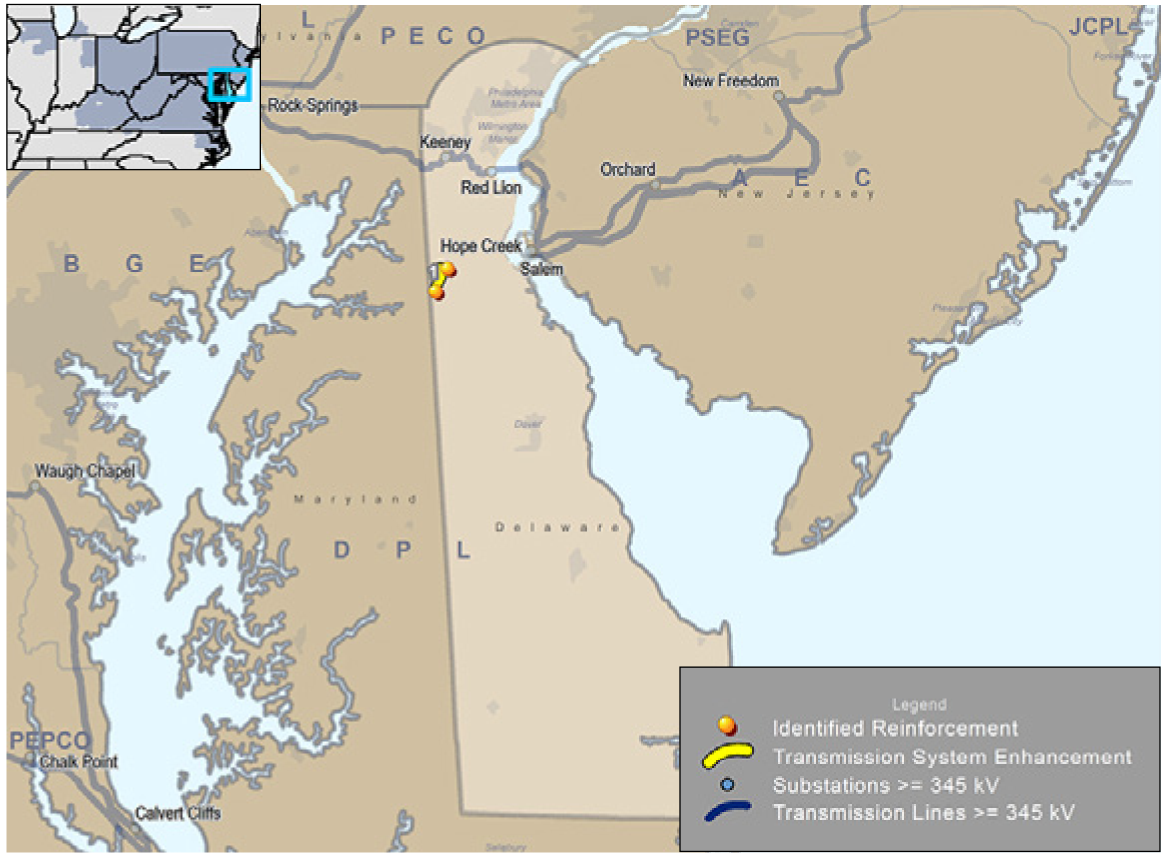


Table 6.6: Delaware Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2489	Construct new 138 kV feed (approx. 4 miles) out of Townsend substation, utilizing an open terminal position, to a new four-breaker ring bus adjacent to customer's existing substation. De-energize remainder of line from existing Middletown Tap to Townsend.	5/31/2025	$23.00	DP&L	2/16/2021

6.1: Northern Illinois RTEP Summary

6.1.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Northern Illinois, including facilities owned and operated by Commonwealth Edison (ComEd) and the City of Rochelle as shown on **Map 6.6**. The Northern Illinois' transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

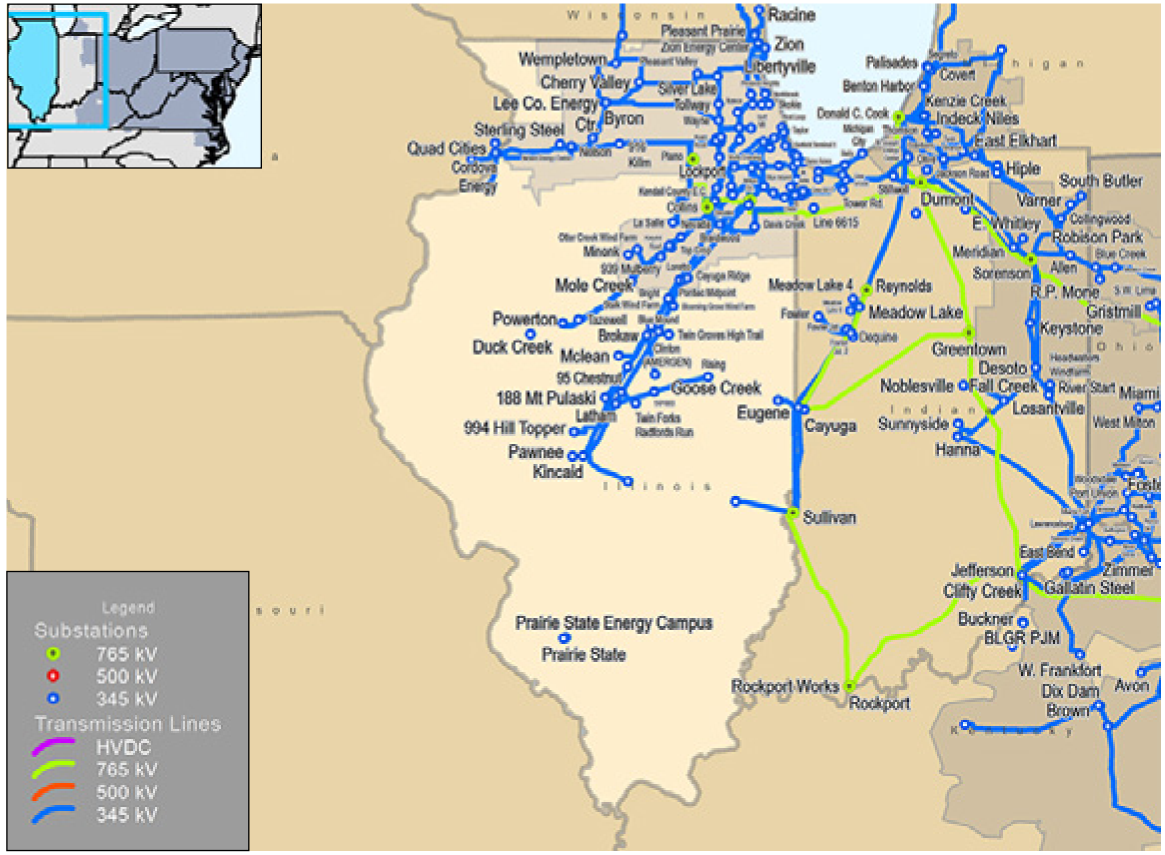
Renewable Portfolio Standards

From an energy policy perspective, Illinois has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

Illinois increased its RPS to 40% renewable energy by 2030 and 50% renewables by 2040. This new RPS target was a component of the Climate and Equity Jobs Act (CEJA) that was enacted in 2021. The RPS also contains specific carve-outs for wind and solar.

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

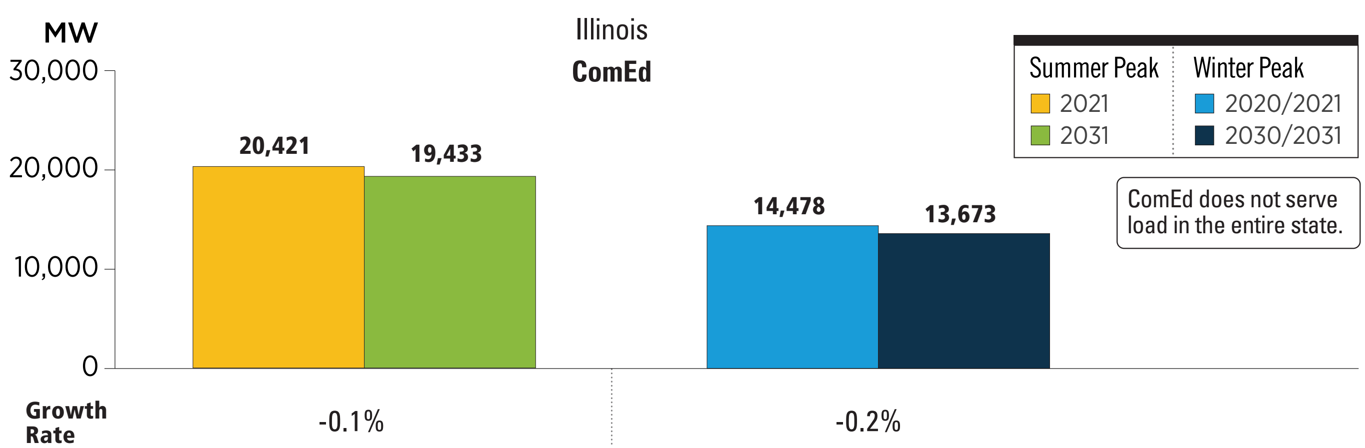
Map 6.6: PJM Service Area in Northern Illinois



6.1.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.6** summarizes the expected loads within Northern Illinois and across PJM.

Figure 6.6: Northern Illinois – 2021 Load Forecast Report



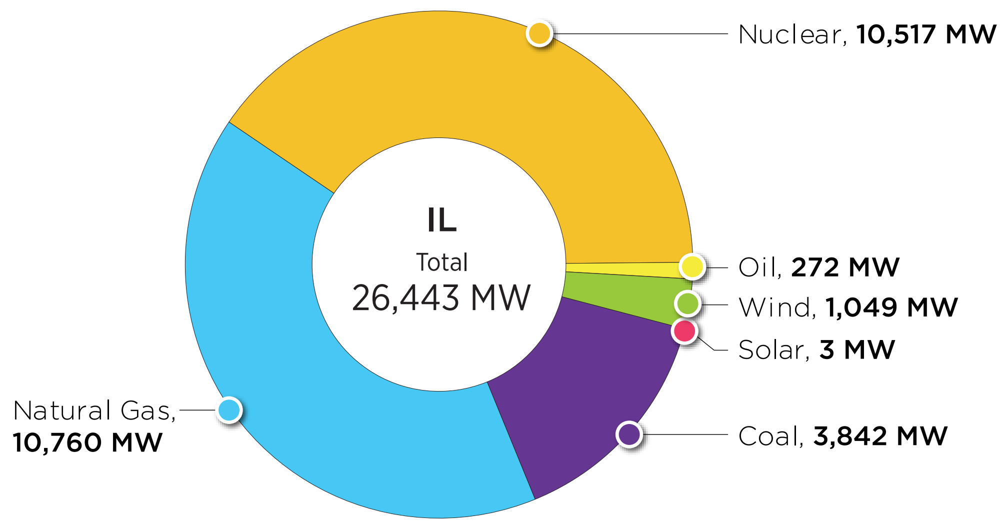
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.1.3 — Existing Generation

Existing generation in Northern Illinois as of Dec. 31, 2021, is shown by fuel type in **Figure 6.7**.

Figure 6.7: Northern Illinois – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.1.4 — Interconnection Requests

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

Specifically, in Northern Illinois, as of Dec. 31, 2021, 211 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.7**, **Table 6.8**, **Figure 6.8**, **Figure 6.9** and **Figure 6.10**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.7: Northern Illinois – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	Northern Illinois Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	12	0.06%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	5,004	26.83%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	0	0.00%	17	0.01%
Other	0	0.00%	331	0.20%
Solar	8,620	46.23%	93,756	57.99%
Storage	3,415	18.31%	34,130	21.11%
Wind	1,597	8.56%	8,800	5.44%
Grand Total	**18,647**	**100.00%**	**161,682**	**100.00%**

Table 6.8: Northern Illinois – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	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	0	0.0	5	3,652.0	5	3,652.0
	Diesel	0	0.0	0	0.0	0	0.0	2	22.0	0	0.0	2	22.0
	Natural Gas	10	1,810.6	2	450.0	10	2,742.9	21	1,703.6	21	8,908.3	64	15,615.4
	Nuclear	0	0.0	0	0.0	0	0.0	10	385.8	5	782.0	15	1,167.8
	Other	1	0.0	0	0.0	0	0.0	0	0.0	6	0.0	7	0.0
	Storage	47	3,415.1	0	0.0	0	0.0	8	0.0	29	1,139.7	84	4,554.8
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	3	90.0	3	90.0
	Hydro	0	0.0	0	0.0	1	12.1	0	0.0	3	14.9	4	27.0
	Methane	0	0.0	0	0.0	0	0.0	3	35.0	14	63.9	17	98.9
	Solar	92	8,562.6	0	0.0	4	57.1	1	3.4	59	2,408.3	156	11,031.4
	Wind	45	1,570.6	0	0.0	1	26.0	31	847.7	111	2,922.4	188	5,366.7
	Grand Total	**195**	**15,359.0**	**2**	**450.0**	**16**	**2,838.1**	**76**	**2,997.5**	**256**	**19,981.5**	**545**	**41,626.1**

Figure 6.8: Northern Illinois – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

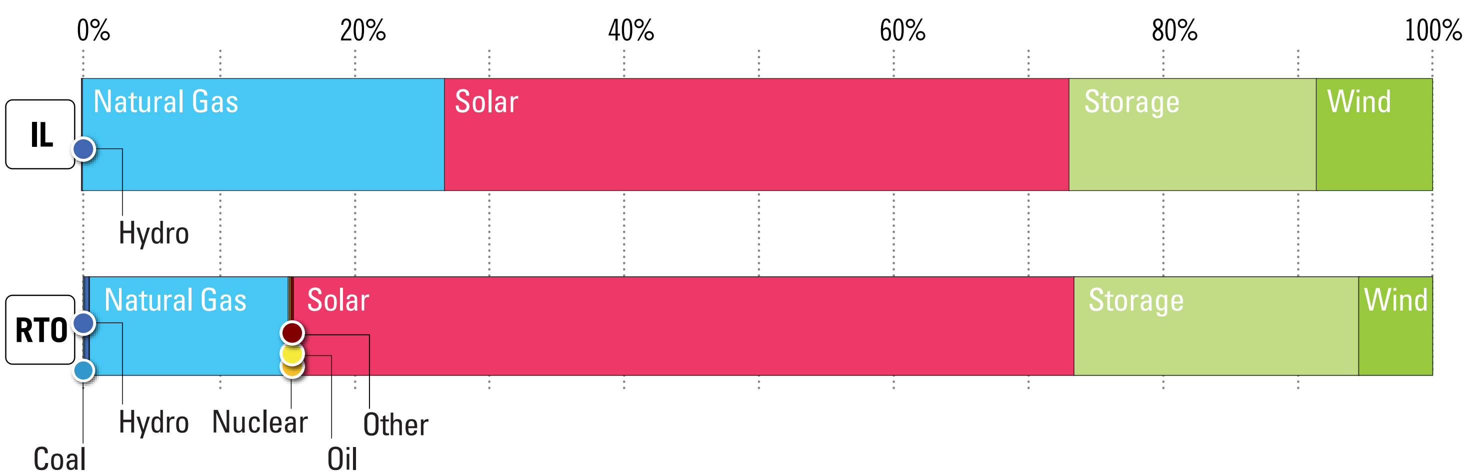
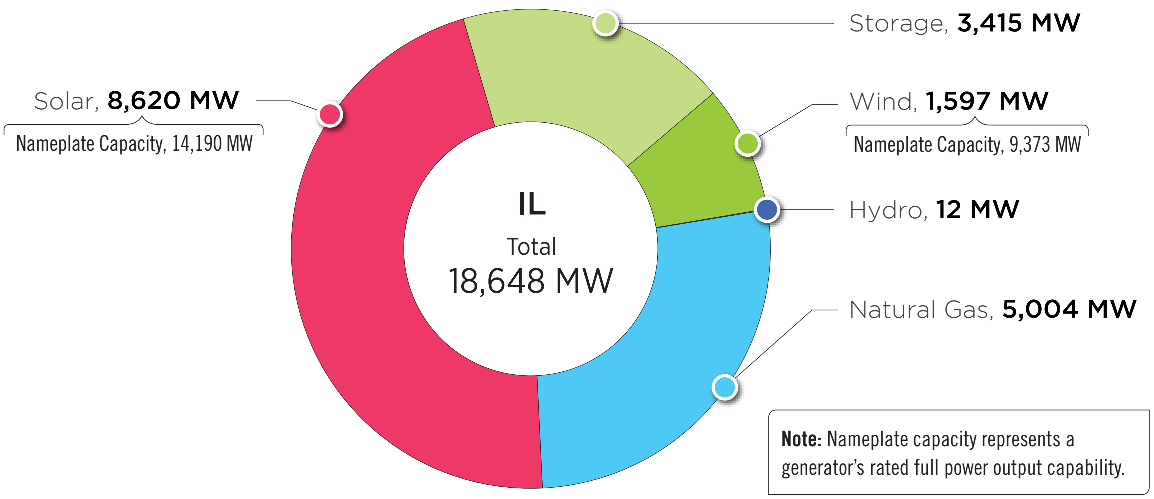


Figure 6.9: Northern Illinois – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.10: Northern Illinois Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

11.8% Requested capacity megawatts

22.9 % Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	8	Interconnection Service Agreements	376 MW	1,678 MW
	5	Wholesale Market Participation Agreements	14 MW	25 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.1.5 — Generation Deactivation

Known generating unit deactivation requests in Northern Illinois between Jan. 1, 2021, and Dec. 31, 2021, are summarized in **Map 6.7** and **Table 6.9**.

Map 6.7: Northern Illinois Generation Deactivations (Dec. 31, 2021)

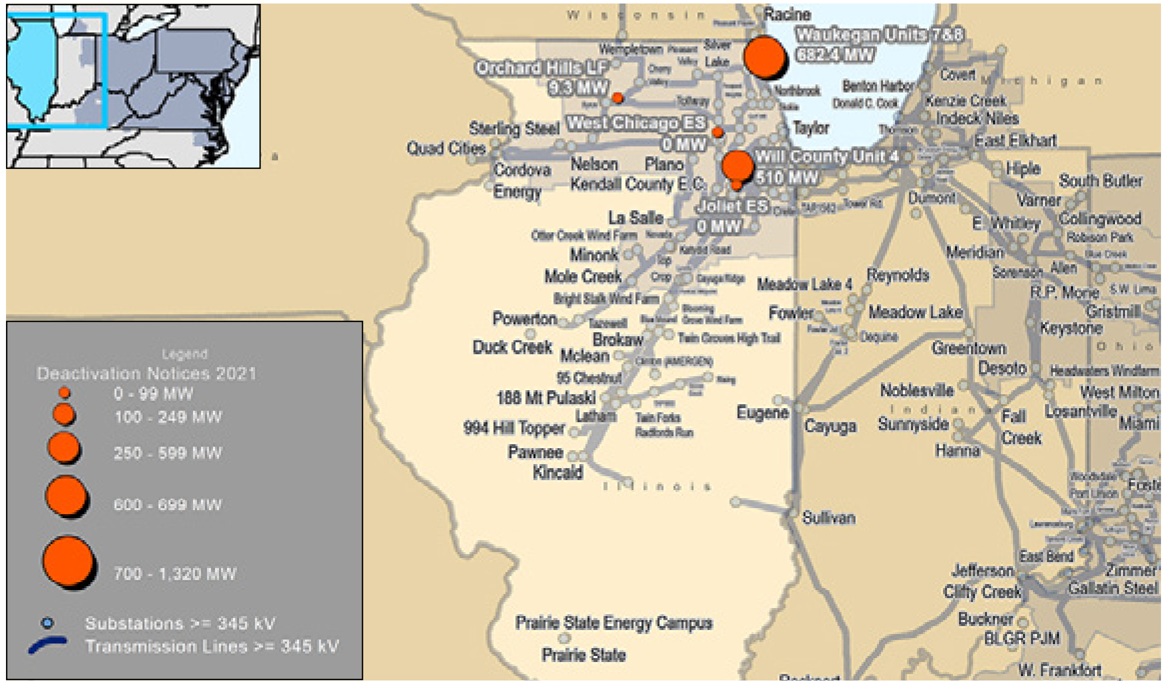


Table 6.9: Northern Illinois Generation Deactivations (Dec. 31, 2021)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Orchard Hills LF	ComEd	Methane	12/30/2021	3/31/2022	5	9.3
Joliet Energy Storage	ComEd	Battery	11/9/2021	2/8/2022	6	0
West Chicago Energy Storage	ComEd	Battery	11/9/2021	2/8/2022	6	0
Will County 4	ComEd	Coal	6/30/2021	5/31/2022	58	510
Waukegan 8	ComEd	Coal	6/30/2021	5/31/2022	59	354.4
Waukegan 7	ComEd	Coal	6/30/2021	5/31/2022	63	328

6.1.6 — Baseline Projects

2021 RTEP baseline projects in Northern Illinois are summarized in **Map 6.8** and **Table 6.10**.

Map 6.8: Northern Illinois Baseline Projects (Dec. 31, 2021)

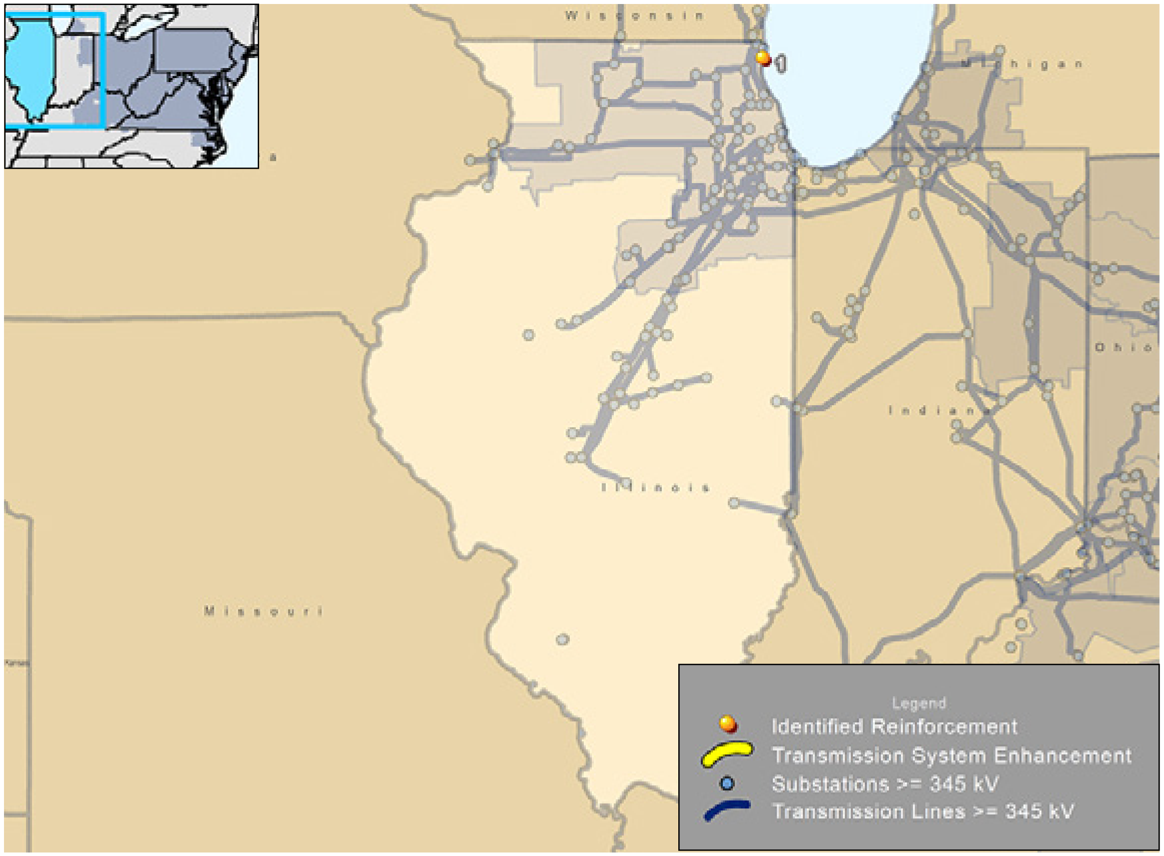


Table 6.10: Northern Illinois Baseline Projects (Dec. 31, 2021)

Map ID	Project	Description	Required In Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3317	Modify backup relay clearing times at the 138 kV STA16 Waukegan station.	6/1/2023	$0.26	ComEd	5/21/2021

6.1.7 — Network Projects

2021 RTEP network projects in Northern Illinois are summarized in **Map 6.9** and **Table 6.11**.

Map 6.9: Northern Illinois Network Projects (Dec. 31, 2021)

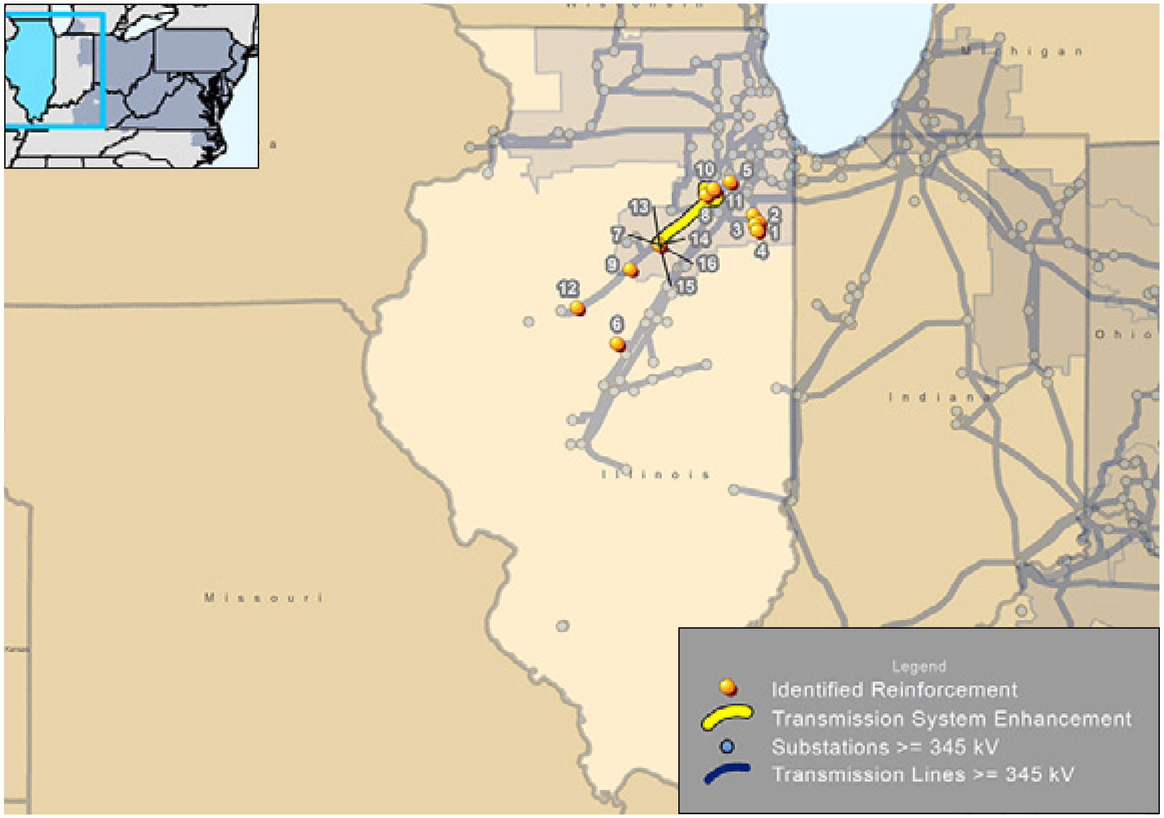


Table 6.11: Northern Illinois Network Projects (Dec. 31, 2021)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N1830	Oversee building the interconnection substation Kensington Ave. TSS 199.	S36	12/31/2011	$0.55	ComEd	11/30/2021
2	N1831	Kensington Ave. TSS199 – Install 138 kV trasmisison line tie in.			$0.11		
3	N1832.1	Perform relay and SCADA modifications at Davis Creek TSS 86.			$0.362		
	N1832.2	Perform relay and SCADA modifications at Bradley TSS 70.			$0.603		
	N1832.3	Perform relay and SCADA modifications at Kankakee TSS 157.			$0.140		

Table 6.11: Northern Illinois Network Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	N1835	Perform relay modifications at TSS 199 Kensington Ave. substation.	S37	12/31/2016	$0.29	ComEd	11/30/2021
5	N6025	Perform expansion of TSS 900 Elwood to accommodate AC1-204 attachment.	AC1-204	6/1/2022	$11.45		
6	N6306	Install line terminal and metering at TSS92 McLean	AB2-047	6/30/2021	$0.5		
	N6307	Install breaker for L91305 at TSS92 McLean.			$2.00		
7	N6391	Consider option to build oversight at TSS 939 Mulberry and TSS924 Three Rivers.	AB1-122	2/1/2022	$4.237		
8	N6392	Install fiber optics cable 13.1 miles TSS 939 Mulberry to station 23 Collins.			$2.00		
9	N6393	Modify 93913 relaying at TSS 908 Mole Creek.			$0.225		
10	N6394	Modify 1202 line relaying station 12 Dresden.			$0.209		
11	N6395	Modify 1227 line relaying station 12 Dresden.			$0.209		
12	N6936	Modify 93915 relaying at Tazewell.			$0.089		
13	N6397	Modify 1202 tie in at TSS 939 Mulberry.			$0.684		
14	N6398	Modify 1227 tie in at TSS 939 Mulberry.			$0.684		
15	N6399	Modify 93913 tie in at TSS 939 Mulberry.			$0.684		
16	N6400	Modify 93915 tie in at TSS 939 Mulberry.			$0.684		

6.1.8 — Supplemental Projects

2021 RTEP supplemental projects in Northern Illinois are summarized in **Map 6.10** and **Table 6.12.**

Map 6.10: Northern Illinois Supplemental Projects (Dec. 31, 2021)

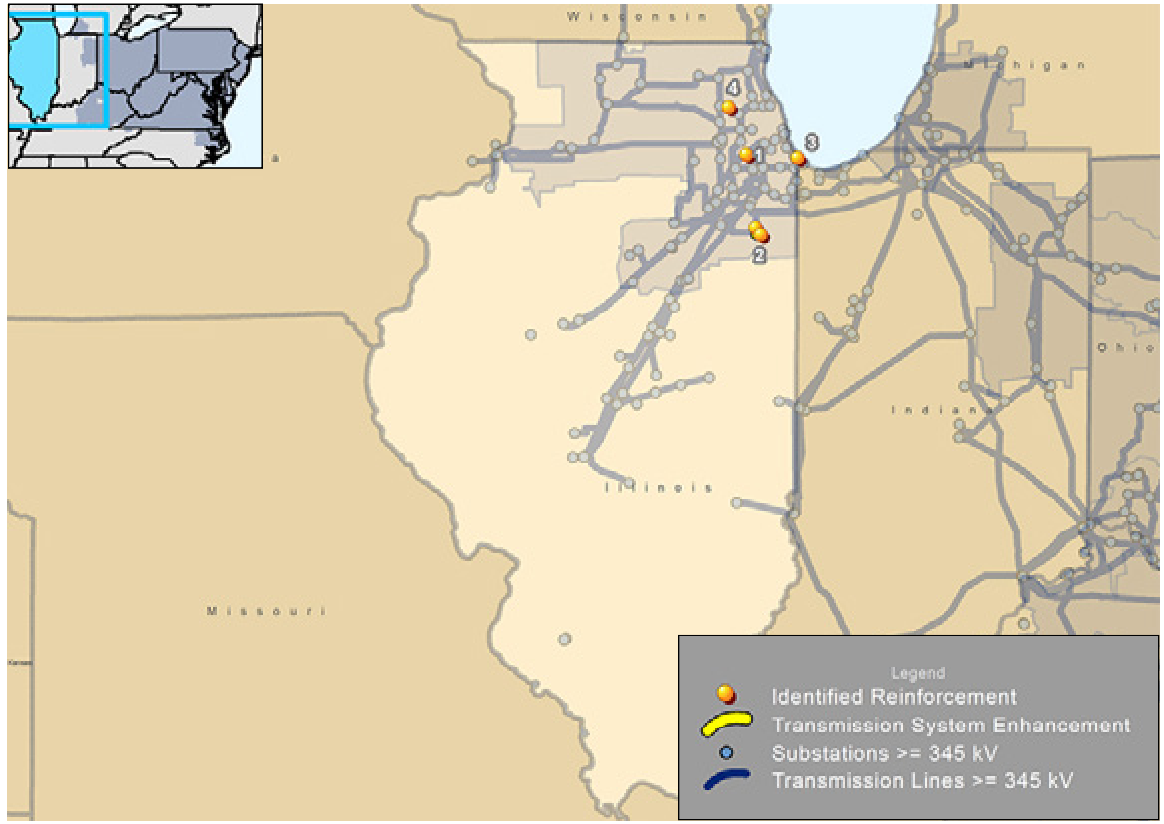


Table 6.12: Northern Illinois Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2463	Replace ESS J310 138 kV breaker BT 1–2.	2/28/2023	$2.10	ComEd	2/17/2021
2	S2519	Rebuild 3.5 miles of line 8604 on steel poles with 1113 kcmil ACSR conductor. Normally close 138 kV line 8604 circuit breaker at Bradley. Replace two overdutied 138 kV circuit breakers at Bradley.	12/31/2023	$22.30		4/16/2021
3	S2520	Install 138 kV circuit breaker on line 0708 (State line substation).		$2.60		
4	S2582	Rebuild Hoffman Estates with BAAH GIS. Extend two 138 kV lines 1.5 miles to new customer substation.		$0.00		7/16/2021

6.1.9 — Merchant Transmission Project Requests

As of Dec. 31, 2021, PJM's queue contained two merchant transmission project requests with a terminal in Northern Illinois, as shown in **Map 6.11** and **Table 6.13**.

Map 6.11: Northern Illinois Merchant Transmission Project Requests (Dec. 31, 2021)

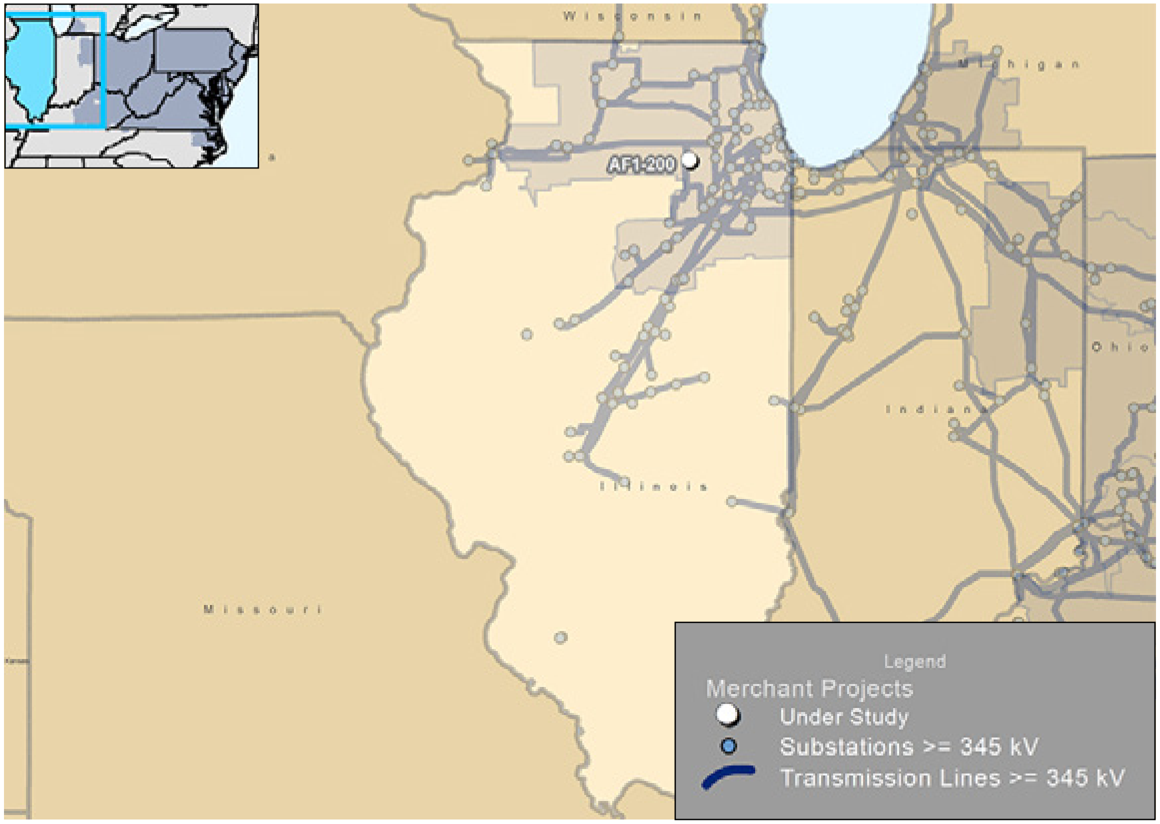


Table 6.13: Northern Illinois Merchant Transmission Project Requests (Dec. 31, 2021)

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

6.2: Indiana RTEP Summary

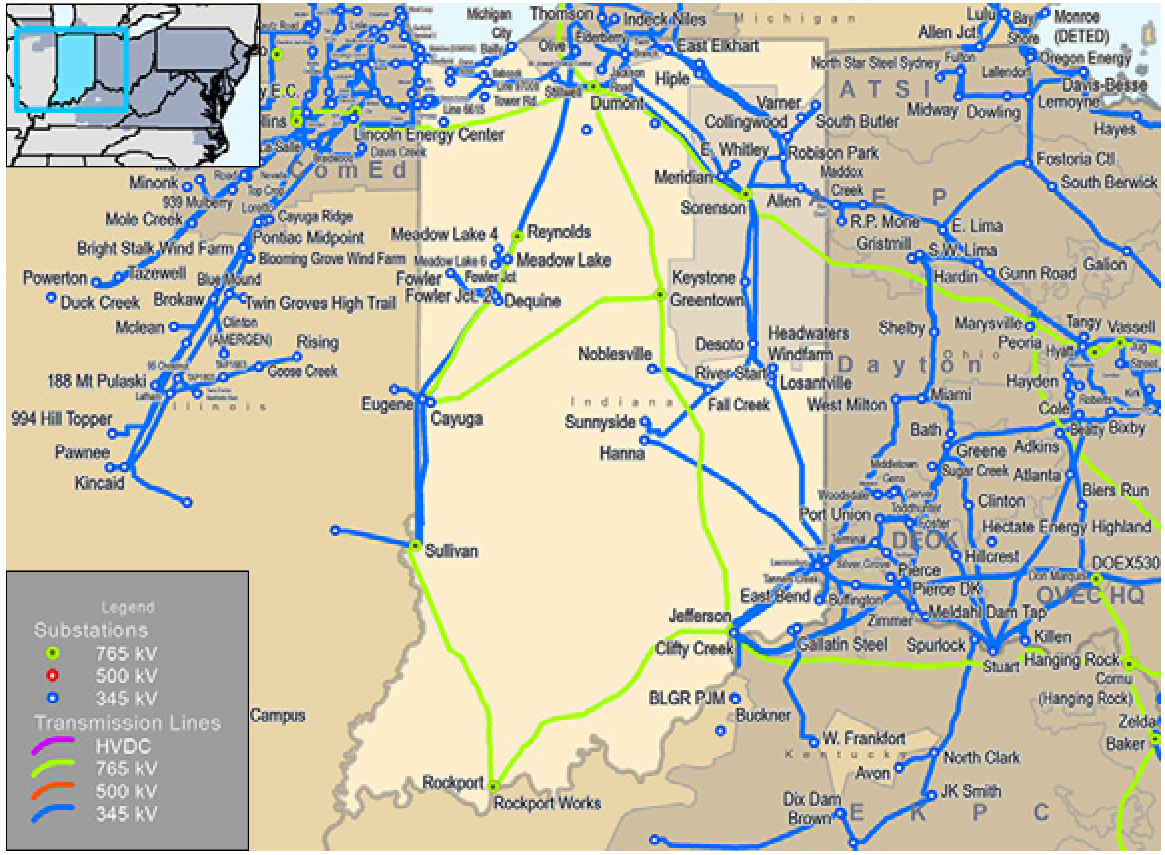
6.2.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Indiana, including facilities owned and operated by American Electric Power (AEP) as shown on **Map 6.12.** Indiana's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

Many states have announced goals to encourage clean and renewable generation in the coming years. From an energy policy perspective, 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.

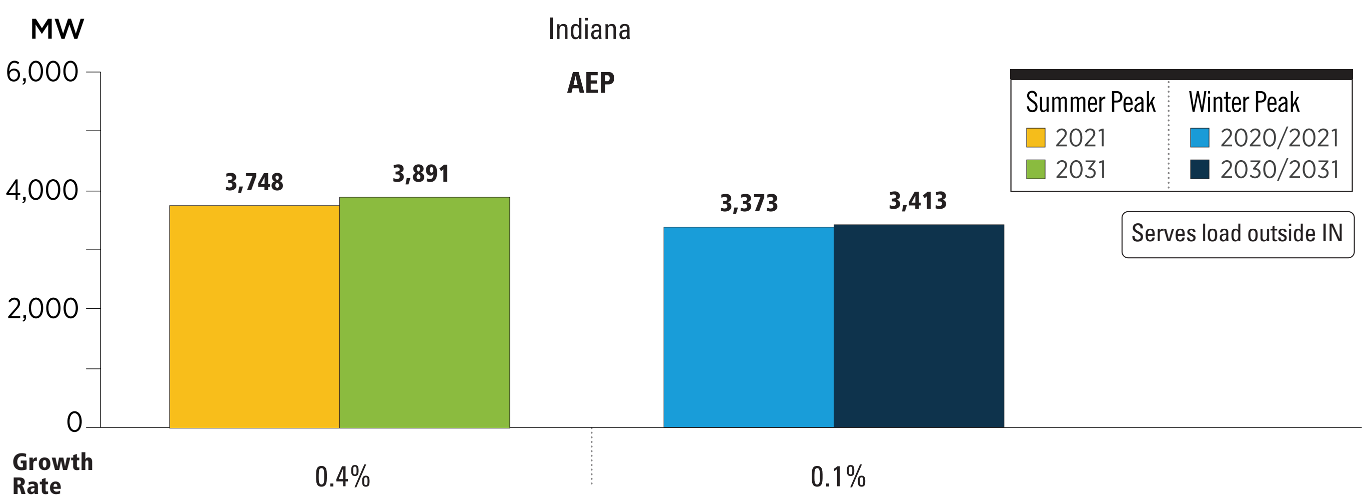
Map 6.12: PJM Service Area in Indiana



6.2.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.11** summarizes the expected loads within the state of Indiana and across PJM.

Figure 6.11: Indiana – 2021 Load Forecast Report



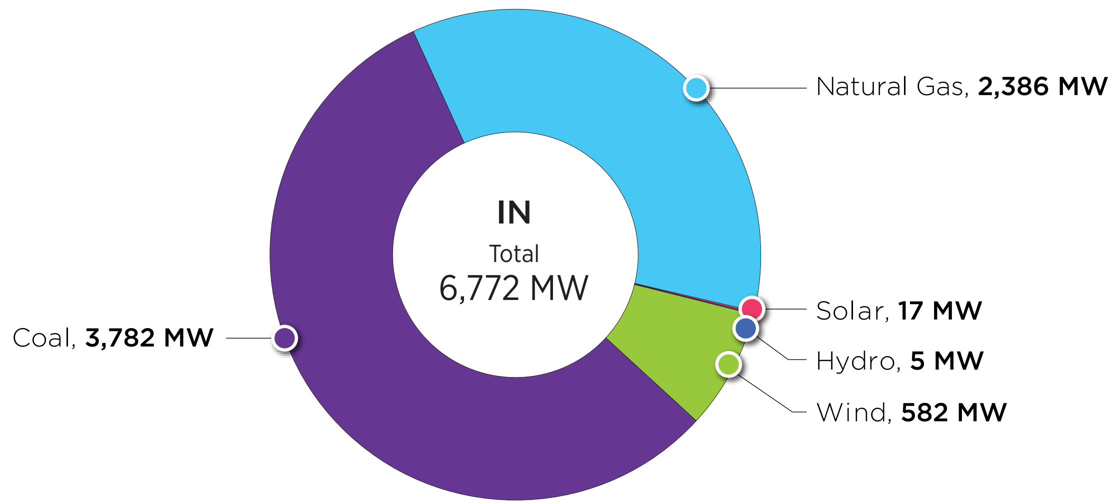
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.2.3 — Existing Generation

Existing generation in Indiana as of Dec. 31, 2021, is shown by fuel type in **Figure 6.12**

Figure 6.12: Indiana – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.2.4 — Interconnection Requests

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

Specifically, in Indiana, as of Dec. 31, 2021, 198 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.14**, **Table 6.15**, **Figure 6.13**, **Figure 6.14** and **Figure 6.15**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.14: Indiana – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	Indiana Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	0	0.00%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	1,885	9.96%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	0	0.00%	17	0.01%
Other	253	1.34%	331	0.20%
Solar	12,594	66.52%	93,756	57.99%
Storage	3,849	20.33%	34,130	21.11%
Wind	351	1.85%	8,800	5.44%
Grand Total	**18,933**	**100.00%**	**161,682**	**100.00%**

Table 6.15: Indiana – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue				Complete					
		Active		Under Construction		In Service		Withdrawn		Grand Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	4	66.0	2	901.0	6	967.0
	Natural Gas	4	1,835.0	1	50.0	5	811.0	2	1,747.0	12	4,443.0
	Other	1	253.4	0	0.0	0	0.0	0	0.0	1	253.4
	Storage	47	3,849.3	0	0.0	0	0.0	13	614.1	60	4,463.5
Renewable	Methane	0	0.0	0	0.0	2	8.0	1	3.6	3	11.6
	Solar	130	12,426.8	3	167.5	4	17.1	29	3,819.6	166	16,431.0
	Wind	12	350.8	0	0.0	11	414.9	50	1,835.6	73	2,601.3
	Grand Total	**194**	**18,715.3**	**4**	**217.5**	**26**	**1,317.0**	**97**	**8,921.0**	**321**	**29,170.8**

Figure 6.13: Indiana – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

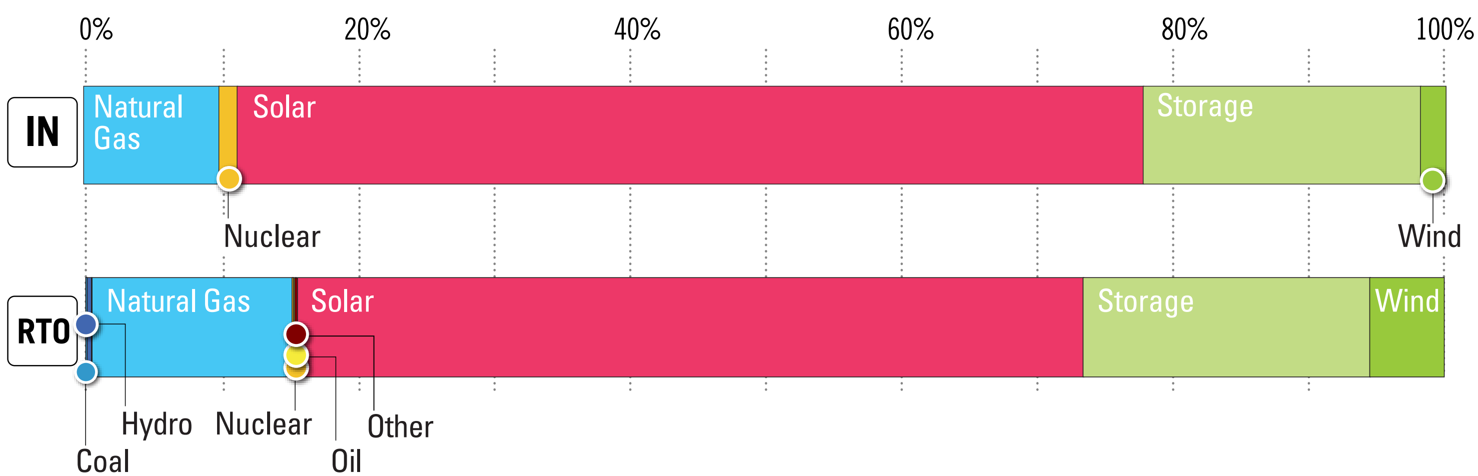
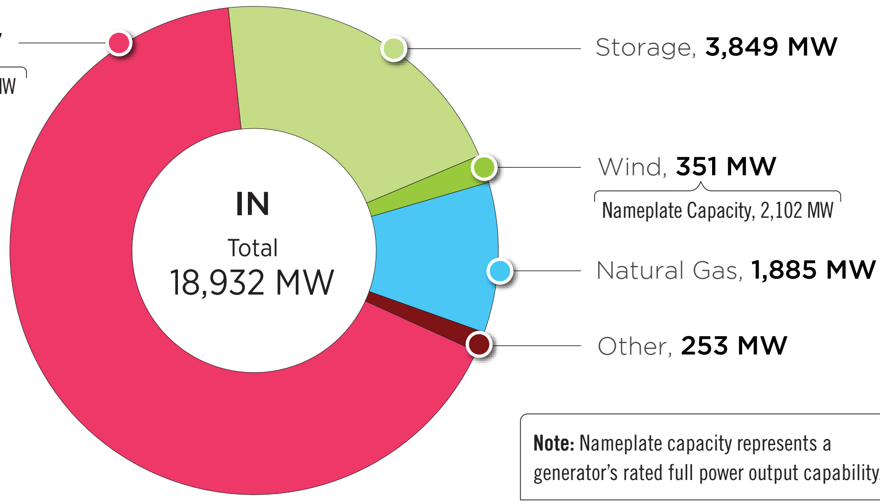


Figure 6.14: Indiana – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.15: Indiana Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

13.8%	Requested capacity megawatts
22.8 %	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	3	Interconnection Service Agreements	74 MW	420 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.2.5 — Generation Deactivation

There were no generating unit deactivation requests in Indiana between Jan. 1, 2021, and Dec. 31, 2021, as part of the 2021 RTEP.

6.2.6 — Baseline Projects

2021 RTEP baseline projects in Indiana are summarized in **Map 6.13** and **Table 6.16**.

Map 6.13: Indiana Baseline Projects (Dec. 31, 2021)

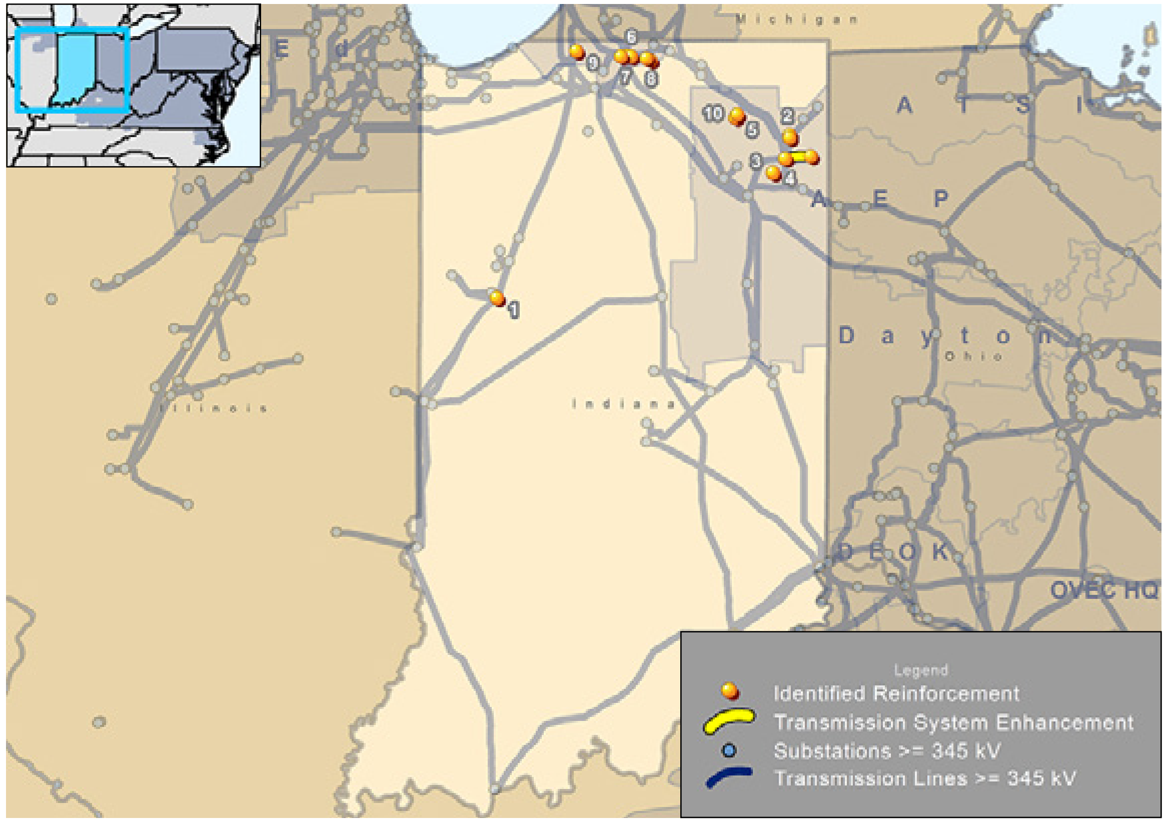


Table 6.16: Indiana Baseline Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B2668	.1	Replace the bus/risers at Dequine 345 kV station.	6/1/2020	$2.30	AEP	11/2/2021
2	B2779	.6	Construct a 345 kV ring bus at Dunton Lake to serve SDI load at 345 kV via two circuits.	6/1/2016	$24.80		12/1/2020
		.7	Retire Collingwood 345 kV station.				
3	B3243		Replace risers at Bass 34.5 kV station.	6/1/2025	$0.10		11/20/2020
4	B3244		Rebuild ~9 miles of the Rob Park-Harlan 69 kV line.		$20.90		

Table 6.16: Indiana Baseline Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5	B3248		Install a low-side 69 kV circuit breaker at Albion 138/69 kV transformer No. 1.	6/1/2025	$0.40	AEP	11/20/2020
6	B3257		Replace two spans of 336.4 26/7 ACSR on Twin Branch-AM General No. 2 34.5 kV circuit.	6/1/2025	$0.14	AEP	11/20/2020
7	B3291		Replace the Russ St. 34.5 kV switch.	6/1/2025	$1.50	AEP	1/15/2021
8	B3296		Rebuild the overloaded portion of the Concord-Whitaker 34.5 kV line (1.13 miles). Rebuild is double circuit and will utilize 795 ACSR conductor.	6/1/2025	$2.80	AEP	1/15/2021
9	B3324		Replace the bus section at Olive.	6/1/2022	$0.10	AEP	8/10/2021
10	B3343		Rebuild ~0.3 miles of overloaded 69 kV line between Albion-Philips switch and Philips switch-Brimfield switch with 556 ACSR conductor.	6/1/2026	$0.61	AEP	11/2/2021

6.2.7 — Network Projects

2021 RTEP network projects in Indiana are summarized in **Map 6.14** and **Table 6.17**.

Map 6.14: Indiana Network Projects (Dec. 31, 2021)

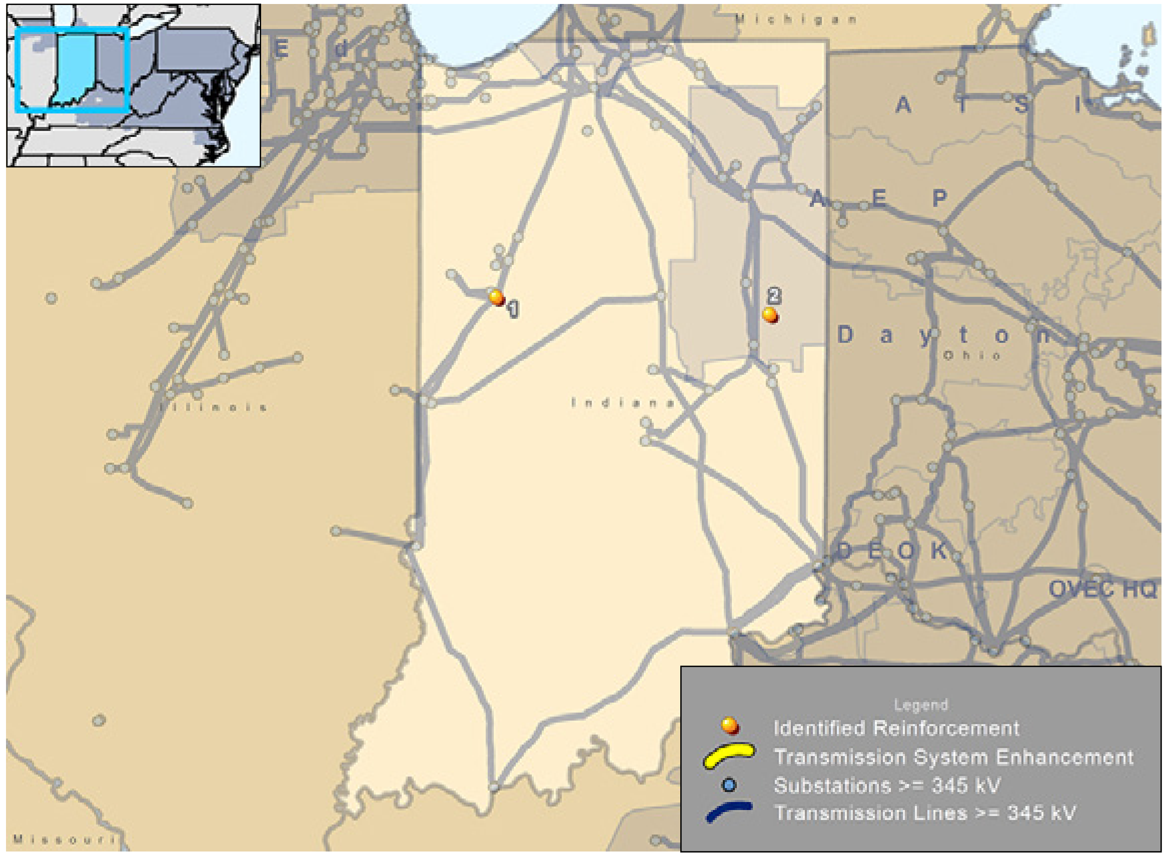


Table 6.17: Indiana Network Projects (Dec. 31, 2021)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5817	Install Dequine 345 kV circuit breaker D.	J468	11/5/2019	$1.167	AEP	11/30/2021
2	N5969	Install 138 kV revenue metering at Jay substation.	AC2-177	10/1/2020	$0.25		

6.2.8 — Supplemental Projects

2021 RTEP supplemental projects in Indiana are summarized in **Map 6.15** and **Table 6.18**.

Map 6.15: Indiana Supplemental Projects (Dec. 31, 2021)

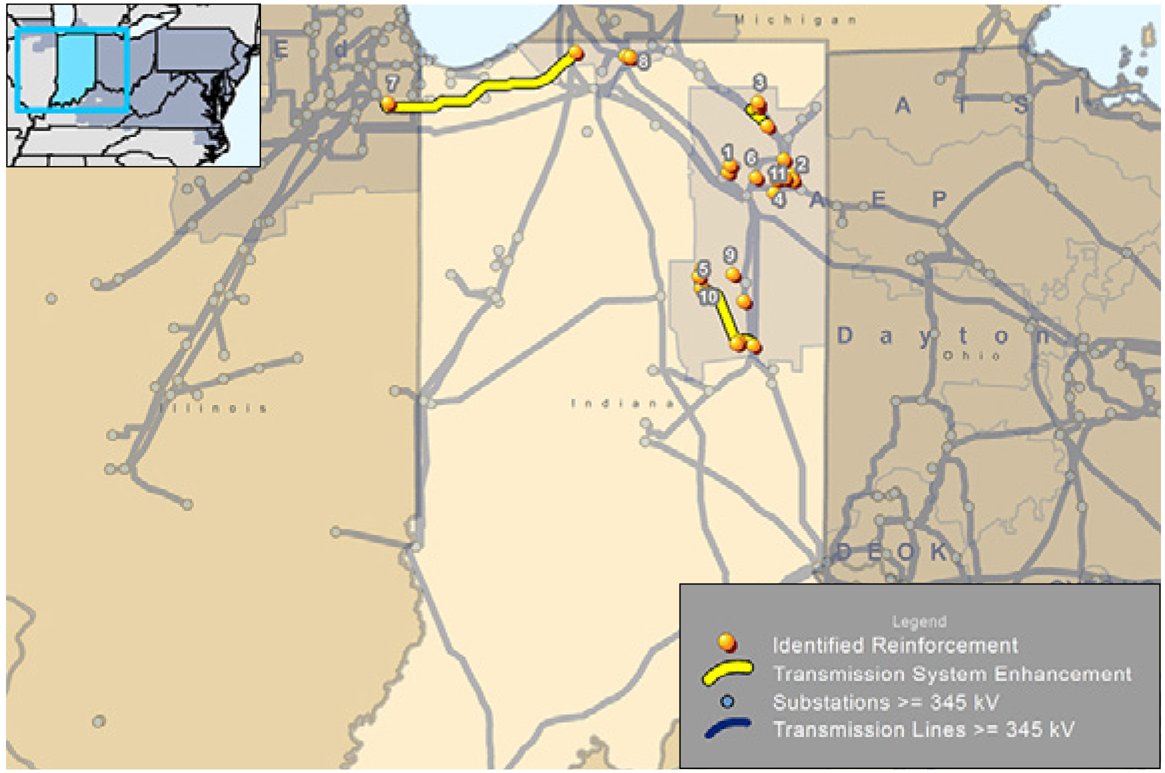


Table 6.18: Indiana Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2391	.1	Replace 69 kV circuit breaker "E" at Gateway station with a 3000A 40kA circuit breaker.	4/3/2023	$1.80	AEP	9/11/2020
		.2	Replace 69 kV circuit breaker "J" at Columbia station with a 3000A 40kA circuit breaker.				
2	S2392	.1	Rebuild the ~7.8 mile 138 kV Rob Park-Lincoln line using Drake 795 ACSR (SN/SE/WN/WE: 257/360/325/404MVA).		$26.30		
		.2	Add a 3000A bus tie circuit breaker at 138 kV Trier station to separate the 4 MOABs in series.				

Table 6.18: Indiana Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S2431	.1	Rebuild North Kendallville 69/1 2 kV station as Henderson 138/12 kV station.	6/1/2024	$17.80	AEP	11/20/2020
		.2	Expand Bixler 138/12 kV station with a second transformer. Rebuild the through path to accommodate the expansion with a bus tie breaker and line MOABs.				
		.3	Add a 138 kV circuit breaker to Kendallville station on the line exit to Henderson.				
		.4	Rebuild the ~1.8 mile North Kendallville 69 kV tap as the 138 kV Henderson-Kendallville line.				
		.5	Build the new ~2.6 mile Henderson-Bixler 138 kV line.				
		.6	Retire the 138 kV Bixler Sw, and the ~.6 mile between Bixler SW and Kendallville station.				
4	S2432	.1	Retire Harvest Park 34.5 kV station and move distribution load source to Lincoln station.	4/3/2023	$34.50	AEP	11/20/2020
		.2	Retire ~.6 miles of the Storm Water-Lincoln line.				
		.3	Retire the ~2.5 mile Anthony-Harvest Park line.				
		.4	Retire Filtration switch.				
		.5	Retire the ~1.1 mile Anthony-Lincoln 34.5 kV line.				
		.6	Retire the ~2.9 mile Anthony-Lincoln 138 kV line.				
		.7	At Lincoln station, move the Storm Water circuit breaker to the 69 kV bus. Install 138/12 kV transformer with new 12 kV distribution bay to replace Harvest Park.				
		.8	Rebuild the Lincoln-Inca line. Line will connect to the new Lincoln 69/34.5 kV extension at Maumee switch.				
		.9	Build a ~0.9 mile 69/34.5 kV double circuit line out of Lincoln station to connect to the Lincoln-Maumee 34.5 kV line and the Lincoln-Stormwater 69 kV line.				
		.10	Install a 34.5 kV POP switch to feed Inca station called Maumee switch.				
		.11	Build a greenfield ~1.7 mile Anthony-Melita 69 kV line.				
		.12	At Storm Water station – Replace transformer No. 1 with a 69/12 kV unit and re-energize station at 69 kV.				
		.13	At Water Pollution station – Re-energize station at 69 kV. Station was previously built to take either 34.5 or 69 kV service.				
		.14	At Omnisource station – Replace transformer No. 1 with a 69/4 kV No. unit and re-energize station at 69 kV.				
		.15	At Melita station – Install a 3000A 40 kA 69 kV circuit breaker for the Anthony line entrance.				
		.16	At Anthony station – Replace both 34.5/12 kV transformers with 69/12 kV, 25 MVA units. Replace two circuit breakers with 3000A 40 kA, 69 kV circuit breakers for the Water Pollution line exit and bus tie positions. Reuse the existing Water Pollution breaker for the new Melita line entrance. Install a 21.6 MVAR capacitor bank. Retire the 138/34.5 kV transformer, the 34.5 kV circuit breakers Q and A, and the existing buswork.				
5	S2466	.1	Install a 138 kV box bay with 138 kV, 3000A MOAB switches at Wes Del station toward Desoto and Deer Creek via Gaston.	1/1/2022	$1.39	AEP	2/17/2021
		.2	Reterminate the existing Desoto-Deer Creek-Delaware 138 kV line into the new station bays at Wes Del station with 0.2 miles of 636 ACSR 26/7. Remove 0.1 miles of the Desoto-Deer Creek-Delaware 138 kV line to accommodate the new connection of Wes Del to the Deer Creek-Desoto 138 kV circuit.				

Table 6.18: Indiana Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
6	S2471		Illinois Road 138/69 kV – Replace the 138/69 kV transformer with a 90 MVA, 138/69 kV transformer.	5/16/2022	$1.70	AEP	3/19/2021
7	S2509		Rebuild the (L97008: Univ. Park S/S-Olive S/S 345 kV) of the ~20 mile double circuit line with monopoles and new conductor utilizing existing right of way (Univ. Park S/S-Olive S/S 345 kV).	6/15/2023	$51.90	NEET	5/11/2021
8	S2510		Rebuild 0.96 miles of the AM General No. 2-Twin Branch 34.5 kV.	10/1/2024	$4.30	AEP	4/16/2021
9	S2511		Expand and upgrade Van Buren station to a three 138 kV breaker ring bus to accommodate three elements (two transmission lines and one transformer) and eliminate the three-terminal line. Replace 138/69/12 kV transformer with separate 138/69 kV and 69/12 kV transformers to separate the distribution load from the transmission transformer's tertiary winding. Replace 69 kV circuit breaker B.	9/1/2022	$9.10	AEP	4/16/2021
10	S2570	.1	Deer Creek-Hartford City 69 kV – Rebuild ~17.67 miles of 69 kV line with the conductor size 556.5 ACSR 26/7 Dove. The following cost includes the line rebuild, line removal and right of way.	10/25/2024	$49.23	AEP	7/16/2021
		.2	Hummel Creek-Deer Creek 34.5 kV – Retire ~4.6 miles of 34.5 kV 1940s wood line.				
		.3	Jonesboro-Gas City 34.5 kV – Retire ~0.99 miles of 34.5 kV 1969 wood line.				
		.4	Deer Creek-Alexandria 34.5 kV – Retire ~2.2 miles of 34.5 kV 1968 wood line.				
		.5	Hummel Creek 34.5 kV Station – Remove the 34.5 kV circuit breaker "M." Replace 34.5 kV circuit breaker "L" with a system spare circuit breaker. Rebuild the 34.5 kV bus to 69 kV standards. Install a 138 kV high-side circuit switcher on the 138/34.5 kV transformer.				
		.6	Deer Creek substation – Remove the 34.5 kV circuit breaker "M." Install a 138/12 kV, 20 MVA transformer with a high-side 138 kV circuit switcher. Also install a low-side 12 kV, 2000A circuit breaker a 12 kV, 2000A bus tie circuit breaker and three 12 kV, 2000A feeder circuit breakers. Install a new high-side 138 kV circuit switcher 138/12 kV transformer No. 4.				
11	S2583	.1	Deptmer 69 kV switch – Install a phase-over-phase switch to feed the new Harber load. Both switch and load are built to 138 kV standards but operated at 69 kV.	2/21/2022	$1.70	AEP	8/16/2021
		.2	Hillcrest-Pleasant 69 kV – Cut Deptmer switch into the 69 kV line.				
		.3	Deptmer-Harber 69 kV Radial – Install a new two-span radial to the Harber load. Radial will be built to 138 kV standards.				

6.2.9 — Merchant Transmission Project Requests

As of Dec. 31, 2021, PJM's queue contained two merchant transmission project requests with a terminal in Indiana, as shown in **Map 6.16** and **Table 6.19**.

Map 6.16: Indiana Merchant Transmission Project Requests (Dec. 31, 2021)

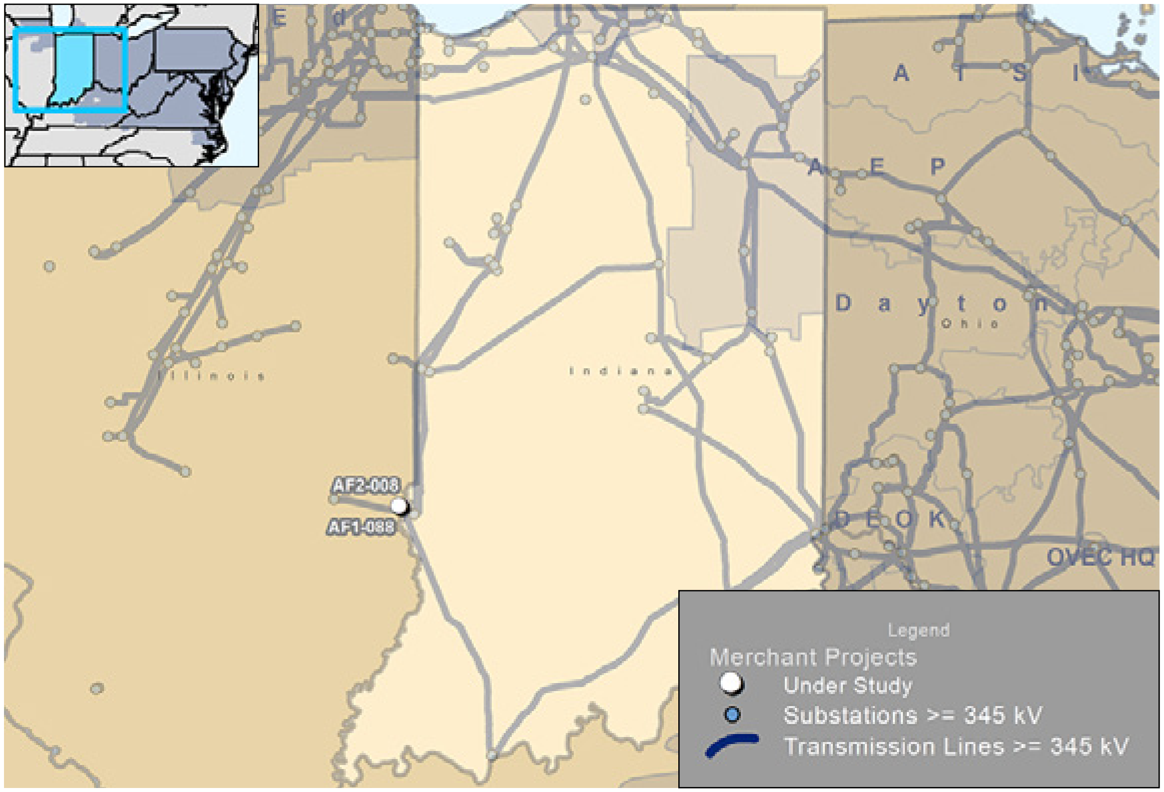


Table 6.19: Indiana Merchant Transmission Project Requests (Dec. 31, 2021)

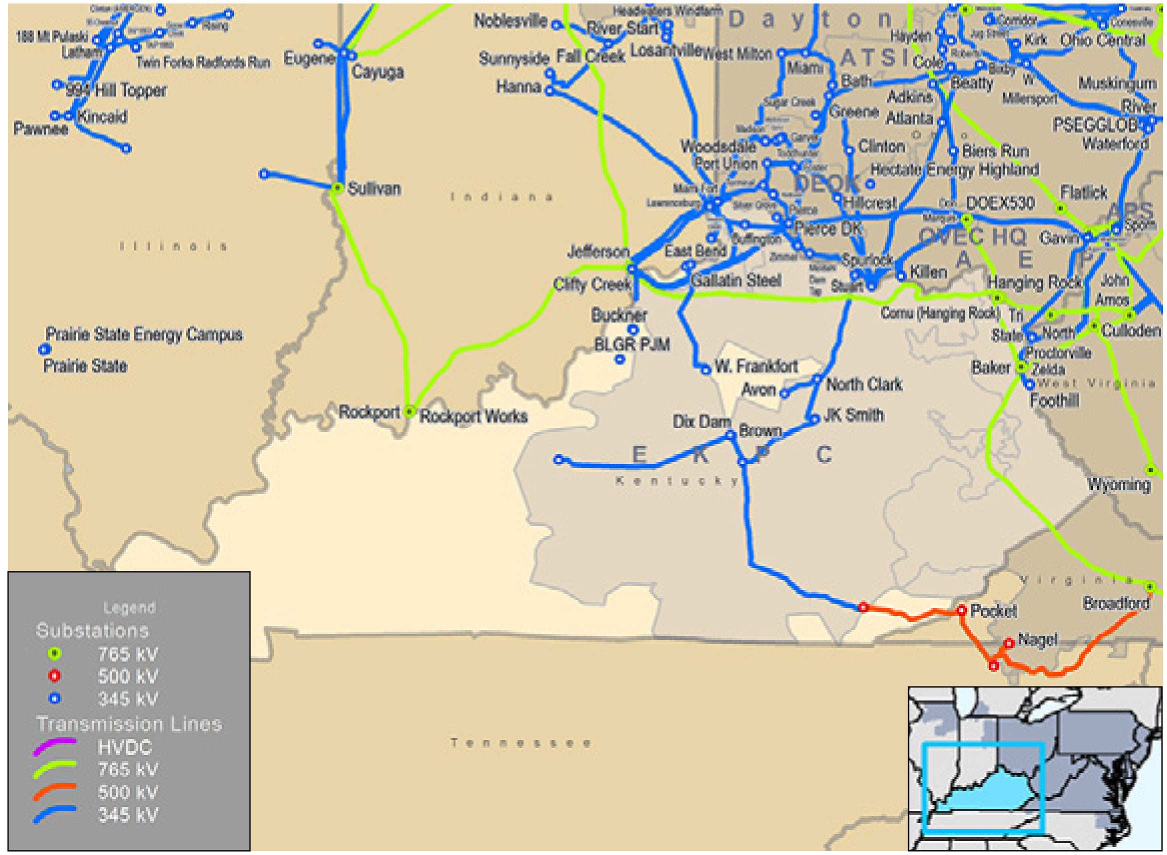
Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AF2-008	Sullivan 345 kV	AEP	Active	12/31/2025	1,000
AF1-088		ComEd			

6.3: Kentucky RTEP Summary

6.3.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Kentucky, including facilities owned and operated by American Electric Power (AEP), Duke Energy Ohio and Kentucky (DEO&K) and East Kentucky Power Cooperative (EKPC) as shown on **Map 6.17**. Duke Energy Ohio and Kentucky owns the Duke transmission delivery facilities in Kentucky rated over 69 kV. Kentucky's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

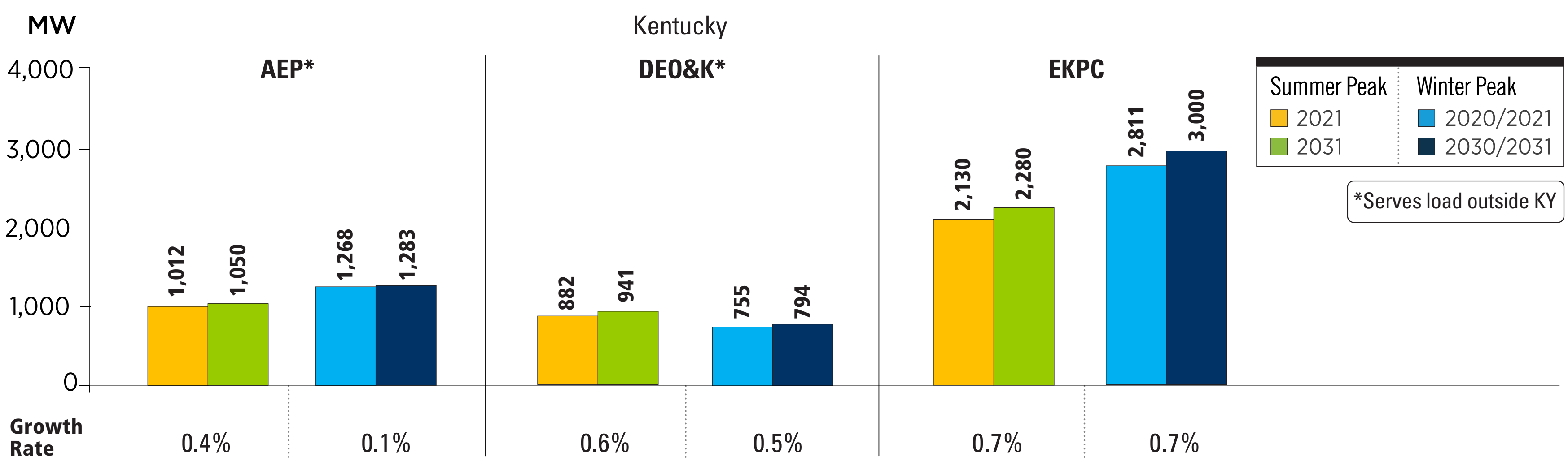
Map 6.17: PJM Service Area in Kentucky



6.3.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.16** summarizes the expected loads within the state of Kentucky and across PJM.

Figure 6.16: Kentucky – 2021 Load Forecast Report



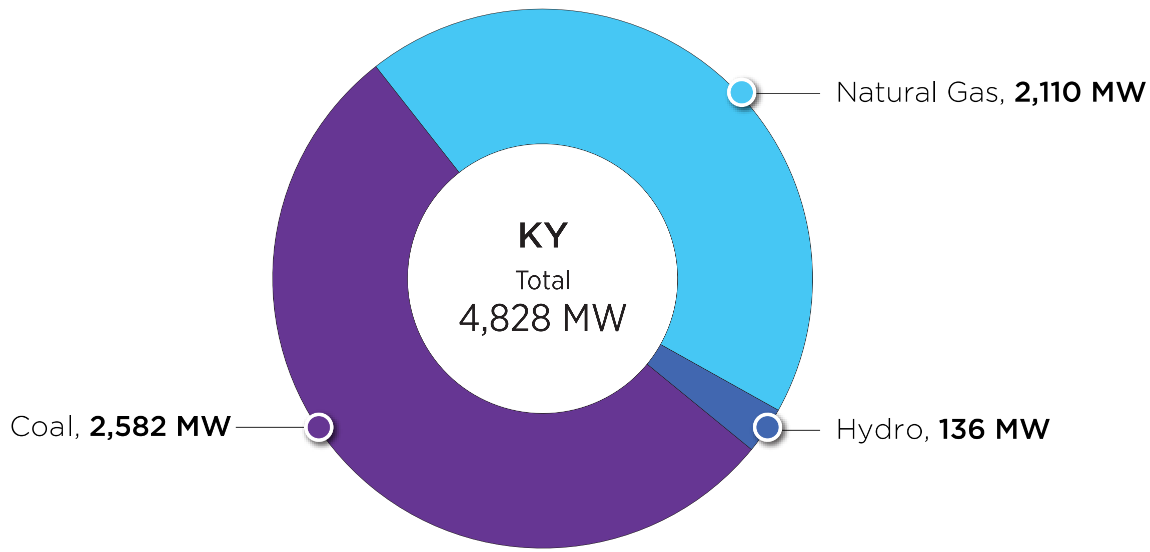
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.3.3 — Existing Generation

Existing generation in Kentucky as of Dec. 31, 2021, is shown by fuel type in **Figure 6.17**.

Figure 6.17: Kentucky – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.3.4 — Interconnection Requests

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

Specifically, in Kentucky, as of Dec. 31, 2021, 124 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.20**, **Table 6.21**, **Figure 6.18**, **Figure 6.19** and **Figure 6.20**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.20: Kentucky – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	Kentucky Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	0	0.00%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	1,100	12.64%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	0	0.00%	17	0.01%
Other	0	0.00%	331	0.20%
Solar	7,248	83.31%	93,756	57.99%
Storage	352	4.05%	34,130	21.11%
Wind	0	0.00%	8,800	5.44%
Grand Total	**8,700**	**100.00%**	**161,682**	**100.00%**

Table 6.21: Kentucky – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	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	0	0.0	6	2,969.0	6	2,969.0
	Natural Gas	0	0.0	1	1,100.0	0	0.0	6	71.0	5	1,704.7	12	2,875.7
	Storage	9	352.0	0	0.0	0	0.0	0	0.0	3	106.2	12	458.2
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	5	198.5	5	198.5
	Hydro	0	0.0	0	0.0	0	0.0	0	0.0	1	70.0	1	70.0
	Solar	110	6,973.7	1	63.8	5	210.2	0	0.0	34	1,630.6	150	8,878.2
	Wind	0	0.0	0	0.0	0	0.0	0	0.0	2	27.3	2	27.3
	Grand Total	**119**	**7,325.7**	**2**	**1,163.8**	**5**	**210.2**	**6**	**71.0**	**56**	**6,706.3**	**188**	**15,476.9**

Figure 6.18: Kentucky – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

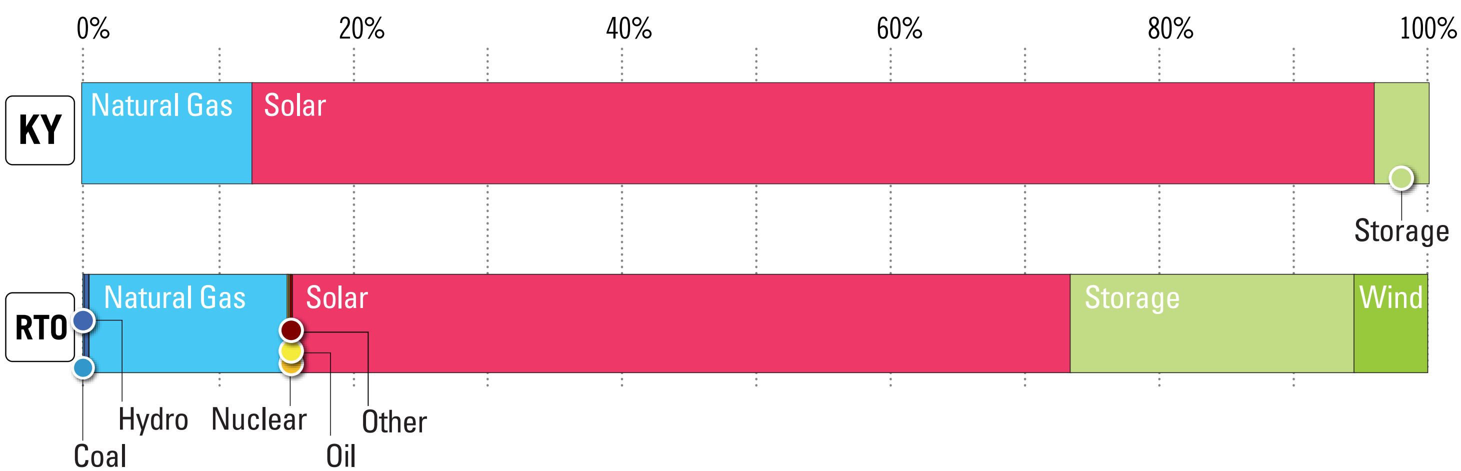
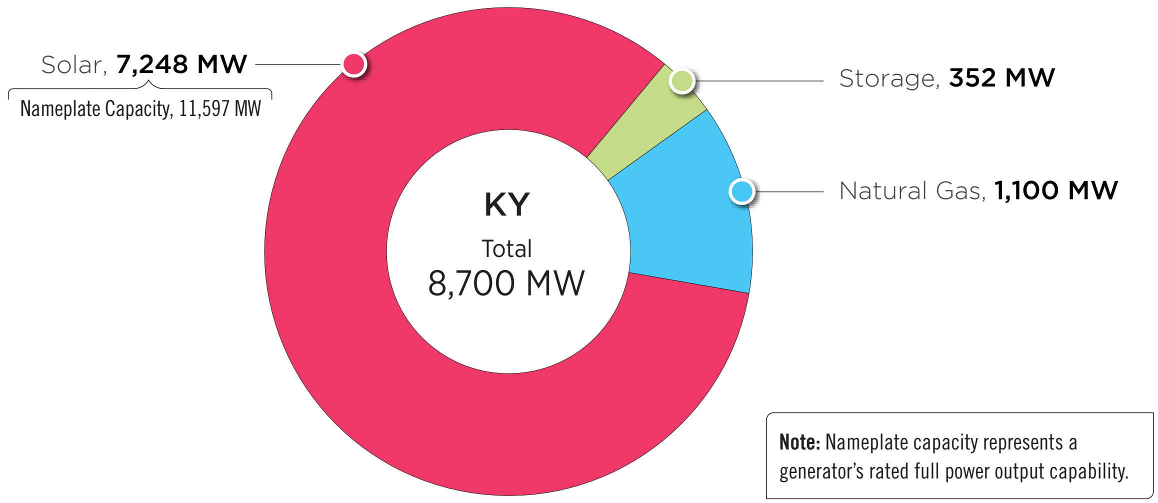


Figure 6.19: Kentucky – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.20: Kentucky Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

0.9%	Requested capacity megawatts
8.8%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	1	Interconnection Service Agreements	80 MW	80 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.3.5 — Generation Deactivation

There were no generating unit deactivation requests in Kentucky between Jan. 1, 2021, and Dec. 31, 2021, as part of the 2021 RTEP.

6.3.6 — Baseline Projects

2021 RTEP baseline projects in Kentucky are summarized in **Map 6.18** and **Table 6.22**.

Map 6.18: Kentucky Baseline Projects (Dec. 31, 2021)

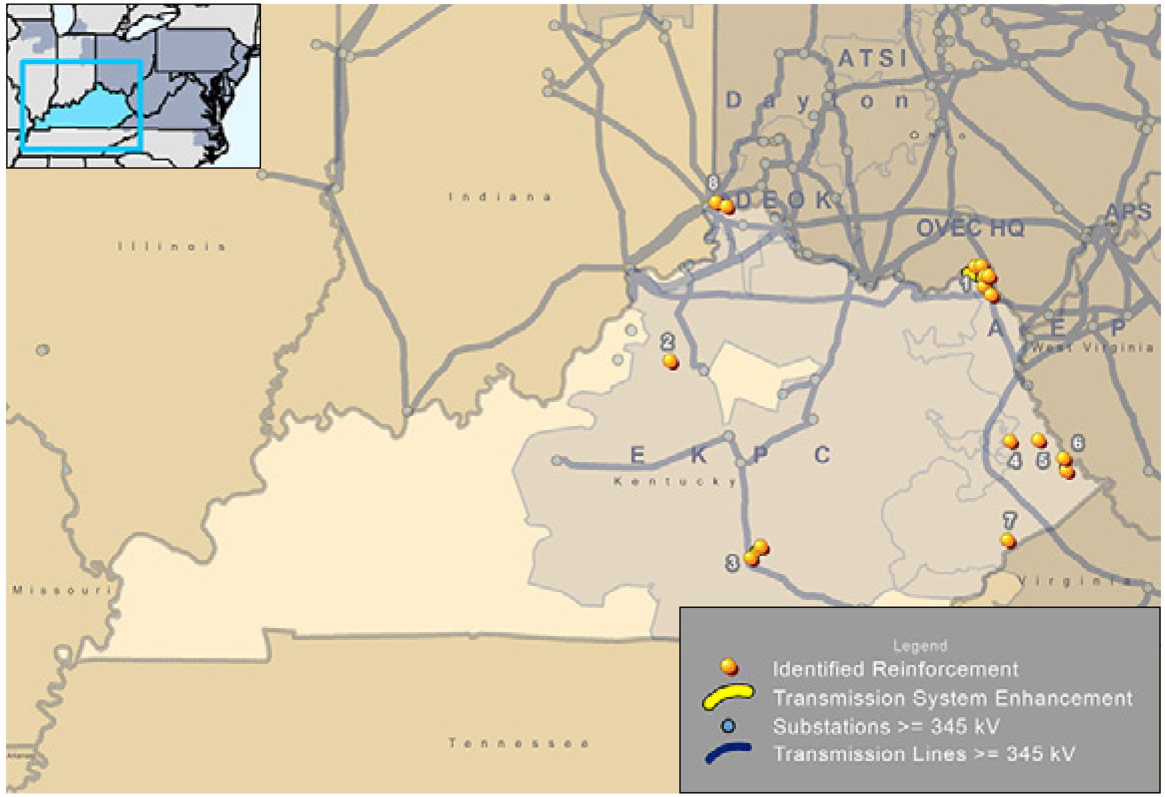


Table 6.22: Kentucky Baseline Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B2604	.1	Remove ~11.32 miles of the 69 kV line between Millbrook Park and Franklin Furnace.	6/1/2019	$39.18	AEP	2/17/2021
		.2	At Millbrook Park station, add a new 138/69 kV transformer No. 2 (90 MVA) with 3000A 40 kA breakers on the high and low side. Replace the 600A MOAB switch and add a 3000A circuit switcher on the high side of transformer No. 1.				
		.3	Replace Sciotoville 69 kV station with a new 138/12 kV in-out station (Cottrell) with 2000A line MOABs facing Millbrook Park and East Wheelersburg 138 kV.				

Table 6.22: Kentucky Baseline Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	B2604	.4	Tie Cottrell switch into the Millbrook Park-East Wheelersburg 138 kV circuit by constructing 0.50 miles of line using 795 ACSR 26/7 Drake (SE 359 MVA).	6/1/2019	$39.18	AEP	2/17/2021
		.5	Install a new 2000A three-way phase-over-phase switch outside of Texas Eastern 138 kV substation (Sadiq switch).				
		.6	Replace the Wheelersburg 69 kV station with a new 138/12 kV in-out station (Sweetgum) with a 3000A 40 kA breaker facing Sadiq switch and a 2000A 138 kV MOAB facing Althea.				
		.7	Build ~1.4 miles of new 138 kV line using 795 ACSR 26/7 Drake (SE 359 MVA) between the new Sadiq switch and the new Sweetgum 138 kV stations.				
		.8	Remove the existing 69 kV Hayport Road switch.				
		.9	Rebuild ~2.3 miles along existing right of way from Sweetgum to the Hayport Rd. switch 69 kV location as 138 kV single circuit and rebuild ~2 miles from the Hayport Road switch to Althea 69 kV with double circuit 138 kV construction, one side operated at 69 kV to continue service to K.O. Wheelersburg, using 795 ACSR 26/7 Drake (SE 359 MVA).				
		.10	Build a new station (Althea) with a 138/69 kV, 90 MVA transformer. The 138 kV side will have a single 2000A 40 kA circuit breaker, and the 69 kV side will be a 2000A 40 kA three-breaker ring bus.				
		.11	Perform remote end work at Hanging Rock, East Wheelersburg and North Haverhill 138 kV.				
2	B3266		Upgrade the metering CT associated with the Clay Village-Clay Village T 69 kV line section to increase the line ratings.	12/1/2021	$0.03	EKPC	12/18/2020
3	B3267		Rebuild the 4/0 ACSR Norwood-Shopville 69 kV line section using 556 ACSR/TW.		$3.79		
4	B3281		Install 138 kV circuit switcher on the 138/69 kV transformer No. 1 and 138/34.5 kV transformer No. 2 at Dewey. Install 138 kV, 2000A 40 kA breaker on Stanville line at Dewey 138 kV substation.	12/1/2025	$1.40	AEP	2/17/2021
5	B3283		Replace the existing Inez 138/69 kV, 50 MVA autotransformer with a 138/69 kV, 90 MVA autotransformer.		$2.96		
6	B3288	.1	Construct ~2.75 mile Orinoco-Stone 69 kV transmission line in the clear between Orinoco station and Stone station.		$21.47		1/15/2021
		.2	Construct ~3.25 mile Orinoco-New Camp 69 kV transmission line in the clear between Orinoco station and New Camp station.				
		.3	At Stone substation, circuit breaker A to remain in place and be utilized as T1 low-side breaker; circuit breaker B to remain in place and be utilized as new Hatfield (via Orinoco and New Camp) 69 kV line breaker. Add new 69 kV circuit breaker E for Coleman line exit.				
		.4	Reconfigure the New Camp 69 kV tap, which includes access road improvements/installation, temporary wire and permanent wire work along with dead-end structures installation.				
		.5	At New Camp substation, rebuild the 69 kV bus, add 69 kV MOAB W and replace the 69 kV ground switch Z1 with a 69 kV circuit switcher on the New Camp transformer.				
7	B3307		Rebuild Fleming station in the clear; Replace 138/69 kV Fleming transformer No. 1 with 138/69 kV, 130 MVA transformer with high-side 138 kV circuit breaker; Install a five-breaker 69 kV ring bus on the low side of the transformer, replace 69 kV circuit switcher AA, replace 69/12 kV transformer No. 3 with 69/12 kV, 30 MVA transformer, and replace 12 kV circuit breaker A and D. Retire existing Fleming substation.		$21.10		
8	B3334		Rebuild the section of Miami Fort-Hebron Tab 138 kV	6/1/2022	$44.30	DEO&K	11/2/2021

6.3.7 — Network Projects

2021 RTEP network projects in Kentucky are summarized in **Map 6.19** and **Table 6.23**.

Map 6.19: Kentucky Network Projects (Dec. 31, 2021)

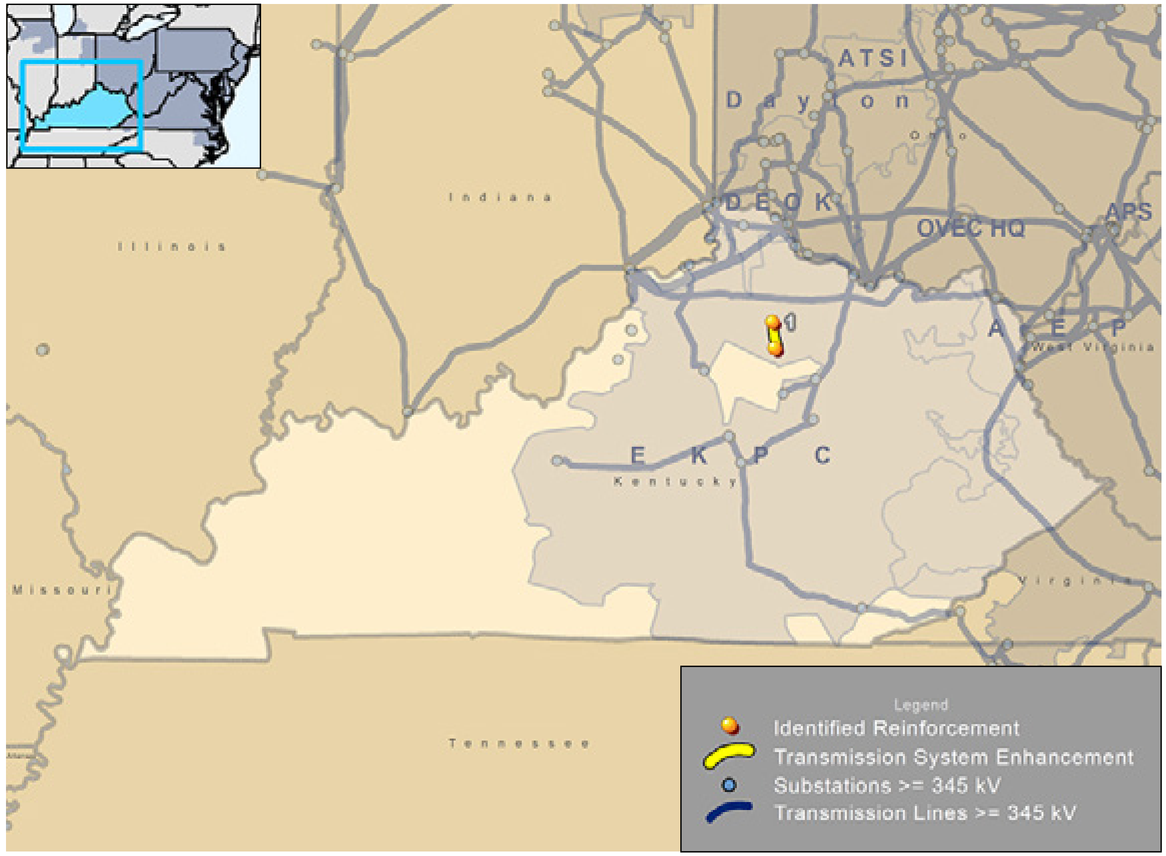


Table 6.23: Kentucky Network Projects (Dec. 31, 2021)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	**N6276**	Install OPGW fiber from the Harrison County-Renaker line section, which is ~9.35 miles in length.	AC1-074	6/1/2019	$1.27	EKPC	11/30/2021

6.3.8 — Supplemental Projects

2021 RTEP supplemental projects in Kentucky are summarized in **Map 6.20** and **Table 6.24**.

6.3.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Kentucky were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the [Project Status] page of the PJM website.

Map 6.20: Kentucky Supplemental Projects (Dec. 31, 2021)

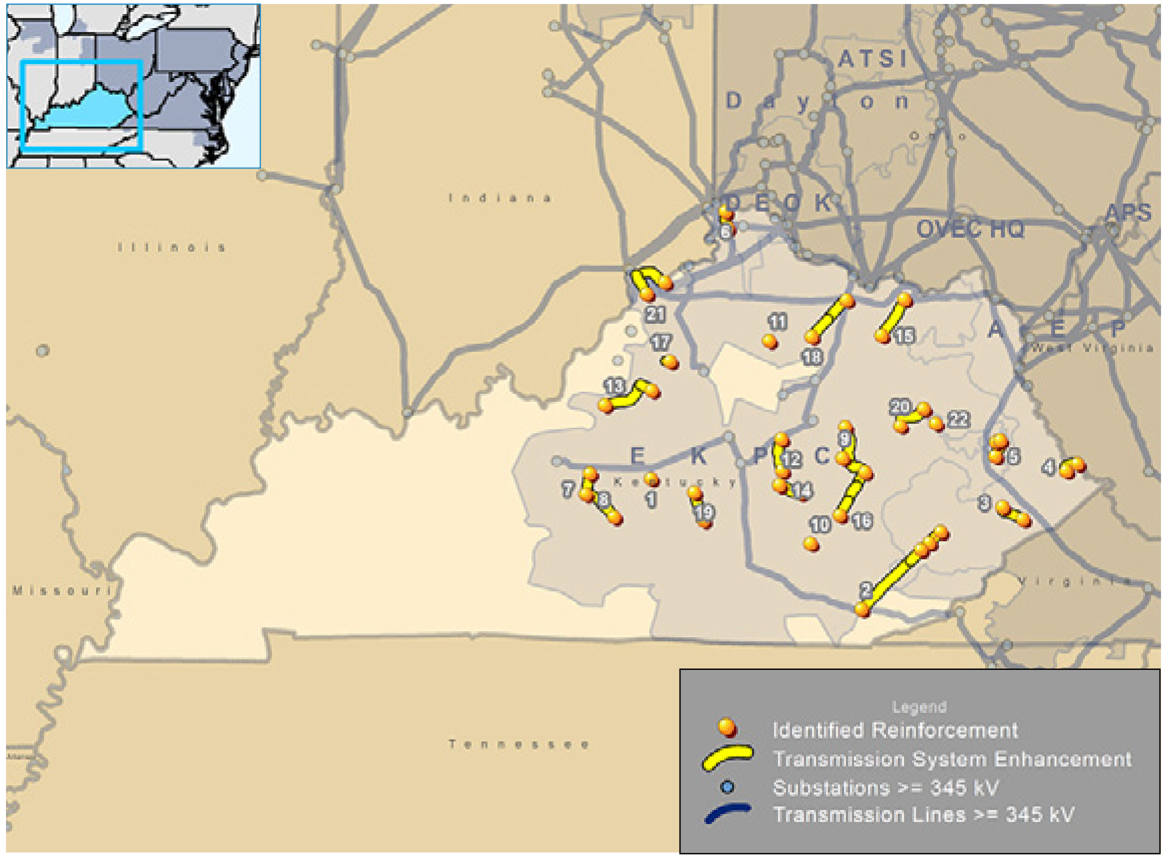


Table 6.24: Kentucky Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2287		Build a new dual transformer 161/13.8 kV 50 MVA distribution station (South Marion County Industrial) and associated 0.25 mile 161 kV line tapping the existing Marion County Industrial 161 kV tap line. Distribution cooperative will lower distribution line to allow adequate clearance for the Marion Co-Marion Co Industrial tap 161 kV line to achieve a maximum operating temperature of 167F to match the rest of the line section.	6/1/2021	$0.00	EKPC	2/21/2020

Table 6.24: Kentucky Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2428	.1	At Wooton station, upgrade relaying to accommodate new OPGW fiber protection.	11/30/2027	$127.33	AEP	11/20/2020
		.2	At Leslie station, reconductor the 161 kV bus, relaying upgrades toward Wooton and Pineville, replace 161 kV, MOAB W, replace 161 kV transformer No. 1 high-side switch. Install DICM.				
		.3	Perform remote end work at Hazard substation.				
		.4	Rebuild ~40 miles of Wooton-Pineville 161 kV line to address the identified asset condition needs. This work also includes line removal work as well as access road construction. Majority of proposed line rebuild is to be constructed on existing center line.				
		.5	Expand existing right of way for the Wooton-Pineville 161 kV line.				
		.6	Relocate ~0.32 mile 69 kV Leslie-Clover Fork, which includes one structure and reconfiguration of the existing line to cross underneath the proposed Wooton-Stinnett 161 kV line.				
		.7	At Stinnett station, upgrade relaying to accommodate new OPGW fiber protection. Provide transition, entry and termination for OPGW connectivity to the Hazard-Pineville fiber route.				
		.8	Provide transition, entry and termination for OPGW connectivity at Leslie substation.				
3	S2436	.1	Construct a greenfield 69/12 kV Osborne station to replace Burton station, including a high-side 69 kV phase-over-phase switch, fiber connectivity, a circuit switcher, and one 69/12 kV, 12/16/20 MVA transformer and associated distribution feeders.	11/30/2024	$26.16		12/18/2020
		.2	Construct a greenfield 138 kV Myra station to replace Elwood station. Install 138 kV double box bay with two 138 kV circuit breakers and line exits to Fremont and Beaver Creek. Install 138/34.5 kV transformer with high-side circuit switcher and associated 34.5 kV breakers. Install fiber connectivity for upgraded relaying.				
		.3	Perform remote end relaying work at Beaver Creek substation. Remove 46 kV Elwood line 46 kV circuit breaker “G” and associated equipment.				
		.4	Perform remote end relaying work at Fremont substation.				
		.5	At Burton station, retire and remove all existing equipment.				
		.6	At Elwood station, retire and remove all existing equipment.				
		.7	Construct a new ~0.5 mile double circuit 69 kV line to the proposed Osborne substation.				
		.8	Reconfigure the existing Beaver Creek-Fleming 69 kV line to facilitate the construction of the new double circuit Osborne 69 kV line to feed the proposed Osborne substation.				
		.9	Construct a new ~2 mile double circuit 138 kV line to the proposed Myra substation.				
		.10	Reconfigure the existing Beaver Creek-Fremont 138 kV circuit to facilitate the construction of the new double circuit Myra extension 138 kV line to feed the proposed Myra substation.				
		.11	Install two replacement structures in order to bypass Elwood station. Transfer wires from old structure to new structure. Tie new structure to Cedar Creek-Henry Clay 46 kV line.				
		.12	Retire ~10.48 mile Beaver Creek-Elwood 46 kV line.				
4	S2446	.1	Replace Belfry substation with Orinoco substation by installing a 69 kV box bay and 12 kV rural bay to be built in the clear southwest of existing Belfry station. Install 69/12 kV, 20 MVA transformer and two 12 kV breakers.	12/31/2024	$9.11		1/15/2021
		.2	Retire Belfry 46 kV substation.				

Table 6.24: Kentucky Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4 Cont.	S2446	.3	Retire 46 kV equipment from Stone substation.	12/31/2024	$9.11	AEP	1/15/2021
		.4	At Hatfield substation, replace MOAB Y with a 69 kV circuit breaker toward Stone 69 kV line via New Camp and Orinoco.				
		.5	Retire the 46 kV equipment at Sprigg station toward Stone (via Belfry).				
		.6	Retire Turkey Creek tap.				
		.7	Retire the ~8.23 miles of the 46 kV Sprigg-Stone 46 kV circuit.				
5	S2470	.1	A greenfield line is to be constructed (Kenwood 69 kV extension) and to be operated at 46 kV. The new extension will provide looped service into Kenwood substation. It will be ~2.25 miles of single circuit construction through mountainous terrain in Floyd and Johnson Counties in Kentucky. The extension will tap the existing Prestonsburg-Thelma 46 kV line around structure K346-50. (SN:53 MVA , SE:61 MVA, WN:67 MVA, WE:73 MVA)	11/30/2023	$12.10	AEP	3/19/2021
		.2	Rebuild the existing ~1.77 mile Kenwood tap line from Kenwood to Van Lear tap structure on the existing center line. (SN:53 MVA , SE:61 MVA, WN:67 MVA, WE:73 MVA)				
		.3	Provide splicing for 2.25 miles of 96 count OPGW on the Kenwood 69 kV extension line and 1.77 mile Kenwood tap line. This extension spans from Kenwood Station to the Prestonsburg-Thelma 46 kV line.				
		.4	At Kenwood substation, extend the walk bus and add second 46 kV line to set up Kenwood station as a looped station with MOABS protecting each exit. Add new H-frame dead end with MOAB and single phase CCVT. Add MOAB and single phase CCVT to existing line. Relocate three phase CCVT's from cap bank AA to 46 kV bus. Add three-bay transclosure and separate battery enclosure. Replace battery and charger.				
		.5	Retire Van Lear switch structure.				
		.6	Perform remote end work at Prestonsburg substation.				
		.7	Retire the ~1.5 mile 46 kV line section from structure 52 to Van Lear switch structure.				
6	S2474		Rebuild the 6.4 mile Boone-Bullittsville 69 kV transmission line using 556.5 ACSR/TW conductor. Build a 69 kV box for a 69 kV breaker addition at the Boone switching station. Boone distribution will be served from this new breaker. 5.25 miles of single structures will be replaced. 1.15 miles of H-frame tangent structures will be evaluated on structure by structure basis.	6/1/2022	$4.03	EKPC	3/19/2021
7	S2475		Rebuild the 8.49 mile Hodgenville-Magnolia 69 kV transmission line using 556.5 ACSR/TW conductor. 8.49 miles of single structures will be replaced.	6/30/2022	$4.75		
8	S2476		Rebuild the 15 mile Summersville-Magnolia 69 kV transmission line using 556.5 ACSR/TW conductor. 10 miles of single structures will be replaced. 5 miles of H-frame tangent structures will be evaluated on structure by structure basis.	12/31/2023	$8.16		
9	S2477		Build a new Millers Creek 161-25 kV distribution substation and associated 0.16 mile 161 kV tap line to the EKPC Beattyville-Powell County 161 kV transmission line. A three-way MOAB switch will be added at the tap point and the existing distribution substation will be retired.	12/1/2021	$0.40		
10	S2478		Remove the 16.2 MVAR capacitor bank at East Bernstadt 69 kV.	12/31/2022	$0.00		
11	S2479		Remove the 10.72 MVAR capacitor bank at Lees Lick 69 kV.				
12	S2514		Construct new 69 kV-25 kV, 18/24/30 MVA distribution substation and associated 4.79 mile tap from the EKPC Crooksville's 69 kV tap line. Upgrade the existing West Berea 138/69 kV, 100 MVA to 150 MVA. Add a 2000A, 138 kV breaker to the 138 kV tie line between the EKPC Fawkes switching station and the LG&E/KU Fawkes stations.	7/1/2022	$2.40		4/16/2021
13	S2515		Rebuild and relocate the Taylorsville distribution substation. Build a new Taylorsville 161-25 kV distribution substation looping into the Bullitt Co-Little Mount 161 kV line section. The existing distribution substation will be retired.	12/31/2023	$1.73		

Table 6.24: Kentucky Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
14	S2516		Rebuild the 9.3 miles, Three Links Junction-Three Links 69 kV transmission line using 556.5 ACSR/TW conductor. Single pole tangent, angle and dead-end structures to be replaced, H-frame tangent will be evaluated on structure by structure basis.	7/31/2024	$6.16	EKPC	4/16/2021
15	S2517		Rebuild the 16.99 mile Goddard-Charters 69 kV transmission line using 556.5 ACSR/TW conductor.	9/30/2024	$9.73	EKPC	4/16/2021
16	S2518		Rebuild the 29.29 mile Beattyville-Tyner 69 kV transmission line using 556.5 ACSR/TW conductor.	12/31/2028	$22.00	EKPC	4/16/2021
17	S2528		Rebuild the 1.6 mile, Clay Village 69 kV tie line using 556.5 ACSR/TW conductor and steel poles and structures (1.25 miles of single structures will be replaced; 0.35 miles of H-frame tangent structures will be evaluated on structure by structure basis).	6/30/2025	$1.05	EKPC	5/21/2021
18	S2529		Rebuild the 19.9 mile Headquarters-Murphysville 69 kV line using 556.5 ACSR/TW conductor and steel poles and structures (19.9 miles of H-frame tangent structures will be evaluated on structure by structure basis).	7/6/2027	$13.74	EKPC	5/21/2021
19	S2530		Rebuild the 14.2 mile Peyton Store-Liberty Junction 69 kV line using 556.5 ACSR/TW conductor and steel poles and structures (2.42 miles of single structures will be replaced; 11.78 miles of H-frame tangent structures will be evaluated on structure by structure basis).	10/26/2026	$9.60	EKPC	5/21/2021
20	S2531		Rebuild the 12.3 mile Maytown tap-Hot Mix Road tap 69 kV line using 556.5 ACSR/TW conductor and steel poles and structures (12.3 miles of H-frame tangent structures will be evaluated on structure by structure basis).	12/20/2028	$8.78	EKPC	5/21/2021
21	S2532		Rebuild the 22.1 mile KU Carrollton-Bedford 69 kV line using 556.5 ACSR/TW conductor and steel poles and structures (all of the single structures will be replaced; the H-frame tangent structures will be evaluated on structure by structure basis).	3/11/2026	$12.30	EKPC	5/21/2021
22	S2533		Build a new White Oak 69-25 kV, 12/16/20 MVA distribution substation and 0.1 mile 69 kV tap line using 266.8 ACSR. Install MOAB switches at the new tap point. Retire the existing South Fork substation.	12/31/2023	$0.10	EKPC	5/21/2021

6.4: Maryland/District of Columbia RTEP Summary

6.4.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Maryland and the District of Columbia, including facilities owned and operated by Allegheny Power (AP), Baltimore Gas & Electric (BGE), Delmarva Power (DP&L), Potomac Electric Power Company (PEPCO) and Southern Maryland Electric Cooperative (SMECO) as shown on **Map 6.21**. Maryland and the District of Columbia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside PJM.

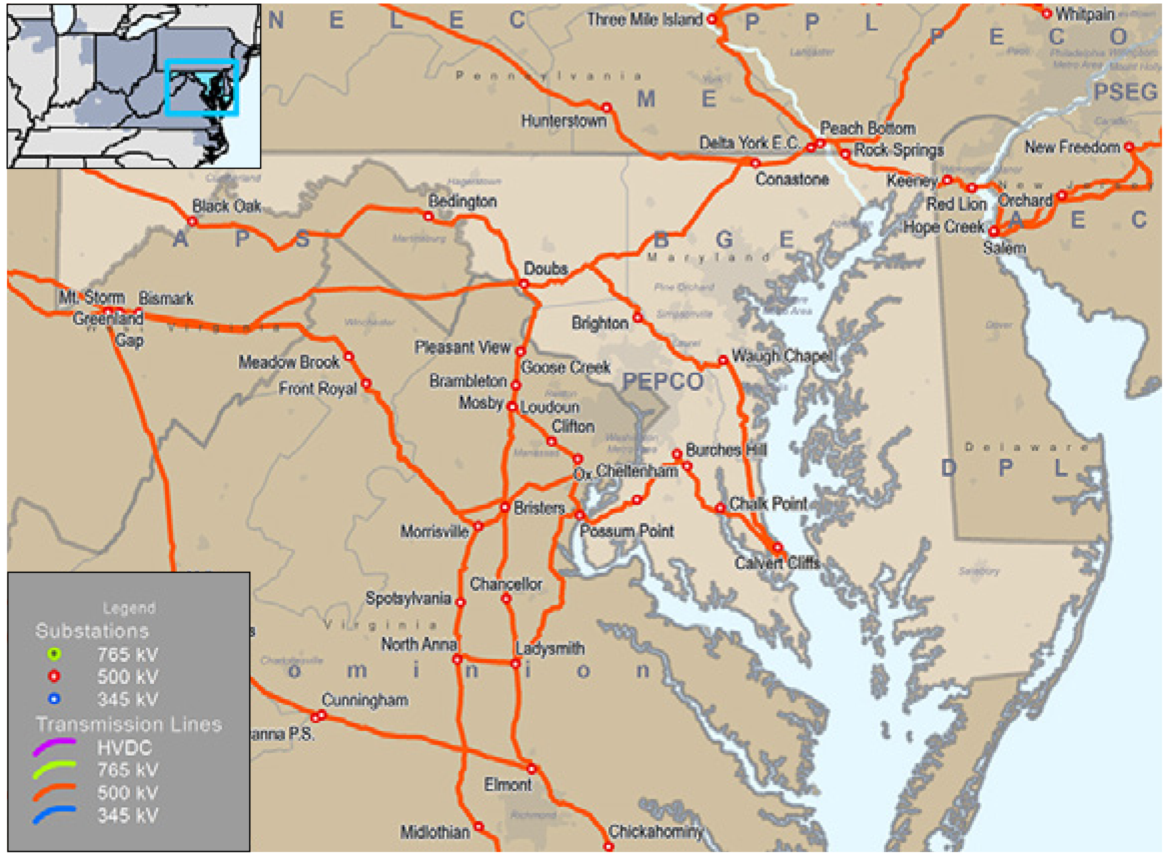
Renewable Portfolio Standards

From an energy policy perspective, Maryland and the District of Columbia both have a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

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

Map 6.21: PJM Service Area in Maryland/District of Columbia



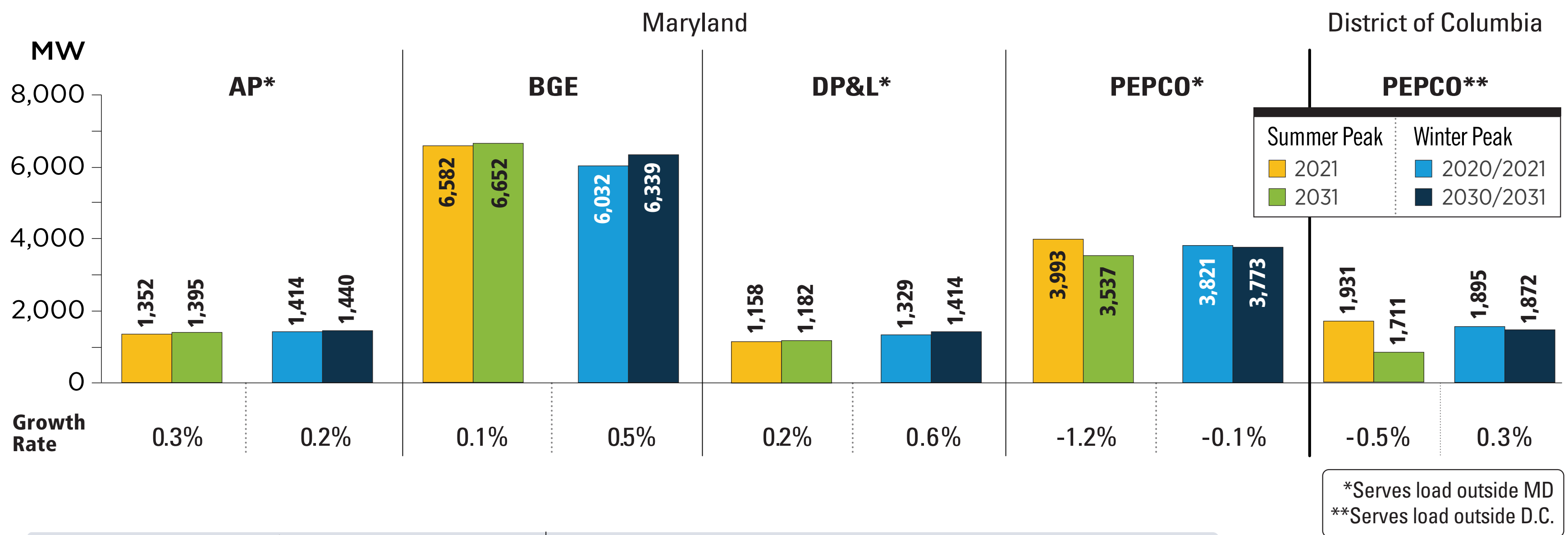
In 2021, Maryland awarded offshore wind renewable energy credits (ORECs) to two more offshore wind projects in order to meet their 2030 target – the 808.5 MW MarWin 2 project and the 846 MW Skipjack 2.1 project. With these additional ORECs being awarded, Maryland is now advancing 2,022.5 MW of offshore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

The District of Columbia has a mandatory RPS target of 100% by 2032. The District's RPS target is one of two in the PJM region set at 100%, with the other being Virginia's. The resources serving D.C.'s RPS target must be Tier 1 renewable resources and must be located within the PJM region. The RPS target also includes a solar carve-out target of 5.5% by 2032 and 10% by 2041.

6.4.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.21** summarizes the expected loads within the state of Maryland and the District of Columbia and across PJM.

Figure 6.21: Maryland/District of Columbia – 2021 Load Forecast Report



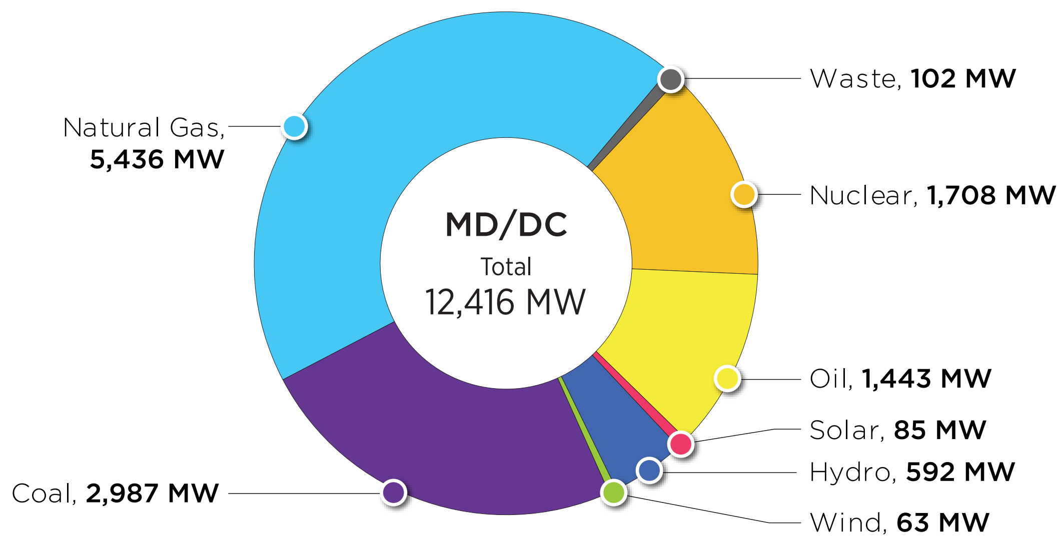
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.4.3 — Existing Generation

Existing generation in Maryland and the District of Columbia as of Dec. 31, 2021, 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, 2021)



6.4.4 — Interconnection Requests

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

Specifically, in Maryland and the District of Columbia, as of Dec. 31, 2021, 119 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.25**, **Table 6.26**, **Figure 6.23**, **Figure 6.24** and **Figure 6.25**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.25: Maryland/District of Columbia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	Maryland/D.C. Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	15	0.35%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	62	1.46%	23,887	14.77%
Nuclear	37	0.87%	81	0.05%
Oil	4	0.09%	17	0.01%
Other	0	0.00%	331	0.20%
Solar	2,973	69.51%	93,756	57.99%
Storage	1,185	27.72%	34,130	21.11%
Wind	0	0.00%	8,800	5.44%
Grand Total	**4,277**	**100.00%**	**161,682**	**100.00%**

Table 6.26: Maryland/District of Columbia – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	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	10.0	0	0.0	1	10.0
	Diesel	0	0.0	0	0.0	0	0.0	1	0.0	1	5.0	2	5.0
	Natural Gas	8	62.3	0	0.0	0	0.0	34	3,827.2	66	33,005.1	108	36,894.6
	Nuclear	3	37.4	0	0.0	0	0.0	1	0.0	4	4,955.0	8	4,992.4
	Oil	2	4.0	0	0.0	0	0.0	2	5.0	2	16.0	6	25.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	4	132.0	4	132.0
	Storage	18	1,168.0	0	0.0	5	17.3	0	0.0	39	454.2	62	1,639.5
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	12	227.6	12	227.6
	Hydro	1	15.0	0	0.0	0	0.0	3	60.0	4	88.4	8	163.4
	Methane	0	0.0	0	0.0	0	0.0	5	14.5	6	18.3	11	32.8
	Solar	48	2,502.5	3	90.8	34	379.3	14	43.0	196	1,623.8	295	4,639.4
	Wind	0	0.0	0	0.0	0	0.0	5	40.3	10	265.6	15	305.9
	Grand Total	**80**	**3,789.2**	**3**	**90.8**	**39**	**396.6**	**66**	**4,000.0**	**344**	**40,791.0**	**532**	**49,067.5**

Figure 6.23: Maryland/District of Columbia – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

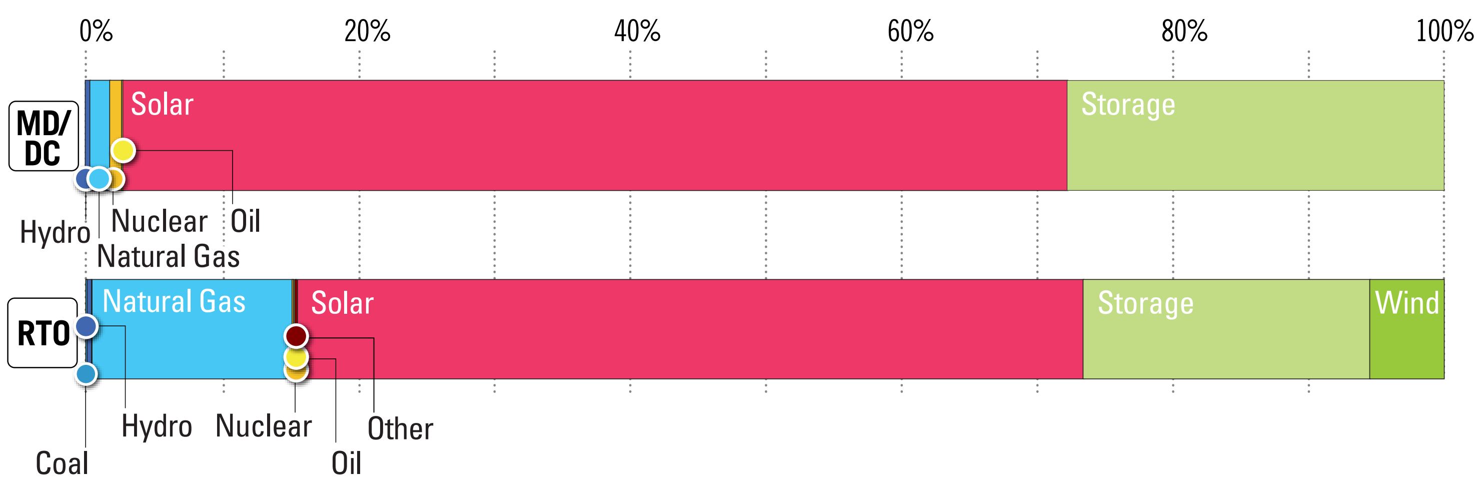
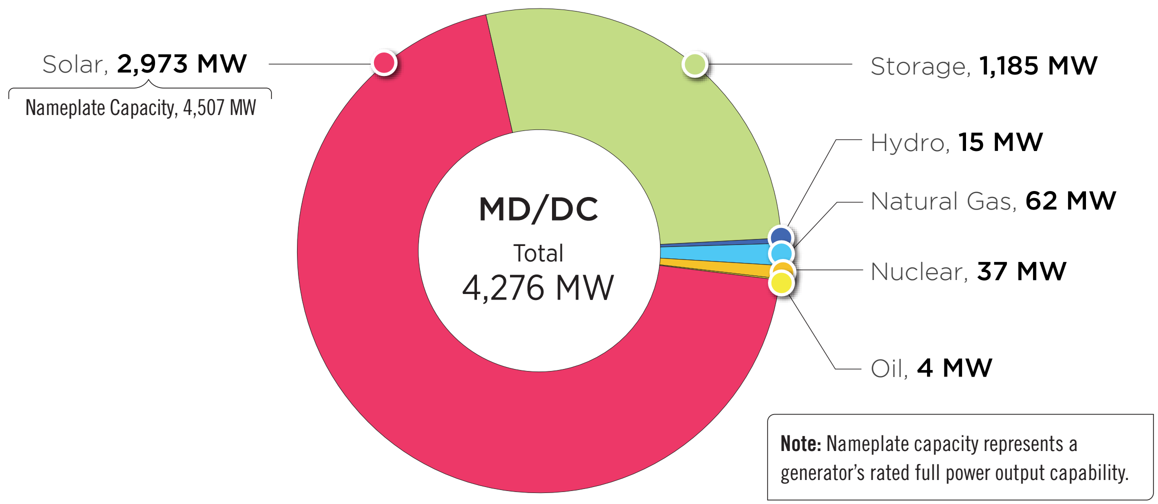


Figure 6.24: Maryland/District of Columbia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.25: Maryland/District of Columbia Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

9%	Requested capacity megawatts
15.4%	Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	28	Interconnection Service Agreements	5,668 MW	6,164 MW
	48	Wholesale Market Participation Agreements	114 MW	229 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.4.5 — Generation Deactivation

Known generating unit deactivation requests in Maryland and the District of Columbia between Jan. 1, 2021, and Dec. 31, 2021, are summarized in **Map 6.22** and **Table 6.27**.

Map 6.22: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2021)

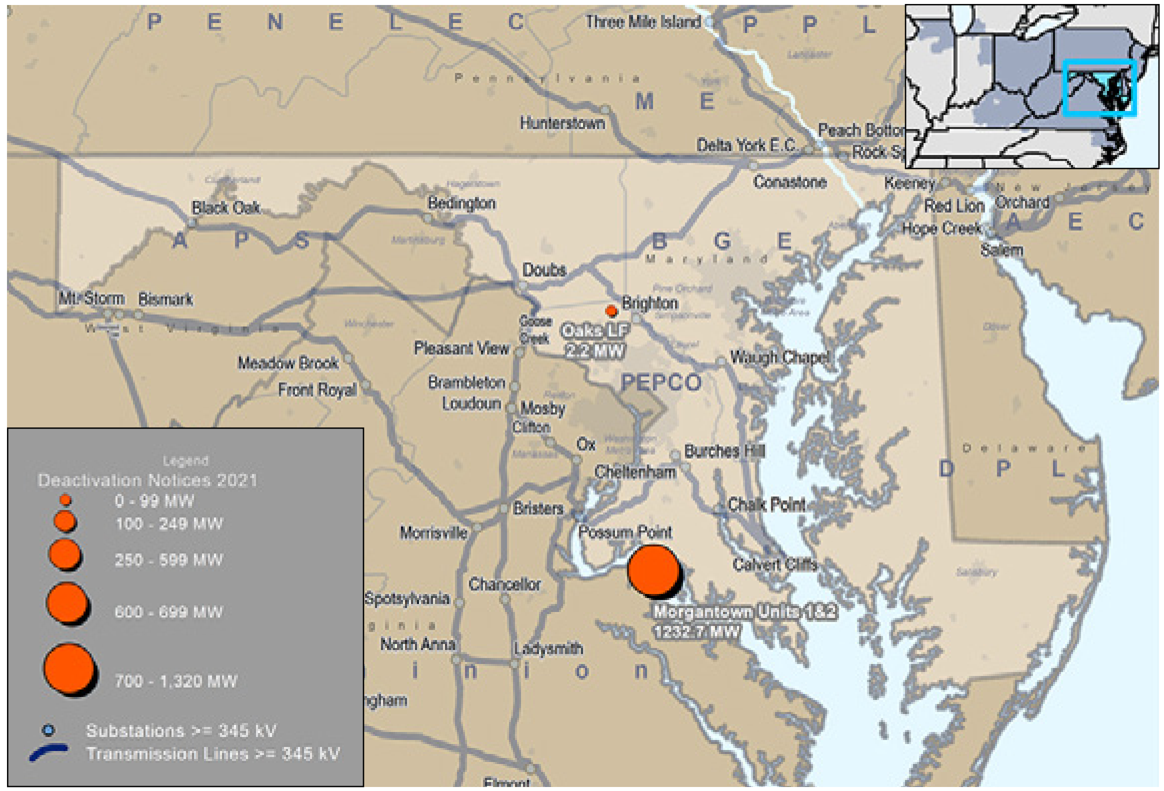


Table 6.27: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2021)

<table>
<tr><th>Unit</th><th>TO Zone</th><th>Fuel Type</th><th>Request Received to Deactivate</th><th>Actual or Projected Deactivation Date</th><th>Age (Years)</th><th>Capacity (MW)</th></tr>
<tr><td>Morgantown Unit 2</td><td rowspan="3">PEPCO</td><td rowspan="2">Coal</td><td>6/9/2021</td><td rowspan="2">5/31/2022</td><td>50</td><td>619.4</td></tr>
<tr><td>Morgantown Unit 1</td><td>6/9/2021</td><td>51</td><td>613.3</td></tr>
<tr><td>Oaks Landfill</td><td>Methane</td><td>4/16/2021</td><td>7/1/2021</td><td>11</td><td>2.2</td></tr>
</table>

6.4.6 — Baseline Projects

2021 RTEP baseline projects in Maryland and the District of Columbia are summarized in **Map 6.23** and **Table 6.28**.

6.4.7 — Network Projects

No network projects in Maryland and the District of Columbia were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.23: Maryland/District of Columbia Baseline Projects (Dec. 31, 2021)

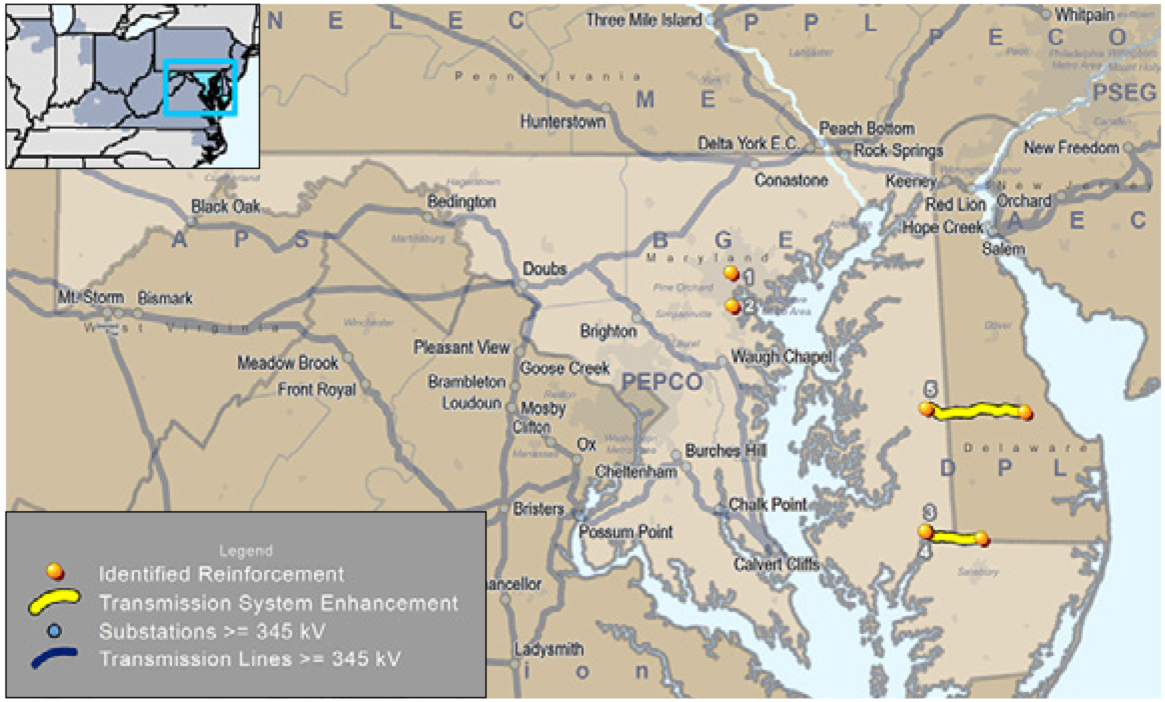


Table 6.28: Maryland/District of Columbia Baseline Projects (Dec. 31, 2021)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3228	Replace two relays at Center substation to increase ratings on the 110552 circuit.	6/1/2025	$0.03	BGE	11/18/2020
2	B3305	Replace Pumphrey 230/115 kV transformer.		$4.69		12/1/2020
3	B3326	Rebuild the 13707 Vienna-Nelson 138 kV line	6/1/2022	$38.50	DP&L	8/10/2021
4	B3328	Upgrade the disconnect switch (13710-L1) and CT at Vienna.		$0.25		8/31/2021
5	B3332	Rerate the 23076 Steel-Milford 230 kV line		$0.60		

6.4.8 — Supplemental Projects

2021 RTEP supplemental projects in Maryland and the District of Columbia are summarized in **Map 6.24** and **Table 6.29**.

6.4.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Maryland and District of Columbia were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the [Project Status](#) page of the PJM website.

Map 6.24: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2021)

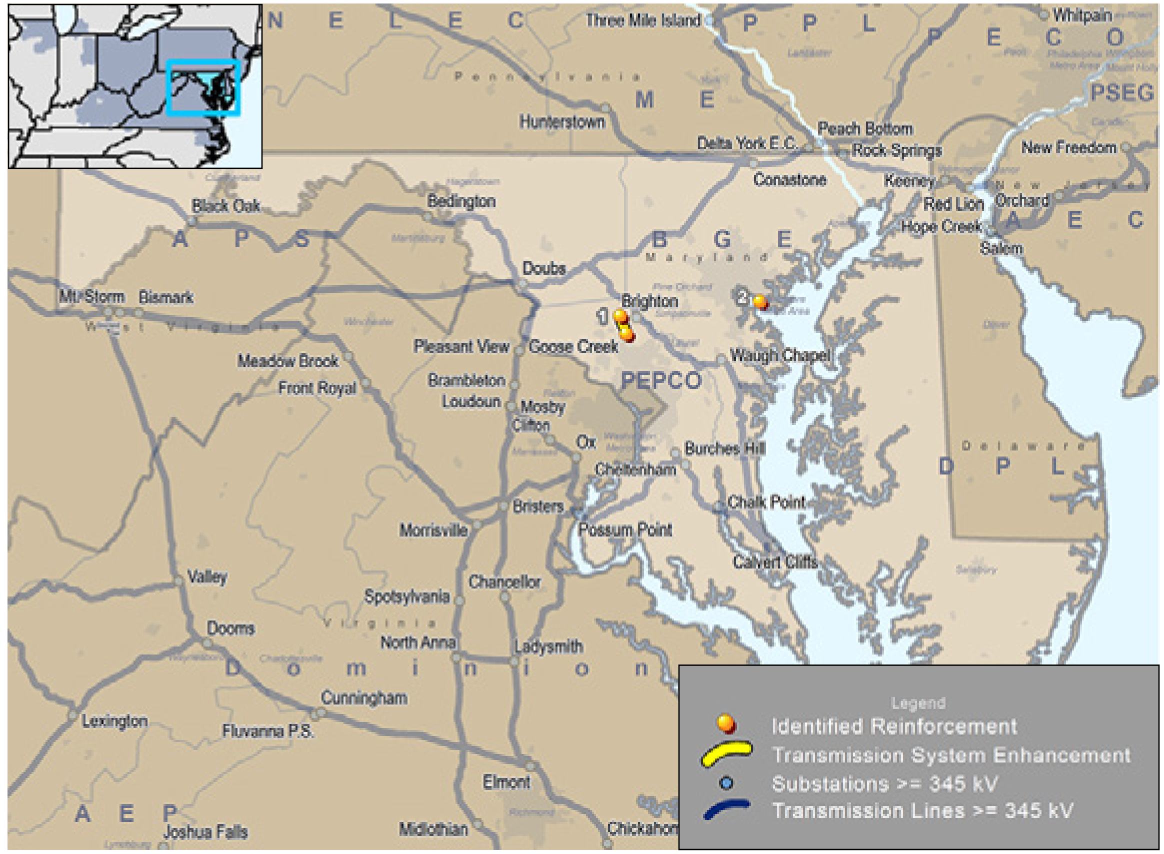


Table 6.29: Maryland/District of Columbia Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2563	Reconductor transmission line 23009 from Mount Zion to Norbeck (4.5 miles) with E3X coated conductor.	6/1/2022	$3.60	PEPCO	3/9/2021
2	S2587	Replace Riverside 230 kV circuit breaker No. B51.	11/30/2021	$1.25	BGE	7/13/2021

6.5: Southwestern Michigan RTEP Summary

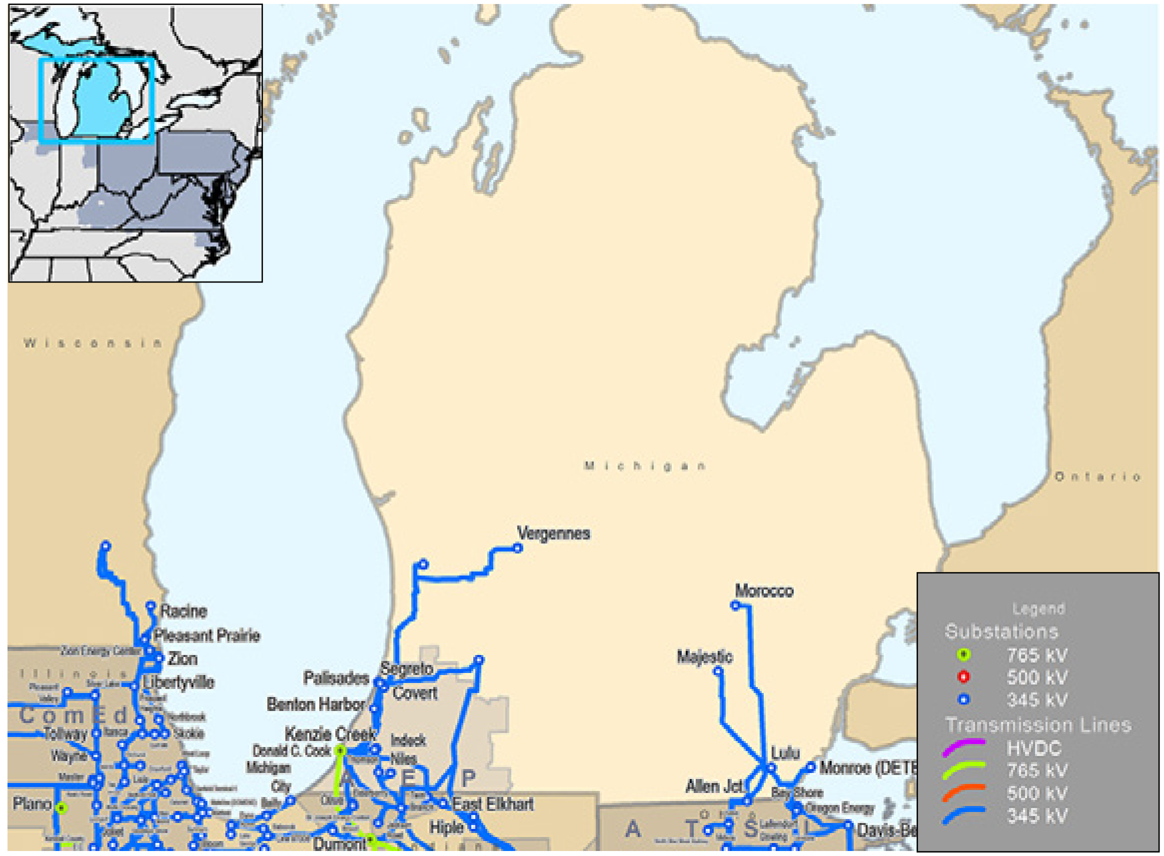
6.5.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Southwestern Michigan, including facilities owned and operated by American Electric Power (AEP) and International Transmission Co. (ITC) as shown on **Map 6.25**. Southwestern Michigan's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, Michigan has a mandatory renewable portfolio standard (RPS) target of 15% by 2021.

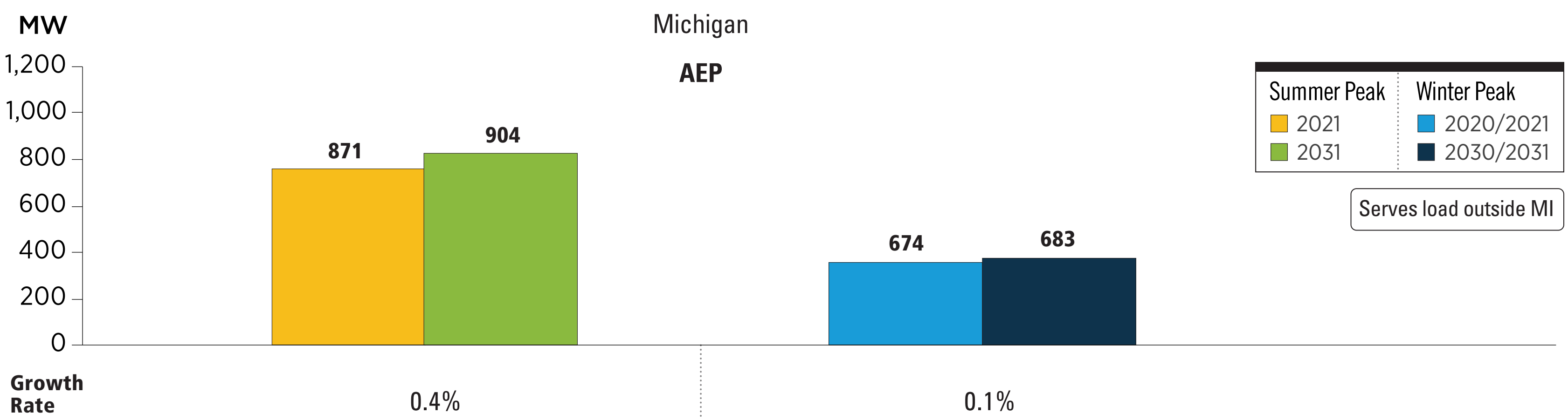
Map 6.25: PJM Service Area in Southwestern Michigan



6.5.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.26** summarizes the expected loads within Southwestern Michigan and across PJM.

Figure 6.26: Southwestern Michigan – 2021 Load Forecast Report



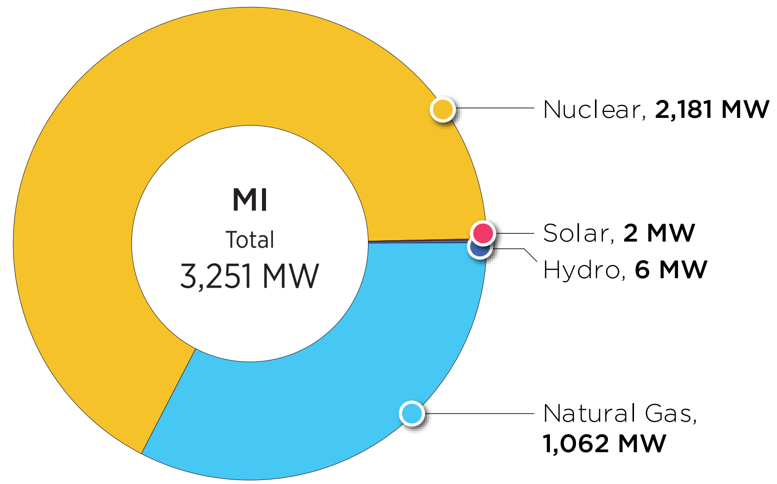
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.5.3 — Existing Generation

Existing generation in Southwestern Michigan as of Dec. 31, 2021, is shown by fuel type in **Figure 6.27**.

Figure 6.27: Southwestern Michigan – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.5.4 — Interconnection Requests

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

Specifically, in Southwestern Michigan, as of Dec. 31, 2021, 21 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.30**, **Table 6.31**, **Figure 6.28**, **Figure 6.29** and **Figure 6.30**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.30: Southwestern Michigan – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	Southwestern Michigan Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	0	0.00%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	1,230	50.10%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	0	0.00%	17	0.01%
Other	0	0.00%	331	0.20%
Solar	1,144	46.59%	93,756	57.99%
Storage	81	3.31%	34,130	21.11%
Wind	0	0.00%	8,800	5.44%
Grand Total	**2,455**	**100.00%**	**161,682**	**100.00%**

Table 6.31: Southwestern Michigan – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		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	1	145.0	2	1,085.0	2	1,055.0	1	1,120.0	6	3,405.0
	Nuclear	0	0.0	0	0.0	3	205.0	0	0.0	3	205.0
	Other	0	0.0	0	0.0	0	0.0	2	0.0	2	0.0
	Storage	3	81.3	0	0.0	0	0.0	1	75.0	4	156.3
Renewable	Methane	0	0.0	0	0.0	3	10.4	0	0.0	3	10.4
	Solar	15	1,143.7	0	0.0	1	2.3	4	237.8	20	1,383.8
	Wind	0	0.0	0	0.0	0	0.0	1	26.0	1	26.0
	Grand Total	**19**	**1,370.0**	**2**	**1,085.0**	**9**	**1,272.7**	**9**	**1,458.8**	**39**	**5,186.5**

Figure 6.28: Southwestern Michigan – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

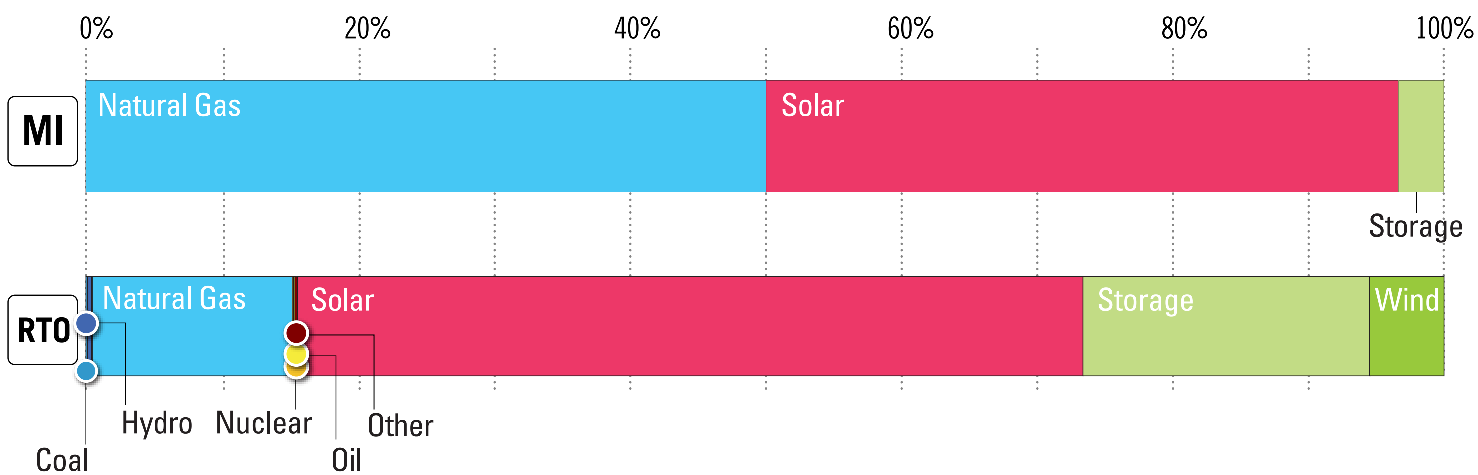
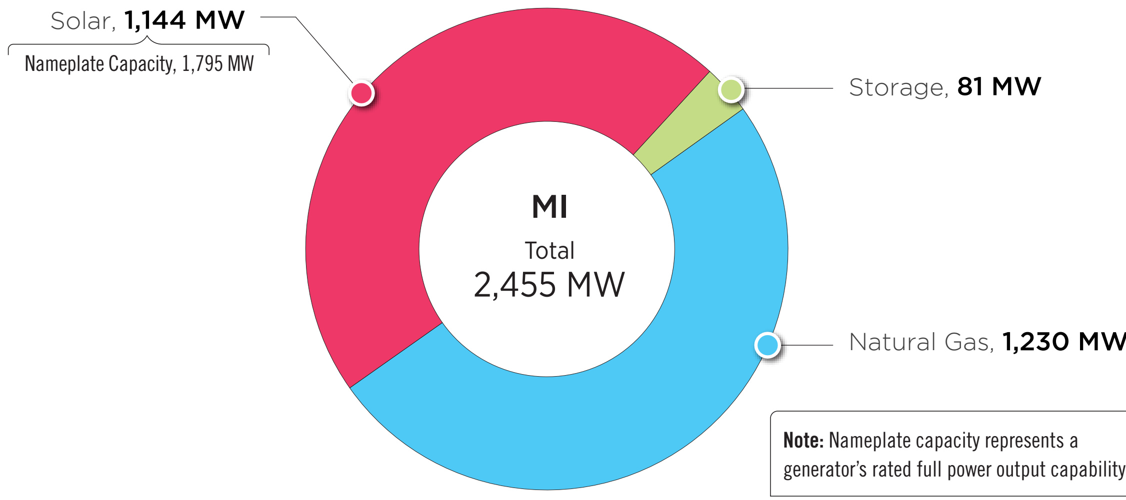


Figure 6.29: Southwestern Michigan – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.30: Southwestern Michigan Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

33.3% Requested capacity megawatts

42.9% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.5.5 — Generation Deactivation

There were no generating unit deactivation requests in Southwestern Michigan between Jan. 1, 2021, and Dec. 31, 2021, as part of the 2021 RTEP.

6.5.6 — Baseline Projects

2021 RTEP baseline projects in Southwestern Michigan are summarized in **Map 6.26** and **Table 6.32**.

6.5.7 — Network Projects

No network projects in Southwestern Michigan were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.26: Southwestern Michigan Baseline Projects (Dec. 31, 2021)

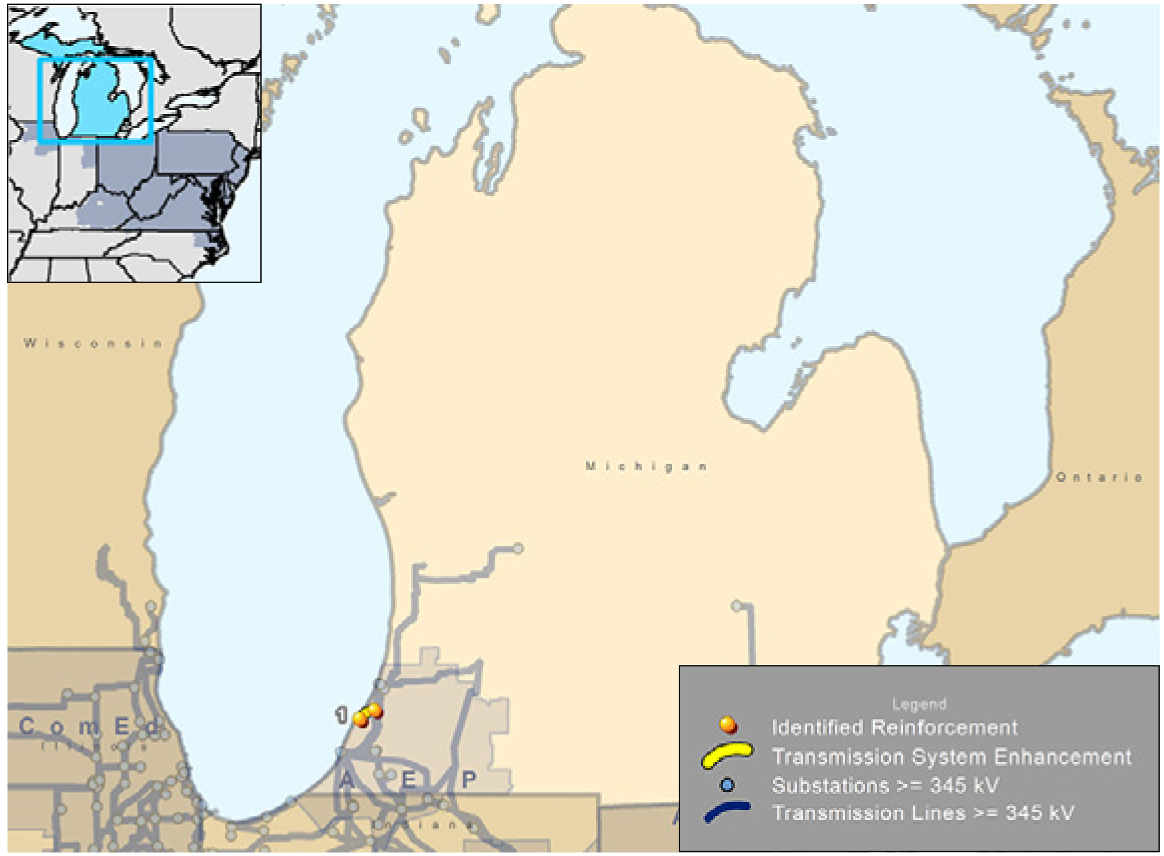


Table 6.32: Southwestern Michigan Baseline Projects (Dec. 31, 2021)

Map ID	Project	Description	Required In Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3336	Rebuild Benton Harbor-Riverside 138 kV double circuit extension (6 miles).	6/1/2022	$14.90	AEP	8/31/2021

6.5.8 — Supplemental Projects

2021 RTEP supplemental projects in Southwestern Michigan are summarized in **Map 6.27** and **Table 6.33**.

6.5.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Southwestern Michigan were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.27: Southwestern Michigan Supplemental Projects (Dec. 31, 2021)

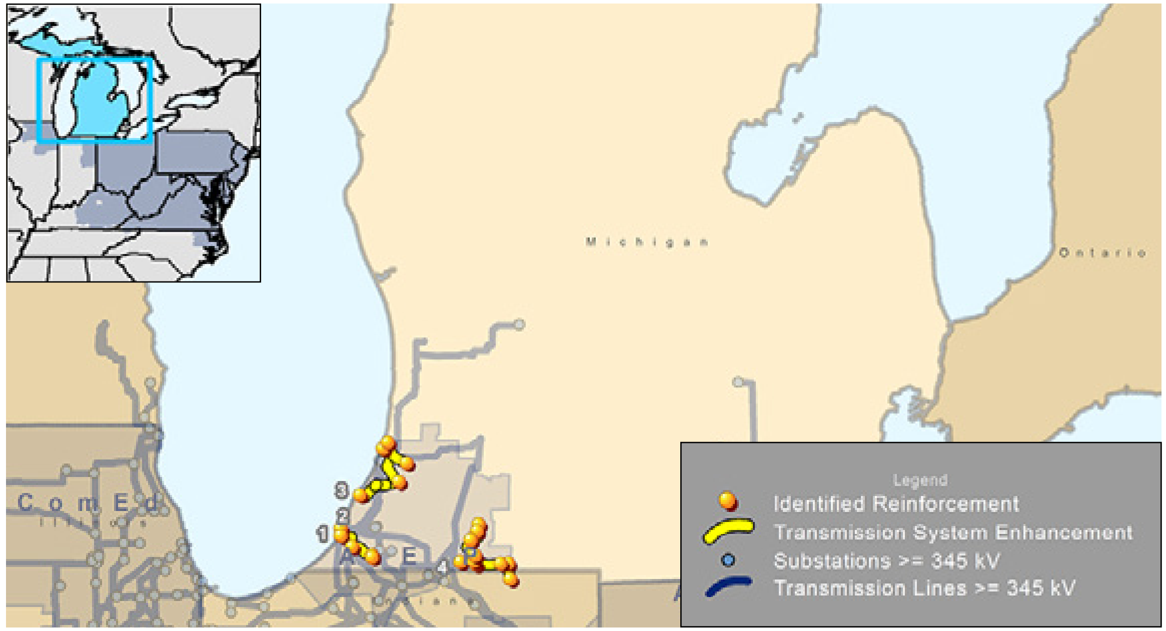


Table 6.33: Southwestern Michigan Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2390		Replace the failed 345 kV breaker N1 at DC Cook 765/345 kV station.	10/17/2020	$0.30	AEP	9/11/2020
2	S2440	.1	Rebuild the 7.7 mile Bridgman-Pletcher line with 556 ACSR conductor.	2/14/2024	$32.00		12/18/2020
		.2	Install new 69/34.5 kV Bucktown station to replace Buchanan Hydro station. Install new 69/34.5 kV transformer with two 34.5 kV line breakers and four 69 kV breaker ring bus.				
		.3	Retire 1 mile of 4/0 copper conductor from Buchanan Hydro to Clark Equipment and Jack's Post customer. Construct 0.1 miles of 34.5 kV line from Jack's Post to new Bucktown station.				
		.4	At Buchanan Hydro station – Retire the transmission and distribution equipment. Install one new 34.5 kV breaker for line protection to Bucktown to continue service to the hydro plant.				

Table 6.33: Southwestern Michigan Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S2571	.1	Riverside-Hartford 138 kV – Rebuild ~14.7 miles of 1950s wood H-frame line with 795 Drake ACSR.	10/28/2024	$65.40	AEP	7/16/2021
		.2	South Haven-Hartford 69 kV – Rebuild ~18.7 miles of 1960s wood pole line with 795 Drake ACSR.				
		.3	Phoenix Switch 69 kV – Replace the switch with a new phase-over-phase switch with line MOABs.				
		.4	Bangor 69 kV – Install a bus tie breaker at Bangor 69 kV station.				
4	S2584	.1	East Elkhart-Mottville Hydro 138 kV – Rebuild ~10 miles of 1950s wood on the East Elkhart-Mottville Hydro 138 kV line using 795 Drake ACSR.	3/25/2025	$91.15		8/16/2021
		.2	Mottville Hydro-Corey 138 kV – Retire the ~9 mile 138 kV line.				
		.3	Moore Park 69 kV tap – Retire the ~9 mile 69 kV line.				
		.4	Moore Park 69 kV SW – Retire the 69 kV phase-over-phase switch.				
		.5	Moore Park 69 kV station – Install a 90 MVA, 138/69 kV transformer with a high-side switcher and low-side circuit breaker. 69 kV circuit breaker "C" will be replaced with the 69 kV circuit breaker "B". Replace 69 kV cap switcher "BB".				
		.6	Retire Sturgis 69 kV station.				
		.7	Stubey Rd. 138/69 kV station – Expand station to include six 69 kV circuit breakers in a ring , four 138 kV circuit breakers in a ring, two 138/69 kV, 130 MVA transformers and two 17.6 MVAR, 69 kV cap banks. Reterminate the Sturgis IP line into Stubey Road. Reterminate the Corey line into Stubey Road to energize the line at 138 kV.				
		.8	Howe (Nipsco)-Sturgis 69 kV – Retire the ~2.9 mile 69 kV line.				
		.9	Mottville Hydro-Stubey Rd. 138 kV – Re-energize the existing line from Mottville-Pigeon River to 138 kV and construct a new ~8.9 mile 138 kV line between Pigeon River and Stubey Road to reestablish the 138 kV through path to Corey station.				
		.10	Pigeon River 69 kV station – Remove 69 kV circuit breaker "K" from Pigeon River to reuse at Stubey Rd.				
		.11	Mottville Hydro 138/69 kV station – Remove 69 kV circuit breaker "D" from Mottville Hydro to reuse at Stubey Rd. E.				
		.12	Corey 138/69 kV station – Remove 69 kV circuit breaker "C" from Corey to reuse at Stubey Rd. E.				
		.13	White Pigeon 69 kV Ext – Build new 69 kV 0.2 mile extension from Corey-Pigeon River to the existing White Pigeon station.				
		.14	Florence Rd. 69 kV station – Replace the line switches at Florence Rd.				

6.6: New Jersey RTEP Summary

6.6.1 — RTEP Context

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

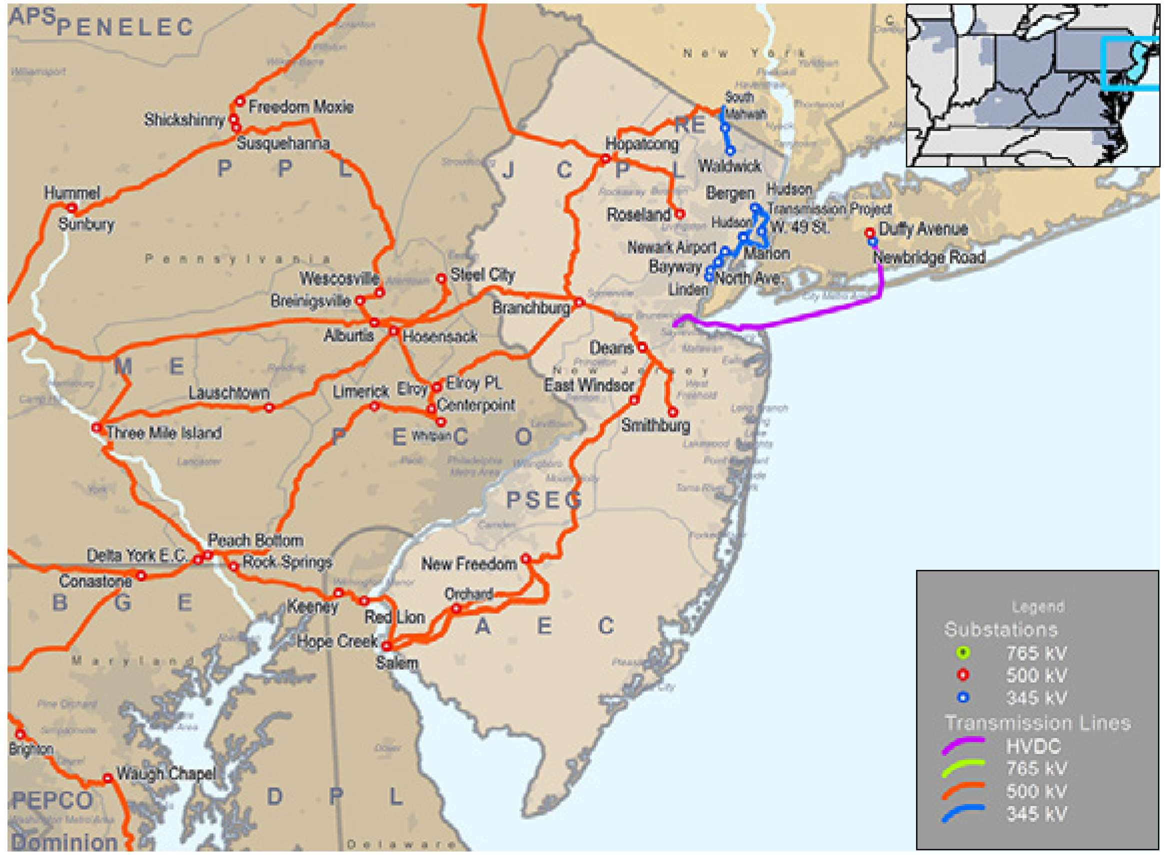
Renewable Portfolio Standards

From an energy policy perspective, New Jersey has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

New Jersey has a mandatory RPS target of 50% Class I renewable resources by 2030. The state also requires 2.5% Class II renewable resources each year. The RPS contains a solar carve-out that peaks at 5.1% in 2021 and declines each year after 2023.

The state of New Jersey is also advancing offshore wind to support its clean energy policies. The Clean Energy Act of 2018 requires New Jersey to procure at least 3,500 MW of offshore wind. The state's offshore wind target was then increased to 7,500 MW by 2035 through Governor Phil Murphy's Executive Order No. 92 (2019).

Map 6.28: PJM Service Area in New Jersey

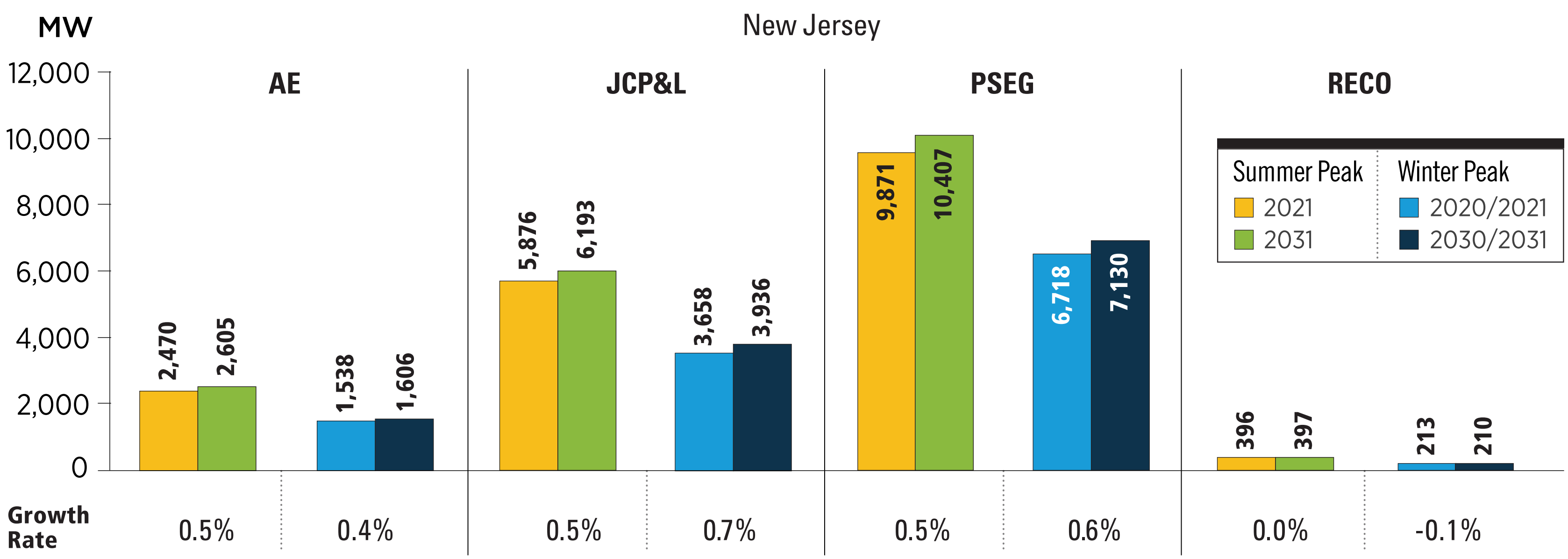


In 2019, New Jersey awarded offshore wind renewable energy credits (ORECs) to the 1,100 MW Ocean Wind 1 project. For its next solicitation, the state sought between 1,200–2,400 MW of offshore wind. In 2021, New Jersey awarded ORECs to two more offshore wind projects – the 1,148 MW Ocean Wind 2 project and the 1,509.6 MW Atlantic Shores project. New Jersey has now awarded ORECs to 3,757.6 MW of offshore wind.

6.6.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.31** summarizes the expected loads within the state of New Jersey and across PJM.

Figure 6.31: New Jersey – 2021 Load Forecast Report



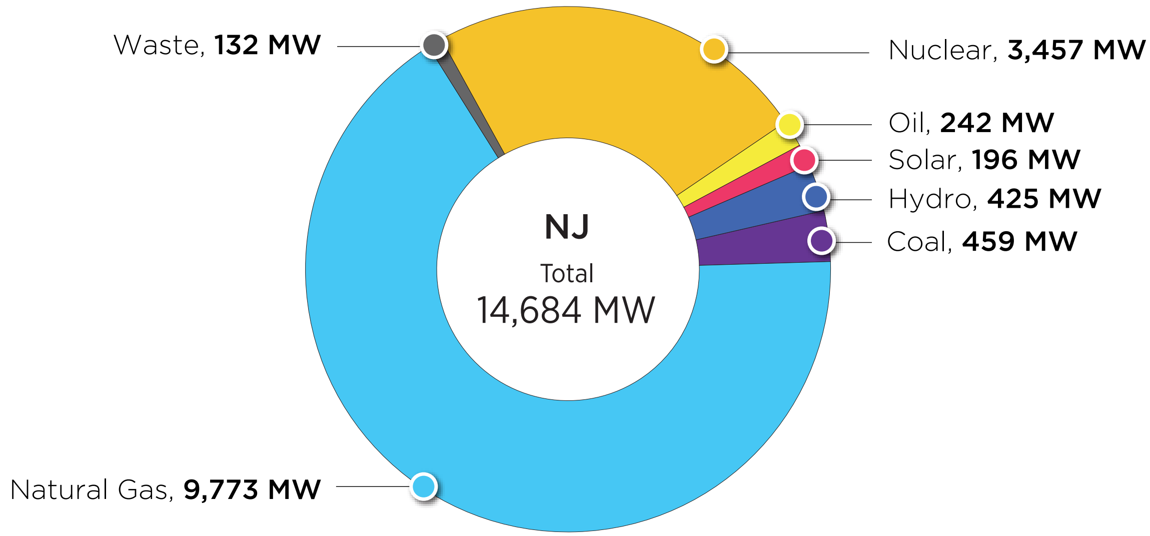
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.6.3 — Existing Generation

Existing generation in New Jersey as of Dec. 31, 2021, is shown by fuel type in **Figure 6.32**.

Figure 6.32: New Jersey – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.6.4 — Interconnection Requests

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

Specifically, in New Jersey, as of Dec. 31, 2021, 169 queued 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**. 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 6.34: New Jersey – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	New Jersey Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	30	0.44%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	1,141	16.56%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	0	0.00%	17	0.01%
Other	0	0.00%	331	0.20%
Solar	913	13.26%	93,756	57.99%
Storage	1,905	27.65%	34,130	21.11%
Wind	2,901	42.10%	8,800	5.44%
Grand Total	**6,891**	**100.00%**	**161,682**	**100.00%**

Table 6.35: New Jersey – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	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	0	0.0	1	15.0	1	15.0
	Natural Gas	5	336.1	2	746.0	4	59.2	79	8,017.9	181	51,838.5	271	60,997.7
	Nuclear	0	0.0	0	0.0	0	0.0	6	381.0	0	0.0	6	381.0
	Oil	0	0.0	0	0.0	0	0.0	2	35.0	8	945.0	10	980.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	7	45.5	7	45.5
	Storage	52	1,903.0	2	0.0	6	2.0	6	4.0	49	244.0	115	2,152.9
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	3	17.3	3	17.3
	Hydro	1	30.0	0	0.0	0	0.0	2	20.5	2	1,001.1	5	1,051.6
	Methane	0	0.0	0	0.0	0	0.0	15	43.3	9	40.6	24	83.9
	Solar	65	873.0	2	8.7	20	31.7	118	257.1	496	1,735.6	701	2,906.1
	Wind	15	2,779.5	0	0.0	1	121.4	1	0.0	21	908.1	38	3,809.0
	Grand Total	**138**	**5,921.5**	**6**	**754.7**	**31**	**214.3**	**229**	**8,758.8**	**777**	**56,790.7**	**1,181**	**72,440.2**

Figure 6.33: New Jersey – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

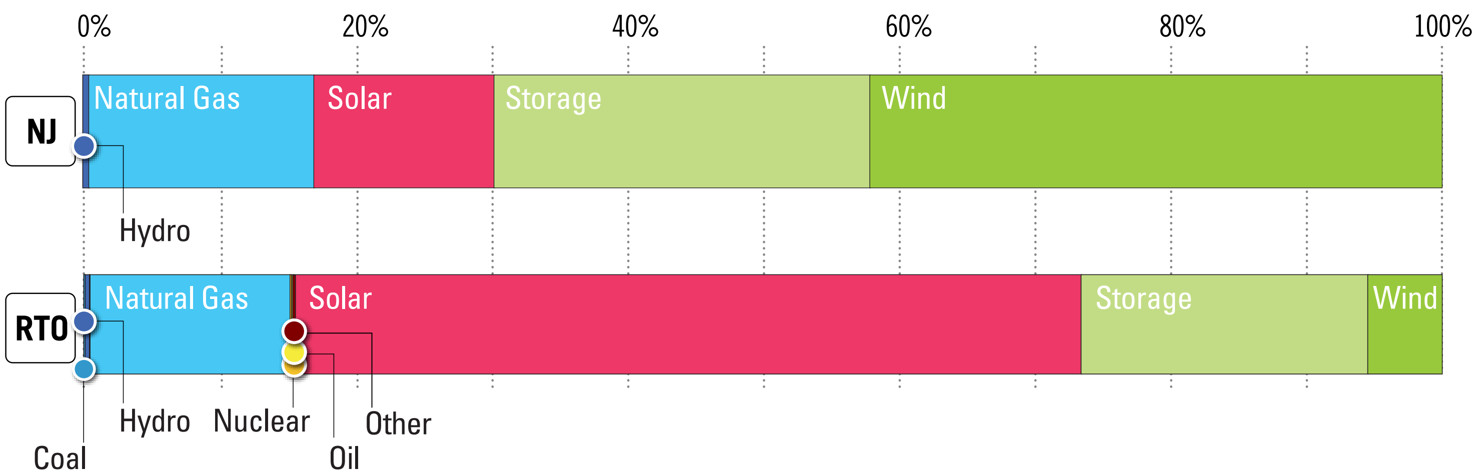
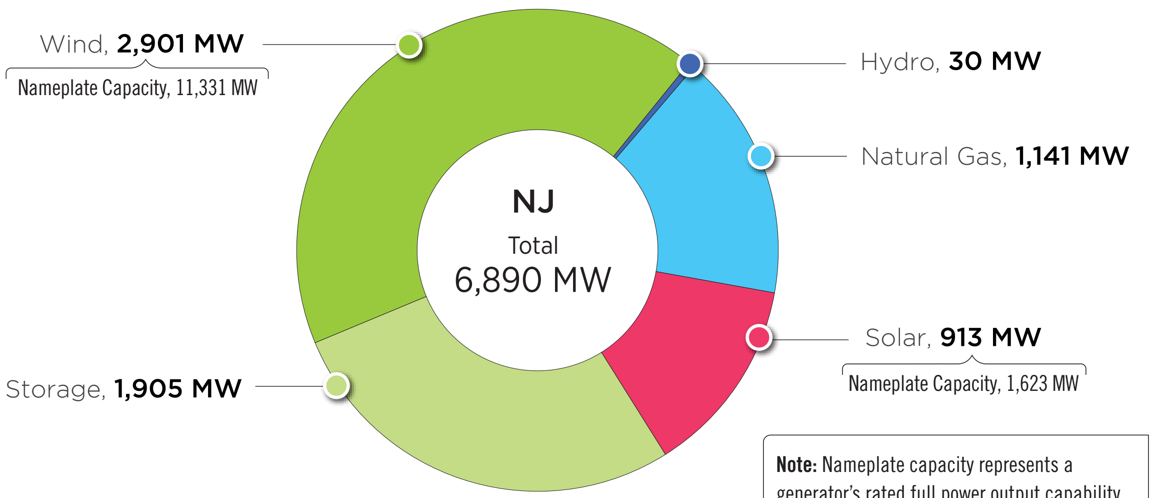


Figure 6.34: New Jersey – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.35: New Jersey Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

13.3% Requested capacity megawatts

23.2% Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	24	Interconnection Service Agreements	2,595 MW	3,067 MW
	149	Wholesale Market Participation Agreements	376 MW	1,075 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.6.5 — Generation Deactivation

Known generating unit deactivation requests in New Jersey between Jan. 1, 2021, and Dec. 31, 2021, are summarized in **Map 6.29** and **Table 6.36**.

Map 6.29: New Jersey Generation Deactivations (Dec. 31, 2021)

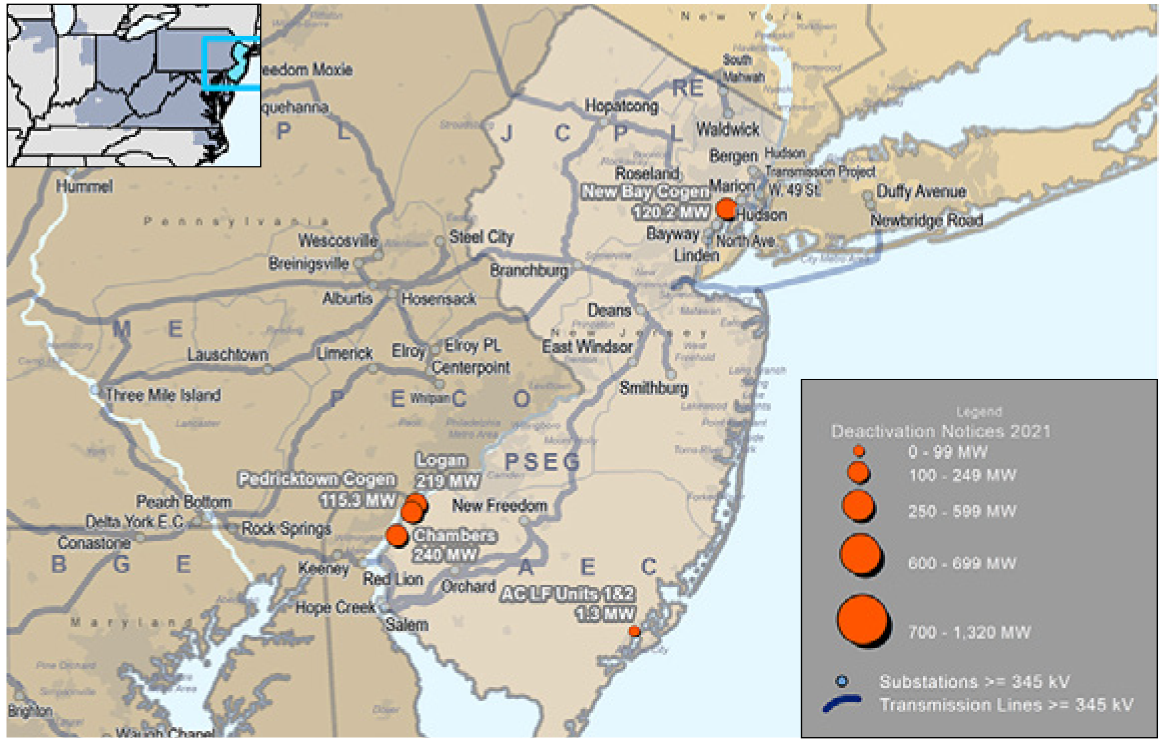
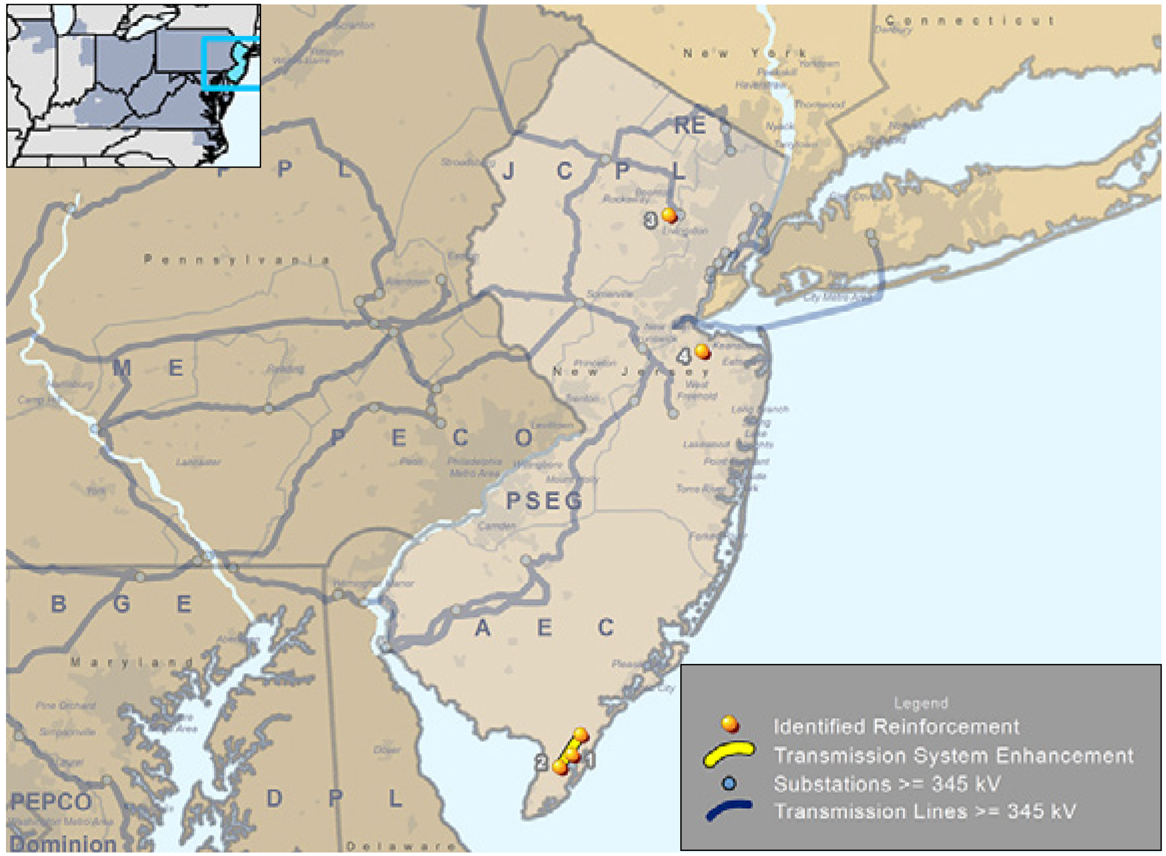


Table 6.36: New Jersey Generation Deactivations (Dec. 31, 2021)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Logan	AE	Coal	12/29/2021	4/1/2022	27	219
Chambers CCLP					27	240
AC Landfill Units 1 and 2		Methane	9/10/2021	12/9/2021	16	1.3
New Bay Cogen CC	PSEG	Natural Gas	7/15/2021	5/31/2022	28	120.2
Pedricktown Cogen CC	AE				29	115.3

Map 6.30: New Jersey Baseline Projects (Dec. 31, 2021)



6.6.6 — Baseline Projects

2021 RTEP baseline projects in New Jersey are summarized in **Map 6.30** and **Table 6.37**.

6.6.7 — Network Projects

No network projects in New Jersey were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Table 6.37: New Jersey Baseline Projects (Dec. 31, 2021)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3226	Add 10 MVAR 69 kV capacitor bank at Swainton substation.	6/1/2025	$2.90	AE	11/18/2020
2	B3227	Rebuild the Corson-Court 69 kV line to achieve ratings equivalent to 795 ACSR conductor or better.		$13.20		
3	B3238	Replace seven overdutied 34.5 kV breakers with 50 kA rated equipment at the Whippany substation.		$8.67	JCP&L	
4	B3239	Replace 14 overdutied 34.5 kV breakers with 63 kA rated equipment.		$5.70		

6.6.8 — Supplemental Projects

2021 RTEP supplemental projects in New Jersey are summarized in **Map 6.31** and **Table 6.38**.

Map 6.31: New Jersey Supplemental Projects (Dec. 31, 2021)

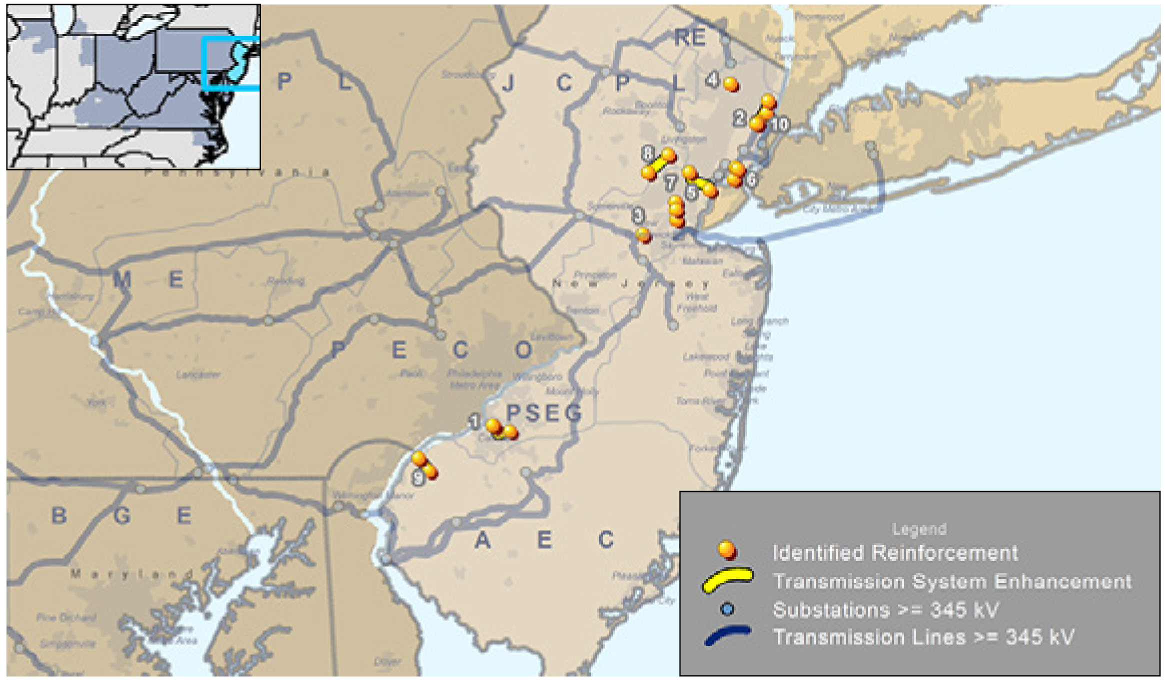


Table 6.38: New Jersey Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2413		Build new 69/13 kV station in Audubon area.	5/31/2025	$48.60	PSEG	11/18/2020
		.1	Purchase property to accommodate new 69/13 kV station (Nickolson) in Audubon area, and install a 69 kV station with two 69/13 kV transformers.				
		.2	Loop in the Gloucester-Lawnside 69 kV into the new station (Nicholson), and build a new 69 kV from Woodlynne-Nicholson.				
2	S2415		Build new 69/13 kV station in Eastern Bergen County area.	4/10/2025	$112.80		
		.1	Eliminate Hudson Terrace 26 kV substation, and construct a 69 kV station with two 69/13 kV transformers on existing substation property.				
		.2	Loop in the new 69 kV station (Cliffs) into the Bergen-Englewood and Bergenfield-Englewood 69 kV circuits.				

Table 6.38: New Jersey Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S2482		Eliminate Albany St. 26 kV station and modify North Brunswick station to pick up existing loads. Add three 69/26 kV transformers at North Brunswick station.	5/31/2024	$29.20	PSEG	1/14/2021
4	S2483		Convert existing Spring Valley Rd. 69/4 kV substation to a 69/13 kV substation. Replace three 69/4 kV transformers with two 69/13 kV transformers at Spring Valley Rd.	12/31/2024	$13.20	PSEG	1/14/2021
5	S2491		Convert existing Elizabeth 26/4 kV substation to a 69/4 kV substation.	5/31/2025	$85.80	PSEG	2/16/2021
		.1	Purchase property to accommodate new construction and install 69 kV substation (Elizabeth) with three 69/4 kV transformers.				
		.2	Cut and loop Linden-Vauxhall 69 kV circuit into new location (Elizabeth).				
		.3	Construct a new circuit from new station (Elizabeth) to NYE Ave. 69 kV.				
6	S2537		Construct a new Constable Hook 69/13 kV substation in the Bergen Neck area to feed Bergen Point load and provide for future load growth.	5/30/2026	$116.00	PSEG	4/14/2021
		.1	Eliminate 26 kV and 4 kV equipment at Bergen Point.				
		.2	Construct 69 kV ring bus Class H on new property (Constable Hook) with two 69/13 kV transformers.				
		.3	Construct a primarily underground 69 kV network between Greenville, Bayonne, Fairmount and Constable Hook. Loop in the Greenville-Bayonne 69 kV into Constable Hook, and build a new 69 kV circuit from Fairmount to Constable Hook.				
7	S2564		Install a new 230 kV substation (Oak Tree Road) with two 230/13 kV transformers. Cut and loop the New Dover-Metuchen 230 kV line in to the 230 kV bus, and transfer load from heavily loaded New Dover and Kilmer to the new station.	5/1/2025	$92.90	PSEG	3/9/2021
8	S2565		Gillette 230 kV substation – Replace line relaying, line trap, CCVT and substation conductor on the Gillette-Traynor 230 kV line.	6/1/2021	$2.00	JCP&L	5/11/2021
		.1	Traynor 230 kV substation – Replace line relaying, line trap, CCVT and substation conductor on the Gillette-Traynor 230 kV line.				
9	S2567		Upgrade Beckett substation area and retire Carney's Point, Pennsgrove, Oldman substations.	12/31/2024	$39.50	AE	5/20/2021
		.1	Upgrade Beckett substation to line bus configuration by installing four 69 kV circuit breakers.	5/31/2023			
		.2	Construct new seven-breaker 69 kV ring bus substation on Churchtown-Monsanto line.	12/31/2024			
		.3	Construct new 5.6 mile 69 kV line from Beckett to new substation.				
10	S2568		Build new 69-13 kV station at new property in Fairview, NJ.	5/30/2026	$99.80	PSEG	5/20/2021
		.1	Purchase property to accommodate new construction, and install a new 69 kV station with two 69-13 kV transformers. Transfer load from heavily loaded Ridgefield to the new station.				
		.2	Construct a 69 kV network in the Southeastern Bergen County area by cutting and looping two existing lines (Bergen-River Rd. and Bergen-Tonnelle Ave. 69 kV circuits) into the new station.				

6.6.9 — Merchant Transmission Project Requests

As of Dec. 31, 2021, PJM's queue contained two merchant transmission project requests with a terminal in New Jersey, as shown in **Map 6.32** and **Table 6.39**.

Map 6.32: New Jersey Merchant Transmission Project Requests (Dec. 31, 2021)

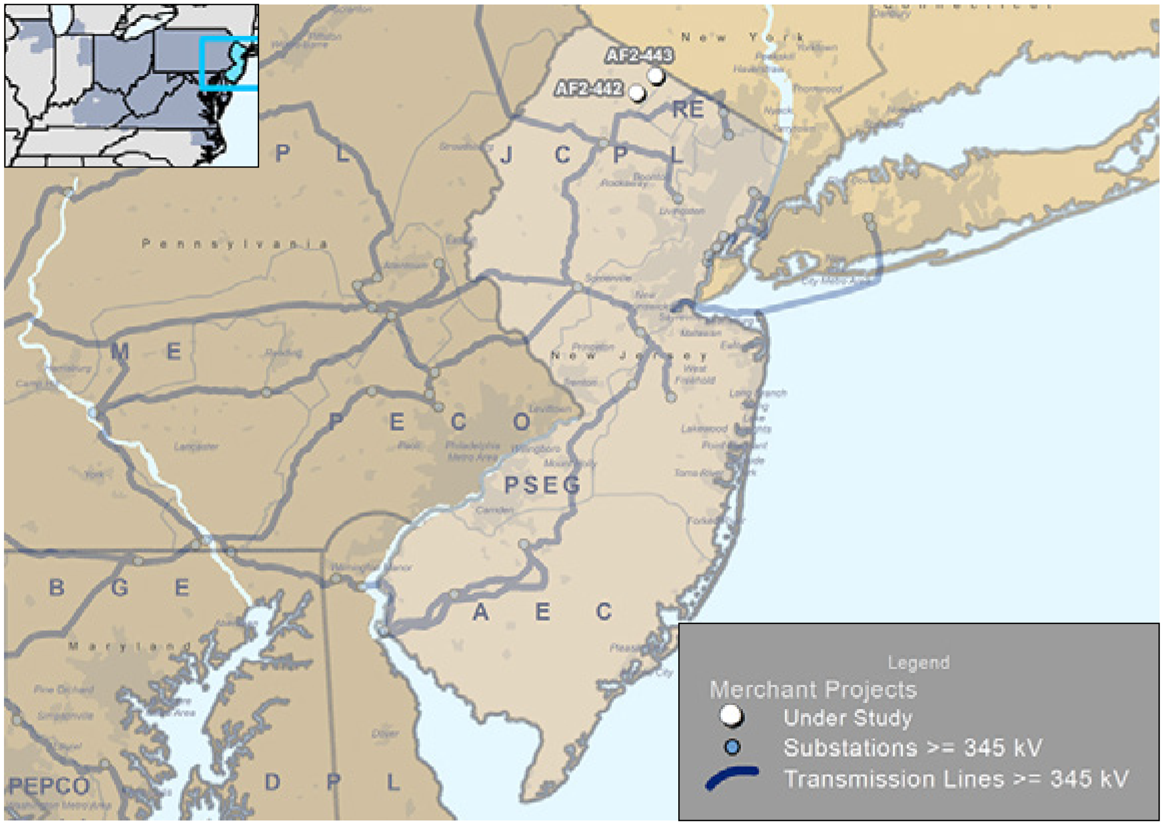


Table 6.39: New Jersey Merchant Transmission Project Requests (Dec. 31, 2021)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AF2-443	Vernon 115 kV	JCP&L	Active	5/31/2023	84
AF2-442					

6.7: North Carolina RTEP Summary

6.7.1 — RTEP Context

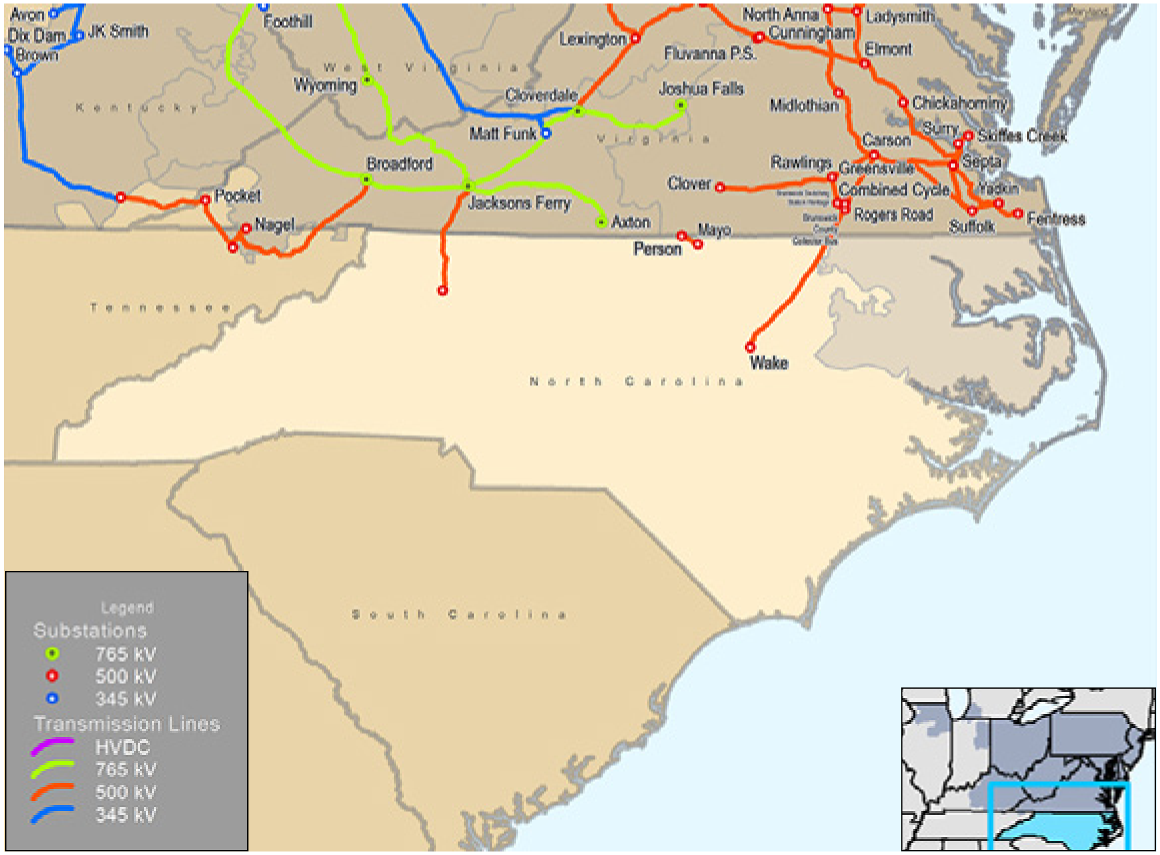
PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in North Carolina, including facilities owned and operated by Dominion as shown on **Map 6.33**. North Carolina's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, North Carolina has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

North Carolina has a mandatory RPS target of 12.5% for investor-owned utilities by 2021. The target is 10% for the state's electric cooperatives and municipalities.

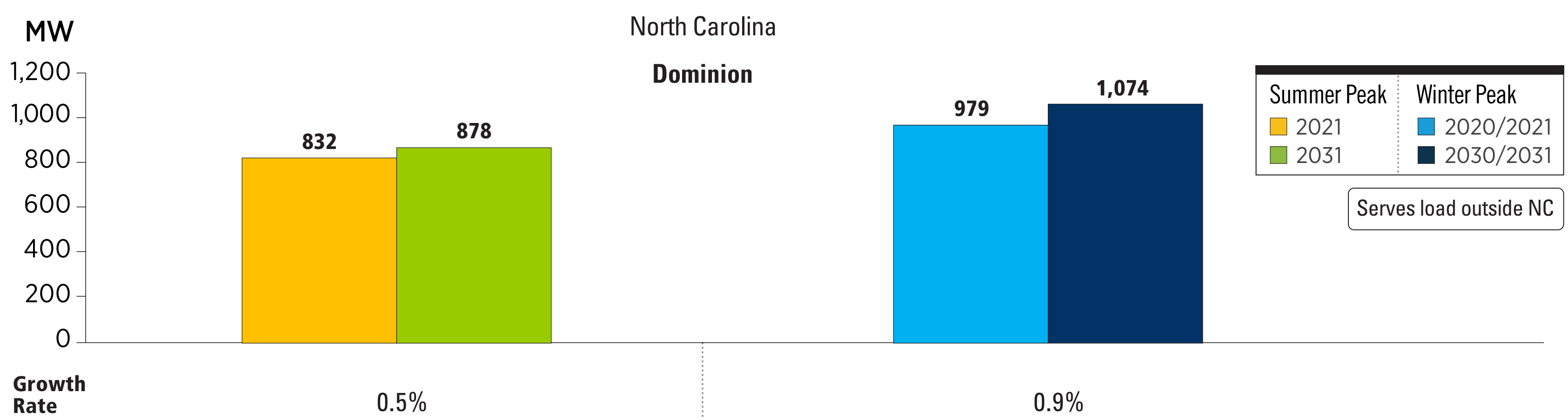
Map 6.33: PJM Service Area in North Carolina



6.7.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.36** summarizes the expected loads within the state of North Carolina and across PJM.

Figure 6.36: North Carolina – 2021 Load Forecast Report



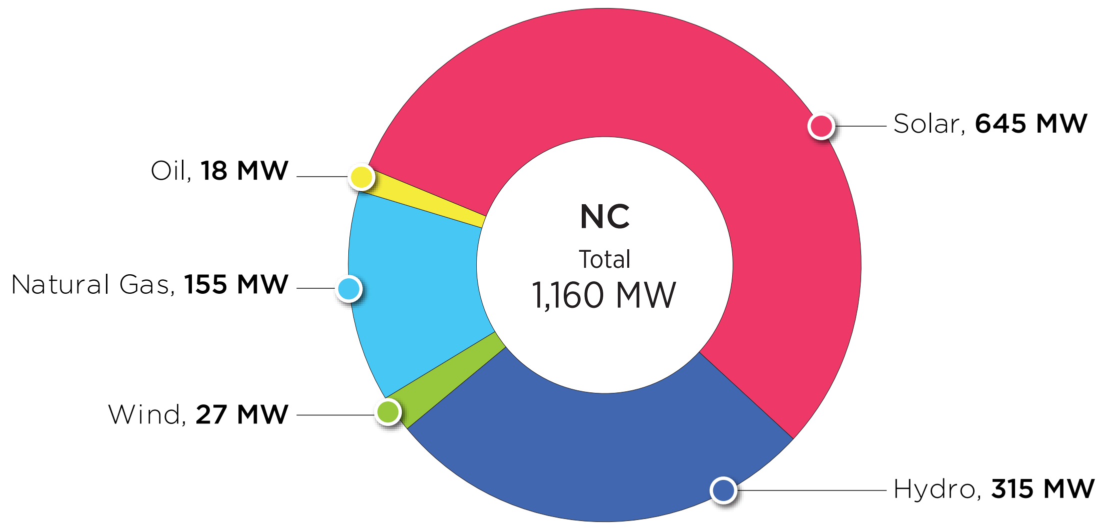
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.7.3 — Existing Generation

Existing generation in North Carolina as of Dec. 31, 2021, is shown by fuel type in **Figure 6.37**.

Figure 6.37: North Carolina – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.7.4 — Interconnection Requests

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

Specifically, in North Carolina, as of Dec. 31, 2021, 67 queued 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**. 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 6.40: North Carolina – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	North Carolina Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	0	0.00%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	0	0.00%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	0	0.00%	17	0.01%
Other	0	0.00%	331	0.20%
Solar	3,391	87.22%	93,756	57.99%
Storage	458	11.78%	34,130	21.11%
Wind	39	1.00%	8,800	5.44%
Grand Total	**3,888**	**100.00%**	**161,682**	**100.00%**

Table 6.41: North Carolina – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Storage	12	458.0	0	0.0	0	0.0	0	0.0	5	130.5	17	588.5
Renewable	Methane	0	0.0	0	0.0	0	0.0	0	0.0	1	12.0	1	12.0
	Solar	49	3,035.8	4	109.1	6	246.1	21	645.0	88	3,310.3	168	7,346.2
	Wind	0	0.0	1	39.0	0	0.0	1	27.0	9	195.3	11	261.3
	Wood	0	0.0	0	0.0	0	0.0	1	50.0	1	80.0	2	130.0
	Grand Total	61	3,493.8	5	148.1	6	246.1	23	722.0	104	3,728.1	199	8,338.0

Figure 6.38: North Carolina – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

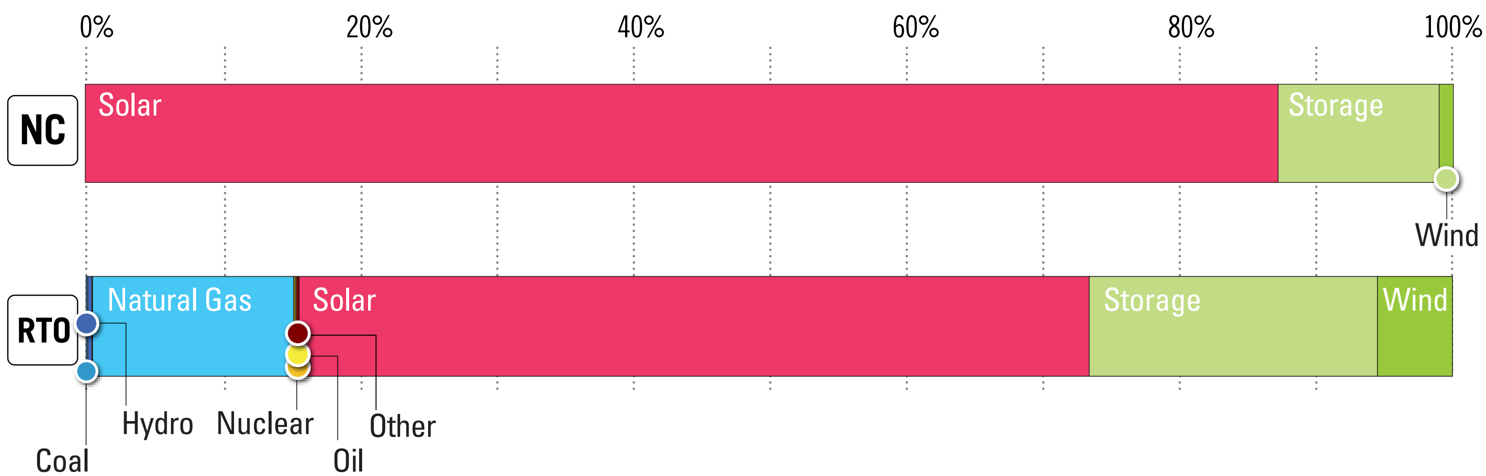
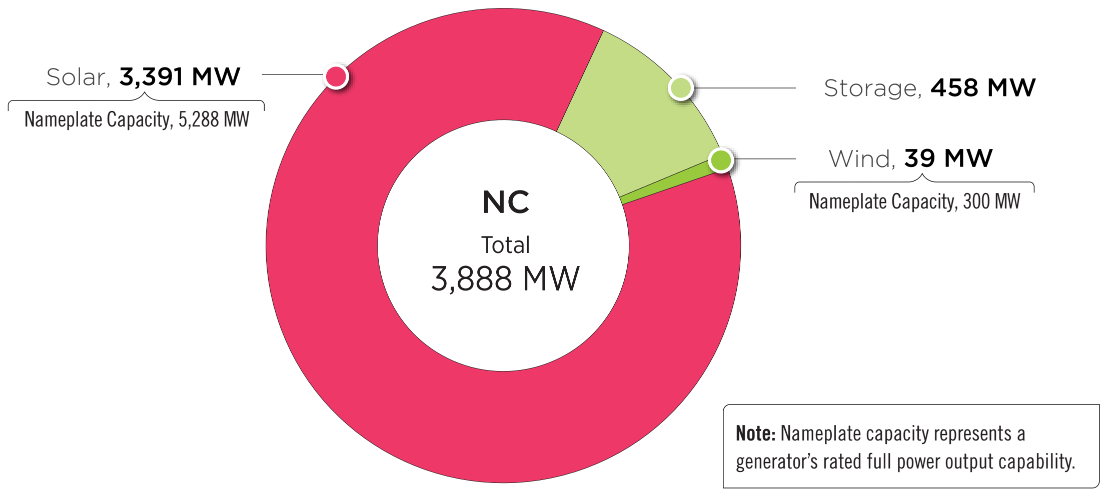


Figure 6.39: North Carolina – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.40: North Carolina Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

16.0% Requested capacity megawatts

18.1% Requested projects

Projects withdrawn after final agreement			Capacity	Nameplate
	7	Interconnection Service Agreements	234 MW	743 MW
	5	Wholesale Market Participation Agreements	44 MW	65 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.7.5 — Generation Deactivation

There were no generating unit deactivation requests in North Carolina between Jan. 1, 2021, and Dec. 31, 2021, as part of the 2021 RTEP.

6.7.6 — Baseline Projects

No baseline projects in North Carolina were identified as part of the 2021 RTEP. PJM Board approved project details are accessible on the Project Status page of the PJM website.

6.7.7 — Network Projects

No network projects in North Carolina were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.7.8 — Supplemental Projects

2021 RTEP supplemental projects in North Carolina are summarized in **Map 6.34** and **Table 6.42**.

6.7.9 — Merchant Transmission Project Requests

No merchant transmission project requests in North Carolina were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.34: North Carolina Supplemental Projects (Dec. 31, 2021)

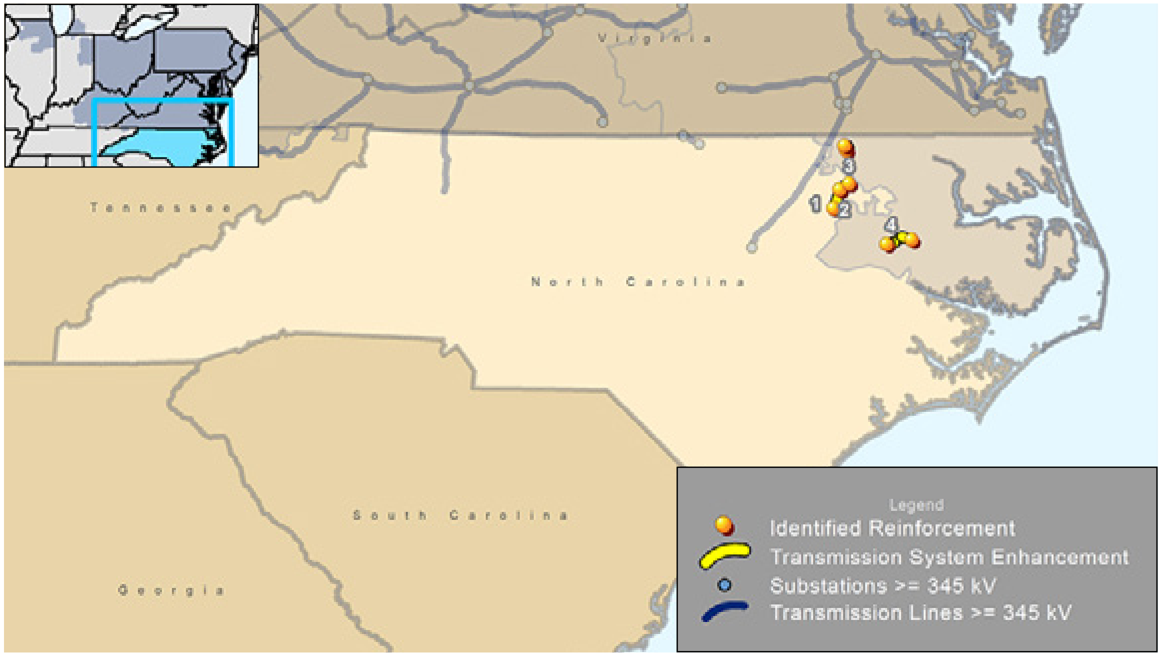


Table 6.42: North Carolina Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2501	Rebuild 114 kV Line No. 1001 (Battleboro–Chestnut) to current 115 kV standards with a minimum summer rating of 261 MVA.	12/15/2024	$14.00	Dominion	11/18/2020
2	S2502	Rebuild 115 kV Line No. 1024 (Chestnut-South Justice Branch) to current 115 kV standards with a minimum summer rating of 261 MVA.	12/31/2023	$5.10		
3	S2612	Rebuild ~1.8 miles single circuit segment of 230 kV Line No. 239 Lakeview-Hornertown to current 230 kV standards. The normal summer rating of this line segment will be 1047MVA. Rebuild ~0.9 mile double circuit segment of 230kV Line No. 239 and 230 kV Line No. 2141 Carolina-Lakeview to current 230 kV standards. The normal summer rating of the line segments will be 1047 MVA.	12/31/2022	$5.00		6/8/2021
4	S2618	Rebuild ~12.4 miles of the Everetts-Parmele 115 kV line. New conductor with a minimum normal summer rating of 262 MVA will be used.	12/31/2022	$27.00		3/18/2021

6.8: Ohio RTEP Summary

6.8.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Ohio, including facilities owned and operated by American Electric Power (AEP), AES Ohio – formerly Dayton Power & Light Company (DAY), American Transmission Systems, Inc. (ATSI), Duke Energy Ohio and Kentucky (DEO&K), the City of Cleveland and the City of Hamilton as shown on **Map 6.35**.

Ohio's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

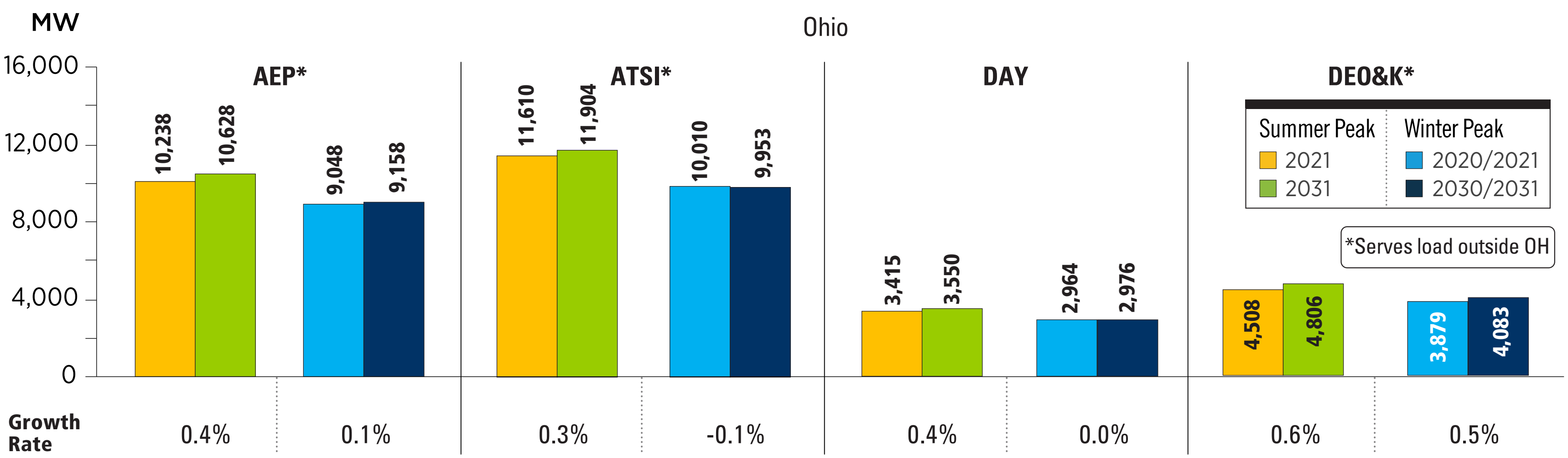
From an energy policy perspective, Ohio has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years. Ohio has a mandatory RPS target of 8.5% by 2026.

Map 6.35: PJM Service Area in Ohio

6.8.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.41** summarizes the expected loads within the state of Ohio and across PJM.

Figure 6.41: Ohio – 2021 Load Forecast Report



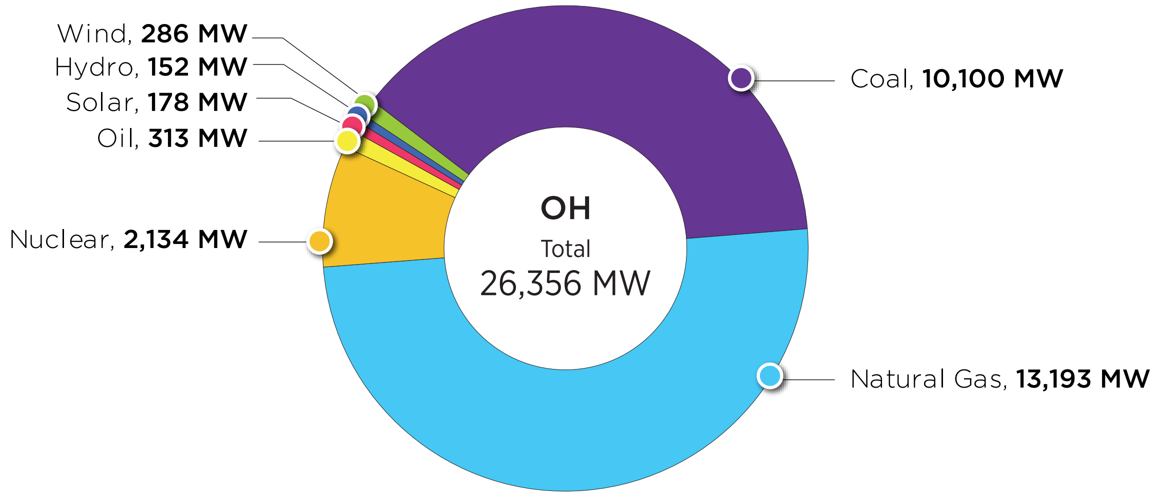
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.8.3 — Existing Generation

Existing generation in Ohio as of Dec. 31, 2021, is shown by fuel type in **Figure 6.42**.

Figure 6.42: Ohio – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.8.4 — Interconnection Requests

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

Specifically, in Ohio, as of Dec. 31, 2021, 393 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.43**, **Table 6.44**, **Figure 6.43**, **Figure 6.44** and **Figure 6.45**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.43: Ohio – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	Ohio Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	40	0.14%	76	0.05%
Hydro	0	0.00%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	5,722	20.20%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	6	0.02%	17	0.01%
Other	48	0.17%	331	0.20%
Solar	17,084	60.30%	93,756	57.99%
Storage	5,171	18.25%	34,130	21.11%
Wind	260	0.92%	8,800	5.44%
Grand Total	**28,331**	**100.00%**	**161,682**	**100.00%**

Table 6.44: Ohio – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	1	11.0	0	0.0	2	29.0	11	239.0	16	8,923.0	30	9,202.0
	Diesel	0	0.0	0	0.0	0	0.0	1	7.0	0	0.0	1	7.0
	Natural Gas	8	629.6	4	2,771.0	4	2,321.0	29	5,058.2	35	13,734.4	80	24,514.2
	Nuclear	0	0.0	0	0.0	0	0.0	1	16.0	0	0.0	1	16.0
	Oil	0	0.0	0	0.0	2	5.5	0	0.0	1	5.0	3	10.5
	Other	4	47.9	0	0.0	0	0.0	0	0.0	5	135.0	9	182.9
	Storage	55	5,171.0	0	0.0	1	0.0	5	0.0	28	1,148.5	89	6,319.6
Renewable	Biomass	0	0.0	0	0.0	0	0.0	1	0.0	3	185.0	4	185.0
	Hydro	0	0.0	0	0.0	0	0.0	1	112.0	8	76.2	9	188.2
	Methane	0	0.0	0	0.0	0	0.0	8	40.9	9	26.1	17	67.0
	Solar	274	15,266.2	1	5.4	35	1,812.9	6	178.0	139	4,957.1	455	22,219.5
	Wind	6	221.3	0	0.0	1	38.7	8	197.4	74	1,832.9	89	2,290.3
	Grand Total	**348**	**21,347.1**	**5**	**2,776.4**	**45**	**4,207.1**	**71**	**5,848.4**	**318**	**31,023.2**	**787**	**65,202.2**

Figure 6.43: Ohio – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

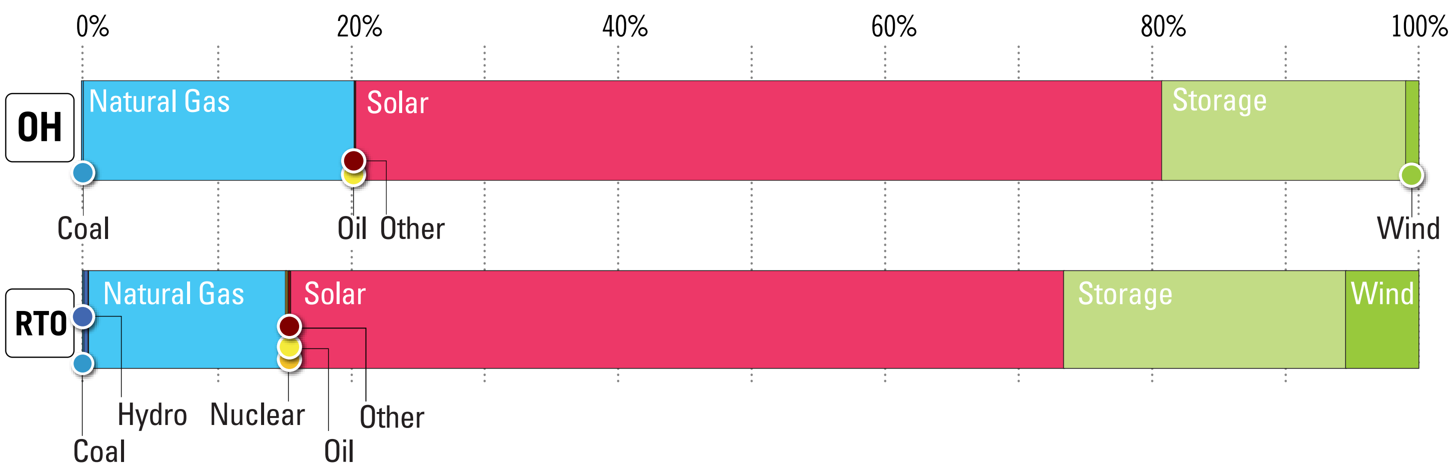
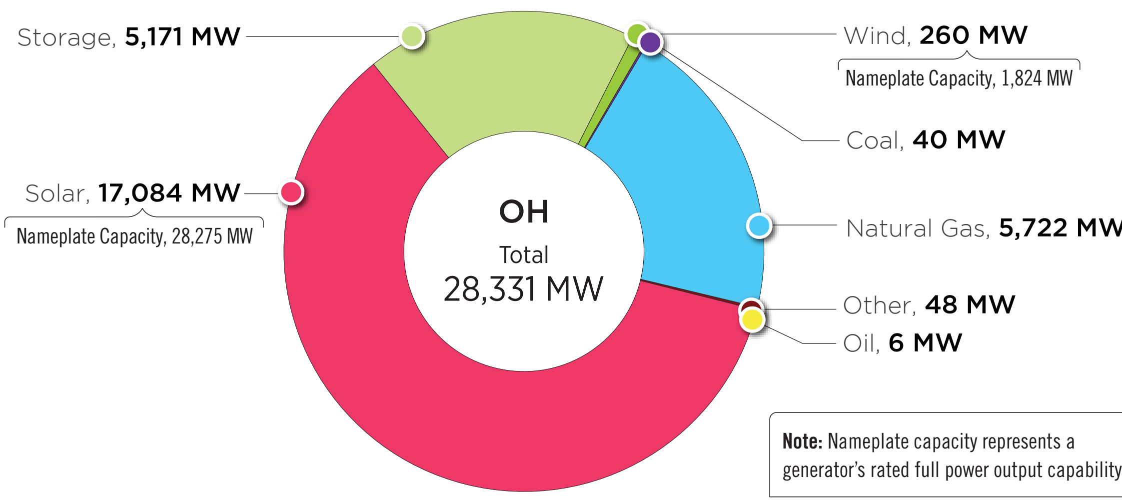


Figure 6.44: Ohio – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.45: Ohio Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

14.4% Requested capacity megawatts

15.0% Requested projects

			Capacity	Nameplate
Projects withdrawn after final agreement	25	Interconnection Service Agreements	3,609 MW	5,799 MW
	12	Wholesale Market Participation Agreements	22 MW	82 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.8.5 — Generation Deactivation

Known generating unit deactivation requests in Ohio between Jan. 1, 2021, and Dec. 31, 2021, are summarized in **Map 6.36** and **Table 6.45**.

Map 6.36: Ohio Generation Deactivations (Dec. 31, 2021)

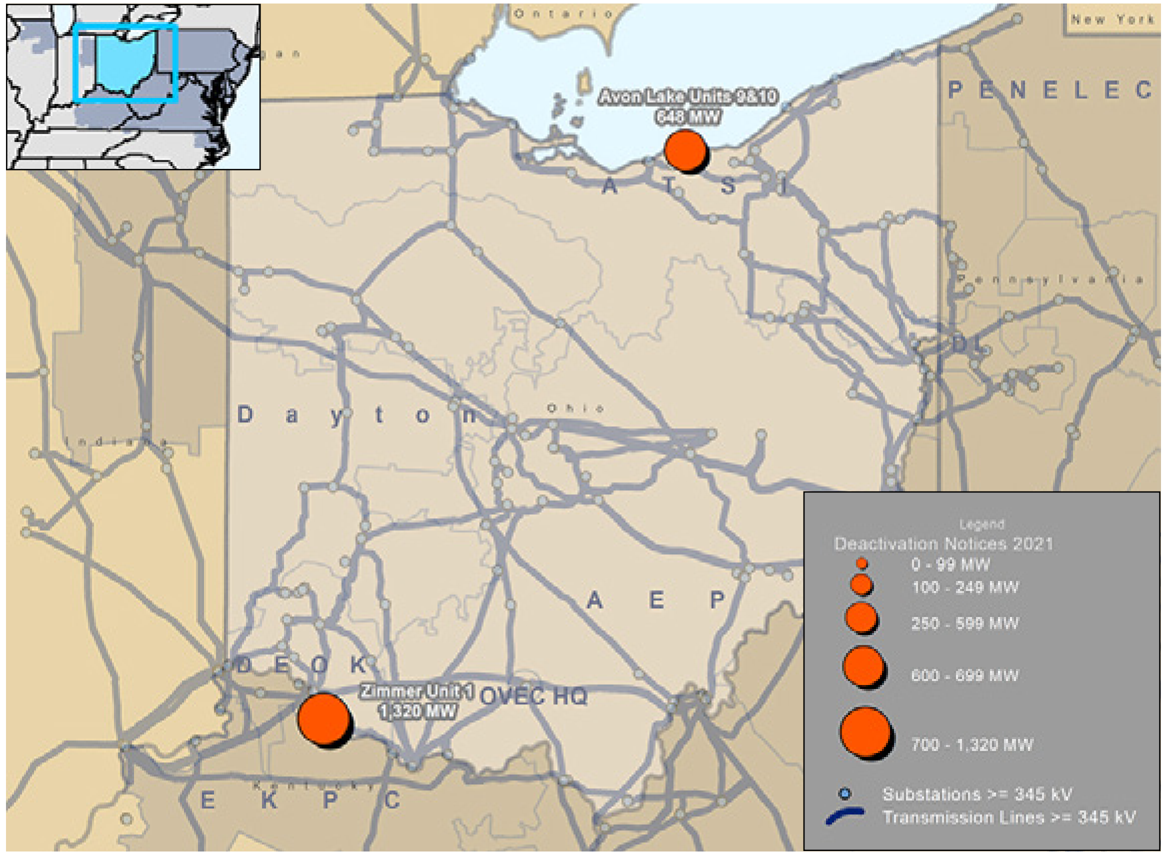


Table 6.45: Ohio Generation Deactivations (Dec. 31, 2021)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Zimmer 1	DEO&K	Coal	7/19/2021	5/31/2022	30	1,320
Avon Lake 9	ATSI		6/9/2021	4/1/2022	51	627
Avon Lake 10		Oil			53	21

6.8.6 — Baseline Projects

2021 RTEP baseline projects in Ohio are summarized in **Map 6.37** and **Table 6.46**.

Map 6.37: Ohio Baseline Projects (Dec. 31, 2021)

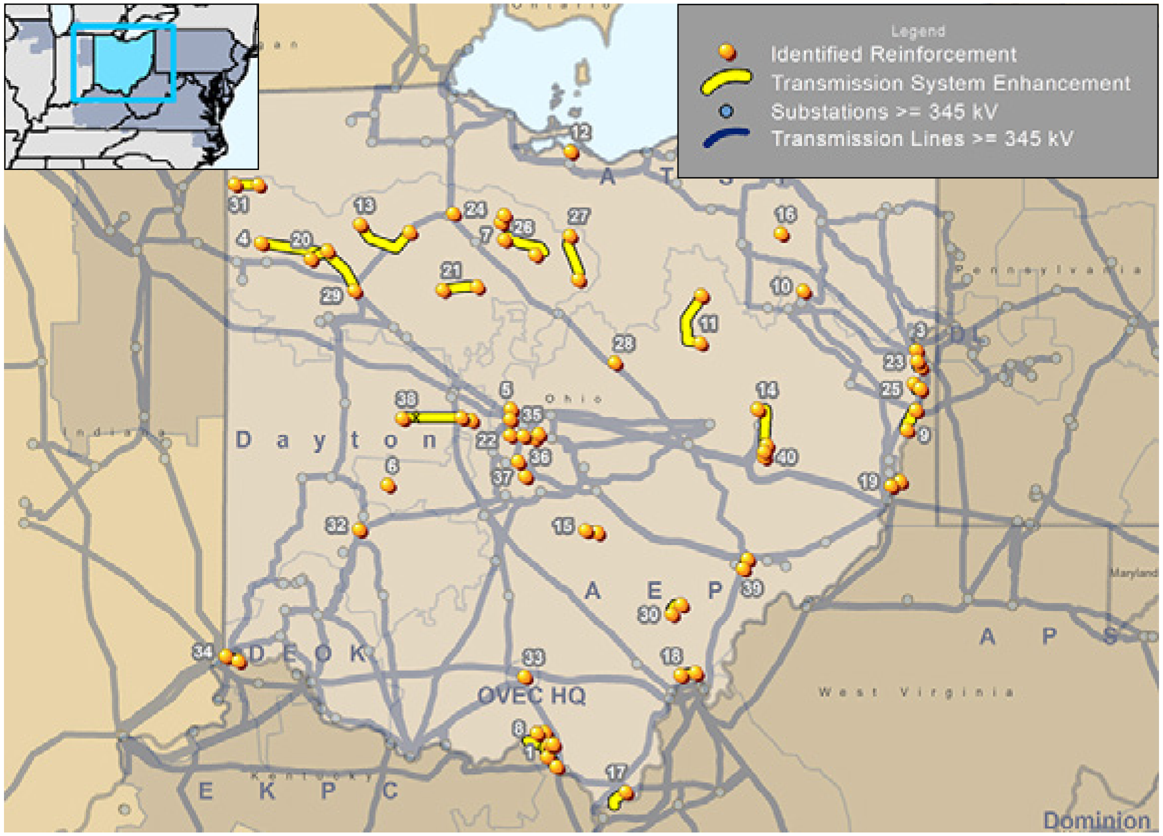


Table 6.46: Ohio Baseline Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B2604	.1	Remove approximately 11.32 miles of the 69 kV line between Millbrook Park and Franklin Furnace.	6/1/2019	$39.18	AEP	2/17/2021
		.2	Millbrook Park station – Add a new 138/69 kV transformer No. 2 (90 MVA) with 3000A 40 kA breakers on the high and low side. Replace the 600 A MOAB switch and add a 3000A circuit switcher on the high side of transformer No.1.				
		.3	Replace Sciotoville 69 kV station with a new 138/12 kV in-out station (Cottrell) with 2000A line MOABs facing Millbrook Park and East Wheelersburg 138 kV.				

Table 6.46: Ohio Baseline Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	B2604 Cont.	.4	Tie Cottrell switch into the Millbrook Park-East Wheelersburg 138 kV circuit by constructing 0.50 miles of line using 795 ACSR 26/7 Drake (SE 359 MVA).	6/1/2019	$39.18	AEP	2/17/2021
		.5	Install a new 2000A three-way phase-over-phase switch outside of Texas Eastern 138 kV substation (Sadiq switch).				
		.6	Replace the Wheelersburg 69 kV station with a new 138/12 kV in-out station (Sweetgum) with a 3000A 40 kA breaker facing Sadiq switch and a 2000A 138 kV MOAB facing Althea.				
		.7	Build ~1.4 miles of new 138 kV line using 795 ACSR 26/7 Drake (SE 359 MVA) between the new Sadiq switch and the new Sweetgum 138 kV stations.				
		.8	Remove the existing 69 kV Hayport Road switch.				
		.9	Rebuild ~2.3 miles along existing ROW from Sweetgum to the Hayport Rd. switch 69 kV location as 138 kV single circuit and rebuild ~2 miles from the Hayport Road switch to Althea 69 kV with double circuit 138 kV construction, one side operated at 69 kV to continue service to K.O. Wheelersburg, using 795 ACSR 26/7 Drake (SE 359 MVA).				
		.10	Build a new station (Althea) with a 138/69 kV, 90 MVA transformer. The 138 kV side will have a single 2000A 40 kA circuit breaker and the 69 kV side will be a 2000A 40 kA three-breaker ring bus.				
		.11	Perform remote end work at Hanging Rock, East Wheelersburg and North Haverhill 138 kV.				
2	B2779	.6	Construct a 345 kV ring bus at Dunton Lake to serve SDI load at 345 kV via two circuits.	6/1/2016	$24.80	AEP	12/1/2020
		.7	Retire Collingwood 345 kV station.				
3	B3123		Sammis 345 kV station – Install a new control building in the switchyard, construct a new station access road, install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and separate all protection and controls schemes.	6/1/2022	$15.30	ATSI	7/11/2019
4	B3131	.1	Rebuild ~12.3 miles of remaining Lark conductor on the double circuit line between Haviland and East Lima with 1033 54/7 ACSR conductor.	12/1/2024	$27.40	AEP	1/15/2021
5	B3235		Extend 138 kV bus work to the west of Tangy substation for the addition of the 100 MVAR reactor bay and one 138 kV, 40 kA circuit breaker.	6/1/2025	$3.70	ATSI	10/16/2020
6	B3236		Extend the 138 kV bus by adding two new breakers and associated equipment and install a 75 MVAR reactor.		$4.50		
7	B3249		Rebuild the Chatfield-Melmore 138 kV line (~10 miles) to 1033 ACSR conductor.		$27.20	AEP	2/17/2021
8	B3253		Install a 3000A 40 kA, 138 kV breaker on high side of 138/69 kV transformer No. 5 at Millbrook Park station. The transformer and associated bus protection will be upgraded accordingly.		$0.63		11/20/2020
9	B3256		Upgrade 500 MCM Cu risers at Tidd 138 kV station toward Wheeling Steel; replace with 1272 AAC conductor.		$0.07		
10	B3258		Install a 3000A 63 kA, 138 kV breaker on high side of 138/69 kV transformer No. 2 at Wagenhals station. The transformer and associated bus protection will be upgraded accordingly.		$1.10		
11	B3259		West Millersburg station – Replace the 138 kV MOAB on the West Millersburg-Wooster 138 kV line with a 3000A 40 kA breaker.		$0.68		
12	B3260		Replace the existing breaker 501-B-251 with a new 69 kV breaker with a higher (40 kA) interrupting capability.	12/1/2021	$0.86	ATSI	12/18/2020

Table 6.46: Ohio Baseline Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
13	B3273	.1	Rebuild and convert the existing 17.6 miles East Leipsic-New Liberty 34.5 kV circuit to 138 kV using 795 ACSR.	6/1/2025	$34.42	AEP	12/1/2020
13	B3273	.2	Convert the existing 34.5 kV equipment to 138 kV and expand the existing McComb station to the north and east to allow for new equipment to be installed. Install two new 138 kV box bays to allow for line positions and two new 138/12 kV transformers.	6/1/2025	$34.42	AEP	12/1/2020
13	B3273	.3	Expand the existing East Leipsic 138 kV station to the north to allow for another 138 kV line exit to be installed. The new line exit will involve installing a new 138 kV circuit breaker, disconnect switches and new dead-end structure along with extending existing 138 kV bus work.	6/1/2025	$34.42	AEP	12/1/2020
13	B3273	.4	Add one 138 kV circuit breaker and disconnect switches in order to add an additional line position at New Liberty 138 kV station. Install line relaying potential devices and retire the 34.5 kV breaker F.	6/1/2025	$34.42	AEP	12/1/2020
14	B3274		Rebuild ~8.9 miles of 69 kV line between Newcomerstown and Salt Fork switch with 556 ACSR conductor.	6/1/2025	$15.89	AEP	12/1/2020
15	B3276	.1	Rebuild the 2/0 Copper section of the Lancaster-South Lancaster 69 kV line, ~2.9 miles of the 3.2 mile total length with 556 ACSR conductor. The remaining section has 336 ACSR conductor.	6/1/2025	$11.15	AEP	12/1/2020
15	B3276	.2	Rebuild the 1/0 Copper section of the line between Lancaster junction and Ralston station 69 kV, ~2.3 miles of the 3.1 mile total length.	6/1/2025	$11.15	AEP	12/1/2020
15	B3276	.3	Rebuild the 2/0 Copper portion of the line between East Lancaster Tap and Lancaster 69 kV, ~0.81 miles.	6/1/2025	$11.15	AEP	12/1/2020
16	B3277		Replace the existing East Akron 138 kV breaker B-22 with 3000A continuous, 40 kA momentary current interrupting rating circuit breaker.	6/1/2025	$0.55	ATSI	5/22/2020
17	B3282	.1	Install a second 138 kV circuit utilizing 795 ACSR conductor on the open position of the existing double circuit towers from East Huntington-North Proctorville. Remove the existing 34.5 kV line from East Huntington-North Chesapeake and rebuild this section to 138 kV served from a new PoP switch off the new East Huntington-North Proctorville 138 kV No. 2 line.	6/1/2025	$10.40	AEP	02/17/2021
17	B3282	.2	Install a 138 kV 40 kA circuit breaker at North Proctorville.	6/1/2025	$10.40	AEP	02/17/2021
17	B3282	.3	Install a 138 kV 40 kA circuit breaker at East Huntington.	6/1/2025	$10.40	AEP	02/17/2021
17	B3282	.4	Convert the existing 34/12 kV North Chesapeake to a 138/12 kV station.	6/1/2025	$10.40	AEP	02/17/2021
18	B3285		Replace the Meigs 69 kV 4/0 Cu station riser toward Gavin and rebuild the section of the Meigs-Hemlock 69 kV circuit from Meigs to approximately structure No. 40 (~4 miles) replacing the line conductor 4/0 ACSR with the line conductor size 556.5 ACSR.	6/1/2025	$12.14	AEP	1/15/2021
19	B3287		Upgrade 69 kV risers at Moundsville station towards George Washington.	6/1/2025	$0.05	AEP	1/15/2021
20	B3290	.1	Build 9.4 miles of single circuit 69 kV line from Roselms to near East Ottoville 69 kV switch.	6/1/2025	$38.90	AEP	1/15/2021
20	B3290	.2	Rebuild 7.5 miles of double circuit 69 kV line between East Ottoville switch and Kalida station (combining with the new Roselms to Kalida 69 kV circuit).	6/1/2025	$38.90	AEP	1/15/2021
20	B3290	.3	At Roselms switch – Install a new three-way 69 kV, 1200A phase-over-phase switch, with sectionalizing capability.	6/1/2025	$38.90	AEP	1/15/2021

Table 6.46: Ohio Baseline Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
20 Cont.	B3290	.4	At Kalida 69 kV station – Terminate the new line from Roselms switch. Move the CS XT2 from high side of T2 to the high side of T1. Remove existing T2 transformer.	6/1/2025	$38.90	AEP	1/15/2021
21	B3293		Replace 2/0 Cu entrance span conductor on the South Upper Sandusky 69 kV line and 4/0 Cu Risers/bus conductors on the Forest line at Upper Sandusky 69 kV station.	6/1/2025	$0.54	AEP	1/15/2021
22	B3297	.1	Rebuild 4.23 miles of 69 kV line between Sawmill and Lazelle station, using 795 ACSR 26/7 conductor.	6/1/2025	$19.80	AEP	1/15/2021
		.2	Rebuild 1.94 miles of 69 kV line between Westerville and Genoa stations, using 795 ACSR 26/7 conductor.				
		.3	Replace risers and switchers at Lazelle, Westerville, and Genoa 69 kV stations. Upgrade associated relaying accordingly.				
23	B3298		Rebuild 0.8 miles of double circuit 69 kV line between South Toronto and West Toronto. Replace 219 kcmil ACSR with 556 ACSR.	6/1/2025	$3.53	AEP	2/17/2021
		.1	Replace the 69 kV breaker D at South Toronto station with 40 kA breaker.				
24	B3299		Rebuild 0.2 miles of the West End Fostoria-Lumberjack switch 69 kV line with 556 ACSR (Dove) conductors. Replace jumpers on West End Fostoria line at Lumberjack switch.	6/1/2025	$0.47	AEP	1/15/2021
25	B3308		Reconductor and rebuild one span of T-line on the Fort Steuben-Sunset Blvd. 69 kV branch with 556 ACSR.	6/1/2025	$0.73	AEP	1/15/2021
26	B3309		Rebuild 1.75 miles of the Greenlawn-East Tiffin line section of the Carrothers-Greenlawn 69 kV circuit containing 133 ACSR conductor with 556 ACSR conductor. Upgrade relaying as required.	6/1/2025	$3.45	AEP	1/15/2021
27	B3310	.1	Rebuild 10.5 miles of the Howard-Willard 69 kV line utilizing 556 ACSR conductor.	6/1/2025	$19.46	AEP	2/17/2021
		.2	Upgrade relaying at Howard 69 kV station.				
		.3	Upgrade relaying at Willard 69 kV station.				
28	B3312		Rebuild ~4 miles of existing 69 kV line between West Mount Vernon and Mount Vernon stations. Replace the existing 138/69 kV transformer at West Mount Vernon with a larger 90 MVA unit along with existing 69 kV breaker 'C'.	6/1/2025	$12.93	AEP	1/6/2021
29	B3313		Add 40 kA circuit breakers on the low and high side of East Lima 138/69 kV transformer.	6/1/2025	$1.20	AEP	3/19/2021
30	B3314	.1	Install a new 138/69 kV 130 MVA transformer and associated protection at Elliot station.	6/1/2025	$3.00	AEP	3/19/2021
		.2	Perform work at Strouds Run station to retire 138/69/13 kV, 33.6 MVA transformer No. 1 and install a dedicated 138/13 kV distribution transformer.				
31	B3315		Upgrade relaying on Mark Center-South Hicksville 69 kV line and replace Mark Center cap bank with a 7.7 MVAR unit.	6/1/2025	$1.25	AEP	3/19/2021
32	B3316		Greene Substation – Replace 138 kV, 40 kA breaker GJ-138C with a 63 kA breaker.	6/1/2025	$0.28	DAY	5/21/2021
33	B3320		Replace the CT at Don Marquis 345 kV.	6/1/2022	$0.08	AEP	8/10/2021
34	B3334		Rebuild the section of Miami Fort-Hebron Tap 138 kV.	6/1/2022	$44.30	DEO&K	11/2/2021
35	B3337		Replace the one Hyatt 138 kV breaker “AB1(101N)” with 3000A 63 kA interrupting breaker.	6/1/2026	$0.48	AEP	9/17/2021
36	B3338		Replace the two Kenny 138 kV breakers, “102” (SC-3) and “106” (SC-4), each with a 3000A 63 kA interrupting breaker.	6/1/2026	$0.76	AEP	9/17/2021
37	B3339		Replace the one Canal 138 kV breaker “3” with 3000A 63 kA breaker.	6/1/2026	$0.48	AEP	9/17/2021

Table 6.46: Ohio Baseline Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
38	B3341	.1	Marysville Substation – Install two 69 kV, 16.6 MVAR cap banks; Install five 69 kV circuit breakers; Upgrade station relaying; Replace 600A wave trap on the Marysville-Kings Creek 69 kV (6660) circuit.	6/1/2026	$2.93	DAY	10/15/2021
		.2	Upgrade remote-end relaying at Darby 69 kV substation.				
		.3	Upgrade remote-end relaying at Kings Creek 69 kV substation.				
39	B3342		Replace the 2156 ACSR & 2874 ACSR bus and risers with 2-bundled 2156 ACSR at Muskingum River 345 kV station to address loading issues on Muskingum-Waterford 345 kV line.		$0.53	AEP	11/2/2021
40	B3345	.1	Rebuild ~4.2 miles of overloaded sections of the 69 kV line between Salt Fork switch and Leatherwood switch with 556 ACSR.		$9.10		
		.2	Update relay settings at Broom Road station.				

6.8.7 — Network Projects

2021 RTEP network projects in Ohio are summarized in **Map 6.38** and **Table 6.47**.

Map 6.38: Ohio Network Projects (Dec. 31, 2021)

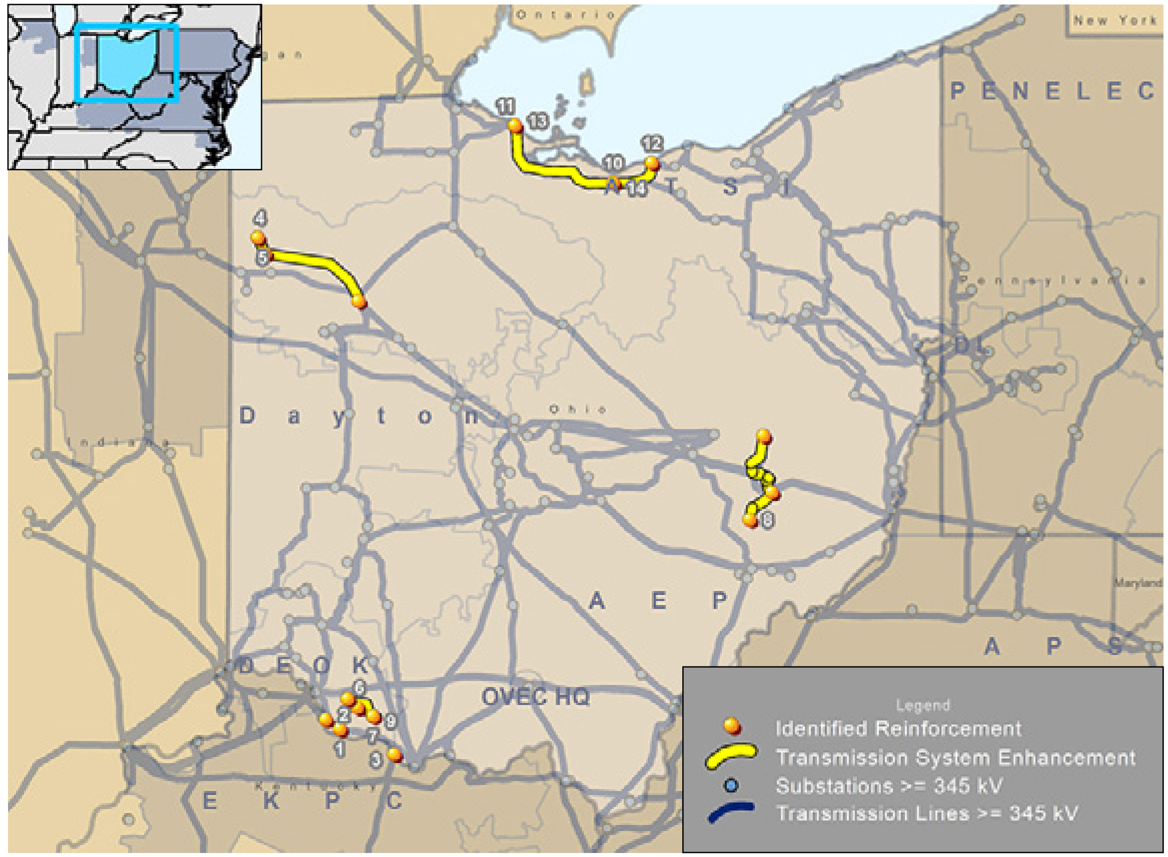


Table 6.47: Ohio Network Projects (Dec. 31, 2021)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N3243	Build transmission loop through new 345 kV Meldahl interconnection substation.	V3-045	12/31/2013	$1.025	DEO&K	11/30/2021
2	N3244	Perform relay modification at Zimmer substation.			$0.016		
3	N3245	Perform relay modification at Spurlock substation.					

Table 6.47: Ohio Network Projects (Dec. 31, 2021) (Cont.)

<table>
<tr><th>Map ID</th><th>Project</th><th>Description</th><th>Generation</th><th>Required In-Service Date</th><th>Project Cost ($M)</th><th>TO Zone</th><th>TEAC Date</th></tr>
<tr><td>4</td><td>N5474</td><td>Perform AC1-173 fiber system modifications at Haviland and East Lima.</td><td rowspan="2">AC1-173</td><td>10/21/2020</td><td>$0.01</td><td rowspan="2">AEP</td><td rowspan="11">11/30/2021</td></tr>
<tr><td>5</td><td>N5648</td><td>Relay Settings – Convert two-terminal gen lead to three-terminal gen lead at AC1-173 substation.</td><td>10/31/2019</td><td>$0.06</td></tr>
<tr><td>6</td><td>N5781</td><td>Provide engineering and construction oversight for the construction of the new AD1-136 substation.</td><td rowspan="2">AD1-136</td><td rowspan="2">6/30/2021</td><td>$5.28</td><td rowspan="2">DEO&K</td></tr>
<tr><td>7</td><td>N5782</td><td>Reconfigure the South Bethel to Brown 69 kV circuit to loop through the new substation and rework the distribution under build on that circuit path to allow for the new substation.</td><td>$0.65</td></tr>
<tr><td>8</td><td>N5793</td><td>Provide station service to Guernsey 765 kV station from Derwent-S. Cumberland 69 kV.</td><td>AB2-067</td><td>4/1/2020</td><td>$0.6</td><td>AEP</td></tr>
<tr><td>9</td><td>N6240</td><td>Perform remote protection and communication work at South Bethel and Brown substations.</td><td>AD1-136</td><td>6/30/2021</td><td>$1.12</td><td>DEO&K</td></tr>
<tr><td>10</td><td>N6699</td><td>Construct new 345 kV AC2-103 interconnection switchyard including SCADA, metering and project management.</td><td rowspan="5">AC1-203</td><td rowspan="5">10/1/2022</td><td>$9.66</td><td rowspan="5">ATSI</td></tr>
<tr><td>11</td><td>N6700</td><td>Loop the Beaver-Davis Besse 345 kV circuit ~400 feet into the proposed AC2-103 three-breaker ring bus near structure numbers 41800 and 41801.</td><td>$1.52</td></tr>
<tr><td>12</td><td>N6701</td><td>Beaver substation – Install standard dual SEL421 panel with UPLC for pilot scheme and DCB, DTT and anti-islanding for the AC2-103 line.</td><td>$0.29</td></tr>
<tr><td>13</td><td>N6702</td><td>Davis Besse substation – Install standard dual SEL421 panel with UPLC for pilot scheme and DCB, DTT and anti-islanding for the AC2-103 line.</td><td>$0.37</td></tr>
<tr><td>14</td><td>N6703</td><td>To support required SCADA (Supervisory control and data acquisition) enhancements – Install ADSS (All-Dielectric Self-Supporting) fiber from the AC2-103 queue position ring bus to the fiber connection point approximately one mile away.</td><td>$0.19</td></tr>
</table>

6.8.8 — Supplemental Projects

2021 RTEP supplemental projects in Ohio are summarized in **Map 6.39** and **Table 6.48**.

6.8.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Ohio were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.39: Ohio Supplemental Projects (Dec. 31, 2021)

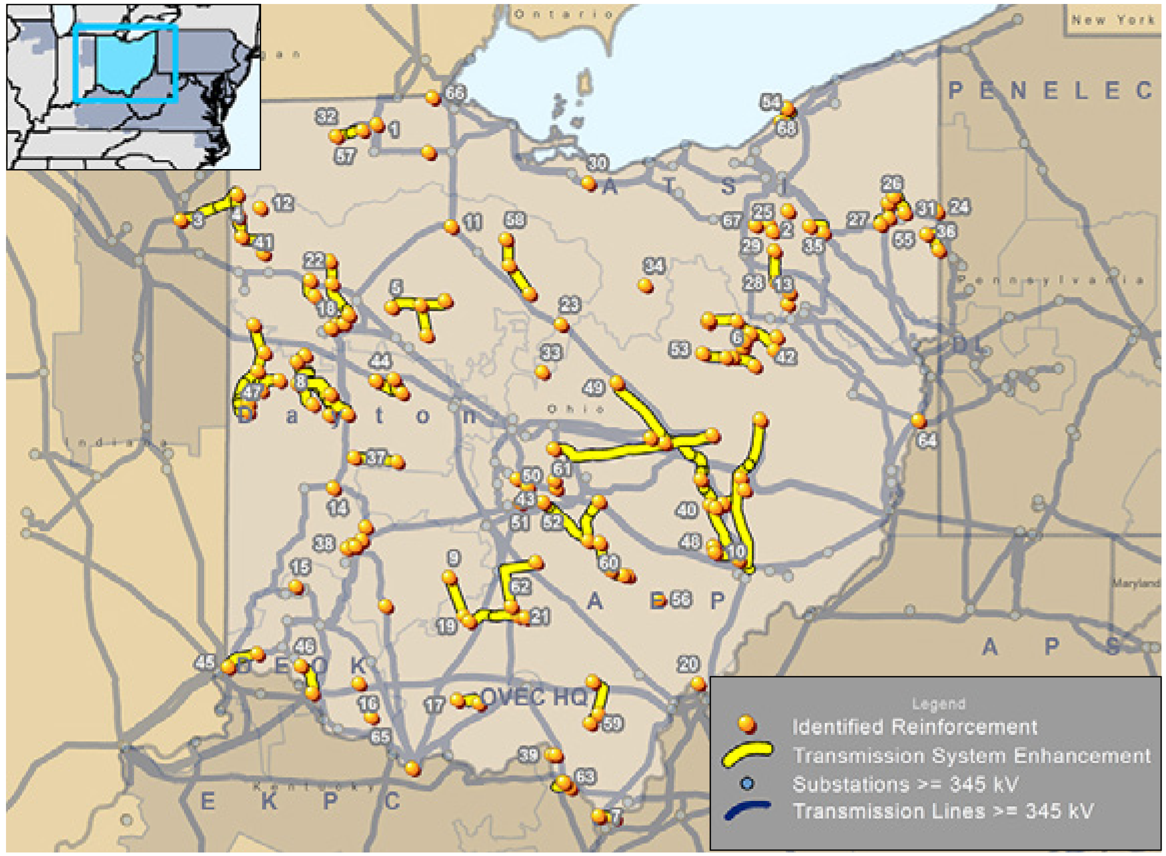


Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2237	.2	S2237.2 is new additional scope to mitigate load-loss criteria violation identified during do-no-harm testing. Construct a new 345 kV four-breaker ring bus. De-energize approx. 1 mile of the Dowling-Fulton 345 kV line. Construct 8.7 miles of 345 kV line to connect the Dowling 345 kV line into the new 345 kV station with 954 ACSR 45/7 bundled (two conductors per phase). New 345 kV line to be built and share structures with the Delta-Wauseon 138 kV line and Delta-Fulton 138 kV line. Replace the wave trap at Dowling 345 kV line to ensure the Dowling-New 345 kV station 345 kV transmission line is the limiting element. Re-terminate the Fulton 345 kV line that serves North Star Steel Sydney into the new 345 kV station. Provide two feeds from the new 345 kV station to North Star Steel Sydney with 95.	6/1/2024	$67.00	ATSI	11/4/2020

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2387		New 138 kV line & Sub 5 Expansion – Build FE Sub 5 138 kV, four-breaker ring bus adjacent to the CF Sub 5 substation; Cuyahoga Falls Muni to expand CF Sub 5 substation to a 138/23 kV substation; Convert Evans 138 kV substation into five-breaker (future six) ring bus; Convert the proposed Darrow five-breaker (future six) ring bus (s1708) into six-breaker ring bus; Build a new 138 kV line from Evans to new FE Sub 5 (~4.4 miles); Build a new 138 kV line from Darrow to new FE Sub 5 (~6.6 miles); Add a 28 MVAR, 138 kV capacitor bank at Theiss substation.	6/1/2025	$44.00	ATSI	1/11/2019
3	S2393	.1	On the South Hicksville-Rob Park 69 kV line – Rebuild the 21.6 miles as currently constructed, including ~2.4 miles of 69 kV double circuit and ~19.2 miles of 69 kV single circuit.	6/2/2023	$54.10	AEP	9/11/2020
		.2	Rebuild the through path of St. Joe 69 kV station. Install a breaker on the Harlan line exit to eliminate four MOABs in series.				
		.3	At Harlan 69 kV (FERC-distribution) station – Replace a switch and line riser in order to accommodate the new line entrance.				
		.4	Replace the West Hicksville 69 kV phase-over-phase switch to accommodate the new line height, route and structure/conductor type.				
		.5	In order to rebuild the line, the in-line switch at Vulcraft 69 kV needs to be replaced. The switch replacement will be a three-way switch with a MOAB toward West Hicksville 69 kV.				
4	S2394	.1	Rebuild ~14.3 miles of the Payne-South Hicksville 69 kV circuit.	11/15/2024	$55.60		
		.2	Rebuild ~9.3 miles of the line between Haviland-Payne 69 kV circuit. Reconductor the remaining 2.7 mile line sections.				
		.3	Install Seiberi switch as a new 69 kV, 1200A, three-way phase-over-phase switch with sectionalizing capability to eliminate the hard tap.				
		.4	Replace Antwerp switch with 69 kV, 1200A, three-way phase-over-phase switches with sectionalizing capability, including 4.3 miles of fiber buildout to allow for sectionalizing.				
		.5	Replace North Antwerp Sw with 69 kV, 1200A,three-way phase-over-phase switches with sectionalizing capability.				
		.6	Replace Latty switch with 69 kV, 1200A,three-way phase-over-phase switches with sectionalizing capability.				
		.7	At Latty Junction switch – Install motor operators, a relay and PTs on existing phase-over-phase switches to add sectionalizing capability.				
5	S2395	.1	Rebuild existing double circuit portion of the Dunkirk-Forest line asset from existing Str 194 to the greenfield Rangeline station (1.35 miles). Rebuild existing ~6.5 mile Arlington-Dunkirk 34.5 kV as Rangeline-East Arlington single 69 circuit from Str 194 to the greenfield East Arlington (formerly Arlington).	6/1/2025	$125.30	AEP	
		.2	Reconfigure ~0.05 mile Dunkirk-Kenton 69 kV line to terminate into Rangeline station.				
		.3	Reconfigure ~0.05 mile Dunkirk-Ada 69 kV line to terminate into Rangeline station.				
		.4	Build ~10.1 mile 69 kV line section between greenfield Buckrun switch and East Arlington as single circuit 69 kV.				
		.5	Rebuild ~5.75 mile 69 kV line section between greenfield West Crawford station and Buckrun switch (outside of Blanchard station) as single circuit 69 kV.				
		.6	Rebuild ~0.22 mile South Vanlue extension to tie into East Arlington-West Crawford 69 kV ckt.				
		.7	Rebuild ~11.5 mile 69 kV line between West Crawford and South Berwick stations.				
		.8	Remove/retire ~10 miles of 69 kV line from Forest to North Wharton switch.				
		.9	Reconfigure North Upper Sandusky-South Berwick 69 kV line to tie into Hurd switch.				
		.10	Remove/Retire ~2.58 mile South Carey-Hurd switch 69 kV line.				

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
5 Cont.	S2395	.11	Carey 69 kV – Install 69 kV Box Bay with 2000A 40 kA MOABs with sectionalizing capability. Remove existing Carey Sw.	6/1/2025	$125.30	AEP	9/11/2020
		.12	West Crawford 69 kV (Rebuild) – Install a new 69 kV ring bus with three 3000A 40 kA circuit breakers to replace West Crawford Sw. Replace cap switcher “AA” and relocate cap bank from Carey Sw to West Crawford 69 kV bus.				
		.13	South Carey Sw 69 kV – Remove South Carey Sw 69 kV.				
		.14	North Wharton Sw 69 kV – Remove North Wharton Sw 69 kV.				
		.15	South Vanlue 69 kV – Replace 69 kV bus and existing switches with 2000A 40 kA line MOABs with sectionalizing capability.				
		.16	Buckrun Sw 69 kV – Install a new 69 kV, 2000A 40 kA, three-way phase-over-phase switch with sectionalizing capability.				
		.17	East Arlington 69 kV – Install a new 69 kV ring bus with three 3000A 40 kA circuit breakers to replace existing Arlington station.				
		.18	Flat Branch Sw 69 kV – Install 69 kV, 2000A 40 kA, three-way phase-over-phase switch with sectionalizing capability.				
		.19	South Berwick 69 kV – Perform remote end work.				
		.20	Rangeline 69 kV – Install a five-breaker (3000A 40 kA) 69 kV ring bus to replace Dunkirk station.				
		.21	Forest 69 kV – Remove 69 kV circuit breaker-H toward South Berwick.				
		.22	Dunkirk 69 kV – Retire Dunkirk 69 kV station.				
6	S2396		Double the size of the existing Walnut Creek 69 kV capacitor bank, from 7.2 to 14.4 MVAR. Update relay settings and SCADA equipment accordingly.	11/1/2020	$0.10		
7	S2397	.1	Rebuild ~1.2 miles of line on the West Huntington-South Point 34.5 kV line between Kenova station and South Point station. Cost drivers on this line section include Ohio River crossing, urban line route through Huntington, WV, and encroachments along the line.	11/1/2023	$10.70		9/11/2020
		.2	Rebuild ~5.5 miles of line on the West Huntington-South Point 34.5 kV line between Kenova station and West Huntington station. This segment of line is classified as distribution and thus has no transmission cost.				
		.3	Install three-way phase-over-phase GOAB switch at Ceredo switch station addressing hard tap.				
		.4	Install three-way phase-over-phase GOAB switch at Sanitary Board station addressing hard tap.				
		.5	Install three-way phase-over-phase GOAB switch at Four Pole Creek station addressing hard tap.				
8	S2398	.1	Amsterdam-West Moulton 138 kV – Rebuild the Amsterdam-St. Marys-West Moulton transmission corridor to double circuit. The project will entail rebuilding existing 69 kV transmission line facilities, replacing terminal equipment and adding new 138 kV circuits to each corridor. The rebuild of the Amsterdam-St. Marys-West Moulton corridor and replacement of in-line 69 kV switches will be 13 miles.	6/1/2024	$65.35	DAY	10/16/2020
		.2	Sidney-Honda Anna 138 kV – Rebuild the Sidney-Amsterdam transmission corridor to double circuit. The project will entail rebuilding existing 69 kV transmission line facilities, replacing terminal equipment and adding new 138 kV circuits to each corridor. The Sidney-Amsterdam corridor will be 8 miles long stopping near Honda Anna where a single circuit 138 kV will be extended to the new substation. At Sidney substation, a 138 kV ring bus will be created.	12/31/2024			
		.3	Honda Anna substation – Construct a new Honda Anna 138 kV ring bus substation.	6/1/2024			
		.4	Amsterdam substation – Expand the Amsterdam substation to include the new 138 kV line and 13827 line (Amsterdam-Shelby 138 kV) in a ring bus arrangement. Also, it will replace the existing Amsterdam transformer and add a second 138/69 kV transformer to the substation to ensure redundancy for the 138 kV source being added to the area. The 69 kV bus would be reconfigured to ensure adequate bus ties and to convert to a more standard design. The existing capacitor will be replaced with two smaller 16 MVAR capacitors, which will help minimize area voltage changes when the capacitors are switched online.				

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
8 Cont.	S2398	.5	6672 (Amsterdam-Minster 69 kV) Rebuild – To address the condition issues on 6672, the solution is to rebuild the 69 kV line and associated terminal equipment replacements at Amsterdam and Minster substations.	6/1/2024	$65.35	DAY	10/16/2020
		.6	West Moulton substation – AEP will install an additional 3000A 63kA circuit breaker to their ring bus being constructed as part of the City of Wapakoneta Project (s1856).			AEP	
		.7	AEP will also install a pole outside of West Moulton substation and a single span of line to connect the West Moulton-Amsterdam 138 kV circuit.				
9	S2399		Tap the Greenfield-Washington Courthouse 6649 69 kV line and install three new poles with a set of one-way switches on each new structure to serve a new South Central Power Ghormley Delivery Point.	6/1/2022	$0.35	DAY	
10	S2401	.1	Install a three 3000A breaker 69 kV ring bus called Grace station to serve the requested delivery point.	5/1/2022	$5.40	AEP	10/16/2020
		.2	Install ~0.2 miles of 69 kV line to tie the greenfield Grace station in-and-out to the Muskingum River-South Rokeby 69 kV circuit.				
		.3	Remove/Relocate ~0.05 miles of line on the Muskingum River-South Rokeby 69 kV line asset between structures 75 and 74A to accommodate the cut in to the new station.				
		.4	Perform remote end work at South Rokeby switch.				
11	S2402	.1	Re-terminate the Fostoria-Hatton line to the new Hatton switch.	11/29/2021	$1.75		
		.2	Rebuild and re-terminate the Hancock Wood Co-op Extension-Hatton line into the new switch.				
		.3	Install a new three-way phase-over-phase switch to serve the customer's station.	11/23/2021			
12	S2403		Add auto-sectionalizing and SCADA control to the existing North Cecil switch. This requires installing PTs, motors, a relay and communication equipment.	11/29/2021	$0.36		
13	S2404		Replace the failed 138-69 kV transformer at Reedurban with a spare 90 MVA transformer. Install a transformer oil containment system. Replace electromechanical transformer protection relays with microprocessor relays, along with 69 kV PTs.	12/10/2020	$1.20		
14	S2423		Replace terminal equipment at the substations listed to facilitate the transition to a 100/0 current split methodology – Bath 345 kV, Clinton 345 kV, Greene, Miami, Shelby 345 kV, Stuart, Sugercreek, West Manchester 69 kV, Wilmington. Once new methodology is put in place starting 1/1/2023, derate listed transmission circuits since equipment replacements will be completed – 34528, 13805, 6666, 6674, 6677, 6905, Overlook Bk-7, Amsterdam 138/69 kV, Trebein 138/69 kV, Staunton 138/69 kV, Bath 345/138 kV, Miami 345/138 kV, W. Milton 345/138 kV, Sugarcreek 345/138 kV N, Sugarcreek 345/138 kV S.	12/31/2022	$4.00	DAY	12/18/2020
15	S2424		Reconductor the 1 mile section of feeder from Yankee to Meadow tap 69 kV. Replace eight poles to achieve proper clearance. Capacity of the line will increase from 97 MVA to 151 MVA.	8/17/2022	$1.65	DEO&K	11/20/2020
16	S2425		Install a new Half Acre substation between Batavia and Eastwood 138 kV with two 138 kV breakers, one circuit switcher, one 138/34 kV, 60 MVA transformer, a control building and two distribution feeder exits. Install a mobile 138/34 kV transformer to serve the customer until the substation is completed.	10/28/2022	$14.78		1/15/2021
17	S2426	.1	Rarden – The existing station will be rebuilt to 69 kV with a new 69 kV breaker (3000A 40 kA) facing Adams and a MOAB switch (2000A) facing Otway.	10/15/2023	$57.43	AEP	11/20/2020
		.2	Adams-Rarden 69 kV – Reroute the line to the rebuilt Rarden station with 795 ACSR 26/7 (SE 179 MVA).				
		.3	Rarden-Otway 69 kV – Install ~8.5 miles of greenfield 69 kV line between Rarden & Otway stations using 556.5 ACSR 26/7 conductor (SE 142 MVA).				

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
17 Cont.	S2426	.4	Otway – Construct a new 69 kV station with four circuit breakers (3000A 40 kA) in a ring bus configuration.	10/15/2023	$57.43	AEP	11/20/2020
		.5	Tick Ridge Extension – Install ~0.1 miles of greenfield line between Otway and Tick Ridge (Adams) stations using 556.5 ACSR 26/7 conductor (SE 142 MVA).				
		.6	Otway-McDermott 69 kV – Install ~7.3 miles of greenfield 69 kV line between Otway & McDermott stations using 556.5 ACSR 26/7 conductor (SE 142 MVA).				
		.7	McDermott – Rebuild the existing station with a 69 kV box bay and 2 MOAB switches (2000A) on the line connections.				
		.8	McDermott-Rosemount 69 kV – Install ~6.3 miles of greenfield line between McDermott & Rosemount stations using 556.5 ACSR 26/7 conductor (SE 142 MVA).				
		.9	Rosemount – Expand the existing station footprint. Install five circuit breakers (3000A 40kA) in a ring configuration.				
		.10	Rosemount Extension – Reroute the line into the Rosemount 69 kV ring bus with 795 ACSR 26/7 (SE 179 MVA).				
18	S2427	.1	Cut-in the Sterling extension (Shawnee Road-Sterling 34.5 kV) line asset at Str. 8 to install the new Lima Petrol switch.	3/25/2022	$0.90		11/20/2020
		.2	Build 0.07 mile line extension from Lima Petrol switch to customer station.				
		.3	Install a new manually operated 1200A three-way phase-over-phase switch named Lima Petrol switch.				
19	S2433	.1	Install a new three-way 1200A, 69 kV switch (Towhee switch) with auto-sectionalizing, MOABs and SCADA to serve the new Paint Creek Delivery Point. Install low-side metering at Paint Creek customer station.	6/30/2022	$0.70		12/18/2020
		.2	Tie Towhee switch into the Biers Run-Buckskin 69 kV circuit.				
		.3	Install ~0.1 mile radial line extension connecting Towhee switch to the structure outside SCP's Paint Creek substation.				
20	S2434	.1	Install a greenfield three-way 69 kV, 1200A phase-over-phase switch (Bryson switch) with auto-sectionalizing, MOABs and SCADA to serve the new requested delivery point. Install metering at the proposed customer station.	12/15/2022	$11.20		
		.2	Build a ~4.3 miles of greenfield single circuit 69 kV transmission line between Hemlock-Bryson switch with 556 ACSR conductor.				
		.3	Hemlock station – Install a new 69 kV, 3000A 40 kA circuit breaker toward Bryson switch.				
21	S2441	.1	At Slate Mills – Rebuild the existing three-way switch as an in-and-out box bay with two 2000A switches on the line exits.	4/25/2022	$2.20		
		.2	Re-terminate the Ross-Highland 69 kV line into the rebuilt station.	4/5/2022			
		.3	Perform remote end relay and coms work at Adena, Biers Run & Ross.	4/25/2022			
22	S2442	.1	Remove and retire the existing Lima-Kalida line asset (~17 miles). Top off poles for distribution underbuilt.	4/15/2022	$20.03		
		.2	Jones City station – Remove all equipment from the existing Jones City 34.5 kV station and retire the station.				
		.3	Gomer station – Cut in the North Delphos-East Side 138 kV line and install a 138 kV box bay with two 138 kV, 3000A auto-sectionalizing MOABs to provide service to AEP Ohio's new Gomer Delivery Point.				
23	S2447		Replace existing electromechanical relaying for Galion 138/69 kV TR No. 1 using SEL-351A for 51G tertiary relay. Also, replace limiting 750 CU substation conductors between TR & bus-side DS with 954 kcmil SAC.	12/1/2021	$1.20	ATSI	11/20/2020
24	S2448		Masury – Replace two 138 kV, 1200A disconnect switches (D133 & D132) with 2000A switches. Replace one 138 kV, 3000A SF6 breaker (B85). Replace one 138 kV CVT. Replace one 138 kV wave trap with a 2000A unit. Replace substation conductor. Upgrade Masury-Maysville 138 kV line relaying.	5/25/2021	$0.80		

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
25	S2449		Babb – Replace two 138 kV disconnect switches (D8 & D10). Replace one 138 kV air-break switch (A11). Replace three 138 kV CVTs (CC12, CC13, & CC14). Replace line drops breaker. Replace three rod gaps with three 108 kV, 84 kV MCOV surge arresters. Valley – Replace one 138 kV circuit breaker (B1). Replace one 138 kV line-side disconnect switch (D4) with a 2000A disconnect switch. Replace three 138 kV CVTs (CC14, CC15, & CC16). Replace three rod gaps with three 108 kV, 84 kV MCOV surge arresters.	12/31/2021	$1.30	ATSI	11/20/2020
26	S2450		Highland – Replace one 138 kV breaker (B158). Replace one 138 kV disconnect switch (D159). Replace three CCVTs. Replace Highland-Mahoningside 138 kV line relaying. Mahoningside – Replace one 138 kV breaker (B67). Replace one 138 kV disconnect switch (D68). Replace three CCVTs. Replace Highland-Mahoningside 138 kV line relaying.	6/1/2022	$1.40		
27	S2451		Highland – Replace one 138 kV breaker (B2). Replace substation conductor. Replace one 138 kV disconnect switch (D3). Replace three CCVTs. Replace Highland-GM Lordstown 138 kV line relaying. Tod – Replace 1200A line switches (A7 & A9) with 2000A switches. GM Lordstown – Replace one 138 kV disconnect switch (D68). Replace one 138 kV transfer bus disconnect switch (A16) Replace three CCVTs. Replace substation conductor. Replace Highland-GM Lordstown 138 kV line relaying.		$1.20		
28	S2452		Dale – On the Dale-West Canton 138 kV line exit, install AMETEK Smartgap. Replace Dale-West Canton 138 kV line primary and backup line relays with FE standard dual SEL-421 protection schemes. Install Power Comm PCM 5350.	3/31/2022	$0.42		
29	S2453		Dale – Replace spark gap arresters with surge arresters. Replace three 138 kV CVTs. Replace line relaying and control with standard relay panel for the Dale-South Akron 138 kV line, include breaker failure relaying for breaker B29. South Akron – Replace one 138 kV line-side disconnect switch (D320). Replace limiting 750 conductor between bus and disconnect switch. Replace three 138 kV CVTs. Replace line relaying and control with standard relay panel for the Dale-South Akron 138 kV line, include breaker failure relaying for breaker B2. Replace existing spark sap arresters with surge arresters. Replace 138 kV insulators.	12/30/2021	$1.00		
30	S2454		Avery – Replace three 138 kV CVTs. Replace three spark gap arresters with new surge arresters. Install AMETEK Smartgap. Replace disconnect switches (D35 & D63). Replace line relaying with dual SEL-421 with DCB over PLC. Install new SEL-501 BFT scheme for 138 kV breaker (B36). Install PowerComm PCM5350. Shinrock – Install AMETEK Smartgap. Install PowerComm PCM5350.	3/31/2022	$0.60		
31	S2455		Niles Central Muni – Replace one 138 kV line trap and tuner. Replace three CCVTs. Replace Central-Packard 138 kV line relaying. Packard – Replace one 138 kV breaker (B13) and associated disconnect switches (D12 & D14). Replace one 138 kV line trap and tuner. Replace three CCVTs. Replace Central-Packard 138 kV line relaying.		$1.40		
32	S2456		Delta – Replace one 138 kV breaker (B13430). Replace 138 kV Wauseon line CCVT. Upgrade one 138 kV wave trap and line tuner. Upgrade substation conductor. Replace Delta-Wauseon 138 kV line relaying. Wauseon – Replace one 138 kV line trap. Replace 138 kV line CCVT. Upgrade substation conductor. Replace Delta line disconnect switch. Replace Delta-Wauseon 138 kV line relaying.	6/1/2022	$1.40		
33	S2457		Cardington – Replace Cardington (Galion) 138 kV line relaying. Galion – Upgrade substation conductor.	12/1/2022	$1.10		
34	S2458		Brookside – Upgrade relay package. Upgrade the CCVTs, wave trap, tuner, co-ax cables and carrier set. Upgrade 400 CU substation conductor, disconnect switches (D76 & D77). Longview – Upgrade relay package. Upgrade the CCVTs, wave trap, tuner, co-ax cables and carrier set. Upgrade relay packages at Brookside and Longview terminals, the CCVTs, wave trap, tuner, co-ax cables and carrier set. Include Smartgap and PCM 5350.	12/20/2022	$1.50		
35	S2459		Hanna – Replace 138 kV breaker (B7) foundation and conduit. Upgrade two 138 kV disconnect switches (D84 & D85) to 138 kV, 2000A DSWs. Replace one 138 kV circuit breaker (B7). Replace line relaying and control consisting of dual SEL-421 over DCB and SEL-501 (BF/B7) for the Hanna-West Ravenna No. 1 138 kV line with a new prewired standard line relaying panel. West Ravenna – Upgrade two 138 kV disconnect switches (D60 & D59) to 138 kV, 2000A DSWs. Replace line relaying and control consisting of dual SEL-421 over DCB and SEL-501 (BF/B21) for the Hanna-West Ravenna No. 1 138 kV line, using a prewired standard line relaying panel. Upgrade one 138 kV transfer bus switch (A61) to 138 kV, 2000A DSW due to condition. Upgrade limiting conductors between the dead end and the disconnect switches.	4/6/2021	$1.50		
36	S2460		Maysville – Replace two 138 kV, 1200A disconnect switches (A1 & D3) with 2000A switches. Replace one 138 kV wave trap with a 2000A unit. Replace one 138 kV CVT. Replace substation conductor. Upgrade Masury-Maysville 138 kV line relaying.	5/25/2021	$1.00		

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
37	S2461	.1	St. Paris-Urbana 69 kV line & KTH Alternate Delivery – Construct a new 12.6 mile single circuit 69 kV line utilizing 1351 AAC conductor (ratings – SN-151, SE-187).	12/31/2023	$21.05	DAY	2/17/2021
		.2	Second KTH Delivery – Provide a second delivery to KTH. Establish a new 69 kV three-way MOAB switch along the St. Paris-Urbana 69 kV line.				
		.3	Urbana substation – Extend the 69 kV west bus and install four new 69 kV circuit breakers. The new line will terminate into a single 69 kV circuit breaker off the existing east bus and relocate the capacitor to a new 69 kV circuit breaker off the west bus. The 138/69 kV transformer will be relocated to a new double-bus, double-breaker string that will serve as a second bus tie at the substation.				
		.4	Casstown switching enhancement – Replace the 65703 line disconnect switch toward St. Paris with a new three-way MOAB switch to eliminate the Casstown hard tap configuration.				
		.5	St. Paris substation – Construct a new four-breaker 69 kV ring bus configuration to terminate the new 69 kV transmission line from Urbana.				
38	S2462	.1	Carpenter substation – To accommodate the installation of a second 69/12 kV transformer, expand the Carpenter 69 kV bus arrangement and install three new 69 kV circuit breakers and associated disconnect switches. The proposed 69 kV ring bus arrangement will be configured in a source sink arrangement.	12/31/2021	$3.50	DAY	2/17/2021
		.2	6622 Alpha-Hempstead 69 kV – To accommodate the new ring configuration, extend the 6622 line four spans to terminate the 6622 line into two new breaker positions.				
39	S2464		Rebuild ~2 miles of 138 kV line between East Wheelersburg and Texas Eastern using 795 ACSR 26/7 Drake (SE 359 MVA).	4/15/2025	$3.41	AEP	2/17/2021
40	S2465	.1	Retire ~3 miles of the Philo-Canton 138 kV line, between Philo and East New Concord.	12/1/2024	$117.42	AEP	2/17/2021
		.2	Retire ~18 miles of the Philo-Torrey 138 kV line, north of Bethel Church/Bloomfield and stopping at Newcomerstown.				
		.3	Rebuild from Philo to Str 62 a ~13.07 mile section of the Philo-Torrey 138 kV line as double circuit, using 795 KCMIL 26/7 ACSR “Drake” conductor.				
		.4	Build a greenfield ~4.76 mile double circuit line between Str. 62 on the Philo-Torrey line to the greenfield East New Concord switch, using 795 KCMIL 26/7 ACSR “Drake” conductor.				
		.5	Rebuild from the greenfield East New Concord switch to Newcomerstown station a ~19.72 mile section of the Philo-Canton 138 kV line as double circuit, using 795 KCMIL 26/7 ACSR “Drake” conductor.				
		.6	Install a three-way phase-over-phase switch, 1200A, 138 kV full SCADA functionality (rustic switch) to replace the hard tap to Bridgeville.				
		.7	Rebuild the 1.9 mile radial T-line tap to Bridgeville as a double circuit in-and-out loop up to the new three-way switch, Rustic switch. The new line will use 556.5 KCMIL ACSR 26/7 “Dove.”				
		.8	Install a three-way phase-over-phase switch, 1200A, 138 kV full SCADA functionality (Chandlersville switch) to replace the hard tap to Chandlersville.				
		.9	A new 0.12 mile double circuit 138 kV loop line is to be constructed to replace the existing tap to GM Co-op Chandlerville station, to supply a loop line circuit to a new switch structure. The new line will use 556.5 KCMIL ACSR 26/7 “Dove.”				
		.10	Install a three-way phase-over-phase switch, 1200A, 138 kV full SCADA functionality (Norfield switch) to replace the hard tap to Bethel Church. Remove the existing Bloomfield one-way switch.				

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
40 Cont.	S2465	.11	A new 0.5 mile double circuit 138 kV line is to be constructed to replace a portion of the Philo-Torrey 138 kV line, to supply a loop line circuit to a new two-pole dead end with one of the poles of the two-pole dead end supporting a new switch structure. From the switch structure, it will connect to an existing structure of the existing tap line to supply the Bloomfield-GM co-op tap. The new line will use 556.5 KCMIL ACSR 26/7 "Dove."	12/1/2024	$117.42	AEP	2/17/2021
		.12	Install a three-way phase-over-phase switch, 1200A, 138 kV full SCADA functionality (East New Concord switch) to replace the hard tap to East New Concord.				
		.13	Upgrade the line protection relays at Philo, replacing the electromechanical relays with modern microprocessor-based relays.				
		.14	Connect OPGW fiber to stations and switches along the route for telecom network connectivity.				
41	S2467	.1	Payne – Replace circuit breakers B and C with 69 kV, 3000A 40 kA breakers. Replace the EM relays with new relays and install a new control house.	7/31/2022	$1.41		
		.2	Install a high-side switch on the 69/12 kV transformer.				
42	S2468		North Strasburg 138 kV – Replace the failed 138 kV circuit switchers with new station line switches. Replace the wood support structures with new steel structures. Add a high-side fuse on the 138/4 kV (2.5 MVA) transformer.	7/1/2021	$0.23		
43	S2472		Fifth Avenue 138 kV – Upgrade the existing 138 kV partial ring bus to a complete 138 kV ring bus and provide a high-side connection for a new distribution transformer. Complete the 138 kV ring bus by adding two 138 kV circuit breakers along with associated bus work and relaying equipment.	5/16/2022	$1.00		3/19/2021
44	S2473	.1	Indian Lake-Russells Point (HTM)-Blue Jacket – Eliminate the radial configuration currently serving the Honda Russells Point facility by rebuilding and rerouting the Indian Lake 69 kV. This project will retire ~3.2 miles of the existing 6648 69 kV transmission circuit that traverses a floodplain and build a new 2.6 mile single circuit 1351 AAC 69 kV line extension from the Honda Russels Point that will loop the radial load and decrease line exposure.	12/1/2024	$17.10	DAY	
		.2	New Russells Point substation – Establish a new 69 kV substation configured in a four-breaker 69 kV ring bus arrangement to the loop the radial load, reduce line exposure and reconfigure the area into a more flexible transmission arrangement.				
		.3	Blue Jacket Tap – Eliminate the three-terminal line arrangement by extending a new single circuit 69 kV 1351 AAC line and looping it in and out of the Blue Jacket substation.				
		.4	Blue Jacket substation – The 69 kV portion of the Blue Jacket substation will be expanded with three new 69 kV breakers to accommodate the new 69 kV line termination eliminating the three terminal line configuration.				
		.5	Harrison Tap – The switches outside of the Harrison REA delivery point will be replaced with a new three-way MOAB with supervisory control to maintain switching flexibility once the Blue Jacket Tap switches are removed.				
		.6	Huntsville Tap – Install a new three-way MOAB switch to increase operator flexibility to restore load during contingency conditions.				
45	S2512		Install a new substation, North Bend. Loop the nearby Miami Fort-Midway 138 kV feeder through North Bend switch connecting the feeder to the bus. Install a 138 kV circuit switcher; a 138/13 kV, 22 MVA transformer; a 13 kV circuit breaker for the low side of the transformer; and 13 kV bus work with circuit breakers for two distribution line exits. Reconfigure distribution lines in the area to include the new capacity available from North Bend substation.	12/1/2023	$7.20	DEO&K	4/16/2021
46	S2513		Expand Newtown substation. Move the Beckjord-Newtown 138 kV feeder by removing the existing line switch, take-off tower and foundations, and installing a new line switch and take-off tower with new foundations. Install new 138 kV bus work, two bus switches and a motor-operated air break switch to feed a new 138/13 kV, 22 MVA transformer. Install 13 kV switchgear. Reconfigure distribution lines in the area to be fed by the new transformer and switchgear.		$1.70		

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
47	S2521	.1	Rockford substation – In coordination with AEP, DP&L will retire the Rockford 69/34.5 kV transformer and construct a new 69 kV three-breaker ring configuration to close in this normally open tie at 69 kV in the future.	12/1/2025	$31.10	DAY	4/16/2021
		.2	Celina-Coldwater-Rockford 69 kV – Rebuild 2.5 miles of the existing 69 kV line to double circuit and construct of 1 mile of new 69 kV line to reroute the Celina-Coldwater-Rockford 69 kV extension into the relocated Celina 69 kV substation.	12/1/2025			
		.3	Celina substation – Retire the existing Celina 69 kV substation due to condition and the limitations to expand at the current location. Establish a new 69 kV breaker and one-half configuration and two new 69 kV capacitor banks at a new substation located on the western edge of Celina. The associated breaker and one-half configuration will reduce the total line exposure, eliminate the three-terminal line arrangement, and provide localized reactive compensation to the Celina load.	12/1/2025			
		.4	Chickasaw Circuit Breaker (6629) – Circuit breakers will be installed at Chickasaw substation to decrease the exposure on the Amsterdam-Coldwater 69 kV 6629 line to improve reliability.	12/1/2025			
		.5	Ft. Recovery Sub & 6684 – 69 kV circuit breakers will be installed at Ft. Recovery substation to decrease the exposure on the line to improve reliability. The tap to Macedon will be brought into a breaker position within Ft. Recovery, which will further decrease exposure on the system. This will require rebuilding ~0.15 miles of 69 kV line as double circuit into the sub.	12/31/2025			
		.6	Sharpsburg, Rosehill, Cooper & Lake Sectionalizing – New automatic 69 kV MOABs switches with supervisory control will be installed at each delivery point to reduce local area interruptions during outage conditions on their associated circuits.	12/31/2023			
48	S2523	.1	West Malta – Replace circuit breaker "A" with a 69 kV, 3000A 40 kA circuit breaker. Replace MOAB "X" with a 69 kV SCADA-controlled switch. Remove capacitor bank "AA" and the circuit switcher.	12/10/2022	$2.56	AEP	5/21/2021
		.2	South Rokeby – Remote end upgrades to coordinate with new relaying at West Malta will require a transclosure at South Rokeby and an upgrade to the existing station service.	12/10/2022		AEP	5/21/2021
49	S2524	.1	Rebuild from Howard to Ohio Central as 138 kV double circuit (64 miles) using 795 ACSR conductor. Note that the ~0.5 mile 138 kV line segments outside Ohio Central station will not be rebuilt, as they are newer and in better condition; connect these existing T-line segments to the rebuilt Philo-Howard line asset.	6/1/2028	$187.84	AEP	5/21/2021
		.2	Rebuild from Ohio Central to Philo as 138 kV single circuit (19 miles), using 795 ACSR conductor. The existing Ohio Central-Philo No. 2 138 kV circuit will be retired. Update both terminal stations to account for the retired circuit.	6/1/2028		AEP	5/21/2021
		.3	Millwood station – Retire the 138 kV flip-flop switching scheme, including the two 138 kV switches. Install two new 138 kV switches and replace the 138 kV through-path risers & bus. Reconfigure the 138 kV T-line entrances.	6/1/2028		AEP	5/21/2021
		.4	West Trinway station – Replace 138 kV through-path risers & bus.	6/1/2028		AEP	5/21/2021
		.5	Modify 138 kV protective relay settings at Philo, Culbertson, Ohio Central, Academia, North Bellville, North Lexington and Howard stations.	6/1/2028		AEP	5/21/2021
50	S2525	.1	Rebuild of the Astor-East Broad 138 kV circuit, ~2.75 miles in length, with 477KCM ACSS.	6/30/2025	$9.62	AEP	5/21/2021
		.2	Astor 138 kV station – Perform remote end work including replacing the line surge arresters, relay settings and line termination.	6/30/2025		AEP	5/21/2021
		.3	East Broad 138 kV station – Perform remote end work including relay settings and line termination.	6/30/2025		AEP	5/21/2021
51	S2526	.1	Cyprus 138 kV station – Establish a greenfield ten-breaker 138 kV (63 kA) laid out as breaker-and-a-half station on property provided by the customer south of AEP's Parsons station. Install 138 kV retail metering toward customer station.	12/1/2022	$16.17	AEP	5/21/2021
		.2	Cyprus-Cyprus (customer) 138 kV No. 1 – Build ~0.3 miles of double circuit 138 kV line using 795 ACSR conductor. Extend fiber cable & install redundant fiber cable for relaying and communication to the customer station. One circuit will serve customer's first building; second circuit will be partially constructed to be utilized for future second building to customer's redundancy requirements.	12/1/2022		AEP	5/21/2021

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
51 Cont.	S2526	.3	Cyprus-Cyprus (customer) 138 kV No. 2 – Build ~0.3 miles of double circuit 138 kV line using 795 ACSR conductor. Extend fiber cable & install redundant fiber cable for relaying and communication to customer station. One circuit will serve customer's first building; second circuit will be partially constructed to be utilized for future second building due to customer's redundancy requirements.	12/1/2022	$16.17	AEP	5/21/2021
		.4	White Road 138 kV – Upgrade line to fiber relaying and remote end work.				
		.5	Canal Street 138 kV – Upgrade line to fiber relaying and remote end work.				
52	S2527	.1	Sifford station – Construct a greenfield 138 kV station served from the existing Bixby to West Lancaster 138 kV circuit to serve the customer facilities. Station includes installation of six 138 kV, 40 kA 3000A circuit breakers laid out in a breaker-and-half arrangement. Retail metering will also be needed.	5/30/2022	$9.65		
		.2	West Lancaster-Bixby 138 kV circuit – A couple dead-end structures will be installed to bring the West Lancaster-Bixby circuit into the new Sifford station.				
		.3	Sifford-Ruble No. 1 138 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.				
		.4	Sifford-Ruble No. 1 138 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.				
		.5	West Lancaster station – Upgrades will be needed on the existing relays at West Lancaster station toward Sifford to ensure proper coordination.				
		.6	Bixby station – Upgrades will be needed to the existing relays at Bixby station toward Sifford to ensure proper coordination.				
		.7	West Millersport-West Lancaster 138 kV Sag Study Mitigation – The new customer will increase loading on the existing West Millersport-West Lancaster 138 kV circuit. Multiple structure and distribution crossing issues will be mitigated on the line in order to allow the line to operate to its conductor's designed maximum operating temperature.				
53	S2534	.1	Construct ~5.1 miles of new 69 kV line between the existing Trail and Alpine delivery points using 556 ACSR conductor.	2/10/2023	$40.04		11/20/2020
		.2	Establish a new delivery point at Winesburg switch by installing a new 1200A, 69 kV phase-over-phase switch with MOABs and metering.				
		.3	Build a new three-way phase-over-phase switch to serve the Holmes-Wayne owned Trail station.				
		.4	Retire West Wilmont junction Sw.				
		.5	Perform West Wilmont-Holmes Wayne co-op line work for Alpine station.				
		.6	Perform Biliar-West Wilmont 69 kV line work for Alpine station.				
		.7	Perform Beartown-West Wilmont 69 kV line work for Alpine station.				
		.8	Build a new station (called Alpine), replacing West Wilmont junction switch. This station will be a four-breaker 69 kV ring bus utilizing 3000A 40 kA breakers.				
		.9	Perform remote end relay work at Beartown station.				
		.10	Perform remote end relay work at Moreland Sw.				
		.11	Retire Shie Hill Sw.				
		.12	Build a new station replacing Shie Hill Sw named Shie Hill. This station will be a three-breaker 69 kV ring bus utilizing 3000A 40 kA breakers.				

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
53 Cont.	S2534	.13	Perform Sugar Creek-Millersburg 34.5 kV line work for Shie Hill station.	2/10/2023	$40.04	AEP	11/20/2020
		.14	Perform Shie Hill-Holmes Wayne co-op line work for Shie Hill station.				
		.15	Perform remote end relay work at Sugarcreek Terminal station.				
		.16	Perform remote end relay work at Berlin station.				
		.17	Install a new 138 kV, 3000A 40 kA breaker at West Millersburg station on the line toward Wooster to reduce contingency impacts and potential low-voltage concerns resulting from the new load.				
		.18	Replace the two-way phase-over-phase switch at North Fredericksburg with a new 1200A, 69 kV phase-over-phase with new MOABs. The switch currently in place is not capable of supporting the necessary new equipment.				
		.19	Perform Moreland Sw-Biliar line work for North Fredricksburg switch.				
54	S2545		Eastlake-Lloyd Q13 138 kV line-Eastlake-Lloyd 138 kV Q-13 – Replace the line relaying and replace terminal equipment such as breakers, associated disconnects, wave traps, CCVTs and line tuners as needed.	3/4/2022	$1.00	ATSI	4/16/2021
55	S2547		Replace two 138 kV breakers (B67 & B68) with two 138 kV, 40 kA 3000A breakers. Upgrade relays at Lincoln Park for the Lincoln Park-Lowellville line terminal. Replace four 138 kV disconnect switches (D82, D81, D99 & D100) with 2000A switches. Replace three 138 kV CVTs (CC91, CC92 & CC93). Install a 138 kV 1200A Lowellville line terminal MOABs and support structure. Replace leads and bus connection with conductor at least 278 MVA/SN, 339 MVA/SE. New transmission line ratings for Lincoln Park-Lowellville 138 kV line: Before proposed solution – 155 MVA SN/155 MVA SE & After proposed solution – 187 MVA SN/191 MVA SE.	12/31/2021	$1.40	ATSI	2/17/2021
56	S2548		Victoria Road 69 kV transmission line tap – Convert and rebuild the Meander-West Austintown 23 kV line to 69 kV between Kimberly substation and West Austintown substation. Tap the Kimberly-West Austintown 23 kV line at or near Victoria Rd. Build ~0.2 miles of 336 ACSR 69 kV line from the tap location to the customer substation.	5/31/2021	$4.14	ATSI	2/17/2021
57	S2553		Construct a 138 kV tap off the Delta-Wauseon 138 kV line to the customer substation. The customer substation tap location is an ~0.8 mile extension from the existing structures to the new customer substation. Provide one 138 kV metering package and add MOAB and SCADA to two existing switches on the Delta-Wauseon 138 kV line.	2/15/2022	$3.20	ATSI	7/16/2021
58	S2575	.1	Install a new three-way phase-over-phase switch (Mousey Sw) and 69 kV metering to serve North Central’s Sycamore station.	11/1/2024	$51.58	AEP	7/16/2021
		.2	Construct ~13 miles of new 69 kV line between Bucyrus Center and the new Mousey switch delivery point using 556 ACSR conductor.				
		.3	Install a new 69 kV, 3000A 40 kA breaker and associated terminal equipment at Bucyrus Center on the line toward Mousey switch.				
		.4	Remove the existing West Rockaway 69 kV switch currently used to radially serve the Sycamore delivery point.				
		.5	Construct ~0.8 miles of new 69 kV line between the existing Sycamore radial line and East Tiffin delivery points using 556 ACSR conductor.				
		.6	Reconfigure East Tiffin station to add in a box bay, a breaker and terminal equipment toward Mousey switch and a new line MOAB toward South Tiffin.				
		.7	Rebuild ~2.3 miles of new 69 kV line between the existing Bucyrus and East Bucyrus delivery points using 556 ACSR conductor.				
		.8	Remove ~16 miles of existing 69 kV line between the existing East Bucyrus and Howard delivery points.				
		.9	Retire the existing ~1.4 miles of the Howard-Bucyrus No. 2 line between Bucyrus station and structure 366.				
		.10	Construct ~1.3 miles of new 69 kV line between the existing East Bucyrus delivery point and structure 336 on the Howard-East Bucyrus No. 2 line. This construction will be coordinated with rebuild project S2156.				

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
59	S2576	.1	Lick-Jefferson 69 kV – Rebuild ~8.3 miles of the 69 kV line from Structure 29 to Jefferson switch station with 556.5 ACSR. Install shield wire from Structure 29 to Lick station, ~4 miles. This work requires tree clearing and access road construction in order to add the shield wire to existing structures. Total access road construction is 5.5 miles.	4/20/2023	$26.70	AEP	7/16/2021
		.2	Echo Valley – Replace existing switch with a three-way phase-over-phase 69 kV 1200A switch with SCADA. There will be auto-sectionalizing enabled toward Firebrick.				
		.3	Perform remote end work associated with the line rebuild at Lick & Firebrick.				
60	S2577	.1	Rebuild the South Lancaster-East Logan 69 kV circuit, ~16.6 miles in length, with 556.5 ACSR Dove conductor.	5/2/2024	$42.31		
		.2	Rebuild the Enterprise switch-Enterprise Metering structure, ~200 feet in length, with 556.5 ACSR Dove conductor.				
		.3	Enterprise switch – Replace the two-way phase-over-phase switch with a new 1200A three-way phase-over-phase switch with auto sectionalizing and SCADA functionality. Replace the CTs, PTs and metering.				
		.4	West Logan – Replace the three way phase-over-phase switch with a new 1200A three way phase-over-phase switch.				
		.5	South Lancaster – Perform remote end work.				
61	S2578	.1	Innovation 138 kV station – Construct a greenfield 138 kV breaker-and-a-half station that includes seven 138 kV, 3000A 63 kA circuit breakers and four total line exits to serve the requested load.	3/31/2023	$27.56		
		.2	Innovation Extension 138 kV – Tap the existing Babbitt-Kirk 138 kV circuit creating the Babbitt-Innovation and Kirk-Innovation 138 kV circuits and construct ~2.2 miles of double circuit line to serve the new station. Extend the telecom fiber into Innovation station for relaying/communication.				
		.3	Conesville-Corridor 345 kV – Relocate a portion of the existing Conesville-Corridor 345 kV single circuit line to accommodate the install of Innovation station. Approximately 0.40 miles of line to be rerouted around station site.				
		.4	Babbitt 138 kV station – Update remote end relay settings and telecom electronics.				
		.5	Kirk 138 kV station – Update remote end relay settings and telecom electronics.				
62	S2579	.1	Westfall 138 kV station – Build a new greenfield 138 kV three-breaker ring configured station. The three breakers installed will be 138 kV, 40 kA 3000A. 138 kV revenue metering equipment will be installed.	3/1/2023	$6.52		
		.2	Westfall-Westfall (SCP) customer 138 kV – Install a 0.02 mile 138 kV single circuit line between Westfall and Westfall (SCP) customer station.				
		.3	Biers Run-Circleville 138 kV – Tap the existing Biers Run-Circleville 138 kV line, removing 0.1 miles and adding two dead-end structures in order to cut the line into the new AEP Westfall station. Extend the telecom fiber into Westfall station for relaying/communication.				
		.4	Circleville 138 kV station – Update remote end relay settings and telecom electronics.				
		.5	Lutz 138 kV station – Update remote end relay settings and telecom electronics.				
63	S2580	.1	Dow Chemical Extension – Rebuild Str. 1, 2 & 3 as double circuit to include the Dow Chemical-Highland 69 kV & Dow Chemical-Hanging Rock circuits. ACSR Osprey 556.5 (18/1) conductor (SE 126 MVA) will be used.		$2.84		
		.2	Raceland-Dow Chemical 69 kV – Replace Str. 16 for new alignment. Remove Str. 17, 18, & replace Str. 19 to facilitate new tie-in arrangement. Reconfigure line from new Str. 16 to Gervais switch. ACSR Osprey 556.5 (18/1) conductor (SE 126 MVA) will be used.				
		.3	Gervais switch – Install a new three-way 69 kV, 1200A 61 kA phase-over-phase switch with one SCADA-controlled MOAB (toward Dow Chemical) and one auto-controlled MOAB (toward Wurtland switch) to serve new PureCycle delivery point. Install a 69 kV revenue meter outside of customer station on monopole steel structure.				

Table 6.48: Ohio Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
63 Cont.	S2580	.4	Purecycle Extension – Install ~0.1 miles of single circuit line to connect the customer to Gervais switch; ACSR Hawk 477 (26/7) conductor (SE 128 MVA).	3/1/2022	$2.81	AEP	7/16/2021
		.5	Hanging Rock – Install the remote end SFP in the CES at Hanging Rock station to provide the connection for the CGR router at Gervais switch.				
64	S2581		Replace failed 69 kV circuit breaker 'AN' at Tidd with a spare 69 kV SF6 gas breaker (3000A/40 kA nameplate).	6/24/2021	$0.10		
65	S2586		Install a 345 kV breaker between the AES bus and the 345/138 kV transformer. Replace the three oil-filled 138 kV breakers. Reconfigure the 138 kV bus into a three-position ring. Terminate in the three positions the 345/138 kV transformer, the 138 kV feeder from Brown substation, and the 138/69 kV transformer. Install a 69 kV breaker connecting the 138/69 kV transformer to the AEP feeder. Build a new control building to house protection, controls and communications equipment. Install fencing to separate Duke Energy facilities from AES facilities.	6/1/2023	$9.40	DEO&K	8/10/2021
66	S2595		Replace breakers B-13295, B-13296, B-13297 and associated disconnects at GM Powertrain substation. Replace breaker B-13329 and associated disconnects at Jackman substation. Replace limiting substation conductors to exceed associated line ratings.	5/2/2022	$1.50	ATSI	8/16/2021
67	S2596		Replace 138 kV bus tie circuit breaker B-22 and breaker leads. Replace disconnect switch D-108 and D-109. Install new SEL-501 breaker failure relying for 138 kV breaker B-22. Replace transfer breaker line relaying for 138 kV breaker B-22.	2/25/2022	$0.70		
68	S2597		Replace B-25, B-28, B-19, B-35, B-22, B-24 and B-27 with associated disconnect switches. Replace and install associated FE standard bus relaying panels, transmission line relying panels, capacitor bank panels and BF relay panels. Replace limiting substation conductors to exceed associated line ratings.	3/2/2023	$7.90		

6.9: Pennsylvania RTEP Summary

6.9.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Pennsylvania, including facilities owned and operated by Allegheny Power (AP), Duquesne Light Company (DLCO), Metropolitan Edison (METED), Pennsylvania Electric Company (PENELEC), PECO, PPL Electric Utilities (PPL), UGI Utilities (UGI), Rock Springs and American Transmission Systems, Inc. (ATSI) as shown on **Map 6.40**.

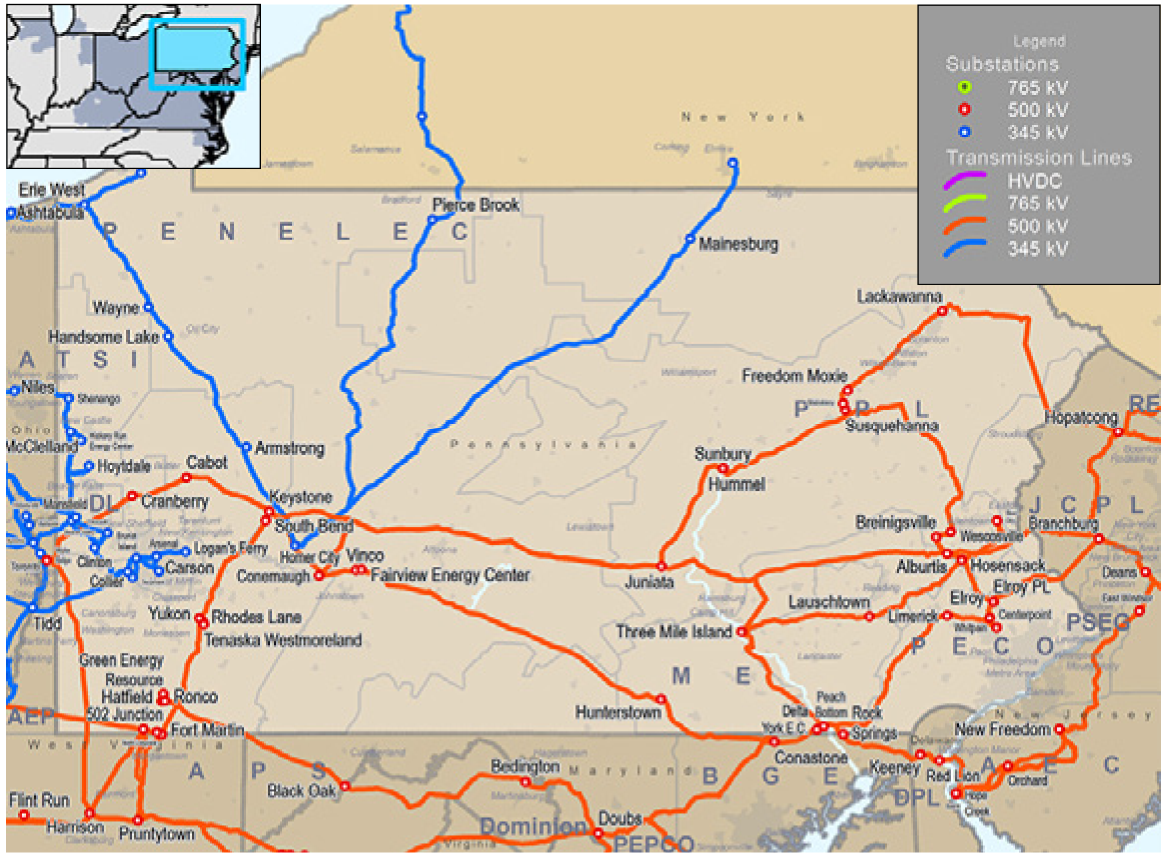
Pennsylvania's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Renewable Portfolio Standards

From an energy policy perspective, Pennsylvania has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

Pennsylvania has a mandatory alternative energy portfolio standard (AEPS) target of 8% Tier 1 resources and 10% Tier 2 resources by 2021. The AEPS includes a solar carve-out of 0.5% by 2021, and solar resources applying toward the AEPS must be located within the commonwealth of Pennsylvania.

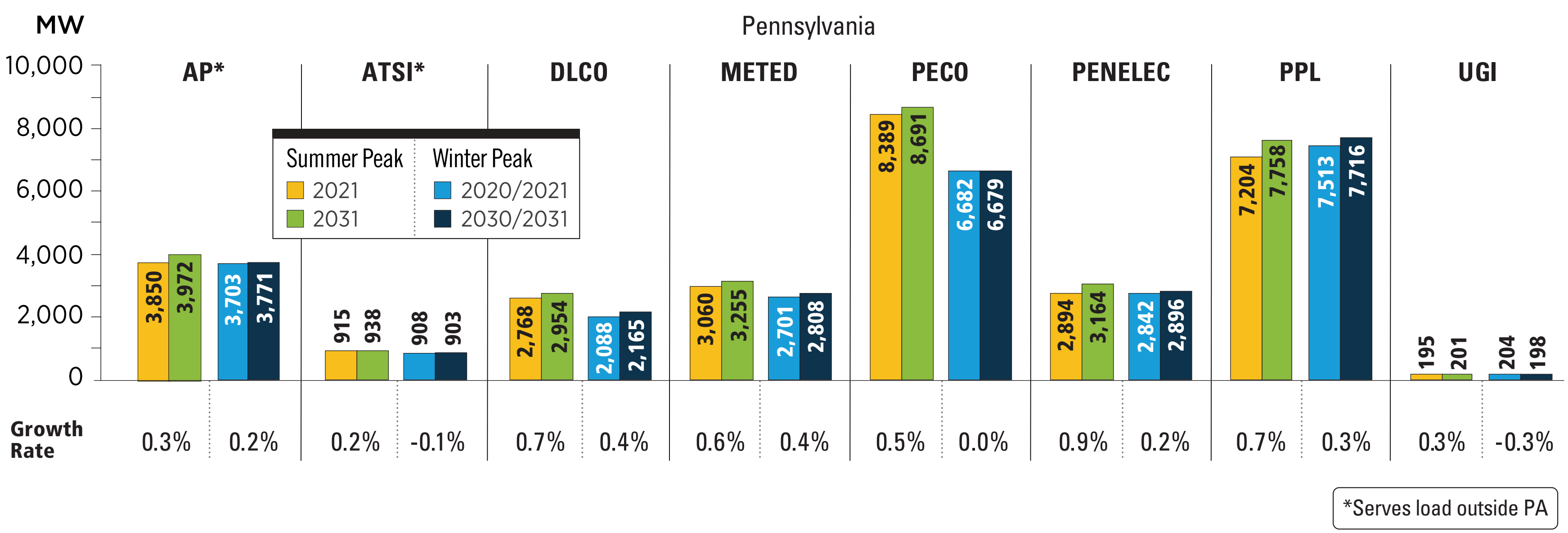
Map 6.40: PJM Service Area in Pennsylvania



6.9.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.46** summarizes the expected loads within the state of Pennsylvania and across PJM.

Figure 6.46: Pennsylvania – 2021 Load Forecast Report



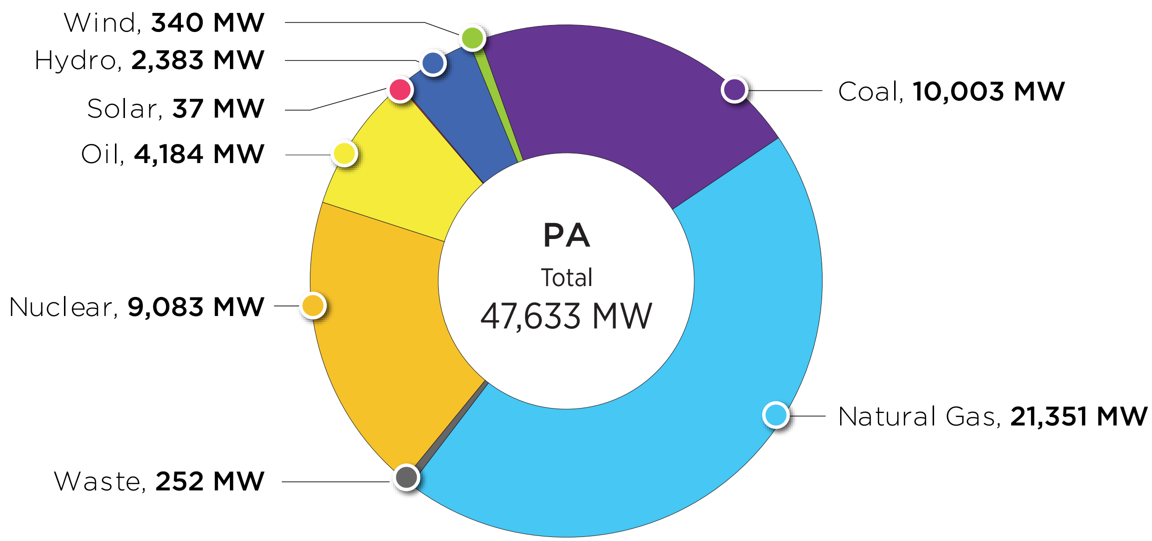
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.9.3 — Existing Generation

Existing generation in Pennsylvania as of Dec. 31, 2021, is shown by fuel type in **Figure 6.47**.

Figure 6.47: Pennsylvania – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.9.4 — Interconnection Requests

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

Specifically, in Pennsylvania, as of Dec. 31, 2021, 620 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.49**, **Table 6.50**, **Figure 6.48**, **Figure 6.49** and **Figure 6.50**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.49: Pennsylvania – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	Pennsylvania Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	509	3.24%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	2,172	13.82%	23,887	14.77%
Nuclear	44	0.28%	81	0.05%
Oil	8	0.05%	17	0.01%
Other	3	0.02%	331	0.20%
Solar	9,744	61.99%	93,756	57.99%
Storage	3,107	19.77%	34,130	21.11%
Wind	132	0.84%	8,800	5.44%
Grand Total	**15,718**	**100.00%**	**161,682**	**100.00%**

Table 6.50: Pennsylvania – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	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	17	229.0	28	14,354.6	45	14,583.6
	Diesel	0	0.0	0	0.0	0	0.0	4	37.4	12	51.5	16	88.9
	Natural Gas	6	295.5	4	1,028.0	19	848.4	107	21,209.9	249	90,886.0	385	114,267.8
	Nuclear	2	0.0	0	0.0	1	44.0	14	2,565.0	12	1,731.0	29	4,340.0
	Oil	0	0.0	0	0.0	6	7.5	3	9.4	9	1,307.0	18	1,323.9
	Other	5	2.9	0	0.0	0	0.0	2	306.5	8	344.0	15	653.4
	Storage	61	3,095.0	3	11.8	0	0.0	5	0.0	48	804.0	117	3,910.8
Renewable	Biomass	0	0.0	0	0.0	0	0.0	2	15.4	4	36.5	6	51.9
	Hydro	6	487.8	0	0.0	2	21.5	12	480.8	18	465.4	38	1,455.4
	Methane	0	0.0	0	0.0	0	0.0	24	130.7	37	201.3	61	332.0
	Solar	433	8,853.9	29	280.1	72	609.6	14	56.9	252	4,560.4	800	14,360.9
	Wind	5	91.1	1	8.7	2	32.0	42	295.9	137	1,757.5	187	2,185.2
	Wood	0	0.0	0	0.0	0	0.0	0	0.0	1	16.0	1	16.0
	Grand Total	**518**	**12,826.1**	**37**	**1,328.7**	**102**	**1,563.0**	**246**	**25,336.9**	**815**	**116,515.1**	**1,718**	**157,569.7**

Figure 6.48: Pennsylvania – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

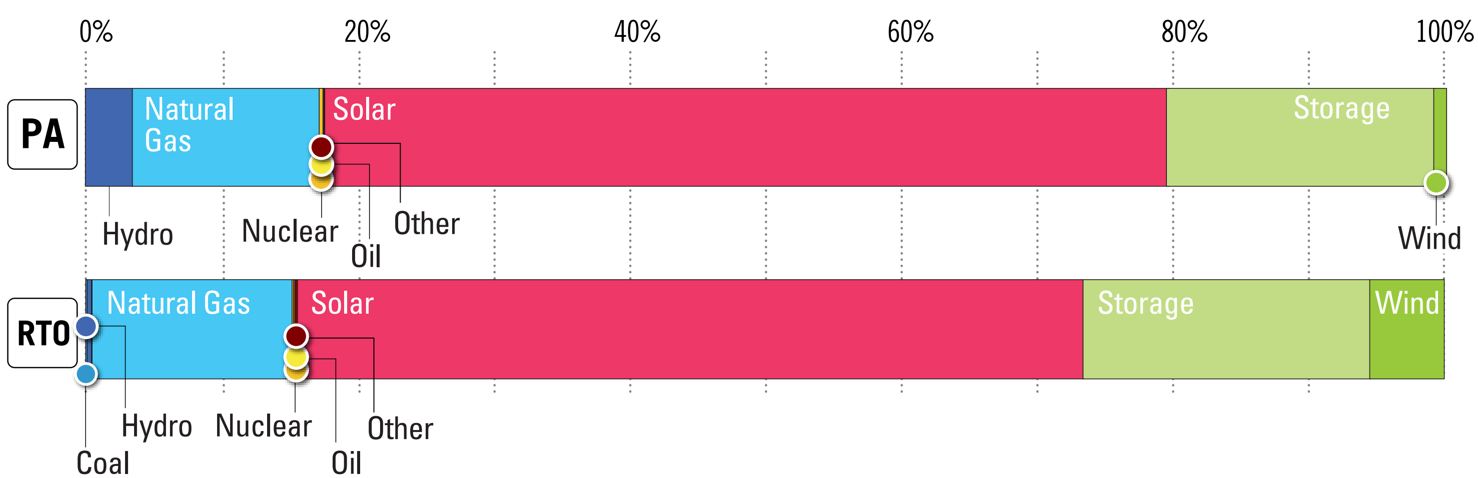
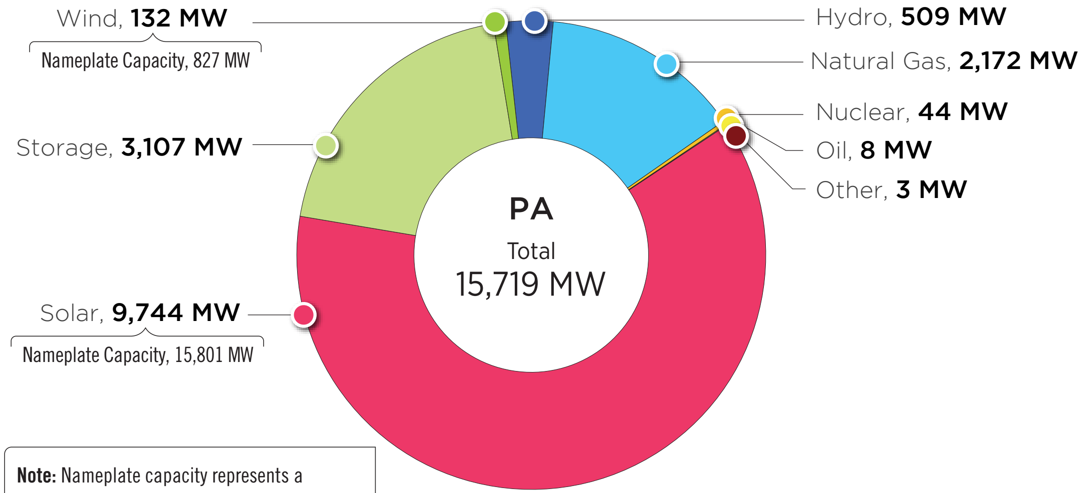


Figure 6.49: Pennsylvania – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.50: Pennsylvania Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Projects withdrawn after final agreement			Capacity	Nameplate
	59	Interconnection Service Agreements	7,173 MW	9,142 MW
	49	Wholesale Market Participation Agreements	308 MW	423 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.9.5 — Generation Deactivation

Known generating unit deactivation requests in Pennsylvania between Jan. 1, 2021, and Dec. 31, 2021, are summarized in **Map 6.41** and **Table 6.51**.

Map 6.41: Pennsylvania Generation Deactivations (Dec. 31, 2021)

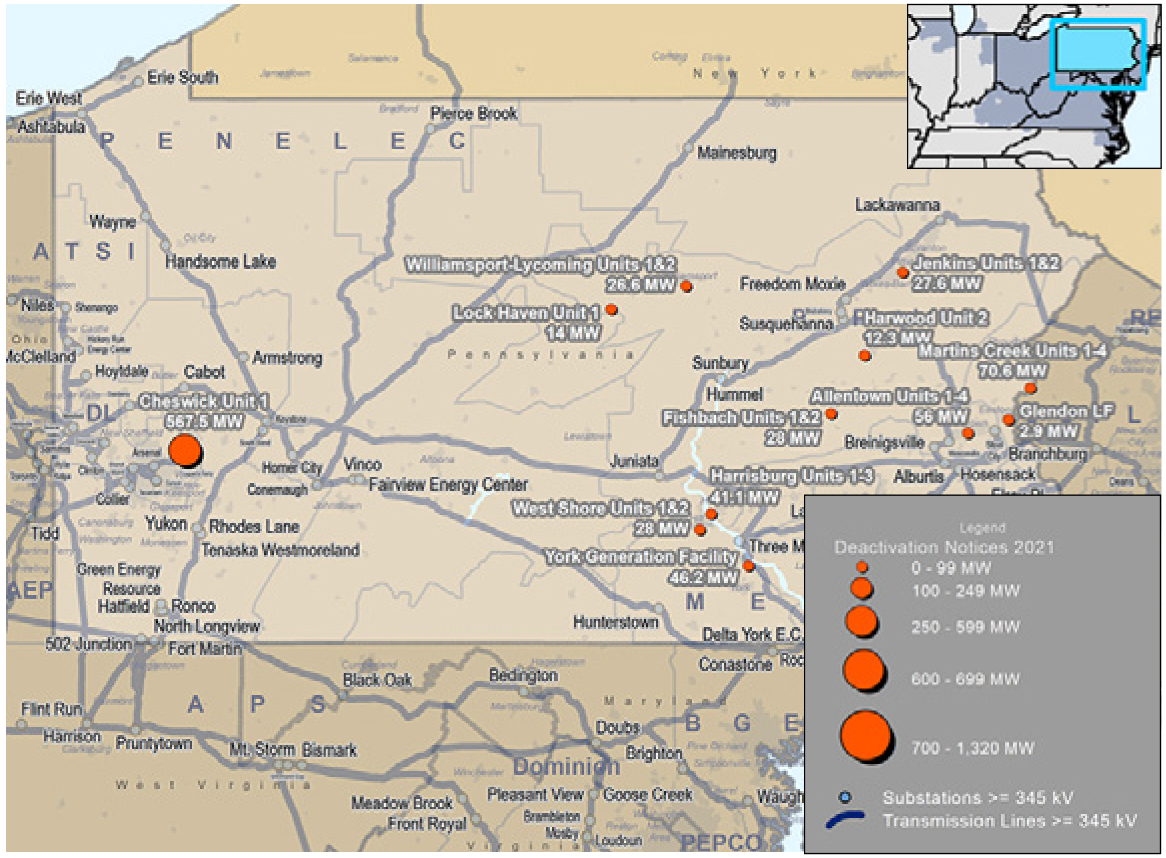


Table 6.51: Pennsylvania Generation Deactivations (Dec. 31, 2021)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Williamsport-Lycoming CT 2	PPL	Oil	9/30/2021	4/1/2022	54	13.4
Williamsport-Lycoming CT 1					54	13.2
West Shore CT 2					52	14
West Shore CT 1					52	14
Martins Creek CT 3				5/31/2023	50	18

Table 6.51: Pennsylvania Generation Deactivations (Dec. 31, 2021) (Cont.)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Martins Creek CT 2	PPL	Oil	9/30/2021	5/31/2023	50	17.3
Martins Creek CT 1	PPL	Oil	9/30/2021	5/31/2023	50	18
Lock Haven CT 1	PPL	Oil	9/30/2021	4/1/2022	52	14
Jenkins CT 2	PPL	Oil	9/30/2021	4/1/2022	52	13.8
Jenkins CT 1	PPL	Oil	9/30/2021	4/1/2022	52	13.8
Harrisburg CT 3	PPL	Oil	9/30/2021	6/1/2022	54	13.8
Harrisburg CT 2	PPL	Oil	9/30/2021	6/1/2022	54	13.9
Harrisburg CT 1	PPL	Oil	9/30/2021	6/1/2022	54	13.4
Fishbach CT 2	PPL	Oil	9/30/2021	4/1/2022	52	14
Fishbach CT 1	PPL	Oil	9/30/2021	4/1/2022	52	14
Allentown CT 4	PPL	Oil	9/30/2021	6/1/2022	54	14
Allentown CT 3	PPL	Oil	9/30/2021	6/1/2022	54	14
Allentown CT 2	PPL	Oil	9/30/2021	6/1/2022	54	14
Allentown CT 1	PPL	Oil	9/30/2021	6/1/2022	54	14
Glendon LF	METED	Methane	9/1/2021	6/1/2022	10	2.9
Cheswick 1	DLCO	Coal	6/9/2021	4/1/2022	51	567.5
Martins Creek CT 4	PPL	Natural Gas	2/25/2021	5/31/2023	50	17.3
York Generation Facility	METED	Natural Gas	6/22/2021	9/20/2021	31	46.2
Harwood 2	PPL	Oil	4/27/2021	5/31/2022	53	12.3

6.9.6 — Baseline Projects

2021 RTEP baseline projects in Pennsylvania are summarized in **Map 6.42** and **Table 6.52**.

Map 6.42: Pennsylvania Baseline Projects (Dec. 31, 2021)

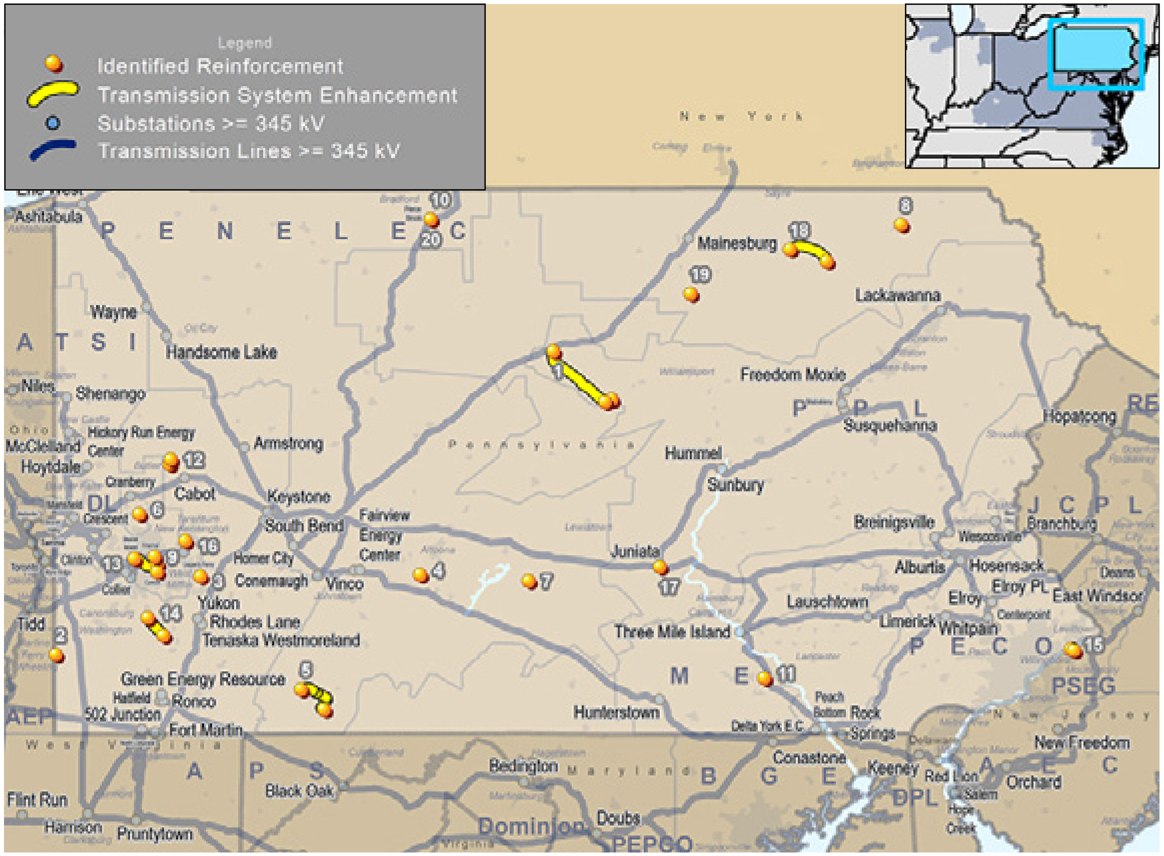


Table 6.52: Pennsylvania Baseline Projects (Dec. 31, 2021)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3222	Install one 7.2 MVAR fixed cap bank on the Lock Haven-Reno 69 kV line and one 7.2 MVAR fixed cap bank on the Lock Haven-Flemington 69 kV line near the Flemington 69/12 kV substation.	6/1/2025	$1.90	PPL	11/18/2020
2	B3230	At Enon substation – Install a second 138 kV, 28.8 MVAR nameplate, capacitor and the associated 138 kV capacitor switcher.		$1.80	AP	11/20/2020

Table 6.52: Pennsylvania Baseline Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	B3231	Replace the existing No. 2 cap bank breaker at Huntingdon substation with a new breaker with higher interrupting capability.	6/1/2025	$0.80	PENELEC	11/18/2020
4	B3232	Replace the existing Williamsburg, ALH (Hollidaysburg) and bus section breaker at the Altoona substation with a new breaker with higher interrupting capability.		$1.70		
5	B3233	Install one 34 MVAR 115 kV shunt reactor and breaker. Install one 115 kV circuit breaker to expand the substation to a four-breaker ring bus.	6/1/2025	$4.90	PENELEC	
6	B3234	Extend both the east and west 138 kV buses at Pine substation, and install one 138 kV breaker, associated disconnect switches and one 100 MVAR reactor.		$3.80	ATSI	10/16/2020
7	B3237	Install two 46 kV 6.12 MVAR capacitors effective at Mt Union.		$4.00	PENELEC	11/18/2020
8	B3245	Construct a new breaker-and-a-half substation near Tiffany substation. All transmission assets and lines will be relocated to the new substation. The two distribution transformers will be fed via two dedication 115 kV feeds to the existing Tiffany substation.		$23.20		
9	B3265	Implement slow circulation on existing underground 138 kV high-pressure fluid filled (HPFF) cable between Arsenal and Riazzi substations.		$2.40	DLCO	11/20/2020
10	B3306	Install a second 125 MVAR 345 kV shunt reactor and associated equipment at Pierce Brook substation. Install a 345 kV breaker on the high side of the No. 1 345/230 kV transformer.		$8.08	PENELEC	12/1/2020
11	B3311	Install a 120.75 kV, 79.4 MVAR capacitor bank at Yorkana 115 kV.	5/31/2022	$2.20	METED	1/6/2021
12	B3318	Reconductor the Shanor Manor-Butler 138 kV line with an upgraded circuit breaker at Butler.	6/1/2022	$1.50	AP	8/10/2021
13	B3319	Add forced cooling to increase the normal rating of the Brunot Island-Carson (302) 345 kV high-pressure fluid filled (HPFF) underground cable circuit.		$22.00	DLCO	
14	B3325	Reconductor the Charleroi-Union 138 kV line and upgrade terminal equipment at Charleroi.		$11.00	AP	
15	B3335	Reconductor a 0.76 mile portion of the Croydon-Burlington 230 kV line.		$0.79	PECO	11/2/2021
16	B3340	Replace one Cheswick 138 kV breaker with a 3000A 63 kA breaker: “Z-53 LF_3”.	6/1/2026	$0.35	DLCO	9/17/2021
17	B3664	Juniata: Replace the limiting 230 kV T2 transformer leads, bay conductor and bus conductor with double-bundle 1590 ACSR. Replace the limiting 1200A MODs on the bus tie breaker with 3000A MODs.		$0.68	PPL	11/2/2021
18	B3665	Replace several pieces of 1033.5 AAC substation conductor at East Towanda 230 kV (on East Towanda-Canyon 230 kV).		$0.41	PENELEC	
19	B3666	Marshall 230 kV substation – Install dual reactors and expand existing ring bus.		$5.83		
20	B3667	Pierce Brook substation – Install second 230/115 kV transformer.		$5.07		

6.9.7 — Network Projects

2021 RTEP network projects in Pennsylvania are summarized in **Map 6.43** and **Table 6.53**.

Map 6.43: Pennsylvania Network Projects (Dec. 31, 2021)

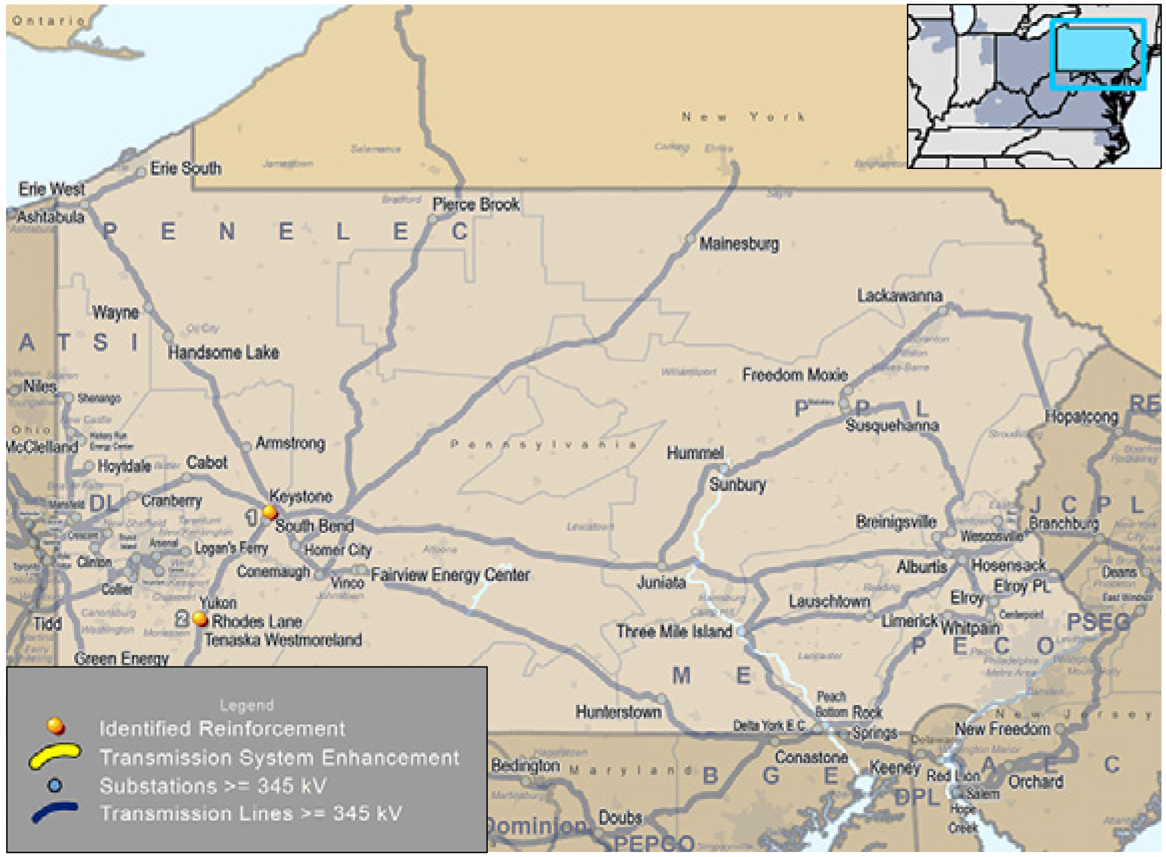


Table 6.53: Pennsylvania Network Projects (Dec. 31, 2021)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N6107	Keystone substation – Revise relay settings on South Bend terminal.	AD2-114	5/31/2022	0.03	AP	11/30/2021
2	N6108	Yukon substation – Revise relay settings on South Bend terminal.					

6.9.8 — Supplemental Projects

2021 RTEP supplemental projects in Pennsylvania are summarized in **Map 6.44** and **Table 6.54**.

6.9.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Pennsylvania were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.44: Pennsylvania Supplemental Projects (Dec. 31, 2021)

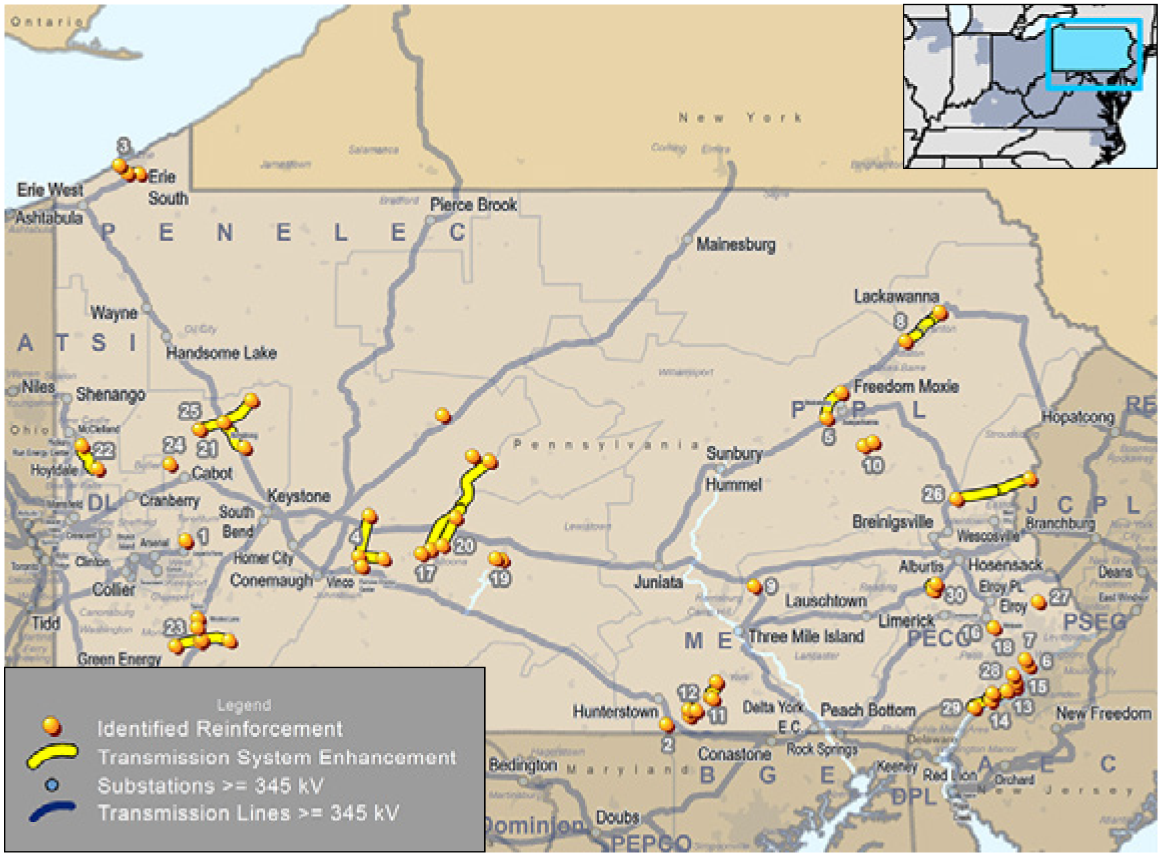


Table 6.54: Pennsylvania Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2400		Replace the two existing 138 kV breakers at Cheswick substation with GE-type DT-1, 145 kV, 63 kA Int., SF6 breaker.	12/31/2021	$0.80	DLCO	10/16/2020
2	S2409		Add a new 115 kV line terminal to the Germantown 115 kV substation and construct ~3.5 miles of 115 kV line to the customer substation.	12/31/2022	$10.80	METED	11/18/2020

Table 6.54: Pennsylvania Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S2411		Replace terminal equipment on the Erie South-Gore junction-Green Garden 115 kV line.	6/1/2022	$2.10	PENELEC	11/18/2020
		.1	Erie South 115 kV substation – Replace line relaying (Erie South-GESG Tap 115 kV line).				
		.2	Gore Junction 115 kV substation – Replace line relaying and disconnect switch (GESG Tap-Gore junction 115 kV line).				
		.3	Green Garden 115 kV Substation – Replace line relaying (GESG Tap-Green Garden 115 kV line).				
4	S2412		Perform Nanty Glo 46 kV substation work.	6/1/2024	$7.90		
		.1	Construct Nanty Glo 46 kV station to six-breaker ring bus.				
		.2	Replace line relaying at Bethlehem 33 46 kV substation on the Nanty Glo-Bethlehem 46 kV circuit.				
		.3	Replace line relaying at Jackson Road 46 kV substation on the Nanty Glo-Jackson 46 kV circuit.				
		.4	Adjust line relaying at Spangler 46 kV substation on the Nanty Glo-Spangler 46 kV circuit.				
5	S2416		Construct new Koonsville 66/13.8 kV distribution substation on neighboring UGI property. Loop in the Berwick-Hunlock 69 kV and build ~200 feet of new 66 kV double circuit line and replace existing 66 kV tap and line MOAB with high-side 66 kV line breakers.	4/30/2022	$2.10	UGI	
6	S2417		Replace Waneeta 230 kV circuit breaker No. 285.	6/1/2022	$0.80	PECO	12/1/2020
7	S2418		Replace Tabor 230 kV circuit breaker No. 905.				
8	S2419		Extend a new double circuit 69 kV tap from the existing Lackawanna-Scranton No. 1 and No. 2 69 kV lines to interconnect a new customer 69-12.47 kV substation. Build 0.1 miles of new 69 kV double circuit line using 556 ACSR conductor.	12/30/2021	$1.00	PPL	12/16/2020
9	S2420		Extend a new single 69 kV tap from the existing Hershey Chocolate Tap (fed from the Harwood-Humboldt No. 2) 69 kV line to interconnect a new customer 69-12.47 kV substation. Build 0.75 miles of new 69 kV single circuit line using 556 ACSR conductor.		$1.90		
10	S2421		Extend a new single 69 kV tap from the Harwood-East Hazleton No. 1 69 kV line to interconnect a new customer 69-12.47 kV substation. Build 0.1 miles of new 69 kV single circuit line using 556 ACSR conductor.	2/28/2022	$0.70		
11	S2480		At North Hanover – Replace substation conductor and line relaying (on the North Hanover-Gitts Tap-Fairview 115 kV line).	12/31/2022	$10.80	METED	1/14/2021
12	S2481	.1	At Jackson – Replace line trap and line relaying (on the Jackson-Menges Mills 115 kV line).		$1.00		
		.2	At PH Glatfelter – Replace substation conductor, line trap, disconnect switches, circuit breaker and line relaying (on the Menges Mills-PH Glatfelter 115 kV line).				
13	S2484		Replace Passyunk 69 kV circuit breaker No. 235.	6/1/2021	$0.60	PECO	
14	S2485		Replace Eddystone 138 kV circuit breaker No. 255.		$0.80		
15	S2486		Replace the Grays Ferry 230 kV circuit breaker No. 375.		$0.90		1/6/2021
16	S2487		Replace the Whitpain 500 kV circuit breaker No. 575.		$1.60		
17	S2493		Perform Eagle Valley & Thirty-First Street 115 kV anti-islanding.		$1.30	PENELEC	2/16/2021
		.1	Shawville 115 kV substation – Replace line-side breaker disconnect, line trap, CCVT and line arresters and install new PLC transmitter/receiver (Shawville-Philipsburg 115 kV).				
		.2	Philipsburg 115 kV Substation – Replace bus section breaker, breaker disconnects, line arresters, CCVT and line trap (Shawville-Philipsburg 115 kV).				
		.3	Eagle Valley 115 kV substation – Install PLC transmitter/receive and adjust existing PLC settings.				

Table 6.54: Pennsylvania Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
17 Cont.	S2493	.4	Westfall 115 kV substation – Adjust PLC settings.	6/1/2021	$1.30	PENELEC	2/16/2021
		.5	Thirty-First Street 115 kV substation – Adjust PLC settings.				
18	S2508		Replace the Whitpain 500 kV circuit breaker No. 385.	6/28/2021		PECO	1/6/2021
19	S2535		Replace in-line switches A-136, A-137 and A-139 on the Raystown-McConnellstown 46 kV circuits.	12/31/2022	$1.50	PENELEC	4/14/2021
		.1	Replace in-line switch on the Allegheny Hydro Tap-Allegheny Hydro 46 kV line.				
		.2	Replace in-line switch on the Allegheny Hydro Tap-RAM junction 46 kV line.				
		.3	Replace in-line switch on the RAM junction-Piney Ridge 46 kV line.				
20	S2536		Tap the Greenwood-Tipton 46 kV line (Gardner Denver Tap-Gardner Denver 46 kV line segment). Construct one span of 46 kV line. Install one 46 kV revenue-metering package. Install two 1200A SCADA-controlled disconnect switches and add SCADA to one existing switch.	7/1/2021	$1.40		
		.1	Replace in-line switch on the Allegheny Hydro Tap-Allegheny Hydro 46 kV line.	12/31/2022			
		.2	Replace in-line switch on the Allegheny Hydro Tap-RAM junction 46 kV line.				
		.3	Replace in-line switch on the RAM junction-Piney Ridge 46 kV line.				
21	S2542		At Karns City 138 kV substation – Install a 138 kV bus tie breaker disconnect switches. Install 138 kV CVTs and support structure. Replace/add 25 kV VTs. Upgrade relaying and protection.	12/22/2023	$1.30	AP	3/19/2021
22	S2546		Tap the Frisco-New Castle Y-205 69 kV line between New Castle and Cemex Cement. Install two 69 kV disconnect switches with SCADA. Construct ~1 span of 69 kV into new substation. Replace two 69 kV disconnect switches at Frisco substation. Adjust relaying at Frisco and New Castle substations.	12/17/2021	$1.05	ATSI	4/16/2021
23	S2549		Allenport-Frazier 138 kV line (new ratings: 294/360 SN/SE): Allenport 138 kV substation – Replace line disconnect switches, CCVT, line trap, line tuner, coax; replace substation conductor, install AMETEK Smart-Gap in-line tuner.Frazier-Layton junction 138 kV line (new ratings: 292/359 SN/SE).Yukon-Smithton Tap 138 kV line (new ratings: 285/351 SN/SE): Yukon 138 kV substation – Replace line disconnect switches, CCVT, line trap, line tuner, coaxial cable; install AMETEK Smart-Gap in-line tuner.Smithton Tap-Layton junction 138 kV line (new ratings: 236/299 SN/SE).Iron Bridge-Layton junction 138 kV line (new ratings: 268/333 SN/SE): Iron Bridge 138 kV substation – Replace line disconnect switch, CCVT, line trap, line tuner, coaxial cable, substation conductor; install AMETEK Smart-Gap in-line tuner.	4/5/2021	$3.80	AP	2/17/2021
24	S2550		At Karns City 138 kV substation – Replace breaker, disconnect switches, line trap, line tuner, coax, CVT and substation conductor. Install MCOV surge arrestors and AMETEK Smart-Gap in-line tuner. At Butler 138 kV substation – Replace breaker, disconnect switches, line trap, line tuner, coax, CVT and substation conductor. Install MCOV surge arrestors and AMETEK Smart-Gap in-line tuner.	12/22/2023	$3.04		3/19/2021
25	S2551		Karns City-Kissinger junction 138 kV line: At Karns City 138 kV substation – Replace breaker, line trap, line tuner, coax and CVT. Install MCOV surge arrestors and AMETEK Smart-Gap in-line tuner. Armstrong-Kissinger junction 138 kV line: At Armstrong 138 kV substation – Install AMETEK Smart-Gap in-line tuner. Burma-Kissinger junction 138 kV line: At Burma 138 kV substation – Replace breaker, disconnect switches, line trap, CVT and substation conductor. Install MCOV surge arrestors and AMETEK Smart-Gap in-line tuner.	12/12/2023	$1.80		3/19/2021
26	S2557		Construct a new 230 kV ring bus adjacent to the existing Martins Creek-Siegfried No. 2 230 kV line, and loop the PPL Martins Creek-Siegfried 230 kV line into the new customer substation.	6/1/2022	$9.20	METED	3/9/2021

Table 6.54: Pennsylvania Supplemental Projects (Dec. 31, 2021) (Cont.)

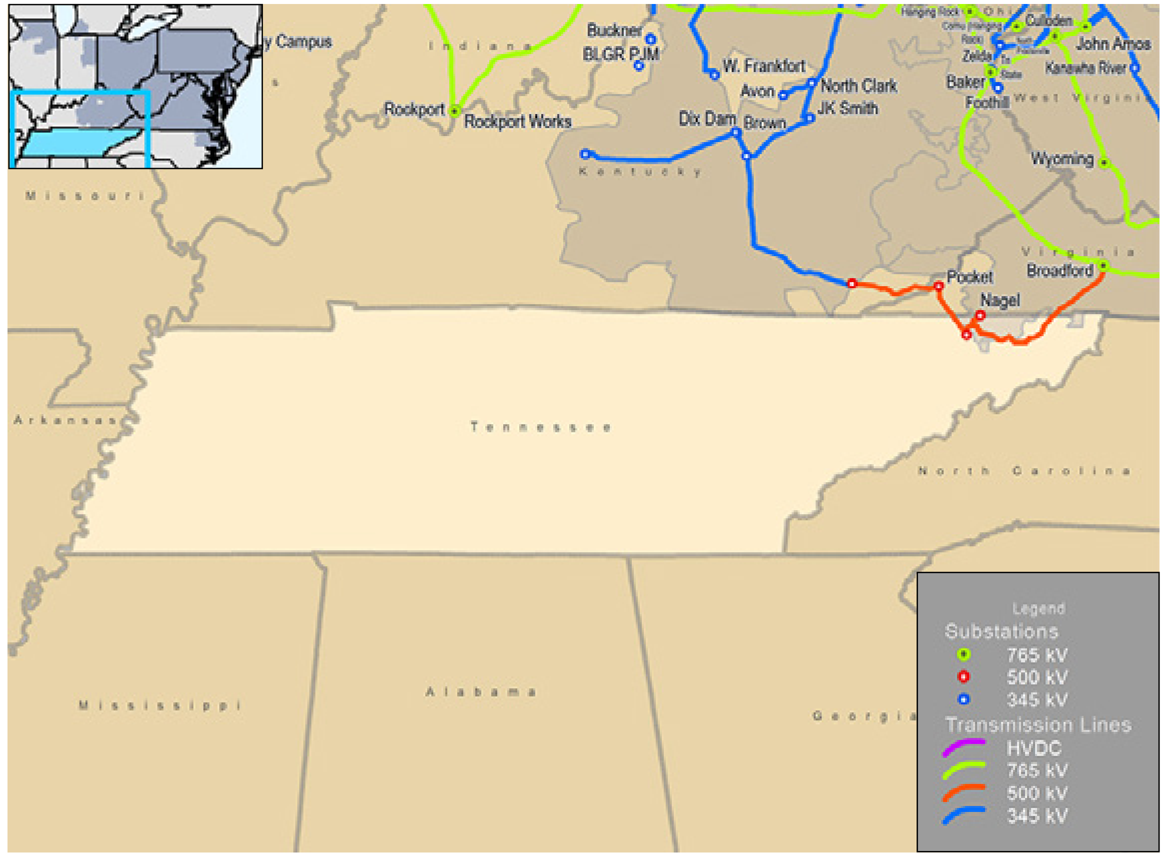
Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
27	S2558		Replace Buckingham 230 kV circuit breaker No. 220.	12/1/2021	$0.80	PECO	3/9/2021
	S2559		Replace Buckingham 230 kV circuit breaker No. 230.		$0.80		
	S2560		Replace Buckingham 230 kV circuit breaker No. 240.		$0.80		
28	S2561		Replace Parrish 230 kV circuit breaker No. 905.		$0.80		
29	S2562		Upgrade Eddystone 230 kV substation equipment.		$1.60		
		.1	Replace relays & remove wave trap at Eddystone on the Eddystone-Island Road 230 kV line.				
		.2	Replace CT & relays at Eddystone on the EddystoneChichester 230 kV line.				
		.3	Replace meters and relays at Eddystone on the Eddystone-Printz 230 kV line.				
		.4	Replace relays at Eddystone on the Eddystone No. 8 230/138 kV transformer.				
30	S2566		At North Boyertown – Replace substation conductor, circuit breaker, disconnect switches and line relaying on the North Boyertown-West Boyertown 69 kV line.	11/20/2022	$0.16	METED	5/20/2021
		.1	At West Boyertown – Replace substation conductor, circuit breaker, disconnect switches and line relaying on the North Boyertown-West Boyertown 69 kV line.				

6.10: Tennessee RTEP Summary

6.10.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Tennessee, including facilities owned and operated by American Electric Power (AEP) as shown on **Map 6.45**. Tennessee's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

Map 6.45: PJM Service Area in Tennessee



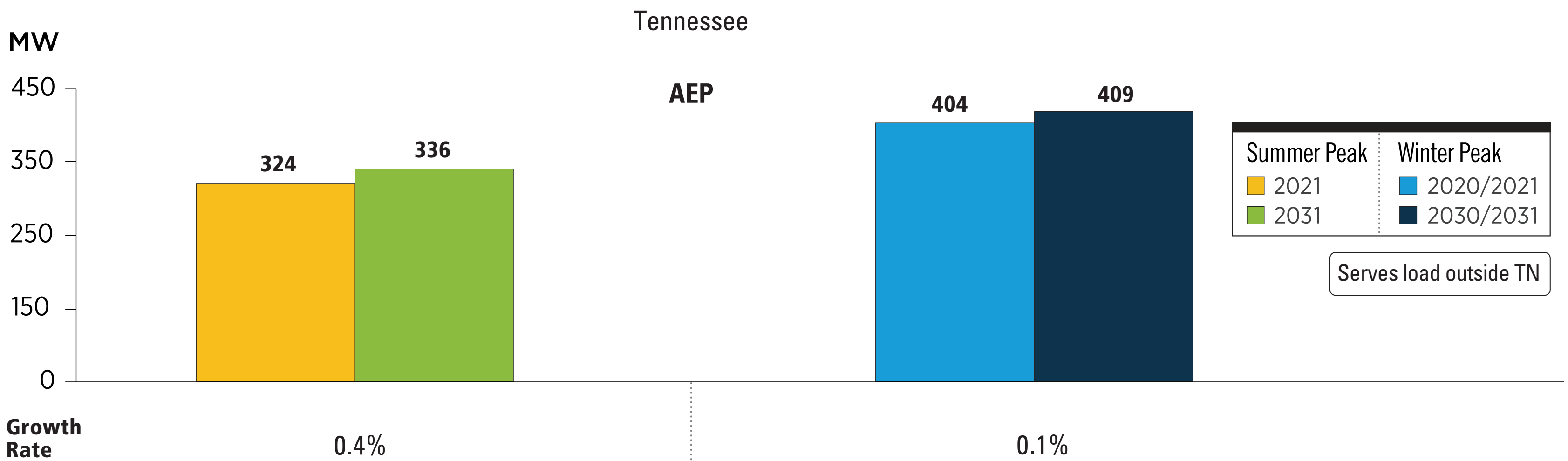
6.10.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.51** summarizes the expected loads within the state of Tennessee and across PJM.

6.10.3 — Existing Generation

There is no existing generation in PJM's portion of Tennessee as of Dec. 31, 2021.

Figure 6.51: Tennessee – 2021 Load Forecast Report



PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.10.4 — Interconnection Requests

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

Specifically, in Tennessee, as of Dec. 31, 2021, two queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.55**, **Table 6.56**, **Figure 6.52**, **Figure 6.53** and **Figure 6.54**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.55: Tennessee – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	Tennessee Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	0	0.00%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	0	0.00%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	0	0.00%	17	0.01%
Other	0	0.00%	331	0.20%
Solar	94	100.00%	93,756	57.99%
Storage	0	0.00%	34,130	21.11%
Wind	0	0.00%	8,800	5.44%
Grand Total	**94**	**100.00%**	**161,682**	**100.00%**

Table 6.56: Tennessee – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue		Complete				Grand Total	
		Active		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0.0	0.0	1	75.0	1	75.0
Renewable	Biomass	0	0.0	2	90.0	0	0.0	2	90.0
	Solar	2	93.8	0	0.0	0	0.0	2	93.8
	Grand Total	**2**	**93.8**	**2**	**90.0**	**1**	**75.0**	**5**	**258.8**

Figure 6.52: Tennessee – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

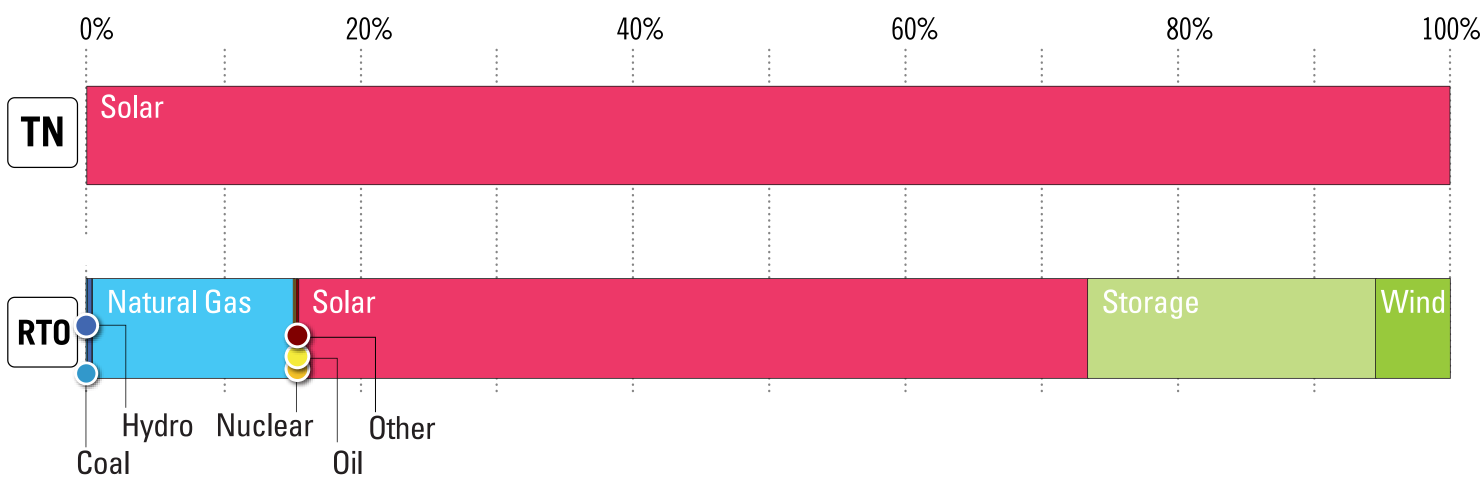
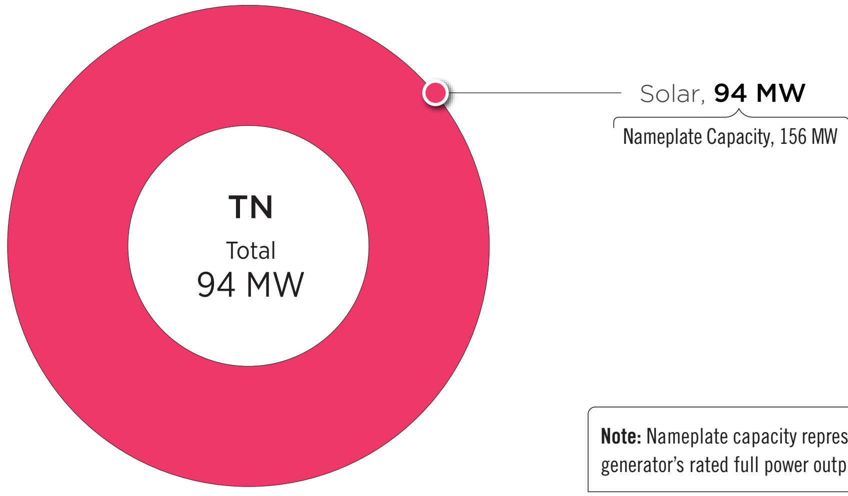


Figure 6.53: Tennessee – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.54: Tennessee Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

54.5%	Requested capacity megawatts
66.7%	Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.10.5 — Generation Deactivation

Known generating unit deactivation requests in Tennessee between Jan. 1, 2021, and Dec. 31, 2021, are summarized in **Map 6.46** and **Table 6.57**.

Map 6.46: Tennessee Generation Deactivations (Dec. 31, 2021)

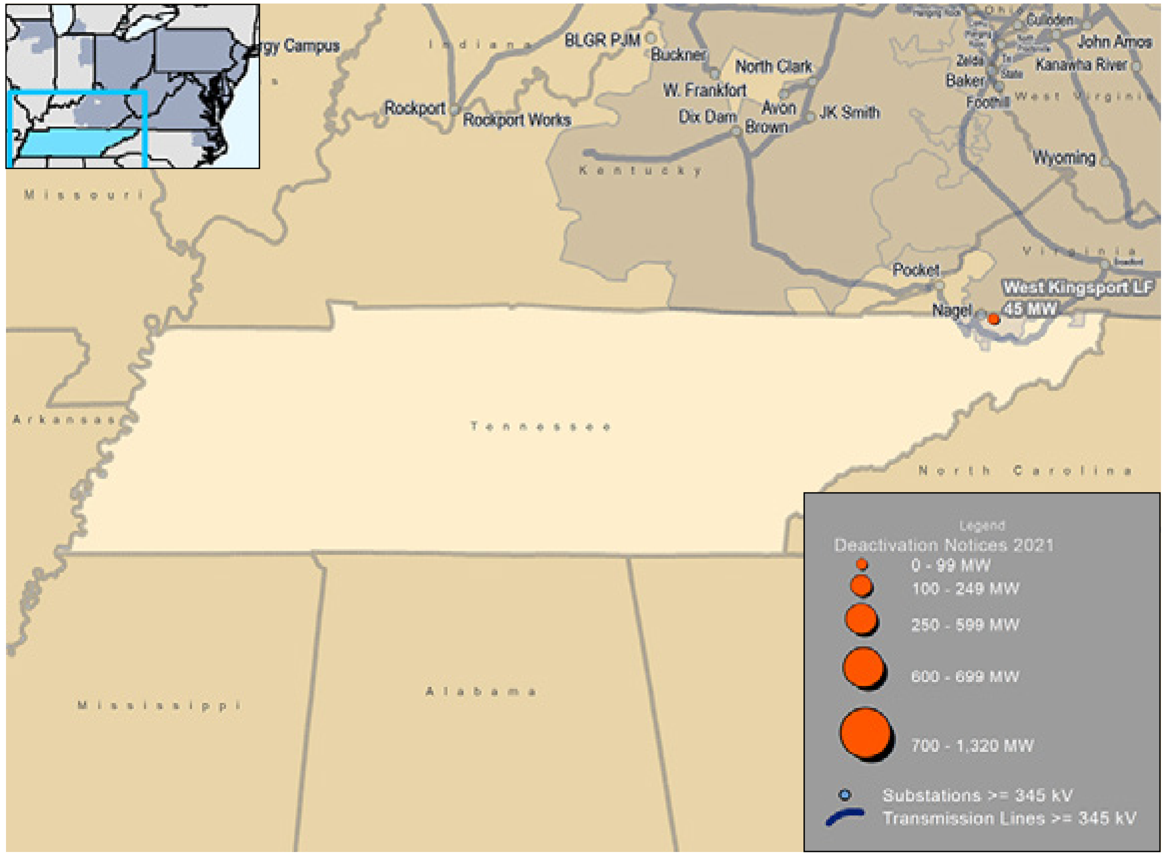


Table 6.57: Tennessee Generation Deactivations (Dec. 31, 2021)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
West Kingsport LF	AEP	Biomass	1/8/2021	5/31/2021	15	45

6.10.6 — Baseline Projects

2021 RTEP baseline projects in Tennessee are summarized in **Map 6.47** and **Table 6.58**.

6.10.7 — Network Projects

No network projects in Tennessee were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.47: Tennessee Baseline Projects (Dec. 31, 2021)

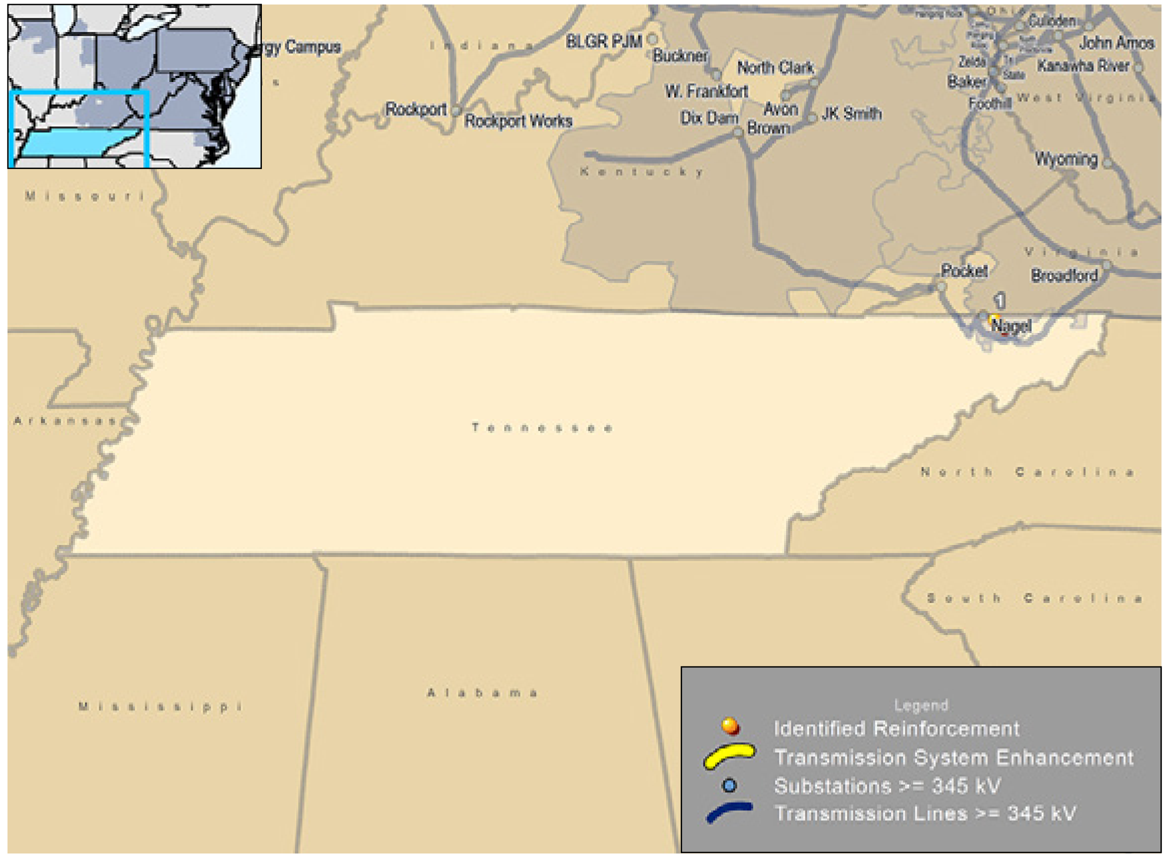


Table 6.58: Tennessee Baseline Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3344	.1	Install two 138 kV circuit breakers in the M and N strings in the breaker-and-a half configuration in West Kingsport station 138 kV yard to allow the Clinch River-Moreland Dr. 138 kV to cut in the West Kingsport station.	11/1/2026	$2.10	AEP	11/2/2021
		.2	Upgrade remote end relaying at Riverport 138 kV station due to the line cut in at West Kingsport station.				

6.10.8 — Supplemental Projects

2021 RTEP supplemental projects in Tennessee are summarized in **Map 6.48** and **Table 6.59**.

6.10.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Tennessee were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.48: Tennessee Supplemental Projects (Dec. 31, 2021)

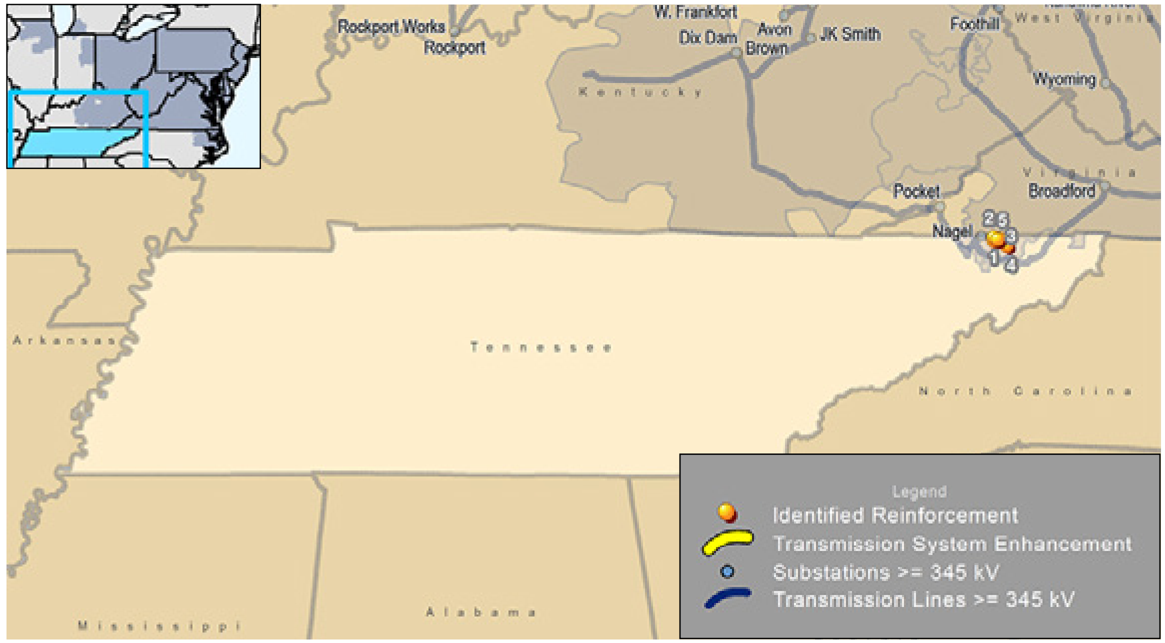


Table 6.59: Tennessee Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2407	.1	Station highside at Lovedale – Replace existing 34.5 kV circuit breakers A, B and G with new 69 kV-rated, 3000A 40 kA circuit breakers.	11/15/2023	$4.20	AEP	10/16/2020
		.2	Required T-line entrance work is necessary to relocate to the new station site (Highland-Lovedale, Fort Rob-Lovedale, Lovedale-Waste Water).				
		.3	Acquire required right of way (Lovedale-Waste Water).				
		.4	Perform remote end work (Highland, Reedy Creek, Fort Robinson).				

Table 6.59: Tennessee Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2408	.1	Rebuild ~12.7 miles of the existing Fort Robinson-Hill 69 kV line between Fort Robinson and Hill stations.	7/1/2023	$46.80	AEP	10/16/2020
		.2	At Fort Robinson station – Replace existing 69 kV circuit breaker E with a new 3000A 40 kA circuit breaker. Replace existing 34.5 kV circuit breaker D with a new 69 kV-rated, 3000A 40 kA circuit breaker. Replace existing ground bank at transformer No. 1 with new ground bank. Replace existing ground MOAB for transformer No. 1 with H.S. circuit switcher. Replace existing line MOABs Y and W with 138 kV circuit breakers. Replace 34.5 kV disconnects on breaker J. Install new low-side 34.5 kV circuit breaker at transformer No. 1.				
		.3	At Hill station – Replace existing 69 kV circuit breaker H with new 40 kA 3000A circuit breaker. Replace existing 69 kV circuit breaker E with new 40 kA 3000A circuit breaker for constructability and flexibility. Existing breaker E can be used as a capital spare. Replace existing 69 kV cap bank circuit switcher AA with new circuit breaker. Replace existing 138/69 kV, 40 MVA transformer No. 1 with new 138/69 kV, 40 MVA transformer No. 1. Add H.S. circuit switcher to the new transformer. Replace existing 138 kV line MOABs W and Y with new 138 kV circuit breakers. Replace ground MOAB switches on 138/12 kV T2 with circuit switcher.				
		.4	Perform remote end relaying work at Clinch River, Wolf Hills, Lovedale, Holston, West Kingsport.				
3	S2435	.1	West Kingsport Station – Install five 138 kV, 40 kA 3000A circuit breakers and reconfigure existing bus No. 2 to a breaker-and-a-half arrangement. Note that the replacement of breaker E was accelerated due to a customer request and constrained outages and is currently in service to feed Industry Drive. Replace existing 34.5 kV circuit breakers A, C and F with three new 69 kV-rated, 3000A 40 kA breakers to be energized at 34.5 kV. Replace existing 34.5 kV bus structures with new box bays built to 69 kV. Remove existing 34.5 kV, 14.4 MVAR cap bank and cap bank switcher.	7/20/2023	$13.40		12/18/2020
		.2	Line work and right of way are required to relocate the North Bristol and Industry Drive 138 kV lines at West Kingsport station into the new configuration. This includes installing three structures (two tower structures and one custom steel pole) to bring North Bristol circuit in and relocate the Industrial Drive circuit to final string of breakers. This also includes re-terminating the Ft. Robinson-West Kingsport 34 kV line, Cumberland-West Kingsport 34.5 kV line, and the Waste Water-West Kingsport 34 kV line into new station bays.				
4	S2437	.1	Eden's Ridge station – Expand the station to install a 138 kV box bay replacing the phase-over-phase switching structure, and replace line switches with motor-operated switches and CCVTs.	4/30/2023	$4.00		
		.2	Line work on the North Bristol-West Kingsport 138 kV circuit will terminate onto the Eden's Ridge station new 138 kV box bay.				
5	S2443		Cumberland Station – Replace existing 34.5 kV circuit breakers A, B and N with three new 69 kV, 3000A 40 kA breakers operated at 34.5 kV. Replace existing capacitor switcher AA with a new 34.5 kV capacitor switcher.	7/20/2023	$2.40		

6.11: Virginia RTEP Summary

6.11.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Virginia, including facilities owned and operated by Allegheny Power (AP), American Electric Power (AEP), Delmarva Power (DP&L) and Dominion as shown on **Map 6.49**. Virginia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

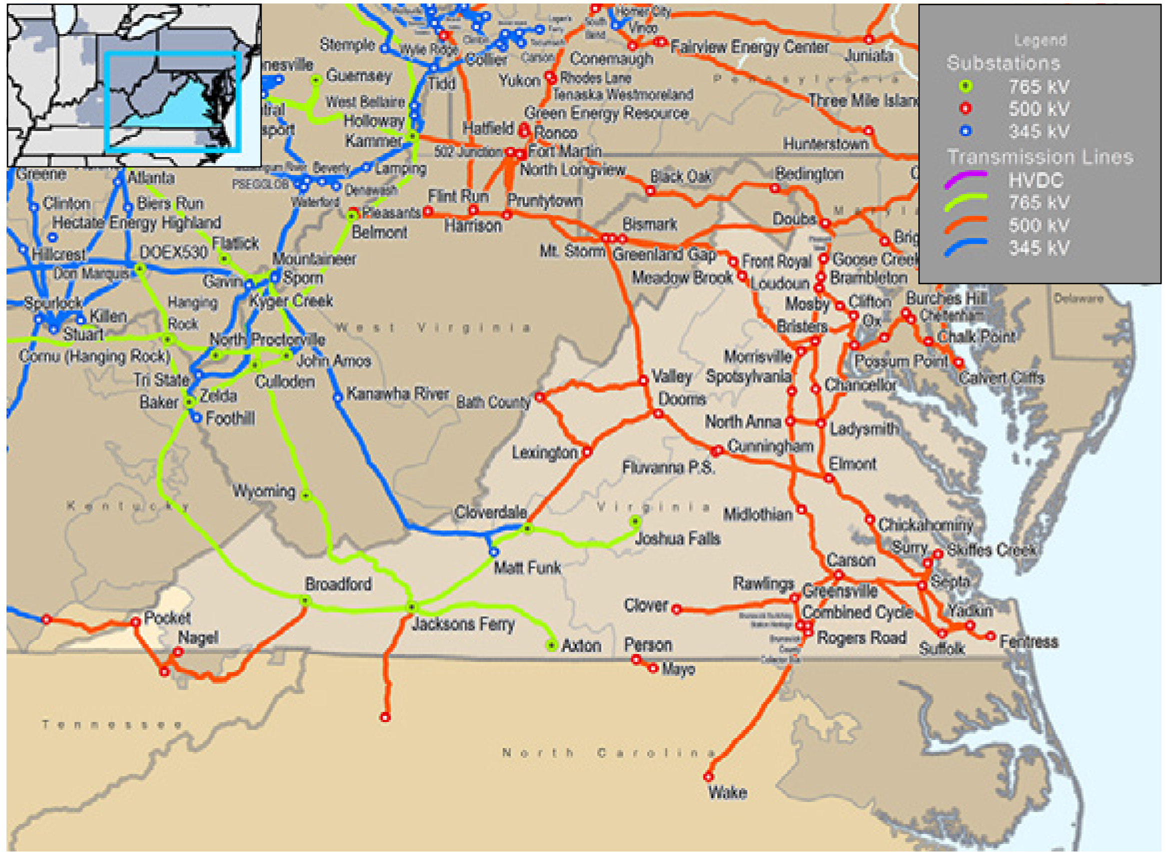
Renewable Portfolio Standards

From an energy policy perspective, Virginia has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years.

Virginia has a mandatory RPS target of 100% by 2045 or 2050, depending on the utility service territory. The state's RPS was a voluntary goal until legislation was passed in 2020. The 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% RPS 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.

Map 6.49: PJM Service Area in Virginia

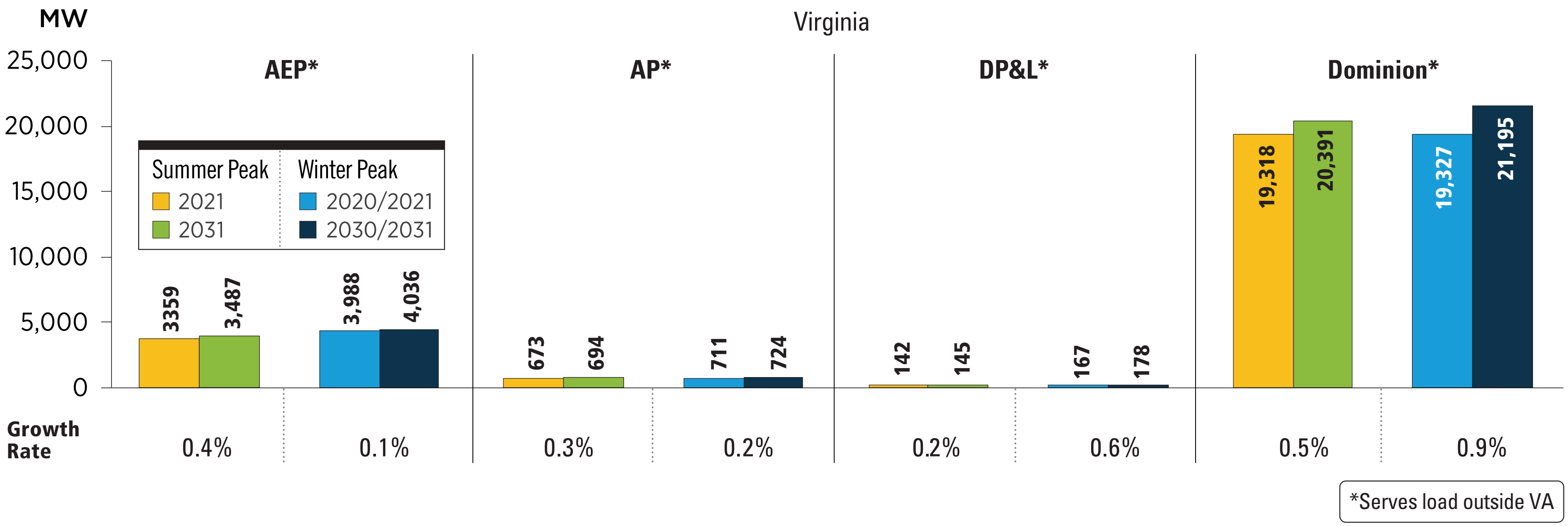


The VCEA also directs Virginia utilities to develop, acquire or enter into agreements with 16,700 MW of solar or onshore wind capacity by 2035. The commonwealth is also looking to develop 3,100 MW of energy storage by 2035 as specified in the VCEA.

6.11.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.55** summarizes the expected loads within the state of Virginia and across PJM.

Figure 6.55: Virginia – 2021 Load Forecast Report



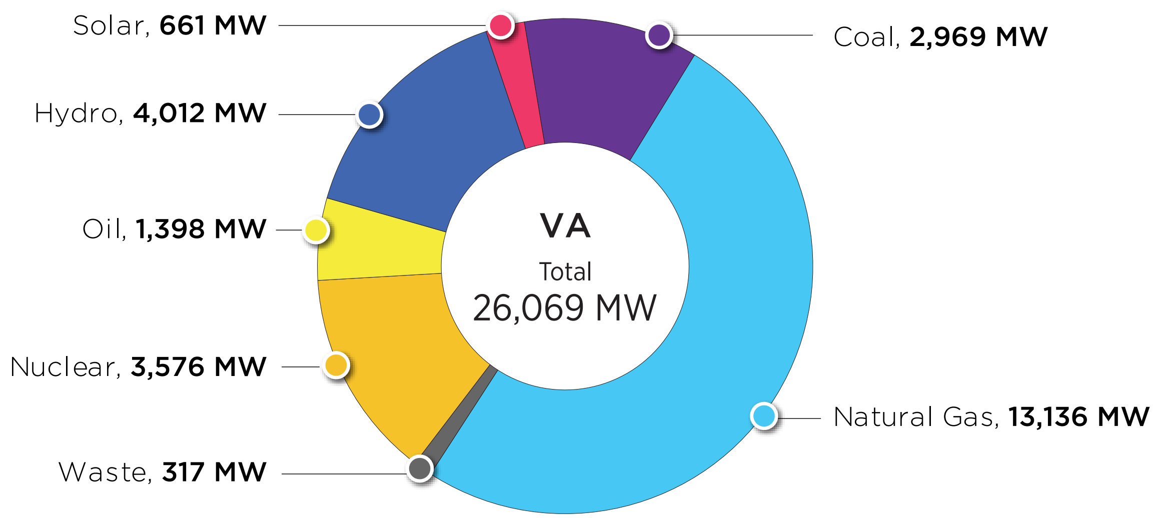
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.11.3 — Existing Generation

Existing generation in Virginia as of Dec. 31, 2021, is shown by fuel type in **Figure 6.56**.

Figure 6.56: Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.11.4 — Interconnection Requests

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

Specifically, in Virginia, as of Dec. 31, 2021, 728 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.60**, **Table 6.61**, **Figure 6.57**, **Figure 6.58** and **Figure 6.59**. 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 6.60: Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	0	0.00%	76	0.05%
Hydro	0	0.00%	596	0.37%
Methane	6	0.01%	6	0.00%
Natural Gas	1,185	2.90%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	0	0.00%	17	0.01%
Other	27	0.07%	331	0.20%
Solar	25,324	61.86%	93,756	57.99%
Storage	13,065	31.91%	34,130	21.11%
Wind	1,331	3.25%	8,800	5.44%
Grand Total	**40,940**	**100.00%**	**161,682**	**100.00%**

Table 6.61: Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	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	8	718.9	2	35.0	10	753.9
	Diesel	0	0.0	0	0.0	0	0.0	2	2.1	2	20.2	4	22.3
	Natural Gas	7	1,185.4	0	0.0	0	0.0	48	7,288.4	46	20,389.8	101	28,863.6
	Nuclear	0	0.0	0	0.0	0	0.0	8	350.0	1	1,570.0	9	1,920.0
	Oil	0	0.0	0	0.0	0	0.0	6	322.2	2	40.0	8	362.2
	Other	4	27.1	0	0.0	0	0.0	1	0.0	2	136.3	7	163.4
	Storage	208	13,005.4	0	0.0	5	60.0	1	0.0	30	1,190.1	244	14,255.6
Renewable	Biomass	0	0.0	0	0.0	0	0.0	5	147.4	4	70.0	9	217.4
	Hydro	0	0.0	0	0.0	0	0.0	9	423.4	2	254.0	11	677.4
	Methane	1	6.0	0	0.0	0	0.0	16	106.8	11	81.8	28	194.6
	Solar	416	22,679.2	8	317.4	77	2,327.7	42	694.6	236	7,675.4	779	33,694.2
	Wind	9	1,321.4	0	0.0	1	9.9	1	1.5	32	895.5	43	2,228.3
	Wood	0	0.0	0	0.0	0	0.0	1	4.0	2	57.0	3	61.0
	Grand Total	**645**	**38,224.5**	**8**	**317.4**	**83**	**2,397.6**	**148**	**10,059.3**	**372**	**32,415.1**	**1,256**	**83,413.9**

Figure 6.57: Virginia – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

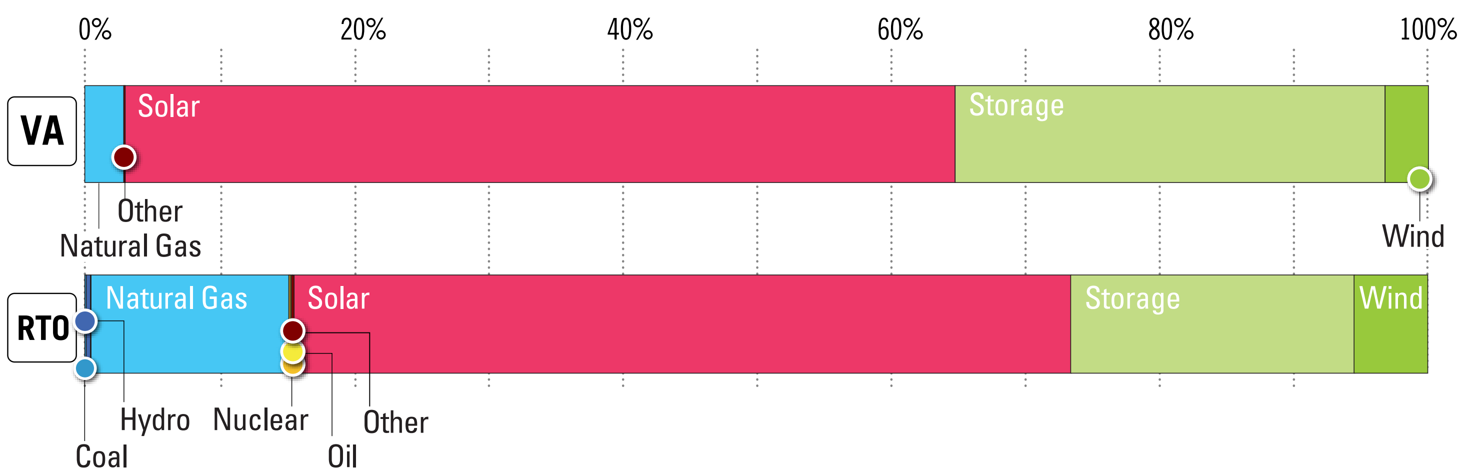
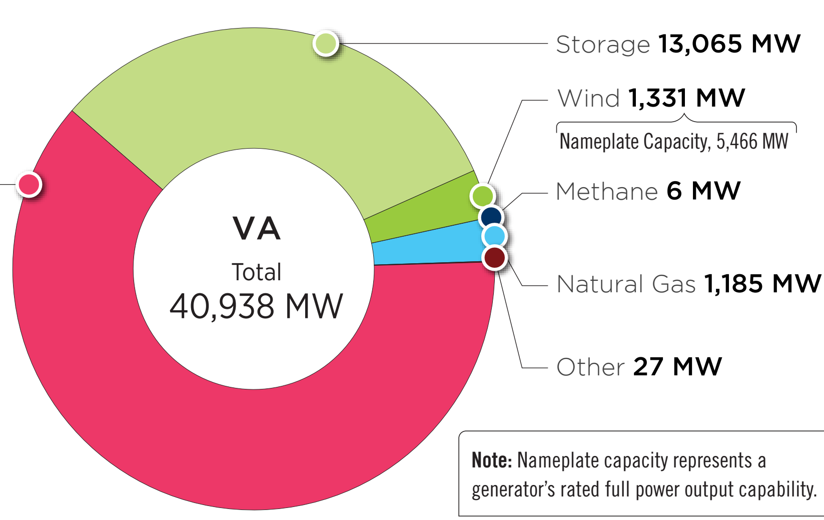


Figure 6.58: Virginia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.59: Virginia Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

24.2%	Requested capacity megawatts
26.0 %	Requested projects

Projects withdrawn after final agreement			Capacity	Nameplate
	19	Interconnection Service Agreements	4,626 MW	5,067 MW
	39	Wholesale Market Participation Agreements	368 MW	612 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.11.5 — Generation Deactivation

Known generating unit deactivation requests in Virginia between Jan. 1, 2021, and Dec. 31, 2021, are summarized in **Map 6.50** and **Table 6.62**.

Map 6.50: Virginia Generation Deactivations (Dec. 31, 2021)

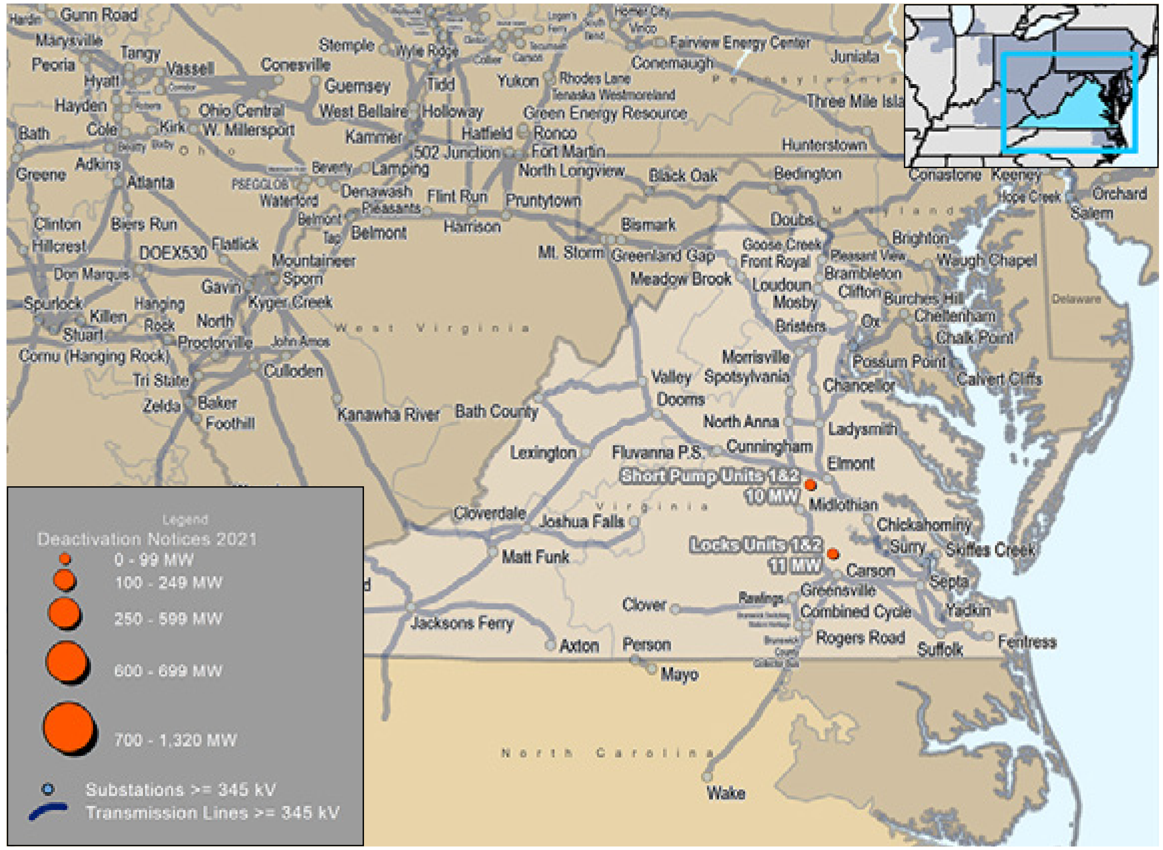


Table 6.62: Virginia Generation Deactivations (Dec. 31, 2021)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Rockville CT (Short Pump 2)	Dominion	Diesel	9/29/2021	6/1/2023	26	4
Lanier 1 CT (Short Pump 1)					21	7
Weakley CT (Locks 2)					21	7
DINWIDDIE 1 CT (Locks 1)					28	3

6.11.6 — Baseline Projects

2021 RTEP baseline projects in Virginia are summarized in **Map 6.51** and **Table 6.63**.

Map 6.51: Virginia Baseline Projects (Dec. 31, 2021)

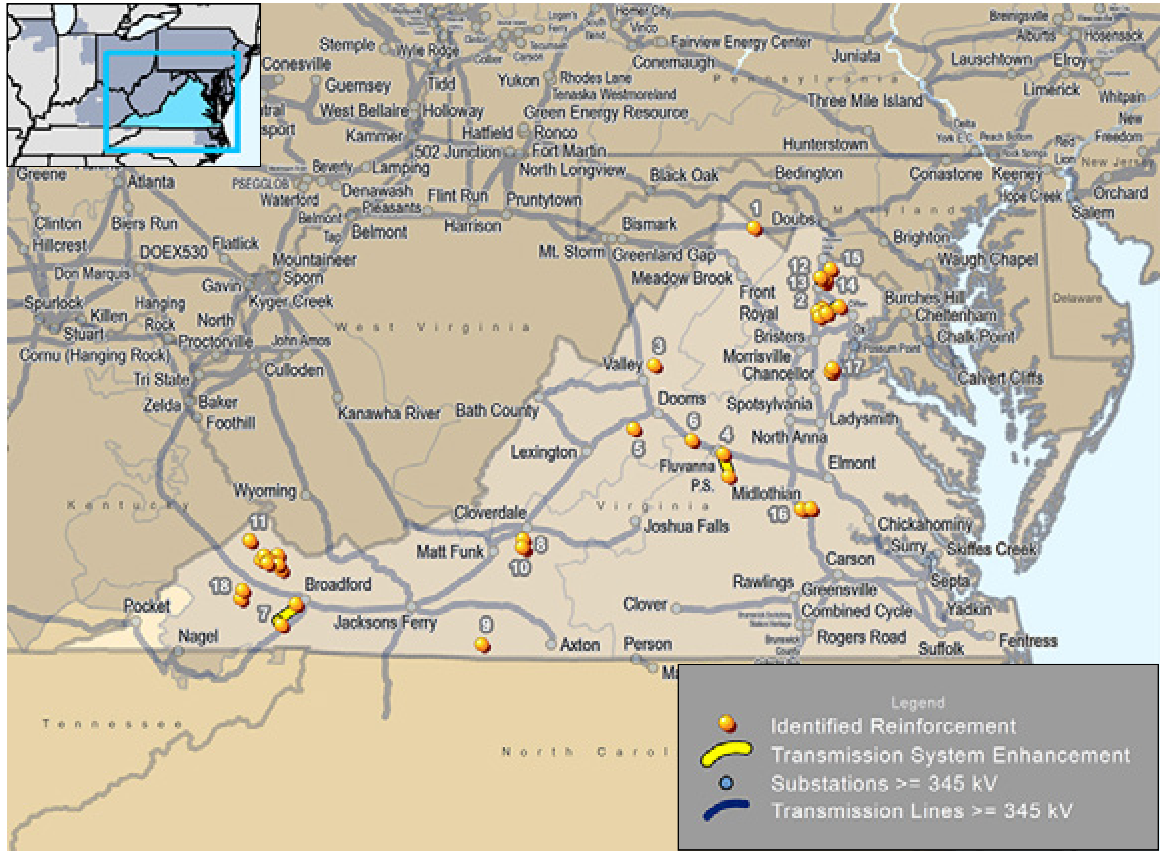


Table 6.63: Virginia Baseline Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3242		Reconfigure Stonewall 138 kV substation from its current configuration to a six-breaker breaker-and-a-half layout and add two 36 MVAR capacitors with capacitor switchers.	6/1/2025	$13.30	AP	11/20/2020
2	B3246	.1	Convert 115 kV line No. 172 Liberty-Lomar and 115 kV line No. 197 Cannon Branch-Lomar to 230 kV to provide a new 230 kV source between Cannon Branch and Liberty. The majority of 115 kV line No. 172 Liberty-Lomar and line No. 197 Cannon Branch-Lomar is adequate for 230 kV operation. Lines to have a summer rating of 1047 MVA/1047 MVA (SN/SE).	6/1/2023	$38.50	Dominion	12/1/2020

Table 6.63: Virginia Baseline Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2 Cont.	B3246	.2	Perform substation work for the 115 kV to 230 kV line conversion at Liberty, Wellington, Godwin, Pioneer, Sandlot and Cannon Branch.	6/1/2023	$38.50	Dominion	12/1/2020
		.3	Extend 230 kV line No. 2011 Cannon Branch-Clifton to Winters Branch by removing the existing line No. 2011 termination at Cannon Branch and extending the line to Brickyard creating 230 kV line No. 2011 Brickyard-Clifton. Extend a new 230 kV line between Brickyard and Winters Branch with a summer rating of 1572MVA/1572MVA (SN/SE).				
		.4	Perform substation work at Cannon Branch, Brickyard and Winters Branch for the 230 kV line No. 2011 extension.				
		.5	Replace the Gainesville 230 kV, 40 kA breaker “216192” with a 50 kA breaker.				
3	B3262		Install a second 115 kV, 33.67 MVAR cap bank at Harrisonburg substation along with a 115 kV breaker.	12/1/2025	$1.25		11/4/2020
4	B3263		Cut existing 115 kV line No. 5 between Bremo and Cunningham substations and loop in and out of Fork Union substation.		$2.50		
5	B3264		Install 115 kV breaker at Stuarts Draft station and sectionalize 115 kV line No. 117 into two 115 kV lines.	6/1/2025	$5.00		
6	B3268		Build a switching station at the junction of 115 kV line No. 39 and 115 kV line No. 91 with a 115 kV capacitor bank. The switching station will built with 230 kV structures but will operate at 115 kV.	12/1/2025	$12.00		12/1/2020
7	B3278	.1	Saltville Station – Replace H.S. MOAB switches on the high side of the 138/69/34.5 kV T1 with a H.S. circuit switcher.		$4.22	AEP	2/17/2021
		.2	Meadowview station – Replace existing 138/69/34.5 kV transformer T2 with a new 130 MVA 138/69/13 kV transformer.				
		.3	Saltville station – Install two 138 kV breakers and bus diff protection.				7/16/2021
8	B3289	.1	Roanoke Station – Install high-side circuit switcher on 138/69/12 kV T5.	6/1/2025	$2.52		1/15/2021
		.2	Huntington Court station: Install high-side circuit switcher on 138/69/34.5 kV T1.				
9	B3292		Replace existing 69 kV capacitor bank at Stuart station with a 17.2 MVAR capacitor bank.	12/1/2025	$0.00		
10	B3294		Replace existing 69 kV disconnect switches for circuit breaker “C” at Walnut Avenue station.	6/1/2025	$0.00		
11	B3295		Grundy 34.5 kV – Install a 34.5 kV, 9.6 MVAR cap bank.		$0.80		2/17/2021
12	B3300		Reconductor 230 kV line No. 2172 from Brambleton to Evergreen Mills along with upgrading the line leads at Brambleton to achieve a summer emergency rating of 1574 MVA.		$2.32	Dominion	12/1/2020
13	B3301		Reconductor 230 kV line No. 2210 from Brambleton to Evergreen Mills along with upgrading the line leads at Brambleton to achieve a summer emergency rating of 1574 MVA.		$2.26		
14	B3302		Reconductor 230 kV line No. 2213 from Cabin Run to Yardley Ridge along with upgrading the line leads at Yardley to achieve a summer emergency rating of 1574 MVA.		$1.75		
15	B3303	.1	Extend a new single circuit 230 kV line (No. 9250) from Farmwell substation to Nimbus substation.		$5.70		
		.2	Remove Beaumeade 230 kV line No. 2152 line switch.				
16	B3304		Perform Midlothian Area 300 MW load drop relief area improvements.		$6.22		
		.1	Cut 230 kV line No. 2066 at Trabue junction.				
		.2	Reconductor idle 230 kV line No. 242 (radial from Midlothian to Trabue junction) to allow a minimum summer rating of 1047 MVA, and connect to the section of 230 kV line No. 2066 between Trabue junction and Winterpock; renumber 230 kV line No. 242 structures to No. 2066.				

Table 6.63: Virginia Baseline Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
16 Cont.	B3304	.3	Use the section of idle 115 kV line No. 153, between Midlothian and Trabue junction, to connect to the section of (former) 230 kV line No. 2066 between Trabue junction and Trabue to create new Midlothian-Trabue lines with new line numbers No. 2218 and No. 2219.	6/1/2025	$6.22	Dominion	12/1/2020
		.4	Create new line terminations at Midlothian for the new Midlothian-Trabue lines.				
17	B3321		Rebuild Cranes Corner-Stafford 230 kV line.	6/1/2022	$19.60		8/10/2021
18	B3333	.1	Rebuild Skeggs Branch substation in the clear as Coronado substation. Establish New 138 kV and 69 kV buses. Install 138/69 kV, 130 MVA transformer, 138 kV circuit switcher and 69 kV breaker. Retire Existing Skeggs Branch substation.	6/1/2023	$40.17	AEP	
		.2	Install new ~1.2 mile 138 kV extension to new Skeggs Branch substation location.				
		.3	Install 46.1 MVAR cap bank at Whitewood substation along with a 138 kV breaker.				
		.4	Rebuild ~9 mile 69 kV line from new Skeggs branch station to Coal Creek 69 kV line. Six-wire the short double circuit section between Whetstone Branch and Str. 340-28 to convert the line to single circuit. Retire Garden Creek to Whetstone Branch 69 kV line section.				
		.5	Retire Knox Creek substation.				
		.6	Retire Horn Mountain substation. This will be served directly from 69 kV bus at New Skeggs branch substation.				
		.7	At Clell substation – Replace two 600A phase-over-phase switches and poles with single two-way 1200A phase-over-phase switch and pole.				
		.8	At Permac – Replace 600A switch and structure with two-way 1200A phase-over-phase pole switch and pole.				
		.9	At Marvin substation – Replace 600A switch and structure with two-way 1200A phase-over-phase pole switch and pole.				
		.10	At Whetstone Branch substation – Replace 69 kV, 600A two-way phase-over-phase switch with 69 kV, 1200A two-way phase-over-phase switch. Remove 69 kV to Skeggs Branch (switch “22” phase-over-phase).				
		.11	At Garden Creek substation – Remove 69 kV Richlands (via Coal Creek) line (circuit breaker F and disconnect switches) and update relay settings.				
		.12	Perform remote end work at Clinch River substation.				
		.13	Perform remote end work at Clinchfield substation.				

6.11.7 — Network Projects

2021 RTEP network projects in Virginia are summarized in **Map 6.52** and **Table 6.64**.

Map 6.52: Virginia Network Projects (Dec. 31, 2021)

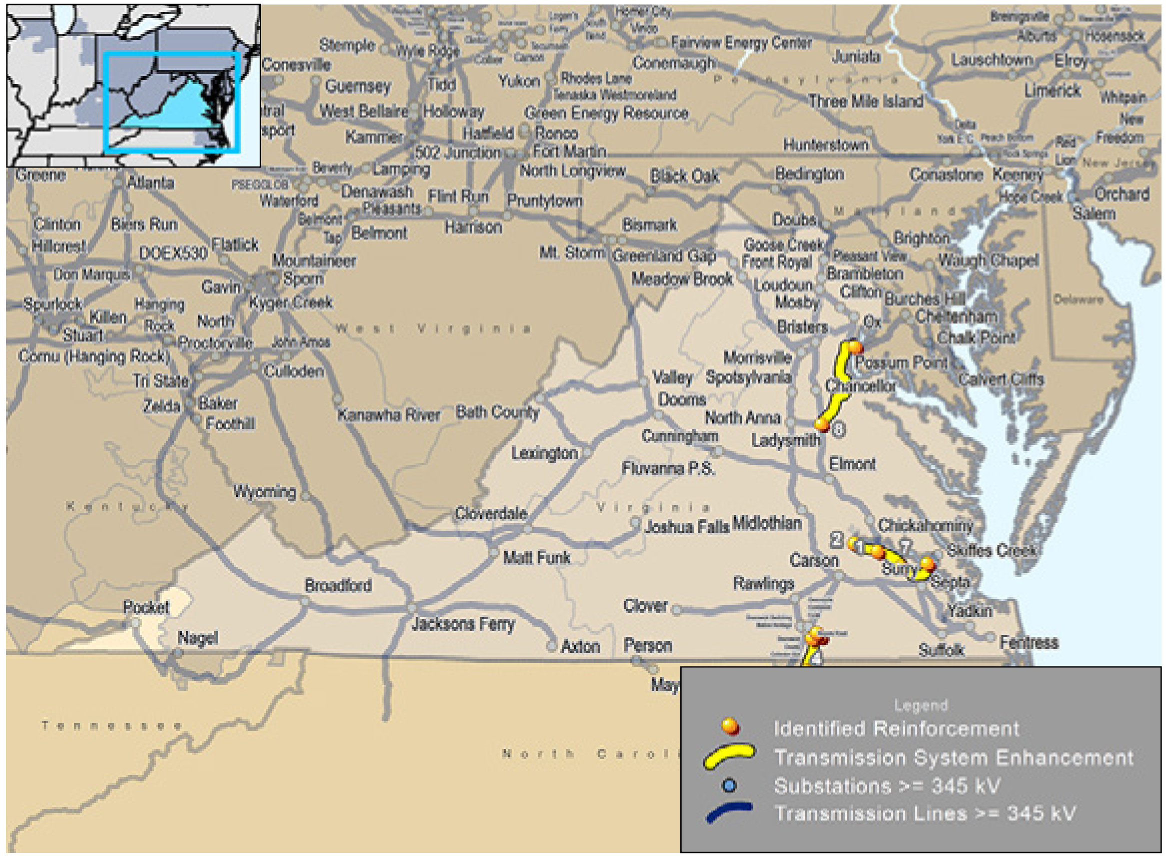


Table 6.64: Virginia Network Projects (Dec. 31, 2021)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	N5202	Build a three-breaker ring bus at Wards Creek substation.	AB2-190	2/1/2019	$5.987	Dominion	11/30/2021
2	N5204	Upgrade relay to accommodate new generation and interconnection substation at Hopewell-Surry line No. 240.			$0.06		
3	N5475	Modify transfer trip equipment at Carolina, Clubhouse and Emporia substations.	AB1-173	3/31/2018	$0.147		

Table 6.64: Virginia Network Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Description	Generation	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
4	**N5803**	Build a new three-breaker ring bus at the new AB2-100 substation.	AB2-100	12/1/2021	$6.028	Dominion	11/30/2021
5	**N5804**	Install new backbone tower on Clubhouse-Lakeview line No. 254.	AB2-100	12/1/2021	$1.291	Dominion	11/30/2021
6	**N5805**	Upgrade protection for Clubhouse-Lakeview line No. 254 to accommodate AB2-100 generator and switching station.	AB2-100	12/1/2021	$0.189	Dominion	11/30/2021
7	**N5826**	Install a forth breaker in ring bus at Colonial Trail.	AC1-216	12/31/2020	$2.5	Dominion	11/30/2021
8	**N6063**	Replace wave trap at both Ladysmith and Possum Point substations for the Ladysmith-Possum Point 500 kV line No. 568. This will increase line rating by 12% to 2913 MVA. Estimated to take 14–16 months to engineer and construct.	AC1-158	10/1/2019	$0.5	Dominion	11/30/2021

6.11.8 — Supplemental Projects

2021 RTEP supplemental projects in Virginia are summarized in **Map 6.53** and **Table 6.65**.

6.11.9 — Merchant Transmission Project Requests

No merchant transmission project requests in Virginia were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.53: Virginia Supplemental Projects (Dec. 31, 2021)

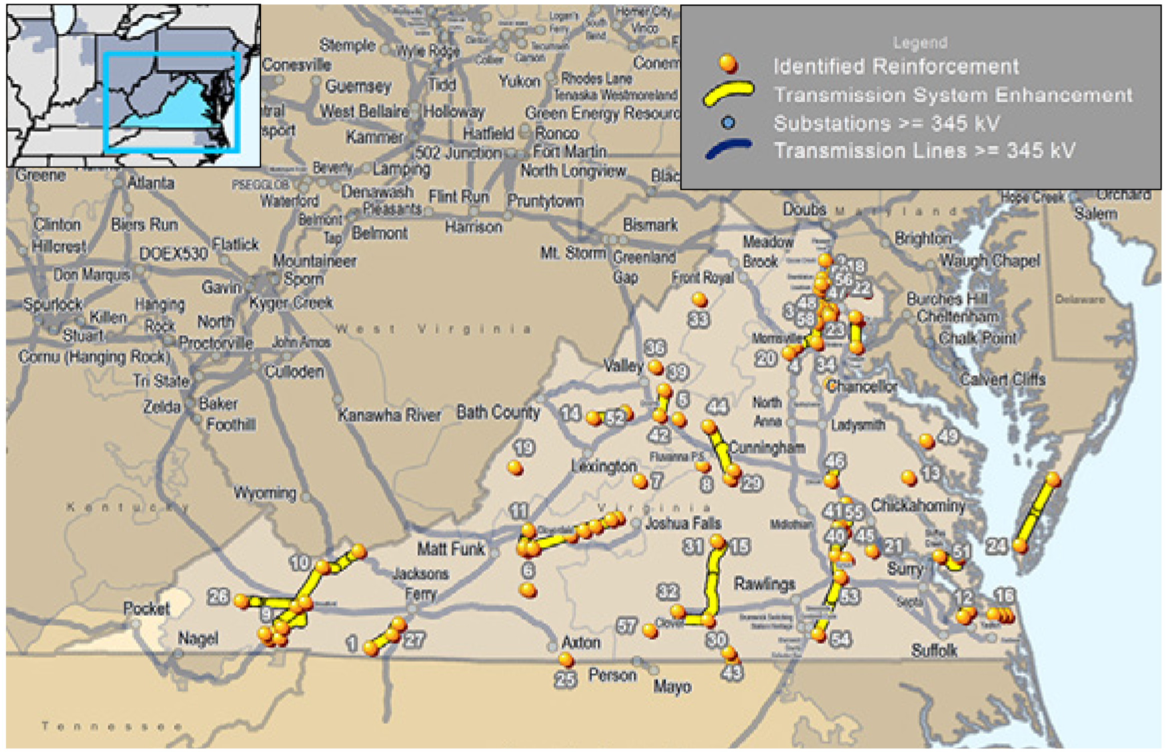


Table 6.65: Virginia Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	s1851	.1	Relocate Independence station to a new property and rebuilt as Point Lookout station. Point Lookout station will consist of a 69 kV bus, a 11.5 MVAR cap bank, two 69 kV circuit breakers. The station will also include a 69/34.5 kV 30 MVA transformer with two 34.5 kV distribution circuit breakers and a 69/12 kV 20 MVA transformer with one 12 kV distribution circuit breaker. The new cap bank at Point Lookout station is replacing the existing cap bank at Fries station due to the space limitations at Fries station associated with remote end work. The cap bank at Fries station cannot be retired due to a voltage violation scenario and the new cap bank will maintain the voltages above our criteria thresholds. Estimated Transmission Cost – $0 (station is considered Distribution).	6/1/2024	$0.00	AEP	5/17/2021

Table 6.65: Virginia Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2324	.2	Build a new substation (Takeoff) by cutting line No. 2008 (Lincoln Park-Loudoun) and line No. 265 (Bull Run-Sully). Terminate all lines in a 230 kV breaker-and-a-half arrangement at Takeoff substation.	12/31/2025	$116.90	Dominion	2/9/2021
		.3	Extend a new 230 kV double circuit line ~3 miles from Aviator to Takeoff.				
		.4	Reconductor 230 kV line segment between Loudoun and Takeoff using a standard high-capacity conductor (~2.21 miles).				
		.5	Reconductor 230 kV line segment between Lincoln Park and Takeoff using a standard high-capacity conductor (~2.63 miles).				
		.6	Reconductor 230 kV line segment between Sully and Takeoff using a standard high-capacity conductor (~1.16 miles).				
		.7	Replace one 230 kV breaker at Brambleton (SC102).				
		.8	Replace three 69 kV breakers at Davis substation (178T186, 18622, T342).				
3	S2328	.9	Cut 230 kV line 2015 (Dulles-Reston) and extend a new double circuit 230 kV line 3.5 miles to Global Plaza substation creating 230 kV line 2015 (Dulles to Global Plaza) and 230 kV line 9225 (Dulles to Reston).		$73.30		
4	S2340		Interconnect the new Rollins Ford substation by cutting and extending 230 kV line No. 2114 (Gainesville-Remington CT). Terminate both ends into a four-breaker ring arrangement to create a Rollins Ford-Gainesville line and a Rollins Ford-Remington CT line.	12/31/2021	$47.00		9/1/2020
		.1	Reconductor 230 kV line No. 2114 from Remington CT to Rollins Ford (~23.17 miles).	12/31/2025			6/8/2021
		.2	Reconductor 230 kV line No. 2222 from Rollins Ford to Gainseville (~1.11 miles).				
5	S2341		Replace switches 23339 and 23336 of line No. 233 at Crozet substation. The replacement switches will be 3000amp to align with Dominion's 230 kV system standard. The section of line No. 233 from Dooms to Crozet will have a summer rating of 925 MVA after the switches have been replaced. Replace two backbone structures, modify existing tower structures along with some conductor work.	10/27/2020	$1.50		9/1/2020
6	S2429		Replacement of all the structures that make up the Grassy Hill Loop and Tank Hill tap 138 kV line asset from the Grassy Hill switch to the Tank Hill tap, consisting of ~0.95 miles of single circuit 138 kV wood poles.	10/31/2021	$1.97	AEP	11/20/2020
7	S2438		Clifford station – Replace the existing 138/69-46 kV, 50 MVA transformer No. 1 and 138/46 kV, 20 MVA transformer No. 3 with two 138/46 kV, 30 MVA transformers.	10/31/2022	$5.90		12/18/2020
8	S2439		At Scottsville station, replace the existing 138/46 kV, 20 MVA transformer No. 1 & No. 2 (connected in parallel) and 138/46 kV, 20 MVA transformer No. 5 with two 138/46 kV, 30 MVA transformers; replace 46/12 kV, 5 MVA transformer No. 3 with 46/12 kV, 20 MVA transformer; replace 46 kV circuit breaker E; add 12 kV circuit breaker & feeder.		$7.00		
9	S2444	.1	At Meadowview station, replace 69 kV circuit breakers F&G with new 69 kV, 3000A 40 kA breakers.	7/1/2024	$98.66		
		.2	At South Abingdon, install a new 90 MVA 138/ 69 kV transformer bank.				
		.3	Construct a new 69 kV line from South Abingdon to Arright of wayhead (~6.6 miles) (SN:129 MVA, SE – 180 MVA, WN – 162 MVA, WE – 202 MVA).				
		.4	At Arright of wayhead station, install three 69 kV, 3000A 40 kA breakers toward Damascus, Hillman Highway, and South Abingdon.				
		.5	Retire the 69 kV section of line from Abingdon to Hillman Highway (~5 miles).				
		.6	Rebuild ~23 miles of the Hillman Highway-Saltville 69 kV line (SN:129 MVA, SE – 180 MVA, WN – 162 MVA, WE – 202 MVA).				
		.7	Retire ~23 miles of the Hillman Highway-Saltville 69 kV line.				

Table 6.65: Virginia Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
9 Cont.	S2444	.8	Perform Hillman Highway remote end work.	7/1/2024	$98.66	AEP	12/18/2020
		.9	At Abingdon station, retire 138/69-12 kV transformer bank No. 1 and associated equipment.				
10	S2445	.1	Hockman station – Construct a greenfield station consisting of one 138 kV line breaker and one MOAB switch in an in-and-out configuration.	11/1/2022	$4.90		1/15/2021
		.2	Perform line work to loop the existing Bluefield-Tazewell 138 kV line in and out of the proposed Hockman 138 kV station.				
		.3	Perform remote end work (including fiber install) at Tazewell and Bluefield Avenue stations.				
11	S2469	.1	Rebuild ~43 miles of double circuit 138 kV line between Reusens and Roanoke substations.	10/31/2028	$177.60		3/19/2021
		.2	Acquire additional Reusens-Roanoke 138 kV right of way as needed for the rebuild.				
		.3	Reconductor ~0.1 mile span into Ivy Hill station.				
		.4	Tie into the existing Roanoke-Cloverdale 138 kV line via a new ~0.3 mile extension.				
		.5	Install new wire as underbuild on the Reusens-Roanoke 138 kV line, and reroute the existing Campbell Avenue-Roanoke 34.5 kV line due to Roanoke substation reconfiguration.				
		.6	Reroute the existing Roanoke-Walnut 69 kV line due to Roanoke substation reconfiguration. Three replacement structures are expected to shift the alignment and follow the western part of the substation fence to terminate into the new box bay at Reusens substation.				
		.7	At Roanoke station, replace 138 kV capacitor bank switcher "BB" with a 3000A 40 kA circuit breaker. Replace 138 kV capacitor bank switcher "CC" with a 3000A 40 kA circuit breaker. Replace 138 kV capacitor bank "CC" with a new 57.6 MVAR capacitor bank. Install high-side circuit switchers on transformers No. 2 (138/34.5 kV) and No. 5 (138/69 kV). Replace transformer No. 5 (138/69/12 kV) with a 130 MVA, 138/69/12 kV transformer. Replace 69 kV circuit breakers "U" and "V" with 2000 A, 40 kA circuit breakers. Replace pilot wire relaying with fiber relaying associated with 69 kV circuit breakers "U" and "V", and 34.5 kV circuit breaker "L".				
		.8	At Centerville station, reconfigure existing 138 kV with two new 138 kV circuit breakers on each line exit toward Cloverdale and Reusens substations rated at 3000A 40 kA to eliminate the three terminal line. Replace MOAB ground switch with circuit switcher on high-side of the transformer No. 1 (138/69/34.5 kV). Replace 69 kV circuit breaker "B," associated disconnect switches and foundations with 3000A 40 kA circuit breaker.				
		.9	At Campbell Avenue station, replace pilot wire relaying with fiber relaying associated with 34.5 kV circuit breaker-B and 69 kV circuit breaker-C.				
		.10	At Walnut Avenue station, replace pilot wire relaying with fiber relaying associated with 69 kV circuit breaker-C.				
		.11	Install fiber extensions and telecom to support SCADA connectivity along the line and at Vinton, Ivy Hill, Coffee and Moseley stations.				
12	S2495		Rebuild ~5.21 miles of 115 kV line No. 87 between Churchland and Hodges Ferry to current 115 kV standards. The summer rating of the line segment will be 262 MVA.	12/31/2023	$8.00	Dominion	10/15/2020
13	S2496		Interconnect the new King and Queen substation by tapping 230 kV line No. 224 to create a tee-tap arrangement with line switches on either side of the tap. Install a 1200 amp, 20 kAIC circuit switcher and any additional transmission related equipment (e.g., 230 kV bus, etc.) deemed necessary to support the interconnection.	6/1/2023	$1.86		11/4/2020
14	S2497		Replace ~17.8 miles of existing single circuit wood H-frame structures on 230 kV line No. 293 and 3.5 miles of double circuit painted/weathering steel structures shared between 230 kV line No. 293 and 115 kV line No. 83 with single and double circuit steel monopoles, as appropriate. New conductor with a normal summer rating of 1047 MVA will be used for the entire line No. 293. The 3.5-mile segment of line No. 83 that is being replaced will use new conductor with a normal summer rating of 261 MVA.	12/15/2025	$44.80		

Table 6.65: Virginia Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
15	S2498		Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the third distribution transformer at Farmwell.	1/1/2023	$0.50	Dominion	11/4/2020
16	S2499		Rebuild 3.37 miles of 230 kV line No. 2007 between Lynnhaven and Thalia to current 230 kV standards. The normal summer rating of the line will be 1047 MVA.	12/31/2025	$7.00	Dominion	11/4/2020
17	S2500		Rebuild ~1.17 miles of 230 kV line No. 2019 between Thalia and Structure 2019/21 to current 230 kV standards. The normal summer rating of the line segment will be 1047 MVA.	12/15/2025	$3.00	Dominion	11/4/2020
18	S2503		Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the fourth distribution transformer at Cumulus.	12/1/2022	$0.50	Dominion	12/1/2020
19	S2504		Rebuild ~14.94 miles of 138 kV line No. 14, between Fudge Hollow to the demarcation point of AEP, to current 138 kV standards and with a minimum rating of 211 MVA.	12/31/2024	$30.00	Dominion	12/16/2020
20	S2505		ODEC has submitted a DP Request (on behalf of REC) to add a new, 56 MVA distribution transformer at Brandy DP in Culpeper County. Install three 35 kV CTs and three 35 kV PTs at lower side of the transformers and associated equipment (the metering cabinet, the meter, the cellular modem, etc.).	12/15/2020	$0.04	Dominion	1/14/2021
21	S2506		Convert existing Garysville DP, in Prince George County, from a distribution sourced delivery to a transmission sourced delivery. Create a tee-tap on 230 kV line No. 240 (Hopewell-Surry) at tower 196 by installing doublecircuit H-frame switch structures on both sides at mid-span and remove tower 196. Replace towers 195 and 197 (suspension towers) with double dead-end steel pole structures to accommodate phase roll. Install terminal structure and H-frame switch structure for the tap span.	12/1/2022	$3.00	Dominion	2/9/2021
22	S2507		Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the third transformer at Shellhorn.	4/15/2022	$6.50	Dominion	2/9/2021
		.1	Reconductor the segments of 230 kV line 2008 between Cub Run and Walney (1.07 miles).	12/31/2025			6/8/2021
		.2	Reconductor the segments of 230 kV line 2008 between Walney to Takeoff (1.94 miles).				
23	S2544		At Gore – Install 138 kV breaker on the Stonewall terminal. Remove existing Stonewall 138 kV line switch. Adjust relaying. At Stonewall – Adjust relaying.	5/1/2021	$0.00	AP	4/16/2021
24	S2552		ODEC area – Install OPGW on the 110 miles of transmission lines with underground fiber in the various areas where the transmission lines are underground such as airport runways or water crossings.	12/31/2028	$0.00	DP&L	5/20/2021
25	S2569	.1	Berry Hill 138 kV station – Establish a new 138 kV, three-breaker ring bus (space for a six-breaker ring). Install 138/34.5 kV, 30 MVA distribution transformer.	4/15/2022	$14.66	AEP	6/15/2021
		.2	Berry Hill 138 kV extension – 0.2 mile relocation of Axton-Danville No. 2 138 kV and installation of a new 138 kV tap structure. Construct ~5.04 miles of double circuit 138 kV line from tap location to new Berry Hill substation.				
26	S2572	.1	Rebuild and reconfigure the Saltville 138 kV station in a three string breaker-and-a-half bus arrangement to allow replacement of 138 kV circuit breakers A, B, C, V, L, and U with new 3000A 40 kA circuit breakers. Replace existing 69 kV circuit breaker J with a new 3000A 40 kA circuit breaker. Replace existing transformer No. 1 with a new 138/69-34.5 kV 50 MVA transformer. Replace existing high side MOAB switches with high side circuit switchers on T2&T5.	7/1/2025	$75.61	AEP	7/16/2021
		.2	Line work and right of way required to relocate the Broadford-Saltville No. 1 138 kV, Broadford-Saltville No. 2 138 kV, Clinch River-Saltville 138 kV lines to terminate into Saltville station's new configuration. This work includes installing two structures (steel tower structures) and total of ~0.24 new wire and old wire replacement.				
		.3	Rebuild ~21 miles of the 138 kV line between Saltville and Tazewell stations (SN/SE/WN/WE – 296/413/375/464 MVA).				
		.4	Perform remote end work Costs Tazewell, Meadowview, Broadford and Clinch River stations.				

Table 6.65: Virginia Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
27	S2574		Once the Jubal Early to Point Lookout line is built, rebuild the existing ~11.4 mile 69 kV Fries-Point Lookout line on the current center line.	5/1/2025	$33.00	AEP	7/16/2021
28	S2598		Interconnect the new Altair substation by cutting and extending 230 kV line No. 201 (Belmont-Brambleton) to the proposed Altair substation. Lines to terminate in a 230 kV four breaker ring arrangement with an ultimate arrangement of a six-breaker ring.	9/1/2024	$15.00	Dominion	3/9/2021
29	S2599		Replace the existing twelve 69 kV breakers with new 69 kV, 3000 amp, 50 kA units. Include other ancillary equipment (arresters, switches, relays, etc.) as needed.	6/30/2022	$5.50		7/12/2021
30	S2600		Add a second 22.4 MVA distribution transformer at Chase City substation. Install a 1200 amp, 25 kAIC circuit switcher and associated equipment (switches, relaying, etc) to feed the new transformer.	2/17/2022	$0.50		3/18/2021
31	S2601		Split 230 kV line No. 235 Clover-Farmville near Chase City substation and extend two single circuit 230 kV lines for ~15 miles to the proposed Cloud substation. Terminate the two 230 kV lines into four-breaker ring bus to create a Cloud-Clover line and a Cloud-Farmville line. Add two 224 MVA 115/230 kV transformers with breakers on both sides. Expand 115 kV bus to four-breaker ring bus. Four additional 230 kV breakers will be paid for by customer (cost not included here).	6/1/2024	$45.00		4/6/2021
32	S2602	.1	Cut and extend 230 kV line No. 2226 Clover-Cloud to the proposed Easters 230 kV substation. Add one 84 MVAR 230 kV cap bank for voltage support. Once conversion from 115 kV to 230 kV substation is complete, remove Easters 115 kV tap and reconnect line No. 137 Kerr Dam-Ridge Road. Eight additional 230 kV breakers will be paid for by customer (cost not included here). (Stage 1 of project interconnects the new 115 kV Easters substation by cutting and extending 115 kV line No. 137 (Kerr Dam-Ridge Road).		$54.00		
		.2	Rebuild ~16 miles between 230 kV Clover Sub and structure No. 235/310 of 230 kV line No. 2226 using a higher capacity conductor and associated substation equipment to achieve an expected rating of 1572 MVA.	6/30/2026			11/30/2021
33	S2603		Replace Edinburg transformer No. 3 with a new three phase, 138/115/13.2 kV, 112 MVA unit. Include other ancillary equipment (arresters, switches, relays, etc.) as needed.	12/31/2022	$3.00		6/15/2021
34	S2604		Replace Fredericksburg transformer No. 7 with a new three phase, 230-115 kV, 224 MVA unit. Replace high side switches, H744M and H644M, with new circuit breakers to provide fault interruption capability. Upgrade high side bus relay panels to current standards. Include any other ancillary equipment (arresters, switches,relays, etc.) as needed.	11/30/2023	$4.00		6/8/2021
35	S2605		Add a second distribution transformer at Hamilton substation. Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (switches, relaying, etc) to feed the new transformer.	12/1/2022	$0.75		5/11/2021
36	S2606		Replace Harrisonburg transformer No. 4 with a new three phase, 230/69/13.2 kV, 168 MVA unit. Include other ancillary equipment (arresters, switches, relays, etc.) as needed.	12/31/2022	$3.20		6/8/2021
37	S2607		Replace Harrisonburg transformer No. 6 with a new three phase, 230/69/13.2 kV, 168 MVA unit. Include other ancillary equipment (arresters, switches, relays, etc.) as needed.	12/31/2023	$3.20		
38	S2608	.1	Interconnect the new substation Hourglass by cutting and extending 230 kV line No. 2196 Pioneer-Sandlot. Terminate both ends into a 230 kV four-breaker ring arrangement with a provision to add two additional 230 kV breakers for an ultimate configuration of a six-breaker arrangement.	6/15/2023	$108.00		5/11/2021
		.2	Reconductor 230 kV line No. 2187 segment Pioneer DP-Liberty using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1572 MVA.	12/15/2026			11/30/2021
		.3	Reconductor 230 kV line No. 2228 segment Pioneer DP-Liberty using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1572 MVA.				
		.4	Reconductor 230 kV line No. 2163 segment Vint Hill-Liberty using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1572 MVA.				

Table 6.65: Virginia Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
38 Cont.	S2608	.5	Reconductor 230 kV line No. 2080 segment Liberty-Railroad DP using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1572 MVA.	12/15/2026	$108.00	Dominion	11/30/2021
		.6	Reconductor 230 kV line No. 2151 segment Railroad DP-Gainesville using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1572 MVA.				
		.7	Install one 840 MVA 500-230 kV transformer at Bristers substation and associated 500 kV and 230 kV equipment. Expand Bristers substation to the north of the existing site to accommodate the 230 kV breaker ring required for the addition of the new transformer. Line terminations for 115 kV line No. 183 Bristers–Ox), 230 kV line No. 2101 Bristers–Vint Hill 230 kV, and 500 kV line No. 539 Ox–Bristers) will be rearranged to accommodate the expansion.				
39	S2609	.1	Interconnect the new substation Interconnection by cutting and extending 230 kV line 2152 Buttermilk-Beaumeade. Terminate both ends into a four-breaker ring arrangement to create an Interconnection-Beaumeade line and an Interconnection-Nimbus-Buttermilk line.	12/15/2024	$176.00		4/6/2021
		.2	Install one 1440 MVA 500-230 kV transformer at Goose Creek substation. Extend the existing 500 kV ring bus at Goose Creek substation to be set up for a future six-breaker ring arrangement. One breaker to be installed initially creating a five-breaker ring bus. Install a new 230 kV ring bus at Goose Creek substation to be set up for a future four-breaker ring arrangement. Three 230 kV breakers to be installed initially. Cut and extend line No. 227 Belmont-Beaumeade into Goose Creek substation.	12/15/2026			11/30/2021
		.3	Reconductor 230 kV line No. 202 Clark–Idylwood, ~4 miles, using a higher capacity conductor and upgrade terminal equipment to achieve an expected rating of 1574 MVA.				
		.4	Install one 1440 MVA 500-230 kV transformer and associated 230 kV breaker ring at Occoquan substation to supply the area with a 500 kV source. Install a 500 kV ring bus and associated 230 kV breaker-and-a-half bus configuration at Occoquan substation. Cut and loop 500 kV line No. 571 Ox–Possum Point as the 500 kV source into the proposed 500 kV ring bus. Existing terminations for 230 kV line No. 2001 Occoquan–Possum Point, line No. 2013 Occoquan–Ox, and line No. 2042 Odgen Martin–Ox will be rearranged to terminate into the rebuilt Occoquan station line No. 215 Hayfield–Possum Point will be rearranged to route over the expanded Occoquan station.				
		.5	Rebuild 230 kV line No. 2013 Occoquan–Ox using a higher capacity conductor, as well as terminal equipment upgrades, to achieve an expecting rating of 1574 MVA.				
		.6	Upgrade two 230 kV breakers 201342 and L142 from 50 kA to 63 kA at Ox substation due to an insufficient breaker duty rating with the expansion in place.				
		.7	Install a new backbone and right of way of breaker-and-a-half equipment to the south of the existing 230 kV Ox yard. Cut and loop 230 kV line No. 237 Braddock-Possum Point into Ox substation				
		.8	Rebuild ~10 miles segment of 230 kV line No. 205 from Locks to Tyler and upgrade the terminal equipment. The minimum summer normal rating of the line segment will be 1572 MVA.				
		.9	Upgrade 230 kV Pleasant View breakers L3T203 and L3T2180 from 50 kA to 63 kA.				
40	S2610		Rebuild all wood H-frame structures on 115 kV line Locks-Chesterfield from Locks to Harright of waygate and reconductor the 5.4 miles with current 115 kV standards construction practices. Upgrade terminal equipment as needed. The normal summer rating of the line will be 393 MVA.	12/31/2022	$6.90		6/15/2021
41	S2611		Rebuild all wood H-frame structures and reconductor the entire 14.0 miles of 115 kV line Chesterfield-Northeast with current 115 kV standards construction practices. Upgrade terminal equipment as needed. The normal summer rating of the line will be 262 MVA.		$18.20		
42	S2613		Wreck and rebuild ~11.5 miles of 230 kV line No. 272 Dooms-Grottoes. Replace weathering CORTEN lattice-type towers with steel monopoles. New conductor to be used will have a normal summer rating of 1047 MVA to meet current 230 kV standards.	12/31/2026	$30.80		4/6/2021

Table 6.65: Virginia Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
43	S2614		Rebuild ~4.7 miles 115 kV line No. 45 between Kerr Dam to Duke Interconnection with current 115 kV standards construction practices. New conductor with a minimum normal summer rating of 262 MVA will be used.	12/31/2022	$11.00	Dominion	8/13/2021
44	S2615		Build a new 230/115 kV switching station connecting to 230 kV network line No. 2028 (Fork Union to Charlottesville), and provide a 115 kV source from the new station to serve Cunningham DP. After Cunningham DP is moved to the new source, the 11-mile segment of 115 kV line No. 5 from Fork Union to Cunningham DP will be retired.	6/30/2023	$16.30		8/13/2021
45	S2616		Wreck and rebuild 115 kV line No. 53 and 115 kV line No. 72, ~3.7 miles from Chesterfield Power station to the Brown Boveri tap (structures 200A to 232) with a minimum summer normal rating of 393 MVA. Uprate the line terminals (wave trap, risers, line/breaker leads, switches, breakers, etc.) at Chesterfield Power station to support/match the increased line rating. The 0.52 mile tap line into Kingsland substation will use the lower rated standard conductor for 115 kV tap lines (175 MVA).	9/30/2022	$9.75		3/18/2021
46	S2617		Rebuild the entire 9.0 miles of 115 kV line No. 73 Elmont-Four Rivers with current 115 kV standards construction practices. Upgrade terminal equipment as needed. The normal summer rating of the line will be 262 MVA.	12/31/2022	$11.70		6/15/2021
47	S2619		Add a fourth distribution transformer at NIVO substation. Expand the substation to include a four-breaker 230 kV ring bus arrangement to comply with the Company's Facility Interconnection Requirements (Section 7.2). Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (relaying, etc. to feed the new transformer).	9/1/2022	$7.00		8/10/2021
48	S2620		Add a second distribution transformer at Nokesville substation. Install a 1200 amp, 50 kAIC circuit switcher and associated equipment (switches, relaying, etc.) to feed the new transformer.	11/1/2022	$0.75		5/11/2021
49	S2621		Replace Northern Neck transformer No. 4 with a three-phase, 230-115 kV, 168 MVA unit from Prince George substation. Include other ancillary equipment (arresters, switches, relays, etc.) as needed.	8/19/2021	$1.70		3/9/2021
50	S2622	.1	Interconnect the new substation Park Center by cutting and extending 230 kV line No. 2043 Reston-Lincoln Park. Terminate both ends into a four-breaker ring arrangement to create a Park Center-Reston line and a Park Center-Lincoln Park line.	8/1/2024	$15.00		5/11/2021
		.2	Reconductor ~3 miles of line No. 2008 from Dulles to Lincoln Park upgrade the terminal equipment. The minimum summer rating of the line segment will be 1572 MVA.	12/15/2026			11/30/2021
51	S2623		Rebuild ~6.2 miles double circuit segment of 230 kV line No. 209 Skiffes Creek-Yorktown and 115 kV line No. 58 Skiffes Creek-Yorktown between Skiffes Creek and C&O Junction to current standards. The normal summer rating of this segment of line No. 209 and line No. 58 will be 1047MVA and 262MVA, respectively. Rebuild ~4.5 miles single circuit segment of 115 kV line No. 58 to current 115 kV standards. The normal summer rating of the line segment will be 262 MVA.	12/31/2025	$19.50		6/8/2021
52	S2624		Wreck and rebuild ~14.6 miles of 115 kV line No. 83 Craigsville-Staunton. Replace lattice steel towers with appropriate structures. New conductor to be used will have a normal summer rating of 262 MVA.	12/31/2023	$23.00		7/12/2021
53	S2625		Replace six existing towers supporting 230 kV line No. 2002 Carson-Poe with new galvanized steel towers of the same structural design on the existing foundations. Preliminary investigations have found that the existing foundation designs have sufficient structural capacity to support the new towers.		$4.25		4/6/2021
54	S2626		Replace five existing double circuit towers supporting 230 kV line No. 238 Carson-Clubhouse and 230 kV line No. 249 Carson-Locks with new galvanized steel towers of the same structural design on the existing foundations. Preliminary investigations have found that the existing foundation designs have sufficient structural capacity to support the new towers.		$3.50		
55	S2627		Upgrade the distribution transformer at Plaza substation. Install a 1200 amp, 20 kAIC circuit switcher and associated equipment (switches, relaying, etc.) to feed the new transformer.	2/28/2022	$0.50		5/11/2021
56	S2628		Interconnect the new substation Racefield by cutting and extending 230 kV line 2094 Brambleton-Loudoun. Terminate both ends into a four-breaker ring arrangement to create a Racefield-Brambleton line and a Racefield-Loudoun line.	7/24/2023	$12.00		6/8/2021
57	S2629		Add a secondnd distribution transformer at Sinai substation. Install a 1200 amp, 25 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer.	11/15/2022	$0.50		8/13/2021

Table 6.65: Virginia Supplemental Projects (Dec. 31, 2021) (Cont.)

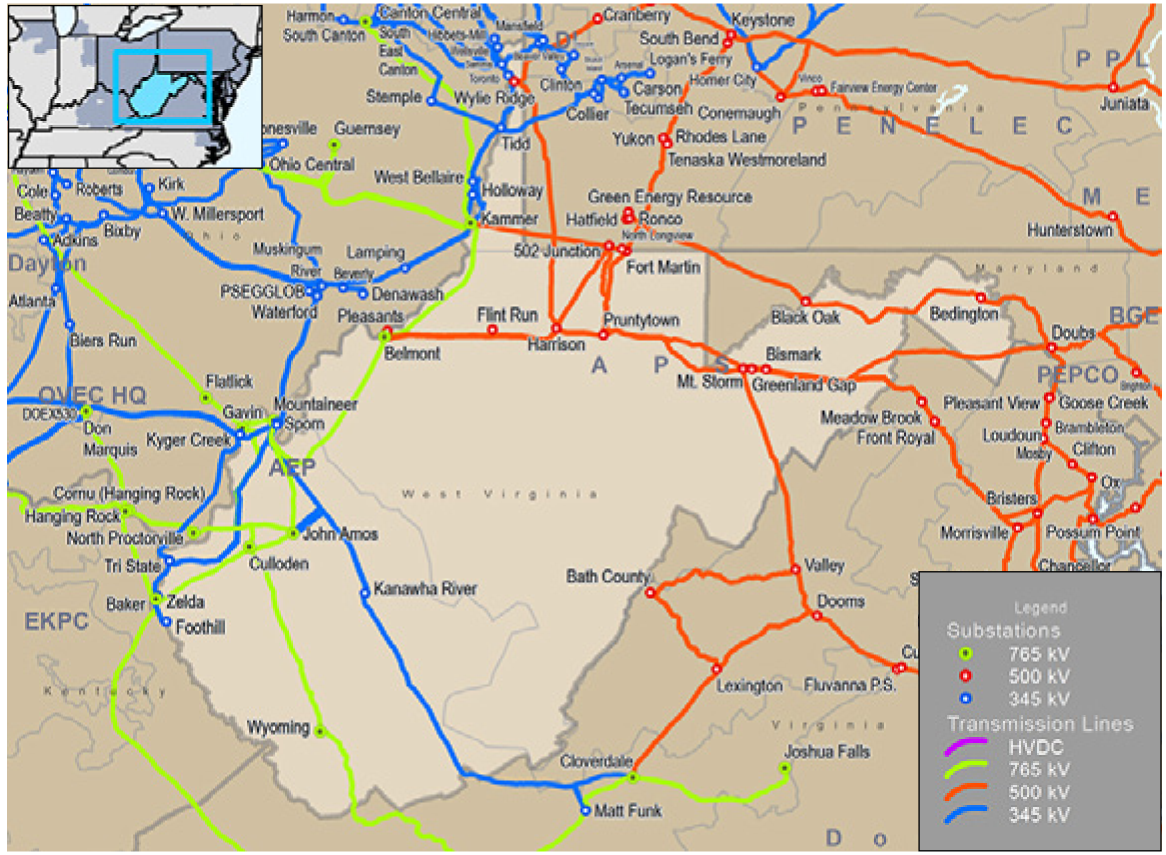
Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
58	S2630	.1	Interconnect the new substation Wakeman by cutting and extending 230 kV line No. 2148 Cannon Branch-Cloverhill. Terminate lines in a four-breaker ring with the station being set up for an ultimate six-breaker ring arrangement.	12/1/2022	$10.60	Dominion	8/10/2021
		.2	Extend a new 230 kV line 0.25 miles between Winters Branch and Wakeman. Add a 230 kV breaker at Winters Branch and Wakeman substations to terminate the new 230 kV line.	6/15/2026			

6.12: West Virginia RTEP Summary

6.12.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in West Virginia, including facilities owned and operated by Allegheny Power (AP) and American Electric Power (AEP) as shown on **Map 6.54**. West Virginia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside of PJM.

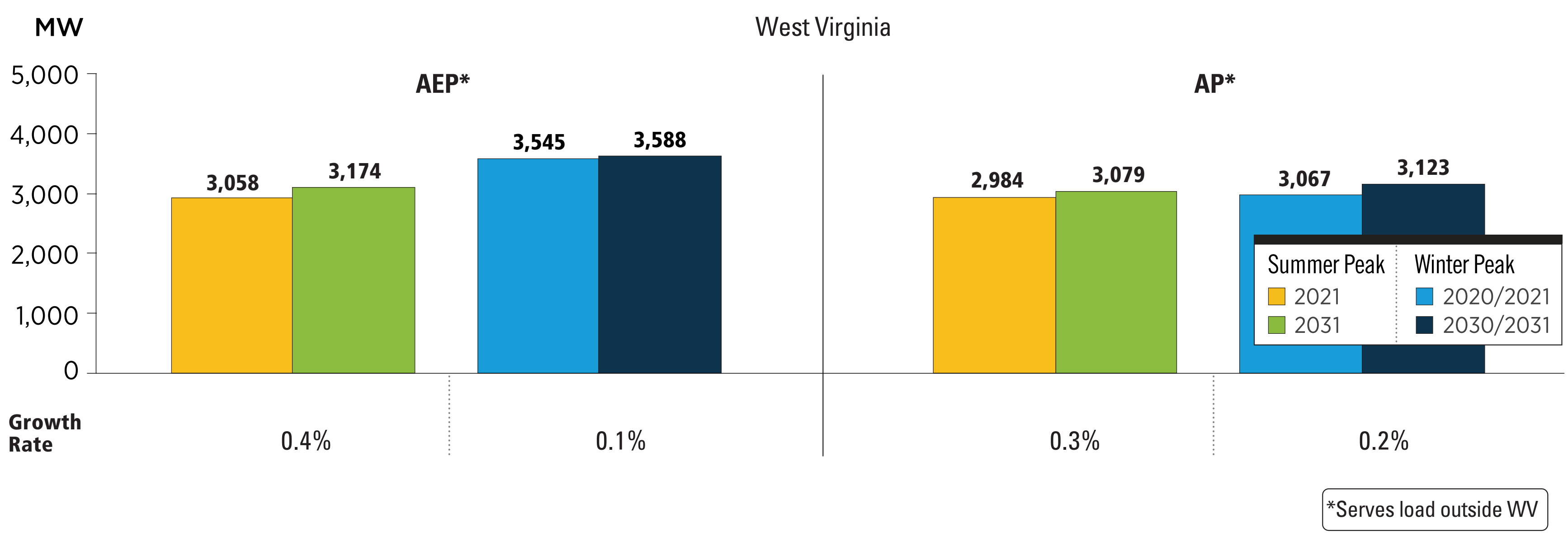
Map 6.54: PJM Service Area in West Virginia



6.12.2 — Load Growth

PJM's 2021 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2021 analyses. **Figure 6.60** summarizes the expected loads within the state of West Virginia and across PJM.

Figure 6.60: West Virginia – 2021 Load Forecast Report



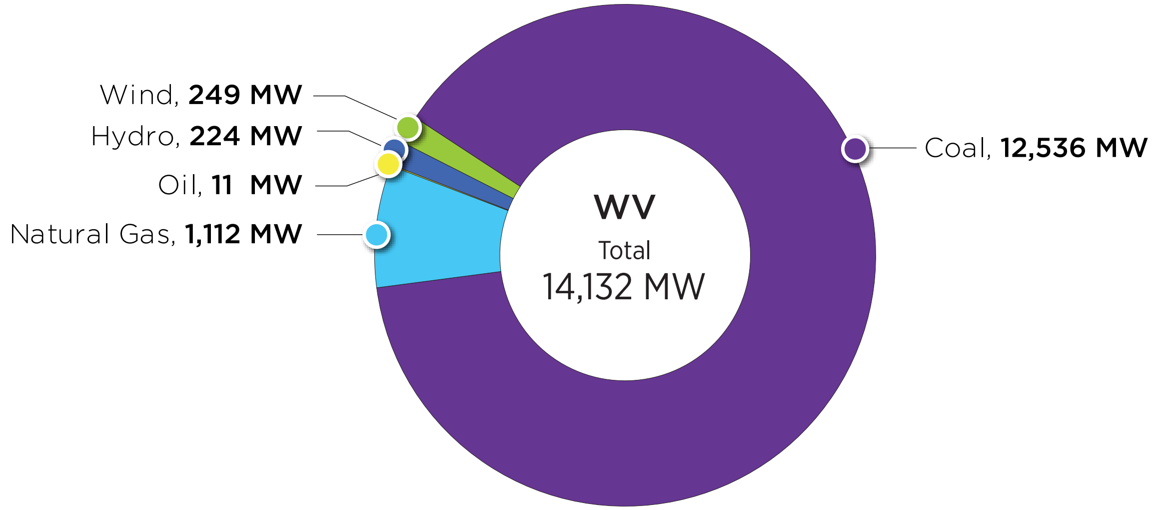
PJM RTO Summer Peak		PJM RTO Winter Peak	
2021	2031	2020/2021	2030/2031
149,224 MW	153,759 MW	132,027 MW	135,568 MW
Growth Rate 0.3%		Growth Rate 0.3%	

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

6.12.3 — Existing Generation

Existing generation in West Virginia as of Dec. 31, 2021, is shown by fuel type in **Figure 6.61**.

Figure 6.61: West Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2021)



6.12.4 — Interconnection Requests

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

Specifically, in West Virginia, as of Dec. 31, 2021, 83 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.66**, **Table 6.67**, **Figure 6.62**, **Figure 6.63** and **Figure 6.64**. 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 6.66: West Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2021)

	West Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Coal	36	0.40%	76	0.05%
Hydro	30	0.33%	596	0.37%
Methane	0	0.00%	6	0.00%
Natural Gas	3,935	43.18%	23,887	14.77%
Nuclear	0	0.00%	81	0.05%
Oil	0	0.00%	17	0.01%
Other	0	0.00%	331	0.20%
Solar	4,049	44.43%	93,756	57.99%
Storage	956	10.49%	34,130	21.11%
Wind	107	1.18%	8,800	5.44%
Grand Total	**9,113**	**100.00%**	**161,682**	**100.00%**

Table 6.67: West Virginia – Interconnection Requests by Fuel Type (Dec. 31, 2021)

		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	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	36.0	10	861.0	7	2,023.0	18	2,920.0
	Natural Gas	3	3,335.0	3	600.0	0	0.0	6	409.7	43	16,140.8	55	20,485.5
	Other	2	0.0	0	0.0	0	0.0	0	0.0	2	66.0	4	66.0
	Storage	13	950.2	1	5.8	1	0.0	1	0.0	4	28.0	20	984.0
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	2	48.0	2	48.0
	Hydro	1	30.0	0	0.0	0	0.0	5	59.2	12	208.8	18	298.0
	Methane	0	0.0	0	0.0	0	0.0	3	5.6	3	13.8	6	19.4
	Solar	55	3,993.5	0	0.0	2	55.2	0	0.0	5	74.2	62	4,122.9
	Wind	3	80.6	0	0.0	2	26.8	10	197.5	27	426.5	42	731.5
	Grand Total	**77**	**8,389.4**	**4**	**605.8**	**6**	**118.0**	**35**	**1,533.0**	**105**	**19,029.2**	**227**	**29,675.4**

Figure 6.62: West Virginia – Percentage of Projects in Queue by Fuel Type (Dec. 31, 2021)

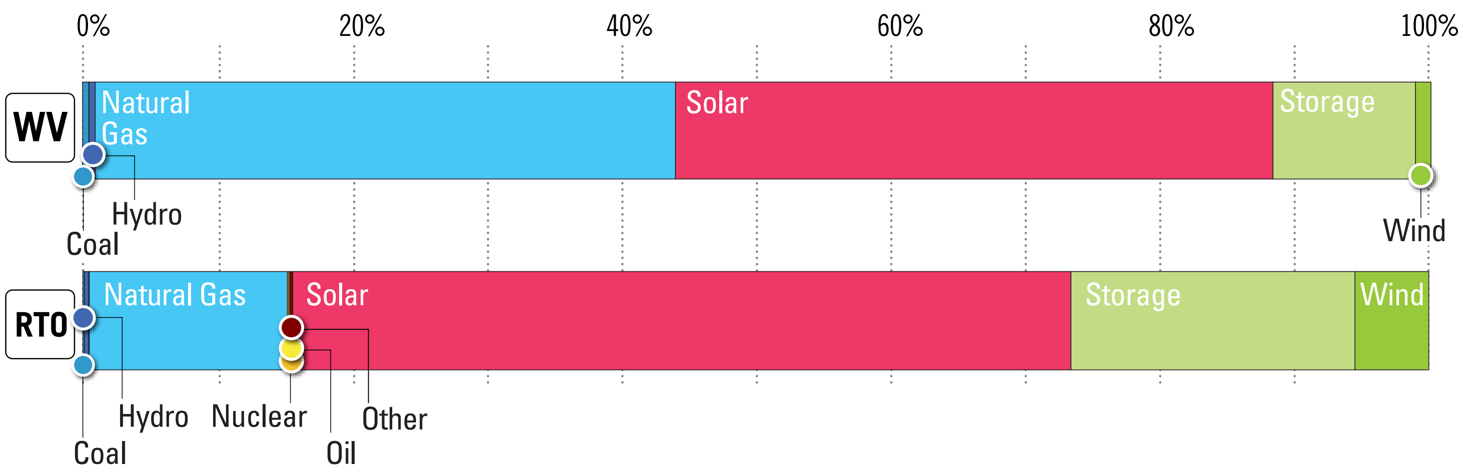
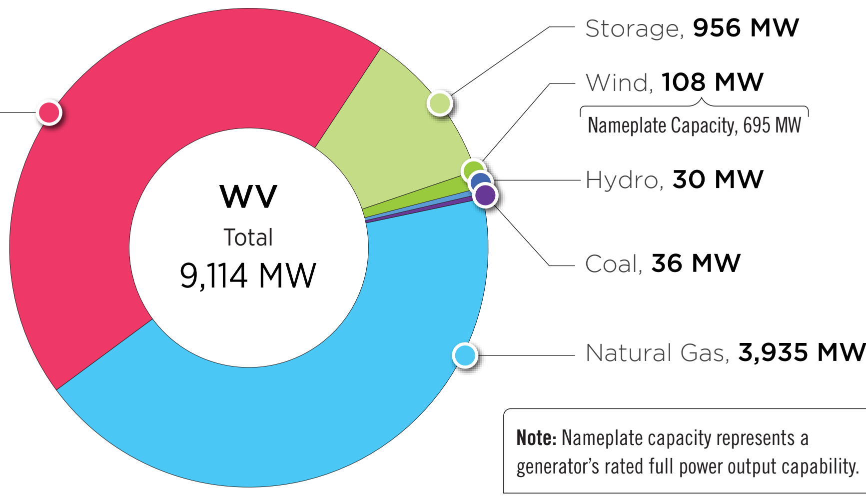


Figure 6.63: West Virginia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2021)



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

Figure 6.64: West Virginia Progression History of Queue – Interconnection Requests (Dec. 31, 2021)

Percentage of planned capacity and projects that have reached commercial operation

7.4%	Requested capacity megawatts
24.7 %	Requested projects

Projects withdrawn after final agreement			Capacity	Nameplate
	12	Interconnection Service Agreements	1,499 MW	1,951 MW
	2	Wholesale Market Participation Agreements	6 MW	11 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

6.12.5 — Generation Deactivation

Known generating unit deactivation requests in West Virginia between Jan. 1, 2021, and Dec. 31, 2021, are summarized in **Map 6.55** and **Table 6.68**.

Map 6.55: West Virginia Generation Deactivations (Dec. 31, 2021)

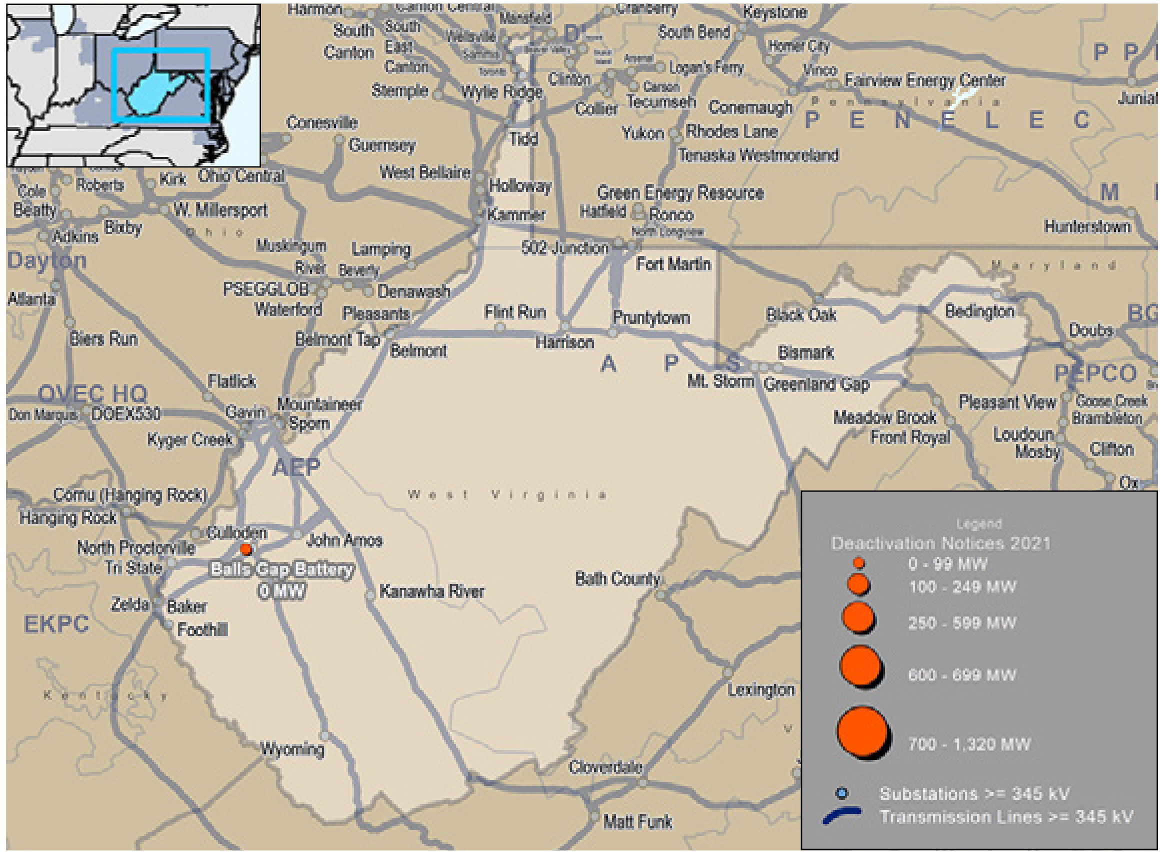


Table 6.68: West Virginia Generation Deactivations (Dec. 31, 2021)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Balls Gap Battery Facility	AEP	Storage	1/21/2021	4/22/2021	12	0

6.12.6 — Baseline Projects

2021 RTEP baseline projects in West Virginia are summarized in **Map 6.56** and **Table 6.69**.

6.12.7 — Network Projects

No network projects in West Virginia were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.56: West Virginia Baseline Projects (Dec. 31, 2021)

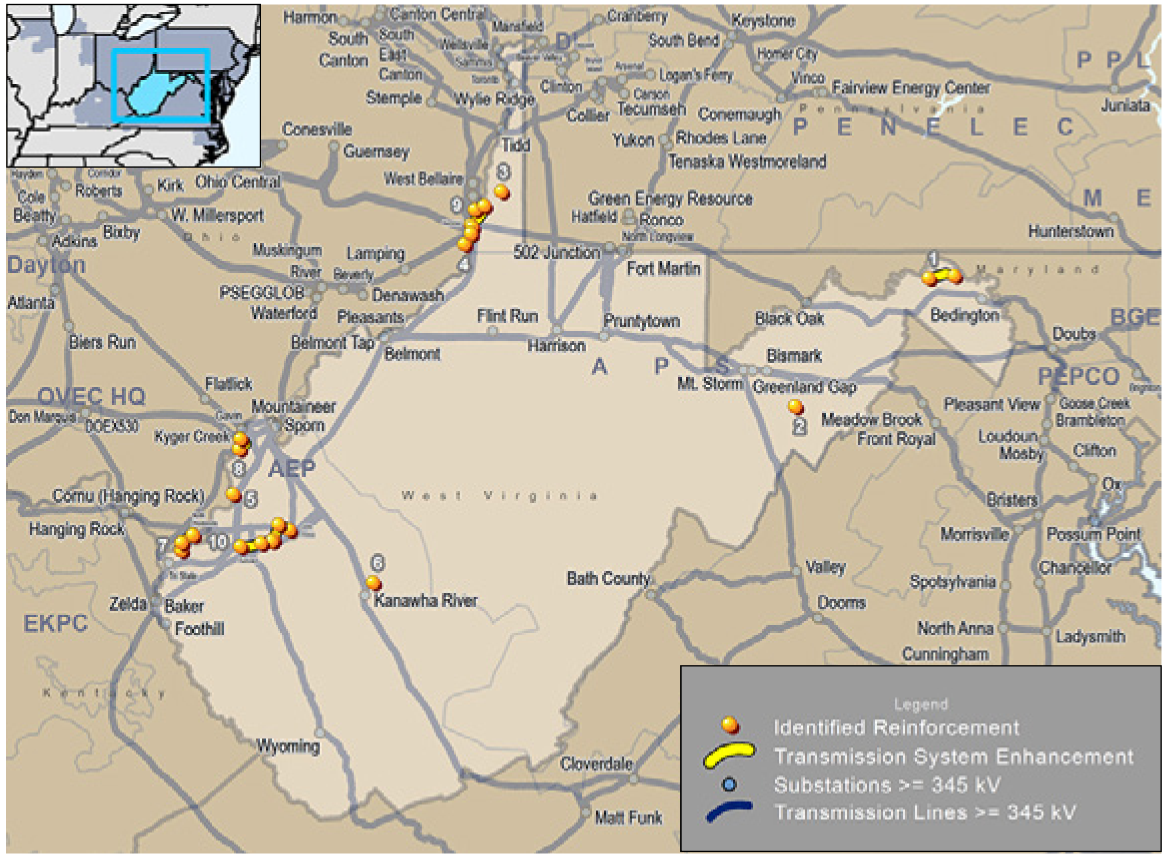


Table 6.69: West Virginia Baseline Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($MW)	TO Zone	TEAC Date
1	B3240		Upgrade Cherry Run and Morgan terminals to make the transmission line the limiting component.	6/1/2024	$0.23	AP	
2	B3241		Install 138 kV, 36 MVAR capacitor and a 5 uF reactor protected by a 138 kV capacitor switcher. Install a breaker on the 138 kV junction terminal. Install a 138 kV, 3.5 uF reactor on the existing Hardy 138 kV capacitor.	6/1/2025	$2.85		11/20/2020
3	B3255		Upgrade 795 AAC risers at Sand Hill 138 kV station toward Cricket Switch with 1272 AAC.		$0.04	AEP	

Table 6.69: West Virginia Baseline Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Required In-Service Date	Project Cost ($MW)	TO Zone	TEAC Date
4	B3275	.1	Rebuild Kammer station-Cresaps switch 69 kV, ~0.5 miles.	6/1/2025	$4.60	AEP	12/1/2020
		.2	Rebuild Cresaps switch-McElroy station 69 kV, ~0.67 miles.				
		.3	Replace a single span of 4/0 ACSR from Moundsville-Natrium str 93L to Carbon Tap switch 69 kV located between Colombia Carbon and Conner Run stations. Remainder of line is 336 ACSR.				
		.4	Rebuild from Colombia Carbon to Columbia Carbon Tap str 93N 69 kV, ~0.72 miles. The remainder of the line between Colombia Carbon Tap structure 93N and Natrium station is 336 ACSR and will remain.				
		.5	Replace the Cresaps 69 kV three-way phase-over-phase switch and structure with a new 1200A three-way switch and steel pole.				
		.6	Replace 477 MCM Alum bus and risers at McElroy 69 kV station.				
		.7	Replace Natrium 138 kV bus existing between circuit breaker-BT1 and along the 138 kV main bus No. 1 dropping to circuit breakerH1 from the 500 MCM conductors to a 1272 KCM AAC conductor. Replace the dead-end clamp and strain insulators.				
5	B3279		Install a new 138 kV, 21.6 MVAR cap bank and circuit switcher at Apple Grove station.		$1.00		2/17/2021
6	B3280		Rebuild the existing Cabin Creek-Kelly Creek 46 kV line (to structure 366-44), ~4.4 miles. This section is double circuit with the existing Cabin Creek-London 46 kV line, so a double circuit rebuild would be required.		$17.90		1/15/2021
7	B3282	.1	Install a second 138 kV circuit utilizing 795 ACSR conductor on the open position of the existing double circuit towers from East Huntington-North Proctorville. Remove the existing 34.5 kV line from East Huntington-North Chesapeake, and rebuild this section to 138 kV served from a new phase-over-phase switch off the new East Huntington-North Proctorville 138 kV No. 2 line.		$10.40		2/17/2021
		.2	Install a 138 kV, 40 kA circuit breaker at North Proctorville.				
		.3	Install a 138 kV, 40 kA circuit breaker at East Huntington.				
		.4	Convert the existing 34/12 kV North Chesapeake to a 138/12 kV station.				
8	B3284		Rebuild ~5.44 miles of 69 kV line from Lock Lane to Point Pleasant.		$13.50		1/15/2021
9	B3287		Upgrade 69 kV risers at Moundsville station toward George Washington.		$0.05		
10	B3347	.1	Rebuild ~20 miles of line between Bancroft and Milton stations with 556 ACSR conductor.	11/1/2026	$56.73		11/2/2021
		.2	Replace the jumpers around Hurrican switch with 556 ACSR.				
		.3	Replace the jumpers around Teays switch with 556 ACSR.				
		.4	Winfield Station relay settings – Update relay settings to coordinate with remote ends on line rebuild.				
		.5	Bancroft Station relay settings – Update relay settings to coordinate with remote ends on line rebuild.				
		.6	Milton Station relay settings – Update relay settings to coordinate with remote ends on line rebuild.				
			Putnam Village station relay settings – Update relay settings to coordinate with remote ends on line rebuild.				

6.12.8 — Supplemental Projects

2021 RTEP supplemental projects in West Virginia are summarized in **Map 6.57** and **Table 6.70**.

6.12.9 — Merchant Transmission Project Requests

No merchant transmission project requests in West Virginia were identified as part of the 2021 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.57: West Virginia Supplemental Projects (Dec. 31, 2021)

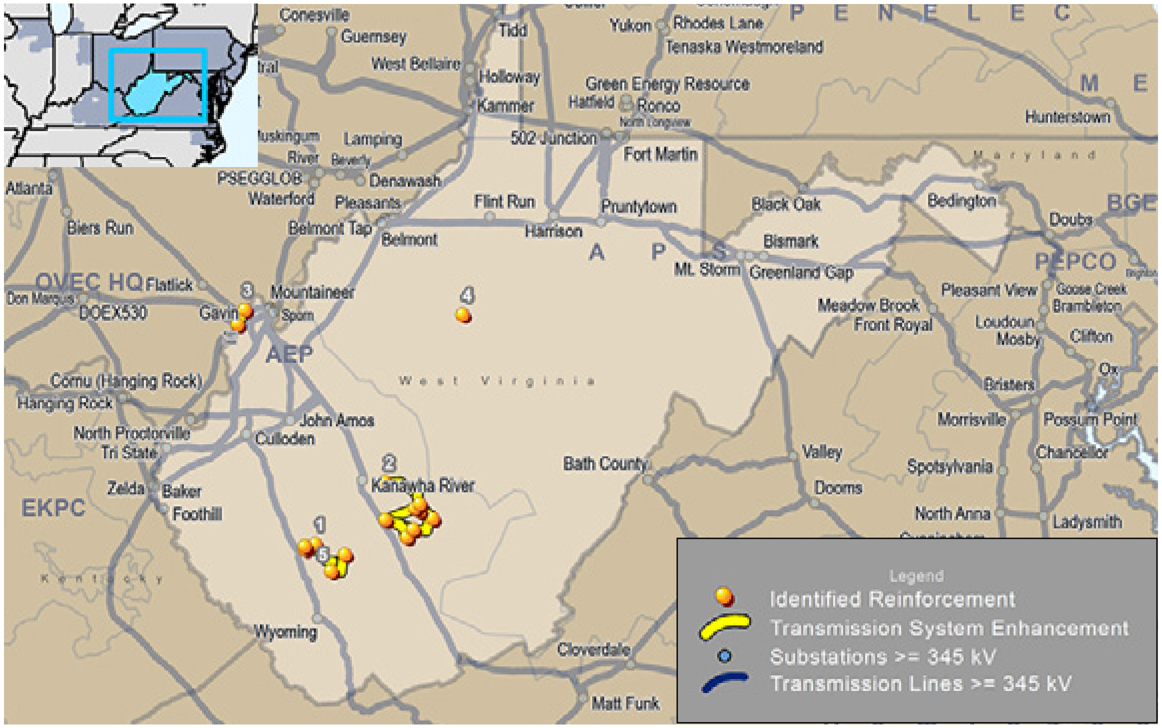


Table 6.70: West Virginia Supplemental Projects (Dec. 31, 2021)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2406		Replace existing 138/69/46 kV, 75 MVA transformer at Bim station with a new 138/69/46 kV, 130 MVA transformer. Replace existing 138 kV ground switch MOAB with a new 138 kV circuit switcher. Replace existing 69 kV circuit breaker D with a new 69 kV, 3000A 40 kA breaker. Replace existing 69 kV shunt cap switcher BB with a new 69 kV, 40 kA cap switcher. Replace existing 46 kV circuit breakers A, B, C and E with four new 46 kV, 3000A 40 kA breakers in a ring configuration. Retire existing 46 kV, 14.4 MVAR cap bank. New DICM will be installed. The new equipment at Bim will result in a ratings increase on the Bim-Bandy branch (Sundial) line section SN/SE/WE/WN: 84 MVA/84 MVA/106 MVA/106 MVA. Remote end work required at Sharples, Skin Fork and Sundial. Line work required on entrance spans due to the new station layout. Currently the 69 kV bus is located on top of the 46 kV bus. In order to perform the work necessary, the two buses will be separated and built in the clear.	6/1/2022	$14.90	AEP	10/16/2020

Table 6.70: West Virginia Supplemental Projects (Dec. 31, 2021) (Cont.)

Map ID	Project	Sub ID	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2430	.1	Construct ~9.6 miles of new 69 kV line from Kincaid station to the new Whitewater distribution station.	9/1/2023	$72.00	AEP	11/20/2020
		.2	Construct ~3.9 miles of new 69 kV line from Whitewater station to Fayetteville 69 kV station. Rebuild the line section between Fayetteville and Elmo substation 69 kV (~1.7 miles).				
		.3	Construct ~1.5 miles of new 69 kV double circuit line from the Carbondale-Tower 117 69 kV circuit to serve the new Victor station in/out.				
		.4	Retire the Kincaid-Scarbro 46 kV/Kincaid-Oak Hill 69 kV double circuit line to a point just outside Scarbro station. Reconfigure and terminate the line towards Oak Hill into Scarbro station.				
		.5	Reconfigure a line section between Tower 117-Carbondale to connect in the new Chestnutburg station.				
		.6	Whitewater station – Establish 69 kV bus and install two new 69 kV, 3000A 40 kA circuit breakers to serve requested distribution delivery point.				
		.7	Victor station – Retire/remove Gauley Mountain 69 kV station. Establish a 69 kV bus and install two new 69 kV, 3000A 40 kA circuit breakers at the new site to be called Victor station to serve requested distribution delivery point.				
		.8	Fayetteville station – Install a new 69 kV three-way phase-over-phase switch outside of the station.				
		.9	Chestnutburg substation – Construct a new three-breaker ring utilizing three new 69 kV, 3000A 40 kA circuit breakers to eliminate a three-terminal line connection.				
		.10	Scarbro station – Establish a 69 kV bus and install a new 69/46 kV, 50 MVA transformer and a new 69 kV, 3000A 40 kA circuit breaker to tie in Tower 117 69 kV line exit.				
		.11	Perform remote end work at Tower 117 station.				
		.12	Perform remote end work at Carbondale station.				
3	S2522	.1	Rebuild the existing 5.36 mile Lakin-Lock Lane 69 kV line.	10/31/2025	$14.00	AEP	5/21/2021
		.2	Point Pleasant station – Replace existing 69 kV circuit breakers G and H with two new 69 kV, 3000A 40 kA circuit breakers. Replace existing cap switcher AA with a new 69 kV cap switcher.				
4	S2543		At Glenville substation – Extend the 138 kV bus. Install 26.4 MVAR, 138 kV capacitor. Install 138 kV capacitor switcher.	6/1/2021	$1.30	AP	4/16/2021
5	S2573	.1	Remove the equipment at Spruce Laurel station.	5/1/2022	$0.45	AEP	7/16/2021
		.2	Remove the equipment at Hampton station.				
		.3	One Transmission line structure at Hampton station will be removed and new guy wires will be added to an existing structure.				

Appendix 1: TO Zones and Locational Deliverability Areas

1.0: TO Zones and Locational Deliverability Areas

The terms transmission owner zone and Locational Deliverability Area, as used in this report, are defined below and shown on **Map 1.1**. They are provided for the convenience of the reader based on definitions from other sources.

A transmission owner (TO) is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a TO. Schedule 15 of the Reliability Assurance Agreement defines the distinct zones that the PJM control area comprises and is available on the PJM website.

A Locational Deliverability Area (LDA) is an electrically cohesive area defined by transmission zones, parts of zones or combination of zones. LDAs are used as part of PJM's RTEP process load deliverability test. They are restated in **Table 1.1** below for ease of reference.

Map 1.1: Locational Deliverability Areas

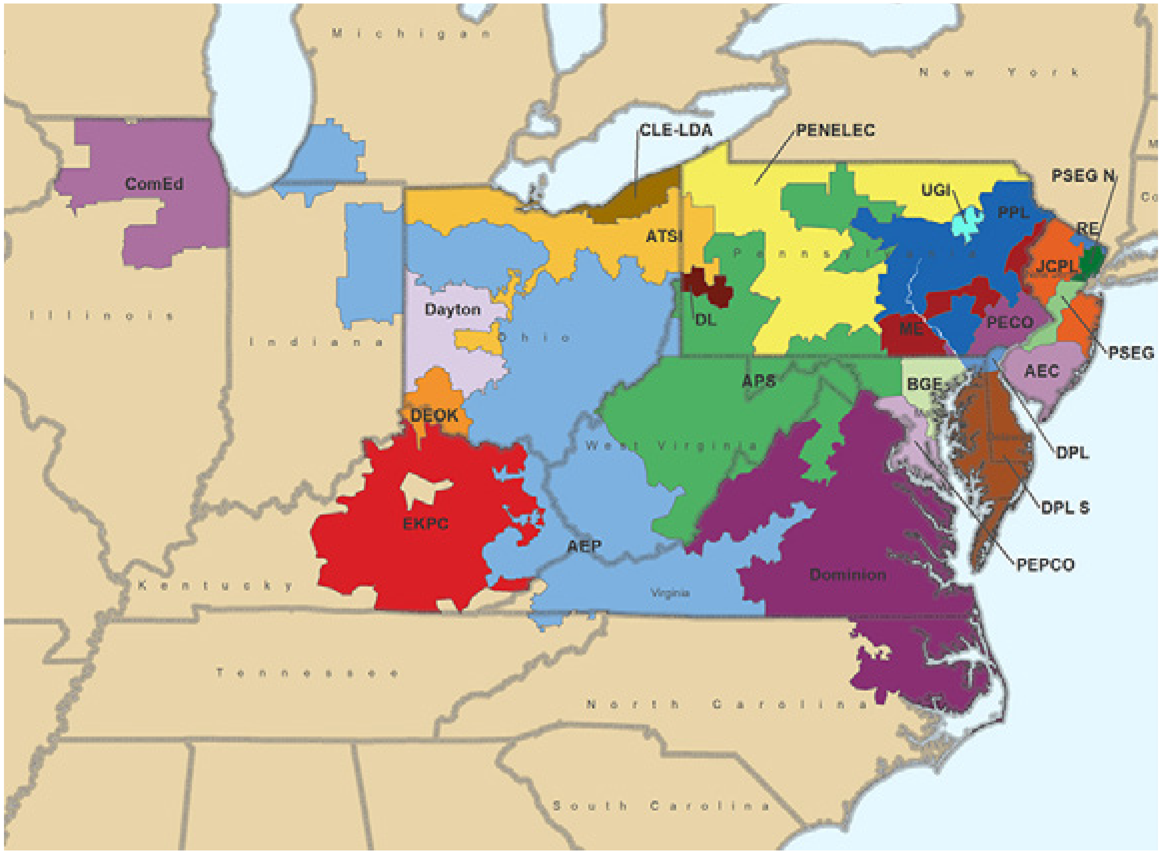


Table 1.1: Locational Deliverability Areas

Entity Name	TO Zone	LDA	Description
AE	▲	▲	Atlantic City Electric
AEP	▲	▲	American Electric Power
AP	▲	▲	Allegheny Power (FirstEnergy – Mon Power, Potomac Edison, West Penn Power)
ATSI	▲	▲	American Transmission Systems, Inc. (FirstEnergy)
BGE	▲	▲	Baltimore Gas & Electric
Cleveland	n/a	▲	Cleveland Area
ComEd	▲	▲	Commonwealth Edison (ComEd)
DAY	▲	▲	AES Ohio (formerly Dayton Power & Light)
DEO&K	▲	▲	Duke Energy Ohio and Kentucky
DLCO	▲	▲	Duquesne Light Company
Dominion	▲	▲	Dominion Energy Virginia and North Carolina
DP&L	▲	▲	Delmarva Power
Delmarva South	n/a	▲	Southern portion of Delmarva Power
Eastern Mid-Atlantic	n/a	▲	Global area: JCP&L, PECO, PSE&G, AE, DPL, RECO
EKPC	▲	▲	East Kentucky Power Cooperative
JCP&L	▲	▲	Jersey Central Power & Light
METED	▲	▲	Metropolitan Edison (Met-Ed)
Mid-Atlantic	n/a	▲	Global area: PENELEC, METED, JCP&L, PPL, PECO, PSE&G, BGE, PEPCO, AE, DPL, RECO
PECO	▲	▲	PECO
PENELEC	▲	▲	Pennsylvania Electric Company (Penelec)
PEPCO	▲	▲	Potomac Electric Power Company (Pepco)
PPL	▲	▲	PPL Electric Utilities Corporation, UGI Utilities
PSEG	▲	▲	Public Service Electric & Gas Company (PSE&G)
PSEG North	n/a	▲	Northern portion of PSE&G
Southern Mid-Atlantic	n/a	▲	Global area: BGE and PEPCO
Western Mid-Atlantic	n/a	▲	Global area: PENELEC, METED, PPL
Western PJM	n/a	▲	Global area: AP, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC, OVEC

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Glossary

The terms and concepts in this glossary are provided for the convenience of the reader and are in large part based on definitions from other sources, as indicated in the "Reference" column for each term.

These references include the following:

- **Mxx:** PJM Manual
- **NERC:** North American Electric Reliability Corporation
- **OA:** PJM Operating Agreement
- **OATT:** PJM Open Access Transmission Tariff
- **RAA:** Reliability Assurance Agreement

Term	Reference	Acronym	Definition
Adequacy	NERC		Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency. "Resources" refers to a combination of electricity generation and transmission facilities, which produce and deliver electricity, and "demand response" programs, which reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
Aluminum Conductor Steel Reinforced		ACSR	This high-capacity, stranded, conductor type is typically made with a core of steel (for its strength properties), surrounded by concentric layers of aluminum (for its conductive properties).
Aluminum Conductor Steel Supported		ACSS	This high capacity, stranded, conductor type is made from annealed aluminum.
Ancillary Service	OATT		Ancillary services are those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Annual Demand Resources			Demand resources can be called on an unlimited number of times any day of the delivery year, unless on an approved maintenance outage. Product type ceases to exist following the commencement of Capacity Performance rules.
Attachment Facilities	OATT		Attachment facilities are necessary to physically connect a customer facility to the transmission system or interconnected distribution facilities.
Auction Revenue Right	OA	ARR	An auction revenue right is a financial instrument entitling its holder to auction revenue from financial transmission rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the annual FTR auction.
Available Transfer Capability	NERC	ATC	The available transfer capability is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Base Capacity Resource	M18		Base capacity resources are capacity resources that are not capable of sustained, predictable operation throughout the entire delivery year. These resources will only be procured through the 2019/2020 Delivery Year, at which point all resources will be Capacity Performance resources starting with the 2020/2021 Delivery Year. See "Capacity Performance."
Baseline Upgrades	M14B		In developing the RTEP, PJM tests the baseline adequacy of the transmission system to deliver energy and capacity resources to each load in the PJM region. The system (as planned to accommodate forecast demand, committed resources and commitments for firm transmission service for a specified time frame) is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, nuclear plant licensee requirements, PJM reliability standards and PJM design standards. Areas not in compliance with the standards are identified, and enhancement plans to achieve compliance are developed. Baseline expansion plans serve as the base system for conducting feasibility studies and system impact studies for all proposed requests for generation and merchant transmission interconnection, and for long-term firm transmission service.
Behind-the-Meter Generation	OATT	BTM	Behind-the-meter generation delivers energy to load without using the transmission system or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of PJM), provided, however, that behind-the-meter generation does not include (1) at any time, any portion of such generating unit's capacity that is designated as a capacity resource, or (2) in an hour, any portion of the output of such generating unit(s) sold to another entity for consumption at another electrical location or in to the PJM Interchange Energy Market.
Bilateral Transaction	OA		A bilateral transaction is a contractual arrangement between two entities (one or both being PJM members) for the sale and delivery of a service.

Term	Reference	Acronym	Definition
Breaker-and-a-Half		BAAH	This substation configuration type is typically composed of two main sections connected by element strings. Each element string is composed of circuit breakers, transformers or line elements.
Bulk Electric System	NERC, M14B	BES	ReliabilityFirst defines the bulk electric system as all individual generation resources larger than 20 MVA, or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher, lines operated at voltages of 100 kV or higher, associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment). The ReliabilityFirst BES definition excludes: (1) radial facilities connected to load-serving facilities or individual generation resources smaller than 20 MVA, or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher; (2) the balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and step-up transformer), which would include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions; and (3) all other facilities operated at voltages below 100 kV.
Capacitor Voltage Transformer		CCVT	This type of transformer is used to step down high voltage signals and provide a low voltage signal for metering or protection devices.
Capacity Emergency	M13		A capacity emergency is a system condition where operating capacity plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet the total of its demand, firm sales and regulating requirements.
Capacity Emergency Transfer Limit	RAA, M14B, M18	CETL	The capacity emergency transfer limit is part of load deliverability analysis used to determine the maximum limit, expressed in megawatts, of a study area's import capability, under the conditions specified in the load deliverability criteria.
Capacity Emergency Transfer Objective	RAA, M14B, M18, M20	CETO	The CETO is the emergency import capability, expressed in megawatts, required of a PJM subregion area to satisfy established reliability criteria.
Capacity Interconnection Rights	OATT	CIRs	Capacity interconnection rights are rights to input generation as a capacity resource into the transmission system at the point of interconnection, where the generating facilities connect to the transmission system.
Capacity Performance			Capacity Performance is a set of rules governing resource participation in the Reliability Pricing Model (RPM). Following a series of transition auctions, Capacity Performance rules will be fully in place starting with the 2020/2021 Delivery Year. See "Base Capacity Resource" and "Capacity Performance Resource."
Capacity Performance Resource	M18		Capacity Performance resources are capable of sustained, predictable operation throughout the entire delivery year. All resources will be Capacity Performance resources starting with the 2020/2021 Delivery Year. See "Capacity Performance."
Capacity Resource	RAA, M14A, M14B		Capacity resources are megawatts of net capacity from existing or planned generation resources or load reduction capability provided by demand resources or interruptible load for reliability (ILR) in the region PJM serves.
Circuit Breaker		CB	This automatic device is used to stop the flow of current in an electric circuit as a safety measure.
Clean Air Interstate Rule		CAIR	The Clean Air Interstate Rule is an Environmental Protection Agency (EPA) rule regarding the interstate transport of soot and smog.
Clean Power Plan		CPP	The Clean Power Plan is an EPA rule regarding carbon pollution from power plants.
Coincident Peak	M19		The coincident peak is a zone's contribution to the RTO or higher level locational deliverability area (LDA) peak load.
Combined Cycle (Turbine)		CC/CCT	This type of turbine is a generating unit facility that generally consists of a gas-fired turbine and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion Turbine		CT	A combustion turbine is a generating unit in which a combustion turbine engine is the prime mover.
Consolidated Transmission Owners Agreement	PJM.com	CTOA	The Consolidated Transmission Owners Agreement is an agreement between transmission owners, which PJM is a signatory to, establishing the rights and commitments of all parties involved.
Contingency			A contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Coordinated System Plan		CSP	A Coordinated System Plan (CSP) contains the results of coordinated PJM/MISO studies required to assure the reliable, efficient and effective operation of the transmission system. The CSP also includes the study results for interconnection requests and long-term firm transmission service requests. Further description of CSP development can be found in the PJM/MISO Joint Operating Agreement.
Cost of New Entry	M18	CONE	The cost of new entry is a Reliability Pricing Model (RPM) capacity market parameter defined as the levelized annual cost in installed capacity $/MW-day of a reference combustion turbine to be built in a specific locational deliverability area.

Term	Reference	Acronym	Definition
Cross-Linked Polyethylene		XLPE	Type of plastic used to insulate power lines; benefits include resistance to temperature fluctuations and other environmental factors.
Cross-State Air Pollution Rule		CSAPR	The Cross-State Air Pollution Rule is an EPA rule regarding reduction in air pollution related to power plant emissions.
Current Transformer		CT	This type of transformer is used to measure electrical flows for purposes of telemetry.
Deactivation	M14D		Deactivation encompasses retiring or mothballing a generating unit governed by the PJM Open Access Transmission Tariff. Any generator owner, or designated agent, who wishes to retire a unit from PJM operations must initiate a deactivation request in writing no less than 90 days in advance of the planned deactivation date.
Deliverability	RAA, M14B, M18		Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver energy from generation facilities to wherever it is needed to ensure only that the transmission system is adequate for delivery of energy to load under prescribed conditions. The testing procedure includes two components: (1) generation deliverability and (2) load deliverability.
Demand Resource	M18	DR	See "Load Management."
Designated Entity			A designated entity can be an existing transmission owner or non-incumbent transmission developer designated by PJM with the responsibility to construct, own, operate, maintain and finance immediate-need reliability projects, short-term projects, long-lead projects, or economic-based enhancements or expansions.
Designated Entity Agreement	OATT	DEA	When a project is designated as a greenfield project that is not reserved for the transmission owner, execution of a Designated Entity Agreement (DEA) is required. The DEA defines the terms, duties, accountabilities and obligations of each party, and relevant project information, including project milestones. Once construction is complete and the designated entity has met all DEA requirements, the agreement is no longer needed. The designated entity must execute the Consolidated Transmission Owners Agreement as a requirement for DEA termination. Once a project is energized, a designated entity that is not already a transmission owner must become a transmission owner, subject to the Consolidated Transmission Owners Agreement.
Distributed Solar Generation			Distributed solar generation is not connected to PJM and does not participate in PJM markets. These resources do not go through the full interconnection queue process. The output of these resources is netted directly with the load. PJM does not receive metered production data from any of these resources.
Distribution Factor		DFAX	A distribution factor is the portion of an imposed power transfer that flows across a specified transmission facility or interface.
Diversity	M18		Diversity is the number of megawatts that account for the difference between a transmission owner zone's forecasted peak load at the time of its own peak and its coincident load at the time of the PJM peak.
Eastern Interconnection Planning Collaborative		EIPC	The Eastern Interconnection Planning Collaborative (EIPC) represents an interconnection-wide transmission planning coordination effort among planning authorities in the Eastern Interconnection. EIPC consists of 20 planning coordinators comprising approximately 95% of the Eastern Interconnection electricity demand. EIPC coordinates analysis of regional transmission plans to ensure their coordination and also provides the resources to conduct analysis of emerging issues affecting the grid.
Eastern Interconnection Reliability Assessment Group		ERAG	The ERAG is a group whose purpose is to further augment the reliability of the bulk power system in the Eastern Interconnection through periodic studies of seasonal and longer-term transmission system conditions.
Eastern MAAC	M14B	EMAAC	Eastern MAAC is a term used in PJM deliverability analysis to refer to the portion of PJM that includes AE, DP&L, JCP&L, PECO, PSE&G and Rockland.
Effective Forced Outage Rate on Demand	M22	EFORd	EFORd is a measure of the probability that a generating unit will not be available due to forced outages or forced de-ratings when there is a demand on the unit to generate. See Manual 22: Generator Resource Performance Indices for the equation.
Electrical Distribution Company		EDC	An electrical distribution company owns and/or operates electrical distribution facilities for the delivery of electrical energy to end-use customers.
End-Use Characteristics	M19		End-use characteristics are the measures of electrical equipment and appliance efficiency used in residential and commercial settings. These are represented in forecast models as part of heating, cooling and other applications.
Energy Efficiency Programs		EE	Energy efficiency programs are incentives or requirements at the state or federal level, which promote energy conservation and wise use of energy resources.
Energy Resource	M14A, M14B		An energy resource is a generating facility that is not a capacity resource.
Extended Summer Demand Resources			Extended summer demand resources can be called on as many times as needed from 10 a.m. to 10 p.m., any day from June through October and during the following May of that delivery year. Product ceases to exist following the commencement of Capacity Performance rules.
Extra High Voltage		EHV	Extra high voltage transmission equipment operates at 230 kV and above.

Term	Reference	Acronym	Definition
Facilities Study Agreement	M14A	FSA	A facilities study agreement is an agreement made between the interconnection customer/developer and PJM to identify the scope of facility additions and upgrades to be included in the interconnection study.
Fault			A fault is a physical condition that results in the failure of a component or facility within the transmission system to transmit electrical power in the manner for which it was designed.
Federal Energy Regulatory Commission		FERC	FERC is an independent federal agency that regulates the interstate transmission of electricity, natural gas and oil.
Financial Transmission Right	M6	FTR	A financial transmission right is a financial instrument entitling the holder to receive revenues based on transmission congestion, measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm Transmission Service	OATT		Firm transmission service is intended to be available at all times to the maximum extent practical. Service availability is subject to system emergency conditions, unanticipated facility failure or other unanticipated events and is governed by Part II of the OATT.
Fixed Series Capacitor		FSC	A fixed series capacitor is a grouping of capacitors used to reduce transfer reactances on bulk transmission corridors.
Flexible Alternating Current Transmission System		FACTS	FACTS is a system composed of static equipment used for the AC transmission of electrical energy, meant to enhance controllability and increase power transfer capability of the network. It is generally a power electronics-based system.
Flowgate			A flowgate is a specific combination of a monitored facility and a contingency that impacts that monitored facility.
Gas Insulated Substation		GIS	This is a high voltage substation in which the major electrical components are contained within a sealed environment with sulfur hexafluoride gas as the insulating medium.
Generation Deliverability	M14B		Generation deliverability is the ability of the transmission system to export capacity resources from one electrical area to the remainder of PJM. The generator deliverability test for reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the transmission system is capable of delivering the aggregate system generating capacity at peak load with all firm transmission uses modeled.
Generator Step-up Transformer		GSU	A GSU transformer "steps-up" generator power output voltage level to the suitable grid-level voltage for transmission of electricity to load centers.
Geomagnetically Induced Current		GIC	This is a manifestation at ground level of space weather; these currents impact the normal operation of electrical conductor systems.
Good Utility Practice	OATT		Good Utility Practice is any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be practices, methods or acts generally accepted in the region.
Group/Gang Operated Air Break		GOAB	A group/gang operated air break is the portion of a circuit breaker that opens and closes to allow or block current to flow through or not. This particular type of break uses air as a dielectric medium, as opposed to others that use gas, oil or air contained within a vacuum. "Gang operated" refers to a mechanical linkage that opens and closes the disconnect.
Horizontal Directional Drilling		HDD	Horizontal directional drilling technology for laying transmission cable employs a long, flexible drill bit to bore horizontally underground. This is a trenchless method in which no surface excavation is required except for drill entry and exit points, which minimizes surface restoration, ecological disturbances and environmental impacts. By contrast, jet-plowing techniques affect the riverbed over the length of the installation.
Independent State Agencies Committee	PJM.com	ISAC	The ISAC is a voluntary, stand-alone committee that consists of members from regulatory and other state agencies representing all of the states and the District of Columbia within the service territory of PJM. The ISAC is an independent committee that is not controlled or directed by PJM, the PJM Board or PJM members. The purpose of the ISAC is to provide PJM with input and scenarios for transmission planning studies.
Independent System Operator		ISO	An independent system operator is an entity that is authorized to operate an electric transmission system and is independent of any influence from the owner(s) of that electric transmission system. See also "RTO."
Installed Capacity		ICAP	Installed capacity is valued based on the summer net dependable rating of the unit as determined in accordance with PJM rules and procedures relating to the determination of generating capacity.
Interconnected Reliability Operating Limit	M14B	IROL	The interconnected reliability operating limit is a system operating limit that, if violated, could lead to instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk electric system.

Term	Reference	Acronym	Definition
Interconnection Construction Service Agreement	M14C	ICSA	The ICSA is a companion agreement to the ISA and is necessary for projects that require the construction of interconnection facilities as defined in the ISA. The ICSA details the project scope, construction responsibilities of the involved parties, ownership of transmission and customer interconnection facilities, and the schedule of major construction work.
Interconnection Coordination Agreement	OATT	ICA	An interconnection coordination agreement is made between transmission owners and/or transmission developers outlining the schedules and responsibilities of each party involved.
Interconnection Service Agreement	M14A	ISA	An interconnection service agreement is made among the transmission provider, an interconnection customer and an interconnected transmission owner regarding interconnection under Part IV and Part VI of the Tariff.
Interregional Market fficiency Project		IMEP	Interregional proposals are designed to address congestion and its associated costs along the MISO/PJM border within the context of the MISO/PJM JOA as identified in long-term market efficiency simulation results.
Joint RTO Planning Committee		JRPC	The JRPC is the decision-making body for MISO/PJM coordinated system planning as governed by the MISO/PJM Joint Operating Agreement.
Light Load Reliability Analysis	M14B		Light load reliability analysis ensures that the transmission system is capable of delivering the system generating capacity during a light load situation (50% of 50/50 summer peak demand level).
Limited Demand Resources			Limited demand resources can be called on up to 10 times from noon to 8 p.m. on weekdays, other than NERC holidays, from June through September. Product type ceases to exist following the commencement of Capacity Performance rules.
Load			Load refers to demand for electricity at a given time, expressed in megawatts.
Load Analysis Subcommittee	M19	LAS	The Load Analysis Subcommittee is responsible for technical analysis and coordination of information related to the electric peak demand and energy forecasts, interruptible load resources for capacity, credit and weather, and peak load studies. The LAS reports to the Planning Committee.
Load Deliverability	M14B		Load deliverability is the ability of the transmission system to deliver energy from the aggregate of available capacity resources in one PJM electrical area and adjacent non-PJM areas to another PJM electrical area that is experiencing a capacity deficiency.
Load Management	M18	LM	Load management is the ability to interrupt retail customer load at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. Load management derives a demand resource or interruptible-load-for-reliability credit in RPM.
Load Serving Entity	RAA, OATT	LSE	Load serving entities (LSE) provide electricity to retail customers. LSEs include traditional distribution utilities.
Local Distribution Company		LDC	A local distribution company (LDC) is a regulated utility involved in the delivery of natural gas to consumers within a specific geographic area. While some large industrial, commercial and electric generation customers receive natural gas directly from high-capacity pipelines, most other users receive natural gas from their LDCs.
Locational Deliverability Area	M14B	LDA	Locational deliverability areas are electrically cohesive load areas, historically defined by transmission owner service territories and larger geographical zones comprising a number of those service areas.
Locational Marginal Price		LMP	The locational marginal price is the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.
Loss-of-Load Expectation	M14B	LOLE	Loss-of-load expectation defines the adequacy of capacity for the entire PJM footprint based on load exceeding available capacity, on average, during only one day in 10 years.
Market Participant			A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met credit requirements as established by PJM. Market buyers are able to make purchases and market sellers are able to make sales in PJM energy and capacity markets.
Maximum Facility Output	M14A, M14G	MFO	This term refers to the maximum amount of power a generator is capable of producing.
Megavolt-Ampere Reactive	OA	MVAR	See "Reactive Power."
Merchant Transmission Facility	OATT		Merchant transmission facilities are AC or DC transmission facilities that are interconnected with, or added to, the transmission system in accordance with the PJM Open Access Transmission Tariff. These facilities are not existing facilities within the transmission system, transmission facilities included in the rate base of a public utility on which a regulated return is earned, or transmission facilities included in previous RTEPs or customer interconnection facilities.
Mercury and Air Toxins Standards		MATS	MATS is an EPA rule limiting the emissions of toxic air pollutants like mercury, arsenic and metals from power plant emissions.

Term	Reference	Acronym	Definition
Mid-Atlantic Subregion	M14B	MAAC	The PJM Mid-Atlantic Subregion encompasses 12 transmission owner zones: Atlantic City Electric (AE), Baltimore Gas and Electric (BGE), Delmarva Power (DP&L), Jersey Central Power and Light (JCP&L), Metropolitan Edison (METED), Neptune, PECO, Pennsylvania Electric Company (PENELEC), Potomac Electric Power Company (PEPCO), PPL Electric Utilities (PPL), Public Service Electric & Gas (PSEG) and Rockland Electric (Rockland). The Neptune Regional Transmission System interconnects with the Mid-Atlantic PJM transmission system at Sayreville substation in Northern New Jersey.
MISO Transmission Expansion Planning		MTEP	MTEP is the Midcontinent Independent System Operator (MISO) plan for enhancing the future of the power grid in their area.
Motor-Operated Air Break		MOAB	A motor-operated air break is the portion of a circuit breaker that opens and closes to allow or block current. This particular type of break uses air as a dielectric medium, as opposed to others that use gas, oil or air contained within a vacuum. “Motor operated” refers to a remote-controlled motorized linkage that opens and closes the disconnect.
Multiregional Model Working Group		MMWG	The Multiregional Model Working Group reports to the ERAG and is responsible for developing all Eastern Interconnection power flow and dynamic base case models, including seasonal updates to summer and winter power flow study cases.
National Renewable Energy Laboratory		NREL	The NREL, part of the Department of Energy, is a federal laboratory dedicated to the research, development, commercialization and deployment of renewable energy and energy efficiency technologies.
Network Reinforcements	OATT		Network reinforcements are modifications or additions to transmission-related facilities that are integrated with and support the transmission provider’s overall transmission system for the general benefit of all users of such transmission system.
Non-Coincident Peak	M19	NCP	The non-coincident peak is a zone’s individual peak load.
North American Electric Reliability Corporation	NERC	NERC	NERC is a FERC-appointed body whose mission is to ensure the reliability of the bulk power system.
Open Access Same-Time Information System		OASIS	The Open Access Same-Time Information System (OASIS) provides information by electronic means about available transmission capability for point-to-point service and a process for requesting transmission service on a non-discriminatory basis. OASIS enables transmission providers and transmission customers to communicate requests and responses to buy and sell available transmission capacity offered under the PJM Open Access Transmission Tariff.
Open Access Transmission Tariff	OATT	OATT	The OATT is a FERC-filed tariff specifying the terms and conditions under which PJM provides transmission service and carries out its generation and merchant transmission interconnection process.
Optical Grounding Wire Communications		OPGW	This is a type of fiber optic cable that is used in the construction of electric power transmission and distribution lines and that combines the functions of grounding and communications.
Optimal Power Flow		OPF	Optimal power flow is a tool used to determine optimal dispatch, subject to transmission constraints. Optimal often means most economical but may also mean “minimum control change.”
Organization of PJM States, Inc.		OPSI	OPSI refers to an organization of statutory regulatory agencies in the 13 states and the District of Columbia within which PJM Interconnection operates. OPSI Member Regulatory Agencies’ activities include, but are not limited to, coordinating activities such as data collection, issues analyses and policy formulation related to PJM, its operations, its market monitor and matters related to the FERC, as well as their individual roles as statutory regulators within their respective state boundaries.
PJM Manuals			PJM Manuals contain the instructions, rules, procedures and guidelines established by PJM for the operation, planning and accounting requirements of the region PJM serves and the PJM Interchange Energy Market.
PJM Member	OA, M33		A PJM member is any entity that has satisfied PJM requirements to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
Planning Committee	OA	PC	The Planning Committee was established under the Operating Agreement to review and recommend system planning strategies and policies, as well as planning and engineering designs for the PJM bulk power supply system.
Planning Cycle	M14B		The planning cycle is the annual RTEP process, including a series of studies, analysis, assessments and related supporting functions.
Planning Horizon	M14B		The planning horizon is the future time period over which system transmission expansion plans are developed based on forecasted conditions.
Probabilistic Risk Assessment	M14B	PRA	PJM assesses risk exposure using a Probabilistic Risk Assessment (PRA) risk management tool. The goal of the PRA model is to minimize asset service cost. PJM’s PRA method integrates the economics of facility loss with the likelihood of that loss occurring.

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Term	Reference	Acronym	Definition
Reactive Power (expressed in MVAR)	M14A		Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers or electrostatic equipment such as capacitors and directly influences electric system voltage. Reactive power is usually expressed as megavolt-ampere reactive (MVAR).
Regional Greenhouse Gas Initiative		RGGI	States and provinces in the northeastern United States and eastern Canada adopted the Regional Greenhouse Gas Initiative to reduce greenhouse gas emissions.
Regional RTEP Project	M14B, OA		A regional RTEP project is a transmission expansion or enhancement at a voltage level of 100 kV or higher.
Regional Transmission Expansion Plan	M14B	RTEP	The Regional Transmission Expansion Plan (RTEP) is prepared by PJM pursuant to Schedule 6 of the PJM Operating Agreement for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the region PJM serves.
Regional Transmission Organization	FERC	RTO	A regional transmission organization is an independent, FERC-approved organization of sufficient regional scope, which coordinates the interstate movement of electricity under FERC-approved tariffs by operating the transmission system and competitive wholesale electricity markets, and ensures reliability and efficiency through expansion planning and interregional coordination.
Reliability	NERC		A reliable bulk power system is one that is able to meet the electricity needs of end-use customers, even when unexpected equipment failures or other factors reduce the amount of available electricity.
Reliability Assurance Agreement	RAA	RAA	The Reliability Assurance Agreement (RAA) among load-serving entities in the region PJM serves is intended to ensure that adequate capacity resources will be planned and made available to provide reliable service to loads within PJM, to assist other parties during emergencies and to coordinate planning of capacity resources consistent with the reliability principles and standards.
Reliability Must Run		RMR	A reliability must run (RMR) generating unit is one slated to be retired by its owners but is needed to be available to maintain reliability. Typically, it is requested to remain operational beyond its proposed retirement date until required transmission enhancements are completed.
Reliability Pricing Model		RPM	The Reliability Pricing Model (RPM) is PJM's resource adequacy construct. The purpose of RPM is to develop a long-term pricing signal for capacity resources and load serving entity obligations that is consistent with the PJM RTEP process. RPM adds stability and a locational nature to the pricing signal for capacity.
ReliabilityFirst Corporation		RFC	ReliabilityFirst is a not-for-profit company incorporated in the state of Delaware, whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. ReliabilityFirst was approved by the North American Electric Reliability Corporation (NERC) to become one of eight Regional Reliability Councils in North America and began operations on Jan. 1, 2006. ReliabilityFirst is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council, the East Central Area Coordination Agreement and the Mid-American Interconnected Network.
Renewable Integration Study		RIS	The RIS is an ongoing study to examine the reliability and market impacts of high wind and solar penetration in the PJM system to meet objectives of state policies regarding renewable resource production.
Renewable Portfolio Standard		RPS	The Renewable Portfolio Standard is a set of guidelines or requirements at the state or federal level requiring energy suppliers to provide specified amounts of electric energy from eligible renewable energy resources.
Right of First Refusal		ROFR or RFR	The right of first refusal is a contractual right that gives the holder the option to enter a business transaction with the owner of an asset, according to specified terms, before the owner is entitled to enter into that transaction with a third party.
Right-of-Way		ROW	A right-of-way is a corridor of land on which electric lines may be located. The transmission owner may own the land in fee; own an easement; or have certain franchise, prescription or license rights to construct and maintain lines.
Security	NERC		The ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by physical or cyberattacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.
Security Constrained Optimal Power Flow		SCOPF	The optimal power flow determines the ideal dispatch, subject to transmission constraints. Optimal usually means "least cost" (or most economical), but may also mean "minimum control change." Security-constrained OPF, or SCOPF, adds contingencies. The SCOPF will seek a single dispatch that does not cause any overloads in the base case, nor any overloads during any of the contingencies.
Southern Subregion	M14B		The PJM Southern Subregion comprises one transmission owner zone – Dominion Energy Virginia and North Carolina.

Term	Reference	Acronym	Definition
Special Protection System	M03	SPS	A Special Protection System (SPS) also known as a remedial action scheme, includes an assembly of protection devices designed to detect and initiate automatic action in response to abnormal or predefined system conditions. The intent of these schemes is generally to protect equipment from thermal overload or to protect against system instability following subsequent contingencies on the electric system. Redundant assemblies may be applied for the above functions on an individual facility – in such cases, each assembly is considered a separate protection system. An SPS consists of protection devices such as relays, current transformers, potential transformers, communication interface equipment, communication links, breaker trip and close coils, switch gear auxiliary switches and all associated connections.
Static Synchronous Compensator		STATCOM	A shunt device of the Flexible AC Transmission System (FACTS) family that uses power electronics to control power flow and improve transient stability on power grids.
Static Var Compensation		SVC	An SVC device rapidly and continuously provides reactive power required to control dynamic voltage swings under various system conditions, improving power system transmission and distribution performance.
Storage as a Transmission Asset		SATA	A storage device that can be utilized on the transmission system to address reliability issues
Subregional RTEP Committee	M14B, OA		This PJM committee that facilitates the development and review of the subregional RTEP projects. The Subregional RTEP Committee is responsible for the initial review of the subregional RTEP projects and for providing recommendations to the Transmission Expansion Advisory Committee concerning the subregional RTEP projects.
Subregional RTEP Project	M14B, OA		A subregional RTEP project is defined in the PJM Operating Agreement as a transmission expansion or enhancement rated below 230 kV.
Sub-Synchronous Resonance		SSR	Power system sub-synchronous resonance (SSR) is the buildup of mechanical oscillations in a turbine shaft arising from the electro-mechanical interaction between the turbine generator and the rest of the power system. This can lead to turbine shaft damage, or even catastrophic loss. The term “sub-synchronous” refers to the fact that the oscillations a shaft can experience occur at levels below 60 Hz (cycles per second).
Supplemental Project	M14B, OA		“Supplemental Project” replaces the term “Transmission Owner Initiated or TOI Project” and refers to a regional RTEP project or a subregional RTEP project that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.
Surge Impedance Loading		SIL	The megawatt loading of a transmission line at which a natural reactive power balance occurs. A line loaded below its SIL supplies reactive power to the system; a line above its SIL absorbs reactive power.
System Operating Limit	M14B	SOL	The value (such as MW, MVAR, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System operating limits are based upon certain operating criteria.
System Stability			Stability studies examine the grid’s ability to return to a stable operating point following a system fault or similar disturbance. Such contingencies can cause a nearby generator’s rotor position to change in relation to the stator’s magnetic field, affecting the generator’s ability to maintain synchronism with the grid. Power system engineers measure this stability in terms of generator bus voltage and maximum observed angular displacement between a generator’s rotor axis and the stator magnetic field. Stability in actual operations is affected by machine megawatt, system voltage, machine voltage, duration of the disturbance and system impedance. Transient stability examines this phenomenon over the first several seconds following a system disturbance.
Targeted Market Efficiency Project		TMEP	TMEP interregional projects address historical congestion on reciprocal coordinated flowgates – a set of specific flowgates subject to joint and common market congestion management.
Temperature-Humidity Index	M19	THI	The temperature-humidity index (THI) gives a single numerical value in the general range of 70 to 80, reflecting the outdoor atmospheric conditions of temperature and humidity during warm weather. The THI is defined as follows: THI = Td – (0.55 – 0.55RH) * (Td - 58), where Td is the dry-bulb temperature and RH is the percentage of relative humidity, when Td is greater than or equal to 58.
Thyristor Controlled Series Compensator		TCSC	A thyristor controlled series compensator is a series capacitor bank that is shunted by a thyristor controlled reactor.
Topology	M14B		Topology is a geographically based or other diagrammatic representation of the physical features of an electrical system or portion of an electrical system – including transmission lines, transformers, substations, capacitors and other power system elements – that in aggregate constitute a transmission system model for power flow and economic analysis.
Transmission Customer	M14A, M14B, M2, OATT		A transmission customer is any eligible customer, or its designated agent, that (1) executes a service agreement or (2) requests in writing that PJM file with FERC, a proposed, unexecuted service agreement to receive transmission service under Part II of the PJM OATT.
Transmission Expansion Advisory Committee	M14B	TEAC	The Transmission Expansion Advisory Committee was established by PJM to provide advice and recommendations to aid in the development of the RTEP.

Term	Reference	Acronym	Definition
Transmission Loading Relief	M03	TLR	Transmission loading relief is a NERC procedure developed for the Eastern Interconnection to mitigate overloads on the transmission system by allowing reliability coordinators to request the curtailment of transactions that are causing parallel flows through their system.
Transmission Owner	M14B, OATT	TO	A transmission owner is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a transmission owner.
Transmission Owner Initiated		TOI	See "Supplemental Project."
Transmission Owner Upgrade	OA		A transmission owner upgrade is an improvement to, addition to, or replacement of part of a transmission owner's existing facility and is not an entirely new transmission facility.
Transmission Provider	M14B, OATT		The transmission provider is PJM for all purposes in accordance with the PJM OATT.
Transmission Service Request	M02	TSR	A transmission service request is a request submitted by a PJM market participant for transmission service over PJM-designated facilities. Typically, the request is for either short-term or long-term service, over a specific path for a specific megawatt amount. PJM evaluates each request and determines if it can be accommodated and, if the requestor so chooses, pursues needed upgrades to accommodate the request.
Transmission System	OATT		The transmission system comprises the transmission facilities operated by PJM used to provide transmission services. These facilities that transmit electricity are within the PJM footprint, meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities, and have been demonstrated to the satisfaction of PJM to be integrated with the transmission system of PJM and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.
Unforced Capacity	RAA	UCAP	Unforced capacity is an entitlement to a specified number of summer-rated MW of capacity from a specific resource, on average, not experiencing a forced outage or de-rating, for the purpose of satisfying capacity obligations imposed under the RAA.
Upgrade	OA		See "Transmission Owner Upgrade."
Upgrade Construction Service Agreement		UCSA	The terms and conditions of a UCSA govern the construction activities associated with the upgrade of capability along an existing PJM bulk electric system circuit in order to accommodate a merchant transmission interconnection request. Facilities constructed under a UCSA are not owned by a developer. All ownership rights of the physical facilities are retained by the respective transmission owner following the completion of construction. PJM and the developer execute a separate UCSA with each impacted transmission owner. A developer retains the right, but not the obligation (option to build), to design, procure, construct and install all or any portion of the direct assignment facilities and/or customer-funded upgrades.
Violation	M14B		A violation is a PJM planning study result that shows a specific system condition that is not in compliance with established NERC, ReliabilityFirst, SERC or PJM reliability criteria.
Weather Normalized Peak	M19		The weather normalized peak is an estimate of the seasonal peak load at normal peak-day weather conditions.
Western Subregion	M14B, OA		The PJM Western Subregion comprises five transmission owner zones: Allegheny Power (AP), American Electric Power (AEP), American Transmission Systems, Inc. (ATSI), Commonwealth Edison (ComEd), AES Ohio – formerly Dayton Power & Light (DAY), Duke Energy Ohio and Kentucky (DEO&K), Duquesne Light Company (DLCO) and Eastern Kentucky Power Cooperative (EKPC).
Wheel			A wheel is the contracted, third-party use of electrical facilities to transmit power whose origin and destination are outside the entity transmitting the power.
Wholesale Market Participation Agreement	M14C	WMPA	A contractual agreement required for generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM's market.
X-Effective Forced Outage Rate on Demand		XEFORd	XEFORd is a statistic that results from excluding events outside management control (outages deemed not to be preventable by the operator) from the EFORd calculation. See "Effective Forced Outage Rate on Demand (EFORd)."
Zone/Control Zone	M14B		A zone/control zone is an area within the PJM control area, as set forth in the PJM OATT and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

Figure 1.1: Board-Approved RTEP Projects as of Dec. 31, 2021

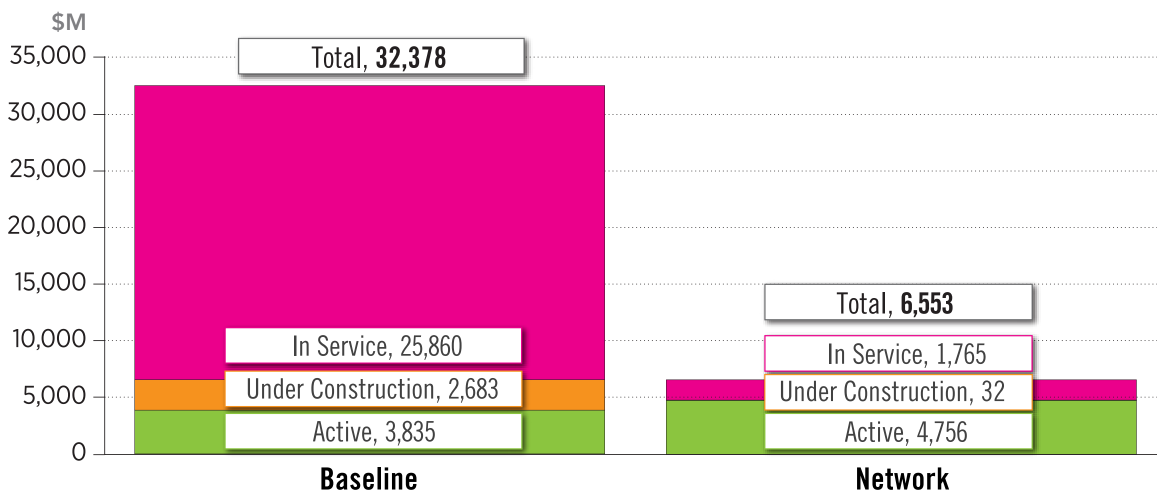


Figure 1.3: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2021)

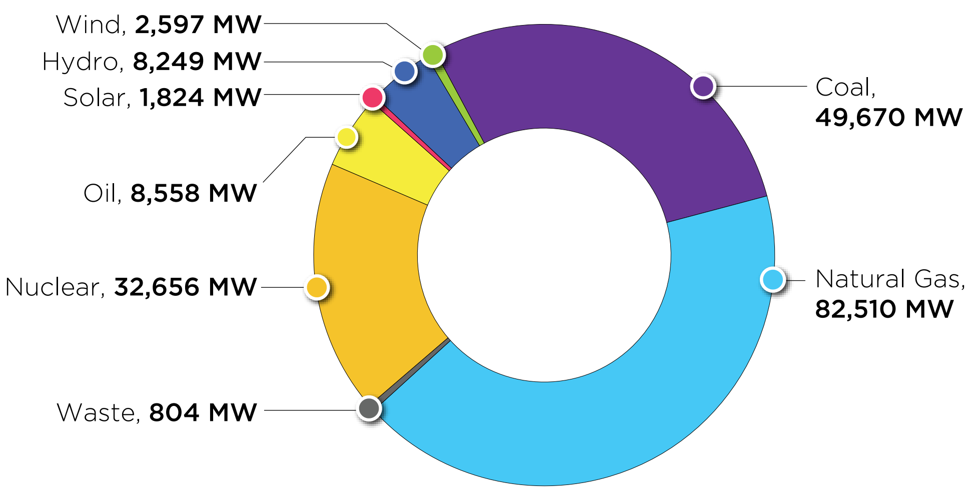
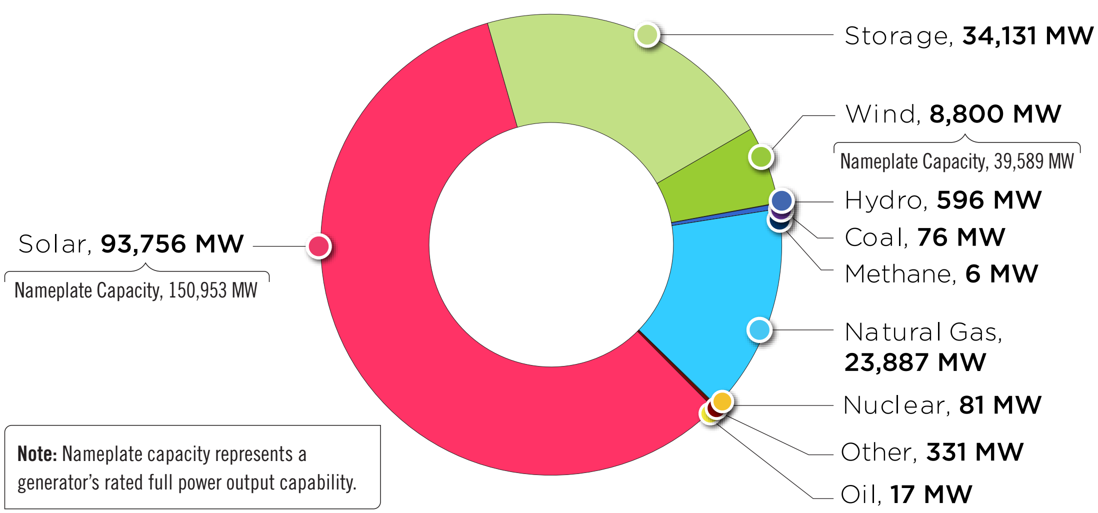


Figure 1.2: Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2021)



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

Table 1.1: Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2021)

		In Queue						Complete					
		Active		Suspended		Under Construction		In Service		Withdrawn		Grand Total	
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	1	11.0	0	0.0	3	65.0	53	2,146.9	70	33,577.6	127	35,800.5
	Diesel	0	0.0	0	0.0	0	0.0	10	68.5	16	76.7	26	145.2
	Natural Gas	52	9,634.5	16	6,695.0	41	7,557.5	355	50,733.0	672	245,831.0	1,136	320,451.0
	Nuclear	5	37.4	0	0.0	1	44.0	43	3,902.8	22	9,038.0	71	13,022.2
	Oil	2	4.0	0	0.0	8	13.0	18	539.8	23	2,314.0	51	2,870.8
	Other	19	331.3	0	0.0	2	0.0	6	336.5	100	858.8	127	1,526.6
	Storage	534	34,033.5	6	17.6	18	79.3	26	4.0	258	6,000.7	842	40,135.2
Renewable	Biomass	0	0.0	0	0.0	0	0.0	11	252.8	40	896.9	51	1,149.7
	Hydro	9	562.8	0	0.0	3	33.6	32	1,155.9	51	2,178.8	95	3,931.0
	Methane	1	6.0	0	0.0	0	0.0	83	404.2	95	490.1	179	900.3
	Solar	1,712	86,883.6	48	875.2	268	5,997.2	221	1,897.3	1,596	33,265.0	3,845	128,918.4
	Wind	110	8,433.2	2	47.7	9	319.2	112	2,022.2	490	14,817.3	723	25,639.6
	Wood	0	0.0	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
	Grand Total	**2,445**	**139,937.3**	**72**	**7,635.6**	**353**	**14,108.8**	**972**	**63,517.9**	**3,437**	**349,497.9**	**7,279**	**574,697.5**

Figure 1.4: Growth of Renewables in PJM Queue

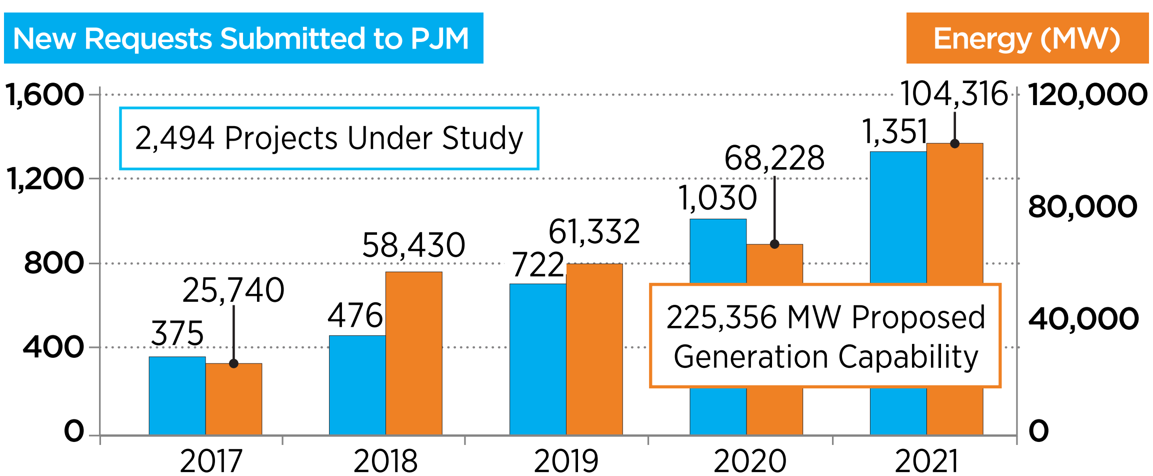


Figure 1.5: Queued Generation Progression – Requested Capacity (Dec. 31, 2021)

			Capacity	Nameplate
Projects withdrawn after final agreement	189	Interconnection Service Agreements	26,351 MW	34,892 MW
	315	Wholesale Market Participation Agreements	1,271 MW	2,577 MW

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2021, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2021.

Map 1.1: PJM Generator Deactivation Notifications Received Jan. 1, 2021, Through Dec. 31, 2021

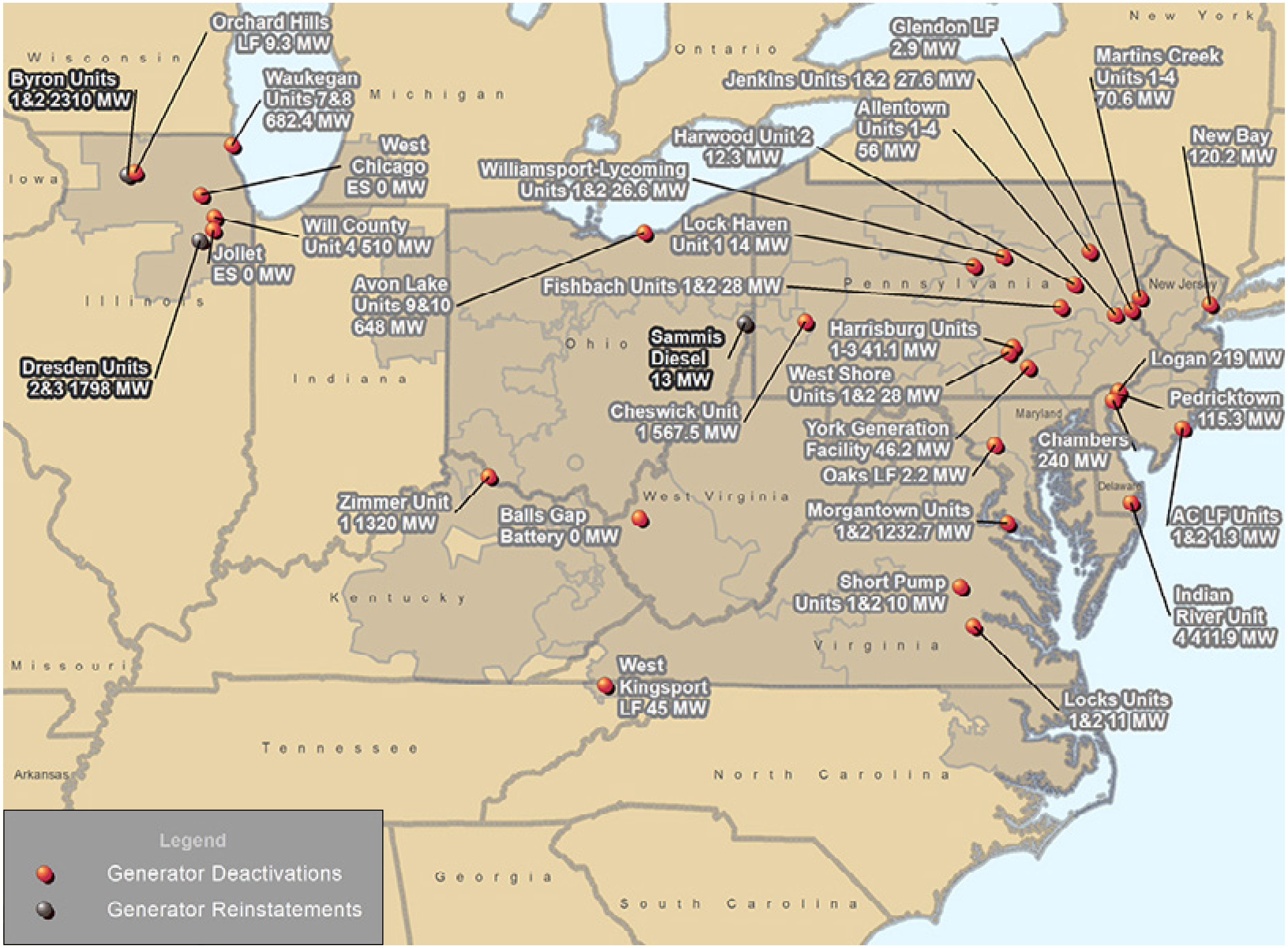
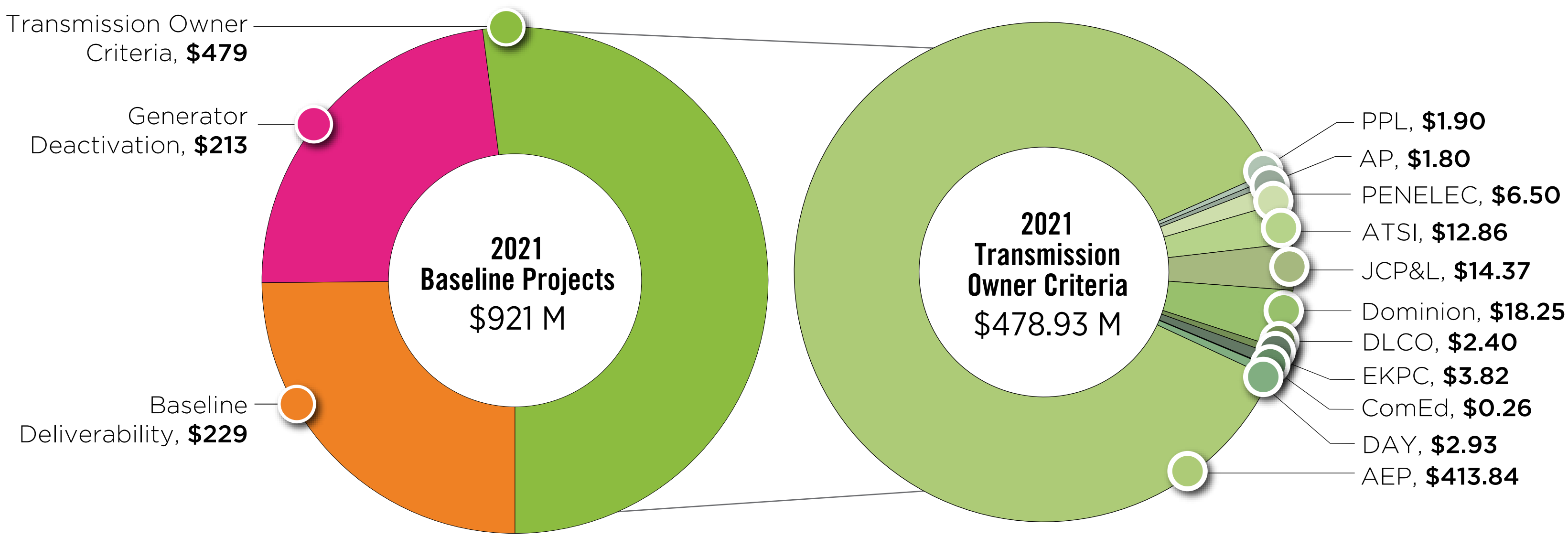
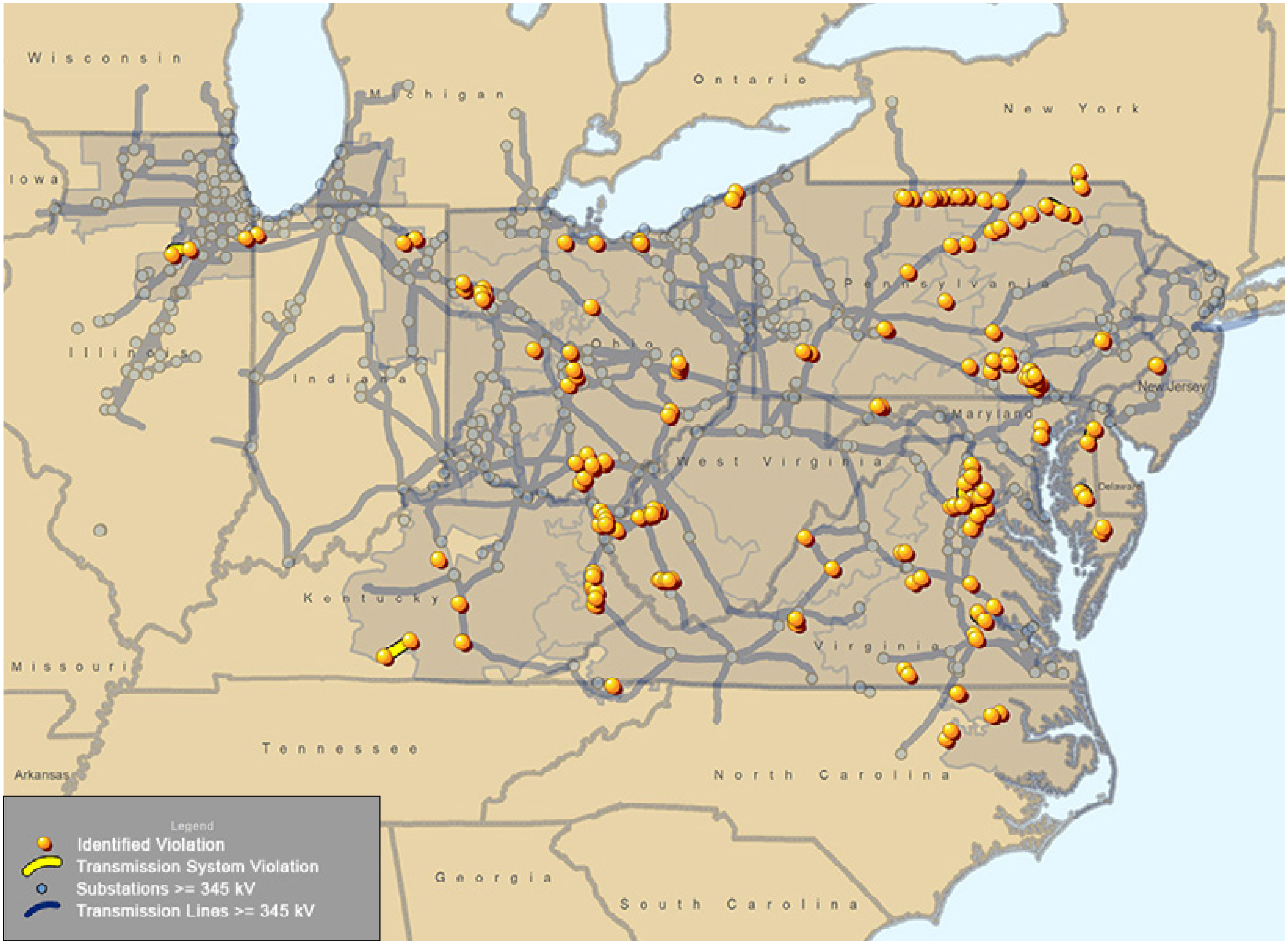


Figure 1.6: 2021 RTEP Baseline Project Driver ($ Million)



Map 1.2: 2021 RTEP Baseline Thermal and Voltage Criteria Violations



Map 1.3: Project 9A – RTEP Baseline Projects B2743 and B2752

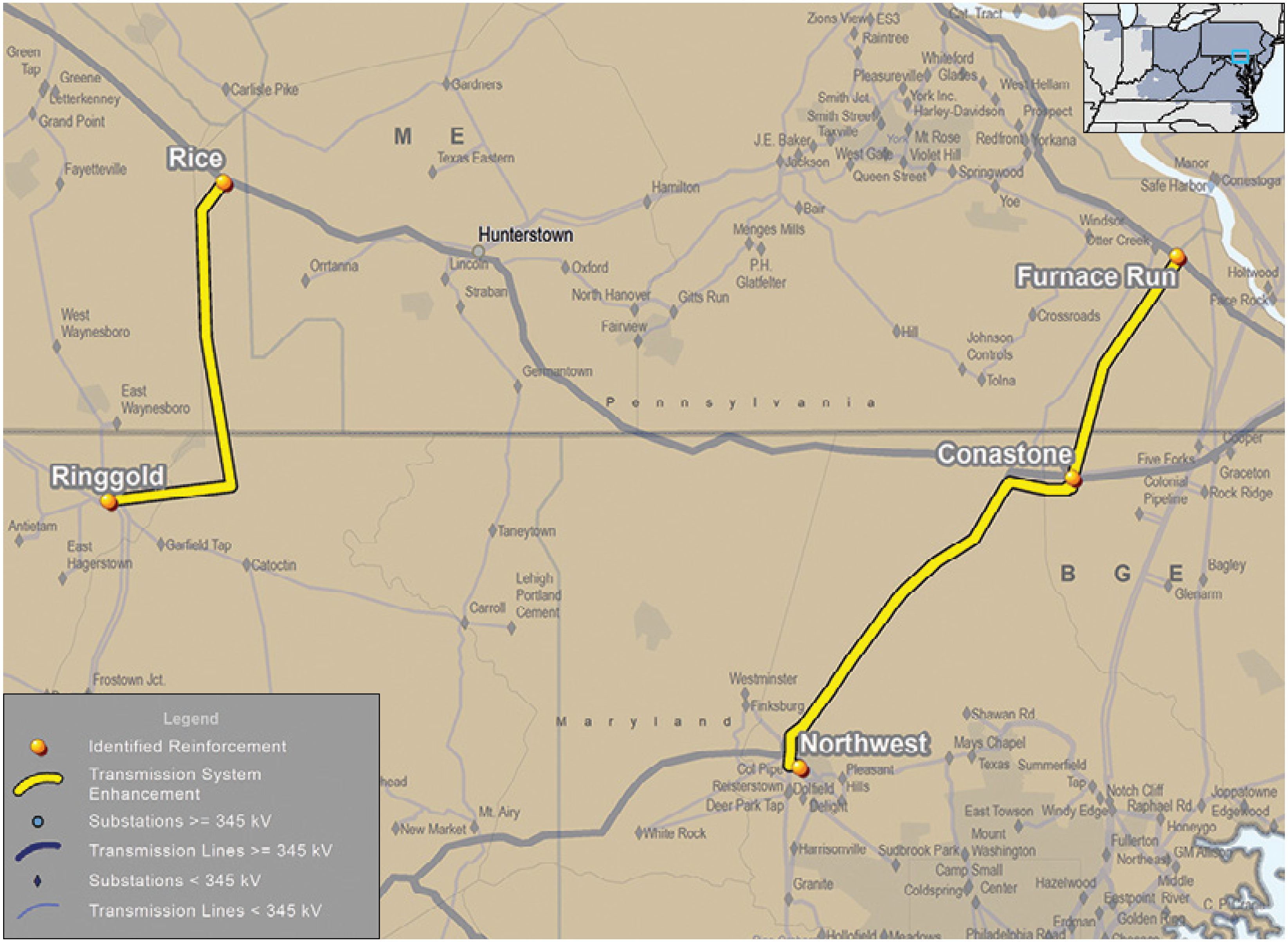


Table 1.2: RTEP Projects Reducing Specific Congestion Drivers: 2026 Analysis

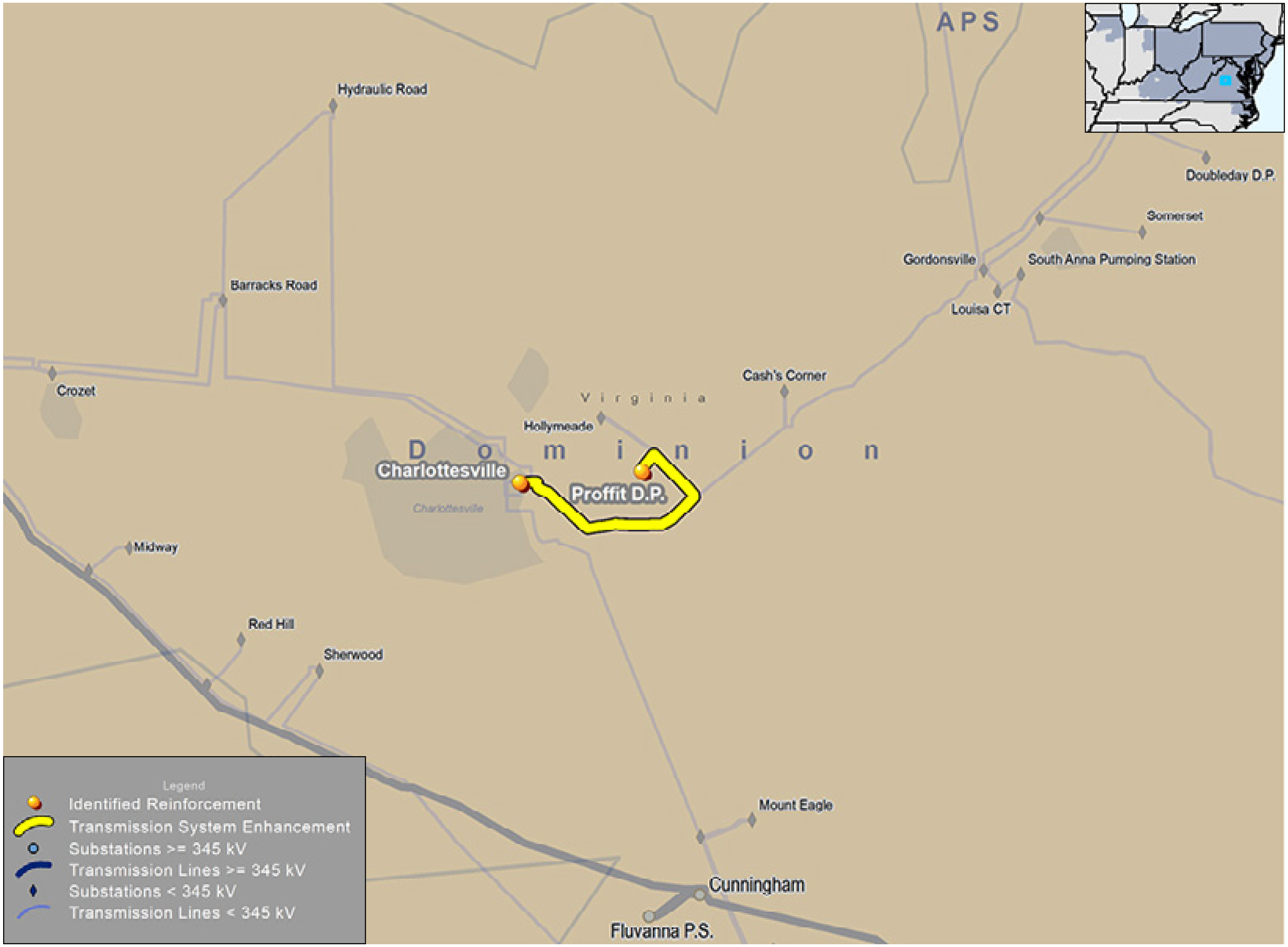
Constraint Name	Upgrade Associated With Congestion Reduction	Area	Type	2026 Study Year: 2022 Topology 2026 Congestion ($M)	2026 Study Year: 2026 Topology 2026 Congestion ($M)	Congestion Savings ($M)
Morgan-Cherry Run 138 kV	B3240: Upgrade Cherry Run and Morgan terminals.	AP	LINE	$6.6	$0.0	$6.6
Gore-Stonewall 138 kV	B3242: Reconfigure Stonewall 138 kV substation.	AP	LINE	$51.3	$0.0	$51.3

Note: The congestion savings for the 2026 study year are calculated as the difference in simulated congestion between with as-is topology and the RTEP topology.

Table 1.3: 2020/2021 Long-Term Window Congestion Drivers

			Market Efficiency Base Case			
			Annual Congestion ($M)		Hours Binding	
			Simulated Year			
Constraint	From Area	To Area	2025	2028	2025	2028
Junction to French's Mill 138 kV	AP	AP	$15.24	$15.72	342	317
Charlottesville to Proffit Rd. Del Pt 230 kV	DOMINION	DOMINION	$7.34	$10.25	164	169
Plymouth Meeting to Whitpain 230 kV	PECO	PECO	$4.03	$2.76	78	89
Cumberland to Juniata 230 kV	PPL	PPL	$9.30	$10.10	209	217

Map 1.4: Baseline Project B3702: Charlottesville-Proffit 230 kV Line Series Reactor



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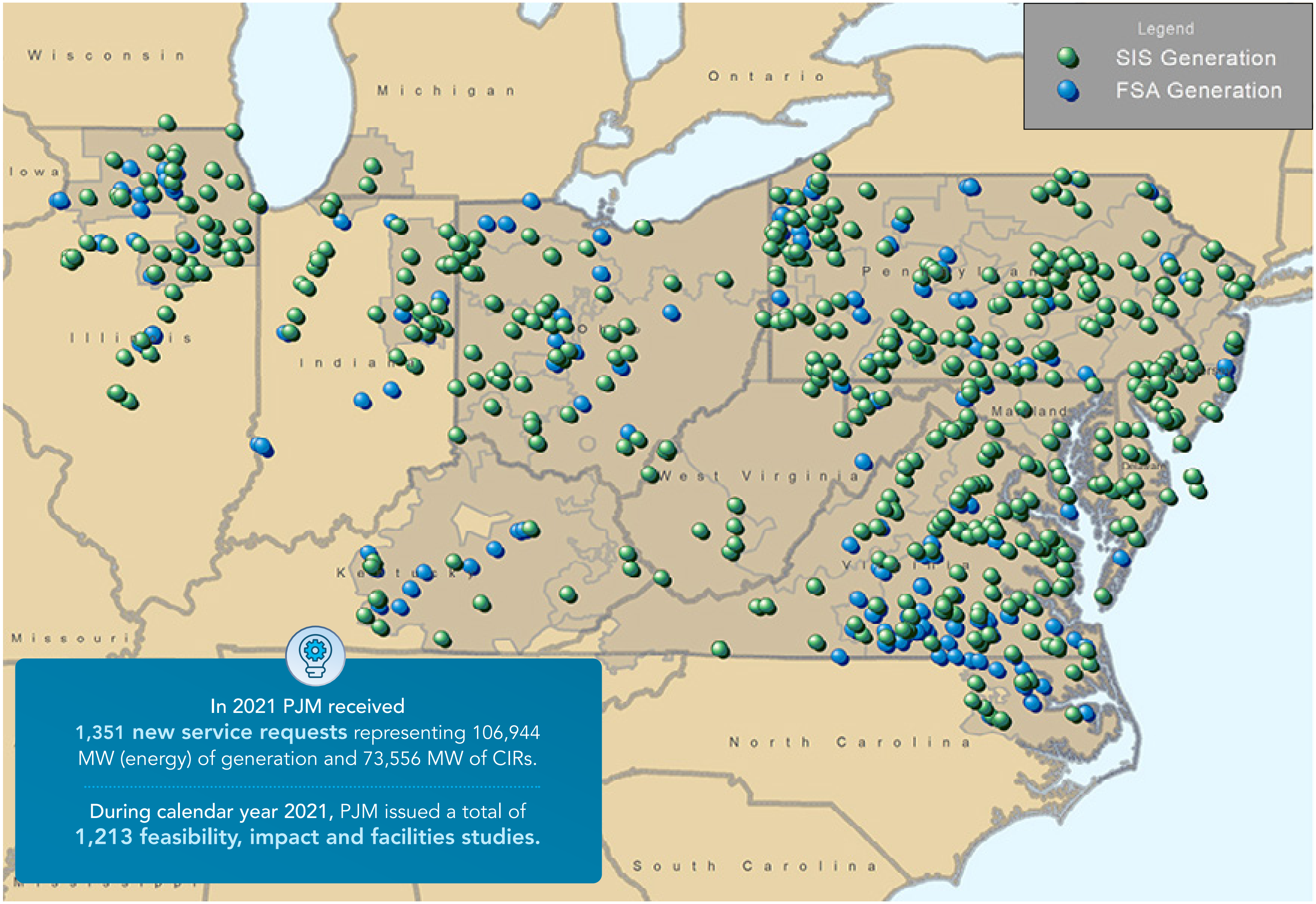
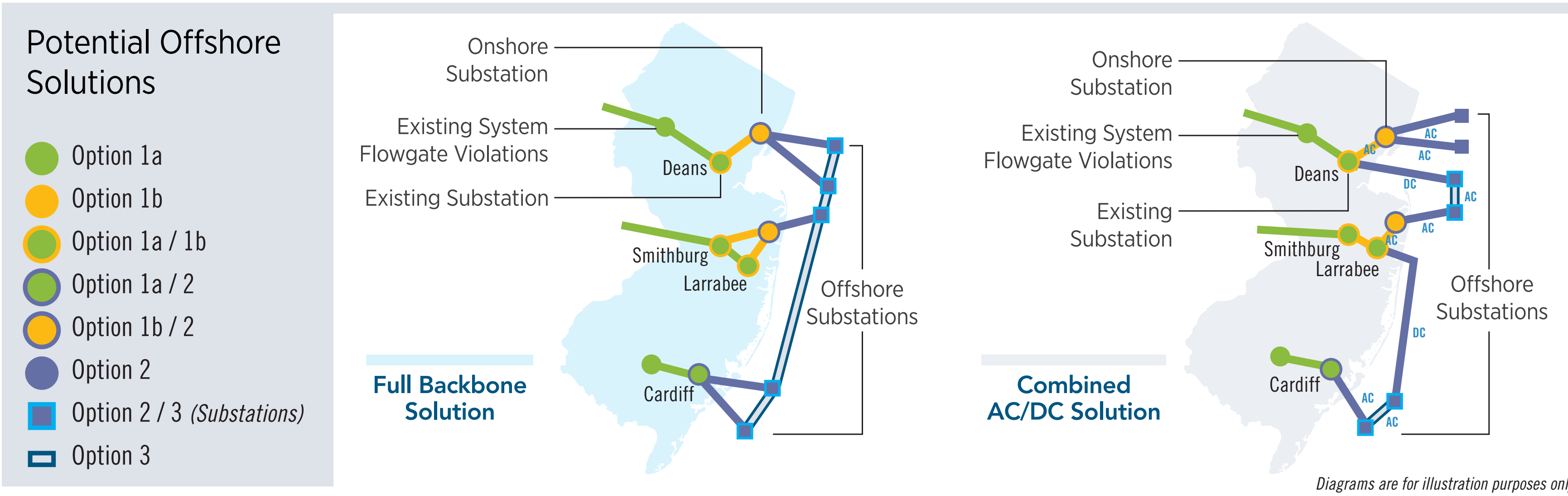
Map 1.5: Feasibility and System Impact Studies Performed in 2021



In 2021 PJM received
1,351 new service requests representing 106,944 MW (energy) of generation and 73,556 MW of CIRs.

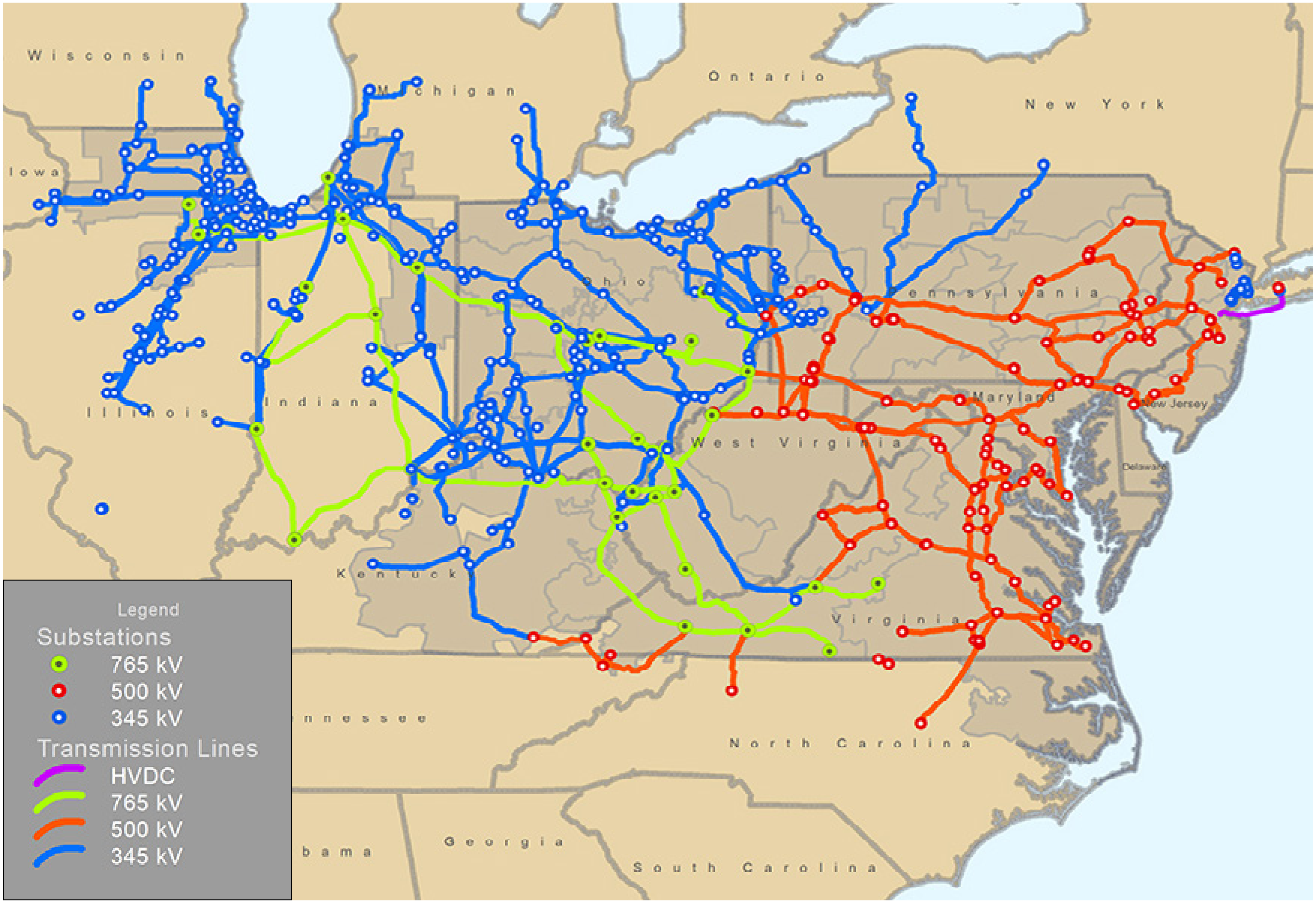
During calendar year 2021, PJM issued a total of
1,213 feasibility, impact and facilities studies.

Figure 1.7: New Jersey Offshore Wind Potential Solutions



Diagrams are for illustration purposes only.

Map 1.6: PJM Backbone Transmission System



Appendix 5: RTEP Project Statistics

5.0: RTEP Project Statistics

This set of figures and tables summarizes the estimated costs for projects presented at the Transmission Expansion Advisory Committee or Subregional TEAC meetings. It is intended to provide a visual representation and consolidate materials presented elsewhere in this report to allow stakeholders to view trends in the identification of violations over time, and by voltage class. Where historical costs are used in the comparison of a graph, the costs have been adjusted for inflation to have a common representation of 2021 dollars, as discussed below.

1. Baseline project was approved by the PJM Board.
2. Supplemental project was presented at the TEAC or Subregional TEAC meetings.
3. Costs are provided by the designated entity or transmission owners. Cost estimation methods may vary by company. Estimated costs in this document may include cost caps or cost containment, even though it isn't specifically noted.
4. Cost estimates may change over time as new information is incorporated into the estimate by the project sponsor. This document reflects the current estimates that are provided to PJM.
5. Estimated project costs are adjusted by average inflation rate from 2011 to 2020 (1.73%).
6. Transmission line mileage is based on FERC Form 1 filed in 2019 or EIA-411 Schedule 6A for 2020.
7. TO peak load is the average of forecasted summer peak load from 2022 to 2026.

Figure 5.1: Project Status as of Dec. 31, 2021

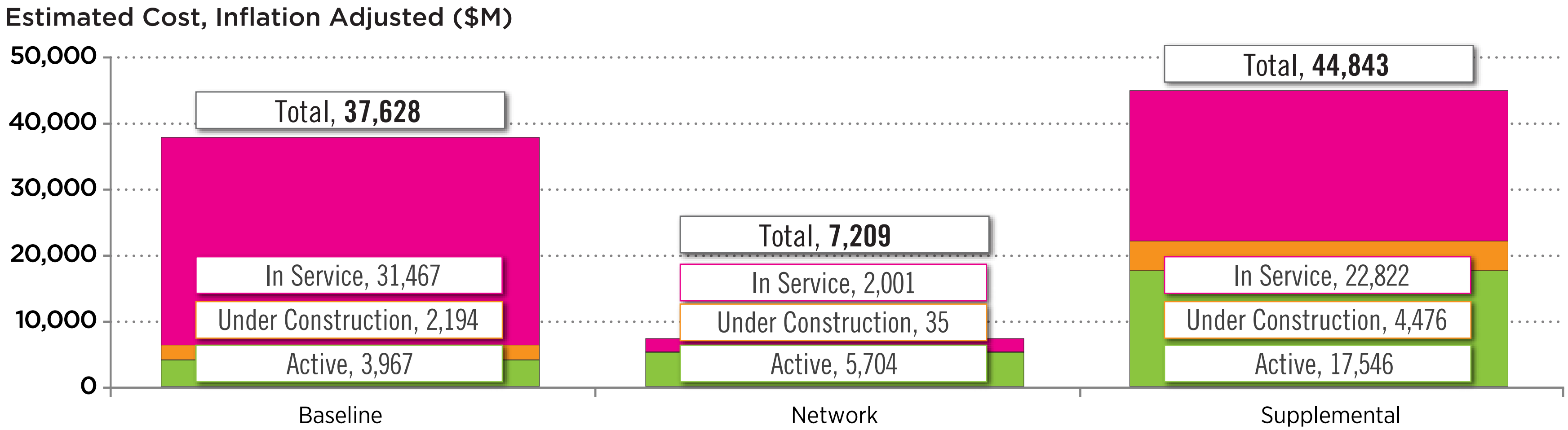


Figure 5.2: Baseline and Supplemental Projects by Year

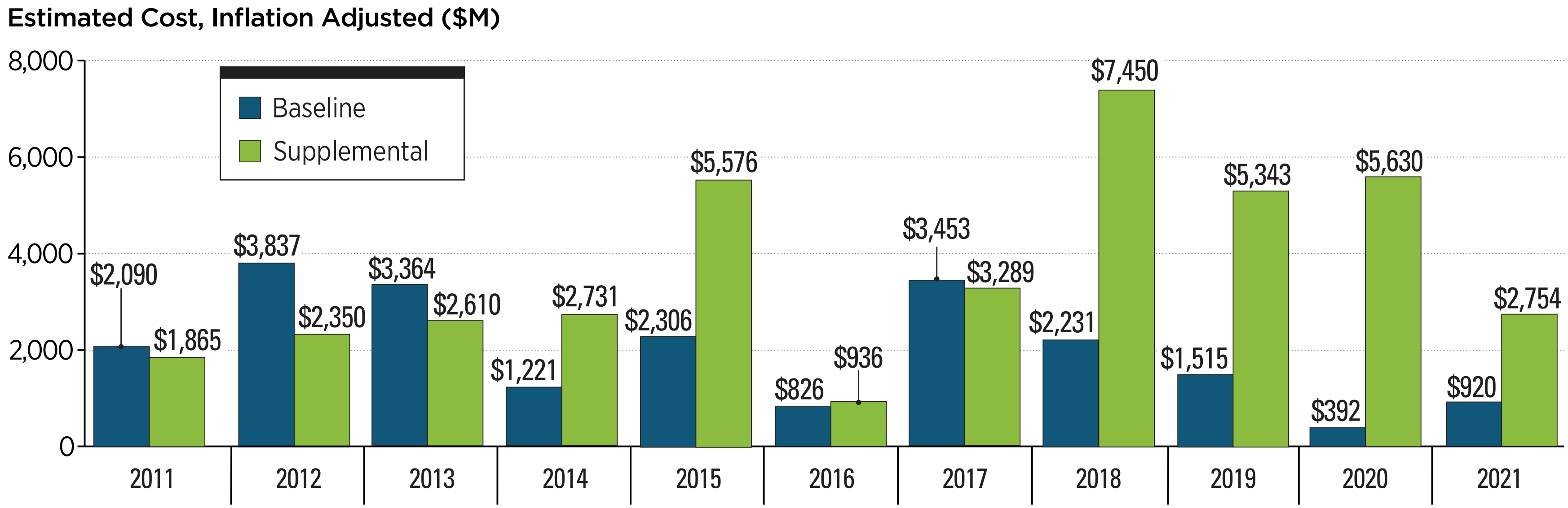


Figure 5.3: PJM Baseline Projects by Criteria

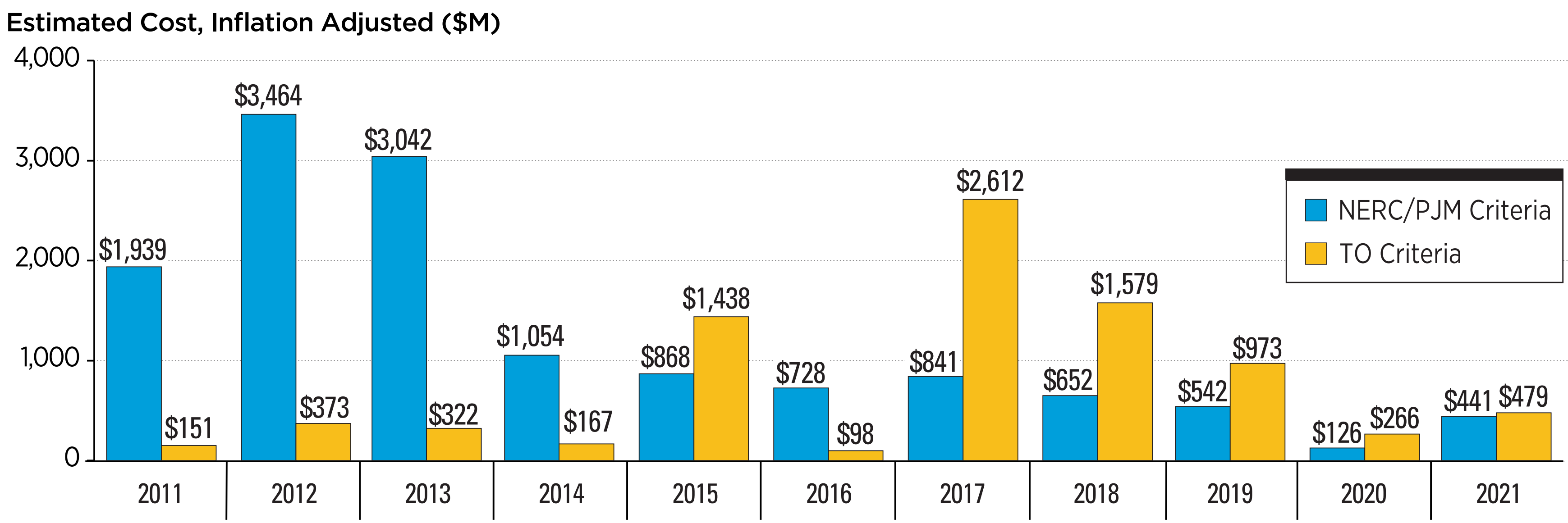


Figure 5.4: Baseline Projects by Voltage

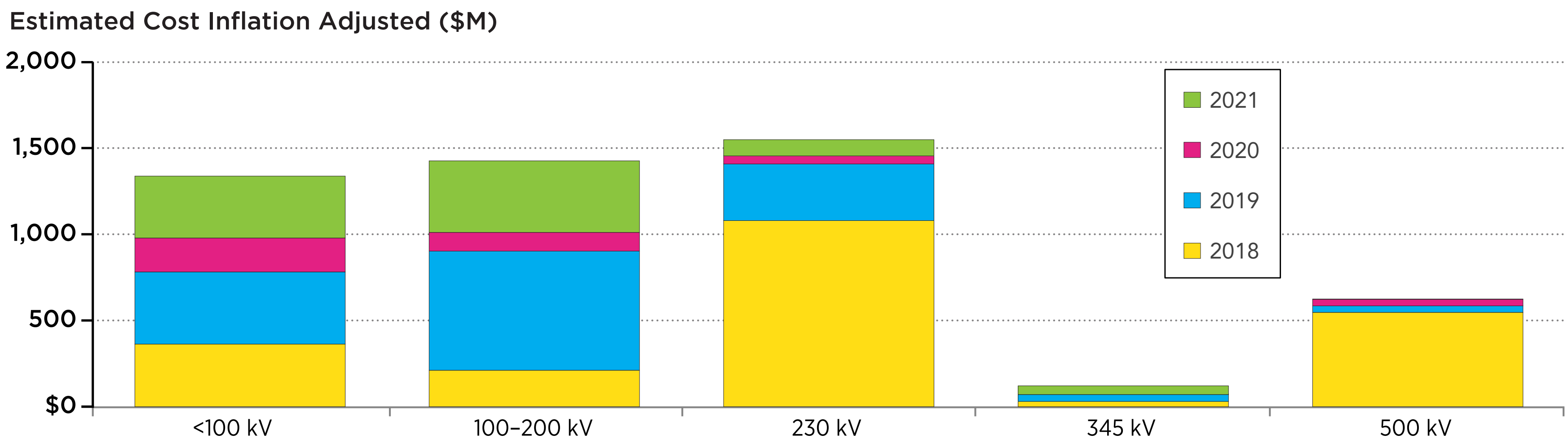


Figure 5.5: Supplemental Projects by Voltage

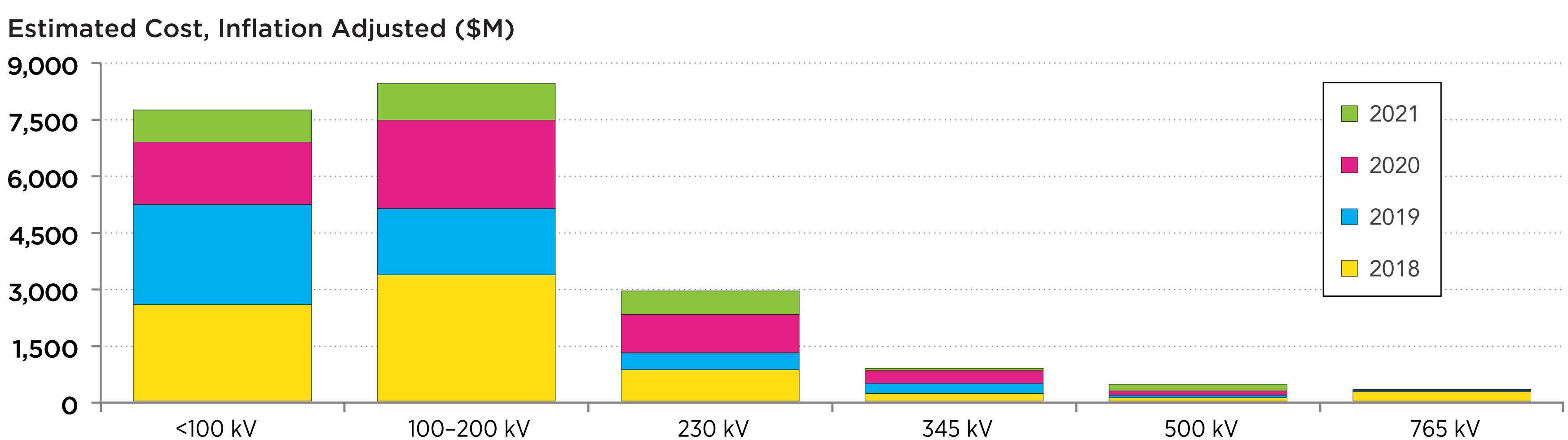


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2011

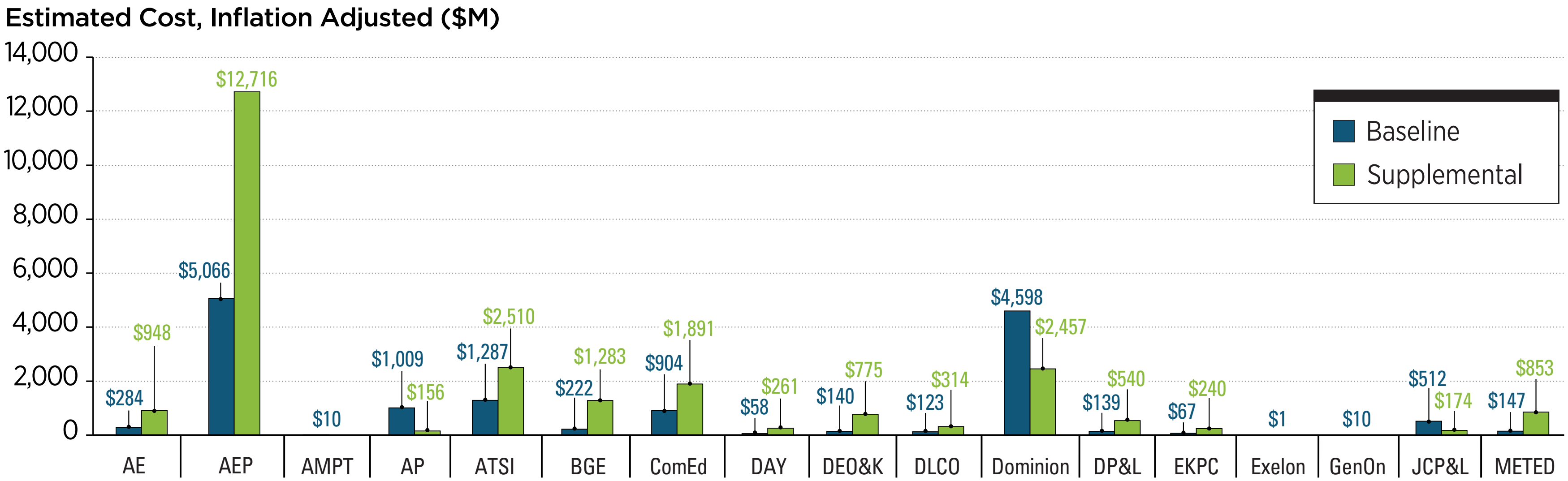


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2011 (Cont.)

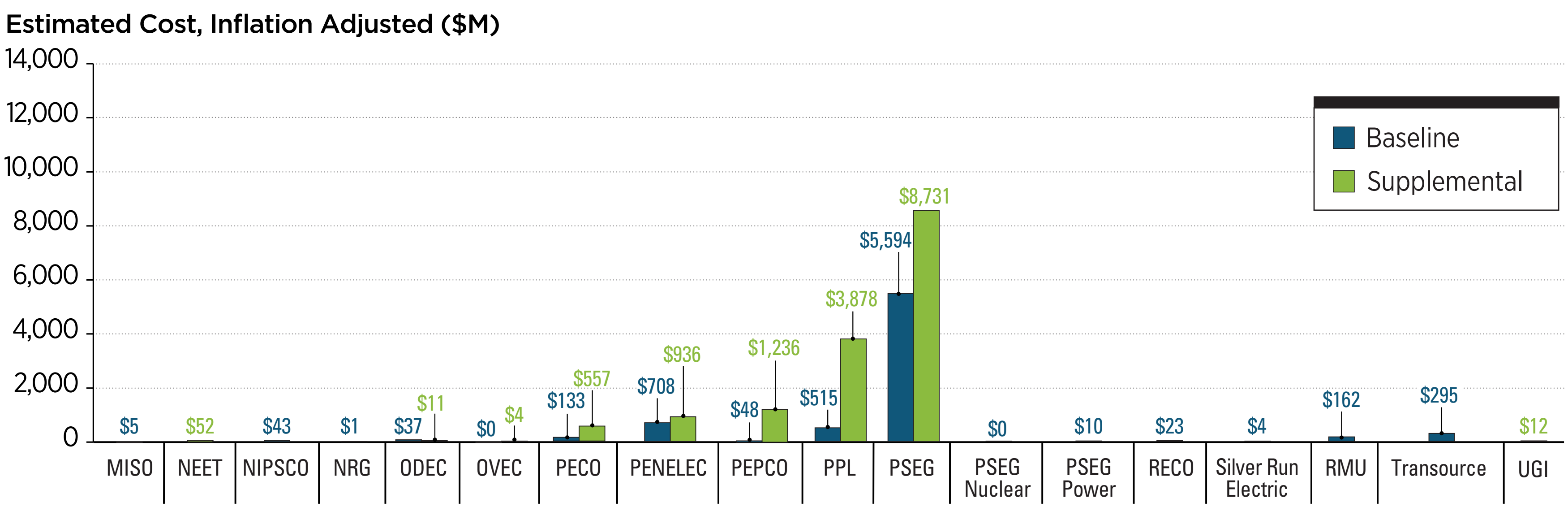


Figure 5.7: 2021 Baseline and Supplemental Projects by Designated Entity

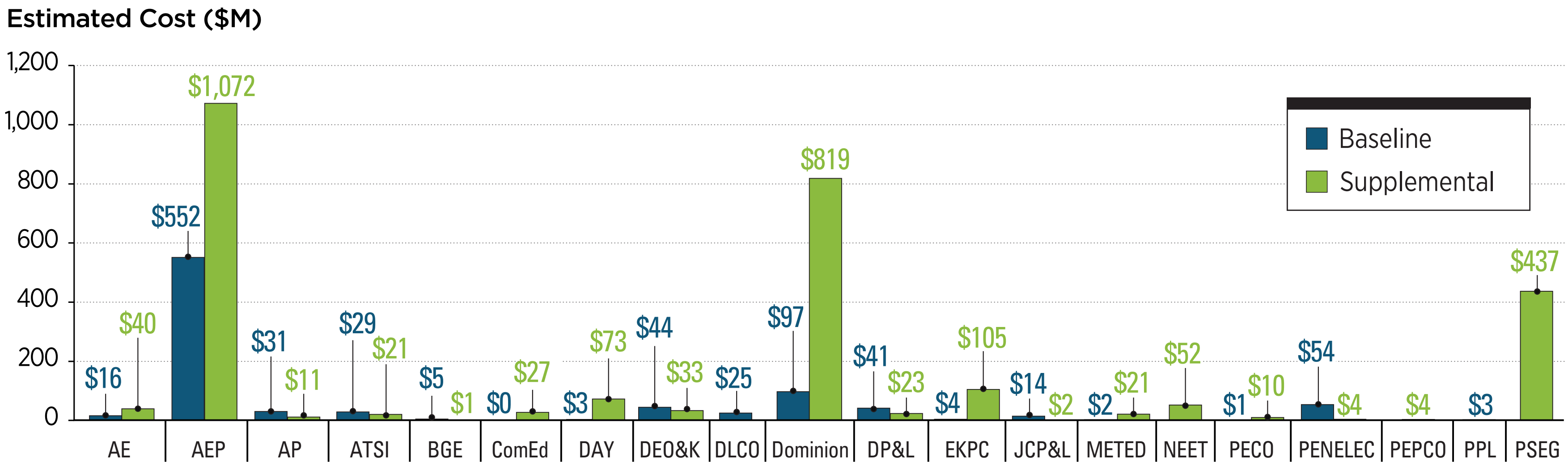


Figure 5.8: Baseline and Supplemental Projects Adjusted by Peak Load Since 2011

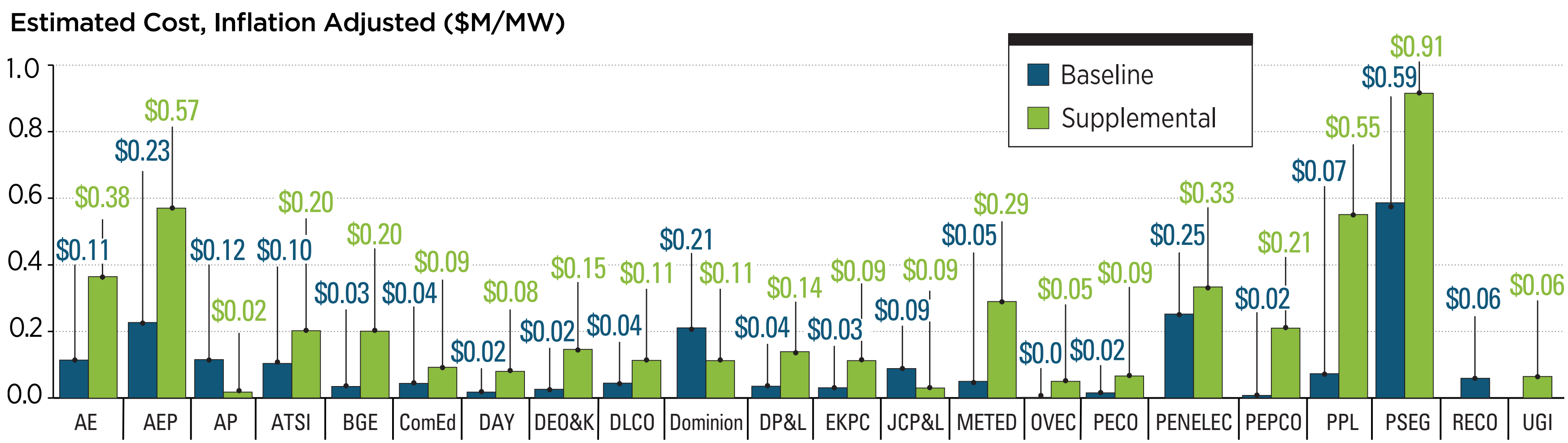


Figure 5.9: 2021 Baseline and Supplemental Projects Adjusted by Peak Load

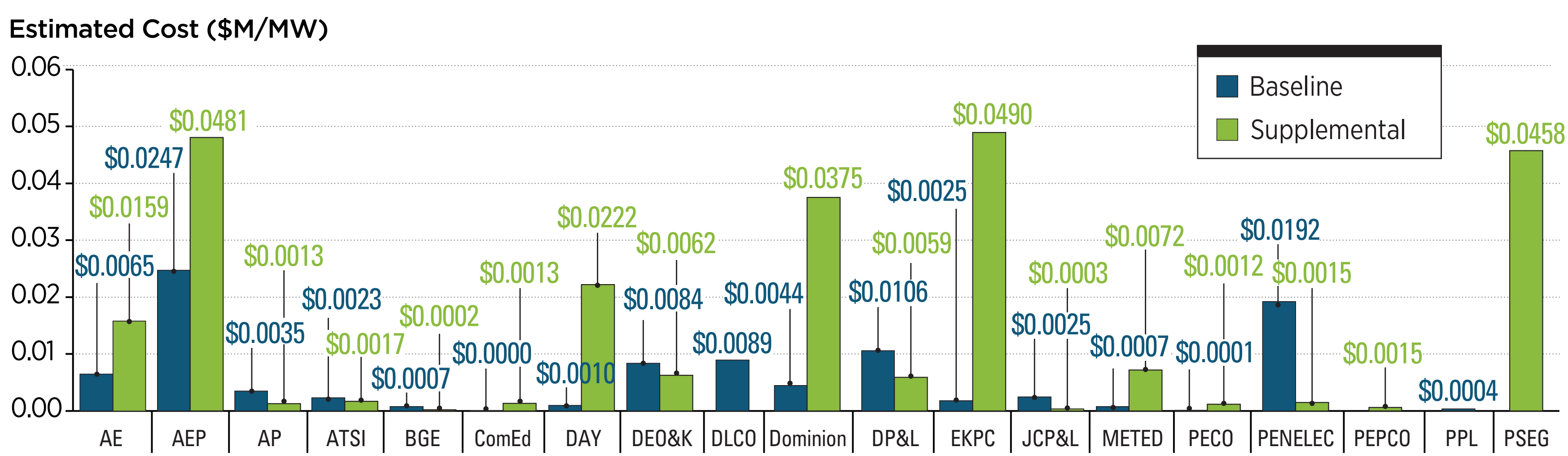


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Figure 5.10: Baseline and Supplemental Projects Adjusted by Circuit Miles Since 2011

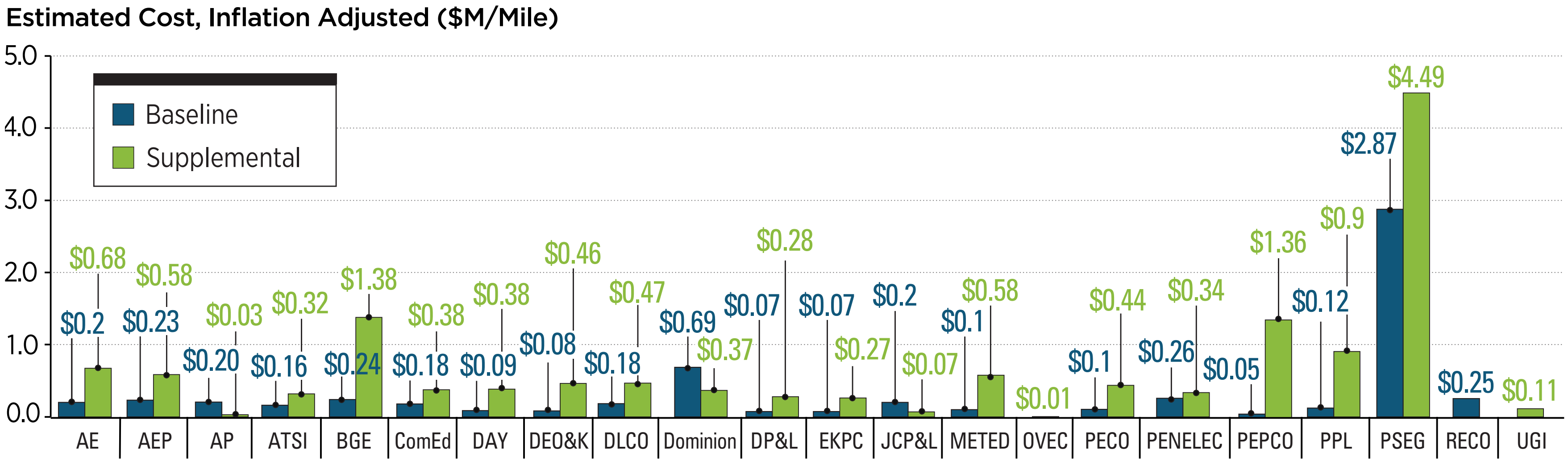

Figure 5.11: 2021 Baseline and Supplemental Projects Adjusted by Circuit Miles