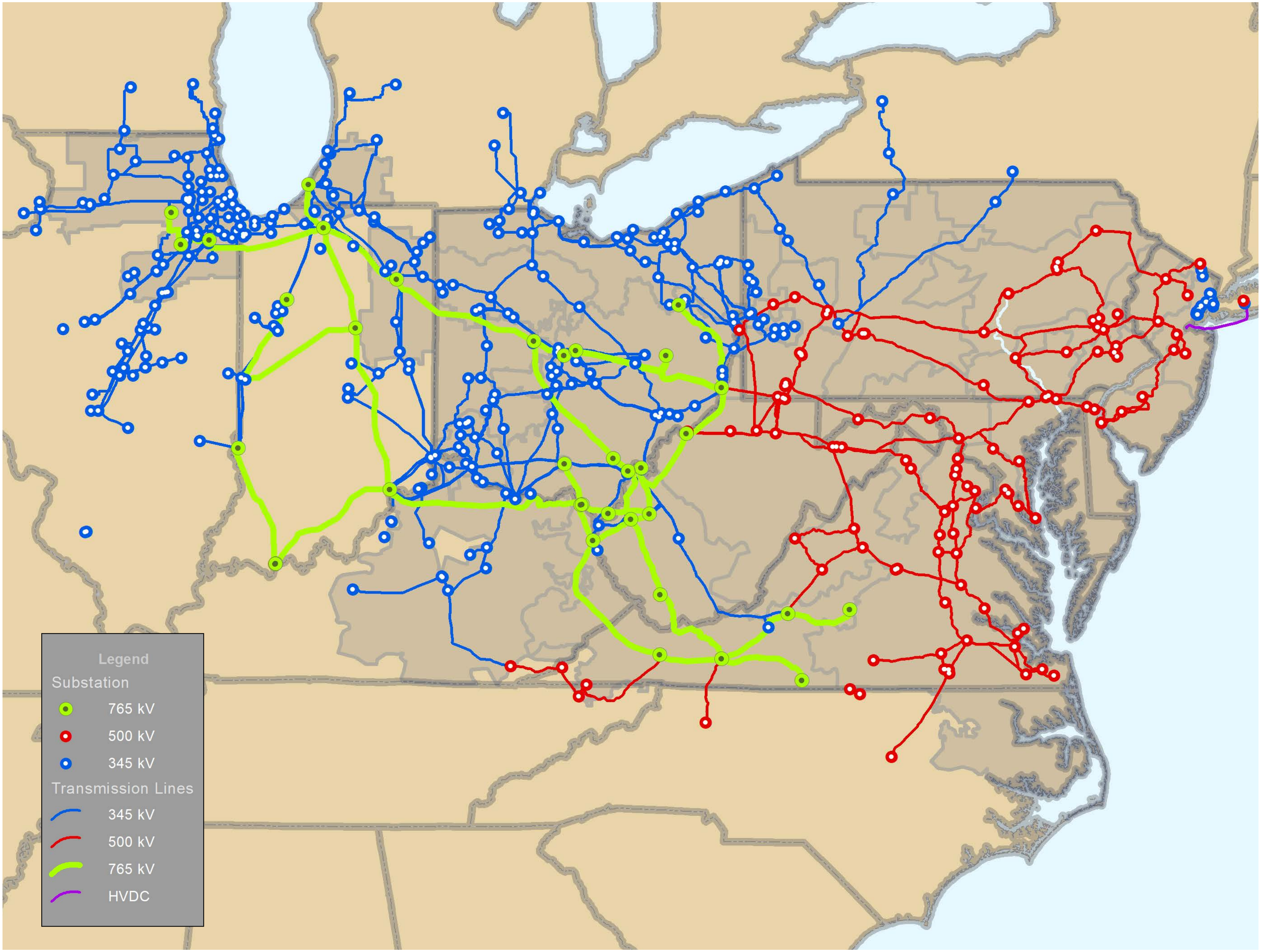
RTEP

2020 REGIONAL TRANSMISSION EXPANSION PLAN

FEBRUARY 28, 2021

pjm®



Legend
Substation
765 kV
500 kV
345 kV
Transmission Lines
345 kV
500 kV
765 kV
HVDC

Preface

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 need.

In 2020, 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 2020 RTEP activities, including process improvements and a summary of projects organized by driver.
- **Section 2** includes an overview and detailed data from PJM's 2020 Load Forecast Report.
- **Section 3** provides 2020 RTEP project highlights, generator deactivations and re-evaluation 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.
- **Appendix 1** – Tranmission Owner Zones and Locational Deliverability Areas
- Glossary
- Topical Index
- Key Maps, Tables and Figures
- RTEP Project Statistics

Planning Community

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

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

RTEP Process Description

The online resources below provide additional description of RTEP process business rules and methodologies:

- The Manual 14 series contains the specific business rules that govern the RTEP process. Specifically, Manual 14B describes the methodologies for conducting studies and developing solutions to solve planning criteria violations and market efficiency issues. PJM Manual 14B, Regional Planning Process, is available on the PJM website.
- Schedule 6 of the PJM Operating Agreement codifies the overall provisions under which PJM implements its Regional Transmission Expansion Planning protocol, more familiarly known (and used throughout this document) as the PJM RTEP process. The PJM Operating Agreement is available on the PJM website.
- The PJM Open Access Transmission Tariff (OATT) codifies provisions for generating resource interconnection, merchant/customer-funded transmission interconnection, long-term firm transmission service and other specific new service requests. The PJM OATT is available on the PJM website.
- The status of individual PJM Board-approved baseline and network RTEP projects, as well as that of Transmission Owner Supplemental Projects, is available on the PJM website.

Stakeholder Forums

The Planning Committee, established under the PJM Operating Agreement, has the responsibility to review and recommend system planning strategies and policies, as well as planning and engineering designs for the PJM bulk power supply system to assure the continued ability of the member companies to operate reliably and economically in a competitive market environment.

Additionally, the Planning Committee makes recommendations regarding generating capacity reserve requirements and demand-side valuation factors. Committee meeting materials and other resources are available on the PJM website.

The Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP committees continue to provide forums for PJM staff and stakeholders to exchange ideas, discuss study input assumptions and review results. Stakeholders are encouraged to participate in these ongoing committee activities. TEAC resources are available on the PJM website.

Each Subregional RTEP committee provides a forum for stakeholders to discuss local planning concerns. Interested stakeholders can access Subregional RTEP committee planning process information from the PJM website:

- PJM Mid-Atlantic Subregional RTEP
- PJM Western Subregional RTEP Committee
- PJM Southern Subregional RTEP Committee

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Section 1: 2020 Executive Summary

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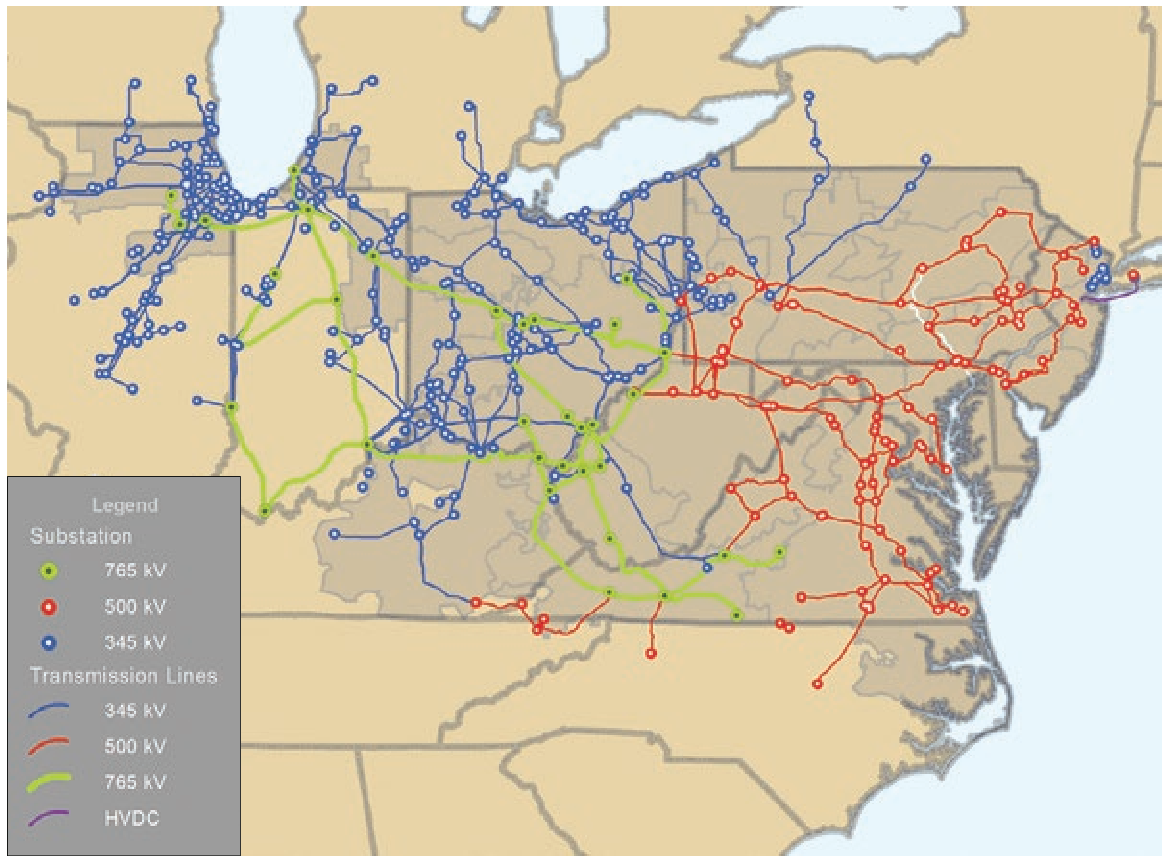
1.0: 2020 Executive Summary

1.0.1 — Regional Planning

PJM, a FERC-approved 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 Illinois western border, including the metropolitan areas in and around Baltimore, Chicago, Columbus, Cleveland, Dayton, Newark and Northern New Jersey, Norfolk, Philadelphia, Pittsburgh, Richmond, Toledo and the District of Columbia.

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

Map 1.1: PJM Backbone Transmission System



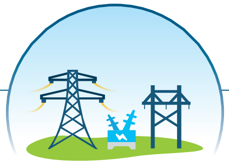
KEY 2020 HIGHLIGHTS

Forty-three new baseline projects were planned during 2020 at an estimated cost of $413 million to ensure fundamental system reliability across the grid. Fifty-five new network transmission projects at an estimated cost of $101 million are required to ensure the reliable delivery of generation seeking interconnection to PJM markets.

Renewables in PJM's interconnection queue now exceed other fuels with 88 percent wind, solar and storage. Overall, nearly 2,000 MW of units across all fuel types reached commercial operation across the PJM region in 2020, including a pilot offshore wind project in Virginia.

PJM and MISO Boards approved the first interregional market efficiency transmission project – replacement of the Michigan City-Trail Creek-Bosserman 138 kV line – based on a competitive planning process.

- Over 1.96 GW of new generation reached commercial operation.
- Wind, solar and storage requests now total over 120,000 MW in PJM's interconnection queue. Solar has more than doubled over 2019, now comprising 56 percent of PJM's queue.
- PJM processed 1,028 requests to interconnect new generation totaling 70,375 MW, nameplate capability, and 44,179 MW of capacity interconnection rights (CIRs) for which 1,424 feasibility, system impact and facilities studies were issued to developers.



- Baseline projects in 2020 driven by TO criteria violations comprised 64 percent ($264 million) of approved baseline projects. 22 percent were driven by generator deactivations. 14 percent were driven by NERC, TO and PJM baseline criteria.
- Twenty-two deactivation notifications totaling 4,428 MW were received during 2020. Twenty-nine units totaling 3,300 MW formally retired in 2020.
- PJM and New Jersey announced the implementation of the RTEP Process State Agreement Approach to develop public policy-driven transmission to satisfy state offshore wind power objectives.

- PJM 2020 forecasted load growth rate remained flat at a 10-year RTO summer, normalized peak growth rate of 0.6 percent.
- Load forecasting improvements continued in 2020, focusing on reducing summer and winter forecast error with refinements to both sector and non-weather-sensitive model components.
- PJM's Installed Reserve Margin for the 2021/2022 Delivery Year declined from 15.1 percent to 14.7 percent, driven by a strong generation performance and a subsequent reduction in generation forced outage rates, particularly for. natural gas-powered combined cycle units.
- The COVID-19 pandemic had an immediate and significant impact on PJM load beginning in mid-March 2020 – reducing energy demand by greater than 10 percent at its most severe level in the spring – and subsiding during the summer. Total COVID-19-related impact on PJM energy in 2020 was estimated to be about negative 5 percent.

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RTO Perspective

PJM's RTEP process spans state boundaries shown in **Map 1.1** and is a key RTO function, as shown in **Figure 1.1**. A regional perspective gives PJM the ability to identify one optimal, comprehensive set of solutions to solve reliability criteria violations, operational performance issues and market efficiency constraints. Specific system enhancements are justified 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. Expected system conditions can change such that justification for a project no longer exists nor 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 of many drivers, including those arising out of reliability, aging infrastructure, operational performance, market efficiency, public policy and demand-side trends. Importantly though, 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

Figure 1.1: RTEP Process – RTO Perspective

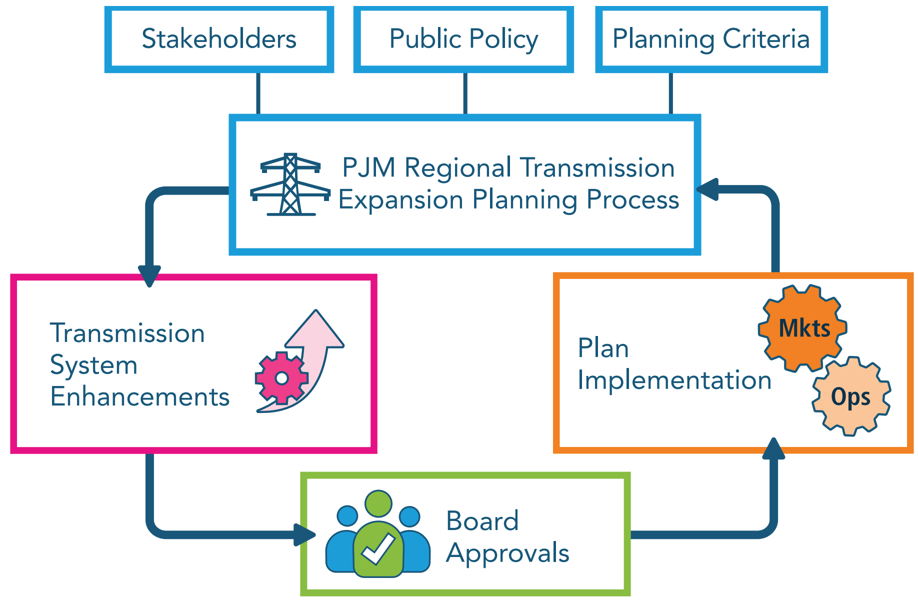
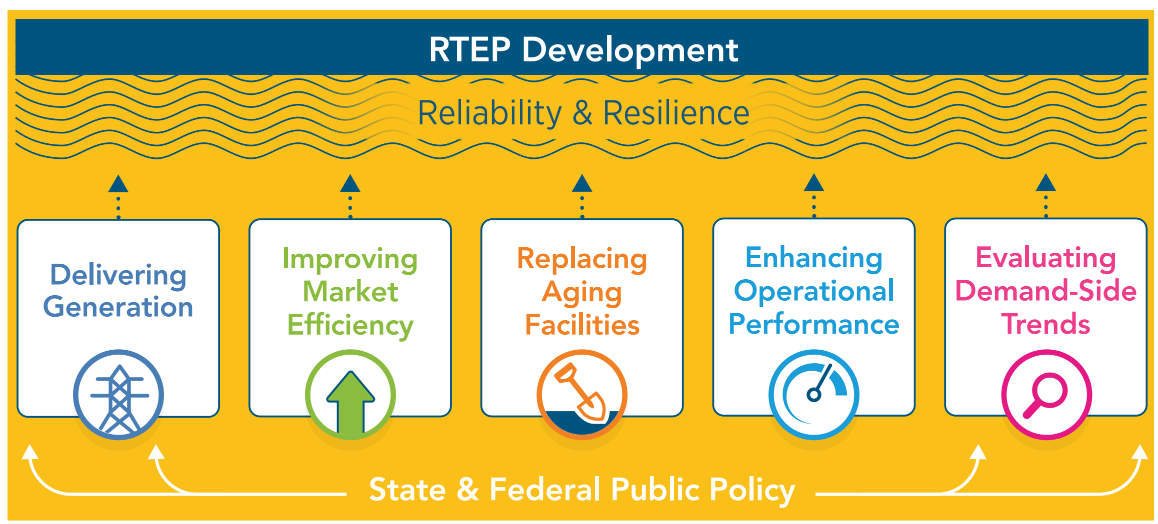


Figure 1.2: System Enhancement Drivers



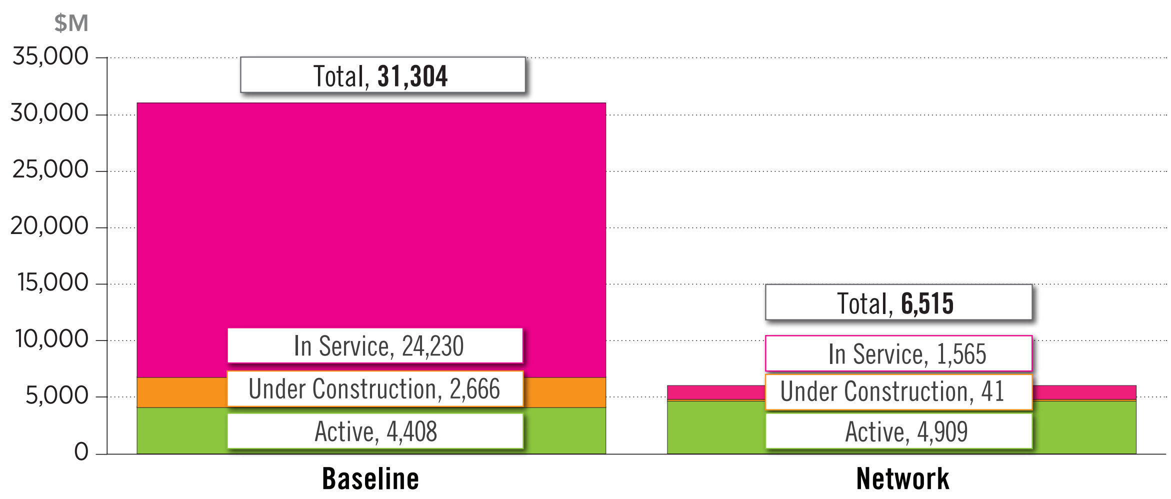
with the thermal, reactive, stability and short-circuit North American Electric Reliability Corp. (NERC) Standard TPL-001-4 as described in **Section 1.2**.

Highlights of projects identified and approved by the PJM Board during 2020 appear in **Section 3**. Details of specific large-scale projects – those greater than or equal to $10 million in scope – are presented in **Section 6**.

1.0.2 — 2020 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 2020 RTEP process continued to yield grid enhancements to ensure that delivery under a historic and unprecedented generation shift is now driven increasingly by public policy and fuel economics.

Figure 1.3: Board-Approved RTEP Projects as of Dec. 31, 2020



- The PJM Board approved 43 new baseline projects during 2020 at an estimated $413 million to ensure that fundamental system reliability criteria across the grid are met. Projects driven by TO criteria violations comprised 64 percent ($264 million) of approved baseline projects. 22 percent were driven by generator deactivations. 14 percent were driven by other NERC and PJM reliability criteria.
- Notably, baseline projects in 2020 also included PJM's first interregional market efficiency transmission project – replacement of the Michigan City-Trail Creek-Bosserman 138 kV – approved by PJM and MISO Boards and was the outcome of an interregional competitive planning process to reduce congestion along the PJM/MISO seam.
- The Board also approved 55 new network transmission projects at an estimated $101 million.

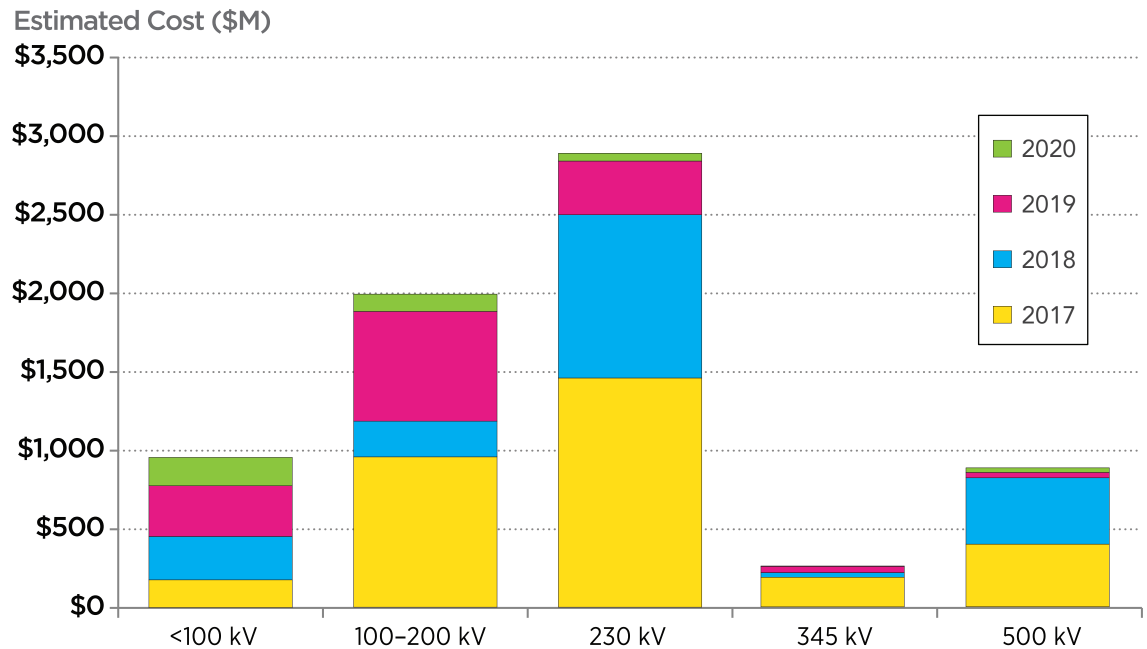
The PJM Board has approved transmission system enhancements totaling approximately $37.8 billion. Of this, approximately $31.3 billion represents baseline projects to ensure compliance with NERC, regional and local transmission owner planning criteria and to address market efficiency congestion relief. 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, 2020, appears in **Figure 1.3**.The numbers provide a snapshot of one point in time, as with an end-of-year balance sheet. The 2020 totals, and likewise those in **Figure 1.3**, reflect revised cost-estimate changes and project cancellations for previously approved RTEP elements. For example, PJM can recommend canceling a network system enhancement from the RTEP when a queued project driving the need for the network project withdraws from the queue. Withdrawals at this point in the interconnection process are typically driven by developer business decisions, including PJM Reliability Pricing Model (RPM) auction activity, siting challenges, financing challenges or other business model factors.

Supplemental projects are identified and developed by transmission owners to address local reliability needs, including customer service; equipment material condition, performance and risk; operational flexibility and efficiency; and infrastructure resilience. PJM reviews them to evaluate their impact on the regional transmission system. A discussion of supplemental projects, including summaries by driver greater than or equal to $10 million, is included in **Section 3.2**.

Shifting RTEP Dynamics

The $413 million of baseline transmission investment approved during 2020 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 one percent. Aging infrastructure, grid resilience, 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 and earlier.

Figure 1.4: Approved Baseline Projects by Voltage 2017–2020



No baseline projects at the 765 kV level were identified for this time period.

Flat Load Growth

PJM's 2020 RTEP baseline power flow model for study year 2025 was based on the 2020 PJM Load Forecast Report, summarized in **Section 2**, showing a 10-year RTO summer, normalized peak growth rate of 0.6 percent. Average 10-year-annualized summer growth rates for individual PJM zones ranged from -0.5 percent to 1.5 percent. 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.

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

PJM's interconnection process is showing trends of increasing renewable generation. With approximately 105,000 MW of interconnection requests, nearly 59,000 MW, or 56 percent, of all requested interconnection rights were for solar generation. Storage and wind generation types constitute 10.4 percent, 6.3 percent respectively. Renewable generation is not the only changing aspect of PJM's capacity mix. Existing RPM-eligible, natural gas-fired generation capacity greatly exceeds that of coal. Natural gas plants totaling nearly 28,000 MW constitute 27 percent of the generation currently seeking capacity interconnection rights in PJM's new services queue. Solar generation has overtaken natural gas as the largest percentage of units seeking capacity interconnection rights. Solar interconnection requests have more than doubled, by megawatt, in the past year.

More than 30,600 MW of coal-fired generation have deactivated between 2011 and 2020. 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. PJM continued to receive deactivation notifications from 10 units totaling 4,428 MW throughout 2020. Approximately 2,500 MW of these announced deactivations were from coal units, with the reaming portion attributable to one nuclear facility. The impacts of deactivation notices received during 2020 are discussed in **Section 3.3.**

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1.1: Generation in Transition

PJM's 184,395 MW of RPM-eligible existing installed capacity reflects a fuel mix comprising 43 percent natural gas, 27 percent coal and 18 percent nuclear, as shown in **Figure 1.5**. Hydro, wind, solar, oil and waste fuels constitute the remaining 11 percent. 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 76,000 MW, renewable fuels are changing the landscape of PJM's interconnection queue. Solar energy comprises 56 percent of the generation in PJM's interconnection queue, a 13 percent increase over the previous year, 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 capacity interconnection rights for generation that was active, under construction or suspended as of Dec. 31, 2020.

Figure 1.5: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2020)

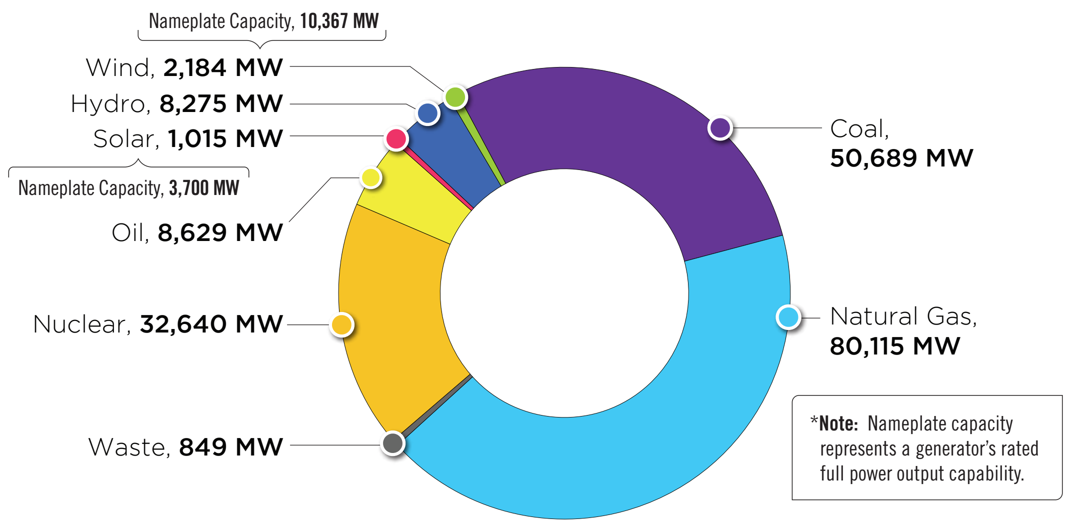


Figure 1.6: Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2020)

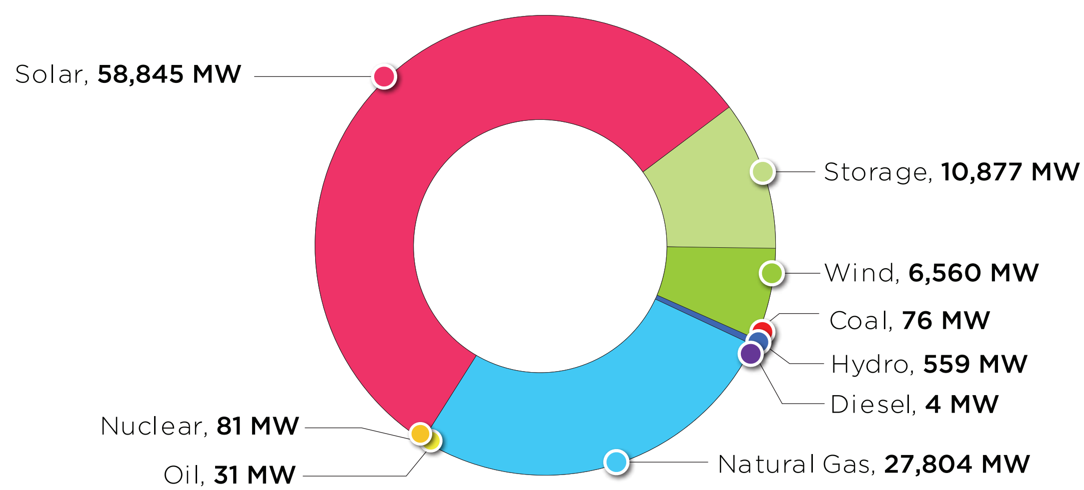


Table 1.1: Requested Capacity Interconnection Rights, Non-Renewable and Renewable Fuels (Dec. 31, 2020)

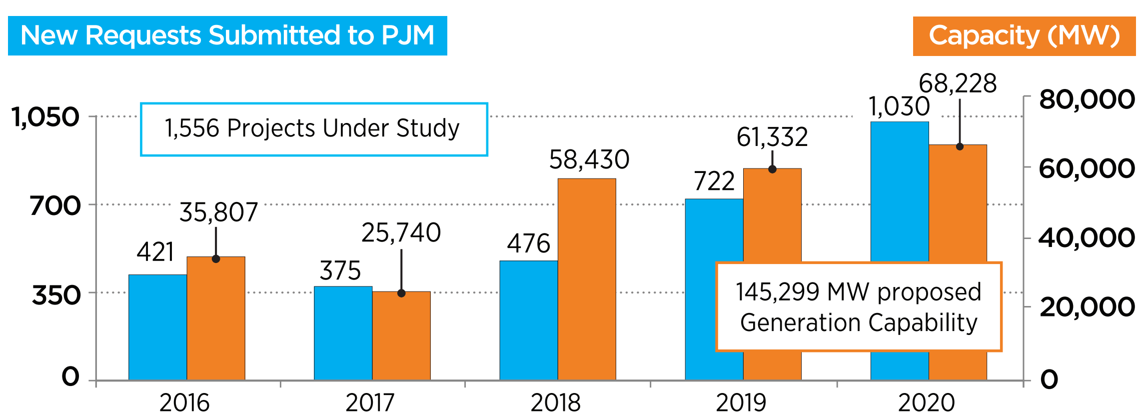
		In Queue						Complete				Grand Total	
		Active		Suspended		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	1	11.0	0	0.0	3	65.0	53	2,146.9	70	33,577.6	127	35,800.5
	Diesel	0	0.0	0	0.0	1	4.1	9	64.4	16	76.7	26	145.2
	Natural Gas	62	10,312.4	9	4,457.0	51	13,034.5	343	48,575.9	659	240,631.2	1,124	317,011.0
	Nuclear	5	37.4	0	0.0	1	44.0	43	3,902.8	22	9,038.0	71	13,022.2
	Oil	3	18.0	0	0.0	8	13.0	18	539.8	22	2,300.0	51	2,870.8
	Other	0	0.0	0	0.0	0	0.0	5	336.5	84	858.8	89	1,195.3
	Storage	250	10,839.5	7	17.6	6	20.0	26	4.0	213	3,730.3	502	14,611.4
Renewable	Biomass	0	0.0	0	0.0	0	0.0	11	252.8	40	896.9	51	1,149.7
	Hydro	7	536.5	0	0.0	2	22.7	32	1,155.9	49	2,146.7	90	3,861.8
	Methane	0	0.0	0	0.0	0	0.0	85	411.8	95	490.1	180	901.8
	Solar	1,120	54,431.2	32	659.1	202	3,754.5	188	1,204.0	1,374	26,271.4	2,916	86,320.3
	Wind	98	6,178.7	6	95.8	11	285.6	105	1,933.2	477	14,300.2	697	22,793.5
	Wood	0	0.0	0	0.0	0	0.0	2	54.0	4	153.0	6	207.0
Other	Battery	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	0.0
	Grand Total	**1,547**	**82,364.7**	**54**	**5,229.6**	**285**	**17,243.4**	**920**	**60,582.0**	**3,125**	**334,470.9**	**5,931**	**499,890.5**

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-powered generation growth. As **Figure 1.6, Figure 1.7** and **Table 1.1** show, queued requests as of Dec. 31, 2020, for Capacity Interconnection Rights (CIRs) totaled 6,560 MW of wind-powered generators that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 31,809 MW. Queued solar-powered

Figure 1.7: Growth of Renewables in PJM Queue



generator requests for CIRs totaled 58,845 MW that were actively under study, suspended or under construction. Those CIRs correspond to nameplate capacity totaling 97,585 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 continually like conventional fossil-fueled power plants, other 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 presents challenges 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 request.

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, 2020)

	Projects	Capacity (MW)	Nameplate Capability (MW)
Active	1,547	82,364.7	145,507
In Service	920	60,582.0	72,723
Suspended	54	5,229.6	7,017
Under Construction	285	17,243.4	21,713
Withdrawn	3,125	334,470.9	426,656
Grand Total	**5,931**	**499,890.5**	**673,616**

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

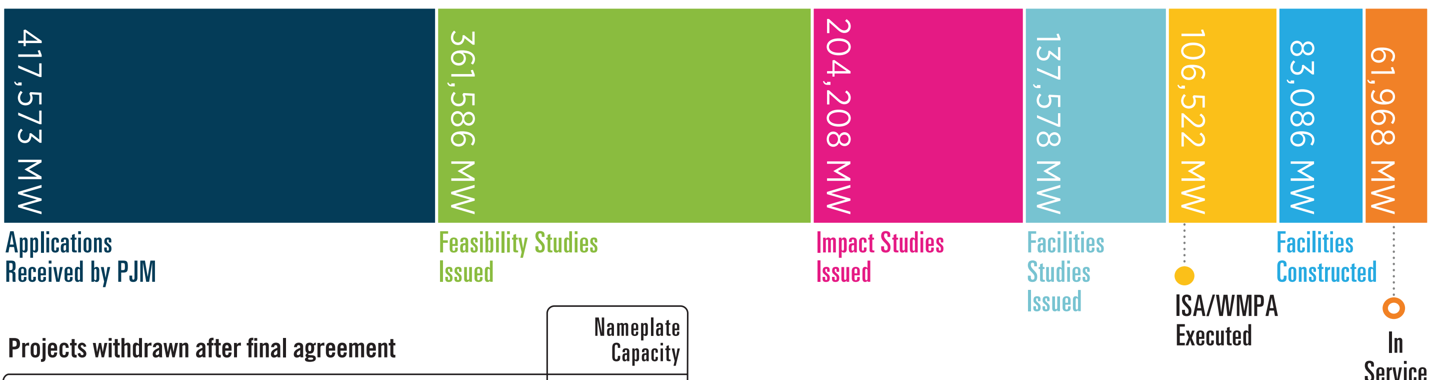
PJM markets have attracted generation proposals totaling 499,891 MW, as shown in **Table 1.2**. Over 82,360 MW of interconnection requests were actively under study and over 22,400 MW were under construction or suspended as of Dec. 31, 2020. PJM's queue-based interconnection process offers developers 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, and regulatory, industry, economic and other competitive factors.

Queue Progression History

PJM reviews generation queue progression annually to understand overall developer trends and their impact on PJM's interconnection process. **Figure 1.8** shows that for all generation submitted in PJM's Interconnection process through Dec. 31, 2020, only 61,968 MW – 14.8 percent – reached commercial operation. Note that **Figure 1.8** reflects requested capacity interconnection rights that are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants, as described earlier.

Following interconnection service agreement (ISA) or wholesale market participant agreement (WMPA) execution, 22,442 MW of capacity with ISAs and 1,107 MW of capacity with WMPAs withdrew from PJM's interconnection process. Overall, 23 percent of requests by project reach commercial operation, whereas only 15 percent of requests by megawatt reach commercial operation.

Figure 1.8: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
177	Interconnection Service Agreements	**22,442** MW	30,294 MW
291	Wholesale Market Participation Agreements	**1,107** MW	2,293 MW

Percentage of planned capacity and projects that have reached commercial operation		
	15% Requested capacity megawatts	**23%** Requested projects

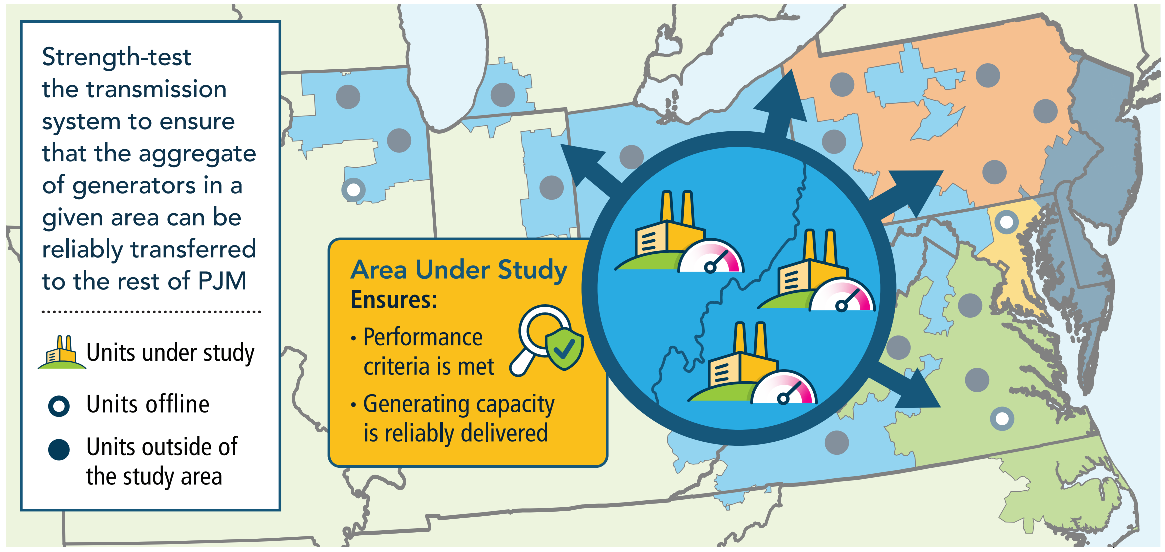
This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, meaning the generation reached in-service operation, began construction, or was suspended or withdrawn. It does not include projects considered active in the queue as of Dec. 31, 2020.

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 $6.5 billion to interconnect over 90,000 MW of new generating resources and satisfy other new service requests – merchant transmission interconnection, for example. The PJM Board approved 55 new network system enhancements totaling over $101 million in 2020 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 the transmission system 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

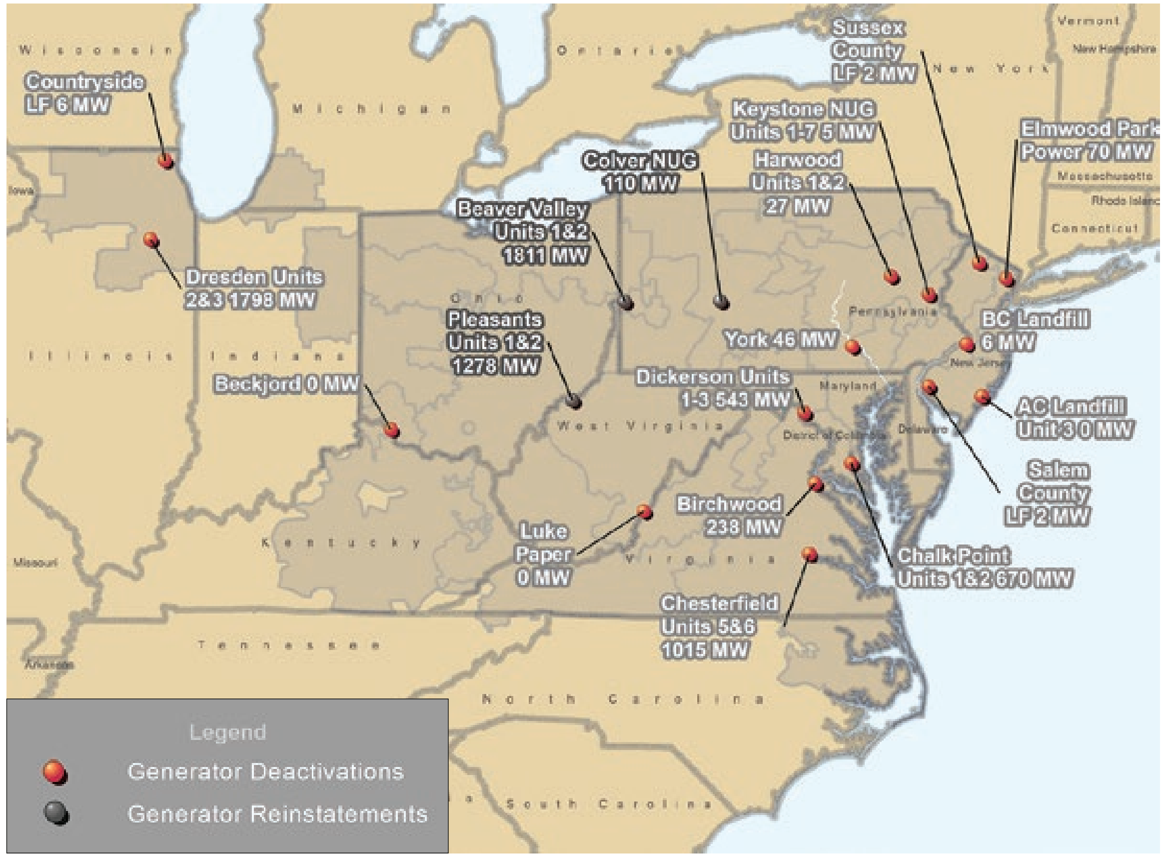
PJM received 22 deactivation notifications in 2020 totaling 4,428 MW, down from the previous eight years. **Map 1.2** shows the deactivation request locations received in 2020.

Generator owners requested the deactivation of these units to take place between June 2020 and May 2023. PJM maintains a list of formally submitted deactivation notifications, 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, undermine voltage support. Deactivation reliability studies comprise thermal and voltage analysis, including generator deliverability, common mode outage, N-1-1 analysis and load deliverability tests. Solutions to address reliability violations resulting from generator deactivations may include upgrades to existing facilities, scope expansion for current baseline projects already in the RTEP, or construction of new transmission facilities. In some instances, potential reliability criteria violations identified through a deactivation study can be solved by RTEP enhancements already approved by the PJM Board and included in the RTEP.

Actual deactivations in 2020 included 29 units for a total of nearly 3,300 MW.

Map 1.2: PJM Generator Deactivation Notifications Received Jan 1, 2020 through Dec. 31, 2020)



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1.2: Baseline Project Drivers

NERC Criteria – RTEP Perspective

PJM's RTEP process rigorously applies NERC 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 can also 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 local and regional factors.

Bulk Electric System Facilities

NERC's planning standards apply to all bulk electric system (BES) facilities, defined by ReliabilityFirst Corp. and the SERC Reliability Corp. 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 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) 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 include facilities below 100 kV, to ensure system compliance with NERC Standard TPL-001-4. If PJM identifies violations, it develops transmission expansion solutions to solve 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 – Common Mode Contingency (bus section)
- P3 – Multiple Contingency (two overlapping singles)
- P4 – Common Mode Contingency (fault plus stuck breaker)
- P5 – Common Mode Contingency (fault plus relay failure to operate)
- P6 – Multiple Contingency (two overlapping singles)
- P7 – Common Mode 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 takes additional facilities out of service, then they are taken out of service as well. 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 is 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 basecase itself.

Common mode analysis is conducted within the context of PJM's deliverability testing methods, discussed in PJM Manual 14B, PJM Region Transmission Planning Process, 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.

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

Transmission Owner Criteria

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

As part of its RTEP process, PJM applies TO criteria to the respective facilities that are included in the PJM Open Access Transmission Tariff (OATT) facility list. Transmission enhancements driven by TO criteria are considered RTEP baseline projects, and are eligible for proposal window consideration, as shown in **Figure 1.10**. (Starting Jan. 1, 2020, TO criteria projects will be included in PJMs competitive proposal process.)

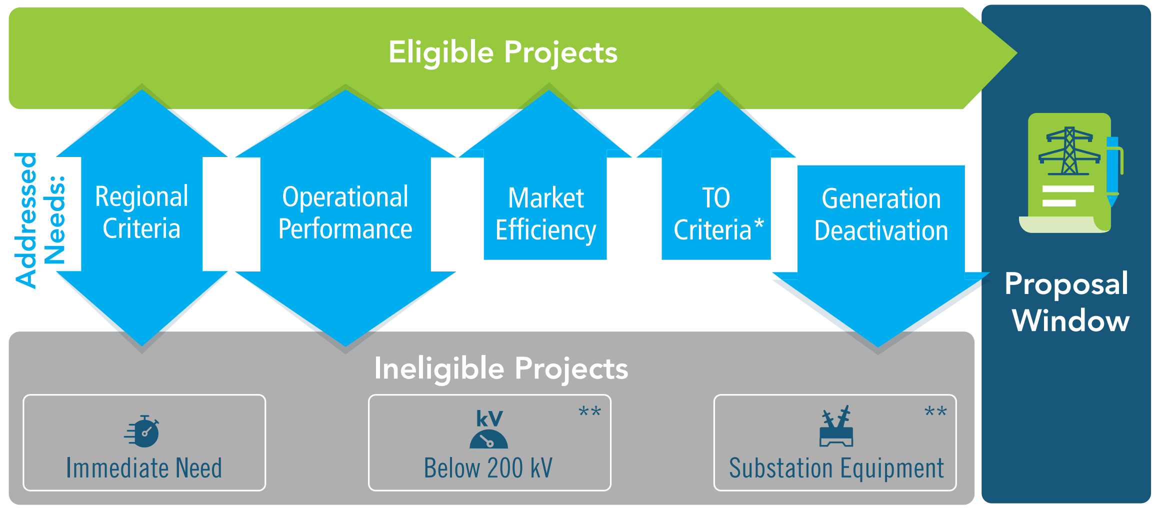
2020 Transmission Owner Criteria-Driven Projects

PJM has observed that TO aging infrastructure criteria drive the need for supplemental 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.

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.

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.*

Developing Transmission Solutions

After PJM identifies a baseline transmission need, including market efficiency, PJM may open a competitive proposal window, depending on the required in-service date, voltage level and scope of likely 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. When the Board approves a proposal, the designated developer becomes responsible for project construction, ownership, operation, maintenance and financing.

2020 Baseline Project Drivers

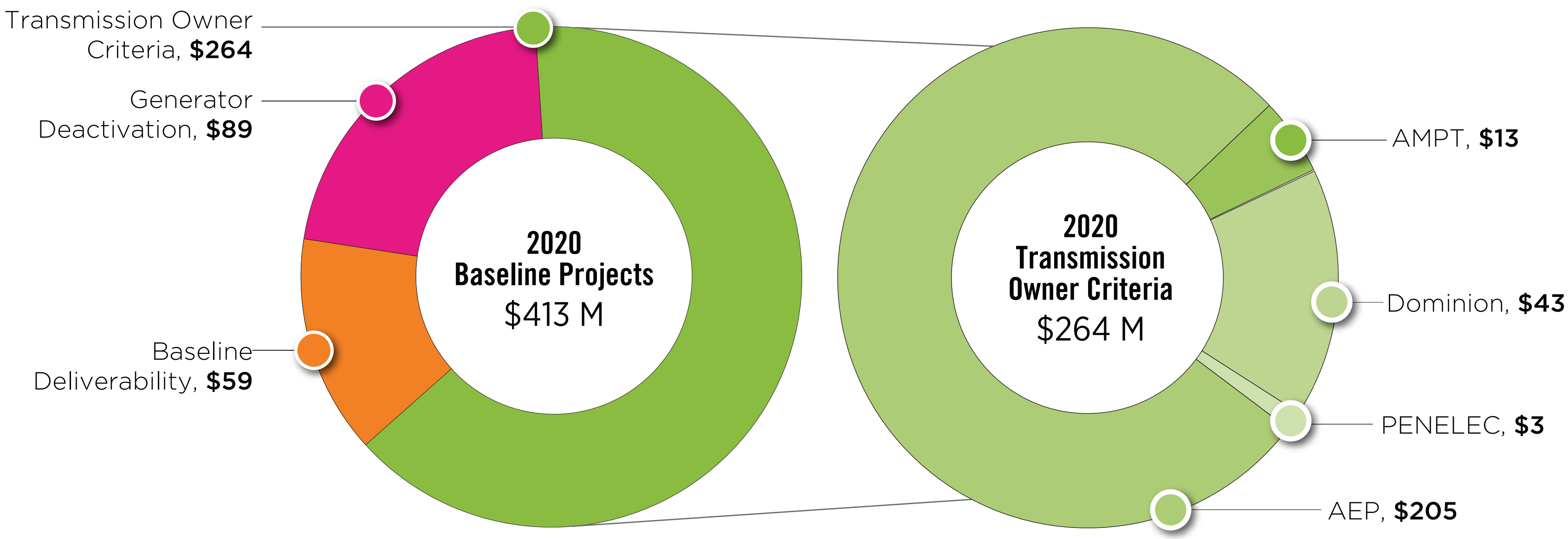
PJM RTEP baseline analysis identifies the need for transmission enhancement projects that span a range of drivers. Those projects identified by PJM and approved by the PJM Board in 2020 were no different, as discussed in later sections of this report and summarized in **Figure 1.11**. As the figure shows, 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 a market efficiency analysis to accomplish the following goals:

- Determine which reliability-based enhancements have economic benefit if accelerated

Figure 1.11: 2020 RTEP Baseline Project Driver ($ Million)

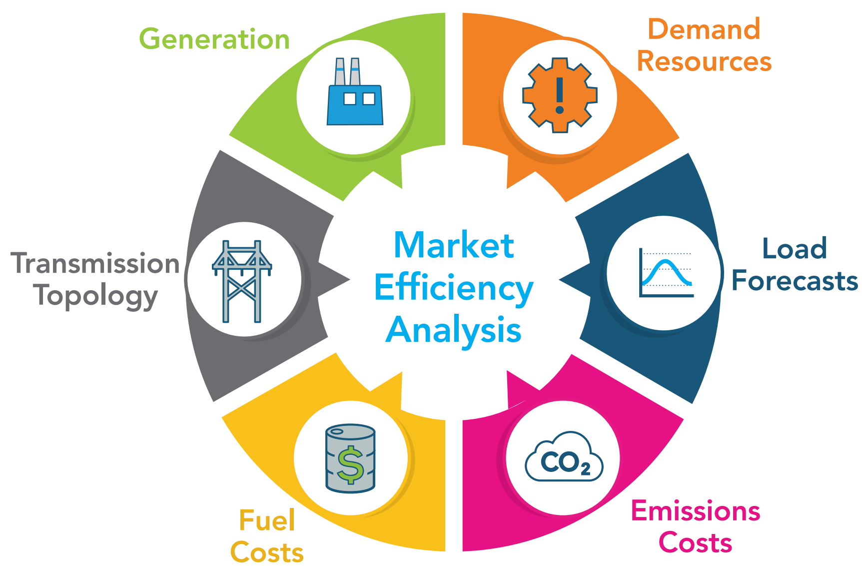


- Identify new transmission enhancements that may realize economic benefit
- Identify the economic benefits associated with reliability-based enhancements already included in the RTEP that, if modified, would relieve one or more congestion constraints, providing additional economic benefit

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**.

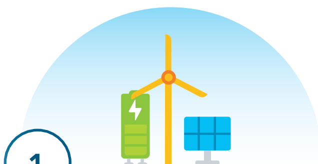
Figure 1.12: Market Efficiency Analysis Parameters



1.3: Grid of the Future

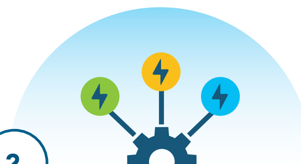
1.3.1 — Overview

PJM's RTEP process continues to evolve, bringing into clearer focus the grid of the future, one driven by decarbonization, renewables, public policy, resource mix and new infrastructure technologies. Strategically over the next five years, PJM will continue to focus on three key trends:



1

Growing renewable energy resources – including offshore wind – are driven by federal and state environmental policy goals, as well as industry goals, to achieve decarbonization and other clean air mandates. PJM's interconnection queue includes more than 140,000 MW, of which 88 percent is wind, solar or battery. Several PJM coastal states have specific offshore wind generation goals totaling more than 14,000 MW by 2035. The first offshore wind facility in PJM became operational in September 2020 – Virginia's 12 MW pilot project, consisting of two 6 MW turbines.



2

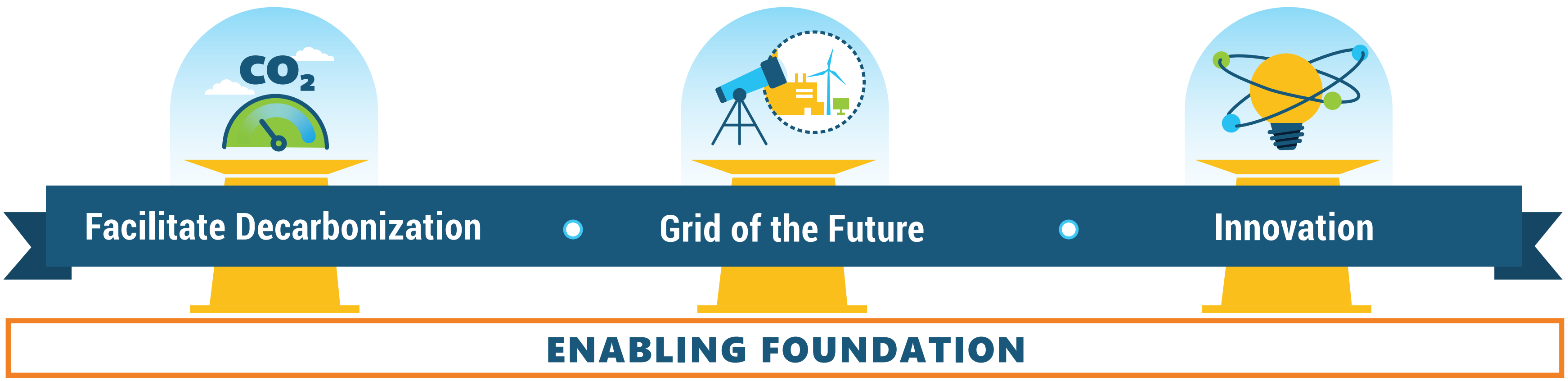
Growing distributed energy resources (DER) – like rooftop solar – are driven by customer preference for green energy solutions, lower energy bills and "distributed resilience" in the face of extreme weather and other severe external events. State and federal policies, along with technological advancements and customer demand, may result in the penetration of millions of DER. The lines between generation, transmission and distribution are thus becoming less distinct. The scope and means by which PJM affects operational control of generation and load will change.

3

Aging infrastructure – 30 percent of which is over 50 years old – continues to require replacement with new assets that embrace new technologies. Modernizing the existing transmission system will provide benefits, including designs that can withstand more extreme events, lower the frequency and duration of outages, reduce public and employee safety risks, and use advanced technology to improve system operability, efficiency and security.

On the basis of these trends, PJM has already begun to integrate RTEP changes in generation, transmission and load forecasting processes with innovative thinking and technologies, as discussed below. Such change, though, will not move forward in a vacuum. A solid foundation of 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.

Figure 1.13: Strategic Pillars



1.3.2 — Evolving Interconnection Process

Given the magnitude of renewable generation interconnection requests that PJM continues to see in each successive queue, a grid of the future necessarily entails revisiting the interconnection component of the RTEP process. That effort is underway. On Oct. 30, 2020, PJM conducted the first of four interconnection process stakeholder workshops, beginning an initiative to promote greater efficiency and effectiveness. The process improvement work ahead will address how to most efficiently reduce current queue backlogs, while also looking at ways to improve the overall process for future interconnection requests.

In particular, the growth in smaller, renewable generation resources is driving a significant increase in individual interconnection request volume. In 2020, for example, PJM received 970 new service requests, more than double the 470 new service requests received two years prior and the most in its history. PJM's ability to efficiently process interconnection requests is critical to the development of those resources. The workshops are part of PJM's effort to serve a fast-changing grid by seeking ways to remove process barriers to increasing volume of renewable resources.

Exploring Ways Forward

Following educational, level-setting presentations at the first session on Oct. 30, stakeholders presented some 200 suggestions, concerns and comments at the second workshop held on Dec. 11, 2020. PJM distilled that stakeholder input into 12 categories: transparency, queue window scheduling, application process, basecase, studies, affected system, cost responsibility, agreements, interim operation, construction, disputes and staffing, as presented at the third workshop on Jan. 29, 2021. Some suggestions have already been incorporated by PJM or have been in progress. Many suggestions will require at least stakeholder endorsement; some will require changes in FERC policy. The fourth workshop, scheduled for March 4, 2021, will explore ways to move forward.

1.3.3 — Offshore Wind

PJM's grid of the future embraces continued commitment to states to advance their renewable power public policy objectives and achieve greater decarbonization. Regionally, the area off PJM Atlantic Coast states has the potential to yield thousands of megawatts of wind-powered energy. Efficiently harnessing that energy through the construction of offshore wind farms will require the development of robust transmission to deliver power onshore to PJM markets. To do so, PJM is collaborating with coastal states to implement its Operating Agreement RTEP Process State Agreement Approach (SAA) to help states achieve RPS policy objectives.

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State Agreement Approach

Historically, baseline projects have been driven by reliability criteria, market efficiency needs and TO criteria requirements. PJM's SAA, authorized by FERC, expands the planning process to enable a state, or group of states, to propose a project to advance public policy requirements as long as the states involved agree to pay all costs of any related build-out included in the RTEP. The SAA was developed seven years ago after extensive consultation with the Organization of PJM States (OPSI) as part of implementing FERC's Order 1000. In that order, FERC required regional grid operators to "provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes."

New Jersey Initiative

The New Jersey Board of Public Utilities on Nov. 18, 2020, announced an initiative to implement the SAA to achieve its offshore wind policy objectives. New Jersey's transmission needs will be part of a competitive proposal window anticipated to open in the first quarter of 2021. Transmission developers may submit proposals to facilitate New Jersey's goal to deliver up to 7,500 MW of offshore wind to consumers by 2035, as discussed further in **Section 5.0.3.**

NOTE:

Nov. 18, 2020 NJBPU Offshore Wind Order.

Multi-State Offshore Wind Study

PJM is also preparing to conduct a scenario study in 2021 that will examine, more broadly, system impacts from offshore wind development. The study will provide a significant opportunity to build collaborative relationships with state commissions that are actively implementing renewable portfolio standard targets. The outcome of the study will summarize grid impacts and associated estimated transmission costs to assist states in their decisions.

1.3.4 — Capacity Value of Intermittent Resources

PJM continues to witness extraordinary growth in energy storage and intermittent generating resources such as wind, solar and other renewable resources. Indeed, PJM's interconnection queue demonstrates that such growth is expected to continue unabated for some years to come, as discussed in **Section 5**. As PJM's resource mix evolution continues to include more of this generation, the manner in which PJM evaluates the contribution of such resources toward resource capacity value also needs to evolve.

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 (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.

Effective Load Carrying Capability

Prior to 2021, intermittent resource capacity value was set at a resource's average output over a defined number of summer peak load hours. This approach has two limitations. One, it weights the output over all hours equally, regardless of an individual hour's actual contribution to the

NOTE:

Limited-duration resources have limited-duration capability. These include, but are not limited to, energy storage resources that receive energy from the grid and store the energy for later injection into the grid: e.g., pumped storage hydro units, compressed air energy storage units, flywheel energy storage units, battery storage units and hydroelectric generating units with reservoir storage capability.

Intermittent Resources are generating units with output that varies as a function of an energy source that is non-continuous and that cannot be directly controlled. Such resources are unable to provide a stated level of output on demand and are unable to maintain a stated level of output for any specified period of time. Intermittent resources include, but are not limited to, wind units, solar units, run-of-river hydroelectric units (without reservoir storage capability) and landfill gas units (without alternate fuel capability).

annual loss of load risk, and, two, it fails to recognize the saturation effect as the amount of intermittent resources in PJM increases. To address these two limitations, PJM performed analysis to assess the reliability value of intermittent resources by using an effective load carrying capability (ELCC) methodology. This more robust methodology recognizes the full value of a resource's output over high-load risk hours and also accounts for the saturation effect.

As part of the process to implement the ELCC, a proposal was developed by the PJM Capacity Capability Senior Task Force (CCSTF) and endorsed by the Markets & Reliability Committee and Members Committee on Sept. 17, 2020. PJM now requires generation owners of ELCC resources to provide specific information about their resources. This information is used by PJM as input to its resource adequacy model.

Pending FERC approval, the ELCC methodology will be applied to intermittent, limited-duration and hybrid resources beginning with the 2023/2024 Delivery Year.

1.3.5 — Distributed Energy Resources

Distributed energy resources (DER) continue to introduce another dynamic into PJM's grid of the future planning process. DER can remain on the customer's side of the meter or participate in PJM markets. DER seeking to participate in PJM's wholesale capacity market must do so via PJM's RTEP new services queue process. This ensures that necessary transmission improvements are in place to preserve reliability and that market participation contracts are executed. Distributed energy devices like rooftop solar remain behind the meter and do not participate in PJM capacity markets. Nonetheless, they impact the demand side of PJM resource adequacy by offsetting load.

FERC Order 2222

The Federal Energy Regulatory Commission (FERC) issued Order 2222 in Docket No. RM18-9-000 on Sept. 17, 2020. The intent of the Order is to remove barriers to entry for smaller-scale generation and storage on the distribution system, along with demand response and energy efficiency, by allowing DER to aggregate and directly compete against larger, more conventional generation in PJM markets. PJM continues to evaluate any potential impacts to its load forecasting process, interconnection process and transmission planning process.

1.3.6 — Aging Infrastructure

The regional high-voltage transmission system is aging, posing a reliability risk to the grid. Many facilities were placed in service in the 1960s and earlier. Many 500 kV lines were constructed in the 1960s; 230 kV and 115 kV lines date to the 1950s and earlier. They are deteriorating and reaching the end of their useful lives. Maintaining older equipment means higher costs to address the greater reliability risk associated with greater probability of facility outages. Addressing this deterioration and the associated costs and risks is part of each transmission owner's broader asset management strategy in parallel with the PJM RTEP process.

NOTE:

PJM is currently seeking feedback from stakeholders, including states and distribution utilities, and developing a proposal to comply with **FERC Order No. 2222**. Submittal of a compliance filing is expected by July 19, 2021.

As equipment continues to age, the approach is shifting from simply maintaining assets to replacing and modernizing them. Asset modernization has gone beyond replacement. Replacement projects offer the opportunity to learn from history and adopt new knowledge, capabilities and technologies that did not exist when original facilities were built.

1.3.7 — Embracing Innovative Industry Technologies

The industry landscape is changing with unparalleled speed in ways impacting PJM as never before. Innovation is empowering all sectors of the industry with more choices as to how electricity is generated, transmitted and used. The outcome of these choices and means by which PJM incorporates them is creating the grid of the future. PJM continues to monitor industry trends and pursue those that will create value for stakeholders.

Energy Storage Resources

Energy storage continues to grow in PJM. Efficient grid operations in an era experiencing rapid growth of intermittent renewable resources will require increased electric system flexibility. Energy storage provides grid operators the ability to meet load requirements when wind, solar and other intermittent resources must alter power output because of weather conditions, or because those units simply are unavailable. Energy storage resources can also improve transmission system efficiency by increasing network utilization factors. PJM has worked with several industry entities including the DOE national laboratories to advance the use of energy storage and ensure that PJM's wholesale market is capable of allowing all forms of energy storage technology to participate competitively.

Storage as Transmission Asset in Regional Planning

PJM, in collaboration with stakeholders, in 2020 continued to explore how storage assets could be included as part of PJM's RTEP process to reinforce the transmission system. Discussions under the auspices of the PJM [Planning Committee] have yielded proposed evaluation, performance and criteria requirements to ensure compliance with NERC and PJM standards.

Electric Vehicles

PJM continues to pay close attention to U.S. transportation sector electrification and, in particular, the impact of electric vehicles (EV) on transmission system needs. The Edison Electric Institute estimates that EVs will grow from one million today to seven million across the country by 2025. EVs would operate essentially in two modes, potentially based on economic signals sent by PJM:

- Charge on-board batteries from electricity purchased from PJM's Energy Market at distributed charging stations
- Discharge power to the grid to earn revenue in PJM markets for energy and related ancillary services, similar to a generation asset

In either mode, PJM must ensure that transmission capability is in place to accommodate the additional flow of power to charging stations, expected to be highly distributed across local and interstate highway systems. The timing of the coincident effect of EV's charging cycles could also drive the need for additional generating resources and related transmission, particularly during peak load periods. This transmission need is amplified if the power needed to charge EV batteries is expected to come from wind and natural gas-fired generating resources, often distant from the population centers they serve.

Impacts to PJM Load Forecast

As part of its 2020 Load Forecast Report, PJM began to incorporate an explicit adjustment for plug-in electric vehicle charging in its peak and energy forecasts. PJM must ensure that it accounts for EV load in its power flow models in order that reliability studies are conducted with greater accuracy as the number of EVs continues to grow.

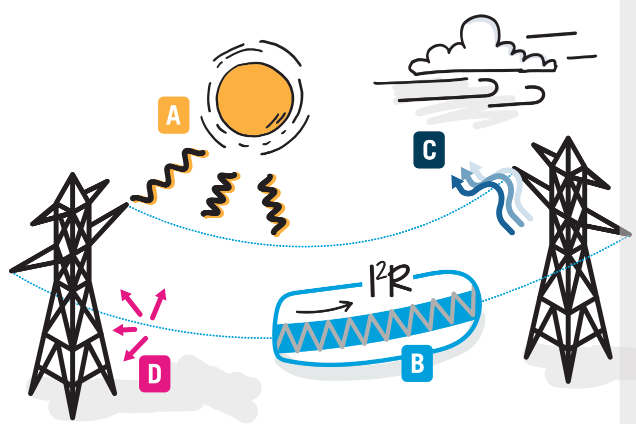
Dynamic Line Ratings

Dynamic Line Rating (DLR) technology – illustrated in **Figure 1.14** – uses advanced sensors and software to monitor real-time ambient temperature, wind speed and conductor tension, and from these data points, determines real-time thermal ratings more frequently than conventional ambient-adjusted temperature ratings in use today. DLR uses real-time measurements to calculate an actual rating for transmission lines based on real-time environmental conditions, versus static ratings. DLR technology can identify additional capacity on transmission lines to relieve congestion and create greater economic efficiencies. Such technology also contributes to system resilience by providing better monitoring of real-time transmission capability.

NOTE:

PJM will continue to work with stakeholders to integrate Storage As a Transmission Asset as part of the PJM RTEP in 2021.

Figure 1.14: Illustration of Dynamic Line Rating 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.

Phasor Measurement Unit Implementation

Since 2009, PJM and its member transmission owners have deployed more than 400 phasor measurement units (PMUs) across the PJM transmission system at more than 120 substations in 10 states, shown on **Map 1.3**. In late 2015, PJM and stakeholders developed a new PMU placement requirement to be included in the generation interconnection queue process. This requirement was put in place to ensure continued expansion of this valuable technology beyond its initial rollout. PMUs – shown geographically in **Figure 1.15** – provide data at a higher resolution and much higher reporting frequency than traditional SCADA (supervisory control and data acquisition) systems, painting a more detailed picture of the status of the grid at any given moment. PJM is developing advanced applications of this technology to improve power system efficiency, reliability and resilience. Investment in PMUs across the system provides operators significantly enhanced means to detect and address instability before it causes service interruptions.

Implementation in PJM

From PJM's perspective, full synchrophasor observability of all EHV equipment at 100 kV and above will provide the ability to detect high-speed grid disturbances – oscillations and cascading equipment failures. In

NOTE:

PJM's technical guidelines for installation of synchrophasor measurement equipment at generation facilities can be found on the PJM website.

Map 1.3: Location of Phasor Measurement Units Across PJM

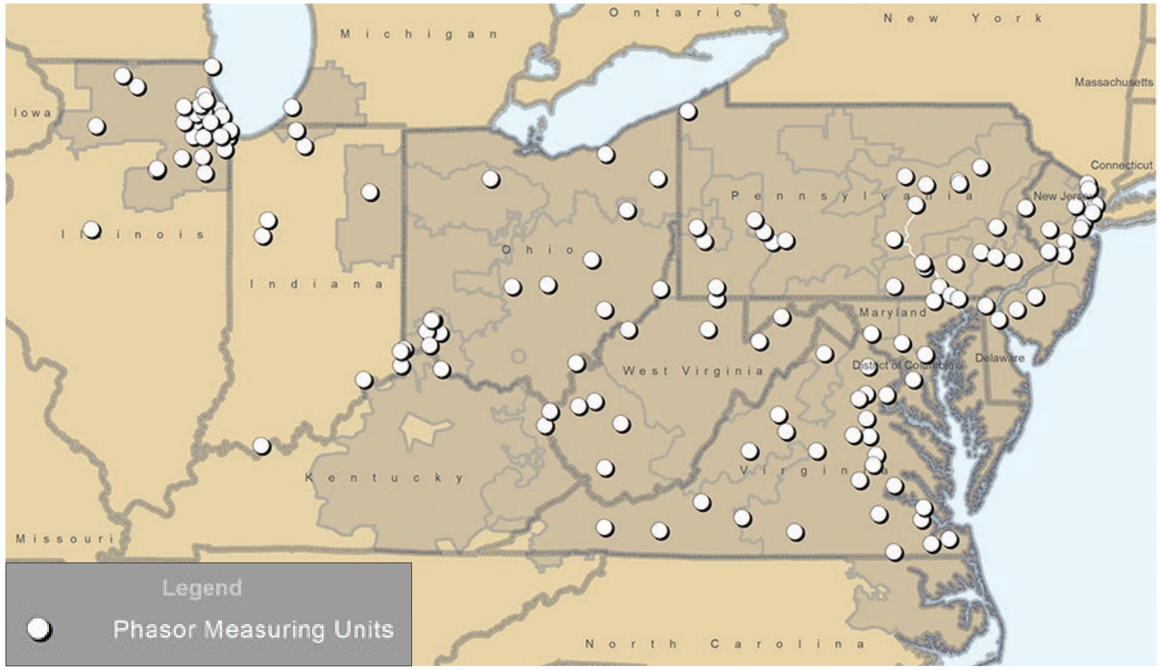
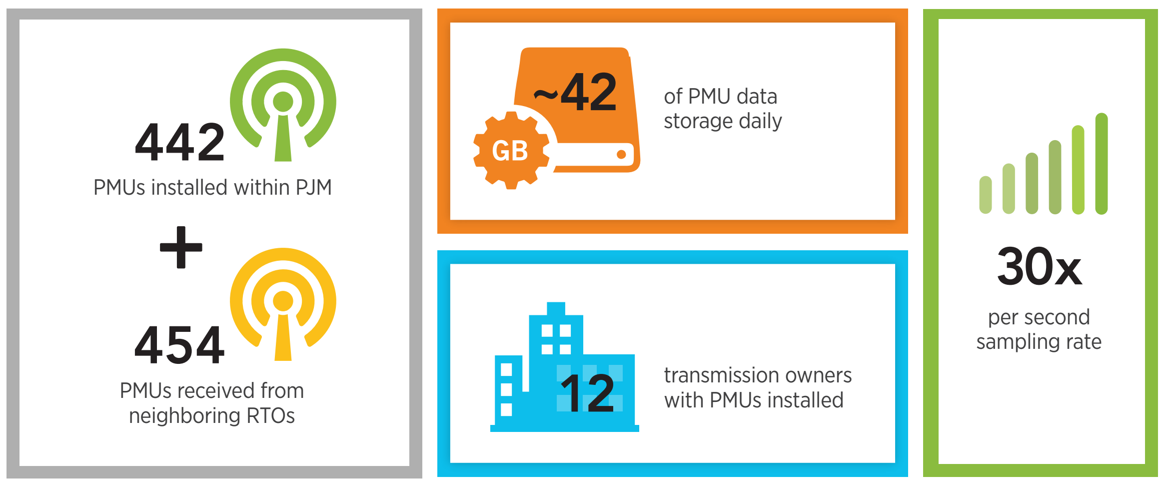


Figure 1.15: Using Phasor Measurement Units in PJM



addition, this data will provide the means for planners to conduct innovative post-event analysis and dynamic model validation.

To that end, PJM worked with the Planning Committee and Operating Committee in 2020 to incorporate PMU placement into the PJM planning process in Manuals 1, "Control Center and Data Exchange Requirements," and 14B, "PJM Region Transmission Planning Process." For substations with three or more non-radial transmission lines at 200 kV or above and four or more non-radial transmission lines between 100 kV and 200 kV, synchrophasor measurement signals will be required for the following equipment locations:

- Bus voltages at 100 kV and above
- Line-terminal voltage and current values for transmission lines at 100 kV and above
- High-side/low-side voltage and current values for transformers at 100 kV and above
- Dynamic reactive device power output (SVC, STATCOM, Synchronous Condenser, etc.)

PJM has committed to periodically evaluate the effectiveness of this new placement requirement, and will work with PJM stakeholders to modify such requirements as necessary.

The requirements will apply to new baseline and supplemental projects presented to the Transmission Expansion Advisory Committee (TEAC) and/or the Subregional RTEP Committees (SRRTEP) to be included in the RTEP after June 1, 2021.

Enhanced Planning Models

Model validation is a key and novel application of PMU-driven data. System Planning, Operations and Market Services rely heavily on power flow and other simulation models, investing significant time and resources to ensure that they accurately depict the physical behavior of the system. In particular, PMU technology allows PJM to recognize, detect and mitigate electromechanical oscillations, which helps system operators quickly identify potential instability before it has a chance to spread and interrupt service. Overall, further penetration of PMUs promises to revolutionize the practice of evaluating the status of the transmission system, making the process faster and the system more resilient.

1.3.8 — Resilience

As the grid of the future continues to develop, PJM must ensure that it does so on a solid foundation of reliability, one that integrates greater resilience into the existing reliability standards by which PJM plans and operates the grid. To that end, PJM continues to contend with a range of emerging challenges, including extreme weather, cyber and physical attacks, changes in the electric generation fleet driven by cheap and plentiful natural gas, and increased deployment of renewable resources. The pace of those changes has pushed grid operators to prepare for future vulnerabilities for which no set of standards currently exist. To be resilient, PJM must prepare for, operate through and recover from threats, as depicted in **Figure 1.16**.

The Role of Transmission in Resilience

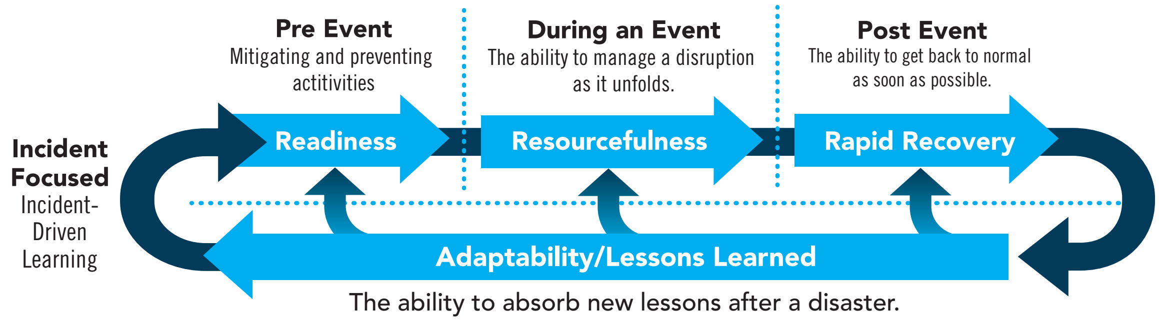
For decades, planning criteria has been developed and applied to power systems around the world to ascertain the need for new transmission. This provides a robust grid so that system operators can address various operating scenarios on any given day. Planners test the system under simulated stressed conditions – extreme weather conditions, for example – to understand where reinforcements are needed to make the grid reliable.

NERC planning criteria require 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 every other transmission facility is in service. Yet in reality, dozens of facilities are out of service on the system on any given day. PJM also simulates more severe, lower-probability events like multiple facility outages. These include the loss of two circuits on a common tower line or a fault on a circuit followed by a breaker failure or two unrelated contingencies, otherwise known as the N-1-1 test.

NERC standards address resilience to a degree. Planning standards also 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 or fire, taking down multiple transmission lines in one corridor. Although an assessment of the impact of these events is required, reinforcement for these low-probability events is not required under current NERC criteria.

Reliability criteria are structured around likely events. Planners must also assess whether the transmission system is sufficiently reinforced to address extreme events such as physical and cybersecurity attacks or extreme weather conditions like hurricanes.

Figure 1.16: Defining Resilience



Resilience: Taking Reliability a Step Further

Resilience and reliability both seek to keep the lights on but are not conceptually the same. PJM already complies with established NERC, regional and TO 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:

- Maintaining reliability in the face of significant events
- Evaluating threats as part of the RTEP 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

PJM has initiated efforts to implement RTEP process criteria and metrics to enhance grid resilience beyond that in place today, as discussed in **Section 1.4.1**.

Cascading Event Analysis Tool Development

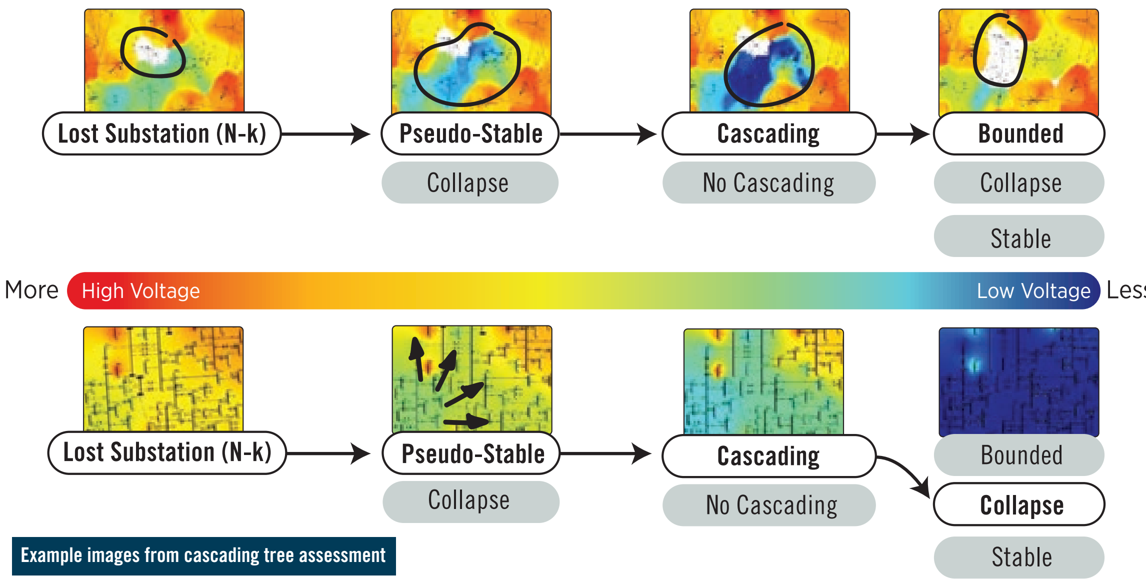
At its most fundamental, a cascading tree evaluates an extreme event that encompasses a risk that may, after some number of additional cascading events, lead to system collapse (i.e., blackout). Major blackouts are usually caused by low-probability, high-consequence events. Since the attacks on the Metcalf substation, 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.

Any such initial precipitating event could cause one or more transmission line overloads (on common right-of-way), transformer overload, loss of substation, generator under-voltage, or load under-voltage conditions, among others. The high-voltage transmission network that crisscrosses the country was planned based on a set of reliability and efficiency criteria. These criteria generally ensure that the transmission system is capable of withstanding a significant outage to one, or a few, critical pieces of equipment. However, these planning criteria do not assess what would happen to the system should a significant disruption of many pieces of equipment occur at once, or in quick succession, as might be triggered by an extreme weather event or a deliberate attack.

Implementing Cascading Trees

PJM has begun developing such an assessment, called "cascading trees," shown conceptually in **Figure 1.17**. The purpose of this new methodology is to assess the probability and consequence of cascading outages in electric systems. A cascading tree is the set of all likely cascading paths. These, in turn, describe a sequence of potential cascading outages that could reasonably be expected.

Figure 1.17: Cascading Tree Concept



These possible outages are then classified as shown in **Figure 1.17** based on whether the propagation of a disturbance can be confined to a certain area, or if the exact extent of the cascading cannot be determined. The initial event equates to the complete loss of a facility. Cascading trees quantify the probability of cascading and the extent of associated consequence, leading to a natural ranking of facilities. Facilities then can be grouped into different tiers, each having a different priority and a discrete set of mitigation actions.

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1.4: RTEP Process Milestones

1.4.1 — 2020 Activities

PJM's RTEP process is continually evolving as the scope of system enhancement drivers it addresses evolves. In addition to the efforts undertaken by PJM to bring the grid of the future into clearer focus, discussed in **Section 1.3**, several milestones were achieved throughout 2020 as PJM continued to implement process improvements, as discussed below.

1.4.2 — Load Forecast Update/Accuracy

PJM annually reviews the load forecast methodology and implements changes when improvements are identified. For the 2021 load forecast, the major changes encompassed refinements to sector models and non-weather-sensitive load, both of which were first introduced with the 2020 load forecast. With respect to sector models, the commercial component of the load model was improved with the addition of service sector employment to more accurately reflect evolving economic conditions. Improvements to non-weather-sensitive models were also made to better align with underlying drivers and historical trends, reducing expected load impacts.

Each year, PJM measures the accuracy of the long-term load forecast model by running it 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 — Storage as Transmission Asset

Building on work PJM performed in previous years, in 2020, PJM initiated an effort to determine how energy storage could be treated as a transmission asset and integrated into the RTEP process to enhance grid reliability. Storage as a transmission asset (SATA) was evaluated by PJM and its stakeholders for suitability as a transmission system enhancement. PJM also reviewed existing rules in PJM governing documents and identified gaps that would affect the integration of SATA into the RTEP.

PJM recognizes the unique characteristics of SATA, which could position it as a potentially more cost effective, efficient grid solution alternative to building new power lines in certain circumstances. PJM is also keenly aware of the complexity that SATA will bring to operations and markets functions. For this reason, PJM chose to study SATA in phases, over multiple years. The Phase 1 scope is to consider SATA solely as a transmission asset, and the ability to address drivers for reliability, market efficiency, operational performance and public policy. With stakeholder input, PJM proposed a package of recommendations for evaluating SATA as part of the RTEP process. These recommendations allow for transparency in studying SATA for suitability in mitigating reliability criteria violations and market efficiency constraints, as well as project cost analysis so SATA can be directly compared to traditional wires solutions.

The Phase 1 work is only the first step in evaluating SATA as part of the RTEP. PJM is committed to work with stakeholders to discuss the feasibility for SATA to have dual-use privileges as a transmission asset when needed for reliability reinforcement, and as a market participant at other times along with associated markets and operations issues.

1.4.4 — 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 2020, PJM continued to pursue opportunities 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 and mitigate the risk of potential future CIP-014 critical infrastructures facilities.

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 which were identified as of Sept. 30, 2018. The locations of these facilities are confidential, but has been publicly identified as not to exceed 20.

Avoidance and Mitigation

Through the Consensus Based Issues Resolution (CBIR) process, stakeholders evaluated and developed a process by which to: (1) Avoid the addition of new critical facilities to the PJM system by evaluating all model updates to minimize the possibility of a new critical facility; and (2) Mitigate the result of any new critical facility identified in PJM's footprint.

Stakeholder review of these concepts and corresponding updates to documentation are following the established PJM committee approval process and are expected to be voted on at the Markets and Reliability Committee in the second quarter of 2021.

1.4.5 — Market Efficiency Process Enhancement Task Force

The Market Efficiency Process Enhancement Task Force (MEPETF) was chartered in January 2018, under the auspices of the PJM Planning Committee. The mission of this group is to review, evaluate and discuss challenges and potential solutions necessary to improve the market efficiency process. The scope of MEPETF activities includes the following:

- Provide educational material
- Evaluate benefit-to-cost calculation
- Evaluate facility study agreement modeling
- Evaluate the market efficiency reevaluation process and mid-cycle assumption update
- Select interregional market efficiency project
- Evaluate regional targeted market efficiency process
- Update market efficiency midcycle assumption and model

Process reviews were conducted in three phases. In April 2019, the MEPETF started work on Phase 3, which entailed investigating a new Regional Targeted Market Efficiency Project process and looking into the separation of energy and capacity benefits in the benefit-to-cost calculations. Phase 3 was completed upon FERC's Dec. 18, 2020, acceptance of PJM's proposed Operating Agreement revisions. Additional discussion on the MEPETF activities, including those that continued throughout 2020, are included in **Section 4.4.**

NOTE:

PJM received endorsement of requisite Manuals 14B and 14F language by the Planning Committee in February 2021. Pending approval of the Markets and Reliability Committee, those manual changes along with additional changes to Schedule 6 of PJM's Operating Agreement will become effective upon FERC acceptance of PJM's anticipated Operating Agreement Critical Infrastructure Stakeholder Oversight filing.

Section 2: Resource Adequacy Modeling

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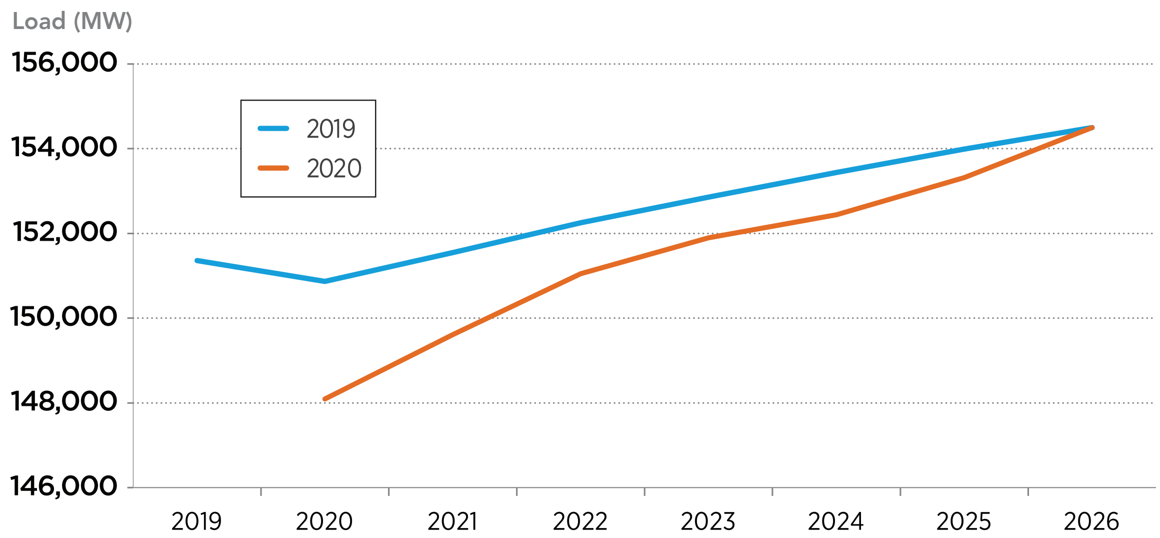
2.0: Power Flow Model Load

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 basecase 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 2020 vs. 2019



2020 RTEP Process Context

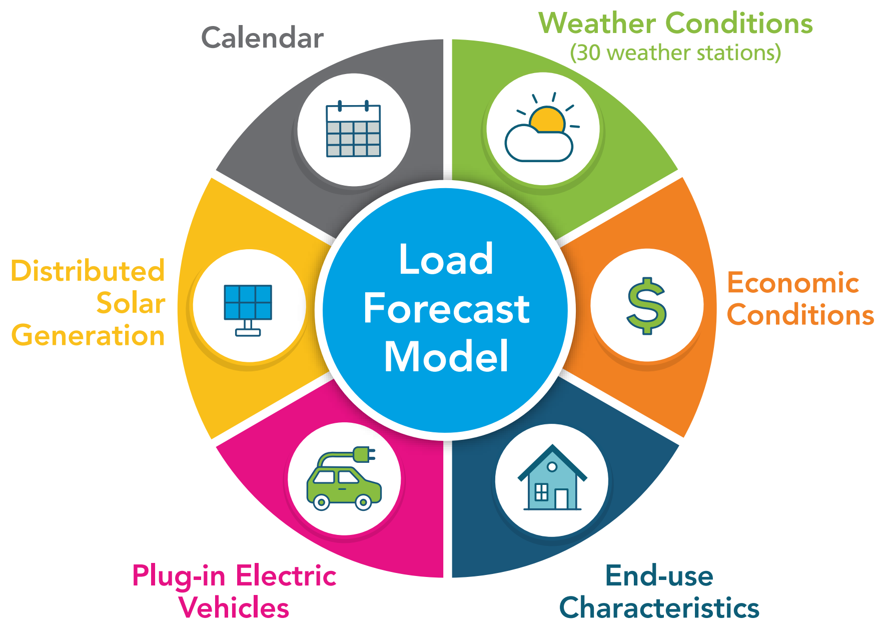
PJM's 2020 RTEP baseline power flow model for study year 2025 is based on the 2020 PJM Load Forecast Report. Summarized in the sections that follow, PJM's January 2020 load forecast covered the 2020 through 2035 planning horizon. From a power flow modeling perspective, the 2025 summer peak from that January 2020 forecast at an overall RTO demand of 153,315 MW was the basis for developing PJM's 2025 basecase power flow model. Doing so will reflect that PJM now projects its RTO summer-normalized peak to grow 0.6 percent annually over the next 10 years, shown in **Figure 2.1**, which is up 0.3 percentage points from the 2019 forecast.

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. And it leverages those relationships to derive forecasted load, shown in **Figure 2.2**

PJM instituted several significant changes starting with the 2020 load forecast, aimed at providing a more accurate forecast that better aligns with ongoing load trends. For the 2020 load forecast, PJM introduced sector models and used the concept of non-weather-sensitive load. 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 new 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

For the first time, 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 plug-in electric vehicles 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 region.

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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. A trend that is further driven by the accelerated proliferation of energy-efficient electric appliances and equipment.

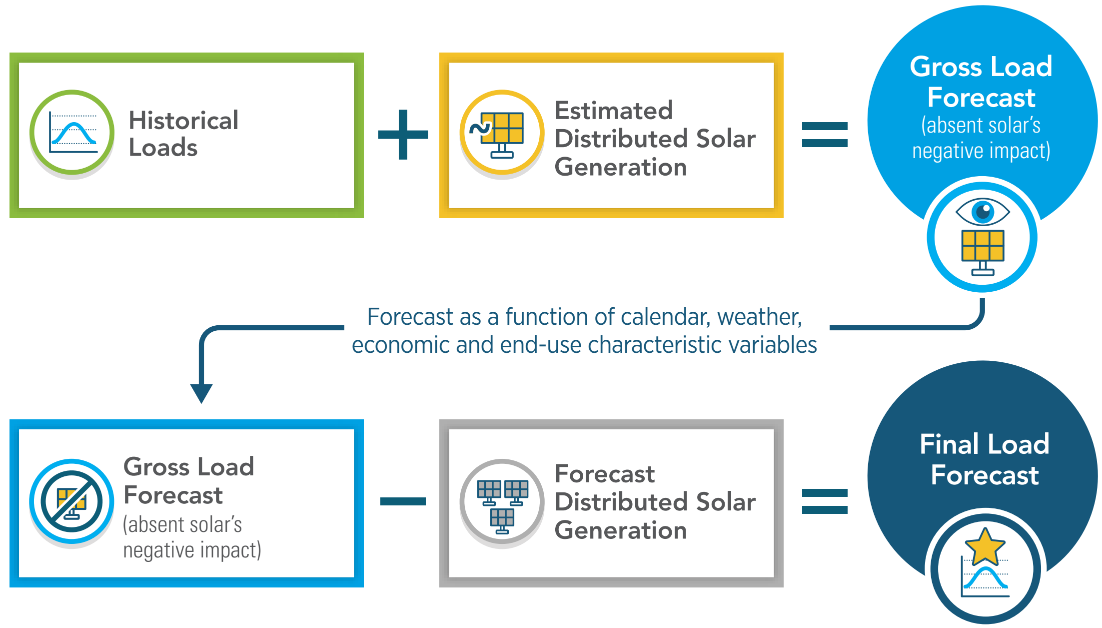
Distributed Solar Generation

Recent years have witnessed a significant ramp-up in behind-the-meter distributed solar resources: more than 4,500 MW since 1998, with more than 95 percent of installations since 2010. Though not a large amount from an RTO perspective, the level of distributed solar is significant in certain areas of PJM 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



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2.1: January 2020 Forecast

PJM's January 2020 load forecast used in 2020 RTEP studies covered the 2020 through 2035 planning horizon, highlights of which are summarized in this section. The complete January [2020 PJM Load Forecast Report] is accessible on the PJM website. As that report states, PJM's 2025 RTO summer peak is forecasted to be 153,315 MW.

Forecasting Trends

Table 2.1 summarizes the seasonal transmission owner zonal summer and winter 10-year forecasts and load growth rates for 2020 through 2030. All load forecasts in the table reflect adjustment for distributed solar generation and plug-in electric vehicles. 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: 2020 Load Forecast Report

	Summer Peak (MW)			Winter Peak (MW)		
Transmission Owner	2020	2030	Growth Rate	2019/20	2029/30	Growth Rate
Atlantic City Electric Co.	2,542	2,773	0.9%	1,543	1,715	1.1%
Baltimore Gas and Electric Co.	6,447	6,558	0.2%	5,859	6,290	0.7%
Delmarva Power & Light Co.	3,979	4,327	0.8%	3,729	4,124	1.0%
Jersey Central Power & Light	5,842	6,122	0.5%	3,669	4,013	0.9%
Met-Ed	3,003	3,287	0.9%	2,686	2,893	0.7%
PECO Energy Co.	8,415	8,677	0.3%	6,792	6,727	-0.1%
Pennsylvania Electric Co.	2,849	2,957	0.4%	2,824	2,816	-0.0%
PPL Electric Utilities Corp.	7,069	7,792	1.0%	7,336	7,772	0.6%
Potomac Electric Power Co.	6,109	5,794	-0.5%	5,699	5,845	0.3%
PSEG	9,792	10,597	0.8%	6,686	7,341	0.9%
Rockland Electric Co.	395	420	0.6%	216	241	1.1%
UGI Utilities	191	184	-0.4%	200	187	-0.7%
Diversity – Mid-Atlantic	-781	-948		-557	-644	
Mid-Atlantic	**55,852**	**58,540**	**0.5%**	**46,682**	**49,320**	**0.6%**
American Electric Power Co.	21,945	24,113	0.9%	22,000	23,544	0.7%
Allegheny Power	8,685	9,373	0.8%	8,851	9,498	0.7%
American Transmission Systems, Inc.	12,378	12,428	0.0%	10,349	10,240	-0.1%
Commonwealth Edison Co.	20,635	20,876	0.1%	14,400	14,621	0.2%
Dayton Power & Light Co.	3,236	3,228	-0.0%	2,909	2,813	-0.3%
Duke Energy Ohio and Kentucky	5,280	5,650	0.7%	4,550	4,894	0.7%
Duquesne Light Co.	2,759	2,855	0.3%	2,070	2,113	0.2%
East Kentucky Power Cooperative	2,004	2,334	1.5%	2,701	3,094	1.4%
Ohio Valley Electric Corp.	95	95	0.0%	125	125	0.0%
Diversity – Western	-1,377	-1,311		-1,403	-1,381	
Western	**75,640**	**79,641**	**0.5%**	**66,552**	**69,561**	**0.4%**
Dominion Virginia Power	19,813	22,336	1.2%	20,382	23,531	1.4%
Southern	**19,813**	**22,336**	**1.2%**	**20,382**	**23,531**	**1.4%**
Diversity – Total	-5,371	-5,644		-4,289	-4,467	
PJM RTO	**148,092**	**157,132**	**0.6%**	**131,287**	**139,970**	**0.6%**

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

Transmission Owner	Adjustment to Summer Peak (MW) Distributed Solar Generation 2020	Distributed Solar Generation 2030	Plug In Electric Vehicle 2020	Plug In Electric Vehicle 2030
Atlantic City Electric Co.	200	263	5	36
Baltimore Gas and Electric Co.	205	562	12	82
Delmarva Power & Light Co.	117	259	5	32
Jersey Central Power & Light	296	459	12	86
Met-Ed	29	57	3	21
PECO Energy Co.	44	106	8	62
Pennsylvania Electric Co.	9	40	3	20
PPL Electric Utilities Corp.	71	132	7	50
Potomac Electric Power Co.	167	525	10	73
PSEG	436	773	20	144
Rockland Electric Co.	9	22	1	6
UGI Utilities	0	2	0	1
American Electric Power Co.	49	397	15	115
Allegheny Power	81	267	7	52
American Transmission Systems, Inc.	55	364	10	72
Commonwealth Edison Co.	101	468	27	201
Dayton Power & Light Co.	12	104	2	19
Duke Energy Ohio and Kentucky	16	173	4	28
Duquesne Light Co.	12	31	3	20
East Kentucky Power Cooperative	5	10	1	7
Ohio Valley Electric Corp.	0	0	0	0
Dominion Virginia Power	406	820	17	121
PJM RTO	**1,963**	**5,445**	**172**	**1,248**

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

	Load Forecast Report Summer Peak (MW)														
	2016			2017			2018			2019			2020		
Transmission Owner	2016	2026	Growth Rate	2017	2027	Growth Rate	2018	2028	Growth Rate	2019	2029	Growth Rate	2020	2030	Growth Rate
Atlantic City Electric Co.	2,524	2,502	-0.1%	2,495	2,445	-0.2%	2,460	2,409	-0.2%	2,450	2,388	-0.3%	2,542	2,773	0.9%
Baltimore Gas and Electric Co.	6,945	7,220	0.4%	6,889	6,911	0.0%	6,848	6,744	-0.2%	6,697	6,663	-0.1%	6,447	6,558	0.2%
Delmarva Power & Light Co.	3,991	4,135	0.4%	4,028	3,983	-0.1%	3,937	4,018	0.2%	3,933	3,962	0.1%	3,979	4,327	0.8%
Jersey Central Power & Light	5,968	6,156	0.3%	6,056	6,108	0.1%	5,942	5,943	0.0%	5,914	5,912	0.0%	5,842	6,122	0.5%
Met-Ed	2,940	3,176	0.8%	2,940	3,028	0.3%	2,974	3,115	0.5%	2,986	3,157	0.6%	3,003	3,287	0.9%
PECO Energy Co.	8,547	9,122	0.7%	8,547	8,693	0.2%	8,642	8,979	0.4%	8,711	9,082	0.4%	8,415	8,677	0.3%
Pennsylvania Electric Co.	2,890	2,919	0.1%	2,891	2,847	-0.2%	2,895	2,922	0.1%	2,897	2,908	0.0%	2,849	2,957	0.4%
PPL Electric Utilities Corp.	7,193	7,560	0.5%	7,132	7,186	0.1%	7,140	7,350	0.3%	7,148	7,347	0.3%	7,069	7,792	1.0%
Potomac Electric Power Co.	6,563	6,813	0.4%	6,614	6,543	-0.1%	6,493	6,466	0.0%	6,466	6,413	-0.1%	6,109	5,794	-0.5%
PSEG	10,090	10,222	0.1%	10,057	10,012	0.0%	9,903	9,876	0.0%	9,904	9,753	-0.2%	9,792	10,597	0.8%
Rockland Electric Co.	407	410	0.1%	404	404	0.0%	402	402	0.0%	404	402	0.0%	395	420	0.6%
UGI Utilities	188	190	0.1%	191	185	-0.3%	190	188	-0.1%	189	188	-0.1%	191	184	-0.4%
Diversity – Mid-Atlantic	-1,072	-872		-1,080	-1,161		-1,225	-1,086		-1,213	-1,135	0.0%	-781	-948	
Mid-Atlantic	**57,174**	**59,553**	**0.4%**	**57,164**	**57,184**	**0.0%**	**56,601**	**57,326**	**0.1%**	**56,486**	**57,040**	**0.1%**	**55,852**	**58,540**	**0.5%**
American Electric Power Co.	23,006	24,891	0.8%	22,945	23,888	0.4%	22,876	24,018	0.5%	22,945	24,072	0.5%	21,945	24,113	0.9%
Allegheny Power	8,817	9,554	0.8%	8,802	9,087	0.3%	8,825	9,447	0.7%	8,707	9,305	0.7%	8,685	9,373	0.8%
American Transmission Systems, Inc.	12,921	13,413	0.4%	12,994	13,177	0.1%	12,952	13,309	0.3%	12,872	13,134	0.2%	12,378	12,428	0.0%
Commonwealth Edison Co.	22,001	23,633	0.7%	22,296	22,872	0.3%	22,121	23,207	0.5%	21,890	22,514	0.3%	20,635	20,876	0.1%
Dayton Power & Light Co.	3,403	3,647	0.7%	3,479	3,503	0.1%	3,459	3,508	0.1%	3,408	3,525	0.3%	3,236	3,228	0.0%
Duke Energy Ohio and Kentucky	5,436	5,853	0.7%	5,497	5,741	0.4%	5,523	5,860	0.6%	5,480	5,742	0.5%	5,280	5,650	0.7%
Duquesne Light Co.	2,893	2,985	0.3%	2,884	2,882	0.0%	2,872	2,924	0.2%	2,862	2,887	0.1%	2,759	2,855	0.3%
East Kentucky Power Cooperative	1,924	2,041	0.6%	1,948	2,010	0.3%	1,960	2,033	0.4%	1,989	2,072	0.4%	2,004	2,334	1.5%
Ohio Valley Electric Corp.										95	95	0.0%	95	95	0.0%
Diversity – Western	-1,572	-1,574		-1,529	-1,468		-1,540	-1,522		-1,612	-1,369		-1,377	-1,311	
Western	**78,829**	**84,443**	**0.7%**	**79,316**	**81,692**	**0.3%**	**79,048**	**82,784**	**0.5%**	**78,636**	**81,977**	**0.4%**	**75,640**	**79,641**	**0.5%**
Dominion Virginia Power	19,531	22,041	1.2%	19,729	20,501	0.4%	19,596	21,161	0.8%	19,391	21,238	0.9%	19,813	22,336	1.2%
Southern	**19,531**	**22,041**	**1.2%**	**19,729**	**20,501**	**0.4%**	**19,596**	**21,161**	**0.8%**	**19,391**	**21,238**	**0.9%**	**19,813**	**22,336**	**1.2%**
Diversity – RTO	-3,403	-4,146		-3,210	-3,604		-3,137	-3,636		-5,980	-6,070		-5,371	-5,644	
PJM RTO	**152,131**	**161,891**	**0.6%**	**152,999**	**155,773**	**0.2%**	**152,108**	**157,635**	**0.4%**	**151,358**	**156,689**	**0.3%**	**148,092**	**157,132**	**0.6%**

2020 Forecast Summer Zonal Load Growth Rates

The PJM RTO weather-normalized summer peak is forecasted to grow at an average rate of 0.6 percent per year for the next 10 years. The PJM RTO summer peak is forecasted to be 157,132 MW in 2030, an increase of 9,040 MW over the 2020 peak of 148,092 MW. Individual geographic zone growth rates vary from -0.5 percent to 1.5 percent, as shown in **Figure 2.4** and **Figure 2.5**.

Figure 2.4: PJM Mid-Atlantic Summer Peak Load Growth 2020-2030

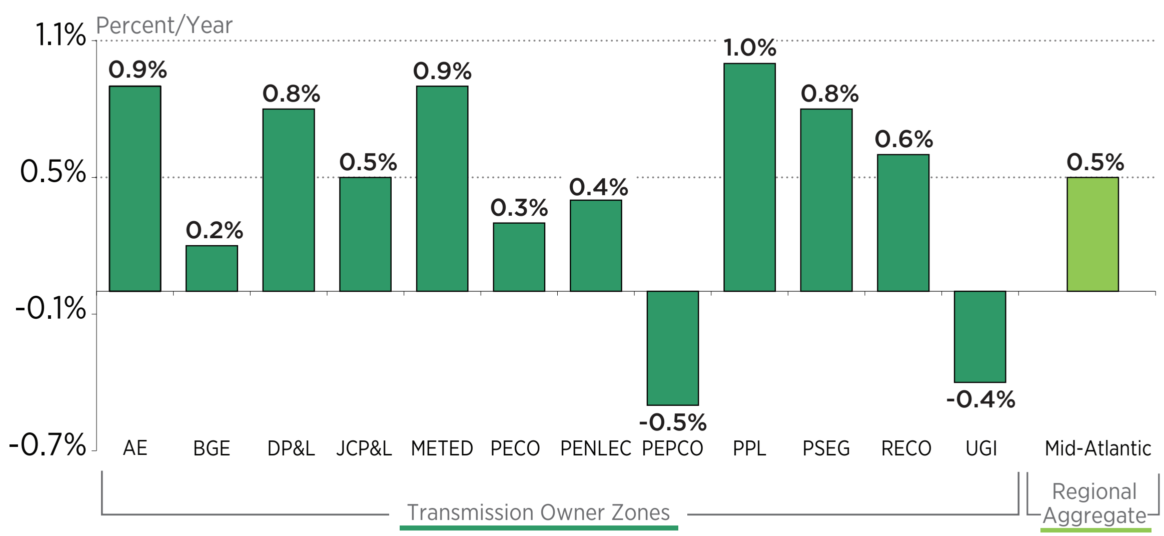
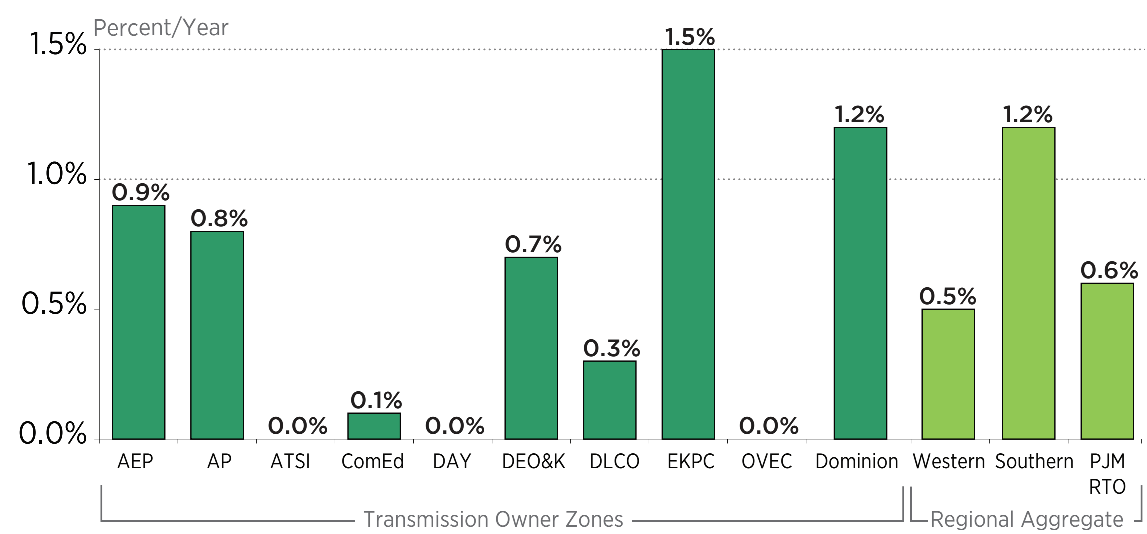


Figure 2.5: PJM Western and Southern Summer Peak Load Growth 2020-2030



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2020 Forecast Winter Zonal Load Growth Rates

The PJM RTO weather-normalized winter peak is forecasted to grow at an average rate of 0.6 percent per year for the next 10 years. The PJM RTO winter peak is forecasted to be 139,970 MW in 2029/2030, an increase of 8,683 MW over the 2019/2020 peak of 131,287 MW. Individual geographic zone growth rates vary from -0.7 percent to 1.4 percent, as shown in **Figure 2.6** and **Figure 2.7**.

Figure 2.6: PJM Mid-Atlantic Winter Peak Load Growth 2020-2030

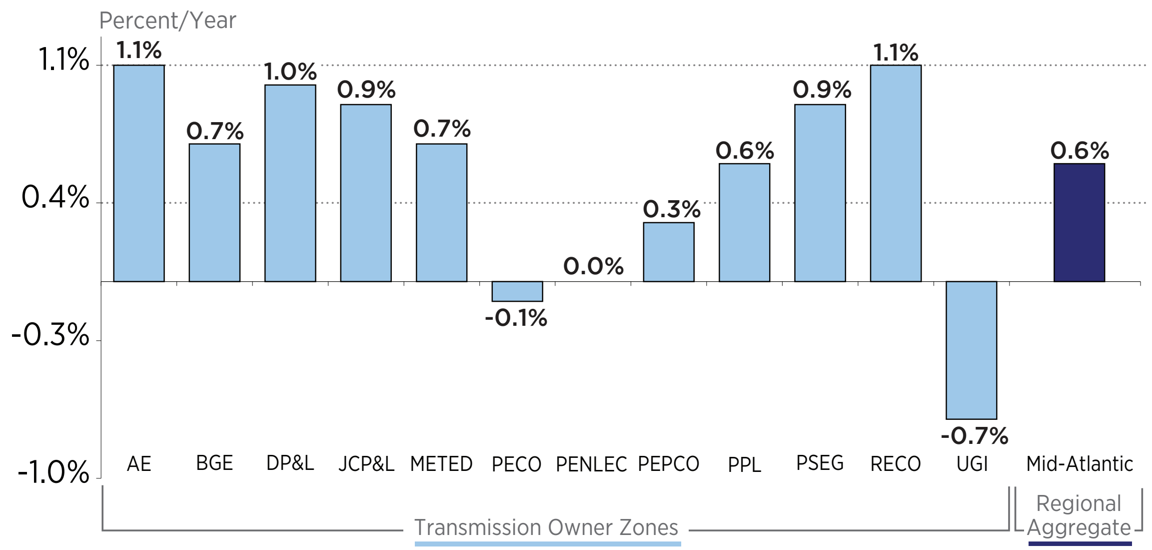
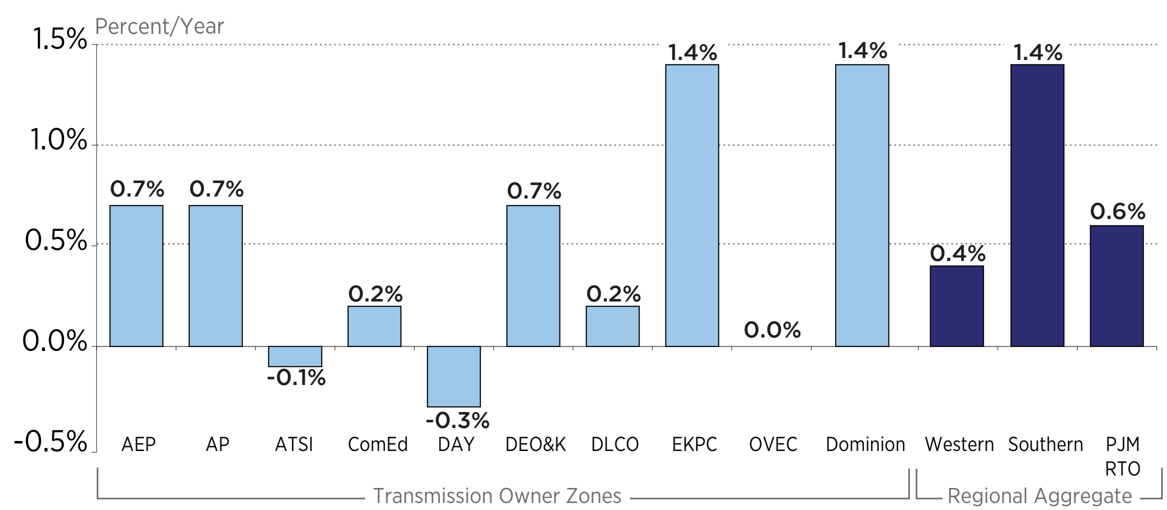


Figure 2.7: PJM Western and Southern Winter Peak Load Growth 2020-2030



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 2016 through 2020, 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 plug-in electric vehicles looking forward in each of the five forecasts.

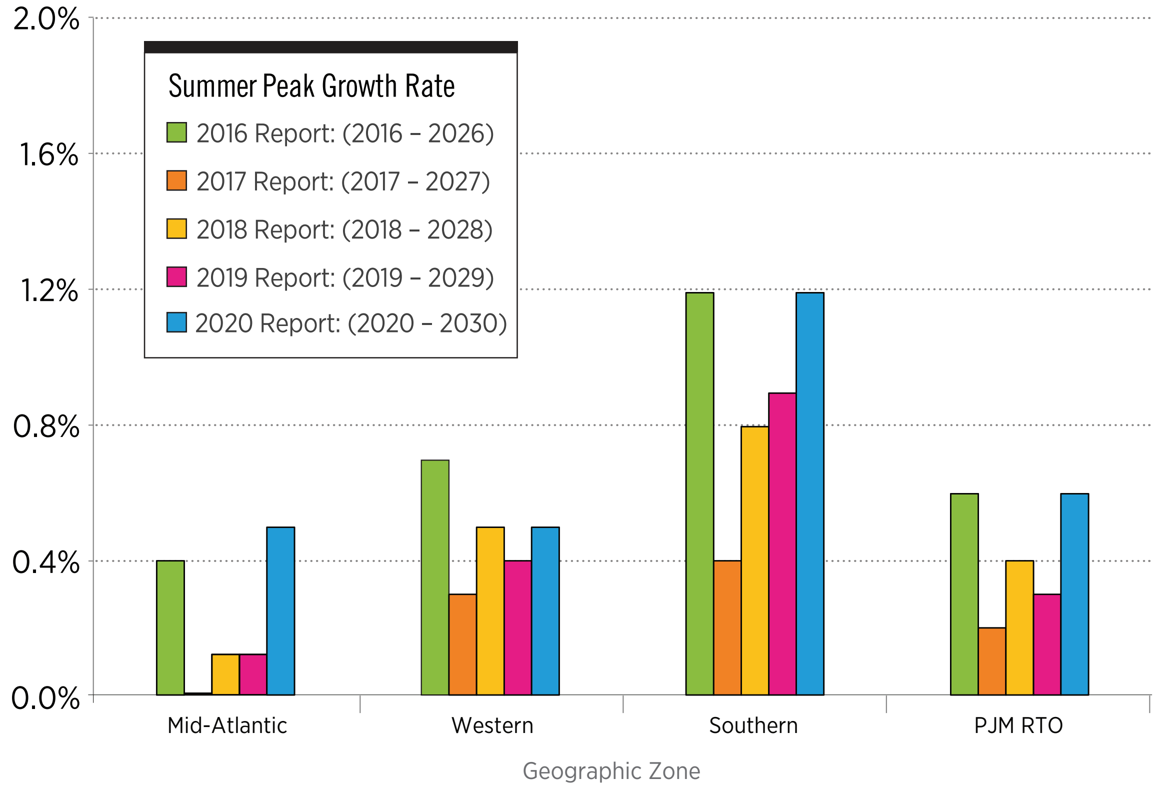
In particular, the 2020 report forecasted that load growth rate for the RTO increased by 0.3 percentage points when compared to the 2019 report.

2.1.1 — Effective Load Carrying Capability

As the resource mix in PJM evolves to include more renewables – such as wind and solar, as well as other emerging technologies, such as energy storage, offshore wind and hybrid resources (generation combined with energy storage) – the way in which PJM evaluates the contribution of such resources toward resource adequacy also needs to evolve. This is required to account for the effect that increased penetration levels of these resources is likely to have on PJM's loss of load probability (LOLP) risk profile.

Recognizing this dynamic, in 2018 the Planning Committee began discussions on a new methodology for calculating the capacity capability of wind and solar. More recently, in 2020, as part of the proceedings surrounding PJM's compliance filing on FERC Order 841 (Energy Storage Resources), PJM responded to FERC that it was committed to investigating a new methodology for calculating the capacity capability of energy storage resources. PJM told FERC that it would start a stakeholder process to address this issue.

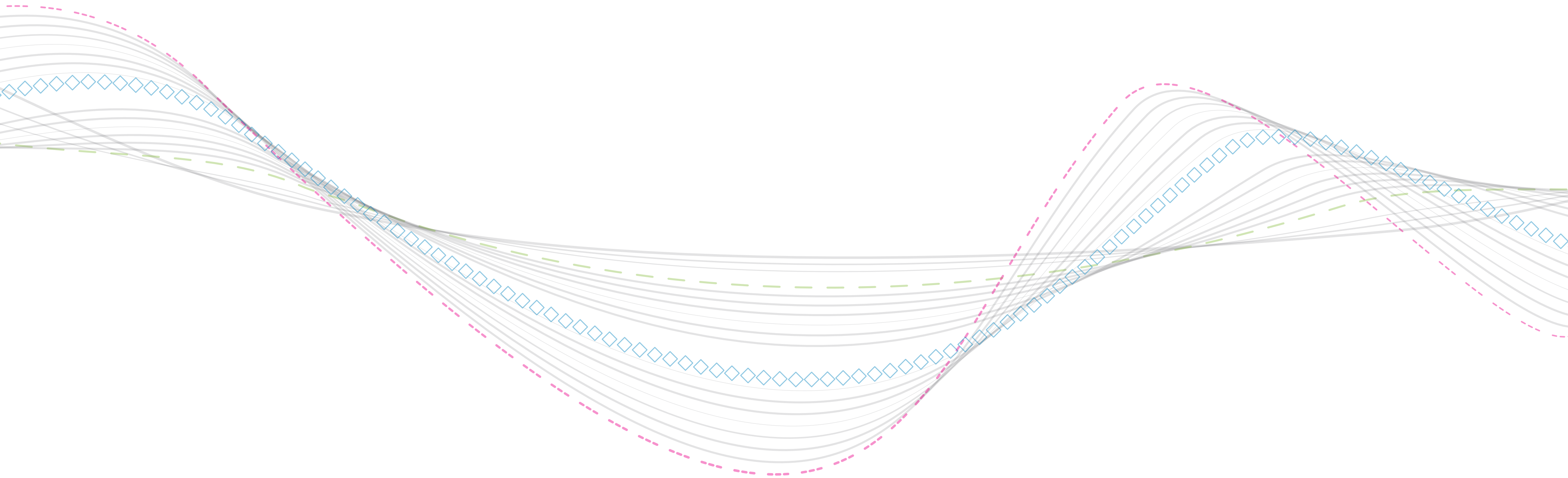
Figure 2.8: PJM 10-Year Summer Peak Load Growth Rate Comparison 2016-2020 Load Forecast Reports



PJM then put forward a Problem/Opportunity Statement and Issue Charge, approved at the March 2020 Markets and Reliability Committee (MRC) meeting, which led to the creation of the Capacity Capability Senior Task Force (CCSTF). The CCSTF was tasked with the development of the provisions necessary to establish an effective load carrying capability (ELCC) method for calculating the capacity capability of certain resources. These will include energy storage resources and intermittent resources, such as wind, solar, hydroelectric power with and without storage reservoirs, and other renewable resources as well as hybrid resources.

ELCC is a well-established methodology based on LOLP calculations employed to estimate the reliability value/capacity capability of resources. At the CCSTF, PJM staff provided education on ELCC, LOLP and PJM Resource Adequacy studies. Also at the CCSTF, PJM and stakeholders developed and discussed multiple solution packages in response to the Problem/Opportunity Statement and Issue Charge. At the September 2020 MRC meeting, a sector-weighted majority of stakeholders voted in favor of one of the solution packages. Some key elements of this member-endorsed solution package include: (1) a simulated output dispatch approach for limited-duration, hybrid and hydro with storage resources; and (2) a transition plan that considers the concept of capacity capability floors for resources.

PJM filed Tariff and Reliability Assurance Agreement (RAA) changes with FERC on Oct. 30, 2020, based on the member-endorsed solution package. PJM is expecting to implement an ELCC in 2021, pending FERC approval.



PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

2.2: Demand Resources and Peak Shaving

PJM accounts for demand resources by adjusting its base, unrestricted, peak load forecast by the amount that clears Reliability Pricing Model auctions. Those amounts, as reflected in the 2020 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.

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., duration, trigger, curtailed-load hourly profile), 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 2020 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 Auction.
- *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.

Table 2.4: 2020 Load Forecast Report Demand Resources

Transmission Owner	Total Load Management 2020	Total Load Management 2030
Atlantic City Electric Co.	70	77
Baltimore Gas and Electric Co.	560	510
Delmarva Power & Light	280	314
Jersey Central Power & Light	142	149
Met-Ed	278	305
PECO Energy Co.	363	374
Pennsylvania Electric Co.	303	315
PPL Electric Utilities Corp.	577	634
Potomac Electric Power Co.	413	394
PSEG	336	363
Rockland Electric Co.	4	5
UGI Utilities	0	0
Mid-Atlantic	**3,326**	**3,440**
American Electric Power Co.	1,174	1,290
Allegheny Power	758	818
American Transmission Systems, Inc.	801	804
Commonwealth Edison Co.	1,492	1,509
Dayton Power & Light	169	168
Duke Energy Ohio and Kentucky	160	171
Duquesne Light Co.	130	134
East Kentucky Power Cooperative	138	161
Ohio Valley Electric Corp.	0	0
Western	**4,822**	**5,055**
Dominion Virginia Power	781	880
Southern	**781**	**880**
PJM RTO	**8,929**	**9,375**

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

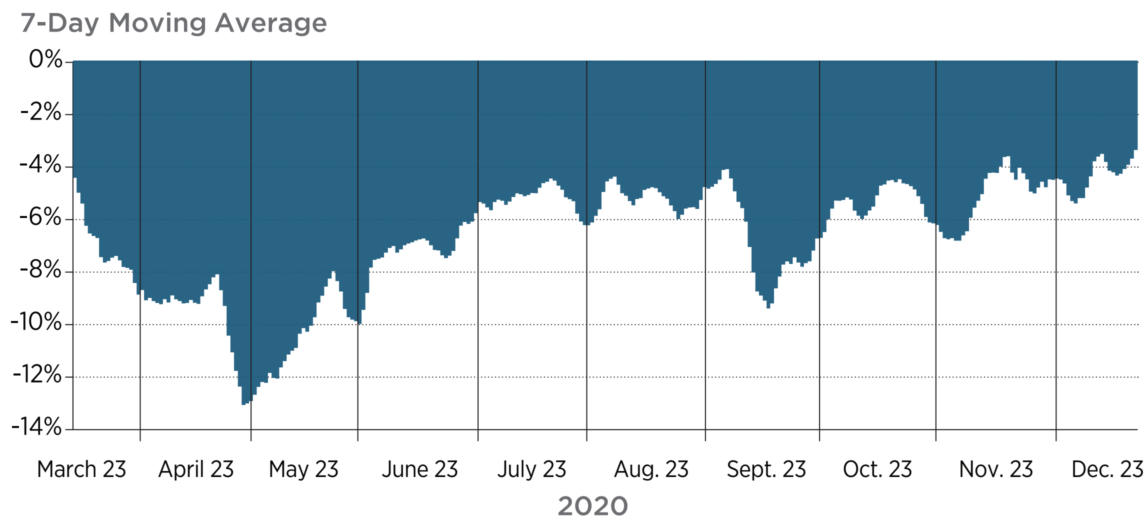
2.3: Load Forecast – COVID-19 Impacts

PJM used the 2020 load forecast to estimate impacts on peaks during the COVID-19 pandemic. The load model is solved with actual daily weather from 2020 and the results are compared to the observed load. The percent difference between these two numbers can be viewed as an estimate of the impact of COVID-19. A rolling 7-day average of these estimated impacts is shown In **Figure 2.9**.

In late March 2020, many states issued stay-at-home orders. This development, along with the broader economic turmoil, weighed heavily on commercial and industrial energy demand, but also shifted a greater proportion of electricity usage to residential customers. In the spring, when weather is generally mild, this resulted in demand impacts greater than 10% at times. As spring turned to summer and subsequently to fall, impacts ebbed and flowed. A consequence of a greater proportion of load being residential is that load is also more weather sensitive than it was pre-covid.

Concurrently, the economy has been slowly rebounding. The interplay of stay at home orders, weather sensitivity and economics, has contributed to varying COVID impacts on load. By the end of 2020 and early 2021, estimated impacts were a fraction of what they were at the pandemic's onset. Any lingering impacts of the pandemic going forward will be reflected in future load forecasts through the economic input variable.

Figure 2.9: 2020 COVID-19 Estimated Daily Energy Impacts 7-Day Moving Average



Section 3: Transmission Enhancements

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

3.0: 2020 RTEP Proposal Window No.1

RTEP Process Context

PJM seeks transmission proposals during each RTEP window to address one or more identified needs – reliability, market efficiency, operational performance and public policy. RTEP windows provide an opportunity for both incumbent and non-incumbent transmission developers to submit project proposals to PJM for consideration. When a window closes, PJM proceeds with analytical, company, 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.

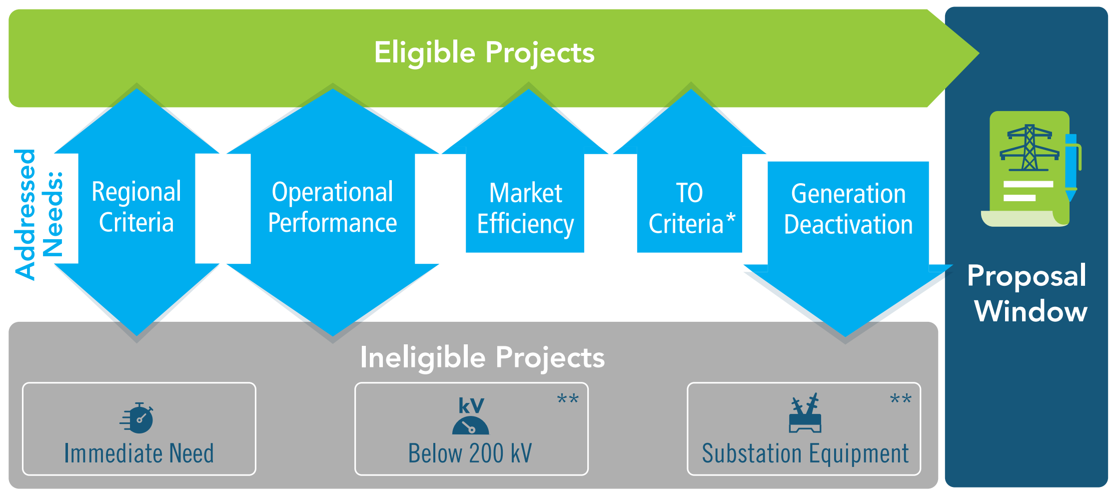
Proposal Window Exemptions

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.

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.

Figure 3.1: RTEP Proposal Window Eligibility

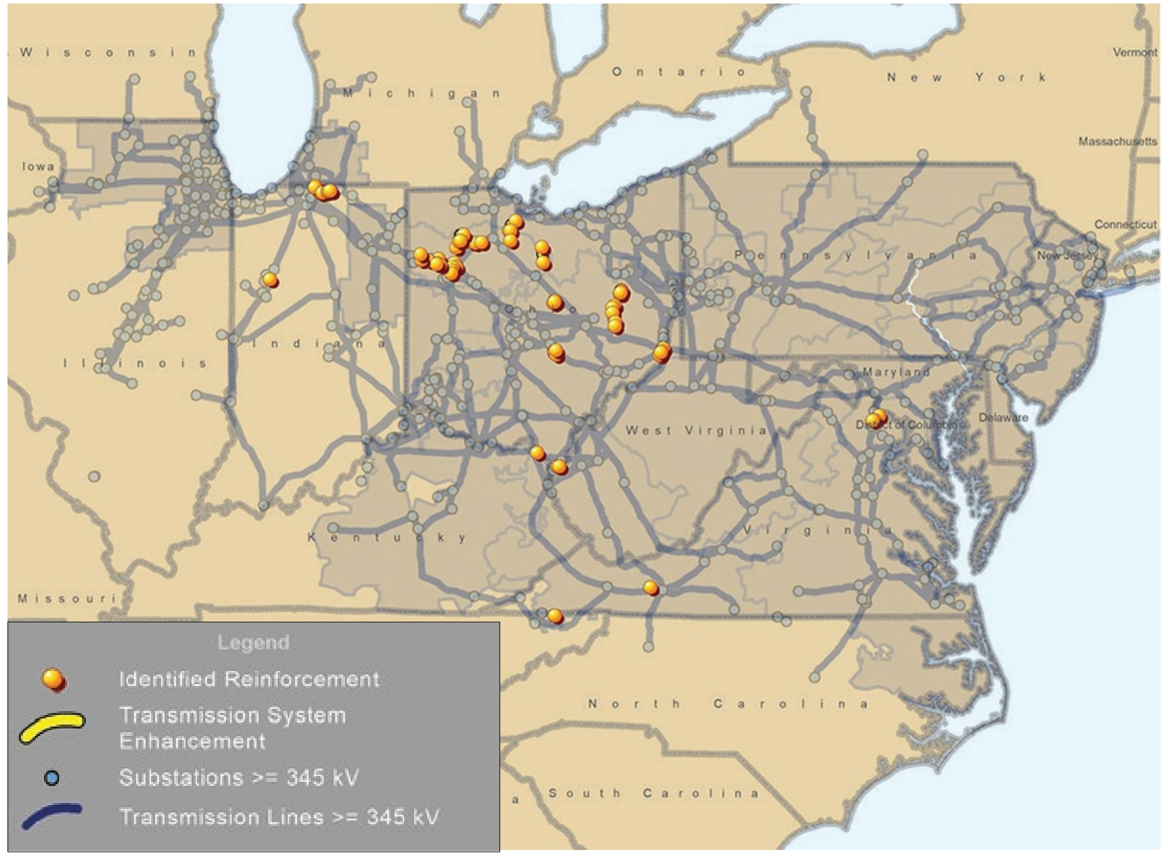


Note: **TO Criteria is eligible for proposal windows as of Jan. 1, 2020.*

***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.*

Proposal Window Baseline Reliability Analysis Results
PJM's analysis of 2025 summer, winter and light load conditions identified 190 thermal and voltage criteria violations and one end-of-life criteria violation. A summary of the 191 violations is shown in **Map 3.1**.

Map 3.1: 2020 RTEP Baseline Thermal and Voltage Criteria Violations



RTEP Proposal Window No. 1 Proposals

RTEP Proposal Window No. 1, which contained 166 flowgates for competition, opened on July 1, 2020, and closed on Aug. 31, 2020. PJM received 47 proposals from eight entities. Eight of the proposals included cost containment provisions, and 11 of the proposals included greenfield construction. The proposals are shown in **Map 3.2** and **Table 3.1**.

Map 3.2: 2020 RTEP Proposal Window No. 1 Submittals

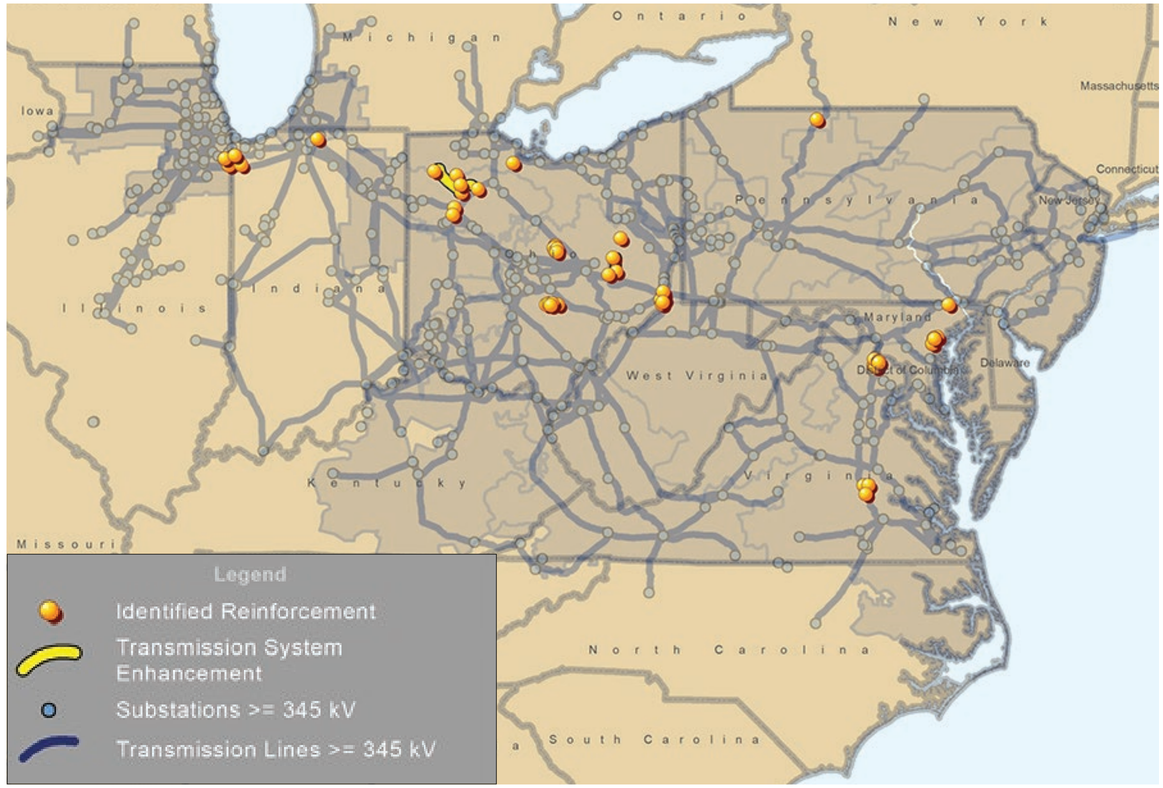


Table 3.1: 2020 RTEP Proposal Window No. 1 Submittals

PJM Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
479	Dominion	230	Thermal, GenDeliv	VEPCO	Upgrade	No	$1.846	Line No. 2172 Partial Reconductor – Brambleton to Evergreen Mills
26	Dominion	230	Thermal, GenDeliv	VEPCO	Upgrade	No	$2.316	Line No. 2172 Full Reconductor Brambleton to Evergreen Mills
740	Dominion	230	Thermal, GenDeliv	VEPCO	Upgrade	No	$2.014	Line No. 2210 Partial Reconductor – Brambleton to Evergreen Mills
735	Dominion	230	Thermal, GenDeliv	VEPCO	Upgrade	No	$2.257	Line No. 2210 Full Reconductor – Brambleton to Evergreen Mills – Full Reconductor

Table 3.1: 2020 RTEP Proposal Window No. 1 Submittals (Cont.)

PJM Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
704	Dominion	230	Load Drop	VEPCO	Greenfield	No	$5.703	Waxpool Loop-Nimbus to Farmwell line extension
376							$17.698	Waxpool Loop-Loop Line No. 2031 Option
883							$41.203	Waxpool Loop-Shellhorn Option
493			Thermal		Upgrade		$1.112	Line No. 2213 Partial Reconductor – Cabin Run to Yardley Ridge
134							$1.747	Line No. 2213 Full Reconductor – Cabin Run to Yardley Ridge
860			Load Drop				$6.219	Relieve 300 MW Load Drop on Line No. 219 and Line No. 2066 (winter N-1-1, Tower, and faulted breaker)
575	ComEd	345	GenDeliv	NextEra	Upgrade	No	$8.250	Crete-St. John 345 kV Reconductoring Proposal
173				ComEd			$22.786	Reconductor 345 kV Line 94507 Crete-St. John
573							$50.251	Reconductor 345 kV Lines 6607 East Frankfort-Crete and 94507 Crete-St. John
148				Central Transmission / LS Power	Greenfield	Yes	$29.629	Cedar Run-Cline 345 kV Transmission Project
281				ComEd	Upgrade	No	$42.485	Rebuild 345 kV double circuit Lines 94507 and 97008 Crete-St. John
354							$88.935	Rebuild 345 kV Lines 6607/6608 East Frankfort-Crete and 94507/97008 Crete-St. John
241							$12.000	Crete-St. John SmartValve
901							$7.998	Install Series Inductor on Line 94507
393				AEP	Greenfield	Yes	$25.910	Zebedee 345 kV Greenfield Station
235							$46.194	Goodenow-Lemon Lake 345 kV Greenfield Line and Stations
602	AEP	69, 138, 35	Thermal	AEP	Greenfield	No	$25.930	North Woodcock-East Leipsic 69 kV Line
957					Upgrade		$34.418	East Leipsic-New Liberty 138 kV Conversion
317				Transource	Upgrade	Yes	$58.514	Richlands to East Lepsic 138 kV
341					Greenfield		$27.149	East Leipsic-Maroe 69 kV Loop

Table 3.1: 2020 RTEP Proposal Window No. 1 Submittals (Cont.)

PJM Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
608	AEP	69, 138, 35	Thermal	Transource	Greenfield	Yes	$25.157	East Leipsic to Maroe 69 kV Single Circuit
270		69		Central Transmission / LS Power			$16.637	Birch Ridge-Natrium 138 kV Transmission Project
804		69, 138	Thermal, GenDeliv	AEP	Upgrade	No	$4.599	Kammer-Natrium Upgrades
538							$5.635	Natrium Area Line Reconfiguration
182		69	Thermal				$15.884	Newcomerstown-Salt Fork Switch 69 kV Rebuild
109							$4.309	West Cambridge Transformer Addition
628							$1.466	Lancaster Area Switching Improvements
915							$11.147	Lancaster Area Line Rebuilds
697		69, 138					$1.286	Mount Vernon Area Line Reconfiguration
872							$12.846	Mount Vernon Area Line Rebuilds
494	BGE	115	GenDeliv	BGE	Upgrade	No	$4.692	Pumphrey Transformer Replacement
763							$0.000	Erdman Reconfiguration
514							$9.010	Pumphrey-Graceton Transformer Replacement
420							$14.730	Constitution-Concord 110567/110568 Reconductor – Partial 110563/110564 Reconductor
836							$20.587	Constitution-Concord 110567/110568 Concord-Monument Street 110563/110564 Reconductor
962							$19.422	Pumphrey Transformer, Constitution-Concord 110567/110568 Reconductor, Partial 110563/110564 Reconductor
191							$25.279	Pumphrey Transformer, Constitution-Concord 110567/110568 Concord-Monument Street 110563/110564 Reconductor
721	Dominion	230	Thermal, GenDeliv, Load Drop	Central Transmission / LS Power	Greenfield	Yes	$29.250	Stonewater-Waxpool 230 kV Transmission Project
855	PENELEC	345	Voltage, Voltage and Magnitude	ATSI / MAIT	Upgrade	No	$8.077	Pierce Brook Substation, Install Second 345 kV Reactor

Table 3.1: 2020 RTEP Proposal Window No. 1 Submittals (Cont.)

PJM Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Description
179	AEP	35, 69	Thermal	AEP	Upgrade	No	$2.020	West New Philadelphia Breaker Installation
848	AEP	35	Thermal	AEP	Upgrade	No	$1.471	Rockhill Circuit Switcher Install
503	AEP	69	Thermal	AEP	Upgrade	No	$1.758	Fremont Breaker and Bloom Road Cap Bank Installation
308	AEP	35	Thermal	AEP	Upgrade	No	$4.894	Dragoon Transformer and Line Addition

RTEP Proposal Window No. 2 Proposals

RTEP Proposal Window No. 2, which contained one flowgate for competition, opened on July 1, 2020, and closed on July 31, 2020. The one flowgate was as a result of Dominion's FERC 715 criteria for end-of-life facilities on the Goose Creek-Doubs 500 kV transmission line. The end-of-life issue identified for the Goose Creek-Doubs 500 kV line is linked to the Attachment M3 process need identified as APS-2020-011. PJM received one proposal from Dominion, the incumbent TO, to rebuild Dominion's portion of the line. The proposal is shown in **Map 3.3** and **Table 3.2**.

Map 3.3: 2020 RTEP Proposal Window No. 2 Submittals

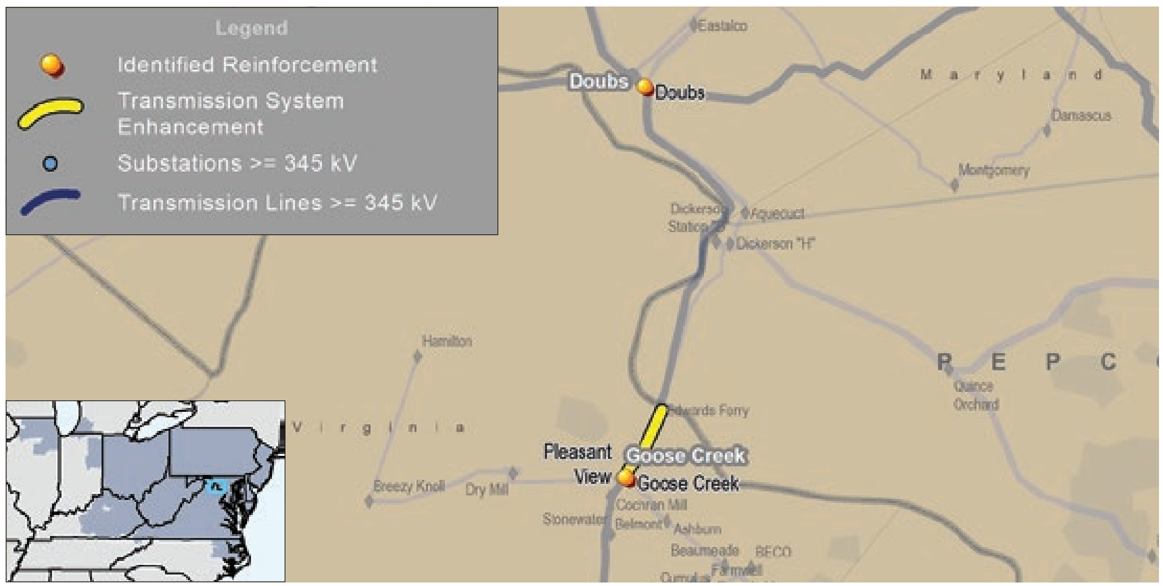


Table 3.2: 2020 RTEP Proposal Window No. 2 Submittals

Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Project Description
441	Dominion	500	End-of-Life	VEPCO	Upgrade	No	7.641	Line No. 514, Goose Creek-Doubs (FE) 500 kV Line Rebuild

RTEP Proposal Window No. 3 Proposals

RTEP Proposal Window No. 3, which contained 24 flowgates for competition, opened on Sept. 18, 2020, and closed on Oct. 19, 2020. Eight flowgates were from RTEP Proposal Window No. 1 violations and 16 flowgates were new to RTEP Proposal Window No. 3. The flowgates were in relation to AEP's FERC 715 criteria of thermal overloads on the following facilities, along with FirstEnergy's FERC 715 criteria short-circuit violations on Greenfield 69 kV breaker 501-B-251:

- Pittsburgh-West Mount Vernon 69 kV
- West Mount Vernon 138/69 kV
- South Mount Vernon-North Mount Vernon 69 kV
- North Mount Vernon-Mount Vernon 69 kV

PJM received two proposals, one from AEP, the incumbent TO, and one joint greenfield proposal from Central Transmission and LS Power. The proposals are shown in **Map 3.4** and **Table 3.3**.

Map 3.4: 2020 RTEP Proposal Window No. 3 Submittals

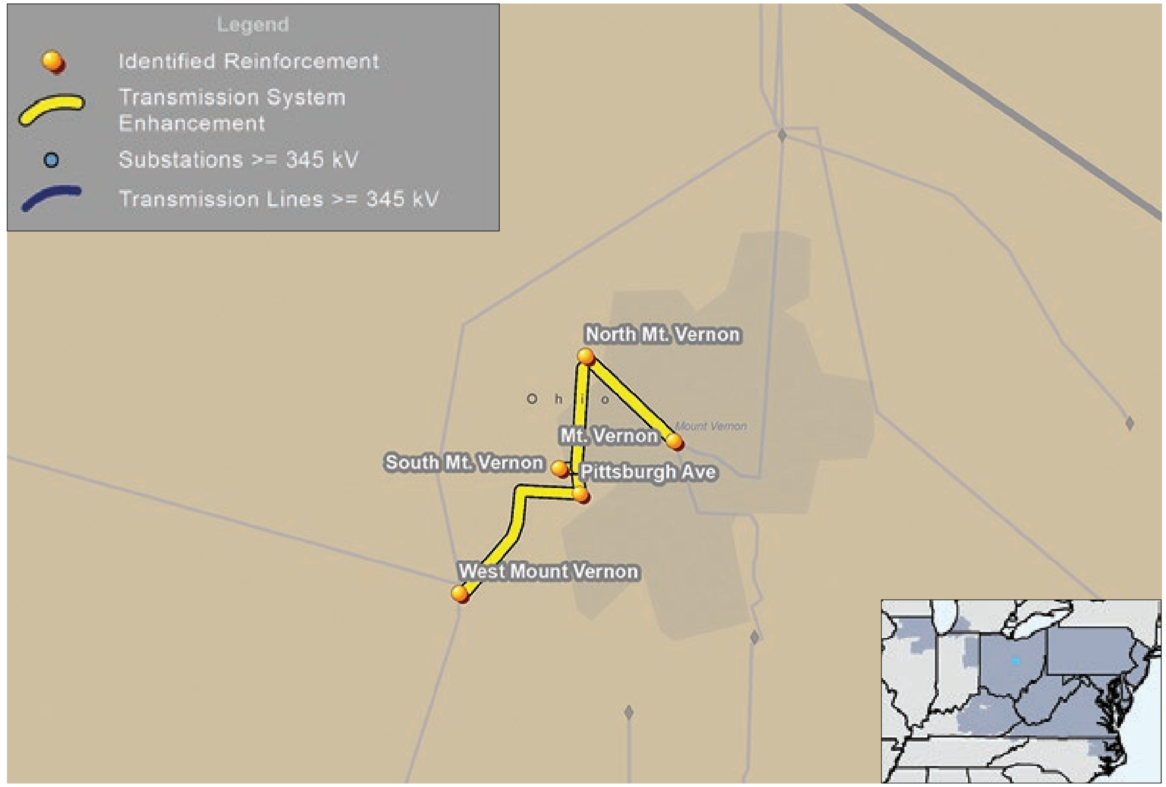
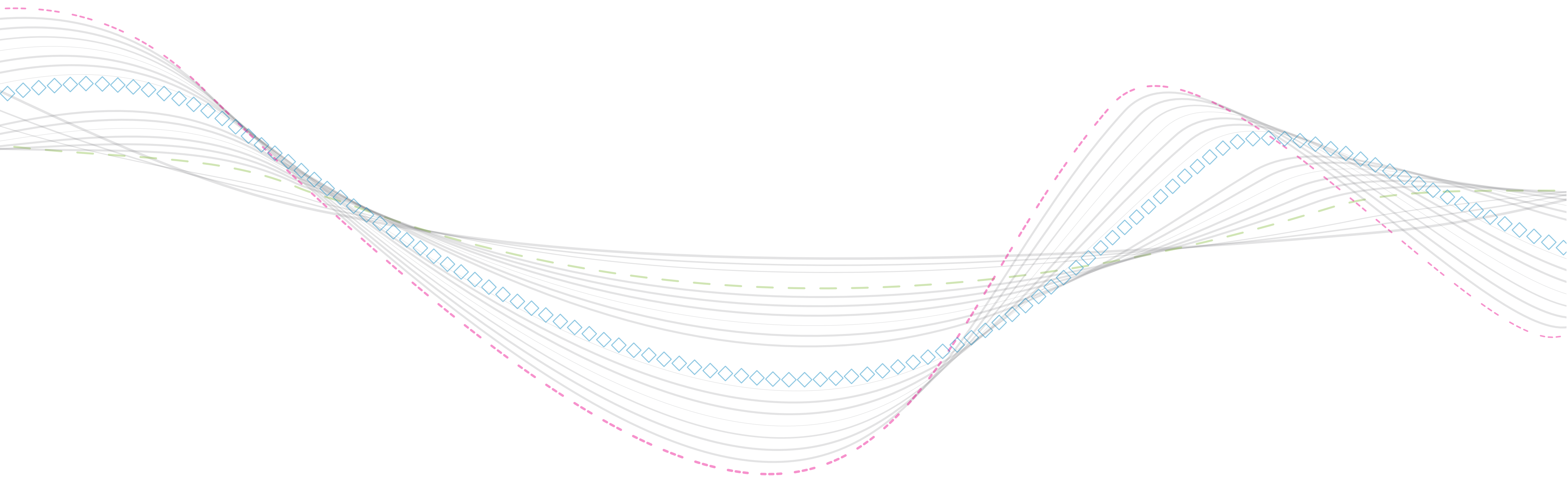


Table 3.3: 2020 RTEP Proposal Window No. 3 Submittals

Proposal ID	Target Zone	kV	Analysis Type	Incumbent	Project Type	Cost Containment	Cost ($M)	Project Description
533	AEP	69, 138	Thermal	Central Transmission / LS Power	Greenfield	Yes	$21.129	Wolf Run-Gambier-Martinsburg Transmission Project
860				AEP	Upgrade	No	$12.926	West Mount Vernon Area Rebuilds



3.1: Transmission Owner Criteria

3.1.1 — Transmission Owner FERC Form 715 Planning Criteria

The PJM Operating Agreement specifies that individual TO planning criteria are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions 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 with an estimated cost of $10 million or greater 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.

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.

NOTE:

Per FERC Order EL19-61, PJM has eliminated the FERC Form 715 transmission owner criteria exclusion from the competitive proposal windows as of Jan. 1, 2020.

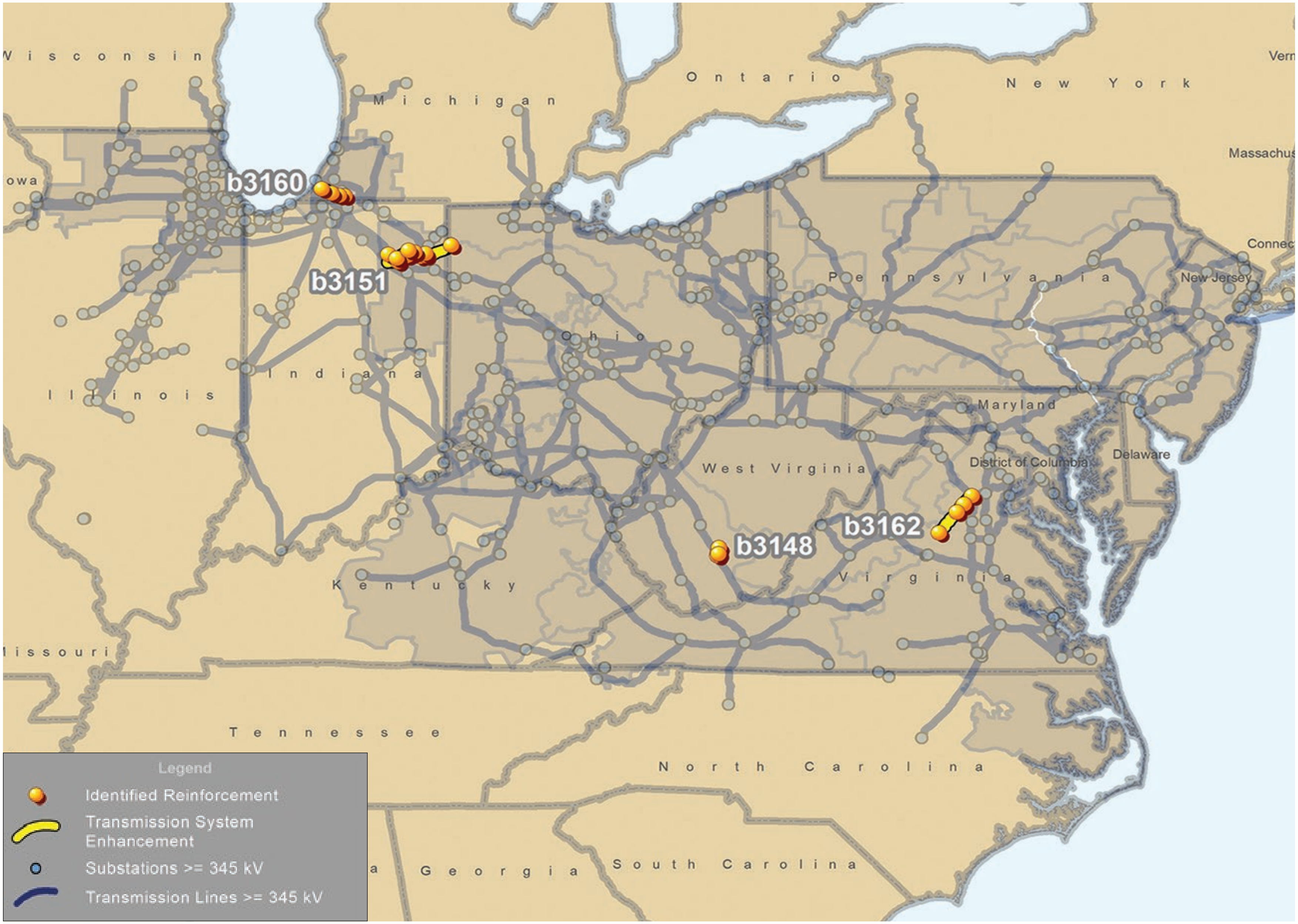
Table 3.4: Transmission Owner Criteria Projects (Greater Than or Equal to $10 Million)

Upgrade ID	Description	TO Zone	Estimated Cost ($M)	Required In-Service	Projected In-Service
B3148	Rebuild the 46 kV Bradley-Scarbro line to 96 kV standards using 795 ACSR to achieve a minimum rating of 120 MVA. Rebuild the new line adjacent to the existing one leaving the old line in service until the work is completed.	AEP	$27.7	12/1/2021	12/1/2021
	Bradley remote end station work, replace 46 kV bus, install new 12 MVAR capacitor bank.				12/10/2020
	Replace the existing switch at Sun substation with a two-way SCADA-controlled MOAB switch.				
	Remote end work and associated equipment at Scarbro Station.				5/6/2021
	Retire Mt. Hope Station and transfer load to existing Sun Station.				12/10/2020
B3151	Rebuild the ~30 mile Gateway-Wallen 34.5 kV circuit as the ~27 mile Gateway-Wallen 69 kV circuit.		$113.0	6/1/2024	6/23/2022
	Rebuild the 2.5 mile Columbia-Gateway 69 kV line.				4/3/2023
	Rebuild Columbia station in the clear as a 138/69 kV station with two 138/69 kV transformers and four-breaker ring buses on the high and low side. Station will reuse 69 kV breakers J & K and 138 kV breaker D.				6/1/2024

Table 3.4: Transmission Owner Criteria Projects (Greater Than or Equal to $10 Million) (Cont.)

Upgrade ID	Description	TO Zone	Estimated Cost ($M)	Required In-Service	Projected In-Service
B3151	Rebuild the 13 mile Columbia-Richland 69 kV line.	AEP	$113.0	6/1/2024	6/1/2024
	Rebuild the 0.5 mile Whitley-Columbia City No. 1 line as 69 kV.				
	Rebuild the 0.5 mile Whitley-Columbia City No. 2 line as 69 kV.				
	Rebuild the 0.6 mile double circuit section of the Rob Park-South Hicksville/Rob Park-Diebold Road as 69 kV.				
	Retire the ~3 mile Columbia-Whitley 34.5 kV line.				
	At Gateway station, remove all 34.5 kV equipment and install one 69 kV circuit breaker for the new Whitley line entrance.				
	Rebuild Whitley as a 69 kV station with two line and one bus tie circuit breakers.				
	Replace the Union 34.5 kV switch with a 69 kV switch structure.				
	Replace the Eel River 34.5 kV switch with a 69 kV switch structure.				
	Install a 69 kV Bobay switch at Woodland Station.				
	Replace Carroll and Churubusco 34.5 kV stations with the 69 kV Snapper station. Snapper will have two line circuit breakers, one bus tie circuit breaker and a 14.4 MVAR cap bank.				
	Remove 34.5 kV circuit breaker AD at Wallen station.				
B3160	Construct a ~2.4 mile double circuit 138 kV extension using 1033 ACSR to connect Lake Head to the 138 kV network.	AEP	$36.2	6/1/2024	4/3/2023
	Retire the ~2.5 mile 34.5 kV Niles-Simplicity tap line.				11/29/2022
	Retire the ~4.6 mile Lakehead 69 kV tap.				6/15/2023
	Build new 138/69 kV drop down station to feed Lakehead with a 138 kV breaker, 138 kV switcher, 138/69 kV transformer and a 138 kV MOAB.				4/15/2023
	Rebuild the ~1.2 mile Buchanan South 69 kV radial tap using 795 ACSR.				
	Rebuild the ~8.4 mile 69 kV Pletcher-Buchanan Hydro line as the ~9 mile Pletcher-Buchanan South 69 kV line using 795 ACSR.				
	Install a phase-over-phase switch at Buchanan South station with two line MOABs.				
B3162	Acquire land and build a new 230 kV switching station Stevensburg with a 224 MVA, 230/115 kV transformer. Gordonsville-Remington 230 kV Line No. 2199 will be cut and connected to the new station. Remington-Mt. Run 115 kV Line No. 70 and Mt. Run-Oak Green 115 kV Line No. 2 will also be cut and connected to the new station.	Dominion	$22.0	6/1/2024	12/31/2023

Map 3.5: Transmission Owner Criteria Projects (Greater Than or Equal to $10 Million)



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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 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, 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:

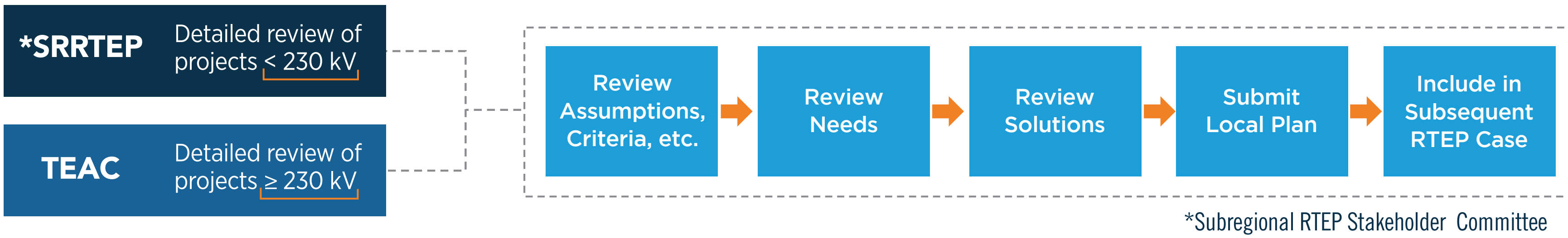
- *Provide necessary facilitation and logistical support* so that supplemental project planning meetings can be conducted as outlined in Attachment M3 of the PJM Tariff.
- *Provide the applicable TO with modeling information* so that TOs can determine if a stakeholder-proposed project can address a supplemental 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: 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 3.2 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 3.3: Attachment M3 Process for Supplemental Projects

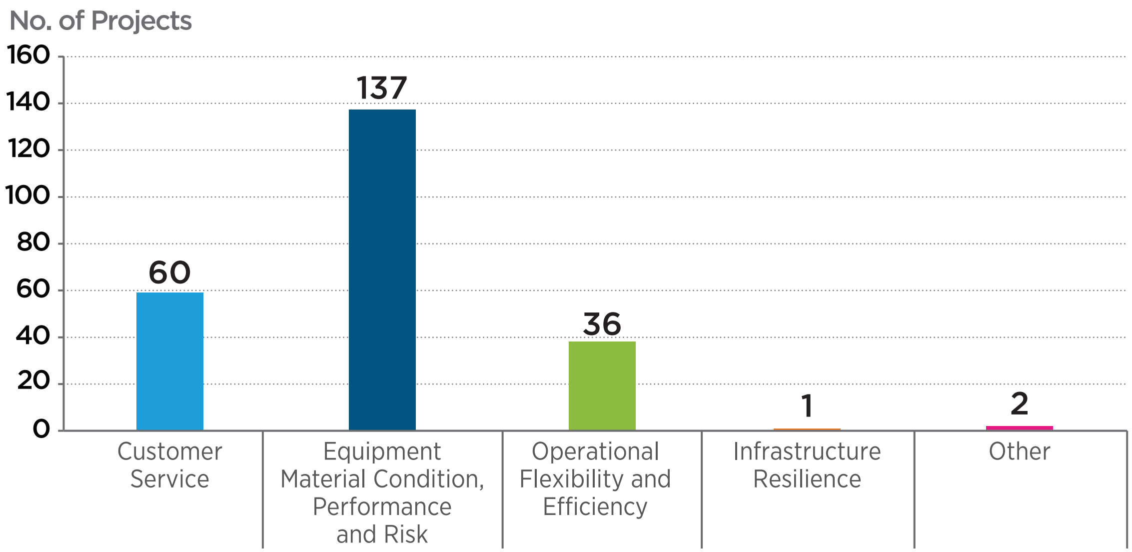


The Attachment M3 process leverages PJM's TEAC and subregional RTEP committees, which provides stakeholders a meaningful opportunity to participate and provide feedback, including written comments, throughout the transmission planning process for supplemental projects, as shown in **Figure 3.3**. Stakeholder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

2020 Supplemental Projects

PJM evaluated approximately $4.7 billion of TO supplemental projects in 2020. **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 2020, projects driven solely by equipment material condition, performance and risk add up to a total of approximately $2.6 billion, while projects driven by customer service requests and operational flexibility and efficiency totaled approximately $615 million and $154 million, respectively.

Figure 3.4: 2020 Supplemental Projects by Driver



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3.3: Generator Deactivations

PJM received 22 deactivation notices, including new requests and revisions to existing requests, totaling 4,428 MW during 2020. **Map 3.6** and **Table 3.5** show the 10 generators being deactivated with a capacity greater than or equal to 100 MW. The remaining 12 generators had a combined capacity of 164 MW. Deactivation notifications in 2020 included nine coal-unit deactivations totaling 2,466 MW. Overall capacity value of deactivation notifications for units greater than or equal to 100 MW totaled 4,263.7 MW in 2020. PJM completed the required analysis to identify reliability criteria violations caused by deactivations. Several deactivations required the completion of existing baseline enhancements, and others had no reliability impacts identified. No new baseline upgrades were identified for the deactivation notifications in 2020.

All units studied in 2020 can retire as requested; operational flexibility will allow PJM to bridge any delays with the completion of required transmission enhancements. On March 13, 2020, PJM received reinstatement notifications from Energy Harbor for the Beaver Valley 1 and 2, and Pleasants Power Station 1 and 2 units, totaling over 3,080 MW. PJM also received reinstatement notification from Colver Power for the Colver non-utility generator, totaling 110 MW. These units will not be deactivating.

Map 3.6: Deactivation Notifications in 2020 Greater Than or Equal to 100 MW

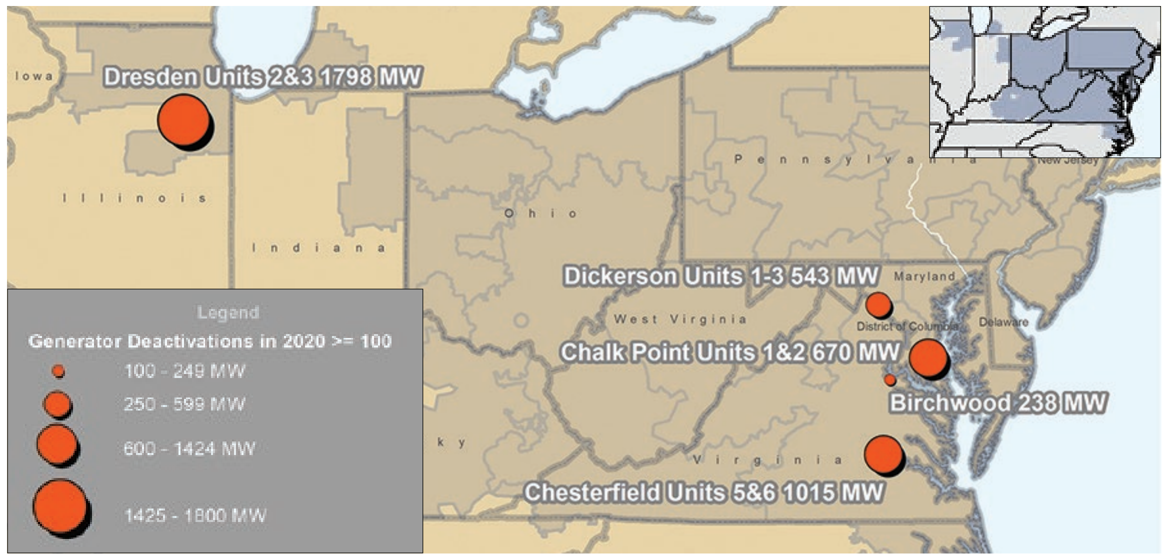

Table 3.5: Deactivation Notifications in 2020 (Greater Than or Equal to 100 MW)

Unit	Capacity (MW)	TO Zone	Age (Years)	Fuel Type	Request Submittal Date	Actual/Projected Deactivation Date
Birchwood Plant	238.0	Dominion	24	Coal	10/6/2020	3/1/2021
Dresden 3	895.5	ComEd	49	Nuclear	8/27/2020	11/1/2021
Dresden 2	902.5		50			
Chalk Point Unit 2	337.2	PEPCO	55	Coal	8/10/2020	6/1/2021
Chalk Point Unit 1	333.1		56			
Dickerson Unit 3	180.5		58		5/15/2020	8/13/2020
Dickerson Unit 2	180.0		60			
Dickerson Unit 1	182.0		61			
Chesterfield 6	678.1	Dominion	51		2/20/2020	5/31/2023
Chesterfield 5	336.8		56			

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3.4: 2020 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 2020 RTEP, PJM performed a retool of the 2025 RTEP analysis, driven by the withdrawn deactivation of the Beaver Valley 1 and 2, Pleasants Power Station units 1 and 2 and the Colver units shown in **Map 3.7**, 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.

Additionally, retool analysis continues, to determine if upgrades identified in previous analysis are still valid. Several baseline upgrades are still required for other deactivations in these areas. A detailed description of the withdrawn deactivation analysis can be found on the PJM website.

Map 3.7: Withdrawn Deactivations Greater Than or Equal to 100 MW

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3.5: Interregional Planning

3.5.1 — Adjoining Systems

PJM's interregional planning activities continue to foster increased interregional coordination. The nature of these activities includes structured, Tariff-driven analyses, as well as sensitivity evaluations to target specific issues that may arise each year. PJM currently has interregional planning arrangements with the New York Independent System Operator (NYISO), the Independent System Operator of New England (ISO-NE), the Mid-Continent Independent System Operator (MISO), the Tennessee Valley Authority (TVA), and to the south through the Southeastern Regional Transmission Planning process (SERTP), shown on **Map 3.8**.

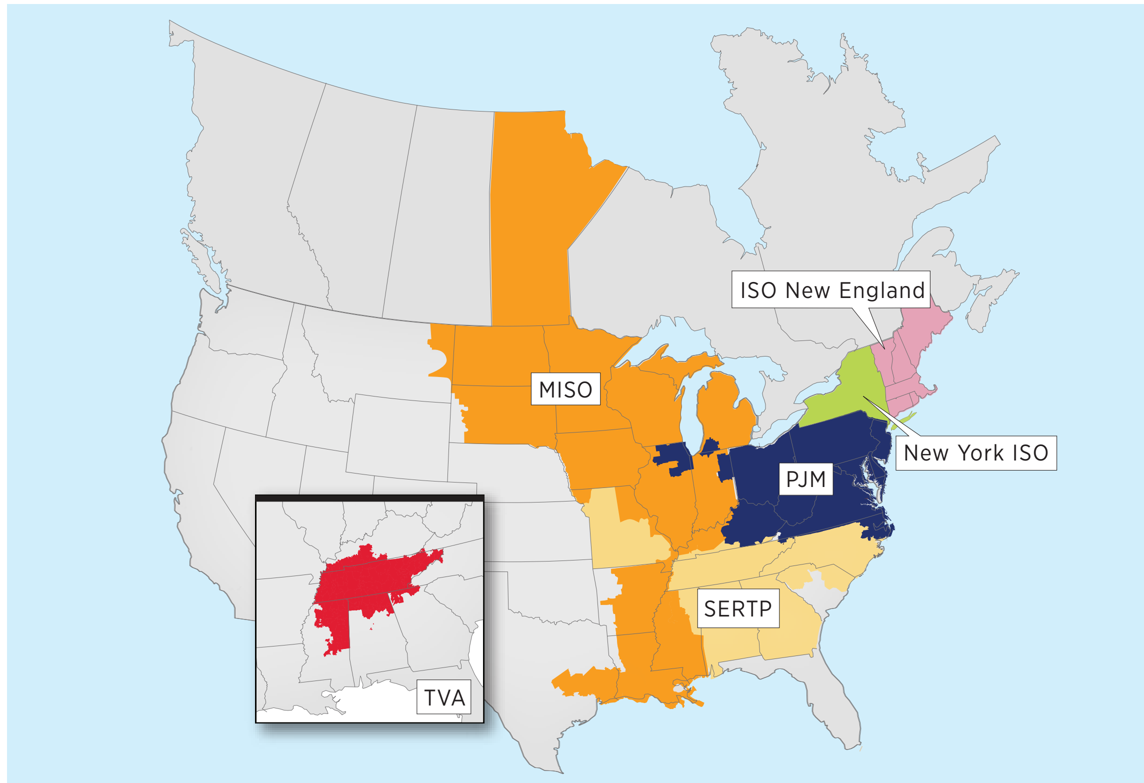
In addition, PJM actively participates in the Eastern Interconnection Planning Collaborative.

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

Map 3.8: PJM Interregional Planning



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.

Table 3.6: PJM Market Efficiency Eligible Market-to-Market Congestion Drivers

2020/2021 RTEP Market Efficiency Window

Eligible Congestion Drivers			
Constraint	**From Area**	**To Area**	**Comment**
Duff to Francisco 345 kV	DUK-IN	DUK-IN	Market-to-Market Constraint
Gibson to Francisco 345 kV			

3.5.2 — MISO

The 2020 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 5**. Deactivation-driven baseline analyses are summarized in **Section 3.4**. 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 2020, PJM and MISO confirmed their commitment to identify market efficiency issues in the fourth quarter.

PJM identified two congestion drivers as candidates for potential interregional market efficiency projects. This is shown in **Table 3.6,** PJM Market Efficiency Eligible Market-to-Market Congestion Drivers. 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 2020.

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 2020.

3.5.3 — Update on 2018/2019 PJM/MISO Interregional Market Efficiency Study

Periodically, the Joint RTO Planning Committee (JRPC), with input from IPSAC, may elect to perform a longer-term CSP study. After review of each RTO's transmission issues and regional solutions, the JRPC initiated a two-year IMEP study in 2018. This follows the CSP study process, including close coordination with PJM and MISO regional market efficiency analyses. For more information on PJM's regional market efficiency process, see **Section 4**.

The 2018/2019 IMEP study resulted in one interregional project to be recommended by both RTOs. The Bosserman-Trail Creek-Michigan City 138 kV project will address persistent historical congestion projected to continue on the NIPSCO/AEP seam. See **Section 4.1** for full details on the Bosserman-Trail Creek-Michigan City project.

The Bosserman-Trail Creek-Michigan City project was approved by the PJM Board in December 2019, conditionally on MISO approval of the same project. At that time, MISO has not completed final approval of the project because of pending filings at FERC regarding regional cost allocation for interregional projects under 345 kV. Since the 2019 provisional approval, FERC approved MISO's cost allocation compliance filing on July 28, 2020, allowing for MISO's board to approve the project on Sept. 17, 2020.

The project was fully approved by the PJM Board in December 2020. The estimated cost for this project is $24.69 million ($22 million of which is allocated to PJM, with a required and projected in-service date of January 2023). The local transmission owners, AEP and NIPSCO, will be designated to complete this work.

3.5.4 — New York ISO and ISO New England

In 2020, PJM, the New York ISO and ISO New England reviewed the status of the ongoing work plan and anticipated 2021 activities. The 2020 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 to seek opportunities for interregional transmission. The next Northeast Coordinated System Plan is anticipated by the second quarter of 2022.

3.5.5 — 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 3.8**, continued interregional data exchange and interregional coordination during 2020. 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 LGE/KU. Duke Energy and LGE/KU are directly connected to PJM. Of the non-jurisdictional entities, only TVA is directly connected to PJM. The remaining five SERTP participants are planning areas south and west of Duke Energy and TVA.

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

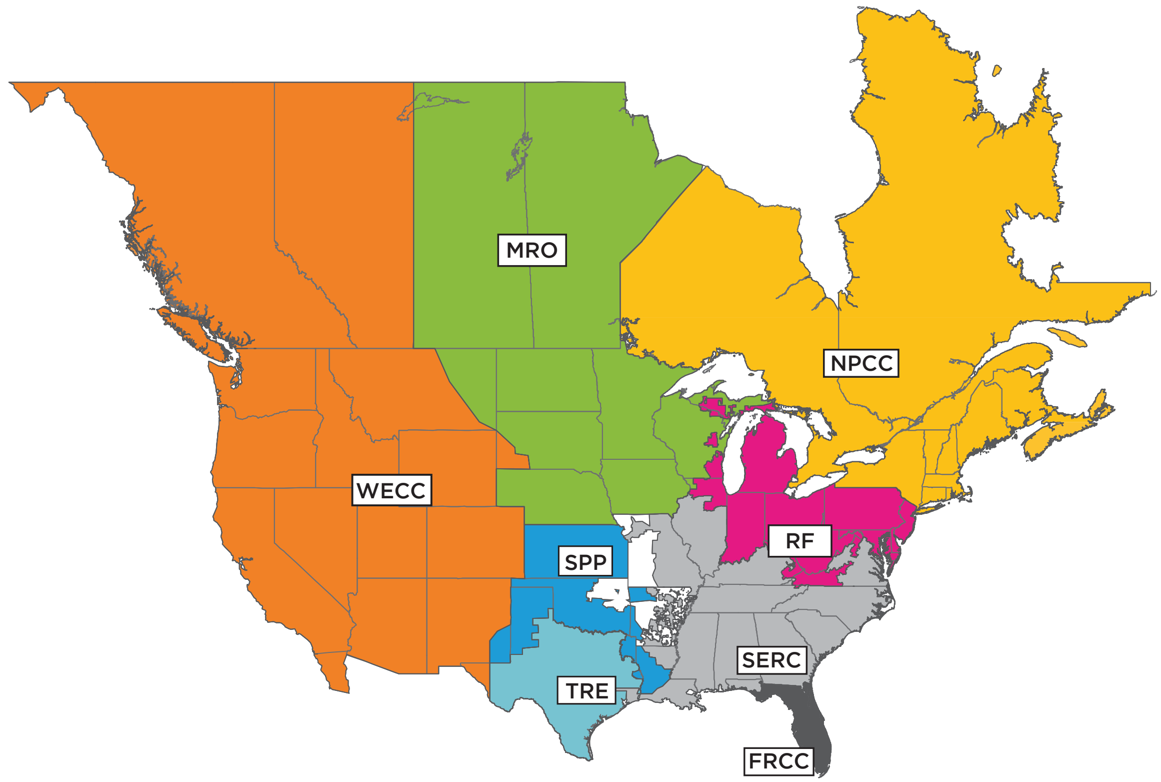
SERC Activities

PJM continues to support its members that are located within SERC – shown on **Map 3.9**. That support includes active participation in the Planning Coordination Subcommittee, the Long-Term Working Group, the Dynamics Working Group, the Short-Circuit Database Working Group, the Resource Adequacy Working Group and the Near-Term Working Group.

PJM actively contributed to SERC committee and working group activities to coordinate 2020 model development and study activities.

PJM transmission owners in the SERC region include Dominion and East Kentucky Power Cooperative (EKPC).

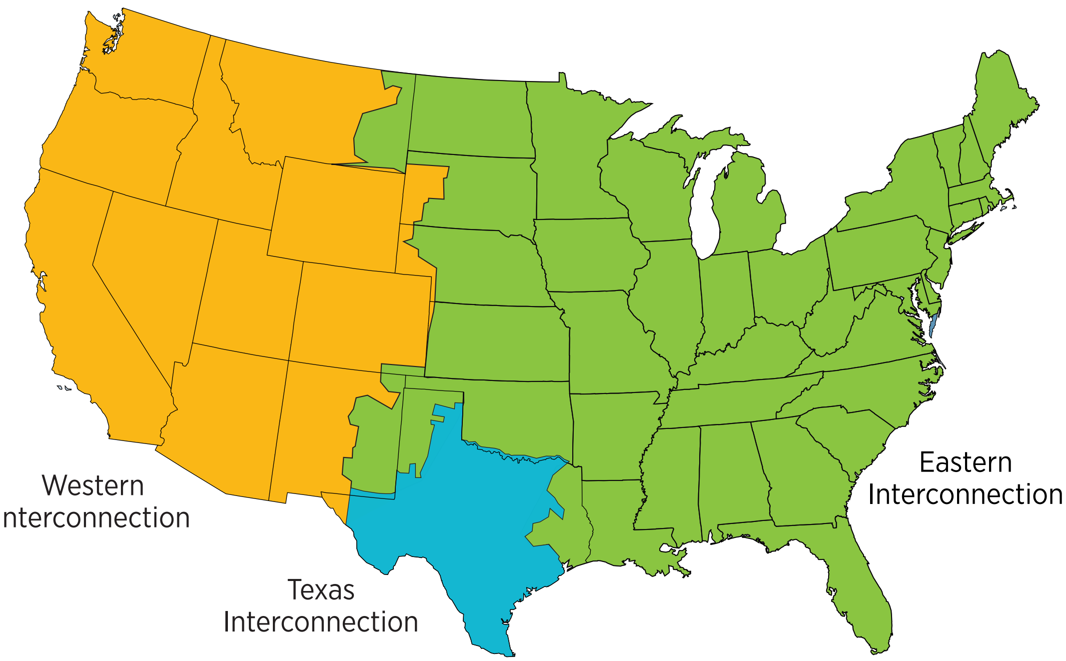
Map 3.9: NERC Areas



3.5.6 — 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 3.10**. EIPC consists of 20 planning coordinators representing approximately 95 percent 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 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 3.10: U.S. Interconnections



EIPC Activities

During 2020, EIPC continued to engage power system planning analysis activities including the following:

- The Frequency Response Working Group (FRWG) performed an evaluation of the Eastern Interconnection's ability to maintain frequency following a disturbance during a low-inertia period.
- The Transmission Analysis Working Group (TAWG) completed its analysis of a "roll-up integration model." This includes summer and winter cases that combine individual plans of each Planning Coordinator (PC).
- The Production Cost Task Force (PCTF) investigated a high-renewables future.

PJM expects many of these activities to continue in 2021, including the low-inertia frequency response study and the joint TAWG/PCTF high-renewables impact study.

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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 2020, PJM investigated the incorporation of dynamic load models in stability studies and potential impacts of distributed energy resources on the transmission system.

Stability Studies Using Dynamic Load Models

Dynamic load modeling plays an important role in system stability, especially in system voltage recovery following a contingency event. The conventional static or complex load (CLOD) model has limitations regarding the modeling of single-phase air-conditional loads, motor stalls, protection trips or reconnections.

To consider more accurate dynamic behaviors of loads in stability studies, PJM is transitioning to adoption of state-of-the-art dynamic load models called composite load models (CMLD) in line with NERC's Load Modeling Task Force (LMTF) initiatives. Compared to the CLOD model, CMLD has the capability of modeling various three-phase motors (commercial or industrial) and single-phase motors (mainly residential air conditioners) as well as motor stalling, tripping or reclosing actions.

The scenario study investigated the impact of CMLD on PJM system stability for normal and stressed operating conditions under various NERC planning and extreme contingency events. Consistent with LMTF's phased approach on the implementation of CMLD in the Eastern Interconnection, the study applied the LMTF proposed CMLD data sets in three-phased stages to the entire PJM footprint. The study also compared the performance of CMLD and a CLOD model previously used in the PJM system. Furthermore, the study included a sensitivity analysis on key CMLD parameters. Future work of this challenging and ongoing task is also addressed, which includes benchmarking and validating the study findings against actual recorded events data from phasor measurement units (PMUs) or field measurements, and more contingency analysis on various system conditions.

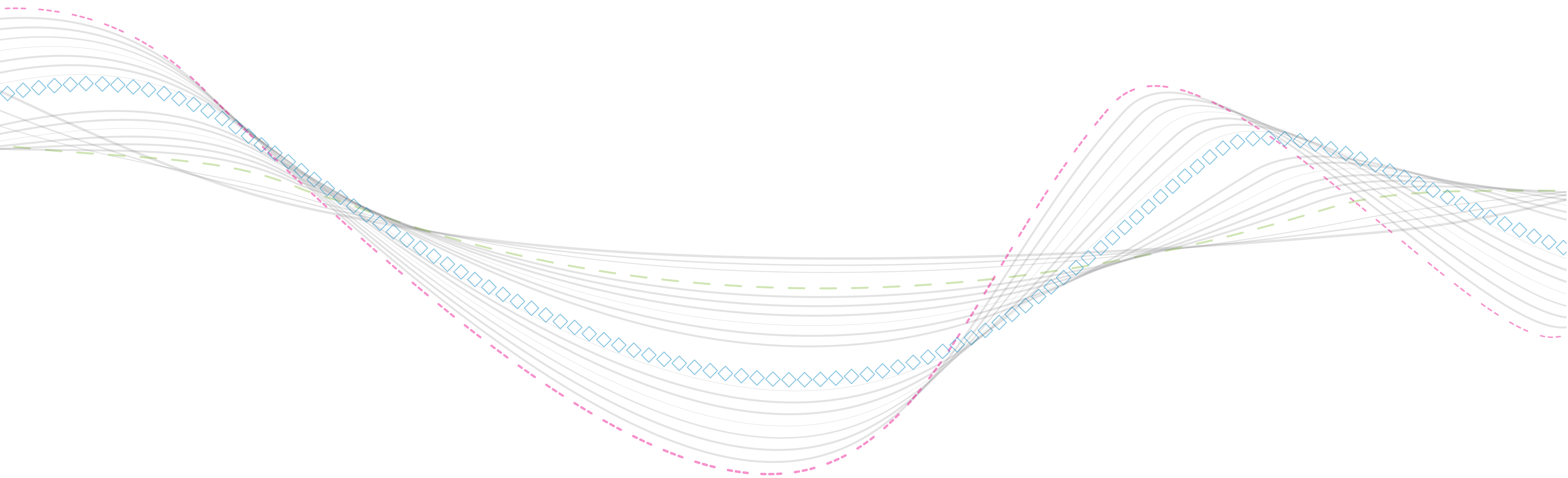
Distributed Energy Resources Sensitivity Study

The current practice for handling distributed energy resources (DER), which includes implicitly modeling most DER as part of the load (netted with actual load at the bus), may lead to skewed study results. There can also be modeling inaccuracies related to the distribution of zonal-level load and behind-the-meter (BTM) solar forecasts. PJM has struggled with collecting DER data from distribution companies, as many of the companies fall below the NERC distribution provider threshold of 75 MW and, as a result, are not required to provide data under NERC jurisdiction. PJM also struggles with modeling DER for the following reasons:

- Current rules that allow for mingling of queue (wholesale) and local (retail) BTM DER
- Net metering that is not simply a reduction in load but an injection in front of the meter
- Distribution system changes that may alter the aggregation point of DER

Determining where to place DER in the planning models, in addition to any associated modeling complexity because of excessive detail, also poses a challenge.

To evaluate potential impacts of DER on its transmission system, PJM coordinated a cross-divisional sensitivity study for areas on the system where known BTM DER poses a current operational concern. PJM also analyzed a few extreme scenarios using the generator deliverability test. The intent of this analysis was to determine if solar DER, whether it be BTM or non-BTM, negatively impact PJM's transmission system in the planning models. Any potential violations identified in this study could provide valuable insight into system vulnerabilities. Recognizing that the full inclusion of explicit BTM DER into the planning models is a long-term goal, based on findings from the extreme scenario analysis, PJM could implement adjustments to the RTEP process to better account for DER in the future.



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3.7: Stage 1A ARR 10-Year Feasibility

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

Scope

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

Table 3.7: 2020/2021 Stage 1A ARR 10-Year Infeasible Facilities

Facility Name	Facility Type	Upgrade expected to Fix Infeasibility	Expected In-Service Date
Kilmer-Raritan River 230 kV Line	Internal	**PJM RTEP B3042:** Replace substation conductor at Raritan River 230 kV substation on the Kilmer line terminal.	2023

Results: 2020/2021 Stage 1A ARR 10-Year Analysis

During 2020, PJM staff completed a 10-year simultaneous feasibility analysis for 2020/2021 Stage 1A ARR selections. The power flow case used in the 10-year feasibility analysis is the same one used in the 2020/2021 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. PJM determined that a transmission solution that will address the violation is already identified in the PJM regional planning process.

The facility along with the project expected to address the infeasibility is provided in **Table 3.7**. The violation is expected to be relieved by an already planned PJM RTEP baseline project. Since a plan has been established to address this violation, no further immediate action is necessary.

Section 4: Market Efficiency Analysis

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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 which models the market conditions and the hourly security-constrained commitment and dispatch of generation over a future annual period. Several basecases are developed. The primary difference between these cases is the transmission topology to which the simulation data corresponds:

- An "as-planned" basecase power flow models PJM Board-approved RTEP projects with required in-service date of June 1 of the five-year-out RTEP study year.
- A "project" case power flow that includes topology for specific projects under study.

PJM can determine a transmission project's economic impact by comparing the results of simulations with the same input assumptions and operating constraints but different transmission topologies. Combining this 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" basecase 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

Simulated transmission congestion results also provide important system information and trends to potential transmission developers and other PJM stakeholders.

24-Month Cycle

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

- Creating and verifying basecase models and results
- Reviewing previously approved economic transmission projects
- Performing analysis to consider benefits of accelerating baseline projects not yet built
- Identifying the congestion drivers associated with the 2020/2021 RTEP long-term window

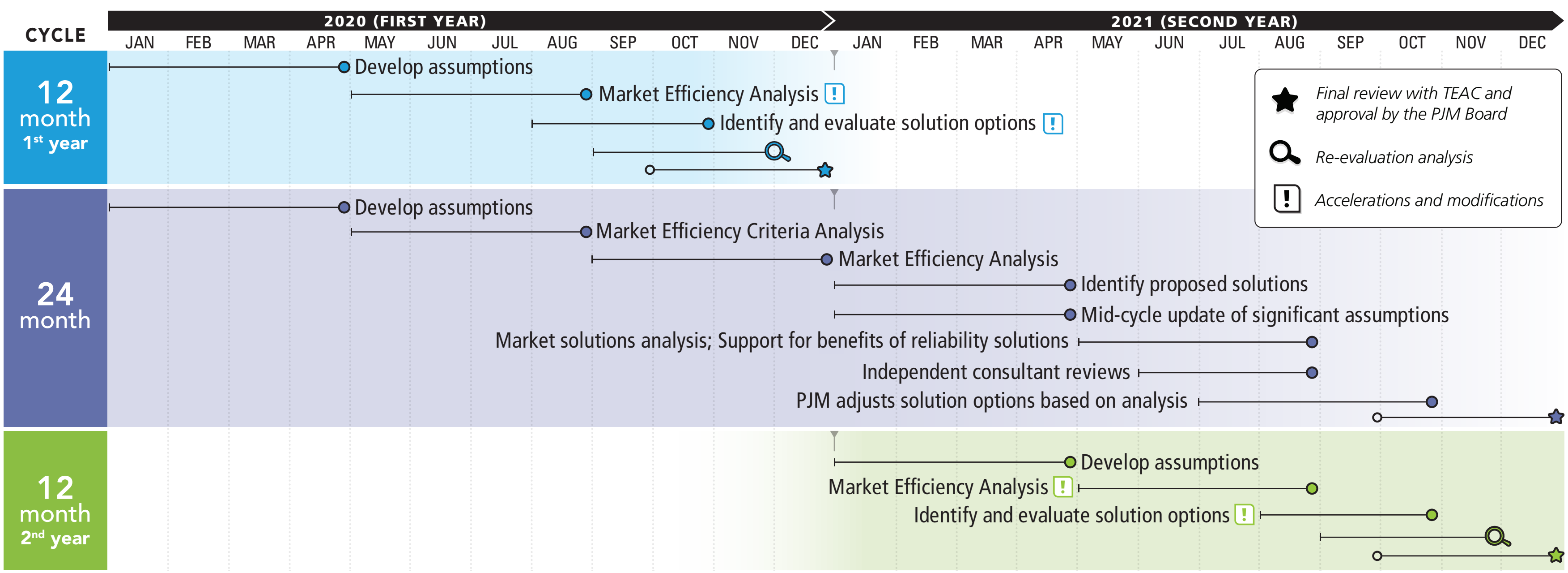
RTEP Project Acceleration Analysis: 2021 and 2025 Study Years

PJM compared simulations of near-term topologies with those of planned topologies to assess the individual and collective economic impacts of RTEP transmission enhancements not yet in service. PJM quantifies the transmission congestion reduction due to recently planned RTEP enhancements by comparing the simulation differences between the "as-is" basecase and the "as-planned" basecase for the 2021 and 2025 study years. Simulation comparisons help PJM to:

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

For example, if a constraint causes significant congestion in the 2021 "as-is" simulation but not in the 2025 "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.

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



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Long-Term Window Simulations: 2021, 2025, 2028, 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 2020 database are broadly described in **Section 4.2**.

Market efficiency projects identified during the 2020/2021 RTEP long-term proposal window, scheduled for early 2021, will initially be evaluated using the cases developed during 2020. However, during the 2021 project evaluation phase, PJM will develop a 2021 mid-cycle update case that incorporates significant RTEP modeling changes. The mid-cycle update case includes potentially significant forecast 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 an updated 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 undergo an independent third-party cost review.

For the majority of proposed projects, PJM determines market efficiency benefits based on energy market simulations. Transmission projects that have identified capacity market drivers may derive economic benefit determined through capacity market simulations.

PJM's market efficiency study process and benefit-to-cost ratio methodology are detailed in Manual 14B, Section 2, PJM Region Transmission Planning Process, which is available on PJM's website.

Energy Benefit – Regional Facilities

Energy benefit calculation for regional facilities is weighted as follows:

- 50 percent to change in system production cost
- 50 percent to change in net-load energy payments for zones with a decrease in net-load payments as a result of the proposed project

The change in system production cost is the change in system generation variable costs (i.e., fuel costs, variable operating and maintenance costs, and emissions costs) associated with total PJM energy production.

The change in net-load energy payment is the change in gross-load payment offset by the change in transmission rights credits. The net-load energy payment benefit is calculated only for zones in which the proposed project decreases the net-load payments. Zones for which the net-load payments increase because of the proposed project are excluded from the net-load energy payment benefit.

Energy Benefit – Lower-Voltage Facilities

Energy benefit calculation for lower-voltage facilities is weighted 100 percent to zones with a decrease in net-load payments as a result of the proposed project. The change in net-load energy payment is the change in gross-load payment offset by the change in transmission rights credits. The net-load payment benefit is only calculated for zones in which the proposed project decreases the net-load payments. Zones for which the net-load payments increase because of the proposed project are excluded from the net-load energy payment benefit.

Capacity Benefit – Regional Facilities

PJM's annual capacity benefit calculation for regional facilities is weighted as follows:

- 50 percent to change in total system capacity cost
- 50 percent to change in net-load capacity payments for zones with a decrease in net-load capacity payments as a result of the proposed project

The change in net-load capacity payment is the change in gross capacity payment offset by the change in capacity transfer rights.

Capacity Benefit – Lower-Voltage Facilities

PJM's annual capacity benefit calculation for lower-voltage facilities is weighted 100 percent to zones with a decrease in net-load capacity payments as a result of the proposed project. The change in net-load capacity payment is the change in gross capacity payment offset by the change in capacity transfer rights.

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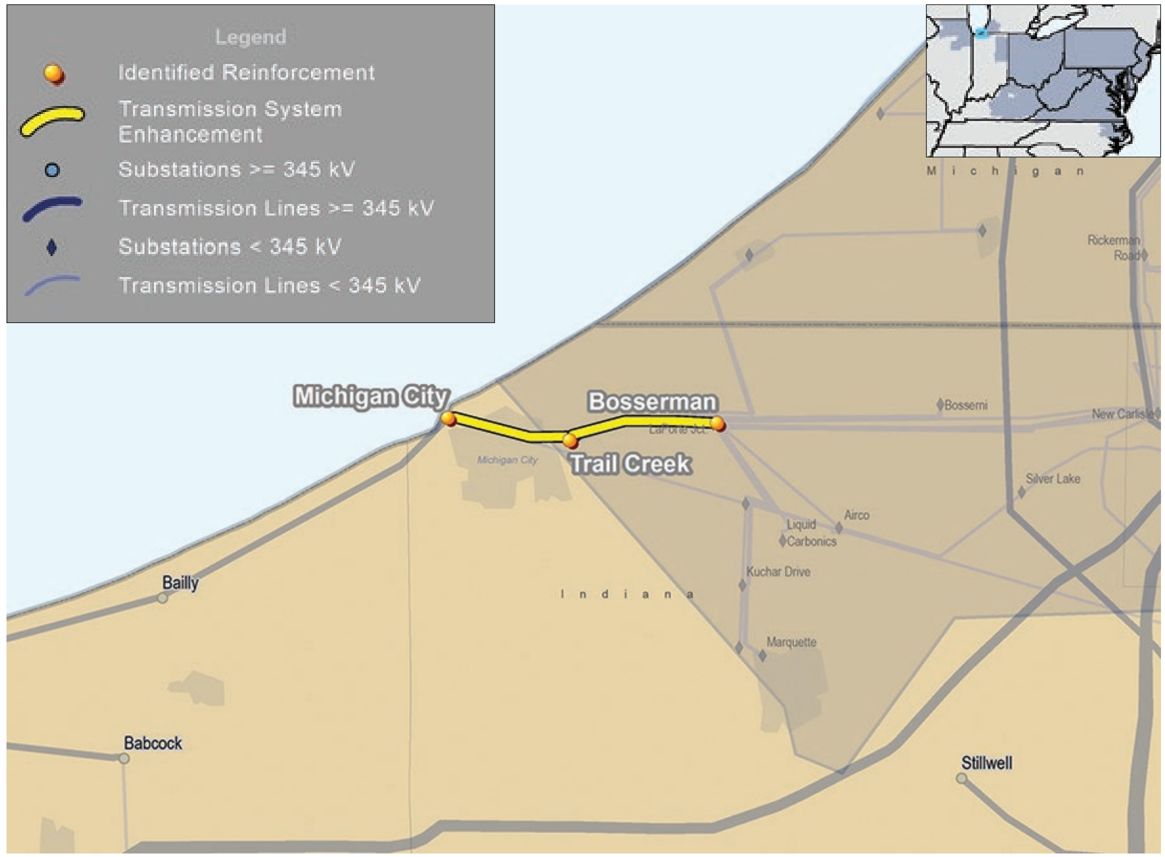
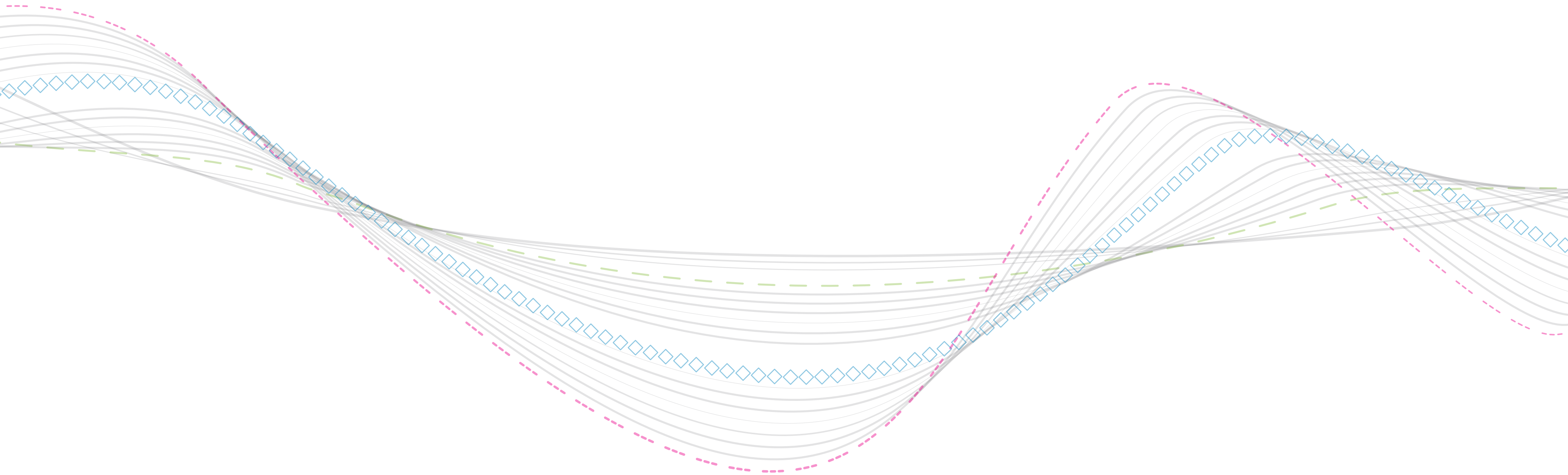
2018/2019 RTEP Long-Term Proposal Window – Interregional Market Efficiency

On Dec. 3, 2019, the PJM Board of Managers conditionally approved the PJM-MISO interregional baseline project B3142, the rebuild of the Bosserman-Trail Creek-Michigan City 138 kV line, shown in **Map 4.1,** subject to MISO Board approval. The project is the first interregional proposal approved through PJM's RTEP long-term proposal window. The Bosserman-Trail Creek-Michigan City 138 kV line was identified as an interregional targeted congestion facility. Simulations performed in advance of the 2018/2019 RTEP long-term proposal window identified over $1.4 million in market congestion on this facility based on 2023 input assumptions and simulation results.

Since the PJM Board's conditional approval, FERC approved MISO's cost allocation compliance filing on July 28, 2020, allowing MISO's Board to approve the project on Sept. 17, 2020. Subsequently, at its December 2020 meeting, the PJM Board confirmed its approval to be included in the RTEP. The estimated cost for this project is $24.69 million, of which $22 million is allocated to PJM, with a required and projected in-service date of January 2023.

Map 4.1: Baseline Project B3142: Bosserman-Trail Creek-Michigan City 138 kV Project





PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

4.1: Input Parameters – 2020 Basecase

Overview

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

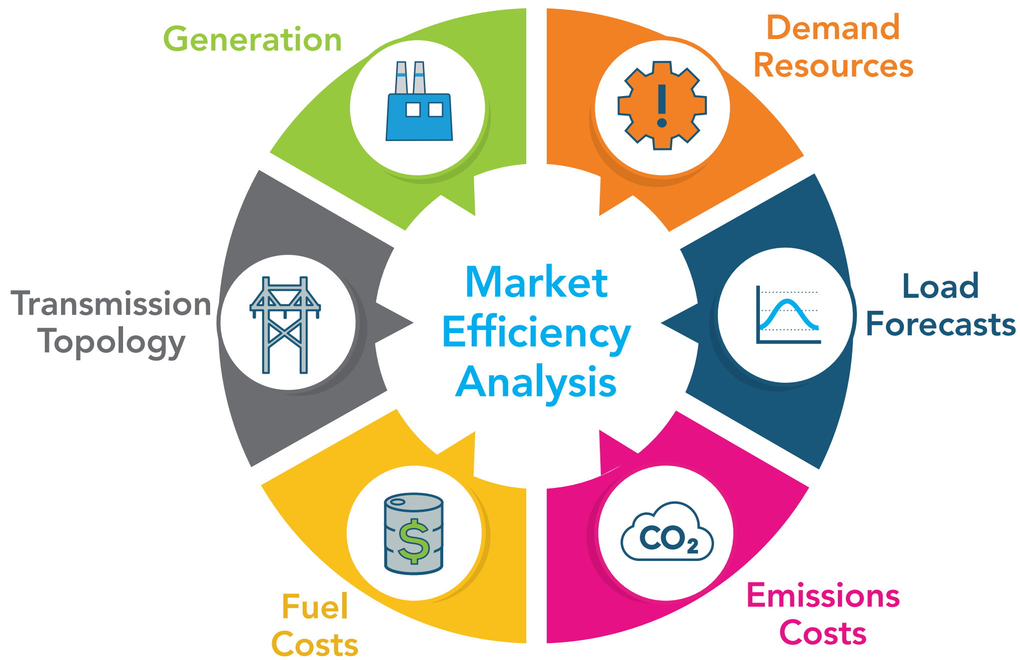
Transmission Topology

Market efficiency power flow models were developed in 2020 to represent:

- The 2021 "as-is" transmission system topology
- The expected 2025 five-year-out system topology

PJM derived the "as-is" system topology from its review of the Eastern Interconnection Reliability Assessment Group's Series 2020 Multiregional Modeling Working Group (MMWG) 2021 summer peak case. It included transmission enhancements expected to be in service by the summer of 2021. PJM derived system topologies for 2025 from the 2025 RTEP case and included significant RTEP projects approved during the 2020 RTEP cycle.

Figure 4.2: Market Efficiency Analysis Parameters



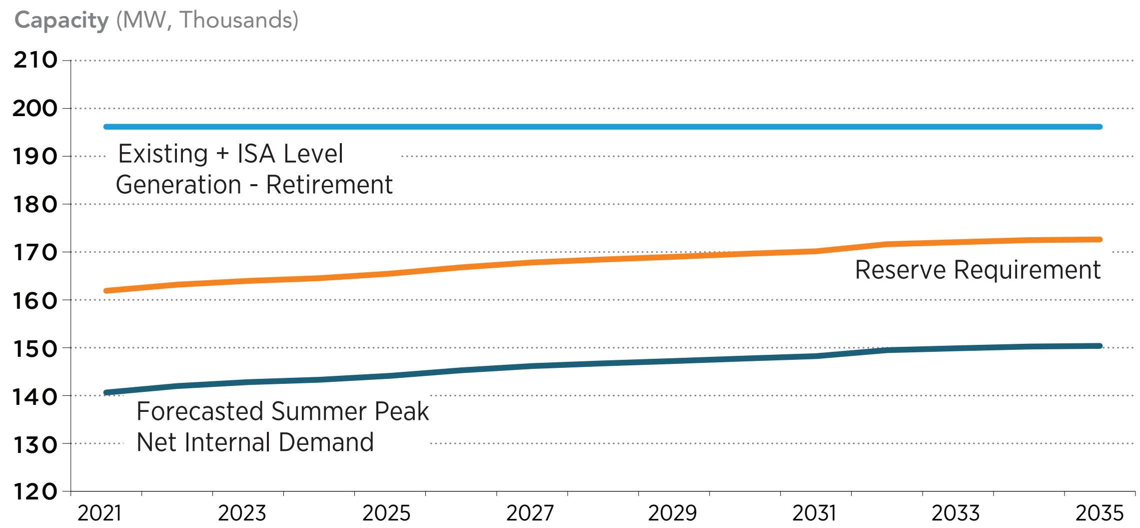
Monitored Constraints

Specific thermal and reactive interface transmission constraints are modeled for each base topology. Monitored thermal constraints are based on actual PJM market activity, historical PJM congestion events, PJM planning studies or studies compiled by NERC. PJM reactive interface limits are modeled as thermal values that correlate to power flows beyond which voltage violations may occur. The modeled interface limits are based on voltage stability analysis and a review of historical values. Modeled values of future-year reactive interface limits incorporate the impact of approved RTEP enhancements on the reactive interfaces.

Generation Modeled

Market efficiency basecase 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**.

Figure 4.3: PJM Market Efficiency Reserve Margin



NOTE:

Figure 4.3: Generation includes existing and projected PJM internal capacity resources. Solar and wind resource capacity are modeled at 38% and 13% of maximum capability, respectively. Model informed by 2025 machines list.

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 2020 market efficiency analysis are represented in **Figure 4.4**.

Load and Energy Forecasts

PJM's load forecast 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 2020 market efficiency cases.

Demand Resources

The amount of demand resource modeled in each transmission zone is based on the 2020 PJM Load Forecast Report. **Table 4.2** summarizes PJM demand resource totals by year.

Figure 4.4: Fuel Price Assumptions

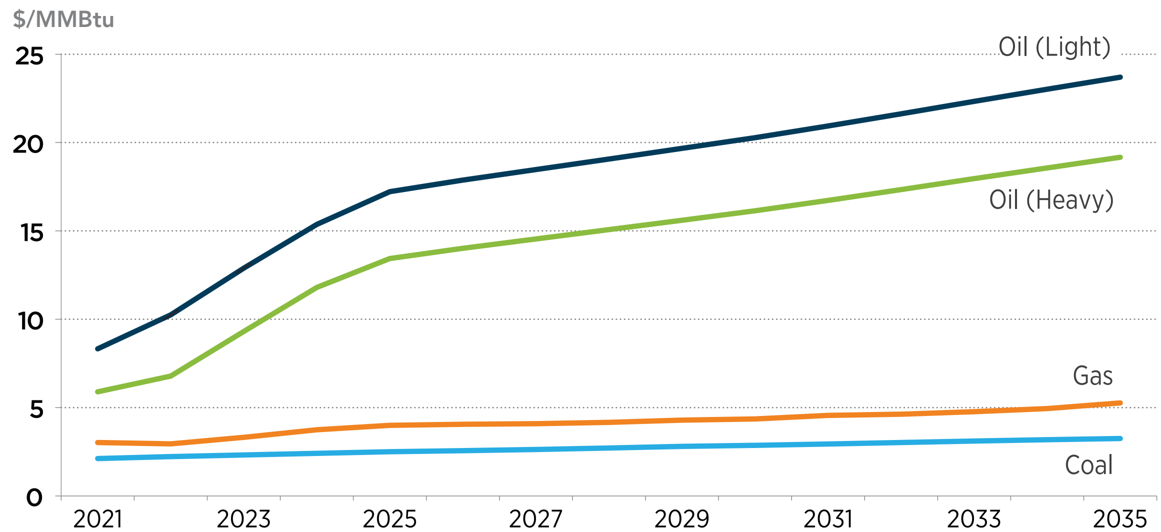


Table 4.1: 2020 PJM Peak Load and Energy Forecast

Load	2021	2025	2028	2031	2035
Peak (MW)	147,064	153,315	156,014	157,637	159,868
Energy (GWh)	771,639	817,966	834,225	843,471	857,016

Note: 1. Peak and energy values for 2025 onward are from the 2020 PJM Load Forecast Report Table B-1 and Table E-1, respectively.
2. Peak and energy values for 2021 are from the July 2020 Forecast Update.

Table 4.2: Demand Resource Forecast

Demand Resource	2021	2025	2028	2031	2035
Demand Resource (MW)	8,955	9,172	9,293	9,405	9,494

Note: Values are from the 2020 PJM Load Forecast Report Table B-7.

Emission Allowance Price Assumptions

PJM currently models three major effluents – SO_2, NO_x and CO_2 – within its market efficiency simulations. Effluents (by trading program) are assigned to generators based on generator location, and release rates assigned based on generator characteristics and the fuel forecast to be used. 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.

Figure 4.5: SO_2 Emission Price Assumption

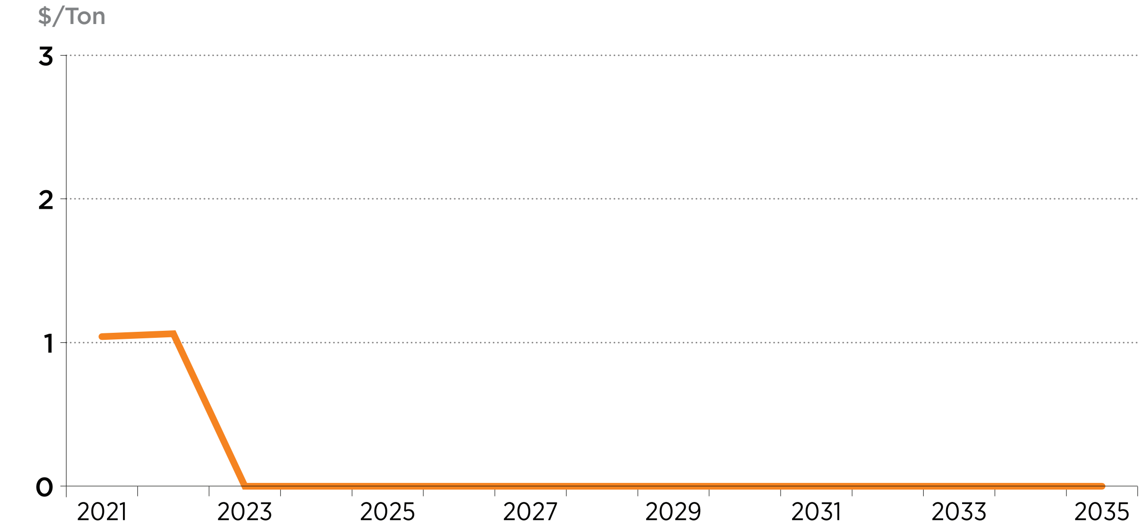
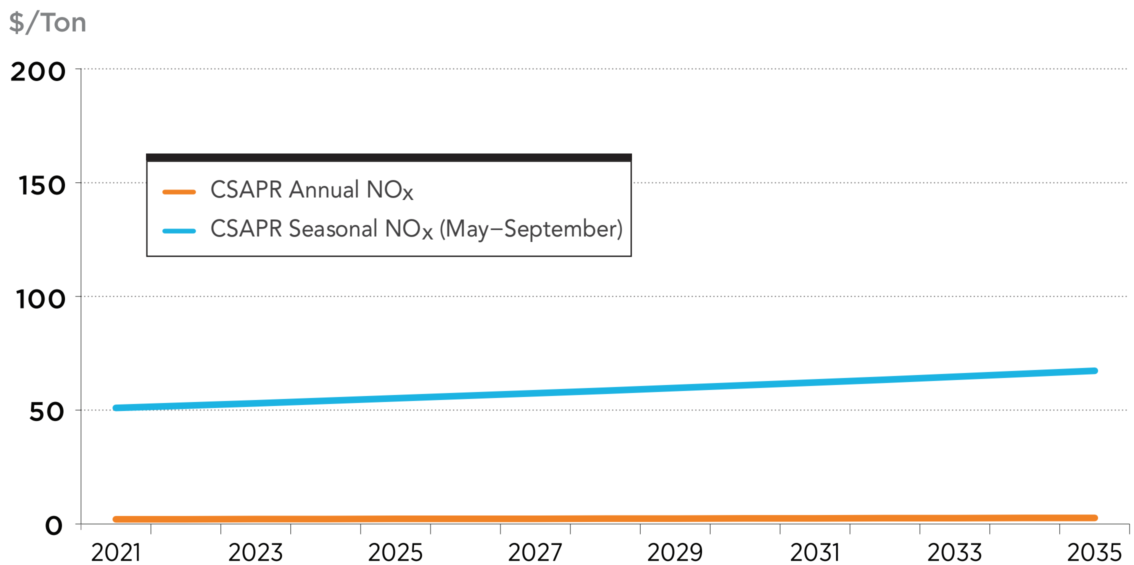


Figure 4.6: NO_x Emission Price Assumption

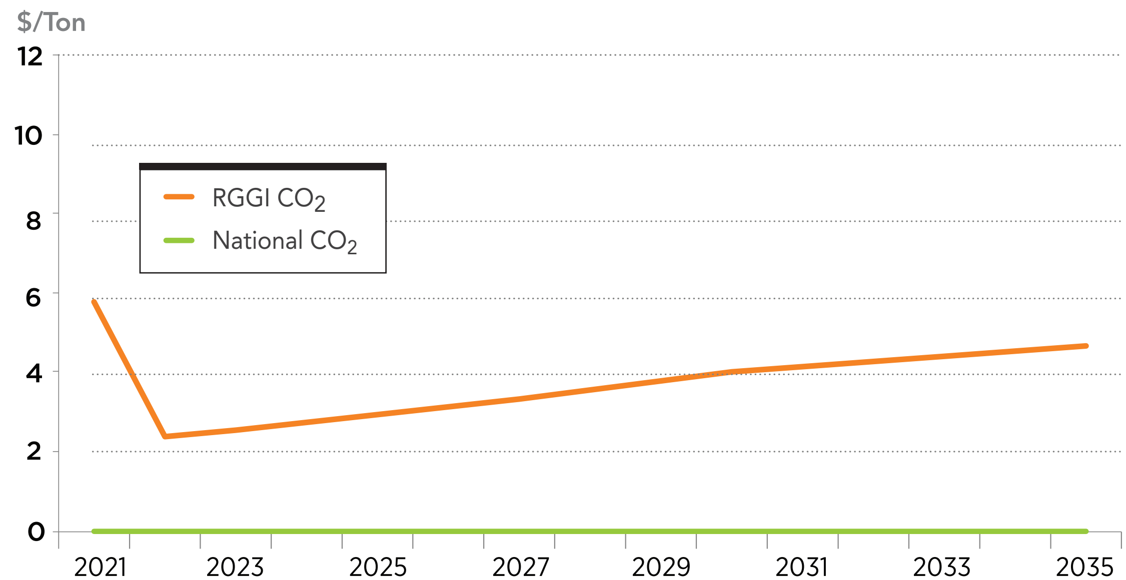


PJM unit CO_2 emissions use a CO_2 emission forecast based on national and regional legislative proposals. PJM units in Maryland, Delaware, New Jersey and Virginia are modeled as part of the Regional Greenhouse Gas Initiative (RGGI) program. The base emission price assumption for both the national CO_2 and RGGI CO_2 program is 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) workbook available on PJM's website. The current annual carrying charge rate and discount rate for this year's analysis are 11.82 percent and 7.37 percent, respectively.

Figure 4.7: CO_2 Emission Price Assumption



4.2: Study Results From 2020 Analysis

Acceleration Results From 2020 Analysis

PJM's 2020 cycle of analysis included near-term simulations for study years 2021 and 2025. These simulations identified collective and constraint-specific transmission system congestion because of the impacts of previously approved RTEP projects not yet in service. PJM conducted the simulations under two different transmission topologies:

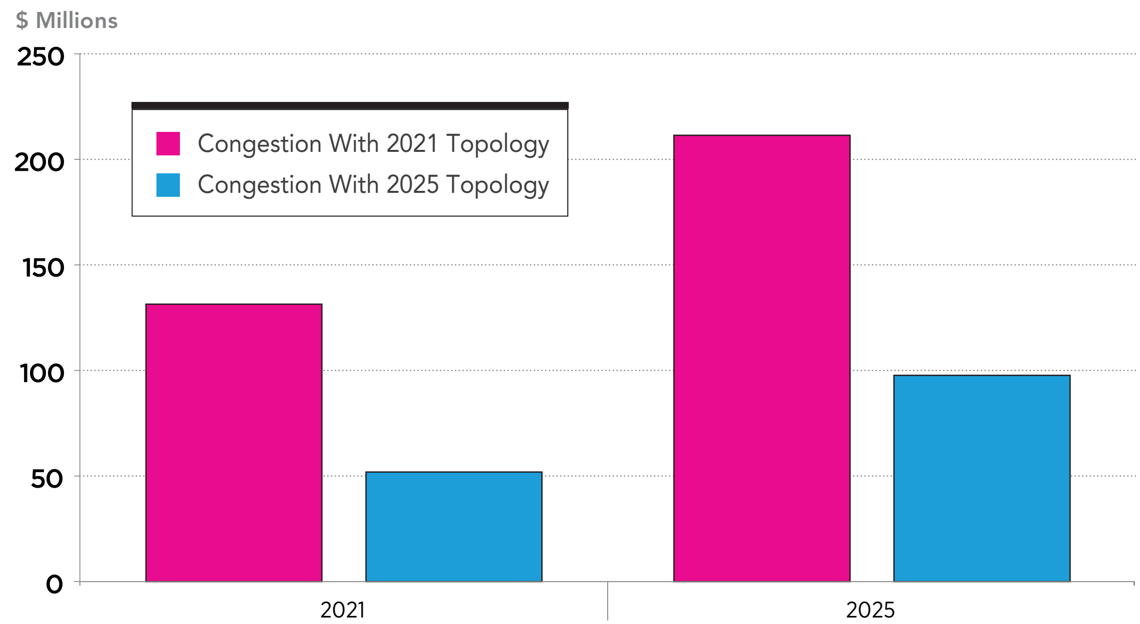
1. 2021 "as-is" PJM transmission system topology
2. 2025 "as-planned" RTEP PJM transmission system topology

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 2021 and 2025 are shown in **Figure 4.8**. There were annual congestion cost reductions of more than $79 million (60 percent) for 2021 and more than $113 million (54 percent) for 2025 using the 2025 RTEP topology. RTEP enhancements that are approved but not yet in service account for the reduction in congestion.

Figure 4.8: 2020 Analysis of Simulated PJM Congestion Costs – 2021, 2025



Project-Specific Acceleration Analysis

PJM identified and evaluated specific RTEP enhancements driving congestion reductions identified in 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.

Baseline project B3157, a $0.23 million upgrade of substation equipment at APS Messick Road and Morgan 138 kV substations, shows significant congestion benefits if accelerated before year 2024. Project B3157 was selected for an accelerated 2021 in-service date with no additional cost as a result of the change.

Long-Term Simulation Results: 2021, 2025, 2028 and 2031 Study Years

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 2025 RTEP "as-planned" transmission system topology and included RTEP projects approved through the 2020 RTEP cycle.

Overall, congestion levels in the 2020 cycle of analyses remain low compared to previous RTEP cycles. This is, in part, because of:

- Low gas-price assumptions coupled with generation portfolio shifts that include increased high-efficiency, gas-fired generation and renewable resources
- Continued high generation reserves
- Continued lower load forecast levels compared to previous forecasts
- RTEP transmission enhancements, which are improving or eliminating potential congestion-causing constraints

PJM will solicit stakeholder proposals for market efficiency projects as part of an RTEP proposal window focusing on congestion identified in the 2020 long-term analysis.

PJM's competitive planning process is detailed in Manual 14F, which is available on PJM's website. Preliminary congestion drivers are shown in **Table 4.3**. These include facilities and their simulated congestion levels. They are part of PJM's solicitation of proposals for the 2020/2021 RTEP long-term proposal window scheduled for early 2021.

Table 4.3: Preliminary 2020/2021 Long-Term Window Congestion Drivers

			Market Efficiency Basecase				
			Annual Congestion ($M)		Hours Binding		
			Simulated Year				
Constraint	From Area	To Area	2025	2028	2025	2028	Comment
Kammer North to Natrium 138 kV	AEP	AEP	$2.54	$12.22	105	249	Internal Flowgate
Maliszewski Transformer 765/138 kV	AEP	AEP	$4.02	$5.64	29	40	
Muskingum River to Beverly 345 kV	AEP	AEP	$1.08	$2.19	112	184	
Cherry Run to Morgan 138 kV	AP	AP	$3.46	$4.12	257	288	
Gore to Stonewall 138 kV	AP	AP	$25.07	$35.00	577	753	
Junction to French's Mill 138 kV	AP	AP	$4.97	$5.89	255	257	
Yukon to AA2-161 Tap 138 kV	AP	AP	$4.31	$5.39	1743	2043	
Charlottesville to Proffit Rd Del Pt 230 kV	DOM	DOM	$2.80	$2.92	116	96	
Plymouth Meeting to Whitpain 230 kV	PECO	PECO	$6.17	$6.40	150	145	
Cumberland to Juniata 230 kV	PLGRP	PLGRP	$5.77	$6.39	151	158	
Harwood to Susquehanna 230 kV	PLGRP	PLGRP	$20.39	$16.47	1145	878	
Duff to Francisco 345 kV	DUK-IN	DUK-IN	$0.86	$3.71	74	118	M2M
Gibson to Francisco 345 kV	DUK-IN	DUK-IN	$4.18	$3.59	195	200	
Quad Cities to Rock Creek 345 kV	ComEd	ALTW	$6.35	$9.01	148	172	

Note: Cumberland-Juniata and Harwood-Susquehanna congestion drivers may be impacted by DLR projects.

NOTE:

Table 4.3: PJM's 120 day 2020/2021 RTEP long-term proposal window opened on Jan. 11, 2021. Updated congestion drivers presented in early 2021 are available at the following: TEAC Market Efficiency Update.

NOTE:

Dynamic line rating (DLR) technology provides a means for determining more precise line ratings based on actual environmental conditions. DLR technology does not modify the physical characteristics of a transmission line. Please see **Section 1.3.7** for additional information concerning DLR.

Table 4.4: 2020 Analysis: Re-evaluation of Projects under $20 Million – Updated Cost

Project ID	Baseline ID	Type	Area	Constraint	Benefit-to-Cost Ratio	Projected In-Service Date	2020 Re-Evaluation Benefit-to-Cost Ratio
201415_1-4I	B2697.1-2	Upgrade	AEP	Fieldale to Thorton 138 kV	101.19	B2697.1: 10/01/2020 B2697.2: 06/03/2021	28.11
201617_1A_RPM_DEOK	B2976	Upgrade	DEO&K	Tanners Creek to Dearborn 345 kV	151.61	3/4/2021	151.61
201819_HL_622	B3145	Upgrade	METED	Hunterstown to Lincoln 115 kV	59.45	6/1/2023	59.45

2020 Re-Evaluation of Previously Approved Market Efficiency Projects

PJM's 2020 analysis included a re-evaluation of approved market efficiency projects from previous long-term window processes. Changes to the criteria used for re-evaluation were implemented in 2019 through the Market Efficiency Process Enhancement Task Force (MEPETF) – discussed in **Section 4.4**. The new re-evaluation criteria include the following:

- Projects that are under construction or that have a Certificate of Public Convenience and Necessity (CPCN), are no longer 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 and, will be re-evaluated using previously determined benefits
- Projects not under construction or without a CPCN, with capital costs greater than $20 million, will have projected costs updated and benefits re-evaluated

Three previously approved projects with projected capital costs less than $20 million have yet to begin construction and are shown in **Table 4.4.** Each maintains a benefit-to-cost ratio greater than 1.25 using the original project benefit with an updated capital cost estimate.

One previously approved project with capital costs greater than $20 million awaits CPCN action by the Pennsylvania Public Utility Commission. This project, identified as Project 9A, which includes RTEP baseline projects B2742 and B2752, is shown on **Map 4.2**. Project 9A, includes system enhancements in Pennsylvania and Maryland. The Maryland portion of the project was granted a CPCN in June 2020.

This project is included as part of the 2020 market efficiency basecase discussed earlier in **Section 4.2**. PJM recalculated economic value through simulations in which the project is removed from the model to determine the benefit that retaining it otherwise still provides. A benefit-to-cost ratio was derived by comparing the base simulation to the individual cases that did not include the project, while adhering to the methods described in **Section 4.0.**

Market efficiency analysis identified interaction between three projects providing congestion relief along the South-Central Pennsylvania and Northern Maryland border regions. The Hunterstown-Lincoln Project (B3145), Project 9A (B2742 and B2752) and Project 5E (B2992) each and collectively support economic transfers between these regions. Additionally, through siting proceedings in Pennsylvania and Maryland, several parties have filed a settlement that offers an alternative configuration of the eastern portion of Project 9A. More information about these topics can be found in the [December 2019 Baseline Market Efficiency Recommendations]() document.

Table 4.5 shows the 2020 re-evaluation results for Project 9A. The project maintains a benefit-to-cost ratio greater than 1.25 either individually or in combination with other important regional projects when sunk costs are excluded from the project costs.

Additionally, PJM analysis indicates that Project 9A supports benefits beyond what is measured by a benefit-to-cost ratio. These benefits include the following:

- Supports state coal retirement legislation
- Enables additional access to Pennsylvania Marcellus Shale
- May provide support for state renewable energy policies; potential increased access to offshore wind power
- Enhances states' access to external generation to support RGGI participation
- Enhances reliability

Map 4.2: Project 9A – RTEP Baseline Projects B2743 and B2752

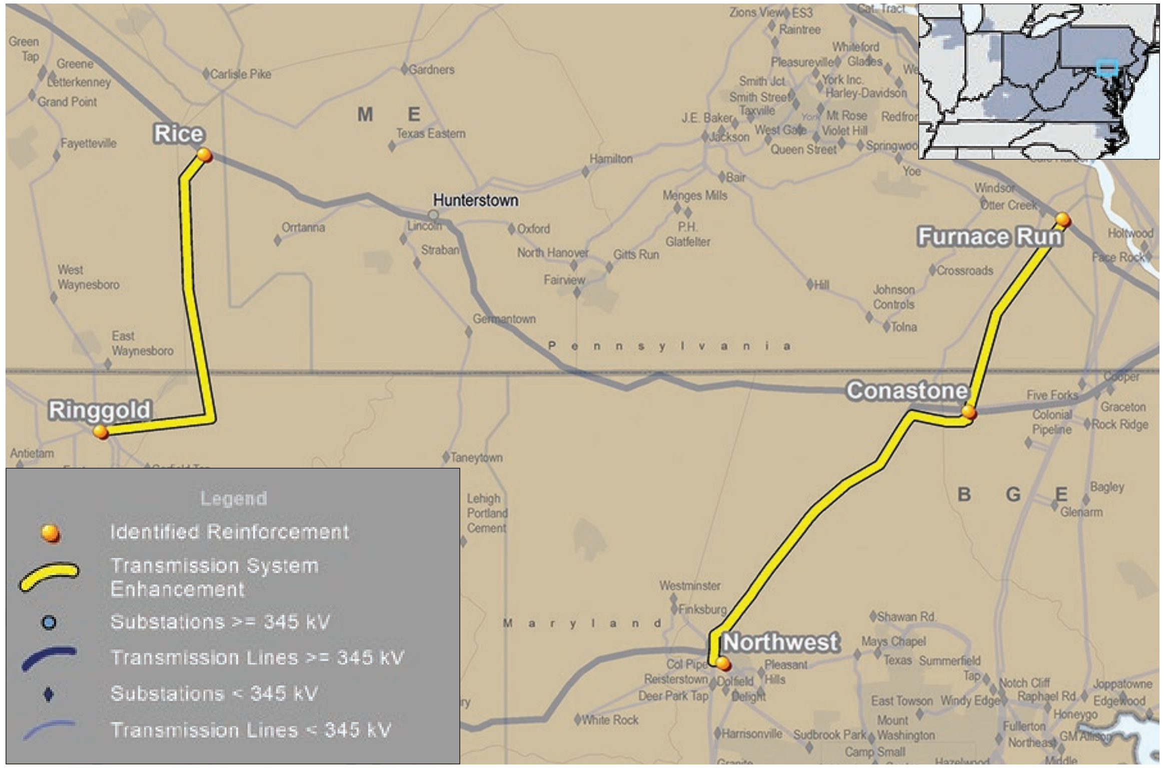


Table 4.5: Re-Evaluation of Projects Greater Than $20 Million – Updated Benefit-to-Cost Ratio, Project 9A

Re-Evaluation	Benefit-to-Cost Ratio Dec. 2020 (Sunk Costs Excluded)	Notes		
		B/C Ratio (In-Service Costs)	Cost	
			In-Service	Sunk
Project 9A (5E + H-L in Basecase)	1.71	1.22	$423.66	$121.03
Project 9A + H-L (5E in Basecase)	3.87	2.78	$430.87	$121.03
Alt. Project 9A (5E + H-L in Basecase)	1.29	1.00	$534.87	$121.03
Alt. Project 9A + H-L (5E in Basecase)	2.87	2.23	$542.08	$121.03

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4.3: 2019/2020 Market Efficiency Process Enhancements

The Market Efficiency Process Enhancement Task Force (MEPETF) was chartered in January 2018, under the auspices of the PJM Planning Committee. The mission of the task force was to review, evaluate and recommend necessary changes to market efficiency process elements, including the following:

- Benefit-to-cost calculation
- Facilities Study Agreement (FSA) modeling
- Market efficiency window
- Interregional Market Efficiency Project (IMEP) selection process
- Market efficiency re-evaluation process
- Regional Targeted Market Efficiency Project (TMEP)
- Market efficiency mid-cycle assumption update

To date, the task force has completed three phases of work and has now concluded its activity.

Phase 1

Phase 1 revisions addressed the following:

- Generation assumptions that go into PJM's market efficiency analysis
- Time period over which the benefit-to-cost analysis is performed

The first set of revisions changed the default treatment of generation with executed FSAs or executed ISAs under suspension. It excluded those generation projects as a default in conducting market efficiency analysis. The second set of revisions limited project evaluation to a 15-year period that begins with the RTEP year. In February 2019, FERC accepted PJM's Operating Agreement revisions from these MEPETF Phase 1 efforts.

Phase 2

As a result of the task force efforts completed during Phase 2, PJM filed revisions to the Operating Agreement, Schedule 6 and Section 1.5.7 (f). This section describes the criteria for market efficiency project re-evaluation. The revisions included specifying a time after which PJM would no longer be required to conduct an annual re-evaluation of previously approved market efficiency projects. The new re-evaluation criteria now include the following:

- Projects where construction activities have commenced at the project site, or that have a Certificate of Public Convenience and Necessity (CPCN), are no longer 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 and will be re-evaluated using previously determined benefits
- Projects not under construction or without a CPCN, with capital costs greater than $20 million, will have projected costs updated and benefits re-evaluated.

On Aug. 22, 2019, FERC accepted PJM's proposed Operating Agreement revisions from MEPETF Phase 2 efforts.

Phase 3

In June 2019, the PJM Planning Committee endorsed amendments to the task force charter to add a third phase. Key areas of review included:

- Concerns with benefit calculations using summation of energy and capacity benefits
- Regional Targeted Market Efficiency Projects (RTMEP)
- Two specific concerns raised by stakeholders on the benefit-to-cost calculation

At the end of Phase 3, PJM filed Operating Agreement and Tariff revisions that clarify PJM's consideration of capacity constraints in PJM's overall market efficiency analysis.

Separation of energy market and capacity market congestion drivers will allow for distinct proposal windows to address the different type of constraints, if appropriate.

On December 18, 2020, FERC accepted PJM's proposed Operating Agreement revisions from MEPETF Phase 3 efforts.

Section 5: Facilitating Interconnection

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5.0: New Services Queue Requests

5.0.1 — Interconnection Activity

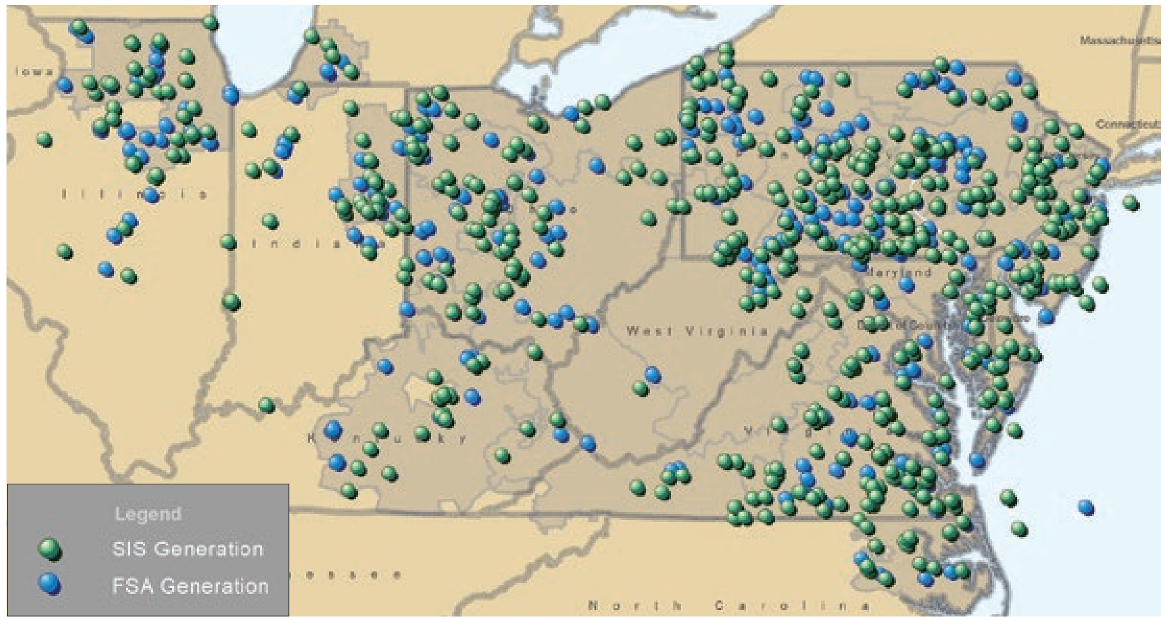
The generation interconnection process has three study phases – feasibility, system impact and facilities studies – to ensure that new resources interconnect without violating established NERC and regional reliability criteria. Each generator that completes the necessary system enhancements becomes eligible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

Generation Queue Activity

PJM markets have attracted generation proposals totaling 502,706 MW, as shown in **Table 5.1**. Over 83,865 MW of interconnection requests were actively under study during 2020. PJM analyzed and issued study reports for 751 feasibility studies and 662 system impact studies, as shown on **Map 5.1**. This unprecedented queue volume, as of Dec. 31, 2020, was composed of 88 percent renewable fuel types – notably, solar – as described later in this section.

Over 21,546 MW of new generation was under construction as of Dec. 31, 2020, 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 2020



In 2020 PJM received
1,028 new service requests
representing 70,375 MW (energy) of generation and 44,179 MW of CIRs

During calendar year 2020,
PJM issues a total of
1,424 Feasibility/Impact/ Facilities studies

Queue Progression History

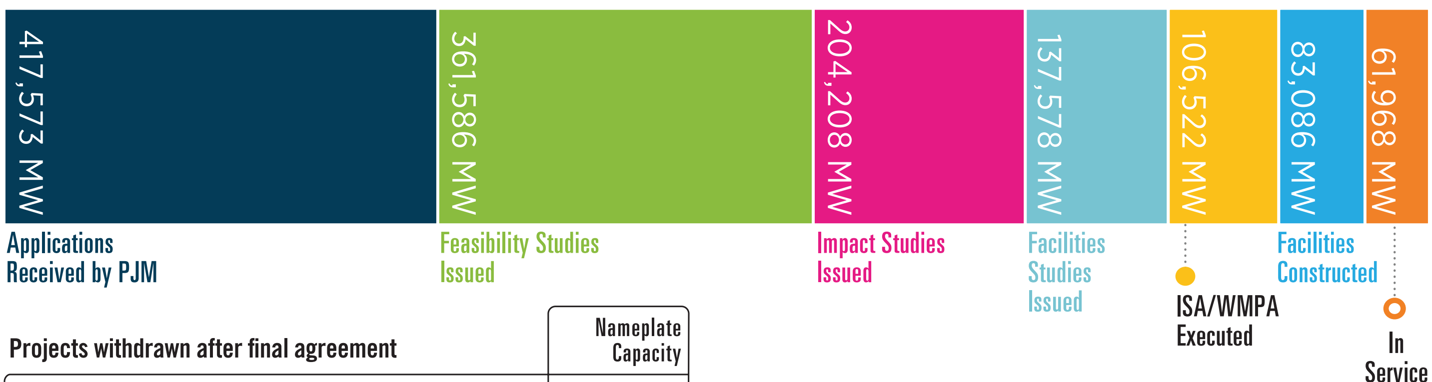
PJM reviews generation queue progression annually to understand overall developer trends more fully and their impact on PJM's interconnection process. **Figure 5.1** shows that for generation submitted in Queue A (1999) through Dec. 31, 2020, only 61,968 MW – 15 percent – reached commercial operation. Note that **Figure 5.1** reflects requested capacity interconnection rights which are lower than nameplate capacity given the intermittent operational nature of wind- and solar-powered plants.

Following execution of an interconnection service agreement (ISA) or wholesale market participant agreement (WMPA), 22,442 MW of capacity with ISAs and 1,107 MW of capacity with WMPAs withdrew from PJM's interconnection process. Overall, 23 percent of projects that requested uprates to existing capacity reached commercial operation. Only 15 percent of new generator requests, by megawatt, reached commercial operation.

Table 5.1: Queued Study Requests

	Projects	Energy (MW)	Capacity (MW)
Active	1,553	147,122	83,865
In Service	927	72,729	60,687
Under Construction	346	27,946	21,546
Withdrawn	3,173	429,133	336,609
Grand Total	**5,999**	**676,931**	**502,706**

Figure 5.1: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
177	Interconnection Service Agreements	22,442 MW	30,294 MW
291	Wholesale Market Participation Agreements	1,107 MW	2,293 MW

Percentage of planned capacity and projects that have reached commercial operation	15% Requested capacity megawatts	23% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

5.0.2 — Interconnection Reliability

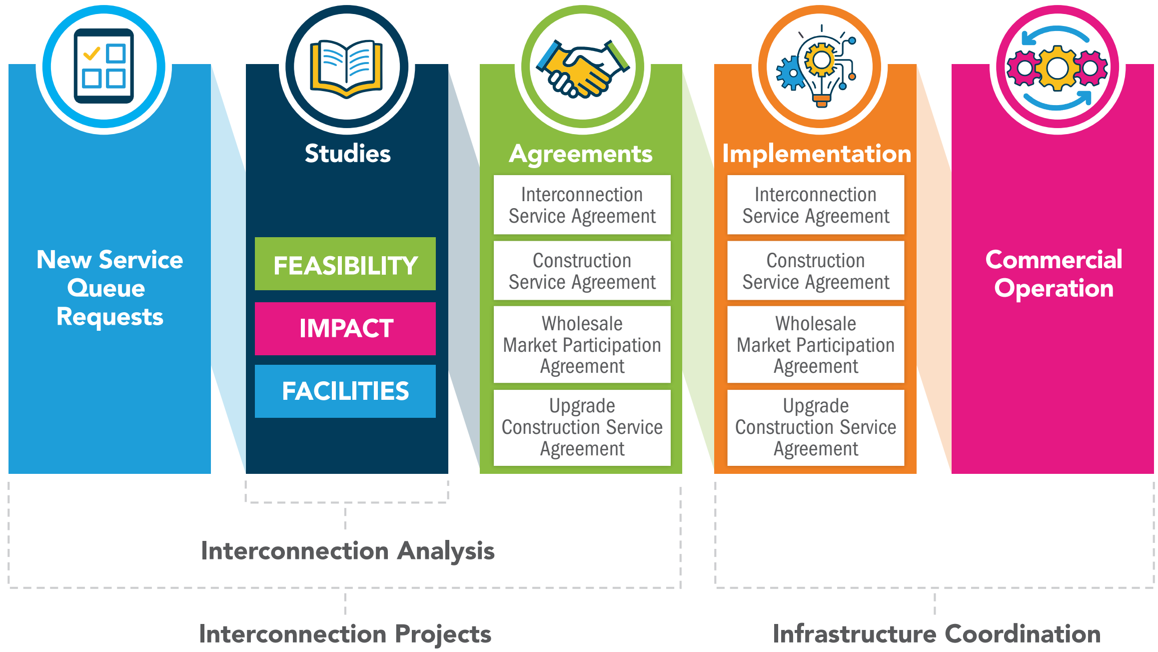
A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission enhancement plans to solve reliability criteria violations identified under prescribed deliverability tests. The PJM Board has approved network facility reinforcements totaling $6.4 billion. The PJM Board approved 95 new network system enhancements totaling over $100 million in 2020 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 the rest of PJM load. In addition to generator interconnection requests, PJM conducts this power flow test as part of baseline analysis under summer and winter peak load conditions, when capacity is most needed to serve load, as well as under light load conditions to ensure that a range of resource combinations and conditions is examined.

Queue Process Overview

PJM's interconnection queue process consists of five phases as shown in **Figure 5.2**. 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, the project is evaluated at a primary and a secondary (optional) point of interconnection. PJM targets to complete the feasibility study of a project within 120 days after the close of the queue window.

Figure 5.2: New Services Queue Process Overview



During the impact study phase, the project elects one of the two points of interconnection, and the study is targeted to be completed 120 days after the start of the system impact study phase for the queue – or 120 days after the agreement is signed – whichever is later. During this phase, PJM coordinates with neighboring entities to conduct an affected system study, if applicable. The facilities study phase is targeted to be completed in 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 analysis to ensure the project's reliable interconnection to PJM's system. When the study phases have been completed, the project 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.

5.0.3 — Offshore Wind

States within PJM have a variety of policies and regulations focused on renewable generation objectives. PJM states on the East Coast are seeking to promote the development of offshore wind generation. The state policies of New Jersey look to incent the interconnection of a total of 7,500 MW of offshore wind generation by 2035. In order to achieve the state's public policy objectives, New Jersey has requested a PJM competitive RTEP proposal window in 2021 under the auspices of the PJM RTEP process State Agreement Approach (SAA). The intent of the window is to solicit transmission proposals to deliver future offshore wind generation through the SAA as defined in PJM's Operating Agreement.

Other states, such as Virginia and Maryland, are also implementing policies that call for an increase in offshore wind generation. Driven by these policies, an increased number of offshore wind generation requests over the past few queue windows have been submitted to PJM. Twenty-seven offshore wind projects, predominantly located along the Atlantic coastline, are currently under study, five of which entered the PJM queue during the 2019 queue window. PJM studies these requests to ensure a reliable interconnection of offshore wind generators to the PJM system.

Section 6: State Summaries

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

6.0: Delaware RTEP Summary

6.0.1 — RTEP Context

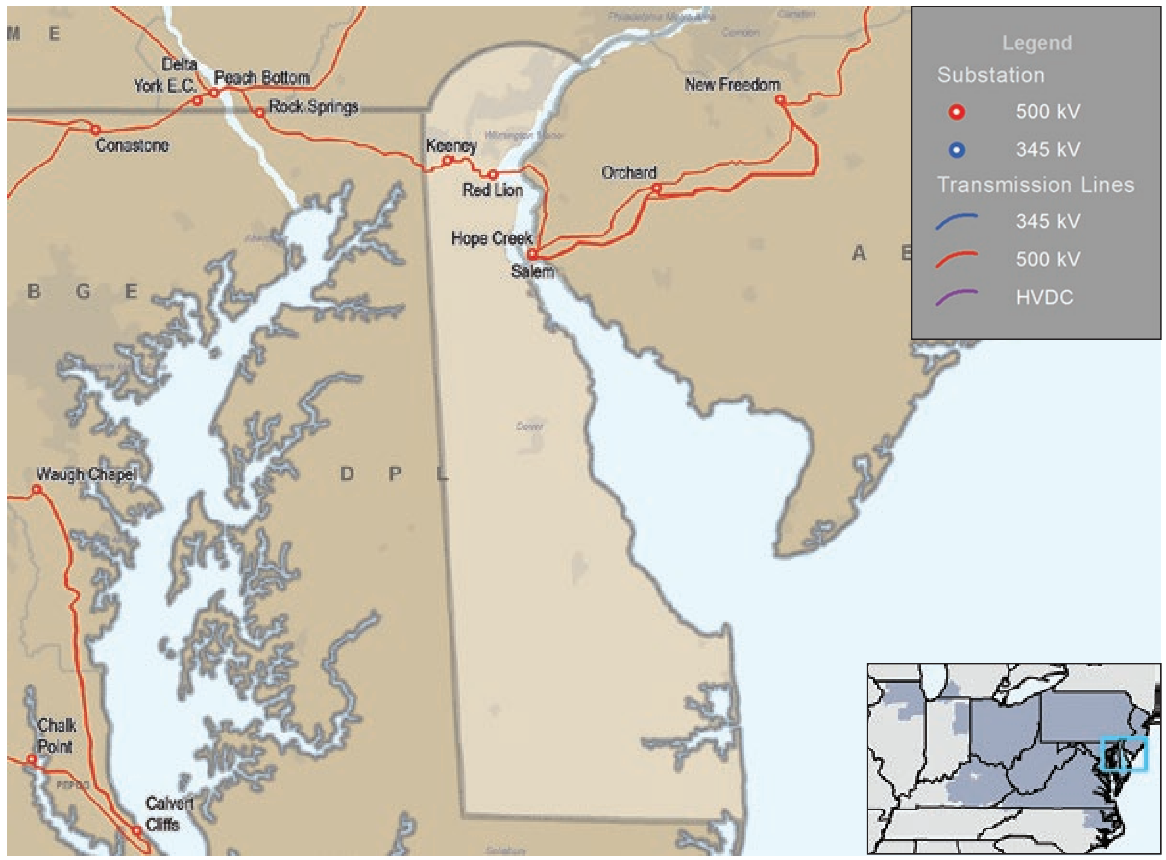
PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Delaware, including facilities owned and operated by Delaware Municipal Electric Corp. (DEMEC), Delmarva Power & Light Co. (DP&L) and Old Dominion Electric Cooperative (ODEC) as shown on **Map 6.1**. Delaware's transmission 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 2020, Delaware has a mandatory RPS target of 25 percent by compliance year 2025-2026. This target includes a minimum solar carve-out of 3.5 percent.

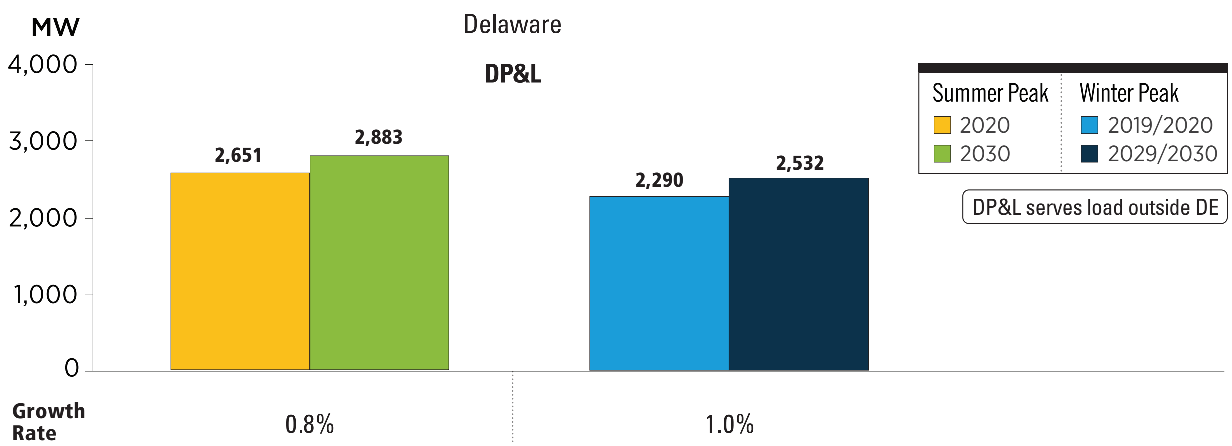
Map 6.1: PJM Service Area in Delaware



6.0.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.1** summarizes the expected loads within the state of Delaware and across PJM.

Figure 6.1: Delaware – 2020 Load Forecast Report



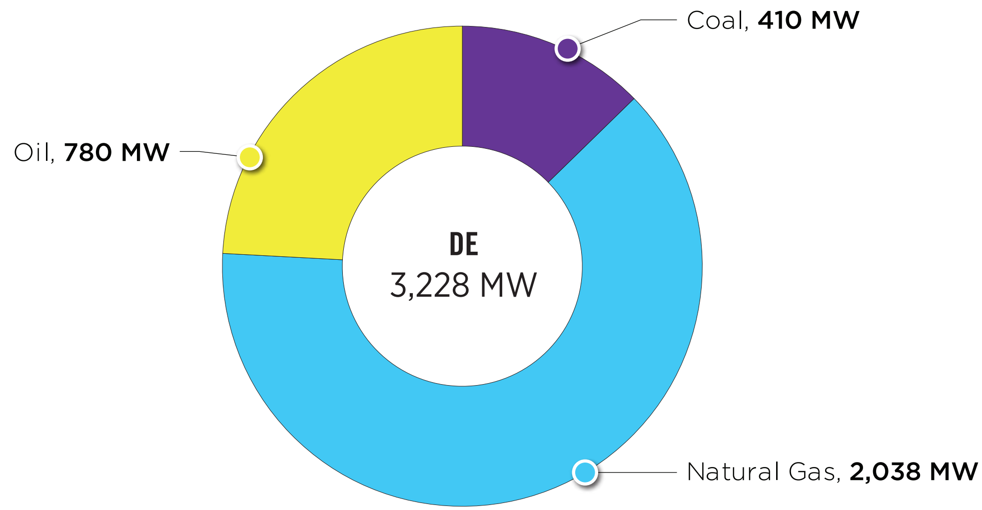
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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, 2020, is shown by fuel type in **Figure 6.2**.

Figure 6.2: Delaware – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 30 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, 2020)

	Delaware Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	451	31.60%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	429	30.06%	58,845	56.13%
Storage	40	2.83%	10,877	10.38%
Wind	507	35.51%	6,560	6.26%
Grand Total	**1,427**	**100.00%**	**104,838**	**100.00%**

Table 6.2: Delaware – Interconnection Requests by Fuel Type (Dec. 31, 2020)

		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	2	23.0	1	630.0	3	653.0
	Natural Gas	0	0.0	1	451.0	0	0.0	19	1,097.1	19	5,556.4	39	7,104.5
	Oil	0	0.0	0	0.0	0	0.0	5	168.2	1	1.0	6	169.2
	Other	0	0.0	0	0.0	0	0.0	2	30.0	0	0.0	2	30.0
	Storage	3	40.4	0	0.0	0	0.0	0	0.0	4	45.0	7	85.4
Renewable	Biomass	0	0.0	0	0.0	0	0.0	1	0.0	4	24.0	5	24.0
	Methane	0	0.0	0	0.0	0	0.0	4	9.0	3	28.8	7	37.8
	Solar	17	391.4	0	0.0	1	37.6	0	0.0	22	231.5	40	660.4
	Wind	7	442.4	0	0.0	1	64.4	0	0.0	5	396.9	13	903.7
	Grand Total	27	874.2	1	451.0	2	102.0	33	1,327.3	59	6,913.6	122	9,668.0

Figure 6.3: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

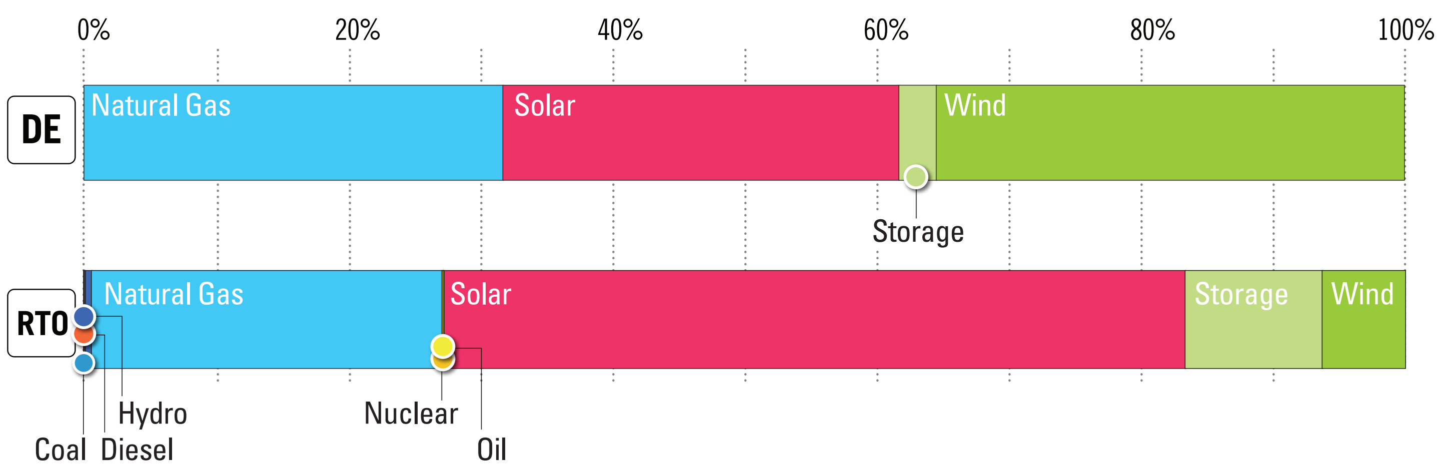


Figure 6.4: Delaware – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

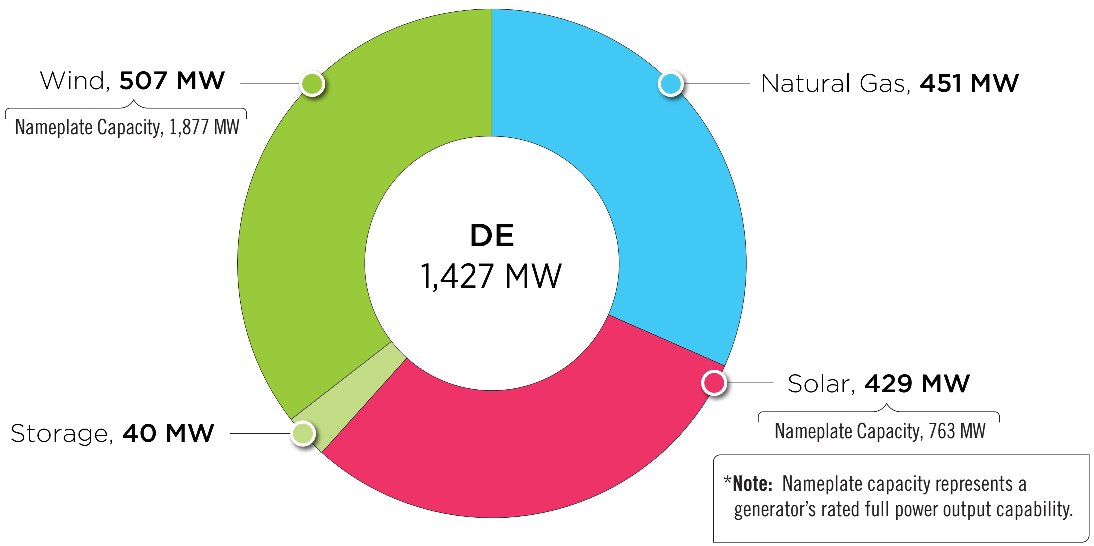
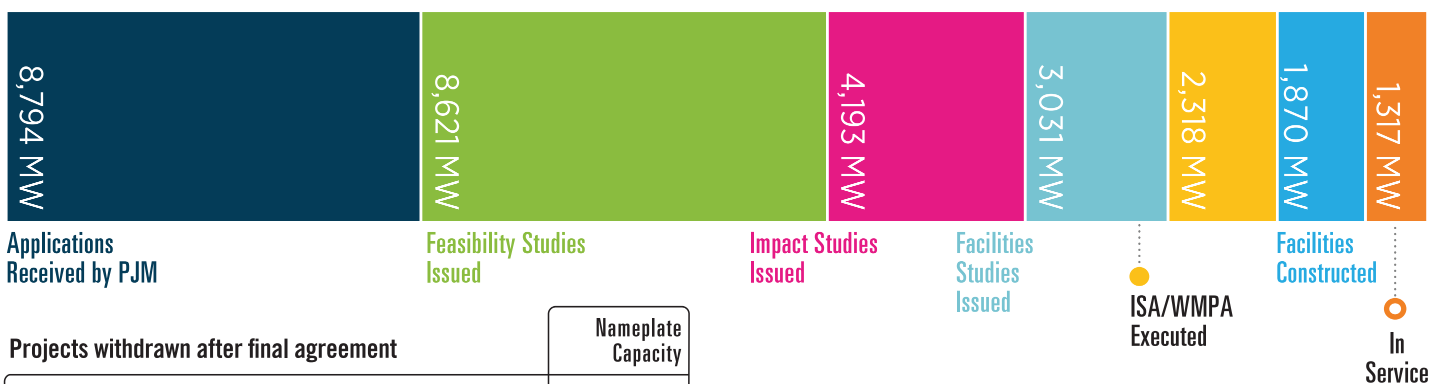


Figure 6.5: Delaware Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
3	Interconnection Service Agreements	420 MW	780 MW
5	Wholesale Market Participation Agreements	18 MW	53 MW

Percentage of planned capacity and projects that have reached commercial operation	15% Requested capacity megawatts	34% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.0.5 — Generation Deactivation

There were no known generating unit deactivation requests in Delaware between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.0.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in Delaware were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.0.7 — Network Projects

No network projects greater than or equal to $10 million in Delaware were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.0.8 — Supplemental Projects

No supplemental projects greater than or equal to $10 million in Delaware were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.0.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Delaware were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.1: Northern Illinois RTEP Summary

6.1.1 — RTEP Context

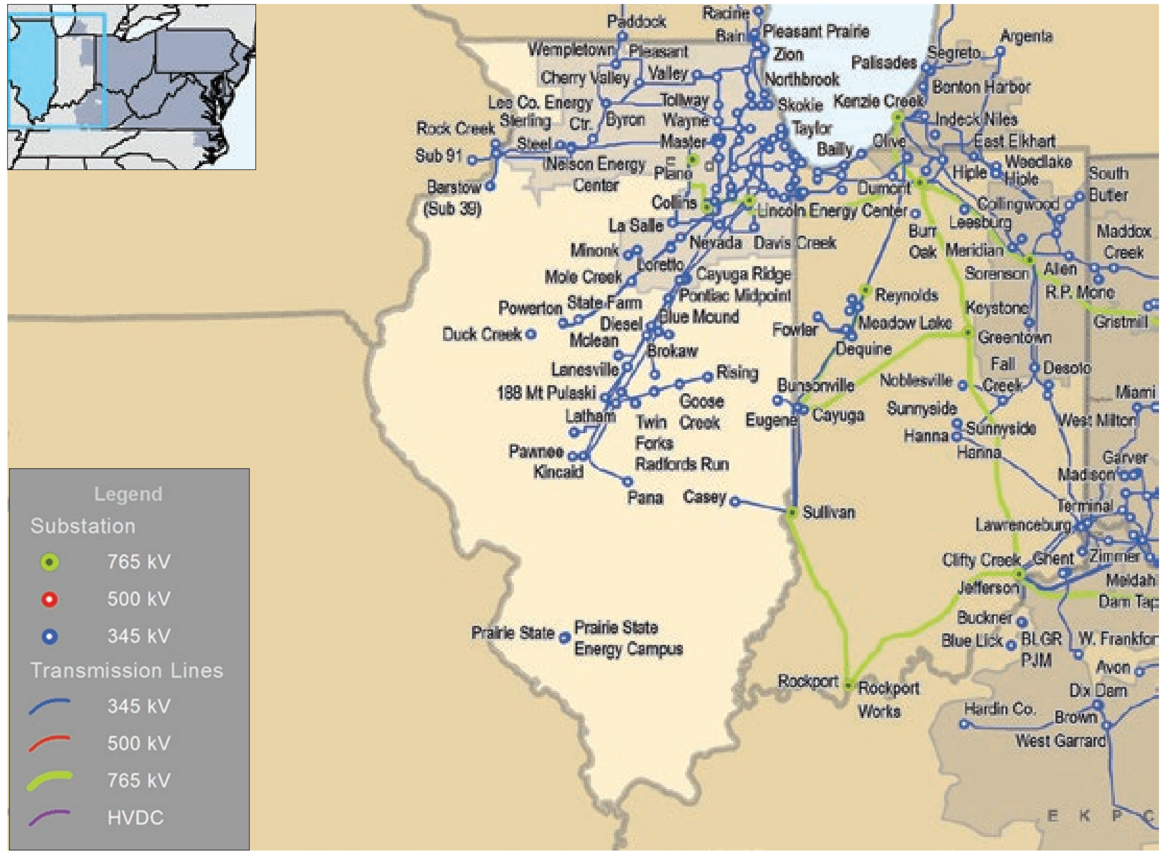
PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Northern Illinois, including facilities owned and operated by Commonwealth Edison Co. (ComEd) and the City of Rochelle as shown on **Map 6.2**. The Northern Illinois' transmission system delivers power to customers from 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 has a mandatory RPS target of 25 percent by energy year 2025-2026, and there is a 6 percent solar carve-out within the standard. Illinois also requires that its investor-owned utilities meet 75 percent of this target with wind or photovoltaic resources each year, and for alternative retail electric suppliers this requirement is 60 percent.

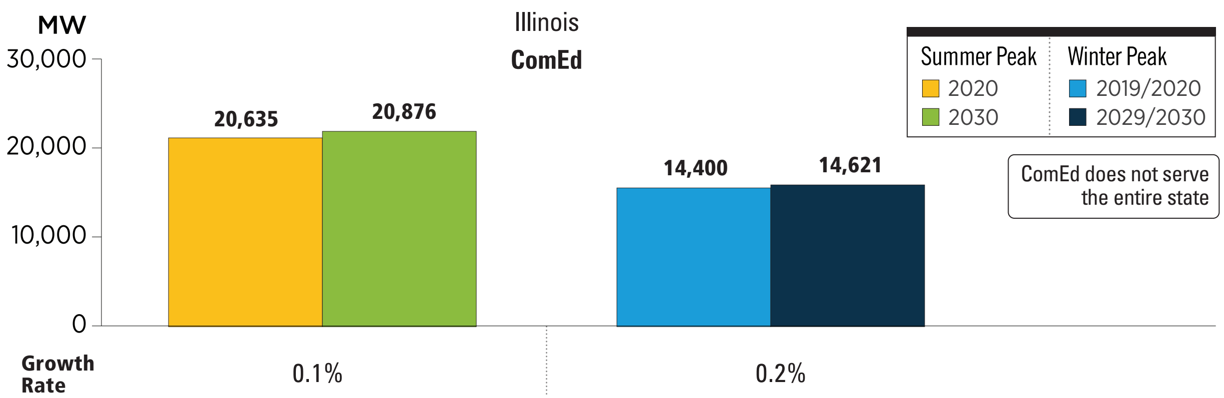
Map 6.2: PJM Service Area in Northern Illinois



6.1.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.6** summarizes the expected loads within the state of Northern Illinois and across all of PJM.

Figure 6.6: Northern Illinois – 2020 Load Forecast Report



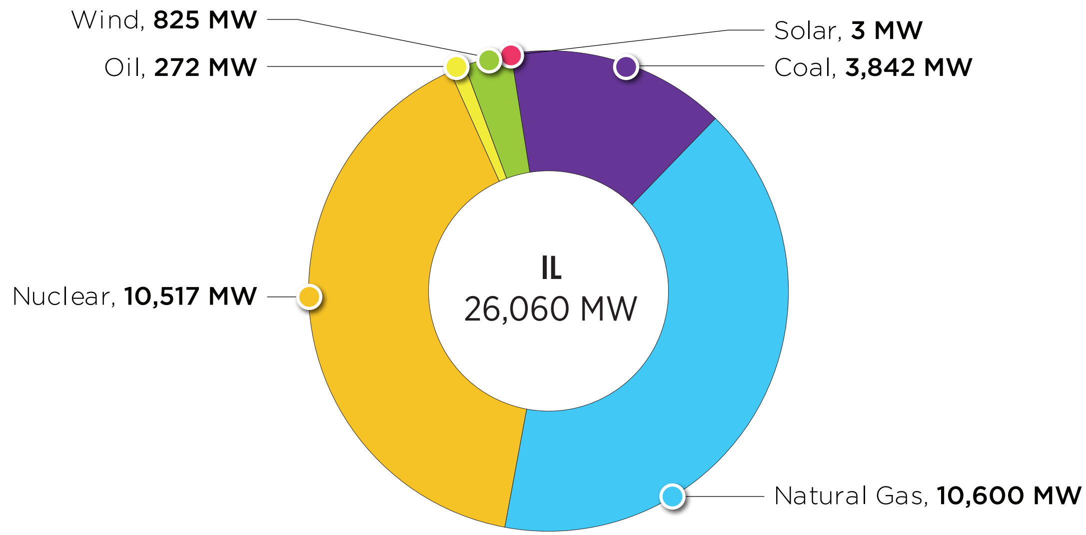
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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, 2020, is shown by fuel type in **Figure 6.7**.

Figure 6.7: Northern Illinois – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 158 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.3**, **Table 6.4**, **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 6.3: Northern Illinois – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Northern Illinois Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	23	0.17%	559	0.53%
Natural Gas	4,812	35.94%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	5,503	41.10%	58,845	56.13%
Storage	1,592	11.89%	10,877	10.38%
Wind	1,460	10.90%	6,560	6.26%
Grand Total	**13,390**	**100.00%**	**104,838**	**100.00%**

Table 6.4: Northern Illinois – 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	Coal	0	0.0	0	0.0	0	0.0	5	3,652.0	5	3,652.0
	Diesel	0	0.0	0	0.0	2	22.0	0	0	2	22.0
	Natural Gas	15	2,413.3	7	2,398.9	20	1,613.6	21	8,908.3	63	15,334.1
	Nuclear	0	0.0	0	0.0	10	385.8	5	782.0	15	1,167.8
	Other	0	0.0	0	0.0	0	0.0	3	0	3	
	Storage	32	1,592.0	0	0.0	6	0.0	24	511.6	62	2,103.5
Renewable	Biomass	0	0.0	0	0.0	0	0.0	3	90.0	3	90.0
	Hydro	0	0.0	2	22.7	0	0.0	2	4.3	4	27.0
	Methane	0	0.0	0	0.0	4	43.0	14	63.9	18	106.9
	Solar	61	5,502.9	0	0.0	1	3.4	50	1,751.4	112	7,257.7
	Wind	40	1,434.0	1	26.0	31	853.5	110	2,856.7	182	5,170.2
	Grand Total	148	10,942.2	10	2,447.6	74	2,921.3	237	18,620.1	469	34,931.1

Figure 6.8: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

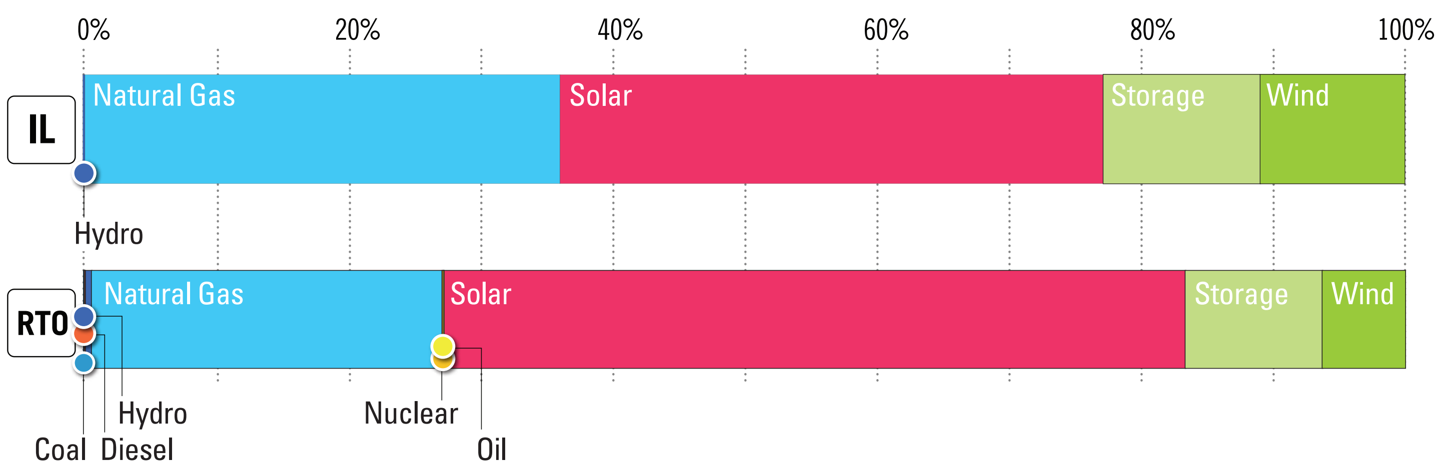


Figure 6.9: Northern Illinois – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

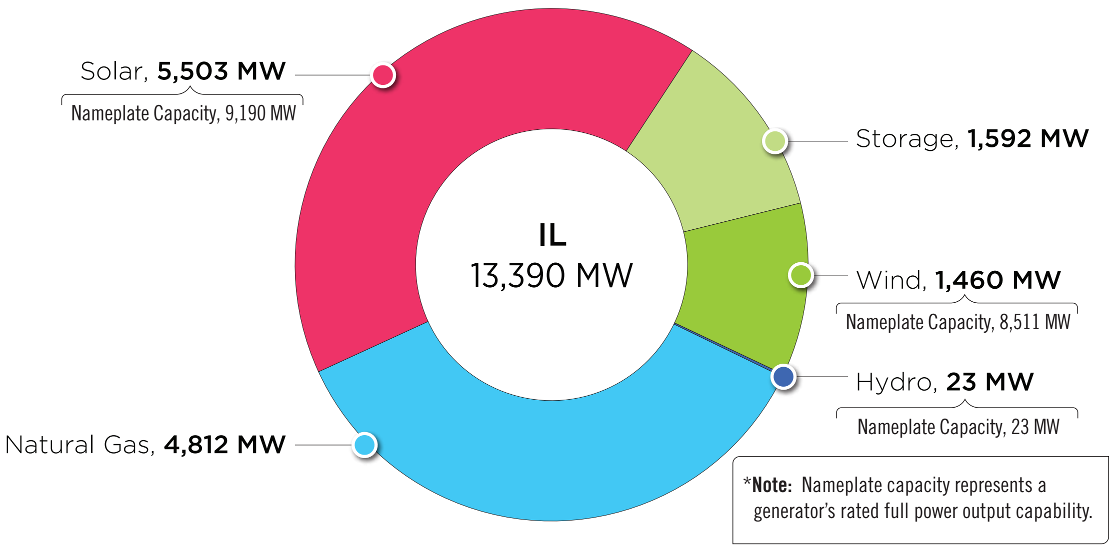
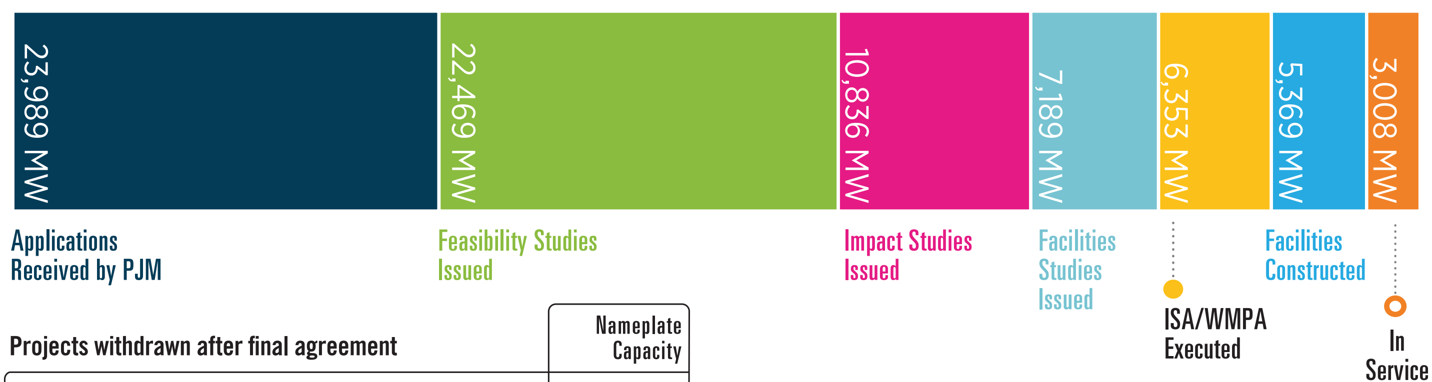


Figure 6.10: Northern Illinois Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement			Nameplate Capacity
9	Interconnection Service Agreements	376 MW	1,678 MW
4	Wholesale Market Participation Agreements	4 MW	15 MW

Percentage of planned capacity and projects that have reached commercial operation	13% Requested capacity megawatts	24 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.1.5 — Generation Deactivation

Known generating unit deactivation requests in Northern Illinois between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.3** and **Table 6.5**.

6.1.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in Northern Illinois were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.3: Northern Illinois Generation Deactivations (Dec. 31, 2020)

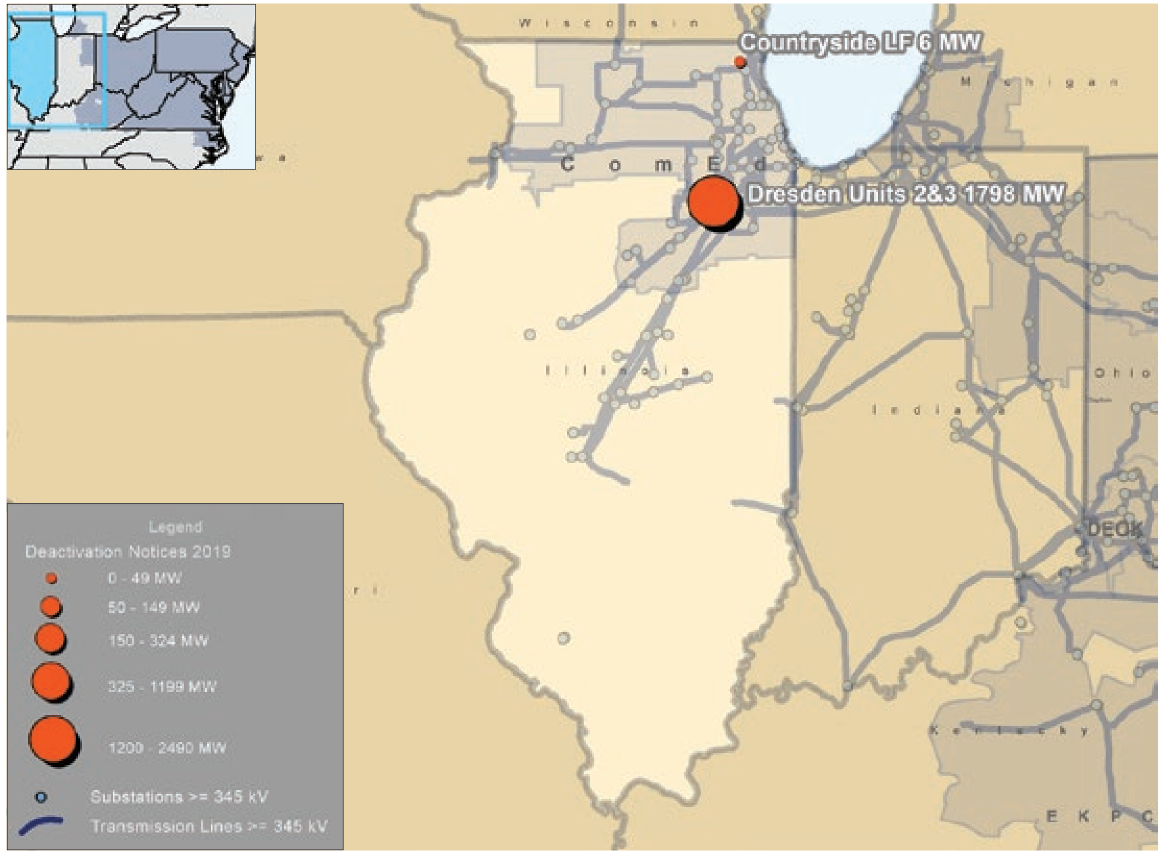


Table 6.5: Northern Illinois Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Countryside Landfill	ComEd	Methane	10/29/2020	1/27/2021	8	5.8
Dresden Unit 2		Nuclear	8/27/2020	11/1/2021	50	902.5
Dresden Unit 3		Nuclear	8/27/2020	11/1/2021	49	895.5

6.1.7 — Network Projects

2020 RTEP network projects greater than or equal to $10 million in Northern Illinois are summarized in **Map 6.4** and **Table 6.6**.

Map 6.4: Northern Illinois Network Projects (Greater Than or Equal to $10M) (Dec. 31, 2020)

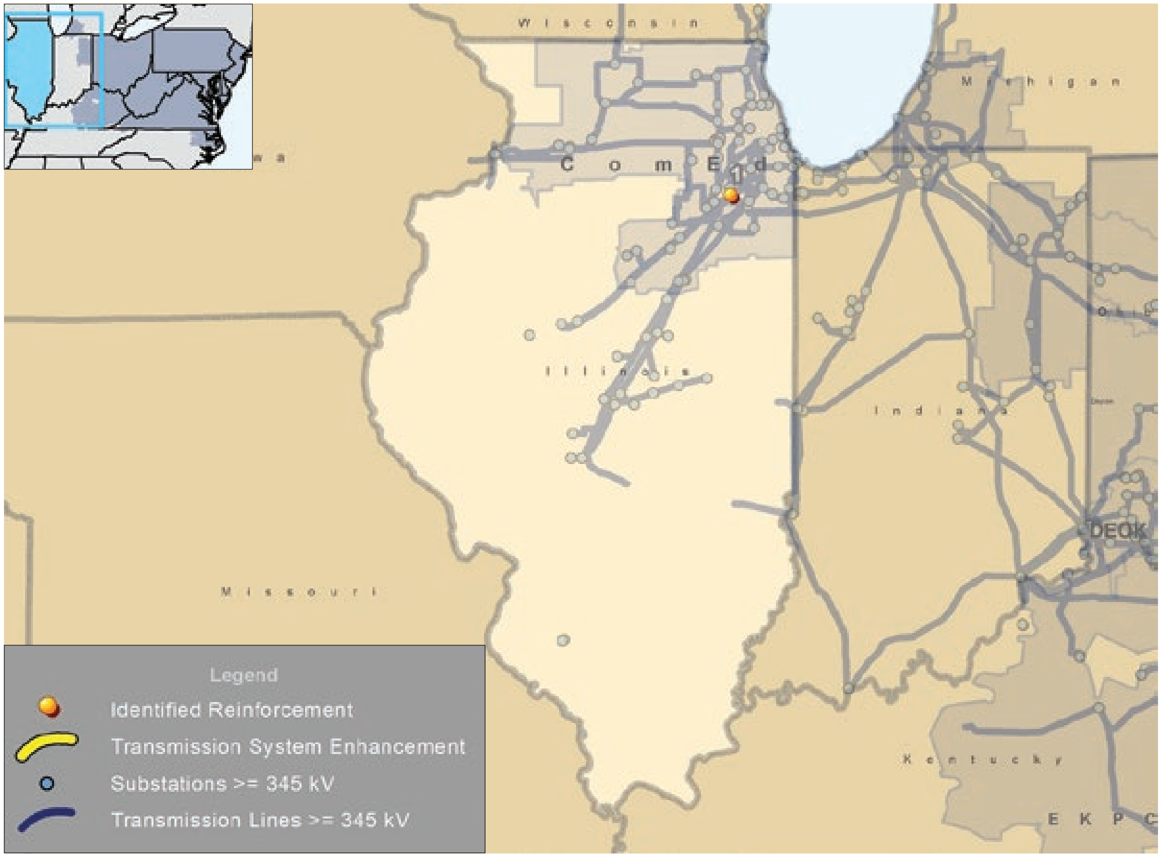


Table 6.6: Northern Illinois Network Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Generation	Required In- Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	**N6025**	Expansion of TSS 900 Elwood to accommodate AC1-204 attachment.	AC1-204	6/1/2022	$35.76	ComEd	9/28/2020

6.1.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Northern Illinois are summarized in **Map 6.5** and **Table 6.7**.

Map 6.5: Northern Illinois Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

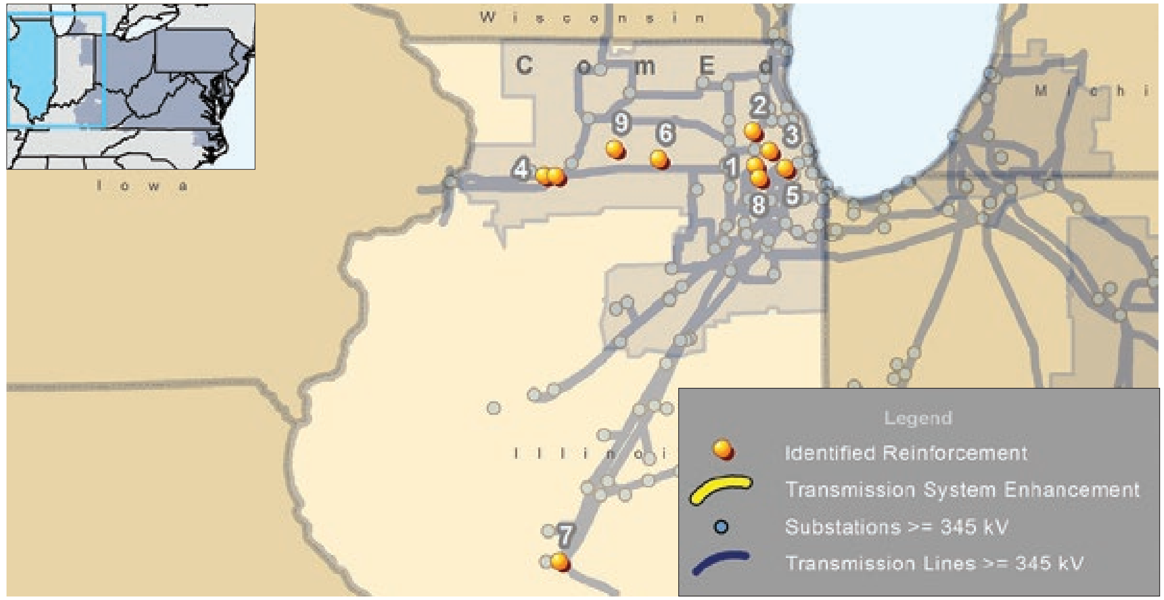


Table 6.7: Northern Illinois Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2247	Replace Lisle Transformer 83. Add high-side CB.	12/31/2021	$10.00	ComEd	4/14/2020
2	S2266	Rebuild Itasca 345 kV bus as an indoor GIS double ring bus expandable to breaker-and-a-half connecting four lines and two transformers. Replace 345/138 kV Transformer 82 and retire tertiary cap bank.	6/1/2024	$65.00		5/12/2020
3	S2267	Rebuild Elmhurst 345 kV bus as indoor GIS double-ring bus, expandable to breaker-and-a-half connecting two lines and three transformers.		$55.00		
4	S2268	Build a second circuit 4.5 miles in existing right-of-way from Nelson 138 kV to tap point and split into a pair of two-terminal lines. Ratings on the new section will be 351/449 MVA SN/SLTE consistent with b2999 project.	6/1/2022	$15.20		5/22/2020
5	S2285	Rebuild McCook 345 kV bus as indoor GIS double ring bus, expandable to breaker-and-a-half (BAAH).	12/31/2024	$64.00		6/2/2020
6	S2349	Cut into existing lines 11323 and 11106. Install new 138 kV breaker-and-a-half substation by Sept. 1, 2021. Install two 138 kV, 43.2 MVAR cap banks, first by June 1, 2022, second by June 1, 2024.	9/1/2021	$61.90		7/17/2020
7	S2350	Replace five 345 kV oil circuit breakers with two-cycle IPO SF6 circuit breakers. Change timer settings for breaker failure relays and remove Kincaid special protection scheme.	12/31/2024	$15.70		7/7/2020
8	S2353	Cut into existing line 1802. Install new 138 kV four-breaker ring bus substation.	6/30/2022	$18.70		8/14/2020
9	S2354	Cut into existing 138 kV line 16914. Install new 138 kV, three-breaker ring substation.	12/31/2021	$15.30		

6.1.9 — Merchant Transmission Project Requests

As of Dec. 31, 2020, PJM's queue contained two merchant transmission project requests with a terminal in Northern Illinois, as shown in **Map 6.6** and **Table 6.8**.

Map 6.6: Northern Illinois Merchant Transmission Project Requests (Dec. 31, 2020)

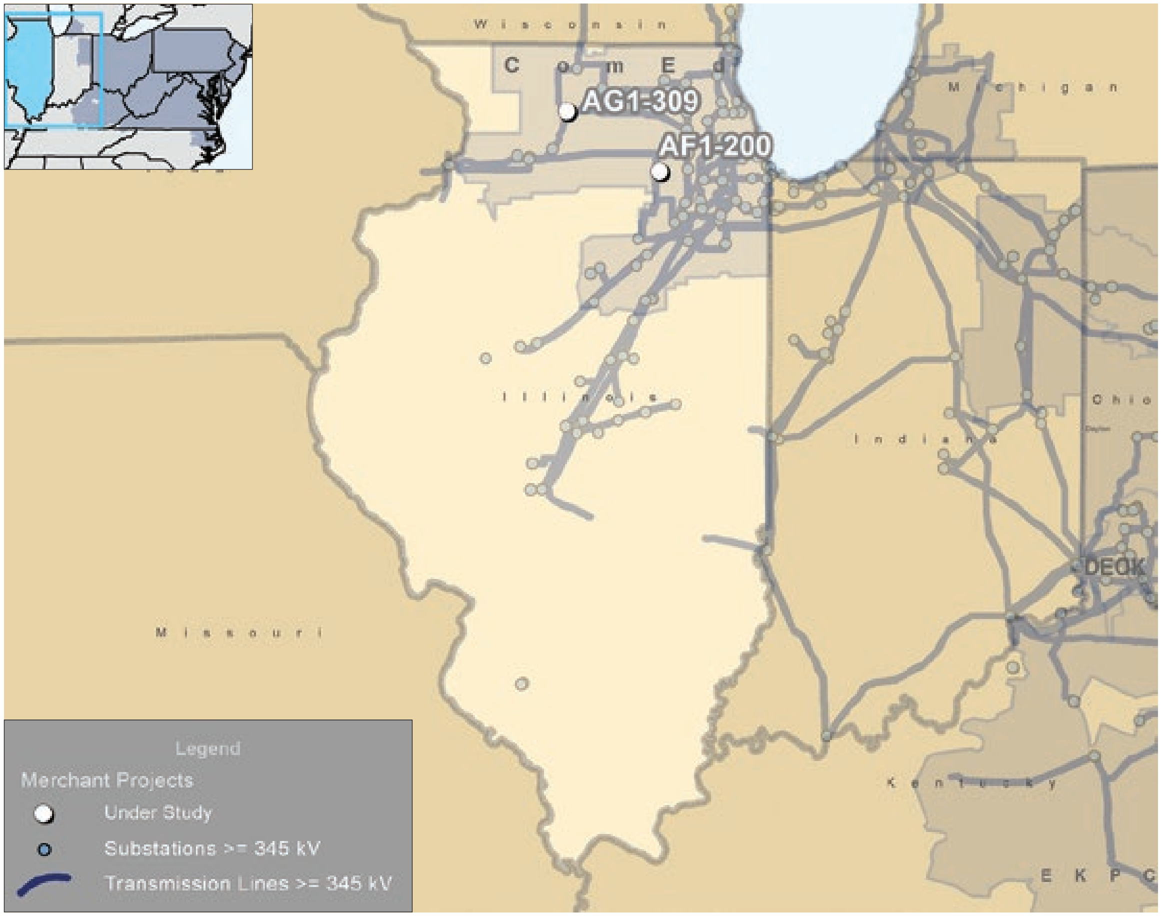


Table 6.8: Northern Illinois Merchant Transmission Project Requests (Dec. 31, 2020)

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
AG1-309	Byron 345 kV		Active		2,100

6.2: Indiana RTEP Summary

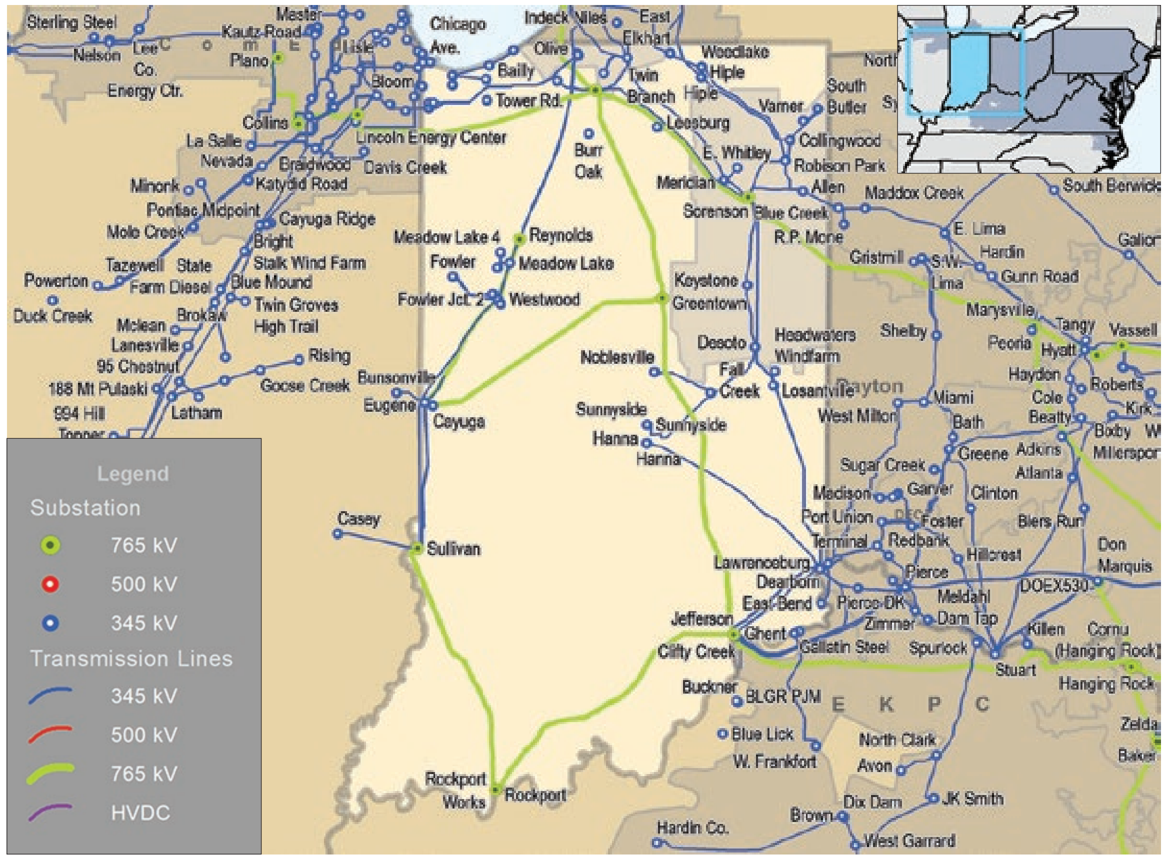
6.2.1 — RTEP Context

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 6.7.** 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 percent by 2025. This target can be met with eligible clean energy technologies, and 50 percent of the qualifying energy must come from within Indiana.

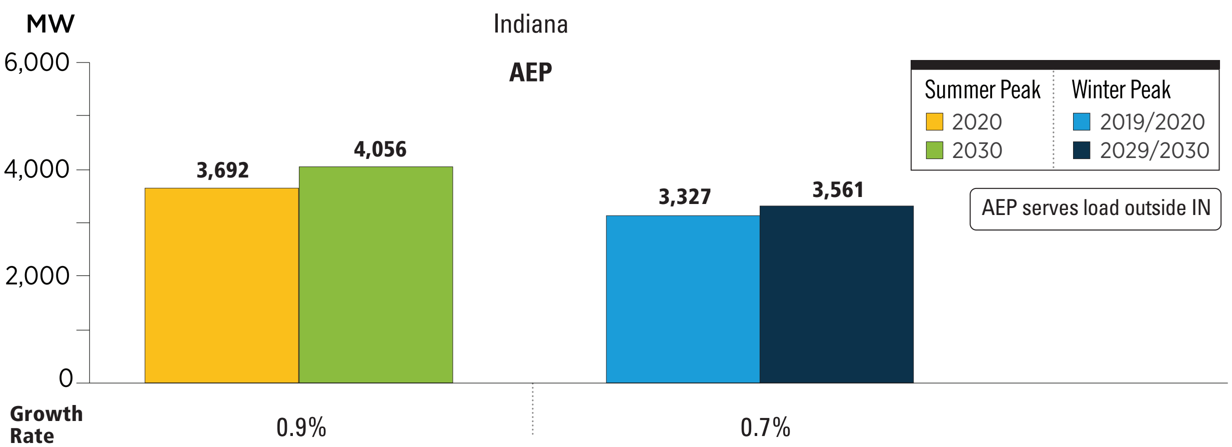
Map 6.7: PJM Service Area in Indiana



6.2.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.11** summarizes the expected loads within the state of Indiana and across all of PJM.

Figure 6.11: Indiana – 2020 Load Forecast Report



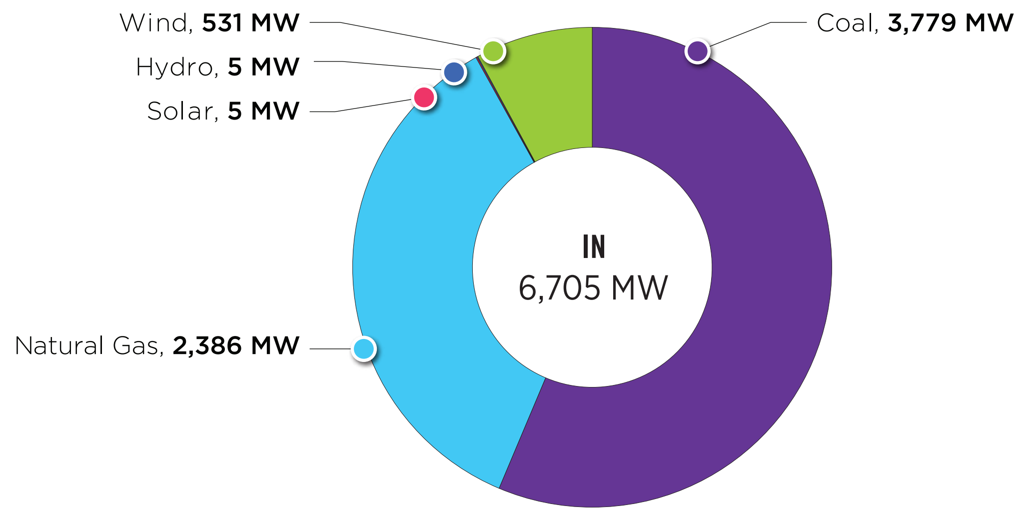
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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, 2020, is shown by fuel type in **Figure 6.12**

Figure 6.12: Indiana – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 112 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.9**, **Table 6.10**, **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 6.9: Indiana – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Indiana Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	1,150	11.44%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	7,469	74.28%	58,845	56.13%
Storage	976	9.71%	10,877	10.38%
Wind	460	4.57%	6,560	6.26%
Grand Total	**10,056**	**100.00%**	**104,838**	**100.00%**

Table 6.10: Indiana – Interconnection Requests by Fuel Type (Dec. 31 2020)

		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	2	1,100.0	1	50.0	5	811.0	2	1,747.0	10	3,708.0
	Storage	14	976.3	0	0.0	0	0.0	9	382.1	23	1,358.5
Renewable	Methane	0	0.0	0	0.0	2	8.0	1	3.6	3	11.6
	Solar	78	7,469.4	0	0.0	3	5.1	22	3,281.2	103	10,755.6
	Wind	16	433.9	1	26.0	10	388.9	45	1,699.7	72	2,548.5
	Grand Total	110	9,979.6	2	76.0	24	1,279.0	81	8,014.6	217	19,349.2

Figure 6.13: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

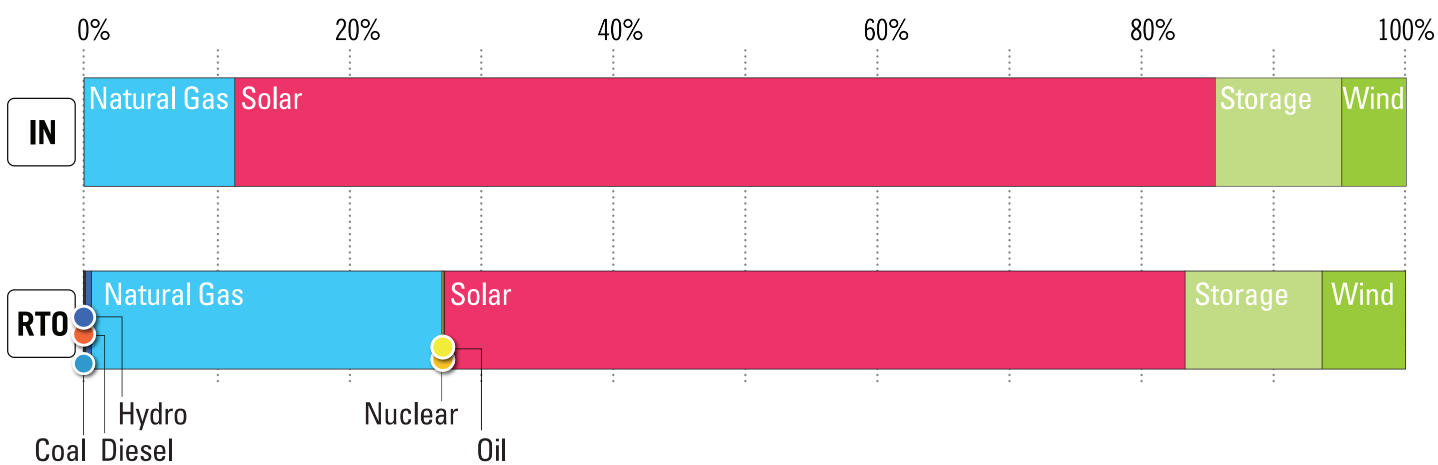


Figure 6.14: Indiana – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

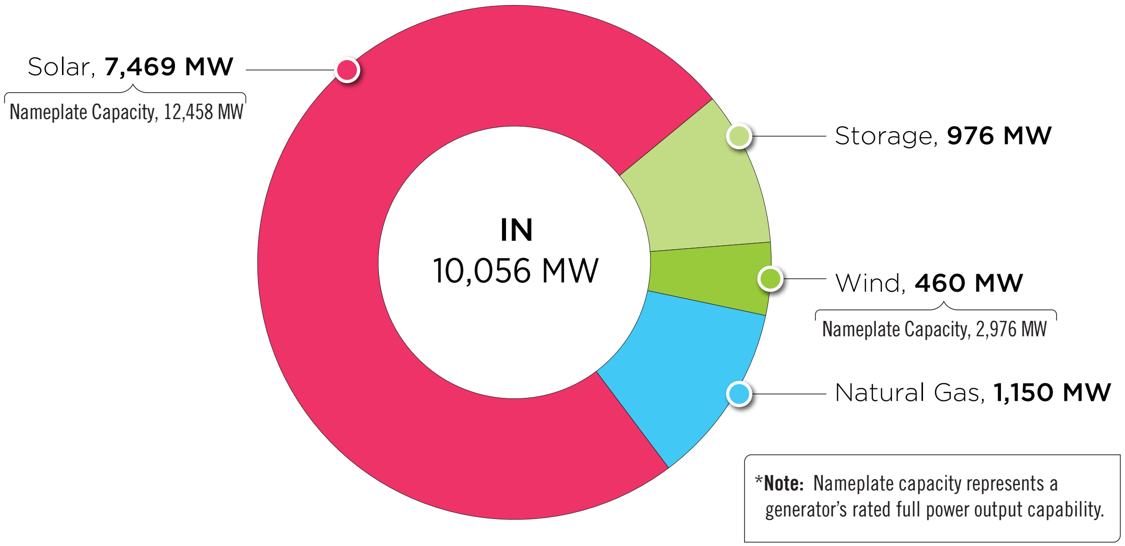


Figure 6.15: Indiana Progression History of Queue – Interconnection Requests (Dec. 31, 2020)

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

Percentage of planned capacity and projects that have reached commercial operation	14% Requested capacity megawatts	23% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.2.5 — Generation Deactivations

There were no generating unit deactivation requests in Indiana between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.2.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Indiana are summarized in **Map 6.8** and **Table 6.11.**

Map 6.8: Indiana Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

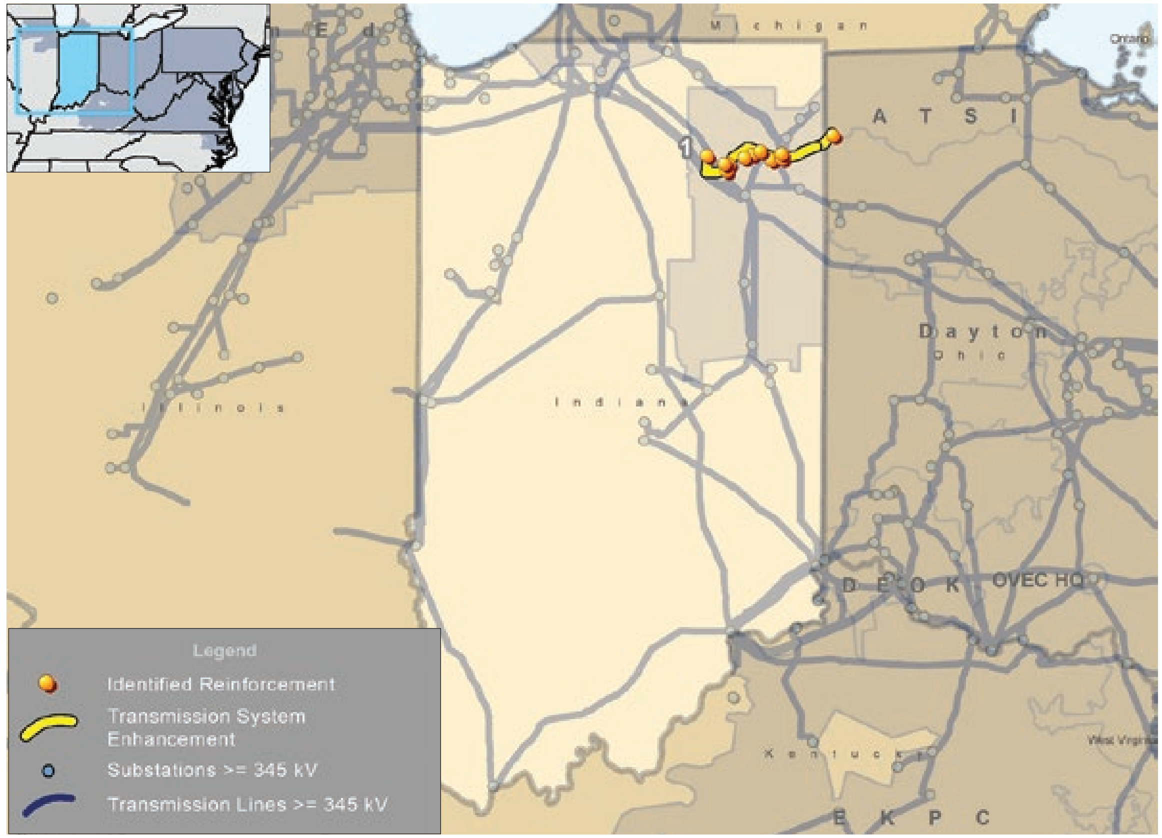


Table 6.11: Indiana Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3151	Rebuild the ~30 mile Gateway-Wallen 34.5 kV circuit as the ~27 mile Gateway-Wallen 69 kV circuit.	6/1/2024	$113.00	AEP	11/22/2019
		Retire the ~3 mile Columbia-Whitley 34.5 kV line.				
		At Gateway station, remove all 34.5 kV equipment and install one 69 kV circuit breaker for the new Whitley line entrance.				
		Rebuild Whitley as a 69 kV station with two line and one bus tie circuit breakers.				
		Replace the Union 34.5 kV switch with a 69 kV switch structure.				

Table 6.11: Indiana Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	B3151	Replace the Eel River 34.5 kV switch with a 69 kV switch structure.	6/1/2024	$113.00	AEP	11/22/2019
		Install a 69 kV Bobay switch at Woodland Station.				
		Replace Carroll and Churubusco 34.5 kV stations with the 69 kV Snapper station. Snapper will have two line circuit breakers, one bus tie circuit breaker and a 14.4 MVAR cap bank.				
		Remove 34.5 kV circuit breaker AD at Wallen station.				
		Rebuild the 2.5 mile Columbia-Gateway 69 kV line.				
		Rebuild Columbia station in the clear as a 138/69 kV station with two 138/69 kV transformers and four-breaker ring buses on the high and low side. Station will reuse 69 kV breakers J and K and 138 kV breaker D.				
		Rebuild the 13 mile Columbia-Richland 69 kV line.				
		Rebuild the 0.5 mile Whitley-Columbia City No. 1 line as 69 kV.				
		Rebuild the 0.5 mile Whitley-Columbia City No. 2 line as 69 kV.				
		Rebuild the 0.6 mile double-circuit section of the Rob Park-South Hicksville / Rob Park-Diebold Road as 69 kV.				

6.2.7 — Network Projects

No network projects greater than or equal to $10 million in Indiana were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.2.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Indiana are summarized in **Map 6.9** and **Table 6.12**.

Map 6.9: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

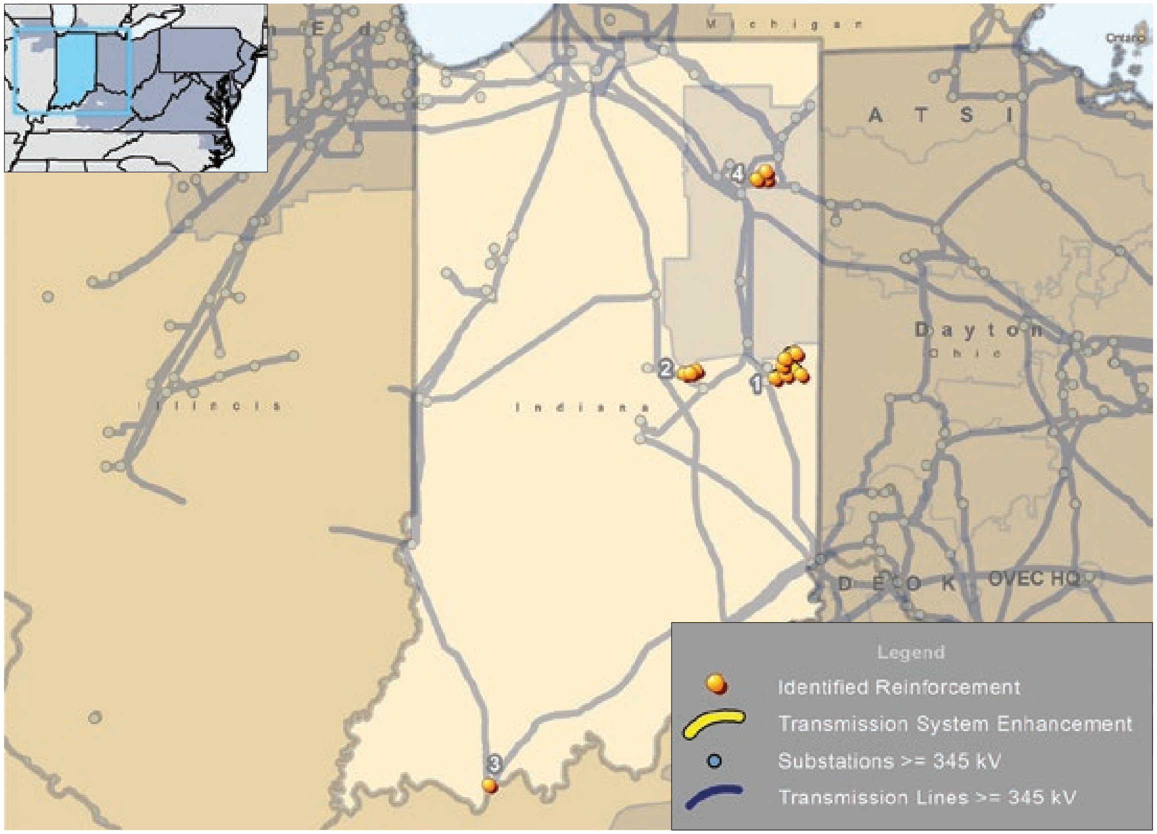


Table 6.12: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2273	Rebuild the 1.25 mile long Anchor Hocking-Winchester 69 kV circuit.	8/1/2025	$68.50	AEP	5/22/2020
		Expand and upgrade Anchor Hocking 69 kV station to a five-breaker ring bus to accommodate five elements (two transmission lines and three distribution transformers).				
		Replace circuit breakers A and B at Winchester 69 kV station.				
		At Modoc station, replace 138/69 kV Transformer No. 1. Install a three-breaker ring bus eliminating the three-terminal line.				
		At Randolph station, replace 138/69/12 kV Transformer No. 1 with a 138/69 kV 90 MVA unit. Move the distribution load to a new 138/12kV transformer and install a 138 kV bus tie circuit breaker. Replace cap switcher AA.				

Table 6.12: Indiana Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	S2273	At Lynn station, install two 69 kV switches for sectionalizing.	8/1/2025	$68.50	AEP	5/22/2020
		Replace the Huntsville (REMC) switch structure on the Modoc-Winchester 69 kV line.				
		Rebuild the 13.4 mile Modoc-Winchester 69 kV line with 11.3 miles as single circuit and 2.1 miles as double circuit.				
		Rebuild the 5.7 mile Buena Vista-Lynn 69 kV line as double circuit.				
		Retire Lobdell station. Move the load from 69 kV to 12 kV.				
		Retire Buena Vista Switch 69 kV.				
2	s2274	Rebuild a 4.17 mile portion of the Madison-Pendleton 138 kV single circuit line with DRAKE 795 ACSR 26/7.	5/1/2023	$10.50	AEP	5/22/2020
		At Meadowbrook station, install two 138 kV circuit breakers to eliminate the three-terminal line.				
3	s2280	Replace Rockport CBs B, B2, C and C2 with 765kV SFMT 4000A CBs.	10/1/2024	$18.50		6/2/2020
4	s2344	Rebuild the ~5.8 mile 69 kV line from Colony Bay to the McKinley-Bass line.	4/3/2023	$15.60		7/17/2020
		Add a 69 kV bus tie CB to Hadley station.				

6.2.9 — Merchant Transmission Project Requests

As of Dec. 31, 2020, PJM's queue contained two merchant transmission project requests which include a terminal in Indiana as shown in **Map 6.10** and **Table 6.13.**

Map 6.10: Indiana Merchant Transmission Project Requests (Dec. 31, 2020)

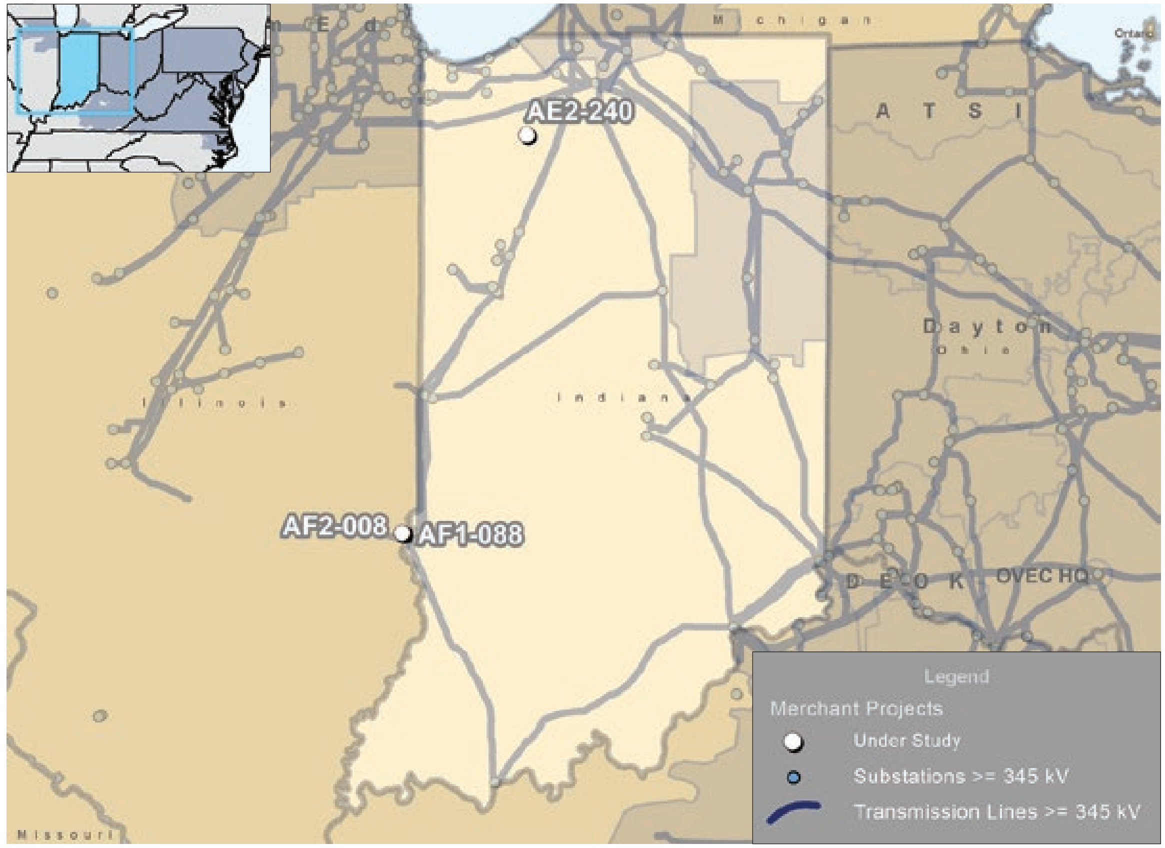


Table 6.13: Indiana Merchant Transmission Project Requests (Dec. 31, 2020)

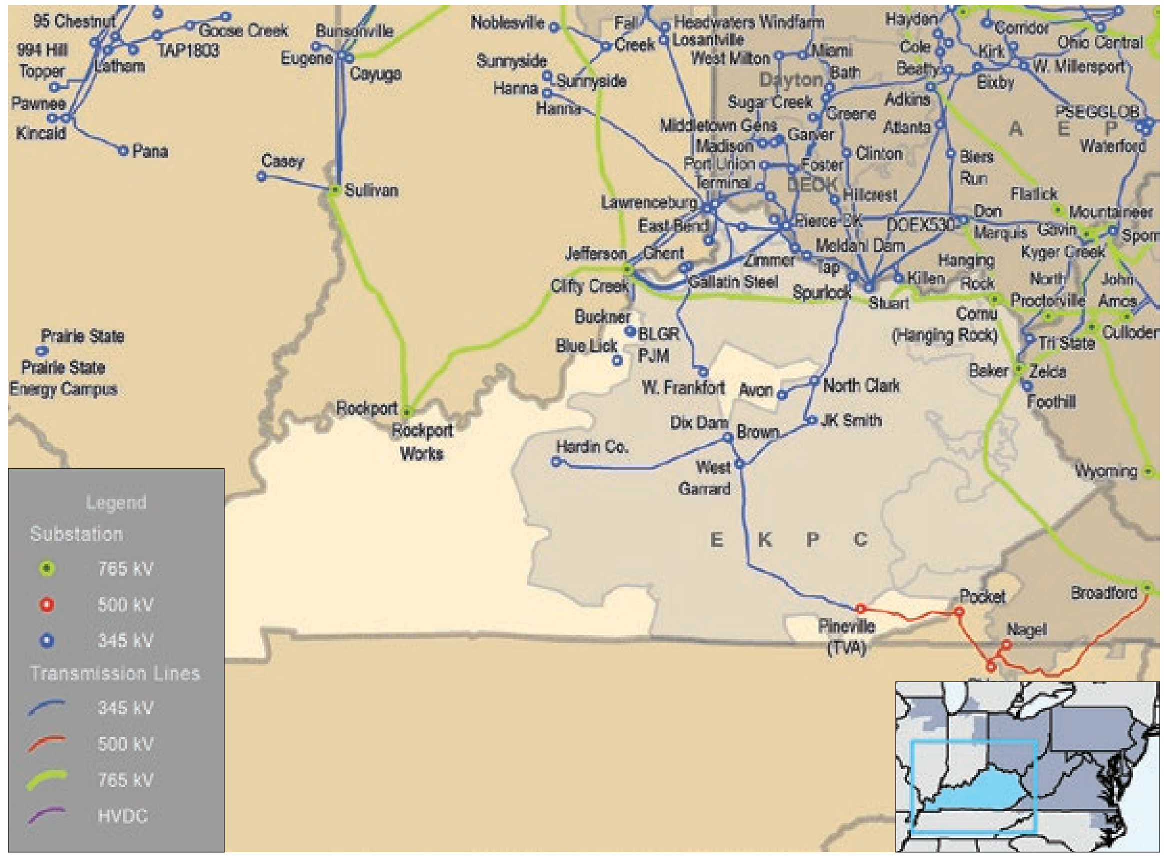
Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AE2-240	Olive-Reynolds 1 & 2 345 kV	AEP	Active	6/1/2019	3,170
AF1-088	Sullivan 345 kV		Active	12/31/2025	1,000
AF2-008	Sullivan 345 kV		Active		2,000

6.3: Kentucky RTEP Summary

6.3.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Kentucky, including facilities owned and operated by American Electric Power (AEP), Duke Energy Corp. (DEO&K), and East Kentucky Power Cooperative (EKPC) as shown on **Map 6.11**. Duke Energy Corp. (DEO&K) 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.

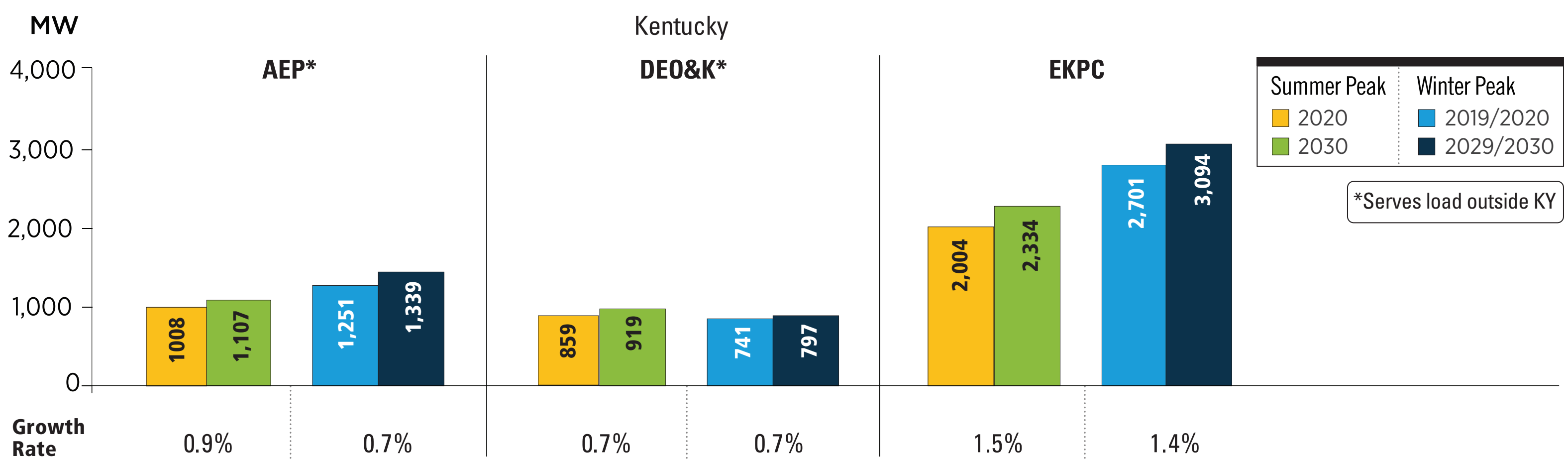
Map 6.11: PJM Service Area in Kentucky



6.3.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.16** summarizes the expected loads within the state of Kentucky and across all of PJM.

Figure 6.16: Kentucky – 2020 Load Forecast Report



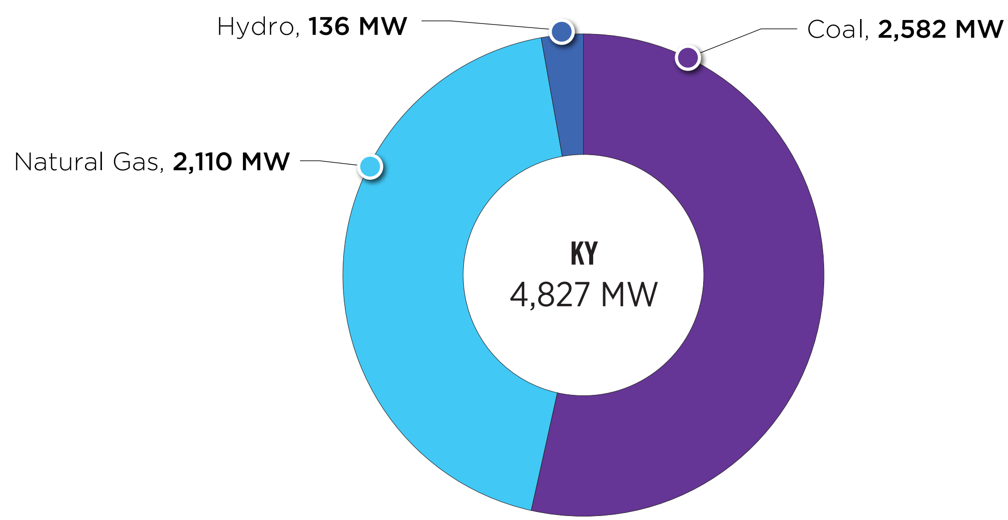
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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, 2020, is shown by fuel type in **Figure 6.17**.

Figure 6.17: Kentucky – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 62 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.14**, **Table 6.15**, **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 6.14: Kentucky – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Kentucky Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	1,100	22.92%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	3,563	74.24%	58,845	56.13%
Storage	136	2.83%	10,877	10.38%
Wind	0	0.00%	6,560	6.26%
Grand Total	4,799	**100.00%**	**104,838**	**100.00%**

Table 6.15: Kentucky – Interconnection Requests by Fuel Type (Dec. 31 2020)

		In Queue				Complete				Grand Total	
		Active		Under Construction		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0.0	0	0.0	0	0.0	6	2,969.0	6	2,969.0
	Natural Gas	0	0.0	1	1,100.0	6	71.0	5	1,704.7	12	2,875.7
	Storage	4	136.0	0	0.0	0	0.0	3	106.2	7	242.2
Renewable	Biomass	0	0.0	0	0.0	0	0.0	5	198.5	5	198.5
	Hydro	0	0.0	0	0.0	0	0.0	1	70.0	1	70.0
	Solar	55	3,434.9	2	127.9	0	0.0	25	1,214.0	82	4,776.8
	Wind	0	0.0	0	0.0	0	0.0	2	27.3	2	27.3
	Grand Total	**59**	**3,570.9**	**3**	**1,227.9**	**6**	**71.0**	**47**	**6,289.7**	**115**	**11,159.5**

Figure 6.18: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

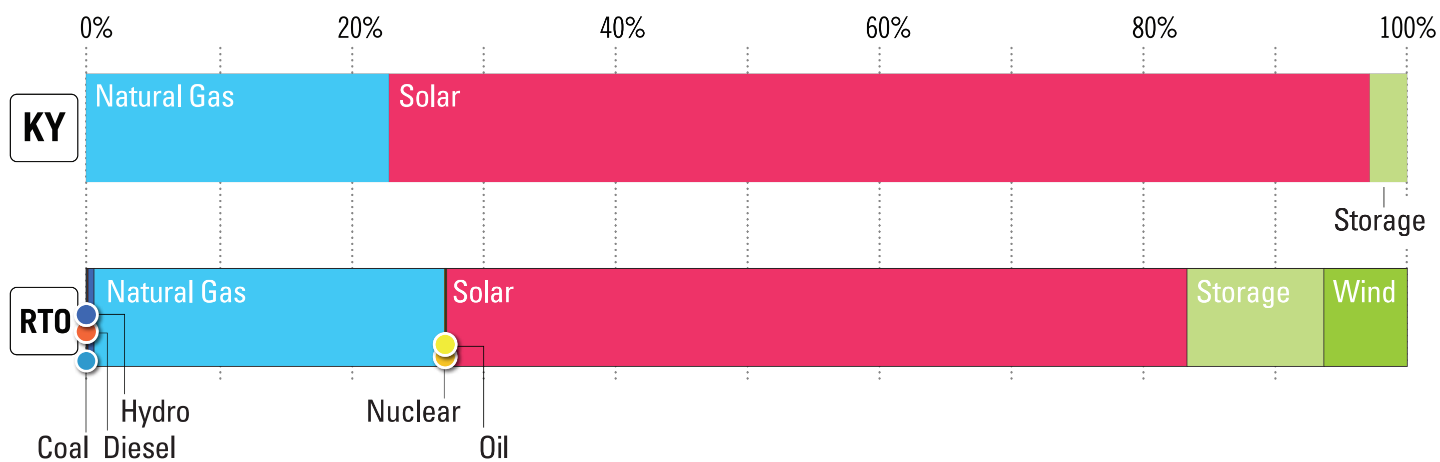


Figure 6.19: Kentucky – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

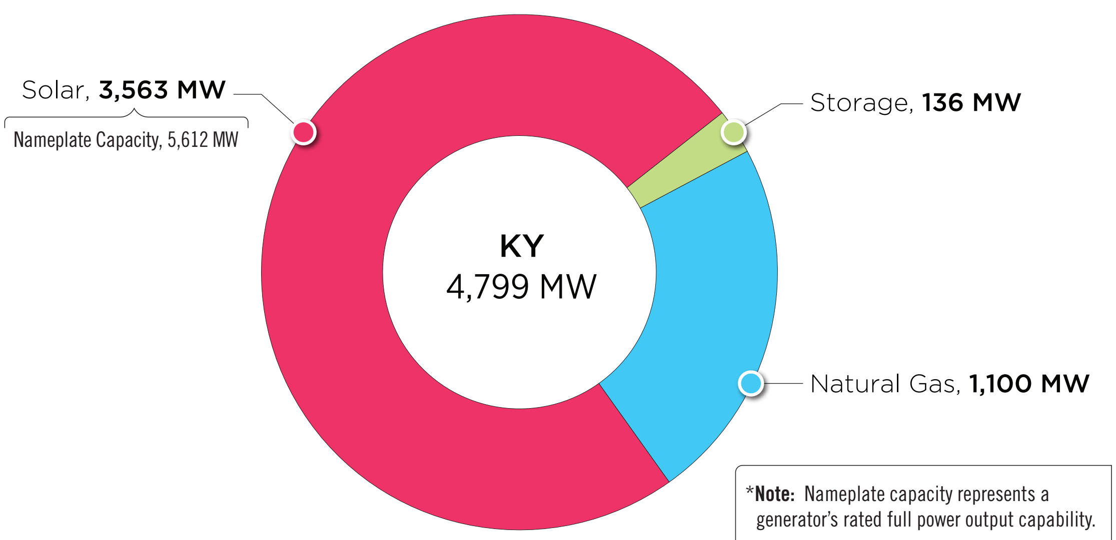


Figure 6.20: Kentucky Progression History of Queue – Interconnection Requests (Dec. 31, 2020)

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

Percentage of planned capacity and projects that have reached commercial operation	1% Requested capacity megawatts	11 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.3.5 — Generation Deactivation

There were no generating unit deactivation requests in Kentucky between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.3.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Kentucky are summarized in **Map 6.12** and **Table 6.16**.

6.3.7 — Network Projects

No network projects greater than or equal to $10 million in Kentucky were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the [Project Status](#) page of the PJM website.

Map 6.12: Kentucky Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

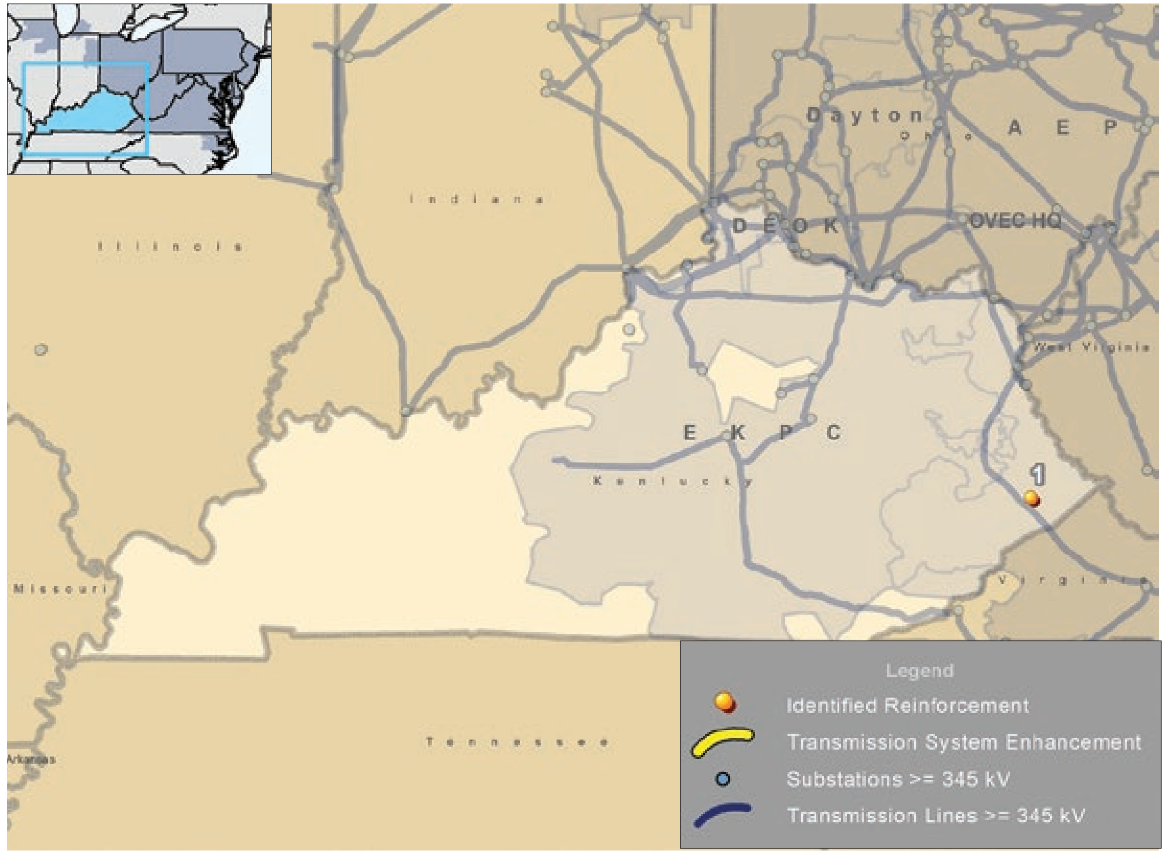


Table 6.16: Kentucky Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3087	Install 28.8 MVAR switching shunt at the new Fords Branch substation.	12/1/2023	$23.70	AEP	10/25/2019

6.3.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Kentucky are summarized in **Map 6.13** and **Table 6.17**.

6.3.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Kentucky were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.13: Kentucky Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

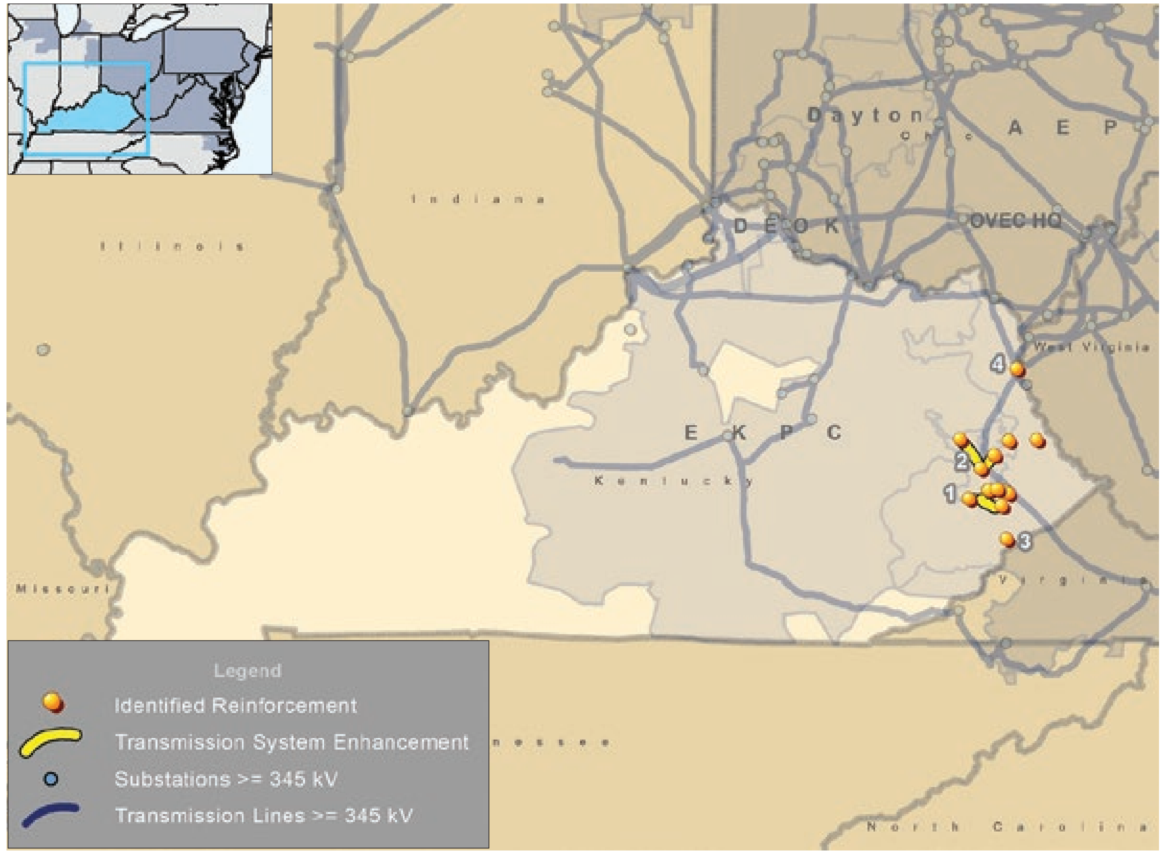
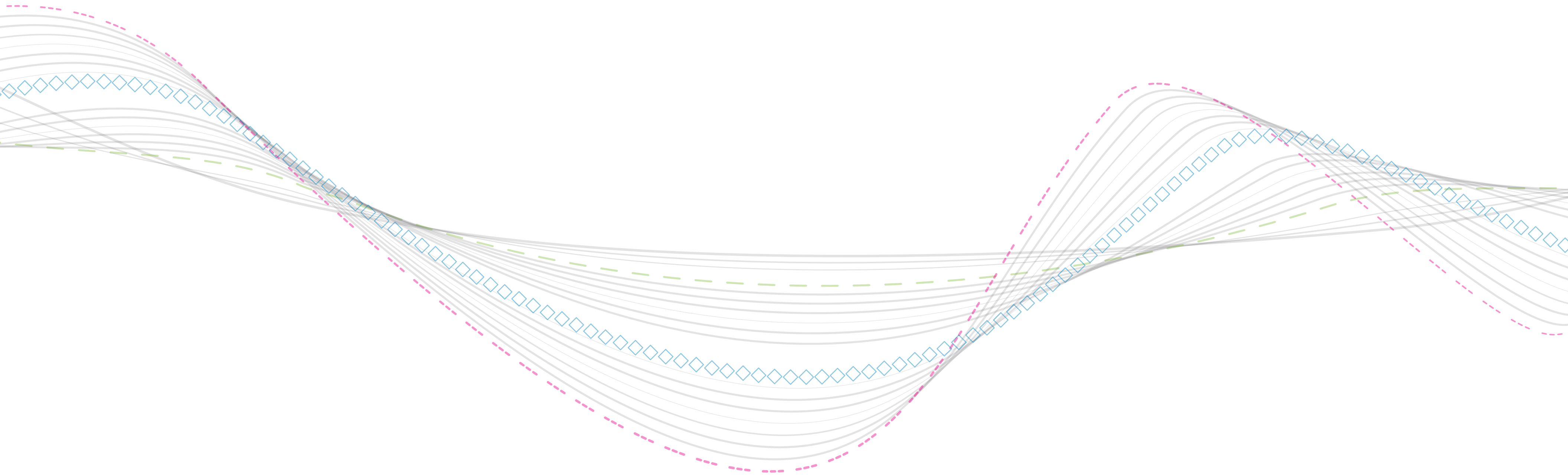


Table 6.17: Kentucky Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2188	Construct ~9.3 miles of single circuit 138 kV from Soft Shell to Garrett picking up Salt Lick Co-op via Snag Fork along the way. Complete associated remote end relaying.	10/31/2023	$81.20	AEP	2/21/2020
		Construct ~3.5 miles of single-circuit 138 kV from the Eastern station to Garrett station. A short extension will be required from the new station to the existing Hays Branch metering point. Construct short extension to existing Morgan Fork-Hays Branch 138 kV circuit from Eastern station.				
		Double circuit cut into existing Hays Branch-Morgan Fork line to tie into new Hays Branch S.S phase-over-phase switch. Install new heavy double circuit dead-end tap structure on the existing Hays Branch-Morgan Fork 138 kV line because of unequal loading on the transmission line.				
		Construct ~0.25 miles of double-circuit 138 kV line named Hays Branch Substation-Eastern. Install three double-circuit suspension structures, one of which is a custom pole structure.				
		New phase-over-phase switch structure at Hays Branch to accommodate new line from Eastern station.				
		Expand Garrett station. Install a 138 kV, three-breaker ring bus and138/12 kV 30 MVA transformer. If space becomes a constraint, we should look at installing a straight bus arrangement with two 138 kV breakers and a circuit switcher on the high side of the transformer.				
		Establish a new 138 kV substation named Eastern south of the existing Hays Branch station. Install two 138 kV breakers (3000A 40kA) at the new Eastern station on exits toward Morgan Fork and Garrett station.				
		Establish Snag Fork substation. Install a three-way phase-over-phase motorized (automated) switching structure near Saltlick to serve the East Kentucky Power Cooperative.				
		Move the existing 69 kV rated circuit breaker G to the Beaver Creek-McKinney No.2 circuit exit at McKinney substation.				
		Install a 138 kV breaker (3000A 40kA) with an exit towards Garrett station (via Snag Fork) at Softshell substation.				
		Retire ~25 miles of the 46 kV Beaver Creek-McKinney No.1 46 KV circuit. Retire Spring Fork Tap.				
2	S2200	Install a 2 MW Battery Energy Storage System (BESS) at Middle Creek substation.	12/1/2020	$41.30	AEP	1/17/2020
		Rebuild ~8.5 miles of 46 kV line between Prestonsburg and Middle Creek station.	4/1/2023			
		Retire ~14.5 miles of 46 kV line between Falcon and Middle Creek.				
3	S2219	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 CB; install a 5-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 breakers A and D. Retire existing Fleming substation.	9/1/2022	$21.10	AEP	3/19/2020
4	S2281	At Inez station, replace Breakers B, B2, C and C1. Install three new 138 kV breakers and create third string in the existing breaker-and-a-half configuration. Replace 138/69 kV Inez Transformer No. 1 with a 138/69 kV/12 kV 90 MVA autotransformer. Move the new Inez 139/69/12 kV Transformer No. 1 and Martiki 138 kV feed to the new string. Install Breaker B1 towards Johns Creek to complete the string. Installation of Breaker B1 and the third string addresses dissimilar zones of protection between the No. 1 bus and the more-than-20-mile Inez to Johns Creek 138 kV circuit and dissimilar zones of protection between the 138 kV bus No. 2, 138/69 kV transformer No. 1, and the 138 kV circuit to the Martiki coal service point. Replace cap bank switchers CS-BB and CS-CC with 138 kV circuit breakers. Replace obsolete relays at Inez substation. Retire 69 kV capacitor bank and the circuit switcher AA.	9/1/2022	$12.40	AEP	6/19/2020
		Remote end work at Big Sandy, Logan, Sprigg and Dewey substations.				

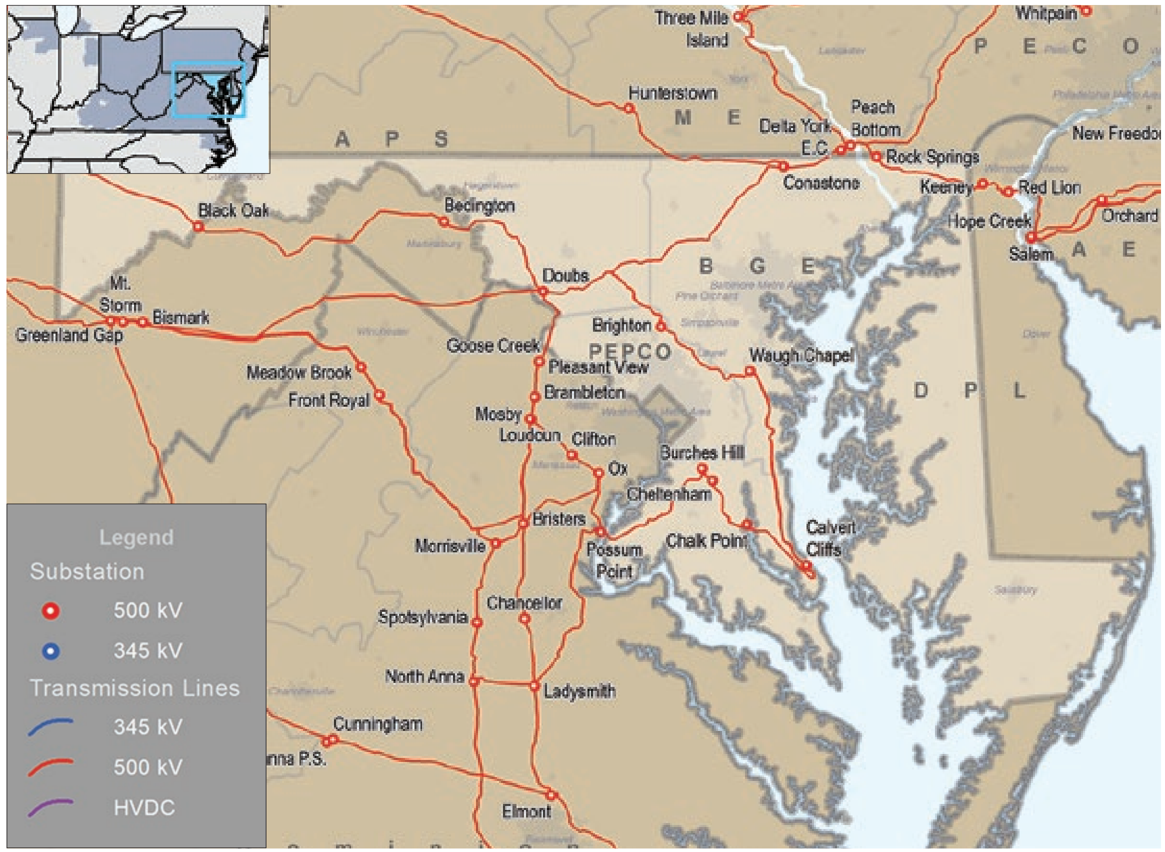


6.4: Maryland/District of Columbia RTEP Summary

6.4.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Maryland and the District of Columbia, including facilities owned and operated by Allegheny Power (AP), Baltimore Gas and Electric Co. (BGE), Delmarva Power & Light Co. (DP&L), Potomac Electric Power Co. (PEPCO) and Southern Maryland Electric Cooperative (SMECO) as shown on **Map 6.14**. Maryland and the District of Columbia's transmission system delivers power to customers from native generation resources in the region and throughout the RTO arising out of PJM market operations, as well as power imported interregionally from systems outside PJM.

Map 6.14: PJM Service Area in Maryland/District of Columbia



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.

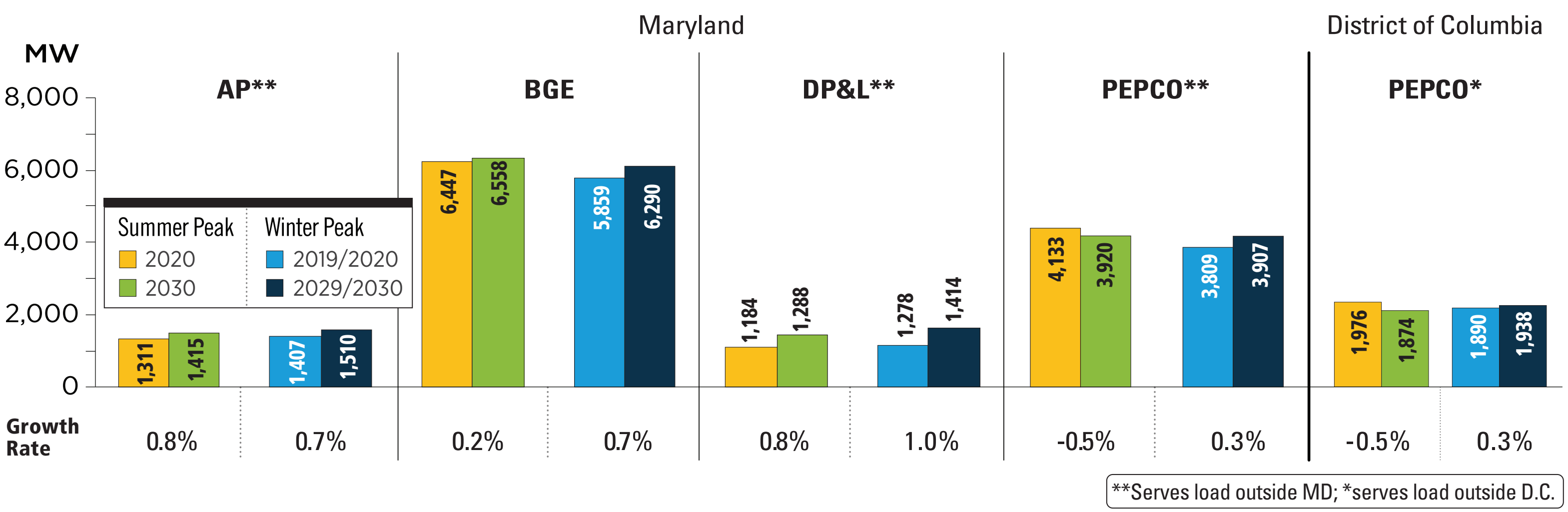
Maryland has a mandatory RPS target of 50 percent Tier 1 renewable resources by 2030. This includes a solar carve-out target of at least 14.5 percent by 2028, which must come from in-state solar resources.

The District of Columbia has a mandatory RPS target of 100 percent by 2032. The District's RPS target is one of two in the PJM region set at 100 percent, with the other being Virginia's. The resources serving D.C.'s RPS target must be Tier 1 renewable resources, and beginning in 2029 can only be resources located within the PJM region. The RPS target also includes a solar carve-out target of 5.5 percent by 2032 and 10 percent by 2041.

6.4.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.21** summarizes the expected loads within the state of Maryland and the District of Columbia and across all of PJM.

Figure 6.21: Maryland/District of Columbia – 2020 Load Forecast Report



PJM RTO Summer Peak

2020	2030
148,092 MW	157,132 MW

Growth Rate 0.6%

PJM RTO Winter Peak

2019/2020	2029/2030
131,287 MW	139,970 MW

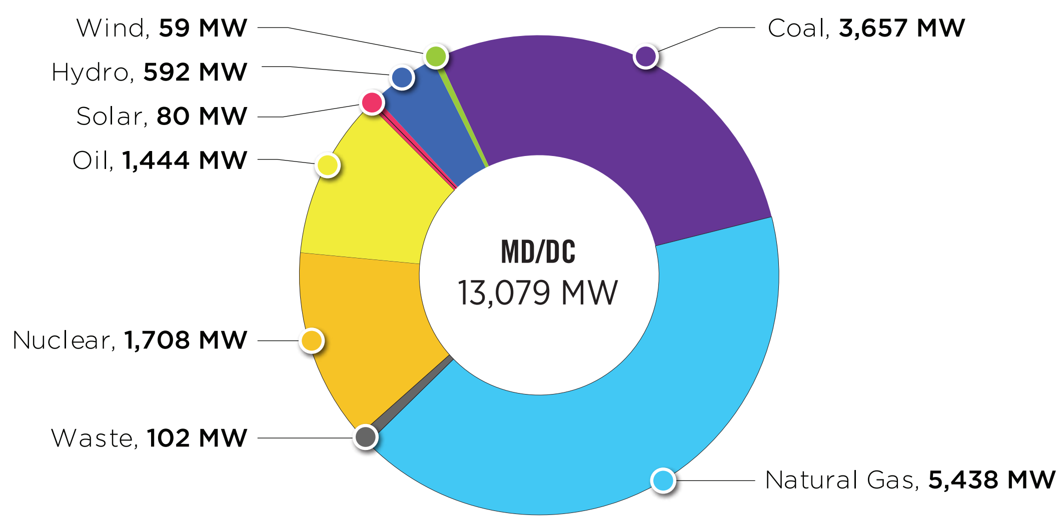
Growth Rate 0.6%

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, 2020, 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, 2020)



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, 2020, 106 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.18**, **Table 6.19**, **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 6.18: Maryland/District of Columbia – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Maryland/D.C. Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	173	6.95%	27,804	26.52%
Nuclear	37	1.51%	81	0.08%
Oil	18	0.72%	31	0.03%
Solar	1,868	75.19%	58,845	56.13%
Storage	388	15.63%	10,877	10.38%
Wind	0	0.00%	6,560	6.26%
Grand Total	**2,484**	**100.00%**	**104,838**	**100.00%**

Table 6.19: Maryland/District of Columbia – Interconnection Requests by Fuel Type (Dec. 31 2020)

		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	172.6	0	0.0	1	0.0	34	3,827.2	64	32,860.5	107	36,860.3
	Nuclear	3	37.4	0	0.0	0	0.0	1	0.0	4	4,955.0	8	4,992.4
	Oil	3	18.0	0	0.0	0	0.0	2	5.0	1	2.0	6	25.0
	Other	0	0.0	0	0.0	0	0.0	0	0.0	4	132.0	4	132.0
	Storage	14	388.2	0	0.0	0	0.0	0	0.0	35	293.2	49	681.4
Renewable	Biomass	0	0.0	0	0.0	0	0.0	0	0.0	12	227.6	12	227.6
	Hydro	0	0.0	0	0.0	0	0.0	3	60.0	4	88.4	7	148.4
	Methane	0	0.0	0	0.0	0	0.0	6	18.5	6	18.3	12	36.8
	Solar	47	1,585.1	7	72.8	22	209.8	13	42.2	172	1,021.6	261	2,931.4
	Wind	0	0.0	0	0.0	0	0.0	5	40.3	10	265.6	15	305.9
Other	Battery	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	1	0.0
	Grand Total	**76**	**2,201.3**	**7**	**72.8**	**23**	**209.8**	**66**	**4,003.2**	**313**	**39,869.2**	**485**	**46,356.2**

Figure 6.23: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

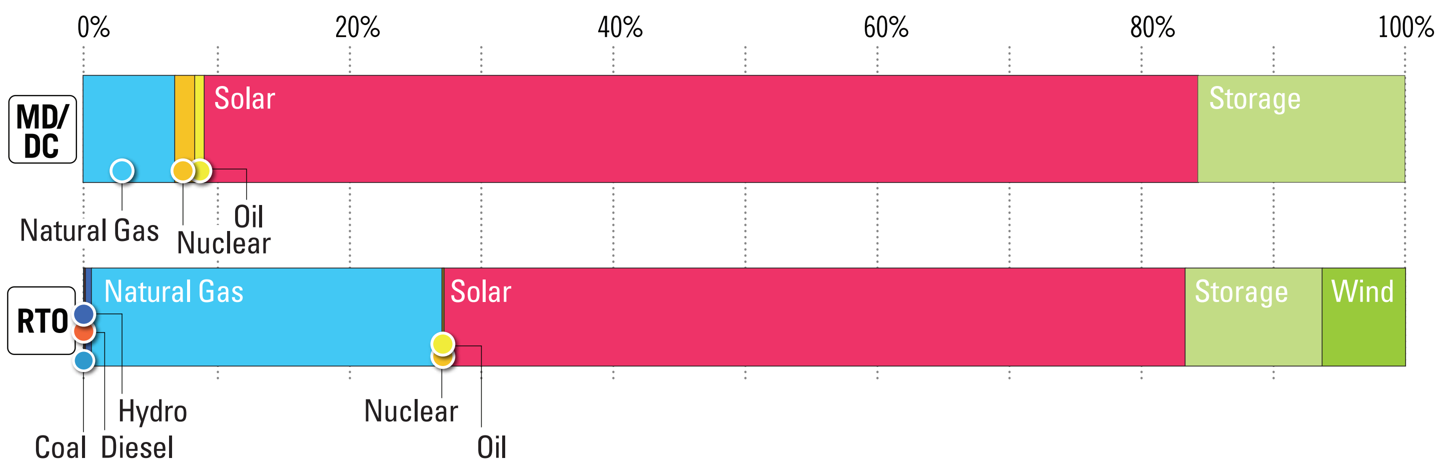
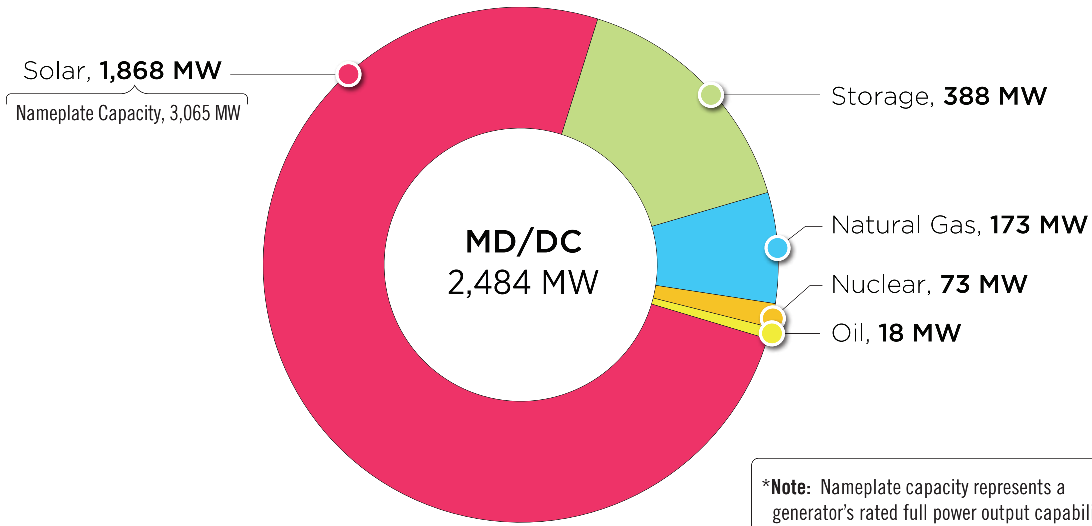
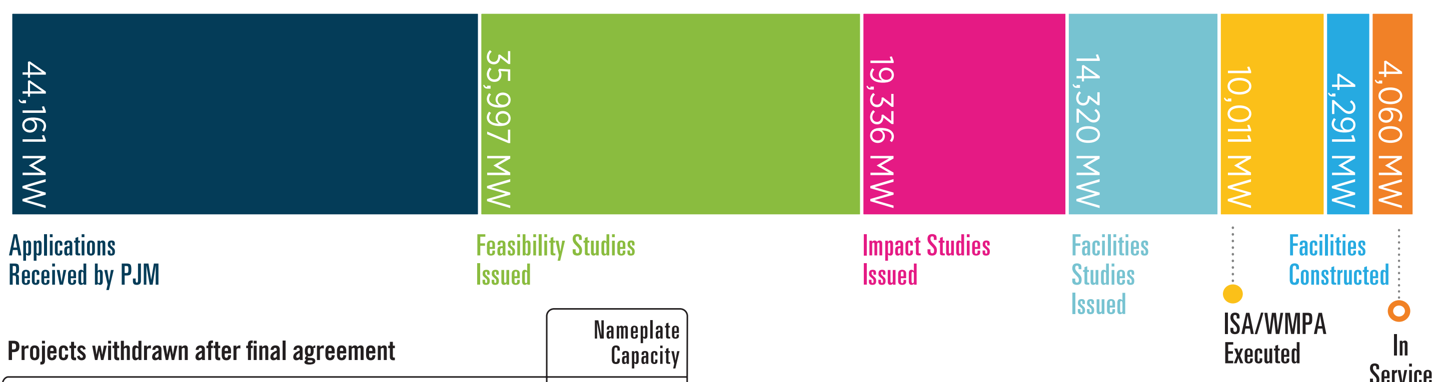


Figure 6.24: Maryland/District of Columbia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)



*__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, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
26	Interconnection Service Agreements	**5,627** MW	6,064 MW
44	Wholesale Market Participation Agreements	**93** MW	179 MW

Percentage of planned capacity and projects that have reached commercial operation	**9%** Requested capacity megawatts	**17%** Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.4.5 — Generation Deactivation

Known generating unit deactivation requests in Maryland and the District of Columbia between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.15** and **Table 6.20**.

Map 6.15: Maryland/Distirct of Columbia Generation Deactivations (Dec. 31, 2020)

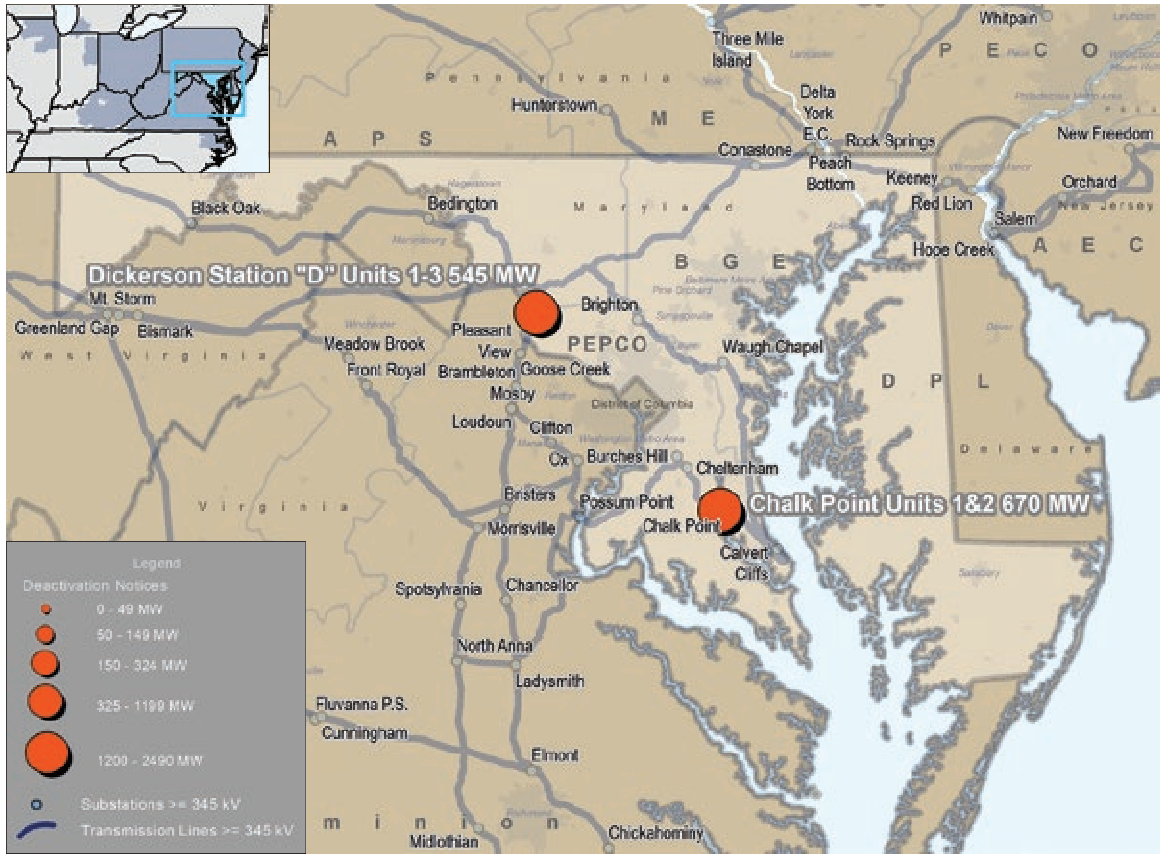


Table 6.20: Maryland/District of Columbia Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Submittal Date	Actual Deactivation Date	Age (Years)	Capacity (MW)
Dickerson Station Unit 1			5/15/2020	8/13/2020	61	182.0
Dickerson Station Unit 2			5/15/2020	8/13/2020	60	180.0
Dickerson Station Unit 3	PEPCO	Coal	5/15/2020	8/13/2020	58	180.5
Chalk Point Unit 1			8/10/2020	6/1/2021	56	333.1
Chalk Point Unit 2			8/10/2020	6/1/2021	55	337.2

6.4.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Maryland and the District of Columbia are summarized in **Map 6.16** and **Table 6.21**.

6.4.7 — Network Projects

No network projects greater than or equal to $10 million in Maryland and the District of Columbia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the [Project Status](#) page of the PJM website.

Map 6.16: Maryland/District of Columbia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

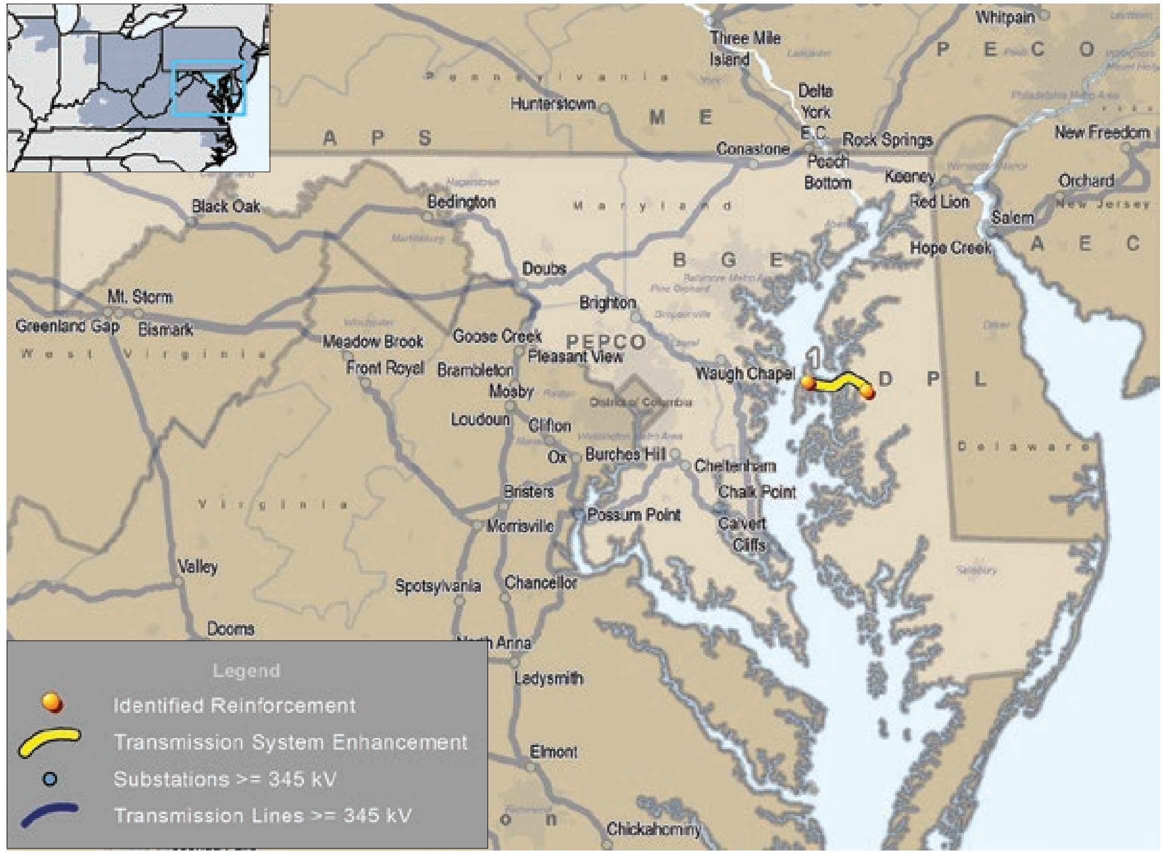


Table 6.21: Maryland/District of Columbia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3155	Rebuild ~12 miles of Wye Mills-Stevensville line to achieve needed ampacity.	12/1/2023	$15.00	DP&L	12/16/2019

6.4.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Maryland and the District of Columbia are summarized in **Map 6.17** and **Table 6.22**.

6.4.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Maryland and the District of Columbia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.17: Maryland/District of Columbia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

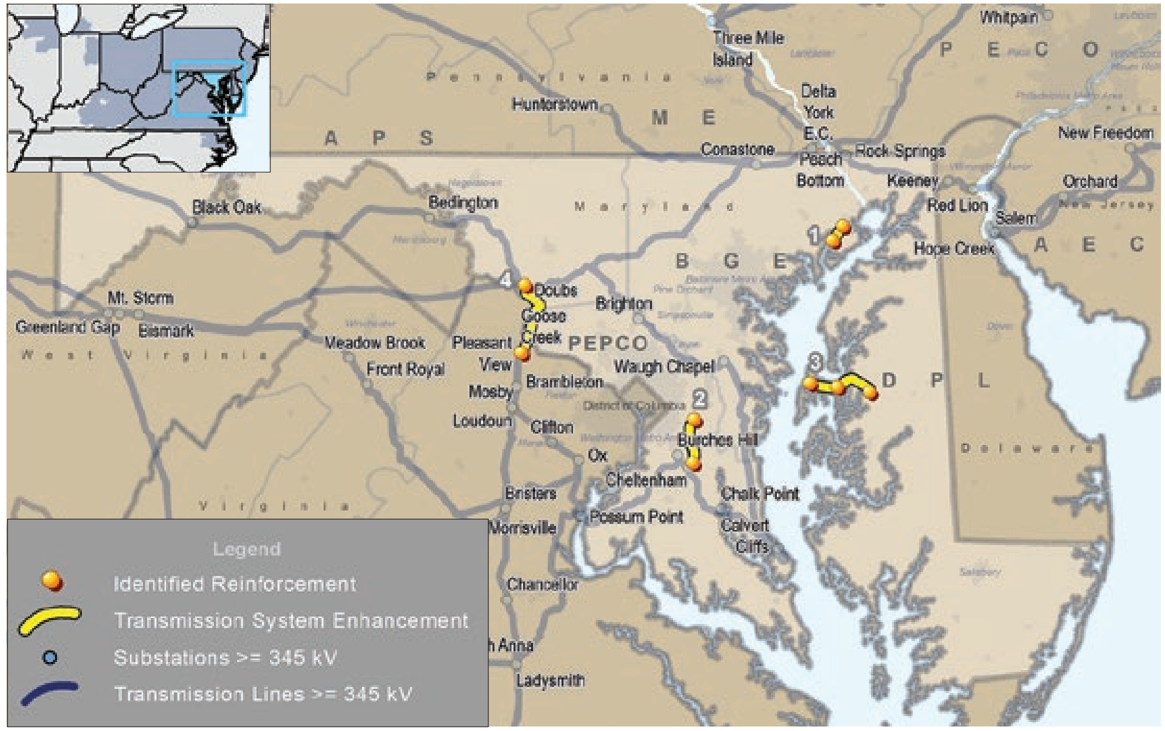


Table 6.22: Maryland/District of Columbia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2209	Rebuild two single-circuit 115 kV wood H-frame circuits (110617/110618) as one double-circuit steel-pole line.	12/31/2021	$21.40	BGE	3/20/2020
2	S2356	Rebuild 10 miles of existing Talbert-Oak Grove 230 kV double-circuit lattice tower transmission lines 23067 and 23087 with new steel monopole structures along the existing route.	12/1/2024	$38.00	PEPCO	9/1/2020
3	S2378	Construct two 69 kV substations along the existing Wye Mills to Stevensville circuit and retire existing Grasonville substation.	6/1/2023	$18.50	DP&L	10/15/2020
		Construct new five-breaker ring bus substation west of existing Grasonville substation (w/30 MVAR Capacitor Bank).				
		Construct new five-breaker ring bus substation west of existing Wye Mills substation (w/30 MVAR Capacitor Bank).				
4	S2386	Rebuild and reconductor the FE portion of the Doubs-Goose Creek 500 kV line (~14.8 miles of steel lattice tower construction) utilizing existing right-of-way. Replace breaker disconnect switches, line metering and relaying, substation conductor and breakers at Doubs 500 kV station.	6/1/2025	$60.00	AP	10/6/2020

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 6.18**. 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

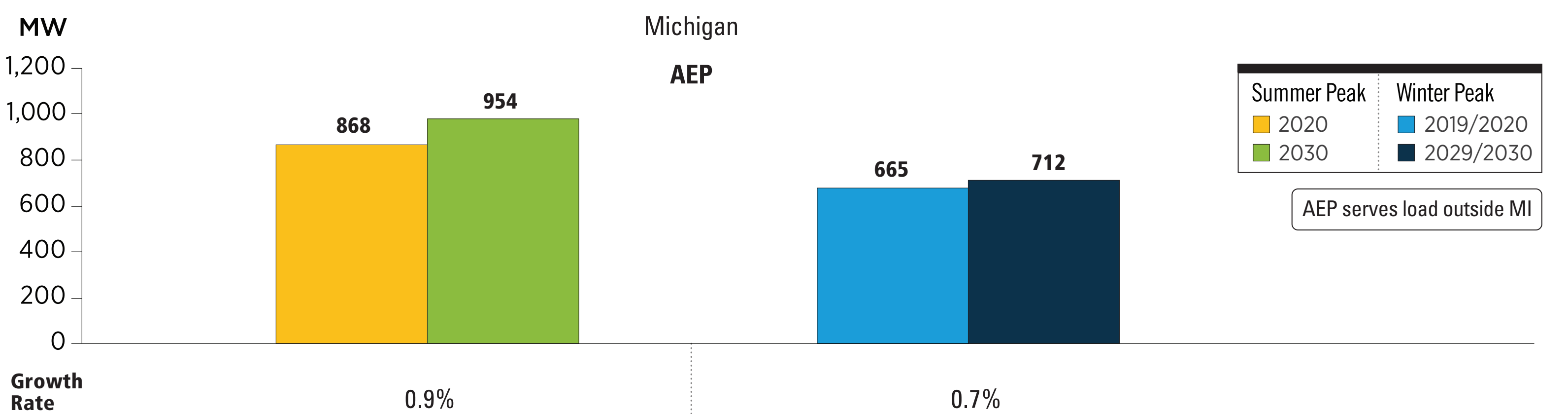
From an energy policy perspective, Michigan has a renewable portfolio standard (RPS) to advance renewable generation. Many states have instituted goals with respect to the percentage of generation expected to be fueled by renewable fuels in coming years. Michigan has a mandatory RPS target of 15 percent by 2021.

Map 6.18: PJM Service Area in Southwestern Michigan

6.5.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.26** summarizes the expected loads within the state of Michigan and across all of PJM.

Figure 6.26: Southwestern Michigan – 2020 Load Forecast Report



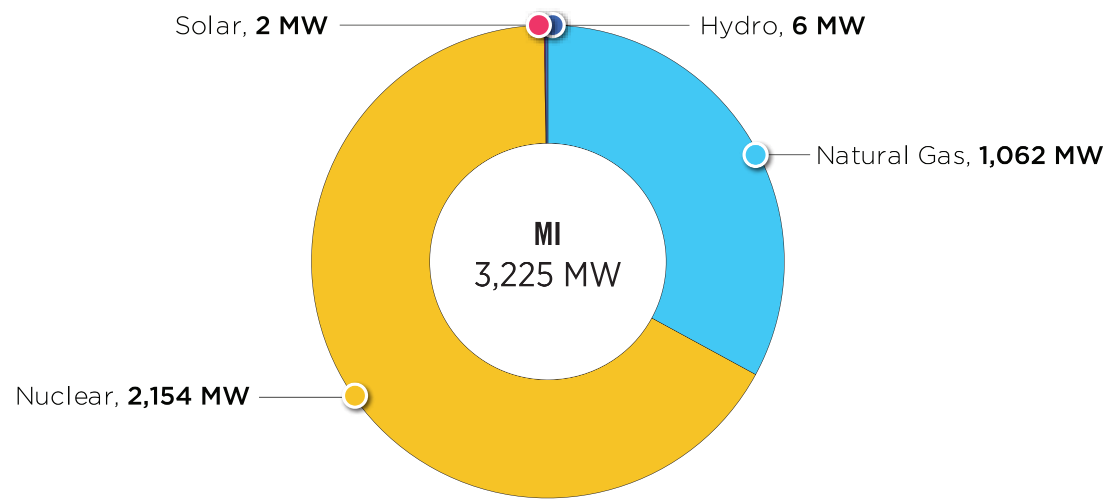
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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, 2020, is shown by fuel type in **Figure 6.27**.

Figure 6.27: Southwestern Michigan – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 13 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.23**, **Table 6.24**, **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 6.23: Southwestern Michigan – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Southwestern Michigan Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	1,230	61.62%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	685	34.30%	58,845	56.13%
Storage	81	4.07%	10,877	10.38%
Wind	0	0.00%	6,560	6.26%
Grand Total	**1,996**	**100.00%**	**104,838**	**100.00%**

Table 6.24: Southwestern Michigan – Interconnection Requests by Fuel Type (Dec. 31 2020)

		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	1	0.0	1	0.0
	Storage	3	81.3	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	7	684.8	0	0.0	1	2.3	4	237.8	12	924.8
	Wind	0	0.0	0	0.0	0	0	1	26.0	1	26.0
	Grand Total	11	911.1	2	1,085.0	9	1,272.7	8	1,458.8	30	4,727.5

Figure 6.28: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

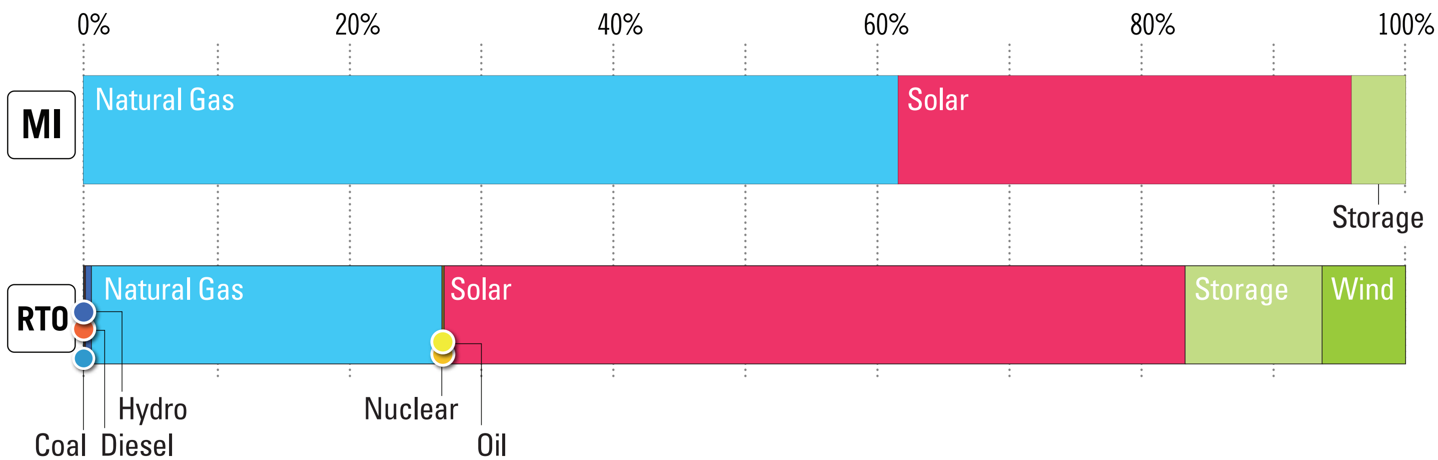


Figure 6.29: Southwestern Michigan – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

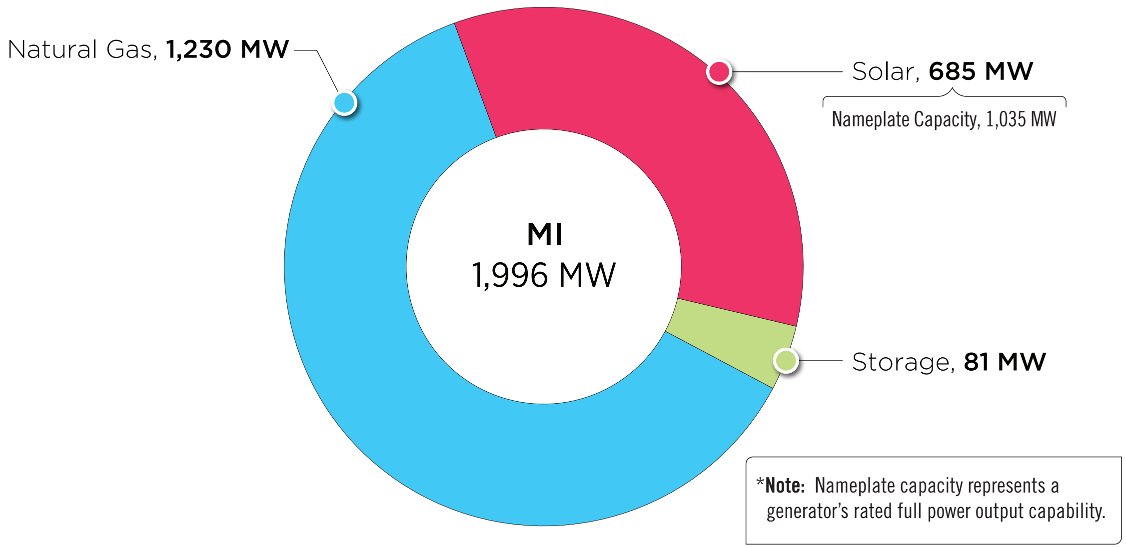
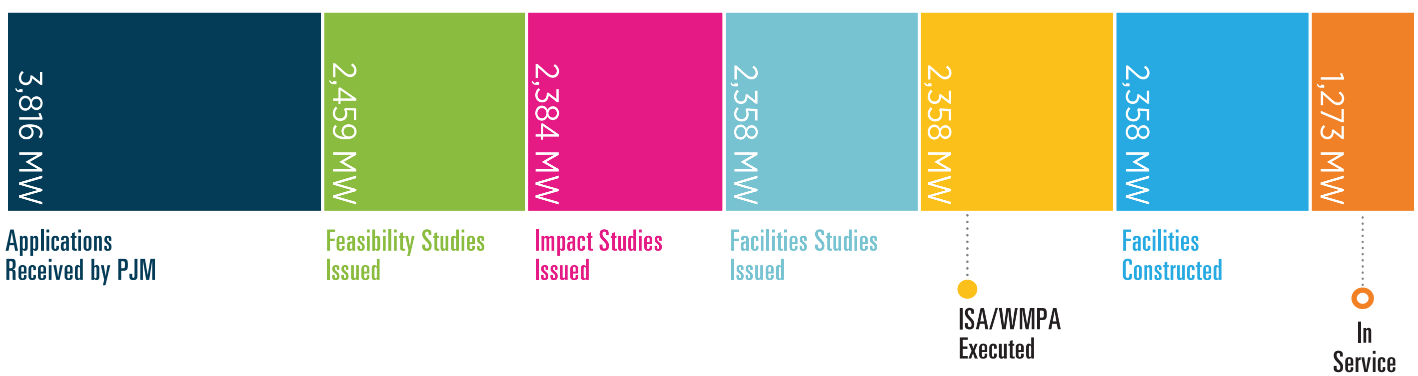


Figure 6.30: Southwestern Michigan Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Percentage of planned capacity and projects that have reached commercial operation	33% Requested capacity megawatts	47 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.5.5 — Generation Deactivations

There were no known generating unit deactivation requests in Southwestern Michigan between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.5.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Southwestern Michigan are summarized in **Map 6.19** and **Table 6.25**.

6.5.7 — Network Projects

No network projects greater than or equal to $10 million in Southwestern Michigan were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.19: Southwestern Michigan Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

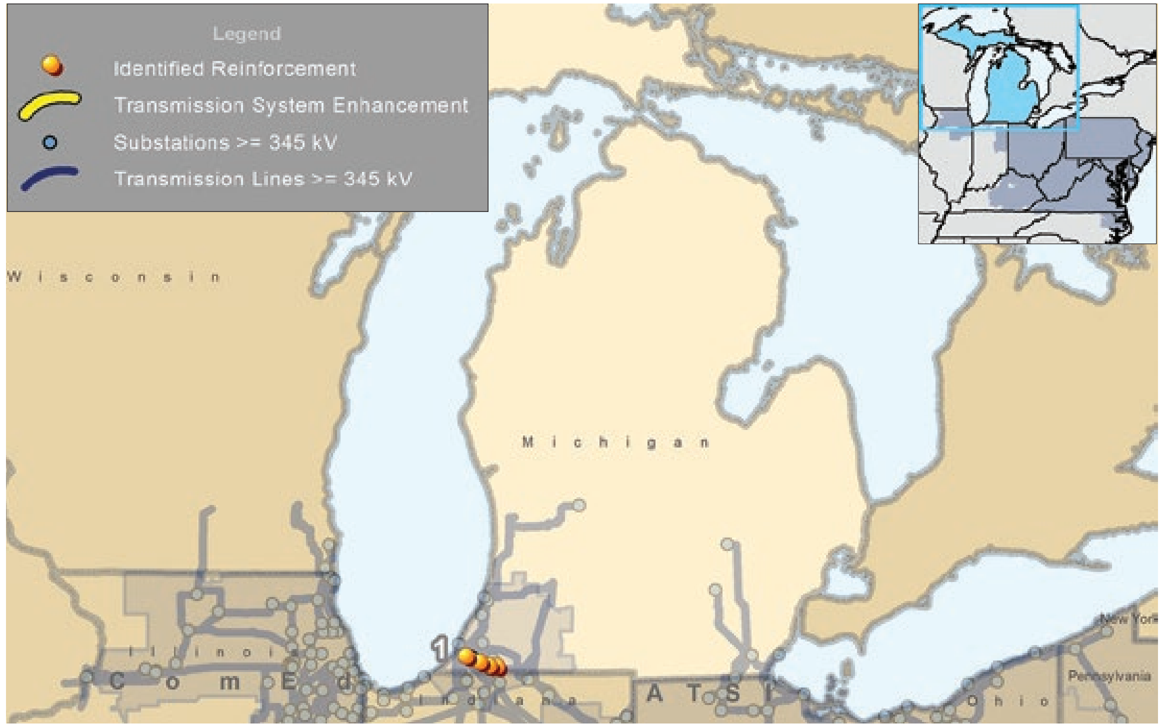


Table 6.25: Southwestern Michigan Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3160	Construct a ~2.4 mile double-circuit 138 kV extension using 1033 ACSR to connect Lake Head to the 138 kV network.	6/1/2024	$36.20	AEP	12/7/2019
		Retire the ~2.5 mile 34.5 kV Niles-Simplicity tap line.				
		Retire the ~4.6 mile Lakehead 69 kV tap.				
		Build a new 138/69 kV drop down station to feed Lakehead with a 138 kV breaker, 138 kV switcher, 138/69 kV transformer and a 138 kV MOAB.				
		Rebuild the ~1.2 mile Buchanan South 69 kV radial tap using 795 ACSR.				
		Rebuild the ~8.4 mile 69 kV Pletcher-Buchanan Hydro line as the ~9 mile Pletcher-Buchanan South 69 kV line using 795 ACSR.				
		Install a phase-over-phase switch at Buchanan South station with two-line MOABs.				

6.5.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Southwestern Michigan are summarized in **Map 6.20** and **Table 6.26**.

6.5.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Southwestern Michigan were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.20: Southwestern Michigan Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

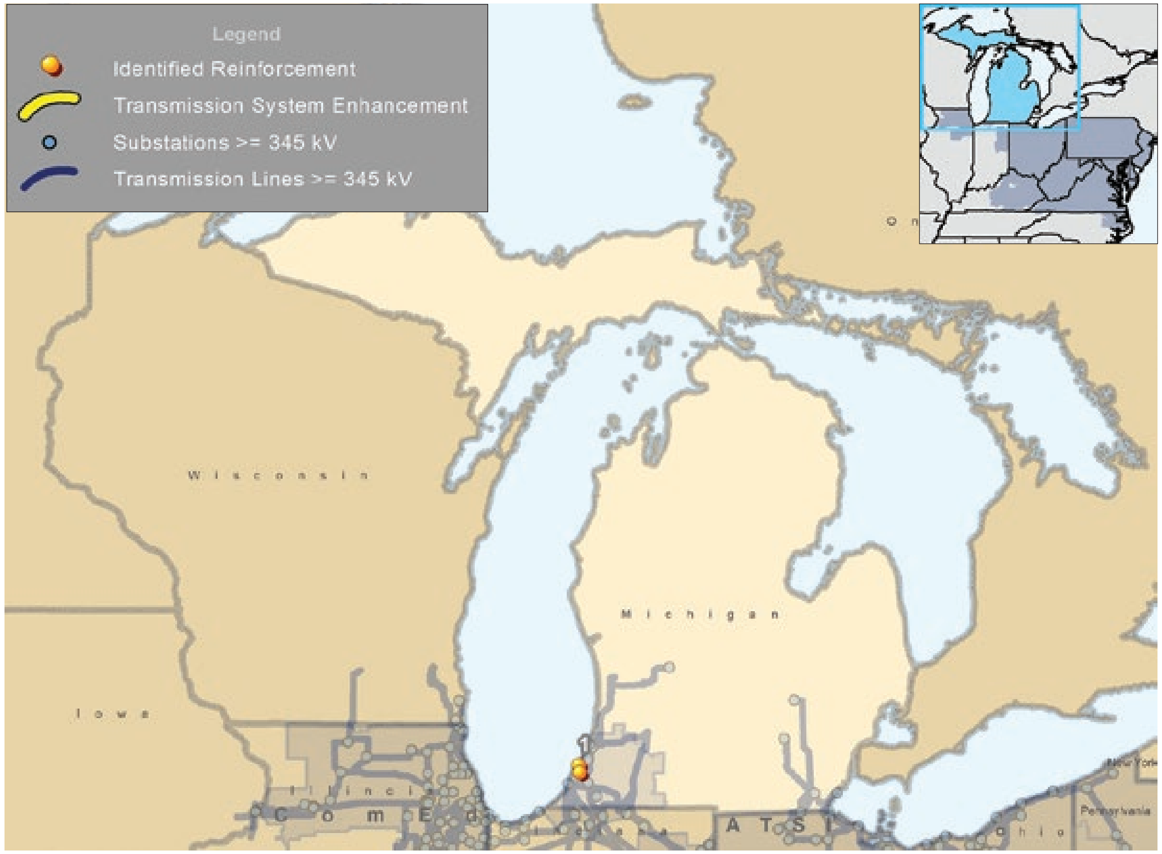


Table 6.26: Southwestern Michigan Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2345	Main St.-Riverside 34.5 kV line: Rebuild on center line ~4.1 miles of Main St.-Riverside 34.5 kV line with DOVE 556.5 ACSR 26/7.	2/14/2024	$16.60	AEP	7/17/2020
		Riverside Station: Replace two 138 kV breakers and two 34.5 kV breakers at Riverside. While at the station and taking advantage of the outage, AEP will install a new 34.5 kV breaker to bring Whirlpool customer, whose delivery point is currently one tower outside of the station, into Riverside station. Install high-side circuit switcher to 138/69/34.5 kV transformer.				

6.6: New Jersey RTEP Summary

6.6.1 — RTEP Context

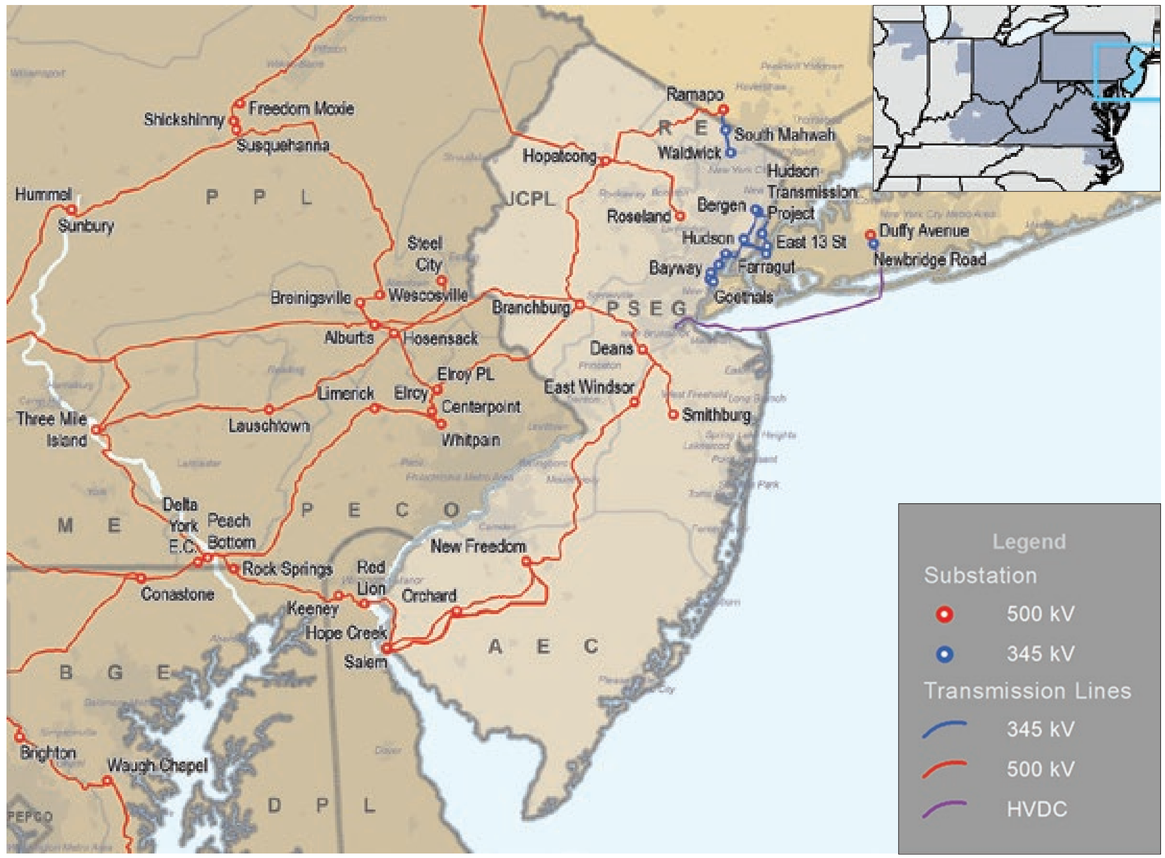
PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in New Jersey, including facilities owned and operated by Atlantic City Electric Co. (AE), Jersey Central Power & Light (JCP&L), Linden VFT (VFT), Neptune Regional Transmission System (Neptune RTS), PSEG and Rockland Electric Co. (RECO), as shown on **Map 6.21**. 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 percent Class I renewable resources by 2030. The state also requires 2.5 percent Class II renewable resources each year. The RPS contains a solar carve-out that peaks at 5.1 percent in 2023 and declines each year thereafter.

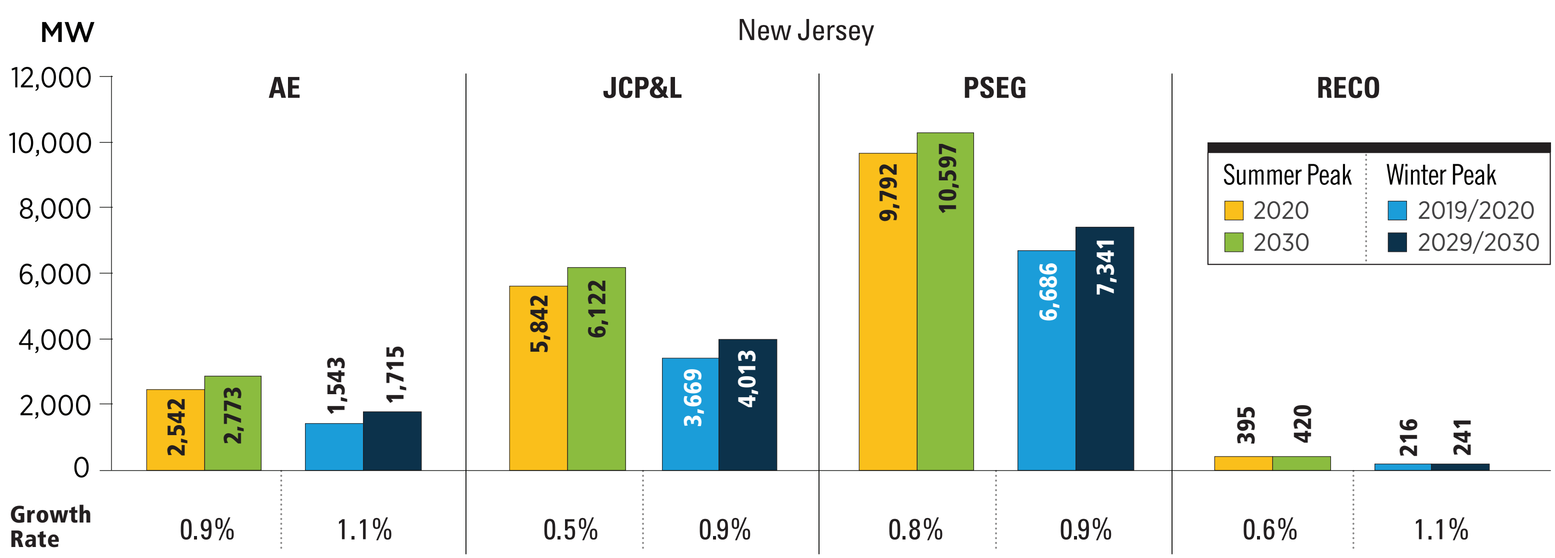
Map 6.21: PJM Service Area in New Jersey



6.6.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.31** summarizes the expected loads within the state of New Jersey and across all of PJM.

Figure 6.31: New Jersey – 2020 Load Forecast Report



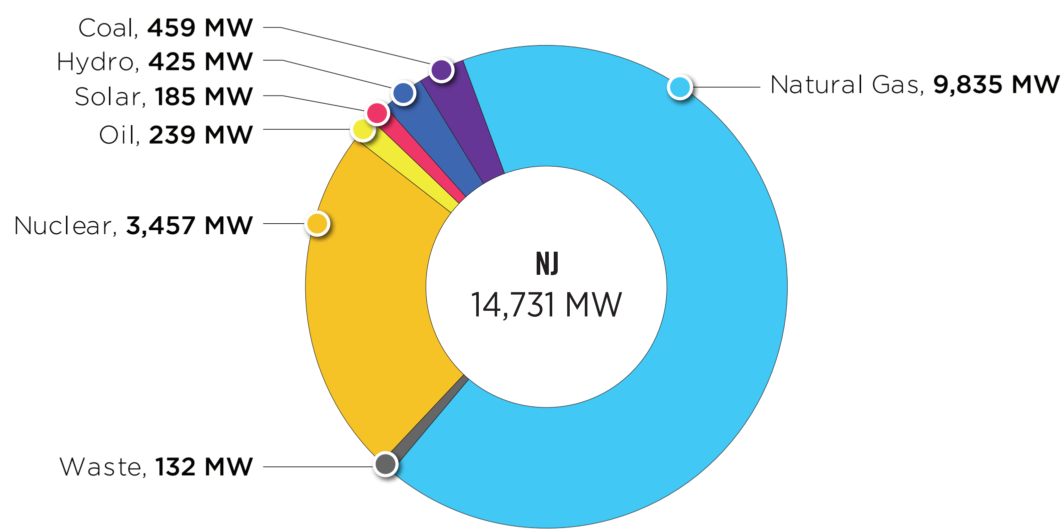
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW

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

6.6.3 — Existing Generation

Existing generation in New Jersey as of Dec. 31, 2020, is shown by fuel type in **Figure 6.32**.

Figure 6.32: New Jersey – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 135 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.27**, **Table 6.28**, **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 6.27: New Jersey – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	New Jersey Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	1,178	21.69%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	724	13.35%	58,845	56.13%
Storage	1,283	23.64%	10,877	10.38%
Wind	2,243	41.32%	6,560	6.26%
Grand Total	**5,428**	**100.00%**	**104,838**	**100.00%**

Table 6.28: New Jersey – Interconnection Requests by Fuel Type (Dec. 31 2020)

		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	6	372.3	2	746.0	2	59.2	80	8,017.9	179	51,724.3	269	60,919.7
	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	39	1,283.2	4	0.0	3	0.0	6	4.0	44	214.0	96	1,501.1
Renewable	Biomass	0	0	0	0.0	0	0.0	0	0.0	3	17.3	3	17.3
	Hydro	0	0	0	0.0	0	0.0	2	20.5	2	1,001.1	4	1,021.6
	Methane	0	0	0	0.0	0	0.0	16	45.3	9	40.6	25	85.9
	Solar	46	692.6	1	4.1	19	27.7	114	248.2	480	1,609.6	660	2,582.3
	Wind	13	2,242.9	0	0	0	0.0	1	0.0	20	683.3	34	2,926.2
	Grand Total	104	4,590.9	7	750.1	24	86.9	227	8,751.9	753	56,295.8	1,115	70,475.6

Figure 6.33: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

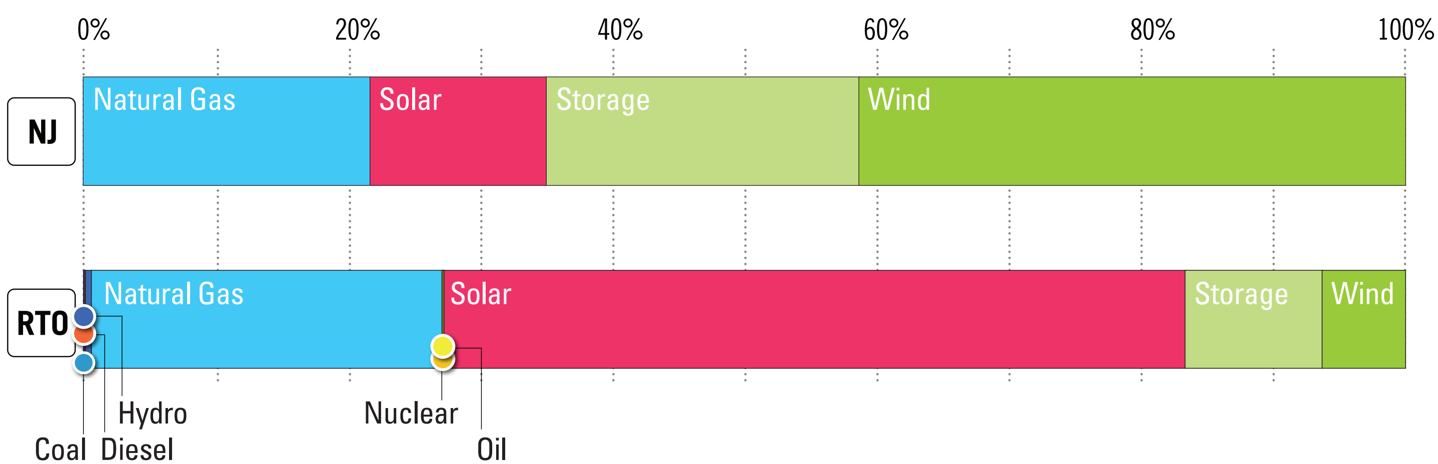


Figure 6.34: New Jersey – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

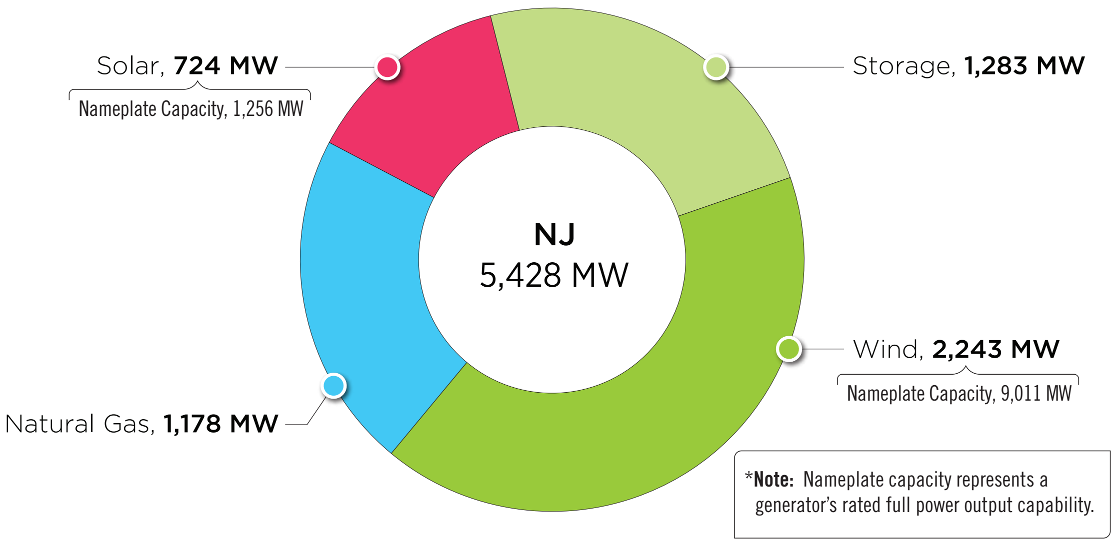
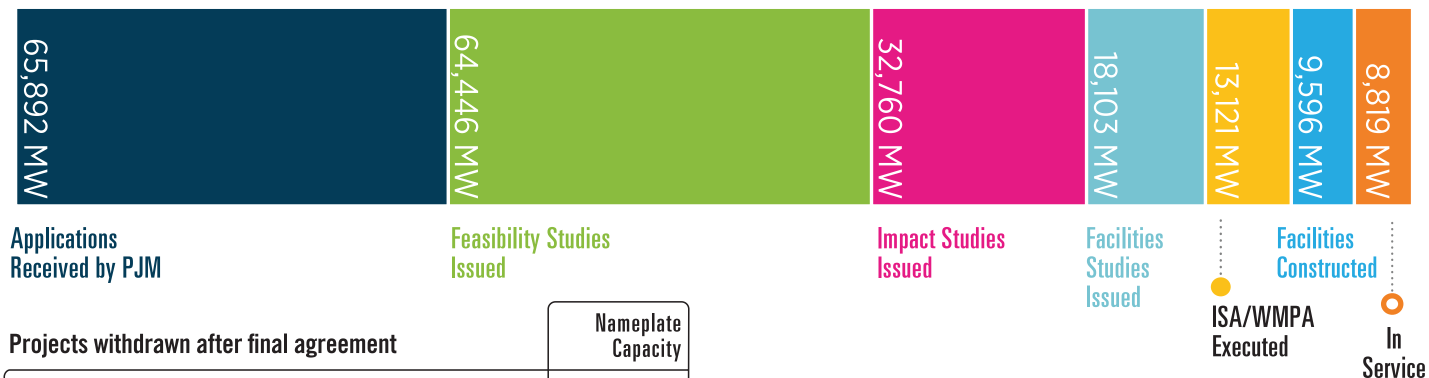


Figure 6.35: New Jersey Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement			Nameplate Capacity
24	Interconnection Service Agreements	2,595 MW	3,067 MW
146	Wholesale Market Participation Agreements	376 MW	1,073 MW

Percentage of planned capacity and projects that have reached commercial operation	13% Requested capacity megawatts	24% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.6.5 — Generation Deactivation

Known generating unit deactivation requests in New Jersey between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.22** and **Table 6.29**.

Map 6.22: New Jersey Generation Deactivations (Dec. 31, 2020)

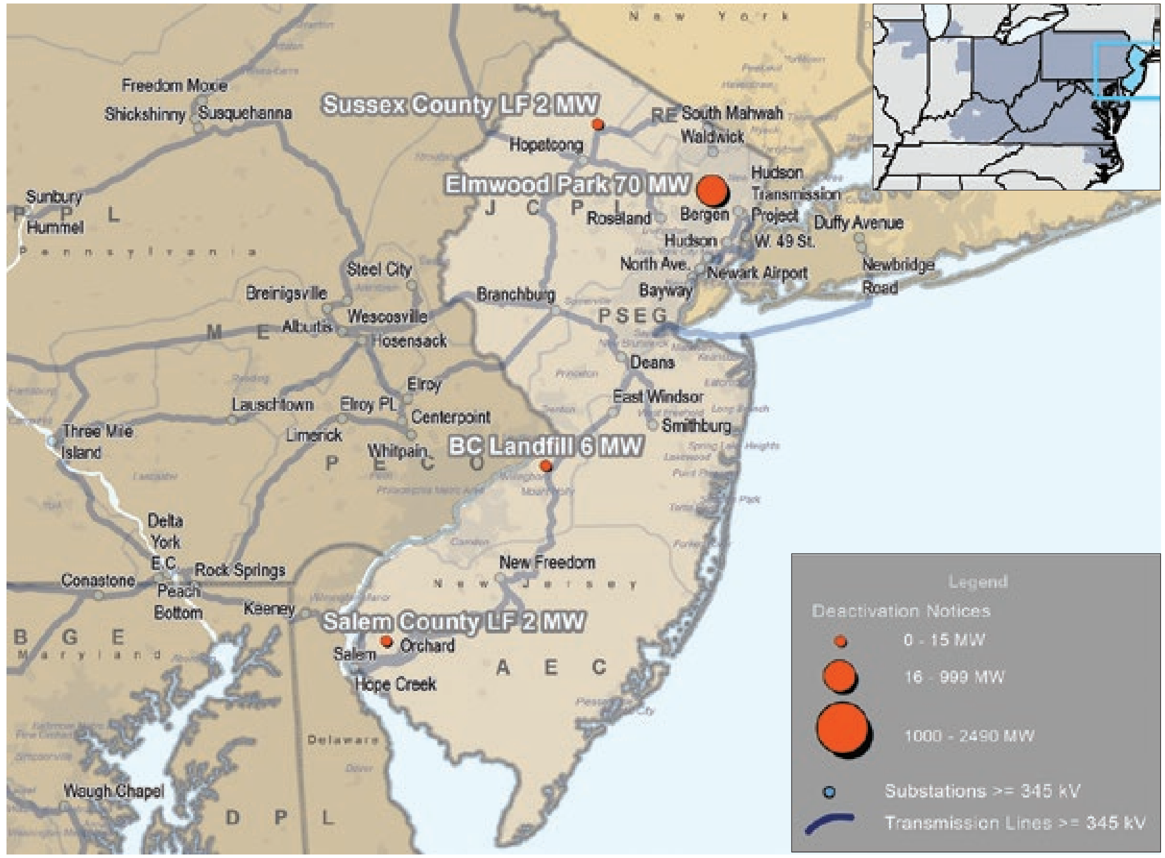


Table 6.29: New Jersey Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
BC Landfill	PSEG	Methane	1/27/2020	6/1/2020	13	6.00
Salem County LF	AE	Methane	1/27/2020	6/1/2020	12	1.70
Sussex County LF	JCP&L	Methane	1/27/2020	6/1/2020	9	2.00
Elmwood Park	PSEG	Natural Gas	12/8/2020	3/12/2021	31	70.30

6.6.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in New Jersey were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.6.7 — Network Projects

No network projects greater than or equal to $10 million in New Jersey were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.6.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in New Jersey are summarized in **Map 6.23** and **Table 6.30**.

Map 6.23: New Jersey Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

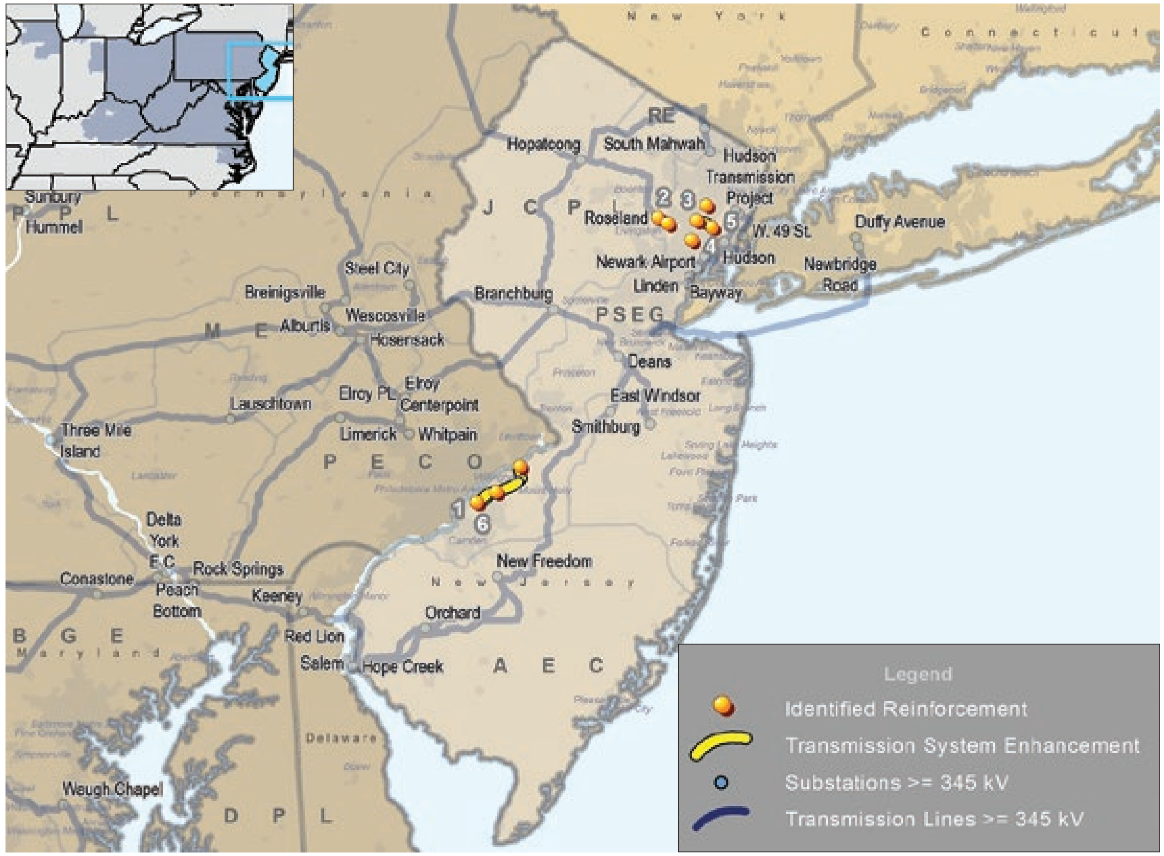


Table 6.30: New Jersey Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2276	Install a new 230/13 kV station (Rancocas) on existing right-of-way with two 230/13kV transformers. Cut and loop the Camden-Burlington 230 kV line in to the 230 kV bus.	5/31/2024	$39.00	PSEG	6/2/2020
2	S2316	Install Livingston 230 kV station with two 230/13 kV transformers. Cut and loop the Roseland-Laurel Ave 230 kV line into the 230 kV bus. Transfer load from heavily loaded Marion Drive and West Caldwell to the new station.	12/31/2024	$29.80		8/4/2020

Table 6.30: New Jersey Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
3	S2317	Construct a new Oak St. 69/13 kV station in Southern Passaic County Area and retire the Oak St. 26 kV station.	9/30/2024	$75.60	PSEG	8/13/2020
		Purchase property to accommodate the new Oak St. 69/13 kV construction.				
		Install Oak St. 69 kV station with two 69/13 kV transformers.				
		Loop in the existing Kuller Rd.-Passaic 69 kV to the new Oak St. and build a new 69 kV line from Harvey to Oak St.				
4	S2318	Construct a new Central Ave. 69/4 kV station in Western Newark area.	5/31/2024	$34.30		
		Purchase property to accommodate the new Central Ave. 69/4 kV station construction.				
		Install a Central Ave. 69 kV station with four 69/4 kV transformers.				
		Loop in the existing McCarter-Clay Street and McCarter-Orange Heights 69 kV circuits to the new Central Ave. 69 kV station.				
5	S2384	Construct new 230-13 kV station along the existing right-of-way at Washington Ave. Cut and loop the Cook Rd.-Kingsland 230 kV line into the new 230 kV bus (Washington Ave.), and Install a 230 kV bus station with two 230/13 kV transformers. Transfer load from heavily loaded Cook Rd. to the new station.		$31.20		10/6/2020
6	S2385	Construct new 230-13 kV station along the existing right-of-way in Pennsauken. Cut and loop the Camden-Cinnaminson 230 kV line into the new 230 kV bus (Pennsauken), and install a 230 kV station with two 230/13 kV transformers. Transfer load from heavily loaded Cuthbert Blvd. to the new station.		$48.60		

6.6.9 — Merchant Transmission Project Requests

As of Dec. 31, 2020, PJM's queue contained five merchant transmission project requests, which include a terminal in New Jersey as shown in **Map 6.24** and **Table 6.31**.

Map 6.24: New Jersey Merchant Transmission Project Requests (Dec. 31, 2020)

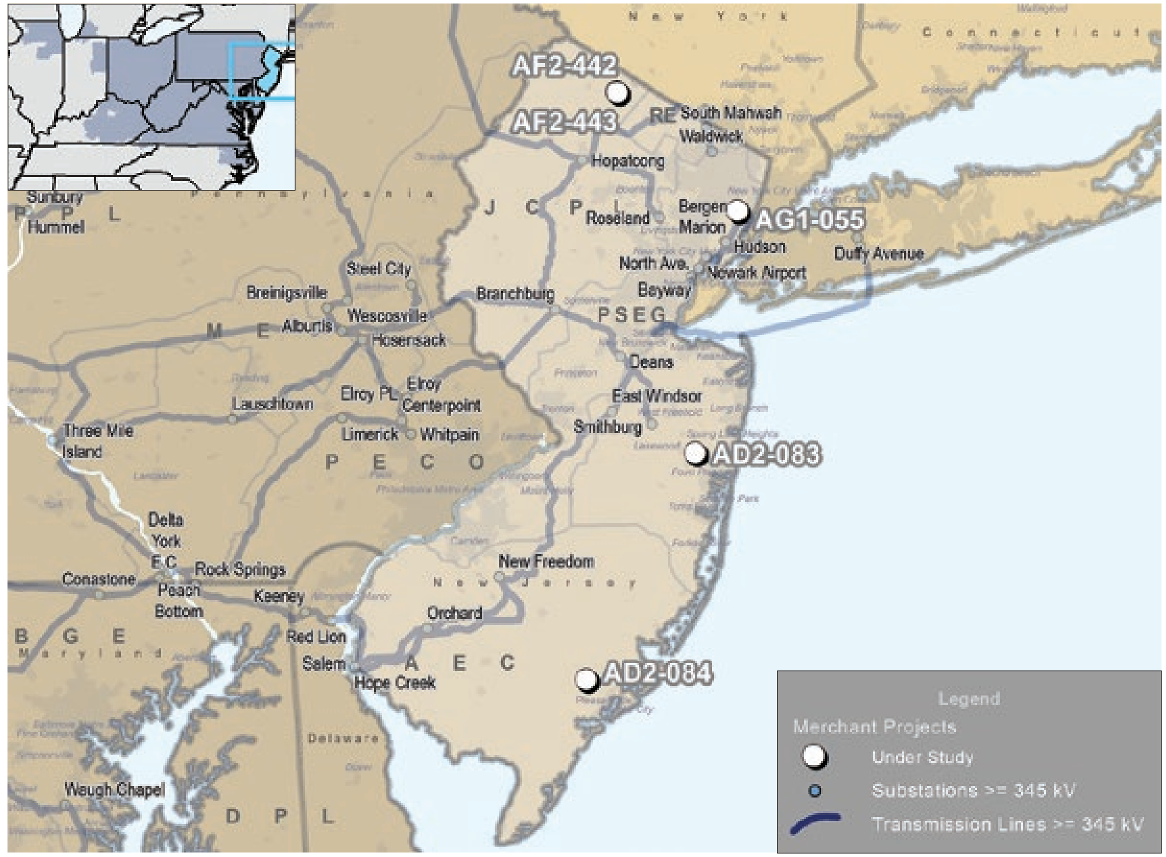


Table 6.31: New Jersey Merchant Transmission Project Requests (Dec. 31, 2020)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
AD2-083	Larrabee 230 kV	JCP&L	Active	12/31/2025	1,100
AD2-084	Cardiff 230 kV	AE	Active		1,100
AF2-442	Vernon 115 kV	JCP&L	Active	5/31/2023	84
AF2-443	Vernon 115 kV		Active		84
AG1-055	Bergen 230 kV	PSEG	Active	6/1/2022	660

6.7: North Carolina RTEP Summary

6.7.1 — RTEP Context

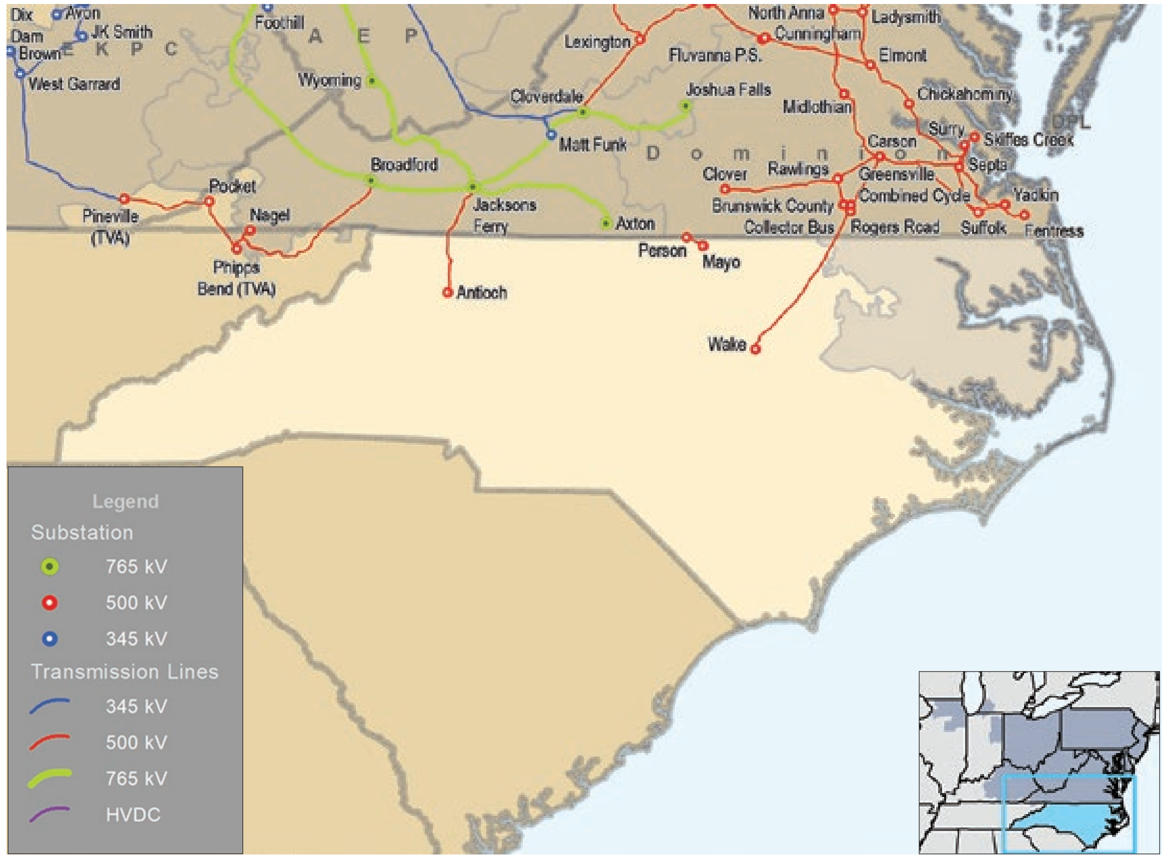
PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in North Carolina, including facilities owned and operated by Dominion as shown on **Map 6.25**. North Carolina's transmission system delivers power to customers from native generation resources in the region and throughout 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 percent for investor-owned utilities by 2021. The target is 10 percent for the state's electric cooperatives and municipalities.

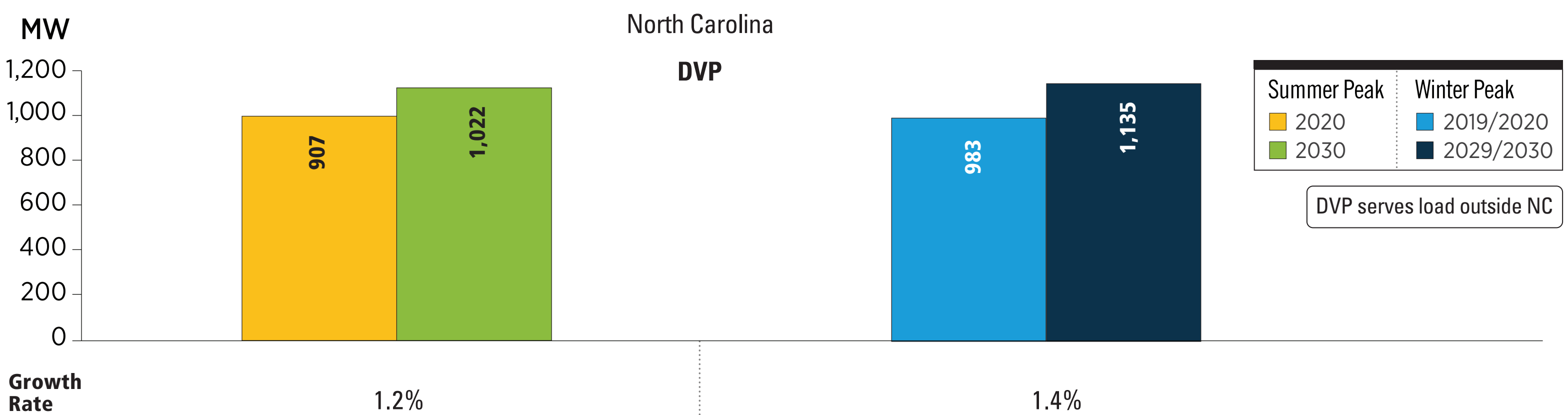
Map 6.25: PJM Service Area in North Carolina



6.7.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.36** summarizes the expected loads within the state of North Carolina and across all of PJM.

Figure 6.36: North Carolina – 2020 Load Forecast Report



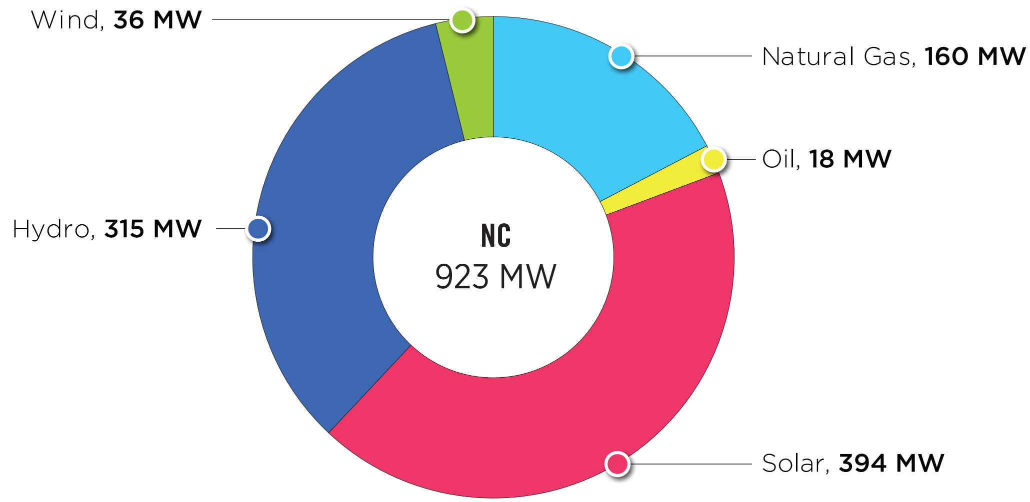
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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, 2020, is shown by fuel type in **Figure 6.37**.

Figure 6.37: North Carolina – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 64 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.32**, **Table 6.33**, **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 6.32: North Carolina – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2020)

	North Carolina Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	0	0.00%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	3,379	89.25%	58,845	56.13%
Storage	368	9.72%	10,877	10.38%
Wind	39	1.03%	6,560	6.26%
Grand Total	**3,786**	**100.00%**	**104,838**	**100.00%**

Table 6.33: North Carolina – Interconnection Requests by Fuel Type (Dec. 31, 2020)

		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	6	368.0	0	0.0	0	0.0	0	0.0	5	130.5	11	498.5
Renewable	Methane	0	0.0	0	0.0	0	0.0	0	0.0	1	12.0	1	12.0
	Solar	44	2,905.1	2	87.5	11	386.8	17	465.1	83	3,166.5	157	7,011.0
	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	50	3,273.1	3	126.5	11	386.8	19	542.1	99	3,584.3	182	7,912.7

Figure 6.38: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

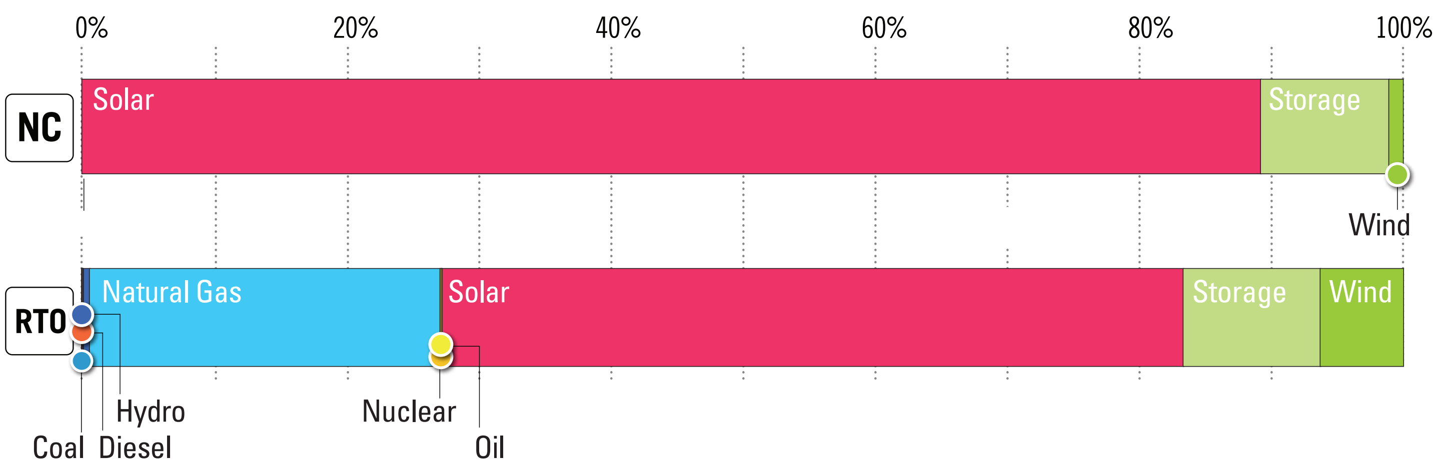
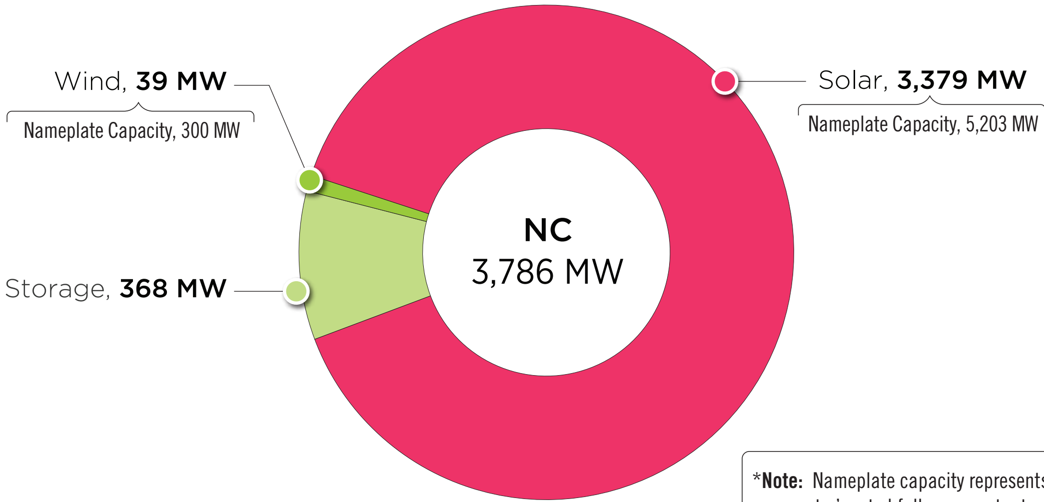
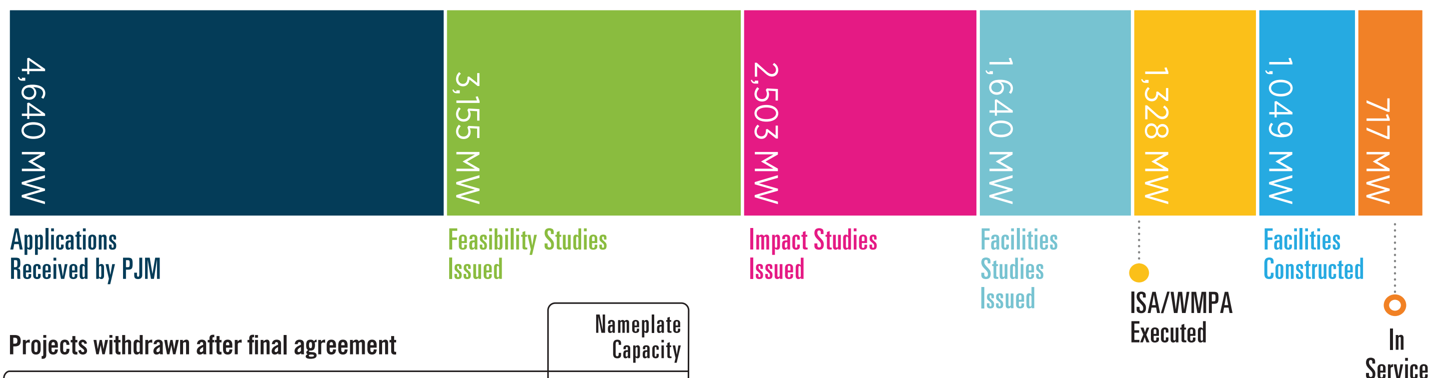


Figure 6.39: North Carolina – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)



*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, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
7	Interconnection Service Agreements	235 MW	744 MW
4	Wholesale Market Participation Agreements	38 MW	55 MW

Percentage of planned capacity and projects that have reached commercial operation	15% Requested capacity megawatts	17 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.7.5 — Generation Deactivation

There were no known generating unit deactivation requests in North Carolina between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.7.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in North Carolina were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.7.7 — Supplemental Projects

No supplemental projects greater than or equal to $10 million in North Carolina were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.7.8 — Network Projects

No network projects greater than or equal to $10 million in North Carolina were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.7.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in North Carolina were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.8: Ohio RTEP Summary

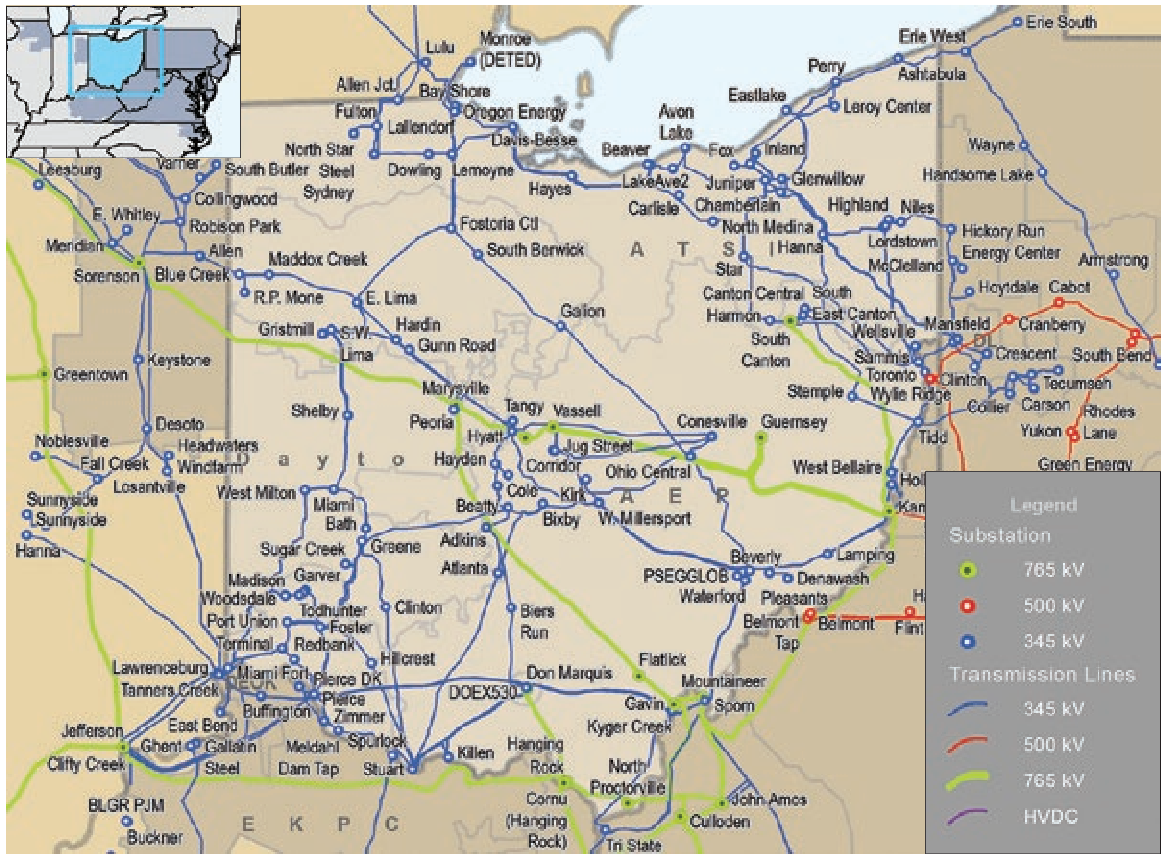
6.8.1 — RTEP Context

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), Dayton Power & Light Co. (DAY), American Transmission Systems, Inc. (ATSI), Duke Energy Corp. (DEO&K), the City of Cleveland and the City of Hamilton as shown on **Map 6.26**. 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 percent by 2026.

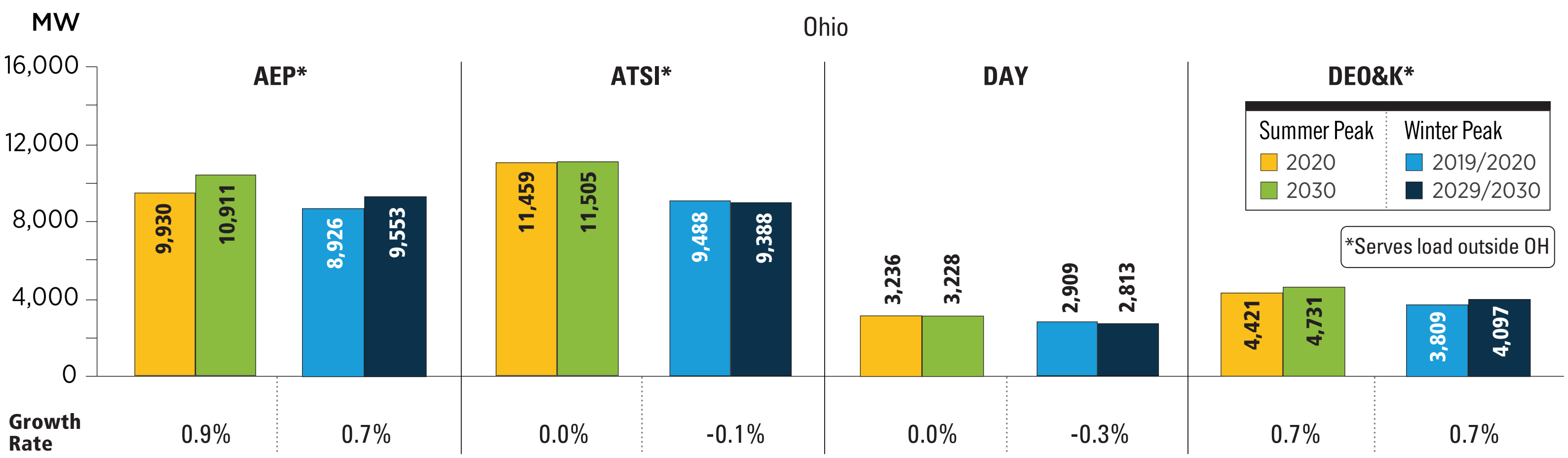
Map 6.26: PJM Service Area in Ohio



6.8.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.41** summarizes the expected loads within the state of Ohio and across all of PJM.

Figure 6.41: Ohio – 2020 Load Forecast Report



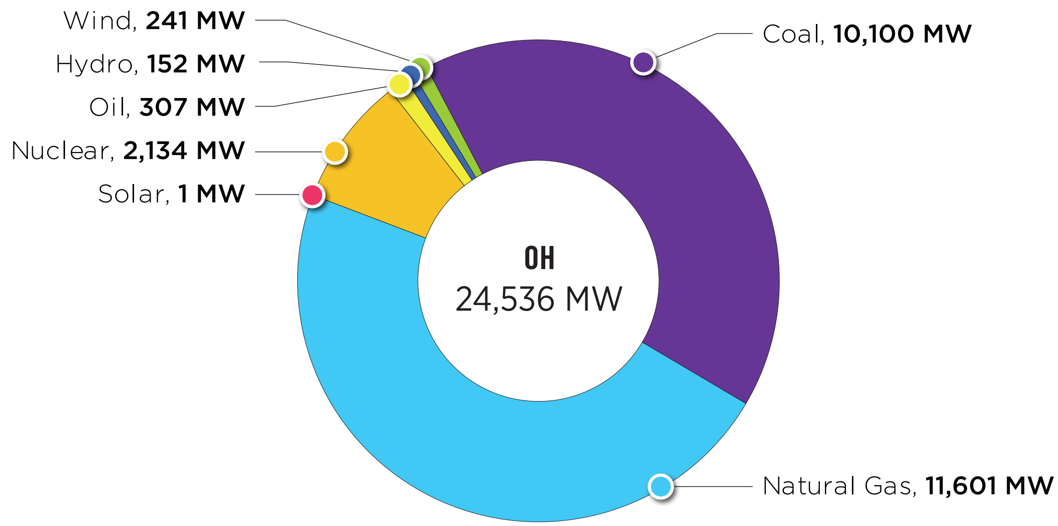
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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, 2020, is shown by fuel type in **Figure 6.42**.

Figure 6.42: Ohio – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 239 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.34**, **Table 6.35**, **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 6.34: Ohio – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2020)

	Ohio Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	40	0.20%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	7,413	36.33%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	6	0.03%	31	0.03%
Solar	11,232	55.04%	58,845	56.13%
Storage	1,417	6.95%	10,877	10.38%
Wind	300	1.47%	6,560	6.26%
Grand Total	20,407	100.00%	104,838	100.00%

Table 6.35: Ohio – Interconnection Requests by Fuel Type (Dec. 31, 2020)

		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	11	2,250.6	2	1,710.0	6	3,452.3	27	3,926.9	33	13,134.4	79	24,474.2
	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	0	0.0	0	0.0	0	0.0	0	0.0	2	135.0	2	135.0
	Storage	22	1,417.4	0	0.0	0	0.0	6	0.0	24	756.2	52	2,173.7
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	167	10,640.1	2	209.0	13	382.5	1	1.0	119	3,655.6	302	14,888.1
	Wind	6	176.3	2	26.0	3	97.2	7	164.9	70	1,773.1	88	2,237.5
	Grand Total	207	14,495.5	6	1,945.0	26	3,966.5	64	4,507.6	285	28,669.6	588	53,584.2

Figure 6.43: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

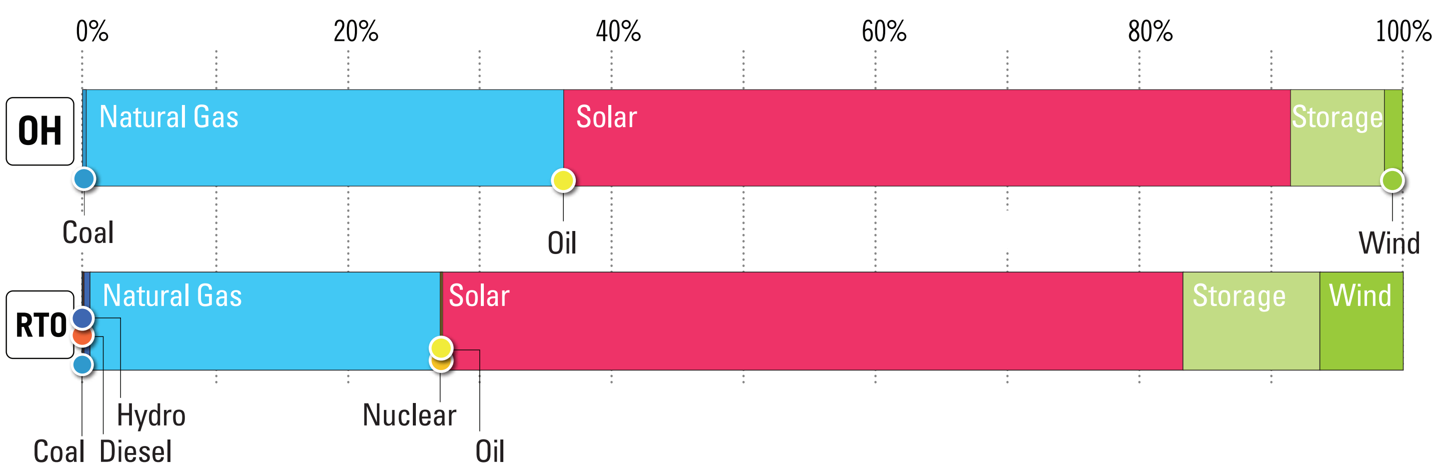


Figure 6.44: Ohio – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)

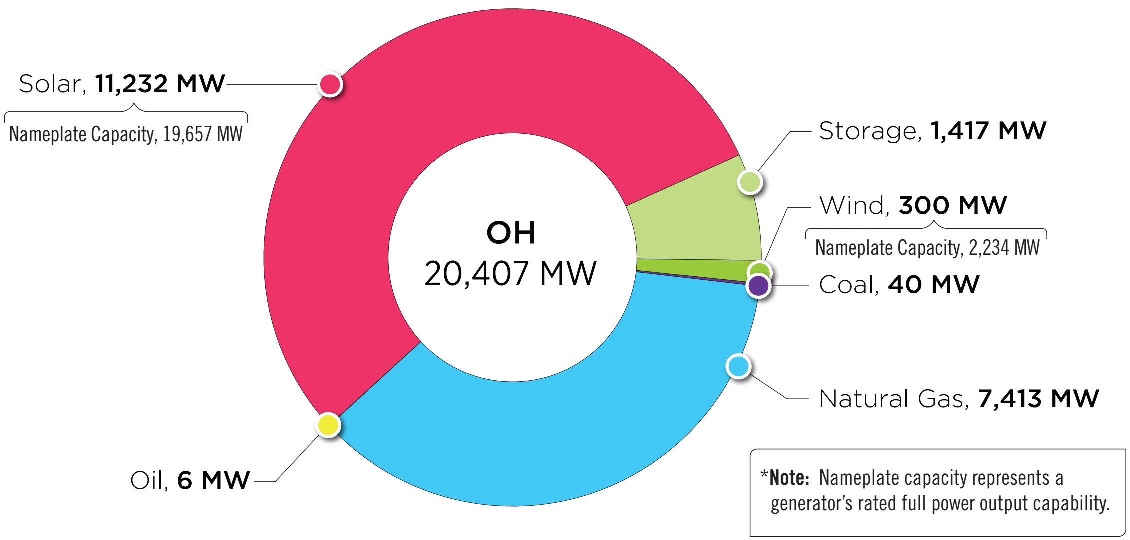
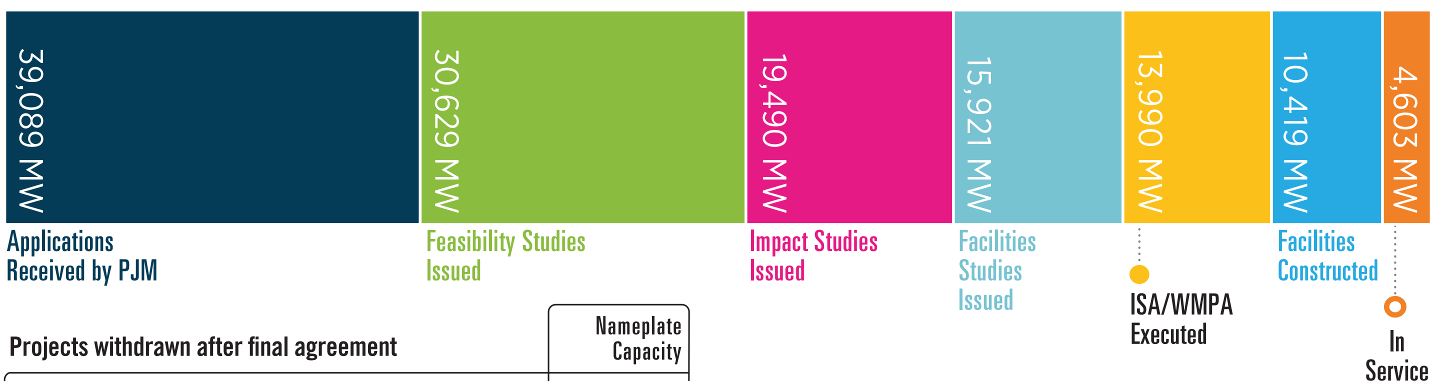


Figure 6.45: Ohio Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement			Nameplate Capacity
22	Interconnection Service Agreements	3,557 MW	5,399 MW
12	Wholesale Market Participation Agreements	22 MW	82 MW

Percentage of planned capacity and projects that have reached commercial operation		
	12% Requested capacity megawatts	18% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

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6.8.5 — Generation Deactivation

Known generating unit deactivation requests in Ohio between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.27** and **Table 6.36**.

Map 6.27: Ohio Generation Deactivations (Dec. 31, 2020)

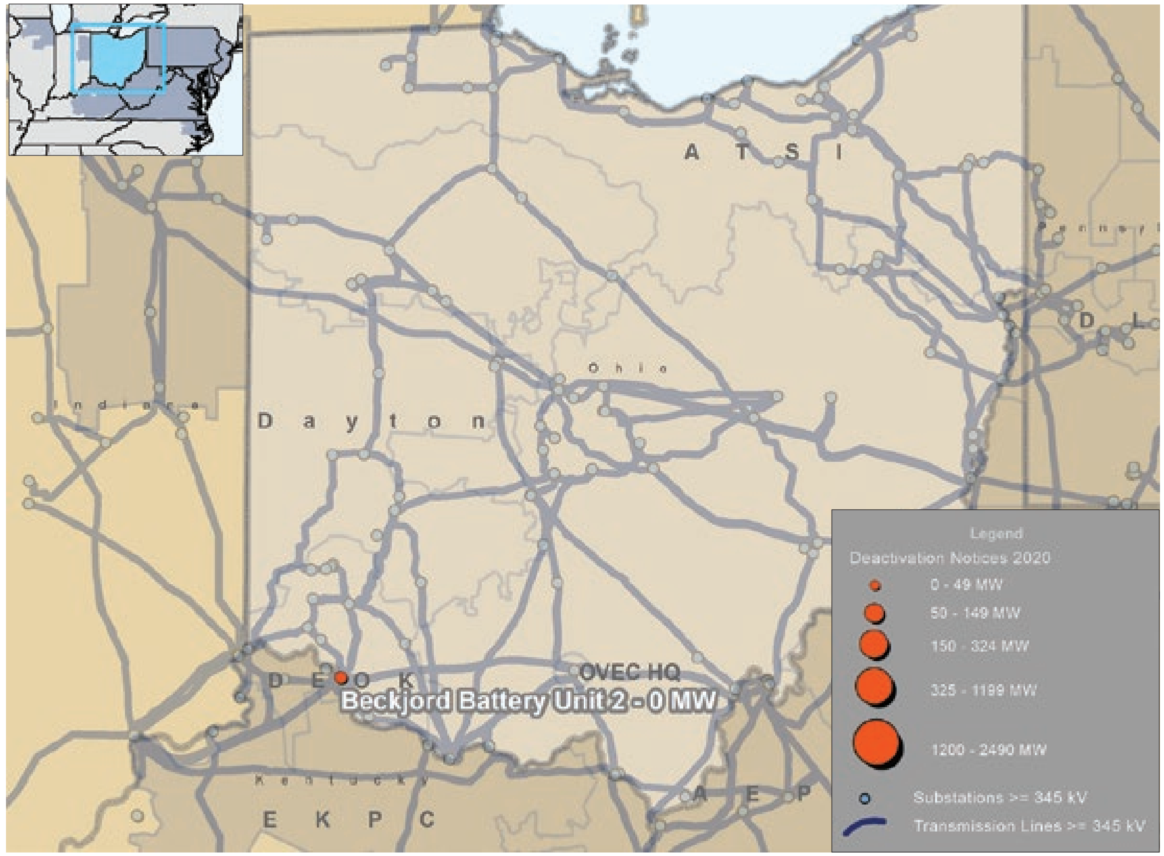

Table 6.36: Ohio Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Beckjord Battery Unit 2	DEO&K	Storage	11/13/2020	2/3/2021	5	0.00

6.8.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Ohio are summarized in **Map 6.28** and **Table 6.37**.

Map 6.28: Ohio Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

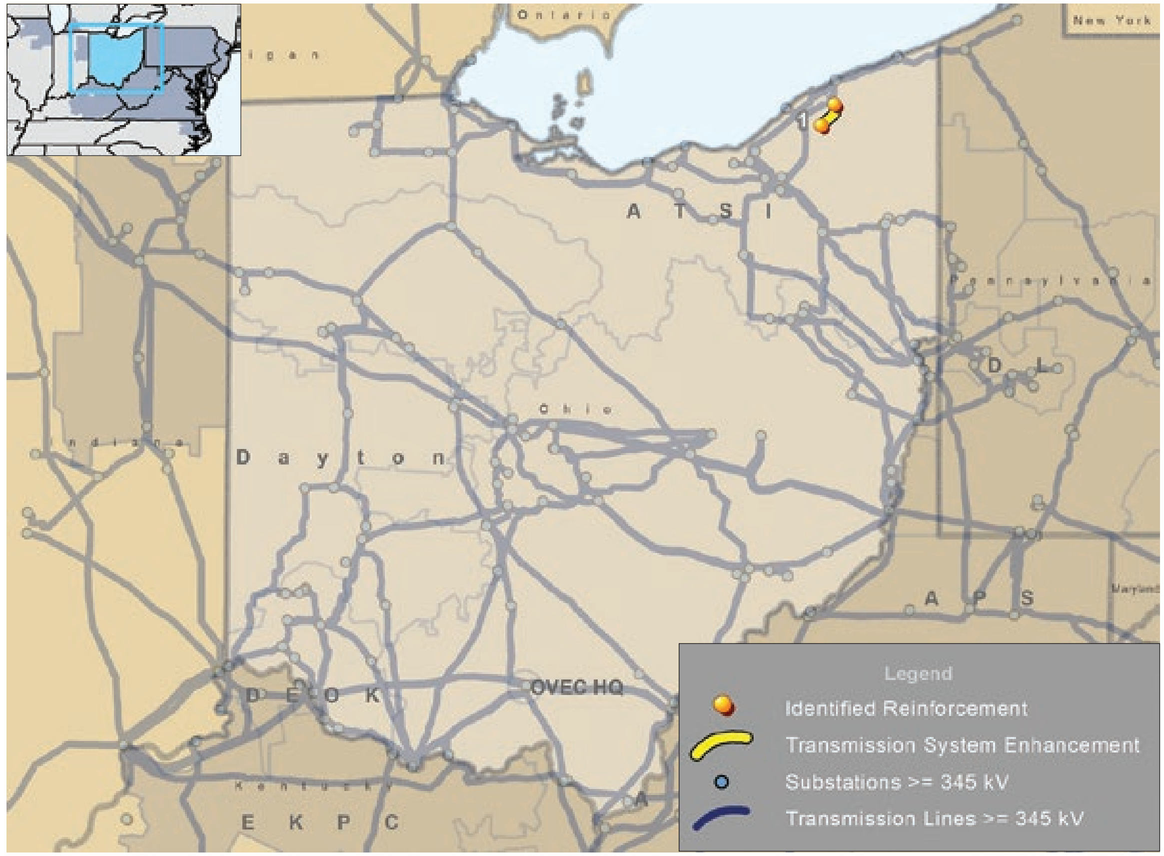

Table 6.37: Ohio Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3152	Reconductor the 8.4 mile section of the Leroy Center-Mayfield Q1 line between Leroy Center and Pawnee tap to achieve a rating of at least 160 MVA/192 MVA Summer Normal/Summer Emergency.	6/1/2024	$14.10	ATSI	11/14/2019

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6.8.7 — Network Projects

No network projects greater than or equal to $10 million in Ohio were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.8.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Ohio are summarized in **Map 6.29** and **Table 6.38.**

Map 6.29: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

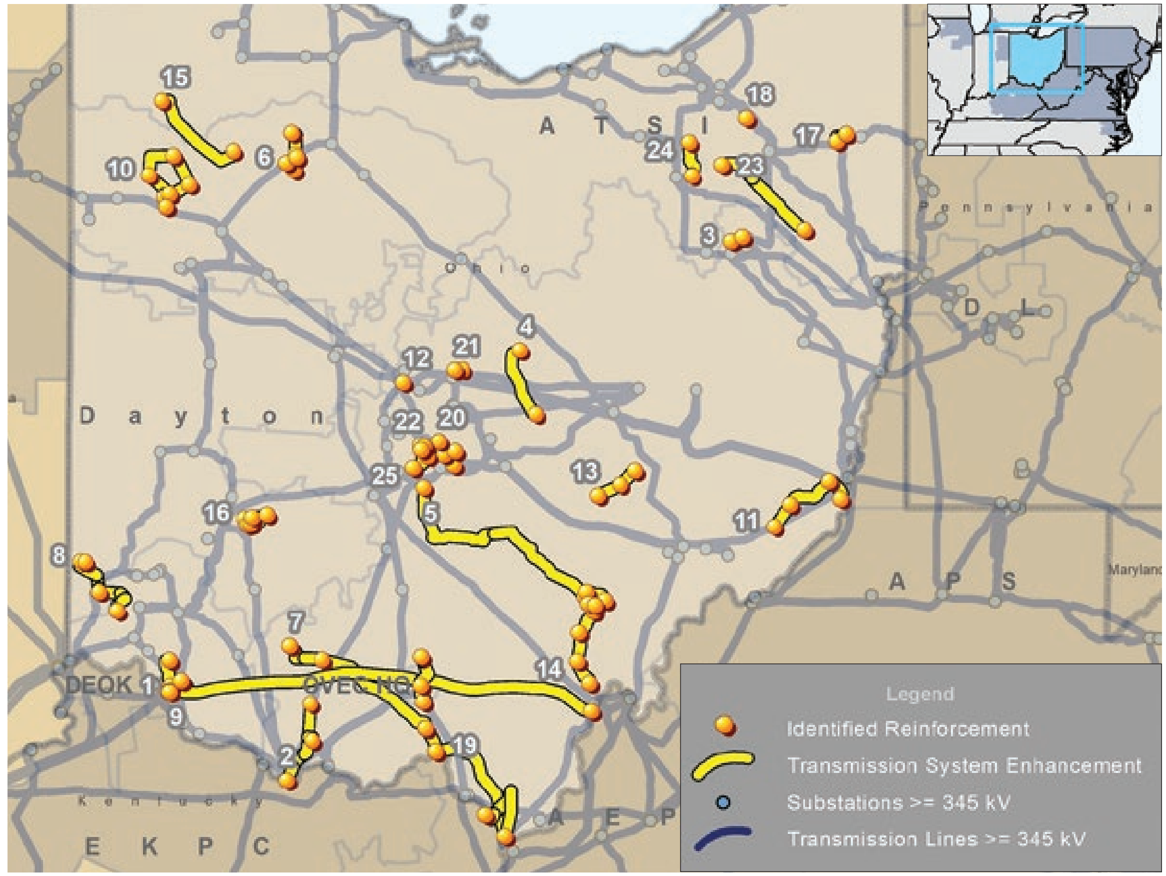


Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2181	At Clermont 138/69 kV: Retire the substation. Remove all equipment, foundations, underground cables, cableways, fencing and the control building. Connect the 138 kV feeder from Beckjord to the feeder from Summerside. Connect the 69 kV feeder from Blairville to the feeder from Amelia. At Beckjord 138/69 kV: Replace the 138 kV oil-filled circuit breaker that connects to the high side of the existing 138/69 kV transformer. Install a new 138 kV breaker connecting to a new 138/69 kV, 150 MVA transformer. Expand the substation and install four 69 kV circuit breakers to form a ring bus.	5/25/2023	$13.30	DEO&K	1/17/2020

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2184	Rebuild 22.0 miles of the existing 28.5-mile Stuart-Seaman 69 kV circuit with 795 ACSR. Retire approximately three miles of the line between West Union and structure 86. Thirty-two of the line's 170 structures were replaced since 2012 and will not be replaced as part of the rebuild.	12/1/2024	$65.00	AEP	2/21/2020
		Construct approximately 2.5 miles of new line from structure 86 on the Stuart-Seaman 69 kV line to Copeland station utilizing 795 ACSR.				
		Rebuild the 2-mile West Union-Copeland 69 kV line utilizing 795 ACSR. The line is part of the Stuart-Seaman 69 kV circuit and is currently radial fed from West Union switch.				
		Establish a 4-breaker 69 kV ring (3000A, 40kA) at the existing Copeland station to serve the Adams Rural Electric Cooperative, Inc. and AEP Ohio customers currently served from a hard tap at the end of the radial.				
		Retire existing West Union switch.				
		Install new 2000A 3-way phase-over-phase switch at Panhandle.				
		Replace the existing Poplar Flats switch with a new 2000A three-way phase-over-phase switch.				
		Remote end upgrade and equipment relocation work will be required at Seaman station to accommodate the new line at the station.				
3	S2185	Rebuild the 4-mile Sunnyside-Torrey 138 kV circuit. Supplement the existing right-of-way as needed to solve encroachments and other constraints.	8/1/2022	$12.70	AEP	2/21/2020
4	S2186	Rebuild the existing 138 kV line with 19.4 miles of new 1033 ACSR.	7/1/2023	$42.20	AEP	2/21/2020
5	S2198	Build new 0.3-mile double-circuit 138 kV extension from the Harrison-Lemaster 138 kV circuit to the new Lockbourne 138 kV station. Fiber will also be installed on the line.	9/23/2021	$13.80	AEP	2/21/2020
		Remove the existing 138 kV radial line from AEP Harrison to SCP Harrison station.				
		Build three short lines to interconnect to SCP's Lockbourne station to serve their three transformers.				
		Build a new 138 kV 5-breaker switch station (Lockbourne) with 3000A 40kA breakers and a capacitor bank (28.8 MVAR) to provide service to three SCP deliveries at the site.				
		Remove existing breaker 3E from the ring bus at Harrison.				

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
6	S2199	Rebuild approximately 3 miles of New Liberty-North Baltimore 34 kV line.	8/1/2022	$85.90	AEP	2/21/2020
		Rebuild 8 miles of North Findlay-North Baltimore No.1 34 kV line (advanced construction date due to imminent failure).				
		Rebuild 0.15 miles of Whirlpool Extension.				
		Build 1 mile of Oilers Switch Extension.				
		Rebuild 2.9 miles of New Liberty-Findlay Center 34 kV line.				
		At North Findlay station, replace 34.5 kV CBs F, G, H, J, K, L with 34.5 kV, 2000A 40 kA breakers. Replace 34.5 kV circuit switcher BB (40kA). Replace T1 and T2 with 90 MVA 138/69/34 kV transformers.				
		At New Liberty station, remove existing T1 and T2. Replace with one 90 MVA ,138/69/34 kV transformer. Install high-side circuit switcher for new transformer. Expand station to build new 34.5 kV ring bus with (6) 2000A 40kA breakers.				
		At Oilers switch station, build new ring bus in the clear with four 2000A 40 kA breakers to replace Morrical switch.				
		At North Baltimore station, rebuild station with four 2000A 40 kA breakers.				
		Install three-way 1200A switch called Touchstone to replace Liberty switch.				
		Replace Cherry Street switch with a two-way 1200A switch.				
		Replace West Melrose switch with 1200A switches.				
		Replace Harvard Avenue switch with a three-way 1200A switch.				
		Install three-way 1200A switch called Totten to eliminate the hard tap to the customer.				
		Install two-way 1200A switch called Centrex to eliminate the hard tap to the customer.				
		Replace Griffith switch with a two-way 1200A switch.				
		Replace Whirlpool MOABs with 1200A capability.				
7	S2201	Rebuild 43.4 miles single-circuit line between Hillsboro-South Lucasville with 1033 ACSR.	9/30/2022	$126.80	AEP	2/21/2020
		Rebuild 8.5 miles double circuit between Millbrook Park-South Lucasville with 1033 ACSR.				
		Install a new three-way 2000A 138 kV, phase-over-phase switch at Sinking Springs.				
8	S2211	Locust ring bus: Install four 69 kV breakers in a ring bus configuration. Split the main feeder into two circuits. Terminate the two new main feeder circuits and the feeder to McGuffey each into their own position on the ring.	6/1/2023	$27.29	DEO&K	3/19/2020
		McGuffey automatic throw over: Install voltage sensing, control and associated equipment to implement an automatic throw-over (ATO) scheme in McGuffey Substation.	12/31/2023			
		Locust-Millville sectionalizing: Install switching facilities with energy management system (EMS) control and an ATO scheme in a new station at the Buckeye Rural Electric Cooperative (BERC) Stillwell-Beckett tap. Loop the main feeder though the new facilities. Install switching facilities with EMS control and transmission line sectionalizing (TLS) in or adjacent to BREC-Oxford Station. Loop the main feeder through the facilities.				
		Millville ring bus: Install four 69 kV breakers in a ring bus configuration. Split the main feeder into two circuits. Extend the feeder that supplies BREC-Layhigh to Millville. Terminate the two new main feeder circuits, the feeder to BREC-Layhigh and the feeder to Hensley each into their own position on the ring.	6/1/2023			
		Millville-Fairfield sectionalizing: Install switching facilities with EMS control and TLS in or adjacent to BREC-Ross. Loop the main feeder though the new facilities. Install switching facilities with EMS control and TLS at or near the tap to BREC-Colerain. Loop the main feeder though the new facilities. Install ATO in River Circle Substation. Loop the main feeder through the facilities.	12/31/2023			

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
9	S2213	Install a new transmission switching station (Arboles) to connect 138 kV lines to Don Marquis, Waverly, and Wakefield as well as four radial lines to serve the two new loads. The station will have 11 CBs (3000A 40 kA) in a breaker-and-a-half configuration. Department of Energy requires three feeds and has requested 138 kV service.	11/1/2021	$34.80	AEP	3/10/2020
		Reconfigure the existing Don Marquis extension in the six-wire configuration for 0.4 miles and rebuild 0.7 miles of the existing Marquis-Wakefield line as double circuit for two feeds from Waverly and Don Marquis.				
		Construct ~0.3 miles of new line to terminate the South Lucasville circuit into Arboles.				
		Construct two independent lines to serve the X-555 substation (DP No.1). The lines will be ~0.4 miles long each.				
		Construct two independent lines to serve the X-5001 substation (DP No.2). The lines will be ~0.8 miles long each.				
		At Don Marquis 345 kV, install three 345 kV, 4000A 63 kA circuit breakers to terminate the OVEC lines from Pierce and Kyger Creek. Install intertie metering. (AEP work)				
		At Kyger Creek station, remove X-530 No.1 exit and associated equipment. Update remote end relaying towards Don Marquis.			OVEC	
		At Pierce station, remove X-530 No.1 Exit and associated equipment. Update the remote end relaying towards Don Marquis.				
		Reconfigure 71.5 miles of the Pierce-Don Marquis line in the six-wire configuration. Construct 0.13 miles of line to tie into Don Marquis station.				
		Reconfigure 50.4 miles of the Kyger Creek-Don Marquis line in the six-wire configuration. Construct 0.5 miles of line to tie into Don Marquis station.				
		At Don Marquis 345 kV, install three 345 kV, 4000A 63 kA circuit breakers to terminate the OVEC lines from Pierce and Kyger Creek. Install intertie metering. (OVEC work)				
10	S2215	Rebuild 16 miles of 69 kV single-circuit line from North Continental Switch (existing switch to be retired) to Roselms Switch (located next to the existing Paulding Putnam Electric Cooperative Roselms station).	8/15/2022	$92.10	AEP	3/19/2020
		Build 9.4 miles of single-circuit 69 kV line from Roselms to near East Ottoville 69 kV Switch.				
		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).				
		Rebuild 5.1 miles of single-circuit 69 kV line from East Ottoville to North Delphos.				
		At North Continental, remove normally open bypass switch.				
		At Fort Brown switch, install a three-way 69 kV, 1200 A phase-over-phase switch with sectionalizing capability.				
		At West Oakwood switch, install a three-way 69 kV, 1200 A phase-over-phase switch with sectionalizing capability.				
		At Roselms switch, install a new three-way 69 kV, 1200 A phase-over-phase switch with sectionalizing capability.				
		At Kalida station, move CB J from low side of Transformer 2 to terminate the new line from Roselms Switch. Move the circuit switcher XT2 from high side of transformer 2 to the high side of transformer 1. Remove existing T2 transformer.				
		Remote end work at North Delphos station.				
		At East Ottoville, install a three-way 69 kV, 1200 A phase-over-phase switch with sectionalizing capability.				
		At Ottoville station, install two three-way 69 kV, 1200 A, phase-over-phase switches with sectionalizing capability.				
		At Fort Jennings, replace hard tap with a three-way 69 kV, 1200 A phase-over-phase switch, with sectionalizing capability.				

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
11	S2216	At Lamping station, install a 138 kV breaker string with two breakers, a 90 MVA, 138-69 kV transformer, and one 69 kV breaker.	5/1/2023	$30.10	AEP	3/19/2020
		Construct a 10-mile 69 kV transmission line between Lamping and the Woodsfield area.				
		At the existing Woodsfield municipal electric station, install a three-way 69 kV switch with SCADA functionality (Cranes Nest Switch).				
		At the existing hard tap to Woodsfield municipal, install a three-way 69 kV switch with SCADA functionality (Standingstone Switch).				
		Remove the existing Cameron two-way switch and install a new three-way 69 kV switch with SCADA functionality.				
		At Switzer station, install two 138 kV line breakers (toward Herlan and Natrium).				
		At the 138 kV remote-end of Natrium, replace the line protection relays to coordinate with the upgrade at Switzer.				
		Modify the existing Switzer-Woodsfield 69 kV transmission line on each side of the switches due to the switch installation.				
12	S2217	At Hyatt station, replace two 345/138 kV, 300 MVA transformers 1A & 1B with 450 MVA units. Install three 345 kV, 5,000A / 63 kA circuit breakers to separate the transformer protection zones. Replace 138 kV breaker 105S with a 3,000A / 63 kA breaker. Install new 138 kV 3,000A breakers to terminate the second transformer.	11/27/2019	$25.00	AEP	3/19/2020
13	S2223	Rebuild ~12 miles of the Crooksville-Philo 138 kV circuit.	9/30/2022	$30.90	AEP	3/19/2020
		Replace Cannelville switch with a new phase-over-phase switch. Relocate the existing Cannesvsville-Guernsey-Muskingum Electric Cooperative 138 kV line to new Cannelville switch. The switch needs to be relocated to maintain service to the customer while the line is being rebuilt.				
14	S2224	Rebuild the existing ~8 mile Elliott-Lee 69 kV line to 138 kV and retire the existing 69 kV line.	10/1/2024	$55.50	AEP	3/19/2020
		Retire approximately 11.5 miles of the Philo-Rutland 138 kV line from Lee station north, including the de-energized portion of the line that runs through the Plains community.				
		Convert Lee to 138 kV service and install two line MOABs connected to the 138 kV line between Dexter and Elliot.				
		At Clark Street, replace 69 kV circuit breakers 61 & 64 (3000A 40 kA).				
		At Elliot, install a new 138/69 kV transformer (130 MVA) in addition to high- and low-side protection (3000A 40 kA) which will replace transformer No. 1 at Strouds Run that will be retired. Replace existing 138 kV circuit breaker 102 and 69 kV circuit breakers 61 and 66 (3000A 40 kA). Install 138 kV circuit breaker (3000A, 40 kA) on the new 138 kV line towards Dexter (via Lee) along with a 138 kV bus-tie breaker (3000 40 kA). Retire 69 kV circuit breaker 67"due to the conversion of Lee station to 138 kV.				
		Rebuild ~3.68 miles of single-circuit line from the Poston-Strouds Run line as double-circuit 138 kV transmission line to eliminate the hard tap on the line.				
		At Strouds Run, install a 138 kV line breaker (3000A 40 kA) towards Lemaster. Replace Transformer No. 2 high-side circuit switcher with a circuit breaker (3000A 40 kA). Replace the 69 kV circuit breaker 66 (3000A 40kA). Retire 138/69/13 kV, 33.6 MVA Transformer No.1, 69 kV circuit breaker 63 and circuit switcher No. 1.				
		At Lemaster station, install a 138 kV breaker (3000A 40kA) to accommodate the new circuit.				
		Remove Rosewood switch.				
15	S2246	Richland-East Leipsic 138 kV Line: Rebuild entire 15.8 mile of the ATSI-owned Richland-East Leipsic 138 kV line. Replace existing conductor (636 ACSR) with 795 ACSR. Install OPGW along the entire line. Upgrade Richland line terminal: Substation equipment for replacement includes: Breaker B13250, disconnect switches, line trap, CVT, tuner and COAX, substation conductor, relaying, and revenue metering.	12/31/2022	$16.90	ATSI	2/21/2020

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
16	S2255	Construct a new 4-breaker ring bus substation called Jasper and build a new 1.5 mile transmission line extension from the existing 63611 switch to the new Jasper Substation for separate 69 kV feeds from Xenia Substation and Glady Run Substation.	12/31/2023	$10.20	DAY	4/20/2020
		Install two new 69 kV breakers at the South Charleston Substation.				
		Install a single 69 kV breaker and switch at the Cedarville Substation.				
17	S2264	Magellan 138 kV breaker-and-a-half: Construct a 138 kV 11-breaker breaker-and-a-half (future 12-breaker) substation. Loop the Highland-GM Lordstown 138 kV line by building approximately 0.5 miles of 138 kV line using 795 ACSR near structure 3069. Provide three 138 kV metering package. Install two capacitors totaling 86.4 MVAR @ 144.1 kV (multiple step). Build roughly 3.5 miles of 138 kV line from Highland to Magellan using 795 ACSR utilizing an open-arm position on the Highland-Lordstown No. 1 345 kV line.	8/31/2021	$31.80	ATSI	4/20/2020
18	S2265	Convert the Streetsboro 69 kV straight bus to a 5-circuit breaker ring bus. Build a double-circuit 69 kV line approximately 1.8 miles from Streetsboro Substation to eliminate the three-terminal line. Create Darrow-Streetsboro (~6.7 miles) and Ravenna-Streetsboro (~8.6 miles) 69 kV lines.	6/1/2020	$10.10	ATSI	1/17/2020
19	S2272	Rebuild the 35 miles of the South Point-Portsmouth double-circuit 138 kV line between Millbrook Park and South Point with 795 ACSR (257 MVA) or equivalent conductor.	12/15/2025	$148.70	AEP	5/22/2020
		Rebuild the 3.8 miles of the Bellefonte Extension line (138 kV) from the South Point-Portsmouth 138 kV line to Bellefonte with 795 ACSR (257 MVA) or equivalent conductor.				
		Perform remote-end work at South Point 138 kV station.				
20	S2282	Rebuild ~5.0 miles of 138 kV line between Astor-Shannon. The existing refugee switch will be retired.	11/1/2024	$60.80	AEP	6/19/2020
		Rebuild ~0.5 miles and construct ~4.6 miles of greenfield 138 kV line between Groves and Shannon to eliminate the three-terminal line.				
		Rebuild ~4.3 miles of 138 kV line between Bixby and Shannon.				
		Reconfigure lines at Shannon to accommodate the new 138 kV circuit from Groves. Install two new 138 kV 3000A 40 kA circuit breakers on circuits towards Brice and Bixby to prevent dissimilar zones of protection when bringing the third 138 kV circuit to the station.				
21	S2283	Build ~3.75 miles of single-circuit 138 kV transmission line from new Condit three-way MOAB switch (tapping the Centerburg-Trent 138 kV circuit) to Lott station (Consolidated Co-op).	6/1/2024	$10.64	AEP	6/19/2020
		Build Condit three-way MOAB 138 kV switch.				
22	S2284	Retire ~3.8 miles of underground oil-filled pipe type 138 kV circuit between Canal St.-Marion Rd.	5/1/2022	$45.00	AEP	6/19/2020
		Build ~3.1 miles of underground single-circuit 138 kV line between Marion Rd. and Mound St. using cross-linked polyethylene-insulated cable.				
		At Canal Street, install two new 138 kV CBs (3000A 63 kA) to electrically terminate the Buckeye Steel-Gay St. 138 kV circuit that runs through the station. Replace breaker 4 with new 138 kV CB (3000A 63 kA).				
		At Mound Street, install new 138 kV CB (3000A 63 kA) to accommodate new circuit from Marion Rd.				
		At Vine Street, install a 2 percent series line reactor towards Gay Street station to limit fault contribution increases from reconfigurations of lines in the area.				
		Perform remote-end relay work at Gay Street.				
		Perform remote-end relay work at Bixby station.				
		Perform relay upgrades and line termination structure replacement at Marion Road.				

Table 6.38: Ohio Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
23	S2297	Convert East Akron 138 kV Substation into breaker-and-half configuration. Install a new control building. Reuse two breakers (B75 and 76). Upgrade three breakers (B43, B46 and B253) with 138 kV, 40 kA, SF6 circuit breaker. Install seven additional 138 kV, 40 kA, SF6 circuit breakers. Replace and install switches, surge arrestors, capacitive voltage transformers, station service voltage transformers. Upgrade wave trap on Knox exit. Replace line tuner and coax.	12/30/2023	$13.80	ATSI	5/22/2020
24	S2298	Convert Barberton 138 kV Substation into double bus, double breaker configuration. Install a new control building. Reuse two breakers (B75 & 76). Upgrade five breakers (B124, B45, B74, B37 & B357) with 138 kV, 40 kA, SF6 circuit breakers. Install nine additional 138 kV, 40 kA, SF6 circuit breakers. Replace and install switches, surge arrestors, CVTs, SSVTs. Upgrade less than 0.1 mile section of the Barberton-West Akron 138 kV line from 605 ACSR conductor to 795 ACSS conductor.	12/1/2024	$14.70	ATSI	5/22/2020
25	S2342	Marion-Parsons 40 kV: Retire ~5.2 miles of double-circuit 40 kV line between Marion and Parsons. Parsons 138 kV Extension: Extend the Canal Street-White Road 138 kV circuit to Parsons with ~2.0 miles of double- circuit 138 kV line (Greenfield) using 795 ACSR, 26/7 Drake conductor. Extend fiber cable and install redundant fiber cable for relaying and communication to Parsons station. Parsons 138 kV substation: Replace existing 40 kV yard with 138 kV ring bus. Perform remote end work at Canal Street and White Road stations. Marion 138 kV substation: Retire existing circuit breaker 21.	8/1/2022	$27.89	AEP	10/16/2020

6.8.9 — Merchant Transmission Project Requests

As of Dec. 31, 2020, PJM's queue contained one merchant transmission project request which includes a terminal in Ohio as shown in **Map 6.30** and **Table 6.39.**

Map 6.30: Ohio Merchant Transmission Project Requests (Dec. 31, 2020)

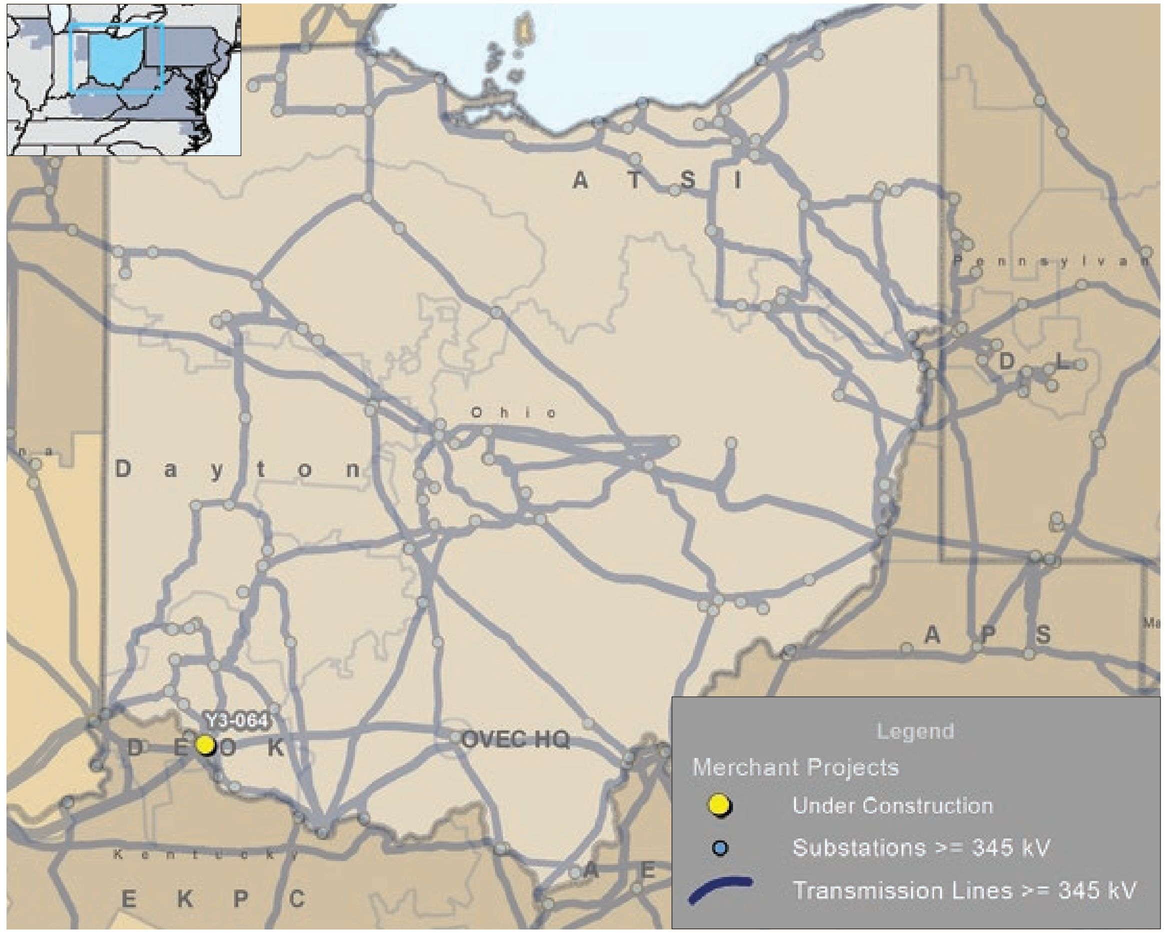


Table 6.39: Ohio Merchant Transmission Project Requests (Dec. 31, 2020)

Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
Y3-064	Pierce-Beckjord 138 kV	DEO&K	Under Construction	12/20/2020	160.0

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 Co. (DLCO), Met-Ed, Pennsylvania Electric Co. (PENELEC), PECO Energy Co. (PECO), PPL Electric Utilities (PPL), UGI Utilities (UGI), Rock Springs and American Transmission Systems, Inc. (ATSI) as shown on **Map 6.31**. 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.

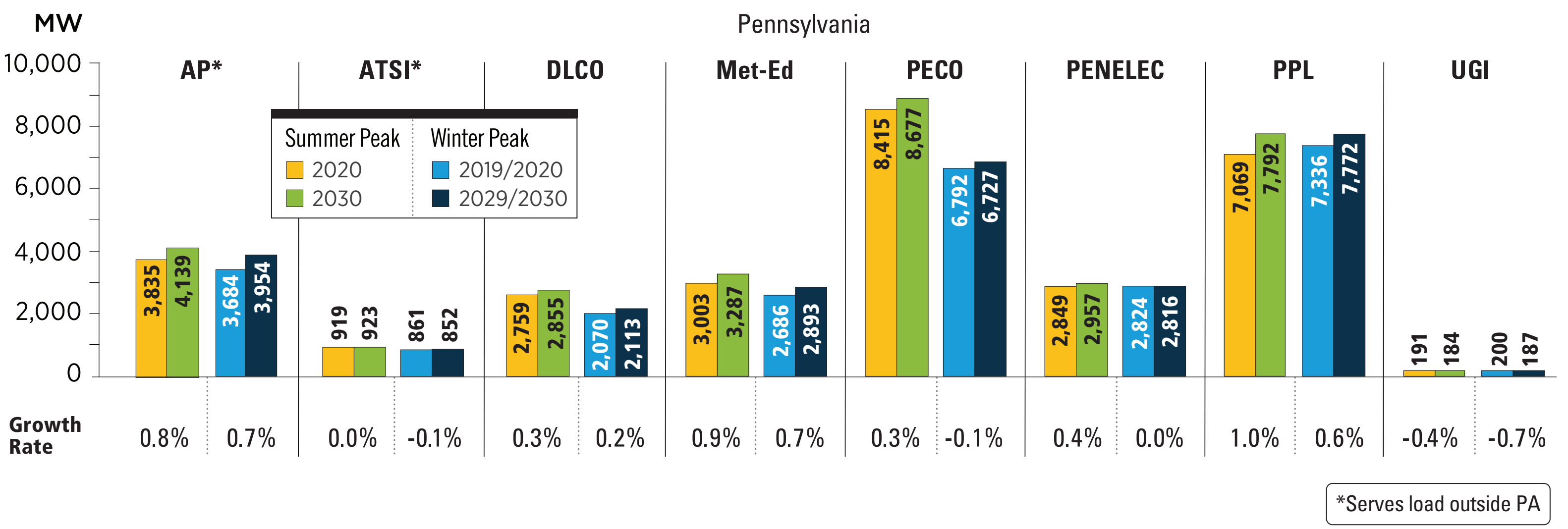
Pennsylvania has a mandatory alternative energy portfolio standard (AEPS) target of 8 percent Tier 1 resources and 10 percent Tier 2 resources by 2021. The AEPS includes a solar carve-out of 0.5 percent by 2021, and solar resources applying toward the AEPS must be located within the state of Pennsylvania.

Map 6.31: PJM Service Area in Pennsylvania

6.9.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.46** summarizes the expected loads within the state of Pennsylvania and across all of PJM.

Figure 6.46: Pennsylvania – 2020 Load Forecast Report



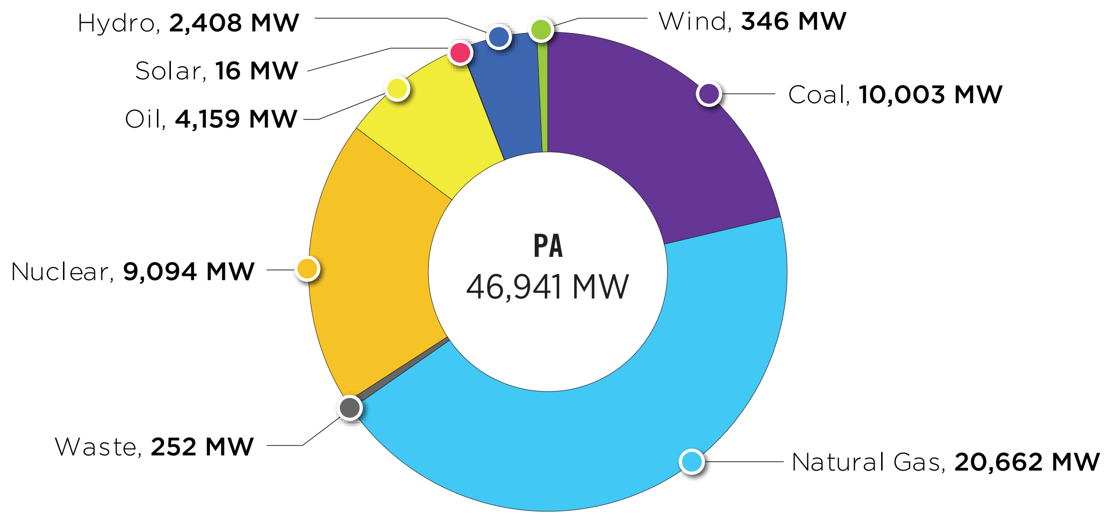
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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, 2020, is shown by fuel type in **Figure 6.47**.

Figure 6.47: Pennsylvania – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 478 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.40**, **Table 6.41**, **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 6.40: Pennsylvania – Capacity by Fuel Type – Interconnection Requests (Dec. 31, 2020)

	Pennsylvania Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	4	0.03%	4	0.00%
Hydro	507	3.94%	559	0.53%
Natural Gas	4,113	31.99%	27,804	26.52%
Nuclear	44	0.34%	81	0.08%
Oil	8	0.06%	31	0.03%
Solar	7,024	54.63%	58,845	56.13%
Storage	988	7.69%	10,877	10.38%
Wind	170	1.32%	6,560	6.26%
Grand Total	**12,857**	**100.00%**	**104,838**	**100.00%**

Table 6.41: Pennsylvania – Interconnection Requests by Fuel Type (Dec. 31, 2020)

		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	1	4.1	3	33.3	12	51.5	16	88.9
	Natural Gas	13	952.6	1	950.0	27	2,210.1	98	20,477.1	245	89,688.0	384	114,277.8
	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	0	0.0	0	0.0	0	0.0	2	306.5	6	344.0	8	650.5
	Storage	38	976.5	2	11.8	1	0.0	5	0.0	39	722.8	85	1,711.1
Renewable	Biomass	0	0.0	0	0.0	0	0.0	2	15.4	4	36.5	6	51.9
	Hydro	6	506.5	0	0.0	0	0.0	12	480.8	17	443.9	35	1,431.1
	Methane	0	0.0	0	0.0	0	0.0	24	130.7	37	201.3	61	332.0
	Solar	312	6,704.5	9	129.4	49	190.2	10	37.4	181	2,961.7	561	10,023.2
	Wind	5	101.7	2	21.4	3	47.0	39	259.6	137	1,749.0	186	2,178.7
	Wood	0	0.0	0	0.0	0	0.0	0	0.0	1	16.0	1	16.0
	Grand Total	**376**	**9,241.7**	**14**	**1,112.7**	**88**	**2,502.9**	**229**	**24,544.2**	**728**	**113,607.2**	**1,435**	**151,008.7**

Figure 6.48: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

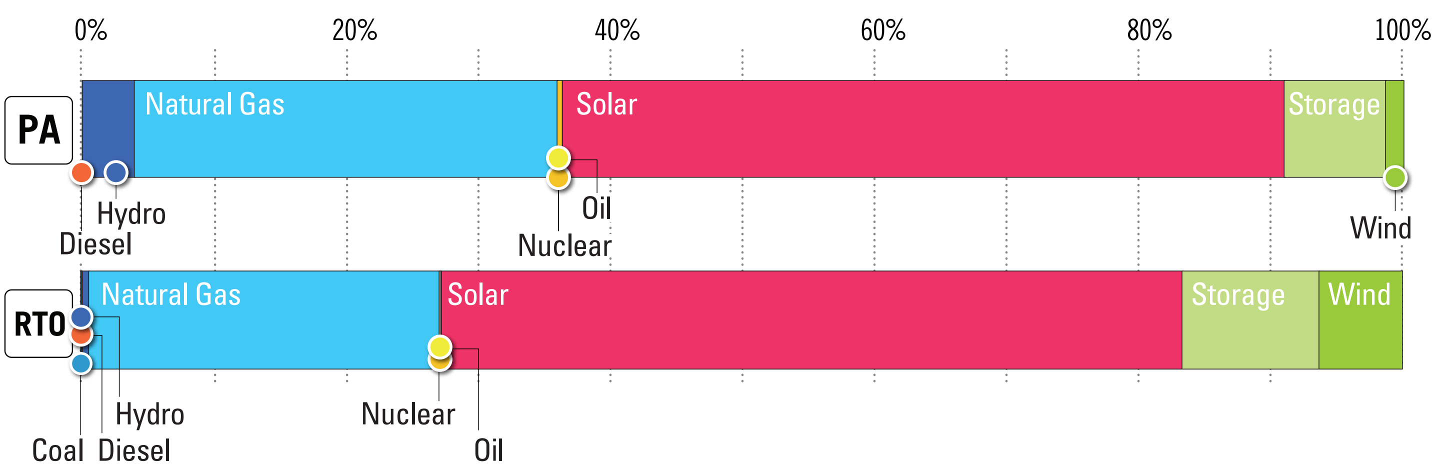
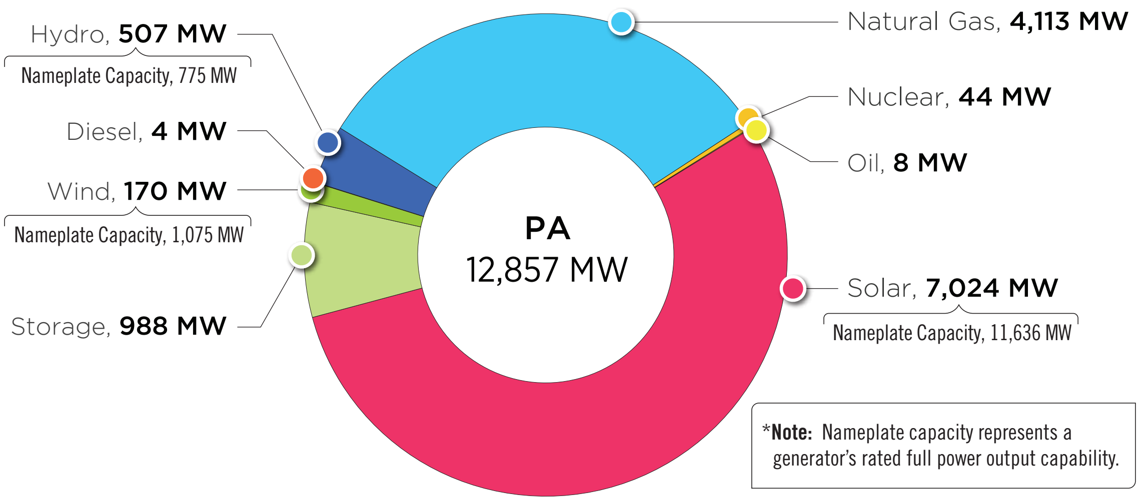
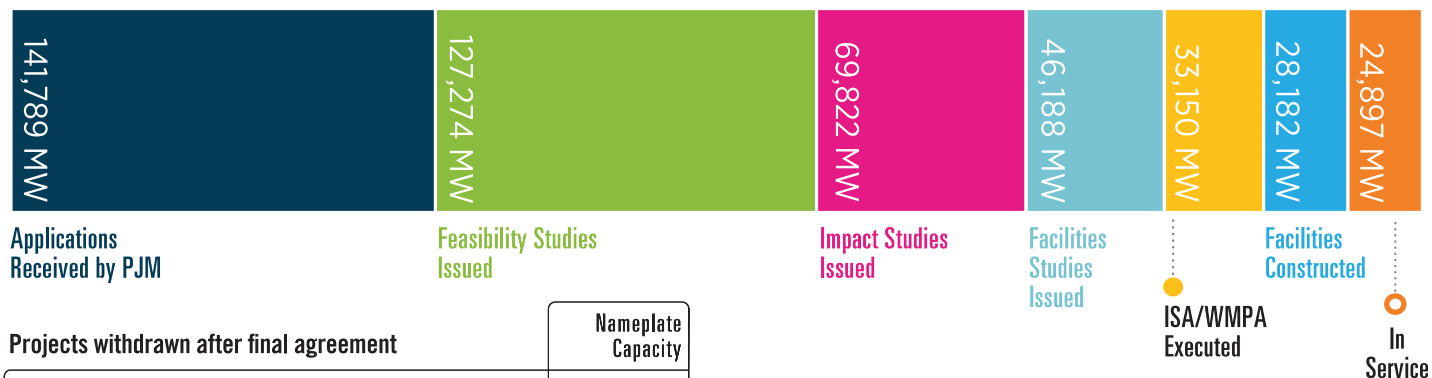


Figure 6.49: Pennsylvania – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)



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

Figure 6.50: Pennsylvania Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
56	Interconnection Service Agreements	6,049 MW	7,836 MW
49	Wholesale Market Participation Agreements	308 MW	423 MW

Percentage of planned capacity and projects that have reached commercial operation	18% Requested capacity megawatts	24 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.9.5 — Generation Deactivations

Known generating unit deactivation requests in Pennsylvania between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.32** and **Table 6.42**.

Map 6.32: Pennsylvania Generation Deactivations (Dec. 31, 2020)

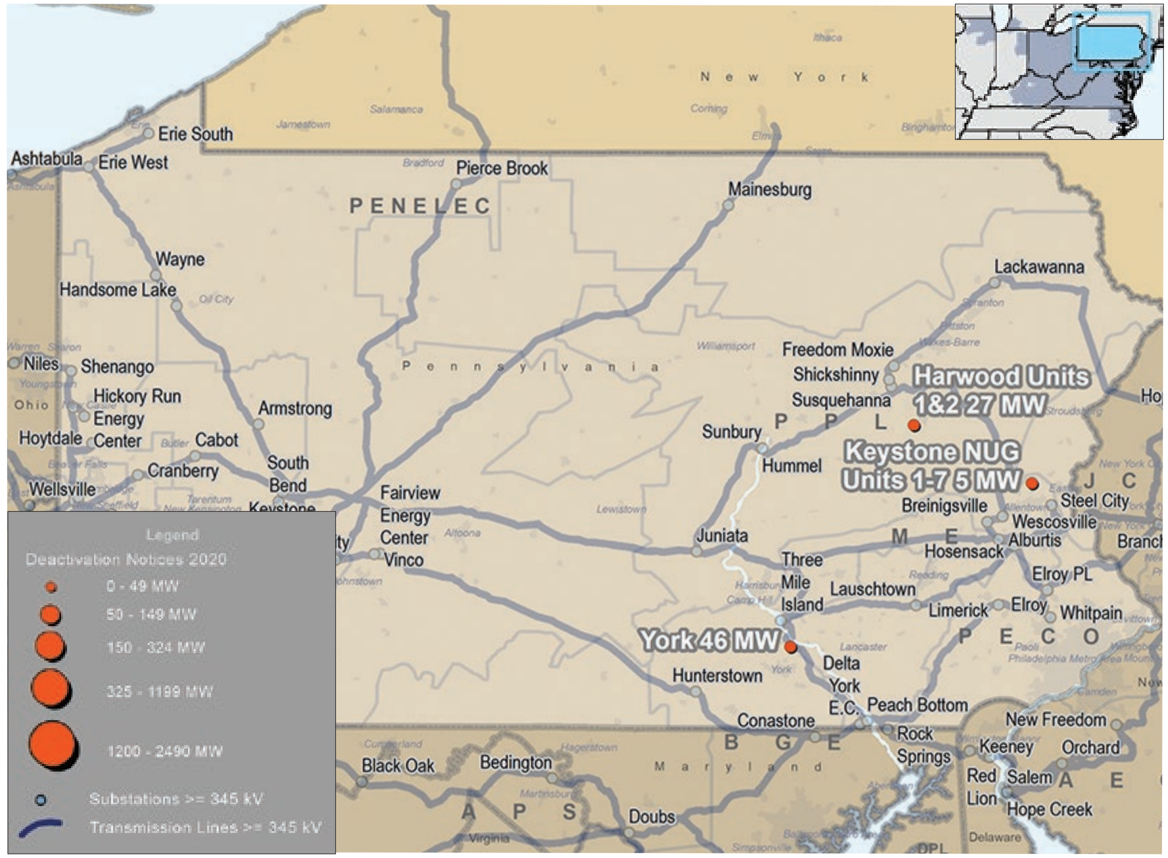


Table 6.42: Pennsylvania Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Keystone NUG Recovery (Units 1–7)	PPL	Methane	2/28/2020	6/1/2020	25	4.90
Harwood Unit 1		Oil	10/29/2020	5/31/2021	53	13.60
Harwood Unit 2			10/29/2020	5/31/2021	53	13.60
York Generation Facility	METED	Natural Gas	10/29/2020	5/31/2022	31	46.20

6.9.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Pennsylvania are summarized in **Map 6.33** and **Table 6.43**.

6.9.7 — Network Projects

No network projects greater than or equal to $10 million in Pennsylvania were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.33: Pennsylvania Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

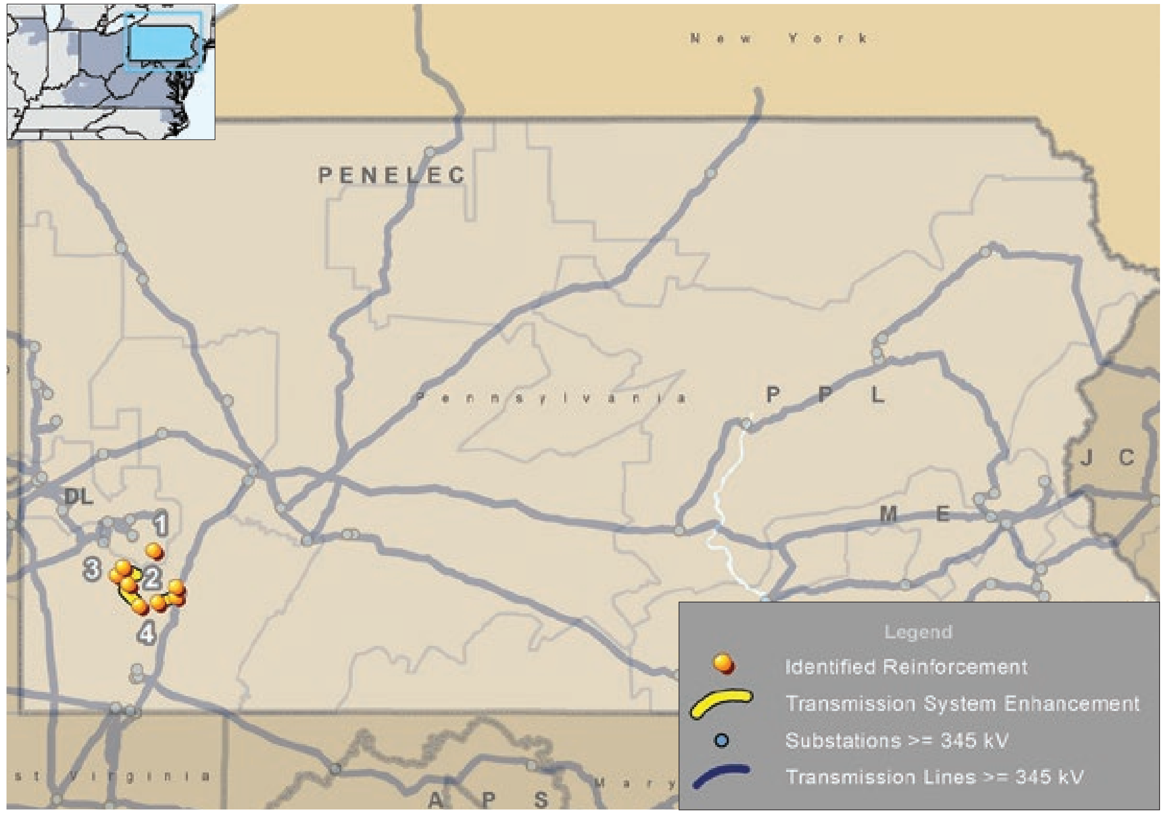


Table 6.43: Pennsylvania Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3011	Upgrade 138 kV breaker Z-78 Logans at Dravosburg.	6/1/2021	$29.42	DLCO	1/17/2020
2	B3015	Upgrade terminal equipment at Mitchell for Mitchell-Elrama 138 kV line.		$39.25	AP	9/12/2019
3	B3064	Upgrade line relaying at Piney Fork and Bethel Park for Piney Fork-Elrama 138 kV line and Bethel Park-Elrama 138 kV line.		$13.05		
4	B3214	Reconductor the Yukon-Smithton-Shepler Hill Jct 138 kV line. Upgrade terminal equipment at Yukon and replace line relaying at Mitchell and Charleroi.	6/1/2023	$21.40		5/12/2020

6.9.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Pennsylvania are summarized in **Map 6.34** and **Table 6.44**.

Map 6.34: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

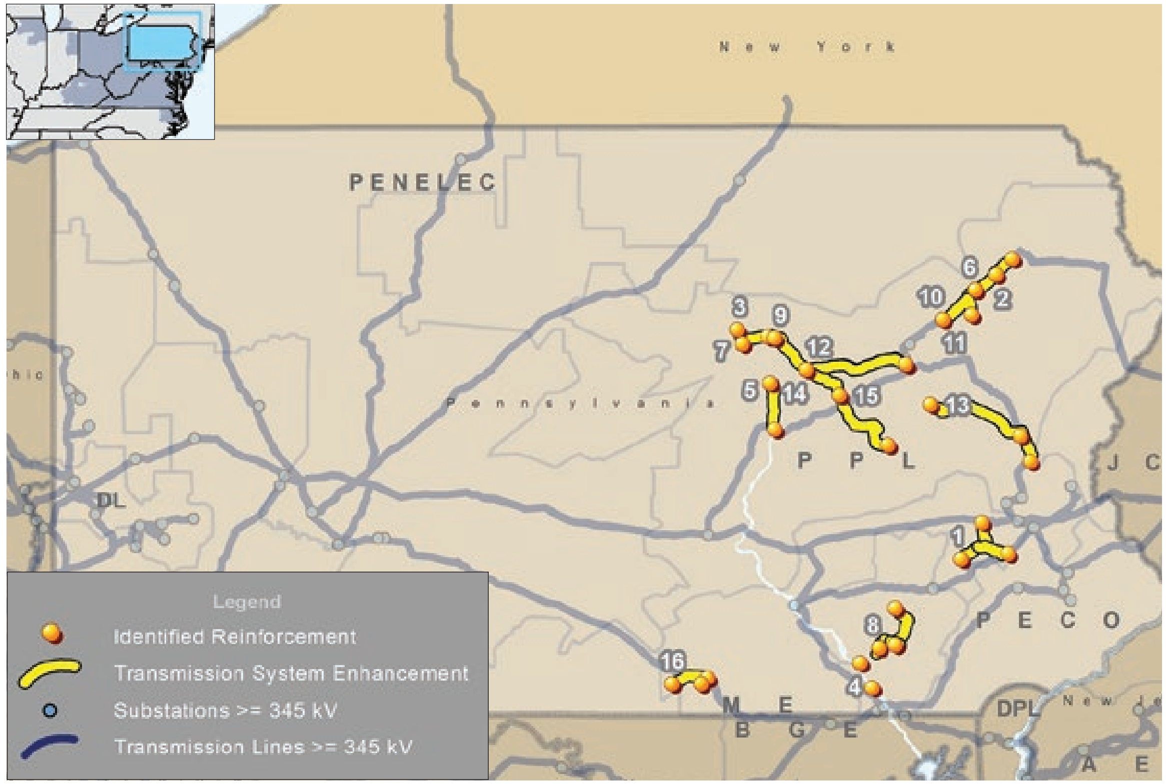


Table 6.44: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	s2310	Rebuild and reconductor Carsonia-Lyons-North Boyertown 69 kV line.	12/31/2025	$26.40	METED	7/16/2020
		Replace disconnect switches, substation conductor and line relaying at Carsonia 69 kV substation.				
		Replace disconnect switches and substation conductor at Friedensburg 69 kV substation.				
		Replace circuit breaker and disconnect switches at North Boyertown 69 kV substation.				

Table 6.44: Pennsylvania Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2363	Rebuild the 5 mile Corten tower section of the Summit-Lackawanna 1 & 2 230 kV circuits with steel monopoles and new conductor.	12/31/2023	$14.30	PPL	10/6/2020
3	S2364	Rebuild the 4.1 mile Corten tower section of the Elimsport-Lycoming 2 & 3 230 kV circuits with steel monopoles and new conductor.		$10.40		
4	S2365	Rebuild the 5.2 mile Corten tower section of the Manor-Millwood 230 kV & Face Rock-Millwood 1 69 kV circuits with steel monopoles and new conductor.	12/31/2024	$13.20		
5	S2366	Rebuild the entire 10.5 miles of the Sunbury-Milton 230 kV and Sunbury-Milton 69 kV line with steel monopoles and new conductor.	12/31/2023	$26.10		
6	S2367	Rebuild the 7.7 mile Corten tower section of the Stanton-Summit 3 & 4 230 kV circuits with steel monopoles and new conductor.	12/31/2025	$21.10		
7	S2368	Rebuild the 8.0 miles of Corten tower sections of the Saegers-Elimsport and Clinton-Elimsport/Clinton-Saegers 230 kV lines. with steel monopoles and new conductor.	12/31/2026	$23.10		
8	S2369	Rebuild the 20.4 mile Corten tower section of the South Akron-Millwood 230 kV and Millwood-Strasburg tie 69 kV lines with steel monopoles and new conductor.	12/31/2025	$53.30		
9	S2370	Rebuild the 6.2 mile Corten tower section of the Montour-Saegers 1 & 2 230 kV lines with steel monopoles and new conductor.	12/31/2027	$17.50		
10	S2371	Rebuild the 8.5 mile Corten tower section of the Jenkins-Stanton and Mountain-Stanton 230 kV lines with steel monopoles and new conductor.	12/31/2028	$22.80		
11	S2372	Rebuild the 9.8 mile Corten tower section of the Mountain-Stanton and Mountain-Jenkins 230 kV lines with steel monopoles and new conductor.	12/31/2029	$27.00		
12	S2373	Rebuild the 21.9 miles of Corten tower sections of the Montour-Susquehanna and Montour-Susquehanna T10 230 kV lines with steel monopoles and new conductor.		$69.60		
13	S2374	Rebuild the 38.0 miles of Corten tower sections of the Siegfried-Harwood and Harwood-East Palmerton/Siegfried-East Palmerton 230 kV lines with steel monopoles and new conductor.	12/31/2026	$136.80		
14	S2375	Rebuild the 9.25 mile Corten tower section of the Montour-Columbia 230 kV line with steel monopoles and new conductor.	12/31/2028	$28.20		
15	S2376	Rebuild the 25.9 mile Corten tower section of the Frackville-Columbia 230 kV line with steel monopoles and new conductor.	12/31/2030	$91.90		
16	S2381	Loop the Hunterstown-Lincoln 115 kV line, approximately 9 miles, into Orrtanna substation by constructing a double-circuit 115 kV line adjacent to the existing radial 963 line. Remove the existing radial 963 line from Orrtanna tap to Orrtanna (~9 miles).	12/31/2021	$38.50	METED	10/15/2020

6.9.9 — Merchant Transmission Project Requests

As of Dec. 31, 2020, PJM's queue contained two merchant transmission project requests which include a terminal in Pennsylvania, as shown in **Map 6.35** and **Table 6.45**.

Map 6.35: Pennsylvania Merchant Transmission Project Requests (Dec. 31, 2020)

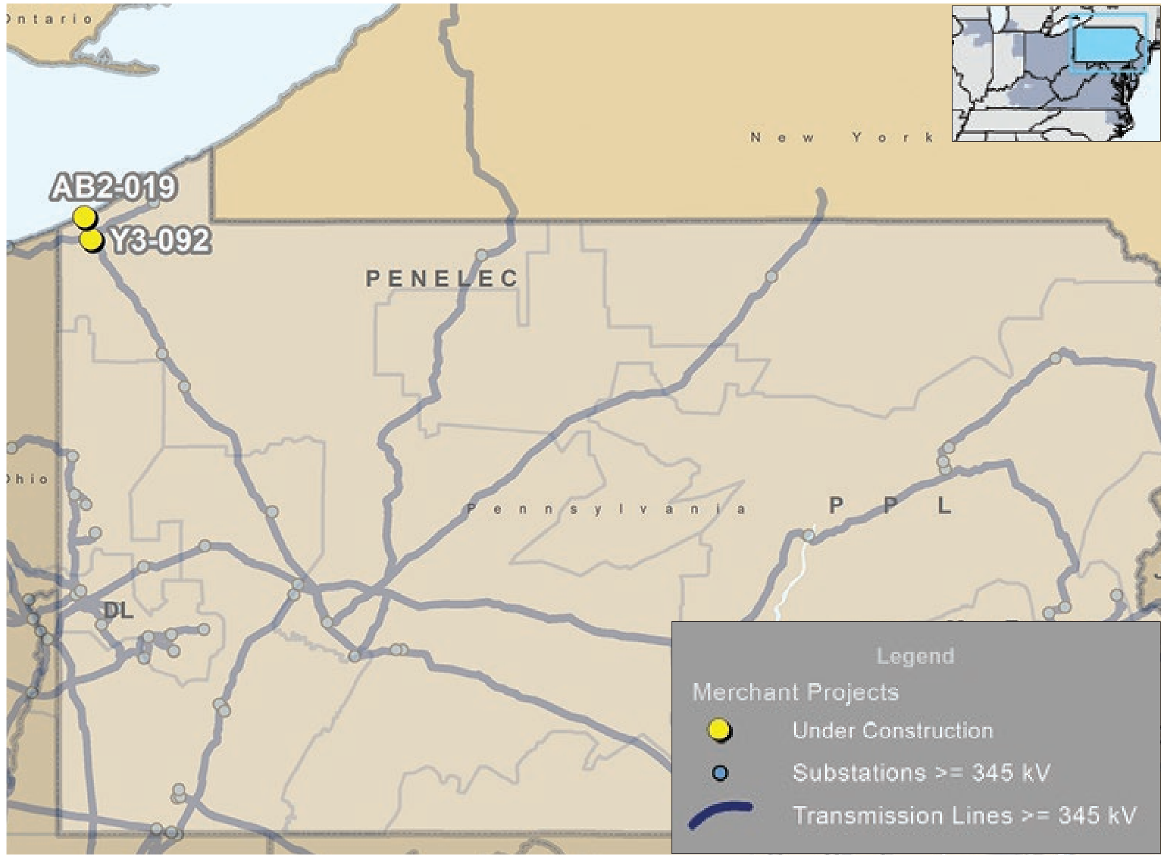


Table 6.45: Pennsylvania Merchant Transmission Project Requests (Dec. 31, 2020)

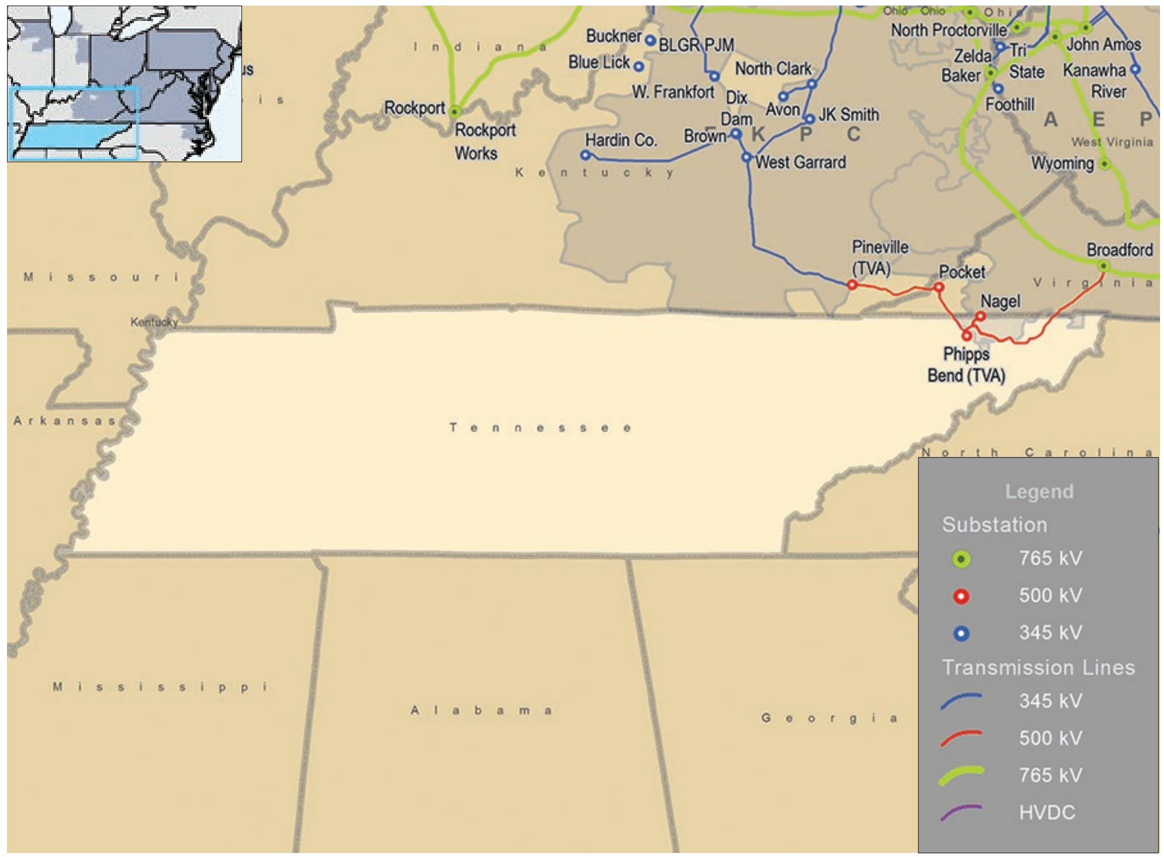
Queue Number	Queue Name	TO Zone	Status	Actual or Requested In-Service Date	Maximum Output (MW)
Y3-092	Erie West 345 kV	PENELEC	Under Construction	3/31/2024	1,000.0
AB2-019	Erie West 345 kV	PENELEC	Under Construction	3/31/2024	28.0

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 6.36**. 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.

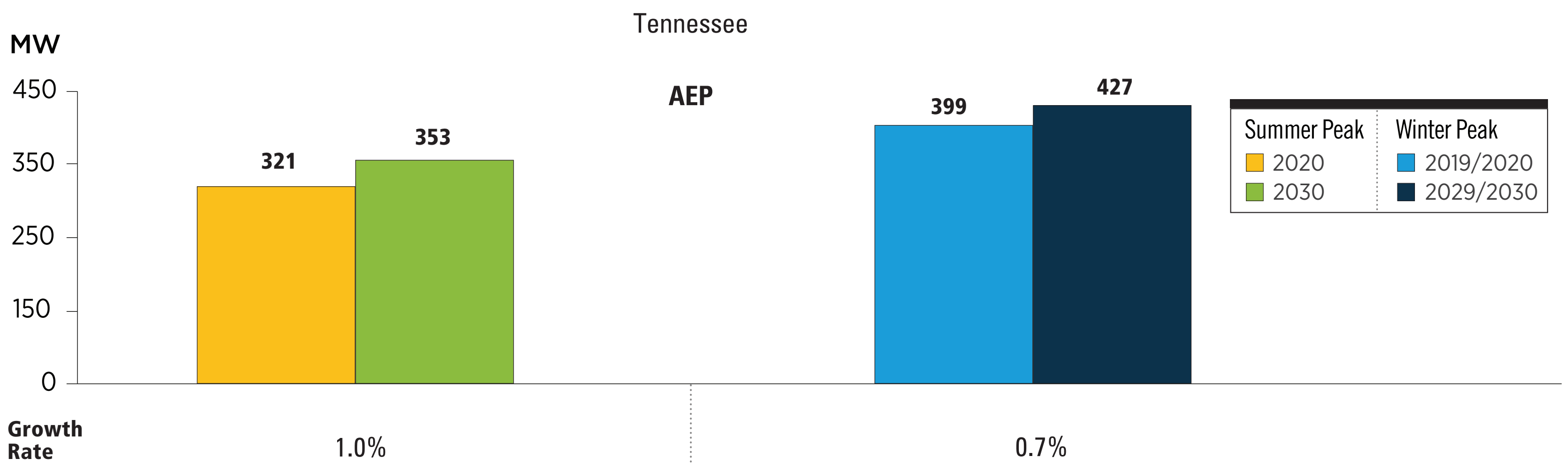
Map 6.36: PJM Service Area in Tennessee



6.10.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.51** summarizes the expected loads within the state of Tennessee and across all of PJM.

Figure 6.51: Tennessee – 2020 Load Forecast Report



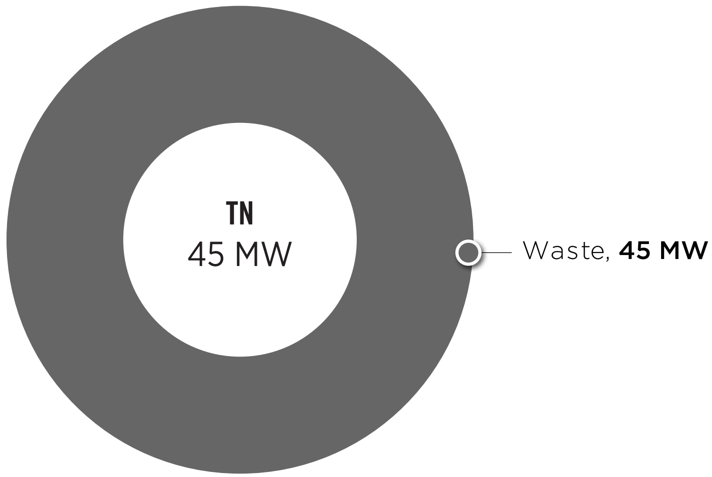
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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.

6.10.3 — Existing Generation

Existing generation in Tennessee as of Dec. 31, 2020, is shown by fuel type in **Figure 6.52**.

Figure 6.52: Tennessee – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



6.10.4 — Interconnection Requests

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, 2020, there were no queued projects actively under study, or under construction as shown in the summaries presented in **Table 6.46** and **Figure 6.53.** These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

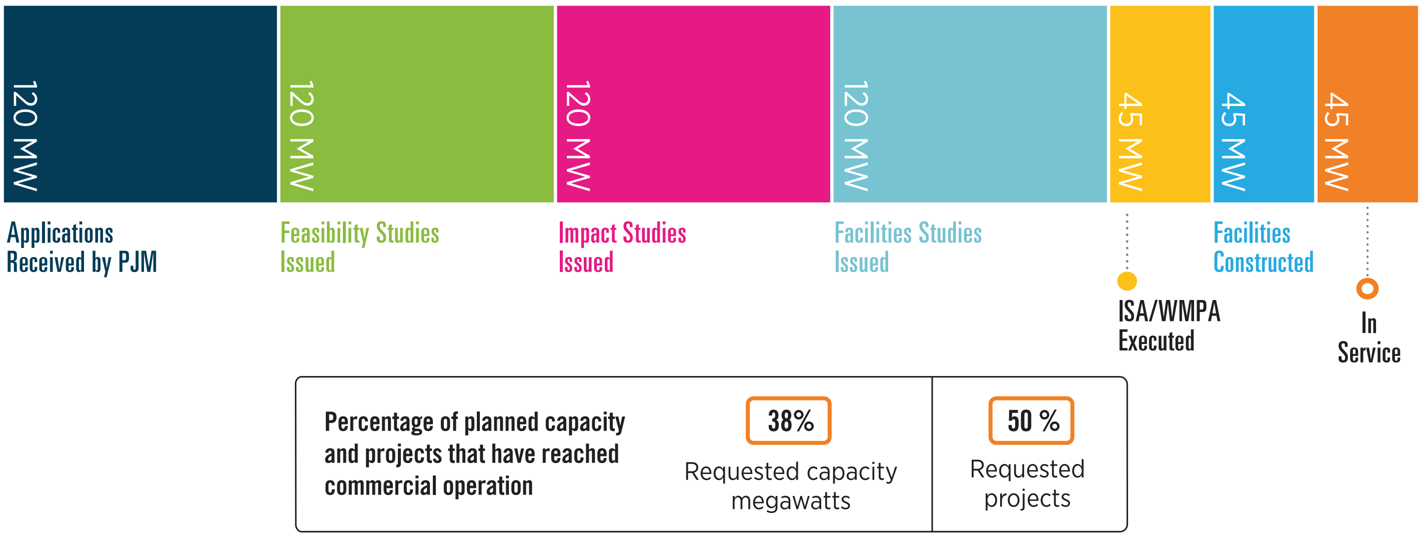
6.10.5 — Generation Deactivation

There were no known generating unit deactivation requests in Tennessee between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

Table 6.46: Tennessee – Interconnection Requests by Fuel Type (Dec. 31 2020)

		Complete				Grand Total	
		In Service		Withdrawn			
		Projects	Capacity (MW)	Projects	Capacity (MW)	Projects	Capacity (MW)
Non-Renewable	Coal	0	0	1	75	1	75
Renewable	Biomass	1	45	0	0	1	45
	Grand Total	1	45	1	75	2	120

Figure 6.53: Tennessee Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.10.6 — Baseline Projects

No baseline projects greater than or equal to $10 million in Tennessee were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.10.7 — Network Projects

No network projects greater than or equal to $10 million in Tennessee were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

6.10.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Tennessee are summarized in **Map 6.37** and **Table 6.47**.

6.10.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Tennessee were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.37: Tennessee Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

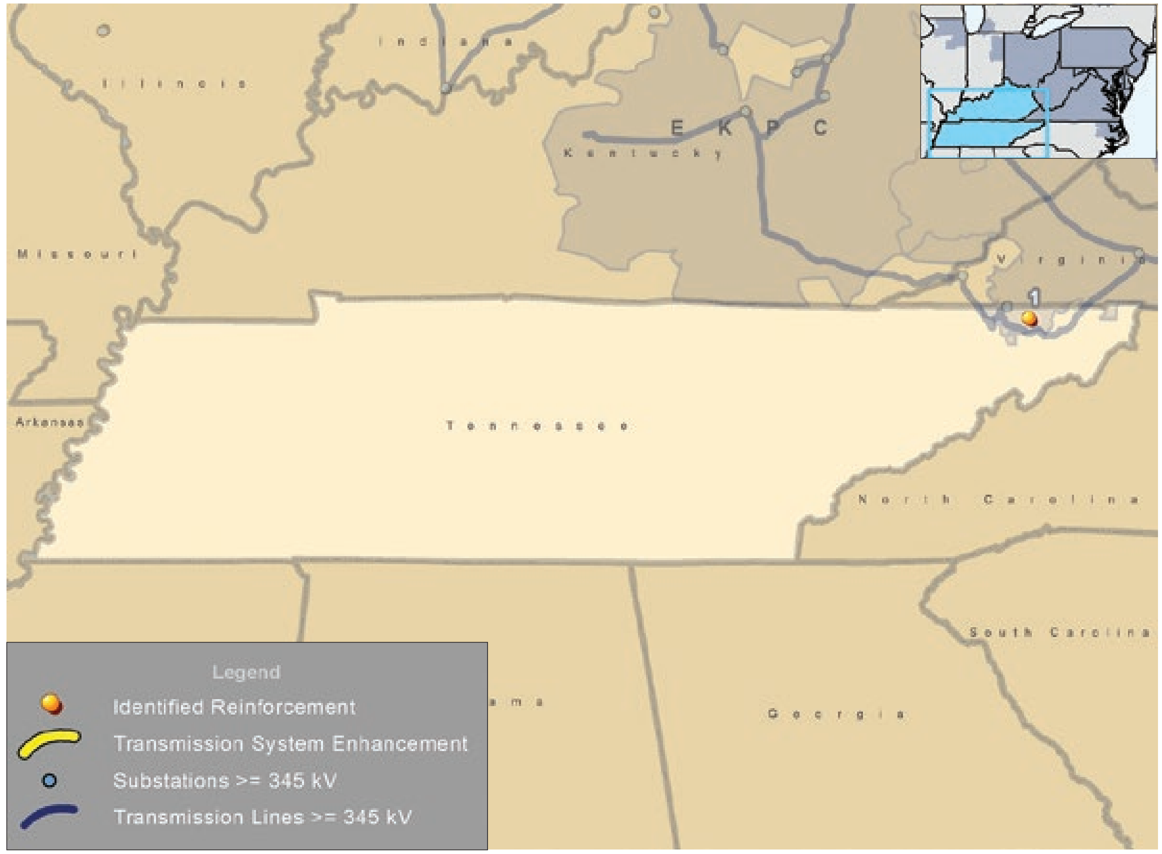


Table 6.47: Tennessee Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2249	Holston substation: Replace existing 138/34.5 kV, 45 MVA transformer No. 1 with a new 138/69/34.5 kV, 90 MVA transformer. Replace existing high-side MOAB switches on transformer No. 1 with new 138 kV, 3000 A 40 KA circuit breaker. Replace existing ground transformers No. 8 and No. 9 with new ground banks. Reconfigure the existing 34.5 kV into a ring bus configuration with five new 34.5 kV breakers.	12/1/2023	$11.50	AEP	4/20/2020

PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

6.11: Virginia RTEP Summary

6.11.1 — RTEP Context

PJM – a FERC-approved RTO – operates and plans the bulk electric system (BES) in Virginia, including facilities owned and operated by Allegheny Power (AP), American Electric Power (AEP), Delmarva Power & Light Co. (DP&L) and Dominion as shown on **Map 6.38**. 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.

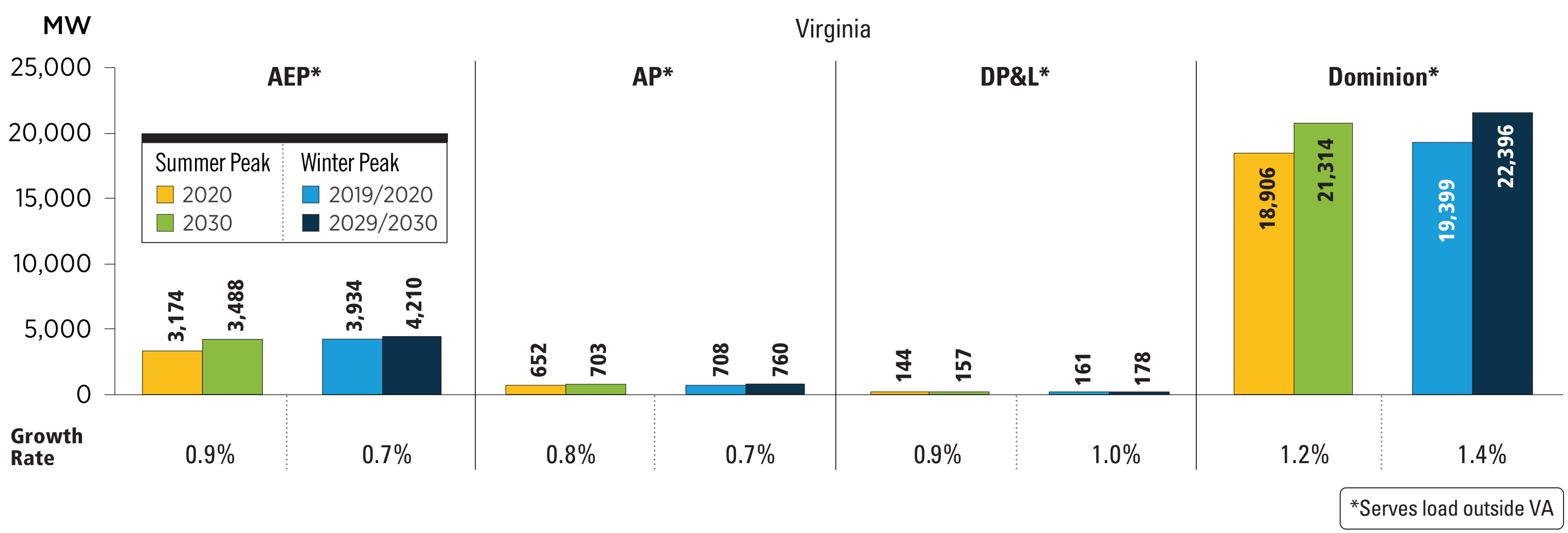
Virginia has a mandatory RPS target of 100 percent by 2045 or 2050, depending on the utility service territory. The state's RPS was a voluntary goal until legislation was passed in 2020. The RPS target is one of two in the PJM region set at 100 percent, with the other being the District of Columbia's.

Map 6.38: PJM Service Area in Virginia

6.11.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.54** summarizes the expected loads within the state of Virginia and across all of PJM.

Figure 6.54: Virginia – 2020 Load Forecast Report



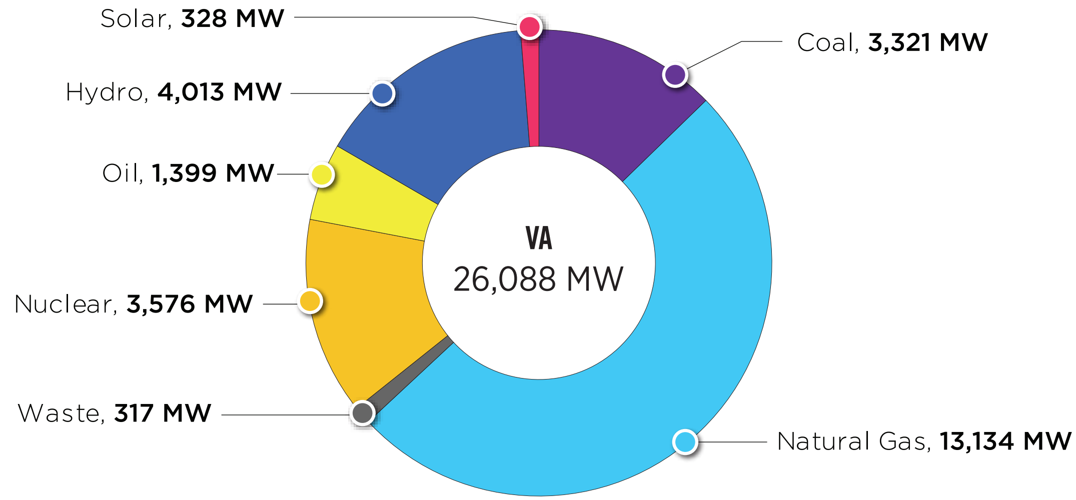
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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, 2020, is shown by fuel type in **Figure 6.55**.

Figure 6.55: Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 438 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.48**, **Table 6.49**, **Figure 6.56**, **Figure 6.57** and **Figure 6.58**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.48: Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	0	0.00%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	0	0.00%	559	0.53%
Natural Gas	4,300	17.78%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	15,343	63.45%	58,845	56.13%
Storage	3,196	13.22%	10,877	10.38%
Wind	1,343	5.55%	6,560	6.26%
Grand Total	24,182	100.00%	104,838	100.00%

Table 6.49: Virginia – Interconnection Requests by Fuel Type (Dec. 31 2020)

		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	4	1,621.0	0	0.0	4	2,679.0	46	7,269.4	43	17,246.8	97	28,816.2
	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	0	0.0	0	0.0	0	0.0	1	0.0	2	136.3	3	136.3
	Storage	69	3,176.0	0	0.0	1	20.0	1	0.0	17	454.3	88	3,650.3
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	0	0.0	0	0.0	0	0.0	15	100.4	11	81.8	26	182.2
	Solar	253	12,794.5	11	156.3	85	2,392.1	28	399.3	185	6,232.0	562	21,974.3
	Wind	9	1,323.9	1	9.4	1	9.9	1	1.5	31	886.2	43	2,230.9
	Wood	0	0.0	0	0.0	0	0.0	1	4.0	2	57.0	3	61.0
	Grand Total	335	18,915.5	12	165.7	91	5,101.0	131	9,738.7	304	27,083.5	873	61,004.3

Figure 6.56: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

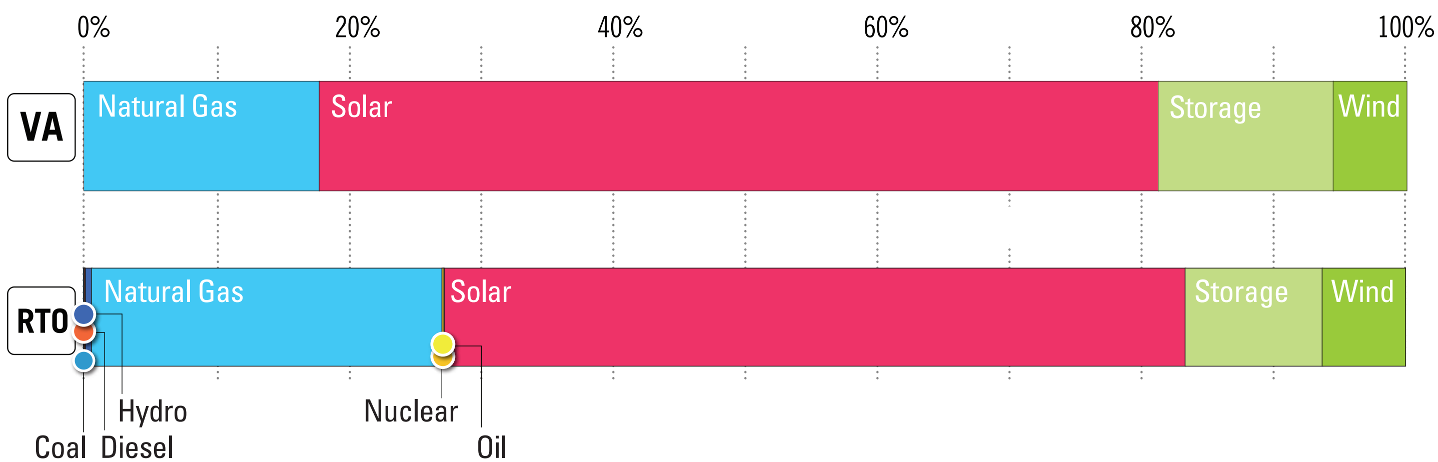
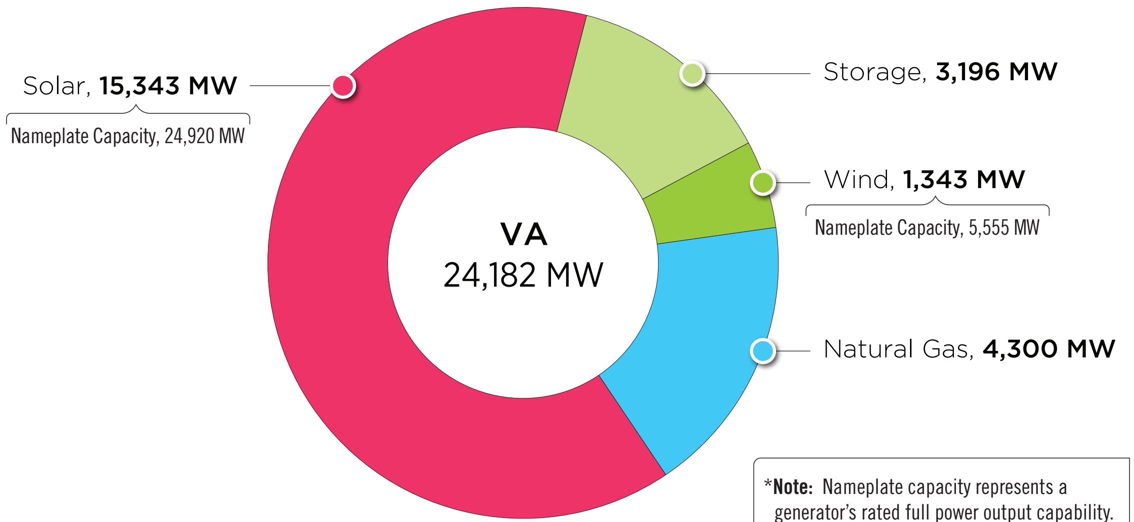
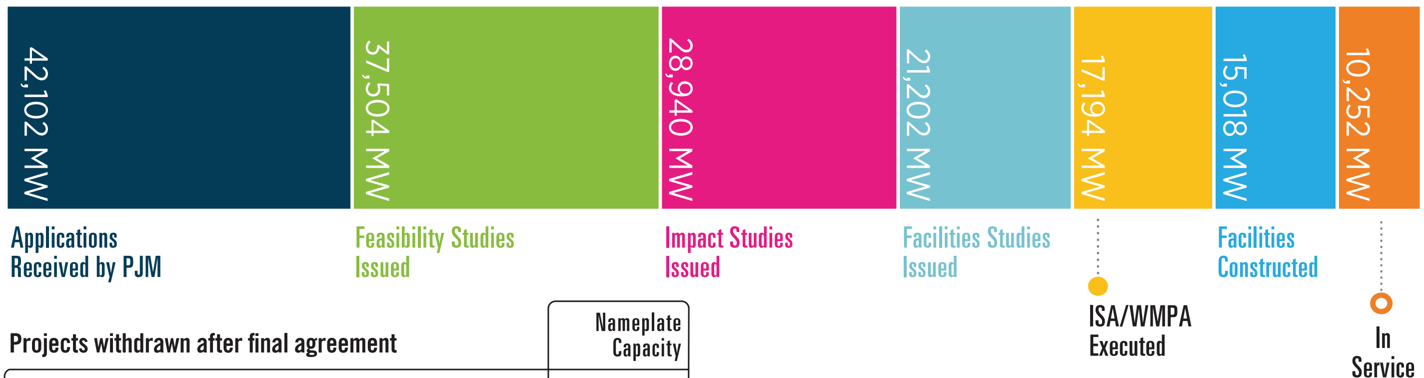


Figure 6.57: Virginia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)



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

Figure 6.58: Virginia Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement			Nameplate Capacity
15	Interconnection Service Agreements	1,934 MW	2,275 MW
25	Wholesale Market Participation Agreements	243 MW	403 MW

Percentage of planned capacity and projects that have reached commercial operation	24% Requested capacity megawatts	27 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.11.5 — Generation Deactivation

Known generating unit deactivation requests in Virginia between Jan. 1, 2020, and Dec. 31, 2020, are summarized in **Map 6.39** and **Table 6.50**.

Map 6.39: Virginia Generation Deactivations (Dec. 31, 2020)

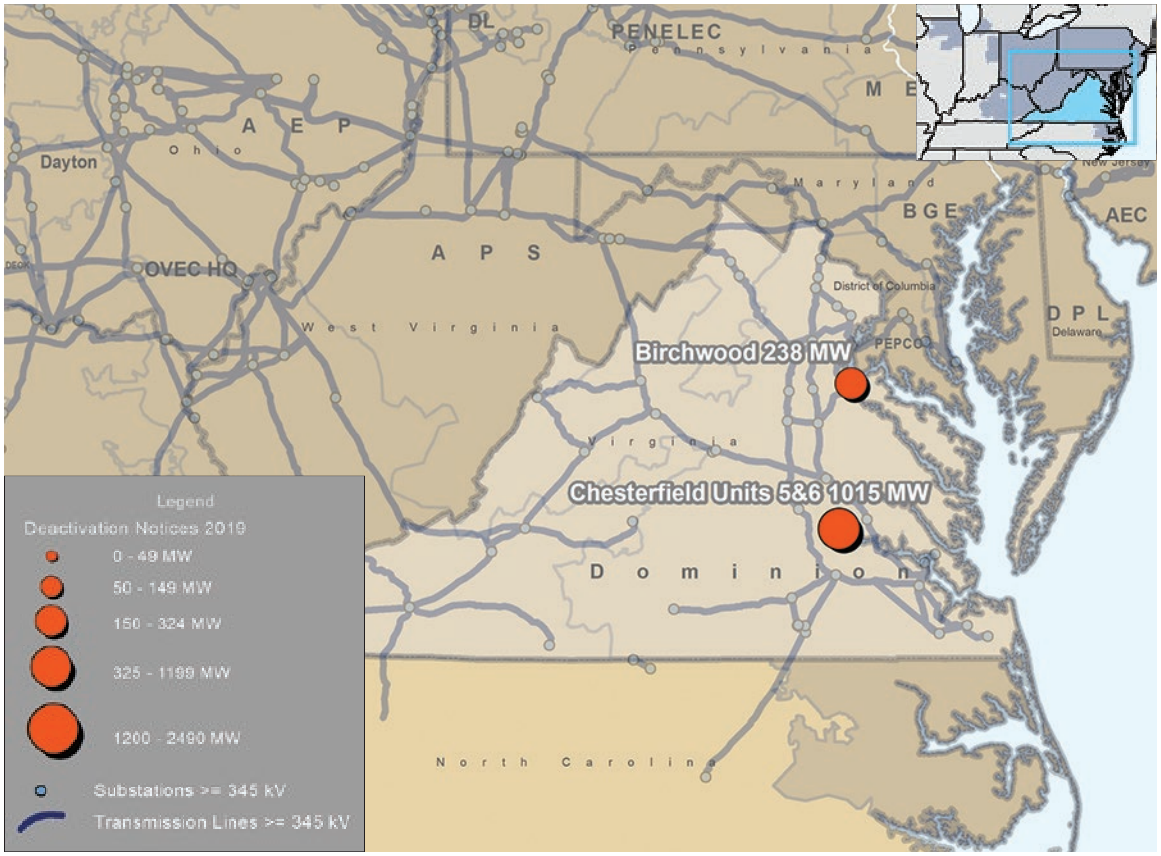


Table 6.50: Virginia Generation Deactivations (Dec. 31, 2020)

Unit	TO Zone	Fuel Type	Request Received to Deactivate	Actual or Projected Deactivation Date	Age (Years)	Capacity (MW)
Birchwood Plant	Dominion	Coal	10/6/2020	3/1/2021	24	238.0
Chesterfield Unit 5			2/20/2020	5/31/2023	56	336.8
Chesterfield Unit 6			2/20/2020	5/31/2023	51	678.1

6.11.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in Virginia are summarized in **Map 6.40** and **Table 6.51**.

Map 6.40: Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

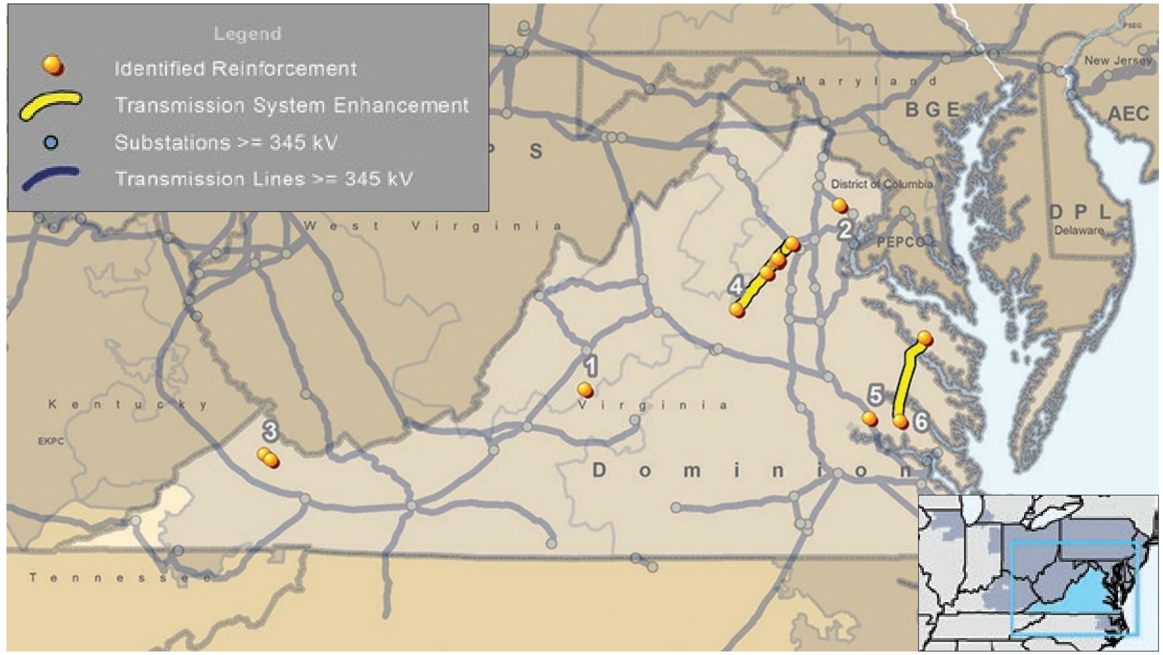


Table 6.51: Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3098	Rebuild Balcony Falls substation.	6/1/2019	$29.00	Dominion	5/21/2020
2	B3110	Replace the Clifton 230 kV breakers 201182 and XT2011 with 63 kA breakers.	12/31/2021	$15.47		8/4/2020
3	B3139	Rebuild the Garden Creek-Whetstone 69 kV line (~0.4 mile).	6/1/2023	$14.00	AEP	10/17/2019
4	B3162	Acquire land and build a new 230 kV switching station (Stevensburg) with a 224 MVA, 230/115 kV transformer. Gordonsville-Remington 230 kV (Line No. 2199) will be cut and connected to the new station. Remington-Mount Run 115 kV (Line No. 70) and Mount Run-Oak Green 115 kV (Line No. 2) will also be cut and connected to the new station.	6/1/2024	$22.00	Dominion	12/16/2019
5	B3213	Install second Chickahominy 500/230 kV transformer.	6/1/2023	$25.76		6/2/2020
6	B3223	Install a second 230 kV circuit with a minimum summer emergency rating of 1047 MVA between Lanexa and Northern Neck substations. The second circuit will utilize the vacant arms on the double-circuit structures that are being installed on the Line No. 224 (Lanexa-Northern Neck) end-of-life rebuild project (B3089).		$23.00		9/1/2020
		Expand the Northern Neck terminal from a 230 kV, four-breaker ring bus to a six-breaker ring bus.				
		Expand the Lanexa terminal from a six-breaker ring bus to a breaker-and-a-half arrangement.				

6.11.7 — Network Projects

No network projects greater than or equal to $10 million in Virginia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the [Project Status](#) page of the PJM website.

6.11.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in Virginia are summarized in **Map 6.41** and **Table 6.52**.

6.11.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in Virginia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the [Project Status](#) page of the PJM website.

Map 6.41: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

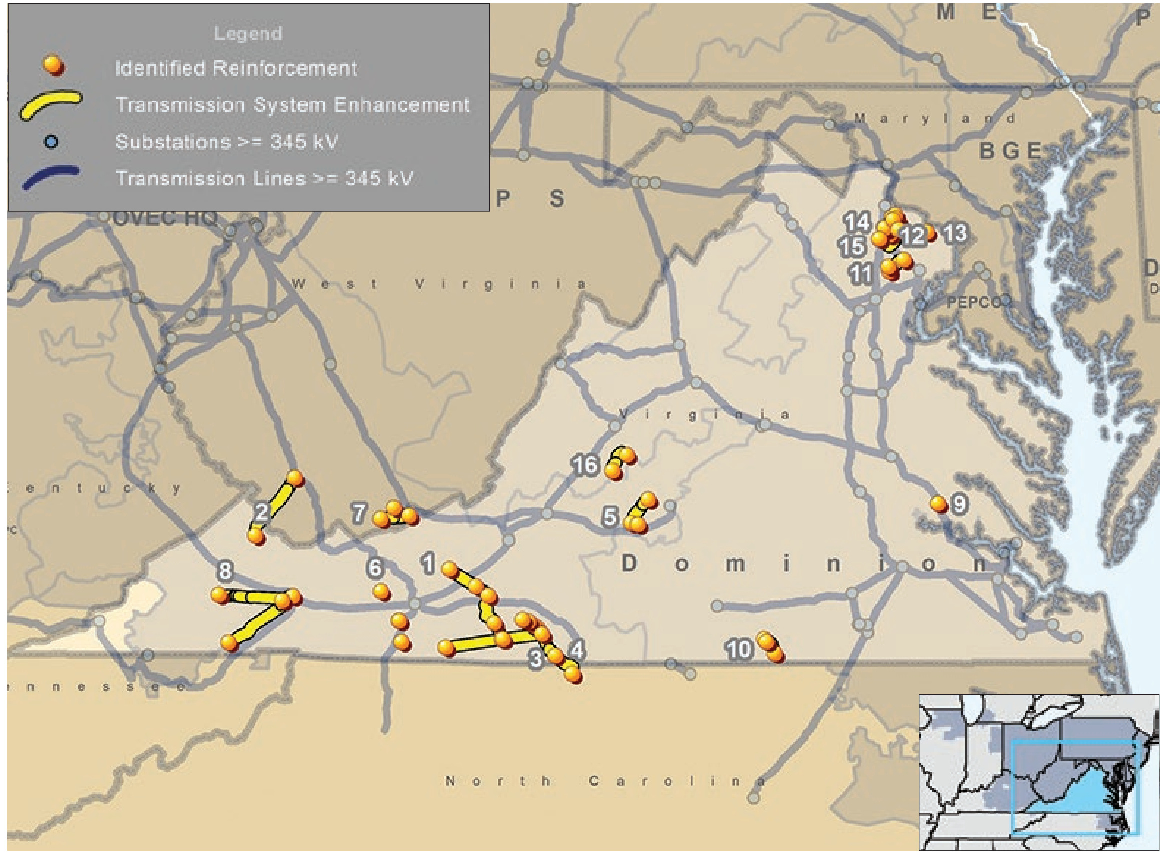


Table 6.52: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S2179	Construct ~12.5 miles of 138 kV line from Alum Ridge to Claytor.	11/1/2027	$326.90	AEP	1/17/2020
		Construct ~6.5 miles of 138 kV line from Alum Ridge to Floyd.	11/2/2026			
		Construct ~7 miles of 138 kV line from Fieldale to Fairystone.	9/2/2024			
		Construct ~1.25 miles of double-circuit 138 kV line to connect Stanleytown.	11/16/2026			
		Construct 0.07 miles of 138 kV line from Bassett Switch to Bassett.	6/1/2026			

Table 6.52: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	S2179	Construct ~1.2 miles of 138 kV line from Philpott Dam to Fairystone.	10/31/2027	$326.90	AEP	1/17/2020
		Construct ~22 miles of 138 kV line from Salem Highway to Willis Gap.	7/1/2024			
		Construct ~21 miles of 138 kV line from Salem Highway to Fairystone.	10/31/2027			
		Construct ~11 miles of 138 kV line from Floyd to Woolwine.				
		Construct ~10 miles of 138 kV line from Salem Highway to Woolwine.	11/1/2024			
		Remove ~11 miles of 69 kV line from Floyd to Woolwine.	6/2/2025			
		Remove ~10 miles of 69 kV line from Stuart to Woolwine.	10/31/2027			
		Remove ~12.2 miles of 138 kV line from Alum Ridge to Claytor.	11/1/2027			
		Remove ~6.25 miles of 138 kV line from Alum Ridge to Floyd.	11/2/2026			
		Remove ~19 miles of 138 kV line from Floyd to West Bassett.	8/14/2026			
		Remove ~6.4 miles of 138 kV line from Fieldale to West Bassett.	6/15/2026			
		Remove ~0.34 miles of 138 kV line from Philpott substation to Philpott.	11/16/2026			
		Remove ~19 miles of 69 kV line from Fieldale to Stuart.	8/14/2026			
		Remove ~7.1 miles of 69 kV line from Fieldale to West Bassett.	6/15/2026			
		Remove ~6.8 miles of 69 kV line from Fieldale to West Bassett.				
		At Floyd station, install two 138 kV circuit breakers (3000 A 40 kA). Install high-side circuit switcher on Transformer 2 (3000A 40 kA). Station expansion to accommodate new equipment and drop-in control module. Install 138 kV line relaying, CCVT's, breaker controls, bus differential protection, Transformer No. 2 protection.	9/1/2025			
		At Fieldale station, retire 69 kV circuit breakers G, D and C. Install CCVTs and arresters on 138 kV West Bassett line.	11/13/2026			
		At Bassett switch, install 138 kV switch with two 138 kV MOABs.	6/1/2026			
		At Bassett station, convert station from 69 kV to 138 kV. Install 138/12 kV transformer with high-side circuit switcher, transclosure and associated distribution feeders.				
		At Claytor 138 kV station, install line relaying. Remove wavetrap. Replace 1590 AAC risers.	11/1/2027			
		Retire Philpott 138 kV switch structure.	11/16/2026			
		At Willis Gap station, install two 138 kV MOABs. Terminate new Salem Highway-Willis Gap 138 kV line.	6/3/2024			
		At Woolwine station, convert station from 69 kV to 138 kV. Retire/remove 69 kV switch structure, 69 kV MOABs and 69/34.5 kV transformer. Install 138 kV three-way switch structure with MOABs and 138/34.5 kV transformer with high-side circuit switcher.	11/1/2024			
		At Salem Highway station, establish new 138 kV station replacing Stuart station. Install 138 kV five-breaker ring bus, 138/34.5 kV & 138/12 kV transformers with high-side circuit switchers. Terminate Huffman, Floyd and Fairystone 138 kV circuits.	9/2/2024			
		At Stuart 69 kV station, retire and remove all existing equipment and control house.	6/2/2025			
		At Stanleytown station, convert station from 69 kV to 138 kV. Retire/remove 69 kV switch structure, 69 kV MOABs, 69/12 kV transformer. Install 138 kV three-way switch structure with MOABs and 138/12 kV transformer with high-side circuit switcher.	11/13/2026			

Table 6.52: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1 Cont.	S2179	At Fairystone station, establish new 138 kV station replacing West Bassett. Install 138 kV, four-breaker ring bus, 138/34.5 kV transformer with high-side circuit switcher and associated distribution feeders. Terminate Salem Highway, Fieldale and Philpott Dam 138 kV circuits.	10/31/2027	$326.90	AEP	1/17/2020
		At Claudville station, establish new 138/34.5 kV distribution station with two 138 kV CBs, 138/34.5 kV transformer and three 34.5 kV feeders.				
		Provide transition, entry and termination for OPGW connectivity at Willis Gap, Claytor, Alum Ridge, Floyd, Woolwine, Stuart, Fairystone, Philpott Dam, Bassett, Stanleytown, Fieldale and Salem Highway to support fiber relaying.	7/1/2024			
2	S2189	Rebuild ~27.8 miles of the existing Baileysville–Hales Branch 138kV circuit.	8/1/2026	$98.50		2/21/2020
3	S2190	Rebuild approximately 15 miles of the AEP-owned portion of the 138 kV line between Fieldale and Dan River stations (AEP/Duke ownership changes at the border of North Carolina and Virginia).	10/31/2022	$32.20		
4	S2191	Construct ~5.75 miles of new double-circuit 138 kV line from the Fieldale-Ridgeway 138 kV circuit to a new Commonwealth Crossing station.	3/1/2020	$15.20		
		Establish a new 138/34.5 kV Commonwealth Crossing station with two 138 kV, 3000 A 40 kA circuit breakers, high-side 3000 A 40 kA circuit switcher, 138/34.5 kV, 30 MVA transformer and three 34.5 kV distribution feeders.				
		Install 5.75 miles of 48 count fiber between Commonwealth Crossing station and Ridgeway station to support SCADA and relaying.				
5	S2192	Rebuild 11.6 mile section of the Reusens-Altavista 138 kV line asset from Reusens to New London. ~5.5 miles consists of double-circuit 138 kV construction and ~6 miles consists of single-circuit 138 kV construction between Reusens and New London.	10/31/2022	$36.20		
		Install a 57.6 MVAR cap bank at Brush Tavern due to low-voltage concerns from operations during construction outages in the area.				
6	S2214	At Galax station, replace existing 69 kV circuit breakers F, G, and H with new 3000A 40 kA circuit breakers.		$10.20		3/19/2020
		At Byllesby station, replace existing 69 kV circuit breakers B and D with new 3000A 40 kA circuit breakers.				
		At Jubal Early station, replace the existing 138/69/34.5 kV 75 MVA XFR with a new 138/69/34.5 kV 90 MVA XFR.				
		At Wythe station, replace existing 138/69 kV, 75 MVA XFR with a new 138/12 kV 20 MVA XFR, remove 69 kV CBs F and M, remove 69 kV bus and install 12 kV bus. Retire Lee Highway station and serve load from Wythe.				
7	S2226	Construct ~10 miles of new 138 kV line between Glen Lyn and Speedway. New right-of-way will be required for the new Glen Lyn-Speedway 138 kV line. Retire the existing section of line from Glen Lyn to Hatcher switch (~8 miles), including Hatcher switch.	5/1/2023	$55.40		
		Retire Hatcher switch. Install MOABs at Speedway on new line to Glen Lyn and existing line towards South Princeton. Install a circuit switcher on the Speedway transformer.				
		Rebuild ~7.3 miles of the Glen Lyn-South Princeton 138 kV circuit between Speedway station and the previous Hatcher switch.	12/1/2026			
8	S2250	Rebuild the existing Broadford-Wolf Hills/Clinch River-Saltville No. 2 138 kV double-circuit line (~26 miles) section between Saltville and Wolf Hills stations.	5/1/2024	$107.10		4/20/2020

Table 6.52: Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
9	S2319	Replace the three single phase 500/230 kV transformer banks and one spare bank with new units at Chickahominy.	9/30/2019	$14.10	Dominion	2/4/2020
10	S2320	Obtain land and build a 115 kV switching station (Cloud), adjacent to MEC's new Coleman Creek DP. Split Line No. 38 (Kerr Dam-Boydton Plank Rd.), extend a double-circuit 115 kV line for ~1.76 miles (new right-of-way) and terminate both lines into the new switching station. The switching station will consist of one breaker separating the two new lines. Provide one 115 kV line to serve MEC's new DP. Additionally, a 33 MVAR capacitor bank will be required at Herbert to provide additional voltage support.	11/30/2020	$16.00		2/11/2020
11	S2321	Install a 1,200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Cloverhill.	6/1/2022	$17.75	Dominion	3/10/2020
		Install a 1,200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Winters Branch.	1/1/2022			5/12/2020
		Install a 1,200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Winters Branch.	3/1/2023			
		Reconductor the 230 kV line No. 2011 from Clifton to Cannon Branch (7.54 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.	12/31/2025			10/6/2020
12	S2324	Interconnect the new Aviator substation by cutting and extending line No. 2137 (Poland-Shellhorn) ~0.5 miles to the proposed substation. Terminate both ends into a four-breaker ring arrangement to create an Aviator-Poland line and an Aviator-Shellhorn line. Dominion's standard high-ampacity conductor (bundled 768 ACSS; normal summer rating: 1572 MVA) will be used for the line extension.	12/15/2024	$22.00		5/12/2020
13	S2326	Construct one 230 kV underground line from Tysons Substation to a new substation named Springhill substation to replace the portion of existing Ohio line No. 2010. Install a 230 kV, 50-100 MVAR variable shunt reactor at Tysons substation.	12/31/2025	$40.00		5/12/2020
14	S2328	Install a 1,200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Waxpool.	10/1/2021	$29.30		6/2/2020
		Install a 1,200 amp, 50 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Pacific.	12/15/2021			8/4/2020
		Install a 1,200 amp, 40 kAIC circuit switcher and associated equipment (bus, switches, relaying, etc.) to feed the new transformer at Cumulus.	3/1/2022			8/4/2020
		Reconductor the 230 kV line 2152 from Beaumeade to Nimbus (2.16 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.	12/31/2025			10/6/2020
		Reconductor the 230 kV line 9173 from Nimbus to Buttermilk (0.94 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.				
		Reconductor the 230 kV line 9185 from Beaumeade to Paragon Park (1.0 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.				
		Reconductor the 230 kV line 2209 from Evergreen Mills to Yardley Ridge (0.16 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.				
		Reconductor the 230 kV line 2095 from Cabin Run to Shellhorn (4.73 miles) using a higher capacity conductor as well as terminal equipment upgrades to achieve an expected rating of 1574 MVA.				
15	S2329	Interconnect the new substation Lincoln Park by cutting and extending line No. 2008 (Dulles-Loudoun) and line No. 2143 (Discovery-Reston) to the proposed substation. Lines to terminate in a six-breaker ring arrangement.	9/1/2023	$10.47		6/2/2020
		Replace 50 kAIC Clifton L282 breaker with 63 kAIC model.	6/1/2025			10/6/2020
16	S2337	Rebuild ~9.771 miles of line No. 26, between Balcony Falls and Buena Vista, to current 115 kV standards and with a minimum rating of 261 MVA.	12/31/2024	$20.00		8/13/2020

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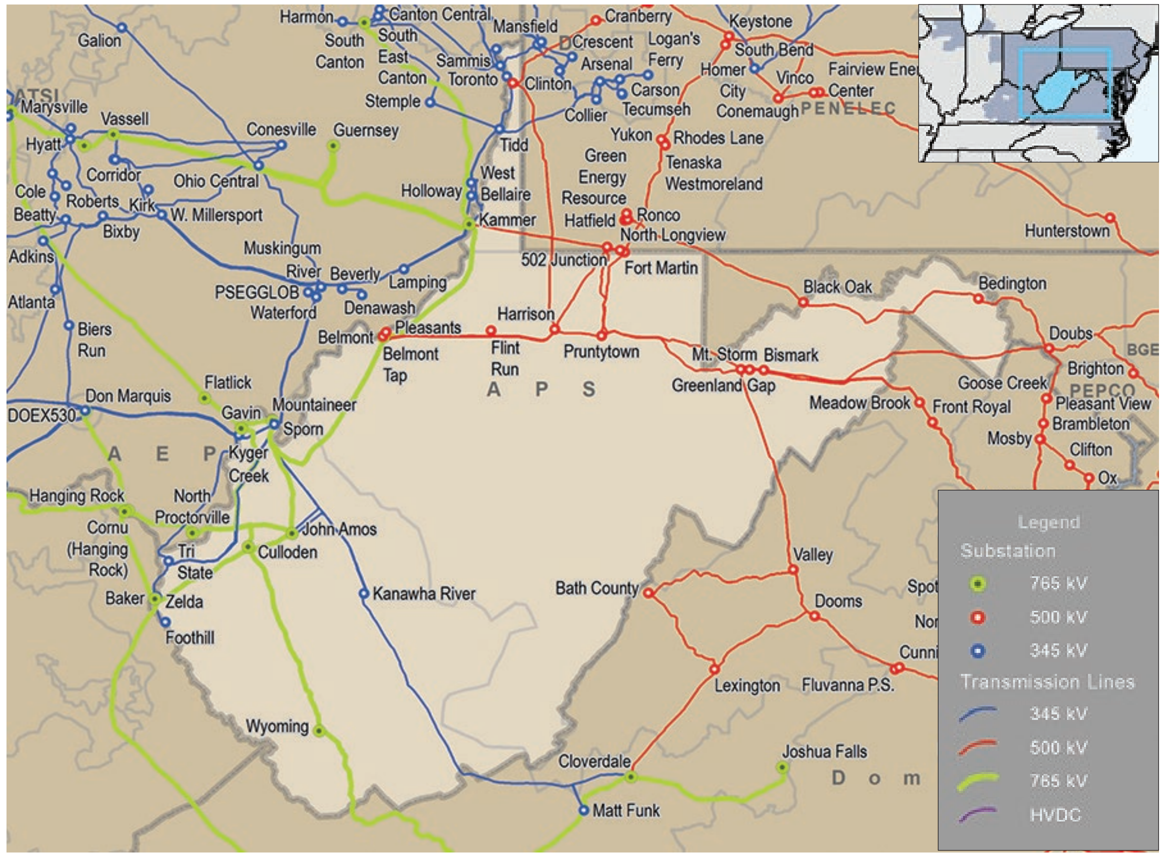
6.12: West Virginia RTEP Summary

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 6.42**. 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.

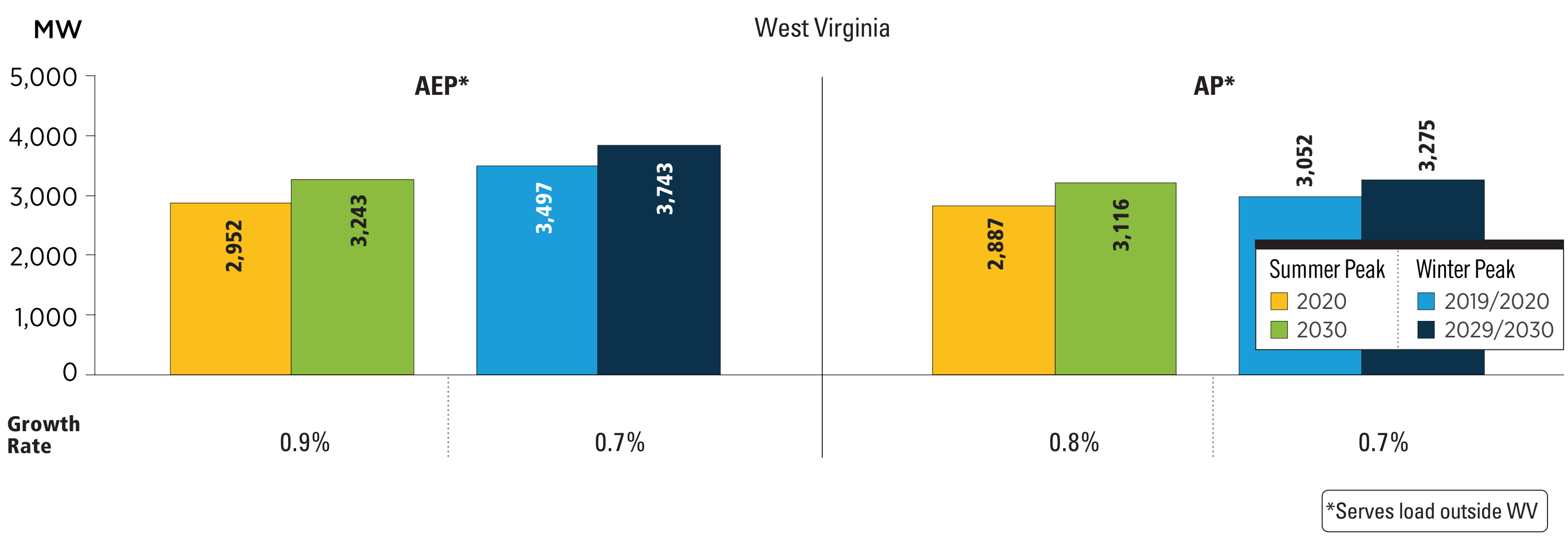
Map 6.42: PJM Service Area in West Virginia



6.12.2 — Load Growth

PJM's 2020 load forecast provided the basis for the loads modeled in power flow studies used in PJM's 2020 analyses. **Figure 6.59** summarizes the expected loads within the state of West Virgina and across all of PJM.

Figure 6.59: West Virginia – 2020 Load Forecast Report



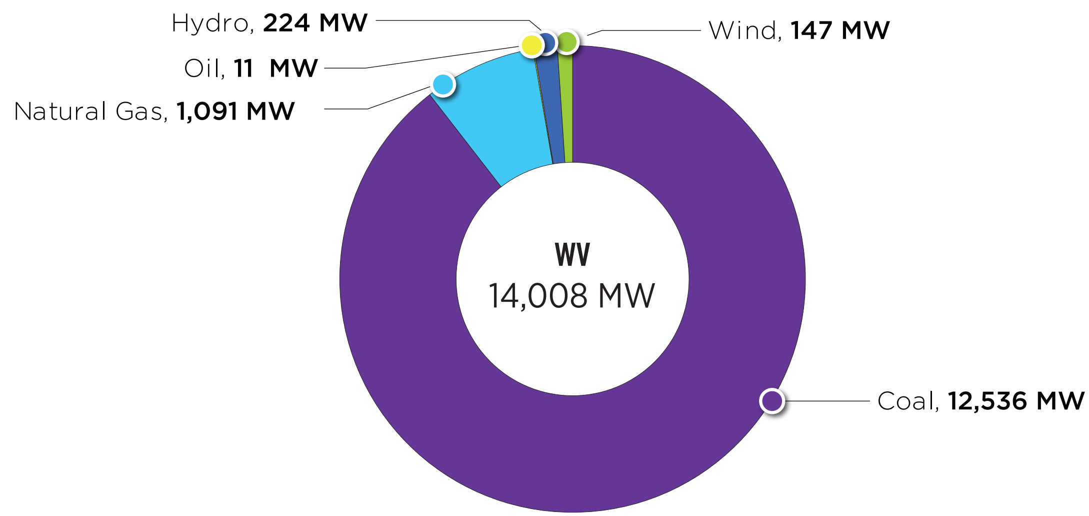
PJM RTO Summer Peak		PJM RTO Winter Peak	
2020	2030	2019/2020	2029/2030
148,092 MW	157,132 MW	131,287 MW	139,970 MW
Growth Rate 0.6%		Growth Rate 0.6%	

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, 2020, is shown by fuel type in **Figure 6.60**.

Figure 6.60: West Virginia – Existing Installed Capacity (MW) by Fuel Type (Dec. 31, 2020)



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, 2020, 38 queued projects were actively under study or under construction as shown in the summaries presented in **Table 6.53**, **Table 6.54**, **Figure 6.61**, **Figure 6.62** and **Figure 6.63**. These graphics summarize new generation in terms of requested Capacity Interconnection Rights (CIRs) as broken down by fuel type and interconnection process status. A full description of CIRs can be found in Manual 21.

Table 6.53: West Virginia – Capacity by Fuel Type – Interconnection Requests (Dec. 31. 2020)

	West Virginia Capacity		PJM RTO Capacity	
	MW	Percentage of Total Capacity	MW	Percentage of Total Capacity
Battery	0	0.00%	0	0.00%
Coal	36	1.07%	76	0.07%
Diesel	0	0.00%	4	0.00%
Hydro	30	0.89%	559	0.53%
Natural Gas	1,885	56.00%	27,804	26.52%
Nuclear	0	0.00%	81	0.08%
Oil	0	0.00%	31	0.03%
Solar	1,317	39.11%	58,845	56.13%
Storage	60	1.78%	10,877	10.38%
Wind	39	1.15%	6,560	6.26%
Grand Total	**3,366**	**100.00%**	**104,838**	**100.00%**

Table 6.54: 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	2	1,285.0	3	600.0	0	0.0	6	409.7	43	16,140.8	54	18,435.5
	Nuclear	0	0.0	0	0.0	0	0.0	0	0.0	2	66.0	2	66.0
	Other	3	54.2	1	5.8	1	0.0	2	0.0	3	18.0	10	78.0
	Storage	0	0.0	0	0.0	0	0.0	0	0.0	2	48.0	2	48.0
Renewable	Biomass	1	30.0	0	0.0	0	0.0	5	59.2	12	208.8	18	298.0
	Hydro	0	0.0	0	0.0	0	0.0	3	5.6	3	13.8	6	19.4
	Methane	23	1,316.7	0	0.0	0	0.0	0	0.0	4	44.2	27	1,360.9
	Solar	2	23.5	0	0.0	1	15.1	10	197.5	26	414.8	39	650.9
	Wind	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
	Grand Total	31	2,709.4	4	605.8	3	51.1	36	1,533.0	102	18,977.4	176	23,876.7

Figure 6.61: Percentage of Projects in Queue by Fuel Type (Dec. 31, 2020)

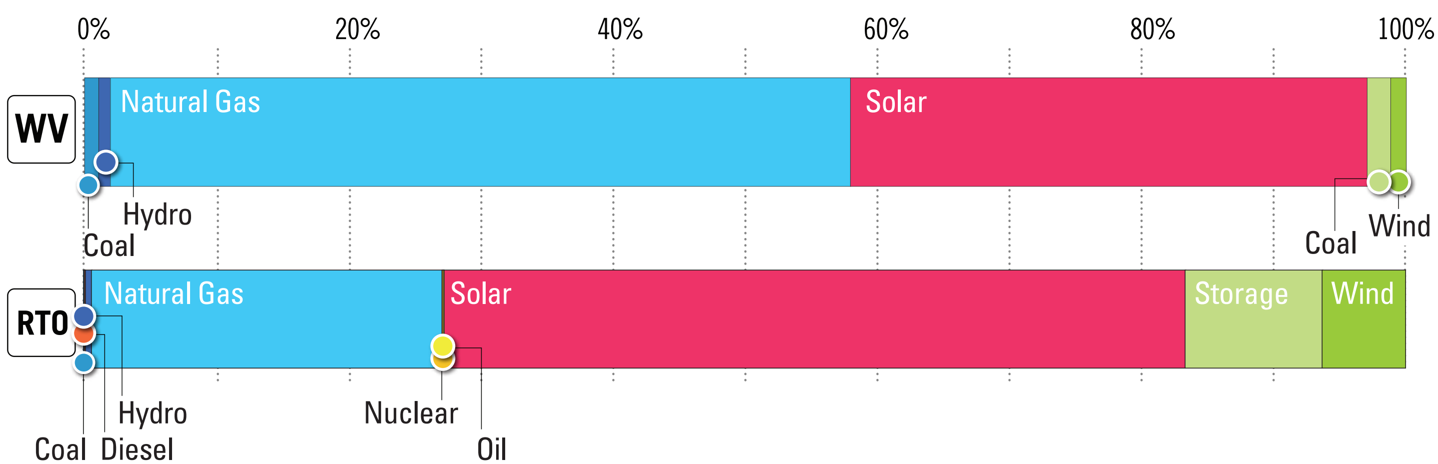
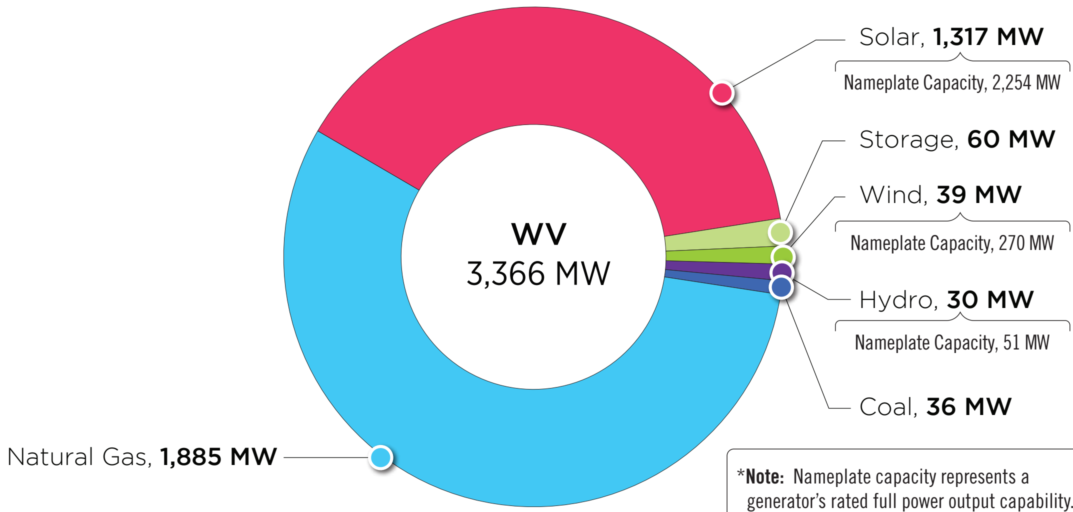
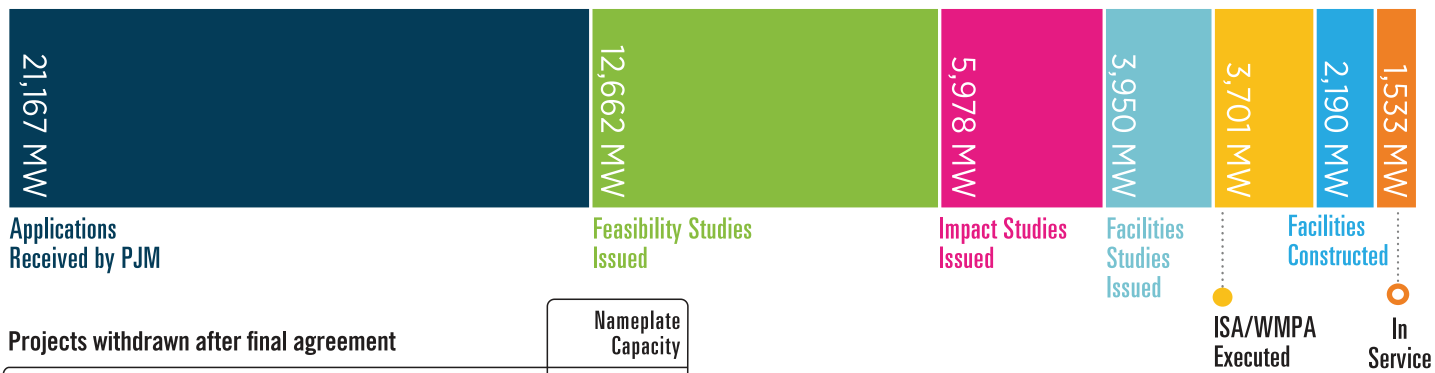


Figure 6.62: West Virginia – Queued Capacity (MW) by Fuel Type (Dec. 31, 2020)



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

Figure 6.63: West Virginia Progression History of Queue – Interconnection Requests (Dec. 31, 2020)



Projects withdrawn after final agreement

			Nameplate Capacity
12	Interconnection Service Agreements	1,499 MW	1,951 MW
2	Wholesale Market Participation Agreements	6 MW	11 MW

Percentage of planned capacity and projects that have reached commercial operation	7% Requested capacity megawatts	25 % Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

6.12.5 — Generation Deactivation

There were no known generating unit deactivation requests in West Virginia between Jan. 1, 2020, and Dec. 31, 2020, as part of the 2020 RTEP.

6.12.6 — Baseline Projects

2020 RTEP baseline projects greater than or equal to $10 million in West Virginia are summarized in **Map 6.43** and **Table 6.55**.

6.12.7 — Network Projects

No network projects greater than or equal to $10 million in West Virginia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.43: West Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

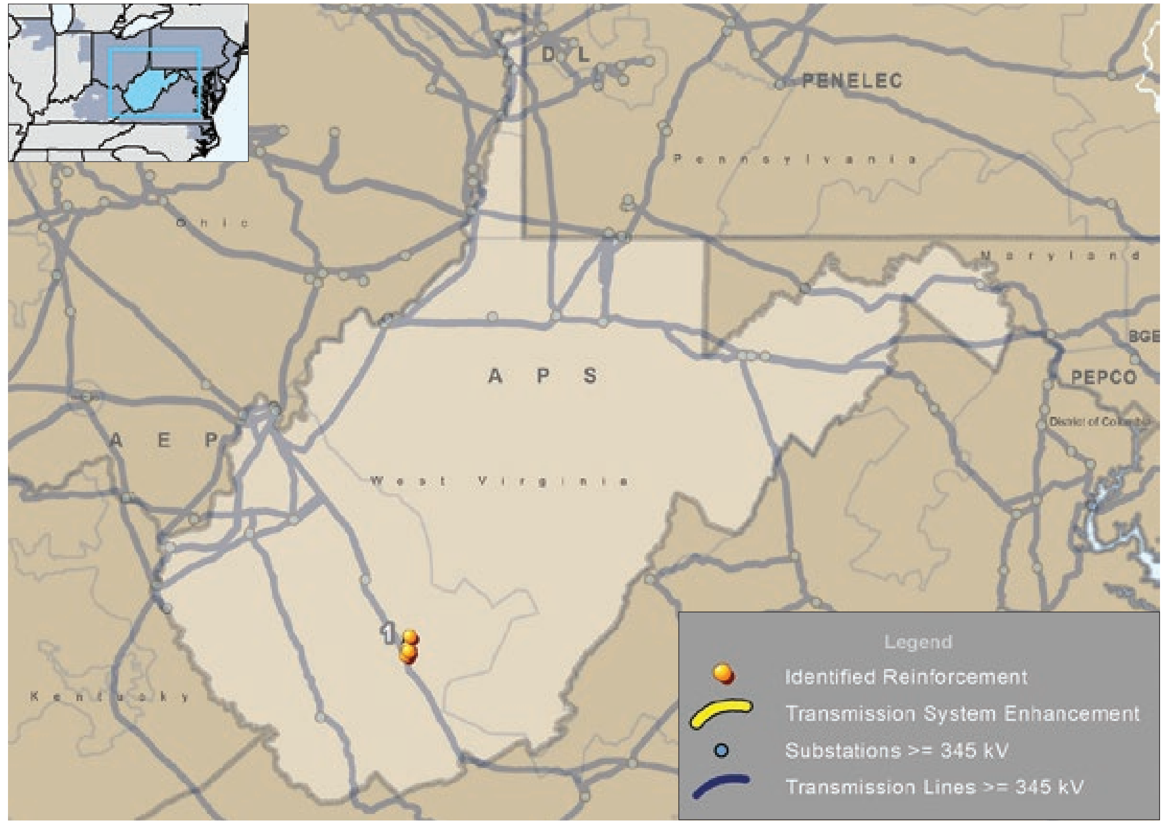


Table 6.55: West Virginia Baseline Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Required In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	B3148	Rebuild the 46 kV Bradley-Scarbro line to 96 kV standards using 795 ACSR to achieve a minimum rater of 120 MVA. Rebuild the new line adjacent to the existing one leaving the old line in service until the work is completed.	12/1/2021	$27.70	AEP	10/25/2019
		Bradley remote-end station work, replace 46 kV bus, install new 12 MVAR capacitor bank.				
		Replace the existing switch at Sun substation with a two-way SCADA-controlled MOAB switch.				
		Remote end work and associated equipment at Scarbro station.				
		Retire Mt. Hope station and transfer load to existing Sun station.				

6.12.8 — Supplemental Projects

2020 RTEP supplemental projects greater than or equal to $10 million in West Virginia are summarized in **Map 6.44** and **Table 6.56**.

6.12.9 — Merchant Transmission Project Requests

No merchant transmission project requests greater than or equal to $10 million in West Virginia were identified as part of the 2020 RTEP. PJM Board-approved project details are accessible on the Project Status page of the PJM website.

Map 6.44: West Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

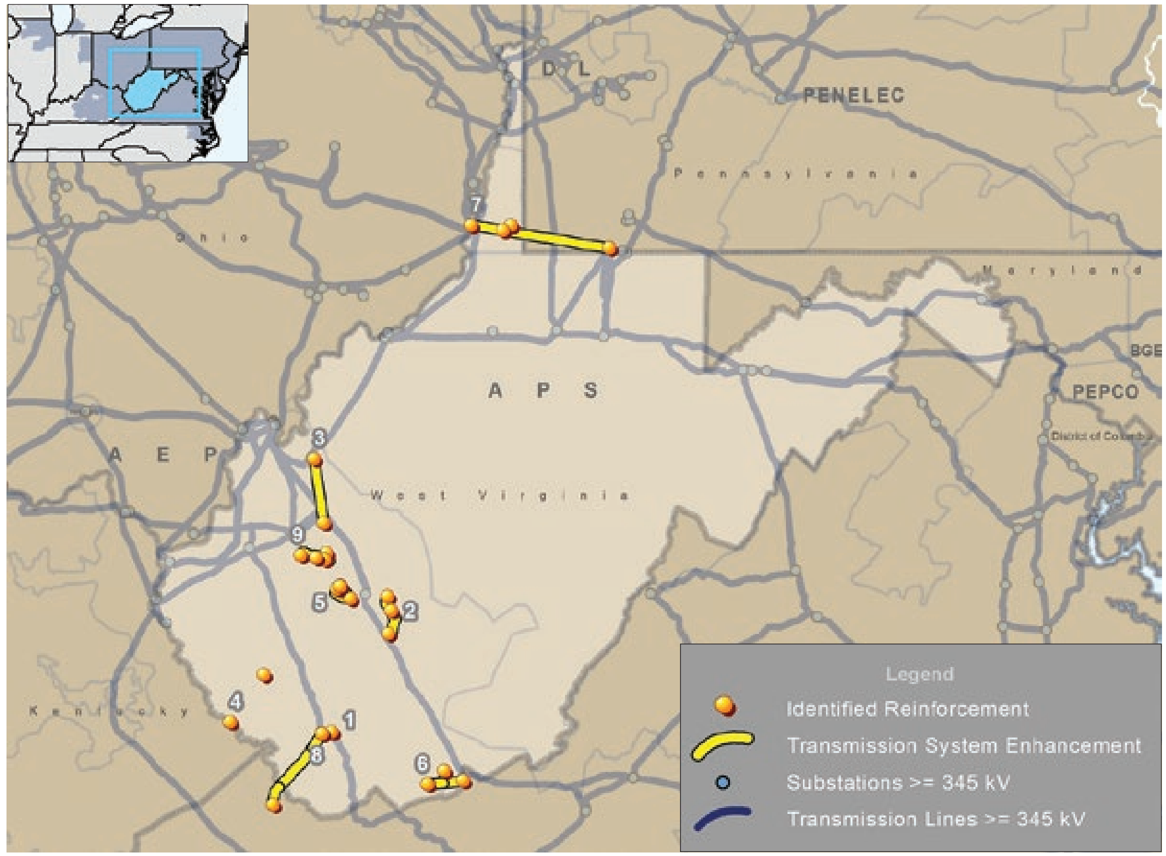


Table 6.56: West Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
1	S1497	Expand Guyandotte 138 kV station, install new 138 kV switch, circuit switcher and 138/12 kV transformer to allow for retirement of Marianna station.	6/1/2021	$78.50	AEP	11/20/2020

Table 6.56: West Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
2	S2177	Rebuild the Carbondale-Kincaid 46 kV line as a single-circuit 46 kV line (~16.3 miles).	6/1/2023	$76.50	AEP	1/17/2020
		Retire the Carbondale-Kincaid No. 1/No. 2 double-circuit 46 kV line.				
		Alloy station: Install a two-way switch to address hard tap.				
		Page substation: Replace existing switch to accommodate new line.				
		Raynes Meter station: Remove/retire station.				
		Boomer station: Remove/retire station.				
		Carbondale station: Replace existing circuit breakers A and G with two new 69 kV circuit breakers. Replace existing 46 kV circuit breakers B, C and F. Retire 46 kV circuit breaker D. Install two new 138 kV circuit breakers and a high-side circuit switcher. Replace existing 138/69/46 kV, 115 MVA transformer with a new 138/69/46 kV, 130 MVA transformer. 138 kV line work needed to accommodate the station work.				
		Kincaid station: Replace existing circuit breakers A and B with two new 46 kV circuit breakers. Retire circuit breaker J. Replace existing ground transformer bank with a new ground transformer bank. Install a new high side circuit switcher to replace the existing ground switch. MOAB on the high side of the transformer.				
3	S2178	Construct a new 138 kV line (~11.5 mi.) from Kenna to the existing Ripley 138 kV station.	11/17/2023	$61.70		1/17/2020
		Construct a new 138 kV line (~10 mi.) from Kenna to the existing Sisson 138 kV station.				
		Install three new 138 kV circuit breakers at Sisson and perform remote end relaying work at Amos station.				
		Install 138 kV bus and two new 138 kV circuit breakers at Kenna.				
		Install one new 138 kV circuit breaker at Ripley.				
4	S2189	Rebuild ~27.8 miles of the existing Baileysville-Hales Branch 138kV circuit.	8/1/2026	$98.50		2/21/2020
5	S2225	Retire the existing 7.5-mile long Belle-Cabin Creek No. 1 and No. 2 circuits from Belle to Cabin Creek.	4/1/2023	$41.80		3/19/2020
		Construct new double-circuit 46 kV line (designed to 138 kV) from Belle to Hernshaw (~4 miles).				
		At Hernshaw station, install four new circuit breakers, 3000 A 40 kA, 46 kV (138 kV design) in a ring configuration. Install two new 138/46 kV, 90 MVA transformers at Hernshaw with two circuit breakers, 3000 A 40 kA, 138 kV, on the high side of each new transformer.				
		Remote end work and retire circuit breakers AA and AB at Cabin Creek station.				
		Install Chesapeake 46 kV substation to eliminate existing hard tap currently serving Praxair. Install a new line extension to Praxair (0.2 miles).				
		Replace the existing switches at Marmet Station to accommodate the new line construction.				
		Marmet hydro hard tap will be relocated to be positioned between 46 kV circuit breaker G at Belle and the new switches at Marmet station. Remote end work required at Marmet hydro station.				
		Belle Station work to replace CCVTs with new 46 kV PTs and upgrade line surge arresters.				
6	S2226	Construct ~10 miles of new 138 kV line between Glen Lyn and Speedway. New right-of-way will be required for the new Glen Lyn-Speedway 138 kV line. Retire the existing section of line from Glen Lyn to Hatcher switch (~8 miles), including Hatcher switch.	5/1/2023	$55.40		3/19/2020
		Retire Hatcher switch. Install MOABs at Speedway on new line to Glen Lyn and existing line towards South Princeton. Install a circuit switcher on the Speedway transformer.				
		Rebuild ~7.3 miles of the Glen Lyn-South Princeton 138 kV circuit between Speedway station and the previous Hatcher switch.	12/1/2026			

Table 6.56: West Virginia Supplemental Projects (Greater Than or Equal to $10 Million) (Dec. 31, 2020) (Cont.)

Map ID	Project	Description	Projected In-Service Date	Project Cost ($M)	TO Zone	TEAC Date
7	S2270	Construct a new 500-138 kV station (Panhandle), connecting to the Kammer-502 Junction 500 kV circuit (~10.3 miles from Kammer, 31.7 miles from 502 Junction). Install a three-breaker 500 kV ring bus; 450 MVA 500-138 kV transformer; three-breaker 138 kV ring bus.	3/1/2022	$68.70	AEP	5/12/2020
		Construct a new 138 kV switching station (Nauvoo Ridge) with eight 138 kV breakers in a breaker-and-a-half design. The station will have one circuit to Gosney Hill, two circuits to the customer's facility, two circuits to Panhandle, and a 23 MVAR, 138 kV cap bank.				
		At Gosney Hill, install a new 138 kV breaker toward Nauvoo Ridge. Update station protection. Replace the 795 AAC risers and strain bus with 2000 AAC risers.				
		Construct a new 4.7-mile, 138kV line south of Gosney Hill station to Nauvoo Ridge. Utilize 1033 ACSR conductor. Acquire new right-of-way.				
		Construct a new 1.3 mile, double-circuit 138 kV line from Nauvoo Ridge to the customer's substation. Acquire new right-of-way.				
		Construct a new 1.5 mile, double-circuit 138 kV line from Panhandle to Nauvoo Ridge. Utilize 1033 ACSR conductor for each circuit. Acquire new right-of-way.				
		Extend the Kammer-502 Junction 500 kV transmission line 0.1 mile into Panhandle station (0.2 mile total).				
8	S2346	Replace existing 138 kV CBs G, H, I, K, L and N with six new 138 kV, 40 kA circuit breakers. Replace existing 138 kV cap bank BB and install a new 138 kV breaker on the new cap bank. Replace existing 46 kV cap bank switcher with a new cap bank switcher. Install a high-side circuit switcher on the existing 138/46 kV transformer. Upgrades will be made to the existing road into the station to improve access and space constraints. A flood wall will be installed to mitigate flooding concerns. Note: 138 kV CS CC failed and has been replaced.	7/1/2022	$10.10		7/17/2020
9	S2348	At Chemical station, replace existing 138/46 kV, 45 MVA transformers No. 1 and No. 2 with two new 138/46 kV, 90 MVA transformers and install two 138 kV high-side circuit switchers on each transformer. Retire 138/46 kV transformer No. 4. Retire 46 kV, 18 MVAR capacitor and switcher DD. Retire 46 kV bus No. 1, bus No. 2 and bus No. 3. Rebuild the 46 kV into a fourteen-breaker ring configuration. Replace grounding banks No. 7 and No. 8.	10/17/2022	$35.30		
		Line work is required to accommodate the new station configuration on the Chemical-Turner 138 kV line and Chemical-Chesterfield 46 kV line.				
		Remote-end work is required at Turner station, Central Avenue station and Ward Hollow stations.				
		Rebuild the Chemical-South Charleston No. 1 and Chemical-South Charleston No. 2 46 kV lines with a new double-circuit 46 kV line (69 kV standards) from Chemical-Criel Mound.				
		At South Charleston, retire the existing circuit breakers A and B and install four new 46 kV, 40 kA circuit breakers in a ring at a new station (Criel Mound) adjacent to the existing South Charleston station.				

Appendix 1: TO Zones and Locational Deliverability Areas

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

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

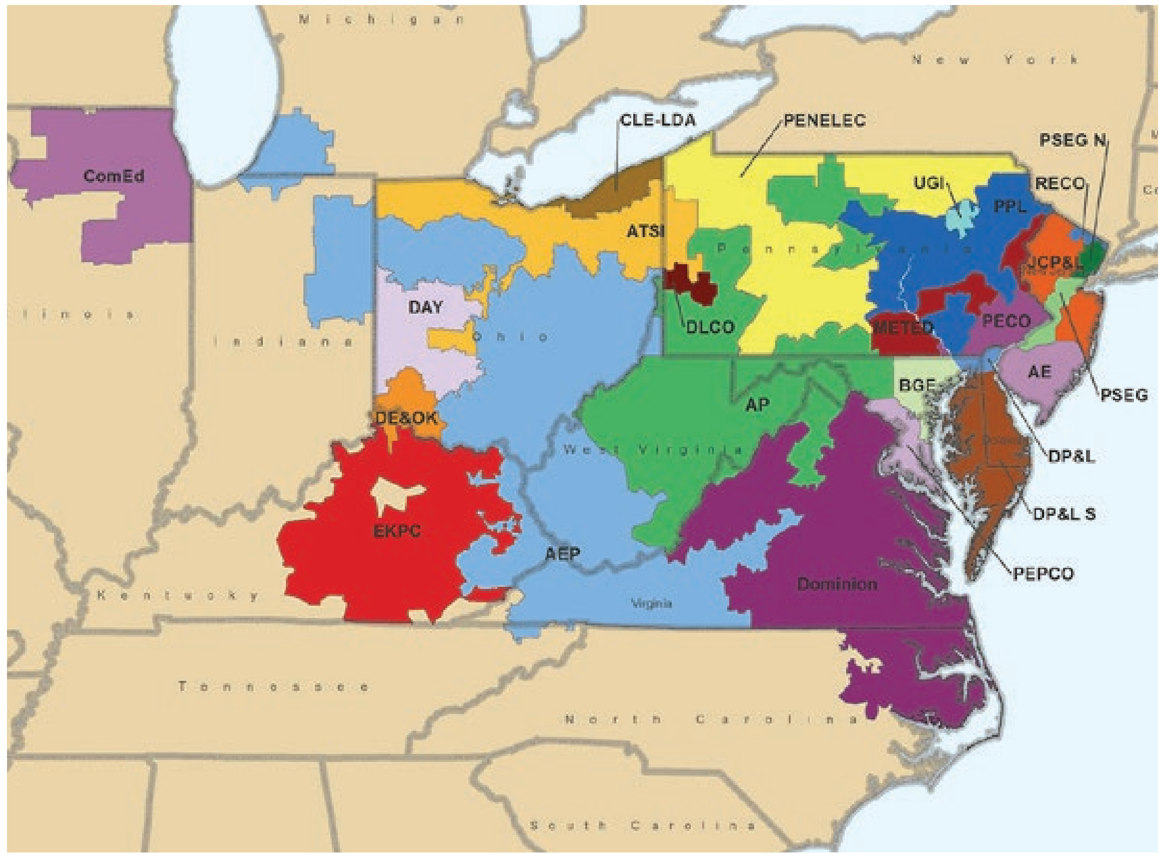


Table 1.1: Locational Deliverability Areas

Entity Name	TO Zone	LDA	Description
AE	▲	▲	Atlantic City Electric Co.
AEP	▲	▲	American Electric Power
AP	▲	▲	Allegheny Power
ATSI	▲	▲	American Transmission Systems, Inc.
BGE	▲	▲	Baltimore Gas and Electric Co.
Cleveland	n/a	▲	Cleveland Area
ComEd	▲	▲	Commonwealth Edison Co.
DAY	▲	▲	Dayton Power & Light Co.
DEO&K	▲	▲	Duke Energy Ohio and Kentucky Corp.
DLCO	▲	▲	Duquesne Light Co.
Dominion	▲	▲	Dominion
DP&L	▲	▲	Delmarva Power & Light Co.
Delmarva South	n/a	▲	Southern Portion of DP&L
EKPC	▲	▲	East Kentucky Power Cooperative
JCP&L	▲	▲	Jersey Central Power & Light
METED	▲	▲	Met-Ed
Mid-Atlantic	n/a	▲	Global Area – PENELEC, METED, JCP&L, PPL, PECO, PSEG, BGE, PEPCO, AE, DP&L, RECO
PECO	▲	▲	PECO Energy Co.
PENELEC	▲	▲	Pennsylvania Electric Co.
PEPCO	▲	▲	Potomac Electric Power Co.
PPL	▲	▲	PPL Electric Utilities and UGI Utilities
PSEG	▲	▲	PSEG
PSEG North	n/a	▲	Northern Portion of PSEG
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, DAY, DLCO, ComEd, ATSI, DEO&K, EKPC, OVEC

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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
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.
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.
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.
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.

Term	Reference	Acronym	Definition
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). 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) that is 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.
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.

Term	Reference	Acronym	Definition
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.
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.
Cross-Linked Polyethylene		XLPE	Type of plastic used to insulate power lines; benefits include resistance to temperature fluctuations and other environmental factors.
Current Transformer		CT	This type of transformer is used to measure electrical flows for telemetry purposes.
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 percent 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, DPL, 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.

Term	Reference	Acronym	Definition
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 that promote energy conservation and the wise use of energy resources.
Energy Resource	M14A, M14B		An energy resource is a generating facility that is not a capacity resource.
Extra High Voltage		EHV	Extra high voltage transmission equipment operates at 230 kV and above.
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.
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.
Fixed Series Capacitor		FSC	A fixed series capacitor is a grouping of capacitors used to reduce transfer reactances on bulk transmission corridors.
Flowgate			A flowgate is a specific combination of a monitored facility and a contingency which 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 which 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.

Term	Reference	Acronym	Definition
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.
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 Efficiency Project		IMEP	Interregional proposals are designed to address congestion and its associated costs along the MISO/PJM border within the context of the MISO/PJM JOA as identified in long-term market efficiency simulation results.
Joint RTO Planning Committee		JRPC	The JRPC is the decision-making body for MISO/PJM coordinated system planning as governed by the MISO/PJM Joint Operating Agreement.
Light Load Reliability Analysis	M14B		Light load reliability analysis ensures that the transmission system is capable of delivering the system generating capacity during a light load situation (50% of 50/50 summer peak demand level).
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.”

Term	Reference	Acronym	Definition
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.
Mid-Atlantic Subregion	M14B	MAAC	The PJM Mid-Atlantic Subregion encompasses 12 transmission owner zones: Atlantic City Electric Company (AE), Baltimore Gas and Electric Co. (BGE), Delmarva Power and Light (DP&L), Jersey Central Power & Light Co. (JCP&L), Met-Ed (METED), Neptune Regional Transmission System (Neptune RTS), PECO Energy Co. (PECO), Pennsylvania Electric Company (PENELEC), Potomac Electric Power Company (PEPCO), PPL Electric Utilities (PPL), PSEG and Rockland Electric Co. (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 research and the 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 analysis and policy formulation related to PJM, its operations, its market monitor and matters related to 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.

Term	Reference	Acronym	Definition
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.
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 cyber attacks. 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.

Term	Reference	Acronym	Definition
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 (Dominion).
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 pre-defined 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.
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.
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.
Subregional RTEP Committee	M14B, OA		This PJM committee 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 build-up 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 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 70–80, 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.

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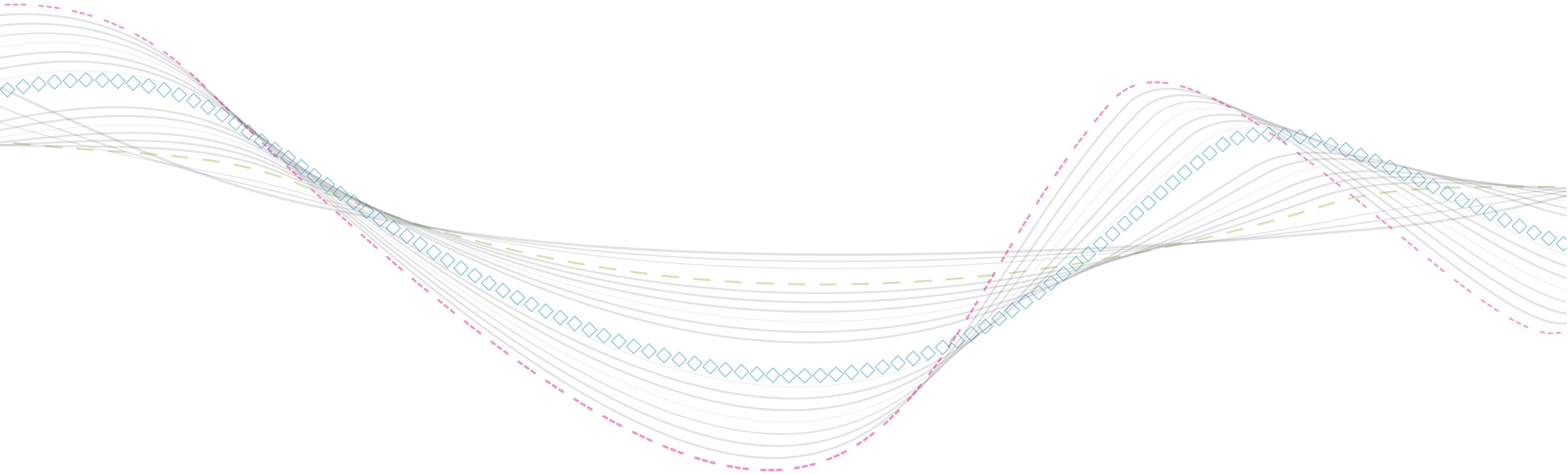
Term	Reference	Acronym	Definition
Transmission Customer	M14A, M14B, M2, OATT		A transmission customer is any eligible customer, or its designated agent, that (i) executes a service agreement or (ii) requests in writing that PJM file with FERC, a proposed, unexecuted service agreement to receive transmission service under Part II of the PJM OATT.
Transmission Expansion Advisory Committee	M14B	TEAC	The Transmission Expansion Advisory Committee was established by PJM to provide advice and recommendations to aid in the development of the RTEP.
Transmission Loading Relief	M03	TLR	Transmission loading relief is a NERC procedure developed for the Eastern Interconnection to mitigate overloads on the transmission system by allowing reliability coordinators to request the curtailment of transactions that are causing parallel flows through their system.
Transmission Owner	M14B, OATT	TO	A transmission owner is a PJM member that owns transmission facilities or leases with rights equivalent to ownership in transmission facilities. Taking transmission service is not sufficient to qualify a member as a transmission owner.
Transmission Owner Initiated		TOI	See “Supplemental Project.”
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 Incorporated (ATSI), Commonwealth Edison Co. (ComEd), Dayton Power & Light Co. (DAY), Duke Energy Corporation (DEO&K), Duquesne Light Company (DLCO) and East 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.



Key Maps, Tables and Figures

PJM DE DC IL IN KY MD MI NJ NC OH PA TN VA WV

Map 1.1: PJM Backbone Transmission System

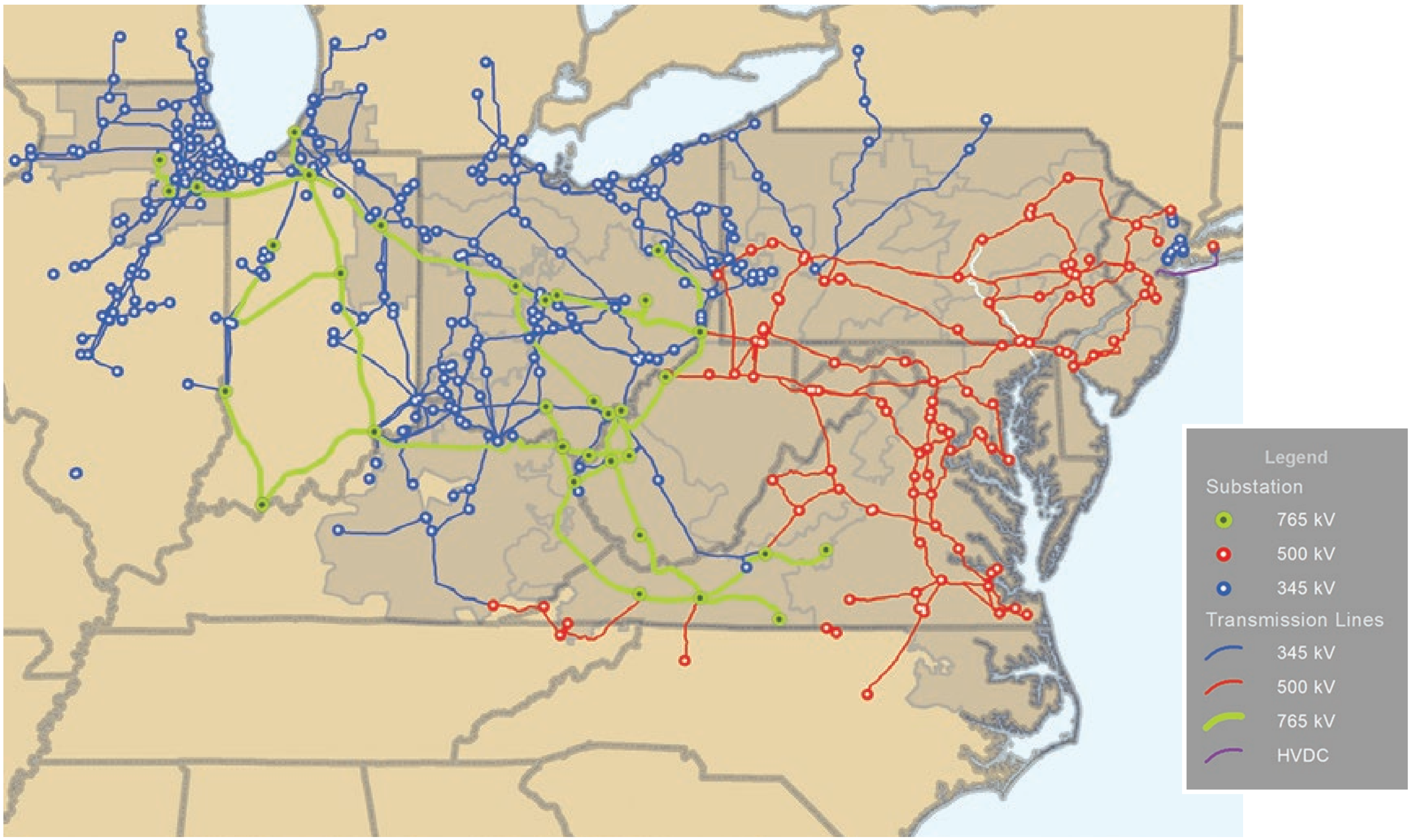


Figure 1.1: RTEP Process – RTO Perspective

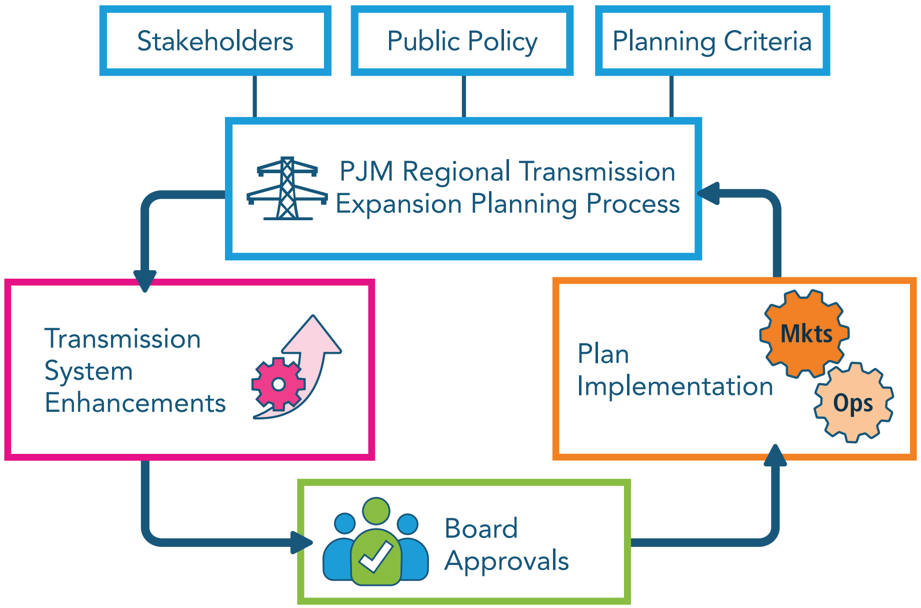


Figure 1.2: System Enhancement Drivers

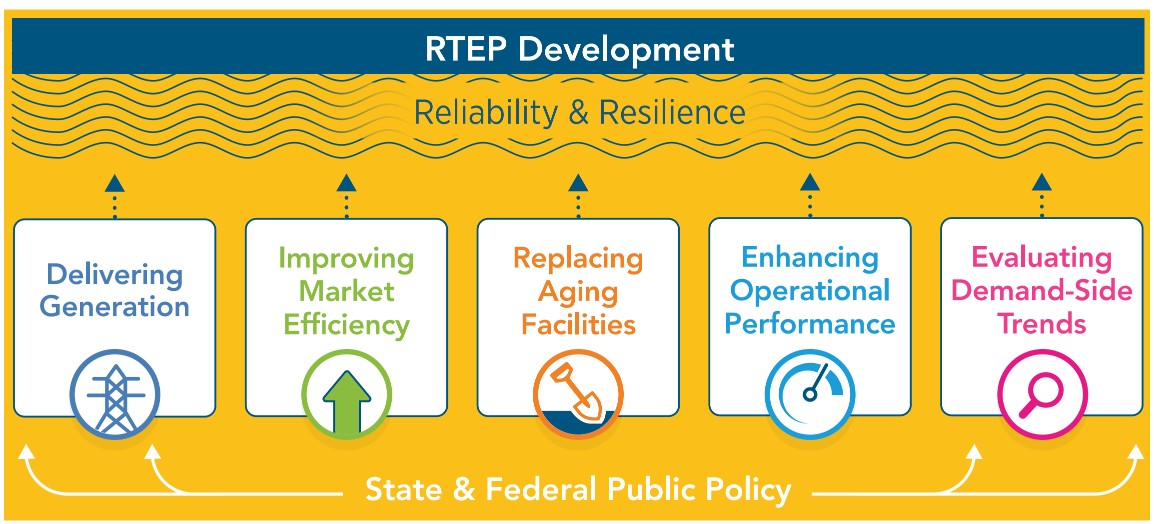


Figure 1.3: Board Approved RTEP Projects as of Dec. 31, 2020

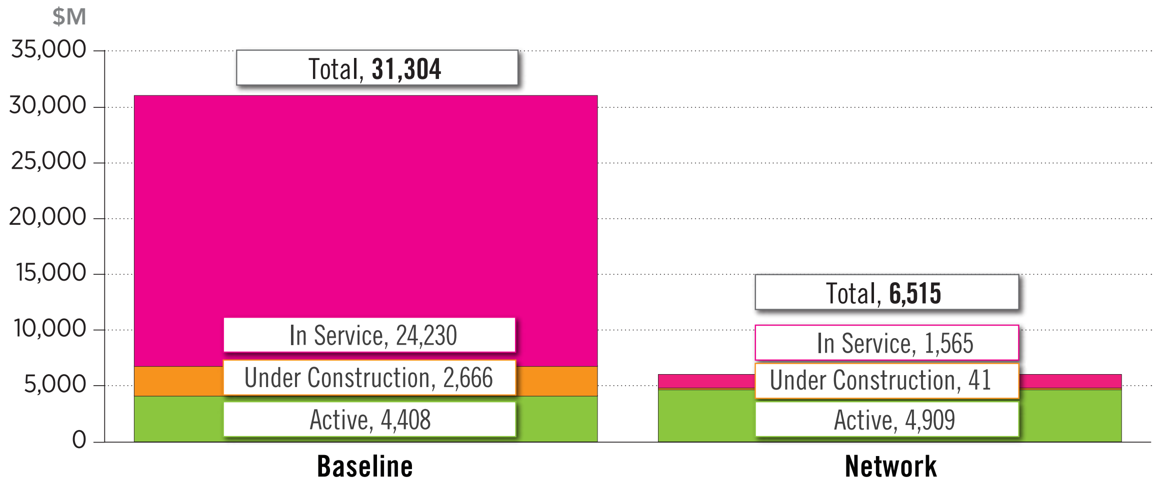
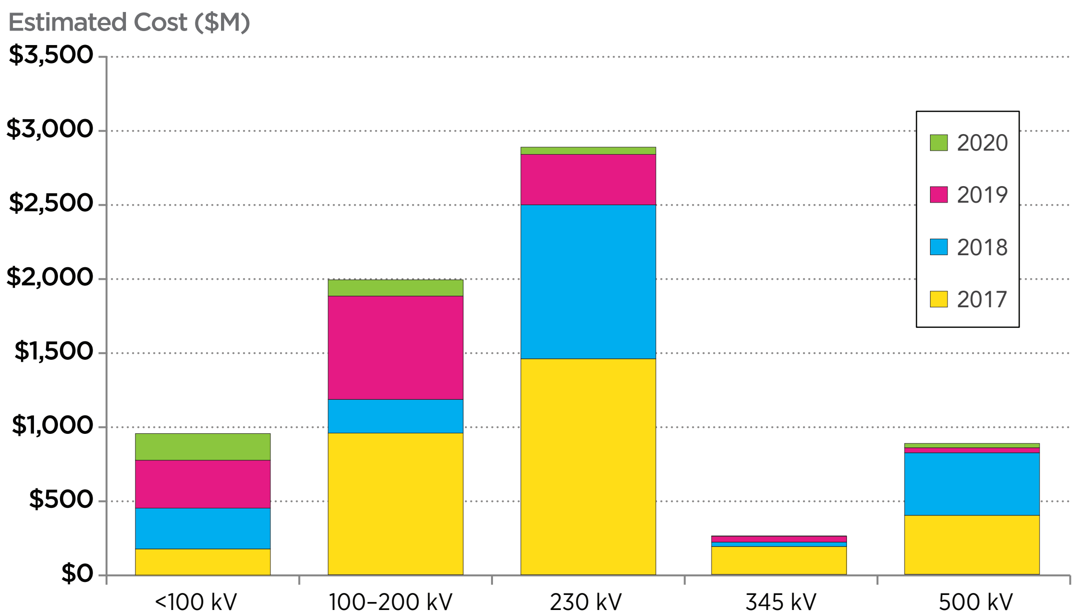


Figure 1.4: Approved Baseline Projects by Voltage 2017-2020



No baseline projects at the 765 kV level were identified for this time period.

Figure 1.5: PJM Existing RPM-Eligible Installed Capacity Mix (Dec. 31, 2020)

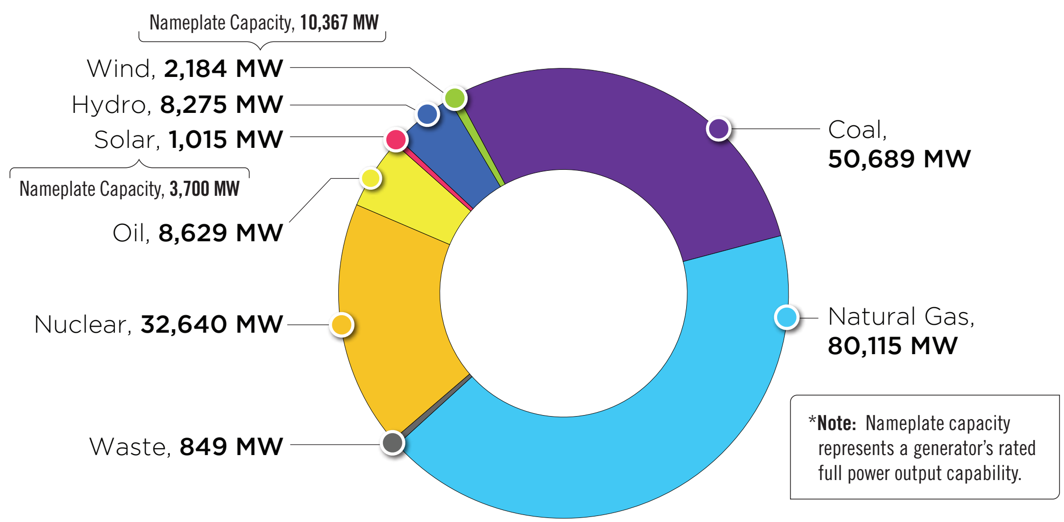


Figure 1.6: Queued Generation Fuel Mix – Requested Capacity Interconnection Rights (Dec. 31, 2020)

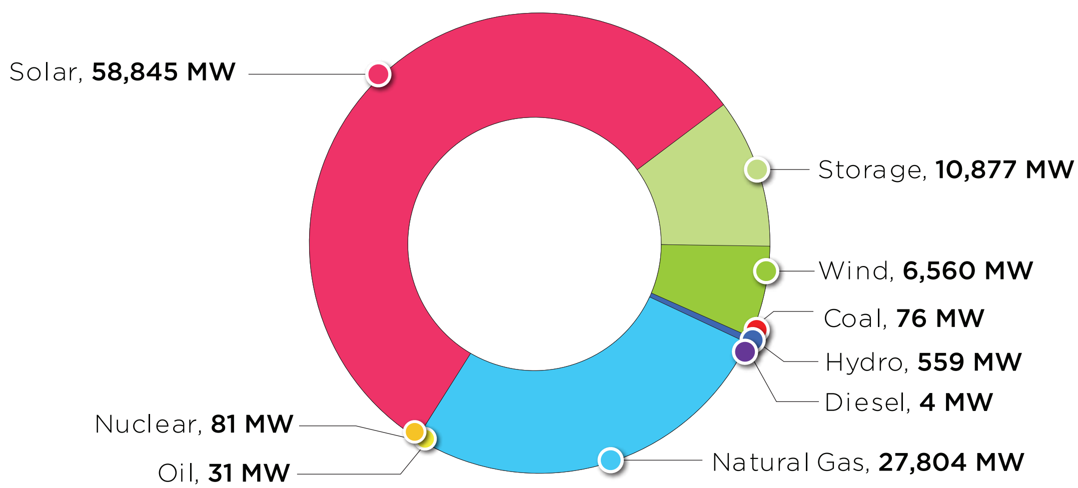


Figure 1.8: Growth of Renewables in PJM Queue

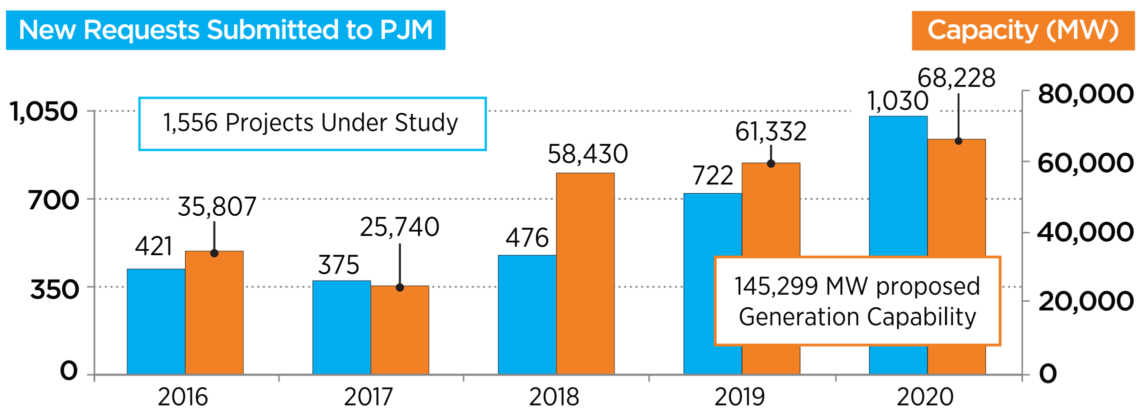
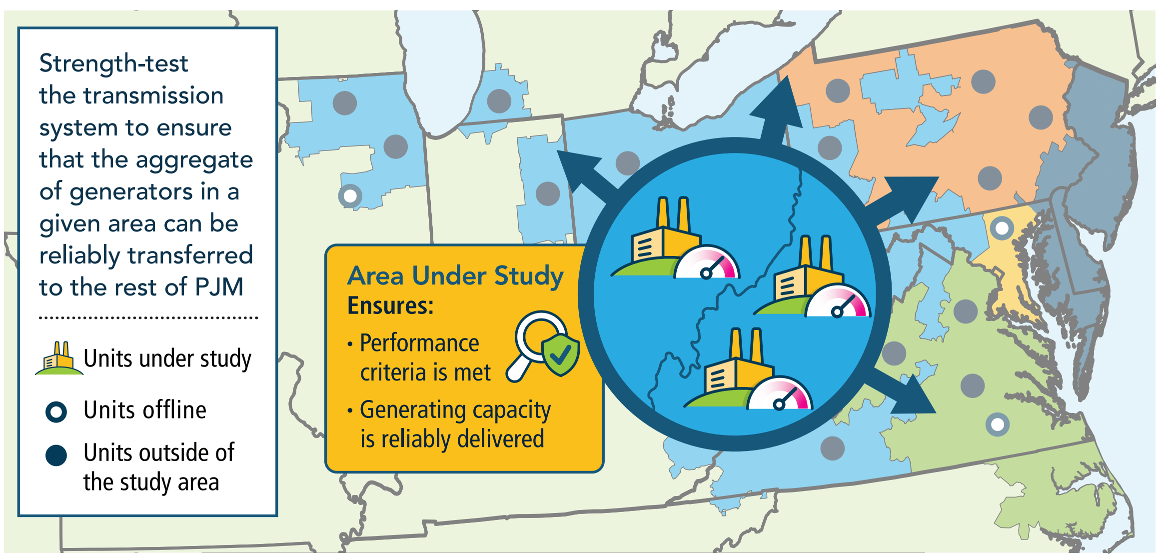


Figure 1.7: Generator Deliverability Concept



Map 1.2: PJM Generator Deactivation Notifications Received Jan 1, 2020 through Dec. 31, 2020)

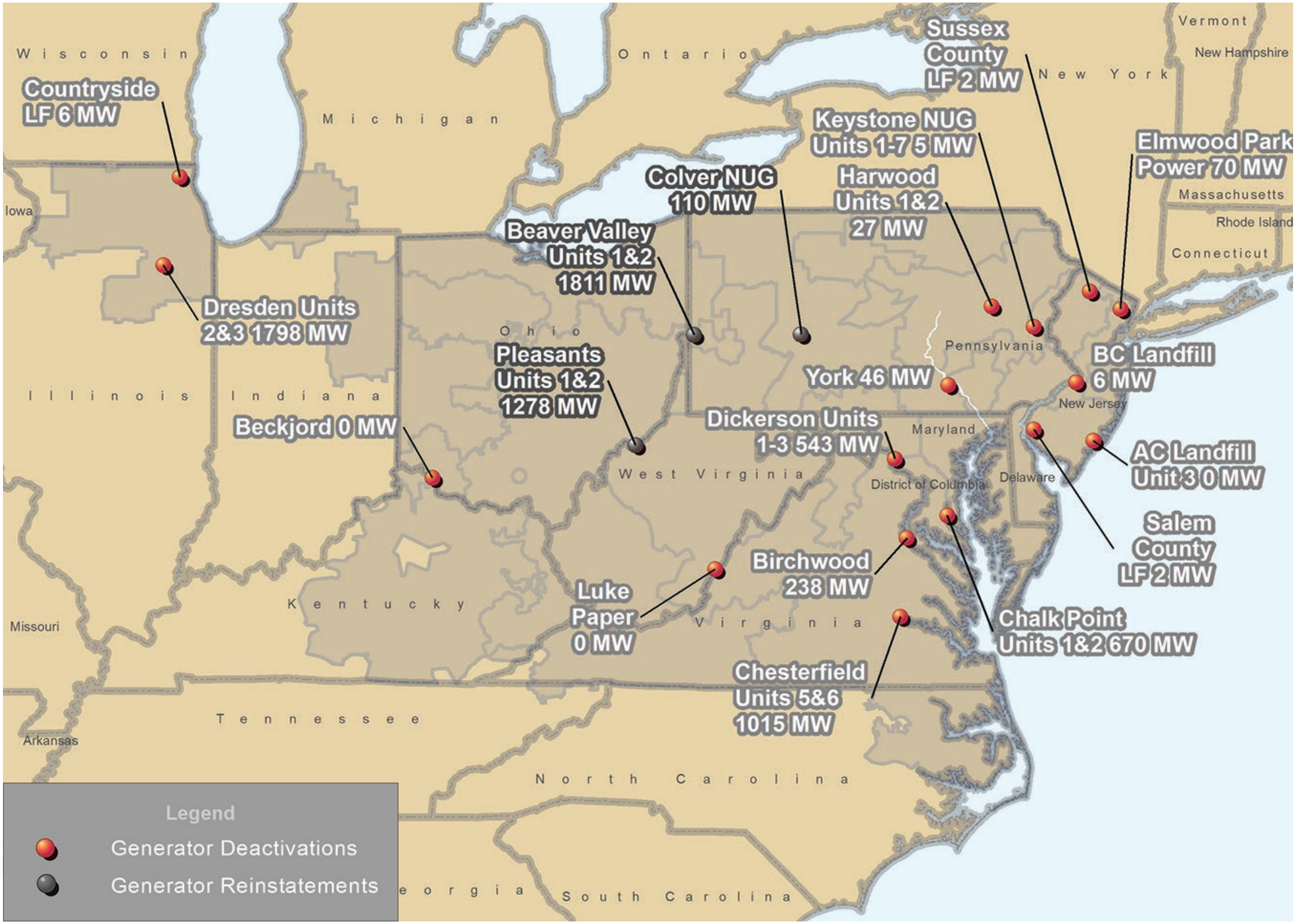
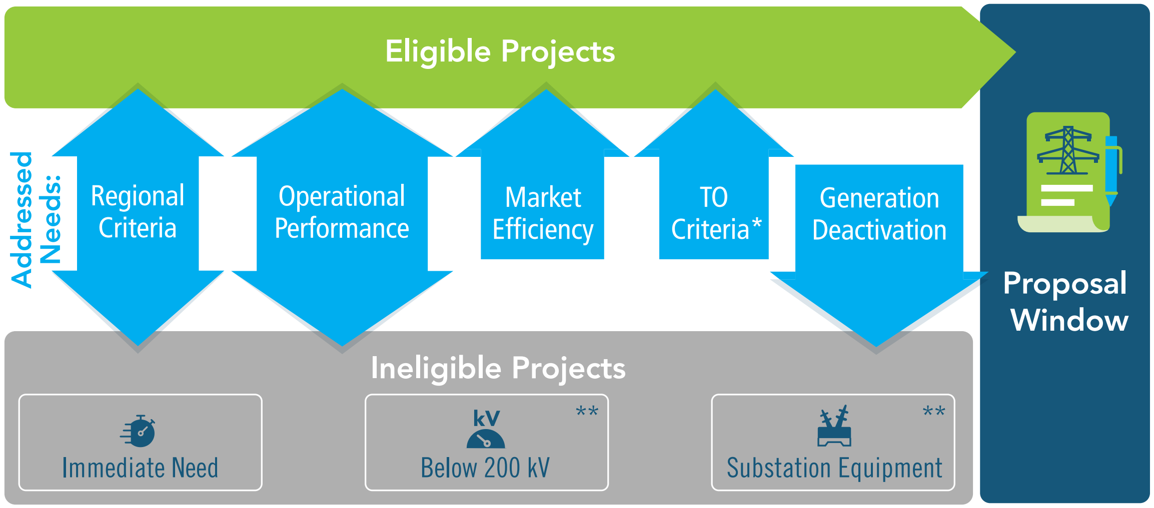


Figure 1.9: RTEP Proposal Window Eligibility



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 1.10: 2020 RTEP Baseline Project Driver ($ Million)

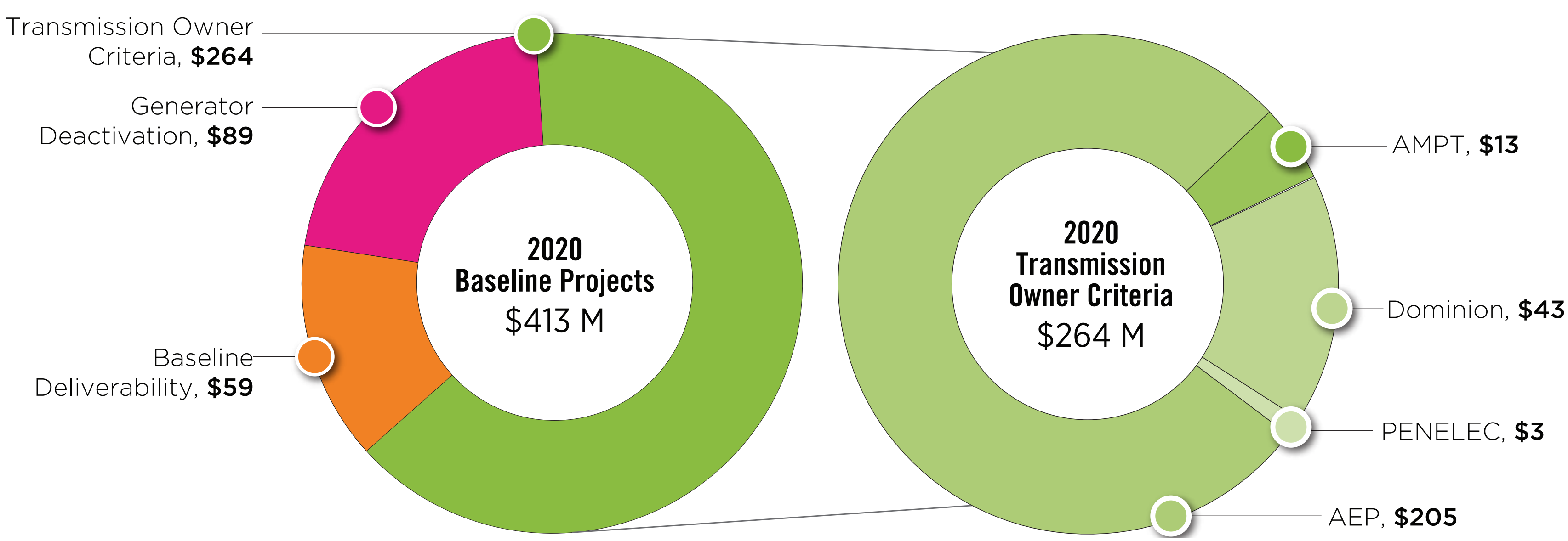


Figure 1.11: Load Forecast Model

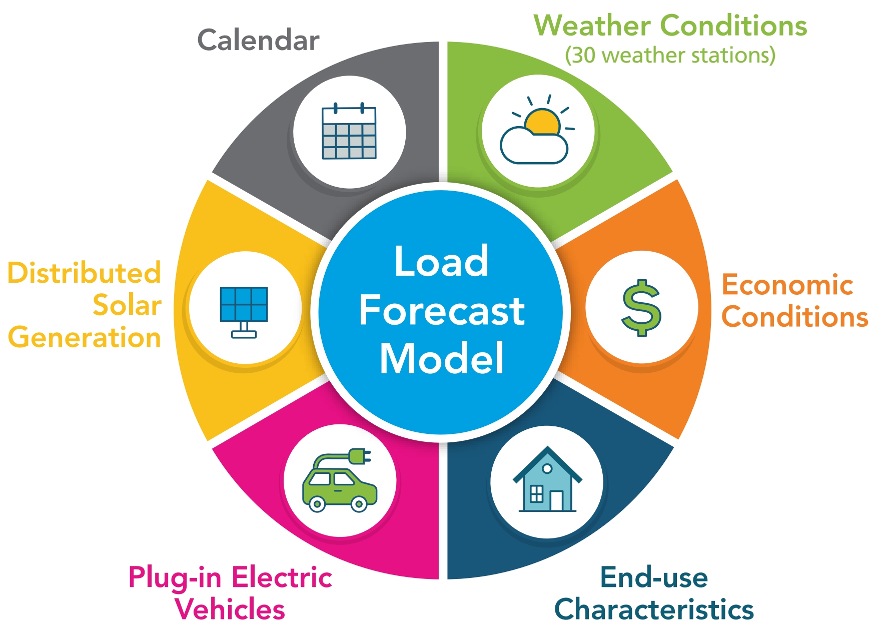
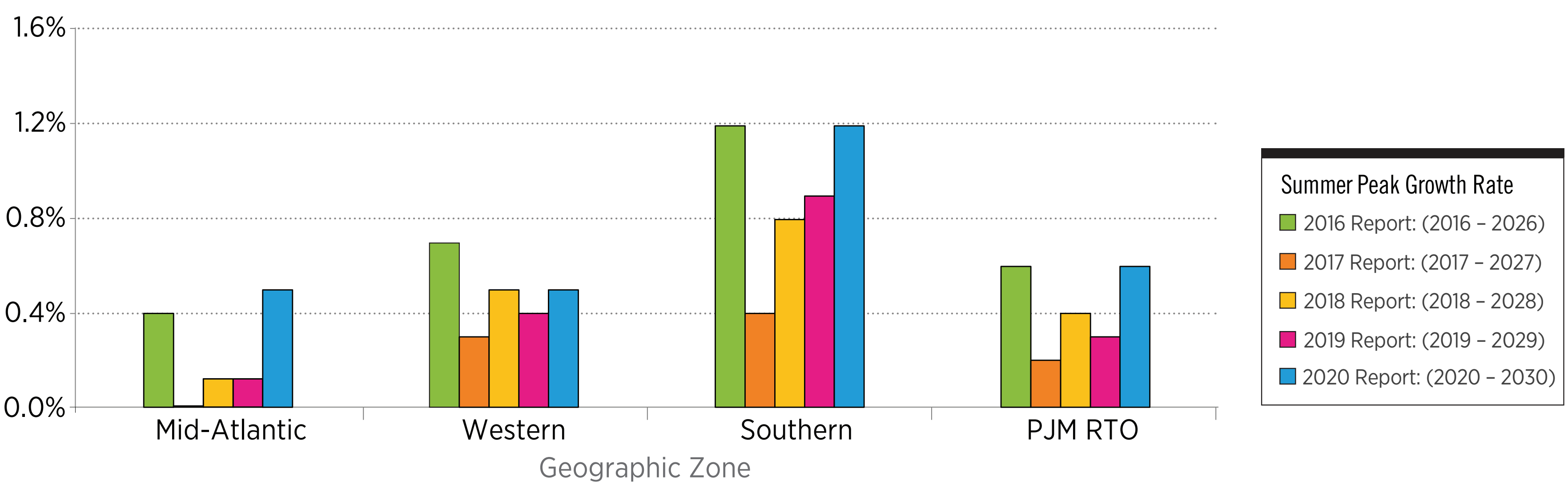


Figure 1.12: PJM 10-Year Summer Peak Load Growth Rate Comparison 2016-2020 Load Forecast Reports



Map 1.3: 2020 RTEP Baseline Thermal and Voltage Criteria Violations

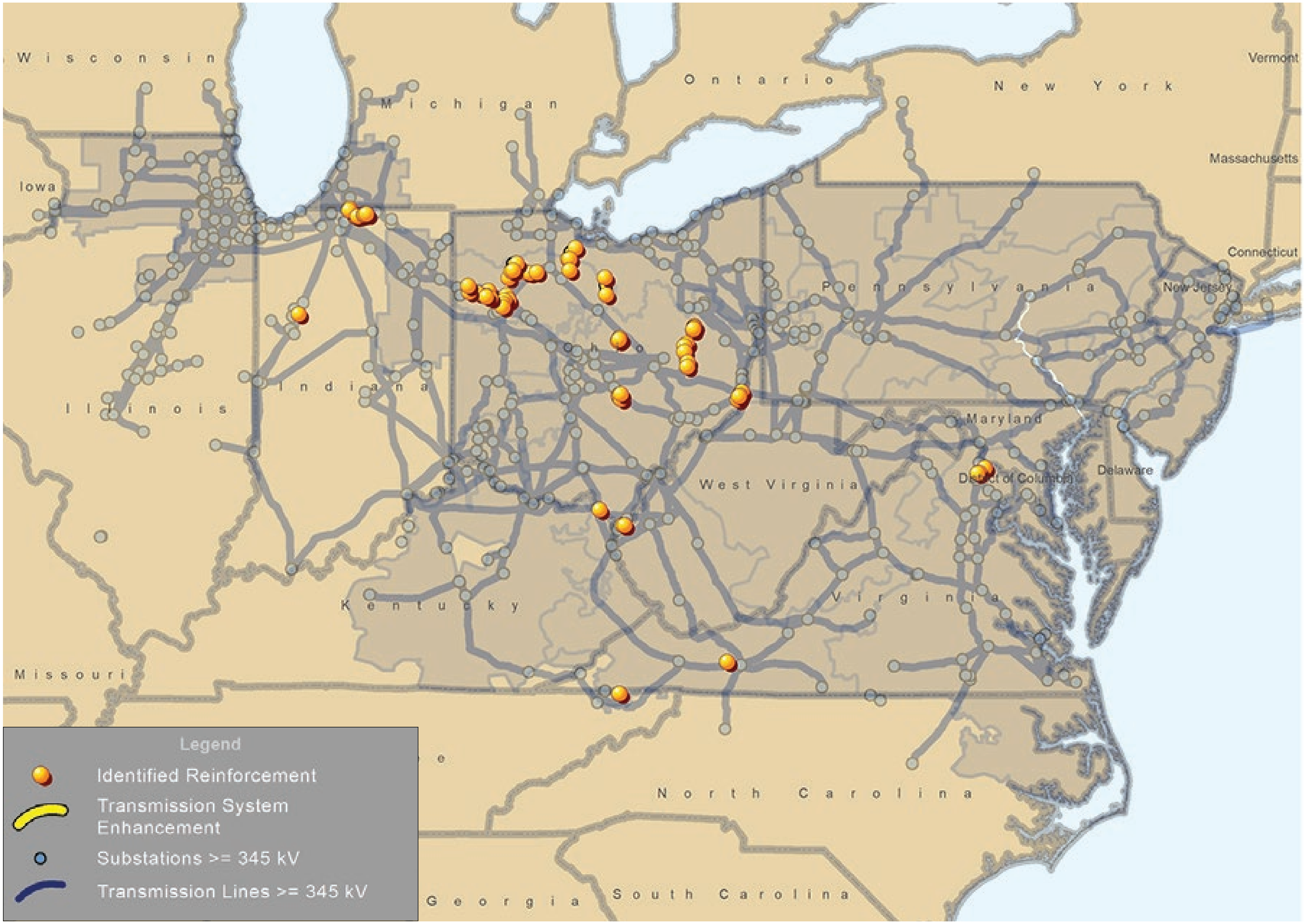
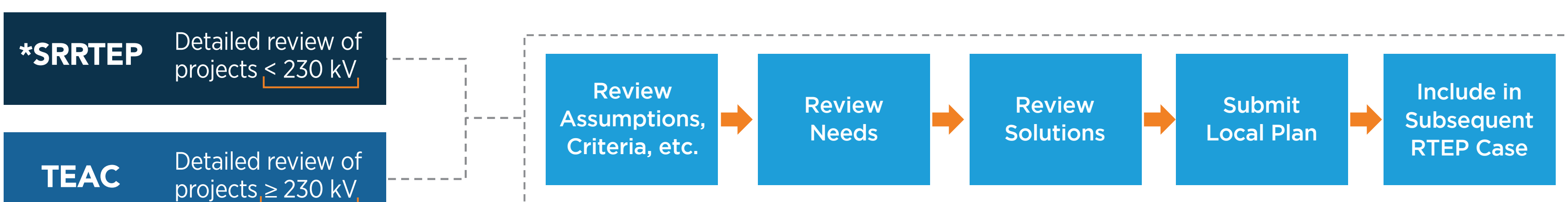


Figure 1.13: Primary Supplemental Project Drivers

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 1.14: Attachment M-3 Process for Supplemental Projects



*Subregional RTEP Stakeholder Committee

Figure 1.15: 2020/2021 Market Efficiency 24-Month Cycle

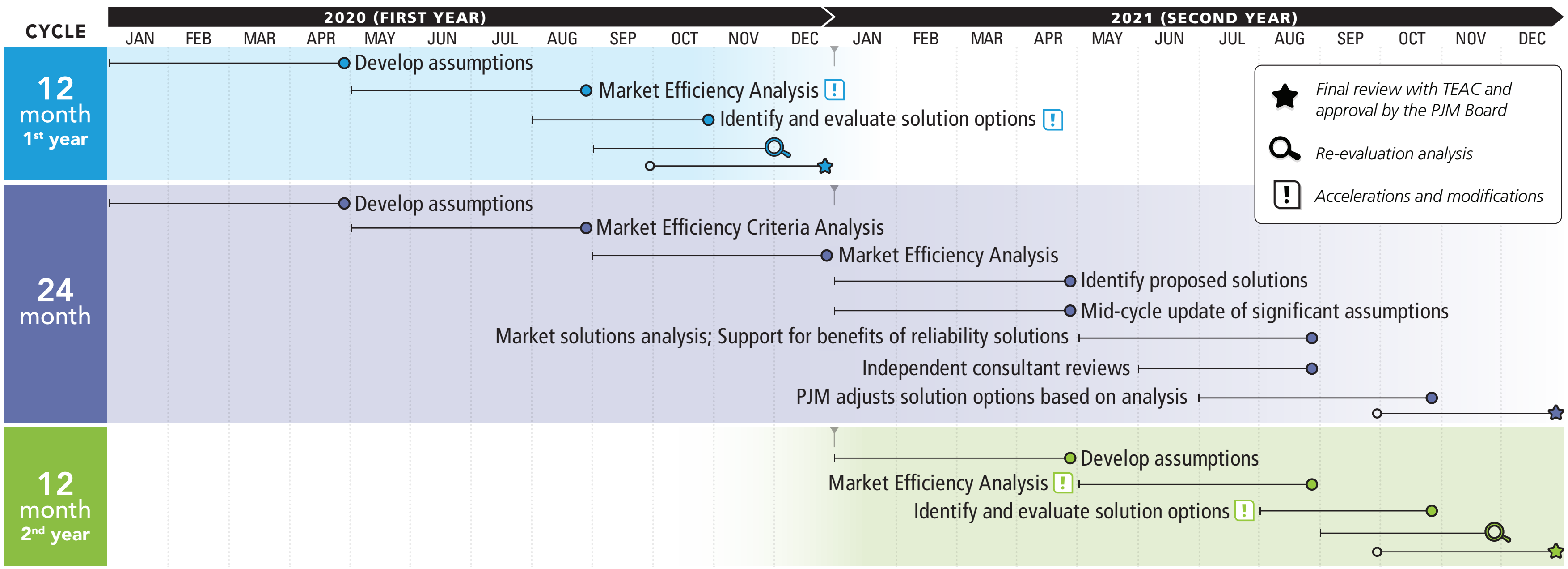
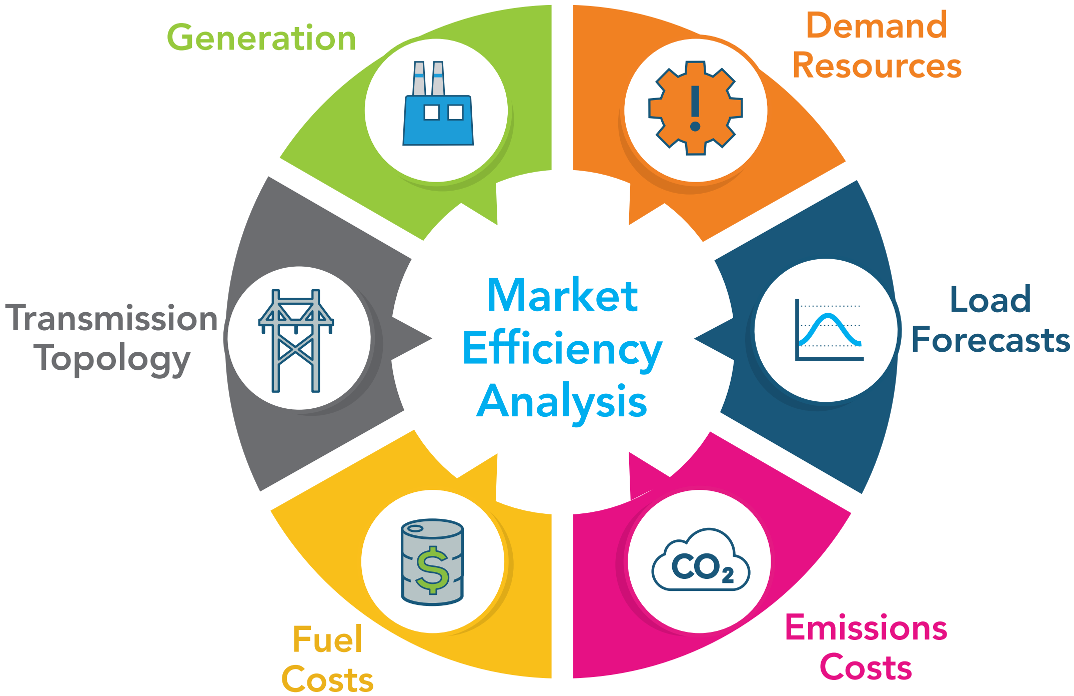
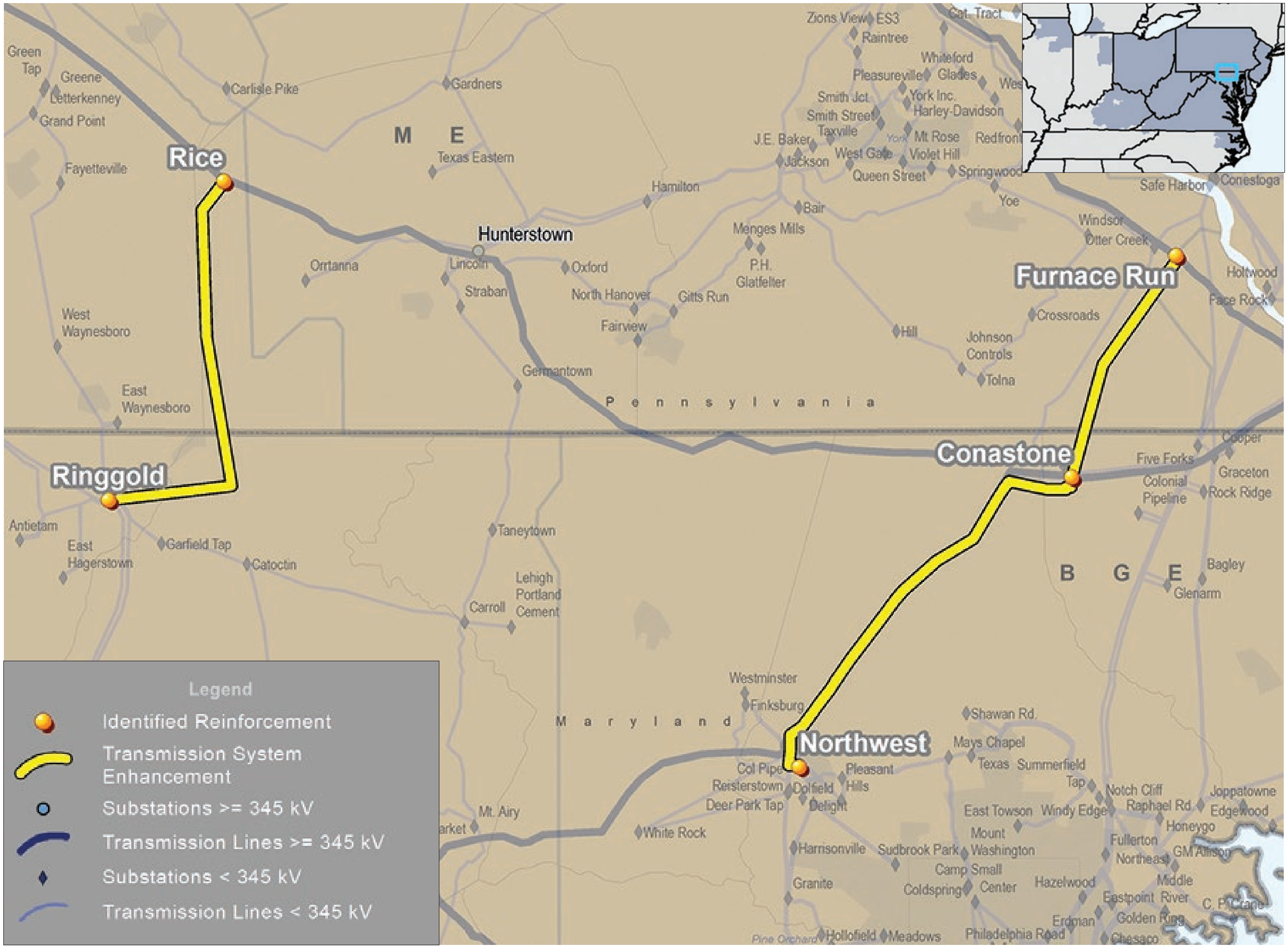


Figure 1.16: Market Efficiency Analysis Parameters



Map 1.4: Project 9A – RTEP Baseline Projects B2743 and B2752



Map 1.5: Feasibility and System Impact Studies Performed in 2020

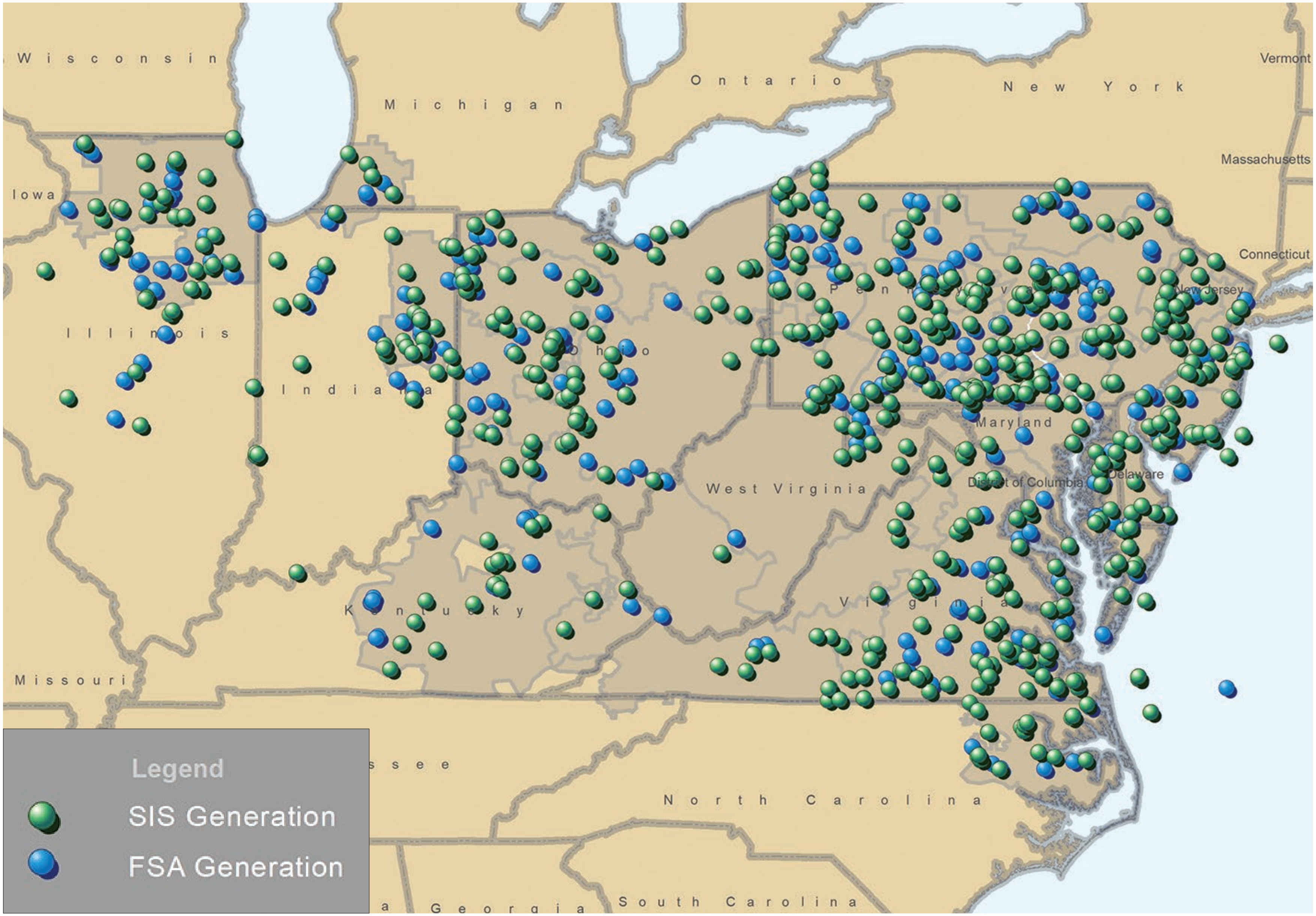
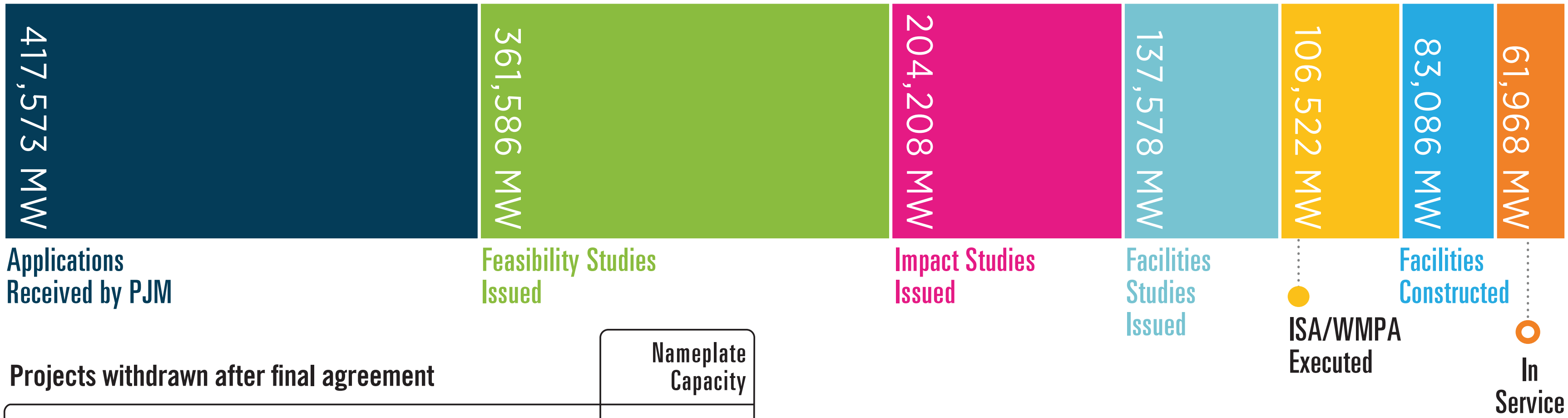


Figure 1.17: Queued Generation Progression – Requested Capacity Rights (Dec. 31, 2020)



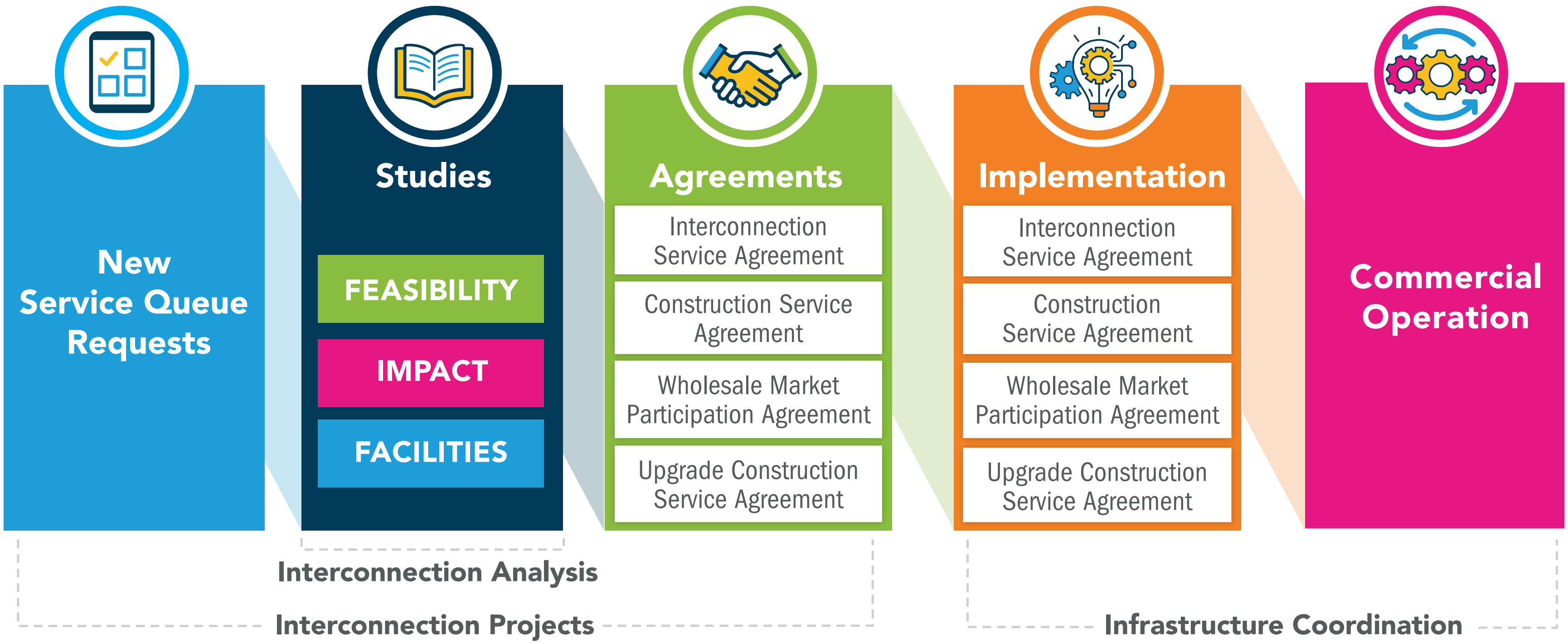
Projects withdrawn after final agreement

			Nameplate Capacity
177	Interconnection Service Agreements	22,442 MW	30,294 MW
291	Wholesale Market Participation Agreements	1,107 MW	2,293 MW

Percentage of planned capacity and projects that have reached commercial operation	15% Requested capacity megawatts	23% Requested projects

This graphic shows the final state of generation submitted to the PJM queue that completed the study phase as of Dec. 31, 2020, 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, 2020.

Figure 1.18: New Services Queue Process Overview



Appendix 5: RTEP Project Statistics

PJM | DE | DC | IL | IN | KY | MD | MI | NJ | NC | OH | PA | TN | VA | WV

5.0: RTEP Project Statistics

This set of figures and tables summarize 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 2020 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 2010 to 2019 (1.77%).
6. Transmission line mileage is based on FERC Form 1 filed in 2019 or EIA-411 Schedule 6A for 2019.
7. TO peak load is the average of forecasted summer peak load from 2021 to 2025.

Figure 5.1: Project Status as of Dec., 31 2020

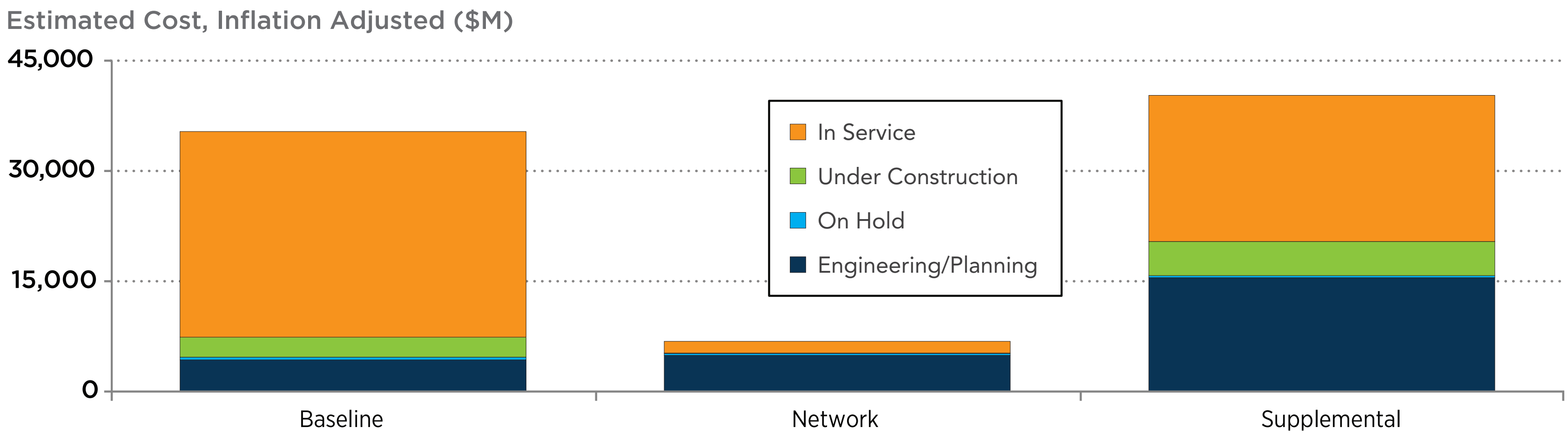


Figure 5.2: Baseline and Supplemental Projects by Year

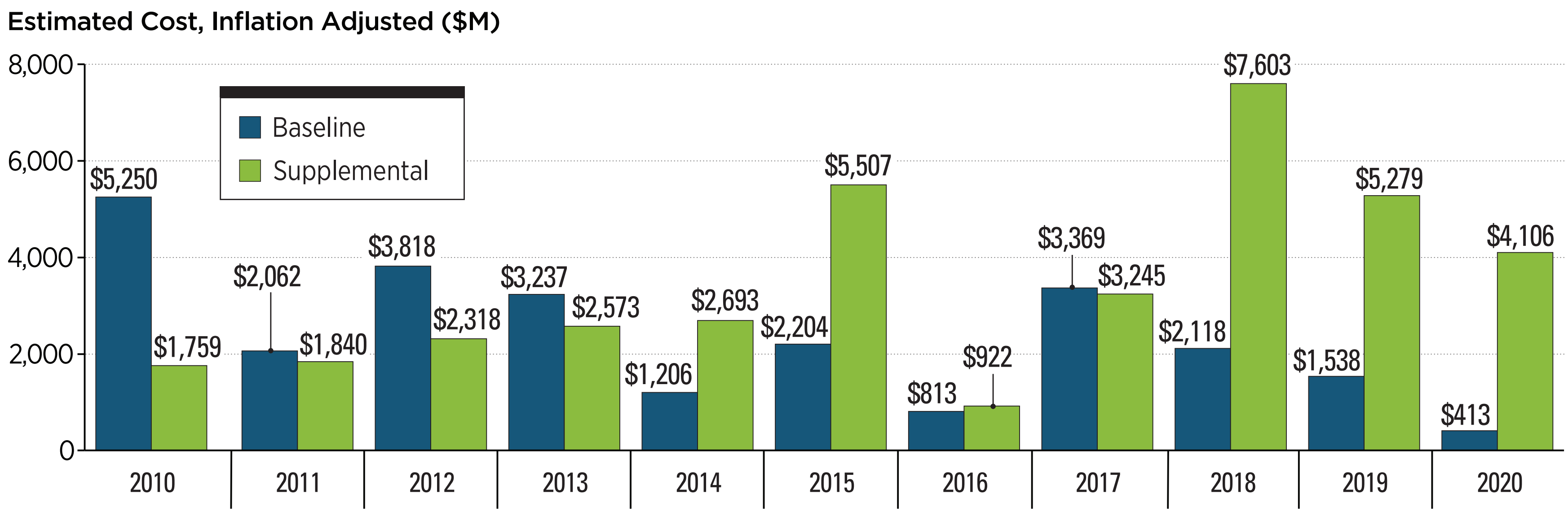


Figure 5.3: PJM Baseline Projects by Criteria

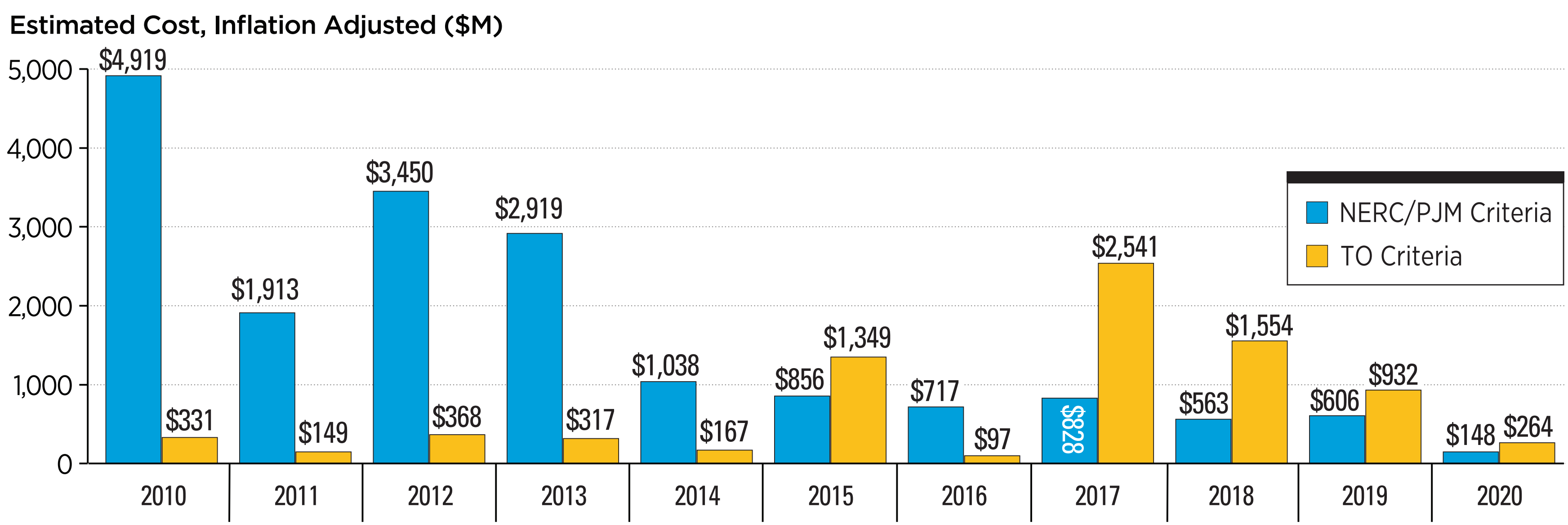


Figure 5.4: Baseline Projects by Voltage

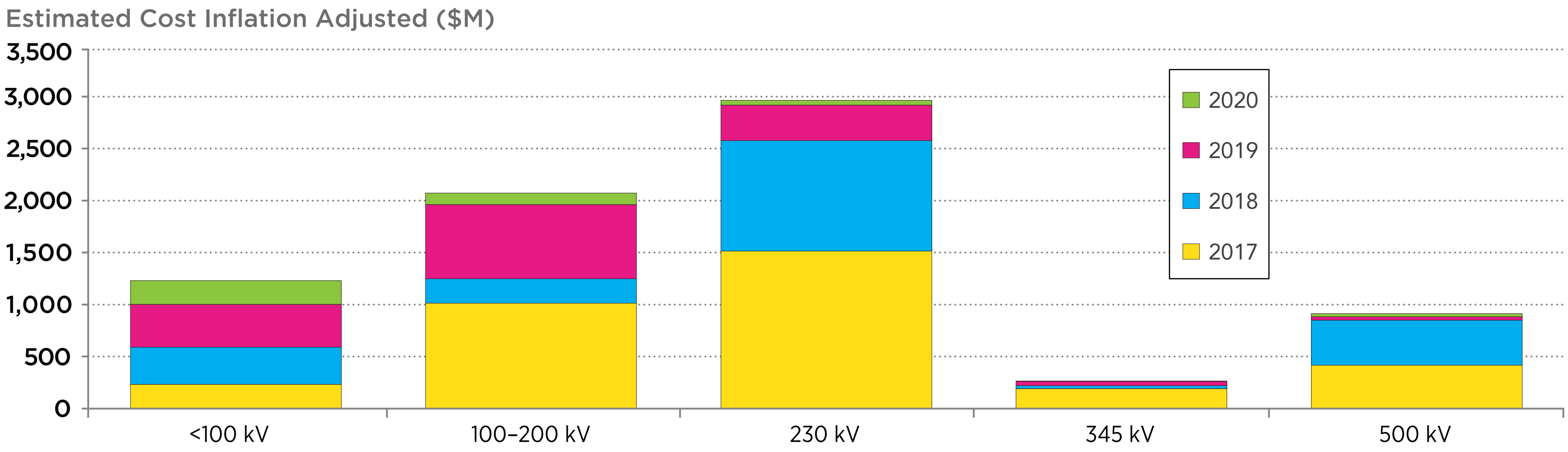


Figure 5.5: Supplemental Projects by Voltage

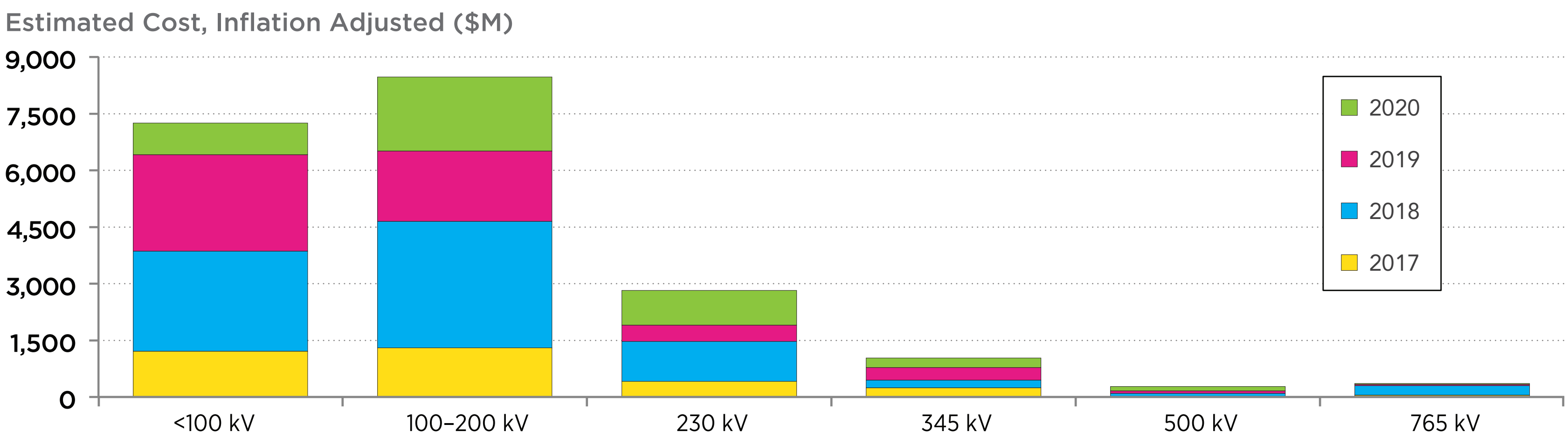


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2010

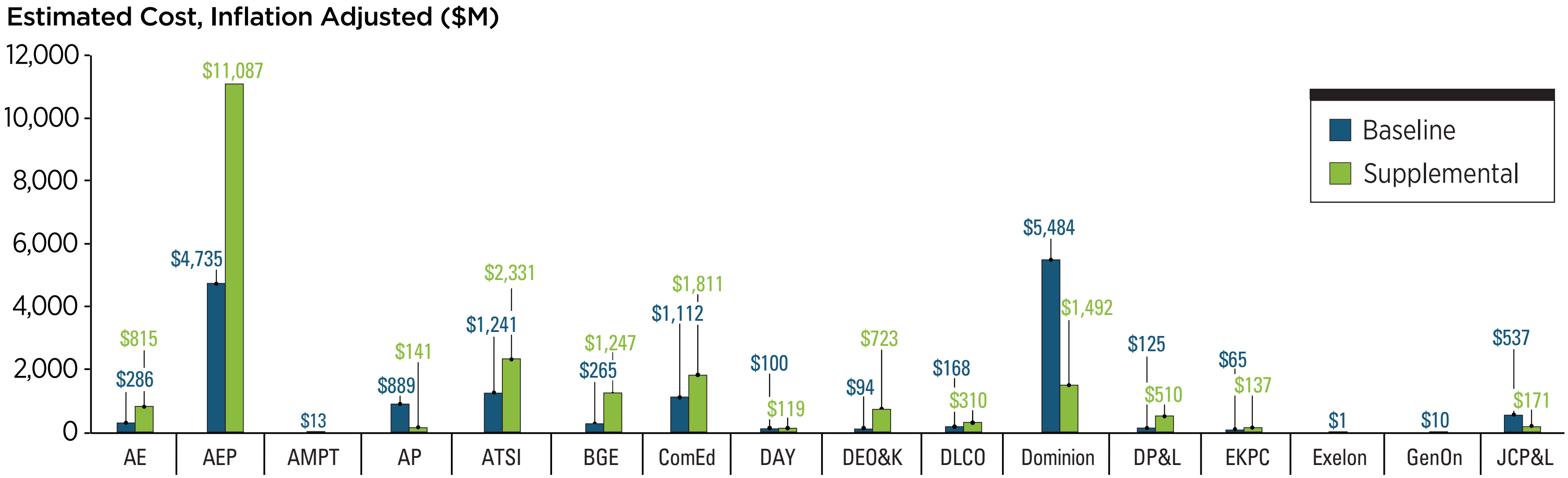


Figure 5.6: Baseline and Supplemental Projects by Designated Entity Since 2010 (Cont.)

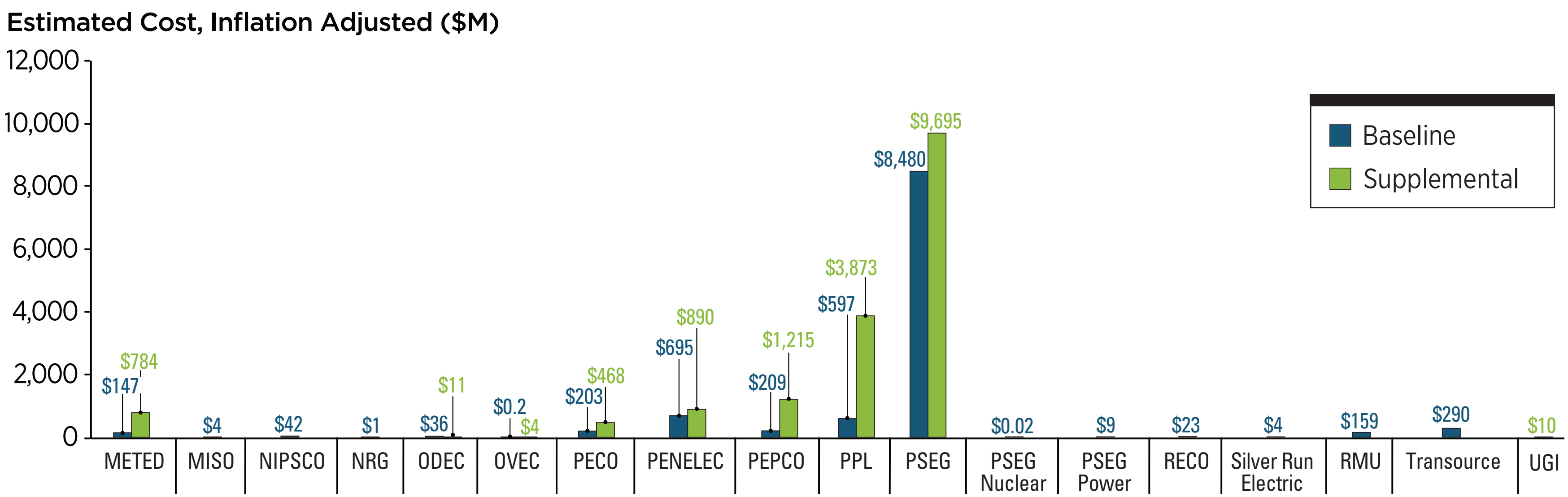


Figure 5.7: 2020 Baseline and Supplemental Projects by Designated Entity

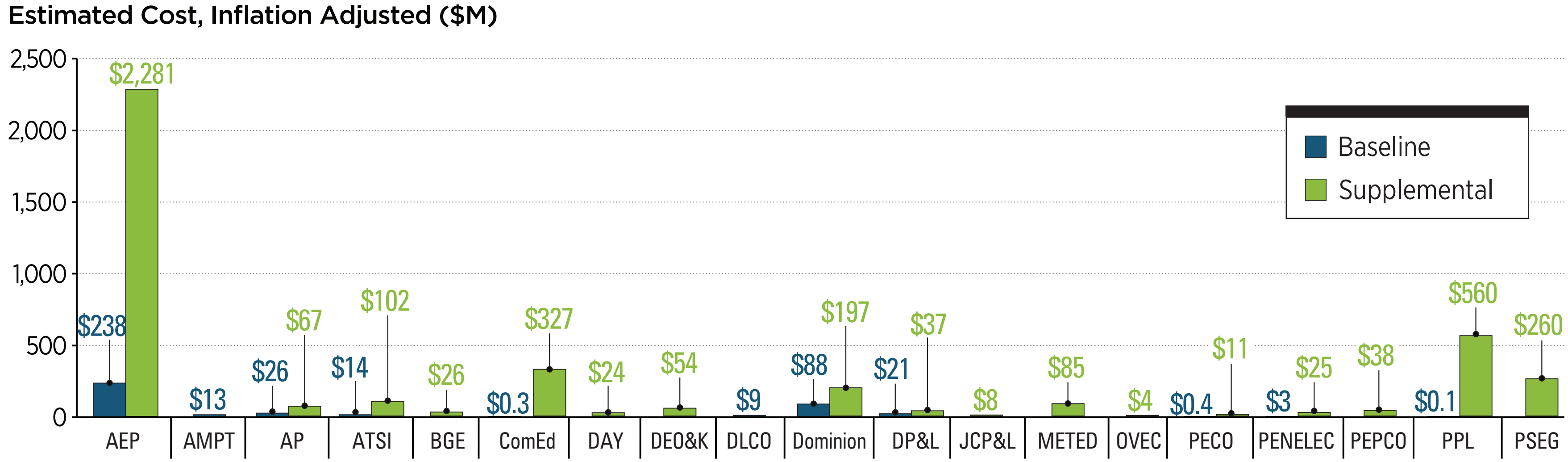


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Figure 5.8: Baseline and Supplemental Projects adjusted by Peak Load Since 2010

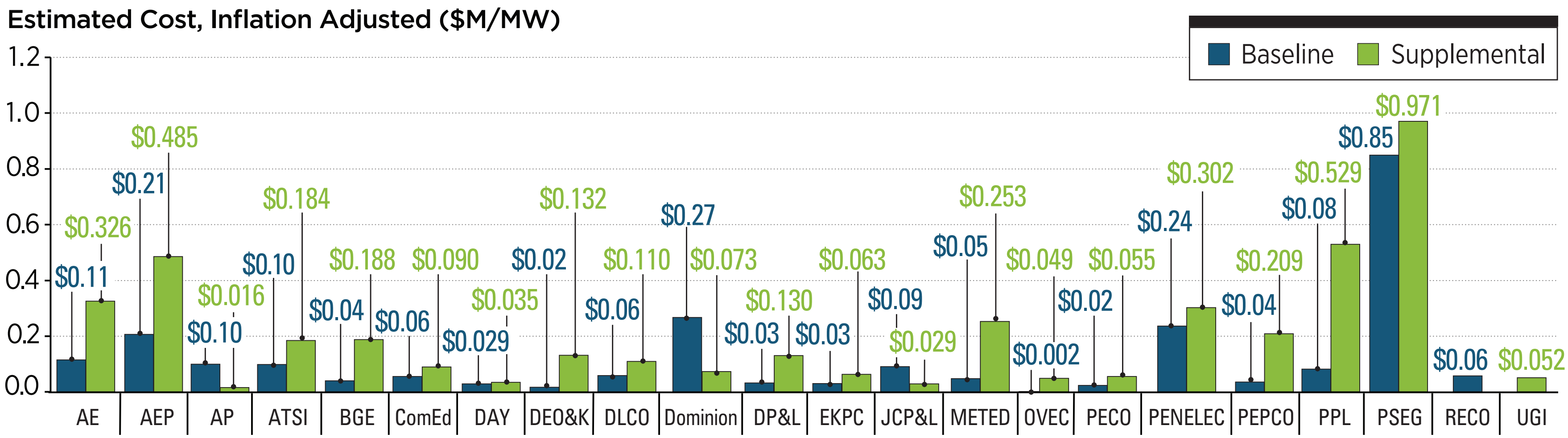

Figure 5.9: 2020 Baseline and Supplemental Projects Adjusted by Peak Load

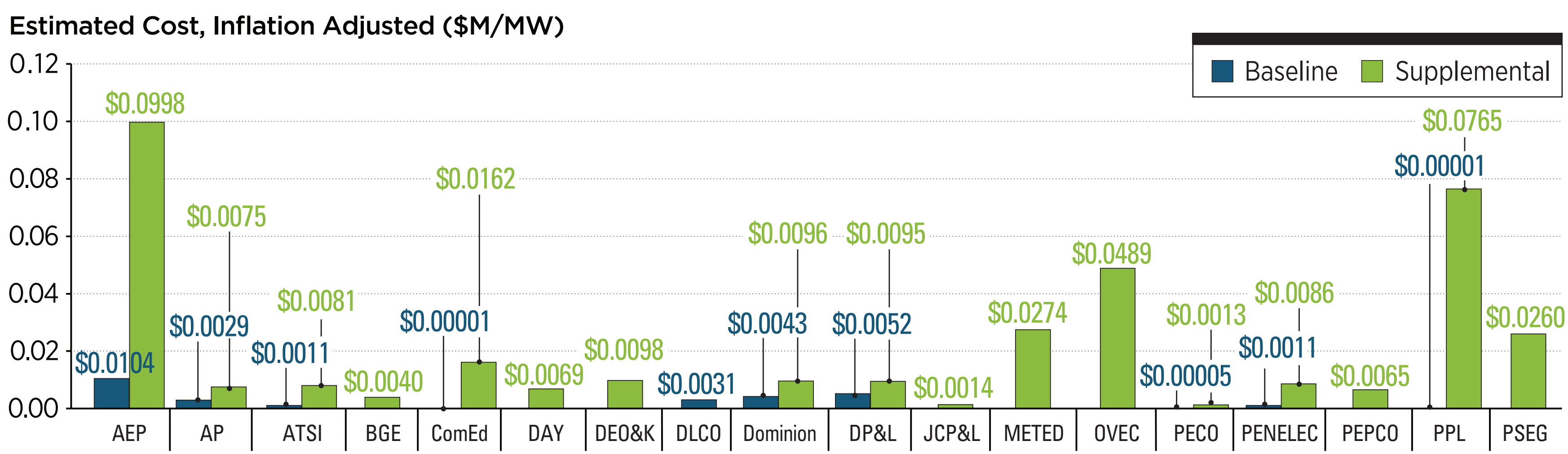

Figure 5.10: Baseline and Supplemental Projects Adjusted by Circuit Miles Since 2010

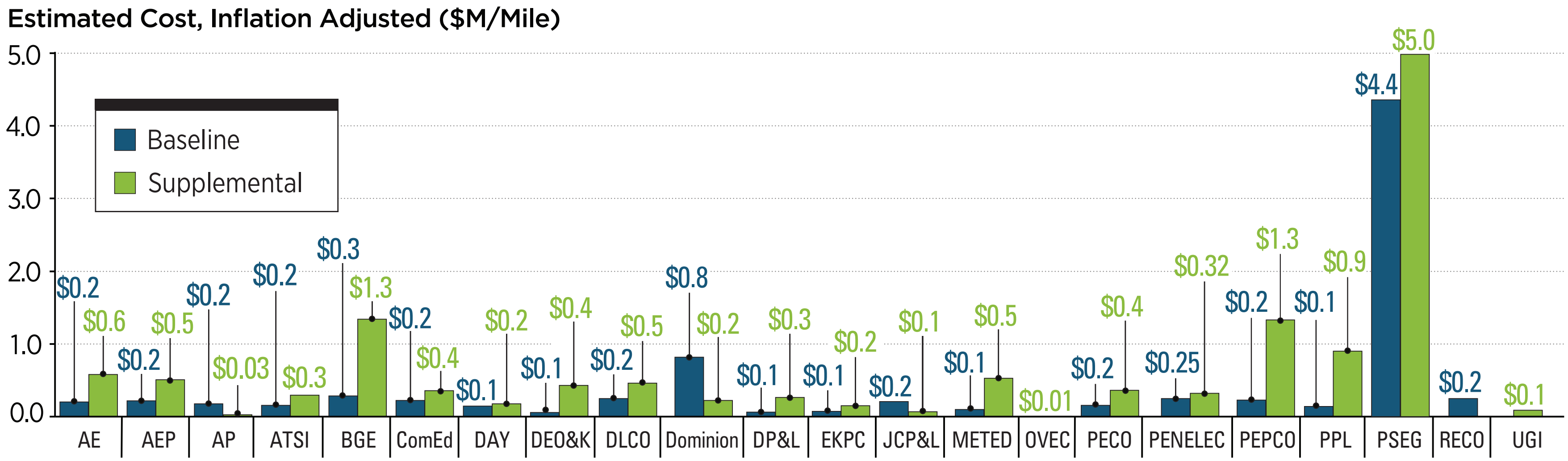

Figure 5.11: 2020 Baseline and Supplemental Projects Adjusted by Circuit Miles