Offshore Wind Transmission Study: Phase 1 Results

PJM Interconnection

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Contents

Executive Summary

The PJM region is experiencing significant growth in planned renewable generation, much of which is being driven by states with clean and renewable energy policies, such as offshore wind objectives. PJM has affirmatively stated through its five-year strategic plan, as well as the advancement of its new State Policy Solutions unit, that it will seek to utilize its expertise to reliably and cost-effectively facilitate state decarbonization policies. This planning study represents a tangible effort toward that desired dynamic.

The Offshore Wind Transmission Study is a PJM-wide reliability study to determine reinforcements to the onshore grid to reliably deliver not only the 14,268 MW of announced offshore wind in the PJM region, but also to achieve all state Renewable Portfolio Standards (RPS) targets in the PJM region by determining the necessary renewable capacity by resource type and location.

By synchronizing the planning of its coastal states' offshore wind deployment, PJM is able to identify transmission solutions that could present a more efficient and economic path for states to achieve their offshore wind policy objectives than if each state integrated their offshore wind generation completely independent of one another.

This study represents a collaborative effort between PJM and the states, and it is purely advisory in nature. The states ultimately reserve the ability to work together on transmission solutions for offshore wind or other clean energy objectives, or can defer to the traditional path of having projects enter the generation interconnection queue with generators being responsible for associated transmission upgrades. PJM and the states agreed that this study would occur in two separate phases. This report details the results of Phase 1 of the study, where PJM analyzed five requested scenarios.

PJM analyzed offshore wind injection totals that ranged from 6,416 MW to 17,016 MW, in addition to modeling all state RPS targets, across short-term and long-term scenarios. Of the agreed-upon five scenarios established for Phase 1, one scenario was short term, modeling out to 2027, while the remaining four scenarios were long term, modeling out to 2035.

The study focused on enhancements to the existing infrastructure required to reliably integrate the megawatts being injected by offshore wind generation. It does not address transmission infrastructure from sea-to-shore or any offshore transmission networks. Further, the consideration of greenfield transmission solutions and offshore transmission facilities can be incorporated in later study phases. A high-level market efficiency analysis was performed for Scenario 1 as an example of what could be provided in later study phases.

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

Phase 1 provides an important starting point for future scenarios that consider the integration of offshore wind and other renewable resources into the PJM system. It also presents a framework for how future collaborative transmission planning studies between PJM and the states can be achieved.

Background

The PJM region is experiencing significant growth in planned renewable generation, much of which is being driven by states with clean and renewable energy policies, such as offshore wind objectives. **Table 1** details the current offshore wind targets of PJM states. To date, the transmission solutions needed to integrate renewable resources have primarily been advanced through PJM's generation interconnection queue. This avenue provides the ability to identify requisite transmission upgrades on a resource-by-resource basis. While such an approach does allow interconnecting resources to achieve commercial operation and maintain system reliability, efficiencies in transmission planning may be lost by not taking a holistic and regional assessment of interconnecting multiple, and in the case of offshore wind, large-scale resources.

Table 1. PJM States' Offshore Wind Targets[1]

State	Offshore Wind Target (MW)	Policy Target Date
Maryland	1,568	2030
New Jersey	7,500	2035
Virginia	5,200	2034

In December 2019, the Organization of PJM States, Inc. (OPSI) sent a letter to the PJM Board of Managers regarding the integration of renewable resources, including offshore wind. The OPSI letter stated that "OPSI would expect PJM to be actively engaged with the States by facilitating information exchange and conducting analyses and modeling studies as requested on an ongoing basis. As changes in the energy landscape are occurring and state policies evolve, we support close interaction between States and PJM in these areas."[2]

Out of this request came the formation of the Offshore Transmission Study Group (OTSG), an independent effort between PJM and the state agencies within the PJM footprint to assess the impact of the coastal states' planned offshore wind generation and to identify regional transmission solutions. In addition to analyzing offshore wind impacts, the study group also decided to incorporate achieving the RPS target of every PJM state with an RPS policy. The reason for including the RPS component is the recognition that offshore wind is not developing in isolation, and the integration of other renewable resources will also impact the transmission system as it is planned into the future.

For PJM, this effort was led by its State Government Policy and Transmission Planning departments. The states were represented in the OTSG by public utility commissions, other invited state agencies with energy and environmental responsibilities, and consumer advocates.

[1] North Carolina also announced an offshore wind target of 8,000 MW by 2040 per Gov. Roy Cooper's Executive Order No. 218, which was issued June 9, 2021. This target was not included in the Offshore Wind Transmission Study's Phase 1 scenarios.

[2] *OPSI Letter* https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20191217-opsi-letter-re-october-board-to-board-discussion-follow-up.ashx

PJM offered to study up to ten total scenarios for the Offshore Wind Transmission Study. This allowed the states to have the opportunity to use a portion of their scenarios as part of a first phase, assess the results, and then have PJM perform a retooled and more comprehensive set of scenario analysis as a second phase. The states elected to go forward with this approach. Five scenarios were utilized in Phase 1, and five scenarios were reserved for a potential Phase 2.

The OTSG began meeting in 2020 with educational sessions led by PJM on offshore wind-specific topics, such as offshore wind policies, technical components of offshore wind facilities, and the environmental and social considerations embedded within offshore wind development. PJM also provided more general education on transmission planning functions, cost allocation, FERC Order 1000 and the State Agreement Approach.[3] From there, PJM and agencies from its five coastal states – Delaware, Maryland, New Jersey, North Carolina and Virginia – met to develop scenarios for the study's first phase. Updates on the scenario development were provided to the broader OTSG participants throughout this process.

The Phase 1 results discussed in this paper were presented to OPSI on July 15, 2021. Additional discussion was then held with the five coastal state agencies to review the five scenario results in greater depth. Following the states' review, results were presented publically to stakeholders on Aug. 10, 2021, at PJM's Transmission Expansion Advisory Committee.[4]

Scenario Development

Overview

Through collaborative discussions with the OTSG in the fourth quarter of 2020, it was determined that the Phase 1 scenario components would encompass offshore wind injection totals at specific points of interconnection (POIs); generator deactivations; and meet the state RPS requirements through utility-scale and behind-the-meter solar, onshore wind and battery storage; as well as incorporate electric vehicle and energy efficiency policy targets captured as part of the PJM load forecast. The scenarios also had the flexibility of being "short-term" or "long-term" scenarios, with a short-term scenario defined as modeling the contributing variables through 2027, and a long-term scenario defined as modeling the contributing variables through 2035. Of the five scenarios established for Phase 1, one scenario was short term (Scenario 1) and the remaining four scenarios were long term.

[3] The State Agreement Approach allows a state (or collection of states) to include its public policy requirements in PJM's planning parameters. Should modeling the public policy result in identified transmission solutions, and the state elects to move forward on any transmission solution being developed, the state agrees to be responsible for 100% of the project's cost allocation. Per Schedule 6, section 1.5.9(a) of the PJM Operating Agreement, "No such costs shall be recovered from customers in a state that did not agree to be responsible for such cost allocation."

[4] *Offshore Transmission Study Group: Phase 1 Results* https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20210810/20210810-item-10-offshore-transmission-study-group-phase-1-results.ashx

PJM worked with the five coastal states through one-on-one meetings to determine each scenario's characteristics as they pertained to the relevant coastal state. Of note, these conversations were used to establish the POIs and offshore wind injection totals the coastal states wanted to model for each of the five scenarios.[5] PJM also used these one-on-one conversations to determine if any in-service generation should be modeled as deactivated, in addition to what was currently scheduled at the time, and to clarify each state's RPS objectives, such as in-state resource carve-outs and state-specific renewable energy certificate considerations. PJM used this RPS information to define the necessary renewable generation capacity, resource types and locations to model as part of each scenario.

There were initially going to be six scenarios in Phase 1 of the Offshore Wind Transmission Study. However, Scenario 3 was removed after the Phase 1 scenarios were developed and before the modeling and analysis commenced. To keep the scenario numbering consistent with the already developed model, the scenario numbers were not changed to account for Scenario 3's removal. Therefore, the Phase 1 results show Scenarios 1–6, with Scenario 3 being absent, for a total of five scenarios.

Offshore Wind

The offshore wind component of the scenarios was made up of two variables: POIs to the onshore transmission system and offshore wind injection amounts at each location. It must be noted that Phase 1 only considered how the injections at specific POIs would impact the onshore system. None of the scenarios included any offshore transmission facilities, such as generator lead lines or an offshore transmission network, and the cost estimates presented in the scenario results also do not include any offshore facilities. The collaboration with the states on the offshore wind variables only focused on determining injection totals at various POIs.

The states had the opportunity to include studying sensitivities in planning their offshore wind endeavors. For example, they could ask PJM to model the same offshore wind injection totals at different POIs to compare system impacts, which New Jersey did within several of the long-term scenarios. The scenarios also allowed the coastal states to have PJM model offshore wind injection totals greater than their current policy targets to assess how much additional capacity the system could handle and the estimated costs of any identified upgrades. Virginia initially elected to utilize this type of sensitivity for all the scenarios. Based on the results of some initial transmission planning studies performed by PJM, Virginia decided to reduce the total injection amounts to match their current policy targets for all scenarios, except for Scenario 4, where they requested PJM to model 7,800 MW of offshore wind injecting into their state by 2035.

The offshore wind injection totals that PJM modeled for Phase 1 are presented below in **Table 2**. These injection totals ranged between 6,416 MW in the short-term Scenario 1 and 17,016 MW in the long-term Scenario 4. The POIs within each of these scenarios are detailed in the scenario results section of the report.

[5] The state of New Jersey already had offshore wind POIs and injection amounts preliminarily defined in its Offshore Wind Transmission Order released prior to the commencement of this study and requested a few variations upon these locations and amounts. For coastal states other than New Jersey, the selection of offshore wind POIs and injection amounts was collaboratively made between PJM and the states based on a combination of several factors including: 1) existing requests for interconnection in the PJM queue, 2) proximity to identified wind lease areas, and 3) the capacity of existing coastal substations.

Table 2. Offshore Wind Injection Totals (MW) by Scenario

	Scenario				
	1	2	4	5	6
Delaware/Maryland	768	1,568	1,568	1,568	1,568
New Jersey	3,048	7,648	7,648	7,648	5,648
North Carolina/Virginia	2,600	5,200	7,800	5,200	5,200
Total (MW)	6,416 MW	14,416 MW	17,016 MW	14,416 MW	12,416 MW

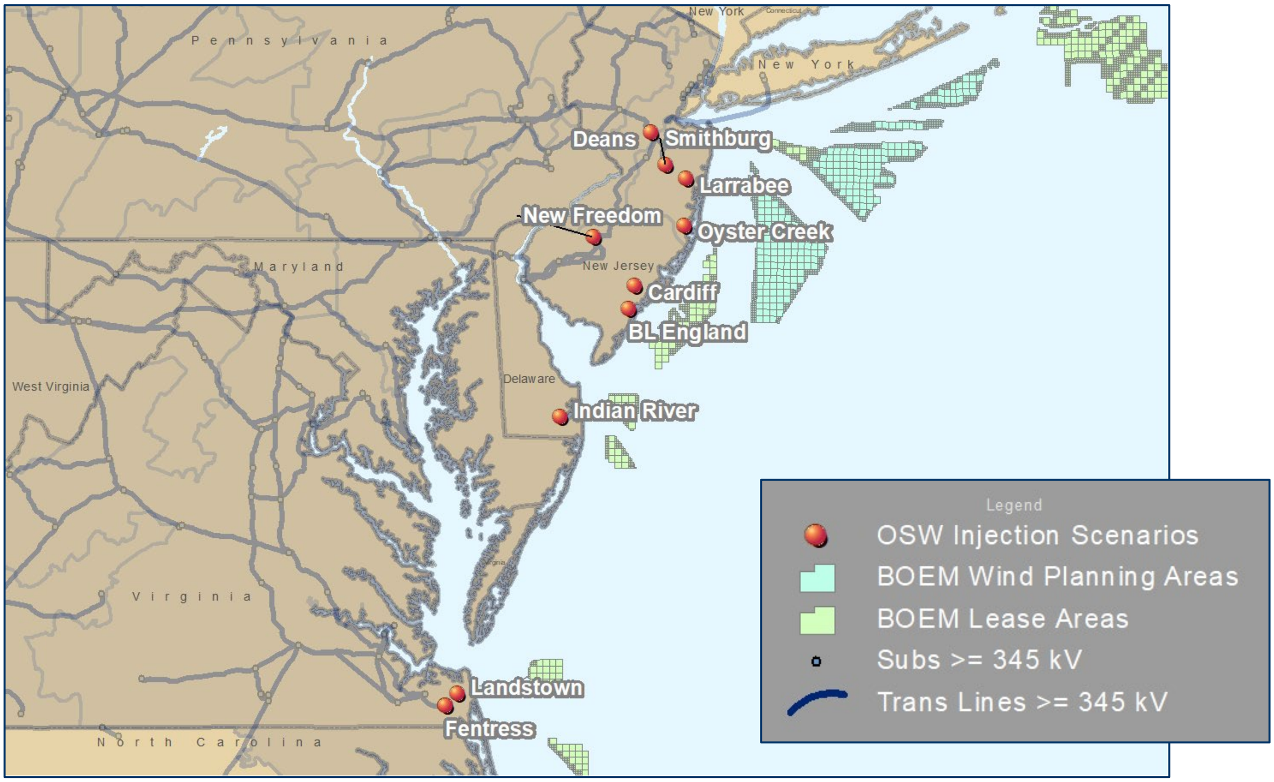
Note – Scenario 1 is the only short-term scenario, meaning the contributing variables were modeled through 2027. Scenarios 2–6 are long-term scenarios and were modeled through 2035. Scenario 3 was abandoned after legislation related to some of the assumptions made in this scenario was withdrawn.

A total of 10 POIs were selected for the Phase 1 scenarios. New Jersey included a total of seven POIs – BL England, Cardiff, Deans, Larrabee, New Freedom, Oyster Creek and Smithburg.[6] However, not every POI for New Jersey was used in each scenario. Delaware and Maryland utilized Indian River as their sole POI in all five scenarios, and North Carolina and Virignia selected Fentress and Landstown as their two POIs. **Map 1** presents the ten POIs in the Offshore Wind Transmission Study and also includes the offshore wind leasing and planning areas.

Because Maryland's planned offshore wind projects are currently seeking interconnection in the state of Delaware, Maryland and Delaware's offshore wind scenario components were combined within each scenario. The same occurred with North Carolina and Virginia, as North Carolina did not have any planned offshore wind policies at the time of Phase 1's scenario development. Therefore, the scenario results present Delaware and Maryland combined into one offshore wind injection location at the Indian River POI, and North Carolina and Virginia are combined into another set of offshore wind injection locations at the Fentress and Landstown POIs.

[6] The Phase 1 study results do not account for New Jersey's second offshore wind solicitation award, as these scenarios were developed before New Jersey awarded its second offshore wind solicitation to Ocean Wind II and Atlantic Shores (2,658 MW in total for both projects).

Map 1. Points of Interconnection Used in Phase 1 Scenarios



Generator Deactivations

Each of the five scenarios accounted for generators planning to deactivate. Oct. 1, 2020, was selected as the date for which all officially announced generator deactivations would automatically be captured in the scenario modeling.[7] Announced deactivations are only those where the generation owner had submitted an official notification to PJM. Generators with anticipated deactivations, such as those announced to the media or driven by legislation but without an official PJM notification, were not considered as an announced deactivation for this study.

The coastal states also had the opportunity to include as part of the scenarios additional generators to be modeled as deactivated that did not have an official notification submitted to PJM as of Oct. 1, 2020. Through the one-on-one meetings, it was decided that as part of the four long-term scenarios, an additional 1,739 MW located in the coastal states (1,280 MW in Virginia and 459 MW in New Jersey) would also be modeled as deactivated generation.

[7] Oct. 1, 2020, was chosen since this was the date of the last PJM baseline study of the transmission model used to develop these scenarios. It was also the date when the scenario planning commenced.

State Renewable Portfolio Standards

There are ten states within the PJM footprint, including the District of Columbia, with mandatory RPS targets. These RPS targets are presented in **Figure 1**. For each of the five scenarios, PJM modeled all of these specific RPS targets as being met with respect to the appropriate study year – 2027 or 2035.[8]

PJM also included state-specific resource carve-outs within the scenario modeling, as applicable to each RPS. Some states have in-state, resource-specific carve-outs, either as a percentage of energy or actual capacity targets, and PJM included the capacity needed to reach these targets within those respective states. Other state RPS targets expand to renewables anywhere within the PJM footprint, and PJM tailored the model with respect to where those renewable resources were located as well.

Figure 1. RPS Targets in PJM States

☼ Minimum solar requirement

State RPS Targets*

☼	**NJ:** 50% by 2030**	☼	**VA:** 100% by 2045/2050 (IOUs)
☼	**MD:** 50% by 2030	☼	**NC:** 12.5% by 2021 (IOUs)
☼	**DE:** 40% by 2035		**OH:** 8.5% by 2026
☼	**DC:** 100% by 2032		**MI:** 15% by 2021
☼	**PA:** 18% by 2021***		**IN:** 10% by 2025***
☼	**IL:** 25% by 2025/2026		

* RPS targets at time of study
** Includes an additional 2.5% of Class II resources each year
*** Includes non-renewable “alternative” energy resources

[8] In the short-term Scenario 1, PJM modeled all RPS targets being met by 2027. In the long-term scenarios, Scenarios 2–6, PJM modeled all RPS targets being met by 2035. PJM modeled the specific interim targets for the states whose RPS targets extend beyond the specific study year.

PJM utilized offshore wind, onshore wind, utility-scale and behind-the-meter solar and battery storage to meet the state RPS targets. Because RPS policies are primarily constructed as a percentage of energy consumed in a given year, PJM needed to convert the RPS energy percentages into capacity values respective of the eligible resource types. The average annual capacity factors PJM used in the megawatt-hour to megawatt conversion are presented in **Table 3**.

Table 3. Average Annual Capacity Factors Used to Convert Energy to Capacity

Resource Type	Average Annual Capacity Factor	Source [9]
Offshore Wind	40%	PJM
Onshore Wind	30%	PJM
Utility-Scale Solar	25%	PJM
Behind-the-Meter Solar	15%	PJM
Storage (Battery)	5%	EIA

As an example of this conversion, Maryland's RPS requires that by 2030, 50% of the electricity serving the state's load comes from renewable resources and 14.5% be derived from in-state solar resources.[10] Using the annual energy forecasts from the 2020 PJM Load Forecast, PJM converted these percentages into megawatts to identify the amount of in-state solar capacity needed within Maryland for 2035.[11] On the other hand, Maryland also allows onshore wind to satisfy its RPS, and this can come from out-of-state onshore wind resources. PJM used this type of information for years 2027 and 2035 for each PJM state with an RPS policy and, in combination with planned renewable resources throughout the PJM footprint, determined how much renewable capacity throughout PJM would be needed in 2027 and 2035 to achieve each state's RPS goals. The total amount of renewable capacity that was modeled in the Offshore Wind Transmission Study is included as Appendix A.

In addition to the annual energy forecast from the January 2020 PJM Load Forecast that was used to determine state RPS targets, the load forecast was also used to calculate the expected load levels that were modeled in each of the summer, winter and light-load power flow cases for the years 2027 and 2035 that were examined in the five scenarios. Energy efficiency and electric vehicle charging levels were included in this forecast as well.

[9] In addition to PJM internal data, several sources of external data, such as those from the EIA and NREL, were considered to derive these capacity factors.

[10] *2019 Maryland Clean Energy Jobs Act* https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/SB0516?ys=2019rs

[11] *2020 PJM Load Forecast Report* https://pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx

Modeling and Analysis

Modeling

The modeling for the Phase 1 scenarios utilized the 2020 Regional Transmission Expansion Plan (RTEP) model, which includes the 2025 and 2028 base cases. To achieve results in 2027, the model's 2025 base case was extrapolated out to 2027. The same extrapolation procedure was used to identify scenario results in 2035 by using the model's 2028 base case. For each scenario, PJM included the offshore wind injection amounts at each selected POI. PJM also included the RPS targets and resource carve-outs for each PJM state, modeling each state as meeting its RPS target by the required date.

Analysis

The analysis for Phase 1 consisted of a PJM-wide generator deliverability reliability analysis – summer, winter and light load. This analysis examined a variety of transmission and generation contingency types, such as single and common mode, and the resulting loadings on PJM transmission facilities to determine which ones became overloaded in each of the modeled scenarios. The deliverability study analyzed the ability of the bulk electric system to deliver the renewable generation to load centers throughout the PJM footprint.

Transmission line conductor limits were used to establish the transmission line overloads and capture the most costly onshore transmission requirements. No offshore transmission facilities, such as generator lead lines for offshore wind resources, were included as part of this analysis. There was also no consideration of an offshore transmission network model. Instead, the analysis focused on how the offshore wind injections at specific POIs, the remainder of the state RPS targets, and other scenario assumptions would impact the onshore transmission system. In addition, Phase 1 was limited to the PJM footprint and did not include at any impacts to or from neighboring systems.

Cost Estimates

Within the reliability studies performed as part of the scenario analysis, PJM identified those facilities that would have reliability violations that would need to be addressed. Optimal transmission solutions were not developed as part of this Phase 1 study. Instead, PJM developed costs to mitigate each individual reliability violation that was identified. Where available, required transmission reinforcements for Scenario 1 came from published interconnection study reports from the PJM queue, within which the PJM Transmission Owners provided approximated cost estimates to reinforce the facilities to a given rating. Any reinforcements from Scenario 1 that utilized queue-level cost estimates that appeared in subsequent scenarios also utilized these queue-level cost estimates. For the remaining required reinforcements, order-of-magnitude cost estimates were developed due to the magnitude of the number of reinforcements required, particularly for Scenarios 2 through 6.

In order to develop order-of-magnitude cost estimates, PJM made certain assumptions about the scope of work that would be required to mitigate the overloads. Where the violation on a transmission line was relatively small, it was assumed that the line could be reconductored and the towers and insulators could be reused. Where the overload was more significant, it was assumed that the transmission line and associated structures would need to be fully rebuilt. Cost estimates for new transformers were based on the high-side kV level of the transformer.

Table 4 below shows the order-of-magnitude cost estimates. These per-unit cost estimates were developed by a leading industry power system consultant that supported PJM with this study.

Table 4. Cost Estimates for New Transformers and Transmission Line Upgrades

Cost Estimates for New Transformers ($M per unit)	**138 kV** High Side	$4
	230 kV High Side	$6
	345 kV High Side	$9
	500 kV High Side	$25
	765 kV High Side	$45

	Upgrades	Reconductor	Loadings	Rebuild	Loadings
Cost Estimates for Transmission Line Upgrades ($M per mile)	**115 kV & 138 kV**	$0.8	≤ 400 MVA	$1.2	> 400 MVA
	230 kV	$1.2	≤ 1,200 MVA	$1.8	> 1200 MVA
	345 kV	$2.0	≤ 1,800 MVA	$3.0	> 1,800 MVA
	500 kV	$5.5	≤ 4,000 MVA	$8.0	> 4,000 MVA
	765 kV	$8.0	≤ 6,000 MVA	$12.0	> 6,000 MVA
	230 kV Cable	$15 ($M per mile)			

Scenario Results

This section presents the five Phase 1 scenario results. Each set of results provides the estimated costs of identified transmission upgrades and the transmission zones where the upgrades are located. The results categorize each PJM zone's upgrade requirements by transmission and transformer kV level.

What these cost estimates do not represent or suggest is cost allocation for any identified transmission upgrade. They indicate in what zone an upgrade was identified and what the associated cost is estimated to be. For upgrades that traversed two transmission zones, the costs were allocated 50% to each zone. Also, transmission upgrades for the Phase 1 scenarios were identified for the current transmission system topology. No greenfield transmission solutions were developed in the Phase 1 scenario modeling.

Because achieving all state RPS targets was incorporated into the modeling, the scenario results also capture transmission upgrades that were driven by renewable objectives beyond offshore wind. As a result, in some scenarios there are upgrades present for transmission zones that are not in proximity to offshore wind injection locations. For the states with offshore wind targets, the estimated costs include both the system impacts from offshore wind and the states' other RPS objectives. The results do not separate out the degree to which each transmission zone's upgrades are driven specifically by offshore wind or other renewable resources built into the model. However, by combining all of these renewable contributions together, this study was able to identify regional transmission needs that may not have been identified using a more isolated approach that separated the offshore wind from other renewable requirements or examined state RPS targets individually.

Scenario 1

Figure 2. Scenario 1 – Short Term (2027)

Offshore Wind Injection – 6,416 MW			
DE & MD	**NC & VA**	**NJ**	
Indian River 230 kV–248 kV Indian River 230 kV–520 kV*	Fentress 500 kV–2,600 MW	Oyster Creek 230 kV–816 MW BL England 138 kV–432 MW	Larrabee 230 kV–1,200 MW* Cardiff 230 kV–600 MW*

Deactivations**	Utility-Scale Solar Onshore Wind | Storage	Distributed Solar EVs | Energy Efficiency
Announced	State RPS for 2027	2020 PJM Load Forecast (2027)

*POI selected by PJM
**Deactivations in PJM announced by Oct. 1, 2020, considered in all scenarios

Table 5. Scenario 1 Results

	<230 kV	230 & 345 kV	500 kV	Transformer	Upgrade Cost ($M)
Atlantic City Electric	$11.30			$5.34	**$16.64**
American Electric Power	$19.10				**$19.10**
Allegheny Power Systems (FirstEnergy)	$15.70				**$15.70**
Baltimore Gas & Electric			$173.50		**$173.50**
Dominion		$22.50		$34.00	**$56.50**
Delmarva Power	$0.20				**$0.20**
Met-Ed		$5.20			**$5.20**
PECO		$5.40	$255.60	$50.00	**$311.00**
PSE&G		$29.50			**$29.50**
Total ($M)	$46.30	$62.60	$429.10	$89.34	**$627.34**

Scenario 1 was the only short-term scenario in Phase 1. The model included an offshore wind injection total of 6,416 MW, and the RPS targets were achieved through 2027. Several of the injection locations and capacity totals represented actual announced offshore wind projects.[12] The 248 MW injecting into Delaware and Maryland is the MarWin offshore wind facility, and New Jersey's first offshore wind solicitation that went to Ocean Wind I is captured at the Oyster Creek and BL England POIs. Scenario 1 only included generator deactivations that were announced as of Oct. 1, 2020, and were included in PJM's RTEP base case. For those offshore wind locations and injection amounts that were not yet announced, PJM selected the POIs based on:

[12] Every scenario has an injection of 248 MW at Indian River for the MarWin project that was awarded ORECs by the Maryland Public Service Commission and signed an Interconnection Service Agreement to interconnect at Indian River. The 816 MW at Oyster Creek and 432 MW at BL England are also included in every scenario and reflect New Jersey's first solicitation of 1,100 MW to Orsted's Ocean Wind I project.

1 | Existing requests for interconnection in the PJM queue

2 | Proximity to identified wind lease areas

3 | Capacity of existing coastal substations

The results of Scenario 1 show that approximately $627.34 million in transmission reinforcements across the PJM system may be required to interconnect projected state offshore wind capacity and achieve other RPS targets by the year 2027. These results indicate the potential need for a new 500 kV tie line between Pennsylvania and Maryland to support the delivery of generation from the mid-Atlantic coastal states to the rest of PJM. This new 500 kV tie line was required in each of the longer-term scenarios as well.

Market Efficiency

Including production cost analysis as part of the Offshore Wind Transmission Study was considered for the Phase 1 scenarios. During the development of the study, it was decided that this type of market efficiency analysis would be better situated in Phase 2, so that reliability needs could first be identified and required transmission reinforcements developed. However, PJM performed a market efficiency production cost analysis on Scenario 1 and provided high-level results to illustrate the output that could be provided for future scenarios. An overview of the Scenario 1 market efficiency results is included in ***Appendix B: Scenario 1 Market Efficiency Analysis, Scope and Procedure***.

Scenario 2

Figure 3. Scenario 2 – Long Term (2035)

Offshore Wind Injection – 14,416 MW		
DE & MD	**NC & VA**	**NJ**
Indian River 230 kV–248 kV Indian River 230 kV–1,320 kV*	Fentress 500 kV–2,600 MW Landstown 230 kV–2,600 MW	Oyster Creek 230 kV–816 MW BL England 138 kV–432 MW Larrabee 230 kV–1,200 MW Deans 500 kV–3,100 MW Smithburg 500 kV–1,200 MW Cardiff 230 kV–900 MW

Deactivations**	Utility-Scale Solar Onshore Wind | Storage	Distributed Solar EVs | Energy Efficiency
Announced & 1,739 MW Unannounced	State RPS for 2035	2020 PJM Load Forecast (2035)

*POI selected by PJM
**Deactivations in PJM announced by Oct. 1, 2020, considered in all scenarios

Table 6. Scenario 2 Results

	<230 kV	230 & 345 kV	500 kV	Transformer	Upgrade Cost ($M)
Atlantic City Electric	$11.30	$27.60		$ 11.34	**$50.24**
American Electric Power	$36.50			$9.00	**$45.50**
Allegheny Power Systems (FirstEnergy)	$37.20				**$37.20**
Baltimore Gas & Electric	$27.60	$95.15	$173.50		**$296.25**
ComEd	$15.10	$38.40			**$53.50**
Dominion	$135.00	$518.10	$ 250.30	$153.00	**$1,056.40**
Delmarva Power	$34.90	$18.50			**$53.40**
Jersey Central Power & Light	$13.80	$15.90			**$29.70**
Met-Ed	$9.20	$ 5.20			**$14.40**
PECO		$ 75.60	$ 303.50	$50.00	**$429.10**
Penelec				$50.00	**$50.00**
Pepco		$0.70			**$0.70**
PPL		$12.15			**$12.15**
PSE&G		$332.90			**$332.90**
Total ($M)	$ 320.60	$1,140.20	$ 727.30	$ 273.34	**$2,461.44**

Scenario 2 was a long-term scenario that looked out through 2035. A total of 14,416 MW were modeled, which captured the actual amount of offshore wind capacity currently planned to be operational in PJM by 2035 based on state legislation and planned project capacity. RPS targets were also modeled as being achieved by 2035. For Scenarios 2, 4, 5 and 6, an additional 1,739 MW were modeled as deactivated in addition to what was announced as of Oct. 1, 2020.

The transmission upgrades for Scenario 2 were estimated to be $2.46 billion. Due to the large increase in renewable penetration levels considered in this scenario, the transmission needs rose considerably from those in Scenario 1. For example, in the Dominion zone alone, the amount of offshore wind doubled, and the amount of solar additions more than doubled. This resulted in an increase from Scenario 1 of $1 billion in transmission requirements in the Dominion zone. Also of note are transmission requirements in PJM zones farther inland such as the ComEd zone, where the estimated transmission costs rose to over $50 million, to support the large addition of onshore wind in the state of Illinois.

Scenario 3

Scenario 3 was abandoned after the Phase 1 scenarios were developed and before the modeling and analysis commenced. This scenario was identical to Scenario 2, except for the inclusion of some additional generators being modeled as deactivated. The reason for Scenario 3's initial inclusion and eventual removal was a result of pending legislation driving the deactivation of these units that was ultimately withdrawn. As a result, PJM removed Scenario 3 from the model.

Scenario 4

Figure 4. Scenario 4 – Long Term (2035)

Offshore Wind Injection – 17,016 MW			
DE & MD	**NC & VA**	**NJ**	
Indian River 230 kV–248 kV Indian River 230 kV–1,320 kV*	Fentress 500 kV–5,200 MW Landstown 230 kV–2,600 MW	Oyster Creek 230 kV–816 MW BL England 138 kV–432 MW Larrabee 230 kV–1,200 MW	Deans 500 kV–3,100 MW Smithburg 500 kV–1,200 MW Cardiff 230 kV–900 MW

Deactivations**	Utility-Scale Solar Onshore Wind | Storage	Distributed Solar EVs | Energy Efficiency
Announced & 1,739 MW Unannounced	State RPS for 2035	2020 PJM Load Forecast (2035)

*POI selected by PJM
**Deactivations in PJM announced by Oct. 1, 2020, considered in all scenarios

Table 7. Scenario 4 Results

	<230 kV	230 & 345 kV	500 kV	Transformer	Upgrade Cost ($M)
Atlantic City Electric	$11.30	$27.60		$11.34	**$50.24**
American Electric Power	$33.50			$9.00	**$42.50**
Allegheny Power Systems (FirstEnergy)	$37.20				**$37.20**
Baltimore Gas & Electric	$27.60	$27.25	$173.50		**$228.35**
ComEd	$15.10	$38.40			**$53.50**
Dominion	$135.00	$557.40	$995.30	$191.00	**$1,878.70**
Delmarva Power	$35.20	$18.50			**$53.70**
Jersey Central Power & Light	$13.80	$15.90			**$29.70**
Met-Ed	$9.20	$5.20			**$14.40**
PECO		$75.60	$303.50	$50.00	**$429.10**
Penelec				$50.00	**$50.00**
Pepco		$0.70			**$0.70**
PPL		$12.15			**$12.15**
PSE&G		$332.90			**$332.90**
Total ($M)	$317.80	$1,111.60	$1,472.30	$311.34	**$3,213.14**

The transmission upgrades for Scenario 4 were estimated to be $3.21 billion, exceeding the total cost estimate for Scenario 2 by over $700 million. The increase in the estimated cost was primarily attributed to a further increase in the state of Virginia's offshore wind assumptions, with an additional 2,600 MW added to the 5,200 MW already included in Scenario 2. This additional offshore wind resulted in the need for multiple new 500 kV line reinforcements across the Dominion zone that were not identified in Scenario 2.

Scenario 5

Figure 5. Scenario 5 – Long Term (2035)

Offshore Wind Injection – 14,416 MW			
DE & MD	**NC & VA**	**NJ**	
Indian River 230 kV–248 kV Indian River 230 kV–1,320 kV*	Fentress 500 kV–2,600 MW Landstown 230 kV–2,600 MW	Oyster Creek 230 kV–816 MW BL England 138 kV–432 MW Larrabee 230 kV–1,200 MW	Deans 500 kV–3,100 MW New Freedom 500 kV–1,200 MW Cardiff 230 kV–900 MW

Deactivations**	Utility-Scale Solar Onshore Wind | Storage	Distributed Solar EVs | Energy Efficiency
Announced & 1,739 MW Unannounced	State RPS for 2035	2020 PJM Load Forecast (2035)

*POI selected by PJM
**Deactivations in PJM announced by Oct. 1, 2020, considered in all scenarios

Table 8. Scenario 5 Results

	<230 kV	230 & 345 kV	500 kV	Transformer	Upgrade Cost ($M)
Atlantic City Electric	$25.20	$27.60		$11.34	**$64.14**
American Electric Power	$37.80			$9.00	**$46.80**
Allegheny Power Systems (FirstEnergy)	$43.80				**$43.80**
Baltimore Gas & Electric	$27.60	$37.15	$173.50		**$238.25**
ComEd	$15.10	$38.40			**$53.50**
Dominion	$135.00	$519.60	$250.30	$147.00	**$1,051.90**
Delmarva Power	$34.90	$83.50			**$118.40**
Jersey Central Power & Light	$16.40	$21.90			**$38.30**
Met-Ed	$9.20	$5.20			**$14.40**
PECO		$75.60	$303.50	$50.00	**$429.10**
Penelec	$0.50			$50.00	**$50.50**
Pepco		$0.70			**$0.70**
PPL		$12.15			**$12.15**
PSE&G		$404.90		$25.00	**$429.90**
Total ($M)	$345.50	$1,226.70	$727.30	$ 292.34	**$2,591.84**

The transmission upgrades for Scenario 5 were estimated to cost $2.59 billion. Scenario 5 was very similar to Scenario 2, with the primary difference of the Smithburg 500 kV offshore wind POI in New Jersey being relocated to the New Freedom 500 kV POI in New Jersey. This relocation resulted in a bottled generation scenario that required additional upgrades exiting the southern portion of New Jersey.

Scenario 6

Figure 6. Scenario 6 – Long Term (2035)

Offshore Wind Injection - 12,416 MW			
DE & MD	**NC & VA**	**NJ**	
Indian River 230 kV–248 kV Indian River 230 kV–1,320 kV*	Fentress 500 kV–2,600 MW Landstown 230 kV–2,600 MW	Oyster Creek 230 kV–816 MW BL England 138 kV–432 MW Larrabee 230 kV–1,200 MW	Deans 500 kV–2,300 MW Cardiff 230 kV–900 MW

Deactivations**	Utility-Scale Solar Onshore Wind | Storage	Distributed Solar EVs | Energy Efficiency
Announced & 1,739 MW Unannounced	State RPS for 2035	2020 PJM Load Forecast (2035)

*POI selected by PJM
**Deactivations in PJM announced by Oct. 1, 2020, considered in all scenarios

Table 9. Scenario 6 Results

	<230 kV	230 & 345 kV	500 kV	Transformer	Upgrade Cost ($M)
Atlantic City Electric	$25.20	$27.60		$11.34	**$64.14**
American Electric Power	$37.80			$9.00	**$46.80**
Allegheny Power Systems (FirstEnergy)	$28.00				**$28.00**
Baltimore Gas & Electric	$27.60	$27.25	$173.50		**$228.35**
ComEd	$15.10	$38.40			**$53.50**
Dominion	$135.00	$516.30	$250.30	$153.00	**$1,054.60**
Delmarva Power	$34.90	$18.50			**$53.40**
Jersey Central Power & Light	$16.40	$10.80			**$27.20**
Met-Ed	$9.20	$5.20			**$14.40**
PECO		$75.60	$255.60	$50.00	**$381.20**
Penelec				$50.00	**$50.00**
Pepco		$0.70			**$0.70**
PPL		$1.05			**$1.05**
PSE&G		$161.00			**$161.00**
Total ($M)	$ 329.20	$882.40	$679.40	$273.34	**$2,164.34**

The transmission upgrades for Scenario 6 were estimated to be $2.16 billion. Scenario 6 was very similar to Scenario 2 and Scenario 5. One of the 1,200 MW New Jersey offshore wind 500 kV POIs was removed, and the remaining New Jersey offshore wind 500 kV POI was reduced by 900 MW for a total reduction in the New Jersey offshore wind injection of 2,000 MW. As expected, this reduction in offshore wind resulted a significant reduction in transmission requirements.

Conclusion

The Offshore Wind Transmission Study is a PJM-wide reliability study to determine reinforcements to the onshore grid to reliably deliver not only the 14,268 MW of announced offshore wind in the PJM region, but also to achieve all state RPS targets in the PJM region by determining the necessary renewable capacity by resource type and location. PJM modeled and analyzed five scenarios that were developed in collaboration with coastal state agencies from within the PJM footprint. The scenarios looked at offshore wind injection totals that ranged from 6,416 MW to 17,016 MW, in addition to modeling all state RPS targets, across short-term and long-term scenarios. The scenarios sought to identify reliability violations and transmission upgrades on the bulk electric system caused by the integration of these renewable resources and to provide cost estimates by transmission zone.

For the five scenarios, these cost estimates were identified to be $627.34 million in the short-term scenario and between $2.16 billion and $3.21 billion for the long-term scenarios. The study does not commit any state to any transmission upgrade, but rather it serves as an opportunity to identify what a potential set of coordinated transmission solutions could be and to help inform state policymakers as they advance their current and any future offshore wind endeavors.

Phase 1 provides an important starting point for future scenarios that consider the integration of offshore wind and other renewable resources into the PJM system. It also presents a framework for how future collaborative transmission planning studies between PJM and the PJM states can be achieved. Based on these Phase 1 results, states can request additional scenarios for PJM to model as part of Phase 2. The results from both phases can help guide the coastal states in crafting their offshore wind solicitations. States can also pursue transmission solutions identified in this study further, such as through the State Agreement Approach.

Appendix

Appendix A: Renewable Capacity in Model to Meet RPS Targets

These figures represent the total amount of generation needed to meet the RPS targets of the PJM states. Some states have specific in-state carve-outs, while others can use renewable generation within the entire PJM footprint. The modeled renewable buildout accounted for both. The total renewable generation modeled in the study includes resources already in service, resources currently in the queue, and additional renewable megawatts needed to fulfill any RPS requirements not already covered by in-service and currently planned generation.

Table 10. Renewable Capacity in Model for Achieving State RPS Targets

State	Year	Offshore Wind (MW)	Onshore Wind (MW)	Solar (MW)	Storage (MW)
NJ	2027	2,900	-	7,111	1,475
	2035	*7,648	-	11,322	2,875
MD	2027	768	210	5,002	-
	2035	1,568	210	5,602	-
DC	2027	-	-	343	-
	2035	-	-	462	-
DE	2027	-	-	468	-
	2035	-	-	595	-
VA	2027	2,600	130	6,270	280
	2035	5,200	130	16,570	3,100
NC	2027	-	600	1,117	-
	2035	-	600	1,153	-
PA	2035	-	1,585	2,185	58
IL		-	7,329	2,406	1,080
OH		-	1,742	3,938	24
MI		-	-	356	-
IN		-	2,325	275	-
Rest of PJM KY, TN, WV *(non-RPS states)*		-	609	713	54
2035 Total		**14,416 MW**	**14,530 MW**	**45,577 MW**	**7,191 MW**

**Note: New Jersey, through solicitations 1–5, is seeking a total of 7,500 MW of offshore wind. Solicitation 1 for 1,100 MW has already been awarded. The actual capability of Solicitation 1 is 1,248 MW. As a result, a total of 7,648 MW of offshore wind was modeled in New Jersey.*

Appendix B: Scenario 1 Market Efficiency Analysis, Scope and Procedure

This section provides the general scope and procedure used for the market efficiency analysis that was conducted for Scenario 1. The analysis conducted for Scenario 1 is to be used as an example of the market efficiency analysis and output that PJM can perform for Phase 2 scenarios.

For this analysis, an energy market simulation tool was used to model the hourly least-cost, security-constrained commitment and dispatch of generation over the 2025 simulated year. A detailed generation, load and transmission system model was used as input in order to simulate hourly generation commitment and dispatch to meet load, while recognizing physical limitations of the transmission system.

PJM identifies the economic benefit of a transmission asset by conducting production cost simulations. These simulations show the impact of a project on the energy market for a specific study year transmission and generation dispatch scenarios. Economic benefit is determined by comparing future-year simulations with and without proposed transmission assets.

PJM conducted this case study in the same manner as it conducts market efficiency analysis as part of its FERC-approved RTEP process. PJM used a market simulation tool to model hourly security-constrained generation commitment and economic dispatch. Two energy market simulation cases were developed:

1 | A “2025 Base Case” base simulation including all future RTEP Board-approved transmission assets modeled

2 | A “2025 RPS” sensitivity study simulation including additional solar, wind and energy storage generation to reach the RPS targets outlined for Scenario 1 (Transmission reinforcements identified in the reliability analysis of Scenario 1 have been applied to the RPS case’s topology.)

The results of the two simulations were compared to determine the impact of Scenario 1 on congestion, production cost, load payments, renewable curtailments and emissions. The results show that in the PJM Energy Market alone, the reliability transmission reinforcements and the RPS generation are expected to reduce costs to customers in combined annual load payments and annual production costs. The transmission reinforcements also help remove the system market inefficiencies manifested by persistent congestion and allow greater access to the lower-cost renewable generation:

- **Congestion Relief –** There was no new significant simulated congestion in the 2025 RPS simulation after the reliability transmission upgrades were applied to the case. The RPS renewable generation helped decrease the overall west-to-east PJM congestion when compared to the base case. It also supported increased exports to MISO.
- **Production Costs Reduction –** Production costs represent the fuel costs, variable operation and maintenance costs, and emission costs of dispatched resources in PJM. Due to the lower cost of renewable generation, the total production cost in the 2025 RPS simulation is lower compared to the base case. The new wind and solar RPS generation is displacing higher-cost fossil fuel generation across the PJM footprint, in the process generating PJM-wide production cost savings.

- **Decrease in Gross Load Payments –** Load payments represent the cost, measured by the locational marginal prices (LMP), for the energy supplied to the consumer. Due to the lower cost of renewable generation, the gross load payments in the 2025 RPS simulation are lower compared to the base case. The largest decreases in gross load payments are in the District of Columbia, Delaware, Maryland, New Jersey, North Carolina, Pennsylvania and Virginia with the rest of the PJM states also enjoying load payments benefits, albeit on a smaller scale.
- Renewable curtailments represent the amount of renewable energy that cannot be dispatched to the system due to transmission constraints. The reliability transmission reinforcements help decrease the wind and curtailments across the PJM footprint. In the RPS case, slight solar curtailment still remains in Maryland and Virginia due to the significant solar buildup.
- Emission savings represent the change in total emissions of the dispatched resources in PJM to serve the PJM load. The clean renewable RPS generation from wind and solar leads to significant decreases of carbon dioxide, nitrogen oxides and sulfur dioxide emissions across PJM's footprint with the highest percent emissions decreases in the coastal states.

Tools and Input Assumptions

As with its conventional RTEP market efficiency analyses, this analysis also used Hitachi ABB Power Grids' PROMOD software tool. PROMOD is fundamental electric market simulation software that incorporates extensive, detailed generating unit operating characteristics, transmission grid topology and constraints, and market system operations. The PROMOD simulation engine employs an hourly chronological dispatch algorithm that minimizes dispatch costs while simultaneously ensuring that defined operating parameters remain within specified constraints: generating unit characteristics, transmission limits, fuel and environmental considerations, transactions and customer demand.

PJM licenses a commercially available database containing the necessary data elements to perform detailed market simulations. This database is periodically updated to include the most recent representation of the Eastern Interconnection and, in particular, PJM markets. PJM's Transmission Expansion Advisory Committee (TEAC) reviews the key analysis input parameters, shown in **Figure 7**. This data is used to develop forecasted system conditions, consistent with established RTEP process practice. Parameters include fuel costs, emissions costs, load forecasts, demand resource projections, generation projections, expected future transmission topology and financial valuation assumptions.

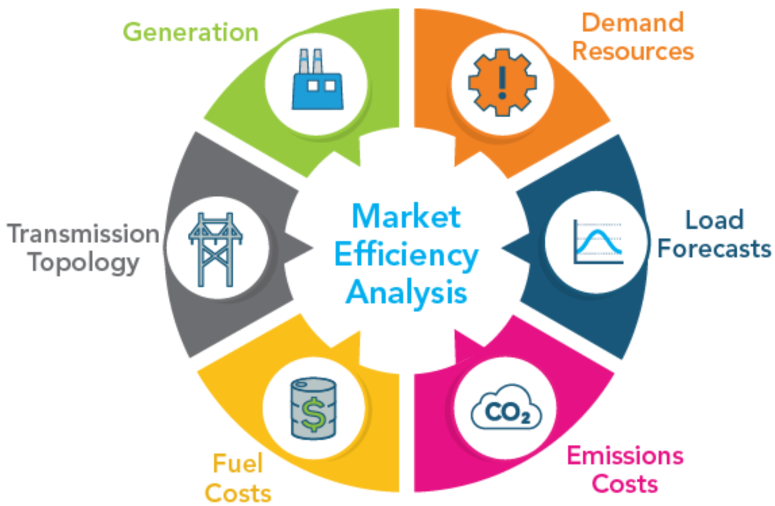
A detailed generation, load and 2025 study year transmission system model was used as the starting point to simulate hourly generation commitment and dispatch to meet load, while recognizing physical limitations of the transmission system. The simulation data model itself was initially seeded with the latest base release of the PROMOD Simulation Ready Data NERC Database for the Eastern Interconnection. This provided a bus-level, interconnection-wide transmission topology and generation model, which PJM then tailors to its own Market Efficiency Process needs by providing:

1 | A more current view of PJM market fundamentals

2 | An updated transmission model for PJM's footprint

Generation Parameters

Figure 7. Market Efficiency Analysis Parameters



Market efficiency simulations model existing in-service generation plus actively queued generation with at least an 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. Production cost simulations incorporate the following generation data parameters:

- Identification of capacity and energy resources expected to be in service during the study period modeled within the current five-year-out RTEP load flow case
- Retirement of existing resources according to officially announced timetables
- Addition or modification of future unit-specific resources based on queue processing and load flow representation
- Scaling of resource capacity to meet planned installed reserve margins, if appropriate

Queued generation includes that which has reached in-service commercial operation and that with signed ISAs/Interim ISAs/or not requiring an ISA.

Fuel Price Assumptions

PJM uses Hitachi ABB Power Grids' 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 and from Hitachi ABB Power Grids' fundamental models, as are all coal price forecasts. Vendor-provided basis adders are applied as well to account for commodity transportation cost to each PJM zone.

Load and Energy Forecasts

PJM's 2021 Load Forecast Report provided the transmission zone peak load and energy data modeled in the simulations. Load data used in the market efficiency simulations is a combination of the load shapes embedded in the annual PROMOD database and values representing PJM's official load forecast characteristics. This process includes incorporating the monthly non-coincident peak and energy values by transmission zone as contained in monthly tables released as part of the PJM Load Forecast Report. These data items are made up of weather-normalized, unadjusted peak and energy values and include assumptions for energy efficiency (EE) and distributed solar.

Demand Resources

The amount of demand response (DR) resources modeled in each transmission zone is based on Table B-7 of the 2021 PJM Load Forecast Report. Production cost simulations model demand resource products as generation resources. Three resource types are defined for each zone: Limited DR, Extended Summer DR and Annual DR. DR resources are modeled as discrete resources based on product type, state, transmission zone and historic LMP trends for the load buses where they are modeled.

Emission Allowance Price Assumptions

PJM currently models three major effluents – sulfur dioxide, nitrogen oxides and carbon dioxide – within its market efficiency simulations. Sulfur dioxide and nitrogen oxides emission price forecasts reflect the implementation of the Cross-State Air Pollution Rule (CSAPR). PJM-unit carbon dioxide emissions are modeled as either part of the national carbon dioxide program or as part of the Regional Greenhouse Gas Initiative (RGGI) program depending on the state that the unit is located in.

External Region Modeling

PJM models adjoining, external regions that include multi-party transactions with commitment and dispatch hurdle rates defined between systems. This allows for economic transactions to flow between control areas within the simulation. PJM's simulation tool also automatically scales generation uniformly to balance the load and losses in inactive external regions to ensure that congestion has not been distorted by parallel flows skewed by original external model development.

Monitored Constraints

PJM's production cost simulation tool monitors specific thermal and reactive interface transmission constraints derived from the following sources:

1 | All transmission facilities on PJM's monitored facility list

2 | Monitored facilities obtained based on historical analysis of real-time constraints

3 | Monitored facilities obtained based on future-looking analysis of the system topology under study. N-1 thermal flowgate screening is utilized to identify monitored facilities.

4 | NERC Book of Flowgates (BOF) constraints to model flowgates jointly controlled by PJM and another region. These are generally external constraints for which PJM generation has a significant Transfer Distribution Factor (TDF).

5 | 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.