Illinois Generation Retirement Study

PJM Interconnection

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Contents

Overview

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. 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.

PJM's RTEP process spans state boundaries and in doing so 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 more distant load centers.

PJM's RTEP process, including that to evaluate deactivation of generation, encompasses a comprehensive assessment of system compliance with the thermal, reactive, stability and short-circuit North American Electric Reliability Corporation (NERC) Standard TPL-001-4.[1] This study focuses on the thermal and reactive dimensions of Standard TPL-001-4.

Background

In PJM's role as a NERC regional planning authority, and in response to the recently passed Illinois law the Climate and Equitable Jobs Act (CEJA), PJM conducted a study to determine impacts to the transmission system resulting from anticipated generation retirements in Illinois through 2045. CEJA mandates the scheduled phaseout of coal and natural gas generation by specified target dates: January 2030, 2035, 2040 and 2045. CEJA also allows for the opportunity to create reliability safety measures[2] and further directs Illinois government to create a working group to collaborate with PJM and MISO starting in 2025 so as to analyze reliability impacts based on this retirement schedule. Further, CEJA contemplates and incentivizes the construction of a significant quantity of renewable resources.

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[1] NERC standard that establishes transmission system planning performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies; TPL-001-4.

[2] See PJM Reliability Guidance: https://www.pjm.com/-/media/committees-groups/committees/oc/postings/illinois-ceja-reliability-guidance.ashx.

Scope

- While generation retirements could occur in Illinois for reasons other than CEJA (e.g., economic factors, federal EPA regulations), the scenarios studied were based upon the two significant target deadlines in CEJA for phasing out fossil generation: 2030 and 2045. Thus, PJM's study encompassed analysis of two study scenarios, 2030 and 2031–2045, as part of identifying overall reliability criteria violations and developing high-level solutions and cost estimates.
- The study includes in its modeling: (i) units that will be leaving the system as a result of already issued retirement notices; (ii) phaseout requirements as set forth in CEJA; and (iii) generation additions based on the current PJM generation interconnection queue.
- The study does not include in its modeling renewable generation that is expected to be added to the system in the future as contemplated and incentivized under CEJA.
- The difference between the 2030 case and the 2031–2045 case was the increased expected deactivations in the latter case. Load and the replacement generation remained consistent between the two scenarios to ensure violations were attributable to the deactivations.
- PJM conducted its standard set of planning reliability studies tests, including generation deliverability, N-1, N-1-1 thermal and voltage drop analyses.[3]
- The study does not include the MISO Long-Range Transmission Plan (LRTP) Tranche 1 project portfolio or the ongoing additional LRTP study work MISO is performing that includes the Illinois area. PJM adopted a number of assumptions that may be updated when PJM, MISO and impacted transmission owners conduct a more rigorous Illinois deactivation reliability study analysis in late 2022/early 2023. PJM monitored MISO facilities along the PJM/MISO seam and coordinated with the most heavily impacted MISO transmission owner (NIPSCO) to review results and provide required high-level transmission solutions and attendant high-level cost estimates. While MISO participated in model development with PJM, MISO indicated that its own timeline for conducting a detailed study of its own system and identification of additional upgrade costs would likely be late 2022 or early 2023.
- To establish the timing of affected generation units' expected deactivation, MISO and PJM analyzed each generating unit's publically available emissions data; published heat rate; and proximity to Illinois environmental justice communities and Restore, Reinvest, Renew (R3) zones to understand CEJA criteria impacts.
- PJM did not attempt to estimate early retirements due to current CEJA operational limits on natural gas-fired generation.
- Modeled PJM replacement generation was based on generation interconnection queue projects with executed Interconnection Service Agreements (ISAs) or Facilities Study Agreements through Jan. 7, 2022, in Queue AF1.

[3] Descriptions of study methodologies can be found in PJM Manual 14B.

Further Framing

- This is a very initial snapshot of the system based upon what PJM knows today, and PJM will iterate on this analysis over time. The timing of deactivations in Illinois, as well as in the rest of the PJM region, and the impact of replacement generation from PJM's interconnection queue will impact future study results.
- PJM notes it is not proposing fixes for PJM RTEP projects based on this study.
- The cost estimates identified in this study will not actually be charged to consumers today; as the system evolves with retirements and additions, PJM will have a better sense of the necessary transmission that will be needed to alleviate any reliability violations.
- New generation located at the same points where units are retiring, or in similarly favorable locations, could decrease the transmission cost estimates outlined in our findings. At the same time, there is the risk of an acceleration of upgrades if existing generators retire earlier than modeled.
- In addition, PJM will combine this analysis with an analysis from MISO to determine whether any interregional transmission planning can assist in optimizing the systems to further reduce costs in the PJM (and MISO) footprint.
- PJM will iterate on this study as we gain more clarity on renewable build out through the Illinois Renewable Energy Access Plan (REAP) and the projects that enter our queue. Currently, PJM's generation interconnection queue consists of approximately 200,000 MW, of which approximately 95% is solar, wind or hybrid; we expect this trend to continue.

Summary of Findings

PJM identified several transmission upgrades that will be needed as Illinois generation retires or is phased out. Initial estimated costs for transmission upgrades are approximately $700 million by 2030 and an additional $1.3 billion by 2045. For reliability reasons, PJM may need to request that certain units operate beyond their desired deactivation dates pursuant to Part V of the PJM Tariff.

Detailed takeaways include the following:

1 | The study identified 69 upgrades to the 138 kV system dispersed over the PJM footprint that accounted for 82% of the thermal upgrade costs; sixteen 345 kV upgrades accounted for 18% of the costs.

2 | The overall study yielded a total upgrade solution cost estimate of $2 billion, or $0.7 billion and $1.3 billion, respectively, for the 2030 and 2031–2045 study scenarios.

(a) Grid upgrades to solve thermal-based reliability criteria violations account for 64%, or $1.3 billion, of the upgrade cost estimate and are almost evenly split between the 2030 and 2031–2045 study scenarios. Fifteen percent of this total is for thermal-based upgrades in ComEd; 85% is for upgrades across the rest of the PJM Western subregion.

(b) Grid upgrades to solve voltage-based reliability criteria violations account for 36%, or $718 million, of the upgrade costs. Unlike thermal violations, which tend to be more linearly aligned with megawatt impacts, voltage violations are nonlinear.

3 | The Illinois fossil resource deactivations create the need to import a substantial amount of remote replacement power to serve load. The PJM interconnection queue provided 14,848 MW dispersed across the footprint, which were applied to both the 2030 and 2031–2045 cases. The studies in the 2030 and 2031–2045 cases show significant east-to-west power-flow increases on the PJM grid, particularly in the Western subregion. These increased flows primarily impact ComEd, FirstEnergy, Duquesne, AEP and NIPSCO (MISO) zones.

(a) The increased east-to-west imports caused numerous, significant thermal-based reliability criteria violations in both the 2030 and 2031–2045 scenarios.

(b) The 2030 study case analysis identified the initial onset of system voltage instability issues in Illinois.

(c) The 2031–2045 study case analysis identified significant voltage stability concerns in Illinois and surrounding states that, if not resolved with system upgrades, could lead to blackouts driven by voltage collapse.

4 | Because Illinois includes parts of both the PJM and MISO footprints, future coordinated interregional studies and solutions are recommended to ensure cost-effective and optimized solutions.

To address the voltage instability concerns, ComEd and NIPSCO proposed static volt-amp reactive compensators (SVCs) and synchronous condensers to replace the megavolt amperes reactive (MVAR) capabilities lost from the deactivation of the generating units that had provided that reactive support at a $525 million and $193 million cost estimate for the SVCs, respectively. With the onset of voltage instability observed in the 2030 scenario, PJM assumed 10% of that cost would be incurred prior to 2030 with the remainder needed after 2030.

Study Assumptions

Base Cases

PJM and MISO agreed to use the 2021-series Multiregional Modeling Working Group (MMWG) 2031 study year power-flow case adjusted for updated loads, anticipated baseline upgrade updates, deactivation estimates and replacement generation for both 2030 and 2045. MISO provided PJM modifications to the MMWG case to reflect generation retirements. PJM then incorporated into that case its own system model from the last completed five-year RTEP summer case – the 2021-series 2026 summer case – with load scaled as shown in **Table 1**, below.

Table 1. Illinois Generation Retirement Study Load Levels

Year	PJM	MISO
2030	2026 scaled to 2031	MMWG 2031
2031–2045		

Publically available data were applied to the deactivation requirement criteria. Deactivations were modeled totaling the following power reductions as shown below in **Table 2**.

Table 2. PJM's Illinois Generation Retirement Study Deactivation Levels

Year	PJM (MW)	MISO (MW)	Illinois Total (MW)
Estimated Illinois for 2030 Case	9,661	1,933	**11,594**
Estimated Illinois for 2031–2045 Case	14,888*	8,003*	**22,891***

* Cumulative and includes all anticipated Illinois CEJA deactivations

Given the level of deactivations, replacement power – shown in **Table 3** – was met with output from generators in its interconnection queue that had either an executed Interconnection Service Agreement, or a generator Facilities Study Agreement, as of Jan. 7, 2022, in Queue AF1. PJM applied a commercial probability of 57% to the requested Capacity Interconnection Rights for those Facilities Study Agreement projects.

Table 3. PJM Illinois Generation Retirement Study Replacement Capacity (as of Jan. 7, 2022, in Queue AF1)[4]

Year	PJM (MW)	MISO (MW)	Total (MW)
ISA	6,315	N/A	6,315
Facilities Study (57% CP x CIRs)	8,533	7,240*	15,773
Total	**14,848**	**7,240**	**22,088**

* MISO provided value and does not constitute 57% CP x CIRs

Detailed Findings

As indicated above, PJM conducted two generation retirement studies – one each for the 2030 and 2031–2045 study cases – using its established set of PJM RTEP deactivation analyses. **Table 4** quantifies the estimated cost for each transmission owner zone to solve identified thermal-based reliability criteria in each study year. **0** quantifies the estimated cost for each transmission owner zone to solve identified voltage-based reliability criteria violations in each study case. The longest duration for upgrade completion for was 60 months.

Transmission owners reviewed and confirmed the identified violations. Where a violation was identified, the transmission owner either provided existing planned upgrades or provided a proposed upgrade solution. For proposed solutions, transmission owners provided high-level cost-per-mile and duration estimates. Existing planned upgrades were excluded from this report, since they will be completed prior to the scenario timing, and the costs are already accounted for in the respective regional expansion plans.

Under PJM's existing RTEP process, once an official retirement notification is received, PJM engages in an intensive process with affected transmission owners to identify transmission network reliability upgrade solutions and attendant estimated costs and in-service dates. If needed, PJM would also develop interim operating procedures until such upgrades were in place.

[4] Based on requested CIRs using PJM's current process, which does not include Effective Load Carrying Capacity (ELCC)

Solutions and Cost Estimates To Solve Thermal-Based Violations

	2030	2031–2045
ComEd	ComEd estimated approximately $100 M of upgrades are required to address thermal overloads. Most of that cost estimate is associated with a new 138 kV transmission line from Haumesser to West Dekalb to Glidden.	ComEd identified an additional $160 M in thermal upgrades.

	2030	2031–2045
AEP	AEP estimated approximately $63.5 M of upgrades to solve thermal overloads. Almost 80% of that cost would be to rebuild the AltaVista to Otter to Johnson Mountain to New London 138 kV line.	AEP estimated $178 M of upgrades to solve thermal overloads. Approximately 85% of that cost was for a proposed new Segreto-Cook 345 kV line and to rebuild the West End Fostoria to Woodville 138 kV line.

	2030	2031–2045
FirstEnergy	FirstEnergy estimated $320 M in upgrades to address the thermal violations caused by an increase in east-to-west power flow. Approximately 60% of that estimate derives from reconductoring five 138 kV circuits: two between Leroy Center and Mayfield and three from Charleroi to Union Junction, Westraver and Yukon.	FirstEnergy estimated $180 M in upgrades to address thermal violations. Over 80% of this estimate would be to conductor the following 138 kV lines: Mitchell to Shepler Hill Junction, Peters to Union Junction, Yukon to Smithton, Leroy Center to Mayfield, and Richland to Lockwood (AEP).

Duquesne	The Duquesne area had the same thermal issues identified in both the 2030 and 2031–2045 study cases. The proposed 2030 fixes also resolve the 2031–2045 study case reliability criteria violations. Duquesne identified upgrades with an estimated cost of $180 M. Most of that estimated cost is for new 138 kV facilities, including a new Elrama substation, two new ties and one new transmission line. Additionally, approximately 35 circuit miles of 138 kV reconductor is required.

MISO (NIPSCO)	Based on PJM’s analyses, NIPSCO identified $125 M of upgrades are needed to address thermal-based reliability criteria violations.

Table 4. PJM Illinois Generation Retirement Study Cost Estimates To Solve Thermal-Based Reliability Criteria Violations

TO	2030 Thermal Upgrades ($M)	2031–2045 Thermal Upgrades ($M)	Overall Thermal Upgrades ($M)
ComEd	98.00	161.50	259.50
FE	320.00	180.00	500.00
DLCO	180.00	0	180.00
AEP	63.55	178.10	241.58
NIPSCO	0	125.40	125.00
Total	**661.75**	**644.33**	**1,306.08**

Solutions and Cost Estimates To Solve Voltage Violations

ComEd

The onset of voltage stability issues was identified in the 2030 study case. However, more widespread voltage stability violations were identified in the 2031–2045 study case N-1-1 voltage analyses. The primary causes are: (1) the lack of reactive support in the ComEd area driven by loss of reactive capability from deactivated generators; and (2) increased power imports into Illinois required to serve load.

In particular, PJM notes that the two lines comprising the East Frankfort-Olive 345 kV would have to support power delivery of 1,730 MW into ComEd in the 2031–2045 study case. Each of the two lines in the corridor consumes about 500 MVAR.

Widespread voltage collapse was observed for many N-1-1 contingencies involving east/west tie line flows and/or large generator contingencies. This is indicative of the need for additional transmission system expansion – reinforcements to existing lines or construction of new lines – on east-west transmission paths between ComEd and AEP.

The generator reactive capabilities modeled in study year 2045 totaled 4,324 MVAR. If actual generation deactivation notices were received, ComEd indicates its voltage stability and dynamic recovery criteria would be triggered. ComEd estimates that if all this lost reactive capability was replaced with SVCs, using an estimate of $0.12 million per MVAR, it would yield an estimated cost of $525 million. Due to the short time frame to develop and evaluate the results of the studies, a more optimal combination of upgrades to address the voltage issues would likely include a combination of new transmission and SVCs, especially in consideration of reliability criteria violation issues that span multiple transmission owner zones.

For purposes of this study, PJM assumed 10% of overall MVAR replacement would be needed in 2030 and the remaining needed in the 2031–2045 study case.

AEP

AEP concurred with ComEd's proposed solution for replacement reactive power devices. AEP also agreed that further study would be needed to ensure the proper balance of transmission and reactive power upgrades.

MISO (NIPSCO)

Based on PJM's study results, NIPSCO estimates $193 million of synchronous condensers would be required to solve voltage-based reliability criteria violations. NIPSCO concurs with PJM that MISO and PJM interregional coordination will be required to properly address voltage issues. Similar to that for ComEd, PJM assumed about 10% of the overall MVAR capability replacement would be needed in 2030, and the remaining needed in the 2031–2045 study case.

Table 5. PJM Illinois Generation Retirement Study Cost Estimates To Solve Voltage-Based Reliability Criteria Violations

TO	2030 Voltage Upgrades ($M)	2031–2045 Voltage Upgrades ($M)	Overall Voltage Upgrades ($M)
ComEd	52.5	472.5	525.0
NIPSCO	19.3	173.7	193.0
Total	**71.8**	**646.2**	**718.0**

Overall Upgrade Cost Estimates

The thermal-based and voltage-based upgrade cost estimates discussed above are enumerated in **Table 6,** below.

Table 6. PJM Illinois Generation Retirement Study Total Estimated Upgrade Costs by Study Year

TO	Thermal Upgrades		Voltage Upgrades		Overall Upgrades ($M)
	2030 ($M)	2031–2045 ($M)	2030 ($M)	2031–2045 ($M)	
ComEd	98.00	161.50	52.50	472.50	784.50
FE	320.00	180.00	0	0	500.00
DLCO	180.00	0	0	0	180.00
AEP	63.75	178.83	0	0	241.58
NIPSCO	0	125.00	19.30	173.70	318.0
Total	**661.75**	**644.33**	**71.80**	**646.20**	**2,024.02**