UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Management	))	Docket No. AD22-8-000

COMMENTS OF THE ORGANIZATION OF PJM STATES, INC.

On December 23, 2022, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued a Notice Inviting Post-Technical Conference Comments following its October 2022 technical conference on transmission planning and cost management.[1] The Organization of PJM States, Inc. ("OPSI"),[2] respectfully submits these comments in response to this Notice.

As detailed in the attachment to these comments,[3] retail regulators in the PJM region exercise varying levels of oversight of transmission development. These comments explain that given the range of different regulatory frameworks within the PJM footprint and the fact that approximately 72%[4] of transmission projects developed in the PJM region since 2014 have not required approval by the PJM Board of Managers, PJM's transmission planning process must operate transparently and in a manner that allows transmission to be built cost-effectively.

Spending and investment on transmission have significantly increased, as well as the costs

[1] *Transmission Planning and Cost Management,* Notice Inviting Post-Technical Conference Comments, Docket No. AD22-8 (December 23, 2022) ("Notice").

[2] OPSI's following members support these comments: the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Maryland Public Service Commission, the Michigan Public Service Commission, the New Jersey Board of Public Utilities, the North Carolina Utilities Commission, the Pennsylvania Public Utility Commission, the Tennessee Public Utility Commission, the Virginia State Corporation Commission, and the Public Service Commission of West Virginia. The Public Utilities Commission of Ohio abstained in the vote on this filing.

[3] OPSI, State Oversight of Transmission Development in the PJM Region (Attachment A).

[4] *See infra* at p. 2, Figure 1 and n. 10 (Since 2014, PJM has spent $46.573B on Supplemental Projects and Baseline Reliability projects. 72.38% of these projects ($33.709 B) were classified as Supplemental Projects which do not require PJM Board consideration prior to their integration into PJM's Regional Transmission Expansion Plan ("RTEP").

being passed on to consumers. In the PJM region, these costs are largely being incurred through spending on supplemental projects, which the PJM Board does not review. Although PJM is obligated under Manual 14B and its governing documents to analyze local projects to determine whether regional projects offer more cost-effective solutions to the problems identified in the local planning process, it is not clearly communicating that it is doing so. Because of this, states fear that PJM may not be conducting the required analysis at all. Further, certain aspects of the planning process are highly complex, lack transparency, and are confidential. Therefore, states are left with the concern that the current level of oversight and planning is not resulting in just and reasonable wholesale rates.

I. FEDERAL AND STATE OVERSIGHT OF TRANSMISSION SPENDING

The Commission's Notice acknowledges concerns that there may be a regulatory gap in the oversight of local, asset management, and regional reliability transmission projects.[5] The Commission notes that some conference panelists argued that some existing state siting processes, formula rate processes, and transparency requirements might not be sufficient to ensure utilities select the most cost-effective set of projects.[6]

In response to FERC's NOPR on regional transmission planning and cost allocation,[7] OPSI stated that "ensuring that local and regional planning processes produce the most cost-effective set of transmission projects is very important to OPSI" and that OPSI was "concerned that the growth of transmission-related costs in PJM over recent years is occurring without any effective oversight…."[8] OPSI commented that from 2018-2021, the PJM region has developed over "$21B

[5] Notice at p. 1, Question 9.
[6] *Id.*
[7] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022) ("NOPR").
[8] *Building for the Future Through Electric Regional Transmission Planning and Cost allocation and Generator Interconnection,* Comments of the Organization of PJM States, Inc., Docket No. RM21-17-000 at p. 5 (August 17,
(continued)

in Supplemental Projects compared to $5B in Baseline Projects."[9] This is notable because the PJM Board of Managers does not approve Supplemental Projects.[10] OPSI urged "[T]he Commission to continue to develop meaningful reforms to ensure that local and regional transmission planning processes are as co-optimized as possible."[11]

The level of oversight each state[12] has influences how retail regulators in the PJM region approach the Commission's questions on transparency, participation, and available expertise. What is clear is that recently, spending on projects that are not subject to oversight by the PJM Board of Managers (Supplemental Projects) has been dramatically outpacing spending on projects they do oversee. And much of this spending is passed on to consumers through the Commission's use of formula rates.

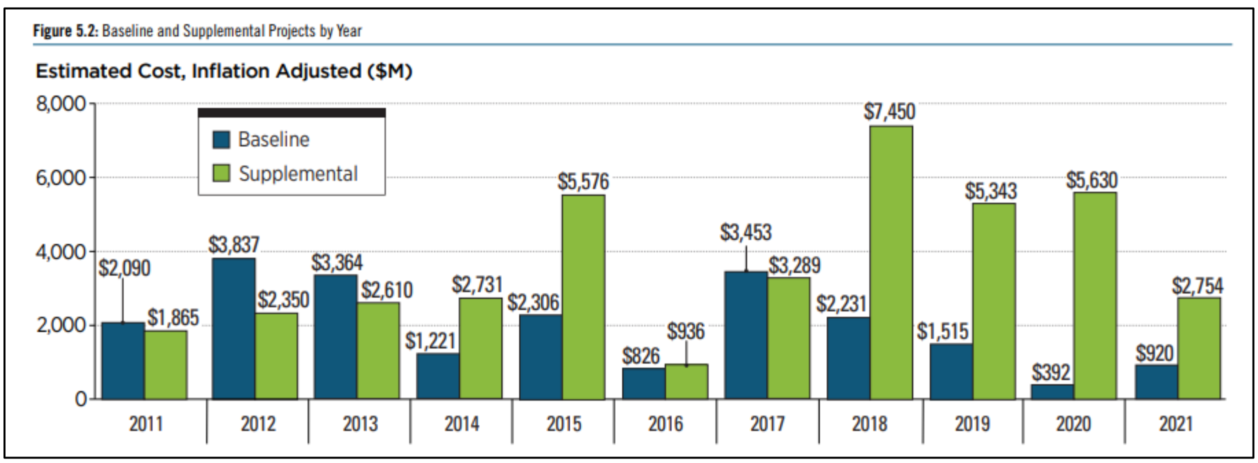

Figure 1 – 2021 RTEP at p 290, Figure 5.2: Baseline and Supplemental Projects by Year.

While PJM tries to identify overlaps of local and asset management projects with baseline

2022) ("OPSI Comments") citing PJM, RTEP21 at p. 290 available at: https://www.pjm.com/-/media/library/reports-notices/2021-rtep/2021-rtep-report.ashx ("2021 RTEP").

[9] *Id.*at n. 16.

[10] PJM, Intra-PJM Tariffs, OA Definitions S – T (17.0.0). A Supplemental Project is defined as a transmission expansion or enhancement 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 and is not a state public policy project pursuant to Operating Agreement, Sched. 6, section 1.5.9(a)(ii).

[11] OPSI Comments at p. 5.

[12] The term "state" is meant to be inclusive of Washington, D.C. in these comments. While these comments primarily highlight oversight that public service commissions exercise, the term "state" may be used when an entity other than a public service commission exercises oversight of transmission development.

reliability projects,[13] the extent and thoroughness of PJM's analysis is often unclear. Therefore, states often must use their own processes, where they exist, to get more information on local and asset management project development beyond what is presented in RTO stakeholder processes.

Some states exercise significant oversight of transmission development and may not need additional transparency or expertise[14] to understand whether the mix of Supplemental Projects and Baseline Projects is appropriate. On the other hand, other states have little to no authority to regulate the transmission development in their state, and most fall somewhere between these two extremes.[15]

A significant fraction of transmission spending is driven by rebuilds and upgrades. Even voltage or length thresholds do not trigger state oversight of rebuild or upgrade projects in some states. In other instances, state oversight may be triggered if a project developer proposes to utilize eminent domain.[16] Regardless, there are a number of instances where states may be allocated costs for Supplemental Projects that are constructed in neighboring states which the hosting state has no opportunity to review, or even if they have the ability to review, their oversight is limited in nature or by the evidence or impacts the authority can consider. Supplemental Projects are often not evaluated from a regional perspective and thus are unlikely to be subjected to the same regional modeling and analysis to ensure cost-effectiveness and efficiency from a region-wide perspective.

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[13] *See* PJM Manual 14B, § 1.4.2., *et seq.*

[14] Notice at p. 4, Question 1.c ("Are there barriers to state regulators and other stakeholders accessing the information that public utility transmission providers provide through their local transmission planning processes (e.g., fees, background checks, etc.)? Do state regulators and other stakeholders have access to the expertise necessary to analyze the information presented and to evaluate the public utility transmission providers' local transmission planning decisions?").

[15] *See* Attachment A.

[16] *See infra* at n. 90 and 91.

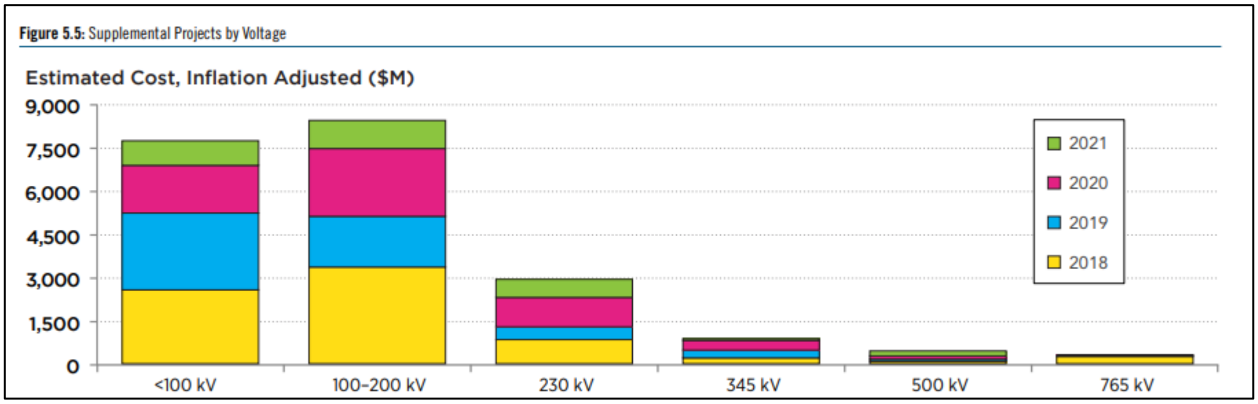

Figure 2 – 2021 RTEP at p. 291, Figure 5.5: Supplemental Projects by Voltage.

OPSI's point in sharing this information and including the attachment and figures in these comments is to show that a sizeable amount of transmission spending in the PJM region occurs with little to no oversight by PJM. The Commission should acknowledge that the review of transmission costs in PJM is insufficient for both baseline and supplemental projects and take appropriate action to document, quantify, and address this insufficiency. In doing so, the Commission should ensure that the jurisdiction of states with significant regulatory authority over transmission development is not diminished in any way.

The issues presented in these comments are based on a lack of oversight, not jurisdiction. FERC has the jurisdiction and responsibility to ensure that wholesale rates for electric service are just and reasonable. The prudence of spending on electric transmission infrastructure is a critical component of just and reasonable rates. Given the absence of oversight at the RTO and state level, the Commission must take appropriate action to protect consumers from the inefficient or unneeded buildout of transmission affecting wholesale rates. FERC's actions could include but are not limited to, eliminating the presumption of prudence for transmission costs which receive no other need or prudence review or is not subject to thorough RTO review. Likewise, the

Commission should affirm that those states with such authority will continue to exercise that authority independent of any action by the PJM Board.

II. LOCAL TRANSMISSION PLANNING UNDER ORDER NO. 890 AND PLANNING FOR ASSET MANAGEMENT PROJECTS

As the Commission considers comments in this docket, it will have been nearly seven years since the Commission issued an Order to Show Cause investigating whether PJM's transmission planning process was providing stakeholders with the opportunity for early and meaningful input as well as complying with Order No. 890.[17] It has been over 20 years since FERC wrote in its Order approving PJM as an RTO that:

> [PJM's regional transmission planning] process must be transparent with respect to the RTO's final plans, so that all market participants will have confidence that the process is fair and efficient. Regional transmission expansion plans must be more than the compilation of traditional, reliability-focused TO expansion plans. Details of the plan's projects must be readily accessible to all market participants.[18]

From year to year, it is incumbent that PJM produce a written summary that explains the level and depth of analysis it carried out when evaluating whether supplemental, baseline reliability, and market efficiency needs overlap. At the very least, having this analysis in writing after each planning cycle would allow stakeholders to compare the types of projects included in the RTEP in a given year against the types of projects included in previous planning cycles to understand why the composition of projects advanced is or is not appropriate and why.

Retail regulators may struggle to recognize the cost-effectiveness of a process that consistently produces a plan with an increasing number of projects not subject to PJM Board oversight, without justification. PJM, in its independent role as an RTO, should more clearly and

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[17] *Monongahela Power Co.*, 156 FERC ¶ 61,134 (2016) (Show Cause Order); *see Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 118 FERC ¶ 61,119, at P 444, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[18] *PJM Interconnection L.L.C.,* Order Provisionally Granting RTO Status, 96 FERC ¶ 61,061 at p. 30 (2001).

proactively explain and provide details on how each year's RTEP includes the most cost-effective set of projects available.

A. TRANSPARENCY INTO LOCAL ASSUMPTIONS AND NEEDS

To assure retail regulators that the regional transmission planning process is resulting in the most effective and efficient use of limited capital, it is incumbent on PJM to provide clear and accessible information on how local planning criteria drove the identification of needs, how those needs informed the selection of transmission solutions, and why a local project is preferable to a regional project.

In the most recent RTEP report, there is little to no discussion about how *local* project needs interacted[19] with baseline needs and whether and how PJM determined that the $920M to $2.75B mix of baseline projects to supplemental projects does, in their opinion, appropriately capture local needs more cost-effectively than the aggregation of local plans as proposed by transmission owners ("TOs").[20] Understanding the interaction between local and regional transmission planning is imperative because local plans form the starting point for the PJM RTEP. Without meaningful insight into the starting point of the process, and absent thoughtful analysis and discussion of the interaction of regional and local needs and solutions, how can states, and the Commission for that matter, have confidence that resulting projects and rates are just and reasonable?

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[19] PJM Manual 14B at p.27 ("In the development of the RTEP, PJM shall examine whether a possible baseline upgrade would more efficiently and cost-effectively address the identified regional need, as well as a supplemental need addressed by a proposed Supplemental Project. If PJM identifies that a possible baseline upgrade would more efficiently and cost-effectively address the identified regional need, as well as a supplemental need, PJM will discuss with the relevant Transmission Owner and other stakeholders at the next appropriate Subregional RTEP or TEAC meeting. PJM shall submit the proposed baseline upgrade to the PJM Board for inclusion in the RTEP.").

[20] 2021 RTEP at p. 61 (The only discussion of an analysis of overlapping needs comes when PJM writes, "The 2021 RTEP supplemental analysis included an evaluation of potential overlap between supplemental projects and a confidential set of 'end-of-life' facilities, identified by the TOs. This process was approved by FERC in December 2020 as part of updates to the Attachment M-3 process, documented in PJM's Operating Agreement.").

Despite the goals of Order Nos. 2000 and 890 to improve the transparency of RTO planning processes, as recently as August 2022, OPSI stated that it continues to "have serious concerns that PJM's process is not sufficiently responsive to provide retail regulators and other stakeholders with assurance that local needs are being effectively considered in regional transmission planning processes."[21] OPSI stated that "[w]hile the M-3 process is transparent in that local planning may be *observed*, OPSI finds it difficult to see the full benefit of participation under the status quo M-3 process since TOs are under no obligation to respond to stakeholder questions and comments or even acknowledge their receipt."[22]

Even if retail regulators and the Commission had complete transparency into local project planning processes, the Commission should continue to explore two things. First, whether transparency in the local planning process alone is enough to ensure the transmission developed in each region in a given year represents the most cost-effective set of solutions, and if not, whether additional expertise and justification is needed.

Second, the Commission should continue to ask, even if PJM transparently identifies and plans more cost-effective transmission solutions than the aggregation of local plans, whether PJM has the authority and fortitude to direct more efficient transmission development. PJM's Manual 14B states that the TO determines whether PJM's proposed baseline upgrade meets the supplemental need addressed by the TO's local project.[23] If the TO determines that PJM's proposed regional project does not address the TO's identified need, then it is purely up to the TO to decide how to classify that project.[24] If a dispute arises, PJM forwards this information to the relevant siting authority and can pursue dispute resolution as described in Attachment M-3 to

[21] OPSI Comments at 4-5.
[22] *Id.* at 6.
[23] Manual 14B at p. 27.
[24] *Id.*

PJM's tariff.[25]

As the Commission concluded in its most recent M-3 dockets, PJM TOs never transferred responsibility for planning local projects to PJM, and the reforms included in Attachment M-3 to PJM's tariff exist not to alter local planning processes already in place but solely to enhance transparency.[26] In Order No. 890, the Commission found that RTO planning processes should focus "on regional problems and solutions, not local planning issues that may be addressed by individual transmission owners."[27]

However, ensuring that regional transmission development is cost-effective requires a holistic examination of TOs' local transmission development to ensure cost-effective transmission planning that results in just and reasonable wholesale rates, including determining whether regional solutions are available to displace less cost-effective local transmission projects. If PJM is unable or unsuitable to conduct this examination, and states do not have the authority to advance these more cost-effective projects, then no one is verifying that a portion of the billions of dollars in Supplemental Projects advanced each year in the PJM region are in fact the most cost-effective solutions available. OPSI encourages the Commission to view this concern in light of the differing levels of oversight described in the attachment to these comments.

OPSI also urges the Commission to encourage PJM to more clearly demonstrate now and on a regular basis how they develop assumptions, identify needs, and analyze the overlap of various needs so that retail regulators and other stakeholders can better understand if these processes are producing just and reasonable rates.

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[25] *Id.*

[26] *PJM Interconnection L.L.C.*, 173 FERC ¶ 61,225 at P 65 (2020) ("[T]he Attachment M-3 Revisions have not changed the current planning for any facilities; transmission projects planned pursuant to the Attachment M-3 Revisions currently are planned by the Transmission Owners and the Attachment M-3 Revisions merely regularizes and enhances the transparency of that planning.").

[27] Order No. 890 at P 440.

B. END-OF-LIFE PLANNING

While PJM TOs do post their own planning criteria to the PJM website,[28] they are under no obligation to share their End-of-Life ("EOL") needs. PJM's Manual 14B describes how TOs provide PJM a candidate EOL needs list and indicates that this list will contain a confidential, non-public, non-binding projection of end of life needs up to five years into the future.[29] Because this list is confidential, even if states have sufficient expertise to analyze the extent to which EOL needs overlap with regional planning needs,[30] they have no way of determining whether PJM is conducting this analysis appropriately or at all. Like the local planning process described above, PJM does not provide detailed information in the final 2021 regional transmission expansion report on how it conducted the analysis to determine whether EOL needs overlap with regional needs.

The Commission must consider increasing transparency around EOL needs to enable interested stakeholders and retail regulators with relevant expertise to analyze EOL lists and determine whether PJM is properly analyzing projects with EOL drivers to ensure that there are no Baseline Projects that may address EOL needs more cost-effectively than the projects proposed by TOs. Without any insight into the process, or oversight over its compliance, it is hard to

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[28] PJM Transmission Owner Planning criteria is available at: https://www.pjm.com/planning/planning-criteria/to-planning-criteria.

[29] PJM, Manual 14B, ("1.4.2.4 Incorporation of EOL Needs into the RTEP The Transmission Owners shall prepare and provide to PJM, on an annual basis, a Candidate EOL Needs List. This The candidate EOL list shall be comprised of a Transmission Owners its non-public confidential, non-binding projection of up to 5 years of EOL Needs that it has identified under the Transmission Owner's processes for identification of EOL Needs. The methodology used by the Transmission Owner to determine inclusion in this EOL list shall be presented to stakeholders annually, and will generally be provided during the assumptions meeting as part of the M-3 process as outlined in Section 1.1. PJM shall identify any potential substantial electrical overlap between an identified PJM planning criteria need identified during the current PJM planning cycle, under the RTEP process and a projected EOL need facility on a Transmission Owner's Candidate EOL Needs List that could potentially be addressed by a single solution., PJM will consult with the relevant Transmission Owner to confirm the projected EOL need still exists. If Transmission Owner confirms the projected EOL need still exists, PJM would post both the PJM planning criteria need and projected EOL need facility as required pursuant to Schedule 6 open window process, noting the overlap on the list of violations posted for the proposal window.").

[30] PJM OATT, Attachment M-3 at (b) 9 ("PJM Planning Criteria Need. 'PJM Planning Criteria Need' shall mean a need to plan a transmission expansion or enhancement of Transmission Facilities other than those reserved to each Transmission Owner in accordance with section (a).").

understand how the Commission is comfortable with whether EOL needs are being identified by TOs, conveyed to PJM, and the degree to which PJM studies these needs to determine whether they overlap with regional needs.

III. <u>INDEPENDENT TRANSMISSION MONITOR</u>

Rather than discussing the potential benefits, shortcomings, or role of what has recently been referred to as an Independent Transmission Monitor ("ITM"), OPSI instead would like to comment on why the shortcomings of existing processes may be driving some to advocate for the creation of an ITM.

Stated succinctly, transmission spending is increasing, and oversight of that spending is decreasing in the PJM region. Retail regulators have the unenviable task of setting end-use rates that often include a significant amount of wholesale costs. In order to be comfortable that wholesale costs are not unjust and unreasonable, states need clear, expert analysis detailing how the collection of transmission projects developed each year, and from year to year, is the best set of projects available from a reliability and cost perspective, while also meeting the needs of each state. States need a responsive and independent expert to answer questions related to all the topics the Commission raises in this docket. Is PJM that entity?

Surely, the RTO *could* carry out this role. But as described above, OPSI has found the local planning process, which forms the basis of the RTEP, to be inadequate. Because the decisions made by TOs in forming their local plans are so consequential in the eventual determination of which transmission projects will be built in PJM – and paid for by customers across PJM – it is imperative that the local transmission planning process works for states and electric consumers. The failures of the local transmission planning process are compounded by PJM's unwillingness to provide an adequate level of detail defending the cost-effectiveness of the eventual RTEP. Further, even if a particular RTEP includes an optimal set of projects from a cost-effectiveness perspective, the RTO does not ensure that the projects are constructed in line with expected costs.[31] Cost overruns can simply go into rates without confirmation of an independent audit or reasonable, pre-established caps on costs. Regardless, even if PJM was willing to conduct the *type* of analyses discussed herein, the result of the analyses would be suspect given the inherent governance problem of asking a Regional *Transmission Organization* to regularly question and oppose its member-*Transmission Owners*. Said differently, to ask PJM to single-handedly address the gaps in oversight described herein would mean putting PJM at odds with the limited number of members it depends on for survival as an organization.

Finally, under the current paradigm, it is impossible to get an appreciation for how TOs are complying with Order No. 890, including the efficiency or effectiveness of the M-3 process. For instance, there is no way to determine whether a TO is consistently applying their local planning assumptions, what weight they provide assumptions, or whether assumptions are consistent across TOs. Since PJM is unwilling or unable to police the local transmission planning process independently, and given the fundamental role the process plays in leading to local and regional transmission facilities, there is a massive gap in oversight that affects wholesale rates, and, coupled with FERC's formula rate recovery, no review or economic regulation occurs.

Should the Commission move forward with an ITM proposal, there is one point on which OPSI members speak with one voice. An ITM should not restrict state oversight of transmission development as it exists now. An ITM should not have standing to litigate or make filings with the

[31] *Competitive Transmission Development Technical Conference*, Pre-Technical Conference Comments submitted on Behalf of PJM Interconnection, Docket No. AD16-18 at p. 3 (May 24, 2016) ("RTOs are not regulatory authorities nor construction managers. Nor do RTOs have an ongoing enforcement arm. As a result, as FERC sorts through the tasks associated with managing a competitive solicitation process, the Commission must recognize the limits of RTO authority and expertise and avoid the temptation to turn the RTO into a quasi-regulator, construction manager or arbitrator of construction disputes.").

Commission in any way that contravenes the outcome of any state's transmission development process.

IV. <u>CONCLUSION</u>

OPSI appreciates the opportunity to comment. As described above, OPSI is concerned with the increasing cost to consumers from transmission development and believes that PJM needs to do more to increase transparency into its processes. This will help states and stakeholders better understand whether PJM's expansion plans are cost-effective. In this environment, retail regulators need transparent information and expertise to effectively engage with PJM's planning processes. But they also need FERC to take action to identify and address the regulatory gap, while respecting states' individualized authority over transmission siting. FERC has a fundamental role to play in ensuring the cost-effective development of regional transmission systems by the RTOs and ISOs that are subject to its direct regulatory jurisdiction.

Respectfully Submitted,

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Dated: March 23, 2023

CERTIFICATE OF SERVICE

I hereby certify that the foregoing has been served in accordance with 18 C.F.R. Section 385.2010 upon each person designated on the official service list compiled by the Secretary in this proceeding.

/s/ Gregory V. Carmean
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Dated at Newark, Delaware this March 23, 2023.

ATTACHMENT A

Table and Description of
State Oversight of Transmission Development in the PJM region
AD22-8-000

	Can your commission approve or reject a project based upon a finding of need? Oversight thresholds?		Do projects require approval for modifications after construction completion?	Can your commission approve or reject a project based upon reasonableness or prudence of cost?	Can your commission require consideration of alternatives in a CPCN proceeding?	Is the standard of review/burden of proof on the utility applicant?	Presumption of convenience or need if project approved by RTO Board?[32]	Proceeding open to interested intervenors?
DE[33]	N	N/A	N	N	N	N	N/A	N/A
DC	Y	69 kV+	No for routine repair and maintenance	Y	Y, alternative sites	Y	N	Y
IL	Need is one of the factors considered. Some projects below 100 kV may be exempt		Y	Can be considered.	Can be considered.	Y	Inclusion in the RTEP may be considered	Y
IN	N	N/A	N/A	N/A	N/A	N/A	N/A	N/A
KY	Y	138kV+ **and** more than one mile long	Y, but not ordinary extensions in usual course of business	Y	Y	Y	N	Y
MD	Y	69 kV+	Y	Y	Y	Y	N	Y
MI	Y	345 kV+ **and** more than five miles long	N	Y	N	Y	N	Y
NJ	N	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NC	Y	161kV+	N, in most circumstances	Y	Y	Y	N	Y
OH	Y	OPSB oversees 100kV+ w/ exceptions	Y	Cost information is required in application	Y	Y	Whether line consistent w/ regional plans is one factor considered	Y
PA	Y	100kV+	Y	Y	Yes, alternative sites	Y	N	Y
TN[34]	Y	Y, no oversight of TVA	Y	Y	Y	Y	N	Y
VA	Y	-	Y for previously certificated projects only	Y	Y	Y	N	Y
WV	Y	-	N	Y	Y	Y	Y	Y

[32] OPSI notes that the majority of transmission projects approved in the PJM region since 2014 have not been approved by the PJM Board of Managers.
[33] These answers apply to projects identified and developed after an initial application is approved. See below for more information.
[34] TN only regulates one utility's transmission development (Kingsport Power).

Delaware

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
DE	N - 34.5 kV+	N	N	N	N	N/A	N/A

The Delaware Public Service Commission (DEPSC) only approves initial projects for new Transmission Companies proposing to provide service to the state. After that initial Application is approved, there's no effective state-level review of further transmission project construction for that applicant. The DEPSC relies on the PJM TEAC meetings to find out what projects existing TOs are planning. Therefore, the answers in this table summarize Delaware's oversight of projects following the initial project review.

See 26 *Del. Admin. C.* § 3011.

After obtaining an initial Electric Transmission Supplier Certificate (i.e. a CPCN) an Electric Transmission Utility does not need to come back to the Delaware PSC for approval of construction, modifications, upgrades, or extensions of facilities within its service territory.[35]

Electric Transmission Facility means facilities located in Delaware, including those in offshore waters, and integrated with onshore electric facilities and owned by a public utility that operates at more than 34,500 volts.[36]

New applicants must obtain an Electric Transmission Supplier Certificate, which is a CPCN granted by the Delaware PSC to the Applicant which fulfilled the Commission's certification requirements and which authorizes the Applicant to construct, operate, own, and maintain transmission facilities. The Commission Order approving an Applicant's application for certification as an Electric Transmission Utility shall serve as the ETSC.[37]

An applicant becomes an Electric Transmission Utility once it is granted an Electric Transmission Supplier Certificate by the Commission.[38]

In its application, the Electric Transmission Supplier Applicant must provide a detailed project description, including a detailed description of the facilities; diagrams of facilities to be constructed, and a facility cost estimate for the project(s), among other things.[39] If the applicant has not been deemed to be the designated entity by PJM, then it must submit additional information pertaining to financial information, bankruptcy, and operational experience.[40]

Commission staff will review the application and recommend to the commission whether to approve conditionally, approve, or deny the application. The commission may approve with conditions, modify or deny the CPCN where it finds doing so is in the public interest.

[35] 26 Del. C. § 203A(3).
[36] 26 Del. Admin. C. § 3001-1.0.
[37] *Id.*
[38] *Id.*
[39] *See Id*. at § 3011-2.2.11 for the complete list.
[40] *See Id.* at § 3011-2.2.13, 2.2.14, and 2.2.15.

An ETSC cannot be transferred. The commission may revoke or suspend an ETSC held by an Electric Transmission Utility for good cause.[41]

A public utility is not required to get CPCN for construction, modifications, upgrades, or extensions within the perimeter of any territory already served by it.[42]

The Commission may revoke CPCN for good cause.[43]

District of Columbia

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
DC	Y - 69 kV+	No for routine repair and maintenance	Y	Y, alternative sites	Y	N	Y

See D.C. Mun. Regs. Tit. 15, § 1500, et seq.

The Commission must issue a CPCN for transmission lines 69 kV and above.[44] Commission approval is not required for routine repair and replacement activities necessary to maintain a transmission line.[45] Part of review includes description of alternative sites considered and an estimation of the cost.[46] A statement regarding PJM's processes and compliance with those processes is required for generation CPCNs but not transmission CPCNs.[47]

The DCPSC may waive requirements and impose new requirements for good cause.[48]

[41] *Id.* at § 3011-2.232.
[42] 26 Del. C. § 203A(3).
[43] *Id.* at Del. C. 203E(e).
[44] D.C. Mun Regs. Tit. 15-2100.
[45] *Id.*
[46] *Id.*
[47] *Id.* at 15-2101
[48] D.C. Mun. Regs. Tit. 15-2112.

Illinois

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
IL	Need is one of the factors considered. Some projects below 100 kV may be exempt.	Y	Can be considered.	Can be considered.	Y	Inclusion in the RTEP may be considered.	Y

See 220 ILCS 5/8-406 and 406.1.

The ICC reviews certificate of public convenience and necessity (CPCN) applications under 220 ILCS 5/8-406, 8-406.1 (expedited procedure), and under certain circumstances may order modifications under 220 ILCS 5/8-503 or eminent domain under 220 ILCS 5/8-509. The Illinois Public Utilities Act states that no public utility shall begin the construction of any new plant, equipment, property, or facility unless it obtains a CPCN from the commission.[49]

In granting a CPCN, the ICC shall determine that proposed construction will promote the public convenience and necessity only if the utility demonstrates: (1) that the proposed construction is necessary to provide adequate, reliable, and efficient service to its customers and is the least-cost means of satisfying the service needs of its customers or that the proposed construction will promote the development of an effectively competitive electricity market that operates efficiently, is equitable to all customers, and is the least cost means of satisfying those objectives; (2) that the utility is capable of efficiently managing and supervising the construction process and has taken sufficient action to ensure adequate and efficient construction and supervision thereof; and (3) that the utility is capable of financing the proposed construction without significant adverse financial consequences for the utility or its customers.[50]

Moreover, "[n]o public utility shall begin the construction of any new plant, equipment, property, or facility which is not in substitution of any existing plant, equipment, property, or facility, or any extension or alteration thereof or in addition thereto, unless and until it shall have obtained from the Commission a certificate that public convenience and necessity require such construction."[51]

The ICC may request data from utilities in reviewing local plans as needed.[52]

The Illinois Climate and Equitable Jobs Act (CEJA) also requires the Commission to open an investigation to develop and adopt a renewable energy access plan to, among other things, achieve transmission capacity necessary to deliver the electric output from renewable energy technologies in the renewable energy access plan zones in Illinois to customers in Illinois and other states in a manner that is most beneficial and cost-effective to customers.[53]

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[49] 220 ILCS 5/8-406.

[50] 220 ILCS5/8 406. For purposes of Sections 8-406 and 8-406.1,"high voltage electric service line" means an electric line having a design voltage of 100,000 or more." 220 ILCS 5/8-406(g).

[51] 220 ILCS 5/8-406(b).

[52] 220 ILCS 5/4-101, 4-201.

[53] 220 ILCS 5/8-512.

Indiana

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
IN	N	N/A	N/A	N/A	N/A	N/A	N/A

In general, the Indiana Utilities Regulatory Commission does not have authority to review and approve specific transmission projects. The IURC's CPCN process only pertains to generation resources. [54] Indiana does not have CPCN process for the consideration of new transmission or modifications to existing transmission, and the IURC does not have a mandatory certification or siting authority for transmission.

However, Indiana has a substantial Integrated Resource Planning rule, and utilities are required to provide information on their transmission systems in these filings—which are accepted and reviewed by IURC staff, but not approved by the commission.[55]

Further, if a utility is changing a distribution or transmission line to a higher voltage level, the utility must give notice to affected customers detailing an explanation as to why the line upgrades are necessary for safe and reliable electric service among other things.[56]

Jurisdictional electric utilities are required to submit Integrated Resource Plans (IRPs) every three years.[57] Although the rules focus is on how utilities plan for resources to meet customer load, there is a requirement to provide information on the utility's transmission system.[58]

There is another law, which is optional to utilities, where they can file (substantial) plans to improve their Distribution and Transmission systems over a period of years, and the IURC can approve the plan, which pre-approves a majority of the costs. [59]

[54] Ind. Code 8-1-8.5-2.
[55] 170 Ind. Admin. Code 4-7-4.
[56] *Id.* at § 4-9-5.
[57] Ind. Code § 8-1-8.5-3(e)(2) and 170 IAC 4-7
[58] 170 IAC 4-7-4 " (27) A brief description of the models, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715:

"(A) The most current power flow data models, studies, and sensitivity analysis.

(B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC).

(C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following:

(i) The limits of the utility's transmission use.
(ii) The utility's assessment practices developed through experience and study.
(iii) Operating restrictions and limitations particular to the utility."

[59] Ind. Code chapter 8-1-39

Kentucky

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
KY	Y, 138kV+ **and** more than one mile long	Y, but not ordinary extensions in usual course of business	Y	Y	Y	N	Y

See Ky. Rev. Stat. 278.020.

In order to begin construction on a transmission project, a utility shall request a CPCN from the Commission. However, "ordinary extensions of existing systems in the usual course of business" do not require a CPCN.[60] Ordinary extensions include replacement or upgrading of existing lines, the relocation of existing lines to accommodate construction or expansion of a roadway or other transportation infrastructure, or lines used to serve a single customer and which will pass over no property other than that owned by the customer to be served.[61] Transmission lines which are 138 kV and above *and* more than 5,280 feet are not considered ordinary extensions in the usual course of business. Inclusion in the RTEP does not create a presumption that a project should be approved. The KPSC standard requires a finding that wasteful duplication not occur, which necessitates a demonstration that a thorough review of all reasonable alternatives has been performed; all relevant factors must be balanced against the foundational fair, just, and reasonable standard.

The Kentucky State Board on Electric Generation and Siting reviews and grants certificates for construction of merchant transmission not regulated by the KPSC. The Siting Board must approve non-regulated transmission lines rated at 69kV or higher.62 (The Siting Board consists of the three KPSC Commissioners, one designee from the Energy and Environment Cabinet, one designee from the Cabinet for Economic Development, and 2 ad hoc local members depending on where the proposed siting is to take place).[63]

<u>*Discussion*</u>

The Kentucky Commission has ongoing issues with visibility into local transmission planning project costs which affects its ability to sufficiently track and review projects due to the CPCN exceptions in Kentucky law. Further, utilities opt to not seek a CPCN for many projects in which it was assumed a CPCN was not necessary or that a statutory exception was met. Often, in the course of a rate case, the Commission may find that a certain local project may have needed a CPCN and that one should have been sought, but by then the project is already built and placed into rate base. Furthermore, a general lack of resources, staffing, and bandwidth at our Commission is an ongoing concern and would likely impair the KPSC's ability to more closely track the local transmission planning process through the RTEP and sub-regional planning meetings even if we had more visibility and ability to review projects and the prudency of their associated costs.

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[60] Ky. Rev. Stat. 278.020.
[61] *Id.*
[62] *Id.* at 278.700, 278.714.
[63] *Id.* at 278.702.

Local projects which are larger in scope may be analyzed periodically as they advance through the M-3 process, but generally there are no dedicated KPSC Staff to track these utilities' proposed projects for reasonableness/prudency or alternatives, unless the project does require a CPCN.

In practice, many local transmission projects which would normally require a CPCN fit into the exception as a rebuild/replacement or an upgrade and so are ultimately considered to be in the usual course of business and are exempted from the CPCN process.

The KPSC does require transmission owners to provide data or reports regarding local transmission projects through the course of a CPCN proceeding, on a case-by-case basis. However, exceptions to the CPCN, or utilities starting and/or completing local projects in the belief a CPCN is not needed prior to Commission knowledge of such projects often precludes the Commission from timely receiving the local transmission project data it needs to properly evaluate and make a determination on those local projects.

The KPSC monitors or tracks the prudence of cost associated with local projects after they are approved by PJM as able but does not have any formal process for tracking the prudency of costs of local projects.

Maryland

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
MD	Y, 69 kV+	Y	Y	Y	Y	N	Y

A CPCN is required for an overhead transmission line designed to carry in excess of 69 kV, anticipated to exercise a right of condemnation with the construction, or construction a submerged renewable energy line.[64]

The Commission considers the effect of the overhead transmission line on electric system stability and reliability; economics; esthetics; historic sites; aviation safety,[65] the need to meet existing and future demand for electric service,[66] and the effect of climate change on the overhead transmission line.[67]

There is a mandatory CPCN waiver if Commission finds that the construction does not require obtaining new real property or additional rights–of–way through eminent domain; or require larger or higher structures to accommodate increased voltage or larger conductors.[68]

The Commission examines alternatives to the construction of new transmission lines, including the use of an existing transmission line of another company, if the existing transmission line is convenient to the service area, or the use of the transmission line will best promote economic and efficient service to the public.[69]

[64] MD Code PUA § 7-207 (a)(3), PUA § 7-207(d)(1).
[65] *Id.* at § 7-207 (e)(2).
[66] *Id.* at § 7-207 (f).
[67] *Id.* at § 7-207 (e)(3).
[68] *Id.* at § 7-207(b)(4)(i).
[69] *Id.* at § 7-209.

The Commission has general supervisory and regulatory authority to consider public safety, economy of the state, maintenance of fair and stable labor standards, conservation of natural resources, preservation of environmental quality, including protection of the global climate and achievement of State climate commitments for reducing statewide greenhouse gas (GHG) emissions.[70]

To obtain approval, the burden is on the applicant to demonstrate that the project meets the public convenience and necessity. While there is no presumption of need based on a project being included in the RTEP, some weight is given to an RTEP-designated project when the Commission considers whether the project is needed. CPCN proceedings are open to intervenors, including county and local governments whose concerns must be given due consideration.[71]

Michigan

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
MI	Y, 345 kV+ **and** more than five miles long	N	Y	N	Y	N	Y

The Michigan PSC has little to no authority to review or approve locally planned transmission projects.[72] A CPCN is needed for projects that are 345 kV or higher, and 5 miles or longer in length.[73] A CPCN approves the siting of major transmission lines. Local projects can, but rarely do, meet this threshold for Commission review.

Additional insight into locally planned transmission projects primarily comes from participation in PJM's TEAC and SRTEP processes. The Michigan Public Service Commission relies on the PJM SRTEP process to review and provide input on local transmission projects, but the Michigan PSC does not formally review or approve local transmission project costs once they are approved in an RTEP.

Just because a project is included in the RTEP does not constitute a need in the CPCN approval process. For transmission lines at least 5 miles in length that are operated at 345kV or above, the Commission must determine that increased charges for ratepayers are justified, which requires a thorough examination of evidence supporting the necessity for the line. The Commission is also required to decide whether the necessity for the line justifies the potential condemnation of private property, as a CPCN takes precedence

[70] *Id.* at § 2-113.

[71] *Id*. at PUA sec. 7-207(e)(4). The Maryland PSC must give due consideration to the consistency of the application with the comprehensive plan and zoning of the county where the proposed system would be located and to efforts to resolve any issues presented by that county.

[72] Mich. Comp. Laws 460.565 ("Except as otherwise provided in section 9, a certificate of public convenience and necessity under this act is not required for constructing a new transmission line other than a major transmission line or for reconstructing, repairing, replacing, or improving an existing transmission line, including the addition of circuits to an existing transmission line.").

[73] Mich. Comp. Laws 460.562 ("(g) 'Major transmission line' means a transmission line of 5 miles or more in length wholly or partially owned by an electric utility, affiliated transmission company, or independent transmission company through which electricity is transferred at system bulk supply voltage of 345 kilovolts or more.").

over any conflicting local ordinance, law, rule, regulation, policy, or practice, in eminent domain proceedings.[74]

A certificate is not required for reconstructing, repairing, replacing or improving existing transmission line, including the addition of circuits to existing transmission line.[75] However, The Michigan PSC requires that rate-regulated utilities include an analysis of potential new or upgraded electric transmission options for the utility when filing Integrated Resource Plans.[76]

Transmission companies may file an application with the commission for a CPCN for a proposed transmission line that does not meet the 5 miles and 345 kV thresholds. Whether to seek a CPCN for the construction of transmission lines[77] other than "major transmission lines" is at the discretion of the electric utility or transmission company.[78] A voluntary CPCN application will trump the local siting and zoning process. Voluntary CPCN approval will be "conclusive and binding" as to public convenience and necessity in eminent domain proceedings.[79] Michigan's law related to regionally cost shared transmission lines does not confer the power of eminent domain.[80] It does not grant the Commission additional oversight authority beyond what is enumerated elsewhere.

New Jersey

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
NJ	N	N/A	N/A	N/A	N/A	N/A	N/A

New Jersey does not have any CPCN requirements for electric transmission projects.

[74] Mich. Comp. Laws 460.570.
[75] *Id.* at §§460.565.
[76] Michigan PSC IRP Filing Requirements, Section XII. *See* Mich. PSC, Opinion and Order, Case No. U-15896 and U 18461, Dec. 20, 2017. *See also* Public Act 341 of Section 6t(3) of Act 341 of 2016, MCL 460.6t(3).
[77] *Id.* "(k) 'Transmission line' means all structures, equipment, and real property necessary to transfer electricity at system bulk supply voltage of 100 kilovolts or more."
[78] Mich. Comp. Laws 460.569 ((1) An electric utility, affiliated transmission company, or independent transmission company may file an application with the commission for a certificate for a proposed transmission line other than a major transmission line. If an electric utility, affiliated transmission company, or independent transmission company applies for a certificate under this section, the electric utility, affiliated transmission company, or independent transmission company shall not begin construction of the proposed transmission line until the commission issues a certificate for that transmission line.).
[79] *Id.* at §§460.570.
[80] Mich. Comp. Laws 460.593.

North Carolina

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
NC	Y, 161kV+	No in most circumstances	Y	Y	Y	N	Y

A certificate of environmental compatibility and public convenience and necessity is needed to construct a transmission line above 161 kV. [81] A certificate is not needed in the following circumstances:

> (1) A line designed to carry less than 161 kilovolts;
>
> (2) The replacement or expansion of an existing line with a similar line in substantially the same location, or the rebuilding, upgrading, modifying, modernizing, or reconstructing of an existing line for the purpose of increasing capacity or widening an existing right-of-way;
>
> (3) A transmission line over which the Federal Energy Regulatory Commission has licensing jurisdiction, if the Commission determines that agency has conducted a proceeding substantially equivalent to the proceeding required by this Article...[82]

Ohio

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
OH	Y, OPSB oversees 100kV+ w/ exceptions	Y	Cost information is required in application	Y	Y	Whether line consistent w/ regional plans is one factor considered	Y

In Ohio, the Ohio Power Siting Board ("OPSB") oversees certification and permitting for an electric transmission line and associated facilities of a design capacity of 100 kV and above, with an exception for replacement of an existing facility with a like facility (no jurisdiction).[83] The OPSB shall not grant a

[81] NC Gen. Stat. 62-100 ("The term 'transmission line' means an electric line designed with a capacity of at least 161 kilovolts.").

[82] NC Gen. Stat. 62-101(c).

[83] Ohio Rev. Code § 4906.04 ("No person shall commence to construct a major utility facility in this state without first having obtained a certificate for the facility. The replacement of an existing facility with a like facility, as determined by the power siting board, shall not constitute construction of a major utility facility. Such replacement of a like facility is not exempt from any other requirements of state or local laws or regulations. Any facility, with respect to which such a certificate is required, shall thereafter be constructed, operated, and maintained in conformity with such certificate and any terms, conditions, and modifications contained therein. A certificate may only be issued pursuant to Chapter 4906 of the Revised Code."); Ohio Rev. Code §4906.01 ("(D) "Certificate" means a certificate of environmental compatibility and public need issued by the power siting board under section 4906.10 of the Revised Code or a construction certificate issued by the board under rules adopted under division (E) or (F) of section 4906.03 of the Revised Code.").

(continued)

certificate for the construction, operation, and maintenance of a major utility facility, either as proposed or as modified by the OPSB, unless it finds and determines that eight criteria are met.[84] One of these determinations is that the electric transmission line is consistent with regional plans for expansion of the electric power grid serving Ohio.[85] Need, cost, and alternatives are also part of the OPSB's determinations.

There is an accelerated review process for electric transmission lines that are two miles or less or that meet other criteria.[86]

An application is required for an amendment of a certificate.[87] The OPSB has developed a requirement matrix to describe three approval paths for electric transmission applications.[88]

Pennsylvania

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
PA	Y, 100kV+	Y	Y	Yes, alternative sites	Y	N	Y

A Certificate of Public Convenience (CPC) is required for transmission lines. By regulation, the Pennsylvania Public Utility Commission (PAPUC) limits its application requirements to high voltage lines which are defined as "overhead electric supply line[s] with a design voltage greater than 100,000 volts."[89] PAPUC regulations are split into two application types, Letters of Notification (LONs) and Full Siting Applications. Because a large proportion of transmission lines fall below the 100 kV line, many supplemental projects are not subject either to LON rules or Full Siting Application requirements.

The Pennsylvania Public Utility Code and Eminent Domain Code require that public utilities receive a certificate of public convenience before exercising the power of eminent domain.[90] If a transmission line is below 100 kV but requires eminent domain authority, the Commission conducts a need determination as it would for high voltage lines.[91]

Ohio Rev. Code § 4906.01 ("'Major utility facility' means ...[a]n electric transmission line and associated facilities of a design capacity of one hundred kilovolts or more"); Ohio Rev. Code 4906.04; Ohio Administrative Code 4906-1-01(HH).

[84] Ohio Rev. Code § 4906.10.

[85] *Id.* at (A)(4).

[86] Ohio Rev. Code § 4906.03(F)(1).

[87] Ohio Rev. Code § 4906.06(E).

[88] Ohio Power Siting Board, Application Requirement Matrix for Electric Power Transmission Lines available at: https://opsb.ohio.gov/wps/wcm/connect/gov/b09eec82-bfb4-49c3-91f2-06c696cd3185/4906-1-01+Appendix+A+Transmission.pdf?MOD=AJPERES&CONVERT_TO=url&CACHEID=ROOTWORKSPACE.Z18_K9I401S01H7F40QBNJU3SO1F56-b09eec82-bfb4-49c3-91f2-06c696cd3185-nL26dTm.

[89] 52 Pa. Code § 57.1.

[90] 66 Pa.C.S. §§ 1101, 1104; 15 Pa.C.S. § 1511 (Eminent Domain Code). (Unless its power of eminent domain existed under prior law, no domestic public utility or foreign public utility authorized to do business in this Commonwealth shall exercise any power of eminent domain within this Commonwealth until it shall have received the certificate of public convenience required by section 1101 (relating to organization of public utilities and beginning of service). 66 Pa.C.S § 1104 (Certain appropriations by right of eminent domain prohibited)).

[91] See e.g., Application of PPL Electric Utilities Corporation, Docket No. A-2011-2267349, 2013 WL 3787567, at 10-12 (Order entered July 16, 2013).

"A certificate of public convenience shall be granted by order of the commission, only if the commission shall find or determine that the granting of such certificate is necessary or proper for the service, accommodation, convenience, or safety of the public. The commission, in granting such certificate, may impose such conditions as it may deem to be just and reasonable."[92]

The PAPUC's regulations govern which transmission facilities require a CPC and the contents of an application.[93] Further, the PAPUC has promulgated policy statements guiding supplemental guidelines for transmission line siting applications.[94]

LONs require less information and apply to construction, reconductoring, or increasing the voltage of lines which are in an existing right-of-way and do not substantially alter the right-of-way, a public road, or have a proposed route of 2 miles or less.[95] Full siting applications apply to high voltage transmission lines which are not eligible for LON treatment.

PAPUC regulations also require lines scheduled to begin construction or acquisition of ROWs within 5 years to be included in Annual Resource Planning Reports. 52 Pa. Code § 57.144.

Tennessee

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
TN[96]	Y, no oversight of TVA	Y	Y	Y	Y	N	Y

Before beginning construction, entities seeking to build electric transmission in the state must come to the commission for a CPCN.[97] However, this does not apply to federal agencies such as the Tennessee Valley Authority.[98]

[92] 66 Pa.C.S. § 1103.
[93] 52 Pa. Code § 57.1 (definitions); 52 Pa. Code § 57.71, *et seq*.
[94] 52 Pa. Code § 69.3101, *et seq.*
[95] 52 Pa. Code § 57.72.
[96] The Tennessee Public Utility Commission only regulates one utility's transmission development (Kingsport Power).
[97] Tenn. Code 65-4-208(a) ("(a) Notwithstanding any other law, no person, firm or corporation not engaged on March 22, 1955, in the business of generating, transmitting, distributing, or furnishing electric power shall extend or construct transmission or distribution lines or other works into or within the state, directly or indirectly enter the state, for the purpose of delivering within the state electric power generated at a point or points outside the state, unless such person, firm or corporation shall have first submitted its plans for such extension, construction or entry to the commission and shall have obtained from the commission a certificate of public convenience and necessity covering the same. The commission shall deny such certificate if, after a hearing, the commission cannot affirmatively establish that the granting of such certificate would serve the public interest.").
[98] *Id.* at (b) ("This section shall not apply to the federal government or any federal agency, to the state of Tennessee or any agency or political subdivision of the state, or to any cooperative association organized under the former Electric Cooperative Act or the former Electric Membership Corporation Act, but shall be fully applicable to any private corporation organized under the laws of this or any other state and to any public corporation of any other state, irrespective of the nature, identity or governmental or other public status of the purchaser, consumer, or other party to whom electric power is to be delivered within the state.")

Virginia

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
VA	Y	Y for previously certificated projects only	Y	Y	Y	N	Y

Prior to constructing, enlarging, or acquiring facilities 138kV or above, a public utility must come to the Virginia State Corporation Commission to obtain a CPCN.[99] However, Ordinary extensions or improvements in the normal course of business are exempted.

SCC staff has a guidance document that identifies seven categories of projects that require a CPCN:

Any transmission line project 138 kilovolts or greater that:

1. proposes construction of a new line more than 0.5 mile long;
2. requires the use of new ROW not supplied voluntarily by the requesting customer(s) for which the project is being undertaken;
3. includes the replacement of more than three existing structures; or
4. requires the replacement of one or more existing structures with a structure that is more than 20% taller than an existing structure being replaced.

Any transmission line project, regardless of voltage, that:

5. requires the construction of structures in (and not simply spanning) a navigable waterway;
6. proposes construction of an underground line; or
7. replaces facilities located within a utility's service territory for a transmission line that received a CPCN after April 8, 1972, and meets the characteristics identified in (2), (3), or (4) above.[100]

[99] Virginia Code Sec. 56-265.2 ("1. Subject to the provisions of subdivision 2, it shall be unlawful for any public utility to construct, enlarge or acquire, by lease or otherwise, any facilities for use in public utility service, except ***ordinary extensions*** or improvements in the usual course of business, without first having obtained a certificate from the Commission that the public convenience and necessity require the exercise of such right or privilege. Any certificate required by this section shall be issued by the Commission only after opportunity for a hearing and after due notice to interested parties. The certificate for overhead electrical transmission lines of 138 kilovolts or more shall be issued by the Commission only after compliance with the provisions of §56-46.1. 2. For construction of any transmission line of 138 kilovolts, a public utility shall either (i) obtain a certificate pursuant to subdivision 1 or (ii) obtain approval pursuant to the requirements of (a) § 15.2-2232 and (b) any applicable local zoning ordinances by the locality or localities in which the transmission line will be located.").

[100] Staff Guidance on Ordinary vs Non-Ordinary Extension Projects, July 6, 2017 available at: https://www.scc.virginia.gov/getattachment/e71dc224-567c-4a4a-9787-df1909168818/StaffGuidanceOrdvsNonOrd.pdf.

Additionally, as part of the CPCN review process, the utility applicant provides information responsive to the Commission Staff's "Guidelines for Transmission Line Applications Filed Under Title 56 of the Code of Virginia," dated August 10, 2017.[101]

West Virginia

	Approval based on need? Limitations?	Approval for modifications?	Review of reasonableness or prudence of cost approval?	Consideration of alternatives?	Burden of proof on applicant?	Presumption based on RTEP inclusion?	Open to intervenors?
WV	Y	N	Y	Y	Y	Y	Y

Oversight for the prudence and need for transmission investments remain within the jurisdiction of state certification and siting authorities. In West Virginia, the state legislature delegates that jurisdiction to the Public Service Commission through its authority to consider and grant or deny CNs.[102]

Any transmission project projected to cost in excess of $20 million must obtain a CN.[103] If a utility believes that a project that will cost over $20 million is in the ordinary course, it can ask for that determination when it files its CN application. If a project is projected to cost less than $20 million, the entity must file a notification with the Executive Secretary describing the project. The Executive Secretary will record the notification as an informational filing. Staff will review and if Staff believes the case should docketed for formal consideration, Staff will recommend that to the Commission. The entity has 10 days to respond.

Once a certificate has been granted any major modifications in the scope, cost, or footprint must be authorized by the Commission.

The Commission considers need (necessity) and rate impacts (convenience) as components that must be balanced. The importance of either factor is a matter of judgment which is usually project specific.

The Commission could reject a project if there was concern that an alternative project or projects would serve the needs underlying the project and that the alternative or alternatives may be more cost effective. Such rejection is allowed, but not required.

The burden is on the entity seeking the Certificate to construct.

The Commission has considered need as being satisfied by a regional need which would be demonstrated by a reliability need determination by PJM. This would not apply if the project had simply been accepted by PJM without being independently identified as needed in the PJM RTEP.

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[101] Guidelines for Transmission Line Applications Filed Under Title 56 of the Code of Virginia, August 10, 2017 available at: https://www.scc.virginia.gov/getattachment/921b6b42-4e06-4ab5-b296-e73fdcd60cac/Trans.pdf

[102] WV Code 24-2-11 and WV Code 24-2-11a(a).

[103] Public Service Commission of West Virginia, General Order No. 265 (Jan. 18, 2023).

Document Content(s)