UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference on Transmission Planning And Cost Management	))	Docket No. AD22-8-000

Statement of Larry Gasteiger
Executive Director, WIRES

WIRES submits the following summary statement with supporting material on behalf of its Executive Director, Larry Gasteiger, in advance of the technical conference scheduled for October 6, 2022 by the Federal Energy Regulatory Commission ("FERC" or "Commission") to explore measures to ensure sufficient transparency into and cost effectiveness of local and regional transmission planning decisions.[1]

WIRES is a non-profit trade association of investor-, publicly-, and cooperatively-owned transmission providers and developers, transmission customers, regional grid managers, and equipment and service companies. Our members include many of the largest transmission owners in the country. WIRES promotes investment in electric transmission and consumer, environmental, and resilience benefits through development of electric transmission infrastructure.[2] Investment in transmission needs to be encouraged and facilitated now more than ever. For instance, the devastating impact of increasingly more frequent extreme weather events like Hurricane Ian highlights how

[1] *Supplemental Notice of Technical Conference*, Docket No. AD22-8 (Sept. 8, 2022) ("Supplemental Notice").
[2] For more information about WIRES, please visit www.wiresgroup.com.

investment in transmission infrastructure provides benefits by supporting critical public safety and health needs during a crisis. Since its inception, WIRES has focused on supporting investment in needed and beneficial transmission infrastructure – investments that Congress and the Commission have recognized are critical to establish a resilient, reliable, cost-effective, modern, and clean bulk power system. As a result, WIRES is uniquely positioned to address many of the issues raised by the Commission in the Supplemental Notice of the October 6th technical conference. Accordingly, WIRES submits the following preliminary comments in advance of the technical conference.

The broad purpose of the October 6th technical conference is to examine the transparency and cost effectiveness of local and regional transmission planning decisions. As part of this examination, it is critical for the Commission to be cognizant of the importance of, the fundamental differences between, and the benefits of regional and local transmission planning, practices, and projects. To that end, WIRES commissioned Charles Rivers Associates to undertake a comprehensive review of the unique value of local transmission planning to support a resilient and clean transmission grid.[3] The report contains a detailed review of reliability standards and their application in the evaluation of the power system needs in both regional and local transmission planning practices, broadly examines the local and regional selection and review processes, and details the challenges associated with any potential consolidation of the local and regional planning

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[3] Charles River Associates, *Value of Local Transmission Planning Report* (December 2021) https://wiresgroup.com/value-of-local-transmission-planning/ (copy attached).

activities into one centralized location. In addition, the report outlines the local planning value in achieving various electric industry and policy goals.

WIRES submits the Charles River Associates Report into this proceeding as it contains information that could pertain to the issues under consideration in the instant technical conference that could benefit participants and Commission staff.

In addition, the Commission's Supplemental Notice indicates that the October 6th technical conference will address "potential approaches to providing enhanced cost management measures and greater transparency and oversight ***if needed*** to ensure just and reasonable transmission rates."[4] As a threshold matter, the Commission implicitly acknowledges that it can only impose a new requirement for transmission owners or transmission providers to establish new or "enhanced" cost management or transparency requirements if it meets the dual burden of section 206 of the Federal Power Act ("FPA"); in other words, the Commission must both show that existing tariffs or rules are unjust and unreasonable and that any new requirements it directs to be put in place are just and reasonable.[5] To date, no such record has been established that would meet this burden.

While the Supplemental Notice does not identify any specific flaws or gaps in any of the existing Commission-approved transmission planning oversight or transparency processes that have been in place for years, or in the implementation of those processes,

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4 September 8 Supplemental Notice at 1 (emphasis added).

5 *See South Carolina Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 64-65 (D.C. Cir. 2014).

the concern appears to be rooted in the general notion that if more transmission facilities get built, consumers will have to pay for the costs of those new facilities.[6] However, simply because more transmission infrastructure may need to be built to meet the needs of a changing resource mix,[7] and customers will pay the costs of these new transmission facilities (as the case has always been), it does not by any means follow that this additional transmission is more likely to result in unjust and unreasonable rates. Nor does it necessarily follow that increasing spending to build more transmission will make current adequate oversight processes unjust and unreasonable. In fact, by the Commission's own reasoning, any transmission that results from the potential reforms to regional transmission planning, cost allocation, and generator interconnection should be <u>more</u> efficient and cost-effective than before and provide greater protection to customers, thereby making the need for any new transparency or oversight requirements even less necessary and more superfluous.[8] The fact of the matter is, there is no evidence that existing processes have not been implemented appropriately such as to warrant any generic action or that the existing Commission-approved processes are producing unjust and unreasonable outcomes.

[6] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 (2021) ("ANOPR") at P 160 ("[I]n light of potential costs of new transmission infrastructure that may be needed to meet the needs of the changing resource mix, we seek comment on whether additional measures may be necessary to ensure that the planning processes for the development of new transmission facilities, and the costs of those facilities, do not impose excessive costs on "consumers.")

[7] ANOPR at P 159.

[8] *Id*.

Finally, as to one potential new measure that has been raised by the Commission and others, namely the requirement to establish an independent transmission monitor, the Commission must be mindful of serious legal obstacles to that proposal. The FPA charges the Commission, not any outside party, with responsibility for ensuring the justness and reasonableness of transmission rates. The creation and authorization of an independent transmission monitor potentially constitutes an illegal subdelegation of the Commission's authority under FPA sections 205 and 206.[9] Even if an independent transmission monitor were not expressly vested with binding decisional authority over rates, terms and conditions of service, the existence of such an entity would be inherently vested with the veneer of the exercise of federal authority given the role's ability to inhibit, interfere, coerce, and influence transmission planning processes and decisions. Rather than creating a ministerial or "neutral" role or function, such an outcome would result in the equivalent of "calling balls and strikes" regarding significant, long term, transmission investments by a third party that would likely exceed the Commission's authority.

With these preliminary comments in mind, WIRES appreciates the opportunity to participate in the October 6th technical conference and to provide this preliminary

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9 *See U.S. Telecom Assoc. v. FCC*, 359 F.3d 554 (D.C. Cir. 2004).

summary statement, and we look forward to the opportunity to submit post-technical conference comments to further provide our views.

Respectfully submitted,

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Date: December 20, 2021

CRA Project No. D35253

Disclaimer

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1. Executive Summary

Charles River Associates (CRA) was engaged by WIRES to produce a report that provides a comprehensive review of the value of local transmission planning. In this report, we define local transmission planning as the "transmission planning process that a public utility transmission provider performs for its individual retail distribution service territory or footprint pursuant to the requirements of Order No. 890".[1] The product of the local transmission planning processes is local solutions that are critical to the integrity of the transmission system. Local projects enable the continued reliable operation of the transmission system by enhancing grid resilience and operational flexibility, addressing transmission asset health and replacing of aging infrastructure.

While we recognize the importance of regional and interregional transmission planning, our report focuses on documenting the value of local transmission planning as a key facilitator of local and regional energy transfer. Analogous to our national road network, local roads and off-ramps are equally important as interstate highways in providing transportation access.

Similar to local roads, local transmission is valuable to access important services in a reliable manner. Meeting reliability requirements is critical for the operation and design of the local and regional power system and ensure access to affordable and reliable electricity to all consumers. The standards and guidelines developed and enforced by all reliability entities, national and regional, provide a basis for reliable design and operation of the transmission system. However, their generic nature does not fully account for differences between local systems. While meeting the established regional reliability standards, local planners with their extensive system experience, also ensure that the local system is designed to accommodate locational system needs documented in their local reliability procedures. Our comprehensive review of the reliability needs assessment planning of six transmission asset owners within three Independent System Operators and Regional Transmission Operators (ISO/RTOs) confirms this complementary nature of local planning.

Local transmission planning is critical to regional planning since it ensures foundational system needs are met. The regional planning process complies with reliability, economic criteria, and public policy initiatives. However, it fails to address additional system needs related to resiliency, interconnecting customers, and replacing aging infrastructure among others that are the primary focus of local planning. In the ISO/RTOs reviewed, the local solutions are incorporated into the regional plan to produce a framework that captures the entire spectrum of the transmission investment benefits. A recent study by Exelon Transmission also shows that local planning projects do not affect or usurp the need for regional reliability projects. This indicates that local project needs are often unique and distinct from regional system issues and solutions. While regional planning processes can be expanded to account for a greater number of benefits, local system development will still be needed to support an expanded regional system.

All three examined regional planning processes offer an open and transparent review of the local projects to their stakeholders. Various stakeholder meetings allow for the review and discussion of local project-related information such as assumptions, drivers for the local solution need and proposed upgrades. The forums also ensure that the feedback provided is considered by the local planners ultimately resulting in modifications to needs, design, and implementation of the transmission solutions. These meetings also allow state commission staff to actively participate in an efficient manner to promote state goals related to clean

1 Order No. 1000, 136 FERC ¶ 61,051 at P 55

energy and grid modernization. Local planning is subject to robust transparency requirements in many regions.

Comments at recent FERC proceedings[2] proposed the consideration of a centralized entity – comparable to ISO/RTO - to oversee both local and regional planning. Even though a full examination of this structure is not within the scope of this report, it is important to inform the discussion regarding the challenges of such a change. Significant additional staffing resources and expertise would be required along with significant data exchange from local to regional planners. Currently ISO/RTOs lack the subject matter experts and local presence to analyze the local system and identify needs related to asset management, resilience, customer impact and other local needs.

In addition, to maintain a fair and transparent local planning oversight, a centralized entity would have to rely on a process that would require the collection, analysis and reporting of all local transmission solution data - activities that could be costly considering the number of local planning projects. Also, since the current coordinating agreements between transmission asset owners and ISO/RTOs do not include such a framework, legal challenges would arise.

To achieve federal and state clean energy goals, both regional and local planning are needed. Clean energy goals require efficient transmission solutions for the integration of renewable resources while maintaining system integrity. Though regional solutions are needed to facilitate the integration of new clean resources and provide for regional reliability and resilience, local planning will continue to offer crucial benefits and support for the regional grid. For instance, grid modernization and distributed energy resources (DER) integration initiatives are supported by local planning since they mostly affect the distribution system connected to local transmission. It would be challenging to expect a non-local entity to design local transmission solutions that enable the decentralization of generating resources and their participation in the wholesale market in accordance with the objective of FERC Order 2222.[3]

For the reasons discussed in this report, local transmission planning provides significant benefits and is foundational to the success of the regional planning process. Combining proximity to the local system with important expertise, local planners design cost-efficient transmission solutions that serve their customers while maintaining system integrity.

The report is organized as follows:

Section 2 summarizes and compares reliability standards and their application in the evaluation of the power system needs in both regional and local transmission practices. The section presents key takeaways compiled from a detailed review of the reliability standard application on local and regional planning practices.

Section 3 explains more broadly the local and regional selection and review processes. The discussion includes information on the results of those processes and their complementary nature.

Section 4 details the challenges associated with a potential consolidation of the local and regional planning activities in one centralized location. This section provides the basis for future discussions.

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2 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024 (2021)

3 FERC Order 2222 (RM18-9-000) was the result of discussion around the efficient integration of distributed energy resources

Lastly, Section 5 summarizes the local planning value in achieving various electric industry goals. The section is not exhaustive but provides a sound basis to inform related discussions.

2. Overview of Local and Regional Planning Criteria

Reliability is at the core of the transmission planning practices codified by well-documented reliability standards and guidelines. In identifying the value of local planning, it is critical to understand the incremental benefits realized from the development and application of more localized planning reliability criteria. Local standards not only comply with the regional and national reliability standards but offer a complementary layer of localized system security not inherently captured by regional planning.

In this section of the report, we compare the applicable reliability standards at the regional and local levels followed by a review of the processes for their application to transmission system studies. Before we proceed with that discussion, we offer a brief background on the development of the reliability standards in the US.

2.1. History of Transmission System Reliability in the US

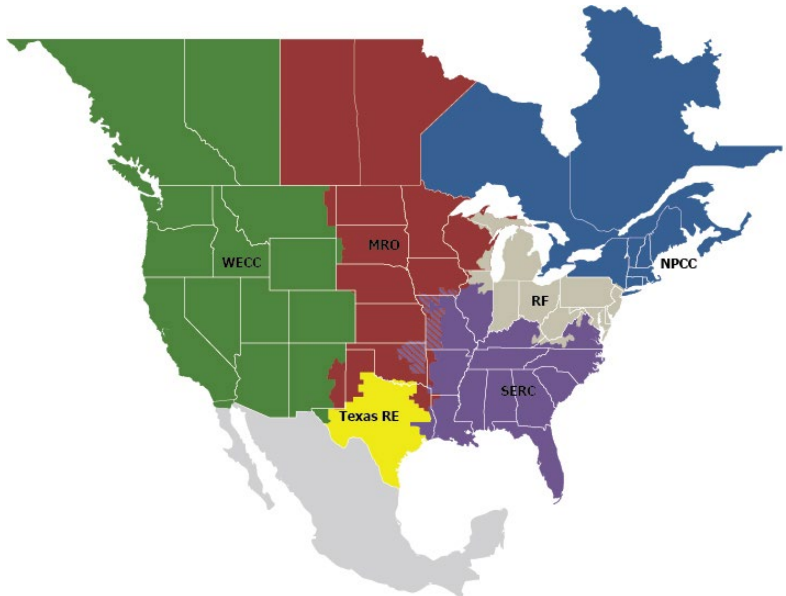
The codified use of reliability standards and criteria in transmission planning and operations has been an important part of the electric power industry. Their importance dramatically increased during the grid expansion and the emergence of new technologies and grid applications. Initially the power systems were relatively simple, whereby a major system disturbance only affected a small area that in turn did not require the development of uniform reliability standards. However, as the power system expanded with the introduction of high voltage alternating current technology, the need for effective and consistent reliability standards became apparent.

The 1965 Northeast Blackout accelerated the development of unified reliability standards throughout North America. At the time, PJM was already enforcing a uniform set of reliability criteria throughout its footprint, with the rest of the regions following. Utilities across North America formed their own regional reliability councils with the objective to maintain, update, and enforce a regionally unified set of reliability criteria. At the time, regional differences in terms of topology and generation mix for example prevented the development of a coordinated set of standards throughout North America. Over time, each regional council developed its own reliability criteria and established procedures for evaluating compliance. Following suit, individual systems and power pools often maintained their own detailed or more stringent criteria in addition to the regional criteria as a minimum. In 1968, the regional reliability councils formed the North American Electric Reliability Council (NERC)[4] to coordinate reliability standard activities across the entirety of North America and to develop collective reliability guidelines.

In 2003, the blackout of the Midwest and Northeast United States and Ontario caused major industry changes that were enacted in the 2005 Federal Power Act. Under Section 215, FERC's authority expanded to include oversight of mandatory reliability rules. The Commission was authorized to designate an Electric Reliability Organization (ERO) to administer the rules and enforce penalties up to a million dollars per day for reliability standard compliance failures. Ultimately, the NERC was designated as the ERO. Currently, the NERC is comprised of six regional entities or councils that support various regions in North America.

[4] Later renamed to North American Electric Reliability Corporation

Exhibit 1 NERC Regional Entities



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Lastly, pursuant to Section 215 of the Federal Power Act, states may disseminate and enforce reliability standards that are more specific than NERC and its regional entities if they don't affect reliability outside of the specific state. For example, New York has the New York State Reliability Council (NYRSC) that is within the Northeast Power Coordinating Council (NPCC) territory and develops and enforces requirements that are more stringent and specific than that of NERC or NPCC.

2.2. Reliability Standards and Criteria

The terms "standards" and "criteria" are often confused when used in the industry. Based on our review, mandatory requirements developed and enforced by NERC are considered "standards" while "criteria" are requirements independently maintained and enforced by the regional reliability entities. Occasionally, the term "guidelines" is used and refers to general requirements addressed by the regional councils through their own criteria. NERC standards are applicable to the Bulk Electric System (BES)[6].

The development of the reliability standards occurs through a NERC process that allows for industry participation throughout the entire process - beginning with the initial creation of a new standard up to its final approval. The NERC Board, residing under FERC's authorization, reviews and approves the proposed standards after a super-majority of registered entities

5 https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

6 The definition of the BES has been a controversial topic over the past several years. FERC has argued for applicability of NERC standards to all transmission facilities 100 kV and higher with approved exceptions. The existing BES definition generally applies to facilities rated at 200 kV or higher but could include some lower voltage facilities that may impact the overall system.

throughout the energy sector is obtained. The regional entities have a similar process for developing and approving reliability criteria within their areas. Any materially affected entities or individuals can initiate the review and approval process. At the state level, state reliability councils, like the New York Reliability Council in New York State, can modify or create new reliability rules that apply only within that state.

The established reliability criteria developed at NERC and its regional councils apply to all entities accountable for reliability in a specific geographical area, such as the regional operators, transmission owners, and generating companies. Additionally, transmission owners have local transmission planning criteria – beyond the regional standards - that are tailored to meet their specific system and area needs. The exhibit below depicts the documents that include all NERC standards.

Exhibit 2 NERC Reliability Standards Documents[7]

Reliability Area	Definition	NERC Reliability Documents
Supply and Demand Balance	Maintains the supply and demand balance of the system under business-as-usual conditions and emergencies	BAL – 001 through 006
Transmission Operations	Ensures that all Reliability Standards are followed by grid operators, that coordinators and operators have the resources needed to address grid issues, and procedures are in place to resolve threats to the system	TOP – 001 through 010
Transmission Planning	Ensures that new transmission facilities are resilient to threats and emergencies	TPL – 001 through 007
Communication	Maintains proper communication and coordination between reliability coordinators and operators of the grid	COM – 001,002
Critical Infrastructure	Ensuring that the grid's critical assets are protected from cyber and physical threats	CIP – 001 through 014
Emergency Preparedness	Ensures that grid operators are prepared for emergencies and have the resources and authority to restore operations if there is a disruption	EOP – 001 through 011
Facilities Design, Connections and Maintenance	Ensures that transmission operators have properly rated their transmission equipment and that adequate maintenance is performed to maintain grid reliability	FAC – 001 through 014, 501
Interchange Scheduling	Ensures that electricity transmission between balancing authorities does not pose a threat to the grid	INT – 001 through 011
Interconnection Reliability	Ensures that reliability coordinators have the authority to enforce reliability by directing grid operators to take necessary action when a threat is perceived	IRO – 001 through 018
Data Analysis	Ensures that grid operators are using accurate and consistent data for the use of transmission planning and reliability	MOD – 001 through 033
Nuclear Operations	Ensures that there is proper coordination between nuclear plant and transmission operators	NUC – 001
Personnel Training	Ensures that grid operations personnel are properly trained and qualified to meet the Reliability Standards	PER – 001 through 006
Protection and Control	Ensures that protection systems that protect the grid are operating as designed	PRC – 001 through 027
Voltage	Ensures that reactive power sources operate within their limits and maintain adequate voltage levels	VAR – 001, 002 and 501

7 https://www.nerc.com/pa/Stand/Pages/USRelStand.aspx

The transmission planning process is mostly structured around compliance with Transmission Planning (TPL) and Facility Ratings (FAC) reliability standards. The first provides an analysis of power system conditions and guidance on measuring performance, while the latter describes information related to the output potential of the analyzed transmission system under specified conditions.

The reliability standards are primarily focused on maintaining reliability during both steady state and dynamic conditions. More specifically, steady state refers to a state when load and generation are in balance and the power system is relatively stable. A common steady state analysis is a contingency analysis, which is used to verify whether the power system is secure after the occurrence of a contingency such as a failure of a line, transformer, generator, or facility for reactive compensation. Besides a single failure, commonly referred to as an ‘N-1 contingency,’ a contingency analysis may also extend to an N-2 contingency- i.e., the simultaneous loss of two generators or transmission lines.

Stability refers to the ability of a system to return to a steady state following a disturbance. According to the CIGRÉ-IEEE[8] task force technical brochure on stability terms and definitions, the following stability phenomena must be investigated during both normal and contingency conditions: (i) Frequency Stability, (ii) Voltage Stability and (ii) Rotor Angle Stability.

Lastly, short circuit analysis – also part of the reliability evaluation - investigates the impact of different types of short circuits on the power systems, including minimum and maximum single-phase or symmetric (three-phase) short circuits or multi-pole short circuits with/without earth contact.

Planners evaluate the system’s responsiveness under various conditions and use established metrics to evaluate the need for specific enhancements.[9]

2.3. Review of ISO/RTO and Local Transmission Reliability Standards

In this report, our objective is to provide different perspectives from a non-technical review of transmission planning standards for regional and local entities.

In total, we examined three RTOs (i) ISO-New England (ISO-NE), (ii) PJM, and (iii) Midcontinent ISO (MISO) and six local transmission owners located within the ISO/RTO areas: (i) Central Maine Power (CMP), (ii) National Grid, (iii) Commonwealth Edison (ComEd), (iv) PPL Electric Utilities (PPL), (v) Great River Energy (GRE) and (vi) Northern Indiana Public Service Company (NIPSCO).

The reviewed documents are provided in the exhibit below.

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8 Definition and classification of power system stability IEEE/CIGRE joint task force on stability terms and definitions, IEEE Transactions on Power Systems, August 2, 2004

9 TPL-001-5 Transmission System Performance Requirements

Exhibit 3 Transmission Planning Criteria Review

Entity	Reviewed Documents
ISO-NE	Transmission Planning Technical Guide Reliability Standards for the New England Area Pool Transmission Facilities (ISO-NE Planning Procedure No. 3) PP3
MISO	BPM – 020-r24 Transmission Planning
PJM	PJM Manual 14B: PJM Region Transmission Planning Process
National Grid	Transmission Group Procedure TGP28 National Grid Planning Guide
CMP	Technical Manual TM 1.2.00 Electric Transmission Planning
ComEd	Exelon Transmission Planning Criteria Applicable to ComEd, PECO, Baltimore Gas and Electric, Potomac Electric Power Company, Atlantic City Electric and Delmarva Power and Light Company
NIPSCO	NIPSCO Transmission Planning 2018 FERC Form 715 Part VI[10]
PPL	Practices Transmission Planning, All PPL EU BES and Non-BES PJM Tariff Facilities
GRE	PLG-CR-0001 System Planning and Strategic Projects

CRA reviewed and compared the documents, and we provide our key conclusions below.

2.3.1. Key Conclusions

The consideration of the applicable reliability requirements is at the core of both local and regional transmission planning practices. The review presented in this report suggests the following conclusions for policy makers and transmission planners to consider when evaluating proposals to merge local and regional planning processes.

- Local planning ensures that the underlying local transmission system is reliable and resilient and provides an important foundation for the regional planning practices to build on. Local planning is not performed in isolation but in coordination with neighboring and regional planning practices. The complementary expertise of the regional planner and the local planner allow for a more robust analysis to mitigate system issues that can cascade from regional to local transmission systems. All reliability standard documents

[10] Document was part of the 2018 NISPCO IRP Appendix F redacted

include information related to coordinating with neighboring local and regional entities to better mitigate intra-regional reliability issues.[11]

- Local planning criteria consider locational needs that are difficult to capture under the broader uniform regional reliability requirements. They also consider the NERC Reliability standards with applicable exceptions related to system differences like geography, configuration, and others. Such exceptions are permitted by the established national criteria and are not considered a violation given the appropriate risk level. For example, varying levels of load shedding are allowed in different jurisdictions, with more stringent requirements seen at the local level. This is reasonable given the available local transmission system modeling detail that allows local planners to have a better understanding of potential issues in the system and design their mitigation. To this point, the facility ratings utilized in various jurisdictions were specific, rather than uniform, to each region to account for geographical and other differences.
- Lastly, the national and regional planning reliability standards primarily focus on compliance with NERC and regional requirements excluding system needs that arise from asset management, resilience, customer impact and other local needs. These critical system needs are assessed through parallel local processes, which are not required by the national and regional standards.

2.4. Structure and Features of the Reliability Needs Assessment

The evaluation of the power system based on the applicable reliability standards occurs in the commonly referred to *reliability needs assessment*. To further understand the complementary nature between regional and local planning, it is important to review how reliability assessments are performed at the regional and local level and describe their differences.[12]

In the reliability needs assessment, transmission planners use transmission system modeling analysis tools to perform steady state load flow, system stability and short circuit analysis to determine any potential violations to planning criteria.

The scope and focus of a reliability assessment dictate the configuration of the load flow models and their input data. In general terms, the input data required in the load flow studies are described as follows:

- System data that includes the overall system topology, technical parameters of the system like transmission line ratings, line and transformer impedances, and location
- Information related to generation dispatch levels and load based on specific assumptions such as season, specific time of day, weather, upcoming resource retirements or additions, generation technology, and others

The process for performing transmission system analysis is as follows:

- *Developing a model of the power system*

This stage includes the gathering and evaluation of the elements within the power system that include transmission lines, transformers, etc. The transmission planner also gathers

[11] Due to the non-technical nature of this report, we did not fully compare criteria such as voltage distortion limits and harmonics. Based on our review, all the technical requirements included in the local and regional reliability standard documents were adequately documented and referenced by well-established entities like IEEE and CIGRE.

[12] In this section, we focus on the reliability component of the transmission planning process excluding others like the economic and environmental impact evaluations.

information related to the system resources that include changes to generation and load. The estimated point demand produced in load forecasting is also a critical component of this effort.

- *Utilize this model to measure the performance of the system for a range of operating conditions and contingencies*

The reliability criteria are applied to evaluate the performance of the system, and the planners identify areas of need after they apply various standard mitigation techniques like generation re-dispatch and others. Lately, enhancements to this stage have included the introduction of stochasticity, which will be needed for the evaluation of future uncertainties.

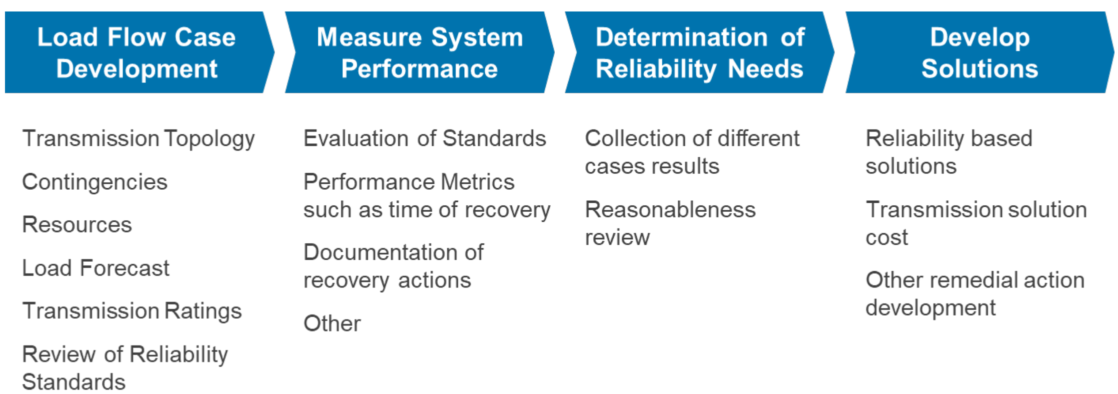
- *Determining those operating conditions and contingencies that have an undesirable reliability impact and result in criteria violations*

Results of the different load flows are organized to assess the complete spectrum of system impacts and the system reliability needs. Planners apply their expertise and system knowledge to assess the reasonableness of the different model outcomes.

- *Developing and evaluating a range of solutions and selecting the preferred solution, taking into account the time needed to place the solution in service*

During this phase, planners use the developed load flow cases to evaluate different solutions to mitigate identified reliability events. The objective is the most cost-effective solution. During this phase, planners coordinate internally with operations, project management and other affected groups.

Exhibit 4 Reliability Assessment Process



Similar to the reliability standard review, we gathered information related to the reliability assessment process performed by entities mentioned in Section 2.3. Our review on the aspects related to the reliability assessment is provided in the exhibit below.

Transmission Planning Component	Examined Regional Transmission Planning Provider	Examined Local Transmission Planning Provider
Source of Power Flow Case	Power flow cases are developed by independent entities. For example, for the Eastern Interconnection, power flow Cases derived primarily from the Modelling Working Group (MMWG)	Provide related data to construct the ISO/RTO case. The result is then used as for local planning including locational details
Source of Load Data Assumptions	All ISO/RTOs rely primarily on stakeholder-driven internal load forecasts for load assumptions	Local planners provide data to ISO/RTO load projections. The finalized information is considered as input to the local process with appropriate locational modifications
Source of Transmission Topology	PJM and MISO use topology assumptions from MMWG and data furnished by member entities. ISO-NE uses topology assumptions from the Regional System Planning Process and Interconnection study processes for internal facilities and the MMWG for facilities external to its system.	Local planners provide the ISO/RTO transmission topology information (ratings etc).
Generation Assumptions	For existing resources, all ISO/RTOs rely primarily on respective stakeholder-driven internal resource studies and regional modeling databases.	In-house generation assumptions shared via the stakeholder process with the ISO/RTO
Stressed Case Conditions	Most ISO/RTOs develop base case(s) with expected generator outages. Additional scenarios and cases are developed to test the system under stressed conditions	Similar framework with additional analysis that incorporates harmonics, etc.
Resolution to Load Flow Violations	Most ISO/RTOs develop transmission solutions as a mitigation measure. These include resource investment (like Demand Response, special protection schemes, and others).	Transmission solutions, special protection schemes, and non-transmission solutions in some cases

2.4.1. Key Conclusions

Overall, the reliability assessment between the two processes is similar. Although performed during different time frames, they appear to be complementary since they evaluate the system from different perspectives. Below we summarize our key takeaways:

System Models: While the basis of the utilized system models is similar between the two processes, local planners consider impacts to the distribution system extending the granularity of the load flow models. Similar to the development of the regional model, local planners incorporate the input of different stakeholders affected by local transmission operations. Coordination with local operations is used to develop practices that better represent the system and how it will respond to various system contingencies. Based on our review, this practice is included in all six local transmission owner planning documents.

Load Scenarios: Our review indicates that local transmission owners analyze more detailed load scenarios applicable to multiple weather patterns compared to the regional process that analyzes mostly only pre-determined forecasts. For example, while CMP refers to the ISO-NE load forecast case as its basis for the load flow development, it also relies on adjustments based on customer needs. Additional sensitivities and scenarios are becoming increasingly important as the grid becomes more dynamic in the changing energy landscape. These types of local studies help to ensure there is adequate transmission capacity to reliably serve load all hours of the year.

Stressed System Evaluation: Experience with their system allows local planners to evaluate more extensive system conditions at the local level. Since the RTO/ISO planers are generally focused on compliance with NERC and regional entity criteria, local planners - where applicable - can examine the needs of the system beyond those guidelines. System familiarity also serves well when interpreting the results of more complex analysis, such as assessing equipment end of life.

3. Transmission Benefits from Local Planning

Apart from meeting the standardized reliability requirements described in the previous section, local transmission solutions deliver additional system benefits related to resilience, operational flexibility, and others. In this section of the report, we briefly describe the full spectrum of the drivers for transmission solutions and their benefits. We also provide an overview of the regional process and how it incorporates local transmission solutions in PJM and MISO. Lastly, we describe the process for reviewing transmission projects at the state level.

Our objective is to inform the discussion around the value of local transmission planning. Our review indicates that:

- Local transmission planning delivers critical benefits not captured under the current regional planning practice.
- The regional process allows for an extensive review of local solutions by the ISO/RTO stakeholders.
- There is adequate review of local transmission solutions to prevent transmission owners from favoring local transmission over regional.

3.1. Transmission Investment Benefits

Originally, transmission planning occurred at the public utility level, often as a component of the local utility's integrated resource planning. Initially, transmission projects rarely crossed state borders as they were designed to deliver electricity from power plants to load centers within a locality. The rapid development of the power grid necessitated the construction of longer transmission projects to interconnect with neighboring utility systems to increase reliability and to access potentially lower priced electricity. The increased complexity of the system required a more extensive selection process for new transmission investments that examined a wider spectrum of reliability, economic, and public policy drivers for transmission enhancements.

The benefits of transmission investment have been categorized and analyzed extensively over the years both in industry and academia. The table below depicts the most mentioned transmission benefits.

Exhibit 5 Transmission Investment Benefits

Area	Transmission Benefit
Energy Production Savings	Congestion reduction, extreme event impacts, reduce wear on generation fleet, and others
Public Policy	Efficiently integrate public policy goals
Market Efficiency	Enhanced competition and market access
Clean Energy	Reduce cost of implementing emission regulations, facilitate integration of renewable technologies, meet climate and energy goals
Reliability/Resource Adequacy	Avoided future generation and transmission investment, allows retirement of high-cost generation, lower planning reserve requirement
Resilience	Storm hardening, system flexibility, and others

Notably, transmission benefits beyond reliability are usually analyzed via a cost-benefit analysis, where the cost of a proposed project is compared with the quantifiable benefits and, in some instances, qualitative benefits which are important but not easily defined. While production cost savings are determined via production cost models, planners have limited analytical tools to evaluate a variety of other benefits like the impact of a proposed solution to the system's storm hardening level.

Although currently conducted by different entities, the local and regional planning processes are complementary, because they capture different sets of benefits produced by different needs. While RTO planning is generally focused on bright line criteria designed to address NERC TPL standards, market congestion, and generation interconnections/deactivations; local planning extends to resilience, asset management, and customer impact. With most of the current transmission system developed in the early part of the 20th century, the benefits from updated infrastructure are significant. The exhibit below provides an overview of various local transmission solution drivers and their benefits.

Exhibit 6 Local Transmission Project Drivers and Benefits[13]

Local Planning Driver	System benefit
Degraded equipment, equipment failure, obsolescence	Enhanced equipment material condition, minimization of performance risk
Minimization of outages, optimal system configuration, increased element restoration capability	Increased Operational flexibility and efficiency
Need to Improve system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather, geo-magnetic disturbances, physical and cyber security challenges, critical infrastructure reduction	Improved Infrastructure Resilience
Service to new and existing customers. Interconnect new customer load. Address customer transmission & distribution load growth, outage exposure, and equipment loading.	Enhanced Customer Service
New Government/State regulations, new industry standards on transmission, pilot projects and other	Addressed other system needs

3.2. Regional Transmission Planning Process Overview

Understanding the involvement of local planning in the regional process requires an overview of the current planning structure at the ISO/RTO level. In the three reviewed regional areas, local solutions are included in the regional and inter-regional transmission planning that occurs at the ISO/RTO level. We concentrate on PJM and MISO planning processes that are similar to ISO-NE and other regional operators.

PJM Regional Planning Process

In PJM, the regional transmission process is performed during the Regional Transmission Expansion Plan (RTEP) process. The RTEP process facilitates planning updates and seeks to resolve issues through open and transparent engagement with members, stakeholders, regulatory agencies, and other parties.

According to PJM, there are three types of transmission planning projects, and are briefly described as follows:

- *Baseline projects* that address national and regional reliability standards. These include projects that mitigate overloads, bus voltage drops, generator instability, and others. They

[13] PJM M-3 Process Presentation by Exelon Transmission

also address generation deactivation, market efficiency criteria, public policy, and PJM's operational performance.

- *Network upgrades* required to interconnect new customers seeking long-term transmission service and connection to the grid.
- *Supplemental Solutions* identified by local transmission owners required for local reliability, resilience, aging, and condition.

Several committees support the process of reviewing recommended planning strategies and policies, as well as planning and engineering designs. The Transmission Expansion Advisory Committee (TEAC) provides a forum for stakeholders and PJM staff to exchange ideas, discuss study assumptions and review results before their approval. Subregional RTEP committees also address lower voltage planning concerns.

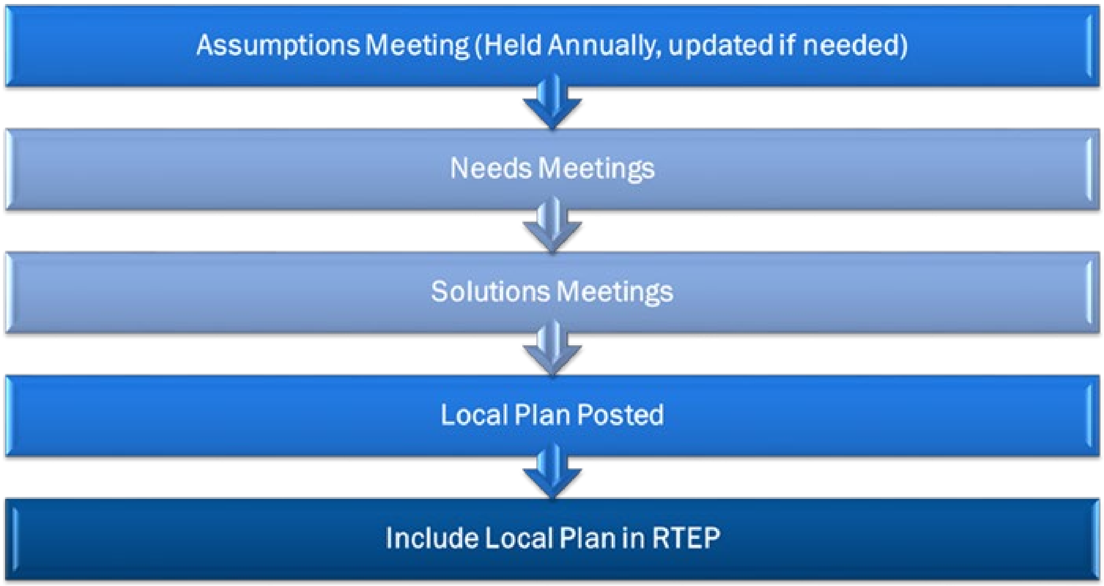
Under the established process described in Attachment M-3 of the PJM tariff, the PJM transmission owners provide for an extensive stakeholder participation during various development stages of the local transmission solutions. Throughout this process, stakeholders can provide comments for consideration by the local transmission asset owner for all proposed supplemental solutions. In a recent order by the FERC,[14] the M-3 attachment was revised to incorporate enhanced transparency towards the review of aging infrastructure replacement projects. As a result, increased opportunity to review and provide feedback was provided to PJM's stakeholders related to asset management activities.

At first, TEAC and subregional RTEP Committees coordinate stakeholder meetings to review the proposed assumptions, criteria and models provided by the transmission Owners that will be used to identify local transmission solutions. The models used in the M-3 Process are the load flow, short circuit, and/or stability models required to review the impacts of potential solutions. Notably, the local transmission solution discussions occur in parallel with the discussions related to other types of transmission solutions such as baseline and network upgrades to ensure consistency.

Following the Assumptions meeting, in the needs meetings transmission owners and other stakeholders can present the identified system needs and their drivers, based on the application of the previously discussed assumptions and criteria. The review of the potential solutions occurs in a subsequent meeting after the needs have been identified and discussed. The proposed projects and evaluated alternatives are presented to the forum for further commenting and feedback.

[14] PJM Interconnection, L.L.C., 172 FERC ¶ 61,136 (August 2020 Order)

Exhibit 7 PJM's Transmission Stakeholder Participation Process



Lastly, local projects are finalized and submitted to the local plan which is incorporated to the RTEP process with the baseline and, network upgrades. PJM planning engineers study the impact of the finalized local projects to the baseline – a process called "no harm"- and other projects and provide feedback to the transmission owners and stakeholders. This process also ensures that local projects do not displace regional transmission enhancements.

In 2020, the PJM Board approved 43 new baseline projects at an estimated cost of $413 million to meet fundamental system reliability across the grid, with a majority costing upwards of $20 million per solution. Based on our review, the number of these projects is not great due to limited regional and national reliability needs over the past few years.

Although the total supplemental projects cost was close to $3.2 billion, it is important to understand their cost composition. Since PJM does not provide detailed cost data for individual supplemental projects, we relied on historical data provided to PJM by its transmission owners. Based on the available information, most of the approved projects in the RTEP process have been supplemental, with the majority costing less than $10 million dollars, dwarfed by the regional project average cost of more than $50 million.

Exhibit 8 Overview or Approved Supplemental Projects included in the RTEP process[15]

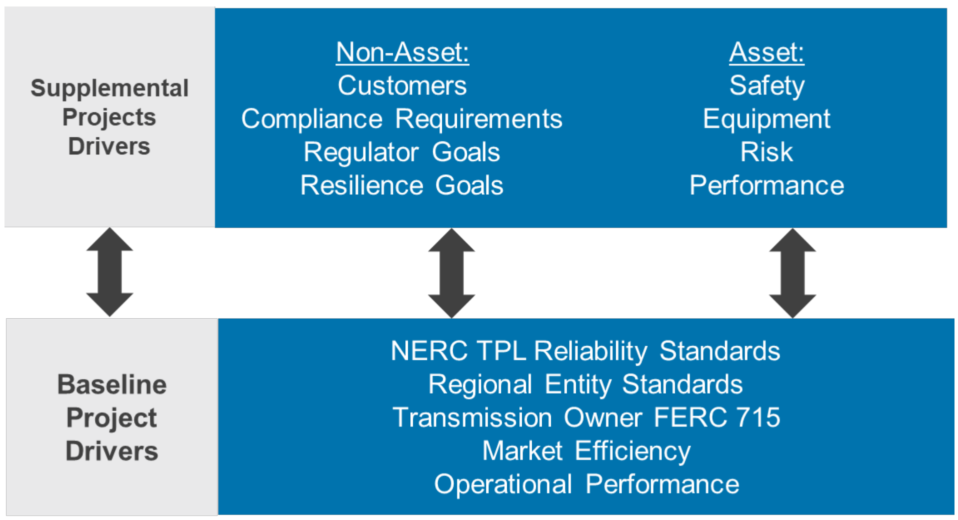
Individual Project Cost ($millions)	Count of projects	%
Less than 0.5	1151	28
Between 0.5 and 4	1420	34
Between 4 and 10	663	16
More than 10	896	22

15 https://www.pjm.com/planning/project-construction

The supplemental projects are categorized by their drivers related to asset and non-asset needs. There exists a sub-set of the supplemental projects that is required to meet reliability requirements – similarly to the baseline projects – but the majority of the transmission solutions are needed to alleviate issues around customer service, asset performance and resilience among others. This confirms the foundational nature of the supplemental projects since they ensure that the local transmission system can support regional projects.

Our review of the supplemental project descriptions did not indicate any overlap with regional projects. The exhibit below indicates the relationship between the two categories and how local projects supplement the limitations of the current regional planning practice at PJM.

Exhibit 9 Transmission Benefits for Supplemental and Baseline Projects



Since the transmission benefits captured by the two processes are not the same, there is no deliberate overlap between the produced transmission solutions.

A recent example provided by Exelon in the FERC ANOPR[16] proceeding reinforces the complementary benefit nature of the supplemental projects. In October 2020, Exelon Transmission[17] performed a transmission study to understand the impact of supplemental projects. The study removed the 72 ComEd supplemental projects from the 2025 PJM model and mimicked the reliability and market efficiency analysis done by PJM. The results demonstrated that the none of the 72 supplemental projects served to alleviate PJM reliability or market efficiency drivers. This result confirmed the concept that supplemental projects do not supplant market efficiency or projects driven by reliability.

MISO Regional Planning Process

The MISO Transmission Expansion Plan, or MTEP, is at the core of MISO's regional planning process, integrating the results of MISO members' local planning processes with the advice and guidance of its stakeholders obtained through multiple meetings. The typical planning cycle occurs over an 18-month period that commences with transmission developers submitting their proposed projects – usually in September. MISO planners evaluate the proposed projects during a multi-month period before sending for approval to the MISO Board. All projects – regional and local – are evaluated through an open and transparent

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[16] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024 (2021)

[17] Parent Company of various transmission owns in North America included ComEd

stakeholder process similar to the process described above for PJM. For local projects, this review largely occurs during sub-regional planning meetings which are open to interested stakeholders in each MISO sub-region. In consultation with stakeholders and the regional planner, transmission owners such as ITC review all proposed projects and potential alternatives at these meetings. This process informs which projects are included in MISO's MTEP.

The projects listed in Appendix A of the MTEP Report constitute the essential transmission projects recommended to the MISO Board of Directors for review and approval on a bi-annual basis. MISO distinguishes between different types of projects and evaluates them based on reliability, economic, and public policy criteria.

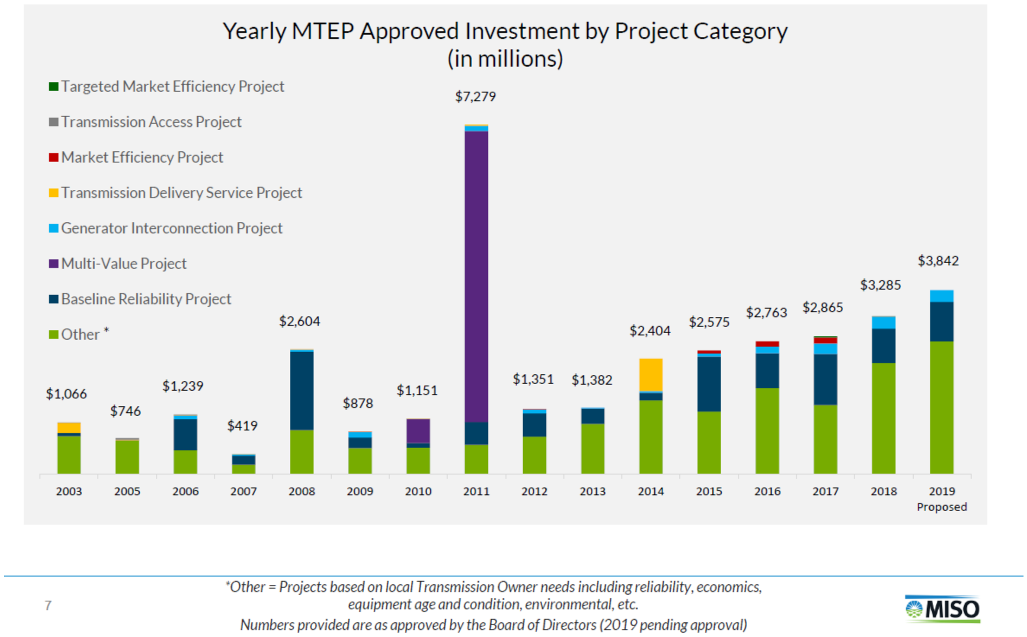
Exhibit 10 Types of MISO Transmission Projects and their drivers[18]

MISO Transmission Projects	Driver
Multi-Value	Provides regional benefits and addresses energy policy laws
Baseline Reliability Projects	NERC Reliability Criteria
Market Efficiency Project	Reduce market congestion when benefits are 1.25 times in excess of costs
Participant Funded (Other)	Transmission owner identified projects that does not qualify for other cost allocation mechanisms
Transmission Delivery Service Project	Transmission Service Request
Generation Interconnection Project	Interconnection Request

Historically, most transmission enhancements in MISO have been developed by local transmission owners. These transmission solutions have been categorized as required to meet load growth, aging infrastructure, and local reliability needs.

18 MISO – Transmission Planning Business Practices Manual BPM-020-r25

Exhibit 11 Historical Approved MTEP investment



Other than 2011, most of the transmission investment has been classified as “other,” defined as being identified and developed by local transmission owners. Looking at the latest MTEP 2020, the “other” composition is as follows:

Exhibit 12 MTEP20 ‘Other Project’ Composition

Individual Project Cost ($millions)	Count of Projects	%
Less than 0.5	611	28
Between 0.5 and 4	834	39
Between 4 and 10	409	19
More than 10	311	14

3.3. Key Conclusions from the Regional Process Review

Our review of the regional planning process as it relates to local projects identified two major themes. First, the current regional planning framework does not evaluate transmission benefits from areas such as aging infrastructure replacement and local resilience and other local needs. The evaluation of those needs occurs at the local level, where planners have the expertise and capabilities to identify and develop plans for their solution. If the current planning framework is modified and the regional reliability category becomes more expansive, it may or may not impact local planning since regional planners will still lack the expertise and proximity to evaluate needs tied to local resilience, new load integration, and aging infrastructure. While the amount of local transmission investment is large compared to regional, that does not indicate a regional project displacement by the local projects as supported by the Exelon analysis.

The second relates to stakeholder participation during the regional planning process. Both ISO/RTOs reviewed have established processes, where stakeholder can weigh in on the proposed local projects. Various meetings that occur during established development stages of the local transmission solutions allow for an open and transparent forum for affected parties to voice their input while reviewing the data provided by the transmission owners.

3.4. State Review Process for Local Transmission

The discussion around the benefits of the value of local planning fails to adequately describe the well-established transmission solutions review at the state level. States have maintained authority over their transmission facilities due to policy principles, as well as design and operation activities. This authority is primarily concentrated on siting of new projects and their impact to the public needs. State commission staff is sensitive to T&D design and operations, due to their responsibilities for coordinating state-policy goals. Other more traditional responsibilities like setting electricity rates, enforcing reliability requirements, and mitigating environmental effects have motivated the staff to thoroughly review new transmission plans within their jurisdictions and at the ISO/RTO level. The ISO/RTO stakeholder participation process has allowed state staff to participate in the development of the local plans more actively than in the past. Given the composition of local projects – small and in large amounts – the ISO/RTO participation process allows for a more efficient review by the state staff.

For larger projects – usually long transmission lines or major transmission infrastructure enhancements – states have relied on more extensive reviews. Through legislation, various states have developed broad selection criteria that are usually applied during the Certificate of Public Convenience and Necessity (CPCN) process. To provide an example of the CPCN process, we focused on two states located within the examined ISO/RTOs: (i) Maine, as part of ISO-NE and (ii) Wisconsin, as part of MISO.

Both CPCN processes are well established and include a lengthy review process that allows multiple stakeholders to examine proposed local transmission projects. It primarily focuses on larger projects with various thresholds in place like miles or voltage level.

The transmission project evaluation standards include, but are not limited to, the following:

- Impact to ratepayers
- Allowing open market access
- Economic impact to the region and economics of the project route
- Compliance with state laws and requirements

In Maine, the process also includes the review of non-transmission alternative solutions and provides the opportunity for stakeholders to propose substitutions for the transmission owner solution.

There are many examples where the CPCN process has provided a sound review and approval of large transmission solutions at the state level. One example is the Cardinal-Hickory Creek project in Wisconsin.[19] During this proceeding, the state commission evaluated the proposed solution based on both qualitative and quantifiable benefits including:

[19] Final Decision Public Service Commission of Wisconsin Docket 5-CE-146, September 26, 2019

energy cost savings, capacity cost savings, insurance value, and avoided reliability and asset renewal benefits.[20]

4. Challenges of Centralized Local Planning

The FERC-issued ANOPR[21], relating to transmission planning reform, raised the possibility of expanding the ISO/RTOs functions – via the creation of an independent monitor- to include local transmission planning oversight. Specifically, FERC stated the following:

"…it would be appropriate for the Commission to require that transmission providers in each RTO/ISO, or more broadly, in non-RTO/ISO transmission planning regions, establish an independent entity to monitor the planning and cost of transmission facilities in the region."

Under a centralized entity, local projects will be subject to regional oversight and open to competition. In our view, a more extensive and comprehensive analysis is required to assess the impacts of such a transition in the future. The analysis would focus on various risks of such transition such as implementation cost and risk of transferring responsibilities from an organization with local planning experience to one that does not and other among other. The analysis should also review potential competitive structures that enable competition at a cost-effective and non-discriminatory manner. As depicted in Section 3.2, the number of local projects at MISO and PJM is significantly greater than the number of regional projects making the development of a cost-competitive framework difficult to manage and having questionable benefits for customers.

In this report, we identify a sub-set of potential areas to further investigate the expected impacts of such transition.

4.1. Staffing

Expanding the transmission planning and engineering responsibilities and oversight from the regional level to the local level will impact the availability of current ISO/RTO planners and require significant additional resources with very different skill sets related to asset management, resilience and other. Based on our review, currently regional transmission planning in both ISO/RTO and non-ISO/RTO regions relies on one of the following[22]:

- In-house standing body of planning staff supported by external consultants. Regional planners focus on modeling and simulation to identify the reliability needs and potential solutions.

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20 Energy Cost Savings: The Energy Cost Savings represent the project's ability to lower overall energy costs for Wisconsin customers. Capacity Loss Savings: These are the savings resulting from the reduction in capacity costs as a result of the project operation. Insurance Value: The Insurance Value is the reduction in the economic impact of severe generation or transmission outages. Avoided Reliability Project Benefits: These are the benefits from avoiding the need to construct future reliability projects if the project constructed. Asset Renewal Benefits: These are the benefits associated with avoiding the need to renew and replace existing transmission lines if each alternative is constructed.

21 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024 (2021)

22 Lawrence Berkeley National Laboratory, A Review of Recent Regional Transmission Plans, September 2016. https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf

- Third party evaluator/s responsible for various analyses of proposed projects, including cost-benefit analysis. An example of this approach is the Florida Reliability Coordinating Council.
- Collaboration between the public state commission staff and regional transmission planning entity. This mostly occurs in non-RTO regions with NTTG as example.[23]

A potential shift to a centralized regional planner for local transmission planning will affect all three practices in various degrees. For the ISO/RTO, any extension on planning responsibilities will require the need for larger planning groups including resources with skills outside the traditional reliability planning like asset management. It is unclear whether planning engineers from the local transmission owner would be able to support a regional entity. Third party evaluators that currently support non-ISO/RTO centralized planners would also require incremental skills that can add to planning costs for a particular area. Without a detailed study, it is difficult to determine whether such a structure is more cost-effective and would enable more robust local planning.

In addition, in most transmission owner organizations, transmission planning is performed in coordination with distribution planning to design and operate the system in an efficient manner. Moreover, in areas like the Midwest, local planners have expertise tied to system intricacies like contractual agreements between smaller transmission owners with infrastructure connected to their system that is not part of the Bulk Electric System. It is unclear how a centralized entity will effectively manage these arrangements to the benefit of the local network customers.

Lastly, local projects related to asset management rely to a decision-making process that has evolved over time and cannot be replicated at the regional level. Even though local engineers deploy software tools and monitoring devices to assess the estimated life of field electrical equipment, they also rely on experience developed over time to conclude on their replacement. Maintaining a balance between replacing an old asset on time and not replacing too soon is a decision making process not easily replicated with a uniform decision making approach at a centralized entity.

4.2. Centralized Entity Infrastructure Needs

The formation of an independent monitor would require enhancements in data sharing and additional infrastructure investments.

In transmission planning, information sharing is critical. Currently, the regional planning process requires a significant amount of confidential data to be transferred related to various transmission system elements collected from local transmission owners and other entities. An expansion of the ISO/RTO planning with the addition of evaluating transmission enhancements driven by asset management, resilience, customer service and other will require the transfer of significantly more critical infrastructure data. This data transfer could amplify the risk of a potential cyber breach event. NERC has instituted the critical infrastructure protocols that provide standards for preventing such an event, but the need to modify or enhance the current standards may be required adding cost to the affected parties.

Larger planning groups would also require supporting infrastructure such as buildings, servers and other that can increase implementation cost with limited benefit. Recent ISO/RTO formation studies can offer insights on the investment cost, but we expect it to differ under different regional oversight structures (greater oversight will require larger infrastructure development).

[23] https://www.nwcouncil.org/sites/default/files/2016_0510_7.pdf

4.3. Project Selection Administrative Cost

Under a centralized entity, we expect the local projects to be subject to regional oversight and open to competition. Maintaining fair and competitive local transmission selection would require the expansion of competitive selection process.

Currently there are two approaches for selecting competitive transmission projects subject to Order No. 1000 bidding requirements in North America: sponsorship and project-based solicitation. Under the sponsorship approach, the competition for a transmission solution includes both the selection of the project and the developer. Under the project-based solicitation approach, the planning process determines the project based on set criteria, while the developer is selected by solicitation.

Regardless of the approach, the ISO/RTOs have in place a robust and resource intensive process designed to meet established criteria propagated by FERC Order 1000 for the selection of both projects and developers – per their selection approach. Even though direct ISO/RTO administrative costs for given competitive processes are recovered via a proposal fee, it is uncertain how this fee will evolve if there are significant numbers of needs or proposals. General and administrative expenses for RTOs/ISOs, including staffing needs to oversee competitive processes, would likely increase significantly. Besides the analytical component, the ISO/RTO staff will have to evaluate the financial status of the developers, administer the solicitation process, report and process the results, and potentially track the status of completion of these solutions more actively.

On the developer side, initial participation costs can take the form of ISO/RTO membership, access to the solicitation process, and others. Our industry experience indicates that the development of a project proposal can be at significant cost and may negatively affect smaller developers. As an example, SPP reported a $500,000 cost for the competitive process for the North Liberal–Walkemeyer 115 kV project.[24]

As described in the previous section, most of the supplemental projects in PJM are less than $4 million. The impact of the developer proposal costs and the ISO/RTO fee on these projects' total budgets is greater, compared to a multi-million-dollar regional project. In order to maintain a competitive bid, compared with an experienced merchant developer, small developers may elect to not participate in the solicitation process for smaller projects.

5. Energy Industry Goals and Local Transmission Planning

Local transmission planning has an important role in the coordination and reliable implementation of emerging policy initiatives since it acts as a bridge between distribution and regional systems.

In this section of the report, we detail how an effective local transmission planning process can address various challenges that stem from these initiatives. The discussion focuses on the importance of local transmission planning in advancing grid modernization efforts, integrating Distributed Energy Resources (DER) into the electric grid, enhancing resilience against severe weather, and achieving various proposed clean energy goals. We recommend policy makers and planners use this section to communicate a comprehensive "business case" for local transmission projects that focus not only on reliability like the previous section but as complementary to achieving state and federal government policy goals.

[24] Prepared Statement of Paul Suskie, Executive Vice President and General Counsel, Southwest Power Pool, Inc., Before the Federal Energy Regulatory Commission, Docket No. AD16-18-000.

5.1. Grid Modernization

Transmission planning benefits related to system resilience and grid modernization have gained more visibility. Recent capital expenditure on grid infrastructure, apart from maintaining and expanding current T&D networks, has also begun to enter the territory of grid modernization to transition the current electric grid into a more dynamic system. Focused on the local level, various utilities and transmission owners are at different stages of incorporating elements of a modern grid into their T&D networks. A general understanding is that a more automated and modernized grid will be the best response to a rapidly changing electric system and world.

Distributed Energy Resources (DERs) have also been driving the modernization of the electric grid. As utilities start to ramp up their investments in DERs, they can be viewed as an almost simultaneous investment in elements of a more modernized grid to improve grid reliability, resiliency, and recovery time. Commonwealth Edison (ComEd), for instance, has successfully prevented over 4.8 million customer interruptions since 2012 with its Energy Infrastructure Act. The Act included the deployment of 2,600 smart switches and 4 million smart meters throughout its service territory.[25]

Additionally, recent investments in the T&D industry show a preference for a more digitized T&D system.[26] National Grid, for example, has begun to digitize substations to create a more dynamic network, which the utility believes provides cost savings for customers and significantly improves flexibility and safety.[27]

These examples of modernizing the electric grid show that this process has thus far been spearheaded by local transmission owners who are closer to the T&D network interface and understand intimately what will best serve their customers. This makes a strong case for why transmission planning needs to be fostered at the local level, as it is likely that those who are most familiar with particular T&D systems are the ones who can make the most informed decisions on what is needed to develop a truly resilient and modernized grid.

5.2. DER Integration and DER Planning

In the U.S. and abroad, households and small businesses are utilizing the grid when adopting technologies that allow them to influence their energy bills and carbon emissions. In parallel, more and more utilities are pivoting towards an increasing adoption of Distributed Energy Resources (DERs) to serve the emerging needs of their consumers while simultaneously meeting state clean energy targets.

Exhibit 13, below, shows in various shades of green the leading states in installed DER capacity, ranging from about 1 GW to 8 GW. Efficient local planning is critical in ensuring that periods of intermittency – particularly from renewable DERs – is addressed by a modernized network.

Local planning ensures that the integrity of T&D networks in terms of reliability and resilience are maintained whilst also decentralizing the energy generation, increasing penetration levels of DERs, and putting some control in the hands of consumers.[28]

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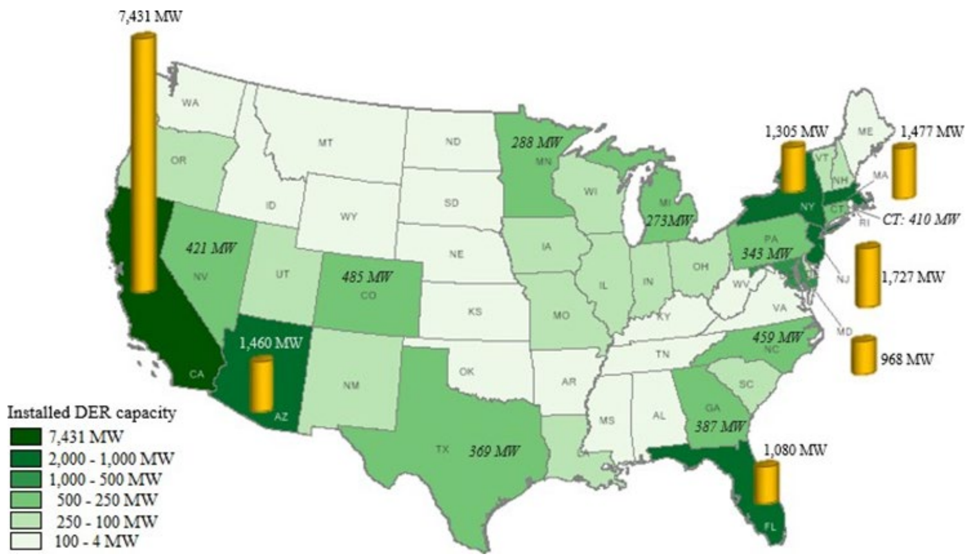
25 Henderson, I. M et al. Electric Power Grid Modernization Trends, Challenges and Opportunities. 2017. Pg. 5

26 2020 Black & Veatch Strategic Directions Electrical Report. Pg 11

27 https://www.tdworld.com/substations/article/20971018/national-grid-advances-digital-substations

28 Henderson, I. M et al. Electric Power Grid Modernization Trends, Challenges and Opportunities. 2017. Pg. 5

Exhibit 13 DER Adoption in the U.S.[29]



Federal and state policy makers have realized that local planning can more efficiently facilitate the integration of DERs. We understand that states, such as New York, are considering the adoption of enhanced local planning standards that will focus on the following principles[30]:

- *Open access:* Local planning is better suited to optimize the investment decisions of customers and third parties by identifying points on the grid where distributed resources have greatest value.
- *Reliability and Security:* Enhancements to local planning can ensure that reliability, physical security, and cybersecurity are maintained as the distribution grid changes.
- *Coordination:* Cost effectiveness is better met with local transmission and distribution plans informing and interacting with other utility planning practices, including integrated resource and capital budget plans.
- *Flexibility:* Local planning adapts faster to changing grid conditions and new technologies because they are closer to the emerging trends than the RTO/ISOs.
- *Inclusion:* Local transmission planning can better assess that all customers have opportunities to participate in grid modernization through tariffs and programs that compensate customers for the value of their distributed resources.

Even though these principles appear generic, they must be considered in a way that better apply to the local system and its stakeholders. This realization has created the need for an active discussion at the state level, where the familiarity of the local system and its complexities by the local planners can advance the enhancement of the current planning standards.

Lastly, FERC Order 2222's objective to enable DER wholesale market access continues the federal commitment for accelerated decentralization of generation. The effect of the Order on transmission planning hasn't been fully studied yet, but we expect changes to occur both in

29 The U.S. Energy Information Administration

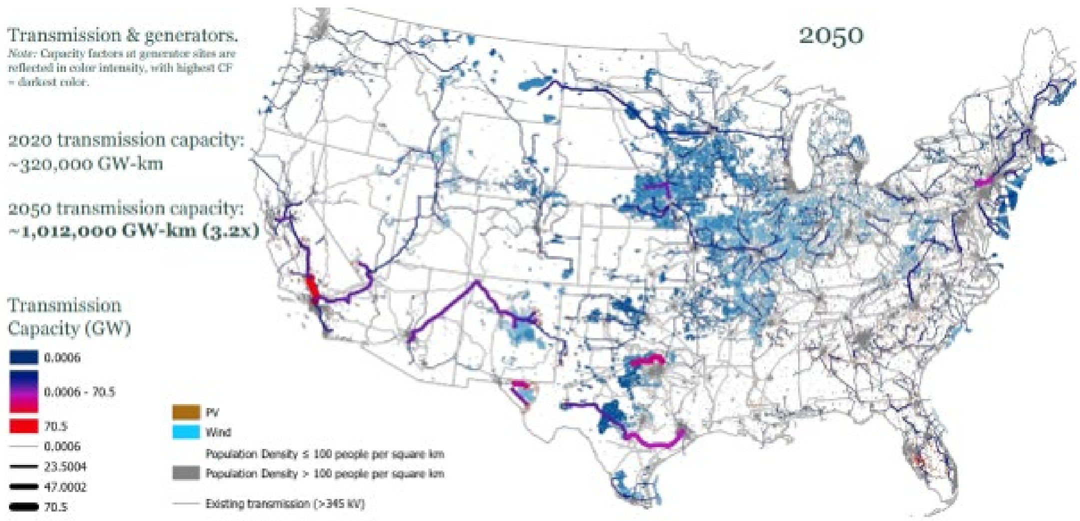
30 New York's CLCPA Transmission Policy Working Group

terms of interconnecting new assets and design and operation of the power grid. The proximity of local planning to these changes provides an advantage in the assessment of the required transmission solutions in an integrated manner with other aspects of planning like resource planning and distribution.[31]

5.3. Clean Energy Goals

The role of transmission in achieving clean energy goals is critical. The aggressive commitments to combat climate change and the growing cost-competitiveness of renewable resources have enabled the widespread adoption of clean energy goals by many U.S. states and the federal government. Notably, in January 2021, the Biden administration announced ambitious decarbonization plans that aim to reach 100% clean electricity by 2035 and net-zero emissions by 2050. Reaching these goals efficiently will require a doubling or tripling of the size and scale of the nation's transmission system. Exhibit 14 below highlights the investment need with over 1 million GW-km of incremental transmission capacity by 2050.

Exhibit 14 Required Transmission Capacity to Support Renewables by 2050[32]



Consequently, as more renewable resources are built, there are increasing demands on local transmission entities to expand their capacities to better accommodate new renewable generation facilities. Black & Veatch's 2020 Strategic Directions report highlights that transmission owning utilities and transmission organizations, particularly in the Mid-West and on the West coast, are facing increasing demand for interconnection requests, predominantly from utility scale renewable generators. There is also the expectation that the increased interest in offshore wind energy on the East Coast will lead to increased demand for local transmission expansion in this part of the country.[33]

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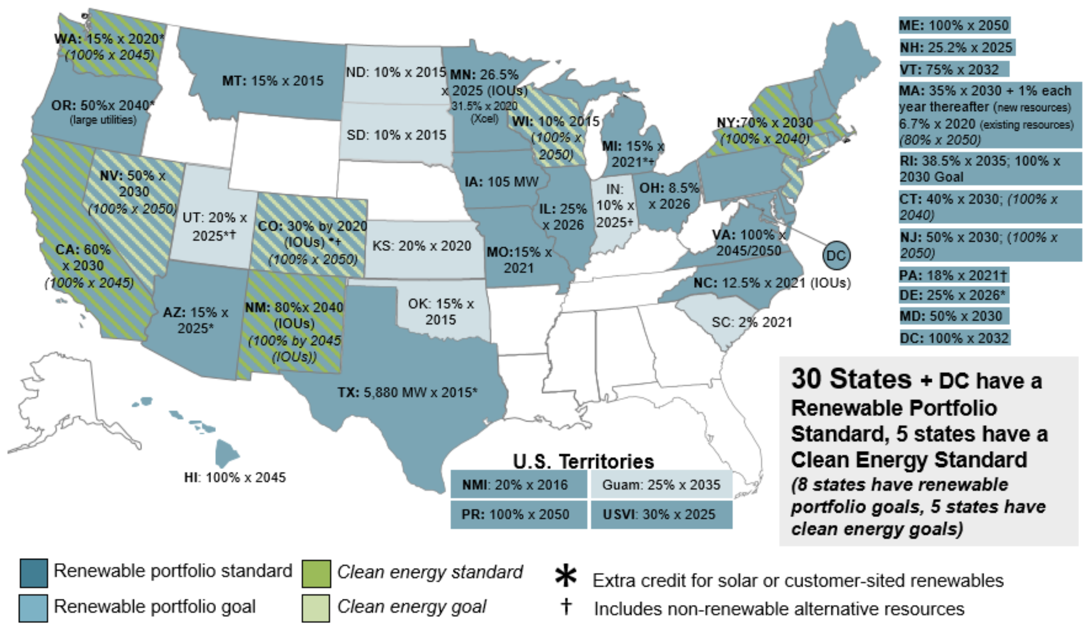
31 CRA has been active in this area supporting various clients with conceptualizing and implementing an integrated resource, transmission, and distribution planning framework. https://www.crai.com/industries/energy/energy-advisory-and-strategy/grid-resource-planning/

32 Larson et al. Net-Zero America. 2020. Pg. 137. https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf

33 2020 Black & Veatch Strategic Directions Electrical Report. Pg 11

Local transmission owners are at the forefront of planning for such demands on the T&D network as evidenced by increasing references in various utility Integrated Resource Plans (IRPs) on how they plan to expand their T&D networks. PacifiCorp, for instance, in their 2021 IRP, highlighted that they will embark on expanding their existing transmission network to enable new renewable resources they are bringing online to efficiently reach their customers.[34]

Exhibit 15 U.S. Renewable Portfolio and Clean Energy Standards by State[35]



One of the challenges that regional solutions are facing is the disparity between the clean energy goals and net-zero commitments between states. As depicted in Exhibit 15, the clean energy goals vary not only in terms of renewable targets but also in terms of compliance timelines. Large regional and inter-regional solutions are needed to support the integration of renewables, but buildout on the regional and inter-regional levels to accommodate clean energy goals necessitates more local projects, not fewer. Local transmission lines would be needed to accommodate increased renewable penetration and transmit power from the new/upgraded regional and inter-regional lines.

Local planning can improve the pathways for renewable generation to reach the regional transmission grid reducing local curtailments. This will enable more efficient regional and inter-regional transfer of renewable power even through states that have different goals than others. Local planning should be viewed as a ramp to a highway. A more efficient ramp enables a larger amount of renewable power to be integrated into the regional system

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34 2021 Integrated Resource Plan. Pacific Corp. 2021. Pg. 9 https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

35 DSIRE. https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2020/09/RPS-CES-Sept2020.pdf