TRANSMISSION PLANNING AND DEVELOPMENT REGIONAL REPORT CARD

Americans for a Clean Energy Grid

JUNE 2023

"This paper from Americans for a Clean Energy Grid represents a true milestone on the path toward a cleaner energy future. We hope these recommendations will kick-start a conversation among policymakers and stakeholders — a dialogue that needs to happen as soon as possible. ACEG looks forward to continued engagement with diverse stakeholders to achieve our shared vision of a cost-effective, reliable, and cleaner energy future."

- CHRISTINA HAYES, *Executive Director, ACEG*

ACKNOWLEDGEMENTS

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Anjali Patel of David Gardiner and Associates and Sarah Shinton of ACEG provided editorial assistance.

The C Three Group LLC and Lawrence Berkeley National Laboratory provided additional data for the Transmission Miles Built and Interconnection Metrics.

Representatives of all planning regions were asked to review initial findings and provide input.

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1 Executive Summary

Effective transmission planning is essential for providing customers with affordable and reliable power. This report evaluates transmission planning performance and practices by region. Overall the grades leave a lot of room for improvement. In this first installment of what we expect to be a regular update, this 2023 issue provides a baseline from which future progress can be compared. California and the Midwest (MISO) score the highest with efforts just over the last two years to proactively plan for the future resource mix. The Southeast region shows the greatest room for growth, while the west (minus California), mid-Atlantic (PJM), New England (ISO-NE), and Texas are also lagging in their planning and development efforts.

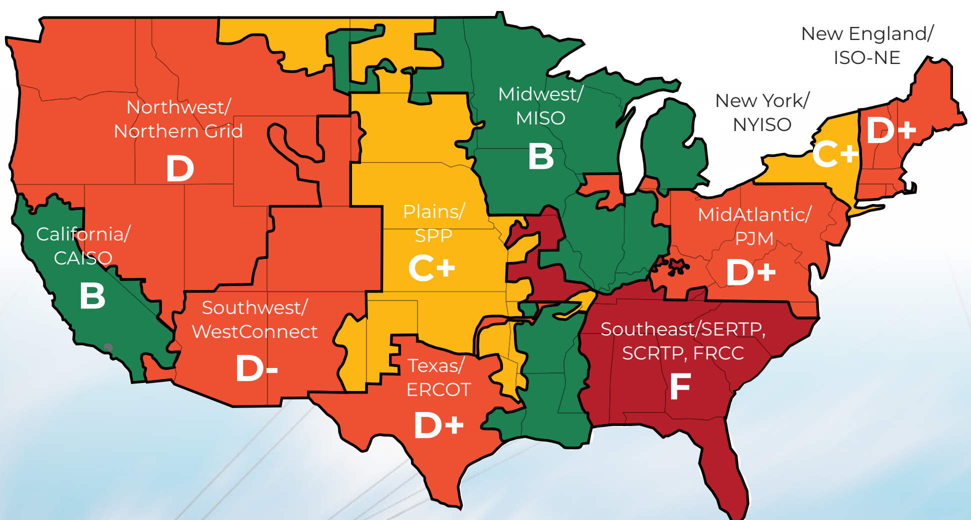
This report is intended to begin conversations about how each region can improve its transmission planning and development. We hope parties in each region can see positive examples in other ones from which they might learn. Our intent is not to criticize. Instead, we aim to show that good performance is possible and achievable, and all regions can improve to reach an 'A' grade in the coming years.

Grading cannot be perfectly objective and subjectivity does enter the process. To address these issues, we used objective metrics and data wherever possible, consult with many parties in developing the grades, and apply consistent methods across all regions.

The overall grades for each region are shown in the map below. The Midwest received the highest grade of any region, finishing a quarter point ahead of California. This grade reflects MISO's leadership in proactive multi-value transmission planning, starting with the Multi-Value Projects over a decade ago and continuing with the approval of the Tranche 1 Long Range Transmission Planning projects last year. However, the Midwest score was held back by MISO South, where relatively little transmission planning activity occurs. For California, their strong grade reflects recent actions in their transmission planning processes, including the 20-year transmission outlook and the recently approved 2022-2023 transmission plan.

New York was the next highest scoring region, also performing in the 'C+' range based on their transmission planning methods and recently developed plans for new transmission. The other regions all fall in the 'C' or below range and have considerable room for improvement.

FIGURE 1 **Overall regional transmission planning grades**



A. Methodology

Regions: The report card evaluated ten regions based in large part on the Federal Energy Regulatory Commission (FERC) Order No. 1000 planning region borders plus ERCOT, as follows:

REGION GRADED	ORDER NO. 1000 PLANNING REGION/REGIONAL PLANNER
California	CAISO
Mid-Atlantic	PJM
Midwest	MISO
New England	ISO-NE
New York	NYISO
Northwest	Northern Grid
Plains	SPP
Southeast	SERTP, SCRTP, FRCC
Southwest	WestConnect
Texas	ERCOT

The report grades regions, not specific entities (RTOs or Order No. 1000 planning entities), because many parties, besides the planning entities, bear responsibility for performance, including utilities, states, and other stakeholders. Consequently, the report also evaluates actions taken by states or utilities within those regions for planning and development. This resulted in credit for transmission-related actions not initiated by the regional planning entities or within the formal planning processes.

The report card is based on four metrics of transmission planning and development performance: 1) Planning methods and best practices, 2) Miles of transmission built and future transmission plans, 3) Transmission capacity available for new resources, and 4) Congestion. For planning methods, we evaluated each region's transmission planning process against known best practices. For miles of transmission built and future transmission plans, we evaluated high-capacity transmission built in recent years and whether a region had future proactive transmission plans that go beyond reliability upgrades. Transmission capacity available for new resources is a combination of three metrics (Cost to Interconnect, Time in Queue, and Project Completion Rate), all of which indicate whether a region's system has sufficient transmission capacity to connect new generation. Finally, we evaluated $/MWh of Congestion, which reflects a representative snapshot of each region's available transmission system capacity. No single metric is entirely dispositive, but in combination, they provide an accurate assessment of transmission capacity.

The transmission planning report card provides regional grades based on these evaluation metrics.

TABLE 1 Overall grade and summary of grades for each metric

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
California/CAISO	A-	C	B-	C	85.8%	B
Mid-Atlantic/PJM	D	D	C+	B	67.5%	D+
Midwest/MISO	A-	B-	C+	C	86.0%	B
New England/ISO-NE	D+	D	F	A	68.0%	D+
New York/NYISO	B-	B	F	C	78.6%	C+
Northwest/ Northern Grid	F	C	B-	D	63.3%	D
Plains/SPP	C+	C	C-	C	77.5%	C+
Southeast/SERTP, SCRTP, FRCC	F	F	A-	D	51.9%	F
Southwest/WestConnect	F	B-	B-	D	62.3%	D-
Texas/ERCOT	D	C-	A	D	68.6%	D+

One of the trends among the more quantitative metrics – transmission capacity available for new resources, congestion, and miles of new transmission built in recent years – is that performance is declining across all regions. Congestion is rising, delays and costs for interconnecting new projects are increasing, and very little new high-capacity transmission is being built.

However, some regions are taking the initiative to plan and build transmission while FERC continues to consider potential reforms to its transmission planning rules.[1] We anticipate these reforms will reverse some of these negative trends and that future report cards will see the country planning a robust high-capacity transmission system that increases reliability and lowers consumer costs.

1 Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 87 Fed. Reg. 26504 (May 2022) (NOPR).

2 Introduction and Background

Transmission has become increasingly important as every aspect of modern life relies on affordable and reliable electricity. Large-scale regional and interregional transmission is critical to support clean energy growth for decarbonization and system reliability during severe weather. Every transmission line provides multiple benefits. For example, if a new transmission line is built to connect and deliver low-cost generation from the center of the U.S. to the East Coast, that line will lower electricity costs for consumers and business, increase reliability for the regions connected by the line, and may help some states and businesses achieve public policy goals. The next section reviews legal and policy framework created to guide the planning and development of regional transmission.

A. Thirty years of FERC promoting regional transmission planning

Pursuant to federal law, the Federal Energy Regulatory Commission (FERC) has promoted regional transmission planning for at least 30 years. In 1993, FERC encouraged it with its Regional Transmission Group (RTG) policy statement: "Properly functioning RTGs will serve the public interest … by providing coordinated regional planning of the transmission system to assure that system capabilities are adequate to meet system demands.[2] Through Orders No. 888 (1996), 2000 (1999), 890 (2007) and 1000 (2011), FERC refined its guidance to enhance transmission planning requirements. However, no new rulemakings have been issued since 2011 and regional planning has still not achieved the Commission's initial goals.

2 FERC, "Policy Statement Regarding Regional Transmission Groups," 58 Fed. Reg. 41626 (August 5, 1993), https://archives.federalregister.gov/issue_slice/1993/8/5/41621-41634.pdf#page=6.

THE FEDERAL POWER ACT

Federal Power Act, 16 U.S.C. § 824, provides:

- "the business of transmitting...electric energy is affected with a public interest."(Sec. 201)
- "Federal regulation of matters relating to ... transmission of electric energy in inter-state commerce ... is necessary in the public interest..." (Sec. 201)
- "For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy." (Sec. 202)
- "All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful." (Sec. 205)
- "Whenever the Commission... shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation." (Sec. 206)

Evolution of FERC Transmission Rules

In 1993, FERC first encouraged regional transmission with its Regional Transmission Group (RTG) policy statement, which stated that "properly functioning RTGs will serve the public interest by enabling the market for electric power to operate in a more competitive, and thus more efficient manner, and by providing coordinated regional planning of the transmission system to assure that system capabilities are adequate to meet system demands."[3]

In 1996, FERC issued Order No. 888 and a pro forma OATT to provide open access to public utility-owned, operated, or controlled transmission.[4] The order provided minimum transmission planning requirements for public utility transmission providers, including accounting for the needs of network customers the same as their own and meeting long-term firm point-to-point transmission services requests with new transmission lines.[5] Order No. 888-A also encouraged, but did not mandate, joint and regional transmission planning.[6]

In 1999, FERC issued Order No. 2000, which promoted regional transmission planning by encouraging transmission owners subject to federal regulation to voluntarily form Regional Transmission Organizations (RTOs).[7] Under transmission planning and expansion, RTOs were supposed to assume responsibility for regional transmission planning and expansion and encourage market-driven investment. The Order also required that RTO regional planning efforts should accommodate multi-state planning efforts and coordinate with existing groups in the region. Order No. 890 found a decline in transmission investment relative to load growth, resulting in increased congestion and less access to alternative sources of energy. This led to the first required transmission planning by every transmission provider.[8] Nine principles, emphasizing the importance of transparency and providing opportunities for stakeholder engagement, were outlined, and the planning processes are required to be outlined in a new attachment, Attachment K, to the Open Access Transmission Tariff (OATT). These nine planning principles required in Attachment K planning include: 1) Coordination; 2) Openness; 3) Transparency; 4) Information exchange; 5) Comparability; 6) Dispute resolution; 7) Regional participation; 8) Economic planning studies; and 9) Cost allocation for new projects.

Order No. 1000:

- All transmission providers, regardless of whether they were a part of an RTO or the RTO themselves, must participate in creating "regional transmission plans."
- Regional plans must identify the reliability, economic, and public policy transmission needs, and allow for stakeholder engagement, and neighboring regions must coordinate on interregional transmission.
- The goal was to remove barriers to regional transmission development, create competition for new transmission projects, and identify the most cost-effective means of providing new transmission capacity.

3 FERC, "Policy Statement Regarding Regional Transmission Groups," 58 Fed. Reg. 41626 (August 5, 1993), https://archives.federalregister.gov/issue_slice/1993/8/5/41621-41634.pdf#page=6.

4 Order No. 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21540 (1996).

5 Section 28.2 of the *pro forma* OATT and Sections 13.5, 15.4, and 27 of the *pro forma* OATT.

6 Order No. 888-A, 62 Fed. Reg. 12274 (Mar. 14, 1997), FERC Stats. & Regs. at 30,311.

7 Order No. 2000, Regional Transmission Organizations, 65 Fed. Reg. 809 (2000).

8 Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, 72 Fed. Reg. 12265 (2007).

B. Overview of national performance on high-capacity transmission development

i. Regional Transmission Planning is Inconsistent

In Order No. 1000, FERC created three categories of transmission need: reliability, economic, and public policy. Transmission lines needed for reliability purposes are projects that solve or prevent violations of NERC standards or other grid requirements and focus on avoiding power losses. Transmission lines driven by economics are usually approved based on production cost analysis and a benefit-cost ratio. Transmission lines can also be used to meet public policy needs. This generally meant the line was needed to help a state meet an enacted law, though now changes in the resource mix are being driven by other factors including economic, utility goals, and customer demands. Because these three categories were defined separately, most regions plan for transmission lines in these siloed categories. Siloing planning by only looking at the benefits a proposed transmission project might have in one category generally leads to a single benefit category not being enough to overcome the costs and very few lines passing the test. Planning that considers benefits across all three categories is a better way to identify the most cost-effective and efficient investments.

Despite FERC's various attempts to encourage regional transmission planning, the results have been lackluster. The Commission itself has recognized that regional transmission planning performance has fallen short. In April 2021, FERC released a Notice of Proposed Rulemaking (NOPR) on Transmission Planning and Cost Allocation.[9] The Commission acknowledged that better planning was needed, stating,

> reforms are needed to the Commission's existing regional transmission planning and cost allocation requirements because they fail to require public utility transmission providers to:
>
> > (1) perform a sufficiently long-term assessment of transmission needs;
> >
> > (2) adequately account on a forward-looking basis for known determinants of transmission needs driven by changes in the resource mix and demand; and
> >
> > (3) consider the broader set of benefits and beneficiaries of transmission facilities planned to meet those transmission needs.[10]

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9 Notice of proposed rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 87 Fed. Reg. 26,504 (May 2022) (NOPR).

10 NOPR at P 35.

In the NOPR, the Commission acknowledged that previous actions have led to insufficient regional transmission planning and buildout on an inconsistent basis.[11] Instead, a significant portion of the transmission system's expansion since issuing Order No. 1000 has occurred outside the regional planning processes,[12] including through the generator interconnection process.[13] As a result, FERC has concluded that the current regional transmission planning regime has not resulted in just and reasonable rates for customers.[14]

The NOPR acknowledges that regional planning under Order No. 1000 failed to adequately plan for and meet transmission needs, driven largely by the changing resource mix and increasing load.[15] Instead, regions have relied on the generator interconnection process to drive most transmission expansion for new resources. However, the generator interconnection process is reactive and does not holistically plan for future needs or evaluate the most efficient transmission solutions to maximize transmission's economic and reliability benefits. It is not achieving economies of scale and is failing to maintain just and reasonable rates.[16]

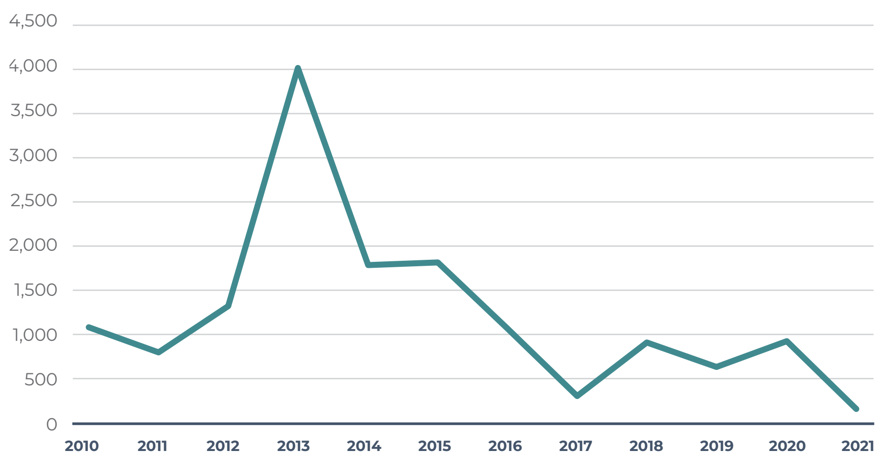
FERC's transmission planning NOPR highlights the problems with the status quo, noting that there have been significant increases in the cost of interconnection-related upgrades.[17] Americans for a Clean Energy Grid has previously found that interconnection costs had historically been less than 10% of total generation project expenditures, but those costs have increased to 50-100% in recent years.[18] For example, MISO West saw interconnection-related upgrade costs triple from $300/kW in 2016 to almost $1,000/kW in 2017.[19]

11 NOPR at P 24.
12 NOPR at P 26, 36.
13 *Id.*
14 NOPR at P 27.
15 NOPR at P 45.
16 NOPR at P 36-38.
17 NOPR at P 37, 38.
18 Jay Caspary, Michael Goggin, Rob Gramlich, & Jesse Schneider, "Disconnected: The Need for New Generator Interconnection Policy," ACEG, Jan. 2021, https://cleanenergygrid.org/wp-content/uploads/2021/09/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.
19 NOPR at P 38.

ii. Very little large-scale regional and interregional transmission is getting built

Construction of new high-voltage lines has fallen steadily over the last decade.[20] In 2013, the nation peaked by adding approximately 4000 miles of high-capacity (+345 kilovolt or kV) lines. In that year, several lines that ERCOT, SPP, and California had proactively planned entered service. Figure 2 below shows the small number of projects since 2013. FERC's NOPR confirms that the miles of high-capacity lines being built annually have decreased.[21]

FIGURE 2 Miles of 345 kV+ Transmission Lines Added Each Year[22]



While aggregate spending has grown significantly from under $5 billion annually 20 years ago to around $25 billion per year now,[23] very little of that spending is on large long-distance regional or interregional lines. From 2013 to 2017, roughly one-half of the approved transmission investments were approved outside of regional planning and cost allocation processes—where the long-distance high-capacity lines are reviewed.[24] In non-RTO regions, no regionally-planned line have been approved to date.[25]

20 Jay Caspary, Michael Goggin, Rob Gramlich and Julia Selker, "Fewer New Miles: The U.S. Transmission Grid in the 2010s," Aug. 2022, pg 1, https://gridprogress.files.wordpress.com/2022/08/grid-strategies_fewer-new-miles.pdf.

21 NOPR at P 39-41.

22 Caspary, "Fewer New Miles," pg 1.

23 Johannes Pfeifenberger and John Tsoukalis, "Transmission Investment Needs and Challenges," June 2021, 3, https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Investment-Needs-and-Challenges.pdf.

24 Rob Gramlich and Jay Caspary, "Planning for the Future: FERC's Opportunity to Spur more Cost-effective Transmission Infrastructure," Americans for a Clean Energy Grid, January 2021, 25-26, https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf.

25 NOPR at P 39.

The common approach of reactively addressing each need incrementally may be the most expensive way to build transmission. For example, the value of comprehensive system upgrades can be seen in the difference in cost between interconnection costs associated with MISO MVP projects and some upgrade costs for generators in MISO's interconnection queue in recent years. In Western MISO, some current generator upgrade costs have been over $750 per kW, roughly double the interconnection costs related to MISO's MVP projects at $400 per kW—not to mention other system-wide benefits of the MVP projects.[26]

iii. Need for expanded transmission capacity

While investment in regional and interregional transmission lines has decreased, the need for transmission has increased, including due to:

- increased vulnerability to severe weather
- increasing load growth in many regions from, among other things, electrification and rising internet commerce
- changing customer demand for a different and cleaner set of domestic generation resources which are often located remotely from the customer's location

EXTREME WEATHER IS INCREASING THE NEED FOR TRANSMISSION

Severe weather events are increasing, with power outages from weather-related events increasing 67% since 2000.[27] Across multiple extreme weather events, studies have found that additional transmission between regions would have provided significant value and helped keep the lights on.[28] For example, during Winter Storm Uri, a study found that "each additional gigawatt of transmission ties between the Texas power grid (ERCOT) and the Southeastern U.S. could have saved nearly $1 billion while keeping the heat on for hundreds of thousands of Texans."[29] The situation was reversed during Winter Storm Elliot, with an analysis finding that the same connection could have transferred power from Texas to the Southeast, providing almost $100 million in value.[30]

26 Brattle-GS, "Transmission Planning for the 21st Century," 12.

27 Kenward, et al, "Power Off: Extreme Weather and Power Outages," Sept. 2020, https://www.climatecentral.org/climate-matters/power-outages.

28 See Goggin, "Transmission makes the power system resilient to extreme weather," Grid Strategies LLC, July 2021, https://cleanenergygrid.org/wp-content/uploads/2021/09/GS_Resilient-Transmission_proof.pdf.

29 *Id.* at 2.

30 Goggin, et al, "The value of transmission during Winter Storm Elliot," Feb. 2023, 1-2, https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf.

The Department of Energy's (DOE) 2023 Transmission Needs Study Draft affirmed the need for more transmission capacity in all regions of the country. The draft found additional transmission capacity is needed to connect a changing resource mix to increasing demand and maintain overall grid reliability, finding that almost all regions studied need to increase transmission deployment to meet demand growth.[31] It also found that moderate load and high clean energy scenarios required a 57% growth in transmission capacity by 2035 over today's system. High load and high clean energy scenarios necessitated doubling U.S. transmission capacity by 2040.[32]

Customer and commercial demand for clean energy is a major driver of today's changing resource mix. Some of the biggest companies in the world and the biggest utilities in the U.S. have significant clean energy goals and are driving demand for cleaner generation. From 2016-2022, commercial and industrial corporations signed deals for over 60 GW of clean energy generation. In 2022 alone, corporations signed contracts for nearly 17 GW of new clean energy generation. These companies are located across the U.S. and many are household names including, McDonald's, U.S. Steel Corporation, Comcast, BASF Corporation, Nestle, and Walmart.[33]

Utilities are also looking to procure cleaner generation. According to one tracker, "84% of U.S. customer accounts are served by an individual utility with a carbon-reduction target, or a utility owned by a parent company with a carbon-reduction target."[34] Distribution cooperatives, generation and transmission cooperatives, investor-owned utilities, and public power utilities have all set carbon-reduction goals, as have some of the biggest utilities across the U.S., such as Southern Company, Duke Energy, Dominion Energy, American Electric Power, Northwestern Energy, Idaho Power, Entergy Corporation, Ameren Corporation, and others.[35]

Several independent models and reports agree on the benefits of transmission and that the U.S. will need additional transmission capacity in the next few decades, including National Renewable Energy Laboratory (NREL), DOE, the Climate Institute, FERC, International Energy Agency (IEA), and the National Academies of Sciences, Engineering and

31 DOE, "National Transmission Needs Study: Draft for Public Comment," Feb 2023, 106, https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf. ("Needs Study")

32 Needs Study, 106-107.

33 Clean Energy Buyers Alliance," CEBA Deal Tracker 2016 through Q1 2023," 2023, https://cebuyers.org/deal-tracker/.

34 Smart Electric Power Alliance, "Utilities' path to a carbon-free energy system," accessed June 2023, https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.

35 *Id.*

Medicine.[36] The studies highlighted the need for and value of increasing high-capacity transmission capacity. A FERC staff report to Congress reiterates these conclusions and emphasizes that increasing high-capacity transmission investments will be necessary. The report states that

> high voltage transmission can improve the reliability and resilience of the transmission system by allowing utilities to share generating resources, enhance the stability of the existing transmission system, aid with restoration and recovery after an event, and improve frequency response and ancillary services throughout the existing system.[37]

New transmission infrastructure can be planned and developed in various ways – through local utility planning, integrated resource planning, merchant development, and regional planning by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

C. Proven best practices for successful planning and development

New transmission infrastructure can be planned and developed in various ways – through local utility planning, integrated resource planning, merchant development, and regional planning by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). The reforms proposed in the FERC Transmission Planning NOPR focus on improving regional planning practices, but the proposed rule has been pending since April 2022, and it is unclear when it will be issued. However, regions — and the transmission owners and operators within — can enact known best practices for transmission planning and development prior to FERC's final rule. Adopting best practices to plan and develop transmission can help to achieve a cost-effective and reliable grid to meet future needs. This report card measures effective planning and development of transmission and does not merely gauge compliance with existing tariffs.

Adopting best practices to plan and develop transmission can help to achieve a cost-effective and reliable grid to meet future needs.

36 American Council on Renewable Energy, "Macro Grid Initiative Resource Library," Accessed May 5, 2021, https://acore.org/mgi-library/.

37 FERC, "Report on Barriers and Opportunities for High Voltage Transmission," June 2020, https://www.congress.gov/116/meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf.

Transmission planning practices proven to work are proactive, multi-value, portfolio-based, and scenario-based. These practices effectively identify reliability and economic constraints and provide efficient and optimal solutions that can unlock competition, lower costs to consumers, and improve the overall reliability of the grid. A comprehensive analysis by The Brattle Group and Grid Strategies identifies the following best practices:

1. Proactively plan for future generation and load
2. Account for the full range of transmission projects' benefits and use multi-value planning
3. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning
4. Use comprehensive transmission network portfolios (as opposed to only line-specific assessments)
5. Jointly plan across neighboring interregional systems[38]

In addition to these practices, three additional best practices have historically contributed to successful transmission planning and development. These practices are

1. Early meaningful stakeholder engagement and input,
2. Consideration of all business models, and
3. Balanced governance of the regional planning process.

In PJM, if transmission expansion is conducted through the generation interconnection study process where one interconnection cluster is evaluated at a time, it approximately doubles the transmission-related interconnection costs of offshore wind generation compared to a more proactive regional study process.

These planning practices have been successfully deployed across the U.S. to build high-capacity transmission and integrate new generation while lowering overall customer costs.[39] MISO has previously applied proactive, multi-value, and scenario-based practices through their MVP, RIIA, and LRTP planning processes. Reviewing the net benefits of their MVP projects, MISO found that they could eliminate $300 mil-

38 Brattle Group & Grid Strategies, *Transmission Planning for the 21st Century*, 14 (2021), https://gridprogress.files.wordpress.com/2021/10/transmission-planning-for-the-21st-century-proven-practices-that-increase-value-and-reduce-costs-7.pdf.

39 *Id.* at 73-77.

lion in smaller reliability transmission projects by using transmission planning best practices.[40] In this same review, MISO found that the MVP projects provided benefits that were more than twice as large as their cost.[41] Transmission planning best practices have also been employed successfully in New York through their Public Policy Transmission Planning Process (PPTPP). California too, uses multi-value scenario-based planning and has recently added a study with a 20-year planning horizon.[42]

A comparison of PJM's 2021 offshore wind integration analysis with individual PJM generation interconnection study results also highlights the benefits of proactive transmission planning as it shows that if transmission expansion is conducted through the generation interconnection study process where one interconnection cluster is evaluated at a time, it approximately doubles the transmission-related interconnection costs of offshore wind generation compared to a more proactive regional study process. The PJM offshore wind study shows that the upgrades necessary to interconnect offshore wind generation also substantially benefit a large portion of the PJM footprint, reducing overall customer costs beyond the 50% reduction in onshore transmission investment cost.[43]

i. Summary of transmission planning best practices

1. Proactively plan for future generation and load

FERC's transmission planning NOPR proposes that transmission planners integrate realistic projections of the generation mix, load levels that include forecasts of end-use electrification, and load profiles for the life of a transmission line. Any models or estimates should be based on the best information available, which is often public. Planning should include both announced retirements and anticipated retirements. Planners should also consider other factors, including utilities' publicly declared decarbonization and clean energy objectives, laws related to generation requirements, and consumer preferences.

Furthermore, these projections should be incorporated into their long-term planning, extending at least 20 years into the future. According to standard economic policy, planning horizons for investments should be over an asset's lifetime. In its transmission planning NOPR, FERC recognized these issues and proposed incorporation of a 20-year planning horizon, which is nowhere near the 60+ year asset life but much longer than many cur-

40 MISO, "MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio," Sep. 2017, pg 11 & 33.

41 MISO, "MTEP17 Triennial Review," pg 4.

42 *Id.* at 15.

43 Brattle-Grid Strategies, *Transmission planning for the 21st Century*, 5.

rent practices.[44] In addition, many utilities conduct their integrated resource planning (IRPs) on a 20-year timeline allowing them to better plan for the changes occurring in their region.[45]

2. Account for the full range of transmission projects' benefits and use multi-value planning

Planners should quantify all of the needs and benefits of a new line across all three categories using multi-value planning, to ensure that the most cost-efficient transmission lines are being chosen. Order No. 1000 defined three broad categories of need: economic, reliability, and public policy.[46] Historically, when planners identified a new transmission line, they justified the need and benefits of the line under those three categories. However, the needs and benefits of new transmission lines often span all three categories, and forcing the evaluation of new lines into just one type misses some of the benefits. As a part of multi-value planning, regions should also incorporate an expanded set of transmission-related benefits. FERC proposed using these expanded benefits in its transmission planning NOPR, noting that they are beneficial for quantifying the multi-value benefits and needs of a new transmission line. The expanded transmission benefits proposed by FERC are:

a. avoided or deferred reliability transmission projects and aging infrastructure replacement;
b. either reduced loss of load probability or reduced planning reserve margin;
c. production cost savings;
d. reduced transmission energy losses;
e. reduced congestion due to transmission outages;
f. mitigation of extreme events and system contingencies;
g. mitigation of weather and load uncertainty;
h. capacity cost benefits from reduced peak energy losses;
i. deferred generation capacity investments;
j. access to lower cost generation;
k. increased competition; and
l. increased market liquidity[47]

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44 NOPR at P 54.

45 Rachel Wilson and Bruce Biewald, "Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans," Regulatory Assistance Project, 2013, 6, https://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf.

46 Advanced Notice of Proposed Rulemaking, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Docket No. RM21-17-000, 176 FERC ¶ 61,024 P 13-16 (proposed July 27, 2021).

47 Notice of Proposed Rulemaking, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Docket No. RM21-17-000, 179 FERC ¶ 61,028 P 185 (Issued Apr. 21, 2022), https://www.ferc.gov/media/rm21-17-000.

3. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning

Transmission planners should utilize scenario-based planning to sufficiently account for future uncertainty, such as a changing resource mix or extreme weather events. Proper scenario-based planning incorporates a range of possible futures that encompass real-world system conditions and challenging grid conditions. The scenarios selected should encompass trends in fuel prices, future load growth, future generation development and location, economic and public policy-driven changes to markets or the industry, and technological advancements. By assessing the effectiveness of the transmission system under different future scenarios, transmission planners can identify potential challenges and develop appropriate mitigation plans. The scenarios should have a sufficiently long-term time frame allowing planners to identify "least-regrets" solutions that can effectively fulfill the grid's needs across the different events.

4. Use comprehensive transmission network portfolios

Planners should evaluate transmission portfolios rather than consider projects individually. Evaluating portfolios of new proposed transmission lines allows planners to better address system's needs, lower overall costs, and simplify cost allocation when using portfolio-based cost recovery. A project-by-project evaluation method likely misses some efficiencies due to the highly interconnected nature of the grid and could lower support for regional cost allocation. Planners should also evaluate and optimize other resources alongside new proposed lines to ensure portfolios are comprehensive and provide the greatest overall efficiency. These resources can include storage, distributed energy resources, grid-enhancing technologies, different combinations of AC and DC transmission lines, reconductored lines, or new transmission lines to capture other network interaction benefits.

5. Jointly plan across neighboring interregional systems

The best practices outlined so far can be summarized as pro-active, multi-value, and scenario-based regional transmission planning. These same principles should also be applied when neighboring regions jointly plan interregional transmission lines. However, because current regional planning focus on planning transmission based on siloed categories of need—such as economic, reliability, or public policy reasons— current practices are not identifying transmission projects that meet different needs or provide multiple benefits across regions. Neighboring regions should be performing joint analysis and planning using a multi-value framework to ensure that interregional planning is identifying the most efficient and effective transmission lines. Proactive, multi-value, scenario-based interregional planning will increase grid resilience, provide geographic diversity benefits, and unlock additional economies of scale.

FERC did not include this category in its transmission planning NOPR but has raised it as a topic for future action.

FERC has shown significant interest in the value of interregional transfer capability and has requested information on the subject in preparation for a potential future rulemaking. Interregional transmission significantly benefits regions by increasing grid reliability and lowering power prices. Geographic diversity between regions means that increasing interregional transfers allows for the same level of reliability but with less generating capacity. In December 2022, FERC hosted a workshop on interregional transmission, where current FERC Chairman Phillips said that interregional transmission covers many of his priorities. "Reliability and resilience because it strengthens the voltage and minimizes the likelihood of load shedding and … affordability because it allows ratepayers to access lower cost generation, and … sustainability because it accommodates the demand for more clean energy," Phillips said. Commissioner Christie also voiced his support for interregional transmission in a July 2022 Joint Federal-State Task Force on Electric Transmission stating, "Interregional transfers do have reliability benefits, no question about it."[48] In a recent June 2023 Senate hearing, the head of NERC, the U.S.'s regulatory authority that oversees grid reliability, echoed these same sentiments stating that "interregional transmission is a terrific way to build resilience and reliability into the grid."[49]

One way that regions examine interregional transfer capability is through "affected system" studies with neighboring areas. A good example of this is the MISO-SPP Joint Targeted Interconnection Queue (JTIQ) process, which was largely focused on interconnecting generation at the border of MISO and SPP. However, the JTIQ process does not necessarily reflect interregional planning best practices. The process has only been reactive studies to interconnection queues and not proactive long-term multi-benefit studies. As outlined in this section, more proactive interregional planning is a best practice and should be implemented with each pair of neighboring regions.

48 FERC, "Fourth Meeting of the Joint Federal-State Task Force on Electric Transmission," July 20, 2022, https://www.ferc.gov/media/webcast-fourth-meeting-joint-federal-state-task-force-electric-transmission.

49 U.S. Senate Committee on Energy and Natural Resources, "Full Committee Hearing to Examine the Reliability and Resiliency of Electric Services in the U.S. in Light of Recent Reliability Assessments and Alerts," June 2023, https://www.energy.senate.gov/hearings/2023/6/full-committee-hearing-to-examine-the-reliability-and-resiliency-of-electric-services-in-the-u-s-in-light-of-recent-reliability-assessments-and-alerts.

ii. Summary of additional transmission planning best practices

For this report card, three additional best practices have contributed to the successful buildout of transmission in the past.

1. Stakeholder engagement and input

Any good transmission development begins with engagement with stakeholders. Planners should seek input and proactively engage with states, utilities, consumers, non-governmental organizations, Tribal Nations, Environmental Justice communities, and other stakeholders. They should provide sufficient opportunity to review, comment, and help develop regional and interregional transmission and cost allocation plans. Such engagement helps ensure that transmission lines are planned to maximize benefits and minimize negative impacts. Previous research from ACEG has demonstrated that for individual transmission lines, developers should undertake meaningful, respectful, and consistent engagement with all stakeholders involved in developing and siting a new transmission line.[50] At the regional level, transmission planners should apply the same principles. Regional transmission planners must maintain a transparent planning process that includes a variety of perspectives. Seeking input and proactively engaging with stakeholders in the beginning of a process guarantees that diverse perspectives are considered. As a result when decisions are made, stakeholder and transmission planners become more informed, achieve greater consensus, and face less litigation risk.

2. Consider All Business Models

Another feature of successful planning and development practices is the consideration of all business models, including third-party proposals, in its transmission planning process. Considering all business models ensures optimal planning and provides a more comprehensive assessment of all potential transmission needs and opportunities. Including consideration of third-party transmission proposals in the transmission planning process means regions will benefit from diverse perspectives, innovative solutions, and potential cost savings. Evaluating the benefits of all transmission proposals allows transmission planners to maximize the integration of new generation, improve grid reliability, and facilitate a more efficient transmission system.

50 Elisabeth Blaug and Nils Nichols, "Recommended Siting Practices for Electric Transmission Developers," Americans for a Clean Energy Grid, Feb. 2023, https://cleanenergygrid.org/wp-content/uploads/2023/04/ACEG-Report-Recommended-Siting-Practices-for-Electric-Transmission-Developers-February-2023.pdf.

3. Governance of the regional planning process

Balanced governance is another feature of good transmission planning and development. Effective governance requires roles for load and generation customers and representation for non-utility companies, transmission companies, non-governmental organizations (NGOs), and consumers. Their participation ensures diverse perspectives and expertise, fostering innovation, transparency, and accountability in transmission planning. In addition, involving representatives from the states in a region increases the likelihood of broad buy-in for regional planning and that the regional transmission planning process is aligned with wider policy objectives and regional and state priorities. In areas with organized markets, a well-structured and inclusive governance framework can promote an efficient transmission planning process.

3 Evaluation and Grading

The report card grades rely on a combination of backward-looking quantitative metrics to determine how regions' high-capacity transmission system have performed in recent years, as well as forward-looking qualitative metrics looking at regional planning methods and planned transmission lines to determine whether regions adequately prepare their high-capacity transmission system for the future.

The report card is intended to begin a constructive conversation around regional transmission planning practices across the U.S, highlighting where regional planning differences are leading to success and where there is room for improvement compared to best practices.

The grades are assigned based on objective measures, with a stated basis for each one so that others may try to replicate the grading. Because there can be subjectivity in the weighting given to various factors and the interpretation of data, a diverse advisory committee was assembled to minimize it. Nevertheless, reasonable people can disagree on individual grades or grading scales chosen. Individual metrics can be dissected differently and may not represent a region's performance alone. While no grade is sacrosanct, a region's overall mark reflects a fair representation of how each region performs compared to well-established best practices.

The ten regions are generally defined using the FERC Order No. 1000 planning region borders and ERCOT (see Figure 3 below). However, three Order No. 1000 planning regions

combined to create the Southeast region: SERTP, SCRTP, and FRCC. Each region was evaluated based on the actions of the regional planning entity as well as those of the states and utilities within those regions, as these entities can significantly influence transmission planning and development. ***Accordingly, grades are assigned to regions, not regional planning entities.*** For example, the Northwest region is defined by NorthernGrid's planning territory and is dominated by Bonneville Power Association. But the region received additional points on its regional grade for actions taken by individual utilities in the region, largely PacifiCorp and NV Energy, for their work on the Gateway and Greenlink Transmission projects, among others.

FIGURE 3 **FERC Order No. 1000 Planning Regions**[51]

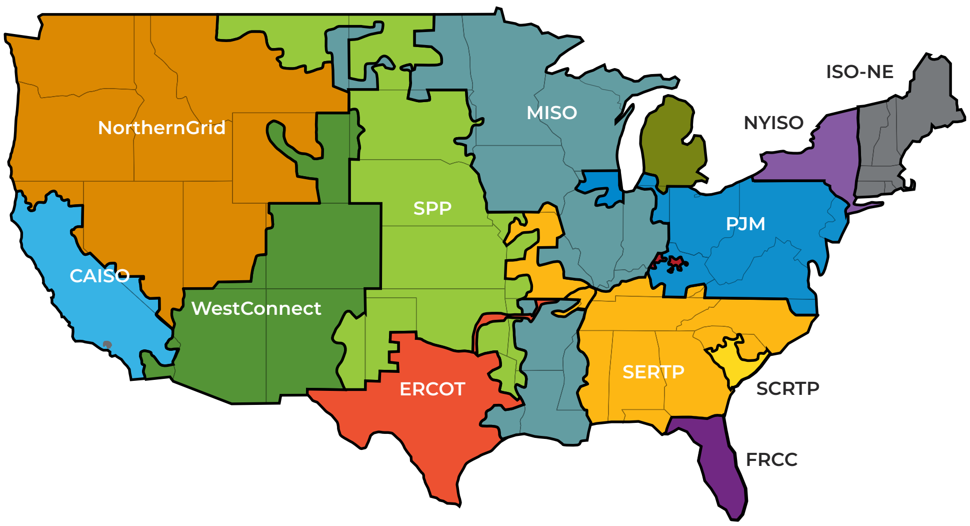

Figure 3 shows the borders of the regions used for grading in the report card. In the Southeast, SERTP, SCRTP, and FRCC were combined into one region, the Southeast. ERCOT was also included in the evaluation and is indicated in gray in Figure 3 above.

The sections below provide a summary grade for each region on the metric being evaluated, then a summary of the methodology used to evaluate the metric. Each section ends with a high-level overview and additional context for each region's grade.

51 FERC, "Regions Map Printable Version Order No. 1000," November 9, 2021, https://www.ferc.gov/media/regions-map-printable-version-order-no-1000.

A. Planning Methods and Best Practices

The grade for transmission planning is based on regional performance across eight transmission planning best practices. This metric accounts for 65% of the overall mark for the report card. It is heavily weighted because it is forward-looking and represents a region's potential to proactively plan for and develop its high-capacity transmission system to address a changing resource mix, increasing demand, and increased extreme weather events.

TABLE 2 Grade summary of transmission planning methods by region (Scale 0 to 4).

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
California/CAISO	4	4	3	4	3	3	3	3	59	91%	A-
Mid-Atlantic/PJM	2	0	0	0	1	3	2	3	42	65%	D
Midwest/MISO	3	4	4	4	3	3	2	3	59	90%	A-
New England/ ISO-NE	2	1	0	1	0	3	2	3	44	67%	D+
New York/NYISO	3	3	3	3	0	3	3	3	52	80%	B-
Northwest/ Northern Grid	1	0	0	3	1	0	2	0	37	57%	F
Plains/SPP	2	2	3	2	2	3	2	3	52	79%	C+
Southeast/SERTP, SCRTP, FRCC	0	0	0	0	0	0	0	0	29	45%	F
Southwest/ WestConnect	2	0	0	0	0	0	2	1	35	54%	F
Texas/ERCOT	1	1	0	1	0	3	1	3	42	65%	D

i. Summary of methodology for transmission planning best practices

Each region's planning methods was assessed for this metric and whether they followed established best practices. This metric is focused on a region's processes and whether those processes are sufficient to plan proactively for future uncertainty. The evaluation was largely based on each's regions most recent planning cycle, its tariff, and any additional actions taken by states or utilities within the region. Best practices and criteria used for evaluation were defined earlier in the report and outlined again in this section. The best practices used for evaluation roughly track what FERC has proposed in its Transmission Planning NOPR. For the assessment of this metric, each of the eight best practices was evaluated on a scale from 0 to 4, similar to a standard GPA grade scale one might see on a school report card.

Below are further details on each metric used to evaluate whether regions incorporate planning best practices in their transmission planning processes.

1. Proactive planning for future generation and load (10%)
    a. Projections of the anticipated generation mix
    b. Include customer and utility commitments or requirements
    c. Load levels and load profiles over the lifespan of the transmission investment
        i. End use electrification estimates
        ii. Extreme weather
    d. Estimated retirements
2. Scenario based (7.5%)
    a. Broad range of plausible futures, goes beyond NERC reliability sensitivities
    b. Including extreme weather
    c. Least regrets approach
3. Multi-value planning (10%)
    a. Are multi-value transmission projects considered?
    b. Are expanded benefits including reliability, resilience, anticipated congestion cost savings, lowest delivered cost of energy taking generation and transmission cost into account?
4. Portfolio of lines for optimal configuration (7.5%)
    a. Evaluate how portfolio of lines interact.
5. Proactive interregional planning with neighbors (7.5%)
    a. Is interregional planning following the proactive, scenario-based, best practices outlined above? Are interregional lines being built?
6. Stakeholder engagement (10%)
    a. Planning committees with diverse membership including consumer interests
    b. Transparency in planning documents

7. Consider merchant, all business models (5%)
    a. Are the benefits of third-party transmission proposals considered in the plans?
8. Balanced governance (7.5%)
    a. Are non-utility and/or transmission companies represented?
    b. Are states represented in any formal way?
    c. Are consumers and NGOs represented in the voting?

ii. Transmission planning methods and best practices regional evaluation

Even though Table 2 provides one summary grade for each region, not all detail and nuance is fully captured there. The section below provides a brief summary highlighting the unique aspects of transmission planning in each region and evidence supporting each grade.

California

TABLE 3 Assessment of California planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
California/CAISO	4	4	3	4	3	3	3	3	59	91%	A-

The California Independent System Operator's (CAISO) transmission planning and actions taken by California Public Utilities Commission (CPUC) have the greatest influence on transmission planning in the California region.

In recent years, CAISO and CPUC together have employed proactive, scenario-based, multi-value transmission planning. The 2022-2023 Transmission Plan used a base case which meets California's emissions target by 2032 and the plan included sensitivities for a high-electrification scenario and "out-of-ISO long-lead time resources."[52] The 20-year Transmission Outlook also incorporated projections of load growth due to electrification.[53]

52 CAISO, "Draft 2022-2023 Transmission Plan," 16, April 3, 2023, http://www.caiso.com/InitiativeDocuments/Draft-2022-2023-Transmission-Plan.pdf.

53 CAISO, *20-year Transmission Outlook*, 16-25 (2022), http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

CAISO used generation and load projections that meet California's 2045 public policy greenhouse gas reduction objectives including projected generation retirements and estimates of distributed resources.[54] For this, CAISO relies on the CPUC's capacity expansion model for renewable energy development and transmission to identify the least-cost resources. Using these projections, CAISO and the California Public Utilities Commission (CPUC) together co-optimize generation and transmission.[55] The process addresses transmission constraints, land-use impacts, environmental impacts, commercial interests, and other factors, all of which influence CAISO's transmission needs.[56] But, the results from this co-optimization are still divided up into the three planning silos of reliability, public policy, and economic for the transmission plan.

CAISO in its planning then sequentially considers reliability, public policy, and economic projects, and revisits previously identified projects to determine if an alternative project identified in a subsequent stage can meet the previously identified need and provide additional benefits not considered earlier in the process.[57] The final step in that sequential process is to determine if a transmission line is needed for economic reasons.[58] CAISO's benefit-cost analysis for economic projects can encompasses a broad range of benefits. For example, in the past, CAISO has used a multi-value, scenario-based Transmission Economic Assessment Methodology (TEAM) planning process.[59] The process considers various benefits, including production cost savings and reduced energy prices from both a societal and customer perspective, mitigation of market power, insurance value for high impact low-probability events, capacity benefits due to reduced generation investment costs, operational benefits, reduced transmission losses, and emissions benefits.[60] However, the 2023 Transmission Plan identified no new economic transmission projects.

California receives a higher grade than most regions for taking a relatively successful and innovative approach to interregional planning. In its 2021-2022 Transmission Plan, CAISO acknowledged that

54 CAISO, "2022-2023 Transmission Plan," May 2023, 22, http://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf.

55 *Id.*, 62-63.

56 See, CPUC, "Modeling Assumptions for the 2022-2023 Transmission Planning Process," Feb. 2022, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF.

57 CAISO, "Draft 2022-2023 Transmission Plan," 19-20.

58 *Id.*, 19-20.

59 Brattle-Grid Strategies, *Transmission planning for the 21st Century*, at 15.

60 CAISO, *2021-2022 Transmission Plan*, at 251-263 (2022), http://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.

> The interregional coordination process has not met expectations and noted there are opportunities to remove certain barriers, foster collaboration with state regulators, and promote more rigor in, and reporting on, interregional coordination efforts. Accordingly, the ISO is exploring a few alternative courses of action to pursue potential interregional opportunities in addition to complying with all expectations, responsibilities, and obligations under the ISO's interregional coordination tariff provisions.[61]

Since then, CAISO has implemented programs to enable import transmission from other regions, such as making the TransWest Transmission line a part of its balancing authority even though it is not in California, and the cost of the line will be paid for by off-takers.[62] Additionally, CAISO identified one interregional project in its 2022-2023 Draft. However, WestConnect did not identify any regional needs in its 2022-2023 planning cycle, so CAISO cannot consider it an Order No. 1000 interregional project, but CAISO did conduct regional policy and economic evaluations of the project.[63]

California also has extensive coordination in its transmission planning process with CAISO and California State Agencies including the California Energy Commission and the California Public Utilities Commission and has extensive stakeholder advisory committees that support the state and CAISO in its transmission planning.

Mid-Atlantic

TABLE 4 Assessment of Mid-Atlantic planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Mid-Atlantic/PJM	2	0	0	0	1	3	2	3	42	65%	D

In the Mid-Atlantic region, regional transmission planning is conducted by PJM which has balanced governance and has transmission planning committees and stakehold-

61 *Id.*, 13.

62 CAISO, "Decision on PTO Application for TransWest Express LLC," December 2022, http://www.caiso.com/Documents/DecisiononPTOApplicationforTransWestExpressLLC-Presentation-Dec2022.pdf.

63 CAISO, "Draft 2022-2023 Transmission Plan," 121-129.

er processes where input is received from a variety of parties.[64] PJM's planning process mostly happens through its Regional Transmission Expansion Planning (RTEP) and is conducted on a 15-year planning horizon.

Like many regions, PJM rolls up the local transmission plans (including supplemental projects) to use as baseline inputs to its RTEP process.[65] It does not independently review whether those local projects could be better addressed with regional options. PJM does not conduct proactive generation and load forecasting and does not independently model retirements over its 15-year planning horizon.[66] Thus it fails on the most basic test of planning for the anticipated resource mix. In 2022, PJM conducted a Grid of the Future Study which incorporated proactive generation and load forecasting that included end-use electrification (EVs), resource additions, and retirements.[67] The RTEP process itself does not include scenarios, but PJM has proposed a list of factors in its Master Plan White Paper that it could consider expand on the assumptions PJM currently uses in developing its long-range planning solutions, but are not currently utilized.[68] In its Grid of the Future Study, PJM also included future scenarios that looked at integrating future offshore wind and renewable development to meet state policy goals.[69] PJM would need to incorporate this information into its actual transmission plan to raise its grade.

PJM's planning process largely remains siloed into reliability, economic, and public policy planning. Economic projects have been limited because PJM's studies consider limited benefits that are largely focused on congestion reduction. PJM also studies public policy proposals separately. PJM does have "Multi-Driver Approach Project" which may be used to address multiple drivers as identified in PJM's RTEP process, but it is infrequently used to justify a project.[70] PJM studied multi-driver proposals for the first time in 2022. However, it solicited proposals, which were studied only using a 5-year-out base case, and only open to reliability and market efficiency solutions.[71] PJM evaluates lines separately in its transmission planning and does not consider supplemental projects as a portfolio.

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64 Eto, "Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans," Lawrence Berkeley National Laboratory, Sept. 2016, 7, https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf.

65 Local transmission plans are generally focused on maintenance and local reliability projects and are composed of smaller and lower-voltage lines.

66 PJM, "RTEP 2022," 3, March 14, 2023, https://www.pjm.com/-/media/library/reports-notices/2022-rtep/2022-rtep-report.ashx

67 *Id.*, 18-26.

68 PJM, "Enhanced 15-Year Long Term Planning (Master Plan) White Paper," May 2022, https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220525-long-term/enhanced-long-term-planning-discussion-document.ashx. "Interregional transfers and criteria," i-v.

69 "RTEP 2022," at 18-26.

70 *See* outline for a multi-driver approach, PJM, "PJM Manual 14B: PJM Region Transmission Planning Process," 2023, Sections 2.1.1 & 2.6, 31, 53, https://www.pjm.com/~/media/documents/manuals/m14b.ashx; Economic benefits are quantified in PJM, "Operating Agreement Schedule 6," Section 1.5.7, at 594, https://pjm.com/directory/merged-tariffs/oa.pdf.

71 "RTEP 2022," at 57-58.

In 2022, for the first time, PJM implemented the State Agreement Approach with New Jersey that was used to help plan for offshore wind development to meet New Jersey's RPS requirements. Generally, the State Agreement Approach allows a state or states to initiate a transmission planning and propose new transmission projects that help the state achieve its public policy goals. However, the state is required cover all costs incurred by the plan, even when customers outside the state benefit.

The Mid-Atlantic has limited interregional planning. PJM and MISO interregional planning is largely focused on operational reliability or short lead-time projects, such as Targeted Market Efficiency Projects, which are focused on congestion management.[72] In addition, PJM conducts limited interregional planning with New York or New England, despite the benefits that would arise related to offshore wind from proactive interregional planning for both regions.[73] The Mid-Atlantic does get some credit though for the first time having one interregional project get through the MISO-PJM Targeted Market Efficiency Process (TMEP), overcoming what is known as the "triple-hurdle."[74] For merchant developers' proposals, PJM studies them through the generator interconnection process, rather than the transmission planning process, which has led to complaints at FERC about delays. Currently, there are only a few lines under development, and they have taken a while to develop.[75]

Midwest

TABLE 5 **Assessment of Midwest planning methods**

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Midwest/MISO	3	4	4	4	3	3	2	3	59	90%	A-

72 TMEP interregional projects address historical congestion on market-to-market flowgates – a set of specific flowgates subject to joint and common market (JCM) congestion management. The JCM congestion management process is described in the MISO/PJM Joint Operating Agreement." "RTEP 2022," at 78; See RMI Comments on PJM/MISO IPSAC's Annual Issues Review – 3rd Party Issues and Feedback, February 17, 2023, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2023/20230217/third-party-issues.ashx.

73 Pfeifenberger, et al, "The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals," The Brattle Group, Jan. 2023, https://www.brattle.com/wp-content/uploads/2023/01/Brattle-OSW-Transmission-Report_Jan-24-2023.pdf.

74 PJM-MISO, "PJM-MISO IPSAC," December 2022, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2022/20221215/ipsac-presentation.ashx.

75 Ethan Howland, "SOO Green transmission project faces PJM obstacles: Are grid operators hindering the energy transition?," Jan. 2022, https://www.utilitydive.com/news/soo-green-pjm-grid-operators-helping-or-hurting-energy-transition/616966/.

The Midwest region comprises the Midcontinent Independent System Operator (MISO) and the states and utilities within MISO's borders. MISO's transmission planning process is called the MISO Transmission Expansion Plan (MTEP). The process happens annually and includes both near-term and long-term planning horizons. MISO collects local transmission plans from member transmission owners, which are considered potential solutions to the overall plan, not simply inputs.

As a part of MTEP, MISO started a process called the Reliability Imperative to address changes happening within its footprint.[76] One element of the Reliability Imperative is Long Range Transmission Planning.[77] MISO recognized that the change in the resource mix, including greater variable resources, and increased extreme weather events will require significant "regional transmission investment."[78] For the Long Range Transmission Planning (LRTP), MISO developed Future Scenarios. The MISO Futures Report outlines three future scenarios, the assumptions made for the scenarios, and summarizes the changes the MISO transmission grid will experience in the next twenty years if the Future Scenario proves accurate.[79]

The scenarios incorporate load growth and modifiers such as electric vehicles, demand response, energy efficiency, and distributed generation.[80] They also include state clean energy laws and utility publicly stated clean energy goals. Finally, the scenarios consider expected generation retirements and additions, some of which are drawn from utility-integrated resource plans (IRPs).[81] Many of these estimates were conducted by outside consulting groups or with national laboratory assistance.[82] These scenarios were intended "to address the uncertainty associated with planning transmission investments decades

MISO's Long Range Transmission Planning process, described above, is an excellent example of scenario-based planning that considered a wide range of factors.

76 *Reliability Imperative*, MISO, https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-reliability-imperative (last visited March 3, 2023).

77 *Id.*

78 *Id.*

79 Midcontinent Independent System Operator, *2021 MISO Transmission Planning Chapter 3.1 Long Range Transmission Planning Overview and Process* 7 (2021). https://cdn.misoenergy.org/MTEP21%20Chapter%203%20-%20Regional%20and%20Interregional%20Planning%20Studies581046.pdf.

80 Midcontinent Independent System Operator, MISO Futures Report, 7-43.

81 *Id.*

82 *Id.*, 82, 94.

out"[83] and demonstrate a range of future outcomes that impact transmission needs and are used to test proposed transmission investments to understand the potential value and robustness.[84]

MISO's Long Range Transmission Planning process, described above, is an excellent example of scenario-based planning that considered a wide range of factors. The LRTP process identified a portfolio of lines in Tranche 1 that met multiple values and MISO conducted a detailed cost benefit analysis.[85] The Tranche 1 projects are designed to "ensure a reliable and efficient regional and interregional transmission system that enables the changing portfolio across the near-term and long-term.[86] MISO has used scenario-based planning in the past with its Multi Value Projects, which included the CapX2020 and RGOS projects. These projects all employed "least-regrets" comprehensive regional network solutions rather than incremental upgrades which helped reduce the cost of generator interconnections along with many other quantified benefits.[87]

As discussed in the Mid-Atlantic section, MISO's planning with PJM is not proactive interregional planning, with only a few short-term projects arising from the process.[88] MISO does get some credit for its MISO-SPP Joint Targeted Interconnection Queue (JTIQ) planning process. The JTIQ process is not necessarily reflective of interregional planning best practices. It arose out of affected systems studies and is largely focused on generator interconnection requests from both MISO and SPP at their seam. The study identified regional upgrades and an interregional transmission project to help connect over 28 GWs of new generation.[89]

MISO has three main stakeholder committees that participate in transmission planning, including the sub-regional planning committees, the Planning Subcommittee, and the Planning Advisory Committee. MISO uses a comprehensive planning process that involves many stakeholders.[90]

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83 *Id.*

84 *Id.*

85 MISO, "LRTP Tranche 1 Portfolio Detailed Business Case," June 2022, https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf.

86 MISO, "Long Range Transmission Planning: Tranche 1," slide 5 (2022), https://cdn.misoenergy.org/20220325%20LRTP%20Workshop%20Item%2002%20Tranche%201%20Portfolio%20and%20Process%20Review623633.pdf.

87 Brattle-Grid Strategies, *Transmission planning for the 21st Century*, at 7; MISO, "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary," at 5-6; MISO, "Multi Value Project Portfolio Results and Analyses," at 5.

88 RMI Comments on PJM/MISO IPSAC's Annual Issues Review – 3rd Party Issues and Feedback.

89 *See* MISO-SPP, "Joint Targeted Interconnection Queue Study," Mar 2022, https://cdn.misoenergy.org/JTIQ%20Report623262.pdf.

90 MISO, "Stakeholder Entities," accessed May 2023, https://www.misoenergy.org/stakeholder-engagement/committees/.

The Midwest would have a higher overall grade on transmission planning best practices if its planning was not resulting in significantly different outcomes between MISO North and MISO South subregions. Generally, MISO North scored high on scenario-based, multi-value transmission planning because of its LRTP practices described above. However, MISO South lowered the score in each of those three categories.

New England

TABLE 6 **Assessment of New England planning methods**

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
New England/ ISO-NE	2	1	0	1	0	3	2	3	44	67%	D+

The New England region encompasses the territory of ISO New England (ISO-NE) and includes the New England states and utilities. New England's transmission planning has traditionally focused on reliability and been reactive, rather than proactive. The region did build a significant amount of transmission in the early 2000s, which reduced a large amount of congestion in energy markets and capacity markets.[91] This buildout means New England still has some headroom on the transmission system, and congestion in the energy and capacity markets remains low. However, there is insufficient capacity for new generation in remote areas such as Northern Maine until transmission is expanded.

ISO-NE regional transmission planning must happen at least once every three years through a process called the Regional System Plan (RSP).[92] The plan occurs over a 5 to 10-year planning horizon.[93] To begin the process ISO-NE determines load, resource additions, and retirements. ISO-NE conducts its own load forecast (capacity, energy, load, and transmission) that includes estimates of end-use electrification.[94] For generation additions, the 2021 RSP accounts for new resource additions through its resource adequacy

91 ISO-NE, "Our History," accessed May 2023, https://www.iso-ne.com/about/what-we-do/history/.

92 ISO-NE, "OATT Attachment K Regional System Planning Process," March 2023, pg 14, https://www.iso-ne.com/static-assets/documents/2021/07/sect_ii_att_k.pdf.

93 *Id.*, 16.

94 ISO-NE, "2021 Regional System Plan," November 2021, Chapter 3, https://www.iso-ne.com/static-assets/documents/2021/11/rsp21_final.docx.

process. The resource adequacy process incorporates new resources or retirements that have cleared the Forward Capacity Market, and resources that have received contracts through states.[95] The ISO is beginning to consider extreme weather events but does not include any extreme weather scenarios in its 2021 RSP.[96]

ISO-NE's transmission planning study process conducts reliability, economic, and public policy studies needs assessments in separate silos. Economic studies generally must be requested by stakeholders and have largely been informational which ISO-NE states can help identify key regional issues.[97] This process has resulted in no economic transmission lines being built in the region. Though ISO-NE does note that "[r]eliability transmission upgrades have resulted in significant market-efficiency benefits by reducing congestion and out-of-merit operating costs."[98] In 2023, ISO-NE also changed its tariff to reflect updates to its economic study process to include four scenarios, but two are for informational purposes.[99] For public policy transmission planning, there were no studies initiated in 2017 or 2020 because the states through NESCOE determined there were no state or federal public policy requirements driving transmission needs.[100] Transmission planning in New England has historically focused on generation interconnection and network reliability. However, ISO-NE does recover cost for network transmission costs based on the entire ISO-NE portfolio, utilizing postage stamp cost recovery.[101]

In terms of interregional planning, New England has done very little to coordinate with New York despite a rapidly growing amount of offshore wind hoping to interconnect close to the seam of both regions and no new interregional projects have been identified to date.[102] As an ISO, New England has a robust stakeholder process and well balanced governance.[103]

Proactive planning and action around transmission development in New England is contingent on the New England states. For example, like the Mid-Atlantic region, ISO-NE is in

95 *Id.*, Chapter 4, 15-19.

96 *Id.*, 20, 67.

97 ISO-NE, "Economic Studies," accessed June 2023, https://www.iso-ne.com/system-planning/system-plans-studies/economic-studies.

98 ISO-NE, "2021 Regional System Plan," at 21.

99 ISO-NE, "OATT Attachment K Regional System Planning Process," Section 17; Benefits considered for Market Efficiency Upgrades are largely focused on production cost savings. ISO-NE, "OATT Attachment N," 2023, 497, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

100 ISO-NE, "2021 Regional System Plan," at 88.

101 Brattle-Grid Strategies, "Transmission Planning for the 21st Century," at 15.

102 *See*, ISO-NE, "2021 Regional System Plan," at 82-84.

103 Eto, "Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans," Lawrence Berkeley National Laboratory, Sept. 2016, 7, https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf.

the process of conducting a 2050 Transmission Study at the request of the New England states that includes proactive generation, load estimates, and future scenarios.[104] The study is still ongoing. Additionally, the New England states are pursuing federal funding for their joint offshore wind transmission initiative.[105]

New York

TABLE 7 Assessment of New York planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
New York/NYISO	3	3	3	3	0	3	3	3	52	80%	**B-**

The New York region's transmission planning is primarily influenced by two entities, the New York Independent System Operator's (NYISO) along with actions taken by the state of New York. The New York Transmission Planning Process is the Comprehensive System Planning Process (CSPP). It consists of four planning processes, the Local Transmission Planning Process (LTPP), the Reliability Planning Process (RPP), the Congestion Assessment and Resource Integration Study (CARIS), and the Public Policy Transmission Planning Process (PPTPP), which are conducted together on a biannual basis.[106] Other than the Public Policy Planning Process, these planning efforts focus solely on reliability and individual (incremental) needs.

The process starts with the local transmission planning processes. Planners then use its results as inputs for the reliability planning process. The reliability study uses a relatively conservative base case for generation and retirements, mostly focused on planned generation.[107] The load forecast comes from NYISO's Gold Book and does include end-use

104 ISO-NE amended its OATT Attachment K planning process to include a long-term, state-led, proactive scenario-based planning process with proactive modeling of future load and generation additions. ISO-NE, "2050 Transmission Study Preliminary Assumptions and Methodology for the 2050 Transmission Study Scope of Work - Revision 2," slides 5-7, November 2021, https://www.iso-ne.com/static-assets/documents/2021/12/draft_2050_transmission_planning_study_scope_of_work_for_pac_rev2_redline.pdf.

105 https://newenglandenergyvision.files.wordpress.com/2023/01/joint-state-innovation-partnership-for-offshore-wind-concept-paper.pdf

106 NYISO, "Comprehensive System Planning Process (CSPP)," accessed May 2023, https://www.nyiso.com/planning#:~:text=The%20NYISO%20CSPP%20is%20comprised,Public%20Policy%20Transmission%20Planning%20Process.

107 NYISO, "Reliability Planning Process Manual," 2022, 17-22, https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf.

electrification.[108] NYISO can include other scenarios for the Reliability Needs Assessment, but they are for informational purposes.[109] Next, planners use the reliability planning process and short-term reliability process base cases as the inputs for the economic and public planning processes, which are conducted over a 20-year planning horizon.[110] Generally, solutions are siloed between the three planning processes. For example, when reliability needs are identified, proposed solutions are not also evaluated for economic benefits. The economic study's main benefit metric is congestion/production cost.[111]

NYISO does have a proactive, scenario-based planning process under the Public Policy Transmission Planning Process.[112] The Public Policy Process incorporates multiple cases and scenarios over a 20-year evaluation time horizon and uses reliability, economic, and public policy metrics to evaluate projects and select a transmission solution. For example, New York, in its 2019 public policy transmission plan, studied transmission lines using three scenarios, including a base case, Clean Energy Standard, and Retirement Scenario, and that same case, including a carbon price. New York also included a separate analysis where the capacity zones were changed because of a change in generation mix and the building of the AC Public Policy Transmission Projects.[113] Public policy projects are evaluated across ten categories of metrics that include project cost and cost containment, operability, expandability, performance, and systemwide economic benefits to production costs, installed capacity costs, and environmental emissions. Those metrics do not include benefits to meeting system reliability needs, such as resource adequacy and transmission security.

This planning process is why New York is graded relatively well. It has identified significant high-voltage transmission needs built in recent years, so it has been successful in planning and developing transmission. The process is also unique among the regions because it requires a formal determination by the New York Public Service Commission (NYPSC) as to which public policy requirements NYISO should be used in its planning study.[114] New York also incorporates independent business models and has several sig-

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108 See NYISO, "Gold Book 2022 Load & Capacity Data," 2022, https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf; NYISO, "2022 Reliability Needs Assessment (RNA)," 2022, https://www.nyiso.com/documents/20142/2248793/2022-RNA-Report.pdf/b21bcb12-d57c-be8c-0392-dd10bb7c6259?t=1669046152728

109 NYISO, "Reliability Planning Process Manual," 23.

110 NYISO, OATT Attachment Y 31.3.1.3.2, at 1666, https://www.nyiso.com/regulatory-viewer.

111 Benefits may also include estimates of reductions in losses, LBMP load costs, generator payments, ICAP costs, Ancillary Services costs, emission costs, TCC payments, and energy deliverability, but are informational only. NYISO, OATT Attachment Y 31.3.1.3.4&5, 1667-1671.

112 Brattle-Grid Strategies, "Transmission Planning for the 21st Century," at 15.

113 See NYISO, "AC Transmission Public Policy Transmission Plan," April 2019, at 14, 19, 25, https://www.nyiso.com/documents/20142/5990681/AC-Transmission-Public-Policy-Transmission-Plan-2019-04-08.pdf/23cbba74-a65e-66c2-708e-eaa0afc9f789; Brattle-GS, "Transmission Planning for the 21st Century," at 15.

114 NYISO, OATT Attachment Y, 31.4.2.1.

nificant transmission lines under development, some through the New York Power Authority.[115]

NYISO does very little proactive interregional transmission planning. In its ANOPR comments, NYISO acknowledged this reality, "to date, no interregional transmission project has been selected under the planning protocol and regional planning processes for cost allocation and cost recovery."[116] As an ISO, NYISO has fairly balanced governance and a robust stakeholder process, including planning committees with a diverse membership including consumer interests. There is generally more transparency in planning documents.

Northwest

TABLE 8 Assessment of Northwest planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Northwest/ Northern Grid	1	0	0	3	1	0	2	0	37	57%	F

In the Northwest, there is no RTO or ISO. The region is defined by NorthernGrid's planning footprint, the FERC Order No. 1000 transmission planning entity. However, a significant portion of the transmission planning and development is led by individual utilities with minimal transparency or regional coordination. The Northwest also includes Bonneville Power Administration (BPA). BPA's role is unique as it owns 80% of the region's high-voltage transmission system. BPA voluntarily adopted FERC open access and tariff standards, following Orders 888, 890, and 1000 on transmission service and planning. However, BPA lacks transparency in its transmission planning processes and does not conduct proactive, scenario-based, or multi-value transmission planning.

As the Order No. 1000 transmission planning authority, NorthernGrid is an entity creat-

115 NYPA, "Major Projects Underway," accessed May 2023, https://www.nypa.gov/power/transmission/transmission-projects#projects-underway.

116 NYISO, "Comments in response to the Commission's Advance Notice of Proposed Rulemaking on Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," October 2021, at 56, https://nyisoviewer.etariff.biz/ViewerDocLibrary//Filing/Filing1835/Attachments/20211012-NYISOCmnts-ANOPR-RM2117000.pdf.

ed by its members. It includes investor-owned FERC jurisdictional utilities and publicly owned utilities that are not FERC-jurisdictional and voluntarily participate. NorthernGrid's planning process is largely driven by its members.[117] NorthernGrid does not have a role for state regulators and other non-utility stakeholders. Instead it relies on its members, who hold all the decision-making authority. Additionally, even though BPA is not a required participant, it maintains a significant role in NorthernGrid.

Proactive planning for future generation and load or using robust scenario-based planning at a regional level is not taking place in the Northwest. Current planning is focused on resolving NERC and WECC violations. It is designed to meet Order 890 and 1000 planning requirements, but not intended to evaluate market efficiencies,[118] and is highly dependent on the transmission projects submitted by its members and third parties.[119] In its 2022-2023 planning process, NorthernGrid noted that most of its future generation and load data comes from utility IRPs. However, it is up to the discretion of the utility what is reported.[120] In addition, data submitted to NorthernGrid is not always consistent, which has resulted in members presenting varied future scenarios. While some utilities include resource additions and retirements from a robust IRP process, others submit data based only on the current queue.[121] Data submissions and projects are then incorporated into a power flow model to determine if system reliability and transmission needs are met.[122] For its base cases, the only scenario it evaluates, NorthernGrid uses the WECC Anchor Data sets, which only extend out 10-years. It modeled no extreme weather events, such as the 2021 heat dome.[123]

The 2022-2023 transmission study scope does include a portfolio analysis that "evaluates the proposed regional transmission projects independently and in different regional combinations,"[124] However, most of the proposed transmission projects from North-

117 *See* NorthernGrid, *Approved Study Scope for the 2023-2023 NorthernGrid Planning Cycle*, 6-7.

118 *Id.*, 21-22.

119 *Id.*, 20; NorthernGrid, "Final Study Scope for the 2020-2021 NorthernGrid Planning Cycle." 9 (2020), https://www.northerngrid.net/private-media/documents/Appendix_B_NG_Study_Scope_clean.pdf.

120 NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle*, 9, 15, 20.

121 NorthernGrid, *Proposed Study Scope for the 2022-2023 NorthernGrid Planning Cycle 9*, https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_DRAFT.pdf. In the current planning cycle, Puget Sound Energy (PSE) submitted 4,090 MW of resource additions and 370 MW in retirements to NorthernGrid, which is similar to its IRP findings. Puget Sound Energy, 2021 PSE Integrated Resource Plan 2-6 (2021), https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/IRP21_Chapter%20Book%20Compressed_033021.pdf. While Portland General Electric (PGE) submitted 19 MW of resource additions and 0 MW retirements to NorthernGrid, despite stating in its IRP a need for 2,800 MW of new resources by 2030 and an exit from Colstrip by 2025. *PGE plans to nearly triple clean resources by 2030*, PGE (Oct. 15, 2021), https://portlandgeneral.com/news/2021-10-15-pge-plans-to-nearly-triple-clean-resources-by-2030. Renewable Northwest, "Comments in response to the Commission's Notice of Proposed Rulemaking Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," August 2022, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220817-5001&optimized=false.

122 *Id.*

123 Id, 5, 21.

124 *See* NorthernGrid, *Approved Study Scope for the 2023-2023 NorthernGrid Planning Cycle*, at 21, 28.

ernGrid members in the 2021-2022 and 2022-2023 plans were intended to support local load service and reliability. In the final 2021-2022 Regional Transmission Plan, none of the non-incumbent or interregional transmission projects were selected.[125] In addition, NorthernGrid's interregional planning with WestConnect and CAISO appears to be focused on addressing potential affected systems issues and has not yet produced a comprehensive plan as other regions have, and no interregional lines are being considered in the 2022-2023 plan.[126]

The Northwest as a region earns points for significant high-voltage transmission development at the utility level. PacifiCorp and NV Energy are both members of NorthernGrid, and both have undertaken the development of substantial high-voltage transmission projects. PacifiCorp has been working on its Gateway Transmission Projects, which expand over a utility service territory larger than some of the other regions. To plan projects, PacifiCorp utilized proactive generation and load forecasting. Additionally, NV Energy has been developing its Greenlink projects to access new renewable energy zones. The Berkshire Hathaway Energy utilities are unique in their geographic size and scope, and unlike most utilities in the country, can build high-capacity long haul transmission within their footprints – including cost allocation and recovery.

Plains/SPP

TABLE 9 Assessment of the Plains region planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Plains/SPP	2	2	3	2	2	3	2	3	52	79%	C+

The Plains region is defined by the Southwest Power Pool (SPP) planning region and states and utilities within SPP's boundaries. Historically, the Plains region has had some promising components within its transmission planning.

125 BPA, *Attachment K Planning Process*, at 41.

126 *See* Northwest & Intermountain Power Producers Comments on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional, Docket No. RM21-17-000, 176 FERC ¶ 61,024 (2021) at 4-5, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=8e249000-1920-ccf9-916d-7c76b0d00000; *See* also Public Interest Organizations Comments on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional, Docket No. RM21-17-000, 176 FERC ¶ 61,024 (2021) at 45-49, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=60f22f6b-c401-c6bc-b293-7c76ae400001. *See* NorthernGrid, *Approved Study Scope for the 2023-2023 NorthernGrid Planning Cycle*, at 3, 22.

SPP conducts its annual ITP on a 10-year planning horizon.[127] A 20-year assessment is conducted once every five years and is informational only.[128] One strength of SPP transmission planning is that it conducts both regional and local planning simultaneously when other regions often have separate processes that include local transmission planning as inputs to regional planning.[129] SPP does conduct its own generation and load planning to assess transmission needs. However, it has acknowledged that its previous forecasts have been too conservative and not adequately captured the changing resource mix, and it is currently working to improve this part of its planning.[130]

SPP uses scenario-based planning for its economic transmission planning studies. In the 2021 ITP, SPP used only two scenarios to evaluate economic transmission projects— a reference case and an emerging technologies case that included EV electrification.[131] SPP's overall planning process allows for multiple benefits to be considered but still largely silos planning and seems to optimize for reliability and economic transmission categories, mainly ignoring the public policy category.[132] SPP does conduct evaluations that include expanded transmission benefits considerations through its periodic Regional Cost Allocation Review (RCAR) assessment that estimates the economic value of all ITP-approved projects and uses many of the expanded transmission benefit metrics.[133] It uses a version of portfolio planning by grouping proposed transmission lines into a "consolidated portfolio," where projects are studied together to determine whether there is a more efficient configuration.[134] But SPP still examines potential economic transmission lines individually and does not account for other economic lines in the portfolio.[135]

SPP gets some credit for its MISO-SPP Joint Targeted Interconnection Queue (JTIQ) interregional planning process. The JTIQ process is not necessarily reflective of all planning best practices. It arose from affected systems studies and primarily focused on generator interconnection requests from both MISO and SPP at their seam. The study identified in-

127 *See* SPP, "Integrated Transmission Planning Manual," 2022, https://www.spp.org/documents/60911/itp%20manual%20version%202.10.pdf.

128 SPP, "Integrated Transmission Planning," accessed June 2023, https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/.

129 SPP, "Integrated Transmission Planning Manual," 32; SPP, "2021 Integrated Transmission Planning Assessment Report," March 2022, 73, https://www.spp.org/documents/66813/2021%20itp%20report%20%20v1.0%20redlined.pdf.

130 SPP observed in its 2019 ITP, "Previous ITP assessments have been conservative in forecasting the amount of renewable generation expected to interconnect to the grid. When the studies were completed, installed amounts had nearly surpassed 10-year forecasts." SPP, "2020 Integrated Transmission Planning Assessment Report, October 2020," at 2, https://www.spp.org/documents/63434/2020%20integrated%20transmission%20plan%20report%20v1.0.pdf.

131 SPP, "Integrated Transmission Planning Manual," 2022.

132 No public policy needs were identified. SPP, "2021 Integrated Transmission Planning Assessment Report," 69.

133 SPP, "RCAR III Draft Report," 2022, https://www.spp.org/Documents/67896/RCAR%20III%20Draft%20Report.zip.

134 SPP, "ITP Transmission Manual," Feb. 2022, 39-43, https://www.spp.org/documents/60911/itp%20manual%20version%202.10.pdf.

135 SPP, "2021 Integrated Transmission Planning Assessment Report," 75-78.

terregional transmission projects to help connect over 28 GWs of new generation.[136] SPP could also better incorporate merchant developers into its planning. Currently, SPP has only a few merchant lines under development, and they have taken a while to develop.

As an RTO, SPP has more balanced governance[137] as well as a significant stakeholder process that includes multiple committees and working groups, such as the Strategic Planning Committee, the Transmission Working Group, the Economic Studies Working Group, the Cost Allocation Working Group, the Regional State Committee (RSC), and the Markets and Operations Policy Committee. SPP is also working on a stakeholder process, the Consolidated Planning Process. This process works on reforming and consolidating of the transmission planning and generator interconnection processes.[138]

Southeast

TABLE 10 Assessment of Southeast planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Southeast/SERTP, SCRTP, FRCC	0	0	0	0	0	0	0	0	29	45%	F

The Southeast has three FERC Order No. 1000 regional transmission planning entities: Southeast Regional Transmission Planning (SERTP), South Carolina Regional Transmission Planning (SCRTP), and Florida Reliability Coordinating Council (FRCC). These entities largely aggregate their utilities' plans and periodically brief stakeholders without seeking significant input and often not sharing sufficient data, methods, or assumptions to enable an assessment of the projects.

FRCC

136 *See* MISO-SPP, "Joint Targeted Interconnection Queue Study," Mar 2022, https://cdn.misoenergy.org/JTIQ%20Report623262.pdf.

137 Eto, "Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans," Lawrence Berkeley National Laboratory, Sept. 2016, 7, https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf.

138 SPP has nine stakeholder groups working on its ITP process which are composed of members, liaison members, industry specialists and consultants who discuss the assumptions and facilitate a thorough evaluation. SPP, 2022 Integrated Transmission Planning Assessment Report, 8-9; SPP, "Consolidated Planning Process Task Force Meeting Materials," accessed May 2023, https://www.spp.org/spp-documents-filings/?id=297513.

The FRCC planning process, known as the Regional Transmission Planning Process, happens on a two-year cycle and contains two separate processes, the Annual Transmission Planning Process (ATPP) and the Biennial Transmission Planning Process (BTPP).[139] The ATPP consolidates FRCC member local transmission plans and focuses on reliability.[140] FRCC relies on 10-Year Site Plans submitted by individual FRCC members for generation and load which are used to develop its bases cases for reliability planning.[141] The BTPP encompasses FRCC's economic and public policy planning by evaluating "cost effective or efficient regional transmission solutions," or "CEERTS" projects.[142] The process relies on submissions of economic or public policy proposals, and according to FRCC's website there were no economic or public policy projects were considered for the 2023-2024 planning cycle or for the 2021-2022 cycle.[143] If a CEERTS project was identified, it will be evaluated using a basic cost-benefit analysis where a proposed CEERTS project cost must be less than the cost of the alternative local projects it would replace, plus the changes to line losses.[144] Overall, the FRCC planning process is difficult for stakeholders to participate in and has not resulted in a regional transmission investment.[145]

SERTP

In SERTP, a regional transmission plan is produced annually, largely consolidating members' local transmission plans.[146] The planning process is a "bottom-up" process that happens over a 10-year horizon. SERTP relies on member utilities' local transmission plans for generation additions, retirements, and load forecasts for development of its power flow model base cases, which are used for determining system reliability.[147] In its 2022 regional

139 FRCC, "Regional Transmission Planning Process FRCC-MS-PL-018," 2022, 4-5, https://www.frcc.com/order1000/_layouts/15/WopiFrame.aspx?sourcedoc=%7BAC2749A7-9B10-4FD8-87A0-7F5C8907DB02%7D&file=FRCC-MS-PL-018_FRCC_Regional_Transmission_Planning_Process.pdf&action=default.

140 *Id.*, 5, 7.

141 *Id.*, 10-13.

142 *Id.*, 5.

143 FRCC, "FRCC Proactive Planning Results and CEERTS Proposal Solicitation Announcement," April 2023, https://www.frcc.com/order1000/Lists/Announcements%20%20Regional%20Projects%20%20Order%201000/DispForm.aspx?ID=46&Source=https://www.frcc.com/order1000/Lists/Announcements%20%20Regional%20Projects%20%20Order%201000/AllItems.aspx&ContentTypeId=0x0104003AB6C5EFE8B9DF48AF25DDC3AA36DCE8; FRCC, "Results of FRCC 2023-2024 BTPP Public Policy Planning Submissions," February 2023, https://www.frcc.com/order1000/Lists/Announcements%20%20Regional%20Projects%20%20Order%201000/DispForm.aspx?ID=43&Source=https%3A%2F%2Fwww%2Efrcc%2Ecom%2Forder1000%2FLists%2FAnnouncements%2520%2520Regional%2520Projects%2520%2520Order%25201000%2FAllItems%2Easpx&ContentTypeId=0x0104003AB6C5EFE8B9DF48AF25DDC3AA36DCE8; FRCC, "Announcements - Regional Projects & Order 1000," accessed June 2023, https://www.frcc.com/order1000/Lists/Announcements%20%20Regional%20Projects%20%20Order%201000/AllItems.aspx.

144 FRCC, "Regional Transmission Planning Process FRCC-MS-PL-018," 2022, 24.

145 *See* Southern Environmental Law Center Pre-Technical Comments on Transmission Planning and Cost Management, Docket No. AD22-8-000 (2022), at 34-37, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2f889473-51c5-c170-8538-8346a2d00000.

146 *See* SERTP, "Regional Transmission Plan & Input Assumptions Overview," December 2022, http://www.southeasternrtp.com/docs/general/2022/2022_Regional_Transmission_Plan_and_Input_Assumptions_Final_Non-CEII.pdf

147 *Id.*, 14-19; Southern Companies, "Open Access Transmission Tariff, Attachment K," 2023, 560, http://www.oasis.oati.com/SOCO/SOCOdocs/Southern-OATT_current.pdf.

plan, SERTP only identified two potential regional lines, and none were selected.[148] For SERTP's regional transmission plan, regional projects are analyzed case by case to see if they address regional transmission needs by displacing local projects. If a regional line could displace a local project, the cost of the regional project is compared to the cost of any potential local projects contained in the baseline regional transmission plan that might be replaced, and does not consider the broader benefits provided by the regional transmission line.[149] As a result of the limited benefits considered, no regional lines have been selected. Economic planning and public policy planning are conducted in a separate process. For the economic study, SERTP may conduct up to five studies that look at bulk-power flows between two areas submitted by stakeholders. However, the results are mostly informational.[150] SERTP also allows stakeholders to submit proposed studies of public policy driven needs, but no public policy proposals were submitted between 2017-2022.[151]

SCRTP

SCRTP has a similar regional transmission planning process to SERTP, except it occurs over a two-year planning cycle and conducts local and regional transmission planning.[152] SCRTP's plan, however, also essentially rolls up local transmission plans. SCRTP relies on utilities for load, and existing and planned generation.[153] These inputs are used to generate base cases which are focused on reliability planning and meeting NERC requirements.[154] Economic and public policy transmission proposals are separately studied if SCRTP decides to review a submission from a stakeholder. Similar to SERTP, SCRTP will conduct up to five economic transmission planning studies of power transfers that are informational in nature.[155] If a regional line were selected, the benefit-cost analysis for SCRTP is similar to SERTP in that it is essentially a cost comparison between the regional line cost, any required upgrades, and power losses compared to canceled projects, re-

148 The 2022 Transmission Plan only identified two regional lines that were considered individually for the impacts. *See* SERTP, 2022 Regional Transmission Analyses, November 2022, http://www.southeasternrtp.com/docs/general/2022/2022_SERTP_Regional_Transmission_Planning_Analyses_Summary_Final.pdf.

149 *Id.*, 12.

150 SERTP, "2022 Economic Planning Studies," 2022, 3, http://www.southeasternrtp.com/docs/general/2022/2022_SERTP_Economic_Study_Results_Final.pdf.

151 SERTP, "SERTP – 1st Quarter Meeting," March 2022, 28, http://www.southeasternrtp.com/docs/general/2022/2022-SERTP-1st-Qtr-Presentation-FINAL.pdf; See also Southern Environmental Law Center Pre-Technical Comments on Transmission Planning and Cost Management, Docket No. AD22-8-000 (2022), 14-15, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2f889473-51c5-c170-8538-8346a2d00000.

152 Dominion Energy, "Attachment K Transmission Planning Process," 7-12, https://www.scrtp.com/assets/pdfs/home/attachment-k-dominion-energy.pdf.

153 *See* SCRTP, "Base Cases," last accessed March 9, 2023, https://www.scrtp.com/base-cases.html.

154 *Id.*

155 Dominion Energy, "Attachment K Transmission Planning Process," 16-20.; See also SCRTP, "Stakeholder Meeting Presentation," May 2020, https://www.scrtp.com/assets/pdfs/meeting-archives/scrtp-meeting-2020-05-05-presentation.pdf.

duction in cost to existing projects, avoided projects, and decrease in power losses.[156] For SCRTP, no regional projects were considered in 2022.[157]

There is very little proactive interregional transmission planning for all three regions, at least not publicly. Interregional planning appears is focused on operational reliability, and no interregional lines have been built since Order No. 1000.[158] In addition, the Southeast does not consider all business models, with no independent transmission developer having ever pre-qualified for a SERTP planning cycle,[159] and the Southern Cross Transmission Line being one of the only major independent lines under consideration.

In the Southeast, a key issue for regional transmission planning is the lack of access to information and transparency, limiting the effectiveness of transmission planning and stakeholder engagement. For example, for FRCC, most information on their website requires a login, and there is very limited opportunity for stakeholder engagement or influence. For SCRTP, an NDA or CEII clearance is needed to access almost all results. In SERTP and SCRTP, state regulators and stakeholders also have little participation or influence over the planning process or outcomes.[160]

Southwest

TABLE 11 Assessment of Southwest planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Southwest/ WestConnect	2	0	0	0	0	0	2	1	35	54%	F

156 Dominion Energy, "Attachment K Transmission Planning Process," 31.

157 SCRTP, "South Carolina Regional Transmission Planning Stakeholder Meeting," 3-4, October 2022, https://www.scrtp.com/assets/pdfs/meeting-archives/scrtp-meeting-2022-10-06-presentation.pdf.

158 *Id.*, 4-5; See SREA Reply Comments on Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional, Docket No. RM21-17-000, 179 FERC ¶ 61,028 (2022) at 10, 20-21, 26-27, 68-70, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=49641b86-b8d1-c3b3-92f4-835740400000.

159 See Southern Environmental Law Center Pre-Technical Comments on Transmission Planning and Cost Management, Docket No. AD22-8-000 (2022), at 16-17, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2f889473-51c5-c170-8538-8346a2d00000.

160 Eto, "Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans," 2016, 7, https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf; See Southern Environmental Law Center Pre-Technical Comments on Transmission Planning and Cost Management, Docket No. AD22-8-000 (2022), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2f889473-51c5-c170-8538-8346a2d00000; SREA Reply Comments on Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional

The Southwest does not have an RTO/ISO; the region is defined by the WestConnect—the FERC Order No. 1000 transmission planning authority—planning footprint. In this region, individual states and utilities lead a significant portion of transmission planning and development.

The WestConnect Regional Transmission Planning Process happens on a two-year cycle, evaluates a 10-year planning horizon, and is largely driven by its Transmission Owners with Load Serving Obligation (TOLSO) members. All committees in WestConnect report to the Planning Management Committee (PMC). The PMC does include roles for State Regulatory Commissions and Key Interest Groups, but currently those seats are vacant.[161] WestConnect has three Subregional Planning Groups, the Southwest Transmission Planning Group (SWAT), the Sierra Subregional Planning Group (SSPG), and the Colorado Coordinated Planning Group (CCPG).[162] These subregional planning groups along with Transmission Owners with Load Serving Obligations help to develop the base cases for the transmission study by submitting Base Transmission Plans for their subregion.[163]

In its last three transmission planning cycles, including the 2022-2023 cycle, WestConnect did not identify any regional transmission needs.[164] Instead, for its Regional Transmission Plan, WestConnect largely roles up the local plans of TOLSO.[165] For the Regional Transmission Plan, WestConnect conducts a Regional Needs Assessment for the transmission plan.[166] For the Regional Needs Assessment, WestConnect starts by creating the Base Transmission Plan, which includes TOLSO's local transmission plans.[167] WestConnect then develops power flow and production cost models, which are used to study reliability and economic projects separately.[168] For this process, WestConnect uses WECC base cases which are supplemented by bottom-up reporting on generation and load, as well as local transmission plans.[169] WestConnect uses these base cases to conduct reliability power flow studies and a separate economic study based on production cost savings.[170] For its economic studies, WestConnect includes sensitivities to its base case, such as emissions

161 WestConnect, "WestConnect Regional Planning Process Business Practice Manual," October 2021, 5, https://doc.westconnect.com/Documents.aspx?NID=17155&dl=1.

162 WestConnect, "2022-23 Planning Cycle Final Regional Study Plan," March 2022, 13, https://doc.westconnect.com/Documents.aspx?NID=20635.

163 *Id.*, 29-43.

164 WestConnect, "WestConnect 2020-21 Regional Transmission Planning Cycle Regional Transmission Report," December 2021, 7, https://doc.westconnect.com/Documents.aspx?NID=20390.

165 WestConnect, "WestConnect Regional Planning Process Business Practice Manual," 18-21, 24,

166 WestConnect, "WestConnect Regional Transmission Planning 2022-23 Planning Cycle," March 2022, 7-8, https://doc.westconnect.com/Documents.aspx?NID=20635&dl=1.

167 *Id.*, 11.

168 WestConnect, "WestConnect Regional Planning Process Business Practice Manual," October 2021, 21-22.

169 *Id.*

170 *Id.*, 23.

costs.[171] For potential Public Policy transmission needs, WestConnect notes they are first addressed through local transmission plans.[172] For the public policy study, WestConnect at a high-level compares renewable energy sales with RPS targets.[173] Any potential regional issues that the reliability and economic studies identify may still be considered local and for an individual TOLSO to resolve.[174] Outside of the regional needs assessment, WestConnect does conduct information-only scenario studies that look at alternate but plausible futures. They represent futures with resource, load, and public policy assumptions that are different in one or more ways than what is assumed in the Base Cases.[175]

Like the Northwest, much of the transmission planning and development in the Southwest occurs at the state, utility, or merchant level. The New Mexico Renewable Energy Transmission Authority (RETA) has been a successful model for state-level transmission development.[176] Colorado created a similar entity called the Colorado Electric Transmission Authority.[177]

Despite active states, utilities, and merchant developers, little is happening regarding interregional coordination. WestConnect's interregional planning with NorthernGrid and CAISO appears to be focused on addressing potential affected systems issues, however it has not yet produced a plan as other regions have.[178] For example, CAISO identified one interregional project in its 2022-2023 Draft. However, WestConnect did not identify any regional needs in its 2022-2023 planning cycle.[179]

171 WestConnect, , "WestConnect Regional Transmission Planning 2022-23 Planning Cycle," 19-20.

172 WestConnect, "WestConnect Regional Planning Process Business Practice Manual," October 2021, 24.

173 WestConnect, "WestConnect Annual Interregional Information," March 2023, slide 29-30, http://www.caiso.com/Documents/Presentation-WestConnect-Annual-Interregional-Information-Mar9-2023.pdf.

174 WestConnect, "WestConnect Regional Planning Process Business Practice Manual," October 2021, 24; WestConnect, "WestConnect Regional Transmission Planning 2022-23 Planning Cycle," 9, https://doc.westconnect.com/Documents.aspx?NID=20635&dl=1.

175 WestConnect, "WestConnect Regional Transmission Planning 2022-23 Planning Cycle, March 2022, 26.

176 New Mexico Renewable Energy Transmission Authority, https://nmreta.com/transmission-lines/.

177 Colorado Electric Transmission Authority, https://energyoffice.colorado.gov/about-us/boards-commissions/colorado-electric-transmission-authority.

178 *See* WestConnect, "WestConnect Regional Planning Process Business Practice Manual," Appendix D; Northwest & Intermountain Power Producers Comments on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional, Docket No. RM21-17-000, 176 FERC ¶ 61,024 (2021) at 4-5, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=8e249000-1920-ccf9-916d-7c76b0d00000; See also Public Interest Organizations Comments on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional, Docket No. RM21-17-000, 176 FERC ¶ 61,024 (2021) at 45-49, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=60f22f6b-c401-c6bc-b293-7c76ae400001.

179 CAISO, "Draft 2022-2023 Transmission Plan," 121-129.

Texas

TABLE 12 Assessment of Texas planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Texas/ERCOT	1	1	0	1	0	3	1	3	42	65%	D

Like other single-state transmission organizations, the Texas region is largely influenced by two entities, the Electric Reliability Council of Texas (ERCOT), which conducts transmission planning, and the state of Texas.

ERCOT conducts Texas transmission planning on a 6-year planning horizon, emphasizing planning for reliability that meets NERC planning requirements.[180] It relies on notifications from entities and highly certain projects from the queue to get generation retirements and additions for the study period.[181] ERCOT does conduct its own 15-year load forecast and has noted that extreme weather events and EV electrification are a source of uncertainty, though EVs are not a part of the forecast yet.[182] For its reliability base cases, ERCOT develops its load forecast through the Steady State Working Group (SSWG), which is used in a set of steady-state power flow models known as "SSWG Cases" that are developed annually.[183] These base cases are largely focused on ensuring ERCOT meets reliability criteria.[184]

Planning for reliability and economic lines are done in separate studies. Economic planning largely centers around reduced production costs and very few other benefits using a base weather year.[185] For the approval of any economic line, the proposed line must produce a cost-benefit analysis, including a production cost savings test that "must include an analysis of whether the levelized ERCOT-wide annual production cost savings

180 *See* ERCOT, "ERCOT Planning Guide," 2023, https://www.ercot.com/files/docs/2023/03/30/April%201,%202023%20Planning%20Guide.pdf.

181 ERCOT, "2022 Regional Transmission Plan Scope and Process," https://www.ercot.com/files/docs/2022/03/11/Draft_2022_RTP_Scope_and_Process_v2_clean.pdf.

182 ERCOT, "2023 ERCOT System Planning Long-Term Hourly Peak Demand and Energy Forecast," 2023, https://www.ercot.com/files/docs/2023/01/18/2023-LTLF-Report.pdf.

183 ERCOT, "2022 Regional Transmission Plan Scope and Process," 2-7.

184 ERCOT, "ERCOT Planning Guide," 26.

185 ERCOT, "2022 Regional Transmission Plan Scope and Process," 8.

attributable to the proposed project are equal to or greater than the first-year annual revenue requirement of the proposed project of which the transmission line is a part."[186] This timeframe is inconsistent with standard benefit-cost analysis, which should be conducted over the life of the investment. This approach has led to the approval of only two economic transmission lines in the past decade. This will change slightly as the Texas PUC issued an order at the end of 2022 requiring ERCOT to develop a new congestion cost savings test for its economic planning. While developing the new test, the PUCT ordered ERCOT to use its old 2011 Generator Revenue Reduction Test and if an economic transmission project passes either the production cost savings or generator revenue reduction test it may be approved. In addition, the order requires ERCOT to conduct a biennial study of grid reliability and resiliency in extreme weather scenarios and allows for the consideration of resiliency benefits of a proposed transmission project based on the study when determining whether to approve the project.[187] This was in response to a law the Texas legislature passed after Winter Storm Uri.

ERCOT does not consider portfolios of projects, instead evaluating individual lines through the Regional Planning Group (RPG). The RPG is a non-voting consensus-based stakeholder group that reviews all proposed lines over $25 million or 345 kV that is not an in-kind replacement.[188] The regional planning group meets monthly and is where

186 ERCOT, "Update on Financial Assumptions for ERCOT Economic Transmission Planning," Slide 2, https://www.ercot.com/files/docs/2023/02/10/Financial%20Assumptions%20for%20ERCOT%20Economic%20Planning%20Criteria_Feb14_2023_v5.0.pdf.

187 Texas PUC, "Order Adopting Amendments to 16 TAC 25.101 as Approved at the November 30, 2022 Open Meeting," December 2022, https://interchange.puc.texas.gov/search/documents/?controlNumber=53403&itemNumber=86.

188 ERCOT, "ERCOT Regional Planning Group Charter," 2018, https://www.ercot.com/files/docs/2018/06/25/ERCOT_Regional_Planning_Group_Charter.docx.

all stakeholder communication related to the RTP happens.[189] But, Texas is one of the only transmission planning entities that considers dynamic line ratings as a part of its economic transmission planning.[190] ERCOT also conducts a Long-Term System Assessment (LTSA) that evaluates transmission needs up to a 20-year planning horizon.[191] The LTSA study incorporates three scenarios and conducts capacity expansion and generator retirement modeling to identify upgrades that may be more robust across the scenarios. Overall, the LTSA does not propose specific solutions and does not impact the RTP planning process.[192]

As a separate interconnection, ERCOT does not conduct interregional planning. ERCOT has jurisdictional independence, and its electricity is not considered to flow in interstate commerce under the Federal Power Act.[193] To avoid impacting ERCOT's jurisdictional status, any interconnection would have to be specially built pursuant to a case-specific declaratory order from the Federal Energy Regulatory Commission, further complicating the process of developing interregional transmission. ERCOT, the PUCT, and the Texas legislature have considered strengthening the ties to neighboring regions but thus far have not. At this point Texas earns the lowest grade for interregional planning.

189 ERCOT, "2022 Regional Transmission Plan Scope and Process," 4.

190 ERCOT, "2022 Regional Transmission Plan," December 2022, 10.

191 The 2022 LTSA only used a 15-year planning horizon. See, ERCOT, "2022 Long-Term Assessment for the ERCOT Region," 2022, https://www.ercot.com/files/docs/2022/12/22/2022_LTSA_Report.zip.

192 ERCOT, "ERCOT Planning Guide," 2023, at 26.

193 *Cottonwood Energy Co., LP*, 118 FERC ¶ 61,198 (2007); *Sharyland Utilities*, LP, 121 FERC ¶ 61,006 (2007); *Cross Texas Transmission, LLC*, 129 FERC ¶ 61,106 (2009).

ERCOT has fairly balanced governance with an independent board and a robust stakeholder process.[194] Like all regions, Texas has a merchant transmission interconnection process but is only considering one major merchant line.[195]

B. Transmission Lines Planned and Transmission Miles Built

The Transmission Lines Planned and Transmission Miles Built is 20% of the overall grade and is composed of two sub-metrics: evaluation of future transmission plans and recent miles of high-capacity transmission lines built. Both metrics are weighted equally.

TABLE 13 Transmission Lines Planned and Transmission Miles Built Grade Summary

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
California/CAISO	15.00	75%	C
Mid-Atlantic/PJM	13.00	65%	D
Midwest/MISO	16.00	80%	B-
New England/ISO-NE	13.00	65%	D
New York/NYISO	17.00	85%	B
Northwest/Northern Grid	15.00	75%	C
Plains/SPP	15.00	75%	C
Southeast/SERTP, SCRTP, FRCC	11.00	55%	F
Southwest/WestConnect	16.00	80%	B-
Texas/ERCOT	14.00	70%	C-

194 ERCOT, "Governance," accessed 2023, https://www.ercot.com/about/governance.

195 ERCOT, "Report on Existing and Potential Electric System Constraints and Needs ," December 2022, https://www.ercot.com/files/docs/2022/12/22/2022_Report_on_Existing_and_Potential_Electric_System_Constraints_and_Needs.pdf.

i. Transmission Lines Planned

The evaluation of future transmission projects, or transmission lines planned, is 10% of the overall grade and is based on whether there are plans for to develop new high-capacity regional transmission projects beyond local and reliability projects.

TABLE 14 Summary of Grades for Proactively Planned New Lines

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
California/CAISO	3	8.5	85%	B
Mid-Atlantic/PJM	1	6.5	65%	D
Midwest/MISO	3	8.5	85%	B
New England/ISO-NE	1	6.5	65%	D
New York/NYISO	3	8.5	85%	B
Northwest/Northern Grid	2	6.5	65%	D
Plains/SPP	2	7.5	75%	C
Southeast/SERTP, SCRTP, FRCC	0	4.5	45%	F
Southwest/WestConnect	2	7.5	75%	C
Texas/ERCOT	0	4.5	45%	F

1. Summary of transmission lines planned evaluation methodology

Evaluation for future transmission lines is based on whether there are proactive, long-term plans for developing new high-capacity regional transmission lines, not including local and reliability projects, planned to actually be built in the region. Additional credit applies if the regional plan considers all business models and for major utility lines in the region that are moving forward and have a good chance of being completed based on permitting progress as well as approved cost allocation. For the future transmission lines planned, each region's planned lines were evaluated on a scale from 0 to 4, similar to school grades.

2. Regional context and evaluation of planned transmission lines

California

In 2023, California approved its 2022-2023 Transmission plan, which called for 45 new projects. The plan is expected to facilitate the development of more than 40 gigawatts (GW) of new resources.[196] In addition, in 2022, CAISO released its 20-year Transmission Outlook, designed to study how new transmission would be required to meet the State's 2045 public policy goals. The study called for over $30 billion in transmission upgrades to connect over 120 GW of new generation resources. However, the 20-year plan did not include specific projects or cost allocation.[197] California and CAISO are supporting new interregional merchant lines, such as the TransWest Express transmission line, through new tariff models and subscriptions which help enable them to be constructed.[198]

Mid-Atlantic

The Mid-Atlantic region has little proactive transmission planned. Most of their transmission plans are driven by local projects proposed by Transmission Owners or projects needed to maintain reliability.[199] The Mid-Atlantic region does receive credit for its first-ever approval of a State Agreement Approach with New Jersey for a $1.1 billion dollar transmission plan to help the state achieve its public policy goal of interconnection 7.5 GW of offshore wind generation by 2035.[200] Additionally, PJM does have a few major merchant lines proposed, including SOO Green and Grain Belt Express, but disputes remain about the capacity contributions from external generators which compete with the internal generators which are much more influential in PJM stakeholder processes.

Midwest

The Midwest has one of the biggest transmission expansions currently planned in the U.S. As described in the planning methods, MISO, in coordination with states and other stakeholders, began the Long-Range Transmission Planning process, which led to the approval of a $10.3 billion transmission plan called Tranche 1 with approximately 2000 miles of lines planned. It also intends to produce two more Tranches of transmission lines.

196 CAISO, "2022-2023 Transmission Plan," 1-10.
197 CAISO, *20-year Transmission Outlook*, 1-4.
198 CAISO, "Decision on PTO Application for TransWest Express LLC."
199 PJM, "RTEP 2022: Appendix 5: RTRP Project Statistics."
200 *Id.* at 1, 55-60.

Tranche 1 does have cost allocation, but none of the lines involve MISO South.[201] MISO also participates in the Joint Targeted Interconnection Queue (JTIQ) process with SPP, as described below.

New England

Currently, little proactive transmission is being planned in New England by ISO-NE. Most of ISO-NE's planned transmission lines are reliability projects, and there has never been an approved economic transmission line.[202] A few independent lines being planned or developed including the New England Clean Energy Connect and Longroad Wind and LS Power Maine Transmission project.[203] In addition, four New England states have submitted an offshore wind transmission concept paper to the Department of Energy, which, if selected for funding, could lead to a competitive solicitation process for offshore transmission solutions.[204]

New York

New York has two major lines planned through the AC Public Policy Transmission Planning Process that will likely be coming online in 2023 or 2024.[205] In addition, the New York Power Authority has four additional significant planned transmission lines under development.[206] Finally, independent companies are developing two major transmission lines, the Champlain Hudson Power Express (CHPE) and the Empire State Connector.[207] These planned lines have a path to finish cost recovery and permitting. Together these transmission projects represent over $9 billion of investment and just under 1200 miles of new transmission lines.

Northwest

In the Northwest, individual utilities advance much of the significant high-voltage trans-

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201 See MISO, "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary and Report," 2022, https://www.misoenergy.org/planning/planning/previous-mtep-reports/#t=10&p=0&s=FileName&sd=desc.

202 See ISO-NE, "2021 Regional System Plan," November 2021, https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

203 New England Clean Energy Connect, https://www.necleanenergyconnect.org/; Howland, "Maine PUC OKs 1-GW Longroad wind farm, LS Power transmission line amid equity and cost concerns," Utility Dive, Feb. 2023, https://www.utilitydive.com/news/maine-puc-longroad-wind-farm-ls-power-transmission-line/641699/.

204 See "Joint State Innovation Partnership for Offshore Wind," January 2023, https://newenglandenergyvision.files.wordpress.com/2023/01/joint-state-innovation-partnership-for-offshore-wind-concept-paper.pdf.

205 NYISO, "2021-2030 Comprehensive Reliability Plan," December 2021, 18-19, https://www.nyiso.com/documents/20142/2248481/2021-2030-Comprehensive-Reliability-Plan.pdf/99a4a589-7a80-13f6-1864-d5a4b698b916?t=1639597243157.

206 NYPA, "NYPA Transmission Projects," accessed May 2023, https://www.nypa.gov/power/transmission/transmission-projects#projects-underway.

207 Champlain Hudson Power Express, https://chpexpress.com/; Empire State Connector, https://empirestateconnector.com/.

mission buildout. PacifiCorp and NV Energy are leading this effort. PacifiCorp's planned transmission lines, known as the Gateway Projects, are shown in Figure 4 below. The Gateway projects are an $8 billion investment and over 2,300 miles of new transmission lines.[208] NV Energy also has almost 600 miles of new transmission lines known as the Greenlink projects, which are just over $2 billion in investments.[209] However, NorthernGrid's 2020-2021 transmission plan did not include any interregional or nonincumbent transmission lines.[210]

FIGURE 4 **PacifiCorp Energy Gateway Transmission Expansion Projects**[211]

PacifiCorp retail service area

Existing substation

New substation

NEW TRANSMISSION LINES:

500 kV minimum voltage

345 kV minimum voltage

230 kV minimum voltage

GATEWAY WEST

B Segment— Populus to Terminal

C Segment— Mona to Oquirrh

C Segment— Oquirrh to Terminal

GATEWAY WEST

D1 Segment— Windstar to Aeolus (future segment)

D2 Segment— Aeolus to Bridger/Anticline

D3 Segment— Bridger/Anticline to Populus (future segment)

E Segment— Populus to Hemingway (future segment)

GATEWAY SOUTH

F Segment— Aeolus to Mona/Clover

G Segment— Sigurd to Red Butte

WEST OF HEMINGWAY

A Segment— Wallula to McNary

H Segment— West of Hemingway

208 PacifiCorp, "Energy Gateway," accessed May 2023, https://www.pacificorp.com/transmission/transmission-projects/energy-gateway.html.

209 NV Energy, " Greenlink Nevada," accessed May 2023, https://www.nvenergy.com/cleanenergy/greenlink.

210 NorthernGrid, "2020-2021 Regional Transmission Plan," December 2021, 7, https://www.northerngrid.net/private-media/documents/2020-2021_Regional_Transmission_Plan.pdf.

211 PacifiCorp, "Energy Gateway."

Plains

The Plains region has a significant transmission planned through its ITP process. SPP has almost 700 miles of new lines planned or in development between ITP and ITP20 projects, just over a $2 billion investment.[212] SPP and MISO are also working on a significant interregional transmission planning and development process known as the Joint Targeted Interconnection Queue (JTIQ). The process has produced a plan with over $1 billion in investment for just under 400 miles of transmission lines on the seams between MISO and SPP.[213] The JTIQ projects do not yet have an approved cost allocation, but a proposed plan is expected to be filed at FERC in 2023.

Southeast

The Southeast has not identified any significant regional needs across the three planning entities and has few new or planned merchant transmission lines.[214]

Southwest

In the Southwest, WestConnect, the regional planning entity, did not identify any regional needs in its previous transmission plan.[215] States, utilities, and merchant developers are driving most of the transmission planning and development in the region. For example, in Colorado, Xcel has planned the Colorado Power Pathway projects, an approximately $2 billion investment in almost 600 miles of high voltage lines that will help Colorado meets its goals by interconnecting 5.5 GW of resources.[216] In New Mexico, the RETA has approximately 1200 miles of new high voltage transmission under development that will interconnect almost 9 GW of new generation and represents over $5 billion in investments.[217]

Texas

In its 2022 Regional Transmission Plan, Texas only identified new transmission lines re-

212 See, SPP, "2023 SPP Transmission Expansion Plan Report," January 2023.

213 See. SPP-MISO, "SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes White Paper," December 2022, https://www.spp.org/documents/68518/spp-miso%20jtiq%20study%20updated%20white%20paper%2020221220.pdf.

214 SERTP, "2022 Regional Transmission Planning Analyses," November 2022, http://www.southeasternrtp.com/docs/general/2022/2022_SERTP_Regional_Transmission_Planning_Analyses_Summary_Final.pdf, SCRTP, "South Carolina Regional Transmission Planning Stakeholder Meeting," at 3-4, October 2022, https://www.scrtp.com/assets/pdfs/meeting-archives/scrtp-meeting-2022-10-06-presentation.pdf.

215 WestConnect, "Regional Planning 2022-2023 Regional Planning Cycle," 2022, http://regplanning.westconnect.com/2022_23_regional_plng_cycle.htm.

216 Xcel Energy, "Colorado's Power Pathway," May 2023, https://www.coloradospowerpathway.com/.

217 New Mexico Renewable Energy Transmission Authority, "Transmission Lines: Creating a Highway for Clean Energy," accessed May 2023, https://nmreta.com/transmission-lines/.

quired for reliability upgrades and only over a 6-year horizon. This lack of new lines is despite the fact that Texas is facing record levels of congestion, and the CREZ projects are over a decade old and fully subscribed. Texas also did not evaluate any potentially economically driven transmission lines in its 2022 Regional Transmission Plan.[218] In the 2021 study, Texas did conduct an economic analysis but only used the research to identify projected transmission constraints and lines to recommend for dynamic rating.[219] In addition, very few interregional or merchant lines are planned in Texas.

218 See ERCOT, "2022 Regional Transmission Plan," December 2022, https://www.ercot.com/gridinfo/planning.
219 See ERCOT, "2021 Regional Transmission Plan," December 2021, https://www.ercot.com/gridinfo/planning.

i. Transmission Lines Built

The first quantitative metric evaluated was recently built high-capacity transmission lines. The evaluation of transmission lines built is 10% of the overall grade. Using data from the C Three Group LLC, evaluation is based on the past three years, 2019-2021, considering how many miles of new transmission lines were built in each region.

TABLE 15 2019-2021 New transmission miles built and operational (345 kV+) compared to expected share of 2012-2017 miles built[220]

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
California/CAISO	119	51	25	26	15	0	0	0	3	5	8	3%	6.50	65%	D
Mid-Atlantic/PJM	10	51	191	172	136	70	52	43	15	14	72	7%	6.50	65%	D
Midwest/MISO	287	470	332	347	501	541	427	213	172	70	455	53%	7.50	75%	C
New England/ ISO-NE	86	89	103	79	11	25	0	0	0	0	0	0%	6.50	65%	D
New York/NYISO	0	8	0	0	0	1	51	70	42	58	170	84%	8.50	85%	B
Northwest/ Northern Grid	352	198	162	166	33	76	28	268	207	90	565	88%	8.50	85%	B
Plains/SPP	601	546	285	247	499	334	329	124	73	24	221	62%	7.50	75%	C
Southeast/ SERTP, SCRTP, FRCC[221]					43	0	55	0	0	0	0	0%	6.50	65%	D
Southwest/ WestConnect	352	198	162	166	33	76	28	268	207	90	565	88%	8.50	85%	B
Texas/ERCOT	1,211	1,379	134	124	298	108	129	180	322	148	650	125%	9.50	95%	A

220 Data on new miles built was provided by the C Three Group LLC. For the data, C Three tracks the actual year of construction of the miles of new transmission lines for lines over 20 miles. C Three's data combines the non-RTO Southeast and West in one region, so similar to the interconnection metrics below, the Northwest and Southwest were evaluated using the same number of miles built due to the granularity of the data.

221 The data in the table above is our own addition, not from the C Three Group, and is not included in our sum of total lines built from 2012-2017 to avoid double counting. It is only used for grading purposes. For the Southeast, C Three combines the region with other non-RTO regions. However, other sources show that only two high-capacity transmission lines were built since 2016, so we evaluated the region based on the assumption that no new miles had been built from 2019-2021. See ACP, "Clean Power Annual Market Report 2021 Executive Summary," 2022, 22, https://cleanpower.org/wp-content/uploads/2022/05/2021-ACP-Annual-Report-Final_Public.pdf.

1. Summary of new transmission lines built evaluation methodology

The grade for miles of high-capacity transmission built is based on a grade scale starting with the miles of high-capacity (greater than or equal to 345 kV) transmission lines built nationally from 2012-2017, which was 10,585 new miles. This period roughly encompasses the building of MISO MVP projects, SPP Priority Projects, and the ERCOT CREZ projects and captures the 2013 peak of new high-capacity transmission miles built.

TABLE 16 Miles of new transmission built from 2012-2017 and expected miles built over a 3-year period adjusted regionally by national share of load

REGION	2021 LOAD (GWH)[222]	PERCENT OF TOTAL US LOAD	EXPECTED SHARE OF NEW MILES BUILT BASED ON TOTAL MILES BUILT FROM 2012-2017	EXPECTED MILES BUILT FROM 2019-2021
California/CAISO	219,186	6%	585	292
Mid-Atlantic/PJM	796,161	20%	2124	1062
Midwest/MISO	642,281	16%	1713	857
New England/ISO-NE	117,117	3%	312	156
New York/NYISO	151,979	4%	405	203
Plains/SPP	267,544	7%	714	357
Southeast/SERTP, SCRTP, FRCC	896,030	23%	2390	1195
Texas/ERCOT	392,520	10%	1047	524
The West (SW + NW) [223]	*485,267*	*12%*	*1294*	*647*
Northwest/Northern Grid	278,463	7%	743	371
Southwest/WestConnect	206,804	5%	552	276
Total	**3,968,085**	**100%**	**10,585**	**5,293**

In Table 16, the total of 10,585 new high-capacity transmission miles built during the period above (2012-2017) was used. Next the total number of miles built out proportional

222 Regional load calculated using EIA 930 data, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.
223 The West row was broken out for grading purposes but is not included in the total load calculations in the row below.

by region was broken down by each region's share of overall load in the U.S.[224] This gave an estimate of how many miles each region would theoretically have to build if the U.S. wanted to reproduce one of the "best recent periods" of high-capacity transmission line development. Then, this calculated "best recent period" of high-capacity line buildout was compared to the actual total miles of high voltage transmission built in each region during the last three years. From this calculation, a simple percentage was derived of the actual miles built from 2019 to 2021 compared to the theoretical miles built by the region if we reproduced the "best recent period" of high-capacity transmission buildout proportionally across the U.S. Finally, a proportion was used to develop a grading scale where a region received the following grade based on its percentage: A = >100%; B = 80%-100%; C =50%-80%; D = 0%-50% or no data.

Using miles built and regional load does not perfectly represent the needed transmission buildout. Many different methods could be used to provide an estimate of the optimal miles of transmission lines a region should build. In addition, in many regions it can be difficult to develop lines even after they are planned. However, based on our grading scale and comparing each region to a historical period, the report card errs on the generous side with grades as most regions built very little new high-capacity transmission between 2019 and 2021.

2. Regional evaluation of transmission lines built

There is limited additional regional context to discuss for this grade. Since 2020, very little new high-capacity transmission has been built, as evidenced by the overall decline in miles built in the table above. Based on the grade above, Texas scored well, but this does not fully reflect recent activities; Texas no longer conducts proactive transmission planning and buildout. Even though significant transmission was built from 2012-2017, the average rate fell by half in subsequent years, from 2019-2021.

Texas, from 2010 to 2013, added 2,400 miles of new transmission lines as a part of their Competitive Renewable Energy Zones (CREZ)

This trend applies throughout the country. Recent transmission expansion simply does not match the past decade's pace of construction. Ten years ago, in 2013, the U.S. built almost 4000

224 The share of U.S. load because it correlates reasonably well with the miles of high-capacity transmission a region needs to reliably meet its demand but is not necessarily a perfect representation for all regions.

miles of high-capacity transmission lines, Texas, from 2010 to 2013, added 2,400 miles of new transmission lines as a part of their Competitive Renewable Energy Zones (CREZ). During the 2010's, SPP also built over 1,800 miles of new lines as a part of their Priority Projects. The other central U.S. region, MISO, invested in thousands of miles of new high-capacity transmission lines in the 2010s as a part of their Multi-Value Projects initiative. Combined Texas's CREZ and SPP's Priority Projects were almost one-third of all new high-capacity transmission line miles built over the decade. These three regional transmission expansion plans enabled nearly 35 GW of new generation.

C. Transmission Capacity Available for New Resources

Slow and costly interconnection queues are an additional indication of a congested transmission system requiring expansion. When evaluating each region on transmission capacity available for new resources, three different metrics were used: cost of interconnection, interconnection queue completion rate, and duration in the interconnection queue. Even though each of these metrics has unique issues regionally, if a region were conducting proactive, scenario-based transmission planning and development, improvement would occur across all three metrics. Such proactive planning could even reduce "speculative" projects.

As noted previously, the MISO MVP projects facilitated over 16 GW of new generation and almost halved interconnection costs associated with the projects compared to some more recent individual interconnection costs.[225] A well-planned and developed grid builds additional capacity on the system, which reduces interconnection upgrade costs for new resources and provides manageable cost burdens for viable renewable resources. Interconnection queues are not the best barometer for grid capacity in a region – for instance, speculative projects or different levels of wind or solar intensity can distort queue size. However, the metrics selected focus on how much time and expense is incurred by completed projects, indicating the extent to which transmission shortages impede viable ones.

The three metrics are a snapshot of current performance. While individually, they may not be a perfect representation of a region's transmission system, cumulatively, when a region is building transmission, their performance on these metrics rises. This means that these metrics do not indicate future performance but, as discussed, would likely improve if a region implemented proactive, scenario-based transmission planning and development.

225 Brattle-GS, "Transmission Planning for the 21st Century," 12.

TABLE 17 Transmission Capacity Available for New Resources Grade Summary

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
California/CAISO	6.13	82%	B-
Mid-Atlantic/PJM	5.88	78%	C+
Midwest/MISO	5.88	78%	C+
New England/ISO-NE	3.75	50%	F
New York/NYISO	3.75	50%	F
Northwest/Northern Grid	6.13	82%	B-
Plains/SPP	5.38	72%	C-
Southeast/SERTP, SCRTP, FRCC	6.75	90%	A-
Southwest/WestConnect	6.13	82%	B-
Texas/ERCOT	7.50	100%	A

i. Summary of Transmission Capacity Available for New Resources evaluation methodology

The Transmission Capacity Available for Interconnection Grade is 7.5% of the overall grade and is composed of three subgrades: 1) Cost of interconnection; 2) Interconnection queue completion rate; and 3) Duration in the interconnection queue. Each are weighted at 2.5% of the overall grade and are discussed in more detail below.

1. Cost of Interconnection

The first sub-metric under transmission capacity available for new resources evaluated is the average cost of interconnection for new generation using a combination of data from LBNL as well as RTOs within the regions. The data evaluated is summarized in Table 18 below along with a grade for each region.

TABLE 18 Average cost of interconnection ($/kW) for last three Phase I interconnection studies

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
California/CAISO				No Data	2.13	85%	B
Mid-Atlantic/PJM (2020, 2021, 2022)	$260.37	$338.10	$224.57	$274.34	1.88	75%	C
Midwest/MISO (2018, 2019, 2020)	$168.98	$175.14	$259.34	$201.15	1.88	75%	C
New England/ISO-NE (Maine and OSW)		$1,498.08	$219.64	$858.86	1.63	65%	D
New York/NYISO (2018, 2019, 2021)	$305.54	$185.08	$138.22	$209.61	1.88	75%	C
Northwest/Northern Grid				No Data	2.13	85%	B
Plains/SPP (2018, 2019, 2020)	$57.27	$263.07	$127.18	$149.17	2.13	85%	B
Southeast/SERTP, SCRTP, FRCC				No Data	2.13	85%	B
Southwest/WestConnect				No Data	2.13	85%	B
Texas/ERCOT				$0.00	2.50	100%	A

The Cost of Interconnection Grade is based on the average cost per kW in transmission upgrades for interconnection for the last three conducted Interconnection Phase I System Impact Studies or the equivalent for the region.[226] Phase I studies were used even though they are considered more speculative, as it is a metric developers use to determine whether to continue through the interconnection process. Because there is not a standardized interconnection process nationally, it is easier to compare Phase I studies across regions. The last three completed interconnection classes/clusters/etc. for a region might not be public information and might go back almost ten years. Our analysis used data collected from regions themselves or the raw data LBNL released with their analysis of interconnection costs in a region.

For the grades, the scale is based on historic interconnection costs. Looking back approximately ten years, as with new transmission miles built, a much lower interconnec-

226 The first round of system impact studies usually evaluates any reliability issues that may arise from a power-flow analysis from the interconnection of the resource to the grid and provides an estimate of any needed upgrade costs to remediate those reliability issues to the developer.

tion costs is seen, with some regions averaging under $100 per kW to interconnect new generation. Based on this historical data, the grade scale is as follows: A = under $100; B = $100-$200 (or no data); C = $200-$300; D = over $300. Many regions did not have regionalized data on interconnection costs.

In regions where interconnection data was unavailable, we are not aware of any complaints or evidence of high interconnection costs, but it is also unclear that the costs are low. Therefore, for these regions are conservatively assigned a 'B' grade on interconnection cost. New England only had two publicly available cluster studies that included interconnection costs; both had very high interconnection costs.

2. Project Completion Rate

The second sub-metric under transmission capacity available for new resources evaluated is the average completion rate weighted by MW for new generation projects in the interconnection queues, again using data from LBNL. Table 19 below summarizes the data and grade for each region.

TABLE 19 Grade for completion rate by MW and queue entry date

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
California/CAISO	6%	2%	5%	1.88	75%	C
Mid-Atlantic/PJM	21%	22%	14%	2.13	85%	B
Midwest/MISO	42%	13%	12%	2.13	85%	B
New England/ISO-NE	28%	19%	15%	2.13	85%	B
New York/NYISO	8%	5%	0%	0.00	0%	F
NW/Northern Grid	20%	8%	8%	1.88	75%	C
Plains/SPP	26%	18%	2%	1.63	65%	D
Southeast/SERTP, SCRTP, FRCC	15%	13%	16%	2.13	85%	B
Southwest/WestConnect	20%	8%	8%	1.88	75%	C
Texas/ERCOT	30%	21%	28%	2.50	100%	A

The Project Completion Rate grade is based on the capacity-weighted (MW) completion rate for projects that entered the queue in 2017, the most recent queue year used for LBNL's average project completion rate. A low percentage queue completion rate may be due to a low barrier to queue entry in some regions. Still, fewer speculative projects would be submitted to the interconnection queues if robust, proactive regional transmission planning occurred, reducing some of the uncertainty associated with speculative projects.

FIGURE 5 **Percent of capacity online by region[227]**

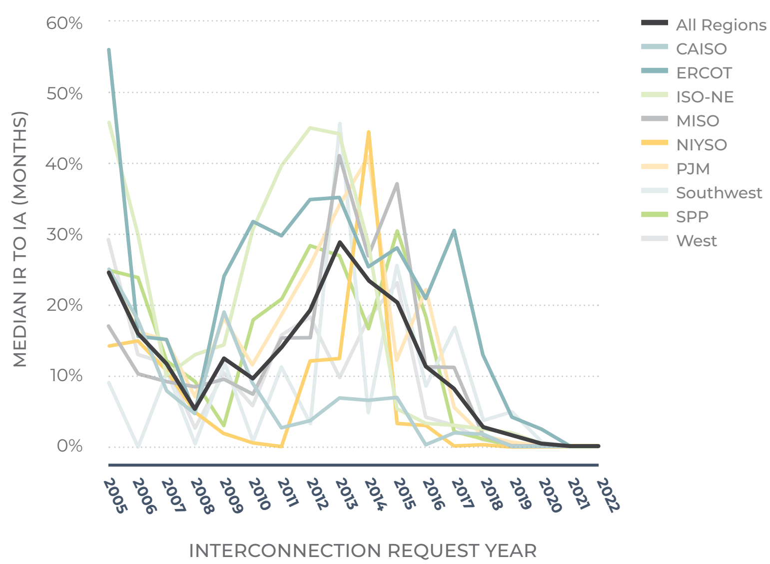

Figure 5 above shows that the U.S. saw a peak in completion rate for projects in the generator interconnection queue around 2013, likely reflecting the transmission expansion that occurred then.

For the grading of complete rates, the scale was based on historical data that shows projects had a much higher success rate. Based on the completion rates in Figure 5, looking back approximately ten years, there are much better completion rates. This success rate corresponds well with prime years of high-capacity transmission buildout. The completion rate grade scale is A = over 20%; B = 10%-20%; C = 5%-10%; D = 1%-5%; F = 0%.

227 Rand, "Queued Up," slide 20.

3. Wait Time in Generator Interconnection Queues

The third sub-metric under transmission capacity available for new resources graded in the report card is the average wait time new generation projects spent in the interconnection queue using data from LBNL. The data used is summarized in Table 20 below along with a grade for each region.

TABLE 20 Grade for median duration from interconnection request to interconnection agreement in Months

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
California/CAISO	31	31	29	2.13	85%	B
Mid-Atlantic/PJM	36	44	46	1.88	75%	C
Midwest/MISO	30	34	39	1.88	75%	C
New England/ISO-NE				0.00	0%	F
New York/NYISO	55	31	37	1.88	75%	C
Northwest/Northern Grid	33	32	32	2.13	85%	B
Plains/SPP	40	42	51	1.63	65%	D
Southeast/SERTP, SCRTP, FRCC	21	15	18	2.50	100%	A
Southwest/WestConnect	33	32	32	2.13	85%	B
Texas/ERCOT	20	21	18	2.50	100%	A

The data from LBNL looks at the median duration (in months) a project takes from the time the developer submitted an interconnection request (IR) through when a developer signs an interconnection agreement (IA). For grading, regional generator interconnection queue wait times for projects that signed an interconnection agreement in 2021, the most recent year of data was examined. As with the completion rate, each region conducts its interconnection queue a little differently, and many regions are currently undergoing a generator interconnection queue reform process. Each section discusses these regional differences and the reforms in each section. However, the same principle described for interconnection completion rate applies. If robust, proactive regional transmission planning occurs in a region, it would likely increase transmission capacity and reduce some of the wait time associated with current generator interconnection queue processes.

FIGURE 6 **Time Spent in the new resources Queue (Median Duration from Interconnection Request to Interconnection Agreement in Months)**[228]

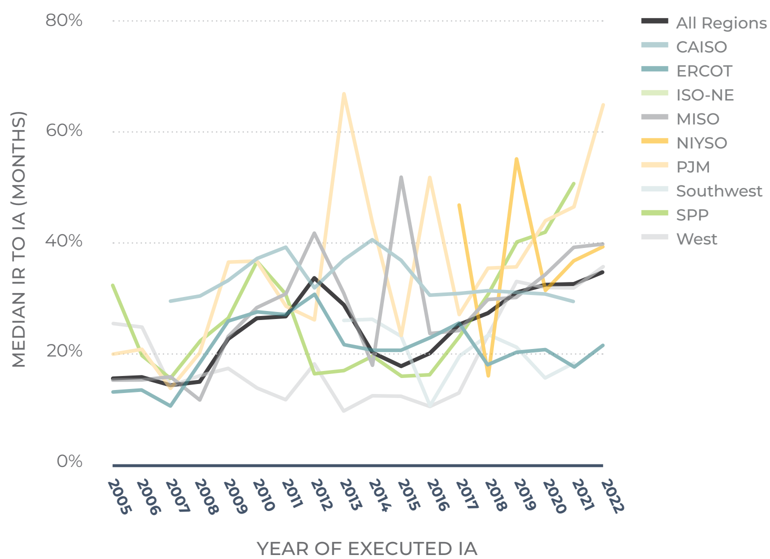

Figure 6 above shows that the U.S. saw some of the lowest wait times for projects in the generator interconnection queue around 2013.

The grade scale for the metric is based on historic duration time in interconnection queues, which were again much lower during the prime years of high-capacity transmission buildout in approximately 2013. The grade scale for wait time in interconnection queues is A = under 24 months; B = 24-36 months; C = 36-48 months; D = over 48 months or no data.

228 Rand, "Queued Up," slide 27.

ii. Transmission Capacity Available for New Resources regional details

California

California has seen some of the biggest jumps in interconnection requests and some of the longest time spent in queue relative to other regions. California also had the longest average times from request to commercial operation, with over 125 months in 2022.[229] In 2021, California had a historically large queue and delayed its 2022 cluster window until 2023, so the state added new interconnection requests in 2022. Despite this pause, LBNL's 2022 Interconnection Queue report showed that California still had the fourth-largest queue, with almost 500 project requests and around 200 GW of capacity requests.[230] With this large queue, California also had one of the lowest project completion rates, with a capacity-weighted completion rate for projects reaching commercial operation of only 5% in the year graded.[231] However, California does not have interconnection cost data, lowering its overall interconnection grade. This report only uses interconnection information to indicate transmission capacity limitations. In some places, such as California, there is likely a significant excess of generation interconnection requests over demand for generation, and it would be regardless of transmission capacity, so this metric is not very meaningful in those regions. Time in the queue has only a small impact on any region's overall grade.

In the 2022-2023 transmission plan, CAISO began to combine some of the interconnection process with transmission planning through their zonal approach to procurement. This combination likely improves transmission capacity and interconnection metrics.[232]

Mid-Atlantic

LBNL's 2022 Interconnection Queue report showed that PJM had the third largest queue, with over 3,000 project requests and around 300 GW of capacity.[233] However, in 2022 PJM paused the review of new interconnection requests until at least 2025, so their queue is likely artificially small. PJM has a relatively average completion rate among regions with capacity-weighted completion rate for projects reaching commercial operation of 14%.[234]

229 "2022 LBNL" at 32.
230 *Id.* at 7, 9.
231 *Id.* at 21.
232 CAISO, "2022-2023 Transmission Plan," 1-10.
233 "2022 LBNL" at 7, 9.
234 *Id.* at 21.

However, the median current time spent in the queue is almost four years, and interconnection costs are above $200 per kW. PJM has also been working on reforms to its queue since it announced the pause in interconnection requests, and in December 2022, FERC approved reforms to PJM's interconnection queue.[235]

Midwest

The Midwest has seen jumps in interconnection costs since 2016, with prices almost quadrupling. These interconnection costs will likely increase even as the interconnection process is completed for the projects currently being studied in queues. LBNL's 2022 Interconnection Queue report showed that the Midwest had one of the largest queues, with over 1700 project requests and almost 350 GW of capacity.[236] The Midwest is performing relatively average in projects completed, with a capacity-weighted completion rate for projects reaching commercial operation of 12% for the year evaluated.[237] Regions were not broken down further into subregions. Within the Midwest, there is significant variability among its four subregions regarding costs, with much of MISO's high interconnection costs coming from the Western and Southern subregions that likely increases the overall average.

New England

New England utilizes both a serial and cluster study process for interconnection requests. However, all serial interconnection studies require CEII clearance to access the results and are therefore not included in this study. ISO-NE did publicly post results for two interconnection cluster studies—one for offshore wind and one for renewables in Maine. The report card includes these results because New England should get credit for having some data available. Compared to interconnection costs in other regions, both cluster studies had relatively high costs. However, LBNL's 2022 Interconnection Queue report does show that the New England region had one of the highest completion rate with a capacity weighted completion rate for projects reaching commercial operation of 15%.[238] The high success rate might be attributed to the fact that there are very few places to build utility-scale renewable projects in New England outside of Maine, and offshore wind projects and developers might be more judicious in selecting locations. New England's interconnection queue is the smallest, with 350 project requests and less than 50 GW capacity.[239]

235 PJM, "Interconnection Process Reform," accessed May 2023, https://www.pjm.com/planning/services-requests/interconnection-process-reform.
236 "2022 LBNL" at 7, 9.
237 *Id.* at 21.
238 "2022 LBNL" at 21.
239 *Id.* at 7, 9.

New York

LBNL's 2022 Interconnection Queue report showed that New York had the third smallest queue, with approximately 450 project requests and around 100 GW capacity.[240] New York has the lowest completion rate, with a capacity weighted completion rate for projects reaching commercial operation of 0% in the year evaluated.[241] NYISO has also seen consistent queue growth since 2016, with most new capacity requests coming from offshore wind. In 2019 New York completed the first round of interconnection queue reforms and, like many other regions, has also initiated a new round of interconnection queue reforms to propose reforms at the end of 2023.

Northwest and Southwest

LBNL's 2022 Interconnection Queue data combined the Northwest and Southwest into one region, the West. The West had one of the largest queues, with over 1800 project requests and almost 600 GW of capacity.[242] However, project capacity-weighted completion rates were one of the lowest nationally, with only 8% of projects reaching commercial operation.[243] The Northwest and Southwest regions do not have an RTO for New Resources costs and rely on individual utilities to interconnect resources. This means there is relatively little public data or transparency around interconnection costs, and aggregation for the limited information that may exist is difficult. Given that the West is experiencing similar trends as the rest of the country with the data that LBNL does provide on interconnection queue wait times and completion rates, it is likely that costs on a $/kW basis are following similar upward trends as seen in RTOs.

Plains

LBNL's 2022 Interconnection Queue report showed that the Plains region had a queue with almost 600 project requests and around 100 GW capacity.[244] The Plains region has one of the lower completion rates, with a capacity weighted completion rate for projects reaching commercial operation of 2% in the year used for evaluation. However, their completion rate only dropped significantly in recent years.[245] It is also important to note that SPP had a historically large queue in 2022. SPP received almost triple the interconnection

240 *Id.* at 7, 9.
241 *Id.* at 21.
242 "2022 LBNL" at 7, 9.
243 *Id.* at 21.
244 *Id.* at 7, 9.
245 *Id.* at 21.

requests compared to their next-highest queue year in 2021.[246] SPP is already experiencing delays in the interconnection queue study process, and this historic queue will likely lead to problems going forward. However, SPP has recognized some of these issues, and as with many regions, they are undergoing a queue reform process. As discussed in the Plains region transmission planning section, SPP is also working on a process that could integrate the interconnection queue process with transmission planning, called the Consolidated Planning Process.[247]

Southeast

LBNL's 2022 Interconnection Queue report showed that the Southeast had a queue size similar to NYISO or SPP, with over 800 project requests and around 100 GW of capacity. For our metrics, the Southeast scored well on completion rates for projects with 16% of projects reaching commercial operation. In addition, the Southeast scored well on time projects spent in the interconnection queue. However, regions without an RTO rely on individual utilities to interconnect resources, and very little aggregated data or transparency exists on those project costs.

Texas

Texas' interconnection process is substantially similar to how interconnection is performed under a "connect and manage" approach to integrated interconnection and transmission planning. New generators only pay for their connection to the grid rather than the broader systems or affected interregional system costs that generators in other regions have to pay. In exchange, generators do not receive firm transmission rights and grid operators curtail them more quickly. This is a relatively efficient way to add new generation to the grid. This efficiency is reflected in LBNL's 2022 Interconnection Queue report, which shows that Texas has the highest project completion rate of any region, with 28% of projects (capacity weighted) reaching commercial operation, and one of the lowest interconnection queue wait times at 18 months.[248] Texas has the fourth largest queue, with 902 projects and almost 250 GW being evaluated.[249]

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246 SPP, "Southwest Power Pool Generation Interconnection Queue Dashboard," accessed May 2023, https://app.powerbi.com/view?r=eyJrIjoiNWRlMjYyN2EtOTA2Ny00NTE0LWI2M2QtMGE3MTAxZTAxOGE0IiwidCI6IjA2NjVkY2EyLTExNDEtNDYyNS1hMmI1LTY3NTY0NjNlMWVlMSIsImMiOjF9.

247 SPP, "Consolidated Planning Process Task Force Meeting Materials," accessed May 2023, https://www.spp.org/spp-documents-filings/?id=297513.

248 "2022 LBNL" at 21.

249 *Id.* at 7, 9.

D. Congestion

i. Summary of congestion evaluation methodology

The final metric, congestion, reflects a representative snapshot of each region's available transmission system capacity which, in turn, informs consumer impacts as greater congestion equates to higher energy delivery costs and limits the opportunity for desired generation resources to add power to the grid. Generally, lower congestion is associated with adequate transmission capacity on the high-capacity transmission system to meet today's load and generation. However, a good grade does not necessarily mean the region is prepared for future expected or needed capacity additions. As with the previous metrics, robust, proactive regional transmission planning occurring in a region it would increase transmission capacity and could help reduce congestion.

Generally, lower congestion is associated with adequate transmission capacity on the high-capacity transmission system to meet today's load and generation. However, a good grade does not necessarily mean the region is prepared for future expected or needed capacity additions.

TABLE 21 Grades for regional congestion ($/MWh)

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
California/CAISO	$2.10	$2.85	$3.60	5.63	75%	C
Mid-Atlantic/PJM	$0.73	$0.69	$1.25	6.38	85%	B
Midwest/MISO	$1.44	$1.90	$4.44	5.63	75%	C
New England/ISO-NE	$0.28	$0.25	$0.43	7.50	100%	A
New York/NYISO	$2.78	$1.98	$3.63	5.63	75%	C
Northwest/Northern Grid				4.88	65%	D
Plains/SPP	$1.70	$1.69	$4.49	5.63	75%	C
Southeast/SERTP, SCRTP, FRCC				4.88	65%	D
Southwest/WestConnect				4.88	65%	D
Texas/ERCOT	$3.28	$3.68	$5.35	4.88	65%	D

The grade for congestion is 7.5% of the overall grade. For the evaluation, congestion was adjusted for the load in each region, so the final congestion number is the total dollars of congestion per total MWh of load in the region. The congestion data was sourced from Annual Market Monitor Reports for each region and a summary of sources can be found in a recently released Grid Strategies report.[250] The grade for each region is based on the most recent year of reported congestion, 2021. The congestion grade scale is as follows: A = Under $1; B = $1-$3; C $3-$5; D = $5 and up or no data.

ii. Congestion regional evaluation

Overall, congestion nearly doubled from 2020 to 2021 as total congestion rose from $3.9 billion to $7.7 billion in RTOs (excluding CAISO). The doubling of congestion from 2020 to 2021 in RTOs nationwide is likely attributed to reduced electricity demand in 2020 resulting from COVID-19.

For our grading, New England received the highest grade for its load weighted congestion, likely because of the residual effects of its significant high-capacity transmission buildout in the early 2000s.

The Mid-Atlantic also earned a good grade on congestion. This grade likely arises because of the region's robust 765 kV grid backbone. Interconnection upgrades may have helped keep congestion low but have also contributed to a massive interconnection queue backlog that forced PJM to reform its queue process and pause interconnection requests. Previous studies in PJM have found that upgrading the transmission system through the interconnection queue process costs more than a comprehensive upgrade.[251] It is unclear what this means for congestion in PJM going forward.

In the transmission capacity available for new resources section, Texas's good performance on the metric was discussed because of the relative ease for developers to add generation. However, easy interconnection without proactive planning can lead to congestion and curtailment as significant amounts of generation are added, filling up existing transmission capacity. This has contributed to the almost doubling of congestion in ERCOT from 2020 to 2021. Congestion rose even higher for ERCOT in 2022, setting a

250 Sherman, "Transmission Congestion Costs in the U.S. RTOs, Appendix A" Grid Strategies, Apr. 2023, pg 8-10, https://gridprogress.files.wordpress.com/2023/04/transmission-congestion-costs-in-the-us-rtos-4.14.pdf. California does not have a CAISO specific congestion metric. However, the DOE National Transmission Needs Study Draft used a proxy by combining Day Ahead Congestion with Real Time Congestion Imbalance Offset Charges as reported by CAISO's Market Monitor (see page 62 of the DOE Needs Study). This method was replicated for this report using CAISO's Annual State of the Market Monitor Reports.

251 Brattle-GS, "Transmission Planning for the 21st Century," 9-11.

record of $2.8 billion.[252]

Congestion in the Plains and Midwest regions was also high in 2021. The overall trend for congestion in both regions is increasing, with levels quadrupling from 2016 to 2021 in the Plains and doubling in the Midwest. The Plains region has seen significant amounts of curtailment of wind generation in recent years, which has likely contributed to higher congestion. For example, in SPP's 2022 State of the Market report, the Market Monitor found that "from 2020 to 2022, average hourly curtailments increased substantially from 244 MW to 1,260 MW."[253] The trend is similar in the Midwest, where the Market Monitor in 2021 found that "wind output now contributes to more than half of the real-time congestion in MISO and resulted in wind curtailments averaging approximately 660 MW per hour and as high as 6.1 GW in some hours."[254] Higher congestion increasingly exposes new wind generation projects to congestion risk. Analysis from EDF Renewables shows that the Midwest and Plains regions have reached "tipping points" where congestion has begun to increase dramatically.[255]

Outside organized markets in the Northwest, Southwest, and Southeast, there is limited data or transparency related to congestion. Given that congestion is rising across the country, it is safe to assume that the trend also applies to these three regions.

252 Potomac Economics, "ERCOT Wholesale Electricity Market Monthly Report," Jan 2023, 16, https://www.potomaceconomics.com/wp-content/uploads/2023/01/Nodal_Monthly_Report_2022-12.pdf.

253 SPP Market Monitoring Unit, "State of the Market 2022," May 2023, pg 53, https://www.spp.org/documents/69330/2022%20annual%20state%20of%20the%20market%20report.pdf.

254 Potomac Economics, "2021 State of the Market Report for the MISO Electricity Markets," June 2022, pg. ii, https://cdn.misoenergy.org/20220622%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20IMM%20State%20of%20the%20Market%20Report625261.pdf.

255 Emma Romack and Rodica Donaldson, "Congestion-Driven Basis Risk: A Challenge for the Development of Clean Energy Projects," EDF Renewables, March 2023, pg 3-4.

4 Conclusion

FIGURE 7 **Overall regional transmission planning grades**

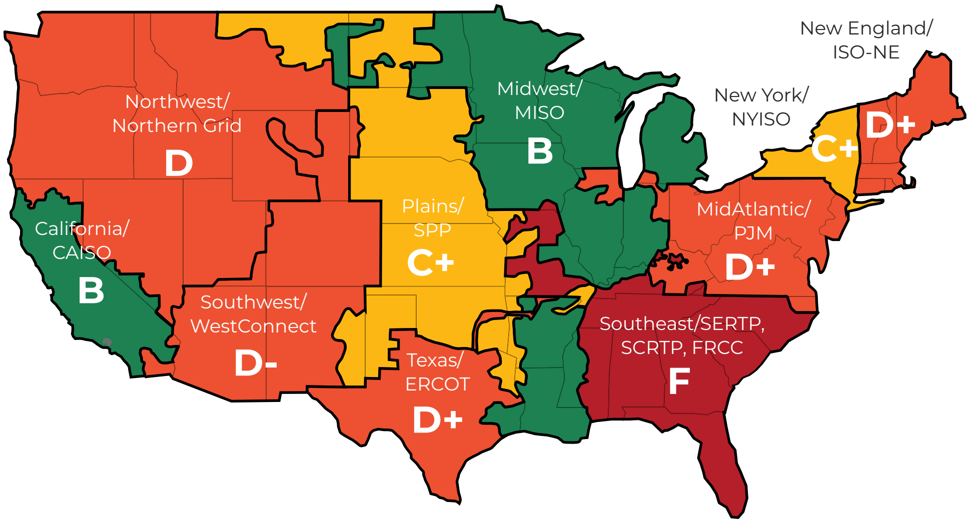

TABLE 22 Overall grade and summary of grades for each metric

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
California/CAISO	A-	C	B-	C	85.8%	B
Mid-Atlantic/PJM	D	D	C+	B	67.5%	D+
Midwest/MISO	A-	B-	C+	C	86.0%	B
New England/ISO-NE	D+	D	F	A	68.0%	D+
New York/NYISO	B-	B	F	C	78.6%	C+
Northwest/ Northern Grid	F	C	B-	D	63.3%	D
Plains/SPP	C+	C	C-	C	77.5%	C+
Southeast/SERTP, SCRTP, FRCC	F	F	A-	D	51.9%	F
Southwest/WestConnect	F	B-	B-	D	62.3%	D-
Texas/ERCOT	D	C-	A	D	68.6%	D+

The overall grades show that every region has the opportunity for improvement. All regions must proactively plan for their future needs and provide more information for public review and scrutiny.

The Midwest/MISO is performing some of the best transmission planning in the country and might have received the only grade in the 'A' range if it were just MISO North. However, the lack of activity for MISO South means this potential A region has more work to do before reaching the honor roll.

California/CAISO is proactively building regional and interregional lines as the region realizes it must achieve geographic diversity in its clean energy portfolio. Although it received one of the highest grades with a 'B,' there is still room for improvement. California needs to develop the lines it is planning, which could create a congestion-specific metric and provide better public access to good interconnection cost data.

New York/NYISO also received a relatively high grade with a 'C+.' After many years of little planning, persistent congestion, and little transmission, New York has improved dramatically in the last few years. Significant lines connecting Quebec, upstate, and downstate areas reduced congestion, improved reliability, and achieved public policy goals.

The Plains/SPP region also received a relatively high grade with a 'C+.' The consolidation of generation and interconnection is a very promising new development. This is one of the regions that would have received an 'A' ten years ago, and it has the potential to achieve 'A' range transmission very soon if it continues with its promising reforms.

New England/ISO-NE earned a 'D+.' Most of its room for improvement comes from planning methods as well. The region should continue finalizing solutions through the 2050 Transmission Planning Plan and work towards more proactive, scenario-based, multi-value transmission planning.

Texas/ERCOT scored low with a 'D+.' It received high marks on interconnection but needs to address congestion soon. It also needs to adopt more proactive, scenario-based, multi-value transmission planning. Further, there is a major need for interregional transmission, as was made clear during winter storms Uri and Eliot.

The Mid-Atlantic/PJM region scored low with a 'D+.' Most of its shortfall comes from planning methods. PJM should build on and adopt many of the planning methods used and proposed in the Grid of the Future Whitepaper and the FERC NOPR. It can also build on the proposed State Agreement Approach work in New Jersey but must continue to consider a regional approach.

The Northwest/NorthernGrid received a 'D' grade, and the Southwest/WestConnect earned a 'D-.' NorthernGrid and WestConnect have not conducted proactive planning. The work of individual utilities or states in the region is much of why the regions managed a 'D' grade.

The Southeast/SERTP, SCRTP, and FRCC region has the lowest grade with an 'F.' The region makes little information available to the public, has limited opportunities for stakeholders to engage meaningfully and has built and planned minimal regional transmission.

As with many students that grow over time, these grades can change as regions evolve their planning processes and transmission build out. This progress does not strictly depend on compliance with potential new rules from FERC, but on the initiative of the regions and their participants in enhancing their planning processes and building much-needed high-capacity regional transmission. Future report cards will watch closely for improvement and look forward to regions moving to the head of the class.

Appendix

A. California

APPENDIX TABLE 1 Grade Summary for California

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
California/CAISO	A-	C	B-	C	85.8%	B

California's grade reflects recent actions taken in their transmission planning processes including the 20-year transmission outlook and the recently approved 2022-2023 transmission plan, which encompasses proactive, multi-value, scenario-based transmission planning. California is also proactively building regional and interregional lines as the region is working to meet its goals. We hope to see this promising planning transition into significant transmission development in future years, which would push California's grade even higher.

Planning Methods

APPENDIX TABLE 2 Assessment of California planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
California/CAISO	4	4	3	4	3	3	3	3	59	91%	A-

The California Independent System Operator's (CAISO) transmission planning and actions taken by California Public Utilities Commission (CPUC) have the greatest influence on transmission planning in the California region.

In recent years, CAISO and CPUC together have employed proactive, scenario-based, multi-value transmission planning. The 2022-2023 Transmission Plan used a base case which meets California's emissions target by 2032 and the plan included sensitivities for a high-electrification scenario and "out-of-ISO long-lead time resources."[256] The 20-year Transmission Outlook also incorporated projections of load growth due to electrification.[257]

CAISO used generation and load projections that meet California's 2045 public policy greenhouse gas reduction objectives including projected generation retirements and estimates of distributed resources.[258] For this, CAISO relies on the CPUC's capacity expansion model for renewable energy development and transmission to identify the least-cost resources. Using these projections, CAISO and the California Public Utilities Commission (CPUC) together co-optimize generation and transmission.[259] The process addresses transmission constraints, land-use impacts, environmental impacts, commercial interests, and other factors, all of which influence CAISO's transmission needs.[260] But, the results from this co-optimization are still divided up into the three planning silos of reliability, public policy, and economic for the transmission plan.

CAISO in its planning then sequentially considers reliability, public policy, and economic projects, and revisits previously identified projects to determine if an alternative project identified in a subsequent stage can meet the previously identified need and provide additional benefits not considered earlier in the process.[261] The final step in that sequential process is to determine if a transmission line is needed for economic reasons.[262] CAISO's benefit-cost analysis for economic projects can encompasses a broad range of benefits. For example, in the past, CAISO has used a multi-value, scenario-based Transmission Economic Assessment Methodology (TEAM) planning process.[263] The process considers var-

256 CAISO, "Draft 2022-2023 Transmission Plan," 16, April 3, 2023, http://www.caiso.com/InitiativeDocuments/Draft-2022-2023-Transmission-Plan.pdf.

257 CAISO, *20-year Transmission Outlook*, 16-25 (2022), http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

258 CAISO, "2022-2023 Transmission Plan," May 2023, 22, http://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf.

259 *Id.,* 62-63.

260 *See,* CPUC, "Modeling Assumptions for the 2022-2023 Transmission Planning Process," Feb. 2022, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K485/451485713.PDF.

261 CAISO, "Draft 2022-2023 Transmission Plan," 19-20.

262 *Id.*

263 Brattle-Grid Strategies, *Transmission planning for the 21st Century*, 15.

ious benefits, including production cost savings and reduced energy prices from both a societal and customer perspective, mitigation of market power, insurance value for high impact low-probability events, capacity benefits due to reduced generation investment costs, operational benefits, reduced transmission losses, and emissions benefits.[264] However, the 2023 Transmission Plan identified no new economic transmission projects.

California receives a higher grade than most regions for taking a relatively successful and innovative approach to interregional planning. In its 2021-2022 Transmission Plan, CAISO acknowledged that

The interregional coordination process has not met expectations and noted there are opportunities to remove certain barriers, foster collaboration with state regulators, and promote more rigor in, and reporting on, interregional coordination efforts. Accordingly, the ISO is exploring a few alternative courses of action to pursue potential interregional opportunities in addition to complying with all expectations, responsibilities, and obligations under the ISO's interregional coordination tariff provisions.[265]

Since then, CAISO has implemented programs to enable import transmission from other regions, such as making the TransWest Transmission line a part of its balancing authority even though it is not in California, and the cost of the line will be paid for by off-takers.[266] Additionally, CAISO identified one interregional project in its 2022-2023 Draft. However, WestConnect did not identify any regional needs in its 2022-2023 planning cycle, so CAISO cannot consider it an Order No. 1000 interregional project, but CAISO did conduct regional policy and economic evaluations of the project.[267]

California also has extensive coordination in its transmission planning process with CAISO and California State Agencies including the California Energy Commission and the California Public Utilities Commission and has extensive stakeholder advisory committees that support the state and CAISO in its transmission planning.

264 CAISO, *2021-2022 Transmission Plan,* at 251-263 (2022), http://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.

265 *Id.,* 13.

266 CAISO, "Decision on PTO Application for TransWest Express LLC," December 2022, http://www.caiso.com/Documents/DecisiononPTOApplicationforTransWestExpressLLC-Presentation-Dec2022.pdf.

267 CAISO, "Draft 2022-2023 Transmission Plan," 121-129.

Transmission Lines Planned and Transmission Miles Built

APPENDIX TABLE 3 Transmission Lines Planned and Transmission Miles Built Grade Summary for California

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
California/CAISO	15.00	75%	C

APPENDIX TABLE 4 California Grade for Proactively Planned New Lines

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
California/CAISO	3	8.5	85%	B

In 2023, California approved its 2022-2023 Transmission plan, which called for 45 new projects. The plan is expected to facilitate the development of more than 40 gigawatts (GW) of new resources.[268] In addition, in 2022, CAISO released its 20-year Transmission Outlook, which was designed to study how new transmission would be required to meet the State's 2045 public policy goals. The study called for over $30 billion in transmission upgrades to connect over 120 GW of new generation resources. However, the 20-year plan did not include specific projects or cost allocation.[269] California and CAISO are supporting new interregional merchant lines, such as the TransWest Express transmission line, through new tariff models and subscriptions which help enable them to be constructed.[270]

268 CAISO, "2022-2023 Transmission Plan," 1-10.

269 CAISO, *20-year Transmission Outlook*, 1-4.

270 CAISO, "Decision on PTO Application for TransWest Express LLC."

APPENDIX TABLE 5 2020-2022 New transmission miles built and operational (300 kV+) compared to expected share of 2012-2017 miles built in California

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
California/CAISO	119	51	25	26	15	0	0	0	3	5	8	3%	6.50	65%	D

Transmission Capacity Available for New Resources

APPENDIX TABLE 6 Transmission Capacity Available for New Resources Grade Summary for California

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
California/CAISO	6.13	82%	B-

APPENDIX TABLE 7 Average cost of interconnection ($/kW) for last three Phase I interconnection studies for California

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
California/CAISO				No Data	2.13	85%	B

APPENDIX TABLE 8 Grade for completion rate by MW and queue entry date for California

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
California/CAISO	6%	2%	5%	1.88	75%	C

APPENDIX TABLE 9 Grade for median duration from interconnection request to interconnection agreement in Months for California

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
California/CAISO	31	31	29	2.13	85%	B

California has seen some of the biggest jumps in the number of interconnection requests and some of the longest time spent in queue relative to other regions. California also had the longest average times from interconnection request to commercial operation, with over 125 months in 2022.[271] In 2021, California had a historically large queue and delayed its 2022 cluster window until 2023, so no new interconnection requests were added in 2022. Despite this pause, LBNL's 2022 Interconnection Queue report showed that California still had the fourth-largest queue, with almost 500 project requests and around 200 GW of capacity requests.[272] With this large queue, California also had one of the lowest project completion rates, with a capacity-weighted completion rate for projects reaching commercial operation of only 5% in the year we graded.[273] However, California does not have interconnection cost data, which affects its overall interconnection grade. This report uses interconnection information as an indicator of transmission capacity limitations, and regional diversity can be hard to capture with these metrics. For example, there are likely more requests for interconnection of generation than there is demand for generation. But within this report, all three metrics are graded on a curve, and some regions are performing well on transmission capacity available for new resources. When the metrics are considered as a whole, it indicates the general availability of transmission capacity available for new resources.

In the 2022-2023 transmission plan CAISO began to combine some or the interconnection process with transmission planning through their zonal approach to procurement which appears likely to improve transmission capacity and interconnection metrics.[274]

271 "2022 LBNL" at 32.
272 *Id.* at 7, 9.
273 *Id.* at 21.
274 CAISO, "2022-2023 Transmission Plan," 1-10.

Congestion

APPENDIX TABLE 10 Grades for regional congestion ($/MWh) for California

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
California/CAISO	$2.10	$2.85	$3.60	5.63	75%	C

California does not have a CAISO specific congestion metric. However, the DOE National Transmission Needs Study Draft used a proxy by combining Day Ahead Congestion with Real Time Congestion Imbalance Offset Charges as reported by CAISO's Market Monitor (see page 62 of the DOE Needs Study). This method was replicated for this report using CAISO's Annual State of the Market Monitor Reports.

B. Mid-Atlantic

APPENDIX TABLE 11 Grade Summary for Mid-Atlantic

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
Mid-Atlantic/PJM	D	D	C+	B	67.5%	D+

The Mid-Atlantic region scored relatively low overall with a 'D+.' Most of its shortfall comes from planning methods because PJM has limited proactive, multi-value, scenario-based transmission planning, instead it takes a more siloed approach to planning that has a heavy emphasis on reliability planning. In recent years, PJM has been studying improvements and changes to its transmission planning methods, which if adopted could improve the Mid-Atlantic's grade. The Mid-Atlantic could also build on the State Agreement Approach work in New Jersey but work towards more holistic regional planning.

Planning Methods

APPENDIX TABLE 12 Assessment of Mid-Atlantic planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Mid-Atlantic/PJM	2	0	0	0	1	3	2	3	42	65%	D

In the Mid-Atlantic region, regional transmission planning is conducted by PJM which has balanced governance and has transmission planning committees and stakeholder processes where input is received from a variety of parties.[275] PJM's planning process mostly happens through its Regional Transmission Expansion Planning (RTEP) and is conducted on a 15-year planning horizon.

Like many regions, PJM rolls up the local transmission plans (including supplemental projects) to use as baseline inputs to its RTEP process.[276] It does not independently review whether those local projects could be better addressed with regional options. PJM does not conduct proactive generation and load forecasting and does not independently model retirements over its 15-year planning horizon.[277] Thus it fails on the most basic test of planning for the anticipated resource mix. In 2022, PJM conducted a Grid of the Future Study which incorporated proactive generation and load forecasting that included end-use electrification (EVs), resource additions, and retirements.[278] The RTEP process itself does not include scenarios, but PJM has proposed a list of factors in its Master Plan White Paper that it could consider expand on the assumptions PJM currently uses in developing its long-range planning solutions, but are not currently utilized.[279] In its Grid of the Future Study, PJM also included future scenarios that looked at integrating future

275 Eto, "Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans," Lawrence Berkeley National Laboratory, Sept. 2016, 7, https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf.

276 Local transmission plans are generally focused on maintenance and local reliability projects and are composed of smaller and lower-voltage lines.

277 PJM, "RTEP 2022," 3, March 14, 2023, https://www.pjm.com/-/media/library/reports-notices/2022-rtep/2022-rtep-report.ashx

278 *Id.*, 18-26.

279 PJM, "Enhanced 15-Year Long Term Planning (Master Plan) White Paper," May 2022, https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220525-long-term/enhanced-long-term-planning-discussion-document.ashx. "Interregional transfers and criteria," i-v.

offshore wind and renewable development to meet state policy goals.[280] PJM would need to incorporate this information into its actual transmission plan to raise its grade.

PJM's planning process largely remains siloed into reliability, economic, and public policy planning. Economic projects have been limited because PJM's studies consider limited benefits that are largely focused on congestion reduction. PJM also studies public policy proposals separately. PJM does have "Multi-Driver Approach Project" which may be used to address multiple drivers as identified in PJM's RTEP process, but it is infrequently used to justify a project.[281] PJM studied multi-driver proposals for the first time in 2022. However, it solicited proposals, which were studied only using a 5-year-out base case, and only open to reliability and market efficiency solutions.[282] PJM evaluates lines separately in its transmission planning and does not consider supplemental projects as a portfolio.

In 2022, for the first time, PJM implemented the State Agreement Approach with New Jersey that was used to help plan for offshore wind development to meet New Jersey's RPS requirements. Generally, the State Agreement Approach allows a state or states to initiate a transmission planning and propose new transmission projects that help the state achieve its public policy goals. However, the state is required cover all costs incurred by the plan, even when customer outside the state benefit.

The Mid-Atlantic has limited interregional planning. PJM and MISO interregional planning is largely focused on operational reliability or short lead-time projects, such as Targeted Market Efficiency Projects, which are focused on congestion management.[283] In addition, PJM conducts limited interregional planning with New York or New England, despite the benefits that would arise related to offshore wind from proactive interregional planning for both regions.[284] The Mid-Atlantic does get some credit though for the first time having one interregional project get through the MISO-PJM Targeted Market Efficiency Process (TMEP), overcoming what is known as the "triple-hurdle."[285] For mer-

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280 PJM, "RTEP 2022," at 18-26.

281 *See* outline for a multi-driver approach, PJM, "PJM Manual 14B: PJM Region Transmission Planning Process," 2023, Sections 2.1.1 & 2.6, 31, 53, https://www.pjm.com/~/media/documents/manuals/m14b.ashx; Economic benefits are quantified in PJM, "Operating Agreement Schedule 6," Section 1.5.7, at 594, https://pjm.com/directory/merged-tariffs/oa.pdf.

282 "RTEP 2022," at 57-58.

283 TMEP interregional projects address historical congestion on market-to-market flowgates – a set of specific flowgates subject to joint and common market (JCM) congestion management. The JCM congestion management process is described in the MISO/PJM Joint Operating Agreement." "RTEP 2022," at 78; *See* RMI Comments on PJM/MISO IPSAC's Annual Issues Review – 3rd Party Issues and Feedback, February 17, 2023, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2023/20230217/third-party-issues.ashx.

284 Pfeifenberger, et al, "The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals," The Brattle Group, Jan. 2023, https://www.brattle.com/wp-content/uploads/2023/01/Brattle-OSW-Transmission-Report_Jan-24-2023.pdf.

285 PJM-MISO, "PJM-MISO IPSAC," December 2022, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2022/20221215/ipsac-presentation.ashx.

chant developers' proposals, PJM studies them through the generator interconnection process, rather than the transmission planning process, which has led to complaints at FERC about delays. Currently, there are only a few lines under development, and they have taken awhile to develop.[286]

Transmission Lines Planned and Transmission Miles Built

APPENDIX TABLE 13 Transmission Lines Planned and Transmission Miles Built Grade Summary for the Mid-Atlantic

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
Mid-Atlantic/PJM	13.00	65%	D

APPENDIX TABLE 14 Mid-Atlantic Grade for Proactively Planned New Lines

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
Mid-Atlantic/PJM	1	6.5	65%	D

The Mid-Atlantic region has little proactive transmission planned. Most of their transmission plans are driven by local projects proposed by Transmission Owners or projects needed to maintain reliability.[287] The Mid-Atlantic region does receive credit for its first ever approval of a State Agreement Approach with New Jersey for a $1.1 billion dollar transmission plan to help the state achieve its public policy goal of connecting 7.5 GW of offshore wind generation by 2035.[288] Additionally, PJM does have a few major merchant lines proposed, including SOO Green and Grain Belt Express, but disputes remain about the capacity contributions from external generators which compete with the internal generators who are much more influential in PJM stakeholder processes.

286 Ethan Howland, "SOO Green transmission project faces PJM obstacles: Are grid operators hindering the energy transition?," Jan. 2022, https://www.utilitydive.com/news/soo-green-pjm-grid-operators-helping-or-hurting-energy-transition/616966/.

287 PJM, "RTEP 2022: Appendix 5: RTRP Project Statistics."

288 *Id.* at 1, 55-60.

APPENDIX TABLE 15 2019-2021 New transmission miles built and operational (345 kV+) compared to expected share of 2012-2017 miles built for the Mid-Atlantic

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
Mid-Atlantic/PJM	10	51	191	172	136	70	52	43	15	14	72	7%	6.50	65%	D

Transmission Capacity Available for New Resources

APPENDIX TABLE 16 Transmission Capacity Available for New Resources Grade Summary for the Mid-Atlantic

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
Mid-Atlantic/PJM	5.88	78%	C+

APPENDIX TABLE 17 Average cost of interconnection ($/kW) for last three Phase I interconnection studies for the Mid-Atlantic

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
Mid-Atlantic/PJM (2020, 2021, 2022)	$260.37	$338.10	$224.57	$274.34	1.88	75%	C

APPENDIX TABLE 18 Grade for completion rate by MW and queue entry date for the Mid-Atlantic

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
Mid-Atlantic/PJM	21%	22%	14%	2.13	85%	B

APPENDIX TABLE 19 Grade for median duration from interconnection request to interconnection agreement in Months for the Mid-Atlantic

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
Mid-Atlantic/PJM	36	44	46	1.88	75%	C

LBNL's 2022 Interconnection Queue report showed that PJM had the third largest queue, with over 3,000 project requests and around 300 GW of capacity.[289] However, in 2022 PJM paused the review of new interconnection requests until at least 2025, so their queue is likely artificially small. PJM has a relatively average completion rate among regions with capacity-weighted completion rate for projects reaching commercial operation of 14%.[290] However, the median current time spent in the queue is almost four years, and interconnection costs are above $200 per kW. PJM has also been working on reforms to its queue since it announced the pause in interconnection requests, and in December 2022, FERC approved reforms to PJM's interconnection queue.[291]

Congestion

APPENDIX TABLE 20 Grades for regional congestion ($/MWh) for the Mid-Atlantic

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
Mid-Atlantic/PJM	$0.73	$0.69	$1.25	6.38	85%	B

The Mid-Atlantic also earned a good grade on congestion. This grade likely arises because of the region's robust 765 kV grid backbone. Interconnection upgrades may have helped keep congestion low but have also contributed to a massive interconnection queue backlog that forced PJM to reform its queue process and pause interconnection requests. Previously, studies in PJM have found that upgrading the transmission system through

289 "2022 LBNL" at 7, 9.

290 *Id.* at 21.

291 PJM, "Interconnection Process Reform," accessed May 2023, https://www.pjm.com/planning/services-requests/interconnection-process-reform.

the interconnection queue process costs more than a comprehensive upgrade.[292] It is not clear what this means for congestion in PJM going forward.

C. Midwest

APPENDIX TABLE 21 Grade Summary for the Midwest

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR INEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
Midwest/MISO	A-	B-	C+	C	86.0%	**B**

The Midwest received the highest grade of any region. This grade reflects MISO's leadership in proactive multi-value transmission planning, starting with the Multi-Value Projects over a decade ago and continuing with the approval of the Tranche 1 Long Range Transmission Planning projects in 2022. However, the Midwest score was held back by MISO South where relatively little transmission planning activity has taken place. The Midwest has also seen congestion increases and reduction in the capacity to connect new projects from the queue. These issues will hopefully be alleviated with the buildout of Tranche 1 projects, but it may take a few years to see success. If MISO can incorporate the South better in its planning for Tranche 2 and 3 transmission, and see the same success rate with the buildout of Tranche 1 as it saw with the MVP projects, it is likely the Midwest's grade will improve.

Planning Methods

APPENDIX TABLE 22 Assessment of the Midwest planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Midwest/MISO	3	4	4	4	3	3	2	3	59	90%	A-

292 Brattle-GS, "Transmission Planning for the 21st Century," 9-11.

The Midwest region comprises the Midcontinent Independent System Operator (MISO) and the states and utilities within MISO's borders. MISO's transmission planning process is called the MISO Transmission Expansion Plan (MTEP). The process happens annually and includes both near-term and long-term planning horizons. MISO collects local transmission plans from member transmission owners, which are considered potential solutions to the overall plan, not simply inputs.

As a part of MTEP, MISO started a process called the Reliability Imperative to address changes happening within its footprint.[293] One element of the Reliability Imperative is Long Range Transmission Planning.[294] MISO recognized that the change in the resource mix, including greater variable resources, and increased extreme weather events will require significant "regional transmission investment."[295] For the Long Range Transmission Planning (LRTP), MISO developed Future Scenarios. The MISO Futures Report outlines three future scenarios, the assumptions made for the scenarios, and summarizes the changes the MISO transmission grid will experience in the next twenty years if the Future Scenario proves accurate.[296]

The scenarios incorporate load growth and modifiers such as electric vehicles, demand response, energy efficiency, and distributed generation.[297] They also include state clean energy laws and utility publicly stated clean energy goals. Finally, the scenarios consider expected generation retirements and additions, some of which are drawn from utility-integrated resource plans (IRPs).[298] Many of these estimates were conducted by outside consulting groups or with national laboratory assistance.[299] These scenarios were intended "to address the uncertainty associated with planning transmission investments decades out"[300] and demonstrate a range of future outcomes that impact transmission needs and are used to test proposed transmission investments to understand the potential value and robustness.[301]

293 *Reliability Imperative,* MISO, https://www.misoenergy.org/about/miso-strategy-and-value-proposition/miso-reliability-imperative (last visited March 3, 2023).

294 *Id.*

295 *Id.*

296 Midcontinent Independent System Operator, *2021 MISO Transmission Planning Chapter 3.1 Long Range Transmission Planning Overview and Process* 7 (2021). https://cdn.misoenergy.org/MTEP21%20Chapter%203%20-%20Regional%20and%20Interregional%20Planning%20Studies581046.pdf.

297 Midcontinent Independent System Operator, *MISO Futures Report,* 7-43.

298 *Id.*

299 *Id.,* 82, 94.

300 *Id.*

301 *Id.*

MISO's Long Range Transmission Planning process, described above, is an excellent example of scenario-based planning that considered a wide range of factors. The LRTP process identified a portfolio of lines in Tranche 1 that met multiple values and MISO conducted a detailed cost benefit analysis.[302] The Tranche 1 projects are designed to "ensure a reliable and efficient regional and interregional transmission system that enables the changing portfolio across the near-term and long-term.[303] MISO has used scenario-based planning in the past with its Multi Value Projects, which included the CapX2020 and RGOS projects. These projects all employed "least-regrets" comprehensive regional network solutions rather than incremental upgrades which helped reduce the cost of generator interconnections along with many other quantified benefits.[304]

As discussed in the Mid-Atlantic section, MISO's planning with PJM is not proactive interregional planning, with only a few short-term projects arising from the process.[305] MISO does get some credit for its MISO-SPP Joint Targeted Interconnection Queue (JTIQ) planning process. The JTIQ process is not necessarily reflective of interregional planning best practices. It arose out of affected systems studies and is largely focused on generator interconnection requests from both MISO and SPP at their seam. The study identified regional upgrades and an interregional transmission project to help connect over 28 GWs of new generation.[306]

MISO has three main stakeholder committees that participate in transmission planning, including the sub-regional planning committees, the Planning Subcommittee, and the Planning Advisory Committee. MISO uses a comprehensive planning process that involves many stakeholders.[307]

The Midwest would have a higher overall grade on transmission planning best practices if its planning was not resulting in significantly different outcomes between MISO North and MISO South subregions. Generally, MISO North scored high on scenario-based, multi-value transmission planning because of its LRTP practices described above. However, MISO South lowered the score in each of those three categories.

302 MISO, "LRTP Tranche 1 Portfolio Detailed Business Case," June 2022, https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf.

303 MISO, "Long Range Transmission Planning: Tranche 1," slide 5 (2022), https://cdn.misoenergy.org/20220325%20LRTP%20Workshop%20Item%2002%20Tranche%201%20Portfolio%20and%20Process%20Review623633.pdf.

304 MISO, "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary," at 5-6; MISO, "Multi Value Project Portfolio Results and Analyses," 5.Brattle-Grid Strategies, *Transmission planning for the 21st Century*, at 7.

305 RMI Comments on PJM/MISO IPSAC's Annual Issues Review – 3rd Party Issues and Feedback, February 17, 2023, https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2023/20230217/third-party-issues.ashx.

306 *See* MISO-SPP, "Joint Targeted Interconnection Queue Study," Mar 2022, https://cdn.misoenergy.org/JTIQ%20Report623262.pdf.

307 MISO, "Stakeholder Entities," accessed May 2023, https://www.misoenergy.org/stakeholder-engagement/committees/.

Transmission Lines Planned and Transmission Miles Built

APPENDIX TABLE 23 Transmission Lines Planned and Transmission Miles Built Grade Summary for the Midwest

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
Midwest/MISO	16.00	80%	B-

APPENDIX TABLE 24 Midwest Grade for Proactively Planned New Lines

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
Midwest/MISO	3	8.5	85%	B

The Midwest has one of the biggest transmission expansions currently planned in the U.S. As described in the planning methods, MISO, in coordination with states and other stakeholders, began the Long-Range Transmission Planning process, which led to the approval of a $10.3 billion transmission plan called Tranche 1 with approximately 2000 miles of lines planned. It also intends to produce two more Tranches of transmission lines. Tranche 1 does have cost allocation, but none of the lines involve MISO South.[308] MISO also participates in the Joint Targeted Interconnection Queue (JTIQ) process with SPP, as described below.

308 *See* MISO, "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary and Report," 2022, https://www.misoenergy.org/planning/planning/previous-mtep-reports/#t=10&p=0&s=FileName&sd=desc.

APPENDIX TABLE 25 2019-2021 New transmission miles built and operational (345 kV+) compared to expected share of 2012-2017 miles built for the Midwest

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
Midwest/MISO	287	470	332	347	501	541	427	213	172	70	455	53%	7.50	75%	C

Transmission Capacity Available for New Resources

APPENDIX TABLE 26 Transmission Capacity Available for New Resources Grade Summary for the Midwest

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
Midwest/MISO	5.88	78%	C+

APPENDIX TABLE 27 Average cost of interconnection ($/kW) for last three Phase I interconnection studies for the Midwest

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
Midwest/MISO (2018, 2019, 2020)	$168.98	$175.14	$259.34	$201.15	1.88	75%	C

APPENDIX TABLE 28 Grade for completion rate by MW and queue entry date for the Midwest

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
Midwest/MISO	42%	13%	12%	2.13	85%	B

APPENDIX TABLE 29 Grade for median duration from interconnection request to interconnection agreement in Months for the Midwest

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
Midwest/MISO	30	34	39	1.88	75%	C

The Midwest has seen jumps in interconnection costs since 2016, with prices almost quadrupling. These interconnection costs will likely increase even as the interconnection process is completed for the projects currently being studied in queues. LBNL's 2022 Interconnection Queue report showed that the Midwest had one of the largest queues, with over 1700 project requests and almost 350 GW of capacity.[309] The Midwest is performing relatively average in projects completed, with a capacity-weighted completion rate for projects reaching commercial operation of 12% for the year evaluated.[310] Regions were not broken down further into subregions. Within the Midwest, there is significant variability among its four subregions regarding costs, with much of MISO's high interconnection costs coming from the Western and Southern subregions that likely increases the overall average.

Congestion

APPENDIX TABLE 30 Grades for regional congestion ($/MWh) for the Midwest

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
Midwest/MISO	$1.44	$1.90	$4.44	5.63	75%	C

Congestion in the Plains and Midwest regions was also high in 2021. The overall trend for congestion in both regions is increasing, with levels quadrupling from 2016 to 2021 in the Plains and doubling in the Midwest. The Plains region has seen significant amounts of curtailment of wind generation in recent years, which has likely contributed to higher congestion. For example, in SPP's 2022 State of the Market report, the Market Monitor found that "from 2020 to 2022, average hourly curtailments increased substantially from

309 "2022 LBNL" at 7, 9.
310 *Id.* at 21.

244 MW to 1,260 MW."[311] The trend is similar in the Midwest, where the Market Monitor in 2021 found that "wind output now contributes to more than half of the real-time congestion in MISO and resulted in wind curtailments averaging approximately 660 MW per hour and as high as 6.1 GW in some hours."[312] Higher congestion increasingly exposes new wind generation projects to congestion risk. Analysis from EDF Renewables shows that the Midwest and Plains regions have reached "tipping points" where congestion has begun to increase dramatically.[313]

D. New England

APPENDIX TABLE 31 Grade Summary for New England

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
New England/ISO-NE	D+	D	F	A	68.0%	**D+**

New England earned a 'D+.' Most of its room for improvement comes from planning methods. ISO-NE does not really have proactive planning, instead focusing mostly on reliability upgrades, though it has made some minor progress by adopting the longer-term planning and economic study changes into its tariff. Most proactive transmission development in New England is occurring through state initiative.

311 SPP Market Monitoring Unit, "State of the Market 2022," May 2023, pg 53, https://www.spp.org/documents/69330/2022%20annual%20state%20of%20the%20market%20report.pdf.

312 Potomac Economics, "2021 State of the Market Report for the MISO Electricity Markets," June 2022, pg. ii, https://cdn.misoenergy.org/20220622%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20IMM%20State%20of%20the%20Market%20Report625261.pdf.

313 Emma Romack and Rodica Donaldson, "Congestion-Driven Basis Risk: A Challenge for the Development of Clean Energy Projects," EDF Renewables, March 2023, pg 3-4.

Planning Methods

APPENDIX TABLE 32 Assessment of New England planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
New England/ ISO-NE	2	1	0	1	0	3	2	3	44	67%	D+

The New England region encompasses the territory of ISO New England (ISO-NE) and includes the New England states and utilities. New England's transmission planning has traditionally been reactive and focused on reliability, rather than proactive. The region did build a significant amount of transmission in the early 2000s, which reduced a large amount of congestion in energy markets and capacity markets.[314] This buildout means New England still has some headroom on the transmission system, and congestion in the energy and capacity markets remains low. However, there is insufficient capacity for new generation in remote areas such as Maine until transmission is expanded.

ISO-NE regional transmission planning must happen at least once every three years through a process called the Regional System Plan (RSP).[315] The plan occurs over a 5 to 10-year planning horizon.[316] To begin the process ISO-NE determines load, resource additions, and retirements. ISO-NE conducts its own load forecast (Capacity, Energy, Load, and Transmission) that includes estimates of end-use electrification.[317] For generation additions, the 2021 RSP accounts for new resource additions through its resource adequacy process. The resource adequacy process incorporates new resources or retirements that have cleared the Forward Capacity Market, and resources that have received contracts through states.[318] The ISO is beginning to consider extreme weather events but does not include any extreme weather scenarios in its 2021 RSP.[319]

314 ISO-NE, "Our History," accessed May 2023, https://www.iso-ne.com/about/what-we-do/history/.

315 ISO-NE, "OATT Attachment K Regional System Planning Process," March 2023, 14, https://www.iso-ne.com/static-assets/documents/2021/07/sect_ii_att_k.pdf.

316 *Id.,* 16.

317 ISO-NE, "2021 Regional System Plan," November 2021, Chapter 3, https://www.iso-ne.com/static-assets/documents/2021/11/rsp21_final.docx.

318 *Id.,* Chapter 4, 15-19.

319 *Id.,* 20, 67.

ISO-NE's transmission planning study process conducts Reliability, Economic, and Public Policy studies needs assessments in separate silos. Economic studies generally must be requested by stakeholders and have largely been informational which ISO-NE states can help identify key regional issues.[320] This process has resulted in no economic transmission lines being built in the region. Though ISO-NE does note that "Reliability transmission upgrades have resulted in significant market-efficiency benefits by reducing congestion and out-of-merit operating costs."[321] In 2023, ISO-NE also changed its tariff to reflect updates to its economic study process to include four scenarios, but two are for informational purposes.[322] For public policy transmission planning, there were no studies initiated in 2017 or 2020 because the states through NESCOE determined there were no state or federal public policy requirements driving transmission needs.[323] Transmission planning in New England has historically focused on generation interconnection and network reliability. However, ISO-NE does recover cost for network transmission costs based on the entire ISO-NE portfolio, utilizing postage stamp cost recovery.[324]

In terms of interregional planning, New England has done very little to coordinate with New York despite a rapidly growing amount of offshore wind hoping to interconnect close to the seam of both regions and no new interregional projects have been identified to date.[325] As an ISO, New England has a robust stakeholder process and well balanced governance.[326]

Proactive planning and action around transmission development in New England is contingent on the New England states. For example, like the Mid-Atlantic region, ISO-NE is in the process of conducting a 2050 Transmission Study at the request of the New England states that includes proactive generation, load estimates, and future scenarios.[327] The study is still ongoing. Additionally, the New England states are pursuing federal funding for their joint offshore wind transmission initiative.[328]

320 ISO-NE, "Economic Studies," accessed June 2023, https://www.iso-ne.com/system-planning/system-plans-studies/economic-studies.

321 ISO-NE, "2021 Regional System Plan," 21.

322 ISO-NE, "OATT Attachment K Regional System Planning Process," Section 17; Benefits consider for Market Efficiency Upgrades are largely focused on production cost savings. ISO-NE, "OATT Attachment N," 2023, 497, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

323 ISO-NE, "2021 Regional System Plan," 88.

324 Brattle-Grid Strategies, "Transmission Planning for the 21st Century," 15.

325 *See,* ISO-NE, "2021 Regional System Plan," 82-84.

326 Eto, "Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans," Lawrence Berkeley National Laboratory, Sept. 2016, 7, https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf.

327 ISO-NE amended its OATT Attachment K planning process to include a long-term, state-led, proactive scenario-based planning process with proactive modeling of future load and generation additions. ISO-NE, "2050 Transmission Study Preliminary Assumptions and Methodology for the 2050 Transmission Study Scope of Work - Revision 2," slides 5-7, November 2021, https://www.iso-ne.com/static-assets/documents/2021/12/draft_2050_transmission_planning_study_scope_of_work_for_pac_rev2_redline.pdf.

328 https://newenglandenergyvision.files.wordpress.com/2023/01/joint-state-innovation-partnership-for-offshore-wind-concept-paper.pdf

Transmission Lines Planned and Transmission Miles Built

APPENDIX TABLE 33 Transmission Lines Planned and Transmission Miles Built Grade Summary for New England

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
New England/ISO-NE	13.00	65%	D

APPENDIX TABLE 34 New England Grade for Proactively Planned New Lines

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
New England/ISO-NE	1	6.5	65%	D

Currently, little proactive transmission is being planned in New England by ISO-NE. Most of ISO-NE's planned transmission lines are reliability projects, and there has never been an approved economic transmission line.[329] There are a few independent lines being planned or developed including the New England Clean Energy Connect and Longroad Wind and LS Power Maine Transmission project.[330] In addition, four New England states have submitted an offshore wind transmission concept paper to the Department of Energy, which if selected for funding, could lead to a competitive solicitation process for offshore transmission solutions.[331]

329 *See* ISO-NE, "2021 Regional System Plan," November 2021, https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

330 New England Clean Energy Connect, https://www.necleanenergyconnect.org/; Howland, "Maine PUC OKs 1-GW Longroad wind farm, LS Power transmission line amid equity and cost concerns," Utility Dive, Feb. 2023, https://www.utilitydive.com/news/maine-puc-longroad-wind-farm-ls-power-transmission-line/641699/.

331 *See* "Joint State Innovation Partnership for Offshore Wind," January 2023, https://newenglandenergyvision.files.wordpress.com/2023/01/joint-state-innovation-partnership-for-offshore-wind-concept-paper.pdf.

APPENDIX TABLE 35

2019-2021 New transmission miles built and operational (345 kV+) compared to expected share of 2012-2017 miles built for New England

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
New England/ ISO-NE	86	89	103	79	11	25	0	0	0	0	0	0%	6.50	65%	D

Transmission Capacity Available for New Resources

APPENDIX TABLE 36

Transmission Capacity Available for New Resources Grade Summary for New England

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
New England/ISO-NE	3.75	50%	F

APPENDIX TABLE 37

Average cost of interconnection ($/kW) for last three Phase I interconnection studies for New England

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
New England/ISO-NE (Maine and OSW)		$1,498.08	$219.64	$858.86	1.63	65%	D

APPENDIX TABLE 38

Grade for completion rate by MW and queue entry date for New England

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
New England/ISO-NE	28%	19%	15%	2.13	85%	B

APPENDIX TABLE 39 Grade for median duration from interconnection request to interconnection agreement in Months for New England

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
New England/ISO-NE				0.00	0%	F

New England utilizes both a serial and cluster study process for interconnection requests. However, all serial interconnection studies require CEII clearance to access the results and are therefore not included in this study. ISO-NE did publicly post results for two interconnection cluster studies—one for offshore wind and one for renewables in Maine. We included the results because we felt New England should get credit for having some data available. Compared to interconnection costs in other regions, both cluster studies had relatively high costs. However, LBNL's 2022 Interconnection Queue report does show that the New England region had the second highest completion rate with a capacity weighted completion rate for projects reaching commercial operation of 22%.[332] The high success rate might be attributed to the fact that there are very few places to build utility-scale renewable projects in New England outside of Maine, and offshore wind projects and developers might be more judicious in selecting locations. New England's interconnection queue is the smallest, with 350 project requests and less than 50 GW capacity.[333]

Congestion

APPENDIX TABLE 40 Grades for regional congestion ($/MWh) for New England

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
New England/ISO-NE	$0.28	$0.25	$0.43	7.50	100%	A

New England received the highest grade for its load weighted congestion, likely because of the residual effects of its significant high-capacity transmission buildout in the early 2000s.

332 "2022 LBNL" at 21.
333 *Id.* at 7, 9.

E. New York

APPENDIX TABLE 41 Grade Summary for New York

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
New York/NYISO	B-	B	F	C	78.6%	C+

New York received a relatively high grade overall with a 'C+.' After many years of little planning, persistent congestion, and little transmission, in the last few years New York has become a most improved player. While the overall planning process remains divided into three distinct processes, the public policy planning portion has produced proactive, multi-value, scenario-based transmission plans. Significant lines connecting upstate and downstate areas, and Quebec, enable reduction of congestion, improved reliability, and efficient achievement of the region's goals.

Planning Methods

APPENDIX TABLE 42 Assessment of New York planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
New York/NYISO	3	3	3	3	0	3	3	3	52	80%	B-

The New York region's transmission planning is largely influenced by two entities, the New York Independent System Operator's (NYISO) along with actions taken by the state of New York. The New York Transmission Planning Process is known as the Comprehensive System Planning Process (CSPP) and consists of four planning processes, the Local Transmission Planning Process (LTPP), the Reliability Planning Process (RPP), the Congestion Assessment and Resource Integration Study (CARIS) and the Public Policy Transmission Planning Process (PPTPP), which are conducted together on a biannual basis.[334] These planning efforts are solely, other than the Public Policy Planning Process, focused on reliability and individual (incremental) needs.

The process starts with the local transmission planning processes. The results from that process are then used as inputs for the reliability planning process. The reliability study uses a relatively conservative base case for generation and retirements, mostly focused on planned generation.[335] The load forecast comes from NYISO's Gold Book and does include end-use electrification.[336] For the Reliability Needs Assessment, NYISO can include other scenarios but they are for informational purposes.[337] The reliability planning process and short-term reliability process base cases are then used as the base case inputs for the economic and public planning processes, which are conducted over a 20-year planning horizon.[338] Generally, solutions are siloed between the three planning processes. For example, when reliability needs are identified, proposed solutions are not also evaluated for economic benefits. In the economic study, the main benefit metric is congestion/production cost.[339]

NYISO does have a proactive, scenario-based planning process under the Public Policy Transmission Planning Process.[340] The Public Policy Process incorporates multiple cases and scenarios over a 20-year evaluation time horizon, and uses reliability, economic and public policy metrics to evaluate projects and select a transmission solution. For example, New York in its 2019 public policy transmission plan studied transmission lines using three scenarios including a base case, Clean Energy Standard and Retirement Scenario, and that same case including a carbon price. New York also included a separate analysis where the capacity zones were changed because of a change in generation mix along with the building of the AC Public Policy Transmission Projects.[341] Public policy projects are evaluated across ten categories of metrics that include project cost and cost containment, operability, expandability, performance, and systemwide economic benefits to

334 NYISO, "Comprehensive System Planning Process (CSPP)," accessed May 2023, https://www.nyiso.com/planning#:~:text=The%20NYISO%20CSPP%20is%20comprised,Public%20Policy%20Transmission%20Planning%20Process.

335 NYISO, "Reliability Planning Process Manual," 2022, 17-22, https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf.

336 *See* NYISO, "Gold Book 2022 Load & Capacity Data," 2022, https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf; NYISO, "2022 Reliability Needs Assessment (RNA)," 2022, https://www.nyiso.com/documents/20142/2248793/2022-RNA-Report.pdf/b21bcb12-d57c-be8c-0392-dd10bb7c6259?t=1669046152728

337 NYISO, "Reliability Planning Process Manual," 2022, 23, https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf.

338 NYISO, OATT Attachment Y 31.3.1.3.2, at 1666, https://www.nyiso.com/regulatory-viewer.

339 Benefits may also include estimates of reductions in losses, LBMP load costs, generator payments, ICAP costs, Ancillary Services costs, emission costs, TCC payments, and energy deliverability, but are informational only. NYISO, OATT Attachment Y 31.3.1.3.4&5, 1667-1671.

340 Brattle-Grid Strategies, "Transmission Planning for the 21st Century," at 15.

341 *See* NYISO, "AC Transmission Public Policy Transmission Plan," April 2019, at 14, 19, 25, https://www.nyiso.com/documents/20142/5990681/AC-Transmission-Public-Policy-Transmission-Plan-2019-04-08.pdf/23cbba74-a65e-66c2-708e-eaa0afc9f789; Brattle-GS, "Transmission Planning for the 21st Century," at 15.

production costs, installed capacity costs and environmental emissions. Those metrics do not include benefits to meeting system reliability needs, such as resource adequacy and transmission security.

This planning process is the reason New York is graded relatively well, because it has identified significant high-voltage transmission needs that got built in recent years, so it has been successful in planning and developing transmission. The process is also unique among the regions because it requires a formal determination by the New York Public Service Commission (NYPSC) as to which public policy requirements NYISO should be using in its planning study.[342] New York also incorporates independent business models and has several significant transmission lines under development, some through the New York Power Authority.[343]

NYISO does very little proactive interregional transmission planning. In its ANOPR comments, NYISO acknowledged this reality, "to date, no interregional transmission project has been selected under the planning protocol and regional planning processes for cost allocation and cost recovery."[344] As an ISO, NYISO has fairly balanced governance and a robust stakeholder process that includes planning committees with diverse membership including consumer interests and there is generally more transparency in planning documents.

Transmission Lines Planned and Transmission Miles Built

APPENDIX TABLE 43 **Transmission Lines Planned and Transmission Miles Built Grade Summary for New York**

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
New York/NYISO	17.00	85%	B

342 NYISO, OATT Attachment Y, 31.4.2.1.

343 NYPA, "Major Projects Underway," accessed May 2023, https://www.nypa.gov/power/transmission/transmission-projects#projects-underway.

344 NYISO, "Comments in response to the Commission's Advance Notice of Proposed Rulemaking on Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," October 2021, at 56, https://nyisoviewer.etariff.biz/ViewerDocLibrary//Filing/Filing1835/Attachments/20211012-NYISOCmnts-ANOPR-RM2117000.pdf.

APPENDIX TABLE 44 New York Grade for Proactively Planned New Lines

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
New York/NYISO	3	8.5	85%	B

New York has two major lines planned through the AC Public Policy Transmission Planning Process that will likely be coming online in 2023 or 2024.[345] In addition, the New York Power Authority has four additional significant planned transmission lines under development.[346] Finally, independent companies are developing two major transmission lines, the Champlain Hudson Power Express (CHPE) and the Empire State Connector.[347] These planned lines have a path to finish cost recovery and permitting. Together these transmission projects represent over $9 billion of investment and just under 1200 miles of new transmission lines.

APPENDIX TABLE 45 2019-2021 New transmission miles built and operational (345 kV+) compared to expected share of 2012-2017 miles built for New York

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
New York/NYISO	0	8	0	0	0	1	51	70	42	58	170	84%	8.50	85%	B

345 NYISO, "2021-2030 Comprehensive Reliability Plan," December 2021, 18-19, https://www.nyiso.com/documents/20142/2248481/2021-2030-Comprehensive-Reliability-Plan.pdf/99a4a589-7a80-13f6-1864-d5a4b698b916?t=1639597243157.

346 NYPA, "NYPA Transmission Projects," accessed May 2023, https://www.nypa.gov/power/transmission/transmission-projects#projects-under-way.

347 Champlain Hudson Power Express, https://chpexpress.com/; Empire State Connector, https://empirestateconnector.com/.

Transmission Capacity Available for New Resources

APPENDIX TABLE 46 Transmission Capacity Available for New Resources Grade Summary for New York

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
New York/NYISO	3.75	50%	F

APPENDIX TABLE 47 Average cost of interconnection ($/kW) for last three Phase I interconnection studies for New York

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
New York/NYISO (2018, 2019, 2021)	$305.54	$185.08	$138.22	$209.61	1.88	75%	C

APPENDIX TABLE 48 Grade for completion rate by MW and queue entry date for New York

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
New York/NYISO	8%	5%	0%	0.00	0%	F

APPENDIX TABLE 49 Grade for median duration from interconnection request to interconnection agreement in Months for New York

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
New York/NYISO	55	31	37	1.88	75%	C

LBNL's 2022 Interconnection Queue report showed that New York had the third smallest queue, with approximately 450 project requests and around 100 GW capacity.[348] New York has the lowest completion rate, with a capacity weighted completion rate for projects reaching commercial operation of 0% in the year we evaluated.[349] NYISO has also seen consistent queue growth since 2016, with most new capacity requests coming from offshore wind. In 2019 New York completed the first round of interconnection queue reforms and, like many other regions, has also initiated a new round of interconnection queue reforms to propose reforms at the end of 2023.

Congestion

APPENDIX TABLE 50 Grades for regional congestion ($/MWh) for New York

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
New York/NYISO	$2.78	$1.98	$3.63	5.63	75%	C

F. Northwest

APPENDIX TABLE 51 Grade Summary for the Northwest

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
Northwest/ Northern Grid	F	C	B-	D	63.3%	D

The Northwest received a 'D' grade. Its planning largely relies on inputs from its members and has not been doing proactive planning and has not approved a regional line for cost allocation. Much of the reason the regions managed a 'D' grade can be attributed to the work of individual utilities or states in the region that have been successful at developing transmission.

348 *Id.* at 7, 9.

349 *Id.* at 21.

Planning Methods

APPENDIX TABLE 52 Assessment of Northwest planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Northwest/ Northern Grid	1	0	0	3	1	0	2	0	37	57%	F

In the Northwest, there is no RTO or ISO. The region is defined by NorthernGrid's planning footprint, the FERC Order No. 1000 transmission planning entity. However, a significant portion of the transmission planning and development is being led by individual utilities with minimal transparency or regional coordination. The Northwest also includes Bonneville Power Administration (BPA). BPA's role is unique as it owns 80% of the region's high-voltage transmission system. BPA voluntarily adopted FERC open access and tariff standards, following Orders 888, 890, and 1000 on transmission service and planning. However, BPA still lacks transparency into its transmission planning processes and does not conduct proactive, scenario-based, or multi-value transmission planning.

As the Order No. 1000 transmission planning authority, NorthernGrid is an entity created by its members, which includes investor-owned utilities that are FERC jurisdictional and publicly owned utilities that are not FERC-jurisdictional and voluntarily participate. NorthernGrid's planning process is largely driven by its members.[350] NorthernGrid does not have a role for state regulators and other non-utility stakeholders, instead it relies on its members who hold all the decision-making authority. In addition, even though BPA is not a required participant, BPA maintains a significant role in NorthernGrid.

Proactive planning for future generation and load or using robust scenario-based planning at a regional level is not taking place in the Northwest. Current planning is focused on resolving NERC and WECC violations and is designed to meet Order 890 and 1000 planning requirements, but not intended to evaluate market efficiencies,[351] and is highly

350 *See* NorthernGrid, *Approved Study Scope for the 2023-2023 NorthernGrid Planning Cycle*, at 6-7.
351 *Id.*, 21-22.

dependent on the transmission projects submitted by its members and third parties.[352] In its 2022-2023 planning process, NorthernGrid noted most of its data on future generation and load comes from utility IRPs, but also states it is up to the discretion of the utility what is reported.[353] In addition, data submitted to NorthernGrid is not always consistent, which has resulted in members submitting varied future scenarios. While some utilities include resource additions and retirements from a robust IRP process, others submit data based only on what is currently in their queue.[354] Data submissions and projects are then incorporated into a power flow model to determine if system reliability and transmission needs are met.[355] For its base cases, the only scenario it evaluates, NorthernGrid uses the WECC Anchor Data sets which only extend out 10-years. No extreme weather events, such as the 2021 heat dome were modeled.[356]

The 2022-2023 transmission study scope does include a portfolio analysis that "evaluates the proposed regional transmission projects independently and in different regional combinations,"[357] However, most of the proposed transmission projects from NorthernGrid members in the 2021-2022 and 2022-2023 plans were intended to support local load service and reliability, and in the final 2021-2022 Regional Transmission Plan none of the non-incumbent or interregional transmission projects were selected.[358] In addition, NorthernGrid's interregional planning with WestConnect and CAISO appears to be focused on addressing potential affected systems issues, however it has not yet produced a comprehensive plan as other regions have, and no interregional lines are being considered in the 2022-2023 plan.[359]

352 *Id.,* 20; NorthernGrid, Final Study Scope for the 2020-2021 NorthernGrid Planning Cycle 9 (2020), https://www.northerngrid.net/private-media/documents/Appendix_B_NG_Study_Scope_clean.pdf.

353 NorthernGrid, *Approved Study Scope for the 2022-2023 NorthernGrid Planning Cycle,* 9, 15, 20.

354 NorthernGrid*, Proposed Study Scope for the 2022-2023 NorthernGrid Planning Cycle 9,* https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_DRAFT.pdf. In the current planning cycle, Puget Sound Energy (PSE) submitted 4,090 MW of resource additions and 370 MW in retirements to NorthernGrid, which is similar to its IRP findings. Puget Sound Energy, *2021 PSE Integrated Resource Plan* 2-6 (2021), https://oohpseirp.blob.core.windows.net/media/Default/Reports/2021/Final/IRP21_Chapter%20Book%20Compressed_033021.pdf. While Portland General Electric (PGE) submitted 19 MW of resource additions and 0 MW retirements to NorthernGrid, despite stating in its IRP a need for 2,800 MW of new resources by 2030 and an exit from Colstrip by 2025. *PGE plans to nearly triple clean resources by 2030,* PGE (Oct. 15, 2021), https://portlandgeneral.com/news/2021-10-15-pge-plans-to-nearly-triple-clean-resources-by-2030. Renewable Northwest, "Comments in response to the Commission's Notice of Proposed Rulemaking Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," August 2022, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220817-5001&optimized=false.

355 *Id.*

356 *Id.,* 5, 21.

357 *See* NorthernGrid, *Approved Study Scope for the 2023-2023 NorthernGrid Planning Cycle,* at 21, 28.

358 BPA, *Attachment K Planning Process*, at 41.

359 *See* Northwest & Intermountain Power Producers Comments on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional, Docket No. RM21-17-000, 176 FERC ¶ 61,024 (2021) 4-5, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=8e249000-1920-ccf9-916d-7c76b0d00000; *See* also Public Interest Organizations Comments on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional, Docket No. RM21-17-000, 176 FERC ¶ 61,024 (2021) at 45-49, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=60f22f6b-c401-c6bc-b293-7c76ae400001.See NorthernGrid, *Approved Study Scope for the 2023-2023 NorthernGrid Planning Cycle,* 3, 22.

The Northwest as a region does earn points for significant high-voltage transmission development that is occurring at the utility level. PacifiCorp and NV Energy are both members of NorthernGrid, and both have undertaken the development of significant high-voltage transmission projects. PacifiCorp has been working on their Gateway Transmission Projects which expand over a utility service territory larger than some of the other regions. For the planning of these projects, PacifiCorp utilized proactive generation and load forecasting. Additionally, NV Energy has been developing its Greenlink projects to access new renewable energy zones. The Berkshire Hathaway Energy utilities are unique in their geographic size and scope, and unlike most utilities in the country are able to build high-capacity long haul transmission within its footprint – including cost allocation and recovery.

Transmission Lines Planned and Transmission Miles Built

APPENDIX TABLE 53 **Transmission Lines Planned and Transmission Miles Built Grade Summary for the Northwest**

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
Northwest/Northern Grid	15.00	75%	C

APPENDIX TABLE 54 **Northwest Grade for Proactively Planned New Lines**

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
Northwest/Northern Grid	2	6.5	65%	D

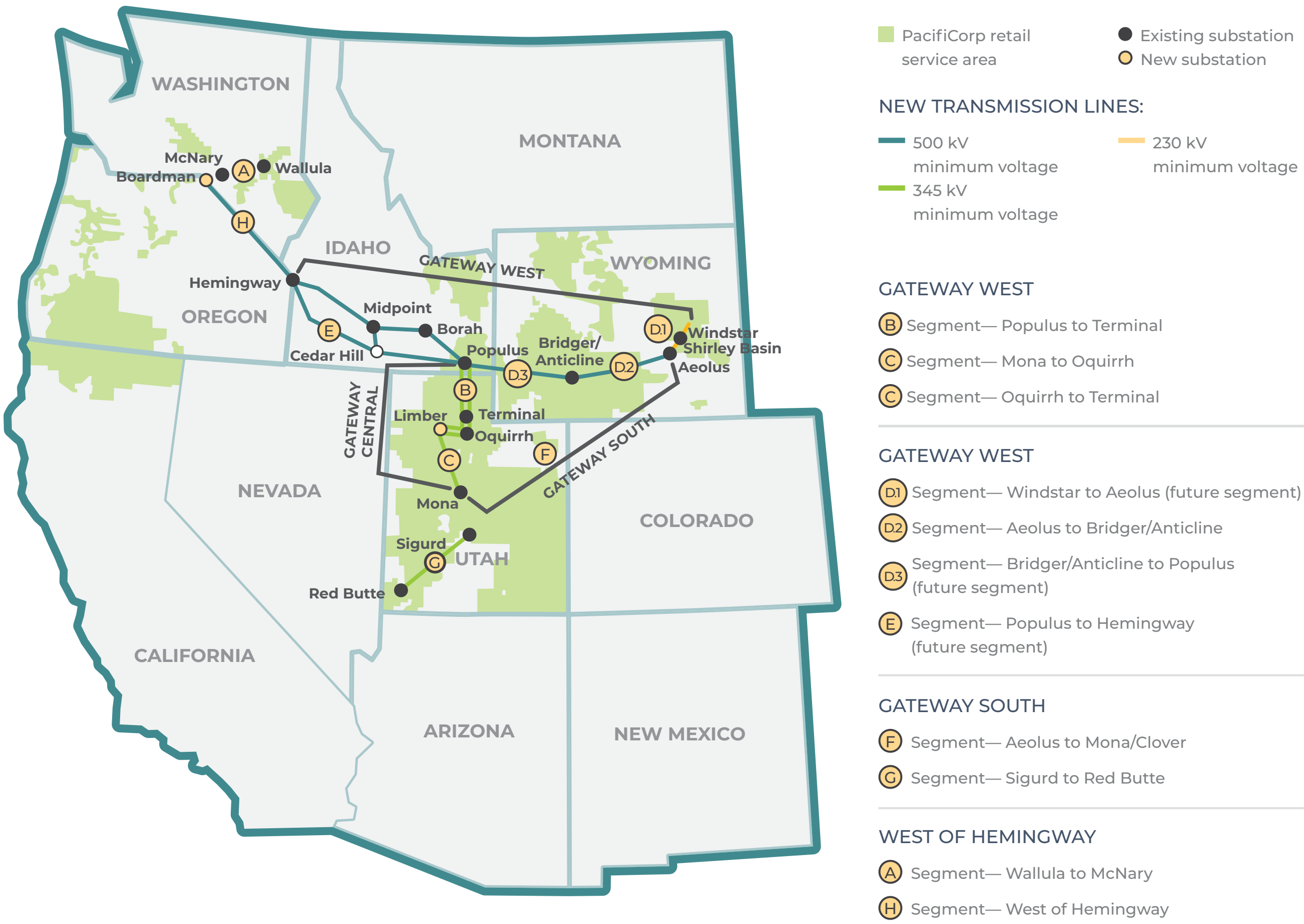
In the Northwest, individual utilities advance much of the significant high-voltage transmission buildout. PacifiCorp and NV Energy are leading this effort. PacifiCorp's planned transmission lines, known as the Gateway Projects, are shown in Appendix Figure 1 below. The Gateway projects are an $8 billion investment and over 2,300 miles of new transmission lines.[360] NV Energy also has almost 600 miles of new transmission lines known as the Greenlink projects, which are just over $2 billion in investments.[361] However, Northern-

360 PacifiCorp, "Energy Gateway," accessed May 2023, https://www.pacificorp.com/transmission/transmission-projects/energy-gateway.html.

361 NV Energy, "Greenlink Nevada," accessed May 2023, https://www.nvenergy.com/cleanenergy/greenlink.

Grid's 2020-2021 transmission plan did not include any interregional or nonincumbent transmission lines.[362]

APPENDIX FIGURE 1 PacifiCorp Energy Gateway Transmission Expansion Projects[363]



362 NorthernGrid, "2020-2021 Regional Transmission Plan," December 2021, 7, https://www.northerngrid.net/private-media/documents/2020-2021_Regional_Transmission_Plan.pdf.

363 PacifiCorp, "Energy Gateway."

APPENDIX TABLE 55	2019-2021 New transmission miles built and operational (345 kV+) compared to expected share of 2012-2017 miles built for the Northwest

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
Northwest/ Northern Grid	352	198	162	166	33	76	28	268	207	90	565	88%	8.50	85%	B

The Northwest and Southwest score well on miles of transmission built. C Three's data combines the non-RTO region, so similar to the transmission capacity available for new resources metrics below, the Northwest and Southwest regions were evaluated using the same number of miles built for the 2019-2021 period.

Transmission Capacity Available for New Resources

APPENDIX TABLE 56	Transmission Capacity Available for New Resources Grade Summary for the Northwest

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
Northwest/Northern Grid	6.13	82%	B-

APPENDIX TABLE 57	Average cost of interconnection ($/kW) for last three Phase I interconnection studies for the Northwest

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
Northwest/Northern Grid				No Data	2.13	85%	B

APPENDIX TABLE 58 Grade for completion rate by MW and queue entry date for the Northwest

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
NW/Northern Grid	20%	8%	8%	1.88	75%	C

APPENDIX TABLE 59 Grade for median duration from interconnection request to interconnection agreement in Months for the Northwest

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
Northwest/Northern Grid	33	32	32	2.13	85%	B

LBNL's 2022 Interconnection Queue data combined the Northwest and Southwest into one region, the West. The West had one of the largest queues, with over 1800 project requests and almost 600 GW of capacity.[364] However, capacity-weighted completion rates for projects were one of the lowest nationally, with only 8% of projects reaching commercial operation.[365] The Northwest and Southwest regions do not have an RTO and rely on individual utilities to interconnect resources. This means there is relatively little public data or transparency around interconnection costs, and aggregation for the limited information that may exist is difficult. Given that the West is experiencing similar trends as the rest of the country with the data that LBNL does provide on interconnection queue wait times and completion rates, it is likely that costs on a $/kW basis are following similar upward trends as we see in RTOs.

364 "2022 LBNL" at 7, 9.

365 *Id.* at 21.

Congestion

APPENDIX TABLE 60 Grades for regional congestion ($/MWh) for the Northwest

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
Northwest/Northern Grid				4.88	65%	D

Outside of organized markets, in the Northwest, Southwest, and Southeast, there is limited data or transparency related to congestion. Given that congestion is rising across the country, we assumed that the trend also applies to these three regions.

G. Plains

APPENDIX TABLE 61 Grade Summary for the Plains

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
Plains/SPP	C+	C	C-	C	77.5%	C+

The Plains region received a relatively high grade with a 'C+.' The Plains region is one of the regions that would have likely received a higher grade ten years ago, and it has the potential to improve its grade if it continues with its promising reforms. However, the Plains region is currently experiencing high and increasing congestion and interconnection costs. It will likely need to plan and develop significant amounts of transmission to address those issues. The region currently has a task force working on the consolidation of generation and interconnection that is a promising new development.

Planning Methods

APPENDIX TABLE 62 Assessment of the Plains planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Plains/SPP	2	2	3	2	2	3	2	3	52	79%	C+

The Plains region is defined by the Southwest Power Pool (SPP) planning region and states and utilities within SPP's boundaries. Historically, the Plains region has had some promising components within its transmission planning.

SPP conducts its annual ITP on a 10-year planning horizon.[366] A 20-year assessment is conducted once every five years, and is informational only.[367] One strength of SPP transmission planning is that it conducts both regional and local planning simultaneously, when other regions often have separate processes that include local transmission planning as inputs to regional planning.[368] In order to assess transmission needs, SPP does conduct its own generation and load planning, though it has acknowledged that its previous forecasts have been too conservative and not adequately captured the changing resource mix, and it is currently working to improve this part of its planning.[369]

SPP uses scenario-based planning for its economic transmission planning studies. In the 2021 ITP, SPP used only two scenarios including a reference case and an emerging technologies case that included EV electrification to evaluate economic transmission projects.[370] SPP's overall planning process allows for multiple benefits to be considered by still largely silos planning and seems to optimize for reliability and economic transmis-

366 SPP, "Integrated Transmission Planning Manual," 2022, https://www.spp.org/documents/60911/itp%20manual%20version%202.10.pdf.

367 SPP, "Integrated Transmission Planning," accessed June 2023, https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/.

368 SPP, "Integrated Transmission Planning Manual," 32; SPP, "2021 Integrated Transmission Planning Assessment Report," March 2022, 73, https://www.spp.org/documents/66813/2021%20itp%20report%20%20v1.0%20redlined.pdf.

369 SPP observed in its 2019 ITP, "Previous ITP assessments have been conservative in forecasting the amount of renewable generation expected to interconnect to the grid. When the studies were completed, installed amounts had nearly surpassed 10-year forecasts." SPP, "2020 Integrated Transmission Planning Assessment Report, October 2020," at 2, https://www.spp.org/documents/63434/2020%20integrated%20transmission%20plan%20report%20v1.0.pdf.

370 SPP, "Integrated Transmission Planning Manual," 2022.

sion categories largely ignoring the public policy category.[371] SPP does conduct evaluations that includes expanded transmission benefits considerations through its periodic Regional Cost Allocation Review (RCAR) assessment that estimates the economic value of all ITP-approved projects and uses many of the expanded transmission benefit metrics.[372] SPP uses a version of portfolio planning by grouping proposed transmission lines into a "consolidated portfolio," where projects are studied together to determine whether there is a more efficient configuration.[373] But SPP still studies potential economic transmission lines individually, and does not account for other economic lines in the portfolio.[374]

SPP gets some credit for its MISO-SPP Joint Targeted Interconnection Queue (JTIQ) planning process. The JTIQ process does not necessarily reflect interregional planning best practices. It arose out of affected systems studies and is largely focused on generator interconnection requests from both MISO and SPP at their seam. The study identified regional upgrades and an interregional transmission project to help connect over 28 GWs of new generation.[375] Additionally, SPP could also better incorporate merchant developers into its planning. Although, SPP has a few merchant lines under development they have taken a while to develop.

As an RTO, SPP has a more balanced governance,[376] as well as a significant stakeholder process that includes multiple committees and working groups, such as the Strategic Planning Committee, the Transmission Working Group, the Economic Studies Working Group, the Cost Allocation Working Group, the Regional State Committee (RSC), and the Markets and Operations Policy Committee. SPP is also working on a stakeholder process, the Consolidated Planning Process. This process works on reforming and consolidation of the transmission planning and generator interconnection processes.[377]

371 No public policy needs were identified. SPP, "2021 Integrated Transmission Planning Assessment Report," 69.

372 SPP, "RCAR III Draft Report," 2022, https://www.spp.org/Documents/67896/RCAR%20III%20Draft%20Report.zip.

373 SPP, "ITP Transmission Manual," Feb. 2022, 39-43, https://www.spp.org/documents/60911/itp%20manual%20version%202.10.pdf.

374 SPP, "2021 Integrated Transmission Planning Assessment Report," 75-78.

375 *See* MISO-SPP, "Joint Targeted Interconnection Queue Study," Mar 2022, https://cdn.misoenergy.org/JTIQ%20Report623262.pdf.

376 Eto, "Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans," Lawrence Berkeley National Laboratory, Sept. 2016, 7, https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf.

377 SPP has nine stakeholder groups working on its ITP process which are composed of members, liaison members, industry specialists and consultants who discuss the assumptions and facilitate a thorough evaluation. SPP, 2022 Integrated Transmission Planning Assessment Report, 8-9; SPP, "Consolidated Planning Process Task Force Meeting Materials," accessed May 2023, https://www.spp.org/spp-documents-filings/?id=297513.

Transmission Lines Planned and Transmission Miles Built

APPENDIX TABLE 63 Transmission Lines Planned and Transmission Miles Built Grade Summary for the Plains

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
Plains/SPP	15.00	75%	C

APPENDIX TABLE 64 Plains Grade for Proactively Planned New Lines

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
Plains/SPP	2	7.5	75%	C

The Plains region has a significant amount of transmission planned through its ITP process. SPP has almost 700 miles of new lines planned or in development between ITP and ITP20 projects is just over a $2 billion investment.[378] SPP and MISO are also working on a significant interregional transmission planning and development process known as the Joint Targeted Interconnection Queue (JTIQ). The process has produced a plan with over $1 billion in investment for just under 400 miles of transmission lines on the seams between MISO and SPP.[379] The JTIQ projects do not yet have an approved cost allocation, but a proposed plan is expected to be filed at FERC in 2023.

378 *See*, SPP, "2023 SPP Transmission Expansion Plan Report," January 2023.

379 *See*. SPP-MISO, "SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes White Paper," December 2022, https://www.spp.org/documents/68518/spp-miso%20jtiq%20study%20updated%20white%20paper%2020221220.pdf.

APPENDIX TABLE 65 2019-2021 New transmission miles built and operational (300 kV+) compared to expected share of 2012-2017 miles built for the Plains

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
Plains/SPP	601	546	285	247	499	334	329	124	73	24	221	62%	7.50	75%	C

Transmission Capacity Available for New Resources

APPENDIX TABLE 66 Transmission Capacity Available for New Resources Grade Summary for the Plains

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
Plains/SPP	5.38	72%	C-

APPENDIX TABLE 67 Average cost of interconnection ($/kW) for last three Phase I interconnection studies for the Plains

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
Plains/SPP (2018, 2019, 2020)	$57.27	$263.07	$127.18	$149.17	2.13	85%	B

APPENDIX TABLE 68 Grade for completion rate by MW and queue entry date for the Plains

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
Plains/SPP	26%	18%	2%	1.63	65%	D

APPENDIX TABLE 69 Grade for median duration from interconnection request to interconnection agreement in Months for the Plains

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
Plains/SPP	40	42	51	1.63	65%	D

LBNL's 2022 Interconnection Queue report showed that the Plains region had a queue with almost 600 project requests and around 100 GW capacity.[380] The Plains region has one of the lower completion rates, with a capacity weighted completion rate for projects reaching commercial operation of 2% in the year used for evaluation. However, their completion rate only dropped significantly in recent years.[381] It is also important to note that SPP had a historically large queue in 2022. SPP received almost triple the interconnection requests compared to their next-highest queue year in 2021.[382] SPP is already experiencing delays in the interconnection queue study process, and this historic queue will likely lead to problems going forward. However, SPP has recognized some of these issues, and as with many regions, they are undergoing a queue reform process. As discussed in the Plains region transmission planning section, SPP is also working on a process that could integrate the interconnection queue process with transmission planning, called the Consolidated Planning Process.[383]

Congestion

APPENDIX TABLE 70 Grades for regional congestion ($/MWh) for the Plains

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
Plains/SPP	$1.70	$1.69	$4.49	5.63	75%	C

Congestion in the Plains and Midwest regions was high in 2021. The overall trend for congestion in both regions is increasing, with levels quadrupling from 2016 to 2021 in the

380 *Id.* at 7, 9.

381 *Id.* at 21.

382 SPP, "Southwest Power Pool Generation Interconnection Queue Dashboard," accessed May 2023, https://app.powerbi.com/view?r=eyJrIjoiNWRlMjYyN2EtOTA2Ny00NTE0LWI2M2QtMGE3MTAxZTAxOGE0IiwidCI6IjA2NjVkY2EyLTExNDEtNDYyNS1hMmI1LTY3NTY0NjNlMWVlMSIsImMiOjF9.

383 SPP, "Consolidated Planning Process Task Force Meeting Materials," accessed May 2023, https://www.spp.org/spp-documents-filings/?id=297513.

Plains and doubling in the Midwest. The Plains region has seen significant amounts of curtailment of wind generation in recent years, which has likely contributed to higher congestion. For example, in SPP's 2022 State of the Market report, the Market Monitor found that "from 2020 to 2022, average hourly curtailments increased substantially from 244 MW to 1,260 MW."[384] The trend is similar in the Midwest.[385] Higher congestion increasingly exposes new wind generation projects to congestion risk. Analysis from EDF Renewables shows that the Midwest and Plains regions have reached "tipping points" where congestion has begun to increase dramatically.[386]

H. Southeast

APPENDIX TABLE 71 Grade Summary for the Southeast

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
Southeast/SERTP, SCRTP, FRCC	F	F	A-	D	51.9%	**F**

The Southeast region has the lowest grade with an 'F.' Regional transmission planning largely relies on aggregating local transmission plans to ensure reliability, with no proactive, scenario-based, multi-value planning occurring and no regional lines having been approved. In addition, very little information is available to the public, there is limited stakeholder engagement, and very little transmission either built or planned.

384 SPP Market Monitoring Unit, "State of the Market 2022," May 2023, pg 53, https://www.spp.org/documents/69330/2022%20annual%20state%20of%20the%20market%20report.pdf.

385 Potomac Economics, "2021 State of the Market Report for the MISO Electricity Markets," June 2022, pg. ii, https://cdn.misoenergy.org/20220622%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20IMM%20State%20of%20the%20Market%20Report625261.pdf.

386 Emma Romack and Rodica Donaldson, "Congestion-Driven Basis Risk: A Challenge for the Development of Clean Energy Projects," EDF Renewables, March 2023, pg 3-4.

Planning Methods

APPENDIX TABLE 72 Assessment of Southeast planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Southeast/SERTP, SCRTP, FRCC	0	0	0	0	0	0	0	0	29	45%	F

The Southeast has three FERC Order No. 1000 regional transmission planning entities: Southeast Regional Transmission Planning (SERTP), South Carolina Regional Transmission Planning (SCRTP), and Florida Reliability Coordinating Council (FRCC). These entities largely aggregate their utilities' plans and periodically brief stakeholders without seeking significant input and often not sharing sufficient data, methods, or assumptions to enable an assessment of the projects.

FRCC

The FRCC planning process, known as the Regional Transmission Planning Process, happens on a two-year cycle and contains two separate processes, the Annual Transmission Planning Process (ATPP) and the Biennial Transmission Planning Process (BTPP).[387] The ATPP is a consolidation of FRCC member local transmission plans and is focused on reliability.[388] For generation and load, FRCC relies on 10-Year Site Plans submitted by individual FRCC members, which are used to develop its bases cases for reliability planning.[389] The BTPP encompasses FRCC's economic and public policy planning through evaluation of "cost effective or efficient regional transmission solutions," or "CEERTS" projects.[390] The process appears to rely on submissions of economic or public policy proposals, and according to FRCC's website there were no economic or public policy projects considered

387 FRCC, "Regional Transmission Planning Process FRCC-MS-PL-018," 2022, 4-5, https://www.frcc.com/order1000/_layouts/15/WopiFrame.aspx?sourcedoc=%7BAC2749A7-9B10-4FD8-87A0-7F5C8907DB02%7D&file=FRCC-MS-PL-018_FRCC_Regional_Transmission_Planning_Process.pdf&action=default.

388 *Id.*, 5, 7.

389 *Id.*, 10-13.

390 *Id.*, 5.

for the 2023-2024 planning cycle or for the 2021-2022 cycle.[391] If an CEERTS project was identified the project will be evaluated using a basic cost benefit analysis where a proposed CEERTS project cost must be less than the cost of the alternative local projects it would replace plus the changes to line losses.[392] Overall, the FRCC planning process is difficult for stakeholders to participate in and has not resulted in a regional transmission investment.[393]

SERTP

In SERTP, a regional transmission plan is produced annually, largely consolidating members' local transmission plans.[394] The planning process is a "bottom-up" process that happens over a 10-year horizon. SERTP relies on member utilities' local transmission plans for generation additions, retirements, and load forecasts for development of its power flow model base cases, which are used for determining system reliability.[395] In its 2022 regional plan, SERTP only identified two potential regional lines, and none were selected.[396] For SERTP's regional transmission plan, regional projects are analyzed case by case to see if they address regional transmission needs by displacing local projects. If a regional line could displace a local project, the cost of the regional project is compared to the cost of any potential local projects contained in the baseline regional transmission plan that might be replaced, and does not consider the broader benefits provided by the regional transmission line.[397] As a result of limited benefits considered, no regional lines have been selected. Economic planning and public policy planning are conducted in a separate process. For the economic study, SERTP may conduct up to five studies that look at bulk-power flows between to areas submitted by stakeholders. However, the results are

391 FRCC, "FRCC Proactive Planning Results and CEERTS Proposal Solicitation Announcement," April 2023, https://www.frcc.com/order1000/Lists/Announcements%20%20Regional%20Projects%20%20Order%201000/DispForm.aspx?ID=46&Source=https://www.frcc.com/order1000/Lists/Announcements%20%20Regional%20Projects%20%20Order%201000/AllItems.aspx&ContentTypeId=0x0104003AB6C5EFE8B9DF48AF25DDC3AA36DCE8; FRCC, "Results of FRCC 2023-2024 BTPP Public Policy Planning Submissions," February 2023, https://www.frcc.com/order1000/Lists/Announcements%20%20Regional%20Projects%20%20Order%201000/DispForm.aspx?ID=43&Source=https%3A%2F%2Fwww%2Efrcc%2Ecom%2Forder1000%2FLists%2FAnnouncements%2520%2520Regional%2520Projects%2520%2520Order%25201000%2FAllItems%2Easpx&ContentTypeId=0x0104003AB6C5EFE8B9DF48AF25DDC3AA36DCE8; FRCC, "Announcements - Regional Projects & Order 1000," accessed June 2023, https://www.frcc.com/order1000/Lists/Announcements%20%20Regional%20Projects%20%20Order%201000/AllItems.aspx.

392 FRCC, "Regional Transmission Planning Process FRCC-MS-PL-018," 24.

393 *See* Southern Environmental Law Center Pre-Technical Comments on Transmission Planning and Cost Management, Docket No. AD22-8-000 (2022), at 34-37, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2f889473-51c5-c170-8538-8346a2d00000.

394 *See,* SERTP, SERTP, "Regional Transmission Plan & Input Assumptions Overview," December 2022, http://www.southeasternrtp.com/docs/general/2022/2022_Regional_Transmission_Plan_and_Input_Assumptions_Final_Non-CEII.pdf

395 *Id.,* 14-19; Southern Companies, "Open Access Transmission Tariff, Attachment K," 2023, 560, http://www.oasis.oati.com/SOCO/SOCOdocs/Southern-OATT_current.pdf.

396 The 2022 Transmission Plan only identified two regional lines that were considered individually for the impacts. *See* SERTP, *2022 Regional Transmission Analyses*, November 2022, http://www.southeasternrtp.com/docs/general/2022/2022_SERTP_Regional_Transmission_Planning_Analyses_Summary_Final.pdf.

397 SERTP, "2022 Regional Transmission Analyses," November 2022, 12, http://www.southeasternrtp.com/docs/general/2022/2022_SERTP_Regional_Transmission_Planning_Analyses_Summary_Final.pdf.

mostly informational.[398] SERTP also allows stakeholders to submit proposed studies of public policy driven needs, but no public policy proposals were submitted between 2017-2022.[399]

SCRTP

SCRTP has a similar regional transmission planning process to SERTP, except it occurs over a two-year planning cycle and conducts both local and regional transmission planning.[400] SCRTP's plan, however, also essentially rolls up local transmission plans. SCRTP relies on utilities for load, and existing and planned generation.[401] These inputs are used to generate bases cases which are focused on reliability planning and meeting NERC requirements.[402] Economic and public policy transmission proposals are separately studied if SCRTP decides to review a submission from a stakeholder. Similar to SERTP, SCRTP will conduct up to five economic transmission planning studies of power transfers that are informational in nature.[403] If a regional line were selected, the benefit cost analysis for SCRTP is similar to SERTP in that it is essentially a cost comparison between the regional line cost, any required upgrades, and power losses compared to canceled projects, reduction in cost to existing projects, avoided projects, and reduction of power losses.[404] For SCRTP no regional projects were considered, in 2022.[405]

For all three regions there is very little proactive interregional transmission planning, at least not publicly. Interregional planning appears to be focused on operational reliability and no interregional lines have been built since Order No. 1000.[406] In addition, the Southeast does not consider all business models, with no independent transmission developer

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398 SERTP, "2022 Economic Planning Studies," 2022, 3, http://www.southeasternrtp.com/docs/general/2022/2022_SERTP_Economic_Study_Results_Final.pdf.

399 SERTP, "SERTP – 1st Quarter Meeting," March 2022, 28, http://www.southeasternrtp.com/docs/general/2022/2022-SERTP-1st-Qtr-Presentation-FINAL.pdf. *See* also Southern Environmental Law Center Pre-Technical Comments on Transmission Planning and Cost Management, Docket No. AD22-8-000 (2022), 14-15, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2f889473-51c5-c170-8538-8346a2d00000.

400 Dominion Energy, "Attachment K Transmission Planning Process," 7-12, https://www.scrtp.com/assets/pdfs/home/attachment-k-dominion-energy.pdf.

401 *See* SCRTP, "Base Cases," last accessed March 9, 2023, https://www.scrtp.com/base-cases.html.

402 *Id.*

403 Dominion Energy, "Attachment K Transmission Planning Process," 16-20; *See* also SCRTP, "Stakeholder Meeting Presentation," May 2020, https://www.scrtp.com/assets/pdfs/meeting-archives/scrtp-meeting-2020-05-05-presentation.pdf.

404 Dominion Energy, "Attachment K Transmission Planning Process," 31.

405 *See* SCRTP, "South Carolina Regional Transmission Planning Stakeholder Meeting," at 3-4, October 2022, https://www.scrtp.com/assets/pdfs/meeting-archives/scrtp-meeting-2022-10-06-presentation.pdf.

406 *See* SCRTP, "South Carolina Regional Transmission Planning Stakeholder Meeting," at 4-5, October 2022, https://www.scrtp.com/assets/pdfs/meeting-archives/scrtp-meeting-2022-10-06-presentation.pdf; *See* SREA Reply Comments on Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional, Docket No. RM21-17-000, 179 FERC ¶ 61,028 (2022) at 10, 20-21, 26-27, 68-70, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=49641b86-b8d1-c3b3-92f4-835740400000.

having never pre-qualified for a SERTP planning cycle,[407] and the Southern Cross Transmission Line being one of the only major independent lines under consideration.

In the Southeast a key issue for regional transmission planning is the lack of access to information and transparency which limits the effectiveness of transmission planning and stakeholder engagement. For example, for FRCC, most information on their website requires a login and there is very limited opportunity for stakeholder engagement or influence. For SCRTP, an NDA or CEII clearance is needed to access almost all results. In SERTP and SCRTP, state regulators and stakeholder also have little participation or influence over the planning process or outcomes.[408]

Transmission Lines Planned and Transmission Miles Built

APPENDIX TABLE 73 Transmission Lines Planned and Transmission Miles Built Grade Summary for the Southeast

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
Southeast/SERTP, SCRTP, FRCC	11.00	55%	F

APPENDIX TABLE 74 Southeast Grade for Proactively Planned New Lines

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
Southeast/SERTP, SCRTP, FRCC	0	4.5	45%	F

The Southeast has not identified any significant regional needs across the three planning entities and has few new or planned merchant transmission lines.[409]

407 *See* Southern Environmental Law Center Pre-Technical Comments on Transmission Planning and Cost Management, Docket No. AD22-8-000 (2022), at 16-17, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2f889473-51c5-c170-8538-8346a2d00000.

408 Eto, "Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans," 2016, 7, https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf; *See* Southern Environmental Law Center Pre-Technical Comments on Transmission Planning and Cost Management, Docket No. AD22-8-000 (2022), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=2f889473-51c5-c170-8538-8346a2d00000; SREA Reply Comments on Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional

409 SERTP, "2022 Regional Transmission Planning Analyses," November 2022, http://www.southeasternrtp.com/docs/general/2022/2022_SERTP_Regional_Transmission_Planning_Analyses_Summary_Final.pdf, SCRTP, "South Carolina Regional Transmission Planning Stakeholder Meeting," at 3-4, October 2022, https://www.scrtp.com/assets/pdfs/meeting-archives/scrtp-meeting-2022-10-06-presentation.pdf.

APPENDIX TABLE 75 2019-2021 New transmission miles built and operational (345 kV+) compared to expected share of 2012-2017 miles built for the Southeast

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
Southeast/ SERTP, SCRTP, FRCC					43	0	55	0	0	0	0	0%	6.50	65%	D

For the Southeast, C Three combines the region with other non-RTO regions. However, other sources show that only two high-capacity transmission lines were built since 2016, so we evaluated the region based on the assumption that no new miles had been built from 2019-2021.[410] The data in the table above is our own addition, not from the C Three Group.

Transmission Capacity Available for New Resources

APPENDIX TABLE 76 Transmission Capacity Available for New Resources Grade Summary for the Southeast

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
Southeast/SERTP, SCRTP, FRCC	6.75	90%	A-

410 The data in the table above was not included in the sum of total lines built from 2012-2017 to avoid double counting. It was used for grading purposes only. For the two lines built, *see* ACP, "Clean Power Annual Market Report 2021 Executive Summary," 2022, 22, https://cleanpower.org/wp-content/uploads/2022/05/2021-ACP-Annual-Report-Final_Public.pdf

APPENDIX TABLE 77 Average cost of interconnection ($/kW) for last three Phase I interconnection studies for the Southeast

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
Southeast/SERTP, SCRTP, FRCC				No Data	2.13	85%	B

APPENDIX TABLE 78 Grade for completion rate by MW and queue entry date for the Southeast

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
Southeast/SERTP, SCRTP, FRCC	15%	13%	16%	2.13	85%	B

APPENDIX TABLE 79 Grade for median duration from interconnection request to interconnection agreement in Months the Southeast

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
Southeast/SERTP, SCRTP, FRCC	21	15	18	2.50	100%	A

LBNL's 2022 Interconnection Queue report showed that the Southeast had a queue size similar to NYISO or SPP, with over 800 project requests and around 100 GW of capacity.[411] For our metrics, the Southeast scored well on completion rates for projects with 16% of projects reaching commercial operation.[412] In addition, the Southeast scored well on time projects spent in the interconnection queue. However, regions without an RTO rely on individual utilities to interconnect resources, and very little aggregated data or transparency exists on those project costs.

411 "2022 LBNL" at 7, 9.

412 *Id.* at 21.

Congestion

APPENDIX TABLE 80 Grades for regional congestion ($/MWh) for the Southeast

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
Southeast/SERTP, SCRTP, FRCC				4.88	65%	D

Outside of organized markets, in the Northwest, Southwest, and Southeast, there is limited data or transparency related to congestion. Given that congestion is rising across the country, we assumed that the trend also applies to these three regions.

I. Southwest

APPENDIX TABLE 81 Grade Summary for the Southwest

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
Southwest/WestConnect	F	B-	B-	D	62.3%	D-

The Southwest earned a 'D-.' The Southwest has not been doing proactive planning. Instead the region relies heavily on inputs from its members to develop its regional plans. Much of the reason the region managed a 'D' grade can be attributed to the work of individual utilities or states in the region, particularly in Colorado and New Mexico, that have been successful at developing transmission.

Planning Methods

APPENDIX TABLE 82 Assessment of Southwest planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Southwest/ WestConnect	2	0	0	0	0	0	2	1	35	54%	F

The Southwest does not have an RTO/ISO; as such, the region is defined by the WestConnect— the FERC Order No. 1000 transmission planning authority—planning footprint. Currently in this region, individual states and utilities lead a significant portion of the transmission planning and development.

The WestConnect Regional Transmission Planning Process happens on a two-year cycle, evaluates a 10-year planning horizon, and is largely driven by its Transmission Owners with Load Serving Obligation (TOLSO) members. All committees in WestConnect report to the Planning Management Committee (PMC). The PMC does include roles for State Regulatory Commissions and Key Interest Groups, but currently those seats are vacant.[413] WestConnect has three Subregional Planning Groups, the Southwest Transmission Planning Group (SWAT), the Sierra Subregional Planning Group (SSPG), and the Colorado Coordinated Planning Group (CCPG).[414] These subregional planning groups along with Transmission Owners with Load Serving Obligations help to develop the base cases for the transmission study by submitting Base Transmission Plans for their subregion.[415]

In its last three transmission planning cycles, including the 2022-2023 cycle, WestConnect did not identify any regional transmission needs.[416] Instead, for its Regional Transmission Plan, WestConnect largely roles up the local plans of TOLSO.[417] For the Regional Trans-

413 WestConnect, "WestConnect Regional Planning Process Business Practice Manual," October 2021, 5, https://doc.westconnect.com/Documents.aspx?NID=17155&dl=1.

414 WestConnect, "2022-23 Planning Cycle Final Regional Study Plan," March 2022, 13, https://doc.westconnect.com/Documents.aspx?NID=20635.

415 *Id.*, 29-43.

416 WestConnect, "WestConnect 2020-21 Regional Transmission Planning Cycle Regional Transmission Report," December 2021, 7, https://doc.westconnect.com/Documents.aspx?NID=20390.

417 WestConnect, "WestConnect Regional Planning Process Business Practice Manual," 18-21, 24.

mission Plan, WestConnect conducts a Regional Needs Assessment for the transmission plan.[418] For the Regional Needs Assessment, WestConnect starts by creating the Base Transmission Plan, which includes TOLSO's local transmission plans.[419] WestConnect then works on the development of its power flow and production cost models, which are used to study reliability and economic projects separately.[420] For this process, WestConnect uses WECC base cases which are supplemented by bottom-up reporting on generation and load, as well as local transmission plans.[421] WestConnect uses these base cases to conduct reliability power flow studies and a separate economic study based on production cost savings.[422] For its economic studies, WestConnect includes sensitivities to its base case, such as emissions costs.[423] For potential Public Policy transmission needs, WestConnect notes they are first addressed through local transmission plans.[424] For the public policy study, WestConnect at a high-level compares renewable energy sales with RPS targets.[425] Any potential regional issues that the reliability and economic studies identify may still be considered local and for an individual TOLSO to resolve.[426] Outside of the regional needs assessment, WestConnect does conduct information-only scenario studies that look at alternate but plausible futures. They represent futures with resource, load, and public policy assumptions that are different in one or more ways than what is assumed in the Base Cases.[427]

Like the Northwest, much of the transmission planning and development in the Southwest occurs at the state, utility, or merchant level. The New Mexico Renewable Energy Transmission Authority (RETA) has been a successful model for state-level transmission development.[428] Colorado created a similar entity called the Colorado Electric Transmission Authority.[429]

Despite active states, utilities, and merchant developers, very little is happening regard-

418 WestConnect, "WestConnect Regional Transmission Planning 2022-23 Planning Cycle," March 2022, 7-8, https://doc.westconnect.com/Documents.aspx?NID=20635&dl=1.

419 *Id.,* 11.

420 WestConnect, "WestConnect Regional Planning Process Business Practice Manual," October 2021, 21-22.

421 *Id.*

422 *Id.,* 23.

423 WestConnect, "WestConnect Regional Transmission Planning 2022-23 Planning Cycle," 19-20.

424 WestConnect, "WestConnect Regional Planning Process Business Practice Manual," 24.

425 WestConnect, "WestConnect Annual Interregional Information," March 2023, slide 29-30, http://www.caiso.com/Documents/Presentation-WestConnect-Annual-Interregional-Information-Mar9-2023.pdf.

426 WestConnect, "WestConnect Regional Planning Process Business Practice Manual," 24; WestConnect, "WestConnect Regional Transmission Planning 2022-23 Planning Cycle," 9.

427 WestConnect, "WestConnect Regional Transmission Planning 2022-23 Planning Cycle," 26.

428 New Mexico Renewable Energy Transmission Authority, https://nmreta.com/transmission-lines/.

429 Colorado Electric Transmission Authority, https://energyoffice.colorado.gov/about-us/boards-commissions/colorado-electric-transmission-authority.

ing interregional coordination. WestConnect's interregional planning with NorthernGrid and CAISO appears to be focused on addressing potential affected systems issues, however it has not yet produced a plan as other regions have.[430] For example, CAISO identified one interregional project in its 2022-2023 Draft. However, WestConnect did not identify any regional needs in its 2022-2023 planning cycle.[431]

Transmission Lines Planned and Transmission Miles Built

APPENDIX TABLE 83 Transmission Lines Planned and Transmission Miles Built Grade Summary for the Southwest

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
Southwest/WestConnect	16.00	80%	B-

APPENDIX TABLE 84 Southwest Grade for Proactively Planned New Lines

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
Southwest/WestConnect	2	7.5	75%	C

In the Southwest, WestConnect, the regional planning entity, did not identify any regional needs in its previous transmission plan.[432] States, utilities, and merchant developers are driving most of the transmission planning and development in the region. For example, in Colorado, Xcel has planned the Colorado Power Pathway projects, an approximately $2 billion investment in almost 600 miles of high voltage lines that will help Colorado meets its goals by interconnecting 5.5 GWs of resources.[433] In New Mexico, the RETA has approximately 1200 miles of new high voltage transmission under development that will inter-

430 *See* WestConnect, "WestConnect Regional Planning Process Business Practice Manual," Appendix D; Northwest & Intermountain Power Producers Comments on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional, Docket No. RM21-17-000, 176 FERC ¶ 61,024 (2021) at 4-5, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=8e249000-1920-ccf9-916d-7c76b0d00000; *See* also Public Interest Organizations Comments on Advance Notice of Proposed Rulemaking, Building for the Future Through Electric Transmission Planning and Cost Allocation and Generator Interconnection Regional, Docket No. RM21-17-000, 176 FERC ¶ 61,024 (2021) at 45-49, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=60f22f6b-c401-c6bc-b293-7c76ae400001.

431 CAISO, "Draft 2022-2023 Transmission Plan," 121-129.

432 WestConnect, "Regional Planning 2022-2023 Regional Planning Cycle," 2022, http://regplanning.westconnect.com/2022_23_regional_plng_cycle.htm.

433 Xcel Energy, "Colorado's Power Pathway," May 2023, https://www.coloradospowerpathway.com/.

connect almost 9 GW of new generation and represents over $5 billion in investments.[434] These lines have regional benefits even if they have not gone through a regional planning process.

APPENDIX TABLE 85 **2019-2021 New transmission miles built and operational (345 kV+) compared to expected share of 2012-2017 miles built for the Southwest**

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
Southwest/ WestConnect	352	198	162	166	33	76	28	268	207	90	565	88%	8.50	85%	B

The Northwest and Southwest score well on miles of transmission built. C Three's data combines the non-RTO region, so similar to the transmission capacity available for new resources metrics below, the Northwest and Southwest were evaluated using the same number of miles built for the 2019-2021 period.

Transmission Capacity Available for New Resources

APPENDIX TABLE 86 **Transmission Capacity Available for New Resources Grade Summary for the Southwest**

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
Southwest/WestConnect	6.13	82%	B-

434 New Mexico Renewable Energy Transmission Authority, "Transmission Lines: Creating a Highway for Clean Energy," accessed May 2023, https://nmreta.com/transmission-lines/.

APPENDIX TABLE 87 Average cost of interconnection ($/kW) for last three Phase I interconnection studies for the Southwest

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
Southwest/WestConnect				No Data	2.13	85%	B

APPENDIX TABLE 88 Grade for completion rate by MW and queue entry date for the Southwest

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
Southwest/ WestConnect	20%	8%	8%	1.88	75%	C

APPENDIX TABLE 89 Grade for median duration from interconnection request to interconnection agreement in Months for the Southwest

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
Southwest/WestConnect	33	32	32	2.13	85%	B

LBNL's 2022 Interconnection Queue data combined the Northwest and Southwest into one region, the West. The West had one of the largest queues, with over 1800 project requests and almost 600 GW of capacity.[435] However, capacity-weighted completion rates for projects were one of the lowest nationally, with only 8% of projects reaching commercial operation.[436] For interconnection costs, the Northwest and Southwest regions do not have an RTO and rely on individual utilities to interconnect resources. This means there is relatively little public data or transparency around interconnection costs, and aggregation for the limited information that may exist is difficult. Given that the West is experiencing similar trends as the rest of the country with the data that LBNL does provide on interconnection queue wait times and completion rates, it is likely that costs on a $/kW basis are following similar upward trends as we see in RTOs.

435 "2022 LBNL" at 7, 9.
436 *Id.* at 21.

Congestion

APPENDIX TABLE 90 Grades for regional congestion ($/MWh) for the Southwest

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
Southwest/WestConnect				4.88	65%	D

Outside of organized markets, in the Northwest, Southwest, and Southeast, there is limited data or transparency related to congestion. Given that congestion is rising across the country, we assumed that the trend also applies to these three regions.

J. Texas

APPENDIX TABLE 91 Grade Summary for Texas

REGION	PLANNING METHODS AND BEST PRACTICES (65%)	TRANSMISSION LINES PLANNED AND TRANSMISSION MILES BUILT (20%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES (7.5%)	CONGESTION (7.5%)	PERCENT	OVERALL GRADE
Texas/ERCOT	D	C-	A	D	68.6%	D+

Texas received a fairly low grade of a 'D+.' It received high marks on transmission capacity for available new resources metrics for the relative ease developers have in connecting new generation but will need to address congestion soon as the region experienced record levels of congestion in 2022. The region needs to adopt more proactive, scenario-based, multi-value transmission planning, and there is a major need for interregional transmission as was made clear during winter storm Uri.

Planning Methods

APPENDIX TABLE 92 Assessment of Texas planning methods

REGION	PROACTIVELY PLANNING GENERATION AND LOAD (10%)	SCENARIO BASED PLANNING (7.5%)	MULTI-VALUE PLANNING (10%)	PORTFOLIO PLANNING (7.5%)	INTERREGIONAL PLANNING (7.5%)	STAKEHOLDER ENGAGEMENT (10%)	CONSIDER ALL BUSINESS MODELS (5%)	GOVERNANCE (7.5%)	SCORE (OUT OF 65)	PLANNING GRADE (%)	PLANNING LETTER GRADE
Texas/ERCOT	1	1	0	1	0	3	1	3	42	65%	D

Like other single-state transmission organizations, the Texas region is largely influenced by two entities, the Electric Reliability Council of Texas (ERCOT), which conducts transmission planning, and the state of Texas.

ERCOT conducts Texas transmission planning on a 6-year planning horizon with an emphasis on planning for reliability that meet NERC planning requirements.[437] To get generation retirements and additions for the study period, ERCOT relies on notifications from entities and highly certain projects from the queue.[438] ERCOT does conduct its own 15-year load forecast and has noted that extreme weather events and EV electrification are a source of uncertainty, though EVs are not a part of the forecast yet.[439] For its reliability base cases, ERCOT develops its load forecast through the Steady State Working Group (SSWG) which is used in a set of steady-state power flow models known as “SSWG Cases” that are developed annually.[440] These base cases are largely focused on ensuring ERCOT meets reliability criteria.[441]

Planning for reliability and economic lines are done in separate studies and economic planning largely centers around reduced production costs and very few other benefits using a base weather year.[442] For the approval of any economic line, the proposed line must produce a cost-benefit analysis including a production cost savings test that “must include an analysis of whether the levelized ERCOT-wide annual production cost savings

437 *See* ERCOT, “ERCOT Planning Guide,” 2023, https://www.ercot.com/files/docs/2023/03/30/April%201,%202023%20Planning%20Guide.pdf.

438 ERCOT, “2022 Regional Transmission Plan Scope and Process,” https://www.ercot.com/files/docs/2022/03/11/Draft_2022_RTP_Scope_and_Process_v2_clean.pdf.

439 ERCOT, “2023 ERCOT System Planning Long-Term Hourly Peak Demand and Energy Forecast,” 2023, https://www.ercot.com/files/docs/2023/01/18/2023-LTLF-Report.pdf.

440 ERCOT, “2022 Regional Transmission Plan Scope and Process,” 2-7.

441 ERCOT, “ERCOT Planning Guide,” 26.

442 ERCOT, “2022 Regional Transmission Plan Scope and Process,” 8.

attributable to the proposed project are equal to or greater than the first-year annual revenue requirement of the proposed project of which the transmission line is a part."[443] This timeframe is inconsistent with standard benefit-cost analysis which should be conducted over the life of the investment. This approach has led to approval of only two economic transmission lines in the past decade. This will change slightly as the Texas PUC issued an order at the end of 2022 requiring ERCOT to develop a new congestion cost savings test for its economic planning. While developing the new test, the PUCT ordered ERCOT to use its old 2011 Generator Revenue Reduction Test and if an economic transmission project passes either the production cost savings or generator revenue reduction test it may be approved. In addition, the order requires ERCOT to conduct a biennial study of grid reliability and resiliency in extreme weather scenarios and allows for the consideration of resiliency benefits of a proposed transmission project based on the study when determining whether to approve the project.[444] This was in response to a law the Texas legislature passed after Winter Storm Uri.

ERCOT does not consider portfolios of projects, instead evaluating individual lines through the Regional Planning Group (RPG). The RPG is a non-voting consensus-based stakeholder group that reviews all proposed lines over $25 million or 345 kV that is not an in-kind replacement.[445] The regional planning group meets monthly and is where all stakeholder communication related to the RTP happens.[446] But, Texas is one of the only transmission planning entities that considers dynamic line ratings as a part of its economic transmission planning.[447] ERCOT also conducts a Long-Term System Assessment (LTSA) that evaluates transmission needs up to a 20-year planning horizon.[448] The LTSA study incorporates three scenarios and conducts capacity expansion and generator retirement modeling to identify upgrades that may be more robust across the scenarios. Overall, the LTSA does not propose specific solutions and does not impact the RTP planning process.[449]

As a separate interconnection, ERCOT does not conduct interregional planning. ERCOT has jurisdictional sovereignty, and its electricity is not considered to flow in interstate

443 ERCOT, "Update on Financial Assumptions for ERCOT Economic Transmission Planning," Slide 2, https://www.ercot.com/files/docs/2023/02/10/Financial%20Assumptions%20for%20ERCOT%20Economic%20Planning%20Criteria_Feb14_2023_v5.0.pdf.

444 Texas PUC, "Order Adopting Amendments to 16 TAC 25.101 as Approved at the November 30, 2022 Open Meeting," December 2022, https://interchange.puc.texas.gov/search/documents/?controlNumber=53403&itemNumber=86.

445 ERCOT, "ERCOT Regional Planning Group Charter," 2018, https://www.ercot.com/files/docs/2018/06/25/ERCOT_Regional_Planning_Group_Charter.docx.

446 ERCOT, "2022 Regional Transmission Plan Scope and Process," 4.

447 ERCOT, "2022 Regional Transmission Plan," 10.

448 The 2022 LTSA only used a 15-year planning horizon. *See,* ERCOT, "2022 Long-Term Assessment for the ERCOT Region," 2022, https://www.ercot.com/files/docs/2022/12/22/2022_LTSA_Report.zip.

449 ERCOT, "ERCOT Planning Guide," at 26.

commerce under the Federal Power Act.[450] To avoid impacting ERCOT's jurisdictional status, any interconnection would have to be specially built pursuant to a case-specific declaratory order from the Federal Energy Regulatory Commission, further complicating the process of developing interregional transmission. ERCOT, the Public Utility Commission of Texas, and the Texas legislature have considered strengthening the ties to neighboring regions but thus far have not. At this point Texas earns the lowest grade for interregional planning.

ERCOT has fairly balanced governance with an independent board and a robust stakeholder process.[451] Texas, like all regions, has a merchant transmission interconnection process but is only considering one major merchant line.[452]

Transmission Lines Planned and Transmission Miles Built

APPENDIX TABLE 93 Transmission Lines Planned and Transmission Miles Built Grade Summary for Texas

REGION	TOTAL SCORE (OUT OF 20%)	MILES BUILT AND PLANNED GRADE (%)	MILES BUILT AND PLANNED LETTER GRADE
Texas/ERCOT	14.00	70%	C-

APPENDIX TABLE 94 Texas Grade for Proactively Planned New Lines

REGION	SCORE (OUT OF 4)	RAW SCORE (OUT OF 10)	SCORE (OUT OF 100%)	MILES PLANNED LETTER GRADE
Texas/ERCOT	0	4.5	45%	F

In its 2022 Regional Transmission Plan, Texas only identified new transmission lines required for reliability upgrades and only over a 6-year horizon. This is despite the fact that Texas is facing record levels of congestion, and the CREZ projects are over a decade old and fully subscribed. Texas also did not evaluate any potentially economically driven transmission lines in its 2022 Regional Transmission Plan.[453] In the 2021 study, Texas did

450 *Cottonwood Energy Co., LP*, 118 FERC ¶ 61,198 (2007); *Sharyland Utilities, LP*, 121 FERC ¶ 61,006 (2007); *Cross Texas Transmission, LLC*, 129 FERC ¶ 61,106 (2009).

451 ERCOT, "Governance," accessed 2023, https://www.ercot.com/about/governance.

452 ERCOT, "Report on Existing and Potential Electric System Constraints and Needs ," December 2022, https://www.ercot.com/files/docs/2022/12/22/2022_Report_on_Existing_and_Potential_Electric_System_Constraints_and_Needs.pdf.

453 *See* ERCOT, "2022 Regional Transmission Plan," December 2022, https://www.ercot.com/gridinfo/planning.

conduct an economic study but only used the research to identify projected transmission constraints and lines to recommend for dynamic rating.[454] In addition, very few interregional or merchant lines are planned in Texas.

APPENDIX TABLE 95 **2019-2021 New transmission miles built and operational (345 kV+) compared to expected share of 2012-2017 miles built for Texas**

REGION	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	SUM (2019-2021)	EXPECTED SHARE OF LINES BUILT FOR 2019-2021	RAW SCORE (OUT OF 10%)	MILES BUILT GRADE (%)	MILES BUILT LETTER GRADE
Texas/ERCOT	1,211	1,379	134	124	298	108	129	180	322	148	650	125%	9.50	95%	A

Texas does score well on the grading scale, which means they have built new transmission. However, this does not fully reflect recent activities; Texas no longer conducts proactive transmission planning and buildout. Even though significant transmission was built from 2012-2017, the average rate fell by half in subsequent years, from 2019-2021.

Transmission Capacity Available for New Resources

APPENDIX TABLE 96 **Transmission Capacity Available for New Resources Grade Summary for Texas**

REGION	TOTAL SCORE (OUT OF 7.5%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES GRADE (OUT OF 100%)	TRANSMISSION CAPACITY AVAILABLE FOR NEW RESOURCES LETTER GRADE
Texas/ERCOT	7.50	100%	A

454 *See* ERCOT, "2021 Regional Transmission Plan," December 2021, https://www.ercot.com/gridinfo/planning.

APPENDIX TABLE 97 Average cost of interconnection ($/kW) for last three Phase I interconnection studies for Texas

REGION	1ST PHASE 1 STUDY	2ND PHASE 1 STUDY	3RD PHASE 1 STUDY	AVERAGE	SCORE (OUT OF 2.5%)	$/KW GRADE (%)	$/KW LETTER GRADE
Texas/ERCOT				$0.00	2.50	100%	A

APPENDIX TABLE 98 Grade for completion rate by MW and queue entry date for Texas

REGION	QUEUE ENTRY DATE (2015)	QUEUE ENTRY DATE (2016)	QUEUE ENTRY DATE (2017)	SCORE BASED ON 2017 COMPLETION RATE (OUT OF 2.5)	2017 COMPLETION RATE GRADE (%)	2017 COMPLETION RATE LETTER GRADE
Texas/ERCOT	30%	21%	28%	2.50	100%	A

APPENDIX TABLE 99 Grade for median duration from interconnection request to interconnection agreement in Months for Texas

REGION	IA IN 2019	IA IN 2020	IA IN 2021	SCORE BASED ON 2021 QUEUE DURATION (OUT OF 2.5)	2021 MEDIAN DURATION GRADE (%)	2021 DURATION LETTER GRADE
Texas/ERCOT	20	21	18	2.50	100%	A

Texas' interconnection process is substantially similar to how interconnection is performed under a "connect and manage" approach to integrated interconnection and transmission planning. New generators only pay for their connection to the grid rather than the broader systems or affected interregional system costs that generators in other regions have to pay. In exchange, generators do not receive firm transmission rights and grid operators curtail them more quickly. This is a relatively efficient way to add new generation to the grid. This efficiency is reflected in LBNL's 2022 Interconnection Queue report, which shows that Texas has the highest project completion rate of any region, with 28% of projects (capacity weighted) reaching commercial operation, and one of the lowest interconnection queue wait times at 18 months.[455] Texas has the fourth largest

455 "2022 LBNL" at 21.

queue, with 902 projects and almost 250 GW being evaluated.[456]

Congestion

APPENDIX TABLE 100 Grades for regional congestion ($/MWh) for Texas

REGION	2019	2020	2021	SCORE (OUT OF 7.5)	CONGESTION GRADE (%)	CONGESTION LETTER GRADE
Texas/ERCOT	$3.28	$3.68	$5.35	4.88	65%	D

In the section above, we discussed Texas's good performance on transmission capacity available for new resources metrics because of the relative ease for developers to add generation. However, easy interconnection without proactive planning can lead to congestion and curtailment, as significant amounts of generation are added, filling up existing transmission capacity. This has contributed to the almost doubling of congestion in ERCOT from 2020 to 2021. Congestion rose even higher for ERCOT in 2022, setting a record of $2.8 billion.[457]

456 *Id.* at 7, 9.

457 Potomac Economics, "ERCOT Wholesale Electricity Market Monthly Report," Jan 2023, 16, https://www.potomaceconomics.com/wp-content/uploads/2023/01/Nodal_Monthly_Report_2022-12.pdf.