Transmission in the United States

What Makes Developing Electric Transmission So Hard? An Update

July 2024

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1. INTRODUCTION

As a follow-up to our June 2021 white paper, “What Makes Building Electric Transmission So Hard?” (the “2021 White Paper”), this paper walks through the developments that have taken place in the last three years and discusses whether they will help solve the issues we identified.

Transmission is a critical piece of the clean energy transition. As has been stated many times, “there is no transition without transmission.” The 2021 White Paper described the challenges associated with building transmission in the following areas: transmission planning, cost allocation, transmission interconnection queues, ratemaking and incentives, and siting and permitting. In the last three years, we have seen important progress in transmission planning and cost allocation, backstop siting, and interconnection queues.

Since 2021, FERC initiated several dockets to address both historical issues, such as lack of interregional transmission, and new issues such as the rapidly changing resource mix. As described later in this paper, FERC has issued some important orders in the last year: Orders 2023, 1977, and 1920. However, the industry continues to face tremendous pushback on siting and permitting across the myriad jurisdictions that can weigh in. Continued uncertainty in ratemaking and incentive treatment may make investing in transmission less attractive in an era when, the industry has agreed, more is needed.

While the industry continues to invest in transmission infrastructure, it is not investing at the pace required to enable the ambitious clean energy targets put forth by the current administration, investor-owned utilities, state legislatures, and various private companies. Importantly, the cost to build transmission (as with other infrastructure) is rising, which means that less is built for the dollars allocated, and the anticipated costs of the transmission build-out needed continues to increase.

In addition, the pace required to meet the needs of the energy transition is accelerating due to the large loads seeking to interconnect to the grid across the country. Demand is increasing at a rate not seen in decades, putting pressure on utilities to increase the capacity of their systems (both in generation and grid infrastructure).

In summary, the changes that have been made in the past three years are a start toward the kind of reform necessary to build more transmission, but they are inadequate to build transmission as quickly as it is needed. The emergence of large loads only increases the urgency of this build-out.

2. TRENDS IN TRANSMISSION DEVELOPMENT

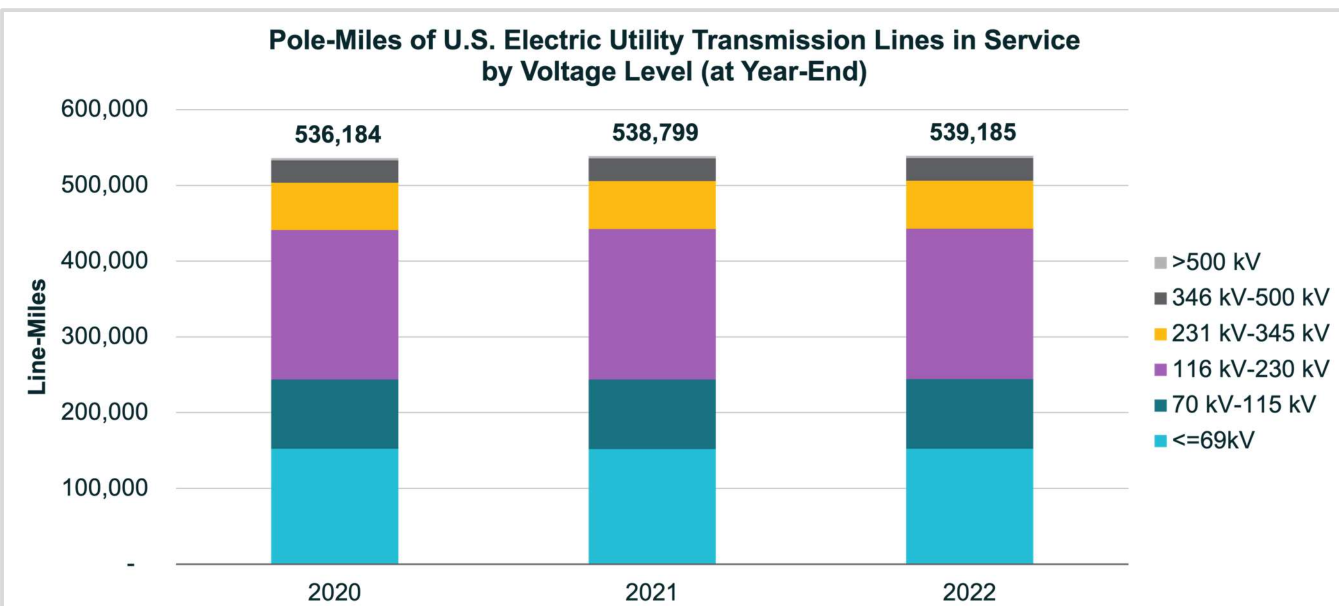
Key Takeaways

- Only a modest amount of transmission has been built over the past several years.
- Most transmission projects have been local, focused on reliability concerns.
- Nearly all projects completed since 2020 and planned as of spring 2024 have been intraregional (versus interregional) projects.
- Despite relatively few line-miles built, utilities and transmission developers are investing in transmission. Investor-owned utilities planned to invest $121 billion between 2020 and 2026. Inflation is playing a role in some of the growth in spending.
- Some regions have identified large, regional investments. Midcontinent ISO, for example, plans to invest nearly $9 billion pursuant to its latest (2023) regional transmission plan plus an additional $10.3 billion in its first tranche (of four) of development under its long-term regional plan and currently estimates a cost of $17 to $23 billion for its second tranche.

Installed Base of Transmission

As of year-end 2022 (the most recent year of comprehensive data), installed pole-miles of transmission lines in service totaled more than 539,000 miles. Most of those miles were 230 kV or less. Very few (approximately 33,000 miles) were in the highest voltages (345 kV or greater). The pole-miles at year-end 2020-2022 are shown in Figure 2.1.

Figure 2.1: Installed Electric Transmission – U.S. Electric Utilities[1]



[1] Edison Electric Institute, Statistical Yearbook of the Electric Power Industry, Table 10.6, from 2020-2022.

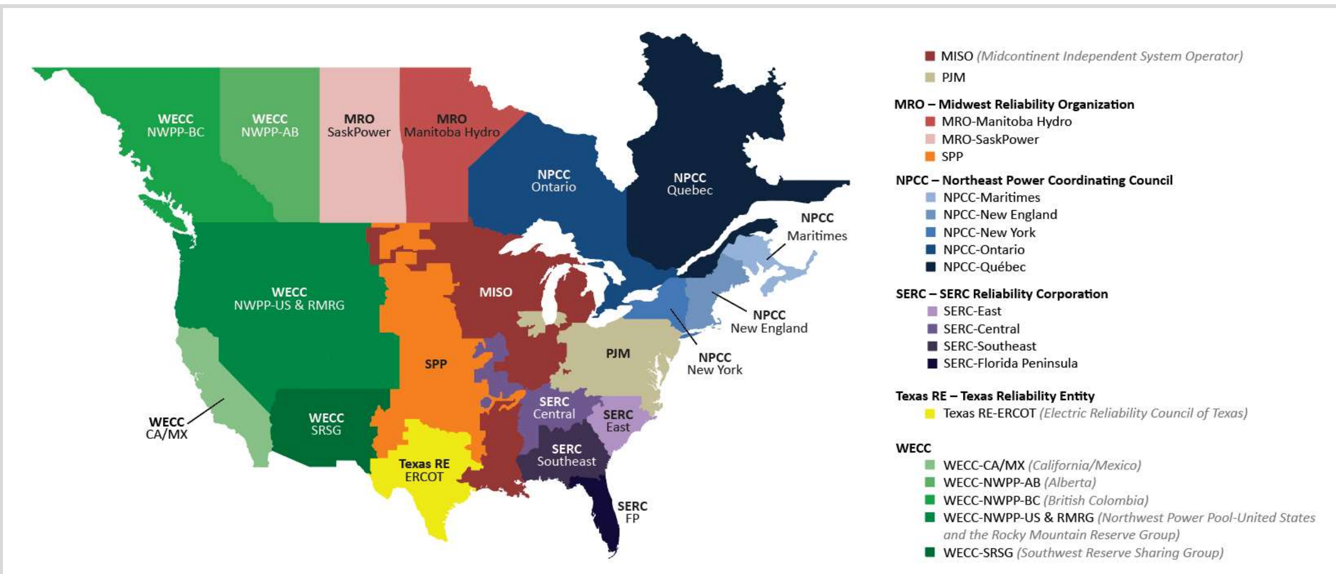
As of year-end 2022, transmission plant balances (net of depreciation) of U.S. electric utilities (including transmission companies) totaled $232 billion, compared with $217 billion in 2020 and $201 billion in 2021.[2]

Historical and Projected Transmission Development (Line-Miles)

There are multiple estimates of installed miles in the United States. FERC tracks infrastructure additions, and the North American Electric Reliability Corporation (NERC) maintains a transmission project database that includes both completed and planned transmission facilities.

In looking at transmission additions, we see several different geographic constructs (see Figures 2.2 and 2.3). One is NERC assessment areas, which are overseen by NERC to assure reliability of the bulk power system. Regional transmission organizations/independent system operators are non-profit organizations that administer the transmission grid on a regional basis, operate energy and related markets, and coordinate transmission planning within their footprints. The seven regional transmission organizations/independent system operators (RTO/ISOs) operating in the United States serve approximately two-thirds of U.S. population.

Figure 2.2: NERC Assessment Areas



[2] S&P Capital IQ Pro, FERC Form 1 data for electric and combination utilities and transmission companies, Net Transmission Plant – End of Year; ScottMadden analysis.

Figure 2.3: RTO/ISO Regions[3]

From 2020 through 2023, approximately 4,126 line-miles of transmission had been added in the United States (see Figures 2.4 and 2.5 for a breakdown by year and voltage).[4] Much of the recent installations was in the 70 kV to 345 kV range. No very large lines (greater than 500 kV) were completed.

[3] ISO/RTO Council

[4] Note that these line-miles do not match up with the installed line-mile snapshots from EEI (not YE 2022 vs. YE 2020 = 3,001 vs. S&P estimate of 1,375 miles added those two years).

Figure 2.4: Installed Electric Transmission (Line-Miles)[5]

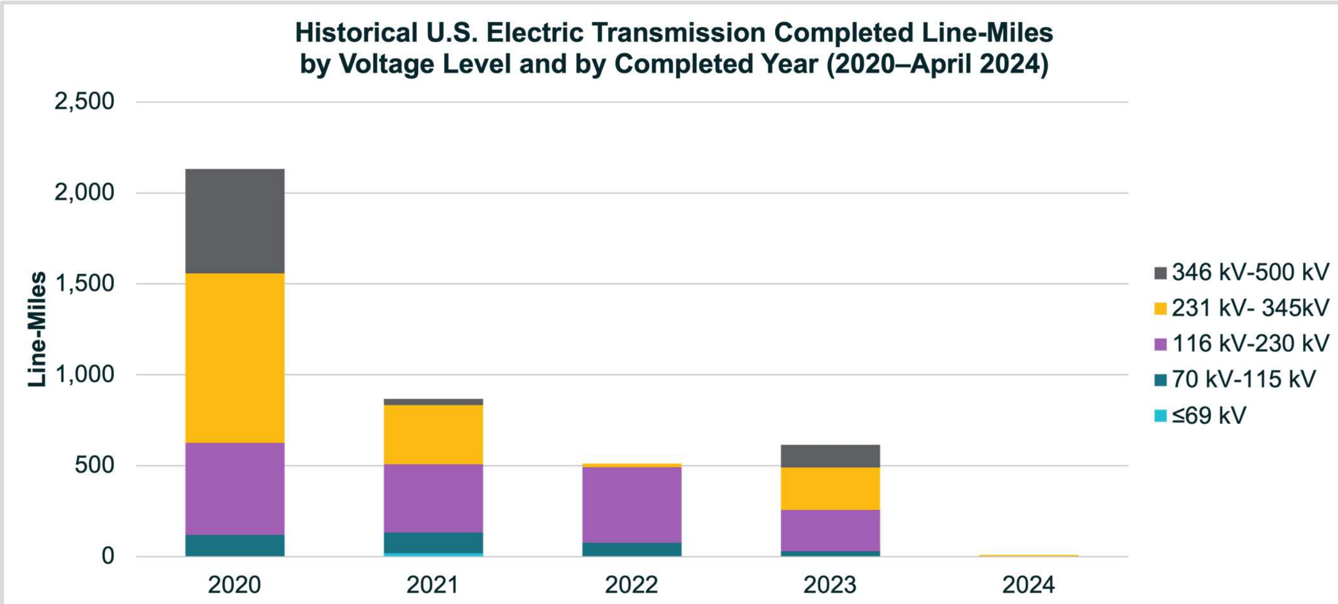
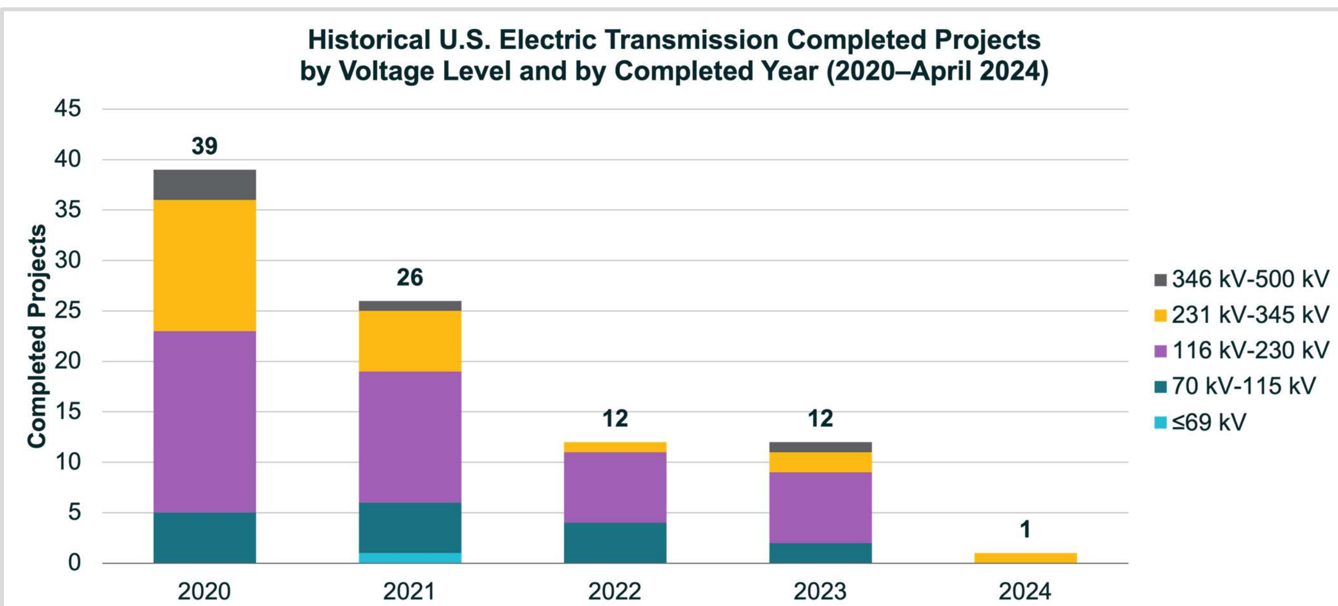


Figure 2.5: Installed Electric Transmission (Projects)[6]



As of late April 2024, there were approximately 339 planned (or operating and planned) U.S. transmission projects representing 20,662 line-miles. These projects include new lines as well as rebuilds and upgrades. These planned projects are split among voltages as shown in Figure 2.6.

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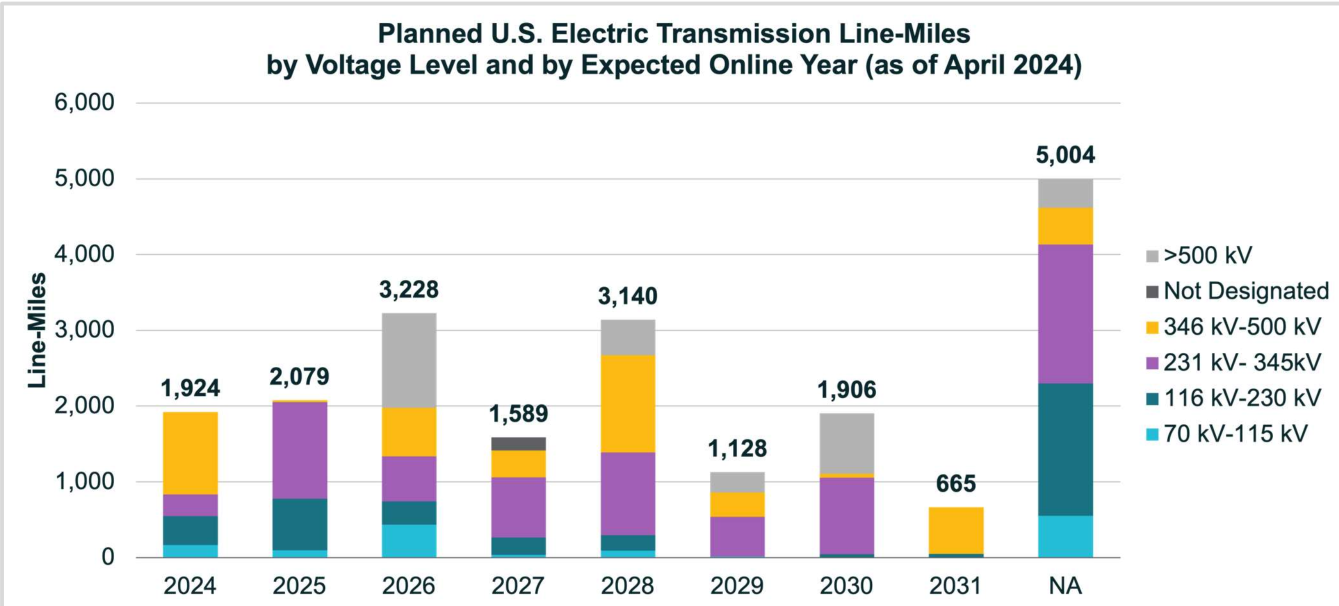
[5] NERC, S&P Capital IQ data as of April 2024; ScottMadden analysis.
[6] Ibid.

Figure 2.6: Projected Electric Transmission[7]



Drivers of Historical and Projected Transmission Installations

There are several drivers of transmission projects, including the following:

- Reliability: Projects that enhance grid reliability
- Economics/congestion: Projects aimed at alleviating congestion on the system, which increases power costs due to redispatch
- Generation integration: Projects that involve upgrades and new lines to accommodate new generation, especially renewable resources

In RTOs, during the transmission planning process, projects are designated as supporting one or more of the drivers above. In some cases, multiple drivers are indicated. These are often designated as multi-value projects.

As documented by NERC, the largest driver of projects completed during the years 2020-2023 was reliability, nearly 88% of projects.[8] About half of projects noting a primary driver listed a secondary driver. Of those, about two-thirds noted economics/congestion as the secondary driver.

Inter- vs. Intraregional Projects

FERC Order 1000 encouraged coordination between regions for planning and cost allocation, where interregional projects could facilitate efficient and cost-effective solutions to regional transmission needs.

[7] Ibid.
[8] NERC, Electricity Supply & Demand Database; ScottMadden analysis.

Despite this policy preference by FERC, in RTO regions, most projects completed since 2020 and planned as of April 2024 are intraregional projects.

Of U.S. projects completed from 2020 to 2023 that originated in an ISO, 68 were intraregional and only two projects were interregional (MISO-ERCOT and New England-New York) (a 34:1 ratio).

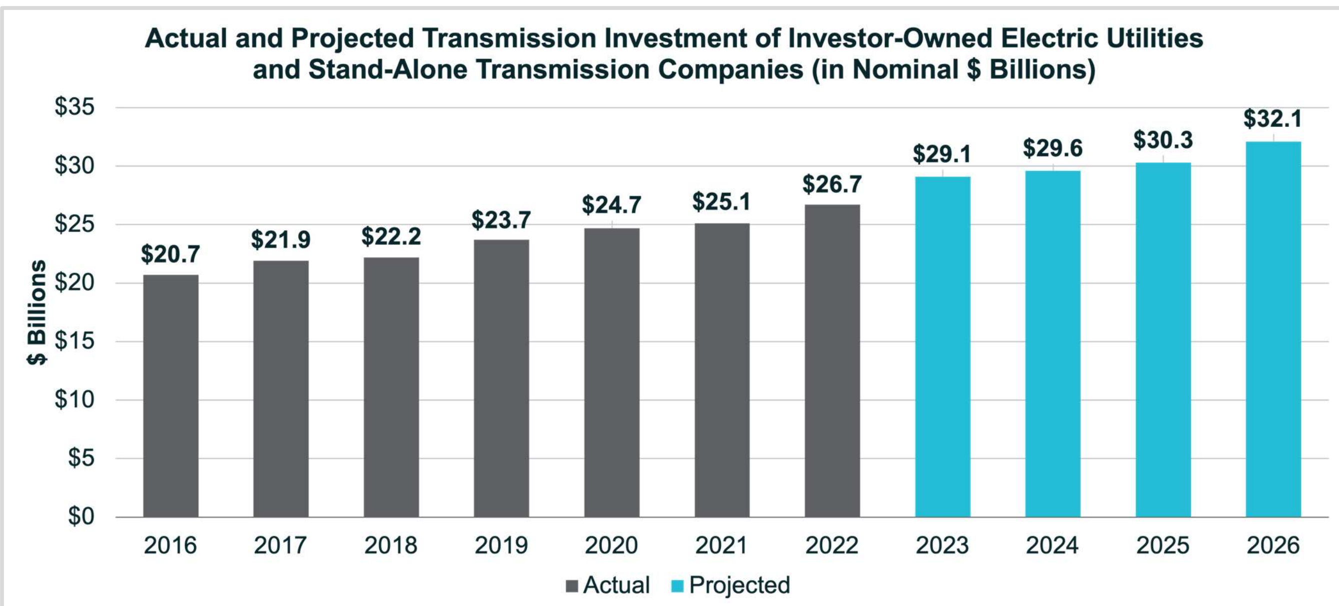
A slightly lower ratio holds for planned projects originating in ISOs, with 195 identified as intraregional and 12 as interregional (16.25:1).

Cost of Transmission Development

Historical and Projected Transmission Investment

Transmission investment by Edison Electric Institute members, comprising most investor-owned utilities in the United States, has been steadily growing at roughly a compound annual growth rate (CAGR) of 4.3% from 2016 to 2022 (see Figure 2.7).

Figure 2.7: Investor-Owned Utility Transmission Investment[9]



EEI members project anticipated transmission investment to grow slightly through 2026 at a compound annual growth rate of 4.7%. Investor-owned electric companies are planning to invest approximately $121 billion (nominal dollars) on transmission construction between 2023 and 2026.

[9] Edison Electric Institute, at https://www.eei.org/-/media/Project/EEI/Documents/Resources-and-Media/bar_actual_and_projected_trans_investment.pdf?la=en&hash=C7C308E6F8F404A5A3BC5EFE7B07257E2B2F81D0 (updated January 2024; accessed April 2024).

Overall Trends in Utility Costs

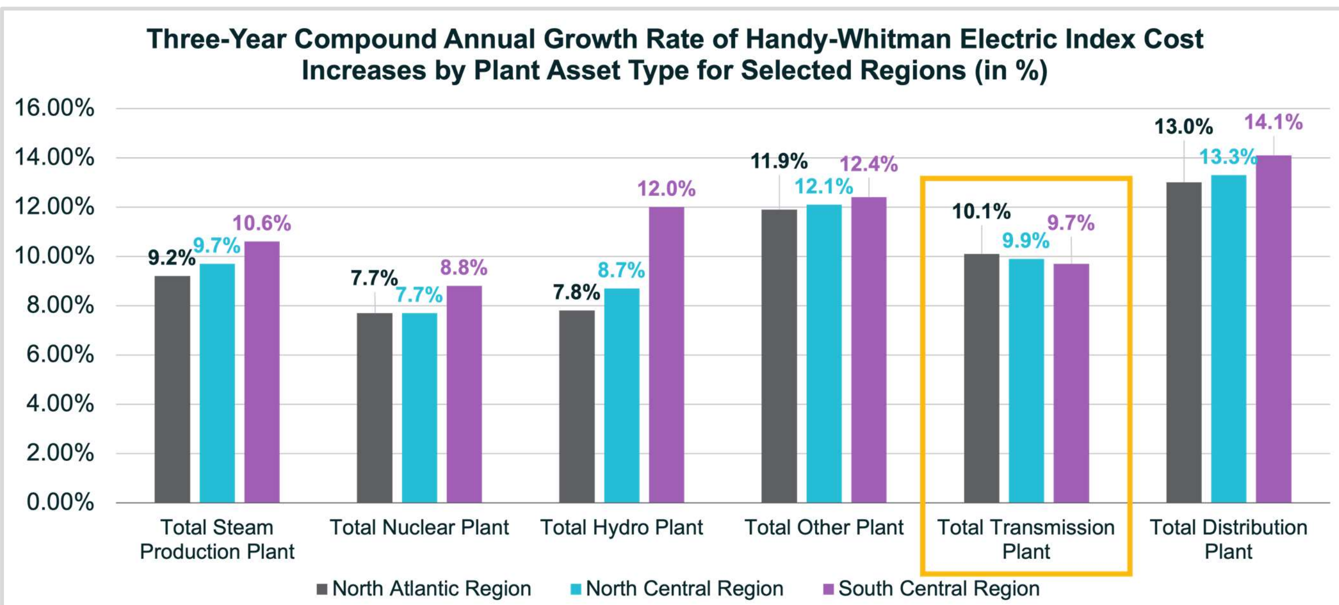
In addition to the growing number of planned transmission projects above, utility capex is increasing, driven by multiple factors, including adaptation and resilience investment, grid modernization, and lower emitting power supply resources.

This investment is growing because of both investment needs and increases in input costs: labor, material, and capital.

Economy-wide inflation has varied over the past several years since the onset of the COVID-19 pandemic in 2020. Year-over-year, core PCE inflation stood at 4.1% for 2023, well above the Federal Reserve's target rate of 2%. As of Q4 2023, annualized PCE inflation had declined to 3.2%.[10] However, the Conference Board has acknowledged that "progress on the path to the Fed's 2% target has slowed" and "the road to 2% is bumpy." [11]

The well-established Handy-Whitman Index of Public Utility Construction Costs estimates that three-year compound annual cost growth (July 2020–July 2023) for transmission plant increased by approximately 10% (see Figure 2.8). Those costs, however, can vary by region based upon labor costs and other factors.

Figure 2.8: Handy-Whitman Utility Cost Index Selected Index Growth Rates (July 2020–July 2023)[12]



[10] The Conference Board, U.S. Economy Watch (Apr. 2024).
[11] Ibid.
[12] Handy-Whitman, Cost Trends of Electric Utility Construction (July 2023); ScottMadden analysis.

Indicative Costs of Transmission Projects

Not all transmission project costs are publicly available. Some estimated costs can be gleaned from press releases, regulatory filings, and other public disclosures.

Figure 2.9 below shows illustrative costs (in $/line-mile) for various projects where estimated cost information is publicly available. Using high-end estimates from S&P Capital IQ data, high/low/median costs per line-mile of projects completed since 2020 are shown below:

Figure 2.9: Range of Estimated Costs per Line-Mile of Completed Transmission Projects (2021–2023) (in $000s)[13]

$000s	2020	2021	2022	2023
High	6,462	8,624	9,000	6,452
Low	338	750	941	2,400
Median	2,081	1,805	2,159	4,426
Sample size (N=)	18	6	5	2

A few observations on these data:

- Reading trends into these data may be misleading given the small sample size of projects with available cost data.
- Costs per line-mile appear to be rising but not consistently (see median values above).

Transmission additions continue but primarily at lower voltage levels (345 kV and less). Spending is growing as well, at nearly 5% annual growth, but costs have been growing as material and labor cost inflation has taken its toll. As was the case in our 2021 review, local projects still dominate regional and interregional transmission expansion.

[13] S&P Capital IQ data; ScottMadden analysis.

3. TRANSMISSION NEEDS AND DRIVERS

Key Takeaways

- Transmission expansion has long been focused on accommodating new resources and resource retirements, managing changing energy flows, and replacing and upgrading aging assets.
- Policy changes such as net-zero targets, renewable resource standards, environmental restrictions on fossil-fired generation and electrification of transportation, and building applications are shifting both supply and demand characteristics and locations. With some policy deadlines within a decade, the pace and magnitude of change in the power system is unprecedented.
- More recently, large loads arising from growing data center capacity to support artificial intelligence, resurgent U.S. manufacturing, and bitcoin mining have led to unexpected and near-term needs for resource and grid expansion to accommodate them.
- The frequency and impact of extreme weather events and growing penetration of variable energy resources is driving interest in investment to improve reliability and resilience.
- Congestion, and its economic and reliability effects, continues to be a key driver of transmission upgrades.
- Regional resource mixes—shifting from large dispatchable resources that are retiring to more dispersed variable energy and storage resources—are changing flows and grid topography, requiring both local and regional upgrades.
- The confluence of these factors means there is significant need for grid enhancement and expansion, but the needs may outpace the industry's ability to build.

As mentioned earlier, a minimal amount of transmission (compared with existing installed base) has been added over the past several years. Most of that development has been focused on intraregional reliability needs.

Congestion relief (or more economic movement of power across a system) has been a primary rationale for much of the balance of projects not primarily for reliability, and it is often a key secondary driver in reliability-driven projects.

Historically, transmission expansion has been focused on accommodating new resources, managing changing energy flows, accommodating generator retirements, and replacing and upgrading aging assets. New and more profound changes in both supply and demand characteristics and performance as well as significant policy-driven changes and incentives are changing the environment in which power infrastructure needs are determined.

In this section, we consider projected RTO/ISO long-term outlooks and regional transmission expansion plans, the Department of Energy's most recent transmission needs study and other assessments, federal programs and funding under the IRA and IIJA, integrated resource plans, and other resources.

While regions differ in their needs, broader power industry trends have introduced "increasing uncertainty driven by pace of change."[14] The changes broadly affect the grid and specifically transmission needs on both the demand and supply sides. These drivers are also being felt both in the near- and longer-term forecasts. Key areas noted were as follows:

- Demand: Electrification of energy end uses; increasing large loads; and extreme weather events requiring additional resilience investment and resource access both within and outside of territorial footprints
- Supply: Renewables integration; accelerating retirement of baseload resources, particularly coal-fired assets; congestion from movement of increasing amounts of energy from renewable resource-rich areas to demand centers; and prospective growth of offshore wind in coastal regions

Federal Funding Programs

While not a driver, federal funding programs arising from significant legislation since June 2021 have established pools of funding that can enable entities seeking to expand transmission to secure funding and also provide enablers for transmission through enhanced siting authorities (discussed further in the *Siting and Permitting* section of this paper). These programs are discussed in detail in *Appendix A*.

Large Loads and Electrification

After experiencing slow demand growth for years, projected electricity peak demand and energy growth rates have surged. Fillings with FERC show planners have increased their projected energy demand for 2028 from 4,351 TWh to 4,509 TWh (3.5% higher), reflecting a 158 TWh increase from 2022 projections to 2023 projections. PJM Interconnection recorded the largest forecasted energy increase through 2028, amounting to 35.2 TWh.[15]

Emerging Large Loads and Ramifications for Transmission

A significant driver behind these increases is the rapid expansion and planned addition of new large loads. The rapid growth of large loads—which can include data centers, manufacturing, and cryptocurrency mining—is spurring utilities to review and revise long-term planning documents. According to a recently published report by the Electric Power Research Institute (EPRI), data centers could account for 4.6% to 9.1% of total U.S. electricity consumption by 2030.[16]

Data centers add large, concentrated point sources of demand onto the existing grid. However, as EPRI has observed:

> The most serious challenges to data center expansion are local and regional and result from the scale of the centers themselves and mismatches in infrastructure timing. A typical new data center of 100 to 1,000 megawatts represents a load equal to that of a new neighborhood of 80,000 to 800,000 average homes. While neighborhoods require many years to plan and build, data centers

[14] NYISO 2023-2032 Comprehensive Reliability Plan (Nov. 28, 2023) (NYISO Reliability Plan), at p. 6.
[15] ScottMadden, The Energy Industry Update, Vol. 24, Issue 1, at pp. 27-28; Grid Strategies, The Era of Flat Power Demand Is Over (Dec. 2023).
[16] Electric Power Research Institute, Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption (May 28, 2024) (EPRI Report).

can be developed and connected to the internet in one to two years. New transmission, in contrast, takes four or more years to plan, permit, and construct. And developing and connecting new generation can also take years.[17]

Goldman Sachs forecasts a 15% compound annual growth rate (CAGR) in data center power demand from 2023 to 2030, driving data centers to make up 8% of total U.S. power demand by 2030 from about 3% currently. They now see a 2.4% CAGR in U.S. power demand growth through 2030 from 2022 levels vs. ~0% over the last decade. Of the 2.4%, about 0.9% of that is tied to data centers.[18]

Recent examples of planning documents discussing large loads include:

- Georgia Power Company is actively assessing transmission required to support the future retirement of remaining coal units operating within their system. The 2023 update to Georgia Power's 2022 IRP also approved development of 6,600 MW of additional supply resources.
- Arizona Public Service Company cites the need to serve high-load customers as a key driver in roughly half of the transmission projects identified in its 10-year transmission plan.
- Dominion Energy notes the 2023 PJM Load Forecast may understate potential reliability concerns due to rapidly increasing load forecasts.

The emergence of large loads is causing grid operators and planners to consider resource adequacy. MISO has stated that tightening reserve margins compounded with new large load additions indicate a growing capacity deficit in the 2025/26 planning year. In a recent announcement, MISO noted that this "underscores the need to accelerate resource additions, monitor large load additions, and delay resource retirements to reliably manage the anticipated growth in electricity demand."[19]

Increasing Electric Demand from Electrification of End-Uses Such as Transportation and Building Heating

In addition to the recent surge in interconnection of large loads, overall demand growth is expected to drive both increases in supply resources as well as need transmission capacity: both new lines and upgrades of existing transmission infrastructure.

Jurisdictions with ambitious decarbonization policies are encouraging electrification of many applications, in particular transportation and heating.

- **Transportation electrification:** U.S. electric vehicle (EV) outlooks vary by region and analyst. In its reliability planning outlook, for example, New York ISO expects that by 2030, nearly all new, light-duty vehicle sales and nearly half of medium- to heavy-duty vehicle sales will be zero emission (i.e., fully electric).[20] However, EV penetration will be determined by battery prices and government incentives.[21]

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[17] EPRI Report, at p. 6.
[18] https://www.goldmansachs.com/intelligence/pages/gs-research/generational-growth-ai-data-centers-and-the-coming-us-power-surge/report.pdf.
[19] MISO Press Release, "OMS-MISO survey results indicate tight resource capacity in the upcoming planning year" (June 20, 2024).
[20] NYISO Reliability Plan, at p. 70.
[21] PJM, Grid of the Future: PJM's Regional Planning Perspective (May 10, 2022) (PJM Grid of the Future), at p. 28.

- Charging behavior shows two ramping periods—in the morning when drivers get to work and in the evening when drivers get home. Charging demands are higher in winter months due to cabin heating and reduced battery performance.[22]
- If EVs comprised as little as one-third of light-duty sales, PJM observes that the "impacts to peak loads would be considerable." However, pricing structures (time of use rates; peak/off-peak pricing), demand charges, and load response programs could help mitigate some of these effects.[23]

- **Building electrification:** Some jurisdictions are incentivizing greater adoption of electric air-source heat pumps. The effects on electric demand depend on the current composition of heating systems. Those regions in which winter heating demand is high, state policy encourages electrification, and current heating systems are largely fueled by natural gas (or wood, oil, or propane) could experience large increases in power demand.
    - ISO-NE notes that replacing those heating systems with air-source or ground-source heat pumps will significantly increase total demand on the New England grid.
    - In its 2050 Transmission Study, ISO-NE notes that New England summer peak demand will grow to 40 GWs in 2050 (from an all-time summer peak of 28 GWs), while winter peak demand would more than double to 57 GWs (compared with an all-time winter peak of 23 GWs) (see ISO-NE case study at *Appendix C*).[24]
    - In its All Options scenario, New England depends upon significant amounts of imported power (requiring import capability) from New York, New Brunswick, and Quebec.[25]

The electrification of heating applications is expected to change seasonality of peak demand, with some regions moving from summer peaking to winter peaking. This has implications for anticipated resources (and their locations) for servicing peak load. For example, early morning in winter, when solar irradiance is low, may cause grid stress as dispatchable, non-weather-dependent resources will have to serve much of that demand. Transmission flows will vary as a result.

A key implication for transmission development is that in a high electrification future, substantially more transmission investment will be required compared with historical levels.[26] Estimates of the amount of required transmission investment vary. In a 2019 report, the Brattle Group estimated that transmission investments of up to $690 billion would be required between 2020 and 2050 to accommodate a highly electrified economy.[27] These investments will be in addition to the investments needed to maintain the existing transmission system and to integrate renewable generation built to meet existing load.

EPRI looked at scenarios that range from a reference case with gradual declines in CO_2 emissions and significant electrification to a 100% renewables scenario. Projected required transmission investment in those scenarios ranged from $30 billion to $300 billion in the 2020-2035 timeframe.[28]

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[22] Ibid., at p. 29.
[23] Ibid.
[24] ISO New England, 2050 Transmission Study (Feb. 2024) (ISO-NE 2050 Study), at pp. 10-11.
[25] Ibid., at pp. 12-13.
[26] U.S. Department of Energy, National Transmission Needs Study (Oct. 2023) (National Transmission Needs Study), at pp. 87-89.
[27] The Brattle Group, The Coming Electrification of the North American Economy (Mar. 6, 2019), at https://wiresgroup.com/the-coming-electrification-of-the-north-american-economy/
[28] EPRI, Powering Decarbonization: Strategies for Net-Zero CO_2 Emissions (Feb. 2021), at p. 11

Finally, Princeton, in its Net Zero America study (published in 2020), shows that required transmission investment is significant. It estimates that $2.7 trillion in investment will be needed between 2020 and 2050.[29] This is not only to accommodate electrification but also to increase interconnection and move energy from non-carbon emitting resources to demand centers.

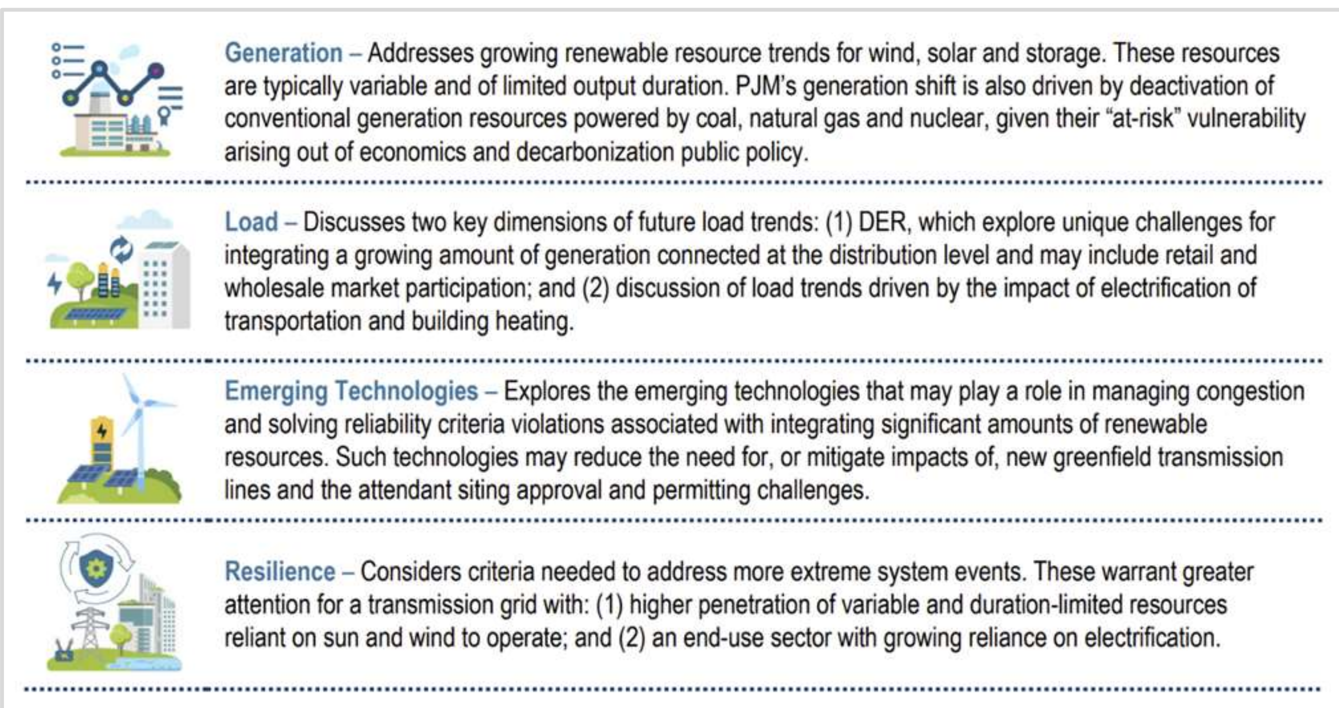
These analyses predate the effects of COVID-19 pandemic dislocations, particularly the subsequent run-up in inflation and interest rates. As such, they likely understate the potential costs.

An example of how utilities are factoring in grid investment from electrification is Avista Corporation's integrated resource plan, which includes an electrification impact analysis that tallies the transmission and distribution investment required for a scenario involving higher adoption of electric vehicles and electric space and water heating.

Studies of Transmission Needs and Drivers

As changes in the electric industry occur and more are expected, grid operators and planners are engaging in long-range scenario planning to identify potential grid needs over the long term (beyond the next decade). In some regions, utility and state net-zero and decarbonization efforts—often with target dates of 2040 or beyond—inform the expected changes in both demand and supply that impact grid topography. Figure 3.1, for example, illustrates PJM's view of long-term trends and drivers of grid expansion.

Figure 3.1: Industry Trends and Drivers for Future Grid Expansion (PJM Example)[30]



[29] Columbia Center on Global Energy Policy, Electrification on the Path to Net Zero: A Comparison of Studies Examining Opportunities and Barriers in the United States (Oct. 2022), at pp. 27-28
[30] PJM Grid of the Future, at p. 2.

Reliability and Resilience

In a recent study, the Department of Energy noted that "high-voltage transmission can improve the reliability and resilience of the transmission system by enabling utilities to share generating resources, enhancing the stability of the existing transmission system, aiding with restoration and recovery from an event."[31]

Grid Support for and Integration of High Levels of Variable Energy Resource Penetration

High levels of penetration of variable energy resources (VER) (i.e., solar photovoltaic and wind) and increased use of electrical inverters as a result pose system reliability concerns. These arise from low inertia, unstable voltage, low fault currents, and unpredictable behavior of those resources during grid disturbances (without precautions).[32]

As noted by MISO, new generation coming online often does not have the same characteristics as the resources it is replacing, introducing the potential risk that the needs of the system will not be met by the transitioning fleet. In particular, MISO points to increasing operational complexity, due to either greater variability or uncertainty, including the following factors:

- Increasing frequency and magnitude of system ramps, largely driven by the growth in renewable resources
- Greater uncertainty of available energy at low margin hours, particularly in winter/spring evenings, as the fleet becomes more weather-dependent

This operational complexity, according to MISO, increases significantly at penetration levels above 30% of load served, although other modeling asserts that a strong transmission network can accommodate high VER penetration (up to 82%) by 2050.

Relevant for transmission needs is the proximity of resources to load centers. Put simply, generation location matters. This, however, can vary by region.

- For example, PJM has observed that, unlike other areas, renewable generation is not seeking interconnection far from load centers. According to PJM, this has significant implications for future grid planning. That is, the "most efficient first-choice grid solution" may not be major long-distance, possible multi-state, backbone transmission lines to deliver RPS-mandated power. As of May 2022, more than 85% of planned generators were within 100 miles from load centers, and about 14% were within 200 miles.[33]
- ISO New England anticipates additions of significant renewable resources in its footprint as state policies are implemented. ISO-NE observes that many of the best locations for renewable resources like large-scale wind and solar farms are not near major load centers

[31] National Transmission Needs Study, at pp 52-53.
[32] Ibid., at p. 54. Some of these issues are being addressed through standards (e.g., requiring solar inverters to be able to "ride through" system disturbances) and technologies (such as grid-forming inverters), which allow inverter-based resources such as PV solar to nearly immediately respond to changes in the external system and attempt to maintain control during challenging network conditions to maintain grid stability and potentially allow those resources to be used for grid restart after a grid failure. See NREL, Introduction to Grid-Forming Inverters: A Key to Transforming our Power Grid (June 2024), at https://www.nrel.gov/docs/fy24osti/90256.pdf.
[33] PJM Grid of the Future, at pp. 5-6.

(i.e., the urban areas of New England). The transmission system will be relied on to deliver the power from these renewable resources to electricity consumers in more populated areas, during nighttime periods or other times when intermittent renewable resources' output is not sufficient to meet the local load. Transmission can also help to provide geographic diversity in renewable resources, smoothing out variations in wind and solar production across the system.[34]

Mitigation of Impacts of Extreme Weather Events

Extreme weather events, primarily in the form of extended heat waves accompanied by drought conditions as well as winter multi-day cold snaps, pose risks to the bulk power system during high demand periods. Regions with growing amounts of VERs risk diminishing availability of solar resources in late afternoon (during summer) and early morning in winter as well as potential low wind conditions. During winter storms, reliance on gas-fired power generation creates fuel deliverability risk when usage by retail gas customers dramatically increases. NERC states the need for a "strong, flexible transmission system" for energy adequacy where there are highly variable supply resources and more weather-sensitive demand.[35]

During 2021's Winter Storm Uri and 2022's Winter Storm Elliott, which involved loss of load in Texas and the Southeast, respectively, generator unavailability was a significant cause of system instability and outages. One area of potential transmission need is increased transfer capability (transmission capacity) between regions, allowing for imports and exports to adjacent regions experiencing capacity shortfalls. During Elliott, for example, utilities relied upon imports including up to 5 GWs from MISO. According to DOE, an additional 1 GW transfer capability from MISO to TVA could have provided $75 million in value during the storm.[36]

Intraregional transmission may also be required to facilitate weather-driven exports. During Elliott, transmission constraints within the PJM footprint limited export capability across its southern interfaces. Those connect directly with southeastern utility systems that were most impacted by the storm.[37]

Regional Congestion and Constraints

Congestion is a major driver of transmission expansion. Such congestion has economic impacts on the bulk power markets as lower-cost resources may not be able to be dispatched and delivered to demand centers, with higher-cost resources serving load, resulting in overall higher wholesale prices for power. Recent estimates of per MWh cost of congestion are shown at Figure 3.2.

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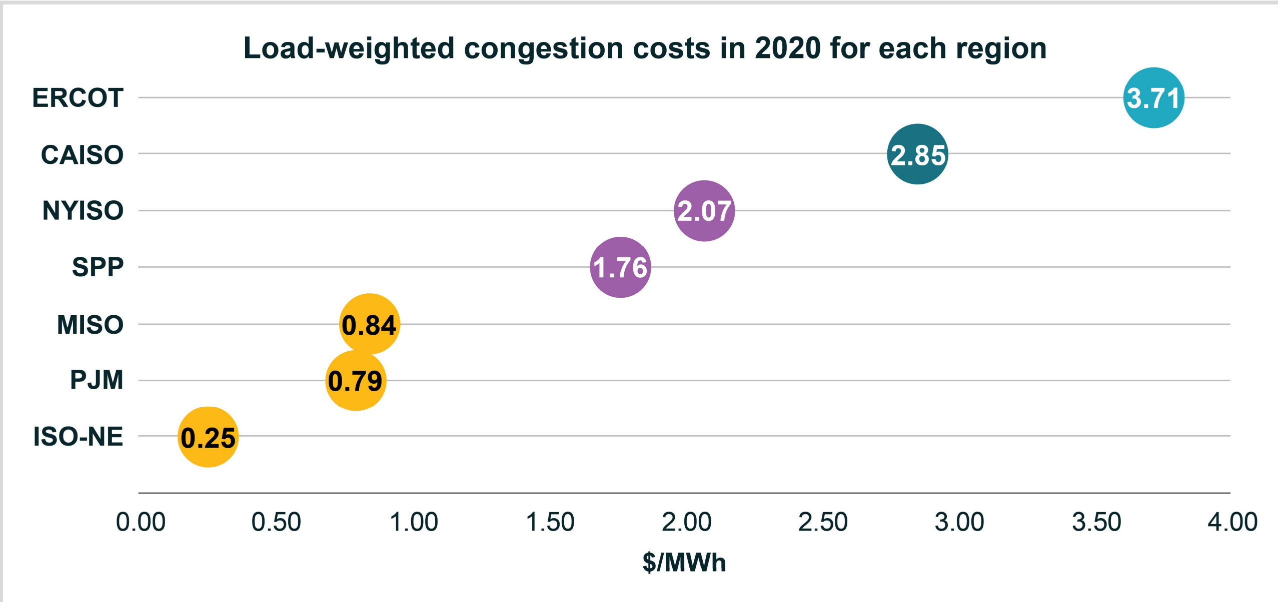
[34] ISO-NE 2050 Study.
[35] NERC, 2023 Long-Term Reliability Assessment (Dec. 2023) (NERC LTRA), at pp. 11.
[36] National Transmission Needs Study, at pp. 55-59.
[37] PJM, Winter Storm Elliott Event Analysis and Recommendation Report (July 17, 2023), at pp. 45-48; National Transmission Needs Study, at p. 58.

Figure 3.2: Summary of Load-Weighted Congestion Costs for RTO/ISO Regions (2020) [38]



RTO/ISO regions evaluate congestion and related costs in identifying and evaluating potential transmission enhancements. In its 2023 National Transmission Needs Study, DOE identified some regional congestion issues. In several cases, congestion is caused by wind output in areas distant from load centers and constraints near significant concentrations of load. Among these, by region, are:

- Upstate New York to Long Island
- Eastern and coastal areas of the Mid-Atlantic
- Within MISO, between upper Midwest region and Delta (south-central and Gulf Coast areas)
- Southeastern SPP in eastern Kansas, southwestern Missouri, and southeastern Oklahoma where high wind generation output flows
- East-to-west in-state congestion as demand in eastern Texas grows

Additional renewable resource development, as dictated by state goals pursuant to initiatives such as New York's Climate Leadership and Community Protection Act, will exacerbate existing transmission congestion over the long term.[39]

As shown in Figure 3.2, ISO New England has significantly lower congestion than other RTOs, which are 5 to 10 times higher than New England congestion costs. These comparatively low costs continue through ISO-NE's latest external market monitor report, covering the 2022 operating year. However, a tradeoff for low congestion costs is higher carrying costs for transmission investment. Per the market monitor:

> "The low level of congestion in New England can be attributed to the substantial transmission investments made over the past decade. These investments have led transmission rates to be

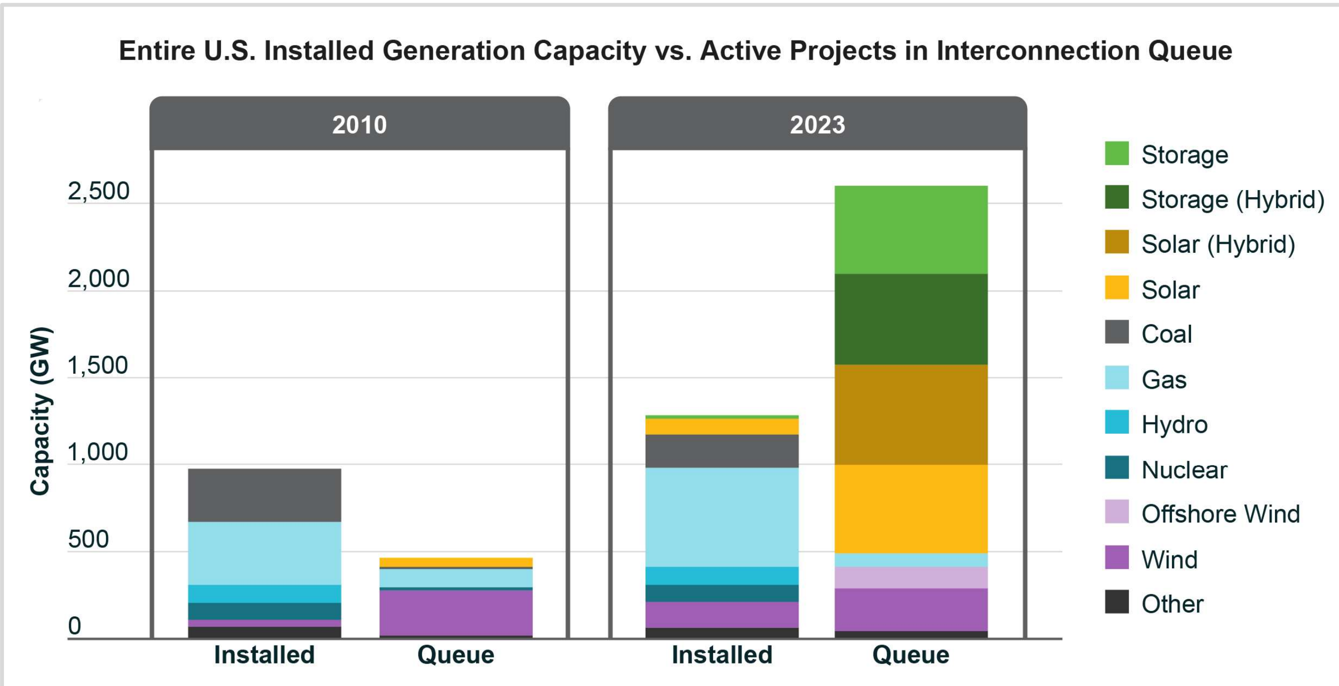
[38] National Transmission Needs Study, at pp. 64-74.
[39] NYISO Reliability Plan, at p. 12.

over $22 per MWh in 2022, which are more than double the average rates in the other RTO areas."[40]

Shifts in Generation from Dispatchable Thermal Resources to Variable Resources and Storage

As shown in the discussion of interconnection queues elsewhere in this paper, proposed utility-scale solar installations dominate expected additions of capacity over the next several years (see Figure 3.3). This influx of capacity would bring substantial inverter-based resources to several regions.

Figure 3.3: U.S. RTO Interconnection Queues[41]



At the same time, public policy preferences are leading many dispatchable thermal resources to retire. New York has observed that the pace of generation retirements has exceeded the pace of resource additions.[42] This trend is leading system operators to study system deficiencies both locationally and across the grid. For example, the potential retirement of some small gas-fired plants in downstate New York without adequate replacement would result in a deficiency in New York City of more than 600 MW.[43]

[40] Potomac Economics, 2022 Assessment of the ISO New England Electricity Markets (June 2023), at pp. 3-5.
[41] ScottMadden, The Energy Industry Update, Vol. 24, Issue 1.
[42] NYISO Reliability Plan, at p. 48.
[43] Ibid.

Retiring fossil-fired generation is often located closer to population centers with renewable generation sited far from retiring facilities and thus cannot rely on the same transmission infrastructure.[44] PJM has observed, however, that most proposed solar projects are within 100 miles of demand centers.[45] So transmission needs with the generation shift are context specific.

PJM, like other RTOs, is analyzing and processing retirements. As it notes:

> "Generator deactivations alter power flows that can cause transmission line overloads and, given the loss of reactive power control capability from large-scale coal-fired and nuclear-powered generators, can undermine voltage control. When PJM receives a formal generator deactivation request, it conducts thermal and reactive studies to ensure that remaining generation continues to be deliverable to load. If criteria violations are identified, PJM develops a solution in coordination with affected transmission owners."[46]

PJM has noted that it received 41.2 GWs of deactivation requests from 2012 to 2021. These deactivations have led to significant transmission investment. Notifications totaling 24.5 GWs have accounted for $4.1 billion of baseline grid enhancements to solve reliability criteria violations. The balance of requests (16.7 GWs) did not require baseline enhancements (see Figure 3.4).

Brandon Shores:
Retirements and Transmission Upgrades

Brandon Shores is a 1.2 GW coal-fired power plant near Baltimore, Maryland. Owner Talen Energy had contemplated repowering the plant with another fuel pursuant to a settlement agreement with the Sierra Club. However, it has decided to retire the plant by mid-2025. FERC approved a PJM-proposed package of $785 million in grid upgrades—including two new 500-kV and 230-kV transmission lines—to meet reliability needs. That package is expected to be operational by the end of 2028.

Meanwhile, Maryland regulators and consumer advocates and the Sierra Club argue that PJM should consider other solutions such as energy storage and contest the $800 million amount proposed by Talen to delay retirement under a reliability must-run arrangement with PJM. Maryland's ratepayer advocate also contests the cost of transmission improvements to be allocated to Maryland customers, which it says would increase utility Baltimore Gas & Electric's transmission rate base by 35%.

[44] National Transmission Needs Study, at p. 75.
[45] PJM Grid of the Future, at pp. 5-6.
[46] Ibid.

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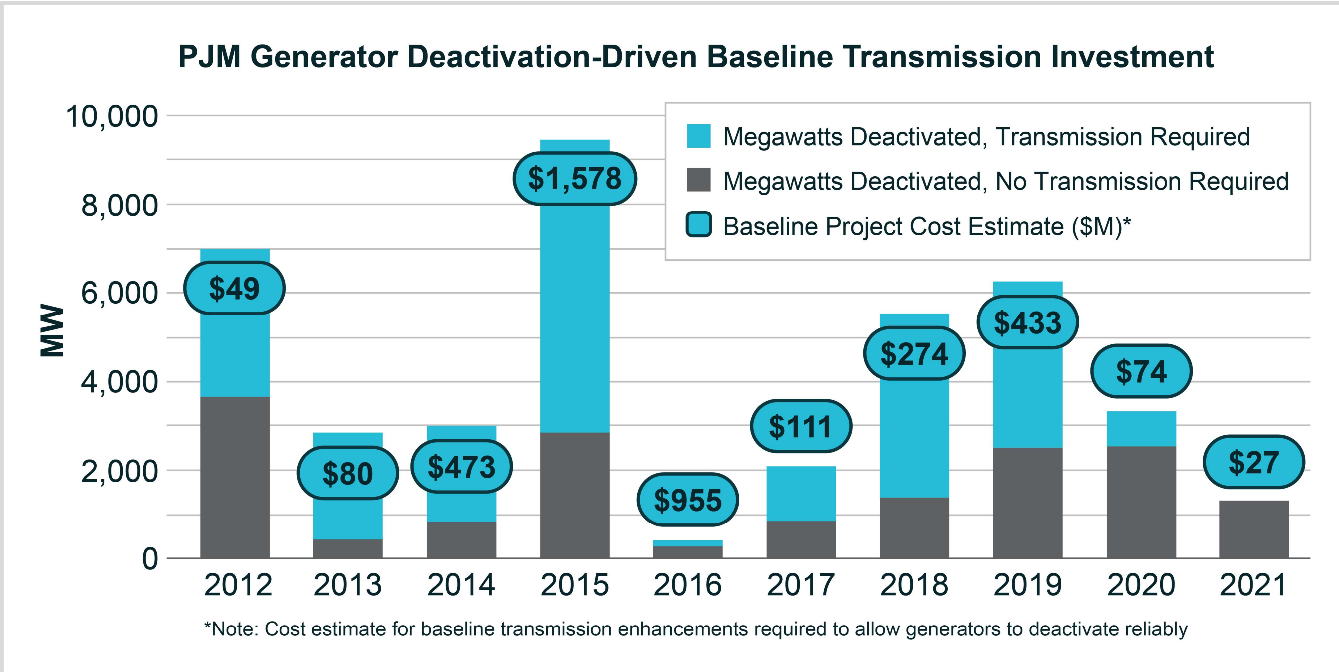
Figure 3.4: PJM Deactivation-Driven Transmission Investment[47]



The replacement of dispatchable generation with large rotating masses that provide system inertia with inverter-based resources has implications for system stability in the case of generator loss or system perturbations. Some technologies, such as grid-forming inverters, are being considered to offset those effects.

Finally, there have been several studies of infrastructure requirements for a significant reduction of greenhouse gas emissions in the power sector. Transmission requirements vary with the degree and manner of carbon reduction required. With increasing renewable and (assumed) dispatchable emissions-free resources (not commercially viable today),[48] modeled transmission capacity expands by anywhere from 70,000 GW-miles to 140,000 GW-miles.[49]

While few new transmission lines have been added in the past several years, many changes, occurring and expected, in bulk power system supply and demand are driving transmission needs. As the Department of Energy summarized in its National Transmission Needs Study:[50]

> **[T]he main determinants of need for transmission expansion identified include grid reliability and resilience, congestion relief, new generation resource interconnection, and load growth accommodation…. [T]ransmission capacity expansion can serve to enhance system stability through improved operational flexibility, resource sharing, and frequency response. Reliability and resilience needs are expected to require additional transmission as economic factors and clean energy targets prompt higher levels of variable energy**

[47] Ibid., Fig. 6, at p. 22
[48] NYISO Reliability Plan, at p. 68.
[49] National Transmission Needs Study, at pp. 75-76.
[50] Ibid., at pp. vi-vii.

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resource integration and as extreme weather events nationwide continue to increase in frequency and intensity….

Throughout the country over the next decade and beyond, increasing consumer demands, electric utility decarbonization targets, and federal and state policy are expected to drive changes in electricity supply and change the way electricity is used, including by increasing electrification of end-use technologies. These changes will put additional burden on the existing transmission system and create significant need for additional transmission investment.

4. GENERATOR INTERCONNECTION

Key Takeaways

- A large number of relatively small, renewable generating facilities are attempting to interconnect to the transmission system, which has resulted in severe interconnection delays and backlogs across the country.
- Order 2023, issued in November 2023, provides incremental improvement in generator interconnection processes. Those processes have been characterized in many regions by clogged interconnection queues, as smaller, more numerous solar resources have been proposed, compared with historically large, central station generation.
- Order 2023 provides for clustered system studies for interconnection (not one at a time), "first ready, first served" (vs. first come) requiring developer site control and financial commitments, and deadlines and penalties for transmission providers for non-timeliness. Proponents hope these changes will expedite project review and hasten development of resources.
- In a separate order, FERC has linked regional planning with interconnection. This provides some visibility into broader transmission needs surfaced in interconnection that have been elusive because of their expense (and reluctance of generation developers to fund them).
- However, as we have observed in PJM, which has a regime similar to Order 2023, it takes time (perhaps measured in years) to work through the existing backlog. Meanwhile, federal incentives under the Inflation Reduction Act are promoting additional solar and wind development, further exacerbating interconnection queue backlogs.

State of the Interconnection Queue (Spring 2024)

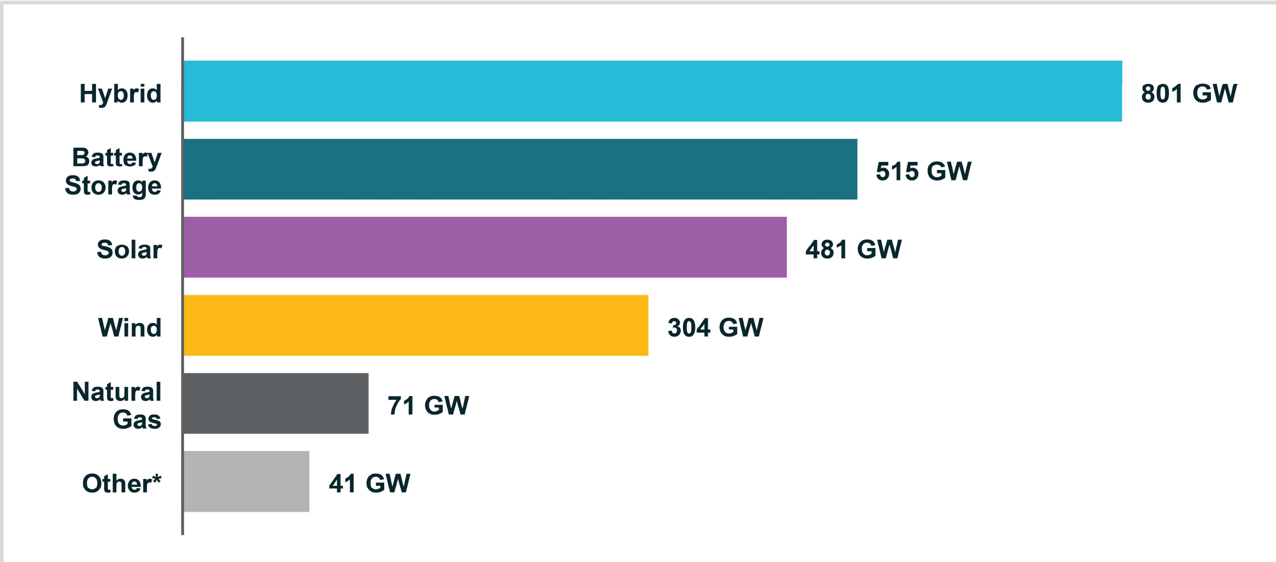
Expanding interconnection queues and slow processing times remain a persistent challenge for the industry. In April 2024, more than 2,200 GW of generation capacity was in the interconnection queues managed by seven system operators and 19 major utilities in the West and southeastern United States.[51]

Renewables, including battery storage and hybrid projects, accounted for more than 90% of the capacity in the interconnection queues (see Figure 4.1 below).

- Renewables account for at least 90% of the interconnection queues in 35 states.
- In six states—Delaware, Maine, New Mexico, Oklahoma, South Dakota, and Vermont—renewables account for 100% of interconnection requests.
- California maintains the largest interconnection queue with 520 GW of capacity awaiting interconnection.

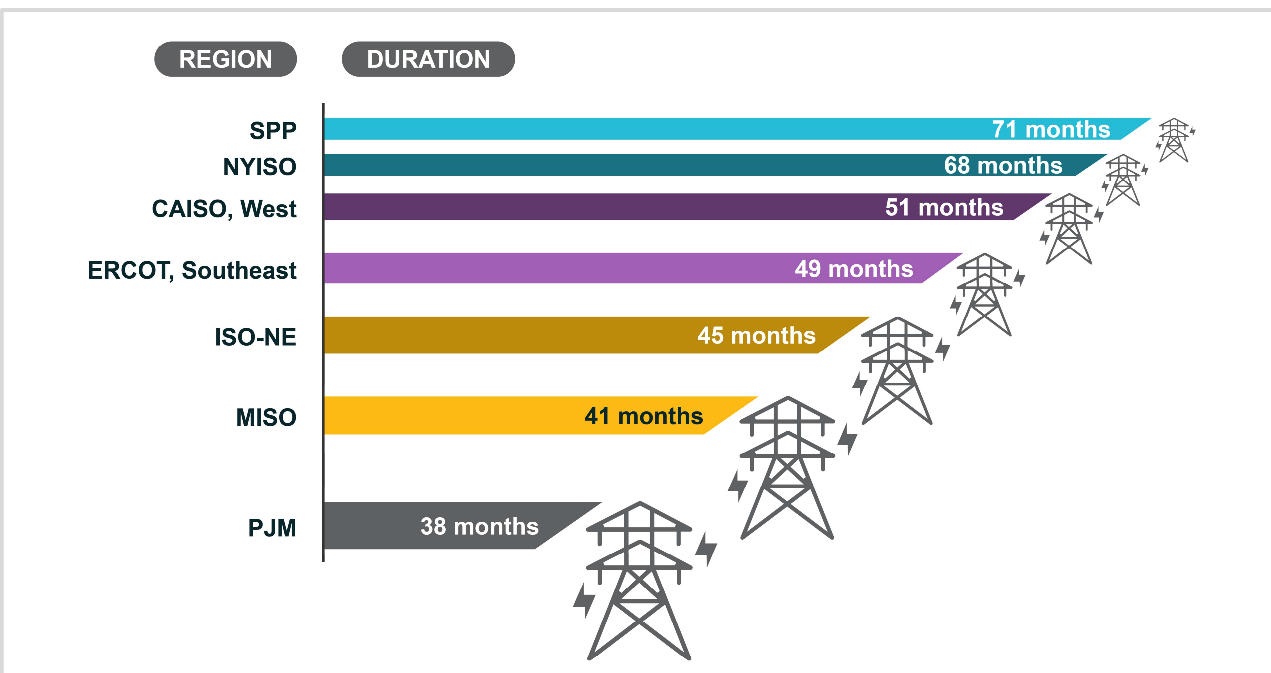
[51] S&P Global, 2024 U.S. Interconnection Queues Analysis (May 2024).

Figure 4.1: Interconnection Queue Capacity by Technology Type (April 2024)[52]



The time a proposed project remains in the interconnection queue remains relatively long. The average time from queue entry date to proposed online date is a minimum of 38 months in PJM and a maximum of 71 months in the Southwest Power Pool (see Figure 4.2).

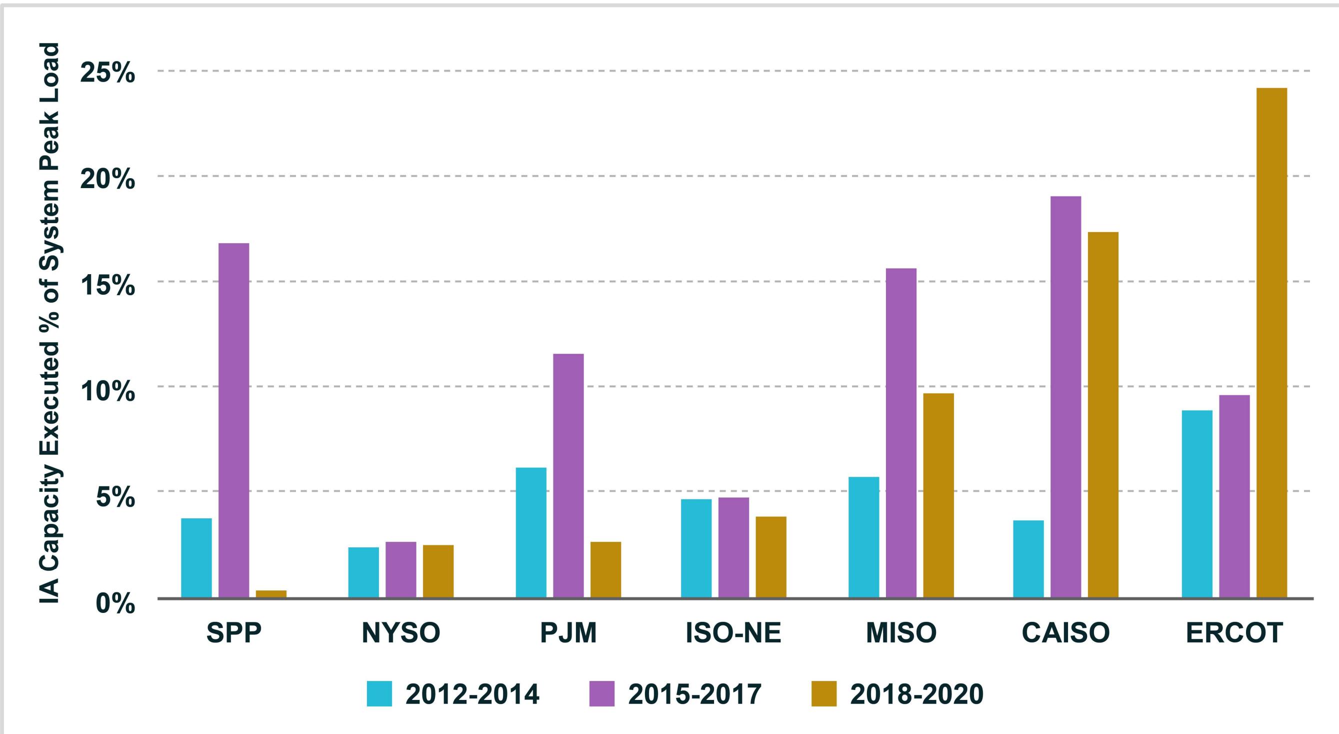
Figure 4.2: Average Time from Queue Entry Date to Proposed Online Date[53]



52 S&P Global, 2024 U.S. Interconnection Queues Analysis (May 2024).
53 Ibid.

As interconnection requests have increased over time, independent system operators have struggled to process and execute interconnection agreements. The average rate of executing interconnection agreements submitted in 2018-2020 is roughly 9% of system peak load (see Figure 4.3). Only CAISO and ERCOT outperform the national average.

Figure 4.3: Interconnection Agreements Executed Through 2022 for Interconnection Requests Submitted from 2012 to 2020[54]



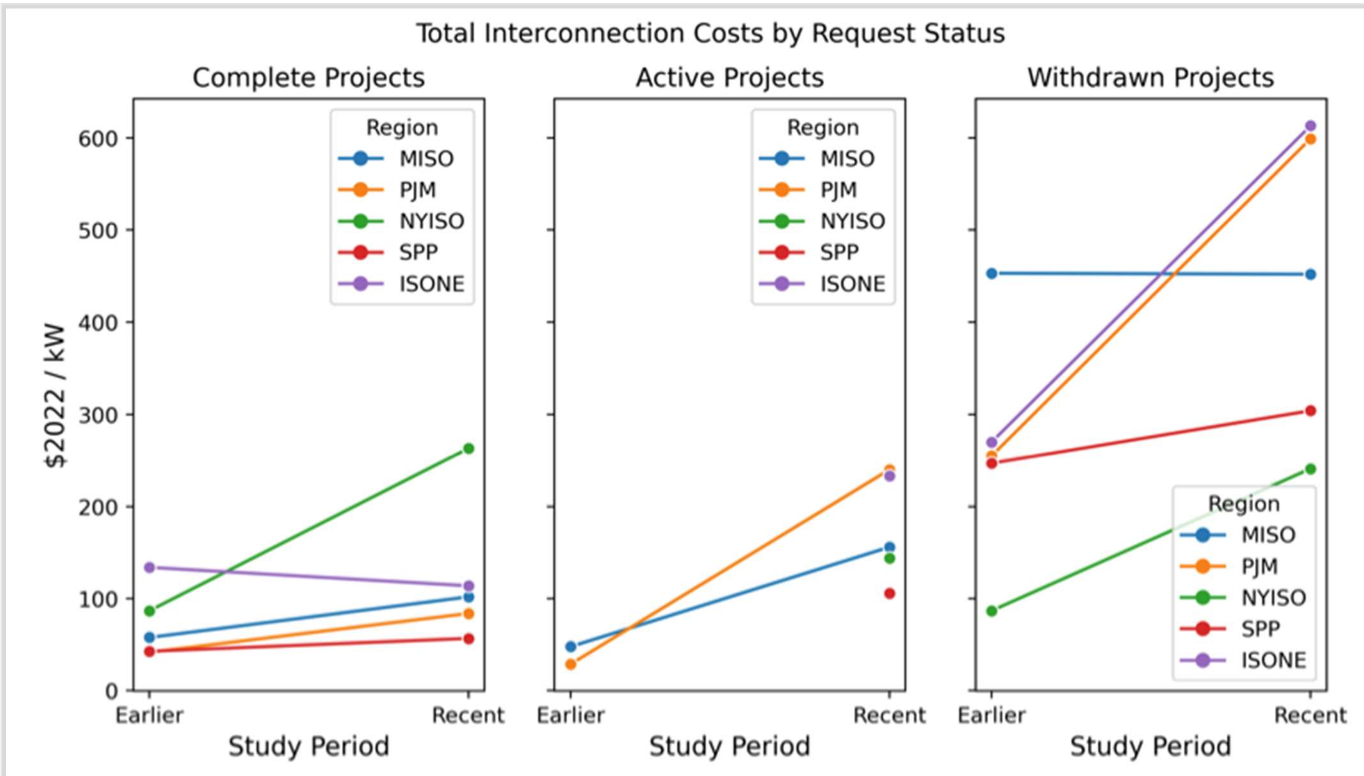
Generators seeking interconnection must also contend with growing interconnection costs. A significant challenge is that reliable interconnection cost estimates can only be obtained by entering the interconnection queue.

To provide insight on interconnection costs, Lawrence Berkley National Laboratory (LBNL) recently reviewed more than 2,500 project-level interconnection cost estimates within five independent system operators: ISO-NE, MISO, NYISO, PJM, and SPP.

LBNL found interconnection costs have grown over time in all regions studied (see Figure 4.4 below).[55] Recent cost increases were attributed to network upgrade costs rather than local interconnection costs. Projects incurring high interconnection costs often drop out of the interconnection queue.

[54] Advanced Energy United, Generator Interconnection Scorecard: Ranking Interconnection Outcomes and Processes of the Seven U.S. Regional Transmission System Operators (February 2024) (AEU Scorecard).
[55] Lawrence Berkley National Laboratory, Generator Interconnection Costs to the Transmission System (June 2023).

Figure 4.4: Average Interconnection Costs by Region[56]



In addition, the study found renewable and storage projects often faced higher costs than natural gas projects.

Generator Interconnection Challenges

In February 2024, Advanced Energy United released a report scoring the seven independent transmission operators on their generation interconnection process. Prepared by Grid Strategies and Brattle, the report is the first robust assessment of the effectiveness of interconnection processes.

The scorecard represents an assessment of historical performance and does not consider ongoing or recently adopted reforms that will impact the generator interconnection process. So it can be seen as a pre-reform summary of the state of interconnection.

[56] "Earlier" is defined as the following: PJM (2000-2018); SPP (2010-2019); PJM (2000/2017-2019); NYISO (2006-2016): and ISO-NE (2010-2017). "Recent" is defined as the following: PJM (2019-2021); SPP (2020-2022); PJM (2020-2022); NYISO (2017-2021); and ISO-NE (2018-2021).

Figure 4.5: Generator Interconnection Scorecard by Region

Region	Key Drivers of Interconnection Performance
ERCOT	• Processes a high volume of resources on a reasonable timeline and at reasonable costs • Lacks proactive regional transmission planning to address system constraints, resulting in high levels of generator curtailment and comprising a major impediment to development and deployment of new generation resources
CAISO	• Has high rates of studying resources, proactive upgrades to its transmission system, transparency, and cost-sharing approach • Uses mitigation strategies to bring projects into operation until upgrades are constructed, appreciated by interconnection customers • Recent delays in interconnection study results have made it more difficult to complete CAISO's queue
MISO	• Recent commitment to transmission expansion both within its system and in coordination with SPP along the seams of the two systems • Gap in planning studies has recently left the system with limited available capacity • Availability of interconnection alternatives permitted outside of queue order • Interconnection process is considered unreliable and slow with unpredictable cost outcomes • Additional concern includes recent changes to MISO's interconnection business practices to raise impact criteria for new projects
NYISO	• Favorably recognized for design of its interconnection process, with mostly reasonable study assumptions and criteria • Process has not produced compelling results with long timelines and unpredictable costs that come late in the process • Use of regional transmission planning to expand opportunities for new generation resources has some promise but is not yet delivering substantial benefits • Availability of interconnection alternatives in NYISO is more limited than in other regions
ISO-NE	• Relatively low interconnection volume • Portions of its system are highly constrained (including Maine and in southeast Massachusetts), making it likely that projects will trigger significant system upgrade costs. Those upgrades, as well as planned transmission expansions, are difficult to build, making it difficult to bring projects online • Unique requirement for a high-cost model with the initial application

Region	Key Drivers of Interconnection Performance
PJM	• Retained a sub-par serial process too long and its transition to a cluster process has frozen opportunities for new projects • Not planned its system to create headroom for new resources, other than its recent process concerning NJ offshore wind • Better than other regions on responding to questions

Spotlight: ERCOT's "Connect and Manage" Approach[57]

ERCOT, favorably cited in the Advanced Energy United scorecard referenced above, uses a "connect and manage" approach as a key to the region's success at maintaining a high processing speed amidst expanding interconnection requests.

The "connect and manage" approach limits interconnection studies to the local system on an energy-only basis. Interconnection costs are limited to certain direct costs related to connecting to the transmission system. Once connected, grid congestion is managed using economic curtailment and congestion pricing.

Overall, developers indicate ERCOT maintains a transparent and predictable process that results in low interconnection costs and fast interconnection times. The tradeoff is production risk related to curtailment and congestion pricing. In addition, a lack of proactive transmission planning limits ERCOT's ability to identify cost-effective upgrades that would reduce congestion.

FERC Issues Order 2023

Background

In late July 2023, FERC issued Order 2023, which reforms FERC's standard generator interconnection procedures and agreements. The reforms are intended to "address interconnection queue backlogs, improve cost and timing certainty, and prevent undue discrimination for new technologies."

Motivating the rule was the finding by FERC that interconnection queues were unacceptably long, and the cost and timing of interconnection are increasingly uncertain, especially as some projects under the existing serial first-come, first-served process drop out, requiring restudy. FERC Chair Phillips characterized the order as "a watershed moment for our nation's transmission grid."

Key Elements of the Order

Order 2023 adopts a comprehensive package of reforms in three general categories: (1) reforms to implement a first-ready, first-served cluster study process, (2) reforms to increase the speed of interconnection queue processing, and (3) reforms to incorporate technological advancements into the interconnection process. Each category is described below in more detail:[58]

- **Transitioning from a First-Come, First-Served Serial Process to a First-Ready, First-Served Cluster Study Process:** Order 2023 requires reforms from transmission providers

[57] AEU Scorecard.
[58] https://www.ferc.gov/explainer-interconnection-final-rule.

and increases requirements on prospective interconnection customers. Specific provisions include:

- Facilitating Public Interconnection Information Access and Transparency**:** Transmission providers must maintain a publicly available interactive heatmap showing available transmission capacity. The heatmaps should allow prospective interconnection customers to identify ideal points of interconnection based on areas of expected congestion.

- Cluster Study Replaces Serial Study: Transmission providers must eliminate the serial study process and instead use a single-phase, 150-day cluster study process. The process is to be first-ready, first-served—i.e., individual requests submitted during a certain time window are processed together with the same priority.

- Increased Financial Readiness and Site Control Requirements: To ensure interconnection queues only include projects likely to be built and to prevent speculative interconnection requests, there are increasing financial commitments and readiness requirements through the study process.

  - Ninety percent site control is required at time of interconnection request, with 100% upon signing of a facilities study agreement. A deposit ($500,000 to $2 million) in lieu of site control is permissible where regulatory limitations prohibit site control.

  - The required deposit upon execution of a large generator interconnection agreement is 20% of network upgrade costs.

- Customer Withdrawal Penalties: Withdrawing interconnection customers may be eligible for refunds of deposits to the extent they exceed study costs incurred. However, those amounts are subject to withdrawal penalties that can range from 2X study costs up to 20% of network upgrade costs.

- **Increase the Speed of Interconnection Queue Processing:** Order 2023 imposes firm deadlines and penalties if transmission providers fail to complete interconnection studies on time and requires a detailed process for studying impacts on neighboring transmission systems (i.e., “affected systems”).

- **Reforms to Incorporate Technological Advancements in the Interconnection Process:** Order 2023 considers technological advancements by allowing multiple resources at a single site, evaluating alternative transmission technologies,[59] and modeling non-synchronous generation. Specific provisions include:

  - Increasing Flexibility: Historically, interconnection requests were limited to a single generating facility. The final rule requires transmission providers to allow more than one resource to co-locate (e.g., solar plus storage) on a shared site behind a single point of interconnection and share a single interconnection request.

  - Incorporating Alternative Transmission Technologies: Requires transmission providers to evaluate alternative transmission technologies (e.g., advanced conductors, advanced power flow control, transmission switching, etc.) when conducting a cluster study.

[59] From a list of eight technologies designated by FERC.

- Modeling and Performance Requirements for Non-Synchronous Generating Facilities: Establishes a variety of requirements regarding modeling and data used in interconnection studies to more accurately model non-synchronous facilities. The final rule also introduces certain capability requirements (e.g., "ride through") for those facilities once they are interconnected.

In May 2024, RTOs and ISOs submitted their compliance filings. FERC is now reviewing compliance filings and orders should be issued later in 2024.

Order 1920 Provision: Coordination of Regional Transmission Planning and Generator Interconnection Processes

On May 13, 2024, FERC issued Order 1920.[60] Order 1920 reforms FERC policies regarding regional transmission planning and cost allocation and is its most significant action on these topics since issuing its Order 1000 in 2011.

One part of Order 1920 requires coordination of regional transmission planning and generator interconnection processes. This rule is intended to address the issue of interconnection-related network upgrades being repeatedly identified during the generator interconnection process, but such upgrades go unresolved because the substantial costs of such upgrades result in the underlying interconnection request being withdrawn.

Order 1920 directs that transmission providers evaluate regional transmission facilities that address certain interconnection-related transmission needs in their existing regional transmission planning and cost allocation processes instead of in long-term transmission planning. FERC's rationale is that evaluation of interconnection-related transmission needs in existing processes is more appropriate because such evaluation occurs at shorter intervals and would result in quicker development of transmission facilities.[61]

FERC set out the following criteria for incorporating and evaluating interconnection-related transmission needs in regional planning processes:

- **Identified in 2+ queue cycles:** The transmission provider has identified interconnection-related network upgrades in interconnection studies in at least two interconnection queue cycles during the preceding five years.
- **Minimum voltage and cost:** The interconnection-related upgrade identified has a voltage of at least 200 kV and an estimated cost of at least $30 million (emphasis added).
- **Interconnection request withdrawn:** Those interconnection-related upgrades have not been developed and are not currently planned to be developed because the underlying interconnection request(s) driving the upgrade has been withdrawn.
- **No interconnection agreement contemplating upgrade:** The transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-

[60] Order 1920 is discussed in greater detail elsewhere in this paper.
[61] Troutman Pepper, "High-Level Summary of FERC Order No. 1920 on Transmission Planning and Cost Allocation" (May 21, 2024), at pp. 8-9; FERC Order 1920.

related transmission need in an executed generator interconnection agreement or an unexecuted generator interconnection agreement filed with FERC.[62]

It is unclear how and where transmission providers plan to incorporate these provisions into their planning processes. That will be clarified upon submittal of compliance filings for Order 1920.

In conclusion, while reforms to the interconnection process may increase the pace at which studies are completed and reduce the speculative queuing seen in some regions, these reforms alone will not "get steel in the ground." Generators have to site and permit facilities, in some cases, facing similar opposition to that of transmission lines. In addition, there is a growing recognition that the changing attributes of the resource mix have important implications for reliability, resiliency, and resource adequacy. These are not solved by resolving challenges with the generator interconnection process. While Order 2023 provides some helpful reforms, it is unlikely to eliminate the backlog of generator interconnection requests in the short term. The IRA will continue to drive renewables to interconnect so the regional interconnection queues will continue to see new requests.

Assuming the nature of interconnection requests remains the same (i.e., largely renewables or renewables and storage), the generation that will be added to the system will not adequately replace the attributes of the baseload and dispatchable resources scheduled to retire.

[62] Ibid.

5. SITING AND PERMITTING

Key Takeaways

- Siting and permitting of electric transmission projects involves numerous federal, state, and local agencies, as well as myriad processes (some complex) and stakeholders, including landowners whose properties are affected by siting. The various interests involved can derail project development, particularly for larger, longer proposed lines.
- Siting and permitting reform dates back to the Energy Policy Act of 2005 (EPACT). EPACT contemplated national interest electric transmission corridors (NIETCs) and federal backstop siting authority in the event of lack of state action on proposed transmission projects in those areas.
- Historically, FERC never exercised its backstop siting authority and federal courts invalidated NIETCs and denied the FERC's siting authority where a state affirmatively denied a project's permit.
- Order 1977, issued in May 2024, seeks to resurrect NIETCs and backstop siting in those areas. FERC exercised authority under the Infrastructure Investment and Jobs Act, which authorized backstop siting by fixing provisions that courts found problematic in the EPACT language. It is unclear whether these provisions will be acted upon by FERC or upheld if challenged any more than the original incarnation of these provisions in EPACT.
- Recent federal executive efforts in the form of project funding and acceleration of the federal permitting process (no more than two years) may benefit projects on federal lands in particular, where there are significant overlapping authorities.
- FERC's mandate of collaborative process plans can help with early understanding of the project, but the expansion of stakeholder engagement can also complicate and delay projects.
- It is unclear whether proposed federal legislative proposals on siting and permitting will go forward or will await how Order 1977 reforms play out.

Issues and Barriers

In the 2021 White Paper, we identified ongoing issues with siting and permitting transmission in the United States. Many of those issues remain.

The transmission siting and permitting process is a complex system of stakeholders and administrative processes, with multiple layers of approval required from federal, state, and local authorities. State laws and regulations primarily govern the approval and construction process for transmission projects; in some states, projects must seek city and county authorization as well.

- Project authorization relies on securing "certificates of public convenience and necessity" from state public utility commissions. This is a siting process informing the public of a determination of need and public interest, including public hearings and economic and environmental reviews.
- On nonfederal lands, states have the authority to use eminent domain in cases where private landowners do not approve of a project.

Projects may require federal authorizations and approvals as well. Projects crossing federal lands are required to obtain right-of-way permits from the relevant land management agencies which often require information differing from that needed by the state.

During the permitting process, relevant federal agencies must issue environmental impact statements, which have a limited shelf life. Project permitting can be further delayed and complicated by litigation at any stage during the process as well as opposition from local, state, and environmental groups.

As a result, very little long-distance transmission, particularly regional and interregional projects, has been completed.

Developments Since Spring 2021

While the process has not been simplified, there have been efforts to speed up transmission timelines on multiple fronts. Actions to facilitate transmission siting have been initiated through legislation, executive department action, and FERC rulemaking.

- Congress provided transmission funding and regulatory reforms through the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA).
- The Department of Energy has taken multiple actions, including designating special transmission corridors and consolidating environmental permitting and authorization from among a variety of agencies.
- Finally, FERC issued Order 1977 in May 2024 that would give it extended permitting authority in DOE's transmission corridors if a state has not acted on or has denied a permit.

Other Congressional Proposals

There have been several congressional proposals[63] that would give FERC siting authority for large interstate transmission lines while preserving state authority for small transmission lines and lines that do not cross state borders. Proponents of these changes argue that a single federal approval process would speed the development of large interstate transmission, while opponents argue that states are better positioned to identify the best path for development. As of June 2024, none of these proposals have been put to a vote.

DOE and Agency Policy Initiatives to Facilitate Siting[64]

Coordinated Interagency Transmission Authorizations and Permits (CITAP) Program

In May 2023, DOE announced a memorandum of understanding (MOU) between multiple federal agencies.[65] Designated the Coordinated Interagency Transmission Authorizations and Permits (CITAP)

[63] The Promoting Efficient and Engaged Reviews Act of 2023 (PEER Act); The Streamlining Interstate Transmission of Electricity Act (SITE Act; S. 946); and The Clean Electricity and Transmission Acceleration Act (CETA Act; H.R. 6747).
[64] https://www.energy.gov/gdo/transmission-siting-and-permitting-efforts.
[65] Department of Agriculture (USDA), Department of Commerce (DOC), Department of Defense (DOD), Department of Energy (DOE), Department of the Interior (DOI), Environmental Protection Agency (EPA), Federal Permitting Improvement Steering Council (Permitting Council), Council on Environmental Quality (CEQ), and the Office of Management and Budget (OMB).

program, the MOU is intended to accelerate federal environmental review and permitting processes for qualifying onshore electric transmission facilities.[66] A qualifying project under CITAP is either:

- A high-voltage electric transmission line (230 kV or above), or other regionally or nationally significant electric transmission lines, with attendant facilities that are used in interstate or international commerce and are expected to require an environmental impact statement OR
- An electric transmission facility that is approved by the Director of the DOE's Grid Deployment Office[67]

The final rule, issued April 25, 2024, aims to consolidate federal environmental reviews and authorizations for qualifying projects into a two-year review timeline overseen by DOE.

The CITAP process allows DOE to develop a project-specific schedule that:

- Provides milestones and deadlines for all necessary federal actions and approvals
- Ensures that the project receives a decision within two years of the DOE's publication of a notice of intent to prepare an environmental review document
- Maintains a consolidated administrative docket of nonconfidential information submitted as well as information assembled by federal entities for authorizations and reviews

There remain concerns about CITAP centered on statutory authority and potential litigation. First, it may lengthen review timelines because only Congress can change statutory requirements that agencies must follow. Binding deadlines from DOE cannot override or violate statutory requirements. Thus, it could add difficulties for agencies to meet new requirements within the required timeframes. Second, efforts to streamline the permitting process could result in legal challenges brought by opponents under applicable laws due to potential errors made during the process. Finally, state lands are not subject to claims of eminent domain under existing federal statutory authority.[68]

Transmission Siting and Economic Development Grant Program[69]

The Transmission Siting and Economic Development (TSED) Grant Program is a $760 million program through the Inflation Reduction Act designed to help overcome permitting challenges that slow the deployment of critical transmission as well as economic development in communities affected by covered transmission projects.

Under TSED, DOE can fund studies and analyses of the impacts of a covered transmission project, examination of alternative siting corridors, participation by the siting authority in regulatory proceedings

[66] Coordinated Interagency Transmission Authorizations and Permits Program - Department of Energy.url; CITAP Draft Standard Permitting Schedule_DOE_2023-0800.pdf.
[67] https://www.energy.gov/gdo/coordinated-interagency-transmission-authorizations-and-permits-program
[68] Vinson & Elkins, "DOE Issues Final Rule on Coordination of Federal Authorizations for Electric Transmission Facilities" (May 6, 2024)
[69] https://www.energy.gov/gdo/transmission-siting-and-economic-development-grants-program; DOE Grid Deployment Office Presentation, DOE's Transmission Siting and Economic Development Grants Program (Sept. 14, 2023), at https://www.energy.gov/sites/default/files/2023-09/GDO%20Transmission%20Siting%20and%20Economic%20Development%20FOA%20Webinar%20Presentation%20Slides%20508%20Compliant.pdf.

at FERC or other regulatory entities, or other measures and actions that may improve the changes of, and shorten the time for, siting approval or permitting a project.[70]

Designation of New NIETCs

DOE has the authority to designate certain geographic areas as National Interest Electric Transmission Corridors (NIETCs) if it determines that consumers are harmed by a lack of transmission, and development of new transmission would advance national interests such as increased reliability and lower consumer costs. [71]

NIETCs were originally designated in 2005, and FERC was granted backstop siting authority if states withheld construction permits on such sites for more than a year. This authority and the original NIETCs were invalidated by federal courts and remained dormant. The IIJA amended the provisions to address issues raised in those court cases. The changes gave FERC authority to permit an application in NIETCs after denial from a state[72] and required DOE to consult with states and consider existing rights-of-way, sensitive environmental areas, and cultural heritage sites.[73]

A NIETC designation can unlock federal financing tools, specifically public-private partnerships through the $2 billion Transmission Facility Financing Program under the Inflation Reduction Act (IRA).[74]

DOE released a list of 10 NIETCs on May 8, 2024 (see Figure 5.1 below). The 2024 NIETC designations were based on findings from the National Transmission Needs Study released in October 2023 and prepared by DOE in consultation with numerous stakeholders. The selected NIETCs are geographic areas with either present or expected transmission congestion, one or more transmission projects in some stage of development, would increase interregional transfer capacity, or address transmission needs identified by regional transmission entities.

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[70] DOE Grid Deployment Office Fact Sheet, Transmission Siting and Economic Development (TSED) Program: What Siting Agencies Need to Know (updated Oct. 2023), at https://www.energy.gov/sites/default/files/2023-10/102023_TSED-SitingAuthorities.pdf.

[71] https://www.energy.gov/gdo/national-interest-electric-transmission-corridor-designation-process; Utility Dive, "DOE unveils 10 potential 'national interest' transmission corridors" (May 8, 2024); DOE, "Preliminary List of Potential NIETCs" (May 8, 2024); S&P Global Market Intelligence, "U.S. DOE finalizes rules to speed transmission permitting, boost grid capacity" (Apr. 25, 2024).

[72] The IIJA changed section 216(b) to include authority for permitting by FERC if a "a State commission or other entity that has authority to approve the siting of the facilities…has denied an application seeking approval pursuant to applicable law."

[73] Congressional Research Service, Electricity Transmission Permitting Reform Proposals (updated May 24, 2024). The IIJA amended section 216 to require the DOE to consult with relevant entities by adding the term "shall consult." Further, the IIJA added section 216(4)(G)(i) and 216(4)(G)(ii) which requires the DOE to consider designations that "maximize existing rights-of-way" and "avoids and minimizes, to the maximum extent practicable, and offsets to the extent appropriate and practicable, sensitive environmental areas and cultural heritage sites."

[74] https://www.energy.gov/gdo/transmission-facility-financing-program.

Figure 5.1: Preliminary List of 10 NIETCs as Proposed by DOE on May 8, 2024[75]

FERC Order 1977

On May 13, 2024, FERC issued Order 1977, which is intended to reinvigorate FERC's limited transmission siting authority (under section 216 of the Federal Power Act) for interstate electric transmission projects and provides a path for FERC to grant siting permits in NIETCs. Permits issued under section 216 confer eminent domain authority. Permits can be issued for a project if:

- A state does not have the authority to approve the siting of the facilities or consider the interstate or interregional benefits.
- The applicant is a transmitting utility that does not qualify to apply in a state.
- A state has not decided on an application within a statutory timeframe (one year) or has denied an application.
- Further, to approve a permit, section 216 requires that FERC must find that the facilities are in the public interest, are used for interstate commerce, reduce transmission congestion, are consistent with national energy policy and enhance energy independence, and maximize the transmission capabilities of existing towers or structures.

FERC seeks to ensure permit applicants make good faith efforts to engage landowners and other stakeholders early in the siting and permitting process. Applicants must show the following:

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[75] DOE Grid Development Office, at https://www.energy.gov/gdo/national-interest-electric-transmission-corridor-designation-process and https://www.energy.gov/sites/default/files/2024-05/PreliminaryListPotentialNIETCsPublicRelease.pdf.

- Evidence of stakeholder engagement
- A plan for public engagement with environmental justice communities and Indian tribes
- Notice to affected landowners within a specified time period
- Fourteen resource reports requiring information on emissions and impact on air quality and noise, impact on visual characteristics, and alternatives to the proposed project, including non-transmission alternatives

The new stakeholder/environmental justice/tribal engagement requirements established by FERC could accelerate the siting process by identifying and resolving issues early in the process, or it could slow the process by providing a whole new set of procedural hurdles and potential litigation.[76]

However, as one firm observed, it is unclear how states will react to developers who proceed with a project pursuant to FERC ruling following state denial of a siting request.[77]

There is continued focus on siting and permitting of electric transmission at FERC, DOE, and in Congress by way of legislative proposals (though none have been enacted). However, fundamental issues of federalism (state vs. federal jurisdiction), landowner rights, and local environmental and cultural concerns remain significant impediments to progress in project siting.

Current efforts, including Order 1977, employ process and engagement approaches to facilitate siting and permitting. Some approaches, such as CITAP, will be helpful for development on federal lands. However, for larger, regional projects—absent a forcing function and clear authority—it does not appear that there will be movement on the issue sufficient to build much needed, long-haul transmission in the near term.

[76] FERC Order 1977; FERC Staff Presentation, Applications for Permits to Site Interstate Electric Transmission Facilities (May 13, 2024); Bracewell, “Order No. 1977: FERC Finalizes Backstop Transmission Siting Reforms” (May 22, 2024).
[77] Bracewell, “Order No. 1977: FERC Finalizes Backstop Transmission Siting Reforms” (May 22, 2024), at p. 4.

6. TRANSMISSION PLANNING AND COST ALLOCATION

Key Takeaways

- FERC's "landmark" Order 1920 aspires to incorporate longer-term transmission planning and encourage more regional transmission facilities for reliability, congestion relief, and public policy (i.e., renewables and storage integration). However, the timeline (see below)—with potential clarification, compliance filings, and litigation of the rule—could mean a lengthy wait before the first long-term planning begins, much less decides on a project portfolio.
- Order 1920 largely hews to Order 1000 principles on cost allocation. Issues remain how to identify and quantify who benefits from projects to justify their bearing a portion of its cost.
- FERC's removal of the distinction of reliability vs. economics vs. public policy (i.e., renewables integration) for cost allocation will be a hotly contested issue, as illustrated by Commissioner Christie's dissent in Order 1920.

Order 1000 Framework

FERC Order 1000 has been the framework for transmission planning and transmission cost allocation for 13 years. The order established the requirements by which FERC-jurisdictional entities plan their transmission systems. Implementation of these requirements is carried out within regions.

As discussed in the 2021 White Paper,[78] FERC required participation in a regional planning process. The plan must consider long-term resource and demand trends, system contingencies, and discrete issues posing potential risks. Under Order 1000, there are three primary types of projects:

- Economic: Improvements that reduce congestion (limits on the amount of energy that can be transmitted through a given part of the system), reducing power costs (more supply, lower cost). These projects typically require a cost-benefit analysis.
- Reliability: Improvements that alleviate constraints or change flows in the system that had experienced or were expected to experience outages, transmission line overloading, short circuits, or other sources of potential system failure.
- Policy-Driven: Improvements that are required by the implementation of state or federal policy requirements, such as clean energy standards, that go beyond reliability-driven needs.

Also under Order 1000, each region needed to develop a manner by which non-incumbent transmission developers could participate in competitive solicitations for certain regional transmission projects.

Regions also are required to define how they would work with neighboring regions to develop infrastructure across seams that may more efficiently or cost-effectively address regional needs.

Finally, each transmission region needed to develop methodologies complying with certain principles by which costs for the projects identified in the transmission plan would be allocated to entities in the region. Generally, costs are to be proportionately allocated to cost causers or beneficiaries to which they cause or benefit from grid upgrades.

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[78] ScottMadden, Transmission in the United States: What Makes Developing Electric Transmission So Hard? (June 2021).

Perceived Gaps in Order 1000 and FERC's Reform Docket

In April 2022, FERC opened a docket captioned "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" to address halting progress in transmission development and generator interconnection.

FERC was concerned that, even with the Order 1000 requirements and related processes:

- Transmission planning is not sufficiently long term and forward looking to meet needs driven by a changing demand and resource mix.
- The absence of longer-term planning is resulting in piecemeal transmission expansion to serve near-term needs, causing inefficient investments in infrastructure and potentially higher costs for customers.[79]

The FERC docket resulted in the promulgation of Order 1920, which the Commission deemed needed to identify long-term transmission needs, account for "determinants" of those needs, and consider a broader set of benefits in meeting those needs.[80]

[79] FERC Order 1920 (May 13, 2024), p. 33, at ¶48. "Those [planning] processes may not be planning transmission on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand….The absence of sufficiently long-term, forward-looking, comprehensive transmission planning processes appears to be resulting in piecemeal transmission expansion to address relatively near-term transmission needs, and that continuing with the status quo approach may cause transmission providers to undertake relatively inefficient investments in transmission infrastructure."
[80] FERC Order 1920 (May 13, 2024), p. 132, at ¶139.

Terms of FERC Order 1920

Applicability

The rule applies to all FERC-jurisdictional transmission providers and is not limited to RTOs and ISOs.[81]

Long-Range Planning that Includes Scenarios

20-year planning horizon: FERC's key mandate of Order 1920 is that transmission operators/providers must revise their regional transmission planning processes to engage in planning on a long-term, forward-looking basis of at least 20 years using best available data[82] to develop well-informed projections of long-term transmission needs. Specifically, operators/providers must develop multiple scenarios that account for multiple factors, as well as a set of cost and efficiency benefits. FERC acknowledged that while "changes in the resource mix and demand are important, …they are only a subset of such drivers [of transmission needs]." FERC chose a 20-year horizon to allow identification of needs, when that need materializes, and the time for planning, siting, permitting, and construction timelines for regional transmission facilities.[83]

Decision deadline: Transmission providers must decide whether to select long-term transmission facilities identified in this process no later than three years from the start of a planning cycle.[84] However, the order doesn't mandate selection or construction of any particular project, adoption of any particular siting plan, or require foregoing state jurisdictional siting proceedings.[85]

Long-term scenarios requirements: Transmission providers must conduct this long-term planning at least every five years. FERC prescribes use of at least three "plausible and diverse long-term scenarios." Plausible means "they must reasonably capture probable future outcomes" and diverse in that "transmission providers must be able to distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each scenario."[86] Each scenario should have one sensitivity for high-impact, low-frequency events (e.g., sustained, wide-area generator and transmission outages due to extreme weather).

Scenario factors: All scenarios must incorporate the following seven specific categories of factors that may affect transmission needs:

1. Laws and regulations affecting the resource mix and demand. These include obligations, incentives (e.g., tax credits), equity and justice laws, and/or restrictions that will affect new or existing generation or demand.

[81] Foley Hoag, "Order No. 1920: A Guide to FERC's Landmark Transmission Planning Order" (May 16, 2024).
[82] FERC acknowledged that there is no "single best available data" but rather that best practices will be used to develop data inputs. FERC characterizes them as "data inputs that are timely, developed using best practices and diverse and expert perspectives, and adopted via a process that satisfies the transmission planning principles of Order Nos. 890 and 1000…. [They] also reflect the list of factors that transmission providers account for in their Long-Term Scenarios." Transmission providers must update, as necessary, all data inputs each time they reassess and revise their Long-Term Scenarios. Order 1920, at ¶633.
[83] FERC Order 1920, at §III.A.3.
[84] Troutman Pepper, "High-Level Summary of FERC Order No. 1920 on Transmission Planning and Cost Allocation" (May 21, 2024) (Troutman Pepper), at p. 3.
[85] Ibid., at p. 2.
[86] Order 1920, at ¶565.

2. Laws and regulations on decarbonization and electrification. FERC deems it necessary to examine factors that limit carbon intensity or electrification as they continue to be key drivers of long-term transmission needs.
3. State-approved integrated resource plans and expected supply obligations for load serving entities.
4. Trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies. Inclusion of this factor is necessary to account for technological changes expected over the planning horizon and is not an endorsement of any fuel or technology.
5. Retirements beyond those that have been publicly announced, with flexibility to account for generation facilities age, projected costs and revenues, emissions profile, and any laws and regulations that may affect continued operation.
6. Generator interconnection requests and withdrawals. However, transmission operators/providers are permitted to determine whether certain interconnection requests are speculative or duplicative and that these requests are unlikely to affect long-term transmission needs.
7. Utility and corporate commitments and federal, state, local, and federally recognized tribal policy goals that affect long-term transmission needs.

Transmission operators/providers are prohibited from discounting factors in categories 1-3 but are permitted to weigh the effects of those in categories 4-7.[87]

Regional transmission facility benefits: Transmission providers must measure and use at least seven enumerated economic and reliability benefits for the evaluation and selection of long-term regional transmission facilities. The seven specific benefits are as follows:

- Avoided or deferred reliability transmission facilities and aging infrastructure replacements
- Either reduced loss of load probability or reduced planning reserve margin
- Production cost savings
- Reduced transmission energy losses
- Reduced congestion due to transmission outages
- Mitigation of extreme weather events and unexpected system conditions
- Capacity cost benefits from reduced peak energy losses[88]

Evaluation process and selection criteria: Transmission providers must develop an evaluation process, including selection criteria, to identify and evaluate long-term regional transmission facilities for potential selection. Transmission providers must make good faith efforts to consult with and seek (not necessarily obtain) support of relevant state entities in developing the process and criteria.[89]

[87] Order 1928, at ¶507, 516.
[88] Order 1920, at §III.D; Troutman Pepper, at p.6.
[89] Order 1920, at ¶994 et seq.

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Evaluation processes must be transparent, not unduly discriminatory, and seek to maximize benefits accounting for costs over time without overbuilding facilities.[90] Further, the process must aim to select more cost-effective or cost-efficient facilities. Specifically, processes must:

- Make clear at which point providers will accept facility proposals, including from non-incumbents
- Estimate costs and benefits of proposed facilities
- Designate a point in the evaluation process to determine whether to select identified long-term facilities (no more than three years from the beginning of the planning cycle)
- Ensure determinations are “sufficiently detailed” for stakeholders to understand why a facility was selected or not[91]

Re-evaluation of selected facilities: Transmission providers must reevaluate a previously selected long-term regional transmission facility if delays in development jeopardize reliability needs, actual or projected costs exceed estimates, or changes in law or regulation make a solution no longer meet selection criteria.

Coordination of Regional Planning and Generator Interconnection Processes

Order 1920 contains provisions to ensure the evaluation of regional transmission facilities that will address certain transmission needs identified through the generator interconnection process and that have not yet been built. These are discussed in the *Generator Interconnection* section of this paper.

Consideration of Advanced Transmission Technologies

Transmission providers must consider, in both long-term planning and existing regional planning, specified alternative transmission technologies for both new transmission facilities and upgrades of existing facilities.[92]

Cost Allocation

Order 1920 does not require a state agreement process on cost allocation for regional transmission facilities. However, transmission providers must have a one-time, six-month engagement period to serve as a forum for negotiation on a cost allocation method and/or state agreement process that allows for meaningful participation by state entities.[93]

Transmission providers are, however, required to provide a long-term regional transmission cost allocation method for a single facility, or portfolio of facilities, as an *ex-ante* regional cost allocation method for long-term transmission facilities.

Transmission providers are permitted to include a state agreement process for cost allocation, but this cannot be the sole cost allocation method. In the absence/failure of a state agreement process or if the

[90] Vinson & Elkins, “FERC Issues Final Rules on Electric Transmission Planning, Cost Allocation, and Backstop Authority Evaluation Procedures” (May 14, 2024) (Vinson & Elkins), at p.3; Troutman Pepper, at p.7.
[91] Troutman Pepper, at p.7.
[92] Order 1920, at ¶¶1198-1200.
[93] Order 1920, at ¶1354; Troutman Pepper, at pp. 10-11; Foley Hoag, at pp. 7-8.

process if found to be unreasonable, unjust, or unduly discriminatory or preferential, the *ex-ante* long-term regional cost allocation method will serve as a backstop.

Any proposed *ex-ante* “backstop” cost allocation methods must conform to Order 1000 cost allocation principles,[94] except that costs may not be allocated according to project type (i.e., reliability vs. economic vs. public policy needs-driven), a key change from Order 1000 principles. Cost allocations based on state agreement need not meet Order 1000 principles but must be shown to allocate costs in a manner “at least roughly commensurate with estimated benefits.”

Local Inputs into the Regional Planning Process

FERC expressed concerns that regional and local planning processes may not adequately coordinate. Order 1920 requires transmission providers to adopt enhanced transparency for local transmission planning and identify potential opportunities to more efficiently and cost-effectively “right-size” replacement transmission facilities.

Order 1920 requires transmission providers to evaluate whether transmission facilities (1) operating above a specified kV threshold (e.g., less than 200 kV) and (2) that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be “right sized” to more efficiently or cost-effectively address a long-term transmission need.

If a “right-sized” solution is selected, transmission providers must establish a federal right-of-first-refusal (ROFR) to develop the “right-sized” facility. This ROFR extends to any part of that facility located within the transmission provider’s retail distribution service territory.[95]

Interregional Transmission Coordination

Order 1920 also requires updates to existing interregional transmission coordination procedures and planning processes to provide for the sharing of information with adjacent regions regarding their long-term transmission needs, as well as long-term regional transmission facilities to meet those needs. It also requires the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address long-term transmission needs.

What Order 1920 Did Not Do

Although FERC voiced “substantial concerns” with incumbent transmission providers’ investment incentives, FERC declined to adopt a federal ROFR conditioned on joint ownership of facilities, nor did it

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[94] ScottMadden, Transmission in the United States: What Makes Developing Electric Transmission So Hard? (June 2021); Order 1000 cost allocation principles are: (1) The costs of selected transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; (2) those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities; (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1; (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs; (5) the method for determining benefits and identifying beneficiaries must be transparent; and (6) there may be different regional cost allocation methods for different types of transmission facilities, such as those needed for reliability, congestion relief, or to achieve public policy requirements.
[95] Troutman Pepper, at p. 14.

make changes to Order 1000 competitive transmission reforms. FERC will consider federal ROFR and other transmission reforms in another docket related to transmission planning and cost management.[96]

Responses to Order 1920

Proponents

A variety of comments support the final rule. Many come from renewable energy advocates. The Harvard Law School's Electricity Law Initiative, often critical of utilities and transmission planners for not prioritizing interregional projects says the order "attempts to push a recalcitrant industry to do more."[97]

R Street Institute noted that the status quo had a "severe lack of economic discipline" because of exemptions to regional economic planning under Order 1000 led to most projects built being local and supplemental projects, which exclude economic criteria.[98] It believes the rule will remedy the forward and comprehensive planning that is not occurring, resulting in "inefficient piecemeal transmission expansion to meet only near-term needs while foregoing projects with better net benefits." It also commended the listing of specific benefits to be captured in planning and "how clarifying consistent benefits categories ultimately improves net benefits to consumers." [99]

Opponents

A key critic of the rule is FERC Commissioner Christie, who wrote a strident dissent to the order as issued. His key substantive objections were:

- The record does not adequately support the finding that rates in question are unjust or unreasonable, permitting FERC action under Federal Power Act §206.
- The rule is unduly preferential toward certain types of generators (i.e., wind and solar).
- The rule does not provide a just and reasonable replacement rate because it serves the profit-making interest of the developers of certain types of generation and shifts the interconnection and network upgrade costs of projects driven by public policies or corporate preferences onto ratepayers who may not have agreed to those policies or preferences.
- The rule infringes on the authority of the states over energy resource mixes.[100]

The National Association of Regulatory Utility Commissioners was also disappointed in potential usurpation of state authority, noting "We are generally disappointed by the significantly diminished state role envisioned by the FERC order with respect to transmission planning and cost allocation. In light of our recent joint task force with FERC on electric transmission and the newly proposed collaboration, we hope there will be future opportunities to ensure that state voices are heard."[101]

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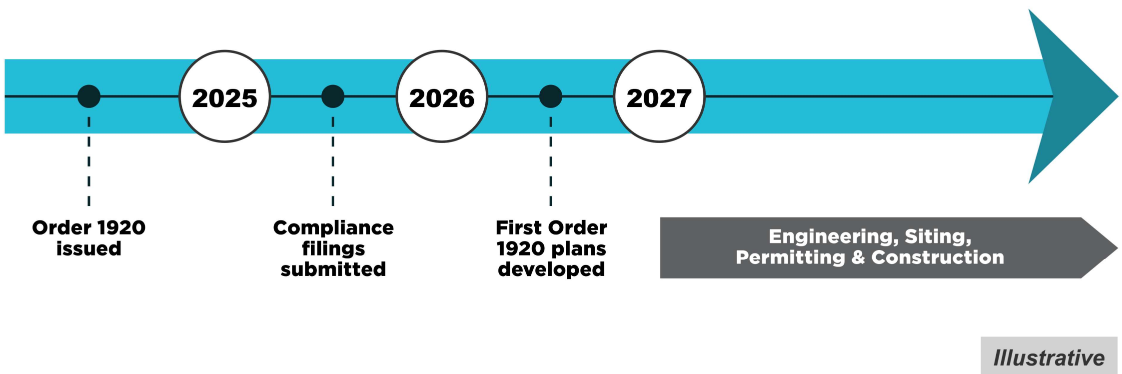
96 Order 1920, at §VIII; Troutman Pepper, at p. 12.
97 PowerGrid International, "FERC's 'watershed' transmission rules are here. Here's what to know about Orders 1920 and 1977" (May 13, 2024).
98 R Street Institute, "FERC Hath Spoken Transmission" (May 14, 2024).
99 Ibid.
100 Order 1920, Dissent of Commissioner Christie.
101 NARUC Press Release, "NARUC Expresses Disappointment in FERC's Order on Transmission Planning" (May 14, 2024).

Open Issues

Litigation: With compliance plans due in May 2025 and related consideration and clarification of the rule during FERC's review of those plans thereafter (or perhaps in a rehearing order before compliance plans are filed), a clarified rule may be well over a year away. Litigation of the rule is likely to be undertaken by numerous affected parties. The outcome of this litigation could be more uncertain with the recent Supreme Court decision striking down the *Chevron* doctrine, which had held that in cases where a federal statute is ambiguous, courts must give federal agencies deference in their reasonable interpretation of the law.[102] So, Order 1920 may not be settled for several years.

Implementation: The breadth of Order 1920 and short timeframe for compliance may lead to requests for extension to file compliance plans, particularly for smaller transmission providers and those outside of RTOs.[103] Even if stated deadlines hold, the first long-term transmission planning cycles will not commence before 2Q 2026 (see illustrative timeline below).[104]



Since the 2021 White Paper, FERC has made another attempt to update and expand upon its landmark Order 1000, seeking to broaden the scope of transmission planning and facilitate allocation of transmission costs. However, even if Order 1920 is implemented as issued, the implementation timeline will not result in the building of transmission for several years. Absent reforms in siting and permitting, this rule may result in better planned and allocated transmission facilities that are never built. FERC has signaled (but deferred) action on incentives or incumbent utility ROFR for transmission projects, which leaves important questions for transmission owners and developers unanswered.

[102] Power Magazine, "The Chevron Deference Is Dead. What Does It Mean for the Power Sector?" (July 2, 2024); Utility Dive, "Supreme Court's Chevron, Corner Post Decisions Could Delay Energy Investments, Spur Litigation: Analysts" (July 2, 2024).
[103] Vinson & Elkins, at p. 4.
[104] Foley Hoag, at p. 11.

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7. RATEMAKING AND INCENTIVES

In the 2021 White Paper, we described how FERC sets the return on equity (ROE) for transmission investments, which helps determine the attractiveness of these investments. As we noted, FERC Order 679 established incentives to encourage investment in transmission, including ROE adders. Those incentives helped increase investment in transmission starting in the mid-2000s. At the time, we observed that it is unclear whether these incentives continue to be effective, and that FERC was revisiting policy in this area.

In Order 1920 (discussed in the *Transmission Planning and Cost Allocation* section of this paper), FERC declined to limit the availability of the construction work in progress (CWIP) incentive for regional facilities, which allows providers to recover the costs of new transmission projects in rates before going into service. CWIP provides up-front regulatory certainty, rate stability, improved cash flow, and potentially lower capital costs.[105] However, FERC is also concerned that it shifts too much risk to ratepayers. FERC said any action on CWIP is better served in a separate proceeding.[106]

While FERC recently granted a series of ROE and non-ROE incentives for transmission projects, much of FERC policy for transmission incentives remains largely unchanged from our last review of this topic in 2021. ROE policy as a whole remains unsettled. However, one important update is the availability of DOE funding (enabled through the IIJA and IRA and discussed in *Appendix A*), which provides financial support of projects meeting certain criteria. These DOE programs may facilitate certain types of projects; however, the grants and other incentives available do not provide the same types of financial incentives available under Order 679.

As stated in our previous paper, incentive treatment can make transmission investment more attractive, but it will not solve the other headwinds these projects face.

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[105] Morgan Lewis, "Revisiting the CWIP Incentive for Long-Term Regional Transmission Facilities – Part 2" (May 3, 2022), at https://www.morganlewis.com/blogs/powerandpipes/2022/05/transmission-nopr-revisiting-the-cwip-incentive-for-long-term-regional-transmission-facilities-part-2.
[106] Order 1920, at §VII.

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8. CONCLUSION

Since releasing the 2021 White Paper, the need for transmission expansion has continued to grow. The drivers for new transmission are abundant and generally well understood within the industry and among policymakers. The ability to move power across the bulk power grid and the expansion of that capacity to meet increasing demand remains critical.

Some the key drivers of needed transmission capability include:

- Electrification: The conversion of end-use energy demand for applications such as heating to electrical
- Integration of renewables: The movement of power from renewable resource-rich regions to demand centers
- Resiliency: The ability to move power across and between regions during weather and other events that stress the grid

More recently, large loads have emerged as a significant driver of energy infrastructure development that was not contemplated in the 2021 White Paper.

Despite these needs, transmission is unlikely to be built quickly enough to even partially address the challenges above. Policy changes, siting efforts, and construction all take time—measured in years—to be implemented.

Certainly, regulators and policymakers have refocused on transmission, pursuing improvements in process, technology, and project funding. However, while reforms under FERC Orders 2023, 1920, and 1977 are attempting to solve some of the challenges to planning and siting transmission, they leave unaddressed key issues identified in our previous paper:

- Siting and permitting: The time for approval and number of stakeholder approvals required to build transmission continues to be a significant challenge. Beyond National Interest Electric Transmission Corridors and proposed backstop siting, still untested, and proposed stakeholder engagement processes, there is no forcing function to accelerate approvals along transmission pathways.
- Incentive treatment: FERC has left for future consideration whether to continue, enhance, or discontinue financial incentives to transmission development.
- Order 1000 competition and ROFR: In its Order 1920, FERC also left for future consideration any potential modifications of policy on competition in transmission development and incumbent ROFR, except for "right sizing" local projects.

Three years later, limited progress has been made in addressing the issues identified in our original paper, and large loads create an immediate, significant further complication for the transmission grid (as well as all other electric infrastructure).

APPENDIX A: OTHER ELECTRIC TRANSMISSION FEDERAL FUNDING PROGRAMS

As discussed in the *Transmission Needs and Drivers* section of this paper, the following are some federal programs that may support current and future transmission development:

Infrastructure Investment and Jobs Act (IIJA) Programs

In November 2021, the passage of the IIJA authorized $1.2 trillion in transportation and infrastructure spending. With a broad scope, the law provides investments in roads, bridges, rails, public transit, broadband, airports, and water infrastructure.

The IIJA also directed significant federal funding toward the power sector and initiatives targeting grid reliability and resiliency. More specifically, transmission investments are encouraged in IIJA through multiple funding programs and enhancements to DOE and FERC authority related to project siting and permitting. The largest source of for transmission funding is $10.5 billion being disbursed through the Grid Resilience and Innovation Partnerships (GRIP) Program. Administered by the DOE Grid Deployment Office, the GRIP Program includes three funding mechanisms:[107]

- **Grid Innovation Program:** Provides $5 billion to governmental entities to coordinate and collaborate with electric sector owners and operators to deploy projects that use innovative approaches to transmission, storage, and distribution infrastructure to enhance grid resilience and reliability.
- **Smart Grid Grants:** Provides $3 billion to increase the flexibility, efficiency, and reliability of the electric power system, with particular focus on increasing capacity of the transmission system, preventing faults that may lead to wildfires or other system disturbances, integrating renewable energy at the transmission and distribution levels, and facilitating the integration of increasing electrified vehicles, buildings, and other grid-edge devices.
- **Grid Resilience Utility and Industry Grants:** Provides $2.5 billion to grid operators to support activities that modernize the electric grid to reduce impacts due to extreme weather and natural disasters.

In addition to the GRIP Program, the IIJA created the $2.5 billion Transmission Facilitation Program (TFP). Administered through the Building a Better Grid Initiative, the revolving fund authorizes DOE to:[108]

- Sign capacity contracts as an anchor customer on new and upgraded transmission lines (up to 50% for up to 40 years) to facilitate the private financing and construction of the line[109]
- Provide loans for the cost of carrying out eligible transmission projects
- Participate in public-private partnerships to co-develop certain transmission projects

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[107] https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program.
[108] https://www.energy.gov/gdo/transmission-facilitation-program.
[109] In October 2023, the DOE announced it had entered capacity contract negotiations for three transmission projects across six states, totaling 3.5 GW of capacity. In February 2024, the DOE released requests for proposals for a second round of capacity contracts and public partnerships to connect remote and isolated microgrids to existing infrastructure. Source: https://www.energy.gov/gdo/transmission-facilitation-program.

Additional funding opportunities that may involve transmission investment include $2.3 billion in formula grants for states and American Indian Tribes to prevent outages and enhance the resilience of the electric grid and $1 billion in financial assistance to improve in rural or remote areas of the United States, the resilience, safety, reliability, and availability of energy, as well as environmental protection from adverse impacts of energy generation.[110]

Inflation Reduction Act (IRA) Programs

In August 2022, the passage of the IRA created additional sources of federal funding that could be used to support transmission investments. Most notable are provisions that appropriate significant funds for transmission development through a combination of loans, grants, and direct federal spending. Administered by DOE's Grid Deployment Office, the funding provisions include:

- **Transmission Facility Financing:** Provides $2 billion in direct loan authority for the construction or modification of transmission facilities designated by the Secretary of Energy to be in the national interest under section 216(a) of the Federal Power Act.[111] Consequently, eligible transmission projects must be in a National Interest Electric Transmission Corridor (NIETC). A preliminary list of NIETC designations was issued in May 2024.[112] Any final designations would occur after environmental reviews and public engagement. Financing will remain available through September 30, 2030.[113]
- **Grants to Facilitate the Siting of Interstate Electricity Transmission Lines:** Provides $760 million to facilitate siting of transmission projects by providing grants to siting authorities to expedite the siting and permitting process and providing grants for economic development activities in communities that may be affected by a transmission project.[114]
  - In August 2023, announced $300 million of grants available through the Transmission Siting and Economic Development (TSED) Grants Program. [115] Funds from the TSED program can be used for two types of funding opportunities:
    - Providing support to siting authorities in carrying out activities to examine siting and permitting applications for certain new or upgraded transmission lines and to reduce the time it takes to process them.
    - Providing funds for economic development activities in communities affected by the construction and operation of such transmission lines, including economically disadvantaged and environmental justice communities.
  - The deadline for full TSED applications was April 2024. Selection notifications are expected in Summer 2024.
- **Interregional and Offshore Wind Electricity Transmission, Planning, Modeling, and Analysis:** The IRA provides $100 million in funding to conduct transmission planning, modeling, and analysis regarding interregional electricity transmission and transmission of

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[110] https://www.energy.gov/gdo/grid-and-transmission-program-conductor-guide.
[111] The White House, "Inflation Reduction Act Guidebook" (website accessed May 7, 2024), at https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/ (IRA Guidebook).
[112] See *Siting and Permitting* section of this paper.
[113] Congressional Research Service, Electricity Transmission Provisions in the Inflation Reduction Act of 2022 (Jan. 4, 2024) [website: https://crsreports.congress.gov/product/pdf/IN/IN11981]
[114] IRA Guidebook.
[115] DOE Grid Deployment Office, "Fact Sheet: Transmission Siting and Economic Development (TSED) Program General Overview" (October 2023).

electricity generated by offshore wind and to convene relevant stakeholders to discuss these issues.[116]

- In 2023, the Pacific Northwest National Laboratory and National Renewable Energy Laboratory launched the West Cost Offshore Wind Transmission Study with funding from the IRA. The 20-month effort will investigate transmission options that will support offshore wind development along the nation's West Coast through 2050.[117]

- **Loan Guarantees:** The DOE Loan Program Office (LPO) can also finance transmission projects at commercial scale with up to $5 billion of available loan guarantees.[118]
  - Through Title 17 Innovative Energy Loan Guarantee Program, the LPO can provide up to $3 billion in loan guarantees for projects utilizing innovative technology, including high-voltage direct current systems, offshore wind transmission, and systems sited along rail and highway routes that follow Department of Transportation guidelines.
  - Through the Tribal Energy Loan Guarantee Program, the LPO can provide up to $2 billion in partial loan guarantees for projects that are wholly or majority owned by a federally recognized tribe or Alaska Native Corporation.
- **New ERA Program:** Rural Transmission investments may also be funded through the Empowering Rural America (New ERA) program. The $9.7 billion program will provide loans and grants to rural electric cooperatives. Administered by the Department of Agriculture's Rural Utilities Service administers (RUS), the application window to submit a Letter of Interest closed on September 15, 2023.[119]

Other Federal Incentives

Beyond the IIJA and IRA, a final federal program worth noting is the Transmission Infrastructure Program (TIP). TIP manages the Western Area Power Administration's (WAPA) statutory $3.25 billion borrowing authority to provide debt financing and development assistance for qualifying transmission projects with at least one terminus in WAPA's 15-state service territory and that facilitate delivery of renewable energy. The program leverages WAPA's transmission project development expertise and WAPA's borrowing authority, partnering with private and other nonfederal co-investment to support the development of critical transmission and related infrastructure in the West.[120]

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[116] IRA Guidebook.
[117] Pacific Northwest National Laboratory, "West Cost Offshore Wind Transmission Study" (accessed May 6, 2024), at https://www.pnnl.gov/projects/west-coast-offshore-wind-transmission-study.
[118] DOE Loan Program Office, "Fact Sheet: Transmission Loan Guarantees," at https://www.energy.gov/lpo/articles/lpo-transmission-fact-sheet.
[119] https://www.rd.usda.gov/programs-services/electric-programs/empowering-rural-america-new-era-program#overview.
[120] https://www.federalregister.gov/documents/2022/01/19/2022-00883/building-a-better-grid-initiative-to-upgrade-and-expand-the-nations-electric-transmission-grid-to.

APPENDIX B: DOE'S TRANSMISSION INTERCONNECTION ROADMAP

In April 2024, the Department of Energy (DOE) released a comprehensive roadmap outlining "solutions to speed up interconnection of clean energy onto the nation's transmission grid and clear the existing backlog of solar, wind, and battery projects seeking to be built."[121]

The solutions recommended in the roadmap go beyond requirements established in FERC Order 2023. Additional issues addressed in the roadmap include data transparency, automation, interconnection studies, cost allocation, and workforce development. The recommendations are intended to complement and support Order 2023 implementation.

Specific goals outlined within the roadmap include:

- **Goal #1: Increase Data Access, Transparency, and Security for Interconnection:** This goal increases interconnection data transparency to improve an interconnection customer's ability to screen and site potential projects, enable third-party modeling, facilitate process automation, enhance competition while ensuring equitable outcomes, and enable benchmarking, tracking, and auditing of interconnection processes and reforms.
- **Goal #2: Improve Interconnection Process and Timeline:** Potential solutions include:
  - **Queue Management**: Several incremental queue management solutions—from automation and expanded access to fast tracks to more stringent commercial readiness requirements and study timelines—may help reduce queue volumes and interconnection delays in the near term and enable transmission providers to handle larger and variable queue volumes in the longer term.
  - **Affected System Studies**: Improvements to transmission provider coordination and methods for affected system studies—including Order 2023's requirements but also voluntary collaboration and joint planning that go beyond them—will remove a significant obstacle to timely processing of interconnection requests.
  - **Inclusive and Fair Process:** Enhancements to interconnection and transmission planning processes—specifically, expanding transmission connection access opportunities—can help achieve inclusive and fair interconnection outcomes.
  - **Workforce Development**: Recommends targeted efforts to increase training opportunities and improved compensation for existing staff and new outreach in higher education settings to highlight interconnection policy and practice.
- **Goal #3: Promote Economic Efficiency in Interconnection**: This goal aims to improve cost allocation, reduce costs to electricity consumers, enhance the coordination between transmission planning and the interconnection process, and optimize the sizing of transmission investment through improvements in interconnection studies.
  - **Cost Allocation:** If current efforts to reduce interconnection bottlenecks are unsuccessful, transmission providers may need to consider alternatives to the current participant funding model of interconnection cost allocation.

[121] https://www.energy.gov/articles/doe-releases-first-ever-roadmap-accelerate-connecting-more-clean-energy-projects-nations.

- **Coordination between Interconnection and Transmission Planning:** More closely align data inputs, assumptions, and process timelines between interconnection and long-term transmission planning.
- **Interconnection Studies:** Interconnection study methods will also need to continually adapt to a changing generation mix, with a greater emphasis on more realistic dispatch assumptions, consideration of multiple time periods rather than static snapshots, and inclusion of all potential mitigation options to relieving transmission constraints.

- **Goal #4: Maintain a Reliable, Resilient, and Secure Grid:** This goal aims to update technical requirements within interconnection studies, models, and tools while also improving industry interconnection standards.
  - **Interconnection Reliability Assessment Models and Tools:** Improve models to account for large disturbance events while aligning to ensure that the appropriate, site-specific models are used in system impact studies.
  - **Interconnection Standards:** Develop comprehensive interconnection standards (e.g. specifying invertor-based resource capabilities) to ensure reliable and secure operation of newly interconnecting plants.

The roadmap also includes four measurable targets for interconnection reform. The following metrics for 2030 can be measured using publicly available data:

- Decreasing average time from interconnection request to interconnection agreement for completed projects to less than 12 months
- Lowering the variance of interconnection costs for all projects to less than $150 per kilowatt
- Increasing completion rates for projects that enter the facility study phase to greater than 70%
- Eliminating annual North American Electric Reliability Corporation disturbance events involving unexpected tripping of invertor-based resources (IBR) that are not identified in analysis due to inaccurate IBR models

APPENDIX C: REGIONAL CASE STUDIES

Midcontinent ISO: Long-Term Regional Planning (and a View of Order 1920 Implementation)[122]

Background

The Midcontinent ISO is the largest RTO in North America based upon geographical scope. MISO covers all or part of 15 U.S. states and the Canadian province of Manitoba, serving a population of 45 million. MISO encompasses 75,000 miles of high-voltage transmission and more than 6,800 generating units. MISO membership is comprised of 57 transmission owners and 135 non-transmission owners. MISO energy markets are large, with more than $40 billion in annual gross market charges. There are more than 500 market participants in MISO.[123]

Figure C.1: MISO Reliability Footprint and Regional Control Center Locations[124]

[122] See section in this paper on *Transmission Planning and Cost Allocation*.
[123] 2023 MISO Transmission Expansion Plan (Dec. 2023) (MTEP23), at pp. 5-6; MISO Corporate Fact Sheet, at https://www.misoenergy.org/meet-miso/media-center/2024/corporate-fact-sheet/.
[124] MTEP23, at p. 5.

Regional Issues and Planning Priorities

MISO has characterized its operating environment as a "hyper-complex risk environment."[125] In its Reliability Imperative report, the RTO identified several "urgent and complex" challenges affecting system reliability. These include the following:

- **Fleet change:** New weather-dependent resources that are being built, such as wind and solar, do not provide the same critical reliability attributes as the conventional dispatchable thermal resources that are being retired.
- **Regulations, policies, and investment criteria:** Increasing challenges to build new dispatchable generation, even if it is needed for reliability.
- **Fuel assurance:** Challenges in economics and availability of gas, coal, and adequate weather conditions to support renewables.
- **Extreme weather events:** Severe weather events that impact electric reliability have been increasing.
- **Load additions:** While economic development is welcome, growing energy-intensive use can pose significant reliability risks if the load additions it spurs cannot be reliably served with existing or planned resources.
- **Incremental load growth:** While electricity demand has been flat for many years, it is expected to increase due to the electrification of other sectors of the economy.

Among the initiatives outlined in the Reliability Imperative report are four pillars: market redefinition, operations of the future, transmission evolution, and system enhancements. The transmission evolution activity involves a holistic assessment of MISO's future transmission needs and associated cost allocation, including transmission to support utility and state plans for existing and future generation resources. Key initiatives under transmission evolution include:

- Developing "Futures" planning scenarios using ranges of economic, policy, and regulatory inputs
- Developing distinct "tranches" (portfolios) of Long-Range Transmission Plan (LRTP) projects
- Enhancing joint transmission planning with seams partners
- Improving processes for new generator interconnections and retirements

MISO's Transmission Planning Process

MISO employs a "value-based" planning approach intended to ensure local needs are integrated with regional requirements. This approach includes:

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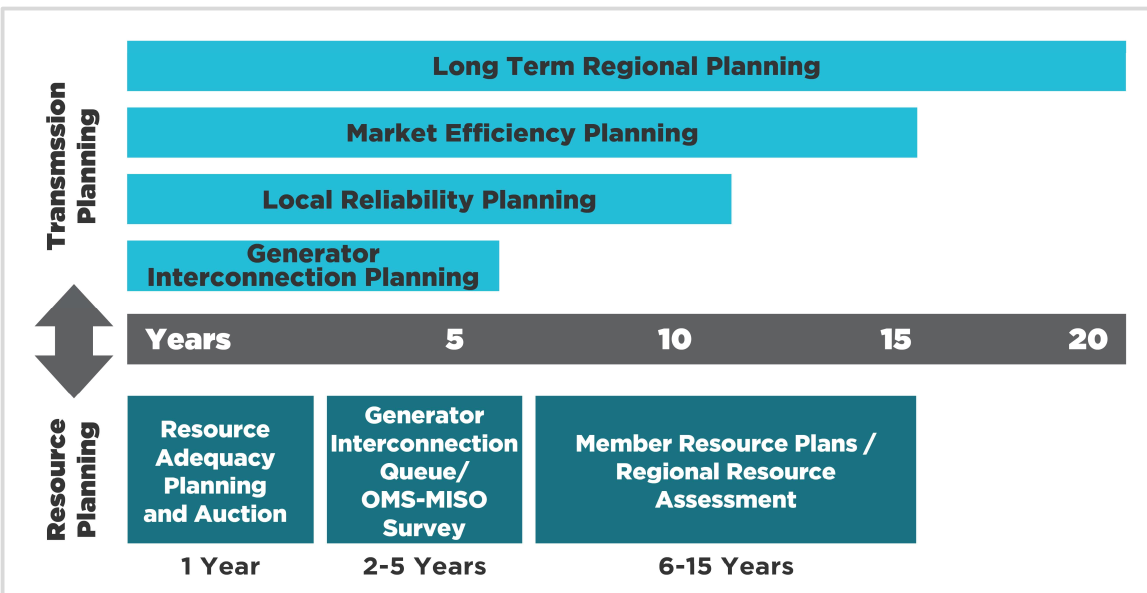
[125] MISO, MISO's Response to the Reliability Imperative – Executive Summary (updated Feb. 2024), at p. 2; Presentation by NERC President Jim Robb to MISO Board of Directors, "Challenges to Reliability and Resilience" (Dec. 7, 2023), available at https://cdn.misoenergy.org/20231207%20Board%20of%20Directors%20Item%2007a%20NERC%20CEO%20Update631092.pdf.

- Local planning (based on member plans and reliability standard requirements in the near term (less than 10 years), with MISO's role ranging from alternative assessment, need validation, no-harm tests and/or transparency, depending on the project submissions
- Regional planning (longer-term broader system needs, including Long-Term Regional Transmission Plan)
- Policy assessment (to study the impact on the transmission system and resource mix)
- Resource planning (system changes required to accommodate new resources)
- Interregional planning (through collaboration with neighboring grid operators)[126]

The goal of the transmission planning process is to identify a least-regrets outcome that meets its member plans, provides reliable power delivery, and appropriately balances local versus regional solutions to ensure a cost-effective outcome for customers. MISO's comprehensive planning process spans short- to long-term horizons, depending on study objectives and need drivers. Each process informs the others to cover the entire planning horizon. A view of the study horizons under MISO value-based planning is shown below at Figure C.2.

Figure C.2: MISO Value-Based Planning Approach Study Horizons[127]



LRTP is a key element of planning the regional grid to be reliable and efficient with a focus on the long-term (i.e., 20 years) planning horizon. LRTP efforts are launched periodically when needed to address significant changes to future conditions that the grid must be prepared to address.

- The LRTP process involves developing scenario-based "Futures" and planning models using those "Futures". These scenarios contemplate ranges of economic, policy, and technological possibilities—such as load growth, electrification, decarbonization, generator retirements,

[126] MTEP23, at pp. 11-12; REGlobal, "Grid Expansion in U.S. Midcontinent: MISO Releases MTEP23 Worth USD9 billion" (Apr. 29, 2024).
[127] MTEP23, at p. 12

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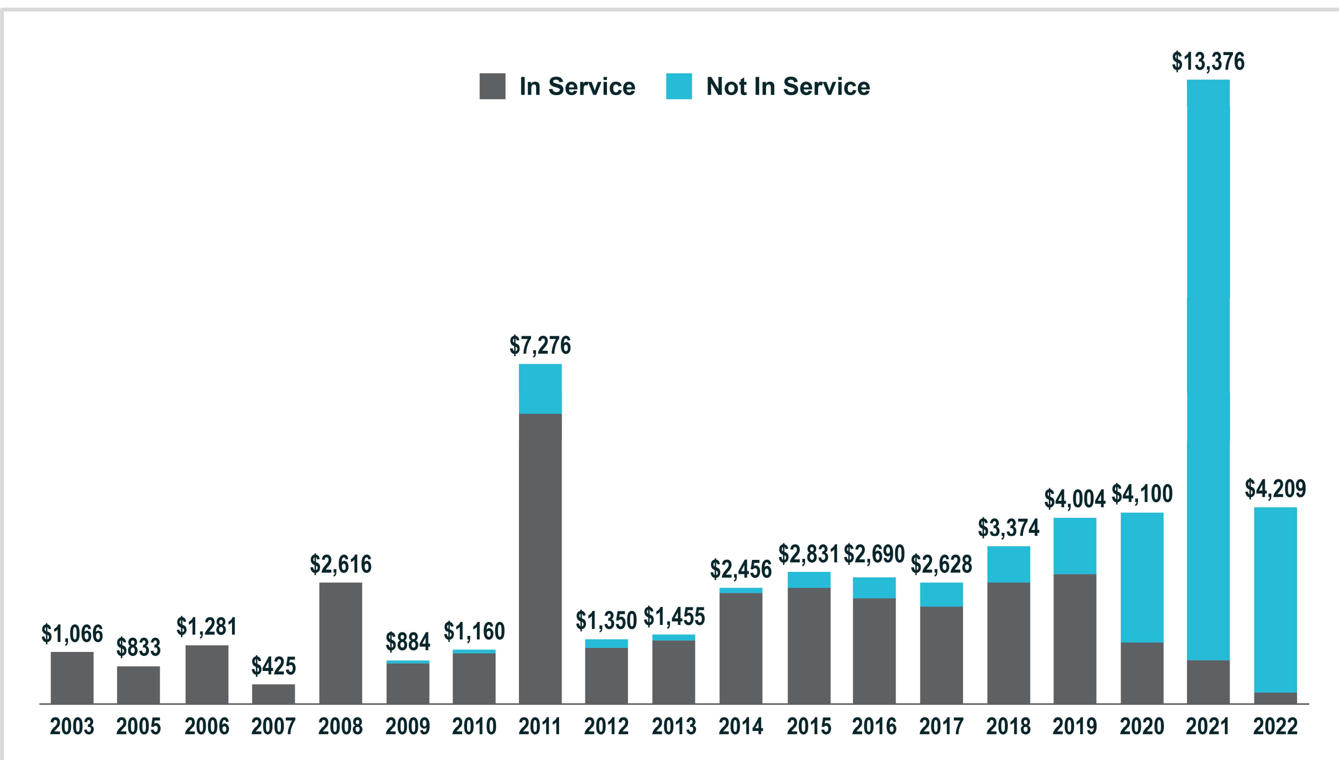
renewable energy levels, fuel prices, and generation capital costs—over a 20-year time horizon.[128]

- This planning results in projects that are regional backbone facilities that move power between geographically dispersed areas. Project recommendations from this process are presented for board review and approval over several annual regional transmission plan cycles as analyses proceed and recommendations are developed.[129]
- The LRTP study identifies a "least-regrets" transmission build-out that accounts for multiple scenarios to manage uncertainty.

MISO develops an annual regional expansion plan known as the MISO Transmission Expansion Plan (MTEP). The MTEP is based on expected use patterns and analysis of the performance of the transmission system in meeting both reliability needs and the needs of the competitive bulk power market, under a wide variety of contingency conditions.

At the time of the release of MTEP23 (in December 2023), MISO has approved $34 billion in investment since its 2003 transmission expansion plan and nearly $24 billion of approved projects are yet to be fully placed in service. Figure C.3 below illustrates annual MTEP investment.

Figure C.3: MTEP Approved Projects by Status ($M)[130]



[128] Ibid., at p. 32.
[129] Ibid., at pp. 15-16.
[130] Ibid., at p. 20

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Of the more than $58 billion in transmission investment that remains active or in service, half has occurred in the last five MTEP cycles (2017-2022). There is a shift in facility type as well, with lower investment in new lines. Since 2003, new lines comprised 39% of investment, with substations at 34% and line upgrades at 27%. Over last six cycles (2017-2022), substations comprised 38% of investment, followed by line upgrades (35%) and new lines (27%).[131]

MTEP21: Large Tranches of Investment

MISO's largest regional transmission investment portfolio came out of its MTEP21 plan. This plan was informed by MISO's Futures Report (published in April 2021 and updated in December 2021). The Futures Report (discussed earlier) was MISO's first attempt at incorporating potential future fleet mixes and demands (see Figure C.4 below). Results of Futures scenarios are driven significantly by utility and state net-zero carbon and renewable energy goals, including both assumed resource additions and assumed unit retirements.[132]

Figure C.4: Summary of MISO Futures Scenario Impacts (2039)[133]

MTEP21 recommended 335 new projects representing $3 billion of investment. Approximately 17% (or $532 million) were for generator interconnection and baseline reliability projects. "Other" projects driven by reliability, age and condition, load growth, and other local needs comprised 83% (or nearly $2.5 billion) of investment.[134]

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131 Ibid., at pp. 18-23.
132 MISO Futures Report (Apr. 2021; updated Dec. 2021), at pp. 10-19.
133 MISO Futures Report (Apr. 2021; updated Dec. 2021), at p. 3.
134 MTEP21, at p. 2.

During the MTEP21 process, the LRTP study process also considered several portfolios (or tranches) of projects to meet goals of MISO's Reliability Imperative and anticipated reliability, economic, and decarbonization needs. LRTP approached transmission portfolios in tranches in part because urgent needs identified were appearing in the near-term for the Midwest subregion, including retirements and resource portfolio changes.

This more urgent need put the focus for Tranches 1 and 2 in the Midwest Subregion.[135] Tranche 3 will shift to focus on the South Subregion,[136] with Tranche 4 then looking to strengthen the connection between the Midwest and South subregions.

The Tranche 1 portfolio was considered "least regrets" because the plan reflects needs that represent a current view of member plans. According to MISO, "those portfolio plans continue to accelerate and expand, making Future 1 the conservative, expected case and presenting reliability implications that the Tranche 1 portfolio addresses."[137]

MISO performs a benefit-cost analysis of long-term regional transmission, looking at the following factors:[138]

- Congestion and fuel savings
- Avoided capital cost of local resources
- Avoided transmission investment
- Resource adequacy savings
- Avoided risk of load shedding
- Decarbonization

LRTP Tranche 1 Portfolio

In July 2022, MISO's board approved Tranche 1 of its long-term plan study. The portfolio consists of 18 transmission projects with an estimated cost of $10.3 billion.[139] Tranche 1 includes more than 2,000 miles of additional transmission lines and will allow up to 53 GW of new generation capacity to connect to the grid.[140] The portfolio can be grouped into six sections with benefits described in Figure C.5 below.

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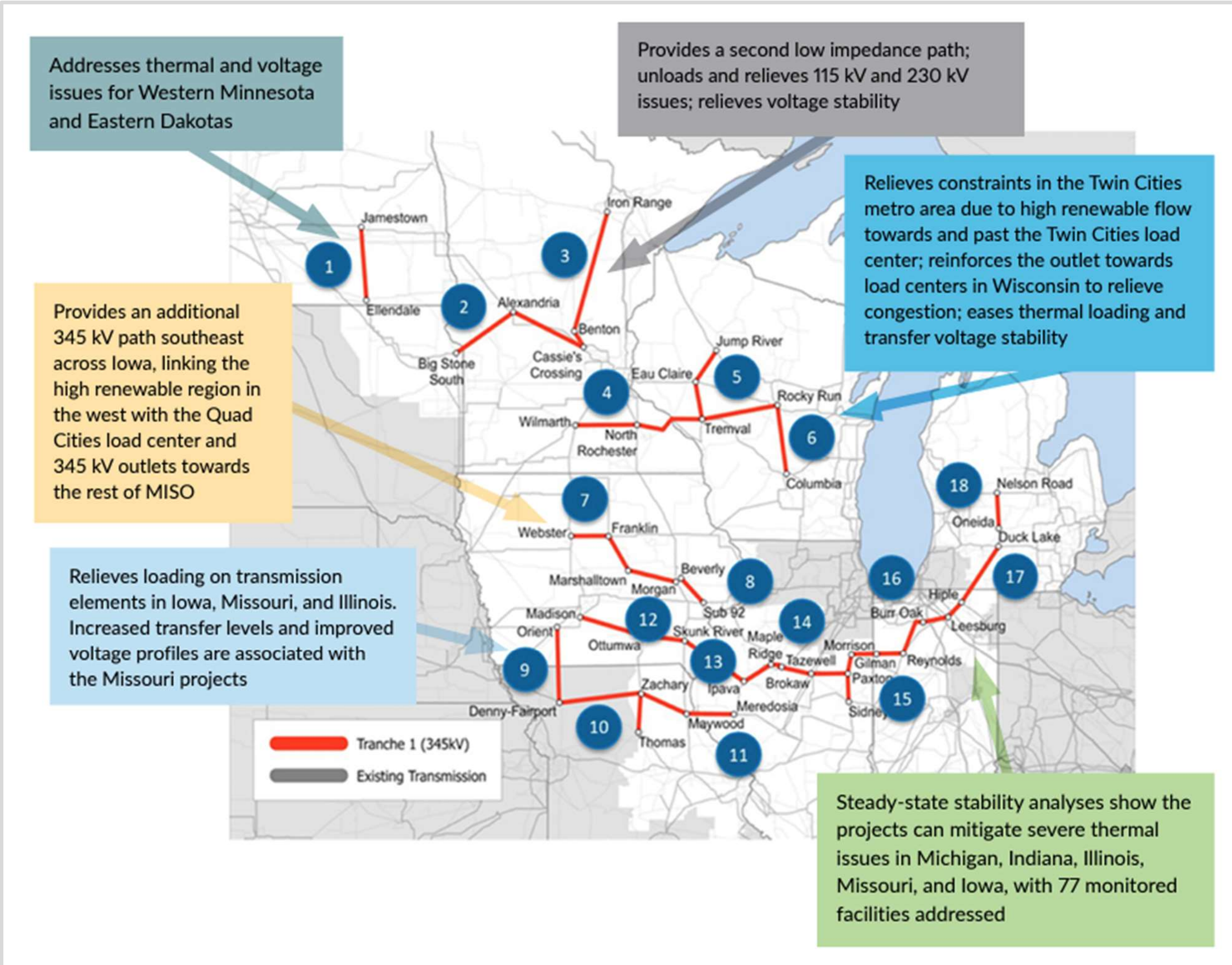
135 i.e., Missouri and north.
136 i.e., Arkansas and south.
137 MTEP21 Report Addendum: Long-Range Transmission Planning Tranche 1, Executive Summary, at p. 5.
138 MTEP21 Report Addendum: Long-Range Transmission Planning Tranche 1, Executive Summary.
139 In 2022$. Note that this approved amount is in addition to more than $3 billion in regional projects approved under MTEP21.
140 PowerGrid International, "MISO approves 2000 miles of new electric transmission after its 'largest and most complex' study" (July 26, 2022), available at https://www.power-grid.com/td/transmission/miso-approves-2000-miles-of-new-electric-transmission-after-its-largest-and-most-complex-study/.

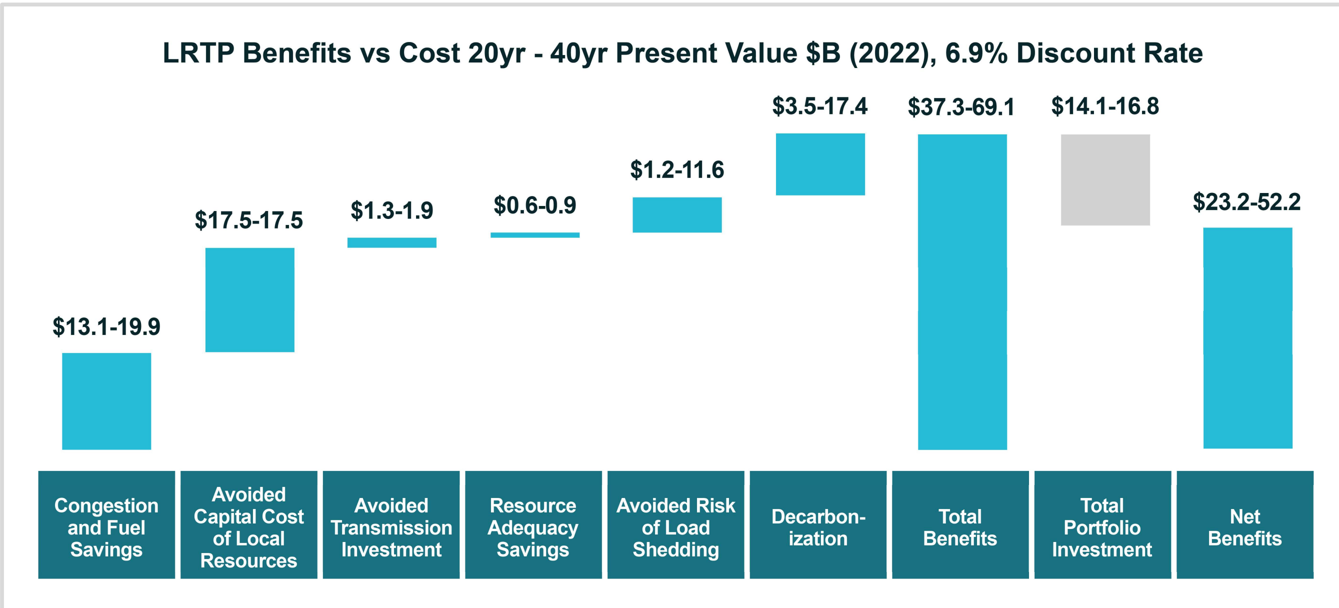
Figure C.5: LRTP Tranche 1 Portfolio Transmission Issues Targeted Solutions[141]



Tranche 1 was estimated to have a positive benefit-to-cost ratio of at least 2:6. Many of the proposed benefits were economic (congestion and fuel savings), avoided local project, and decarbonization.

141 MTEP21 Report Addendum: Long-Range Transmission Planning Tranche 1, Executive Summary, at p. 9.

Figure C.6: LRTP Tranche 1 Portfolio Benefits vs. Cost[142]



As of December 2023, projected in-service dates for Tranche 1 projects ranged from June 2028 to June 2030.[143] Transmission owners have been working on detailed engineering and construction plans as well as regulatory filings.[144] It is unclear whether cost estimates for these projects have been or are being revised in light of changing economic conditions.

LRTP Tranche 2 Portfolio

In 2023, MISO updated its Futures scenarios (Series 1A) to reflect most current plans of states, utilities, and policymakers. This study update resulted in Futures 1A, 2A, and 3A (compare Figure C.6 above). The updated Futures reflected that "members' and states' plans were refined, new legislation and policies took effect, and prices, along with incentives for various resources, saw significant changes."[145] The key change in the scenarios reflected an accelerating fleet transition versus prior analysis.

The Tranche 2 portfolio is expected to address economic and reliability constraints that vary by region, including:

- Overloaded facilities (10% to 20%)
- Curtailments of energy (more than 15% annually)
- Energy losses
- Constraints on transfers between regions

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142 Ibid., at p. 3.
143 LRTP Tranche 1 Appendix A-4 Schedule 26A Indicative, at https://cdn.misoenergy.org/LRTP%20Tranche%201%20Appendix%20A-4%20Schedule%2026A%20Indicative625788.xlsx (accessed May 31, 2024).
144 MTEP23, at p. 41.
145 MISO Futures Report Series 1A (Nov. 2023), at p. 2.

- Import and export power swings between day and night[146]

The portfolio focuses on creating a 765 kV transmission "highway" within MISO based upon "land use, line distances, transfer levels and costs." MISO anticipates finalizing the Tranche 2 portfolio and securing board approval in 2024. Expected cost of Tranche 2 totals between $17 billion and $23 billion.[147] The projected benefits, however, have been subject to debate among stakeholders.[148]

Interregional Planning

FERC Order 1000 also provides for interregional transmission coordination to develop transmission infrastructure across seams to address constraints and increase transfer capacity. MISO has engaged with neighboring RTOs PJM and SPP as well as the Southeastern Regional Transmission Planning to coordinate annually to review of respective regional plans.[149] PJM and MISO are studying transmission upgrades as part of an interregional transfer capability study.[150]

MISO's approach to planning—using scenarios, trying to align long-term, regional, and local reliability planning—can be seen as a prototype of the transmission planning approach advocated by FERC in its Order 1920. This has led to development of significant projects, first through Multi-Value Projects circa the early 2010s and most recently through its LRTP tranches. Transmission spending under these regional, long-term programs has been and will be significant. It remains unclear, however, how soon new projects can be constructed, whether all parties will be satisfied with cost allocation, and whether these projects will yield the benefits promised.

146 MISO Tranche 2: Initial Draft Portfolio – LRTP Workshop Presentation (Mar. 4, 2024).
147 Ibid.
148 S&P Global Market Intelligence, "MISO likely overestimates benefits of transmission plan – watchdog" (May 31, 2024.
149 https://www.misoenergy.org/planning/interregional-coodination/.
150 Utility Dive, "PJM, MISO to study transmission upgrades to bolster interregional power flows" (May 10, 2024), at https://www.utilitydive.com/news/pjm-miso-interregional-transmission-transfer-capacity/715769/.

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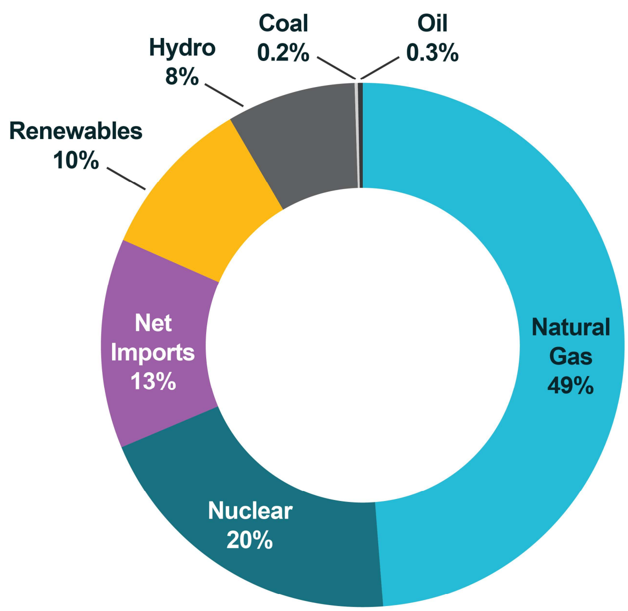
ISO New England (ISO-NE): Balancing Generation Changes with Reliability

Background

ISO-NE is a FERC-designated regional transmission organization, which footprint covers six states[151] in New England. It serves approximately 14.5 million customers across 68,000 square miles.[152] Approximately 9,000 miles of transmission connect the region. ISO-NE has nearly 31 GWs of installed generating capacity. Approximately 70% of net energy for load in 2023 was thermal resources (primarily natural gas and nuclear) (see Figure C.7 below).[153]

Figure C.7: ISO-NE 2023 Energy by Fuel Type



Coal- and oil-fired power plants comprise about 6 GW[154], or 22% of capacity[155] in ISO-NE and are retiring.[156]

The New England region has pipeline constraints on gas imports (including for power generation) on peak demand days and particularly during winter cold snaps.[157] It supplements gas supply through an existing liquified natural gas terminal, Everett LNG. During extreme cold weather, ISO-NE leverages oil and dual (gas/oil) fuel-fired capacity; oil-fired units provided more than a quarter of New England's energy during its cold spell of Winter 2017-18.[158]

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151 States are Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.
152 NERC LTRA.
153 ISO New England, New England Power Grid 2023–2024 Profile (April 2024) (2023-24 Profile).
154 NERC LTRA, at p. 56.
155 2023-24 Profile.
156 Ibid.
157 FERC Staff, 2024 Energy Primer (Dec. 2023).
158 https://www.iso-ne.com/about/key-stats/resource-mix.

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New England imports a significant amount of energy. Since 2019, it has imported between 13% and 21% of energy from neighboring energy systems in New York, Quebec, and New Brunswick.[159]

Greenhouse Gas Emissions Reduction Policies

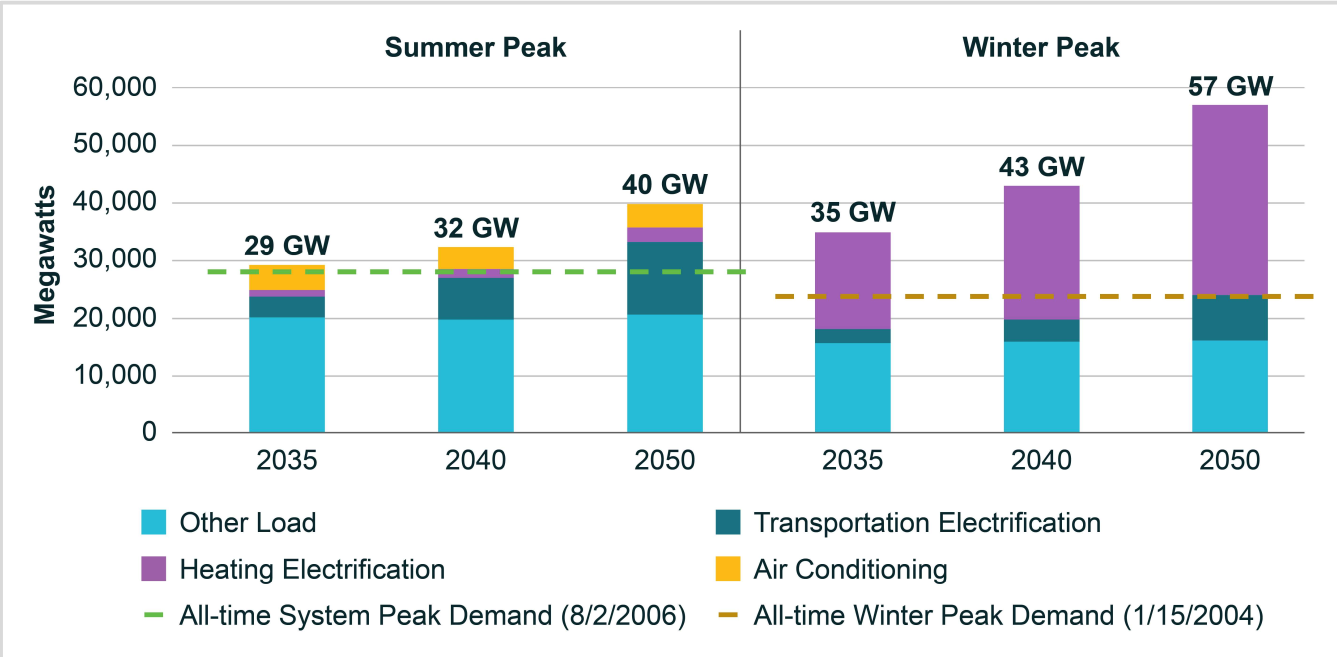
Five of six New England states (excluding NH) have committed to reducing their carbon dioxide emissions by at least 80% by 2050, prompting changes in the region's resource mix and the expected increased electrification of the heating and transportation sectors.

These statewide commitments have led a shift toward development of renewable resources such as wind and solar photovoltaic generation. Based upon the interconnection queue, the ISO forecasts 12 GW of solar within a decade.[160] Battery storage and wind resources dominate ISO-NE's interconnection queue. Wind power resource proposals, primarily offshore, totaling 17.6 GW account for nearly half of the interconnection request queue. Battery storage technologies dominate new resource proposals, with more than 18 GW proposed.[161] Over the next several decades, these renewable resources are expected to substantially displace natural gas-fired generation as the region's primary resource type. New England states also seek to expand transmission to import additional non-emitting energy to meet state targets.

At the same time, increased electrification is expected to significantly increase consumer demand for electricity and drive changes in usage patterns that include seasonal and daily shifts in peak demand.[162] Overall demand—even with efficiency and behind-the-meter solar—is expected to grow 2.3% annually through 2032, with peak demand increasing at a rate of 1.1% annually. Vehicle and especially heating electrification will shift New England from its current summer peaking character to be winter peaking, with heating representing 13% of the winter peak and 6% of total energy use by 2034.[163] Energy adequacy is a concern during periods of prolonged cold and is expected to remain so, with the greatest concern during mornings in winter when gas supplies for generation may be limited.[164]

[159] 2023-24 Profile.
[160] Ibid.
[161] Ibid.
[162] TDI New England, New England Clean Power Link portal, at http://www.necplink.com/index.php; Vermont Biz, "Welch Promotes New England Clean Power Link," at https://vermontbiz.com/news/2023/august/06/energy-clean-heat-standard-coming-electric-costs-rising.
[163] Presentation to CBIA 2024 Energy & Environment Conference, ISO New England Power Grid Outlook (June 6, 2024).
[164] https://www.iso-ne.com/about/regional-electricity-outlook/pillar-three-energy-adequacy/; NERC LTRA, at p. 59.

Figure C.8: ISO-NE 2050 Transmission Study Base Case – Seasonal Peak Load Projections vs. Historical Peaks[165]



Need for "Robust" Transmission

Anticipating these resource and demand shifts and given the decarbonization requirements established in the region, New England states requested that ISO-NE conduct a comprehensive longer-term (>10 years) study (the 2050 Transmission Study) to determine the region's transmission needs to reliably serve load and develop roadmaps for transmission upgrades designed to satisfy those needs while considering both the feasibility of construction and cost. The roadmaps are conceptual but address high likelihood concerns and the amount and type of transmission infrastructure necessary to provide reliable, cost-effective energy to the region throughout the clean energy transition.[166]

ISO-NE found that about half of line miles in New England (100 kV or above and over which the ISO has planning jurisdiction)—4,200 miles out of 9,000—are overloaded in 2050 as are 90 out of 150 transformers, assuming a 57 GW winter peak (see Figure C.8 above).[167] These are driven primarily by high heating load.[168] The other takeaways from the 2050 Transmission Study were:

- Reducing peak load significantly reduces transmission cost.
- Targeting and prioritizing high likelihood concerns is highly effective.
- Incremental upgrades can be made as opportunities arise.

[165] ISO-NE 2050 Study.
[166] 2050 Study.
[167] ISO-NE, 2050 Transmission Study Fact Sheet (Feb. 2024) (2050 Study Fact Sheet).
[168] ISO-NE, 2050 Transmission Study Informational Public Webinar Presentation (May 1, 2024).

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- Generator location can have a significant impact on the transmission upgrades required for reliability.
- Transformer capacity is crucial.[169]

The ISO looked at projects to remedy high-likelihood concerns. Dependent upon scenario, transmission investment could total between $16 billion and $26 billion through 2050 (see Figure C.9 below), with costs between $6 billion and $9 billion through 2035.[170]

Figure C.9: 2050 Transmission Study Cost Estimates vs. Historical Cost of Transmission Upgrades in ISO-New England[171]

Timeframe	Average Cost Per Year	Total Costs
2002-2023	$0.73 billion	$15 billion
2024-2050 (51 GW peak)	$0.62 billion to $0.65 billion	$16 billion to $17 billion
2024-2050 (57 GW peak)	$0.88 billion to $1.00 billion	$23 billion to $26 billion

The 2050 study is scenario based, informational, and does not trigger construction of any new transmission project. However, the ISO is currently discussing the second phase of the longer-term transmission study, with tariff changes that will establish a process to enable the New England states to move policy-related transmission projects forward, with associated cost allocation.[172]

Lessons of History: Challenges of Building Transmission in New England

Building transmission in ISO-NE has not been easy. Local opposition and cost concerns have led to slow progress on transmission expansion, even when the expansion is intended to tap non-emitting hydroelectric resources. For example, going back to 2016, there were several projects contemplated to facilitate imports.[173] The 182-mile, 1.1 GW Northern Pass project through New Hampshire, launched in 2008, was abandoned in 2019.[174] The $1.6 billion, 1 GW high-voltage direct current New England Clean Power Link project connecting Quebec and Vermont with 150 miles of line, 100 miles of which are to run under Lake Champlain, started studies in Fall 2013 but has yet to break ground.

More recently, the New England Clean Energy Connect project, with an intended 145-mile pathway from Canada across Maine and terminating in Massachusetts, was slowed for months by a 2021 Maine ballot referendum objecting to the line. After litigation, the ballot initiative was overturned and development and

[169] ISO-NE 2050 Study, at p. 16 et seq.
[170] ISO-NE 2050 Study, at p. 55, Table 5-8.
[171] ISO-NE 2050 Study Fact Sheet.
[172] ISO-NE 2050 Study, at p. 9.
[173] Engineering News-Record, “High Voltage, High Stakes in Northeast” (Mar. 3, 2016).
[174] https://www.nhpr.org/environment/2023-06-27/after-abandoning-northern-pass-plans-eversource-turns-over-some-land-to-recreation-and-forest-management.

permitting was restarted in May 2023. However, with the delay came higher project costs; its original $1 billion costs have grown to $1.5 billion.[175]

Most New England states have aggressive decarbonization goals that have electrification as a key component of their respective strategies. With high electrification of heating, winter peak load could more than double the region's historical winter peak. ISO-NE will need significant investment in "robust" transmission to move variable resources and hydropower from offshore and inland New England and Canada to demand centers. Based upon history, it is unclear whether New England will be able to construct transmission quickly enough to meet its aggressive decarbonization goals. However, Order 1920 compliance (discussed elsewhere) may be a catalyst for required long-term planning and cost allocation.

[175] Engineering News-Record, "Embattled Maine Power Line Restarts as Cost Balloons to $1.5B" (Aug. 3, 2023), at https://www.enr.com/articles/56895-embattled-maine-power-line-restarts-as-cost-balloons-to-15b.

PJM: Large Loads and Transmission Investment

Large Loads Emerge in PJM

As mentioned in the *Transmission Needs and Drivers* section above, after experiencing slow demand growth for years, projected electricity peak demand and energy growth rates have surged. A significant driver behind these increases is the rapid expansion and planned addition of new large loads. These large loads are primarily in three categories of energy users: new domestic manufacturing, data centers, and cryptocurrency mining.

In 2023, data centers consumed roughly a quarter of Virginia's electricity—the highest in the United States—followed by North Dakota at more than 15%, and Iowa, Nebraska, and Oregon each exceeding 11%. Future data center electricity consumption by 2030 in Virginia could range from 29.3% to 46% depending on the rate of growth of new data centers and efficiency improvements.[176]

This large load growth in Virginia is in PJM, a regional transmission organization that oversees transmission planning and operations for 13 Mid-Atlantic states and the District of Columbia.

Energy in PJM serves Loudon County, Virginia, the largest data center market in the world. Since 2019, Dominion has connected 81 data centers totaling 3.5 GW in capacity to their system.[177] According to PJM, the construction of these data centers is creating "major pockets of significant increasing demand," with PJM identifying growth rates of more than 300% in some areas.[178]

Data Centers Driving Transmission Needs in PJM

The demand increases from large loads are prompting a transmission expansion response from regional transmission providers such as PJM, as well as individual transmission owners. In 2023, PJM's Regional Transmission Expansion Plan process identified 48 new baseline transmission projects at an estimated cost of around $6.6 billion to maintain fundamental grid reliability.[179] One of these projects, the $627 million Wishing Star substation, was approved to address increased load in Loudon County, Virginia, in northern Virginia, home to a cluster of data centers known as "Data Center Alley."[180]

Further, PJM received approval from FERC in April 2024 for $5 billion in transmission upgrades over the next five years. More than $1.1 billion of these projects is to support data center development in northern Virginia.[181] The package of transmission solutions is intended to address up to 7.5 GW in new electricity demand from data centers in Virginia and Maryland and the retirement of more than 11 GW of power generation capacity across the PJM footprint. Under the plan, about half of the costs will be borne by

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[176] Electric Power Research Institute, Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption (May 28, 2024) (EPRI Report), at pp. 2, 13, available at https://www.epri.com/research/products/3002028905.
[177] S&P Capital IQ, "Utilities face challenges, opportunities from AI-driven data center power demand growth: report" (Apr. 1, 2024).
[178] PJM Regional Transmission Expansion Plan, pp. 18 (Mar. 7, 2024).
[179] S&P Capital IQ, "PJM approved $6.6B of incremental baseline power transmission projects in 2023" (Mar. 11, 2024).
[180] PJM Regional Transmission Expansion Plan, pp. 222, (Mar. 7, 2024).
[181] S&P Capital IQ, "PJM awards $5B in grid upgrades to meet data center growth, plant retirements" (Dec. 13, 2023).

customers in “Data Center Alley,” and approximately 10% of the costs would be allocated to customers in Maryland.[182]

Maryland’s consumer advocate petitioned to have the costs borne by Virginia[183], but this proposal was rejected by FERC. FERC Commissioner Clements wrote in a concurrence to FERC’s order that “Seeking to isolate any infrastructure affected by state public policy and require the state enacting such policy to shoulder the infrastructure's costs absent voluntary agreement to do so, as Maryland People's Counsel appears to suggest, ignores the regional nature of PJM's transmission system and the full distribution of benefits of regional infrastructure,” Clements wrote. “Adopting Maryland People's Counsel's suggested outcome would be impractical and unworkable."[184]

Paying for Large Loads

There have been other proposals to address paying for transmission expansion for large loads in PJM’s service territory. One proposal by American Electric Power (AEP) would see data centers required to guarantee payments to the electricity provider. The proposal, filed with the Public Utilities Commission of Ohio in May 2024, would create a new rate category for data center customers and cryptocurrency mining/mobile data center operations. The proposed rate structure would require new data centers with loads greater than 25 MW and crypto mining/mobile data center operations with loads greater than 1 MW to agree to meet certain requirements before infrastructure is constructed to serve them. Data center operators would be required to sign 10-year contracts to pay for a minimum of 90% of the energy they say they need each month—even if they use less. This would provide a guaranteed return for AEP as it builds up transmission infrastructure to support new large loads.[185] The proposal is designed to address

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182 S&P Capital IQ. “FERC approves PJM's $5.1B transmission plan, dismisses datacenter cost concerns” (Apr. 9, 2024).

183 S&P Capital IQ, “Md. office says Virginia should pay more data center costs in $5B PJM grid plan” (Feb. 12, 2024).

184 Ibid.

185 In testimony regarding the proposed rate category, AEP Ohio’s Vice President of Regulatory and Finance testified as follows:

> AEP Ohio is proposing to create new customer classes and tariffs for data centers to address the challenges that AEP Ohio and our customers face in serving these new customers.
>
> First, AEP Ohio’s proposal is designed to mitigate the risk that transmission infrastructure will be built for speculative data center projects, and when it comes time to serve, the data center projects either will be cancelled or be using significantly less power than they had planned. If this happens, more of the costs of the transmission buildout will be borne by retail customers in the PJM region including AEP Ohio’s other customers. As described below, AEP Ohio’s proposed data center tariffs will require data centers to make long-term financial commitments – to have more skin in the game – to mitigate the risk that transmission infrastructure will be built for data centers but not needed.
>
> Second, AEP Ohio’s data center tariff proposal is designed to keep AEP Ohio’s service territory open for economic development. As described by Company witnesses Ali and Kelso, data center growth has nearly used up available transmission capacity in Central Ohio. Without requiring data centers to make long-term financial commitments to support transmission investment, data center load growth could leave AEP Ohio with insufficient transmission capacity to support the kind of ordinary, non-data-center economic growth that creates jobs and powers Ohio’s economy. If the Commission accepts AEP Ohio’s proposal to require data center customers to make long-term financial commitments, that decision will

the expected 5,000 MW of data center demand in central Ohio by 2030, up from 600 MW as of April 2024.[186] Marc Reitter, AEP Ohio's president and COO, said in a May 13, 2024, statement, "We need accurate plans and solid commitments from large data center customers, so the right facilities are built at the right time. We need to ensure they can follow through with their commitments as significant new investments are made to serve them."[187]

Socialization of transmission costs is a controversial issue in PJM. Both Exelon and AEP have objected to Talen Energy Corporation's supply arrangement with Amazon Web Services, tapping power from the Susquehanna nuclear power plant. As argued by those parties, "The co-located load should not be allowed to operate as a free rider, making use of, and receiving the benefits of, a transmission system paid for by transmission ratepayers…. We have no objection to co-location per se, but such load should pay its fair share of system use and other charges, just like other loads and customers."[188]

> support transmission investment to facilitate both the growth of ordinary job-creating economic development and the growth of data centers….
>
> The recent growth of data center load in AEP Ohio's service territory is an unprecedented phenomenon. As AEP Ohio witness Ali describes, existing peak demand in Central Ohio is approximately 4,000 MW, and this peak demand will likely more than double in the coming years, driven in large part by new data center customers who have already signed binding electric service agreements ("ESAs") with AEP Ohio to bring on approximately 5,000 MW of data center load by 2030. Beyond that, customers have expressed interest in building additional data centers with more than 30,000 MW of load in the Central Ohio portion of AEP Ohio's service territory.
>
> With this new data center load growth comes new challenges. There is no RTO controlled generation in Central Ohio. This means that AEP Ohio must rely on the extra high-voltage ("EHV") transmission system to import power from generators located elsewhere. As AEP Ohio witness Ali makes clear, AEP Ohio can import enough power over the EHV backbone transmission system to serve the new data centers that have signed ESAs to bring approximately 5,000 MW of data center load by 2030. But to serve more data centers will likely require new EHV transmission lines to import large amounts of additional energy to Central Ohio. According to Mr. Ali, building a new EHV transmission line to Central Ohio could cost billions of dollars and take 7-10 years to plan, design, site, and construct.
>
> This new transmission investment to support data centers should not begin without assurances that the new data center customers will follow through with their plans. If billions of dollars of new transmission investment were built for data centers but not fully used, this would harm AEP Ohio's other customers through higher rates.
>
> Commitments from data centers are also needed to make sure that new transmission investment can happen under the PJM planning process. PJM transmission investments are based on each transmission owner's load forecasts, as AEP Ohio witness Ali explains. It can be risky, however, to include projected data centers in a load forecast without commitments from customers that they will build their planned data centers and use as much power as they say they will.
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> (Direct Testimony of Matthew S. McKenzie on Behalf of Ohio Power Company, Public Utilities Commission of Ohio, Case No. 24-508-EL-ATA (filed May 13, 2024))

[186] Power Engineering, "AEP files proposal to handle surging data center development in Ohio" (May 14, 2024) https://www.power-eng.com/news/aep-files-proposal-to-handle-surging-data-center-development-in-ohio/#gref.
[187] PR Newswire, provided by AEP Ohio, https://www.prnewswire.com/news-releases/aep-ohio-files-plan-to-secure-grid-resources-for-data-centers-protect-residential-customers-302143900.html (May 13, 2024).
[188] Nuclear Engineering International, "U.S. power utilities challenge Talen's nuclear-powered data centre deal with AWS" (July 5, 2024), at https://www.neimagazine.com/news/us-power-utilities-challenge-talen-energys-deal-with-amazon-data-centre-at-susquehanna-npp/?cf-view.

PJM is ground zero for the phenomenon of data center-driven rapid load growth, but it is not alone. Several regions are experiencing similar growth in large loads. PJM is also managing a significant shift in its resource mix as baseload generators continue to retire while more variable energy resources come online. Driven by the expansion of data centers and large loads, coupled with the reconfiguration of the resource mix, organizations like PJM are taking significant efforts to manage this demand through strategic planning and transmission upgrades.