NATIONAL LABORATORY OF THE ROCKIES

Lessons Learned for Transmission Cost Allocation in U.S. Regional Markets

Amy Rose, Christina Simeone, Ellie Estreich, and Nicholas Foss

National Laboratory of the Rockies

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Technical Report
NLR/TP-6A40-97370
February 2026

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Suggested Citation
Rose, Amy, Christina Simeone, Ellie Estreich, and Nicolas Foss. 2026. *Lessons Learned for Transmission Cost Allocation in U.S. Regional Markets*. Golden, CO: National Laboratory of the Rockies. NLR/TP-6A40-97370.
https://www.nlr.gov/docs/fy26osti/97370.pdf.

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Acknowledgments

In researching this report, we received valuable feedback from staff at various transmission planning regions, including ISO New England (ISO-NE), Midcontinent Independent System Operator (MISO), SPP, and California Independent System Operator (CAISO). The authors are also greatly indebted to several individuals for their thoughtful feedback and guidance on this report, including Faith Smith, Andrew Alberg, Alyssa Kody, Bethany Frew, Kate Anderson, Jaquelin Cochran, and Mark Ruth (National Laboratory of the Rockies, NLR), Johannes Pfeifenberger (The Brattle Group), and Alissa Baker from the U.S. Department of Energy's Grid Deployment Office. Jennifer Korte (NLR) provided editing and design support.

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List of Acronyms

AC	alternating current
CAISO	California Independent System Operator
DFAX	distribution factor analysis
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
ICC	Illinois Commerce Commission
ISO	independent system operator
ISO-NE	ISO New England
JTIQ	Joint Targeted Interconnection Queue
kV	kilovolt
MISO	Midcontinent Independent System Operator
MTEP 11	MISO 2011 Transmission Expansion Plan
MVP	Multi-Value Project
MW	megawatt
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
OATT	open access transmission tariff
PJM	PJM Interconnection
PPTPP	Public Policy Transmission Planning Process
PTF	pool transmission facility
RDDA	Rate Design and Disbursement Agreement
RSC	Regional State Committee
RTO	regional transmission organization
SPP	Southwest Power Pool
SPPT	Synergistic Planning Project Team

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Executive Summary

Expanding electric transmission can facilitate generator interconnection and improve grid reliability. Assigning costs for new transmission infrastructure within a transmission planning region and between regions is highly contentious because these costs can have a direct impact on energy prices and ratepayer bills. In this report, we evaluate what factors influence successful transmission cost allocation agreements. Through a review of legal disputes, existing cost allocation practices, and regional case studies, we identify cost allocation trends and potential strategies to minimize cost allocation disputes for future projects.

Transmission projects advance most effectively when regions use flexible, easy-to-apply methods, evaluate benefits relative to costs across portfolios, and actively engage stakeholders to ensure broadly distributed benefits and support.

The six regional project case studies revealed common trends and lessons learned for transmission cost allocation. These include lessons on the planning approach used to identify and evaluate projects and the actual cost allocation method design. Figure ES-1 summarizes six lessons learned for transmission cost allocation.

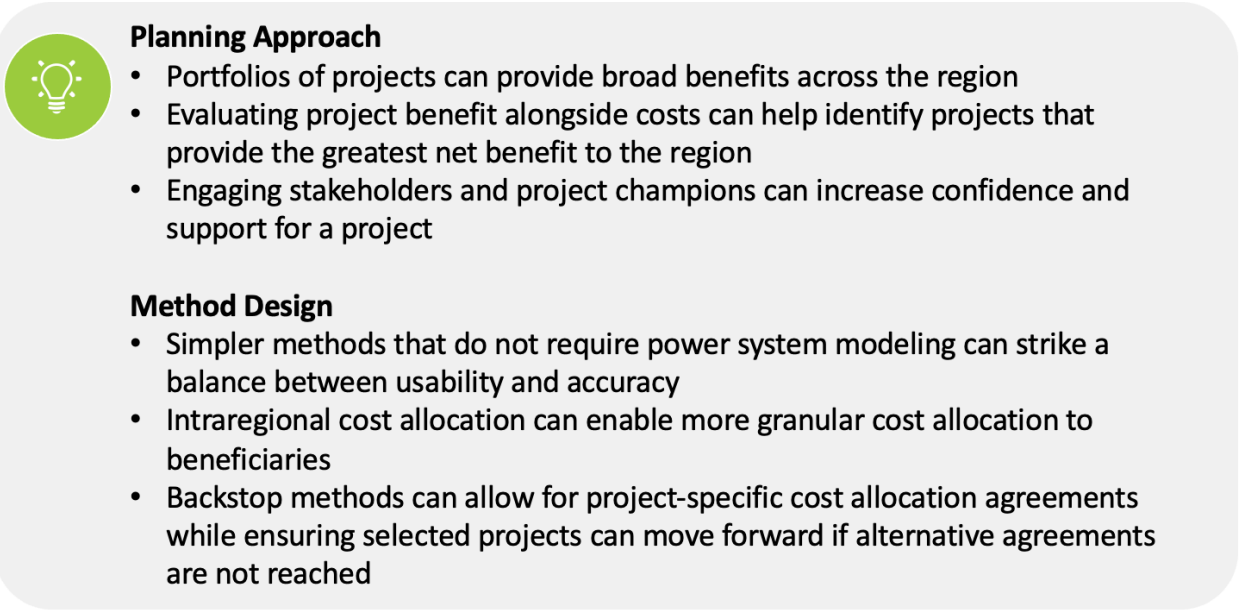

Figure ES-1. Lessons learned for transmission cost allocation

Regional transmission planners use discretion granted through federal regulations to develop a range of cost allocation methods.

Regional transmission planners have used the discretion granted through Federal Energy Regulatory Commission (FERC) Order 1000 to adopt diverse approaches to allocate costs for transmission projects, reflecting regional preferences and system conditions. To allow comparisons across regions, we develop a cost allocation taxonomy whereby we group transmission projects and cost allocation methods into six project types and five cost allocation approaches. Figure ES-2 compares the cost allocation approaches used by each region. Usage-

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based methods, such as allocation in proportion to load (postage stamp), are the most common. However, even when regions use the same approach, they are often implemented differently. For example, each of the seven regions has some form of cost allocation in proportion to electricity load, but no two regions use the same method to calculate this "load ratio share."

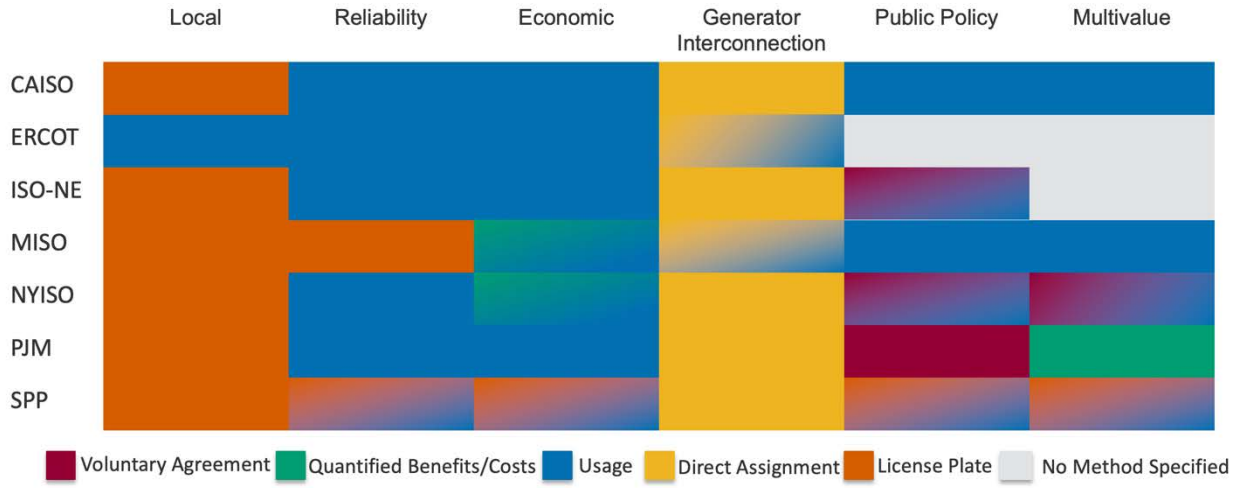

Figure ES-2. Summary of cost allocation methods used in each regional transmission organization/independent system operator for different project types.

CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; ISO-NE = ISO New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; PJM = PJM Interconnection; SPP = Southwest Power Pool

Successful cost allocation methods strike a balance between precision and practicality.

The review of legal disputes over transmission cost allocation and project case studies reveals successful cost allocation methods are both detailed enough to ensure costs are allocated to project beneficiaries and feasible to implement in a real system. This tension appears primarily in relation to (1) identifying project beneficiaries and (2) quantifying project costs and benefits. Current regulations allow discretion in implementing cost allocation methods, provided these decisions are evidence based, cost and benefits are relatively balanced, costs are assigned to project beneficiaries, and the analytic cost allocation methods roughly identify project beneficiaries given future uncertainties and imperfect analytical tools. The most successful application of benefit evaluation in our case studies was for the purposes of project selection and communication with stakeholders, not cost allocation.

Regions have multiple pathways to update their cost allocation methods, but the process remains complex and requires stakeholder engagement.

The report also highlights the processes by which regions can update their cost allocation methods, including through compliance filing to federal regulations and exercising filing rights from Sections 205 and 206 of the Federal Power Act. As the summary highlights, implementing changes is not simple because each region has split authority among multiple stakeholder groups to file cost allocation changes.

This report focuses on the seven U.S. grid operators, either regional transmission organizations or independent system operators. The case studies are focused on projects identified through the

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regional transmission organization/independent system operators regional planning process rather than those developed through a local planning process or independently with negotiated, rather than regulated, service agreements. Although we do not consider cost allocation methods currently under development for compliance with FERC Order 1920, the trends and lessons learned identified in this report can inform discussions on effective cost allocation methods to reduce barriers for transmission development.

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1 Introduction

Expanding electric transmission infrastructure can facilitate generator interconnection and improve grid reliability. Recent national studies published by federal government agencies, national laboratories, and research organizations demonstrate that significant transmission expansion is the lowest-cost option to meet growing demand and maintain grid reliability (U.S. Department of Energy (DOE) 2024; Larson et al. 2021; Electric Power Research Institute (EPRI) 2021; Denholm et al. 2022; U.S. Department of Energy (DOE) 2023).

Despite these findings, transmission capacity additions across the United States have declined steadily over the last 10 years. Focused primarily on incremental reliability needs, only 3,300 circuit-miles of new or upgraded transmission and 70 circuit-miles of interregional transmission were added annually, on average, from 2011 to 2020 (U.S. Department of Energy (DOE) 2023). By comparison, studies such as the U.S. Department of Energy's National Transmission Planning Study estimate annual additions of more than 4,000 circuit-miles of new high-voltage transmission can unlock the lowest-cost mix of transmission, generation, and storage resources to meet growing system needs through 2035 (U.S. Department of Energy (DOE) 2024). The slowing of additions of transmission has led to increasing congestion across the grid and a backlog of interconnection requests. The result has been nearly 12,000 projects and over 2,500 gigawatts waiting in interconnection queues by the end of 2023, rising interconnection costs, longer generation project development timelines, and an increasing number of project cancellations (Rand et al. 2024).

The challenges with developing bulk transmission can be broadly characterized by the "three Ps"—planning, permitting, and paying (cost allocation) (Gavan and Gramlich 2021). Planning is a challenge because transmission exhibits large economies of scale and identifying least-cost transmission investments requires long-term, multivalue planning and coordination across multiple jurisdictions and wide geographic areas. Permitting a bulk transmission project is a multiyear process that typically requires numerous authorizations and compliance with a complex set of U.S. federal, state, and local requirements (U.S. Department of Energy (DOE) 2023).

Paying, or cost allocation, for transmission—the focus of this report—is often cited as the hardest of the "three Ps" (Gavan and Gramlich 2021). Assigning the costs of transmission projects to network users is highly contentious because these costs can have a direct impact on energy prices and ratepayer bills. Across U.S. regional markets, transmission charges accounted for over 20% of wholesale power costs, on average, during 2019 through 2022 (Figure 1).

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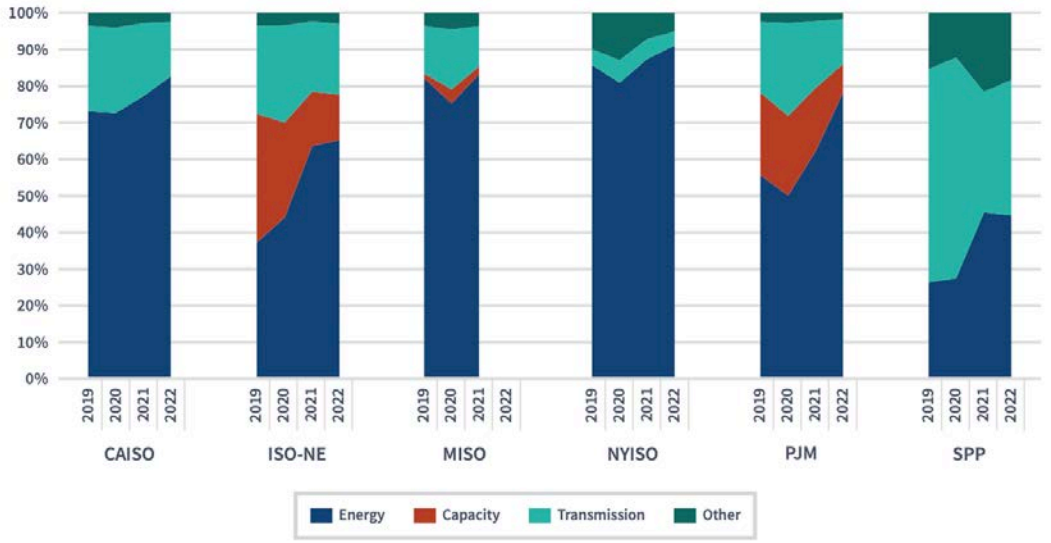

NOTE: The values for capacity in NYISO are not available as the NYISO does not record the capacity components of total wholesale power. MISO did not have data available for 2022 at the time data submissions were due.

Source: FERC-922 information collection.

Figure 1. Wholesale power costs by charge type. ***Source: (Sheets et al. 2024)***

CAISO = California Independent System Operator; ISO-NE = Independent System Operator of New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; PJM = PJM Interconnection; SPP = Southwest Power Pool

Unlike merchant transmission projects—where transmission costs are paid by interconnecting generator-customers with negotiated service agreements—regionally planned transmission project costs are allocated to project beneficiaries. Determining who benefits from a project can be challenging because the benefits of a high-voltage transmission project are often distributed across a broad geographic area and a diverse set of network users. Further, the benefits and beneficiaries of a transmission project change over the multidecadal lifetime of the project. As a result, there is generally no single network user willing to pay for a regional project because they would receive only a fraction of the benefits. Across the United States, different regions have developed a multitude of cost allocation methods designed to assign costs to project beneficiaries. Legal disputes over the methods used to calculate project benefits have led to litigation between utilities, regulators, and customer groups.

In this report, we evaluate what factors influence successful transmission cost allocation agreements and identify lessons learned to minimize cost allocation disputes for future projects. These findings will inform potential opportunities for federal, regional, and state regulators and project developers to reduce cost allocation barriers for bulk transmission development.

1.1 Regulatory and Legal Background of Transmission Cost Allocation

Transmission cost allocation is the assignment of costs among network users for building and operating a transmission facility. These costs are ultimately paid by the end consumer through direct charges on ratepayer bills or in the form of higher per-unit energy rates. The objectives of transmission charges are to guarantee cost recovery for prudent network investments and to send efficient locational signals to network users regarding the costs of installing their facilities in

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different parts of the grid (Olmos 2013). In Order 1000, the Federal Energy Regulatory Commission (FERC) requires that transmission costs "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 benefits" (FERC 2011). Order 1000 was purposefully designed to allow transmission providers flexibility to develop their own cost allocation methods in accordance with this "beneficiary pays" principle. As a result, there exist a variety of transmission cost allocation methods across the United States.

The beneficiary pays principle is a simple concept—ubiquitous in cost-of-service rate regulation—that is difficult to implement in practice.[1] Although transmission costs are usually well defined, the benefits of a transmission facility are more difficult to quantify. There is no universal catalog of transmission benefits. Chang, Pfeifenberger, and Hagerty developed a comprehensive list of transmission benefits, including more than 30 possible items (Chang et al. 2013). The challenge, as their list demonstrates, is that some benefits (e.g., production cost savings) are relatively straightforward to measure but others (e.g., increased market liquidity, improved reliability) are difficult to measure and quantify. Even standard metrics such as production cost savings are subject to disagreements over input assumptions and model scenarios used to quantify the benefits. In addition, the estimated benefits quantified ex ante through various models can vary across different future scenarios and be very different from realized benefits ex post in operations (Shu and Mays 2025). Further, the nature and magnitude of benefits may change over the lifetime of the project. One recommended approach to address these challenges is to allocate costs "roughly commensurate" with, but not formulaically based on, quantified benefits (Pfeifenberger, 2025). Network usage is generally accepted as a proxy for how much each network user benefits from a transmission facility. Here, too, there are implementation challenges because there is no universally accepted method to measure how much each agent uses the network (Olmos 2006).

In 2024, FERC passed Order 1920, which focuses on long-term regional transmission planning and cost allocation (FERC 2024a). Similar to Order 1000, the regulations for cost allocation reinforced the principle of "beneficiary pays." These were focused on high-level principles[2] and process improvements for developing cost allocation methods rather than methods themselves, and these regulations leave transmission providers with the flexibility to design their own approach for transmission cost allocation. Notably, Order 1920 removed the principle that regions could have different regional cost allocation methods for different types of transmission

[1] Also known as the "cost causation" principle, this is derived from the Federal Power Act's "just and reasonable" standard for rates and charges for interstate electricity transmission and wholesale sale of electricity ("Federal Power Act" 2018).

[2] The six cost allocation principles from Order 1000 include: (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.

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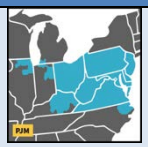
facilities and further explained that transmission providers cannot adopt different ex ante methods for different types of regional transmission projects, such as those needed for reliability or congestion relief or to achieve public policy requirements. With respect to cost allocation, FERC Order 1920 requires:

- Development and tariff inclusion of one or more default (ex ante) cost allocation methods for new long-term regional transmission facilities
- Flexibility to allow for a state agreement approach process for voluntary cost allocation methods associated with specific long-term regional transmission facilities
- Engagement with relevant state entities on cost allocation methods.

The discretion granted to transmission providers to develop their own cost allocation methods in compliance with FERC regulations allows regions to innovate and develop cost allocation approaches that reflect regional preferences and system conditions. However, competing interests from different network users have also led to disputes. Further, transmission providers, FERC, and courts do not always agree on the appropriate cost allocation method or conclusions of the implementing entity. Table 1 provides a summary of selected legal disputes relevant to transmission cost allocation, with more detailed information available in Appendix A.

Table 1. Key Themes and Illustrative Legal Cases for Cost Allocation Legal Cases

Theme	Case		Finding
Beneficiary Identification		*Public Service Enterprise Group v. FERC* (U.S. Court of Appeals for D.C., March 2021)	Cost allocation method (flow-based) inaccurately identified beneficiaries for the stability-related reliability issue
		Illinois Commerce Commission (ICC) v. FERC (U.S. Court of Appeals for 7th Circuit, June 2014)	Insufficient evidence that utilities in the West benefit from regionally beneficial lines in the East
Evidence-Based Decision-Making		*ICC v. FERC* (U.S. Court of Appeals for 7th Circuit, August 2009)	Insufficient evidence and analysis to support FERC's approval of the cost allocation scheme
		ICC v. FERC (U.S. Court of Appeals for 7th Circuit, June 2013)	Insufficient evidence to overturn FERC approval of the cost allocation scheme
Free Ridership		*South Carolina Public Service Authority v. FERC* (U.S. Court of Appeals for D.C., August 2014)	Cost allocation method results in unintended free-rider beneficiaries outside the planning region, but this is permissible to balance regulatory goals
		Con Edison v. FERC (U.S. Court of Appeals for D.C., August 2022)	Exempting de minimis beneficiaries from cost allocation violates the cost causation principle

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Theme	Case		Finding
Estimation of Costs and Benefits		*Midwest ISO Transmission Owners v. FERC* (U.S. Court of Appeals for D.C., July 2004)	The project costs must be compared to benefits. Allocation does not have to be exact but cannot be arbitrary or capricious.
		Hecate v. NYISO (U.S. Court of Appeals for D.C., July 2023)	Transmission tariffs for generator interconnection must provide enough information to assess potential interconnection costs without explicitly detailing every practice.
System-Wide Benefits		*Old Dominion v. FERC* (U.S. Court of Appeals for D.C., August 2018)	Cost allocation scheme cannot allocate costs of regionally beneficial lines only to local entities.
		National Association of Regulatory Utility Commissioners v. FERC (U.S. Court of Appeals for D.C., January 2007)	Network upgrades "at or beyond" the point of generator interconnection benefit all customers and can, therefore, be allocated to all customers.

At a high level, these disputes center around the balance between precision and practicality; the cost allocation method must be detailed enough to ensure costs are allocated to project beneficiaries but also feasible to implement in a real system and under long-term uncertainties. This tension between precision and practicality appears throughout the legal disputes in relation to (1) identifying project beneficiaries and (2) quantifying project costs and benefits. Figure 2 summarizes the key findings we identified from these cases.

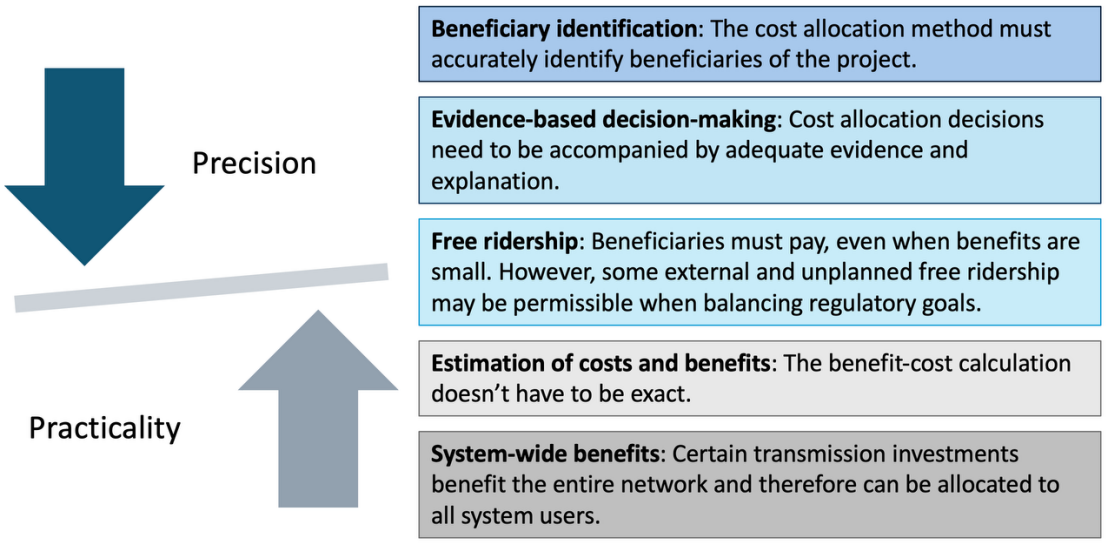

Figure 2. Key lessons from transmission cost allocation legal disputes

Overall, these cases indicate there is discretion in implementing cost allocation methods, provided these decisions are evidence based, cost and benefits are relatively balanced, costs are

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assigned to project beneficiaries, and the analytic cost allocation methods roughly identify project beneficiaries. Courts have ruled benefits do not have to be calculated "to the last penny or, for that matter to the last million or ten million or perhaps hundred million dollars" for the purposes of cost allocation so long as there is more than "no benefits." (U.S. Court of Appeals for 7th Circuit, August 2009). And regions do not have to use a particular formula as long as they can justify the method allocates costs "roughly commensurate" with the benefits received (U.S. Court of Appeals for D.C., August 2018).

Emerging Cost Allocation Issues on the Horizon

Growing interconnection requests from large loads may raise new cost allocation disputes. In November 2024, FERC rejected an amended interconnection service agreement in the PJM region that sought to facilitate a co-location arrangement between existing generation and a large load (*PJM's Susquehanna Co-Location Proposal* 2024). In its ruling and a separate docket from a technical conference to address issues raised by this type of arrangement (FERC 2024b), FERC commissioners and participating panelists agreed large loads must pay their share of transmission costs, but there was disagreement as to what these costs entail and how they should be evaluated. As demand for data centers continues to grow, new methods may be needed to evaluate transmission cost responsibility from large loads.

1.2 Analysis Scope and Analytical Approach

In this report, we evaluate what factors influence successful transmission cost allocation agreements. Specifically, we investigate whether the following factors influence the outcome of a cost allocation agreement:

- **Method complexity:** Are simpler methods such as those based on load ratio share more successful than more complex methods based on power flows or quantified benefits?
- **Regional flexibility:** Are cost allocation methods that allow intraregional differentiation more successful than those that apply uniformly across the region?
- **Project portfolio:** Are multivalue projects or bundled projects more successful to cost allocate than single-purpose or single projects?
- **Project champion:** Does the existence of an external project "champion," such as a state, lead to more successful project outcomes?

To answer these questions, we review current cost allocation practices across different transmission planning regions to identify common trends and key differences in approaches. We use a selection of six case studies to identify drivers and contextual factors that influence project outcomes.

This report focuses on the seven U.S. grid operators, either regional transmission organizations (RTOs) or independent system operators (ISOs). These RTOs and ISOs oversee delivery of two-thirds of electricity used in the country (FERC 2023). All but the Electric Reliability Council of Texas (ERCOT) are under FERC jurisdiction and therefore must comply with FERC's transmission cost allocation requirements. The case studies are focused on projects identified through the RTO/ISO regional planning process rather than those developed through a local planning process or independently with negotiated, rather than regulated, service agreements. We do not consider cost allocation methods currently under development for compliance with FERC Order 1920.

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2 Current Trends in Transmission Cost Allocation and Investments

ISOs and RTOs have used the discretion granted through FERC Order 1000 to develop a range of different transmission cost allocation methods. This section presents a summary of current cost allocation approaches and investment trends and identifies common themes and key differences among regions.

2.1 Taxonomy of Transmission Projects and Cost Allocation Methods

One challenge with comparing cost allocation approaches across regions is that each region has a unique approach to characterize different types of projects and allocate costs. Across the seven ISOs/RTOs, there are nearly 20 different labels applied to transmission projects and more than a dozen different methods to allocate costs.

To allow comparisons across regions and project types, we developed a cost allocation taxonomy whereby we group the transmission projects and cost allocation methods into six project types and five cost allocation approaches. Table 2 and Table 3 show how project types and cost allocation methods from each region were grouped into common categories.

Table 2. Grouping of ISO/RTO Transmission Project Labels Into Six Project Types

	Local	Reliability	Economic	Generator Interconnection	Public Policy	Multivalue
CAISO	Local transmission facilities	Reliability projects	Economic projects	Generator interconnection	Public policy projects	Multivalue[3]
ERCOT		Reliability projects	Economic projects	Generator interconnection		
ISO-NE	Local system plans	Reliability transmission upgrade	System efficiency transmission upgrade	Generator interconnection	Public policy upgrade and longer-term transmission upgrade	
MISO	Other projects	Baseline reliability projects	Market efficiency projects	Generator interconnection	Public policy projects[4]	Multivalue projects

[3] CAISO employs a sequential review process when planning transmission projects, considering reliability, public policy, and economic needs in distinct stages. Although there is no "multivalue" transmission category in the tariff, the sequential approach allows CAISO to consider and approve projects that provide multiple benefits (CAISO, 2025).

[4] MISO does not have a standalone category of public policy transmission projects. Policy-driven transmission needs are considered alongside economic and reliability needs as part of the MISO Value-Based Planning process to identify multivalue projects.

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	Local	Reliability	Economic	Generator Interconnection	Public Policy	Multivalue
NYISO	Local transmission projects	Regulated reliability transmission projects	Regulated economic transmission projects	Generator interconnection	Regulated transmission solutions to public policy transmission needs	Multivalue[5]
PJM	Local projects	Baseline reliability projects	Baseline market efficiency projects	Generator interconnection	State agreement approach	Multidriver projects
SPP	Zonal reliability upgrades	Zonal projects	Zonal projects	Generator interconnection	Public policy projects[6]	Integrated transmission planning upgrades

Historically, these project types have been identified through different planning mechanisms and, at times, by different planning entities. FERC Order 1000 classifies reliability, economic, and public policy projects as those identified by the regional transmission provider as necessary to satisfy reliability standards, reduce congestion, and meet transmission needs driven by public policy requirements established by state or federal laws and regulations, respectively (FERC 2011). Multivalue projects provide some combination of these benefits. These categories of projects are identified through regional transmission planning processes. By contrast, local and generator interconnection projects have generally been identified outside of the regional planning process. Local transmission projects are identified by incumbent transmission providers to meet local needs. Generator interconnection projects are identified through grid studies associated with new interconnection requests.[7]

Table 3. Grouping of ISO/RTO Transmission Cost Allocation Methods Into Five Approaches

Approach	Description	Regions Where Method Is Used
Usage	Regional allocation based on network usage—measured through load ratio share, voltage level, or power flow analysis—as a proxy for benefits. This includes postage stamp methods where transmission costs are recovered uniformly from all loads in a defined market area based in proportion to load and distribution factor analysis methods that allocate costs across the region based on	CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, SPP*

[5] The NYISO considers multiple project benefits when evaluating projects to meet public policy needs but does not have a separate multivalue project category in its tariff.
[6] SPP uses a Public Policy Transmission Planning Process to integrate policy-driven transmission needs into its long-term transmission planning. These projects are implemented as Integrated Transmission Planning upgrades.
[7] Order 1920 reduces these siloed processes by directing transmission providers to consider activity in the interconnection queue, opportunities to right-size local projects, and multiple drivers of transmission needs in the regional planning process.

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Approach	Description	Regions Where Method Is Used
	contributions to power flows using power flow simulations.	
Direct Assignment	Allocation to a particular class of network user (e.g., interconnecting generator).	CAISO, ISO-NE, MISO, NYISO, PJM, SPP
License Plate	Allocation based on transmission pricing zone or transmission owner service territory where the project is located and/or reliability violation is being addressed. Each utility then recovers the cost from loads within its service territory.	ISO-NE*, MISO, NYISO, PJM, SPP*
Quantified benefits/ costs	Allocation to all network users in the defined market area in proportion to estimated benefits or share of costs of each cost driver.	MISO, NYISO*, PJM
Voluntary Agreement	State or network user agreement.	ISO-NE*, NYISO*, PJM

*Method is used in combination with other methods (e.g., 50% to region based on load ratio share and 50% to local pricing zone includes features of usage and license plate methods).

2.2 Comparison of Cost Allocation Methods

Using the transmission project types and cost allocation methods described in the previous section, Figure 3 shows the cost allocation approach used by each RTO/ISO. More detailed information on the specific method used by each region is provided in Appendix B.

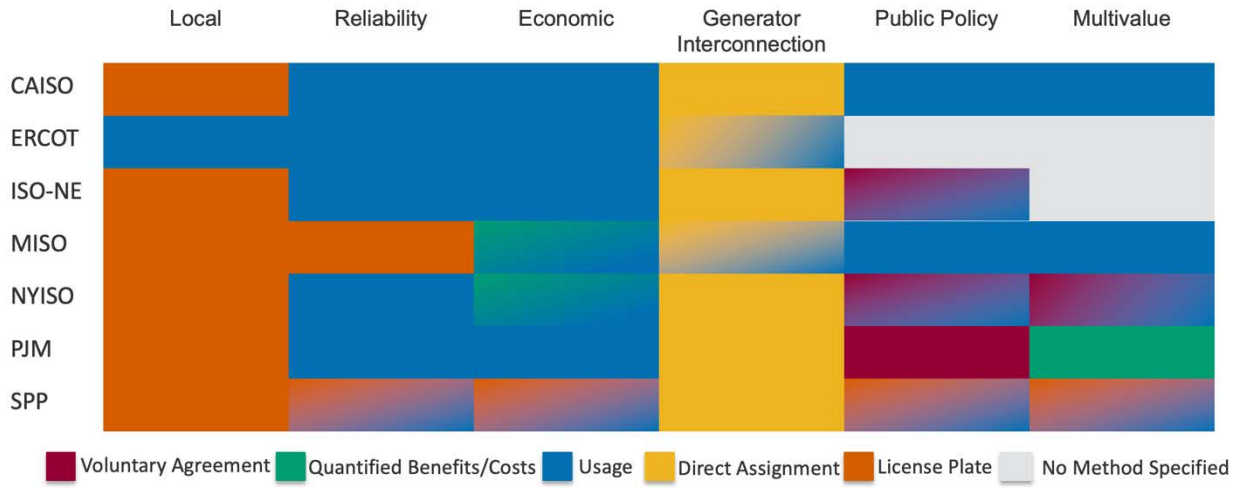

Figure 3. Summary of cost allocation methods used in each RTO/ISO for different project types

In comparison of the cost allocation methods used by different regions, several trends emerge.

1. **The costs for local projects are allocated primarily using license plate approaches**. Costs for these projects are allocated to the local pricing zone in which the project is being built (i.e., SPP, PJM, MISO) or to the local transmission owner (i.e., CAISO, NYISO, ISO-NE). The philosophy behind these approaches is that local projects will have localized benefits and should not be paid for by the broader planning region. The

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sole exception is ERCOT, which allocates costs based on network usage across the region.

2. **Generator interconnection projects are almost exclusively paid for by direct assignment to the interconnecting generator**. In all regions, except ERCOT and MISO, transmission upgrades to meet generator interconnection requests are fully cost allocated to the interconnecting customer. In MISO, the costs for interconnection projects below 345 kilovolts (kV) are allocated to the interconnecting generator. At or above 345 kV, 90% of costs are assigned to the generator, and 10% are allocated across the region based on usage. This approach assumes high-voltage lines provide broader benefits across the region, not just to the interconnecting customer. In ERCOT, interconnecting generation customers pay a limited interconnection cost to cover certain direct costs of connecting to the transmission system, and the remaining costs are passed to customers based on usage (Wilson et al. 2024).
3. **Usage-based methods are the most common approach for regional cost allocation.** Outside of local[8] and generator interconnection projects, most regions and project types use some type of usage-based method to allocate costs. The most common usage-based approach is a postage stamp method that uses electricity load as a proxy for usage. Some regions, such as SPP, combine usage-based methods with other methods, such as license plate allocation, to limit the usage-based cost responsibility to specific subregions or zones. While usage-based allocation is primarily based on load ratio share in most regions, PJM also uses power flow modeling to approximate network usage.
4. **Direct cost allocation based on quantified benefits or costs is rarely used.** Most regions use network usage as a proxy for benefits rather than allocating costs based on quantified benefits or costs. MISO and the NYISO use estimated benefits to allocate costs among load zones for economic projects, which account for a small share of total transmission investments. Within each load zone a usage-based approach is then used to allocate costs. PJM's framework uses a cost-causer approach for its multi-driver projects that meet multiple needs such as reliability or economic or public policy. Costs for this project type, which has not been utilized to date, would be allocated by dividing the project costs between the individual drivers (i.e., reliability, economic) and assigning costs using the method developed for the project type under that driver.
5. **Even when regions use the same method, it is often implemented differently.** Regions have developed different approaches for implementing their cost allocation methods, reflecting regional preferences and system conditions. For example, each of the seven regions has some form of postage stamp method that allocates costs in proportion to electricity load, but no two regions use the same method to calculate this "load ratio share" (Table 4).

[8] Note that many local transmission charges are based on usage by local load. This analysis is focused on allocation for regional projects based regional usage.

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Table 4. Comparison of Regional Approaches To Calculate Load Ratio Share

Region	Application	Description
CAISO	All projects 200 kV or greater	Each transmission owner's contribution to **"gross load"** measured as demand adjusted for distribution losses or customer loads directly connected to the transmission or distribution network.
ERCOT	Reliability and economic projects	Contribution to **the highest coincident 15-min interval peaks for the months of June, July, August, and September** (4-coincident peak, 4CP, method)
ISO-NE	Reliability, Economic, Public policy and longer-term transmission upgrades	Each transmission owner's hourly load contribution coincident with the hour of maximum monthly load for each local network **("Monthly Peak")**. For public policy projects, only 70% of the public policy project costs recovered with this method. The other 30% is recovered by the state driving the need.
MISO	Multivalue and other projects	Contribution to subregional or system-wide share of **annual energy usage** for both subregional and system-wide multivalue projects, respectively.
NYISO	Economic and public policy projects	Contribution of each load serving entity to **total system energy consumption over the last 12 months**
PJM	Reliability or market efficiency projects	Contribution to **annual (non-coincident) peak load from the 12-month period ending October 31** of the preceding calendar year (single non-coincident peak, 1NCP).
SPP	Integrated Transmission Planning upgrades	Contribution to **annual average of coincident peaks for the last 12 months** for each pricing zone divided by regional peak load (12CP).

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3 Impact of Cost Allocation on Project Development: Case Studies

As shown in the previous section, transmission cost allocation approaches vary across regions. This section details six project case studies to identify potential drivers and contextual factors that may influence successful cost allocation and project outcomes.

3.1 Case Study Selection

The case studies selected for investigation are designed to capture diverse factors that may influence the outcome of a cost allocation agreement. These include the complexity of the cost allocation method, the regional flexibility with which costs are assigned, the portfolio of the transmission project(s), and the existence of a state project champion. In addition, the case studies include a range of different RTOs/ISOs, including single-state and multistate systems.

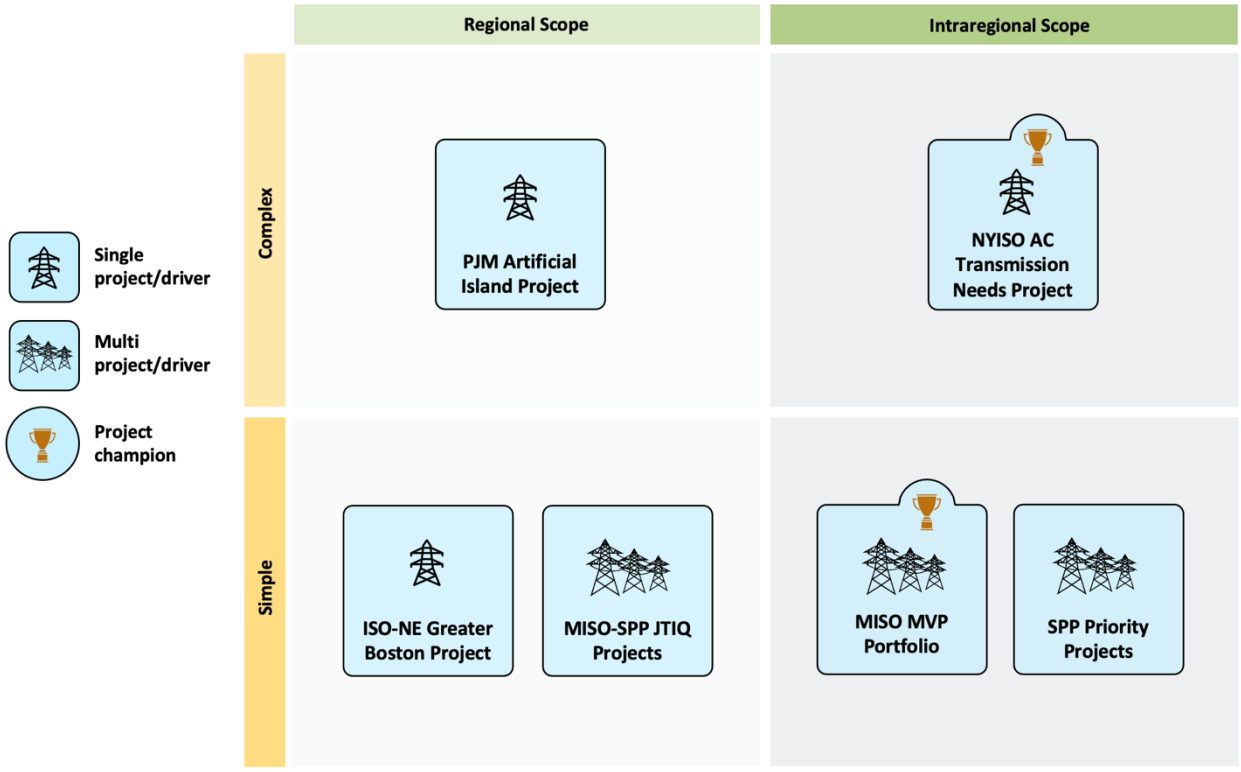

Figure 4. Summary of project case studies classified by factors that may influence the cost allocation outcome

Figure 4 classifies our selected case studies according to these factors.

- **Method complexity:** The complexity of the cost allocation method refers to the input data, modeling, and calculations required to identify cost responsibility. Methods that require production cost or power flow modeling are considered more "complex." We consider "simple" cost allocation methods to be those that do not require economic- or reliability-based power system modeling. This includes variations of the load ratio share, whereby costs are allocated in proportion to electricity load.

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- **Regional flexibility:** The regional flexibility refers to the ability to assign costs differently within a given region. Methods that spread project costs across an entire planning region based on a single formula are considered to have "regional scope." Methods that allow for intraregional variation in cost responsibility are considered to have "intraregional scope."
- **Project portfolio**: Transmission planning regions take varied approaches in how they bundle and categorize approved projects for cost allocation. "Single project/driver" examples refer to cases in which costs are allocated for a single transmission project with a specific driver (i.e., reliability). "Multi-project/driver" projects refer to cases in which costs are allocated for projects that provide multiple grid services or multiple projects have been bundled into a portfolio for a purpose of cost allocation.
- **Project champion:** A "project champion" is an external (i.e., not the project sponsor) state entity that advocates for the development of a transmission project or portfolio of projects. These entities may be responsible for identifying the transmission need and supporting the transmission planning region in the identification and cost allocation of transmission solutions to meet that need.

3.2 Case Study Summaries

The following sections provide details on each case study, highlighting the project details and cost allocation outcomes. More information on each case study is provided in Appendix C.

3.2.1 MISO Multi-Value Project Planning Portfolio

The MISO Multi-Value Project (MVP) portfolio demonstrates the application of a portfolio approach (i.e., multi-project/driver) to project planning and cost allocation and a balance of rigorous technical analysis for project benefits evaluation combined with a simple method for cost allocation.

The initial MVP portfolio includes 17 projects identified through MISO's 2011 Transmission Expansion Plan (MTEP 11).[9] These projects were initially championed by the governors of seven member states with growing concerns over the "crisis" generation developers face because of a lack of transmission for interconnection (MISO 2011; Boyd and Garvey 2021). Various regional initiatives organized by the states assisted MISO in developing cost allocation proposals as well as model inputs and assumptions that were used for the MTEP 11 (MISO 2011).

Figure 5 shows the projects included in the 2011 MVP portfolio. The projects consist of high-voltage alternating current (AC) transmission upgrades at 345 kV or higher and are distributed throughout MISO's Midwestern planning footprint.[10] As of March 2025, all but 1 of the 17 proposed projects have been constructed and are in service (MISO 2025).

[9] More information about subsequent MISO MVP portfolios is available at: https://www.misoenergy.org/planning/multi-value-projects-mvps/#t=10&p=0&s=Updated&sd=desc.
[10] At the time, this only included what is today the MISO Midwest subregion.

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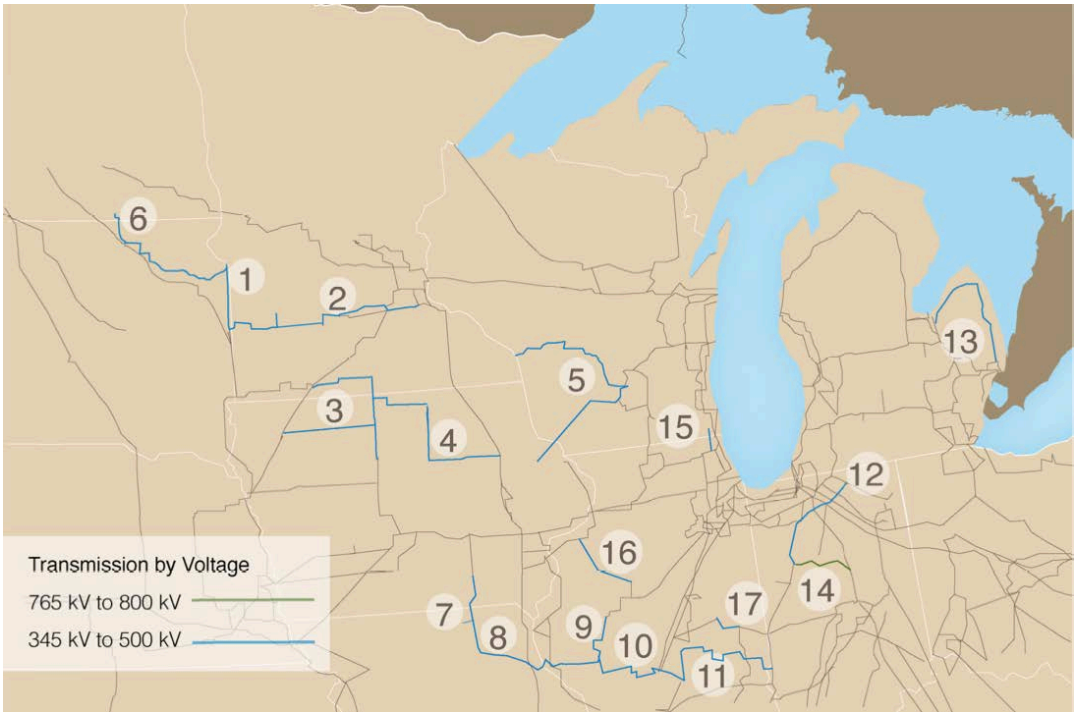

Figure 5. Seventeen transmission projects that make up the MTEP 11 portfolio. *Source: (MISO 2014)*

MVPs are large, regional projects that provide reliability, economic, and public policy benefits throughout the MISO footprint or subregion.[11] MISO quantified multiple economic benefit metrics for the portfolio, including production cost savings, reduced transmission losses, and deferred capacity and transmission investments. These benefits were calculated for individual cost allocation zones, which align with utility and (roughly) state boundaries, to allow state regulators and members to assess the benefits attributed to the zone covering their state. However, the quantified benefits are not used for cost allocation. Instead, MISO uses a simple load ratio share method to allocate costs for the entire portfolio. MISO's load ratio share is calculated based on each transmission owner's monthly energy use (i.e., withdrawals) rather than peak demand to allocate costs among load zones. The energy-based load ratio share method was selected to reflect changing load profiles and network usage that may arise as a result of growth in industrial output, electrification, or energy efficiency, among others (MISO 2023). MISO does, however, calculate each zone's ratio of benefits to zonally-allocated costs to show that every zone's benefits exceed its assigned costs, even though the benefit-to-cost ratios vary by zone and depend on uncertain future conditions and modeling assumptions.

3.2.2 New York Independent System Operator AC Transmission Needs

The Public Policy Transmission Planning Process (PPTPP) at the NYISO provides an example of a regional planning process that defines a backstop ex ante cost allocation method and allows

[11] MISO tariff includes an MVP subregional option, in which MVP costs can be allocated to the Midwest or South subregion. The subregional division is intended to reflect the physical limitations of the system—there is a single transmission line connecting Zones 1–7 and Zones 8–12—that may prevent projects from having widespread benefits across the entire MISO footprint.

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for project-specific analysis to develop an alternative cost allocation method based on factors driving the transmission need.

The AC Transmission Needs project was identified in 2019 through the NYISO's PPTPP. This is a joint planning process conducted by the NYISO and the New York Public Service Commission (NYPSC) (Patton et al. 2019; NYISO 2019b). The NYPSC identified the public policy need for transmission to deliver energy from central/upstate New York to downstate New York and, through the PPTPP, the NYISO planned the AC Transmission Needs project to meet this need.

The project includes two segments (Figure 6): Segment A consists of upgrading existing lines from 230 kV to 345 kV to increase transfer capacity from central to east New York; Segment B consists of replacing older 115-kV and 69-kV facilities with new double-circuit 345-kV transmission lines between Albany and downstate New York (NYISO 2019c). The NYISO evaluated both project costs and benefits when selecting the solutions for Segments A and B. For both segments, the proposed solutions had higher costs compared to alternatives but were found to provide greater net benefits in terms of increased transfer capacity, deferred transmission upgrades, greater operational flexibility, and more resilient structure design. Both segments were completed and operational in 2023 (NYISO 2024).

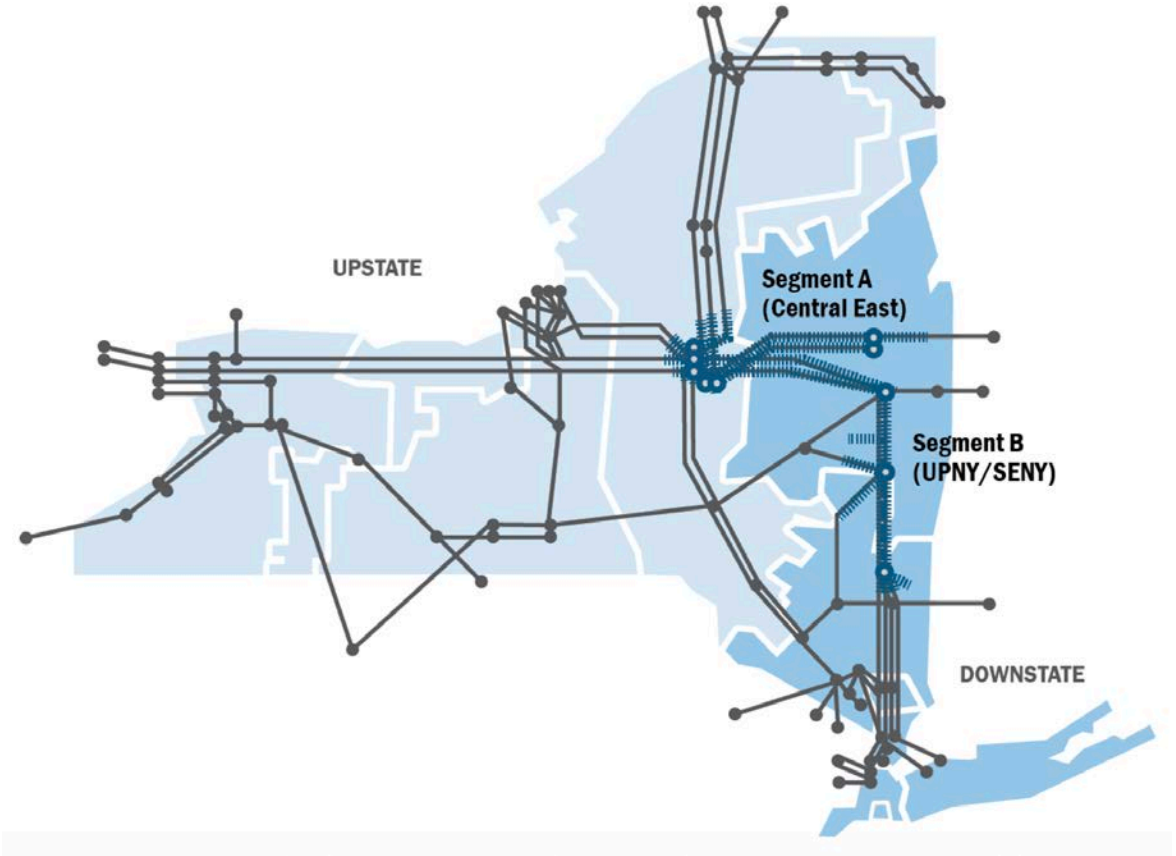

Figure 6. AC Transmission Needs public policy project's Segments A and B routes. *Source: (NYISO 2019a)*

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The NYISO defines a backstop cost allocation method based on load ratio share for public policy projects but allows for alternative methods to be developed to fit each transmission project need. Alternative cost allocation methods can be proposed by the NYPSC or the entity selected by the NYISO to develop the project with NYPSC approval. For the AC Transmission Needs project, the NYPSC recommended an alternative cost allocation scheme whereby 75% of costs would be allocated to economic beneficiaries, measured as reductions in anticipated congestion over a 10-year period, and 25% would be based on load ratio share based on forecasted summer peak demand (*State of New York Public Service Commission Order Finding Transmission Needs Driven by Public Policy Requirements* 2015). This alternative was adopted by the NYISO because it allows for more granular cost allocation to load downstate, which bears the largest cost responsibility.

3.2.3 SPP Priority Projects

SPP applies a unique cost allocation approach to its "Priority Projects" and "Integrated Transmission Plan" (ITP) projects based on a voltage threshold to allocate costs on a load ratio share basis between regions and local zones, also known as the Highway/Byway method.

The SPP Priority Projects consisted of five 345-kV single-circuit and double-circuit transmission lines in Kansas, Oklahoma, Texas, Nebraska, and Missouri (Figure 7). These projects were identified in 2009 by the Synergistic Planning Project Team (SPPT) to relieve congestion across the network, integrate new generation resources, and connect the east and west portions of SPP's footprint (SPP 2009). The SPPT estimated the Priority Projects would provide $3.7 billion in benefits across the region through a range of quantified benefits, including production cost savings, reduced losses, deferred capacity investments, and improved reliability (SPP 2010b). After approval by the SPP Board of Directors in 2010, all Priority Projects were completed in 2017 (SPP 2025a).

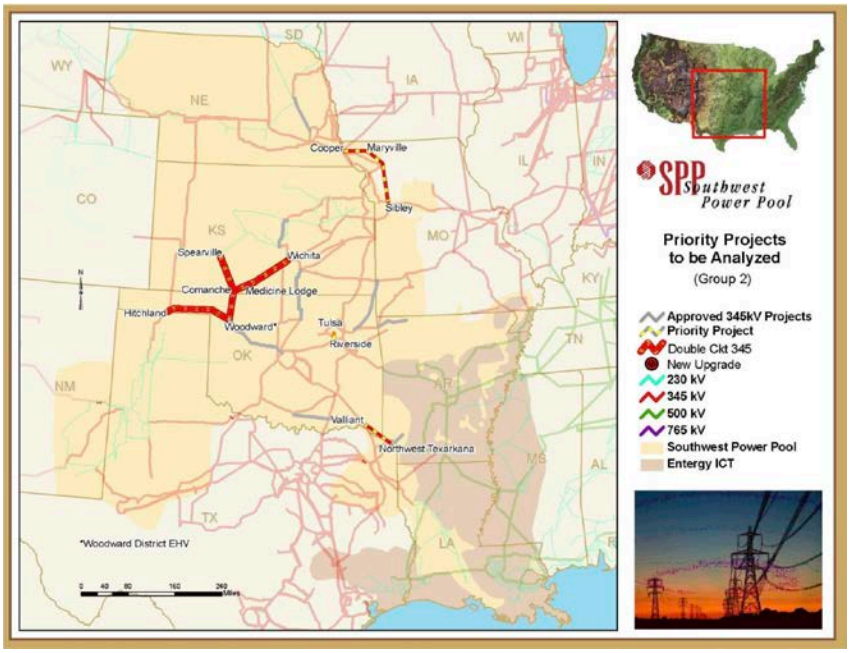

Figure 7. SPP Priority Projects. ***Source: (SPP 2010b)***

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Costs for SPP's Priority Projects and subsequent ITPs are allocated through the region's unique Highway/Byway method. The philosophy behind this method is that higher-voltage lines provide benefits across the entire region, whereas lower-voltage lines provide more localized benefits. As a result, costs for higher-voltage lines should be borne by the entire region, and those for lower-voltage lines should be paid by the local zones where the project is located. The SPP's Regional State Committee (RSC) developed a Highway/Byway approach to replace SPP's three existing methods at the time, which included separate rates for zonal projects and regional projects, a load ratio share rate for Balance Portfolio projects, and a new yet-to-be-determined rate for extra-high-voltage projects. The SPPT noted that members felt these disparate approaches were "fragmented, confusing, and difficult to administer." SPP used power flow modeling to support the establishment and application of voltage thresholds for cost allocation (SPP 2010c). The resulting Highway/Byway method allocates 100% of costs for facilities greater than 300 kV to the region on a load ratio share basis. For lower-voltage lines greater than 100 kV, one-third of costs are allocated regionally on a load ratio share basis, and two-thirds are allocated to the local transmission-owner zone where the facility is located. Facilities less than 100 kV are cost allocated 100% to local zones (Table 5).

Table 5. Highway/Byway Cost Allocation Overview

Upgrade Voltage	Region Pays	Local Zone Pays
>300 kV	100%	0%
100–300 kV	33%	67%
<100 kV	0%	100%

Once implemented, the Highway/Byway method has been used for more than 741 transmission upgrades in service by January 2020 (SPP 2023). SPP currently estimates there are 489 projects identified through its Integrated Transmission Planning process and subject to Highway/Byway cost allocation in its active portfolio, accounting for more than 88% of the total portfolio budget (SPP 2025b).

3.2.4 PJM Artificial Island Project

The PJM Artificial Island Project provides an example of the challenges to using detailed power system modeling for cost allocation.

The $266.5 million Artificial Island Project was proposed in 2015 to resolve the stability issues identified by PJM at the Salem and Hope Creek nuclear plants in New Jersey and to relieve congestion on the Delmarva Peninsula (PJM 2015a). The project consisted of 12 transmission enhancements—5 would operate above a threshold of a 500-kV or 345-kV double circuit, and the remaining 7 were planned below this threshold, including a 3-mile 230-kV underwater cable beneath the Delaware River (Figure 8). These projects were the first to be planned under PJM's Order 1000 transmission tariff as part of the Regional Transmission Expansion Planning process (PJM Inside Lines 2021).

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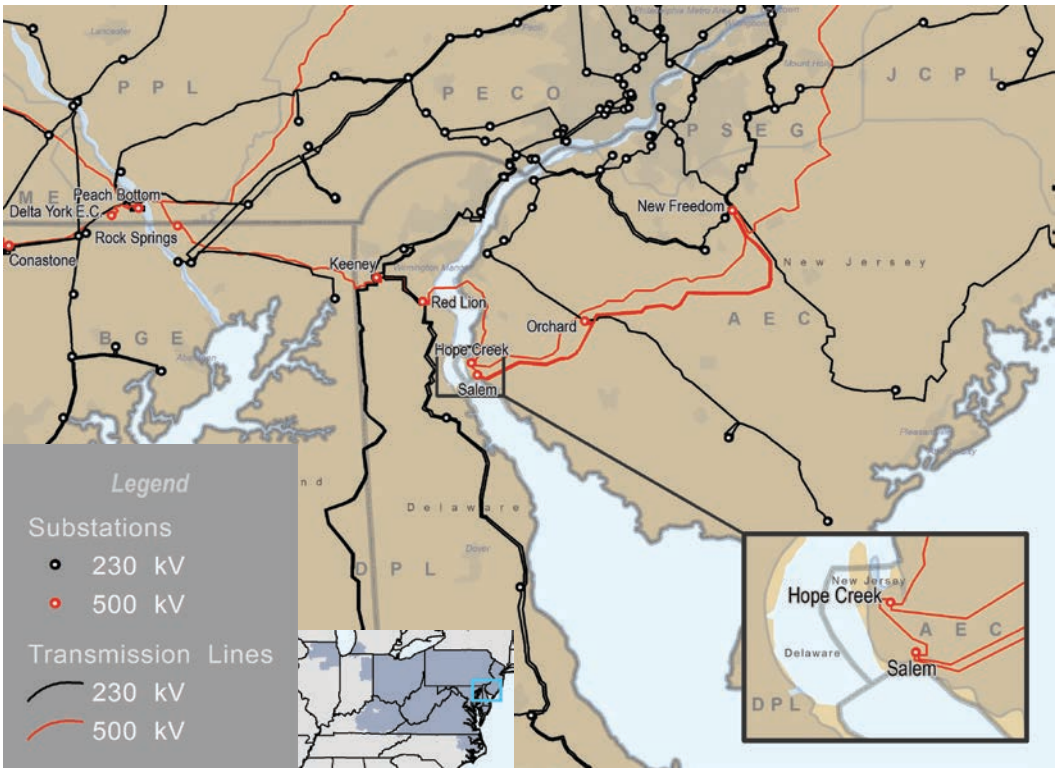

Figure 8. PJM Artificial Island Project. ***Source: (PJM 2015a)***

PJM's transmission tariff combined electricity load and power flow metrics to approximate network usage and, by extension, network benefits. Under the tariff, the costs for facilities greater than 500 kV or double-circuit 345 kV are allocated 50% across the region based on load ratio share and 50% using a method called distribution factor analysis, or DFAX (PJM 2010). The DFAX method determine cost allocations based on simulated power flows over a new transmission line to customer zones using hourly production cost simulations of network operations for the existing system with the added transmission upgrade (PJM 2024). For lower-voltage facilities—defined as facilities operating below 500 kV, or below 345 kV in the case of double-circuit 345-kV lines—100% of costs are allocated using the DFAX method.

In August 2015, PJM filed the cost allocation for the Artificial Island Project with FERC in accordance with its transmission tariff (PJM 2015b). Under this method, 50% of the costs for the five high-voltage lines were assigned based on load ratio share, and all remaining costs were assigned based on the DFAX method, including the underwater cable. The resulting cost allocation assigned nearly 98% of the costs to Delmarva Power and Light, which serves customers in Delaware and Maryland. State regulators filed a complaint with FERC, citing the DFAX method results were unjust, unreasonable, and unduly discriminatory or preferential (*Public Service Electric and Gas Company, Petitioner v. Federal Regulatory Commission* 2021). Although FERC originally denied the complaint, it later reversed this decision and, after rehearing, found the cost responsibility assigned by the DFAX method to be unjust and unreasonable for transmission enhancements that address stability-related reliability issues for the broader PJM region. FERC found the beneficiaries of transmission enhancements to solve stability issues are not captured by the DFAX method, which is designed to identify flow-based beneficiaries.

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In March 2020, after years of proceedings and litigation over alternative cost allocation approaches, FERC accepted PJM's reallocation of costs for the Artificial Island Project using a new stability deviation method. Using the stability deviation method, Delmarva Power and Light was allocated only 13% (PJM 2020) of the project's costs compared to 98% under the DFAX method. The 230-kV transmission line running under the Delaware River, along with the upgraded substations and new transformer, were completed in fall 2020 with the remaining upgrades completed in spring 2021 (PJM Inside Lines 2021).

3.2.5 ISO New England's Greater Boston Transmission Project

This project illustrates project portfolio planning designed to identify reliability needs and cost allocation based on project costs rather than project benefits.

The ISO-NE's Greater Boston Transmission Project, selected in 2015, is a reliability project consisting of a portfolio of new transmission lines, reconductoring of existing lines, new transformers, and other transmission-related upgrades. The project was identified in the ISO-NE's Regional System Plan to address numerous thermal and voltage violations and increase transfer capacity into Boston. The final work on an underground 115 kV line was completed in December 2024 and Hudson station work was completed in 2025 was completed in 2025 (ISO-NE 2025b).

Although reliability projects are the primary driver for transmission investments across the United States, ISO-NE is notable in that the region has never constructed a transmission project based on economic/system efficiency needs or a public policy goal (ISO-NE 2025b). This is due to a combination of planning rules and methodologies. A report from the External Market Monitor notes that ISO-NE has "aggressive local reliability planning criteria" and experiences 10% to 20% less congestion than other RTOs, both of which would favor transmission investments for reliability over economic needs (Potomac Economics 2023). The process to identify a reliability need takes fewer process steps than for a system efficiency project, which requires demonstrating a reduction in production costs. While production cost is used as the main metric, the ISO also considers transmission construction avoided by proposed system efficiency projects, avoided transmission losses, avoided capital costs, and reduced unserved energy as other metrics. Finally, the ISO's tariff defines selection criteria for approving projects based on project cost (ISO-NE 2025a). There is no mechanism to evaluate or communicate quantified benefits for reliability projects.

The Greater Boston Transmission Project was one of the largest and most expensive reliability projects planned in the ISO-NE, originally estimated to be $822 million (ISO-NE 2023b). These costs are allocated regionally based on load ratio share. In September 2020, an additional $188.6 million was requested to underground a 115-kV transmission line originally designed as an overhead line but was unable to secure property rights. The Reliability Committee did not recommend approval of this request, and the additional cost for the undergrounding project remains under review by ISO-NE (ISO-NE 2020).

3.2.6 MISO-SPP Joint Targeted Interconnection Queue Projects

The MISO-SPP Joint Targeted Interconnection Queue (JTIQ) projects demonstrate interregional planning and cost allocation for generator interconnection projects that would not otherwise be selected as part of the regional planning process in either participating region.

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The JTIQ concept originated from developers that wanted to build and interconnect generation along the MISO-SPP seam but were facing prohibitive interconnection costs. In response, MISO and SPP conducted a joint study that identified five projects along the seam totaling approximately $1 billion (Figure 9). The projects are expected to come online in 2031.

Figure 9. MISO-SPP JTIQ projects. ***Source: (MISO 2024b)***

The initial JTIQ study (SPP and MISO 2022b) established a cost allocation methodology for JTIQ projects similar to MISO's generator interconnection cost allocation scheme. In this method, 90% of the engineering and construction costs are paid for by the interconnecting generators, and 10% is paid for by load in SPP and MISO in proportion to each region's calculated adjusted production cost benefit. Of the 10% allocation to load, 7% was allocated to SPP and 3% to MISO-based production cost modeling to estimate the benefit to each region. Costs to interconnection generators would be spread over generator interconnection projects across multiple queue clusters to reduce the impact on any single interconnecting customer (SPP and MISO 2023). Electricity load between MISO and SPP would continue to pay for operations and maintenance costs and would serve as a backstop for undersubscribed capacity. In November 2024, FERC approved the JTIQ cost allocation proposal (FERC 2024c).

The JTIQ transmission projects do not meet the criteria as a reliability or economic project as defined in the MISO or SPP tariffs and would not have been identified as transmission solutions in either region's transmission planning process (FERC 2024c). The joint planning and cost allocation approach taken by MISO and SPP helped identify projects that support generator interconnection and provide regional benefits that may not have otherwise been built.

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3.3 Lessons Learned

The literature reviews, legal outcomes, and project case studies reveal several common trends and lessons learned for transmission cost allocation. These include lessons on the planning approach used to identify and evaluate projects and the actual cost allocation method design. These lessons are summarized in Figure 10 and explained in more detail in the following sections.

Planning Approach

- Portfolios of projects can provide broad benefits across the region
- Evaluating project benefit alongside costs can help identify projects that provide the greatest net benefit to the region
- Engaging stakeholders and project champions can increase confidence and support for a project

Method Design

- Simpler methods that do not require power system modeling can strike a balance between usability and accuracy
- Intraregional cost allocation can enable more granular cost allocation to beneficiaries
- Backstop methods can allow for project-specific cost allocation agreements while ensuring selected projects can move forward if alternative agreements are not reached

Figure 10. Lessons learned for transmission cost allocation

3.3.1 Planning Approach

The planning approach refers to the transmission study, project evaluation process, and contextual factors eventually leading to project selection and the calculation of cost responsibility. Three planning trends emerged that led to more successful transmission development outcomes:

1. A **portfolio approach** can identify a suite of projects that provide broad benefits across a region and reduce the need for project-by-project evaluations and cost allocation. This approach was seen across many of the case studies. In PJM, ISO-NE, and the NYISO, the portfolios were designed for a single type of transmission need (e.g., reliability, generator interconnection) or benefit to a specific subregion. By contrast, the MISO MVP and SPP ITP portfolios of projects were driven by a combination of system needs, and the JTIQ projects provided benefits across multiple subregions in both MISO and SPP.

   A benefit of the portfolio approach is the mix of projects can be designed so that each zone within the region or subregion receives some benefit. In addition, the benefits could be more evenly distributed among zones and, for multi-benefit portfolios, the range of benefits may be more stable over time compared to the benefits of individual projects (Pfeifenberger and DeLosa 2022).

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2. **Evaluating project benefits alongside costs** can help identify projects that provide the greatest net benefit, communicate project impacts, and inform which costs are justified for regional cost recovery. In MISO and the NYISO, the tariff requires each region to evaluate project benefits as part of the MVP and PPTPP processes, respectively. Both regions' tariffs allow for additional benefit metrics to be included through stakeholder processes such as the Organization of the MISO States in MISO and NYPSC in the NYISO. The flexibility to include alternative benefit metrics allows each region to be responsive, as benefits may change over time and new tools and methods are developed to quantify benefits that were previously difficult to evaluate.

   In MISO, the evaluation of benefits for individual cost allocation zones allows it to transparently communicate the costs and benefits of a given transmission portfolio to member states and show that MISO's load-ratio approach yields cost allocations that are roughly commensurate with received benefits. This information can be used by state regulators, policymakers, and other stakeholders when deciding whether to support a given portfolio. In the NYISO, the board is empowered to choose public policy transmission solutions based on qualitative as well as quantitative criteria defined by the NYPSC, such as maximizing the use of existing right-of-way. This holistic approach to selection criteria can support project selection that reflects the complexity of the underlying public policy need and goal. For example, the selected solutions for the AC Transmission Needs project were higher cost than some alternatives but provided greater benefits such as infrastructure resilience and operational flexibility that were deemed important by the NYPSC. By contrast, the ISO-NE tariff does not provide a specific mechanism to evaluate or communicate monetized project benefits. As a result, highly beneficial projects may not be selected because there is no defined means to evaluate whether the additional benefits to the region could outweigh additional cost.

   Quantifying project benefits is useful for evaluating projects and communicating impacts, but quantified benefits are difficult to use for cost allocation. In general, it is easier to calculate estimated project costs over the multidecade lifetime of a transmission project than the estimated benefits (Shu and Mays 2025). Current tools are designed to quantify a narrow set of benefits, and those benefits can change over the lifetime of the facility (FERC 2024a). The most successful application of benefit evaluation in our case studies was for the purposes of project selection and communication with stakeholders, not cost allocation.

3. **Stakeholder engagement and strong champions** can increase confidence and support for the project. These groups can build external support for transmission projects among stakeholders; directly inform planning through scenario design, initial studies, and analysis; and provide input on evaluation criteria and cost allocation.

   In two case studies, stakeholders outside of the RTO/ISO or project developer team initiated the transmission planning process that ultimately led to regional projects. The most influential project champions tend to be state-related stakeholders. In MISO, the governors from Midwest states led efforts to develop more transmission to meet their state needs. This led to studies of transmission expansion in the region. In the NYISO, the state legislature sets state policy goals that inform public policy transmission needs

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identified by the NYPSC. The NYPSC also has a defined role to identify additional benefit criteria that will be used for project selection.

3.3.2 Cost Allocation Method Design

The design of the cost allocation method itself will determine the cost responsibility among network users. Three lessons in method design were identified:

1. **Simple methods** that can identify project beneficiaries but do not require detailed power system modeling can improve consistency and predictability in cost allocation outcomes, reduce cost allocation disputes, and strike a balance in method usability and accuracy. As discussed in Section 2.2, methods that consider network usage a proxy for benefits are the most common approach for cost allocation.

   Among the case studies, MISO, SPP, and ISO-NE all use a form of load ratio share to approximate network usage and to allocate costs. The benefit of using load ratio share is the calculation does not require power system modeling and cost allocation is not strictly based on calculated benefits, which can reduce disputes over study assumptions and benefit metrics. Rather, input data on load forecasts or historic load can be readily obtained to validate and predict cost allocation outcomes. In addition, the approach is flexible and can be implemented in different ways, including allowing for regular updates to reflect changing system conditions. For example, ISO-NE uses monthly peak demand, MISO uses monthly energy use, and ERCOT focuses on peak demand during the summer months.

   PJM's Artificial Island Project illustrates some of the challenges using a more complex cost allocation approach. The DFAX and stability deviation methods used by PJM require power system modeling to determine each zone or customer's contribution to power flows or angle deviations, respectively. As seen in the case study, the results are sensitive to the modeling assumptions and type of model used, reducing the consistency and predictability of the results. In addition, quantifying different types of transmission benefits with detailed modeling may require a range of power system models, increasing the complexity and effort required.

   The JTIQ and the NYISO's AC Transmission Needs projects combine simple and complex methods. Similar to most generator interconnection projects, the JTIQ portfolio is funded primarily by interconnection customers with 10% of the capital cost originally allocated to load. Although the cost share to load is small, it requires not only production cost modeling to assess the economic benefits to each region but agreement between SPP and MISO on modeling assumptions and methods to reach a common solution. Similarly, the NYISO's AC Transmission Needs project used a combination of quantified economic benefits and load ratio share. However, the backstop method that would be used in the absence of an alternative is a simple 100% allocation based on load ratio share.

2. **Regional flexibility** that allows for intraregional differentiation in cost responsibility can enable more granular cost allocation to users that bear the greatest cost responsibility or receive the greatest benefits from the project. The SPP and MISO tariffs illustrate two approaches to subregional cost allocation.

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SPP's Highway/Byway method uses a voltage threshold to determine the distribution of project costs among local and regional ratepayers. The underlying philosophy is lower-voltage projects primarily benefit local network users, whereas higher-voltage projects have regional benefits. The MISO footprint consists of a diverse mix of states divided into two subregions, MISO Midwest and MISO South. Although the case study took place before MISO South was added, subsequent MISO MVP tranches allow costs to be allocated to one or both subregions based on the benefits the projects provide. Subregional cost allocation can enable MISO to focus cost responsibility on the subregion driving the transmission need and receiving the most. The regional flexibility also allows MISO to use different cost allocations for other types of transmission projects.

Regional flexibility enables more granular cost allocation without introducing a complex method based on power system modeling. In both MISO and SPP, the actual cost allocation of the regionally-allocated project is based on a simple load ratio share. Power system models are used prior to cost allocation to evaluate project benefits in MISO and to validate the Highway/Byway method in SPP but are not part of the cost allocation calculation. In addition, both MISO and SPP evaluate and quantify a broad range of benefit types, which has the added advantage of producing a set of benefits that is more evenly distributed and more stable over time than any single metric–thereby facilitating cost allocation. In contrast, when only individual metrics are used, such as power flows in PJM, the resulting uneven distribution of benefits can more readily lead to disputes.

3. A **backstop or default cost allocation method** allows flexibility for project-specific cost allocation agreements while also ensuring selected projects can move forward if an alternative agreement is not reached. The NYISO's PPTPP and SPP-MISO JTIQ projects illustrate the application of a backstop method to reduce the risk of projects stalling as a result of disputes about cost allocation methods.

   For public policy projects in the NYISO, the NYPSC can recommend an alternative cost allocation method tailored to the characteristics of the project. For the NYISO's AC Transmission Needs projects, the NYPSC identified an alternative cost allocation method that assigns more cost responsibility to the zones that receive economic benefits from the project. If an alternative is not used, project costs are applied across the entire region based on load ratio share in line with the view that policy-driven projects benefit all network users.

   The JTIQ projects present a different approach to backstop cost allocation. In this case, the projects are driven by interconnecting customers across multiple states and transmission planning regions rather than the policy of a single state. The costs to interconnecting customers are spread across multiple queue clusters to avoid prohibitively expensive costs for the first generators and free ridership for generators that connect later. To reduce the risk to project developers, electricity load in SPP and MISO serves as the backstop in case the transmission capacity is undersubscribed by generators. This approach enables the projects to move forward through the planning and permitting processes without the need to wait for generators to fully subscribe to the transmission capacity.

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4 Cost Allocation Changes: Regulatory Paths Forward

The previous sections outline existing methods and lessons learned for transmission cost allocation. This section presents the regulatory options for regions to update their cost allocation methods and compares the processes different regions have adopted to implement these options.

4.1 Regulatory Options To Update Cost Allocation Methods

Implementing new or alternative cost allocation methods requires navigating formal procedures to revise RTO/ISO governing documents and/or transmission owner tariffs.[12] These documents are institution-specific rules and operating procedures, and changes must be reviewed and approved by FERC. The three pathways to submit proposed amendments to these governing documents for FERC review are (1) compliance with FERC rulemaking, (2) exercising Federal Power Act (FPA) Section 206 filing rights, and (3) exercising FPA Section 205 filing rights.

Compliance With Federal Energy Regulatory Commission Rulemaking

FERC can require RTO/ISOs to revise their governing documents through a broad-based regulatory order. In general, FERC issues regulatory requirements or principles in the rulemaking order that allow for regional flexibility in each RTO/ISO's compliance plan. To date, FERC rulemaking related to cost allocation has been limited. Order 1000 required regions to include a cost allocation method for new facilities selected through regional planning according to six principles (FERC 2011). Order 1920 builds on this but adds more structural and procedural guidelines related to developing a default or ex ante cost allocation method, state involvement, and engagement periods (Building for the Future Through Electric Regional Transmission Planning and Cost Allocation 2024).

Exercising Federal Power Act Section 206 Filing Rights

Section 206 filing rights are broadly available to different stakeholder groups, giving them the right to challenge existing RTO/ISO governance document provisions and give FERC the authority to investigate and modify these rates if they are found to be unjust, unreasonable, unduly discriminatory, or preferential ("Federal Power Act" 2018). However, FERC is not required to respond to Section 206 filings. Compared to Section 205 rights, Section 206 requires a higher burden of proof for the filer. Under these rights, the existing rules must be found to be unjust, unreasonable, or unduly discriminatory, and the new proposal must be found to be just, reasonable, and not unduly discriminatory.

Exercising Federal Power Act Section 205 Filing Rights

FPA section 205 gives the holder of the filing rights the ability to propose changes to certain governing documents ("Federal Power Act" 2018). When filing for changes, the filer must prove their proposed revisions are just and reasonable. FERC has a passive and reactive role to 205 filings, meaning it can approve, reject, make minor modifications, or make modifications with

[12] The primary governing document is the RTO/ISO's OATT, but may also include Transmission Control Agreement, Transmission Owners Agreement, Operating Agreement, and so on.

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utility agreement to the proposed change but cannot propose an entirely new strategy or approach (U.S. Court of Appeals for D.C., October 1984).

Beyond changing RTO/ISO governing documents, Section 205 filing rights are also important because they are the primary method through which transmission-owning utilities change their transmission tariffs. Section 205 rights can be assigned or shared differently in each RTO/ISO region; however, transmission-owning utilities generally maintain 205 rights over their revenues requirement and rates, and the RTO/ISOs generally maintain 205 rights over their open access transmission tariffs (OATTs) (U.S. Court of Appeals for D.C., July 2002).[13] In many areas transmission owners must jointly agree on 205 filings related to cost allocation methods for regionally planned transmission facilities. There are also provisions in some RTO/ISO areas that allow state entities to add their alternative cost allocation method proposals to the 205 filing of the TOs or RTO/ISOs. Appendix D provides more details on how these rights are exercised across different regions.

[13] See an example TO (PG&E) tariff in CAISO at https://www.pge.com/assets/pge/docs/regulation/wholesale-transmission-service/transmission-owner-tariff.pdf.

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5 Summary and Conclusions

Aging infrastructure and increasing electricity demand are driving the need for increased investment in transmission infrastructure. Accelerating transmission investment depends, in part, on reaching successful cost allocation agreements to pay for new infrastructure.

By examining legal disputes, current practices for allocating costs, and examples from different regions, this report highlights several trends and lessons that can support successful cost-allocation agreements. The legal cases show that cost allocation works best when it balances precision with practicality. It's important to identify who benefits from a project and ensure they contribute to project costs. Giving regions flexibility in how they allocate costs within the region can also assist in obtaining broader stakeholder support and allow costs to be more accurately assigned to areas that receive the most benefit. However, given the complexities of trying to estimate project benefits and beneficiaries for individual stakeholders—especially over the long life of a transmission project–cost and benefit estimates do not have to be perfectly precise.

Several strategies can reduce potential opposition to new projects, including quantifying and communicating the full range of project benefits, not just costs, and engaging with stakeholders and state champions to build external support. Bundling projects into a portfolio can identify a suite of projects that provide a broader distribution of benefits across the region, facilitating regional cost allocation. Finally, establishing a backstop method can help ensure cost-effective projects can go forward in case project-specific cost allocation agreements cannot be reached.

The process to implement any of these lessons through changes to cost allocation methods is not simple. Each region has split authority to file cost allocation changes among multiple stakeholder groups. However, transmission providers now have an opportunity to engage stakeholders and implement changes as part of their compliance filing for FERC Order 1920. The trends and lessons identified in this report can inform discussions on effective cost allocation methods.

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Appendix A. Select Cost Allocation Legal Disputes

Table A-1 provides a detailed summary of legal disputes relevant to transmission cost allocation reviewed as part of this report.

Table A-1. Summary of Select Transmission Cost Allocation Legal Disputes

Case	Significance	Plain Language Description
Midwest ISO Transmission Owners v. FERC **(U.S. Court of Appeals for D.C., July 2004)**	This ruling emphasizes the cost causation principle of comparing the cost burden imposed on a party to the benefits drawn. The ratemaking agency is not required to allocate costs with "exacting precision" but cannot be "arbitrary or capricious."	Though not related to transmission project cost allocation, this decision is often cited in transmission cost allocation cases. Here, a per-megawatt-hour cost adder was allocated to new wholesale transmission loads and unbundled retail loads to recover MISO administrative costs, but other loads that benefit from MISO services were excluded (e.g., grandfathered). The court affirmed the Federal Energy Regulatory Commission's (FERC's) action to require MISO to allocate costs to all system loads because all benefit from MISO services.
National Association of Regulatory Utility Commissioners v. FERC **(U.S. Court of Appeals for D.C., January 2007)**	This ruling affirmed network upgrades to support generator interconnection must benefit the entire network, not just the generator, and costs can be allocated to all customers.	State and utility petitioners objected to various aspects of FERC Order 2003 related to standardization of generator interconnection agreements and procedures. Among other grievances, the petitioners objected to FERC's "At or Beyond" guidance for cost allocation of generator interconnection-related costs, in which the generator is assigned all the costs associated with interconnection up to the point of interconnection, and the transmission provider is assigned the costs of network upgrades at or beyond the point of interconnection.[14] The court affirmed FERC's at-or-beyond approach because upgrades to expand the network generally benefit all customers.
Illinois Commerce Commission v. FERC **(U.S. Court of Appeals for 7th Circuit, August 2009)**	The decision to uniformly allocate costs of any new >500-kV lines to all regional load was not supported by evidence and thus was arbitrary.	The court remanded FERC's determination that all PJM utilities should pay for any new high-voltage (>500-kV) lines on a uniform, pro rata basis because determining the benefits of these lines is difficult and contentious, and because these lines improve the reliability of the whole system. No evidence, data, or estimates were provided to substantiate FERC's claims, and concerns were raised about uneven benefits to western versus eastern PJM utilities.

[14] Order 2003 also affirmed the interconnection customer/generator can pay the up-front cost of these network upgrades if the non-independent transmission provider chooses not to fund them up front. In this case, the interconnection customer is credited (i.e., reimbursed) over time by the non-independent transmission provider. For independent transmission providers—such as regional transmission organizations/independent system operators (RTO/ISOs) that have locational pricing—the interconnection customer may be assigned network upgrades that were not otherwise needed "but for" that generator (i.e., participant funded).

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Case	Significance	Plain Language Description
Illinois Commerce Commission v. FERC **(U.S. Court of Appeals for 7th Circuit, June 2013)**	Insufficient evidence was provided to support overturning FERC's approval of the cost allocation scheme. "[E]vidence of cost versus benefit imbalance is required."	The court affirmed FERC's approval of MISO's Multi-Value Project (MVP) regional cost allocation method—to support construction of high-voltage lines to integrate location-constrained public policy wind resources, improve reliability, and reduce congestion—against objections from states that argued (among other things) the benefits of MVP projects may not surpass costs. MISO presented significant evidence of benefits, whereas complainants did not present evidence of cost-benefit imbalance.
S.C. Public Service Authority v. FERC **(U.S. Court of Appeals for D.C., August 2014)**	The commission can balance "competing goals" to ensure cost allocation maximally reflects cost causation.	The D.C. Circuit Court affirmed FERC Order 1000 after years of legal challenges. Petitioners believe FERC did not go far enough in its cost allocation reforms. They object to reforms that limit regional cost allocation to only within-region users, specifically for extra-high-voltage and interregional facility costs. They believe this is inconsistent with the cost causation principle, and some beneficiaries will not pay (i.e., "free riders"). FERC claimed these limits, including that each region must agree upon interregional cost allocation, were needed to minimize burdens and geographic planning scope creep into interregional planning.
Illinois Commerce Commission v. FERC **(U.S. Court of Appeals for 7th Circuit, June 2014)**	It is not appropriate to "shift a grossly disproportional share of costs" from regionally beneficial high-voltage projects to utilities that may or may not benefit from these lines.	The court reviewed a dispute over whether western PJM utilities can be required to contribute evenly (i.e., through a postage stamp method) to the costs of building new 500-kV lines in eastern PJM when the western utilities were unlikely to commensurately benefit from these lines. The court found FERC presented no evidence the postage stamp method was acceptable or it was the only possible alternative. There was no attempt to estimate benefits and compare them to costs to determine if utilities were being under- or overcharged.
Old Dominion Electric Cooperative v. FERC **(U.S. Court of Appeals for D.C., August 2018)**	It is undisputed that high-voltage projects benefit the regional system, beyond just the local utility. The cost allocation scheme was too local.	The court ruled against FERC's decision to approve a cost allocation change that denied regional cost sharing and allowed the costs associated with rebuilding two regionally beneficial high-voltage lines to be allocated only to a local zone based on the planning criteria of an individual utility.
Public Service Elec & Gas v. FERC **(U.S. Court of Appeals for D.C., March 2021)**	The court found PJM's flow-based distribution factor analysis (DFAX) method of cost allocation did not capture the beneficiaries of non-flow-based (e.g., stability) projects and	This case involved the construction of a new underwater high-voltage transmission line into Delaware to address stability issues (i.e., loss of generator synchronization with the grid) to accommodate three nuclear power plants located on an island in New Jersey and owned by a subsidiary of a New Jersey utility. Of the total

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Case	Significance	Plain Language Description
	required a new method to be developed that assigned costs to beneficiaries.	cost of the project, 90% was allocated to the Delmarva zone (Delaware, Maryland) using the solutions-based DFAX method. FERC initially supposed the DFAX cost allocation method then reversed its opinion—after examination of evidence and finding flow-related and stability-related reliability issues are "analytically unique." FERC found the need for the project related to the inability of the New Jersey zone to absorb the output of the nuclear plants, and the Delmarva zone would not benefit from the project, as its transmission system was adequate to serve its load. A new cost allocation method was developed that shifted primary cost responsibility to utilities in New Jersey.
Consolidated Edison Company of NY v. FERC **(U.S. Court of Appeals for D.C., August 2022)**	The court found inadequate justification was given to explain why flow-based DFAX was appropriate for non-flow issues such as short circuit but inappropriate for stability issues (i.e., Artificial Island). The court also found even de minimis beneficiaries require allocation of costs.	This case concerned multiple issues surrounding a 2013 flow-based cost allocation for a collection of projects to address short circuit issues on transmission infrastructure owned by a New Jersey utility (Bergen corridor and Sewaren substation) through the DFAX method. Most of the costs for these projects were initially allocated to New York utilities outside of PJM, and merchant interregional transmission lines. In addition, some benefits to large utilities were deemed de minimis (<1% of flows), and no costs were allocated. The court found (1) FERC did not adequately explain why the DFAX method was appropriate for short circuit projects but not for stability projects (i.e., Artificial Island) and (2) the de minimis threshold is unlawful because it violated the cost causation principle. It also addressed several other issues.
Hecate Energy Greene County LLC v. New York Independent System Operator, Inc. **(U.S. Court of Appeals for D.C., July 2023)**	This case explored the issue of how detailed tariffs must be with respect to just and reasonable rates (for grid interconnection costs, in this case).	A solar project developer objected to the NYISO's $10 million in grid upgrade costs to interconnect to the grid, alleging the independent system operator's (ISO's) tariff was not detailed enough to understand that interconnection of certain nonjurisdictional projects would be incorporated into the base case of the developer's interconnection study. The court found the tariff did cross reference attachments detailing base case assumptions, and it rejected the solar developer's petition for review.
El Paso Electric Company v. FERC **(U.S. Court of Appeals for 5th Circuit, August 2023)**	It is not just or reasonable to force jurisdictional utilities to assume the cost of serving nonjurisdictional utilities that benefit (i.e., free ride) from transmission investments of the former.	Jurisdictional utilities objected to the WestConnect FERC Order 1000 compliance scheme that required jurisdictional utilities to plan and pay for the transmission needs of nonjurisdictional utilities (e.g., cooperatives). The court noted a high likelihood that nonjurisdictional utilities would opt out of paying for transmission facilities they were likely to benefit from.

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Appendix B. Detailed Regional Results

The following sections provide detailed information on existing transmission cost allocation practices across RTOs and ISOs.

B.1 CAISO

CAISO defines three primary transmission planning project types in its regional planning process (reliability, economic, and public policy projects) (*2023-2024 Transmission Plan* 2024). However, CAISO has also stressed in formal reply comments in FERC proceedings that its iterative planning process allows for consideration of transmission projects with "multiple benefits streams (e.g., reliability, public policy, and economic)" (*Reply Comments of the California Independent System Operator Corporation*, n.d.). Therefore, CAISO may pursue forms of multivalue planning, even if multivalue projects are not explicitly defined as a regional transmission project type. Table B-1 summarizes the cost allocation methods and relevant reference in CAISO's tariff for each type of transmission investment. Figure B-1 illustrates how CAISO is divided into transmission planning zones.

Table B-1. CAISO Cost Allocation Summary

Project Type	Description	Cost Allocation	Source/Subsection
Local Transmission Facilities	Transmission facilities under CAISO operational control, owned by a transmission owner, less than 200 kV, and located entirely within a transmission owner footprint or service territory	100% allocation to transmission owner	CAISO Fifth Replacement Tariff Appendix F. Rate Schedules, Section 12. Procedure for Division of Certain Costs Between the Regional and Local Transmission Charges, Subsection 12.1. Division of Costs; CAISO Fifth Replacement Tariff Section 26. Rates and Charges, Subsection 26.1. Access Charge ("Section 26" 2025)
Generator Interconnection Upgrade	Needed to reliably connect new generation to the transmission grid	100% allocation to interconnecting customer. For generation interconnection projects studied together (i.e., as a group study) that require short circuit upgrades, costs are split according to how much fault current each project adds to the system. Other non-short circuit costs are shared among interconnecting customers in a group study on a megawatt basis. The interconnecting customer also bears the full cost of	CAISO Fifth Replacement Tariff Appendix DD, Generator Interconnection and Deliverability Allocation Procedures (GIDAP), Subsection 8.3, Cost Responsibility for Reliability Network Upgrades (CAISO 2025); Appendix Y, Generator Interconnection Procedures (GIP) For Interconnection Requests Generator Interconnection Procedures, Subsection 6.5, Identification and Cost Allocation for

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Project Type	Description	Cost Allocation	Source/Subsection
		interconnection reliability network upgrades, unless it is mandated to be shared among other interconnecting customers.	Network Upgrades (CAISO 2024)
Reliability Projects	New or upgraded transmission facilities greater than 200 kV needed to maintain system reliability	100% allocation to participating transmission owner service territory via gross load ratio share	CAISO Fifth Replacement FERC Electric Tariff, Subsection 24.14, Cost Responsibility for Transmission Additions or Upgrades (CAISO 2025)
Economic Projects	Transmission facilities greater than 200 kV that reduce congestion	100% allocation to participating transmission owner service territory via gross load ratio share	CAISO Fifth Replacement FERC Electric Tariff, Subsection 24.14 Cost Responsibility for Transmission Additions or Upgrades (CAISO 2025)
Public Policy Projects	Transmission facilities greater than 200 kV that address state, federal, municipal, and county requirements or directives	100% allocation to participating transmission owner service territory via gross load ratio share	CAISO Fifth Replacement FERC Electric Tariff, Subsection 24.14 Cost Responsibility for Transmission Additions or Upgrades (CAISO 2025)

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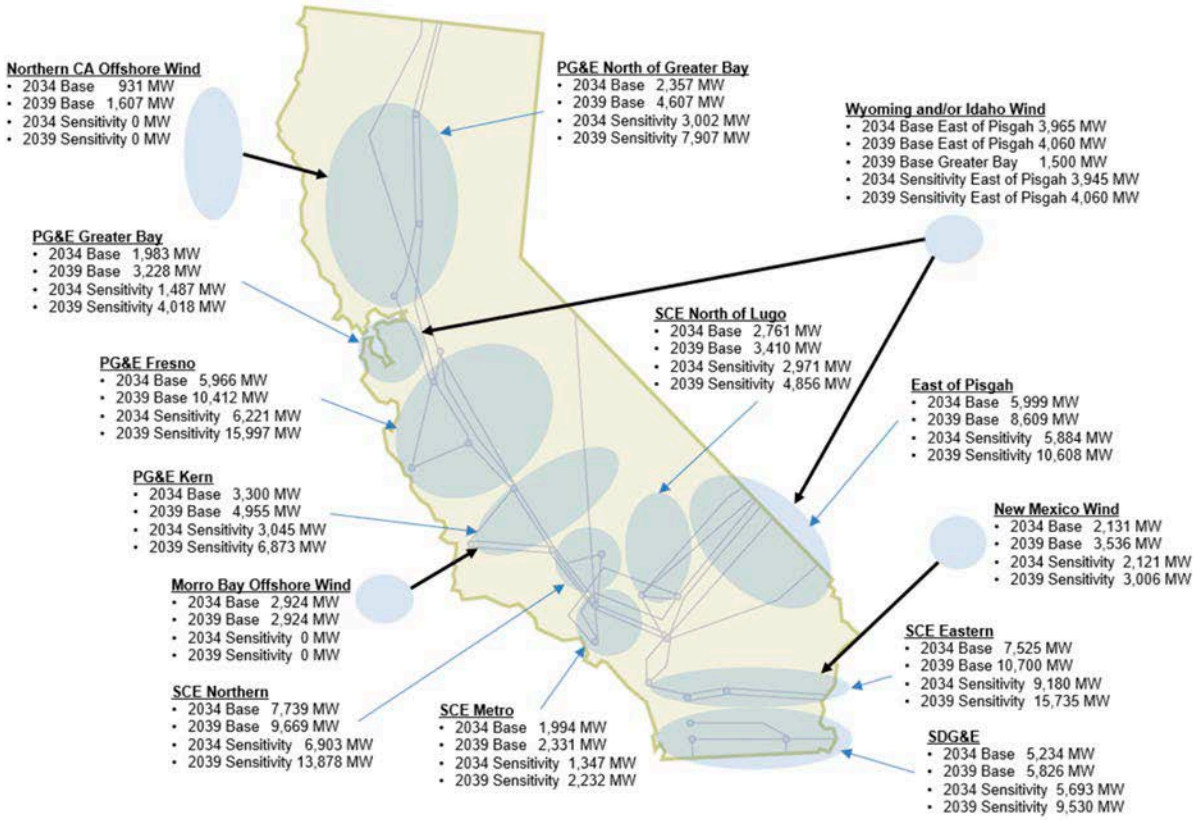

Figure B-1. CAISO transmission planning zones. ***Source: (2023-2024 Transmission Plan 2024)***

B.2 ERCOT

Table B-2 summarizes the cost allocation methods and relevant reference in ERCOT's tariff for each type of transmission investment. Figure B-2 illustrates how ERCOT is divided into load zones.

Table B-2. ERCOT Cost Allocation Summary

Project Type	Description	Cost Allocation	Source/Subsection
Generator Interconnection Upgrade	Generator allowed to interconnect without network upgrades under ERCOT's "connect and manage" approach	Generator interconnection customers are generally responsible for interconnection costs and are directly responsible for additional network upgrade costs only in excess of certain amounts ("allowances")[1]	Section 35.004, Provision of Transmission Service, Sections (d-1) and (d-2), Public Utility Regulatory Act (Utilities Code), Chapter 35, Energy Providers; (Fernandes 2024; Trabish 2025)
Reliability Projects	New projects or upgrades to existing transmission	100% allocation to transmission/distribution service providers via peak load ratio share (4-	("Comments of NRG Energy, Inc., Regarding Project No. 58484 Evaluation of

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Project Type	Description	Cost Allocation	Source/Subsection
	facilities to address reliability violations	Coincident Peak or 4CP methodology). Transmission/distribution service providers then recover costs through wires charges.	Transmission Cost Recovery Before the PUC of Texas," n.d.; "Consideration of the Appropriate Economic Measure for Evaluating Transmission Projects in ERCOT," n.d.)
Economics Projects	New projects or upgrades to transmission facilities that aim to relieve congestion and reduce production costs	100% allocation to distribution service providers via peak load ratio share (4CP methodology). Distribution service providers then recover costs through wires charges.	("Comments of NRG Energy, Inc., Regarding Project No. 58484 Evaluation of Transmission Cost Recovery Before the PUC of Texas," n.d.; "Consideration of the Appropriate Economic Measure for Evaluating Transmission Projects in ERCOT," n.d.)

[1]According to the Utilities Code Title 2, Public Utility Regulatory Act, Subtitle B. Electric Utilities, Chapter 35, Section 35.004 (d-1), "The Commission [PUCT] by rule shall establish a reasonable allowance for transmission-owning utility costs to interconnect generation resources directly with the ERCOT transmission system at transmission voltage. The allowance must take into account: (1) the potential to reduce the costs to consumers of generation interconnection; (2) historical generation interconnection costs; and (3) any other factor that the commission considers reasonable to accomplish the goal of this subsection" (Utilities Code, Title 2, Public Utility Regulatory Act, Subtitle B, Chapter 35 n.d.).

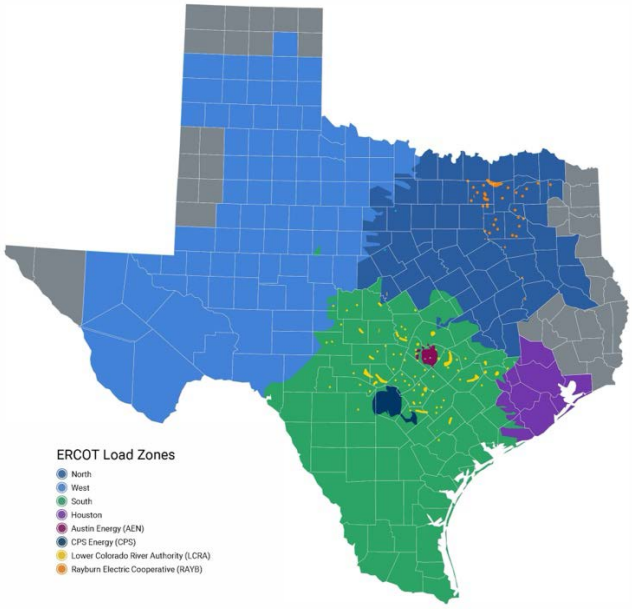

Figure B-2. ERCOT load zones. ***Source: (ERCOT 2023)***

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B.3 ISO-NE

Table B-3 summarizes the cost allocation methods and relevant reference in ISO-NE's tariff for each type of transmission investment. Figure B-3 illustrates how ISO-NE is divided into load zones.

Table B-3. ISO-NE Cost Allocation Summary (ISO-NE 2025a)

Project Type	Description	Cost Allocation	Source/Subsection
Local System Planning	Transmission upgrades for non-pool transmission facilities (PTFs)[1] generally less than 69 kV that are not part of the regional plan	100% allocation to "entity or entities causing or subject to such Localized Costs." Localized costs are not included in recoverable costs for regional transmission upgrades in ISO-NE.	ISO-NE Open Access Transmission Tariff (OATT), Schedule 21 (ISO-NE 2025a)
Generator Interconnection Upgrade	Needed to reliably connect new generation to the transmission grid	100% allocation to interconnecting customer, "including all Direct Interconnection Transmission Costs and any applicable tax gross-up amounts, to the extent such costs would not have been incurred but for the interconnection."	ISO-NE OATT, Schedule 11, Docket No. ER25-1324-001; ("Schedule 11 Generator Interconnection Related Upgrade and Elective Transmission Interconnection Related Upgrade Costs," n.d., 11) ("Schedule 11 Generator Interconnection Related Upgrade and Elective Transmission Interconnection Related Upgrade Costs," n.d.)
Reliability Transmission Upgrade	Transmission upgrades for PTFs that ensure the system's continued reliability	100% postage stamp allocation to the region via load ratio share	ISO-NE OATT, Schedule 12, Section B. Transmission Cost Allocation by Category, Subsection 5. Regional Benefit Upgrades (ISO-NE, n.d.)
System Efficiency Transmission Upgrade	Transmission upgrades that increase overall system efficiency by implementing projects that have benefits that exceed the cost and are above a fixed cost threshold.	100% postage stamp allocation to the region via load ratio share	ISO-NE OATT, Schedule 12, Section B. Transmission Cost Allocation by Category, Subsection 5. Regional Benefit Upgrades (ISO-NE, n.d.)
Public Policy Transmission Upgrade	Transmission upgrades that meet state, federal,	70% postage stamp allocation to region via	ISO-NE OATT, Schedule 12, Section B. Transmission Cost

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Project Type	Description	Cost Allocation	Source/Subsection
	and local public policy requirements	load ratio share and remaining 30% allocation to each state "in direct proportion to the state's share of the public policy planning need that gives rise to the…upgrade" via load ratio share	Allocation by Category, Subsection 6. Public Policy Transmission Upgrade Costs (ISO-NE 2025a); ISO-NE OATT, Schedule 13, Docket No. ER25-1325-001 (ISO-NE 2025a)
Longer-Term Transmission Upgrade[2]	Transmission upgrades that advance policy-based objectives in the New England States	100% to region via load ratio share if benefits exceed costs or alternative cost allocation method upon request by the New England States Committee on Electricity (NESCOE). If costs exceed benefits, a portion of costs equal to the benefit-cost ratio multiplied by the total cost of the upgrade is allocated using the same cost allocation method as for reliability projects; the remaining portion is allocated 100% to regional network load in states that volunteer or a sponsor.	ISO-NE OATT, Schedule 12, Section 10. Longer-Term Transmission Upgrades, Subsections (a) and (b) (ISO-NE 2025a)

[1]PTFs are owned by participating transmission owners in the ISO-NE, over which the ISO has operational control, and are those facilities eligible for regional cost support (ISO-NE, n.d.).

[2]Longer-term transmission upgrades were a project type in place prior to FERC Order No. 1920 in ISO-NE.

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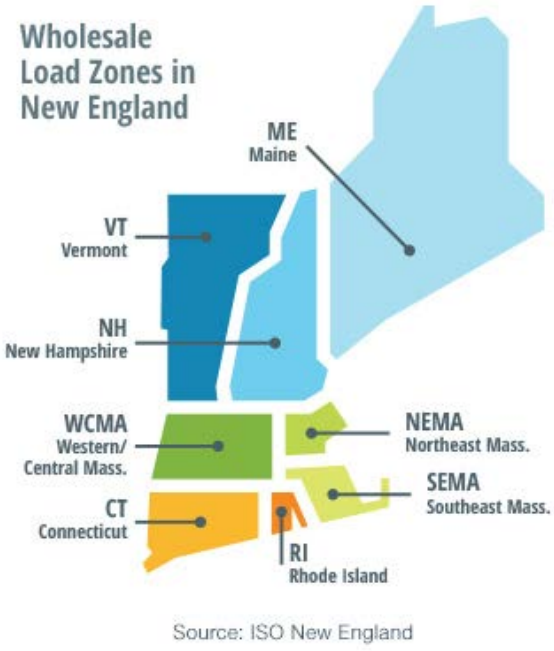

Figure B-3. The ISO-NE load zones. ***Source: (ISO-NE, n.d.-a)***

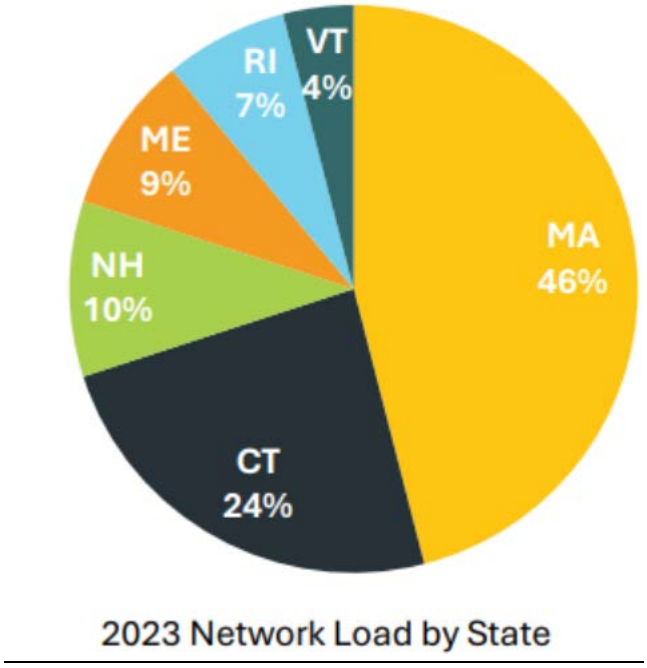

Figure B-4. ISO-NE load ratio share by state used for transmission cost allocation. ***Source: (Adams, 2025)***

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B.4 MISO

Table B-4 summarizes the cost allocation methods and relevant reference in MISO's tariff for each type of transmission investment. Figure B-5 and Figure B-6 illustrate how MISO is divided into cost allocation subregions and cost allocation zones, respectively.

Table B-4. MISO Cost Allocation Summary

Project Type	Description	Cost Allocation	Source/Subsection
Other Projects	Address local reliability issues and/or provide local economic benefits in the form of transmission congestion relief	100% allocation to transmission pricing zone	("MISO Regional and Interregional Cost Allocation" 2023, 3)
Baseline Reliability Project	Required to meet standards for both North American Electric Reliability Corporation (NERC) and regional reliability. Projects may involve several facilities that constitute a single project for cost allocation based on the judgment of the transmission provider.	100% allocation to transmission pricing zone	MISO Tariff as Filed, Attachment FF, III.A.2.c (MISO 2024a); ("MISO Regional and Interregional Cost Allocation" 2023)
Generator Interconnection Project	Needed to reliably connect new generation to the transmission grid. JTIQ Upgrades are treated distinctly from standard generator interconnection projects.	In general, 100% to requesting entity for generation interconnection <345 kV: 100% to generator 345 kV+: 90% to generator and 10% to region based on load ratio share	MISO Tariff as Filed, Attachment FF, III.A.2.d (MISO 2024a); ("MISO Regional and Interregional Cost Allocation" 2023)
Market Efficiency Project	Address transmission congestion and avoided reliability project savings. Market efficiency projects must (a) have a project cost of $5 million or more, (b) involve facilities with 230 kV or higher voltage, (c) are distinct from multivalue projects, (d) have regional benefits. Only projects with a positive benefit-cost-ratio can be included in regional plans.	100% allocation to transmission pricing zones proportionate to the zone's expected benefit and based on benefit metrics defined in the OATT	MISO Tariff as Filed, Attachment FF, III.A.2.f (MISO 2024a); ("MISO Regional and Interregional Cost Allocation" 2023)

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Project Type	Description	Cost Allocation	Source/Subsection
Multi-Value Project	Provide regional public policy, economic, and/or reliability benefits. MVPs must meet one of three criteria that cover different types of benefits an MVP can generate. MVP projects must also meet a set of conditions, including having a capital cost of at least $20 million and including new construction or improvement of facilities above 100 kV.	100% regional postage stamp allocation to load if benefits distributed broadly; 100% subregional postage stamp allocation if benefits distributed broadly across a subregion	MISO Tariff as Filed, Attachment FF, Section II.C.1, II.C.2, and II.C.3 for criteria and conditions of MVP Projects; MISO Tariff as Filed, Attachment FF, Section III.A.2.g for cost allocation methodology (MISO 2024a); ("MISO Regional and Interregional Cost Allocation" 2023)

Transmission pricing zones are at the utility level and are used to allocate baseline reliability projects. Transmission pricing zones are grouped into cost allocation zones, which mostly reflect state boundaries.

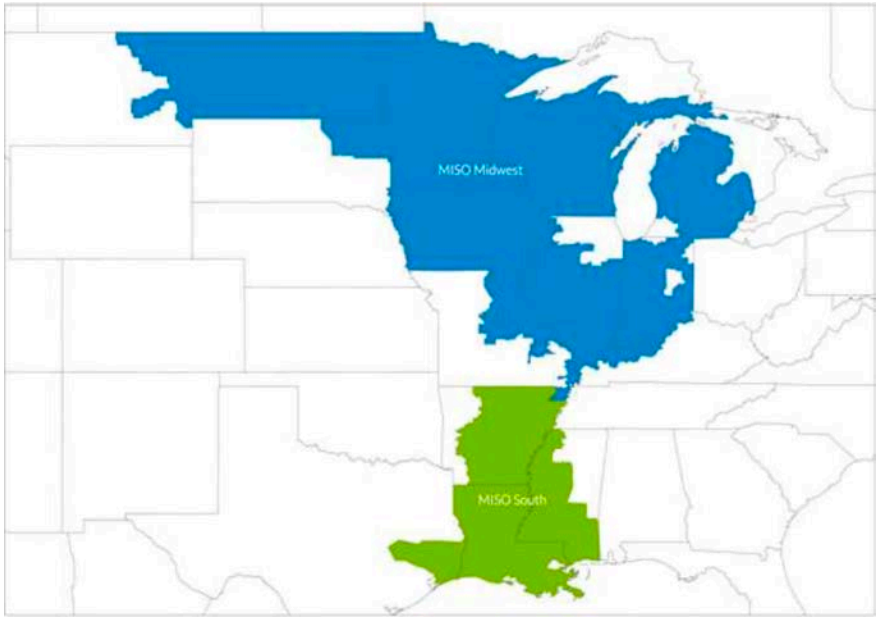

Figure B-5. Map of MISO MVP cost allocation subregions. ***Source: (MISO 2022)***

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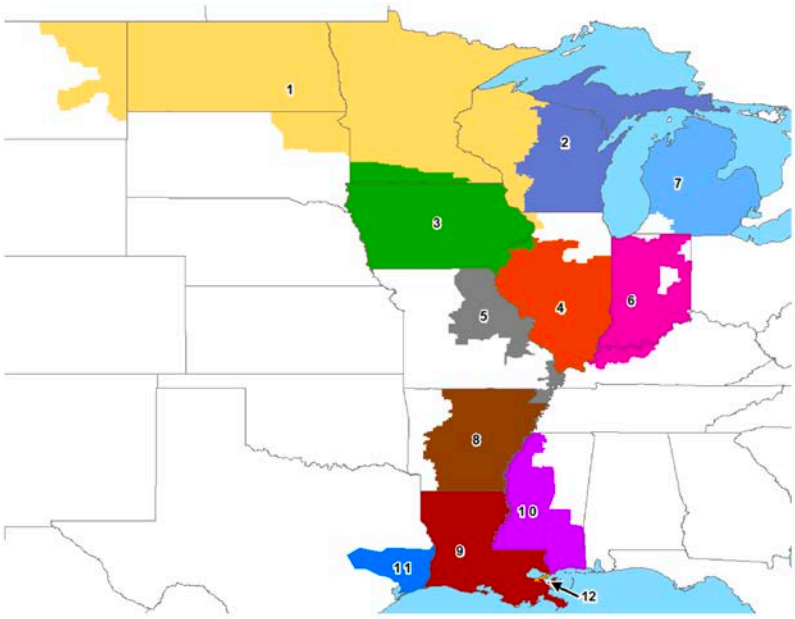

Figure B-6. Map of MISO cost allocation zones. ***Source: (MISO 2018)***

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B.5 NYISO

Table B-5 summarizes the cost allocation methods and relevant reference in NYISO's tariff for each type of transmission investment. Figure B-7 illustrates how NYISO is divided into control area load zones.

Table B-5. NYISO Cost Allocation Summary (NYISO 2025)

Project Type	Description	Cost Allocation	Source/Subsection
Local Transmission Projects	Transmission projects that satisfy a need identified in a transmission owner's local transmission plan	100% allocation to transmission owner; each transmission owner executes cost recovery according to its own rate recovery mechanisms	NYISO OATT, Section 31. Cost Allocation and Cost Recovery, Subsection 31.5.1.5, LTP Facilities ("NYISO Open Access Transmission Tariff" 2025, 2041)
Generator Interconnection Projects	Needed to reliably connect new generation to the transmission grid	100% allocation to interconnecting customer. The developer is also responsible for the costs of the interconnection studies incurred by the ISO and transmission owner.	NYISO OATT, Section 30, Subsection 30.11 Standard Large Generator Interconnection Agreement and Subsection (Standard Large Generator Interconnection) and page 2242 (Small Generator Interconnection Procedures)
Regulated Reliability Transmission Projects	Transmission projects needed to satisfy a reliability need identified in the reliability planning process	Costs for solutions to reliability needs are allocated in this hierarchy: 1. 100% coincident peak ratio share for costs attributable to resolving resource adequacy needs 2. 100% power flow ratio share for each subzone's contribution to the thermal issue 3. 100% load ratio share to each subzone contributing to a voltage security issue 4. 100% load ratio share to each subzone contributing to a dynamic stability issue 5. 100% of the costs of remaining short circuit issues will be allocated as local projects	Subsections covering the sequential cost allocation steps are detailed in NYISO OATT, Section 31. Cost Allocation and Cost Recovery ("NYISO Open Access Transmission Tariff" 2025). Step 1 is covered in Subsection 31.5.3.2.1, Resource Adequacy Reliability Solution Cost Allocation Formula. Step 2 is covered in Subsection 31.5.3.2.2, BPTF Thermal Transmission Security Cost Allocation Formula. Step 3 is covered in Subsection 31.5.3.2.3, BPTF Voltage Security Cost Allocation. Step 4 is covered in Subsection 31.5.3.2.4,

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Project Type	Description	Cost Allocation	Source/Subsection
			Dynamic Stability Cost Allocation. Step 5 is covered in Subsection 31.5.3.2.5, Short Circuit Issues.
Regulated Economic Transmission Projects	New or upgraded transmission facilities that relieve congestion and reduce production costs	Allocated to zones identified as economic beneficiaries based on a present value calculation that determines the share of total project based on the ratio of zonal benefits to total economic benefits (i.e., Zonal cost allocation = Project cost * [Zonal benefits / Sum of benefits in zones with positive net benefits])	NYISO OATT, Section 31, Cost Allocation and Cost Recovery, Subsection 31.5.4.4.4.1 ("NYISO Open Access Transmission Tariff" 2025, 2071)
Regulated Transmission Solutions to Public Policy Transmission Needs	Transmission projects identified by the NYPSC that are driven by public policy requirements	Backstop cost allocation based on 100% load ratio methodology to load serving entities if the NYPSC does not propose an alternative cost allocation methodology or approve an alternative cost allocation methodology proposed by the entity the ISO has identified to build the project	NYISO OATT, Section 31. Cost Allocation and Cost Recovery, Subsection 31.5.5. Regulated Transmission Solutions to Public Policy Transmission Needs, Subsection 31.5.5.4, Cost Allocation for Eligible Projects ("NYISO Open Access Transmission Tariff" 2025, 2078)

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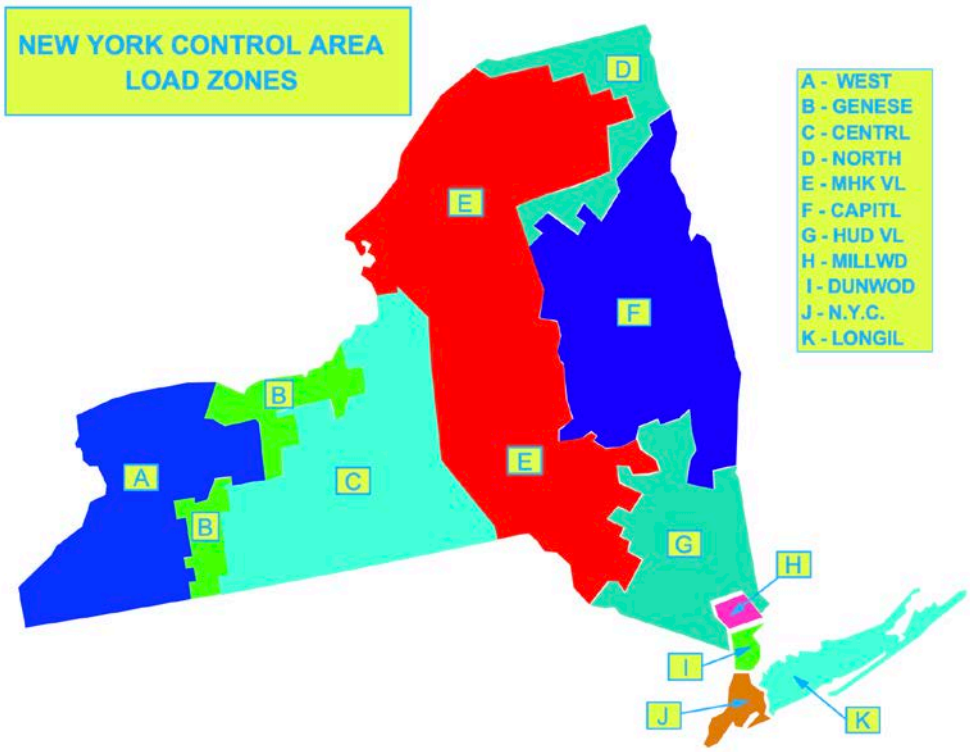

Figure B-7. New York Control Area (NYCA) load zones. ***Source: (NYISO, n.d.-b)***

B.6 PJM

Table B-6 summarizes the cost allocation methods and relevant reference in PJM's tariff for each type of transmission investment.

Table B-6. PJM Cost Allocation Summary

Project Type	Description	Cost Allocation	Source/Subsection
Local Project	Local facilities not required to meet PJM planning criteria that are less than $5 million and less than 200 kV	100% to PJM zone in which the project is constructed	PJM Manual 14A; PJM OATT 218.1. Local Upgrades and Network Upgrades on Affected Systems (PJM 2023a)
Generator Interconnection Project	Needed to reliably connect new generation to the transmission grid	100% allocation to interconnecting customer	PJM Manual 14A, Attachment B. Cost Allocation Procedures, Subsection B.2, Scope, and B.3, PJM Generation and Transmission Interconnection Cost Allocation Methodologies (PJM 2023a)
Baseline Reliability or Market	Regional projects and necessary lower-voltage facilities needed to	50% allocation on a regional load share basis and 50% allocation using	PJM OATT, Schedule 12, Transmission Enhancement Charges,

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Project Type	Description	Cost Allocation	Source/Subsection
Efficiency Project	comply with NERC reliability standards (>500 kV or double circuit between 345 kV and 500 kV) or that address market transmission congestion and reduce production costs on the system that are more than $5 million and greater than 1.25 benefit-cost analysis	distribution factor analysis (DFAX)[1] or stability deviation methodology to PJM zone	Subsection (b), Designation of Customers Subject to Transmission Enhancement Charges; Subsection (i), Regional Facilities and Necessary Lower Voltage Facilities; Subsection (A), Cost Responsibility for Regional Facilities and Necessary Lower Voltage Facilities (PJM 2010)
Baseline Reliability or Market Efficiency Project (Lower-Voltage Facilities)	Lower-voltage facilities required to meet reliability standards	100% allocation using distribution factor analysis (DFAX) or stability deviation methodology to PJM zone	PJM Manual 14B, Attachment A, PJM Baseline Reliability Upgrade Cost Allocation Procedures (PJM 2024)
Multi-Driver Project	Provide regional public policy, economic, and/or reliability benefits	Cost allocation proportional to share of costs of each component driver	PJM OATT, Schedule 12, Transmission Enhancement Charges; Subsection (b), Designation of Customers Subject to Transmission Enhancement Charges; Subsection (xiv), Multi-Driver Projects (PJM 2010)
State Agreement Approach	Projects that advance a state's public policy requirements through transmission buildout	100% allocation to the state or group of states pursuing the transmission project(s)	(PJM 2025)

[1]DFAX refers to analyzing the fraction of power flow from a defined source to sink using a model of the electric network and power flow simulations. The distribution factor is given as the change in flows with the added line as power transmitted from PJM generation (source) to each PJM load zone (sink). The formula for the distribution factor is given as Distribution factor = (After-shift power flow – Pre-shift power flow)/Total amount of power shifted, via PJM OATT, Docket No. ER22-1606-000, Page 5, Subsection (iii) DFAX Analysis for Reliability Projects (PJM 2010).

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B.7 SPP

Table B-7 summarizes the cost allocation methods and relevant reference in SPP's tariff for each type of transmission investment. Figure B-8 illustrates how SPP is divided into transmission pricing zones.

Table B-7. SPP Cost Allocation Summary (SPP 2012)

Project Type	Description	Cost Allocation	Source/Subsection
Zonal Reliability Upgrades	Locally planned transmission projects based on SPP-approved zonal planning criteria/ reliability metric thresholds for each zone for local reliability issues	100% allocation to local pricing zone	Attachment J, Recovery of Costs Associated with New Facilities;, Subsection V, Other Network Upgrades, (d) Zonal Reliability Upgrades (SPP 2012)
Generator Interconnection Project	Needed to reliably connect new generation to the transmission grid	100% to interconnecting customer. For interconnection requests part of cluster studies, costs are allocated to each interconnection customer based on proportional power flow impacts.	Attachment V, Generator Interconnection Procedures (GIP), Section 4, Interconnection Request Evaluation Process, 4.2.5. Study Cost and Network Upgrade Cost Allocation (SPP 2012)
Highway Project	Transmission facilities 300 kV and greater	100% allocation on a regional, postage stamp basis	("FERC Order Accepting Tariff Revisions" 2024)
Byway Project	Transmission facilities at least 100 kV and less than 300 kV	33% allocation to region on a regional load share basis and 67% allocation to local pricing zone where facilities are located	("FERC Order Accepting Tariff Revisions" 2024)
SPP Zonal Project	Transmission facilities at or below 100 kV	100% allocation to local pricing zone	("FERC Order Accepting Tariff Revisions" 2024)

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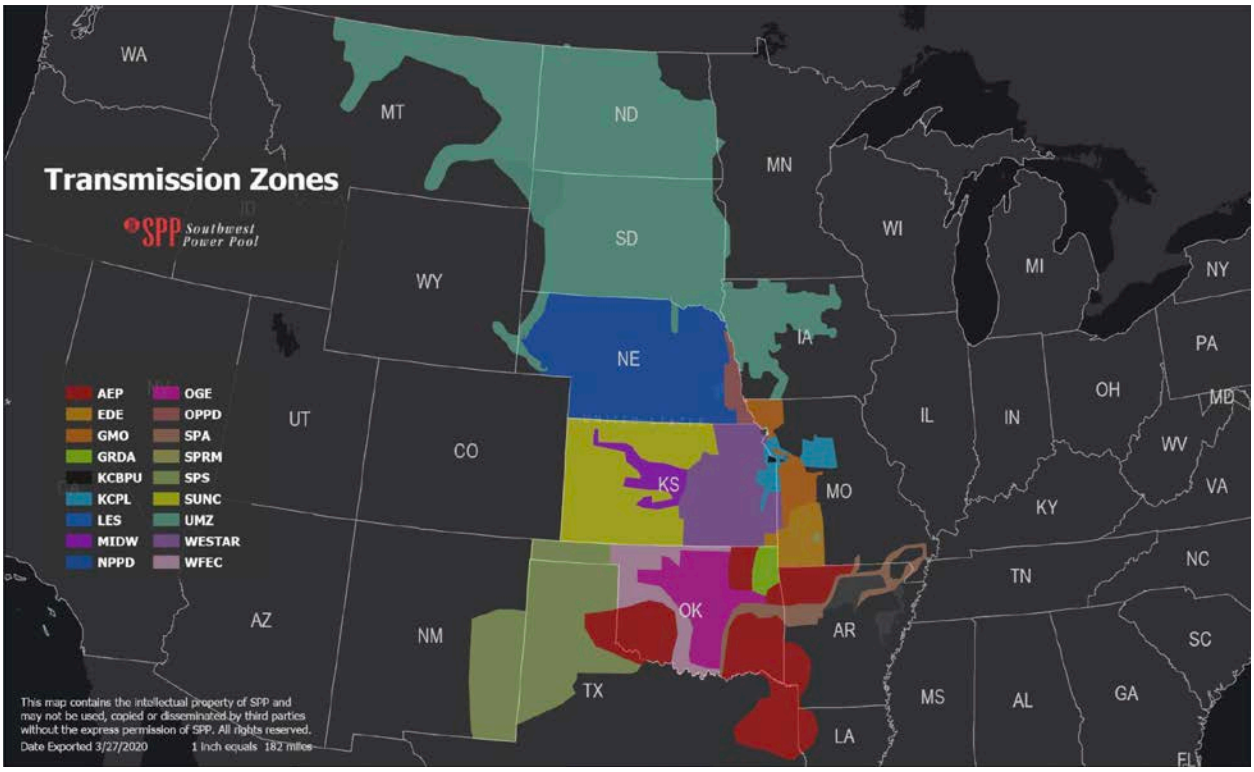

Figure B-8. SPP transmission pricing zones. ***Source: (Frerking 2021)***

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Appendix C. Detailed Case Study Results

The following sections provide more detailed summaries of transmission project case studies.

C.1 MISO Multi-Value Project Planning Portfolio

MISO's approach to multivalue planning and cost allocation is based on the philosophy that the benefits of transmission will change over time but coordination among states to deploy regional transmission infrastructure will ensure broad-based shared benefits (Doner 2023). The MISO Multi-Value Project (MVP) portfolio includes 17 projects identified through MISO's 2011 Transmission Expansion Plan (MTEP 11) (MISO 2011). The MVP portfolios were originally championed by the governors of Minnesota, Iowa, Wisconsin, North Dakota, and South Dakota interested in transmission development to enable increased generator interconnection toward their respective state policy mandates. In 2008, these governors announced the creation of the Upper Midwest Transmission Development Initiative to identify wind generation resources and necessary transmission infrastructure (State of Minnesota 2008). The initiative would also develop a cost allocation proposal for the new transmission to propose to MISO and contribute alongside state public utility commissions and the Organization of MISO States to MISO's analysis of wind energy in the region as part of the "Regional Generation Outlet Study" published in 2010 (MISO 2010). This study was followed by the MTEP 11 that included the first tranche of MVP projects. The MVP portfolio includes projects distributed throughout MISO's footprint at the time and what is today the MISO Midwest subregion.

MISO defines the qualifying criteria, benefit metrics, and cost allocation methods for MVP projects in its OATT (MISO 2024a). The underlying principle for MVP regional cost allocation is the assumption that MVP projects provide regional benefits in excess of costs. To qualify for MVP cost allocation, projects must meet at least one of three criteria roughly aligned with providing public policy, economic, and reliability benefits[15]:

1. **Public policy:** Reliably and economically deliver energy under the constraints of existing state and federal energy policy mandates, laws, and regulatory requirements.
2. **Economic:** Provide multiple types of economic benefits across multiple pricing zones. Benefit-to-cost ratio must exceed 1.0.
3. **Reliability:** Address at least one reliability issue in violation of a NERC or local utility standard and provide at least one economic benefit that provides value across multiple pricing zones.

The MISO Board approved the MVP portfolio in 2011 under Criterion 1 because the projects helped MISO states meet their renewable portfolio standards.[16]

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[15] Additional tariff requirements for MVPs include projects must be evaluated as a portfolio, have a minimum cost of $20 million, be at least 100 kV, and provide benefits that are at least as much as costs (B/C ratio of 1.0) for projects selected under criteria 1 and 3. The tariff also specifies benefits to be looked at over a 20-year time frame and allows MISO to develop other benefits to evaluate MVP portfolios.

[16] The MVP cost allocation scheme was adjudicated, but the U.S. Court of Appeals for the Seventh Circuit upheld FERC's order approving MISO's cost allocation for MVP projects in *Illinois Commerce Commission v. FERC* (*Illinois Commerce Commission, et al., v. Federal Energy Regulatory Commission* 2014).

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MISO calculates the benefits of the portfolio, including production cost savings, reduced cost of meeting operating and planning reserve requirements, reduced transmission line losses, and deferred investments in future baseline reliability upgrades. These benefits are calculated for each cost allocation zone, aligned roughly with state boundaries, to show how costs and benefits are distributed throughout the region. Two Triennial Reviews have taken place in 2014 and 2017 to recalculate the benefit-to-cost ratio for the MTEP 11 MVP portfolio. Although the 2017 Triennial Review shows an overall increase in benefit-to-cost ratios compared to those calculated in MTEP 11, the trends vary over time and by region **Error! Reference source not found.**.

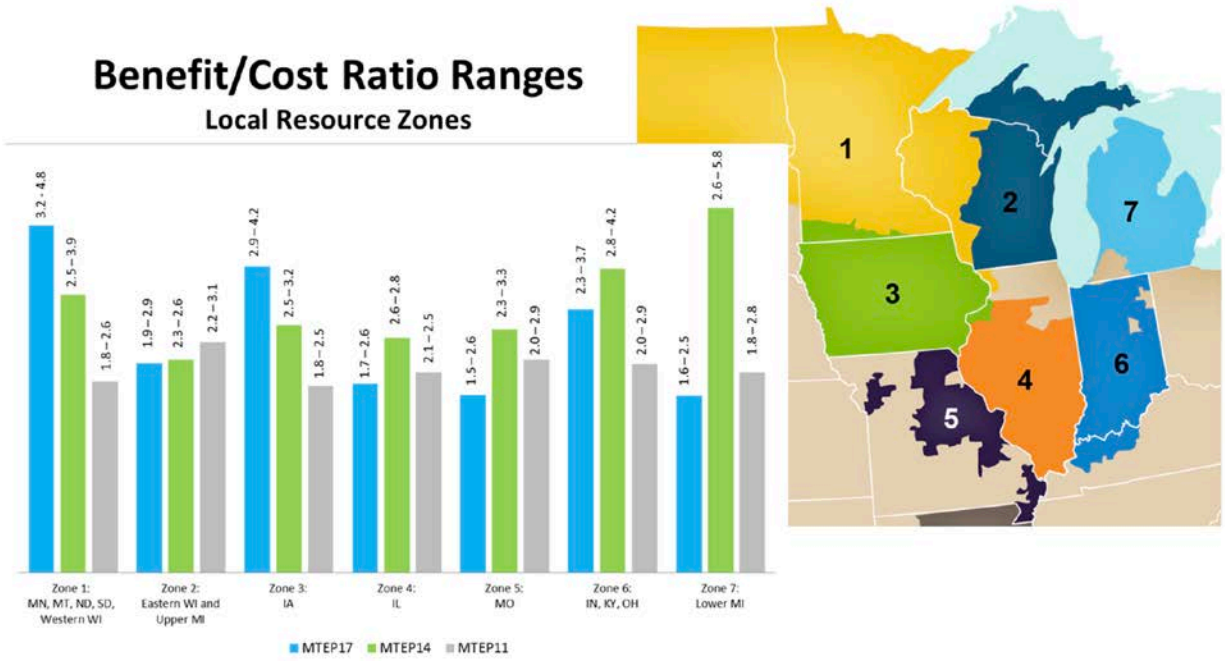

Figure C-1. MVP portfolio total benefit distribution

Recognizing calculated transmission benefits will change over time, MISO does not use quantified benefits for cost allocation. Costs for MVP projects are allocated using an energy-based load ratio share. For the MTEP 11 projects, this was applied to the entire MISO footprint at the time. As MISO has expanded, the RTO footprint is now divided into two subregions, MISO Midwest and MISO South, to reflect the physical power flow constraints on the system. Cost allocation for subsequent MVP portfolios can be applied to individual subregions as necessary.

C.2 New York Independent System Operator AC Transmission Needs

The PPTPP is a joint planning process conducted by the NYISO and NYPSC as part of the NYISO's Comprehensive System Planning Process (NYISO, n.d.-a). The process represents an innovative partnership between the ISO and regulator, establishing a role for the NYPSC to identify transmission needs and cost allocation solutions for projects to meet public policy requirements. The PPTPP starts with the NYISO identifying and submitting transmission needs to NYPSC for consideration to be included as a public policy transmission need. After approval from NYPSC, the NYISO then solicits input from developers and stakeholders to identify and evaluate transmission solutions to meet the public policy transmission need.

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The AC Transmission Needs project was initiated through an order from NYPSC in December 2015 identifying a public policy need to increase transfer capacity along two corridors from upstate to downstate New York (*Proceeding on Motion of the Commission To Examine Alternating Current Transmission Upgrades* 2015). The identified need followed a State Transmission Assessment and Reliability Study (NYISO Board of Directors 2019) led by the NYISO and Energy Highway Blueprint released by Governor Andrew Cuomo (New York Energy Highway Task Force 2012). The order required no less than 350 megawatts (MW) of transfer capability for Segment A and 900-MW transfer capability for Segment B. The NYISO issued a solicitation for solutions to meet this need in February 2016 followed by an order from the NYPSC in January 2017 affirming the NYISO's determination of AC Transmission Needs and directing the NYISO to evaluate and select transmission solutions to meet this need. The PPTPP allows for flexibility in designing the scenarios and sensitivities used for project evaluation based on the project context and stakeholder input. It also authorizes the NYPSC to identify additional benefit criteria—both quantitative and qualitative—and the NYISO Board to select projects based on multivalue criteria rather than solely on project cost.[17]

The selected solutions consist of upgrades to existing lines from 230 kV to 345 kV between central and east New York (Segment A) and replacing 115-kV and 69-kV lines with new double-circuit 345-kV lines between Albany and downstate New York (Segment B) (NYISO 2019c). The proposed solutions for both segments had higher costs than alternatives but were selected based on the projects' benefits including increased transfer capacity, deferred transmission upgrades, greater operational flexibility, and more resilient structure design.

The PPTPP allows the NYPSC and project developers opportunities to develop a project-specific cost allocation but retains a backstop cost allocation method based on load ratio share to prevent project delays in cases in which an alternative agreement cannot be reached. For the AC Transmission Needs study, the NYPSC recommended the NYISO adopt an alternative cost allocation scheme in its December 2015 order (*State of New York Public Service Commission Order Finding Transmission Needs Driven by Public Policy Requirements* 2015). The adjusted method assigns 75% of costs to load zones based on reduced energy payments estimated over a 10-year period and 25% of costs to all load zones in the New York Control Area based on load ratio share of the forecasted summer peak demand. The adopted approach allows for more granular cost allocation to load downstate, which bears the largest cost responsibility.

C.3 SPP Priority Projects

SPP's Priority Projects originated in 2009 from a short-term working group called the Synergistic Planning Project Team (SPPT) created to review transmission planning processes and cost allocation methodologies and to provide recommendations to SPP (SPP 2009). The

[17] Section 31.4.8.1 in Attachment Y of the NYISO's OATT and the Public Policy Transmission Planning Manual defines some of the benefits metrics used to evaluate potential projects against: capital costs, cost-per-megawatt ratio, impact of proposed project on future construction (expandability), operational flexibility, operational performance (utilization, power flows), developer access to property rights, and any other metrics defined by the NYPSC (NYISO 2020). In addition to the transfer capacity minimum thresholds, the NYPSC, in its December 2015 Order, defined other criteria for the NYISO to include in its evaluation of potential solutions. For example, any solution must have access to existing right-of-way, minimize the acquisition of property rights, cannot cross the Hudson River, and the NYISO should favor solutions that replace aging infrastructure.

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SPPT comprised state regulators from the regional state committee (RSC), SPP members, representatives of SPP, an independent external stakeholder, and a facilitator.

In its final report to the SPP Board, the SPPT recommended SPP identify a portfolio of "Priority Projects" to recommend to the RSC (SPP 2009). The Priority Projects portfolio consisted of upgraded transmission facilities that past transmission planning studies had previously identified as solutions, including the numerous extra-high-voltage overlay studies to address network congestion, connect new generation resources, and improve connectivity between the east and west portions of the SPP footprint.[18] In April 2010, the SPP Board of Directors approved a portfolio of five Priority Projects, and the projects were built in 2017.

The SPPT report also called for the RSC to establish the Highway/Byway cost allocation method for all new regional transmission facilities and to determine whether to use the new Highway/Byway cost allocation proposal for the Priority Projects.[19] The justification for the recommendation of a new cost allocation method was twofold. First, the SPPT noted that SPP was currently using three different methods for different project planning processes, including separate rates for zonal projects and regional projects, a postage stamp rate for Balance Portfolio projects, and a new yet-to-be-determined rate for extra-high-voltage overlay projects. The SPPT report (SPP 2009) continued, "SPP members and staff have expressed concern that these cost recovery methods are fragmented, confusing, and difficult to administer as it requires a complex system to track cost by project over the life of the project… the SPPT recommends expanding and including a comprehensive review of all cost allocation methodologies for possible consolidation under a unified system using the recommended 'highway-byway' approach." Second, the SPPT determined that postage stamp cost allocation "tends to support robust regional projects" and that a Highway/Byway method based on a voltage limit would convince some SPP members who did not support a traditional postage stamp rate.

SPP justified the new Highway/Byway cost allocation method to FERC by citing previous studies that explored the power flow dynamics of high-voltage transmission facilities compared to lower-voltage transmission facilities throughout the SPP footprint.[20] One such study was a transmission distribution analysis, which analyzes the power flow response of transmission facilities at different voltages across the footprint to assess which facilities are responsible for regional power flows and which are used primarily for local power flows (SPP 2010d). Discussing the results of the transmission distribution analysis performed, the SPPT report states that "the Transmission Distribution Analysis indicated that extra-high-voltage facilities (300 kV or above) were far more responsive to interzonal flows (98 percent for the Balanced Portfolio extra-high-voltage facilities and 77 percent for the existing SPP extra-high-voltage facilities) than were lower-voltage facilities (38 percent for the 115–138 kV facilities and 14 percent for

[18] At the time, SPP would perform cluster studies for groups of generator interconnection requests that would often identify transmission needs for new wind generation wanting to interconnect at the time. Priority Projects also consistently were identified as solutions in SPP's Aggregate Study Process, where SPP aggregates all requests for new transmission service and studies the needs collectively.
[19] The RSC approved the Highway/Byway cost allocation methodology recommended by the Cost Allocation Working Group in October 2009.
[20] FERC approved SPP's proposed Highway/Byway cost allocation method for use in the Priority Projects and future Integrated Transmission Planning (ITP) projects in June 2010 (*Order Accepting Tariff Revisions* 2010).

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the existing 69 kV facilities)" (Cost Allocation Working Group 2019). The transmission distribution analysis demonstrated that higher-voltage facilities contributed more to interzonal power flows and, therefore, higher regional utilization than lower-voltage facilities.

In a follow-up study to the transmission distribution analysis, SPP conducted an injection withdrawal transmission utilization analysis, which estimates the utilization rate for transmission facilities for local utilization or "other" utilization, which indicates general regional usage. To perform the analysis, SPP used a unit-commitment economic dispatch model representing the existing topology of the SPP system. The average utilization of high-voltage transmission facilities across all hours in the analysis was 78%, indicating high-voltage facilities predominantly support regional transmission services and lower-voltage facilities serve local transmission services (SPP 2010a). SPP filed the results of these studies with their application to FERC for tariff revisions to adopt the Highway/Byway cost allocation methodology (*Order Accepting Tariff Revisions* 2010).

The Highway/Byway method and the preceding processes, studies, and stakeholder groups represent a unique approach to ex ante cost allocation. SPP performed a rigorous analytical study of the system topology and power flows to justify an ex ante regional cost allocation method that allocates costs to network users or beneficiaries without the need for detailed study of each project. This cost allocation method would apply to all future transmission upgrades, regardless of the underlying project driver.

C.4 PJM Artificial Island Project

The PJM Artificial Island Project was recommended to the board in a white paper to resolve stability issues identified by PJM at the Salem and Hope Creek nuclear plants in New Jersey and to relieve congestion on the Delmarva Peninsula. LS Power was awarded the competitive bid to build the transmission line, and Public Service Electric & Gas and Pepco Holdings were tasked with upgrading the substations on either end (RTO Insider 2020). The project consisted of 12 transmission enhancements, 5 would operate above a threshold of 500-kV or 345-kV double circuit, and the remaining 7 were planned below this threshold, including a 3-mile 230-kV underwater cable beneath the Delaware River.

PJM opened its first Order 1000 Regional Transmission Expansion Planning (RTEP) process window in April 2013. Under its approved Order 1000 tariff for cost allocation for regional facilities, the costs of transmission facilities greater than 500 kV or double-circuit 345 kV would be allocated 50% to the region on a load ratio share basis and 50% using the distribution factor analysis method, or DFAX method (PJM 2010). For lower-voltage facilities, 100% of the costs are allocated using the DFAX method. The DFAX method is intended to measure each transmission zone's use of the upgrade to serve zonal load through changes in power flows.

The first regional project to be planned under PJM's Order 1000 rules was the New Jersey Artificial Island transmission need (PJM Inside Lines 2021). PJM identified stability issues and requested proposals for improved operational performance in the Artificial Island area where the Salem 1 and 2 and Hope Creek 2 nuclear power plants are located. Of the 12 total transmission enhancements that made up the Artificial Island Project, 5 of the projects were planned to operate at 500 kV (345-kV double circuit) or higher with a cost allocation of 50% allocated to the region via load ratio share and 50% via solution-based DFAX method. The remaining 7

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projects were planned to operate below the voltage thresholds, and 100% of the cost of these projects was to be allocated via the solution-based DFAX method, including the 3-mile 230-kV underwater cable beneath the Delaware River.

This original cost allocation using DFAX and load ratio share allocated the majority of the cost of the transmission project, including nearly all the cost for the 230-kV underground transmission line, to Delmarva Power and Light, which serves customers in Delaware and Maryland. After requests for rehearing from state regulators, FERC found the DFAX method was not suitable to identify beneficiaries of stability-based upgrades because it is based on flow-based calculations. PJM proposed two alternative ex ante cost allocation approaches for identifying the beneficiaries of transmission projects that address stability-related reliability issues—the stability deviation method and the stability interface DFAX method. FERC found the stability deviation method to be just and reasonable and included the tariff provisions in the February 28, 2019, order and directed PJM to make a compliance filing with the additional provisions. A group of other state regulators and transmission owners sued and took FERC to court, arguing the commission changed its decision without proper evidence. The case went to the United States Court of Appeals for the District of Columbia (*Public Service Electric and Gas Company, Petitioner v. Federal Regulatory Commission* 2021). The D.C. Appeals Court denied the petition for review of FERC orders by Public Service Electric and Gas and other petitioners, deciding FERC made the right decision in adopting the alternate cost allocation method for stability issues. In March 2020, FERC accepted PJM's reallocation of costs for the Artificial Island Project. Using the stability deviation method, Delmarva Power and Light was allocated only 13% (PJM 2020) of the costs, compared to nearly 98% (PJM 2015b) using the DFAX methods. The 230-kV transmission line running under the Delaware River, along with the upgraded substations and new transformer, were completed in fall 2020, with the remaining upgrades completed in spring 2021 (PJM Inside Lines 2021).

C.5 ISO New England's Greater Boston Transmission Project

The Greater Boston Transmission Project is a reliability project consisting of a portfolio of new transmission lines, reconductoring of existing lines, new transformers, and other transmission-related upgrades. It illustrates the ISO's approach to planning transmission projects around project costs rather than project benefits.

Costs for regional reliability projects are allocated on a postage stamp basis to the region using load ratio share. Reliability projects must satisfy evaluation factors defined in Attachment K and reliability standards in Attachment N of the ISO's tariff (ISO-NE 2025a). The tariff defines the criteria that ISO-NE may use in selecting proposals to satisfy reliability needs, but there is no benefit quantification for reliability projects. The ISO's Transmission Cost Allocation Review process can be summarized in four steps (ISO-NE 2023a):

1. **Transmission owners submit a transmission cost allocation application,** requesting regional rate recovery for their project(s).
2. **ISO reviews project costs** and determines if costs are "reasonable and in accordance with good utility practice."
3. **The Reliability Committee provides advisory input to ISO-NE** on whether the proposed project includes localized costs.

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4. **ISO determination** of how much of project's costs are applicable for regional cost recovery.

The Greater Boston Transmission Project was one of the largest and most expensive reliability projects planned in the ISO-NE, originally estimated to be $822 million (ISO-NE 2023b). The Reliability Committee voted to recommend the project in June 2017. Costs for reliability projects are generally based on load ratio share. The final cost allocation for this project has not been determined yet. In September 2020, an additional $188.6 million was requested to underground a 115-kV transmission line originally designed as an overhead line but was unable to secure property rights. The Reliability Committee did not recommend approval of this request, and the additional cost for the undergrounding project remains under review by ISO-NE (ISO-NE 2020).

C.6 MISO-SPP Joint Targeted Interconnection Queue Projects

The JTIQ concept originated from developers that wanted to build and interconnect generation along the MISO-SPP seam but were facing prohibitive interconnection costs. A joint study by MISO and SPP originally identified seven projects with a total cost of roughly $1.6 billion (MISO 2022). Two of the initial 7 JTIQ projects were found to have benefits to load and qualify as MVP projects in MISO's tariff and were removed from JTIQ and placed in MISO's Long Range Transmission Planning Tranche 1 portfolio (SPP and MISO 2022a).

The initial JTIQ study (SPP and MISO 2022b) established a cost allocation methodology for JTIQ projects similar to MISO's generator interconnection cost allocation scheme, whereby 90% of the engineering and construction costs are paid for by the interconnecting generators and 10% is paid for by load in SPP and MISO in proportion to each region's calculated adjusted production cost benefit. Of the 10% allocation to load, 7% was allocated to SPP and 3% to MISO-based production cost modeling to estimate the benefit to each region. After the projects received $464.5 million in grants through the Department of Energy's Grid Resilience and Innovation Partnership program, the cost allocation was updated to 100% of the remaining engineering and construction costs would be paid for by interconnection generators (MISO Planning Advisory Committee 2023). These costs would be spread over generator interconnection projects across multiple queue clusters to reduce the impact on any single interconnecting customer (SPP and MISO 2023). Electricity load between MISO and SPP would continue to pay for operations and maintenance costs and would serve as a backstop for undersubscribed capacity. In November 2024, FERC approved the JTIQ cost allocation proposal (FERC 2024c).

The JTIQ transmission projects do not provide reliability or economic benefits as defined in the MISO or SPP tariffs and would not have been identified as transmission solutions in either region's transmission planning process (FERC 2024c). The joint planning and cost allocation approach taken by MISO and SPP helped identify projects that support generator interconnection and provide regional benefits that may not have otherwise been built.

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Appendix D. Summary of Cost Allocation Related to Section 205 Filing Rights by Region

Table D-1 provides a summary of cost allocation related to the Federal Power Act (FPA) section 205 filing rights by ISO/RTO. The rules and procedures in each region are nuanced and complicated. Although Table D-1 provides a summary of filing rights and cost allocation provisions, the tariff and governing documents can provide more detailed information.

Table D-1. Summary of FPA Section 205 Filing Rights Related to Regional Transmission Cost Allocation, by ISO/RTO

ISO/RTO	Transmission Owner Exclusive Filing Rights	Cost Allocation Provisions	Other Relevant Provisions	Key Governance Documents or Reference
CAISO	Transmission owners have 205 rights over their local and regional transmission revenue requirement and rates and rate design to recover those revenues	Per Section 24 of the CAISO OATT, when CAISO determines the need for a transmission addition or upgrade, the cost of the addition or upgrade is borne by the participating transmission owner that will own the project; this cost will be reflected in the transmission owner's revenue requirement. Costs for these new regional transmission facilities will be included in the grid-wide component of the CAISO regional access charge.	CAISO's OATT (Section 26) also requires transmission owners to make conforming changes to its tariff to accommodate the allocation of the transmission owner's transmission revenue requirement between the local and the regional revenue requirement.	• CAISO 2025 Section 24, Section 26, Appendix F • Individual transmission owner tariffs[21]
ISO-NE	Per the ISO-NE Transmission Operating Agreement (TOA) (ISO-NE 2025c), Participating Transmission Owners have 205 filing authority over the transmission revenue requirement, rates for their own territory,	The 205 filing rights for actions related to the methodology used to allocate costs of new transmission facilities and upgrades in the ISONE OATT are included in the TOA and the Rate Design and Disbursement	Transmission owners must notify the ISO and stakeholders in advance of their intent to file the 205. The transmission owners and the ISO are encouraged to try	• ISO-NE 2025c Section 3.04 • ISO-NE 2006

[21] See CAISO's website for a list of TO-specific TO Tariffs, https://www.caiso.com/library/participating-transmission-owner-tariffs.

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ISO/RTO	Transmission Owner Exclusive Filing Rights	Cost Allocation Provisions	Other Relevant Provisions	Key Governance Documents or Reference
	terms and conditions of local service, and rates for recovery of new facilities or upgrades.	Agreement (RDDA) (ISO-NE 2006). The TOA states the transmission owners must act jointly, in accordance with the RDDA, when filing a 205 for this cost allocation method. The RDDA joint transmission owner 205 filing procedures include achieving more than 65% transmission owner approval thresholds, subject to other specific criteria.	to agree upon the filing. If fewer than all the transmission owners support the filing, the position of the dissenting transmission owners must be communicated to the ISO and stakeholders. If regional state committee (NESCOE) develops an alternative, transmission owners must include NESCOE's proposal in their filing.	
MISO	For transmission upgrades and new transmission facilities, each transmission owner has full and exclusive 205 rights to submit filings for transmission upgrades and new transmission facilities that only impact rates within that transmission owner's zone.	Both the transmission owner(s) and MISO have 205 filing rights on cost allocation regarding transmission upgrades and new transmission facilities impacting multiple zones, subject to the transmission owners following the joint transmission owner governance provisions for transmission owner filings, and subject to the coordination provisions for both transmission owner and MISO filings.	When MISO and the transmission owners both have 205 rights and intend on filing on an issue, there are provisions that require notification and encourage the parties to meet and determine if a joint MISO/transmission owner filing can be achieved. Organization of the MISO States can request MISO use its 205 filing rights to file an alternative cost allocation method if 66% of the	• *MISO Agreement of Transmission Facility Owners (MISO 2013)*, Appendix K

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ISO/RTO	Transmission Owner Exclusive Filing Rights	Cost Allocation Provisions	Other Relevant Provisions	Key Governance Documents or Reference
		Section 205 rights subject to joint transmission owner governance encourage joint transmission owner 205 filings that must be conceived through a majority vote of eligible transmission owners on a one-owner-one-vote basis. Alternatively, a minority of at least 3 eligible transmission owners can file a joint 205 filing provided their combined gross transmission plant assets are more than $2.5 billion.	Organization of the MISO States board supports the proposal.	
NYISO	Transmission owners have filing rights related to tariffs or cost recovery related to their own facilities	Rate changes that affect more than one transmission owner footprint or broad regional cost allocation will involve both transmission owners and the NYISO, and the Public Service Commission	The NYISO must obtain agreement from the NYISO Board and Management Committee before filing tariff changes	NYISO OATT (NYISO 2025) Attachment Y
PJM	Per the PJM Transmission Owners Agreement (TOA), each transmission owner will have the exclusive, unilateral right to make a 205 filing at FERC at any time for revenue requirement under the PJM tariff for its transmission facilities for delivery within or outside of its zone, and for rates and	Transmission owners may only collectively file under 205 to change PJM Regional Rate Design that applies to all PJM zones, Joint Transmission Rates, or any other provision related to recovery of transmission-related costs by TOs. They may not file individually.	PJM is required by the OATT to notify the transmission owners of its intent to file a 205 on an issue that impacts transmission owner revenue requirement or rate design. If PJM and the transmission owners have a dispute related to the 205 filing,	• PJM OATT (PJM 2010; PJM 2023a) • Consolidated Transmission Owners Agreement (PJM 2013) • Atlantic City Settlement (which allocates which 205 rights

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ISO/RTO	Transmission Owner Exclusive Filing Rights	Cost Allocation Provisions	Other Relevant Provisions	Key Governance Documents or Reference
	charges for transmission for delivery within its zone. Section 9 of the PJM OATT reflects similar language related to transmission owner rights.	Collective transmission owner voting requirements for cost allocation relevant matters include achieving both a concurrence of two-thirds majority vote and net book value-weighted voting thresholds. PJM Tariff Schedule 12 outlines cost allocation methods and options for transmission owner rate recovery for transmission enhancements.	specific dispute resolution processes are outlined in the TOA and OATT.	transmission owners retain versus what is transferred to PJM) (U.S. Court of Appeals for D.C. 2002)
SPP	SPP has 205 filings rights over the OATT. Transmission owners have 205 filing rights over rates, rate structure, and revenue requirement.	The cost allocation provisions for base plan zonal and region wide charges, and recovery of costs for new facilities is in the SPP OATT.	Transmission owners must notify SPP of intent to file a 205 and provide a copy of the filing to SPP. • The SPP OATT requires the base plan regional and zonal allocation methodology and factors to be reviewed at least once every 6 years. The transmission owner or RSC can initiate a review at any time and the two entities will collaborate on the review and analysis. • The RSC can have SPP use its 205 filing rights on certain issues,	• SPP Bylaws and Membership Agreement (SPP 2010e) Section 2.2.1, Section 3.1, Section 7.2 • SPP OATT (SPP 2012) Part V, Schedule 11, and Attachment J

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ISO/RTO	Transmission Owner Exclusive Filing Rights	Cost Allocation Provisions	Other Relevant Provisions	Key Governance Documents or Reference
			including whether license plate or postage stamp rates will be used for the regional access charge.	

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