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Transmission Cost Allocation Practices

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Introduction

This brief provides an overview of different approaches to allocating costs of transmission facilities between generators and loads, among different jurisdictions, between customer classes, and for reliability, economic, and public policy drivers. The brief also discusses lessons learned from stakeholder engagement for transmission projects between jurisdictions with differing public policy goals, using counterfactuals for transmission cost allocation, and Federal Energy Regulatory Commission (FERC) and court decisions on cost allocation proposals.

The brief has five main sections:

- Transmission cost allocation methodologies
- Transmission cost allocation to generators and specific customer classes
- Planning approaches and stakeholder processes for public policy projects
- Considerations related to potential use of counterfactuals for transmission cost allocation
- Controversial and rejected cost allocation proposals.

1. Transmission Cost Allocation Methodologies

Regional Transmission Operators (RTOs) and Independent System Operators (ISOs) in the United States allocate the costs of transmission infrastructure through two main processes: (1) generator interconnection and (2) transmission planning. Other countries may use methods that differ significantly from U.S. methods. This section reviews cost allocation practices for U.S. RTOs/ISOs and select other countries.

U.S. methods for allocating transmission costs often vary by driver. FERC Order 1000 defined three kinds of transmission drivers: reliability:

- *Reliability transmission* is needed to meet the North American Electric Reliability Corporation's reliability standards.
- *Economic transmission* cost-effectively reduces transmission congestion when the transmission system already meets reliability standards.
- *Public policy transmission* is needed to meet public policy goals.

As the following examples illustrate, these three drivers are often difficult to isolate, which complicates transmission cost allocation.

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1.1 Cost Allocation for Generator Interconnection

When generators request to interconnect to a transmission system, the grid operator studies their application to determine potential system impacts. System impact studies determine whether any upgrades to the transmission system (network upgrades) will be needed to: (1) ensure that generators can operate reliably; (2) allow generators to deliver energy to loads for resource adequacy; and (3) be eligible to participate in capacity markets, where they exist.

In most RTOs/ISOs, the costs of these network upgrades are allocated to generators (Table 1-1). FERC Order 2003 allowed RTOs and ISOs to charge generators for the cost of network upgrades without reimbursement because of their independent status. ISO-New England (ISO-NE), NYISO, and PJM use a but for method for cost allocation for transmission upgrades, which makes generators responsible for the cost of network upgrades incurred but for the interconnecting generators.

Table 1-1. Cost allocation methods for transmission network upgrades in interconnection

RTO/ISO	Cost allocation method
CAISO	Generators pay initial cost of network upgrades; CAISO refunds costs to generators over time (FERC crediting policy)
ERCOT	Limited network upgrades triggered in interconnection; transmission providers pay for any incremental costs needed to connect generators
ISO-NE	Generators pay for the cost of network upgrades (*but for* method)
NYISO	Generators pay for the cost of network upgrades (*but for* method)
MISO	Generators pay for the cost of network upgrades; generators can be refunded for up to 10% of the cost of upgrades ≥345 kilovolts (kV)
PJM	Generators pay for the cost of network upgrades (*but for* method)
SPP	Generators pay for the cost of network upgrades

Sources: CAISO (2025), Appendix Y. ERCOT (2025), Section 5. ISO-NE (2024), Schedule 11. MISO (2024), Attachment X. PJM (2024a), Section 217. SPP (2025), Attachment Z1.

All RTOs/ISOs, except ERCOT,[1] charge some transmission costs to generators in the interconnection process, and some to loads through the transmission planning process. Historically, transmission planning often focused on transmission needs driven by load growth, while interconnection captured transmission needs driven by new generation.[2] Under FERC Order 1920, more generation-driven transmission needs may be captured in transmission planning than occurs today.
Network upgrade costs in interconnection are a significant share of total transmission investment costs for some RTOs and ISOs. In PJM, interconnection-related network upgrades accounted for 14% of total, cumulative board-approved Regional Transmission Expansion Plan (RTEP) projects (total $48 billion) as of December 31, 2023.[3] Interconnection-related network upgrades accounted for 13% of $27 billion of approved transmission projects between 2020 and 2024 in the MISO Transmission Expansion Plan (MTEP).[4] Other RTOs/ISOs do not report allocations of transmission costs between transmission planning and generator interconnection.

[1] In ERCOT, transmission service providers pay for all generator interconnection costs. ERCOT assumes that most issues identified in interconnection studies can be managed through real-time operations, rather than triggering network upgrades.
[2] Most RTOs/ISOs used a planning horizon of 10 years or less for reliability and economic transmission planning, 10-year load forecasts, and existing or committed generation less retirements. See, for instance, PJM (2024b).
[3] PJM (2024b), p. 4.
[4] Appendix A. Based on MISO MTEP reports from 2020 through 2024. https://www.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd=.

1.2 Cost Allocation in Transmission Planning in the United States

Table 1-2 summarizes the cost allocation methods used in the United States, including the basis for transmission charges, investment driver, and example of where each method is used. Cost allocation methods can be applied to individual transmission projects as well as portfolios of transmission projects. Experts emphasize that the portfolio approach to cost allocation has facilitated stakeholder acceptance in many regions, such as MISO and ISO-NE, because each state values one or more projects in the portfolio, rather than focusing on the potential impacts of individual projects.[5]

Table 1-2. Cost Allocation Methods and Basis for Transmission Charges

Cost Allocation Method	Basis for Transmission Charges	Investment Driver	Examples
Load Ratio Share (Postage Stamp)	Energy (MWh) or peak demand (MW)	Reliability / Economic / Public Policy	CAISO, ERCOT, ISO-NE, MISO Multi-Value Projects (MVPs)[6]
Zonal (License Plate)	Physical location of the investments	Reliability / Economic	Lower voltage projects for various ISOs/RTOs
Highway-Byway (combination of Load Ratio Share and Zonal)	Energy (MWh) or demand (MW), with an increase in the geographic scope as voltage increases	Reliability / Economic / Public Policy	SPP
Granular Approach ("Beneficiary Pays")	Distribution of benefits	Reliability / Economic / Public Policy	Market efficiency (economic) projects in most ISOs/RTOs
Power Flows	Share of power flows contributing to a reliability problem or a transmission solution	Reliability	PJM
Public Policy Supplement	Reduction in total cost based on supplemental contribution of a specific state, with remaining cost allocated to other states in proportion to benefits	Public Policy	ISO-NE

Source: Adapted from Azar (2024).

Following are descriptions of each of these methods, including advantages, disadvantages and historical reasons why the ISO/RTO chose the approach, after accounting for stakeholder input and regional considerations.

1.2.1. Load Ratio Share (Postage Stamp)

The Load Ratio Share method, often referred to as the Postage Stamp approach, allocates transmission costs across a defined geographic area in proportion to load. Load can be stated in

[5] Conversations with Hannes Pfeifenberger, The Brattle Group (March 14, 2025), and Abe Silverman, Northeast States Collaborative on Interregional Transmission (March 24, 2025).
[6] For MISO, MVPs are transmission projects that deliver multiple values (reliability, economic, public policy), have broad geographic benefits, have a project cost greater than $20 million, and operate at voltages greater than 100 kV. See Attachment FF of the MISO tariff, https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

terms of electricity consumption (e.g., monthly or annual), coincident system peak demand,[7] or non-coincident local peak demand. This approach implicitly assumes that all users of the grid derive proportional benefit from the regional transmission infrastructure and that allocation based on usage reflects relative benefit.

The primary advantages of the Load Ratio Share method are its transparency and ease of implementation, including updates that reflect changing demand patterns over time (as frequently as monthly). By aligning costs with usage, the Load Ratio Share method can mitigate free ridership and incorporate intangible benefits that are difficult to quantify and monetize. The primary disadvantage of this method is that the shares may not be well aligned with actual use of the transmission system. For example, a sub-region with high peak demand could have high transmission charges even if a significant portion of the load does not actually use the transmission system. Load Ratio Shares could further misalign costs and benefits if cost allocation is based on overall consumption instead of coincident peak usage.

CAISO, ERCOT, and ISO-NE allocate costs for all or most transmission projects using Load Ratio Share. MISO used this method for allocating MVP costs approved in 2011. The MVP process later became the Long Range Transmission Planning (LRTP) process. MISO continues to use Load Ratio Share for LRTP projects.

MISO adopted Load Ratio Share for MVP to address two problems.[8] First, MISO did not have an established cost allocation method for regional projects that could deliver multiple values — reliability, economic, and especially public policy. Second, at the time MISO's generator interconnection process allocated 50% of network upgrade costs triggered in interconnection to generators and 50% to local zones, even if upgrades were for generation that would mainly serve customers in other load zones. MISO had many new wind projects in remote areas that were large relative to utility loads in those areas, so allocating 50% of interconnection-related upgrade costs to the local zone was unsustainable.[9] After extensive stakeholder deliberations, MISO ultimately settled on a compromise solution that would: (a) change cost allocation for generator interconnection so that generators would pay for most network upgrade costs (see section 1.1) and (b) allocate costs for MVPs to loads on a Load Ratio Share basis.[10] MISO chose Load Ratio Share for MVP cost allocation because it is administratively straightforward and allocates costs based on benefits roughly commensurate with costs, particularly for portfolios of transmission investments.

[7] Coincident peak (CP)-based allocation can be based on annual coincident peak, an average of CP demands over two or more months, or several of the highest peak demand hours. PJM uses a 5-CP allocation for Load Ratio Share of some reliability projects, based on the five highest coincident demand hours in any month during June, July, August, and September.
[8] David Boyd and Edward Garvey, 2021. "A Transmission Success Story: The MISO MVP Transmission Portfolio." https://www.aeslconsulting.com/wp-content/uploads/2021/11/MISO-MVP-History.pdf.
[9] For instance, Boyd and Garvey (2021) describe the example of Otter Tail Power, which had about 600 MW of load and 10,000 MW of wind generation seeking to interconnect in the utility's zone.
[10] Other final proposals for cost allocation methods in these deliberations allocated some costs to generators and some costs to loads, and either changed interconnection allocation or left it as is. For a fuller discussion, see section IV of Boyd and Garvey (2021).

1.2.2. Zonal (License Plate)

The Zonal method, commonly known as the License Plate approach, assigns transmission costs to the sub-region of the transmission investment, based on the zones in which the infrastructure is located. Load-serving entities (LSEs) in the zone where an investment is made are responsible for its associated costs. This method is most often used for lower voltage or local facilities and can be incorporated into hybrid cost allocation approaches for broader regional systems.

While the Zonal method is straightforward and easy to implement at a local level, it presents challenges when applied to large regional lines that cross multiple zones. Disadvantages include potential lack of alignment of costs with sub-regional benefits and inadequately capturing non-monetary benefits, increasing the potential for free ridership, especially as usage patterns change over time.

Some RTOs/ISOs, including MISO and SPP, apply the Zonal cost allocation method for lower voltage projects that are located within a single sub-region. While these projects may deliver modest, secondary benefits to other zones, planners can reasonably expect that the local sub-region is the major driver for the investment and receives a vast majority of the benefits. Therefore, a more complicated cost allocation method that may be more difficult to implement is unnecessary.

1.2.3. Highway-Byway

The Highway-Byway approach is a hybrid model that allocates costs according to the voltage level of transmission projects, combining elements of both the Load Ratio Share and Zonal methods. Under the Highway-Byway approach, costs for lower voltage lines are allocated to the local sub-region using the Zonal method, because smaller transmission projects have more localized benefits. Costs for high-voltage lines are allocated based on Load Ratio Shares, because larger transmission projects deliver broad regional benefits.

Highway-Byway cost allocation seeks to balance fairness and simplicity by recognizing that larger infrastructure projects have more widely shared benefits, and thus costs are allocated based on sub-regional Load Ratio Shares. However, this approach has the same issues as its component methods – Load Ratio Share and Zonal – most notably that costs may not reflect the actual geographic distribution of benefits.

The SPP Highway-Byway method applies a Load Ratio Share that allocates 100% of costs to the entire region for transmission lines at 300 kV and above (Table 1-3) due to the broad regional benefits for these higher voltage lines, including to integrate wind generation facilities to meet state goals. Transmission lines at 100 kV and below apply the Zonal method, considering primarily local expected benefits. For transmission lines above 100 kV and below 300 kV, 33% of costs are allocated regionally, and the remaining 67% is based on zone. SPP chose this hybrid method after extensive stakeholder input and determining that it appropriately allocates transmission costs in correlation with benefits of the enhancements.[11] In 2010, FERC approved the SPP method, ruling that "the

[11] Southwest Power Pool. "The History of The Regional State Committee for the Southwest Power Pool." April 2023. https://www.spp.org/documents/58610/history%20of%20rsc%202023.pdf.

proposed Highway/Byway methodology is an important step in facilitating investment in new transmission facilities to integrate the eastern and western portions of the SPP grid, reduce congestion, efficiently integrate new resources, and accommodate new or growing loads."[12]

Table 1-3. SPP Transmission Highway-Byway Cost Allocation Method

VOLTAGE	REGIONAL	ZONAL
300 kV and above	100%	0%
Above 100 kV and below 300 kV	33%	67%
100 kV and below	0%	100%

Source: SPP (2023)

1.2.4. Granular Approach (Beneficiary Pays)

The Granular or Beneficiary Pays approach relies on modeling to estimate and attribute the benefits of transmission projects. The transmission provider uses these granular benefit calculations, including monetary savings and reliability improvements, to proportionally allocate costs. This approach aims to align cost responsibility closely with the value received and is often applied at the time of project approval using forward-looking scenarios.

The primary advantage of the Granular approach is that it provides a clear basis for allocating costs in proportion to benefits, particularly for large regional projects. However, it may be challenging to achieve broad stakeholder acceptance of this approach due to its complexity. In addition, the Granular approach relies heavily on modeling assumptions, input data, and long-term forecasts that may prove to be inaccurate.

Currently, the Granular approach is used primarily for allocating the costs of economic (market efficiency) transmission projects. Transmission providers use production cost models to estimate the congestion mitigation benefits of new transmission to different zones, and allocate the costs of new economic transmission on the basis of these benefits.

1.2.5. Power Flows

The Power Flows method allocates transmission costs based on power flows through transmission facilities, typically quantified using distribution factors. This approach seeks to align costs with those who most directly cause transmission reliability issues or most directly use new transmission capacity.

The Power Flows method allocates costs based on estimated use of transmission facilities, and is thus consistent with allocating costs commensurate with benefits. However, the Power Flows approach typically relies on power flow modeling and tends to be complex and less transparent. In addition, it

[12] Docket No. ER10-1069-000.

may be more difficult to allocate the costs of new transmission for some drivers, such as power system stability or transmission congestion, based solely on power flows.

PJM uses solution-based distribution factors to allocate a portion of the cost of regional transmission facilities and some lower voltage transmission facilities. "Solution-based" distribution factors are power flows on the transmission solution (e.g., a new line), rather than on the facilities with the reliability issues that led to the solution.

1.2.6. Public Policy Supplement

ISO-NE's Longer-Term Transmission Planning (LTTP) process facilitates achievement of state policy-based goals by enabling development of transmission infrastructure. For projects with a benefit-to-cost ratio greater than 1.0, cost allocation follows a "core process" where all costs are allocated to the entire ISO-NE footprint on a Load Ratio Share basis. An important distinction for ISO-NE's process is that for projects with a benefit-to-cost ratio below 1.0, states may use a supplemental process to agree to pay the costs of the project.

Under the Public Policy Supplement, the portion of costs that fall below this threshold are allocated to all six New England states based on their respective Load Ratio Share (using the *ex ante* cost allocation method).[13] Remaining costs in excess of the 1.0 benefit-to-cost ratio threshold are allocated to one or more states that voluntarily elect to fund remaining costs. As an example, if a project has a benefit-to-cost ratio of .95, 95% of costs would be allocated to all New England states on a load share basis, and one or more states would fund the remaining 5% of costs.

The advantage of ISO-NE's supplemental process is that all states pay for the regional benefits they receive from public-policy driven projects, while still providing a path for states to elect to move projects forward when some costs and benefits may not be regionalized.

The approach in ISO-NE evolved from transmission planning reforms developed between the six New England states, organized through the New England States Committee on Electricity (NESCOE) and ISO-NE. NESCOE issued a vision statement supporting "the efficient use of existing transmission facilities and the construction of new facilities, where necessary and appropriate, to ensure the transmission grid's reliability, efficiency, and ability to integrate clean energy resources, consistent with certain States' legal requirements and other mandates." ISO-NE worked with NESCOE and other stakeholders to develop a longer-term transmission planning process to develop rules and cost allocation processes to facilitate this vision.

[13] Under FERC Order 1920-A, an *ex ante* cost allocation method is one that is agreed upon by Relevant State Entities and filed with FERC in advance of a long-term transmission planning cycle. See FERC, 2024. Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, Order 1920-A, 189 FERC ¶ 61,126, https://www.ferc.gov/media/e-1-rm-21-17-001.

1.3 Cost Allocation in Other Countries

Transmission cost allocation in other countries can provide useful reference points, but comparisons must be kept in context. PJM is much larger than many countries. This section uses examples to illustrate a few key areas and points, but is not intended to be a comprehensive review.

- **Cost allocation to loads and generators.** In Europe, half of the 36 countries covered in a 2021 survey of transmission tariffs in the European Network of Transmission System Operators for Electricity (ENTSO-E) allocate all transmission costs to loads.[14] Only 9 countries allocate more than 10% of transmission costs to generators, mostly through connection charges.[15] For instance, the United Kingdom's Transmission Network Use of System (TNUoS) charge is a location-based tariff that applies to: (1) generators based on their interconnection capacity and (2) retail suppliers based on their transmission use.[16] In some larger countries, such as China and India, costs for interstate (or interprovincial) transmission have often been incorporated into charges for generation that exports across states (provinces).[17]
- **Challenges of interstate or cross-border cost allocation.** Cost allocation for interstate (interprovincial) transmission in larger countries or cross-border transmission is often bilateral and separate from within-state/province or within-country transmission. For instance, costs for most interprovincial transmission in Canada have been bilaterally negotiated.[18] In China, interprovincial transmission costs are mostly paid for by wealthier importing provinces as part of national development strategy. In Europe, cross-border transmission costs are often shared through bilateral agreements for individual projects.[19] In India, the interstate transmission system is effectively separate from the intrastate system, both from a regulatory and an operational perspective.
- **Use of distribution factors.** Few countries use distribution factors to allocate transmission costs. To our knowledge, the only other country that uses distribution factors is India.[20] Limited use of distribution factors may be due more to their complexity than the accuracy of allocating benefits.
- **Diversity in cost allocation designs.** Some countries have multi-part designs for cost allocation mechanisms. For instance, Germany uses a two-part tariff to allocate transmission costs (load ratio share to loads), with a peak demand charge (€/kW) and an energy usage (€/kWh) charge.[21] The UK's TNUoS tariff is based on generation interconnection capacity (£/kW) and peak demand usage (£/kW per month).

[14] ENTSO-E (2022).
[15] *Ibid.* and ACER (2023).
[16] For more see, https://www.neso.energy/industry-information/charging/tnuos-charges#tnuos-tariffs.
[17] In China, costs for transmission between provinces are paid on a per transaction (yuan/kWh) basis, which is effectively a charge on generators that export between provinces. In India, designated interstate transmission system customers, including interstate generators, pay for the interstate transmission system. Transmission charges are rolled in to generation tariffs.
[18] For more on the challenges of building an interregional transmission system in Canada, see E3 (2022).
[19] These agreements appear to be negotiated allocations of individual project costs. For an example, see https://www.cre.fr/fileadmin/Documents/Actualites/import/Delib_2023-75_Decision_VE_01.pdf.
[20] CERC (2020).
[21] See https://www.netztransparenz.de/en/About-us/Grid-fees.

2. Transmission Cost Allocation to Generators and Customer Classes

Regional transmission costs are allocated at two levels: (1) RTO/ISO to Transmission Owners and (2) Transmission Owners to retail customers. Cost allocation methods vary between RTOs/ISOs as well as between these two levels.

2.1 Methods in Use for Cost Allocation to Generators

As discussed in section 1.1, in the United States allocation of transmission costs to generators primarily occurs through interconnection. In most RTOs/ISOs, generators are responsible for transmission costs to connect the generator to the grid and may be responsible for broader upgrades to the transmission system. This section provides a more detailed summary of interconnection cost allocation to generators by RTOs/ISOs.

Generation projects typically cannot request information on interconnection costs before entering the queue. In addition to costs for direct connection, there also may be broader transmission network upgrades required to meet reliability standards. If a new generator causes reliability violations, the generator may be required to pay for transmission network upgrades. Specific requirements, rates, and tariffs vary across RTOs/ISOs. Interconnection costs vary significantly across projects, with some having very high $/kW costs. High interconnection costs appear to influence firm behavior as withdrawn projects tend to have higher costs.[22]

PJM: Generators are responsible for both direct connection and network upgrade costs. When multiple projects benefit from a network upgrade, costs are allocated among them as specified in PJM Manual 14H. PJM employs a "first-ready, first-served" cluster process. Generators pay for 100% of attachment facilities that connect a project to the transmission grid. If a system upgrade is required to interconnect the project, the project pays 100% of those costs. If multiple projects benefit from an upgrade, costs are allocated to each project's contribution to the need. In addition to these interconnection costs, PJM issues a Cost Responsibility Assignment report assigning upgrades and costs to each generator. The costs are split based on relative MW impacts using DFAX.

CAISO: Generators pay 100% of attachment facility costs and local network upgrades at or near the point of interconnection. Generators also pay for reliability network upgrades. In addition, a deliverability assessment is conducted to allocate costs associated with deliverability of energy to load centers. Generators fund the initial cost of network upgrades but are reimbursed over time.

NYISO: Generators pay 100% of attachment facility costs. If system upgrade facilities are necessary to maintain system reliability due to the interconnection of a new generator, the generator pays 100% of the upgrades if they are not part of the Annual Transmission Baseline Assessment. The generator's cost is adjusted accordingly if a developer's project reduces the need for other planned upgrades. Generators also are responsible for system deliverability upgrades that ensure the generators' output can be delivered to load centers.

[22] Seel et al., 2023.

SPP: Generators are responsible for 100% of attachment facility costs. They also are responsible for network upgrades to maintain system reliability due to interconnection. SPP established two funding mechanisms for network upgrades: (1) the generator pays the costs during project construction and (2) the transmission owner may pay network upgrade capital costs upfront, and the interconnecting generator pays back those costs over time.
SPP uses the Highway/Byway methodology for allocating costs of transmission projects.

ISO-NE: Generators are responsible for 100% of attachment facility costs and system reliability upgrades required due to the interconnection. ISO-NE allows the generator to choose between direct funding during construction or repayment over time, with the transmission owner paying the capital costs. ISO-NE makes a distinction between large (>20 MW) and small (≤20 MW) generators in terms of study requirements. Large generators have a more extensive study requirement that generally involves additional modeling, data, and time.

MISO: Generators are responsible for 100% of attachment facility costs. They also are responsible for costs of system reliability upgrades due to interconnection. They pay 90% of upgrade costs for projects ≥345 kV and 100% for projects < 345 kV. Generators are not responsible for costs associated with MVP or LRTP projects. Currently, cost allocation for MVP or LRTP projects is assigned 100% to load, based on the sum annual revenue requirements divided by the proportion of the sum of load. MISO considered but did not adopt a proposal that would have allocated costs to generators and load according to a 20/80 split. The proposal also would have added a weighted sum of annual generation to the denominator. This would create a cost allocation to generators based on generation ratio that is essentially the same as the load ratio-based cost allocation currently in use.

Transpower: This New Zealand-owned enterprise provides the infrastructure and market systems that connect generators to major electricity users and distribution networks that deliver electricity to homes and businesses around the country (but does not own, generate, or sell electricity). Transpower uses a cost allocation method that includes generators in addition to loads. They estimate the market benefits for a generator or generator group as the change in profits. $Price \times generation - fuel\ cost$ is estimated for a scenario with the generator group, and for a counterfactual scenario without the generator. The difference in profit to the generator between the two scenarios is considered the generator's benefit. For cost allocation purposes, each generator and load group are allocated the sum of the required costs divided by their share of the estimated benefits.

Most RTOs/ISOs have transitioned interconnection studies from a serial process that studies interconnecting projects one by one to a cluster process that studies projects in groups. FERC mandated cluster study processes in Order 2023. They allow for the costs of network upgrades triggered in interconnection to be allocated across multiple projects. This partially addresses the “first mover” problem, in which generators are reluctant to connect in certain areas of the transmission system because they would have to pay all of the costs for network upgrades, even if generators that connect later would use these upgrades.[23]

[23] Before Order 2023, some RTOs/ISOs developed cost-sharing mechanisms that require later-in-time generators to reimburse earlier-in-time generators for network upgrade costs. These mechanisms have historically been controversial.

Another approach to address the first mover problem is CAISO's "location constrained resource interconnection policy," developed in the late 2000s. The tariff developed under this policy, for new transmission that meets certain criteria, provides for interconnecting generators to reimburse transmission owners over time.[24] SPP's consolidated planning process, which integrates interconnection and transmission planning into a single process, has considered a similar tariff-based approach.[25] The tariff-based approach shares costs more equally with generators, but may require ratepayers to pay for the costs of any underutilized line, relative to the forecasted need for the line.

2.2 Literature on Cost Allocation to Generators

A variety of methods for cost allocation have been developed and extended to generators. Following are mathematical descriptions for all of the methods currently in use, as well as some that have been developed in academic literature but have not been adopted by any RTO or ISO.

2.2.1 Load/Generation Ratio

Cost allocation according to load ratio is used by several regional grid operators including PJM and MISO. It is based on the load's proportion to total load or peak load. This type of cost allocation can be extended to generators using the same principle, allocating costs in proportion to generation. This method can include a weighting factor. This factor can calibrate the overall share that is to be paid by load vs. generators.

When a weighting factor is included, the formula for the tariff to generator g is:

$$\frac{Annual\ Generation_g \times Weight\ factor \times \sum_{rr=1}^{RR} Annual\ Revenue\ Requirements}{\sum_{l=1}^{L} Annual\ Load + Weight\ factor \times \sum_{g=1}^{G} Annual\ Generation}$$

The drawback to this type of cost allocation method is that it is based on annual generation and does not consider the location of the generator in relation to the transmission line(s). If power flows on a transmission line from export region to import region, a generator located in the export region will benefit from the line, and cost allocation to such generators is reasonable. However, generators that are located in the import region do not benefit from the transmission line and will often be disadvantaged by the presence of the line. Allocating costs to such import region-located generators would not satisfy requirements of allocating costs in approximate proportion to benefits.

2.2.2 Economic Disaggregation

A set of papers have developed a methodology for estimating the benefits of transmission according to standard microeconomic theory to develop metrics to estimate the benefits to consumers,

[24] For more information on the location constrained resource interconnection policy, see https://www.caiso.com/library/location-constrained-resource-interconnection-policy.
[25] For more information on the consolidated planning process, see SPP, Consolidated Planning Process Task Force, https://www.spp.org/stakeholder-groups-list/organizational-groups/board-of-directorsmembers-committee/consolidated-planning-process-task-force/.

producers, and the transportation industry.[26] In an electricity market, generators can be considered producers, LSEs as consumers, and transmission owners as the transportation industry. Using these principles, the benefits to different stakeholders in the market can be estimated.

The benefits to generators are profits (revenue – cost) over the long term, and producer surplus (revenue – variable operating cost) in the short term. Using this method, the benefits can be computed for generators as a group or for a specific generator within a nodal production cost model. These values can be used to estimate the share of benefits accruing to a specific generator or set of generators. Costs can then be allocated in proportion to the share of benefits to each generator and LSE.

Considering benefits to all stakeholders, and allocating costs appropriately, can improve overall efficiency in two dimensions.

- First, there may be cases where the benefits of transmission expansion to transmission owners and LSEs are less than the costs. However, when generator benefits are included, the overall benefits are sufficiently greater than the infrastructure cost. In this case, if generators are not included as part of the decision-making process, less than optimal transmission will be built.
- Second, there may be incentives for some market participants to free-ride on the benefits. If all beneficiaries are not included in the cost allocation, cooperation can be reduced and less than efficient amounts of transmission may be built.

This method is in use currently in New Zealand's transmission planning process. It also has been applied to some long-term planning research studies, but those studies did not include actual cost allocation.[27] The European Union study used modeled wholesale power market prices to estimate the benefits. The U.S. national transmission planning study used modeled power purchase agreement contracts to model prices.

2.2.3 Power Flow Based

Several transmission cost allocation methods have been proposed based on power flow modeling. Lima et al. (2009) reviewed several of these methods, including pro rata (load/generation ratio), proportional sharing factors, equivalent bilateral exchanges, power flow sensitivity, and Z-bus network matrix. All of these methods can allocate costs to generators and load.

While the choice of method can be based on desired tariff properties, there is no clear best method in all dimensions. Load/generation ratio provides stability and continuity in the tariffs, but does not incorporate new investments well and provides poor locational estimates. The proportional share factors method incorporates new investments well, but provides less tariff stability. Z-bus is recommended as the overall middle ground method, yielding good performance across the measures considered, but other methods outperform it in specific measures.

[26] Hogan 2018; CAISO 2017.
[27] Seel et al., 2023.

2.2.4 Game Theoretic

Several papers outline cost allocation methods based on game theoretic approaches. These approaches draw from the concept that building transmission infrastructure often requires cooperation among groups that are primarily looking to serve the interests of their own constituents. Game theory has developed methods that are most likely to create and sustain cooperation in these situations.

Kristiansen et al. (2018) show how the Shapley Value[28] can be used to make cooperation most likely in a situation where any region can veto a line that goes through its territory. This approach can be valuable in situations where a portfolio of transmission lines provides the largest overall benefits (i.e., is the most cost-effective), but where individual lines are not beneficial to all regions. Approving each line individually is likely to result in one or more regions exercising a veto on each line, resulting in few projects and a more costly overall system. The Shapley Value approach produces a cost allocation that minimizes incentives that individual regions may have to opt out of cooperation. Using a cost allocation approach based on the Shapley value would increase the likelihood of building the most cost-effective portfolio of projects through cooperation amongst the regions.

Mays (2017) introduced a cost allocation approach based on the Shapley Value that incorporates both generation and load. The approach examines how changes in load or generation affect locational marginal prices in the system, allocating transmission costs accordingly. Khan et al. (2016) developed a game-theoretic cost allocation approach based on attributed transmission line losses. An advantage is that the fraction allocated to generators vs. load is estimated as part of the modeling, whereas the load/generation ratio method must decide on the weighting factor without a guiding model estimate.

2.3 Cost Allocation to Specific Customer Classes

This section provides examples of retail rates and payments for costs allocated to specific customer types, or classes, or to an individual customer outside of the regional transmission planning process.

2.3.1 Cost Allocation by Utilities

Allocation of transmission costs to customer classes. The standard process for allocating costs to specific types of retail customers is through the utility ratemaking process.[29] The ratemaking process for transmission cost allocation typically begins with a utility cost-of-service study that estimates the annual revenue requirement for the utility for transmission, distribution, energy and other costs. Based on the study, the utility estimates the portion of the revenue requirement to be recovered from different customer classes—including residential, commercial, and industrial—based on cost causation.

[28] *In cooperative game theory, the Shapley value is a method (solution concept) for fairly distributing the total gains or costs among a group of players who have collaborated.* Wikipedia (n.d.).

[29] As discussed elsewhere in this document, RTOs and ISOs initially allocate costs to transmission operators and large customers separately during the long-term transmission planning process.

For regulated utilities, the public utility commission determines rates for each customer class. Rate structures vary by customer class. Billing determinants typically include fixed charges (dollars per month) and variable charges based on electricity usage (cents per kWh). Large customers typically also pay demand charges ($/kW) based on peak demand.[30] Utilities also may allocate costs to different customer classes based on voltage levels or regions. That allows for more targeting of transmission costs to beneficiaries where transmission infrastructure is used.

Allocation of transmission costs to a specific customer. If a large-load customer is the primary or sole beneficiary of a dedicated transmission line, the cost is not allocated to a customer class broadly. Instead, the cost is assigned to a single customer. For example, Xcel Energy's negotiated rate for transmission for a Google data center in Minnesota is reputed to fully pay for the cost of energy delivery and not raise cost for other customers.[31] Entergy in Arkansas negotiated with Big River Steel to provide 450 MW of energy for a steel mill. Under a special rate, Entergy paid $73 million for transmission lines.[32]

Consumer advocates have raised concerns that such direct assignment of costs to a single large customer do not always cover the full costs of transmission infrastructure. Martin and Peskoe (2025)[33] make five recommendations to properly assign costs to the cost causer—in this case, a data center: "A) establishing guidelines for reviewing special contracts, B) shifting new data centers from special contracts to tariffs, C) facilitating competition and the development of "energy parks" that are not connected to any utility-owned network, D) requiring utilities to provide more frequent demand forecasts, and E) allowing new data centers to take service only if they commit to flexible operations." Direct payment by the large-load customer of the revenue requirement for transmission infrastructure, instead of payment through retail rates that are designed based on usage or peak demand, also can address this issue.

2.3.2. Cost Allocation by Others

Bonneville Power Authority (BPA) has a provision in its transmission tariff schedule that allows for direct assignment of costs to a specific customer. This allows BPA to collect capital and related costs under an advance funding rate or use-of-facilities rate. The provision can apply when transmission infrastructure is built for the sole use and benefit of a particular customer.[34]
Similarly, SPP's transmission tariffs include a provision for direct assignment of facilities that are constructed "for the sole use/benefit of a particular transmission customer or a particular group of customers or a particular Generation Interconnection Customer requesting service." In these cases, the transmission customer is charged the full cost of the transmission facilities.[35]

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[30] Lazar, J., Chernick, P., Marcus, W., and LeBel, M., 2020. Electric Cost Allocation for a New Era. *Regulatory Assistance Project*. https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.
[31] https://mn.gov/puc/about-us/news/archives/index.jsp?id=14-384560.
[32] https://goentergy.com/big-river-steel-mega-project-selects-arkansas-for-groundbreaking-mill.
[33] Martin, E. and Peskoe, A. (2025) ***Extracting profits from the public: How utility ratepayers are paying for Big Tech's power***. Cambridge, MA: Harvard Law School Environmental & Energy Law Program. Available at: https://eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf
[34] https://www.bpa.gov/-/media/Aep/rates-tariff/current-power-rates/2024-Final-Proposal-Transmission-Rate-Schedules-and-GRSPsFERC-approved.pdf.
[35] https://www.spp.org/documents/11238/4%20-%20attachment%20j%20highway-byway%20rtwg%20010610.doc.

PJM's OATT also includes a provision for direct assignment of facilities charges, when "PJM determines that the Transmission System is not capable of providing Firm or Non-Firm Point-to-Point Transmission Service without:

- Degrading or impairing the reliability of service to Native Load Customers, Network Customers, and Transmission Customers taking Firm Point-to-Point Transmission Service, or
- Interfering with PJM's ability to meet prior firm contractual commitments to others."

In this case, the customer must agree to compensate the transmission owner(s) for 100 percent of the necessary additions.[36]

ISO-NE includes a direct assignment facility charge, as well. Rather than paying the full cost of the transmission investment upfront, the customer pays a monthly flat fee based on the annualized cost of the investment. This fee is calculated by spreading the total cost of the investment over its expected lifetime to compute the annual revenue requirement, which is then divided into monthly installments.[37]

3 Planning Approaches and Stakeholder Processes for Public Policy Projects

All RTOs/ISOs have processes in place to consider public policy in electric transmission planning and cost allocation based on the FERC Order 1000 requirement that local and regional transmission planning processes consider transmission needs driven by public policy requirements in state or federal laws or regulations.[38] These processes vary significantly. FERC Orders 1920 and 1920-A enable expanded state oversight and more comprehensive long-term transmission planning.

Cost allocation for regional public policy-driven projects is often fraught with disagreement due to differing state goals and objectives and reluctance to pay for transmission in one state that enables few opportunities for another state's economic development, such as job creation. This section provides an overview of U.S. RTO/ISO cost allocation methods and mechanisms for public policy projects, as well as stakeholder processes.

PJM: PJM allows states to propose public policy projects through its State Agreement Approach (SAA), "… a provision in PJM's Operating Agreement [Schedule 6, section 1.5.9] that enables a state to propose a transmission project for inclusion in PJM's Regional Transmission Expansion Plan that advances that state's Public Policy Requirements, as long as the state agrees to assume the cost of the project's build-out."[39] The first state to use this approach was New Jersey, in 2021, to address its offshore wind goals in PJM's regional transmission planning process.[40]

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[36] https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m27/m27v98-open-access-transmission-tariff-accounting-06-01-2023.pdf
[37] https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch21/sch_21_nep.pdf
[38] https://www.ferc.gov/sites/default/files/2020-04/OrderNo.1000.pdf
[39] https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/the-state-agreement-approach.pdf
[40] https://www.nj.gov/bpu/about/divisions/ferc/saa.html

The advantage of the SAA process is that it provides an avenue for states in PJM to advance their public policy requirements through developing transmission infrastructure. The disadvantage of the process is that the state (or group of states) pursuing projects through the SAA are responsible for project costs, and no costs may be recovered from customers in states that do not agree to be responsible for those project costs. This provision can potentially result in benefits received not being commensurate with allocation of costs — for example, if states that do not pay for costs of public policy-driven transmission infrastructure yield benefits. In FERC Order 1920-A, the Commission allowed continue use of this existing approach if PJM and the Relevant State Entities in the region agree, and if PJM "... propose[s] and demonstrate[s] on compliance that its State Agreement Approach complies with all of the State Agreement Process requirements set forth in Order No. 1920."[41]

Stakeholder processes: The New Jersey Board of Public Utilities (NJBPU) developed a State Agreement Approach Process Guidance Document that provides an overview of the timeline and mechanics of the solicitation process which they coordinated with PJM.[42] On April 1, 2024, FERC approved[43] PJM and NJBPU's second SAA Study Agreement (SAA 2.0).[44]

ISO-NE: In compliance with Order No. 1000, ISO-NE allocated 70% of the costs of public policy-driven projects on a regional load-ratio basis and 30% to states with public policies driving the need for the projects. On July 8, 2024, FERC approved[45] ISO-NE's LTTP and Cost Allocation Proposal (ER24-1978)[46] which provides another path for public policy-driven projects.

ISO-NE's LTTP was pursued in two phases. Phase 1 developed a long-term transmission planning process to advance state-level policy-based objectives, approved by FERC. New England states can request system planning analyses to identify transmission infrastructure necessary to meet state energy policies, mandates, or goals. Phase 2 develops a process for states to move any identified transmission upgrades into developable projects and includes a cost allocation mechanism.

States agreed to use a benefit-to-cost ratio greater than 1.0 to select potential solutions. Cost allocation follows a "core process" where all costs are allocated to the entire ISO-NE footprint on a load ratio share basis,[47] although states can request an alternative cost allocation method. For projects that do not meet the benefit-to-cost threshold, states may use a supplemental process to agree to pay the costs of the project. Under this process, the portion of costs up to the benefit-to-cost ratio of 1.0 are allocated to all six New England states based on their respective load ratio share

[41] These include that cost allocation methods must be just, reasonable, non-discriminatory, and non-preferential, and must allocate costs in a manner that is roughly commensurate with estimated benefits. See https://www.ferc.gov/media/e-1-rm-21-17-001 (p. 207).
[42] https://www.nj.gov/bpu/pdf/ofrp/SAA%20Process%20Overview.pdf.
[43] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=6dc0c592-a85f-cebb-9454-8e9b8bc00000.
[44] https://www.pjm.com/pjmfiles/directory/etariff/FercDockets/7935/20240202-er24-1187-000.pdf.
[45] https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-iso-nes-longer-term-transmission-planning-and.
[46] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240708-3091&optimized=false.
[47] As referenced in the Notational Order ER24-1978-000, this cost allocation method is identical to ISO-NE's Order No. 1000 regional cost allocation method for Regional Benefit Upgrades. These are transmission upgrades that: (i) are rated 115 kV or above; (ii) meet all of the non-voltage criteria for Pool Transmission Facility classification specified in the Tariff; and (iii) are included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the Tariff.

(using the ex-ante cost allocation method). Remaining costs are allocated to one or more states that voluntarily elect to fund the project. As an example, if a project has a benefit-to-cost ratio of .95, 95% of costs are allocated to all New England states on a load ratio share basis, and one or more states would fund the remaining 5% of costs.[48]

The advantage of this approach is that all states pay for the regional benefits they receive from public-policy driven projects. That's a key difference from PJM's State Agreement Approach, which requires a single state to pay the entire cost of a project to serve its public policy needs, even if other states benefit.[49]

Stakeholder processes: ISO-NE worked with the New England States Committee on Electricity (NESCOE) and stakeholders to develop rules that would enable the region's states to seek solutions to the longer-term needs identified and create a cost allocation framework for the associated transmission infrastructure.[50]

MISO: MISO includes public policy drivers in its LRTP process, which considers future planning scenarios with different economic, policy, and technology requirements to inform capacity expansion modeling over a 20-year planning horizon. To inform scenarios, MISO relies on stakeholders, policy directions, and industry trends to make plausible assumptions that identify transmission needs and enable solutions for states and utilities to meet energy transition goals.[51] MISO develops distinct "tranches" (portfolios) of LRTP projects for the planning scenarios. Currently, four tranches consisting of 18 projects create a new backbone of transmission for the region.

Cost allocation is an integral component of the LRTP process. MISO's tariff requires a roughly commensurate "beneficiaries pay" approach to cost allocation. For projects with public policy drivers, MISO uses an MVP cost allocation mechanism, allocating costs to the subregion where benefits are realized.[52]

The advantage of MISO's MVP cost allocation mechanism is that it is relatively simple to apply, *provided* that the cost allocation for the tranche (via load ratio share) is roughly commensurate with overall benefits. A robust planning and selection process is used to develop a portfolio of beneficial transmission projects.

Stakeholder processes: MISO's MVP cost allocation mechanism arose from a lengthy stakeholder process where state governors, public utilities, transmission owners, and other stakeholders worked to promote development of renewable energy zones to meet state policy objectives while balancing

[48] https://www.iso-ne.com/static-assets/documents/100007/a04.2_2024_01_23_tc_nescoe_supplemetnal_process_ltts.pdf.
[49] https://blog.advancedenergyunited.org/nescoe-and-iso-ne-trailblaze-on-transmission-planning-and-procurement-ahead-of-ferc-ruling#:~:text=Phase%202%2C%20the%20LTTP%20framework%20ISO%2DNE%20just,transmission%20solutions%20to%20meet%20our%202050%20goals.&text=Perhaps%20the%20most%20significant%20aspect%20of%20Phase,amongst%20all%20six%20states%20on%20cost%20allocation.
[50] https://nescoe.com/wp-content/uploads/2024/05/NESCOE-Comments-ER24-1978.pdf.
[51] https://www.misoenergy.org/planning/futures-development/.
[52] https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

fairness and economic development opportunities between states. Notable stakeholder processes that paved the way for MISO's LRTP process and MVP cost allocation approach are the Regional Expansion Criteria and Benefits Task Force and the Cost Allocation and Regional Planning Initiative.

As discussed earlier in this brief, MISO's legacy tariff specified that 50% of network upgrade costs were allocated to the interconnection customer and 50% to the local load zone, and limited other cost allocation models.[53] To address these cost allocation issues, MISO stakeholders developed the Regional Expansion Criteria and Benefits Task Force, a forum for discussing cost allocation policies for transmission projects with regional or interregional costs and benefits. The task force developed cost allocation principles, including the following:[54]

- *Eliminate/Minimize Free Riders: The transmission cost allocation methodology should allocate the costs of lumpy transmission upgrades to all present and future beneficiaries from those upgrades.*
- *Ensure the "Right" Loads Pay: The cost of transmission upgrades should be borne by the loads benefiting from those investments even if they are remote from the transmission investment and/or affected generation.*
- *Reflect Changing System Usage Over Time: The cost allocation should be able to change over time to reflect changes over time in those who benefit from the investments.*
- *Balance Attributes of System Use: The cost allocation should strike a balance among alternative methods for assigning costs:*
    - *The direct causer of a transmission project vs. all beneficiaries.*
    - *Local vs. regional beneficiaries of the transmission project.*
    - *Transmission to meet reliability needs vs. to reduce the cost of energy or to meet environmental goals.*

Concurrently, the Organization of MISO States developed the Cost Allocation and Regional Planning Initiative to educate state regulators, debate options for cost allocation, formulate concepts, and discuss proposals. Stakeholders considered several cost allocation options, became conversant in cost allocation methods, and ultimately decided on a Postage Stamp methodology for its simplicity, provided that benefits were commensurate with costs for a proposed set of transmission projects.[55]

SPP: SPP has used a Highway-Byway cost allocation methodology for allocating costs of public policy-driven projects since its inception.[56] A notable change to the process was proposed by SPP and accepted by FERC in 2022, to allow SPP to regionalize the cost of Byway projects that exported most of their energy to other zones (primarily applied to wind farms) through a cost allocation waiver

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[53] https://www.aeslconsulting.com/wp-content/uploads/2021/11/MISO-MVP-History.pdf.
[54] https://www.aeslconsulting.com/wp-content/uploads/2021/11/MISO-MVP-History.pdf.
[55] https://www.misostates.org/images/stories/meetings/Cost_Allocation_Principles_Committee/Cost_Allocation_Background_20201005_-_MISO.pdf.
[56] SPP highlighted that developing extra-high voltage transmission facilities would provide the flexibility to comply with federal and state energy policies as well as facilitate public policy goals. See https://www.spp.org/documents/12468/2010-06-17_order%20-%20highway-byway%20cost%20allocation_er10-1069.pdf#:~:text=SPP%20also%20states%20developing%20EHV%20transmission%20facilities,resources%20and%20provide%20greater%20access%20to%20a.

process. FERC reversed this decision[57] on rehearing, noting the lack of clear criteria and discretion of the SPP board in determining cost allocation of Byway facilities.

The advantage of SPP's highway-byway cost allocation methodology is that it does allow for cost allocation based on a voltage threshold basis which allocates costs to both regional and local facilities. However, as shown in SPP's cost allocation waiver process for byway facilities, this method can result in benefits not commensurate with costs if most power from local generation facilities (like wind farms in SPP) is exported.

Stakeholder processes: SPP evaluates the need for public policy projects as part of its Integrated Transmission Planning (ITP) Process,[58] which enables robust stakeholder input throughout the assessment.[59] SPP evaluates the need for public policy projects based on curtailment of renewable energy generation, which would prevent utilities from meeting energy-based renewable portfolio standards (mandates or goals). Renewable policy requirements are identified through a renewable policy review process. [60] SPP seeks approval of the renewable policy review from all interested stakeholders, particularly those in the Economic Studies Working Group.[61]

NYISO: In NYISO, the mechanism for incorporating public policy-driven transmission needs is through the Public Policy Transmission Planning Process. The process is part of a comprehensive planning process including local transmission planning, reliability planning, and a congestion assessment and resource integration study. Interested entities can propose, and the New York Public Service Commission (NYPSC) can identify, transmission needs that are driven by public policy requirements. NYISO evaluates proposed solutions and shares findings and recommendations in its Public Policy Transmission Planning report for NYISO stakeholder review.[62] For selected public policy projects, NYISO utilizes a statewide Postage Stamp cost allocation method, based on load-ratio share (a beneficiaries pay approach).[63]

Stakeholder processes: NYISO initiates the public policy process with stakeholders by soliciting proposed transmission needs driven by public policy requirements (defined as federal or New York state statutes or regulations, including a NYPSC order adopting a rule or regulation that may relate to transmission planning). Stakeholders can propose transmission needs within 60 days of the notice. NYISO posts all submittals on its website and submits them to the NYPSC. The NYPSC reviews proposed transmission needs and identifies specific transmission solutions to be evaluated by the NYISO as part of the public policy process. The NYPSC also may independently identify public policy transmission needs during this phase. The agency then posts these needs to the NYISO website, and stakeholders and other interested parties provide input to the NYPSC prior to its final determination

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[57] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230713-3088&optimized=false.
[58] https://www.spp.org/engineering/transmission-planning/integrated-transmission-planning/.
[59] For example, the 2024 ITP process conducted 138 stakeholder working group meetings. https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf.
[60] Renewable policy requirements include those enacted by state laws, public power initiatives, and the courts. https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf.
[61] https://www.spp.org/documents/73639/2026%20itp%20renewable%20policy%20review%20&%20resource%20plan%20-%20phase%201%20transmittal.pdf.
[62] https://www.nyiso.com/documents/20142/2924447/M-36_Public%20Policy%20Manual_v1_0_Final.pdf.
[63] https://nyisoviewer.etariff.biz/viewerdoclibrary/mastertariffs/9TariffSections/OATT_31.5%20FID912%20redline_16588.pdf (see page 30).

of the need. Once NYPSC finalizes public policy transmission needs, it issues a statement to the NYISO, and the NYISO solicits proposals for solutions.[64] NYISO conducts viability and sufficiency assessments and presents them to stakeholders for comment. For projects that pass this phase, the NYISO assesses the solution for efficiency or cost-effectiveness. The results of this analysis are published in the Public Policy Transmission Planning Report for stakeholder review.[65]

CAISO: CAISO includes public policy objectives in its transmission planning and approval process for transmission additions and upgrades needed to support state or federal public policy requirements and directives.[66] The California Public Utilities Commission (CPUC) and CAISO work together in the transmission planning process. The CPUC provides the future portfolio of resources expected to be online. CAISO provides technical analysis to determine the transmission needed to enable the future resource mix the CPUC identifies. CAISO allocates the costs of public policy-driven transmission to all LSEs using a transmission access charge.

Stakeholder Process: CAISO conducts an annual transmission planning process, conducted in three phases with stakeholder feedback. Phase 1 establishes methodologies, assumptions, and models for planning studies that include solutions for public policy mandates. The draft unified planning assumptions and study plan is posted for stakeholder review and comment. In phase 2, CAISO performs studies to identify transmission solutions, presented in an annual comprehensive transmission plan to meet reliability, public policy, and economic-driven needs. CAISO conducts stakeholder meetings throughout phase 2 to gather public comment. Phase 3 is a competitive solicitation process for identified transmission needs. CAISO evaluates proposals based on tariff selection criteria.[67]

4 Considerations Related to Potential Use of Counterfactuals for Transmission Cost Allocation

The PJM Order 1920 flowchart for scenario planning and Long-Term Regional Transmission Planning (LTRTP) timeline[68] indicate the possible use of a counterfactual scenario in the third year of the planning cycle. The LTRTP process includes a Backstop Plan that addresses core long-term needs to meet the 1-in-10 loss of load expectation requirement. PJM has indicated that this Backstop Plan can serve as a counterfactual relative to the Holistic Plan that addresses additional long-term needs, including voluntary commitments.[69] Transmission Owners may use the Backstop Plan to determine how costs from the Holistic Plan are allocated regionally to load and how costs are allocated to states sponsoring Additional Long Term Needs.

64 https://www.nyiso.com/documents/20142/2924447/M-36_Public%20Policy%20Manual_v1_0_Final.pdf.
65 https://www.nyiso.com/documents/20142/2924447/M-36_Public%20Policy%20Manual_v1_0_Final.pdf
66 https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-Study-Plan-2024-2025-Transmission-Planning-Process.pdf.
67 https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-2024-2025-Transmission-Plan.pdf
68 PJM State Outreach Presentation and Session with PARSEC – FERC Order No. 1920. March 27, 2025. Order 1920 flowchart (slide 3) and LTRTP timeline (slide 12).
69 PARSEC Order 1920 Cost Allocation Discussion Topics. April 21, 2025. Counterfactual considerations (slides 6-7).

Many ISO/RTOs, including PJM,[70] MISO,[71] and NYISO,[72] conduct this type of counterfactual analysis for economic (market efficiency) projects to estimate the change in congestion costs with and without a project. Costs are then allocated based on which zone receives the cost reductions (either production costs or market costs). National Lab research has not identified examples of using a counterfactual for cost allocation in regional transmission planning processes other than these economic projects, which have a small set of clearly defined benefits and methods for evaluating them. Nonetheless, this section summarizes considerations for applying counterfactuals to transmission cost allocation.

A counterfactual is a reference scenario, such as a "base case" or "business-as-usual" case, to compare against alternative futures. For example, utilities commonly use a reference case in integrated resource planning, part of a scenario planning framework to find an optimal combination of supply and demand-side resource options to satisfy future energy service demands and public policy requirements in an economic and reliable manner.

In regional transmission planning, a counterfactual could be used to compare estimated benefits attributable to an individual transmission project, or a portfolio of transmission projects, in alternative investment scenarios. Estimated benefits relative to the counterfactual scenario, including distribution of benefits across sub-regions, could inform cost allocation by indicating potential changes in benefits compared to the status quo.

While PJM, MISO, and other RTOs/ISOs have developed and applied planning scenarios, in addition to substantial sensitivity analyses, alternative futures developed focused on project selection, not cost allocation. Effectively applying a counterfactual as part of the LTRTP process would require defining a set of clearly defined benefits and methods for evaluating them, such as when PJM, MISO, and NYISO evaluate the change in congestion costs with and without an individual economic project. Applying a counterfactual to a transmission portfolio that includes a mix of economic- and policy-driven projects (such as the Holistic Plan) would be significantly more complex.

It is unclear how stakeholders may issue a counterfactual request and how it would be addressed in such a short timeframe. PJM currently indicates that a counterfactual request could be made six months prior to board approval of the transmission plan. Conducting and reviewing a counterfactual analysis to inform cost allocation in this timeframe would be challenging. Stakeholders would have to agree on the parameters for the counterfactual scenario and reevaluate the entire transmission portfolio under this scenario. Many changes could result from different planning assumptions. In addition, using a counterfactual to inform cost allocation would require more time for updating the analysis. To the extent that reduced the frequency of updates, it would result in less frequent calibration to changes in demand patterns over time.

[70] https://www.pjm.com/-/media/DotCom/planning/rtep-dev/market-efficiency/2022-me-study-process-and-rtep-window-project-evaluation-training.pdf. The Net Load Payment benefit for a zone is defined as "The change in the Net Load Payment with the addition of the project versus without the project determines the project benefits to the demand zones" (slide 46).
[71] https://docs.misoenergy.org/miso12-legalcontent/Attachment_FF_-_Transmission_Expansion_Planning_Protocol.pdf.
[72] https://www.nyiso.com/documents/20142/2924447/epp_caris_mnl.pdf/6510ece7-e0a6-7bee-e776-694abf264bae.

5 Controversial or Rejected Cost Allocation Proposals

This section analyzes examples of cost allocation proposals that have been controversial or rejected by the courts or FERC (Table 5-1), providing insights on their views on cost allocation for transmission projects that may have regional benefits.

Table 5-1. Court and FERC cases reviewed

Courts	FERC
Dominion v. FERC. Court Order No. 17-1040 (D.C. Cir. 2018)	Southwest Power Pool, Inc., FERC Docket Nos. ER17-2256-000, ER17-2257-000, 161 FERC 61,026 (2017)
Illinois Commerce Commission, et al., v. FERC. Court Order No. 11-3421 (7th Cir. 2013)	Southwest Power Pool, Inc., FERC Docket Nos. ER22-1846-002, ER22-1846-003, 184 FERC 61,028 (2023)
Illinois Commerce Commission, et al., v. FERC. Court Order No. 08-1306 (7th Cir. 2009)	Midcontinent Independent System Operator, Inc., FERC Docket No. ER17-2246-000, 161 FERC 61,004 (2017)
El Paso Electric Company v. FERC. Court Order No. 18-60575 (5th Cir. 2023)	Midcontinent Independent System Operator, Inc., FERC Docket No. ER22-995-000, 179 FERC 61,124 (2022)
Public Service Electric and Gas Company, v. FERC. Court Order No. 19-1091 (D.C. Cir. 2021)	PJM Interconnection, LLC, FERC Docket No. ER24-843-000, 187 FERC 61,012 (2024)

5.1. Courts

The cases examined indicate that the courts will rule in favor of sharing the costs across utilities, so long as the benefits are shared equally across regions. For example, in a case where FERC approved a cost allocation methodology submitted by PJM that eliminated cost sharing for projects undertaken only to satisfy an individual utility's planning criteria, the Court of Appeals for the District of Columbia Circuit held that such decision was arbitrary, since it included high voltage power lines. The Court further stated that, given significant regional benefits of high-voltage power lines in the PJM network, an amendment that prohibits cost sharing for high-voltage projects disregards the regional benefits that accrue to all members of the PJM transmission system. In summary, the Court considered FERC's approval of the cost allocation of some lines to a single utility "arbitrary and capricious," since nearby utilities could benefit from these lines as well (Dominion v. FERC, Court Order No. 17-1040 (D.C. Cir. 2018)).

The Seventh Circuit Court of Appeals reviewed FERC's approval of MISO's cost allocation method for MVPs, which assigns costs across all utilities drawing power from MISO's grid in accordance with the amount of electrical energy used. The Commission's approval was challenged by state utility commissions, industrial customers, electric cooperatives, and a representative for municipalities. The Court reviewed in detail MISO's criteria for a project to be "multi-value": the cost is at least $20 million, it includes high-voltage transmission lines, and it helps MISO members meet state renewable energy requirements, fix reliability problems, or provide economic benefits in multiple pricing zones.

In this case, the Court reviewed MISO's proposal to build wind farms in the Great Plains and the necessary transmission lines to deliver the electricity to urban centers and elsewhere, which MISO estimated to have multiple, across-the-board benefits. The Court upheld MISO's cost allocation method based on the shared benefits it would provide throughout the region (Illinois Commerce Commission, et al., v. FERC. Court Order No. 11-3421 (7th Cir. 2013)).

The Seventh Circuit Court of Appeals reviewed a challenge to a FERC decision concerning the reasonableness of rates for transmission of electricity over facilities owned by utilities that belong to PJM. Specifically, the Court looked into FERC's decision that, for higher-voltage facilities (≥500 kV), all utilities in PJM's region would contribute "pro rata," or that their rates should be raised by a uniform amount sufficient to defray the facilities' costs. The majority held that FERC is "not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members" (pg. 9). It considered that FERC has a duty to compare "the costs assessed against a party to the burdens imposed or benefits drawn by that party" and that it failed to make a reasoned decision based upon substantial evidence. The Court ruled in favor of the petition concerning the pricing of new facilities that have a capacity of ≥500 kV and remanded the case for further proceedings (Illinois Commerce Commission, et al., v. FERC, Court Order No. 08-1306 (7th Cir. 2009)).

The Fifth Circuit Court of Appeals ruled in a case brought by El Paso Electric Company that the "cost causation principle that binds FERC does not authorize it to force its regulated jurisdictional utilities to assume the costs of providing service to non-jurisdictional utilities" (pg. 2). The Court emphasized that all approved rates must reflect, to some degree, the costs actually caused by the customer who must pay them and that benefits should be at least roughly commensurate with costs. Principle 1 of FERC's Order No. 1000 ("cost causation principle"), among other purposes, aims to combat "free ridership" – or an entity receiving benefits it is not required to pay. El Paso Electric Company asked the Court to review FERC's orders implementing Order No. 1000. In the Court's opinion, FERC failed to apply the cost causation principle for approximately half of the utilities in the WestConnect region, since FERC did not explain: (1) why non-jurisdictional utilities have an incentive or obligation to participate in binding cost allocation when they can get many of the same benefits at the jurisdictional utilities' expense and (2) how lack of participation in cost allocation by those beneficiaries would not result in unjust and unreasonable rates. The Court ruled that FERC violated the Federal Power Act's cost-causation requirement since it refused to allocate costs to those who cause the costs to be incurred and who reap the resulting benefits, resulting in a "free rider problem" by non-jurisdictional utilities (El Paso Electric Company v. FERC. Court Order No. 18-60575 (5th Cir. 2023)).

The D.C. Circuit Court of Appeals reviewed three of FERC's orders concerning cost-sharing for certain upgrades to the Mid-Atlantic electricity transmission grid. Specifically, FERC reviewed a project to improve the reliability of three nuclear power plants in New Jersey, which consisted of a new high-voltage transmission line connecting the plants on Artificial Island in the state to the Delmarva transmission zone (Delaware and parts of Maryland and Virginia). In 2016, the Commission approved PJM's cost allocation, which assigned nearly 90% of the cost to the Delmarva transmission zone using the solution-based DFAX method. In 2018, on rehearing, FERC reversed course, considering the cost allocation method violated cost-causation principles and was therefore unjust and unreasonable. The Commission's analysis centered on "analytically unique" stability-related reliability issues that "result from an imbalance of generation and load" and, "depend[ing] on the nature of the problem," can "be either a very local event or spread into a more substantial problem." Therefore, the benefits of a facility built to stabilize a specific generating unit are "not necessarily captured" by measuring power flows. The Commission's new method shifted primary cost responsibility for the Artificial Island Project from the Delmarva zone to utilities in New Jersey. In determining whether the Commission's order was arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law, the Court found that, overall, FERC's decision to grant a rehearing of the 2016 Order was consistent with Order No. 1000, and that its change of position was adequately explained and supported by substantial evidence. (Public Service Electric and Gas Company v. FERC, Court Order No. 19-1091 (D.C. Cir. 2021)).

5.2. FERC

FERC's position on cost allocation depends on how the ISO/RTO presents the distribution of benefits. According to principle 1 of Order No. 1000, costs should not be allocated to customers who receive little to no benefits of the proposed projects — the cost of transmission facilities must be allocated to those in the transmission planning region that benefit from the facilities in a manner that is at least roughly commensurate with estimated benefits. In cases where RTO/ISOs have allocated costs of projects with granular benefits to a broad footprint, the Commission has considered such an approach to go against this principle. Based on the cases analyzed for this document, when RTO/ISOs are able to adequately identify who will receive benefits, the Commission favors a more granular approach to cost allocation.

For example, in a case analyzed by the Commission, SPP was proposing to allocate its share of two projects — one within its footprint and another outside the footprint — by inserting costs for the projects into the annual transmission revenue requirement of SPP's Highway/Byway cost allocation methodology. The methodology is based on a load ratio share spread among all SPP members. In its review, FERC considered that SPP had failed to demonstrate on a project-by-project basis that the costs of these projects were allocated to beneficiaries in a "roughly commensurate manner." Specifically, FERC found "inappropriate" SPP's allocation of costs on a regionwide, load ratio share basis, based on insufficient evidence of benefits to the SPP region for both projects (Southwest Power Pool, Inc., FERC Docket Nos. ER17-2256-000, ER17-2257-000, 161 FERC 61,026 (2017)).

FERC also rejected SPP's proposal to, on a case-by-case basis, allocate 100% of the costs of certain Byway facilities to the entire SPP region on a Postage Stamp basis. The Commission considered that the proposal gave the SPP board "too much discretion" in allocating the costs of Byway facilities. For example, the proposal did not require the SPP board to approve a reallocation request if the Capacity, Flow, and Benefit criteria are met.[73] The proposal also allowed the SPP board to rely on any type of

[73] "To meet the Capacity Criterion, an applicant must show that the total nameplate capacity of generating resources that are physically connected in the zone where the Byway facility is located (and that are not affiliated with load in that zone) exceeds 100% of the prior calendar year's average 12-CP resident load used in calculating the base plan zonal load ratio share for the zone.[23] To meet the Flow Criterion, an applicant must show that the energy flow on each Byway facility that is attributed to generating resources physically connected in the zone where the Byway facility is located and that are not affiliated with load in that zone exceeds 70% of the sum of flows on the Byway facility attributed to: (1) generating resources affiliated with the load in the zone where the Byway facility is located; and (2) generating resources that are physically connected in the zone

benefit when reviewing requests, potentially leading to disparate treatment (Southwest Power Pool, Inc., FERC Docket Nos. ER22-1846-002, ER22-1846-003, 184 FERC 61,028 (2023)).

FERC accepted MISO's proposal to allocate its share of costs of a Targeted Market Efficiency Project (TMEP) with PJM to MISO Transmission Pricing Zones in proportion to each zone's share of the relative positive congestion contribution benefits from the TMEP. The Commission found that the method and associated benefits calculation ensure that the costs allocated to each zone are at least roughly commensurate with the benefits that a TMEP provides in the form of avoided congestion costs (Midcontinent Independent System Operator, Inc., FERC Docket No. ER17-2246-000, 161 FERC 61,004 (2017)).

Recently, FERC reviewed and approved MISO's revisions to its Open Access Transmission, Energy, and Operating Reserve Markets Tariff to modify the cost allocation method for MVPs. By assigning costs of the transmission facilities only to the Midwest subregion or the South subregion that benefit from MVP portfolios, FERC considered the cost allocation to be at least roughly commensurate with the estimated benefits. The Commission analyzed steps in the process for determining whether an MVP portfolio provides benefits systemwide or subregionally (Midcontinent Independent System Operator, Inc., FERC Docket No. ER22-995-000, 179 FERC 61,124 (2022)):

- Identify transmission issues,
- Determine the appropriate scope of a planning study to resolve the issues,
- Evaluate transmission issues,
- Identify a portfolio of transmission facilities,
- Evaluate whether the transmission issues addressed and the benefits provided by the identified portfolio of transmission facilities are systemwide or limited to a single subregion, and
- Determine the adequate cost allocation method.

Commissioner Christie concurred with the granular cost allocation approach. He based his opinion on the strong involvement and support from the Organization of MISO States in the process, which played a central role in the proposal and did not suggest an alternative cost allocation method. Nevertheless, the Commissioner expressed concerns regarding allocation of costs in the two subregions based on the Postage Stamp method. Specifically, he questioned testimony offered in support of MISO's filing, which presented benefit calculations based on MISO's own 2017 analysis of the costs and benefits of MISO's 2011 MVP Portfolio. According to the Commissioner, no information was presented on the level of independent scrutiny that MISO received on its 2017 analysis of benefit-cost ratios for MVP projects. That is to say, the report was never authenticated by a witness and, as a third-party report offered as evidence, it requires to be scrutinized and subjected to

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and not affiliated with load in the zone.[24] Lastly, to meet the Benefit Criterion, an applicant must show that the Byway facility for which it is requesting 100% regional, postage-stamp cost allocation provides benefits to load outside the pricing zone where the Byway facility is located. Benefits may be quantified in terms of adjusted production cost savings or savings through the Integrated Marketplace. Sufficient benefit to load outside the pricing zone is demonstrated if the benefit exceeds either: (1) 50% of the Byway facility's projected total benefit to load in the SPP region; or (2) the portion of the Byway facility's annual revenue requirement projected to be borne by load outside the Byway facility's zone under 100% regional, postage-stamp cost allocation." (Southwest Power Pool, Inc., FERC Docket Nos. ER22-1846-002, ER22-1846-003, 184 FERC 61,028 (2023), pg. 5).

discovery, cross-examination, or competing testimony in litigation (Midcontinent Independent System Operator, Inc., FERC Docket No. ER22-995-000, 179 FERC 61,124 (2022)).

In another case, FERC accepted PJM's proposed revisions to Schedule 12, Appendix A and C. The case dealt with PJM's Operating Agreement, which considers state Public Policy Objectives (PPO) and Public Policy Requirements (PPR) as part of its regional transmission planning process. Maryland People's Council (MPC) contested the costs of the 2022 RTEP Window 3 projects. In MPC's opinion, the cost of these projects should have been allocated to Virginia, given the state's historical subsidies for the development of data centers, which require large amounts of electricity to operate. In MPC's view, these subsidies represent PPOs and PPRs and that would qualify the RTEP Window 3 projects as Multi-Driver Projects. In addition, MPC asserted that PJM could have accommodated Virginia's PPOs and PPRs (collectively, PPROs) through the SAA process, which allocates the costs of transmission projects to the state that agrees to be responsible for the costs of such projects. The Commission considered that such arguments were beyond the scope of the Commission's review of proposed cost responsibility assignments, yet it briefly analyzed the complaint.[74] FERC concluded that none of the 2022 RTEP Window 3 Projects are, or include components that are, SAA projects under Section 1.5.9(a) of Schedule 6 of the PJM Operating Agreement.[75] Therefore, the projects contested by MPC did not qualify as Multi-Driver Projects with a state Public Policy Requirement component under PJM Operating Agreement (PJM Interconnection, LLC. FERC Docket No. ER24-843-000, 187 FERC 61,012 (2024)).

The decision included two concurrent opinions. Commissioner Clements' opinion underscored the regional nature of PJM's transmission system and the distribution of benefits of regional infrastructure. In the Commissioner's view, it would be challenging to disentangle the effects of public policies on the need for new transmission, and reliability could suffer if necessary transmission upgrades are contingent on a state's voluntary assumption of costs. In this case, PJM determined that the transmission projects were needed for grid reliability. In addition, if Maryland

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[74] The Commission reviews the proposed revisions to Schedule 12 Appendix A and Appendix C to "determine whether PJM appropriately followed its Tariff provisions in allocating costs." MPC's arguments are based on the contention that the 2022 RTEP Window 3 Projects qualify as Multi-Driver Projects, which escapes FERC's review of the cost responsibility assignments for transmission projects selected in the RTEP. According to the Commission, MPC's protest should have been filed as a complaint, rather than as a protest to the instant filing.

[75] PJM, Intra-PJM Tariffs, OA Schedule 6 § 1.5, OA Schedule 6 § 1.5 Procedure for Development of the Regional Transmission Expansion Plan (28.0.0), § 1.5.9 **State Agreement Approach**.

(a) State governmental entities authorized by their respective states, individually or jointly, may agree voluntarily to be responsible for the allocation of all costs of a proposed transmission expansion or enhancement that addresses state Public Policy Requirements identified or accepted by the state(s) in the PJM Region. As determined by the authorized state governmental entities, such transmission enhancements or expansions may be included in the recommended plan, either as a (i) Supplemental Project or (ii) state public policy project, which is a transmission enhancement or expansion, the costs of which will be recovered pursuant to a FERC-accepted cost allocation proposed by agreement of one or more states and voluntarily agreed to by those state(s). All costs related to a state public policy project or Supplemental Project included in the Regional Transmission Expansion Plan to address state Public Policy Requirements pursuant to this Section shall be recovered from customers in a state(s) in the PJM Region that agrees to be responsible for the projects. No such costs shall be recovered from customers in a state that did not agree to be responsible for such cost allocation. A state public policy project will be included in the Regional Transmission Expansion Plan for cost allocation purposes only if there is an associated FERC-accepted allocation permitting recovery of the costs of the state public policy project consistent with this Section.

(b) Subject to any designation reserved for Transmission Owners in the Operating Agreement, Schedule 6, section 1.5.8(l), the state(s) responsible for cost allocation for a Supplemental Project or a state public policy project in accordance with the Operating Agreement, Schedule 6, section 1.5.9(a) may submit to the Office of the Interconnection the entity(ies) to construct, own, operate and maintain the state public policy project from a list of entities supplied by the Office of the Interconnection that pre-qualified to be Designated Entities pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a).

did not participate, it would allow the state to be a free rider, since it would be receiving reliability benefits of new infrastructure without paying for them. The Commissioner concluded that necessary infrastructure for reliable, affordable system operation should not depend on an opt-in structure requiring the affirmative consent of all affected parties to the precise costs that they are allocated. Therefore, transmission should be planned based on known and foreseeable conditions and then costs assigned based on the allocation of reliability and economic benefits (PJM Interconnection, LLC. FERC Docket No. ER24-843-000, 187 FERC 61,012 (2024)).

Commissioner Christie's concurrent opinion reflected on whether it is time to reconsider the definition of public policy projects. PJM's current tariff only considers public policy projects as those supplemental projects requested by a state. The Commissioner reflected on Maryland's new climate law, which mandates the closure of certain coal power plants, and questioned whether transmission projects that result from these state policy choices, rather than from organic load growth and economic resource retirements, should be considered public policy projects — especially since the transmission upgrades are similar to those caused by New Jersey's offshore wind projects. The Commissioner considered this question relevant for all multi-state RTOs. Finally, the Commissioner proposed that FERC use its convening role to initiate a proceeding for states to review the definition of a public policy transmission project and whether the current definition needs to be changed for purposes of regional cost allocation. (PJM Interconnection, LLC, FERC Docket No. ER24-843-000, 187 FERC 61,012 (2024)).

Relevant to this topic is FERC's Order Accepting the SAA Agreement between PJM and NJBPU. The Commission considered that the proposed SAA Agreement was just and reasonable and not unduly discriminatory or preferential. FERC highlighted that the Agreement includes a consideration that no costs will be allocated to customers outside of New Jersey unless and until the Commission accepts a future cost allocation filing as just and reasonable. Therefore, any cost allocation to "future users" is contingent on the Commission reviewing and accepting a future cost allocation filing and would not, consequently, be allocated to states other than New Jersey unless approved by the Commission (PJM Interconnection, LLC. FERC Docket No. ER22-902-000, 179 FERC 61,024 (2022)).

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