THE PLANNING PARADOX OF REGIONAL TRANSMISSION COST ALLOCATION: FEDERAL POLICY RECOMMENDATIONS FOR EFFICIENT TRANSMISSION DEPLOYMENT

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Abstract

Current regional cost allocation procedures for transmission deployment do not reach the level of deployment necessary to support the domestic energy transition and unlock the full potential of the Inflation Reduction Act of 2022. Regional transmission capacity expansion of 2.3%/year is needed to support domestic clean energy goals, enable generator interconnection, protect system reliability amidst a changing generation mix, and ensure access to electricity at the lowest cost. There is a policy failure in regional transmission cost allocation due to a failure in the overarching regional transmission planning process, named the “planning paradox.” An integrated literature review was conducted through a survey of reputable publications to synthesize the current policy state of regional transmission cost allocation procedures and identify improvements. The representative literature was used to generate new perspectives and make policy recommendations. The results found dual improvements to regional cost allocation and planning procedures would maximize efficient transmission deployment at 2.3%/year and solve the “planning paradox.” Policy recommendations include standardized improvements to benefit assessment, encouragement of the multi-value portfolio approach for project evaluation, increased stakeholder and state involvement, and increased transparency between local and regional planning. Additional recommendations include voluntary participation in joint planning and improved coordination between interconnection processes and regional planning.

Executive Summary

The capstone project builds upon prior knowledge and technical writing skills gained through previous graduate coursework completed for the Master of Science in Energy Policy and Climate program at Johns Hopkins University. Relevant coursework included *The Electric Grid: Technology and Policy*, *Renewable Energy Project Development and Finance*, and *Solar Energy: Science, Technology, and Policy*, among others. Coursework taught by professor Jeremy Lin, capstone project mentor, improved the researcher's technical knowledge on transmission electrical engineering and grid design.

The researcher's professional employment in the distributed solar industry deepened their interest in transmission and interconnection processes. As a project developer, the researcher advances distributed solar projects through interconnection, permitting, and origination activities prior to construction. In this role, the researcher observed first-hand the industry-wide negative effects of high network upgrade costs on solar projects through the interconnection queue process, including project delays and cancellations. The researcher observed how project economics can be affected by interconnection costs and the availability of robust transmission capacity. Thus, transmission was identified as a barrier to renewable deployment.

This left the researcher wondering how to reduce deployment barriers and asking the question of "Which stakeholders should pay for these capital-intensive transmission projects to upgrade the electricity grid?" Additional research uncovered the topic of transmission cost allocation as a political and controversial topic among policymakers. Given that the federal framework governing cost allocation was enacted within the past 20 years, the researcher was interested in learning how the policy framework had changed over time and could improve.

During the students matriculation at Johns Hopkins University, the Biden-Harris Administration passed the Inflation Reduction Act of 2022, which unlocked historical investment and financial commitments to the energy transition through direct incentives, loans, tax provisions and more. The Inflation Reduction Act added significance to the research, since the Act's success is predicated on transmission capacity to support and enable renewable generation interconnection at the rapid pace required to successfully meet dometic clean energy goals.

In addition, the capstone project was informed by technical, market, and policy knowledge gained through the researcher's previous employment in residential solar and utility partnerships, as well as from their Bachelor of Arts in Environmental Policy degree from Western Washington University's Institute for Energy Studies.

After completion of the capstone project, the researcher has deepened their knowledge on federal regulation of interstate transmission and regional cost allocation. The researcher has developed a stronger understanding of regional market design and policy decisions in regional planning. The researcher directly developed their proficiency in research design, technical writing, and project execution through completion of the capstone project. The skills gained will directly inform the researcher's development of community solar projects in policy-driven regional markets through a deeper understanding of regional market design and transmission policy. The researcher now has the tools to successfully interpret a relevant policy topic that will undoubtedly inform the overall renewable energy industry within the next decade.

Acknowledgments

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Introduction

According to PJM (Pennsylvania-New Jersey-Maryland Interconnection), transmission is known as the "great equalizer" (PJM, 2019a, p. 1). High voltage AC and DC transmission systems reliably deliver continuous electricity from generation to load centers and tie the electricity grid together across regions. Robust transmission enables the lowest cost generation to be dispatched through the competitive wholesale market, in turn lowering the cost of electricity for end-use customers through reduced production costs and lower wholesale prices (PJM, 2019). Transmission supports reliability policy goals by providing a robust grid and a high system margin, which gives grid operators flexibility to address unexpected grid events, such as loss of a generator or substation, or critical peak load periods (PJM, 2019, p. 8). Transmission also enables grid resilience, defined as "The ability to prepare for and adapt to changing conditions, and to withstand and recover rapidly from disruptions," such as natural disasters, cyber attacks, and climate change (DOE, 2020, p. 22).

A robust transmission system is needed to support the domestic energy transition, but transmission projects are not getting built at the optimum pace necessary to support existing and future generation. As part of the broader energy transition, the transmission grid is experiencing rapid changes, defined by the Brattle Group (2022) as the "3D's" - decarbonization, decentralization, and digitalization (p. 6). More regional transmission capacity is needed to enable new generator interconnection, protect system reliability amid a changing generation mix, and ensure access to electricity at the lowest cost.

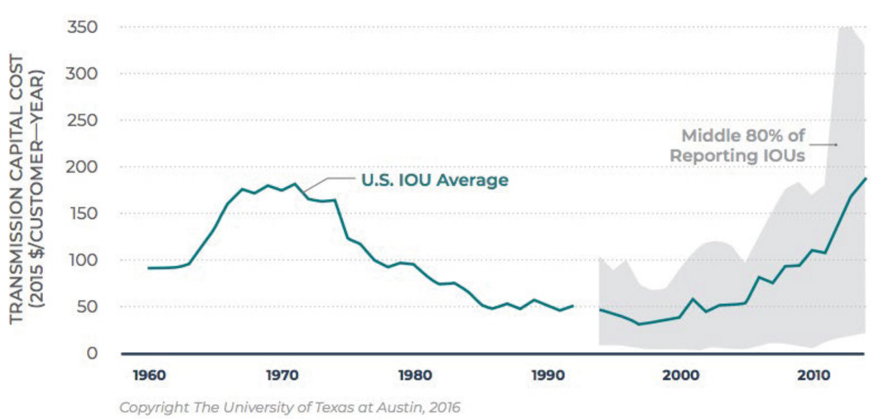
Robust transmission can support public policy goals by enabling new generator deployments. The energy transition is changing the traditional generation mix through a rapid growth in renewable deployment, natural gas generation, and distributed generation. According to the Lawrence Berkeley National Laboratory (2020), 2019 saw over 700 GW (Gigawatt) of generation in regional interconnection queues including 367 GW of solar, 226 GW of wind, 77

GW of natural gas, 55 GW of stand-alone storage, and 8 GW of nuclear and coal. In PJM, 24,000 MW (Megawatt) of coal-fired generation retired between 2011-2018 (PJM, 2019). During the same period, 29,500 MW of natural gas generation and 5,910 MW of renewable generation were interconnected (PJM, 2019). Generator retirements can negatively affect transmission systems by altering voltage and reactive power levels, so more transmission is needed to uphold reliability standards and respond to reliability violations (PJM, 2019).

The existing transmission grid is aging and will need to be replaced in order to support current load. Two-thirds of PJM transmission assets are over 40 years old, including deteriorating tower structures and foundations constructed from wood and iron (PJM, 2019). The Brattle Group (2022) estimates $10 million in annual costs to replace aging transmission infrastructure between 50-80 years old. As demonstrated in Figure 1, the United States (U.S.) is in a second investment cycle to replace transmission originally built in the 1960s and 1970s (Brattle, 2022). In 2020, the Department of Energy (DOE) stated annual investment is “More than five times greater than it was during the years prior to 2005,” with an average annual investment of $18 to $22 billion since 2014 (DOE, 2020, p. vi).

Figure 1

Average Cost of Investment in New Transmission System Capital Infrastructure



Note. Reprinted from “*Planning for the Future: FERC’s Opportunity to Spur More Cost-Effective Transmission Infrastructure*” by Gramlich and Caspary, 2021.

In tandem, the modern grid is shifting to embrace digitalization and decentralization through a process known as asset modernization, defined as the practice of replacing aging assets with smarter and modern technologies (PJM, 2019).

Transmission projects can be likened to the Interstate Highway System, which both provide continuous benefits to society (PJM, 2019). Electrons are represented by cars and system capacity is represented by the total number of highway lanes to carry electrons to their final destination. When a highway is heavily traveled, there can be traffic jams and congestion, similar to a constrained transmission system. Transmission constraints lead to transmission congestion, defined as the negative economic impacts on electricity costs resulting from higher wholesale electricity prices (DOE, 2020). When a transmission system is constrained, locational marginal pricing will differ on either end of the transmission constraint, which leads to a price difference quantified as the cost of transmission congestion (DOE, 2020). According to the U.S. DOE (2020), congestion costs can be improved through transmission investment. PJM (2019) estimates that transmission capacity additions have saved an average of $288 million/year in reduced congestion costs.

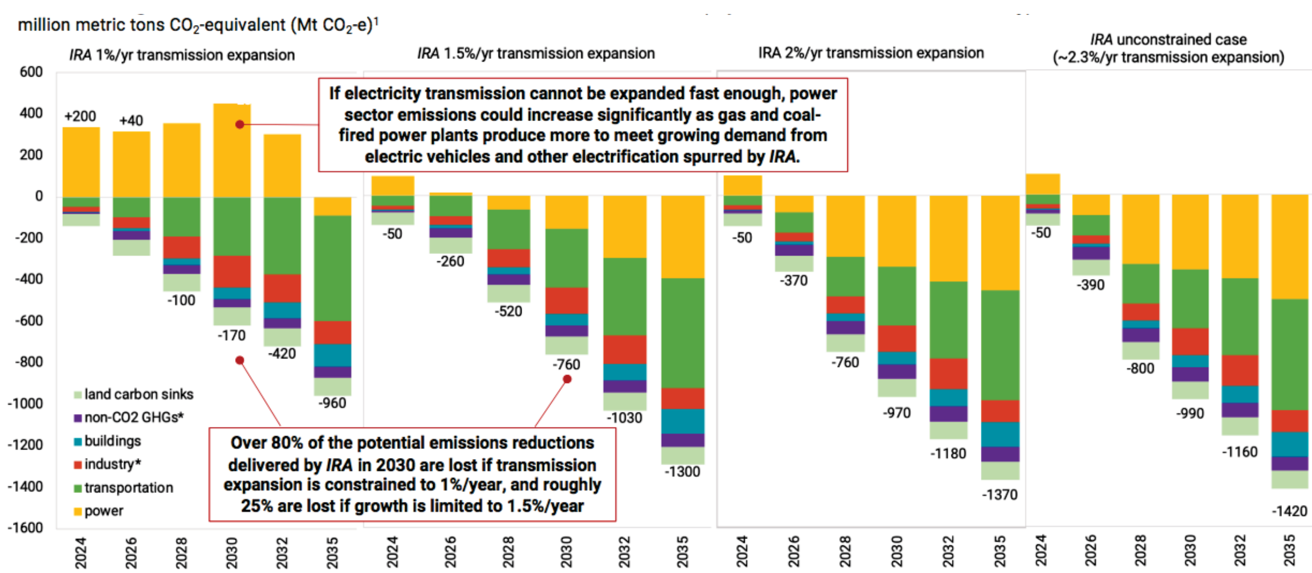
In 2021, the Eastern Interconnection Planning Collaborative, including members such as MISO (Midcontinent Independent System Operator), PJM, Duke, and Southern Company, issued a report to identify challenges observed by system operators and planners when integrating wind and solar generation (EIPC, 2021). Issues identified include the variable output and remote locations of renewable generation and non-traditional load patterns due to residential rooftop solar and storage (EIPC, 2021). The report identified that renewable generation is often sited in optimal wind and solar production zones, but not optimally sited for adequate transmission capacity (EIPC, 2021). Transmission system constraints can lead to curtailed and stranded generation, especially generation sited in rural areas far from load centers. EIPC (2021) recommended investment in additional transmission capacity to assist with cost-effective and reliable renewable integration. In addition, the National Renewable

Energy Laboratory (NREL) Seams study found transmission investment must double in order to support high renewable integration. The study found an additional investment of up to 60 million MW-miles of AC and 63 million MW-miles of DC would be needed to add to the existing 150 million MW-miles (Pfeifenberger et al., 2021).

The REPEAT project from Princeton University states transmission expansion is the key to translating the recently-passed Inflation Reduction Act of 2022 (IRA) into the maximum reduction of U.S. carbon emissions. The study found the historical growth of transmission expansion to be 1%/year, but argues expansion must reach 2.3%/year in order to utilize the IRA's maximum emissions reduction potential (Jenkins et al., 2022). As seen in Figure 2, if transmission expansion stays at 1%/year, 80% of emissions reductions would be lost by 2030. If transmission expansion grows to 1.5%/year, 25% of emissions would be lost (Jenkins et al., 2022).

Figure 2

Annual Change in Net U.S. Greenhouse Gas Emissions Relative to No IRA (Bipartisan Infrastructure Law Only)

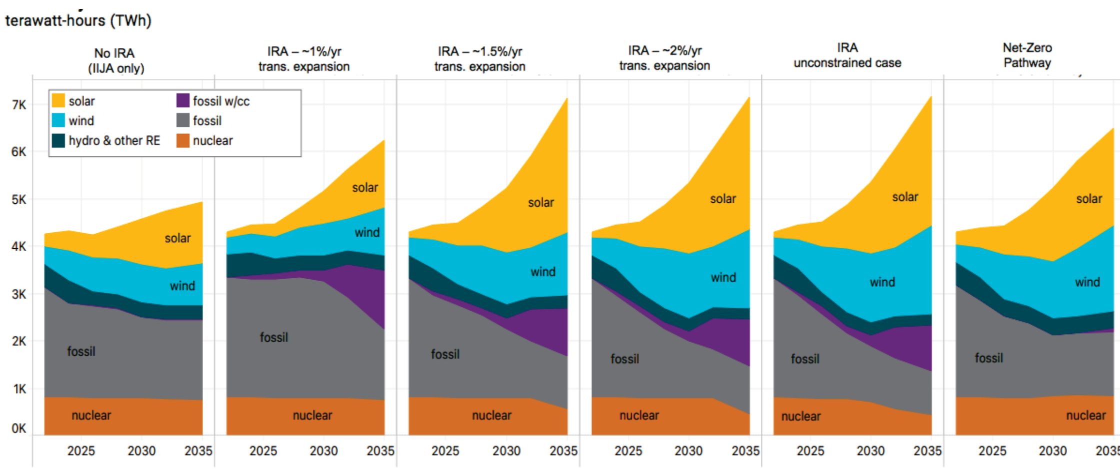


Note. Reprinted from "*Electricity Transmission is Key to Unlock the Full Potential of the Inflation Reduction Act*" by Jenkins et al., 2022.

The emissions findings are tied to future generator mix scenarios and their associated emissions profiles, as well as to the grid's ability to decarbonize through renewable capacity additions (See Figure 3).

Figure 3

Annual Change in U.S. Electricity Generation Relative to No IRA (Bipartisan Infrastructure Law Only)



Note. Reprinted from "*Electricity Transmission is Key to Unlock the Full Potential of the Inflation Reduction Act*" by Jenkins et al., 2022.

Without robust investment, transmission could become the bottleneck that limits new generator interconnections and constrains national clean energy goals. Given transmission construction timelines of 5-10 years, policy decisions made in the present day will affect the future transmission grid for decades into the future (Pfeifenberger et al., 2021).

Research Problem

More transmission capacity is needed to enable new generator interconnection, protect system reliability amid a changing generation mix, and ensure access to electricity at the lowest cost. Current regional cost allocation procedures do not maximize transmission deployment and are inefficient. There is a policy failure in regional transmission cost allocation due to a failure in the overarching regional transmission planning process.

Research Statement and Question

The purpose of this research is to conduct an integrated literature review of the current state of regional transmission cost allocation procedures, within the broader context of regional transmission planning and the overarching federal rulemaking process. The research will identify what gaps are missing from current allocation approaches, then suggest policy recommendations to maximize transmission deployment through the federal regulatory framework. What policy reform is needed *at the federal level* to improve current regional cost allocation procedures and maximize efficient transmission deployment?

Hypothesis

The researcher hypothesizes the federal regulatory framework could be improved through stronger guidance on both regional cost allocation and regional transmission planning. Improvements could be made through policy recommendations that dually incentivize regional transmission planning and regional cost allocation to work together simultaneously to improve transmission deployment. The study hypothesizes that improvements could be made to share costs more evenly across stakeholders through interregional cost sharing and interregional planning, increase collaboration through greater state and public involvement, and quantify transmission benefits more accurately through a stronger cost benefit analysis.

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Methods

The researcher used literature review and a survey of reputable publications to synthesize the existing policy state using qualitative methods. The researcher generated new knowledge about the topic by reviewing, critiquing, and synthesizing representative literature to generate new frameworks and perspectives. The new frameworks and perspectives were considered in the context of efficient transmission deployment. The researcher used representative literature to identify what elements were missing from the current policy landscape, then developed a strategy and generated new ideas for improvement. The new ideas and perspectives were used to make policy recommendations to maximize efficient transmission deployment.

The researcher utilized public and federal industry resources such as the U.S. DOE, Energy Information Administration, Congressional Research Service (CRS), and National Laboratories. Dockets and rulemaking at the Federal Energy Regulatory Commission (FERC) level were utilized and cited appropriately. The researcher conducted a database search via Google Scholar to find additional valid primary sources such as journal articles, policy briefs, and scientific papers. The database search was conducted using keywords such as regional cost allocation, regional transmission planning, transmission deployment, and FERC rulemaking. Representative literature found via Google Scholar was read, then a decision was made on whether the literature was appropriate for the paper, given the source's level of robustness, validity, and relevancy. Data was borrowed from representative literature and cited properly throughout the paper. Data was analyzed within the scope of the research statement.

The scope included domestic regional transmission planning and cost allocation rulemaking from 1996 until present. The paper focused on RTO/ISO-level regional planning and cost allocation rather than non-RTO/ISO transmission providers. Rather than focus on one RTO/ISO such as PJM, the paper focused on three RTO/ISO, PJM, MISO, and SPP (Southwest

Power Pool) in order to provide a more broad overview of approaches. The paper majorly focused on the federal FERC regulatory framework overseeing RTO/ISO-level regional cost allocation and transmission planning procedures.

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Analysis: Background, History, and Existing State

1996 to Present: FERC Regulation of Regional Transmission Planning and Cost Allocation

FERC's Authority

FERC is an independent federal agency with the authority to regulate interstate transmission and the sale of wholesale electricity in interstate commerce, as granted by sections 205 and 206 of the Federal Power Act (FPA) of 1935. FERC grants RTO/ISO the authority to regulate and operate transmission over 100 kV (Kilovolt) in size, and to plan infrastructure typically owned and operated by transmission owners (TO) who have an obligation to serve their local footprint (PJM, 2019a; Gramlich and Caspary, 2021). The term transmission providers will be used to encompass both RTO/ISO and non-RTO/ISO regions. TO's invest in the transmission system and receive a return on investments once projects are built, with prices set by a region's transmission pricing zones. Typically, states have authority over siting transmission projects, though FERC technically has backstop authority under the Energy Policy Act of 2005, however this authority has never been exercised.

The principles and frameworks for regional cost allocation methodologies are defined by FERC rulemaking as part of the broader transmission planning process. Regional cost allocation methodologies are approved by RTO/ISO Boards or alternative governance structures held by non-RTO/ISO regions. FERC ultimately approves regional cost allocation methodologies.

FERC has the duty to maintain just and reasonable Commission-jurisdictional electricity rates that are not unduly discriminatory or preferencial (FERC, 2022). Under section 206 of the FPA, the Commission has authority to change cost allocation frameworks if existing rates are found to be "unjust, unreasonable, unduly discriminatory, or preferencial" (CRS, 2012). Policy reform happens through FERC’s Notice of Proposed Rulemaking (NOPR) process. Below is a summary of federal rulemaking pertaining to regional cost allocation and regional transmission planning from 1996 to present.

Order 888

FERC has promoted competitive and fair use of the transmission grid through market restructuring and non-discriminatory transmission access (Fink et al., 2011). In 1996, FERC passed Order 888 which unbundled the sale of wholesale power and transmission into separate rates and weakened the traditional utility natural monopoly. The passage of Order 888 set the Open Access Transmission Tariff (OATT) procedure and standards (Fink et al., 2011).

Order 2003

Order 2003 revised the OATT and outlined cost allocation standards for individual generators including the requirement that generators pay for all network upgrades associated with interconnection (Fink et al., 2011). Order 2003 also allowed RTO/ISO to propose cost allocation variations for generator-connected projects, so long as the variations were just and reasonable (Fink et al., 2011).

Order 890

A series of court cases, including *Illinois Commerce Commission v. FERC*, 576 F. 3d 470 (7th Cir. 2009) which debated the socialization of transmission costs among PJM customers who would not benefit, led FERC to seek clarity on regional cost allocation. FERC was concerned about cost allocation for more complex projects, such as multi-state projects, or projects with broad economic benefits and multiple beneficiaries (CRS, 2012).

In 2007, FERC passed Order 890 to further amend the OATT, requiring transmission providers to practice local and regional transmission planning through a series of nine guidelines:

1. **Coordination**, with customers and transmission owners
2. **Openness**, including open transmission planning meetings for affected stakeholders
3. **Transparency**, in underlying assumptions used in transmission plans
4. **Information Exchange**, for customers to submit data on load
5. **Comparability**, using data obtained from information exchange to inform transmission planning
6. **Dispute Resolution**, to solve disagreements
7. **Regional Coordination**, requiring transmission providers to plan regionally and sub-regionally
8. **Economic Planning Studies**, to identify transmission congestion costs
9. **Cost Allocation**, directing transmission providers to develop a cost allocation methodology alongside stakeholders to file with FERC
    a. Order 890. (123 FERC ¶ 61,299 (2007)

Included in the cost allocation rulemaking was flexibility for transmission providers to establish their own methodologies based on regional criteria (CRS, 2012).

Order 1000

In 2009, FERC requested comments on regional cost allocation and planning with the goal to further clarify regional cost allocation procedures with a more direct approach (CRS, 2012). In 2011, FERC passed Order 1000, which set further guidelines for transmission providers to develop a regional transmission plan and a regional cost allocation methodology, to be used for multi-state reliability, economic, or public policy projects approved under the regional transmission plan (FERC, 2021). The methodology must satisfy the following six regional cost allocation principles:

1. Allocate costs commensurate with benefits
2. Non-beneficiaries should not be involuntary allocated costs

3. If using a benefit cost analysis, a sufficient ratio of 1.25 should be utilized as a threshold, unless there is justification for another ratio
4. Costs must be allocated within a transmission planning region unless there is voluntary agreement to assume costs outside of the region
5. Determination of transmission benefits must be transparent to stakeholders
6. Transmission providers can utilize multiple allocation methodologies depending on the transmission facility driver, such as reliability or economic
    a. Order 1000. (136 FERC ¶ 61,051 (2011).

For joint or interregional transmission planning, an interregional cost allocation methodology must be developed and must follow a similar set of interregional cost allocation principles (CRS, 2012).

The regional cost allocation principles stated that costs can only be allocated to those who receive benefits to prevent involuntary allocation of costs. However, the Order did not define specific benefits for allocation of costs commensurate with benefits. Order 1000 discussed a few benefits, such as reliability, economic, and public policy, but did not set a definition due to recognizing difficulties (CRS, 2012). Order 1000 did not recommend a single approach to cost allocation and continued to allow flexibility for transmission planning regions to develop their own methodologies in accordance with regional criteria and policies (CRS, 2012). Thus, interpretations have been broad and methodologies continue to be left to RTO/ISO with varying approaches.

Background on Regional Transmission Planning Process

Regional transmission planning is closely connected with regional cost allocation. Prior to paying for a transmission project, the project must first be planned and approved by a transmission provider. Transmission providers have been required to engage in regional transmission planning since the passage of FERC Order 890. Traditional transmission planning within PJM, MISO, and SPP has been focused on a narrow scope of immediate reliability and local needs (Lieberman, 2021). Thus, transmission projects have been built in an incremental manner to address local reliability needs, which has led to higher deployment costs (Pfeifenberger and Chang, 2016).

Types of Transmission Upgrades

There are a few key drivers for regional transmission expansion. The evaluation of a potential transmission project is typically undertaken based on the dominant driver: reliability, economic, or public policy (Fink et al., 2011). Evaluation approaches vary depending on the driver and RTO/ISO methodologies. External to regional planning, RTO/ISO also facilitate additional network upgrades through an external generator interconnection process. Additional external upgrades may occur through "tariff services" due to customer load additions or region-specific needs (Gramlich and Caspary, 2021, p. 96).

Reliability Upgrades

PJM, MISO, and SPP conduct reliability planning to resolve North American Electric Reliability Corporation (NERC) violations. Each RTO/ISO has their own local and regional planning methodologies to assess reliability against a range of future scenarios. All assessments include an analysis of NERC criteria for thermal and voltage violations (Lieberman, 2021).

Economic Upgrades

PJM, MISO, and SPP conduct regional planning for economic or "market efficiency" projects with the goal to identify projects that alleviate congestion. RTO/ISO methodologies typically conduct a cost benefit analysis (CBA) using a range of future load scenarios (Lieberman, 2021). Projects are typically ranked based on the cost-to-benefit (B/C) ratio, which cannot exceed 1.25 as required by FERC Order 1000.

Public Policy Upgrades

Public policy upgrades are discussed in Order 1000 as a transmission benefit. However, no distinct public policy project methodologies exist within PJM, MISO, or SPP, even though all three do consider regional public policy within futures scenarios (Lieberman, 2021).

Network Upgrades (External)

Network upgrades are traditionally assessed external to RTO/ISO regional planning and paid for by the interconnecting generator. There is little interaction between the generator interconnection process and PJM, MISO, and SPP's regional transmission planning (Lieberman, 2021). Network upgrades occur when a proposed project in the generator interconnection queue is found to cause reliability violations through the RTO/ISO study process and must be paid prior to interconnection (Rose, 2017). Full upgrade costs are allocated to the "cost-causing" or "marginal" interconnecting generator, although subsequent generators who interconnect nearby will typically reimburse the cost-causer over time (Seiler, 2021, p. 3). Most RTO/ISO have adopted the above cost allocation methodology known as participant funding where costs are allocated to willing participants as defined by Order 2003 (Gramlich and Caspary, 2021). Due to the generator's primary role in funding network upgrades, some generators withdraw due to high costs, which can cause gridlock and delays for subsequent projects that must be re-studied. Historically, only 15% of projects in PJM's queue were successfully interconnected (Lieberman, 2021). The lack of generator interconnection has created cascading negative effects outside the scope of the paper, but please refer to page ix in Lieberman (2021) to read about the negative feedback loop where future generation scenarios are underestimated in regional transmission planning models.

According to Pfeifenberger et al. (2021) the network upgrade process is inefficient and overburdensome to the generator. Under participant funding, generators are required to pay 100% of the costs, even though many network upgrades provide broader, system-wide benefits to the transmission grid. Participant funding requires generators to be allocated full costs and exempts other beneficiaries from payment. Gramlich and Caspary (2021) refer to this as the "free rider" economic problem where generators fund a public good that others will benefit from, leading to an underinvestment in public goods (p. 28). Network upgrades assign the cost burden to individual generators and place the onus on generators to fund regional grid upgrades (Pfeifenberger et al., 2021). The high costs of network upgrades draw attention to the overdue system-wide regional upgrades needed to support the energy transition.

Since projects in the queue are studied individually, the benefits of larger, portfolio-wide regional investments are overlooked. For example, the results of a 2021 PJM offshore wind integration study found $6.4 billion in network upgrades to interconnect 15.5 GW of offshore wind (Pfeifenberger et al., 2021). In contrast, the results of a 2021 PJM region-wide offshore wind study estimated $3.2 billion to interconnect 17 GW of offshore wind, less than half the cost of the first study (Pfeifenberger et al., 2021). The individual network upgrades study process ignores the potential economies of scale from regional projects and results in higher overall costs (Pfeifenberger et al., 2021).

Regional versus Local Planning

Transmission projects can occur at the local planning level, typically lower voltage and smaller-footprint projects, outside of the regional planning process (Gramlich and Caspary, 2021). Local projects are defined by Order 1000 as "A transmission facility located solely within a transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation," (176 FERC ¶ 61,024 at p. 22 (2021). Local projects are approved at the TO level with minimal regional review except a reliability analysis to ensure local projects do not create reliability violations (176 FERC ¶ 61,024 at p. 17 (2021). The Brattle Group found half of RTO/ISO transmission investments between 2013 and 2017 were approved outside of regional planning processes, for a total investment cost of $35 billion (Gramlich and Caspary, 2021). SPP is the only RTO/ISO who combines local and regional planning into one analysis. The primary focus on local planning leads to incremental and inefficient transmission upgrades without a single unified regional planning vision. Local planning does not provide enough opportunity for stakeholder review or comments, which can diminish public confidence that upgrades are cost-effective or appropriate (Gramlich and Caspary, 2021).

TO's have their own set of local planning guidelines to update and maintain owned transmission assets, including the authority to make "in-kind" replacements as transmission assets reach end of life (Gramlich and Caspary, 2021). In-kind replacements restore the asset with an identical asset, rather than make capacity or voltage upgrades through a "right-sizing" or asset modernization process. In-kind replacements, carried out under the local planning process, do not have transparency requirements under existing federal guidelines (176 FERC ¶ 61,028 at p. 300-303 (2022). Forgoing asset modernization leads to piecemeal, lower voltage, and more costly transmission deployments.

Supplemental projects are a part of the local planning process and not subject to regional oversight or transparency requirements. Even though Order 1000 requires RTO/ISO to conduct regional transmission planning, local projects such as PJM supplemental projects remain exempt (Gramlich and Caspary, 2021). Gramlich and Caspary (2021) argue section 205 of the FPA requires transmission providers to demonstrate justification for rate increases, which does not occur under the supplemental process. Supplemental projects represent an inefficiency in transmission planning and cost allocation, yet there may be incentives to pursue supplemental projects since local projects increase a TO's rate base and provide a rate of return (Pfeifenberger et al., 2021).

Interregional and Joint RTO/ISO Planning

The "seams," defined as the shared border between RTO/ISO planning regions, have historically experienced congestion and trapped generation. FERC Order 1000 requires regions to conduct interregional planning with neighboring regions and to jointly identify interregional projects (Gramlich and Caspary, 2021). The fourth regional cost allocation principle states that joint planning and cost allocation must be voluntary. Joint planning is governed by an RTO/ISO Joint Operating Agreement (JOA) which oversees joint planning and shared interconnection queues. Interregional projects must be approved through both RTO/ISO regional planning processes with separate CBA methodologies, benefits assumptions, and B/C ratios (Gramlich and Caspary, 2021). According to Gramlich and Caspary (2021), joint project approvals are challenging to achieve from both RTO/ISO due to differing regional modeling assumptions. According to Lieberman (2021), since the passage of Order 1000, interregional planning has been ineffective and very few interregional seams projects have been approved through PJM/MISO or MISO/SPP.

Background on Regional Cost Allocation

Regional cost allocation, defined as the method to determine which stakeholders pay for proposed transmission projects, is one element within the broader regional planning process. Prior to project approval, transmission providers and customers seek to understand their cost obligations (Gramlich and Caspary, 2021). Projects often get stuck or canceled during the planning process amid discussion of who pays in a metaphorical “planning paradox.” There is a policy failure in transmission cost allocation due to a failure in the overarching transmission planning process. Transmission projects are visually large projects which can draw attention to high capital costs and become an easy target in which to attribute rising electricity costs (Penrod, 2022). According to the CRS (2012), multi-state cost allocation is one of the most contentious policy issues today.

Market restructuring fundamentally redefined the traditional utility transmission model and elevated cost allocation to its current status as a contentious issue. Prior to market restructuring and deregulation, utilities sold bundled electricity and “socialized” the cost of new transmission by sharing costs among all customers, whether or not a particular customer received benefits (CRS, 2012, p. 7). Since utility costs were bundled, cost allocation was less contentious due to the natural monopoly and lack of market competition (CRS, 2012). Open access transmission required non-discriminatory transmission access and utilities were permanently distanced from being the sole builder, owner, and operator of transmission (CRS, 2012). Now, although utilities can still own and build transmission, independent RTO/ISO can operate transmission lines to ensure non-discriminatory access by TO (CRS, 2012). More broadly, restructuring introduced complexity and weakened the clear connection between utilities and transmission.

Fink et al. (2011) state that cost allocation is a key factor in the decision to build transmission, especially in multi-state projects where it is difficult to distribute benefits and costs to stakeholders. The benefits from a regional project cross multiple states, so states may be reluctant to fund a project with uneven benefits to their state (Brattle, 2022). Within the regional planning process, there is a lack of federal guidelines on the types transmission benefits to assess and quantify. Without proper measurement of benefits, proper buy-in from stakeholders to authorize transmission spend can be difficult to achieve. States want to maximize self interest and may push back on multi-state projects where benefits are assigned unevenly (Penrod, 2022). Stakeholder confidence is important to gather political support for cost allocation.

Below are examples of cost allocation methodologies:

1. **License Plate**: utility recoups cost locally from customers through transmission tariffs. Often used in local transmission projects.
2. **Beneficiary Pays**: costs are recovered from benefitting TO, who allocate costs to customers using license plate methodology.
3. **Postage Stamp**: costs are recovered from load or transmission zones. The methodology may use a metric such as load ratio share, which is calculated

using regional loads and multiplied by TO annual revenue requirement, a metric for the cost of transmission expansion (Lieberman, 2021).

4. **Participant Funding**: costs are allocated to the marginal cost causing generator through the interconnection process. Also known as **Direct Assignment.**
    a. (Brattle, 2022)

Cost Benefit Analysis

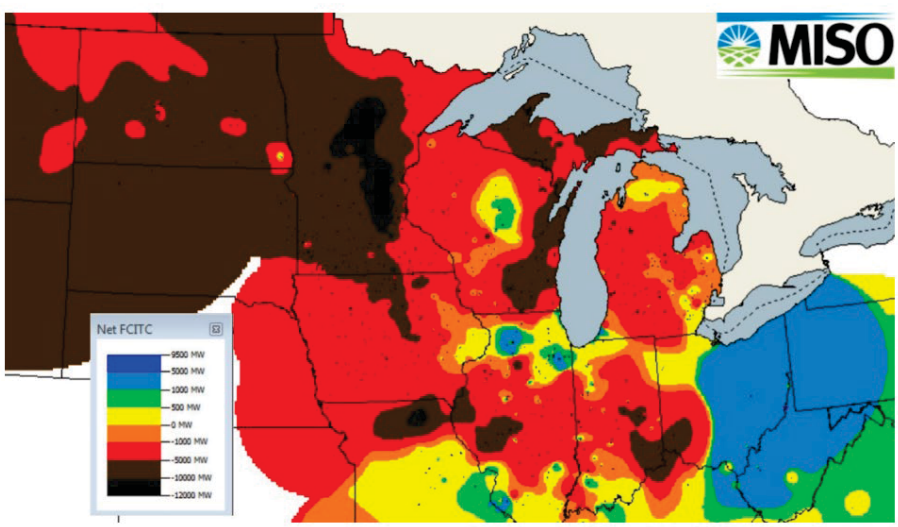
According to the Wires Group, the benefits of transmission have "often been overlooked or prematurely dismissed," (Pfeifenberger and Chang, 2016, p. 3). Today's regional transmission planning models are not appropriately identifying the true value of transmission by understating the full range of benefits (Lieberman, 2021). In order to conduct an effective CBA, stakeholders must first agree on which benefits to include and how to assess them. Transmission benefits can be hard to quantify, since benefits are broad in scope across a large geographic region, and not all stakeholders will capture all benefits throughout the full 50-year project lifecycle (Brattle, 2022). For example, the first widespread transmission deployment, built in the 1960s and 1970s, has provided more benefits than policymakers could have imagined when projects were originally built and planned for (Pfeifenberger and Chang, 2016). Challenges in benefits quantification can lead to challenges in estimating benefits across stakeholders and contentious cost allocation (Brattle, 2022).

Since additional benefits are challenging to quantify, an RTO/ISO will often rely on a narrow range of benefits in CBA, such as Adjusted Production Cost (APC) savings and forgo consideration of additional benefits (Lieberman, 2021). But despite challenges with assessing benefits, the high price tag of investment remains. To quote FERC, "Failure to account for all the benefits of a transmission facility while taking into account all the costs of the transmission facility does not allow for a fair examination of whether the costs are allocated roughly commensurate with the benefits," (176 FERC ¶ 61,024 at p. 61 (2021). Existing approaches create an overall landscape of inefficient transmission deployment with higher integration costs and higher electricity prices (Brattle, 2022).

CBA methodologies to assess transmission benefits are not standardized across RTO/ISO planning regions; Regions may assess different benefits or use different evaluation metrics (Lieberman, 2021). RTO/ISO attempting to engage in joint or interregional planning may reach a stalemate where projects cannot be approved under incompatible CBA. For projects that can pass both CBA, RTO/ISO cost allocation methodologies may not be aligned and there may be cost disagreements (Lieberman, 2021). Lack of alignment in regional planning models leads to an understatement of the true value of regional transmission, especially at the seams, and a lack of coordinated joint planning (Lieberman, 2021). When benefits are understated, congestion is exacerbated, since only incremental and local transmission upgrades can be approved within a single region (Brattle, 2022). For example, Figure 4 depicts MISO's transmission capacity deficit of 1,000-10,000 MW in red and brown (Pfeifenberger et al., p. 8, 2021).

Figure 4

Transmission Interconnection Capacity Deficit in MISO



Note. Reprinted from "*Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*" by Pfeifenberger et al., 2021.

RTO/ISO evaluations of transmission projects are based on the main project driver and considered within a benefit "silo." For example, if a reliability project provided broad economic benefits, economic benefits would be excluded from the reliability evaluation. Pfeifenberger et al. (2021) refer to this as "compartmentalization" of benefits, which fails to consider the full range of transmission benefits and leads to underinvestment (p. 31). Reliability-driven projects do not utilize CBA and fail to consider the most economic and cost-effective solutions (Brattle, 2022). Between 1996-2019, 90% of transmission investment has been driven by reliability projects, while economic and public policy projects accounted for only 10% of investment (Brattle, 2022).

Economic and public policy projects rely on CBA to determine if the project is economical and typically use APC savings as the benefits metric. APC models the baseline production cost to operate a generator under normal conditions, including import and export revenues, as well as the cost to operate the generator with the proposed transmission upgrade (Lieberman, 2021). APC savings captures fuel cost savings from the ability to dispatch the lowest-cost generation due to increased transmission capacity (Pfeifenberger et al., 2021). However, APC only studies the project under normal conditions and assumptions, leaving out extreme weather conditions, planned transmission outages, and transmission line losses (Lieberman, 2021; Pfeifenberger et al., 2021). Please reference Appendix B of Pfeifenberger et al. (2021) for a discussion on methods to capture additional assumptions within APC models. APC does not typically account for additional benefits such as a reduction in line losses, a reduction in reserve margin, load diversity benefits, or resource adequacy (Lieberman, 2021; Pfeifenberger et al., 2021). Only incremental and piecemeal solutions can be approved under a limited CBA scope that utilizes APC savings.

PJM Regional Transmission Planning and Cost Allocation

PJM conducts annual regional transmission planning through Regional Transmission Expansion Planning (RTEP) and determines benefits of new baseline projects across multiple states and transmission zones. The RTEP process is primarily driven by reliability; Over the past 20 years, PJM attributes 80% of upgrades to baseline reliability projects, valued at $29.9 billion (PJM, 2019a; PJM, 2019).

The RTEP analysis conducts a system compliance assessment of NERC reliability standards on a 15-year planning horizon using various generation mix scenarios, load expectations, and public policy futures (PJM, n.d.; Rose, 2017). Baseline economic projects may be identified to meet needs such as congestion, though projects typically fall under one benefit driver (PJM, 2019). If new baseline transmission projects are identified, the projects are brought to public stakeholder meetings, then reviewed by PJM Board for approval (PJM, n.d.). Once approved, TO's are obligated to build the projects to maintain reliable service, and the projects are included in future RTEP planning models (PJM, n.d.).

Proposed baseline economic projects are assessed in RTEP through CBA using an Energy Market Benefit (APC savings) and a Reliability Pricing Market benefit, which simulates the capacity market with and without the proposed project (Lieberman, 2021). Until projects are built, benefits are re-assessed each year and must pass with a B/C ratio of 1.25; changes can be made to the final RTEP projects based on results of B/C ratio (PJM, 2019a; Lieberman, 2021).

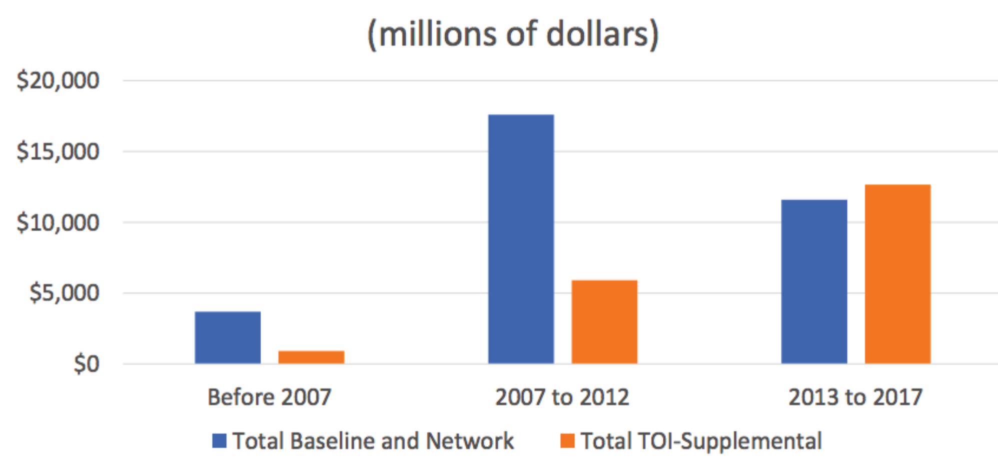
Baseline RTEP cost allocation is regulated under PJM's OATT Schedule 12 (Rose, 2017). Baseline project costs are recovered through the beneficiary pays methodology which requires benefiting customers and load-serving entities to pay commensurate with benefits by transmission zone (Seiler, 2021). For reliability baseline projects, 50% of costs are allocated depending on load-ratio with the remainder depending on distribution factor, a technical term relating to voltage (PJM, 2019). The beneficiary pays method socializes costs to all network customers who benefit from reliability improvements (PJM, 2019, p. 8).

Supplemental projects are proposed by TO's to improve local reliability on lower-voltage lines such as replacing equipment, providing infrastructure resilience, or upgrading due to increased end-use loads (Thomas, 2019). Supplemental projects are introduced to PJM through inclusion in RTEP planning scenarios, but do not require approval by PJM Board and largely function outside of RTEP (Lieberman, 2021). Costs are allocated using the beneficiary pays methodology where the TO allocates costs to customers in the incumbent transmission zone through base electricity rates (Rose, 2017).

A report commissioned in 2017 for American Municipal Power, representing 135 municipal power suppliers across nine states, reported a recent increase in PJM supplemental projects (Matyi, 2017). In PJM, TO's Total Annual Revenue Requirement increased by 294.5% between 2011-2017 (Rose, 2017). As seen in Figure 5, investment in supplement projects increased relative to baseline and network upgrades.

Figure 5

PJM Transmission Project Estimated Cost by Year



Note. Reprinted from "*Survey of PJM Transmission Rates and Charges: Transmission Study for American Municipal Power, Inc. (AMP)*" by Rose, 2017.

PJM's supplemental projects lack stakeholder involvement and are not transparent. Until 2018, there was no stakeholder involvement. In 2018, FERC required changes to PJM's supplemental planning process, known as Attachment M-3, to stay compliant with Order 890's transparency and coordination requirements (Thomas, 2019). The changes required stakeholders to receive more information about supplemental projects such as assumptions, models, alternatives, and proposed solutions with three 25-day review periods for stakeholder feedback (Thomas, 2019).

MISO Regional Transmission Planning and Cost Allocation

MISO's Transmission Expansion Plan (MTEP) is an annual planning analysis to identify and approve transmission projects for baseline reliability, economic, and multi-value-driven projects through the MISO Board. Projects are identified throughout four planning regions over short, intermediate, and long term time horizons between 1-20 years (Lieberman, 2021). The analysis considers a range of future scenarios based on energy efficiency, renewable development, electrification, public policy, fuel needs, and regional demand (Lieberman, 2021). Other transmission projects are externally driven with participant funding cost allocation, including network upgrades (Fink et al., 2011).

Baseline reliability projects are driven by the local TO planning process, where the TO identifies potential projects to participate in MTEP (Lieberman, 2021). Baseline reliability project costs are allocated using the postage stamp methodology (Lieberman, 2021). If baseline reliability projects are identified to also meet economic needs within the next 36 months, projects can be expedited under MISO's "Immediate Need Reliability Project" category (Lieberman, 2021).

Economic projects, also known as market efficiency projects in MISO, arise out of the MTEP planning model. According to the MISO tariff, economic projects must reduce market congestion and have a B/C ratio of 1.25 (Lieberman, 2021). The model considers benefit metrics for APC savings, Avoided Baseline Reliability Project savings, and the MISO-SPP Settlement Metric which assesses the impact of costs paid from MISO to SPP for capacity sharing (Lieberman, 2021). The three benefits aggregated must exceed 1.25. The benefit metrics assessed are narrowly focused on reducing market congestion and do not acknowledge broader economic benefits (Fink et al., 2011). Economic projects allocate costs using the postage stamp methodology to all transmission zones who benefit according to the model (Lieberman, 2021).

MISO has a third category of projects known as multi-value projects (MVP). The MVP model has been incorporated in MTEP since the methodology was approved by FERC in 2011 (Fink et al., 2011). The approach was developed by MISO to assist with meeting multi-state RPS and public policy goals (Pfeifenberger et al., 2021). According to the MISO tariff, MVP projects must be over 100 kV and meet the following criteria:

1. **Criterion 1:** reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirements that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation.
2. **Criterion 2**: multiple types of economic value across multiple pricing zones with a Total MVP B/C Ratio of 1.0 or higher.
3. **Criterion 3**: MVP must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity reliability standard and must provide economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs (i.e., a B/C ratio of 1.0 or higher).
    a. MISO, FERC Electric Tariff, Attachment FF, § II.C.1, II.C.2, and II.C.3

Projects that qualify as MVP are bundled into a portfolio, studied as a portfolio, and approved by the MISO Board as a portfolio (Lieberman, 2021). MVP projects are evaluated using the same benefits as economic projects, but also include production cost savings, capacity cost savings due to reduction of transmission losses, capacity cost savings due to reduction in planning reserve margin, long-term cost savings, and economic development over 20 years (Lieberman, 2021). Costs are shared regionally using the postage stamp methodology (Lieberman, 2021).

SPP Regional Transmission Planning and Cost Allocation

SPP's Transmission Expansion Plan (STEP) is informed by the region's Integrated Transmission Plan (ITP). SPP is the only RTO/ISO whose local and regional transmission planning is coupled into one planning process known as the ITP, with the exception of one TO who has a separate local process (Lieberman, 2021). The ITP occurs annually to review economic and reliability needs over a 10-year horizon across SPP's territory using three future scenarios which include public policy futures (Lieberman, 2021). Every three years, a 20-year horizon is assessed (Lieberman, 2021). SPP's 2020 ITP report underestimated renewable deployment; The 10-year forecast included in the report matched 2020 installed renewable capacity at the time of publishing (Lieberman, 2021). This could have occurred since states without Renewable Portfolio Standards (RPS) goals were forecasted in ITP with low renewable deployments, even though renewable development was still occurring (Lieberman, 2021). To conclude the ITP, projects are given a need-by date, using unique methodologies based on the project driver. The final portfolio of projects is reviewed and consolidated based on overlapping needs, then approved by the SPP Board (Lieberman, 2021).

The ITP process identifies baseline reliability projects through the model. For projects identified, SPP uses a "Highway Byway" cost allocation methodology, a type of postage stamp methodology, which assigns 100% of costs regionally based on benefits (Lieberman, 2021). The

Highway Byway methodology is reviewed for unjust and unreasonable rates every six years via the Regional Cost Allocation Review process (Lieberman, 2021).

The ITP identifies economic projects based on transmission constraints and effects of congestion. Constraints are ranked and given a score, then economic projects are evaluated and chosen based on cost effectiveness, highest net APC benefit, or ability to meet both metrics (Lieberman, 2021). SPP's APC metric quantifies the production cost associated with fuel costs, dispatch, and congestion, as well as cost savings from reduced emissions (Lieberman, 2021). All projects must meet a 0.5 B/C ratio for 1 year or a 1.0 net present value (NPV) over 40 years (Lieberman, 2021). After projects are selected and approved, additional benefits can be assessed such as capacity cost savings from reduced line losses, avoided reliability projects, marginal energy losses, increased wheeling revenues, and public policy benefits (Lieberman, 2021). Economic projects are also allocated using the Highway Byway cost allocation methodology.

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Analysis: Potential Improvements to Existing State

Proposed Changes in FERC's 2022 Notice of Proposed Rulemaking

In 2021, FERC formally began the process to amend Order 1000 and "remedy deficiencies" in existing federal requirements in response to evidence that electricity rates were unduly discriminatory amid a changing generation mix and market landscape (FERC, 2022). If enacted, this would be FERC's first major ruling on regional transmission planning and cost allocation in a decade.

On July 15, 2021, FERC released an Advanced Notice of Proposed Rulemaking (ANOPR), which sought comments on whether primary project drivers such as reliability, economic, and public policy projects were "inappropriately siloed," and whether the silos "Influence[d] the consideration of potential benefits of a regional transmission facility (and the associated beneficiaries for purposes of allocating the costs of such a facility)," (176 FERC ¶ 61,024 at p. 6 (2021). The ANOPR solicited comments on whether additional benefits criteria should be considered and used to determine cost allocation, and whether existing planning requirements may have resulted in an "unduly narrow set" of benefits assessed and imposed "significant costs on customers," (176 FERC ¶ 61,024 at p. 8 (2021). The Commission sought comments on whether customers were appropriately protected from excessive costs given the high price tag of needed transmission investment to meet a changing generation mix (176 FERC ¶ 61,024 at p. 8 (2021). The ANOPR expressed that participant funding for network upgrades may not align costs commensurate with benefits and burden the interconnecting generator with upgrades that may benefit a broader region or TO (176 FERC ¶ 61,024 at p. 81 (2021). ANOPR comments were solicited from diverse stakeholders in the energy industry.

On April 21, 2022, FERC released a NOPR, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, which was informed by the ANOPR process and comments (FERC, 2022). NOPR initial and reply comments were solicited from stakeholders and due on September 19, 2022. FERC plans to finalize the NOPR and formally amend Order 1000 by the end of 2022. Below is a NOPR summary which highlights three of the six major proposals within the scope of the paper.

Proposals not discussed: changes to Construction Work in Progress Incentive, Exercise of Federal Right of First Refusal/Non-incumbent Transmission Developer Reform, and Consideration of Dynamic Line Ratings and Grid Enhancing Technologies in Long-Term Regional Transmission Planning.

Proposed Changes to Long-Term Regional Transmission Planning

The proposed reform would require all transmission providers to conduct long-term regional transmission planning on a “sufficiently forward-looking basis” over a minimum of 20 years past project in-service date with four long-term scenarios to assess changing resource mixes and use best available data (FERC, 2022). FERC selected 20 years minimum as a middle ground between short-term planning and the full 40-50 year useful life of a transmission facility, given the speculative nature of predicting future scenarios (Degrandis et al., 2022). Transmission providers would be required to coordinate with states to define transparent criteria to be used for selection of transmission projects in regional planning and cost allocation, then amend OATT with criteria (FERC, 2022). The criteria must be transparent and aim to maximize both consumer benefits and efficient transmission deployment, but flexibility would be left to transmission providers to define their own criteria in consultation with states (176 FERC ¶ 61,028 at p. 197 (2022). The additional requirements would expand existing regional planning guidelines outlined in Order 1000.

Within the proposed long-term regional plans, FERC proposes transmission providers improve coordination with generator interconnection processes by evaluating interconnection upgrades that could provide broader regional benefits (176 FERC ¶ 61,028 at p. 141-149 (2022). FERC proposes that transmission providers evaluate interconnection upgrades that have been identified in at least two interconnection queue cycles, but have not yet been completed or assigned through a generator interconnection agreement (Degrandis et al., 2022). FERC proposes these changes to remedy the NOPR finding that transmission deployment has been primarily occurring through the local and generator interconnection processes, found to have resulted in generator withdrawals and higher electricity rates (Degrandis et al., 2022). Decker and DeVore (2022) use the term “sticker shock” to refer to the high withdrawal rate of generators from the interconnection queue. Interconnection project upgrades found to have broader benefits would be partially allocated to stakeholders and reduce cost burdens for interconnecting generators. The NOPR does not fully address interconnection reform and instead plans to address in subsequent rulemaking (176 FERC ¶ 61,028 at p. 9 (2022).

FERC proposes to extend the NOPR’s long-term regional planning requirements to apply to neighboring planning regions engaged in interregional or joint transmission planning. The proposed changes would require transmission providers to revise existing interregional procedures, first established under Order 1000, to include the NOPR reform (Degrandis et al., 2022). Regions would identify facilities that could more efficiently meet interregional needs and could propose regional projects to be interregional projects (176 FERC ¶ 61,028 at p. 333-334 (2022).

FERC proposes a set of 12 benefits for transmission providers to consider in long-term regional planning over 20 years (176 FERC ¶ 61,028 at p. 149-150 (2022). FERC identifies 12 benefits to be considered, but benefit selection would be left up to transmission providers and additional benefits could be considered. Transmission providers would amend their OATT with definitions of chosen benefits and chosen benefit methodologies. Below is the proposed list of 12 benefits:

1. Production cost savings
2. Avoided or deferred reliability transmission projects and aging infrastructure replacement
3. Either reduced loss of load probability or reduced planning reserve margin
4. Reduced transmission energy losses
5. Reduced congestion due to transmission outages
6. Mitigation of extreme events and system contingencies
7. Mitigation of weather and load uncertainty
8. Capacity cost benefits from reduced peak energy losses
9. Deferred generation capacity investments
10. Access to lower-cost generation
11. Increased competition
12. Increased market liquidity
    a. (176 FERC ¶ 61,028 at p. 158 (2022).

In addition, transmission providers would be allowed and encouraged to evaluate chosen benefits using a multi-value portfolio approach for regional transmission planning and cost allocation, which would combine benefits analyses within a single regional planning process and bundle projects into one portfolio (176 FERC ¶ 61,028 at p. 68-72 (2022). The multi-value portfolio approach would not be required and transmission providers would be responsible for compliance with Order 1000. The NOPR found that the portfolio approach would be more stable, more administratively efficient, and enable agreement on cost allocation, (176 FERC ¶ 61,028 at p. 190 (2022). Many commenters were supportive of broadening the range of benefits and consideration of the multi-value portfolio approach. The U.S. DOE commented that the approach "Is more likely to result in an accurate evaluation of the benefits of transmission facilities than would an approach requiring evaluation of each facility individually," (176 FERC ¶ 61,028 at p. 188 (2022).

Proposed Changes to Regional Transmission Cost Allocation

FERC proposes to widen state involvement in regional transmission cost allocation decisions in order to remedy underlying the challenges with fair cost allocation for multi-state projects (Degrandis et al., 2022). Transmission providers would be required to propose revisions to regional cost allocation methodologies and seek state agreement on proposed changes (FERC, 2022). With state approval, transmission providers would amend their OATT with the approved revisions (FERC, 2022). The NOPR states that this reform is needed in tandem with the proposed reform to require long-term scenario planning, which has the potential to exacerbate the complexity of regional cost allocation and lead to disagreement between states (176 FERC ¶ 61,028 at p. 236 (2022). Many commenters were supportive of increasing states roles in cost allocation for stronger alignment between stakeholders and supportive of the evaluation of a wider set of benefits for purposes of regional cost allocation (176 FERC ¶ 61,028 at p. 227-235 (2022). FERC states that cost allocation will only succeed among stakeholders when the methodology is "transparent, equitable, and practicable," which includes a fair assessment of all benefits (176 FERC ¶ 61,024 at p. 50 (2021).

The proposed reform would require transmission providers to work alongside states to select one of the following cost allocation methodologies for long-term regional transmission facilities:

1. An *ex-ante* long-term approach
2. An *ex-post* State Agreement approach
3. A combination of 1 and 2

The *ex-ante* approach defines the cost allocation methodology *before* transmission projects are selected in the long-term regional plan (Troutman Pepper, 2022). The *ex-post* approach requires the transmission provider to gain voluntary agreement from state entities to pay for long-term regional projects *after* projects are selected (Troutman Pepper, 2022). State entities are defined by FERC as any entity responsible for utility regulation or transmission siting, such as public utility commissions (176 FERC ¶ 61,028 at p. 242 (2022). Transmission providers must work with state entities to select one of the methodologies and document best efforts to seek agreement, since state entities can forgo involvement and FERC does not have jurisdiction to regulate or require state participation (176 FERC ¶ 61,028 at p. 243-245 (2022).

According to FERC, the proposed changes would increase the likelihood of stakeholder agreement and increase confidence that costs are commensurate with benefits for large and complex projects (176 FERC ¶ 61,028 at p. 248 (2022). FERC believes "Providing an opportunity for state involvement in regional transmission planning processes is becoming more important as states take a more active role in shaping the resource mix and demand," (176 FERC ¶ 61,028 at p. 196 (2022).

Proposed Changes to Enhance Transparency and Coordination between Local and Regional Planning Processes

FERC proposes to increase transparency criteria in the local transmission planning process. The proposed changes would require transmission providers to engage in transparent local planning and increase coordination with regional planning. FERC would require local transmission providers to define transparency criteria and models within their OATT and establish a stakeholder process for feedback in coordination with regional planning (176 FERC ¶ 61,028 at p. 314 (2022). FERC states that stronger local and regional coordination could lead to more cost-effective solutions for transmission replacements such as right-sizing (176 FERC ¶ 61,028 at p. 316 (2022). FERC proposes a right-sizing process to identify local projects over 230kV that could be upgraded to include additional circuits or higher voltage within ten years as part of the regional planning process (Troutman Pepper, 2022). The proposed transparency guidelines are in line with FERC's obligation to ensure electricity rates are just and reasonable.

Potential Improvements to Cost Benefit Analyses for Regional Transmission Planning

According to Dr. William Hogan from Harvard, "A forward-looking cost-benefit analysis provides the gold standard for ensuring that transmission investments are efficient," and is the only option to truly determine whether an investment is efficient (Gramlich and Caspary, p. 44, 2021). Improvements could be made to CBA approaches to assess additional benefits metrics. Table 1 from Pfeifenberger et al. (2021) contains a comprehensive list of transmission benefits.

Table 1

Electricity System Benefits of Transmission Investments

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic "Day 1" market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

Note. Reprinted from "*Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*" by Pfeifenberger et al., 2021.

Transmission projects can prevent brownouts and blackouts through reliability and resource adequacy benefits. According to Gramlich and Caspary, reliability benefits are easy to quantify and measure (Gramlich and Caspary, 2021). Pfeifenberger et al. (2021) believe all transmission projects provide reliability benefits, even projects where reliability is not the primary driver, such as economic or public policy projects.

Transmission projects can alleviate constraints and reduce the probability for loss of load, also known as generator curtailment, by serving as an additional route for electricity to flow from generation to load (Pfeifenberger et al., 2021). Pfeifenberger et al. (2021) refer to this benefit as transmission's "insurance value" by reducing the frequency of generator curtailment during grid emergencies or system contingencies (p. 38). In addition, transmission projects that shorten the distance from generation and load can reduce line losses.

Transmission projects can reduce the required system planning reserve margin by providing resource adequacy and taking advantage of regional load diversity (Pfeifenberger et al., 2021). Resource adequacy benefits can be measured by generation capacity cost savings (Pfeifenberger et al., 2021). For example, during winter storm Uri in 2021, central regions of MISO and SPP were able to avoid blackouts by importing power from their eastern regions using MISO MVP projects, whereas the Electric Reliability Council of Texas (ERCOT) could not import more than 0.8 GW of power and experienced widespread blackouts and fatalities (Pfeifenberger et al., 2021). MISO and SPP were able to utilize regional load diversification and operational flexibility to meet demand by importing electricity from regions with a generator surplus outside the storm's path.

Transmission projects can defer or avoid additional reliability project upgrades. According to Pfeifenberger et al. (2021) proposed economic and public policy-driven projects can reduce or defer the need for additional reliability projects, since reliability is an inherent benefit of all transmission projects, which in turn reduces upgrade costs. To quote Gramlich and Caspary, "In many cases, today's economic upgrade addresses tomorrow's reliability need," (Gramlich and Caspary, 2021, p. 100). This benefit can be estimated by comparing the present value of the "Revenue requirements of reliability-based transmission upgrades without the proposed projects (the Base Case) to the lower revenue requirements reflecting the avoided or delayed reliability-based upgrades assuming the proposed projects would be in place (the Change Case)," (Pfeifenberger et al., 2021, p. 37). SPP already models this benefit for proposed economic projects (Pfeifenberger et al., 2021).

Additional generation capacity cost savings can be gained in the form of market benefits. Robust transmission projects can provide generator cost savings in the form of reduced wholesale electricity costs, reducing the cost of retail electricity bills (Pfeinfenberger and Chang, 2016). Transmission can provide both transmission-related benefits and generation-related benefits (Pfeifenberger and Chang, 2016). Generation benefits are amplified by the average retail electricity bill where transmission accounts for 10% costs, but generation accounts for 50% (Pfeifenberger and Chang, 2016).

Transmission projects can connect remote areas to load centers and improve access to low-cost generation, including remote renewable generation with characteristically low wholesale electricity prices (Pfeifenberger et al., 2021). Pfeifenberger et al. (2021) acknowledge that more remote areas tend to have lower costs for generation investment overall such as lower siting, permitting, and labor costs. Transmission can increase the capacity value of existing generation, especially renewable generation, and lead to greater utilization of the generation asset and reduced curtailment (Pfeifenberger et al., 2021). Transmission can reduce losses during peak demand hours. MISO's MVP portfolio reduced 150 MW of transmission losses, which offset 1-2% of the portfolio cost (Pfeifenberger et al., 2021).

There are more benefits that can be harder to quantify or are project-specific. For example, transmission can provide market benefits from increased wholesale market competition and increased market liquidity (Pfeifenberger et al., 2021). Transmission projects can provide environmental benefits through decarbonization by facilitating dispatch of lower-emissions generation such as renewable generation, or assist with meeting public policy goals (Pfeifenberger et al., 2021). MISO found that by co-optimizing local and regional wind development with transmission development, wind investment savings could be reduced by $80 billion (Pfeifenberger et al., 2021). It is important to note that not all transmission projects can provide positive environmental benefits, since the scale of total emissions reductions depends on the emissions profiles of the generation mix (Pfeifenberger et al., 2021). Public policy benefits can be indirect in certain cases, since there is an additional investment cost required to meet policy goals (Pfeifenberger et al., 2021). According to Pfeifenberger e al. (2021) "Despite the fact that both transmission and retail electricity rates may increase, the transmission investment can reduce the overall cost of satisfying public policy goals," (p. 53). Please see Appendix C in Pfeifenberger et al. (2021) for a discussion on additional project-specific benefits.

There are a few suggested approaches to evaluate an expanded set of benefits under a CBA. Benefits across CBA methodologies could be required and standardized across transmission providers for alignment on joint planning and regional cost allocation. Alternatively, as FERC proposes in the NOPR, a list of expanded benefits could be suggested with selection left to transmission providers. Another approach could be the two-tier approach used by SPP, where the transmission provider uses one set of benefits metrics to identify projects and then applies a more robust set of additional metrics to assess the final portfolio (Lieberman et al., 2021). Gramlich and Caspary (2021) suggest to only include public policy benefits when affected states have set renewable public policy goals, since not all states in a region will have public policy goals, although there could be an opportunity to assess public policy benefits at specific market nodes only in states with goals. Gramlich and Caspary (2021) suggest at minimum that transmission providers should assess APC savings, resource adequacy including avoided or deferred reliability projects, reduced planning reserve margin, reduced line losses, generation capacity cost savings, and voltage support.

Lieberman et al. (2021) identified concerns with the expansion of benefits assessment due to the risk of overcomplicating a regional planning model. In addition, Lieberman et al. (2021) noted some benefits could be considered subjective and could be difficult to assign to beneficiaries, which could cause stakeholder disagreement on cost allocation, as opposed to the straightforward evaluation of quantifiable benefits. Difficult to quantify benefits are often unrelated to electricity costs, such as public policy goals, resiliency, and economic development (Lieberman et al., 2021). Not all states set RPS or other public policy goals. There are varying opinions on how long transmission benefits should be assessed for, given that transmission projects have a lifecycle of 40-50 years. Some believe a shorter timeline of 10-20 years is more realistic and easier to quantify, but others would rather see benefits assessed over the full project lifecycle despite uncertainty. Gramlich and Caspary (2021) note that benefits grow over time and transmission assets depreciate over time, even with a discount rate, so this can create a mismatch of CBA and lead to an understatement of benefits.

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Model: MISO MVP Model and Multi-Value Portfolio Planning

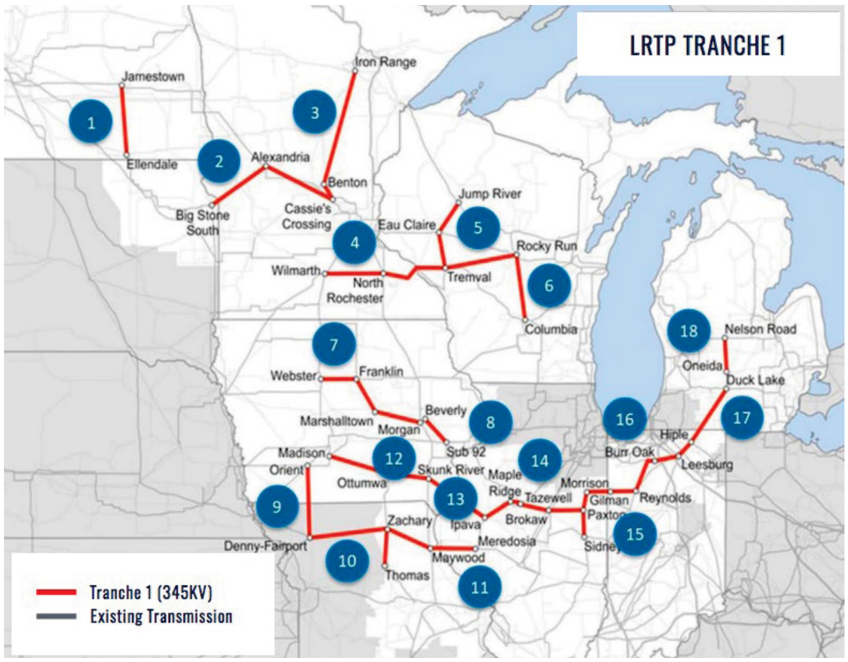
MISO has proven the success of multi-value portfolio planning through the MVP model and delivered greater benefits at lower costs (Pfeifenberger et al., 2021). The MVP model is the only integrated regional planning and cost allocation methodology that recognizes a broad suite of benefits across a portfolio of projects. The multi-value approach combines multiple projects' benefits assessments into one analysis and allocates costs based on the results of the analysis, for projects that meet specific MVP criteria (Gramlich, 2022). A full suite of benefits are assessed beyond traditional APC savings (Pfeifenberger et al., 2021). The model reviews multi-state and multi-utility resource plans in order to accurately forecast future generation and zonal transmission needs (Gramlich, 2022). The portfolio approach to cost allocation is commonly used for public works programs such as roads (Pfeifenberger et al., 2021).

MISO's MVP model serves as an excellent example of integrated multi-value portfolio planning and cost allocation. Pfeifenberger et al. (2021) recommend multi-value planning as an integrated and cost-effective planning approach that more accurately assesses benefits under a CBA. Pfeifenberger et al. (2021) also recommend the portfolio approach to cost allocation as an efficient and less complex cost allocation approach. In the portfolio approach, benefits are more evenly distributed and stable across a broader geographic range and over time, which can provide confidence to stakeholders that costs are commensurate with benefits and reduce controversy in cost allocation (Pfeifenberger et al., 2021; Brattle, 2022). Benefits are spread "more uniform" across the wider portfolio and costs are recovered across the portfolio (Pfeifenberger, 2021, p. 42). The portfolio approach has the potential to be more successful with gathering political support for a multi-state portfolio of projects.

Recently MISO utilized the MVP model in their Long Range Transmission Plan (LRTP) to assess benefits for the Tranche 1 portfolio shown in Figure 6, consisting of 18 projects estimated at $10.3 billion across seven northern and central zones (Howland, 2022c). LRTP goals were to achieve stakeholder support to authorize transmission expansion, successfully allocate costs, accelerate generation mix changes, and receive state regulatory approval for project siting (Gramlich, 2022).

Figure 6

Portfolio Map of 18 Projects, MISO LRTP Tranche 1



Note. Reprinted from "*Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis: A Case Study of MISO's Long Range Transmission Planning*" by Gramlich, 2022.

The LRTP began by identifying the magnitude of transmission needs across northern and central zones through a review of multi-state RPS policies and multi-utility resource plans, then designed the Tranche 1 portfolio to provide multi-state benefits across seven zones (Gramlich, 2022). Seven benefits were assessed in the Tranche 1 CBA portfolio analysis:

1. Congestion and fuel savings (production cost savings)
2. Avoided capital costs of local resource investments
3. Avoided transmission investment
4. Reduced resource adequacy requirements

5. Avoided risk of load shedding

6. Decarbonization

7. Reliability issues addressed in LRTP

8. Other qualitative and indirect benefits

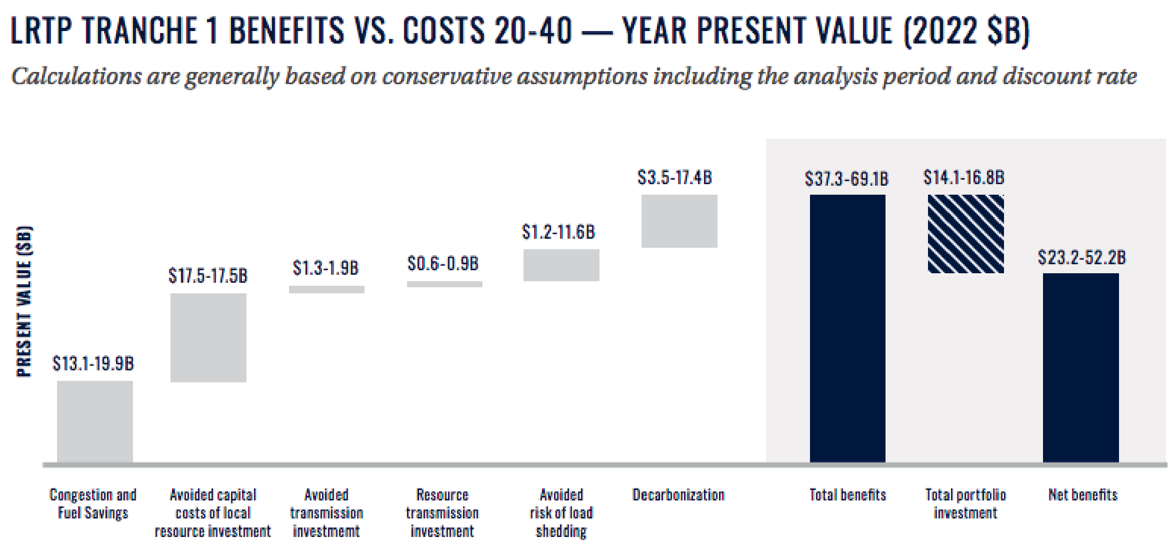
    a. (Gramlich, 2022)

It took two years for MISO stakeholders to agree on the seven benefits through a stakeholder working group called the Regional Expansion Cost and Benefits Working Group (Gramlich, 2022). One of the key stakeholders was the Organization of MISO States (OMS) representing the interest of affected states. Concurrently, OMS conducted two cost allocation working groups (Gramlich, 2022).

The LRTP analysis found $37.3 billion in benefits with a 3.6 B/C ratio across the region and a minimum of 2.2 B/C ratio for individual zones, shown in Figure 7 (Gramlich, 2022).

Figure 7

Benefits by Category Compared to Cost, MISO LRTP Tranche 1

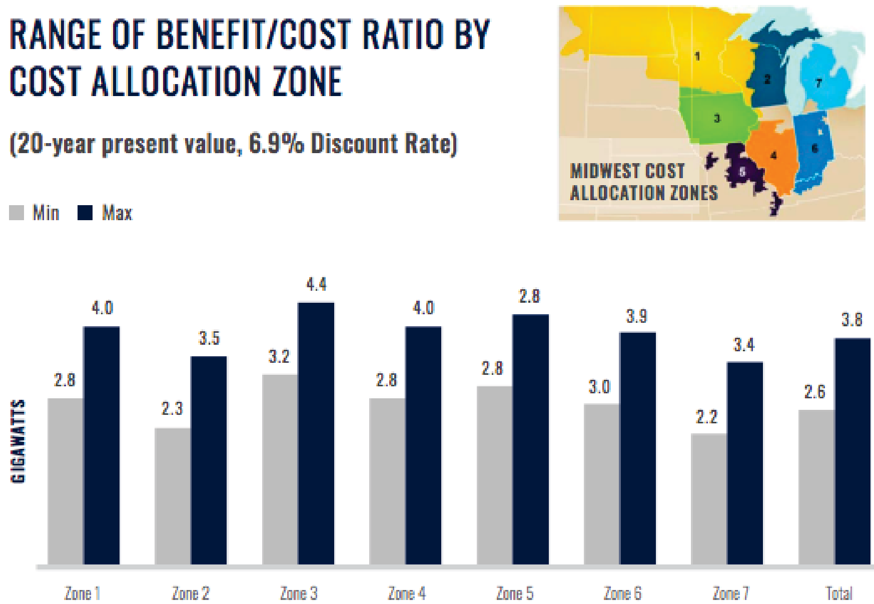


Note. Reprinted from "*Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis: A Case Study of MISO's Long Range Transmission Planning*" by Gramlich, 2022.

The benefits were widely distributed and spread evenly across the seven zones, shown in Figure 8 (Gramlich, 2022). Gramlich believes that the even distribution of benefits across zones and states helped to secure buy-in from affected states to allocate costs across the region, which he noted as the “hardest obstacle” to build transmission (Gramlich, 2022, p. 2).

Figure 8

Incidence of Benefits Across Cost Allocation Zones, MISO LRTP Tranche 1



Note. Reprinted from “*Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis: A Case Study of MISO’s Long Range Transmission Planning*” by Gramlich, 2022.

The full $10.3 billion transmission plan was approved by the MISO Board on July 25th, 2022 and is expected to support 53 GW of renewable energy reaching commercial operations in 2028 (Gramlich, 2022; Howland, 2022b). Next steps will be to formally measure and report transmission benefits by zone in order to ensure the cost allocation methodology properly aligns costs with benefits (Gramlich, 2022). The costs will be socialized across benefitting zones using the postage stamp methodology (Lieberman, 2021). Next, MISO plans to replicate the study across other MISO zones and tranches (Howland, 2022b).

Tranche 1 of the LRTP was successful due to the high level of stakeholder and public engagement, who had the opportunity to directly participate in methodology development (Howland, 2022c). The public could submit oral and written comments to MISO and receive a response, similar to the FERC rulemaking and comment process (Gramlich, 2022). Stakeholders could visualize regional benefits, which helped reduce concerns regarding excess transmission spend and helped gather support from state entities who oversee regulatory and siting approvals (Howland, 2022c). However, MISO said the study took two years and “Was the most complex transmission planning study effort in MISO’s history,” (Gramlich, 2022, p. 3).

Gramlich (2022) suggests more transmission providers follow the MVP model, as it represents a strong industry example of regional transmission planning and cost allocation, although he believes the model could be improved. Gramlich (2022) suggests expanding the list of benefits used by the MVP model to include the 12 benefits listed in FERC’s NOPR. He notes that seven of the proposed FERC NOPR transmission benefits were not included in the LRTP Tranche 1 analysis (Gramlich, 2022). Gramlich (2022) believes all benefits from every portfolio should be considered as a best practice even though some benefits are difficult to quantify, under the reasoning that omission could be argued as unjust and unreasonable. Gramlich (2022) recommends screening proposed transmission projects for each benefit and then applying a more robust analysis to the benefits expected to occur. In contrast, the Chair of OMS believes the CBA should utilize benefits that are quantifiable, can be replicated, are not duplicative, and are forward looking (Howland, 2022c).

Model: SPP/MISO Cross-Seams JTIQ Study for Joint Regional Planning and Cost Sharing

In 2020, SPP and MISO collaborated on a first-of-its-kind study known as the Joint Targeted Interconnection Queue (JTIQ) Study with the goal to reduce chronic transmission congestion at the seam between the two regions. Congestion led to difficulty interconnecting generation at the seam due to high network upgrade costs, despite the seam's wind-rich potential and high wind speeds (Howland, 2022a). As of Q1 2022, there were 127 GW of generation in the MISO queue and 97 GW in the SPP queue (MISO & SPP, 2022).

The study is an excellent example of joint regional planning using a portfolio approach with shared benefit assumptions. For the first time, the JTIQ approach combined regional transmission planning with the generator interconnection process for one study outcome. Reliability and economic benefits were assessed alongside potential network upgrades across two joint planning regions (Howland, 2022a). By assessing benefits concurrently, MISO and SPP (2022) were able to efficiently assess the most cost effective methods to alleviate transmission congestion and unlock generator interconnection. MISO & SPP expected the study results to accelerate network upgrades along the seams and reduce delays through a portfolio of transmission projects (MISO & SPP, 2022).

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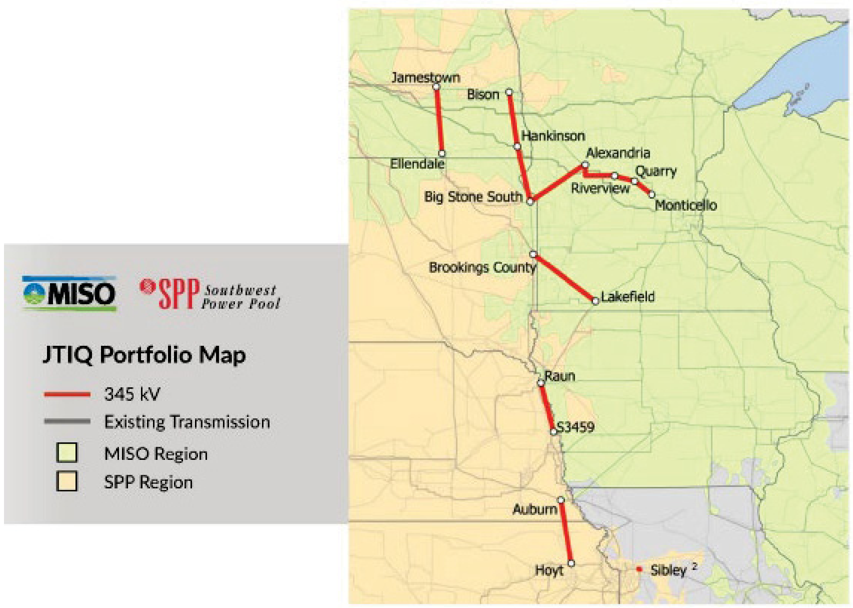
Historically, MISO and SPP's JOA tariff did not define a joint cost-sharing allocation methodology and the two regions had not identified any interregional projects as of 2019 (MISO & SPP, 2022; Lieberman, 2021). In 2019, FERC approved changes to the JOA to allow simultaneous benefit assessment models through a joint model framework (Lieberman, 2021). Shortly after, the JTIQ study commenced in 2020 to identify a portfolio of seven potential transmission projects shown in Figure 9 along the shared border with a portfolio project cost of $1.65 billion (MISO & SPP, 2022). The study was completed in 2022 after 18 months of stakeholder collaboration using a traditional APC benefit assessment.

Figure 9

JTIQ Portfolio Map of 7 Projects



Note. Retrieved from "*Joint Targeted Interconnection Queue Study Report*" by MISO and SPP, 2022.

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The results in Table 2 concluded the portfolio of projects would provide reliability benefits through alleviating transmission constraints and economic benefits through APC savings of $724 million in MISO and $247 million in SPP with a B/C ratio of 0.60 (MISO & SPP, 2022). The combined reliability and economic benefits could allow up to 28 GW of generator interconnections according to MISO's conservative assumptions, and 53 GW of generator interconnections according to SPP's assumptions (MISO & SPP, 2022).

Table 2

Summary of JTIQ Portfolio Estimated APC and Reliability Benefits Across MISO and SPP

JTIQ Selected Portfolio Estimated APC and Reliability Benefits	MISO APC Benefit ($M)	SPP APC Benefit ($M)	Number of Reliability Constraints resolved in MISO models	Number of Reliability Constraints resolved in SPP models
Big Stone South – Alexandria – Riverview – Quarry – Monticello 345	$487	$32	17	5
Jamestown – Ellendale 345	$405	$56	8	3
Bison – Hankinson – Ellendale 345	$274	$144	11	6
Brookings Co. – Lakefield 345	$278	$8	12	1
Raun – S3452 345	$213	$192	1	0
Auburn – Hoyt 345	$223	$14	2	2
Sibley 345 Bus Reconfiguration*	-	-	9	6
JTIQ Selected Portfolio	**$724**	**$247**	**33**	**15**

*The economic benefits of Sibley 345 kV bus upgrades are not quantified as this bus upgrade could not be simulated in the tools available. This upgrade changes the bus configuration and the definition of current contingencies, and hence mitigates the constraint.

Note. Retrieved from "*Joint Targeted Interconnection Queue Study Report*" by MISO and SPP, 2022.

A joint cost allocation methodology does not yet exist between the SPP and MISO, so the two regions are working alongside stakeholders to develop a framework methodology. The goal will be "To equitably distribute the cost of recommended transmission upgrades to multiple parties that benefit from those upgrades," (MISO & SPP, 2022, p. 17). The methodology may use a weighted scoring system to assign costs between generator and load, depending on benefits and regional load contributions (MISO & SPP, 2022). Next steps are to finalize the methodology and file with FERC for approval (Howland, 2022a). Once approved, the portfolio of projects will be brought to the respective Boards for approval in early 2023 (MISO & SPP, 2022). Long-term goals seek improved coordination between the two RTO/ISO through further collaboration to prepare both regions for generation mix changes (MISO & SPP, 2022). The collaboration could lead to more seams study and the development of more joint assumptions and models (Walton, 2020).

The JTIQ approach was successful due to frequent stakeholder engagement. In addition to weekly meetings between SPP and MISO, there were eight public-facing stakeholder meetings over the study period, which gave stakeholders from both regions the ability to provide feedback (MISO & SPP, 2022). In relation to the study, Natalie McIntire with Clean Grid Alliance said “I have never seen a study like this where two RTO have come together to evaluate what transmission solutions can bring broad benefits to load and at the same time can help to enable new generation interconnection near the seam,” and hopes JTIQ can serve as a model for transmission expansion (Howland, 2022a).

The JTIQ model serves as an example for other RTO/ISO to jointly align regional transmission planning with generator interconnection along shared seams. Even though the JTIQ model used the traditional APC benefit assessment, projects were still found to be economical. The CBA could have been expanded using the multi-value approach to include a broader suite of economic and reliability benefits. To replicate the study, two RTO/ISO would need a JOA to govern the process. Two regions seeking to engage in joint regional planning would need to develop a joint cost allocation methodology. According to the Brattle Group (2022), the failure to conduct seams studies, which utilize the most cost-efficient outcomes, will result in building higher-cost localized and piecemeal transmission projects and higher-cost electricity prices in the long term.

Results

Policy Recommendations

Policies that regulate both transmission planning and cost allocation should be dually incentivized, since the two are interconnected. The findings are in line with the hypothesis that the federal regulatory framework could be improved through stronger guidance and dual incentives for both cost allocation and transmission planning.

Federal reform should be carried out by FERC, using authority from the FPA, to improve regional transmission cost allocation and planning beyond its existing state. FERC has authority to uphold just and reasonable electricity rates and ensure no unduly discriminatory rates. Below are a list of policy recommendations for FERC that dually incentivize transmission planning and cost allocation. In order to successfully meet public policy goals related to the energy transition, policy recommendations should be enacted within the next year given the 5-10 year transmission construction timeline (Pfeifenberger and Chang, 2016).

The process for FERC reform has already begun through the NOPR process and should be expanded. **FERC should require a standardized list of seven benefits to be used in CBA**, as taken from the NOPR:

1. Production cost savings
2. Avoided or deferred reliability transmission projects and aging infrastructure replacement
3. Either reduced loss of load probability or reduced planning reserve margin
4. Reduced transmission energy losses
5. Reduced congestion due to transmission outages
6. Mitigation of extreme events and system contingencies
7. Mitigation of weather and load uncertainty
    a. (176 FERC ¶ 61,028 at p. 158 (2022).

The researcher recommends seven reliability benefits, since they are easily quantifiable. Transmission providers should be allowed to consider additional generation capacity cost savings, market, and environmental benefits on a voluntary basis to allow flexibility by region. FERC should keep the maximum B/C ratio at 1.25 for project approvals. Benefits should be evaluated on a 20-year time horizon in accordance with the NOPR recommendation. The researcher believes FERC has the authority to carry out the recommendations under the duty to uphold just and reasonable electricity rates and not impose unduly costs on customers.

The policy recommendations are in line with Lieberman (2021) who recommends a centrally-coordinated and unified regional planning approach with aligned benefit methodologies. The recommendations agree with Gramlich and Caspary (2021) who recommend FERC require transmission providers consider a minimum set of benefits and set a floor, not a ceiling, on additional benefits. In contrast to Gramlich and Caspary (2021), the researcher does not believe “difficult to quantify” benefits should be required by FERC (p. 58). The recommendations match the hypothesis that a more accurate quantification of benefits is needed through a stronger CBA.

FERC should recommend, but not require, a two-tier CBA approach similar to the SPP ITP evaluation of economic projects. Projects would be evaluated and chosen for the initial portfolio using one set of benefit metrics. Once projects were selected, an additional set of benefit metrics would be applied to determine the final portfolio and cost allocation. Both sets of benefit metrics would be left to transmission providers to decide, as long as FERC’s seven benefits were utilized.

The Commission should allow and highly encourage transmission providers to evaluate projects using a multi-value portfolio approach for regional transmission planning and cost allocation following the MISO MVP model. Projects would be studied as a portfolio rather than individually, with portfolio costs allocated to beneficiaries commensurate with benefits. The standardized list of seven benefits would be required for portfolio evaluation as part of the CBA, although additional benefits could be considered. The recommendations go farther than FERC's proposed NOPR reform by highly encouraging the multi-value approach, rather than just allowing the practice. Additionally, after a test period, rulemaking could be amended in the next 5-7 years to require the multi-value portfolio approach be used by some or all transmission providers. The MVP model would be encouraged as the norm, rather than the exception (Gramlich and Caspary, 2021). The recommendations are in line with Pfeifenberger (2021) who recommends that transmission providers approach all projects with the multi-value portfolio approach to planning and cost allocation. Gramlich and Caspary (2021) also recommend FERC encourage the use of portfolio-based cost allocation.

In line with NOPR recommendations, **the Commission should require transmission providers attempt to develop planning and cost allocation criteria alongside states**. In accordance with FERC's authority, states would not be required to participate in development of cost allocation methodologies, but would have the option for participation. In an interview with FERC Chairman Richard Glick, he recommends state involvement in regional transmission planning to assist with cost allocation and siting (Howland, 2021).

In addition to NOPR recommendations, **FERC should impose further transparency requirements for transmission providers to consult with a diverse mix of stakeholders such as siting authorities, industry trade associations, and the public**. The consultation would include stakeholder invitations to planning and cost allocation meetings with a stakeholder comment period. Chairman Glick recommends public involvement from those "directly affected" by transmission and environmental justice communities (Howland, 2021). The recommendations match the paper hypothesis that greater stakeholder involvement is needed from states and the public.

To maximize transmission deployment, Federal guidelines should be updated to include harmonization between regional and local planning. In accordance with proposed NOPR changes, **transmission providers should be required to increase coordination and**

transparency criteria between local and regional planning, including a right-sizing process to require an evaluation of local projects over 230kV with potential for upgrades. **Federal incentives should be passed through Congress to create a 10% Investment Tax Credit (ITC) for projects determined to be candidates for right-sizing**. **FERC guidelines should encourage, but not require, the coupling of local and regional planning into one analysis similar to the SPP ITP.**

The Commission should encourage the voluntary creation of a shared cost allocation methodology between two planning regions similar to the JTIQ study. FERC does not have authority to require the creation of a shared cost allocation methodology, since Order 1000 requires voluntary agreement for any cost allocation occurring outside of a transmission planning region. **The Commission should encourage voluntary joint seams studies similar to JTIQ to include an evaluation of the network upgrades process**. The recommendations match the paper hypothesis that costs should be shared more evenly through interregional or joint cost sharing.

In accordance with NOPR recommendations, **transmission providers should be required to coordinate the interconnection process with regional planning to provide greater harmonization between the two processes.** Coordination would require an evaluation of proposed network upgrades with potential to provide broader regional benefits. As proposed by FERC, transmission providers would be required to evaluate interconnection upgrades that were identified in multiple cycles but failed execution. More research is needed to make formal recommendations on cost allocation, but proposed network upgrades also found to have regional benefits would likely be funded through individual generators and through the long-term regional planning process in accordance with beneficiaries.

Discussion

The results found an expansion of benefits could ensure portfolio and project costs are commensurate with benefits for purposes of cost allocation. The policy recommendations could improve the acceptance of cost allocation and more appropriately assign benefits to all beneficiaries. If a greater percentage of uncaptured benefits were to be included in CBA and assessed correctly, the results revealed the stakeholder process would be less contentious and more transparent. The researcher concluded that some benefits should be shared and standardized across transmission providers, otherwise successful alignment on joint or interregional planning would be limited. The proposed recommendations go farther than the NOPR, which suggests a list of 12 benefits to consider but does not require them. However, the policy recommendations only require a list of seven benefits rather than all 12 NOPR benefits. The proposed recommendations still enable regional flexibility by allowing additional benefits to be assessed.

The expansion of benefits under a CBA would improve the value of transmission so more projects could be approved. The policy recommendations get transmission providers closer to identifying the true value of transmission and full range of benefits offered. However, perfection should not be the enemy of the good. The capstone results uncovered the difficulty in reaching the true “full value” without a burdensome and comprehensive analysis. It is unlikely all uncaptured transmission benefits could be successfully captured without risk of overcomplicating the process. For example, a burdensome and prescriptive process could be created if the comprehensive benefit list from Table 1 were required by FERC. Gramlich (2022) refers to the 12 NOPR benefits as the “closest to a best practice,” however the best practice may not be feasible nor time-efficient (p. 9). According to Penrod (2022), given FERC’s limited involvement in transmission rulemaking and the historically local nature of grid planning, it would be challenging to amend federal law to standardize transmission planning criteria in a prescriptive manner.

The results revealed that some transmission benefits can be challenging to quantify. Thus, the recommendations focus on reliability benefits, found to be the easiest to quantify. The researcher expects some resistance to implementation from transmission providers, since there are sentiments that the majority of transmission benefits are too challenging to quantify. The recommended 20-year time horizon would help minimize uncertainty in benefit quantification by spreading benefits over a long period without introducing too much uncertainty. The time horizon strikes the right balance between an insufficiently short time horizon and an uncertain future time horizon over the full lifecycle of a project. The two-tier approach to benefit assessment would help reduce friction to implementation by encouraging a modest evaluation for initial portfolio selection. Final portfolio selection would apply more robust criteria for the purposes of cost allocation, since an accurate evaluation of benefits is key for increasing stakeholder confidence in cost allocation. Transmission providers could use the two-tier approach to test out more subjective benefits, such as market or environmental benefits, as a pilot program prior to region-wide benefit adoption.

Encouragement of the multi-value portfolio approach would reduce benefit silos in favor of a unified regional vision. The approach was found to be more efficient and cost effective, since the portfolio would be studied as one analysis (Gramlich and Caspary, 2021). The portfolio method for cost allocation was found to be less contentious and to improve stakeholder acceptance for multi-state cost allocation (Pfeifenberger et al., 2021). The multi-value model was found to distribute costs more evenly over a wider portfolio and geographic region. However, the multi-value portfolio model is not without challenges, since portfolios are larger and more expensive overall. The portfolio approach could lead to longer deployment timelines due to an increase in the number of projects to permit and construct.

The multi-value portfolio approach may be difficult to conduct in non-RTO/ISO regions and may not be the best fit, even though it would be the most efficient approach. The recommendations propose a test period for transmission providers to pilot the multi-value model prior to an amendment to require some form of multi-value or portfolio planning. If a mandate were proposed, there could be an exemption for non-RTO/ISO regions to avoid a top-down federal approach. It is unclear whether a mandate could be enacted under FERC's authority.

An expansion of stakeholder involvement would include a more diverse set of interests in regional planning and cost allocation decisions. The results revealed that increased stakeholder involvement has the potential to increase alignment and develop confidence in cost allocation, especially in multi-state scenarios. The recommendations have the potential to reduce complexity barriers and increase transparency through improved communication on project selection and costs commensurate with benefits. Chairman Glick believes public involvement would lead to increased public confidence in selected projects (Howland, 2021). The recommendations are flexible since states would not be required to participate.

The results revealed that the right-sizing process could encourage larger and lower-cost regional transmission projects. The approach would focus on deployment of the most cost-efficient transmission projects, rather than immediate local reliability projects, which could reduce overall deployment and electricity costs. The ITC incentive could improve the economics of projects, which could benefit ratepayers and stakeholders.

The results found the combination of local and regional planning would increase efficiency of transmission deployment and reduce costs. One combined analysis would be more time efficient and streamline communication between stakeholders. The recommendations would discourage the PJM supplemental process by involvement of a larger group of stakeholders. Combined planning would not be feasible or desired by every RTO/ISO, so the practice would be encouraged but not required.

The results uncovered that voluntary joint seams studies have the potential to enable more generator interconnections and reduce congestion. The required list of seven standardized benefits would align benefit methodologies and planning models across transmission providers, which could improve execution of joint studies and cost allocation. The recommendations would lead transmission providers closer towards a coordinated multi-region and multi-value planning approach, which was found to maximize transmission deployment.

The results revealed that greater coordination between interconnection and regional planning could reduce the upgrade cost burden on individual generators and enable more interconnections. The approach has the potential to reduce interconnection study bottlenecks by identifying repeated interconnection upgrades that have failed execution. The approach would be expected to reduce the cost burden on the interconnecting generator from 100% to a more fair percentage commensurate with benefits. This is likely to face some pushback from stakeholders who believe interconnecting generators should be responsible for all grid upgrades related to their interconnection. More research is needed on this topic as an additional area of study to assess how cost allocation could be conducted in a fair manner.

FERC would face challenges if the proposed policy recommendations were adopted. Some stakeholders or transmission providers could challenge the proposed recommendations in court through the argument that FERC overreached authority under the FPA. The recommendations would be most likely to face resistance from non-RTO/ISO regions who have less advanced market design and less resources for implementation. The capstone analysis was limited to RTO/ISO regions due to the scope of the study and time limitations. Thus, most recommendations were applicable for RTO/ISO regions and not considered in the context of non-RTO/ISO regions. Additional research would be required to study the effect of proposed recommendations on non-RTO/ISO regions.

FERC is a slow-moving and independent agency, so it is unlikely that policy recommendations outside of the NOPR could be enacted within the next five years without a separate rulemaking process. It is most practical for FERC to enact policy recommendations consistent with the NOPR as a first step, then consider additional recommendations for future rulemaking. Future rulemaking would consist of comment periods and stakeholder input from diverse members of the energy industry.

Proposed future research would include a robust analysis on barriers to interregional planning and collaboration. According to the Brattle Group (2022), “no major interregional transmission projects have been built in the last decade.” Since there were no strong examples of interregional planning, the topic was omitted from the capstone due to time limitations. However, interregional planning could be a strong area for future policy improvement as improvements are made to regional planning and cost allocation.

Due to scope, the capstone research did not thoroughly cover interconnection and network upgrade reform, although this would be a strong area for future research. The topic is hotly debated and the policies are in need of reform due to interconnection bottlenecks. The NOPR stated that interconnection reforms would be fully addressed in future rulemaking.

An area of future study could include an analysis of additional improvements to regional planning models beyond the CBA. Improvements could be made to the underlying future scenario assumptions used to forecast future transmission needs, including assumptions related to future generation and fuel mixes. More research is needed to understand the effects of future scenario assumptions on future transmission needs. More research should be conducted on the time horizon of future scenario forecasts.

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Conclusion

In conclusion, dual improvements to regional cost allocation and planning procedures would maximize efficient transmission deployment and solve the “planning paradox.” The proposed recommendations would improve transmission expansion and ensure transmission could deliver greater benefits to stakeholders while upholding reliability standards. The proposed recommendations would increase transmission deployment at a more rapid pace in alignment with the REPEAT Project’s recommended transmission expansion of 2.3%/year to maximize IRA emissions reductions by 2030.

The proposed reform would increase the ability to build multi-state transmission projects and reduce opposition to project costs. In addition, the proposed policy recommendations would increase generator interconnections and encourage asset modernization. The reform would support existing and future generation through robust transmission capacity. The deployment of robust transmission would increase the electricity grid’s ability to adapt to the energy transition, including adaptation to generation mix changes and asset retirements. Efficient and cost-effective transmission deployments would ensure access to electricity at the lowest cost.

Glossary

ANOPR Advanced Notice of Proposed Rulemaking
APC Adjusted Production Cost
B/C Cost-benefit Ratio
CBA Cost Benefit Analysis
CRS Congressional Research Service
DOE Department of Energy
ERCOT Electric Reliability Council of Texas
FERC Federal Energy Regulatory Commission
FPA Federal Power Act of 1935
GW Gigawatt
IRA Inflation Reduction Act of 2022
ITC Investment Tax Credit
ITP Integrated Transmission Plan
JOA Joint Operating Agreement
JTIQ Joint Targeted Interconnection Queue Study
kV Kilovolt
OATT Open Access Transmission Tariff
OMS Organization of MISO States
LRTP Long Range Transmission Plan
MISO Midcontinent Independent System Operator
MTEP MISO Transmission Expansion Plan
MVP Multi-value Projects
MW Megawatt
NERC North American Electric Reliability Corporation
NOPR Notice of Proposed Rulemaking
NPV Net Present Value
NREL National Renewable Energy Laboratory
PJM Pennsylvania-New Jersey-Maryland Interconnection
RPS Renewable Portfolio Standard
RTEP Regional Transmission Expansion Planning
RTO/ISO Regional Transmission Organization/Independent System Operator
SPP Southwest Power Pool
STEP SPP Transmission Expansion Plan
TO Transmission Owner
US United States

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