Mind the Regulatory Gap

How to Enhance Local Transmission Oversight

Report / November 2024

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About RMI

RMI is an independent nonprofit, founded in 1982 as Rocky Mountain Institute, that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut climate pollution at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; Abuja, Nigeria; and Beijing.

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Executive Summary

In the coming years, the United States will need to substantially expand the capacity of its electric transmission grid to replace aging infrastructure, accommodate load growth from data centers and end-use electrification, interconnect low-cost clean generation, and ensure reliability and resilience in the face of increasingly severe weather. Transmission expansion will require significant new investment — yet many Americans already struggle to pay their monthly electricity bills. To achieve affordability through the clean energy transition, it will therefore be essential for planners and regulators to ensure that ratepayer money is spent efficiently.

To expand the transmission grid in an efficient manner, smart planning is essential. A key ingredient of this will be ensuring the right mix of **local projects** (those that are built by a single utility to meet needs within its own footprint) and **regional projects** (those that are regionally planned to meet multiple utilities' needs). To achieve the needed local and regional balance, all transmission projects will need to receive the appropriate regulatory scrutiny, including identifying where local projects could be scaled up to simultaneously meet regional needs (a process known as **right-sizing**[i]).

Today, however, there is a **regulatory gap**. Local projects are receiving little oversight. This gap results from a number of factors, including:

- Regional planning entities, such as regional transmission organizations (RTOs) and independent system operators (ISOs), consider local projects outside of their purview;
- The Federal Energy Regulatory Commission (FERC) assumes project costs were prudently incurred unless stakeholders can prove otherwise; and
- State public utility commissions (PUCs) often have limited oversight authority when it comes to local projects.

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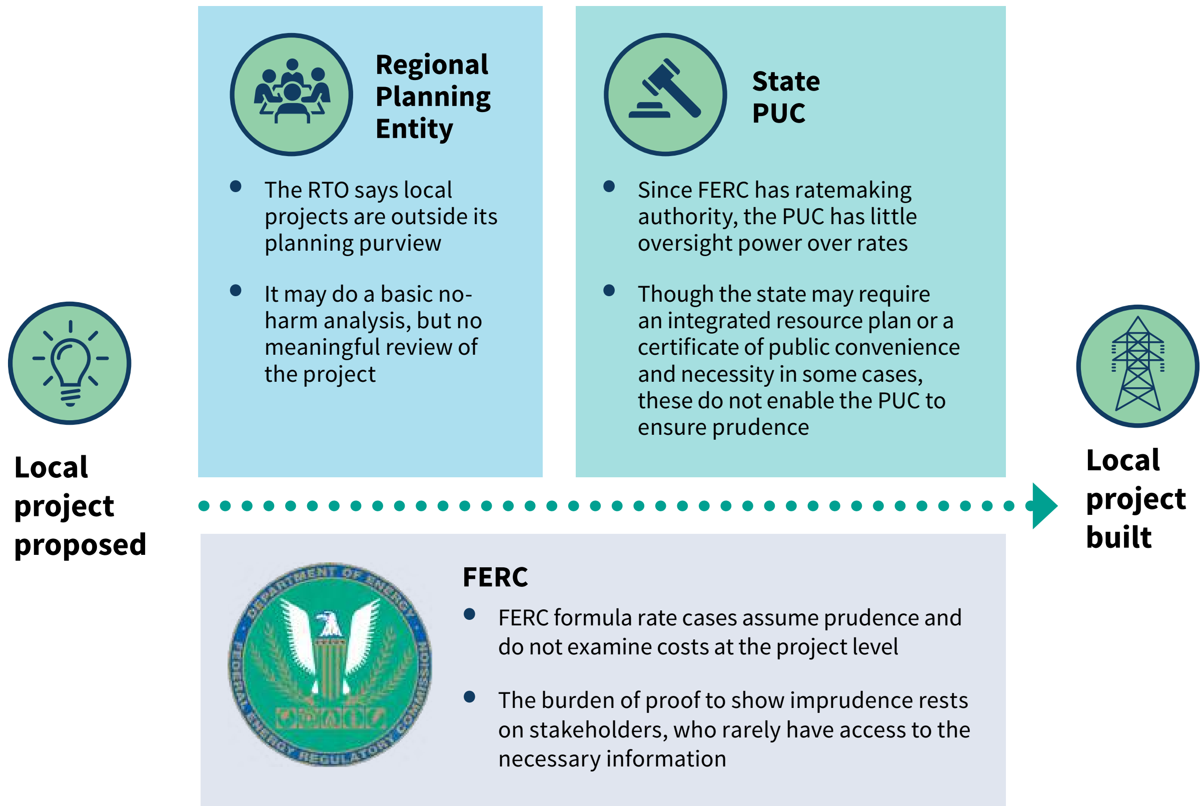
i Right-sizing means considering whether a larger project could better meet both local and regional needs than the smaller project. It is a vital aspect of sound planning because often a single large project is able to more cost-effectively meet multiple needs than a series of individually planned small projects, while reducing total land use and environmental impacts.

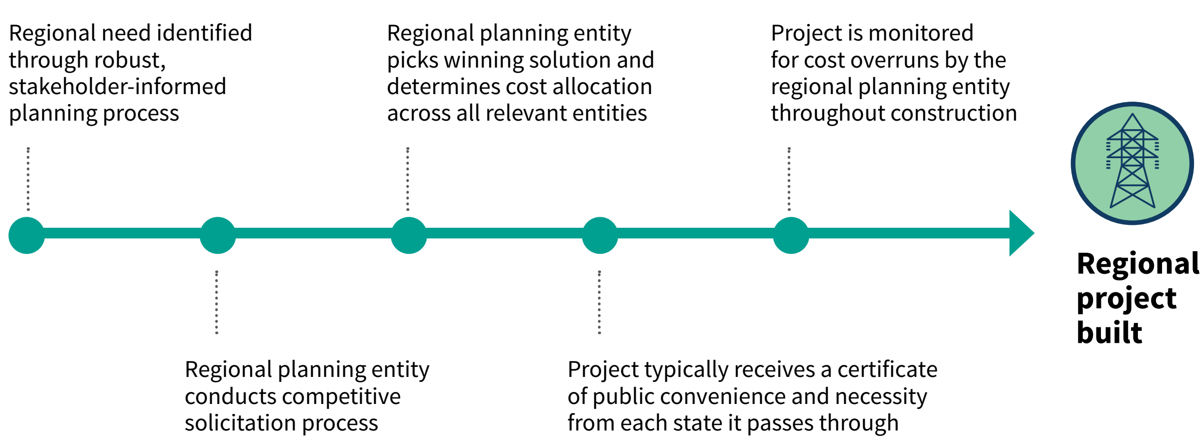
Exhibit ES1 summarizes the main factors that contribute to the regulatory gap. Exhibit ES2 then compares the lack of review that local transmission projects receive to the robust review process for regional projects.

Exhibit ES1 The Regulatory Gap for Local Transmission Projects



RMI Graphic.

Exhibit ES2 Regional Transmission Project Review Process



RMI Graphic.

As illustrated in Box ES1, this regulatory gap has corresponded with a broad nationwide shift in transmission spending from regional transmission projects to local projects. This shift can in part be attributed to the incentives created by a lack of accountability resulting from the regulatory gap, as we explore further in this report.

Box ES1

Evidence of the Shift in Transmission Spending to Local Projects

- According to the FERC *State of the Markets 2021* report, since 2014, the percentage of spending on transmission projects in the United States with voltages of 230 kilovolts or higher has been steadily declining, from 72% in 2014 to just 34% in 2021.[1]
- A recent analysis by Grid Strategies found that while transmission spending hit an all-time high in 2023, the United States built only "20% as much new transmission [mileage-wise] in the 2020s as it did in the first half of the 2010s." Only 55 miles of new high-voltage transmission were added in 2023, compared to a record 4,000 miles in 2013.[2]
- Analysis by the Brattle Group found that 90% of recent transmission spending has been on lower-voltage reliability upgrades, with 50% of all spending going toward local projects.[3]

Regional trends, where data is readily available, confirm these national trends.

- In the mid-Atlantic (PJM Interconnection), spending on local projects (i.e., Supplemental projects) increased from 9% of total spend from 2005 to 2013 to 73% of total spend from 2014 to 2021.[4]
- In New England (ISO New England), spending on local projects (i.e., asset condition projects) increased eightfold from 2016 to 2023.[5]
- In the Midwest (Midcontinent Independent System Operator), local projects (i.e., Other projects) have increased from 54% of total spend in 2017 to 78% in 2022.[6]
- In California (California Independent System Operator), 63% of projects from 2018 to 2022 were local (i.e., self-approved projects) and thus not eligible for state or regional review.[7]

We identified the regulatory gap and its impacts through interviews with state regulators, consumer advocates, and others, as well as review of FERC filings and related evidence. We recommend 11 regional, federal, and state reforms to address the regulatory gap:

Regional Reforms

- Regional planning entities can **implement regional-first planning**, which we describe further in Exhibit ES3. Regional-first planning would ensure right-sizing is considered for all local needs. FERC could require regional-first planning or individual regional planning entities could adopt it on their own.
- FERC can **standardize local project definitions and tracking** across regional planning entities.
- FERC and regional planning entities can **strengthen state input and influence at the regional level**.

Federal Reforms

- FERC could **reform the formula rate process** to apply only to projects that receive adequate regional and/or state review. This could help address the cause of the regulatory gap by enabling greater scrutiny of local project expenditures to ensure prudence.
- FERC could **establish an independent transmission monitor** (ITM), either a single federal ITM or one for each planning region.
- FERC could **explore performance-based regulation** for transmission.

State Reforms

- Some states require PUCs to approve transmission projects through the issuance of a certificate of public convenience and necessity (CPCN). State PUCs can **leverage and expand CPCN authority** for local transmission projects.
- PUCs could **offer expedited cost recovery** for local projects that have undergone a robust regional review, rather than making expedited recovery via rate riders the default option for all transmission costs.
- PUCs could **update integrated resource plans** (IRPs) to incorporate transmission, including regional-first planning.
- States could **create and fully leverage electric transmission authorities**, which are independent bodies established to coordinate transmission development, to help enable regional-first planning.
- State legislatures and others could **help PUCs grow their regulatory staff capacity and expertise** to more effectively conduct oversight where they have existing authority.

Exhibit ES3 Components of Regional-First Planning

Utilities submit proposed local needs. Transmission owners submit anticipated local needs at the start of each regional planning cycle, whether it involves planning over the short term or the long term.

Planning entity identifies the region's needs. The regional planning entity determines all regional needs holistically in addition to submitted local needs

Planning entity identifies the best solutions. The regional planning entity determines the best solutions to the identified local and regional needs, including whether local projects can be right-sized to meet regional needs and whether alternative transmission technologies can be utilized.

Transmission owner optionally submits additional local projects. Following the regional planning entity's identification of solutions, each transmission owner can propose additional local projects for consideration if they feel there are unmet local needs. Such projects must still undergo state and federal review and may be held to a higher standard.

RMI Graphic.

Continuing the status quo approach to transmission planning, which separates local and regional planning, perpetuates this regulatory gap and is an inherently inefficient way to expand the grid. Many uncoordinated local projects will generally be more costly than larger, well-planned regional projects, and they will also tend to have greater land use and environmental impacts.[ii] Additionally, well-planned regional projects can offer significant economic, operational, and emissions reduction benefits that local projects may not offer.[iii] This approach also misses a key opportunity to proactively design the grid of the future rather than simply rebuild the grid of the past.[iv] Although regional planning can require a considerable up-front investment in time and resources to produce high-quality results, we believe that this investment is essential to produce the most beneficial results for customers as well as better land use and environmental outcomes.

ii Even if a regional project is built at larger scale to meet local needs in addition to regional ones, it can reduce land use and environmental impacts by obviating the need for additional local projects. In contrast, if local needs are separately addressed via several locally planned projects, the overall result is likely to have more land usage and related environmental impacts.

iii Well-planned regional projects such as MISO's Multi-Value Projects process and Texas's Competitive Renewable Energy Zones process have been credited with returning significant economic benefits to the grid. In contrast, local projects almost always lack even a simple cost-benefit analysis ("Texas as a National Model for Bringing Clean Energy to the Grid," Americans for a Clean Energy Grid, October 13, 2023, **https://www.cleanenergygrid.org/texas-national-model-bringing-clean-energy-grid/;** and *MTEP17 MVP Triennial Review,* MISO, September 2017, **https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf)**.

iv For an example of the missed opportunities that can arise when we do not plan proactively for the grid of the future, please refer to the following resource on the post–Hurricane Maria grid rebuild in Puerto Rico: Isaac Toussie et al., *The Role of Renewable and Distributed Energy in a Resilient and Cost-Effective Energy Future for Puerto Rico,* RMI, December 2017, **https://rmi.org/wp-content/uploads/2017/12/Insight_Brief_Puerto_Rico_Resilient_CostEffective_Energy.pdf.**

Each of the reforms we identify addresses a different aspect of the regulatory gap, and if adopted together they would complement one another. Therefore, we recommend that actors at the regional, federal, and state levels pursue appropriate reforms in parallel. Exhibit ES4 illustrates our proposed reforms to alleviate the regulatory gap by geographic level. Taken together, these could help address the regulatory gap, improving the quality of transmission planning in the United States and producing better results for customers and society.

Exhibit ES4 Proposed Reforms to Alleviate the Regulatory Gap

Geographic Level	Proposed Change
Regional	• Implement regional-first planning • Standardize local project definitions and tracking • Strengthen state input and influence at the regional level
Federal	• Reform the formula rate process • Establish an ITM • Explore performance-based regulation for transmission
State	• Leverage and expand CPCN authority • Offer expedited cost recovery for local projects that have undergone a robust regional review • Update IRPs to incorporate transmission • Create and fully leverage electric transmission authorities • Grow regulatory staff capacity and expertise

Note: Multiple parties across geographies may need to take action to fully realize some reforms. For instance, implementing regional-first planning will likely require action by FERC.

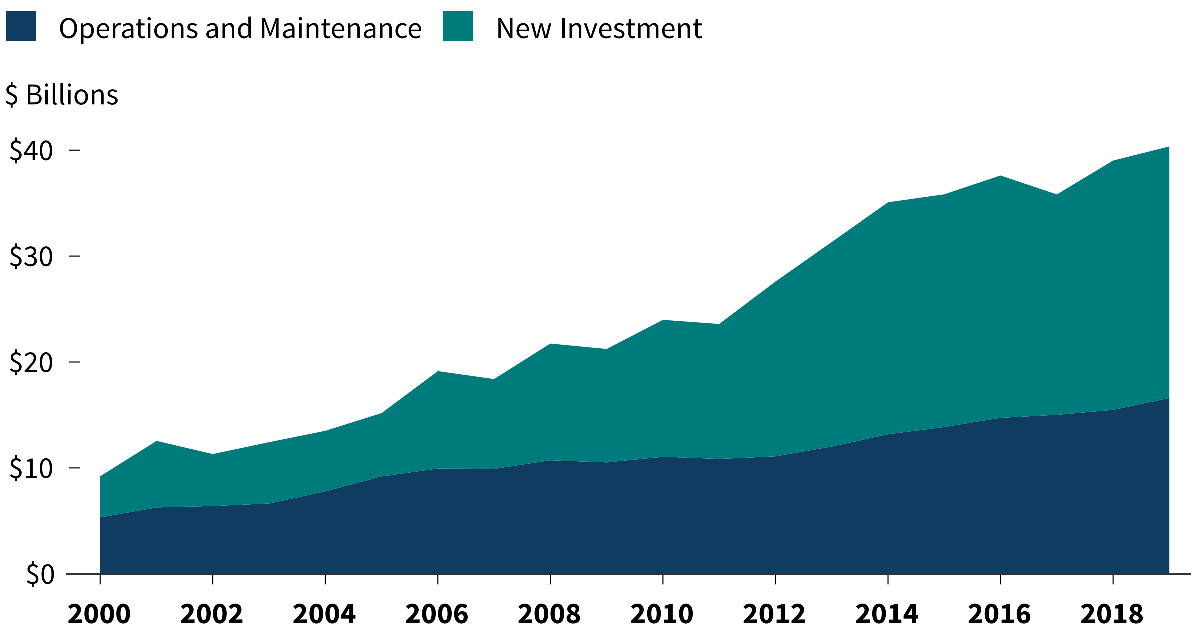
RMI Graphic.

Introduction: The Regulatory Gap

Across the country, transmission spending has been rising rapidly, driven by a combination of needs including replacing aging infrastructure, connecting new generation resources, and addressing load growth. The US Energy Information Administration found in 2021 that spending on the electric transmission system has increased almost fivefold in the past two decades, from $9.1 billion in 2000 (2019 dollars) to $40 billion in 2019.[8] Looking ahead, the clean energy transition is going to require even greater investment in transmission to connect new low-cost generation resources to load centers — up to a 60% increase in total transmission capacity by 2030 and a tripling by 2050, according to researchers at Princeton University.[9]

Exhibit 1

Annual Utility Spending on the US Transmission System (2000–19)



RMI Graphic. Source: US Energy Information Administration

The need for more transmission will best be met through efficient regional planning to ensure that cost-effective solutions are developed at scale. However, in recent years, there has been a dramatic shift in spending by utilities from regional projects, which are centrally planned at the regional level by federally designated regional planning entities, to local projects, which are planned and built by a single utility to meet needs within that utility's footprint.[v] The Federal Energy Regulatory Commission (FERC), for instance, recognized in 2022 that the "vast majority of investment in transmission facilities" in the past decade "has been in local transmission facilities."[10]

v For more data on this spending shift, see the section *Consequences of the Regulatory Gap*.

Box 1

Defining Local Transmission Projects

We define a **local project** as a project planned and built by a single utility to meet needs within that utility's footprint (i.e., transmission zone). These needs may include replacing aging infrastructure (this is typically called an asset management project), interconnecting new loads, enhancing operational flexibility, and ensuring that local reliability standards are met. Local projects go by different names in different grid regions; for example, asset condition projects in New England (ISO New England), self-approved projects in California (California Independent System Operator), Supplemental projects in the mid-Atlantic (PJM Interconnection), and Other projects in the Midwest (Midcontinent Independent System Operator). Local projects differ from regional projects, which are planned at the regional level and may span multiple utilities' footprints. In contrast to regional projects, local projects are frequently not thoroughly reviewed by regional planning entities, as we explore in the ***How Local Projects Are Currently Considered in Regional Planning*** section.

One of the key reasons behind this shift in spending is a lack of sufficient state, regional, or federal oversight of local projects, which we refer to as the **regulatory gap**. At the state level, local projects are often legislatively exempted from review by the public utility commissions (PUCs) that regulate utilities.[vi] State regulators may not become aware of projects until after the utility has already begun advanced planning or construction, and projects are not typically tracked during the construction process for potential cost overruns.[vii] At the regional level, regional transmission planning entities generally claim that local projects are not within their purview. At the federal level, oversight has been streamlined in ways that provide very limited project-level review. As a result, local transmission projects often receive little scrutiny, offering utilities a low-risk investment opportunity compared to regional projects, which are required to undergo significantly more oversight.[viii]

The timing for this recent shift in spending to local projects could not be worse. At a time when the US grid needs to significantly expand its capacity to prepare for the parallel demands of load growth and the clean energy transition, utilities are choosing to invest primarily in local projects, with no mechanisms in place to ensure that these projects are being adequately reviewed by planners and regulators. Relying heavily on local projects rather than coordinating their development with regional planning needs is an inefficient way to meet overall grid needs. Coordinated regional planning can ensure that local projects are synergistically designed alongside regional projects to minimize costs as well as land use and environmental impacts. As FERC noted when it established regional transmission planning, "a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity . . . there is a danger that separate transmission investments will work at cross purposes and possibly even hurt reliability."[11]

vi Many state legislatures, for instance, have exempted projects that are lower voltage or that consist of like-for-like asset replacements, which local projects often are, from receiving a state certificate of public convenience and necessity. For more information, see ***Exhibit 5: State-Level CPCN Review Authority by Voltage***.

vii For example, Greg Poulos with the Consumer Advocates of PJM States recently discovered that 31 FirstEnergy Supplemental projects arrived at PJM when they were already initiated, under construction, or completed, and filed a hotline complaint at FERC (available upon request).

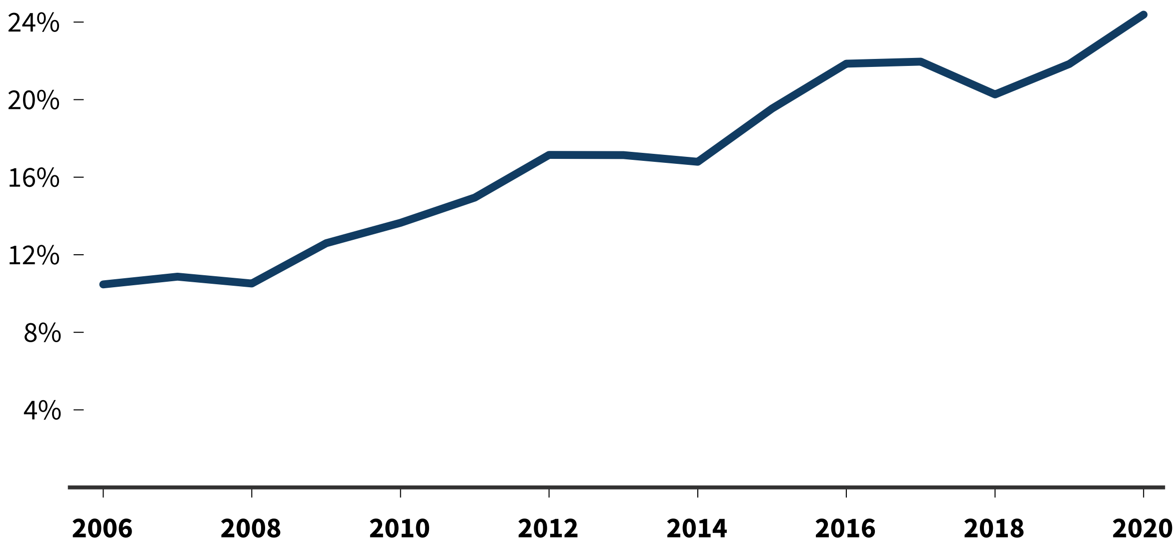
viii Regional projects, for instance, must be selected by regional planning entities to meet centrally and independently identified regional needs with robust stakeholder input. Projects are often selected via a competitive bidding process. Most regional projects are also required to receive state-level oversight in the form of a certificate of public convenience and necessity from the relevant PUC. Regional projects are also monitored by regional planning entities throughout construction, including for potential cost overruns.

Many Americans are increasingly struggling to pay their monthly electricity bills, underscoring the need for more proactive, least-cost regional planning rather than decentralized local investments. RMI found that in 2023, "nearly 70 million adults — one in every four — reported forgoing necessary expenses, such as for food or medicine, to pay their energy bills."[12] Furthermore, the share of customer bills represented by transmission and distribution costs has been increasing steadily, from 10% in 2005 to 24% in 2020 (see Exhibit 2).[13] To achieve affordability through the clean energy transition, it will be essential for planners and regulators to ensure that ratepayer money is spent efficiently.

Relying heavily on local projects rather than coordinating their development with regional planning needs is an inefficient way to meet overall grid needs.

Exhibit 2

Portion of Residential Bill Spending on Transmission and Distribution



RMI Graphic. Source: RMI Utility Transition Hub

To better understand the impacts of the regulatory gap and identify reforms on the regional, federal, and state levels that could address it, we interviewed state PUC commissioners and staff, consumer advocates, and legal experts across a geographically diverse set of 18 states. We also reviewed relevant FERC filings and related evidence.[14,ix] The recommendations we present in the remainder of this report leverage the findings from our research.

ix This review focused on FERC Docket No. AD22-8 on Transmission Planning and Cost Management. It included the technical conference held by FERC on October 6, 2022, the pre- and post-technical conference comments filed by over 80 organizations, and the related meeting of the Joint Federal-State Task Force on Electric Transmission held by FERC and the National Association of Regulatory Utility Commissioners on November 15, 2022.

This report is structured as follows. To provide context for understanding the regulatory gap, we first outline the transmission planning landscape in the United States, including what oversight is currently performed on the regional, federal, and state levels (particularly with respect to local projects). Next, we utilize recent transmission spending data to illustrate the extent and scope of the gap. Finally, we describe potential interventions at the regional, federal, and state levels that could help address the regulatory gap.

Transmission Planning and Ratemaking in the United States

Electric transmission planning is a complex affair in the United States. It varies not only by state and region but also by the nature of the project. Understanding the regulatory gap requires a basic understanding of these planning processes and the actors involved, so we provide a high-level overview of key aspects of the system before diving into the findings from our research.

Transmission consists of the high-voltage wires, as well as the necessary supporting infrastructure (e.g., poles, transformers), needed to move electricity from where it is produced to where it will be used. Most users do not take power directly from the transmission system but instead from the lower-voltage distribution system. In the United States, transmission generally refers to lines above 69 kilovolts (kV) and distribution to lines that carry lower voltages.

Federal Ratemaking Authority

The transmission business is rate regulated as a public utility because electricity transmission has the characteristics of a natural monopoly.[x] In general, FERC regulates transmission rates,[15] whereas distribution rates are under the jurisdiction of the states.[xi] Typically, PUCs simply pass through FERC-approved transmission charges to customers via retail transmission charges. Once FERC has approved a rate, interested parties, including state regulators, do not have the authority to seek modifications to the rate without appealing it at FERC through a formal review process or filing a formal complaint.

Utilities have two options for setting transmission charges at FERC: **stated rates** and **formula rates**. For both options, FERC is responsible for setting the allowed rate of return that the utility can earn on its investments. Under the stated rate approach, the utility presents all anticipated investments and expenses, and FERC then reviews these in detail and determines which of its incurred costs the utility will be permitted to recover via rates. Once a stated rate goes into effect, it remains in place without modification until the next time rates are reset. Though stated rates enable a detailed review of transmission expenditures, setting them is time- and effort-intensive.

FERC also offers utilities the formula rate option. Under this option, a utility files a formula for calculating its transmission costs with FERC. Once FERC approves the formula, the inputs used in the formula are updated annually, but the formula itself is not revisited by FERC unless the utility requests it or a formal challenge to it is filed by another party. Under FERC's formula rate protocol, state regulators, consumer advocates, and ratepayers can intervene to request more information about the annual inputs or to bring forward formal challenges.

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x A natural monopoly is an industry subject to large economies of scale that make it difficult for more than one firm to successfully compete. Building transmission infrastructure is very capital intensive, and once one set of wires is in place, it becomes very difficult for other potential transmission operators to enter the market.

xi Non-FERC-jurisdictional regions include US states and territories whose grids are not connected to other states or territories, such as Alaska, Hawaii, and most of Texas. For the purposes of this report, we focus on solutions relevant in FERC-jurisdictional areas. We also note that in some states with vertically integrated utilities (i.e., utilities own both generation and transmission/distribution assets), state PUCs exercise some ratemaking authority over transmission. How states exercise this authority varies. For the purposes of this report, we focus on ratemaking reforms that FERC can take and do not fully explore state-level ratemaking reforms.

FERC introduced the formula rate option to incentivize transmission expansion by reducing the burden of the rate-setting process. This was an important goal when FERC first adopted formula rates, and it is arguably even more critical today. Uptake of the formula rate option has been popular: as of 2019, 106 FERC-regulated utilities had formula rates, whereas only 31 used stated rates.[16] However, although formula rates can encourage transmission investment by streamlining the rate-setting process, they also have an important downside, which is that they tend to create weaker incentives to keep costs in check than the more traditional process of setting rates afresh every few years does.[xii]

Box 2

Components of a FERC Formula Rate

FERC formula rates are intended to enable the utility to recoup its cost of service (i.e., the cost it must incur to provide transmission service to its customers). The components of a formula rate include allowances for the utility's capital costs (including both the return of capital — i.e., depreciation expense — and return on capital), operating expenses, and taxes. Though every FERC-approved formula rate employs inputs specific to the utility, all have a common structure. This structure is shown below.[17]

Cost of Service = R + O&M + DE + OE + IT + OT − OR

R = return (rate of return × rate base)
O&M = operations and maintenance expense
DE = depreciation expense
OE = other expenses
IT = income taxes
OT = taxes other than income taxes
OR = other operating revenue

Additionally, FERC's formula rate process may not provide adequate oversight of utility spending decisions. One key shortcoming is that FERC assumes that all investments that go into the formula rate are prudent unless proven otherwise. This is a different standard than that used in state regulatory proceedings, which typically require the utility to demonstrate an investment was prudent before it can recover those costs from customers. In contrast, FERC's formula rate prudence presumption places the burden on other parties to demonstrate why an investment is likely not prudent before FERC will consider disallowing it. However, other parties (for example, state regulators and consumer advocates) often do not have access to the information they would need to make the case for additional review, as this information is held by utilities and not routinely disclosed. Parties' challenges are limited by the terms of the formula rate, and in a formula rate update proceeding, there is no opportunity for other parties to file evidence. Typically, other parties can challenge only whether the utility followed its approved formula. As various industrial customer organizations

xii Formula rates tend to create weaker cost-containment incentives than traditional rate cases (for example, those used to set FERC's stated rates) because whenever the utility's costs rise, the formula rate updates the company's revenue allowance to match. In contrast, in a traditional rate case, the utility would have to submit its new costs to regulatory scrutiny in order to receive a rate increase, which increases the risk that the regulator may deem some of those costs imprudent and disallow them for recovery. As a result, formula rates generally decrease the utility's incentive to manage its costs carefully. In cases where the benefits of formula rates are compelling, such as for the purpose of encouraging swift transmission expansion, FERC can consider taking steps to strengthen the utility's incentive to spend cost-efficiently. We describe some recommended actions that FERC could take in the ***Federal Reforms*** section of this report.

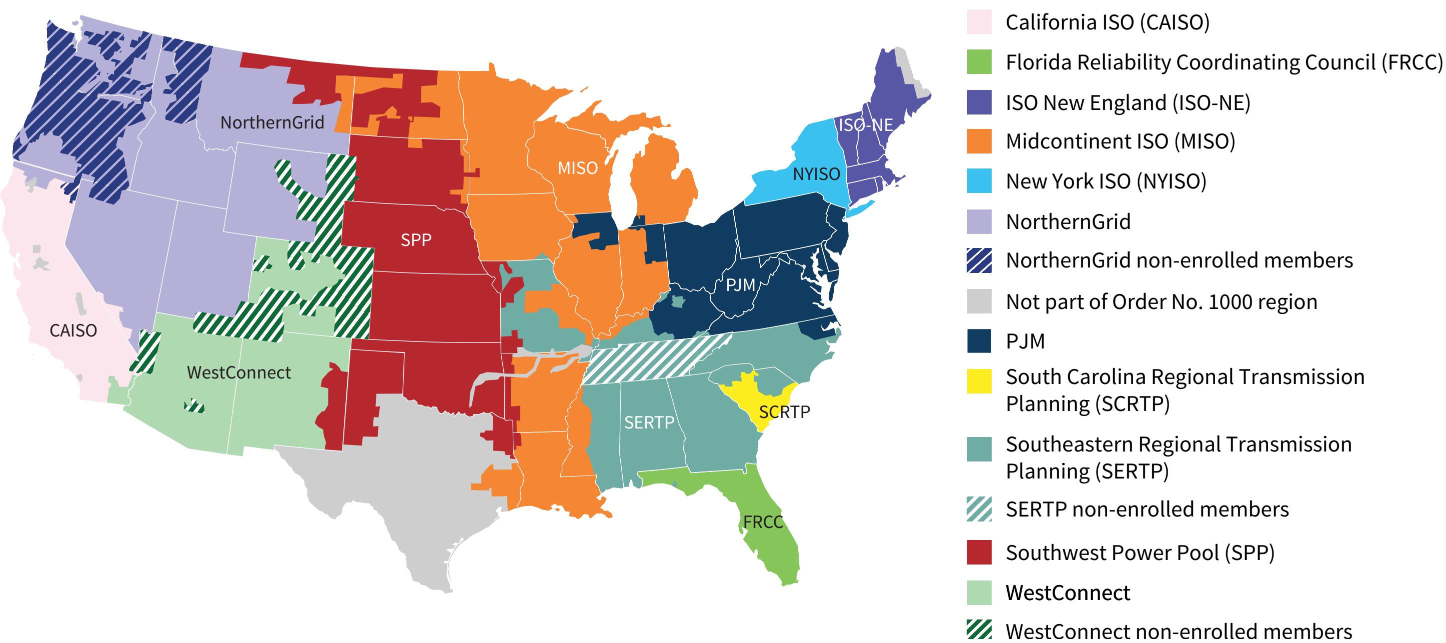
wrote in comments to FERC in 2023 as part of Docket No. AD22-8, formula rates "continue to allow a near-automatic transmission cost recovery with no meaningful check on additions to transmission rate base."[18]

Regional Planning

In addition to regulating the rates that utilities can charge, FERC also regulates the planning procedures for most of the US grid. Regional planning entities, approved by FERC in 2011 through Order No. 1000, are responsible for implementing these planning procedures. These entities are intended to leverage input from utilities, states, and other stakeholders to identify transmission investments that meet regional needs and deliver regional benefits, such as ensuring system reliability, reducing costs for customers, and implementing state and federal public policies. In much of the continental United States, the role of regional planning entity is filled by a regional transmission organization (RTO) or independent system operator (ISO), with exceptions in the western and southeastern parts of the country.[xiii] Exhibit 3 shows the Order No. 1000 regional planning entities in the continental United States.

Exhibit 3 **FERC Order No. 1000 Regional Planning Entities in the United States**

Color areas are intended to approximate the scope and location of the transmission region but are for **illustrative purposes only**.



Note: Cross-hatching indicates utilities that are not FERC jurisdictional but have chosen to participate in Order No. 1000 regional planning processes (e.g., power marketing administrations, such as Bonneville Power Administration). Gray areas indicate areas that are not in FERC's jurisdiction and do not participate in Order No. 1000 regional planning processes. These include the Electricity Reliability Council of Texas (ERCOT) as well as municipally owned utilities and cooperatives. Hawaii and Alaska, which are not shown, are also not FERC jurisdictional and do not participate in Order No. 1000 regional planning. At the time of publication, SERTP and SCRTP had announced that they were planning on merging, but such a merger had not yet occurred, so the two regions are left separate in this exhibit.

RMI Graphic. Source: FERC

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xiii In Order Nos. 888 and 2000, FERC outlined the parameters it would use to review utility applications to create ISOs and RTOs. FERC then approved ISO and RTO proposals in subsequent orders submitted by interested utilities.

In a region with an RTO or ISO, that entity is responsible for independently operating the transmission system and ensuring open access to it for all qualified parties. In a region without an RTO or ISO, the responsibility of operating the grid is divided among several utilities in the region and the regional planning entity serves as a forum for coordination among individual utility planning efforts.[19] These entities perform regional planning on different timescales.[xiv]

How Local Projects Are Currently Considered in Regional Planning

FERC Order No. 1000 allows for the separate categorization and treatment of local transmission projects. As noted previously, local projects are projects planned and built by a single utility to meet needs within that utility's footprint.[xv] These needs may include replacing aging infrastructure (this is typically called an asset management project), interconnecting new loads, enhancing operational flexibility, and ensuring that local reliability standards are met. Local projects are generally not required to undergo a thorough review at the regional level — and in certain instances, FERC has explicitly exempted them from regional planning processes.[xvi]

Local projects are generally not required to undergo a thorough review at the regional level — and in certain instances, FERC has explicitly exempted them from regional planning processes.

As a result, local projects are typically included in regional planning as an assumed input, such that regional projects are only identified to meet any remaining needs.[xvii] Unfortunately, this is not an efficient approach to planning because an uncoordinated set of local investments is likely to cost more than a strategic approach at the regional level. For example, the PJM Interconnection (PJM) has estimated that regional planning efficiencies already yield $300 million in annual benefits to ratepayers "by considering the region as a whole, rather than by individual states or separate transmission-owner territories, in determining transmission needs."[20] In Tranche 1 of its Long-Range Transmission Planning process, approved in 2022, the Midcontinent Independent System Operator (MISO) estimated that efficient regional planning of projects could save up to $1.9 billion in avoided transmission investment over a 40-year period.[21] These savings could be even greater if regions were to fully integrate local projects into their regional planning processes by allowing for better identification of transmission needs and additional planning efficiencies.

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xiv Recently in Order No. 1920, FERC required entities to begin conducting long-term planning (looking 20 years out) in addition to existing shorter-term regional planning processes. We discuss Order No. 1920 in more detail in the ***How FERC Order No. 1920 Will Change the Consideration of Local Projects in Regional Planning*** section of this report.

xv Specifically, the word *footprint* refers to a transmission zone. Though a transmission zone is specific to one utility, it can span more than one state for a multistate utility (e.g., PacifiCorp). This is distinct from the service territories that PUCs use to regulate utility distribution service at the state level.

xvi For instance, in Order No. 890, FERC explicitly exempted asset management projects from regional planning, an exemption that has been maintained in subsequent FERC orders.

xvii For example, the MISO Transmission Owners noted in comments to FERC in Docket No. AD22-8-000 that asset management projects are "considered bottom-up projects for purposes of analysis under MTEP" (MISO Transmission Expansion Plan, MISO's annual regional transmission plan), (Docket No. AD22-8-000, "Comments of the MISO Transmission Owners," March 23, 2023, **https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20230323-5211&optimized=false**).

Although some regional planning entities theoretically review local projects to assess whether they could be replaced by more regionally efficient solutions, this may not happen much in practice. For instance, in comments filed at FERC, the Iowa consumer advocate noted that in MISO, "local projects are not considered for more efficient and cost-effective transmission solutions."[22] As another example, in PJM it is up to each utility to identify whether local needs can be met regionally.[23] However, as state regulators in PJM have noted in comments filed at FERC, utilities have a disincentive to do this because regional planning could expose them to competition.[24] In non-RTO regions, planning is almost entirely conducted at the local level by the utilities, with the regional planning entity not independently reviewing projects for maximum efficiency.[xviii]

Concerningly, state decision makers may trust regional planning entities to do a comprehensive review of local projects, even though it is unclear to what extent each entity does this. For instance, Greg Poulos, commenting on behalf of the Consumer Advocates of PJM States, noted that many state regulators in PJM have "reduced staff or ceded transmission regulatory authority" under the belief that regional planning entities are providing sufficient oversight, even though this has been difficult to verify.[25]

> **"At the state level, regulatory bodies assume that the FERC-sanctioned regional planning process has adequately considered the most economic alternatives and proceed to approve the local projects the utilities present to them. The utilities then point to the state regulatory processes as comprehensive, holistic, and the rightful forum for transmission expansion."**
>
> — **Nick Guidi**, Southern Environmental Law Center, pre-FERC technical conference comments[26]

How FERC Order No. 1920 Will Change the Consideration of Local Projects in Regional Planning

Local transmission projects today often receive scant regulatory oversight. As already discussed, state regulators are limited in their ability to oversee the planning process — and they may also struggle to obtain basic levels of transparency from utilities concerning the need for projects, their projected costs, and the alternative options considered. Customers, consumer advocates, and other stakeholders who should be able to examine utility decisions in FERC proceedings can face even greater obstacles to obtaining the information they need to intervene effectively. FERC has recognized this problem and recently took action to increase transparency through Order No. 1920, which imposes a number of reforms to current regional transmission planning processes.[27]

One of the new requirements under Order No. 1920 is that utilities must hold a series of three meetings for each proposed local project detailing the assumptions, needs, and solutions. These meetings must be open to state regulators and other stakeholders, separated by at least 25 calendar days, and have meeting materials posted at least five calendar days in advance. However, this three-meeting requirement does not apply to asset management projects, which, as explained earlier, involve replacing an existing facility.

xviii Non-RTO regions refer to the FERC-jurisdictional Order No. 1000 planning regions that do not have RTOs or ISOs.

FERC exempted these projects from regional planning in Order No. 890, issued in 2007.[xix] Given that asset management projects can make up a large component of local transmission spending,[xx] the asset management project carve-out will substantially limit Order No. 1920's effectiveness.

FERC's new three-meeting requirement is based on PJM's Attachment M-3 process.[28] Unfortunately, it is not clear how effective the M-3 process has actually been in improving transparency or the decisions that PJM utilities ultimately make. One limitation of the M-3 process is that although utilities are required to hold meetings, they are not required to respond to stakeholder comments or questions. This means they can decline to provide any explanation to concerns raised by stakeholders, and if they choose to respond, they can choose what information to include or omit. This greatly limits stakeholders' ability to understand utility planning decisions, much less influence them.[xxi] Order No. 1920 marginally improves this situation because it requires utilities to "respond to questions or comments from stakeholders such that it allows stakeholders to meaningfully participate," but it stops short of requiring replies to all comments or questions.[29] FERC claims that "such a requirement could be too prescriptive in certain circumstances" and that "some responses may be unduly burdensome to the transmission provider."[30] We believe, however, that requiring utilities to address all stakeholder questions and comments is a small price to pay when put in the perspective of the total cost of transmission infrastructure. Absent a requirement to respond to all stakeholder inquiries, FERC's "meaningfully participate" standard is going to require significant oversight and enforcement by FERC or regional planning entities to ensure that answers provided by utilities are robust and useful to stakeholders.

Another aspect of PJM's M-3 process that has limited its effectiveness is that utilities can bring local projects to the process after construction has commenced or, in some extreme cases, even after it has been completed.[31] Naturally, this greatly limits the ability of stakeholders to influence utility planning decisions. Unfortunately, Order No. 1920 does not include any mention of the timing of projects with regards to local project review, raising the possibility that this shortcoming of the M-3 process will be replicated at a broader level.

A second requirement under Order No. 1920 is that regional planning entities engage more fully in **right-sizing.** Right-sizing, as illustrated in Exhibit 4, means considering whether a larger project could better meet both local and regional needs than the smaller project. It is a vital aspect of sound planning because often a single large project is able to more cost-effectively meet multiple needs than a series of individually planned small projects, while reducing total land use and environmental impacts.

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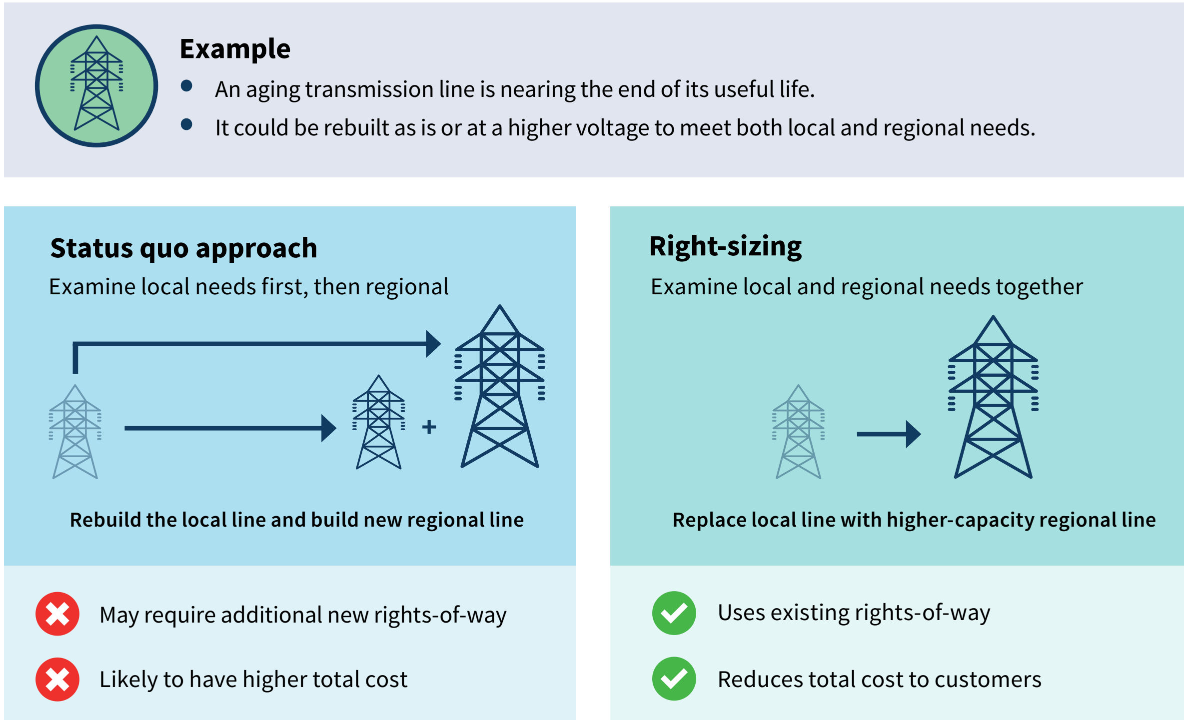
xix FERC justified this exemption with the reasoning that asset management projects do not involve expansion of the transmission grid, which FERC has historically considered to be a limit on its jurisdiction. We assert in this report that at a time of accelerating load growth and the clean energy transition, this exemption no longer makes sense and that asset management projects must be more fully incorporated into regional planning through regional-first planning to ensure that the most efficient and cost-effective planning is happening. Asset management projects, for instance, can be right-sized and thus be utilized to expand the transmission grid.

xx For example, in PJM, out of the $71.8 billion spent on Supplemental projects since 2005, 66% has gone to projects associated with the Equipment Material Condition, Performance, and Risk driver, compared to 16% on Customer Service, 13% on Operational Flexibility and Efficiency, 3% on Infrastructure Resilience, and 1% on Other (about 2% had no driver listed). For more information, see "Transmission Cost Planner," PJM Interconnection, accessed September 30, 2024, **https://tcplanner.pjm.com/tcplanner.**

xxi As Kent Chandler, the former chair of the Kentucky Public Service Commission, explained in filed comments, "Through the M-3 process, stakeholders can comment, ask questions, or propose solutions until they are blue in the face. However, the relevant utilities do not have to respond to comments, answer questions, or acknowledge proposed solutions. In this way, M-3 meetings provide no more of an opportunity to participate in local planning than if stakeholders instead chose to scream their comments, questions, and solutions into a cosmic void" (Docket No. AD22-8-000, "Pre-Conference Comments of Kentucky Public Service Commission Chairman and Commissioner Kent A. Chandler," September 16, 2022, **https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220916-5215&optimized=false).**

Exhibit 4 How Right-Sizing Works



RMI Graphic.

Under Order No. 1920's right-sizing provision, during each long-term regional planning cycle utilities will be required to submit "sufficiently early" a list of transmission assets that they anticipate replacing in kind over the next 10 years.[32,xxii] If the regional planning entity identifies that a right-sized replacement facility would meet the long-term regional need in a more efficient or cost-effective manner than a new-build solution, then that project must be considered by the regional planning entity for selection.[33] It is up to each planning region to set a voltage threshold above which this new right-sizing provision applies, although FERC sets an upper limit of 200 kV.

Order No. 1920's right-sizing provision applies only to long-term regional planning processes and not to short-term ones, which will limit its impact. Nevertheless, this provision represents an important step in the right direction, and regional planning entities could build on it. As we discuss in more detail in the ***Implement Regional-First Planning*** section of this report, regions could adopt (or FERC could require) right-sizing as a best practice for all time frames of planning, and thereby reduce the cost, land use, and environmental impacts of siting new transmission infrastructure.

A third requirement under Order No. 1920 is the inclusion of alternative transmission technologies, including several grid-enhancing technologies (GETs) and advanced conductors, in regional planning for

xxii FERC defines an in-kind replacement as one that "would result in no more than an incidental increase in capacity over the existing transmission facility" and "located in the same general route as, and/or uses the existing rights-of-way of, the existing transmission facility" (Order No. 1920, p. 1169 at 1678). Right-sizing would increase the capacity of the facility, but it would still be located in the same general route as and/or use the existing rights-of-way. This requirement can include asset management projects.

all timescales (i.e., short and long term).[xxiii] Research has shown these technologies can save vast amounts of money by enabling grid operators to make more efficient use of transmission infrastructure, yet they are greatly underutilized in the United States.[34] A key reason these technologies are not being fully considered or deployed on the US grid is the misalignment between the financial incentives of utilities (who are able to earn a return on every dollar they invest in infrastructure) and the interests of customers (who ultimately must pay for that infrastructure).[xxiv] FERC's requirement, if fully implemented in planning regions, has the potential to accelerate deployment of these technologies.

More remains to be done to reform local planning, even after Order No. 1920.

When considered together, the three key requirements in Order No. 1920 detailed above that most directly relate to local transmission — the three-meeting requirement, the right-sizing consideration, and the alternative transmission technology consideration — will significantly improve opportunities for synergistic transmission planning and regulatory oversight. However, these requirements will not close the regulatory gap. More remains to be done to reform local planning, even after Order No. 1920. As we explore further in this report, there are additional solutions, such as fully linking regional and local planning and enhancing federal and state review processes, that could help ensure transmission projects across the United States are being planned in a maximally efficient and cost-effective manner.

State Regulatory Authority

On the state level, PUCs perform several regulatory functions with respect to transmission. Depending on the state, these may include:

1. Issuing a certificate of public convenience and necessity (CPCN) for each transmission project that is legislatively required to receive one;
2. Reviewing transmission as part of integrated resource plans (IRPs) where IRPs are required;
3. Approving retail rates to recover transmission costs from end-use customers; and
4. Engaging in regional planning processes.

Even in states where the PUC performs all four of these functions, the degree to which they result in meaningful oversight of transmission projects varies. As Southeast Public Interest Groups described in filed comments about the first three functions, "these three layers of review do not fit together seamlessly, such that many transmission facilities slip through the cracks and do not receive an affirmative designation as a prudent investment worthy of cost recovery."[35] We describe each of these functions in greater detail in the following sections.

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xxiii GETs are a suite of technologies that can help extract more capacity from the grid for less money, including dynamic line ratings, topology optimization, and advanced power flow control. Advanced conductors are materials that can enhance the carrying capacity of power lines. For more information on these technologies, please refer to Russell Mendell, Mathias Einberger, and Katie Siegner, "FERC Could Slash Inflation and Double Renewables with These Grid Upgrades," RMI, July 7, 2022, https://rmi.org/ferc-could-slash-inflation-and-double-renewables-grid-upgrades/.

xxiv For more details, see Carina Rosenbach et al., *The Nuts and Bolts of Performance Based Regulation, RMI, 2024,* https://rmi.org/insight/the-nuts-and-bolts-of-performance-based-regulation/.

Certificate of Public Convenience and Necessity

In most states, transmission projects are required to receive a CPCN, which is essentially a permit from the PUC or other entity for a project to be built.[xxv] CPCNs frequently focus on issues pertaining to the siting of a line, with the PUC's ability to consider project prudence and cost potentially limited by CPCN scope. Even if a CPCN includes consideration of prudence or cost, the process is designed to focus on a single transmission project rather than the more holistic picture of all projects in a planning cycle. This limits regulators' ability to utilize the CPCN as a way to ensure proactive planning is happening.

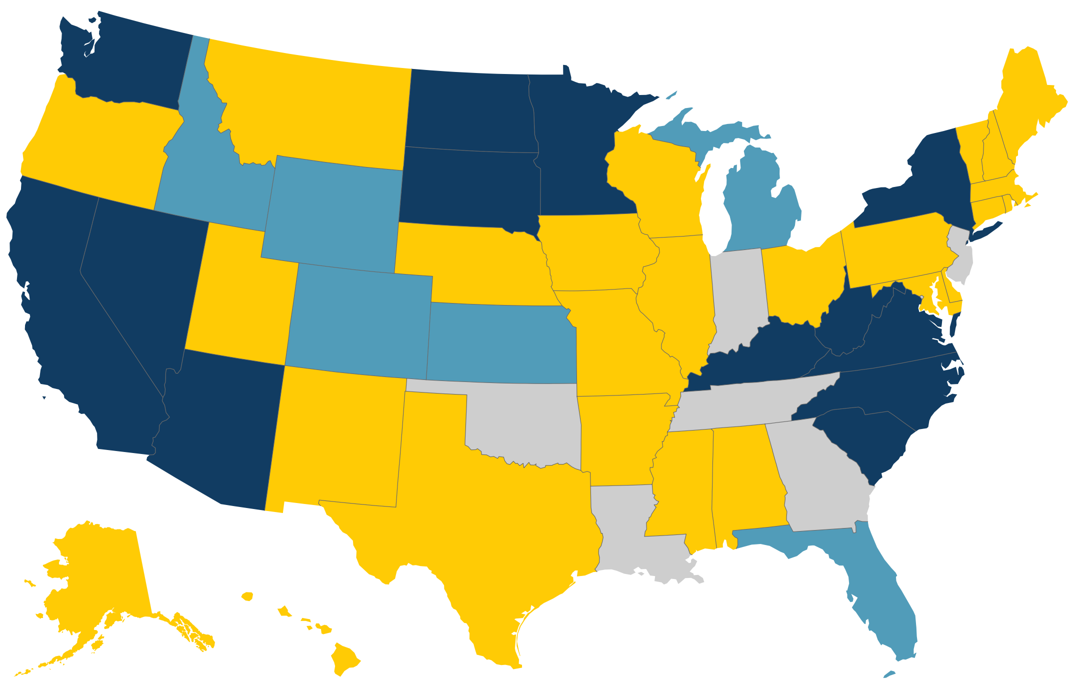
As shown in Exhibit 5, state CPCN requirements vary substantially. Six states do not require a state-level CPCN,[xxvi] and many others do not require a CPCN for projects below a certain voltage threshold. Where CPCNs are not required for lower-voltage projects, this can substantially limit the PUC's ability to review local transmission projects. It is also common for states to not require a CPCN for projects that are identified as replacements of existing assets. This further exempts many local projects from being reviewed for a CPCN.

Exhibit 5

State-Level CPCN Review Authority by Voltage

Several states have set voltage thresholds below which transmission assets do not need to receive a CPCN.

No CPCN requirement ≤100 kV or no threshold ≤200 kV >200 kV



RMI Graphic. Source: National Association of Regulatory Utility Commissioners; Joshua C. Macey and Elias van Emmerick, "Towards a Greater Federal Role in Transmission Planning," *Harvard Environmental Law Review 49* (forthcoming 2025)

xxv In some states, another entity such as a siting board issues the CPCN instead of the state PUC (William H. Smith Jr., *Mini Guide on Transmission Siting: State Agency Decision Making,* Figure 1, National Council on Electricity Policy, December 2021, https://pubs.naruc.org/pub/C1FA4F15-1866-DAAC-99FB-F832DD7ECFF0).

xxvi Some of these states handle siting at the county or another governance level (Smith, *Mini Guide on Transmission Siting,* Figure 1, December 2021).

Given the variation in CPCN review authority and its emphasis on siting rather than prudence or cost, it is generally not an effective way for PUCs to ensure efficient investment. This is widely recognized by state regulators and advocates. For instance, Chair Phil Bartlett of the Maine PUC noted in comments filed at FERC that the CPCN is "an isolated evaluation of a single project rather than a more comprehensive assessment of transmission investments by the utility or for the region as a whole."[36] Southeast Public Interest Groups similarly noted that "proposed transmission investments arrive at the state commissions fully baked. Opposing utility-selected transmission facilities during a CPCN proceeding rarely, if ever, succeeds."[37] James McLawhorn, who is on the Public Staff at the North Carolina PUC, shared at the FERC 2022 technical conference that when a project falls below 161 kV (the state's voltage threshold for CPCN review), staff "find out about it . . . when it shows up in rates." When a project does need a CPCN, utilities often assert that failing to issue the CPCN would threaten grid reliability — as McLawhorn explained, they effectively argue "we're out of time and we need you to move forward with it."[38]

Given the variation in CPCN review authority and its emphasis on siting rather than prudence or cost, it is generally not an effective way for PUCs to ensure efficient investment.

For all these reasons, a CPCN is not a substitute for comprehensive oversight of transmission planning. If a PUC is expected to ensure that transmission investments are prudent, its role must start earlier and extend to the full suite of projects under consideration. The PUC should perform this role in partnership with regional planning entities.

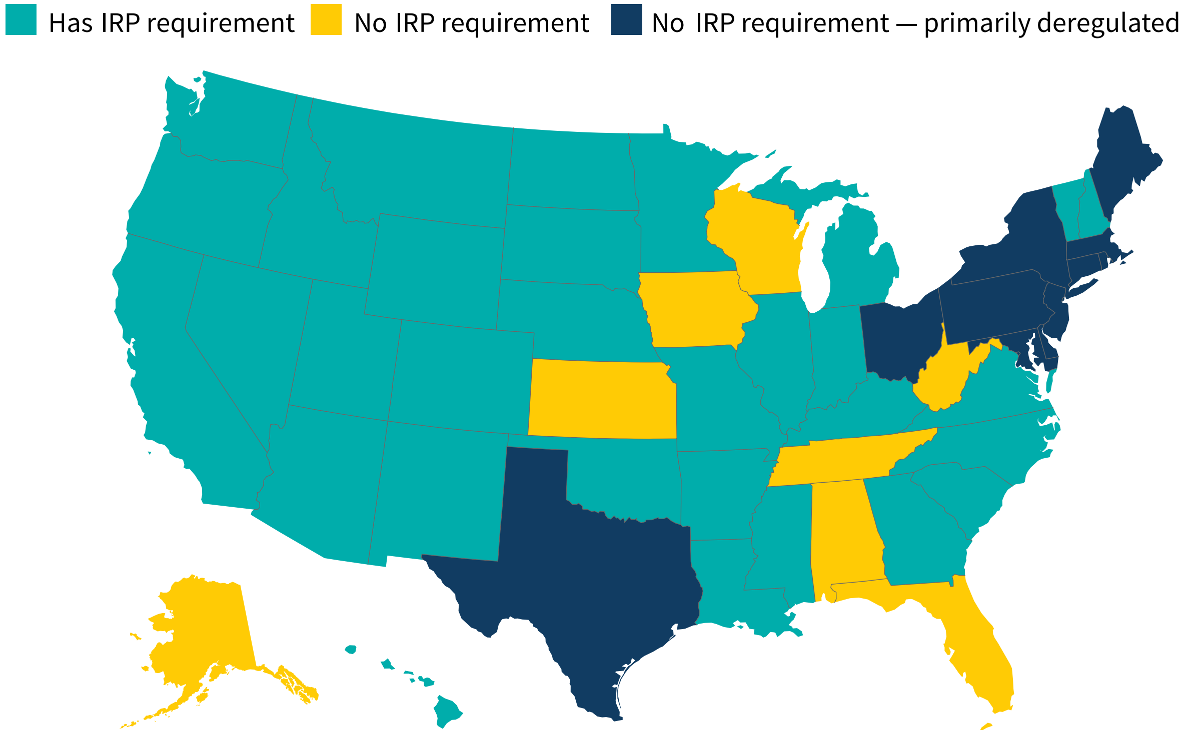
Integrated Resource Planning

IRPs are resource-planning exercises that require utilities to develop portfolios of future investments sufficient to meet projected load growth and state policy goals over a set time horizon (often 10 to 30 years). In many states, IRPs are also a critical venue for stakeholders to provide input into utility assumptions about future demand and supply options. As shown in Exhibit 6, most states with vertically integrated utilities — in which the generation function is subject to PUC rate regulation — have some type of an IRP requirement.

IRP rules and guidelines vary state to state and impact what is included in plans, how planning is done, and how much influence plans have on decision-making and investments. Similarly, the role of the commission varies: some states only require the utility to file an IRP but do not require the PUC to approve it.[xxvii] Today, most IRPs focus on generation planning, and transmission, if included at all, is treated as a secondary consideration.

xxvii State IRP requirements vary in many ways. For more details about the use of IRPs by US states, see Mark Dyson, Lauren Shwisberg, and Katerina Stephan, *Reimagining Resource Planning, RMI, 2023,* https://rmi.org/insight/reimagining-resource-planning/.

Exhibit 6 IRP Requirements by US State



RMI Graphic. Source: US Environmental Protection Agency, *State Energy and Environment Guide to Action: Resource Planning and Procurement*, Figure 2; RMI analysis of EIA-860M to add distinction for primarily deregulated states

IRPs are not designed to be the primary venue for effectively coordinating or planning at a regional level. These plans are often utility-specific, and state PUCs do not have authority over how FERC-jurisdictional projects are planned or how FERC sets rates to recover their costs. However, the IRP process can still be useful in advancing smart transmission planning and investment. Commissions can require utilities to identify and consider different alternatives to meeting demand through IRPs, and the planning process can provide greater transparency into the utility's plans for transmission and the potential costs associated with various options. To realize these benefits, transmission, both local and regional, must be incorporated into the IRP process, and the IRP process itself must be well designed and implemented effectively.[xxviii]

State-Level Rate Cases

PUCs hold periodic rate cases for each of the utilities they regulate in which they review utility expenditures for prudence, approve or deny costs for recovery, and set rates to recover those costs from the utility's customers. However, for most transmission expenditures, FERC determines the cost the utility is eligible to recover from customers, not the PUC. Once FERC sets the amount a utility is eligible to recover, the PUC reviews and approves the retail rates that recover those costs from end-use customers within that utility's

xxviii For more information on best practices for modern IRP development, please see "Task Force on Comprehensive Electricity Planning," National Association of Regulatory Utility Commissioners and National Association of State Energy Officials, accessed September 18, 2024, **https://www.naruc.org/committees/task-forces-working-groups/retired-task-forces/task-force-on-comprehensive-electricity-planning/home/.**

service territory. The PUC is not allowed to change the FERC-approved amount to be recovered. As a result, PUCs commonly employ a rate rider to pass those costs through to customers with little additional scrutiny.

Engaging in Regional Planning

PUCs, as well as state consumer advocates and other state-level stakeholders, can engage in the stakeholder processes facilitated by regional planning entities. However, their ability to meaningfully influence the planning process varies by region.

Some RTO and ISO governance structures, for instance, can limit state decision makers' ability to influence the actual decision-making that takes place. These governance structures are complex and widely studied.[39] However, governance reforms are beyond the scope of this report.

> **"In practice, state control is often an illusion. Even in vertically integrated states, state commissions minimally exert input or direction into utility transmission planning. Transmission is rarely integrated into utility integrated resource plans; many states removed transmission when they modernized IRP rules. Even where state commissions pre-approve transmission investments, regulators' insight into screening criteria for needs and alternatives is murky at best. Said more plainly, state commissions are often not presented with the most economic choices, which are often interstate projects that extend beyond their jurisdictions."**
>
> — **Devin Hartman**, director, R Street Institute
> and **Kent Chandler**, former chair, Kentucky Public Service Commission[40]

Consequences of the Regulatory Gap

In the preceding discussion, we showed that federal, regional, and state entities do not adequately review local transmission projects — there is a **regulatory gap**. Exhibit 7 summarizes the local transmission regulatory gap and Exhibit 8 compares it to the more thorough review used for regional projects. While FERC Order No. 1920's new meetings, right-sizing, and alternative transmission technologies requirements may lead to incremental improvements, these are partial solutions that will not fully closethe regulatory gap.

Exhibit 7 The Regulatory Gap for Local Transmission Projects

Local project proposed

Regional Planning Entity

- The RTO says local projects are outside its planning purview
- It may do a basic no-harm analysis, but no meaningful review of the project

State PUC

- Since FERC has ratemaking authority, the PUC has little oversight power over rates
- Though the state may require an integrated resource plan or a certificate of public convenience and necessity in some cases, these do not enable the PUC to ensure prudence

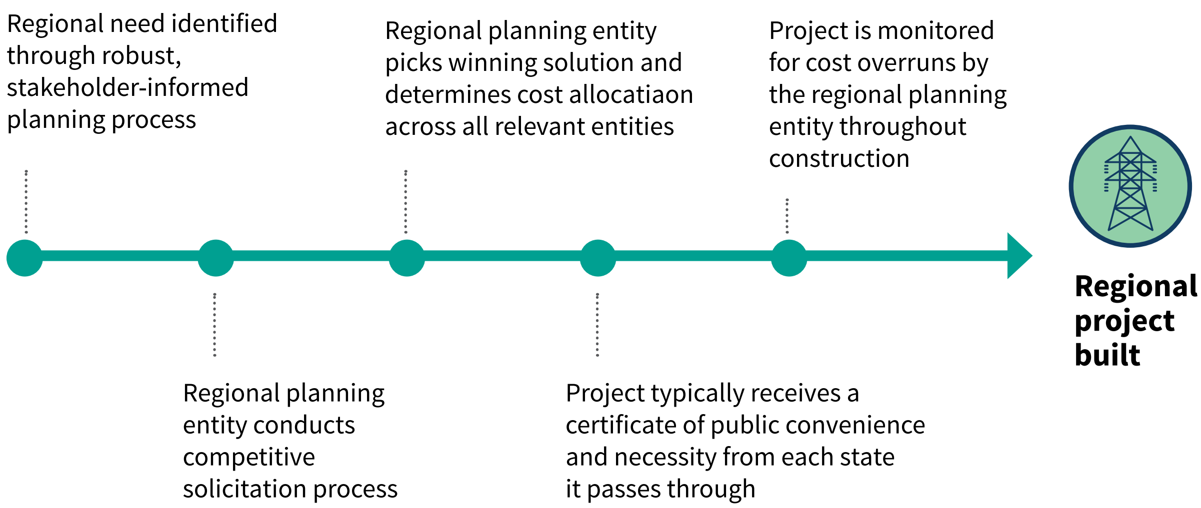
FERC

- FERC formula rate cases assume prudence and do not examine costs at the project level
- The burden of proof to show imprudence rests on stakeholders, who rarely have access to the necessary information

Local project built

RMI Graphic.

Exhibit 8 Regional Transmission Project Review Process



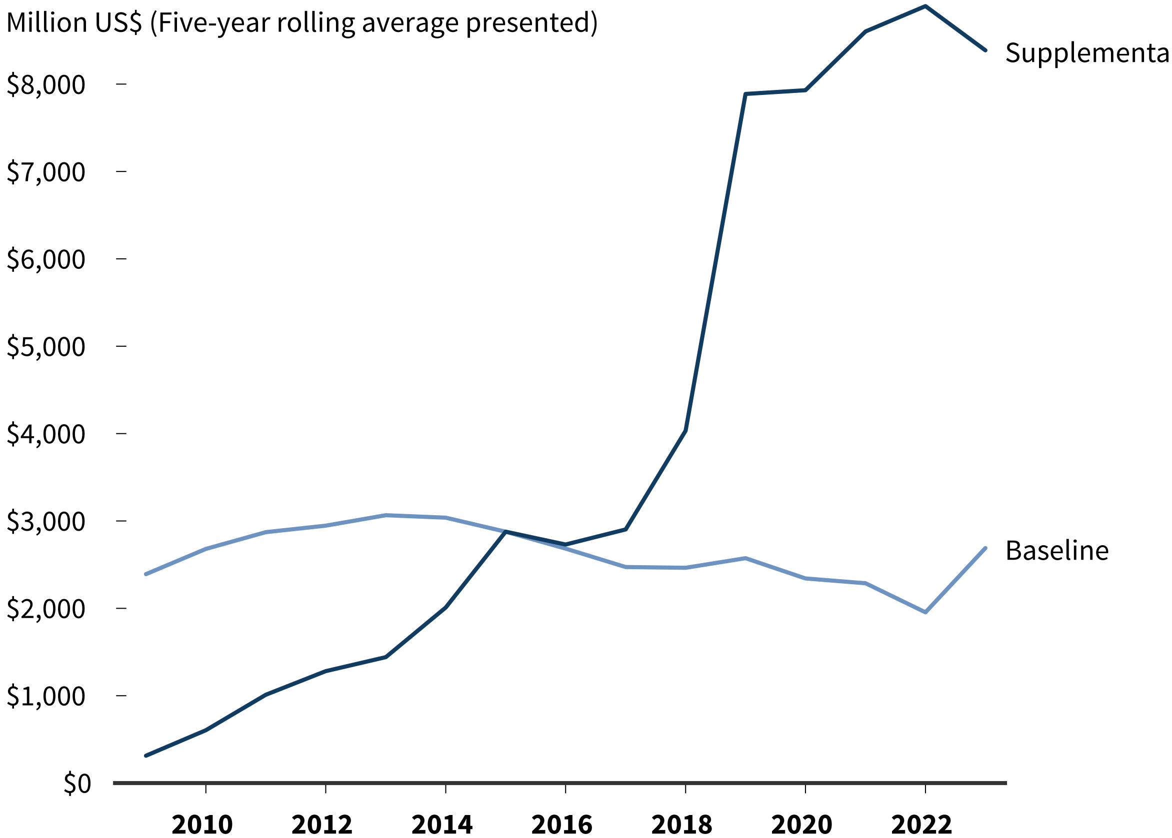
RMI Graphic.

The regulatory gap is not just a theoretical problem. Transmission spending patterns reveal real-world consequences on the types of projects utilities are building and the impacts on customer bills.

Transmission spending patterns reveal real-world consequences on the types of projects utilities are building and the impacts on customer bills.

In RTO regions, utilities have shifted spending dramatically toward local projects. In PJM, spending on local projects (which PJM calls Supplemental projects) increased 26-fold from 2009 to 2023, as illustrated in Exhibit 9, while spending on regional projects (which PJM calls Baseline projects) stayed relatively flat.[41] In ISO New England (ISO-NE), spending on local projects (called asset condition projects) increased eightfold from 2016 to 2023.[42] The same story holds in the California ISO (CAISO) with local projects (called self-approved projects), where 63% of projects from 2018 to 2023 were self-approved projects not eligible for state or CAISO review.[43] In MISO, local projects (called Other projects) have increased from 54% of total spend in 2017 to 78% in 2022.[44]

Exhibit 9 PJM Transmission Spending

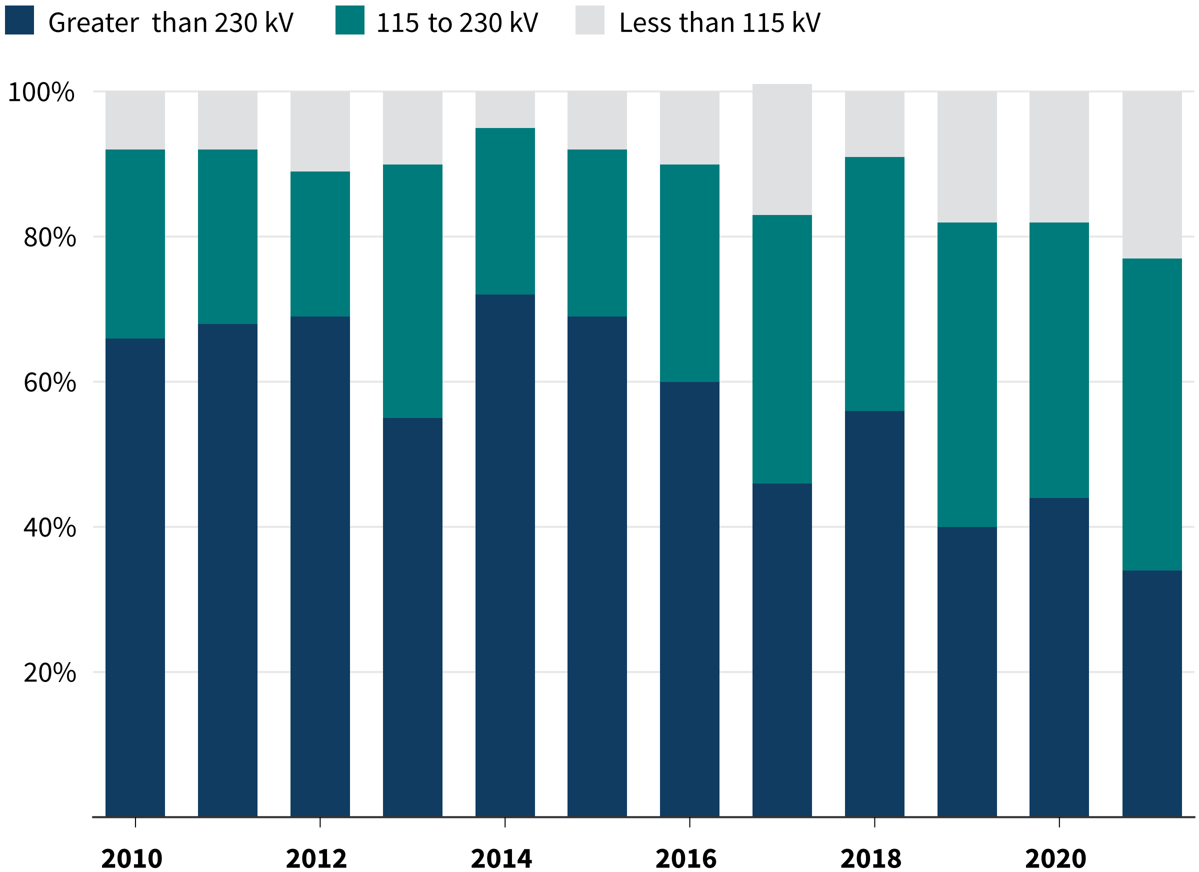


RMI Graphic. Source: PJM Interconnection

In non-RTO regions, limited data accessibility and the lack of effective regional planning entities make it difficult to evaluate specific spending trends. In these regions, utilities conduct transmission planning for only their service territories. Although there are a few select cases of planning across multiple utilities, not a single regional project has been planned and approved by non-RTO regional planning entities since FERC's Order No. 1000 created them in 2011.[45] Consequentially, these regions' transmission investments have consisted entirely of local projects.

Together, regional spending trends show a concerning nationwide trend: regional transmission investments have been falling while local transmission spending has risen. Since 2010, the percentage of spending on projects with voltages greater than 230 kV has been steadily declining, from a high of 72% in 2014 to just 34% in 2021, as illustrated in Exhibit 10.[46]

Exhibit 10 Share of Total US Transmission Spending by Voltage



RMI Graphic. Source: FERC

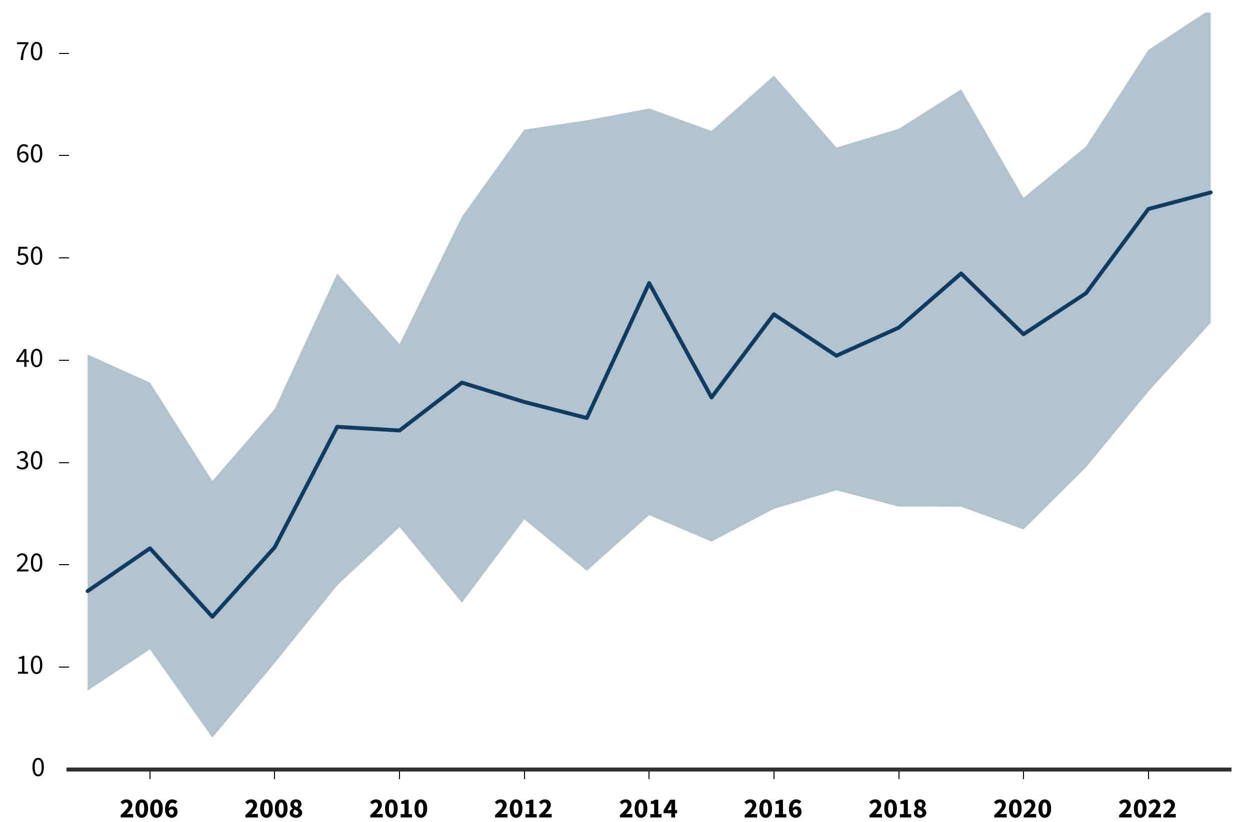
With spending concentrated on smaller local projects, the miles of transmission built have declined. Grid Strategies found that while transmission spending hit an all-time high in 2023, the United States built only "20% as much new transmission [mileage-wise] in the 2020s as it did in the first half of the 2010s." The analysis also found that only 55 miles of new high-voltage transmission were added in 2023, compared to a record 4,000 miles in 2013.[47] Similarly, the Brattle Group found that 90% of recent transmission spending has been on lower-voltage reliability upgrades, with 50% of all spending going toward local projects.[48]

Though other factors could partly account for the growth in local transmission spending — such as the need to replace aging infrastructure — the strong trends we've identified suggest a shift in how utilities make transmission spending decisions. The regulatory gap is a likely suspect because it enables utilities to invest more money in local transmission projects without having to justify their investment decisions to regulators. Further, utilities can usually pursue local projects without competition, in contrast to many regional projects that Order No. 1000 requires be open to competitive bidding.

If the spending trend toward local projects continues, there is a risk that as utilities increase spending on local projects, those costs could crowd out investments in regional transmission that have the potential to also bring system-wide cost savings. Regulators and consumer advocates are understandably hesitant to spend more on regional infrastructure when local transmission costs are already driving up bills.

However, the problem extends beyond the costs of just transmission itself. If utilities do not proactively build enough regional transmission infrastructure, customers will miss out on the benefits of regional transmission. Cheap renewable generation resources in remote regions will struggle to interconnect, driving up both costs and carbon emissions, as is already evident from the yearslong interconnection queue delays across the United States, shown in Exhibit 11. US grid regions will also be unable to efficiently share generation capacity, leading to overbuilt generation capacity and greater costs. In addition, inefficient grid architecture could prevent grid operators from redirecting power when severe weather hits, threatening reliability and imposing economic costs on affected areas. Finally, a lack of regional transmission can also increase transmission congestion costs. As shown in Exhibit 12, congestion costs in the United States have tripled in recent years, with our country's transmission network at capacity and struggling to expand efficiently.[49]

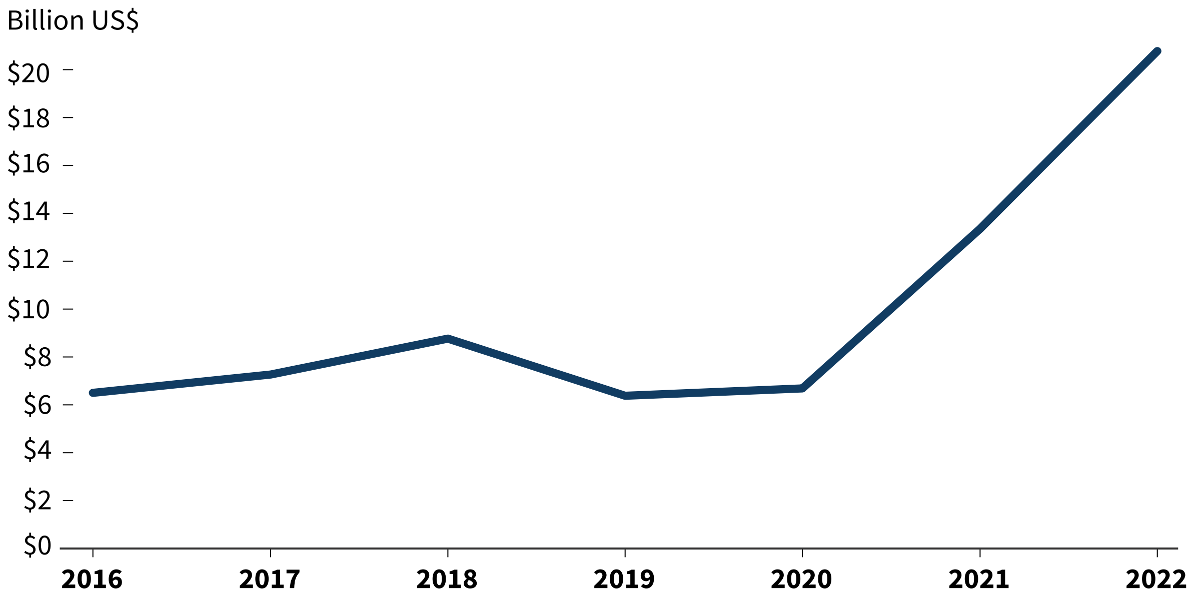
Exhibit 11 Months Interconnection Requests Spend in US Queues



Note: The data represents the time, in months, that projects have spent in interconnection queues in the US on average between 2005 and 2023, from submission of an interconnection request to commercial operation date. The line displays the median amount of time for projects that reached commercial operation date in that year, with the light blue range representing the 25th and 75th percentile bounds. Data is averaged across US grid regions.

RMI Graphic. Source: Lawrence Berkeley National Laboratory

Exhibit 12 Annual Congestion Costs for the US Grid



RMI Graphic. Source: Grid Strategies

Right-sized regional projects could help resolve many of these challenges — interconnection delays, increased congestion costs, sharing of generation capacity, and reliability during extreme weather events — while also reducing land use and environmental impacts. Ensuring well-planned and cost-effective transmission projects should therefore be a policy priority, and achieving this will require adequate, comprehensive regulatory review.

As one state regulator we interviewed explained, "I have a hard time believing that simply rebuilding the grid of 80 or 90 years ago will produce the right grid for 50 or 60 years from now, which is how long these facilities are going to last."

With 70% of transmission lines approaching the end of their lifespan,[50] this problem is urgent. Now is the time to ensure we do not just rebuild the grid of the past through local replacement projects but proactively build the grid of the future. As PJM has noted, "greenfield transmission-level voltage solutions may not always be the most cost-effective solution, given the practicalities of siting and building such facilities. Enhancements to existing sub-transmission level voltage facilities — e.g., 230 kV or lower — may indeed be the more cost-effective solution to achieve the same level of reliability."[51] The utility Xcel also recognized in filed comments that "in some situations, regional projects may be more cost-effective than local projects, in particular in the current environment where climate goals are driving a virtually wholesale replacement of existing generation resources with more dispersed and often more remote renewable resources."[52]

Unfortunately, the regulatory gap is a barrier to efficient regional planning. As one state regulator we interviewed explained, "I have a hard time believing that simply rebuilding the grid of 80 or 90 years ago will produce the right grid for 50 or 60 years from now, which is how long these facilities are going to last."

Box 3

Illustrating the Regulatory Gap: The X-178 Project

One recent example of the regulatory gap in action is the X-178 project, currently proposed by Eversource Energy in New Hampshire. First proposed in February 2024, the project involves a full rebuild of a 115 kV line, despite the fact that only 43 of the 594 structures of the line have been identified as high priorities for replacement and that many of the structures are younger than their estimated useful lives. The project is estimated to cost $385 million.[53]

New England state regulators, through the New England States Committee on Electricity (NESCOE), have submitted feedback on multiple instances to Eversource and ISO-NE. These regulators have cited the "lack of compelling evidence to support the scope of the project" and requested additional information from Eversource on the project and cost drivers. Eversource failed to provide the requested information, however. Despite the objections from stakeholders, Eversource is currently planning on proceeding with a full rebuild and it does not need to obtain any additional approvals from ISO-NE.[54] The project is also not required to receive a state-level CPCN, although New Hampshire's Site Evaluation Committee (the entity responsible for issuing CPCNs for transmission projects) has discretionary authority to issue one. Local advocates have petitioned for this authority to be utilized.

In an August 1, 2024, letter to Eversource, NESCOE wrote that "Eversource's disregard of requests for information that states believe would help assess proposals was troubling. . . . Eversource's plan, despite broad state and stakeholder discomfort and outstanding requests for information, illustrates how the lack of sufficient federal oversight on the asset condition project pathway governing billions of dollars of spending per year is not adequately protecting New England consumers."[55]

It is important to note that this is one instance where state regulators have noticed and called attention to the shortcomings of a local project. As many of our interviewees noted, however, this level of enhanced scrutiny is not being applied equally to all local projects currently.

Addressing the Regulatory Gap

State, regional, and federal actors can all take steps to reduce the impact of the regulatory gap. Below, we recommend complementary reforms to improve oversight at the regional, federal, and state levels. Because the reforms are synergistic, parallel reforms at all three levels will be most effective.

Regional Reforms

State, regional, and federal actors can all take steps to reduce the impact of the regulatory gap on US transmission planning.

Overwhelmingly, the regulators and advocates we spoke with noted how essential it is for local projects to receive adequate consideration at the regional planning level. One key reason for this is that many local projects span multiple states, and only the regional planning entity has the necessary bird's-eye view over all the region's needs. As the US Department of Energy has recognized, "in many cases, [the] flexibility and optionality provided by a robust transmission plan may not be captured in individual or more narrowly focused planning processes."[56]

To address this need, we propose three reforms to strengthen regional review of local projects. These include implementing regional-first planning, standardizing local project definitions and tracking, and increasing state input into regional planning entity decision-making and governance structures. Both RTO and non-RTO regions could benefit from these actions, but they could be particularly impactful in non-RTO regions where there is no effective regional planning.

> **"Consumers and state regulators cannot make an informed decision as to whether it is necessary to rebuild a 70-year-old 138 kV line in an area that once had significant manufacturing unless it also has information as to what is going on with other utilities around the area. But in individual project reviews, such information is rarely available."**
>
> — **LS Power**, post-FERC technical conference comments[57]

Implement Regional-First Planning

FERC Order No. 1920's right-sizing requirement for local projects is limited to long-term regional planning; Order No. 1920 does not reform shorter-term regional planning or asset management projects, which could limit the provision's effectiveness. We recommend FERC require all regions to implement what we call **regional-first planning**, which would extend the right-sizing requirement to ensure that local projects are reviewed within the regional context.

We outline regional-first planning below and summarize the approach in Exhibit 13.

1. **Utilities submit local needs.** At the start of each regional planning cycle — whether short term or long term — utilities would submit all anticipated local transmission system needs within a certain forward-looking time horizon to the regional planning entity. These submissions would build on Order No. 1920 by ensuring that proposed local needs are considered in all types of planning, with the required time horizon for need identification tailored to the length of the planning cycle (e.g., 5 years for short-term and 10 years for long-term planning cycles). Importantly, we recommend that utilities submit local needs, not just local projects, to enable the regional planning entity to subsequently evaluate all needs (local and regional) at once and identify the most efficient project solutions.[xxix] A utility would also be permitted to submit local needs or projects outside of the designated submission window, but it would need to explain why it was not able to identify them earlier. If a utility submits local needs or projects outside the normal window, these should be flagged by the regional planning entity for greater scrutiny at either the state (PUC) or federal (FERC) level.

2. **Planning entity identifies the region's needs.** As already required by Order Nos. 1000 and 1920, the regional planning entity would determine what needs are likely to arise on the regional system over the planning time horizon. These needs are in addition to the local needs identified by each utility.

3. **Planning entity identifies the best solutions.** Next, the regional planning entity would determine the most appropriate solutions to meet the identified local and regional needs. During this process, it should prioritize minimizing cost and also consider the land use and environmental impacts of alternative solutions. The solutions considered should address both the local needs submitted by the utilities and the identified regional needs. Solution identification should prioritize right-sizing and alternative transmission technologies, such as GETs and advanced conductors, to maximize spending and land use efficiencies. The regional planning entity should post the selected solutions publicly, as well as all alternatives considered and the rationale for each selection.

4. **Utilities have the option to submit additional local projects.** Following the regional planning entity's identification of solutions, each utility would have the option to propose additional local projects for consideration if it feels that there are still local needs that have not been met. Any such projects would still need to undergo review by state and federal regulators and may be held to a higher standard of review.

xxix Utilities could also submit proposed local projects that could meet those needs, if desired. However, utilities should not submit projects without identifying the underlying needs those projects are intended to address.

Exhibit 13 Components of Regional-First Planning

Utilities submit proposed local needs. Transmission owners submit anticipated local needs at the start of each regional planning cycle, whether it involves planning over the short term or the long term.

Planning entity identifies the region's needs. The regional planning entity determines all regional needs holistically in addition to submitted local needs

Planning entity identifies the best solutions. The regional planning entity determines the best solutions to the identified local and regional needs, including whether local projects can be right-sized to meet regional needs and whether alternative transmission technologies can be utilized.

Transmission owner optionally submits additional local projects. Following the regional planning entity's identification of solutions, each transmission owner can propose additional local projects for consideration if they feel there are unmet local needs. Such projects must still undergo state and federal review and may be held to a higher standard.

RMI Graphic.

To our knowledge, no regional planning entity currently employs an approach comparable to the suggested regional-first planning,[xxx] and we believe FERC action will be necessary to implement such an approach at scale on a reasonable time frame. In the absence of FERC action, regional planning entities could act on their own. However, regional planning entities alone may struggle to implement regional-first planning due to resistance from the incumbent utilities that have outsized influence in the governance structures of these entities.[xxxi] Regions would also be limited by precedent, such as the exemption of asset management projects that FERC established in Order No. 890. This exemption would need to be overturned by FERC to enable regional planning entities to independently adopt regional-first planning that encompasses all types of local projects, including asset management projects.

It is important to recognize that regional planning can require considerable time and resources to produce high-quality results. This process may include setting up effective planning protocols, hiring skilled staff at the regional planning entity, and preparing modeling tools that can handle multiple inputs from different utilities. Robust stakeholder involvement, which is critical to ensure the outputs reflect diverse state and local interests, can introduce further complexities. Though the up-front investment in such a process is not trivial, the potential to reduce system-wide costs justifies the expense, as well as the potential to make better use of land and improve environmental outcomes.[58]

xxx New York ISO is starting to implement some of these practices in its Coordinated Grid Planning Process.

xxxi In many RTOs, for instance, incumbent utilities still hold significant power over how transmission planning protocols are designed. For more information, see Ari Peskoe, "Replacing the Utility Transmission Syndicate's Control," *Energy Law Journal,* 2023, **https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4577049**.

> **"One of the drawbacks and risks of the 'build-as-you-go' transmission process is the risk of construction of short-lived transmission assets that must be replaced long before the end of their useful lives due to later generation development that renders these assets inadequate and saddles ratepayers with paying for both the new and the replaced transmission assets, when pro-active planning may have produced a more efficient transmission system."**
>
> — **James McLawhorn**, North Carolina Utilities Commission, pre-FERC technical conference comments[59]

Standardize Local Project Definitions and Tracking

Although Order No. 1920 will help improve oversight and review of local projects, FERC could do more in making basic improvements to the local transmission planning process across planning regions.

One change that could help increase transparency would be to standardize the definitions of concepts used in planning processes, specifically the drivers and criteria associated with local projects.[xxxii] Currently, in some regions different utilities use different terms to refer to the drivers and criteria that determine the need for local projects. This can make it difficult for state regulators and advocates to compare projects proposed by different utilities and to meaningfully engage in regional planning processes. For instance, each utility may have different age-based thresholds for determining when to rebuild infrastructure. Terminology also varies across regions, making it difficult to compare and contrast investment patterns across the country.

Regional entities, for instance, could be required to create a standardized list of local project criteria and drivers that all utilities in their region must utilize, accompanied by clear definitions of the point at which infrastructure needs to be built.[xxxiii] FERC could then require utilities to submit this list in its existing Form No. 715.[xxxiv] Alternatively, FERC could create a standardized list for all regional entities to adhere to. Whether regional entities or FERC decide on the standardized terminology, interviewees noted that such a standardization should draw on established North American Electric Reliability Corporation (NERC)

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xxxii Drivers refer to the reason a project is deemed necessary, while a criterion is the specific violation or standard that justifies moving forward with a project at this time. An example of a driver (from PJM) is equipment material condition, performance, and risk, whereas an example of criteria is the North American Electric Reliability Corporation (NERC) reliability criteria.

xxxiii PJM, for instance, utilizes a list of five standardized drivers to describe Supplemental projects: Customer Service; Equipment Material Condition, Performance, and Risk; Operational Flexibility and Efficiency; Infrastructure Resilience; and Other (*PJM Transmission Owners Attachment M-3 Process Guidelines,* Version 0.2, last updated August 15, 2022, **https://www.pjm.com/-/media/planning/rtep-dev/pjm-to-attachment-m3-process-guidelines.ashx**).

xxxiv FERC requires that all transmitting utilities that operate "integrated transmission system facilities that are rated at or above 100 kV" must submit information via Form No. 715, otherwise known as the Annual Transmission Planning and Evaluation Report, on an annual basis. For more information, see "Form No. 715 – Annual Transmission Planning and Evaluation Report," FERC, accessed September 30, 2024, **https://www.ferc.gov/industries-data/electric/electric-industry-forms/form-no-715-annual-transmission-planning-and-evaluation-report**.

reliability criteria. Interviewees also suggested that regions assign weights to criteria to help regulators prioritize the most important needs.

Going further, FERC or regions should establish a standardized approach for tracking the progress of local projects in planning and construction. For instance, regional entities could be required to share local project information in a centralized database, including data on project need, criteria, and drivers as well as updates on project costs (including cost underruns or overruns), construction status, and location. This would help stakeholders more effectively participate in the various stages of transmission planning and also monitor project cost through construction. Some RTOs have already established data sharing platforms, although the amount of data shared varies.[xxxv]

Strengthen State Input and Influence at the Regional Level

To ensure proposed projects are subjected to sufficient scrutiny at the regional level and alternative solutions are adequately considered, state regulators, consumer advocates, and other state-level stakeholders should be given ample opportunity to participate in planning. Utilities should be required to respond to stakeholder questions about the specific needs each project would meet, whether potential regional synergies and right-sizing opportunities have been sufficiently considered, and about the selection criteria applied in the process. Regional planning entities should also respond to stakeholder questions pertaining to the parts of the planning process they conduct.

Currently, however, stakeholders often have difficulty obtaining basic information about transmission investment decisions. As we have documented, many state regulators and consumer advocates have found that utilities either fail to respond to their questions or provide answers with insufficient detail to prove useful.

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xxxv For instance, PJM's Transmission Cost Planner tool shares some data on local project name, driver, and cost. However, the tool does not share construction-stage updates, including any information on cost underruns or overruns. For more information, see "Transmission Cost Planner," PJM Interconnection, accessed August 26, 2024, **https://tcplanner.pjm.com/tcplanner**.

Strengthening the ability of state-level stakeholders to provide input to and influence regional transmission planning processes is therefore another strategy that could help address the regulatory gap. Where RTOs and ISOs exist, they could consider adding voting authority for state voices or other special forums for input. For instance, MISO has a voting sector comprised of public consumer advocates.[60] Any special forums should ensure that adequate information is shared by utilities to allow state-level stakeholders to meaningfully participate.

Forming independent groups to enable state regulators and consumer advocates to more effectively engage in regional planning processes could also help close the regulatory gap. Today, regulators in the four multistate RTOs have regional groups of state regulators, as does the non-RTO West.[xxxvi] Expanding this model to the non-RTO Southeast could strengthen state influence in planning. PJM also has an active regional organization representing state consumer advocates, called the Consumer Advocates of PJM States (CAPS), but no other regional planning entity has a similar consumer advocates group to our knowledge. Expanding the CAPS model to all the planning regions could help foster dialogue, collaboration, and collective advocacy among state consumer advocates.

FERC could also give state regulators an explicit role in regional transmission plan development. State regulators, for instance, could be given an easily accessible pathway to submit any concerns to FERC with the completion of each regional plan.[xxxvii] Such a requirement could establish a routine pathway for PUCs to provide input on the regional plan, help elevate their important perspectives, and alert FERC to issues it should consider examining in detail. If persistent concerns emerge, FERC could then take action via Section 206 of the Federal Power Act to amend that regional planning entity's planning processes.

Regardless of the mechanism of input, PUCs, consumer advocates, and other state-level stakeholders have critical roles to play in ensuring that planning processes at the regional level are conducted in a rigorous and transparent manner. They can also push for changes in how planning is conducted, such as by advocating for the adoption of regional-first planning. This could be particularly impactful in non-RTO regions where regional planning has yielded no regionally planned projects to date, because this has left significant potential savings on the table.[61]

Federal Reforms

In addition to the regional reforms laid out above, FERC could take several steps to ensure that local transmission projects receive adequate oversight. We recommend FERC consider refining the formula ratemaking process, establishing an independent transmission monitor (ITM), and exploring performance-based regulation (PBR) for transmission. FERC could take action on these items under its open AD22-8 docket on transmission planning and cost management, or the commission could address them in other venues.

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xxxvi In RTO states, these groups are the Organization of PJM States, Inc. in PJM; Organization of MISO States in MISO; Regional State Committee in the Southwest Power Pool (SPP); and NESCOE in ISO-NE. For more information, see Christopher Parent et al., *Governance Structures and Practices in the FERC-Jurisdictional ISOs/RTOs*, Exeter Associates, prepared for New England States Committee on Electricity, February 2021, **https://nescoe.com/wp-content/uploads/2021/02/ISO-RTOGovernanceStructureandPractices_19Feb2021.pdf**. In the non-RTO West, the Committee on Regional Electric Power Cooperation (CREPC) and Western Interconnection Regional Advisory Body (WIRAB) are made up of regulators and state energy officials from all 14 states and 2 provinces in the Western interconnect. CREPC and WIRAB engage on regional electricity issues including markets, reliability, and transmission.

xxxvii There are examples of states in RTOs exercising authority over other topics related to transmission planning. In SPP, for instance, the Regional States Committee has retained filing rights under Section 205 of the Federal Power Act over transmission cost allocation and resource adequacy matters. In ISO-NE, NESCOE can request that utilities file an alternative proposal related to transmission cost allocation. For more information, see Parent et al., *Governance Structures and Practices in the FERC-Jurisdictional ISOs/RTOs*, February 2021.

Reform the Formula Rate Process

As noted earlier, under FERC formula rates, project investments are approved through an annual update filing rather than a contested process. This reduces the opportunity for challenges to FERC's presumption of prudence. In addition, the rate of return granted by FERC's formula rates is generous and can be larger than the rates PUCs offer utilities for the investments they regulate at the state level.[xxxviii] This means that if a utility overspends on a local transmission project, it can expect to earn an attractive return with little risk that it will be denied cost recovery by any regulator.

To address these issues, we recommend FERC:

1. **Remove the presumption of prudence for projects that have not undergone a robust regional or state regulatory review.** The reason natural monopolies like transmission are rate regulated is to protect customers from being overcharged, so ensuring that investments are prudent is a core duty of regulators. Thus, if a project has not already undergone a rigorous regional or state-level review, FERC should not automatically assume that the project is needed or that expenditures on the project were prudent. Instead, FERC should require that the utility demonstrate that the investment was prudent, just as the utility would be expected to do if it presented the costs for recovery in a rate case. It would then be up to the utility to convince FERC that the project was prudent or, alternatively, to seek a robust regional or state review. Such a review could include a thorough study by a regional planning entity (including a right-sizing analysis, the evaluation of alternatives, consideration of alternative transmission technologies, and cost-benefit analyses) or prior approval by a PUC at the state level (e.g., through issuance of a CPCN).

xxxviii In the United States, evidence indicates that the returns on equity (ROEs) utilities earn are generally substantially more than their true cost of equity (i.e., the ROE they actually need to attract equity investors). This is indicated by the fact that most utilities have price-to-book ratios above 1. A utility's price-to-book ratio reflects the enterprise-wide ROE (i.e., both the allowed ROE set by the PUC for state-regulated assets and the ROE set by FERC for transmission assets), but there is no obvious reason to believe that FERC-set ROEs are less generous than PUC-set ROEs. In fact, the opposite may be true, both because the FERC-set ROEs are often higher than those set by state PUCs, and because the formula rate process employed by FERC reduces the risk to utility investors that the utility's costs will not be recovered. For more on this topic, see Mark LeBel et al., *Improving Utility Performance Incentives in the United States: A Policy, Legal and Financial Framework for Utility Business Model Reform*, pp. 20–27, Regulatory Assistance Project, **https://www.raponline.org/wp-content/uploads/2023/10/rap-improving-utility-performance-incentives-in-the-united-states-2023-october.pdf**; and Jim O'Reilly, FERC Regulatory Review, RRA Regulatory Focus, S&P Global, Topical Special Report, pp. 14–17, June 28, 2024, **https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/file?keyfileversion=FB57DFC2-A117-68C7-A0CF-63E5307FD8A0&KeyFileFormat=3&isNewsletter=1**.

2. **Lower the evidentiary standard for parties interested in raising challenges as part of formula rate cases.** Because FERC currently assumes that all transmission investments are prudent, the burden falls on other stakeholders to prove otherwise. Any challenges must meet an evidentiary standard referred to by FERC as "serious doubt."[62] Yet state regulators and other stakeholders are often unable to assess prudence because they lack access to key transmission data and modeling tools, and to gain access, they would somehow need to produce preliminary evidence of imprudence. Several interviewees noted that as a result of this catch-22, it has proven difficult for stakeholders to challenge the prudence of local transmission projects before FERC. FERC could address this by lowering the evidentiary standard required to trigger consideration of prudence from "serious doubt" to one of "reasonable questions" raised by parties about factors such as project cost or consideration of alternatives. Parties should also be allowed to conduct discovery without the restrictions imposed by a utility's formula rate protocols, which can limit information disclosure requirements. This would allow these parties to more easily meet the evidentiary standard.

3. **Remove the return on equity (ROE) adder for RTO membership for local projects that do not undergo a robust regional review.** FERC currently offers an ROE adder (a type of financial incentive) for all transmission projects that are built by a utility with membership in an RTO or ISO, the purpose of which is to encourage participation in these regional entities. However, this logic does not hold for local projects that are not effectively part of the regional planning process. It would therefore be reasonable for FERC to remove this adder for projects that have not been sufficiently reviewed by a regional planning entity. Doing this would also create a financial incentive for utilities to seek regional review of local projects.

4. **Reduce the allowed ROE for local projects.**[xxxix] In addition to removing the ROE adder for local projects that have not undergone a robust regional review, FERC could consider reducing the allowed ROE on all local projects to incentivize greater investment in right-sized regional solutions. This may also be appropriate on the grounds that utilities face less risk when building small local projects than when building larger regional ones.

Establish an Independent Transmission Monitor

Many of the state regulators and staff we interviewed emphasized that even if transmission planning processes were improved, their ability to rigorously review local transmission projects would still be hampered by limited staff expertise and insufficient information and data from utilities. An ITM, whether established for each regional planning entity or housed within FERC at the federal level, could serve as an important information clearinghouse for state regulators. For instance, the ITM could regularly review utility spending trends, consider whether projects are subject to sufficient regulatory oversight, and evaluate whether transmission spending is economically efficient. The ITM could also assist state regulators, upon request, to understand information about a specific project presented by a utility. Moreover, the ITM could help ensure that regional-first planning, once implemented, is functioning properly. FERC could further explore what needs an ITM could fill and how it should be structured; several comments in its AD22-8 docket are relevant to these questions and could provide a basis for consideration of the ITM idea. Regardless of where the ITM is housed, it will be important to structure it in a way that provides value to states and ratepayers without unnecessarily adding additional barriers to transmission deployment.

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xxxix The allowed ROE is the return included by FERC in the formula by which rates are set. This may be higher or lower than the realized ROE, which is the return the utility actually earns.

Explore Performance-Based Regulation for Transmission

Performance-based regulation is an alternative to traditional cost-of-service regulation that seeks to better align the incentives utilities face with the interests of customers and society. PBR is not a single mechanism, but rather a set of tools that regulators can tailor to the specific needs and policy priorities of their jurisdictions. Though PBR has mainly been applied by PUCs in the United States, FERC could adopt PBR aspects at the federal level.[xl]

In Order No. 679 in 2006,[xli] FERC noted that "the development of PBR measures may represent a long-term goal for the industry and the Commission to pursue . . . [and] we intend to continue to work with the industry to encourage development of PBR proposals."[63] However, to date FERC has yet to issue additional PBR guidance.[xlii]

FERC could use PBR to improve transmission regulation in various ways by discouraging perverse utility incentives and rewarding efficient transmission planning. PBR could help address the existing incentive utilities have to spend more than necessary on capital projects (a perverse incentive known as gold-plating) and address the incentive to prefer capital investments over other alternatives (a perverse incentive known as capital expenditure [capex] bias). For example, PBR could offer utilities a share of any cost savings they can achieve through lower-cost alternative transmission technologies.[64] In addition, a number of capex–operational expenditure (opex) equalization strategies exist that could help level the playing field between utility capital projects and alternative opex solutions, such as third-party services and demand flexibility programs.

xl PBR has also been used to regulate utilities in the Canadian provinces of Alberta, Ontario, and Quebec; Great Britain; Australia; and many other countries.

xli This rulemaking followed the Energy Policy Act of 2005, which in Section 219 required that FERC explore incentive-based ratemaking for transmission.

xlii In RM 20-10 — in which a Notice of Proposed Rulemaking (NOPR) was issued on March 20, 2020, and a Supplemental NOPR was issued on April 15, 2021 — FERC indicated that it may consider revisiting the ROE adders first explored as part of Order No. 679. These include a 100 basis point adder for transmission technologies that enhance reliability and increase efficiency and capacity. However, FERC has yet to act on these notices.

Performance incentive mechanisms (PIMs) could also be worth exploring. A PIM ties a financial incentive — in the form of a reward, a penalty, or both — to utility performance in a defined area. PIMs could be used in various ways to encourage more efficient transmission operation and planning. For example, one PIM could reward utilities for reducing system congestion and another PIM used to penalize them for failing to participate appropriately in regional planning processes.[xliii]

The thoughtful use of these and other PBR tools could save customers money, encourage the development of more innovative solutions to grid needs, and reduce land use and environmental impacts. If FERC wishes to take up the topic of PBR in transmission once more, a technical conference or notice of inquiry could be an appropriate way to begin the discussion.

State Reforms

In addition to regional and federal improvements, states can play important roles in regulating local transmission investments. Below, we suggest some reforms states can implement to strengthen the oversight of local projects.

Leverage and Expand CPCN Authority

Even where PUCs have few tools to influence local project planning, they may have the authority to review projects at the siting stage when the utility applies for a CPCN. While a CPCN requirement is not enough to enable a PUC to ensure utility projects are well planned and prudent, it does provide additional transparency and the ability to require siting-related changes. Strengthening a state's CPCN requirement — or if no such requirement exists, establishing one — is one potential strategy states can use to strengthen oversight.

As discussed earlier, many states have a voltage threshold and/or asset replacement exemptions for CPCN review. These exemptions can significantly limit the PUC's ability to review smaller local projects and may also create an incentive for utilities to prefer smaller local projects over larger ones. The state legislature could address this issue by updating the CPCN requirement to give PUCs broader authority. For example, if the enabling statute currently specifies a voltage threshold of 138 kV, reducing it to 69 kV would ensure that more local projects are reviewed by the PUC. If an asset replacement exemption is in place, the state legislature could also update the statute to require that all projects replacing or expanding existing infrastructure receive a CPCN. If a standard CPCN is deemed impractical, these projects could require an expedited CPCN instead.

Even in the absence of legislative reforms, PUCs can take steps to strengthen existing CPCN review requirements. For instance, PUCs could require utilities to document that they have sufficiently explored project alternatives when they apply for a CPCN. This requirement could identify specific alternatives that must have been examined (e.g., GETs, advanced conductors, and non-wires alternatives such as storage), certain steps that must have been taken (e.g., consideration of right-sizing), and particular information about the downselection process that must be provided (e.g., the criteria used and how each alternative was rated based on those criteria). As another example, a PUC could require the utility to demonstrate

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xliii For more on perverse incentives, as well as PIMs, capex-opex equalization strategies, and other elements of the PBR toolkit, see Kaja Rebane and Cara Goldenberg, *How to Restructure Utility Incentives: The Four Pillars of Comprehensive Performance-Based Regulation*, RMI, 2024, **https://rmi.org/insight/how-to-restructure-utility-incentives-four-pillars-of-comprehensive-performance-based-regulation/**.

that the project received robust regional review by the relevant regional planning entity — or if it did not, to explain why that is the case. Once such requirements are in place, the PUC could deny the CPCN if the utility fails to meet them.

Expanding CPCN review in these ways could strengthen the PUC's ability to conduct oversight of local projects. However, even a well-designed CPCN requirement is not a substitute for robust regional planning, and it cannot on its own bridge the regulatory gap.[xliv]

Offer Expedited Cost Recovery for Local Projects that Undergo a Robust Regional Review

Even though states cannot unilaterally change FERC-approved transmission charges, they do have the ability to design the rates for end-use customers through which the allowed costs are recovered. Though most PUCs have adopted the use of rate riders that quickly pass through the FERC-approved transmission costs to customers, this is not the only option. For example, a PUC could instead review and approve transmission costs for recovery during rate-case proceedings, just as other utility capital costs are traditionally handled. Approving transmission costs for recovery during rate cases would still enable the utilities to recover their approved costs, but it would also increase regulatory lag (i.e., the time between when a cost is incurred and when it is recovered from customers). Because of the time value of money, utilities prefer rate riders over this more traditional ratemaking treatment, but both are equally valid from a regulatory perspective.

This means states could offer utilities the option of more favorable rate design as a carrot for good transmission planning, rather than adopting it as the default option. Kansas is an example of a state that has adopted this approach, as detailed in Box 4.

xliv Interviewees also noted that when local projects span multiple states, regional review is even more essential for cost-efficient and effective transmission planning.

Box 4

How Kansas Encourages More Efficient Transmission Planning

For years, Kansas had permitted utilities to recover transmission-related costs through a rate rider called the transmission delivery charge, which is codified in K.S.A. 66-1237. However, in the last few years, state policymakers became concerned about the increasing share of utility spending devoted to local transmission projects. At the time, the PUC (the Kansas Corporation Commission) and stakeholders had limited visibility into these projects, including the specific problems they were intended to solve, the process that led to their selection, and their projected costs. Policymakers also recognized that because the ROE offered by FERC for local transmission projects was higher than the ROE offered by the state for distribution projects, utilities might be inclined to seek ways to substitute transmission spending for distribution spending.

To address these concerns, in 2023 Kansas amended K.S.A. 66-1237 to distinguish between the use of the transmission delivery charge for cost recovery related to RTO-directed projects versus local projects.[65] Under the amended statute, transmission projects that have passed through the RTO's planning process remain eligible for rider treatment with no further conditions, but if a utility wishes to use the rider to recover the costs of a local project it must fulfill two additional conditions:

1. **Transparency.** The first condition is a set of requirements designed to increase transparency. These include the provision of key information about each project (e.g., the expected in-service date, cost, and location; whether the project is classified as a new build, rebuild, upgrade, or other type of project; a description of the purpose of the project; the vintage of any facilities the project is intended to replace; and the identification of any load additions or economic development benefits). The utility is also required to conduct a technical conference with PUC staff and other parties within 90 days of each compliance filing and a public workshop within 120 days of the filing.

2. **ROE.** The second condition is that the utility must accept the use of the state-approved ROE instead of the FERC-designated ROE.

If a utility does not wish to comply with these two conditions, it remains eligible to apply for cost recovery for its local project through means other than the rider. However, the attractiveness of the transmission delivery charge to utilities, primarily associated with reduced regulatory lag, creates an incentive for utilities to consider their options.

The amended statute has already had a positive impact on transparency in Kansas. It has enabled both regulators and stakeholders to better understand local transmission planning and to ask the utility questions, such as why a particular facility needed to be replaced or why a utility chose a traditional upgrade rather than a GETs alternative.

Although Kansas's approach is not sufficient to resolve the regulatory gap, it may reduce utilities' incentive to pursue local projects instead of regional ones. Kansas's legislation also increases regulators' and stakeholders' visibility into local transmission planning decisions. This enables greater transparency, and if a utility expects to have to publicly justify the decisions it makes, it may be inclined to make better decisions in the first place.

Update Integrated Resource Plans to Incorporate Transmission

Most PUCs that regulate vertically integrated utilities require the investor-owned utilities in their state to develop and file IRPs. Most of these IRPs do not consider transmission costs or evaluate transmission as a solution to meet demand.

Updating IRP requirements to incorporate transmission into planning is one near-term strategy states can use to gain more insight into utility transmission planning and influence the process early on. For example, states could require that within the IRP process, utilities include specific details about their transmission expansion plans, evaluate technologies that increase transmission capacity, such as GETs, and model transmission as a resource, along with new generation options.[xlv] More broadly, states could require utilities to discuss how they are utilizing a regional-first planning approach in partnership with the regional planning entity.[66]

Create and Fully Leverage Electric Transmission Authorities

Through legislative action, a few US states have created **electric transmission authorities** to coordinate transmission development. Examples include the New Mexico Renewable Energy Transmission Authority and the Colorado Electricity Transmission Authority (CETA). These bodies have been designed to operate in an independent fashion, which makes them well positioned to support cost-effective and reliable system planning and to identify gaps between utility-proposed projects and state needs. Transmission authorities can be of particular help in non-RTO regions, where regional planning is generally much more reduced in scope.

Existing transmission authorities have already had a positive impact on transmission development by enabling a cost-effective planning approach. In Colorado, for example, CETA was tasked with analyzing the need for expanded transmission capacity and evaluating all of the transmission technology options available (including new builds, rebuilds, reconductoring, and GETs).[xlvi] CETA identified over 3,700 miles of transmission needs, approximately 80% of which could be met through cost-effective rebuild or reconductoring solutions.[67] To realize similar benefits and better enable regional-first planning, states that do not currently have transmission authorities could consider creating them and task them with conducting a study on the transmission needs within their state and region.

Grow Regulatory Staff Capacity and Expertise

Even when PUCs have the authority to oversee aspects of the transmission planning process, their ability to conduct high-quality oversight is often limited by insufficient staff capacity and expertise. Although these constraints also affect other spheres of PUC activity, our interviews indicated that they may be particularly pronounced where transmission is concerned. This lack of sufficient staff capacity and expertise can also limit a state PUC's ability to engage thoroughly at the regional level as part of regional transmission planning processes.

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xlv The Oregon Public Utilities Commission requires utilities to consider transmission as a resource option alongside generation assets in their resource plans. This includes incorporating traditional and nontraditional benefits of transmission ("Disposition: Appendix to Order No. 07-002 Corrected," Oregon PUC, February 9, 2007, **https://apps.puc.state.or.us/orders/2007ords/07-047.pdf**).

xlvi SB23-016 requires CETA to study the need for expanded transmission capacity in the state of Colorado by January 31, 2025 (SB23-016: Greenhouse Gas Emission Reduction Measures, Colorado General Assembly, 2023, **https://leg.colorado.gov/bills/sb23-016**).

State legislatures could help address this issue by increasing the budgets and staff capacity of PUCs, either overall or in a manner targeted at transmission specifically. This could enable PUCs to hire more staff, provide more training opportunities to help staff develop transmission-specific expertise, and hire third-party experts where necessary to supplement in-house resources.[xlvii]

Though state legislatures have the largest role to play in ensuring PUCs have sufficient resources to conduct proper oversight, other actors can also play valuable roles in developing commissioner and staff expertise. For example, the National Association of Regulatory Utility Commissioners (NARUC) offers trainings and other educational resources geared to the needs of its membership, and some nonprofit organizations host workshops, offer fellowships that focus on developing specialized expertise, and support professional networks that enable peer-to-peer learning.[xlviii] By tailoring their offerings to focus on key transmission-related topics, these organizations could help PUCs develop the in-house expertise they need.

xlvii For example, the North Carolina Utility Commission recently put out a request for proposals for technical expertise to help them review transmission projects better (see the remarks by James McLawhorn at the FERC technical conference on October 6, 2022). For broader discussion of reforms that could help PUCs be more effective, see Jessie Ciulla et al., *The People Element: Positioning PUCs for 21st-Century Success*, RMI, 2022, **https://rmi.org/insight/puc-modernization-issue-briefs/**.

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Conclusion

The effectiveness of transmission planning in the United States is currently hampered by a regulatory gap, in which many local transmission projects do not receive adequate review by state, regional, or federal entities. Utilities can take advantage of this gap by pursuing local projects instead of pursuing more cost-effective regional solutions.

This is an inherently inefficient way to conduct the process of grid investment. Many uncoordinated local projects will generally be more costly than larger, well-planned regional projects, and they will also tend to have greater land use and environmental impacts and fewer economic and operational benefits. This approach also misses a key opportunity to proactively design the grid of the future rather than simply rebuild the grid of the past.

Unfortunately, evidence indicates that local transmission spending has increasingly displaced regional investment in recent years. If this trend continues, it will be difficult to meet the dual demands of accelerating load growth and the clean energy transition in a cost-effective manner. At a time when many customers already struggle to pay their utility bills, this is a problem that policymakers should proactively work to address.

In this report, we identify a number of reforms at the regional, federal, and state levels that can help strengthen the regulatory oversight of local transmission investments and produce better planning results. Only then can customers be confident that they are getting the most "bang for their buck," as former FERC Commissioner Rich Glick phrased it, with respect to transmission investment.[68]

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