High Voltage, High Reward Transmission

Evidence from Operational Transmission Projects that Deliver Cost Savings to American Consumers

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Authors and Acknowledgments

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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.

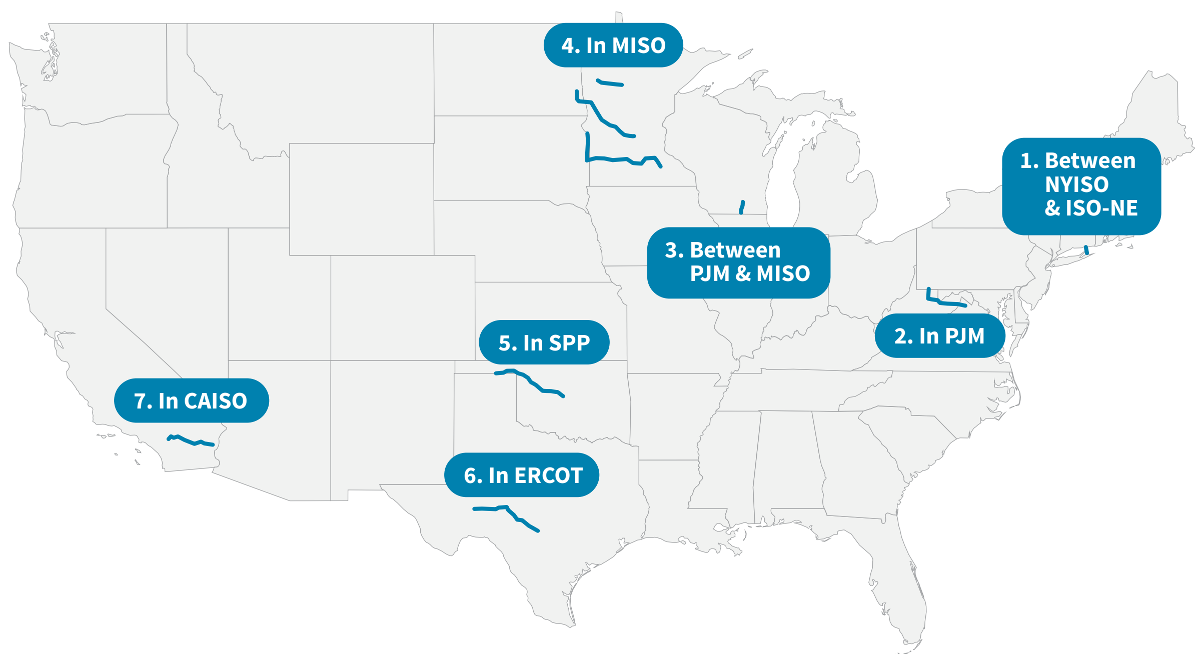
Contents

Executive Summary

Planners and regulators are actively evaluating new investments in transmission projects to address growing electricity demand; integrate new, lower-cost electricity generation resources into the grid; and maintain a reliable and resilient system, among other drivers. As the need for and scale of proposed transmission investments grow, so do concerns about rising costs, underscoring the importance of a well-planned and coordinated regional and interregional transmission system to maximize benefits and reduce costs for families and businesses.

This report uses evidence from seven case studies of operational regional and interregional transmission projects to show the savings that large-scale transmission can bring to ratepayers — residential, commercial, and industrial. The projects are geographically diverse, touching all seven regional transmission organizations (RTOs), and include enough historical data for meaningful evaluation after the line was energized (10+ years). See Exhibit ES1 for a map of the seven projects.

Exhibit ES1 Seven case studies touch the seven RTOs in the United States



From East to West, the seven case studies are located (1) between the New York Independent System Operator (NYISO) and the Independent System Operator of New England (ISO-NE), (2) in Pennsylvania-New Jersey-Maryland Interconnection (PJM), (3) between the PJM and the Midcontinent Independent System Operator (MISO), (4) in the MISO, (5) in the Southwest Power Pool (SPP), (6) in the Electric Reliability Council of Texas (ERCOT), and (7) in the California Independent System Operator (CAISO).

RMI Graphic. Source: Department of Homeland Security, and RMI analysis

The analysis looks at actual line performance, specifically the realized benefits and costs of the projects in operation. We consider three ways that transmission saves money for consumers: reduced grid congestion ("congestion relief savings"), access to cheaper sources of generation capacity ("resource adequacy savings"), and access to renewable sources of generation that meet public policy goals ("public policy savings"). In this report we calculate the benefit-to-cost ratio of the seven transmission lines and **find that every one of them has provided benefits that exceed their costs**. Even under a conservative assessment of a narrow range of benefits, these lines lowered overall electricity system costs, rather than raising them.

Key findings

Finding 1: Ratepayer savings exceed costs

Although the seven projects were built for various purposes, including reliability, economics, and public policy needs, for every dollar invested, ratepayers received at least that amount or more in savings. All seven projects achieved benefit-to-cost ratios between 1.1 and 3.9 (see Exhibit ES2, next page). These results highlight large-scale transmission's ability to deliver tangible cost savings to American consumers and businesses while addressing critical grid needs.

Finding 2: Projects aimed at delivering economic benefits exceeded planners' expectations

Our analysis looked at five projects that were built with economic benefits in mind — multi-benefit (blue in Exhibit ES2) or public policy driven (green in Exhibit ES2). We found these projects outperformed planners' original expectations. Three projects with pre-existing benefit-cost analyses (BCAs) exceeded the anticipated benefit-to-cost ratios in the original plans (shown by white dashed lines in Exhibit ES2). The other two projects, while lacking pre-existing BCAs, also delivered significant economic benefits. Regionally planned non-reliability projects are expected to surpass the Federal Energy Regulatory Commission's (FERC) 1.25 benefit-to-cost ratio standard. Each of these five non-reliability projects significantly surpassed that threshold.

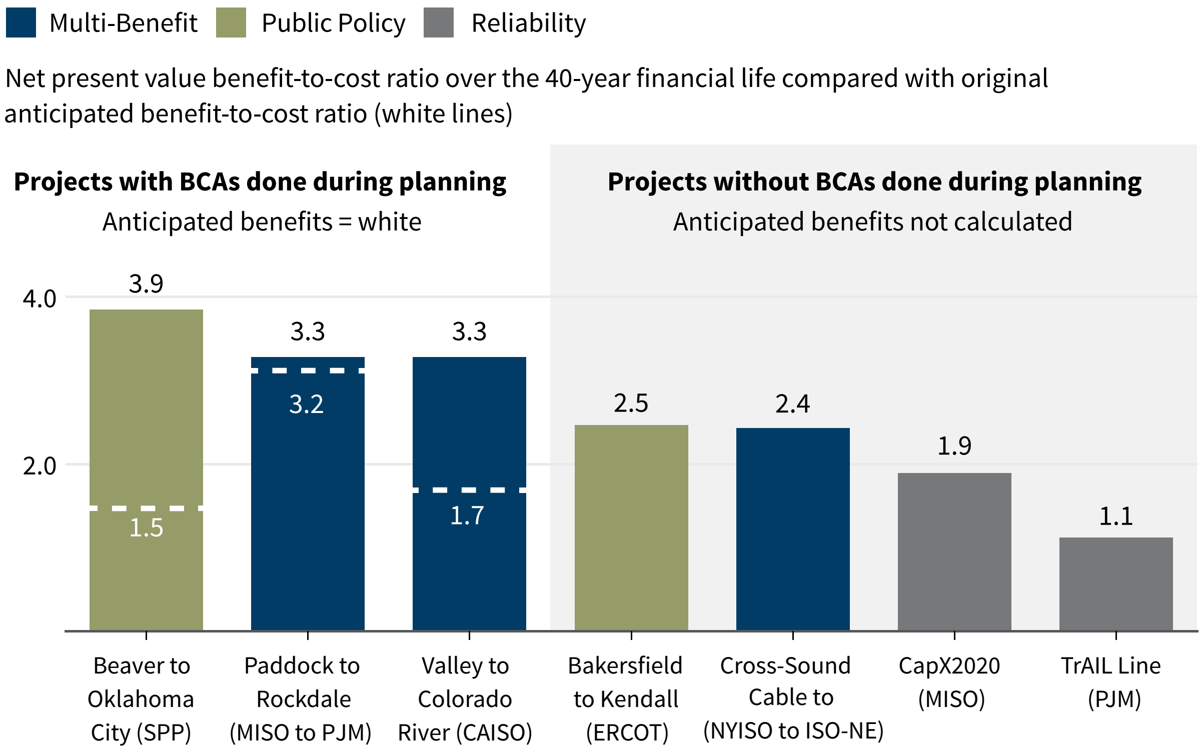
Finding 3: Reliability-driven projects delivered unintended economic benefits

Our analysis looked at two projects (gray in Exhibit ES2) that were built to address critical reliability issues on the grid. In these instances, economic benefits were not anticipated or factored into the original planning process. Our analysis shows that, in addition to successfully addressing their reliability objectives, these projects also generated significant, unexpected economic benefits. These reliability projects are not required to meet the FERC 1.25 benefit-to-cost ratio standard because the investments are necessary to maintain grid safety and functionality.

Finding 4: Transmission is a long-term investment, delivering enduring savings over time

Transmission projects represent long-term infrastructure assets with financial lifespans of over 40 years, and operational lifespans often extending decades beyond. Benefit-to-cost ratios improve over time, as up-front capital costs depreciate and benefits remain stable. While benefits may take time to exceed costs, they ultimately will surpass total cost, delivering enduring savings to ratepayers. The payback period — the date when benefits exceed total lifetime costs — for these seven projects occurs between 8 and 34 years.

Exhibit ES2 The seven lines delivered significant benefits to ratepayers, exceeding planners' expectations



RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources.

Implications for policymakers and stakeholders

These findings demonstrate that regional and interregional transmission projects can serve as prudent investments that meet many priorities simultaneously. These projects showcase cost-effective investments that deliver long-term savings to ratepayers. Strong planning processes, collaboratively implemented with state input, can support:

- A resilient, reliable, modern grid
- Lowered congestion costs and wholesale electricity market efficiency
- Long-term cost avoidance and affordability
- Integration of lower-cost energy sources
- Economic growth

Regulators and planners can move forward with confidence that regional and interregional transmission investments will not only meet today's energy challenges but also provide long-term value for American consumers and businesses — all while strengthening the grid. They should prioritize and invest in multi-benefit, large-scale, coordinated regional and interregional transmission projects that deliver system-wide savings ("regional-first planning").[i] These projects, when designed and implemented effectively, are poised to pay for themselves, often many times over.

i Additional resources on regional planning can be found in the Conclusion.

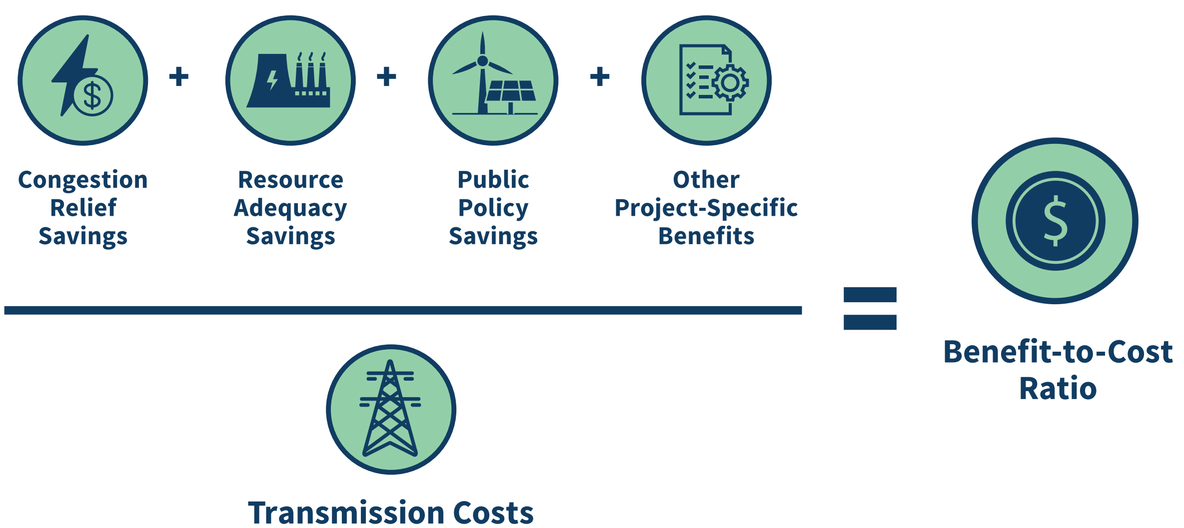
Introduction

Grid planners and regulators will increasingly need to evaluate substantial new electric transmission investments to address surging load, prevent grid emergencies, enable the connection of new resources, and implement recent reforms by FERC. Given the anticipated scale and need for these investments, coupled with valid concerns surrounding rising electricity costs, it is prudent for planners and regulators to carefully assess the justifications, ratepayer impacts, and long-term benefits of proposed projects and plans. Prudence will be critical to ensure transmission expansion effectively supports grid reliability, efficiency, and resilience, while managing financial and operational considerations.

Our analysis of the performance of operational, large-scale transmission adds to a body of evidence that strengthens regulator confidence in transmission as a cost-effective investment for ratepayers.[ii] Specifically, we evaluate the benefits and costs of seven regional and interregional transmission projects currently in operation, using a retrospective approach that focuses on projects placed into service at least a decade ago.

We consider three ways that transmission saves money: reduced congestion ("congestion relief savings"), access to cheaper sources of generation capacity ("resource adequacy savings"), and access to renewable sources of generation that meet public policy goals ("public policy savings"). The primary output is a ratepayer benefit-to-cost ratio, assessed over the project's life to date and financial life, compared — when possible — to the anticipated benefit-to-cost ratio from the project's original plans. Exhibit 1 provides a high-level overview of the BCA; more details can be found in the *Methodology* section and *Appendix C*.

Exhibit 1 Visual summary of RMI's BCA



RMI Graphic. Source: RMI analysis

ii Additional resources on the benefits of transmission can be found in the *Conclusion*.

This study is one of the few retrospective analyses of US transmission and, to our knowledge, the only one to assess projects across multiple RTOs nationwide. This approach provides valuable insights into how the energy system benefits from new transmission capacity. While regional and interregional lines are often planned to meet targeted uses, unforeseen factors often contribute to the ultimate value that transmission projects deliver to ratepayers.

Grid operators plan transmission to meet a range of critical needs. Reliability projects are essential to ensure the grid operates safely and efficiently, addressing potential system violations and contingencies, and maintaining the integrity of aging infrastructure by replacing or upgrading lines as needed. Market-efficiency projects are planned to reduce grid congestion, allowing cheaper electricity to flow more freely. Public policy projects facilitate new generation to meet state or utility goals. Ideally, grid operators should plan regional and interregional projects to serve multiple objectives, maximizing benefits to consumers. These are referred to as multi-benefit projects.

Transmission infrastructure, beyond its initial driver, is designed to adapt to unforeseen changes or events. Several projects have enabled the significant integration of renewable resources like solar, wind, and storage, far exceeding original expectations because of substantial decreases in technology costs. This has lowered generation costs for ratepayers. Additionally, many projects have played critical roles in maintaining grid reliability during unforeseen extreme events, such as winter storms and heat waves, ensuring that the lights remain on for consumers. Transmission also drives economic development. For instance, one project facilitated new wind generation and additional electric demand, aligning with Texas's dual goals, at that time, of becoming a leader in wind energy development while also supporting the growth of the oil and natural gas industries. The diverse range of projects demonstrates that transmission lines are inherently flexible and serve as a neutral tool for advancing a variety of state and local policy objectives.

We have organized our report as follows. First, we describe our overall findings based on all seven case studies. Second, we summarize the methodology and rationale for our approach, including an overview of the benefit calculations, cost calculations, and the overall BCA. Finally, we conclude with key takeaways and additional resources for understanding the benefits of transmission. In addition, we detail our findings for each of the seven transmission projects in *Appendix A* and provide more details about our assumptions and methodology in *Appendices B and C* (*Appendix* C is a separate document).

Case Studies on Regional and Interregional Transmission Savings Delivered to Ratepayers

Seven regional or interregional transmission projects that are currently in operation were selected for this study. Exhibit 2 shows a map of the United States with all seven projects, and Exhibit 3 shows more details for each project. These seven projects were selected to:

- Touch each of the seven RTOs in the United States;[iii]
- Provide at least 10 years of operational data;[iv]
- Showcase examples of large-scale regional and interregional transmission projects;[v] and
- Showcase a variety of development drivers[vi]

In *Appendix B*, we discuss the process of selecting the seven projects in more detail.

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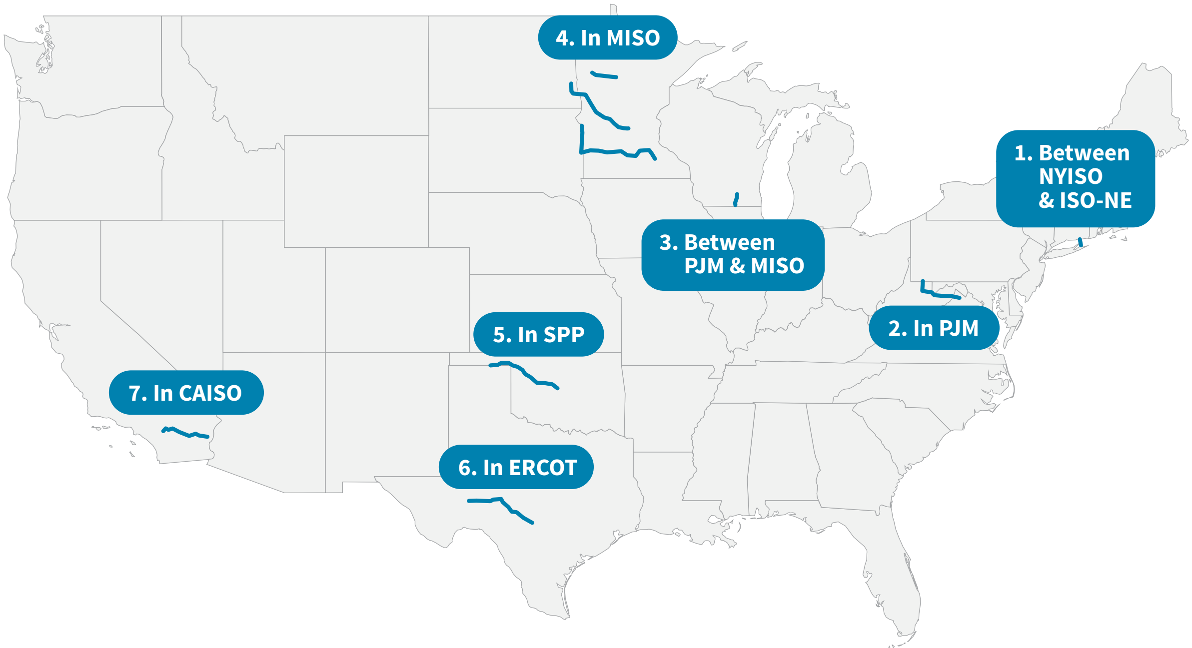
iii We did not review lines in non-RTO regions because the analysis relies on historical data related to economic dispatch, capacity procurement, and environmental attribute procurement, which is unavailable in those areas. In some regions, no transmission assets were available for evaluation because of limited or absent regional and interregional transmission development. Notably, ISO-NE, NYISO, and MISO-South have not developed regional transmission projects that meet the characteristics we filtered for or that fall within our time span.

iv We chose lines that were built after 2000 but before 2014. This enabled us to capture at least 10 years of results from 2014 to 2023.

v We picked lines that were over 100 miles and higher than 200 kilovolts to embody typical regionally planned lines. We picked lines that crossed regional planning entity boundaries for examples of interregional lines. These lines were not necessarily developed through a regional or interregional planning process.

vi We categorized the primary development drivers as reliability, multi-benefit, and public policy drivers based on independent research. Each project was assigned a primary driver; however, some projects had multiple drivers.

Exhibit 2 Seven case studies touch the seven RTOs in the United States



From East to West, the seven case studies are located (1) between the New York Independent System Operator (NYISO) and the Independent System Operator of New England (ISO-NE), (2) in Pennsylvania-New Jersey-Maryland Interconnection (PJM), (3) between the PJM and the Midcontinent Independent System Operator (MISO), (4) in the MISO, (5) in the Southwest Power Pool (SPP), (6) in the Electric Reliability Council of Texas (ERCOT), and (7) in the California Independent System Operator (CAISO).

RMI Graphic. Source: Department of Homeland Security, and RMI analysis

Exhibit 3 Seven case studies showcase geographic diversity and a variety of development drivers

Name	Type of Line	RTO	Number of Segments	Voltage	Right-of-Way Mileage	Online Year	Primary Development Driver
Cross-Sound Cable	Interregional	NYISO & ISO-NE	1	150 kV DC	24	2003	Multi-Benefit
TrAIL	Regional	PJM	1	500 kV AC	152	2011	Reliability
Paddock to Rockdale	Interregional	MISO & PJM	1	345 kV AC	35	2010	Multi-Benefit
CapX2020	Regional	MISO	6	230-345 kV AC	758	2011	Reliability
Beaver to Oklahoma City	Regional	SPP	2	345 kV AC	220	2010	Public Policy
Bakersfield to Kendall	Regional	ERCOT	2	345 kV AC	251	2013	Public Policy
Valley to Colorado River	Regional	CAISO	2	500 kV AC	153	2013	Multi-Benefit

Note: Segments are defined by S&P Global Market Intelligence. Each segment is evaluated individually.
RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources.

Each transmission project we profile comes from a distinct regulatory, political, and market context. Some projects emerged in response to state legislation, while others addressed needs identified by utilities or regional transmission operators. The benefits realized from these projects depend on their unique circumstances, such as being in states with public policy mandates or regions with capacity markets. In *Appendix A*, we take a deeper look at the regulatory context and benefits of each project, aiming to provide confidence in the analysis and calculated savings through a detailed project-by-project assessment.

In this section, we highlight our four overall findings across the seven case studies.

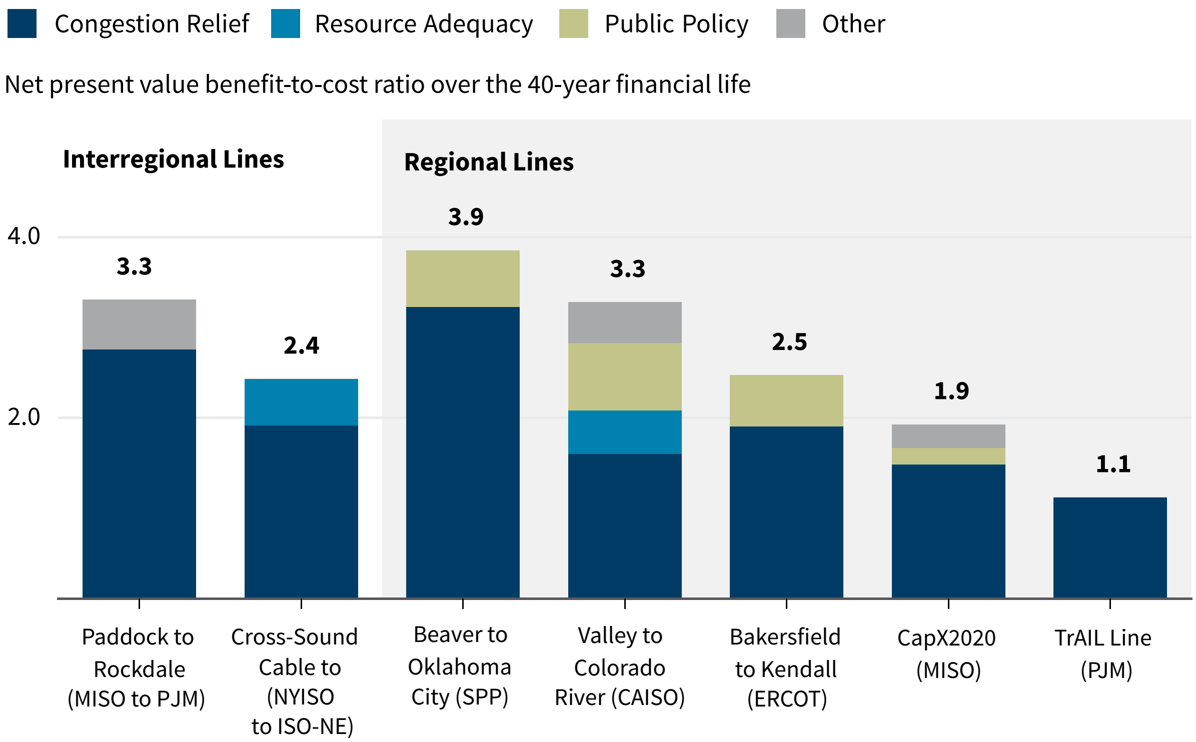
Finding 1: Ratepayer savings exceed costs

All seven projects deliver significant economic savings to ratepayers in excess of their cost, even with conservative accounting of savings. As we discussed in the *Introduction*, transmission projects are built for various reasons. The seven projects we evaluated were a mix of multi-benefit, reliability, and public policy driven projects. Regardless of the original driver, our analysis finds that savings exceed costs over the 40-year lifespan. Exhibit 4 shows the benefit-to-cost ratio for each project, broken down by benefit type. The benefit-to-cost ratios range from 1.1 to 3.9. A ratio above 1.0 indicates that, on average, annual savings exceeded annual costs. Another way to interpret the ratio is how many times the project pays for itself.

Across the seven projects, congestion relief savings made up a large majority of the benefits to ratepayers. Congestion relief is the most straightforward benefit of transmission because it reduces fuel and variable costs, ensuring the grid operates as efficiently as possible. However, as we explore in the individual case studies in *Appendix A*, benefits such as resource adequacy, public policy, and other savings are equally tangible, contributing to lower bills for ratepayers.

Exhibit 4

Regional and interregional projects generate significant savings for ratepayers



RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources.

Finding 2: Projects aimed at delivering benefits exceeded planners' expectations

Of the seven projects, five were designed to deliver economic benefits through multi-benefit planning (Paddock to Rockdale, Valley to Colorado River, and Cross-Sound Cable, in blue in Exhibit 5) or public policy planning (Beaver to Oklahoma City and Bakersfield to Kendall, in green in Exhibit 5). These projects enabled access to low-cost generation and capacity, improved resilience to extreme events, and enabled states to meet their public policy goals. All the projects were built with economic benefits in mind; however, only three of these five projects had benefit-to-cost projections in their original plans.

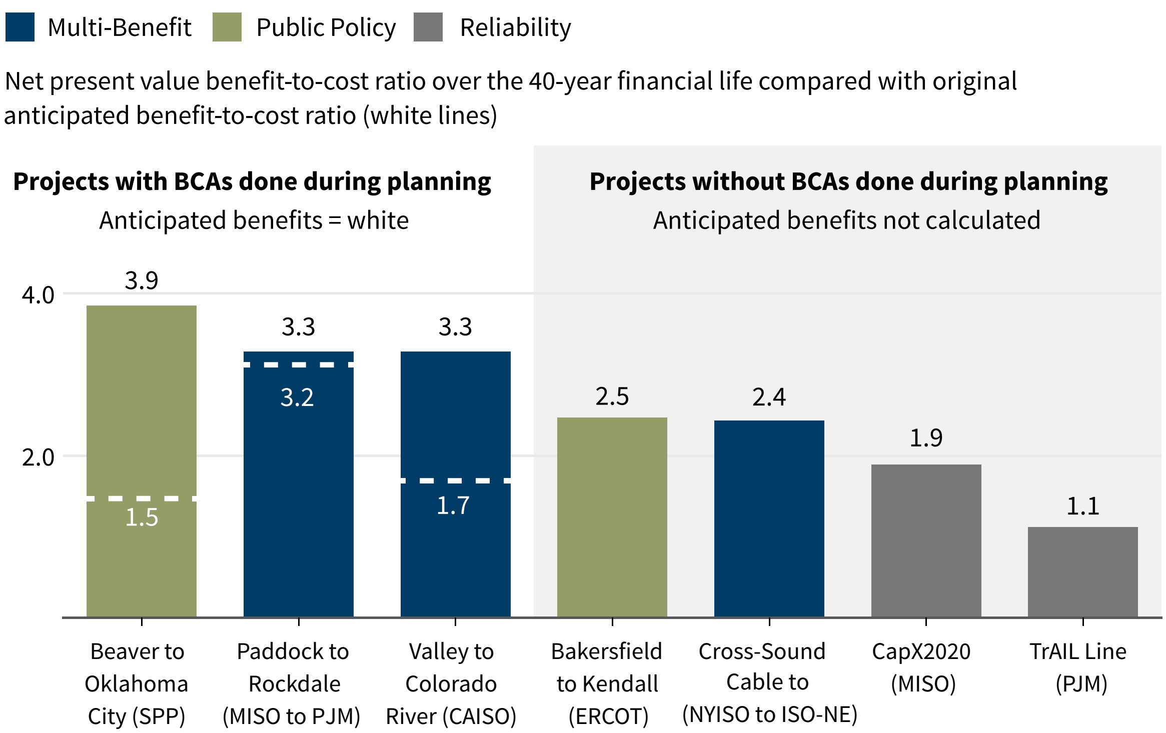
The retrospective analysis evaluates each project's performance within a rapidly changing grid and compares actual outcomes with planners' original forecasts. The three projects with pre-existing BCAs outperformed their initial cost-benefit projections (shown by white dashed lines in Exhibit 5). The other two projects, while lacking pre-existing BCAs, also delivered significant economic benefits. Regionally planned non-reliability projects are expected to surpass FERC's 1.25 benefit-to-cost ratio standard, and each of the five non-reliability projects significantly surpassed that threshold. In Exhibit 5, we highlight the benefit-to-cost ratio over the 40-year lifespan of the three multi-benefit projects (in blue) and two public policy projects (in green) compared with original projections, when available.

Finding 3: Reliability-driven projects delivered unintended economic benefits beyond keeping the lights on

Of the seven projects, two (CapX2020 and Trans-Allegheny Interstate Line, or TrAIL) were designed primarily to address critical reliability issues on the grid, and as such, economic benefits were not factored into the original planning process. These projects solved issues such as fixing voltage stability, meeting projected load growth, and enabling necessary rebuilds, among other concerns. As reliability projects, they were deemed necessary to ensure grid safety and function and were therefore not required to meet the FERC 1.25 benefit-to-cost ratio standard. However, our analysis shows that, in addition to addressing their reliability objectives, these projects **also** generated significant economic benefits, approaching or exceeding that threshold. In both cases, the projects paid for themselves with just their unintended economic benefits. Exhibit 5 depicts the benefit-to-cost ratio over the 40-year lifespan of the two reliability projects in dark gray.

Exhibit 5

The seven lines delivered significant benefits to ratepayers, exceeding planners' expectations



RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources.

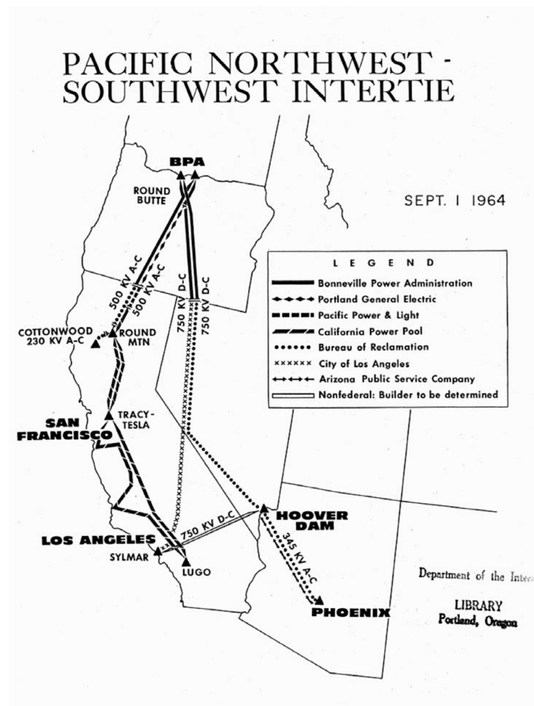
Finding 4: Transmission is a long-term investment, delivering enduring savings over time

Across the country, transmission projects have long financial lifespans (40–60 years) and often remain operational for decades beyond their financial lives.

Our analysis finds that some of the projects immediately begin paying for themselves, while others take longer over the course of their 40-year financial life. Nevertheless, all the projects provided positive net benefits by the end of their financial life and will continue to provide benefits for many years thereafter. This is due to two main drivers. First, because transmission projects are large capital investments, most of their costs are depreciated over time, meaning annual costs in the final year are significantly lower than in the first year.[vii] Second, benefits typically remain stable or go up over time.[viii]

One of the most critical arteries of the Western grid, the Pacific direct current (DC) and alternating current (AC) intertie has been in operation for over 54 years and has paid for its original $700 million price tag many times over.[ix]

Given these two effects, the projects we studied are long-term investments that become more compelling over time. Exhibit 6 shows the cumulative benefit-to-cost ratios over the 40-year lifespans of the seven projects. Across all seven projects, the benefit-to-cost ratios increase with time and the payback periods occur between 8 and 34 years.



Pacific Intertie Map from
Bonneville Power Administration, 1964

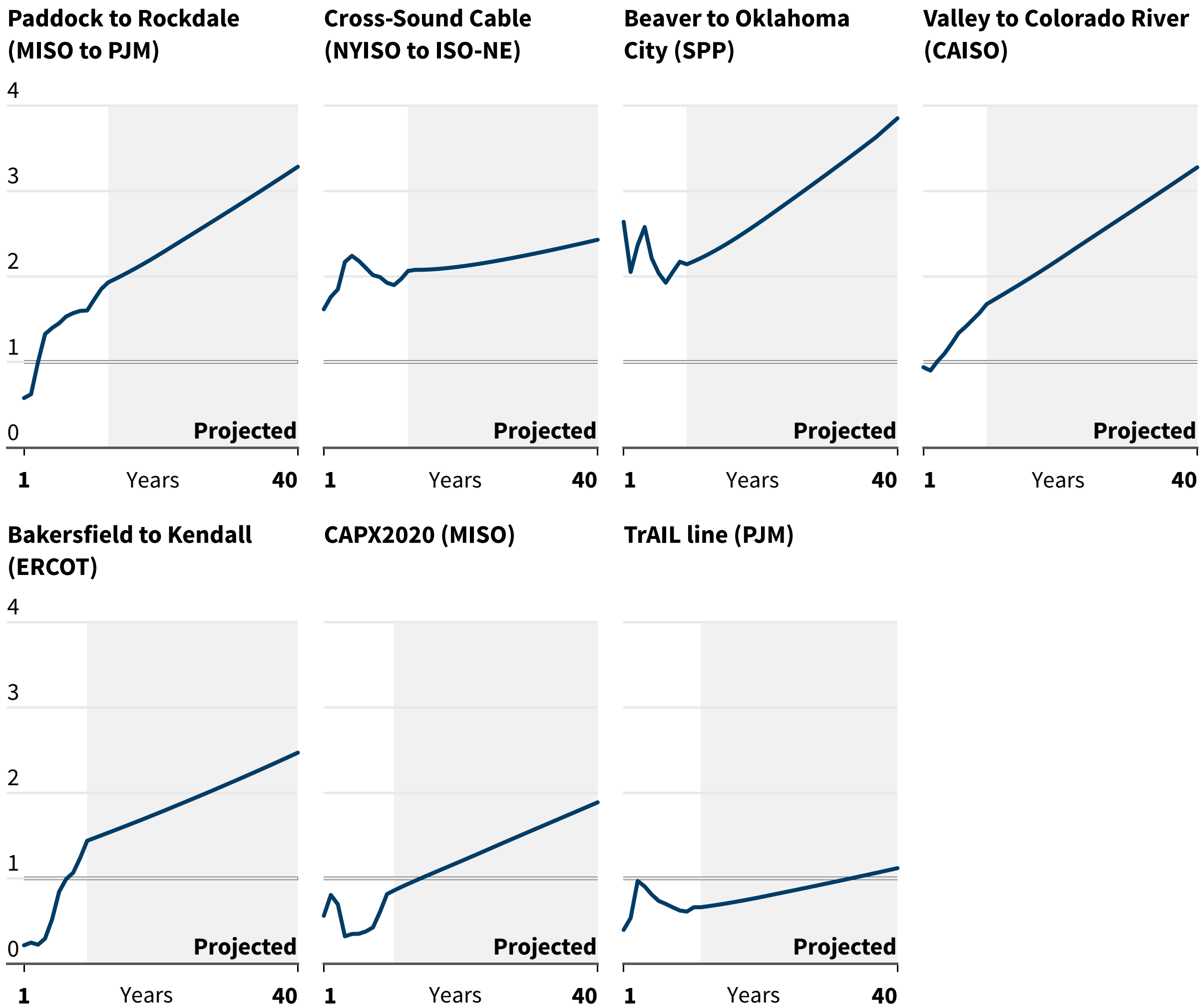
vii The annual revenue requirement in the 40th year for projects owned by investor-owned utilities is approximately 25% of the first year, while for projects owned by public power utilities, it is approximately 40% of the first year. These approximate values were calculated for a hypothetical $100 million project with generic inputs. Each project will be different. More details can be found in the *Methodology* and *Appendix C*.

viii Typically, the net present value of benefits stays stable over time as inflation increases and the value of money decreases. Our analysis uses a 2.45% inflation rate and a 3% discount rate, which assumes a relatively stable but slight decrease over time. In nominal terms, benefits increase and costs decrease over time.

ix The initial intertie consisted of two 500 kilovolt (kV) AC lines and two 800 kV DC lines from Oregon to Southern California. They were energized in 1968, 1969, and 1970. An estimate from 1976 projected that Southern California saved $600,000 per day. Later, Charles Luce, the administrator of the Bonneville Power Administration, estimated that the construction cost of the project would be paid back each year over its estimated 50 years of life. See "Pacific Intertie: The California Connection on the Electron Superhighway," Northwest Power Planning Council, May 2001, **https://www.nwcouncil.org/sites/default/files/2001_11.pdf**; and "The Future of Electric Transmission," Orkas Energy Endurance, February 23, 2019, **https://www.orkas.com/the-future-of-electric-transmission/**.

Exhibit 6 **Transmission projects are long-term investments that continue delivering benefits to ratepayers over time**

Cumulative benefit-to-cost ratio over the 40-year financial life

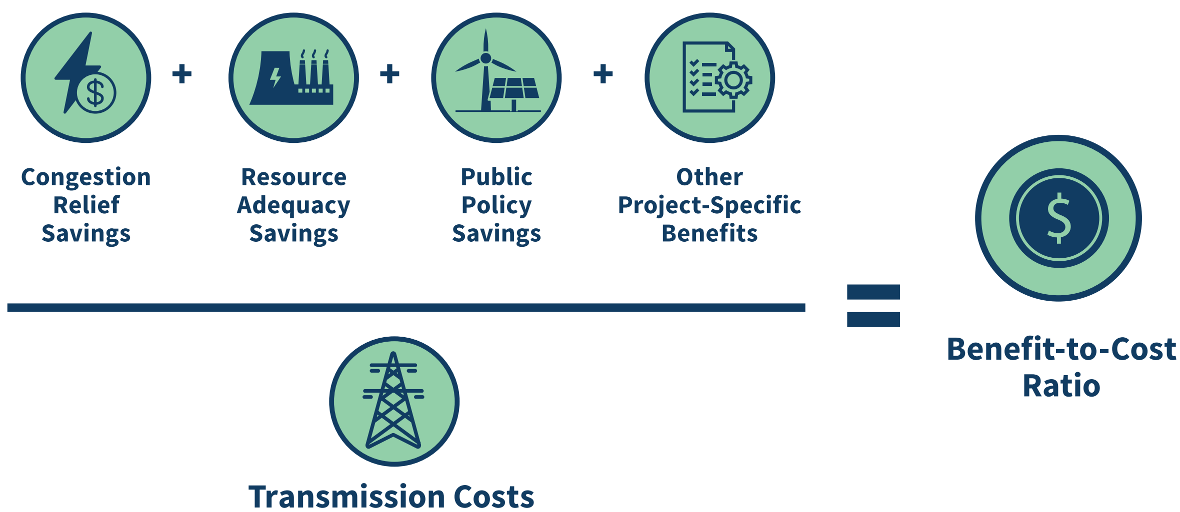


RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources.

Methodology

We calculate the benefits and costs for seven transmission projects,[x] focusing on three core savings, derived from publicly available data, along with additional project-specific benefits, when available. The primary output is a benefit-to-cost ratio, using the net present value (NPV) (2024 dollars) of annual benefits and costs. When possible, we compare this ratio with the anticipated benefit-to-cost ratio from the project's original plans. Costs and benefits are calculated as total rate impacts for all ratepayers (residential, commercial, and industrial), rather than a societal BCA.[xi] Our approach is like other BCAs conducted by transmission planners in the United States.[xii] Exhibit 7 shows a high-level overview of the analysis.

Exhibit 7 **Visual summary of RMI's BCA**



RMI Graphic. Source: RMI analysis

In this section, we provide a rationale for our methodology and a high-level overview of benefit calculations, cost calculations, and the overall BCA.

A comprehensive overview of the methodology and a greater discussion of assumptions and sources can be found in *Appendix C*.

x A project can be a single transmission line or can be made up of multiple transmission line segments. When a project is made up of multiple transmission segments, each segment is evaluated independently and then aggregated.

xi We do not include societal impacts such as health, employment, tax revenue, and other upstream and downstream effects.

xii Our approach was informed by similar BCAs completed by utilities, RTOs, and others. The main difference is we take a retrospective approach. For example, MISO takes a comparable approach and calculates similar benefits for its Long-Range Transmission Planning and Multi-Value Portfolio efforts. See "Long Range Transmission Planning, MISO, **https://www.misoenergy.org/planning/long-range-transmission-planning/**.

Rationale for methodological approach

This analysis is uniquely and intentionally structured to calculate the benefits and costs of transmission projects by using observed performance, rather than modeled performance. This approach provides unique insights by capturing unforeseen factors that often influence the ultimate value that transmission projects deliver to ratepayers and highlighting the difference between the current transmission planning process and operational reality. Empirical data used includes:

- Congestion relief benefits: Historic hourly day-ahead and real-time locational marginal prices.
- Resource adequacy benefits: Historic capacity market clearing prices (ISO-NE, PJM, MISO, and NYISO) or resource adequacy contracts (CAISO).
- Public policy benefits: Historic individual plant-level and average RTO-wide capacity factor and associated levelized cost of energy.

By using this approach, there are several considerations to be aware of:

Our list of benefits is conservative in nature

Our study focused on three core transmission benefits, though many additional benefits could be quantified. FERC Order No. 1920-A identifies seven benefit categories,[1] MISO's long-range transmission planning identified six benefit categories,[2] and The Brattle Group outlines eight benefit categories.[3] Therefore, our estimate of net benefits is likely conservative because other methodologies include many more benefits than we considered.

Additionally, going forward, grid planners will be required by FERC Order No. 1920-A to plan for and quantify seven specific benefits.[4] This means our analysis likely underestimates the full range of benefits that grid planners will be using in the coming years.

We used a conservative approach to calculate congestion relief and resource adequacy savings

The congestion relief and resource adequacy savings were calculated using observed historic price differences between two points on the grid (nodes). This price difference represents the marginal cost — the cost of the next unit of electricity required to meet demand. This approach provides a conservative estimate because, without the transmission line, the price disparity would likely be even greater.

This holds true for both congestion relief and resource adequacy. At the higher-priced node, more energy or capacity would need to be acquired, driving prices up. Conversely, at the lower-priced node, less energy or capacity would be needed, pushing prices down. Overall, this would increase the price disparity. As a result, calculating the true counterfactual scenario — where operating or fixed costs of power generation are higher without the additional transmission capacity — would likely reveal a higher economic value for the transmission.[xiii]

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xiii We did not calculate the true counterfactual scenario because it would be complex and require assumptions and modeled data to be introduced into the analysis versus looking solely at observed data.

Evaluating transmission lines in isolation is a reasonable approach to simplify complex interactions

We evaluate transmission lines in isolation to directly assess their associated benefits and costs. We do this by estimating their incremental power-carrying capabilities based on mileage and voltage — the physical characteristics most directly influencing a line's capacity.[xiv] However, the full physics of the grid, including how power flows across interconnected systems, is complex. Factors such as line impedance, voltage constraints, dynamic stability, shift factors, and system-wide interactions contribute to the carrying capacity. These factors result in transmission capacities that vary depending on network configuration, operational constraints, and environmental conditions. As such, we would expect the actual carrying capacity and power flows of the lines to differ from our estimates in upward and downward directions.[xv]

That said, our estimate of carrying capacity in isolation is a reasonable attempt to calculate the associated benefits and cost of each line. This approach has been used in other studies, including the Department of Energy's *National Transmission Needs Study*.[5]

Distribution of benefits and costs among different ratepayers is not in scope

While this analysis evaluates benefits from the ratepayer perspective, it does not assess how benefits and costs are distributed among different ratepayers. Within an RTO and across RTOs, ratepayers across utilities will accrue different benefits and costs from these projects. Therefore, the benefit-cost ratio calculated may differ depending on the specific ratepayers considered. Assessing the precise distribution of costs and benefits across ratepayers would introduce complexity beyond the scope of this analysis.

Importantly, FERC has established regulatory safeguards to ensure that costs are allocated fairly and commensurate with the benefits received. The cost of a new transmission line is typically allocated based on rules from RTOs, federal regulations, or state agreements. As regulators and planners assess the benefits and costs of new lines, they must also in earnest agree to fair methodologies to allocate costs.

Calculating transmission benefits

Benefits included

We consider three ways that transmission saves money: reduced congestion (congestion relief savings), access to cheaper sources of generation capacity (resource adequacy savings), and access to sources of generating capacity that meets public policy goals (public policy savings). While all the projects we studied provided congestion relief savings, we attributed resource adequacy savings only to states or markets that had resource adequacy programs or capacity markets, and public policy savings only to projects that enabled clean-energy investment. On a project-by-project basis, we examined additional project-specific benefits, as available. Exhibit 8 provides an overview of the lines and their associated benefits.

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xiv We calculated the power-carrying capabilities (MW) of uncompensated AC transmission projects at different voltage ratings and lengths from the National Regulatory Research Institute. More details can be found later in this section and in *Appendix C*. See *Some Economic Principles for Pricing Wheeled Power*, National Regulatory Research Institute, 1987, 52.

xv For example, the Cardinal Hickory Creek project in MISO is a 345 kilovolt line of 102 miles. By our estimate it has a carrying capability of 860 megawatts. However, it, along with a handful of other projects in the MISO Multi-Value Projects portfolio, enabled over 24.5 gigawatts of wind and solar plants.

Exhibit 8 Each line delivered distinct benefits

Project	Region	Congestion Relief Savings	Resource Adequacy Savings	Public Policy Savings	Other Project-Specific Benefits
Cross-Sound Cable	ISO-NE & NYISO	X	X		
TrAIL	PJM	X	X*		
Paddock to Rockdale	MISO & PJM	X	X*		X
CapX2020	MISO	X	X*	X	X
Beaver to Oklahoma City	SPP	X	X*	X	
Bakersfield to Kendall	ERCOT	X		X	
Valley to Colorado River	CAISO	X	X	X	X

Note: An X indicates that savings or benefits were evaluated. Resource adequacy savings were evaluated for six of the seven projects, but savings were not identified for the four marked with an asterisk.

RMI Graphic. Source: RMI analysis

Estimating incremental transmission capacity to calculate benefits

For each alternating current line, we estimate the savings enabled by the incremental transmission capacity (megawatts) provided between two nodes on the grid (line start and end point), calculated using the line's mileage and voltage (see Exhibit 9).[xvi] This simplified model enables us to calculate benefits driven by economic differences between the nodes, such as variations in fuel and generation costs, the cost of adding new capacity, and the quality of local energy resources.

For direct current lines, we use the lines' rated power-carrying capability in megawatts.

xvi We calculated the power-carrying capabilities (MW) of uncompensated AC transmission projects at different voltage ratings and lengths using data from the National Regulatory Research Institute. More details about our approach and the limitations of this approach can be found in *Appendix C*. See *Some Economic Principles for Pricing Wheeled Power*, National Regulatory Research Institute, 1987, 52.

Exhibit 9 Cost savings are driven by new power-carrying capacity

Approximate power carrying capabilities (megawatts) of uncompensated AC transmission lines at different voltage ratings and lengths from the National Regulatory Research Institute

Line Length (mi)	Nominal Voltage (kV)					
	138	161	230	345	500	765
50	145	195	390	1,260	3,040	6,820
100	100	130	265	860	2,080	4,660
200	60	85	170	545	1,320	2,950
300	50	65	130	420	1,010	2,270
400	NA	NA	105	335	810	1,820
500	NA	NA	NA	280	680	1,520
600	NA	NA	NA	250	600	1,340

RMI Graphic. Source: Department of Energy's National Transmission Needs Study and the National Regulatory Research Institute.

Congestion relief savings

Benefit description

Congestion refers to the situation in which a suboptimal dispatch of the generation fleet is necessary because bottlenecks in the transmission system require a more expensive generator to run while a cheaper generator operates at reduced capacity or while wind and solar are curtailed. Relieving congestion through transmission investments can allow cheaper power to flow while expensive generators remain on standby, thereby lowering fuel costs.

Ratepayers accrue congestion relief savings through the reduction in fuel and other variable operating costs of power generation. These costs are typically reflected in wholesale market prices. At a high level, this benefit is reflected in increasing the use of more efficient (lower-cost) generators over inefficient (higher-cost) ones.

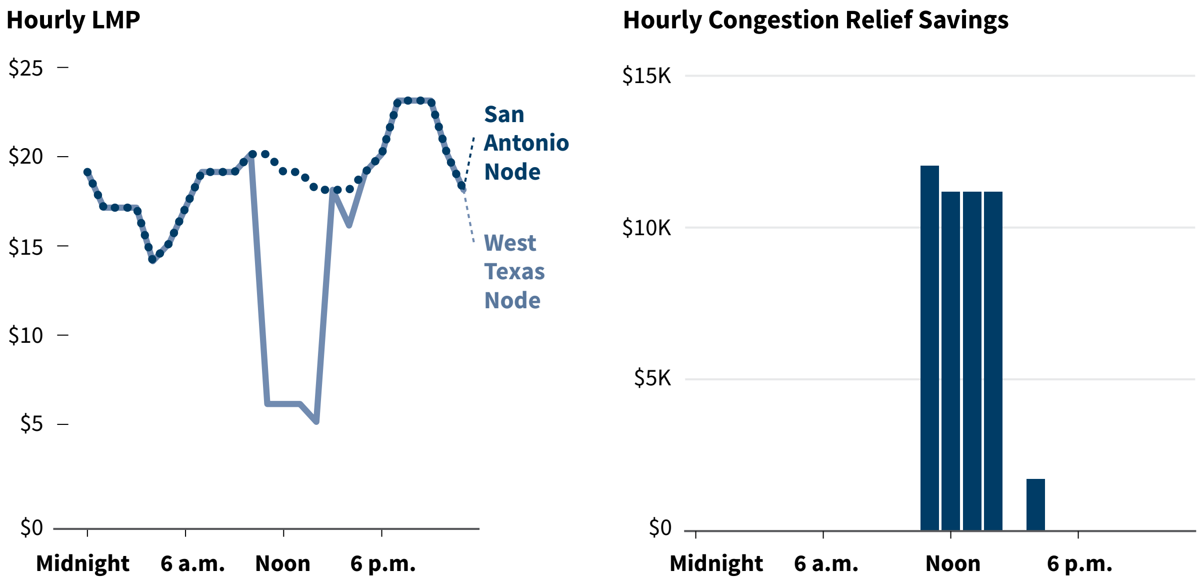
High-level calculation

Our analysis calculates this benefit by multiplying the transmission capacity of the line in question by the historical hourly spread between the locational marginal prices (LMPs), measured in dollars per megawatt-hour ($/MWh), on either end of the transmission line.[xvii] For many hours, there is little or no difference in

xvii We use day-ahead market prices and real-time market prices at each node. The day-ahead prices are weighted at 90%, while the real-time prices are weighted at 10%, reflecting the relative size of each market.

the LMP, but for some hours there is significant congestion.[xviii] In hours when there is significant congestion, the transmission capacity allows more efficient (lower-cost) generators at one node to replace less efficient (higher-cost) generators at the other node.

Exhibit 10 Nodal differences in LMPs drive congestion relief savings



RMI Graphic. Source: S&P Global Market Intelligence and RMI analysis

Example

The Bakersfield to Kendall project, a pair of 345 kilovolt (kV) lines between West Texas and San Antonio, enables lower-cost energy from wind and solar power plants in West Texas to serve the more expensive market in San Antonio. Exhibit 10 shows a representative day of the hourly LMPs at each end and economic congestion benefits, which is the cumulative difference between the two LMPs. On this day, there was a price difference in five hours, which produced a cumulative economic congestion benefit of $47,300 for Texan ratepayers. One way to think about this benefit is that, without the line, higher-cost power in San Antonio would have been used to generate energy, rather than relying on the lower-cost power from West Texas.

xviii The Lawrence Berkeley National Laboratory had similar findings, including that "extreme conditions and high-value periods play an outsized role in the value of transmission, with 50% of transmission's congestion value coming from only 5% of hours." See Dev Millstein et al., *Empirical Estimates of Transmission Value Using Locational Marginal Prices*, Lawrence Berkeley National Laboratory, August 2022, **https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf**.

Resource adequacy savings

Benefit description

Resource adequacy standards are standards to ensure the ability of the electric grid to supply enough electricity to meet demand under a range of future conditions.[xix] Grid operators need enough power-plant capacity to meet the standard and ensure reliable service. The cost of procuring capacity is heavily influenced by location and is a function of several factors, including land acquisition costs, permitting and siting regulations, fuel infrastructure availability, and resource availability.

Ratepayers accrue resource adequacy savings from transmission by enabling access to power plants with lower capital and fixed operation and maintenance (O&M) costs. These costs are typically reflected in wholesale capacity market prices or through resource adequacy programs. At a high level, this benefit is reflected in building and maintaining generating capacity at a lower cost in one location over another location.

High-level calculation

Our analysis calculated this benefit by comparing historical capacity market prices or resource adequacy costs in dollars per kilowatt-year ($/kW-yr) between the two nodes. For each node, we assign a subregional or zonal price. For every year of the period considered, we multiply the difference in the resource adequacy costs between the two nodes by the transmission capacity. In years when there is a difference in price, the transmission capacity allows lower-cost generators to replace higher-cost generators in the other region.

We calculated this benefit for the six projects in RTOs with resource adequacy programs or capacity markets; however, only two of the lines had nodes in separate subregional capacity zones with distinct prices and had evidence of capacity contracts from one subregion to another.

Example

The Cross-Sound Cable project, a 300-megawatt (MW) direct current line between NYISO and ISO-NE, enables Long Island, New York, to access relatively lower-cost natural gas capacity in ISO-NE. In one year, the average clearing price was $28/kW-yr in ISO-NE's Rest-of-Pool Capacity Zone and $43/kW-yr in NYISO's Long Island zone (Zone K).[xx] For this year, the total resource adequacy savings were $4.5 million, which is the difference in price ($15/kW-yr) multiplied by the capacity of the project (300 MW). If there was no difference in the clearing price, then there would be no resource adequacy savings benefit. One way to think about this benefit is that, without the line, higher-cost capacity in Long Island would have been procured, rather than relying on the lower-cost capacity from ISO-NE.

xix For example, a resource adequacy standard might be less than one day of outages in 10 years caused by a lack of generation. Once the target or metric is established, power system planners perform grid simulations of many possible power-plant outages under different system conditions to ensure the system can achieve the resource adequacy standard. See *Resource Adequacy Basics*, National Renewable Energy Laboratory (NREL), **https://www2.nrel.gov/research/resource-adequacy**.

xx Based on information from S&P Global Market Intelligence.

Public policy savings

Benefit description

Many states have public policies requiring load-serving entities to procure a certain percentage or amount of a specific technology, typically renewable or clean technology. The cost of procuring renewable energy is heavily influenced by location and is a function of several factors, including land acquisition costs, permitting and siting regulations, quality of wind and irradiation, and resource availability.

Ratepayers accrue public policy savings from transmission by enabling access to high-quality and low-cost energy for a state's statutory requirement or utility goals. These costs are typically reflected in the power purchase agreement signed by utilities or capital investments made by the utility. At a high level, this benefit is reflected in higher-quality and lower-cost wind and solar resources in one location over another location.

High-level calculation

Our analysis calculated this benefit by comparing the levelized cost of energy in dollars per megawatt-hour ($/MWh) between individual wind and solar plants enabled by the transmission line to the average cost of similar resources of the same type across the RTO. Solar and wind plants are considered "enabled" if they are within 15 miles of the line and were operational after the transmission line became energized.[xxi] For each enabled plant, we multiply the annual generation of the plant by the difference in the levelized cost of energy between the plant and the average cost of similar resources across the RTO. This approach is applied in specific cases where transmission projects have demonstrably enabled substantial renewable deployment. We ensure that the capacity of enabled generation does not exceed the capacity of the transmission line.

We calculated this benefit for the four projects that enabled new renewable resources and had public policy goals at the time of energization, regardless of whether those goals have since been discontinued or eliminated.

Example

The Valley to Colorado River project, a 500 kV transmission project in California, enables solar resources to connect to the Los Angeles Basin. We found this line enabled 24 solar plants (within 15 miles of the line) for a total of 3.9 gigawatts (GW). While the typical solar plant built in CAISO in 2017–22 has a levelized cost of energy of $52/MWh, 17 of the solar plants enabled by this line are cheaper. One of them is Blythe Solar II, shown in Exhibit 11, with a capacity of 131 MW and an average output of 323 gigawatt hours (GWh) per year. This is a capacity factor of 28%, which the National Renewable Energy Laboratory categorizes as a Class 3 solar resource and estimates has a levelized cost of energy of $42/MWh. The calculated benefit for this single

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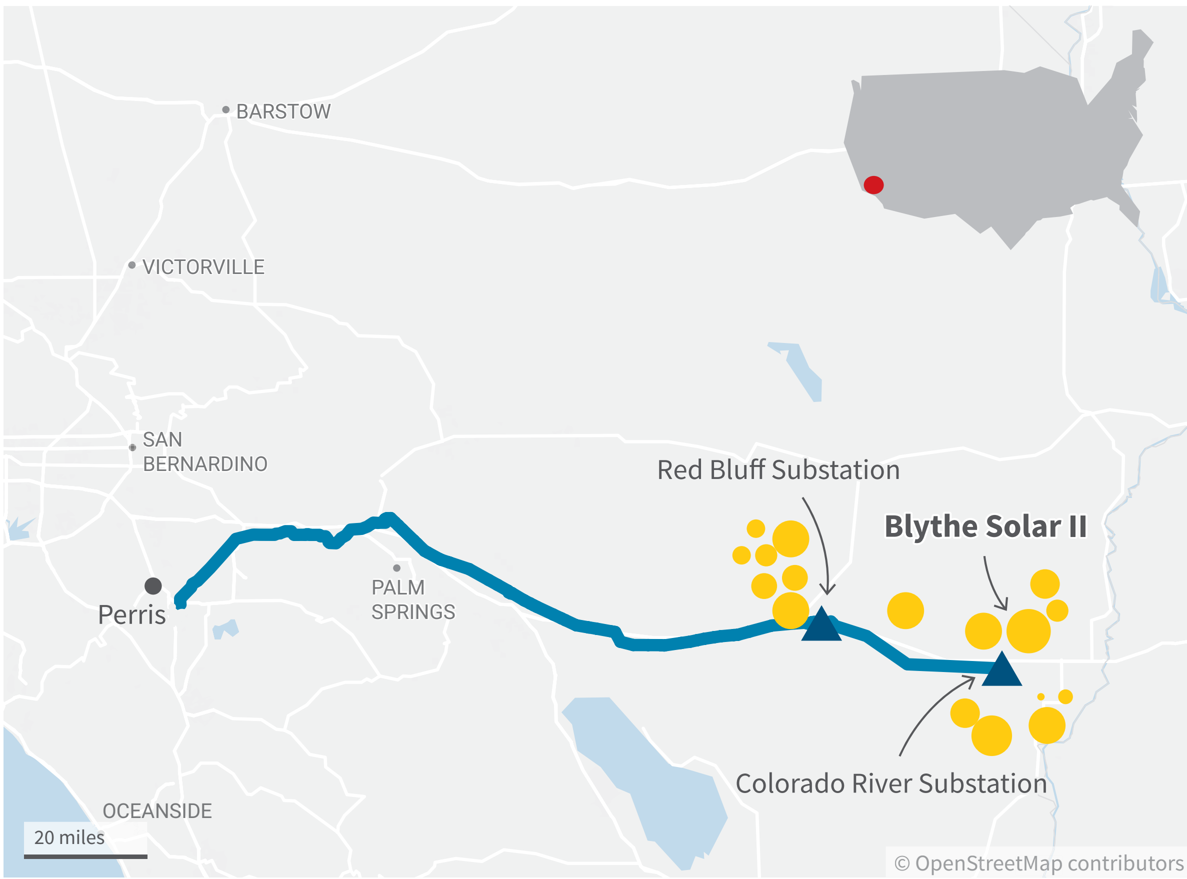
xxi We decided on 15 miles as an estimated range for enabled plants. Our analysis shows that most of these plants are much closer to transmission lines. However, in more rural areas, especially where wind resources are abundant, some plants are closer to 15 miles from the line. These enabled power plants typically connect to the bulk transmission system through short radial transmission lines leading to the point of interconnection (POI), which is typically a large substation. Generation project developers often bear the costs associated with constructing these spur lines and POI investments. For more details, see Will Gorman, Andrew Mills, and Ryan Wiser, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy*, Lawrence Berkeley National Laboratory, October 2019. We also include power plants that were operational within one year of the transmission line being energized.

enabled plant was $3.2 million per year, which is the difference in price ($52 – $42 = $10/MWh) multiplied by the generation of the plant (323 GWh). This methodology was replicated for all 17 enabled plants near the Valley to Colorado River transmission project. One way to understand this benefit is that, without the transmission line, California utilities would have to secure power purchase agreements at a higher cost from other parts of the CAISO system, compared with the lower price achieved with the line in place.

Exhibit 11 Clean energy power plants enabled by transmission drive public policy savings

Valley to Colorado River transmission line enables significant solar generation.



Note: The exact location and size of each individual project is approximate.

RMI Graphic. Source: S&P Global Market Intelligence and RMI analysis

Other project-specific benefits

Benefit description

Ratepayers accrue other project-specific benefits from transmission in a variety of ways. The Brattle Group's report on transmission benefits provides an overview of 8 types of transmission-related benefits (see Exhibit 12).[6] While some are considered in our three core benefits, many are not included, such as reduced transmission line losses that lower overall energy and system capacity needs.[xxii]

Exhibit 12

Transmission investments provide numerous economic benefits to ratepayers

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated
1a-1i. Additional Production Cost Savings	(a) Reduced transmission energy losses, (b) reduced congestion due to transmission outages, (c) mitigation of extreme events and system contingencies, (d) mitigation of weather and load uncertainty, (e) reduced cost due to imperfect foresight of real-time system conditions, (f) reduced cost of cycling power plants, (g) reduced amounts and costs of operating reserves and other ancillary services, (h) mitigation of reliability-must-run conditions, and (i) more realistic representation of system utilization in Day-1 markets
2. Reliability and Resource Adequacy Benefits	(a) Avoided/deferred reliability projects and (b) reduced loss of load probability, or (c) reduced planning reserve margin
3. Generation Capacity Cost Savings	(a) Capacity cost benefits from reduced peak energy losses, (b) deferred generation capacity investments, and (c) access to lower-cost generation resources
4. Market Benefits	(a) Increased competition and (b) increased market liquidity
5. Environmental Benefits	(a) Reduced emissions of air pollutants and (b) improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Development Benefits	(a) Increased employment and economic activity and (b) increased tax revenues
8. Other Benefits	Examples: storm hardening, increased load-serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

RMI Graphic. Source: The Brattle Group

xxii Building additional higher voltage transmission lines lowers line losses by reducing the current on existing lines, which significantly decreases resistive losses. New lines often provide shorter or lower-impedance paths, reducing resistance and enabling optimized power flow, which minimizes overall energy waste.

High-level calculation

On a project-by-project basis, we consider these additional benefits when applicable, typically relying on the transmission developers' original benefits projections. Unlike the three core benefits, these benefits are not validated ex post. Instead, they are taken as reported by the developers because of the challenges of independent verification. Nonetheless, these benefits are significant and provide real value to ratepayers. Among the seven projects, additional project-specific benefits were included in three. Exhibit 13 outlines the type of benefit, its annual value, and the associated transmission project. We describe each benefit in more detail in the case studies in *Appendix A*.

Exhibit 13 Other benefits are analyzed on a project-by-project basis

Transmission Project	Type of Benefit	Annual Benefit
Paddock to Rockdale	Insurance benefit during system failure events	$2M
	Enhanced competitiveness limited market-based pricing	$3M
	Capacity savings from reduced transmission losses	$1M
CapX2020 (Capacity Expansion by 2020)	Energy savings from reduced transmission losses	$11M
	Capacity savings from reduced transmission losses	$14M
Valley to Colorado River	Operational savings	$20M
	Non-CO_2 emissions benefits	$2M
	Reduced transmission losses	$1M

RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources.

In addition, we included nonquantifiable benefits in the discussion of each project in *Appendix A: Project-by-Project Assessment*. Nonquantifiable benefits include nonquantified resiliency benefits, employment and economic development benefits, and qualitative public policy impacts.

Example

As an example of quantified benefits, the developer for the Capacity Expansion by 2020 portfolio identified $14 million per year in capacity savings and $11 million per year in energy savings from reduced transmission losses.[7] These were categorized in the BCA as other project-specific benefits.

As an example of nonquantified benefits, in the Beaver to Oklahoma City project, a pair of 345 kV lines between the Oklahoma Panhandle and Oklahoma City enabled significant economic development and tax revenue. A study on one of the lines highlighted $66 million in direct wage earnings, 1,477 full-time equivalent jobs, and $6.02 million in tax revenue. These are included in the case study description in *Appendix A* but were not included in the BCA.

Calculating transmission costs

Ratepayers pay for new transmission lines through different rate mechanisms, which depend on the transmission ownership structure. This section provides an overview of the financial models we used to calculate transmission costs for each of the three types of ownership structures. The seven lines we evaluated include:

- Five owned by investor-owned utilities;
- One owned by public power utilities; and
- One owned by an independent merchant developer.

The rate mechanisms for all ownership structures distribute the full construction, financing, regulatory, and operational costs over the project's 40-year financial life.[xxiii] For lines that are jointly owned by multiple utilities, the largest share owner is used for the financial model.

Investor-owned and public power utilities

Transmission costs for investor-owned and public power utilities are calculated as the annual revenue requirement to repay the cost of the line over the project's 40-year financial life. Components included in the revenue requirement are listed in Exhibit 14.

Exhibit 14

Investor-owned and public power utilities include distinct components in their revenue requirements

Expense	Investor-owned utility	Public power utility
Fixed operational and maintenance	X	X
Interest	X	X
Depreciation	X	X
Property taxes	X	X
State and federal taxes	X	
Return on equity	X	
Debt coverage		X

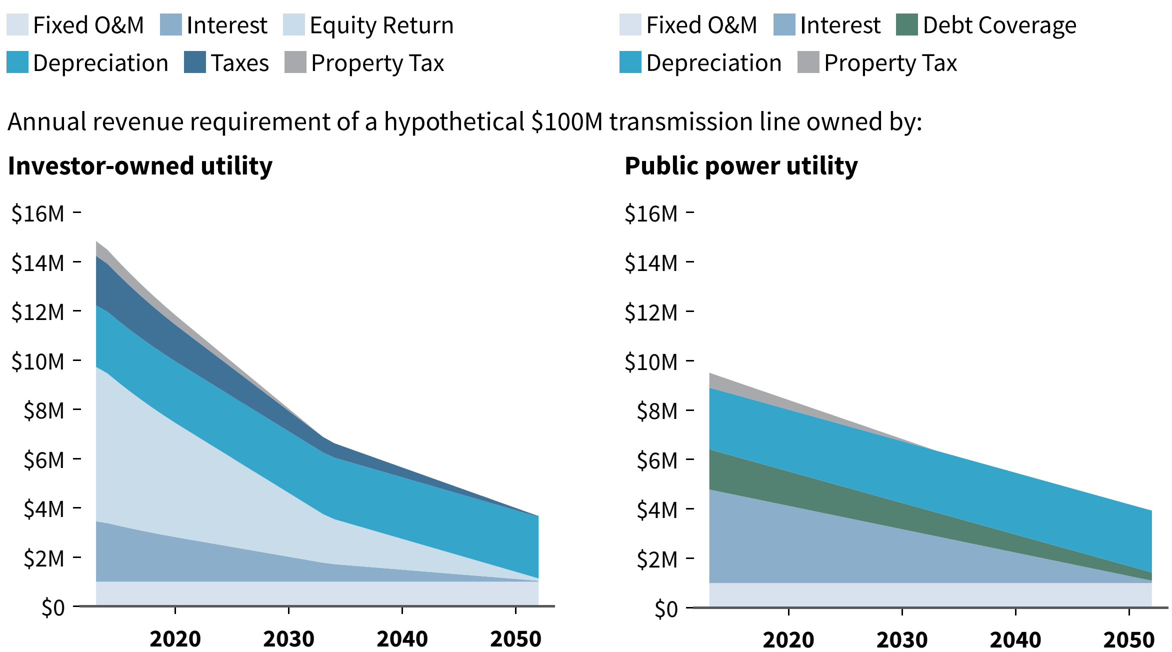
RMI Graphic. Source: RMI analysis

xxiii We used a 40-year financial life for our financial model to be conservative. However, transmission projects can be depreciated over a longer period. For example, some utilities use a 55-year life for transmission lines.

For investor-owned utilities, the inputs used to calculate the revenue-requirement components include total costs, fixed operating costs, debt-to-equity ratio, cost of debt, return on equity, composite tax rate, and state property-tax rate. The primary difference between the ownership structures is that public power utilities do not earn a return on equity but rather have additional coverage of debt service. This enables them to have financial flexibility to pay debt service and other fixed charges in the event of a downturn in revenue or an increase in operating costs.

Exhibit 15 shows the annual revenue requirement for a hypothetical $100 million transmission line owned by an investor-owned utility and a public power utility, respectively.

Exhibit 15 **Investor-owned and public power utilities use distinct financial structures to recover transmission costs**



RMI Graphic. Source: RMI analysis

Independent merchant developers

For independent merchant developers, the total annual revenue requirement is a fixed lease charge for the transmission rights across the line. This is typically paid by one or more utilities that rent the transmission rights. For the merchant transmission project in our study, we sourced the annual charge from utility filings. Independent merchant developers will structure their rate mechanisms differently depending on their lease arrangements and market structures.

More details on the financial models and assumptions can be found in *Appendix C*.

Benefit-cost analysis

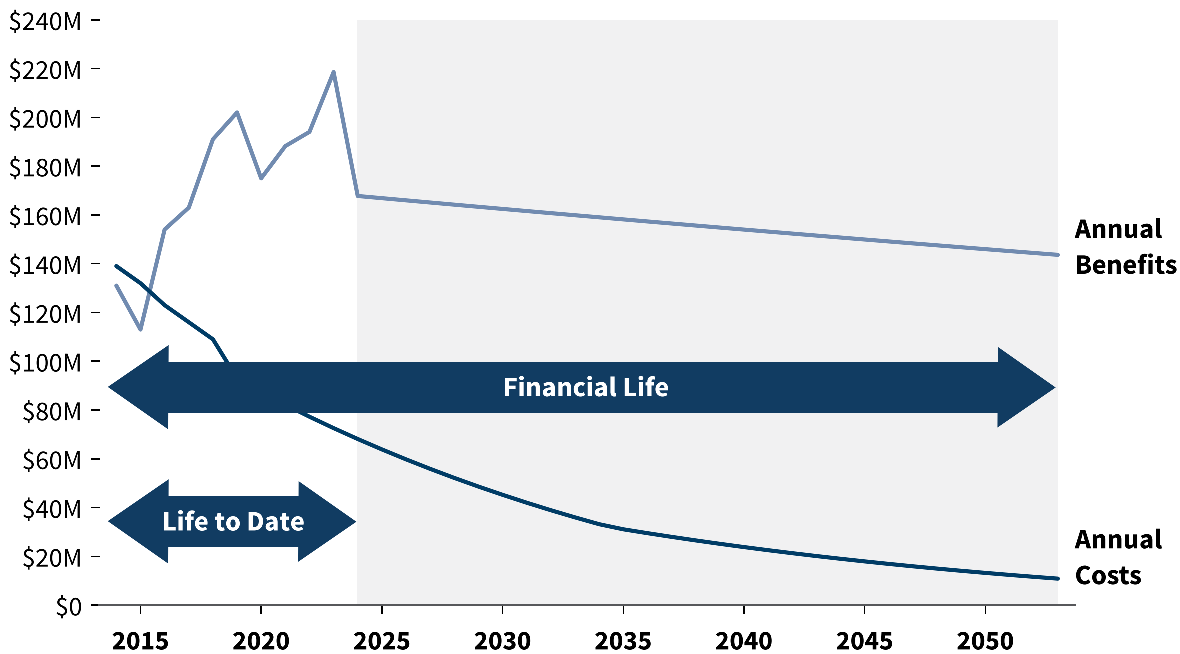
The primary outputs of the analysis are benefit-to-cost ratios calculated for two distinct time frames:

- **Project life to date:** The actual time the line has been in operation to date (January 1 of the year following the in-service year to January 1, 2024)
- **Project financial life:** The 40-year depreciation life of the asset (January 1 of the year following the in-service year to January 1, 40 years later).

Exhibit 16 shows the annual benefits and costs of the studied transmission line in California over its life to date and projected 40-year financial life.

Exhibit 16 Benefits remain stable and up-front capital costs depreciate over the financial life of transmission projects

Net present value benefits and costs of Valley to Colorado River transmission line over its life to date and 40-year financial life



RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources.

A secondary output of the analysis is the payback period for each project. The payback period represents the time required, in years, for the cumulative benefits up to that point to exceed total costs over the project's financial life.

All benefits and costs were converted from nominal to 2024 NPVs to reflect the time value of money.[xxiv] We use a discount rate of 3% to align with MISO's societal discount rate.[8]

The seven lines evaluated were energized between 2003 and 2014 and have been operational for less than 40 years. We therefore forecast benefits and costs for future years. For costs, we calculate the nominal annual revenue requirement for the entire 40-year financial life of the project. For benefits, we only calculate the nominal annual benefits in the years that the project was in service, up to January 1, 2024. For future years, we project the benefits by taking the average of the operational years of service and applying an inflation rate of 2.45%.[xxv] The stream of operational and projected benefits is then converted to a 2024 NPV using a 3% discount rate.

A comprehensive overview of the methodological approach can be found in *Appendix C*.

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xxiv The NPV considers all the costs and benefits of a transmission project and converts those returns into today's dollars. We use NPV because money in the future is less valuable; inflation diminishes its purchasing power, and today's dollars can be invested or used for other purposes.

xxv The inflation rate of 2.45% represents the annual inflation rate in the United States over the past 20 years, based on US Bureau of Labor Statistics data.

Conclusion: Seizing the Benefits of Regional and Interregional Projects

In this report, we examine the costs and benefits of seven operational regional and interregional transmission projects. We compare each project's actual operational benefits during its financial lifetime with the benefits anticipated during the development of the project. We find that all projects delivered a wide range of economic benefits, regardless of the original intent of the project, with benefit-to-cost ratios ranging from 1.1 to 3.9. We find that the benefit-to-cost ratios increase throughout the financial lifetime of the investments, making the case that these projects are long-term investments that only get better over time. Finally, we find that all seven projects outperformed their predicted benefits and are on track to pay for themselves over their financial lifetime.

Our findings suggest that regulators and planners can have confidence in the regional and interregional transmission investments being planned and constructed today. These projects are likely to pay for themselves, potentially multiple times over, underscoring the importance of strong, coordinated, and multi-benefit regional and interregional planning to maximize benefits and reduce costs for families and businesses.

Luckily, planners and regulators have a critical moment to encourage the development of cost-effective regional and interregional projects. Load growth, falling costs for new technology, and new federal regulations are driving renewed interest and need for regional and interregional projects. Specifically, FERC Order No. 1920-A revolutionizes regional planning to ensure benefits are comprehensively evaluated in long-term planning and that transmission is viewed through a multi-value lens that simultaneously considers multiple drivers, such as reliability and economics.

The resources below provide a deeper dive into transmission benefits and the opportunity that FERC Order No. 1920-A opens.

- **The Brattle Group's reports on transmission benefits** and **transmission planning for the 21st century** offer an overview of various transmission-related benefits, ways to incorporate these benefits into the planning process, and past examples of how benefits have been integrated into planning efforts.[9]

- **RMI's fact sheet on Order No. 1920-A** provides an overview of the order, implications of the order, and a summary of the seven benefits that will need to be quantified in regional planning.[10]

- **The Lawerence Berkley National Laboratory's annual report *Empirical Estimates of Transmission Value Using Locational Marginal Prices*** uses a technique like our congestion relief savings methodology and finds significant value in regional and interregional interconnections across the United States.[11]

- **Grid Strategies' annual report on congestion** finds that congestion relief is responsible for billions in annual costs across the United States.[12]

Furthermore, RMI has an educational mission to increase understanding among regulators and policymakers of cost-effectiveness in transmission planning. To that end, we are available to provide additional briefings on these topics and offer resources to public utility commissions and staff, legislators, transmission planners, and others.

Appendices

Appendix A: Project-by-Project Assessment

Appendix A provides more details about the seven case studies in the report. In this section, we take a deeper look into the regulatory context and benefits of each project, aiming to provide confidence in the analysis and calculated benefits through a detailed project-by-project assessment.

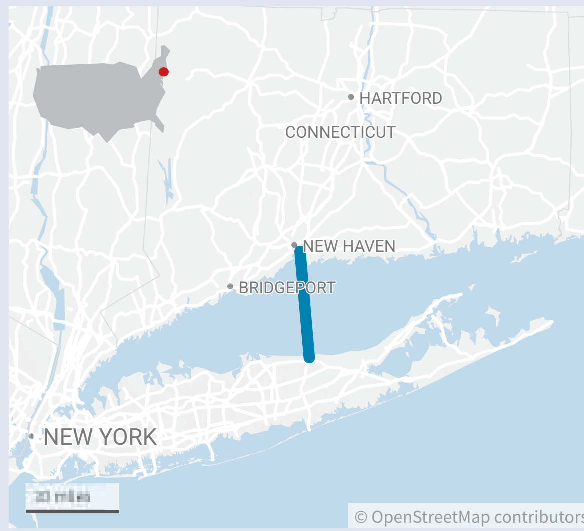
Cross-Sound Cable

Regulatory background

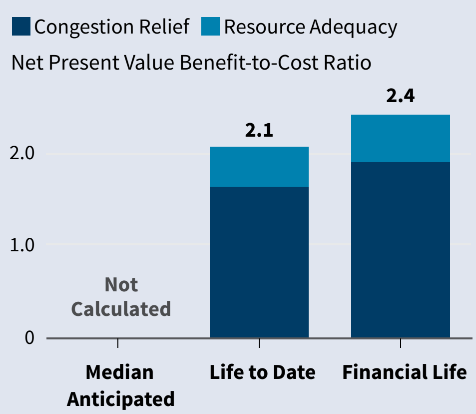
The Cross-Sound Cable project was developed by Cross-Sound Cable Company LLC and was the first merchant transmission project in the United States.[xxvi] The transmission rights were leased to Long Island Power Authority.[13] Designed as a multi-benefit economic project, its primary goals were to alleviate capacity shortfalls in the Long Island zone of NYISO and increase market competition.[14] Despite its economics focus, it did not have a BCA, and benefits were not calculated.

Exhibit A1 Cross-Sound Cable details, map, benefit-to-cost comparison, and benefit-to-cost ratio details

Line Segment	Cross-Sound Cable
Length (miles)	24
Voltage (kV)	150
In-Service Date	2003
Developer	Cross-Sound Company LLC
Originating Point	South Central Connecticut Planning Region, CT
Terminating Point	Suffolk, NY
Anticipated Benefit-to-Cost Ratio	Not Calculated



Benefit-to-Cost Comparison



Benefit-to-Cost Ratio Details

Net Present Value of 40-Year Financial Life

Congestion Relief	$1.133B
Resource Adequacy	$303M
Public Policy	--
Other	--
Total Benefit	$1.436B
Total Cost	$591M
Benefit-to-Cost Ratio	2.4

RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources

xxvi Cross-Sound Cable Company is an independent transmission developer. It is a joint venture of TransÉnergie U.S., United Capital Investments Inc., and TransÉnergie HQ. According to the ABB review, the project was the first merchant transmission project in the United States. See, "Special Report: 60 years of HVDC," ABB, 2014, **https://library.e.abb.com/public/aff841e25d8986b5c1257d380045703f/140818%20ABB%20SR%2060%20years%20of%20 HVDC_72dpi.pdf**.

Designed to deliver bidirectional power between the ISO-NE and NYISO grids, the project aimed to alleviate Long Island's reliance on local, high-cost generation by providing access to competitive energy markets in ISO-NE. The New York Public Service Commission noted that the cable would "reduce the locational capacity requirement" and result in a "measurable improvement in the overall economic efficiency of power markets."[15]

Realized benefits

Since 2010,[xxvii] the Cross-Sound Cable project has generated substantial economic savings for ratepayers, yielding a financial life benefit-to-cost ratio of 2.4 (see Exhibit A1, page 33).

The project's interregional congestion relief analysis, which used an ISO-NE node and a NYISO node, revealed significant congestion relief savings. However, market-seam inefficiency between ISO-NE and NYISO means that trading between the two regions is not as optimal as our analysis suggests. For example, the market monitor found that "the efficiency of real-time trades has been deteriorating, achieving 'optimal' real-time transactions during only 11% of all trading periods in 2022, down from 23% in 2018."[16] These market seam–related trading inefficiencies show a minor limitation in our analysis, which we discuss in *Appendix C*.[xxviii] That said, this is a problem that could be solved by the RTOs implementing intertie optimization across the seam.[xxix]

The resource adequacy savings are driven by the Long Island Power Authority's (LIPA) capacity procurements in ISO-NE. From 2007 to 2021, the power authority had a capacity and power purchase agreement for up to 345 MW of capacity from Jack Cockwell Station, a pumped hydro power plant in Massachusetts.[17] Since then, LIPA has secured capacity through a request for proposals of capacity in the Rest-of-Pool Capacity Zone of the ISO-NE Control Area.[18] This procured capacity is more cost-effective than that available within its own capacity zone (Zone K) of the NYISO control area. In its latest New England procurement, LIPA projected savings of $4.5 million in the 2024–25 delivery period and $5.4 million in the 2025–26 period.[19]

Additional nonquantifiable benefits include the cable's role in stabilizing the grid after the August 2003 Northeast blackout. On August 14, 2003, the cable delivered 100 MW of emergency energy flows from ISO-NE to NYISO, helping restore power as well as provide valuable voltage support and stabilization services for the electric transmission systems in ISO-NE and NYISO.[20]

The cable delivered 100 MW of emergency energy flows from ISO-NE to NYISO "to alleviate the post-blackout disruptions in electric transmission service, as well as provide valuable voltage support and stabilization services for the electric transmission systems in both New England and New York."[21]

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xxvii Data between energization in 2003 and 2010 was not available.

xxviii Market-seam related inefficiencies are most prevalent during real-time trading. Our analysis primarily relies on day-ahead prices, with a weighting of 90% for day-ahead prices and 10% for real-time prices in the congestion relief analysis. This limits the impact of the seam-related inefficiencies.

xxix The Brattle Group and Willkie Farr & Gallagher LLP identify market seam–related trading inefficiencies as a problem and propose using intertie optimization as a solution. See Johannes P. Pfeifenberger et al., *The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission*, October 2023.

Case Study 2 TrAIL

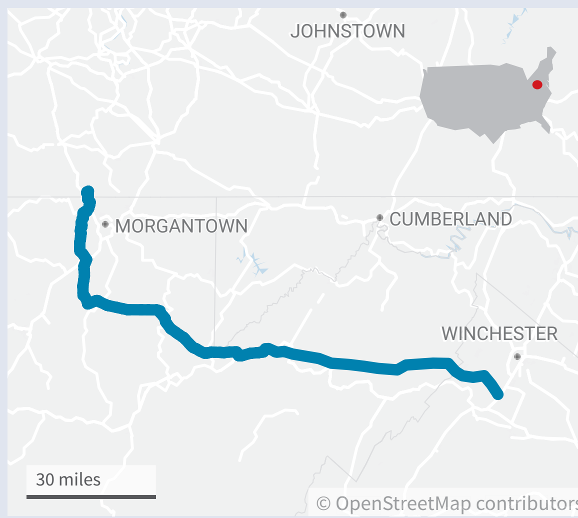
Regulatory background

The Trans-Allegheny Interstate Line (TrAIL), developed by the Trans-Allegheny Interstate Project Company (TrAILCo), an affiliate of Allegheny Power, was proposed to address critical reliability concerns within PJM's system. A BCA was not conducted because the project aimed to resolve reliability violations rather than economic considerations.

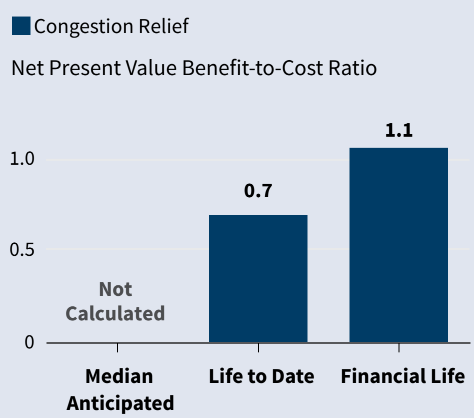
The project targeted two overloads and two voltage collapse issues identified by PJM and Allegheny Power, as detailed in TrAIL's Certificate of Public Convenience and Necessity application and the West Virginia Public Service Commission's final order.[22] The project also facilitated the necessary rebuild of the aging

Exhibit A2 TrAIL details, map, benefit-to-cost comparison, and benefit-to-cost ratio details

Line Segment	Trans-Allegheny Interstate Line (TrAIL)
Length (miles)	152
Voltage (kV)	500
In-Service Date	2011
Developer	Trans-Allegheny Interstate Line Company
Originating Point	Greene, PA
Terminating Point	Frederick, VA
Anticipated Benefit-to-Cost Ratio	Not Calculated



Benefit-to-Cost Comparison



Benefit-to-Cost Ratio Details

Net Present Value of 40-Year Financial Life

Congestion Relief	$2.815B
Resource Adequacy	--
Public Policy	--
Other	--
Total Benefit	$2.815B
Total Cost	$2.512B
Benefit-to-Cost Ratio	1.1

RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources

Mount Storm–Doubs 500 kV transmission project, which posed a “significant risk to the reliability of the mid-Atlantic and northern Virginia areas.”[23] Without TrAIL, the prolonged rebuild could have meant that “a five-year outage during non-summer months alone could easily result in well over $1 billion in congestion costs.”[24]

Realized benefits

Since its energization in 2011, the TrAIL project has generated substantial benefits for ratepayers, despite its initial focus on reliability, yielding a financial life benefit-to-cost ratio of 1.1 (see Exhibit A2, page 35).

Although PJM has a capacity market, our analysis did not identify any resource adequacy savings because both nodes were within the same subregional capacity zone (Allegheny Power).[25]

Additional nonquantifiable benefits include those associated with the rebuild of the Mount Storm–Doubs 500 kV project. If not for the TrAIL project, the rebuild could not have been completed without significant reliability risks and high congestion due to the prolonged outage of a critical east-to-west project in PJM.

Without TrAIL, the necessary rebuild of the aging Mount Storm–Doubs 500 kV transmission project would have posed “significant risk to the reliability of the mid-Atlantic and northern Virginia areas” and “a five-year outage during non-summer months alone [that] could easily result in well over $1 billion in congestion costs.”[25]

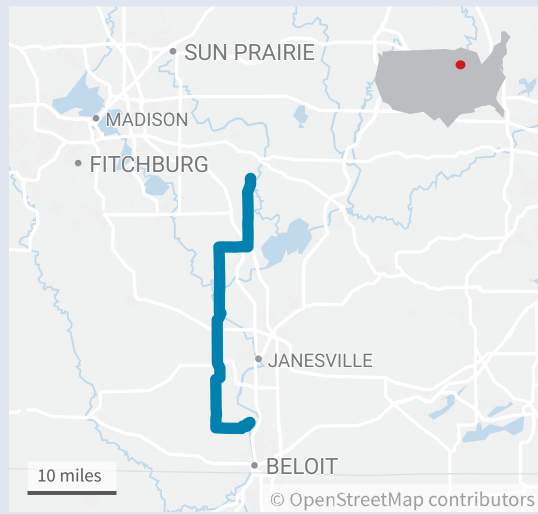
Paddock to Rockdale

Regulatory background

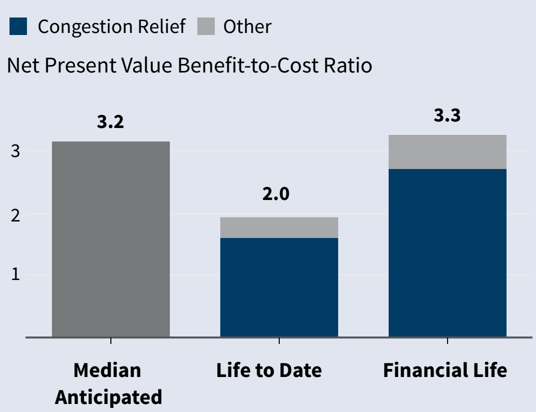
Developed by the American Transmission Company (ATC), the Paddock to Rockdale project was the first transmission project approved by the Wisconsin Public Service Commission for economic rather than reliability purposes.[26] ATC's planning assessment evaluated six benefits across seven plausible futures, identifying it as a multi-benefit economic project with an anticipated benefit-to-cost ratio of 0.5–5.2 and a median anticipated benefit-to-cost ratio of 3.2, based on the project's original plans.[xxx]

Exhibit A3 Paddock to Rockdale details, map, benefit-to-cost comparison, and benefit-to-cost ratio details

Line Segment	Paddock to Rockdale
Length (miles)	35
Voltage (kV)	345
In-Service Date	2010
Developer	American Transmission Company
Originating Point	Rock, WI
Terminating Point	Dane, WI
Anticipated Benefit-to-Cost Ratio	0.5–5.4



Benefit-to-Cost Comparison



Benefit-to-Cost Ratio Details

Net Present Value of 40-Year Financial Life

Congestion Relief	$1.153B
Resource Adequacy	--
Public Policy	--
Other	$229M
Total Benefit	1.374B
Total Cost	$418M
Benefit-to-Cost Ratio	3.3

RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources

xxx The median anticipated benefit-to-cost ratio for the Paddock to Rockdale project was calculated using the results from Table 32 on page 63 of *Planning Analysis of the Paddock–Rockdale Project*, American Transmission Company, April 5, 2007, **https://www.atcllc.com/oasis/Customer_Notices/Filed_CPCN_Economic_Analysis_PR_051607.pdf**.

The Paddock to Rockdale project was designed to increase transfer capability within MISO and between MISO and PJM to alleviate congestion and access lower-cost resources, particularly given significant load growth forecasts. The project plan notes that "as load grows, so too will congestion and the differential in energy prices between ATC and the neighboring hubs (MISO Minnesota, MISO Illinois, and PJM Illinois). Therefore they [ATC customers] support additional import capability (beyond that associated with projects scheduled to be in service by 2010) in order to reduce the financial risks of congestion."[27]

Realized benefits

While load growth did not match ATC's initial expectations,[xxxi] the Paddock to Rockdale project has generated substantial savings for ratepayers and is on track to exceed its anticipated benefits, achieving a financial lifetime benefit-to-cost ratio of 3.3 compared with the anticipated median ratio of 3.2 (see Exhibit A3, page 37).

While the project was developed to increase transfer capacity between MISO and PJM, our analysis uses two internal MISO nodes, reflecting only congestion relief savings within MISO. This approach was chosen for two reasons. First, the expanded transmission capacity between MISO and PJM was a result of multiple transmission investments, not solely the Paddock to Rockdale project. As a result, it is unclear whether the expanded transmission capacity should be solely credited to the project. Second, market-seam inefficiency between MISO and PJM means that trading between the two regions is not as optimal as our congestion relief methodology would suggest. For example, the 2024 *PJM State of the Market* report indicates that power flows in the wrong direction between PJM and MISO approximately 45% of the time.[28] These market seam–related trading inefficiencies are a limitation in our analysis, which we discuss in *Appendix C*. That said, this is a problem that could be solved by the RTOs implementing intertie optimization across the seam.[xxxii] When the congestion relief analysis uses a MISO node and a PJM node, congestion relief savings nearly double, suggesting the true benefits likely fall between these two estimates.[xxxiii]

Our analysis also did not identify resource adequacy savings because both nodes were within the same subregional capacity zone (MISO Zone 2).[29]

Other benefits identified by ATC's economic plan for the project include $2 million annually in insurance benefit during system failure events, $3 million annually from enhanced competitiveness limited market-based pricing, and $1 million annually in capacity savings from reduced transmission losses.[30]

Additional nonquantifiable benefits include enhanced regional resilience to extreme weather and cold snaps, which proved especially valuable during Winter Storm Elliot in 2022. During that event, a single gigawatt of transmission — comparable to the Paddock to Rockdale project — was valued at $26 million between MISO North and PJM ComEd over a four-day period.[31]

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xxxi The initial BCA looked at six scenarios of varying annual load growth between a low-growth scenario of 0.5% and a high-growth scenario of 3.0%. The actual growth in the MISO region between 2010 and 2024 was 1.06% for summer peak load, 0.26% for winter peak load, and 0.88% for total energy load, based on data from S&P Global Market Intelligence.

xxxii The Brattle Group and Willkie Farr & Gallagher LLP identify market seam-related trading inefficiencies as a problem and propose using intertie optimization as a solution. See Johannes P. Pfeifenberger et al., *The Need for Intertie Optimization Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission*, October 2023.

xxxiii A separate congestion relief analysis, based on the same methodology and similar data, was performed to calculate the interregional economic congestion benefits between a MISO node and a PJM node. These numbers are for reference and were not included in the BCA.

Case Study 4

CapX2020 (Capacity Expansion by 2020)

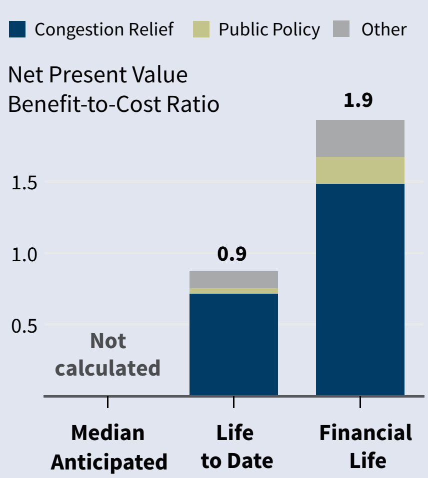
Regulatory background

Capacity Expansion by 2020 (CapX2020) is a joint initiative of 10 transmission-owning utilities in Minnesota and neighboring states to expand transmission to ensure electric reliability and to increase access to renewable energy sources. The portfolio consisted of five 345 kV transmission projects and a single 230 kV project (see associated line segments in Exhibit A4). Because the project was primarily reliability driven, a BCA was not conducted.

Exhibit A4 CapX2020 details, map, benefit-to-cost comparison, and benefit-to-cost ratio details

Line Segment	Bemidji–Grand Rapids	Big Stone South–Brookings	Brookings County–Hampton	Monticello –St. Cloud	Fargo–St. Cloud	Hampton-Rochester–LaCrosse
Length (miles)	70	70	250	28	212	128
Voltage (kV)	230	345	345	345	345	345
In-Service Date	2012	2017	2015	2011	2015	2016
Developer	Multiple Utilities (Minnkota Power Cooperative — Largest Owner)	Multiple Utilities (Northern States Power Company — Largest Owner)	Multiple Utilities (Northern States Power Company — Largest Owner)	Multiple Utilities (Northern States Power Company — Largest Owner)	Multiple Utilities (Northern States Power Company — Largest Owner)	Multiple Utilities (Northern States Power Company — Largest Owner)
Originating Point	Beltrami, MN	Grant, SD	Brookings, SD	Wright, MN	Stearns, MN	Dakota, MN
Terminating Point	Itasca, MN	Brookings, SD	Dakota, MN	Stearns, MN	Cass, ND	La Crosse, WI
Anticipated Benefit-to-Cost Ratio	Not Calculated	Not Calculated	Not Calculated	Not Calculated	Not Calculated	Not Calculated

Benefit-to-Cost Comparison



Benefit-to-Cost Ratio Details

Net Present Value of 40-Year Financial Life

Congestion Relief	$5.060B
Resource Adequacy	--
Public Policy	$637M
Other	$879M
Total Benefit	$6.448B
Total Cost	$3.411B
Benefit-to-Cost Ratio	1.9

RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources

The portfolio was designed to address three key needs across the regional utilities: community service reliability, system-wide growth, and new generation development. The community service reliability need focused on meeting critical service requirements in specific communities while enhancing reliability in others. The system-wide growth need aimed to accommodate an expected demand increase of 4 to 6 GW by 2020. The new generation development need was driven by Minnesota's 2007 legislative initiative mandating 25% of retail energy to come from renewable sources by 2025. The commission agreed with these needs, concluding that the proposed projects "would provide a more reliable electric system both within specifically vulnerable communities and in the region at large and enable more electricity from renewable sources to reach customers."[32]

Realized benefits

Since the projects were energized, the CapX2020 portfolio has generated substantial savings for ratepayers, despite its initial focus on reliability, yielding a financial life benefit-to-cost ratio of 1.9 (see Exhibit A4, page 39).

Although MISO has a capacity market, our analysis did not identify resource adequacy savings for the portfolio because all nodes were within the same subregional capacity zone (Zone 1).[33]

The public policy savings are driven by 1.5 GW of operating wind power in the Brookings, South Dakota, region and 130 MW of operating wind power plants in the Fargo, North Dakota, region. Many of these plants have power purchase agreements that include renewable energy credits with utilities in the region.[xxxiv] The demand for new renewable resources was driven by renewable portfolio standards throughout the region, including Minnesota, North Dakota, Wisconsin, and South Dakota.[xxxv]

Other benefits identified in the application for the certificate of need for the CapX2020 345 kV projects include $13.9 million per year in capacity savings and $10.9 million per year in energy savings from reduced transmission losses.[34]

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xxxiv RMI's research, based on S&P Global Market Intelligence data, found that wind power plants had power purchase contracts with North Central Power, Northwestern Wisconsin Electric, Great Lakes Utilities, Northern States Power Company, and Great River Energy, among others.

xxxv Minnesota has a renewable portfolio standard of 55% by 2035 and requires 100% clean energy by 2040. North Dakota had a renewable portfolio standard of 10% by 2015. Wisconsin had a renewable portfolio standard of 10% by 2015. South Dakota had a renewable portfolio standard of 10% by 2015. See "State Renewable Portfolio Standards and Goals," National Conference of State Legislatures, August 13, 2021, **https://www.ncsl.org/energy/state-renewable-portfolio-standards-and-goals**.

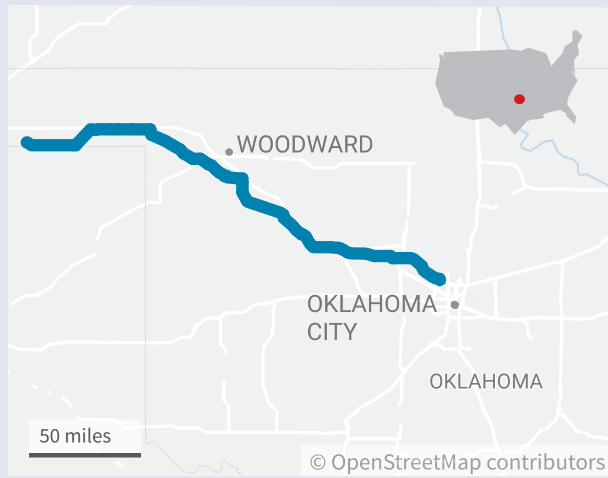
Case Study 5 — Beaver to Oklahoma City

Regulatory background

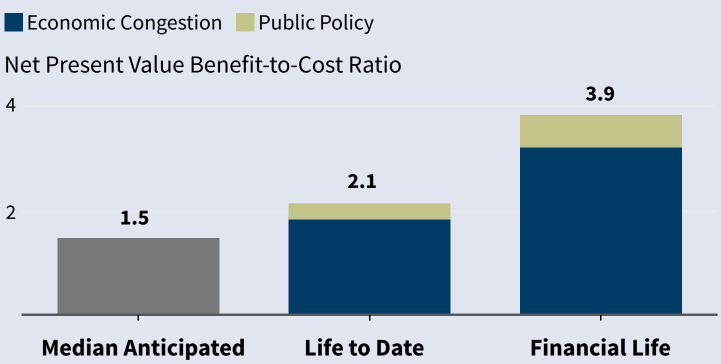
Developed by the Oklahoma Gas and Electric Company, the Windspeed Transmission (Woodward to Oklahoma City) and Beaver–Woodward transmission lines were primarily designed to support Oklahoma's public policy goals. These lines were developed in response to legislative efforts to expand wind power in the state and achieve renewable energy goals (which have since been discontinued).[xxxvi]

Exhibit A5 Beaver to Oklahoma City details, map, benefit-to-cost comparison, and benefit-to-cost ratio details

Line Segment	Windspeed (Woodward to Oklahoma City)	Beaver–Woodward
Length (miles)	121	99
Voltage (kV)	345	345
In-Service Date	2010	2014
Developer	Oklahoma Gas and Electric Co.	Oklahoma Gas and Electric Co.
Originating Point	Oklahoma City, OK	Beaver, OK
Terminating Point	Woodward, OK	Woodward, OK
Anticipated Benefit-to-Cost Ratio	Not Calculated	1.19–1.48



Benefit-to-Cost Comparison



Benefit-to-Cost Ratio Details

Net Present Value of 40-Year Financial Life

Congestion Relief	$4.072B
Resource Adequacy	--
Public Policy	$788M
Other	--
Total Benefit	$4.860B
Total Cost	$1.262B
Benefit-to-Cost Ratio	3.9

RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources

xxxvi In 2007, The Oklahoma legislature created the Oklahoma Electric Power Transmission Task Force and requested a transmission study by the SPP. The study concluded that significant expansions of 345 kV systems from western Oklahoma to regional market areas warranted serious consideration. Subsequently, in May 2010, the Oklahoma legislature enacted the Oklahoma Energy Security Act (H.B. 3028), establishing a renewable energy goal for electric utilities operating in the state. See "Oklahoma Renewable Energy Goal," Database of State Incentives for Renewables & Efficiency, https://programs.dsireusa.org/system/program/detail/4178; and "Direct Testimony of Jesse B . Langston," Case No. PUC 200800148, Oklahoma Gas & Electric Company, May 19, 2008, https://public.occ.ok.gov/WebLink/DocView.aspx?id=7295970&dbid=0&repo=OCC&searchid=54e9ffc4-5ba6-4ab6-be3a-21c96866e582.

The Windspeed Transmission project did not have a BCA. While benefits were not calculated, testimony granting preapproval of the Windspeed Transmission project highlighted that it would "help protect customers from higher than expected fuel prices and risks associated with future environmental mandates" and that its associated "wind generation may provide fuel and environmental benefits to OG&E's customers."[35]

The Beaver–Woodward project was part of SPP's first portfolio of Priority Projects, which underwent an economic impact study. The portfolio was developed to enhance the grid in the following ways: "improve the regional electric grid by reducing congestion on the power projects, better integrating SPP's east and west regions, improving SPP members' ability to deliver power to customers, and facilitating the addition of new renewable and nonrenewable generation to the electric grid."[36] The Priority Projects economic study evaluated two project portfolios across five benefit categories, with the Beaver–Woodward project included in both. Oklahoma Gas and Electric had a benefit-to-cost ratio of 1.19 in Study Group 1 and 1.48 in Study Group 2.[37] Ultimately, Study Group 2 was recommended and approved by SPP.[38]

Realized benefits

Since both projects were energized by 2014, the combined portfolio has generated substantial savings for ratepayers, exceeding anticipated benefit estimates with a financial life benefit-to-cost ratio of 3.9 compared with the anticipated median ratio of 1.5 (see Exhibit A5, page 41).

Although Oklahoma Gas and Electric and SPP have resource adequacy standards, our analysis did not find resource adequacy savings because of the lack of a capacity market and pricing data. Regardless, it is likely that the line provides resource adequacy savings.

The public policy savings are driven by over 2.9 GW of operating wind power plants in the Woodward and Beaver, Oklahoma, regions. Many of these plants have power purchase agreements that include renewable energy credits with Public Service Company of Oklahoma, other utilities, and corporate entities.[xxxvii] At the time, the state had a renewable portfolio standard of 15% by 2015.[39]

Additional nonquantifiable benefits include Oklahoma's emergence as a leader in wind energy and the economic and employment gains from these projects. Both projects were part of a state legislative effort to position Oklahoma as a leader in wind energy.[40] The wind power plants enabled by the projects were some of the first in the state and directly added 2.1 GW of capacity. Today, the state boasts 11.8 GW of installed capacity, ranking second nationally in wind energy.[41] A study on the Beaver–Woodward project highlighted further economic benefits, including $66 million in direct wage earnings, 1,477 full-time equivalent jobs, and $6.02 million in tax revenue.[42]

xxxvii RMI's research, based on S&P Global Market Intelligence data, found that wind power plants had power purchase contracts with Public Service Company of Oklahoma, Western Farmers Electric Cooperative, Google, and Evergy, among others.

Case Study 6

Bakersfield to Kendall

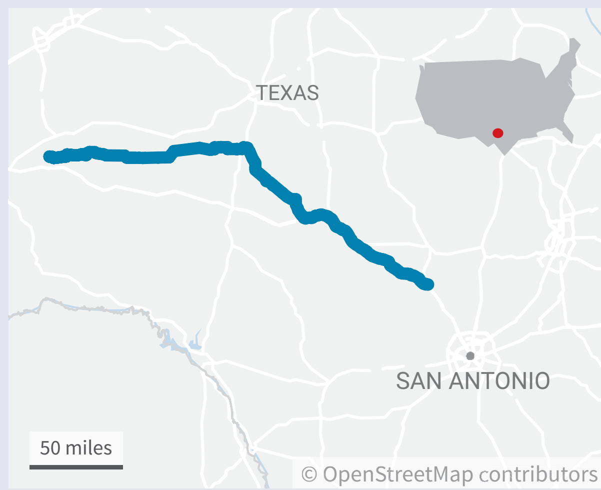
Regulatory background

Big Hill to Kendall and Bakersfield to Big Hill are a pair of transmission lines developed by the Lower Colorado River Authority Transmission Services Corporation and the Southern Texas Electric Company, respectively. Designed to support the state's public policy goals and wind generation expansion, both projects were developed through Texas's Competitive Renewable Energy Zones (CREZ) process. State legislators ordered the Public Utilities Commission of Texas to establish the CREZ process to plan for transmission infrastructure improvements, direct wind power investment to high-potential areas, and support the state's renewable portfolio standards (which have since been discontinued).

The CREZ process did not include a BCA, and benefits were not calculated. Rather, the process focused on developing a plan "that provides transfer capability for the estimated maximum generating capacity per

Exhibit A6 Bakersfield to Kendall details, map, benefit-to-cost comparison, and benefit-to-cost ratio details

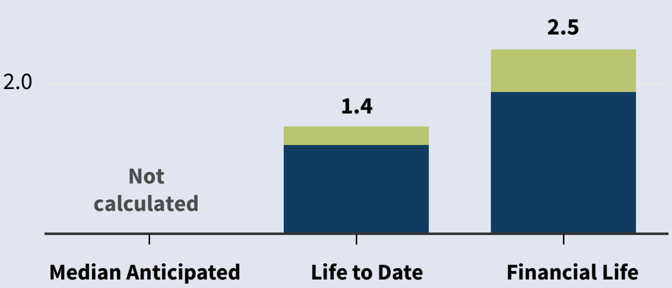
Line Segment	**Big Hill to Kendall**	**Bakersfield to Big Hill**
Length (miles)	139	112
Voltage (kV)	345	345
In-Service Date	2013	2013
Developer	Lower Colorado River Authority Transmission Services Corporation	Southern Texas Electric Company
Originating Point	Schleicher, TX	Pecos, TX
Terminating Point	Kendall, TX	Schleicher, TX
Anticipated Benefit-to-Cost Ratio	Not Calculated	Not Calculated



Benefit-to-Cost Comparison

Congestion Relief   Public Policy

Net Present Value Benefit-to-Cost Ratio



Benefit-to-Cost Ratio Details

Net Present Value of 40-Year Financial Life

Congestion Relief	$1.974B
Resource Adequacy	--
Public Policy	$586M
Other	--
Total Benefit	$2.560B
Total Cost	$1.036B
Benefit-to-Cost Ratio	2.5

RMI Graphic. Source: RMI analysis and multiple data sources; see *Appendix C* for a full list of data sources

CREZ in the most beneficial and cost-effective way to customers."[43] Instead of a benefit-to-cost ratio, the process maximized a wind investment-to-transmission cost ratio.[44]

While benefits were not quantified, the project applications described how the CREZ portfolio was "necessary to deliver to customers the energy generated by renewable resources in the CREZ, in a manner that is most beneficial and cost-effective to the customers."[45] Final project approval emphasized their necessity for achieving Texas's renewable energy goals.[46]

Realized benefits

Since both projects were energized by 2013, the combined portfolio has generated significant economic savings for ratepayers, yielding a financial life benefit-to-cost ratio of 2.5 (see Exhibit A6, page 43).

The public policy savings are driven by over 1.1 GW of operating solar power plants and over 2.0 GW of operating wind power plants in Big Hill and McCamey, Texas. Many of these plants have power purchase agreements that include renewable energy credits with Texas utilities and corporate entities.[xxxviii] At the time, the state had a renewable portfolio standard of 5,880 MW by 2015 and 10,000 MW by 2025.[47]

Additional nonquantifiable benefits include Texas's emergence as a leader in wind energy, the economic and employment gains from these projects, and CREZ being used to connect new loads associated with oil and gas development:

- The transmission project was part of the state legislative effort to position Texas as a leader in wind energy.[48] The wind power plants enabled by the project were some of the first in the state and directly added over 1.9 GW of capacity. While the state no longer has a renewable portfolio standard, the CREZ effort had a profound impact on Texas's role in the wind industry. Today, the state boasts 37.1 GW of installed capacity, ranking first nationally in wind energy.[49]

- A 2018 study found that the economic value of solar and wind energy in Texas led to $210 million in annual property tax revenues to local government, $90.4 million in lease payments to landowners, 33,000 jobs in Texas, $2 billion in annual wages, and between $0.8 and $2.4 billion in the combination of reduced non-CO_2 emissions and avoided water consumption environmental savings.[50]

- An unforeseen outcome of the new lines built via the CREZ process was the ability to connect new loads associated with oil and gas development in Western Texas to the ERCOT system.[51] Between 2010 and 2024, Texas's natural gas production increased by 64% and crude oil production increased by 480%,[52] in part because of the ability to quickly connect new loads to the grid. This outcome underscores transmission as a neutral tool for advancing a variety of policy and economic development objectives.

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xxxviii RMI research, based on S&P Global Market Intelligence data, found that wind power plants had power purchase contracts with CPS Energy; AEP Energy; County of Denton, Texas; Kimberly Clark; Apple; and eBay, among others.

Case Study 7

Valley to Colorado River

Regulatory background

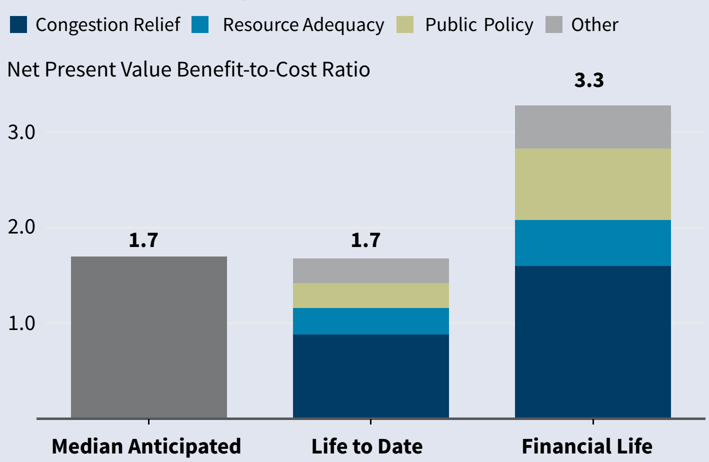
Southern California Edison (SCE) initially proposed this project as an Arizona to California transmission line.[53] The original project was economically driven, with multiple benefits assessed using the CAISO's Transmission Economic Assessment Methodology. This approach identified an anticipated benefit-to-cost ratio of 1.2–3.2 in the project's original plans.[54]

The Arizona portion was canceled in 2007 after the Certificate of Environmental Compatibility was rejected by the Arizona Corporate Commission.[55] In 2009, the California Public Utilities Commission (CPUC)

Exhibit A7 Valley to Colorado River details, map, benefit-to-cost comparison, and benefit-to-cost ratio details

Line Segment	Devers–Valley	Devers–Colorado River
Length (miles)	42	111
Voltage (kV)	500	500
In-Service Date	2013	2013
Developer	Southern California Edison	Southern California Edison
Originating Point	Riverside County, CA	Riverside County, CA
Terminating Point	Riverside County, CA	Riverside County, CA
Anticipated Benefit-to-Cost Ratio	1.2–3.2	1.2–3.2

Benefit-to-Cost Comparison



Benefit-to-Cost Ratio Details

Net Present Value of 40-Year Financial Life

Congestion Relief	$3.124B
Resource Adequacy	$942M
Public Policy	$1.451B
Other	$874M
Total Benefit	$6.391B
Total Cost	$1.950B
Benefit-to-Cost Ratio	3.3

RMI Graphic. Source: RMI analysis and multiple data sources, see *Appendix C* for a full list of data sources.

approved a modified, California-only Valley to Colorado River project, assuming it would still provide operational and reliability benefits.[56]

The Valley to Colorado River project was designed to increase transfer capability between load centers in Southern California and the promising solar potential in the Blythe, California, area. This aimed to allow ratepayers access to competitively priced resources while reducing congestion on existing transmission paths, leading to lower energy prices and congestion charges for Southern California ratepayers. SCE sought to access “potential new renewable and conventional gas-fired generation in the Blythe, California area … to help enable California to meet its renewable energy goals.”[57] Following CPUC’s approval of the transmission project, several large solar projects in the Blythe area, including the Blythe Solar Power Project and Genesis Solar Energy Project, sought interconnection to the grid, requiring an expansion of one of the substations along the line.[58]

Realized benefits

Since energization in 2013, the Valley to Colorado River project has generated substantial savings for ratepayers, exceeding anticipated benefit estimates with a financial life benefit-to-cost ratio of 3.3 compared with the anticipated median ratio of 1.7 (see Exhibit A7, page 45).

The resource adequacy savings are driven by a 525 MW combined cycle natural gas plant and over 2.2 GW of operating battery energy storage plants in the Blythe, California, region. The natural gas plant is contracted to SCE on a resource adequacy and power purchase contract,[59] and the battery energy storage resources are likely similarly contracted to SCE and other utilities in CAISO.[xxxix]

The public policy savings are driven by over 3.9 GW of operating solar power plants in the Blythe, California, region. Many of these plants have power purchase agreements that include renewable energy credits with SCE and other utilities in CAISO.[xl]

Other benefits identified by SCE include operational savings of $20 million per year, non-CO_2 emissions benefits of $2 million per year, and reduced transmission project losses of $1 million per year.[60]

Additional nonquantifiable benefits include enhanced regional resilience to extreme heat and wildfire. During California’s 2018–21 extreme drought and wildfire events, for instance, increased transmission connectivity was critical to keeping the lights on as rising temperatures drove up demand and wildfire activity and smoke caused outages in the state.

xxxix RMI’s research, based on S&P Global Market Intelligence data, found that battery energy storage plants had capacity and power purchase contracts with SCE and Pacific Gas and Electric.

xl RMI’s research, based on S&P Global Market Intelligence data, found that solar power plants had power purchase contracts with SCE and Pacific Gas and Electric.

Appendix B: Overview of Transmission Line Selection

In *Appendix B*, we provide additional details on the selection process. As described in the *Methodology* section, we selected seven projects as examples of large-scale regional and interregional transmission. Exhibit B1 shows an overview of the process. Exhibit B2 shows the number of lines, by region, based on each step of the selection criteria. The line selection process included five steps:

Step 1: Identify projects with sufficient **operational data** to analyze.

- 10 or more years of data — projects built and electrified between 2000 and 2014.
- **Result:** 457 projects.

Step 2: Identify a **geographically diverse** representation of lines.

- Lines that touch the seven RTOs in the United States.
- We did not review lines in non-RTO regions because of a lack of publicly available data.[xli]
- **Result:** 343 projects.

Step 3: Identify potential **interregional projects**.

- Separate out interregional projects.[xlii]
- Lines of any mileage or voltage that enhanced transmission capacity between regional transmission planning entities.
- **Result:** 9 interregional projects and 334 other projects.

Step 4: Identify **long-distance, high-voltage regional** lines.

- Lines over 100 miles and higher than 200 kV to embody typical regionally planned lines.
- High-voltage result: 200 projects greater than 200 kV.
- **Result:** 31 projects greater than 200 kV and longer than 100 miles.

Step 5: Prioritize projects with a **BCA** or **specific development drivers** from the planning and development phase.

- We prioritized projects with a BCA conducted during the development of the project. We found that few projects built during this time frame had BCAs. Only three projects were prioritized.
- We categorized the primary development drivers into reliability, economic, and public policy drivers based on independent research. Each project was assigned a primary driver; however, some projects had multiple drivers. We aimed to choose a wide variety of drivers.
- Certain projects such as CapX2020, Bakersfield to Kendall, and Beaver to Oklahoma City were grouped as a portfolio of lines to best represent the intentions of the planners and developers. For example, Bakersfield to Kendall was developed to bring new generation resources from Western Texas to San Antonio. Evaluating only the Bakersfield to Big Hill or Big Hill to Kendall portions would not accurately reflect the benefits and rationale for the lines.
- **Result:** the 7 projects analyzed.

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xli The analysis relies on historic data on economic dispatch, capacity procurement, and environmental attribute procurement. In non-RTO regions, we lack this data.

xlii Interregional projects are between two regional transmission planning regions, as opposed to being entirely within a regional planning region.

Exhibit B1

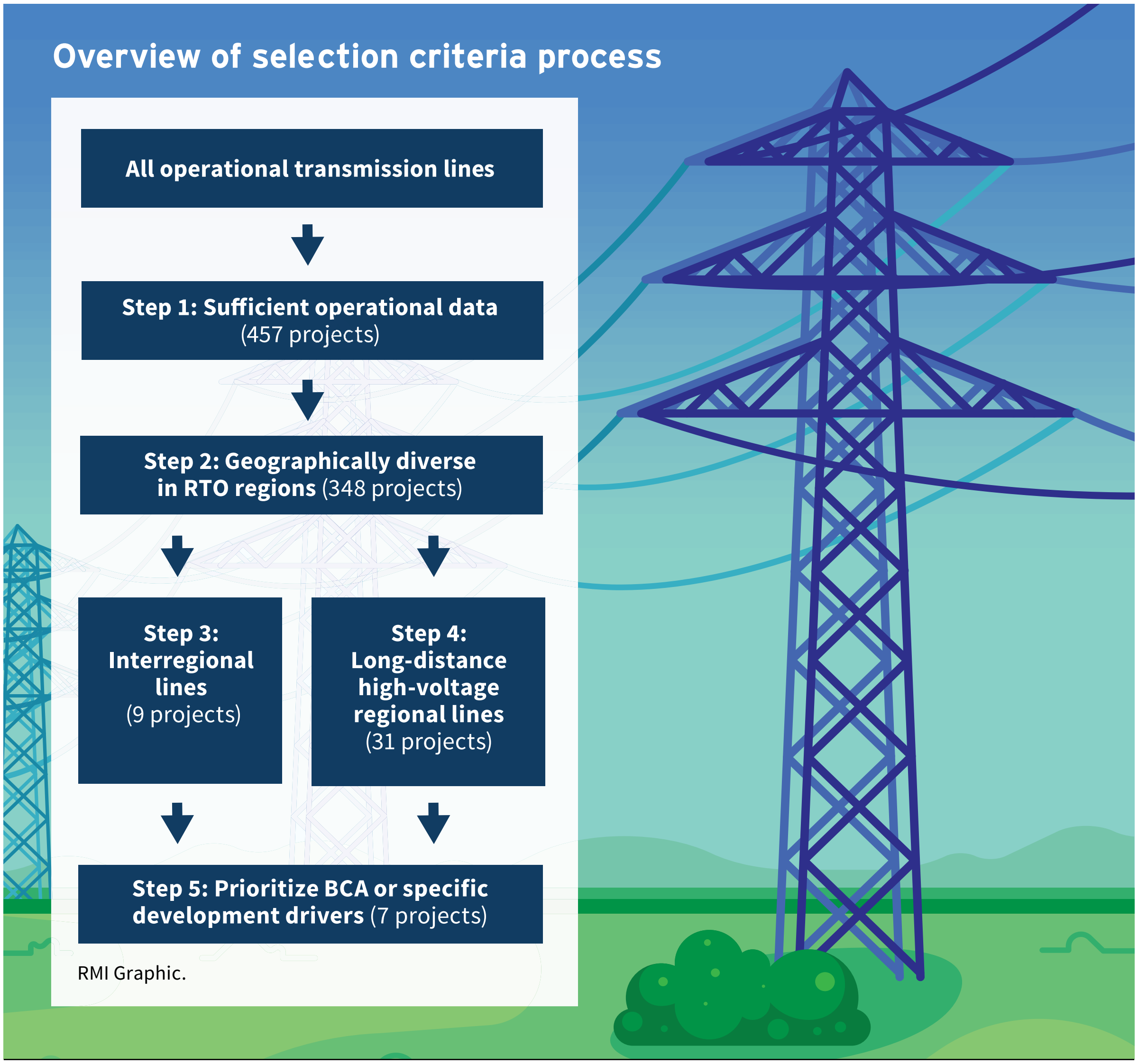

Exhibit B2

Number of lines by region based on different selection criteria in our selection process

	ISONE	NYISO	PJM	MISO North	MISO South	ERCOT	SPP	CAISO
Step 1 & 2: All lines with operational data (2000–2014)	33	10	55	80	18	81	45	26
Step 3: Interregional projects	2	4	3	1	0	0	0	4
Step 4: Regional Projects	31	6	52	79	18	81	45	22
Step 4a: High-Voltage (Over 200kV)	14	1	37	35	14	55	29	15
Step 4b: Long-Distance (Over 100 mi)	0	0	3	6	0	9	9	4

RMI Graphic. Source: RMI analysis and S&P Global Market Intelligence

Appendix C: Overview of Benefit-Cost Analysis

Appendix C provides additional details on the methodologies and inputs of the analyses. This appendix can be found in a separate file at **https://rmi.org/download/43903/?tmstv=1740505531**.

Endnotes

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