Delaying transmission increases costs and reduces benefits for consumers

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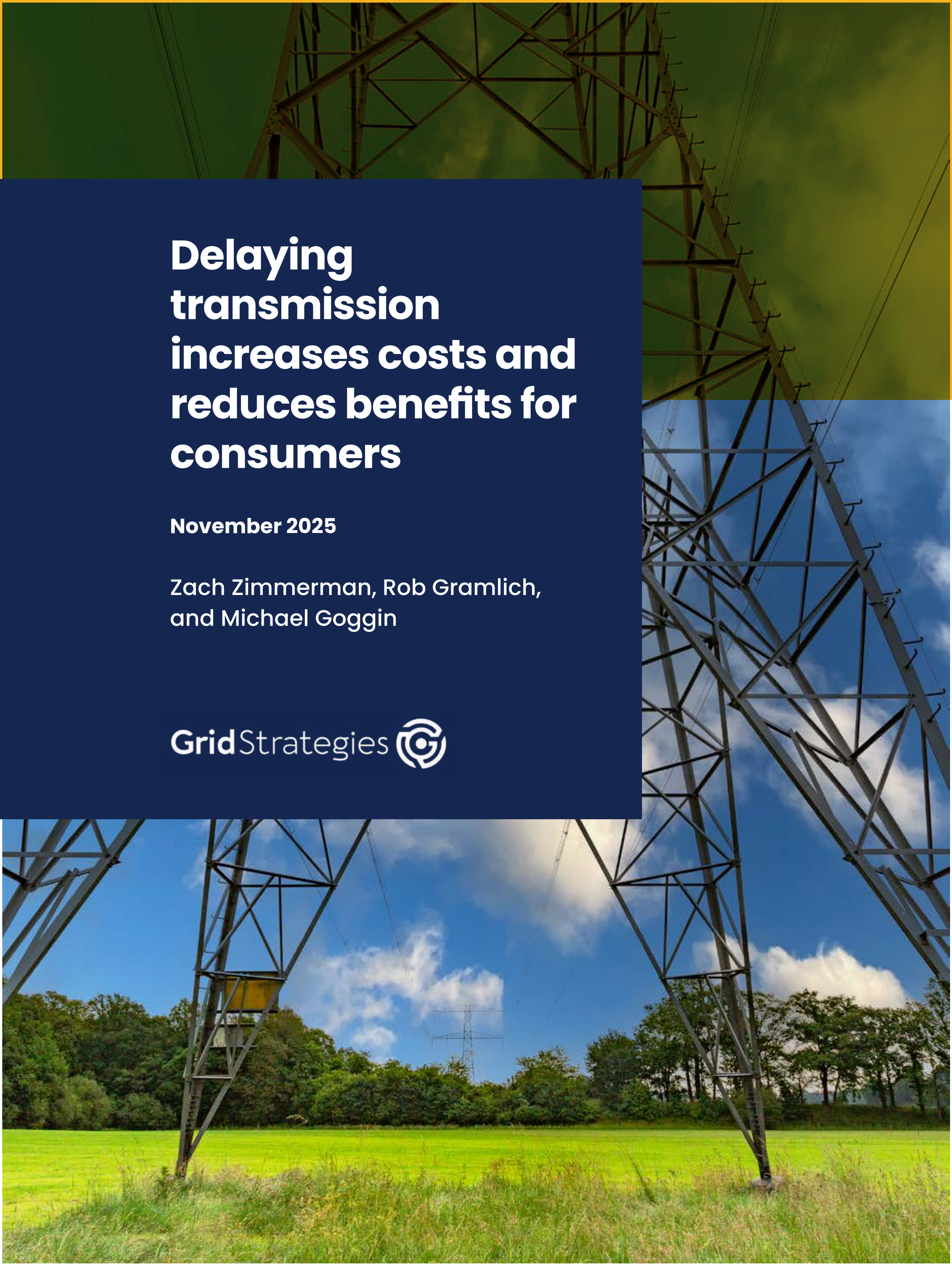
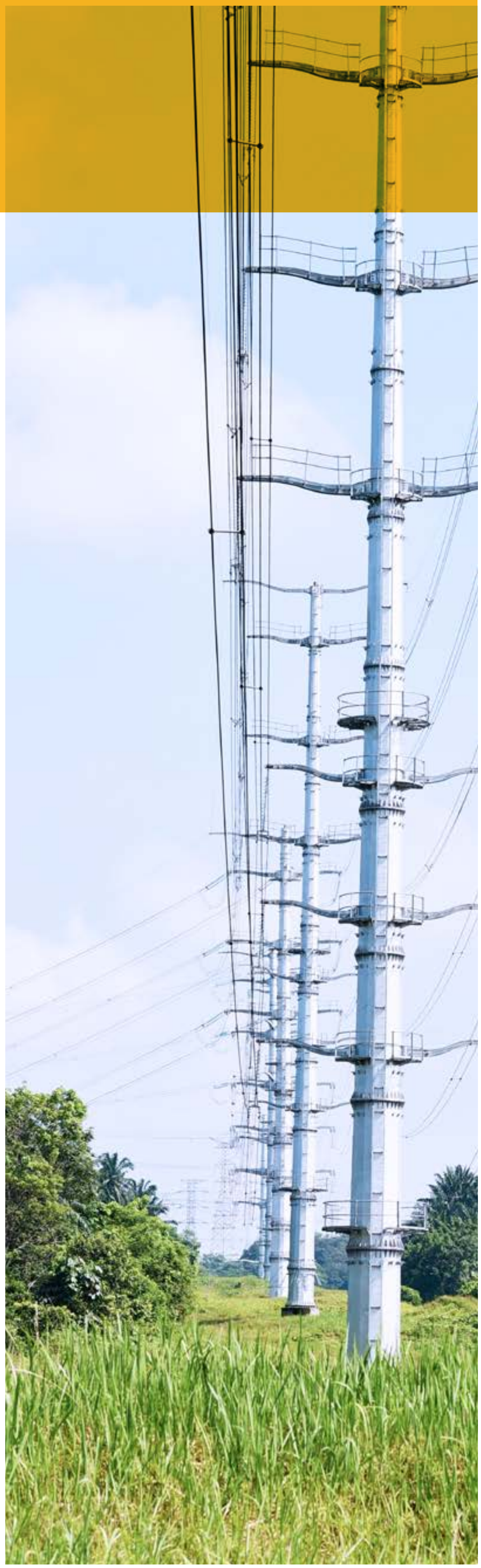
Grid Strategies





EXECUTIVE SUMMARY

The electric grid supports nearly all of our modern economy and day-to-day American life. Insufficient expansion and modernization of the electric grid to meet the growing needs of Americans' homes and businesses, as well as delays in development of new grid capacity, not only holds back economic growth but also costs consumers money.

Many studies have demonstrated the significant societal benefits stemming from development of electric transmission infrastructure, including economic and reliability benefits. By providing access to lower-cost sources of electricity and reducing costly congestion, transmission reduces electricity production costs. This benefit extends to leveraging regional and interregional diversity of supply portfolios and demand patterns. Furthermore, a robust transmission system facilitates reliable and resilient power delivery without costly service interruptions. In turn, a more reliable and resilient power system benefits national economic and technological competitiveness (i.e., dominance in artificial intelligence), economic growth, and job creation.

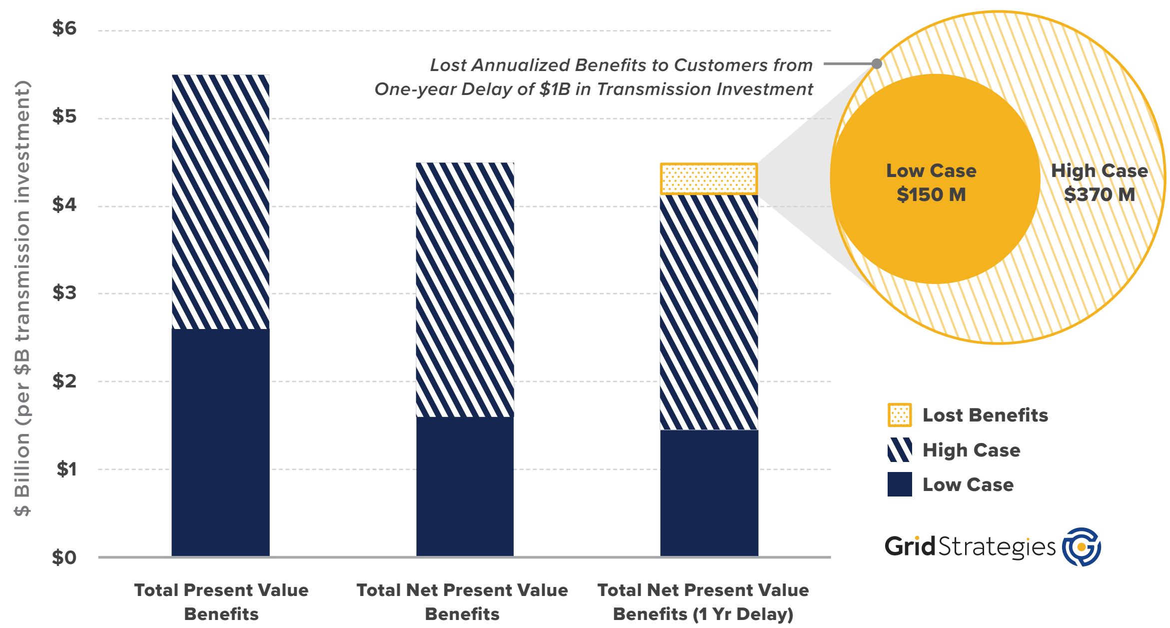
Developing transmission infrastructure entails complexity in the engineering, financing, planning, construction, operations, and cost recovery of transmission—the entire development cycle. Challenges are exacerbated by the number of interested entities, including federal, state, and local authorities with sometimes overlapping jurisdiction and the many other stakeholders that have an interest in the process or outcomes of linear infrastructure development. The result is that there are numerous opportunities for delay.

This report takes one approach to quantify how delays in developing transmission impose costs on consumers by postponing or forfeiting benefits. For the report, we review eight benefit-cost studies for transmission portfolios across the country. Using each study's reported total benefits, we convert those benefits to an annualized value and estimate the cost of a one-year delay in foregone benefits. The report is focused only on the economic and reliability costs of delaying transmission to consumers and is not intended to catalog all causes of delay, assess specific project timelines, or offer policy prescriptions.

We find that for every $1 billion investment in well-planned, large-scale transmission that is delayed, it costs consumers approximately $150 million to $370 million in lost net benefits for each year of delay, while also impeding job creation, slowing economic growth, and impacting national security.

Furthermore, our review of economic impact studies finds that each $1 billion of delayed transmission investment defers an estimated 11,000 to 25,000 direct, indirect, and induced job-years. The additional transmission capacity available as a result of the investment also allows businesses to grow, such as new data centers or new or expanded manufacturing facilities, which provide additional jobs and economic growth.

FIGURE ES-1 | Benefits lost from delaying transmission one year (per $Billion invested)



Consumers benefit most when transmission projects are energized as soon as possible. Our estimates represent real losses in benefits to consumers, including through lower fuel and capacity costs and improved power system reliability—explored further in the first section of this report. Because many of these benefits come from more efficient operation of the system, they are not just pushed into the future but rather are lost forever if the transmission projects are not placed in service as planned. In addition, the time value of money means delays to infrastructure development also forfeit the highest-value near-term savings. In other words, the affordability of electricity supply depends in no small part on timely execution of efficient and cost-effective transmission expansion.

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INTRODUCTION

Transmission capacity of the nation's vast, complex power network needs to expand to meet significant current and forecasted growth in electricity demand. This level of development is necessary to ensure reliability, resilience, facilitate energy trade in advancement of efficiency and affordability of the power system, and, significantly, to support US competitiveness in the information technology and artificial intelligence space by supporting energy-intensive data center expansion.

Over the last 20 years, the power industry has been operating under conditions of limited electricity demand growth, with a transmission grid that required only limited expansion to ensure reliable service to meet that demand. However, utilities across the country are now seeing significant jumps in load forecasts. In a recent Grid Strategies analysis, we concluded that expected load growth has increased fivefold from the 2022 to the 2024 forecast. In 2029, less than 5 years from now, that analysis shows total peak demand growing by 15%.[1]

The sudden shift from flat electricity demand into a mode of rapid growth has led to growing consensus around the need for new large-scale transmission investment. In the Federal Energy Regulatory Commission (FERC)'s 2024 State of the Market Report, the agency reported that nearly 1,000 miles of new transmission placed into service over the last year was driven by load growth, making it the second-largest driver of new transmission projects after reliability needs.[2] This is an increase in the miles of load-growth-driven transmission that came online in 2023 and

1 J. Wilson, *et al.*, Grid Strategies LLC, *Strategic Industries Surging – Driving US Power Demand*, at 3 (Dec. 2024), https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf.

2 Federal Energy Regulatory Commission (FERC), *2024 State of the Markets,* at 32-34 (Mar. 2025), https://www.ferc.gov/media/state-markets-report-2024.

2022.[3] Some regional grid operators have already noted that their transmission system has or will reach capacity soon due to load growth.[4] This trend is also developing in large customer service areas served by vertically integrated utilities with larger footprints, that in some instances serve greater loads than some regional grid operators.

Recognizing that the existing transmission network is strained under current demand levels and significant expansion is required, national identification of large-scale planned transmission is on the rise. New transmission projects tied to rising electricity demand, along with North American Electric Reliability Corporation (NERC)'s 2024 Long-Term Reliability Assessment (LTRA), show a significant increase in planned transmission miles over the past year, both for regional grid operators and for large integrated utility footprints witnessing similar load growth. The 2024 LRTA reports there are 28,275 miles of transmission (>100 kV) planned or under construction through 2034. This estimate is almost 10,000 miles higher than the 2023 LTRA 10-year projections and is well above the average of 18,900 miles over the past five years of NERC's LTRA reporting.[5]

Given the clear need for large-scale transmission expansion, it is critical to understand the impacts if infrastructure expansion is not achieved on a timely basis. This report covers key economic and reliability benefits of transmission. The report then draws on eight separate benefit-cost analyses from around the country to estimate the costs of these delays to consumers.

3 FERC, *2023 State of the Markets,* at 42-44 (Mar. 2024), https://www.ferc.gov/media/2023-state-markets-report; FERC, *2022 State of the Markets,* at 27-29 (Mar. 2023), https://www.ferc.gov/media/report-2022-state-market.

4 J. Wilson & Z. Zimmerman, Grid Strategies LLC, *The Era of Flat Power Demand is Over*, at 20, (Dec. 2023), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

5 North American Electric Reliability Corporation (NERC), *2024 Long-Term Reliability Assessment,* at 34 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

BENEFITS OF TRANSMISSION TO CONSUMERS AND SOCIETY

Investment in transmission provides numerous direct and indirect benefits to consumers. These benefits include resource adequacy value and economic benefits through the aggregation of diverse sources of load as well as generation while also increasing the reliability and resilience of the overall transmission system, especially during times of extreme weather and system stress. Regional transmission organizations and independent system operators (RTOs/ISOs), which coordinate organized wholesale markets and plan the bulk power system consistently account for reliability benefits from transmission projects but may not always completely account for the economic benefits to consumers. Likewise with utility planners in non-RTO/ISO regions. Investment in transmission also provides broader benefits, such as new jobs and economic development or support for the national security of the Unites States, which are not usually quantified. We will take each of these categories of benefits in turn.

AFFORDABILITY AND RELIABILITY BENEFITS OF TRANSMISSION TO CONSUMERS

RTOs/ISOs have produced numerous regionwide studies and reports documenting the direct economic and reliability value transmission investment provides to consumers. The benefits typically quantified for these analyses include lower electricity costs through lower fuel and capacity costs for consumers and improved power system reliability and resilience.

Lower costs for consumers

Across the country, transmission investments have delivered significant and measurable benefits to consumers by allowing access to lower cost generating resources and the associated reduction in production and congestion costs. For example, in the early 2000s, ISO-New England (ISO-NE) invested nearly $4 billion to expand its transmission system. As a result, congestion costs and reliability "uplift" payments dropped from around $700 million annually in 2005 and 2006 to under $100 million annually over the past decade. These costs now make up less than 2 percent of wholesale energy costs in the region.[6] Similarly, a 2019 PJM Interconnection (PJM) report found that coordinated transmission planning and operations provided $4 billion in expected annual benefits, including a $3.78 billion reduction in capacity costs and nearly $300 million in annual congestion cost savings.[7]

Other regions have seen similar returns. After reevaluating lines initially planned in 2012 and 2014, Southwest Power Pool (SPP) found that the expected benefits of these transmission

6 ISO-NE, *On the Horizon: 2022 Regional Electricity Outlook,* at 28 (June 2022), https://www.iso-ne.com/static-assets/documents/2022/06/2022_reo.pdf; *See also* ISO-NE, "Transmission," accessed July 3, 2025, https://www.iso-ne.com/about/key-stats/transmission.

7 *See* PJM, "PJM Value Proposition, (2019), https://www.pjm.com/-/media/DotCom/about-pjm/pjm-value-proposition.pdf.

investments rose from an initial estimate of $12 billion to $16.6 billion.[8] In 2017, Midcontinent Independent System Operator (MISO) also evaluated the long-term value of its Multi-Value Projects and projected between $12 billion and $53 billion in net benefits to consumers over 20 to 40 years. Compared to initial estimates from 2011, this represented a roughly 20 percent increase in net benefits, with an updated benefit-to-cost ratio of 2.2 to 3.4 to 1.[9] These results underscore the lasting value to consumers of proactive, long-term transmission planning.

Additionally, due to economies of scale, high-voltage transmission delivers power at the lowest per-unit cost and therefore underpins many of the benefits in this report. On a dollar-per-megawatt-mile basis, which reflects the average cost to develop infrastructure to deliver one megawatt of power one mile, economies of scale are substantial. A 765 kV line costs approximately 75% less than lower-voltage lines (230 kV) on a per-unit of power transfer capability basis. These technical efficiencies of scale make higher-voltage transmission more cost-effective for consumers than lower-voltage projects where multiple needs for transmission may arise.[10]

Improved power system reliability and resilience

FERC and grid operators across the country have repeatedly emphasized that transmission is central to both grid reliability and resilience. In a 2020 report to Congress, FERC highlighted how high-voltage transmission allows utilities to share resources, recover more quickly after disruptions, and support grid stability and ancillary services.[11] Two years earlier, FERC launched a proceeding on bulk power system resilience that required RTOs and ISOs to explain how they assess and address resilience challenges. In their responses, every region underscored the need to prioritize transmission.[12] PJM, MISO, and California ISO (CAISO) all called for resilience to be explicitly incorporated into planning processes, stressing that transmission is not just a reliability tool but a necessary safeguard against a wide range of threats.[13] Beyond planning, operators such as New York ISO (NYISO), ISO-NE, and SPP showed how interregional connections and recent transmission upgrades have improved system performance during periods of stress, enabling greater resource diversity and operational flexibility.[14] Electric Reliability Council of Texas (ERCOT) and the Public Utility Commission of Texas added that transmission must be designed to continue delivering power even after unexpected losses of generation or

8 Sw. Power Pool, Inc. (SPP), *The Value of Transmission,* at 16 (Jan. 2016), https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf.

9 Midcontinent Indep. Sys. Operator (MISO), *MTEP17 MVP Triennial Review*, at 4-5 (Sept. 2017), https://cdn.misoenergy.org/MTEP17 MVP Triennial Review Report117065.pdf ("*MTEP17*").

10 MISO, *Transmission Cost Estimation Guide for MTEP24* (May 2024), https://web.archive.org/web/20240705181508/https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf.

11 FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, June 2020, https://www.congress.gov/116/meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf.

12 *See Grid Resilience in Regional Transmission Organizations and Independent System Operators,* Docket No. AD18-7-000, 162 FERC ¶ 61,012 (2018).

13 *See Comments and Responses of PJM Interconnection, L.L.C.*, FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5192&optimized=false; *See also Responses of the Midcontinent Independent System Operator Inc.*, FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5105; *See also Comments of the California Independent System Operator Corporation in response to the Commission's request for comments about system resiliency and threats to resilience*, FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5193&optimized=false.

14 *See Response of the New York Independent System Operator, Inc.*, FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5183&optimized=false; *See also Response of ISO New England Inc.,* FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5121&optimized=false; *See also Comments of Southwest Power Pool, Inc. on grid resilience issues,* FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5161&optimized=false.

infrastructure.[15] Together, these perspectives reflect broad agreement that transmission is a critical foundation for a grid that can withstand and adapt to disruption.

These reliability and resilience benefits also provide economic savings to ratepayers, as they allow the same level of reliability to be met with less power plant capacity. This drives a significant share of the billions of dollars in regional benefits discussed in the preceding section.

OTHER BENEFITS OF TRANSMISSION

Generally, RTO/ISO benefit-cost analyses for regional transmission portfolios do not evaluate, or evaluate separately, the broader societal benefits transmission investments provide. This section discusses additional benefits transmission investments provide that are not direct economic benefits for ratepayers including national security benefits as well as new jobs and economic development.

Support for the national security of the United States

A robust and well-connected transmission network is essential to national security. The U.S. military relies on the electric grid for communications, intelligence operations, cybersecurity, logistics, and day-to-day readiness. During Winter Storm Uri, 12 of the 15 military installations in Texas experienced power disruptions and greater than 1,000 hours of unplanned outages were reported at Department of Defense installations.[16] A more resilient grid, reinforced by

15 *See Joint comments of the Electric Reliability Council of Texas, Inc. and the Public Utility Commission of Texas*, FERC Docket No. AD18-7-000 (2018), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20180309-5123&optimized=false.

16 Converge Strategies, *Transmission Expansion for National Defense*, at 13 (April 2024), https://convergestrategies.com/wp-content/uploads/2024/05/TransmissionExpansionForNationalDefenseTREND_April2024_CSL_ADC.pdf.

expanded transmission, ensures that military operations remain fully functional, including during emergencies, and that power can be quickly rerouted to critical installations when disruptions occur.

In addition, while backup generation is essential for mission readiness, it cannot replace the reliability of a resilient grid connection. According to NERC data, transmission lines, across voltages, typically achieve about 99.85% availability (with the broader transmission system performing at a considerably higher rate), far exceeding any single generation source.[17] As an example of a close call, during Winter Storm Uri, a U.S. Air Force base in Louisiana switched to backup generators that performed as designed, but the installation struggled to secure enough fuel to keep them running.[18]

New jobs and economic development

Transmission projects are major infrastructure investments that often require hundreds of millions to billions of dollars in capital. Due to their scale, both the construction and ongoing operation of these projects generate a significant number of jobs. In addition, transmission infrastructure facilitates the development and interconnection of new generation resources, which themselves create substantial employment opportunities across similar categories. Furthermore, transmission development helps reduce electricity costs, which can drive broader economic growth by attracting new industries and supporting existing businesses through improved access to affordable and reliable power. A subsequent section reviews economic literature to assess the employment effects from delayed transmission development.

Significant investment in transmission infrastructure generates skilled-labor employment opportunities across construction, operations, and maintenance, while also reinforcing domestic manufacturing and supply chains. Building new transmission lines can stimulate U.S.-based production of essential equipment such as conductor cables, towers, transformers, and circuit breakers. As demand for these components grows, it can lead to expanded domestic manufacturing capacity and additional jobs in areas like engineering, logistics, and project management.[19]

Beyond these direct impacts, expanded transmission capacity is essential to advancing national strategies aimed at revitalizing American manufacturing and securing resilient supply chains. Access to reliable and affordable electricity is a key consideration for businesses, particularly in energy-intensive industries such as manufacturing and data centers. Elevated electricity costs can undermine competitiveness and prompt firms to move operations abroad. By facilitating access to reasonably priced and reliable power, transmission development supports industrial growth and strengthens the long-term economic position of the United States.

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17 NERC Transmission Availability Data System. https://www.nerc.com/pa/RAPA/tads/pages/default.aspx ("*Transmission Expansion for National Defense»*).

18 *Transmission Expansion for National Defense* at 13.

19 *See generally,* J. Pfeifenberger & D. Hou, The Brattle Group & WIRES, *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada* (May 2011), https://www.brattle.com/wp-content/uploads/2017/10/8209_employment_and_economic_benefits_of_transmission_infrastructure_investmt_pfeifenberger_hou_may_2011_wires.pdf ("*Employment and Economic Benefits of Transmission*").

IMPACTS OF DELAYS IN TRANSMISSION PLANNING AND DEVELOPMENT

Transmission is generally a small portion of consumers' bills,[20] but delaying development prevents consumers from reaping the benefits, thereby increasing costs and postponing the realization of broader benefits. When transmission development is postponed, consumers and the country face both direct and indirect costs.

We find the following costs of delays: (1) reduced production cost savings (i.e., the ability to operate the power system more efficiently); (2) delays in connecting lower cost generation; (3) potential increased need for less comprehensive solutions; (4) increased direct costs from other factors such as siting and permitting delays; (5) increased materials-related costs; and (6) indirect societal costs from reduced economic growth, including job creation.

This section discusses the results of the analysis along with the economic and reliability impacts of delay in greater detail and assesses how those costs accumulate beyond foregone benefits.

RESULTS: DELAYING TRANSMISSION PLANNING AND DEVELOPMENT HAS SIGNIFICANT RELIABILITY AND ECONOMIC IMPACTS ON CONSUMERS

For this report's methodology, we evaluated eight benefit-cost analyses for transmission portfolios across the country, including transmission portfolios from NYISO, MISO, SPP, and ERCOT. The analysis was constituted of the following steps to arrive at comparable and generalizable results:

- First, we extracted total reliability and economic benefits identified in each study and converted them to annualized benefits using the study's stated discount rate and analysis period.
- Second, we also calculated annualized costs using the same discount rate and each study's cost assumptions.
- Third, we calculated annual net benefits as annualized benefits minus annualized costs.
- Finally, we estimated the consumer cost of a one-year delay by treating it as one-year of foregone annualized net benefits that accrues when the in-service date of each regional transmission portfolio is delayed one year.

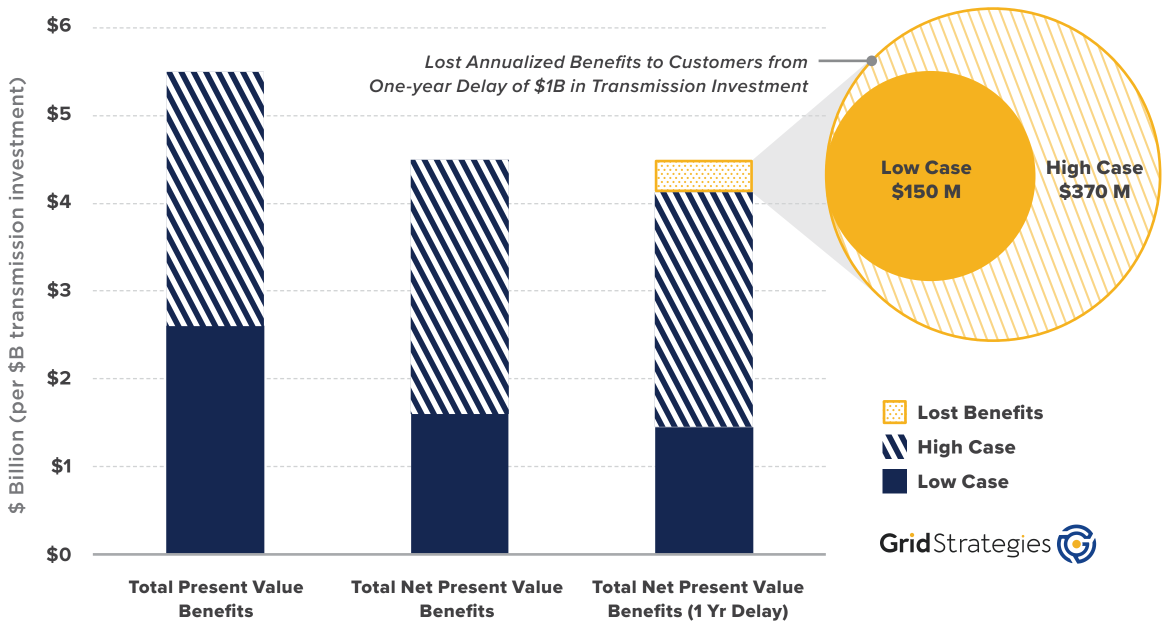
For a more detailed discussion of the methodology and regional portfolios, please see the appendices.

20 EIA, *Annual Energy Outlook 2025: Table 8. Electricity Supply, Disposition, Prices, and Emissions* (Apr. 2025), https://www.eia.gov/outlooks/aeo/tables_ref.php.

Estimated cost of delay to customers per unit of infrastructure investment

Using the methodology described above, we find that for every $1 billion in delayed, proactive, large-scale transmission investments, consumers lose out on benefits of $150-$370 million every year, even after accounting for the cost of transmission.

FIGURE 1 | Benefits lost from delaying transmission one year (per $Billion invested)



Considering the time value of money, the near-term benefits that consumers lose due to delayed large-scale transmission projects are those with the highest value to consumers. The time value of money reflects that consumers could invest money saved on their electric bills today, yielding greater value in future years. Because of this concept, the benefits to consumers from transmission development — and particularly large-scale, coordinated planned transmission — are greater the sooner the projects are actually energized and can begin delivering those benefits to consumers.

Much of the estimated cost in delay for each transmission plan and portfolio stems from forgone production cost savings, which may be especially pronounced in regions with abundant low-cost resources. In particular, MISO, SPP, and ERCOT have some of the lowest generation costs in the country. As a result, the projected production cost savings from transmission expansion in these areas may be higher than in regions with higher generation costs. However, because these regions already have relatively lower generation costs, the incremental benefits of new transmission on generation costs may be less significant than in regions where there are more opportunities for transmission to allow low-cost resources to displace higher-cost energy sources.

As discussed above, our analysis was based on a review of eight different transmission portfolios from across the country. These portfolios represent billions in investments and thousands of miles of large-scale transmission. Climate benefits that were quantified were removed where possible, and we provide detailed discussion of the portfolios, benefit-cost analyses, and consumer costs for each region in Appendix II. The table below provides a summary of each regional transmission portfolio and the associated cost to the region from delaying the energization of the portfolio one year.

TABLE 1 | Summary of regional transmission portfolios evaluated and estimated cost of delay

Region	Portfolio	Total Benefits	Upfront Cost	Benefit-Cost Ratio	Estimated consumer cost from 1-year delay
MISO	MVP	$12 billion	$6.5 billion	1.8	$1.4 billion
MISO	LRTP Tranche 1	$27 billion	$10.3 billion	2.6	$1.8 billion
MISO	LRTP Tranche 2.1	$44 billion	$21.9 billion	1.8	$1.5 billion
ERCOT	CREZ	$84 billion	$6.9 billion	12.2	$6.3 billion
SPP	RCAR III	$42 billion	$7.3 billion	5.76	$2.9 billion
SPP	2023 ITP	$2.6 billion	$1.1 billion	2.29	$0.123 billion
SPP	2024 ITP	$88.7 billion	$7.7 billion	8.23	$7.7 billion
NYISO	AC PPTN	$1.7 billion	$1.1 billion	1.5	$0.132 billion

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Estimated cost of national delay

To further illustrate the national value of transmission beyond the regional portfolios for which benefit analyses were available, we extrapolated the regional portfolio results described above to estimate the national consumer cost of a one-year delay. This hypothetical assumes every region of the country planned a transmission portfolio similar to those studied, and that those portfolios were all similarly timed for development and then delayed by a year. We estimate that delaying by one year such a set of national transmission investments, sized to the average of the regional portfolios we evaluated, would cost Americans between $15 billion and $41 billion. To arrive at this estimate, we annualized each regional portfolio's total net benefits, divided by load to derive dollars per megawatt-hour (MWh), and weighted by portfolio size. This analysis is based on the broader finding that large scale transmission development delays cost consumers an average of $3.89–$9.88 per MWh of electricity consumed in regions where transmission portfolios are planned and may be delayed.

While the national extrapolation described above is an unrealistic scenario, other research using different methods of analysis produces similar results. A report titled *Power Delayed: Economic Effects of Electricity Transmission and Generation Development Delays* released in May 2025 finds that delaying a set of nationwide transmission investments would increase the cost of electricity and natural gas together by $22 billion.[21] While our analysis relies on extrapolation from existing regional benefit-cost analyses, the *Power Delayed* report relies on a top-down modeling approach that uses a power sector model that represents the US and Canadian grids to look at the impact on electricity prices if national transmission capacity expansion is delayed.[22] Despite the differences in methodology, both reports show similar costs to US consumers from delays in transmission development.

Discussion of transmission benefits lost to delays

The portfolios we reviewed show that transmission delivers substantial benefits. A significant portion of the benefits comes from reduced production costs, which include lowering congestion, fuel savings, and reduced variable operating expenses. Benefits also accrue by avoiding or deferring generation investments by enabling regions to share power across geography and time. For both categories of benefits, when transmission is delayed the benefits are not recoverable. Operational savings do not accrue retroactively, and delayed transmission can lock in higher-cost generation to meet reliability and resource adequacy. Delays in transmission development therefore permanently diminish consumer value.

As an example, today, where grid operators are facing significant load growth, delaying transmission may require additional generation development to meet increased demand. This is, in part, due to the timing mismatch between the addition of load, development of generation, and transmission. It may take only one or two years to connect new load to the grid, but analysis from Lawrence Berkeley National Laboratory shows it may take almost 5 years from interconnection request to commercial operation to connect new generation, and new transmission may take even longer (MISO's Tranche's 1 and 2.1 estimated in-service dates are between 6 and 10 years).[23] The time it takes to develop large-scale transmission is one key reason why proactive transmission planning is critical.

RELATED PROJECT COSTS INCREASE WHEN TRANSMISSION IS DELAYED

In addition to reducing benefits for consumers, delays in transmission construction also result in direct increases to project costs. These cost increases can stem not only from increased material or labor expenses, but can also arise from other related factors, such as engineering and procurement costs or legal fees associated with litigation.

Once a transmission project is planned, there are numerous categories of project costs that begin to add up if the project experiences delays. Some of these costs can include legal and public relations fees, administrative and project management overhead, engineering and procurement costs, as well as permitting and regulatory fees (e.g., environmental studies).

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21 D. Shawhan, *et al.*, Resources for the Future, *Power Delayed: Economic Effects of Electricity Transmission and Generation Development Delays*, at v (May 2025), https://media.rff.org/documents/WP_25-14.pdf .

22 *Id.* at 5-10.

23 Rand, Joseph, *et al. Queued Up: 2024 Edition, Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2023*, Lawrence Berkeley National Laboratory at 41 (2024). https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf; MISO, *LRTP Tranche 1 Appendix A*, (2022), https://cdn.misoenergy.org/LRTP%20Tranche%201%20Appendix%20A-4%20Schedule%2026A%20Indicative625788.xlsx; MISO, "LRTP Tranche 2.1 Portfolio Update," at 2 (2024), https://cdn.misoenergy.org/20240924%20LRTP%20Workshop%20Item%2002%20Tranche%202.1%20Final%20Portfolio%20Overview649676.pdf.

Based on estimates from developers, project engineering and procurement costs, excluding the cost of capital, contribute significantly to project cost escalation when there are delays. Interviews with utility and independent transmission developers suggest that each year of delay increases project costs by at least 20%.[24] As an example, it takes an average of 4.5 years for relevant authorities to complete an environmental impact statement (EIS) under the National Environmental Policy Act (NEPA), but it takes longer than six years for roughly one quarter of transmission projects. That 1.5-year delay alone can increase project costs by almost one-third.[25]

Currently, there is a lack of comprehensive data regarding cost escalation for transmission projects that have experienced delays. One example where some data does exist is the New England Clean Energy Connect (NECEC). The NECEC is a 145-mile, 320 kV HVDC transmission line that involves both greenfield transmission development and upgrades to existing transmission lines to move 1,200 MW of power from Canada into New England. The construction of the transmission line was delayed for roughly two years from 2021 to 2023 due to a ballot initiative in Maine and legal challenges. The line is now slated to come online in late 2025 or 2026. The original cost estimate from 2019 was just under $1 billion. The two-year delay in construction led to $521 million in overall project cost increases, an almost 50% escalation, bringing total project costs to just over $1.5 billion.[26]

Taking another example, in the Midwest, the Cardinal-Hickory Creek line has faced similar delays while under construction. Cardinal-Hickory Creek is a 100-mile, 345 kV AC transmission line, planned as part of MISO's 2011 MVPs. The original plan had the transmission line in-service in 2020, with an estimated cost of $798 million. Litigation caused delays, such that the line did not enter into service until the end of 2024.[27] The final project cost, according to MISO, was $1.034 billion. This means that delays added a little over $200 million to the original cost, or roughly a 25% increase. These kinds of cost escalations represent a cost to consumers but are not captured by our analysis in this report.

Delays in transmission development can defer job creation and may result in permanent losses in economic growth

Delaying the development of transmission also has near-term economic impacts in the communities and sectors that rely on electric service. Since the assumption is the lines will eventually get built, the effects of the delay are less permanent, but can have cascading effects for the economic health or growth of a state or region.

In terms of job creation, both alternating and direct current transmission lines yield substantial, though slightly different, employment opportunities. Based on a review of several different

24 J. Connaughton, Wall Street Journal Opinion, "A Simple Way to Cut NEPA's Red Tape," (Dec. 2024), https://www.wsj.com/opinion/a-simple-way-to-cut-nepas-red-tape-environmental-laws-supreme-court-38e7f6fd?st=LoHZG3&reflink=article_copyURL_share; Information in opinion article supplemented in subsequent emails with author.

25 *See* Council on Environmental Quality, "Environmental Impact Statement Timelines (2010-2018)," (Jun. 202), https://ceq.doe.gov/docs/nepa-practice/CEQ_EIS_Timeline_Report_2020-6-12.pdf.

26 *See* J. Knapschaefer, ENREast, "Embattled Maine Power Line Restarts as Cost Balloons to $1.5B," (Aug. 2023), https://www.enr.com/articles/56895-embattled-maine-power-line-restarts-as-cost-balloons-to-15b; *See also* B. Mohl, Commonwealth Beacon, "Mass. ratepayers to pay $521m more for hydroelectricity because of Maine political delays," (Oct. 2024), https://commonwealthbeacon.org/energy/mass-ratepayers-to-pay-521m-more-for-hydro-electricity-because-of-maine-political-delays/#:-:text=Under%20terms%20of%20the%20power,to%20just%20over%20$1.5%20billion.

27 A. Durish Cook, "Conservation Groups File Another Lawsuit to Stop Cardinal-Hickory Creek's Last Mile," RTO Insider, (Mar. 2024), https://www.rtoinsider.com/73353-conservation-groups-lawsuit-stop-cardinal-hickory-creek-last-mile/#:-:text=(See%20Wisconsin%20Tx%20Project%20Clears,the%20route%20through%20the%20refuge.

economic impact studies, investment in direct current transmission projects creates around 4,000 direct job-years for every $1 billion invested, and 7,300 indirect and induced job-years. For alternating current transmission projects, per $1 billion invested, there are around 11,500 new direct job-years and 15,500 indirect and induced job-years. The table below summarizes the results from five different economic input-output models estimating the direct, indirect, and induced job-years created by transmission construction.

TABLE 2 | Summary of studies of job creation from transmission investment

Type of line *(AC or DC)*	**Construction Direct Job-Years** *(per $1 billion invested)*	**Construction Direct, Indirect, and Induced Job-Years** *(per $1 billion invested)*
AC[28]	9,000 to 14,000	19,000 to 35,000
AC + DC[29]	11,720	N/A
AC + DC[30]	4,250	12,500
DC[31]	3,000 to 4,000	N/A
DC[32]	5,050	11,300

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28 *See* MISO, *Economic Impact of MTEP In-Service Projects from 2005-2015*, (Jul. 2015).

29 *See* D. Swenson, *Economic Impact & Job Creation Relative to Large-Scale, High Voltage Transmission Infrastructure*, (Jul. 2018), http://www2.econ.iastate.edu/prosci/swenson/Publications/The%20Interconnection%20Seam%20Study%20Amended%20Title.pdf.

30 See Employment and Economic Benefits of Transmission.

31 *See* J. Duan & J. Frayer, *Estimating Macroeconomic Benefits of Transmission Investment with the REMI PI+ Model* (May 2018), http://www.remi.com/wp-content/uploads/2018/05/WIRES-modeling_0501_final-v3.pdf.

32 *See* E. Lantz & S. Tegen, *Jobs and Economic Development from Net Transmission and Generation in Wyoming* (Mar. 2011), https://www.nrel.gov/docs/fy11osti/50577.pdf.

Looking at $55 billion of planned transmission investments in the MISO and SPP regions that have not yet been constructed, using the estimates in the table above, delaying those projects would defer the development of 638,000 direct job-years and nearly 150,000 indirect and induced job-years. The table below provides a summary of the jobs impacted by delays to the individual transmission portfolios in MISO and SPP.

TABLE 3 | **Direct, indirect, and induced job-years impacted by delaying planned transmission projects (MISO LRTP Tranche 1 & 2.1 and SPP 2023 & 2024 ITP)**

Large-scale Regional Expansions	Total Cost	Direct Jobs-Years	Indirect Jobs-Years
MISO LRTP Tranche 1	$14.1 billion	162,225	218,651
MISO LRTP Tranche 2.1	$28.6 billion	328,900	443,300
SPP 2024 ITP	$11.6 billion	133,538	179,986
SPP 2023 ITP	$1.1 billion	13,110	17,670
Total	$55.4 billion	637,773	859,607

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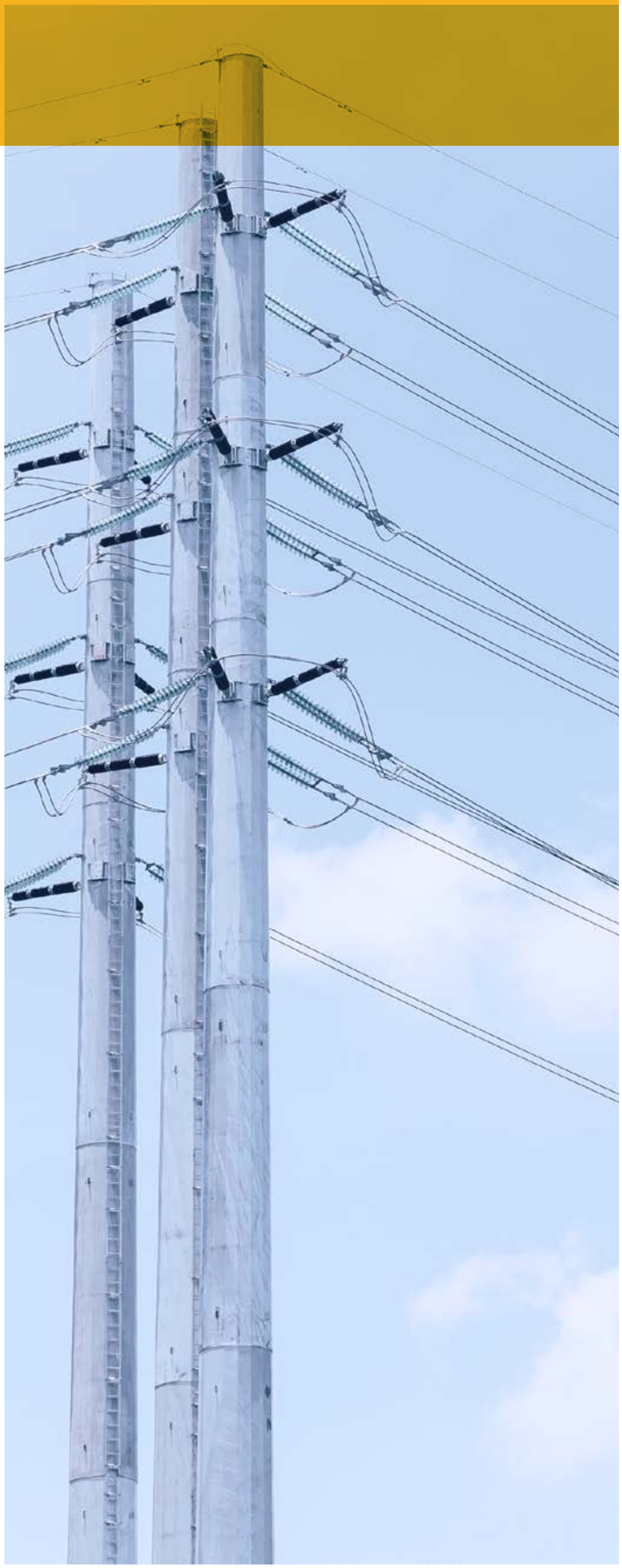
The direct and indirect job-year creation estimates do not account for any of the jobs related to new generation investments that are enabled by new transmission capacity. As an example, as previously discussed, approximately 17 GW of new generation across 160 projects depended on the construction of the Cardinal-Hickory Creek transmission line.[33] Not only did the construction delays prevent new generation from coming online, but based on economic literature, they also impacted an additional 180,000 direct and indirect jobs.[34]

Additionally, the PA Consulting Group found that delaying the CREZ projects for five years would have reduced the total economic output of Texas from 2010-2017 by $8 billion and would have cost Texans, on average, 5,800 new direct, indirect, and induced jobs. Their estimate was from both induced economic output from new jobs and due to retail consumer energy cost savings and increased construction and economic operations activities.[35] These benefits would have been delayed nearly half a decade, or never realized, if the CREZ projects had not been planned and constructed.

33 American Transmission Co, ITC Holdings Corp., Dairyland Power Cooperative, "Cardinal-Hickory Creek Transmission Line Project," accessed July 3, 2025, https://www.cardinal-hickorycreek.com/.

34 Luigi Aldieri, Jonas Grafström, Kristoffer Sundström, and Concetto Paolo Vinci, "Wind Power and Job Creation," Sustainability, (December 18, 2019), at 16, available at: https://www.mdpi.com/2071-1050/12/1/45/pdf, showing 4.03 direct and 10.64 direct and indirect jobs per MW of wind capacity; and The Solar Foundation, National Solar Jobs Census 2018, at 30, available at: https://resources.solarbusinesshub.com/images/ reports/206.pdf, showing 3.3 installation and development jobs/MW for utility-scale solar, rounded up to 4 jobs/MW to account for manufacturing and other supply chain jobs.

35 PA Consulting Group at 24-27.



CONCLUSION

Delays in large-scale regional transmission development impose substantial and lasting economic loss on consumers; while diminishing the economic and reliability benefits that regional transmission projects and portfolios can achieve. Evaluation of benefit-cost analyses from regions across the country, including ISO-NE, NYISO, MISO, SPP, and ERCOT, demonstrate that a single year of delay to planned transmission projects costs consumers delayed net benefits of $150 million to $370 million for every $1 billion in transmission investment. The benefits foregone are particularly valuable in the near term, when timely investment could deliver the greatest savings and economic impact on a real dollar basis for customers. Delays can also increase project costs through increased project expenses while also delaying job creation and slowing economic development by reducing access to reliable, low-cost electricity for new businesses. These costs to consumers highlight the importance of timely development of regional transmission to ensure consumers realize the full scope of benefits associated with large-scale infrastructure expansion.

APPENDIX I
METHODOLOGY

This Appendix describes the methodology that was used to process the results from the various RTO/ISO benefit-cost analyses and how those results were then used to calculate the cost to customers of delays in transmission development.

1. **Collect study results**: We began by collecting studies of the benefits and costs of eight regional transmission portfolios.[36]
    a. Some studies report a low and high range for some transmission benefits. Where available, these were used to develop the low and high cost estimates in our analysis.

2. **Annualize cost and benefit expectations:** Starting from total customer benefits and customer costs from ISO/RTO studies, we annualized benefits and costs using the same discount rates and study periods used in each benefit-cost study.
    a. It is important to note that year-over-year benefit streams and revenue requirements are not the same as the annualized results, but generally they are close and, importantly, making use of annualized results allows us to compare across studies.
    b. This approach was further necessitated by the fact that some regions have detailed year-by-year benefits and revenue requirements across the study period, other benefit-cost analyses evaluated in this report do not include detailed year over year trajectories, so we were not able to report those details or compare on the basis of annual cost and benefit trajectories with a high degree of granularity.

3. **Calculate net benefits:** Once we had annualized benefits and costs, we calculated annual net benefits by taking the difference between the two.

4. **Calculate lost net benefit per unit of investment:** To estimate costs to consumers of lost net benefits resulting from a one-year delay per unit of investment, we summed the annualized net benefits for each portfolio for a single year and divided by the total upfront investment for all of the portfolios.
    a. For our analysis, it was assumed that the foregone annualized net benefits when the in-service date of each regional transmission portfolio is delayed is the equivalent of cost to consumers.

5. **Calculate total load expectations for regions with benefit studies, as well as total nationwide load expectations:** For the national extrapolation, we used total electricity consumption (in MWh) during the study period, either as reported in the benefit-cost

36 The benefit-cost analyses used for the analysis are cited above in the results and discussion section of the report.

analysis or obtained from the region's annual load forecast or FERC Form 714.[37] We then multiplied this total consumption by the lost net benefits per unit for the regions covered in the RTO/ISO benefit studies.

   a. If the load forecast did not cover the full study period, we extrapolated the remaining years using the region's annual growth rate in the load forecast.

6. **Calculate net benefits lost per unit of energy consumed**: Calculate costs to consumers in dollars per MWh by dividing the total net benefits lost by total electricity consumption for the relevant region.

7. **Calculate net benefits lost for hypothetical nationwide case:** To estimate total cost to U.S. consumers, we used the national total annual energy from FERC Form 714 data. We then multiplied the cost to consumers in dollars per MWh (above) by FERC's Form 714 total annual energy.

37 FERC, "Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report," accessed September 2024, https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data.

APPENDIX II
REGIONAL RESULTS

This Appendix provides an in-depth discussion of the eight regional transmission portfolios from MISO, ERCOT, SPP, and NYISO reviewed in this report. The Appendix includes discussion of the portfolio's benefit-cost analyses, identifies the main drivers of benefits, and summarizes the costs to consumers if the portfolios are delayed.

MISO

For MISO, we looked at three major portfolios MISO developed over the last 15 years: the Multi-Value Projects (MVP); the Long Range Transmission Planning (LRTP) Tranche 1; and the LRTP Tranche 2.1. MISO approved the initial MVPs in 2011, which consisted of 11 projects totaling just over $6.5 billion.[38] When MISO reevaluated the initial projects in 2017, MISO found that the benefits had increased from the initial 2011 analysis to provide between $12 and $53 billion of estimated new benefits over the next 20 to 40 years, increasing the benefit-to-cost ratio from the originally estimated 1.8 to 3.0, to the new estimate of 2.2 to 3.4.[39]

For the MVPs, the benefit-cost analysis showed that most of the savings to consumers come from production cost savings, specifically fuel and congestion savings. Over 90% of the savings to consumers from the MVPs—$20.1 billion out of $22.1 billion—are fuel and congestion savings that are achieved through more efficient grid operations. The remaining 10% of benefits come from lower power losses across the system ($234 million), avoided transmission investments ($299 million), and more efficient siting of new generation ($1.3 billion).[40] Based on the 2017 analysis, we find that if construction of the entire portfolio had been delayed one year it would have cost MISO North and Central[41] consumers around $1.4 billion, or $2.84 per MWh in forgone net benefits.

Our findings are similar for MISO's LRTP Tranches 1 and 2.1 portfolios. MISO's LRTP Tranche 1 consists of 18 transmission projects estimated to cost just over $10.3 billion, with benefit-to-cost ratios ranging from 2.6 to 3.8, depending on the scenario.[42] Similar to the MVPs, one of the largest benefits to consumers of the Tranche 1 projects comes from congestion and fuel savings. MISO estimates that the more efficient operation of the grid will provide $13.1 billion in benefits, or 35% of the total benefits to consumers. However, the largest benefit of the LRTP Tranche 1 portfolio is avoiding higher costs from otherwise building less efficient generation. MISO estimates the avoided additional capital investments to be $17.5 billion, or 47% of the total

38 MISO, *Regionally Cost Allocated Project Reporting Analysis: 2011 MVP Portfolio Analysis Report* (Apr. 2025), https://cdn.misoenergy.org/MVP%20Dashboard117055.pdf?v=20240131144844.

39 *MTEP17* at 4-6.

40 MTEP17 at 23.

41 MISO operates the electric transmission system in portions of 15 states in the Midwest and the South, plus the Canadian province of Manitoba. MISO North and Central includes all states not in the MISO South region, which includes parts of Arkansas, Mississippi, Louisiana, Texas. MISO added the South region in 2013 after the approval of the MVP portfolio. FERC, *Participation in Midcontinent Independent System Operator (MISO) Processes* (Apr. 2024), https://www.ferc.gov/participation-midcontinent-independent-system-operator-miso-processes.

42 MISO, *MTEP 2021 Report Addendum: Long Range Transmission Planning Tranche 1* (May 2025), https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf ("MTEP 2021").

consumer benefits. The remaining 18% of benefits came from avoided transmission investments ($1.3 billion), resource adequacy savings ($600 million), avoided power outages ($1.2 billion), and reduced emissions ($3.5 billion), the last of which we did not include in our analysis.[43] We find that delaying the construction of the LRTP Tranche 1 portfolio one year would cost MISO North and Central consumers approximately $1.8 billion per year, or $3.62 per MWh in forgone net benefits. If we include emissions benefits the societal cost to consumers rises to $2.2 billion per year, or $4.26 per MWh in forgone net benefits.

The second phase of MISO's LRTP process led to the approval of a 24-project, $21.8-billion portfolio (i.e., MISO LRTP Tranche 2.1). MISO estimates the lines will be in service between 2032 and 2034 and, once energized, will provide between $1.80 to $3.50 in benefits to MISO consumers for every $1 invested.[44] For the LRTP Tranche 2.1 transmission projects, MISO evaluated additional reliability benefits, resulting in the second largest benefit to consumers, making up 29% of the total, of $14.8 billion in savings from power outage reductions. The single largest benefit MISO estimated was avoided generation investments of $16.3 billion, or 32% of the total consumer benefits. Congestion and fuel savings were the third largest benefit at 16% of the total benefits of $8.1 billion. The remaining benefits represent 22% of the total benefits and include savings from more efficient transmission lines ($3.5 billion), reduced impacts from extreme weather ($400 million), avoided investments in transmission lines ($1.2 billion), and reduced emissions ($7.2 billion), the last of which we did not include in our analysis.[45] We find that delaying the construction of this portfolio by one year would cost MISO North and Central consumers another $1.5 billion, or $2.83 per MWh in forgone net benefits to consumers.[46] If we include emissions benefits the societal cost to consumers rises $2.2 billion, or $4.13 per MWh in forgone net benefits to consumers.

ERCOT

For ERCOT, we review analysis of the Competitive Renewable Energy Zone (CREZ) portfolio, which ERCOT started planning in 2005. The CREZ portfolio includes more than 3,500 miles of 345 kV transmission lines, which enabled the interconnection of 18.5 GW of new generation and cost $6.9 billion.[47] In 2018, the PA Consulting Group estimated that the CREZ projects had already provided almost $6 billion in benefits and would provide an additional $78 billion through 2037.[48] Using the results from this analysis, we find that delaying construction of the CREZ projects for one year would have cost ERCOT consumers around $6.3 billion, or $13.34 per MWh in forgone net benefits to consumers. These costs to consumers come from delaying two benefits: production cost savings from more efficient power grid operation and the addition of lower-cost energy. Production cost savings represent about 44% of the total benefits, or $36.7 billion, while lower energy costs are the remaining 56%, or $47.5 billion.[49]

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43 MTEP 2021 at 3.

44 *Id.*

45 MTEP 2024 at 159-162.

46 MISO, *MTEP 2024 Transmission Portfolio*, at 159-162 (Dec. 2024) https://cdn.misoenergy.org/MTEP24%20Chapter%202%20-%20Regional%20Long%20Range%20Transmission%20Planning658124.pdf ("MTEP 2024").

47 Powering Texas, *Transmission & CREZ Fact Sheet*, https://www.poweruptexas.org/wp-content/uploads/2020/11/Transmission-and-CREZ-Fact-Sheet.pdf (last accessed May 27, 2025).

48 PA Consulting Group, *The Long-Term Impact of Marginal Losses on Texas Electrical Retail Customers,* at 6 (Apr. 2018), https://interchange.puc.texas.gov/Documents/47199_93_977285.PDF ("PA Consulting Group").

49 *Id.*

SPP

For SPP, we looked at three major benefit-cost analyses: Regional Cost Allocation Review (RCAR) III; the 2023 Integrated Transmission Plan (ITP); and the 2024 ITP. In the RCAR III, SPP reviewed all projects under its Highway/Byway Cost Allocation Methodology[50] that were approved for construction after 2010 and placed in service prior to 2020. SPP found these lines to be highly beneficial to SPP consumers, estimating total benefits over 40 years to be around $42 billion with an overall benefit-to-cost ratio of 5.76 to 1.[51] Based on these findings, we estimate that delaying construction of the projects that SPP evaluated in its RCAR III for one year would have cost consumers in SPP around $2.9 billion, or $7.70 per MWh in forgone net benefits. In the RCAR III study, 88% of the benefits come from what SPP calls "Operational Results," which include the benefits from a more efficient grid, such as fuel cost and congestion savings.[52]

For SPP's more recent ITPs, we see similar results. We estimate that delaying construction of SPP's 2023 and 2024 ITP projects for one year would have cost consumers $123 million and $7.7 billion, or $0.28 or $16.37 per MWh in forgone net benefits to consumers, respectively.

The 2023 ITP portfolio was smaller portfolio than in 2024, with only 51 new miles of 345 kV transmission, costing $1.1 billion. Even so, SPP estimates the 2023 ITP projects will still reduce production costs by $2.61 to $2.98 billion over 40 years, resulting in a benefit-to-cost ratio of 2.29-2.61.[53] According to SPP, "[t]he recommended consolidated portfolio is expected to be cost beneficial within the first year of being placed in-service and to pay back the total investment within the first 10 years."[54] These are tangible savings that will lead to increases in residential electric bills if the 2023 ITP portfolio is delayed.

The 2024 ITP is a larger plan that adds nearly 1,500 miles of 345 kV lines and almost 300 miles of 765 kV lines, and costs $7.68 billion. Though higher cost, the plan likewise yields higher benefits. SPP estimates the 2024 ITP projects will lower production costs by $88.7 to $95.7 billion over 40 years, resulting in a benefit-to-cost ratio of 8.23 to 8.88.[55]

As with the RCAR evaluation, the main benefit in SPP's 2023 and 2024 ITPs was production cost savings. In the 2023 and 2024 ITPs, production cost savings accounted for 85% of the total benefits to SPP consumers.[56]

50 SPP has a hybrid cost allocation methodology where it allocates the costs of high-voltage transmission facilities (300 kV+) regionally on a postage-stamp basis. For lower-voltage transmission facilities (100 kV-300kV), 33% of the costs are still allocated regionally on a postage-stamp basis, while 67% of the costs are allocated to the SPP pricing zone in which the facilities are located. Under 100 kV, costs are allocated entirely to the SPP pricing zone in which the facilities are located. *See Sw. Power Pool, Inc.*, 187 FERC ¶ 61,123 (2024), https://spp.org/documents/71722/20240531_order%20-%20byway%20facilities%20allocated%20on%20a%20region-wise%20basis_er24-1583-000.pdf.

51 SPP, *Regional Cost Allocation Review (RCAR III) Final Report*, at 42 (Jan. 2023) https://www.spp.org/documents/71083/rcar%20iii%20report%20final%2020230130.pdf.

52 *Id.*

53 SPP, *2023 Integrated Transmission Planning Assessment Report*, at 1 (Nov. 2023), https://spp.org/documents/70584/2023%20itp%20assessment%20report%20v1.0.pdf ("SPP 2023 ITP").

54 *Id.* at 4.

55 SPP, *2024 Integrated Transmission Planning Assessment Report*, at 1 (Jan. 2025), https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf ("SPP 2024 ITP").

56 SPP 2023 ITP at 160; SPP 2024 ITP at 185.

NYISO

For NYISO, we reviewed the benefit-cost analysis for NYISO's AC Public Policy Transmission Needs Segments A and B, which NYISO approved in 2017. NYISO estimated the two projects would cost New York consumers an estimated $1.1 billion and provide between $1.7 and $2.8 billion in benefits.[57] Based on these findings, we estimate that delaying construction of Segments A and B for one year would have cost consumers in New York around $132 million, or $0.81 per MWh in forgone net benefits to consumers. These costs of delay are smaller than for some of the regional portfolios we reviewed. However, this is not surprising given that the plan includes only two projects (Segments A and B). The benefits to New York consumers are relatively evenly split between production cost savings (45%), avoided generation investments (22%), and avoided transmission investments (33%).[58]

57 NYISO, *AC Transmission Public Policy Transmission Plan*, at 39, 69, 130 (Apr. 2019), https://www.nyiso.com/documents/20142/5990681/AC-Transmission-Public-Policy-Transmission-Plan-2019-04-08.pdf/23cbba74-a65e-66c2-708e-eaa0afc9f789.

58 *Id.* at 39, 69, 130.

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