

Advancing FERC Order No. 1920 Benefit Evaluation Development and Implementation

Practical Lessons Learned from Mock Long-Term Regional
Transmission Planning Projects

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EXECUTIVE SUMMARY

FERC Order No. 1920 represents a landmark advancement in transmission planning by establishing requirements for long-term regional transmission planning and cost allocation. The rule is intended to ensure that transmission providers proactively identify and address future grid needs driven by evolving resource mixes, load growth, technological advancements, and public policy objectives. To achieve this goal, Order No. 1920 requires transmission providers to evaluate transmission solutions at least every 5 years, over a minimum 20-year planning horizon, consider multiple future scenarios, assess the use of Advanced and Alternative Transmission Technologies, and evaluate the multiple value streams that long-term transmission investments can provide.

In the first phase of this work, Grid Strategies and Electric Power Engineers published an assessment of existing regional transmission benefit evaluation methods, proposed approaches, industry best practices, and common challenges associated with quantifying the seven Order No. 1920 benefits. The assessment found that while many regions already evaluate portions of the required benefits, methodologies vary significantly across planning regions, and no existing regional framework fully aligns with all seven benefits identified in Order No. 1920. The review also highlighted a range of methodological, modeling, and implementation challenges that will influence the development of future Order No. 1920 planning processes. Importantly, many of these challenges can be effectively addressed if they are recognized and incorporated early in the development of benefit evaluation methodologies.

Building on the findings from the first phase, this report focuses on advancing the development and practical application of Order No. 1920 benefit evaluation methodologies. Using a series of mock long-term regional transmission planning project examples and detailed benefit calculations conducted on a modified MISO transmission system, the report demonstrates the comprehensive evaluation process using currently available software tools. These practical case studies show how various benefit assessment methodologies can be applied in real-world planning contexts, while also highlighting key methodological tradeoffs, implementation considerations, and lessons learned in quantifying the value of long-term regional transmission investments. Beyond the findings associated with any individual benefit metric, several broader conclusions emerge regarding the implementation of the Order No. 1920 framework as a whole.

First, the seven Order No. 1920 benefits function as an integrated system rather than seven independent analyses. The benefits are interconnected through shared assumptions, common planning models, and explicit carve-outs designed to prevent double counting. The credibility of the framework depends on deriving all benefits from a single, internally consistent modeling foundation. Regions that compute benefits in siloed processes risk double counting some value while stranding others. Total portfolio value must be conserved across the framework, with each benefit representing a distinct component of overall value rather than a separate and unrelated calculation. This study

demonstrates that preventing double counting is not merely a technical adjustment but one of the central requirements for credible benefit-to-cost evaluation.

Second, the quality and magnitude of benefit results are determined as much by planning assumptions and scenario selection as by the underlying transmission investment itself. Because transmission assets operate over multi-decade horizons, benefit estimates are highly sensitive to assumptions regarding load growth, resource development, electrification, public policy, fuel prices, and extreme weather conditions. The study further demonstrates that resilience-related benefits can vary significantly depending on the specific stress events selected for evaluation. Robust assessments therefore require diverse future scenarios and structured, criteria-based approaches for evaluating extreme conditions rather than reliance on a limited set of deterministic cases.

Third, transmission value frequently extends beyond traditional planning boundaries. Several analyses conducted in this study show that a project's impacts may be distributed across neighboring regions or even the broader interconnection. In one example, losses increased modestly within the study footprint while declining significantly across the Eastern Interconnection as a whole. These results suggest that analyses confined to administrative planning boundaries may systematically undervalue projects that reshape power flows, improve interregional resource sharing, or create benefits that accrue outside the sponsoring region.

Fourth, credible benefit evaluation requires capturing the full range of project impacts, including both positive and negative effects. Transmission investments can simultaneously create value in some areas while reducing value in others. The framework demonstrated in this study appropriately records both gains and offsets, producing a more complete and defensible assessment of net portfolio value. This balanced accounting becomes particularly important as benefit results increasingly serve as the basis for cost allocation discussions among states, regulators, and stakeholders.

Fifth, successful implementation of Order No. 1920 will depend as much on model integration, workflow modernization, and analytical capability as on benefit methodology itself. Assessing the full range of benefits requires coordination among capacity expansion models, resource adequacy tools, production cost simulations, and reliability assessments. No single commercial platform currently performs the entire workflow, and some transmission technologies, particularly Advanced and Alternative Transmission Technologies, remain difficult to represent fully within existing planning tools. As a result, future planning effectiveness will increasingly depend on improved platform integration, automation, data governance, and streamlined analytical workflows.

Taken together, these conclusions suggest that the industry's transition under Order No. 1920 is fundamentally a transition from siloed, single-purpose planning toward integrated, multi-value, portfolio-based planning. With compliance proposals under review, interregional implementation efforts advancing, and the first long-term planning cycles commencing amid unprecedented load growth, benefit quantification is rapidly becoming the analytical foundation for transmission

investment and cost allocation decisions. The methodologies demonstrated in this report--including consistent model sets, explicit double-counting controls, transparent sensitivity analyses, and comprehensive benefit accounting--provide a practical foundation for that transition and for the continued evolution of long-term transmission planning practice.

INTRODUCTION

FERC Order No. 1920 represents a landmark advancement in transmission planning by establishing requirements for long-term regional transmission planning (LTRTP) and cost allocation. The rule is designed to ensure that transmission providers proactively identify and address future grid needs driven by objectives such as changing resource mixes, load growth, technology advancement, and public policy. Order No. 1920 requires transmission providers to evaluate and select transmission solutions over a minimum 20-year planning horizon, consider a broad range of future system conditions, evaluate the use of Advanced and Alternative Transmission Technologies (ATTs), and assess the multiple value streams that long-term transmission investments can provide.

A cornerstone of Order No. 1920 is its requirement for scenario-based planning to identify long-term transmission needs under future system uncertainty. Transmission providers must develop at least three distinct long-term scenarios using best-available data and a minimum 20-year planning horizon, with scenarios reassessed at least every five years. To develop these scenarios, transmission providers must consider a broad set of factors that influence future transmission needs. At a minimum, scenarios must reflect applicable federal, state, local, and tribal laws and policies affecting resource mix and demand; decarbonization and electrification initiatives; utility integrated resource plans and load-serving obligations; trends in fuel prices and energy technologies; expected generator retirements; generator interconnection activity; and utility commitments and policy goals affecting resource development and demand growth¹. Collectively, these factors are intended to capture the major drivers of future changes in generation, load, and transmission requirements over the long-term planning horizon.

To balance and optimize both near-term and long-term transmission needs, Order No. 1920 also requires transmission providers to consider ATTs that can enhance the utilization and performance of existing transmission infrastructure. Specifically, transmission providers must consider and evaluate dynamic line ratings (DLR), advanced power flow control devices, advanced conductors, and transmission switching when developing solutions to address identified transmission needs.

ORDER NO. 1920 SEVEN BENEFITS

One of the most significant aspects of Order No. 1920 is its requirement to evaluate the benefits of LTRTP facilities, projects, and portfolios using a multi-value framework. To support this evaluation, Order No. 1920 identifies seven benefits that transmission providers may measure within each long-

¹ Federal Energy Regulatory Commission (FERC), *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920-A, November 21, 2024, available: <https://www.ferc.gov/explainer-transmission-planning-and-cost-allocation-final-rule>

term scenario when assessing potential transmission investments. The following are benefits that must be considered in the benefit-to-cost analysis of long-term transmission planning²:

1. **Avoided or deferred reliability transmission facilities and aging infrastructure replacement:** Calculates the costs that are avoided when proposed new long-term regional transmission facilities address reliability needs and eliminate, or delay, the need to replace existing infrastructure.
2. **Either reduced loss of load probability or reduced planning reserve margin:** Calculates the reduction in frequency of power outages or the reduction in capital costs of generation needed to be built to meet planning reserve margins.
3. **Production cost savings:** Calculates the savings in fuel and other operating costs of generation that are realized when new long-term regional transmission facilities allow for the increased dispatch of lower-cost generators, displacing generation suppliers with higher production costs. This benefit also includes the reduction in market prices as lower-cost generation suppliers increasingly set market-clearing prices.
4. **Reduced transmission energy losses:** Calculates the reduction in total energy necessary to meet demand stemming from reduced energy losses during the movement (i.e., transmission) of power from generation to loads.
5. **Reduced congestion due to transmission outages:** Calculates the reduction in production costs resulting from avoided congestion during transmission outages.
6. **Mitigation of extreme weather events and unexpected system conditions:** Calculates the reduction in production costs during extreme weather events and unexpected system conditions, such as unusual weather conditions, fuel shortages, and generation and transmission outages.
7. **Capacity cost benefits from reduced peak energy losses:** Calculates the benefit of using a transmission facility to reduce the investment in power plants needed to meet peak electric usage, for example, on very hot days. These savings would be passed on to customers through lower generation capacity costs.

HOW EXISTING BENEFIT EVALUATION PRACTICES MUST ADAPT TO ACCOMMODATE ORDER NO. 1920

In the first phase of this work, Grid Strategies and Electric Power Engineers (EPE) published an assessment of existing regional transmission benefit evaluation methods, proposed approaches,

² Id. at 5

industry best practices, and common challenges associated with quantifying the seven Order No. 1920 benefits (referred to throughout this report as the “*Regional Practices* assessment”).³ The objective of the assessment was to support the development of benefit evaluation methodologies by identifying common analytical approaches, key methodological considerations, and opportunities for improvement. The *Regional Practices* assessment provides insights to help regions advance toward long-term, multi-value transmission planning. Five key findings were identified:

Finding 1: The required Order No. 1920 benefits are currently considered by some, but not all, regional planners in their existing near-term transmission evaluation processes. Most regions already consider the benefits associated with increased access to lower-cost generation during typical operating conditions and avoided or deferred local transmission investments when evaluating major transmission projects. However, many of the other benefits identified in Order No. 1920 are either not evaluated consistently or are not explicitly quantified in current regional planning processes.

Finding 2: Even though many regional planners consider multiple metrics in benefits evaluation, they are not all aligned with Order No. 1920. Still, they can be used to determine best practices. No single region's existing benefit evaluation framework fully aligns with all seven benefits identified in Order No. 1920. Nevertheless, the methodologies currently used across regions provide a valuable foundation for developing Order No. 1920-compliant approaches, with existing practices often representing leading examples for specific benefits.

Finding 3: There are many important modeling considerations that must be decided when establishing the full planning process. These choices will impact final benefits evaluation and selection. Key methodological decisions can significantly influence benefit estimates and project selection outcomes. Important considerations include evaluating benefits across multiple future scenarios, selecting appropriate generation and transmission assumptions, conducting portfolio-based rather than project-by-project evaluations, assessing benefits over multiple future years, and applying consistent financial assumptions when monetizing long-term benefits.

Finding 4: A review of best practices leads to the following methods for evaluating the required Order No. 1920 benefits. While no single method is appropriate for every region, these approaches provide a foundation for consistent and transparent benefit quantification.

³ Brooks, A., *Modeling the Order 1920 Benefit Metrics: A Review of Regional Transmission Planning Best Practices*, Grid Strategies and Electric Power Engineers, May 2026, available: <https://gridstrategiesllc.com/wp-content/uploads/O1920-Benefit-Metrics-Report.pdf>

	ORDER No. 1920 BENEFIT	METHOD (DELTA of TWO CASES)	MONETIZATION (NPV)
1	Avoided or deferred reliability transmission facilities and aging infrastructure replacement	Identify planned transmission facilities—as determined by local utilities—that are deferred or avoided from the candidate project AND Difference in future thermal overloads between base and change cases	Transmission capex [\$] of avoided facility additions / upgrades. AND Proxy costs for transmission facilities to overcome thermal overloads
2	Reduced Costs Related to Resource Adequacy	a) Difference in unserved load between base and change cases OR b) Difference in generation capacity needed to meet PRM requirements between base and change cases	a) Avoided unserved load [MWh] x value of lost load [\$/MWh] OR b) Avoided cost of new entry [\$/kW-yr] x generation [MW]
3	Production cost savings	Difference in production costs between base and change cases (ignoring transmission losses) under typical conditions	Avoided production costs [\$]
4	Reduced transmission energy losses	Difference in production costs between base and change cases (for only transmission losses) under typical conditions OR Difference in transmission losses between base and change cases, calculated using known electrical parameters and expected power flow	Avoided production costs [\$] OR Avoided losses [MWh] x shadow node price [\$/MWh]
5	Reduced congestion due to transmission outages	Difference in production costs between base and change cases (including transmission losses) under contingency conditions	Avoided production costs [\$]
6	Mitigation of extreme weather events and unexpected system conditions	Difference in production costs between base and change cases (including transmission losses) under stress conditions AND Difference in unserved load between base and change cases under stress conditions	Avoided production costs [\$] AND Avoided unserved load [MWh] x value of lost load [\$/MWh]
7	Capacity cost benefits from reduced peak energy losses	Difference in generation capacity needed to makeup system transmission losses during peak demand hour between the base and change cases	Avoided cost of new entry [\$/kW-yr] x peak hour losses [MW]

Finding 5: There are many challenges to designing effective benefits evaluations. These challenges can be overcome if considered early when developing benefit evaluation methodologies. Common challenges include the complexity of benefit modeling, avoiding double counting across benefit metrics, maintaining consistency with neighboring regions, monetizing benefits that have not historically been quantified, and overcoming siloed planning processes. Addressing these challenges early in methodology development can improve the accuracy, transparency, and credibility of benefit evaluations.

Since the *Regional Practices* assessment was published, Order No. 1920 implementation has accelerated markedly. FERC's orders on rehearing, Order No. 1920-A and Order No. 1920-B, sustained the core requirements of the rule while substantially expanding the role of Relevant State Entities in shaping long-term regional cost allocation^{4 5}. Through mid-2026, FERC has received dozens of compliance proposals from the Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), and transmission providers in the non-RTO planning regions, with interregional coordination filings due by December 12, 2026⁶. Judicial challenges to the rule have been consolidated before the Fourth Circuit⁷, but regions have proceeded with implementation, and the first long-term regional transmission planning cycles are commencing. The practical consequence is that benefit evaluation methodology is no longer a design-stage question: within the next planning cycle, the numbers these methodologies produce will inform project selection and the allocation of costs among states and customers. The bar for methodological rigor, transparency, and defensibility has risen accordingly.

PURPOSE AND SCOPE OF THIS REPORT

Building on the findings from the *Regional Practices* assessment, this report moves beyond a review of existing practices and focuses on the practical application of Order No. 1920 benefit evaluation methodologies. While the *Regional Practices* assessment identified best practices, methodological options, and implementation challenges across regions, an important next step is understanding how these methodologies perform when applied in a realistic planning and simulation setting. The

⁴ Federal Energy Regulatory Commission (FERC), *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920-A, Docket No. RM21-17-000, November 21, 2024.

⁵ Federal Energy Regulatory Commission (FERC), *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920-B, Docket No. RM21-17-000, April 11, 2025.

⁶ Federal Energy Regulatory Commission (FERC), *Order No. 1920 Compliance Filings Schedule*, Federal Energy Regulatory Commission, available: <https://www.ferc.gov/news-events/news/order-no-1920-compliance-filings-schedule>.

⁷ Judicial Panel on Multidistrict Litigation, *In re Federal Energy Regulatory Commission, Order No. 1920 Litigation*, MCP No. 190, Consolidation Order, August 8, 2024, available: https://www.jpml.uscourts.gov/sites/jpml/files/MCP-190-Consolidation_Order-8-8-2024.pdf.

objective of this report is to bridge the gap between high-level methodological concepts and the detailed calculations, assumptions, and decisions required to implement them in practice.

To accomplish this objective, the report utilizes a series of mock LTRTP portfolio examples to illustrate the process of quantifying Order No. 1920 benefits. The examples demonstrate practical calculation methodologies for the various benefit metrics while also examining the role of ATTs, particularly dynamic line ratings and advanced conductors, within a long-term regional transmission planning framework. Particular attention is also given to benefit metrics where industry practice is still evolving, where multiple methodological approaches may be appropriate, and where existing planning processes provide limited guidance. Rather than prescribing a single "correct" methodology, the report explores alternative approaches, highlights the tradeoffs associated with different assumptions and modeling choices, and provides practical examples that planners can use to inform the ongoing methodology developments.

The report also examines the implementation challenges associated with benefit evaluation. These challenges extend beyond the calculation itself and include scenario development, model construction, data requirements, interactions among planning models, and coordination across planning processes. Through the example studies, the report identifies situations where benefits may be under- or over-evaluated and explores how methodological decisions can influence the assessment of transmission value.

More broadly, this report seeks to provide planners, regulators, and stakeholders with practical insights into the development of Order No. 1920 benefit evaluation frameworks. By working through representative examples, the report generates observations, lessons learned, and discussion points that may help regions refine their methodologies, improve consistency across planning processes, and support more robust long-term, multi-driver, and multi-value transmission planning.

In doing so, this report presents one of the first comprehensive demonstrations of all seven Order No. 1920 benefits evaluated within a single, internally consistent modeling framework using commercially available tools, providing a practical benchmark for future methodological development.

MODIFIED SYSTEM AND MOCK LTRTP PROJECTS

MODIFIED MISO SYSTEM

STUDY SYSTEM FOUNDATION

The starting study system used in this work is based on the MISO footprint. The power flow, capacity expansion, resource adequacy, and production cost models (PCM) developed for the study all originate from a common representation of the existing MISO transmission network. MISO was selected as the study region due to its longstanding leadership in regional transmission planning through the MISO Transmission Expansion Plan (MTEP) process, including its Multi-Value Project (MVP) and Long-Range Transmission Planning (L RTP) initiatives. In addition, MISO's transparent planning processes and extensive public reporting provide a strong foundation for developing realistic study assumptions and evaluating transmission benefits across the full range of Order No. 1920 metrics.

While the study is anchored in a real geographic region and informed by realistic transmission planning assumptions, significant system modifications were intentionally introduced to disconnect the study from both current and expected future MISO system conditions. As such, the analysis is not intended to replicate actual future operating conditions, predict future transmission needs, or infer future MISO expansion decisions.

Rather, the objective is to provide a realistic but not real, and yet controlled planning environment for demonstrating Order No. 1920 benefit evaluation methodologies. Using a familiar-enough system enables readers to better understand the underlying transmission trends, planning drivers, and general characteristics, while the controlled modifications help ensure that all seven Order No. 1920 benefits can be meaningfully illustrated and evaluated within a single study framework.

DESIGNED SYSTEM MODIFICATIONS

A key design feature of the study was the deliberate amplification of an existing north-to-south transfer constraint within the MISO footprint. To amplify this known north-to-south transmission constraint well beyond its existing thermal and transfer limitations, peak load in MISO South was increased by approximately 6,000 MW across the region, and peak load in MISO North and MISO Central was kept the same. The same load assumptions were applied consistently across both the Base and Change Cases, ensuring that observed differences in benefits were attributable to the transmission additions themselves rather than differences in underlying demand assumptions.

While the modifications were designed for analytical control, it is far from hypothetical in character. Concentrated multi-gigawatt load growth – driven by data centers, industrial electrification, and onshoring of manufacturing – arriving faster than transmission can be developed is now the defining planning challenge across nearly every U.S. region, and it has drawn direct regulatory attention,

including FERC's 2026 show-cause proceedings on large-load interconnection⁸. The study system therefore functions as a rehearsal of precisely the planning problem that Order No. 1920's long-term, scenario-based framework was created to address anticipating major demand shifts early enough to plan efficient regional solutions rather than reactive piecemeal upgrades.

This intentional stress on the north-south interface created conditions under which additional transmission capacity would provide a clear and measurable impact. The resulting system served as a useful test bed for evaluating how different methodological choices influence the calculation of the seven Order No. 1920 benefits and for illustrating the multi-faceted value that long-term regional transmission investments can provide.

To further demonstrate the multi-value nature of regional transmission planning, as well as the compounding effects of successive transmission investments over time, the study models were updated to reflect major planned transmission portfolios across the MISO footprint. These included the major 345-kV and 765-kV facilities developed through MISO's 2011 MVP portfolio, along with the more recent LTRTP Tranche 1 and Tranche 2.1 portfolios, representing successive generations of regional transmission investment within the MISO footprint. Incorporating these planned facilities creates a more representative foundation for evaluating future transmission expansions and illustrates how new LTRTP projects build upon prior regional investments to deliver additional reliability, economic, and capacity benefits.

MOCK LTRTP PROJECTS

Based on the modified MISO system, the development of the mock LTRTP projects in this work was guided by the multi-value and multi-driver planning principles of Order No. 1920. However, developing a fully optimized LTRTP portfolio was not the primary objective of this study. Instead, the focus was on creating a limited set of representative mock LTRTP projects capable of demonstrating the calculation of the Order No. 1920 benefits and the associated methodological considerations. As a result, a deliberate tradeoff was made between portfolio comprehensiveness and study practicality. While the resulting projects are designed to produce meaningful benefit outcomes, they should not be viewed as the optimal transmission solutions for the underlying system conditions.

To identify candidate solutions, an initial PCM analysis was performed to understand system congestion patterns and locate potential transmission expansion opportunities between MISO North and MISO South. Particular attention was given to high-voltage nodes associated with persistently

⁸ Federal Energy Regulatory Commission (FERC), *FERC Launches Aggressive Targeted Action to Speed Large Load Integration*, Federal Energy Regulatory Commission, June 18, 2026, available: <https://www.ferc.gov/news-events/news/ferc-launches-aggressive-targeted-action-speed-large-load-integration>.

low locational marginal prices (LMPs) in the north and high LMPs in the south, indicating opportunities for increased power transfers and congestion relief. Based on this assessment, a set of potential 345-kV and 765-kV transmission endpoints was identified. EPE then evaluated various transmission configurations using power flow analysis, with particular emphasis on both N-1 and N-1-1 reliability performance.

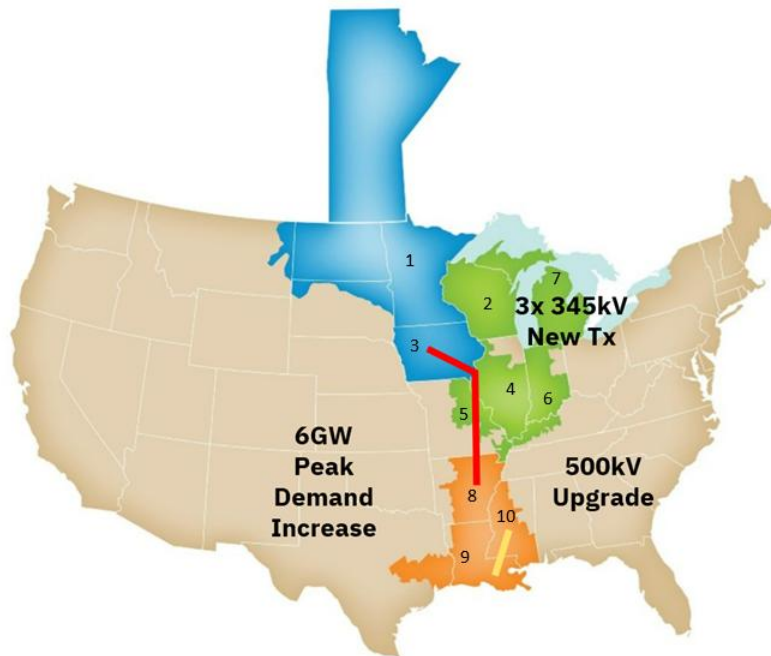
While 765-kV double-circuit configurations demonstrated significant potential for increasing transfer capability and complemented the recently approved LRTP Tranche 2.1 portfolio, the study ultimately selected a 345-kV triple-circuit configuration. Under N-1-1 conditions, where two of the three circuits are out of service, the triple-circuit design exhibited flexibility while avoiding the complete loss of the transmission path. Although a 765-kV solution would likely deliver stronger overall system benefits, the purpose of this effort was to evaluate representative mock project concepts rather than develop an optimized long-term transmission portfolio. The N-1-1 limitations identified for the 765-kV double-circuit configuration could likely be mitigated through alternative 765-kV corridor designs and broader portfolio-level solution development, which were beyond the scope of this study.

In addition, both the PCM and power flow analyses consistently identified a 500-kV transmission corridor in MISO South as a frequent binding constraint and thermal violation appearing under near-term system assumptions. This outcome was largely driven by the intentional increase in load within MISO South, which was designed to create additional stress on the local transmission network as part of the study modification. To unlock the full value of the proposed 345-kV transmission pathway and prevent downstream bottlenecks from limiting its effectiveness, an upgrade to this 500-kV corridor was also introduced as an LRTP project.

The final set of traditional mock LRTP projects is summarized below and illustrated in Figure 1. Figure 1 also shows MISO's nine Load Resource Zones (LRZ).

- A new 345-kV triple-circuit 5,000 MW transmission pathway connecting MISO North and MISO Central.
- A new 345-kV triple-circuit 5,000 MW transmission pathway connecting MISO North and MISO South.
- A reconductor of an existing 500-kV transmission corridor in MISO South, providing approximately 1,000 MW of incremental capability.

Figure 1 Mock LTRTP Projects Development



CONSIDERATION OF ADVANCED AND ALTERNATIVE TRANSMISSION TECHNOLOGIES

The identification of a 500-kV corridor with near-term limitations created an opportunity to consider and evaluate ATTs in replacement of a traditional transmission upgrade. For this study, the two new mock 345-kV LTRTP projects remained unchanged, while alternative solutions were evaluated for the constrained 500-kV corridor.

Several ATT options were considered, including dynamic line ratings (DLR), high performance conductors (HPC), advanced power flow control devices, and transmission switching. DLRs and HPCs were selected for further assessment in this study. This selection does not imply that advanced power flow control devices or transmission switching provide less value. Rather, the decision was driven by practical modeling considerations. Specifically, the suite of software and analytical workflows required to perform the Order No. 1920 benefit evaluations does not readily support the automated feedback mechanisms needed to accurately represent the interactions between system conditions identified in production cost and power flow analyses and the dynamic control actions or operating states of these technologies. As a result, capturing their full operational value would require additional model integration and tool capabilities beyond the scope of this study. Specialized planning platforms, including tools such as GridAstra and NewGrid, have been developed to automate and evaluate these advanced transmission technologies; however, those capabilities were not incorporated into the modeling framework used for this assessment.

In contrast, DLR and HPC solutions can be more readily represented as transmission capacity enhancements within existing resource adequacy, capacity expansion, production cost, and power flow modeling frameworks. As a result, they provide a practical, transparent, and consistent means of evaluating the potential benefits of ATTs within the context of this benefit methodology demonstration. We note that the explicit omission of the other two ATT candidate solutions means that this plan would not be compliant with Order No. 1920, which requires consideration of all four technologies.

As detailed in the following section, preliminary power flow and PCM screening determined that DLR was the only realistic solution for the specific 500 kV corridor identified in this case study. Consequently, a detailed assessment, including all benefit calculations, was conducted only for the DLR candidate option and compared against the traditional reconductoring upgrade alternative for the identified 500 kV transmission path.

EVALUATION OF ORDER NO. 1920 BENEFITS

There are several common modeling choices across all benefits, most notably the system assumptions in the Base and Change Cases. The Base Case represents the production cost model of the MISO system. The model incorporated regional load forecasts, the projected generation fleet, and the transmission network expected to be in service during the study period, including existing facilities as well as the approved MVP, LRTP Tranche 1, and LRTP Tranche 2.1 transmission portfolios. The Change Case was developed by adding the mock LRTP projects to the Base Case while maintaining all other modeling assumptions consistent between the two cases. The mock LRTP projects were assumed to all go into service in the year 2030.

The primary approach for calculating benefits is to perform modeling simulations using a Base Case without the LRTP projects and a corresponding Change Case that includes the LRTP projects, and to take the difference between the benefits resulting in each Case. To ensure a consistent comparison, both cases typically use the same assumptions, forecasts, and modeling inputs, with the transmission projects and portfolio being the primary difference between the two cases. An alternative approach is to define the Base Case not simply as the Change Case without the projects, but as a counterfactual future representing how transmission and generation investments might reasonably develop in the absence of the LRTP projects.

Benefit evaluations were discounted using the 2.5% inflation rate and the 7% discount rate applied in MISO economic planning studies. Those benefits based on expected unserved energy were monetized using MISO's tariff-based Value of Lost Load (VOLL) assumption of \$10,000/MWh. Benefits were measured for both the Base and Change Cases in years 2032, 2037, and 2042, and interpolated or extrapolated for the intervening years through 2049. The benefit evaluation assumptions are found in Table 1. Benefits were calculated for the set of mock LRTP projects as a whole, rather than calculating for each project individually.

Table 1 Interpolation Assumptions

Discount Rate	7.0%
Current Year	2026
In Service Year	2030
Inflation Rate	2.5%

To evaluate the potential of advanced transmission technologies as alternatives to conventional transmission upgrades, EPE assessed both DLR and HPC candidate solutions within the 500-kV corridor rather than a traditional reconductor solution. The other new triple-circuit 345-kV transmission facilities of the mock LRTP projects were left unchanged.

A review of the preliminary power flow analysis results indicates that, for the identified 500 kV corridor in MISO South, the normal and emergency rating increases provided by the traditional reconductoring upgrade option were sufficient to mitigate the worst-case thermal overloads observed across all study snapshots. In other words, the additional rating gains achievable through DLR or HPC would not demonstrate a significant advantage under the snapshot-based assessment approach traditionally used in reliability transmission planning studies.

In contrast, the preliminary PCM results provided additional insight into system performance over the full year. Following the traditional reconductoring upgrade, the total number of binding congestion hours in the 8,760-hour simulation was reduced significantly, from an average of approximately 2,300 hours to fewer than 100 hours in a year. This finding suggests that the traditional reconductoring solution addresses the majority of congestion on the identified 500 kV transmission path. While HPC solutions, which can support ratings much higher than those of traditional conductors, may deliver additional economic benefits, the preliminary assessment indicates that these incremental benefits are likely to be relatively modest compared with those achieved through the traditional reconductoring upgrade. DLR, however, remained a worthwhile option for further evaluation because its time-varying rating characteristics have the potential to provide additional economic benefits that are not fully captured by snapshot-based reliability analyses and may contribute to Benefits 2 through 7 considered in this study.

To evaluate a candidate DLR solution among the larger mock LTRTP projects, EPE developed hourly transmission ratings along the 500-kV corridor between the MISO zones 9 and 10. These dynamic ratings were calculated using established IEEE standards⁹ and assumptions regarding wind direction, maximum wind speed, and ambient temperature. The dynamic ratings were further informed by the hourly wind and solar generation profiles represented in the production cost model. The resulting DLR ratings are shown in Figure 2. The resulting hourly ratings were incorporated into the same Base Case and Change Case framework used for the standard portfolio analysis, enabling a consistent comparison of the benefits associated with dynamic line ratings relative to conventional transmission upgrades. Overall, the DLR was implemented to provide rating increases ranging from 3% to 127%, with an average increase of 82% over the original rating. This average annual increase is consistent with findings of other DLR assessments.¹⁰

⁹ IEEE Power and Energy Society, “IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors (IEEE Std 738-2012)” (2013), available: <https://ieeexplore.ieee.org/document/6692858>.

¹⁰ Brown, P., Obika, K., Bredenkamp, S., Lu, L. “Hourly dynamic line ratings for existing transmission across the contiguous United States (preliminary results)” National Laboratory of the Rockies (2024) at 3, available: <https://docs.nlr.gov/docs/fy25osti/91599.pdf>

Figure 2 Dynamic Line Rating Profile by Hour

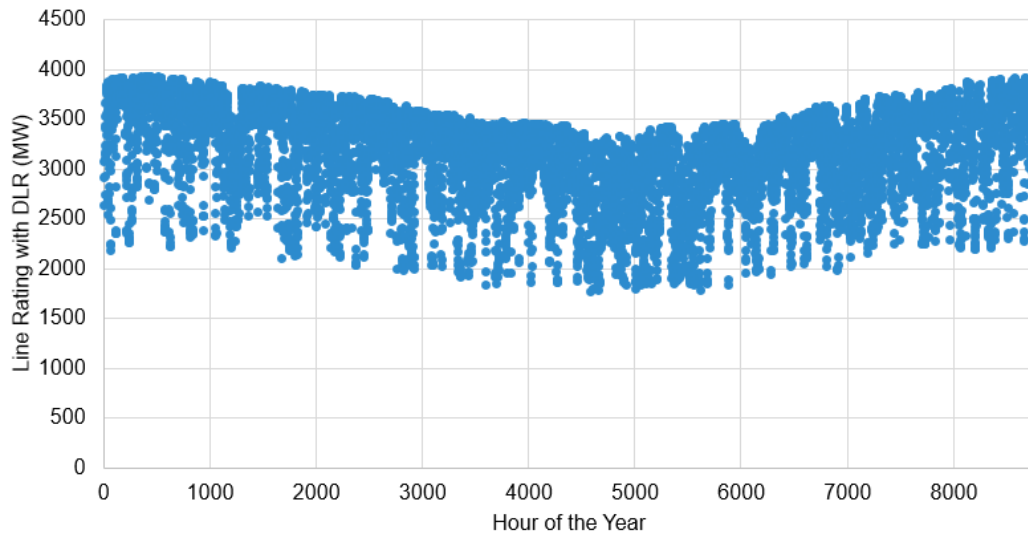


Table 2 shows a summary of the benefits for each of the two sets of mock LTRTP projects considered in this case study. Overall, the traditional transmission projects demonstrated substantial benefits, particularly for Benefits 1, 2, and 3. Some benefits associated with losses and outage-related conditions, especially Benefits 4, 5, and 7, were found to be negative. In addition, the estimated value of Benefit 6 varied significantly depending on the extreme weather scenario considered, ranging from -\$0.5 million under hurricane conditions to \$118.1 million under a heat wave scenario.

The projects incorporating the DLR candidate solution also demonstrated significant value across multiple benefit categories, particularly Benefits 1, 2, and 3. Although the benefits associated with the DLR solution were generally lower than those of the traditional transmission projects, this outcome is expected given the time-varying nature of DLR ratings, which limits the availability of additional transmission capacity during certain hours. These results are particularly noteworthy when considering the relative cost and deployment timeline of DLR technology. While traditional transmission upgrades may deliver greater overall benefits, DLR can often be implemented more quickly and at a significantly lower cost¹¹. As a result, DLR may represent an attractive option when evaluating overall cost-effectiveness and speed of deployment. In particular, DLR can help address near-term reliability and congestion challenges while providing additional time for the planning, permitting, and construction of longer-term transmission solutions.

The methodologies, assumptions, and considerations used to quantify these benefit values, as well as the context surrounding each benefit metric and results, are discussed in detail in the following sections.

¹¹ AES Corporation and LineVision. *Lessons from First Deployment of Dynamic Line Ratings* (Apr. 2024) at 14. available: <https://www.aes.com/sites/aes.com/files/2024-04/AES-LineVision-Case-Study-2024.pdf>.

Table 2 Benefit Summary of Mock LTRTP Projects

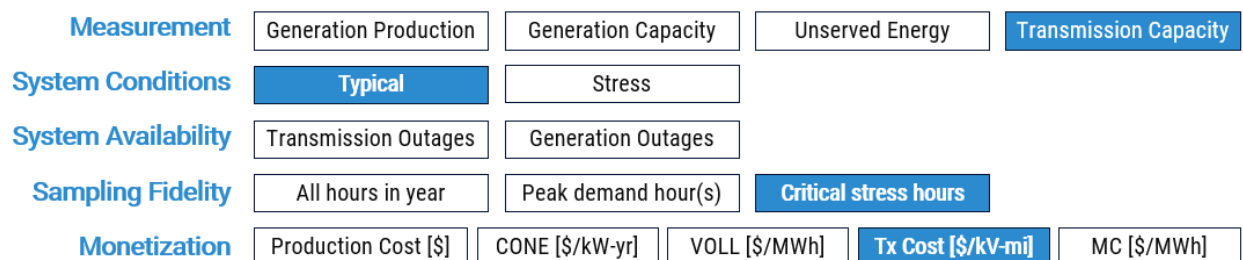
Order No. 1920 Benefit	Traditional	Traditional + DLR
1	\$140.7 million	\$140.7 million
2	2a \$951.6 million 2b \$342.3 million	2a \$633.2 million 2b \$171.1 million
3	\$1,815 million	\$663.5 million
4	-\$7.7 million	-\$133.2 million
5	-\$5.0 million	\$36.2 million
6	Hurricane: -\$0.5 million Heat Wave: \$118.1 million	Hurricane: -\$1.5 million Heat Wave: \$15.2 million
7	-\$8.0 million	\$12.3 million

BENEFIT 1: AVOIDED INFRASTRUCTURE UPGRADES

BENEFIT OVERVIEW

Benefit 1 captures reduced costs achieved by delaying or avoiding transmission facility additions and upgrades to address reliability needs and replace aging infrastructure. Unlike Benefits 2–7, which are generally derived from production cost, resource adequacy, or capacity expansion modeling and monetized in dollars of avoided operating or capacity cost, Benefit 1 is fundamentally a transmission capital cost avoidance metric. It measures whether the LTRTP facilities, projects, and portfolios make other planned or otherwise-needed local transmission projects unnecessary or deferrable.

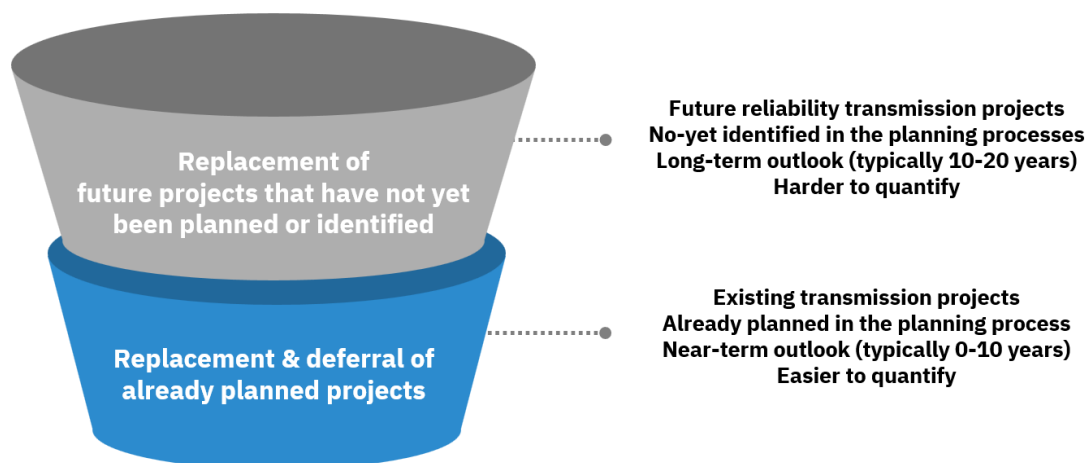
Figure 3 Benefit 1 Modeling Framework



It is important to recognize that this benefit can be decomposed into two distinct categories. The first category consists of the replacement or deferral of already planned transmission projects. This benefit reflects the avoided cost of projects that have already been identified through reliability

planning processes, which typically evaluate system needs over a 5- to 10-year horizon based largely on NERC reliability planning criteria. Because these projects have already been identified through regional and local reliability transmission planning processes, they are generally more straightforward to identify, collect, characterize, and evaluate in comparison to the newly developed LTRTP projects. The second category consists of the replacement of future transmission projects that have not yet been planned or identified. Quantifying this benefit is inherently more challenging because most reliability transmission planning processes do not extend beyond a 10-year horizon, whereas Order No. 1920 requires a 20-year planning horizon. As a result, there is a significant gap in visibility into transmission investments that may be needed during years 10 through 20. Nevertheless, these future projects represent real costs that could potentially be avoided through proactive development of a long-term regional transmission projects.

Figure 4 Two Distinct Categories of Displaced Transmission Projects for FERC 1920 Benefit 1 Calculation



The distinction between these two categories is important because current industry practice is heavily weighted toward the first category of already planned projects. In most regions, evaluations of Benefit 1 focus primarily on the ability to replace or defer projects that are already included in existing transmission plans. By contrast, future reliability-driven projects that would likely be required in the absence of the LTRTP facilities, projects, and portfolios are often not systematically identified or quantified. This omission can result in a material underestimation of Benefit 1, as it excludes a potentially significant portion of the transmission investments that long-term regional transmission planning is intended to avoid.

As discussed in detail in the next section, Benefit 1 is also distinct from Benefits 2–7 in that its evaluation requires multiple types of reliability assessments. Transmission reliability needs arise from different physical phenomena operating across a wide range of timescales, and no single analytical approach can capture all these reliability drivers. While steady-state analysis is the most commonly used method for evaluating Benefit 1, it represents only one dimension of system

reliability. Short-circuit, dynamic and transient stability, and electromagnetic transient (EMT) analyses may also be required to provide a comprehensive assessment, as each addresses reliability concerns that are not fully captured by steady-state methods.

Correspondingly, transmission planners rely on a broad suite of analytical tools to quantify Benefit 1. Commonly used software platforms include PSS®E, PowerGEM TARA, PSLF, and PowerWorld for steady-state and contingency analysis; ASPEN for short-circuit and protection studies; DSATools, PSS®E, and PSLF for transient stability analysis and dynamic security assessment, and EMTP and PSCAD for EMT analysis. Because each tool is designed to model specific reliability phenomena, no single software platform is capable of performing the full range of analyses required to comprehensively evaluate Benefit 1. Therefore, a robust assessment often requires the coordinated use of multiple study methodologies and software tools.

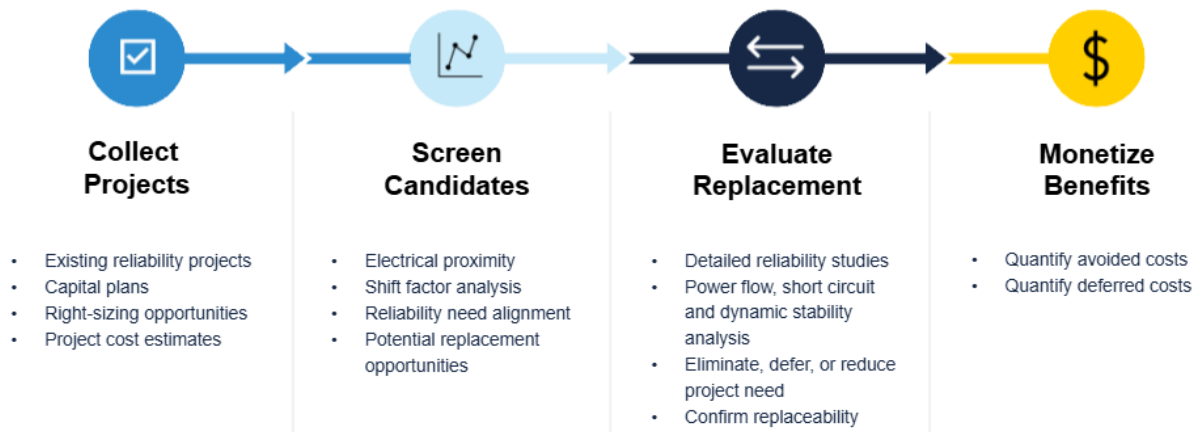
BENEFIT 1 CALCULATION METHODOLOGY

BENEFIT 1 CALCULATION FRAMEWORK

For already planned projects (the first category), the methodology generally consists of four sequential steps. First, planners compile the relevant existing project dataset from the transmission provider or ISO/RTO reliability planning process, including in-kind replacement projects, capital plans, right-sizing opportunities, local reliability projects, and associated cost estimates. Second, a screening process is conducted to identify a subset of potentially replaceable projects for each LTRTP facility, using indicators such as electrical proximity, shift factors, and the nature of the underlying reliability need. Third, detailed replacement studies are performed to evaluate whether the LTRTP project can eliminate, defer, or otherwise reduce the need for the screened projects. These studies typically rely on power flow and other reliability analyses to confirm project replaceability. Finally, the benefit is monetized by quantifying the total capital costs of the replaceable projects that can be avoided or deferred. This process provides a systematic framework for estimating the reliability-related capital cost savings attributable to the LTRTP projects.

One important consideration is that many already planned projects, particularly like-for-like asset replacement projects, originate from utility asset management and capital investment programs intended to maintain system reliability, asset condition, and operational performance. These projects are often incorporated into regional planning assumptions as part of the baseline system plan, and opportunities to evaluate alternative solutions or broader regional coordination options may therefore be limited. As a result, the practical potential for an LTRTP project to defer, replace, or avoid such projects may be more limited than suggested by a purely technical assessment of project replaceability.

Figure 5 Benefit 1 Calculation Framework for Already Planned Projects



For projects not yet formally identified (second category), the methodology focuses on estimating the reliability-driven transmission investments that would likely be required in the absence of the LTRTP facilities, projects, and portfolios. The process begins with a comparative reliability assessment in which reliability studies are performed with and without the LTRTP projects across multiple study years and system conditions, consistent with applicable NERC and local reliability criteria. Next, the reliability impacts of the portfolio are identified by determining which violations are mitigated by the LTRTP projects, including an assessment of violation types, contingency conditions, and the extent to which operational measures, such as generation redispatch, could reasonably address the issues. This step is important to ensure that only violations requiring a transmission-based solution are considered.

Based on the identified reliability needs that are resolved by the LTRTP projects, there are two primary approaches for quantifying the associated Benefit 1 value. The first approach is a proxy project method, in which local transmission projects are developed to represent the facilities that would likely need to be constructed in the absence of the transmission projects. These proxy solutions are designed to address specific reliability violations and include assumptions regarding facility scope, construction approach, and capital cost. An optimization process may then be applied to identify the most cost-effective set of proxy projects capable of resolving the identified reliability needs. The Southwest Power Pool (SPP) and ISO New England (ISO-NE) are examples of existing planners which use a similar method in their transmission benefit evaluation processes.¹²

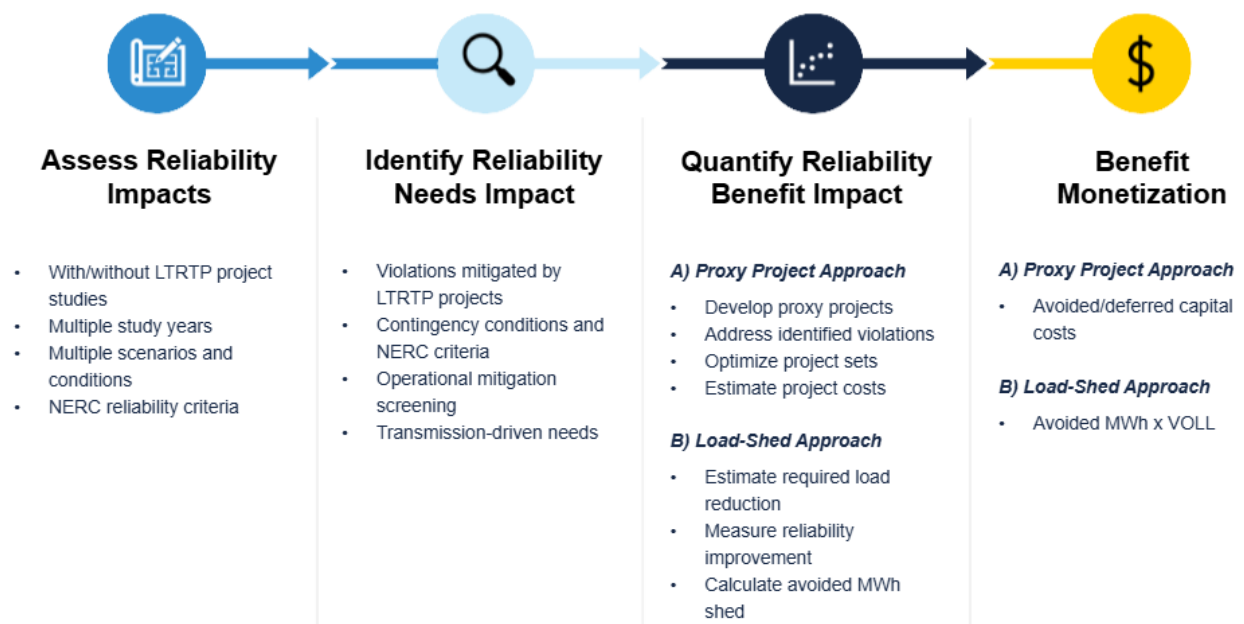
The second approach is a load-shed-based method, which estimates the amount of load reduction or involuntary load shedding that would be required to maintain compliance with reliability criteria if the LTRTP projects were not developed. Under this approach, the reliability value of the portfolio

¹² Brooks (2026) at 67

is measured by the extent to which it avoids customer interruptions and improves system reliability. MISO uses a version of this benefit evaluation approach for Tranche 2 of their LTRTP process.¹³

The monetization of Benefit 1 depends on the selected approach. Under the proxy project method, Benefit 1 is quantified as the aggregate capital cost of the avoided or deferred transmission projects, typically using standardized equipment and construction cost assumptions to promote consistency and comparability across study areas. Under the load-shed-based method, Benefit 1 is quantified by multiplying the amount of avoided load shedding (MWh) by an appropriate VOLL or similar reliability value metric. Both approaches seek to estimate the costs that would otherwise be incurred absent the LTRTP projects, albeit through different representations of the underlying reliability need.

Figure 6 Benefit 1 Calculation Framework for Projects Not Yet Formally Identified



ASSESSMENTS NEEDED TO QUANTIFY BENEFIT 1

Benefit 1 calculation requires multiple types of reliability assessments because transmission reliability needs arise from different physical phenomena occurring across different timeframes. A comprehensive evaluation should therefore consider a range of planning studies as needed, including steady-state, short-circuit, transient and dynamic stability, and electromagnetic transient (EMT) analyses.

- Steady-state analysis evaluates system conditions after a disturbance once the system has reached a stable operating point. These studies assess thermal loading, voltage performance, and transfer capability under normal and contingency conditions.

¹³ *Id.*

- Short-circuit analysis evaluates fault current levels throughout the system and determines whether existing protection systems and equipment ratings remain adequate as system conditions evolve.
- Transient and dynamic stability analysis evaluates the system's ability to maintain reliable operation following major disturbances, such as faults or the loss of critical system elements. These studies assess rotor angle stability, frequency response, voltage recovery, and other dynamic performance characteristics.
- Electromagnetic transient (EMT) analysis examines system behavior at sub-cycle timescales and is increasingly important in systems with high penetrations of inverter-based resources. EMT studies evaluate fast electromagnetic and control interactions that cannot be adequately represented in traditional stability models.

METHODOLOGY ADOPTED FOR THE CASE STUDY

For this report, EPE focused on quantifying benefits for the second category of future transmission projects (those that have not yet been planned or identified) because they represent the least-established component of Benefit 1 from a methodological perspective and are therefore most in need of further evaluation and refinement. Of the two possible monetization methods presented, the proxy project approach was selected rather than the load-shed approach. This decision was driven by the fact that load assumptions in transmission reliability planning models are not always intended to represent actual expected system demand and may be adjusted to stress the system and reveal potential reliability needs. As a result, load-shed estimates derived directly from reliability planning studies may not accurately reflect real-world interruption impacts. A production cost simulation-based approach could potentially provide a more comprehensive and realistic assessment of expected load-shed quantities and associated customer impacts.

To evaluate benefits, two study snapshots representing both peak-load and off-peak-load conditions were analyzed. Reliability assessments included N-1 contingency analysis across both the MISO North and MISO South regions. To focus the assessment on reliability impacts most relevant to the proposed LTRTP projects, contingencies involving facilities located within ten electrical levels of the project facilities were included in the analysis. This approach provided a targeted assessment of the reliability benefits attributable to the projects while maintaining a manageable study scope.

The contingency analysis conducted in this study focused primarily on thermal violations. For each identified N-1 violation, potential operational mitigation measures, including generation redispatch and transmission element switching, were evaluated to determine whether the violation could be addressed operationally without the need for a transmission solution. This screening step helped ensure that only reliability needs requiring a project-based solution were advanced for further consideration, thereby avoiding the development of unnecessary proxy projects.

Violations that remained unresolved after consideration of operational actions were compared between the cases with and without the proposed LTRTP projects to identify the incremental reliability benefits provided by the projects. The resulting violations were passed to EPE's Network Upgrade Analysis Tool, which automatically develops and evaluates candidate transmission upgrades to mitigate identified reliability issues. Using contingency analysis results as input, the tool identifies the limiting facilities, determines the required rating improvements, and develops feasible brownfield upgrade solutions, including reconductoring, line rebuilds, and new double-circuit configurations. For each candidate solution, the tool estimates project costs, generates the necessary network model updates, and validates effectiveness through a subsequent power flow analysis. The result is a set of technically feasible and cost-estimated proxy transmission projects that can be used for planning and benefit evaluation.

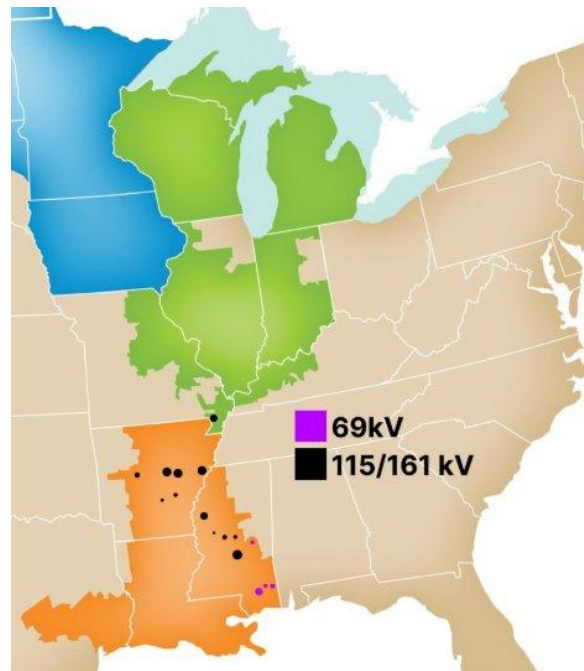
BENEFIT 1 RESULTS AND DISCUSSIONS

The contingency analysis comparing the Base Case and Change Case, with and without the mock LTRTP projects, identified 501 monitored facility–contingency pairs. These violations involved 87 unique transmission facilities above 69 kV and 204 unique contingency definitions. Most of the violations mitigated by the LTRTP projects were located within the MISO South region, with a smaller number occurring near the MISO North–South interface. This result is consistent with expectations, as the aggressive load growth assumptions in MISO South increase the need for both local reinforcements and power imports into the region. Without the LTRTP projects, the existing transmission system, including the MISO North–South transfer interfaces and the local transmission network serving MISO South, became overloaded under a number of contingency conditions.

Using the identified list of 501 monitored facility–contingency pairs, the EPE planning tool developed a set of 33 candidate transmission solutions designed to address the observed thermal violations. These candidate solutions span voltage levels from 69 kV to 500 kV and include a combination of line reconductoring and transmission line rebuild projects. Following a technical review of the candidate solutions, projects with voltage ratings above 200 kV were removed from further consideration to avoid potential double-counting. This screening approach is adopted assuming that higher-voltage regional transmission projects would typically be identified and evaluated as part of the LTRTP projects development process and the broader MTEP framework.

After completing the review and screening process, 24 transmission projects ranging from 69 kV to 161 kV were retained as proxy transmission investments that would likely have been required in the absence of the mock LTRTP projects. Similar to the geographic distribution of the identified violations, these proxy projects are concentrated within the MISO South footprint, with a limited number located near the MISO North–South boundary. The approximate locations and voltage levels of the retained proxy projects are illustrated in the figure below.

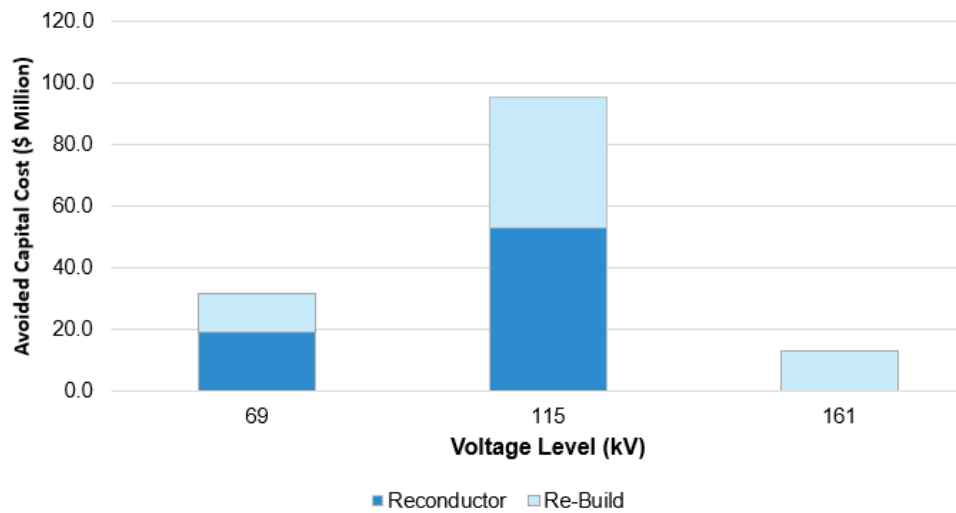
Figure 7 24 Identified Proxy Transmission Projects that could be Avoided or Deferred for Benefit 1 Calculation



For monetization of Benefit 1, the total estimated cost of the 24 identified proxy transmission projects that could be avoided or deferred was **\$ 140.7 million**. The individual project costs are shown in the figure below and range from approximately \$0.5 million to \$13.1 million per project. These proxy project costs represent transmission investments that would likely have been required to mitigate the reliability violations identified in the Base Case in the absence of the mock LTRTP projects.

For this specific example, the resulting Benefit 1 value is identical to the traditional solutions. This outcome is expected because the ATT implementation was evaluated on facilities at the 500 kV voltage level, while proxy transmission solutions above 200 kV were excluded from the Benefit 1 assessment to avoid potential overlap with regional transmission projects that would otherwise be evaluated through the Order No. 1920 planning process. Consequently, the set of retained proxy projects used for Benefit 1 monetization remained unchanged between the traditional and DLR candidate solutions, resulting in the same quantified Benefit 1 value.

Figure 8 Estimated Cost of the 24 Identified Proxy Transmission Projects that Could Be Avoided or Deferred



COMMON SOURCES OF BENEFIT 1 UNDER-EVALUATION

Benefit 1 is commonly undervalued because assessments often focus only on existing, identified reliability projects and overlook future reliability-driven investments that would likely be required absent the LTRTP projects and portfolio. To capture the full reliability value, evaluations should consider both existing replaceable projects and future replaceable projects estimated either by a proxy project or load shedding approach. Limiting the analysis to currently planned or approved reliability upgrades can materially understate the avoided-cost benefits of long-term regional transmission investments.

In addition, reliability value extends beyond resolving NERC planning criteria violations, particularly when evaluations rely primarily on steady-state analysis. Transmission investments can also provide operational benefits, including reduced reliance on Reliability Must-Run (RMR) arrangements, fewer operating procedures and nomograms, improved outage flexibility, enhanced system strength, and greater operational resilience. While these benefits are often recognized by planners and operators, they are rarely quantified or monetized, leading to further underestimation of Benefit 1.

COMMON SOURCES OF BENEFIT 1 OVER-EVALUATION

While Benefit 1 is more commonly underestimated than overestimated in existing practices, there are several areas where caution is warranted to avoid overstating reliability benefits. Detailed assessment and judgment are essential in determining whether an identified reliability issue truly requires a transmission project solution. Factors such as contingency classification, violation frequency and severity, and the availability of operational mitigations should be considered before developing proxy projects. Otherwise, reliability needs may be overstated, leading to an inflated estimate of avoided project costs.

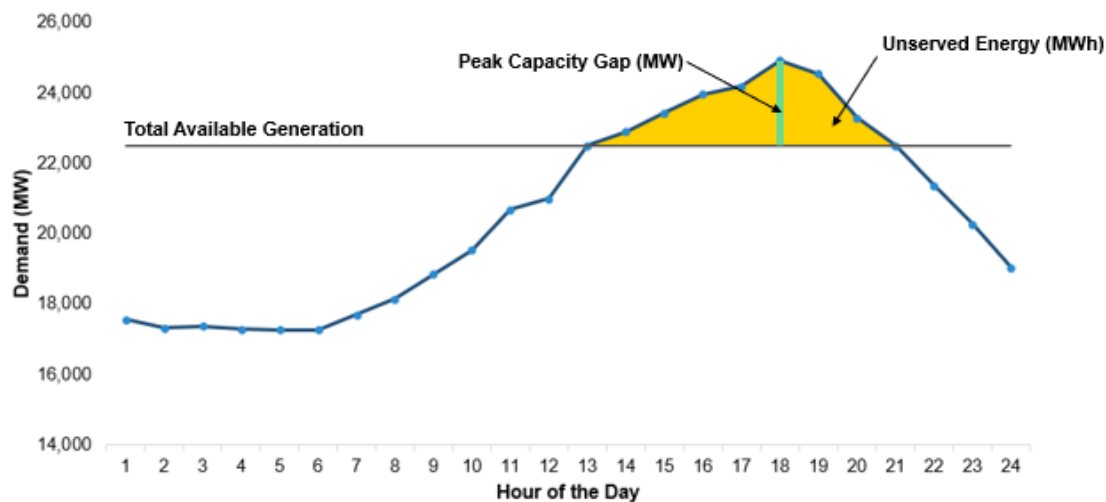
BENEFIT 2: REDUCED COSTS RELATED TO RESOURCE ADEQUACY

BENEFIT OVERVIEW

Benefit 2 captures the enhanced resource adequacy benefit that LTRTP projects can deliver. Transmission facilities can enhance resource adequacy by increasing transfer capability between zones and regions, enabling loads to be served with fewer local resources. It is achieved either by reducing the amount of generation needed to maintain the loss of load expectation (LOLE) or by reducing expected unserved energy (EUE). Order No. 1920 frames these two outcomes as distinct sub-methods, presenting planners with an either/or choice between the two approaches rather than requiring both.

The first sub-method, 2a, addresses reduced loss of load probability. This approach focuses on reducing the total amount of expected unserved energy (yellow area in Figure 9) across hundreds of scenarios that vary weather and outage conditions, capturing reliability improvements through the lens of energy that would otherwise go unserved during stress/tail events. The second sub-method, 2b, addresses reduced planning reserve margin. Rather than focusing on unserved energy, this approach reduces the total amount of peak capacity needed (green line in Figure 9) across those same hundreds of weather and outage scenarios, capturing value through lower capacity requirements instead.

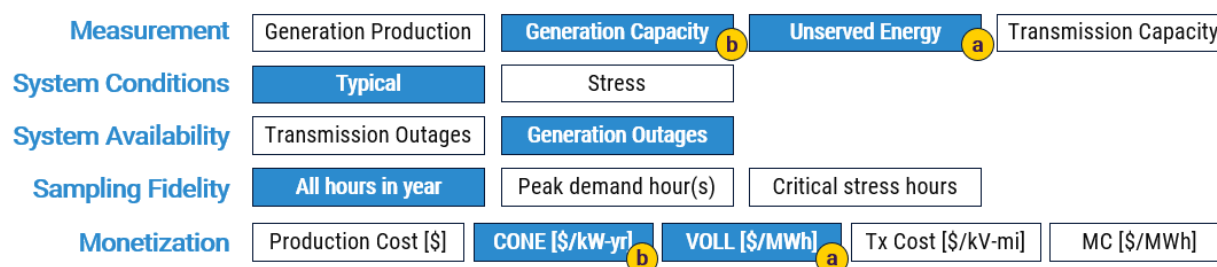
Figure 9 Illustration of Peak Capacity Gap and Unserved Energy



Together, these two sub-methods give planners flexibility in how they quantify and demonstrate the resource adequacy benefits of a given LTRTP facility, project, or portfolio, depending on which metric – unserved energy or peak capacity need – best fits the planning framework being used. However, they are fundamentally measuring different things, and it is likely that there will be discrepancies

between the benefits calculated using the 2a methodology vs. those calculated using the 2b methodology.

Figure 10 Benefit 2 Modeling Framework



Because Benefit 2a and 2b represent two valuation lenses on the same underlying resource adequacy improvement, the selection of a pathway should be driven by data availability, stakeholder acceptance of VOLL (used to monetize Benefit 2a) versus capacity cost (used to monetize Benefit 2b) assumptions, and consistency with the region's existing resource adequacy framework. Once selected, the pathway should be applied consistently across the LTRTP projects and planning horizon to preserve comparability of benefit-to-cost results.

Adoption of this benefit remains uneven across the industry, and not all regions currently evaluate resource adequacy benefits as part of the LTRTP process.¹⁴ As regions move toward Order No. 1920 compliance, most are expected to adopt either the avoided capacity requirement approach (Benefit 2a) or the avoided unserved energy approach (Benefit 2b), with some variation in implementation based on existing planning practice.

The software used to evaluate Benefit 2 generally falls into two categories. Resource adequacy-focused tools, such as GE MARS and SERVM, are used to evaluate metrics such as LOLE, EUE, and planning reserve requirements. Capacity expansion-focused tools, such as PLEXOS LT Plan, EnCompass, GridSim, and AURORA are used to assess how transmission investments affect long-term resource build-out and capacity needs. In some cases, production cost models may also be used to support these analyses. The selected methodology largely determines the software requirements, making Benefit 2 one of the more variable benefits to implement across regions.

BENEFIT 2 CALCULATION METHODOLOGY

BENEFIT 2 CALCULATION FRAMEWORK

Benefit 2 captures the value of transmission in maintaining resource adequacy, and FERC treats it as a single underlying benefit measured through two mutually exclusive pathways. Both pathways rely on the same core modeling suite: determine zonal transfer capability (e.g. through AC power flow

¹⁴ Brooks (2026) at 55-58

analysis, or adapted from PCM model), followed by probabilistic resource adequacy (Monte Carlo) modeling with and without the proposed transmission.

Benefit 2a, Reduced Loss of Load Probability, holds the target planning reserve margin (PRM) fixed and measures the reduction in EUE between the Base and Change Cases, monetized by multiplying the reduction in EUE by a value of lost load. Benefit 2b, Reduced Planning Reserve Margin, instead holds the target LOLE constant and measures the reduction in generation capacity needed to meet resource adequacy requirements, monetized either through a full capacity expansion model or a simpler multiplier applying an assumed capacity cost (e.g., net cost of new entry [CONE]) to the avoided generation capacity.

The key trade-offs between the two options center on sensitivity and complexity. Benefit 2a is simpler to calculate but hinges on an agreed upon measure of VOLL. The *Regional Practices* assessment notes administratively determined values of VOLL are considered highly subjective, have a very wide range used across the industry, and can make the transmission benefits highly sensitive to this assumption. Additionally, in highly reliable systems, EUE reductions may also be minor, understating true value (explained in more detail later). Benefit 2b more explicitly captures avoided generation capital investment but requires either a full capacity expansion run (methodologically robust but resource-intensive) or a simpler capacity-price multiplier (easier but reliant on an assumed \$/kW-year value).

METHODOLOGY ADOPTED FOR THE CASE STUDY

To demonstrate the range of methodologies permitted under Order No. 1920, EPE evaluated Benefit 2 using both the avoided capacity requirement approach and the avoided unserved energy approach. Because PCM simulations for Benefits 3 through 6 were performed in PROMOD to align with MISO's established conventions, a separate platform was selected to illustrate the additional workload associated with performing resource adequacy and capacity expansion analyses. For this purpose, PLEXOS was used to evaluate Benefit 2.

Model alignment between PROMOD and PLEXOS was based on key planning inputs, including generation capacity by technology and zone, zonal load profiles, and transfer capability between zones. Using separate software platforms for Benefit 2 and Benefits 3 through 6 required additional effort to ensure consistency between the models. This included model translation, data reconciliation, and validation activities, all of which increase study complexity and introduce potential sources of mismatch between assumptions and results.

For this demonstration, transfer capability between zones was represented using the aggregate thermal limits of transmission interfaces to approximate the ratings of major system paths. However, transfer capability can be defined in multiple ways depending on the planning framework, including rated system paths, flowgate-based limits, and area interchange capabilities. In addition, transfer capability may be evaluated under a range of system conditions rather than a single snapshot. The selected definition and evaluation approach can materially affect the calculated resource adequacy

benefit and should be consistent with the region's planning practices, reliability criteria, and study objectives. The parameters used of Benefit 2 monetization can be found in Table 3 Parameters Used for Benefit 2 MonetizationTable 3.

Table 3 Parameters Used for Benefit 2 Monetization

Benefit Parameters	Value
LOLE Target	0.1 days/year
VOLL	\$10,000/MWh (MISO Tariff)
PRM	Established through RA analysis
Cost of Capacity	Established through Capacity Expansion

To evaluate the resource adequacy and capacity impacts of ATTs, DLR implementation was represented as increases in transfer capability between MISO zones 9 and 10 within the RA and capacity expansion models. Because DLR performance depends on ambient weather conditions, the additional transfer capability can vary significantly over time, with periods of high temperatures and low wind speeds reducing or eliminating the incremental capability provided by DLR. A single DLR rating profile was applied across all RA simulations in this analysis. A more robust approach would directly integrate DLR ratings into the RA framework, allowing line ratings to be correlated with demand, renewable output, and other weather-driven system conditions.

BENEFIT 2 RESULTS AND DISCUSSIONS

2a Reduced loss of load probability: Under the reduced loss of load probability approach, the LTRTP projects reduced expected unserved energy from 33,956 MWh per year (on average) in the Base Case to 25,561 MWh per year (on average) in the Change Case. This represents an average annual reduction of 8,395 MWh of expected unserved energy attributable to the LTRTP projects.

$$\text{Benefit 2a} = \sum_{2026}^{2045} \text{DeltaEUE} * \text{VOLL} * \text{discount rate}$$

Based on these assumptions, the present value of Benefit 2a is approximately **\$951.6 million** in 2026 dollars. This result indicates that the mock LTRTP projects provide a meaningful resource adequacy benefit by reducing expected unserved energy across the modeled probabilistic reliability outcomes.

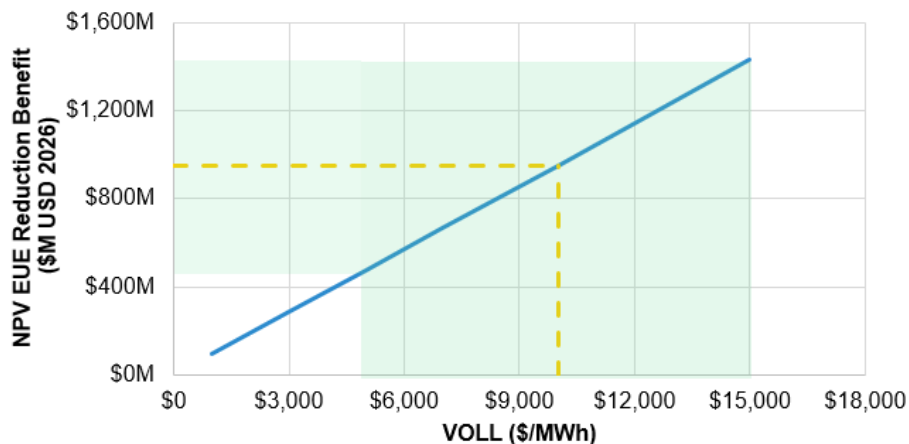
For the DLR candidate solution, the time-varying nature of the line ratings meant that the additional transfer capability was not always available during the most stressed system conditions. Nevertheless, the increased transfer capability provided meaningful support to southern portions of the system across many hours, reducing expected unserved energy by 5,586 MWh/year. The resulting resource adequacy benefit was estimated at **\$633.2 million** in 2026 dollars. See Table 4 for a summary of the measured benefits across all candidate LTRTP solutions.

Table 4 Measured EUE for Benefit 2a Calculation

Candidate LTRTP Projects	Base Case EUE (avg MWh/yr)	Change Case EUE (avg MWh/yr)	Delta EUE (avg MWh/yr)
Traditional	33,956	25,561	8,395
Traditional + DLR	33,956	28,370	5,586

As previously noted, the calculated benefits are highly sensitive to the assumed Value of Lost Load (see Figure 11). Although VOLL is typically represented as a single static value, it is intended to approximate the aggregate value customers place on maintaining electric service. In practice, this value can vary significantly by customer class, outage duration, time of day, season, and local economic conditions. As a result, Benefit 2a can become a point of stakeholder debate because different VOLL assumptions can materially change the final benefit estimate. Consider the following plot showing the relationship between VOLL and the final Benefit 2a value.

Figure 11 Benefit 2a Results vs. VOLL



2b Reduced planning reserve margin: Under the reduced planning reserve margin approach, the LTRTP projects lowered the average planning reserve margin requirement from 22.48% in the Base Case to 22.45% in the Change Case, a reduction of 0.03 percentage points. The capacity expansion results indicate that this lower reserve requirement reduced total capacity additions from 82,989 MW to 82,036 MW, resulting in 954 MW of avoided capacity additions.

The amortized cost of new capacity was \$166/kW-year based on the results of the capacity expansion analysis. Applying this capacity cost to the 954 MW reduction in required capacity and discounting the resulting annual savings using MISO's 7% discount rate produces a Benefit 2b value of approximately **\$342.3 million** in 2026 dollars.

For the DLR candidate solution, the dynamic nature of the line ratings reduced the amount of capacity value relative to the traditional reconductor upgrade. Even so, DLR reduced required capacity additions by approximately 582 MW, resulting in a quantified benefit of **\$171.1 million** in 2026 dollars. While the capacity benefit is lower than that of the traditional reconductor option, the results demonstrate that DLR can still provide meaningful resource adequacy value by increasing transfer capability during many system conditions. See Table 5 for a summary of the measured benefits across all candidate LTRTP solutions.

Table 5 Measured PRM and Capacity Addition for Benefit 2b Calculation

Candidate LTRTP Projects		Avg PRM (%)	Total Capacity Additions (MW)
Traditional	Base Case	22.48	82,989
	Change Case	22.45	82,036
	Delta	0.03	954
Traditional + DLR	Base Case	22.48	82,989
	Change Case	22.47	82,407
	Delta	0.01	582

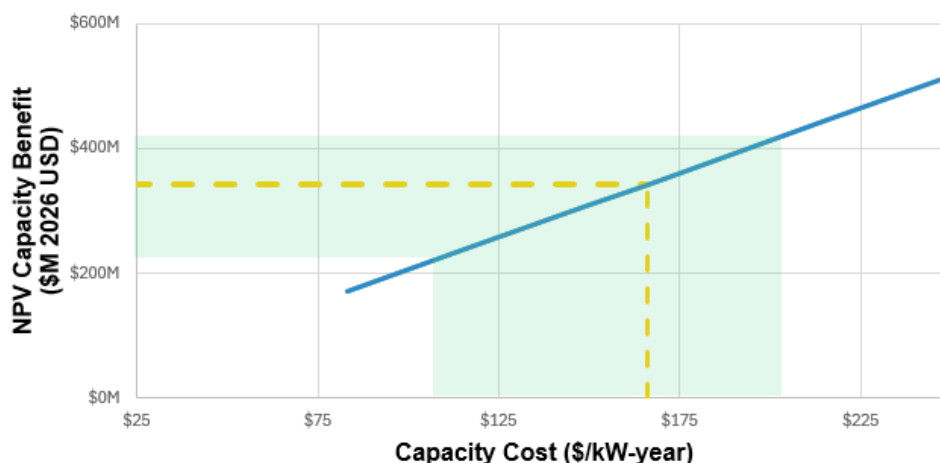
The Benefit 2b result is roughly one-third of the Benefit 2a result in this mock LTRTP projects analysis. This difference should not be interpreted as evidence that the reduced loss of load probability (2a) approach will always produce a larger value than the reduced planning reserve margin (2b) approach. Rather, the relative magnitude of the two results depends on several modeling and valuation assumptions, including the selected VOLL, the assumed cost of capacity, the underlying resource adequacy outcomes, and the relationship between changes in expected unserved energy and changes in capacity need.

For this analysis, EPE used a capacity expansion exercise to estimate the cost of capacity. In other applications, analysts may instead choose to use a CONE value, a Net CONE assumption, or another proxy for the cost of new capacity. Because the Benefit 2b calculation is directly tied to this assumed capacity cost, sensitivity analysis is useful for understanding how alternative capacity cost assumptions affect the final benefit estimate. As will VOLL, the choice of new capacity costs will impact the total estimated benefits (see Figure 12).

Overall, the comparison of Benefit 2a and Benefit 2b illustrates that the selected resource adequacy valuation pathway can materially affect the quantified benefit. Both approaches are defensible, but they measure different manifestations of the same underlying reliability improvement: reduced expected unserved energy versus reduced capacity needed to achieve the target reliability standard.

For this reason, the selected methodology should be clearly documented and applied consistently across projects.

Figure 12 Benefit 2b Result vs. Capacity Cost



In this case study, although the capacity expansion analysis resulted in a higher level of generation development in MISO South under the Base Case, the overall amount of new resource additions across the MISO footprint remained broadly similar between the Base and Change Cases, resulting in modest differences in resource adequacy outcomes. However, large-scale regional or interregional transmission projects can, in principle, enable substantially different generation build-out trajectories, influencing both the technologies selected and their geographic distribution. In addition, capacity expansion results may differ depending on whether the analysis is performed over the MISO footprint alone or across a broader interregional footprint, as a larger study area can provide greater opportunities for resource sharing and transmission-enabled resource optimization. For this analysis, the expansion exercise was limited to the MISO footprint only.

In cases where transmission expansion significantly alters resource development patterns, the resulting changes may create additional value beyond avoided resource adequacy costs. For example, transmission-enabled access to lower-cost resources, renewable energy development, or carbon emission reduction opportunities could provide incremental benefits if supported by applicable policy or regulatory objectives. Such benefits would be separate from the seven benefits identified in Order No. 1920, which establishes a minimum set of benefits to be evaluated rather than an exhaustive list.

COMMON SOURCES OF BENEFIT 2 UNDER-EVALUATION

Several sources of benefit understatement are common to both Benefit 2a and 2b, and they largely stem from modeling sequencing and stress-condition assumptions. Chief among these is the sequencing and calibration of resource adequacy simulations: if the Base Case without transmission is already calibrated to the reliability criterion before the LTRTP projects are tested, the transmission

addition will show minimal benefit because the system is already secure, so it is recommended that the system be calibrated to the criterion with transmission first, then have transmission removed to measure degradation.

Related understatement arises from modeling forced generator outages as independent of weather, which fails to capture the correlated outage risk that drives the highest-value reliability events, and from assuming "firm" imports from neighboring regions during system stress, which overstates external support and understates the transmission projects' true contribution. Static or administratively defined zonal topologies – based on utility footprints or state boundaries rather than actual electrical and transfer relationships – can also misrepresent how a transmission addition changes zone definitions and thus understate its value.

Within Benefit 2a specifically, understatement is most likely in systems already built to a high reliability standard, since in this scenario the savings from reduced EUE may be relatively minor compared to other benefits, even where the transmission provides meaningful reliability value that is simply masked by an already-low baseline EUE. Within Benefit 2b, understatement risk centers on how the Planning Reserve Margin is established: if the PRM is instead set administratively without a link to probabilistic analysis, it may be difficult to demonstrate a quantifiable benefit from a new transmission projects. Similarly, if a capacity expansion model does not allow the resource mix to evolve differently between the higher- and lower-PRM cases, the full system value of avoided generation investment may not be fully captured.

It is important to note that the resource adequacy benefits of ATTs may be understated in this analysis. The RA and capacity expansion models used in this study rely on a zonal representation of the transmission system, while many ATT applications address localized constraints within a zone. As a result, improvements in deliverability, congestion relief, and transfer capability provided by ATTs may not be fully captured when represented only as changes to zonal transfer limits. More granular nodal representations and tighter integration between transmission and resource adequacy models could better reflect the full reliability and capacity value of these technologies.

COMMON SOURCES OF BENEFIT 2 OVER-EVALUATION

For Benefit 2a, the most consequential over-evaluation lever is the Value of Lost Load assumption itself: estimates for VOLL can vary wildly, ranging from \$2,000/MWh to \$20,000/MWh, and since the chosen VOLL can swing the calculated benefits by many multiples, an aggressively high VOLL selection can substantially inflate the monetized result. For Benefit 2b, the principal risk is double counting through the capacity expansion model pathway: if the analysis attempts to monetize benefits using Net Present Value (NPV) reductions from a Capacity Expansion Model, there is a risk of double counting, and planners need to isolate distinct "avoided capacity" benefits from general reductions in operating costs in the Capacity Expansion Model. For clarity, the Capacity Expansion Model is minimizing the NPV of the total cost over the planning horizon, which is a combination of investment costs, fixed annual costs, and production costs. So it is considering the resource's impact

on both capacity cost and production cost when making a selection, meaning it may not necessarily choose the cheapest unit to build if it sees material production cost savings from a more capital intensive unit. This is not a concern if Benefit 2b is monetized using CONE or another metric rather than that derived from the Capacity Expansion Model, but planners should ensure to include annual O&M in their CONE calculations. EPE isolated the investment cost and annual fixed O&M costs to derive the capacity costs from the Capacity Expansion Model.

There is also a potential double-counting risk between Benefits 2 and 7. Benefit 2 captures the capacity value of transmission by evaluating its contribution to resource adequacy across a wide range of operating conditions. Benefit 7, by contrast, focuses specifically on the capacity value associated with reducing transmission losses during peak-demand periods. Because both benefits can ultimately be expressed as avoided capacity additions, care is needed to ensure that the capacity value attributed to peak-loss reductions under Benefit 7 has not already been captured within the resource adequacy framework used for Benefit 2. Clear delineation of the underlying value streams and consistent benchmarking assumptions are therefore essential to avoid counting the same avoided capacity benefit twice.

BENEFIT 3: PRODUCTION COST SAVINGS

BENEFIT OVERVIEW

Order No. 1920 Benefit 3 calculates the savings in fuel and other operating costs of generation that are realized under typical system operating conditions when new LTRTP facilities, projects, and portfolios allow for the increased dispatch of lower-cost generators, displacing generation suppliers with higher production costs. This benefit also includes the reduction in market prices as lower-cost generation suppliers increasingly set market-clearing prices. As illustrated in Figure 13, production cost simulations under typical system operating conditions typically evaluate hourly system operations across a representative year while assuming all planned transmission and generation facilities are in service and excluding outage events. As a result, the analysis measures the production cost under normalized operating conditions rather than under infrequent or extreme system events. This approach provides a clear assessment of the baseline economic value of transmission by focusing on the conditions that occur most frequently and contribute most significantly to annual system operating costs.

Figure 13. Benefit 3 Modeling Framework

Measurement	Generation Production	Generation Capacity	Unserved Energy	Transmission Capacity
System Conditions	Typical	Stress		
System Availability	Transmission Outages	Generation Outages		
Sampling Fidelity	All hours in year	Peak demand hour(s)	Critical stress hours	
Monetization	Production Cost [\$]	CONE [\$/kW-yr]	VOLL [\$/MWh]	Tx Cost [\$/kV-mi] MC [\$/MWh]

While most transmission planning regions in the United States already consider production cost savings as a benefit in their long-term regional transmission planning processes, the analysis horizon is typically limited to 10-15 years. In contrast, Order No. 1920 requires evaluation of benefits over a 20-year planning horizon. In addition, because nodal production cost simulations are computationally intensive and typically require hourly resolution, most planning studies evaluate only a limited number of representative years, often selecting two to three study years at five- to ten-year intervals. Extending the analysis horizon to 20 years introduces important considerations around study-year selection. Beyond regular intervals, representative years can be selected to capture major system changes, such as load growth, resource mix transitions, and transmission expansion. Another key consideration is whether benefits should be evaluated over 20 years from the study year or over the 20 years following a project's in-service date, as this can materially affect the calculated benefits.

Regions across the United States use a variety of nodal production cost simulation platforms, including PROMOD, PLEXOS, UPLAN, GridView, AURORA, EnCompass, and SAint. Each platform offers unique strengths and capabilities. Some tools are widely adopted across the industry and are supported by standardized ISO/RTO-specific databases and processes. Other platforms provide advantages in areas such as mathematical flexibility, scenario management, market modeling, easy integration of ATTs, or integration with power flow analysis.

BENEFIT 3 CALCULATION METHODOLOGY

BENEFIT 3 CALCULATION FRAMEWORK

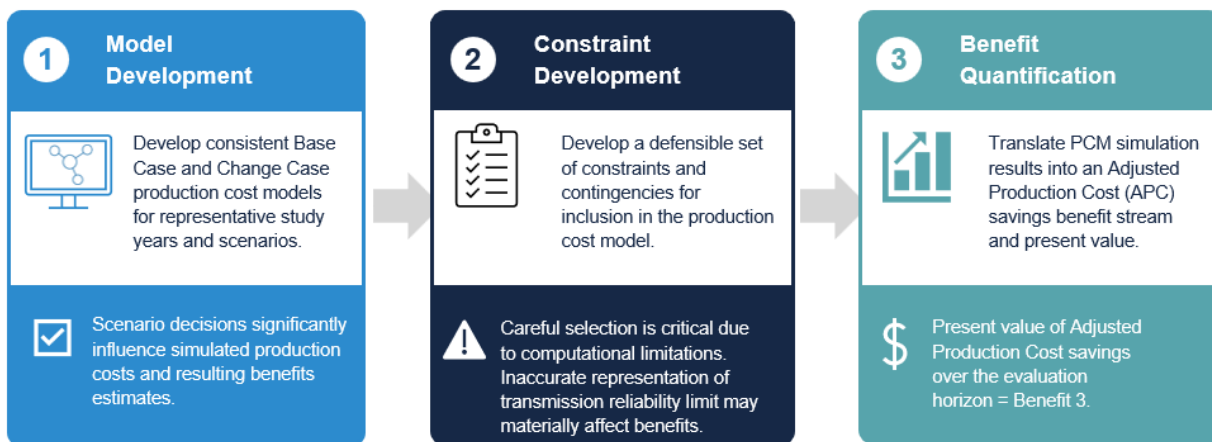
The general workflow for Benefit 3 calculation is illustrated in the figure below. The first step is model development. In addition to defining the Base Case and Change Case structure, key modeling considerations include the treatment of planned generation projects in the interconnection queue, siting of future resources identified through capacity expansion modeling, updates to transmission topology, selection of weather years, scenario design assumptions, hourly load and renewable generation profiles, and the level of detail used to represent neighboring systems. These decisions can significantly influence simulated production costs and resulting benefit estimates.

The second step involves developing a defensible set of constraints for inclusion in the production cost model. Constraints such as transmission line limits, interface limits, nomograms, and other operating constraints should be reviewed and updated as necessary. Because it is computationally

impractical to model an exhaustive list of constraints and contingencies, careful selection is required. When transmission projects are driven by voltage or stability concerns, it is also important not to overlook how limits identified through AC power flow or stability studies are translated into the DC-based production cost modeling framework, as inaccurate representation of these limits may materially affect the calculated benefits.

The final step is translating the PCM simulation results into a Benefit 3 value. The Adjusted Production Cost (APC) difference between the Base Case and Change Case is calculated for each modeled study year. For years that are not explicitly simulated, interpolation is used to estimate APC savings, creating a complete stream of annual benefits across the evaluation horizon. These annual benefit values are then discounted to NPV to produce the final Benefit 3 quantification.

Figure 14 Benefit 3 calculation framework



METHODOLOGY ADOPTED FOR THE CASE STUDY

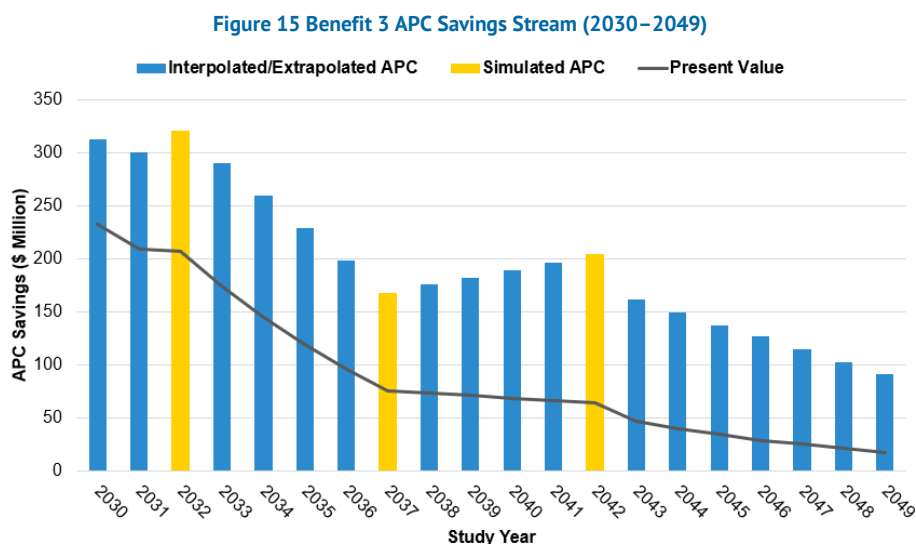
Contingency analysis was performed to include new monitored elements and contingencies that are directly affected by the LTRTP projects, ensuring the model properly reflects the electrical impact of the new facilities. The contingency analysis procedure begins with a completed production cost simulation. A set of representative hours is selected from this output using criteria like load levels, renewable output, and highest and lowest shadow price on a monthly basis. A list of potential contingencies is also formed using criteria such as kV level and area of scope. Then, the representative hours are screened to uncover any currently non-monitored element which would have a high probability of binding if it were to be monitored in a subsequent production cost simulation. This screening is performed again, but this time including potential N-1 contingencies. The result is a list of additional monitored elements and monitored facility–contingency pairs that will be included in the subsequent production cost simulations.

Using the updated monitored elements and contingencies, production cost simulations were performed for representative study years 2032, 2037, and 2042. Simulation results were interpolated across the planning horizon using the assumptions summarized in Table 1. To maintain consistency

with planning practices within the MISO footprint, the APC methodology used by MISO was adopted for this analysis. MISO's APC calculation methodology takes into account many different variables from the production cost simulation to estimate the total economic cost of serving load across the footprint. This includes production costs, variable O&M, start-up costs, and within pool and inter pool exports and imports.

BENEFIT 3 RESULTS AND DISCUSSIONS

With the mock LTRTP projects assumed to enter service in 2030, Benefit 3 was evaluated over the 20-year post-in-service period from 2030 through 2049, and APC savings for non-simulated years were estimated through interpolation between the representative study years and then discounted to present value in 2026 dollars. The analysis indicates a total Benefit 3 value of approximately **\$1,815 million** in 2026 dollars over the evaluation period. The annual benefit profile over the 20-year period is shown in the figure below.



Where Order No. 1920 Benefits 1 and 2 are calculated for the entire MISO territory, Benefit 3 is calculated for each LRZ individually. High APC savings were found in those zones which host the mock LTRTP projects: zones 3, 4, 8, 9, and 10 across all model years, as shown in Figure 16.

Figure 16 Production Cost Savings by Zone for the Simulated Years

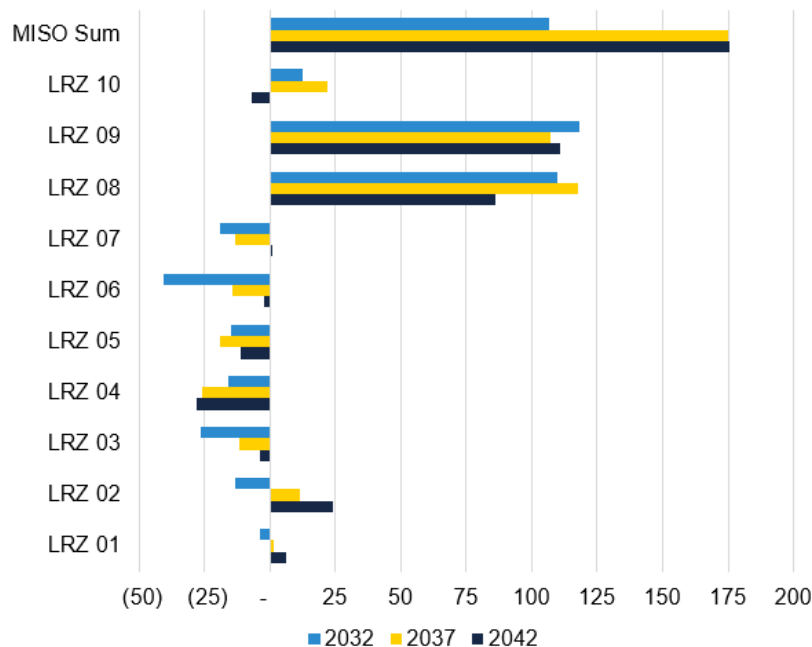
BENEFIT #3 PRODUCTION COST SAVINGS

LTRTP Project: Traditional

\$ 2026 Values (USD Millions)	Simulated 2032	Simulated 2037	Simulated 2042
MISO	320	167.5	203.7
LRZ 01	-21	3	5.3
LRZ 02	-26.3	0.4	10.4
LRZ 03	130.1	32.4	44.2
LRZ 04	47.2	20.7	8
LRZ 05	-20.7	-15.1	-9.2
LRZ 06	-32.9	-10.7	6.4
LRZ 07	-5.1	-8.9	6.5
LRZ 08	37.5	47.3	38.3
LRZ 09	183.7	75.7	78.6
LRZ 10	27.4	22.6	15.2

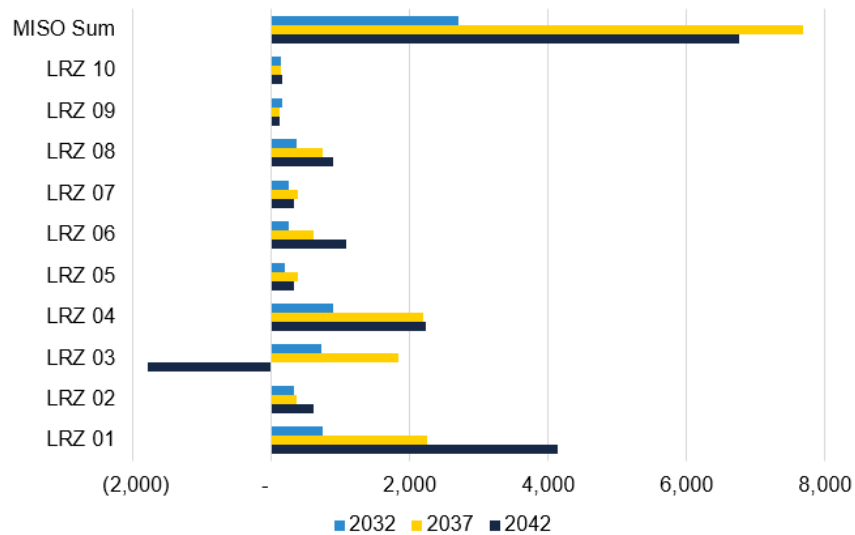
This APC benefit was due to many different aspects. LRZs 8 through 10 imported lower-cost energy from MISO North. This enabled less reliance on high-cost thermal generation in MISO South, lowering overall production costs. Figure 17 illustrates the thermal production cost for each zone, with MISO South showing large annual decreases for all model years.

Figure 17 Thermal Generator Sum - Production Cost Savings (\$ Millions)



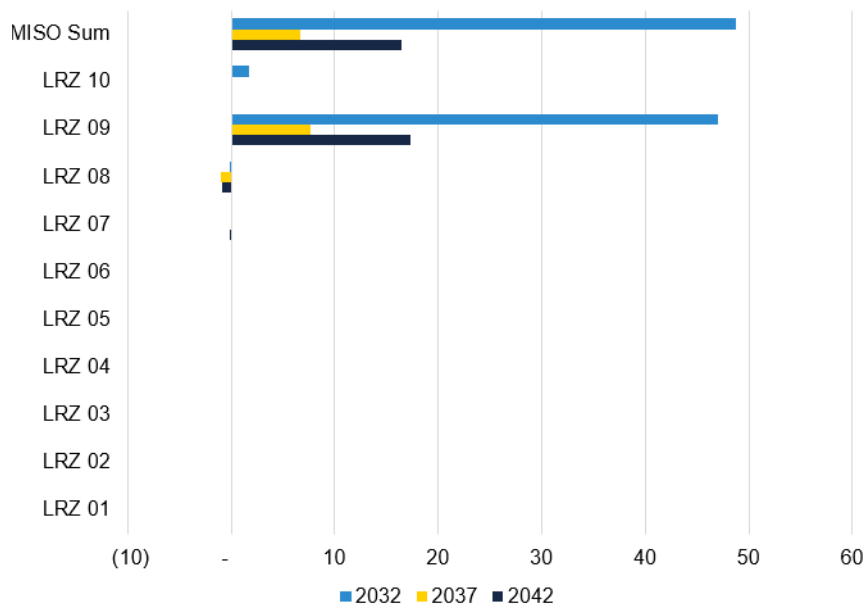
MISO South acted as a sink for low-cost renewable energy, leading to less solar and wind energy being curtailed in MISO North. LRZs 1 through 4 showed substantial, consistent drops in renewable curtailment for all model years, as shown in Figure 18.

Figure 18 Reduction in Wind + Solar Curtailment (GWh)



Finally, the mock LTRTP projects led to a significant decrease in Emergency Energy in MISO South. The increased transfer capability into the MISO South region driven by the new LTRTP projects allowed a much larger pool of resources to meet the high load levels present in the South. This significantly lowered the instances where nodal LMP rose above \$1000/MWh, leading to significant APC savings and real-world reliability benefits in the South. Figure 19 shows the emergency energy statistics for the models.

Figure 19 Emergency Energy Reduction (GWh)



The production cost savings associated with the DLR candidate solution exhibited a similar overall trend across MISO LRZs compared to the traditional reconductoring option. In particular, both solutions delivered significant congestion reduction benefits in MISO North, while higher congestion

costs remained concentrated on lower-voltage transmission facilities in MISO South. Although the time-varying nature of DLR ratings means that additional transmission capability is not continuously available, the DLR candidate solution still provides substantial economic value, with production cost savings estimated at **\$663.5 million** in 2026 dollars.

COMMON SOURCES OF BENEFIT 3 UNDER-EVALUATION

Benefit 3 may be understated when production cost simulations do not fully represent the system needs and phenomena that the LTRTP projects are designed to address. In particular, studies that omit or simplify critical operational constraints, such as key thermal limits, interface transfer limits, voltage constraints, and stability-driven constraints, may not fully capture the benefit enabled by the transmission projects. As a result, the estimated production cost savings and market benefits may be materially understated.

In addition, production cost studies often rely on a predefined static generation fleet and may not fully capture how transmission investments influence future resource siting, and development decisions, which can result in potential under-evaluation of further production cost savings. This is especially true if higher-cost, local generation which would likely be built to serve load absent a regional transmission buildout is omitted from the Base Case.

COMMON SOURCES OF BENEFIT 3 OVER-EVALUATION

Risk of over-evaluation exists if local transmission projects considered as avoided reliability investments under Benefit 1 are not reflected in the production cost modeling Base Case. This consideration is most relevant for reliability-driven projects that have not yet been planned or incorporated into the Base Case but would likely be needed to maintain a reliable system. In such cases, the Base Case may not represent a realistic transmission configuration, potentially resulting in higher modeled production costs and overstated APC savings. Therefore, this issue is best viewed as a Base Case design and counterfactual representation consideration. Consistent assumptions between reliability and economic studies are therefore important to ensure a clear separation of benefits.

In addition, if reductions in losses are included within the production cost savings calculation for Benefit 3 while also being quantified separately under Benefit 4, a portion of the losses benefit may be double counted. Clear coordination between Benefit 3 and Benefit 4 methodologies is necessary to ensure that transmission loss savings are attributed to only one benefit metric.

Although emergency energy costs are included in the APC calculation, simulations used to quantify Benefit 3 are intended to represent typical system conditions and therefore should result in little, if any, load shedding or emergency energy utilization. This reinforces that Benefit 3 is designed to capture the economic value of transmission under normal operating conditions, while the value associated with stressed or extreme operating conditions is more appropriately reflected in Benefits 5 and 6.

BENEFIT 4: REDUCED TRANSMISSION ENERGY LOSSES

BENEFIT OVERVIEW

Energy losses occur as electricity is transmitted from generation resources to load across the transmission network. These losses are driven by the physical characteristics of the system, including the resistive and reactive impedance of transmission lines, transformers, and other network equipment. Improved regional transmission planning can reduce energy losses by enabling power to flow over more efficient pathways, thereby lowering the equivalent electrical impedance between generation and load.

As illustrated in the figure below, Benefit 4 is evaluated within a modeling framework that is very similar to the production cost savings analysis used for Benefit 3. From a modeling perspective, the assessment still measures the amount of generation required to serve load under normal system operating conditions across all hours of the study year. The value of Benefit 4 is quantified by comparing system energy losses between the Base Case and the Change Case, with lower losses translating into reduced generation requirements and associated system costs.

Figure 20 Benefit 4 Modeling Framework

Measurement	Generation Production	Generation Capacity	Unserved Energy	Transmission Capacity
System Conditions	Typical	Stress		
System Availability	Transmission Outages	Generation Outages		
Sampling Fidelity	All hours in year	Peak demand hour(s)	Critical stress hours	
Monetization	Production Cost [\$]	CONE [\$/kW-yr]	VOLL [\$/MWh]	Tx Cost [\$/kV-mi]
				MC [\$/MWh]

Depending on the specific calculation methodology selected, the software requirements for evaluating Benefit 4 can vary. In general, two primary approaches are available, which are discussed in detail in the following subsection. The first is a PCM-based approach, in which annual simulations are performed, and the reduction in generation required to serve lower transmission losses is calculated directly. The second is a hybrid approach that requires PCM and AC power flow interaction, which explicitly models network flows and captures both real and reactive power losses using a more detailed representation of transmission system physics. From a software perspective, the tools used for Benefit 3 can generally also be used for Benefit 4 when applying the PCM-based approach. If an AC power flow analysis is required, software such as PSS®E, PowerGEM TARA, PSLF, or PowerWorld will be needed to accurately model system losses and assess the impact of transmission investments.

BENEFIT 4 CALCULATION METHODOLOGY

BENEFIT 4 CALCULATION FRAMEWORK

Overall, the calculation of Benefit 4 generally consists of two steps: (1) quantifying the reduction in transmission energy losses resulting from the LTRTP projects, and (2) monetizing those loss reductions. Key methodological decisions include whether losses are evaluated using hourly simulations or representative snapshots, whether only resistive losses or both resistive and reactive losses are considered, and whether losses are measured from a zonal level, or directly at a nodal or transmission element level.

One important consideration is that transmission losses are often embedded within the load forecast used in PCM studies. This simplification avoids the computational burden of calculating losses across every transmission element in every hour and committing and dispatching generation accordingly. However, Order No. 1920 requires transmission loss reductions to be evaluated as a distinct benefit metric. As a result, planners must account for the limitations of embedded loss assumptions and ensure that loss-related benefits are explicitly quantified to avoid double counting. This may require updating the assumed loss factors in the load forecast or adopting modeling approaches that more directly represent losses and their response to transmission investments.

There are two primary approaches to calculating Benefit 4. The primary approach is PCM-based, using hourly simulations to estimate the reduction in generation required to serve load as transmission losses decrease. This approach is used by several system operators, including MISO and ISO-NE, today to evaluate transmission projects.¹⁵ This approach typically captures only resistive losses and evaluates benefits from a generation perspective. The most rigorous implementation separates transmission losses from the load forecast and allows the PCM to calculate losses and associated redispatch endogenously. Most PCM platforms provide varying levels of loss modeling fidelity, allowing a tradeoff between computational efficiency and accuracy. The resulting loss reductions are then monetized using LMPs or marginal shadow prices, either at the zonal or nodal level.

The second approach builds upon the PCM-based methodology by incorporating AC power flow analysis. Under this hybrid framework, PCM dispatch results are passed to an AC power flow model to calculate detailed network losses using a full AC representation of the transmission system. The Southeast Regional Transmission Planning (SERTP) organization is an example of a system planner that proposes to use this method to evaluate LTRTP solutions.¹⁶ This enhancement captures both real and reactive losses while addressing the limited transmission flow visibility typically available from PCM outputs. As a result, it provides a more complete assessment of transmission loss reduction benefits by combining realistic hourly system conditions from the PCM with the detailed system physics of AC power flow analysis. While the hybrid approach offers the highest level of accuracy, it is also the most computationally intensive and may not be necessary for all studies. To reduce computational burden, a representative subset of PCM hours can be selected and evaluated in the

¹⁵ Brooks (2026) at 46

¹⁶ *Id.* at 47

AC power flow model, with the results extrapolated to annual values. This approach preserves the realistic dispatch produced by the PCM while providing a more accurate estimate of losses and a more defensible basis for monetizing the resulting benefits.

METHODOLOGY ADOPTED FOR THE CASE STUDY

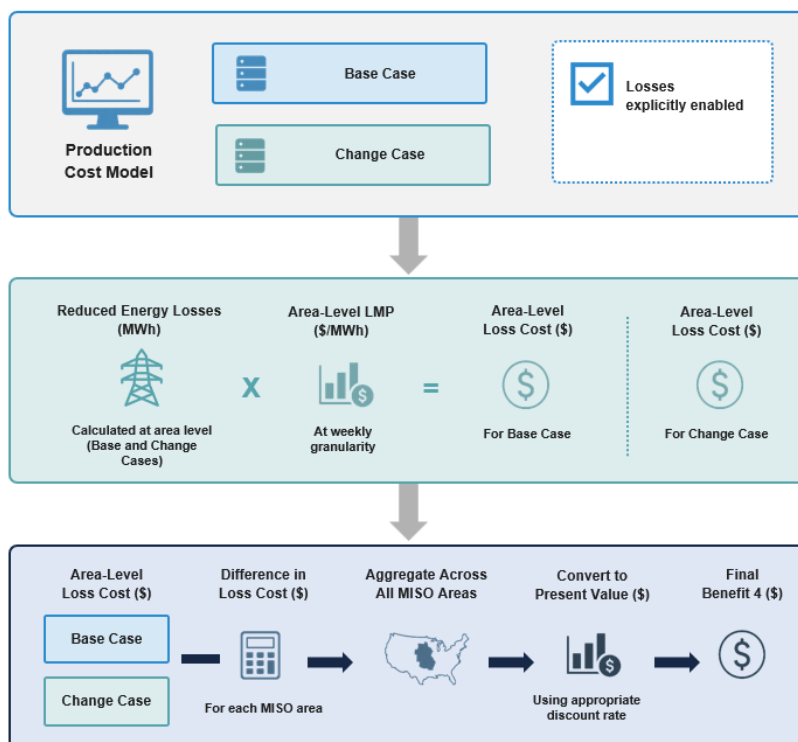
The key steps adopted for Benefit 4 are largely similar to those used for Benefit 3. The analysis consists of a series of PCM simulations using the same simulation years, hourly temporal granularity, and nodal resolution. While the impact of transmission losses embedded in the load forecast was considered during model development, no additional adjustments were made for this analysis. This decision was considered reasonable because the study was performed on a modified MISO system with significant load growth assumptions. As a result, the absolute level of transmission losses is inherently detached from real-world system conditions and provides limited additional insight. For Benefit 4, the primary objective is to quantify the incremental reduction in transmission losses between the Base Case and Change Case, making the relative difference between cases more relevant than the absolute loss values.

EPE calculated Benefit 3 (production cost savings excluding losses) and Benefit 4 (the value of reduced transmission losses) from a single, internally consistent set of simulations with losses enabled. This approach allows the total project value to be cleanly allocated between the two benefits, avoiding both double-counting of loss savings in Benefit 3 and the omission of loss-related benefits altogether.

EPE's calculation of Benefit 4 for the mock LTRTP projects followed these steps, illustrated in Figure 21:

1. **Simulate with losses enabled:** Base and Change Case production cost models were run with losses explicitly turned on rather than using a lossless model with a load-scaling proxy.
2. **Calculate total loss cost:** Total reduced energy losses were calculated at an area level in MWh for Base and Change Cases. These losses were then multiplied by their respective area-level LMPs at weekly granularity to obtain area-level loss cost.
3. **Monetize:** The difference in loss costs between the Base and Change Cases was calculated for each MISO area. The resulting loss-cost savings were then aggregated across all MISO areas and converted to net present value, producing the final Benefit 4 estimate.

Figure 21 Workflow of Benefit 4 Adopted Methodology

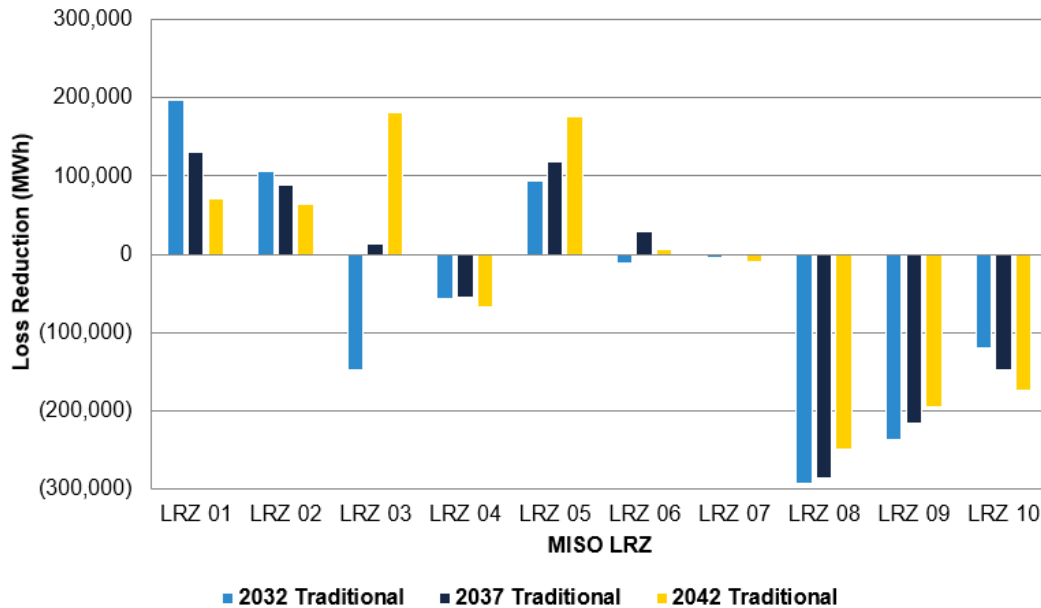


BENEFIT 4 RESULTS AND DISCUSSIONS

At first glance, the result for Benefit 4 may appear counterintuitive. At the MISO system level, total transmission losses increased under the Change Case, with annual average losses reaching 331,826 MWh when the mock LTRTP projects were in service. More specifically, as shown in Figure 22, the MISO zones located closest to the projects experienced an increase in losses, with the most notable impacts occurring in MISO South, while several other areas within the MISO footprint saw modest reductions in losses.

From a high-level perspective, the LTRTP projects increase the transfer capability between MISO North and MISO South, enabling greater delivery of energy to support the assumed 6 GW load increase in the MISO South region. As a result, power flows on portions of the MISO transmission network increase relative to the Base Case. Because transmission losses generally increase as power transfers increase, the higher utilization of these transmission networks leads to a modest increase in aggregate transmission losses within the MISO footprint.

Figure 22 LTRTP Project Loss Reduction Between Change and Base Case by MISO LRZ



When converting transmission losses into Benefit 4 monetization, hourly Company-level losses were multiplied by the corresponding Company-level LMPs within each LRZ and aggregated on a weekly basis. As a result, the benefit reflects both the magnitude of loss changes and the market value of those losses at the time they occur. The quantified benefit 4 for the mock LTRTP projects was **-\$7.7 million** in 2026 dollars. It is worth noting that loss energy in LRZ 9 was reduced during periods with relatively high LMPs, resulting in a positive economic benefit even though total loss energy within the MISO system increased, as shown in Figure 23. This outcome demonstrates that the mock LTRTP projects are functioning as intended.

Figure 23 Production Cost Savings w/o Losses by Zone for the Simulated Years

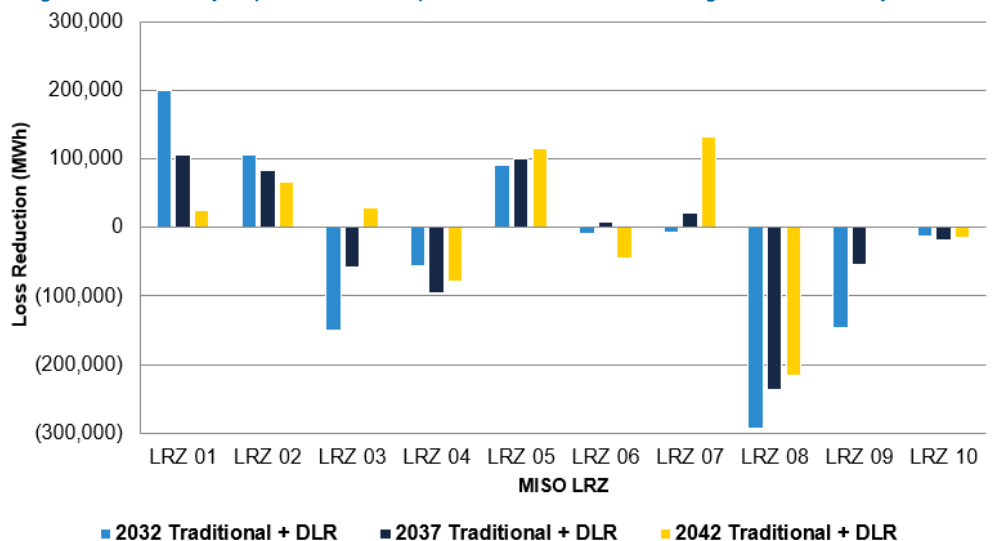
BENEFIT #4 PRODUCTION COST SAVINGS FROM REDUCED TRANSMISSION LOSSES
LTRTP Project: Traditional

\$2026 Values (USD Millions)	Simulated 2032			Simulated 2037			Simulated 2042		
	APC Savings w/o Loss	APC Savings w Loss	Delta APC Savings	APC Savings w/o Loss	APC Savings w Loss	Delta APC Savings	APC Savings w/o Loss	APC Savings w Loss	Delta APC Savings
MISO	320	320.9	0.9	167.5	161.9	-5.6	203.7	207.1	3.4
LRZ 01	-21	-21.1	-0.1	3	2.0	-1.0	5.3	5.4	0.1
LRZ 02	-26.3	-26.2	0.1	0.4	1.4	1.0	10.4	11.7	1.3
LRZ 03	130.1	122.4	-7.7	32.4	29.5	-2.9	44.2	44.0	-0.2
LRZ 04	47.2	42.6	-4.6	20.7	17.1	-3.6	8	4.7	-3.3
LRZ 05	-20.7	-20.8	-0.1	-15.1	-14.8	0.3	-9.2	-6.7	2.5
LRZ 06	-32.9	-35.2	-2.3	-10.7	-11.6	-0.9	6.4	6.1	-0.3
LRZ 07	-5.1	-6.5	-1.4	-8.9	-10.2	-1.3	6.5	5.9	-0.6
LRZ 08	37.5	36.6	-0.9	47.3	47.5	0.2	38.3	37.8	-0.5
LRZ 09	183.7	206.8	23.1	75.7	81.8	6.1	78.6	88.0	9.4
LRZ 10	27.4	22.2	-5.2	22.6	19.0	-3.6	15.2	10.1	-5.1

This conclusion is further supported when losses are evaluated across the entire Eastern Interconnection rather than within MISO alone. The Benefit 4 calculation is currently designed to capture impacts within the MISO footprint. However, when these results are compared with power flow analysis in the broader Eastern Interconnection, total system losses are observed to decrease significantly, ranging from 340 to 600 MW based on the snapshots at the interconnection level. Most of the loss reductions result from decreased power transfers from SPP, PJM, and the Southeast into MISO South. In other words, the assumed significant load increase in MISO South, combined with the addition of the mock LTRTP projects, changes power flow patterns across the Eastern Interconnection. The projects enable more increased delivery of energy from MISO North to MISO South, reducing the need for less efficient imports from neighboring regions and thereby lowering losses across the broader system. While the mock LTRTP projects increase overall power flows within portions of the MISO network, particularly near the project termination points, resulting in higher losses within MISO, the net effect on the Eastern Interconnection is a reduction in total losses. Consequently, the overall loss-reduction benefit is positive from an interconnection-wide perspective, even though the loss impact observed within MISO alone appears negative.

The quantified benefit 4 for the mock LTRTP projects with the DLR candidate solution was **-\$133.2 million** in 2026 dollars. The difference in losses was similar to the traditional transmission upgraded projects, with the same general trends manifesting for nearly all MISO load zones, shown in Figure 24.

Figure 24 LTRTP Project (Traditional + DLR) Loss Reduction Between Change and Base Case by MISO LRZ



COMMON SOURCES OF BENEFIT 4 UNDER-EVALUATION

Under-evaluation can stem from the choice of loss estimation methodology. Resistive loss estimation derived from the production cost model is computationally efficient, but it does not provide the same level of accuracy as detailed power flow analysis when estimating aggregate system losses. In addition, the adjusted load profile approach does not fully capture the uneven distribution of transmission losses across the network. This limitation is further compounded by the voltage-level scope of the analysis. By monitoring only high-voltage facilities, the study may not capture congestion and associated losses on lower-voltage facilities that could be relieved by new transmission investments.

Most importantly, these findings highlight the potential for benefits to be understated when the assessment scope is limited to a single planning region. As demonstrated by the loss analysis, a portion of the project value is realized through changes in power flows across neighboring systems and the broader Eastern Interconnection. Because these interregional impacts are generally not captured within traditional regional transmission planning benefit frameworks, the resulting benefits may be under-evaluated. This example underscores the importance of considering interregional effects when assessing the full value of major transmission investments, particularly those that facilitate large-scale power transfers across multiple regions.

COMMON SOURCES OF BENEFIT 4 OVER-EVALUATION

The primary risk is potential double counting with Benefit 3 (Production Cost Savings), as both benefits are derived from production cost simulations that reflect average system operating conditions. To avoid overlap, the Benefit 4 calculation should be limited to the incremental value associated with changes in transmission losses between the Base Case and Change Case, while all remaining economic differences should be attributed to production cost savings.

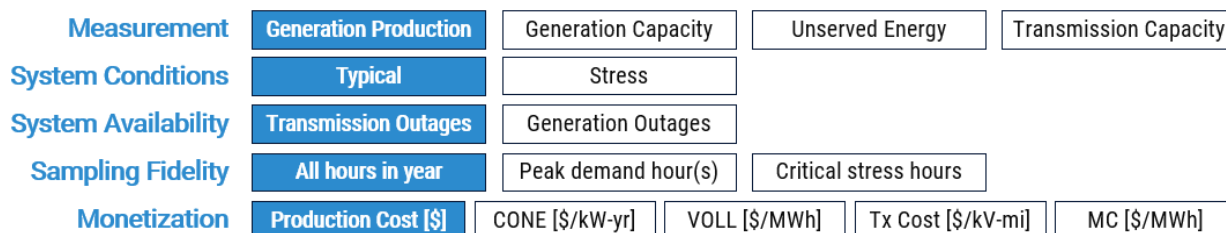
A related risk exists with Benefit 7 (Avoided Capacity from Reduced Losses). In this case, the same reduction in transmission losses during peak-demand periods could be monetized twice if the underlying impacts are not clearly separated. Care should therefore be taken to distinguish energy-related loss savings (Benefit 4) from capacity-related loss savings (Benefit 7) to ensure that each benefit metric captures a unique value stream and that the overall project benefits are not overstated.

BENEFIT 5: REDUCED CONGESTION DUE TO TRANSMISSION OUTAGES

BENEFIT OVERVIEW

Benefit 5 addresses reduced cost of generating electricity resulting from avoided congestion during planned and forced transmission outages. As illustrated in the figure below, while Benefit 3 captures production cost savings under normal system operating conditions, Benefit 5 evaluates the additional value provided by the transmission portfolio when existing transmission facilities are out of service and the system becomes more constrained. New additional transmission capacity can reduce the economic impacts of transmission outages by providing additional pathways for lower-cost generation to reach load and reducing the need to redispatch higher-cost generation.

Figure 25 Benefit 5 Modeling Framework



While the simulation tools and techniques are similar to those used for Benefit 3, the *Regional Practices* assessment finds that only MISO and SPP fully account for the benefits associated with increased access to lower-cost generation during contingency conditions currently.¹⁷ MISO evaluates N-1 contingencies and statistically represents approximately five years of historical operational outage data. SPP developed a normalized routine transmission outage methodology to capture the impacts of transmission outages in its production cost simulations. A key technical challenge is the selection of outage samples used in the analysis. Transmission outages generally fall into two categories: planned outages, which are scheduled in advance for maintenance activities, and unplanned outages, which are forced and occur unexpectedly. The selection of outage scenarios, as

¹⁷ *Id.* at 41

well as the methods used to simulate them, can vary significantly and will be discussed in the methodology section that follows.

BENEFIT 5 CALCULATION METHODOLOGY

BENEFIT 5 CALCULATION FRAMEWORK

Benefit 5 follows the same general production cost modeling framework as Benefit 3; however, the simulations incorporate transmission outage scenarios rather than the normal conditions evaluated in Benefit 3. Identical outage scenarios are applied to both the Base Case and Change Case, enabling the incremental benefits of the LTRTP projects to be quantified by comparing APC, emergency energy, and other system performance metrics under outage conditions.

The simulation approaches for planned and forced outages differ significantly. For planned maintenance outages, because they are scheduled in advance, generation commitment and dispatch decisions can be adjusted to account for the outage. In contrast, forced outages occur unexpectedly, meaning that system commitment and dispatch processes do not anticipate them. Therefore, it is important to first establish the original commitment schedule before simulating a forced outage, ensuring that the optimization does not unrealistically account for the outage ahead of time.

The selection of outage samples is another critical aspect of the analysis. Historical outage and operational data provide valuable insights for developing representative outage scenarios. One approach is to directly apply major outage events observed in historical records. Alternatively, outage samples can be generated probabilistically based on the statistical characteristics of historical outages, such as voltage level, geographic region, transmission asset type, and substation configuration.

METHODOLOGY ADOPTED FOR THE CASE STUDY

For this exercise, EPE focuses on the latter approach, generating forced outage samples using a statistical framework. The following describes the methodology and key steps used to develop these outage samples.

1. **Facility Screening:** EPE established a list of existing transmission facilities that were most relevant to the LTRTP projects rather than modeling outages interconnection-wide. Relevancy included being geographically “close” to the LTRTP projects as a first filter. EPE only included lines that were in the MISO, SPP, AECI, and western regions of PJM and TVA. This approach focused the outages on facilities that could reasonably alter the utilization or economic value of the projects, while also avoiding outages that would add no value to the simulation and hinder the simulation runtime.
2. **Outage Characterization:** For each facility type included in the screening set, EPE characterized the expected frequency and duration of outages based on transmission voltage level and season. Historical outage characteristics were used to establish the relative

probability that an outage would occur and the expected duration of the outage. Seasonal weighting was incorporated to reflect differences in transmission outage patterns and system conditions throughout the year. Approximately 70% of simulated forced outages were assigned to the higher-stress Summer and Winter seasons, with the remaining 30% occurring during Spring and Fall. Voltage level was also incorporated into the outage characterization. Higher-voltage facilities were assigned lower forced outage rates, consistent with their generally lower historical failure frequency, but longer expected outage durations when an outage occurred.

3. **Stochastic Outage Array Generation:** EPE used a Monte Carlo-based outage generator to translate the outage characteristics into transmission outage files that could be directly incorporated into the production cost simulations. For each model year, the outage generator produced three independent outage arrays, with each array containing around 500 unique transmission outage events across the target regions. The resulting arrays aimed to provide a representative sample of potential outage conditions rather than a single deterministic outage scenario. Using multiple independently generated arrays also reduced the potential for the calculated benefit to be disproportionately influenced by a small number of individual outage events. The resulting outage files were incorporated into PROMOD through the Power Dated Transmission Record (PDTR) table.
4. **Simulation:** EPE simulated the Base and Change cases for each of the outage sets, keeping the transmission projects the only difference between the two cases. This meant three outage sets with three model years and two cases required 18 total simulations, not including Benefit 3 simulations.
5. **Benefit Calculation:** For each outage array, EPE calculated the production cost savings associated with the transmission projects. The resulting APC savings were then averaged across the outage arrays to develop an expected production cost benefit under transmission outage conditions. Because this outage-based calculation includes the production cost savings that the projects would receive under normal system operating conditions, the Benefit 3 value was subtracted from the outage-inclusive APC benefit. This step isolates the incremental value attributable specifically to transmission outages and prevents double counting of normal-condition production cost savings in both Benefit 3 and Benefit 5.

BENEFIT 5 RESULTS AND DISCUSSIONS

Three separate transmission outage arrays were developed and completed for each modeled study year to achieve the benefit monetization for Benefit 5. Each outage array consisted of approximately 500 unique transmission outages applied to high-voltage facilities (345 kV and above) across the MISO, SPP, PJM, and AECI regions. The modeled outages represent a range of realistic outage durations, from approximately 8 hours to 5 days, to capture both short-duration transmission events

and more extended system impacts. The total number of outages evaluated was limited by production cost model simulation memory constraints. Larger outage sets including lower kV transmission and a higher number of higher kV transmission outages could be used in the future if computation constraints allow. Increasing these outage sets would undoubtedly cause more flow on non-outaged facilities, leading to a more congested and stressed model. This could cause overall model APC numbers to become much higher, which would add runway for additional APC savings for Benefit 5.

The Benefit 5 value for the LTRTP projects was found to be **-\$5.0 million** in 2026 dollars. Overall, as shown in Figure 26, the Benefit 5 analysis produced trends similar to those observed for Benefit 3, with the LTRTP projects providing comparable production cost savings under outage conditions. This indicates that the LTRTP projects continue to deliver value during stressed system conditions, but do not provide substantial incremental benefits beyond those observed under normal operating conditions. Average APC savings by LRZ for the three forced outage sets were calculated for each simulated year (2032, 2037, and 2042), also presented in Figure 26. Comparing these results to the corresponding Benefit 3 value showed limited incremental benefit attributable to the selected outage samples. Given the high estimated cost of the portfolio, the incremental benefit seen here for Benefit 5 can be considered negligible and has minimal impact on the overall combined benefits number.

Figure 26 Production Cost Savings w/wo Transmission Outage by Zone for the Simulated Years

BENEFIT #5 PRODUCTION COST SAVINGS FROM REDUCED CONGESTION DUE TO TRANSMISSION OUTAGES									
LTRTP Project: Traditional									
\$2026 Values (USD Millions)	Simulated 2032			Simulated 2037			Simulated 2042		
	APC Savings w/o Outage	APC Savings w Outage	Delta APC Savings	APC Savings w/o Outage	APC Savings w Outage	Delta APC Savings	APC Savings w/o Outage	APC Savings w Outage	Delta APC Savings
MISO	320.0	314.0	-6.0	167.5	169.0	1.5	203.7	205.1	1.4
LRZ 01	-21.0	-19.3	1.7	3.0	3.6	0.6	5.3	5.3	0.0
LRZ 02	-26.3	-26.6	-0.3	0.4	0.7	0.3	10.4	10.2	-0.2
LRZ 03	130.1	129.9	-0.2	32.4	32.8	0.4	44.2	44.0	-0.2
LRZ 04	47.2	47.7	0.5	20.7	20.0	-0.7	8.0	9.3	1.3
LRZ 05	-20.7	-19.1	1.6	-15.1	-14.6	0.5	-9.2	-8.3	0.9
LRZ 06	-32.9	-31.3	1.6	-10.7	-9.7	1.0	6.4	5.9	-0.5
LRZ 07	-5.1	-8.3	-3.2	-8.9	-9.0	-0.1	6.5	6.1	-0.4
LRZ 08	37.5	37.3	-0.2	47.3	46.6	-0.7	38.3	38.4	0.1
LRZ 09	183.7	176.5	-7.2	75.7	75.8	0.1	78.6	79.3	0.7
LRZ 10	27.4	27.3	-0.1	22.6	22.9	0.3	15.2	14.9	-0.3

However, this conclusion should be interpreted with caution. EPE recommends simulating at least five outage sample arrays to capture a broader range of transmission outage patterns and better

characterize the potential impacts of transmission outages. Evaluating a sufficient number of outage samples helps ensure that extreme or atypical outage conditions do not disproportionately influence the results.

Although the DLR ratings varied with system conditions, the modeled DLR capability provided comparable performance under the outage conditions that were tested. As shown in Table 6, the LTRTP projects with the DLR candidate solution yielded lower average APC savings considering outage conditions compared to the traditional LTRTP projects. However, the difference between APC savings calculated with and without outages demonstrates that DLRs provide additional value under outage conditions by increasing transmission capability when it is most needed. Based on this analysis, the Benefit 5 value for the LTRTP projects with the DLR candidate solution was estimated at **\$36.2 million** in 2026 dollars.

Table 6 MISO-Wide APC Savings from Transmission Outages for Various Candidate LTRTP Projects

MISO-Wide APC Savings from Reduced Congestion Due to Transmission Outages (\$ Millions)											
Candidate LTRTP Projects			Simulated 2032			Simulated 2037			Simulated 2042		
			APC Savings w/o Outage	APC Savings w Outage	Delta APC Savings	APC Savings w/o Outage	APC Savings w Outage	Delta APC Savings	APC Savings w/o Outage	APC Savings w Outage	Delta APC Savings
Traditional	320.0	314.0	-6.0	167.5	169.0	1.5	203.7	205.1	1.4		
Traditional + DLR	3.3	-7.4	-10.7	108.5	117.3	8.8	115.4	127.7	12.3		

COMMON SOURCES OF BENEFIT 5 UNDER-EVALUATION

Benefit 5 results may be understated when only a limited set of outage scenarios is considered. A set that does not capture the entire range of credible transmission events the system may experience at both high- and low-voltage levels would lead to some benefits not being captured. It is important to balance outage scenario detail with total computation time for each set of outages.

Additionally, inclusion of widespread or correlated outage events is likely to result in greater benefit to the system. Power system planners are increasingly considering ways to account for correlated

outages in their modeling.¹⁸ Relying only on a Monte-Carlo simulation to produce these outages without appropriate correlation assumptions could underestimate the ability of the transmission projects to improve system resilience during severe operating conditions.

COMMON SOURCES OF BENEFIT 5 OVER-EVALUATION

Benefit 5 may be overstated when the selected outage scenarios are overly severe or not operationally credible, resulting in modeled impacts that may not reasonably occur in actual system operations. An example would be a sequence of outages that produce an unrealistically large amount of emergency energy, leading to massive benefit numbers for LTRTP projects that incrementally lowers a fraction of it. Similarly, assuming unrealistically high outage frequencies or durations can inflate the calculated resilience benefits by overstating the likelihood and magnitude of avoided emergency conditions.

BENEFIT 6: MITIGATION OF EXTREME WEATHER EVENTS

BENEFIT OVERVIEW

Benefit 6 captures the reduced cost of generating electricity and loss of load during extreme weather events and unexpected system conditions, including the impacts of transmission outages, generation outages, and elevated resilience and reliability risks. While traditional transmission planning appropriately focuses on normal conditions to avoid overbuilding the system and imposing unnecessary costs on customers, extreme events can reveal significant reliability and resilience value that is not visible under typical system conditions. Benefit 6 therefore serves an important role in addressing this planning blind spot.

Because Benefit 6 focuses on stressed grid conditions, a significant portion of the quantified value is often driven by a relatively small number of critical hours during which the system is most constrained. Although simulations are typically performed across an entire study year, the differences between Base and Change Cases are often concentrated during these high-impact periods.

¹⁸ Dion, J. "Resource Accreditation Considering Correlated Outages," Energy Systems Integration Group (2022) available: <https://www.esig.energy/attachment/serve/session-5-resource-accreditation-considering-correlated-outages-joel-dion-2>;

Murphy, S. "Modeling correlated outages with NREL's PRAS," presentation to FERC Software Conference on *Improving grid planning by modeling correlated generator failures* (2022) available:

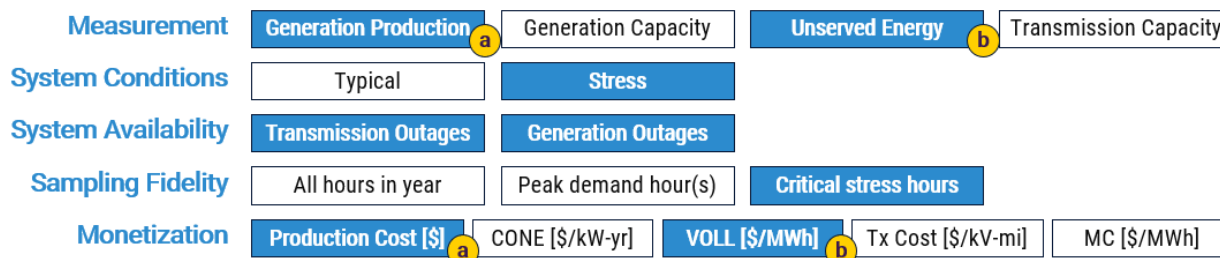
<https://www.ferc.gov/media/improving-grid-planning-modeling-correlated-generator-failures>;

Murphy, S. "Modeling correlated thermal generator outages," IEEE Resource Adequacy Working Group (2023) available: <https://cmte.ieee.org/pes-rawg/wp-content/uploads/sites/164/2023/08/5.-Murphy-IEEE-RAWG-072123-animated.pdf>;

Sainani, M. "Evolving Resource Adequacy Models: Correlated Outages," NYISO (2024) available: <https://www.nyiso.com/documents/20142/43834042/5%20Evolving%20Resource%20Adequacy%20Models%20Correlated%20Outages.pdf>;

Two primary approaches can be used to quantify Benefit 6: (1) comparing production costs, including the impacts of transmission losses, between the Base and Change Cases under stressed system conditions, and (2) comparing unserved energy or load-shedding outcomes between the Base and Change Cases.

Figure 27 Benefit 6 Modeling Framework



Although the simulation techniques and software required for Benefit 6 are not fundamentally different from those used for other benefits, it remains one of the least mature and least commonly evaluated Order No. 1920 benefits. Most regions do not currently perform formal Benefit 6 assessments, and the *Regional Practices* assessment found that only 23% of surveyed planners consider the related benefit of increasing access to lower-cost generation under stressed system conditions.¹⁹

An additional consideration is that production cost analyses assume markets continue to function normally during extreme weather events. Under severe Emergency Energy Alert (EEA) conditions, however, operators may take actions based on reliability and physical system constraints rather than market economics. In these circumstances, the value of regional transmission projects may be understated if measured solely through avoided production costs or extreme marginal costs, as their primary benefit may be reducing the likelihood, magnitude, or duration of load loss. As a result, reliability-based metrics such as avoided unserved energy or the Value of Lost Load (VOLL) may better capture the full value of transmission investments during extreme events.

BENEFIT 6 CALCULATION METHODOLOGY

BENEFIT 6 CALCULATION FRAMEWORK

Scenario selection is one of the most consequential and challenging design decisions for Benefit 6. Planners must establish a defensible definition of what constitutes an "extreme" event within the context of long-term regional transmission planning. Extreme weather events may include prolonged heat waves, cold snaps, or severe storms, and should be evaluated alongside other stressed system conditions such as fuel supply disruptions, unexpected load changes, and multiple or sustained generation and transmission outages.

¹⁹ Brooks (2026) at 16

A key challenge is ensuring that selected events remain relevant as the grid evolves over the 20-year planning horizon. This may require substantial pre-analysis to identify emerging system risks and understand how extreme events may change over time. For weather-driven scenarios, planners must determine whether temperature-based extremes alone are sufficient or whether broader system stress conditions should also be considered. Potential approaches include: (1) recreating specific historical events, (2) developing representative scenarios based on historical event analysis and statistical characterization, and (3) creating forward-looking scenarios informed by climate projections and evolving system conditions. Scenario selection should therefore balance historical experience with future-looking assessments of grid risk, while avoiding a bias toward events that either overly favor or disadvantage specific LTRTP facilities, projects, and portfolios.

The linkage between weather-related extreme events and power system modeling is another critical consideration for Benefit 6. In an ideal case, historical extreme-event datasets would include both detailed power system information, such as load impacts, generation outages, transmission outages, fuel supply disruptions, and operational actions, as well as corresponding weather observations for the same locations and time periods. Geospatially referenced datasets are particularly valuable, as they allow weather conditions to be directly linked to specific assets and system components, enabling more accurate modeling of outage correlations, equipment performance, and system-wide impacts during extreme events. Stronger integration of weather and power system data can improve both the realism and defensibility of extreme-event assessments.

Two primary approaches can be used to quantify Benefit 6: (1) comparing production costs, including the impacts of transmission losses, between the Base and Change Cases under stressed system conditions, and (2) comparing unserved energy or load-shedding outcomes between the Base and Change Cases. The first approach mainly relies on production cost modeling. Extreme-event scenarios can be represented through adjustments to load profiles, renewable generation output, forced outage assumptions for generation and transmission facilities, fuel availability constraints, and other parameters. Additional PCM simulations can then be performed to estimate the change in production costs between extreme conditions and normal conditions.

The second approach focuses on reliability impacts and can be implemented using either PCM or, more ideally, a resource adequacy framework. Within PCM, benefits can be measured through reductions in load shedding or emergency energy usage during stressed conditions. Resource adequacy models provide a more probabilistic assessment by quantifying changes in reliability metrics such as LOLE, EUE, or other adequacy indicators. These metrics can then be monetized to estimate the reliability and resilience value provided by transmission investments during extreme events.

METHODOLOGY ADOPTED FOR THE CASE STUDY

EPE's calculation of Benefit 6 for the mock LTRTP projects followed these steps:

1. **Event-specific Base and Change Case modeling:** Production cost modeling was performed on the Base Case and Change Case with the inclusion of extreme weather inputs, run for study years 5, 10, and 15, with each study year limited to a 1-week to 1-month window representative of realistic events in MISO South.
2. **Incremental benefit extraction:** The results from the weather-event simulations were compared with those from Benefit 3 over the same timeframe to determine the incremental APC benefit – i.e., the portion of benefit attributable specifically to the extreme event, above and beyond normal-condition production cost savings.
3. **Present value conversion:** APC benefits from the modeled years were converted to present value and averaged to create a single value for each weather event type.
4. **Unserved energy proxy:** Notably, the APC calculation from the PROMOD simulation results takes Emergency Energy into account, which can be used as a placeholder for Unserved energy, allowing EPE to capture a proxy for the loss-of-load component of the benefit within the same production cost run rather than requiring a fully separate reliability model.

Weather events selected: EPE selected a hurricane and a summer heat wave for evaluation based on their relevance to the MISO South region and their historical prevalence as high-impact weather events. The hurricane scenario spanned one week in September for each of the three study years. Generator outages were modeled from several hours before landfall through up to four days after landfall based on historical outage patterns. Similarly, selected transmission facilities were placed on outage for periods ranging from several hours to four days following landfall. These assumptions were intended to reflect operational experience from previous hurricane events, during which geographically exposed generation and transmission facilities, particularly those located near coastal areas or major river corridors, experienced elevated outage rates. Load levels declined significantly following landfall, reaching approximately 50% of pre-hurricane levels before gradually recovering over the subsequent days.

The heat wave scenario was modeled over most of August in each of the three study years. Relative to the Base and Change Cases used in the previous benefit assessments, hourly load levels were increased by approximately 20-35% during daytime periods and 10-20% during overnight periods. In addition, transmission ratings on monitored facilities within the affected area were reduced by 10-20% during daytime hours, and the DLR ratings were also adjusted accordingly. These adjustments were intended to represent the system impacts commonly observed during prolonged heat waves, including increased electricity demand driven by cooling requirements and reduced transmission capability resulting from higher ambient temperatures and lower conductor cooling.

Each weather scenario was represented by a single set of assumptions and outage conditions. As a result, the Benefit 6 findings should be interpreted as illustrative of the specific hurricane and heat wave events modeled rather than as definitive estimates of extreme-weather impacts. Evaluating additional hurricane and heat wave scenarios, including alternative outage patterns, storm tracks,

and weather severities, would provide a more robust assessment of LTRTP project performance and help ensure that the results are not unduly influenced by any single scenario.

BENEFIT 6 RESULTS AND DISCUSSIONS

Hurricane

Based on the simulation results shown in Figure 28, the mock LTRTP projects produced positive production cost savings under both normal operating conditions and the modeled hurricane event. However, when comparing APC savings under normal conditions with those observed during the hurricane event to isolate the project's incremental value under extreme conditions, Benefit 6 was estimated at **-\$0.5 million** in 2026 dollars, based on the average results across the three simulated weeks.

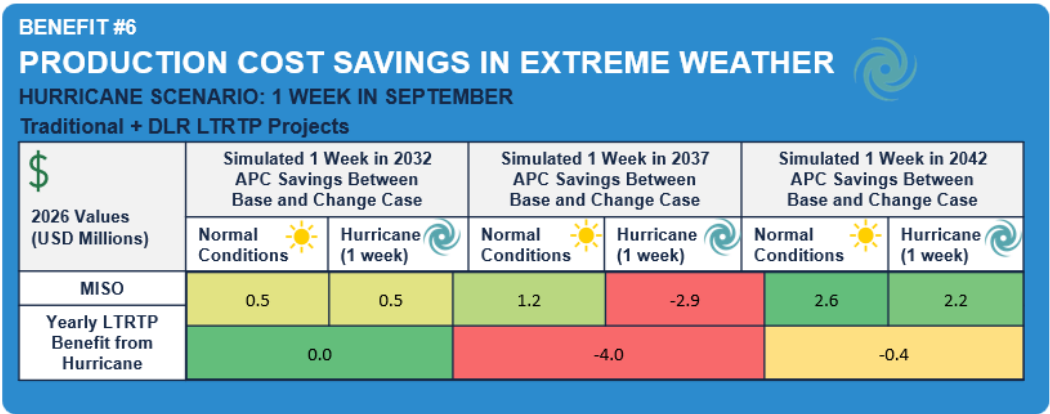
Although the underlying Base Case experienced substantial APC increases during the hurricane event, the mock transmission projects did not provide material additional relief in the areas affected by hurricane-related congestion. Project facility utilization was also slightly lower during the event, limiting the ability of the new transmission facilities to influence dispatch outcomes. Consequently, APC savings during the hurricane event were generally consistent with those observed under normal operating conditions, indicating that the LTRTP projects' value was largely captured through its normal-condition production cost benefits rather than through a distinct hurricane extreme weather benefit.

Figure 28 Production Cost Savings under Hurricane Scenario for the Traditional LTRTP Projects

BENEFIT #6 PRODUCTION COST SAVINGS IN EXTREME WEATHER 						
HURRICANE SCENARIO: 1 WEEK IN SEPTEMBER						
Traditional LTRTP Projects						
\$ 2026 Values (USD Millions)	Simulated 1 Week in 2032 APC Savings Between Base and Change Case		Simulated 1 Week in 2037 APC Savings Between Base and Change Case		Simulated 1 Week in 2042 APC Savings Between Base and Change Case	
	Normal Conditions 	Hurricane (1 week) 	Normal Conditions 	Hurricane (1 week) 	Normal Conditions 	Hurricane (1 week) 
MISO	1.2	0.8	1.1	1.2	3.4	2.4
Yearly LTRTP Benefit from Hurricane	-0.4		0.1		-1.0	
LRZ 01	-0.3	-0.4	0.1	0.1	0.2	0.0
LRZ 02	-0.4	-0.4	1.2	1.1	1.4	1.4
LRZ 03	0.5	0.6	0.8	0.8	1.7	1.3
LRZ 04	0.8	0.5	-0.4	-0.5	-0.5	-0.6
LRZ 05	-0.4	-0.4	-1.1	-1.2	-0.9	-0.9
LRZ 06	-0.4	-0.5	-0.7	-0.6	-0.3	-0.4
LRZ 07	-0.2	-0.2	0.0	0.0	0.4	0.5
LRZ 08	0.2	0.2	-0.1	0.6	-0.2	0.4
LRZ 09	1.1	1.3	0.9	0.4	1.2	0.3
LRZ 10	0.4	0.1	0.4	0.4	0.3	0.4

A similar trend was observed for the LTRTP projects that included the DLR candidate solution, as shown in Figure 29. Benefit 6 was estimated at **-\$1.5 million** in 2026 dollars, based on the average results across the three simulated weeks. The limited change in benefits between the normal conditions and hurricane scenario indicates that the LTRTP projects with the DLR candidate solution provided little incremental value under the modeled hurricane conditions.

Figure 29 Production Cost Savings under Hurricane Scenario for the Traditional + DLR LTRTP Projects



Heat Wave

During the heat wave event, higher load levels and reduced effective transmission ratings, which were intended to reflect increased line sag under elevated temperatures, resulted in substantially higher APC in the affected LRZs and MISO system as a whole. These conditions increased congestion and dispatch costs relative to normal operating conditions, creating a more stressed system environment and increasing the value of additional transmission capability.

Under these conditions, the LTRTP projects captured significantly greater benefits, with Benefit 6 estimated at **\$118.1 million** in 2026 dollars. The added transfer capability helped alleviate transmission constraints that became more binding during the heat wave, enabling more economical dispatch and reducing congestion costs. As shown in Figure 30, the resulting APC savings exceeded those observed under normal operating conditions, demonstrating that the mock LTRTP projects provided meaningful resilience benefits during the modeled heat wave event.

Figure 30 Production Cost Savings under Heat Wave Scenario for the Traditional LTRTP Projects

BENEFIT #6 PRODUCTION COST SAVINGS IN EXTREME WEATHER 						
HEAT WAVE SCENARIO: AUGUST Traditional LTRTP Projects						
 2026 Values (USD Millions)	Simulated 1 Month in 2032 APC Savings Between Base and Change Case		Simulated 1 Month in 2037 APC Savings Between Base and Change Case		Simulated 1 Month in 2042 APC Savings Between Base and Change Case	
	Normal Conditions 	Heat Wave (August) 	Normal Conditions 	Heat Wave (August) 	Normal Conditions 	Heat Wave (August) 
MISO	77.7	187.3	21.3	131.7	18.5	152.9
Yearly LTRTP Benefit from Heat Wave	109.6		110.5		134.3	
LRZ 01	0.3	6.2	0.8	6.6	0.2	13.7
LRZ 02	0.0	5.6	0.6	2.2	1.5	4.5
LRZ 03	9.2	18.1	3.0	7.3	4.8	13.8
LRZ 04	3.9	7.9	2.1	4.0	0.4	2.8
LRZ 05	0.2	5.6	-2.2	-1.7	-0.7	0.8
LRZ 06	4.3	28.8	-0.9	3.1	0.3	7.4
LRZ 07	2.9	13.9	-0.5	5.2	1.1	6.5
LRZ 08	3.3	2.1	2.8	5.5	2.7	5.0
LRZ 09	47.6	48.8	13.3	87.1	7.0	85.9
LRZ 10	6.0	50.3	2.3	12.4	1.3	12.5
LRZ 10	0.0	0.0	0.0	0.0	0.0	0.0

The LTRTP projects considering DLR candidate solution also produced higher benefits during the heat wave relative to normal operating conditions, with Benefit 6 estimated at **\$15.2 million** in 2026 dollars, based on the average results across the three simulated weeks shown in Figure 31. This increase was driven primarily by greater utilization of the DLR facility during nighttime hours, when load levels in MISO South were approximately 10% higher than those observed under normal conditions. During daytime hours, the DLR facility was generally already operating at or near its thermal limit under normal conditions, limiting the opportunity for additional benefits during the heat wave. As a result, the incremental value of the DLR candidate solution was realized primarily during nighttime periods, when the combination of elevated load and increased transmission capability enabled more efficient system dispatch and additional congestion relief.

Figure 31 Production Cost Savings under Heat Wave Scenario for the Traditional + DLR LTRTP Projects

BENEFIT #6
PRODUCTION COST SAVINGS IN EXTREME WEATHER 
HEAT WAVE SCENARIO: AUGUST
Traditional + DLR LTRTP Projects

 2026 Values (USD Millions)	Simulated 1 Month in 2032 APC Savings Between Base and Change Case		Simulated 1 Month in 2037 APC Savings Between Base and Change Case		Simulated 1 Month in 2042 APC Savings Between Base and Change Case	
	Normal Conditions 	Heat Wave (August) 	Normal Conditions 	Heat Wave (August) 	Normal Conditions 	Heat Wave (August) 
MISO	2.0	10.1	8.0	23.6	8.7	30.7
Yearly LTRTP Benefit from Heat Wave	8.1		15.6		21.9	

COMMON SOURCES OF BENEFIT 6 UNDER-EVALUATION

Benefit 6 is particularly susceptible to under-evaluation because only a limited number of extreme-event scenarios can typically be studied. If the selected events do not fully represent the range, frequency, or severity of future system stresses, important reliability and resilience benefits may be missed. In addition, simplified representations of weather impacts, outage correlations, and fuel supply disruptions may not fully capture the value of transmission in mitigating extreme-event risks. As a result, the quantified benefit may represent only a subset of the reliability and resilience value provided by a transmission investment.

COMMON SOURCES OF BENEFIT 6 OVER-EVALUATION

Benefit 6 may be over-evaluated if extreme-event scenarios are selected that are overly severe, unrealistic, or disproportionately favor a particular transmission investment. Because a significant portion of the benefit is often driven by a relatively small number of critical system conditions, results can be highly sensitive to event selection, scenario assumptions, and monetization parameters such as VOLL. Careful scenario development, probability weighting where appropriate, and transparent documentation of assumptions are therefore important to ensure benefit estimates remain credible and representative of actual system risks.

BENEFIT 7: CAPACITY BENEFIT FROM REDUCED PEAK ENERGY LOSSES

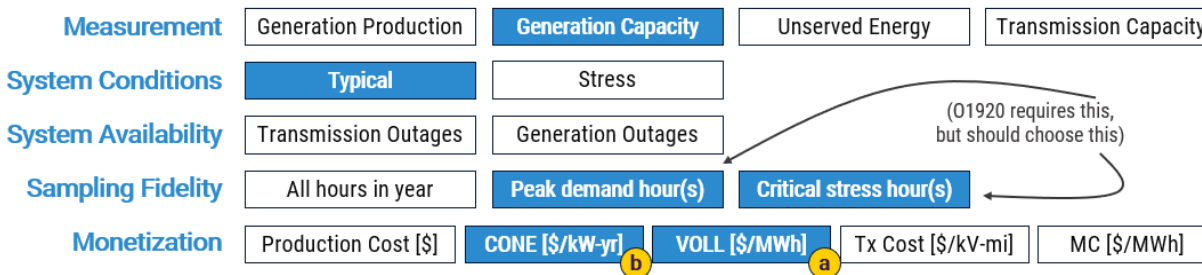
BENEFIT OVERVIEW

Benefit 7 addresses the reduced generation capacity investments required as a result of lower transmission losses during peak demand conditions. As transmission facilities become more heavily loaded during peak periods, electrical losses increase approximately with the square of current (I^2R).

Consequently, reducing transmission losses during these periods can lower the amount of generation capacity needed to reliably serve peak demand. Benefit 7 is closely related to Benefits 2 and 4, both in concept and in calculation methodology. Benefit 2 quantifies the reduction in generation capacity needs attributable to the LTRTP facilities, projects, and portfolios, excluding the impact of transmission losses. Benefit 7 isolates and quantifies the incremental capacity savings associated specifically with the reduction in transmission losses during peak demand conditions. While Benefit 4 evaluates the energy value of reduced transmission losses across all hours of the year, Benefit 7 focuses specifically on the capacity value of those loss reductions during peak conditions. The benefit represents the avoided generation capacity that would otherwise be required to serve transmission losses at times when the system is most stressed.

Order No. 1920 does not prescribe a specific definition of "peak demand," leaving methodological flexibility in how the metric is evaluated. Peak demand may be defined as the single highest load hour of the year, an average of daily, weekly, or monthly peak hours, or another representative set of high-load conditions. Alternatively, it is also possible to choose to focus on critical stress conditions, such as hours associated with elevated LOLE, where reductions in transmission losses can directly reduce resource adequacy requirements. By evaluating generation capacity savings at the hour of greatest resource adequacy requirements (which may or may not correlate with peak load), the capacity savings available during peak load hour would inherently be captured.

Figure 32 Benefit 7 Modeling Framework



The software requirements for evaluating Benefit 7 generally follow those established for Benefits 2 and 4, as Benefit 7 combines transmission loss analysis with capacity valuation. The specific software needs depend on the methodology selected.

BENEFIT 7 CALCULATION METHODOLOGY

BENEFIT 7 CALCULATION FRAMEWORK

Benefit 7 builds directly upon the frameworks established for Benefit 2 (Avoided Capacity Investments) and Benefit 4 (Reduced Transmission Energy Losses). In essence, Benefit 4 provides the estimate of transmission loss reductions during peak demand conditions, while Benefit 2 provides the framework for translating those loss reductions into avoided generation capacity investments.

A key first step is defining the peak conditions under which transmission loss reductions will be evaluated and estimating transmission loss reductions during those periods. This estimation leverages the same approaches described under Benefit 4, namely:

- A PCM-based approach using production cost simulation outputs, or
- An hourly AC power flow approach using dispatch results from the production cost model.

Because Benefit 7 focuses only on a limited set of peak or reliability-critical hours, performing AC power flow analysis for those selected hours rather than the full 8760 hours generally results in little loss of fidelity compared to the broader analysis performed for Benefit 4. A key distinction between Benefits 4 and 7 is that transmission loss reductions are typically estimated using production cost simulations or power flow analyses that represent expected system operations, whereas resource adequacy studies focus on weather and conditions that drive reliability risk, especially capturing the tail-ends. Consequently, the loss reductions calculated for Benefit 4 may not be fully representative of the periods that determine resource adequacy needs.

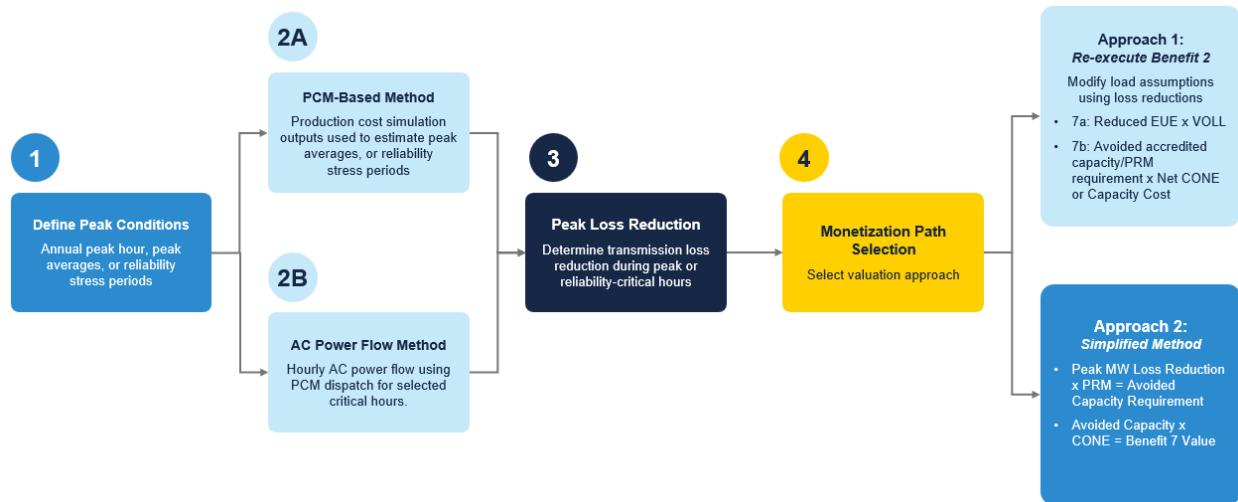
After the reduction in peak-period transmission losses has been quantified, there are two general approaches for monetizing the benefit. In the first approach, the estimated loss reductions are incorporated into Benefit 2 for re-execution as modified load assumptions, and monetized through either of the same pathways used for Benefits 2a and 2b:

- Benefit 7a (Reliability Value Approach): Monetizes the reduction in EUE associated with lower transmission losses by applying a VOLL.
- Benefit 7b (Capacity Value Approach): Monetizes the reduction in required accredited capacity or PRM resources using either a capacity expansion model or an avoided capacity cost metric such as Net CONE.

The tradeoffs are similar to those discussed for Benefit 2. The EUE-based approach can capture reliability benefits directly but depends on the selection of VOLL and may understate benefits in highly reliable systems where unserved energy is infrequent. The capacity-based approach more directly reflects avoided generation investment requirements, but it either requires additional capacity expansion modeling or relies on well-supported assumptions regarding capacity costs.

A second and simplified approach avoids additional Benefit 2 re-execution. Under this approach, the reduction in peak transmission losses attributable to the transmission projects is converted directly into avoided capacity requirements. Specifically, the reduction in peak MW losses is converted into the corresponding reduction in required generation capacity, either directly or by applying the applicable PRM to estimate the avoided installed capacity requirement. The resulting avoided capacity quantity is then monetized using the CONE or another avoided capacity cost metric. Since this approach doesn't capture the full tail risk that a full resource adequacy analysis might, there is potential that it might under-value this benefit.

Figure 33 Benefit 7 Methodology



METHODOLOGY ADOPTED FOR THE CASE STUDY

EPE employed the simplified approach to calculate Benefit 7 for the mock LTRTP projects. Specifically, the analysis utilized the transmission loss reductions estimated through the PCM-based methodology developed for Benefit 4 and then monetized those reductions using the avoided capacity cost established under Benefit 2. This approach was selected to demonstrate the alternative valuation methodology while avoiding the additional modeling effort associated with re-running the Benefit 2 analysis. The process consists of the following steps:

1. **Establish the Incremental Relationship to Benefit 2:** EPE treated Benefit 7 as incremental to Benefit 2. Benefit 2 quantifies the reduction in generation capacity requirements attributable to the proposed LTRTP projects, excluding the impact of transmission losses. Benefit 7 isolates and quantifies the additional capacity savings associated specifically with changes in transmission losses during peak-demand conditions.
2. **Determine Peak-Hour Loss Reductions:** EPE derived the average reduction in transmission losses, measured in MW, during selected peak-demand hours using the production cost modeling performed for Benefit 4 through loss calculation in PCM. Loss reductions were calculated as the difference between Base Case losses and Change Case losses. While Benefit 4 evaluates transmission losses across the full study year, Benefit 7 focuses on the subset of hours most relevant to generation capacity requirements and system reliability.
3. **Monetize the Capacity Impact of Loss Reductions:** Using the avoided capacity cost established under Benefit 2 and the average peak-hour loss reduction calculated in Step 2, EPE quantified the incremental capacity benefit associated with reduced transmission losses during peak-demand conditions. Under this simplified approach, the reduction in transmission losses during peak-demand conditions, as determined from the Benefit 4 simulation results, was treated as the corresponding reduction in generation capacity

requirements and monetized using the avoided capacity cost metric established under Benefit 2.

Similar to the methodology applied for the traditional transmission upgrade scenario, the average reduction in transmission losses during peak hours for the two ATT candidate solutions was converted into an avoided capacity requirement and valued using the capacity cost established through the Benefit 2 analysis.

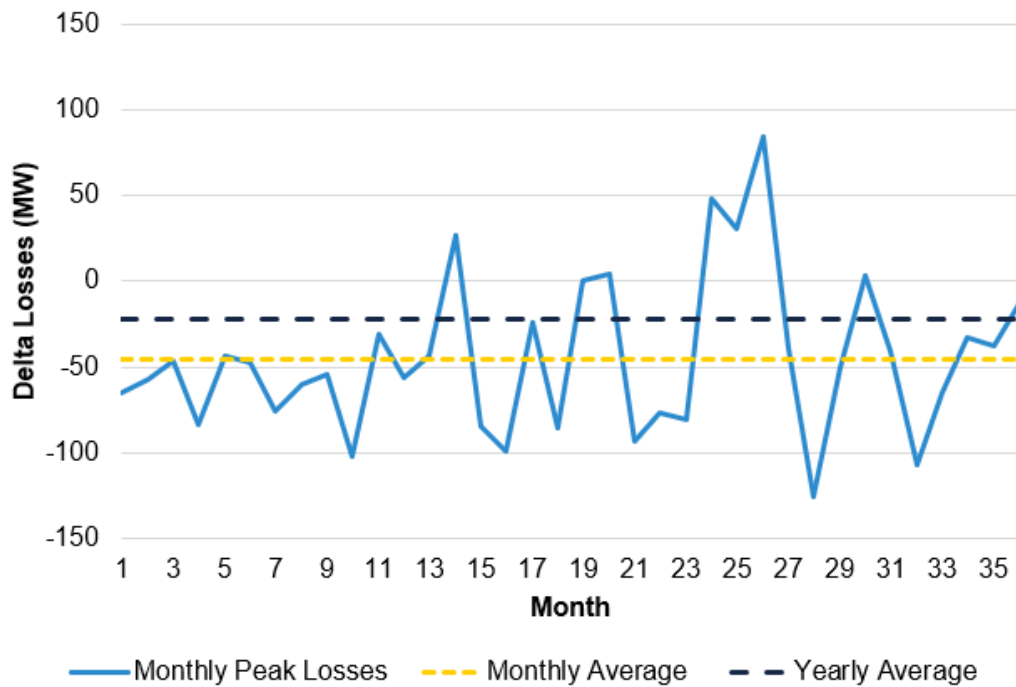
BENEFIT 7 RESULTS AND DISCUSSIONS

For this analysis, EPE examined the change in transmission losses observed during both the annual system peak and monthly peak-demand hours from the Benefit 4 simulation results to help establish an appropriate definition of peak conditions. Delta losses were calculated as the difference between Base Case losses and Change Case losses, measured in MW across the modified MISO system.

As discussed in Benefit 4, a key finding was that the mock LTRTP projects altered power transfer patterns within the MISO footprint. Specifically, the project reduced imports into MISO South from neighboring systems while increasing north-to-south transfers within MISO. Although these changes improved the efficiency of power flows across the broader interconnection, they resulted in a modest increase in losses when evaluated solely within the MISO footprint. Consequently, the Change Case produced slightly higher transmission losses during peak-demand periods, resulting in negative delta-loss values.

The results presented in the figure below indicate that the average monthly peak-hour delta loss was approximately -45 MW, while the delta loss during the annual system peak hour was approximately -22.5 MW. Using the average delta loss observed during the annual system peak hour, the transmission projects are estimated to increase peak-period capacity requirements by approximately 22.5 MW. This incremental capacity requirement was monetized using the avoided capacity cost developed under the Benefit 2b methodology, resulting in an estimated Benefit 7 value of **-\$8.0 million** in 2026 dollars over the study horizon. The valuation is based on an avoided capacity cost of \$166/kW-year in 2026 dollars, consistent with the outcome in Benefit 2b. The negative value indicates that the project increases transmission losses during peak-demand periods within the MISO study footprint, thereby increasing generation capacity requirements and reducing the net capacity benefits of the LTRTP projects by approximately \$8 million.

Figure 34 Monthly and Yearly Losses During Peak Load Conditions



These results indicate that, from a MISO-only perspective, the mock LTRTP project increased peak-period transmission losses and therefore resulted in a negative Benefit 7 value. However, this outcome reflects the study boundary selected for the analysis and does not capture the reduction in losses realized across the broader interconnection.

As discussed under Benefit 4, transmission losses increased in the DLR candidate solutions relative to the Base Case. However, focusing on just the peak periods, the mock LTRTP projects with the DLR candidate solution slightly decreased the average change in peak-period losses by 34.8 MW, resulting in a present value benefit of **\$12.3 million** in 2026 dollars. While the DLR scenario performs slightly better than the traditional reconductor upgrade candidate solutions from a loss during peak-load condition perspective, the observed difference is modest regarding the performance of the two solution approaches.

COMMON SOURCES OF BENEFIT 7 UNDER-EVALUATION

In addition to the potential sources of undervaluation inherent in Benefits 2 and 4, this assessment highlights several considerations that are particularly relevant to Benefit 7.

First, the analysis demonstrates the importance of evaluating transmission losses over an appropriately defined geographic footprint. As illustrated by the mock LTRTP projects, assessing losses solely within a single balancing authority or transmission region may significantly understate the overall benefits of a project. Transmission investments can alter power transfer patterns across regional boundaries, resulting in loss reductions at the interconnection level even when losses

appear to increase within the study region. Consequently, limiting the analysis to a single region may materially understate both the loss reductions and associated capacity benefits.

Second, the definition of peak-demand conditions can materially influence the magnitude of Benefit 7. Different approaches, such as using the annual peak hour, monthly peak hours, or reliability stress periods, may produce different estimates of peak-period loss reductions and therefore different estimates of avoided capacity requirements.

Finally, transmission losses are typically estimated based on production cost simulations or power flow analyses that represent expected system operating conditions. In contrast, resource adequacy assessments are designed to evaluate system performance under a wide range of weather conditions, generator outage patterns, and other reliability risks, particularly during the tail-end events that drive resource adequacy requirements. As a result, the loss reductions estimated for Benefit 7 may not fully capture transmission system behavior during the most critical reliability periods. This disconnect has the potential to understate the contribution of transmission loss reductions to resource adequacy and, consequently, the monetized value of Benefit 7.

COMMON SOURCES OF BENEFIT 7 OVER-EVALUATION

A risk arises under the Benefit 7b approach if a capacity expansion model captures broader system cost savings beyond those directly attributable to loss-driven capacity reductions. In such cases, the resulting valuation may overstate the specific capacity benefit associated with transmission loss reductions. Finally, Benefit 7 results can be overstated through the use of aggressive monetization assumptions, such as a high Net CONE under the 7b approach or an elevated VOLL under the 7a approach. As with Benefit 2, the results are sensitive to these underlying cost assumptions and should be evaluated accordingly.

LESSONS LEARNED AND FUTURE CONSIDERATIONS

The evaluation of the seven Order No. 1920 benefit metrics provided valuable insights into both the strengths and limitations of current planning practices. The lessons learned identify opportunities to improve benefit quantification, strengthen coordination across planning processes and models, better capture emerging sources of transmission value, and enhance the efficiency and consistency of future long-term transmission planning studies.

ACCURACY AND COMPLETENESS OF BENEFIT QUANTIFICATION

Quantifying the benefits of long-term transmission investments is inherently challenging because the value of transmission is realized across multiple planning horizons, system conditions, and geographic footprints. The following observations summarize the key lessons learned for improving the accuracy, completeness, and credibility of benefit assessments and for ensuring that transmission decisions are informed by a comprehensive understanding of system value.

SCENARIO-BASED PLANNING IS FOUNDATIONAL TO COMPREHENSIVE BENEFIT ASSESSMENT

A key lesson across all Order No. 1920 benefit metrics is that benefit estimates are highly dependent on the future scenarios considered during the planning process. Because LTRTP facilities, projects, and portfolios are intended to address long-term system needs, assessments should evaluate a broad range of plausible futures shaped by factors such as policy and regulatory changes, generation additions and retirements, load growth, electrification, weather and climate trends, fuel prices, and supply-chain constraints. Evaluating project performance across diverse futures provides a more complete understanding of benefits and helps identify least-regret investments that remain valuable under changing landscapes.

At the same time, traditional planning appropriately emphasizes normal system conditions to avoid overbuilding the system and imposing unnecessary costs on customers. However, extreme weather events, equipment outages, fuel supply disruptions, and other low-probability, high-impact events can reveal substantial reliability and resilience value that may not be visible under normal conditions. Benefits 5 and 6 represent an important step toward addressing this gap by explicitly evaluating transmission value during forced outage and extreme weather conditions. Further evaluation of low-probability, high-impact events within reliability planning frameworks, including studies similar to those performed under NERC Transmission Planning standards, and within probabilistic resource adequacy assessments may help capture additional transmission benefits. This broader perspective can better quantify the reliability, resilience, and risk-mitigation value of transmission investments across a wider range of system conditions than is represented in traditional planning analyses.

DOUBLE COUNTING IS THE MOST SIGNIFICANT SOURCE OF POTENTIAL OVER-EVALUATION

The most significant risk of over-evaluating transmission benefits across the seven Order No. 1920 benefit metrics is double counting. Several benefit metrics capture related value streams and therefore require careful methodological design and consistent benchmarking assumptions to ensure that the same underlying value is not monetized multiple times. Examples include:

- Resource adequacy benefits (Benefit 2) versus production cost savings (Benefit 3). Benefit 2b explicitly quantifies avoided capacity needs, while Benefit 3 is intended to capture production cost and operational savings. Particular care is required when capacity expansion model outputs are used to monetize capacity benefits through changes in total system NPV. Because the capacity expansion model is minimizing NPV of total costs, which is a combination of investment, fixed O&M, and production costs, the analyst needs to ensure that only the investment and fixed O&M are considered in the capacity cost calculation. In addition, the capacity expansion model may not always select the cheapest possible capacity if it sees material production cost savings from a more capital-intensive unit. In these cases, it can be difficult to separate capacity selected purely for capacity reasons, or for a combination of its contribution to capacity need and reduction in production cost. However, the holistic view of the resources' impact on total costs is still a defensible approach for resource selection and adds an additional layer of realism into the overall portfolio build-outs as generation build decisions are always made based on a view of the total value of the asset to the system, not just for a single value stream.
- Production cost savings (Benefit 3) versus reduced transmission losses (Benefit 4). Many production cost models represent losses directly or indirectly through locational marginal pricing formulations. When losses are already reflected in the production cost analysis, a separate monetization of loss reductions under Benefit 4 could lead to double counting unless the two value streams are clearly separated.
- Resource adequacy benefits (Benefit 2) versus avoided capacity associated with transmission loss reductions (Benefit 7). Benefit 2 evaluates transmission's contribution to meeting resource adequacy requirements across a broad range of operating conditions, while Benefit 7 focuses specifically on capacity needs associated with transmission losses during peak conditions. Clear delineation is necessary to avoid counting the same avoided capacity value in both categories.

Without consistent benefit accounting and transparent benchmark assumptions, the same underlying transmission value may be captured multiple times across different benefit metrics. Therefore, methodologies should be designed not only to comprehensively identify transmission benefits, but also to clearly distinguish between overlapping value streams and minimize the risk of double counting.

CONSISTENCY ACROSS PLANNING MODELS IS CRITICAL

Many benefit methodologies rely on multiple analytical tools, including power flow models, production cost models, resource adequacy models, and capacity expansion models. Inconsistencies in network topology, resource assumptions, operating constraints, or other study inputs across these models can distort benefit estimates and reduce confidence in the results. In addition, a comprehensive assessment often requires iterative feedback among planning models, as insights from one analysis may influence assumptions or outcomes in another. Establishing a coordinated modeling framework and maintaining a consistent set of planning assumptions across all analytical tools are therefore essential to ensuring that benefits are measured transparently and consistently. This topic is discussed further in the subsequent section on planning model alignment and iterative study processes.

MONETIZATION ASSUMPTIONS CAN DOMINATE FINAL RESULTS

Several benefits rely on monetization parameters that are inherently uncertain and can vary significantly across studies. Metrics such as VOLL, Net CONE, outage probabilities, and extreme-event weighting assumptions can have a larger impact on results than the underlying physical system changes being evaluated. Transparent documentation, sensitivity testing, and stakeholder review of key valuation assumptions are therefore critical to maintaining credibility.

TRANSMISSION BENEFITS OFTEN EXTEND BEYOND PLANNING BOUNDARIES

Several benefit metrics demonstrate that transmission value often extends beyond individual planning regions. Restricting analyses to a single planning region and utility footprint can overlook benefits associated with interregional transfers, production cost reductions, transmission loss savings, resource adequacy contributions, and improved system resilience that occur across the broader interconnected grid. As transmission projects increasingly facilitate power flows across regional boundaries, administrative study boundaries may not fully capture the physical impacts of transmission investments, creating a potential source of systematic under-evaluation. Expanding assessments to consider regional and interregional effects can provide a more complete representation of transmission value and better reflect the interconnected nature of the bulk power system.

CHALLENGES IN CAPTURING BENEFITS OF ATTS

The evaluation of Advanced and Alternative Transmission Technologies presents unique challenges that are not always fully addressed by traditional transmission planning methodologies. Assessment of ATTs across the seven Order No. 1920 benefit metrics shows that current modeling tools and study approaches can have limitations in capturing their full value.

One challenge stems from the simplified representation of the transmission system in some planning models. For example, capacity expansion and resource adequacy studies are often conducted using zonal rather than nodal representations of the grid. When ATT deployment and associated constraints occur within a zone, benefits such as increased transfer capability, congestion relief, and

improved deliverability may not be fully reflected, resulting in a potential undervaluation of the technology.

A second limitation is the difficulty of separating the value of the technology from the value of the transmission solution itself. Many ATTs provide operational benefits through rapid, dynamic responses occurring on timescales from milliseconds to minutes, improving system stability, controllability, and operational flexibility. However, most planning studies focus on hourly or seasonal performance and therefore fail to capture many of these benefits.

Finally, many ATTs operate through continuous feedback between system conditions and device response. Their performance depends on rapid interactions with changing flows, voltages, frequencies, and operating conditions. Existing planning tools often cannot fully represent these closed-loop interactions across multiple timescales, particularly when linking long-term planning models with operational and dynamic simulations. As a result, some ATT benefits may remain unquantified or only partially captured within current assessment frameworks.

For all these reasons, an ATT may appear to have the same benefit as a traditional transmission solution. In this case, the added value of the ATT would then become apparent in benefit-to-cost analysis and feasibility study, where the lower investment costs of and time to deploy ATT solutions compared traditional new transmission builds would be considered.

ADDITIONAL TRANSMISSION VALUE CONSIDERATIONS

Beyond Order No. 1920 benefits, additional considerations may be relevant depending on the planning objectives, system characteristics, and stakeholder priorities of a region. For example, on the transmission capability side, transmission investments can provide resource deliverability benefits beyond the avoided or deferred costs of transmission infrastructure. Transmission can also provide enhanced grid flexibility and increased market competition by expanding access to diverse resources, improving outage management flexibility, reducing operational constraints, and increasing optionality for system operators. These benefits are often only partially reflected in traditional production cost metrics. Finally, transmission investments can support broader public policy and environmental objectives, including renewable energy integration, decarbonization goals, and emissions reductions. These benefits could be evaluated as “other” metrics under Order No. 1920, as done by many planning organizations today.²⁰

An additional consideration when evaluating the benefits of regional transmission projects during extreme weather conditions is that these analyses generally assume wholesale markets continue to function and dispatch remains driven by economic principles. However, under severe system stress, particularly during elevated Emergency Energy Alert (EEA) conditions where the risk of controlled load shedding or widespread outages exists, system operators may be required to take actions based

²⁰ Brooks (2026) at 70-73

on physical reliability needs rather than market outcomes. In these situations, LMPs and marginal production costs may no longer provide an adequate measure of transmission benefits, as operator actions are focused on preserving system stability and avoiding customer interruptions. Consequently, the value of regional transmission projects under extreme conditions may be more appropriately measured by their ability to reduce the likelihood, magnitude, or duration of load loss and monetized using metrics such as VOLL rather than avoided exposure to scarcity pricing or extreme LMPs. This also highlights a potential role for frameworks such as TPL-008, which may help address a gap in benefit quantification by recognizing that, under extreme events, system behavior is governed more by physics and reliability requirements than by normal market economics.

BENEFIT-TO-COST ANALYSIS

The preceding sections presented each of the seven Order No. 1920 benefits individually, along with the methodologies, assumptions, and double-counting controls used in their calculation. The mock LTRTP projects evaluated in this study were selected to demonstrate the benefit-calculation framework and provide a representative example of future grid development, including reinforcement of the MISO North-South transmission backbone. They were not designed or refined to maximize net benefits, minimize costs, or represent a preferred regional transmission portfolio. As a result, calculating Benefit-to-Cost (B/C) ratios for these illustrative projects would provide limited planning insight.

More generally, a robust B/C evaluation requires both benefits and costs to be developed on a consistent financial basis, including capital expenditures, ongoing operations and maintenance costs, evaluation horizons, discount rates, and dollar-year assumptions. Developing project cost estimates suitable for a selection-grade B/C analysis was outside the scope of this case study.

Nevertheless, this exercise highlights the important role that B/C considerations can play throughout the regional planning process. Although B/C analysis is often applied near the end of the process to support portfolio selection, its value extends beyond a final screening metric. Preliminary benefit and cost information can help guide transmission solution screening, project refinement, portfolio coordination, and optimization efforts. Incorporating B/C considerations iteratively during portfolio development can help ensure that economically effective solutions are advanced while maintaining focus on the overall value delivered to customers. In practice, B/C analysis is most effective when used not only as the final step in project selection, but also as a tool to inform key planning decisions throughout the development of transmission solutions and portfolios.

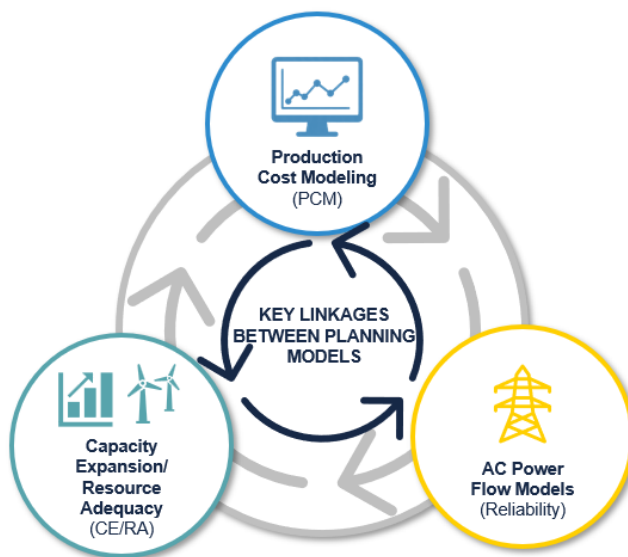
ALIGNMENT AND ITERATION ACROSS PLANNING MODELS

One of the key takeaways from this study is that the accuracy and effectiveness of long-term assessment models are critical to producing credible Order No. 1920 benefit evaluations. The 20-year planning horizon introduces significant uncertainty related to future load growth, resource

development, policy outcomes, technology adoption, and transmission expansion. As a result, no single model or planning process can adequately capture all aspects of future system evolution.

This section highlights key points of interaction, alignment, and iteration among the three primary modeling pillars used in Order No. 1920 benefit evaluations: capacity expansion and resource adequacy models, production cost models, and AC power flow-based reliability models.

Figure 35 Key Planning Models for Alignment



PRODUCTION COST & AC POWER FLOW MODELS

Alignment between PCM and AC power flow models is important when both are intended to represent the same transmission network. At the same time, differences between models may be intentional to prevent double counting across benefits. For example, local transmission projects represented as avoided reliability investments under Benefit 1 should generally be reflected in the PCM Base Case; otherwise, their value could be counted both as avoided transmission investment costs under Benefit 1 and as production cost savings under Benefit 3.

The representation of transmission constraints is another critical area of alignment. Benefit 3 may be understated when production cost simulations do not adequately represent the system limitations that the Order No. 1920 portfolio is designed to address. Key thermal limits, interface transfer limits, voltage constraints, and stability-related restrictions can materially affect congestion and dispatch outcomes and therefore should be reflected where practical.

PCM results can also provide valuable feedback to reliability assessments. The dispatch patterns produced by PCM provide a more realistic representation of generator utilization under least-cost system operations and can help determine whether reliability violations identified in power flow studies can reasonably be mitigated through redispatch. Furthermore, PCM provides insights into the

frequency and persistence of congestion and operating constraints over time, complementing the snapshot-based perspective of traditional AC power flow studies.

Finally, emergency energy and load-shedding outcomes identified in PCM may indicate not only resource adequacy concerns but also transmission limitations that restrict the delivery of available generation.

PRODUCTION COST & CAPACITY EXPANSION / RESOURCE ADEQUACY MODELS

The future resource mix is a critical input to production cost simulations and is typically derived from capacity expansion studies. As a result, alignment between these models is important, particularly with respect to generation siting assumptions and the translation of zonal resource additions into more detailed nodal representations. In some cases, iterative analysis may be warranted, as transmission investments can influence future resource development, siting decisions, and generation economics, potentially resulting in additional production cost savings that may not be captured when relying on a static generation fleet.

Resource adequacy studies can also provide valuable inputs to production cost simulations, particularly regarding outage assumptions and resource availability. This linkage is especially important for evaluating stress-condition benefits, such as those captured under Benefit 5.

In addition, emergency energy usage and load shedding within PCM results can serve as useful sanity checks. While emergency energy costs are included in Adjusted Production Cost (APC), Benefit 3 is intended to represent normal operating conditions and therefore should produce little, if any, emergency energy utilization. Significant emergency energy costs may indicate resource adequacy concerns or modeling issues that warrant further investigation.

CAPACITY EXPANSION / RESOURCE ADEQUACY & AC POWER FLOW MODELS

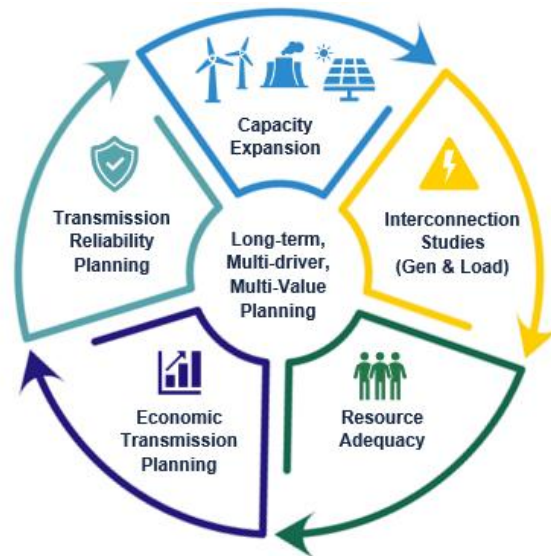
Strong coordination is also needed between capacity expansion, resource adequacy, and reliability planning models. For Benefit 2 evaluations, zonal transfer capability assumptions often require input from detailed AC power flow analyses. Conversely, when resource adequacy assessments are performed at a sub-zonal level, AC power flow models can help determine appropriate zone boundaries and transmission interfaces.

Alignment of generation assumptions is equally important. Existing generation, planned resources, and future capacity additions must be represented consistently across zonal and nodal models. In particular, the outputs of capacity expansion studies should be translated carefully into AC power flow models to ensure that future reliability assessments accurately reflect the anticipated resource mix and geographic distribution of generation.

INTEGRATION ACROSS PLANNING PROCESSES

Beyond alignment among planning models, effective implementation of Order No. 1920 also requires greater integration across planning processes. Historically, generation planning, reliability transmission planning, economic transmission planning, and interconnection studies have often been conducted in organizational silos, with different teams operating under separate objectives, assumptions, and timelines. As industry moves toward a more long-term, multi-driver and multi-value planning framework, stronger coordination among these processes is increasingly important to improve planning outcomes and ensure that benefits are neither overlooked nor double counted.

Figure 36 Key Planning Processes for Integration



GENERATION PLANNING AND TRANSMISSION PLANNING INTEGRATION

Generation and transmission planning are inherently interdependent. Generation additions drive transmission needs, while transmission availability influences resource siting, interconnection opportunities, deliverability, congestion, and resource economics. Historically, these processes have often been performed sequentially, resulting in transmission expansion lagging behind resource development. Greater coordination between generation and transmission planning can improve the identification of least-cost, long-term solutions and reduce the risk of infrastructure becoming a constraint to future resource development. In addition, accurate long-term forecasts help ensure that transmission solutions are developed with a clear understanding of future resource development pathways. Over time, more iterative and integrated planning approaches can enable better co-optimization of generation and transmission investments.

ECONOMIC AND RELIABILITY TRANSMISSION PLANNING INTEGRATION

Historically, reliability planning and economic planning have been conducted through separate processes, often resulting in different project lists, study assumptions, and planning outcomes. Within transmission planning, greater integration between economic and reliability assessments represents a significant opportunity for improvement. Reliability considerations are typically

embedded throughout the planning process—from need identification to solution development and project justification—whereas economic analysis is often concentrated in later stages, such as portfolio evaluation and benefit assessment. At a minimum, assumptions and modeling inputs should be aligned across reliability and economic studies.

More importantly, economic considerations should play a larger role throughout the planning process, including need assessment, solution development, and portfolio selection. This is particularly important in a Order No. 1920 framework, where transmission projects are expected to provide multiple value streams rather than addressing a single planning objective. A more integrated approach can help identify solutions that simultaneously address reliability, economic, resilience, and public policy needs.

COORDINATION ACROSS LOCAL, REGIONAL, INTERREGIONAL, AND INTERCONNECTION PLANNING

Transmission planning also requires coordination across multiple geographic and organizational levels. Local transmission planning, regional transmission planning, interregional transmission planning, and generation and load interconnection processes all evaluate different aspects of the same grid but are often performed independently. This fragmentation can lead to duplicate solutions, inconsistent assumptions, and missed opportunities for broader regional investments.

For different planning layers, local planning processes, regional transmission planning, and interregional transmission planning should be aligned to ensure that needs and solutions are consistently evaluated and that opportunities for broader geographic footprint solutions are not overlooked.

Coordination between transmission planning and generation and load interconnection studies is becoming increasingly important. Interconnection requests often provide early indicators of future resource and load growth, while the network upgrades identified through interconnection studies can serve as valuable inputs to local, regional, and interregional transmission planning. Greater coordination can help identify broader regional solutions, avoid duplicative investments, and ensure that transmission development proactively supports future generation and load growth.

CAPACITY EXPANSION AND RESOURCE ADEQUACY INTEGRATION

Within generation planning, capacity expansion and resource adequacy assessments should be closely coordinated. Capacity expansion models identify economically efficient future resource portfolios, while resource adequacy studies determine whether those portfolios can reliably serve demand under a wide range of operating conditions. Integrating these processes can improve both economic efficiency and reliability by ensuring that resource portfolios are not only least-cost but also capable of meeting reliability objectives. Improved coordination also provides more consistent inputs to production cost modeling and transmission planning studies.

IMPROVING PLANNING EFFICIENCY THROUGH PLATFORM INTEGRATION AND AUTOMATION

We assessed the modeling and implementation complexity associated with each of the seven Order No. 1920 benefit metrics. The objective of this assessment is to provide transparency into the level of modeling effort, analytical complexity, computational burden, and result defensibility required to quantify each benefit. Understanding these dimensions helps planners and stakeholders understand not only the complexity and scalability of evaluating each benefit, but also the importance of platforms integration and automation that can improve efficiency, maintain data consistency, streamline workflows, and enhance coordination across planning studies and teams.

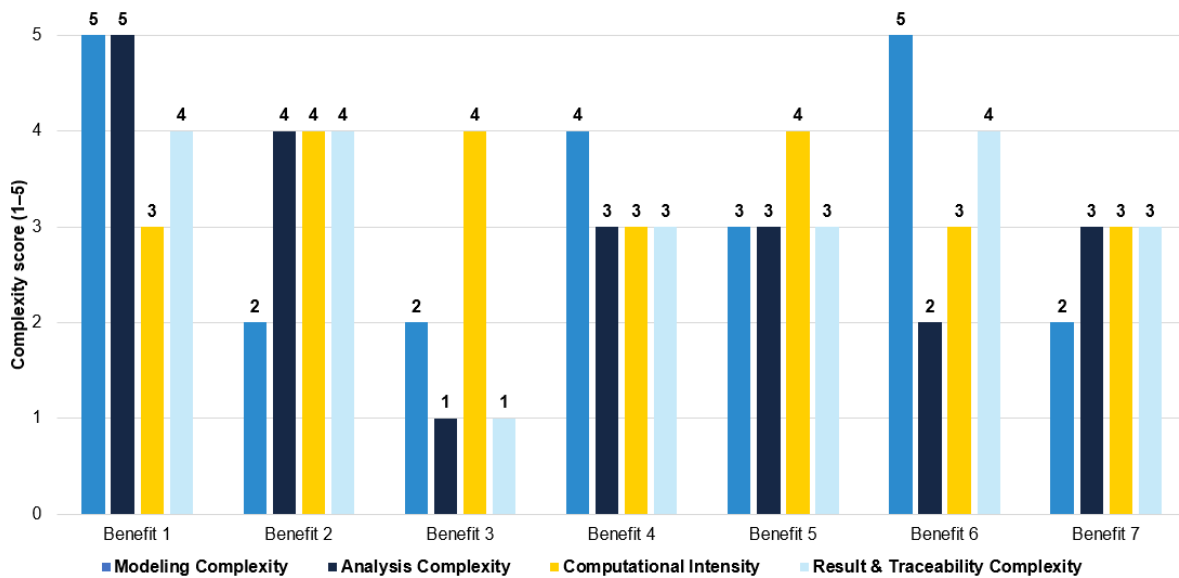
The complexity of each benefit was evaluated across four dimensions shown in Table 7:

Table 7 Four Dimensions of Order No. 1920 Complexity

	Modeling Complexity	Analysis Complexity	Computational Intensity	Results & Traceability Complexity
What It Measures	Effort to develop, calibrate, maintain, and update the model	Sophistication and number of analytical methods required	Runtime and computational resources required	Ability to explain, verify, and defend results
Why It Matters	Affects engineering effort and model governance	Affects study design and expertise requirements	Affects study cost and duration	Affects stakeholder and regulatory acceptance

While some benefits can be estimated using well-established methodologies and readily available datasets, others require multiple analytical frameworks, significant assumptions, or extensive scenario analysis. As a result, complexity varies considerably across the seven benefit metrics. The figure below compares the relative complexity of each benefit across these four dimensions. The comparison highlights which benefits are straightforward to model and communicate, and which require more advanced analytical techniques, computational resources, or interpretation to support decision-making and regulatory review.

Figure 37 Comparison of Complexity Dimensions by Order No.1920 Benefit



As transmission planning becomes more integrated, multi-disciplinary, and long-term in nature, the associated analytical workload continues to grow. Order No. 1920 requires planners to evaluate multiple benefit metrics using a wide range of analytical methods, resulting in greater coordination across teams, planning processes, and software platforms. This increasing complexity presents challenges not only for organizations and planning workflows, but also for the engineering resources required to develop, maintain, and execute these studies.

A key challenge is that no single software platform can perform all analyses required across the Order No. 1920 benefit framework. Production cost modeling, resource adequacy assessments, capacity expansion studies, reliability evaluations, power flow analysis, stability studies, and EMT analysis are often performed using different tools, each optimized for a specific purpose. As a result, planners must frequently translate data, assumptions, and results between multiple software environments, introducing additional effort and potential inconsistencies. The industry would benefit from both improved best practices for data exchange and stronger integration among planning platforms, including expanded software capabilities that reduce the need for manual model translation.

At the same time, automation, workflow management tools, and artificial intelligence have an important role to play in improving planning efficiency and consistency. Many planning activities, including data preparation, model translation, assumption management, quality assurance, and result processing, remain highly manual and time-consuming. Increased automation can help reduce repetitive tasks, improve traceability, and minimize the risk of human error. By reducing the time spent on data manipulation and model maintenance, planners can devote more effort to engineering analysis, scenario development, and the expert judgment needed to support long-term planning decisions.

THE ROAD AHEAD: EPE AND GRID STRATEGIES PERSPECTIVE ON ORDER NO. 1920 IMPLEMENTATION

Order No. 1920 represents a significant evolution in regional transmission planning by establishing a more structured process for identifying, evaluating, and selecting transmission projects and portfolios based on a broad set of long-term benefits. However, the rule should be viewed as the beginning of a longer industry transition rather than the final destination. Successful implementation will require planners, regulators, transmission owners, and stakeholders to move beyond compliance and continue advancing the analytical tools, planning processes, and governance frameworks needed to support long-term transmission development.

From EPE and Grid Strategies' perspective, this study highlights that benefit evaluation should not be treated as a purely mechanical exercise. Many of the most consequential implementation decisions involve assumptions regarding future resource mixes, load growth, electrification, extreme weather conditions, technology adoption, and regional coordination. As demonstrated throughout this report, reasonable assumptions can materially influence the magnitude and distribution of benefits. Maintaining transparency regarding these assumptions, conducting sensitivity analyses, and clearly communicating uncertainty will be critical to ensuring stakeholder confidence in future planning outcomes.

Another key lesson is that need assessment, portfolio development, and benefit evaluation should be viewed as iterative processes rather than sequential steps. Historically, transmission planning has often focused on identifying reliability needs first and evaluating economics afterward. Order No. 1920 creates an opportunity to integrate benefit and cost considerations much earlier in the planning process. Preliminary benefit assessments can inform project screening, solution refinement, portfolio coordination, and optimization, while subsequent iterations can improve both technical performance and economic effectiveness. Realizing this vision will require greater integration across planning tools, analytical platforms, datasets, and organizational processes. Reliability transmission planning, production cost modeling, capacity expansion analysis, and resource adequacy assessment can no longer operate as largely siloed workflows. Instead, planners will increasingly need connected and iterative planning environments that allow insights from one analysis to inform and refine the others throughout the development of transmission solutions and portfolios.

Finally, Order No. 1920 should not be viewed solely as a compliance requirement. At its core, the rule is an attempt to improve the industry's ability to identify transmission investments that create long-term value for customers. The success of the rule will depend on whether regional planning processes can consistently identify transmission portfolios that are cost-effective, broadly beneficial, and adaptable to an increasingly uncertain future. The methodologies presented in this case study provide one possible foundation for that effort. While further refinement, improved tool integration, and practical implementation experience will undoubtedly advance these approaches, the results

demonstrate that a comprehensive and transparent evaluation of Order No. 1920 benefits is both achievable and capable of supporting more informed long-term regional transmission planning decisions.