APPENDIX F1

MISO LRTP Tranche 1 Project 4 Benefit-Cost Analysis Technical Report

MISO LRTP Tranche 1 Project 4 Benefit-Cost Analysis

TECHNICAL REPORT

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DAIRYLAND POWER COOPERATIVE
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I. Project 4 Background and Report Purpose

Dairyland Power Cooperative ("Dairyland" or "DPC") is submitting an application to the Public Service Commission of Wisconsin ("Commission" or "PSCW") for a Certificate of Public Convenience and Necessity ("CPCN") for the Alma-Blair 345 kilovolt ("kV") transmission line. The Alma-Blair 345 kV transmission line is the Wisconsin portion of the larger Wilmarth-North Rochester-Tremval 345 kV transmission line that the Midcontinent Independent System Operator ("MISO") included as Project 4 in Tranche 1 of its Long-Range Transmission Planning ("LRTP") process in 2022 and awarded to Dairyland to build in December 2023.

The purpose of this report is to summarize the reliability, economic, and policy benefits, and costs of the LRTP Tranche 1 portfolio applicable to Wisconsin ratepayers, and to specifically evaluate the net benefits and costs of Project 4 to Wisconsin ratepayers in support of Dairyland's CPCN application. Project 4 is evaluated relative to a "No Action" case in which no new transmission facilities are added on the Project 4 corridor. The report also analyzes the benefits and costs of all three LRTP projects located in Wisconsin (LRTP Projects 4–6).

The Project 4 benefits to Wisconsin ratepayers are compared to the benefits of two alternative cases, a lower voltage alternative ("LVA") and a non-transmission alternative ("NTA"). In both cases, the Minnesota portion of Project 4 is built and the Wisconsin portion is replaced by the proposed alternative. In the LVA case, DPC installs a second Alma-Blair 161 kV transmission line in place of the 345 kV line approved by MISO. In the NTA case, DPC installs 100 megawatt ("MW") of battery energy storage at the Briggs Road substation north of La Crosse, Wisconsin to support additional transfers across the existing 345 kV transmission system.

The benefits to Wisconsin ratepayers for each alternative case are evaluated under three scenarios, accounting for different assumptions related to future electricity demand and generation resources and the Commission's approval of Projects 5 and 6.

The report is structured in the following way:

- Section II summarizes MISO's development and evaluation of the LRTP Tranche 1 portfolio and the benefits of the Tranche 1 portfolio and Project 4, particularly in reference to Wisconsin ratepayers;

- Section III summarizes the benefit-cost analysis of Project 4, the Tranche 1 portfolio, and the two alternative cases (LVA and NTA) for Wisconsin ratepayers;
- Section IV provides a detailed description of the approach, assumptions, and results of the benefits analysis of the each case analyzed relative to a No Action case.

II. MISO LRTP Tranche 1 Process and Portfolio Analysis

MISO has been an industry leader over the past two decades in developing portfolios of transmission projects through its Multi-Value Project ("MVP") transmission planning process that addresses multiple future market needs across its system, including reliability, economic, and policy needs. MISO is a federally regulated entity that plans its future high-voltage regional system based on its Open Access Transmission Tariff ("OATT"), approved and overseen by the Federal Energy Regulatory Commission ("FERC"). MISO approved its first portfolio of 18 MVP projects in 2011 that included $6 billion of upgrades.[1] MISO initiated the LRTP process in 2020 to identify additional portfolios of cost-effective, multi-value transmission upgrades with a focus on the MISO Midwest subregion in Tranche 1 and Tranche 2, the MISO South subregion in Tranche 3, and strengthening the connection between the MISO Midwest and MISO South subregions in Tranche 4.[2]

MISO completed Tranche 1 of its LRTP studies in 2022 to prepare for future system needs in the MISO Midwest subregion. The Tranche 1 planning process included extensive analysis by MISO and its stakeholders to identify projects that meet MISO's future system needs, evaluate their benefits, and finalize the Tranche 1 portfolio of projects. MISO based its Tranche 1 analysis on its most conservative outlook for long-term demand and generation resources at the time, Future 1 from the Series 1 MISO Futures.[3] MISO presented updates throughout the process at 11 stakeholder workshops held between April 2021 to April 2022.[4] Stakeholders had the opportunity to submit alternatives to the candidate solutions developed by MISO to support

1 MISO, MTEP14 MVP Triennial Review, September 2014, p. 4.

2 MISO, MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary, 2022, p. 1. ("MISO Tranche 1 Summary")

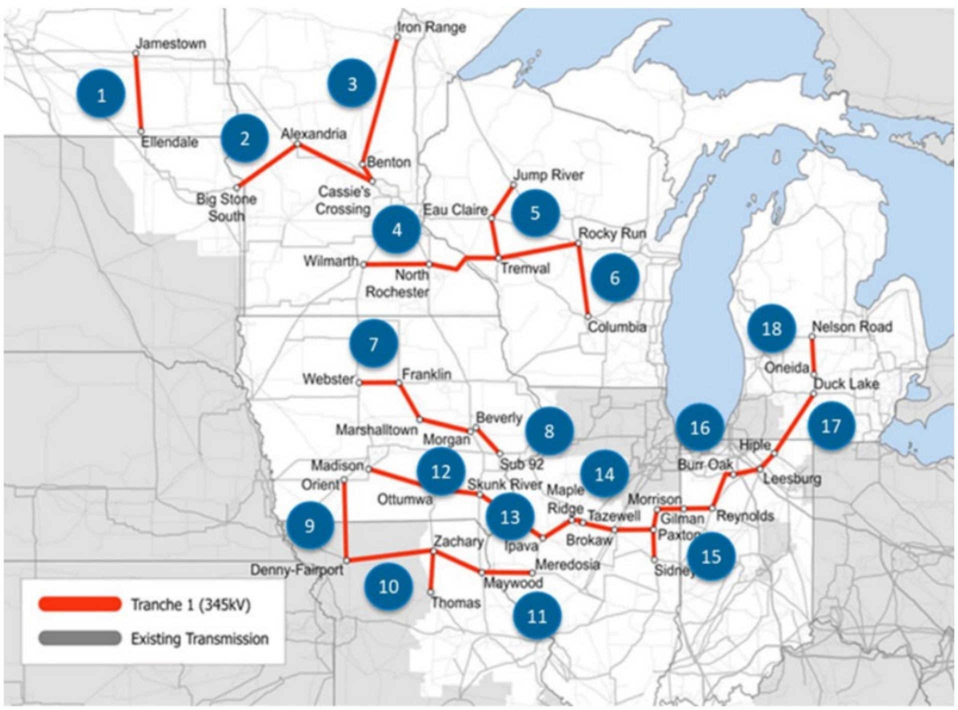
3 MISO Tranche 1 Summary, p. 5.

4 MISO Tranche 1 Summary, pp. 7–8.

identifying the most cost-effective transmission solutions for Tranche 1. MISO evaluated the candidate LRTP solutions together as a portfolio to ensure that they jointly provided net benefits to the MISO Midwest region overall and to each zone within the region.

The Tranche 1 process resulted in the MISO Board approving a portfolio of 18 projects in July 2022, as shown below in Figure 1, with a total estimated capital cost of $10.3 billion (2022 dollars).[5] Project 4 is a $689 million (2022 dollars) east-west line between Minnesota and Wisconsin that MISO identified to increase transfer capacity across the Mississippi River and resolve reliability, economic, and policy needs on its system. Project 4 connects to two other LRTP projects in Wisconsin at a new 345 kV substation located near Blair, Wisconsin.[6] Project 5 adds transfer capability to northern Wisconsin and Project 6 expands the 345 kV system into eastern Wisconsin.

FIGURE 1: MISO LRTP TRANCHE 1 PORTFOLIO



Source: MISO Tranche 1 Summary.

[5] MISO Tranche 1 Summary, pp. 1–2.

[6] Since the assignment of the projects to the transmission developers, the location of the substation where Projects 4–6 connect has been moved to the Blair 345 kV substation. We refer to the Tremval 345 kV substation throughout the report based on the original location proposed by MISO.

Soon after the MISO Board approval of Tranche 1, MISO began its analysis of additional cost-effective upgrades through the LRTP Tranche 2 process in 2022.[7] The second set of LRTP projects is meant to build on the transmission projects included in Tranche 1.[8] In Tranche 2, MISO considered future system conditions based on the updated Future 2A scenario that reflect significantly higher electricity demand and a faster transition of the generation fleet to renewable energy and storage resources than projected in Future 1.[9] In December 2024, the MISO Board of Directors approved Tranche 2.1, which includes $21.8 billion of investment in a 765 kV backbone across MISO Midwest.[10]

The rest of this section summarizes the results of the Tranche 1 planning process with a focus on the Wisconsin-specific impacts of the Tranche 1 portfolio and Project 4 in particular.

A. Portfolio Development

MISO developed the LRTP Tranche 1 portfolio "to ensure that the regional transmission system can meet demand in all hours while supporting the resource plans and renewable energy penetration targets reflective of MISO member utilities' goals and state policies."[11] MISO began by developing a roadmap for transmission needs across each of its three Futures scenarios and then performed more detailed reliability analyses relying on Future 1 assumptions.[12] MISO specifically reviewed needs in five focus areas across its Midwest region, including the Minnesota-Wisconsin border.[13]

MISO identified a need for transmission upgrades near the Minnesota-Wisconsin border as the system relies more heavily on renewable energy due to the "strong flows West to East across Minnesota to Wisconsin and a need for [an] outlet for those renewables in time of high availability to deliver that energy to load centers in MISO."[14] The projected flows in this portion of the MISO system overload the existing transmission facilities resulting in voltage stability

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7 MISO, MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report, 2022, p. 6. ("MISO Tranche 1 Report")

8 MISO Tranche 1 Summary, p. 5.

9 MISO, Long Range Transmission Planning (LRTP): Tranche 2—Frequently Asked Questions, June 7, 2024, p. 7. ("MISO Tranche 2 FAQs")

10 MISO, LRTP Tranche 2.1 – Fact Sheet, December 2024, p.1.

11 MISO Tranche 1 Summary, p. 1.

12 MISO Tranche 1 Report, p. 17.

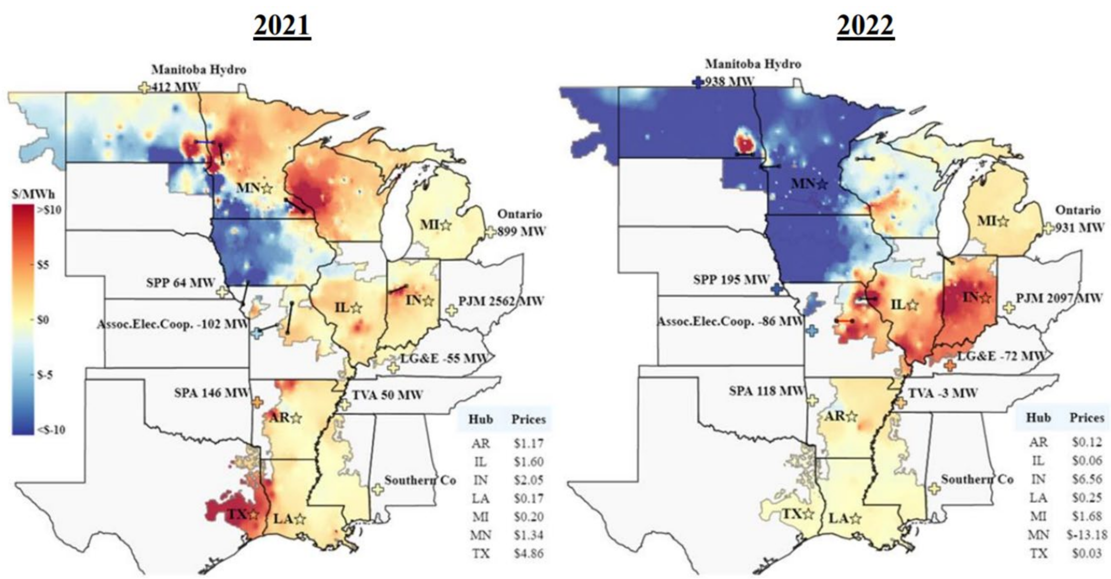
13 MISO Tranche 1 Report, p. 22.

14 MISO Tranche 1 Report, p. 30.

issues and thermal violations in the vicinity of the Twin Cities and the corridors into Wisconsin. These flows and the resulting congestion create a need for transmission system upgrades to ensure the future reliability of the system and to cost-effectively dispatch the generation resources to enable low-cost resources in Minnesota and Iowa to serve load centers in Wisconsin and to the east.

The immediate need for upgrades between Minnesota and Wisconsin is also evident from recent historical energy prices in the MISO wholesale market. MISO real-time energy prices from 2021 and 2022 demonstrate the significant congestion between Minnesota and Wisconsin, resulting in higher prices for energy in Wisconsin, as shown in Figure 2 below. Wisconsin’s real-time energy prices from 2021 to 2024 were on average $18/megawatt hour (“MWh”) higher than Minnesota prices, ranging from $11/MWh to $28/MWh higher in each year.[15]

FIGURE 2: 2021 AND 2022 MISO REAL-TIME CONGESTION



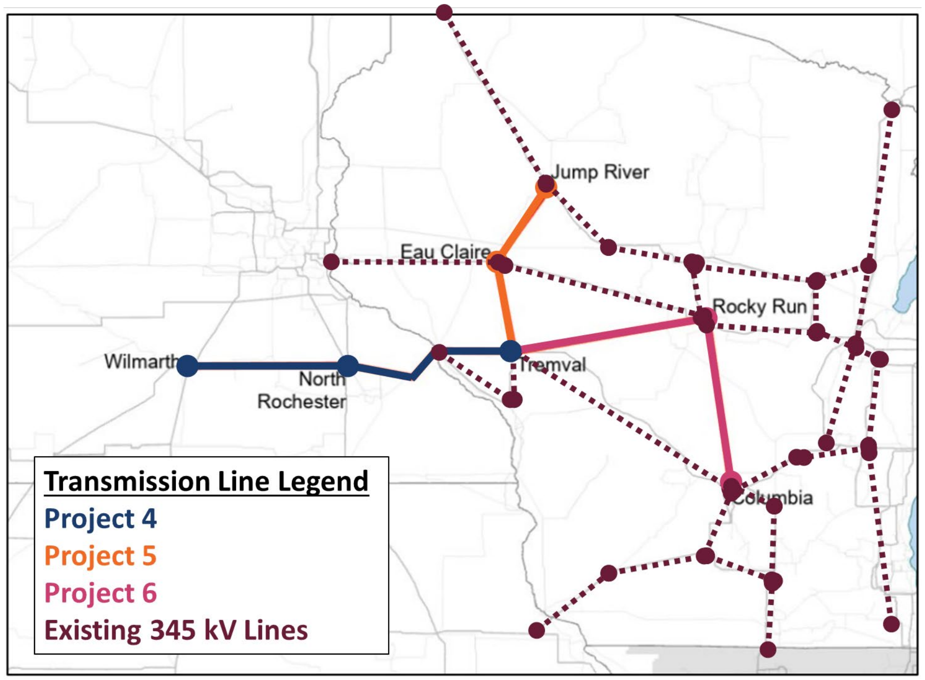
Source: Potomac Economics, 2022 State of the Market Report for The MISO Electricity Markets, June 15, 2023.

Project 4 will increase the east-west transfer capability across the Mississippi River, as shown in Figure 3 below, reducing future congestion between Minnesota and Wisconsin and increasing access to low-cost imports to serve Wisconsin load. Project 4 will connect to the existing Badger-Coulee 345 kV transmission line, which provides an outlet for the additional flows across the river to reach load centers in southeastern Wisconsin. Projects 5 and 6 further

[15] Hourly average real-time locational marginal prices (LMP) for the years 2020 to 2024 were retrieved for a representative node in both Minnesota and Wisconsin from the Hitachi ABB Velocity Suite. The hourly absolute differences were calculated, and then the average was taken for each year.

increase the north-south transfer capability within Wisconsin by networking the three existing 345 kV lines in western and northern Wisconsin, as shown in Figure 3. Both projects increase the transfer capability to the existing 345 kV lines that serve eastern Wisconsin load centers at Green Bay/Appleton, Madison, and Milwaukee. MISO highlights in its Tranche 1 benefits report that these projects "complete an outlet for renewable power flow across Wisconsin to the Madison and Milwaukee area load centers."[16]

FIGURE 3: WISCONSIN LRTP TRANCHE 1 PROJECTS AND EXISTING 345 KV LINES



During its stakeholder process, MISO considered several alternatives to addressing the needs in this region, including a "southern corridor" along the Minnesota-Iowa border.[17] MISO ultimately selected and approved the Project 4 upgrades as the most cost-effective alternative because Project 4 will increase transmission capacity at the interface between Minnesota and Wisconsin and tie into load centers in Minnesota as well as reduce congestion across the Mississippi River.

[16] MISO Tranche 1 Report, p. 32.

[17] MISO Tranche 1 Report, p. 35.

B. Analytical Approach

MISO evaluated the benefits of the Tranche 1 portfolio using a multi-value framework that accounts for the reliability, economic, and policy benefits of the proposed projects in a single process. MISO specifically quantified the following six benefit metrics for the Tranche 1 portfolio:[18]

- *Congestion and Fuel Savings*: LRTP projects reduce congestion on the transmission system and allow more low-cost resources to generate, replacing higher-cost resources and lowering the cost to serve load. MISO uses the Adjusted Production Cost ("APC") Savings metric to quantify congestion and fuel savings for each transmission provider in MISO. The APC accounts for production costs, market purchase costs, market sales revenues, and transmission revenues within each transmission provider's service territory to estimate the impact of the projects on its customers' costs.
- *Decarbonization:* LRTP projects enable a higher penetration and utilization of renewable energy resources that result in a reduction of carbon dioxide emissions.
- *Avoided Capital Cost of Local Resources*: LRTP projects allow lower cost additions of renewable generation and storage resources in areas where they can be more productive compared to a local buildout that would be necessary absent regional transmission upgrades, reducing costs of building new capacity necessary to achieve future system reliability and clean energy needs.
- *Avoided Transmission Investment*: LRTP projects avoid the need for future transmission upgrades by reducing flows on overloaded constraints that would have otherwise required upgrades and replacing aging transmission facilities projected to be rebuilt in the next 10–20 years due to age and condition.
- *Resource Adequacy Savings*: LRTP projects increase transfer capability, which allows access to resources in constrained areas and defers the need for investment in local resources;
- *Avoided Risk of Load Shedding*: LRTP projects enhance the resilience of the grid and reduce risk of load loss caused by severe weather events.

To estimate each of the benefit metrics for the LRTP portfolio, MISO utilized forward-looking projections of electricity demand, generation resources, and fuel prices based on the December

[18] MISO Tranche 1 Report, p. 16.

2021 Series 1 MISO Futures Report.[19] The Series 1 MISO Futures include three forward-looking scenarios (Future 1, Future 2, and Future 3) that incorporate progressively higher levels of electrification demand, coal and gas plant retirements, and renewable energy additions. MISO considered the transmission needs in each future scenario in developing the Tranche 1 portfolio and then specifically modeled the Future 1 scenario for the LRTP Tranche 1 benefits analysis.

Future 1 accounts for the following assumptions for electricity demand, generation resources, and natural gas prices:

- *Electricity Demand*: Future 1 assumes electricity demand growth is driven by existing economic factors, with limited EV adoption, resulting in a demand growth rate for MISO of 0.5% per year, lower than the demand growth of 1.1% per year for Future 2 and 1.7% per year for Future 3.[20] Specifically for Wisconsin, 2039 demand projections are 85,500 GWh, compared to 69,876 gigawatt hour ("GWh") of demand in 2022, a 1.2% per year growth rate.[21]
- *Renewable Energy Capacity*: Future 1 accounts for achieving 85% of non-legislated state goals, including Wisconsin's goal to be carbon free by 2050, and 100% of utility integrated resource plan ("IRP") announcements resulting in a 40% reduction in carbon dioxide emissions by 2039 relative to a 2005 baseline.[22] Total MISO-wide renewable energy capacity in 2039 is 82 gigawatt ("GW") in Future 1 compared to 109 GW in Future 2 and 183 GW in Future 3.[23] Renewable energy generation as a share of total 2039 generation in Future 1 is 26%. Future 2 reaches 35% renewable energy generation and Future 3 includes 46%.
- *Natural* Gas *Prices*: MISO developed generator-specific natural gas prices at a monthly granularity using its Gas Price Competition Model ("GPCM") based on the best-available information as of Q1 2020.[24] Average annual Henry Hub gas prices were $2.65/million British thermal units ("MMBtu") in 2030, $2.85/MMBtu in 2035, and $3.10/MMBtu in 2040 (in 2018 dollars).

As noted above, MISO's Future 1 scenario represents a conservative outlook of the future power sector with less electricity demand and renewable energy generation than Future 2 and

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19 MISO, MISO Futures Report, December 2021. ("MISO Futures Report")

20 MISO Futures Report, p. 20.

21 EIA, EIA-861 Annual Electric Power Industry Report, October 5, 2023.

22 MISO Futures Report, pp. 3, 12.

23 MISO Futures Report, pp. 4–6.

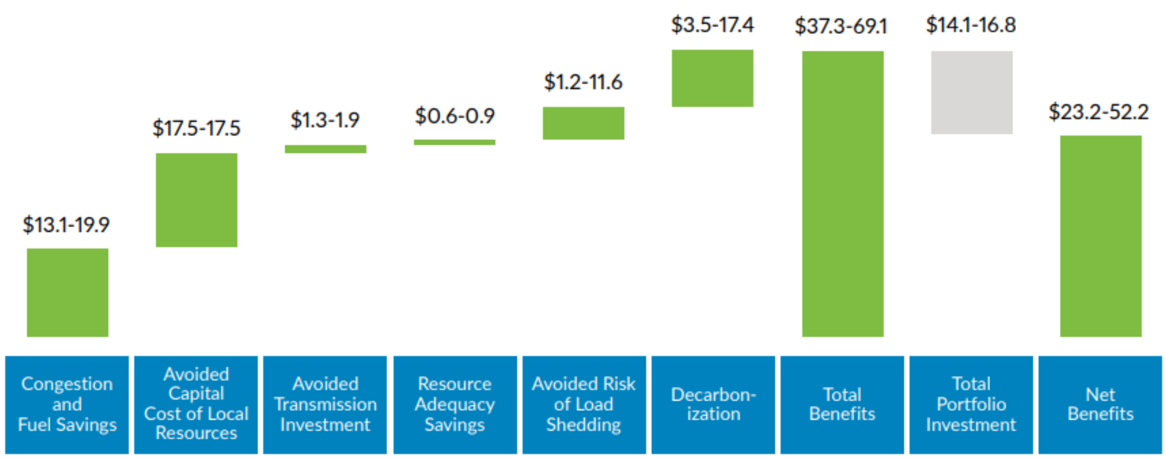
24 MISO Futures Report, p. 91

Future 3. Analyzing the benefits of transmission projects included in the Tranche 1 portfolio using conservative assumptions results in lower benefits than the benefits of the same project in a future scenario with higher demand and renewable energy generation. The lower demand and renewable energy generation in Future 1 limits the stress on the system when transmission upgrades are the most valuable.

C. Benefits Results

MISO identified total benefits of the Tranche 1 portfolio of $37–69 billion compared to $14–17 billion of costs, resulting in $23–52 billion in net benefits and a benefit-cost ratio between 2.6 and 3.8, as shown in Figure 4 below.[25] The majority of the Tranche 1 benefits are due to reduced congestion and fuel savings, reduced greenhouse gas ("GHG") emissions, and avoided costs of local generation resources. These results demonstrate that the proposed investment in the Tranche 1 projects provides significant long-term value to MISO customers, even under conservative Future 1 assumptions.

FIGURE 4: TRANCHE 1 20–40 YEAR PRESENT VALUE OF BENEFITS VS. COSTS (2022$ BILLION)



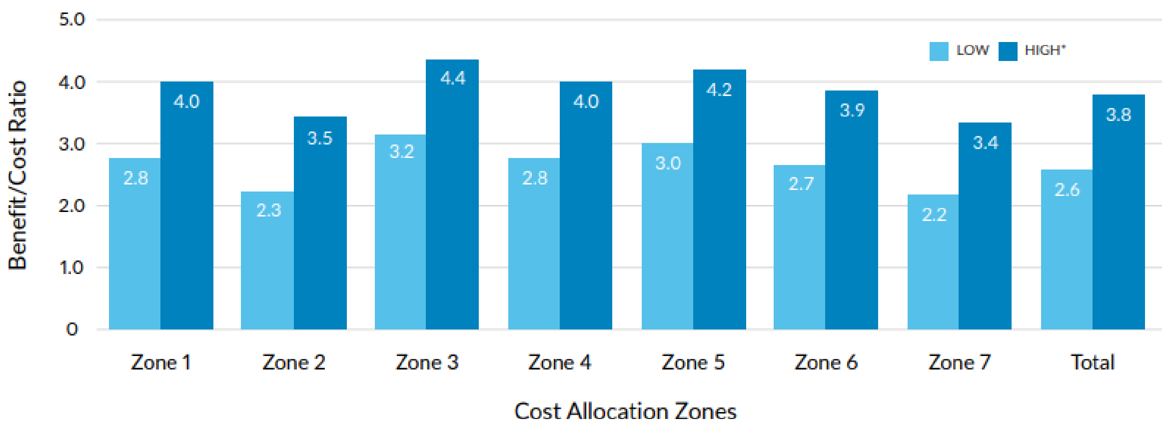
Source and notes: MISO Tranche 1 Summary, p. 3. Assumes a 6.9% discount rate.

The benefits of the Tranche 1 portfolio are widespread across the MISO Midwest region. MISO estimates that the benefit-cost ratio of the Tranche 1 portfolio is at least 2.2 across all zones, as shown in Figure 5 below. Wisconsin ratepayers are located in both Zone 1 (17%) and Zone 2 (83%). Both of these zones have a similar range of benefits relative to their costs, with a

[25] MISO quantified the benefits and costs of the LRTP Tranche 1 portfolio using two assumptions for the timeframe (20 years and 40 years) and two discount rates (utility weighted-average cost of capital of 6.9% nominal and a societal discount rate of 3.0% nominal). MISO Tranche 1 Summary, p. 3.

benefit-cost ratio of 2.3–2.8 at the low end and 3.5–4.0 at the high end.[26] MISO's analysis demonstrate that the drivers of benefits are generally consistent across zones, with Zone 2 having a slightly higher share of its benefits from avoided costs of local generation and avoided transmission costs relative to other zones.

FIGURE 5: TRANCHE 1 ZONAL BENEFIT-COST RATIOS, 20-YEAR PRESENT VALUE



Source: MISO Tranche 1 Summary, p. 4.

MISO did not calculate state-level costs and benefits, but the zonal analysis demonstrates that Wisconsin ratepayers will receive significant benefits from the Tranche 1 portfolio. Based on the Zone 1 and Zone 2 results, the Tranche 1 portfolio will produce about $5.0–9.0 billion of benefits to Wisconsin ratepayers over the life of the projects, compared to $2.1–2.5 billion in costs.[27]

MISO evaluated the benefits of the Tranche 1 portfolio as a whole to ensure that the portfolio provides net savings to the MISO Midwest regions that would be allocated its costs. MISO included each project in the portfolio to meet a specific need identified by reliability, economic, and policy drivers reviewed during the portfolio development process.

The Tranche 1 projects benefit Wisconsin ratepayers by enabling greater imports of low-cost energy from Minnesota and improving its deliverability within Wisconsin. MISO expects west to east flows from Minnesota to Wisconsin will increase as renewable buildout continues in Minnesota. The Tranche 1 projects, especially the southern Minnesota-Wisconsin projects (Projects 4, 5, and 6), will reduce congestion on transmission paths into Wisconsin and provide an outlet to deliver that energy to the Madison and Milwaukee area load centers in Wisconsin.

26 MISO Tranche 1 Summary, p. 4.

27 We assume Wisconsin ratepayer benefits are weighted based on its share of load in Zone 1 (17%) and Zone 2 (83%) and that its costs are equal to 15.5% of total MISO Midwest costs.

These projects also bolster voltage stability, increase the transfer capability into and across Wisconsin, and relieve overloads on 345 kV and 161 kV facilities throughout central Wisconsin, avoiding higher-cost upgrades that provide limited congestion benefits and production cost savings.[28] An updated analysis of the overloaded facilities relieved by Project 4 and avoided transmission upgrade costs is summarized below in Section IV.D.

The MISO Future 1 analysis understates the congestion and fuel savings benefits of the Tranche 1 portfolio by modeling a conservative future scenario with low load growth, limited fossil fuel retirements, and lower than projected adoption of renewable energy and storage. For example, the recent historical absolute price difference between Minnesota and Wisconsin has been $18/MWh, as noted above, but the simulated price difference is only $8/MWh in 2030 for Future 1.

In addition, MISO's market simulations do not include the most challenging system conditions when transmission provides the most value to the system. Lawrence Berkeley National Laboratory ("LBNL") found that 50% of the value of transmission to relieve system congestion occurs in 5% of hours during the most challenging market conditions.[29] MISO's production cost models do not consider the value of transmission during cold snaps, heat waves, transmission outages, and generation outages. The MISO analysis only considers day-ahead energy market conditions in a normalized weather year, but not the real-time market that frequently experiences challenging system conditions. Incremental transmission capacity will provide additional benefits in the real-time energy market by increasing the system's flexibility to respond to unexpected disturbances, such as higher than expected load and lower renewable energy output than projected in the day-ahead energy market and unplanned generation and transmission outages. Incorporating the real-time impacts of additional transmission capacity between regions with 30–40% renewable energy penetration can increase production cost savings by 300–600%.[30,31]

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[28] MISO Tranche 1 Report, pp. 30–36.

[29] Millstein, Dev, et al., Empirical Estimates of Transmission Value using Locational Marginal Prices. August 2022. p. 3.

[30] Future 1 includes sufficient solar and wind generation resources to meet 18% of MISO Midwest annual energy demand and Future 2A meets 37% of annual energy demand with solar and wind.

[31] Van Horn, Kai, et al. The Value of Diversifying Uncertain Renewable Generation through the Transmission System. September 2022. p. 24.

Despite these factors, MISO identified significant benefits across several drivers of new transmission, including reliability, economic, and policy drivers, under conservative conditions, highlighting the crucial need to increase transmission capacity across MISO and in Wisconsin.

III. Project 4 Costs and Benefits to Wisconsin Ratepayers

Project 4 adds transmission capacity for Wisconsin utilities to access low-cost resources—especially wind—from Minnesota and Iowa. We estimated the costs and benefits of Project 4 to Wisconsin ratepayers relative to the No Action case across three future scenarios. We compare the net benefits of Project 4 against a lower-voltage alternative (LVA) and a non-transmission alternative (NTA). To further demonstrate the benefits of Project 4, we evaluated the net benefits of the full portfolio of Wisconsin LRTP Tranche 1 projects (LRTP 4–6, or "the Tranche 1 portfolio"). Our analysis of Project 4, the Tranche 1 portfolio, and the alternative cases' benefits to Wisconsin ratepayers closely follows MISO's stakeholder-vetted approach to quantifying Tranche 1 benefits and costs.

This section summarizes the alternative cases for increasing transfer capability into Wisconsin, the future scenarios evaluated, the analytical approach to estimating benefits, and the benefits and costs to Wisconsin ratepayers. Section IV provides additional details on the analysis of each benefit metric.

A. Alternative Cases Evaluated

We considered the following four alternative cases for evaluating the net benefits of the Alma-Blair 345 kV project.

NO ACTION CASE

The No Action Case assumes no portion of Project 4 is built in either Minnesota or Wisconsin. The other Wisconsin LRTP Tranche 1 projects (Projects 5 and 6, or "LRTP 5" and "LRTP 6") are assumed not to be built in two out of three scenarios we evaluated. All of the other Tranche 1 projects located outside of Wisconsin are included in the No Action case and the alternative cases analyzed. The No Action case serves as the "base case" against which the other cases' benefits are evaluated in this analysis.

PROJECT 4 CASE

The Project 4 Case assumes that Project 4 ("LRTP 4"), including the Alma-Blair 345 kV line, is built as approved by MISO. Dairyland constructs the new Alma-Blair 345 kV line in Wisconsin on a double circuit tower, rebuilding the existing Alma-Tremval 161 kV on the second circuit position. The existing Badger Coulee 345 kV line is cut-in to the new Blair 345 kV substation. The Minnesota portions of Project 4 are also built, including the new Wilmarth-N. Rochester-Alma 345 kV line and the Kellogg 161/69 kV substation in Minnesota. The Project 4 case adds about 1,600 MW of transmission capacity (under normal operating conditions) between Minnesota and Wisconsin.[32]

Based on estimated capital costs of $689 million (in 2022 dollars) for Project 4, the total present value of revenue requirements ("PVRR") over a 40-year timeframe is $1.1 billion (2022 dollars). As a MISO MVP project, Wisconsin ratepayers are allocated a portion of the Project 4 costs based on Wisconsin's projected load-ratio share within the MISO Midwest region of 15.5%. [33] Based on this cost allocation approach, the Project 4 PVRR allocated to Wisconsin ratepayers is $174 million (in 2022 dollars).[34]

TRANCHE 1 CASE

To further demonstrate the benefits of Project 4, we also evaluated the net benefits of adding all three LRTP Tranche 1 projects located in Wisconsin as a portfolio ("Tranche 1 case").[35] As with the other transmission alternative cases, we estimated the net benefits of the Tranche 1 portfolio by comparing it to the No Action case. MISO estimates total capital costs of the Wisconsin portfolio of Tranche 1 projects to be $2.2 billion (in 2022 dollars) with a 40-year PVRR of $3.8 billion (2022 dollars). The PVRR of the three Tranche 1 projects allocated to Wisconsin ratepayers is $566 million (in 2022 dollars).

[32] Normal operating limits of new Alma-Tremval 345 kV line provided by Dairyland.

[33] Purdue University State Utility Forecasting Group, 2023 MISO Independent Energy and Peak Demand Forecast, November 2023.

[34] Project 4 capital costs based on MISO Tranche 1 Summary, p. 2. The revenue requirement is calculated consistent with MISO's approach in the LRTP Tranche 1 Detailed Business Case Analysis spreadsheet assuming a 6.9% discount rate.

[35] In addition to Project 4, the Wisconsin Tranche 1 projects include the Tremval-Eau Claire-Jump River 345 kV line (Project 5) and Tremval-Rocky Run-Columbia 345 kV line (Project 6).

LOW VOLTAGE ALTERNATIVE CASE

The Low Voltage Alternative (LVA) Case assumes Dairyland builds the new Alma-Blair transmission line at 161 kV instead of 345 kV. The Minnesota 345 kV portion of Project 4 is still built as approved by MISO, terminating at the Kellogg substation with a new Kellogg 345/161 kV transformer added to the Kellogg substation. The new 161 kV line is then built from Kellogg to the Tremval 161 kV substation in Wisconsin on a double circuit tower and the existing Alma-Tremval 161 kV is installed on the new towers. The LVA case adds about 400 MW of transmission capacity between Minnesota and Wisconsin.[36]

Dairyland estimates the total capital costs of the Minnesota portion of Project 4 and the Kellogg-Blair 161 kV line are $622 million (2022 dollars), lower than the $689 million (2022 dollars) capital costs of Project 4 as proposed by MISO.[37] The Kellogg-Blair 161 kV line ($87 million capital costs, in 2022 dollars) does not qualify for MISO MVP cost allocation and instead would be paid for solely by Dairyland's customers, with 65% of the PVRR allocated to Dairyland's Wisconsin ratepayers.[38] Thus, the LVA PVRR allocated to Wisconsin ratepayers would be $227 million (in 2022 dollars) over a 40-year timeframe, including $135 million for the Wisconsin share of the Minnesota portion of Project 4 (as in the Project 4 case) and $92 million for the new Kellogg-Blair 161 kV line (2022 dollars). Despite providing only 25% of the transfer capacity of Project 4, the PVRR allocated to Wisconsin ratepayers is 30% higher than Project 4 due to the cost allocation for LRTP projects and local upgrades.

NON-TRANSMISSION ALTERNATIVE CASE

The Non-Transmission Alternative (NTA) Case assumes Dairyland builds 100 MW of battery storage capacity at the Briggs Road 345 kV substation to support cost-effective transfers across the existing Badger Coulee 345 kV line. The capacity of the battery storage resource was sized such that the capital costs for the battery energy storage system ("BESS") are similar to the gross costs of the Wisconsin portion of Project 4. No new transmission lines related to Project 4 are built in Wisconsin and the existing Alma-Tremval 161 kV line is not rebuilt. The Minnesota

[36] Normal operating limits of new Alma-Tremval 161 kV line provided by Dairyland.

[37] Dairyland estimated LVA capital costs based on MISO's MTEP22 cost estimation guide for consistency with Project 4 cost estimates. MISO, Transmission Cost Estimation Guide For MTEP22, April 12, 2022.

[38] We assume Dairyland's Wisconsin customers pay for their load-ratio share of the PVRR (65%).

portion of Project 4 is built up to the Kellogg substation, but only the Wilmarth-North Rochester 345 kV line is energized.[39]

Dairyland estimated the capital costs of the transmission facilities in Minnesota in the NTA case to be $538 million (2022 dollars).[40] The 100 MW battery storage resource is built in 2030 and then fully replaced in 2050 assuming a 20-year life of battery storage resources. The PVRR of the NTA case to Wisconsin ratepayers is $390 million (2022 dollars), including $136 million (2022 dollars) for the Minnesota upgrades and $254 million (2022 dollars) for the battery storage resource.[41]

COSTS OF ALTERNATIVE CASES

The costs of the alternative cases are summarized in Table 1 below. For each case, we converted the capital costs of the transmission projects to the 40-year PVRR values using MISO's revenue requirement assumptions. For LRTP projects, Wisconsin ratepayers will pay for their load-ratio share of the transmission revenue requirements of 15.5%. In the LVA and NTA cases, the revenue requirements for non-LRTP projects (including the new 161 kV line for the LVA case and the battery storage for the NTA case) are fully allocated to Dairyland ratepayers.

TABLE 1: PROJECT 4 AND ALTERNATIVE CASE COSTS (2022 DOLLARS, MILLION)

	Project 4 Case	Tranche 1 Case	LVA Case	NTA Case
Total Transmission Capital Costs	**$689**	**$2,244**	**$622**	**$538**
WI-Allocated Transmission PVRR	$174	$566	$227	$136
WI-Allocated Battery Storage PVRR	---	---	---	$254
WI-Allocated Total PVRR	**$174**	**$566**	**$227**	**$390**

39 Energizing the N. Rochester to Kellogg 345 kV line without a high-voltage outlet at the Kellogg 345 kV substation creates congestion that increases Wisconsin ratepayer costs.

40 In Table 1, the difference between $689 million transmission capital costs in the Project 4 Case and the $538 million transmission capital costs in the NTA case is $151 million, which is the transmission capital costs of the Wisconsin portion of Project 4 that is not built in this case. Dairyland estimated NTA transmission capital costs based on MISO's MTEP22 cost estimation guide for consistency with Project 4 cost estimates. MISO, Transmission Cost Estimation Guide For MTEP22, April 12, 2022.

41 The projected 2030 battery storage overnight capital costs are from NREL 2024 Annual Technology Baseline ($1,965/kW, nominal dollars), assuming a cost recovery period of 20 years, and the conservative scenario for the NREL ATB 4-hour storage technology (due to recent supply chain issues resulting in cost increases). The annual revenue requirement was assumed to be 10.75% of the projected capital costs over 20 years, based on the recently updated PJM CONE values. This results in an annual revenue requirement for the initial 20 years (2030–2040) of $21.2 million per year (nominal dollars). Revenue requirements in later years are slightly higher, $22.49 million for 2050–2069, due to projected increases in battery storage capital costs. PJM CONE source: The Brattle Group and Sargent & Lundy, Sixth Review of PJM's RPM VRR Curve Parameters: Preliminary Gross Cone And E&As Methodology, November 2024.

Note: "PVRR" stands for Present Value of Revenue Requirements.

B. Future Scenarios Analyzed

We evaluate the alternative cases for increasing transfers between Minnesota and Wisconsin under three future scenarios that differ in the following ways:

- MISO-developed a long-term projection of demand and generation resources (i.e., Future 1 vs. Future 2A),
- Modifications to future Wisconsin generation resources requested by PSCW Staff, and
- The approval and construction of Projects 5 and 6 are constructed in the No Action case.

The assumptions for each of the three scenarios are summarized in Table 2 and further explained below.

TABLE 2: STUDY SCENARIO DEFINITIONS

Scenario	MISO Future	PSCW Resource Updates	LRTP 5&6
Scenario 1	MISO Future 1	Included	Not Built
Scenario 2	MISO Future 2A	Included	Not Built
Scenario 3	MISO Future 2A	Not Included	Built

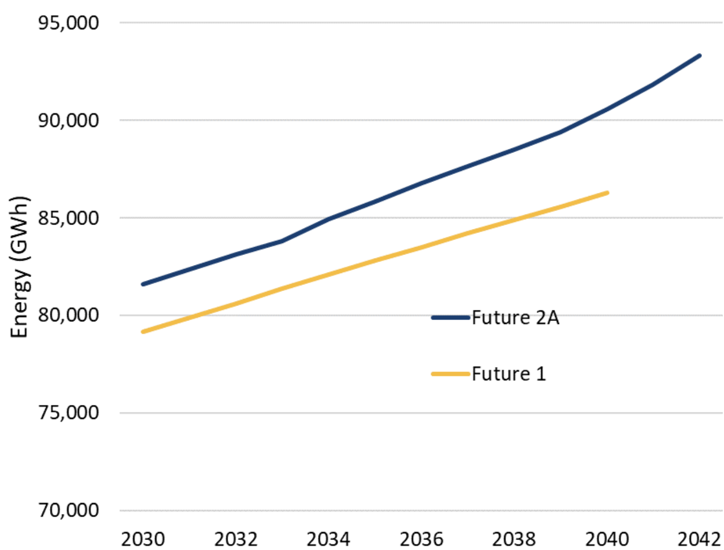
MISO FUTURE 1 AND FUTURE 2A

MISO regularly updates its long-term projection of electricity demand and generation resources in its "Futures" reports. The Futures report includes three scenarios with increasing demand growth and changes to its resource mix. The Futures were most recently developed in 2020 (Series 1) and 2022 (Series 1A). MISO evaluated all three futures in developing needs for its future transmission system in both Tranche 1 and Tranche 2 and specifically utilized Future 1 ("F1") from Series 1 in analyzing the benefits of the Tranche 1 portfolio and Future 2A ("F2A") from Series 1A in analyzing the Tranche 2.1 portfolio. As noted above, F1 is a more conservative case with less load growth and changes in the generation mix, while F2A assumes significantly higher load growth and greater generation resource additions and retirements in Wisconsin and throughout MISO.

The market assumptions in the PROMOD simulations reflect the following assumptions included in MISO F1 and F2A:

- *Electricity demand*: MISO peak demand grows at 0.7% per year and annual energy demand grows by 0.7% per year in F1 while F2A projects higher peak load growth of 1.1% per year and annual energy growth of 1.25% per year. The projected demand growth results in Wisconsin demand of 86 terawatt hour (“TWh") in 2040 in F1 and 93 TWh in 2042 in F2A, as shown in Figure 6 below.[42] Total MISO demand reaches 776 TWh in 2040 in F1 and 858 TWh in 2042 in F2A. Notably, MISO released an updated load forecast in December 2024 that accounts for the recent increase in large load customers (i.e., data centers and manufacturing facilities) locating within MISO. Based on this updated process, the MISO forecasts shows that its peak load is projected to increase by 1% to 2% per year through the 2040s, a substantial increase from the 0.4% to 1.1% per year rate reported in the Futures Series 1A report.[43]

FIGURE 6: WISCONSIN ELECTRICITY DEMAND GROWTH PROJECTIONS THROUGH 2042



Sources: MISO Future 2A PROMOD Database and MISO Future 1 PROMOD Database.

- *Wisconsin electrification, energy efficiency and distributed resource projections*: MISO assumes significant increases in the adoption of transportation and building electrification, energy efficiency, distributed generation resources, and demand response relative in F2A compared to F1. MISO assumes 12.5 million EVs on the road by 2039, adding 40 TWh of demand, and that heating electrification adds another 80 TWh of demand in F2A. MISO also assumes that demand response capacity increases from 0.9 GW to 11.2 GW (a 12x increase from Future 1), distributed solar increases from 3.5 GW to 19.9 GW (a 6x increase), and

[42] The given total demand values include impacts of energy efficiency and electrification, but do not account for reductions due to customer solar.

[43] MISO, Long-Term Load Forecast, December 2024, p. 3.

demand reductions due to energy efficiency increase from 31 TWh to 76 TWh (a 2.5x increase). Table 3 summarizes MISO's projections of distributed energy resources by 2040-2042.

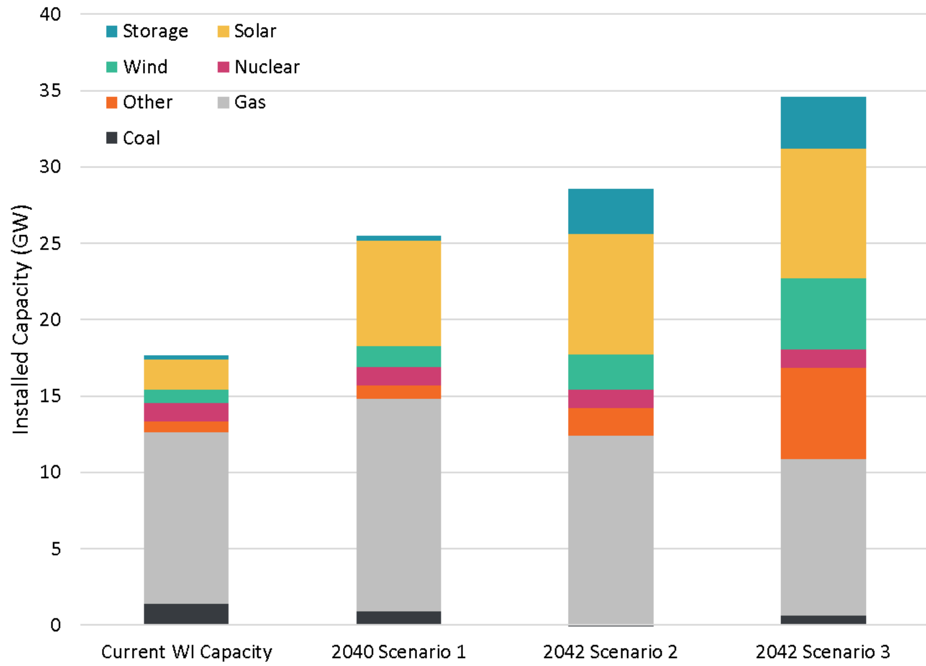
TABLE 3: 2040-2042 DISTRIBUTED ENERGY RESOURCE PROJECTIONS BY MISO FUTURE SCENARIO

	Capacity (GW)		Energy (GWh)	
	Future 1	Future 2A	Future 1	Future 2A
Demand Response	0.9	11.2	118	1,147
Energy Efficiency	7.8	17.7	30,801	75,620
Distributed Generation	3.5	19.9	5,709	34,977
Wisconsin Customer Solar	0.3	1.6	601	2,724

Sources: MISO Futures Report and MISO Futures Series 1A Report.

- *Wisconsin supply resources*: MISO assumes the Wisconsin generation mix undergoes an extensive transformation through the early 2040s across all scenarios due to the projected resource costs, resource adequacy needs, and future clean energy goals, as shown in Figure 7 below. In 2024, coal and gas resources make up over two-thirds of Wisconsin's generation resources, while wind and solar account for less than a fifth of installed nameplate capacity. By 2040, Scenario 1, based on MISO F1, includes relatively small changes to the existing fossil fleet (adding 3 GW of gas and retiring 0.5 GW of coal), but adds 5 GW of solar. Scenario 2 and Scenario 3, based on MISO F2A, sees a much more extensive transformation of the Wisconsin generation fleet adding 6-7 GW of solar, 1-4 GW of wind, and 3 GW of storage, while seeing minimal shifts in gas and retiring nearly all coal. Scenario 2 and 3 generation resources differ due to changes to the F2A resources requested by PSCW described further below.

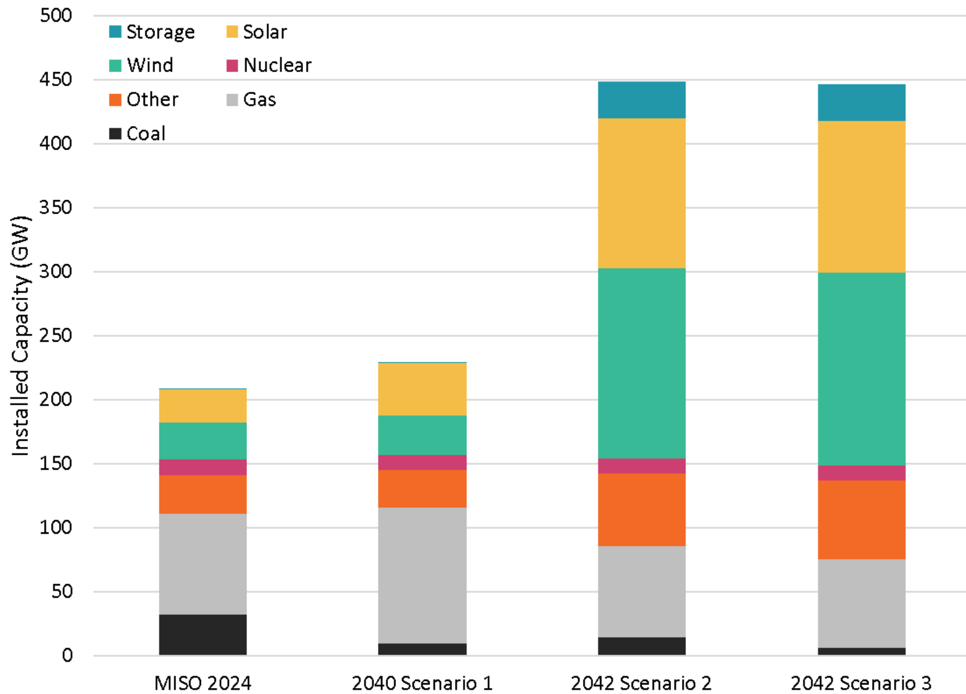
FIGURE 7: WISCONSIN INSTALLED CAPACITY BY SCENARIO



Notes: "Other" include RICE, Oil, Hydro, Transaction, Geothermal, Industrial Loads, Demand Response, Flex.

- *MISO supply resources*: MISO assumes limited changes to the MISO Midwest resource in Future 1, but much more significant transformation of generation resources in Future 2A. By 2040, Scenario 1 (based on Future 1) includes an additional 15 GW of solar and 2 GW of wind and retires 23 GW of coal. By 2042, Scenario 2 and 3 (based on Future 2A) have a similar MISO Midwest similar resource mix (differing slightly based on PSCW modifications) that, when compared to 2024 values, includes an additional 119-122 GW of wind, 91-92 GW of solar, and 28 GW of storage, while reducing gas capacity by 7-9 GW and coal capacity by 18-26 GW. The regional growth in renewable capacity, particularly new wind installations in southern Minnesota and northern Iowa, will intensify historically observed transmission congestion along the Minnesota-Wisconsin interface and increase the need for the additional transfer capacity to cost effectively serve Wisconsin demand.

FIGURE 8: MISO INSTALLED CAPACITY BY SCENARIO

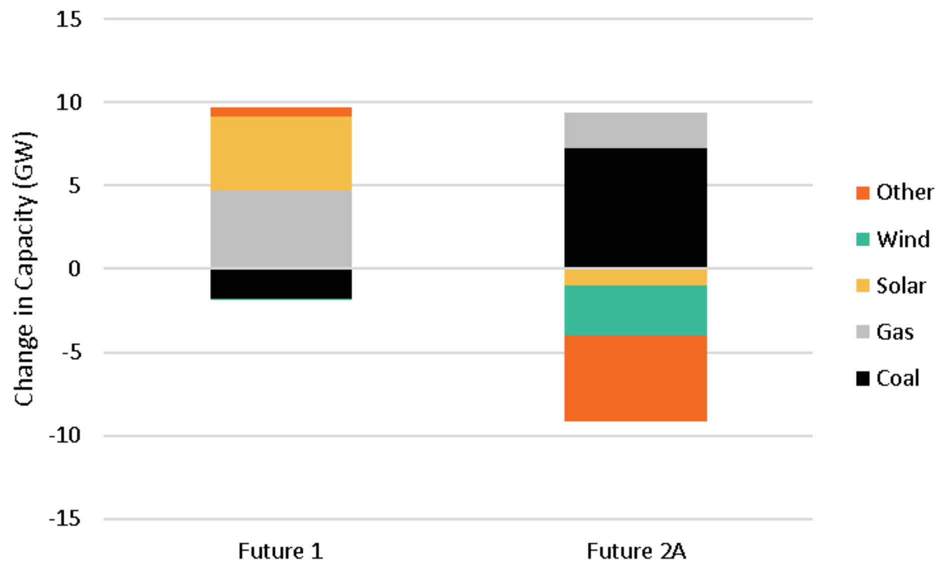


Notes: “Other” include RICE, Oil, Hydro, Transaction, Geothermal, Industrial Loads, Demand Response, Flex.

PSCW STAFF RESOURCE MODIFICATIONS

The PSCW Staff reviewed the generation assumptions in F1 and F2A and requested several changes to the future generation resource mix, primarily adding Wisconsin resources that have come online since the development of the MISO scenarios, removing new units within Wisconsin that have not yet received Commission approval for construction, and adding back resources in Wisconsin and surrounding states that have not yet officially announced a retirement date. The requested changes reflect the limited certainty of existing generation resources retiring and new generation resources being added to the system primarily in Wisconsin as projected by MISO in its Futures development. Figure 9 shows the total modifications of capacity by resource type requested by PSCW Staff. For Future 1, PSCW Staff modifications increase gas (+6.5 GW), solar (+5.0 GW), wind (+0.7 GW), and storage (+0.6 GW) and decrease coal (-3.0 GW). For Future 2A, the PSCW Staff requested to delay the retirement of gas (+2.1 GW) and coal (+7.8 GW) and remove wind (-3.0 GW), solar (-0.9 GW), and not-yet-approved “flex” units (-5.1 GW) included in the “Other” category.

FIGURE 9: PSCW STAFF REQUESTED CHANGES IN GENERATION RESOURCES



Notes: For Future 2A, the significant change in "Other" category is due to Flex decreasing capacity by 4.3 GW. Nuclear not included as change is zero. The PSCW resource updates affect mostly Wisconsin resources, with a minority of changes affecting other states' supply mix.

LRTP PROJECTS 5 & 6 ASSUMPTIONS

Concerning the other Wisconsin-based LRTP projects, MISO developed the Tranche 1 portfolio of projects so that each project provides net benefits to the system. MISO then analyzed the Tranche 1 projects as a portfolio to demonstrate the overall benefits across the MISO Midwest system. As noted above in Section III, MISO specifically developed Projects 4, 5 and 6 as a package to resolve several issues along the Minnesota and Wisconsin border. Regardless of origin of the projects, the Commission must decide whether to approve the construction of each project on its own merits. For that reason, we are primarily evaluating the benefits of Project 4 on its own, utilizing scenarios that either include Projects 5 and 6 (Scenarios 1 and 2) or do not include these projects (Scenario 3). As noted above the Tranche 1 case includes Projects 4, 5 and 6 and is compared to the No Action case without Projects 4, 5 and 6 and so is only evaluated in Scenarios 1 and 2.

C. Benefits Analysis Approach

The Project 4 benefits analysis considers the following four benefit metrics, which account for the majority of the total Zone 1 and Zone 2 benefits MISO calculated for the Tranche 1 portfolio.[44] Additional details on the approach to analyzing each benefit metric are included in Section IV.

- *Fuel and Congestion Cost Savings*: The MISO APC metric captures ratepayer costs based on each company's total generation fleet production costs, import payment costs, export sales revenues, and transmission congestion revenues.[45] We calculate the APC savings to Wisconsin customers based on PROMOD simulations of the MISO system, similar to MISO. Our Scenario 1 analysis simulates the years 2030 and 2035, while our Scenario 2 analysis simulates the years 2032, 2037, and 2042. Consistent with MISO's Tranche 2 analysis, we hold the resource mix constant between the No Action and the alternative cases.[46] For each simulation, we compare each utility's APC in the No Action case to its APC in the alternative cases. We calculate the fuel and congestion cost savings benefit to Wisconsin as the sum of the APC savings for all Wisconsin utilities.[47] We extrapolate the benefits of each case over a 40-year timeframe by assuming the APC savings in the last year simulated remain constant in real dollars.
- *Decarbonization Benefits of Reduced GHG Emissions*: The alternative cases each enable Wisconsin access to clean and low-cost generation produced from neighboring regions, reducing GHG emissions in Wisconsin and other states. We calculate the difference in MISO-wide GHG emissions between the No Action case and each of the alternative cases based on the results of the PROMOD simulations. Due to Wisconsin's commitment to reduce GHG emissions in line with the Paris Agreement, we include all GHG emissions reductions enabled by the Commission's decision to approve Project 4 in the benefits analysis, noting in Section IV.B below that most GHG emissions reductions occur within Wisconsin. We value emissions reductions at $85–$249/metric ton (2024 dollars) consistent with MISO's updated

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[44] In the MISO LRTP Tranche 1 Detailed Business Case Analysis spreadsheet, the 40-year NPV of Zone 1 and Zone 2 benefits using a 6.9% discount rate ranges from $15.1 billion to $22.6 billion (2022 dollars). The benefits from the four metrics included in this analysis (Congestion and Fuel Savings, Avoided Capital Cost of Local Resource Investment, Avoided Transmission Investment, and Decarbonization) range from $14.5 billion to $18.8 billion.

[45] MISO, MISO Adjusted Production Cost Calculation White Paper, April 22, 2021.

[46] In Tranche 1, MISO added 20 GW of renewable energy and storage resources to the Change Case with the Tranche 1 projects.

[47] For the APC calculation, we consider Dairyland and Northern States Power with 65% and 17% of the benefits applied to Wisconsin, respectively. Additionally, we consider 100% of the benefits applied to Wisconsin, based on the results from Alliant East, Madison Gas and Electric, Wisconsin Electric Power Company, and Wisconsin Public Service Company.

carbon price assumptions in its Tranche 2 benefits analysis based on recent state and federal regulatory proceedings.[48]

- *Avoided Local Generation Capital Costs*: Project 4, Tranche 1, and the LVA lower Wisconsin utilities' costs by increasing transfer capability from Minnesota and enabling procurement of lower-cost out-of-state wind capacity instead of higher-cost local solar. We calculate this benefit as the net costs savings of Minnesota wind compared to Wisconsin solar resources.[49] This approach differs from the MISO approach to calculating the avoided local generation capital costs in its Tranche 1 analysis, in which regional upgrades reduce the future system's total renewables and storage capacity buildout needs. We provide an estimate of the benefits using MISO's Tranche 1 approach for informational purposes. For the NTA case, we estimated the avoided costs of a new gas-fired combustion turbine resource due to the addition of the BESS based on (1) the capacity accreditation of BESS and gas combustion turbine and (2) the most recent estimate of the cost of new entry or "CONE" in MISO's capacity market.
- *Avoided Transmission Capital Costs*: If Project 4 were not built, several upgrades in DPC and neighboring territories would be required to maintain system reliability or replace aging infrastructure. Project 4 addresses these transmission needs more cost-effectively than the portfolio of avoided upgrades, thereby benefiting Wisconsin in the long term. The analysis of avoided transmission costs is based on updated reliability analysis for each alternative case. The results of the reliability analysis are summarized in a technical report included in the Project 4 CPCN application.[50] This analysis accounts for only the avoided capital costs of the transmission upgrades allocated to Wisconsin ratepayers.

D. Net Benefits Results for Alternative Cases

Based on our analysis of the alternative cases across the three scenarios, the Project 4 case results in positive net benefits to Wisconsin ratepayers across all scenarios ranging from $337

[48] The greenhouse gas prices used in the analysis of LRTP are consistent with MISO's assumptions in its LRTP report that are based on the value of GHG reductions in federal and state regulatory proceedings. See more information at MISO, LRTP Tranche 2.1 Benefit Metrics Development: Overview of Methodologies, June 10, 2024, p. 51.

[49] We define net energy value savings as the difference between levelized cost and energy market revenues, scaled to the transfer capability expansion enabled by each Transmission Upgrade alternative.

[50] Dairyland Transmission Planning, Alma-Blair 345 kV Transmission Planning Reliability Review, June 2024; Dairyland Transmission Planning, Supplement Analysis to the Alma-Blair 345 KV Transmission Planning Reliability Review, February 2025.

million to $1,083 million (2022 dollars), as shown in Table 4 below. Project 4 net benefits are significantly higher than the LVA and NTA net benefits. Project 4 benefits are the highest in Scenario 2 ($846–$1,083 million, 2022 dollars) based on the MISO F2A scenario and without Projects 5 and 6 online, and the lowest in Scenario 1 ($337–$456 million) based on the more conservative MISO F1 scenario. The Tranche 1 results further demonstrate that Project 4 provides net benefits to Wisconsin as a part of the broader Tranche 1 portfolio of projects located in Wisconsin, resulting in the largest benefit across all cases analyzed of $580 million to $1,740 million (2022 dollars).

TABLE 4: 40-YEAR NET BENEFITS OF PROJECT 4 AND ALTERNATIVES (2022 DOLLARS, MILLION)

	Scenario 1	Scenario 2	Scenario 3
Project 4 Case	$337–$456	$846–$1,083	$652–$800
Tranche 1 Case	$580–$1,057	$1,213–$1,740	—
LVA Case	($82)–($37)	$240–$327	$229–$336
NTA Case	($331)–($307)	($165)–($134)	—

Notes: The NTA and Tranche 1 cases do not have Scenario 3 net benefits because the NTA case with 100 MW BESS did not get re-run through Scenario 3 (previously modeled an older NTA case that included 14 MW BESS in Scenario 3) and Scenario 3 already includes LRTP 5 and 6 in the Scenario 3 base case.

The LVA case results in a lower net benefit of negative $82 million to positive $336 million (2022 dollars) across scenarios, significantly lower than Project 4 and Tranche 1. The NTA results in negative net benefits to Wisconsin ratepayers in both scenarios due to limited APC savings, reduced GHG emissions, and avoided transmission costs.

PROJECT 4 CASE

Project 4 increases Wisconsin's ability to import low-cost power from Minnesota and Iowa by reducing congestion across the Wisconsin-Minnesota border and providing a low-impedance path for low-cost wind resources to reach Wisconsin. In Table 4, the largest benefit in the Project 4 case corresponds to the category of congestion and fuel cost savings ($162 million-$548 million, 2022 dollars) based on the APC savings calculated from PROMOD simulations. Project 4 benefits Wisconsin customers by reducing energy prices—particularly at the Minnesota-Wisconsin border—and cost savings from reduced fuel consumption as more renewable energy flows into Wisconsin. The second largest benefit for the Project 4 Case is the avoided capital costs of local generation ($1250 million–$341 million, 2022 dollars) by allowing Wisconsin utilities to procure lower cost wind resources to meet their renewable energy and GHG goals instead of local solar resources. The addition of Project 4 reduces cumulative GHG emissions over 40 years by 7.6 MMT to 17.3 MMT, resulting in $47 million - $309 million in benefits across scenarios. Finally, the addition of Project 4 will avoid $52 million to $60 million in local reliability and asset renewal projects. In summary, compared to Project 4 Case costs of $174 million (2022 dollars), Project 4 Case has a benefit-cost ratio of 2.9–3.6 for Scenario 1, 5.9–7.2 for Scenario 2, and between 4.8–5.6 for Scenario 3.

TABLE 5: PROJECT 4 DETAILED 40-YEAR NET BENEFITS (2022 DOLLARS, MILLION)

Scenarios	Scenario 1	Scenario 2	Scenario 3
WI Costs (PVRR)	**$174**	**$174**	**$174**
WI Benefits	**$511–$630**	**$1,020–$1,257**	**$826–$974**
Congestion and Fuel Cost Savings	$162	$548	$431
Reduced GHG Emissions Benefit	$47–$138	$105–$309	$61–$178
Avoided Generation Capital Costs	$250–$278	$307–$341	$279–$310
Avoided Transmission Capital Costs	$52	$60	$56
WI Net Benefits	**$337–$456**	**$846–$1,083**	**$652–$800**
Benefit–Cost Ratio	2.9–3.6	5.9–7.2	4.8–5.6

Notes: Present value as of 2030, assuming 6.9% discount rate consistent with MISO LRTP Tranche 1 Business Case.

Figure 10 below shows that the $846 million to $1,083 million (2022 dollars) of Project 4 net benefits in Scenario 2 derive primarily from avoided congestion and fuel savings ($548 million) and avoided capital costs of local generation capacity ($307–$341 million) and far exceed its costs to Wisconsin ratepayers of $174 million (2022 dollars).

FIGURE 10: 40-YEAR PROJECT 4 BENEFITS AND COSTS TO WISCONSIN RATEPAYERS (SCENARIO 2)

Notes: Assumes 6.9% discount rate, consistent with Tranche 1 analysis.

The APC savings we estimate are conservative because the simulations do not capture several key drivers of transmission value that would increase realized Project 4 benefits:

- *High-demand periods* like heat waves or cold snaps strain the transmission system by increasing the likelihood of transmission and generation outages and requiring more generation resources to serve load. Additional transmission capacity would relieve some of this strain by increasing the headroom available for transfers and redirecting power flows away from the most congested elements.
- *Transmission outages* on parallel lines reduce Wisconsin's ability to import low-cost renewable energy from out of state. These outages would increase congestion along the Minnesota-Wisconsin interface, further pushing up energy prices for Wisconsin. Project 4 provides additional import capability into Wisconsin, thereby helping to hedge against transmission outages on the parallel 345 kV lines, including North Rochester-Briggs Road-Columbia, King-Eau Claire, Arrowhead-Stone Lake, and Cardinal-Hill Valley-Hickory Creek. An outage on one of these lines would represent the loss of a low-impedance transmission path into Wisconsin, increasing the potential for congestion at the Minnesota-Wisconsin border and energy prices for Wisconsin consumers.

- *Generation outages* can increase transmission congestion and require the use of more expensive local peaking resources to fill in for the missing supply. Project 4 would reduce system congestion and provide an alternate, lower-cost source of energy to serve Wisconsin load during generation outages.
- *Uncertainty in real-time load and renewable generation* can produce operational inefficiencies that require expensive adjustments to day-ahead dispatch schedules. Project 4 will provide additional flexibility to address this uncertainty by increasing imports, such as when Wisconsin wind generation is significantly lower in real-time than projected in the day-ahead market.
- *Higher natural gas prices* would increase the energy price differences across the Minnesota-Wisconsin interface and therefore the relative value of energy imports enabled by Project 4. As noted below, the projected natural gas prices assumed in Future 2A are lower than current gas futures prices and significantly lower than prices in 2022 that reached $6/MMBtu.
- *Higher than projected load growth* from large new customers like datacenters, industrial facilities, and others would increase Wisconsin energy prices as the state relies on less efficient generation resources to meet demand. The additional energy imports enabled by Project 4 would therefore become more valuable. The recently updated MISO Long-Term Load Forecast demonstrates that the latest forecasts are projecting higher electricity demand in MISO than Future 2A starting in the early 2030s.

In addition to higher APC benefits, Project 4 provides the following additional benefits that were not quantified in our analysis:

- *Utilization of Existing Transmission Corridors*: Project 4 relies on existing transmission corridors in Wisconsin and across the Mississippi River that reduce the costs and environmental impacts relative to alternative routes for a new 345 kV line between Minnesota and Wisconsin that MISO considered in its Tranche 1 analysis.
- *Avoided Generation Capital Costs due to Reduced Losses*: Project 4 reduces losses on the 345 kV transmission system between Minnesota and Wisconsin by offloading the existing lines. To the extent that Wisconsin utilities rely on imports to meet its policy and resource adequacy needs, Project 4 will reduce the quantity of capacity from out-of-state resources due to the reduction in losses.
- *Reduced Cost of Federal Emissions Regulations*: In April 2024, the U.S. EPA released its final Section 111 rule setting carbon pollution standards to reduce greenhouse gas emissions

from existing coal and gas power plants and new gas combustion turbine plants.51 This rule is likely to reduce the output of existing coal and gas resources and increase the demand for renewable energy resources. MISO's Future 2A includes significant coal and gas plants retirements but it does not yet account for potential run limitations of plants that remain operational and potentially higher retirement rates. Project 4 benefits are likely to be even higher once accounting for these changes in resource mix, further increasing Wisconsin's reliance on renewable energy resources and need for access to the rest of the MISO market.

TRANCHE 1 CASE

The portfolio of Tranche 1 projects creates more net benefits to Wisconsin ratepayers than Project 4. Tranche 1 creates \$1,213-\$1,740 million (2022 dollars) of net benefits for Wisconsin in Scenario 2 (resulting in a 3.1-4.1 benefit-cost ratio) and \$580-\$1,057 million (2022 dollars) of net benefits in Scenario 1 (resulting in a 2.0-2.9 benefit-cost ratio).

Tranche 1 net benefits exceed those of Project 4 alone because Projects 5 and 6 more tightly network the 345 kV lines in western and northern Wisconsin and distribute the net imports over Project 4 to customers across the state. The Tranche 1 projects increase imports and offset additional higher cost resources within Wisconsin. As explained in later sections, 2032 imports from Minnesota and Iowa into Wisconsin increase from 15,980 GWh in the No Action Case to 16,820 GWh in the Project 4 case to 19,950 GWh in the Tranche 1 case under Scenario 2. Avoided 2032 thermal generation (i.e., gas and coal generation) within Wisconsin increases from 535 GWh in the Project 4 case to 3,470 GWh in the Tranche 1 case under Scenario 2. The increase in imports and avoided in-state generation results in \$578 million in APC savings in Scenario 1 and \$871 million in Scenario 2 (2022 dollars). Due to the larger scale of avoided thermal generation compared to the Project 1 case, the Tranche 1 case results in a greater benefit from reduced GHG emissions as well of \$233 million to \$749 million (2022 dollars).

We conservatively assume that Projects 5 and 6 do not further increase the ability for Wisconsin to import clean energy from Minnesota and Iowa, but provide access for those imports to a broader set of Wisconsin customers. In addition, Tranche 1 avoids \$345 million (2022 dollars) in transmission upgrades in Scenario 2 and \$85 million in Scenario 1.

[51] U.S. EPA, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, May 13, 2024.

TABLE 6: TRANCHE 1 DETAILED 40-YEAR NET BENEFITS (2022 DOLLARS, MILLION)

	Scenario 1	Scenario 2
WI Costs (PVRR)	**$566**	**$566**
WI Benefits	**$1,146–$1,624**	**$1,779–$2,307**
Congestion and Fuel Cost Savings	$578	$871
Reduced GHG Emissions Benefit	$233–$683	$256–$749
Avoided Generation Capital Costs	$250–$278	$307–$341
Avoided Transmission Capital Costs	$85	$345
WI Net Benefits	**$580–$1,057**	**$1,213–$1,740**
Benefit–Cost Ratio	2.0–2.9	3.1–4.1

Notes: Present value as of 2030, assuming 6.9% discount rate consistent with MISO LRTP Tranche 1 Business Case.

LVA CASE

The LVA case shows net benefits in Scenario 2 ($240 to $327 million, 2022 dollars) and Scenario 3 ($229 to $336 million, 2022 dollars), but negative net benefits in Scenario 1 (-$82 to -$37 million, 2022 dollars). The LVA case is less beneficial than the Project 4 case because the LVA upgrades increases transfer capability into Wisconsin much less than Project 4 and its costs are not subject to MISO cost allocation mechanisms. The benefits for the LVA Case are lower than Project 4 across all drivers of cost savings.

TABLE 7: LVA DETAILED 40-YEAR NET BENEFITS (2022 DOLLARS, MILLION)

	Scenario 1	Scenario 2	Scenario 3
WI Costs (PVRR)	**$227**	**$227**	**$227**
WI Benefits	**$145–$190**	**$467–$554**	**$456–$564**
Congestion and Fuel Cost Savings	$33	$314	$299
Reduced GHG Emissions Benefit	$20–$58	$41–$120	$52–$152
Avoided Generation Capital Costs	$63–$69	$77–$85	$70–$77
Avoided Transmission Capital Costs	$30	$36	$35
WI Net Benefits	**($82)–($37)**	**$240–$327**	**$229–$336**
Benefit–Cost Ratio	0.6–0.8	2.1–2.4	2.0–2.5

Notes: Present value as of 2030, assuming 6.9% discount rate consistent with MISO LRTP Tranche 1 Business Case.

NTA CASE

The NTA creates negative net benefits to Wisconsin in both Scenario 1 (-$331 million to -$307 million, 2022 dollars) and Scenario 2 (-$165 million to -$134 million, 2022 dollars). The NTA does not improve the transmission transfer capability between Minnesota and Wisconsin and its costs are fully allocated to Dairyland customers. In Scenarios 1 and 2, the energized portion of Project 4 in Minnesota actually increases congestion on the existing transmission facilities across the Minnesota-Wisconsin border, resulting in increased in-state thermal generation to provide counterflows. The 100 MW BESS resource at Briggs Road enables modest increases in Wisconsin imports, producing overall congestion and fuel cost savings in Scenario 2 of $93 million (2022 dollars). However in Scenario 1, the increased costs of in-state generation outweigh the cost savings of the increased imports enabled by the BESS resulting in an increase in APC to Wisconsin customers of $15 million (2022 dollars). The NTA likewise increases GHG emissions and emission costs by $12 million to $36 million in Scenario 1 due to the increase in in-state Wisconsin generation, but provided GHG emissions cost reductions of $16 million to $47 million (2022 dollars) in Scenario 2 due to the increase in imports. Avoided generation costs are the NTA's largest value stream because the new storage resource offsets the cost of building a new peaking resource to meet resource adequacy needs.

TABLE 8: NTA DETAILED 40-YEAR NET BENEFITS (2022 DOLLARS, MILLION)

	Scenario 1	Scenario 2
WI Costs (PVRR)	**$390**	**$390**
WI Benefits	**$59–$83**	**$225–$256**
Congestion and Fuel Cost Savings	($15)	$93
Reduced GHG Emissions Benefit	($36)–($12)	$16–$47
Avoided Generation Capital Costs	$110	$110
Avoided Transmission Capital Costs	$0	$6
WI Net Benefits	**($331)–($307)**	**($165)–($134)**
Benefit–Cost Ratio	0.2	0.6-0.7

Notes: Present value as of 2030, assuming 6.9% discount rate consistent with MISO LRTP Tranche 1 Business Case. The NTA case reduces MISO-wide production costs but results in a slight increase in Wisconsin APC because the Wilmarth-N. Rochester portion of Project 4 increases congestion across the Minnesota-Wisconsin border.

IV. Project 4 Detailed Benefits Analysis

This section provides details on the analysis completed for quantifying the benefits of Project 4 and the alternative cases to Wisconsin ratepayers. The quantified benefits include:

- Fuel and congestion cost savings
- Reduced GHG emissions benefit
- Avoided local generation capital costs
- Avoided transmission capital costs

A. Fuel and Congestion Cost Savings

This benefit quantifies the reduction in Wisconsin ratepayer costs as the Wisconsin APC savings attributable to Project 4, the Tranche 1 portfolio, and the alternative cases. Additional transmission capacity will lower ratepayer costs by increasing the state's ability to import and deliver low-cost energy to Wisconsin load centers, enabling more efficient in-state unit commitment and dispatch, and reducing congestion on the transmission system.

1. Production Cost Simulation Assumptions

We calculate fuel and congestion cost savings based on 38 hourly simulations of the MISO system using the same PROMOD production cost model as MISO did for their Tranche 1 and Tranche 2.1 benefits analyses. The PROMOD simulations were run by Hitachi Energy ("Hitachi"), the developer of PROMOD, at the direction of consultants at The Brattle Group. Hitachi calculated the APC for each company based on the results for each simulation case using the APC Reporter software.[52]

The assumptions in PROMOD primarily rely on MISO Futures projections, as summarized in Section II above. The No Action case serves as a reference case for each study year. We then

[52] The results of this method for calculating the MISO APC were validated based on the MISO Tranche 1 Portfolio APC results, using the MISO provided Tranche 1 Base Case and Change Case. The Tranche 1 portfolio total APC values from the Hitachi-run simulations were within 5% of the results reported by MISO in its Tranche 1 Business Case results. MISO did not include more detailed APC savings to validate the APC reporter software outputs.

simulate each of the alternative cases (Project 4, LVA, and NTA) and the Tranche 1 case, comparing their results to the No Action case to estimate the APC savings for Wisconsin customers.

All scenarios include the following changes in PROMOD to better reflect future market conditions in Wisconsin and MISO:

- All Wisconsin battery storage resources were modeled as dynamic units responsive to market conditions instead of pre-determined fixed profiles set by MISO;[53]
- Operational characteristics of the Rocky Run-North Appleton 345 kV line were updated to reflect a planned upgrade in the Future 2A 2037 and 2042 models based on input provided by ATC;
- Constraints on lower voltage (<200 kV) transmission lines and transformers with significant congestion in the MISO Future 1 and 2A models were removed to account for future upgrades through generation interconnection or local transmission planning processes.[54] The lower voltage constraints were primarily removed in the 2037 and 2042 cases and either near future wind farms in Minnesota or Iowa or near load centers in eastern Wisconsin. The topology that MISO used in developing the Future 2A simulations is the MTEP22 Year 2032 Summer Peak case, which does not account for local transmission upgrades in the later years.[55]

We completed additional simulations for the Scenario 2 2032 case with alternative assumptions about the completion of LRTP 5 and 6. As noted above, Scenario 2 assumes that neither project is included in the No Action case nor the Project 4 case. The additional simulations included Projects 5 and 6 in the following combinations in both the No Action and Project 4 cases: (1) only Project 5 is built, (2) only Project 6 is built, and (3) both Projects 5 and 6 are built. The APC

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[53] MISO's Future 2A PROMOD database models storage resources as having fixed charge/discharge schedules determined outside of the market simulations. A dynamic representation of these resources better reflects how they would operate in the MISO market, which may change with the addition of Project 4. See MISO, MISO Economic Planning Model - Series 1A Battery Modeling, October 2023.

[54] "As with Tranche 1, Tranche 2 does not resolve all identified issues. Instead, the Tranche 2 transmission lines focus on creating a logical next step in the development of a regional backbone (e.g., highway system), balancing needs with benefits and cost. MISO's existing processes will support future resource and load additions as they become more certain (e.g., local roads). MISO's other planning processes, such as annual MTEP reliability and generator interconnection processes, will identify the transmission needed to address local issues not resolved by Tranche 2. MISO will continue to work with stakeholders in those processes to identify these local transmission needs, which will build-off the regional transmission highway identified in Tranche 2." MISO Tranche 2 FAQs, p. 16.

[55] MISO Tranche 2 FAQs, p. 9.

savings between the No Action and Project 4 cases are attributable to the incremental addition of Project 4 in these simulations since the other projects are included in both the No Action and Project 4 cases. This differs from the Tranche 1 case results that assess the incremental addition of all three projects (Projects 4, 5 and 6) by comparing the No Action case without Projects 4, 5 and 6 to the Tranche 1 case with all three projects added.

2. Production Cost Simulation Results

a) Project 4 Case Results

Project 4 provides Wisconsin ratepayers $162-548 million (2022 dollars) in APC savings across the three study scenarios by enabling low-cost energy imports from Minnesota and Iowa and reducing Wisconsin energy prices. Out-of-state imports reduce the production costs of relatively more expensive Wisconsin generation resources, while lower energy prices reduce Wisconsin's net market purchase costs.

Today, the MISO system sees substantial congestion on low-voltage lines across the Wisconsin-Minnesota border (Figure 2).[56] Project 4 adds east-west transmission capacity south of the Twin Cities and across the Mississippi River, offloading the existing low-voltage (<200 kV) lines and providing a more direct path from abundant Minnesota wind resources to Wisconsin load centers. Project 4 bypasses the existing Wabaco-Alma 161 kV constraint to inject power at the Tremval 345 kV substation. From Tremval, the additional imports utilize the existing Badger-Coulee 345 kV line and the lower-voltage network to reach Wisconsin load centers. In our 2030 and 2032 simulations, adding Project 4 reduces congestion on the Wabaco-Alma 161 kV corridor by 66-81% and reduces congestion across the Wisconsin, Minnesota, and Iowa system by $12-104 million per year, increasing the efficiency of regional markets.

The changes in 2032 flows across the 345 kV system along the Minnesota – Wisconsin border in Scenario 3 demonstrate the impacts of Project 4, as shown in Figure 11 below. In these simulations, Project 4 increases Wisconsin net imports over the N. Rochester-Tremval corridor by 2,600 GWh, displacing 5% of Wisconsin's in-state generation.[57] Eastward flows over Project 4 total 4,900 GWh, offsetting 2,350 GWh of imports over the parallel N. Rochester-Briggs Rd.-

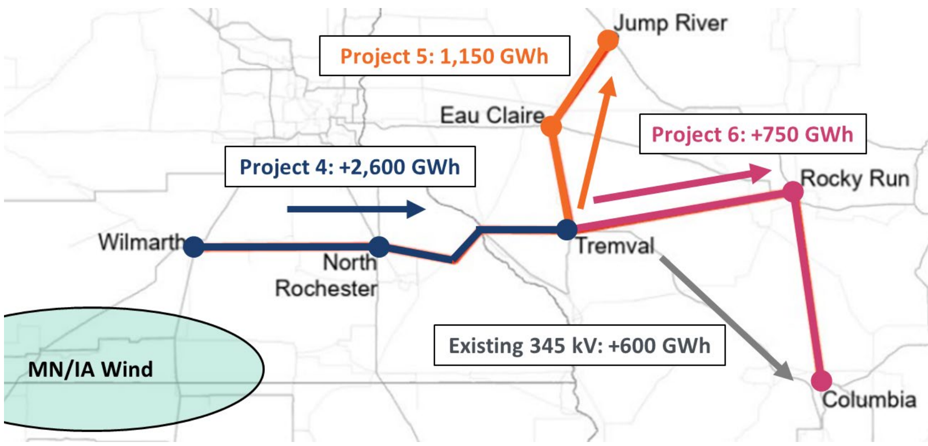
[56] The 161 kV transmission corridor from Wabaco to Alma and the 138 kV corridor between Darlington and Bass Creek in Southern Wisconsin are particularly congested. In the Scenario 2 2032 No Action case simulation, these constraints see $9 million and $25 million (nominal) per year, respectively, in congestion costs.

[57] Wisconsin utilities generate 56.6 TWh using owned resources in our Scenario 2 simulations of 2032. We estimate DPC and NSP generation to Wisconsin based on the Wisconsin load share of each utility.

Tremval 345 kV line. The existing 345 kV lines, together with Projects 5 and 6, distribute the increased net imports over Project 4 to load centers in the state:[58]

- Tremval to North Madison delivers an additional 600 GWh to the Madison region.[59]
- Project 5 transfer 1,150 GWh from Tremval to the northern 345 kV lines into the Green Bay/Appleton load center.
- Project 6 delivers the remaining 750 GWh to Rocky Run and on to the Green Bay/Appleton load center.

FIGURE 11. SCENARIO 3 CHANGES IN 2032 POWER FLOWS WITH THE ADDITION OF PROJECT 4



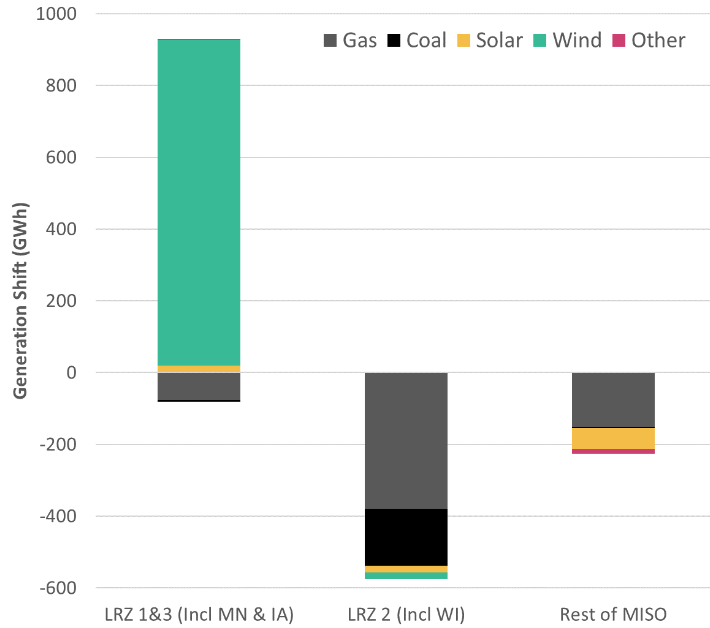
Note: Figure does not show power flows on other existing 345 kV lines.

In reducing congestion and increasing Wisconsin imports, Project 4 helps deliver 890 GWh of Minnesota and Iowa wind power to Wisconsin customers, offsetting 740 GWh of fossil generation located primarily in Wisconsin in our 2032 Scenario 3 simulation, as shown in Figure 12. A similar pattern occurs in the Scenario 3 simulations for 2037 and 2042 with the addition of Project 4: wind generation increases by 820–1,010 GWh and offsets 522–580 GWh of emitting generation, primarily in Wisconsin.

[58] Net imports decrease by 600 GWh over the existing 345 kV east-west lines as imports over Project 4 flow onto these lines via Projects 5 and 6.

[59] Project 4 involves cutting in the existing Badger-Coulee line at the new Tremval substation.

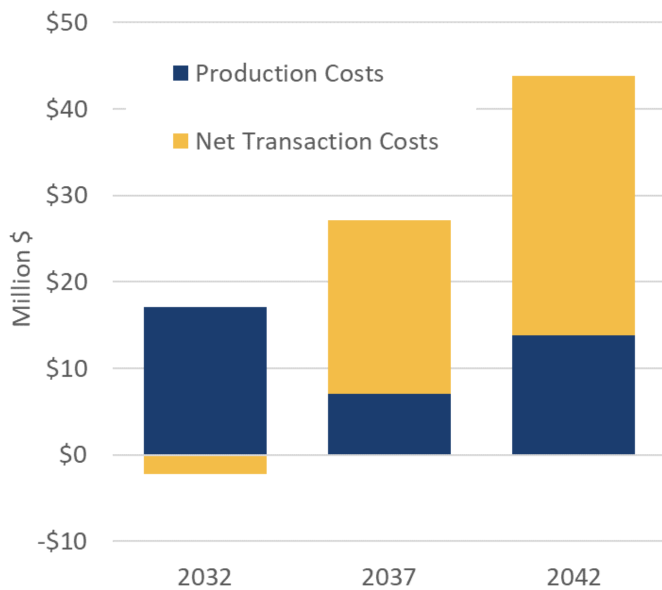
FIGURE 12: SCENARIO 3 2032 CHANGE IN GENERATION DUE TO PROJECT 4 (GWH)



Project 4 reduces costs of serving Wisconsin load in 2032 by $14.9 million (nominal dollars) in Scenario 3. The additional imports from Minnesota increase Wisconsin purchase costs by $2.2 million (nominal dollars), but decrease the cost of local utility-owned generation costs by $17.1 million (nominal dollars). Wisconsin APC savings under Scenario 3 increase to $27 million in 2037 and $44 million in 2042 (nominal dollars), as shown in Figure 13 below. Project 4 renewable energy integration benefits increase between 2032 and 2037, as demand growth and renewables deployment increase in Wisconsin, Minnesota, and Iowa. Net imports over Project 4 into Wisconsin increase to 3,400 GWh in 2037 and 3,100 GWh in 2042, leading to a greater reduction in Wisconsin energy market prices and ratepayer costs.[60]

[60] Imports over Project 4 decrease in 2042 because of growing load and congestion in Minnesota/Iowa and renewable deployment in Wisconsin.

FIGURE 13. SCENARIO 3 WISCONSIN APC SAVINGS BY COMPONENT AND YEAR

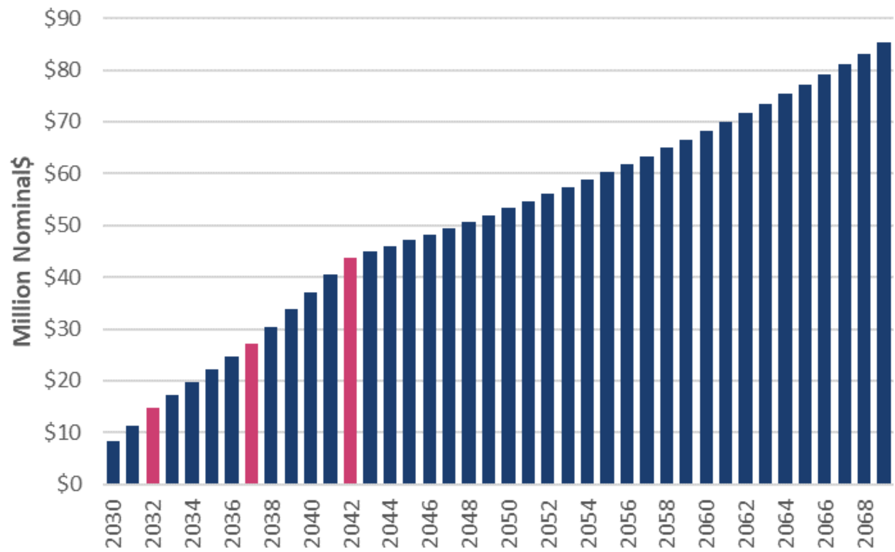


Notes: Values given in nominal dollars.

Longer-term APC savings are projected over the assumed 40-year life of the asset, as shown in Figure 14 for Scenario 3, by conservatively assuming long-term APC savings escalate at an assumed inflation rate of 2.5% per year (stay constant in real dollars).[61]

[61] This approach to extrapolating long-term benefits is less advantageous for Project 4 in Scenario 3 than MISO's approach in its Tranche 1 benefits analysis.

FIGURE 14: SCENARIO 3 ANNUAL APC SAVINGS FOR WISCONSIN RATEPAYERS



Note: Pink bars indicate PROMOD simulation results in 2032, 2037, and 2042. Blue bars are estimated by interpolating and extrapolating results using MISO's methodology. Values beyond 2042 are extrapolated assuming APC savings remain constant in real dollars, escalating at 2.5% per year in nominal dollars.

As shown in above, Project 4 provides the greatest APC savings to Wisconsin customers in Scenario 2 of $548 million (2022 dollars), compared to $431 million (2022 dollars) in Scenario 3. The higher benefits in Scenario 2 reflect changes to the Wisconsin resource mix requested by the PSCW that reduce in-state renewable capacity (Figure 7) and the lack of Projects 5 and 6, both of which increase the value of renewable energy imports from Minnesota and Iowa. This finding highlights the impact of the Wisconsin resource mix assumptions on the Project 4 benefits.

Scenario 1 shows the lowest Project 4 benefits of $162 million (2022 dollars), as it models a low demand and low-renewables future (MISO Future 1) with additional in-state renewables per PSCW guidance. With lower renewable penetration MISO-wide, Project 4 primarily reshuffles thermal generation, shifting production from higher-cost Wisconsin thermal plants to lower-cost Minnesota and Iowa thermal units. While benefits are lower, they remain larger than Project 4 costs.

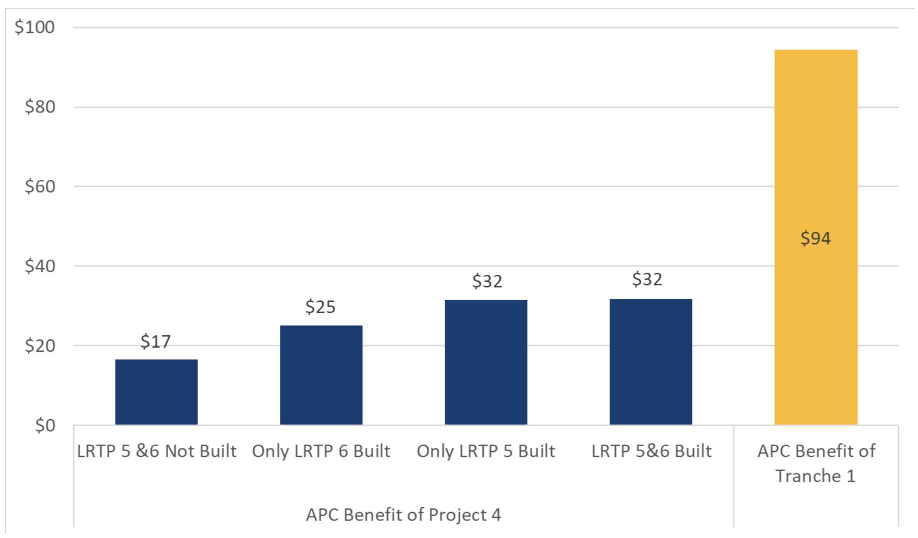
PROJECT 4 BENEFITS WITH ALTERNATIVE ASSUMPTIONS FOR PROJECTS 5 AND 6

We ran a series of 2032 Scenario 2 cases to test the incremental value of Project 4 with all possible combinations of Projects 5 and 6 either built or not built. The analysis demonstrates that Project 4 reduces costs for Wisconsin ratepayers in 2032 regardless of whether Projects 5 and/or 6 are built, but its benefits increase if built as a portfolio with Projects 5 and 6 as intended by MISO.

Project 4 provides APC savings of $17 million (nominal) when neither Project 5 or 6 is built, as shown in Scenario 2 results above. The 2032 benefits of Project 4 increases to $25 million (nominal) when LRTP 6 has been built and $32 million (nominal) when LRTP 5 has been built, as shown in Figure 15. Including both LRTP 5 and 6 results in $32 million of savings from the addition of Project 4.

The benefits of Project 4 across these different cases are lower than the benefits provided by the full portfolio of Wisconsin Tranche 1 projects of $94 million (nominal) in 2032, as shown in the yellow bar in the Figure 15 below. These findings indicate that (1) the APC savings of LRTP 4 for Scenarios 1 and 2, as reported above, are conservative if LRTP 5 and 6 are approved by the Commission, and (2) the results of the Project 4 and Tranche 1 cases bookend the range of Project 4 values across all LRTP 5 and 6 approval outcomes.

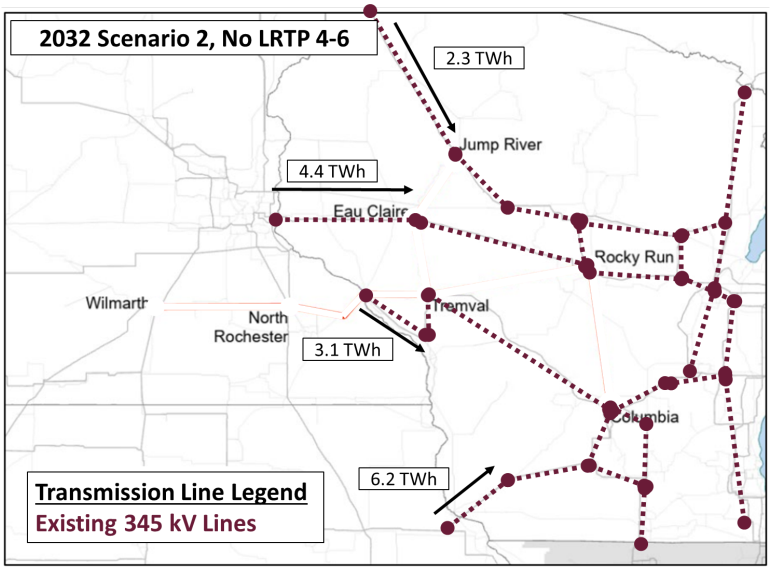
FIGURE 15: 2032 WISCONSIN APC SAVINGS, PROJECT 4 CASE UNDER ALTERNATIVE ASSUMPTIONS FOR LRTP 5&6 AND TRANCHE 1 CASE (MILLION $, NOMINAL)



LRTP 5 and 6 increase the incremental APC savings of LRTP 4 by providing additional outlets for delivering power imported over Project 4 to load centers in eastern Wisconsin. In the No Action scenario, there are four east-west 345 kV corridors delivering a total 16 TWh from Minnesota and Iowa to Madison, Milwaukee, and Green Bay/Appleton, as shown in Figure 16.[62]

[62] These corridors include Arrowhead-Stone Lake, King-Eau Claire, N. Rochester-Briggs Rd-North Madison, and Cardinal-Hickory Creek.

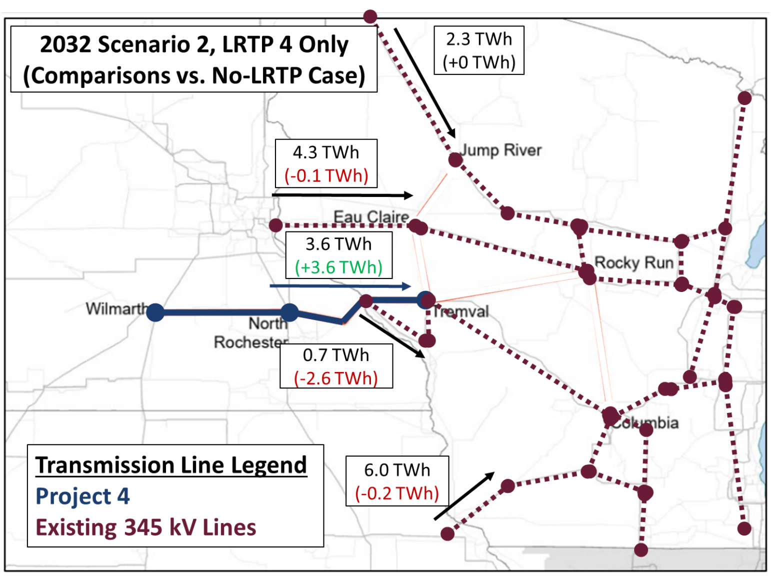
FIGURE 16. SELECTED MODELED FLOWS, 2032 SCENARIO 2 NO ACTION



Note: Map adapted from Figure 6-7 of the MISO MTEP 21 Report Addendum. Colored and dotted line overlays present indicative locations of selected Wisconsin transmission facilities without striving for perfection in representing all facilities and their exact paths.

Project 4 provides APC savings for Wisconsin ratepayers by expanding access to imports via the existing 345 kV Badger-Coulee line. Without Projects 5 and 6, Project 4 increases Wisconsin imports by 0.9 TWh relative to the No Action case, as shown in Figure 17. Transfers on the recently built Cardinal-Hickory Creek line also decreases slightly with the addition of Project 4. The 2032 Scenario 2 Project 4 APC savings without Projects 5 and 6 built are $16.6 million (nominal).

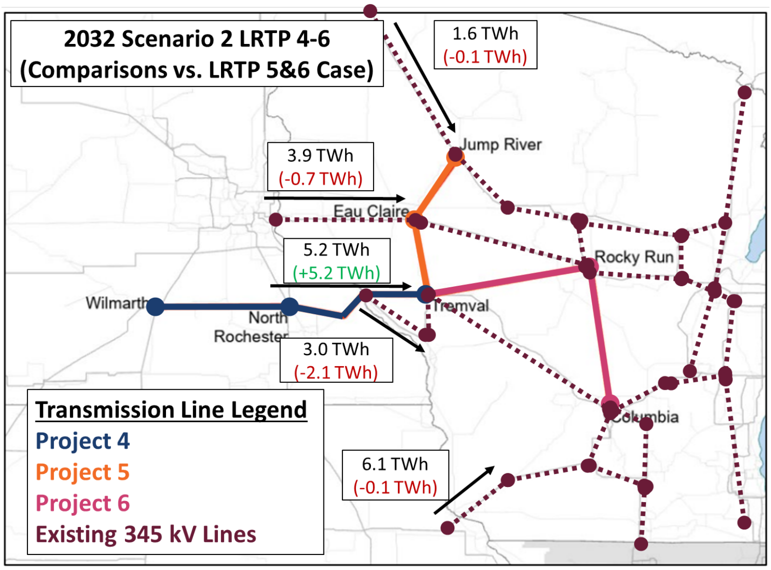
FIGURE 17. SELECTED MODELED FLOWS, 2032 SCENARIO 2 LRTP 4 CASE, LRTP 5&6 NOT BUILT



Note: Differences do not add up to 0.9 TWh due to rounding.

Projects 5 and 6 increase the potential for economic imports over Project 4 by creating north-south paths from Tremval to eastern load centers via Wisconsin's existing 345 kV lines (Figure 18). With Projects 5 and 6 built, Project 4 increases Wisconsin imports by 2.2 TWh relative to the No Action case. The 2032 Scenario 2 Project 4 APC savings with Projects 5 and 6 built are $31.7 million (nominal).

FIGURE 18. SELECTED MODELED FLOWS, 2032 SCENARIO 2 LRTP 4 CASE, WITH LRTP 5&6 BUILT



b) Tranche 1 Case Results

Adding the LRTP 4-6 portfolio reduces Wisconsin ratepayer APC more than LRTP 4 alone, creating $578 million in Wisconsin APC savings in Scenario 1 and $871 million in Scenario 2 (2022 dollars). Project 4 increases Wisconsin's import capability, while Projects 5 and 6 help deliver imports to Wisconsin load centers by networking the state's existing 345 kV east-west transmission corridors. Under Scenario 2, the LRTP 4-6 portfolio increases Wisconsin's net 2032 imports from Minnesota and Iowa by 3.8 TWh relative to the No Action case, displacing almost 7% of Wisconsin's in-state generation.[63] LRTP 4-6 reduce Minnesota and Wisconsin transmission congestion by $154 million (nominal) relative to the No Action case, thereby decreasing the average price Wisconsin's of market purchases.[64]

[63] Wisconsin utilities generate 56.6 TWh using owned resources in our Scenario 2 simulations of 2032. We estimate DPC and NSP generation to Wisconsin based on the Wisconsin load share of each utility.

[64] Wisconsin utilities' 2032 average market purchase prices are -$1.67/MWh in the Scenario 2 No Action case. In the Tranche 1 case, average Wisconsin market purchase prices are -$1.89/MWh. Building Project 4 alone reduces Wisconsin's average market purchase prices by $0.09/MWh (5%) compared to a No Action case.

c) LVA Case and NTA Case Results

The LVA and NTA cases result in lower Wisconsin APC savings than Project 4 due to their limited ability to relieve congestion and facilitate power transfers across the Wisconsin-Minnesota border. Neither alternative provides the same level of transfer capability as the Alma-Blair 345 kV line, restricting the efficient import of Minnesota power to Wisconsin load centers and providing limited congestion relief compared to Project 4.

The LVA case APC savings of $33-314 million (2022 dollars) across scenarios are 30-80% lower than those in the Project 4 case because the LVA adds less transfer capability than the Alma-Blair 345 kV line. Although the LVA case reduces congestion compared to the No Action case and provides APC savings to Wisconsin customers, the reductions are significantly smaller than those achieved with the addition of Project 4. In Scenario 2, congestion costs on the Kellogg-Alma 161 kV line decline from $8.8 million in the No Action case to $5.0 million in the LVA case, but fall further to $1.6 million in the Project 4 case. The limited congestion reduction under LVA dampens its economic benefits, leaving congestion costs elevated and reducing the efficiency of power transfers across the Wisconsin-Minnesota border.

The NTA case results in $93 million in APC savings in Scenario 2 and negative $15 million in APC savings in Scenario 1 (2022 dollars). The NTA does not introduce new transmission infrastructure to support power injections into Wisconsin, and the 100 MW storage resource at Briggs Road does not increase imports to the same extent as Project 4. In Scenario 2, the NTA increases 2032 power flows over the Badger-Coulee 345 kV line from Briggs Road to Madison by 0.06 TWh (2% increase), while Project 4 increases flows by 1.07 TWh (34% increase).[65] The NTA reduces 2032 price differentials at the Minnesota – Wisconsin border by $0.10/MWh, while Project 4 reduces cross-border price differentials by $0.84/MWh (nominal). The increased cross-border flows and decreased price differentials result in $8.59 million in 2032 APC savings in the NTA case.

While the NTA increases imports slightly, it also increases congestion across the Minnesota-Wisconsin border because the existing system in this portion of the system lacks capacity to deliver the incremental flows on the new Wilmarth-N Rochester 345 kV line to Wisconsin load

[65] Power flows over the 345 kV Badger-Coulee line are a key metric for comparing the impacts of Project 4 and the NTA on power imports, as this line is one of the primary east-west 345 kV corridors serving Wisconsin load centers (Figure 17). While lower-voltage line flows (161 kV and below) also influence regional power dynamics, they are more complex to summarize and are not the focus of this comparison.

centers.[66] The Wilmarth–North Rochester 345 kV line instead increases flows on the existing 161 kV system, increasing congestion on the Alma–Kellogg 161 kV line by $27 million in Scenario 2.[67] To mitigate these increased congestion levels, generation increases at the John P. Madgett ("JPM") coal plant to provide counterflows against power injections from Minnesota. However, these adjustments do not fully alleviate congestion, leading to diminished economic benefits compared to Project 4.[68]

In the Scenario 1 NTA case, Wisconsin APCs increase by $15 million (2022 dollars), primarily due to the increased congestion costs. The NTA increases Wabaco-Alma 161 kV congestion by $24 million in Scenario 1, leading to a $0.30/MWh increase in the Minnesota-Wisconsin price differential (nominal dollars).[69] The higher price differential results in negative APC savings in Scenario 1.

To demonstrate the impacts of the LVA and NTA cases relative to Project 4 and Tranche 1 cases, we show the changes in dispatch for Zone 1 (Minnesota and western Wisconsin), Zone 2 (eastern Wisconsin and Michigan's Upper Peninsula), and Zone 3 (Iowa) for Scenario 1 in Figure 19 and Scenario 2 in Figure 20 below. The green bars represent wind generation shifts between cases, while the dark gray bars represent net shifts in other types of generation (excluding wind), accounting for both increases and decreases in thermal and renewable production. In both Scenario 1 and Scenario 2, adding Project 4 and Tranche 1 results in a significant shift of generation from Zone 2 to Zones 1 and 3. This shift is larger in the Tranche 1 case due to the addition of Projects 5 and 6. By comparison, the LVA and NTA cases result in minimal shifts in generation across zones and thus limited (or negative) APC savings. The Project 4 and Tranche 1 generation shifts are similar in magnitude across Scenario 1 and Scenario 2. In scenario 2,

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[66] In the NTA case, the energized portion of Project 4 creates a low impedance path from Wilmarth to North Rochester, with eastward outlets to Wisconsin via the Badger-Coulee 345 kV line and the 161 kV system to Alma.

[67] We did not explicitly measure the shift factor (i.e., the proportion of power injected at N Rochester that flows toward the Wisconsin border via the 161 kV network.

[68] In Scenario 2, JPM's 2032 annual generation in the No Action case is 327 GWh. Under the NTA case, JPM generation increases by 47 GWh to 374 GWh, reflecting the plant's role in providing counterflows against Minnesota injections. In contrast, JPM generation decreases under the LVA and Project 4 cases by 45 GWh and 105 GWh, respectively, bringing total JPM output to 281 GWh in the LVA case and 221 GWh in the Project 4 case.

[69] In Scenario 1, 2030 Wabaco to Alma 161 kV line congestion increases from $55.6 million in the No Action case to $79.5 million (nominal) in the NTA case, a 43% increase. Project 4 reduces Wabaco to Alma congestion by 66% to $18.9 million (nominal). 2030 JPM generation increases from 1.32 TWh in the No Action case to 1.35 TWh (+29.4 GWh, or 2%). With Project 4, 2030 generation decreases to 1.05 TWh (-270 GWh, or 20%). Annual 2030 Power flows to Madison via the Badger-Coulee line increase from 2.8 TWh in the No Action case to 2.9 TWh in the NTA case (+3%) and 3.8 TWh in the Project 4 case (+37%).

however, the increase in generation in Zones 1 and 3 comes primarily from wind resources (green bars), resulting in larger APC savings than in Scenario 1.

FIGURE 19: 2030 SCENARIO 1 GENERATION SHIFTS FOR ALTERNATIVE CASES

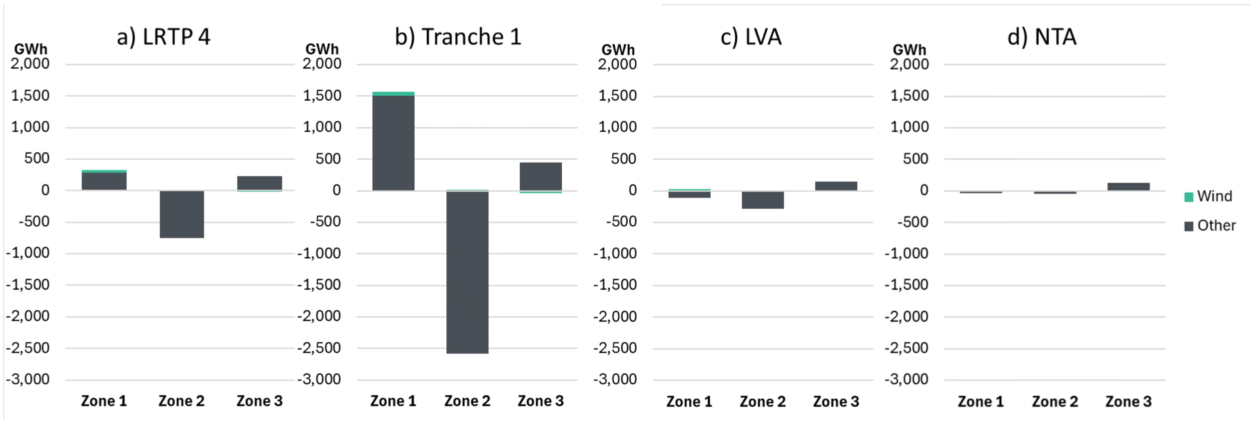
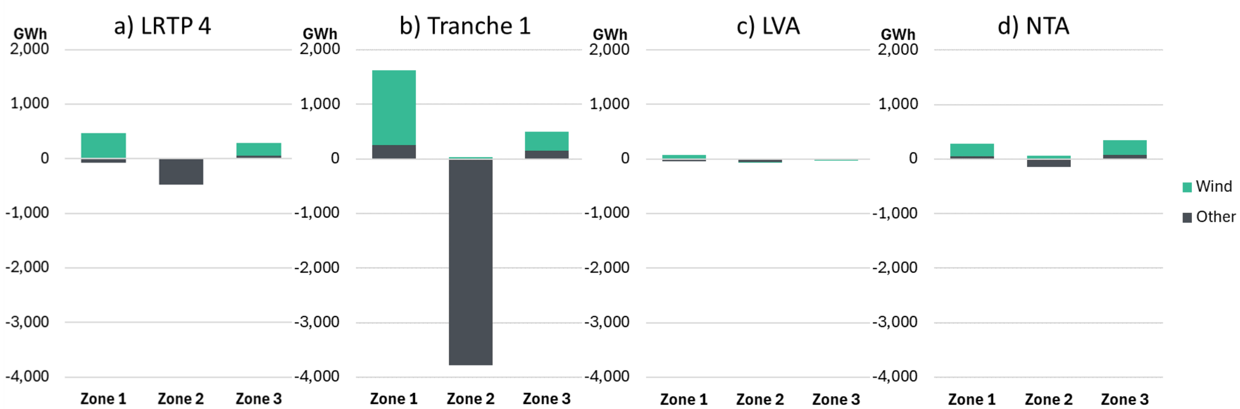


FIGURE 20: 2032 SCENARIO 2 GENERATION SHIFTS FOR ALTERNATIVE CASES



Annual power flows on 345 kV lines from Minnesota and Iowa into Wisconsin decrease in the LVA and NTA cases, mirroring the reductions in Minnesota wind generation, as shown in Table 9.[70] Accordingly, the average Wisconsin market purchase prices fall less in the LVA and NTA cases than they do in the Project 4 and Tranche 1 cases.

70 Including Arrowhead to Stone Lake, King to Eau Claire, N. Rochester to Briggs Road (and N. Rochester to Tremval with Project 4 in place), and Cardinal-Hickory Creek.

TABLE 9: 2032 SCENARIO 2 IMPORTS AND CROSS-BORDER PRICE DIFFERENTIALS

	345 kV Imports From MN and IA			WI-MN LMP Delta		
Case	Value	Delta vs No Action Case		Value	Delta vs No Action Case	
	GWh	*GWh*	*%*	*$/MWh*	*$/MWh*	*%*
No Action	15,981	0	0.0%	$9.75	$0.00	0.0%
Project 4	16,821	841	5.3%	$8.91	-$0.84	-8.7%
Tranche 1	19,949	3,969	24.8%	$6.77	-$2.98	-30.5%
LVA	15,966	-15	-0.1%	$9.58	-$0.17	-1.7%
NTA	15,948	-33	-0.2%	$9.65	-$0.10	-1.0%

Notes: The "345 kV Imports From MN and IA" sum total net flows, defined as flows into Wisconsin minus flows out of Wisconsin, for the major east-west 345 kV lines, including North Rochester-Briggs Road-Columbia, King-Eau Claire, Arrowhead-Stone Lake, and Cardinal-Hill Valley-Hickory Creek. The "WI-MN LMP Delta" indicates the annual average load-weighted LMP differential across the Wisconsin-Minnesota border.

B. Reduced GHG Emissions Benefit

The reduced GHG emissions benefit metric quantifies the value of reducing regional carbon dioxide emissions enabled by the addition of Project 4 and the alternative solutions. Wisconsin and other states in MISO have set goals to reduce carbon dioxide emissions and increase renewable energy resources in the supply mix. This benefit metric quantifies the impact that the Commission's decision about whether to approve Project 4 or the alternative solutions will have on the efficient use of new renewable resources and fossil resources and reduction of regionwide GHG emissions.

Consistent with MISO's approach to calculating decarbonization benefits, we consider the difference in total MISO-wide carbon dioxide emissions between the No Action Case and the alternative cases for each year simulated in PROMOD. We calculate a monetary benefit using the range of carbon dioxide costs that MISO is assuming in its Tranche 2 analysis. The Tranche 2 carbon dioxide costs are significantly higher than Tranche 1, based on recently updated federal costs[71] of $85/metric ton and Minnesota Public Utility Commission costs of $249/metric ton in 2024 (2024 dollars).[72] The increased carbon dioxide costs reflect the updated social cost of carbon estimated by the U.S. Environmental Protection Agency ("EPA") of $230/metric ton in 2030 (2020 dollars).[73] The latest EPA values reflect updated assumptions for estimating global

[71] Under the Biden administration.

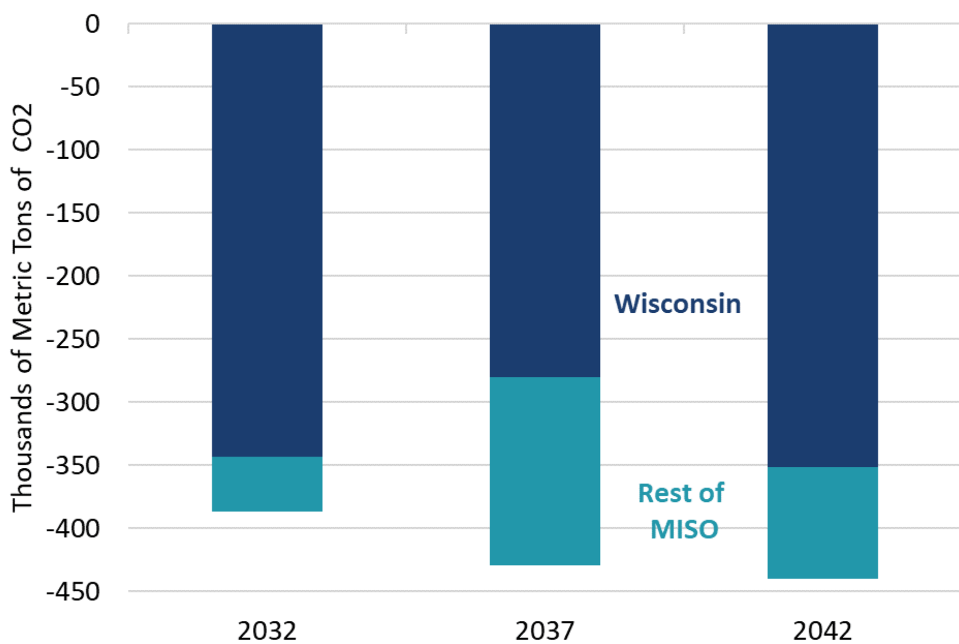
[72] MISO, LRTP Tranche 2.1 Benefit Metrics Development, June 2024, p. 51.

[73] U.S. EPA, EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, November 2023, p. 4.

damages of climate change and recent trends in market returns that result in a higher social cost of carbon than previously estimated and utilized in the Tranche 1 benefit-cost analysis.

Adding Project 4 results in a cumulative reduction in MISO-wide carbon dioxide emissions of 7.6-17.3 million metric ton of CO2 over a 40-year period (see Table 10). Across scenarios and years, the annual GHG emissions reductions due to Project 4 ranged from 0.2 million metric ton of CO2 per year (in Scenario 1, year 2035) to 0.4 million metric ton ("MMT") of CO2 per year (in Scenario 2, year 2042). Figure 21 presents the change in 2032, 2037 and 2042 CO2 emissions for Scenario 2, showing a reduction in emissions (negative change) of about 0.4 MMT in each year.

FIGURE 21: PROJECT 4 CHANGE IN CARBON DIOXIDE EMISSIONS BY YEAR (SCENARIO 2)



Note: Change in CO2 emissions are measured against each base case. Negative values mean a reduction of CO2 emissions compared to the base case simulations.

Increased renewable energy deliveries from the rest of MISO reduce output from thermal generation in Wisconsin, resulting in a reduction of CO2 emissions throughout the 40-year period of analysis. In 2032, reductions in natural gas-fired generation account for approximately 70% of carbon dioxide emissions reductions, with the other 30% coming from a reduction in baseload generation, especially coal-fired resources. The lower reduction in carbon dioxide emissions in 2037 and 2042 aligns with changes in the generation mix as renewables deployment continues. The majority of MISO-wide GHG reductions are from generation resources located within Wisconsin with reductions of 89% in 2032, 65% in 2037, and 80% in 2042.

The NTA and LVA cases result in lower cumulative CO2 emissions reductions over a 40-year period of 3.0-8.0 MMT in the LVA case and -2.1–1.3 MMT in the NTA case. Table 10 lists the cumulative MISO-wide CO2 emissions reductions across modeled Scenarios and Cases.

TABLE 10. 40-YEAR CUMULATIVE CARBON DIOXIDE EMISSIONS REDUCTIONS BY CASE AND SCENARIO (MILLION METRIC TONS OF CO2)

Case	Scenario 1	Scenario 2	Scenario 3
LRTP 4	7.6	17.3	9.3
Tranche 1	38.4	33.3	---
LVA	3.0	7.7	8.0
NTA	-2.1	1.3	---

Notes: The NTA and Tranche 1 cases do not have Scenario 3 net benefits because the NTA case with 100 MW BESS did not get re-run through Scenario 3 (we previously modeled an older NTA case that included 14 MW BESS in Scenario 3) and Scenario 3 already includes LRTP 5 and 6 in the Scenario 3 base case.

The LRTP Tranche 1 Case brings the largest cumulative benefits of all cases, reducing cumulative CO2 emissions by 33 MMT to 38 MMT over 40 years. These GHG benefits confirm the results obtained in the APC savings, where Tranche 1 yields the greatest benefits in fuel savings.

C. Avoided Local Generation Capital Costs

This metric quantifies the cost savings of procuring lower-cost capacity rather than relying on higher-cost in-state resources alone. Project 4 enables these savings by increasing the transfer capability between Wisconsin and Minnesota. We calculate the avoided local generation capital cost savings to Wisconsin ratepayers outside of the model because PROMOD results only consider operational costs like fuel and variable maintenance costs. This benefit metric is additive to the APC savings described above.

This benefit is particularly important for Wisconsin's ability to cost-effectively meet its decarbonization goals, as it will likely need to rely on both in-state renewable energy resources and imports of renewable energy from other regions in MISO. The state has set goals requiring 100% of electricity consumed within the state to be carbon-free by 2050.[74] MISO developed Future 2A assuming all states meet their GHG and renewable/clean energy goals, including Wisconsin's 100% clean energy by 2050 goal. Based on that approach, Future 2A includes 7.0

[74] The State of Wisconsin, Office of the Governor, *Executive Order #38: Relating to Clean Energy in Wisconsin*, August 16, 2019.

GW of solar and 6.3 GW of wind contracted to serve Wisconsin loads by 2042.[75] The 2042 output of in-state solar, wind, nuclear, and hydro capacity is about 49,000 GWh, or 55% of its 2042 electricity demand of 90,000 GWh.[76] To fill the remaining gap to meet its clean energy goals, Wisconsin will need to increase its transmission capacity with neighboring states to both access out-of-state resources and cost-effectively integrate its in-state resources with the rest of the MISO system.

1. Project 4 Case Results

Project 4 provides needed export capacity for a historically constrained region of the MISO system, supporting the interconnection of new renewable energy capacity that Wisconsin could procure to meet its goals. Currently, the MISO interconnection queue includes 10.9 GW of renewable energy resources (5.1 GW of wind and 5.8 GW of solar projects) located in Minnesota and Iowa that will be supported by the addition of Project 4 in the DPP-2022 cycle.[77] By comparison, the MISO interconnection queue includes 2.4 GW of Wisconsin resources (mostly solar) in the DPP-2022 cycle.

Project 4 increases the transmission capacity available to import out-of-state renewable energy into Wisconsin. While the normal operating limit of Project 4 is about 1,600 MW, the high-voltage 345 kV transmission system along the Minnesota-Wisconsin border is voltage limited, such that the incremental ability for Wisconsin utilities to import renewable energy into Wisconsin will be lower than the full thermal rating. MISO's analysis of the Tranche 1 portfolio under normal operating conditions shows that Project 4 will increase the Safe Loading Limit of the 345 kV Minnesota-Wisconsin Export Limit (MWEX) by 540–600 MW.[78] The analysis of the avoided location generation capital costs of Project 4 assumes a one-to-one loading of Project 4 for each MW of renewable capacity contracted from out of state.[79] In reality, the meshed property of the transmission network means that each MW of out-of-state renewable energy

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[75] These values allocate Dairyland Power Cooperative and Northern States Power wind and solar capacity to Wisconsin loads based on the portion of these utilities' loads located in Wisconsin.

[76] Net of reductions due to customer solar.

[77] MISO Interconnection Queue. Only Active projects included. A total of 18 GW of solar and wind capacity is currently active or completed in the interconnection queue across all cycles in Iowa and Minnesota.

[78] MISO, MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report, 2022, p. 34. As another reference point, MISO finds that the Tranche 1 Portfolio will increase the Zone 2 Capacity Import Limit (CIL) by 1,035 MW, accounting for both Project 4 and Project 5. See Table 7-3 on Page 57 of the Tranche 1 report.

[79] The "loading" we refer to can be called a "distribution factor" or a "shift factor" and refers to the change in power flow over a transmission line resulting from a change in power injection at a specific generation facility.

contracted to Wisconsin would load Project 4 by less than the injection amount.[80] Thus, our estimation of the avoided local generation capital costs benefit is conservative.

We use two approaches to calculate the avoided capital costs of local generation enabled by Project 4. The first approach estimates the benefits of Project 4 allowing Wisconsin entities to substitute higher-cost in-state solar generation with an equal quantity of lower-cost wind generation procured from Minnesota or Iowa. The approach uses the estimated net energy costs for each resource, which we calculate as the per-MWh costs of new builds in each location net of the energy market value of their generation. Increasing the capacity to import out-of-state wind by 540–600 MW will allow Wisconsin to procure an additional 2,080–2,310 GWh of wind energy from Minnesota or Iowa.[81] This resource shift reduces the amount of Wisconsin solar builds required to meet Wisconsin's 2040 clean energy goals by 1,030–1,140 MW due to the lower capacity factor of solar in Wisconsin.[82]

The cost savings of procuring out-of-state renewable energy accounts for the costs of procuring the resource net of its energy market value. Based on the NREL 2023 Annual Technology Baseline ("ATB"), the levelized cost of Minnesota wind in 2030 is $25/MWh (2022 dollars) compared to $37/MWh (2022 dollars) for Wisconsin solar, resulting in a $12/MWh cost savings (in 2022 dollars).[83] The energy market value of Wisconsin solar energy is about $8–9/MWh higher than Minnesota wind, resulting in a net cost savings of Minnesota wind of $5–10/MWh for 2032 to 2042. Based on this approach, the present value of the net generation cost savings over the 40 year life of Project 4 in Scenario 2 is $307 – $341 million (in 2022 dollars).

The second approach is based on MISO's Tranche 1 analysis in which regional transmission expansion reduces the amount of in-state renewable capacity needed by providing access to out-of-state renewable energy resources. MISO found in its analysis that the Tranche 1 portfolio of regional transmission upgrades provides access to 20 GW of regional renewable resources (mostly solar) and avoids about 42 GW of local renewable resources, or 2.1 GW of local renewable resources for each 1 GW of additional regional renewable resources. The 22

80 For example, MISO assumed in its Tranche 1 analysis that resources with a distribution factor of at least 5% on the Tranche 1 projects were dependent on the lines for delivery.

81 The estimate of wind generation assumes a 51% capacity factor of Minnesota wind.

82 The estimate of wind generation assumes a 28% capacity factor for Wisconsin solar.

83 Levelized Cost of Energy (LCOE) for Wind using the 2023 ATB, Land-based wind class 5, Moderate cost trajectory, 30-yr cost recovery. LCOE for solar uses the 2023 ATB, Utility-scale solar class 7, moderate cost trajectory, 30-yr cost recovery.

GW net reduction in total renewable capacity GW in MISO's analysis creates significant cost savings to ratepayers.[84]

For estimating the avoided local generation capital cost savings of Project 4, we apply MISO's ratio of avoided local renewable capacity additions to the 540–600 MW increase in access to out-of-state capacity provided by Project 4. This approach results in a 1,130–1,260 MW estimate of avoided local capacity and a net reduction of 590–660 MW of renewable capacity that Wisconsin would need to procure to meet its energy goals. MISO assumed that the avoided local capacity would primarily be solar resources and based its projection of future solar costs on the NREL ATB. Based on the 2023 NREL ATB solar capital cost assumptions of $1,297/kW in 2030 (nominal dollars), the present value of generation capital cost savings due to Project 4 is $575 million to $639 million (in 2022 dollars).

For the benefit-cost analysis, we rely on the more conservative estimates based on the first approach because it is more applicable to evaluating a single transmission line instead of evaluating a portfolio of regional transmission lines. The benefit-cost ratio of Project 4 increases to 6.9–7.9 based on the results of the second approach.

2. LVA Case and NTA Case Results

The LVA will not increase the capacity of the 345 kV system but will increase the thermal rating of the lower-voltage 161 kV system by about 400 MW. To estimate the avoided generation capital cost savings in the LVA case, we assume that the LVA case will support an additional 135–150 MW of imports based on the ratio of the thermal rating of the LVA case to the Project 4 case (25%). With this transfer capability, the present value of the net generation cost savings over the 40 year life of the LVA case is $75 - $84 million (in 2022 dollars) in Scenario 2.

For the NTA case, the addition of BESS to improve transfers across the Minnesota – Wisconsin border will reduce the costs of procuring other resources to meet Dairyland's annual planning reserve requirements. We estimated the avoided local generation capital costs of 100 MW battery storage accounting for the summer capacity accreditation of battery storage (50%) and gas resources (88%) and the incremental costs of new gas-fired resources estimated by MISO, known as the cost of new entry ("CONE"), for Planning Year 2025/26 in Load Resource Zone 2 of

[84] The MISO-wide analysis found that a total of 91 GW of additional capacity would need to be built if each LRZ were to rely on local builds to meet its renewable capacity requirements. Allowing regional builds in its capacity expansion decreased the total amount of required new capacity to 43 GW. MISO, MTEP 21 Report LRTP Tranche 1, September 2022.

$125,090/MW-year. We conservatively assumed that the gas resource would need to be replaced after 20 years (consistent with our assumptions for calculating the 40-year costs for battery storage). Based on these assumptions, the NTA case results in $110 million (2022 dollars) of avoided local generation costs in Scenario 2.

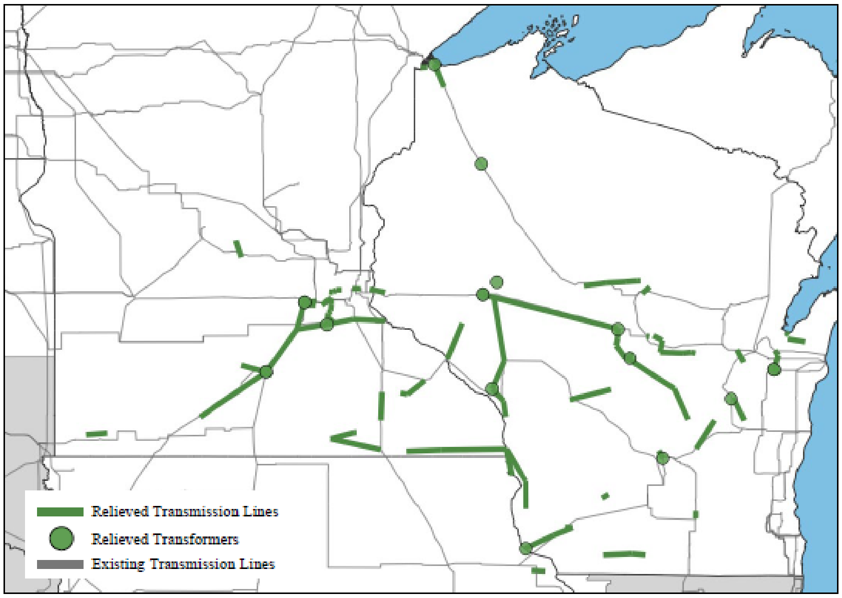
D. Avoided Transmission Capital Costs

The avoided transmission capital costs benefit metric quantifies the ratepayer cost savings of avoiding future investments in the transmission system that would be necessary if Project 4 were not built. Project 4 may avoid future transmission investments in two ways: (1) if Project 4 resolves a future reliability violation that would require an upgrade in its absence, the avoided cost of the reliability upgrade to resolve that violation at a future date is a cost savings to ratepayers; (2) if Project 4 replaces aging transmission facilities that would have been rebuilt in its absence, the avoided cost of the asset renewal upgrade to rebuild those facilities when required is also a cost savings to ratepayers.

MISO identified in its Tranche 1 reliability analysis (based on Future 1 market conditions) significant transmission overloads on transmission elements along the Minnesota-Wisconsin border that are relieved by Tranche 1 Projects 4–6, as shown in Figure 22 below. The need for future reliability upgrades in this corridor was further confirmed in the MISO Tranche 2 reliability analysis based on Future 2A. Even with the Tranche 1 projects in place, MISO identified further needs on the 345 kV system between Minnesota and Wisconsin.[85]

[85] MISO, LRTP Tranche 2 Reliability & Economic Study Update, March 2024, p. 7.

FIGURE 22: MISO ANALYSIS OF AVOIDED RELIABILITY UPGRADES RELIEVED BY TRANCHE 1



Source: MISO Tranche 1 Report, p. 31.

Dairyland performed an updated reliability analysis of Project 4, Tranche 1, and the alternative cases using both 2040 Future 1 and 2042 Future 2A power flow models for summer peak and shoulder average wind conditions, as documented in their reliability analysis report filed with the Commission.[86] Dairyland identified the costs of reliability upgrades and asset renewal upgrades that are avoided under the alternatives being considered.

The alternative cases resulted in the following avoided reliability upgrades, as further detailed in the Dairyland reliability reports:

- Project 4 avoids a significant upgrade of the Adams-Beaver Creek 161 kV line and lower cost upgrades on the Briggs Rd - Blair 345 kV line, two other lower voltage lines, and a 345/115 kV transformer.
- Tranche 1 avoids upgrades in Scenario 2 on a major 345 kV line in northern Wisconsin (Stone Lake-Jump River-Gardner Park-Highway 22 345 kV) and the Brigg Rd - Blair 345 kV line, along with thirteen lower voltage (138 kV and 161 kV) line upgrades, and seven transformers. The avoided costs are lower in Scenario 1 due to much fewer reliability violations identified in the more conservative Future 1 powerflow models.

[86] Dairyland Power Transmission Planning, Alma-Blair 345 kV Transmission Planning Reliability Review, June 2024; Dairyland Power Transmission Planning, Supplemental Analysis to the Alma-Blair 345 kV Transmission Planning Reliability Review, February 2025.

- The LVA case avoided upgrade costs are lower than Project 4 as it does not avoid the upgrade on the Adams-Beaver Creek 161 kV line, but does avoid a smaller upgrade on the Helena-Hampton Corners 345 kV line south of the Twin Cities and two lower voltage lines and a 345/115 kV transformer.
- The NTA case also avoids the upgrade on the Helena-Hampton Corners 345 kV line as well as one 115 kV line, and a 345/115 kV transformer.

Dairyland also identified one avoided asset renewal upgrade for the Project 4, Tranche 1, and LVA cases. Without Project 4 and the LVA, Dairyland will need to rebuild the aging Alma-Tremval 161 kV in the next 20 years. MISO did not include the Alma-Tremval 161 kV upgrade projects as avoided costs in its Tranche 1 Business Case based on feedback from Dairyland that the upgrade likely would not be necessary until after 2040. Due to the relevance of this upgrade for the Project 4 benefits analysis, we included it as an avoided cost starting at a later date (2041–2045) than the other upgrades.

The avoided reliability upgrades are for violations on assets located in Minnesota, Iowa, and Wisconsin. Among these projects, the avoided reliability upgrades that are located in the NSP, Dairyland, or American Transmission Company (ATC) service territories will reduce future transmission-related costs to Wisconsin ratepayers. If these upgrades were built in a future without Project 4, a portion of the costs of the reliability upgrades would be allocated to Wisconsin ratepayers, based on the share of Wisconsin ratepayers in company's each service territory (17% for Northern States Power, 65% for Dairyland, and 100% for ATC). Consistent with MISO's Tranche 1 analysis, we assume that these upgrades would be required from 2036 to 2040 and estimate the avoided costs to customers based on that timeframe.

The total avoided transmission capital costs for Wisconsin ratepayers across each case and scenario are shown in Table 11.

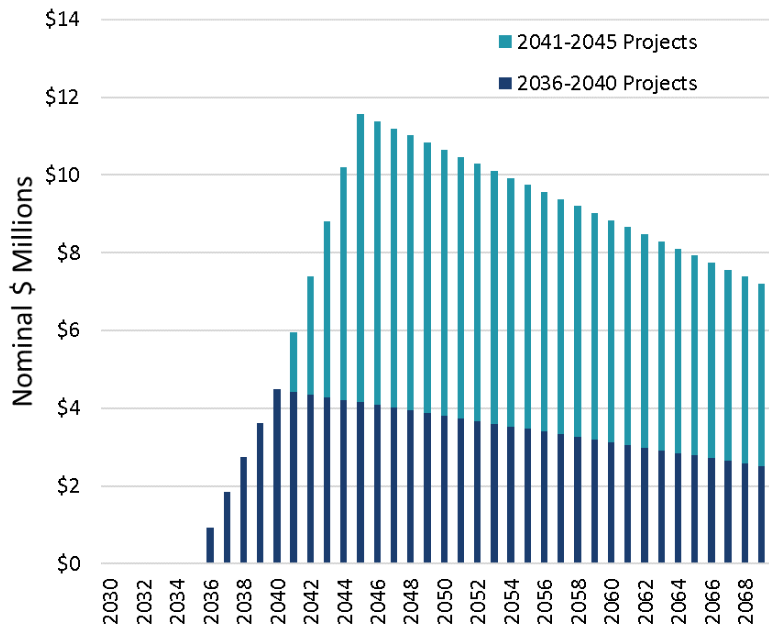
TABLE 11: AVOIDED TRANSMISISON CAPITAL COSTS FOR WISCONSIN CUSTOMERS BY CASE AND SCENARIO (2022 DOLLARS, MILLION)

Case	Scenario 1	Scenario 2	Scenario 3
LRTP 4	$55.8	$63.2	$59.0
Tranche 1	$86.2	$326.9	---
LVA	$35.0	$40.5	$40.4
NTA	$0.0	$5.5	---

Note: Avoided asset renewal upgrade costs associated with the Alma-Tremval 161 kV line rebuild total $35 million in each case except the NTA. The rest of the costs are for avoided reliability upgrades.

We next calculate the avoided costs to Wisconsin customers based on the annual revenue requirements for the avoided transmission upgrades and asset renewal projects, relying on MISO's assumptions for revenue requirements for its Tranche 1 benefit-cost analysis.[87] Figure 23 below shows the future avoided transmission costs for Wisconsin ratepayers by year for Project 4 in Scenario 3, separately displaying savings attributable to the avoided reliability upgrades that would be required in 2036–2040 ("2036-2040 Projects") and the asset renewal upgrade in 2041–2045 ("2041-2045 Projects"). The total 40-year present value of avoided costs of the avoided reliability upgrades due to Project 4 for Wisconsin ratepayers is $60.7 million (2022 dollars).

FIGURE 23: PROJECT 4 AVOIDED TRANSMISSION COSTS BY YEAR (SCENARIO 3)



[87] The transmission revenue requirement assumptions for avoided transmission projects are the same assumptions used to calculate the costs of transmission to Wisconsin customers for each of the alternative cases studied.