INFORMATION SHEET

PRESIDING: Chair Mitchell, Presiding; Commissioners Brown-Bland, Clodfelter, Duffley, Hughes, McKissick, and Kemerait
PLACE: Dobbs Building, Raleigh, NC
DATE: Friday, September 23, 2022
TIME: 9:30 a.m. to 12:46 p.m.
DOCKET NO.: E-100, Sub 179
COMPANY: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC
DESCRIPTION: 2022 Biennial Integrated Resource Plan and Carbon Plan

VOLUME NUMBER: 22

APPEARANCES
(See attached.)

WITNESSES
(See attached.)

EXHIBITS

(See attached.)

CONFIDENTIAL COPIES OF TRANSCRIPTS AND EXHIBITS ORDERED BY:

REPORTED BY: Linda Garrett
TRANSCRIBED BY: Linda Garrett
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DOCKET NO.: E-100, Sub 179
TIME IN SESSION: 9:30 A.M. TO 12:46 P.M.
BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.
Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Progress, LLC, and
Duke Energy Carolinas, LLC,
2022 Biennial Integrated Resource Plans
and Carbon Plan

VOLUME 22

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EXAMINATIONS

E X H I B I T S

IDENTIFIED/ADMITTED

/A

Docket No. E-100, Sub 179

William E. Powers on Behalf of NC WARN et al.

Exhibit 1 (Part 1 of 2)

Docket No.: R.20-11-003
Exhibit No.:
Witness: Bill Powers, P.E.
Commissioner: Marybel Batjer
ALJ: Brian Stevens

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021.	Rulemaking 20-11-003 (Filed November 19, 2020)

PREPARED OPENING TESTIMONY OF BILL POWERS, P.E. ON BEHALF OF THE PROTECT OUR COMMUNITIES FOUNDATION

Bill Powers, P.E. - Technical Advisor
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Dated: January 11, 2021

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OPENING TESTIMONY OF BILL POWERS, P.E. ON BEHALF OF THE PROTECT OUR COMMUNITIES FOUNDATION

PLEASE STATE YOUR NAME, PLACE OF EMPLOYMENT, AND BUSINESS ADDRESS.

My name is Bill Powers, P.E. I am the owner and principal of Powers Engineering, located at 4452 Park Boulevard, Unit 209, San Diego, CA 92116.

PLEASE DESCRIBE YOUR QUALIFICATIONS FOR PROVIDING THIS TESTIMONY.

I am a registered professional engineer, with extensive knowledge and experience in the fields of energy and environmental engineering, air emissions control, and regional energy planning. A copy of my resume is included as **Exhibit A** to this testimony.

WHAT IS THE PURPOSE OF THIS TESTIMONY?

I submit this opening testimony on behalf of The Protect Our Communities Foundation ("PCF") who provides testimony (PCF Presentation), pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, on actions the Commission can adopt by April 2021 to increase energy supply and decrease demand during the peak demand and net demand peak hours in the event that a heat storm similar to the August 2020 storm occurs in the summer of 2021.

My testimony details that California already has adequate energy supplies for the summer of 2021 with available resources. Consistent with the Scoping Memo's focus "on those actions that the Commission can adopt by April 2021 and that the parties can implement before or during the summer of 2021,"[1] the short-term focus of the Commission should be on crafting measures to avoid further financial burdens on California's ratepayers caused by the activities of wholesale sellers and traders in the markets administered by the California Independent System Operator (CAISO).

[1] R.20-11-003, Assigned Commissioner's Scoping Memo and Ruling (December 21, 2020), p. 1.

The Assigned Commissioner's focus on procurement must be accompanied by effective and aggressive use of the Commission's and the CAISO's existing authority to assure reliability, including measures to prevent physical and economic withholding and gaming. The August 2020 blackouts should not be used as justification to fast-track new gas-fired procurement for the summer of 2021, especially without a factual record that supports any new procurement.

I. AVAILABLE EVIDENCE INDICATES THAT THE MISMANAGEMENT OF AMPLE SUPPLIES CAUSED THE AUGUST 2020 BLACKOUTS, NO EVIDENCE SUPPORTS THE NEED FOR ADDITIONAL SUPPLY TO BE PROCURED FOR THE SUMMER OF 2021.

The mismanagement of ample supplies by CAISO during mid-August 2020 led to such substantial load and supply impacts that it compromised grid reliability and resulted in rolling blackouts on August 14-15, 2020. The blackouts were initiated at actual demand levels below the CAISO's forecast 1-in-2 peak demand for the summer of 2020.[2] There was nothing exceptional or historic about the demand on the grid at the time of the blackouts. The Commission requires the load serving entities (LSE) to procure adequate resources to meet CAISO's summer peak demand forecast. As a result, ample supplies of electricity were available and under contract to meet demand on August 14-15, 2020. However, in the immediate wake of the blackouts, and prior to any investigation, CAISO identified inadequate supply as the primary cause of the blackouts and dismissed improper market activity as a contributing factor.[3]

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[2] CAISO, *2020 Summer Loads and Resources Assessment*, May 15, 2020, p. 3 (Forecast summer 1-in-2 peak = 45,907 MW); CAISO Today's Outlook website (click on Demand) (August 14, 2020 blackout initiated (18:36) = 45,716 MW; August 15, 2020 blackout initiated (18:20) = 44,662 MW), available at http://www.caiso.com/TodaysOutlook/Pages/default.aspx.

[3] Dale Kasler, *California power prices have skyrocketed. Is this normal — or more Enron-style 'manipulation'?*, Sacramento Bee (August 19, 2020) ("But top ISO officials have said they've seen no evidence of anything improper. They're convinced the heat wave is largely driving conditions on the grid . . . Berberich said the commission has failed to implement a strict 'resource adequacy' regulation that would force the utilities to procure a greater share of their power in advance."), available at https://www.sacbee.com/news/california/article245048140.html.

The December 21, 2020 Scoping Memo and Ruling accepts CAISO's initial and erroneous claim of a supply shortage at face value, framing the factual inquiry to increasing supply and reducing demand for the summer of 2021. This testimony explains why no physical supply shortage exists that must be addressed with additional fast-track bilateral gas contracts, or any other procurement not already in the procurement pipeline, for the summer of 2021. The Commission should instead focus on identifying and rectifying CAISO supply management deficiencies and lax resource adequacy contract terms[4] prior to the summer of 2021 to ensure that all resources already under contract are delivered to and used for the benefit of California's ratepayers. The Commission should also focus on enforcing General Order 167 and its authority under Section 761 et seq. to ensure sufficient generation resources are available and their output delivered for use by California ratepayers. Focusing on delivery and use by Californians of the electricity resources for which they have already contracted comports with the Commission's recognition that issues of "(1) safety, (2) reliability, (3) load and supply impact, and (4) cost allocation"[5] are properly included within the scope of this proceeding. Without ensuring the availability and delivery of those electricity resources already under contract, the Commission cannot ensure safety and reliability or assess load and supply impact appropriately.

[4] CAISO Department of Market Monitoring, *Import Resource Adequacy* (September 10, 2018), p. 1 ("Resource adequacy imports are not required to be resource specific or to represent supply from a specific balancing area, but only that they be on a specific intertie into the ISO system. Further, scheduling coordinators are only required to submit energy bids for resource adequacy imports in the day-ahead market. Imports can be bid at any price and do not have any further obligation to bid into the real-time market if not scheduled in the day-ahead energy or residual unit commitment process."), available at http://www.caiso.com/documents/importresourceadequacyspecialreport-sept102018.pdf.
[5] R.20-11-003, Assigned Commissioner's Scoping Memo and Ruling (December 21, 2020), p. 2.

The events of August 14-15, 2020 and the immediate reaction to pursue expensive supply as the only solution, recapitulate precisely the well-known pattern from the 2000-01 Energy Crisis.[6] In preparing for summer 2021, the Commission and California should take every action within their power to avoid being herded into expensive and unnecessary electricity contracts once again.

The August 2020 blackouts were accompanied by extremely profitable price gouging by sellers throughout the West. In proceedings at FERC initiated in October 2020, immediately after the publication of the October 6, 2020 Preliminary Root Cause Analysis (PRCA), a large number of sellers have disclosed – and attempted to justify – prices during and after the blackout period that exceeded the $1,000/MWh soft cap in the Western Interconnect.[7] All three large California utilities have intervened at FERC to request unwinding of these transactions and refunds.[8] The cost impacts on California ratepayers were unjust and unreasonable. FERC has not yet acted.

The Department of Market Monitoring at the CAISO (DMM) has intervened at FERC and requested that FERC provide guidance going forward on the use of non-generator costs to justify high bids (bilateral contract prices and published indices).[9] FERC has not yet acted. Notably, neither the CAISO nor the DMM have addressed price gouging and the possibility of

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[6] *See, generally*, Morgan Stanley Capital Group Inc. v. PUD Number 1 of Snohomish County, 554 US 527 (2008); Snohomish v. FERC, 471 F.3d 1053 (9th Cir. 2006) and cases cited at 471 F.3d at 1067-68.
[7] *See e.g.* ConocoPhillips, Docket ER21-40; Tenaska Power Services, ER21-42; Exelon, ER21-43; Mercuria, ER21-46; Tucson Electric Power (Fortis), ER21-47; UNS Electric, Inc. (Fortis), ER21-48; BP Energy, ER21-51-001; Public Service Company of New Mexico, ER21-52; Mesquite Power (IIF), ER21-55; El Paso Electric (IIF), ER21-61-001; Guzman Energy, ER21-56; Shell Energy North America, ER21-57; TransAlta Energy Marketing, ER21-58; Brookfield Renewable Trading and Marketing, ER21-59; PacifiCorp, ER21-60; Uniper Global Commodities North America, ER21-62; Macquarie Energy, ER21-64; Tri-State Generation and Transmission Association , ER21-65; EDF, ER21-135.
[8] FERC Docket No. ER21-40-000, Comments of SCE (October 28, 2020); Comments of PG&E (October 28, 2020); Motion to Intervene filed Out-of-Time by SDG&E (November 2, 2020).
[9] FERC Docket No. ER21-40-000, Comments of the CAISO DMM (October 28, 2020).

market manipulation for purposes of revenue and profit maximization in any of the preliminary reports or analyses to date. The Commission should address the pricing issues arising from the CAISO's conduct of its markets and should examine the utilities' filings and evidence about price gouging before it potentially compounds the problem by ordering additional unneeded procurement for the summer of 2021.

This supply can be diminished through withholding – physical or economic – or through actions that make it otherwise unavailable. Thus to ensure the availability and actual delivery of all the supply that Californians have already paid for, the Commission should focus on actions to ensure the availability and delivery of the currently-contracted-for supply, rather than order additional procurement to be purchased.

With proper management by CAISO of available supply, and new supply additions scheduled to be online by the summer of 2021, CAISO will have up to 9,000 MW of additional supply available in the summer of 2021 beyond what it had available on the afternoon of August 14, 2020. The composition of the additional supply is described in Section II. 1,000 MW of DR can also be added by the summer of 2021 by enrolling residential customers with smart thermostats in opt-out smart thermostat DR programs, as discussed in Section III.

II. UP TO 9,000 MW OF ADDITIONAL SUPPLY WILL BE AVAILABLE TO CAISO IN THE SUMMER OF 2021 WITHOUT NEW PROCUREMENT.

A. CAISO's Curtailment of Exports Would Add Up To 4,500 MW of Additional Supply.

Ongoing investigation, summarized in the October 6, 2020 PRCA,[10] the October 9, 2020 CAISO August Heatwave Update (Update), and the November 24, 2020 DMM Report on System and Market Conditions, Issues and Performance: August and September 2020 (DMM

[10] The Final PRCA has not been released at the time this opening testimony was prepared.

Report), do not support the CAISO's initial conjecture about the cause of the blackouts. The PRCA indicates that a CAISO "software error" enabled thousands of MW of power to be exported from CAISO to neighboring states as blackouts were called by CAISO in California.[11] The amount of power being exported at the time of the blackouts on August 14th and 15th 2020 was far in excess of the demand reduction achieved with the rolling blackouts. According to the CAISO's own data, about 4,500 MW of power was being exported from CAISO to neighboring states when CAISO called a 1,000 MW rolling blackout on August 14th.[12] About 3,500 MW of power was being exported to neighboring states on August 15th when CAISO initiated a 470 MW rolling blackout.[13]

The DMM, the entity within CAISO whose role is to assure that the market functions properly, claims to have been unaware until recently that, contrary to CAISO's tariff, CAISO would allow exports to continue under potentially tight CAISO supply conditions.[14] Is this a "software error" or a policy choice to promote exports in the name of regional grid integration? If the former, steps should be taken to correct the error, at no cost to consumers. If the latter, it needs to be corrected before consumers spend money for new procurements that would purport to pay exporters for "opportunity costs" associated with foregone exports.

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[11] PRCA, p. 13-14 ("After a review of the August 14 event, it was discovered that a prior market enhancement was inadvertently causing the CAISO's RUC process to mask the load under-scheduling and convergence bid supply effects, reinforcing the signal that more exports were supportable.").
[12] *Id.* at p. 100.
[13] *Id.* at p. 100.
[14] CAISO DMM, *Report on system and market conditions, issues and performance: August and September 2020* (November 24, 2020), p. 71 ("Prior to the August heat wave, the CAISO tariff and business practice manuals described day-ahead market exports not supported by specific generation being clearly prioritized below CAISO load in real-time. Therefore, it was DMM's understanding that CAISO already had such a carefully defined process in place. Now, it is DMM's understanding that CAISO may not have such a procedure and that its policy may not be aligned with export curtailment policies of other western balancing areas.").

In its FERC Comments, the DMM describes plausible scenarios for "exports" chasing high prices throughout the West, including re-import into California through devices such as megawatt laundering and wash trades.[15] Was it a software error, or a "market enhancement" through which sellers exploited the opportunity to remove available supplies from California at the expense of California consumers? These revelations do not inspire confidence that CAISO possesses or uses adequate internal market controls to manage exports or guard against price gouging under conditions of tight supply. A thorough investigation needs to provide answers to these questions before California load-serving entities and their retail customers are compelled to pay more to purchase existing power supplies.[16]

Several parties to this proceeding, including PCF, PG&E, TURN, UCAN, and CEJA, have attributed the continued exporting of large amounts of power out-of-state as the primary cause of August 14-15, 2020 rolling blackouts.[17] The DMM concurs and its December 18, 2020 presentation specifically finds that "Exports increased demand above levels that could be supported by physical generation."[18] The Commission should support the DMM's recommendation that "Further changes and clarifications in the rules and processes for limiting and curtailing exports should be discussed and pursued."[19] Curtailing exports during tight

[15] FERC Docket No. ER21-40-000, Comments of the Department of Market Monitoring of the California Independent System Operator Corporation (October 28, 2020), p. 5-6, 8-9.
[16] No new construction can occur before June 2021, so any Commission order for more procurement will simply constitute an order to buy from currently existing supply.
[17] R.20-11-003, PG&E Reply Comments (December 10, 2020), p. 10-11; CEJA et al Reply Comments (December 10, 2020), p. 3; TURN Opening Comments (November 30, 2020), p. 4-5; UCAN Opening Comments (November 30, 2020), p. 1-2.
[18] CAISO DMM, *Report on System and Market Conditions, Issues and Performance: August and September 2020* (December 18, 2020), PowerPoint p. 16, available at http://www.caiso.com/Documents/Presentation-Report-MarketConditions-Issues-Performance-August-September2020-Dec18-2020.pdf
[19] *Id.* at p. 21.

supply conditions will boost supply in the summer of 2021 by at least 3,500 MW, at no cost to the California ratepayer.

The Commission should intervene at FERC to support the utilities' demands for refunds, to support the DMM's requests both for the clear guidance sought by the DMM that prohibits self-referential cost justification for high bids, and a reduction of the caps from $1,000/MWh to $500/MWh, based on the SCE formula.[20] The Commission should also direct the CAISO to develop clear scheduling and other market protocols to prioritize retail load within California over exports under tight supply conditions. PCF recommends that this proceeding incorporate an examination of the protocol revisions needed to prioritize the needs of California customers and the adequacy of retail service in California, as California Public Utilities Code Section 345.5(b)(5) requires.[21]

The efficacy of this practice has already been demonstrated by CAISO. The curtailment by CAISO of exports during peak hours on August 18, 2020 and September 6, 2020 enabled CAISO to meet significantly higher peak loads than those it experienced on August 14-15, 2020 without resorting to rolling blackouts,[22] thereby ensuring the safety and reliability of the system.

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[20] FERC, Docket No. ER21-40-000, SCE Comments (October 28, 2020), fn. 14, p. 5 ("During the August events, natural gas prices were in the range of $13.50/mmBtu, GHG prices were less than $18/ton, and data from Hitachi Powergrids Velocity Suite indicate no generation within the CAISO has an incremental heat rate above 30,000 Btu/kWh. Assuming a conversion factor of 0.0531148mtCO2e/mmBtu, then, conservatively, no generation within the CAISO had a marginal cost that exceeded $440/MWh. (30 mmBtu/*13.5/mmBtu + 30*0.0531148mtCO2e/mmBtu*$18/ton = $433.68/MWh).").

[21] Pub. Util. Code, § 345.5, subd. (b)(5) ("Independent System Operator shall manage the transmission grid and related energy markets in a manner that is consistent with all of the following . . . Conducting internal operations in a manner that minimizes cost impact on ratepayers to the extent practicable and consistent with the provisions of this chapter.").

[22] CAISO Today's Outlook (click on Demand) (August 14, 2020 peak (17:00) = 46,777 MW; August 14, 2020 blackout initiated (18:36) = 45,716 MW; August 15, 2020 peak (18:00) = 44,913 MW; August 15, 2020 blackout initiated (18:20) = 44,662 MW; August 18, 2020 peak (16:00) = 47,067 MW; September 6, 2020 peak (16:40) = 46,864 MW), available at http://www.caiso.com/TodaysOutlook/Pages/default.aspx.

B. OTC Unit Performance Should Be Carefully Scrutinized.

CAISO speculates that no manipulation of supply sources contributed to the blackouts because, based on its (anecdotal) polling of generators, the generator outages that occurred were legitimate.[23] However, over 1,400 MW of SoCal OTC capacity, nearly 40 percent of the total SoCal OTC capacity, was unavailable when the 1,000 MW rolling blackout were initiated by CAISO on August 14th with demand at 45,716 MW.[24] In contrast, all of the SoCal OTC units were available to meet the substantially higher peak demand on September 6, 2020, increasing OTC supply by over 1,000 MW.

Section 761.3 requires generators to record plant status information daily and to maintain a Control Operator Log, a "formal record of real time operating events as well as the overall status of the generating units" under the operator's control and to report the reasons for any unit curtailments to the CPUC and the CAISO.[25] Yet CAISO has declined to provide the reasons that the generators must officially record, from the formal reporting requirements for the outages of the SoCal OTC units that were unavailable on August 14-15, 2020.[26]

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[23] CAISO DMM, *Report on System and Market Conditions, Issues and Performance: August and September 2020* (November 24, 2020), p. 22 ("DMM has reviewed major outages which occurred on August 14 and 15. Based on data available to DMM *at this time*, there is no indication that on these days any outages were falsely declared at strategic times in order to allow generation owners to profit from higher prices.").
[24] **Exhibit B**: R.19-11-009, Response of CAISO to Data Request Number PCF-CAISO-2020RA-02 by Protect Our Communities Foundation (November 16, 2020); R.20-11-003, PCF Reply Comments (December 10, 2020), p. 5.
[25] Pub. Util. Code § 761.3, subd. (e) ("…[The generator] shall provide a monthly report to the Independent System Operator that identifies any periods during the preceding month when the unit was unavailable to produce electricity or was available only at reduced capacity. The report shall identify the reasons for any such unscheduled unavailability or reduced capacity. The Independent System Operator shall immediately transmit the information to the Oversight Board and the commission."); CPUC General Order 167, Appendix B (applicable to all thermal units in California over 50 megawatts).
[26] **Exhibit B**: R.19-11-009, CAISO, Response of the California Independent System Operator Corporation to Data Request Number PCF-CAISO-2020RA-02 by Protect Our Communities Foundation (November 16, 2020).

More concerning, the DMM's assertion that there were no deliberate outages does not appear to be based on a review of the Control Operator Logs, if indeed they are still maintained. The Control Operator Log specifically must include a record of "communications between the facility and outside entities including but not limited to the Independent System Operator (ISO), scheduling coordinators or headquarters facilities…"[27] This information would shed light on the actual dispatch instructions received by the plant operators, as well as other communications about operation and dispatch. The Commission should activate its reporting and enforcement mechanisms and both demand and then publish monthly CAISO "after action" outage reports for all California-based generation.

The primary purported purpose for utilizing outdated and high environmental impact OTC units in the past has been to provide additional supply during peak demand periods. A critical fact that the Commission must examine and understand involves why those plants could not perform on August 14-15 and why they could perform on September 6. A 40 percent unavailability rate at the hour of critical need is clearly unacceptable.

C. Properly Maintained Utility-Owned Combined Cycle Units Adds 500 MW in Summer of 2021.

California investor-owned utilities (IOU) own a total of five combined cycle power plants: PG&E's Colusa Generating Station (August NQC = 595 MW) PG&E's Gateway Energy Station (August NQC = 523 MW), SCE's Mountainview Energy Center (August NQC = 1,110 MW), SDG&E's Palomar Energy Center (August NQC = 566 MW), and SDG&E's Desert Star Energy Center (August NQC = 419 MW).[28]

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[27] CPUC General Order 167, Appendix B, p. 35.
[28] CAISO, Final Net Qualifying Capacity Report for Compliance Year 2020 (xls) (December 15, 2020), available at http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

Two of these five utility-owned combined cycle power plants, Gateway Energy Center and Desert Star Energy Center, experienced substantial forced outages on August 14th and 15th, 2020. On August 14th, at the start of the 1,000 MW rolling blackout at 6:36 pm, Gateway was experiencing a partial curtailment of 180 MW.[29] At this same time, Desert Star was experiencing a partial curtailment of 280 MW.[30] The combined curtailment at these two combined cycle plants was approximately 460 MW when the rolling blackout was initiated on August 14th.[31]

On August 15th at the start of the 470 MW rolling blackout at 6:20 pm, Gateway was experiencing a partial curtailment of 164 MW.[32] Desert Star was experiencing a partial curtailment of 130 MW.[33] The combined curtailment at these two combined cycle plants was approximately 300 MW when the rolling blackout was initiated on August 15th. The high forced outage rate at utility-owned combined cycle plants, with two of five combined cycle plants substantially impacted, materially reduced available supply at the time the rolling blackouts were initiated on August 14th and 15th, 2020.

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[29] CAISO August 13-16, 2020 outage summary (xls) CAISO, Outage Data for August 13-16 and Responses to Stakeholder Questions (September 11, 2020), available at http://www.caiso.com/Documents/OutageData-August13-16-Responses-StakeholderQuestions.html; http://www.caiso.com/Documents/ISO-Stage-3-Emergency-Declaration-Lifted-Power-Restored-Statewide.pdf.

[30] *Ibid.*

[31] **Exhibit C**: T. Popik – Foundation for Resilient Societies, *August 2020 Blackouts in CAISO*, PowerPoint, (November 5, 2020), p. 16, available at https://www.nerc.com/comm/RSTC/EGWG/Foundation_for_Resilient_Societies_EGWG_Sept_29_2020_r2%20(002).pdf.

[32] CAISO August 13-16, 2020 outage summary (xls) CAISO, Outage Data for August 13-16 and Responses to Stakeholder Questions (September 11, 2020), available at http://www.caiso.com/Documents/OutageData-August13-16-Responses-StakeholderQuestions.html; http://www.caiso.com/Documents/ISORequestedPowerOutagesFollowingStage3EmergencyDeclarationSystemNowBeingRestored.pdf.

[33] *Ibid.*

D. New Supply – Already in Development – Adds 2,400 MW by Summer 2021.

There is no dispute that 2,100 MW of storage and hybrid storage resources and approximately 300 MW solar and wind resources, already under development by LSEs, will be online by the summer of 2021.[34] This additional supply, already under contract and paid for by California ratepayers, should be factored into any modeling or analyses of supply shortages before the Commission orders additional procurement.

E. Shedding Load at 3% Operating Reserve Margin Adds 1,500 MW of Supply.

CAISO insists it must maintain 3,000 MW of reserves and initiate controlled load shedding if it drops below that reserve level.[35] 3,000 MW of reserves equates to approximately 6 percent at a peak demand of 45,000 MW, the approximate peak loads on August 14th and 15th. The insistence on maintaining at least a 6 percent operating reserve margin contradicts CAISO's stated operating practice, that it will initiate controlled load shedding when operating reserves reach 3 percent.[36] The capacity difference between a 6 percent operating reserve margin and 3 percent operating reserve margin, at a demand of 45,000 MW, totals 1,500 MW, an amount of resources that would have clearly covered the 1,000 MW of rolling blackouts the CAISO called on August 14th and the 470 MW of rolling blackouts the CAISO called on August 15th.

An issue that must be addressed before the summer of 2021 is CAISO's real-time accounting of available capacity on its public website. The available capacity data on the public website indicated that CAISO initiated the rolling blackout on August 15, 2020 at an operating

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[34] PRCA, p. 64.
[35] Jeff St. John, *California's Shift from Natural Gas to Solar Is Playing a Role in Rolling Blackouts*, GreenTech Media (August 17, 2020), p. 4 ("'For those who say we can rely on our reserves, you are wrong,' Berberich said in response to criticism that CAISO called its emergencies while it still had reserve generation capacity available. CAISO must retain its roughly 3,000 megawatts of reserve capacity to prevent the possibility of an even more widespread grid collapse, which could occur if a power plant were to drop offline or a key transmission line were to be forced out of service, he said.").
[36] R.20-11-003, PCF Opening Comments (November 30, 2020), p. 4.

reserve margin of approximately 9 percent.[37] Yet the calculated real-time operating reserve margin displayed on a separate CAISO website was showing an operating reserve margin at or below 6 percent.[38] CAISO does not clarify the basis for this discrepancy in the PRCA or in its data request responses to PCF in the resource adequacy proceeding, R.19-11-009. The Commission should request clear and consistent information be provided to all of California before the CAISO decides to shed load at reserve levels above 3 percent.

F. 9,000 MW of Additional Supply Is Already Available to CAISO for Summer 2021 with No Further Procurement Action by the Commission.

Curtailing exports (4,500 MW), accounting for new supply already in development for summer 2021 (2,400 MW), assuring all utility-owned combined cycle units are available when needed (500 MW), and following established NERC and CAISO protocol on initiating controlled load shedding at a 3% operating reserve margin (1,500 MW) would collectively add approximately 9,000 MW of supply to the supply-demand balance faced by CAISO on the afternoon of August 14th. 9,000 MW of this additional supply can be obtained at no cost to ratepayers.

III. REDUCING DEMAND

A. Reversing Attrition in DR Programs Adds 1,000 MW by Summer 2021.

The PRCA also indicates that the most likely focus of any new supply for the summer of 2021 will involve "demand side" resources such as demand response (DR).[39] However, CAISO has resisted expanding use of DR resources in the past, despite DR's prioritization at the top of the Loading Order for new resources. CAISO's institutional resistance to DR has been effective.

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[37] **Exhibit D**: Calculation of real-time operating reserve margin during August 15, 2020 rolling blackout, D. Marcus, September 22, 2020.
[38] CAISO OASIS database, Ancillary Services, Actual Operating Margin (accessed January 11, 2021): http://oasis.caiso.com/mrioasis/logon.do.
[39] PRCA, p. 65.

In 2012, CAISO identified 2,296 MW of DR at its disposal to offset demand at the summer peak.[40] In 2020, CAISO identified only 1,339 MW of DR available for this purpose.[41] Had CAISO simply maintained the amount of DR available to it in 2012 through the summer of 2020, it would have possessed an additional 957 MW of DR to deploy on August 14th and 15th as an alternative to calling rolling blackouts.

The Commission should take advantage of available but underutilized DR assets, increase incentives, reduce dispatch activity limits, and clarify its expectations regarding when programs are dispatched, to replenish this nearly 1,000 MW of the formerly available DR capacity by the summer of 2021. Over one million of California homes with central air conditioning (A/C) currently have smart thermostats installed.[42] Yet only a fraction of these homes are enrolled in IOU DR programs.[43] These customers form an obvious pool of candidates to reduce residential central A/C loads during heat waves, and should be enrolled immediately in IOU DR programs.

Enrollment for all customers with smart thermostats should be "opt-out" programs, following the approach used by the IOUs with their opt-out residential customer TOU tariffs. Opt-out DR programs – involving those customers already equipped with low-cost smart thermostats for cycling of central A/C units[44] – can achieve 95 percent participation.[45] For the DR programs to maximize their potential, they must be structured as opt-out programs.

SCE achieved an average of 1 MW reduction per 1,000 participating smart thermostat customers in the first hour of deployment (5 to 6 pm) over several heat waves in the summer of

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[40] CAISO, *2012 Summer Loads and Resources Assessment* (March 15, 2020), Table 1, p. 4.
[41] CAISO, *2020 Summer Loads and Resources Assessment* (May 15, 2020), p. 5.
[42] R.20-11-003, Google Opening Comments on Order Instituting Rulemaking (November 30, 2020), p. 3.
[43] *Ibid.*
[44] Portland General Electric, Smart Thermostat Program website, available at https://www.portlandgeneral.com/residential/energy-savings/thermostats/smart-thermostat-programs.
[45] FERC, *A National Assessment of Demand Response Potential* (October 2009), Table 1, p. 24.

2019.[46] The average SCE peak load reduction in the first hour was more than 50 MW and involved over 50,000 residential customers.[47] Based on these results, adding a million new residential customers in the CAISO control area has the potential to achieve a demand reduction of 1,000 MW.

Payments to smart thermostat participants should be decoupled for CAISO market prices to assure these DR resources play no role in driving marginal pricing in CAISO markets during heat waves. Customers should be paid a fixed price per annum for a limited number of dispatches, whether or not these DR resources are dispatched. For example, customers would be paid $50 in the form of a bill credit for up to 10 dispatches of up to 4 hours duration each in 2021.

The onerous dispatchability requirements that CAISO has placed on DR resources should also be relaxed to increase available DR capacity when it is needed. In the case of residential A/C load reduction via smart thermostat control, this DR resource should be scheduled for dispatch in the day-ahead market two hours before the day-ahead forecast net peak. Scheduling DR resources in the day-ahead market is fundamentally no different than dispatching slow-start resources (OTC units) a day in advance to assure they are operating at capacity when peak loads occur the following day.

B. Reliability of CAISO Day-Ahead Forecasts in Heat Waves Must Be Improved.

[46] SCE, *Southern California Edison Smart Energy Program: 2019 Load Impact Evaluation*, PowerPoint (May 4, 2020), p. 5 (Summer 2019 average, 5-6 pm, number of customers = 52,239, average load reduction = 1.02 kW, total load reduction = 52,239 customers x 1.02 kW per customer = 53,284 kW (53.3 MW).).
[47] *Ibid.*

The facts show that CAISO ordered the rolling blackouts at demand levels that were less, at 45,716 MW and 44,524 MW respectively, than the CAISO summer 2020 forecast 1-in-2 one-hour peak load of 45,907 MW.[48,49] Augmenting supply for the summer of 2021, when availability of supply was not the cause of August 2020 blackouts, will not prepare California to ensure reliability during any heat waves that might occur in 2021. Authorizing CPM procurement to augment supply, when supply constraints were not a cause of the August 14-15, 2020 rolling blackouts, would conflict with the Commission's statutory obligation to ensure just and reasonable rates.

This proceeding should examine closely the accuracy of CAISO's day-ahead forecasts in the week following the August 14-15, 2020 blackouts. The day-ahead forecast for Monday, August 17th, was nearly 5,000 MW higher, at 49,825 MW, than the actual peak of 45,094 MW. The next day, August 18th, the day-ahead forecast was 3,300 MW higher, at 50,485 MW, than the actual peak of 47,067 MW.[50] CAISO asserts that extraordinary voluntary conservation is the reason for the discrepancy between these day-ahead forecasts and the actual peak demand,[51] implying that the forecasts were accurate and the exceptional voluntary conservation was unanticipated.

These exceptionally high day-ahead demand forecasts created near-panic in California in the wake of blackouts on August 14th and 15th. The CAISO provides no evidence to support its

[48] CAISO, *2020 Summer Loads and Resources Assessment* (May 15, 2020), p. 3.
[49] CAISO, CAISO Today's Outlook (click on Demand) (see "demand trend" curves for August 14, 2020 and August 15, 2020), available at http://www.caiso.com/TodaysOutlook/Pages/default.aspx..
[50] *Ibid.* (see "demand trend" curves for August 17, 2020 and August 18, 2020).
[51] CAISO/CPUC/CEC, *Preliminary Root Cause Analysis* (October 6, 2020), p. 39 ("As a result of the conservation messaging and awareness created by the State of Emergency, the state was successful in significantly reducing peak demand by as much as 4,000 MW (compared to day-ahead forecasts) on August 17 through 19.").

position that unexpected voluntary conservation was the only reason for the large difference between the day-ahead forecasts on August 18th and 19th and actual peak demand on those days. The Commission should examine whether the forecasts themselves were highly inaccurate. The Commission should corroborate whether the CAISO possesses the capability to conduct accurate day-ahead forecasts during heat waves, as the efficient allocation of supply resources depends largely on those day-ahead forecasts.

The day-ahead demand forecasts of large California public utilities, LADWP and SMUD, and investor-owned utilities in neighboring states that were subject to the same heat wave (Arizona Public Service, Tucson Electric Power, NV Energy) should be evaluated to determine if the CAISO high day-ahead forecasts for August 17-19, 2020 were an outlier or were consistent with the day-ahead forecasts of major California public utilities and IOUs in neighboring states. This information should be used to assess whether CAISO's day-ahead forecasts for the August 17-19, 2020 period were erroneously high. If so, action must be taken to improve the accuracy of CAISO day-ahead forecasts in the midst of heat waves, and not allow erroneously high forecasts to be used to justify supplemental CPM procurement for the summer of 2021.

IV. TO ENSURE SAFETY AND RELIABILITY – THE COMMISSION MUST ADDRESS INADEQUATE CAISO GRID MANAGEMENT THAT MAY COMPROMISE SUMMER 2021 GRID RELIABILITY.

Actual historic blackouts in the CAISO control area have been caused by mismanagement of available supply, and not by a shortage of supply. For example, inadequate CAISO grid management in SDG&E service territory has led to three major blackouts in the last decade. These blackouts are summarized in Table 1.

Table 1. Major blackouts in SDG&E service territory, 2010-2020

Year	Impact	Cause
2010 April	250,000 customers lose power in San Diego	Improper action by CAISO operators, ordering SDG&E to shed 290 MW. Attributed by FERC to inadequate training and lack of documented operating procedure.[52]
2011 Sept	Regional blackout: SDG&E, Imperial Irrigation District, Baja California	Insufficient local generation online on highest demand day of year. Largest OTC plant (1,000 MW) and combined cycle plant (600 MW) in San Diego area not producing power when major transmission line shut down,[53] led to trip of San Onofre Nuclear Generating Station and regional blackout.
2020 August	Rolling blackouts at modest summer loads	CAISO orders blackout in SDG&E territory with demand less than 3,800 MW (all-time SDG&E peak = 4,890 MW)[54]

Inadequate management of available supply has been the cause of these blackouts, not lack of supply. The focus of Commission efforts to minimize the potential for a repeat of the blackouts of 2020 must be on CAISO grid management and market practices, and not on simply adding more supply while largely ignoring the management and market issues.

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[52] FERC, *In re California Independent System Operator Corporation, Docket No. IN13-4-000, Order Approving Stipulation and Consent Agreement* (December 14, 2012), p. 2 ("The investigation examined possible violations of the NERC Reliability Standards by CAISO surrounding a Disturbance in the San Diego area of the state of California on March 31-April 1, 2010 (the Disturbance). CAISO admitted to the violations set forth below and agreed to pay a civil penalty of $200,000 to the United States Treasury.").

[53] NERC/FERC, *Arizona-Southern California Outages on September 8, 2011 – Causes and Recommendations* (April 27, 2012), p. 25, 33, 50 ("CAISO, the TOP for SDG&E and SCE, did not have any alarms specifically tied to the operation of the SONGS separation scheme either. CAISO only has alarms for when Path 44 exceeds its Path rating, but had no ability to monitor the SONGS separation scheme, set at 3,100 MW (8,000 amps). After the loss of H-NG, which caused Path 44 to exceed its Path rating, CAISO operators were primarily concerned with returning flows on Path 44 to below the Path rating of 2,500 MW, but believed they had 30 minutes to do so. Unlike Path ratings, the separation scheme would not allow CAISO operators 30 minutes to reduce flows on Path 44. CAISO did attempt to dispatch additional generation within SDG&E to reduce flows on Path 44. The other method to reduce flows would have been to manually shed load in SDG&E in time to prevent operation of the SONGS separation scheme. SDG&E estimates that it could have shed approximately 240 MW in between two and two-and-a-half minutes. However, SDG&E was never instructed to shed load and was unaware of the need to shed load.").

[54] R.20-11-003, PCF Reply Comments (December 10, 2020), p. 4.

V. CONCLUSION

Proper management by CAISO of available supplies in the summer of 2021 will add up to 9,000 of supply capacity to meet peak loads with no new procurement. 1,000 MW of DR resources can also be added by the summer of 2021 by enrolling residential customers who have already added smart thermostats in IOU opt-out smart thermostat programs.

To summarize the programmatic recommendations for 2021 to avoid blackouts, ensure safety and reliability and to avoid price gouging, the Commission should:

(A) Assure that supply-side resources within the CAISO are available to serve CAISO loads by:

(1) prioritizing California loads over exports, a CAISO responsibility;

(2) enforcing generator operation and maintenance standards including enhanced monitoring and reporting under GO 167, a CAISO and Commission responsibility;

(3) completing storage and renewable projects already under contract for 2021, a Commission and California LSE responsibility;

(4) Completing a thorough and professional root cause analysis to determine, among other things, appropriate behaviors by scheduling coordinators, a CAISO/Commission/CEC responsibility;

(5) if necessary reform contract terms to establish the priority for serving California retail load, without paying for rents associated with exports, withholding or other forms of market power that create the appearance of scarcity, a CAISO and Commission joint responsibility.

(B) Assure that demand is accurately forecasted and managed within existing programs and technologies by:

(1) Complying with existing requirements for load shed events at 3 percent reserve level, a CAISO responsibility;

(2) Improving load forecasting, a CAISO responsibility;

(3) Reversing attrition of demand response programs including smart thermostats, a Commission responsibility;

The central focus of the Commission should be on measures to avoid the safety and reliability disruptions and the further financial burdens on California ratepayers caused by the activities of wholesale sellers and traders in CAISO markets. Focusing on procuring new gas-fired procurement without addressing the generation outages and the market flaws that allowed up to 4,500 MW of exports at a time of high demand cannot assure grid reliability or sufficient safety in the summer of 2021.

Respectfully submitted,

/s/ Bill Powers, P.E

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Dated: January 11, 2021

EXHIBIT A:

Bill Powers Resume

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Bachelor of Science – Mechanical Engineering, Duke University
Master of Public Health – Environmental Sciences, University of North Carolina

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
Registered Professional Engineer, Missouri (Certificate 2018039156)
American Society of Mechanical Engineers
Institute of Electrical and Electronics Engineers

TECHNICAL SPECIALTIES

Thirty-five years of experience in:

- Air quality and utility commission proceedings - expert witness
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Power plant cooling system conversion and air emission control assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

RECENT AIR QUALITY AND UTILITY COMMISSION PROCEEDINGS

Compressor Station Gas Turbine Air Emission Controls. Assessed the air emission controls and siting issues related to two proposed pipeline compressor station projects in the vicinity of Nashville, Tennessee utilizing Solar Turbines, Inc Titan gas turbines. The result, based on application of a Reasonably Available Control Technology (RACT) requirement, was the reduction of the proposed air permit nitrogen oxides (NOx) emission limit from 25 parts per million (ppm) to 9 ppm.

Combined Heat and Power Plant Gas Turbine Air Emission Controls. Evaluated the air emission controls proposed for a combined heat and power (CHP) plant at Duke University that would utilize Solar Turbines, Inc Titan gas turbine. Applicant proposed a 25 ppm NO_x limit using dry low-NO_x combustion as Best Available Control Technology (BACT) in its Certificate of Public Convenience and Necessity (CPCN) application to the North Carolina Utilities Commission. Argued that NO_x BACT for the CHP plant should be use of selective catalytic reduction (SCR) to achieve a 2 ppm NO_x emission limit. Applicant withdrew its CPCN application.

SDG&E 36-Inch Transmission Pipeline. Expert witness for non-profit client advocating that existing 16-inch pipeline did not require replacement with new $600 million 36-inch pipeline. Underscored in testimony that SDG&E had recently completed extensive inline inspection of existing 16-inch pipeline and found that pipeline was in good condition for long-term operation at 512 psig transmission pressure. Demonstrated that reduction of pressure to 320 psig would not increase safety of existing pipeline, as ILI could no longer be done periodically at lower pressure. Commission accepted this reasoning and denied SDG&E's application.

Cove Point LNG Export Terminal. Expert witness in two separate administrative proceedings before the Maryland Public Service Commission, in 2014 and 2017, regarding air permit conditions for the proposed Cove Point LNG export. The plant site is located in a non-attainment area for ozone. Testimony addressed deficiencies in the proposed air emission limits and proposed control technology for combustion equipment – including gas turbines, auxiliary boilers, and flares, fugitive emission sources, and marine loading vapor recovery systems.

Corpus Christi LNG Expert Terminal. Expert witness in Texas Commission on Environmental Quality contested air permit proceeding in 2013 before the State Office of Administrative Hearings. Testimony addressed deficiencies in the proposed control technology for compressor-drive gas turbines, flares, and fugitive emission sources, and marine loading vapor recovery systems.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Roadmap to 100 Percent Local Solar by 2030 in the City of San Diego. Author of the May 2020 *Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego* strategic energy plan for San Diego. The *Roadmap* outlines a strategy to maximize the use of solar energy and battery storage in the City of San Diego (City) to provide 100 percent clean electricity to all San Diegans by 2030. The City's Climate Action Plan sets a mandatory target of 100 percent clean electricity by 2035. The *Roadmap* describes how the City can best deliver lower-cost electricity and provide local job growth by choosing local solar power paired with battery storage, complemented by smart energy efficiency and demand response programs, to reach 100 percent clean energy.

North Carolina Clean Path 2025 Plan. Author of the August 2017 *North Carolina Clean Path 2025* strategic energy plan for North Carolina. *NC Clean Path 2025* implements local solar power, battery storage, and energy efficiency measures to rapidly replace fossil fuel-generated electricity in the state. The plan is substantially less costly than the $40 billion expansion of natural gas infrastructure, nuclear power, and transmission infrastructure being planned for North Carolina. Implementation of *NC Clean Path 2025* would reduce power generated by coal- and natural gas-fired plants by about 60 percent by 2025, and 100 percent by 2030. All in-state coal-fired plants would be closed and gas-fired plants would be used only for backup supply. Existing transmission and distribution infrastructure would be maintained and not expanded.

Bay Area Smart Energy 2020 Plan. Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The preliminary decision issued by the presiding CEC commissioner in the case recommended denial of the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines. No final decision has yet been issued in the proceeding (as of May 2009).

San Diego Smart Energy 2020 Plan. Author of October 2007 *San Diego Smart Energy 2020*, an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy weather, and for grid reliability support.

COOLING SYSTEM CONVERSION AND POWER PLANT EMISSION CONTROL ASSESSMENTS

Closed-Cycle Cooling Alternative at California Nuclear Plant.
Lead engineer on review of Bechtel assessment of wedgewire screens and closed-cycle cooling for Diablo Canyon nuclear plant. Demonstrated that wedgewire screens were not likely to be effective in substantially reducing entrainment at the site, and that lower cost closed-cycle retrofit alternatives could be utilized to allow a "cost reasonable" cooling tower retrofit. Plume-abated back-to-back cooling towers located in secondary parking lots to the southeast of the turbine building were identified as the most cost-effective alternative.

Closed-Cycle Cooling Alternative at Florida Nuclear Plant.
Evaluated closed cycle cooling tower feasibility assessment for Turkey Point Nuclear Units 3 and 4. Closed-cycle cooling would replace the existing closed-cycle cooling canals. Wet cooling towers for Units 3 and 4 are feasible and could be operational within four years of submittal of applications for the necessary permits.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 °F and 13 °F were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 °F and 13 °F. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 °F. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Ameren Missouri Coal Units – Causes of Opacity and Opacity Reduction Alternatives. Lead engineer to assess the root causes of opacity exceedances and evaluate potential alternatives to eliminate opacity violations from the Labadie, Meramec, and Rush Island power plants.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NO_x and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

NON-WIRES ALTERNATIVES TO TRANSMISSION LINES

Ameren Missouri Mark Twain 345 kV Transmission Line. Responsible for evaluating: 1) the expected peak load growth of Ameren Missouri (MO) in general and in Northeast MO specifically over the next decade, 2) the likelihood of wind projects moving forward in the Northeast MO over the next decade, 3) the feasibility and cost of reconductoring with high capacity composite conductors the three 161 kV line segments that would experience NERC violations if 450 to 500 MW of wind power was constructed in Northeast MO, and 4) the feasibility and cost-effectiveness of substituting local solar for wind power to allow Ameren MO to meet its 2021 Renewable Portfolio Standard (RPS) obligation without building the proposed 345 kV transmission line or upgrading the three existing 161 kV lines interconnecting at the Adair Substation.

American Transmission Corporation Badger-Coulee 345 kV Line. Responsible for evaluating: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the proposed ATC Badger-Coulee 345 kV transmission line.

San Diego Gas & Electric Wood Pole to Steel Pole Replacement Project.
Lead engineer assessing need and alternatives to replacement of existing wooden 69 kV poles with larger steel 69 kV poles as a response to the fire hazard potential of wooden poles in rural, high fire risk areas. Wooden poles in good condition and not a source of fire ignition. Utility would continue to shut off power to customers during low humidity, high wind conditions. Prepared alternative, solar with batteries for the ~10,000 affected customer meters, to allow customers to ride-through high fire hazard preventive grid power shut-offs at far less cost than replacing wood poles with steel poles.

San Diego Gas & Electric 500 kV Sunrise Transmission Line.
Lead engineer assessing the validity of load growth forecasts used by the utility to justify the need for the 500 kV line, and for developing a no-wires alternative, net-metered solar power with some battery support, to meet the identified reliability need at little or no net cost to the utility customer base.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the local availability of urea. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are

certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines will be equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea will be used as the SCR reagent to avoid trigger hazardous material storage requirements. A separate permit will be obtained for the NO_x and CO continuous emissions monitoring systems. The ATCs is pending.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion (SCONO$_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.
Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and SCONO$_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.
Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and SCONO$_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM.
Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM then passed the annual RATA without problems as a result of changes to some CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 °F) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 °F and 20 °F were evaluated. The annualized cost of the fin-fin air-cooler with a 20 °F approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

Oil and Gas Production Air Engineering/Testing Experience

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.

Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops. Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility.

Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Assessment of operational deficiencies of Camisa pipeline – Peru. Project leader of multi-year assessment of root causes of ruptures on Camisea 14-inch natural gas liquids pipeline for non-profit client. Determined that primary causes of hurried construction in difficult and unstable terrain, unstable right-of-way in the jungle sector due to inadequate erosion control practices, and inadequate pipe wall thickness to withstand external lateral forces. Two assessments were developed during the course of the project documenting deficiencies and recommending remedial actions.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern

Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*More Distributed Solar Means Fewer New Combustion Turbines*," Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

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Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Number 2, September 2010, pp. 19-26.

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Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective*," Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, *"Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,"* presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, *"Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,"* presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., *"Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers,"* presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

/A

Docket No. E-100, Sub 179

William E. Powers on Behalf of NC WARN et al.

Exhibit 1 (Part 2 of 2)

EXHIBIT B:

CAISO Response to PCF Data Request

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations	Rulemaking 19-11-009 (Filed November 7, 2019)

RESPONSE OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO DATA REQUEST NUMBER PCF-CAISO-2020RA-02 BY PROTECT OUR COMMUNITIES FOUNDATION

Request Date: 10/12/2020
Response Date: 11/16/2020

Below are the California Independent System Operator Corporation's (CAISO) responses to Protect Our Communities Foundation (PCF) Data Request – *PCF-CAISO-2020RA-02*.

General Objections

The CAISO objects to PCF's data request because it is unduly burdensome and intrusive. PCF's data request relates to resource performance from August 14, 2020 through August 26, 2020 and September 5, 2020 through September 7, 2020. Furthermore, the CAISO objects to the extent any questions call for information that is privileged, attorney-client work product, or otherwise confidential.

In addition, to the extent possible, the CAISO provides responses to PCF's specific questions below.

PCF Request No. 1

Please provide the megawatt output for each of the following OTC units for August 14-26 and Sept 5-7 from during the hours ending (HE) 13 to 24.

1.1. Huntington Beach 2
1.2. Alamitos 3
1.3. Alamitos 4
1.4. Alamitos 5
1.5. Redondo Beach 5

1.6. Redondo Beach 6
1.7. Redondo Beach 8
1.8. Ormond Beach 1
1.9. Ormond Beach 2

The attached spreadsheet is provided for ease of response.

CAISO Response to Request No. 1

PCF Request No. 1 is unduly burdensome, overly broad, intrusive, and not reasonably calculated to lead to the discovery of admissible evidence in the resource adequacy (RA) proceeding. Specific generation outage details, as opposed to aggregate data, are not directly relevant to RA Program.

Notwithstanding the objections above, the CAISO provides its response in the attached Excel spreadsheet.

Day/hour output (MW) of SoCal OTC boiler plants proposed for extended operation, August 14-26, Sept 5-7, 2020 heat wave

Date/hour	Huntington Beach 2 (215 MW)	Alamitos 3 (320 MW)	Alamitos 4 (320 MW)	Alamitos 5 (480 MW)	Redondo Beach 5 (175 MW)	Redondo Beach 6 (175 MW)	Redondo Beach 8 (480 MW)	Ormond Beach 1 (806 MW)	Ormond Beach 2 (806 MW)
13-Aug-20									
HE13	0	86	0	0	75	41	131	0	400
HE14	0	87	0	0	75	34	132	0	398
HE15	0	134	0	0	77	11	132	1	706
HE16	0	283	0	2	80	10	228	0	704
HE17	0	291	0	4	75	10	378	0	704
HE18	0	289	0	6	80	10	401	0	704
HE19	0	291	0	20	0	39	450	0	705
HE20	0	290	0	63	0	10	453	0	704
HE21	0	314	0	71	0	10	459	0	705
HE22	0	192	0	71	0	10	455	1	656
HE23	12	120	0	71	0	10	209	-1	407
HE24	24	50	0	151	0	10	132	0	406
14-Aug-20									
HE13	204	267	0	240	0	10	241	8	404
HE14	208	315	0	239	0	15	251	12	492
HE15	220	312	0	240	0	108	363	17	686
HE16	220	315	0	400	0	147	430	21	713
HE17	220	313	0	448	0	140	430	21	713
HE18	220	312	0	472	0	140	435	21	715
HE19	220	314	0	476	0	140	462	20	720
HE20	222	314	0	477	0	140	459	40	721
HE21	220	313	0	476	0	140	455	102	723
HE22	190	315	0	476	0	137	231	99	726
HE23	64	313	0	328	0	15	196	104	712
HE24	66	313	0	183	0	21	181	105	699
15-Aug-20									
HE13	65	189	0	275	0	21	270	429	407
HE14	222	314	0	468	0	137	382	703	693
HE15	221	313	0	473	0	140	438	710	703
HE16	223	314	0	472	0	140	441	710	702
HE17	222	314	0	472	0	139	441	709	701
HE18	221	313	0	472	0	140	459	706	703
HE19	224	315	0	472	0	141	460	707	702
HE20	222	315	0	473	0	140	461	708	702
HE21	211	226	0	405	0	134	437	607	601
HE22	111	201	0	349	0	21	299	696	698
HE23	65	181	0	198	0	21	181	695	700
HE24	0	116	0	184	0	21	181	499	700
16-Aug-20									
HE13	65	189	0	244	0	21	241	419	411
HE14	221	311	0	462	0	138	441	700	700
HE15	221	315	0	471	0	141	446	702	706
HE16	220	315	0	471	0	141	445	703	705
HE17	222	316	0	471	0	141	447	703	707
HE18	219	313	0	470	0	142	449	701	707
HE19	216	315	0	470	0	141	450	706	707
HE20	213	256	0	412	0	92	377	706	709
HE21	80	135	0	231	10	21	181	707	710
HE22	65	72	0	180	9	20	181	707	710
HE23	66	21	0	179	8	21	181	705	709
HE24	65	20	0	179	10	21	181	409	404
17-Aug-20									
HE13	66	264	58	470	9	21	453	656	687

HE14	217	309	21	472	42	140	439	657	686
HE15	213	311	21	472	85	142	441	654	693
HE16	195	311	22	472	106	141	441	654	693
HE17	193	309	39	473	107	141	440	656	692
HE18	0	309	70	472	107	140	452	652	689
HE19	0	306	68	473	106	141	449	652	689
HE20	0	306	69	473	105	140	452	651	688
HE21	0	289	52	472	68	141	449	652	689
HE22	0	234	21	473	0	109	441	650	689
HE23	0	190	18	374	0	21	209	652	689
HE24	0	129	21	210	0	21	181	651	691
18-Aug-20									
HE13	0	311	320	472	0	141	442	657	697
HE14	0	312	320	473	0	141	440	653	697
HE15	0	312	320	474	0	141	441	658	700
HE16	0	311	318	471	0	142	440	660	700
HE17	0	311	317	472	0	140	415	662	702
HE18	0	313	319	472	4	140	441	662	700
HE19	0	311	318	471	10	140	440	660	699
HE20	0	312	321	471	52	140	441	650	693
HE21	0	312	319	471	52	140	440	660	696
HE22	0	312	317	460	11	137	440	657	697
HE23	0	158	316	460	10	21	440	587	674
HE24	0	84	170	262	10	20	227	401	400
19-Aug-20									
HE13	0	56	61	472	51	21	440	653	696
HE14	0	155	155	472	50	21	441	653	698
HE15	0	312	320	473	51	76	440	653	699
HE16	0	312	320	473	50	140	442	655	699
HE17	0	314	321	472	44	140	440	656	700
HE18	0	313	320	473	11	140	440	655	698
HE19	0	314	316	473	10	140	441	654	700
HE20	0	314	319	473	10	135	453	648	697
HE21	0	182	243	317	10	21	214	410	408
HE22	0	120	168	223	10	20	211	485	423
HE23	0	49	103	179	10	21	181	413	410
HE24	0	21	35	161	11	21	180	411	410
20-Aug-20									
HE13	22	255	239	219	23	32	224	591	655
HE14	65	312	303	372	50	58	211	634	681
HE15	205	314	318	467	10	21	366	642	669
HE16	215	312	321	465	83	94	441	653	694
HE17	206	314	322	466	105	140	441	602	495
HE18	174	314	319	466	105	141	440	631	639
HE19	65	310	295	466	105	140	441	406	410
HE20	21	246	127	360	100	134	367	404	411
HE21	20	236	90	213	10	21	281	403	414
HE22	21	154	37	179	10	20	181	403	410
HE23	21	85	22	180	10	21	181	361	355
HE24	21	21	21	152	10	20	181	208	256
21-Aug-20									
HE13	86	40	40	221	10	23	272	520	464
HE14	113	26	28	242	10	21	425	543	641
HE15	176	95	95	219	10	20	440	543	639
HE16	206	195	195	371	103	140	440	427	413
HE17	195	192	194	466	105	140	441	549	506
HE18	190	202	213	466	104	140	441	493	464
HE19	190	192	198	467	104	140	336	399	406
HE20	191	190	196	410	104	119	240	400	425
HE21	143	190	193	237	104	76	198	404	404
HE22	66	121	125	222	11	21	181	385	406
HE23	65	51	58	179	10	21	180	201	399

HE24	0	22	18	181	10	0	187	104	255
22-Aug-20									
HE13	66	21	19	152	10	0	131	104	54
HE14	119	99	97	176	20	0	190	328	326
HE15	140	191	191	186	31	0	292	604	600
HE16	63	189	194	152	105	0	300	424	412
HE17	64	313	319	242	105	0	301	410	404
HE18	65	313	320	228	105	0	301	414	413
HE19	66	311	283	251	105	0	303	413	414
HE20	65	262	218	250	105	0	300	413	414
HE21	65	191	193	250	100	0	288	411	414
HE22	65	119	125	180	10	0	181	203	380
HE23	65	50	58	180	10	0	187	103	108
HE24	65	21	21	203	11	0	137	107	56
23-Aug-20									
HE13	65	22	21	180	10	0	181	104	54
HE14	65	92	93	215	104	0	225	196	237
HE15	66	189	190	251	105	0	342	415	409
HE16	115	187	195	250	105	0	438	410	411
HE17	195	186	194	251	105	0	439	419	414
HE18	61	191	193	250	105	0	439	421	416
HE19	0	189	193	250	105	0	439	421	414
HE20	0	195	194	251	105	0	439	415	414
HE21	0	191	193	251	105	0	430	414	412
HE22	0	120	126	180	10	0	211	411	421
HE23	0	52	59	179	11	0	181	205	383
HE24	0	20	19	181	10	0	181	198	255
24-Aug-20									
HE13	0	190	194	181	10	0	205	413	407
HE14	0	243	232	242	10	1	242	655	695
HE15	0	311	320	373	43	10	440	655	701
HE16	0	311	321	464	10	10	440	657	703
HE17	0	310	320	464	10	10	441	655	706
HE18	0	310	318	466	27	10	431	657	705
HE19	0	310	306	464	10	0	431	655	706
HE20	0	309	309	466	10	0	431	656	705
HE21	0	310	310	464	10	0	432	657	705
HE22	0	309	308	463	10	0	425	656	701
HE23	0	152	161	273	9	0	227	402	401
HE24	0	85	96	178	0	0	181	403	400
25-Aug-20									
HE13	0	94	93	330	10	0	181	309	408
HE14	0	192	193	466	10	0	240	422	408
HE15	0	278	260	466	10	0	417	424	411
HE16	0	312	319	466	10	0	430	654	680
HE17	0	311	320	466	10	0	431	656	699
HE18	0	312	317	466	10	0	435	654	698
HE19	0	312	321	466	10	0	432	655	701
HE20	0	312	265	466	10	0	312	655	700
HE21	0	284	193	375	10	0	253	657	701
HE22	1	189	193	241	11	0	226	637	688
HE23	11	132	137	181	11	0	181	401	401
HE24	21	67	77	152	10	0	181	402	402
26-Aug-20									
HE13	66	23	25	189	10	0	181	211	253
HE14	94	98	100	230	10	0	363	233	296
HE15	133	188	193	242	10	0	380	411	305
HE16	207	313	320	438	10	0	271	475	308
HE17	219	311	319	466	10	0	270	653	304
HE18	0	311	320	465	10	0	271	655	306
HE19	0	312	322	466	103	0	271	654	305

HE20	0	262	256	466	30	0	271	655	303
HE21	0	192	197	466	10	0	260	654	304
HE22	0	193	195	465	10	0	229	655	306
HE23	0	122	126	275	10	0	181	357	301
HE24	0	54	61	180	10	0	181	120	257
5-Sep-20									
HE13	65	190	193	223	10	20	239	413	411
HE14	108	240	246	305	10	39	241	651	680
HE15	174	249	243	347	10	20	279	655	696
HE16	176	313	319	471	85	80	341	657	697
HE17	175	314	321	471	110	80	413	656	697
HE18	175	314	323	469	110	80	439	655	698
HE19	174	315	319	469	110	80	446	657	697
HE20	175	311	295	405	110	31	455	655	697
HE21	131	200	195	244	111	20	455	655	698
HE22	67	125	127	241	97	20	448	477	698
HE23	60	56	60	241	11	20	216	401	388
HE24	21	21	23	185	10	20	131	385	254
6-Sep-20									
HE13	176	293	291	348	109	80	412	489	507
HE14	174	315	322	474	110	81	441	655	690
HE15	175	314	318	472	110	81	440	654	694
HE16	175	315	319	472	109	81	440	658	699
HE17	175	315	318	472	109	81	440	659	702
HE18	174	314	320	474	110	80	439	656	704
HE19	175	316	320	472	110	81	441	652	701
HE20	177	312	319	472	110	81	450	656	702
HE21	176	314	317	472	110	80	441	656	706
HE22	167	316	323	472	12	20	429	655	706
HE23	60	152	173	333	10	20	189	389	383
HE24	21	87	110	203	10	20	188	214	259
7-Sep-20									
HE13	66	193	195	242	10	20	241	405	405
HE14	66	187	193	241	10	20	240	655	695
HE15	66	192	193	241	10	20	240	655	701
HE16	64	192	191	255	10	20	240	656	700
HE17	65	191	193	263	39	30	240	656	700
HE18	65	190	193	266	77	80	240	659	700
HE19	65	191	194	241	110	80	240	659	702
HE20	65	192	195	241	109	80	240	658	704
HE21	65	191	195	240	108	70	241	657	703
HE22	65	190	194	241	11	20	233	422	702
HE23	59	161	159	182	10	20	181	170	376
HE24	22	94	101	178	10	20	181	107	100

EXHIBIT C:

T. Popik – Foundation for Resilient Socieities, *August 2020 Blackouts in CAISO*, PowerPoint

Docket No. E-100, Sub 179
William E. Powers on Behalf of NC WARN et al.
Exhibit 1

Foundation for
Resilient Societies

August 2020 Blackouts in CAISO

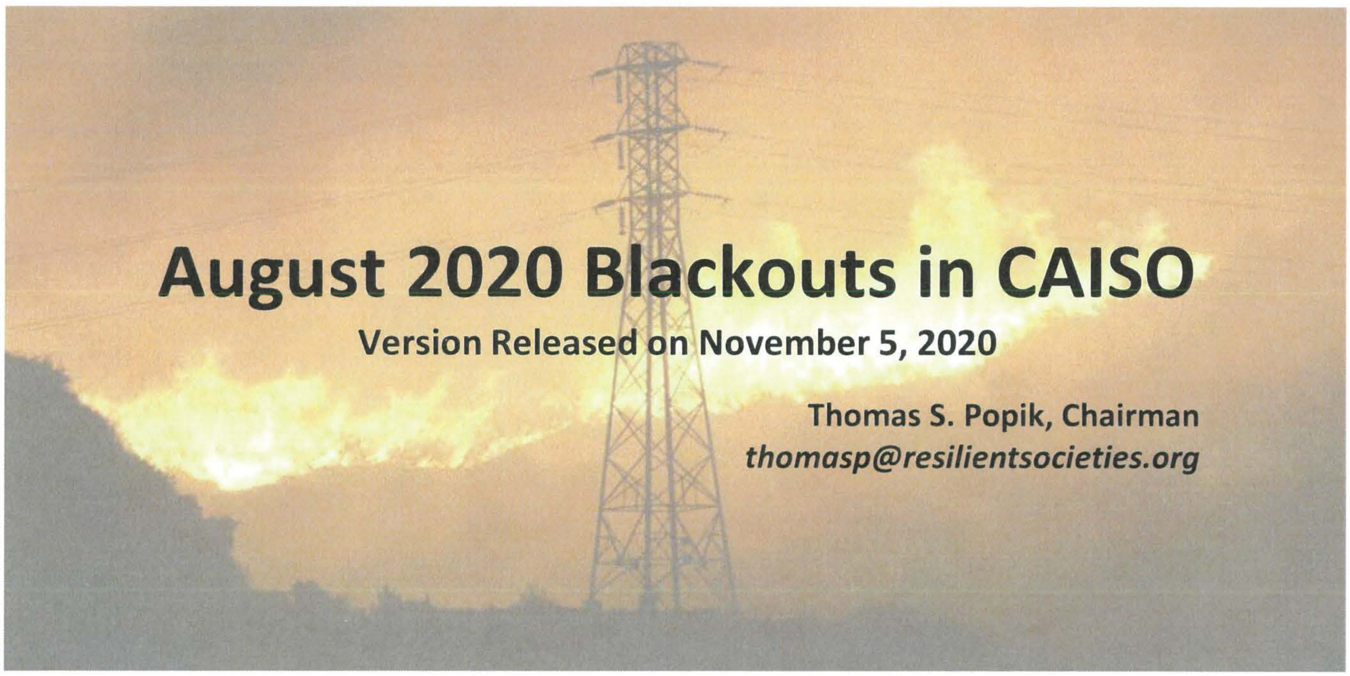


Image Credit: Gene Blevins/Reuters

www.resilientsocieties.org

Foundation for
Resilient Societies

Agenda

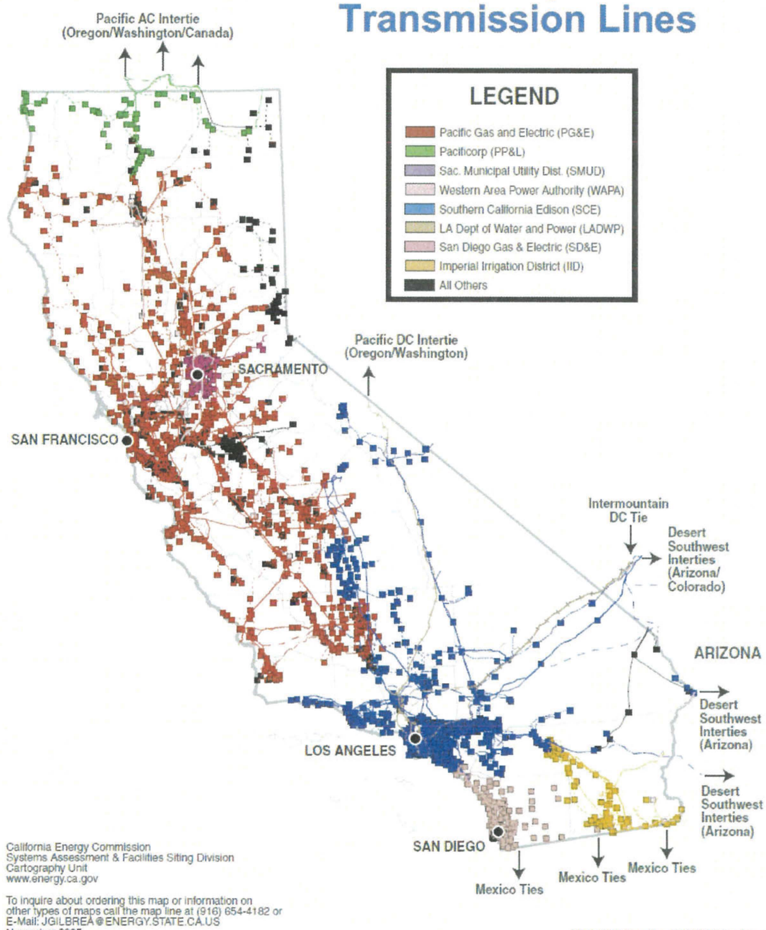
- California ISO (CAISO) System Characteristics
  - Geographic Configuration and Interties
  - Seasonal Loads
  - Capacity by Energy Sources
  - Imports
- Blackouts (aka "Load Sheds") in August 2020
  - "CAISO 2020 Summer Loads and Resources Assessment"
  - Sequence of Events
  - Realized Operating Reserves
  - Estimated Resource Adequacy
- Restoration Challenges After System Collapse
  - Secondary Fuel Sources for Gas-Fired Generators
  - Electric-Gas Interdependence
  - Essential Reliability Services
- Data-Based Observations

CAISO System Characteristics

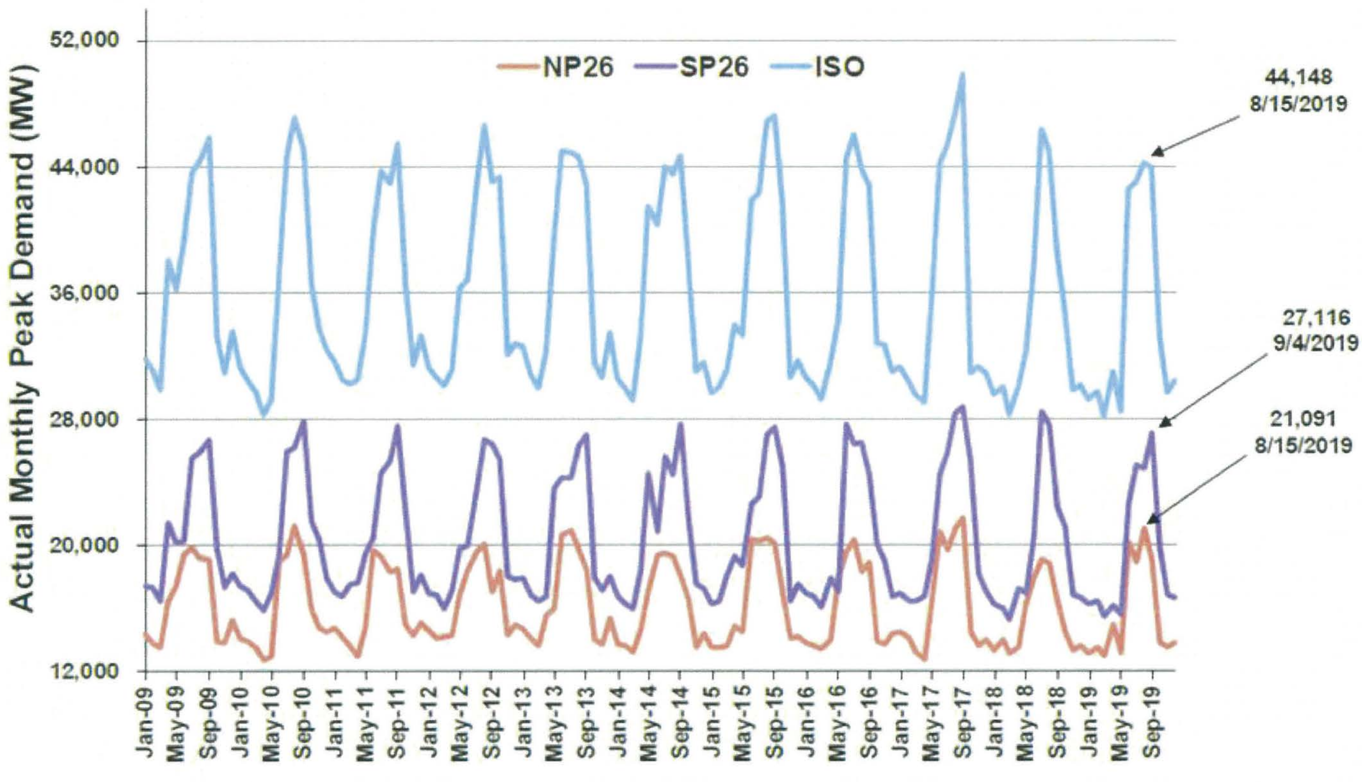
Foundation for Resilient Societies

August 2020 Blackouts in CAISO

California's Major Electric Transmission Lines

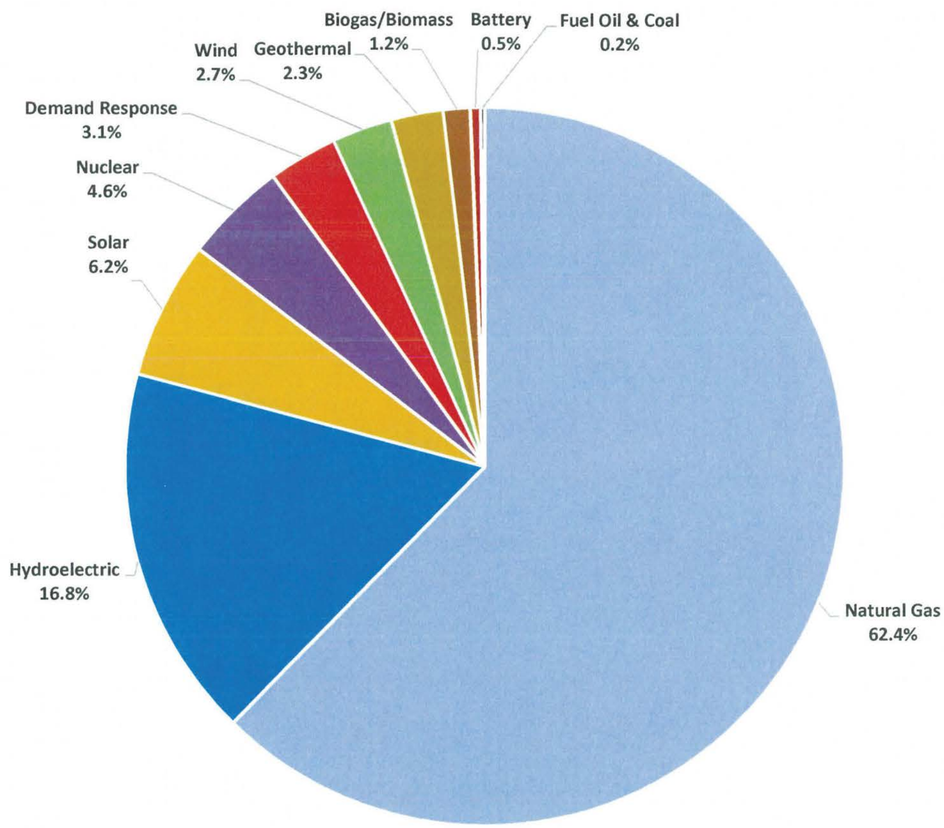


CAISO, North California (NP), and South California (SP) Load Profiles



Source: CAISO 2020 Summer Loads and Resources Assessment

CAISO Net Qualified Capacity for August 2020—49.2 GW



Source: CAISO 2020 NQC List, Foundation for Resilient Societies Analysis

CAISO Imports Often Below 7 GW During Peak Loads

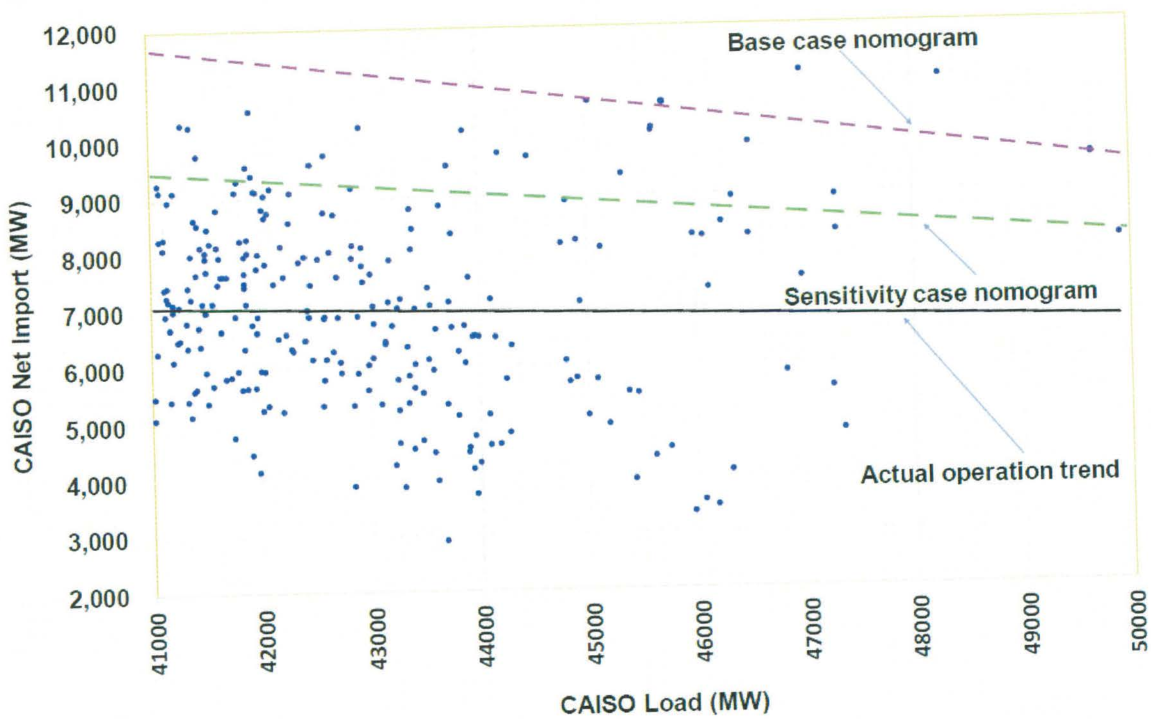


Figure 1 shows CAISO net imports at time of daily peaks above 41,000 MW vs. CAISO load from 2017 to 2019.

Source: CAISO 2020 Summer Loads and Resources Assessment

Key Points on CAISO System

- "Northern Path" Is Principally PG&E
- "Southern Path" Is Principally Southern California Edison and San Diego Gas & Electric
- CAISO Has Critical Interties With Grids in Other States
- Big Difference Between Summer Peak Load and Other Times of Year
- 62.4% of CAISO Capacity Is Gas-Fired
- Solar (6.2%), Wind (2.7%), and Hydro (16.8%) Capacity Not Always Available
- CASIO Imports Historically Less When Peak Load Is High

Blackouts in August 2020

CAISO 2020 Summer Loads and Resources Assessment

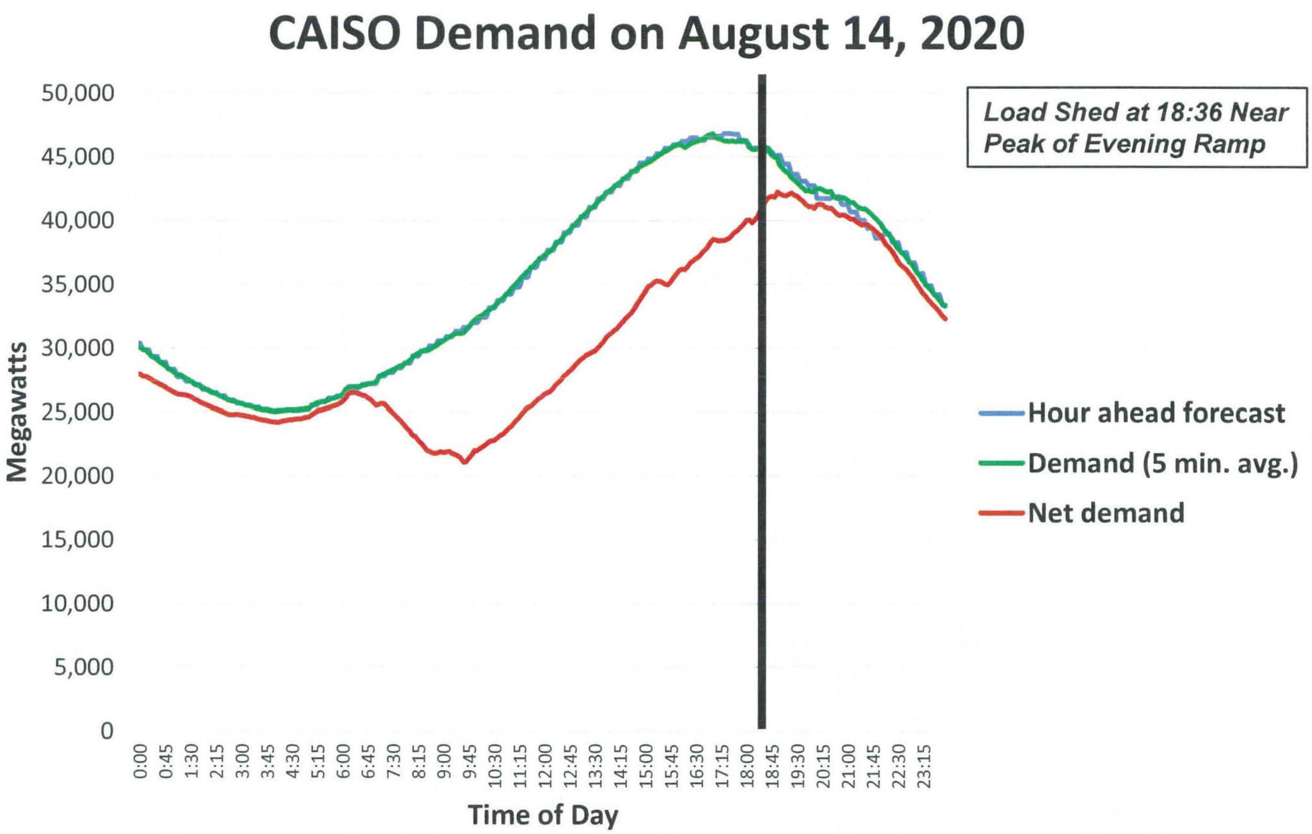
- "The base case results show that the CAISO has a low probability of experiencing operating conditions that would lead to shedding firm load in summer 2020."
- "[I]f a heat wave occurs that impacts a broader area than the CAISO, the availability of surplus energy to import into the CAISO could be diminished."
- "While the CAISO has a low probability of a system capacity shortfall, there is a material risk of shortfalls in load following up capacity, particularly in the late afternoon when solar generation is near or at zero and net imports diminish from neighboring BAs while system demand is increasing."

Sequence of events Friday August 14

12:00 p.m.	Unable to secure additional energy, a Warning was issued effective 12:00 p.m. through midnight
2:56 p.m.	Loss of generation – 475 MW
2:58 p.m.	Dispatched contingency reserves to recover
3:20 p.m.	Forecasting a shortage of energy for next few hours - Declared CAISO Stage 2 Emergency, began procuring Emergency Assistance from external entities
5:15 p.m.	Dispatched approximately 800 MW of demand response to maintain load and resource balance
6:36 p.m.	Unable to maintain load and contingency reserve obligation – ordered 500 MW of load shed pro-rata to CAISO Utility Distribution Companies (UDC's) – Stage 3 Emergency declared
6:46 p.m.	Ordered an additional 500 MW of load shed pro-rata to CAISO UDC's
7:56 p.m.	Load decreased and resources were adequate to meet CAISO load and contingency reserve obligations. Ordered all load to be restored.

Sequence of events Saturday August 15

4:10 p.m. to 5:10 p.m.	Total wind output increased quickly requiring other generation to ramp down quickly
5:10 p.m. to 6:05 p.m.	Total wind decreased quickly requiring other generation to ramp up quickly. CAISO ACE was -1421 MW.
6:13 p.m.	While recovering our ACE, a generator ramped down quickly from 400 MW.
6:25 p.m.	Ordered 470 MW of load shed pro-rat from UDC's
6:47 p.m.	Received Emergency Assistance, wind ramped back up, load began to trend down, additional resources available. Ordered all load be restored.

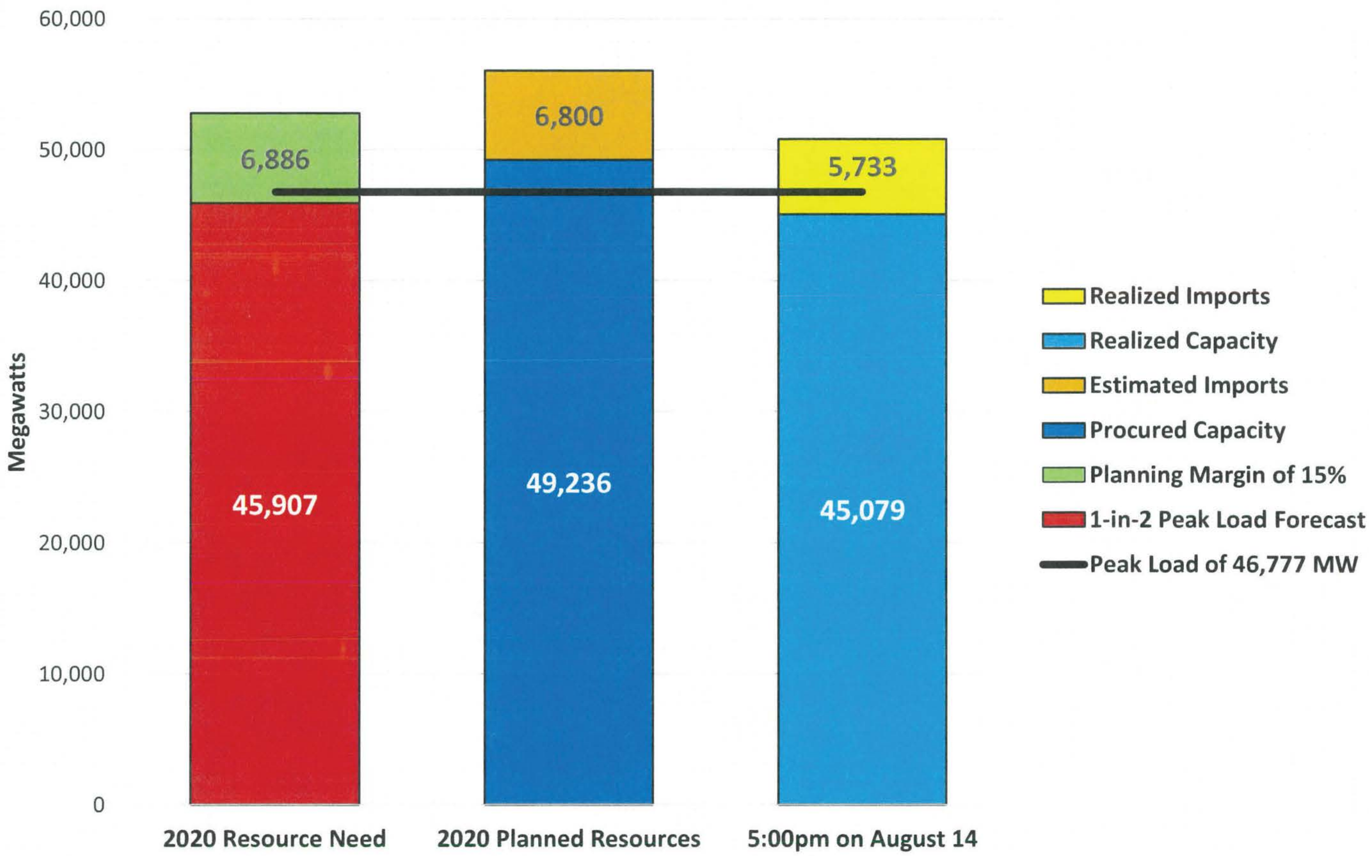


Source: CAISO website; https://www.caiso.com/TodaysOutlook/Pages/demand.html

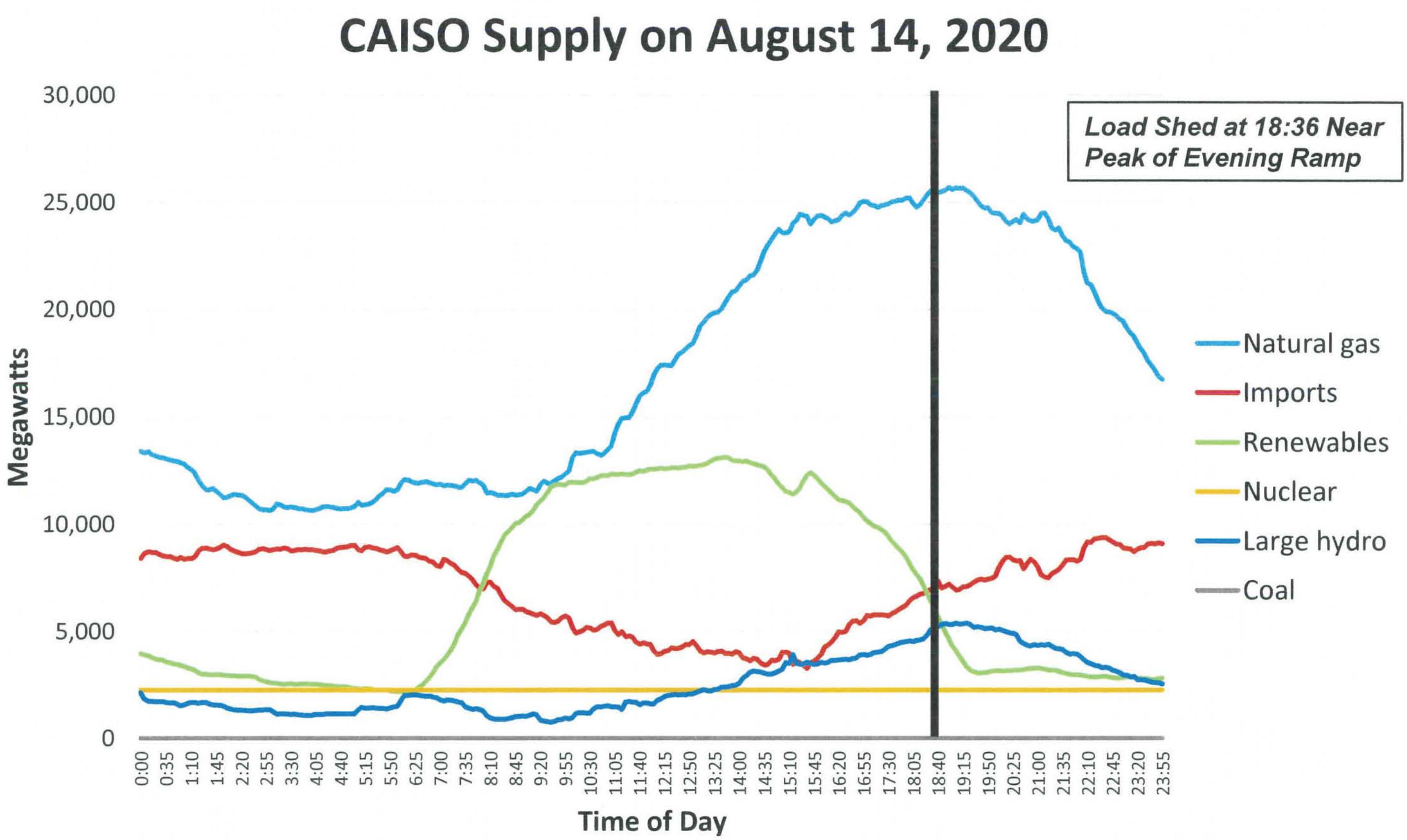
Foundation for
Resilient Societies

August 2020 Blackouts in CAISO

Peak Load at 5:00pm on August 14, 2020 Compared to Resources



CAISO Summer Loads & Resources Assessment, CAISO 2020 NQC List, CAISO Outage List, Foundation for Resilient Societies Analysis



Source: CAISO website: https://www.caiso.com/TodaysOutlook/Pages/supply.html

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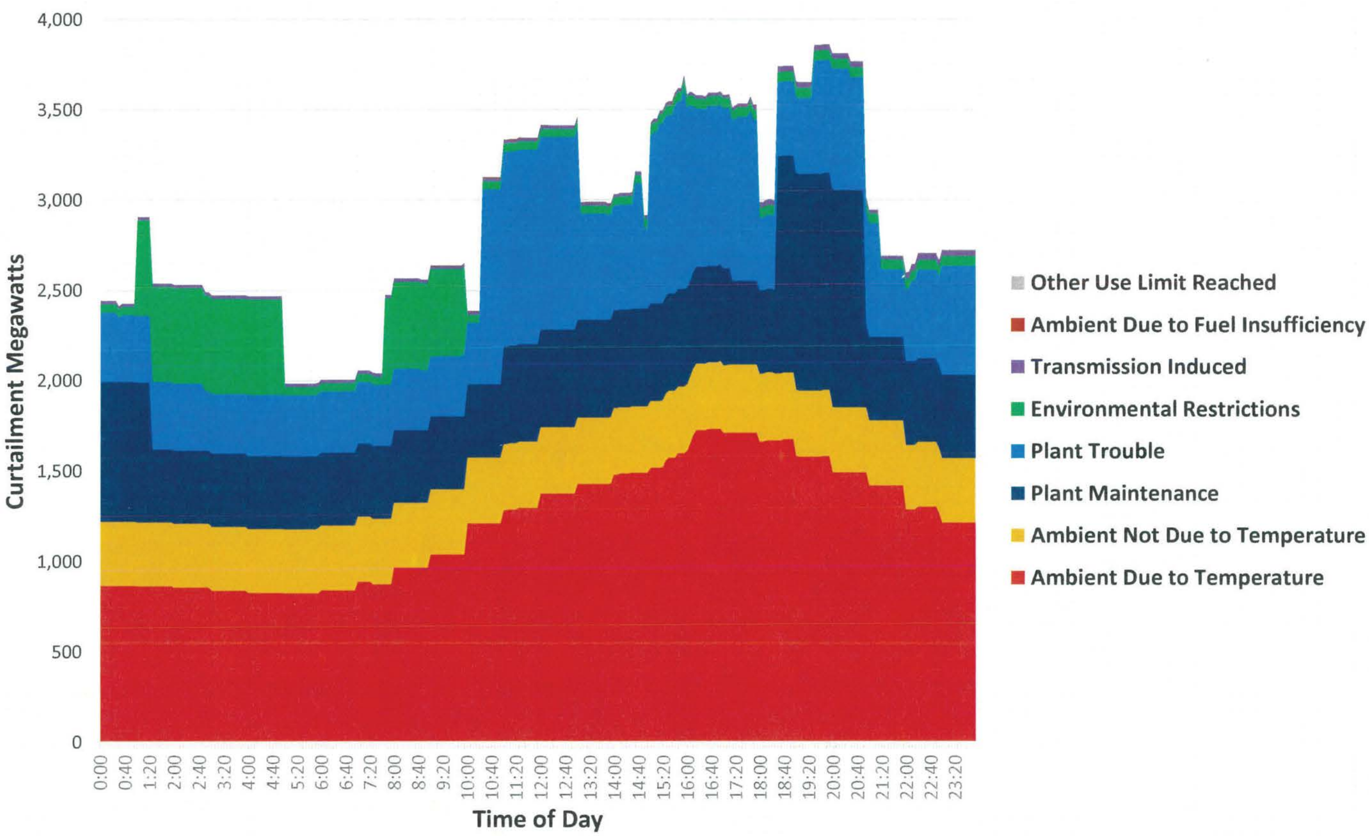
Forced Thermal Plant Outages in CAISO on August 14, 2020

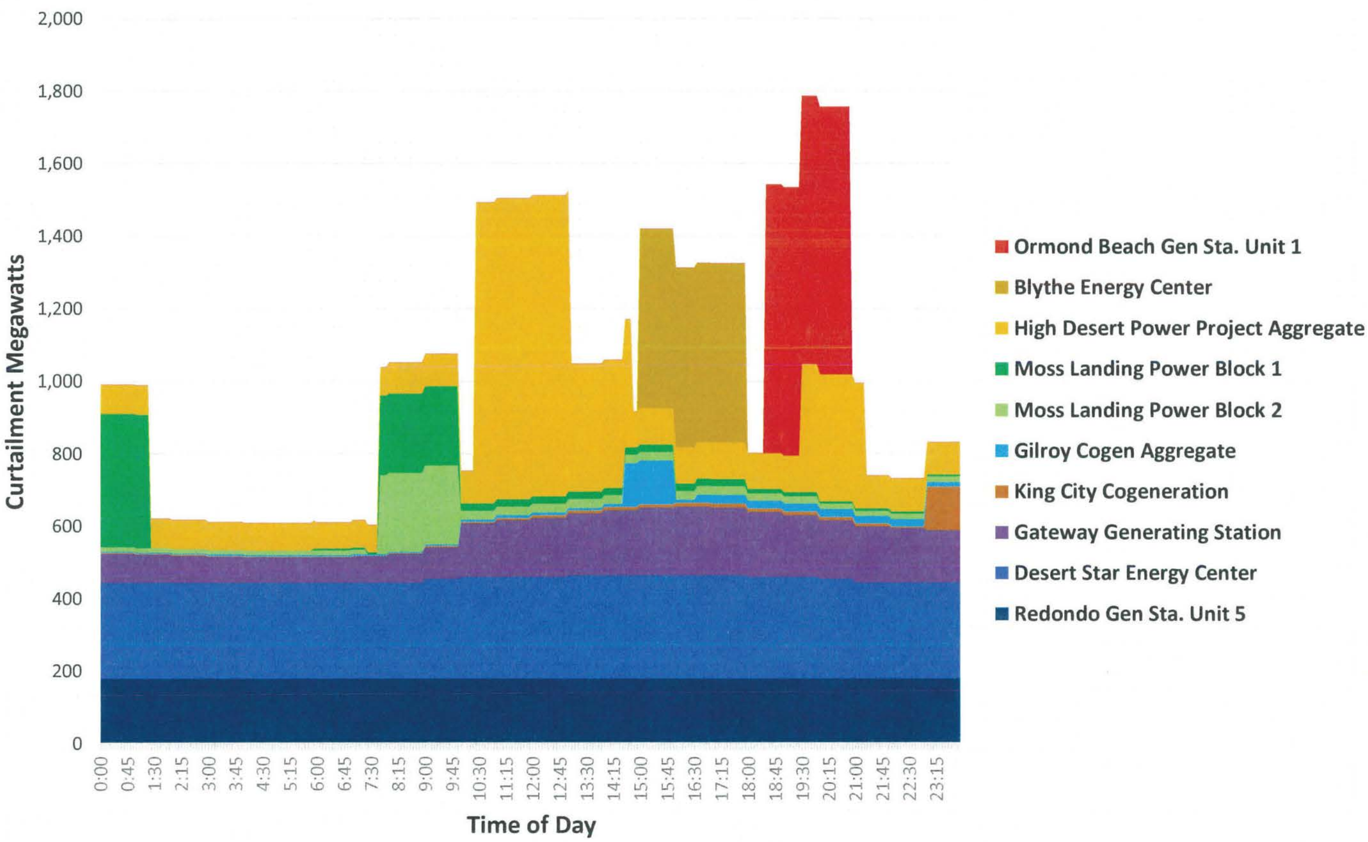


Source: CAISO "Aug13-16-2020-CAISO-Balancing-Authority-Area-Resource-Outages," Foundation for Resilient Societies Analysis

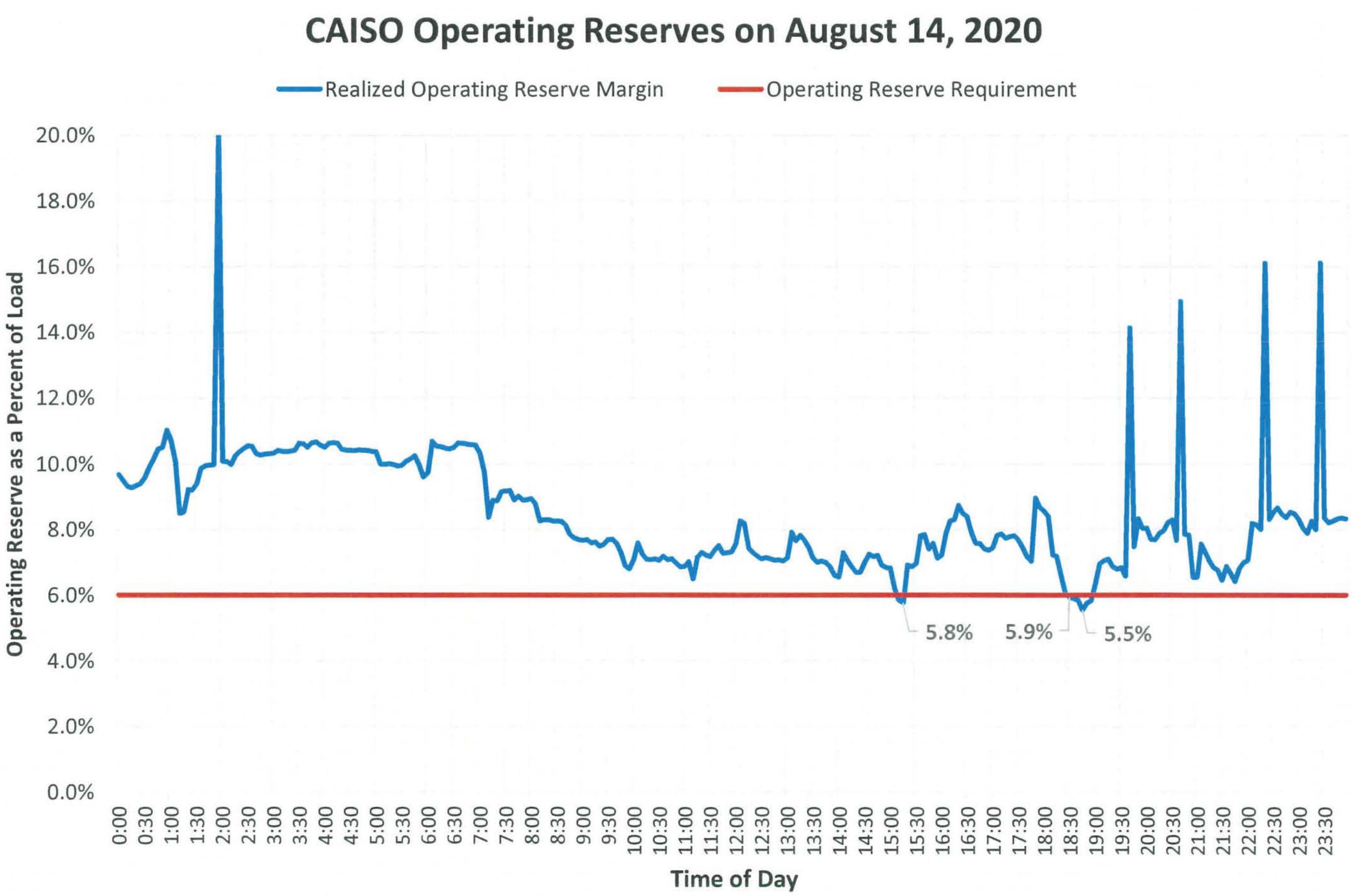
Foundation for
Resilient Societies

August 2020 Blackouts in CAISO

Sequence of Major Forced Outages in CAISO on August 14, 2020



Source: CAISO "Aug13-16-2020-CAISO-Balancing-Authority-Area-Resource-Outages," Foundation for Resilient Societies Analysis



Source: CAISO OASIS

Alternative Estimate of CAISO Resource Adequacy on August 14, 2020

	Megawatts		
	6:25pm	**6:30pm**	**7:30pm**
Net Qualified Capacity Excluding Solar, Wind, Hydro	36,573	36,573	36,573
Planned Outages Excluding Solar, Wind, Hydro, Imports	(388)	(388)	(388)
Forced Outages Excluding Solar, Wind, Hydro, Imports	(2,997)	(3,739)	(3,859)
Deployed Demand Response	(800)	(800)	(800)
Total Firm Capacity	32,387	31,646	31,526
Solar Generation	3,798	3,460	195
Wind Generation	1,058	1,050	990
Hydroelectric	5,194	5,440	5,528
Imports	6,873	6,920	7,270
Total Non-Firm Capacity & Imports	16,923	16,870	13,983
Total Capacity & Imports	49,310	48,516	45,509
Total Demand (Net of Demand Response and Load Sheds)	(45,743)	(45,857)	(42,941)
Operating Reserve	3,567	2,659	2,568
Operating Reserve (Percent)	7.8%	5.8%	6.0%
Largest Contingency (Diablo Canyon Nuclear Plant)	2,264	2,265	2,266
Operating Reserve Less Largest Contingency	1,303	394	302

Source: Foundation for Resilient Societies analysis. Unit commitments and realized generation not available from CAISO for this estimate.

Key Points on Blackouts In August 2020

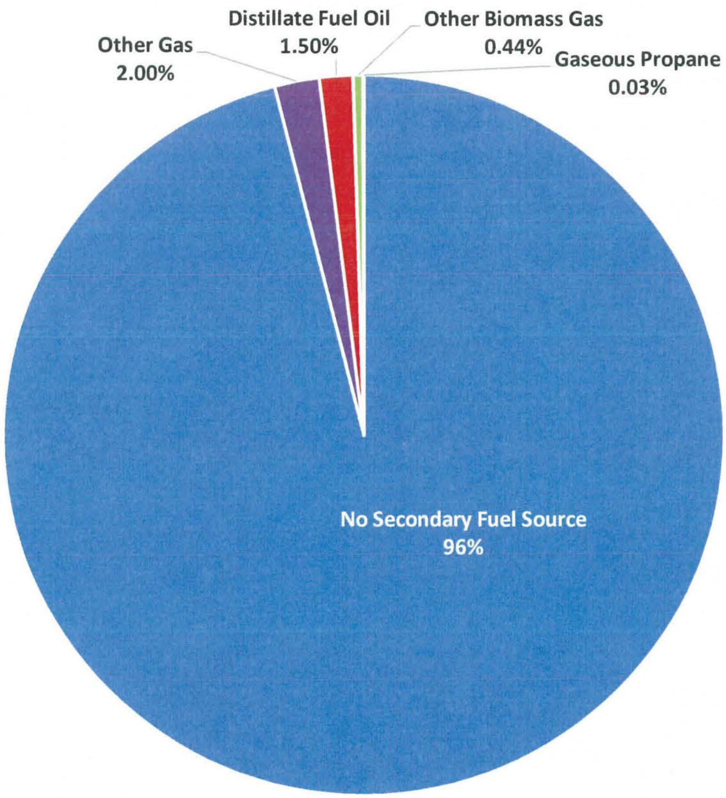
- CAISO Predicted Risk (But Not Probability) of Load Sheds/Blackouts During Summer Heatwaves
- Imports Were Constrained
- Hydroelectric Constrained Because of Reservoir Levels
- Large Forced Outages at Gas-Fired Plants
- Solar Generation Rapidly Fell During Evening Hours
- Wind Generation Variable and Unpredictable
- Committed Generator Capacity Less Than Realized Need

↓

CAISO Grid Operator Ordered Rolling Blackouts

Restoration Challenges After System Collapse

Secondary Fuel Sources for CAISO Gas-Fired Plants



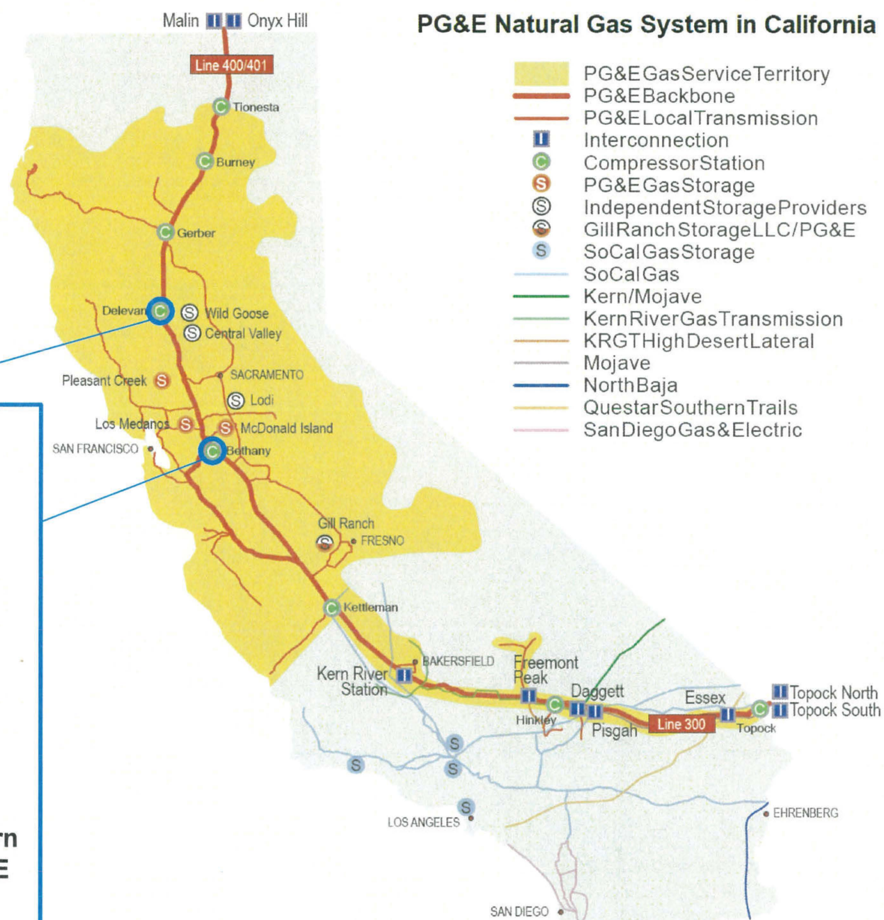
Source: EIA Form 860 for 2019, Foundation for Resilient Societies Analysis

2020 California Gas Report

- "If core supplies are insufficient to meet core demand, PG&E can divert gas from noncore customers, including [Electric Generation] EG customers, to meet it."
- "Since little, if any, alternate fuel-burn capability exists today, supply diversions from the noncore would necessitate those noncore customers to curtail operations."
- "The implication for the future is that under supply-shortfall conditions—such as an [Abnormal Peak Day] APD—a significant portion of [Electric Generation] EG customers could be shut down with the impact on electric system reliability left as an uncertainty."

Foundation for Resilient Societies

August 2020 Blackouts in CAISO



- **Northern California Generators Are Dependent on PG&E Natural Gas Pipelines**
- **At the Delevan Compressor Station, 2 Out of 3 Compressors Are Electric-Drive**
- **At the Bethany Compressor Station, Both Compressors Are Electric-Drive**
- **These Electric-Drive Compressors Are In Turn Dependent on the PG&E Transmission System**

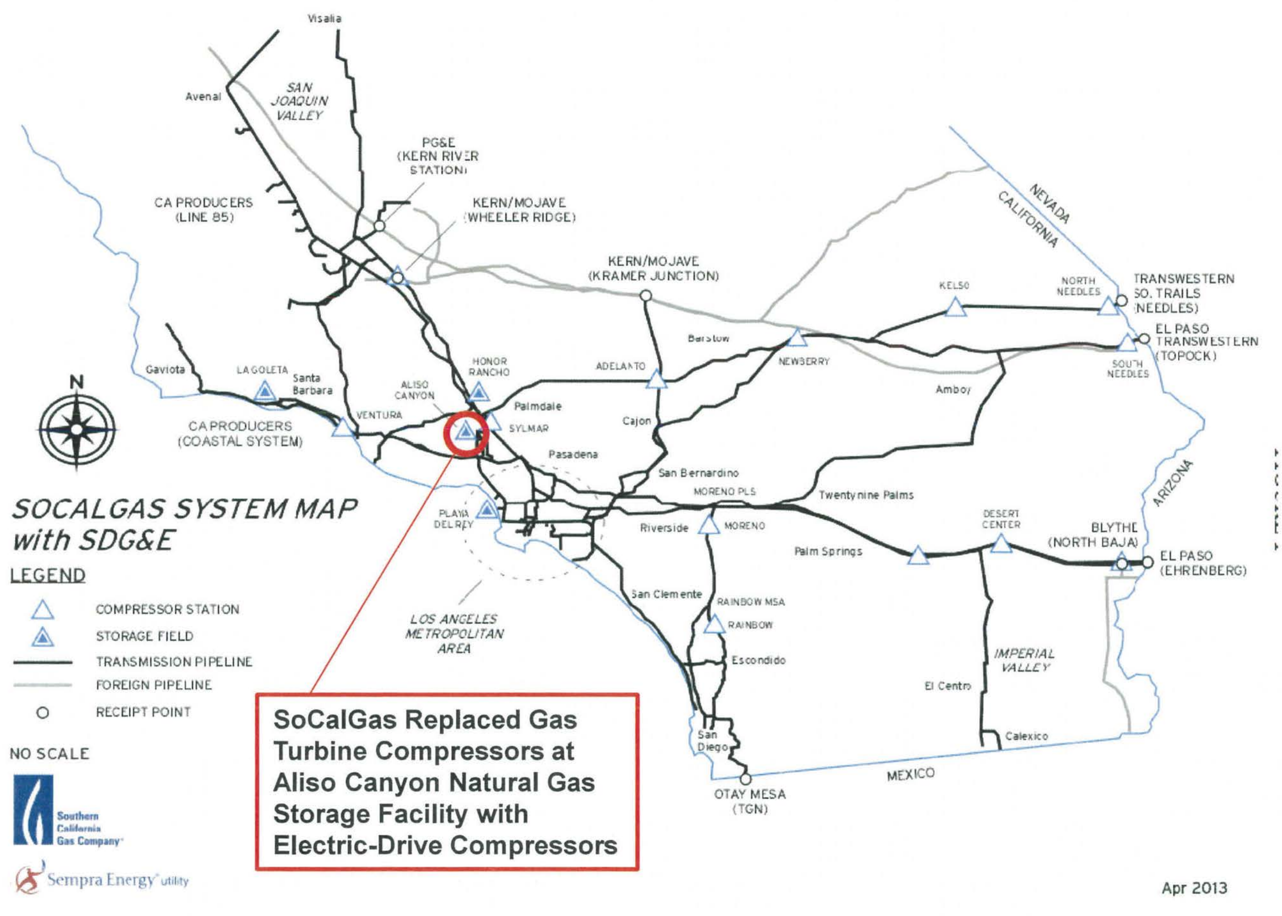
Adapted from PG&E "California Pipeline/Storage Facilities" on www.pge.com

2020 California Gas Report

- "Aliso Canyon directly supplies 17 gas-fired power plants with a combined total 9,800 MW of electric generation in the Los Angeles basin and indirectly impacts 48 plants with a combined total 20,120 MW of electric generation across Southern California."
- "There are limitations in attempting to shift power supply from resources affected by Aliso Canyon to resources that are not affected because of certain factors, such as local generation requirements, transmission constraints and other resource availability issues."

Foundation for Resilient Societies

August 2020 Blackouts in CAISO



Docket No. E-100, Sub 179
William E. Powers on Behalf of NC WARN et al.
Exhibit 1

Foundation for
Resilient Societies

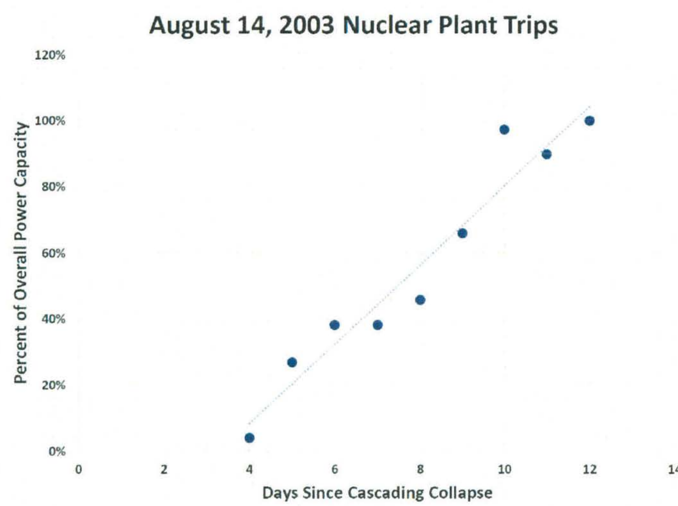
August 2020 Blackouts in CAISO

Diablo Canyon Nuclear Plant

2,256 MW Dual-Unit Plant Provides Reactive Power & Frequency Response

Image Credit: Tracy Adams

Diablo Canyon Forced Outage Expected After System Collapse Causes Plant Trip



Source: U.S. Nuclear Regulatory Commission, Foundation for Resilient Societies Analysis

Key Points on CAISO System Restoration

- 96% of CAISO Gas-Fired Capacity Has No Backup Energy Source and Is Dependent on "Just-In-Time" Fuel
- Electric-Gas Interdependence
  - PG&E Pipeline in North
  - Aliso Canyon Natural Gas Storage Facility In South
- Diablo Canyon Nuclear Plant Likely Not Available for System Restoration

Data-Based Observations

- Stress on CAISO System Occurred Near Sunset
  - Rapidly Falling Solar Generation
- Dispatchable Capacity Had Large Forced Outages
- Imports Not Sufficient To Replace Local Capacity
- Result: Operating Reserves Dipped Below Planning Margin
- Blackouts Occurred in CAISO Two Days in a Row
  - Recent Experience Shows This Is Not a "Low Probability"
  - Root Causes Not Clear From Data Available From CAISO
- System Restoration Risks
  - Lack of Dual-Fuel Plants
  - Electric-Gas Interdependence
  - Reactive Power and Frequency Response

About the Foundation for Resilient Societies

- Thank you for your attention to the important issue of electric reliability for the state of California.
- The Foundation for Resilient Societies is a non-profit organization engaged in scientific research and education with the goal of protecting technologically-advanced societies from infrequently occurring natural and man-made disasters.
- Learn more about us on our website: www.resilientsocieties.org
- For any updates or enhancements to this presentation, please visit our Home and/or Research web pages.

EXHIBIT D:

Calculation of ORM During August 15, 2020 Rolling Blackout, D. Marcus

Docket No. E-100, Sub 179
William E. Powers on Behalf of NC WARN et al.
Exhibit 1

ISO data for 8/15/20

load	available generation[1]	reserves	time	ISO alert level	solar MW	wind MW
		>12%	1800	Warning	4188	1306
		>11%	1805	Warning	3788	1254
		>11%	1810	Warning	3396	1226
		>10%	1815	Warning	3065	1227
		>10%	1820	Warning	2804	1240
44505	48774	9.59%	1825	Stage 2	2326	1270
43960	47872	8.90%	1830	Stage 3	2057	1321
43572	47976	10.11%	1835	Stage 3	1903	1428
43522	47835	9.91%	1840	Stage 3	1664	1534
43435	47759	9.96%	1845	Stage 3	1502	1669
43529	47803	9.82%	1850	Stage 2	1345	1830
43457	48080	10.64%	1855	Stage 2	1192	1929
43363	47973	10.63%	1900	Stage 2	1054	1997
43149	47569	10.24%	1905	Stage 2	913	2047
42970	47368	10.24%	1910	Stage 2	787	2071

Sources:

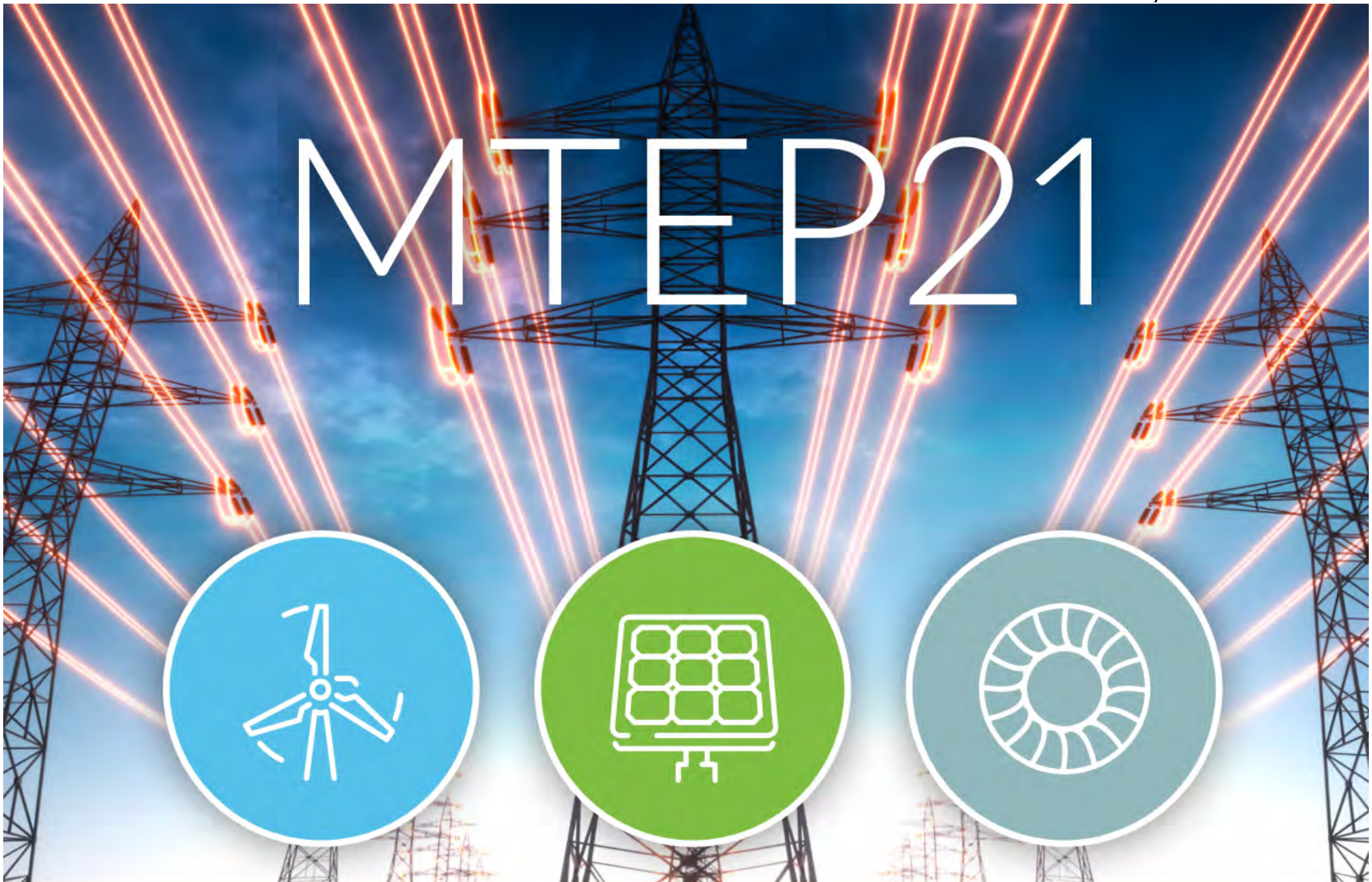
Load and available resources:	http://www.caiso.com/TodaysOutlook/Pages/default.aspx	(non-archived #s from top of page, not graphs)
Wind and solar generation:	http://www.caiso.com/TodaysOutlook/Pages/supply.aspx	(note that generation data is archived)

1) Load and "available generation" values recorded in real-time at 5-minute intervals from CAISO Today's Outlook "Demand" web page

D. Marcus, 9/22/20

/A

CCEBA/MAREC - Gonatas Exhibit 1
Docket No. E-100, Sub 179



MTEP21 REPORT ADDENDUM: LONG RANGE TRANSMISSION PLANNING TRANCHE 1 EXECUTIVE SUMMARY

Highlights

- This addendum proposes a portfolio of 18 transmission projects located in the MISO Midwest Subregions with a total investment of $10.3 billion, and benefit-to-cost ratios average of 2.6, where benefits well exceed costs

- This Tranche 1 portfolio of least-regrets transmission projects will help to ensure a reliable, resilient and cost-effective transmission system as the resource mix continues to change over the next 20 years

- The Tranche 1 portfolio, with more than 2,000 miles of transmission line, represents the most complex transmission study efforts in MISO's history

misoenergy.org

MISO's Long Range Transmission Planning to address the Reliability Imperative: Tranche 1 Portfolio

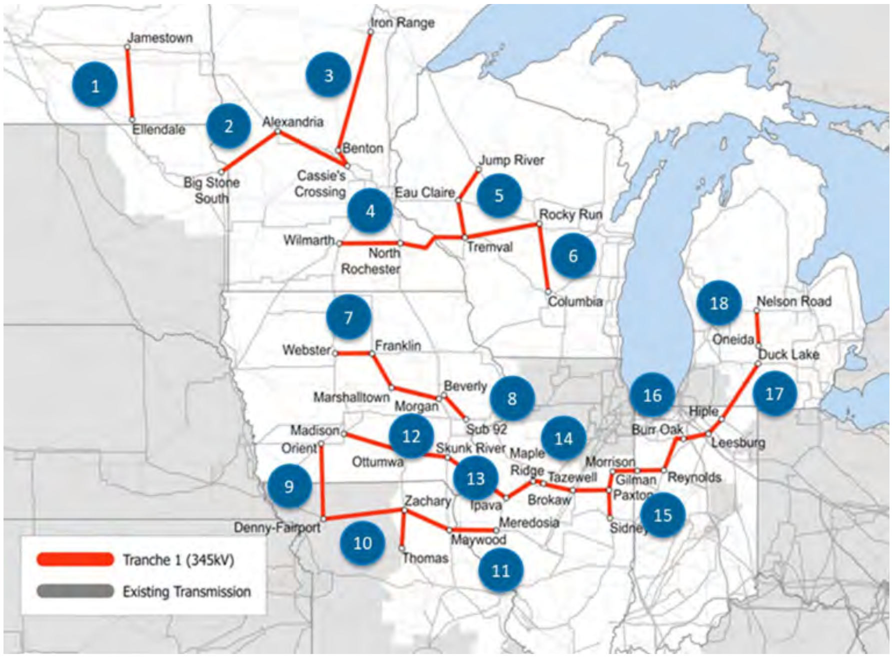
The *Long Range Transmission Planning (LRTP) Tranche 1 Portfolio* report presents the study findings and benefits analysis associated with the development of regional transmission solutions needed to provide reliable and economic delivery of energy. The report proposes a set of least-regrets transmission projects that will help to ensure a reliable, resilient and cost-effective transmission system as the resource mix continues to change and represents the largest and most complex transmission study effort in MISO's history. Since the last major set of regional overlay projects was approved in 2011, the pace towards more variable renewable generation has increased. Carbon-free and clean energy goals set by MISO member utilities, state and municipal government policies and customer preferences continue to drive growth in wind, solar, battery and hybrid projects. Indeed, the anticipated landscape changes are much more significant and require transformational changes at a faster rate than the previous 2011 portfolio of projects were built to accommodate.

The resulting urgency has required a much more intensive and focused effort. While it took four years to develop the 2011 portfolio of projects, this LRTP Tranche 1 portfolio, which is significantly larger in terms of the cost and line miles, came to fruition in less than half that time, without sacrifice of analytical quality or identification of robust solutions. The resulting portfolio includes 18 transmission projects located in the MISO Midwest subregion, with a total initial investment of $10.3 billion.

The LRTP Tranche 1 portfolio was developed 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. LRTP approached transmission portfolios in tranches in part because the urgent needs identified by the Reliability Imperative are appearing in the near-term for the Midwest subregion, including retirements and resource portfolio changes. This more urgent need put the focus for Tranches 1 and 2 in the Midwest Subregion. Tranche 3 will shift to focus on the South Subregion, with Tranche 4 then looking to strengthen the connection between the Midwest and South subregions.

Further, reflecting the portfolio's urgency, the LRTP Tranche 1 portfolio makes use of existing routes, where possible, to reduce the need to acquire additional greenfield right-of-way, which lowers costs and allows a shorter time to implementation. Construction of new transmission routes across navigable waterways, protected areas and high-value property faces extensive cost and regulatory risks that impede progress in meeting future reliability needs. Co-locating new facilities with existing transmission assets enables more efficient development of transmission projects and minimizes the environmental and societal impacts of infrastructure investment needed to achieve the needs identified in MISO's Future 1.

In addition to the primary benefits of system reliability, the LRTP Tranche 1 portfolio meets the criteria for Multi-Value Projects defined in the Tariff through addressing policy, reliability or economic needs, meeting the minimum cost threshold, and exceeding a benefit-to-cost ratio of 1.0. The types of economic benefits that could be used to meet these criteria represent a broad range of benefits provided by this portfolio of projects.



ID	DESCRIPTION	EXPECTED ISD	EST COST ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689
5	Tremval – Eau Claire – Jump River	6/1/2028	$505
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755
8	Beverly – Sub 92	12/31/2028	$231
9	Orient – Denny – Fairport	6/1/2030	$390
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769
11	Maywood – Meredosia	6/1/2028	$301
12	Madison – Ottumwa – Skunk River	6/1/2029	$673
13	Skunk River – Ipava	12/31/2029	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572
15	Sidney – Paxton East – Gilman South – Morrison Ditch	6/1/2029	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261
17	Hiple – Duck Lake	6/1/2030	$696
18	Oneida – Nelson Rd.	12/29/2029	$403
	TOTAL PROJECT PORTFOLIO COST		$10,324

Figure 1: LRTP Tranche 1 portfolio includes 18 projects in MISO's Midwest Subregion, with an investment cost of $10.3 billion

QUANTIFIED BENEFITS INCLUDE:

- **Congestion and Fuel Savings** – LRTP projects will allow more low-cost resources to be integrated, replacing higher-cost resources and lowering the overall cost to serve load.
- **Avoided Capital Cost of Local Resources** – LRTP projects will allow renewable resource build-out to be optimized in areas where they can be more productive compared to a wholly local buildout.
- **Avoided Transmission Investment** – LRTP projects will reduce loading and avoid future reliability upgrades, avoiding the cost for replacing facilities due to age and condition.
- **Resource Adequacy Savings** – LRTP projects will increase transfer capability, which will allow access to resources in otherwise constrained areas and defer the need for investment in local resources.
- **Avoided Risk of Load Shedding** – The LRTP portfolio will enhance the resilience of the grid and reduce risk of load loss caused by severe weather events.
- **Decarbonization** – The higher penetration of renewable resources enabled by the LRTP portfolio will result in less carbon dioxide emissions.

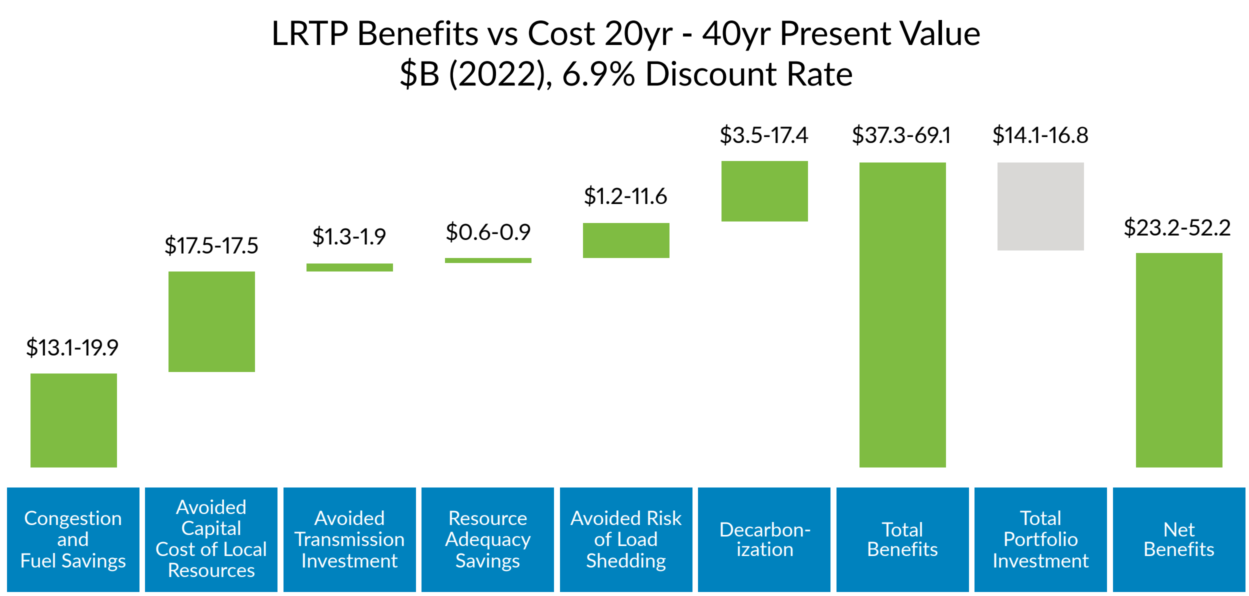


Figure 2: LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)*

*Note: This implies benefit-to-cost (B/C) ratio ranges of 20-yr PV B/C = 2.6 and 40-yr PV B/C = 4.0

The Tranche 1 portfolio has a benefit-to-cost ratio of between 2.6 and 3.8, and MISO studies show benefits of this investment at a benefit-to-cost ratio of at least 2.2 for every zone, with benefits well in excess of the LRTP costs. The proposed projects and costs are spread across the entire MISO Midwest subregion, allowing it to benefit multiple states, MISO members and customers. Benefits include more reliable and resilient energy delivery; congestion and fuel savings; avoided resource and transmission investment; improved distribution of renewable energy; and reduced carbon emissions.

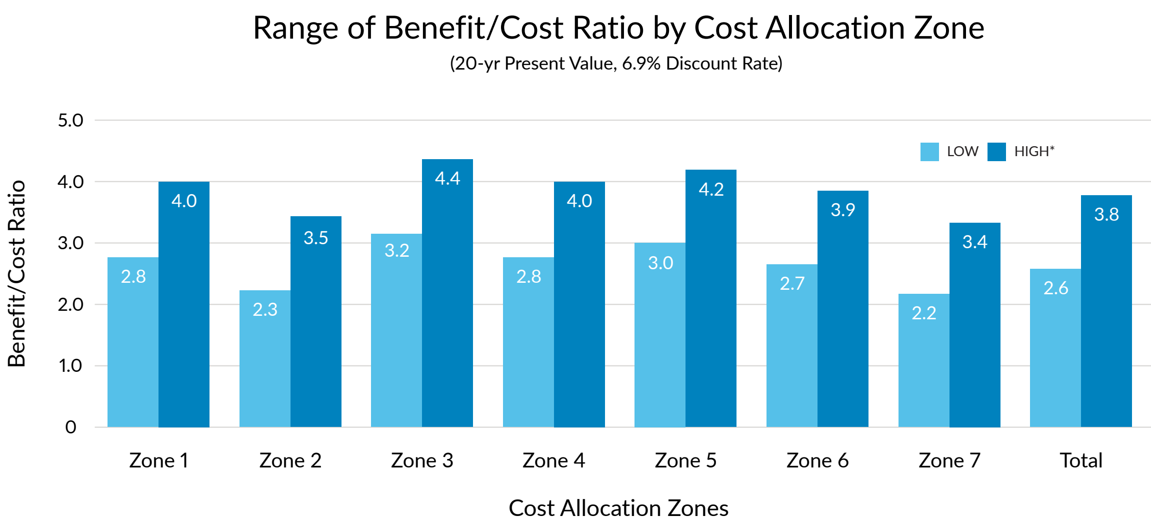


Figure 3: Benefits from the LRTP Tranche 1 portfolio exceed costs in every Midwest Subregion cost allocation zone

* The low and high range of benefit/cost ratios by Cost Allocation Zone are driven by changing two assumptions in the 20-year present value analysis: 1) increasing the Value of Lost Load (VOLL) from \$3,500/MWh (low) to \$23,000/MWh (high); and 2) increasing the price of carbon from \$12.55/ton (low) to \$47.80/ton (high).

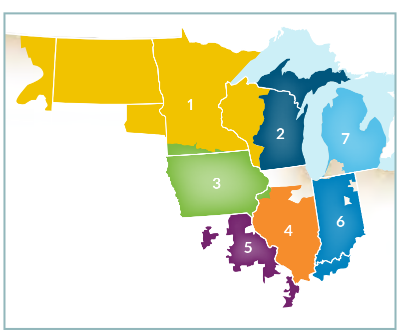


Figure 3a: Map of Midwest Cost Allocation Zone Boundaries (MISO Tariff, Attachment WW)

Transmission for the Future: LRTP Tranche 1 Projects are a "Least Regrets" Imperative

This least-regrets portfolio meets the needs of the first of MISO's three future planning scenarios, Future 1, which incorporates known and projected generation and load presented by member plans. This portfolio is "least regrets" because MISO is planning for an uncertain future and has chosen to plan towards the needs that represent a current view of member plans. Those portfolio plans continue to accelerate and expand, making Future 1 the conservative, expected case and presenting reliability implications that the Tranche 1 portfolio addresses. That's why Tranche 1 is a "yes-and" set of transmission that the Tranche 2 study will build off of to continue to meet the increasing renewable penetration levels and electrification growth that the MISO system is expected to see in the future.

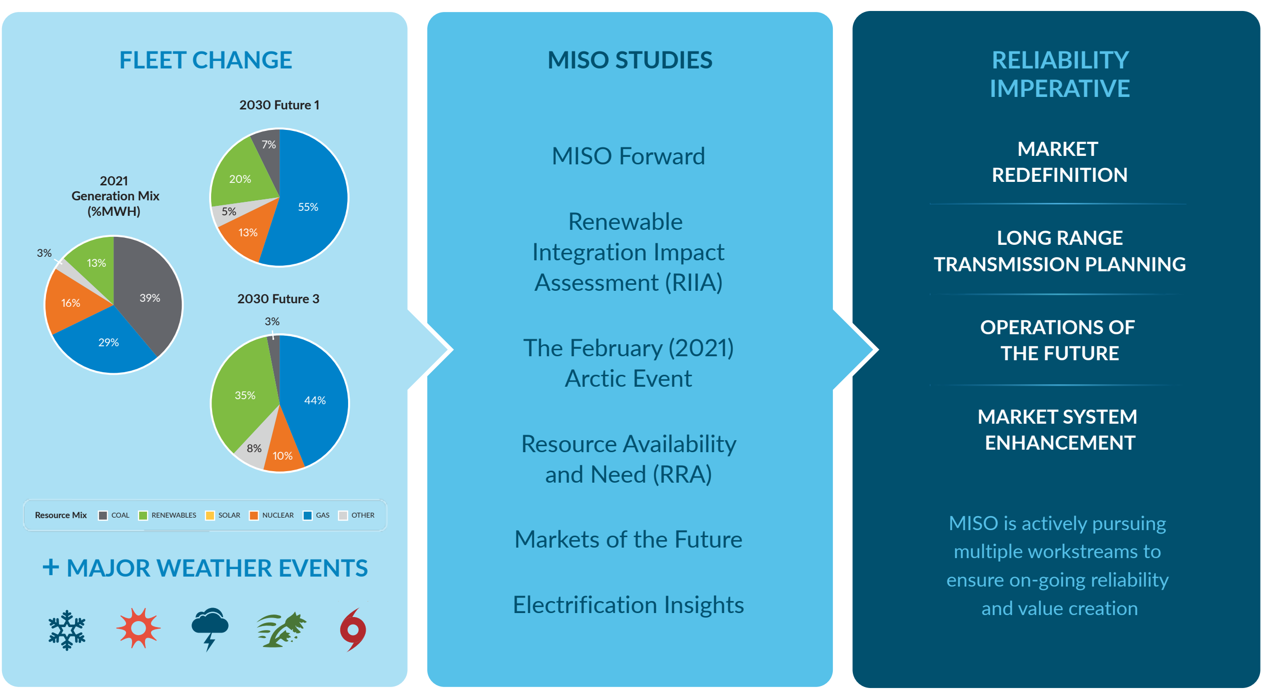


Figure 4: Challenges resulting from the changing resource portfolio and increasing extreme weather risk have created an imperative for broad changes

Subsequent tranches will improve interconnectivity, which helps to move power from where it's generated to where it's needed and, in doing so, not only integrates weather-based resources but improves resiliency during emergency events. Collectively, the multiple tranches of the LRTP comprise one of the four key elements of MISO's Reliability Imperative, which outlines a shared responsibility to evolve MISO's planning, markets, operations, and systems in an orderly fashion that preserves system reliability in the face of rapid changes in the MISO region. Unlike generation resource additions and retirements, which take as little as six months to complete, transmission projects can take up to 10 years from conception to in-service date. Given the long lead time, we must act now to ensure the transmission infrastructure is in place by 2030 to move both renewable and conventional generation across the grid in an efficient and reliable manner.

RELIABLE SYSTEM	Maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply
COST EFFICIENT	Enable access to lower-cost energy production
ACCESSIBLE RESOURCE	Provide cost-effective solutions allowing the future resource fleet to serve load across the footprint
FLEXIBLE RESOURCES	Allow more flexibility in the fuel mix for customer choice

Figure 5: The LRTP Tranche 1 results were identified consistent with the objectives of the LRTP effort

How the Portfolio Evolved: MISO, Stakeholders Execute Accelerated, Robust Study

In response to resource shift trends, MISO began working with its stakeholders through the Planning Advisory Committee (PAC) and LRTP workshops to identify the transmission infrastructure needed to support these changes and ensure reliability. MISO introduced the LRTP conceptual roadmap to stakeholders in March 2021 and began discussions on the study scope and approach. A few months later, MISO began a series of monthly technical workshops to seek input from stakeholders on the study methods and assumptions and to provide regular status updates on the ongoing work and analysis findings. In September 2021, MISO introduced a business case development process to identify the components and define the metrics for quantifying the benefits provided by the initial LRTP Tranche 1 portfolio of LRTP transmission investments.

In parallel, MISO engaged its stakeholders to develop an appropriate cost allocation methodology for such a transmission portfolio through the Regional Expansion Cost and Benefits Working Group (RECBWG).

The conceptual roadmap provided a long-range conceptual regional transmission plan to map out further study and potential solution ideas needed to address future transmission needs. Reliability analysis was then conducted on a series of study models representing various system conditions and dispatch patterns, as reviewed by MISO and stakeholders. Next, MISO evaluated potential alternative solutions developed by stakeholders and MISO to identify the most effective transmission solutions, including both reliability and economic analysis.

Once Tranche 1 projects were identified, MISO calculated the economic benefits of the portfolio. While the primary objective of the LRTP projects was to address reliability issues considering a range of system conditions, their value can extend well beyond reliability. This is especially true for investments like the LRTP projects, whose regional scope and high voltage levels can enable significant broad economic benefits as well.

COSTS COMMENSURATE WITH BENEFITS

The transmission limitations between MISO Midwest and MISO South subregions effectively reduced the flow of benefits between the two subregions. To ensure costs align with beneficiaries, MISO submitted a cost allocation option for new Multi-Value Project portfolios, the cost of which would be regionally allocated on a subregional basis.

In February 2022, after months of work with stakeholders and state regulators, MISO filed with FERC for a cost allocation methodology for Multi-Value Projects to meet the unique needs of the region in developing the LRTP projects. The filing, supported by a majority of MISO transmission owners, was submitted and subsequently approved on May 18, 2022.

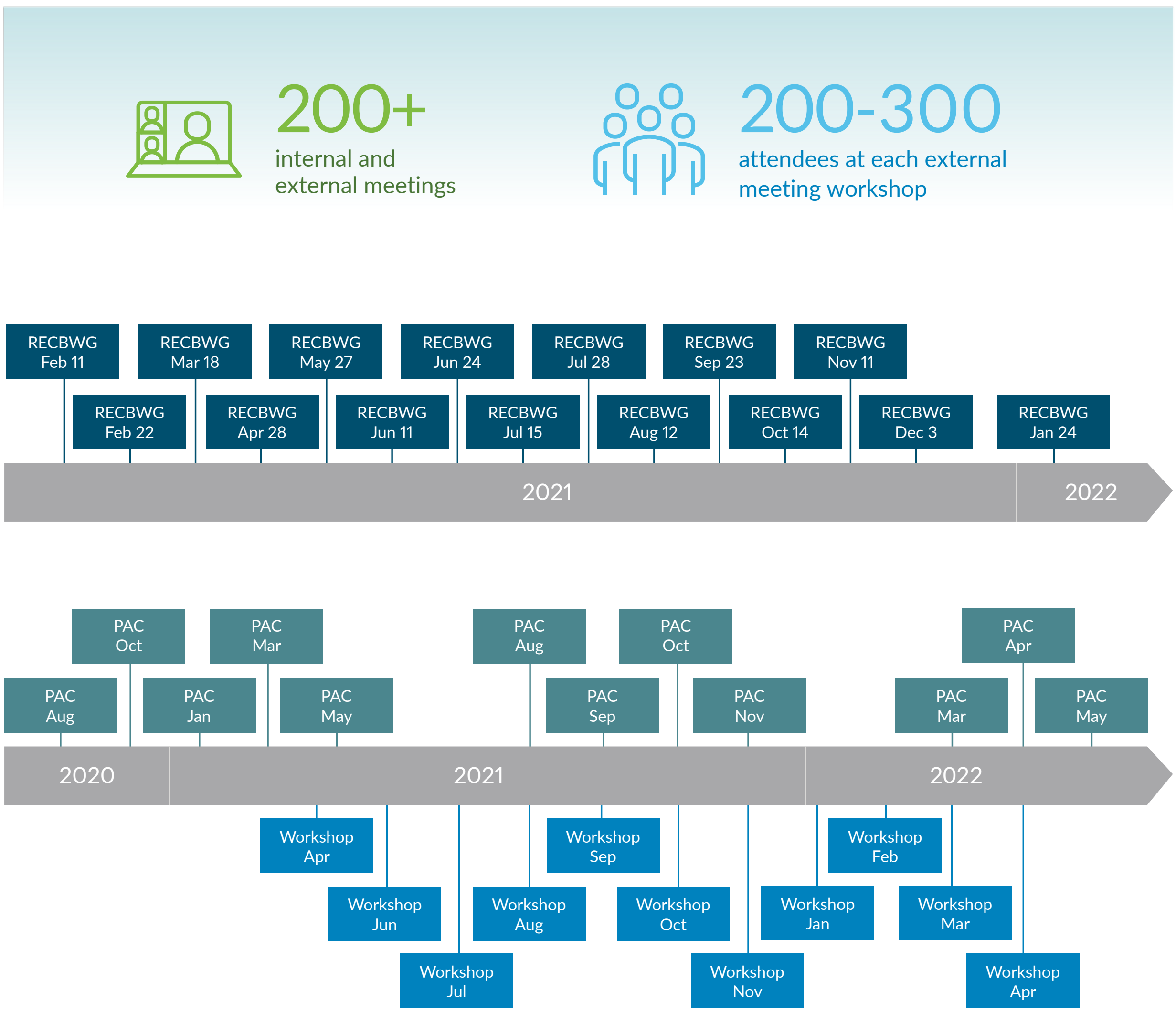


Figure 6: MISO's Long Range Transmission Plan Tranche 1 followed an extensive stakeholder process

Tranche 1 projects solve specific transmission issues across the MISO footprint

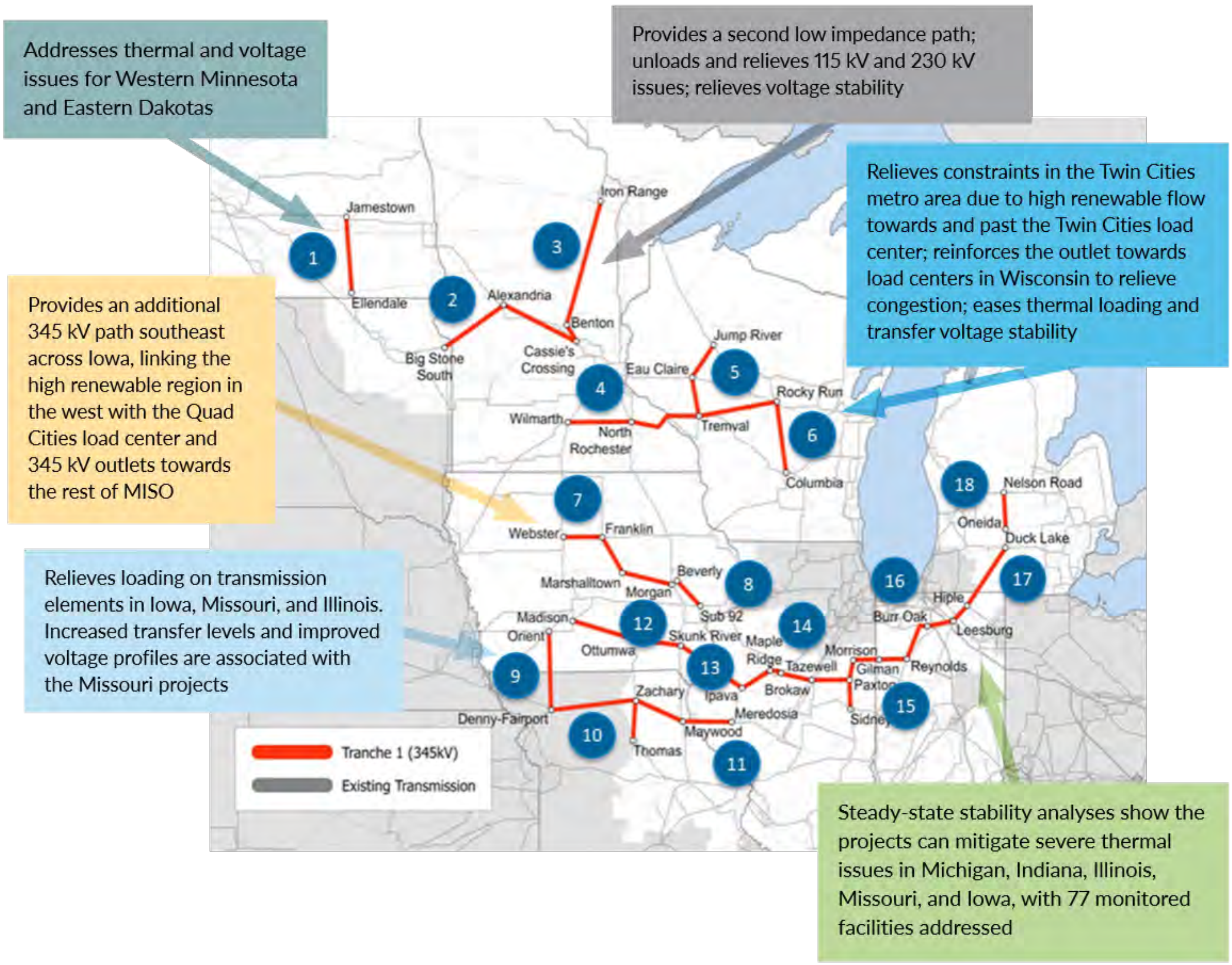
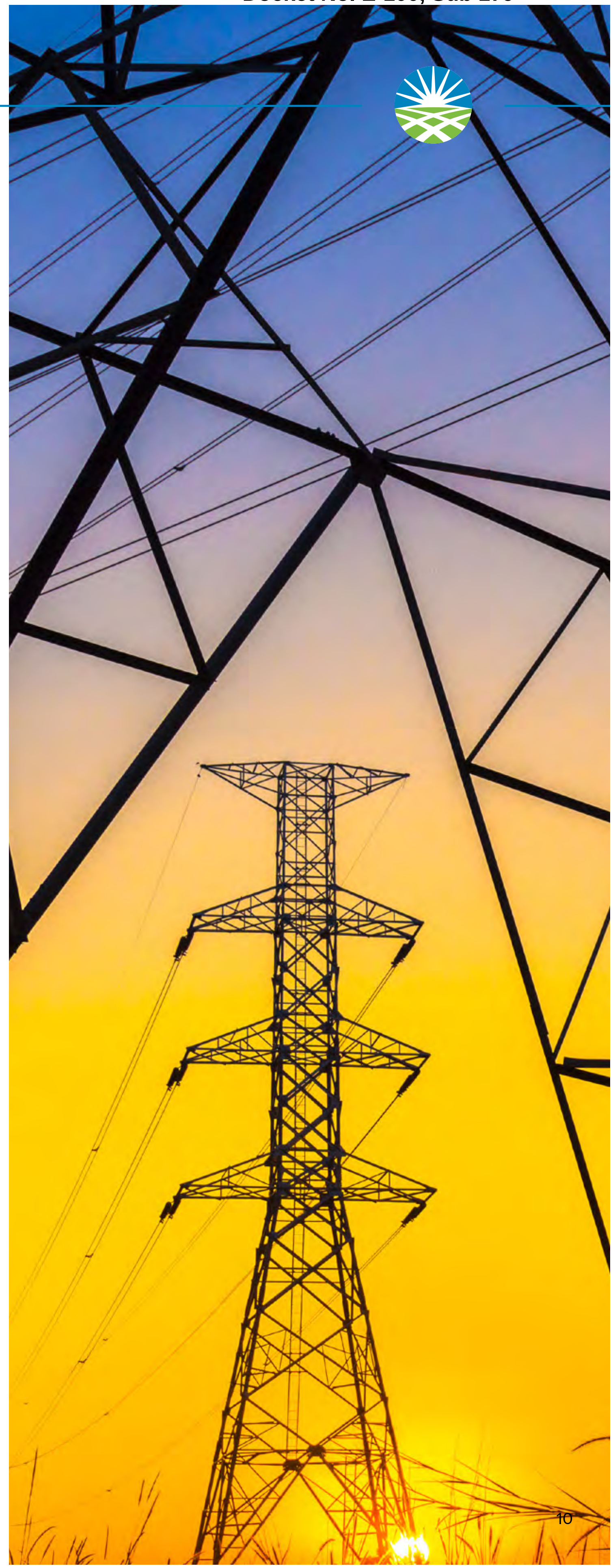


Figure 7: The Tranche 1 portfolio of 18 transmission projects can be divided into six sections with unique regional benefits

ID	DESCRIPTION
1	Jamestown – Ellendale
2	Big Stone South – Alexandria – Cassie's Crossing
3	Iron Range – Benton County – Cassie's Crossing
4	Wilmarth – North Rochester – Tremval
5	Tremval – Eau Claire – Jump River
6	Tremval – Rocky Run – Columbia
7	Webster – Franklin – Marshalltown – Morgan Valley
8	Beverly – Sub 92
9	Orient – Denny – Fairport
10	Denny – Zachary – Thomas Hill – Maywood
11	Maywood – Meredosia
12	Madison – Ottumwa – Skunk River
13	Skunk River – Ipava
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East
15	Sidney – Paxton East – Gilman South – Morrison Ditch
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple
17	Hiple – Duck Lake
18	Oneida – Nelson Rd



Next Steps: A Foundation for Future Needs

A more interconnected system is stronger. Additional study work and stakeholder engagement will help identify the nature and benefits of future LRTP tranches needed to address further deployment of variable, weather-dependent resources, continued volatility created by severe weather events and the benefits of improved interregional connectivity.

While Tranche 1 provides a meaningful start, much work is left to ensure that the shifting resource fleet transition occurs in an orderly, efficient and reliable manner. Though Tranche 1 provides a more robust system in the Midwest, future tranches are needed to address other parts of the MISO footprint and future levels of fleet transition beyond what is captured in Future 1. MISO looks forward to continuing the conversation with stakeholders and regulators to ensure adequate planning to meet future needs.

MISO

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MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report

Table of Contents

1 Introduction

MISO's multi-year Long Range Transmission Planning (LRTP) initiative assesses reliability risks looking 10-20 years into the future to identify the transmission investments needed to enable regional delivery of energy. Projections show a drastically different resource fleet, along with other influences such as electrification, that is driving a need for the bulk electric system to be better prepared for these massive shifts. MISO proposes a Tranche 1 Portfolio of 18 transmission projects, equaling approximately $10 billion of investment, to enhance connectivity and maintain adequate reliability for the Midwest Subregion by 2030 and beyond (Figure 1-1, Table 1-1).

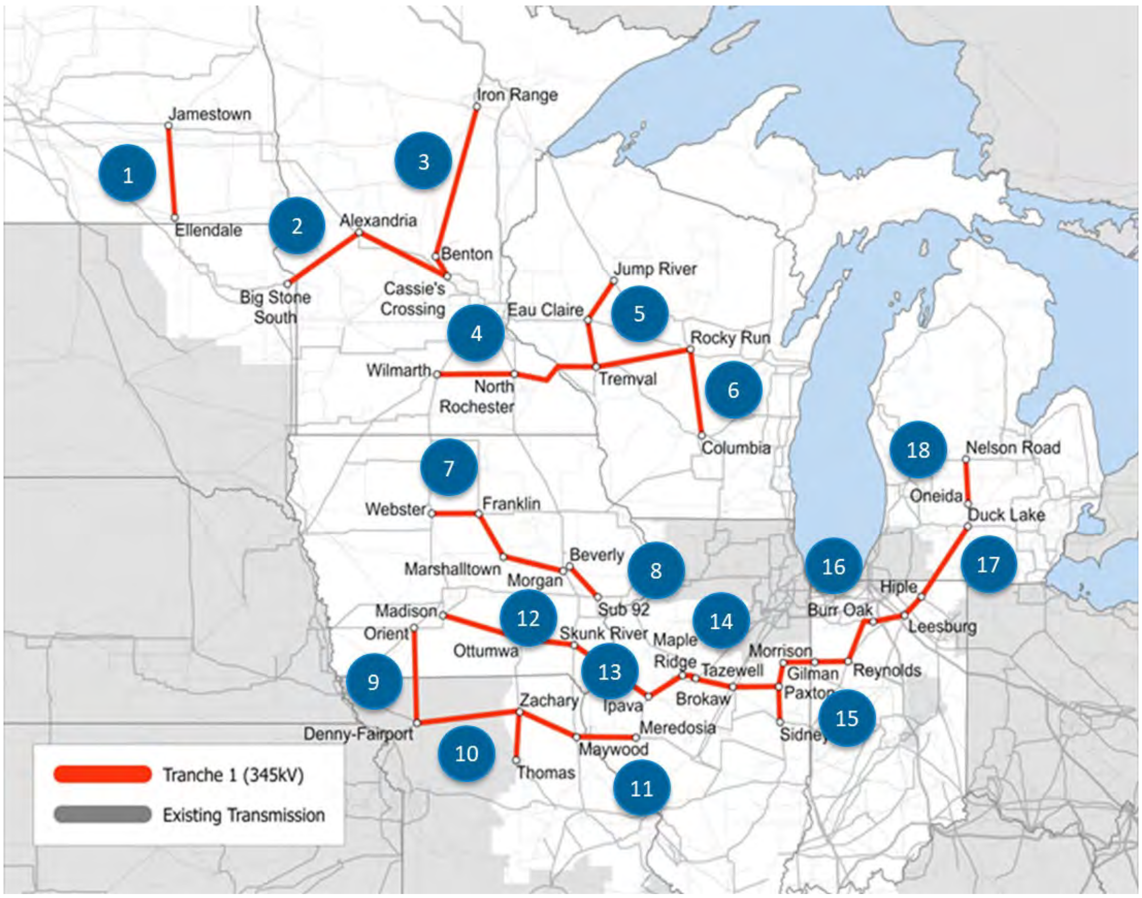


Figure 1-1: LRTP Tranche 1 Transmission Portfolio

LRTP Tranche 1 Portfolio of Projects

ID	Description	Expected ISD	Estimated Cost ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439M
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574M
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970M
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689M
5	Tremval – Eau Claire – Jump River	6/1/2028	$505M
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050M
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755M
8	Beverly – Sub 92	12/31/2028	$231M
9	Orient – Denny - Fairport	6/1/2030	$390M
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769M
11	Maywood – Meredosia	6/1/2028	$301M
12	Madison – Ottumwa – Skunk River	6/1/2029	$673M
13	Skunk River – Ipava	12/31/2029	$594M
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572M
15	Sidney – Paxson East – Gilman South – Morrison Ditch	6/1/2029	$454M
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261M
17	Hiple – Duck Lake	6/1/2030	$696M
18	Oneida – Nelson Rd.	12/29/2029	$403M
	Total Project Portfolio Cost:		$10,324M

Table 1-1: Proposed Tranche 1 Portfolio of Projects
(Costs as of June 1, 2022 and are subject to change. Costs represent "overnight" costs)

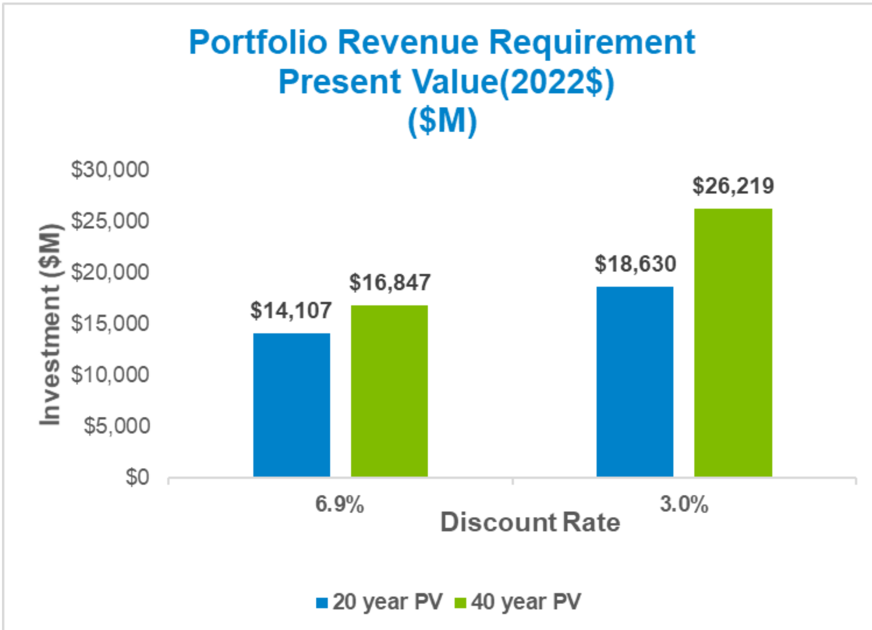


Figure 1-2: Present Value of LRTP Tranche 1 Portfolio (values as of 6/1/2022)

The Tranche 1 Portfolio has a benefit to cost ratio of between 2.6 and 3.8, and MISO studies show benefits of this investment at a benefit to cost ratio of at least 2.2 for every Cost Allocation Zone, well in excess of the LRTP Tranche 1 Portfolio costs (Figure 1-2 and 1-3). The proposed projects and costs are spread across the entire MISO Midwest Subregion, allowing it to benefit multiple states, MISO members and customers. Benefits include more reliable and resilient energy delivery; congestion and fuel savings; avoided resource and transmission investment; improved distribution of renewable energy; and reduced carbon emissions.

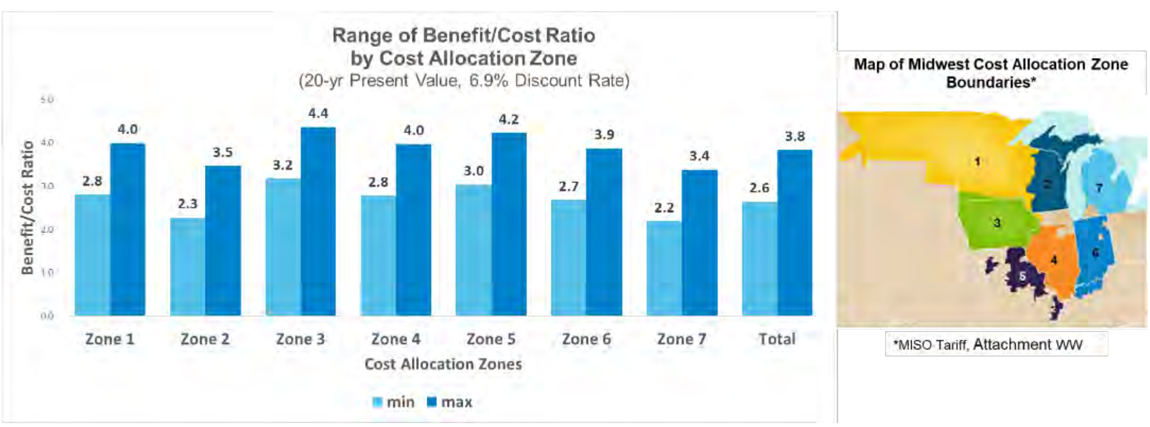


Figure 1-3: Distribution of benefits to Cost Allocation Zones in Midwest (MISO Tariff Attachment WW) (values as of 6/1/22)

The LRTP study was initiated in 2020, and the LRTP Tranche 1 Portfolio Report is the first iteration of MISO's findings and recommendations. This report identifies reliability challenges in the Midwest Subregion associated with MISO's Future 1.

Efforts on Tranche 2 will be underway in the second half of 2022 and will continue to focus on the Midwest Subregion and addressing the needs identified in MISO's Futures. Tranche 3 of the LRTP study will focus on identifying system needs in the MISO South Subregion, and Tranche 4 will look at the part of the system connecting the Midwest and South Subregions.

While the Tranche 1 Portfolio is the result of MISO's long-range planning process being executed for only the second time, the rapid change within the industry will require that it become a more routine aspect of the MISO planning process going forward.

2 History of MISO's Innovative Long Range Transmission Planning Process

The transmission grid, while not top of mind for many people, is a critical component of ensuring the lights come on when a switch is flipped, our favorite devices can be charged, and life-saving machines can operate. But even with that level of importance, transmission investments, especially on a large scale, are very difficult to undertake and are not very common in the United States currently. However, the clear direction of the industry, towards a cleaner energy future, requires investments of this nature. Fortunately, MISO has a proven process, experience, and an engaged stakeholder community to draw upon as we embark on this very difficult journey. This is not the first time we have been here, or successfully facilitated significant grid investment.

As a Regional Transmission Organization/Independent System Operator, MISO coordinates with its members to facilitate transmission system investments needed to ensure continued reliable and efficient delivery of least-cost electricity across the MISO region. This requires a continuous execution of MISO's recurring transmission planning process. The culmination of the extensive work executed during each 18-month planning cycle, including proposed new projects, are codified annually in a MISO Transmission Expansion Plan (MTEP). These plans have put in motion approximately $42 billion in transmission investments going back to 2003.

Section 1.2 of MTEP21 provides an overview of MISO's overall transmission planning process, so only the primary aspects are described here to provide high-level context. The process involves both top-down and bottom-up identification of issues and potential solutions associated with transmission system maintenance and enhancement. There are also several aspects, or objectives of different components of MISO's transmission planning process, including resolving grid reliability issues, transmission expansion needed to connect new generation resources to the grid, and reducing congestion on the system. Assessing these types of needs can occur as often as annually and involves looking out 5-15 years to identify near- and mid-term needs.

The overall process also includes a component that has been exercised less frequently, the long-range transmission planning (LRTP) process, which considers challenges projected in the 20 year and beyond timeframe. Given the extensive lead time associated with large-scale transmission investment, this process is designed to be responsive to situational grid needs and utilized when incremental transmission system fixes, upgrades, and/or additions will not be sufficient to effectively or efficiently address those needs. These situations require that MISO consider the range of potential future states, the implications of those outcomes for the industry, and the transmission system needs this will create. Those potential future scenarios serve to provide bookends for the uncertainty that exists when planning this far out.

The inaugural iteration of MISO's long range planning process culminated in the first-of-its-kind portfolio of projects being approved by the MISO Board of Directors in 2011. Beginning in 2007, in response to an increase of individual Renewable Portfolio Standards within MISO states, MISO began the initial execution of the LRTP process to mitigate the significant impact on the future generation mix and the reliability of the system. During this multi-year effort, a new project type — Multi-Value Project (MVP) — was developed. As codified in the MISO Tariff, a project must meet one or more of the following criteria to be included in an MVP portfolio:

> *Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.*
>
> *Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.*
>
> *Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.*

As the criteria demonstrate, economic benefits are a significant part of the requirements for these types of projects. Given the regional scope of these projects, the level of investment, and the uncertainty associated with the time horizon, a strong business case is paramount. The types of economic benefits that could be used to meet these criteria were defined through collaboration with stakeholders. Those benefits are:

- *Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be* *realized through reductions in both transmission congestion and transmission energy losses. Production cost savings can also be realized through reductions in Operating Reserve requirements.*

- *Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.*
- *Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.*
- *Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.*
- *Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System and related to the provisions of Transmission Service.*

The ground-breaking work executed during this process culminated in a nearly $6 billion portfolio, with a projected 1.8-3.1 benefit-to-cost ratio, being approved by the MISO Board of Directors in 2011. MISO was required to periodically reassess the projected benefits to determine if modifications to the MVP criteria were necessary. Each of those analyses found that the projected benefits remained consistent with, and were sometimes greater than, initially estimated, as shown in Figure 2-1. This, along with the fact that all but one of the 17 MVP projects are currently (as of June 2022) in service and fully utilized, demonstrates the effectiveness of MISO's value-based planning process and the use of future scenarios to bookend uncertainty and identify robust solutions, and to project benefits.

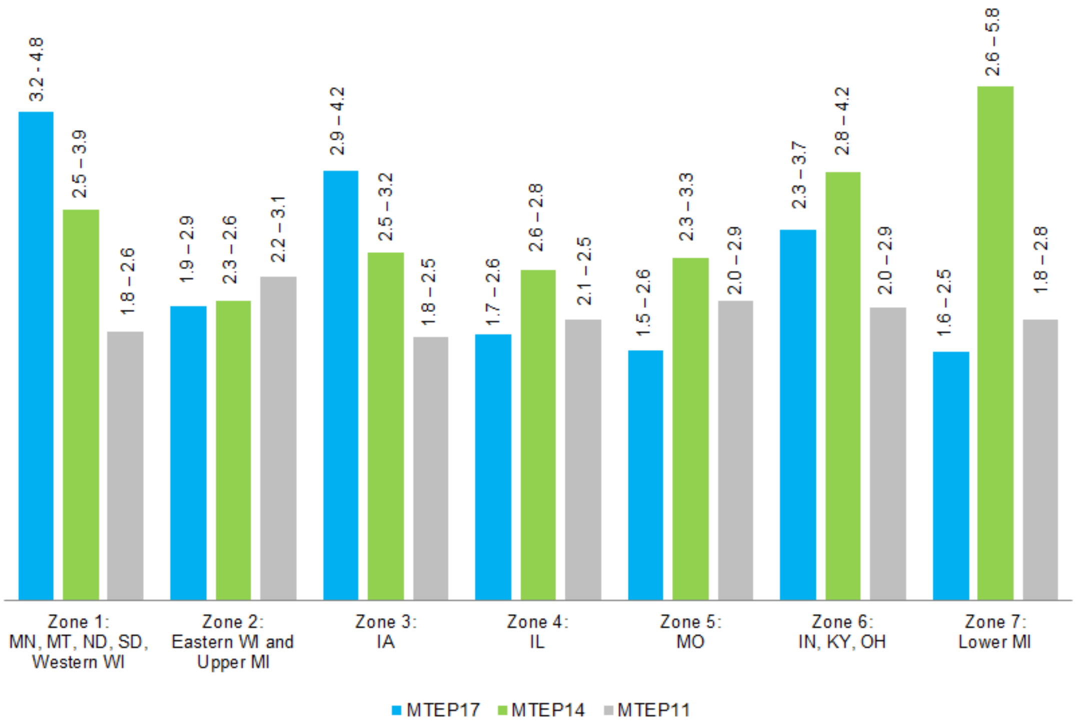


Figure 2-1: Zonal benefit to cost ratios for the original MTEP11 MVP Analysis and subsequent MTEP14 and MTEP17 Triennial Reviews

In the years immediately following the approval of the MVP portfolio, the level of annual investment put forward in MTEP reports returned to historical levels of approximately $1.5 billion annually. Upgrades or replacements of aging assets, and the added investment associated with the integration of the South Subregion have contributed to the annual average investment rising to $3.4 billion over the last five years, but still well below the level approved in 2011 with the MVPs. While this increased rate of investment is strengthening the grid in the MISO Region, it is not reflective of the magnitude of change that has been occurring across the landscape during this time.

3 The Long Range Transmission Planning Component of MISO's Broad-Based Response to Current Industry Change

The generation mix evolution in the MISO Region that drove the need for the MVP portfolio didn't end with that portfolio's approval. In fact, the pace towards more renewables has increased since that time. Progressively increased carbon-free and clean energy goals set by MISO member utilities, state and municipal government policies and customer preferences continue to drive growth in wind, solar, battery storage and hybrid projects. MISO made a number of incremental changes to its markets, tools, and processes along the way to mitigate the early impacts of this change. However, beginning in 2016, the challenge was becoming obvious and more difficult to mitigate.

Change Drivers and Implications Contributing to Aligning Interests

Over the last several years, MISO began to experience operational situations that required the use of emergency procedures, even outside of the summer period when demand peaks occur, and supply becomes strained. In the real time horizon, when resource margins are projected to be significantly low, MISO will begin to implement the steps in its emergency procedures in an attempt to gain access to additional resources. While not having to make a single emergency declaration in the two years preceding 2016, 41 such emergency declarations have been required since 2016. These events are largely the result of reduced generation capacity due to the retirement of conventional generation as the fleet has transitioned toward more renewable resources and greater reliance on Load Modifying Resources for meeting capacity requirements.

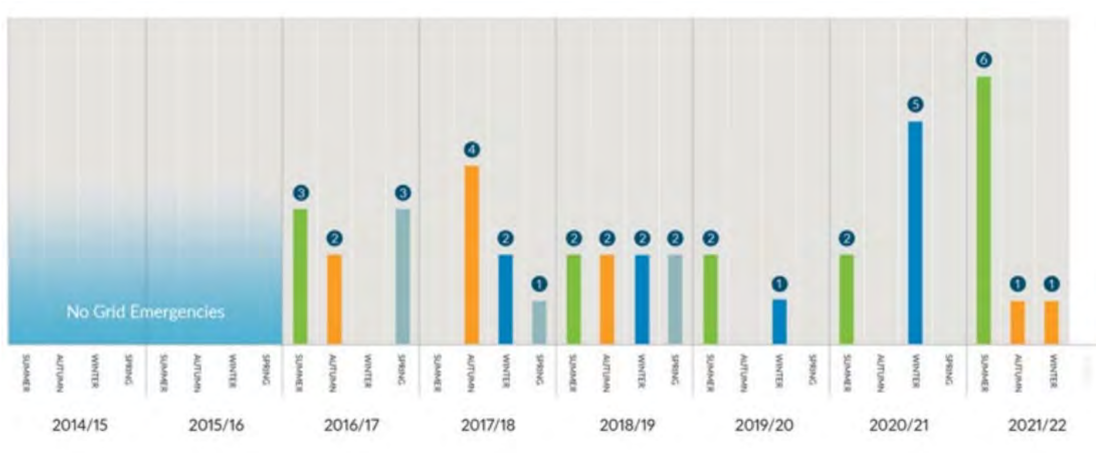


Chart indicates the number of days under a max gen alert, warning or event.

Figure 3-1: Historical MISO MaxGen Alerts, Warnings, and Events

In response to this growing challenge, MISO launched the Resource Availability and Need (RAN) initiative to understand the drivers and identify a variety of changes to markets and resource adequacy process solutions to generation availability issues.

At the same time, and driven by the ongoing fleet shift, MISO executed a multiple-year study called the Renewable Integration Impact Assessment (RIIA) to deepen its understanding of the implications of more renewable generation on the system. This assessment identified inflection points, or renewable energy penetration levels where challenges would get increasingly more complex. It also identified key risks that would result, including insufficient transmission infrastructure.

- ***Stability Risk*** requires multiple transmission technologies, operating and market tools to incentivize availability of grid services
- ***Shifting periods of grid stress*** requires flexibility and innovation in transmission planning processes
- ***Shifting periods of energy shortage risk*** requires new unit commitment tools, revised resource adequacy mechanisms
- ***Shifting flexibility risk*** requires market products to incentivize flexible resources
- ***Insufficient transmission*** requires proactive regional transmission planning

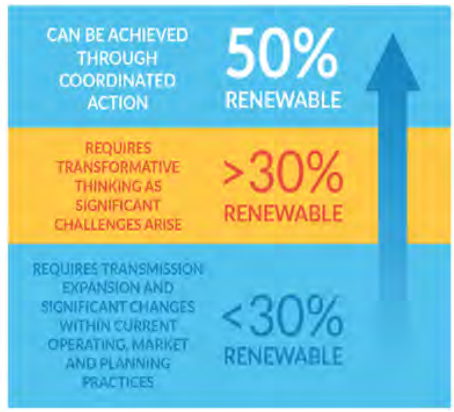


Figure 3-2: RIIA Study Identified Key Risks with increasing levels of Renewable Energy

The timing of when the region would reach these inflection points was then uncertain. However, an additional driver emerged that accelerated the pace towards more renewables: a growing customer preference for clean energy. MISO began to see a growing number of member utilities and state policies incorporating decarbonization goals into their resource fleet strategies. Around this same time another trend was emerging on the demand side as well. The movement towards electrification will have a significant impact on electricity demand, which has in recent years been relatively stable.

This level of uncertainty makes it very difficult to plan for the future with confidence. However, as demonstrated with the development of the 2011 MVP portfolio, MISO has an existing process to effectively manage these types of risks. MISO, in collaboration with stakeholders, establishes future planning scenarios to understand the economic, policy and technological impacts on future resource needs. Starting in 2019, MISO examined three future scenarios to define and bookend regional resource expectations over the next 20 years (MISO Futures Report[1]). These Futures recognize the widespread clean energy goals of states and utilities within the region, as well as the associated rapid pace of regional resource transformation.

[1] MISO Futures Report

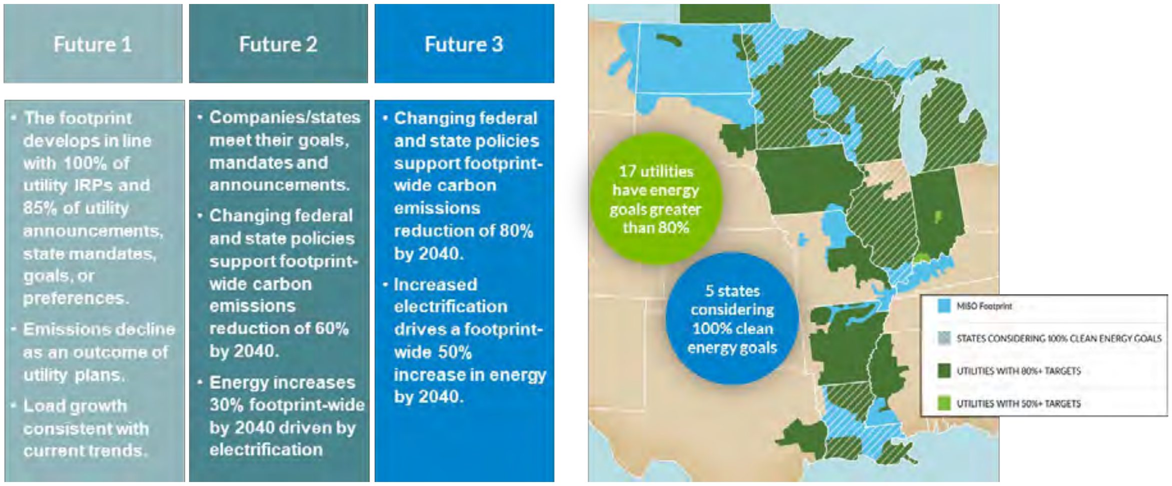


Figure 3-3: MISO Futures Key Drivers

MISO's Reliability Imperative Response: The Long Range Transmission Planning Initiative

These future scenarios reflect the significance of the changes the region must prepare for, and similar to the situation facing the region back in 2007, incremental changes will no longer be adequate. The magnitude of landscape changes has created an imperative for transformational changes across MISO's markets, planning, operations, and technology. The Reliability Imperative Report[2] documents the collection of related initiatives that address the growing risks and that are required to enable member resource plans and strategies. MISO, members, regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges.

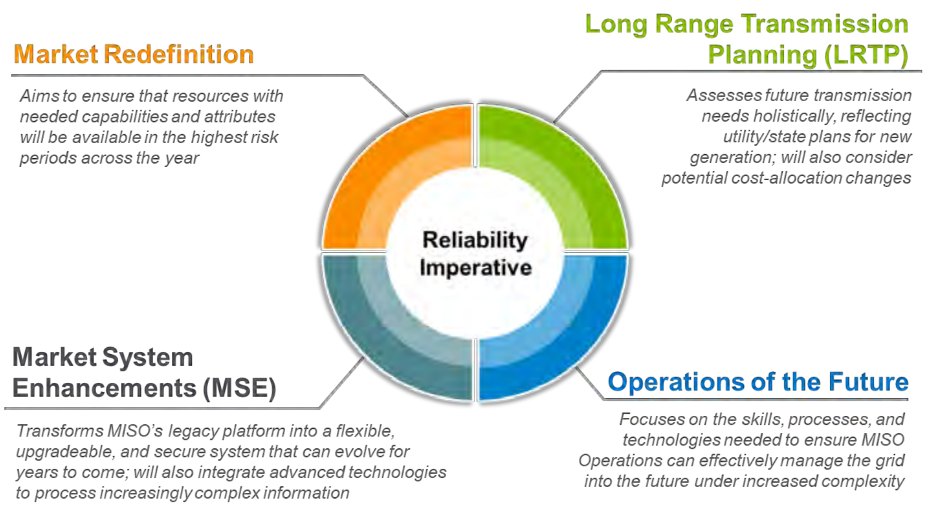


Figure 3-4: MISO's Reliability Imperative Key Initiatives

[2] MISO'S Response to the Reliability Imperative

As work has been underway, an additional risk emerged that has increased the urgency associated with progressing these initiatives. An increase in the frequency of extreme weather events is exacerbating the risks and challenges that originally drove the need for the Reliability Imperative. These types of scenarios can force a large number of generators out of service in a local area, putting reliability at risk. This has contributed to the emergency procedure declarations over the last several years (Figure 3.1).

Robust Business Case for Long-Range Transmission Plan

As the region faces both a changing resource fleet and increased prevalence of extreme weather events, the ability to move electricity from where it is generated to where it is needed most becomes paramount. One needs only to consider the need for increased power flow within and between regions during Winter Storm Uri in February 2021 to understand the importance of transfer capability. MISO can leverage its large geographic footprint and diversity of resources to ease some of these challenges. However, adequate transmission infrastructure is key.

With the landscape once again shifting and expected to do so even more dramatically in the future, the transmission planning aspect of the Reliability Imperative includes the second execution of MISO's long-range transmission planning process. The MISO LRTP initiative, introduced to stakeholders in August 2020 to invite their collaboration, provides a regional approach to transmission planning that addresses future challenges of the resource fleet evolution and electrification. The transformational changes occurring in the industry necessitate the identification of transmission solutions to ensure continued grid reliability and cost-effective transmission investments that will serve future needs.

The objective of LRTP is to provide an orderly and timely transmission expansion plan that supports these primary goals:

- **Reliable System** – maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply
- **Cost Efficient** – enable access to lower-cost energy production
- **Accessible Resources** – provide cost-effective solutions allowing the future resource fleet to serve load across the footprint
- **Flexible Resources** – allow more flexibility in the fuel mix for customer choice

LRTP is designed to assess the region's future transmission needs in concert with utility and state plans for future generation resources.

LRTP is a multi-year effort to address the myriad and complex issues associated with the significant resource transformation underway. Because there is urgency to keep pace with this rapid evolution, MISO is seeking to recommend projects identified in the LRTP effort over several MTEP cycles as work progresses. While it is important to move quickly, MISO must ensure reliable power delivery for customers with investment decisions that appropriately balance generation and transmission solutions on a regional scale to ensure the best cost outcomes for customers.

LRTP continues the MISO Value-Based Planning approach to extend value beyond the traditional planning processes to achieve a more efficient comprehensive long-term system plan.

Tariff Requirements

The needs driving the LRTP portfolio, the scope of the projects and types of benefits they enable aligns relatively well with those of the MVP portfolio and the associated MVP tariff requirements are being applied for the LRTP. The criteria to meet the project definition are listed in their entirety in Section 2, and in summary are: 1) enable the transmission system to reliably and economically deliver energy in support of documented energy policy mandates or laws, 2) provide multiple types of economic value, with a benefit-to-cost of 1.0 or greater, or 3) address at least one reliability issue and provide at least one type of transmission-based economic value.

LRTP Cost Allocation Aligned with Beneficiaries

A condition that must be met prior to any transmission investment being approved is to determine how the costs will be allocated. The original MVP ruleset established a cost allocation methodology of spreading costs footprint-wide on a load-ratio share basis. With the initial Tranche of LRTP projects identified to address reliability issues in MISO's Midwest Subregion only, this approach was not going to meet FERC's requirement of costs spread roughly commensurate with benefits.

To address this risk, MISO proposed a modified MVP methodology where costs could be spread to a subregion only, if the projects within the portfolio primarily provide benefits to a single subregion. This proposal was approved by FERC on May 18, 2022 with a May 19, 2022 effective date. With FERC's approval the costs of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion.

4 Rigorous, Collaborative Approach Ensures Robust LRTP Solutions

With this being the second execution of MISO's long-range transmission planning process, it was not groundbreaking, but it is no less significant than the first execution that developed the 2011 MVP portfolio. In fact, the landscape changes being planned for are much more significant now and require prompt action to address the fast pace of transformational changes occurring in the industry. The initial tranche of LRTP projects was developed in a focused effort to deliver a set of least regrets solutions that would be ready to address needs in the next 10 years.

While the process was executed in significantly less time, the quality of the analysis and commitment to identifying robust solutions was not sacrificed. This portfolio of projects represents over 2,000 miles of transmission, a significant level of investment unprecedented in the industry and will have its benefits and costs shared broadly. Given this backdrop, it is incumbent on MISO to perform a rigorous analysis to ensure we identify a robust set of projects that most effectively and efficiently resolve the identified issues and future system needs.

The process MISO follows to identify projects and create a portfolio is designed to result in a business case that justifies the investments. As described in Section 3 of this report, the first step in this process is to create potential future scenarios, or Futures, to essentially establish a target for our planning efforts. In some situations, the Futures could bookend very different directions for the region's generation fleet due to uncertainty around energy policy and other factors. However, given the current clear trends that include Members and States increasingly establishing clean energy goals, the continued retirement of fossil fueled resources from the system, and a growing trend toward electrification, the current set of futures reflect different progressions or the velocity of change in that singular direction.

MISO developed a long range conceptual regional transmission plan to explore and further study possible solutions needed to address future transmission needs. The conceptual plan serves as a set of solution ideas that guide the development of candidate transmission projects that meet the objective of long range planning to achieve reliable and economic delivery of energy in a range of future scenarios. Reliability analysis is conducted on a series of study models that represent various system conditions and dispatch patterns to identify issues. MISO then evaluates the candidate projects and potential alternative solutions developed by MISO and stakeholders to identify the most effective transmission investments to address the issues and performs an economic analysis that factors into selecting the best of the options. Section 5 of this report is a detailed walk-through of the reliability analysis that was undertaken, with the results provided in Section 6.

Once the portfolio of projects is identified, MISO then calculates the economic benefits created by the portfolio. The primary objective of the LRTP projects was to address reliability issues identified in the planning studies that considered a range of system conditions. However, while transmission investments are usually built for a specific purpose, the value that any particular investment brings can extend well beyond addressing the singular issue driving it. That is especially true for investments like the LRTP projects, whose regional scope and high voltage levels can enable significant economic benefits as well.

While the objective of LRTP is primarily focused on the need for reliable energy delivery, the analysis of economic benefits is essential to the demonstration of value of the portfolio as required by the Tariff for eligibility as regionally cost shared projects. The economic benefit types that can be assessed were identified in Section 2 of this report in the discussion on Multi-Value Projects, which the LRTP will be categorized as. The specific metrics that were used to determine the economic benefits of the LRTP portfolio are:

- Congestion and fuel savings – LRTP projects will allow more low-cost renewables to be integrated, which will replace higher-cost resources and lower the overall production cost to serve load.
- Avoided local resource capital costs – LRTP projects will allow renewable resource build-out to be optimized in areas where they can be more productive compared to a wholly local resource build out.
- Avoided future transmission investment – LRTP projects will reduce loading on other transmission lines, in some cases preventing lines from becoming overloaded in the future and thus avoiding the need to upgrade those lines.
- Reduced resource adequacy requirement – LRTP projects will expand transfer capability, which will in certain situations increase the ability for a utility to use a new or existing resource from another part of the MISO region, rather than construct one locally, to meet its resource adequacy obligation.
- Avoided risk of load shed – the LRTP portfolio will increase the resilience of the grid and lower the probability that a major service interruption occurs.
- Decarbonization – the higher penetration of renewable resources that the LRTP portfolio will enable will result in less CO_2 emissions.

The methodology used to calculate each of these economic benefits and the results are the focus of Section 7.

As described in Section 8 of this report, the allocation of LRTP portfolio costs is spread broadly to the entire Midwest Subregion. The Federal Energy Regulatory Commission requires that transmission costs associated with investments of this nature be allocated roughly commensurate with how the benefits are realized. Given the large-scale of the LRTP projects and the fact that they span the Midwest Subregion, benefits flow to the entire subregion. To illustrate this and demonstrate support of FERC's guidance, Section 8 shows the benefits by MISO Cost Allocation Zone.

Given the expected continued key role of natural gas generation, volatility in the price of natural gas can have a significant impact on the cost of producing electricity. The recommended LRTP Tranche 1 Portfolio can partially offset the gas price risk by providing additional access to generation powered by fuels other than natural gas. Chapter 8 includes a sensitivity analysis performed using a range of natural gas prices to demonstrate the robustness of the LRTP Tranche 1 Portfolio across a range of scenarios.

5 LRTP Tranche 1 Portfolio Development and Scope

Most good plans result not from a single work effort, but rather develop from refinements to an effective starting point. The latter characterizes the path to the LRTP Tranche 1 Portfolio. In anticipation of reliability needs in a future with growing renewable penetration and load consumption, MISO developed an indicative transmission roadmap of potential transmission expansions throughout the region for both Future 1 and a combined Future 1, 2, and 3. The roadmap provides an indication of the potential magnitude of transmission expansions that may be needed to maintain reliable and efficient operations under the expected Futures and candidate transmission solutions to be used as a starting point in determining potential projects. This roadmap was developed by MISO planning staff as extensions of the existing grid that would provide for logical connections that could increase connectivity, close gaps between subregions, and support a more robust and resilient grid by enabling the delivery of energy from future resources to future loads and increasing the reliance on geographic diversity to manage the increased dispatch volatility and uncertainty associated with the future resource fleet. The indicative roadmap is not a final plan but instead a starting point for considering solutions to transmission issues expected.

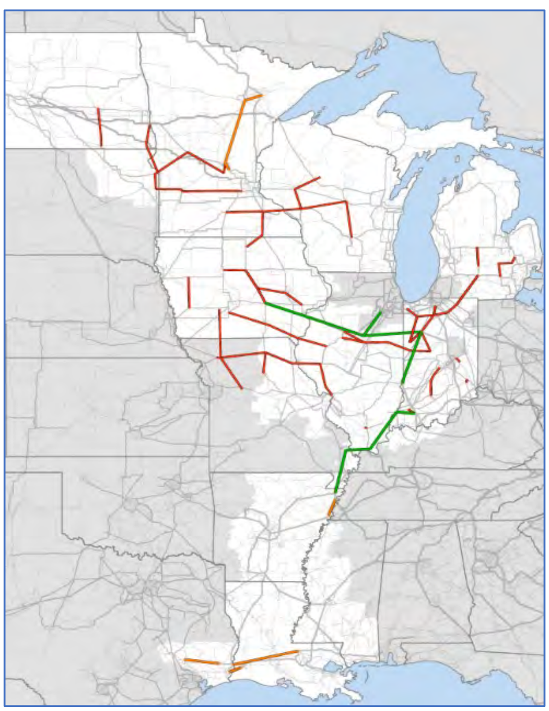


Figure 5-1: Future 1 Indicative Roadmap

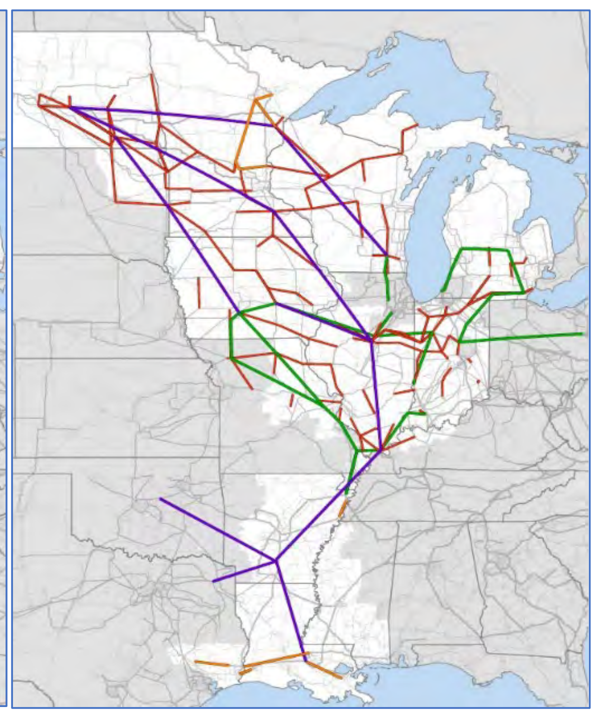


Figure 5-2: Futures 1, 2, & 3 Indicative Roadmap

The initial tranche of the LRTP is focused primarily on enabling the resource expansion and load forecasts associated with the 10- and 20-year timeframe under Future 1 in the Midwest

Subregion. In Future 1, the most significant aspects are resource retirements and increased renewable penetration.

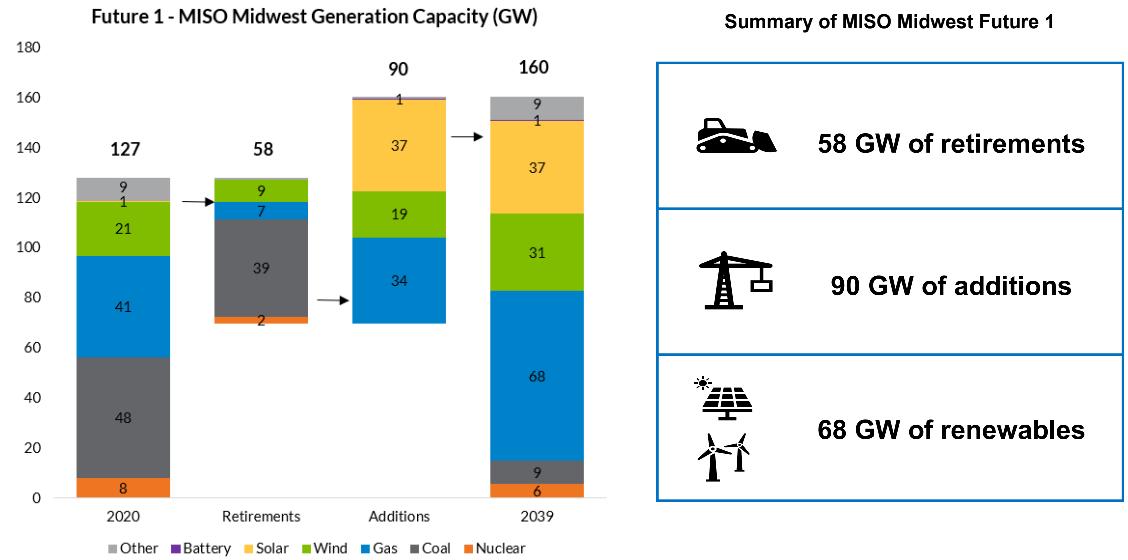


Figure 5-3: Future 1 changes in Generation Capacity for Midwest Subregion

In Futures 2 and 3, higher levels of resource retirements and renewable resource penetration coupled with higher levels of electrification will be significant. Later tranches of LRTP will focus more on Future 2 and Future 3 scenarios.

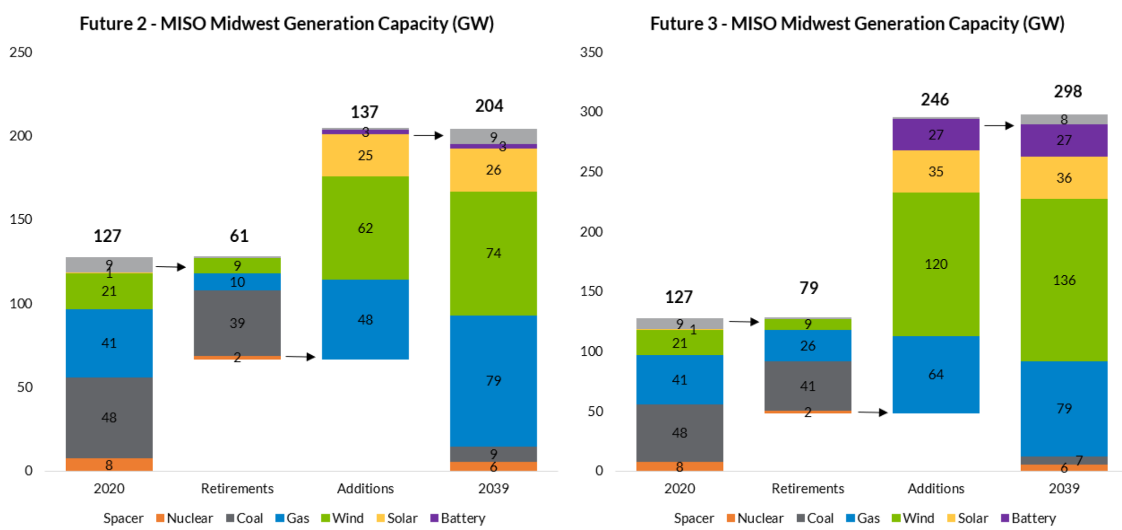


Figure 5-4: Future 2 & 3 changes in Generation Capacity for Midwest Subregion

Reliability Study Scope

MISO developed snapshots of system stress under a Future 1 resource expansion in the 10-year and 20-year timeframe. These scenarios, or base cases, vary based on season of the year, time of the day, load level, and coincident availability of renewable resources. MISO then used the scenarios to test the impact of the LRTP Tranche 1 Portfolio.

Model	Season	Hours	Range of dates and hours used to characterize the model	LRTP modeling definition of load level
1	Summer Peak	Day	Summer :6/21 to 9/20 Hours ending 7:00 to 22:00 EST	The Summer Peak demand expected to be served. (system load >=90 percentile during day)
2	Summer Peak	Night	Summer: 6/21 to 9/20 Hours NOT ending 7:00 to 22:00 EST	The Summer Peak demand expected to be served (system load >=90 percentile during night)
3	Fall/Spring Light load	Day	Fall: 9/21 to 12/20 Spring: 3/21 to 6/20 Hours ending 8:00 to 21:00 EST	Fall / Spring Light load within 50-70% of Summer Peak (Day)
4	Fall/Spring Light load	Night	Fall: 9/21 to 12/20 Spring: 3/21 to 6/20 Hours NOT ending 8:00 to 21:00 EST	Fall / Spring Light load within 50-70% of Summer Peak (Night)
5	Fall/Spring shoulder load	Day	Fall: 9/21 to 12/20 Spring à 3/21 to 6/20	70% to 80% of the Summer Peak Load (Day)
6	Winter Peak	Day	Winter: 12/21 - 3/20 Hours ending 8:00 to 19:00 EST	The Winter Peak demand expected to be served (system load >=90 percentile during day)
7	Winter Peak	Night	Winter: 12/21 - 3/20 Hours NOT ending 8:00 to 19:00 EST	The Winter Peak demand expected to be served (system load >=90 percentile during night)

Table 5-1: Temporal and load parameters for defining base models

The purpose of the reliability study is to ensure the MISO Transmission System can reliably deliver energy from future resources to future loads under a range of projected load and dispatch patterns associated with the Future 1 scenario in the 10-year and 20-year time horizon. The analysis includes ensuring transmission system performance is reliable and adequate with both an intact system and one where contingencies have occurred, and high regional power transfer scenarios that result when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty. Techniques used to analyze projected performance with and without the proposed transmission solutions included steady state contingency analysis to identify thermal loading and voltage issues under normal and contingency conditions, transfer analysis to ensure MISO can rely upon geographic diversity to manage renewable dispatch volatility and uncertainty and voltage stability analysis to ensure voltage stability in the Midwest subregion.

Steady-state contingency analysis is performed to identify any thermal and voltage violations that exist in the seven base reliability cases for each of the 10-year and 20-year models. The analysis requires simulation of the MTEP20 NERC Category P0, P1, P2, P4, P5, and P7 contingency events and selected NERC Category P3, P6 events. Facilities in the Midwest Subregion were monitored for steady state thermal loading in excess of 80% of applicable ratings and for voltage violations per the Transmission Owner voltage criteria.

Transfer analysis is performed to test for robust performance under varying dispatch patterns. The LRTP transfer study includes eight transfer scenarios to assess import requirements in situations where unexpected loss of renewable and thermal resources could occur due to changing weather conditions.

Scenario	Description	Objective	Resource	Sink
1	Central to Iowa	Support resource deficient areas due to unexpected drops in high concentration areas of renewables	All Gen. Local Resource Zones (LRZ) 4-6	Wind in LRZs 1&3
2	MISO to Michigan	Support resource deficient areas due to unexpected drops in high concentration areas of renewables	Renewables in LRZs 1-6	Renewable in LRZ 7
3	Michigan to MISO	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	Renewables in LRZ 7	Renewables in LRZs 1-6
4	Iowa/MN to MH	Support resource deficient areas due to unexpected high magnitude resource outages due to extreme weather events (Uri, polar vortex) – renewable or thermal	Renewables in LRZs 1 and 3	Manitoba Hydro load
5	MISO West to Wisconsin	Support resource deficient areas due to unexpected high magnitude resource outages due to extreme weather events (Uri, polar vortex) – renewable or thermal	Renewables in LRZs 1 and 3	Renewables in LRZ 2
6	Central Renewables to rest of MISO Midwest	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	Renewables in LRZs 4-6	Gen. in LRZs 1,2,3,7
7	MISO Midwest to Central Region	Ensure reciprocal export capability to MISO Subregions in high resource deficiencies	Gen. in LRZs 1,2,3,7	Gen. in LRZs 4-6
8	MISO West to East across the Mississippi	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	MISO West of the Mississippi River Renewables in LRZs 1,2,3,5	MISO East of the Mississippi river Gen. in LRZs 4,6,7

Table 5-2: Transfer Scenarios

Economic analysis supports reliability analysis evaluation of project candidates as needed for selecting the preferred solutions. Production cost simulations analyze the impact of the proposed project on production costs to assess how the economic performance of a project compares to other alternatives that have been proposed. These results are used to supplement the reliability analysis results and provide an additional measure of economic performance to aid in selecting the preferred solution.

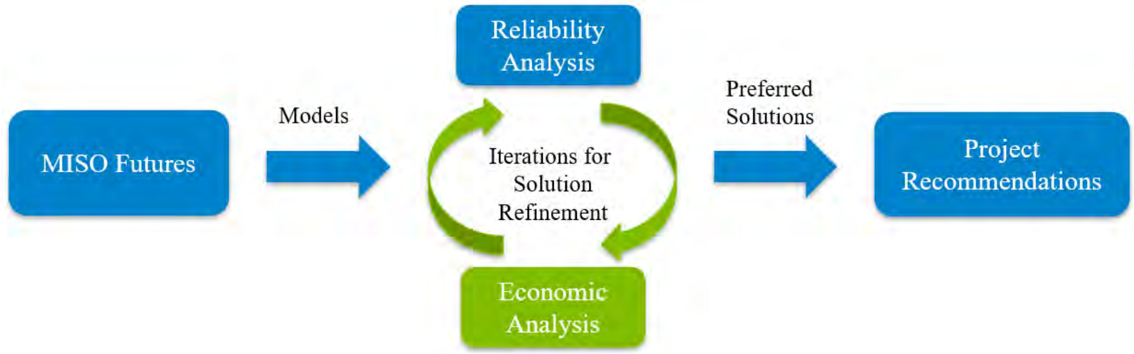


Figure 5-5: Iterative Solution Refinement

The results of the reliability analysis contained in Section 6 of this report discusses the detailed results from this iterative selection process and explains the reasons for selecting the preferred solution, including a summary of any significant economic analysis findings, for projects to be included in the LRTP Tranche 1 Portfolio.

6 LRTP Tranche 1 Projects and Reliability Issues Addressed

The reliability studies were performed on the Future 1 power flow models to assess the system performance and identify any necessary upgrades to ensure reliable energy delivery under different load and dispatch patterns. Analysis of the Future 1 10-year and 20-year base case models without the LRTP Tranche 1 Portfolio indicated numerous thermal and voltage violations throughout the Midwest Subregion. Additionally, transfer analysis was performed to assess transfer capability and identify limiting constraints to be addressed to assess effectiveness of projects under broader future assumptions. Variations of candidate projects identified in the LRTP indicative roadmap were studied to determine areas of focus for project development.

It is important to understand that LRTP is not a NERC compliance study whereby every issue identified must be resolved according to NERC standards and requirements. A NERC compliance study, which is more local in nature in terms of modeling assumptions, is different than the approach taken in a long-range transmission planning study. From that perspective, the LRTP reliability solution testing sought to find solutions that provided a balance between issues resolved and cost to mitigate. This included discounting some issues, for example, as more local in nature or others that will be dealt with in the generator interconnection process. It is also related to the fact that more study work will be done in the next tranches using other Futures and additional needs will be dealt with at that time.

In doing so, MISO used the roadmap as a starting point for testing system solutions but also looked to alternative solutions either from MISO or submitted by stakeholders. Several alternatives have been considered for the Tranche 1 effort. The final portfolio represents those solutions that provided the best fit solution. It is also important to note that the ability to efficiently use existing corridors in developing transmission is a key element. As final solutions were developed, the ability of those solutions to use existing system right of way was a key consideration. Ultimately though final routing will be determined by the applicable state and/or local authorities.

Project selection involved detailed analysis in five geographic focus areas:

- Dakotas and Western Minnesota
- Minnesota – Wisconsin
- Central Iowa
- Northern Missouri Corridor
- Central-East Corridor

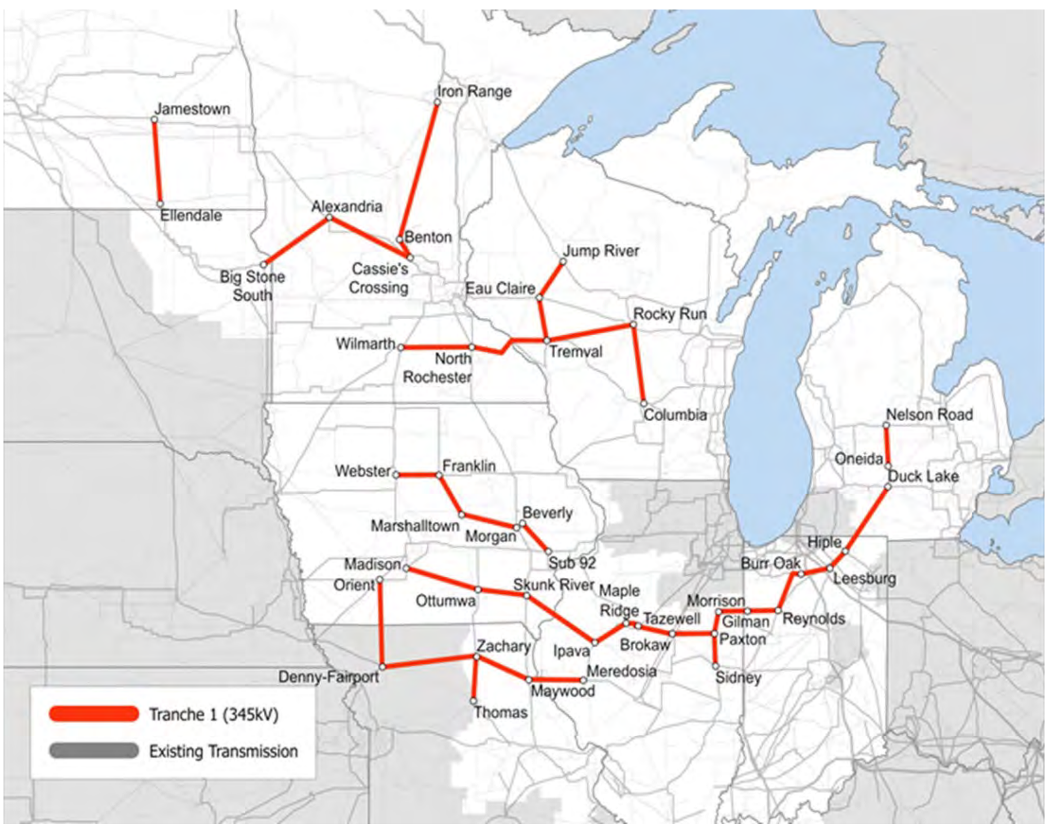


Figure 6-1: LRTP Tranche 1 Transmission Portfolio

Dakotas and Western Minnesota

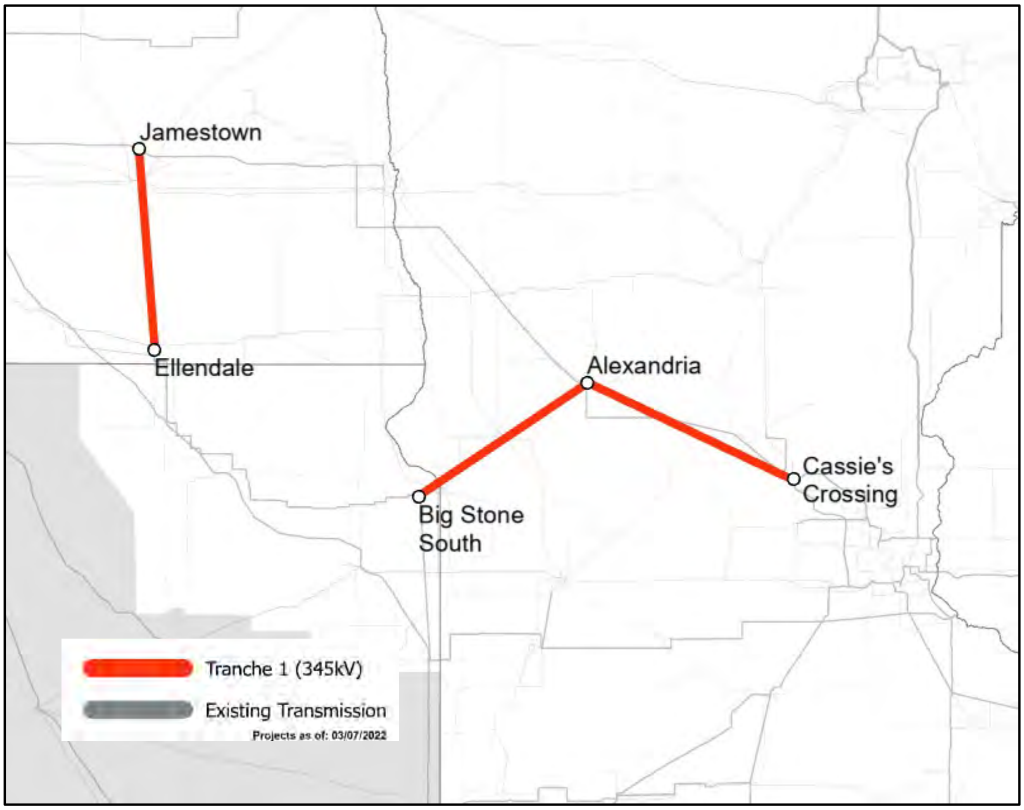


Figure 6-2: Dakotas and Western Minnesota Final Solution

Projects:
Jamestown - Ellendale 345 kV
Bigstone – Alexandria – Cassie's Crossing 345 kV

Rationale:
The Eastern Dakotas and Western/Central Minnesota 230 kV system is heavily constrained for many different seasons through the year. This 230 kV system has been playing a key role in transporting energy across a large geographical area as generation is needing to be transported out of the Dakotas and into Minnesota. Under shoulder load levels and high renewable output, this energy has a bias towards the Southeast into the Twin Cities load center. During peak load, particularly in Winter, this system is a key link for serving load in central and northern Minnesota. The 230 kV system is at capacity and shows many reliability concerns not only for N-1 outages in Future 1, but also for system intact situations. The 345 kV lines in the area provide additional outlets for the Dakotas by tying two existing 345 kV systems together. These lines unload the 230 kV system of concern and improve reliability across the greater Eastern Dakotas and Minnesota.

Issues Addressed:

The Dakotas and Western Minnesota project addresses many thermal and voltage issues for Western Minnesota and Eastern Dakotas. Most notable, the 230 kV system from Ellendale and Big Stone South to Fergus Falls is relieved for all N-1 and N-1-1 outages, as you can see in Figure 6-3 geographically. The solid green lines in Figure 6-3 depict Transmission Lines which no longer have overloads because of the project with circles depicting transformers that are relieved. Voltage depression was seen for a wide geographical area along the South Dakota, North Dakota, and Minnesota border typically described as the Red River Valley Area. Table 6-1 describes overloads seen in Future 1 for the Dakotas and Western Minnesota area which are relieved by the Big Stone South – Alexandria – Cassie's Crossing & Jamestown – Ellendale project. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

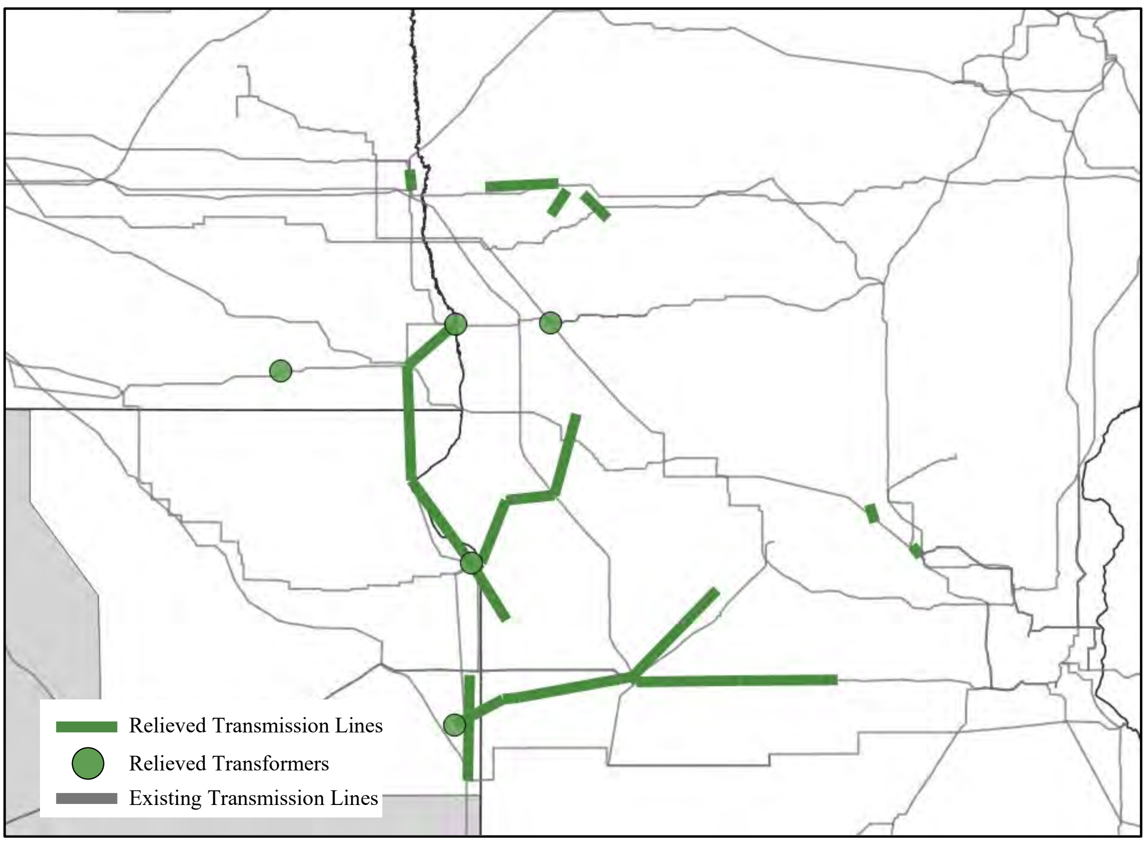


Figure 6-3: Dakotas and Western Minnesota map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	40	214	70	209
230 kV Lines	18	157	25	153

Table 6-1: Elements with thermal issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Minimum p.u. voltage Pre-Project	Count Elements	Minimum p.u. voltage Pre-Project
All	97	0.80	91	0.81
345 & 230 kV Buses	23	0.80	30	0.81

Table 6-2: Elements with voltage issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases for the OTP area (620)

Alternatives Considered:
Big Stone South – Alexandria 345 kV & Jamestown – Ellendale 345 kV
Without double circuit to Cassie's Crossing there are new N-1 issues around Alexandria.

Big Stone South – Hankinson – Fergus Falls 345 kV & Jamestown – Ellendale 345 kV
Solves overloads of concern on 230 kV system around Wahpeton but creates new issues on the 230 kV and 115 kV system around Fergus Falls.

Big Stone South – Hazel Creek – Blue Lake 345 kV & Jamestown – Ellendale 345 kV
Reduces nearly all overloads of concern but not to the extent of the preferred project.

Big South – Alexandria 345 kV & Big Stone South – Hazel Creek – Blue Lake 345 kV & Jamestown – Ellendale 345 kV.
Combination of alternative 1 and 3. This alternative creates new overloads on the 115 kV system around Alexandria but fully relieves reliability issues of concern as the preferred project. However, as this is a combination of alternatives, the southern circuit to Blue Lake (Alternative 3) does not add enough additional value over the preferred project.

Big Stone South – Breckenridge – Barnesville 345 kV & Jamestown – Ellendale 345 kV
Solves many issues in the area of concern without any new issues. However, there are still a few key overloads on the key 230 kV system around Wahpeton which are not solved by this alternative.

Western Minnesota - Dakota

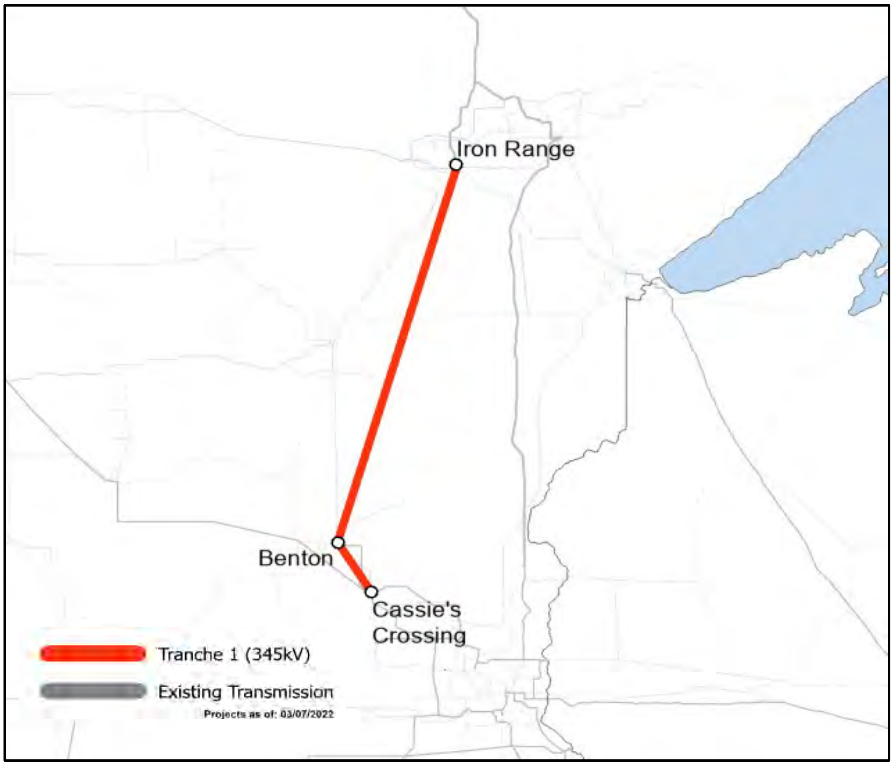


Figure 6-4: Western Minnesota - Dakota Final Solution

Project:
Iron Range – Benton - Cassie's Crossing 345 kV

Rationale:
Minnesota has and is projected to continue to undergo fleet change. This generation shift has resulted in central and northern Minnesota to have a drastic decrease in generation resources creating a large geographical area to be served by only 115 kV and 230 kV transmission. Central to northern Minnesota has moderate load, with heavy load being further north relating to iron mining operations. During the winter, Minnesota load increases significantly. This causes strain on the widespread 115 kV and 230 kV system as power is needing to get from the twin cities to the north to serve load. This large geographical disparity in generation and weak transmission causes voltage stability concerns for a majority of the Minnesota system north of the Twin Cities. The Iron Range – Benton – Cassie's Crossing 345 kV line provides a second low impedance path for power flow from southern Minnesota to the north. This unloads and relieves the 115 kV and 230 kV issues seen and relieves voltage stability concerns.

Issues Addressed:
Iron Range – Benton – Cassie's Crossing 345 kV prevents many thermal and voltage issues on the lower voltage system in central and northern Minnesota, especially for situations where the single 500 kV line heading north from the Twin Cities is lost. Under heavy winter loading situations central and northern Minnesota suffer from voltage collapse issues during transfer scenarios.

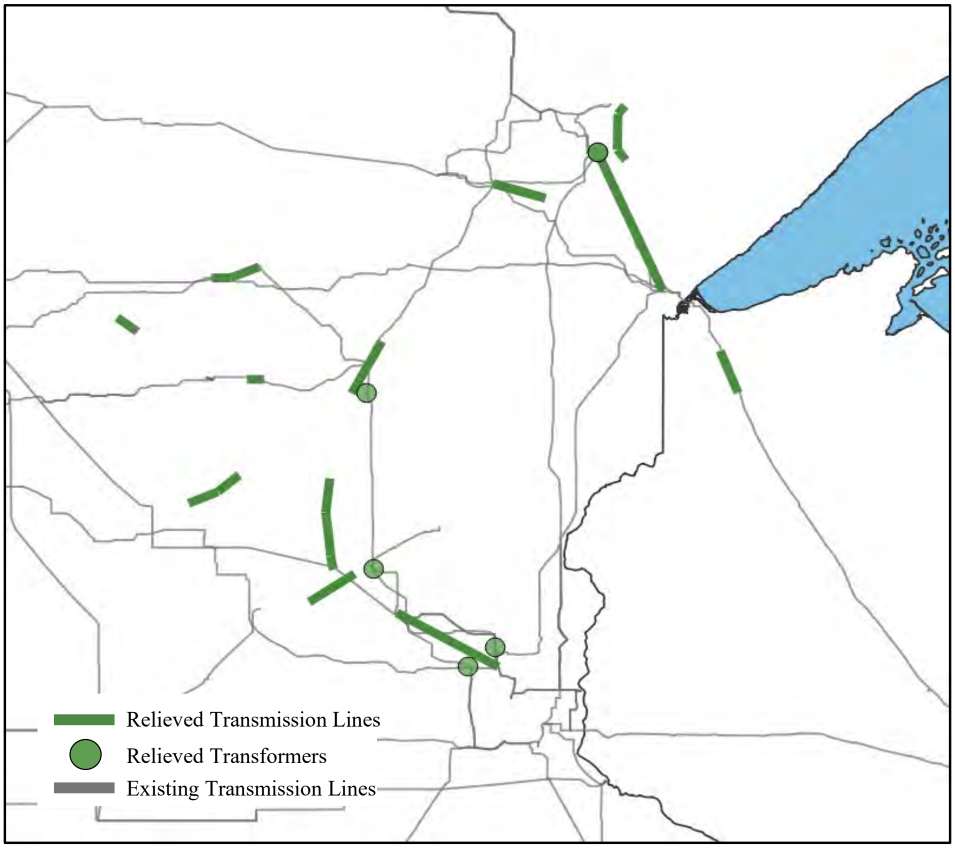


Figure 6-5: Central and Northern Minnesota map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

The chart below is a graph of the Red River Valley area (northwestern Minnesota) voltage after loss of the 500 kV line from Chisago to Forbes for varying levels of transfer to the north through Minnesota. Without Iron Range – Benton – Cassie's Crossing voltage collapses for transfers less than 500 MW. Post project, transfers through Minnesota can be greater than 2000 MW without voltage collapse.

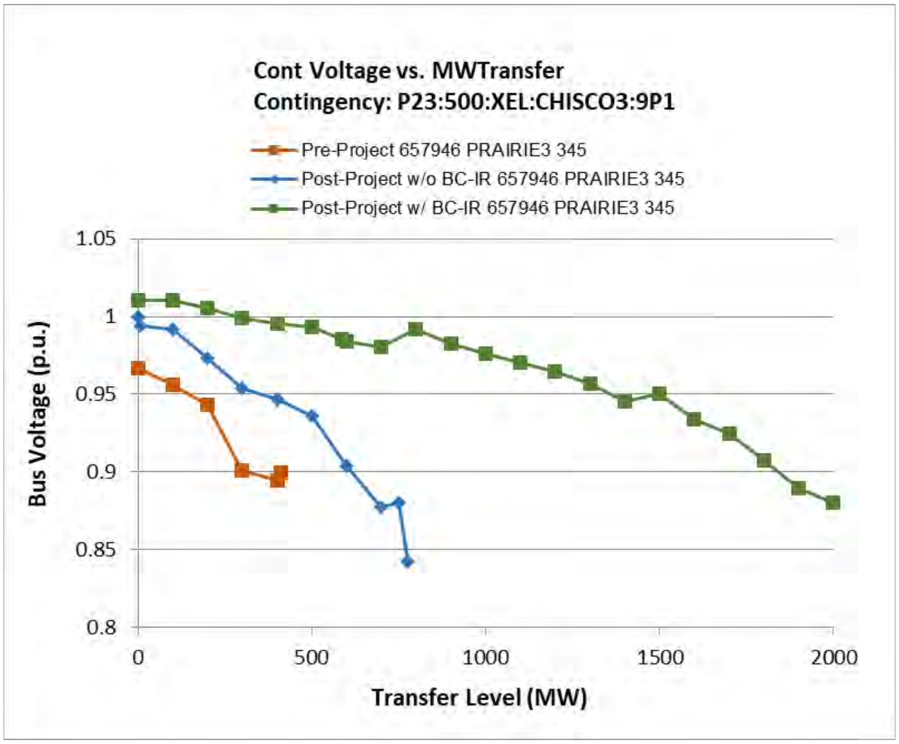


Figure 6-6: Voltage Stability Analysis P-V curve for Minnesota transfers after losing the 500 kV lines from Chisago to Forbes

The tables below describe thermal and voltage issues relieved by the Iron Range to Benton to Cassie's Crossing 345 kV line. Figure 6-5 shows geographically lines and transformers relieved by the project. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	15	110	25	165

Table 6-3: Summary of elements relieved by the Minnesota – Wisconsin projects in Future 1 power flow cases.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Minimum p.u. voltage Pre-Project	Count Elements	Minimum p.u. voltage Pre-Project
All	23	<0.80	105	0.80
230 kV Buses	3	0.93	18	0.85

Table 6-4: Elements with voltage issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases for the MP area (608).

Alternatives Considered:

1. Iron Range – Alexandria 500 kV
2. Iron Range – Arrowhead 500 kV
3. Iron Range – Bison 500 kV
4. Iron Range – Benton 500 kV

A study interface was created to analyze alternatives to the Iron Range – Benton – Cassie's Crossing line. This interface is defined as the northern Minnesota interface (NOMN) which includes the Forbes – Chisago 500 kV line and six underlying 230 kV lines which connect central and northern Minnesota to the Twin cities and North Dakota. This interface was determined to study the system's ability to meet two primary goals.

1. Understand an operating limit for central and northern Minnesota to ensure the ability to serve peak load with a 10% or greater stability margin.
2. Maintain the ability to serve the existing 1400 MW Manitoba Import Limit while also achieving goal 1.

The proposed project, Iron Range – Benton County – Cassie's Crossing double circuit 345 kV meets both goals. Alternatives 1 (Iron Range – Alexandria 500 kV), 2 (Iron Range – Arrowhead 500 kV), and 3 (Iron Range – Bison 500 kV) do not achieve the above goals. Alternative 4 (Iron Range – Benton 500 kV) achieves both goals, however the double circuit 345kV was chosen for many reasons over the 500 kV as described below:

a. Double circuit 345 kV has a higher capacity
    i. 500 kV: 1732 MVA
    ii. 345 kV: 1195 MVA per circuit (2390 MVA Total)
b. Double circuit 345 kV is cheaper per mile compared to 500 kV
    i. 500 kV: $3,036,384 per mile
    ii. 345 kV: $2,829,742 per mile
c. A double circuit creates two lines for N-1 protection
d. Series compensation near Riverton would allow for easier 345/230 kV conversion for future expansion and support for central Minnesota as 345 kV to lower kV is more standard in the Minnesota area than 500 kV to lower kV transformation

Minnesota – Wisconsin

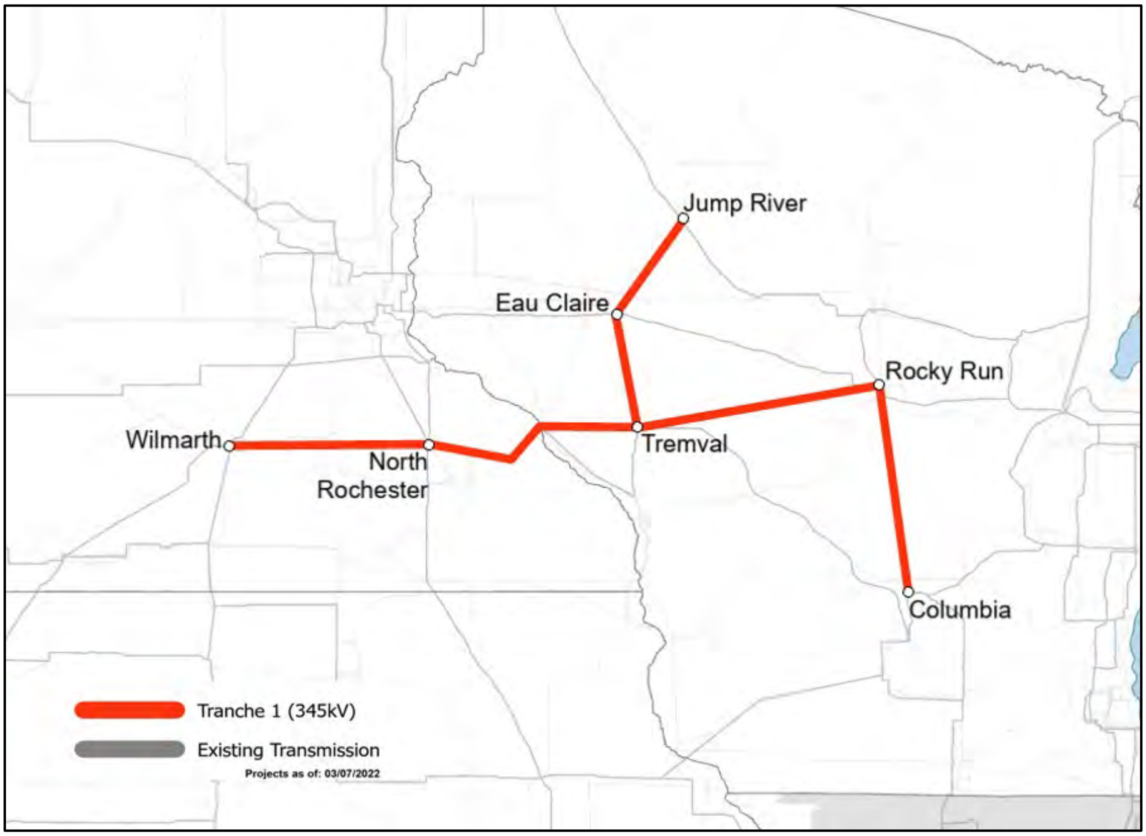


Figure 6-7: Minnesota-Wisconsin Final Solution

Projects:
Wilmarth – North Rochester – Tremval – Eau Claire – Jump River 345 kV
Tremval – Rocky Run – Columbia 345 kV

Rationale:
The transmission system in southern Minnesota is a nexus between significant wind and renewable resources in Minnesota and North and South Dakota, the regional load center of the Twin Cities, and transmission outlets to the East and South. In a future with significant renewable energy growth, MISO sees strong flows West to East across Minnesota to Wisconsin and a need for outlet for those renewables in times of high availability to deliver that energy to load centers in MISO. The Minnesota to Wisconsin projects relieve constraints in the Twin Cities metro area due to high renewable flow towards and past the Twin Cities load center. The projects also reinforce the outlet towards load centers in Wisconsin, providing relief of congestion as well as easing both thermal loading and transfer voltage stability.

Issues Addressed:
The Minnesota – Wisconsin series of projects work together to relieve a number of related issues. Table 6-5 summarizes overloads seen in the Future 1 models which are relieved by the LRTP Tranche 1 Portfolio attributed to the Minnesota – Wisconsin set of projects. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Those same elements are shown on a map in Figure 6-8.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	39	95-132%	96	95-151%
345 kV Lines	6	98-119%	9	97-120%
345/xx kV Transformers	9	97-132%	12	95-132%

Table 6-5: Summary of elements relieved by the Minnesota – Wisconsin projects in Future 1 power flow cases

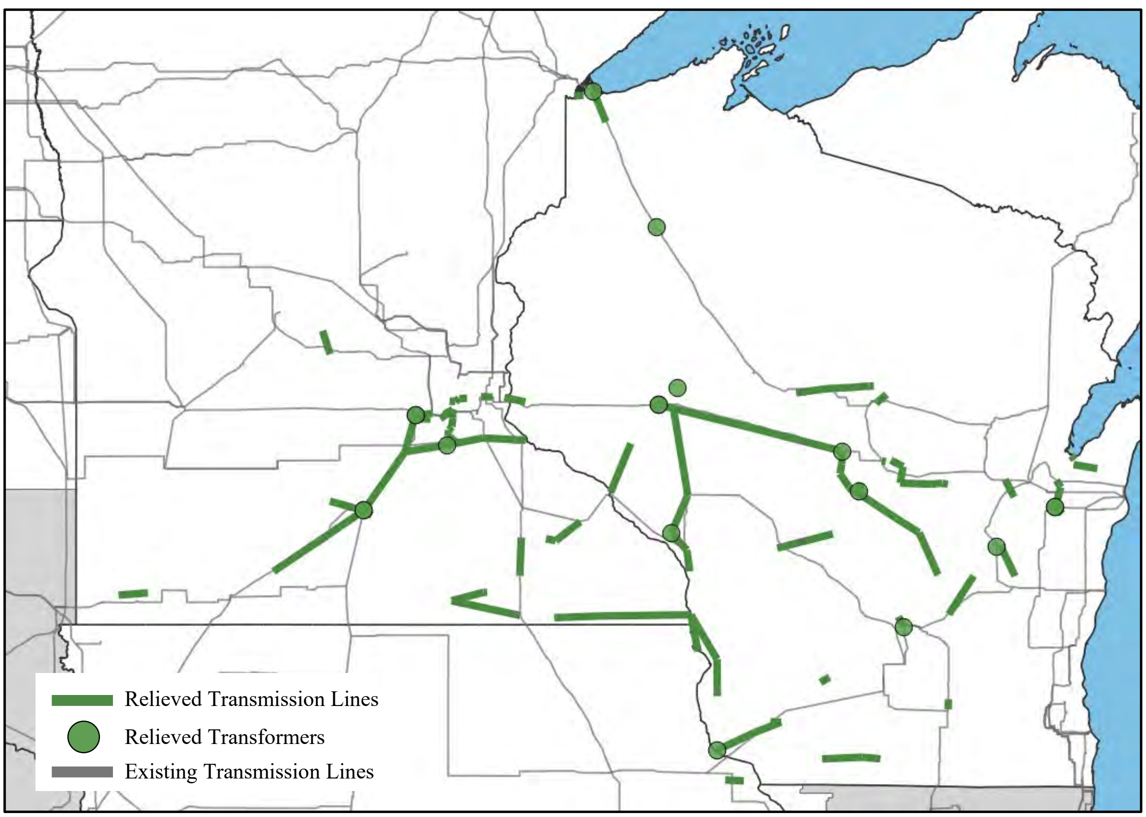


Figure 6-8: Map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Wilmarth to North Rochester parallels a number of 345 kV lines across the Southern Twin Cities that are heavily loaded under high renewable output from southwestern Minnesota and northwestern Iowa. In doing so, it relieves several 345 kV lines and 345/115 kV transformers in the region including Wilmarth – Shea's Lake – Helena – Chub Lake 345 kV and 345/115 kV transformers at Wilmarth and Scott County. These increased flows cause new congestion and overloads on the existing Crandall – Wilmarth 345 kV line. This project includes the rebuild of that line. If uprated, the congestion savings associated with the Wilmarth – North Rochester circuit specifically, and the rest of the Minnesota – Wisconsin project generally, increase significantly.

The connection out of North Rochester towards Tremval and east creates a lower impedance path that pulls power across Wilmarth – North Rochester and diverts power from other heavily loaded Twin Cities facilities, increasing the efficacy of that line. The sections from Tremval to Eau Claire and Jump River relieve loading on a handful of 161 kV and 115 kV facilities in Northwest Wisconsin. Those facilities increase the redundancy of the two Northern 345 kV circuits across Wisconsin and relieve overloads seen on one of the Eau Claire 345/161 kV transformers.

The new path from Tremval to Rocky Run to Columbia completes an outlet for renewable power flow across Wisconsin to the Madison and Milwaukee area load centers. These circuits also bolster voltage stability limited transfer capability across and into Wisconsin. It also relieves overloads on a variety of 345 kV and 138 kV facilities throughout central Wisconsin.

The traditional analysis of voltage stability for the voltage stability interface across Western Wisconsin uses a load to load transfer. MISO performed this analysis for a transfer using Local Resource Zone 2 (LRZ2, roughly comprised of ATC member companies in eastern and central Wisconsin) as the destination subsystem, to capture the impact of directly serving LRZ2 load. MISO measured the impact to voltage stability both with and without Tremval – Rocky Run and Rocky Run – Columbia segments are included in this project. The addition of these facilities adds 250 MW to the transfer capability. Figure 5-9 shows the post-contingent bus voltage for the most limiting bus and outage for either the pre-project or post-project case. Those buses and outages are:

Eau Claire 345 kV for loss of King – Eau Claire 345 kV
Eau Claire 345 kV for loss of Stone Lk. – Gardner Pk 345 kV
Briggs Rd. 345 kV for loss of Stone Lk. – Gardner Pk 345 kV

Both the steady state voltages and the final nose of the stability curve can be seen to improve, with the increase measured from either point being approximately 250 MW. MISO also reviewed this analysis for scenarios using a wide area load subsystem consisting of both Wisconsin load and loads further East in MISO's system. Those cases also showed an approximate increase of 250 MW in the low voltage and voltage stability limits of the system.

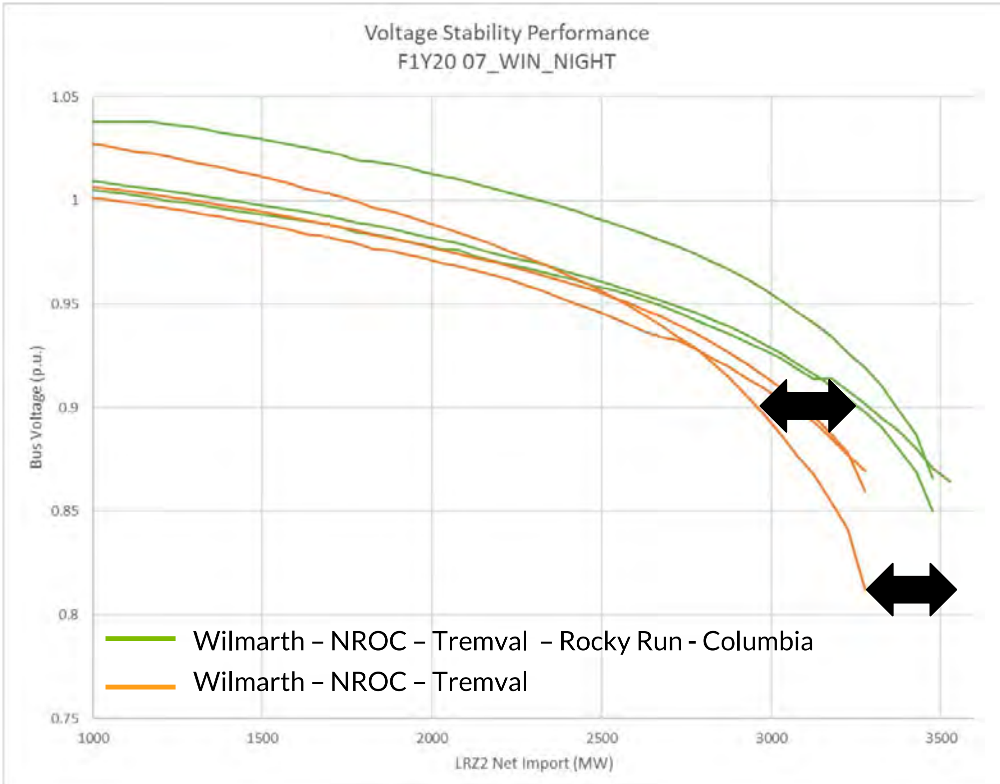


Figure 6-9: Voltage performance for key buses and outages for transfers into LRZ2. Orange lines indicate buses and outages with just Wilmarth – North Rochester – Tremval 345 kV, while green lines indicate performance with Tremval – Rocky Run – Columbia 345 kV included as well

System Design Benefits of Tremval – Eau Claire – Jump River

To date there are three 345 kV lines that connect Minnesota to Wisconsin. The lines and their lengths are listed below:

Arrowhead – Stone Lake - Gardner Park:	220 Miles
King – Eau Claire – Arpin - Rocky Run:	183 Miles
North Rochester – Briggs Road – North Madison:	250 Miles

Assuming an average Surge Impedance Loading (SIL) value of approximately 400 MW for legacy 345 kV lines such as the ones above, the Safe Loading Limits on these three 345 kV long lines based on the St. Clair curve would be as follows:

Arrowhead – Stone Lake - Gardner Park:	460 MW
King – Eau Claire – Arpin - Rocky Run:	560 MW
North Rochester – Briggs Road – North Madison:	440 MW

Safe Loading Limits[3] were proposed to avoid or mitigate excessive operating risks by limiting the voltage drop along a transmission circuit to 5% or less while maintaining a Steady State Stability Margin of 30% or greater along the transmission circuit. The excessive 345 kV line lengths between Minnesota and Wisconsin result in safe loading limits for these 345 kV lines well below the thermal limits of the lines. Even more alarming is the fact that under an N-1 contingency, the combined Safe Loading Limit on the 345 kV MWEX lines would fall from 1,460 MW to 900 MW, and for an N-2 contingency, the combined Safe Loading Limit on the 345 kV MWEX lines would fall to 440 MW.

The addition of the fourth 345 kV circuit from Minnesota – Wisconsin will significantly improve the situation above by adding additional transmission capacity across MWEX. In the case of a North Rochester – Rocky Run line, the length and Safe Loading Limit of this additional 345 kV line would be as follows:

North Rochester – Rocky Run 345 kV Mileage:	162 – 187 Miles
North Rochester – Rocky Run Safe Loading Limit:	540 MW – 600 MW

While the fourth 345 kV circuit adds considerable benefit, for an N-2 contingency with the fourth 345 kV circuit added, the combined safe loading limit of the 345 kV circuits falls to about 900 MW.

An effective method to strengthen the four parallel 345 kV circuit is to add an intermediate connection between the four 345 kV circuits as close to the midpoint as possible. A major benefit of the Tremval 345 kV Substation and the Tremval – Eau Claire – Jump River 345 kV line is that under contingency conditions, the overall reduction in the combined Safe Loading Limit of the parallel 345 kV circuits is minimized. For example, for a loss of the Eau Claire – Arpin 345 kV circuit, a 345 kV connection remains between the King - Eau Claire 345 kV circuit, and the other three 345 kV lines across the MWEX interface. This not only mitigates loading issues on the transformers at Eau Claire, but also reduces the effective 345 kV impedance across the MWEX interface, which in turn increases the capacity and combined safe loading limit of the MWEX interface. In addition, because the King – Eau Claire 345 kV circuit is still connected at the midpoint of the MWEX interface, the distributed line capacitance associated with the King – Eau Claire 345 kV circuit is available to support voltages in western Wisconsin. Lower overall impedance coupled with higher distributed capacitance means a higher effective SIL for the MWEX interface under contingency conditions.

In summary, there are desirable benefits of tying together long lines at an intermediate point, and there are examples of this technique throughout North America. These types of system design benefits will be crucial to the success of the future transmission system to operate with reliability,

[3] Dunlop, R.D., Gutman, R., Marchenko, P.P., *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-98, No. 2, March/April 1979.

robustness, and resilience under a future with higher renewable generation penetration and electrification.

Alternatives Considered:

MISO reviewed a wide variety of project alternatives in the project focus area between Minnesota and Wisconsin – many of them submitted by stakeholders.

MISO began by reviewing the performance of an LRTP roadmap project against identified needs. This project included Wilmarth – North Rochester – Tremval – Eau Claire – Jump River as well as a double circuit rebuild between Adams and North Rochester, and a new 345 kV line from Colby to Adams. MISO found that the Wilmarth – North Rochester segment was important for resolving Twin Cities area loading, and that the river crossing from North Rochester to Tremval and then Tremval to elsewhere in Northern Wisconsin was effective at both relieving loading across Western Wisconsin and boosting the effectiveness of Wilmarth – North Rochester by providing an outlet and a shorter electrical path towards load centers. The double circuit from North Rochester to Adams directly relieved loading on parallel facilities. Colby – Adams relieved some loading associated with a large amount of future generation sited at Adams, but the effects were very localized.

Several stakeholders submitted alternative projects along the "Southern Corridor". These included a line from Huntley to Pleasant Valley (between Adams and North Rochester), and from Adams to Genoa and Hill Valley. One stakeholder also submitted Colby – Adams as an alternative. MISO reviewed the performance of Huntley – Pleasant Valley and Colby – Adams as alternatives to the Wilmarth – North Rochester line. Colby – Adams by itself is not effective at reducing the West to East loading across Southern Twin Cities 345 kV facilities and shows little reliability value on its own. Huntley – Pleasant Valley, when combined with a double circuit rebuild between Pleasant Valley and North Rochester, resolved many but not all of the same 345 kV and 345 stepdown transformer overloads as Wilmarth – North Rochester. It also showed higher adjusted production cost savings when included in PROMOD simulations. However, the difference in production cost savings was less than the difference in increased cost of Huntley-Pleasant Valley to North Rochester. MISO sees Huntley – Pleasant Valley as a valuable project that may be helpful in reinforcing this region in future cycles of the LRTP study.

Another proposed stakeholder alternative was a line from Adams to Genoa and Hill Valley. MISO initially viewed this project as an alternative to North Rochester – Tremval – Jump River – Eau Claire. However, analysis showed these paths address different sets of reliability concerns, with the Adams – Genoa – Hill Valley project better addressing constraints across northeast Iowa and southern Wisconsin. When tied into Hill Valley, once the Hickory Creek – Hill Valley line is in service, this would effectively form an additional path parallel to Adams – Hazleton 345 kV, and relieve flows being pushed south across eastern Iowa. MISO is prioritizing a northern path (North Rochester – Tremval) in order to address the voltage stability interface and tie into load centers. For that reason, MISO does not propose pursuing Adams – Genoa Hill Valley at this time, but

MISO understands the project's value, especially when paired with Huntley-Pleasant Valley, to potentially reinforcing the region in future cycles of the LRTP study.

MISO initially viewed Tremval – Eau Claire – Jump River and Tremval – Rocky Run – Columbia as alternatives to each other, specifically due to their relationship to the existing voltage stability interface. After some review, though, MISO found them to be addressing separate but complementary sets of issues. Tremval – Eau Claire -Jump River has only a minor impact to the voltage stability performance but relieves a variety of constraints across northern Wisconsin, including several sub-345 kV facilities and some high loading on one of the 345/161 kV transformers at Eau Claire. Tremval – Rocky Run – Columbia has a more significant impact on the voltage stability performance and resolves a number of thermal constraints East of Tremval and Eau Claire. That complimentary performance is what prompted MISO's recommendation of both project segments. MISO also reviewed several variations on the Tremval – Eau Claire – Jump River segment, which proposed different endpoints along either North Rochester – Briggs Rd – North Madison 345 kV or Stone Lake – Gardner Park. MISO found that a line from Alma to Eau Claire would have very similar cost and perform just as well electrically, when compared to Tremval – Eau Claire. MISO sees Tremval as a better tie-in point, due to its more easterly location with better accessibility, which would position it as a better long term hub. A line from Eau Claire to Stone Lake, in comparison to Eau Claire – Jump River, would be significantly more expensive and MISO's screening showed that it was less effective at relieving thermal loading on lines that Eau Claire – Jump River successfully unloaded.

Central Iowa

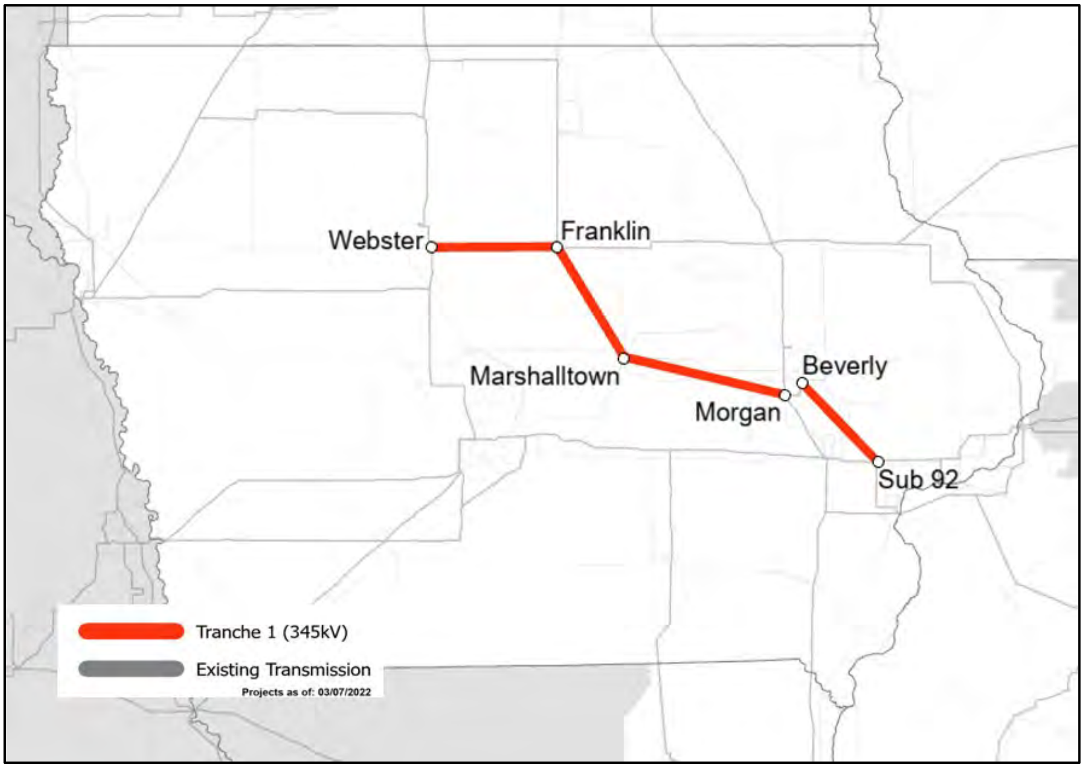


Figure 6-10: Central Iowa Final Solution

Projects:
Webster – Franklin – Morgan Valley 345 kV
Beverly – Sub 92 345 kV

Rationale:
Within MISO's system, the state of Iowa acts as both a major source of renewable energy and a gateway between MISO's members in the upper Midwest and MISO's Central planning region – Missouri, Illinois, and Indiana. Wind resources sited in Iowa are located primarily in the north and west parts of the state, and a large amount of wind resources are also located in western Minnesota and the Dakotas. During hours with high renewable output levels, power must flow southeast across and out of this region towards MISO load centers. In the LRTP models as well as in previous MISO planning studies, we have seen overloads and congestion across Iowa's central corridor. This project is intended to provide an additional 345 kV path southeast across the state, linking the high renewable region in the west with the Quad Cities load center and 345 kV outlets towards the rest of MISO. In doing so, we form a corridor both west-east and north-south across central Iowa.

Issues Addressed:
The Central Iowa projects between Webster and Sub 92 relieve a number of related issues. Table 6-6 summarizes overloads seen in the Future 1 models which are relieved by the LRTP Tranche 1 projects and attributed to the Central Iowa set of projects. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Those same elements are shown on a map in Figure 6-11.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	21	95-128%	34	96-132%
345 kV Lines	6	96-128%	7	97-128%
345/xx kV Transformers			4	96-127%

Table 6-6: Elements relieved by the Central Iowa projects in Future 1 power flow cases

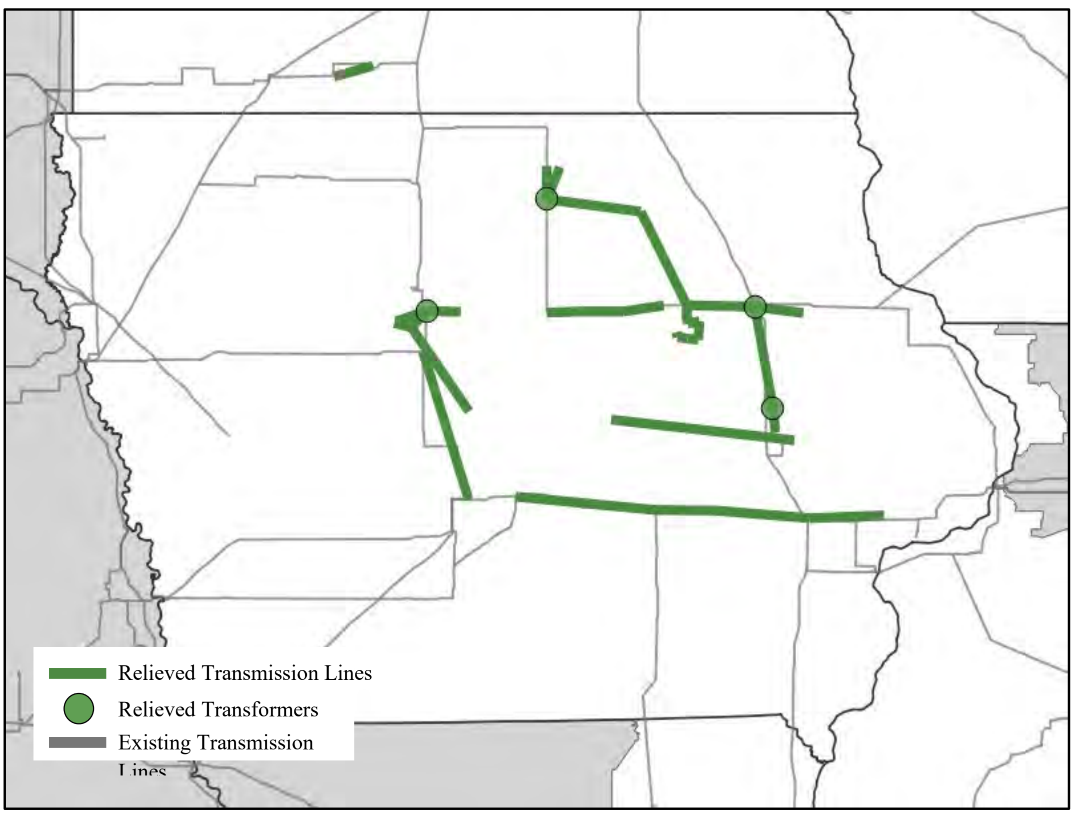


Figure 6-11: Map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Webster – Franklin – Marshalltown – Morgan Valley 345 kV forms a new connection from the 345 kV network in northwest Iowa (roughly west and north of Lehigh) to the north-south corridor across eastern Iowa (Adams – Hazleton – Hills – Maywood 345 kV). A previously approved line from Morgan Valley to Beverly stretches a few miles to the east, from which a new line can connect south from Beverly to Sub 92 345 kV. With that added segment, the overall path also completes a link from the northern 345 kV across central Iowa (Ledyard – Colby – Killdeer – Blackhawk – Hazleton 345 kV) down to a southern corridor (Bondurant – Montezuma – Hills – Sub 92 345 kV). By reinforcing the system in both directions, the project relieves loading on both west-east and north-south transmission facilities paralleling it. This loading is primarily seen in high renewable output cases, when renewable resources across western Iowa and southern Minnesota are producing high output. Lines seeing the greatest relief include Hazleton – Arnold 345 kV, Lehigh – Beaver Creek – Grimes 345 kV, and Montezuma – Diamond Trail – Hills 345 kV.

Alternatives Considered:

MISO reviewed several project alternatives and variations of the proposed central Iowa project set.

MISO began by reviewing the performance of an LRTP roadmap project against identified needs. This project included the proposed version of this project (Webster – Franklin – Marshalltown – Morgan Valley 345 kV and Beverly – Sub 92 345 kV), as well as some additional facilities. These included a new line between Marshalltown and Montezuma, with both the Franklin – Marshalltown and Marshalltown – Montezuma lines built as double circuit 345 kV. Two transformers were also sited at Franklin and Marshalltown. MISO found that the double circuit line sections did not relieve an appreciable number of additional facility overloads. MISO saw that the inclusion of a line from Marshalltown to Montezuma contributed minimal reliability benefit. Of the proposed transformers, MISO found no clear benefit to including 345/161 kV transformers at Franklin. At Marshalltown, a single 345/161 kV transformer can relieve some local loading on the lower kV system, but a second 345/161 kV transformer did not appear necessary.

MISO also reviewed a roadmap project in western Iowa that was submitted as a stakeholder alternative as well. Ida County – Avoca 345 kV would create a new line between Ida County in NW IA and a new 345 kV substation in SW Iowa adjacent to the existing Avoca 161 kV station. In comparison to the proposed project, this project was similarly successful at relieving loading on Lehigh – Beaver Creek – Grimes 345 kV and parallel facilities, but ineffective at relieving constraints east of that corridor, or generally east of the Des Moines metro area.

MISO reviewed portions of the Iowa – Michigan corridor project and the Iowa – Missouri project, in comparison to the proposed project. These facilities were not effective at relieving most of the facilities north and east of Des Moines that are relieved by the proposed project. They did relieve overloads in the Des Moines metro area and in southeastern Iowa and reduced some of the loading that the proposed project moved into southeastern Iowa. Within Iowa, MISO sees the reliability benefit of these two additional project groups as additive, in addition to the benefits of the central Iowa project.

East-Central Corridor

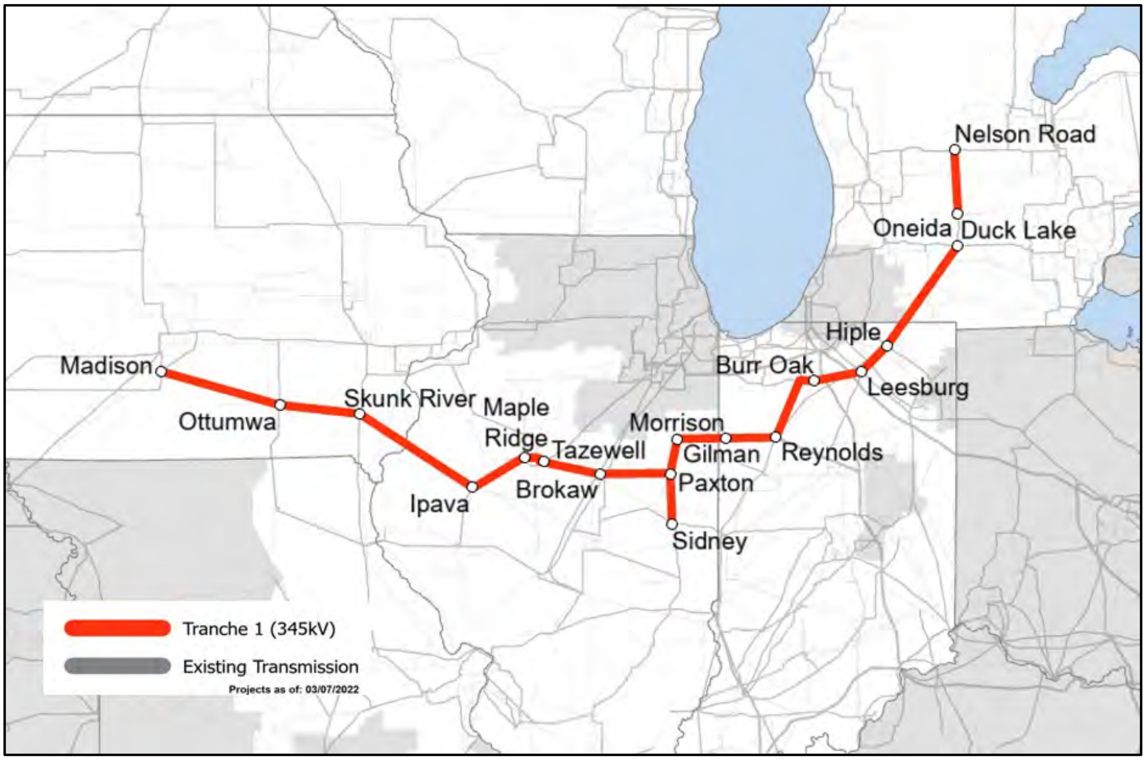


Figure 6-12: East-Central Corridor (Iowa to Michigan) Final Solution

Projects:
Madison – Ottumwa – Skunk River – Ipava – Maple Ridge 345 kV
Tazewell – Brokaw - Paxton – Gilman – Morrison – Reynolds – Hiple – Duck Lake 345 kV
Paxton – Sidney 345 kV
Oneida – Nelson Road 345 kV

Rationale:
MISO performed steady-state and voltage stability analyses on the proposed Iowa to Michigan LRTP projects. The steady-state results show the projects can mitigate severe thermal issues in Michigan, Indiana, Illinois, Missouri, and Iowa, with 77 monitored facilities addressed. The top 20 monitored facilities with worst-case contingencies are shown in Table 6-7.

The voltage stability results further demonstrate the effectiveness of the projects in improving voltage profiles and increasing transfer levels from West-East/East-West (Figures 6-14, 6-15, 6-16).

Issues Addressed:
The Iowa to Michigan projects addresses 600 thermal violations associated with 77 unique monitored facilities (Figure 6-13). For this metric, a constraint was considered relieved if its worst

pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the projects.

- 28 issues resolved in Michigan
- 16 issues resolved in Indiana
- 19 issues resolved in Missouri and Illinois
- 14 issues resolved in Iowa

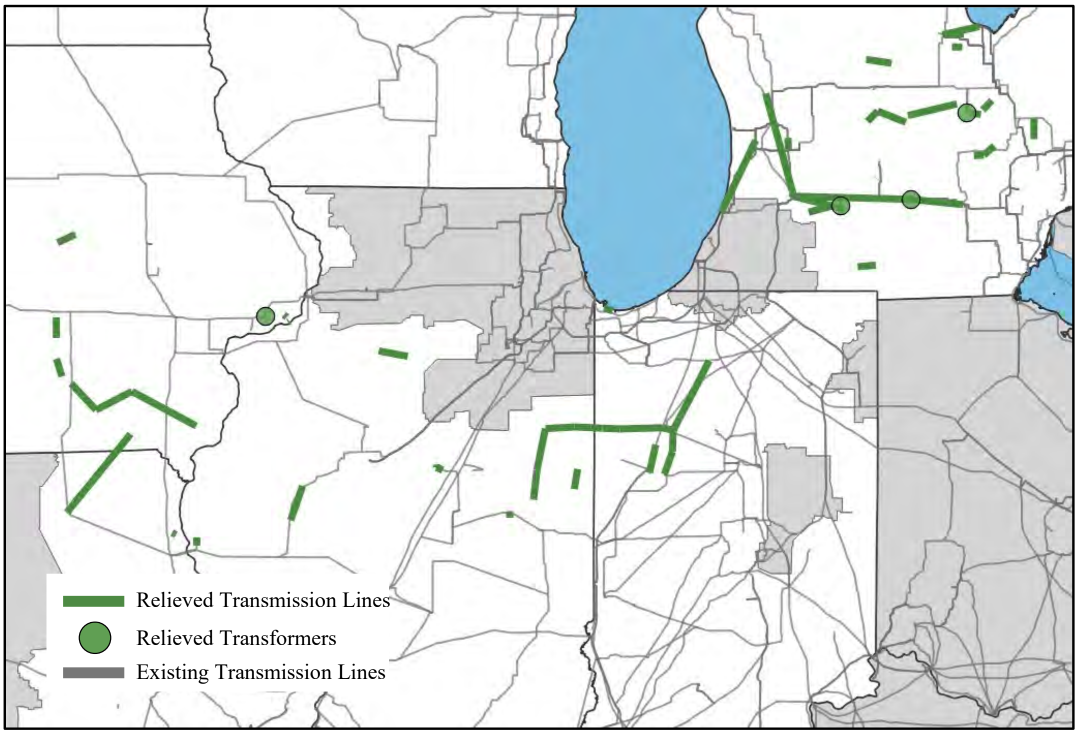


Figure 6-13: East-Central Corridor (Iowa to Michigan Line) map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

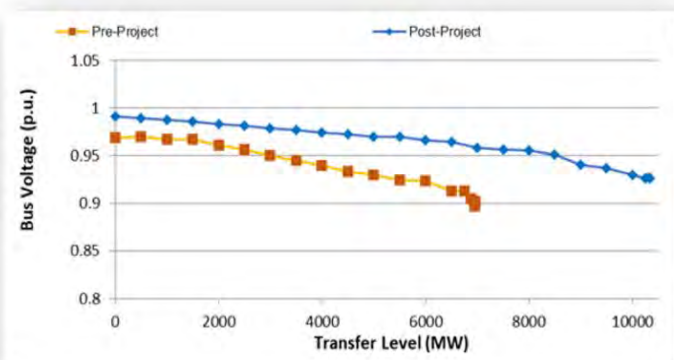
Monitored Facility	Area	% Loading: Base + West LRTP*	% Loading: + IA to MI Projects
Goodland – Reynolds 138 kV Ckt. 1	NIPS	383	< 65
Reynolds 345/138 kV Transformer	NIPS	278	86
Reynolds – Magnetation 138 kV Ckt. 1	NIPS	264	67
Monticello – Magnetation 138 kV Ckt. 1	NIPS	263	67
Springboro – Monticello 138 kV Ckt. 1	DEI/NIPS	230	72
Lafayette 2 – Springboro 138 kV Ckt. 1	DEI	186	< 65
Morrison Ditch – Sheldon South 138 kV Ckt. 1	NIPS/AMIL	181	< 65
Gilman – Paxton East 138 kV Ckt. 1	AMIL	171	< 65
East Winamac – Headlee 138 kV Ckt. 1	NIPS	163	79

Westwood – South Prairie 138 kV Ckt. 1	DEI/NIPS	163	<65
Sheldon South – Watseka 138 kV Ckt. 1	AMIL	157	< 65
Burr Oak – East Winamac 138 kV Ckt. 1	NIPS	155	72
Island Rd 138 kV Bus	METC	155	67
Ottumwa 345/161 kV Transformer	ALTW	150	96
Poweshiek – Irvine 161 kV Ckt. 1	ALTW	144	98
Monticello – Headlee 138 kV Ckt. 1	NIPS	144	< 65
Gilman – Watseka 138 kV Ckt. 1	AMIL	136	< 65
Goodland – Morrison Ditch 138 kV Ckt. 1	NIPS	135	< 65
Tompkin – Majestic 345 kV Ckt. 1	METC/ITCT	133	82
Mahomet 138 kV Bus	AMIL	127	93

*Base + West LRTP projects = Ell-Jam, BSS-Alex-Cass, MN-WI

Table 6-7: Top 20 thermal issues addressed by East-Central Corridor

Transfer levels increase and voltage profiles improve in Indiana, Missouri, and Michigan with the IA – MI projects (Figures 6-14, 6-15, and 6-16).



Pre-Project = No LRTP Projects
Post-Project = + IA to MI Line

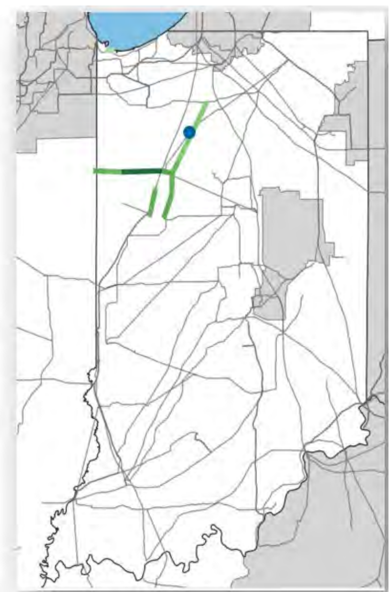


Figure 6-14: Improved voltage profiles in Indiana and Increased transfer levels with the Iowa to Michigan Projects

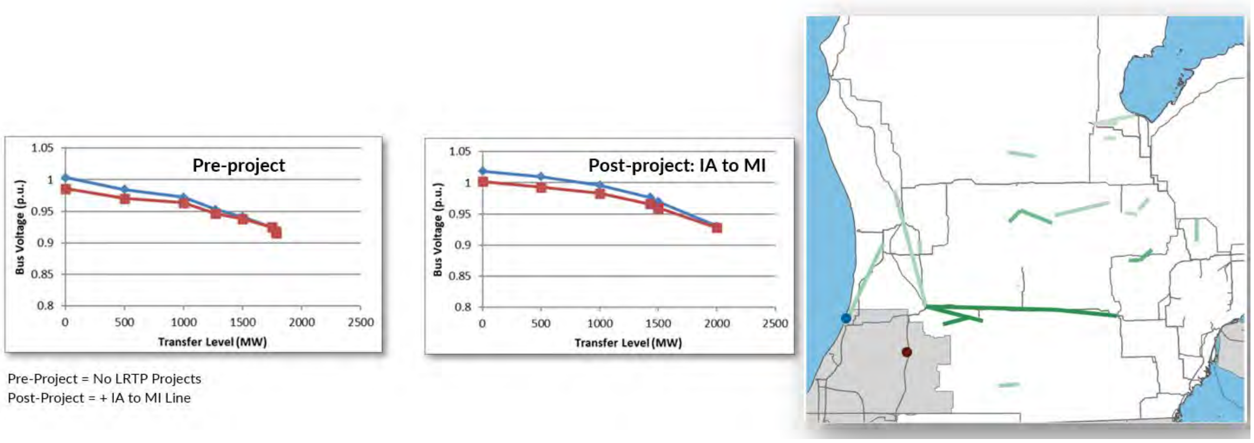


Figure 6-15: Improved voltage profiles in Michigan and Increased transfer levels with the Iowa to Michigan Projects

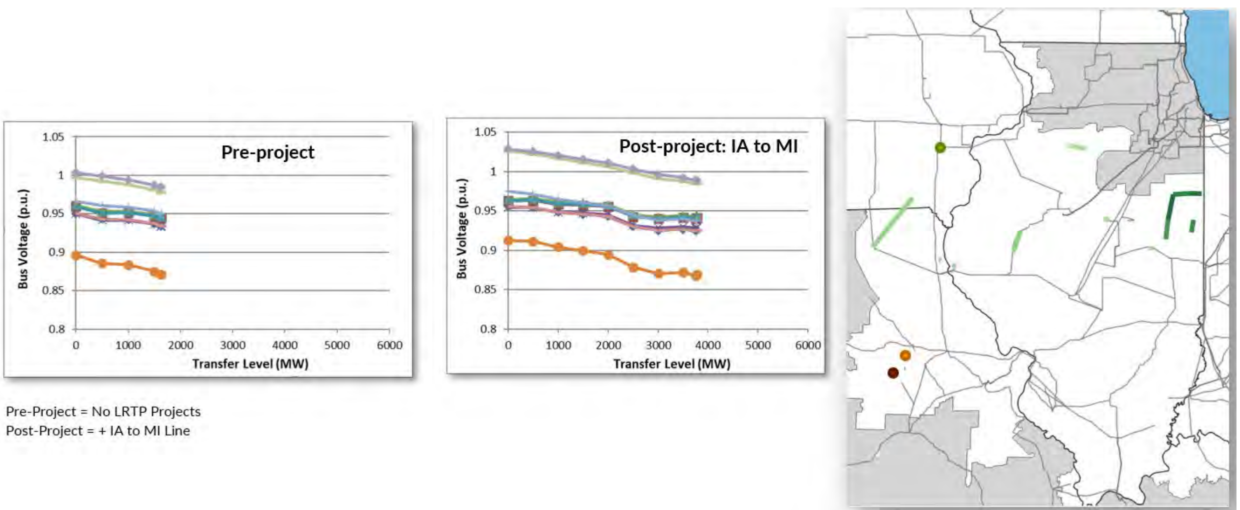


Figure 6-16: Improved voltage profiles in Missouri and Increased transfer levels with the Iowa to Michigan Projects

Alternatives Considered:
Two alternative solutions were received during the alternative submittal period, Duck Lake to Weeds Lake and Hiple to Duck Lake (MISO Main Proposal). Four additional alternatives were also evaluated. The alternative solutions resolve issues in Michigan, but fewer unsolved contingencies are associated with the road map project or MISO Main Proposal.

- Duck Lake to Weeds Lake, resolves 28 thermal issues:
- Hiple to Duck Lake (MISO main proposal), resolves 28 thermal issues
- Tie One Circuit in Argenta (resolves 28 thermal issues)
  - Argenta – Hiple
  - Argenta – Duck-Lake
- Oneida to Madrid (double-circuit), resolves 36 thermal issues
- Iowa to Indiana with Duck Lake Configuration, resolves 15 thermal issues

Northern Missouri Corridor

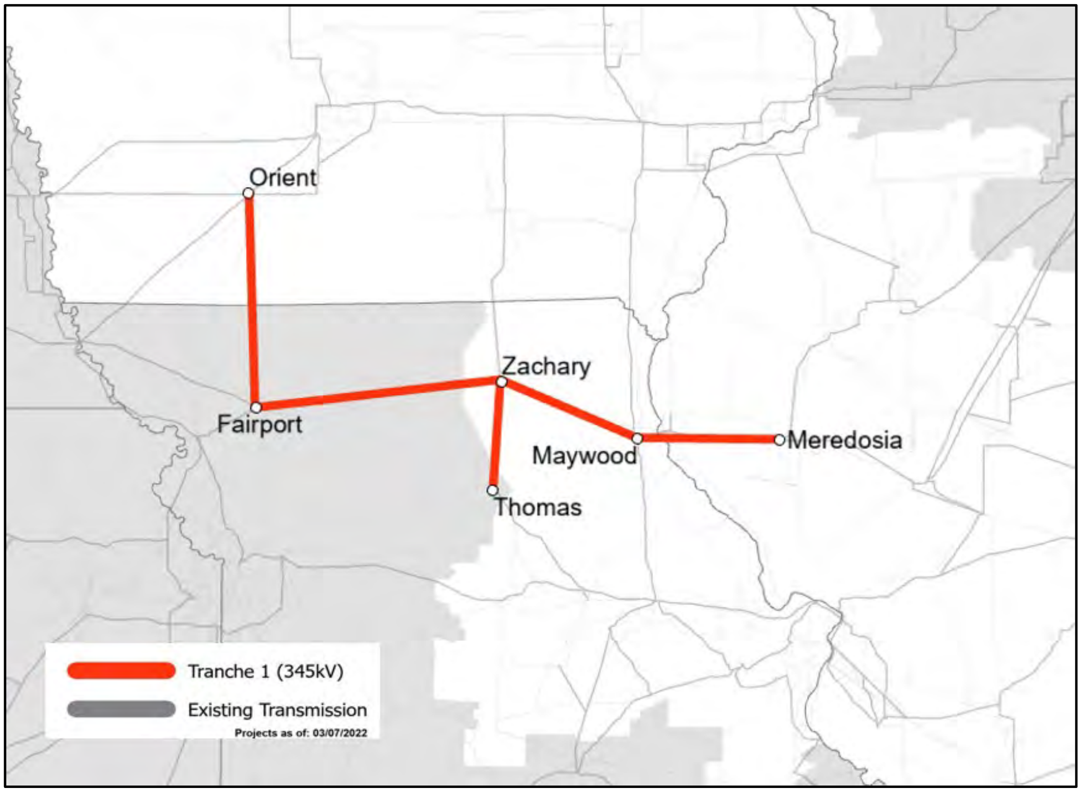


Figure 6-17: Northern Missouri Corridor Final Solution

Projects:
Orient – Fairport – Zachary – Maywood – Meredosia 345 kV
Zachary – Thomas 345 kV

Rationale:
The northern Missouri Corridor relieves loading on transmission elements in Iowa, Missouri, and Illinois. Increased transfer levels and improved voltage profiles are associated with the Missouri projects (Figure 6-17).

Issues Addressed:
The Missouri Corridor addressed thermal issues (Figure 6-18). Facilities mitigated by the Missouri Corridor are listed in Table 6-8. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

- 14 issues resolved in Missouri and Illinois
- 5 issues resolved in Iowa

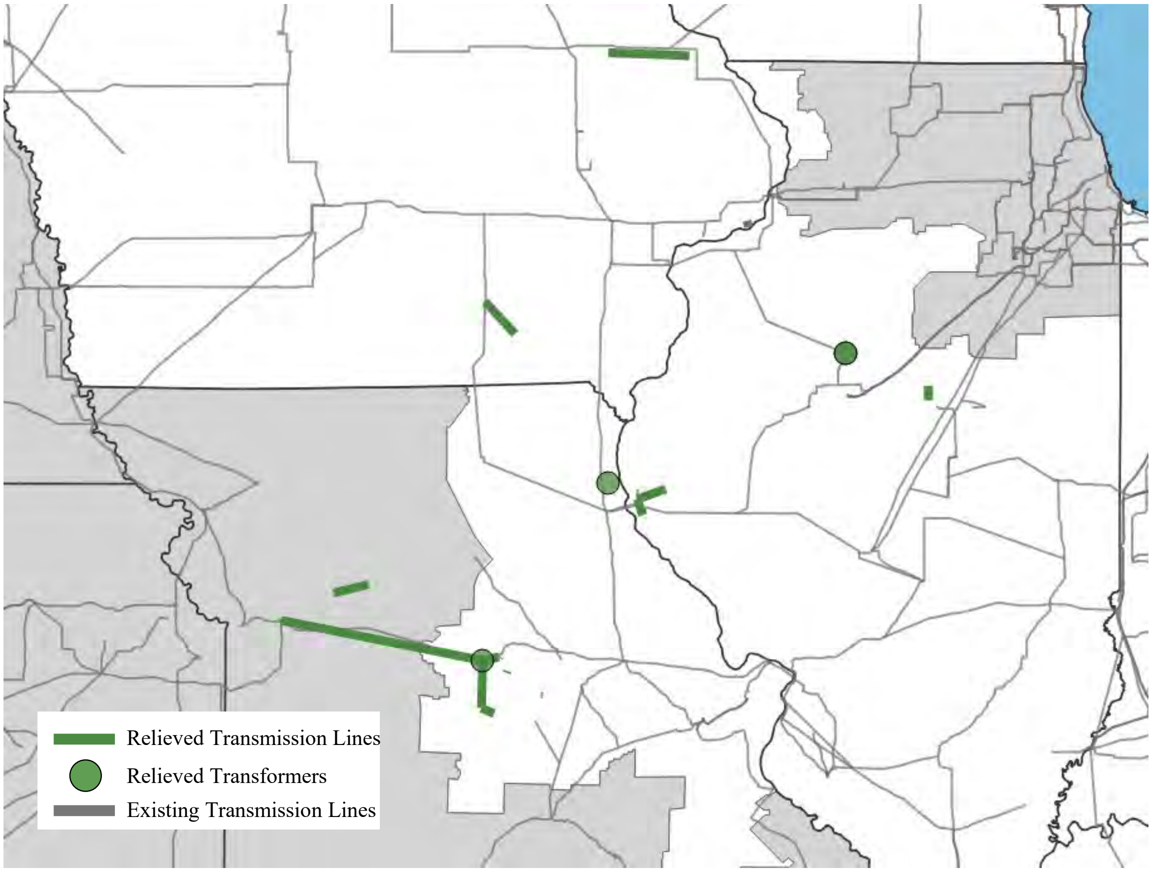


Figure 6-18: Northern Missouri Corridor map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Monitored Facility	Area	% Loading: Base + West LRTP*	% Loading: + IA to MI Project + MO Projects
Marblehead 161/138 kV Transformer	AMIL	137	85
Fargo 345/138 kV Transformer 1	AMIL	122	98
Fargo 345/138 kV Transformer 2	AMIL	122	98
Herleman 3 – Quincy S. 138 kV Ckt. 73	AMIL	120	79
Herleman 1 – Quincy N. 138 kV Ckt. 50	AMIL	120	79
Diamond Start Tap – White Oak Wind Bus 138kV Ckt. 1	AMIL	114	100
Overton 345/161 kV Transformer	AMMO	109	97
Overton – Sibley 345 kV Ckt. 1	AMMO	102	88
Huntsdale – Overton 1 161 kV Ckt. 1	AMMO	101	91
California 161 kV Bus 1 – Overton 2 161 kV Ckt. 1	AMMO	98	88
Huntsdale – Perche Creek 161 kV Ckt. 1	CWLD	97	87
McBaine Bus #2 – McBaine Tap 161 kV Ckt. 1	AMMO	97	85

Maurer Lake 161 kV Bus 1 – Carrollton 161 kV Ckt. 1	AMMO	96	70
California 161 kV Bus	AMMO	95	85
Sub 71 – Sub 88 161 kV Ckt. 1	MEC	109	98
Heights – Ottumwa 161 kV Ckt. 1	ALTW	103	95
Heights – Woody 161 kV Ckt. 1	ALTW	101	93
Liberty – Hickory Creek 161 kV Ckt. 1	ALTW	98	91
Liberty – Dundee 161 kV Ckt. 1	ALTW	98	91

*Base + West LRTP projects = Ell-Jam, BSS-Alex-Cass, MN-WI

Table 6-8: Facilities mitigated by the Missouri Corridor

The Missouri projects can help power delivery, in addition to increasing transfer levels from East-West/West-East. Moreover, the projects address voltage instability in Missouri (Figure 6-19).

- In the Pre-project case (without LRTP projects), with the transfer level reaching 1640 MW, one 345 kV bus in Missouri shows voltage dropping to 0.87 p.u. following loss of a large generating plant, which demonstrates voltage instability in this source area
- With the proposed IA – MI 345 kV line, the transfer level is increased to 3773 MW
- With the addition of the MO Project, the transfer level is further increased to 6000 MW

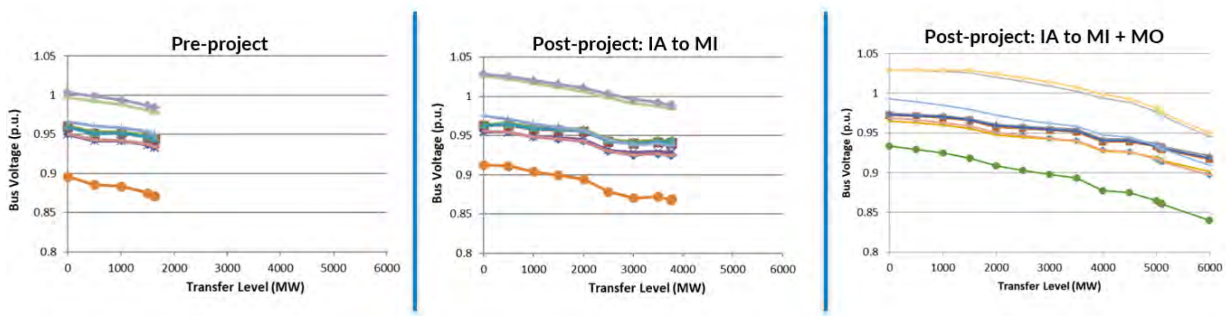


Figure 6-19: Bus Voltage Profiles

Alternatives Considered:
Segments of the Missouri corridor were considered separately, the full Missouri path (Orient – Fairport – Zachary – Maywood – Meredosia 345 kV / Zachary – Thomas 345 kV) is a better solution, with 19 issues addressed by the full path compared to:

- Zachary – Thomas – Maywood – Meredosia, resolves 11 issues
- Thomas – Zachary, resolves 4 issues
- Zachary – Maywood, resolves 6 issues
- Zachary – Maywood – Meredosia, resolves 9 issues
- Zachary – Maywood – Thomas, resolves 5 issues

7 LRTP Tranche 1 Portfolio Benefits

In accordance with the guiding principles of the MISO planning process, the allocation of costs for the transmission investment must be roughly commensurate with the expected benefits. As Multi-Value Projects, the eligibility of LRTP projects is established by Tariff requirements that define the need to demonstrate financially quantifiable benefits in excess of costs.

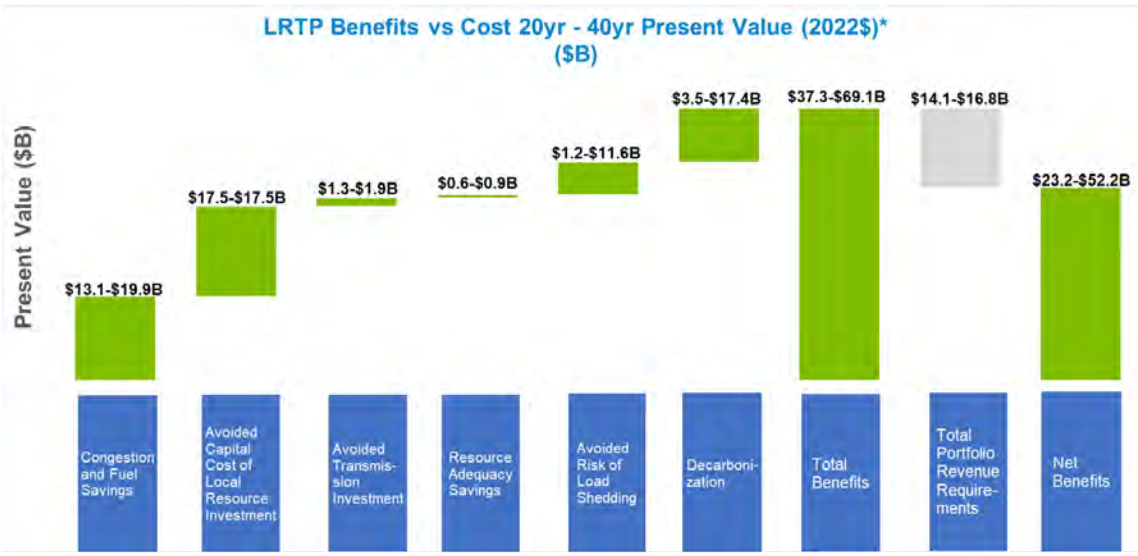


Figure 7-1: Financially Quantifiable Benefits of LRTP Tranche 1 Portfolio (values as of 6/1/22)

Guided by the allowable economic benefits defined in the tariff for MVP projects, the following benefit components were evaluated to determine the amount of value delivered by the LRTP Tranche 1 Portfolio:

- Congestion and fuel cost savings
- Avoided capital costs of local resource investment
- Avoided future transmission investment
- Reduced resource adequacy requirements
- Avoided risk of load shedding
- Decarbonization

Each benefit metric represents a distinct piece of the overall value resulting from either the transmission investments or the generation changes enabled by the transmission projects. Each benefit component is discussed in more detail, explaining what is captured in the metric, how LRTP projects impact the value being measured, and the methodology used to calculate the benefit. Starting from their assumed in-service year of 2030, benefits were calculated over a twenty-year horizon to evaluate eligibility as a multi-value project, and over a forty-year period to demonstrate the additional value provided over the expected useful life of the assets.

For consistency and comparability, a general set of assumptions and variables was applied in the analysis of benefits. All benefit values are expressed in 2022 dollars. An inflation rate of 2.5% is assumed when adjusting for the benefit period. A rate of 3 percent is used to represent the value a ratepayer would typically receive on a risk-adjusted investment. A discount rate of 6.9 percent is used to calculate the minimum value used to assess the benefit to cost ratio and based on the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments. The benefits analysis also includes evaluation of a natural gas price sensitivity to determine how benefits change with respect to swings in natural gas prices. While the benefits of the LRTP Tranche 1 Portfolio business case are analyzed for a Future 1 resource expansion scenario based on a specific gas price assumption, the sensitivity analysis offers additional insights into the value of LRTP under a broader set of assumptions.

Congestion and Fuel Cost Savings

In the MISO Futures[4], transmission limitations require robust solutions that not only reduce system congestion but also facilitate access to the diverse, ever-changing resource mix. The LRTP Tranche 1 Portfolio helps deliver economic benefits by providing more transmission infrastructure to distribute loading on other facilities and by enabling the connection of more low-cost resources.

Congestion and Fuel Savings benefit analysis is determined by calculating Adjusted Production Cost (APC[5]) savings between a reference case and a change case production cost model. The makeup of the reference case includes sufficient resources to meet Future 1 energy requirements, without applying the limitations of the transmission system, as well as Future 1 Regional Resource Forecast (RRF) resources that do not require the LRTP Tranche 1 Portfolio to connect to the system. The change case includes the LRTP Tranche 1 Portfolio and Future 1 RRF resources enabled by regional transmission to connect to the system. To determine which RRF resources are included in the reference and change case models, MISO performed a distribution factor (DFAX[6]) analysis on reliability constraints addressed by the LRTP Tranche 1 Portfolio. Only renewable RRF resources with $\geq$ 5% DFAX are included in the change case and renewable RRF resources with < 5% DFAX will be included in both the reference and change cases (Figure 7-2).

[4] MISO Futures Report
[5] MISO APC White Paper
[6] The DFAX analysis utilized LRTP Powerflow models and identified LRTP reliability issues addressed by the LRTP Tranche 1 Portfolio and involves the computation of change in flow on a network branch in the transmission model to the injection of power at a bus where generation is located which determines the amount of generator impact on facility loading.

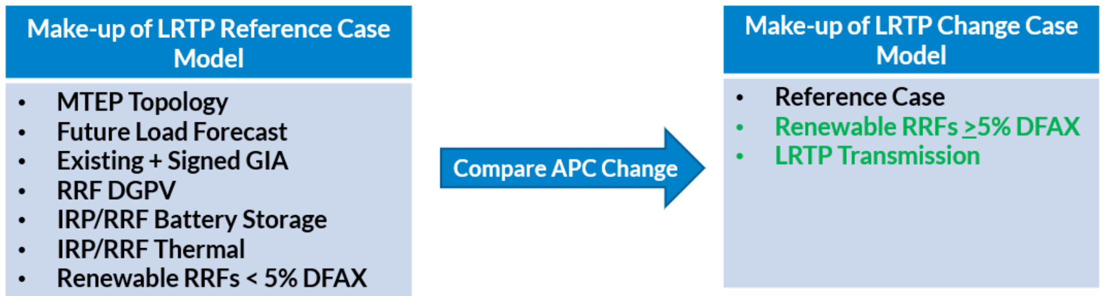


Figure 7-2: LRTP Reference and Change Case Criteria

As seen in Figure 7-3, application of this criteria resulted in 136.6 GW of resources being added to the LRTP Reference Case to meet Future 1 energy requirements and left 20.4 GW of renewable RRF resources available for DFAX analysis. This assessment resulted in the enablement of 20.1 GW of renewable RRF resources being added to the change case. Reference Figure 7-4 for geographical representation of the enabled renewable RRF resources in relation to the LRTP Tranche 1 portfolio.

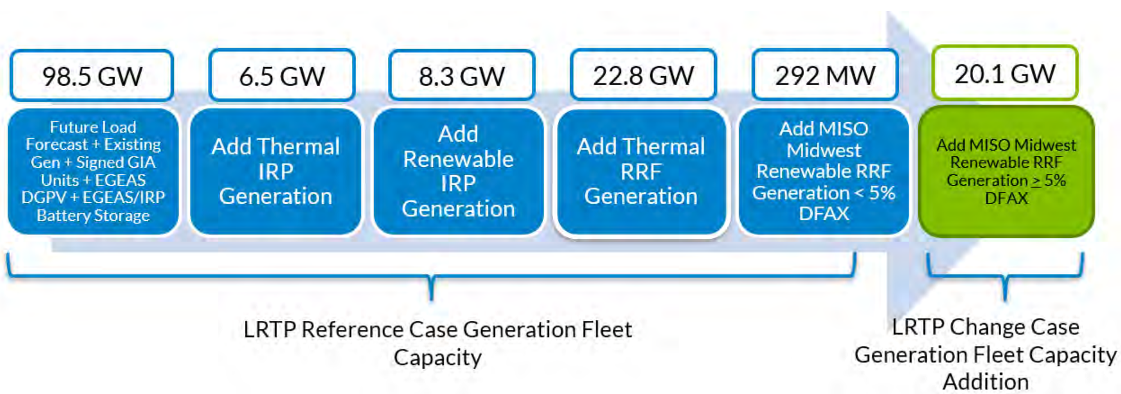


Figure 7-3: LRTP Reference and Change Case Criteria Capacity Result

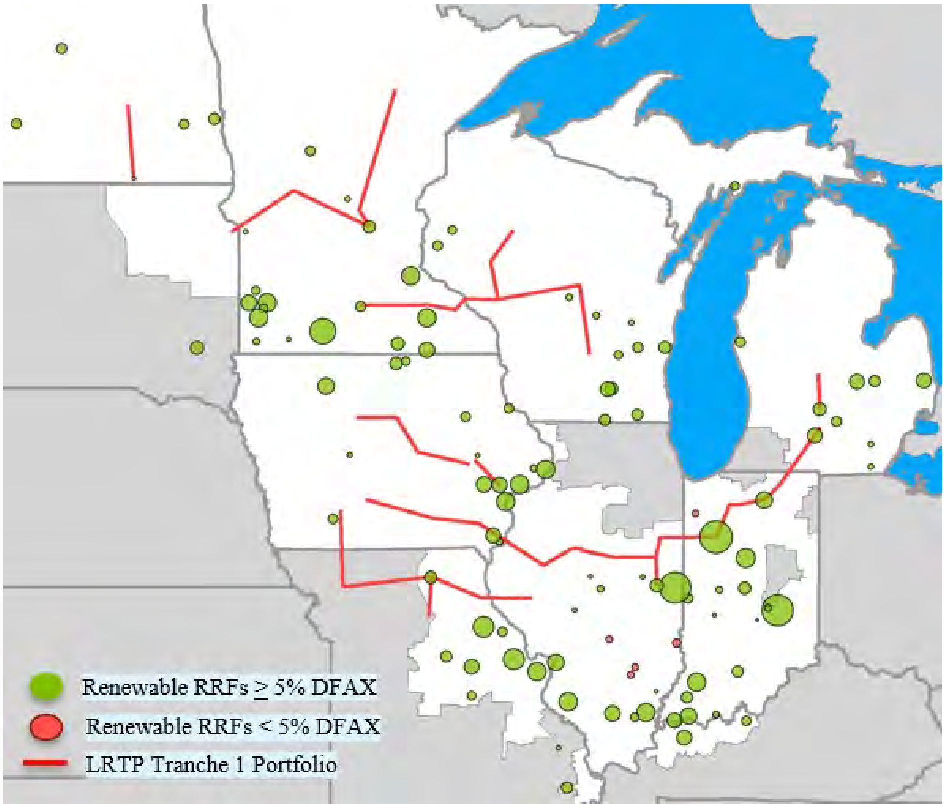


Figure 7-4: Geographic Map of RRF Resources Enabled by LRTP Tranche 1 Portfolio

The APC savings created by the LRTP Tranche 1 Portfolio generated $13.1 billion in congestion and fuel savings benefits over a 20-year period at a 6.9% discount rate. See Table 7-1 for additional benefit details on a Cost Allocation Zone (CAZ) granularity.

Present Value		20-year PV (Millions-2022$)		40-year PV (Millions-2022$)	
Discount Rate		6.9%	3.0%	6.9%	3.0%
CAZ	1	$3,169	$4,455	$4,668	$8,797
	2	$1,049	$1,511	$1,667	$3,313
	3	$2,195	$3,060	$3,151	$5,823
	4	$1,352	$1,934	$2,107	$4,133
	5	$1,471	$2,078	$2,205	$4,210
	6	$2,884	$4,133	$4,517	$8,890
	7	$1,006	$1,432	$1,543	$2,993
		$13,125	**$18,603**	**$19,858**	**$38,160**

Table 7-1: LRTP Tranche 1 Portfolio Congestion and Fuel Savings Benefits

Avoided Capital Costs of Local Resource Investments

The Avoided Capital Costs of Local Resource Investments metric captures the cost savings realized from a more cost-effective regional resource buildout that is enabled by regional transmission investment instead of depending on a more costly local resource buildout that is required due to local transmission limitations. In this specific case, the cost savings created by the LRTP Tranche 1 Portfolio will be determined by calculating an increase in costs for the resources enabled by the LRTP Tranche 1 Portfolio using a local versus regional capacity ratio.

To determine what the local resource investments would be, MISO had to first build local resource expansion models in EGEAS utilizing the same Future 1 assumptions[7] used in the regional expansion plan.

The local expansion plan EGEAS model assumptions are as follows:

- Local representation would be represented by Local Balancing Authority (LBA) granularity.
- Each LBA is treated as its own pool, self-constructing resources necessary to meet simulation constraints such as Planning Reserve Margin (PRM) and emissions.
- MISO PRM value of 18% was scaled for each LBA based upon its alignment to the MISO coincident peak.
- Utilizes the same assumptions as the regional Future 1 analysis and resources are attributed to LBAs based on resource ownership.
- Capacity purchases are enabled for the first year to meet each LBA's PRM due to limitations driven by the construction lead time for new resource alternatives.
- LBA-specific wind and solar profiles are used instead of the regional profiles which averaged multiple profiles from different locations across MISO.

[7] MISO Futures Report

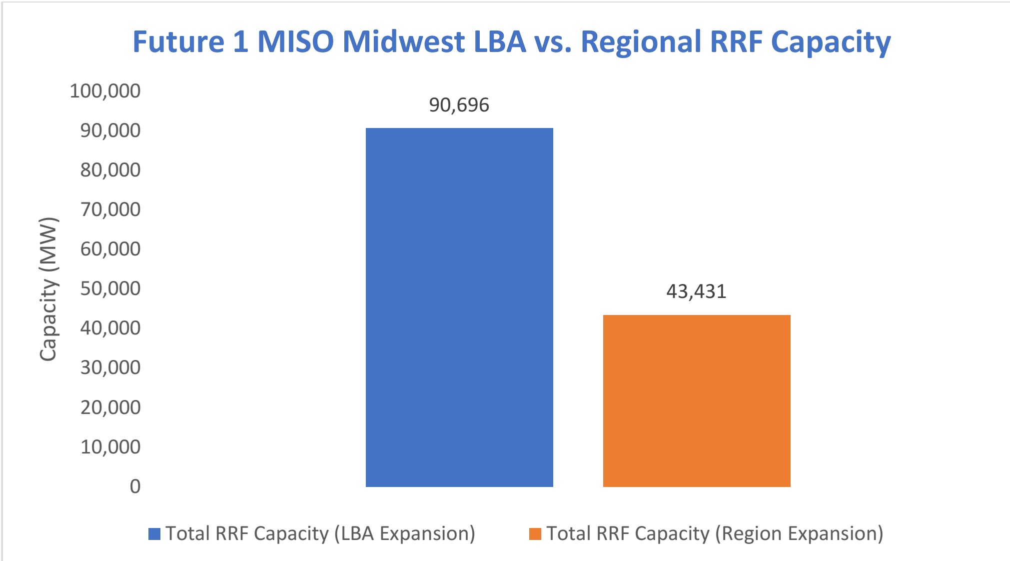


Figure 7-5: Future 1 LBA vs. Regional RRF Expansion Plan

As indicated in Figure 7-5, the LBA-specific scenario requires a much greater amount of localized resource expansion due to limited transmission capability, which is represented by isolating each LBA into its own EGEAS (transmission-less) model, compared to the equivalent regional expansion.

While Future 1 assumptions[8] were modeled consistently between the regional and LBA EGEAS models, the avoided capital cost benefit cannot be calculated by directly subtracting the regional expansion capital costs from local LBA expansion capital costs, as this would over-state the benefit created directly by regional transmission. To avoid this situation MISO had to consider what cost savings the Tranche 1 Portfolio would create. After evaluating several different options[9] with stakeholders to link the LRTP Tranche 1 Portfolio to the regional and local expansion, MISO proposed revised calculations and reviewed the details of the changes with stakeholders in the LRTP workshop discussions.[10] The ultimately decided on calculations are shown in equations (1) and (2) below:

$$Adjusted\ Capital\ Cost_{LBA\ Expansion} = \sum_{Year\ 2020}^{Year\ 2040} Enabled\ RRF\ Capital\ Cost_{Region\ Expansion} \times \frac{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{LBA\ Expansion})}{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{Regional\ Expansion})} \quad (1)$$

[8] MISO Futures Report
[9] January 21, 2022, LRTP Workshop
[10] February 25, 2022 LRTP Workshop

$$Avoided\ Capital\ Cost\ of\ Local\ Resource\ Investments\ = \quad (2)$$
$$Adjusted\ Capital\ Cost_{LBA\ Expansion} - Enabled\ RRF\ Capital\ Cost_{Region\ Expansion}$$

Equation (1) is used to determine what the assumed local resource expansion cost would be by increasing the cost of the enabled resources by a ratio set by the LBA and regional EGEAS expansion results.

- $Adjusted\ Capital\ Cost_{LBA\ Expansion}$ represents the assumed capital cost of a local (LBA) resource expansion for MISO Midwest
- $Enabled\ RRF\ Capital\ Cost_{Regional\ Expansion}$ is the capital cost associated with the enabled[11] Regional Resource Forecasting (RRF) units determined by EGEAS using Future 1 assumptions[12], reduced to MISO Midwest
- $Total\ RRF\ Capacity_{LBA\ Expansion}$ is a summation of MISO Midwest's LBA RRF capacity determined through EGEAS by applying Future 1 assumptions on a LBA level
- $Total\ RRF\ Capacity_{Regional\ Expansion}$ is a summation of MISO Midwest's regional RRF capacity determined through EGEAS by applying Future 1 assumptions on a regional level

Equation (2) is used to determine what the Avoided Capital Costs of Local Resource Investments would be by subtracting the $Enabled\ RRF\ Capital\ Cost_{Regional\ Expansion}$, that is already accounted for, from the assumed LBA expansion capital cost calculated in equation (1).

As a result of being able to utilize the regional transmission buildout of the LRTP Tranche 1 Portfolio, approximately $17.5 billion of savings can be realized through the avoidance of local resource investment (Figure 7-6).

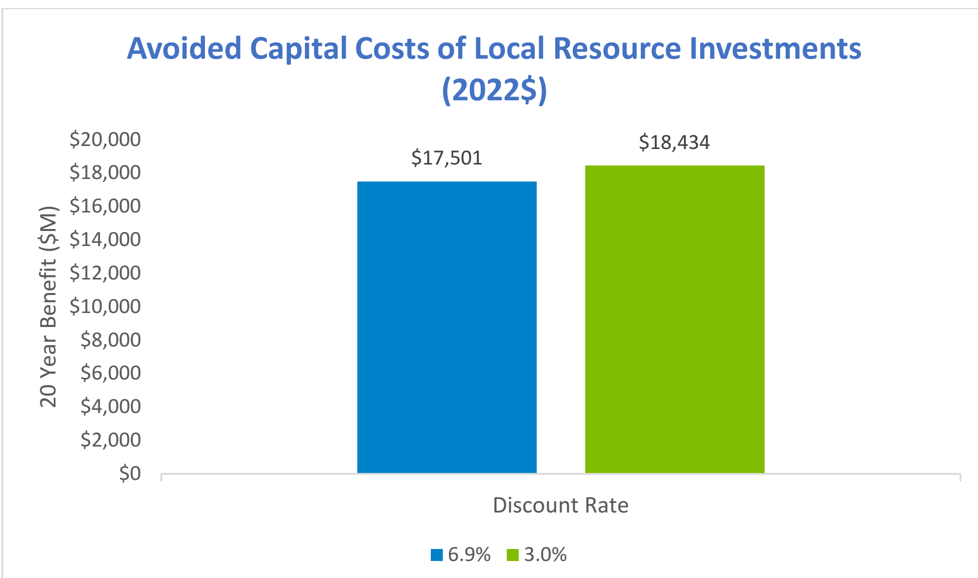


Figure 7-6: Avoided Capital Cost of Local Resource Investments Created by LRTP Tranche 1 Portfolio

[11] Renewable RRFs located in MISO Midwest Subregion which have >5% DFAX on reliability constraints addressed by LRTP Projects
[12] MISO Futures Report

Avoided Transmission Investment

The development of the LRTP Tranche 1 Portfolio provides a regional solution to addressing the future energy needs rather than an incremental approach to reliability planning. Avoided Transmission Investment captures the benefit provided by LRTP regional projects that address both avoided reliability projects and avoided age and condition replacement projects on right-of-way shared by LRTP projects.

LRTP projects deliver benefits by addressing future reliability issues and avoiding the costs of future upgrades that would have been required absent the LRTP Tranche 1 Portfolio. Benefits of avoided future reliability upgrades are based on potential overloads in the future rather than issues observed within the LRTP study period, in order to avoid double counting of benefits.

Identification of future upgrades considers facilities with high thermal loading but not overloaded in the 20-year reference case without LRTP reinforcements, and uses the thermal loading observed in the 10-year reference case to calculate the projected overload (equation below).

$$Flow_{proj} = Flow_{20} + (Flow_{20} - Flow_{10})$$

These projected overloads are analyzed in the LRTP case to determine if the LRTP Tranche 1 Portfolio mitigates the overload condition and are included as candidates for avoided future upgrades.

For future avoided transmission facilities >=345 kV a cost adjustment is applied to reduce the value by 50% to offset future production cost benefits that may be realized. These upgraded extra high voltage (EHV) facilities will reduce future congestion and offset production cost savings in the long term and discounting reduces potential for double counting of benefits. EHV facilities support regional energy delivery and generally have greater influence on production cost than lower voltage facilities that provide local reliability.

LRTP solutions in some cases make use of existing transmission corridors to reduce the need for new right-of-way and often the existing facilities have long been in service and in need of replacement. The avoided transmission investment benefit component also includes the avoided cost of upgrades where LRTP Tranche 1 projects are constructed on existing right-of-way with facilities that would have required upgrades as a result of facility age and condition. Where LRTP Tranche1 projects require rebuilding the structures and facilities of the aging circuits to accommodate the new transmission line, the future cost of the replacement is eliminated.

Facilities included in the Avoided Transmission Investment metric were verified with Transmission Owners to determine if facility upgrades are already planned or existing circuits on shared right-of-way are not candidates for age and condition replacement and were excluded from further consideration. Costs for avoided transmission investment use exploratory cost estimates that are based on the type of upgrade or replacement required. MISO estimated costs are derived from the MISO *Transmission Cost Estimation Guide for MTEP21* and are show in Table 7-2 below.

Upgrades are assumed to be needed prior to the end of the LRTP 20-year study period, and capital investment is assumed to be spread equally over the 5-year period prior to the in-service date of 2040.

Facility Improvement Type	Unit Cost($M)	Quantity/Miles	Cost ($M)
Bus-tie Replacement	$1.50	2	$3
Transformer Replacement =345	$5.00	4	$20
Transformer Replacement <345	$3.00	5	$15
Transmission line Replacement =345kV (per mile)	$2.65	21	$56
Transmission line Replacement <345kV (per mile)	$1.60	1012	$1,617
Transmission line upgrade=345kV (per mile)	$0.56	230	$64
Transmission line upgrade <345kV (per mile)	$0.34	124	$43
		Total	**$1,819**

Table 7-2: Estimated Costs of Avoided Transmission Investment (values as of 6/1/22)

Analysis Results
Cost savings associated with avoided future upgrades and future facility replacement for age and condition yields 20-40 year present value benefits from $1.3B to $1.9B (2022$).

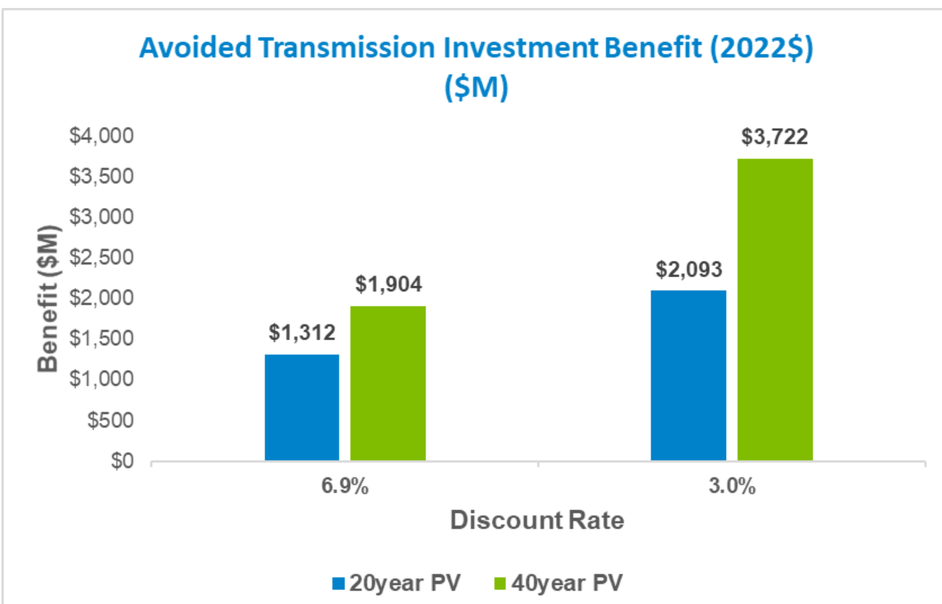


Figure 7-7: Avoided Transmission Investment Benefit (values as of 6/1/22)

Reduced Resource Adequacy Needs

The Reduced Resource Adequacy benefit metric represents a deferral of capacity that would be needed to address resource adequacy requirements due to increased zonal import limits. The transmission enhancements provided by the LRTP Tranche 1 Portfolio increases import capability and enables access to resources across the subregion. This decreases the need to procure capacity locally to meet resource adequacy needs.

The load serving entities (LSEs) that are located within the Local Resource Zones (LRZ) in MISO are required to meet two planning reserve margins in the Planning Resource Auction (PRA): the zonal planning reserve margin requirement (PRMR), which is based on the MISO-wide coincident peak load and MISO-wide PRM, and the local clearing requirement (LCR), which is based on each zone's non-coincident peak load and the local reliability requirement (LRR). The resource adequacy benefits presented in this section are related to the LCR.

Modeling and Assumptions

The modeling includes two parts; the first one involves a transfer analysis and the second one includes the monetization of the benefit.

1. Transfer Study: The CIL analysis generally aligns with the study methodology used in the Planning Resource Auction (PRA). The transfer analysis starts with the Future 1-2040 "peak load day" power flow model and associated input files (monitored elements and contingencies and sub-systems). These are then used in the TARA simulation tool to determine the incremental amount of power that can be transferred from source to sink. The First Contingency Incremental Transfer Capability (FCITC) is determined and the CIL is calculated for a base case (without LRTP Tranche 1 Portfolio) and change case (including LRTP Tranche 1 Portfolio). The definition of each case, in terms of the resource dispatch and demand levels, is consistent with the LRTP Future 1 reliability models.

2. Economic value of LCR reductions: The economic value of the LCR reduction is estimated as a function of the total unforced capacity (UCAP), CIL, and the LRR. The 2040 unforced capacity for each LRZ is determined using forced outage rates for thermal resources and the effective load carrying capability for non-thermal resources.

   The excess capacity within each LRZ is calculated as follows:

   Excess Capacity (LRZ_i) = 2040 UCAP (LRZ_i) – 2040 LCR (LRZ_i; without LRTP),
   where "i" represents the LRZ number (from 1-7).

   The RA benefits are estimated as follows:

   If Excess Capacity < 0 → Benefit = (Cost of new entry) x (-Excess Capacity)
   If Excess Capacity > 0 → Benefit = $0/year

   The LRR-UCAP percentages from the PY22-23 LOLE Study and the 2040 non-coincident peak load forecasts are used to set the LRR for each LRZ. The cost of new entry (CONE) assumptions is also consistent with the PY22-23 MISO LOLE study.

Analysis Results

The resulting CIL, with and without the LRTP Tranche 1 Portfolio, are shown in Table 7-3. The CIL values include the net-area interchange (e.g., the base transfer) gathered from the power flow model. Although their impact on the LCR benefit is negligible, the other components used in the CIL equation, e.g., border external resources (BER), coordinated owner (CO), and exports are kept unchanged in the base and reference cases.

Local Resource Zone	CIL (Base)	CIL (Change-With LRTP)	Delta CIL(MW)
1	5412	6070	658
2	4188	5223	1035
3	5062	6453	1391
4	7117	7609	492
5	6131	6183	52
6	6005	6171	166
7	3367	4659	1292

Table 7-3: Change in Capacity Import Limits (CIL)

A summary of the UCAP, LCR, LRR, and the Excess Capacity calculated for each LRZ is included in Table 7-4. The excess capacity shown in row 7 reflects the pre-LRTP scenario and a negative value represents a potential shortfall situation. The excess capacity shown in row 8 reflects the case with LRTP and confirms the ability of Tranche 1 projects to hedge against potential shortfall situations. The total 20-year and 40-year net present values are shown in Figure 7-8.

Row Number	Summary of resource adequacy benefits								
	LRZ	1	2	3	4	5	6	7	Formula Key
1	2040 Unforced Capacity (MW)	22,981	15,458	12,079	11,111	8,274	20,659	23,982	A
2	2040 Local Reliability Requirement Unforced Capacity (MW)	23,672	16,431	12,405	14,230	12,391	24,196	27,814	B
3	Without LRTP CIL (MW)	5,412	4,188	5,062	7,117	6,131	6,005	3,368	C
4	With LRTP CIL (MW)	6,070	5,223	6,453	7,609	6,183	6,171	4,659	D
5	Without LRTP LCR (MW)	18,260	12,243	7,343	7,113	6,260	18,191	24,446	E=B-C
6	With LRTP LCR (MW)	17,602	11,208	5,952	6,621	6,208	18,025	23,155	F=B-D
7	Excess capacity after LCR	4,721	3,216	4,737	3,998	2,014	2,468	-465	G=A-E

	without LRTP (MW)								
8	Excess capacity after LCR with LRTP (MW)	5,379	4,251	6,128	4,490	2,066	2,634	827	H=A-F
9	Deferred capacity value (M$)	0	0	0	0	0	0	-44	I=G*CONE

Table 7-4: Summary of resource adequacy benefits

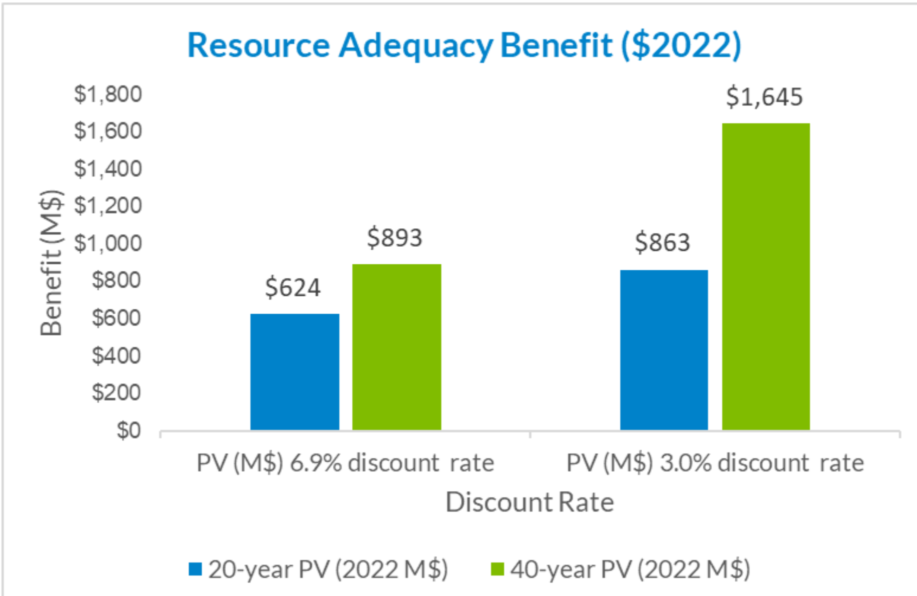


Figure 7-8: Resource Adequacy Benefit Total 20-year and 40-year Present Value

Avoided Risk of Load Shedding

Avoided Risk of Load Shedding is one of several metrics that is used to quantify the benefits provided by the LRTP Tranche 1 Portfolio. The method for determining this resiliency value considers high impact events with an expectation of a significant amount of controlled load shedding to ensure reliable system performance and/or prevent system collapse. While smaller, more common contingencies can result in the need for load shedding actions to maintain reliability, these events are often local in nature and beyond the scope of this analysis, which examines the impact of large-scale generation loss events caused by changing weather conditions or under extreme weather events. In a future with extensive penetration of renewable resources, the variability in weather introduces the potential for loss of renewable production. Additionally, extreme winter weather patterns can cause fuel supply disruptions that may result in extensive thermal generation outages. LRTP projects help to enable regional transfers mitigating the risk associated with these high impact generation outage events.

Analysis of load shedding risk was performed using 2040 winter peak reliability powerflow models, which represent system conditions under which the severe winter weather generation loss event is expected to occur. Weather events may be limited in scale to smaller areas that can affect a single resource zone or may be extreme in nature and have widespread impacts across the footprint. Study scenarios are defined for zonal and system-wide events that specify the generation outages resulting from severe winter weather impacts. Analysis of severe winter weather impacts on generation performance is generally straightforward but captures only one area of the risk associated with loss of load. This narrow focus results in a conservative estimate of the value of avoided risk of load shedding.

Historical weather event data is used to understand and develop assumptions about the frequency of significant winter weather events that could lead to large scale generation loss. MISO analyzed information on significant freeze and storm events over the past 40 years that have resulted in significant economic impact in order to establish the frequency of occurrence for evaluating risk (Figure 7-9).

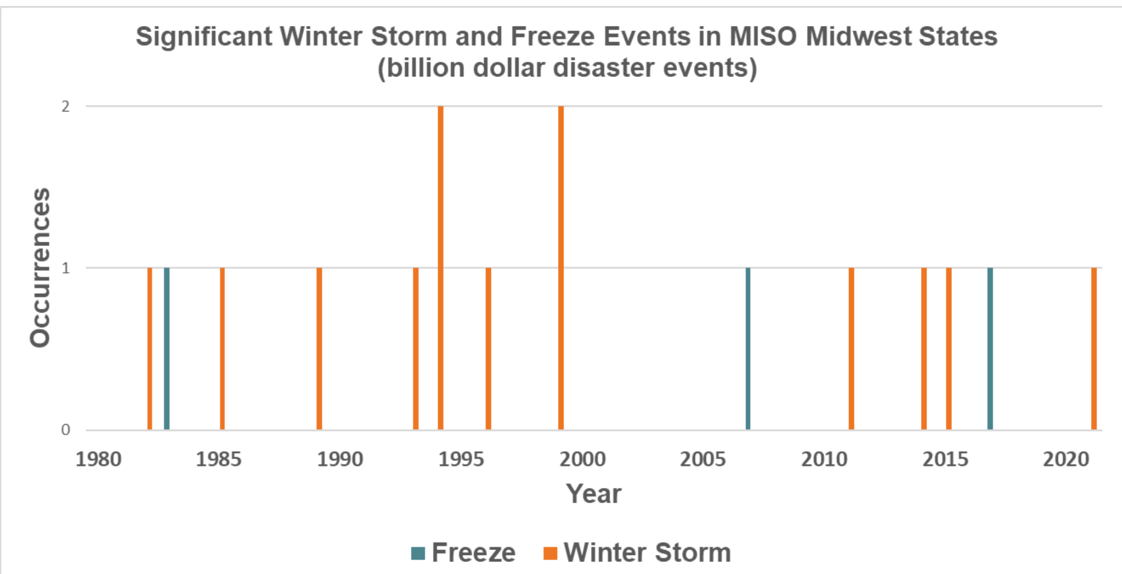
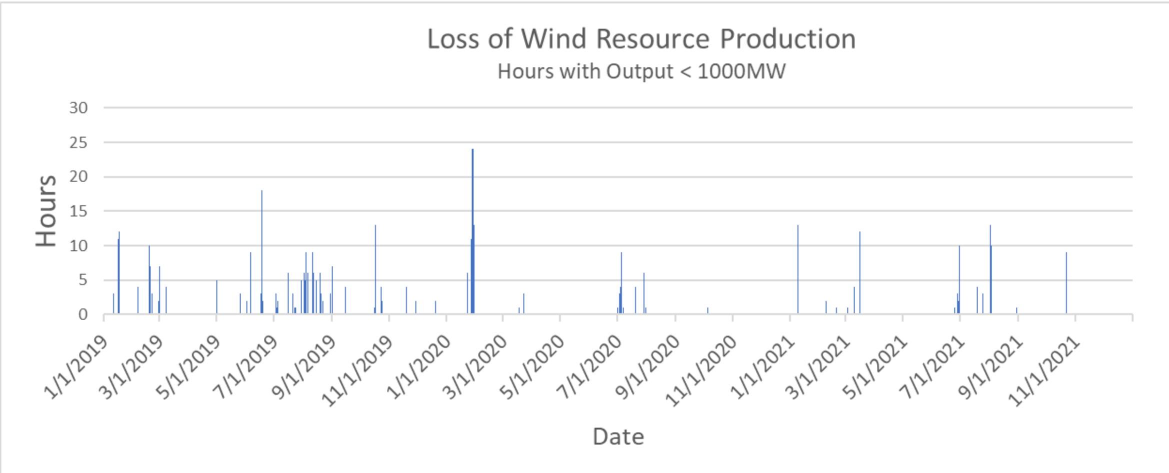


Figure 7-9: Winter storm and freeze events have been occurring every three years on average

Data Source: NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2022). https://www.ncei.noaa.gov/billions/, DOI: 10.25921/stkw-7w73

Additionally, operational event data was analyzed to examine trends in resource availability events over time when severe winter weather conditions occur, which provides insights into how fleet composition affects the risk of generation deficiency. While many of these weather events have not caused major disruption of generation supply in the past, recently there have been a growing number of instances where weather conditions caused the need to implement emergency measures to maintain adequate supply. In the last five years, tight generation supply during winter conditions presented operational challenges that will continue with growing dependency on renewable resources and gas-fired generation. The MISO response to the Reliability Imperative report[13] notes a key indicator of the change in risk profile for the region is seen in the 41 MaxGen emergencies that have been declared since 2016.

Historical generation output data highlights recurring risks associated with periods of low renewable production which can occur during any season and any time of the day (Figure 7-10). Such events can leave a significant amount of generation capacity unavailable to meet load requirements and where the duration of generation shortfall can last several hours.



Data Source: MISO Historical Hourly Wind, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc

Figure 7-10: Periods of low wind production may last several hours

The interruption of load may have far reaching impacts that include risk to public health and safety, financial loss, and regulatory/legal burdens, which are difficult to accurately quantify. The monetization of value of lost load is often considered in the context of customer willingness to pay to avoid interruption. While the application of the MISO Tariff defined Value of Lost Load (VOLL) in the LRTP business case does not suggest that VOLL represents the full value of risk, it does provide a reasonable measure that is indicative of the LRTP benefits and closely aligns with other business processes. The value of avoided risk of load loss of the LRTP Tranche 1 Portfolio considers a range of VOLL from \$3,500/MWh to \$23,000/MWh. The \$3,500/MWh is currently defined by the MISO Tariff for use in market pricing while \$23,000/MWh is a value recommended by the MISO Independent Market Monitor to be more representative of the value. This value of VOLL is applied to the calculated MW value of load loss determined by the zonal and system-wide studies in order to capture the benefits associated with the LRTP Tranche 1 Portfolio.

[13] MISO's Response to the Reliability Imperative

Method for Calculating Value of Avoided Risk of Load Shedding

Scenario Development

Analysis of historical winter storm and freeze event data from the past 20 years and recent extreme winter weather events indicates that significant winter storms are recurring every three years on average with extreme winter storms and temperature conditions observed periodically (polar vortex, Uri). The increased influence of weather due to the variability of renewable resources and impact of cold temperatures on fuel supply and availability of gas-fired generation will result in more periods of risk for load loss. Thus, each occurrence of a severe winter event every one out of three years represents a risk of load shedding due to the widespread generation outages. This risk persists beyond a single day since winter storms often occur over multiple days.

Duration of the load loss was derived using hourly wind production data to examine periods of low wind output since variability in wind output will have a large influence on the risk of an event. While the duration of low wind output events can range from 1 hour to 24 hours for a given day (Figure 7-10), approximately half of the events occurring in winter season are greater than 10 hours and period of risk for load loss is assumed to be eight hours per day over a two-day period for the purpose of assessing the risk of load shedding caused by a severe winter weather event.

A series of event scenarios were developed to represent significant generation loss due to weather related conditions. Events were created to reasonably reflect the loss of future renewable and thermal resources within defined zones or groups of zones. Loss of wind resources was modeled to represent a 90% drop in output from the maximum capacity and loss of solar output was modeled as a 50% reduction from maximum capacity. For regional and zonal event analysis, loss of thermal generation was derived by using outage information from the recent extreme winter storm event to establish a 50% outage rate in regional scenarios and 40% outage rate in zonal scenarios to capture the higher impact from future growth in gas-fired resources. Where modeled wind output is less than 10% of maximum capacity or solar output less than 50% in either zonal or regional scenarios, no adjustment is applied to the wind or solar output.

Load Loss Analysis

In zonal load loss analysis, the 2040 winter peak powerflow models were used to evaluate available generation, load requirements, and import capability for a given local resource zone. Load is escalated by 5% to assess the risk of load higher than normally forecast in planning analysis. Reliability analysis models normally apply a 50/50 load forecast, which reflects the normal peak load expected in the planning horizon. However, during extreme weather conditions, the peak load is expected to reach a 90/10 peak load forecast level, which is typically 5% higher. Resources were grouped within a single zone and event generation outage scenario applied to determine the amount of generation remaining. The amount of shortfall or surplus, in MW, is then calculated by subtracting the total zone load and losses and adding any net imports into the zone. The future CIL calculated in the resource adequacy analysis is used to determine if sufficient import capability exists to support any shortfall and any change in CIL due to the addition of the

LRTP projects is used to determine the amount of benefit, in MW, provided by the LRTP Tranche 1 Portfolio.

Area/Zonal Event Scenario

Generation Loss:
Thermal: 40% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Capacity Import Limit (CIL)

For all LRZ 1-7

LoadLossMW = GenMW_{net} – 1.05 * LoadMW – TxLossMW + Capacity Import Limit (MW)
where $\text{GenMW}_{net} = \text{GenMW}_{cap} - \text{GenMW}_{loss}$

In regional load loss analysis, the 2040 winter peak powerflow models were used to evaluate available generation, load requirements, and import capability for a given group of local resource zones. Similar to zonal analysis, the load is escalated by 5% to assess the risk of load higher than normally forecast in planning analysis due to the extreme weather. Resources were grouped within a set of zones and event generation outage scenario applied to determine the amount of generation remaining. In the regional analysis scenarios, the amount of thermal generation loss is escalated to 50% of capacity to represent a more extreme condition with regional scale impacts. The amount of shortfall or surplus, in MW, is then calculated by subtracting the total load and losses and adding any net imports into the study group. The incremental transfer capability is calculated using the power flow model and added to the existing group net imports to determine the total transfer capability to support any shortfall and the change in total transfer capability due to the LRTP projects is calculated to determine the amount of benefit, in MW, provided by the LRTP Tranche 1 Portfolio.

Two scenarios are included for evaluating risk of load loss for regional scale events:

Scenario 1 assesses the impact of an extreme winter storm primarily on the western part of the MISO footprint causing large scale loss of generation in MISO upper Midwest areas and Southwest Power Pool (SPP) with SPP imports assumed to be 7,500 MW.

Scenario 2 assesses the impact of extreme winter storm activity in the MISO central areas and Ohio Valley with PJM exports curtailed to 0 MW.

Regional Event Scenario

Generation Loss:
Thermal: 50% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Total Transfer Capability

Scenario 1: Source: MISO Zones 4-7 + PJM
Sink: MISO Zones 1-3 + SPP

Scenario 2: Source: MISO Zones 1-3 + SPP
Sink: MISO Zones 4-7

LoadLossMW = $GenMW_{net}$ - 1.05 * LoadMW – TxLossMW + Total Transfer Capability (MW)
where $GenMW_{net} = GenMW_{cap} - GenMW_{loss}$

The value of avoided risk of load shedding is monetized by the use of the Value of Lost Load (VOLL) to represent a portion of the outage costs associated with load curtailment during generation deficiency events. While VOLL is based on outage costs, it is a market pricing mechanism that considers a customer's willingness to pay for energy to avoid load curtailment under emergency conditions and does not fully consider the related impacts or the effects of extended outages in more extreme scenarios. Furthermore, there is a wide range of opinion concerning the appropriate value that should be used with $3,500/MWh currently being used in the MISO market pricing structure while MISO's Independent Market Monitor has recommended a value of $23,000/MWh to be used in the MISO market. Thus the $3,500/MWh figure is a conservative estimate for capturing the benefit of avoided risk of load loss with the $23,000/MWh value used to establish the upper bound of the value.

The load loss hours are summed for all scenarios to obtain the load risk of load loss in MWhr and the range of values for VOLL is applied to obtain the monetary value.

Avoided Load Loss Value ($) = VOLL * LoadLossMW * duration(hrs.)
where VOLL – Value of Lost Load: $3,500- $23,000[14]

[14] IMM Quarterly Report: Summer 2020,

Analysis Results

The additional transfer capability provided by the LRTP Tranche 1 Portfolio enables power transfers to address supply deficiency caused by weather related generation outages and delivers 20- to 40-year present value benefits of $1.2 billion to $11.6 billion (2022$).

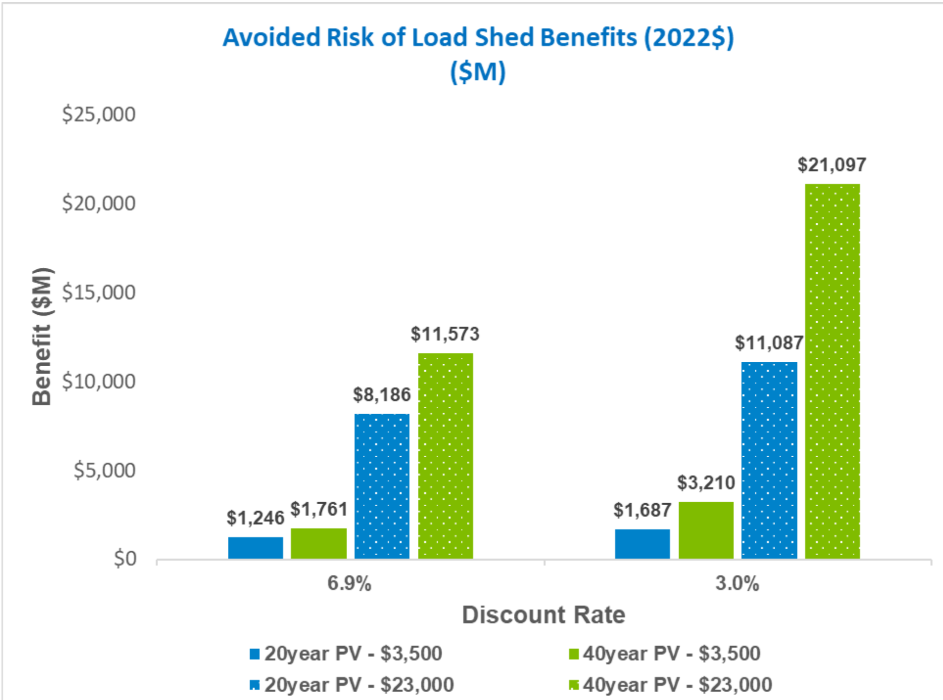


Figure 7-11: Benefits of Avoided Risk of Load Shedding (values as of 6/1/2022)

Decarbonization

MISO continues to explore how the rapid growth of members' decarbonization goals creates additional needs and opportunities to provide value. The robust transmission planning embodied by the LRTP initiative can signal better locations that deliver decarbonization, among other benefits. This item captures a range of potential cost savings from LTRP-enabled Decarbonization.

MISO acknowledges there is no cost of carbon applicable to the entire footprint currently. However, with the energy transition and changing landscape, it is possible that additional emissions standards may be placed on the electric industry. Since the 1990s, sulfur dioxide has decreased by 94%, nitrogen oxides by 88% and mercury emissions by 95% across the U.S. electric power sector.[15] Many of the benefits associated with these emission reductions have already been captured throughout the footprint.

[15] Edison Electric Institute: Climate and Clean Air

Over the past several years, MISO members have announced large carbon emission reduction goals that will rely on intermittent low-cost energy. The LRTP initiative aims to help ensure an efficient dispatch of energy across MISO during this fleet transition. With the rationale above, MISO conducted research to develop a price range to express Decarbonization's value. MISO chose sources within the U.S., at state and federal levels, within and outside of the MISO footprint. The range in prices draws from regulatory and market-based approaches, both of which are influenced by policy. From MISO's PROMOD analysis, carbon emissions are reduced by 399 million metric tons over 20 years and 677 million metric tons over 40 years of LRTP Tranche 1 project life (Figure 7-11).[16]

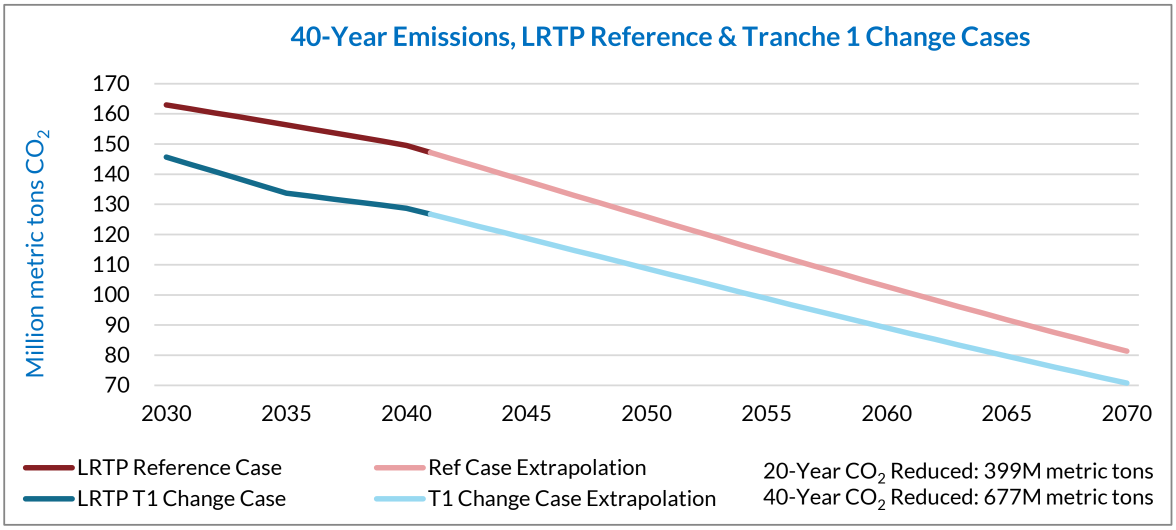


Figure 7-12: 40-Year CO_2 Emissions of LRTP Reference and Tranche 1 Change Cases

MISO took two steps to standardize price terms. First, as applicable, MISO converted source price data to dollars per metric ton, using a conversion factor of one U.S. (short) ton = 0.9071847 metric tons.[17] Second, MISO converted prices from nominal dollar-years of origin into 2022 dollars using the Consumer Price Index Inflation Calculator.[18] For consistency, the month of January was used for dollar-year conversions except in cases related to market prices, which used the month of auction settlement as the origin date. A range of CO_2 emission prices were identified to estimate a benefit value, and are summarized below:

- The Minnesota Public Utility Commission (MN PUC) price began with the 2022 Low[19] price of $9.46 per short ton in 2015 dollars and yielded $10.43 per metric ton; $12.55 per metric ton in 2022 dollars.

[16] MISO interpolated emissions data among PROMOD model years 2030, 2035, and 2040 and used linear extrapolation for post-2040 emissions reductions. 20-year and 40-year benefits refer to projects' in-service value to 2050 and 2070, respectively.
[17] U.S. Energy Information Administration
[18] U.S. Bureau of Labor Statistics Consumer Price Index Inflation Calculator
[19] Minnesota Public Utility Commission

- The Regional Greenhouse Gas Initiative (RGGI) Q4 2021 Auction average (mean)[20] price of $12.47/short ton yielded $13.75/metric ton; $13.87 in 2022 dollars.
- The California and Quebec (CA-QC) Cap-and-Trade Program Q4 2021 Auction settlement[21] price of $28.26/metric ton is $28.59 in 2022 dollars.
- The Federal price is the average of two price data inputs: the 45Q Tax Credit and the Social Cost of Carbon.[22] The 45Q Tax Credit follows a prescribed price schedule; starting with $31.77/metric ton in 2020, increasing to $50 by 2026, and inflation-adjusted afterwards by 2.5% annually. This interpolation yields a 2022 value of $37.85. The Social Cost of Carbon (SCC) follows a similar schedule, but in 2020 dollars. Converting the SCC schedule in 2020 dollars from $51/metric ton (2020) yields $55.58 and $85 (2050) yields $92.64 for those price-years, in 2022 dollars. The SCC's 2022 value in 2022 dollars is $57.76. Beyond 2050, annual inflation of 2.5% is applied. To produce the Federal price, the annual values of 45Q and SCC through 2069 are averaged, beginning in 2022 at $47.80/metric ton in 2022 dollars.

The Decarbonization assessment employs the following overall methodology:

- From the Congestion and Fuel Cost Savings analysis, calculate the difference in CO_2 emissions between the LRTP Reference case and LRTP Change case
- Convert the reduced emissions to metric tons
- Use range of carbon prices to produce yearly values at 2.5% inflation as applicable
- Multiply yearly values by annual reduced emissions and discount rates to produce discounted annual benefits
- Sum discounted annual benefits to yield net present values for 20- and 40-year emission reduction benefits along the price range (Figure 7-12, Table 7-4, Table 7-5)

Detailed assumptions, calculations and formulas are found in the supplementary LRTP Business Case Analysis workbook.

	MN PUC	RGGI Q4 2021	CA-QC Q4 2021	Federal
2022$/metric ton	$12.55	$13.87	$28.59	$47.80
20-Year Benefit (2022$, M):	$3,473	$3,839	$7,913	$13,438
40-Year Benefit (2022$, M):	$4,548	$5,026	$10,361	$17,364

Table 7-4: Full Range of Carbon Prices and Tranche 1 Decarbonization Benefits at 6.9% Discount Rate

[20] Regional Greenhouse Gas Initiative (Q4 2021 average [mean] price)
[21] California-Quebec Carbon Allowance Price (November 2021)
[22] Federal: 45Q Tax Credit, Social Cost of Carbon

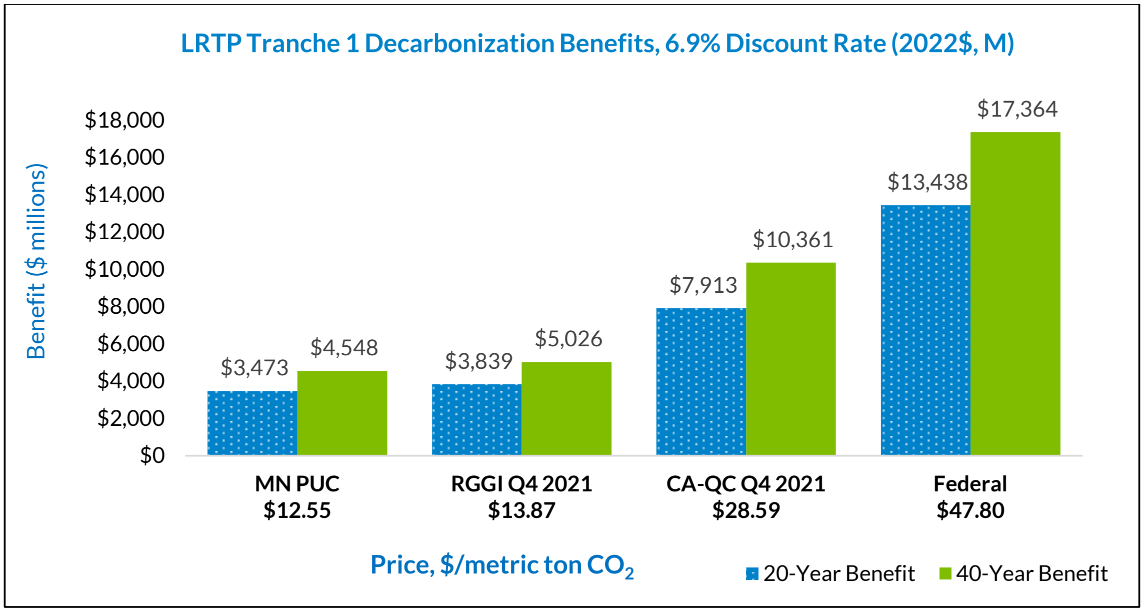


Figure 7-13: LRTP Tranche 1 Decarbonization 20- and 40-Year Benefits Using Full Carbon Price Range, Applying 6.9% Discount Rate (2022$, M)

	6.9% Discount Rate		3% Discount Rate	
	MN PUC (Min)	Federal (Max)	MN PUC (Min)	Federal (Max)
2022$/metric ton	$12.55	$47.80	$12.55	$47.80
20-Year Benefit (2022$, M):	$3,473	$13,438	$4,781	$18,404
40-Year Benefit (2022$, M):	$4,548	$17,364	$7,818	$29,498

Table 7-5: Min/Max Carbon Prices and Tranche 1 Decarbonization Benefits at Two Discount Rates

8 Benefits Are Spread Across the Midwest Subregion

The LRTP Tranche 1 Portfolio of projects was developed to address regional energy delivery needs for the MISO Midwest subregion. As Multi-Value-Projects, the costs of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion. Analysis of benefits examined how much each benefit accrued to the Midwest Subregion Cost Allocation Zones in order to compare the relative impacts between zones and the relationship with cost allocation. The distribution of benefits of the LRTP Tranche 1 Portfolio is shown to yield significant benefits for all Cost Allocation Zones (CAZs) well in excess of the share of portfolio costs.

Distribution of Benefits

Congestion and fuel savings are distributed to CAZs based on the production cost simulations used to calculate the savings and aggregated to the CAZs.

Avoided capital cost of local resource investment benefits are assigned based on load ratio share of each CAZ and aligns with the goal of the resource expansion to meet the future energy needs of the Midwest Subregion.

Avoided transmission investment benefits are allocated to the CAZ in which the baseline transmission upgrades, and age and condition replacement facilities are located. Costs for these avoided projects would otherwise be borne by the local pricing zone which yields a benefit to those specific CAZs.

Reduced Resource Adequacy savings are assigned directly to the CAZs in which the cost savings are realized since each CAZ has a responsibility for their own resource adequacy needs, and the CAZs in the Midwest Subregion align with the Local Resource Zones used for resource adequacy.

Avoided Risk of Load Shedding benefits are distributed to CAZs based on load ratio share to reflect the widespread protection against load loss in the interconnected electric system.

Decarbonization captures the benefits of reduced carbon emissions in energy production that is used to serve load across the Midwest subregion and is allocated by load ratio share to CAZs.

Distribution of LRTP Tranche 1 Portfolio Costs

The cost for Multi-Value Projects are allocated to load in the Midwest Subregion according to load ratio share of energy withdrawals. To determine the benefit/cost ratios by Cost Allocation Zone the energy withdrawals by the applicable LBAs included in each zone have been aggregated for Figure 8-1. Additionally, indicative annual MVP usage rates for the LRTP Tranche 1 Portfolio were calculated over a 40-year period using the current project cost estimates and estimated in-service dates. This information on the estimated MVP usage rates is provided in Appendix A-3.

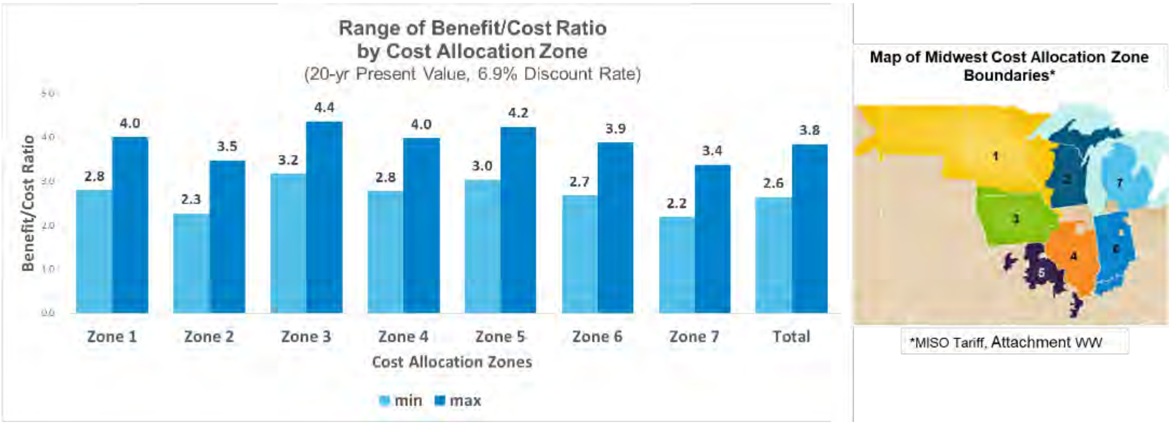


Figure 8-1: Distribution of benefits to Cost Allocation Zones in Midwest Subregion (MISO Tariff Attachment WW) (values as of 6/1/22)

The LRTP Tranche 1 Portfolio provides broad distribution of benefits across the Midwest subregion zones and delivers a benefit to cost ratio of at least 2.2 for every CAZ. Analysis of the zonal benefit distribution indicates that the spread of benefits is roughly commensurate with the allocation of portfolio costs.

9 Natural Gas Price Sensitivity

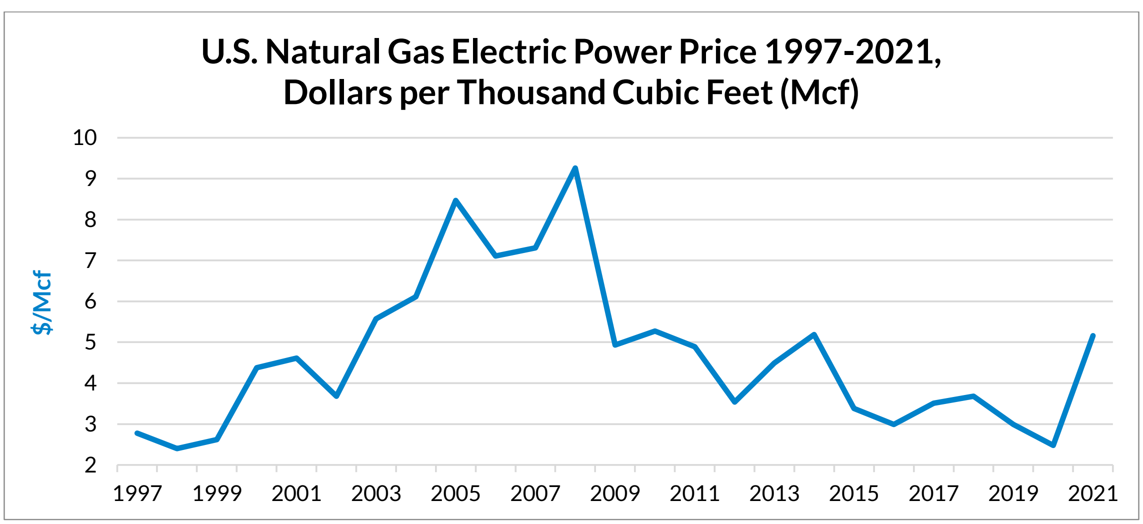


Figure 9-1: Historic U.S. Natural Gas Electric Power Prices

Beginning in 2021, natural gas prices increased sharply, reversing the general price decline seen over the last decade as production grew dramatically from the shale revolution (Figure 9-1).

U.S. export capacity of liquefied natural gas (LNG) has grown rapidly since beginning in 2016, from 0.55 billion cubic feet per day (Bcf/d) to an estimated peak of 11.6 Bcf/d as of November 2021. The U.S. Energy Information Administration estimates U.S. LNG peak export capacity will reach 16.3 Bcf/d by the end of 2024.[23]

Considering the expansion of LNG exports along with the growing prevalence of extreme weather events and current geopolitical developments, U.S. gas price exposure to the global market has increased as well. The recommended LRTP Tranche 1 Portfolio can partially offset the gas price risk by providing additional access to generation powered by fuels other than gas.

Two sensitivity analyses were performed on the LRTP Tranche 1 Congestion and Fuel Savings Reference and Change Case PROMOD models to quantify the impact of changes in gas prices. The sensitivity cases maintained the same production cost modeling assumptions from the business case analysis, except for the gas prices. The sensitivity assumed gas price increases of 20 and 60 percent, respectively. For both analyses, the prices increased starting in the year 2030 and escalated by inflation thereafter.

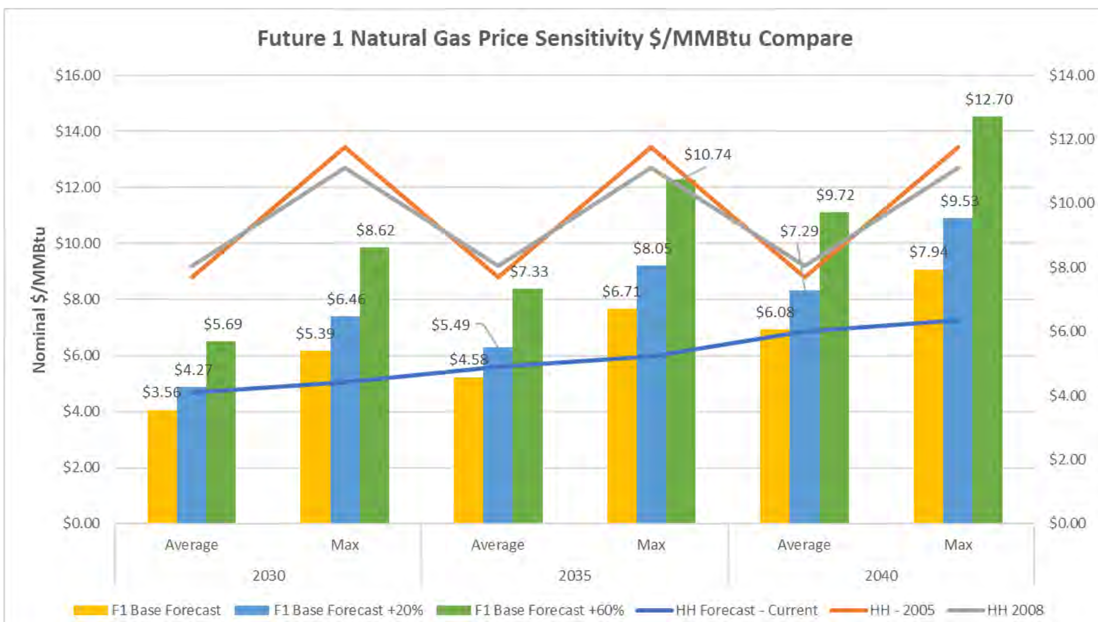


Figure 9-2: Future 1 Natural Gas Price Sensitivity $/MMBtu per LRTP PROMD Study Year

The resulting natural gas price increases achieved (Figure 9-2) created a gas price increase that ensures each study year's average fuel cost is greater than current Henry Hub (HH) projections as

[23] https://www.eia.gov/todayinenergy/detail.php?id=50598

well as representing HH highest historical sale prices from 2005 and 2008. This sensitivity concluded that the LRTP Tranche 1 Portfolio offsets gas price volatility by providing additional Congestion and Fuel Savings benefits by enabling access to renewable energy, as shown in Figure 9-3.

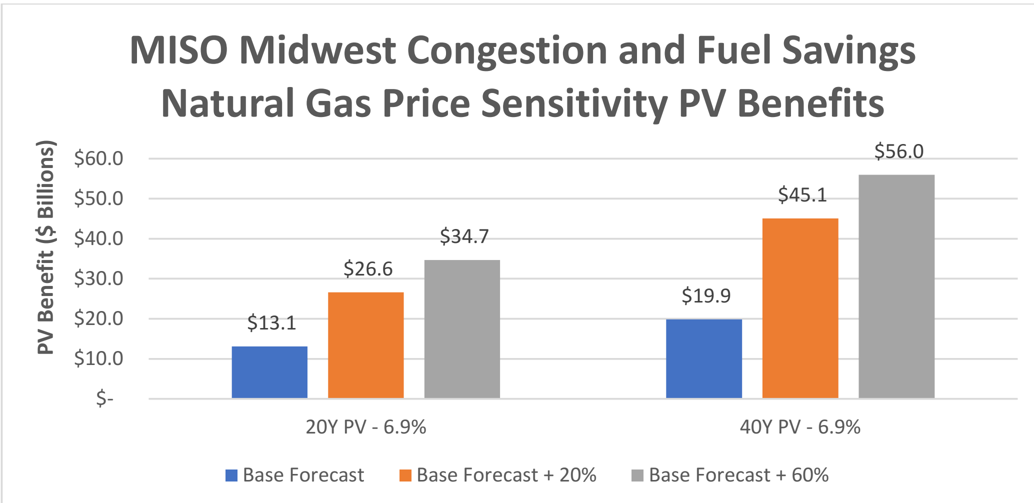


Figure 9-3: Natural Gas Price Sensitivity Results

10 Other Qualitative and Indirect Benefits

In addition to the quantifiable economic and reliability benefits, the LRTP Tranche 1 Portfolio enables other value streams that are reflected qualitatively.

Transmission reinforcements strengthen the grid to support the stability of the larger interconnection and provide greater resilience to recover from unexpected system events without adverse impacts. The interconnected nature of the power system provides support between neighboring systems during severe system disturbances. Regional transmission projects bolster the network, enabling greater bulk power transfers to address the developing conditions and avoid further degradation of the system performance.

Investment in regional transmission projects expand access to a greater diversity of lower-cost resources across the footprint, allowing more options for customer choice of fuel mix. Transmission allows for leveraging of the wide geographic and fuel diversity offered by the MISO region. The stronger regional ties offer more flexibility to handle the variability of renewable output caused by differences in weather patterns across different areas of the MISO footprint. This capability offers greater protection against both market price risk and possible load curtailment measures.

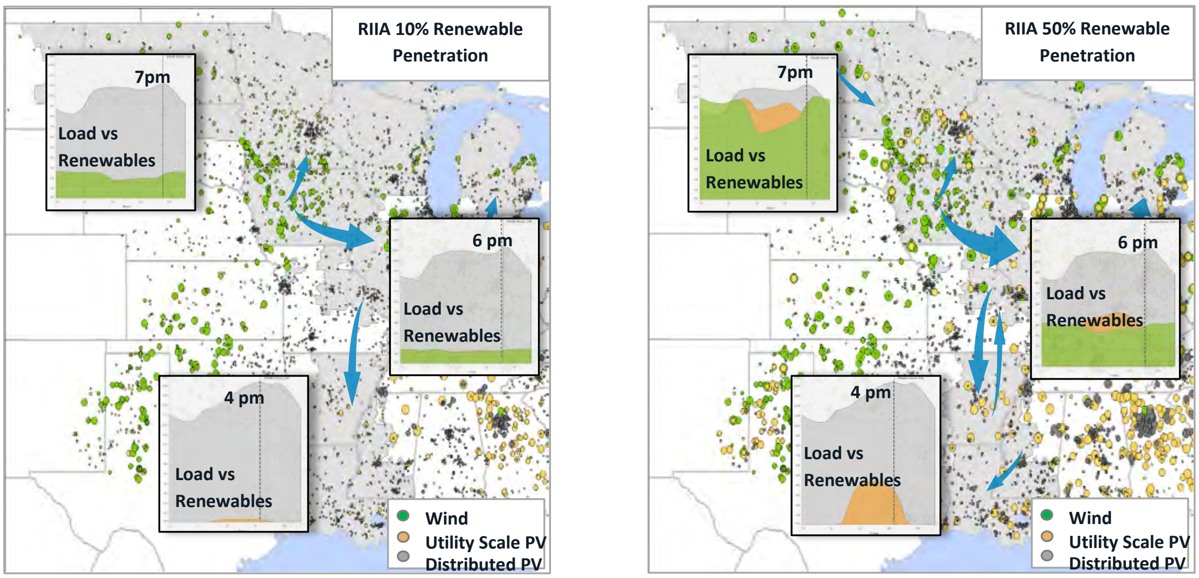


Figure 10-1: Illustration of flow changes with increasing renewable penetration spread throughout the MISO footprint (MISO Renewable Integration Impact Assessment (RIIA) Summary Report, February 2021 https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf)

The addition of transmission facilities allows greater operational flexibility related to unplanned and planned transmission facility outages. While the Congestion and Fuel Savings metric described earlier captures economic value related to reduced congestion, it represents value under normal system intact conditions. In practice, numerous outages occur throughout the year which introduce additional congestion which is not reflected in the calculation of the economic benefits. Furthermore, as the grid moves to a higher penetration of renewables and seasonal load curve flattens, outage scheduling becomes more challenging. Additional transmission improves system utilization and allows more opportunity for scheduling transmission outages with less risk of causing operational issues or rescheduling of outages.

The LRTP Tranche 1 Portfolio makes use of existing routes, where possible, to reduce the need to acquire additional greenfield right-of-way which lowers costs and allows a shorter time to implementation. Construction of new transmission routes across navigable waterways, protected areas and high value property faces extensive cost and regulatory risks that impede progress in meeting future reliability needs. Co-locating new facilities with existing transmission assets enables more efficient development of transmission projects and minimizes the environment and societal impacts of infrastructure investment needed to achieve the needs identified in MISO's Future 1.

The LRTP Tranche 1 Portfolio gives more flexibility to better support diverse policy needs. The proactive long-range approach to planning of regional transmission provides regulators greater confidence in achieving their policy goals by reducing uncertainty around the future resource expansion plans. Elimination of much of the high transmission cost barriers allows resource planners to assume less risk in making resource investment decisions.

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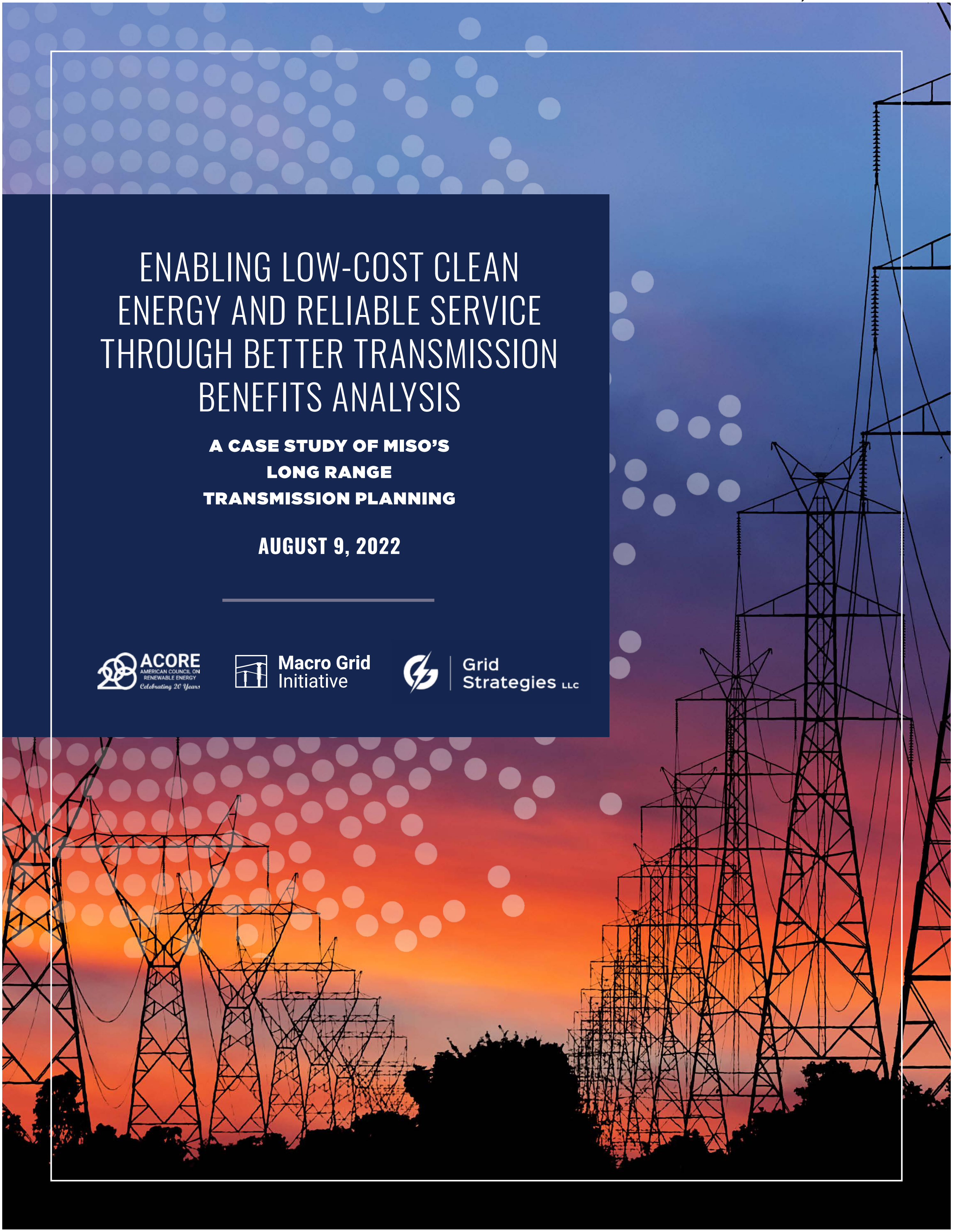

ENABLING LOW-COST CLEAN ENERGY AND RELIABLE SERVICE THROUGH BETTER TRANSMISSION BENEFITS ANALYSIS

A CASE STUDY OF MISO'S LONG RANGE TRANSMISSION PLANNING

AUGUST 9, 2022

ACORE AMERICAN COUNCIL ON RENEWABLE ENERGY Celebrating 20 Years

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EXECUTIVE SUMMARY

Large-scale regional transmission plays a key role in ensuring low costs for consumers and electric system reliability, resilience, and decarbonization. Yet investment has lagged in recent years for high-capacity, long-distance lines in all regions of the United States. Over the last few years, the Midcontinent Independent System Operator (MISO) developed a new plan for a set of lines (known as Tranche 1) in its region that would enable around 56 gigawatts (GW) of new renewables. This plan was based on scenario modeling of state and utility emissions reduction goals that showed carbon emissions falling by more than 60% in 2040 from 2005 levels. The Tranche 1 portfolio was approved by the MISO Board of Directors on July 25, 2022.

To achieve regulatory approval and sufficient stakeholder support for such plans, it is important to measure the various benefits, and determine who receives those benefits. While the US Federal Energy Regulatory Commission (FERC) has jurisdiction over transmission planning and cost allocation, it has no standards in place on the types of benefits of or how to measure them to date. MISO worked with stakeholders and developed support for a set of benefits and methods, identifying approximately $37.3 billion worth of benefits delivered from a portfolio with $14.1 billion in 20-year total revenue requirement.

This analysis finds that MISO's methodologies generally follow best practice benefits estimation, with some areas that could be improved. Other planning entities and FERC could follow MISO's approach, along with the potential improvements, in their work on transmission planning. Similarly, electricity customers in MISO's footprint could benefit from potential improvements described in this paper as the region proceeds to the next phases of transmission development to meet additional expected changes in resources and load in the region.

INTRODUCTION

Transmission infrastructure expansion is critical for electric system reliability, accessing low-cost resources, and meeting climate and clean energy goals. After a wave of transmission expansion in some regions of the United States from 2008-2013, there has been an unfortunate lull for the last decade.[1] Failure to proactively plan and stay ahead of the resource transition has led to clogged interconnection queues, congestion, and frequent and costly curtailment of operating generators in most regions of the country. When regional planning entities have worked with states and stakeholders to proactively plan regional transmission networks and allocate costs broadly to all beneficiaries, it has generally been successful, even in getting these projects permitted, because of the consensus and evidence of benefits from the planning process. A central part of this successful approach to transmission expansion is to include multiple types of needs and benefits in the assessment and compare aggregate benefits to costs.[2]

Multi-value transmission planning sums the multiple benefits of proposed transmission, as opposed to many regions' standard practice of putting transmission projects into economic, reliability, or public policy siloes and only evaluating benefits within that silo, ignoring the project's other benefits. Like MISO's previous success with the Multi-Value Projects (MVPs), and similar success in ERCOT, SPP, and CAISO, in its most recent planning effort MISO used proactive transmission planning to identify the transmission need for the generation resources needed under state policies and utility generation plans. As it did with the MVPs, MISO planned a portfolio of networked facilities that provide benefits across the MISO North and Central footprint, which helps secure broad political support from all states. That support is essential for overcoming the hardest obstacle to building transmission — securing buy-in from each state to broadly allocate the cost of the transmission across the region.

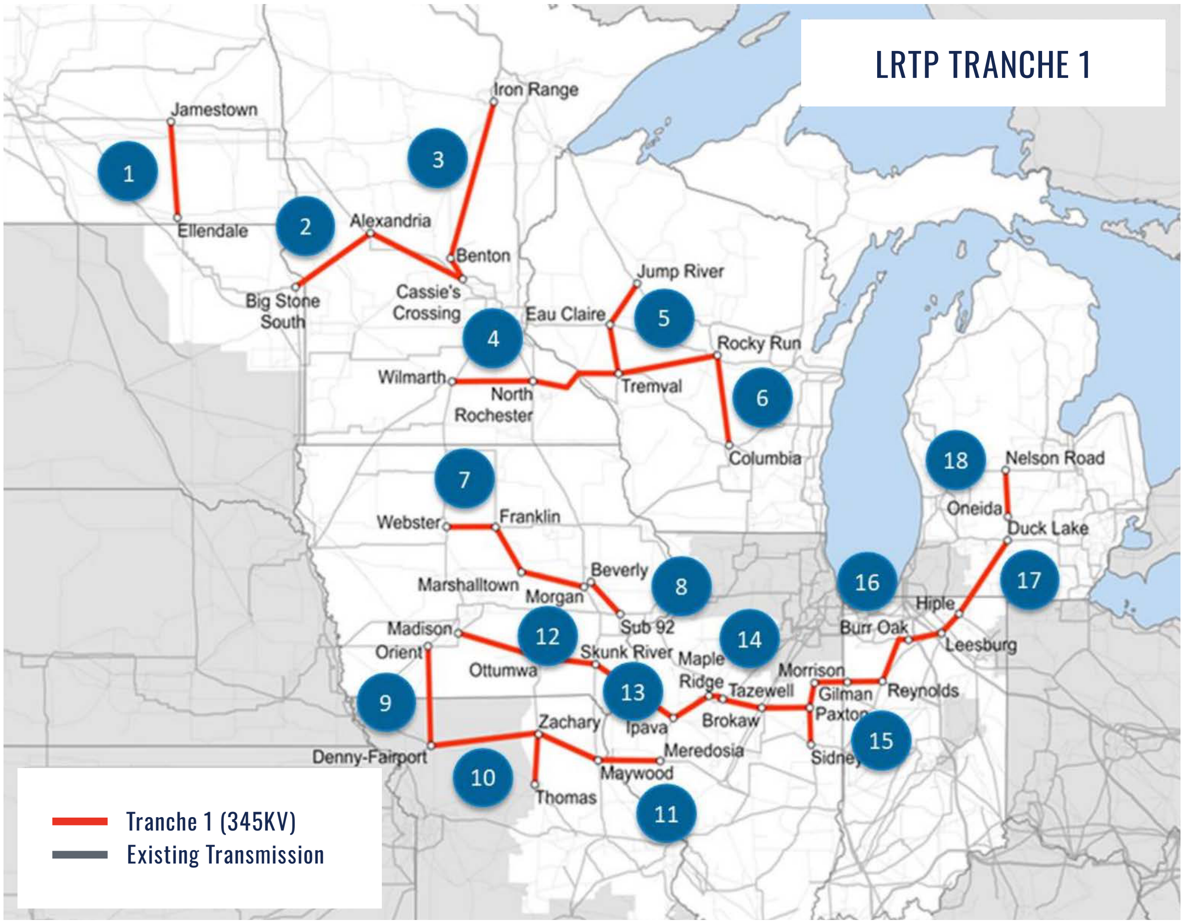
While this general approach of authorizing investment when benefits exceed costs is standard practice in the 100-year history of public utility regulation across many regulated industries, it is not yet standard practice in the US transmission sector. One area where practices still vary widely across the country is choosing the benefits to include in regional transmission assessments and determining how to quantify them. This paper seeks to further the development of consensus best practice benefits assessment by reviewing the benefits assessment in MISO's Long Range Transmission Plan (LRTP) "Tranche 1" portfolio.

In the spring of 2022 MISO released its LRTP Tranche 1 and in July the board unanimously approved the set of projects it proposes to move forward with in the near term. The MISO Board-approved projects are as follows:

1 See, e.g., Pfeifenberger, Gramlich, Spokas, Goggin, Hagerty, Caspary, Tsoukalis, Schneider, "Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs."

2 Pfeifenberger, Gramlich, Spokas, Goggin, Hagerty, Caspary, Tsoukalis, Schneider, "Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs."

FIGURE 1. *MISO LRTP Map of Tranche 1 Projects and Estimated Costs*[3]



MISO notes that this plan was "the culmination of two years of Futures development, modeling, and engineering and represents the most complex transmission planning study effort in MISO's history."[4] The plans help to achieve 60 percent decarbonization goals (saving 639 MMT of CO_2 emissions over 40 years) and facilitate the development of 70 GW of new renewables.[5]

Achieving sufficient regional support is critical for such plans to secure agreements on cost allocation and ultimately gain siting permits from states. In pursuit of such regional support, MISO undertook a general high-level effort with its states and stakeholders called its "Reliability Imperative," aimed at ensuring reliability with the rapidly evolving grid needs. The Reliability Imperative followed a focused analysis on the impacts of renewable energy growth in its Renewable Integration Impact Assessment, which highlighted the need for changes to

3 "Reliability Imperative: Long Range Transmission Planning," 7.
4 Ibid.
5 "MISO Futures Report," 3–4.

transmission, resource adequacy, market design, and other areas of MISO's grid management.[6] MISO performed scenario analysis through its MISO Futures Report, outlining three "futures," representing a low, medium, and high degree of clean energy expansion, decarbonization, and load growth driven by electrification.[7] MISO is now in the process of turning these "futures" into transmission plans, beginning with the Tranche 1 portfolio corresponding to "Future 1." Future 1 is a scenario that is 63% decarbonized, with 70 GW of new renewable capacity additions, 10% energy growth based on meeting most (but not all) of utility clean energy targets in the region.[8]

In many ways, MISO's planning is like what other grid planners around the world are now doing as they all face similar changing grid needs. For example, this year the California Independent System Operator released its 20 Year Transmission Outlook[9] and the Australia Energy Market Operator released an Integrated System Plan.[10] However, in three key ways MISO is on the cutting edge of this work and ahead of most US regional planning entities:

1. by proactively planning for a future resource mix based on many states' and utilities' projections,
2. performing multi-benefit analysis including the incidence of benefits to different beneficiaries,
3. and identifying specific portfolios of transmission projects.

As a pioneer in this work, MISO is having to blaze a new trail in certain areas. Benefits assessment is one area where there is no standard path. As of the date of this report, there are no standards provided by FERC. MISO has noted in comments to FERC that "identifying

6 "Renewable Integration Impact Assessment."
7 "MISO Futures Report."
8 "LRTP Business Case," 6.
9 "20 Year Transmission Outlook."
10 "2022 Integrated System Plan for the National Electricity Market."

additional benefit metrics has proved challenging. The process to identify the two new benefit metrics for [Market Efficiency Projects] required years of stakeholder review."[11] Benefits assessment for MISO's Market Efficiency Projects has been discussed and debated for much of the last decade and has been the subject of contested proceedings at FERC and litigation in courts. Different regional planning efforts around the country have used somewhat different categories of benefits. One review of benefits assessments showed the following set of somewhat varying categories:

FIGURE 2. *Benefits assessments in previous planning studies*[12]

	SPP *2016 Regional Cost Allocation Review, 2013 Metrics Task Force*	MISO *2011 Multi Value Projects Analysis*	CAISO *2007 Team Analysis of Devers–Palo Verde No. 2 Transmission Line Project*	NYISO *2015 Study of Proposed AC Transmission Upgrades*
QUANTIFIED	1. production cost savings value of reduced emissions reduced AS costs 2. avoided transmission project costs 3. reduced transmission losses capacity benefit energy cost benefit 4. lower transmission outage costs 5. value of reliability projects 6. value of meeting policy goals 7. increased wheeling revenues	1. production cost savings 2. reduced operating reserves 3. reduced planning reserves 4. reduced transmission losses 5. reduced renewable generation investment costs 6. reduced future transmission investment costs	1. production cost savings and reduced energy prices from both a societal and customer perspective 2. mitigation of market power 3. insurance value for highimpact low-probability events 4. capacity benefits due to reduced generation investment costs 5. operational benefits (RMR) 6. reduced transmission losses* 7. emissions benefit	1. production cost savings (includes savings not captured by normalized simulations) 2. capacity resource cost savings 3. reduced refurbishment costs for aging transmission 4. reduced costs of achieving renewable & climate goals
NOT QUANTIFIED	8. reduced cost of extreme events 9. reduced reserve margin 10. reduced loss of load probability 11. increased competition/liquidity 12. improved congestion hedging 13. mitigation of uncertainty 14. reduced plant cycling costs 15. societal economic benefits	7. enhanced generation policy flexibility 8. increased system robustness 9. decreased nat. gas price risk 10. decreased CO_2 emissions 11. decreased wind volatility 12. increased local investment and job creation	8. facilitation of the retirement of aging power plants 9. encouraging fuel diversity 10. improved reserve sharing 11. increased voltage support	1. production cost savings (includes savings not captured by normalized simulations) 2. capacity resource cost savings 3. reduced refurbishment costs for aging transmission 4. reduced costs of achieving renewable & climate goals

11 "Comments of the Midcontinent Independent System Operator," 24.

12 Pfeifenberger, Gramlich, Spokas, Goggin, Hagerty, Caspary, Tsoukalis, Schneider, "Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs." P. 31.

To achieve the current level of agreement on benefits, MISO, its stakeholders, and the Organization of MISO States (OMS) engaged in lengthy discussions about which benefits to include and how to estimate them. Stakeholders wanted to compare the benefits to the $10.3 billion estimated overnight cost[13] of the Tranche 1 transmission portfolio, both in aggregate and in terms of benefits and costs accruing to load in each zone. MISO's MVP tariff requires "The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs."[14] MISO's board also directs it to "[m]ake benefits of an economically efficient electricity market available to customers by identifying transmission solutions that enable access to the electricity at the lowest total electric system cost."[15] MISO ultimately arrived at a set of benefits to incorporate and quantified them to be $37.3 billion,[16] thus estimating a 3.6 benefit-cost ratio.

In this paper we review the set of benefits in MISO's LRTP Tranche 1 and how they were measured, to inform ongoing national discussions about how benefits assessments should be performed. This paper does not evaluate in any depth other aspects of the LRTP such as planning methods. On the surface it appears this plan and future tranches could be improved by better coordination with neighboring regions. On the positive side, the use of existing corridors is impressively high, near 90 percent for the lines,[17] but that is not the subject of this paper either. We now turn to the benefits assessment.

13 "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report," 4.
14 "LRTP Tranche 1 Portfolio Detailed Business Case," 7.
15 Ibid, 3.
16 "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report,"5.
17 "Reliability Imperative: Long Range Transmission Planning," 19.

MISO LRTP BENEFITS AND THEIR QUANTIFICATION

MISO analysis and distribution of benefits involved extensive stakeholder discussions in its Regional Expansion Cost and Benefits Working Group.[18] Minutes from this committee show that frequently over 150 people participate. Stakeholder input is received in these meetings as well as in writing, and MISO provides public oral and written responses to these comments, much like FERC does in its orders.[19]

In parallel to MISO's stakeholder group, **OMS ran a Transmission Cost Allocation Work Group (TCAWG) and a Cost Allocation Principles Committee (CAPCom) to develop a set of cost allocation principles.**[20] **OMS, for example, recommended zonal determination of benefits:** "The OMS TCAWG believes that LRTP projects will generate multiple benefits, and each benefit will accrue to a particular geographic area or zone. While some project attributes might benefit the entire MISO region, others might accrue only to smaller regions."[21]

18 "MISO Regional Expansion Criteria and Benefits Working Group."

19 "RECBWG: Granular Benefits Identification and Cost Allocation (20220228)." . Responses provided here: https://cdn.misoenergy.org/20220527%20PAC%20Item%2002a%20MTEP21%20Addendum%20Appendix%20F%20-%20LRTP%20Tranche%201%20Substantive%20Comments624805.pdf

20 "Organization of MISO States Statement of Principles: Cost Allocation for Long Range Transmission Planning Projects."

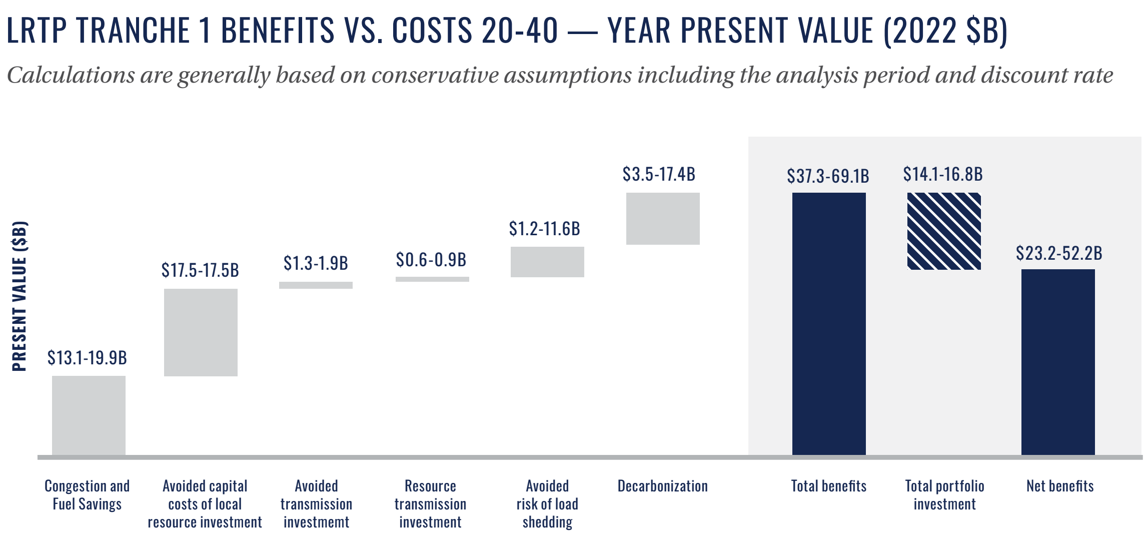
21 "RECBWG: Granular Benefits Identification and Cost Allocation (20220228)."

MISO's resulting set of benefit categories for LRTP Tranche 1 benefit-cost analysis includes the list below. Items A-D were included in previous MISO Multi-Value Project assessments, while items E and F were new categories or updated from the MVP methods:

A. Congestion and fuel savings
B. Avoided capital costs of local resource investments
C. Avoided transmission investment
D. Reduced resource adequacy requirements
E. Avoided risk of load shedding
F. Decarbonization
G. Reliability issues addressed by LRTP
H. Other qualitative and indirect benefits.[22]

The benefit of categories A-F in MISO's analysis are listed below.

FIGURE 3. *Benefits by category compared to cost, MISO LRTP Tranche 1*[23]



22 "LRTP Tranche 1 Portfolio Detailed Business Case," 10 Summarized from MISO Tariff - Attachment FF, II.C.5.
23 "Reliability Imperative: Long Range Transmission Planning," 8.

MISO noted there were stakeholder views in both directions—suggesting the benefits were either over-stated or under-stated. MISO stated, "In developing the methodology for each of the six benefit metrics, MISO was mindful to avoid overstating the value of benefits attributed to each metric, and most stakeholders broadly have agreed this transmission portfolio provides various benefits captured in the metrics."[24]

We compare the MISO LRTP Tranche 1 benefits assessment with best practice benefits assessment in the next section.

COMPARISON TO BEST PRACTICE BENEFITS ASSESSMENTS

Discounting approach

A general comment on each of MISO's estimates is that the discount rate and asset life should be changed to reflect standard economic welfare analysis. Standard economic policy analysis would include benefits over the life of the asset,[25] so the 40-year benefits would be the proper number to use. Ratepayers' valuation of future benefits is closer to the social discount rate of 3% than the cost of borrowing for investments of 6.9%, so the lower number should be used for discounting future benefits. Use of the lower discount rate approximately doubles the benefits.[26]

Benefits categories

The closest to a best practice, standard set of benefits can now be found in FERC's Notice of Proposed Rulemaking.[27] This set of benefits tracks closely with recommended practices in recent papers summarizing various multi-benefit planning efforts.[28] The exact definitions and organization of issues into distinct categories provided in FERC's taxonomy is slightly different from other approaches. As a FERC proposal, the taxonomy fits neatly within FERC's authority. There may be other benefits such economic development, environmental quality, and public health that may also be useful information to provide to stakeholders, but these benefits could be subject to challenge by parties to whom costs are allocated under authorities in the Federal Power Act. Ultimately, a cost allocation tariff must be approved by FERC based on its authority before any transmission plans can move forward, and specific allocations can be challenged at FERC.

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24 "Planning Advisory Committee Summary of Review and Advice to Advisory Committee and Board of Directors MISO Transmission Expansion Plan (MTEP21) Addendum Appendix F."

25 Zerbe and Scott, "A Primer for Understanding Benefit-Cost Analysis," 20.

26 See each benefit category in "LRTP Tranche 1 Portfolio Detailed Business Case."

27 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 179 FERC ¶ 61,028 (2022).

28 Pfeifenberger, Gramlich, Spokas, Goggin, Hagerty, Caspary, Tsoukalis, Schneider, "Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs."

This section compares MISO LRTP benefits assessment with the 12 categories of benefits described by FERC.

(1) "Avoided or deferred reliability transmission projects and aging infrastructure replacement."[29]

This benefit is important because there are so many aging assets requiring replacement to comply with reliability standards, yet it is often more efficient to replace them with regionally planned portfolios. This benefit has been incorporated into a number of planning studies and plans.[30]

LRTP incorporated this benefit, estimating it at $1.3 billion to $1.8 billion.[31] This estimate includes 836 miles of expected asset replacements.

Based on benefits over the 40-year asset life discounted at the social discount rate of 3 percent, this benefit category should be reported as MISO's estimate of $3.7 billion.[32]

(2) "Either reduced loss of load probability or reduced planning reserve margin."[33]

This benefit is important because generation capacity is so expensive for consumers. Transmission can reduce the system-wide reserve requirements. As suggested by the name of the category, one can measure it in terms of the value of avoided loss of load or the reduced required reserve margin savings. Reduced loss of load expectation can be estimated by the value of lost load. Valuing averted load loss has been done in a number of cases.[34] One can also measure this same value in terms of the generation capital cost savings achievable through transmission. The alternative means of calculating this benefit of the generation cost savings from a lower Planning Reserve Margin has also been used in multiple cases.[35]

As MISO stated in its stakeholder process, "transmission is the enabler of reserve sharing for the MISO pool so that each load serving entity does not need to cover its own reserves but can share those resources when needed most."[36]

LRTP estimates this benefit at $624-893 million.[37]

It is not clear that MISO's analysis fully considers the capacity cost savings that result when

29 Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 179 FERC ¶ 61,028 at P 189-193 (2022).

30 Order No. 1000, 136 FERC ¶ 61,051 at P 81; See, e.g., S.C. Elec. & Gas Co., 143 FERC ¶ 61,058, at 232 (2013); Pfeifenberger et al., "Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs," Pfeifenberger, Gramlich, Spokas, Goggin, Hagerty, Caspary, Tsoukalis, Schneider, "Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs." p. 37; SPP Engineering, SPP Benefit Metrics Manual, at 15 (2020); Newell et al., "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," 114.; "Proposed Multi Value Project Portfolio," 42-44. "2022 Integrated System Plan for the National Electricity Market," 64.

31 "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report," 55.

32 Ibid.

33 179 FERC ¶ 61,028 at P 194-197

34 "Benefits for the 2013 Regional Cost Allocation Review," 25; Frayer et al., "How Does Electric Transmission Benefit You?: Identifying and Measuring the Life-Cycle Benefits of Infrastructure Investment."

35 "Proposed Multi Value Project Portfolio: Business Case Workshop," at 36-38; "Benefits for the 2013 Regional Cost Allocation Review," Section 5.1. ; Public Service Commission (PSC) of Wisconsin (WI), Order, re Investigation on the Commission's Own Motion to Review the 18 Percent Planning Reserve Margin Requirement, Docket 5-EI-141, PSC REF#:102692, dated October 9, 2008, received October 11, 2008, p 5; Southwest Power Pool (SPP), The Value of Transmission, January 26, 2016, p 16; "MISO Value Proposition 2020," Detailed Circulation Description, n.d., p 22.; "PJM Value Proposition," 2.; "2022 Integrated System Plan for the National Electricity Market," 64.

36 "Planning Advisory Committee Summary of Review and Advice to Advisory Committee and Board of Directors MISO Transmission Expansion Plan (MTEP21) Addendum Appendix F," 4.

37 "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report," 55.

the renewable energy portfolio is geographically diversified, as is enabled by transmission expansion. That benefit is not mentioned in its business case. The geographic diversification effect was about 5% capacity value increase in the Eastern Wind Integration and Transmission Study.[38] On-peak import capacity should be increased by the LRTP lines, yet it appears to be fixed at 2,331 MW ("unforced capacity," or UCAP).[39]

At a minimum the $1.6 billion based on a 3% discount rate and 40 year asset life should be used.

(3) Production cost savings.[40]

Production cost savings is the most basic and widely used type of benefit. It can be studied relatively easily with standard production cost software and data. It is proposed in the FERC NOPR and has been used in a number of planning efforts.[41] The category includes fuel and variable operating cost savings, and adjustments for imports from neighboring regions.

MISO LRTP incorporates this benefit, using the term "Congestion and Fuel Savings."[42] MISO reports benefits in this category of $13.1 billion over 20 years and $19.9 billion over 40 years at based on a discount rate of 6.9% to reflect the Weighted Average Cost of Capital.[43]

While these are significant benefits, using the 13.1-19.9 billion under-reports the benefits. MISO estimates 40-year benefits discounted at 3% are $38.2 billion, so that number should be used.

MISO also incorporates the value of carbon emissions reductions. Carbon cost savings can be included in the production cost category because it is the expected savings based on future environmental regulations. It is standard practice in RTOs to consider SOx and NOx permit costs as a standard operating cost of generators, used for market power monitoring and mitigation purposes. MISO LRTP estimates carbon savings to be $3.5 billion to $17.4 billion but includes this value under a separate metric.[44]

MISO LRTP's congestion and fuel savings analysis is very conservative due to the use of low natural gas prices. The sensitivity cases raise prices 20 and 60%.[45] Yet actual natural gas prices have doubled just in the last year.[46] While they could decline, the volatility itself in natural gas prices poses costs. A higher range for sensitivity analysis would show greater benefit.

(4) Reduced transmission energy losses.[47]

These are real operational savings from the lower losses that result from greater transmission

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38 "Eastern Wind Integration and Transmission Study," 54.

39 "Planning Year 2022-2023 Loss of Load Expectation Study Report," 22

40 179 FERC ¶ 61,028 at P 198-201.

41 MISO, FERC Electric Tariff, Attach. FF, Benefit Metrics § (I)(A)(1) (33.0.0). See PJM Interconnection L.L.C.,142 FERC ¶ 61,214, at P 416 (2013) (PJM First Regional Compliance Order); New York Independent System Operator Corp.,143 FERC ¶ 61,059 at PP 268, 269, n.516 (2013) (NYISO First Regional Compliance Order); NYISO, NYISO Tariffs, OATT, attach. Y, § 31.5 (27.0.0), § 31.5.4.3.2. Pub. Serv. Co. of Colo., 142 FERC ¶ 61,206, at P 314 (2013); ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137-CE-149, app. C, Ex. 1, at 34-38 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007). "Regional Cost Allocation Review (RCAR II)," 5; "2022 Integrated System Plan for the National Electricity Market," 64.

42 "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report," 47.

43 Ibid.

44 Ibid.

45 Ibid, 69-71.

46 "Natural Gas Weekly Update."

47 179 FERC ¶ 61,028 at P 202-204

capacity.[48] This has been calculated in various studies.[49]

LRTP did not explicitly estimate or report potential benefits in this area.

(5) Reduced congestion due to transmission outages.[50]

This is important because in the real world congestion tends to be much higher than it is in planning models, which assume all facilities are in service. In terms of benefits taxonomy, this could be considered as part of Adjusted Production Cost, or as a separate category as FERC does. As stated by MidAmerican in the LRTP process, "MidAmerican believes the production cost models used for this analysis provide conservative values for the congestion benefits because the transmission system is, for nearly all periods of time, in a state with more outages than the N-1 conditions assumed in MISO's models (i.e., there is nearly always multiple planned and forced outages at any given point in time which can have significant impacts on congestion)."[51]

LRTP does not explicitly calculate benefits from this category. MISO does note that the analysis is conservative because "the adjusted production cost value is understated because the model begins with a system intact state, which seldom is the case in MISO (i.e., there is nearly always multiple planned and forced outages at any given point in time which can have significant impacts on congestion)."[52]

48 179 FERC ¶ 61,028 at P 202

49 ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137-CE-149, app. C, Ex. 1, at 34-38 (Wisc. Pub. Serv.; "Regional Cost Allocation Review (RCAR II)," 5.

50 179 FERC ¶ 61,028 at P 205

51 "Planning Advisory Committee Summary of Review and Advice to Advisory Committee and Board of Directors MISO Transmission Expansion Plan (MTEP21) Addendum Appendix F," 3.

52 Ibid.

(6) Mitigation of extreme events and system contingencies.[53]

This category is increasingly important as weather changes present new conditions that should be included in planning. FERC defines this benefit as "reductions in production costs resulting from reduced high-cost generation and emergency procurements necessary to support the transmission system during extreme events (such as unusual weather conditions, fuel shortages, or multiple or sustained generation and transmission outages) and system contingencies."[54]

MISO includes this benefit but estimates it based on reduction of emergency events rather than reduction of production cost.

LRTP estimates this type of benefit to be $1.2 billion to $11.5 billion.[55] The wide range reflects the difference between the $3500/MWh and $23,000/MWh Value of Lost Load (VOLL), with the latter being recommended by the Independent Market Monitor (IMM).

Using the IMM recommended VOLL, 3% discount rate, and 40-year asset life in MISO's estimates yields a benefit in this category of $21.1 billion. Thus, $21 billion should be incorporated into the benefits assessment and reporting.

The analysis is also very conservative in several respects. As stated by the Environmental Sector in its comments on the plan, "MISO's methodology for estimating this benefit is limited to extreme winter weather events, both winter storms and extreme cold temperatures. This narrow perspective is a highly conservative measure of the total LRTP benefits of avoided loss of load. Extreme heat, hurricanes, drought, and flooding are all projected to impact the MISO territory as climate change impacts worsen."[56] A more thorough assessment of conditions could be drawn from National Oceanic and Atmospheric Administration and other authorities. MISO noted that "the adoption of reliability/resiliency benefits such as avoided risk of load shedding was intentionally limited in scope due to the challenges not only in analyzing the future weather impacts, but also in monetizing the value to the customer."[57] The description of the estimate should at a minimum characterize it as very conservative given this stated approach.

(7) Mitigation of weather and load uncertainty.[58]

This is an additional benefit stemming from the uncertainty associated with load and generation, and the value of transmission to integrate areas with load, generation, and "net load" diversity.[59] It has been incorporated in certain cases.[60]

MISO discusses these benefits in two qualitative categories: "reliability issues" and "other qualitative benefits." Neither category was quantified. But MISO explains, "Regional energy transfers increase in magnitude and become more variable, leading to a need for increased

53 179 FERC ¶ 61,028 at P 206-207

54 179 FERC ¶ 61,028 at P 206.

55 "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report," 64.

56 "Planning Advisory Committee Summary of Review and Advice to Advisory Committee and Board of Directors MISO Transmission Expansion Plan (MTEP21) Addendum Appendix F," 29.

57 Ibid.

58 179 FERC ¶ 61,028 at P 208-209.

59 Ibid.

60 ERCOT, Economic Planning Criteria: Question 1: 1/7/2011 Joint CMWG/PLWG Meeting, at 10 (Mar. 4, 2011). The $57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant Energy estimated probabilities for the same scenarios.

extra-high voltage transfer capabilities."[61]

(8) Capacity cost benefits from reduced peak energy losses.[62]

This is also a distinct benefit category included by FERC.[63] It has been measured before.[64]

LRTP does not measure benefits in this category. MISO staff shared that the benefits were expected to be too small to factor in, given they were calculated in the 2011 MVP Portfolio and amounted to <1% of the total benefits.

(9) Deferred generation capacity investments.[65]

This benefit reflects the substitution of transmission for generation, which may result in savings.[66] These savings can be calculated and have been.[67] FERC defines this as transmission that "either defers or negates the need to invest in generation capacity resources within a transmission planning region by increasing import capability from neighboring regions into resource-constrained areas."[68] Thus it is a more localized concept, and separate from the system-wide resource adequacy benefit defined above.

LRTP does not explicitly use this category, though it is at least partially covered by the category below: access to lower cost generation. Specifically, MISO looked at how the Tranche 1 lines optimized renewable energy siting across the region and avoided more costly local development.[69] Other benefits that MISO could track include higher renewable energy capacity value due to geographic distribution and the import and export benefits. More explanation of this category would help stakeholders understand whether this benefit is incorporated.

(10) Access to lower-cost generation.[70]

This benefit is widely recognized though rarely actually incorporated. Generation capacity cost savings are separate from production cost savings described above. It is included in FERC's list[71] and has been included in a number of transmission valuation efforts.[72] There is often a tradeoff between more remote low-cost generation delivered with transmission, and more local higher cost generation that requires less transmission. Remote generation is not only typically higher quality resources in terms of resource adequacy contributions, but also are more diverse resources which also improves their capacity value contribution. Planners should assess this

61 "LRTP Tranche 1 Portfolio Detailed Business Case," 47.

62 179 FERC ¶ 61,028 at P 210-212.

63 179 FERC ¶ 61,028 at P 210-212.

64 ITC Holdings Co., Joint Application, Docket No. EC12-145-000, at Ex. ITC-600, 77-78 (Test. of Pfeifenberger) (filed Sept. 24, 2012); Southwest Power Pool, SPP Priority Projects Phase II Report, Rev. 1, April 27, 2010, p 26.; ATC, Planning Analysis of the Paddock-Rockdale Project, April 5, 2007 (filed in PSCW Docket 137-CE-149, PSC Reference # 75598), pp. 4, 63; Midwest ISO (MISO), "Proposed Multi Value Project Portfolio," 25 and 27.

65 179 FERC ¶ 61,028 at P 213-215.

66 Ibid.

67 ITC Holdings Co., Joint Application, Docket No. EC12-145-000, at Ex. ITC-600 (Test. of Pfeifenberger) (filed Sept. 24, 2012) at 58-59.; "2022 Integrated System Plan for the National Electricity Market," 64.

68 179 FERC ¶ 61,028 at P 214.

69 "Reliability Imperative: Long Range Transmission Planning," 20.

70 179 FERC ¶ 61,028 at P 216-218.

71 Ibid.

72 Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project, Application 05-04-015 (Cal. Comm'n Jan. 27, 2007); Midwest ISO, RGOS: Regional Generation Outlet Study, November 19, 2010, p. 32 and Appendix A.; Billo, "The Texas Competitive Renewable Energy Zone Process."; "2022 Integrated System Plan for the National Electricity Market," 64.; American Transmission Company LLC (ATC), Arrowhead-Weston Transmission Line: Benefits Report, February 2009, p 7.

tradeoff. As available local sites are used up over time, it is reasonable to expect a greater need for and reliance on remote resources, justifying more transmission.

MISO's Regional Generation Outlet Study in 2010 was innovative in this area, showing a "bathtub" curve with higher prices for high reliance on only local or only remote generation, with a lower middle sweet-spot of an optimal combination of transmission, remote, and local generation.[73] This benefit is realized by accessing more productive renewable resource areas, so a comparable amount of renewable energy generation (measured in MWh) can be obtained with a smaller investment in the amount of installed renewable capacity (measured in MW). By accessing some amount of remote, cheaper generation, MISO's initial analysis found that its MVP portfolio reduced the present value of wind generation investments by between $1.4 billion and $2.5 billion, offsetting approximately 15% of the transmission project costs.[74]

MISO LRTP incorporates this benefit and values it at $17.5 billion.[75]

This benefit should be reported as $18.4 billion which is what MISO estimates using the social discount rate.

(11) Increased competition.[76]

This category is important because transmission can broaden the "geographic market," enabling more suppliers to compete and preventing the exercise of localized market power in both energy and capacity markets, driving down prices. FERC described a few ways to analyze this benefit.[77] It has been incorporated in some instances.[78]

LRTP does not mention or incorporate this benefit.

Increased market liquidity.[79]

This distinct benefit relates to the increased number of transactions when more trade is possible, reducing the variation in prices and increasing the transparency of the market.[80]

LRTP does not mention or include benefits in this area.

73 "Multi Value Project Portfolio: Results and Analysis," 16.

74 "Proposed Multi Value Project Portfolio," 25 and 38-41.

75 "MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report," 53.

76 179 FERC ¶ 61,028 at P 219-224.

77 179 FERC ¶ 61,028 at P 219-224, citing Pfeifenberger et al., "Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs," 46-47, and Wolak, F. A., "Managing Unilateral Market Power in Electricity," 8.

78 Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project, Application 05-04-015 (Cal. Comm'n Jan. 27, 2007); ATC, Planning Analysis of the Paddock-Rockdale Project, at 44-49 (Apr. 5, 2007). CAISO, Transmission Economic Assessment Methodology, Chapter 4, 1-12 (2004).

79 179 FERC ¶ 61,028 at P 225

80 Ibid.; Pfeifenberger, Gramlich, Spokas, Goggin, Hagerty, Caspary, Tsoukalis, Schneider, "Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs." P. 50.

GENERAL ASSESSMENT OF LRTP BENEFITS ASSESSMENT

MISO's LRTP for its Tranche 1 portfolio is a sound approach generally, reflecting the main benefits of transmission. The method reflects a conservative view of the types of benefits to include and the methodologies and assumptions used to calculate them. Seven of FERC's 12 categories are not included.

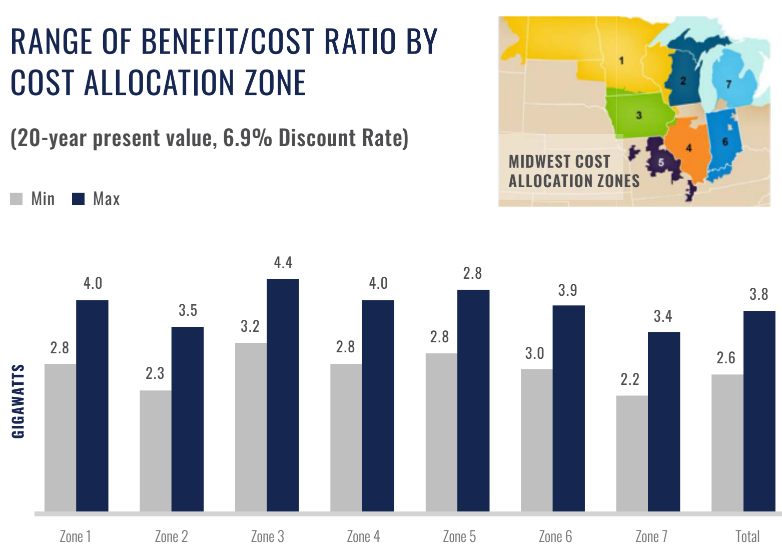
More explanation is required to understand why resource adequacy benefits were estimated to be so low. It is not clear why that category is not in the billions of dollars of value along with the other categories.

BENEFITS INCIDENCE ANALYSIS

What really matters for each stakeholder's support for transmission investment plans is the amount of costs assigned to them. MISO's LRTP Tranche 1 did estimate how much each load zone benefitted from the plans.

A common aspect of multi-benefit plans is that when multiple benefits are incorporated, the benefits tend to be pretty evenly spread, as the figure below illustrates.

FIGURE 4. *Incidence of Benefits*[81]



81 "Reliability Imperative: Long Range Transmission Planning," 9.

As a result of the wide distribution of benefits, all regions were estimated to have greater than 2 benefit-cost ratios. Courts' interpretations of the Federal Power Act require cost assignment that is roughly commensurate with benefits. Determining which customers should pay how much for transmission tends to be less contentious when benefits happen to be widely distributed. Because securing broad cost allocation across the region is essential for transmission projects to move forward, it is important to measure and report the benefits by load zone, even when the benefit estimates come out evenly spread.

IMPLICATIONS

MISO's effort of working with stakeholders to determine an acceptable set of benefits to include, and means of calculating them, will be very beneficial for future benefits analysis in the Midwest and around the country.

MISO and its stakeholders should consider the seven other benefit categories listed by FERC, and at least evaluate whether any of them might lead to a significant change in the results. The new categories can also be included as MISO proceeds to the next tranches of transmission including focusing on drivers from Futures 2 and 3 in its Futures Report.

It is important to consider all the benefits from every portfolio of lines. Transmission provides a varied array of benefits but not every line or set of lines provide benefits in the same categories. Recent work suggests that any given line or group of lines may have different types and magnitudes of benefits than others. A recent report by Telos for the Energy Systems Integration Group finds "different transmission projects can show large differences in the types of value they bring."[82] Since some of these categories can be difficult and resource intensive to quantify, a good practice would be to screen each category initially for every set of lines in a plan, then spend time and modeling resources to thoroughly evaluate both the benefits and the incidence of benefits on those categories where benefits are likely to be significant.

It is arguably unjust and unreasonable to completely ignore known and quantifiable benefits from the benefit-cost equation. Now that a few regional planning entities are settling on a relatively common set of benefits and benefit calculation methodologies, and FERC is increasing its guidance to each region, it should be easier for each regional planner to determine categories of benefits and methodologies of calculation.

82 Stenclik and Deyoe, 6.

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Duke Energy Progress

Preliminary Resource Additions and Retirements

Line	Utility	Coal Retirements (1)	Solar (2)	Onshore Wind (3)	Battery (4)	CC (5)	CT (6)	Offshore Wind (7)	Small Modular Reactor (8)	Pumped Storage Hydro (9)
	Portfolio 1 - Interim Target Achievement in 2030									
1	Duke Energy Carolinas	(1,700)	3,800	0	800	1,200	0	0	0	0
2	Duke Energy Progress	(3,200)	3,400	600	2,400	1,200	0	800	0	0
3	Total	(4,900)	7,200	600	3,200	2,400	0	800	0	0
	Portfolio 2 - Interim Target Achievement in 2032									
4	Duke Energy Carolinas	(1,700)	4,100	0	1,100	1,200	0	0	0	0
5	Duke Energy Progress	(3,200)	3,100	1,200	1,900	1,200	0	1,600	0	0
6	Total	(4,900)	7,200	1,200	3,000	2,400	0	1,600	0	0
	Portfolio 3 - Interim Target Achievement in 2034									
7	Duke Energy Carolinas	(3,100)	5,000	0	900	1,200	0	0	300	1,700
8	Duke Energy Progress	(3,200)	4,600	1,200	2,600	1,200	0	0	0	0
9	Total	(6,300)	9,600	1,200	3,500	2,400	0	0	300	1,700
	Portfolio 4 - Interim Target Achievement in 2034									
10	Duke Energy Carolinas	(3,100)	5,000	0	900	1,200	0	0	300	1,700
11	Duke Energy Progress	(3,200)	3,700	1,200	1,800	1,200	0	800	0	0
12	Total	(6,300)	8,700	1,200	2,700	2,400	0	800	300	1,700

Source:
Appendix E, Tables E-48, E-49, E-50, and E-51.

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The Role of Electricity Prices in Structural Transformation: Evidence from the Philippines

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The Role of Electricity Prices in Structural Transformation: Evidence from the Philippines*

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ABSTRACT

The Philippines provides an extreme example of Rodrik's observation that late developing countries experience deindustrialization at lower levels of per capita income than more advanced economies. Previous studies point to the role of protectionist policies, financial crises, and currency overvaluation as explanations for the shrinking share of the industry sector. We complement this literature by examining the role of electricity prices in the trajectory of industry share. We make use of data at the country level for 33 countries over the period 1980-2014 and at the Philippine regional level for 16 regions over the period 1990-2014. We find that higher electricity prices tend to amplify deindustrialization, causing industry share to turn downward at a lower peak and a lower per capita income, and to decline more steeply than otherwise. In a two-country comparison, we find that power-intensive manufacturing subsectors have expanded more rapidly in Indonesia, where electricity prices have been low, whereas Philippine manufacturing has shifted toward less power intensive and more labor-intensive subsectors in the face of high electricity prices.

Keywords: electricity prices, structural transformation, deindustrialization

JEL codes: O10, O14, Q40, Q41

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The Role of Electricity prices in Structural Transformation: Evidence from the Philippines

1. INTRODUCTION

One of the arguments for making power more affordable is that cheaper power may help to ameliorate premature deindustrialization, i.e. the peaking of industry's share in employment and value added at substantially lower levels of per capita income than historically observed in developed countries (Dasgupta and Singh 2007; Rodrik 2016). Premature deindustrialization can have adverse productivity effects and slow development generally. For example, deindustrialization in Latin American and African countries has been accompanied by growth of low productivity informal and non-traded goods sectors and increased rural-to-urban migration (Rodrik 2016).

While it is not difficult to imagine why high power-prices could be disadvantageous to manufacturing, empirical analysis of the relationship between electricity prices and industry is wanting, as is understanding of the mechanisms by which electricity prices influence structural change. The high cost of power may act as a deterrent to investment in power-intensive industries thereby biasing growth towards more labor-intensive sectors as well as industrial subsectors. Some manufacturing industries, e.g. electronics assembly lines, can also be sensitive to the quality of power. A few seconds of fluctuating electric current may waste a whole batch, substantially increasing costs.

From 1991 to 2000, the power industries in Indonesia, Malaysia, Thailand, and the Philippines were all vertically integrated and highly subsidized. With the Philippines' passage of the Electric Power Industry Reform Act (EPIRA) in 2001, the power industry went through a major restructuring. Generation was privatized and a transition to more competitive retailing was mandated. [1] Transmission and distribution were left as regulated monopolies. Due to implementation delays and the loss of subsidies, however, industrial electricity prices remain high, although the rate of price increase has slowed significantly (Ravago et al. 2018c).

Electricity prices have been high in the Philippines relative to its ASEAN neighbors (International Energy Agency 2016). Philippine residential rates in 2015 were \$0.19/kWh versus \$0.16/kWh in Singapore, \$0.13/kWh in Thailand, \$0.12/kWh in Indonesia, and \$0.08/kWh in Malaysia. Industrial rates were also higher in the Philippines (\$0.12/kWh) than in the rest of ASEAN with the exception of Singapore (at \$0.13/kWh).

There are many reasons why electricity prices have been high in the Philippines, including governance failures in the form of red tape (Clarete 2018), onerous licensing requirements (Escresa 2018), and local–central government standoffs, e.g., the Redondo case (Fabella 2018). These have dampened the appetite of investors (Alonzo and Guanzon 2018) resulting in a paucity of new generation capacity in the face of growing demand (Abrenica 2014). Taxes and subsidies (Clarete 2018), sub-optimal fuel mix (Ravago et al. 2018a), feed-in-tariffs, and missionary charges also contribute to the high cost of electricity (Ravago and

[1] As of 2018, implementation of EPIRA has experienced delays and the competitive retail sector has not fully materialized. See also Alonzo and Guanzon (2018) on the evolution of Philippine electricity policy and Ravago et al. (2018c) for further discussion of EPIRA implementation and timeline.

Roumasset 2018). Lack of competitiveness and possible transfer pricing from generation companies to affiliated distribution utilities may also increase prices (Ravago et al 2018b, Abrenica 2014). While transmission costs are slightly higher in an archipelago, high prices persist even in large population clusters on the major islands, e.g., within the National Capital Region and surrounding areas.

In this paper, we seek to illuminate how high electricity prices can exacerbate premature deindustrialization. High prices of an input tend to discourage the growth of sectors that use that input more intensively. Specifically, we illustrate the role that electricity prices play in the growth and composition of industry in the Philippines. We show that the composition of Philippine manufacturing shifted in favor of subsectors that use power less intensively (e.g. machinery). This is in contrast to Indonesia's experience, where manufacturing growth has been largely driven by more power-intensive subsectors. We adapt Rodrik's (2016) analysis to capture the relationship between electricity prices and the share of industry in total output. We then simulate how industry's share changes with electricity prices.

In cross-country analysis, we find that higher electricity prices are associated with a downward shift in the share of industrial gross value added (GVA) and the peaking of industry shares at lower per capita incomes. In analysis of Philippine data at the regional level, we similarly find higher electricity prices being associated with the industry share in output peaking at substantially lower levels of per capita income and declining at a much faster rate. While data limitations constrain definitive conclusions about causality, it appears that structural transformation is not independent of electricity prices, particularly in the Philippines.

The paper is organized as follows: Section 2 documents some stylized facts about electricity prices and structural transformation in the Philippines and neighboring countries. The Philippine development path displays Rodrik's rule with a vengeance; the share of manufacturing turned downwards at a relatively low maximum and descended faster. Comparing the Philippines with its higher per-capita income Southeast Asian neighbors, the shares of the industrial sectors are inversely correlated with electricity prices. With the exception of Singapore, Philippine electricity prices are highest and industry shares lowest. Controlling for subsector, the electricity cost shares tend to be higher in the Philippines than in Indonesia. The descriptive analysis helps motivate further analysis of premature deindustrialization and its relationship to electricity prices. Section 3 outlines the empirical methodology adapted from Rodrik (2016) to examine the issue more formally. It then presents the estimation results of the cross-country analysis and for regions of the Philippines. Section 4 provides conclusions and policy implications.

2. STRUCTURAL TRANSFORMATION AND ELECTRICITY PRICES: STYLIZED FACTS

There are several mechanisms through which electricity prices can influence growth in industry and hence the structural development of an economy. One mechanism operates through business investment, since higher electricity prices increase the marginal cost of production according to the cost share of electric power. The demanded quantities of energy intensive goods will also decline. Using National Income and Product Account data from the U.S. Bureau of Economic Analysis, Edelstein and Kilian (2007) analyzed how energy price shocks influence non-residential fixed investment and concluded that while the estimated negative response of business fixed investment to energy price shocks tends to be small, it satisfies conventional statistical significance criteria.

Abeberese (2017) looked at the impact of electricity prices on manufacturing productivity and found that firms switch to less power-intensive production in response to higher electricity prices. If less power-intensive industries involve lower technology products, then higher electricity prices could result in less product sophistication and consequently, lower productivity. Electricity rates can also influence national output. Alvarez and Valencia (2016) showed that in Mexico a 13% reduction in electricity prices due to substitution of fuel oil for natural gas could increase Mexico's manufacturing output by 1.4% to 3.6%.

High electricity prices can also have a negative effect on foreign direct investment (FDI). The literature is replete with studies illustrating how FDI can increase productivity and growth of the manufacturing sector (e.g., Arnold and Javorcik 2009). Nonetheless, few have looked at the impact of energy prices on FDI inflows. Bilgili et al. (2012) is one of the rare examples, which found that high-energy prices deterred FDI entry into Turkey, particularly at times when FDI inflow was high in other countries.

The Philippine experience has long puzzled development scholars. In the early 19^{th} century, the Philippines was the third Asian country (and the first in Southeast Asia) to enter the so-called "5% industrial growth club"—those countries that had experienced industrial growth rates of at least 5% a year (De Dios and Williamson 2015). This continued until the early 1960s when the Philippines had the most developed manufacturing sector in Southeast Asia, albeit supported by import protection (Bautista and Power 1979; Power and Sicat 1971). However, industrialization stagnated from the late 1960s, with the Philippines thereby missing the East Asian Miracle which brought the dramatic ascent of newly industrialized economies across Asia in the 1970s through the 1990s (e.g., Vos and Yap 1996). With the relative decline of industry in the Philippines, in particular manufacturing, came the rise of services. Workers from rural and agricultural areas, in search of better living standards, often found themselves in low-skill, traditional service-oriented jobs or as contract workers overseas.

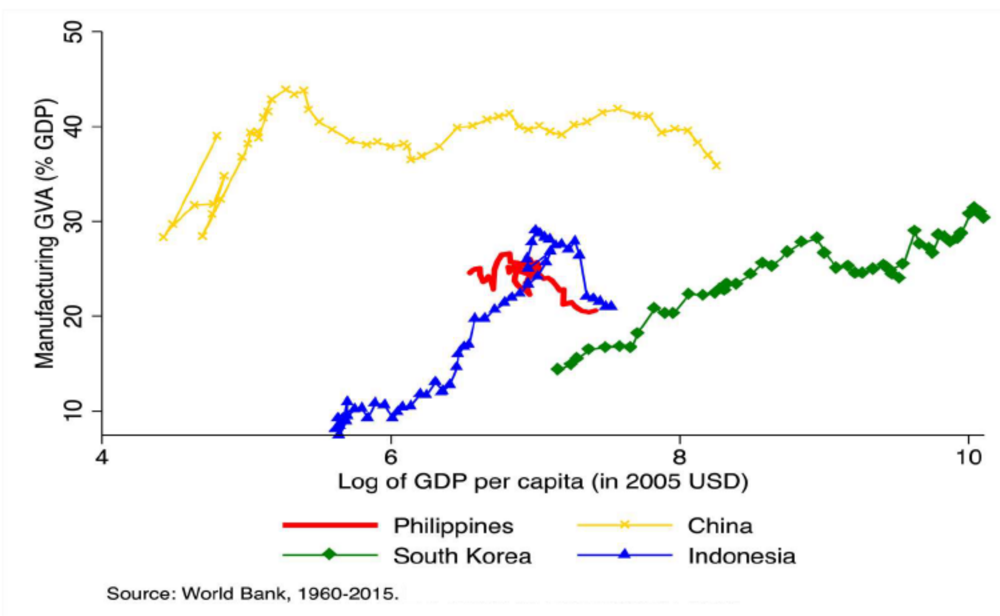
Daway and Fabella (2015) and de Dios and Williamson (2015) attribute the country's premature deindustrialization to decades of protectionism, political instability, insufficient export promotion, financial crises, and real exchange rate overvaluation. Recent anecdotal accounts, however, stress how higher electricity prices may have also stunted industrial growth. For instance, Rimando and Mercado (2013) and Deloitte (2014) assert that high power costs hampered the Philippines' ability to compete in the manufacturing sector. Philippine small and medium enterprises in particular are said to be hit hardest by high power costs (Remo 2014). For those manufacturing industries that did operate in the Philippines, the high cost of power is often cited as among the constraints to expansion. Unreliability of power supply further increases usage costs. Since 2006, the Philippines has ranked below Indonesia, Malaysia, and Thailand in terms of power quality according to the Global Competitiveness Report of the World Economic Forum (World Bank WEF 2018). In 2016-2017, out of the 138 countries surveyed, the

Philippines ranked 94th whereas Indonesia, Malaysia, and Thailand ranked 89th, 39th, 61st, respectively (World Bank WEF 2018).[2]

The Philippines is not unique in its industrial under-performance. Using data from the Groningen Growth and Development Center (Timmer et al. 2014) covering 42 countries, Rodrik (2016) observed that the vast majority of developing countries today are experiencing deindustrialization at lower levels of per-capita income. His analysis indicates that manufacturing employment shares in late peaking countries (after 1990) were about one-third that of earlier peaking countries.

To further motivate the discussion, we examine data on manufacturing output shares from the World Development Indicators (WDI) for China, Indonesia, South Korea, and the Philippines. Manufacturing is the largest component of the industrial sector, which also includes mining and quarrying, construction, and supply of electricity, gas, and water. Figure 1 shows the relationship between gross domestic product (GDP) per capita and the share of manufacturing gross value added (GVA) in GDP. Manufacturing share in the Philippines reached its peak at a low level of GDP per capita relative to its neighbors. As Figure 1 shows, the manufacturing share in the Philippines peaked at a lower level and at a lower GDP per capita compared to China, South Korea and Indonesia. The horizontal distance of each line reflects the growth of each economy from 1960 to 2015. For example, the percentage increase in South Korea's per capita GDP was an order of magnitude greater than that in the Philippines.

Figure 1. Manufacturing Share vs. GDP per capita, 1960-2015



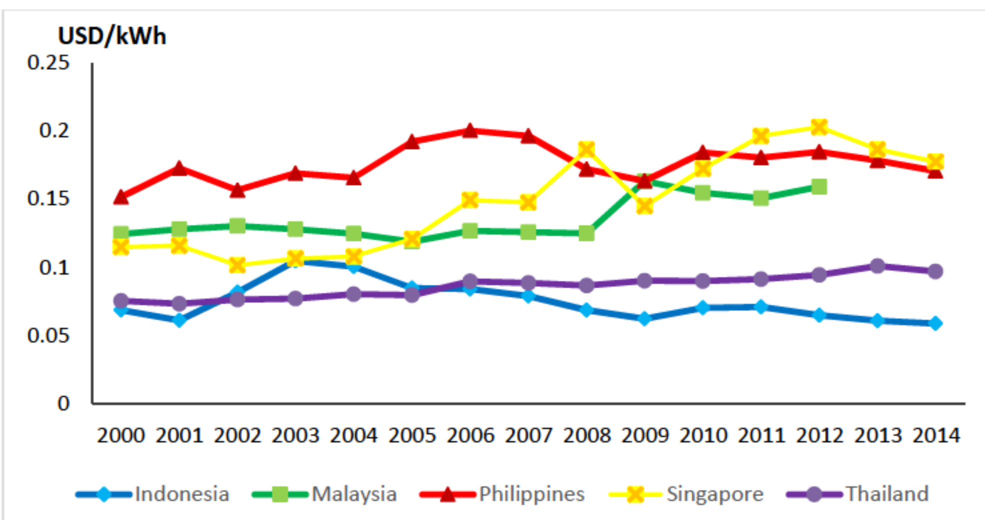
Manufacturing share in the Philippines fell fast and from a relatively low level.
Data source: World Development Indicators .

[2] While the Philippines is ranked a respectable 29th in the world for "getting electricity" (well below Malaysia and Thailand and only slightly above Indonesia in the *Rankings and Ease of Doing Business Score,* World Bank 2018), this metric is presumably more about accessibility grid connections) than quality and reliability.

The Philippine growth path vis-à-vis its Asian neighbors is characterized by an early substitution away from manufacturing toward services at significantly lower levels of per capita income. With the Plaza Accord in 1985, Japanese firms sought to restore their competitive advantage by developing a regionally integrated supply chain of component and assembly plants. This impetus, and the competitive response of European and American firms, led countries in East and Southeast Asia to develop particular niches within their own manufacturing sectors according to their own comparative advantages. Thailand was the recipient of major Japanese investments and became a prime location for automotive manufacturing. South Korea and Taiwan became hubs of electronic and semiconductor production. Malaysia was able to boost its information technology industry, while Vietnam gained foreign attention as a promising new economy for low cost, labor intensive manufacturing. The Philippines, in contrast, seems to have failed to partake in this industrial renaissance, not only losing ground in manufacturing for much of the latter part of the 20th century but doing so at a comparatively rapid rate.[3]

Have electricity prices played a significant role in hampering Philippine industrialization? Since the 1990s, electricity rates in the Philippines have been consistently high relative to neighboring countries such as Indonesia, Malaysia, and Thailand, and this trend persisted throughout the 2000s (Figure 2).

Figure 2. Industrial electricity prices in Southeast Asian countries (constant 2010 USD/kWh)



Electricity rates in the Philippines have been high, especially relative to Indonesia, Malaysia, and Thailand. The pronounced price declines for the Philippines and Singapore in 2009 were primarily due to the global financial crisis, which depressed demand and lowered input costs (NEMS 2009). *Data sources:* Aldaba (2003), Enerdata (various years), Meralco (various years), MEIH Statistics (various years), Singapore National Library Board (various years), Singapore Statistics (various years).

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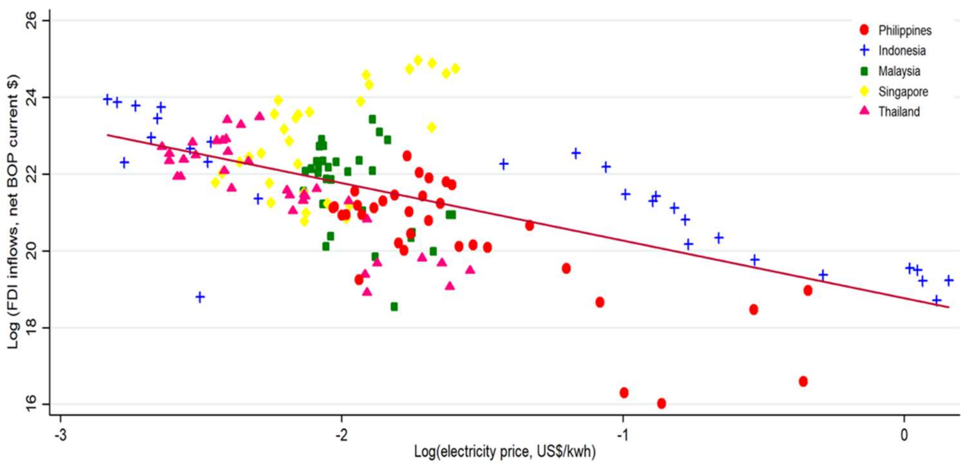
[3] Recently, however, the manufacturing sector has shown signs of resurgence (Deloitte 2014). From 2009 to 2013, the sector grew at 7.9% in value added terms, owing to greater competitiveness and an improved business climate in the country.

High electricity rates in the Philippines date back to the 1980 to early 1990 period when FDI inflows to East Asia were at record high levels. Indonesia, with its low industrial rates, remained competitive, as did Thailand. Power industries in these countries are vertically integrated and highly subsidized. Figure 3 shows a strong negative correlation between FDI inflows and industrial rates. In Indonesia, where average national electricity prices remained fairly flat at low levels, FDI inflows increased from the late 1980s up to 1997 and again after recovery from the Asian Financial Crisis from 2004 to 2010. In contrast, electricity prices in the Philippines have risen continuously and the amount of net FDI inflows has remained low. Anecdotal accounts of foreign business leaders cite both the prices and the quality of electricity to be major deterrents to investing in the Philippines (Enerdata 2014).

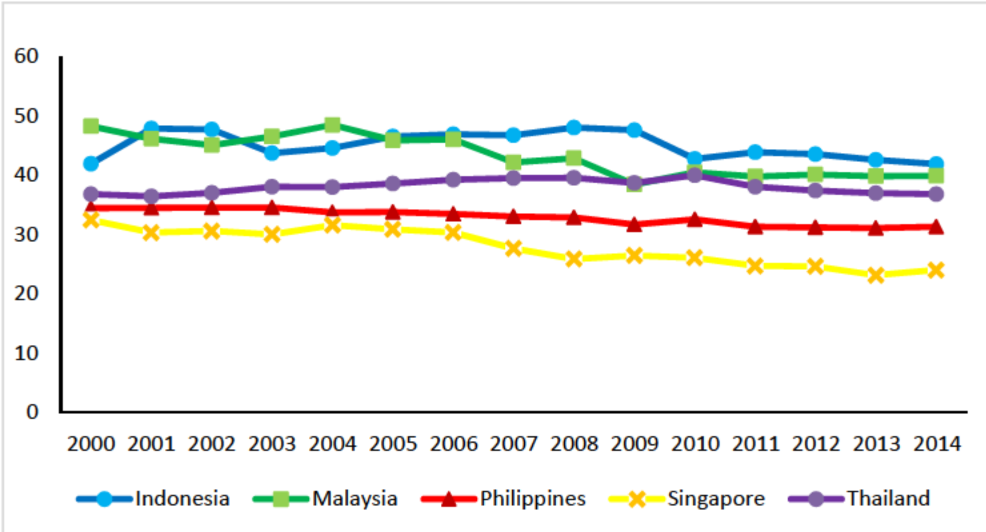
Figure 3. Correlation between FDI inflow and industrial electricity rates, 1984-1992



FDI inflow (Balance of payments, current million USD) is negatively correlated with industrial electricity rates (in US cents/kWh).

As shown in Figure 4, the ordering of countries with respect to industry shares is opposite that of electricity prices. Indonesia, Malaysia, and Thailand have higher industry shares than the Philippines, even though they had higher per capita GDPs during the period. That Singapore's industrial share is even lower than that of the Philippines is not surprising given the country's much higher per capita income, high level of re-exporting, and large complementary service sector (e.g. finance).

Figure 4. Industry value added (% of GDP)



The share of industry is higher for Indonesia, Malaysia, and Thailand relative to the Philippines.
Data source: World Bank, World Development Indicators.

To further explore the link between electricity prices and economic development, we examine the changing composition of manufacturing in the Philippines and Indonesia, which had relatively high and low electricity rates respectively. Table 1 reports electricity cost shares in output value by manufacturing subsector for the two countries. For most subsectors electricity cost shares were higher in the Philippines than in Indonesia, in some cases roughly double or more. Cost share rankings of industries are similar in both countries. Chemicals and related products (ISIC 35) and basic metals (ISIC 37) rank at or near the top for both; wood and related products (ISIC 33) and other manufacturing (ISIC 39) rank at or near the bottom. Divergence in ranking for some subsectors may be due to different product composition within the subsectors.

Table 1. Electricity cost shares by manufacturing subsector, Philippines and Indonesia, 1998-1999

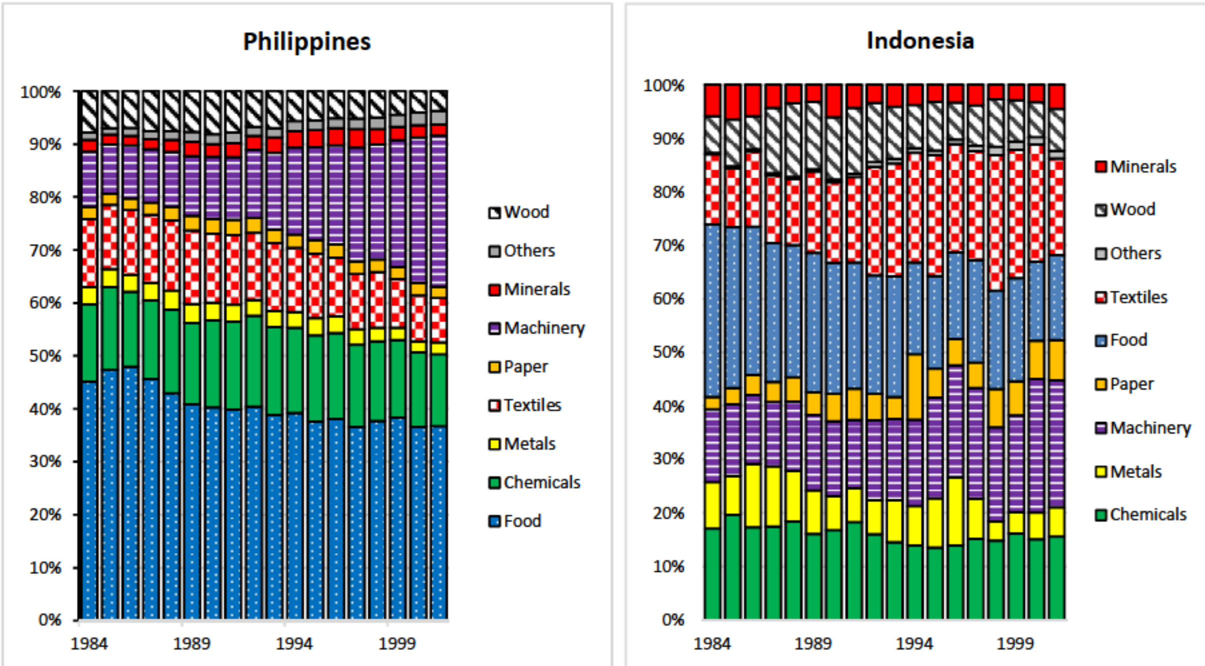
ISIC Code	Industry	Philippines		Indonesia	
		Electricity cost/ Output value	Rank	Electricity cost/ Output value	Rank
31	Manufacture of Food, Beverages, and Tobacco	0.048	1	0.023	5
35	Chemicals and Chemical, Petroleum, Coal, Rubber and Plastic Products	0.043	2	0.043	1
37	Basic Metal Industries	0.038	3	0.041	2

32	Textile, Wearing Apparel, and Leather Industries	0.035	4	0.019	6
34	Paper and Paper Products, Printing and Publishing	0.034	5	0.026	4
36	Non-Metallic Mineral Products, except Products of Petroleum and Coal	0.032	6	0.012	9
38	Fabricated Metal Products, Machinery and Equipment	0.032	6	0.032	3
39	Other Manufacturing Industries	0.028	8	0.015	7
33	Wood and Wood Products, Including Furniture	0.022	9	0.013	8

Data sources: Philippine Statistics Authority (PSA) (Annual Survey of Philippine Business and Industry (ASPBI)) and Badan Pusat Statistik – Statistics Indonesia (Industri Manufaktur - Census of Manufacturing).
Note: ISIC is International Standard Industrial Classification. The figures reflect averages for 1998-1999.

Figure 5 shows the changing shares of manufacturing subsectors for the two countries during the period 1984-2001. The composition of Philippine manufacturing shifted in favor of machinery and other subsectors with low electricity cost shares and away from food, chemicals, and other subsectors with high electricity cost shares. The fastest growing subsector in the Philippines was machinery, driven mainly by labor intensive assembly operations in semi-conductors and electronic products. The more power-intensive subsectors of textiles, metals, and chemicals grew at annual rates of just 0.4%, 0.7%, and 2.4%, respectively. In contrast, growth in Indonesian manufacturing has been driven by power-intensive subsectors, including metals, which grew at 15.3% annually and machinery, which grew at 19.4%. Compared with its ASEAN neighbors, Indonesia's electricity prices were both lower and flatter during the period, and its more power-intensive sectors were growing rapidly.

Figure 5. Manufacturing subsector shares, 1984-2001



Subsectors are ranked according to electricity cost share with the bottom subsector having the highest cost share. The composition of Philippine manufacturing has shifted toward subsectors with lower electricity cost shares (especially machinery) and away from higher cost subsectors (notably food). In contrast, shares of Indonesia's more power-intensive sectors were growing rapidly.
Data sources: Philippine Statistics Authority (PSA) 2010 Annual Survey of Philippine Business (ASBPI) and Industry and 1983-2001 Badan Pusat Statistik – Statistics Indonesia (Industri Manufaktur - Census of Manufacturing)
Note: ISIC codes are as follows: Food, 31; Textiles, 32; Wood, 33; Paper, 34; Chemicals, 35; Minerals, 36; Metals, 37; Machinery, 38; Others, 39.

The contrast between the Philippines and Indonesia also manifests in the growth of manufacturing in the aggregate. During the 1984-2001 period, manufacturing gross value added grew at annual rates of 2.8% in the Philippines versus 14.6% in Indonesia.

The descriptive analysis of this section gives an indication of how electricity prices may influence growth of the manufacturing sector and industry more broadly. We examine this issue more formally in the next section.

3. EMPIRICAL ANALYSIS

The descriptive statistics in Section 2 suggest that electricity prices may augment the premature deindustrialization described by Rodrik (2016). In this section, we examine this hypothesis more formally by adding electricity price as an explanatory variable to Rodrik's econometric model of industry shares in output. We follow Rodrik in emphasizing real measures (aggregation at constant prices) of output in order to keep quantities distinct from price movements for purposes of understanding structural change. Estimation using nominal shares is also included for completeness. We estimate the model using unbalanced panel data, first at the country level and then for regions within the Philippines.

3.1 Empirical model

To examine the relationship between the share of industry in output and electricity prices in conjunction with rising output per capita, we estimate the following equation:

$$S_{ct} = \alpha + \beta_0 P_{c,t} + \beta_1 GDP_{c,t} + \beta_2 GDP_{c,t}^2 + \beta_3 P_{c,t} GDP_{c,t} + \beta_4 P_{c,t} GDP_{c,t}^2 + \delta X + \varepsilon_{ct} \quad (1)$$

where S_{ct} is the share of industry in GDP (in real or nominal terms) of country or Philippine region c in year t; $P_{c,t}$ is the unit price of electricity; $GDP_{c,t}$ is GDP per capita; X' is a $k \times 1$ vector of other controls, including population, fixed effects by country or region to account for unobserved time-invariant heterogeneity in cross section (e.g., initial resource endowments, history), and decade dummies (i.e., 1980s, 1990s, and 2000s); and ε_{ct} is the error term. Electricity price, GDP per capita, and population are expressed in logarithms. GDP per capita and population are included in both levels and quadratic form, and GDP per capita and its quadratic form are both interacted with electricity price to account for the possibility that the relationship between industry share and GDP per capita is influenced by electricity prices.

An issue of concern in the estimation of equation (1) is the potential endogeneity of electricity prices. The estimated effect of electricity prices on industry shares will be biased if an omitted variable correlated with electricity price movements also affects a country's industrial trajectory. As Rodrik (2016), points out, adding period dummies captures the effects of common shocks on industrial share in each period relative to the excluded period (pre-1980 for the cross-country analysis and pre-1990 for the Philippine regional analysis). The period dummies used in the regression analysis help to control for any endogeneity of electricity prices. To check for the robustness of our results, we use one-period lagged values for electricity price and GDP per capita, which captures the sluggish response of macroeconomic variables to energy price shocks.

3.2 Data

For the cross-country analysis, we use annual data for 1980-2014 for 33 OECD and Southeast Asian countries. Industry share figures, reflecting gross value added of industry relative to GDP, are from World Bank WDI. Electricity price data come from various sources. For the OECD countries, data were obtained from the International Energy Agency, - OECD Library, and are expressed in USD/kWh in purchasing-power-parity terms. For the Southeast Asian countries data are from power distribution utility companies (Meralco, Malaysia Energy Information Hub, and Singapore Public Utilities Board) supplemented by data from Enerdata and individual country statistics offices. We also rely on Aldaba (2003) for earlier electricity prices from 1980 to 1991 for select Southeast Asian countries. Table 2 presents summary statistics for the cross-country data.

Table 2. Cross-Country Summary Statistics, 1980-2014

	Obs	Mean	St Dev	Min	Max
Industry share in GDP, real	947	28.38	8.00	10.72	49.20

Industry share in GDP, nominal	930	28.80	6.60	10.67	48.53
Electricity price (constant 2010 USD/kWh)	944	0.16	0.12	0.05	1.26
GDP per capita (constant 2005 prices, thousand USD)	1102	29.81	21.11	1.23	111.97
Population (million)	1155	42.46	59.91	0.36	318.56
Number of years (1980-2014)	35				
Number of countries	33				
Observations	1155				

Data sources: Aldaba (2003); Enerdata (various years); Meralco (various years); Malaysian Energy Information Hub Statistics (various years), Singapore National Library Board (various years), Singapore Statistics (various years), WDI (various years); International Energy Agency OECD (various years), International Labor Organization-Laborsta (various years)

For the Philippine regional analysis, we use annual data for 16 regions for 1990-2014 (the longest period for which comparable regions exist). Regional gross domestic product (RGDP) data are from the regional income accounts publications of the Philippine Statistics Authority (PSA). Electricity prices (PhP/kWh, measured in constant 2000 prices) are derived from revenue and sales data for distributional utilities (DUs) reported by the Philippine Department of Energy (DOE) with prices taken as the weighted averages. For the three regions covered by Meralco, the biggest DU which operates in Metro Manila and surrounding provinces, the shares of regional consumption compared to total consumption are used to weight each of three regions. As a check on the accuracy of our DOE-derived prices, we compute the simple correlation coefficient with the official electricity price indices reported by PSA. The two series are highly correlated (0.98 for the Philippines; 0.95 for Luzon; 0.92 for the Visayas; 0.95 for Mindanao; and 0.91 for the National Capital Region). Summary statistics are presented in Table 3.

Table 3. Philippine Regional Summary Statistics, 1990-2014

	Obs	Mean	St Dev	Min	Max
Average electricity price (PhP/kWh, weighted by sales, constant 2000 prices)	386	4.27	0.89	0.97	6.37
Industry share (% of RGDP)	386	25%	8%	4%	46%
Manufacturing share (% of RGDP)	386	14%	8%	1%	29%
RGDP per capita (constant 2000 prices, in thousand PhP)	386	587	1162	105	7983
Population (million)	400	5.03	3.07	1.15	16.22
No. of years (1990-2014)	25				
No. of regions	16				

Data sources: Philippine Statistics Authority; Department of Energy, Philippines.

3.3 Cross-country analysis and simulations

Results from estimating equation (1) using cross-country data are presented in Table 4. Period dummies are excluded in columns (1) to (3) and included in columns (4) to (6). Within each group, two different dependent variables are incorporated: industrial output share in real terms and industrial output share in nominal terms.[4]

In the specifications without period dummies, we find that holding other things constant, electricity price (in real terms) is negatively and significantly associated with the both the real output shares of industry. This relationship is not preserved using nominal variables however (columns 2). As suggested by Rodrik (2016), this may be due to the confounding effects of price movements.

Period dummies (1980s, 1990s, and 2000s) are included to capture time trends and to control for common shocks on industrial share in each decade relative to the years before 1980. The results in column (4) of Table 4 show a remarkable set of regularities. First, we find that there is a strong and statistically significant negative association between electricity prices and output shares of industry (in real terms). This finding empirically validates our descriptive analysis in the previous section. We find an inverted U-shaped relationship between industry shares and GDP per capita in that industry shares are related positively to GDP per capita and negatively to the square of GDP per capita. We also find a strong association between the electricity price interacted with GDP per capita variables and the industrial shares (in real terms). Our finding suggests that with higher electricity prices the rate of growth of industry shares is slower and, after a certain per capita GDP level, the rate of decline in industry shares is faster.

Table 4. Regression results for industry shares in GDP, cross country, 1980-2014

	(1) Real output	(2) Nominal output	(4) Real output	(5) Nominal output
Electricity price	-90.86***	-50.82	-83.50***	-42.33
	(24.03)	(31.48)	(25.36)	(33.28)
GDP/capita	86.13***	78.69***	78.72***	66.99***
	(14.77)	(18.22)	(15.06)	(16.31)
(GDP/capita)^2	-4.32***	-4.10***	-3.85***	-3.32***
	(0.78)	(1.00)	(0.80)	(0.88)
Electricity price*(GDP/capita)	20.11***	10.44	18.37***	8.35
	(5.54	(6.72)	(5.85)	(7.18)
Electricity price*(GDP/capita)^2	-1.10***	-0.54	-0.99***	-0.40
	(0.31)	(0.36)	(0.33)	(0.38)
Population	59.80**	63.30*	43.78	34.91

[4] Results using one-period lagged values for price and GDP per capita are shown in Appendix Table A1. The intent of using lagged values is to capture any potential sluggishness in the response of macroeconomic variables to energy price shocks. The signs on coefficients of key variables are consistent with the results in Table 4.

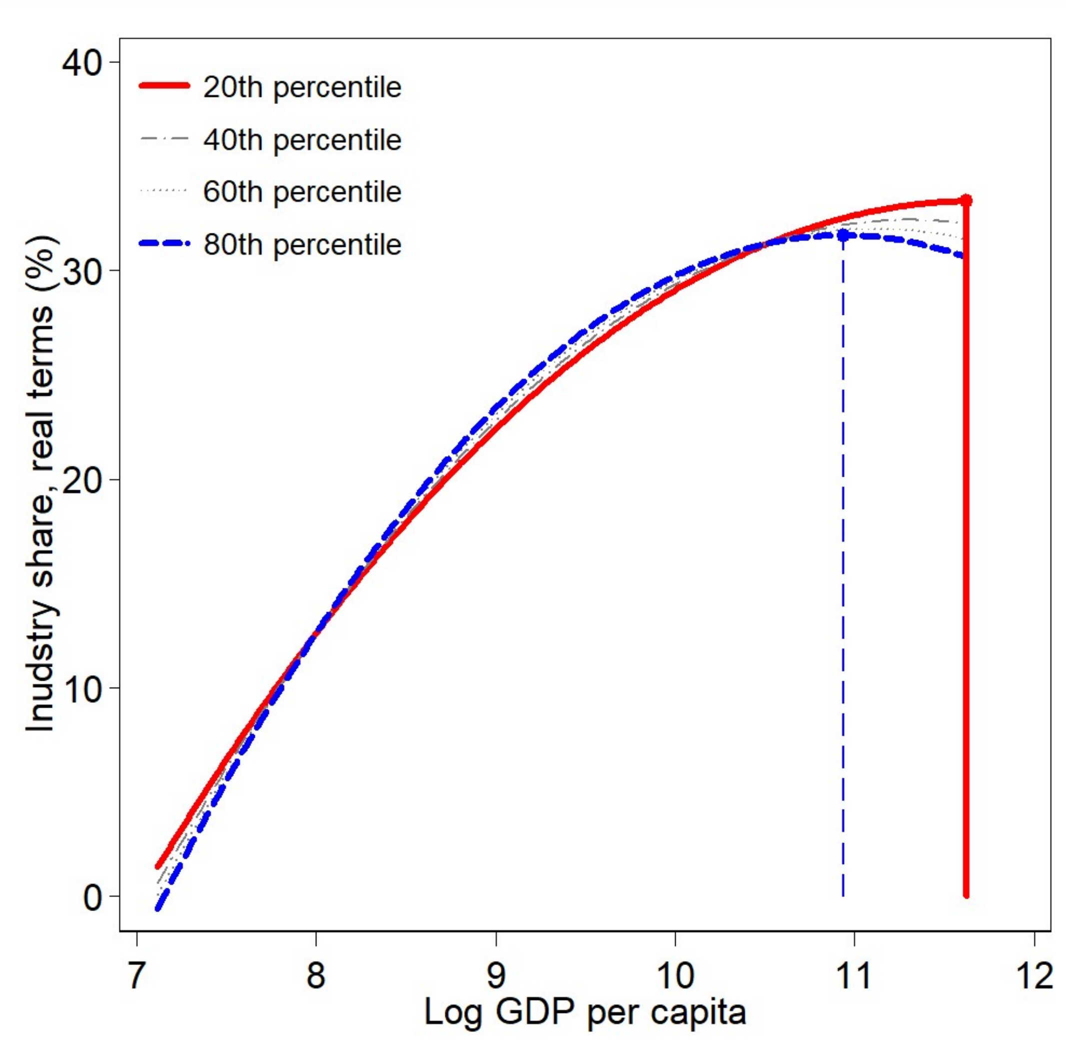
	(26.94)	(32.20)	(26.72)	(28.66)
Population^2	-2.32***	-2.23**	-1.79**	-1.29
	(0.82)	(0.96)	(0.83)	(0.85)
1980s			1.69**	3.79***
			(0.76)	(1.03)
1990s			1.59***	2.64***
			(0.50)	(0.55)
2000s			1.14***	2.15***
			(0.30)	(0.37)
Constant	-745.82***	-776.87**	-598.59**	-529.07*
	(249.06)	(320.88)	(243.30)	(279.44)
Country fixed effects	Yes	Yes	Yes	Yes
Observations	815	798	815	798
R^2 (adjusted)	0.48	0.38	0.51	0.45
R^2 (within)	0.49	0.39	0.52	0.46

Estimation results are from equation (1). Electricity price, GDP per capita, and population are expressed in logarithms. Real output shares are based on constant 2005 USD. Robust standard errors clustered by country are given in parentheses. *, **, *** correspond to 10, 5, and 1 percent significance levels, respectively.

To more vividly show how electricity prices influence the relationship between industry share and GDP per capita, we use the estimates from equation (1) under the specification with period dummies (column 4 of Table 4) to conduct simulations. We select four different electricity prices representing quantile values from the distribution of prices across the 33 countries and 35 years of our sample (see Appendix Figure A.1).

We plot the simulation paths in Figure 6 and provide key quantitative results in Table 5. Each curve in Figure 6 represents predicted industry share as a function of log GDP per capita at a different electricity price quintile. Higher energy prices increase the slope of the curve, implying an earlier turning point and a more rapid decline. The vertical lines indicate the level of GDP per capita at which the industry share reaches a maximum. The peak for an electricity price at the 80th percentile, as represented by the dashed vertical line, occurs at a lower per capita income than the peak for an electricity price at the 20th percentile, as represented by the solid vertical line.

Figure 6. Simulated paths of industry share by electricity price, country level



Each curve represents the simulated path of industry share at a different electricity price quintile. The vertical lines point to the log GDP per capita levels at which industry shares peak, the solid line for an electricity price at the 20th percentile, the dashed line for an electricity price at the 80th percentile.

Table 5 shows quantitative magnitudes for the simulation exercises. Electricity prices range from 0.10 USD/kWh at the 20th percentile to 0.19 USD/kWh at the 80th percentile. For an electricity price at the 80th percentile, the turning point comes at a relatively low GDP per capita, about USD56,184 (in 2005 USD) with the industrial share peaking at 31.7% of GDP. By contrast, for an electricity price at the 20th percentile, the turning point comes at a much higher US$111,968 (in 2005 USD) with a peak in the industrial share of 33.3%.

Table 5. Simulated GDP per capita turning points of industry share by electricity price, country level

Electricity price		GDP/capita turning points (USD thousand)		Industry shares at peak (%)	
Percentile	USD/kWh	Real output	Nominal output	Real output	Nominal output
80	0.19	56.2	22.7	31.7	29.7
60	0.15	67.3	22.7	32.0	29.6
40	0.13	81.6	22.5	32.4	29.4
20	0.10	111.6	22.2	33.3	29.2

The table pertains to the simulated GDP per capita where industry share peaks using parameter estimates from Table 4, columns (4) and (5). Electricity prices are in constant 2010 USD and GDP per capita values in constant 2005 prices.

In sum, our results imply that a higher electricity price tends to shift the inverted U relationship between industrial share and GDP per capita down and to the left. This suggests that high electricity prices amplify premature deindustrialization, i.e., deindustrialization occurs sooner in terms of GDP per capita and at lower industry shares.

The Philippines represents an extreme version of premature deindustrialization. Comparing the Philippines with its higher per capita income Southeast Asian neighbors, we find, with the exception of Singapore,[5] a lower industry share and, higher electricity prices. Higher electricity prices in the Philippines appear to have exacerbated premature deindustrialization.

3.4. Philippine regional analysis and simulations

We now turn to the influence of electricity prices on industry shares across Philippine regions. We estimate equation (1) using panel data for 16 regions of the Philippines over the years 1990-2014. The dependent variable is the share of industry GVA in RGDP in real terms. To mitigate the effects of measurement error associated with electricity price data in small regions we weight observations by population using the maximum population over the sample time frame for each region. Such population weighting ensures that our regression results are driven by data points that are deemed more accurate by giving them more influence in estimating parameters. This increases the efficiency of the estimation compared to unweighted regression.[6] We then use the resulting estimates to simulate the path of industry share with respect to RGDP per capita holding electricity price constant at different levels.

Table 6 presents regression results for equation (1). Annual dummies are included to capture year effects for the years 1990-2014. The results show a negative and statistically

[5] The Singapore exception is consistent with its high per capita income and high transshipment and intermediary trade, all of which contribute to a large services sector.

[6] Cooperatives distributing electricity in small regions generally charge higher prices but offer subsidies supported by the National Electrification Administration that may not be reflected in reported price data.

significant association between electricity prices and industry share. As with the cross-country analysis, higher electricity prices appear to reduce the share of industry in RGDP.[7]

Table 6. Regression results for industry share, Philippine regions, 1990-2014

	Real output
Electricity price	-2.183*
	(1.082)
RGDP/capita	0.820
	(0.580)
(RGDP/capita)^2	0.058
	(0.043)
Electricity price*(RGDP/capita)	-0.676*
	(0.325)
Electricity price*(RGDP/capita)^2	-0.051*
	(0.024)
Population	2.751*
	(1.465)
Population^2	-0.076*
	(0.040)
Constant	-21.304
	(13.352)
Year dummies	Yes
Observations	350
R^2	0.380

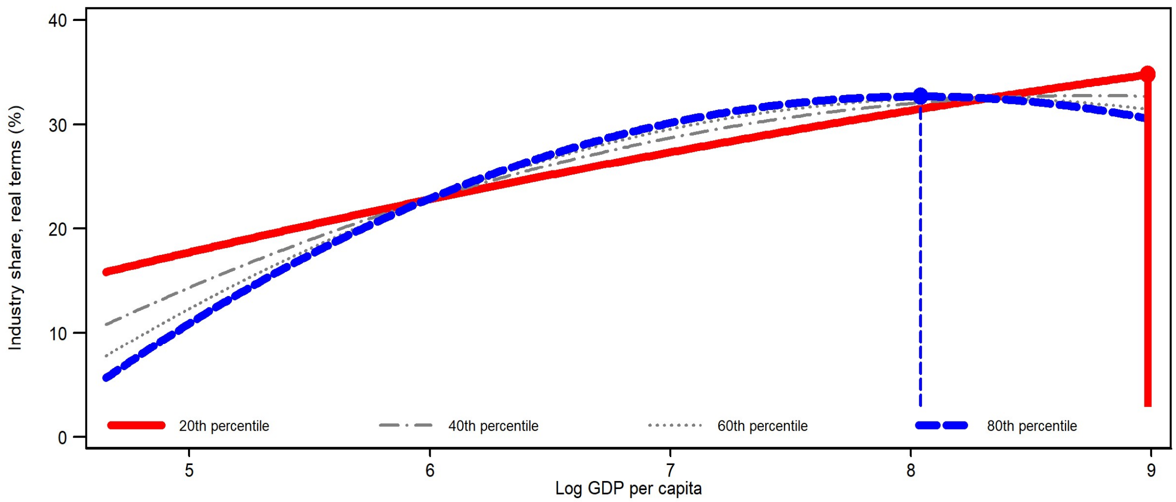
Estimation results are from equation (1). Electricity price, RGDP per capita, and population are expressed in logarithms. Electricity prices and industry shares are based on constant 2000 PhP prices. Robust standard errors clustered by region are in parentheses. *, **, *** correspond to 10, 5 and 1 percent significance levels, respectively.

We use the estimates in Table 6 to simulate the path of industry share with respect to RGDP per capita with results depicted in Figure 7 and key magnitudes reported in Table 7. Figure 7 shows that higher electricity prices are associated with an earlier and lower peak in industry share. For an electricity price at the 20th percentile, we do not see a turning point in industry share; it rises to the upper limit of RGDP per capita used in the simulation exercise. For electricity prices at higher quantiles, however, industry share reaches turning points within the

[7] Another way to examine the influence of electricity price on structural change is to estimate services share as a function of GDP per capita and electricity price. We estimated equation (1) using services share as the dependent variable for the Philippine regional database. The resulting coefficient for the electricity price variable is positive albeit not statistically significant. A similar finding holds for the agriculture sector.

simulation range. For an electricity price at the 40th percentile, the turning point is 6,425 PhP per capita while for an electricity price at the 80th percentile it falls to 3,105 PhP per capita.

Figure 7. Simulated paths of industry share by electricity price, Philippine regional level



Each curve represents the simulated path of industry share at a different electricity price quintile. The vertical lines indicate the per capital RGDP levels at which industry shares peaked. The solid red line corresponds to the RGDP per capita for the (low) 20th percentile price. The dashed line shows the per capita RGDP where industry peaks for the case wherein electricity price is set at the 80th percentile.

Table 7. Simulated RGDP per capita turning points of industry share by electricity price, Philippine regional level

Electricity price (Percentile)	(PhP/kWh)	**RGDP/capita turning points** (PhP)	**Industry share at peak** (%)
80	5.46	3,105	32.7
60	4.97	3,775	32.5
40	4.48	6,425	32.8
20	3.62	-	34.8

Note: For the 20th percentile, industry share is still rising at the end point of the simulation range (RGDP per capita = 8000 PhP). Electricity prices and industry shares are based on constant 2000 PhP prices.

4. CONCLUSIONS AND POLICY IMPLICATIONS

Motivated by the Philippine experience of deindustrialization at a low level of per capita income, we study the role of high electricity prices in the process of structural transformation using data at both country and Philippine regional levels.

High electricity prices can plausibly augment other factors that induce premature deindustrialization. We adapt Rodrik's (2016) model of deindustrialization to investigate how industry share moves in connection with GDP per capita and electricity prices. We estimate the model with respect to 33 countries for the period 1980-2014 and with respect to 16 regions of the Philippines for the period 1990-2014.

For both the country and Philippine regional estimations, we find that higher electricity prices are associated with industry share turning downward at lower peaks and at lower levels of GDP per capita. Moreover, the downtrend tends to be steeper the higher are electricity prices. Data limitations constrain definitive conclusions about causality, but it appears that structural transformation is not independent of electricity prices. Descriptive analysis of the Philippine case relative to other Southeast Asian nations provides further evidence of a connection.

Electricity prices can impact industry via several pathways, including business investment, manufacturing productivity, and foreign direct investment. Untangling the relative contributions of the various pathways is a promising agenda for further research.

The Philippine manufacturing sector still accounts for a 20% share of the country's output. The Philippine government has recently targeted a substantial increase in manufacturing's share. Several promising strategies have been identified—from increasing value added in the electronics sector to improving the competitiveness of paper mills. Realizing this potential may be difficult without lowering the price of electricity and improving its quality and reliability.

Lowering electricity prices by relaxing bureaucratic red-tape and increasing the competitiveness of generation and retailing would confer a win-win in terms of power market efficiency and enhancing manufacturing's ability to act as a growth engine. Whether electricity-rate subsidies are warranted to further augment externalities of investment coordination, knowledge and new-good creation remains an open question.

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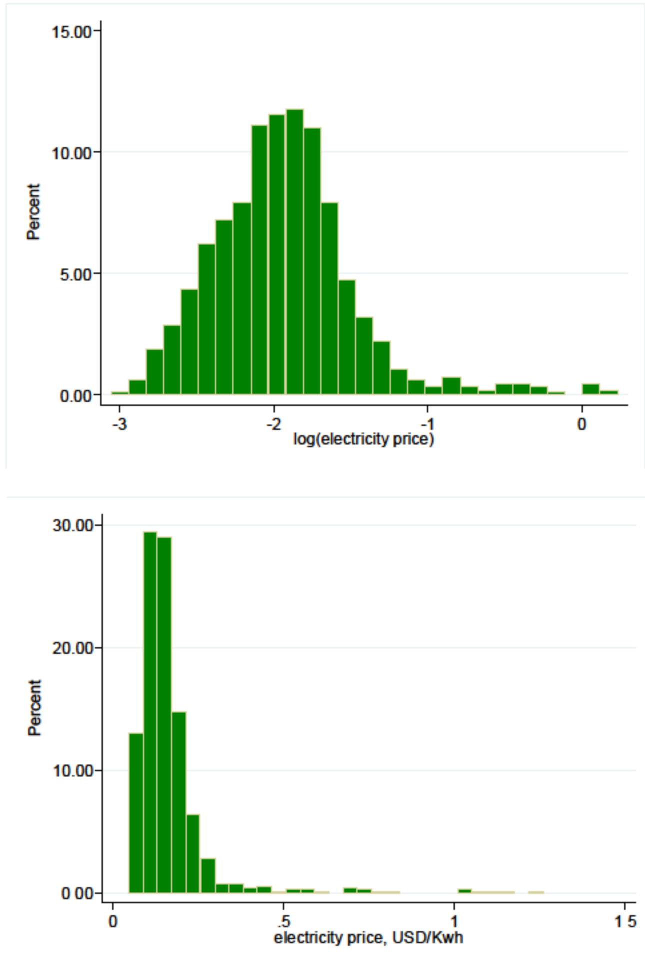
APPENDIX

Figure A1. Distribution of electricity prices, in log transformed and USD/kWh terms across 33 countries over 35 years



Distribution of Electricity price across 33 countries in 35 years	
Percentile	USD/kWh
80	0.19
60	0.15
40	0.13
20	0.10

Note: Prices are in constant 2010 USD.

Source: Data sources: Aldaba (2003); Enerdata (various years); Meralco (various years); Malaysian Energy Information Hub Statistics (various years), Singapore National Library Board (various years), Singapore Statistics (various years), International Energy Agency OECD (various years),

Table A1. Regression results for industry shares with lagged independent variables, cross country, 1980-2014

	(1) Output share, real	(2) Output share, nominal	(3) Employment share
Electricity price$_{t-1}$	-87.768***	-42.314	-48.768
	(24.615)	(31.142)	(30.211)
(GDP/capita)$_{t-1}$	81.385***	67.465***	90.491***
	(14.702)	(15.379)	(15.153)
(GDP/capita)$_{t-1}^2$	-4.050***	-3.421***	-4.791***
	(0.782)	(0.832)	(0.883)
Electricity price$_{t-1}$*(GDP/capita)$_{t-1}$	19.438***	8.466	10.750
	(5.692)	(6.758)	(6.632)
Electricity price$_{t-1}$*(GDP/capita)$_{t-1}^2$	-1.055***	-0.415	-0.576
	(0.321)	(0.364)	(0.356)
Population$_t$	43.802	36.358	-36.036
	(26.218)	(27.695)	(21.237)
Population$_t^2$	-1.770**	-1.289	1.050*
	(0.817)	(0.817)	(0.604)
1980s	1.318*	3.167***	6.473***
	(0.765)	(1.009)	(1.436)
1990s	1.427***	2.343***	5.040***
	(0.484)	(0.543)	(0.841)
2000s	1.113***	2.110***	3.331***
	(0.292)	(0.364)	(0.549)
Constant	-611.986**	-546.330*	-90.316
	(238.347)	(267.777)	(228.898)
Country fixed effects	Yes	Yes	Yes
Observations	798	783	896
R^2, adjusted	0.495	0.440	0.709
R^2, within	0.501	0.447	0.712

Note: Estimation results are from equation (1). Electricity price, GDP per capita, and population are expressed in logarithms. Real output shares are based on constant 2005 USD. Robust standard errors clustered by country are in parentheses. *p<0.10; **p<0.05; ***p<0.01.