ORIGINAL

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

ELECTRONIC 2020 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	Case No. 2020-00299

Responses to Office of the Attorney General's
Initial Data Requests
dated February 26, 2021

FILED: March 19, 2021

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
2020 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2020-00299

VERIFICATION

I, Nathanial A. ("Nathan") Berry, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Nathanial A. ("Nathan") Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Nathanial A. ("Nathan") Berry on this the 19th day of March, 2021.

Notary Public, Kentucky State at Large
Kentucky ID Number KYNP16841
My Commission Expires October 31, 2024

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
2020 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2020-00299

VERIFICATION

I, Christopher S. ("Chris") Bradley, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Christopher S. ("Chris") Bradley

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Christopher S. ("Chris") Bradley on this the 19th day of March, 2021.

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
2020 INTEGRATED RESOURCE PLAN OF
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VERIFICATION

I, Mark J. Eacret, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Mark J. Eacret

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark J. Eacret on this the 19th day of March, 2021.

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
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VERIFICATION

I, Michael S. ("Mike") Mizell, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Michael S. ("Mike") Mizell

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael S. ("Mike") Mizell on this the 19th day of March, 2021.

Katherine Ridley

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

BIG RIVERS ELECTRIC CORPORATION

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2020 INTEGRATED RESOURCE PLAN OF
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VERIFICATION

I, Marlene S. Parsley, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Marlene S Parsley

Marlene S. Parsley

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Marlene S. Parsley on this the 19th day of March, 2021.

Katherine Blay

Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
2020 INTEGRATED RESOURCE PLAN OF
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VERIFICATION

I, Russell L. ("Russ") Pogue, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

____
Russell L. ("Russ") Pogue

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Russell L. ("Russ") Pogue on this the 19th day of March, 2021.

____
Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
2020 INTEGRATED RESOURCE PLAN OF
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VERIFICATION

I, Paul G. Smith, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Paul Smith
____
Paul G. Smith

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Paul G. Smith on this the 19th day of March, 2021.

Kathu Roley
____
Notary Public, Kentucky State at Large

Kentucky ID Number KYNP16841

My Commission Expires October 31, 2024

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
2020 INTEGRATED RESOURCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2020-00299

Response to the Office of the Attorney General's
Initial Data Requests
dated February 26, 2021

March 19, 2021

Item 1) ***Provide the amount of power BREC is currently receiving from the Southeastern Power Administration ("SEPA"). State this quantity also in terms of the percentage of BREC's total power requirements on an average monthly basis.***

a. Provide a discussion regarding the potential for BREC to secure rights to additional hydropower, whether from SEPA or any other source, and whether doing so would or could be cost-effective, especially in light of the Biden Administration's plan to require the electric utility industry to achieve carbon neutrality by 2035.

b. Provide the results of any cost-benefit analyses the Company may have conducted regarding its continued participation in the SEPA contract. With regard to any such cost-benefit analysis: (i) explain whether the emissions-free nature of the SEPA power was also taken into consideration; and (ii) provide a discussion of whether the purchase of the SEPA hydropower could provide further benefits to BREC and its members in the event that either the federal

government imposes a carbon tax, or MISO institutes carbon pricing.

c. Provide the capacity factor of BREC's 178 MW share of SEPA.

Response) Contract No. 89-00-1501-1141 between SEPA and Big Rivers makes 178,000 kilowatts of dependable capacity available to Big Rivers, scheduled on a monthly basis in accordance with provisions of the contract. Big Rivers' allocation of energy is 1,500 kilowatt-hours for each kilowatt of contract demand, or 267,000 MWhs per year, with the contract year running from July 1 through June 30 of the following calendar year. Per the contract, the energy is scheduled monthly with a maximum take of 240 hours per kilowatt of contract demand, or 42,720 MWhs, and a minimum scheduled per month of not less than 60 hours per kilowatt of contract demand, or 10,680 MWhs. In calendar year 2020, SEPA accounted for approximately 9% of Big Rivers' Members' Load requirements. The table on the next page provides a monthly breakdown of energy requirements for 2020, since 2020 was the first year following the Cumberland System's return from only partial scheduling ability due to a Force Majeure at the Wolf Creek Dam. Full scheduling ability was restored on January 1, 2020.

Big Rivers Electric Corporation SEPA - % of Big Rivers Energy Requirements 2020	
Month	**Percentage**
January	7.0
February	5.0
March	8.0
April	14.0
May	14.0
June	15.0
July	9.0
August	8.0
September	7.0
October	8.0
November	10.0
December	9.0
Annual	9.0

a. The potential for Big Rivers to secure rights to additional hydropower depends on the availability of hydropower. SEPA would need to approve any additional hydropower from the Cumberland System under the power marketing policy for the Cumberland Basin System of Projects which was published in the Federal Register on August 5, 1993, 58 F.R. 41762, or as otherwise authorized by the Federal Government. Analysis of expected market prices and costs would determine cost-effectiveness of any additional hydropower that could be available, whether through SEPA Cumberland or another resource.

While it is not possible to determine what impacts the Biden Administration's statement about carbon neutrality will have until such time as the EPA or other departments within the Administration formulate draft rules address the topic, Big Rivers received its initial allocation of SEPA Cumberland hydropower in 1963, and its continued participation in the SEPA contract is only one component of Big Rivers' diversification of its generation portfolio over time. In fact, as illustrated by the charts in the attachment to this response, Big Rivers' 2013 resource mix included a 87%

reliance on coal, while Big Rivers' more balanced portfolio effective 2024[1] will include hydro, gas, solar and only a 31% reliance on coal. Continuing to retain SEPA Cumberland Power is further supported by the 2020 IRP modeling, as discussed more fully below.

b. Big Rivers' 2020 IRP modeling included results of cost-benefit analyses of its continued participation in the SEPA contract. The LT Plan model had the option to exit the SEPA contract, if doing so provided a least–cost solution. As stated on page 155 of Big Rivers' 2020 IRP, the preliminary least–cost solution did have Big Rivers exiting the SEPA contract while replacing the SEPA power with additional Natural Gas Combined Cycle ("NGCC") capacity. From the LT Plan model results, Big Rivers developed portfolio options to run on the ST Plan model to further evaluate. Please see Big Rivers' response to Item 39 of the Commission Staff's First Request

[1] Includes Big Rivers' proposed conversion of Green Station's units to natural gas. See *In the Matter of: Electronic Application of Big Rivers' Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing the Conversion of the Green Station Units to Natural Gas-Fired Units and an Order Approving the Establishment of a Regulatory Asset*, Ky. P.S.C. Case No. 2021-000079.

for Information for a further explanation between LT Plan and ST Plan models.

The ST Plan model results are discussed on pages 155-156 of Big Rivers' 2020 IRP and at Table 8.8 ST Plan Portfolio Results – Base Case on page 157. These results show the optimal (least–cost) option included keeping the SEPA contract. The Base Case achieves Big Rivers' objectives to both right-size its generation portfolio to its native load and diversify the portfolio between coal, natural gas, hydro and solar resources to give Big Rivers the best opportunity to keep its Member-Owners rates stable and competitive in light of the uncertainty in environmental regulation and changing market conditions.

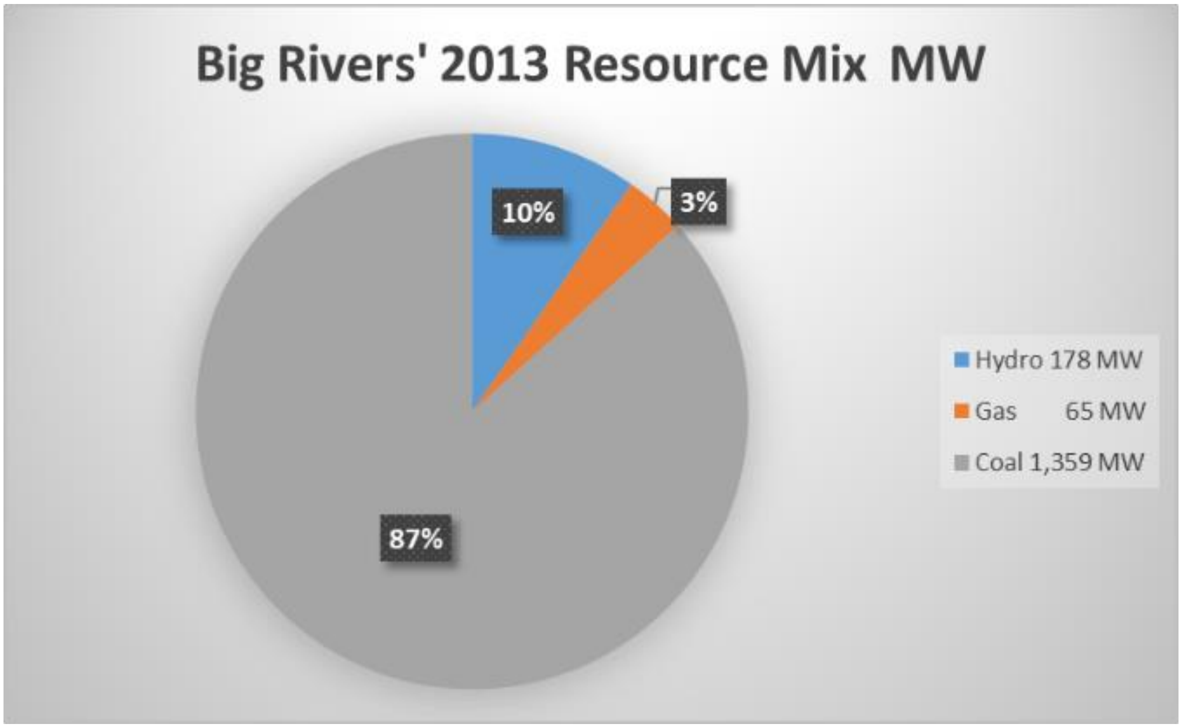
Additionally, Big Rivers planned resource mix allows it to build a more balanced portfolio without over-exposing its Members to the risks associated with any one generation type.

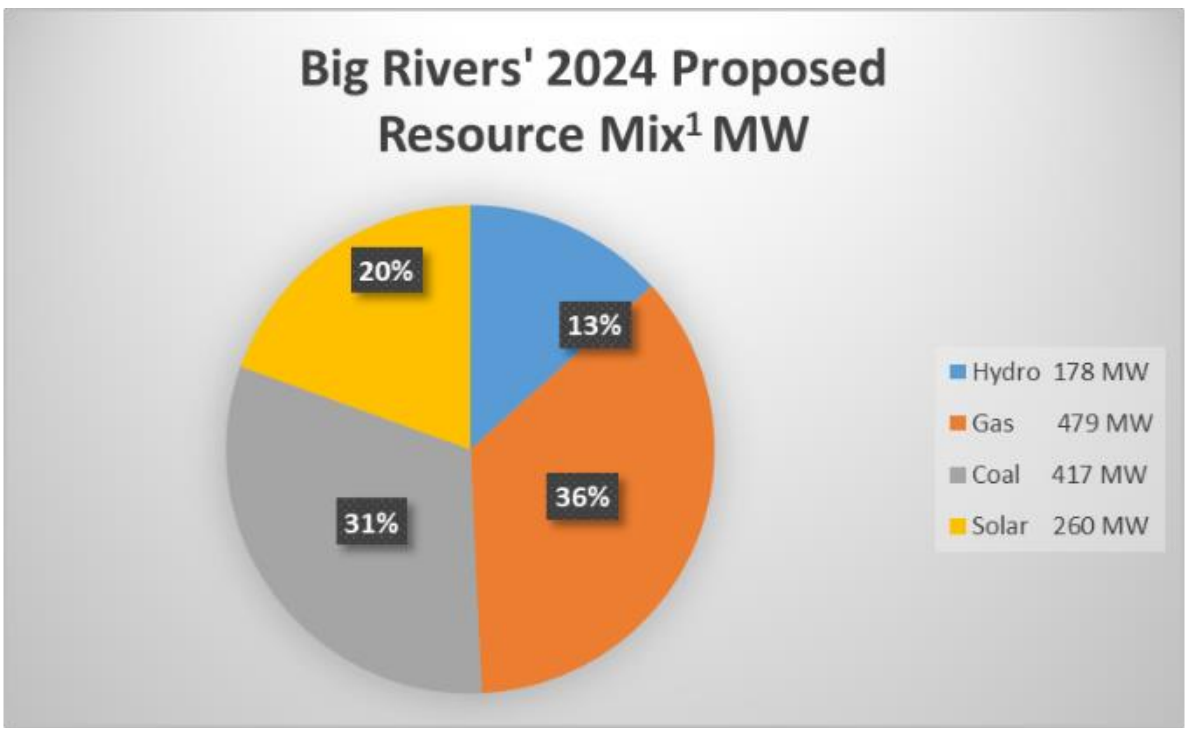
c. Capacity Factor for Big Rivers' SEPA allocation is 17.12%.

[17.12% = 267,000 MWhs *divided by* (178 MWs *x* 8,760 hours)].

Witness) Marlene S. Parsley

Big Rivers Electric Corporation
Case No. 2020-00299
Resource Mix





[1] Includes Big Rivers' proposed conversion of Green Station's units to natural gas. See *In the Matter of: Electronic Application of Big Rivers' Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing the Conversion of the Green Station Units to Natural Gas-Fired Units and an Order Approving the Establishment of a Regulatory Asset*, Ky. P.S.C. Case No. 2021-000079.

Item 2) Provide an update on the project to transfer the Coleman FGD to the Wilson unit, including any cost projections for the project.

Response) Following the Commission's August 6, 2020, order approving Big Rivers' 2020 Environmental Compliance Plan ("ECP"),[1] Big Rivers immediately began to execute the project. An Authorization for Investment Proposal ("AIP") was approved on August 12, 2020, and project accounts were established in the Big Rivers' business software systems. On August 20, 2020, Big Rivers entered into a Limited Notice to Proceed ("LNTP") agreement with Amec Foster Wheeler Industrial Power Company, Inc. ("AFWIP") to undertake preliminary work to perform engineering services to feed into the overall project while negotiations took place to develop a mutually agreed–upon contract structure and terms for the final definitive contract to provide the design and supply of equipment, performance guarantee, and associated design engineering services. AFWIP is best suited for this part of the D.B. Wilson WFGD

[1] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of its 2020 Environmental Compliance Plan, Authority to Recover Costs through a Revised Environmental Surcharge and Tariff, the Issuance of a Certificate Of Public Convenience and Necessity for Certain Projects, and Appropriate Accounting and Other Relief*, Case No. 2019-00435. Application filed February 7, 2020.

(Wet Flue Gas Desulfurization) Retrofit Project, due to being the original equipment manufacturer of the Coleman FGD; their knowledge of original design and supply information; and their ability to provide performance guarantees. As part of their scope of work, AFWIP will provide certain materials and equipment that are necessary for them to be able to provide performance guarantees. As a work product from its scope of work, AFWIP will provided technical bid packages, including scope of work, drawings and specifications applicable to the package, to assist Big Rivers in the competitive bidding of all other equipment, materials and construction that are not related to guaranteed performance and that are being supplied by Big Rivers. The design and supply of equipment and associated design is being provided on a firm–price basis, and the engineering services and freight for AFWIP equipment and materials are being provided on a reimbursable cost basis.

Big Rivers used a technical bid package developed by AFWIP, as part of the LNTP, to issue a Request for Quotation ("RFQ") HND20050 for the deconstruction of the existing Coleman Station FGD absorber into transportable pieces and shipment to Wilson Station, along with other support equipment, and the reconstruction of the absorber at Wilson Station on a new foundation provided by others. On January 26, 2021, Big Rivers issued a purchase order to Graywolf Integrated Construction Company for the Coleman Station FGD absorber deconstruction/reconstruction scope–of–work.

The current focus of AFWIP's design work is on the specification and procurement of schedule–critical path items such as the refurbishment of existing equipment, long–lead equipment and materials, and the initial construction contract for the absorber foundation at Wilson Station.

The $111.77 million estimated total capital cost projections for the project have not changed from the amounts included in the 2020 ECP filing. Through the month of February 2020, a total of $29.98 million has been committed by awarded contracts, and a total of $3.19 million of costs have been expended, on the work outlined above.

The Title V permit application to install the new FGD and add a diesel generator was deemed complete on October 22, 2020. The completeness determination allows Big Rivers to proceed with the FGD construction. Application has not yet been made to bring the changes to FGD wastewater handling into the current Kentucky Pollutant Discharge Elimination System ("KPDES") permit. Once a final wastewater treatment (WWT) system design is determined, the FGD effluent streams can be identified in the application for KPDES permit modification.

The current project schedule remains the same as presented in the 2020 ECP filing, with the tie-in outage in the spring 2022.

Witness) Nathanial A. Berry

Item 3) ***Regarding the Green units, refer to the IRP Plan, Ch. 8, p. 137, and Ch. 9, p. 176. Explain the meaning of the phrases on p. 137 that Green units will be "idled", and on p. 176 that the units would be "suspended." In particular, explain whether these terms refer to mothballing the units (as was done with the Coleman units), actual retirement, or some other status.***

a. If the Green units are placed into mothball status, explain whether the costs of doing so entered into any applicable cost-benefit analyses.

Response) The phrases "idled" and "suspended" have the same meaning in that Big Rivers would mothball the Green units.

a. Big Rivers accounted for the cost and process of laying the Green units up, as it did when it mothballed Coleman Station. Please see Big Rivers' response to Item 38 of the Commission Staff's First Request for Information, explaining why retirement costs were modeled at zero expense.

Witness) Nathanial A. Berry

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
2020 INTEGRATED RESOURCE PLAN OF
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CASE NO. 2020-00299

Response to the Office of the Attorney General's
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Item 4) ***If and when BREC actually retires the two Green units, confirm that the only remaining unit at Sebree Station would be the Reid CT (Reid Unit 2). If so confirmed, provide the cost estimates for any remaining demolition to be done at Sebree Station.***

a. In the event BREC decides to move forward with its Preferred Plan of entering a partnership to own or purchase 90 MW of a 592 MW natural gas combine cycle ("NGCC") unit referenced at p. 17 and in Chapters 8 and 9 of the IRP Plan, explain whether the demolition of the Green units and any other plant at Sebree Station requiring demolition would be completed enough to begin construction of the NGCC by the estimated construction start date of 2024.

b. Explain whether construction of the NGCC at Coleman Station would offer more transmission benefits over constructing it at Sebree Station.

c. Provide the estimated remaining lifespan of the Reid CT.

d. In light of the Biden Administration's plan to require the electricity utility industry to achieve carbon neutrality by 2035, explain

whether the Company believes it needs to develop a revised plan regarding cost-effectiveness of the plan of procuring a share in the generation output of a NGCC.

Response) Confirmed. Big Rivers would only have the Reid Combustion Turbine ("Reid CT") left at Sebree Station when the two Green units are retired. No costs for demolition of the Green units were included in Big Rivers' 2020 IRP, but Big Rivers' most current estimate is that the demolition of the two Green units would cost $10.0 million.

a. Big Rivers would not have to demolish the Green units or any other plant at Sebree Station to construct a Natural Gas Combined Cycle ("NGCC").

b. Building the NGCC at Coleman Station would not offer more transmission benefits than if the NGCC were built at Sebree Station.

c. Assuming the Reid CT continues to operate nominally as it has for the past forty-two (42) years, and parts are available for continued maintenance, an expected life span of sixty (60) years should be achievable for the Reid CT.

d. It is not possible to determine what impacts the Biden Administration's statement about carbon neutrality will have until such time as the United States Environmental Protection Agency or other departments within the Administration formulate draft rules addressing the topic.

Witness) Nathanial A. Berry

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
2020 INTEGRATED RESOUCE PLAN OF
BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2020-00299

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Item 5) ***Reference the IRP Plan at pp. 176-177.***

a. ***Regarding the statement, "[c]onverting the [Green] units to natural gas as a capacity-only resource is currently uneconomical and would involve regulatory risk." Explain the regulatory risk involved.***

b. ***Regarding the statement, "A recent (August 2020) EPA order may create an opportunity to extend life of the Green units through December 31, 2028." Provide a copy of the order, or a link to it.***

c. ***Reference Case Number 2021-00079, "Electronic Application of Big Rivers Electric Corporation For A Certificate Of Public Convenience And Necessity To Convert Green Station To Natural Gas And Authority To Establish A Regulatory Asset." Provide a discussion regarding how the application in this docket will change BREC's IRP analyses***

i. ***Explain the types of studies BREC may have conducted that led it to the filing of Case No. 2021-00079.***

d. If the Commission does not approve BREC's application in Case No. 2021-00079: (i) confirm that the Green units will be fully retired; and (ii) if so confirmed, provide a detailed explanation of how BREC intends to replace the generation that the Green units provided. Explain also whether the Company will file an updated application in the instant case.

e. In the event the Commission approves BREC's application in Case No. 2021-00079: (i) provide the expected useful life of the gas-fired Green units; and (ii) in the event the lifespan is less than the full planning period covered by the current IRP, explain whether BREC will supplement the current application with revised analyses pertaining to the years of planning period extending beyond that lifespan.

Response)

a. Please see the Direct Testimony of Michael T. Pullen in Case No. 2021-00079 for a discussion of the quoted statement and the regulatory risk.

b. On August 31, 2020, the EPA announced final revisions to the EPA Steam Electric Reconsideration Rule in a "Pre-Publication Notice," which can be found on the EPA website, through the following link: https://www.epa.gov/sites/production/files/2020-08/documents/steam_electric_reconsideration_rule_final_frn_08_31_2020.pdf

c. The electronic application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity to convert Green Station to natural gas and authority to establish a regulatory asset (case number 2021-00079) does not change Big Rivers' IRP analysis. A natural gas combined cycle (NGCC) is the best solution for providing the lowest cost energy and capacity for Big Rivers Member-Owners in the IRP analysis from 2024 to 2043. The CPCN filing (case number 2021-00079), if approved, would fill a capacity need while Big Rivers' continues to work on finding partners for a future NGCC.

d. Confirmed, Big Rivers would retire the Green units on June 1, 2022 if the Commission does not approve application in Case No. 2021-00079. Big

Rivers would purchase capacity and load from MISO until enough partners are obtained to build a NGCC at Sebree Station.

e. Assuming the Green units operate based upon the hours submitted within Big Rivers' model and parts are available for continuous maintenance, the expected lifespan exceeds the full planning period covered by the current IRP. The Green gas conversion was evaluated over a 7 year period and fully amortized over that period.

Witnesses) Nathanial A. Berry (*a., c., d., and e. only*)
Michael Mizell (*b. only*)

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC
2020 INTEGRATED RESOURCE PLAN OF
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Item 6) ***Regarding the current BREC Preferred Plan's reference to entering a partnership to own or purchase 90 MW of a 592 MW NGCC, explain whether BREC would be the MISO market participant regarding sales of power produced from such a plant.***

Response) Big Rivers prefers to be the market participant representing the new NGCC in the MISO market, but is open to one of the other partners being the market participant with the appropriate contractual protections.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

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Item 7) ***Confirm that the Reid coal unit (Reid Unit 1) has been retired.***

Response) Confirmed. While the decommissioning of Reid Station Unit 1 continues,[1] Big Rivers' Reid Station Unit 1 was retired on September 30, 2020.

Witness) Nathanial A. Berry

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[1] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for Review of Its MRSM Credit for Calendar Year 2020*, P.S.C. Case No. 2021-00061, Application Exhibit B, the Direct Testimony of Michael T. Pullen.

BIG RIVERS ELECTRIC CORPORATION

**ELECTRONIC
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Item 8) ***Explain whether there will be any stranded costs associated with the retirement of the Green units, including any environmental control plant and equipment. If so confirmed, confirm further that BREC has no ability to write-off any such stranded cost as tax losses.***

a. Provide an analysis of the stranded costs that will be incurred if the Commission approves BREC's application in Case No. 2021-00079.

b. Provide an analysis of the stranded costs that will be incurred if the Commission does not approve BREC's application in Case No. 2021-00079.

Response) Big Rivers plans to retire all plant equipment not associated with a natural gas conversion. This includes, but is not limited to, pulverizers, material handling, FGD, hydrated lime, and carbon injection.

a. If the Commission approves Big Rivers' application in Case No. 2021-00079,[1] there will be no stranded costs, as Big Rivers is asking to recover

[1] See *In the Matter of: Electronic Application of Big Rivers for a Certificate of Public Convenience and Necessity Authorizing the Conversion of the Green Station Units to Natural Gas-Fired*

the remaining net book value of the assets that will be retired through its new TIER credit mechanism. The remaining net book value of the assets that will no longer be utilized after the natural gas conversion are shown in that proceeding in the Direct Testimony of Paul G. Smith, in Exhibit Smith-5.

b. The stranded costs that will be incurred if the Commission does not approve Big Rivers' application in Case No. 2021-00079 are also shown in that proceeding in the Direct Testimony of Paul G. Smith, in Exhibit Smith-5.

Witness) Paul G. Smith

Units and an Order Approving the Establishment of a Regulatory Asset, Ky. P.S.C. Case No. 2021-00079.

Item 9) ***Confirm that in 2016, BREC undertook a multi-million dollar project to install new environmental controls at the Green units to make them MATS-compliant.***

- ***a. Explain whether any type of the environmental control equipment, and /or any plant of any type or sort from the Green units could be used as potential spare parts for the Wilson unit.***
- ***b. Explain whether any of the plant and equipment remaining at Coleman station could be used as potential spare parts for the Wilson unit.***

Response) Confirmed. Big Rivers installed both hydrated lime and carbon injection at its Green Station to make the units MATS-compliant.

- a. The environmental control equipment at Green Station could not be used as spare parts for Wilson Station. However there are several pieces of equipment at Green Station that can be used as spare parts at Wilson Station. These spare parts consist of electrical and digital controls systems ("DCS") equipment.

b. Electrical and DCS equipment from Coleman Station can be used as spare parts at Wilson Station. Big Rivers is in the process of moving the Coleman Flue Gas Desulfurization ("FGD") system to Wilson Station. The Commission approved this project as part of its review of Big Rivers' 2020 Environmental Compliance Plan.[1]

Witness) Nathanial A. Berry

[1] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of its 2020 Environmental Compliance Plan, Authority to Recover Costs through a Revised Environmental Surcharge and Tariff, the Issuance of a Certificate of Public Convenience and Necessity for Certain Projects, and Appropriate Accounting and Other Relief*, Case No. 2019-00435. [Application filed February 7, 2020].

Item 10) ***Provide an update on the status of demolition at Coleman Station.***

Response) Big Rivers awarded the contract for asbestos removal and demolition to Complete Demolition Services (CDS). Demolition is now scheduled to start the first week of April 2021 with a 12–month completion schedule.[1]

Witness) Nathanial A. Berry

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[1] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for Review of Its MRSM Credit for Calendar Year 2020*, P.S.C. Case No. 2021-00061, Application Exhibit B, the Direct Testimony of Michael T. Pullen.

BIG RIVERS ELECTRIC CORPORATION

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Item 11) ***Explain whether the Reid CT is fired exclusively with natural gas, or if it ever uses fuel oil.***

Response) The Reid CT has the ability to fire using either fuel oil or natural gas; however, since the dual fuel conversion was completed the CT fires primarily on natural gas, which is the most economical at the existing natural gas prices.

Witness) Nathanial A. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 12) ***Explain whether Wilson has black start capability, and if so, whether MISO provides any additional monetary contribution / reimbursement for that capability.***

a. If Wilson lacks black start capability, explain whether BREC has conducted any studies regarding the cost and benefits of adding that capability.

Response) Wilson does not have black start capability.

a. Big Rivers has conducted studies to make Wilson black start capable by utilizing the Reid combustion turbine ("Reid CT"). In one of those studies, Big Rivers would need to install a generator and upgrade the current voltage regulator at the Reid CT. At that point, the Reid CT would be able to provide black start capabilities to Wilson Station.

Witness) Nathanial A. Berry

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Item 13) ***Reference IRP Plan § 6.2, Transmission Transfer Capability, in particular the follow statement: "…the existing transmission system is sufficient to support the export of all Big Rivers generation power greater than the amount required to serve Member load."***

a. Provide a discussion of whether any MISO projects over the next four years could affect congestion in or near BREC's service territory and/or whether any such projects could in any manner impair or impede BREC's continued ability to engage in off-system sales. Provide copies of any studies performed in this regard.

b. Include in your response a discussion of whether any additional MISO projects are or will be necessary or helpful in assisting BREC's ongoing off-system sales, including the increasing likelihood of regional HVDC transmission.

Response)

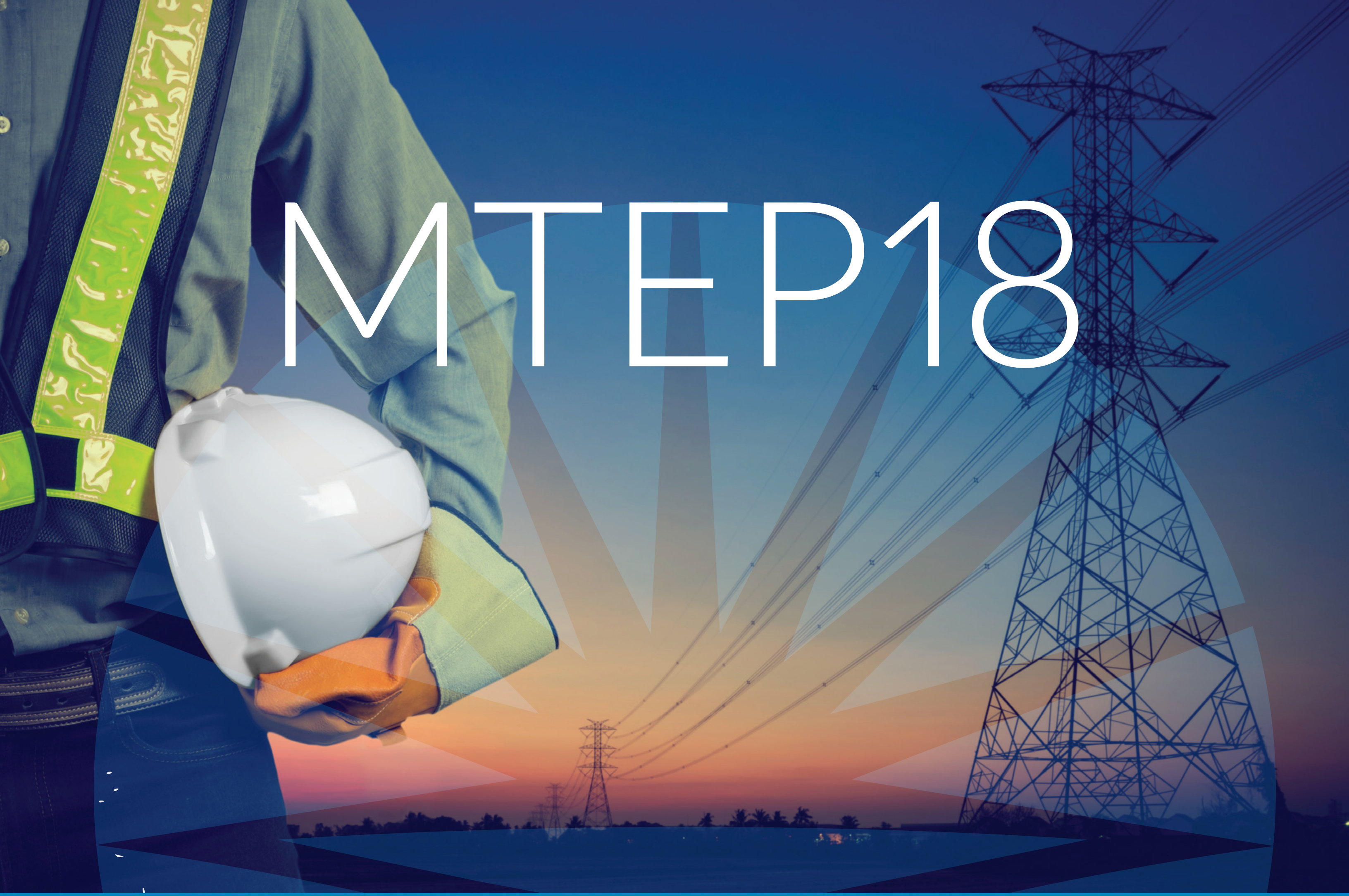
a. The Wilson to BR Tap to Paradise 161 kV upgrade project included in MISO Transmission Expansion Plan ("MTEP18") is expected to reduce congestion along the Big Rivers/TVA/LG&E-KU interface near Big Rivers' Wilson generating station. The reduced congestion is expected to improve Big Rivers' ability to engage in off-system sales. The project is described in Section 5.3 of the MTEP18 study report[1] attached hereto. Big Rivers is not aware of any planned projects that may impair or impede the continued ability to engage in off-system sales.

b. Big Rivers continues to participate in the MISO MTEP and monitors projects that have the potential to benefit Big Rivers by reducing transmission congestion. While Big Rivers has identified no specific MISO projects that will be helpful, Big Rivers is closely monitoring the MISO efforts to evaluate the North-South interface. Additional details can be found in Chapter 3 of the publically available MTEP20.[2]

Witness) Christopher S. Bradley

[1] MISO's MTEP18 Study Report can also be found at: https://www.misoenergy.org/planning/planning/previous-mtep-reports/#t=10&p=0&s=FileName&sd=desc.

[2] See: https://www.misoenergy.org/planning/planning/mtep20/.



MTEP18

Transmission Enhancement Plan

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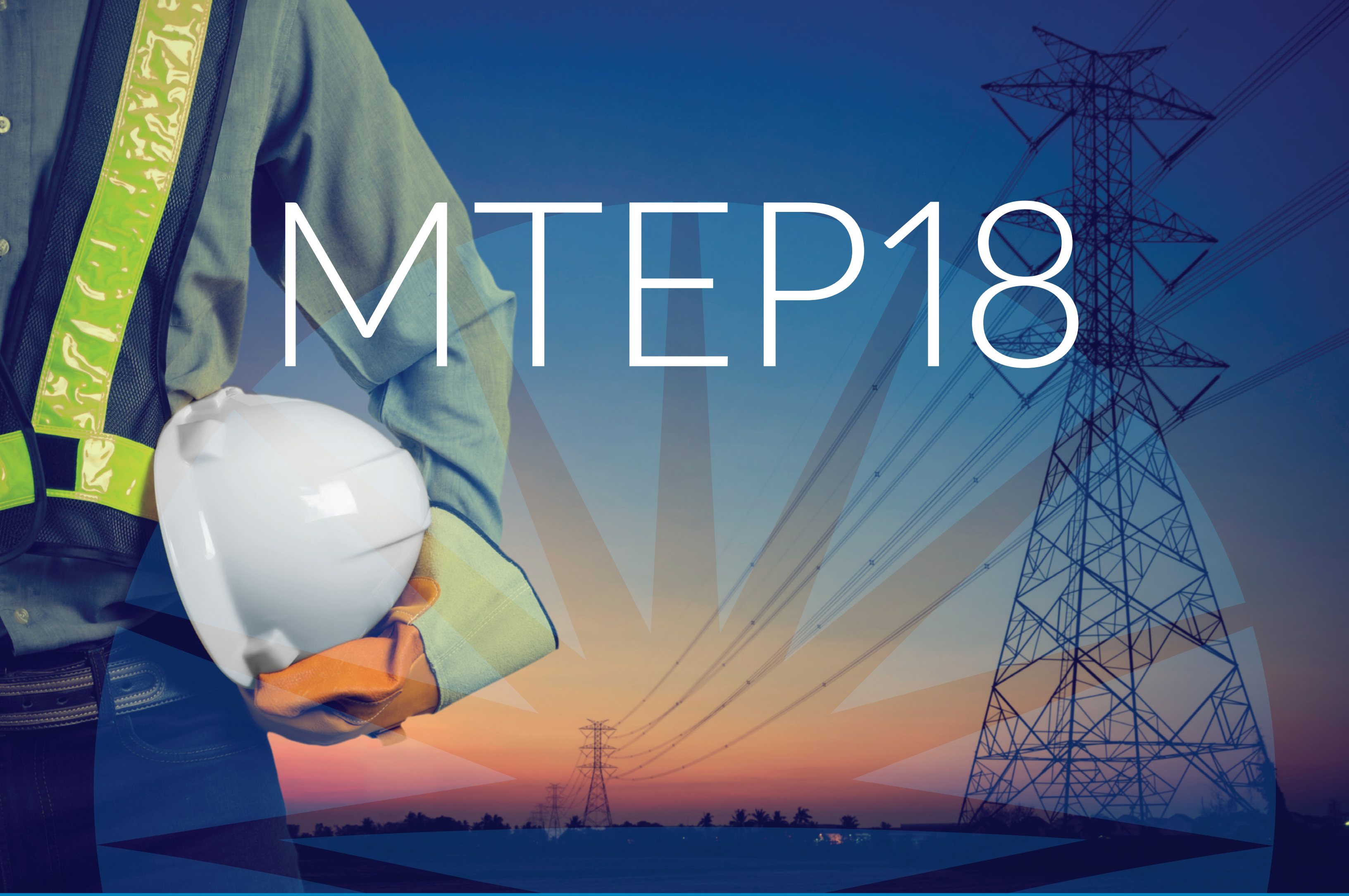
MTEP18



In this MISO Transmission Expansion Plan, MISO staff recommends $3.3 billion of new transmission enhancement projects for Board of Directors' approval.

Highlights

- 442 new projects for inclusion in Appendix A
- $19.1 billion in projects constructed in the MISO region since 2003
- Over 4,467 MW of generation enabled by new network upgrades that will be included in MTEP18
- Recommendation to approve two interregional projects with PJM

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MTEP18

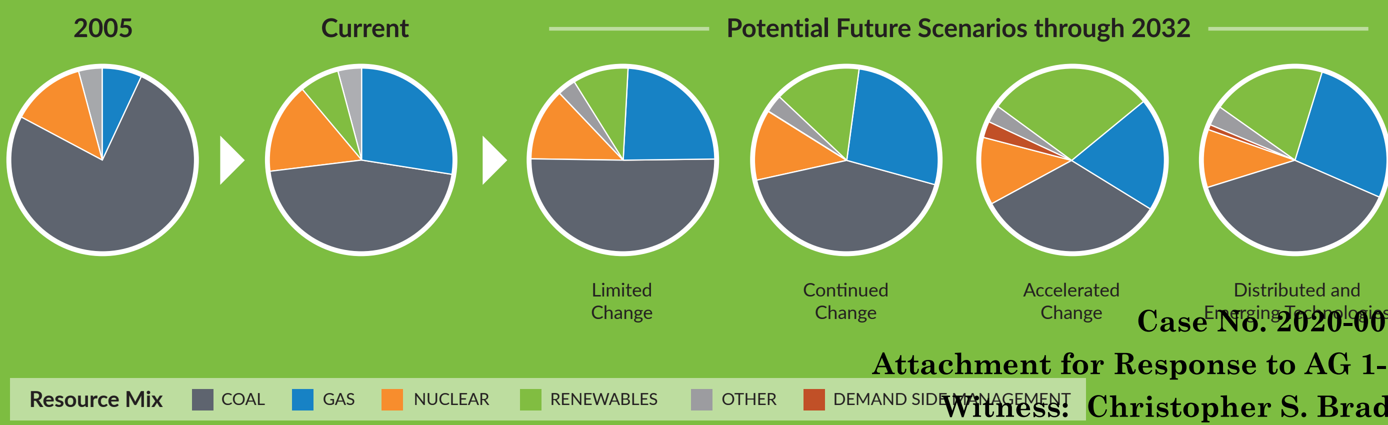
MISO looks to the future

Driven by changing economics, energy policies, and customer preference the MISO landscape is changing dramatically. Analysis indicates continued increases in renewable energy, additions of demand-side resources, and additional conventional resource retirements across the footprint. Future expectations reveal continued trends toward "Three Ds" – Decentralization from large stations to smaller distributed resources, Digitalization of electricity consuming devices and the internet of things, and Demarginalization of resource costs. This evolution will necessitate changes in the transmission system to allow more flexibility and integration of diverse resource types.

While no one knows exactly how quickly this transition will occur, or exactly what the fleet will look like in 15 years, MISO knows that the transmission system needed to economically and reliably support the future resource mix will be different from that which exists today. And the incremental, bit-by-bit approach to system planning is expensive and inefficient.

MISO's charge is to build an efficient and economic plan for a robust, flexible, no-regrets grid that can effectively meet future system needs. Developing such a grid that can accommodate future resource fleet changes requires a long-term system view with an increased emphasis on planning to meet demand every hour of the year, not just the summer peak. Projects in MTEP18 continue to support local reliability and market efficiency, as MISO continues to work with its stakeholders to plan for the future.

The Changing Energy Landscape



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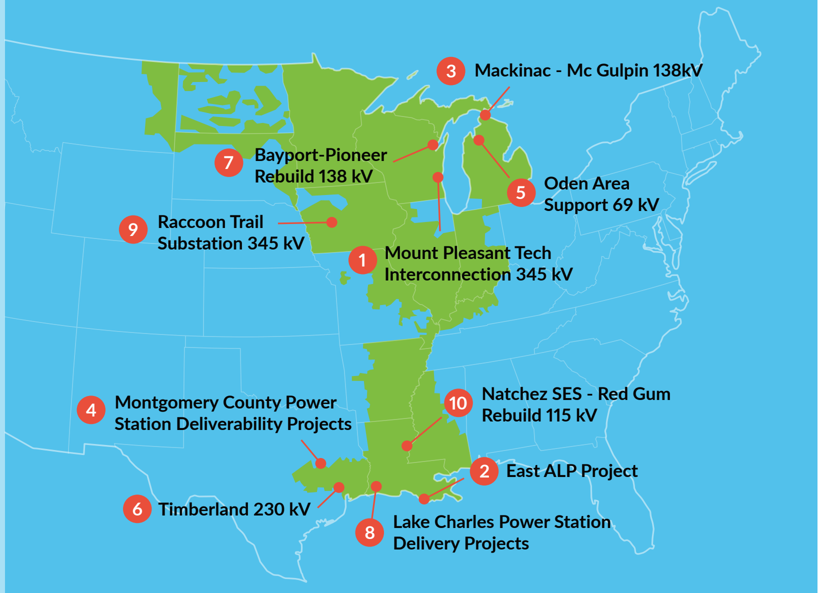
The 10 largest projects represent 23 percent of the total cost and are distributed across the MISO region. These projects support safe, reliable transmission to enable load and generation interconnection, NERC reliability compliance and other local needs.



Top 10 proposed MTEP18 projects

(In descending order of cost)

MTEP18 Appendix A Overview

MTEP Appendix A projects are vetted by MISO through the planning process and are ready for execution. The 442 new Appendix A projects in MISO's 2018 Transmission Expansion Plan (MTEP18) represent $3.3 billion in transmission infrastructure investment and fall into the following categories:

- **81 Baseline Reliability Projects (BRP)** that are required to meet standards for both North American Electric Reliability Corporation (NERC) and regional reliability
- **16 Generator Interconnection Projects (GIP)** needed to reliably connect new generation to the transmission grid
- **341 Other projects** that address a wide range of needs, such as those that support lower-voltage transmission systems or replacement of existing, but do not meet the threshold to qualify as Market Efficiency Projects
- **3 Other projects**, totaling $29 million, that specifically provide local economic benefit
- **2 Transmission Deliverability Service Projects (TDSP)** that enable power delivery
- **2 interregional Targeted Market Efficiency Projects** with Pennsylvania-based PJM, that address congestion along the MISO-PJM seam

As the MISO region experiences changes and growth, the MTEP also reflects analysis of specific issues to ensure the region is well-positioned to meet future electricity demand and regulatory mandates. Notable work efforts performed during this planning cycle include:

- Ongoing evaluation of transmission needs and identification of solutions through Market Congestion Planning Studies
- Providing transparency around the Resource Adequacy outlook in the MISO Region
- Greater interregional planning collaboration along MISO's seams
- Updating MTEP18 Futures and adding a fourth planning future - Distributed & Emerging Technologies - to consider emerging technology trends
- Improving understanding of increased renewable penetration impacts through the Renewable Integration Impact Assessment (RIIA)
- Increasing alignment of project benefits and costs through a cost allocation proposal, anticipated FERC filing timeline of Q4 2018, which was the culmination of over three years of stakeholder process, and is the first to integrate cost allocation rules for the region as a whole following the South region integration period

System Planning Guiding Principles

- Make the benefits of an economically efficient electricity market available to customers by identifying transmission projects that provide access to electricity at the lowest total electric system cost
- Develop a transmission plan that meets all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs
- Support state and federal energy policy requirements by planning for access to a changing resource mix
- Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects
- Analyze system scenarios and make the results available to state and federal energy policy makers and other stakeholders to provide context and to inform their choices
- Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations

A strong foundation serves and grows MISO's membership

Reliability is a multi-layered, interdependent journey with MISO and its transmission-owning members. The planning process, in conjunction with an inclusive, transparent stakeholder process, must identify and support development of a sufficiently robust transmission infrastructure to meet local and regional reliability standards as well as enable competition among wholesale capacity and energy suppliers.

Reliability planning, including age and condition upgrades, at the local level constitutes the majority of the overall projects recommended for Board approval in each cycle

Regional conversations lead to interregional planning that affects the Eastern Interconnection. All of these decisions must remain compliant with mandates such as FERC's Order 1000. MISO's interregional planning process covers the collaboration between MISO and neighboring grid operators SPP and PJM, but it doesn't stop there. Coordination happens beyond those borders to include IESO of Ontario and Southeastern Regional Transmission Planning region. MISO and all its stakeholders stand to benefit not only from the efficiencies inherent in collaboration, but also the economic enhancements of potential future projects.

Provide MISO members the most value

It's not enough to have a strong set of operating values that ensure communication and inclusive planning practices. The evolving generation fleet and changing system conditions also require an integrated approach. For example, in the MTEP18 cycle, MISO combined the Market Congestion Planning Study with Sub-regional Planning Meetings to allow greater coordination between both MISO and stakeholder reliability and economic planning processes.

FERC Order 1000 opened up opportunities for more providers to participate in building transmission in the MISO footprint on regionally cost-shared projects. As a result, MISO created a Competitive Transmission Process to evaluate and select

Forecasted capacity balances declined for 2019, largely due to decreased availability of resources

Regional 2019 Outlook from OMS-MISO Survey:
Committed Capacity Projection Variations Since Prior Survey, in GW (Installed Capacity)

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a developer for these eligible projects. This year's planning process did not identify a project eligible for competitive selection. However, the process to select a developer for the Hartburg-Sabine Junction 500 kV Economic Project, identified in MTEP17, is proceeding according to schedule, and will result in the announcement of a selected developer by the end of 2018.

In general, MTEP18 shows lower congestion across the footprint relative to previous transmission planning cycles. This result is due in large part to mitigating the top congested elements, competitive fuel prices and stagnant net demand growth – though congestion in specific areas of the footprint is on the rise driven by fleet change and renewable additions. MTEP18 includes several projects to meet local economic needs, reducing congestion and increasing access to lower-cost generation in those areas.

In addition to improving planning processes, MISO is also carefully incorporating resource adequacy considerations and cost allocation improvements. The footprint has sufficient resources for 2019. However risks exist in subsequent years as generation retires and is replaced by often lower-capacity resources like wind and solar.

Further, MISO is moving towards a more granular cost allocation methodology for regional and interregional economic projects. This new methodology will improve the alignment of who benefits with who pays given the scope of the MISO footprint and nature of the projects in question.

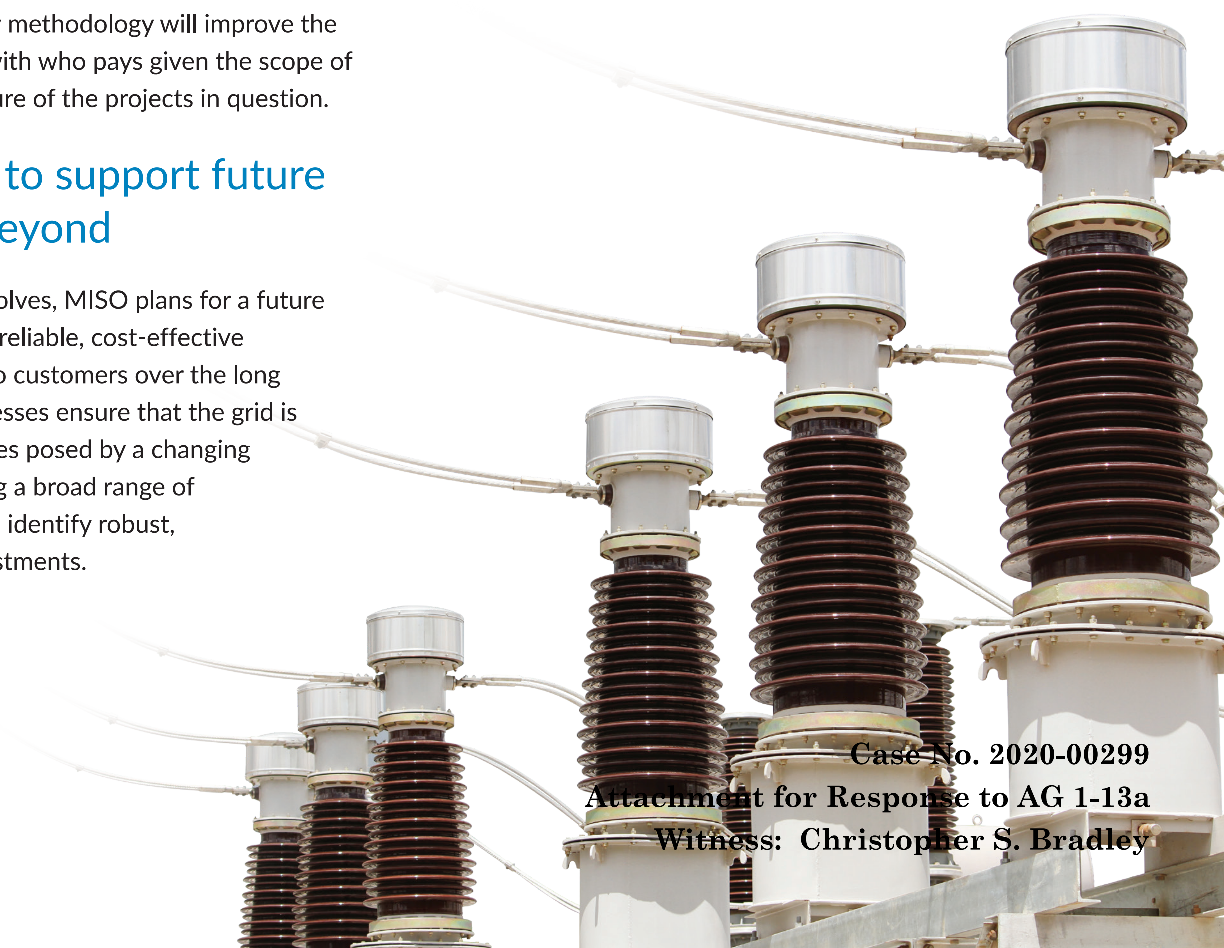
MTEP18 - a plan to support future grid needs and beyond

As the electrical industry evolves, MISO plans for a future system designed to achieve reliable, cost-effective electricity, providing value to customers over the long term. MISO's planning processes ensure that the grid is well-positioned for challenges posed by a changing resource fleet by considering a broad range of potential future scenarios to identify robust, beneficial transmission investments.

MTEP18 studies what the grid could look like for the next 20-plus years as energy sources shift, policy changes, and emerging technology becomes a larger player. This report takes a hard look at potential future grid needs that will need to be addressed in subsequent planning efforts. MISO's MTEP18 process also examines current efforts to manage its largest interconnection queue ever – 80,000-plus MW, mostly wind and solar generation – in addition to the early emergence of storage interconnection requests, on a system that today totals 175,000 MW of installed capacity.

MISO's current interconnection queue consists of 483 projects totaling 81.5 GW

Ongoing studies explore the implications of integrating increasing penetrations of renewables on the grid; retirements in conventional energy sources; and the current emphasis on energy-based planning, such as integrating intermittent and distributed energy resources.



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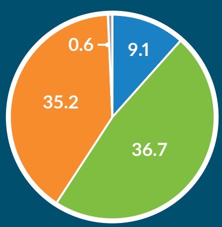
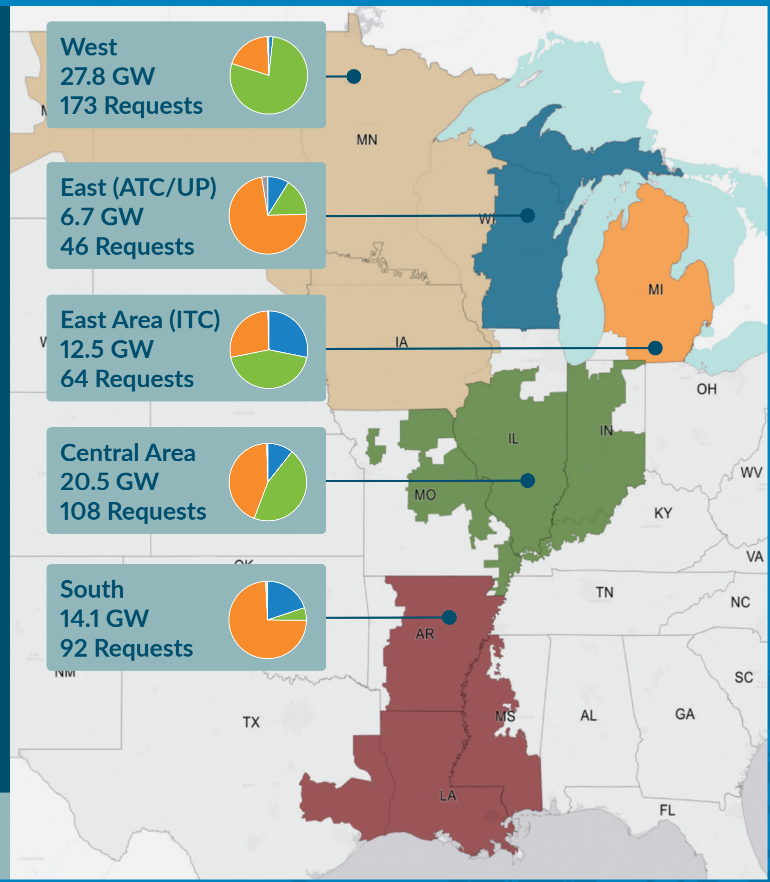
MISO's current generator interconnection queue consists of 483 projects totaling over 80 GW

MISO Active Queue by Study Area

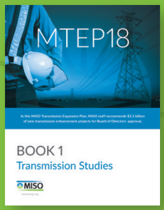


Total Queue:
81.5 GW

Fuel Type WIND GAS SOLAR OTHER



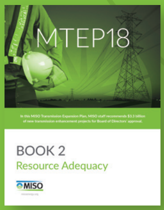
MTEP18 is organized into four books and a series of detailed appendices.



BOOK 1

TRANSMISSION STUDIES

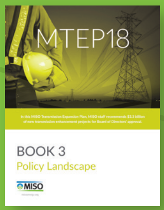
Summarizes this cycle's projects and the analyses behind them.



BOOK 2

RESOURCE ADEQUACY

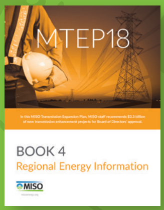
Describes annual and targeted analyses for Resource Adequacy.



BOOK 3

POLICY LANDSCAPE

Presents the policy landscape with a summary of regional and interregional studies.



BOOK 4

REGIONAL ENERGY INFORMATION

Presents additional regional energy information.

APPENDICES A-F

Provides detailed assumptions, results, project information and stakeholder feedback.

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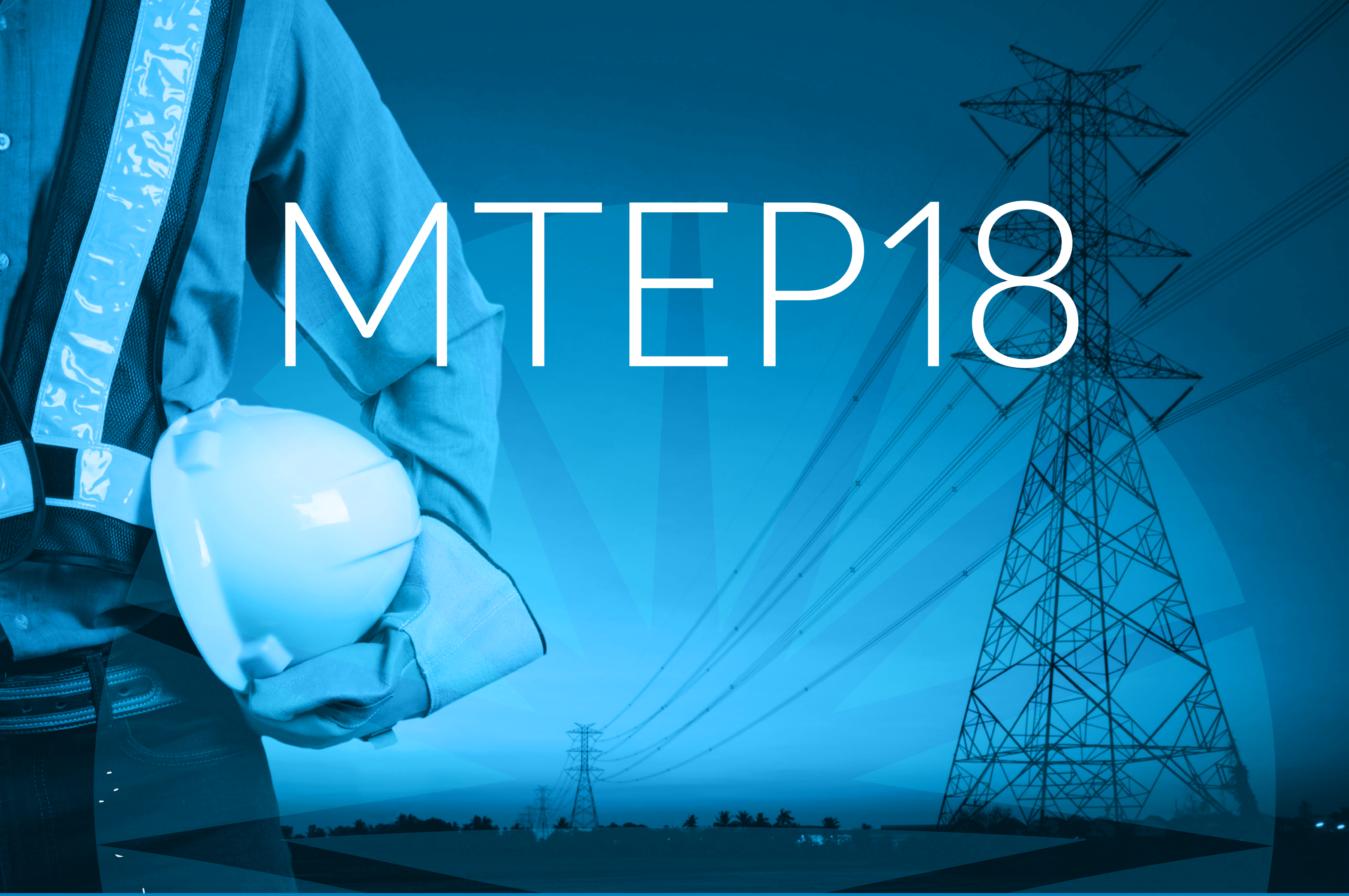

MTEP18

In this MISO Transmission Expansion Plan, MISO staff recommends $3.3 billion of new transmission enhancement projects for Board of Directors' approval.

BOOK 1
Transmission Studies

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MTEP18
Transmission Studies

Summary

The MTEP18 cycle proposes 442 new projects and $3.3 billion of new transmission investment — but how did MISO get there? Transmission studies, featuring robust reliability and economic analyses, help MISO members make prudent planning and investment decisions to continue delivering reliable, least-cost energy. Reliability projects, including age and condition upgrades, a vital part of MTEP planning, account for the majority of all recommended projects.

BOOK HIGHLIGHTS

- Congestion across the footprint is lower relative to past cycles as the result of previously approved projects mitigating the top congested elements, competitive fuel prices, and stagnant net demand growth – though congestion in specific areas of the footprint is on the rise driven by fleet change and renewable additions
- MISO has its largest interconnection queue ever of more than 80 GW, mostly wind and solar generation, in addition to the early emergence of storage interconnection requests
- MISO's move towards a more granular cost allocation methodology for regional and interregional economic driven projects will improve the alignment of who benefits with who pays given the scope of the MISO footprint and nature of the projects in question. This proposal is the product of over three years of discussion and stakeholder engagement, and is the first to integrate cost allocation rules for the region as a whole following the South region integration period.
- Updated MTEP18 futures model Limited Fleet Change, Continued Fleet Change, and Accelerated Fleet Change scenarios. Additionally, a Distributed and Emerging Technologies future was added to reflect the emergence of new technologies.
- This book provides an overview of MTEP18 project proposals and a status update of projects approved in prior MTEP cycles

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Section 2: MTEP Overview

2.1 Investment Summary

2.2 Cost Sharing Summary

2.3 MTEP Process and Schedule

2.4 MTEP Project Types and Appendix Overview

2.5 MTEP Model Development

2.1 Investment Summary

The 442 new Appendix A projects in MISO's 2018 Transmission Expansion Plan (MTEP18) represent $3.3 billion[1] in transmission infrastructure investment and fall into the following categories:

- **81 Baseline Reliability Projects (BRP) totaling $709 million**— BRPs are required to meet standards for both North American Electric Reliability Corporation (NERC) and regional reliability
- **16 Generator Interconnection Projects (GIPs) totaling $255 million** — GIPs are required to reliably connect new generation to the transmission grid
- **341 Other Projects totaling $2.3 billion** — Other projects include a wide range of projects, such as those that support lower-voltage transmission systems or provide local economic benefit, but do not meet the threshold to qualify as Market Efficiency Projects. Three Other projects, totaling $29 million, were identified through the Market Congestion Planning Study.
- **2 Transmission Deliverability Service Projects (TDSP) totaling $285,000** — TDSPs are network upgrades driven by Transmission Service Requests (TSR)
- **2 Targeted Market Efficiency Projects (TMEP) totaling $4 million** — TMEPs are interregional projects, with Pennsylvania-based PJM, that address historical Market-to-Market congestion along the MISO-PJM seam

The 10 largest projects represent 23 percent of the total cost and are distributed across the MISO region (Figure 2.1-1).

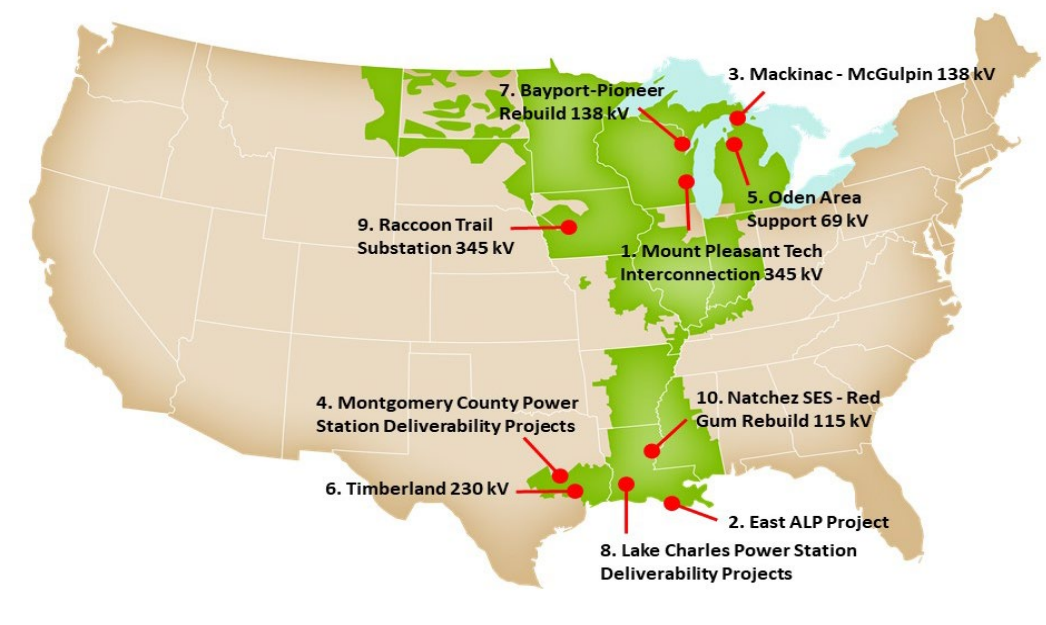

Figure 2.1-1: Top 10 MTEP18 new Appendix A projects (in descending order of cost)

[1] The MTEP18 report and project totals reflect all project approvals during the MTEP18 cycle, including those approved on expedited project review basis prior to December 2018.

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The new projects recommended for approval in MTEP18 Appendix A are broken down by region and project type (Table 2.1-1). New projects in MTEP18 Appendix A contain four cost-shared Generator Interconnection Projects. Cost sharing information is provided in Section 2.2: Cost Sharing Summary.

MISO Region	GIP	Other	TDSP	TMEP	BRP	Total
Central	$11,936,823	$468,850,975		$4,475,000	$39,050,415	$524,313,213
East	$8,376,000	$348,151,409			$206,432,000	$562,959,409
South	$149,651,049	$303,143,174	$285,025		$333,140,582	$786,219,830
West	$84,931,359	$1,196,817,962			$130,356,259	$1,412,105,580
Grand Total	$254,895,231	$2,316,963,520	$285,025	$4,475,000	$708,979,256	$3,285,598,032

Table 2.1-1: MTEP18 New Appendix A investment by project category and planning region

Other Project Type

The majority of Other projects address localized reliability issues — either due to aging transmission infrastructure, or local non-baseline reliability needs that are not dictated by NERC and regional reliability standards (Figure 2.1-2). A small percentage of projects target localized economic benefits or line relocations to accommodate other infrastructure.

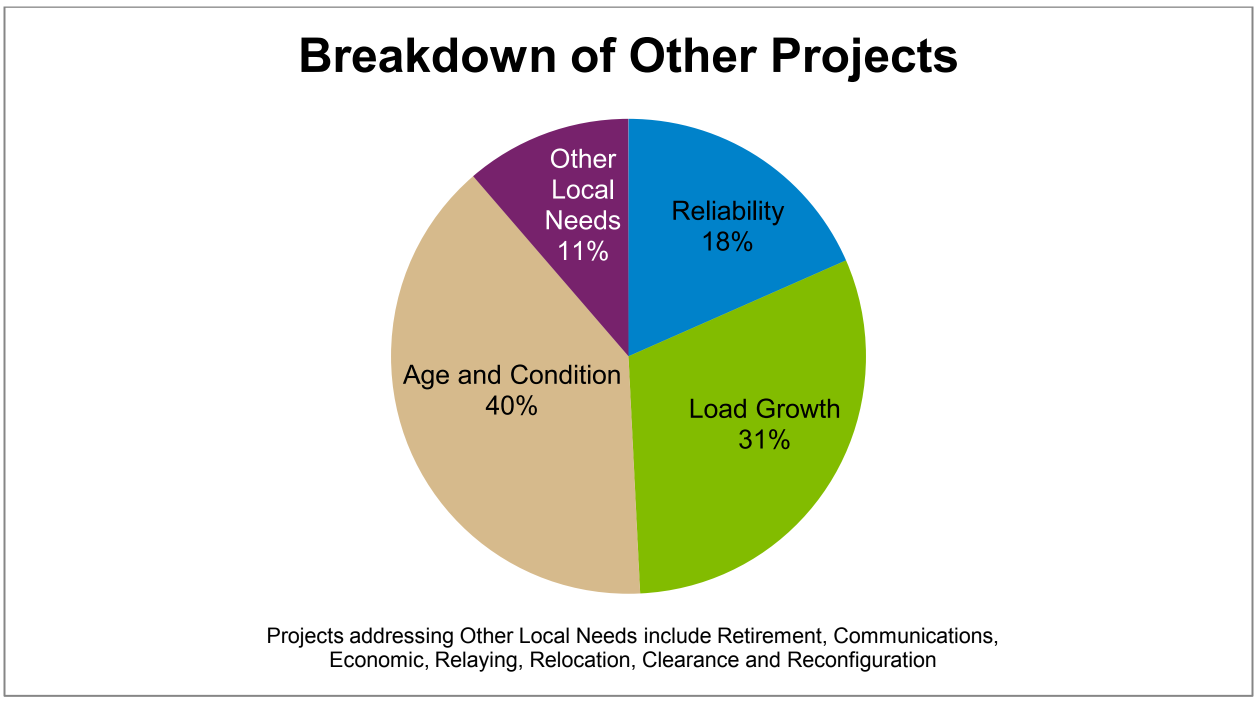

Figure 2.1-2: Breakdown of new MTEP18 Appendix A Other projects

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Facility Type

Each MTEP project is composed of one or more facilities, where each facility represents an individual element of the project. Examples of facilities include substations, transformers, circuit breakers or various types of transmission lines (Figure 2.1-3). The majority of facility investment in this cycle, based on a facility estimated cost of 50 percent, is dedicated to substation or switching station related construction and maintenance. This includes completely new substations as well as terminal equipment work, circuit breaker additions and replacements, or new transformers. Thirty-five percent of MTEP facility costs go toward line upgrades, which include rebuilds, conversions and relocations. Only about 15 percent of facility costs are dedicated to new lines on new right-of-way across the MISO footprint.

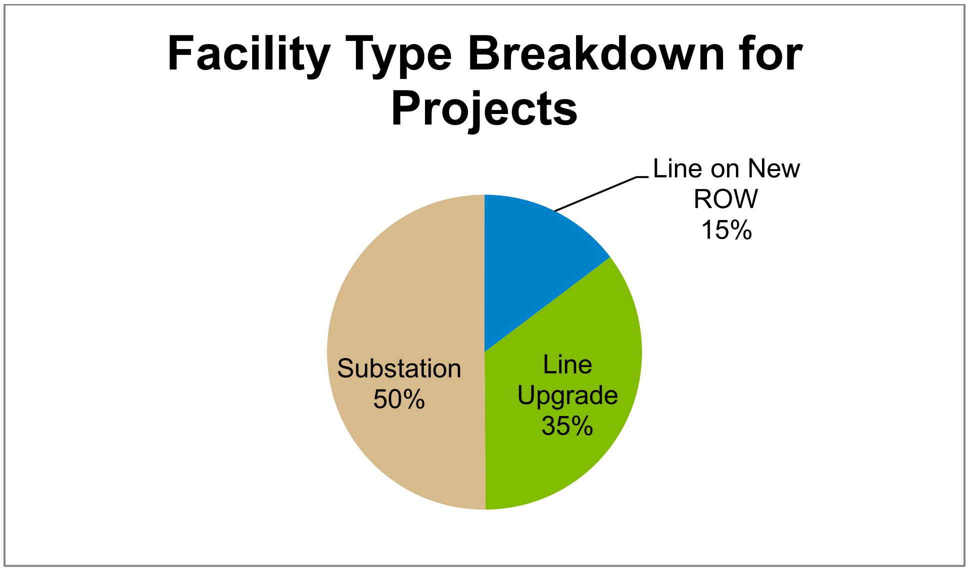

Figure 2.1-3: Facility type for new MTEP18 Appendix A projects

New Appendix A projects are spread over 14 states, with 10 states scheduled for more than $100 million in new investment (Figure 2.1-4). A few projects have investment in more than one state, but the statistics in the figure are aggregated to the primary state. These geographic trends vary greatly year to year as existing transmission capacity in other parts of the system is consumed and new build becomes necessary.

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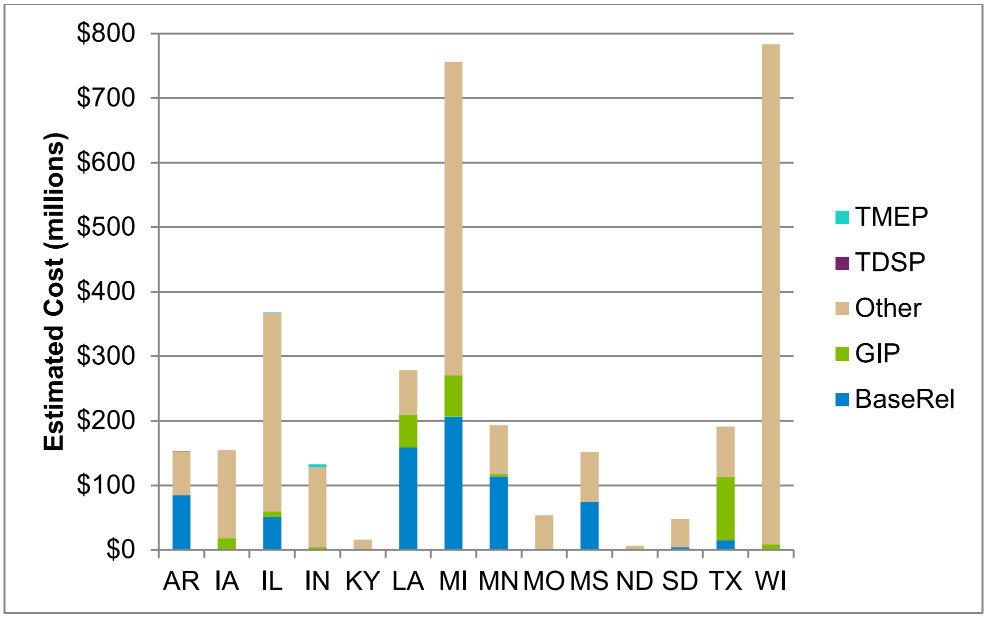

Figure 2.1-4: New MTEP18 Appendix A investment categorized by state

Active Appendix A Investment

The active project spending for Appendix A, with the addition of MTEP18 new projects, increases to 1,081 projects amounting to approximately $13 billion of investment through the next 10 years (Figure 2.1-5). The list of Active Appendix A projects contains newly approved projects and previously approved projects that are not yet in service. Projects may be comprised of multiple facilities. Large-project investment is shown in a single year but often occurs over multiple years (Figure 2.1-6). Investment totals by year assume that 100 percent of a project's investment is fulfilled when the facility goes into service. It does not reflect projected cash flow or the fact that certain components of a project may be placed in service as a project progresses.

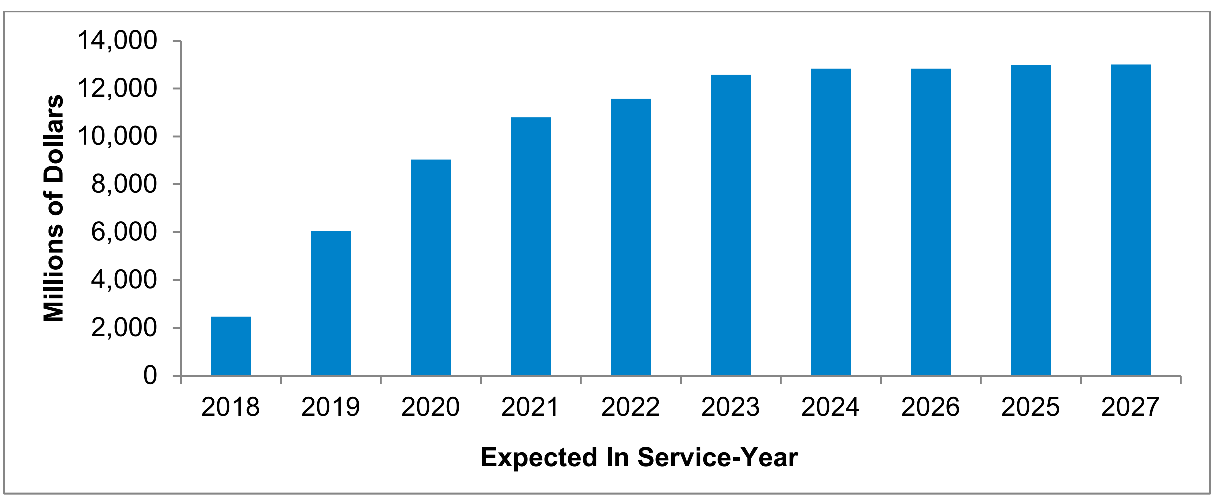

Figure 2.1-5: MTEP18 Appendix A projected cumulative investment by year

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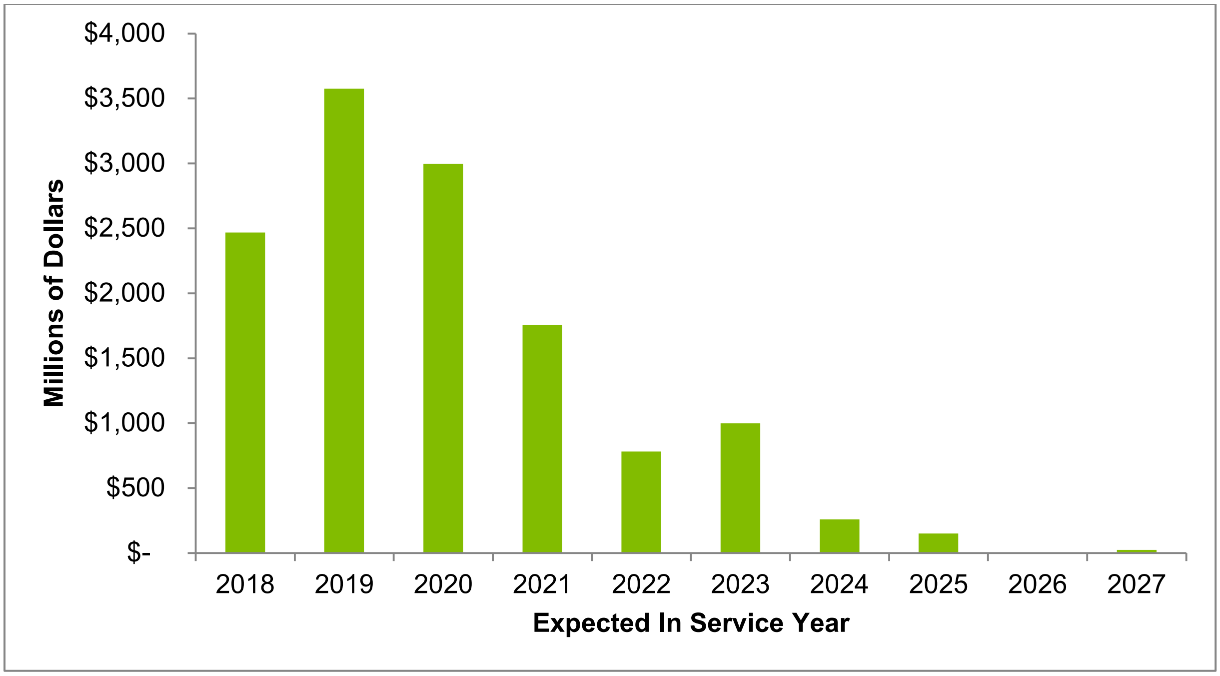

Figure 2.1-6: MTEP18 Appendix A projected incremental investment by year (includes projects from previous MTEP cycles not yet in service)

MISO Transmission Owners[2] have committed to significant investments in the transmission system (Table 2.1-2). Cumulative MTEP transmission investment for Appendix A is approximately $14.4 billion with another $3.4 billion in Appendix B. New MTEP18 Appendix A projects represent approximately $3 billion of this investment. Projects associate primarily with a single planning region, though some projects may involve multiple planning regions. About $3.8 billion of the $14.4 billion cumulative in Appendix A is from the active Multi-Value Projects (MVP) approved in MTEP11. Projects are spread across the four MISO geographic planning regions: East, Central, West and South (Figure 2.1-7).

[2] https://cdn.misoenergy.org/Current%20Members%20by%20Sector95902.pdf

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MISO Region	Number of Appendix A Projects	Appendix A Estimated Costs	Number of Appendix B Projects	Appendix B Estimated Costs
Central	214	$2,289,577,702	61	$159,479,940
East	240	$1,879,742,495	39	$547,218,000
South	206	$3,699,198,701	86	$1,712,533,292
West	421	$6,615,834,004	63	$957,622,980
Grand Total	1081	$14,484,352,902	249	$3,376,854,212

Table 2.1-2: Projected transmission investment by planning region

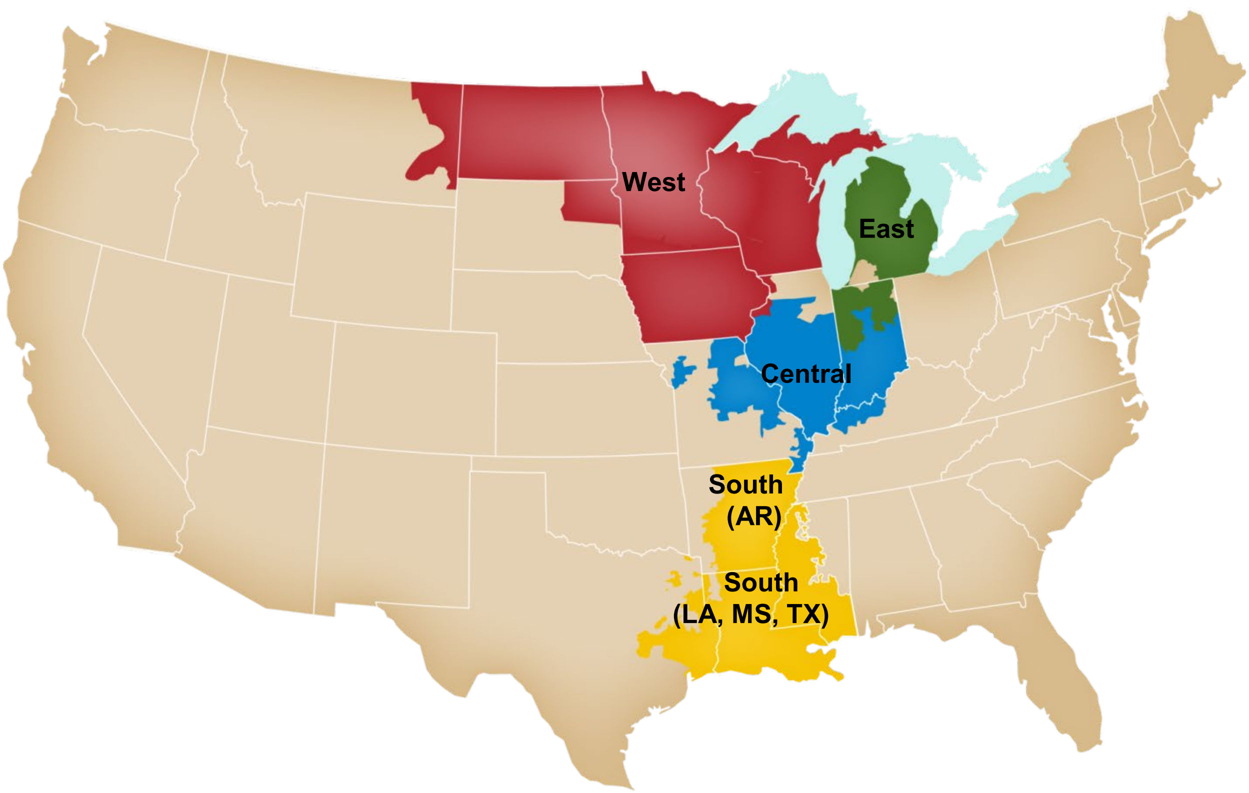

Figure 2.1-7: MISO footprint and planning regions

Active Appendix A Line Miles Summary

MISO has approximately 68,500 circuit-miles of existing transmission lines. There are approximately 5,900 circuit-miles of planned new or upgraded transmission lines projected in the 10-year planning horizon in MTEP18 Appendix A (Figure 2.1-8, Table 2.1-3).

- 4,000 circuit-miles of upgraded transmission line on existing corridors are planned
- 1,900 circuit-miles of new transmission line on new corridors are planned

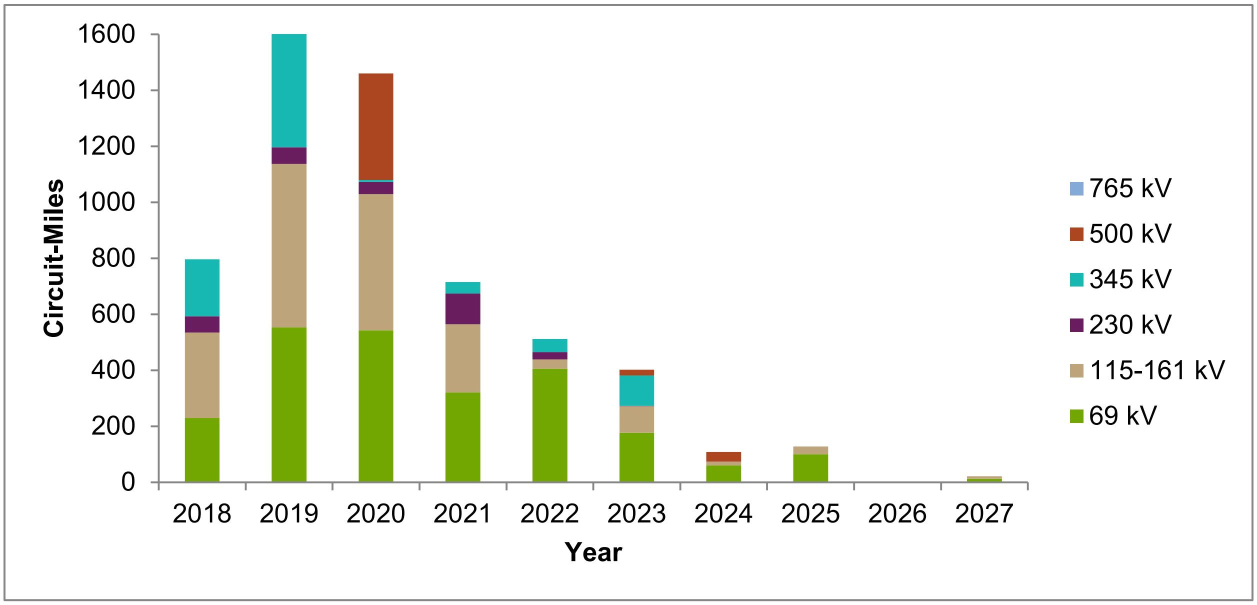

Figure 2.1-8: Planned new or upgraded line circuit-miles by voltage class (kV) in Appendix A through 2028

Year	<100 kV	115-161 kV	230 kV	345 kV	500 kV	765 kV	Grand Total
2018	303	305	58	204			870
2019	632	585	59	406			1682
2020	576	486	45	7	380		1493
2021	341	243	110	42			736
2022	408	32	27	47			514
2023	177	94	1	108	22		402
2024	60	14			35		108
2025	100	27					127
2026							
2027	12	9					21
Grand Total	2609	1796	300	813	437		5955

Table 2.1-3: Planned new or upgraded line circuit-miles by voltage class (kV) in Appendix A through 2028

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2.2 Cost Sharing Summary

New MTEP18 Appendix A Cost-Shared Projects

MTEP18 recommends a total of 11 new cost-shared eligible projects for Appendix A with an estimated cost of $91.4 million. The 11 eligible projects include:

- Nine Generator Interconnection Projects (GIP) with a total estimated project cost of $86.9million, where $37.4 million is allocated to load, and the remaining $49.5 million is allocated directly to generators.[3]
- Two Targeted Market Efficiency Projects (TMEP) with a total cost of $4.5 million, where the MISO cost responsibility is $4.2 million, and the remaining $300,000 is allocated to PJM.

MISO employs a collection of cost allocation mechanisms that seek to match the costs of transmission investment to those who benefit

MISO employs a collection of cost allocation mechanisms that seek to match the costs of transmission investment to those who benefit from that investment. For GIPs, 10 percent of the cost of associated 345 kV network upgrades is allocated to load on a region-wide basis based on load ratio share. In some special situations, costs of GIP network upgrades greater than 100 kV may be distributed to benefiting pricing zones on the basis of line outage distribution factor calculations. For Market Efficiency Projects, a portion of costs are distributed to Cost Allocation Zones based on the adjusted production cost benefits; the remaining is distributed among the applicable planning area by company load ratio share. TMEPs with PJM are allocated amongst each RTO by the ratio of Day-Ahead and Excess Congestion Fund congestion, offset by historical market-to-market payments. The MISO portion is then allocated to the MISO Transmission Pricing Zones using historical nodal load congestion data.

Cost Allocation between Planning Areas for GIPs and MEPs

The integration of the MISO South region on December 19, 2013, started a cost allocation transition period that determines how approved cost-allocated projects are shared amongst the pricing zones in the MISO North/Central and MISO South planning areas. The transition period concludes when certain Tariff criteria are met, currently scheduled for the end of MTEP18.[4] The cost-shared projects in MTEP18 all terminate exclusively in one planning area, and are cost shared amongst their respective pricing zones (Table 2.2-1).

[3] Note that the costs indicated as "allocated to generators" does not account for the Transmission Owners who reimburse qualifying generators 100 percent of the costs incurred for Generation Interconnection Projects.
[4] According to the Tariff: ***Second Planning Area's Transition Period:*** The period: (i) commencing when the first Entergy Operating Company conveys functional control of its transmission facilities to the Transmission Provider to provide Transmission Service under Module B of this Tariff; (ii) consisting of at least five consecutive years, plus the time needed to complete the MTEP approval cycle pending at the end of the fifth year; (iii) ending on the day after the conclusion of such MTEP approval cycle, which in no case shall be more than six years after the start of that period.

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Type and Location of Project	Approved Before Transition Period		Approved and/or Identified During Transition Period		Approved After Transition Period Ends
	Treatment During Transition Period	Treatment After Transition Period	Treatment During Transition Period	Treatment After Transition Period	
GIPs and MEPs terminating exclusively in one planning area	Within North/Central planning area	Within North/Central planning area	Within applicable planning area	Within applicable planning area	Applicable to both planning areas
GIPs and MEPs terminating in both planning areas	Not Applicable	Not Applicable	Applicable to both planning areas	Applicable to both planning areas	Applicable to both planning areas

Table 2.2-1: Cost-shared GIP and MEP transition period Tariff provisions

Cumulative Summary of All Cost-Shared Projects since MTEP06

A total of 207 projects have been eligible for cost sharing since cost-sharing methodologies were first incorporated into the MTEP process. Cost sharing began in 2006 with Baseline Reliability Projects[5] (BRP) and GIPs, and was later augmented with MEPs in 2007 and Multi-Value Projects (MVP) in 2010. Cost sharing further expanded in 2017 with the addition of TMEPs with PJM. Starting with MTEP13 and going forward, the costs for BRPs were removed from cost sharing and allocated to the pricing zone of the project location. The cost-shared eligible projects represent $10.7 billion in transmission investment, including the portion of project costs allocated directly to generators for GIPs (Figure 2.2-1, Table 2.2-2). The distribution of cost-shared projects includes:

- Baseline Reliability Projects (BRP) — 71 projects, $3.2 billion
- Generation Interconnection Projects (GIP) — 106 projects, $745.7 million (including the portion of project costs allocated directly to the generator)
- Market Efficiency Projects (MEP) — 5 projects, $317.4 million
- Multi-Value Projects (MVP) — 17 projects, $6.5 billion
- Targeted Market Efficiency Projects (TMEP) – 7 projects, $10.8 million

[5] For Baseline Reliability Projects effective June 1, 2013, all project costs are allocated to the pricing zone where the project is located.

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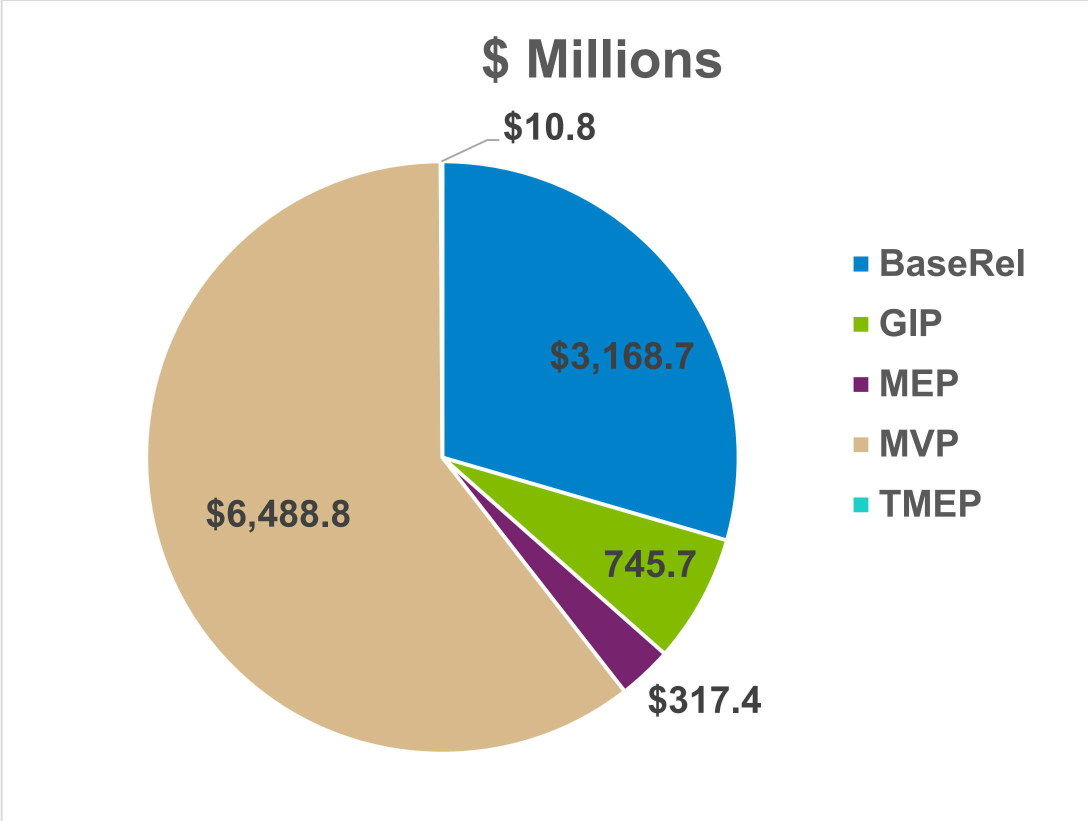

Figure 2.2-1: MTEP cumulative cost sharing by project type ($millions)

Cost-Shared Project Type	BaseRel ($M)	GIP ($M)	MEP ($M)	MVP ($M)	TMEP ($M)	Total ($M)
A in MTEP06	$583.6	$68.9	$0	$0	$0	$652.5
A in MTEP07	$180.9	$34.4	$0	$0	$0	$215.2
A in MTEP08	$1,392.9	$33.3	$0	$0	$0	$1,426.2
A in MTEP09	$165.0	$102.3	$5.6	$0	$0	$272.9
A in MTEP10	$41.1	$5.0	$0	$504.0	$0	$550.1
A in MTEP11	$397.0	$72.8	$0	$5,984.8	$0	$6,454.6
A in MTEP12	$408.2	$53.9	$12.0	$0	$0	$474.1
A in MTEP13	$0	$8.0	$0	$0	$0	$8.0
A in MTEP14	$0	$35.4	$0	$0	$0	$35.4
A in MTEP15	$0	$15.0	$62.1	$0	$0	$77.2
A in MTEP16	$0	$67.1	$108.0	$0	$0	$175.1
A in MTEP17	$0	$163.9	$129.7	$0	$6.3	$299.8
A in MTEP18	$0	$85.8	$0	$0	$4.5	$90.2
Total	**$3,168.7**	**$745.7**	**$317.4**	**$6,488.8**	**$10.8**	**$10,731.3**

Table 2.2-2: MTEP06 to MTEP18 cost-shared project costs by MTEP cycle and project type (shown in $millions)

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For the approved portfolio of MVPs, the costs are allocated 100 percent region-wide (North/Central only) and recovered from customers through a monthly energy charge that is calculated using the applicable monthly MVP Usage Rate. The MVP charge applies to all MISO load and export and through transactions sinking outside the MISO region. However, the MVP charge does not apply to load under grandfathered agreements.

For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.69 per month over the next 20 years

Indicative annual MVP Usage Rates[6] (dollar per MWh) are based on the approved MVP portfolio using current estimated project costs and in-service dates. The MVP usage rates have been calculated for the period 2019 to 2054 and are shown by the blue line (Figure 2.2-2).[7] The red and green lines represent an average of the estimated MVP Usage Rates over 20 and 40 year periods. For the average residential household that uses 1,000 kWh each month, the estimated monthly cost for MVPs averages to $1.69 per month over the next 20 years.

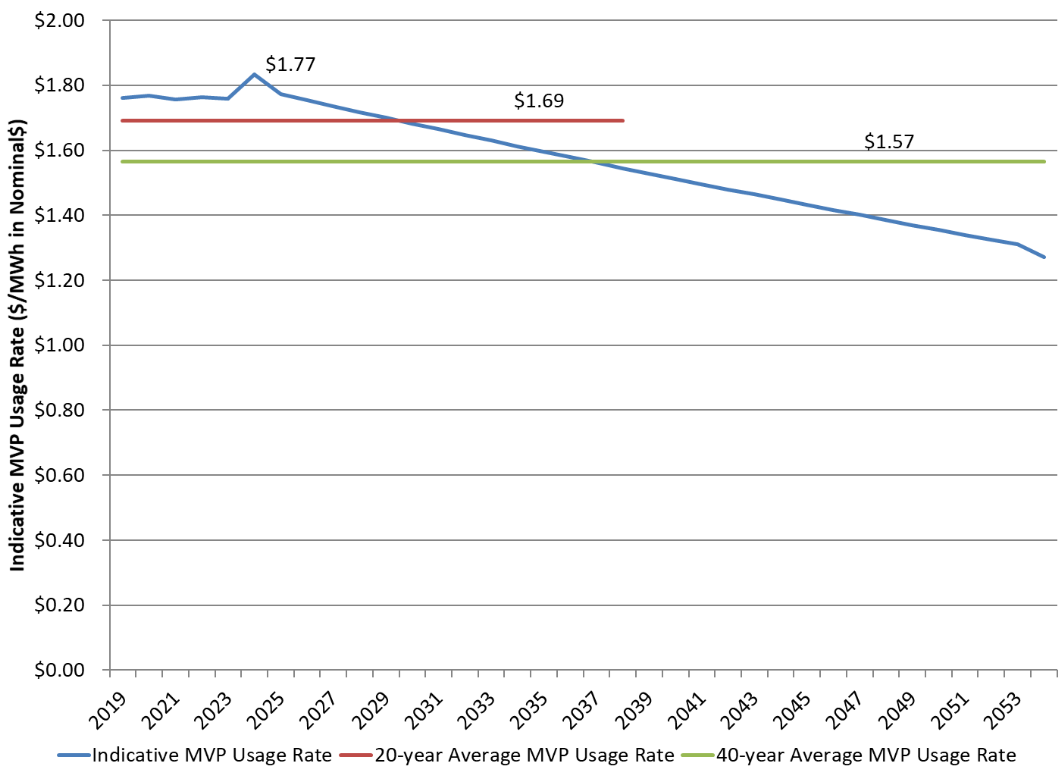

Figure 2.2-2: Indicative MVP usage rate for approved MVP portfolio from 2019 to 2054

[6] The MVP Usage Rate is charged via Schedule 26-A to: 1) Export and Through-Schedules; and 2) Monthly Net Actual Energy Withdrawals, excluding those Monthly Net Actual Energy Withdrawals provided under GFAs. For Withdrawing Transmission Owners with obligations for approved Multi-Value Projects those charges are recovered through Schedule 39.

[7] The annual estimated MVP Usage Rates for 2018 to 2054 shown in Figure 2.2-2 are included in Appendix A-3. Additional information on the indicative annual MVP Usage Rates, including indicative annual MVP charges by Local Balancing Authorities can be found on the MISO public website.

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2.3 MTEP18 Process and Schedule

This MTEP report is the result of 18 months of in-depth research and analysis to create a comprehensive plan for transmission expansion. Each MTEP cycle entails model-building, stakeholder input, reliability analysis, economic analysis, resource assessments and report writing to create a list of recommended projects, which are listed in MTEP Appendix A. It requires many interactions between various work streams and stakeholders (Figure 2.3-1).

The process ends when this report and a list of recommended projects for inclusion in MTEP18 Appendix A go before MISO's Board of Directors December meeting for official approval.

MTEP is MISO's annual process to study and recommend transmission expansion projects based on reliability, economic and public policy needs for inclusion in MTEP Appendix A. Along the way, the process includes sub-deliverables such as Planning Reserve Margins, resource forecasts, regional policy studies and interregional studies.

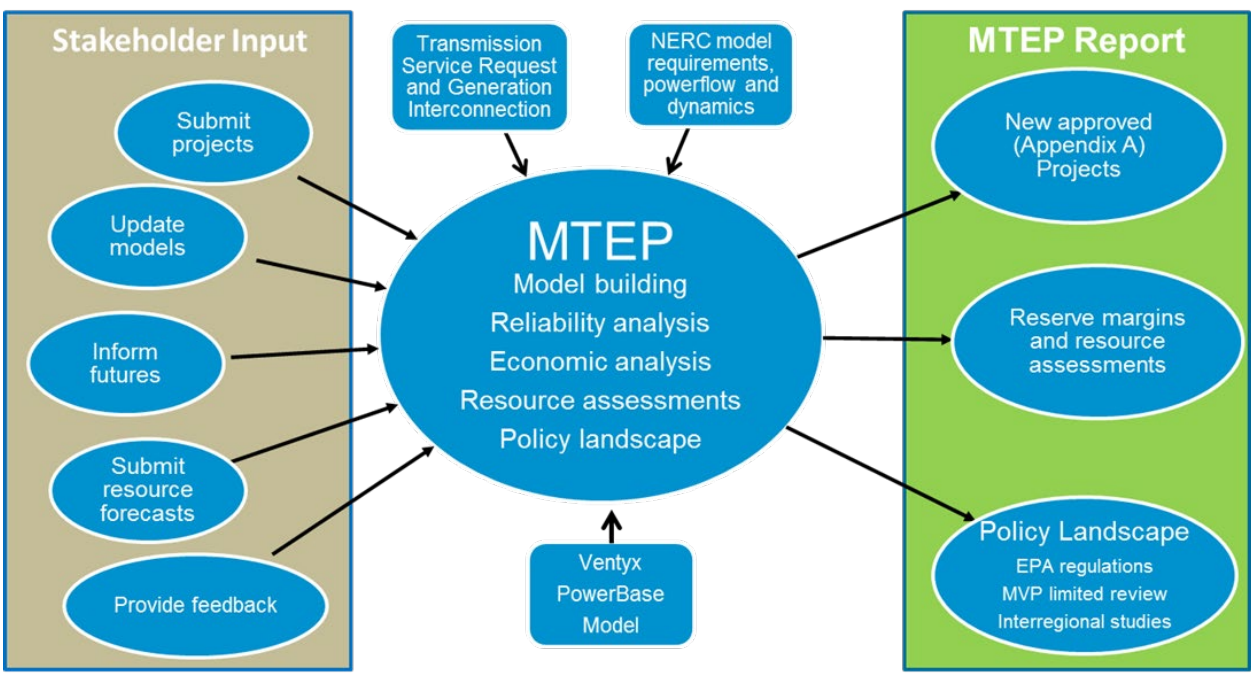

Figure 2.3-1: MTEP inputs and outputs

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MTEP Planning Approach

MISO's Value-Based Planning Approach incorporates multiple perspectives by conducting reliability and economic analyses. MISO evaluates long-term transmission service requests (TSR) to move energy in, out, through or within the MISO market footprint, and generator requests to connect to the grid via the Generator Interconnection Queue. MTEP also reports on studies that address public policy questions (Figure 2.3-2).

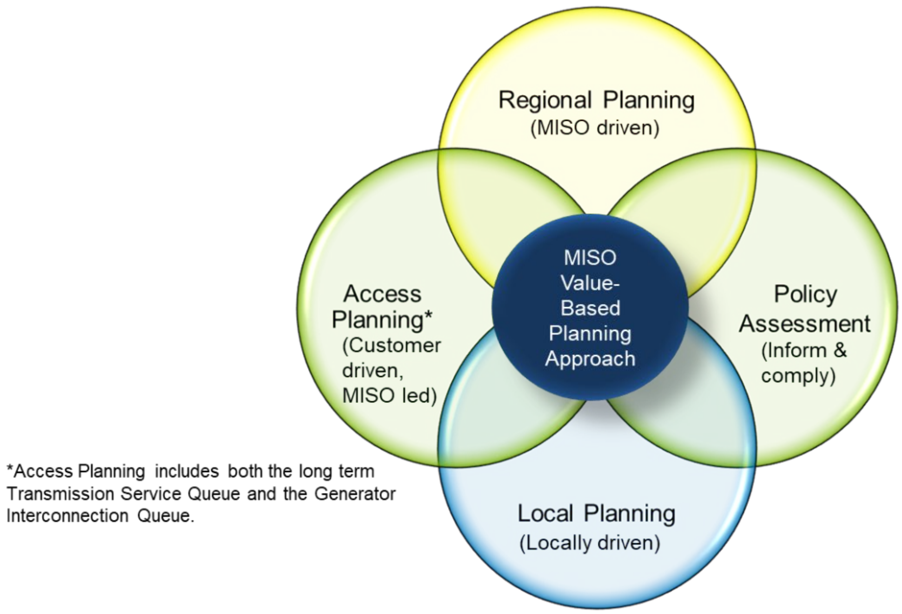

Figure 2.3-2: MISO's value-based planning approach

MTEP18 Workstreams

Completion of MTEP18 requires coordination between multiple subject-matter experts and different types of analyses (Figure 2.3-3). It integrates reliability, transmission access, market efficiency, public policy and other value drivers across all planning horizons.

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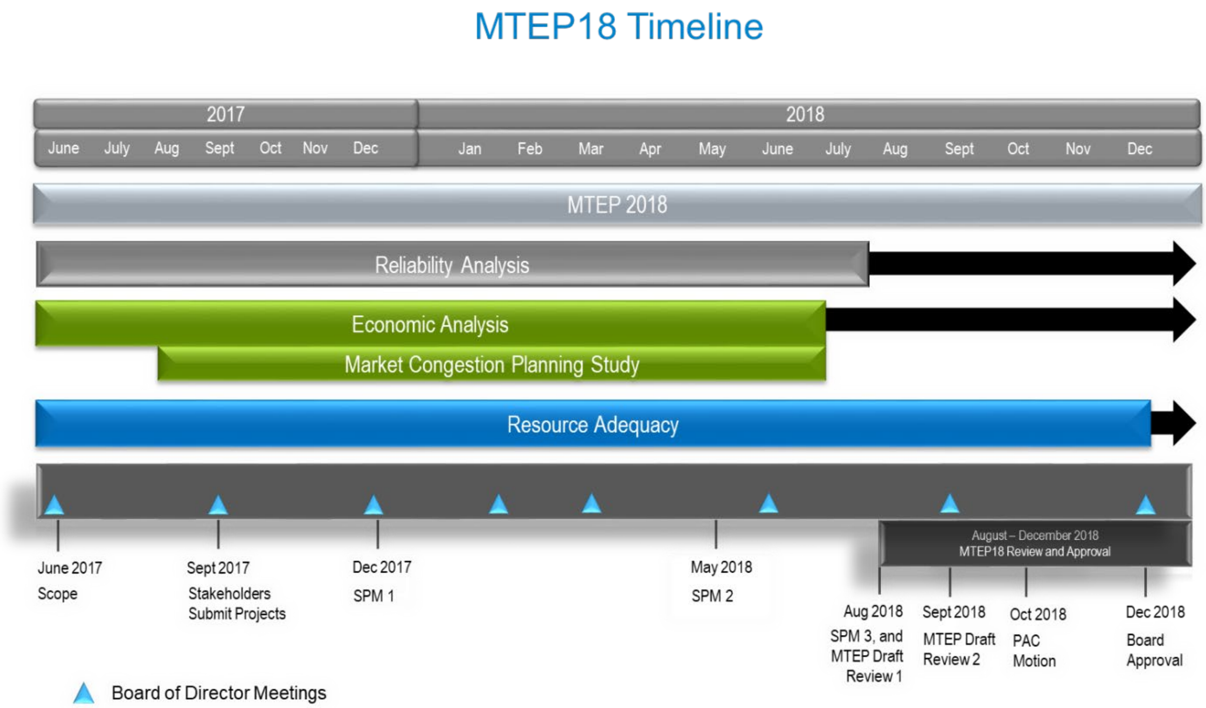

Figure 2.3-3: MTEP18 timeline

Stakeholder Involvement in MTEP18

Stakeholders provide model updates, project submissions, input on appropriate assumptions and comments on results and report drafts. This feedback occurs through a series of stakeholder forums. Each of the four MISO subregions holds Subregional Planning Meetings (SPM) at least three times annually (per FERC Order 890 requirements) to review projects specific to its region. MISO staff and stakeholders review system needs and effectiveness for each project. Some projects may also use stakeholder Technical Study Task Forces (TSTF) as needed to discuss analytical results in greater detail or when these results are Critical Energy Infrastructure Information (CEII). The SPMs report up to the Planning Subcommittee (PSC). The Planning Advisory Committee (PAC) reviews the full MTEP report in detail, and provides formal feedback to the System Planning Committee (SPC), which is made up of members of the MISO Board of Directors. The SPC makes its recommendations to the full Board, which has final approval authority (Figure 2.3-4).

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Figure 2.3-4: MTEP stakeholder forums

MTEP18 Schedule

Each MTEP cycle spans 18 months. MTEP18 began June 2017 and ends December 2018, with Board approval consideration (Table 2.3-1).

Milestone	Date
Stakeholders submit proposed MTEP18 projects	September 2017
First round of Subregional Planning Meetings (SPM)	December 2017
Second round of Subregional Planning Meetings (SPM)	May 2018
MTEP18 Report first draft posted	August 2018
Third round of SPM meetings	August 2018
Planning Advisory Committee final review and motion	October 2018
MISO Board System Planning Committee review	November 2018
MISO Board of Directors meeting to consider MTEP18 approval	December 2018

Table 2.3-1: MTEP18 schedule, major milestones

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A Guide to MTEP Report Outputs

The MTEP18 report is organized into four books and a series of detailed appendices.

- Book 1 summarizes this cycle's projects and the analyses supporting the recommendation of these projects
- Book 2 describes annual and targeted analyses for Resource Adequacy — including Planning Reserve Margin (PRM) requirement analysis and Long Term Resource Assessments
- Book 3 presents Policy Landscape. It summarizes regional studies and interregional studies.
- Book 4 presents additional regional energy information to show a more complete picture of the regional energy system
- Appendices A through F provide the detailed project information, as well as detailed assumptions, results and stakeholder feedback

2.4 MTEP Project Types and Appendix Overview

MTEP Appendices A and B contain the projects vetted by MISO through its planning process. The appendices in the MTEP report indicate the status of a given project in the MTEP review process.

Appendix A contains projects approved by the MISO Board of Directors, thereby creating a good-faith obligation for the Transmission Owner to build it.

Appendix B lists projects that have been validated by MISO as the preferred solution to address an identified need based on current information and forecasts, but that are not yet ready for execution. A move from Appendix B to Appendix A is the most common progression through the appendices; however projects may remain in Appendix B for a number of planning cycles.

Appendix A includes projects from prior MTEPs that are not yet in service, as well as new projects recommended to the MISO Board of Directors for approval in this cycle. Find the newest projects in the Appendix A spreadsheet by looking for “A in MTEP18” in the “Target Appendix” field.

There are three distinct categories of transmission projects:

- Bottom-Up Projects
- Top-Down Projects
- Externally Driven Projects

The specific types of transmission projects include:

- Other Projects
- Baseline Reliability Projects
- Market Efficiency Projects
- Multi-Value Projects
- Generation Interconnection Projects
- Transmission Delivery Service Projects
- Market Participant Funded Projects
- Targeted Market Efficiency Projects

Specific transmission project types align to their parent transmission project categories (Table 2.4-1).

	Bottom-Up Projects	Top-Down Projects	Externally Driven Projects
Other Projects	X		
Baseline Reliability Projects	X		
Market Efficiency Projects		X	
Multi-Value Projects		X	
Generation Interconnection Projects			X
Transmission Delivery Service Projects			X
Market Participant Funded Projects			X
Targeted Market Efficiency Projects		X	

Table 2.4-1: Transmission project type-to-category mapping

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Bottom-Up Projects

Bottom-up projects — transmission projects classified as Other projects and Baseline Reliability Projects — are not cost shared and are generally developed by Transmission Owners in collaboration with MISO and stakeholders. MISO will conduct independent assessment on effectiveness of all bottom-up projects and alternatives submitted by Transmission Owners and stakeholders and determine that the projects represent prudent solutions to one or more identified transmission issues.

- **Baseline Reliability Projects (BRP)** are required to meet North American Electric Reliability Corp. (NERC) standards and regional reliability standards. Since MTEP13, Baseline Reliability Projects are no longer cost shared.
- **Other Projects** address a wide range of localized drivers and system needs. Some of these drivers may include local reliability needs; economic benefits and/or public policy initiatives; or projects that are not a part of the bulk electric system under MISO functional control. Because of this variety, Other projects are generally driven by one of the following factors: clearance, condition, load interconnection, economic, local multiple benefit, metering, operational, performance, reconfiguration, relay, reliability, relocation, replacement or retirement.

Top-Down Projects

Top-down projects are transmission projects classified as Market Efficiency Projects, Multi-Value Projects, and Targeted Market Efficiency Projects. Regional or sub-regional top-down projects are developed by MISO working in conjunction with stakeholders to address regional economic and/or public policy transmission issues. Interregional top-down projects are developed by MISO and one or more neighboring planning regions in conjunction with stakeholders to address interregional transmission issues. Interregional projects are cost shared per provisions in the Joint Operating Agreement and/or MISO Tariff, first between MISO and the other planning regions, then within MISO based on provisions in Attachment FF of the MISO Tariff.

- **Multi-Value Projects (MVP)** meet Attachment FF requirements to provide regional public policy, economic and/or reliability benefits. Costs are shared with loads and export transactions in proportion to metered MWh consumption or export schedules.
- **Market Efficiency Projects (MEP)**, formerly referred to as regionally beneficial projects, meet Attachment FF requirements for reduction in market congestion and are eligible for regional cost allocation. Projects qualify as MEPs based on cost and voltage thresholds and are developed to produce a benefit-to-cost ratio of 1.25 or greater.
- **Targeted Market Efficiency Projects (TMEP)** are interregional projects, with PJM, that address historical Market-to-Market congestion along the MISO-PJM seam. TMEPs are low cost, quick implementation upgrades that complement the existing Order 1000 interregional project types.

Externally Driven Projects

Externally driven projects are driven by needs identified through customer-initiated processes under the MISO Tariff. Externally driven projects are Generation Interconnection Projects, Transmission Delivery Service Projects and Market Participant Funded Projects.

- **Generation Interconnection Projects (GIP)** are upgrades that ensure the reliability of the system when new generators interconnect. The customer may share the costs of network upgrades if a contract for the purchase of capacity or energy is in place, or if the generator is designated as a network resource. Not all network upgrades associated with GIPs are eligible for cost sharing between pricing zones.
- **Transmission Delivery Service Project (TDSP)** projects are required to satisfy a transmission service request. The costs are generally assigned to the requestor.
- **Market Participant Funded Projects** represent transmission projects that provide benefits to one or more market participants but do not qualify as Baseline Reliability Projects, Market

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Efficiency Projects or Multi-Value Projects. These projects are not cost shared through the MISO Tariff. Their construction is assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Transmission Owners Agreement upon execution of the applicable agreement(s).

MTEP Appendix A

MTEP Appendix A contains transmission expansion plan projects recommended by MISO staff and approved by the MISO Board of Directors for implementation by Transmission Owners.[8] All projects in Appendix A address one or more MISO-documented transmission needs. Projects in Appendix A may be eligible for regional cost sharing per provisions in Attachment FF of the Tariff.

Projects in Appendix A have a variety of drivers. Many are required for maintaining system reliability in accordance with NERC Planning Standards[9]. Others may be required for Generation Interconnection or Transmission Service. Some projects may be required for Regional Reliability Organization standards, while others may be required to provide interconnections for load-serving entities.

Appendix A projects may be required for economic reasons, to reduce market congestion or losses in a particular area. They may also decrease resource adequacy requirements through reduced losses during system peak or reduced planning reserve needs. Projects may be necessary to enable public policy requirements, such as current state renewable portfolio standards or Environmental Protection Agency standards.

Projects must go through a specific process to move into Appendix A. MISO staff must:

- Review the projects via an open stakeholder process at Subregional Planning Meetings
- Validate that the project addresses one or more transmission needs
- Consider and review alternatives
- Consider and review planning-level costs
- Endorse the project
- Verify whether the project is qualified for cost sharing as a Generation Interconnection Project, Market Efficiency Project or Multi-Value Project per provisions of Attachment FF or if it will be participant-funded
- Hold a stakeholder meeting to review a project or group of projects in which costs can be shared, or other major projects for zones where 100 percent of costs are recovered under the Tariff
- Take the recommended projects to the Board of Directors for approval. Projects may move to Appendix A following a presentation at any regularly scheduled board meeting.

The MTEP Active Project List is periodically updated and posted as projects go through the MTEP process and are approved. Projects generally move to Appendix A in conjunction with the annual approval of the MTEP report. In addition to the regular annual approval process, under specific circumstances, recommended projects need not wait for completion of the next MTEP for MISO Board of Directors approval and inclusion in Appendix A, but can go through an Expedited Project Review process.

MTEP Appendix B

MTEP Appendix B contains all bottom-up projects that have been validated by MISO as the preferred solution to address an identified system need based on current information and forecasts, but where it is prudent to defer the final recommendation of a solution to a subsequent MTEP cycle.

[8] Projects with a Target Appendix A in the current MTEP cycle are not officially placed into Appendix A until Board of Directors approval in December of the cycle year.
[9] http://www.nerc.net/standardsreports/standardssummary.aspx

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This generally occurs when the preferred project does not yet need a commitment based on anticipated lead time and there is still some uncertainty as to the prudence of selecting this project over an alternative project given potential changes in projected future conditions. MTEP Appendix B is limited to bottom-up projects only (Baseline Reliability Projects and Other Projects) and the projects will be reviewed by MISO in subsequent cycles in order to:

- Remove the projects that will be recommended for approval in the current cycle, or was previously included to address identified system needs that no longer exist, or is determined to no longer be the best solution to an identified need
- Add new bottom-up projects in the current cycle that have been determined to be the preferred solution

2.5 MTEP18 Model Development

Transmission system models are the foundation of the MTEP analytical processes. The viability of the study results hinges on the accuracy of the models used. Planning model development at MISO is a collaborative process with significant stakeholder interaction and neighbor coordination. Stakeholders provide modeling data, help develop assumptions for modeling future transmission system scenarios and review the models. MISO coordinates its MTEP models with neighboring entities, so as to have accurate representation of adjacent systems.

MTEP18 model-building continues MISO's submittal of modeling data to Eastern Interconnection model development per MOD-032-1

The MTEP16 model development process underwent some changes in data submission obligations per NERC Standard MOD-032-1 with inclusion of generator owners and load-serving entities, which continues as part of the MTEP18 model development process. In addition to NERC Standard TPL-001-4 requirements, MISO built a powerflow and dynamic models suite to support the Eastern Interconnection modeling process per MOD-032 requirements. For the MTEP18 planning process, MISO built two sets of powerflow models. One model set, called Appendix A Only, contained approved future projects from MTEP17 Appendix A. The other model set, called Target A, contained approved MTEP17 Appendix A projects and projects targeted for approval in MTEP18.

For MTEP studies, models for steady-state powerflow and dynamic stability reliability analyses are built to represent a planning horizon spanning the next 10 years; economic studies represent a 15-year planning horizon. The primary sources of information used to develop the models are:

- MISO's Model on Demand (MOD) powerflow database, which contains existing transmission system data, substation level load profiles, future transmission projects, generator interconnection projects and transmission service related project information
- MISO members, including Transmission Owners, Generation Owners and Load-Serving Entities
- Eastern Reliability Assessment Group (ERAG) Multi-regional Modeling Working Group (MMWG) series models, for external area representation
- ASEA Brown Boveri (ABB) PROMOD PowerBase database
- External model updates from neighboring planning entities

MTEP models are interdependent with multiple major data inputs within the process (Figure 2.5-1).

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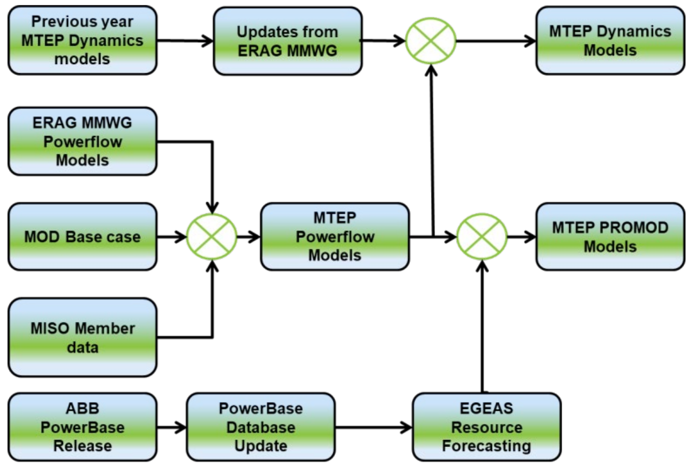

ERAG – Eastern Interconnection Reliability Assessment Group. EGEAS – Electric Generation Expansion Analysis System
MMWG – Multi-regional Modeling Working Group. MTEP – MISO Transmission Expansion Plan

Figure 2.5-1: MTEP model relationships

Reliability Study Models - Powerflow Models

MISO developed regional powerflow models for MTEP18 as required by the TPL-001-4 standard and ERAG MMWG process (Table 2.5-1). Developed model base cases and sensitivity cases are listed with the TPL-001-4 requirement[10]. The table includes renewable wind resource levels at percent of nameplate. All models assume solar generation at 50 percent of nameplate except Light Load models, which are modeled at 0 percent.

Model Year	Base case	Sensitivity
Year 2	2020 Summer Peak with wind at 15.6% (*TPL requirement R2.1.1*)	2020 Light Load (minimum load level) wind at 0% (*TPL requirement R2.1.4*)
Year 5	2023 Summer Peak with wind at 15.6% (*TPL requirement R2.1.1*)	2023 Summer Shoulder (70-80% peak) with wind at 90% (*TPL requirement R2.1.4*)
Year 5	2023 Summer Shoulder (70-80% peak) with wind at 40% (*TPL requirement R2.1.2*)	2023 Light Load (minimum load level) with wind up to 90% (*TPL requirement R2.1.4*)
Year 5	2023-2024 Winter Peak with wind at 40%	
Year 10	2028 Summer Peak with wind at 15.6% (*TPL requirement R2.2.1*)	

Table 2.5-1: MTEP18 powerflow models

Per TPL-001-4 requirement R1.1, the system model contains representations of the following:

- R1.1.1 Existing Facilities: MISO's Model on Demand (MOD) database is used to store modeling data for all the existing facilities. MOD base case is updated monthly in collaboration with MISO members.

[10] http://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/TPL-001-4_Standard_Application_Guide_endorsed.pdf

- R1.1.2. Known Outages: MISO models any known outage(s) of generation or transmission facility with a duration of at least six months using data from Control Room Operations Window (CROW) Outage Scheduling System.
- R1.1.3. New planned facilities and changes to existing facilities: MOD is also used to capture all the future transmission upgrades and changes to existing facilities, which go into models per their in-service dates. To support MTEP study requirements, two sets of powerflow models were developed:
    - MTEP17 Appendix A Only: These models include only approved future transmission facilities first approved in MTEP17 and future projects approved in prior MTEP studies. Approved future transmission projects also include network upgrades associated with generator interconnection and transmission delivery service requests.
    - MTEP17 Appendix A plus MTEP18 Target Appendix A: These models include future transmission projects approved in Appendix A through prior MTEP studies and new transmission projects submitted for approval in the MTEP18 planning cycle to verify their need and sufficiency in ensuring system reliability.
- R1.1.4. Real and reactive load forecasts: Substation-level real and reactive load is modeled based on seasonal load projections provided by MISO MOD member companies.
- R1.1.5. Known commitments for Firm Transmission Service and Interchange: MISO models known commitments based on Open Access Same-Time Information System (OASIS) information confirmed by both the transacting parties.
- R1.1.6. Resources (supply or demand side) required for load: Resources are modeled based on seasonal projections submitted by members in MOD. All the existing generators are included. Planned generators with signed Generation Interconnection Agreements are included according to their expected in-service dates. Generator retirements that have completed the MISO Attachment Y retirement study process are modeled off-line when the unit can be retired.

LBA Generation Dispatch Methodology

The generation dispatch in steady-state powerflow models is done at the Local Balancing Authority (LBA) level. Network Resource-type generation is dispatched in an economic order to meet the load, loss and interchange level for each LBA. The area interchange for each LBA is determined by the transaction table agreed upon by transaction participants, and the generation is dispatched to account for the cumulative MISO net area interchange level. LBA generation dispatch includes some energy resources, such as wind and solar, which are dispatched in models in support of renewable energy standards. Wind generation is dispatched at capacity credit level in summer peak models and at average and high levels in off-peak models. The system average wind capacity credit is 15.6 percent based on MISO's Loss of Load Expectation study. Solar generation is dispatched at 50 percent of nameplate except Light Load models, which are modeled at 0 percent. The percentage values for wind generation (Table 2.5-1) are based on the nameplate capacity.

- 15.6 percent represents the wind capacity credit value
- 40 percent represents the average wind output level
- 90 percent represents the high wind output level and transmission design target level
- 40 percent represents the wind output level in the winter model

The LBA dispatch process determines the output of generators and considers several factors such as seasonal output variations, equipment limitations, policy regulations, approved retirements and local operating guides for reliable grid operation. Behind-the-meter generation, hydro machines and non-MISO generation information is retained from generation and load profiles submitted in MOD. Several thousand MW of thermal energy resources are not dispatched, wind and solar renewable energy resources are dispatched per study assumptions.

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During the model development process, preliminary powerflow models are posted for stakeholder review and comment. MISO planning staff produces a model data check and case summary documents, which are posted for stakeholder review. Stakeholders submit topology corrections back to MISO MOD system for inclusion in subsequent versions of the models.

Generation, load and area interchange data totals for each MISO LBA for 2020 summer and 2023 summer peak models are shown in Table 2.5-2. There may be differences in the load values for each area from Module E load values due to inclusion of station service loads and non-member loads contained within the MISO members' model areas.

Area	2020 Summer Peak (All values in MW)				2023 Summer Peak (All values in MW)			
	Generation	Load	Losses	Area Interchange	Generation	Load	Losses	Area Interchange
HE	1,369	688	41	640	1,368	695	41	633
DEI	6,907	7,193	284	(578)	7,048	7,254	287	(500)
SIGE	2,016	1,790	33	193	2,038	1,799	32	207
IPL	3,459	2,837	69	549	3,737	2,887	69	777
NIPS	3,354	3,678	79	(408)	3,394	3,731	73	(415)
METC	11,275	10,039	303	934	11,609	10,065	326	1218
ITCT	10,867	11,319	231	(683)	10,544	11,196	236	(888)
WEC	6,567	6,788	104	(340)	6,565	6,810	101	(362)
MIUP	571	533	22	14	571	534	22	13
BREC	1,378	1,631	20	(274)	1,368	1,635	18	(286)
EES-EMI	4,053	3,933	109	5	3,923	3,966	105	(155)
EES-EAI	9,159	7,410	158	1583	9,266	7,415	153	1690
LAGN	1,292	1,834	7	(549)	1,291	1,950	8	(667)
CWLD	230	385	2	(157)	233	398	3	(167)
SMEPA	1,240	809	20	412	1,386	845	20	521
EES	19,083	19,477	345	(850)	19,638	19,906	332	(712)
AMMO	8,504	8,227	182	95	8,855	8,325	189	341
AMIL	10,295	9,557	248	490	10,350	9,510	237	603
CWLP	474	424	3	47	467	418	3	46
SIPC	358	344	10	4	374	353	10	10
CLEC	3,693	3,121	82	490	3,705	3,124	91	490
LAFA	191	502	9	(320)	191	516	6	(331)
LEPA	82	180	0	(98)	82	180	0	(98)
XEL	9,695	10,361	244	(932)	9,903	10,595	237	(952)
MP	1,315	1,522	74	(283)	1,342	1,559	69	(287)
SMMPA	125	602	2	(479)	121	607	2	(488)
GRE	2,678	2,891	93	(309)	2,761	3,012	95	(349)
OTP	2,133	2,046	94	(11)	2,130	2,167	97	(138)
ALTW	4,023	4,020	84	(81)	4,119	4,131	85	(97)
MPW	260	162	2	97	255	165	2	89
MEC	5,989	5,980	84	(74)	6,077	6,291	85	(300)
MDU	467	615	13	(162)	467	636	13	(182)
BEPC-MISO	6	92	-	(86)	6	94	-	(89)
DPC	812	1,050	38	(276)	812	1,065	39	(291)
ALTE	3,859	2,851	71	931	4,168	2,940	76	1146
WPS	2,553	2,607	50	(109)	2,524	2,649	48	(179)
MGE	293	708	10	(427)	233	711	10	(490)
UPPC	46	215	4	(173)	50	217	4	(171)
Total	**140,669**	**138,420**	**3,221**	**(1,177)**	**142,970**	**140,351**	**3,224**	**(810)**

Table 2.5-2: System conditions for 2020 and 2023 models, for each MISO area

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Dynamic Stability Models

Dynamic stability models are used for transient stability studies performed as part of NERC TPL assessment and generation interconnection studies. Stability models are required for the study of the TPL-001-4 standard (Table 2.5-3).

Model Year	Base case	Sensitivity
Year 0	2018 Summer Peak with wind at 15.6%	
Year 5	2023 Summer Peak with wind at 15.6% (*TPL requirement R2.4.1*)	2023 Light Load (minimum load level) with wind up to 90% (*TPL requirement R2.4.3*)
Year 5	2023 Summer Shoulder (70-80% peak) with wind at 40% (*TPL requirement R2.4.2*)	2023 Summer Shoulder (70-80% peak) with wind at 90% (*TPL requirement R2.4.3*)

Table 2.5-3: MTEP18 dynamic stability models

The MTEP17 dynamics data is the starting point for MTEP18 dynamics model development. This data is reviewed and updated with stakeholder feedback. Additionally, the ERAG MMWG 2017 series dynamic stability models are reviewed and any improved modeling data in external areas is incorporated in the MTEP18 dynamics models.

Dynamic load modeling is driven by Requirement 2.4.1 of the TPL-001-4 standard, which started in MTEP16 dynamic models and continues into MTEP18 dynamics models. The dynamic load models must be represented by complex or composite load models to adequately capture the impact of induction motor loads. Assumptions for generator dispatch for stability models are the same as steady-state powerflow models.

The dynamics package is verified by running a 20-second, no-disturbance simulation and sample disturbances at select generator locations in the MISO footprint. Test simulations are performed to enable a review of model performance. Charts showing simulation results are posted for stakeholder review.

During the MTEP18 dynamic models development process, stakeholders were asked to provide inputs on:

- Updates to existing dynamics data
- Additional dynamic models for new equipment
- Output quantities to be measured

Economic Study Models

Economic study models are developed for use in the MTEP economic planning studies. These models are forward-looking, hourly models based on assumptions discussed and agreed upon through the stakeholder process. For MTEP18, the Planning Advisory Committee (PAC) approved the following future scenarios:[11]

- Limited Fleet Change
- Continued Fleet Change
- Accelerated Fleet Change
- Distributed and Emerging Technologies

[11] For more details on these assumption scenarios, see Sections 5.2: MTEP Futures Development and 5.3: Market Congestion Planning Study.

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The base data used in all future scenarios is maintained through the PROMOD PowerBase database. This database uses data provided annually by ABB as a starting point. MISO then goes through an annual, extensive model development process that updates the source data provided by ABB with MISO-specific updates.

Updates for MTEP18 include data obtained from the following sources:

- MISO Commercial Model for verifying generator maximum capacities and hub data
- Generator Interconnection Queues (MISO and neighbors) for future generators
- Module E data for energy and demand forecasts, behind-the-meter generation, interruptible loads and demand response data
- Powerflow model (developed through the MTEP process) for topology
- Publicly announced generation retirements
- Specific stakeholder comments/updates
- Generation capacity expansion (developed by MISO staff — see Section 5.2: MTEP Future Development)

As part of the economic model development process, the PowerBase database is verified to ensure data accuracy through numerous checks. Model verification is broadly comprised of generator economic data validation, demand and energy data checks and PowerBase-powerflow network topology mapping.

The PowerBase database, including system topology, was posted for stakeholder review in September 2017. During the review period stakeholders were asked to provide:

- Updates to generator data
    - Maximum and minimum capacity
    - Retirement dates
    - Emission rates
- Updates to powerflow model mapping to PowerBase
    - Generator bus mapping
    - Demand mapping
- Updates to contingencies and flowgates/interfaces monitored

In addition to the stakeholder review process, MISO collaborates with its tier one immediate neighbors as part of the model development process to accurately reflect neighboring systems. Highlights of this collaboration include extensive updates from PJM and Southwest Power Pool (SPP).

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Section 3: Historical MTEP Plan Status

3.1 MTEP Approved Appendix A Project Status Report

3.2 MTEP Implementation History

3.1 MTEP Approved Appendix A Project Status Report

MISO's transmission planning responsibilities include the monitoring of previously approved MTEP Appendix A projects. MISO surveys all Transmission Owners and Selected Developers on a quarterly basis to determine the progress of each project. Since 2006, these status updates are reported to the MISO Board of Directors and posted to the MISO MTEP Studies web page. This report provides the status of active MTEP-approved Appendix A projects as of MISO's third quarter, September 30, 2018, and elaborates on the status of the Multi-Value Projects (MVP) approved in MTEP11.

Active projects consist of previously approved Appendix A projects that are not withdrawn or in service. As of the third quarter of 2018, MISO was tracking 1,157 active projects totaling $9 billion of approved investment. Of the total active investment, 38 percent of the projects were approved in MTEP17 and the remaining 62 percent were approved in MTEP03 through MTEP16. Since the first MTEP report in 2003, a total of $36 billion in transmission projects have been approved. Of this approved investment, $19.1 billion have been constructed; $4.4 billion have been withdrawn; and the remaining $12.3 billion are in various stages of design, planning or construction through the third quarter of 2018.

MISO transmission planning responsibilities include monitoring progress and the implementation of previously approved MTEP Appendix A projects.

Following the approval of an MTEP, MISO continues to provide transparency through its publication of quarterly project status updates. This monitoring of previously approved MTEP Appendix A projects ensures that a good-faith effort is being made to move projects forward, as prescribed in the Transmission Owners' Agreement. Transmission Owners and Selected Developers provide updated costs, in-service dates and various other status updates as required by the MISO Tariff and BPM-020.

MISO tracks the status of these projects (Figure 3.1-1) along with the total current investment for each MTEP cycle. The most common facility type based on investment is line on new right-of-way (ROW) (47 percent) followed by substation projects (36 percent) and line upgrades (17 percent) (Figure 3.1-2).

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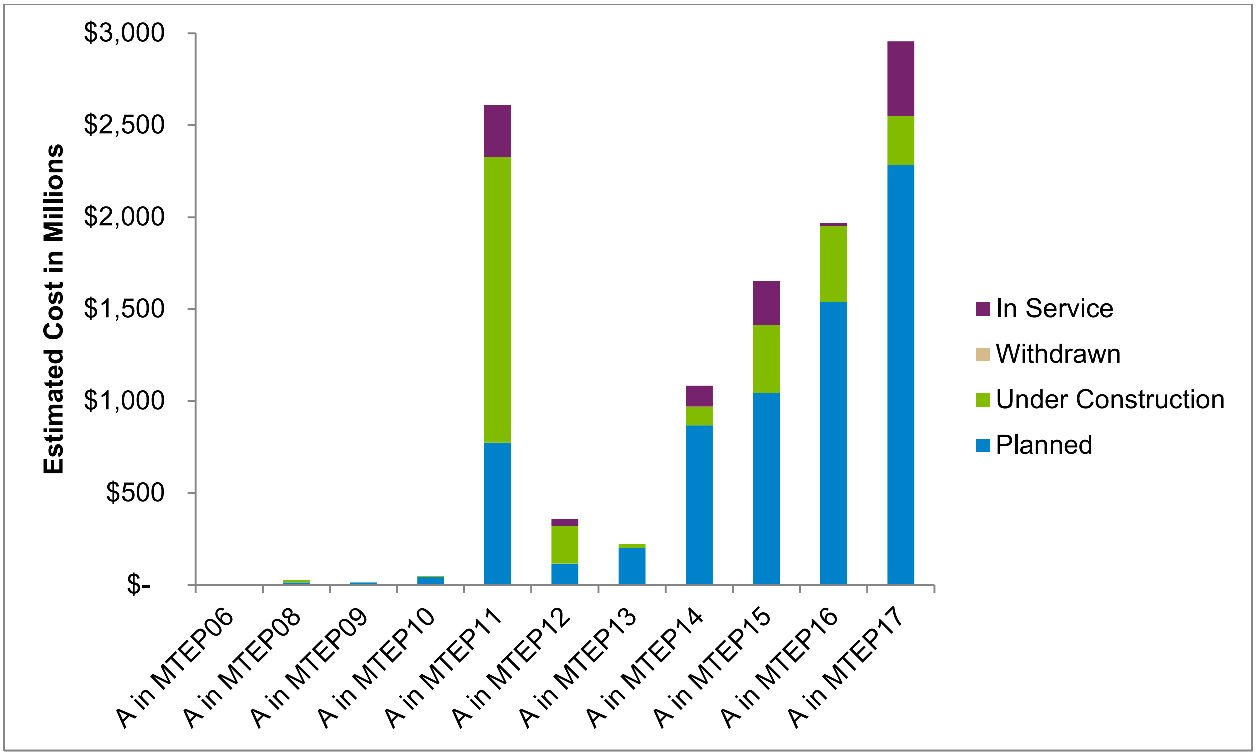

Figure 3.1-1: Project status of active projects

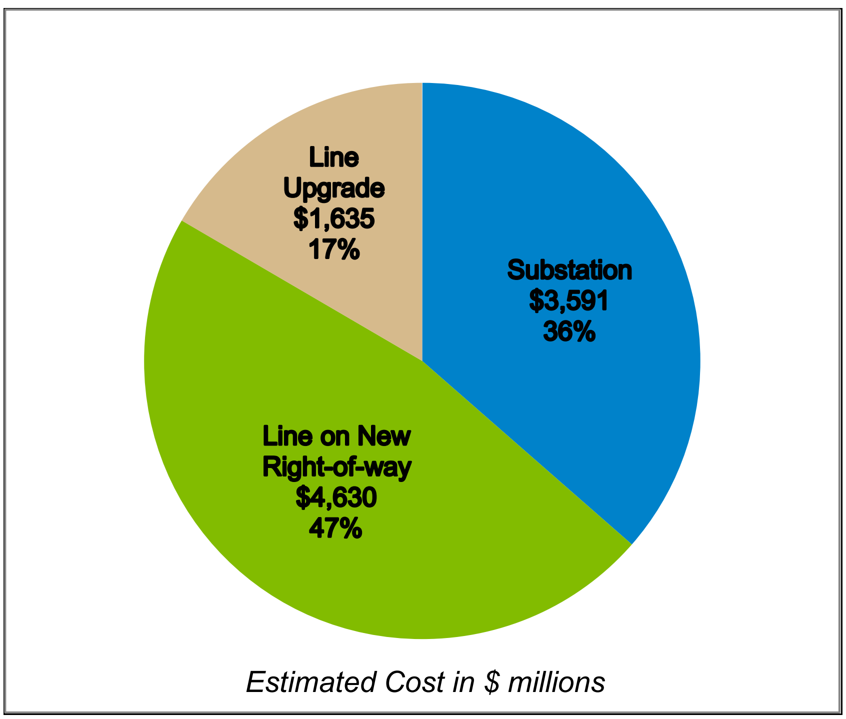

Figure 3.1-2: Facility cost of active projects

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Multi-Value Project Portfolio Status

The Multi-Value Projects (MVP) are part of a regionally planned portfolio of transmission projects. The MVP portfolio represents the culmination of more than eight years of planning efforts to find cost-effective regional transmission solutions while meeting local energy and reliability needs. The MVP portfolio is expected to[12]:

- Provide benefits in excess of its costs under all scenarios studied with benefit-to-cost ratios ranging from 1.8 to 3.0
- Resolve reliability violations on approximately 650 elements for more than 6,700 system conditions and mitigate 31 system instability conditions
- Enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals

As of September 2018, 10 MVPs are in service, six are at least partially under construction and the remainder are in progress with state regulatory approvals (Figure 3.1-3).

The MVP dashboard is updated quarterly. The most up-to-date version can be found on the MISO website.

[12] Source: Candidate MVP Report. A review of the MVP Portfolio's benefits is contained in Section 7.2: MVP Limited Review.

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MVP No.	Project Name	State	Estimated in Service Date[1]		Status		Cost [2]			Explanation [6]
			MTEP Approved	September 2018	State Regulatory Status	Construction	MTEP Approved [3]	MTEP Approved Dollars Adjusted to Estimated ISD [4]	September 2018 [5]	
1	Big Stone - Brookings	SD	2017	2017	●	Complete	$227	$263	$141	
2	Brookings, SD - SE Twin Cities	MN/SD	2011-2015	2013-2015	●	Complete	$738	$738*	$670	
3	Lakefield Jct - Winnebago - Winco - Burt area & Sheldon - Burt Area - Webster	MN/IA	2015-2016	2015-2018	●	Complete	$550	$654	$651	A - E
4	Winco - Lime Creek - Emery - Black Hawk-Hazleton	IA	2015	2015-2019	●	Underway	$469	$571	$564	B, C, D & E
5	N. LaCrosse - N. Madison - Cardinal (a/k/a Badger - Coulee Project)	WI	2018	2018	●	Underway	$798	$1,073	$1,034	A, F
	Cardinal - Hickory Creek	WI/IA	2020	2023	◐	Pending				A, D, F
6	Big Stone South - Ellendale	ND/SD	2019	2019	●	Underway	$331	$403	$274	
7	Ottumwa - Zachary	IA/MO	2017-2020	2018-2019	●	Pending	$152	$186	$223	A,B,C,D
8	Zachary - Maywood	MO	2016-2018	2016-2019	●	Underway	$113	$137	$175	A, D, E
9	Maywood - Herleman - Meredosia - Ipava & Meredosia - Austin	MO/IL	2016-2017	2016-2017	●	Complete	$432	$501	$723	A, B
10	Austin - Pana	IL	2018	2016-2017	●	Complete	$99	$115	$135	A,B
11	Pana - Faraday - Kansas - Sugar Creek	IL/IN	2018-2019	2015-2019	●	Underway	$318	$388	$404	A,B
12	Reynolds - Burr Oak - Hiple	IN	2019	2018	●	Underway	$271	$322	$405	B,C
13	Michigan Thumb Loop Expansion	MI	2013-2015	2012-2015	●	Complete	$510	$563	$504	
14	Reynolds - Greentown	IN	2018	2013-2018	●	Complete	$245	$299	$348	B
15	Pleasant Prairie - Zion Energy Center	WI	2014	2013	●	Complete	$29	$30	$36	E, F
16	Fargo- Sandburg - Oak Grove	IL	2014-2019	2016-2018	●	Complete	$199	$237	$201	
17	Sidney - Rising	IL	2016	2016	●	Complete	$83	$94	$88	
						Total	**$5,564**	**$6,573**	**$6,577**	

Footnotes:
[1] Estimated ISD provided by constructing Transmission Owners.
[2] Costs stated in millions.
[3] MTEP11 approved cost estimates provided by constructing Transmission Owners.
[4] MTEP11 approved cost estimates escalated to the estimated in-service year dollars based on MISO's 2.50% annual inflation rate.
[5] Current cost estimates provided by constructing Transmission Owners. This represents the estimated cost for ratebase purposes.
[6] Explanation for cost variance beyond annual inflation escalation. See below for explanation.
* MTEP11 approved cost estimate was provided in nominal (expected year of spend) dollars.

State Regulatory Status Indicator Scale	
○	Pending
◐	In regulatory process or partially complete
●	Regulatory process complete or no regulatory process Requirements

Explanations	**Examples:** Detailed information can be found in the MTEP Quarterly Status Update (https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=1945).
A. Regulatory Requirements	Routing changes, timing delays, structure changes, and equipment modifications necessary to fulfill regulatory requirements.
B. Engineering & Design Standards	Modifications to foundations, structures, lines, and substations resulting from detail design, route selection and/or new NERC standards.
C. Material / Commodity Pricing	Price escalation variances above and beyond standard escalation assumption (including labor).
D. Schedule Delay	Increased cost due to changes in scheduling and, if applicable, the resulting higher AFUDC.
E. Costs associated with delayed ISD	Route changes due to legal or right-of-way issues, changes in material availability or costs, and new standards.
F. Other	Described in the MTEP Quarterly Status Update.

Figure 3.1-3: MVP planning and status dashboard as of September 2018

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3.2 MTEP Implementation History

The annual MTEP report is the culmination of more than 18 months of collaboration between MISO and its stakeholders. Each report cycle focuses on identifying issues and opportunities, developing alternatives for consideration and evaluating those options to determine effective transmission solutions. With the MTEP18 cycle, the MTEP report now represents 15 years of planning these essential upgrades and expansions to the electric transmission grid.

The number of projects and investment can vary dramatically from year to year depending on a variety of system needs. Project drivers could include changes in generation mix due to economics; public policy and regulations; emerging new technologies; the need to mitigate system congestion at load delivery points; or the addition of large industrial loads. These projects improve the deliverability of energy both economically and reliably to consumers in the MISO footprint and beyond.

After projects are approved by the MISO Board of Directors, these projects will go through any required approval processes by federal or state regulatory authorities and subsequent construction. The system needs originally driving these projects may change or disappear. When these material system changes transpire, MISO collaborates with transmission owners and stakeholders to withdraw or partially withdraw an approved project and reflect the changes in the following quarterly project status reports.

The cumulative investment dollars for projects, categorized by plan status for MTEP03 through the current MTEP18 cycle, is more than $35 billion (Figure 3.2-1). MTEP18 data depicted in this figure, subject to board approval, will be added to the data tracked for the MISO Board of Directors. These statistics only include projects for MISO members who participated in this planning cycle. Previously approved projects for prior MISO members are not included in these statistics.

- $4.3 billion of MTEP projects are expected to go into service in 2018

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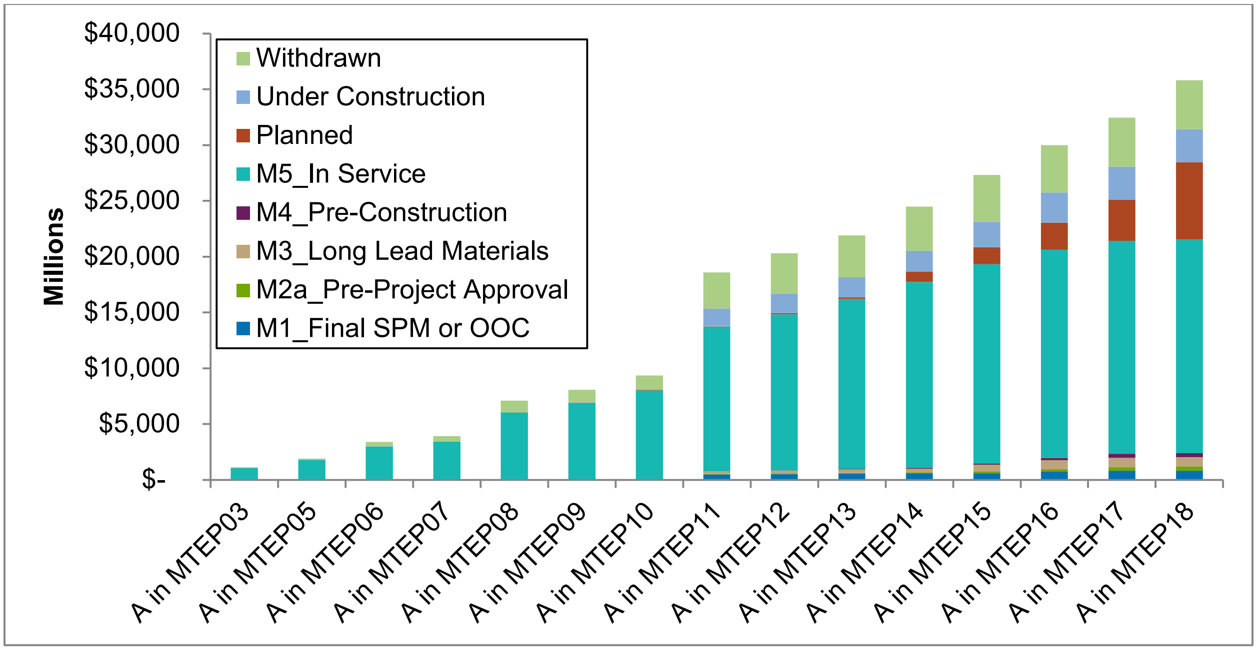

Figure 3.2-1: Cumulative transmission investment by facility status[13]

The historical perspective of project investment for each MTEP cycle shows extensive variability in development (Figure 3.2-2). This is caused by the long development time of transmission plans and the periodic updating of the transmission plans. Approval of the Multi-Value Projects (MVP) portfolio explains the large increase between MTEP10 and MTEP11.

Highlights or points of interest in prior MTEP cycles include:

- MTEP06 and MTEP07 were approved in the same calendar year, which accounts for the comparatively small incremental value of projects in MTEP07
- MTEP08 shows the number of developing needs increased the number of planned projects, including several large upgrades
- MTEP09 was a year for analyses and determination of the best plans to serve those needs. The in-service category increased as projects were built
- MTEP10 contains significant adjustments for reduced load forecasts
- MTEP11 contains the MVP portfolio, which accounts for the significantly higher investment totals compared to other MTEPs. MVP status and investment totals are tracked via the MVP Dashboard.
- MTEP12 and MTEP13 reflect a return to a more typical MTEP, primarily driven by reliability projects
- MTEP14 reflects a continuation of a typical MTEP, primarily driven by reliability projects, but with the inclusion of the new MISO South region projects. A single transmission delivery service project accounts for around 25 percent of the total MTEP14 investment.
- Beginning in MTEP15, MTEP participants began planning to meet a series of new, more stringent NERC reliability standards
- MTEP16, MTEP17 and MTEP18 further reflect a continuation of a typical MTEP, primarily driven by reliability projects

[13] Project milestones described in Section 3.1: Prior MTEP Plan Status

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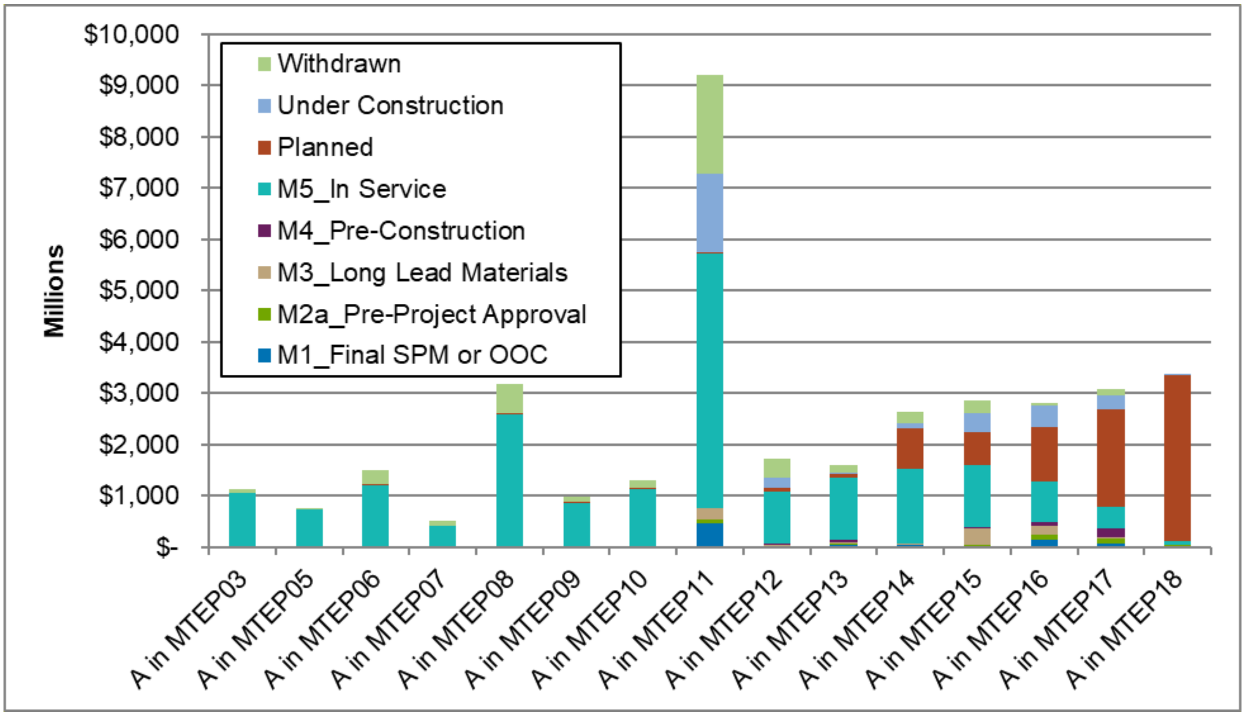

Figure 3.2-2: Approved transmission investment by MTEP cycle[14]

Since MTEP03, approximately $4.4 billion in approved transmission investment has been withdrawn. Common reasons for a project withdrawal include:

- The customer's plans changed or the service request was withdrawn
- A material system change resulted in no further need for the project
- An alternative solution is pursued and/or further evaluation shows the project is not needed

MISO documents all withdrawn projects and facilities to ensure the planning process addresses required system needs.

[14] New Appendix A projects in the MTEP18 column contain a few in service and under-construction projects. There are a few reasons why this occurs. Generator Interconnection Projects with network upgrades are approved via a separate Tariff process and are brought into the current MTEP cycle after their approval. There are also projects driven by conditions that must be addressed promptly to maintain system reliability. There are clearance projects that should be addressed promptly to maintain system reliability. Finally, there are relocation projects driven by others' schedules.

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Section 4: Reliability Analysis

4.1 Reliability Assessment and Compliance

System reliability is the primary purpose of all MTEP planning cycles. To fulfill this purpose, MISO planners study reliability from multiple perspectives to confirm the transmission system has sufficient capacity to provide reliable service to customers.

Continued reliability of the transmission system is measured by compliance with applicable NERC and regional reliability standards and local Transmission Owner (TO) planning criteria. These standards define minimum requirements for long-term system planning and require explicit solutions for violations that occur in a two-, five- and 10-year timeframe. As planning coordinator, MISO is required to find a solution for each identified violation that could otherwise lead to overloads, loss of synchronism, voltage collapse, equipment failures or blackouts.

The results of these reliability analyses, along with the proposed mitigating transmission projects, were presented and peer-reviewed at a series of Subregional Planning Meetings that were held in December 2017, May-June 2018 and August 2018. Each project included in MTEP Appendix A is the preferred solution to a transmission need when its implementation timeline requires near-term progress towards regulatory approval and construction.

This section summarizes the MTEP18 reliability assessment; read the complete results in Appendix D.

Process Overview

The MTEP reliability assessment is a holistic study process that begins with MISO building a series of study cases. Using these models, MISO performs an independent reliability analysis of its transmission system. This independent assessment results in identification of system needs, which are mapped to project submittals by the area transmission planning entities. Finally, MISO staff coordinates with area transmission planners to verify needs, identify alternative solutions and resolve gaps where additional system upgrades may be required (Figure 4.1-1).

MISO staff coordinates with area transmission planners to verify needs, identify alternative solutions and resolve gaps where additional system upgrades may be required

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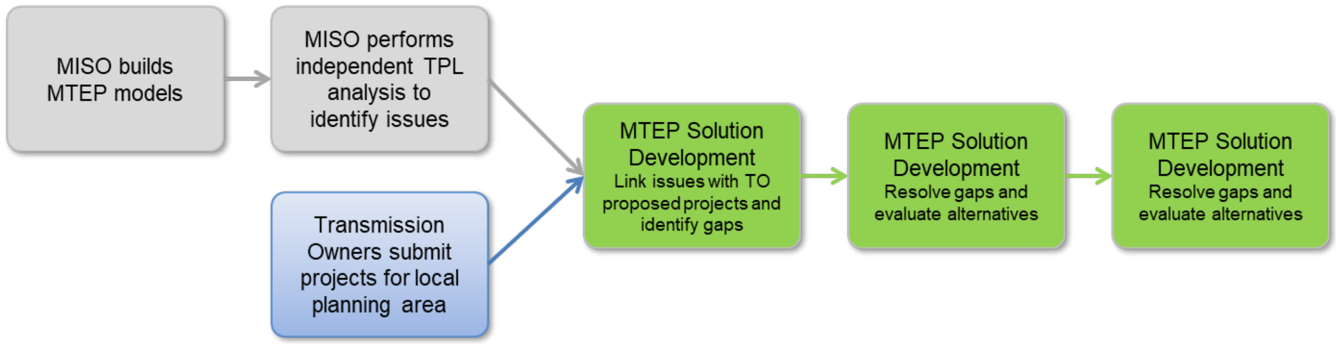

Figure 4.1-1: MTEP18 Reliability Study Process

Models

In MTEP18, MISO conducted regional studies using the following base cases and sensitivity cases developed collaboratively with its stakeholders:

- 2020 Summer Peak (wind at 15 percent, solar at 50 percent)
- 2020 Light Load (wind at 0 percent, solar at 0 percent)
- 2023 Summer Peak (wind at 15 percent, solar at 50 percent)
- 2023 Shoulder Peak (wind at 40 percent, solar at 50 percent)
- 2023 Shoulder Peak (wind at 90 percent, solar at 50 percent)
- 2023 Winter Peak (wind at 40 percent, solar at 50 percent)
- 2028 Summer Peak (wind at 15 percent, solar at 50 percent)

Interchanges, generation, loads and losses are inputs into each planning model used in the MTEP18 reliability analysis.

MISO member companies and external Regional Transmission Organizations use firm drive-in and drive-out transactions to determine net interchanges for these models. These are documented in the 2017 series Multiregional Modeling Working Group (MMWG) interchange.[15] MISO determines the total generation dispatch needed for each of the models after aggregating the total load with input received from TOs.

The results of these analyses create a cohesive long-term system reliability assessment, as well as documentary evidence for future NERC compliance

Generation dispatch within the model-building process is complex. Inputs from a variety of processes and expected shifts in the generation portfolio within the MISO footprint are key factors in this complexity.

Inputs in the dispatching process include:

- Generation retirements
- Generator market cost curves
- Generator deliverable capacity designation
- Wind generation output modeling under various system conditions
- Incremental generation needed to meet applicable renewable mandates

15 https://rfirst.org/ProgramAreas/RAPA/ERAG/MMWG/Pages/MMWG.aspx

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Loads are modeled based on direct input from MISO members. Generation dispatch is based on a number of assumptions, such as the modeling of wind. For example, wind generation is dispatched at 14 to 15.6 percent of nameplate in the summer peak case and from 40 percent to 90 percent of nameplate in the shoulder cases. These wind dispatch levels were selected through the MISO planning stakeholder process. Read more about the models in Appendix D2 of this report.

NERC Reliability Assessment

MISO conducts baseline reliability studies to ensure the transmission system is planned to comply with the following planning standards and criteria:

- Applicable North American Electric Reliability Corp. (NERC) reliability standards
- Reliability standards adopted by Regional Entities (RE) applicable within the transmission provider region
- Local Transmission Owner (TO) planning criteria after it is filed and approved by Federal Energy Regulatory Commission (FERC)

The NERC reliability assessment, performed by MISO, identifies potential thermal and voltage reliability issues. MISO and its TOs are required to develop and implement solutions for each identified violation of applicable planning standards and criteria. Violations are mitigated via system reconfiguration, generation redispatch, implementation of an operating guide, or with a transmission upgrade, as appropriate and consistent with the requirements of the applicable reliability standards. Identified transmission solutions to longer term system issues are investigated further in subsequent MTEP cycles when solutions lead times allow.

The results of these analyses create a cohesive long-term system reliability assessment, as well as documentary evidence for future NERC compliance. The complete study is available in Appendices D2-D8 of this report, which is posted on the MISO SFTP site. Confidential appendices, such as D2 through D8, are available on the MISO MTEP18 Planning Portal. Access to the Planning Portal site requires an ID and password.

Each MTEP assessment undergoes three specific types of analysis: steady-state, dynamic stability and voltage stability.

Steady-State Analysis

Appendix E1.5.1 documents contingencies tested in steady-state analysis. These contingencies were used in the MTEP18 2020 summer peak and shoulder peak models; the 2023 summer peak, shoulder peak, winter peak and light-load models; and the 2028 summer peak model. All steady-state analysis-identified constraints and associated mitigations are contained in the results tables in Appendix D3, demonstrating compliance with applicable NERC transmission standards.

Dynamic Stability Analysis

Appendix E1.5.2 documents types of disturbances tested in dynamic stability analysis. Disturbances were simulated in MTEP18 2023 light load, shoulder (wind at 40 percent), shoulder (wind at 90 percent) and summer peak load models. Results tables listing all simulated disturbances along with damping ratios are tabulated in Appendix D5, demonstrating compliance with applicable NERC transmission standards.

Voltage Stability Analysis

Appendix E1.5.3 documents types of transfers tested in voltage stability analysis. A summary report with associated power/voltage (PV) plots is documented in Appendix D4.

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Subregional Planning Meetings

MISO presents the project proposals and reliability study results to stakeholders through a series of public Subregional Planning Meetings (SPM). The locations of these SPMs are determined based on the four MISO planning subregions (Figure 4.1-2). The four MISO planning subregions are: Central, East, South and West.

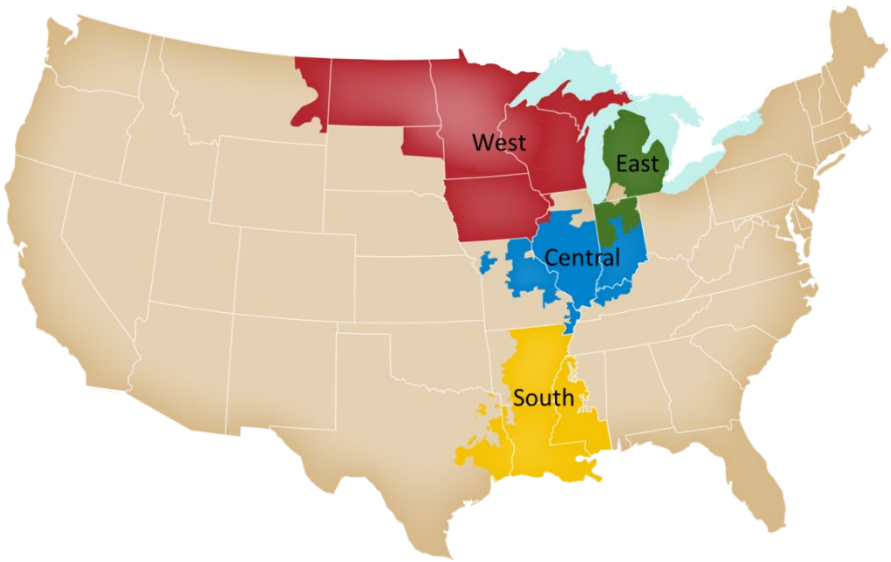

Figure 4.1-2: MISO planning subregions

Additionally, Technical Study Task Force (TSTF) meetings are convened for each MISO planning subregion on an as-needed basis to discuss confidential system information (Table 4.1-1). These meetings are open to any stakeholders who sign Critical Energy Infrastructure Information (CEII) and non-disclosure agreements.

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Date	Meeting	Location
12/6/2017	East SPM No. 1	Detroit, MI
12/8/2017	West SPM No. 1	Eagan, MN
12/11/2017	South SPM No. 1	Metairie, LA
12/12/2017	Central SPM No. 1	Carmel, IN
1/25/2018	West TSTF	Conf. Call
1/26/2018	South TSTF	Conf. Call
3/2/2018	South TSTF	Conf. Call
5/18/2018	East TSTF	Jackson, MI
5/25/2018	Central SPM No. 2	Carmel, IN
5/30/2018	South SPM No. 2	Metairie, LA
5/31/2018	East SPM No. 2	Novi, MI
6/1/2018	West SPM No. 2	Eagan, MN
7/31/2018	West TSTF	Conf. Call
8/7/2018	East TSTF	Livonia, MI
8/23/2018	South SPM No. 3	Metairie, LA
8/28/2018	Central SPM No. 3	Carmel, IN
8/29/2018	West SPM No. 3	Eagan, MN
8/30/2018	East SPM No. 3	Cadillac, MI

Table 4.1-1: MTEP18 Subregional Planning Meeting schedule

Project Approval

After MISO completes the independent review of all proposed projects and addresses any stakeholder feedback received during the SPM presentations, MISO staff formally recommends a set of projects to the MISO Board of Directors for review and approval. These projects make up Appendix A of the MTEP18 report and represent the preferred solutions to the identified transmission needs of the MISO reliability assessment. Proposed transmission upgrades with sufficient lead times are included in Appendix B for further review in future planning cycles. Details of the project approval process and the approved transmission projects reviewed this cycle are summarized in Chapter 2 and Appendix D1 of the MTEP18 report.

4.2 Generation Interconnection Projects

MISO provides safe, reliable, transparent, equal and non-discriminatory access to the electric transmission system for all new generation interconnection requests. MISO's interconnection process identifies network upgrades for all new generator interconnection requests, as necessary, to ensure that the injection from new generation capacity does not deteriorate the reliability of the existing transmission system. All network upgrades emanating from the interconnection process are included in the final MTEP as Generator Interconnection Projects (GIPs) at the end of every calendar year.

MTEP18 contains Target Appendix A GIPs totaling approximately $255 million (Table 4.2-1). These GIPs are associated with the generation interconnection requests (Table 4.2-2, Figure 4.2-1).

MTEP Project ID	Project Name	Submitting Company	Preliminary Share Status	Region	Estimated Cost ($)
13619	New Ruby 345 kV breaker substation	AMIL	Shared	Central	$8,425,441
13769	J704/J711 GIC – Silver River substation Interconnection and Network Upgrades	ATC	Shared	ATC	$19,700,000
13784	J703 GIC – Huron substation, Interconnection and Network Upgrades	ATC	Shared	ATC	$17,100,000
13796	J515 - Cayuga CT 345 kV breaker substation	DEI	Shared	Central	$3,511,382
14024	J041 – Generator Interconnection	ITCM	Not Shared	West	$7,751,624
14025	J438 – FCA Affected Systems Upgrade	ITCM	Not Shared	West	$2,386,020
14030	J407 - Generator Interconnection	ITCM	Not Shared	West	$3,383,715
14032	J449 – Generator Interconnection	ITCM	Not Shared	West	$60,000
14204	J704/J711 GIC – Silver River substation Interconnection and Network Upgrades	ATC	Shared	ATC	$18,700,000
14625	J475/J555 North English	MEC	Shared	West	$2,750,000
14626	J438 English Farms	MEC	Not Shared	West	$4,800,000
14744	Lake Charles Power Station Deliverability Projects	EES	Not Shared	South	$50,681,159
14745	Montgomery County Power Station Deliverability Projects	EES	Not Shared	South	$98,969,890
14925	J505 GIC, Apollo substation, Generator Interconnection and Network Facilities	ATC	Shared	ATC	$8,300,000
15493	J538 GIC – Knowles 138 kV breaker substation	METC	Not Shared	East	$6,920,000
15496	J533 GIC – Slate 345 kV breaker substation	METC	Not Shared	East	$1,456,000
Total Estimated Cost					**$ 254,895,231**

Table 4.2-1 Generation Interconnection Projects in MTEP18 Target Appendix A[16]

[16] A detailed description how a shared project is determined is in Attachment FF, starting with Section II.C, page 57 of the Tariff.

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GI Project No.	TO	County	State	Study Cycle	Service Type	Point of Interconnection	Max Summer Output	Fuel Type	GIA
J704	ATC	Baraga	MI	DPP-2016-AUG-MI/DPP-2017-FEB-MI	NRIS	Silver River 138 kV Substation	54.9	Gas	GIA
J703	ATC	Marquette	MI	DPP-2016-AUG-MI/DPP-2017-FEB-MI	NRIS	Huron 138 kV Substation	128.1	Gas	GIA
J711	ATC	Baraga	MI	DPP-2016-AUG-MI/DPP-2017-FEB-MI	NRIS	Silver River 138 kV Substation	130	Wind	GIA
J505	ATC	Manitowoc	WI	DPP-2016-FEB-ATC	NRIS	Apollo 138 kV Substation	99	Solar	GIA
J468	AMIL	Douglas	IL	DPP-2016-FEB-Central	NRIS	Ruby 345kV Line	202	Wind	GIA
J484	EES	Calcasieu	LA	DPP-2016-AUG-South	NRIS	Nelson Power Station	1056.19	CCT	*
J515	DEI	Benton & Warren	IN	DPP-2016-FEB-Central	ERIS	Cayuga 345 kV Substation	400	Wind	GIA
J472	EES	Montgomery	TX	DPP-2016-AUG-South	NRIS	Lewis Creek 138 kV and 230 kV Substations	1044.8	Gas	GIA
J041	ITCM	Grundy	IA	DPP-2015-AUG-West	NRIS	Wellsburg 161 kV Substation	90	Wind	GIA
J438	MEC	Poweshiek	IA	DPP-2015-AUG-West	NRIS	Poweshiek-Parnell 161 kV Line	170	Wind	GIA
J407	ITCM	Freeborn	MN	DPP-2015-FEB-West	NRIS	Glenworth 161 kV Substation	200	Wind	GIA
J449	ITCM	Mitchell	IA	DPP-2015-AUG-West	NRIS	Pioneer Prairie I 345 kV Substation	202	Wind	GIA
J475	MEC	Poweshiek	IA	DPP-2016-FEB-West	NRIS	Montezuma 345 kV Substation	200	Wind	GIA
J555	MEC	Poweshiek	IA	DPP-2016-AUG-West	NRIS	Montezuma 345 kV Substation	140	Wind	GIA
J538	METC	Hillsdale	MI	DPP-2016-FEB-MI	NRIS	Knowles 138kV breaker substation	150	Wind	GIA
J533	METC	Gratiot	MI	DPP-2016-FEB-MI	NRIS	Slate 345kV breaker substation	200	Wind	GIA

***GIA in process**

Table 4.2-2: Generation Interconnection Requests associated with Target Appendix A

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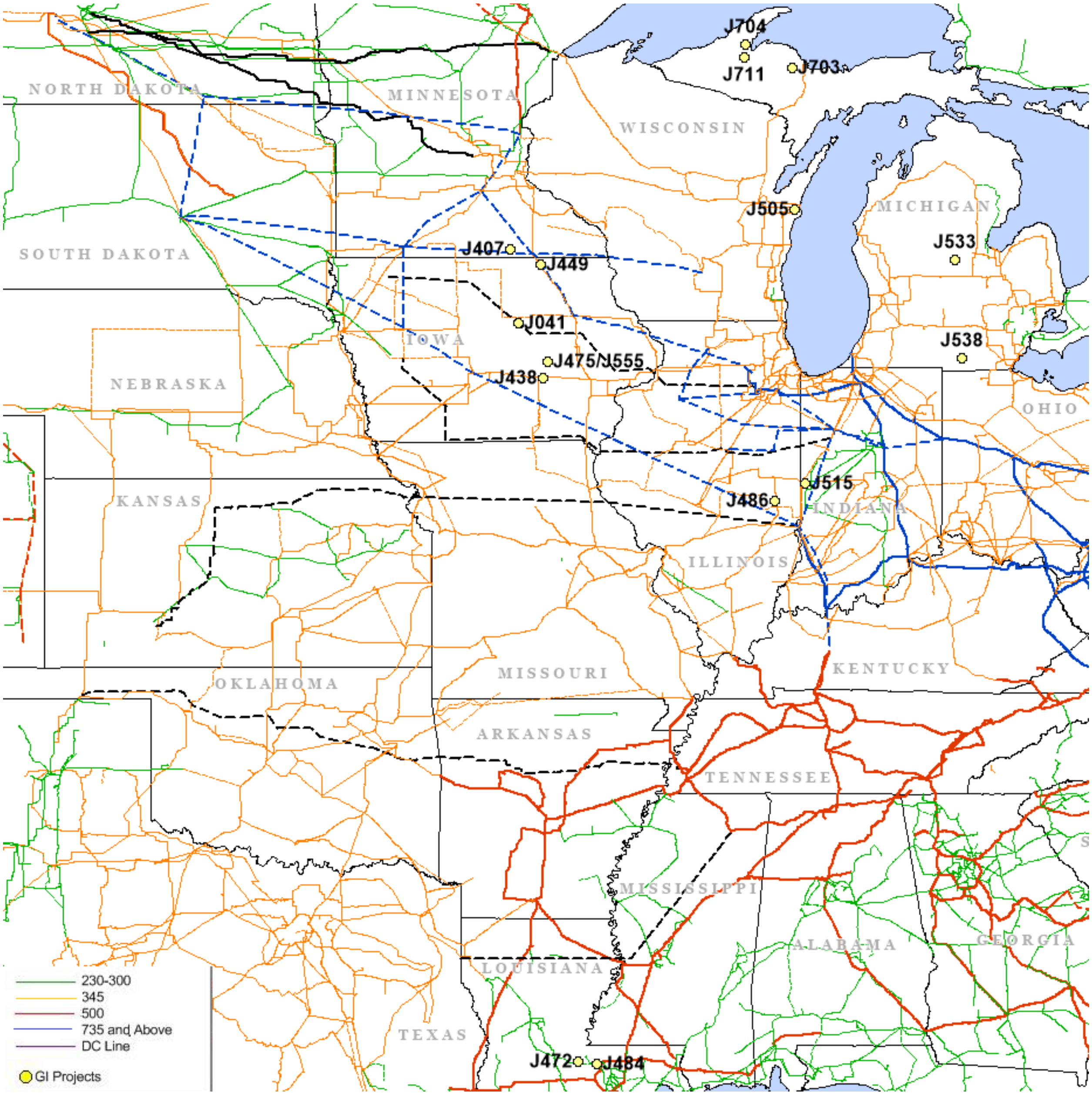

Figure 4.2-1: Generation Interconnection Requests associated with MTEP18 Target Appendix A

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MTEP18 Target Appendix A

MTEP Project 13619 – Ameren Electric Service Co.

- Perform network upgrades for J468 GIP
- J468 – 202 MW Wind Generator
- Point of interconnection: Ruby 345 kV Substation
- Construct a three-position initial (six-position ultimate), 3000 A 345 kV switching station in a ring bus configuration at structure 100 in the Kansas-Sidney 345 kV line 4560 for the interconnection of Broadlands Wind Farm.
- Anticipated completion date: October 1, 2019
- Anticipated cost: $8,425,441

MTEP Project 13769 – American Transmission Co.

- Perform network upgrades for J704 GIP
- J704 – 54.9 MW Gas Generator
- Point of interconnection: Silver River 138 kV Substation
- Construct a new eight-position 138 kV Silver River Substation in a breaker-and-a-half configuration adjacent to the Silver River substation.
- Anticipated completion date: January 31, 2019
- Anticipated cost: $19,700,000

MTEP Project 13796 – Duke Energy Corporation

- Perform network upgrades for J515 GIP
- J515 – 400 MW Wind Generator
- Point of interconnection: Cayuga 345 kV Substation
- Cayuga CT 345kV Ring Bus Expansion - to accommodate wind farm connection - J515
- Anticipated completion date: June 1, 2019
- Anticipated cost: $3,511,382

MTEP Project 13784 – American Transmission Co.

- Perform network upgrades for J703 GIP
- J703 – 128.1 MW Gas Generator
- Point of interconnection: Huron 138 kV Substation
- Construct a new six-position 138-kV Huron Substation in a breaker-and-a-half configuration constructed adjacent to the new power plant. The substation will: be designed for a 10-position ultimate design; tie in the Freeman-National 138 kV (FREG11) and Presque Isle – Empire (Goose Lake) 138 kV lines creating a double circuit loop.
- Anticipated completion date: January 23, 2019
- Anticipated cost: $17,100,000

MTEP Project 14024 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J041 GIP
- J041 – 90 MW Wind Generator
- Point of interconnection: Wellsburg 161 kV Substation
- Rebuild Wellsburg 161 kV to a breaker-and-a-half configuration; customer-dedicated facilities at Wellsburg (TOIF); 161 kV Line relocation; and Newton to Maytag terminal upgrade at Newton
- Anticipated completion date: September 1, 2019
- Anticipated cost: $7,751,624

MTEP Project 14025 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J438 GIP

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- J438 – 170 MW Wind Generator
- Point of interconnection: Poweshiek-Parnell 161 kV Line
- Replace existing 161/69 kV transformer at Poweshiek
- Anticipated completion date: December 14, 2018
- Anticipated cost: $2,386,020

MTEP Project 14030 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J407 GIP
- J407 – 200 MW Wind Generator
- Point of interconnection: Glenworth 161 kV Substation
- Expand 161 kV ring and add a 161 kV terminal at Glenworth; customer dedicated facilities at Glenworth; Replace Glenworth 161/69 kV transformer with a 150 MVA unit
- Anticipated completion date: August 7, 2020
- Anticipated cost: $3,383,715

MTEP Project 14032 – International Transmission Co. Transmission Midwest

- Perform network upgrades for J449 GIP
- J449 – 202 MW Wind Generator
- Point of interconnection: Pioneer Prairie I 345 kV Substation
- Change relay settings at Mitchell County 345 to allow for project J449 interconnection via common facilities with existing project G172
- Completion date: July 1, 2018
- Cost: $60,000

MTEP Project 14204 – American Transmission Co.

- Perform network upgrades for J711 GIP
- J711 – 130 MW Wind Generator
- Point of interconnection: Silver River 138 kV Substation
- SILVER RIVERG22 and ATLANTIC69 line reroutes to accommodate generator lead line
- Anticipated completion date: September 23, 2020
- Anticipated cost: $18,700,000

MTEP Project 14625 – MidAmerican Energy Co.

- Perform network upgrades for J475/J555 GIP
- J475/J555 – 340 MW Wind Generator
- Point of interconnection: Montezuma 345 kV Substation
- Generator Interconnection Project
- Completion date: July 1, 2018
- Cost: $2,750,000

MTEP Project 14626 – MidAmerican Energy Co.

- Perform network upgrades for J438 GIP
- J438 – 170 MW Wind Generator
- Point of interconnection: Poweshiek-Parnell 161 kV Line
- Generator Interconnection Project
- Anticipated completion date: December 15, 2018
- Anticipated cost: $4,800,000

MTEP Project 14744 – Entergy - Louisiana

- Perform network upgrades for J484 GIP
- J484 – 1056.19 MW Gas CCT Generator
- Point of interconnection: Nelson Power Station

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- Upgrade Nelson Substation equipment to 1958 MVA
- Rebuild the Nelson – Spanish Trail – Mossville 138 kV line
- Upgrade Alfol 69 kV Substation
- Upgrade Conoco 138 kV Substation
- Anticipated completion date: February 28, 2020
- Anticipated cost: $50,681,159

MTEP Project 14745 – Entergy - Texas

- Perform network upgrades for J472 GIP
- J472 – 1044.8 MW Gas Generator
- Point of interconnection: Lewis Creek 138 kV and 230 kV Substations
- Construct new 230 kV line from Lewis Creek to Porter with a minimum through path rating of 1956 Amps. Construct a 230 kV ring bus at Porter.
- Rebuild Lewis Creek – Goree 138 kV line section and upgrade terminal equipment to achieve a minimum through path rating of 1300 Amps. Rebuild Goree - Rivtrin 138 kV line section and upgrade terminal equipment to achieve a minimum through path rating of 1200 Amps.
- Reconductor/Rebuild Lewis Creek – Sheawill – Fort Worth Pipe 138 kV and upgrade terminal equipment to achieve a minimum through path rating of 1300 Amps.
- Cut in Mossville – Marshall 138 kV line into J634 substation. Upgrade J634 Tap – Mossville 138 kV to at least 168 MV
- Anticipated completion date: June 1, 2021
- Anticipated cost: $98,969,890

MTEP Project 14925 – American Transmission Co.

- Perform network upgrades for J505 GIP
- J505 – 99 MW Solar Generator
- Point of interconnection: Apollo 138 kV Substation
- Construct a new Apollo 138 kV substation to interconnect the J505 generation interconnection request. The new substation will be built as a three-position ring bus expandable to six positions. The new station will be located adjacent to the existing Kewaunee-Shoto 138 kV line.
- Loop in the existing Kewaunee-Shoto 138 kV line to the new station.
- Perform required remote end work at Kewaunee and Shoto substations
- Anticipated completion date: January 28, 2021
- Anticipated cost: $8,300,000

MTEP Project 15493 – Michigan Transmission Electric Transmission Co.

- Perform network upgrades for J538 GIP
- J538 – 150 MW Wind Generator
- Point of interconnection: Knowles 138 kV substation
- Construct a new Knowles 138 kV substation to interconnect the J538 generation interconnection request. The new substation will be built as a three-breaker ring bus. The new station will be located between the Moore Road and Beecher 138 kV line.
- Anticipated completion date: October 1, 2020
- Anticipated cost: $6,920,000

MTEP Project 15496 – Michigan Transmission Electric Transmission Co.

- Perform network upgrades for J533 GIP
- J533 – 200 MW Wind Generator
- Point of interconnection: Slate 345 kV Substation
- Install a 345 kV breaker at the Slate 345 kV substation
- Install two disconnects at the Slate 345 kV substation
- Anticipated completion date: October 1, 2019
- Anticipated cost: $1,456,000

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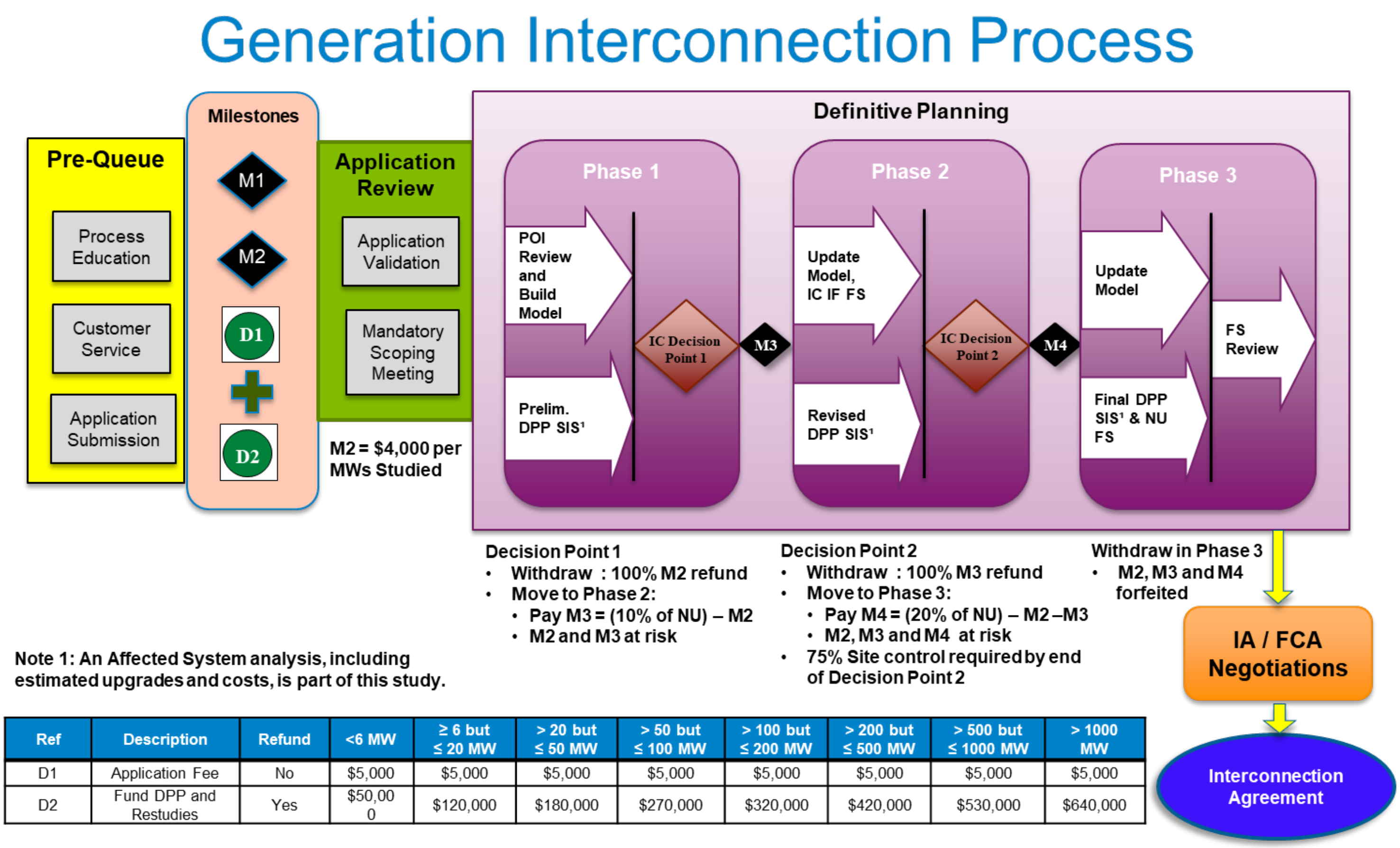
The Queue Process

Interconnection requests to connect new generation to the transmission system are studied and approved under the Generation Interconnection queue process. Each generator must fund the necessary studies to ensure new interconnections will not cause system reliability issues. Each project must meet technical and non-technical milestones in order to move to the next phase (Figure 4.2-2).



Ref	Description	Refund	<6 MW	≥ 6 but ≤ 20 MW	> 20 but ≤ 50 MW	> 50 but ≤ 100 MW	> 100 but ≤ 200 MW	> 200 but ≤ 500 MW	> 500 but ≤ 1000 MW	> 1000 MW
D1	Application Fee	No	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
D2	Fund DPP and Restudies	Yes	$50,000	$120,000	$180,000	$270,000	$320,000	$420,000	$530,000	$640,000

Figure 4.2-2: Generator interconnection process

Since the beginning of the queue process, MISO and its Transmission Owners have received approximately 2,371 generator interconnection requests totaling 442.8 GW (Figures 4.2-3, 4.2-4 and 4.2-5). Among them, 78.7 GW out of the 442.8 GW or 17.8 percent now have a Generation Interconnection Agreement (GIA). These generation additions enhance reliability, ensure resource adequacy, provide a competitive market to deliver benefit to ratepayers and help the industry meet renewable portfolio standards.

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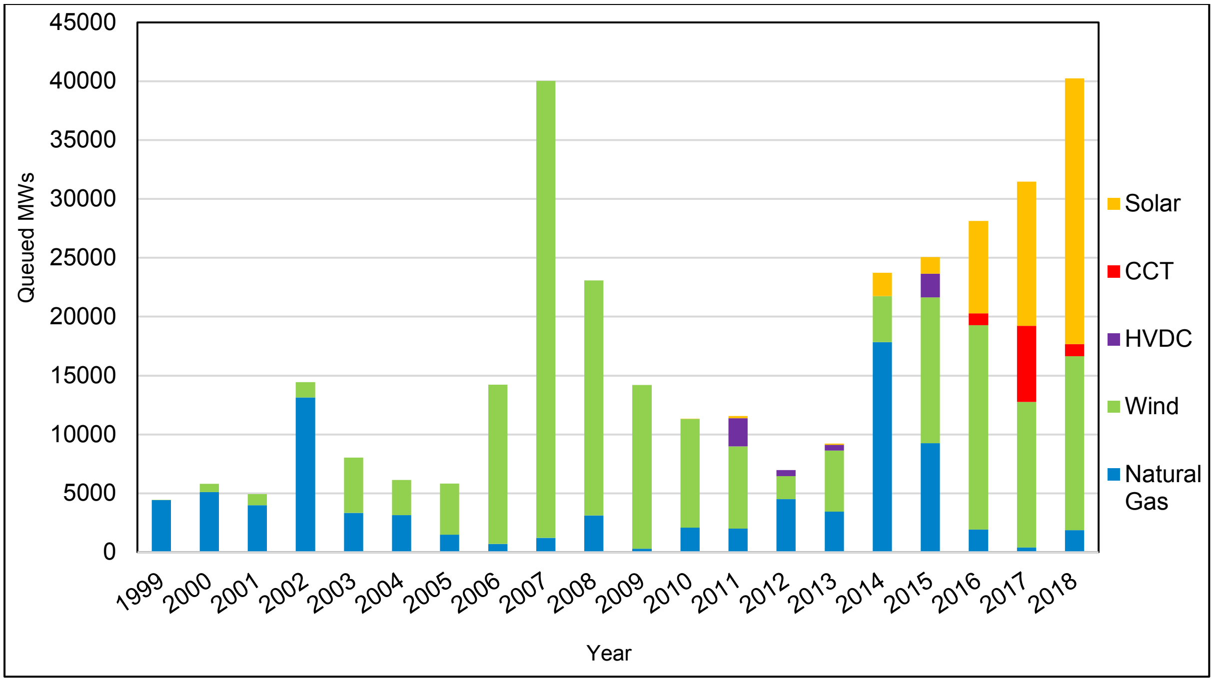

Figure 4.2-3: Queue Trends

Renewable Portfolio Standards (RPS) have become more common since the late 1990s. Although there is no RPS program in place at the national level, 29 states and the District of Columbia and three territories have enforceable RPS or other mandated renewable capacity policies (Figure 4.2-4). In addition, eight states and one territory adopted voluntary renewable energy standards.

Between 2005 and 2008, MISO experienced exponential growth in wind project requests. In 2007, wind generation requests in the MISO queue peaked at approximately 39 GW. The requests for wind have now stabilized in the last several years in the MISO footprint (Figure 4.2-5).

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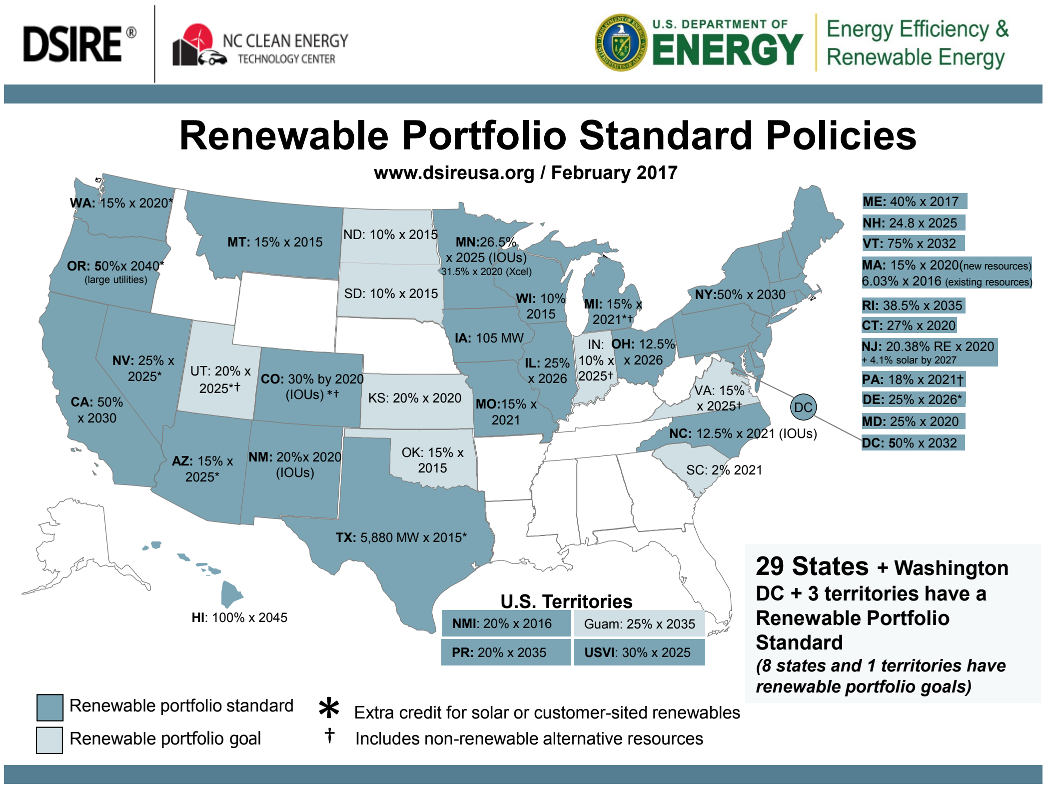

Figure 4.2-4: States and territories with Renewable Portfolio Standards

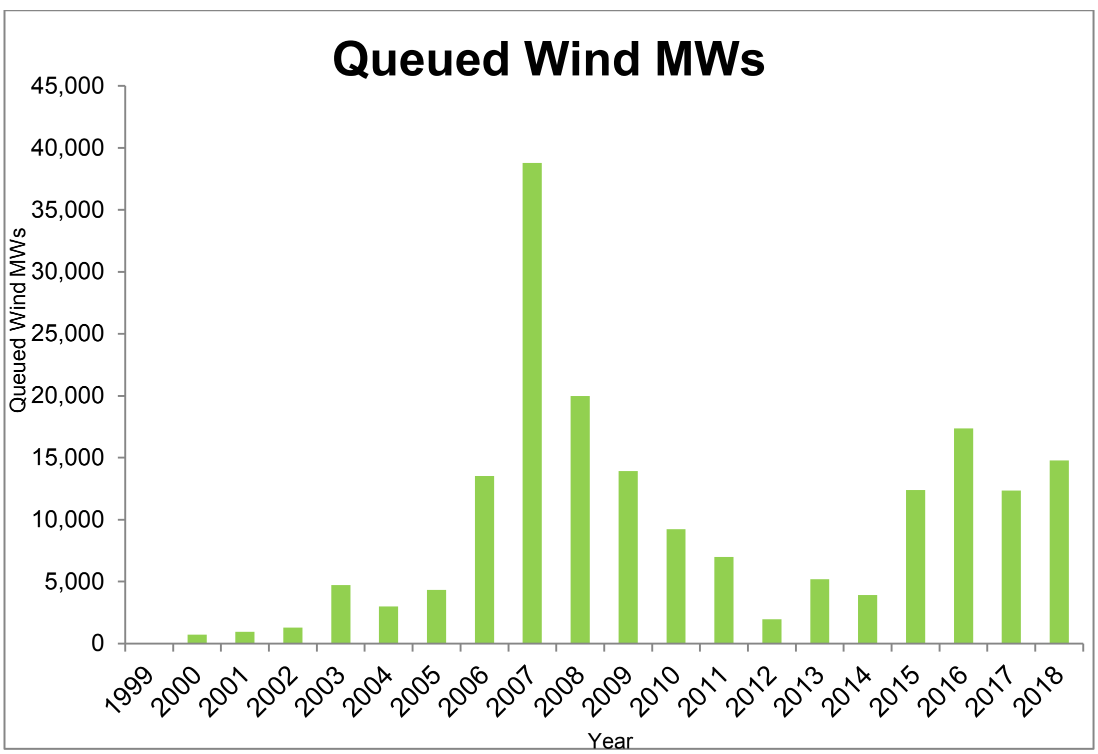

Figure 4.2-5: Wind – queued interconnection requests

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As a result of the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standard (MATS) and its compliance requirements, MISO's generator interconnection queue has seen a fluctuation in natural gas interconnection requests and then a substantial drop (Table 4.2-3).

Year	Queued CT & CCCT MW	% Of All New Requests
2012	4,509	63%
2013	3,835	30%
2014	9,424	58%
2015	9,076	35%
2016	4,472	12.6%
2017	6,882	21.8%
2018	2,906	4.6%

Table 4.2-3: Combustion turbine (CT) and combined cycle combustion turbine (CCCT) – queued interconnection requests

Furthermore, there are approximately 22.5 GW of solar generation interconnection requests in the definitive planning phase (DPP) as of April 2018 (Figure 4.2-6). This could be the result of recent federal energy legislation and the economic stimulus package, and lower prices of solar photovoltaic modules.

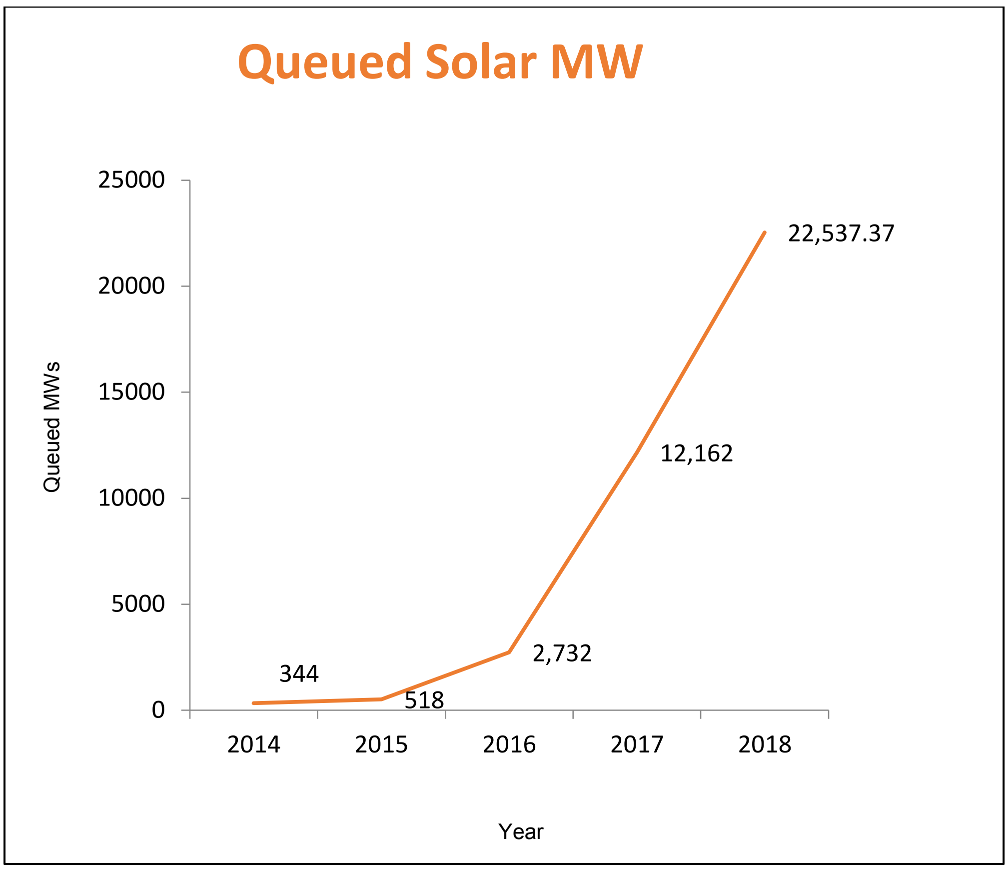

Figure 4.2-6: Solar – queued interconnection requests

Process Improvement

Over the past 13 years, the MISO Interconnection Process has evolved from a first-in, first-out methodology to first-ready, first-served methodology to move projects more efficiently through the generation project queue lifecycle.

With significant changes implemented in the latest 2017 interconnection FERC approved Queue Reform, which largely addressed backlogs in the generator interconnection queue and late-stage withdrawals of generator interconnection agreements, MISO expects that its new three-phase process will allow Interconnection Customers to withdraw their Interconnection Requests earlier in the process and thus reduce restudies and delays in completing studies (System Impact and Facility studies).

MISO continues to seek more opportunities to improve the queue process, while following basic guiding principles: reliable interconnection; timely processing; certainty in process; and Targeted Risk Allocation. The current drivers for this effort include re-studies caused by project withdrawals, evolving industry standards, more variable generation in the queue and changing technology.

MISO has reviewed the past process and study criteria, and identified areas for significant improvement. Process improvement focus areas that MISO continues to work on are:

- Compliance with new TPL-001-4 standards
- Consistency in the planning model
- Attachment Y process coordination
- Interconnection study timeline improvement
- Seams coordination
- Continuing to streamline the queue process with MISO energy market and capacity construct
- Exploring economic analysis-related options

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4.3 Transmission Service Requests

Transmission Service Request (TSR) acquisition is the first step in creating schedules to move energy in, out, through or within the MISO market. When a customer or Market Participant submits and confirms a TSR on the MISO Open Access Same-Time Information Service (OASIS), it reserves transmission capacity. Long-term TSRs (one year or longer) must be evaluated for impacts to system reliability taking into account the deliverability of network resources in the MISO footprint. Short-term TSRs (less than one year) are evaluated based on the real-time Available Flowgate Capacity values by MISO Tariff Administration.

From July 2017 to June 2018, MISO Transmission Service Planning processed 131 long-term TSRs (Figure 4.3-1) and completed 16 System Impact Studies for a total of 16 TSRs (Figure 4.3-1). Of these System Impact Studies, five TSRs were confirmed, three were refused/withdrawn, three executed a Facilities Study Agreement and five await the completion of a corresponding external Affected System Impact Study. Remainders of TSRs were either rollover TSRs, which don't require a System Impact Study or withdrawn TSRs during the process.

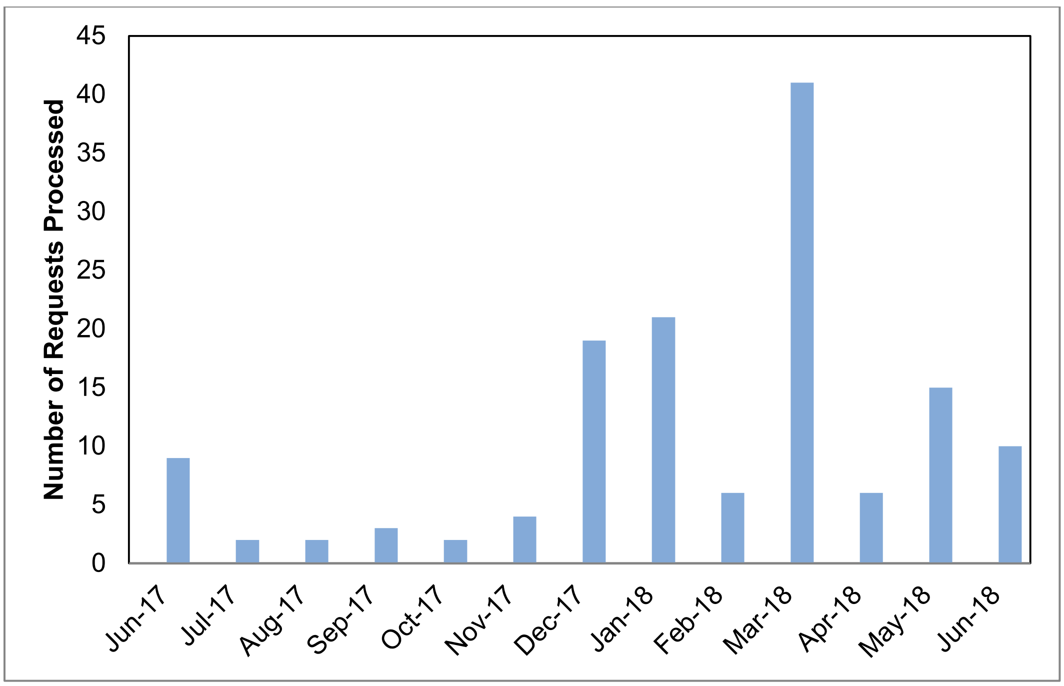

Figure 4.3-1: MISO Long-Term TSRs processed from July 2017 through June 2018

Long-term TSRs processed and evaluated by MISO planning staff are either Firm Point-to-Point or Network Transmission Service. Point-to-Point Transmission Service is the reservation and transmission of capacity and energy from the point(s) of receipt to the point(s) of delivery. Network Transmission Service allows a network customer to utilize its network resources, as well as other non-designated generation resources, to serve its network load located in the Transmission Owner's Local Balancing Authority area or pricing zone.

Short-term TSRs have a term of less than one year and can be firm or non-firm. Established MISO tools review the Available Flowgate Capacity on the 15 most-limiting constrained facilities on a TSR path to verify adequate capacity. If the Available Flowgate Capacity is positive for all 15 constrained facilities, the

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request is likely to be approved. Negative Available Flowgate Capacity on one or more of the 15 constrained facilities results in either a counter-offer or denial.

New long-term TSRs are processed based on queue order and type in the Triage phase (Figure 4.3-2). A TSR can be one of the three following types: original, a new TSR; renewal, a continuation of an existing TSR; or redirect, the changing of the source and/or sink of an existing TSR.

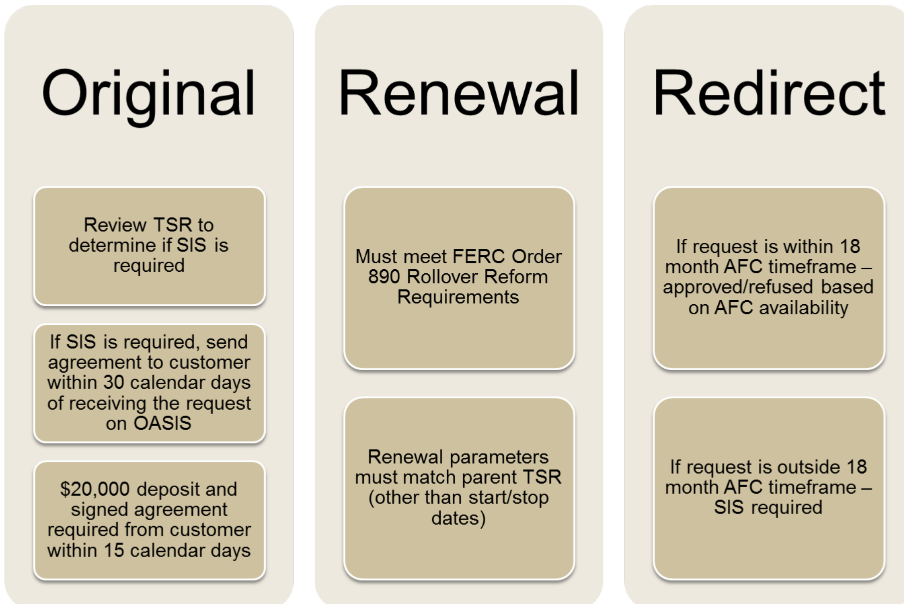

Figure 4.3-2: TSR triage phase processing

If a System Impact Study (SIS) is needed and the transmission customer returns the executed study agreement and deposit, MISO must complete the study within 60 calendar days from the time the agreement and deposit are received. MISO can accept the TSR and request specification sheets from the transmission customer if no constraints are identified in the study or if partial capacity can be granted. A Facilities Study is required if constraints are identified in the SIS and the customer choses to move forward with the TSR.

MISO then sends out a Facility Study Agreement within 30 calendar days for the customer to return along with a study deposit, should they want to move forward. If the agreement and deposit are not received, the TSR is refused. The Facility Study provides the costs and schedules to build upgrades required to mitigate the constraints identified in the SIS. Once complete, the customer has the option to take a reduced amount of transmission service, as identified in the SIS, proceed with a Facility Construction Agreement (FCA), or withdraw the TSR.

If the customer signs the FCA, the identified upgrades are included in MTEP Appendix A as Transmission Delivery Service Projects (TDSP). The cost of these upgrades is either directly assigned or rolled-in as per Attachment N of the Tariff. MISO can then request specification sheets and conditionally accept the TSR until all upgrades are in service.

Transmission Service Restriction

On March 28, 2014, the Federal Energy Regulatory Commission (FERC) accepted, over MISO's objection, a Transmission Service Agreement filed by Arkansas-based Southwest Power Pool (SPP),

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requiring MISO to pay SPP for any flow on SPP's transmission system above the existing 1,000 MW contract path between MISO North and MISO South.

MISO, SPP and Joint Parties reached a settlement that was subsequently filed with FERC in October 2015. The settlement provisions regulate the firm and non-firm utilization of the MISO North-MISO South contractual path from the date of acceptance of the settlement by FERC. The settlement was accepted by FERC in January 2016.

MISO instituted a contract path limit in TSR studies (in addition to the flow-based limitations) for the TSRs going across the MISO South-MISO North interface in both directions. An OASIS document has been posted to list out the latest contract path limit and the source sink combinations that are restricted. This document will be updated as/when the contract path rating is updated in future.

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4.4 Generation Retirements and Suspensions

The permanent or temporary cessation of operation of generation resources can significantly impact the reliability of the transmission system. The MISO Attachment Y process provides a mechanism to ensure transmission system reliability in response to the retirement or suspension of a generation resource.

Under the Tariff provisions, MISO may require the asset owner to maintain operation of the generation as a System Support Resource (SSR) if the generator is needed to avoid violations of applicable NERC, Regional or Transmission Owners' (TO) planning criteria. In exchange, the generator will receive compensation for its applicable costs to remain available. SSR costs are paid by the loads in areas that benefit from the SSR generation. An SSR is considered a temporary measure where no other alternatives exist to maintain reliability until transmission upgrades or other suitable alternatives are completed to address the issues caused by the unit change in status.

The MISO Attachment Y provides a mechanism to ensure transmission system reliability in response to the retirement or suspension of a generation resource

Attachment Y Requests and Status

MISO received 23 new Attachment Y Notices (4,371 MW) for unit retirement/suspension during the first seven months of 2018 (Figure 4.4-1). In the same period (January-July) in 2017 MISO received 11 Attachment Y retirement/suspension notices (1,219 MW) (Figure 4.4-1). MISO completed assessments and resolved a total of 14 Attachment Y Notices (3,249 MW) for unit retirement/suspension in the first seven months of 2018 (Figure 4.4-1).

The continuing evolution of the generation fleet and prevailing market economics continues to drive further retirements of uneconomic and less efficient resources.

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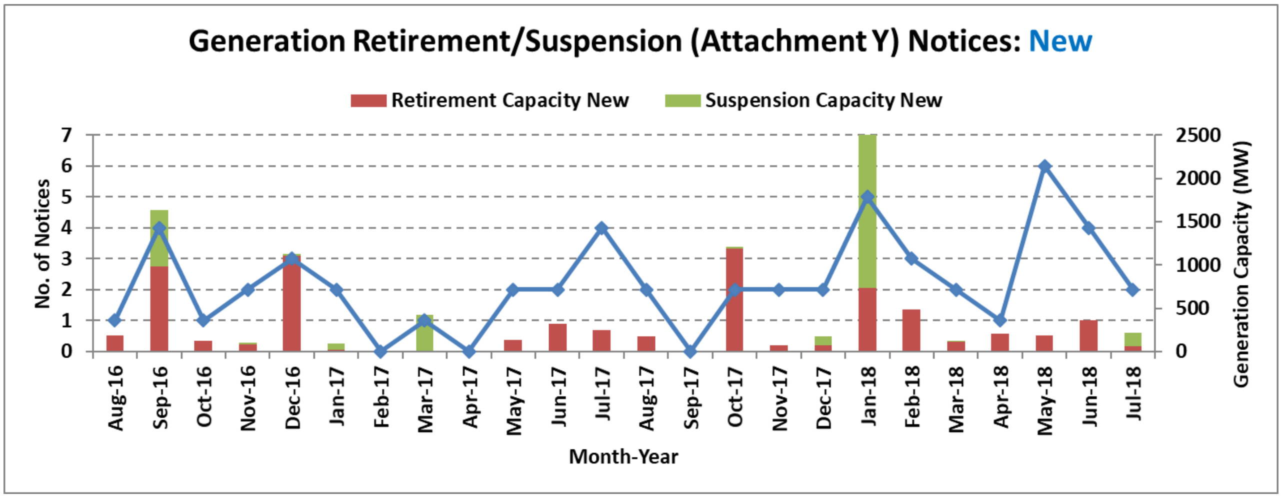

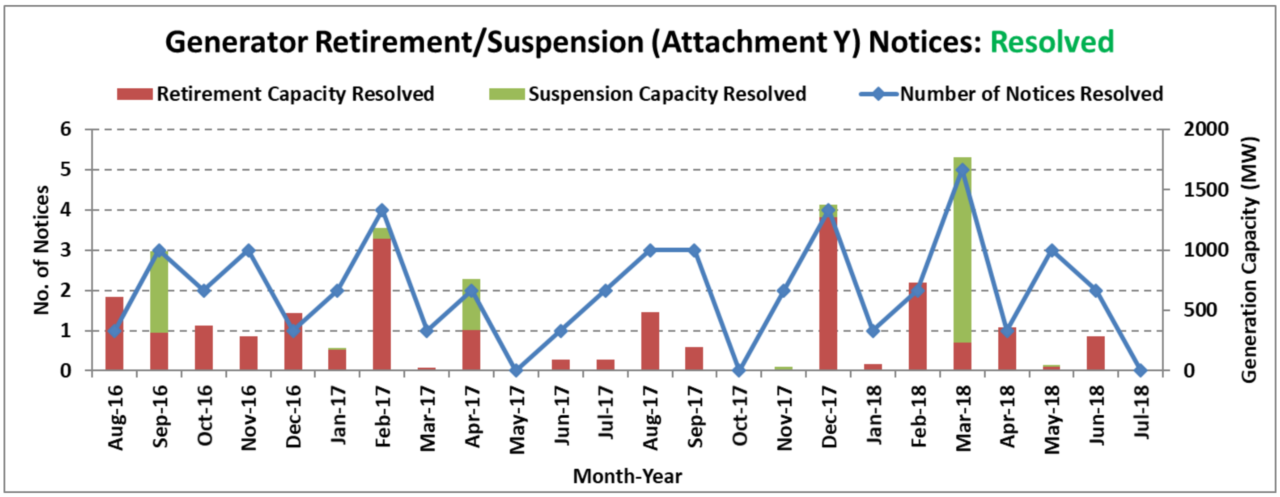

Figure 4.4-1: Generation Retirement/Suspension (Attachment Y) Notices – new and resolved

Overall, 3,848 MW of generation capacity is retiring in 2018 and an additional 359 MW of generation capacity will retire in 2019 (Figure 4.4-2). This includes 2,680 MW of coal generation, 991 MW of gas generation and 177 MW of oil generation that is approved for retirement in 2018 and 359 MW of coal generation in 2019.

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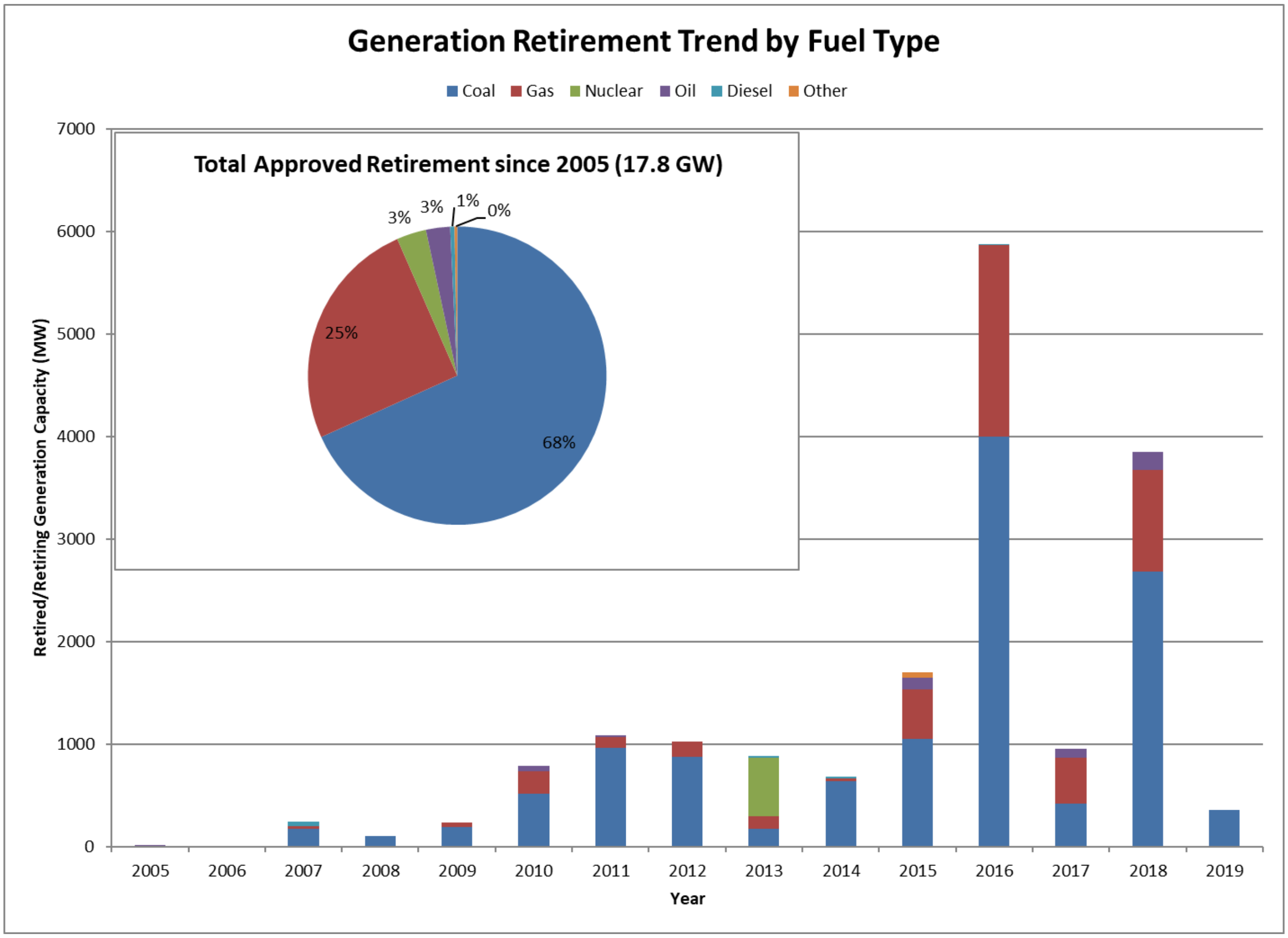

Figure 4.4-2: Generation capacity (aggregate MW) approved for retirement

2018 FERC Activity, Tariff Changes

Independent Market Monitor Recommendation

In May 2017, MISO filed changes to the Attachment Y Tariff provisions to address Independent Market Monitor (IMM) Recommendation 2013-14 related to the alignment of the Planning Resource Auction (PRA) and the Attachment Y process governing retirements and suspensions. The proposed Tariff changes remove barriers to participation in the PRA by providing more flexibility for resources to continue operation after MISO Approves the Attachment Y Notice based on the outcome of the Planning Resource Auction. All Attachment Y Notices will be initially submitted as suspension requests with limited opportunity to rescind within a three year-period. After the Attachment Y Notice has been approved the owner may defer a retirement decision until the results of the Planning Auction are determined.

MISO is awaiting a FERC Order on the filing.

SSR Agreement Activity

Since the inception of the SSR program in 2005, MISO has implemented 10 SSR agreements with only one agreement currently remaining active: Teche Unit 3 (Figure 4.4-3).

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Teche 3 (335 MW) –The Cleco-Teche Unit 3 has been operating under an SSR agreement since April 1, 2017. MISO conducted an annual review of continued SSR need and determined that the unit is needed to continue operation as an SSR unit until the Terrebonne-Bayou Vista 230 kV Transmission Project is completed. MISO renewed the SSR Agreement for an additional 12-month term, which will end on April 1, 2019.

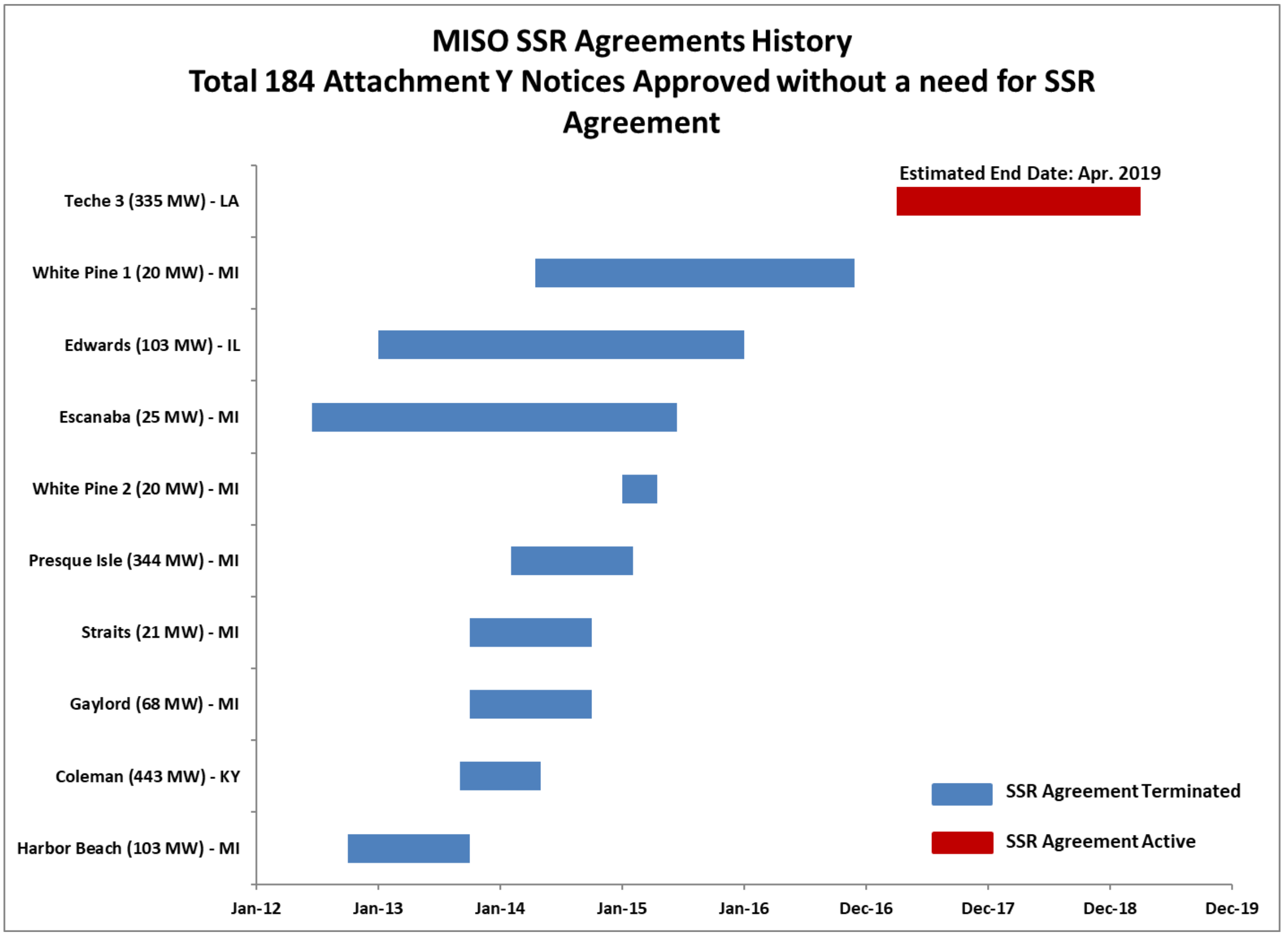

Figure 4.4-3: SSR history

Process

Market participants that own or operate generation resources seeking to retire or suspend operation of a generator are required to submit an Attachment Y Notice to MISO at least 26 weeks prior to the effective date of the change in status (Figure 4.4-4). MISO performs a reliability analysis with the participation of the TOs to determine if any violations of applicable NERC and TO planning criteria are caused by the unit retirement/suspension.

Within a 75-day period, MISO provides a response to the market participant indicating the study conclusion. MISO will approve the Attachment Y Notice if there are no violations of applicable planning criteria or if the issues are resolved by a planned upgrade. Any unresolved issues are presented in a stakeholder-inclusive process to evaluate alternatives that would avoid the need for an SSR contract.

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If reliability issues are found in the study, MISO convenes an open stakeholder review of the Attachment Y issues and alternatives through Universal Non-disclosure Agreement (UNDA) and Critical Energy Infrastructure Information (CEII)-protected Technical Study Task Force meetings. Alternatives that provide comparable benefit to retaining the SSR unit are considered and evaluated for effectiveness in relieving the violations and include such options as new/re-powered generation, reconfiguration, remedial action plans or Special Protection Schemes, demand response and transmission reinforcements. If an alternative is available, the Attachment Y Notice is approved. If the alternative does not eliminate all the violations of reliability criteria that require the need for the SSR Unit, MISO and the market participant will negotiate the terms of the SSR Agreement, which will be filed with FERC prior to the effective date. The agreement is subject to an annual review and renewal to allow the opportunity to terminate the need for an SSR Agreement if an alternative becomes available. Attachment Y information is considered confidential unless a reliability issue is identified in the study or the owner has otherwise publicly disclosed the information.

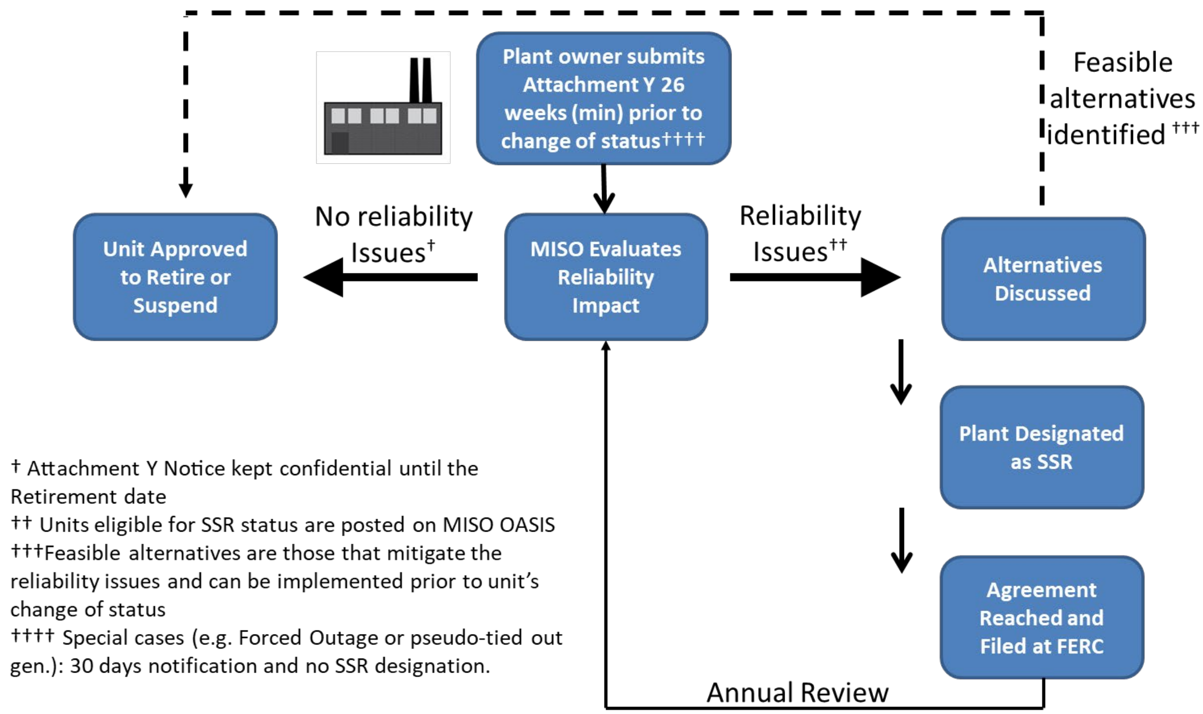

Figure 4.4-4: MISO Attachment Y process

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4.5 Generation Deliverability Results

MISO performs generator deliverability analysis as a part of the MTEP18 process to ensure continued deliverability of generating units with firm service, including Network Resource Interconnection Service (NRIS). Results of the assessment are based on an analysis of near-term (five-year) summer peak scenario.

Analysis results revealed five constraints that restrict existing deliverable amounts in the MTEP18 near-term scenario (Table 4.5-1).

A total of three projects were identified to alleviate identified congestion

Constraints observed that restrict generation beyond the established network resource amounts will be mitigated. MTEP projects have been identified for the mitigation required to alleviate the constraints identified within MISO; external constraints will be validated and the mitigation coordinated with the appropriate system.

Table 4.5-1 shows the preliminary list of constraints requiring mitigation. These constraints, and their associated mitigation, will be discussed throughout the MTEP19 study process.

- “Overload Branch” is caused by bottling-up of aggregate deliverable generation
- “Area” is the Transmission Owner of the facility

Overloaded Branch	Area
Plaisance 138 kV – Champagne 138 kV	EES / CLECO
Addis 230 kV – Tiger 230 kV	EES
Tezcuco 230 kV – Frisco 230 kV	EES
Batesville 161 kV – Tallhache 161 kV	TVA
Batesville 161 kV – Batesville 161 kV	TVA

Table 4.5-1: MTEP18 Near-term Preliminary Constraints that Limit Deliverability

FERC Order 2003 mandates that “Network Resource Interconnection Service provides for all of the network upgrades that would be needed to allow the Interconnection Customer to designate its Generating Facility as a Network Resource and obtain Network Integration Transmission Service. Thus, once an Interconnection Customer has obtained Network Resource Interconnection Service, any future transmission service request for delivery from the Generating Facility would not require additional studies or Network Upgrades”[17] to be funded by the Interconnection Customer.

Constraints recognized as needing mitigation were identified in the 2023 scenario (Figure 4.5-1). Deliverability was tested only up to the granted network resource levels of the existing and future network resource units modeled in the MTEP18 2023 case. No new interconnection service is granted through the

[17] FERC Order 2003 Final Rule, paragraph 756: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=9746398

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annual MTEP deliverability analysis. Changes to aggregate deliverability could be caused by changes in load and transmission topology.

The total MW restricted varies in the near term and is summarized by Local Resource Zone (Figure 4.5-2).

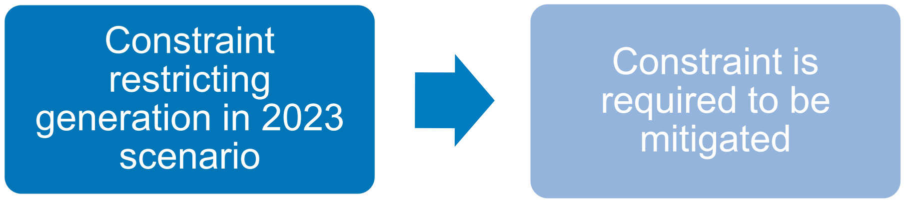
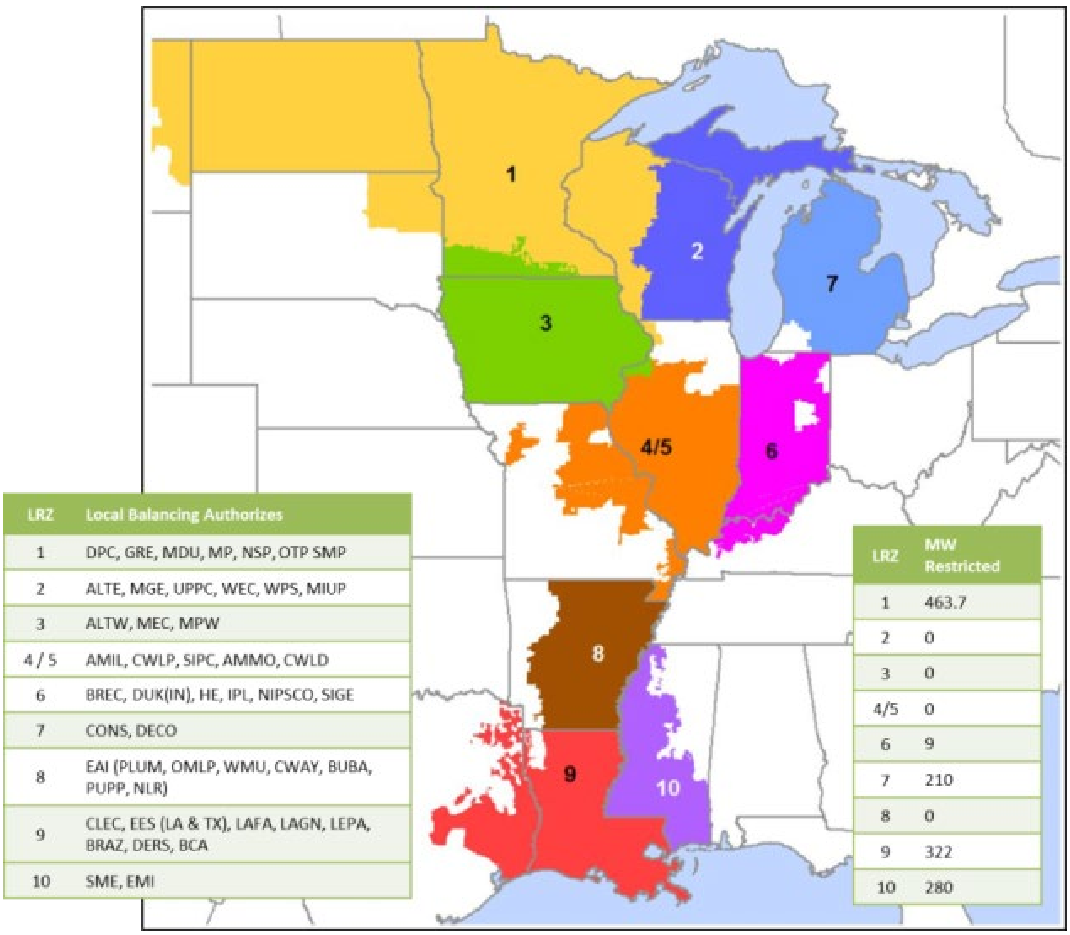


Figure 4.5-1: MTEP Deliverability Study Process Overview



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4 / 5	AMIL, CWLP, SIPC, AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI (PLUM, OMLP, WMU, CWAY, BUBA, PUPP, NLR)
9	CLEC, EES (LA & TX), LAFA, LAGN, LEPA, BRAZ, DERS, BCA
10	SME, EMI

LRZ	MW Restricted
1	463.7
2	0
3	0
4/5	0
6	9
7	210
8	0
9	322
10	280

Figure 4.5-2: Local Resource Zones (LRZ)

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MTEP18 Mitigation

MTEP18 near-term (five-year) summer peak deliverability analysis results showed constraints that require mitigation. Preliminary mitigations submitted to alleviate limitation are shown in Table 4.5-2. These projects, along with any other mitigation identified for the constraints, will be reviewed by stakeholders in the MTEP19 planning process and recommended for approval as appropriate. A mitigation stated as TBD already has verbal mitigation submitted with project submission pending. MISO will continue to evaluate and coordinate with Tennessee Valley Authority (TVA) to resolve the constraints seen on TVA's system.

Overloaded Branch	Area	Mitigation (MTEP ID)	Notes
Plaisance 138 kV – Champagne 138 kV	EES / CLECO	15584	Mitigated by Targeted Appendix A in MTEP19
Addis 230 kV – Tiger 230 kV	EES	15566 13894	Mitigated by Targeted Appendix A in MTEP19
Tezcuco 230 kV – Frisco 230 kV	EES	15605	Mitigated by Targeted Appendix B in MTEP19

Table 4.5-2: Preliminary projects to alleviate constraints that limit deliverability of network resources

MTEP17 Mitigation

MTEP17 near-term (five-year) summer peak deliverability analysis results showed four constraints that require mitigation. Mitigation was submitted for each of these constraints to alleviate limitation. Table 4.5-3 shows the projects provided for each of the four constraints requiring mitigation.

Overloaded Branch	Area	MW Restricted	Mitigation (MTEP ID)
Nashwauk 115 – 14L Tap 115 kV	MP	189.68	9646
Esso 230 – Delmont 230 kV	EES	16.47	9793
Star 115 kV – Mendenhall 115 kV	EES	116.47	13865
Lewis 138 kV – Sheawill 138 kV	EES	204.9	13864
Sheawill 138 kV – FW Pipe 138 kV	EES	8.12	13864
GRE Maple 69 kV – GRE Maple 69 kV	GRE	8.76	14145
Pere Marquette 138 kV – Lake County 138 kV	METC	1,157.9	13574

Table 4.5-3: MTEP17 projects submitted to alleviate constraints that limited deliverability of network resources during that cycle

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4.6 Long Term Transmission Rights Analysis Results

MTEP evaluates the ability of the transmission system to fully support the simultaneous feasibility of Long Term Transmission Rights (LTTR). To that effect, MISO performs an annual review of the drivers of the LTTR infeasibility results from the most recent annual Auction Revenue Rights (ARR) Allocation and determines the sufficiency of MTEP upgrades to resolve this infeasibility.

LTTRs are Auction Revenue Rights (ARR) allocated in the Stage 1A of the Annual ARR Allocation process. These LTTRs carry annual rollover rights lasting 10 years or more.

MISO details the financial uplift associated with infeasible LTTRs for its regions (Table 4.6-1) and documents planned upgrades that may mitigate the drivers of LTTR infeasibility identified using the annual Financial Transmission Rights (FTR) auction models (Table 4.6-2).

As part of the annual Auction Revenue Rights (ARR) allocation process, MISO runs a simultaneous feasibility test to determine how many ARRs, in megawatts, can be allocated. This test determines to what extent LTTRs granted the prior year can be allocated as feasible LTTRs in the current year. The remaining unallocated LTTRs are deemed infeasible, and their cost is uplifted to the LTTR holders.

For the 2018-2019 planning year, the total LTTR payment is $387.5 million. The LTTR infeasibility uplift ratio is 2.93 percent (Table 4.6-1).

Region	Total Stage1A (GW)	Total LTTR Payment ($M) (including infeasible uplift)	Total Infeasible Uplift ($M)	Uplift Ratio
MISO-wide	$440.6	$387.5	$13.0	2.93%

Table 4.6-1: Uplift costs associated with infeasible LTTR in the 2017 Annual ARR Allocation

Infeasibility in any annual allocation of LTTRs can occur due to near-term conditions and their impact on the ARR allocation models. However, as MTEP projects are completed, reliability limits are eliminated and economic congestion is reduced across the transmission system. This provides for the more reliable and efficient use of resources associated with LTTRs in general, resulting in reduced infeasibility of financial transmission rights over time.

Mitigations associated with limited LTTR feasibility are included where planned mitigation has been identified. in Table 4.6-2. Binding constraints are filtered for those with values greater than $200,000. Other constraints will continue to be monitored in the annual allocation process for feasibility status. MISO will coordinate with its Transmission Owners to investigate constraints in the MTEP18 planning cycle. Additionally, MISO will coordinate with adjacent regional transmission organizations on seams constraints.

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Constraint	Summer 2018	Fall 2018	Winter 2018	Spring 2019	Grand Total	Planned Mitigation
NSES - RAM452 161 FLO BLACKBERRY - NEOSHO 345	$252,145	$453,889	$259,777	$545,135	$1,510,946	N/A- Outside of MISO planning scope
GIBSON - PETERSBURG 345 FLO GIBSON - FRANCIS CREEK 345	$987	$727,536	$-	$26,415	$754,939	N/A
NASHUA T1_H 345/1 FLO NASHUA - HAWTHORN 345	$-	$234,736	$146,801	$223,077	$604,614	N/A- Outside of MISO planning scope
LONGMIRE - PONDER 138 FLO CONROE BULK - PONDER 138	$171,175	$314,655	$-	$-	$485,830	MTEP Project 12090 - Reconductor/rebuild to 1950A. ISD: 06/2021
WAPELLO TR92 161/69 FLO HILLS - MONTEZUMA 345	$224,718	$9,001	$107,201	$93,736	$434,657	N/A
STAUNTON - 08ALEN JUNCTION 138 FLO BLOOMINGTON E - BLOOMCIN H 230	$1,021	$326,693	$61,859	$22,781	$412,354	N/A
BOGALUSA AT3 500/230 FLO FRANKLIN - MCKNIGHT 500	$115,480	$-	$258,125	$29,235	$402,840	N/A
GRIMES - MT ZION 138 FLO HARTBURG - CYPRESS 500	$19,574	$129,400	$101,210	$94,314	$344,498	MTEP Project 10487 - Western Region Economic Project(WREP): New Grimes to Lewis Creek 230 kV Line, New Grimes 345/230 kV Auto, & Newton Bulk to Leach 138 kV reconductor ISD 06/2020
MT ZION - LN485 138 FLO GRIMES - PONDER 230	$-	$-	$62,641	$221,709	$284,350	MTEP Project 10487 -- Western Region Economic Project(WREP): New Grimes to Lewis Creek 230 kV Line, New Grimes 345/230 kV Auto, & Newton Bulk to Leach 138 kV reconductor ISD 06/2020

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Constraint	Summer 2018	Fall 2018	Winter 2018	Spring 2019	Grand Total	Planned Mitigation
FRANKLIN - BOGALUSA 500 FLO FRANKLIN - MCKNIGHT 500	$-	$88,147	$-	$191,725	$279,872	N/A
ARK NU - PLEASANT HILL 500 FLO ARK NU - MABELVALE 500	$-	$155,786	$84,647	$-	$240,432	8041 Replace Terminal equipment to increase line rating ISD 04/2017
SHADELAND - LAFAYETTE 138 FLO 08NW TAP - W LAFAYETTE 138	-$7,358	$182,743	$2,826	$60,152	$238,361	N/A
MARBLEHEAD N 161/138 TR1 FLO MAYWOOD-HERLEMAN 345	$56,311	$67,579	$56,657	$56,546	$237,092	N/A
BATESVILL - HUBBLE 138 FLO TRIMBLE COUNTY - CLIFFY CREEK 345	$-	$218,794	$-	$-	$218,794	N/A
GRIMES - MT ZION 138 FLO GRIMES AT4 345/230	$214,178	$-	$-	$-	$214,178	MTEP Project 10487: Western Region Economic Project(WREP): New Grimes to Lewis Creek 230 kV Line, New Grimes 345/230 kV Auto, & Newton Bulk to Leach 138 kV reconductor
GRIMES - MT ZION 138 FLO GRIMES - BENTWATER 138	$-	$153,135	$58,097	$-	$211,232	MTEP Project 10487: Western Region Economic Project(WREP): New Grimes to Lewis Creek 230 kV Line, New Grimes 345/230 kV Auto, & Newton Bulk to Leach 138 kV reconductor

Table 4.6-2: Infeasible Uplift Breakdown by Binding Constraints from the 2018 Annual FTR Auction

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Section 5: Economic Analysis

5.1 Economic Analysis Introduction

The MISO Value-Based Planning Process endeavors to develop transmission expansion plans that minimize total electric costs; maintain an efficient market; and enable state and federal public energy policy — all while maintaining adequate system reliability.

The objective of MISO's value-based planning approach is to develop cost-effective transmission plans while maintaining system reliability. Cost-effectiveness considers not only the capital cost of transmission projects but also the projected cost of energy (production cost) and generation capacity.

MISO's Value-Based Planning Process ensures the benefits of an economically efficient energy market are available to customers by identifying transmission projects that provide the highest value

MISO previously performed a generator outlet study that provided extensive information for determining an optimal balancing point between transmission investment and generation production costs. The study determined that expansion plans that minimized transmission capital costs, but had high production costs through the use of less-efficient local generation resources, yielded the highest total system cost. Similarly, it was found the same high cost was present with expansion plans that minimized generation costs by siting generation optimally, but away from load centers, and invested heavily in regional transmission development. The MISO Value-Based planning approach incorporates multiple perspectives by conducting reliability and economic analyses (Figure 5.1-1).

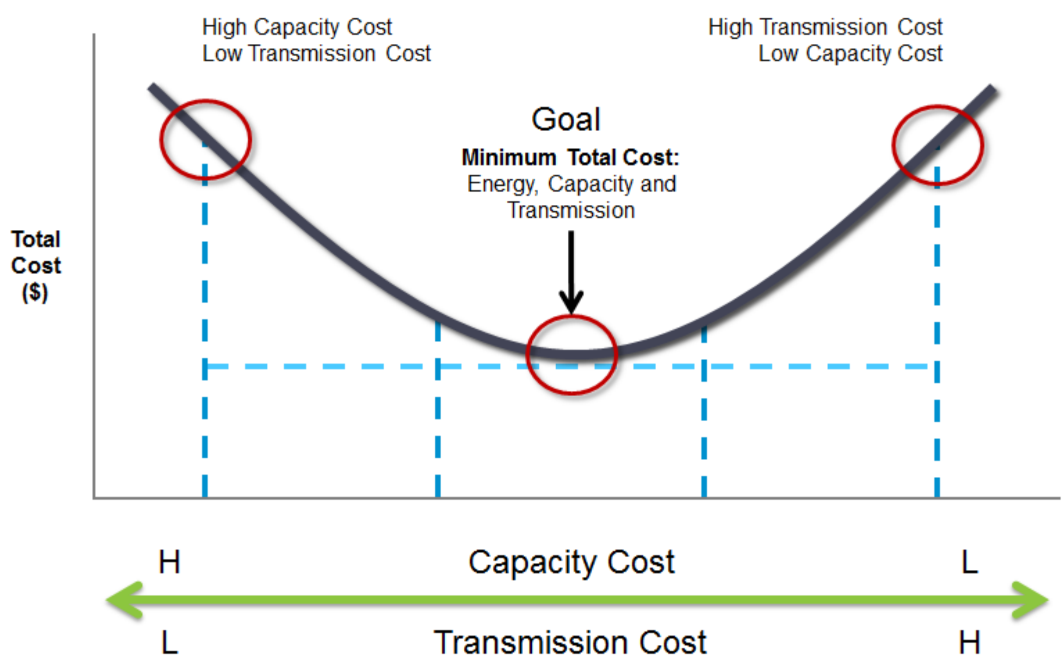

Figure 5.1-1: The goal of the MISO Value-Based Planning Process

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Since MTEP06, the MISO planning process has used multiple future scenarios to model out-year policy and economic and social uncertainty. While MISO's analysis may influence market participants' out-year resource plans, MISO is not a regional resource planner. Instead MISO's futures provide multiple reasonable resource forecasts based on probable out-year conditions including, but not limited to: fuel costs; fuel availability; environmental regulations; demand and energy levels; and available technology. Regional resource forecasts are developed based on a least-cost methodology. Generation and demand-side management resources are geographically sited based on a stakeholder resource planning vetted hierarchy. MISO regional resource forecasts include the consideration of thermal units, intermittent resources, demand-side management, and energy efficiency programs. These regional forecasts ensure that out-year planning reserve margins are maintained.

Policy assessment requires a continuous dialogue between MISO, local entities and regulatory bodies. This dialogue must identify new and existing policies and discuss how local entities intend to comply with them. It should also identify any potential regional needs or solutions to policy-driven issues. State and federal energy policy requirements and goals are the primary drivers and the first step of MISO's Value-Based Planning Process.

Value-Based Planning Process

The objective of MISO's Value-Based Planning Process is to develop the most robust plan under a wide variety of economic and policy conditions as opposed to the least-cost plan under a single scenario. While the best transmission plan may be different in each policy-based future scenario, the best-fit transmission plan — or most robust — against all these scenarios should offer the most value towards supporting the future resource mix.

A planning horizon of at least 15 years is needed to accomplish long-range economic transmission development, since it is common for large projects to take 10 years to complete. Performing a credible economic assessment over this time is a challenge. Long-range resource forecasting, powerflow and security-constrained economic dispatch models are required to extend to at least 15 years. Since no single model can perform all of the functions for integrated transmission development, the Value-Based Planning Process integrates multiple study techniques using the best software available, including:

- Energy Planning – PROMOD and PLEXOS
- Reliability Planning – PSS/E, POM, TSAT and TARA
- Decision Analysis – GE-MARS, PROMOD and EGEAS
- Strategic Planning – EGEAS
- Resource Portfolio Development – EGEAS

MISO's Value-Based Planning Process is also known as the Seven-Step Planning Process (Figure 5.1-2). While the Value-Based Planning Process is chronologically sequenced, not all projects start at Step 1 and end at Step 7. For example, depending on scope, a project may begin with pre-existing assumptions or plans and therefore start in Steps 4 or 5. Generally, Steps 1 and 2 are performed only annually. The Value-Based Planning Process is cyclical, and therefore the outputs and project approvals from one cycle are used as inputs in the next cycle. Additionally, the Step 7 to Step 1 link serves as the bridge between planning and operations to refresh assumptions based on approved projects.

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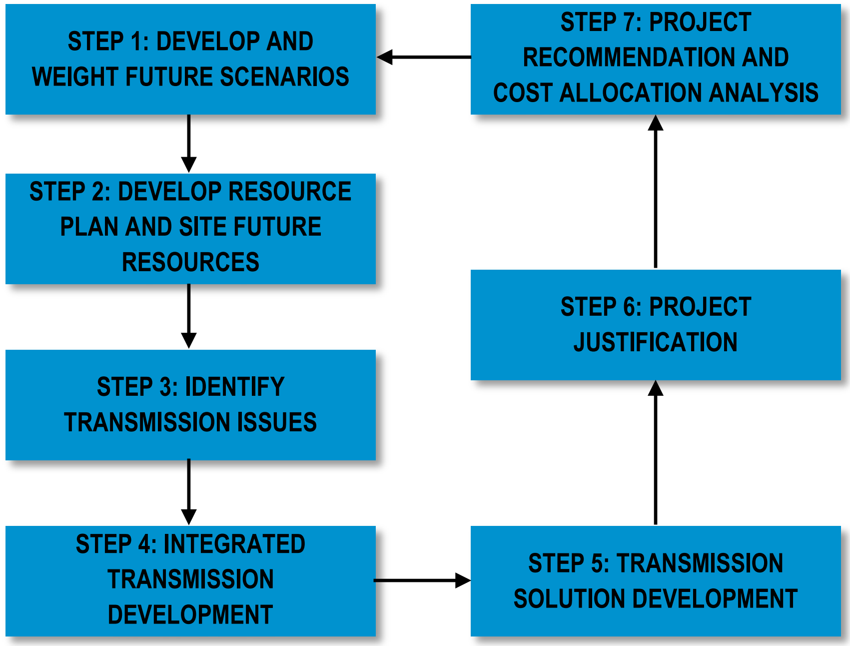

Figure 5.1-2: MISO's Value-Based, Seven-Step Planning Process

Step 1: Develop and Weight Future Scenarios

Scenario-based analysis provides the opportunity to develop plans for different future scenarios. A future scenario is a postulate of what could be, which guides the assumptions made about a given model. The outcome of each modeled future scenario is a generation expansion plan, or resource portfolio. Resource portfolios identify the least-cost generation required to meet reliability criteria based on the assumptions for each scenario.

Future scenarios and underlying assumptions are developed annually and collaboratively with stakeholders through the Planning Advisory Committee. The goal is a range of futures, linked to likely real-life scenarios that provide an array of outcomes that are significantly broad, rather than a single expected forecast.

A more detailed discussion of the assumptions and methodology around the MTEP18 future scenarios is in Section 5.2: MTEP Future Development.

Step 2: Develop Resource Plan and Site Future Resources

Resources forecasted from the expansion model for each of the future scenarios are specified by fuel type and timing; however, these resources are not site-specific. Future resource units must be sited within all planning models to provide an initial reference position five to 20 years into the future. Completing the process requires a siting methodology tying each resource to a specific bus in the powerflow model. A guiding philosophy and rule-based methodology, developed in conjunction with industry expertise, is used to site forecasted resources. The siting of regional resource forecast units is reviewed annually by the Planning Advisory Committee. A more detailed discussion of the siting methodology around each MTEP18 future is in Section 5.2: MTEP Future Development.

Step 3: Identify Transmission Issues

A key component of value-based transmission planning is the identification of transmission issues. In most cases, transmission issues addressed by value-based planning include economic value opportunities and public policy compliance issues. Economic value opportunities typically include

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transmission congestion issues where solutions are desired to eliminate costly redispatch. In the value-based planning process, these congestion issues are identified in a bifurcated process using a) a list of top congested flowgates derived from Market Congestion Planning Studies and b) a range of economic opportunities derived from indicative congestion relief analysis for each defined Future.

This analysis typically includes simulation of a non-constrained case and a constrained case, where the non-constrained case relaxes transmission constraints and the constrained case enforces transmission constraints. This analysis reveals such information as total congestion costs, congestion costs by constraint, and geographic-based congestion patterns. This data can be used to inform the value-based planning process both at a high and low level. The low-level view tends to identify specific constraints and data associated with those constraints such as shadow prices, binding hours and binding levels. The lower-level view is often considered alongside the historic congestion data. The high-level view provides insight into geographic pricing and congestion patterns for potential corridors for new transmission development.

Step 4: Integrated Transmission Development

After transmission issues are identified, stakeholders will be given the opportunity to submit solutions to these issues. The solution submission window typically opens in the January/February timeframe and lasts for six to eight weeks. Solution ideas are used to inform the planning process. MISO, while working with stakeholders, may modify solution ideas throughout the value-based planning process.

MISO may also submit its own solution ideas to address transmission issues. MISO will continue to work with stakeholders to ensure solutions properly address any transmission issues.

Step 5: Transmission Solution Evaluation

The first step in transmission solution evaluation is to screen each of the transmission solution ideas. Projects that meet a pre-defined threshold (typically a 0.9 benefit-to-cost ratio) are evaluated further. These projects then undergo a full present value analysis, which utilizes all modeled years and future assumptions to come up with a future weighted benefit-to-cost ratio. Projects that still perform well through this phase then undergo contingency screening to identify any new flowgates that may be needed because of the project. Any new flowgates that are identified will be added to the project's event files and a full present value analysis will be conducted again to see how much of an impact the new flowgates have on a project's benefits. This process can be iterative, especially as transmission solutions evolve.

Detailed reliability analysis is required to identify additional issues that may be introduced by the long-term transmission plans developed through economic assessment. These plans may need to be adjusted to ensure system reliability. Reliability analyses will address NERC standards and local planning criteria and may include, but are not limited to, powerflow, transient and voltage stability, and short circuit. Additionally, the reliability assessment determines the reliability-based value contribution of the long-term plans. As value-driven regional expansions are justified, traditionally developed intermediate-term reliability plans may be affected. The combined impact of both reliability and value-based planning strategies must be fully understood in order to further the development of an integrated transmission plan.

Once robustness testing has been conducted, it may be necessary to develop appropriate portfolios of transmission projects to complete the overall, long-term plan. One key consideration in consolidating and sequencing plans is the need to maintain flexibility in adapting to future changes in energy policies. To create a transmission infrastructure that will support changes to resources and market requirements with the least incremental investment and rework, a comprehensive plan, which offers the most benefit under all outcomes, is developed from elements of the best-performing preliminary plan.

Step 6: Project Justification

A business case will be created for all projects including a detailed analysis of benefits and costs. While the project justification is continuously developed throughout the solution evaluation step, additional scenarios or sensitivities may be developed that evaluate the impact certain future assumptions may have on a project. These sensitivities help to ensure that the projects that proceed to recommendation are robust. These sensitivities may include, but are not limited to, changes in generation siting and future retirement assumptions. Additional sensitivities are developed with the input and guidance of stakeholders throughout the process.

Step 7: Project Recommendation and Cost Allocation Analysis

MISO, with input from stakeholders and considering all analysis performed to determine benefits and costs, will recommend projects to the MISO Board of Directors for approval. This recommendation will be only for those projects that meet or exceed all criteria for the type of project recommended. Projects meeting or exceeding all project type criteria will be recommended to the MISO Board of Directors in the last quarter of each MTEP cycle, or as otherwise defined in the MISO Tariff.

MISO employs a collection of cost allocation mechanisms that seek to match the costs of transmission investment to those who benefit from that investment (Table 5.1-1). In general, the cost allocation method is dependent on whether the transmission is needed to maintain reliability, improve market efficiency, interconnect new resources and/or support energy policy mandates and goals. Cost allocation mechanisms are developed and revisited in a collaborative and open stakeholder process through the Regional Expansion Criteria and Benefits (RECB) Working Group.

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Allocation Category	Driver(s)	Allocation to Beneficiaries
Market Efficiency Project	Reduce market congestion when benefits exceed costs by 1.25 times	Distributed to Cost Allocation Zones commensurate with expected benefit; 345 kV and above 20 percent postage stamp to load
Transmission Delivery Service Project	Transmission Service Request	Generally paid for by transmission customer; Transmission Owner can elect to roll-in into local zone rates
Generation Interconnection Project	Interconnection Request	Primarily paid for by requestor; 345 kV and above 10 percent postage stamp to load
Multi-Value Project	Address energy policy laws and/or provide widespread benefits across footprint	Postage stamp to load
Market Participant Funded	Transmission Owner-identified project that does not qualify for other cost allocation mechanisms; can be driven by reliability, economics, public policy or some combination of the three	Paid for by market participant
Baseline Reliability Project	NERC Reliability Criteria	Local pricing zone

Table 5.1-1: Summary of MISO Cost Allocation mechanisms

MISO's Value-Based Planning Process continues to evolve to better integrate different planning functions, take advantage of new technology and meet stakeholder needs, in both scope and complexity. Enhancements to the existing value-based planning process to accommodate Order 1000 requirements have been identified and implemented through a robust stakeholder process, including:

- Identification and selection of transmission issues through a multifaceted needs assessment up front, encompassing both public policy needs and economic congestion issues/opportunities
- Open and transparent transmission solution idea solicitation with a formalized form to document and track solutions
- Development of an integrated transmission development process to categorize issues identified, screen solution ideas, refine solution ideas and formulate most-cost-effective projects

In MTEP18, MISO's Value-Based Planning Process is exemplified in the MTEP Future Development (Section 5.2), and Market Congestion Planning Study (Section 5.3).

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5.2 MTEP Futures Development

MTEP future scenario-based analysis provides the basis for developing robust, reliable, value creating transmission plans. MTEP futures are a stakeholder-driven postulate of what the industry landscape could be in the 10-20 year planning horizon. With the increasingly interconnected nature of utilities, electric industry organizations, and state and federal interests, forecasting a range of plausible futures greatly enhances the robustness of the planning process for electric infrastructure. The futures development process provides information on the bulk-electric-system impacts of varying load growth, environmental legislation, fuel-price variability, renewable development, demand-side management programs, energy storage, legislative decisions and many other potential scenarios.

The goal of the MTEP futures is to bookend uncertainty by defining a wide range of potential plausible outcomes. Futures are intended to be long-term and consider not only outcomes that could come to be within the next five years, but also plan for uncertainty that could affect our industry through the next 15 years. To accomplish this goal, MISO, in coordination with stakeholders, updated the three previous MTEP17 Futures while adding a fourth Distributed and Emerging Technologies future, to consider emerging technology trends (Table 5.2-1).

MTEP18 Future	Limited Fleet Change	Continued Fleet Change	Accelerated Fleet Change	Distributed & Emerging Technologies
Demand and Energy	Low (10/90) High LRZ9 Industrial	Base (50/50)	High (90/10) Low LRZ9 Industrial	Base + EV *Energy: 1.1%* *Demand: 0.6%*
Fuel Prices	Gas: Base -30% Coal: Base -3%	Base	Gas: Base +30% Coal: Base	Base
Demand Side Additions *By Year 2032*	EE: - GW DR: 2 GW	EE: - GW DR: 3 GW	EE: 5 GW DR: 4 GW	EE: 2 GW DR: 3 GW Storage: 2 GW
Renewable Additions *By Year 2032* *(% Wind and Solar Energy)*	10%	15%	30%	20%
Generation Retirements[1] *By Year 2032*	Coal: 9 GW Gas/Oil: 17 GW	Coal: 17 GW Gas/Oil: 17 GW	Coal: 17 GW+ Gas/Oil: 17 GW	Coal: 17 GW Gas/Oil: 17 GW Nuclear: 2 GW
CO_2 Reduction Constraint *From Current Levels by 2032*	None	None	20%	None
Siting Methodology[2]	MTEP Standard	MTEP Standard	MTEP Standard	"Localized"

EV: Electric Vehicles EE: Energy Efficiency DR: Demand Response

1. In Accelerated Fleet Change Scenario 17 GW of coal retired instead of the 24 GW in the MTEP17 Accelerated Alternative Technologies Future. Instead of additional retirements, must-run was removed and coal units run only seasonally five years before their retirement date.
2. "Localized" renewable siting assumes that at least 50 percent of incremental wind and solar energy will be sourced within each Local Resource Zone. Two-thirds of solar sited as distributed.

Table 5.2-1: MTEP18 Key Attributes

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Futures Narratives

Limited Fleet Change (LFC)

Existing generation fleet remains relatively static without significant drivers of change. Some coal fleet reductions are expected as units reach the end of their useful life. Renewable additions are driven solely by current Renewable Portfolio Standards under low demand and energy growth rates.

- Footprint wide, demand and energy growth rates are low; however, as a result of low natural gas prices, industrial load along the Gulf Coast increases.
- Natural gas prices are low due to increased well productivity and supply chain efficiencies along with low demand and energy growth.
- Low demand and energy and natural gas prices reduce the demand for and economic viability of new generation technologies.
- Thermal generation retirements are driven by unit useful life limits. Nuclear units are assumed to have license renewals granted and remain online.
- Lower levels of demand-side management programs are assumed due to low demand and energy growth.

Continued Fleet Change (CFC)

The fleet evolution trends of the past decade continue. Coal retirements reflect historical retirement levels based on average age of retirement. Renewable additions continue to exceed current Renewable Portfolio Standard Requirements as a result of economics, public appeal, and the potential for future policy changes. Natural gas reliance increases as a result of new capacity needed to replace retired coal capacity.

- Demand and energy growth rates are modeled at a level equivalent to a 50/50 Module E forecast.
- Natural gas prices are consistent with industry long-term reference forecasts.
- Renewable additions continue along current trends. Wind and solar serve 15 percent of MISO energy by 2032.
- Maturity cost curves for renewable resources reflect some advancement in technology and supply chain efficiencies.
- Oil and gas generators retired at the useful life limit age. Coal units will be retired reflecting age and historical retirements in advance of age limits. Nuclear units are assumed to have license renewals granted and remain online.
- Demand-side management programs modeled to reflect growth and technical potential of current programs.

Accelerated Fleet Change (AFC)

A robust economy with increased demand and energy drives higher natural gas prices. Carbon regulations targeting a 20 percent reduction from current levels are enacted in response to increased demand and energy driving coal to decrease production. Increased renewable additions are driven beyond renewable portfolio standards by need for new generation, technological advancement, and carbon regulation. Natural gas reliance increases as a result of new capacity needs driven by the need to replace retired capacity and provide flexibility to support the integration of intermittent renewable resources.

- Demand and energy grows at a high rate due to a robust economy; however, as a result of high natural gas prices, industrial load along the Gulf Coast decreases.
- Natural gas prices are high due to increased demand.

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- Thermal retirements, economics, and potential regulations drive renewable additions. Maturity cost curves for renewable technologies applied reflecting greater technological advancement.
- Oil and gas generators will be retired in the year the age limit is reached. Coal units will be retired reflecting age and historical retirements in advance of age limits. Nuclear units are assumed to have license renewals granted and remain online.
- A 20 percent carbon reduction for current levels is modeled to reflect future national or state-level carbon regulation.
- High demand and energy levels and carbon regulation drive greater potential for demand-side management programs.

Distributed and Emerging Technologies (DET)

Fleet evolution trends continue, primarily driven by local policies and emerging technology adoption. State level policies reflect desires for local reliability and optionality. Coal retirements reflect historical retirement levels based on average age of retirement. Increased renewable additions are driven by favorable economics resulting from technological advancements and state-level renewable portfolio standards and goals with targeted increases in distributed solar. Natural gas reliance increases as a result of new capacity needs driven by load growth largely driven by electric vehicles, the need to replace retired capacity and provide flexibility to support the integration of intermittent renewable resources.

- Demand and energy forecast begins with level equivalent to a 50/50 Module E forecast and has high growth rate to reflect adoption of electric vehicle technology on a broader scale. Energy grows faster than demand reflecting smart-charging of electric vehicles.
- Natural gas prices are consistent with industry long-term reference forecasts.
- Maturity cost curves for renewable technologies applied reflecting advancement in technologies and supply-chain efficiencies. Renewable additions reach about 20 percent of MISO energy by 2032; increase from 15 percent in Continued Fleet Change Future driven primarily by solar.
- Increased deployment of energy storage devices driven by economies of scale resulting from commercial mass production of lithium ion batteries and other viable technologies.
- Oil and gas generators will be retired in the year the age limit is reached. Coal units will be retired reflecting age and economics. Nuclear units are assumed to retire at license expiration dates.
- Demand-side management programs modeled to reflect growth and technical potential of current programs.

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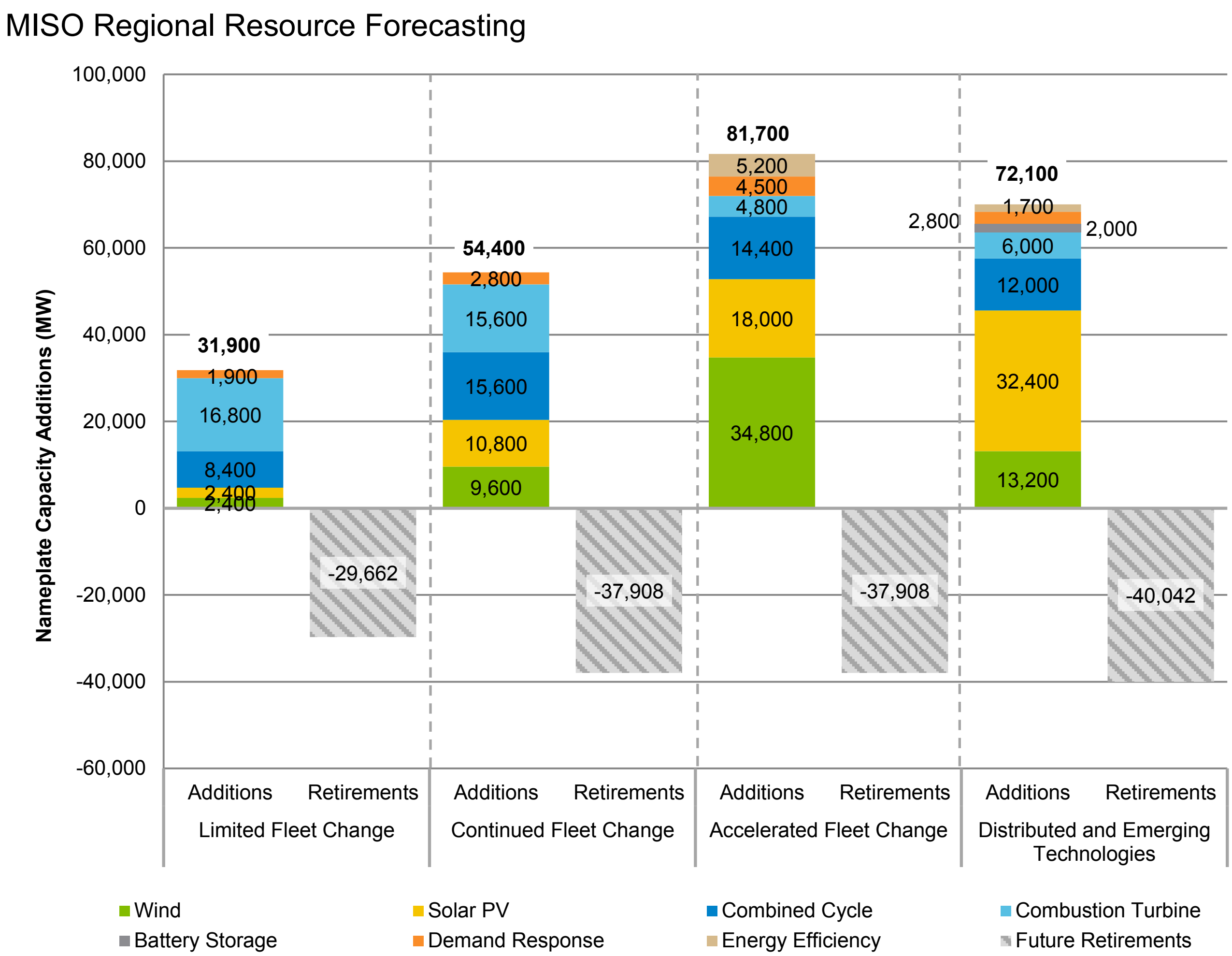

Figure 5.2-1: Forecasted MISO Capacity Expansion under the MTEP18 Futures (2017 – 2032)

MTEP18 futures result in various levels of resource additions and retirements displayed in Figure 5.2-1. Results are reflective of the retirement, load-growth, renewable levels and emissions constraints applied.

Limited Fleet Change resources added are a direct result of the lower demand and energy growth assumption and lower assumed age-related retirements. Renewables are only added to meet RPS requirements, achieving 10 percent wind and solar energy. Selection of combustion turbines over combined cycles reflects a lower gas price and the need for more peaking capacity rather than energy-providing baseload units.

Continued Fleet Change experiences a balanced buildout of gas units and renewables to reflect fleet progression based on historical trends. Wind generation has lower initial cost, selected initially to meet the RPS requirement while solar generation cost declines make it the more favorable selection in later years. Both solar and wind cost trends from the National Renewable Energy Laboratory's Annual Technology Baseline forecasts.

The Distributed and Emerging Technologies future renewables level was set to 20 percent energy highlighting the adoption of more distributed technologies, mainly solar, in a system with high energy

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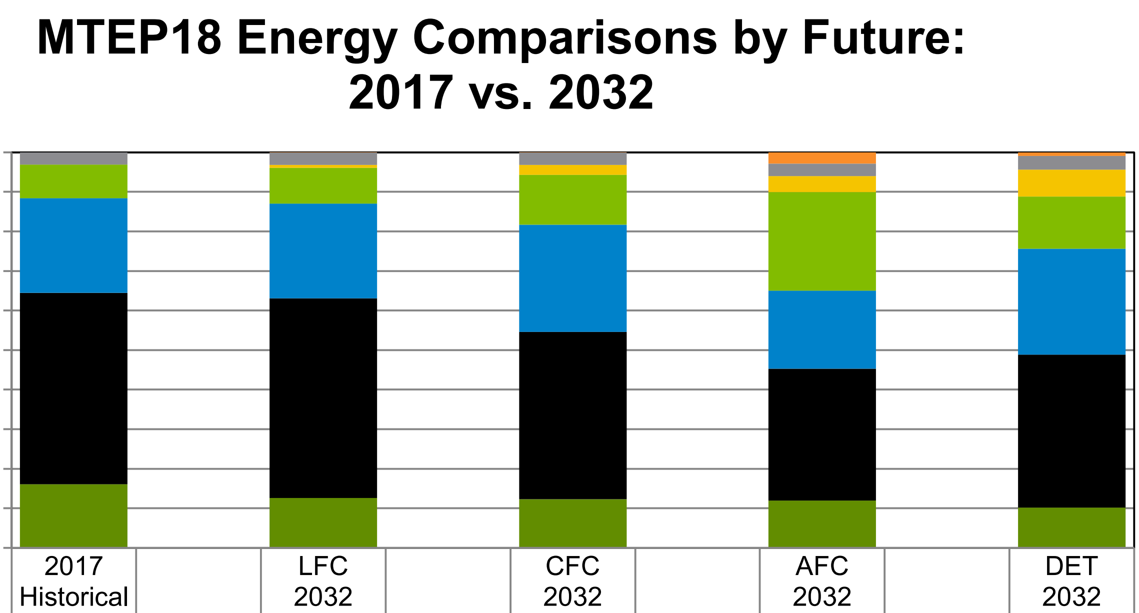
growth from electric vehicle deployment. In this scenario the cost of solar matures more quickly due to faster penetration and adoption of solar technology. Battery storage is also projected within the Distributed and Emerging Technologies future.

Accelerated Fleet Change experiences the greatest increase in renewable additions driven by a 20 percent carbon dioxide reduction from current levels along with more aggressive renewable cost maturity curves. Combined with an increased level of coal retirements and load growth, this scenario achieves 30 percent renewable energy by 2032. Twice as much renewable capacity is required to replace the retired thermal capacity and meet future demand due to the low capacity credits of wind and solar.



	2017 Historical	LFC 2032	CFC 2032	AFC 2032	DET 2032
DSM	0%	0%	0%	3%	1%
Other	3%	3%	3%	3%	3%
Solar	0%	1%	3%	4%	7%
Wind	9%	9%	13%	25%	13%
Gas	24%	24%	27%	20%	27%
Coal	48%	50%	42%	33%	39%
Nuclear	16%	13%	12%	12%	10%

Figure 5.2-2: MTEP18 Futures Energy by Future (2017 vs. 2032)

Figure 5.2-3 shows the energy utilization of the system in year 2017 actuals compared to the forecasts for year 2032 for each of the MTEP18 futures. It can be seen that futures energy consumption trends track with the input assumptions of the respective futures. So LFC with lower renewable energy requirements, coal retirements and lower growth means longer reliance on coal energy because of less fleet change. Going up from there, reliance shifts to more gas and renewables as retirements, load growth, and renewable requirements or carbon dioxide constraints impact fleet dispatch.

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MTEP18 Futures	Gross Growth Rates		Net Growth Rates	
	Demand	Energy	Demand	Energy
Limited Fleet Change	0.3%	0.3%	0.3%	0.3%
Continued Fleet Change	0.5%	0.5%	0.5%	0.5%
Accelerated Fleet Change	0.7%	0.7%	0.4%	0.5%
Distributed and Emerging Technologies	0.6%	1.1%	0.5%	1.0%

Table 5.2-2: Gross and Net Demand and Energy Growth Rates

Table 5.2-2 compares the gross and net demand and energy growth rates by future. Net demand growth rates are a result of the selected energy efficiency programs provided by Applied Energy Group (AEG). Because the base Module E forecasts are apparently net of older, well-established energy efficiency (EE) programs, it was assumed that not all low-cost AEG developed EE programs were available, and so were reduced to not double EE inherent in the forecasts.

Capacity Siting

Generation resources forecasted from EGEAS[18] are specified by fuel type and timing, but these resources are not site specific. The process requires a siting methodology tying each resource to specific buses in the power flow model and represented using the MapInfo Professional Geographical Information System (GIS) software.

MISO's capacity siting, the process used to predict likely locations where future generators will be built, is differentiated by fuel type i.e. the process is tailored differently to site thermal natural gas units and renewable units. The siting process generally utilizes a priority based approach which first identifies sites using the MISO Generator Interconnection Queue, and looks at existing site expansion or replacement, and finally explores greenfield sites. More detailed siting guidelines, methodologies and the results for the other futures are depicted in Appendix E-2 (Figures 5.2-3 through 5.2-6).

[18] Electric Generation Expansion Analysis System: a forecasting tool that uses the future-specific variables to predict economic future generation needs

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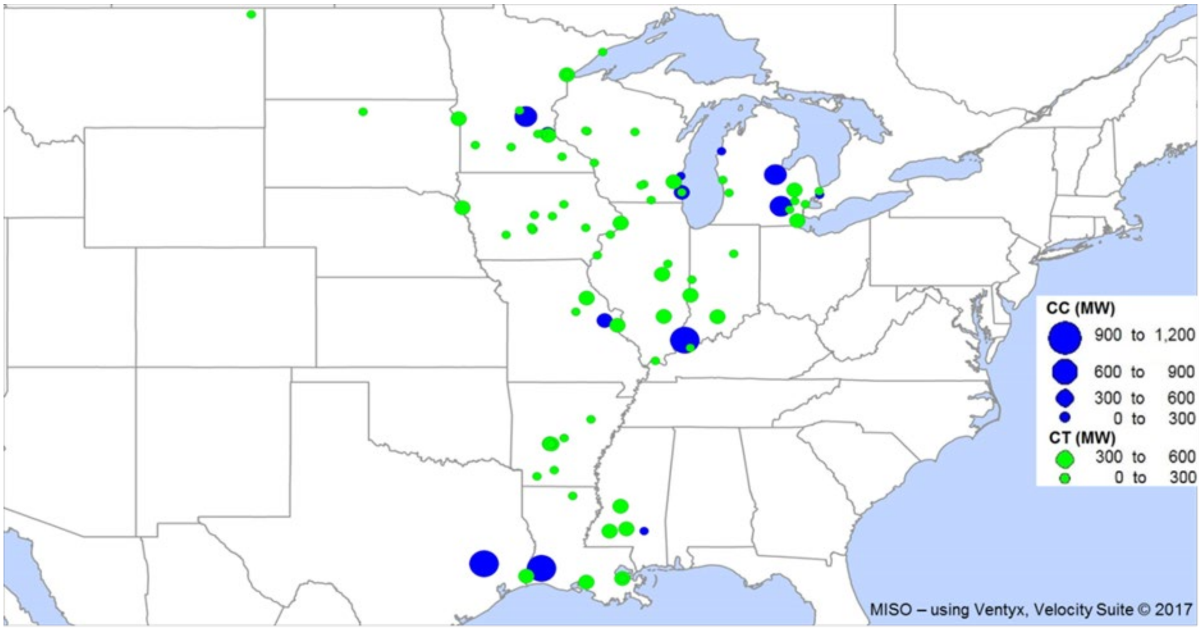

Figure 5.2-3: Limited Fleet Change Thermal Generation Additions Siting Map

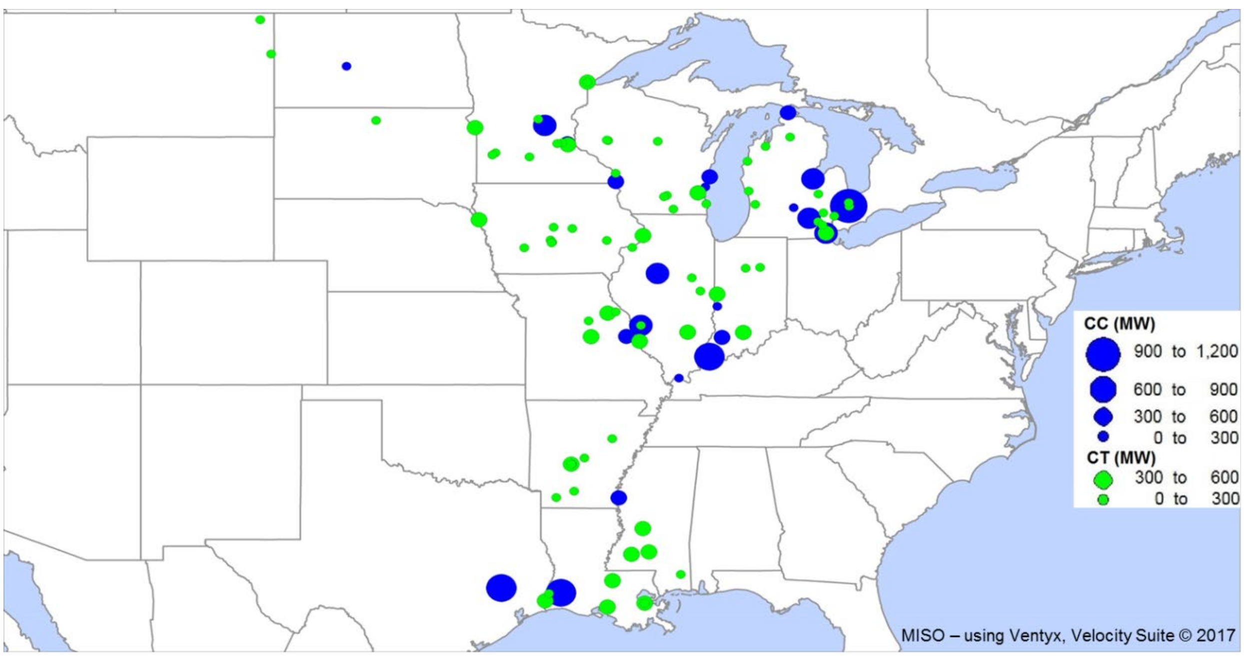

Figure 5.2-4: Continued Fleet Change Future Thermal Generation Additions Siting Map

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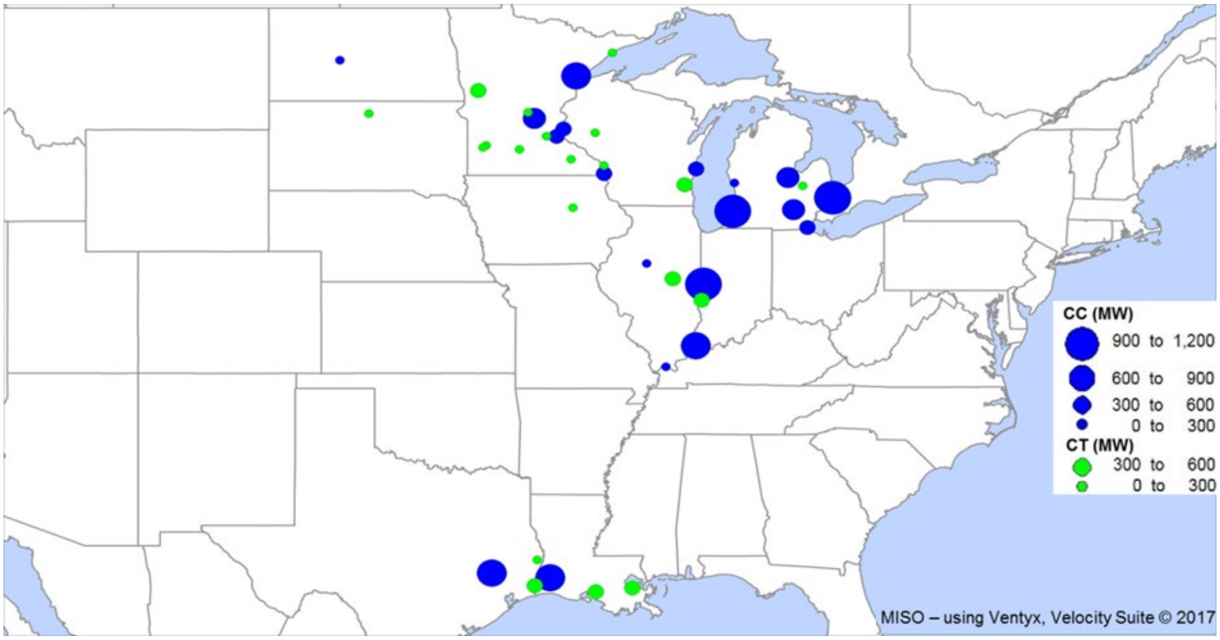

Figure 5.2-5: Accelerated Fleet Change Future Thermal Generation Additions Siting Map

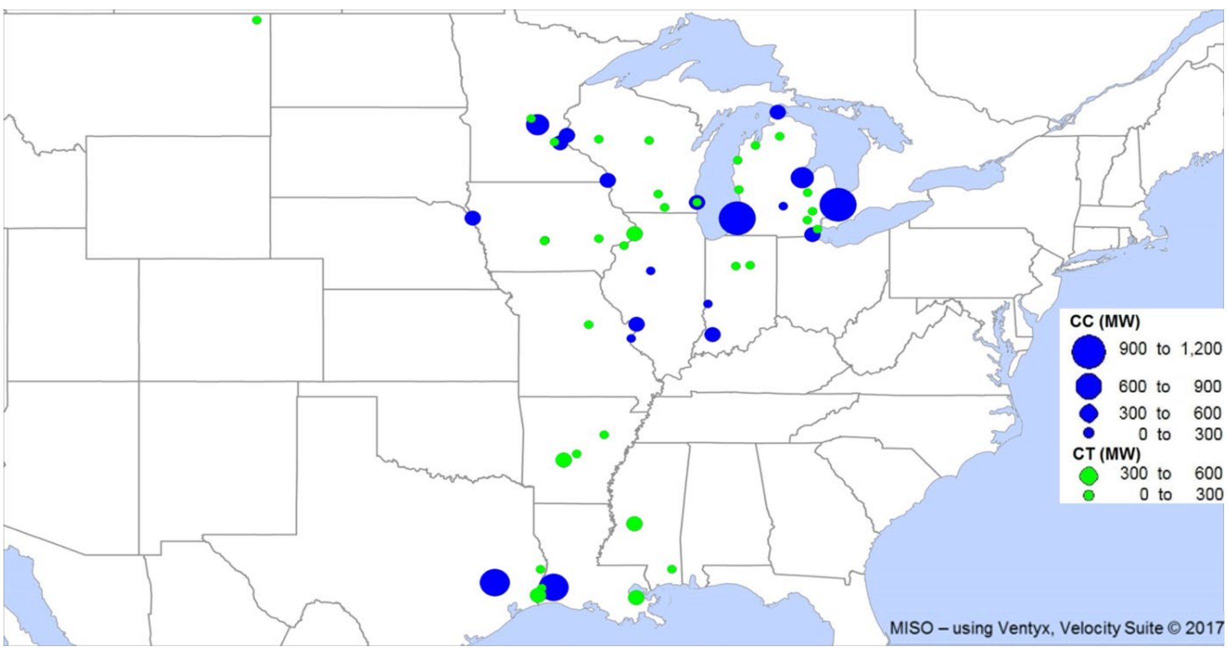

Figure 5.2-6: Distributed and Emerging Technologies Future Thermal Generation Additions Siting Map

5.3 Market Congestion Planning Study

The Market Congestion Planning Study (MCPS) develops transmission plans that offer MISO customers better access to the lowest electric energy costs through the markets. From a regional perspective, the study seeks to identify both near-term transmission congestion and long-term economic opportunities and the appropriate network upgrades to enhance the efficiency of the market. The solutions may therefore vary in scale and scope, classified as either Economic-Other or Market Efficiency Projects. As an integral part of MISO's value-based planning, the MCPS looks to develop the most robust transmission upgrades that offer the highest future value under a variety of both current and projected system scenarios.

A consolidated economic planning effort has been undertaken for the MISO North/Central and South regions in MTEP18 in order to better align the study process across the MISO footprint.

Study Summary: MCPS North/Central Region

In the MISO North/Central MCPS, a total of 13 top congested flowgates in five focus areas were identified based on the level of congestion. The five focus areas are: Dakotas/Minnesota, Wisconsin, Iowa, Northern Indiana and Southern Indiana/Kentucky.

MISO staff and stakeholders collaborated on the development of transmission solutions to mitigate congestion in the five focus areas. Each solution was tested for its robustness to address system needs under a wide variety of scenarios, embodied by the MTEP18 futures. A total of 68 transmission solutions were proposed and studied. Four project candidates were established for further analysis to ensure both economic needs will be met and will not degrade reliability. Of the four project candidates, three were selected as best-fit projects with a weighted benefit-to-cost ratio above 1.25 to both MISO and local Transmission Pricing Zone (TPZ). These three best-fit projects relieved primary flowgate congestion, passed reliability no-harm test and showed robust economic benefits under multiple scenarios evaluated. None of the projects meet the voltage threshold to be eligible as Market Efficiency Project (MEP). Consequently, the three projects below will be included in MTEP18 as Economic Other projects for Board of Director approval.

- Rebuilding the existing Wabaco to Rochester 161 kV with an estimated cost of $11 million.
- Adding series reactor on Forest Junction to Elkhart Lake 138kV with an estimated cost of $2 million.
- New Wilson to BR Tap 161 kV line, re-conductoring BR Tap to Paradise 161 kV, upgrading terminal equipment at Matanzas and removing switch at BR Tap with an estimated cost of $16 million.

Study Summary: MCPS South Region

Since its integration, the MISO Board of Directors has approved significant transmission investments in the MISO South region leading to a reduction in congestion. The 2018 MCPS study effort for the South region is built on the progress made during previous MTEP cycles, which identified several congested flowgates and evaluated the applicable transmission solutions. The 2018 cycle focuses on four specific areas in MISO South: Arkansas, Louisiana, Texas and Mississippi.

In the MTEP18 MCPS study effort, transmission solutions were designed in a collaborative effort between MISO and stakeholders. Each solution was tested for robustness to address system needs under a variety of scenarios, embodied by the MTEP18 futures. None of the solutions analyzed for the South region met the requirements for economic project benefits. However, a single Baseline Reliability Project is being recommended to address both reliability and economic needs in the Natchez focus area.

MCPS Study and Process Overview

The MCPS begins with a bifurcated Flowgate Identification approach to identify both near- and long-term transmission issues. The top congested flowgate analysis identifies near-term, more localized congestion while the longer-term congestion relief analysis explores broader economic opportunities (Figure 5.3-1). Given the targeted focus of the MTEP18 MCPS, emphasis was placed on the top congested flowgate analysis. The congestion relief analysis will be employed in future broader-scoped planning studies.

With the needs defined, the study evaluates multiple transmission alternatives in an iterative fashion with both economic and reliability considerations. The Project Candidate Identification phase includes: screening analysis to identify solutions with the highest potential; economic evaluation over multiple years and futures to assess robustness; and reliability analyses to ensure the projects do not degrade system reliability. Using this approach, optimal economic transmission upgrades (best-fit solutions) are identified to address market congestion.

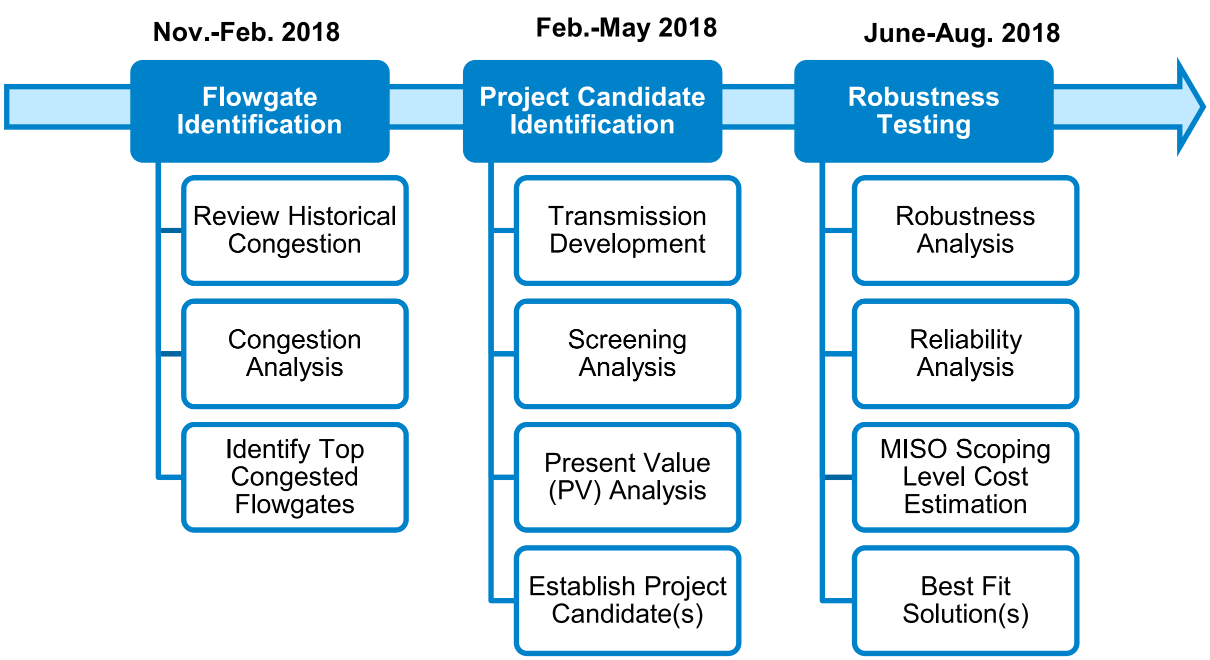

Figure 5.3-1: MCPS Process Overview

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MISO Models and Futures

The production cost models utilized for this study are based on data from PROMOD Powerbase and the corresponding MTEP powerflow cases. The data is refreshed with the most current information and with the system variables (fuel cost, demand, etc.) reflecting the MTEP futures definitions. The future scenarios -– Limited Fleet Change (LFC), Continued Fleet Change (CFC), Accelerated Fleet Change (AFC) and Distributed and Emerging Technologies (DET) -– each have a future weight for the MTEP18 MCPS study (Table 5.3-1)

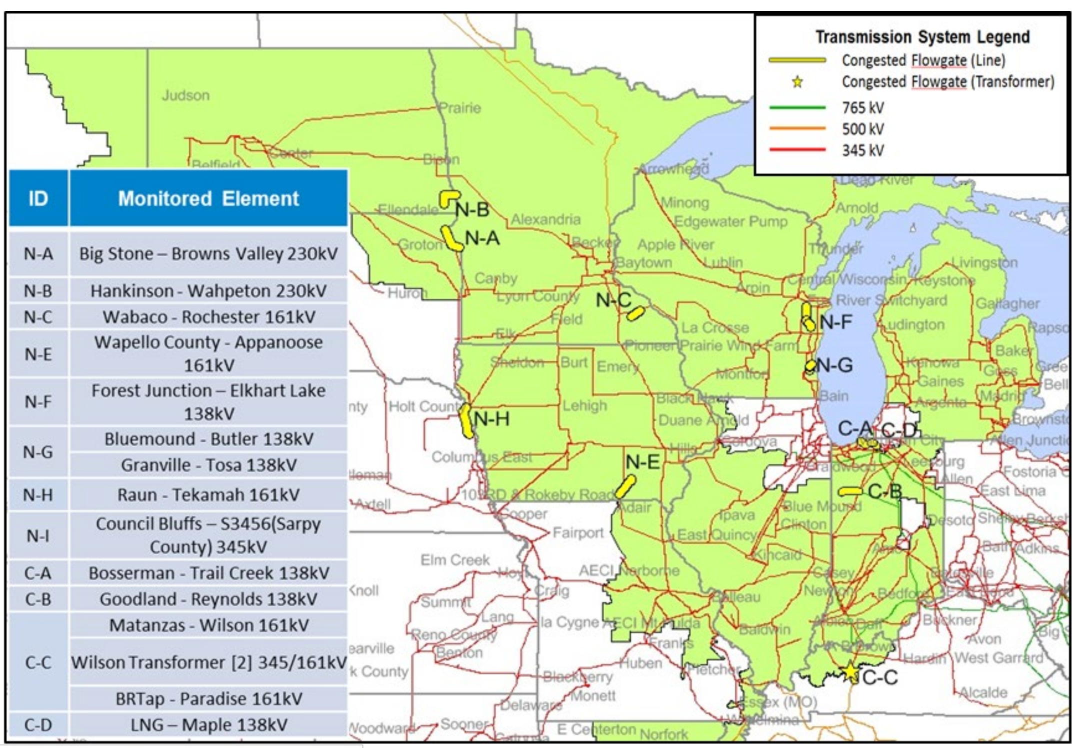
MTEP18 Future	Future Weight (%)
Limited Fleet Change (LFC)	25
Continued Fleet Change (CFC)	30
Accelerated Fleet Change (AFC)	20
Distributed and Emerging Technologies (DET)	25

Table 5.3-1: MTEP18 MCPS Future Weights

MISO assigns weights to each future considering input from the Planning Advisory Committee (see Section 5.2, MTEP Future Development).

Top Congested Flowgate Analysis

The top congested flowgate analysis identifies system congestion trends based on both the historical market data (day-ahead, real-time, and market-to-market) and out-year production cost model analysis. The MCPS identifies and prioritizes highly congested flowgates within the MISO market footprint and on the seams (Figures 5.3-2 and 5.3-3).



MISO, using Velocity Suite © 2018

Figure 5.3-2: Projected Top Congested Flowgates in MISO North/Central Region

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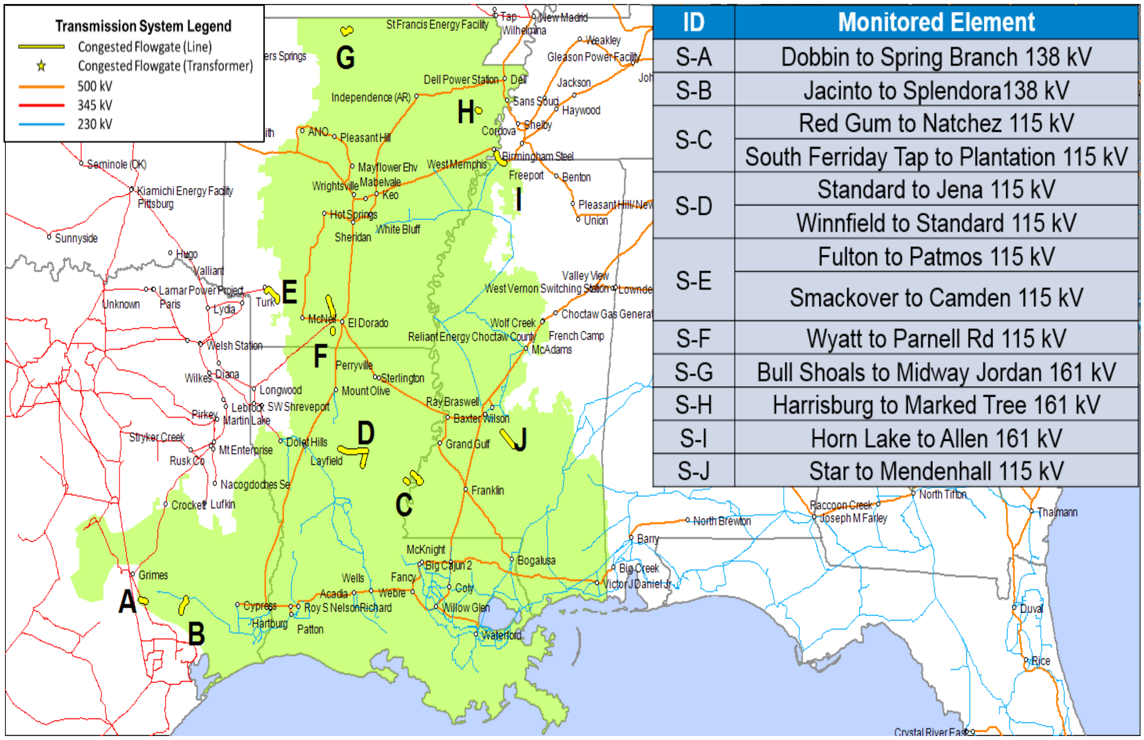

ID	Monitored Element
S-A	Dobbin to Spring Branch 138 kV
S-B	Jacinto to Splendora138 kV
S-C	Red Gum to Natchez 115 kV
	South Ferriday Tap to Plantation 115 kV
S-D	Standard to Jena 115 kV
	Winnfield to Standard 115 kV
S-E	Fulton to Patmos 115 kV
	Smackover to Camden 115 kV
S-F	Wyatt to Parnell Rd 115 kV
S-G	Bull Shoals to Midway Jordan 161 kV
S-H	Harrisburg to Marked Tree 161 kV
S-I	Horn Lake to Allen 161 kV
S-J	Star to Mendenhall 115 kV

Figure 5.3-3: Projected Top Congested Flowgates in the MISO South Region

Project Candidate Identification

Project candidate identification is a partnership between MISO and stakeholders to find network upgrades that address the top congested flowgates. Solution ideas may be submitted by stakeholders or developed by MISO staff. The solution ideas include those designed to directly address specific flowgates, provide energy transfer paths, and/or to unlock economic resources by connecting import-limited areas to export-limited areas.

A screening process is used to identify the most cost-effective solutions to relieve the congestion of interest. The screening does not preclude any solutions, but rather refines the pool of projects that will be analyzed in detail as MISO determines the optimal solution. The screening index for each solution is calculated as the ratio between the 15-year-out Adjusted Production Cost (APC) savings and the corresponding project cost:

$$\textit{Screening Index} = \frac{15\ \textit{year out Future Weighted APC Savings}}{\textit{Solution Cost} \times \textit{MISO Aggregrate Annual Charge Rate}}$$

MISO uses a screening index of 0.9 to identify which projects have the greatest potential to provide benefits in excess of cost after further testing and refinement. In addition to identifying the projects with the highest potential, the screening analysis provides information that can be used to modify and improve the solutions that do not pass the screening. In general, transmission solutions do not pass the screening index threshold for one of at least three reasons: the solution does not relieve all of the congestion on a targeted top flowgate(s); the solution relieves congestion on one flowgate but increases congestion on other flowgate(s); or the solution relieves congestion but the project cost is high relative to benefit.

By considering the specific reason for a project's screening performance, the project can be refined to better address the congestion. Corresponding to the above three reasons, the refinement may include:

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expanding and/or reconfiguring a project; combining projects that address related flowgates; and pruning projects to keep the most effective elements. The refinement of the solutions properly considers the balance of achieving synergistic benefits and avoiding excessive transmission build-outs that produce diminishing returns.

This study phase determines the project candidates that move on to a more comprehensive analysis.

Robustness Testing

Once the preliminary project candidates are identified, an iterative process takes place between economic robustness evaluation and reliability assessment. Robustness testing identifies the transmission solutions that provide the best value under most future outcomes; the reliability assessment ensures system reliability is at least maintained.

Project Cost Estimation

MISO creates cost estimates in order to evaluate transmission solutions in the Market Congestion Planning Study process. To support the creation of cost estimates, MISO developed and published its own cost estimation guide for MTEP18. MISO's cost estimation guide describes the approach and provides the cost data that it uses in developing cost estimates. This document is reviewed yearly with stakeholders.

MISO uses two levels of cost estimate detail: planning-level cost estimates; and scoping-level cost estimates. Planning-level cost estimates are utilized to compare potential projects with the same cost data and the same indicative assumptions. Scoping-level cost estimates are utilized where a project would be eligible for competitive solicitation. MISO's scoping-level cost estimate utilizes the same cost data as its planning-level cost estimates, and refines its assumptions for each specific potential project. For new facilities, MISO performs a desktop analysis to determine project-specific assumptions for it, and for upgrades of existing facilities, MISO consults with the local Transmission Owner to discuss project scope of work assumptions. Scoping-level cost estimates are used as the basis for project recommendation.

In 2018, MISO provided cost estimates for the North/Central focused Market Congestion Planning Study, and for the South focused Market Congestion Planning Study.

Project Benefit and Cost Analysis

The MISO Tariff measures a MEP's benefit by the APC savings realized through the project under each of the MTEP future scenarios. APC savings are calculated as the difference in total production cost adjusted for import costs and export revenues with and without the proposed project in the transmission system. Given the five-year transition period following MISO South integration in 2013, the benefits for each project are counted only for the relevant MISO sub-region, North/Central or South. Data from three simulation years (2022, 2027 and 2032) are used as the basis for evaluating the project impact. A 20-year benefit is calculated by linearly interpolating and extrapolating from these three years. The total project benefit is determined by calculating the present value (PV) of annual benefits for the multi-future and multi-year evaluations.

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As further detailed in Attachment FF of the MISO Tariff, a MEP must meet the following criteria:

- Have an estimated cost of $5 million or more
- Involve facilities with voltages of 345 kV or higher; and may include lower-voltage facilities of 100 kV or above that collectively constitute less than 50 percent of the combined project cost
- Benefit-to-cost ratio of 1.25 or greater

Although prescribed for MEPs, the stated metric and analysis is used to evaluate all economic projects. To arrive at the best solution, projects with a benefit-to-cost ratio of 1.25 or greater but not meeting all the MEP criteria are also considered.

Reliability Analysis

The reliability analysis uses a no-harm test to determine the impact of project candidates on the thermal and voltage stability; on transient stability as needed; as well as the short circuit capability under system impact and contingent events. A project candidate passes the reliability no-harm test if there is no degradation of system reliability with the addition of the project.

The no-harm test compares the contingency analysis results between two models, a base model and a model including the project candidate, to find if any violations are worsened by the addition of the project candidate.

North/Central Focus Areas

In the North/Central region, the identified 13 top congested flowgates were split into five major focus areas. Those areas are: Dakotas/Minnesota, Wisconsin, Iowa, Northern Indiana and Southern Indiana/Kentucky. A total of 68 solutions were evaluated for the 13 identified flowgates (Table 5.3-2).

2018 N/C MCPS Overview (Number of Solutions)	Dakotas/ Minnesota	Wisconsin	Iowa	Northern Indiana	Southern Indiana /Kentucky
Evaluated	20	10	11	20	7
Passed one-year screening	6	3	2	2	4
Passed 20-year present value analysis	2	3	1	1	1
Project candidates identified	1	1	0	0	1

Table 5.3-2: Summary of MTEP18 MCPS North/Central Solution Evaluation

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Dakotas/Minnesota

There were three top congested flowgates identified in the Dakotas/Minnesota focus area (Figure 5.3-4).

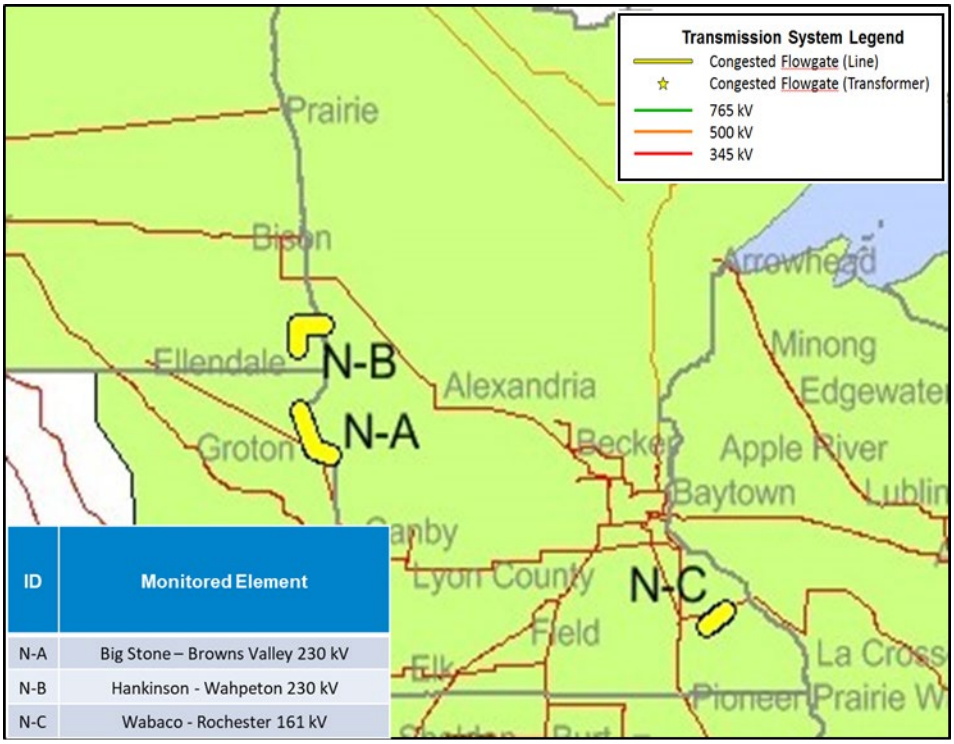

Figure 5.3-4: Dakotas/Minnesota Top Congested Flowgates

On the border of North Dakota/South Dakota and Minnesota, existing and future wind generation located in the Ellendale and Big Stone areas flows east to load centers in the Twin Cities area of Minnesota. Hankinson to Wahpeton 230 kV (N-B, as shown in Figure 5.3-4) and Big Stone to Browns Valley 230 kV (N-A, as shown in Figure 5.3-4) are the two 230 kV lines in the west-to-east flow path. These two lines show binding when any other west-to-east 230 kV or 345 kV line is out. In Southern Minnesota, Wabaco to Rochester 161 kV (N-C, as shown in Figure 5.3-4) is one of the bottle necks in the corridor of west-to-east power transfer from Iowa/Southern Minnesota to Wisconsin. It shows a significant amount of congestion when other 345 kV in the interface of Minnesota to Wisconsin is out.

In total of 20 solutions were evaluated in this area and six of those passed the one-year screening analysis. The six solutions that passed screening were moved forward for present value analysis and the study results as shown in (Table 5.3-3). The costs utilized in present value analysis are the planning-level costs that MISO estimated according to the guidance.

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Transmission Solution	Cost Estimate (2018-$M)	Benefit-to-Cost Ratios to MISO N/C					20-year PV Benefit ($M)	% Congestion Relieved
		AFC	CFC	DET	LFC	Weighted		
Adams - Tremval 345 kV	356.0	1.91	0.13	0.24	0.06	0.50	217.52	N-C: 89%
Adams - North Rochester - Tremval 345 kV	383.0	2.41	0.12	0.23	0.06	0.59	278.68	N-C: 70%
Colby - Adams - North Rochester - Tremval 345 kV	523.0	1.99	0.12	0.23	0.04	0.50	322.29	N-C: 57%
Rebuild Wabaco to Rochester 161 kV	***11.0****	***20.82***	***3.49***	***4.64***	***1.70***	***6.79***	***87.69***	***N-C: 100%***
Upgrade Wavetraps on Hankinson - Wahpeton 230 kV	2.2	24.00	2.99	8.55	0.18	7.88	20.34	N-B: 70%
Rebuild Hankinson - Wahpeton 230 kV	42.3	1.52	0.16	0.44	0.09	0.48	23.99	N-B: 100%

*Scoping-level cost estimation

Table 5.3-3: Dakotas/Minnesota Present Value Analysis Results

Of the two solutions sought to address congestion on Hankinson to Wahpeton 230 kV, rebuilding Hankinson to Wahpeton 230 kV did not pass the present value analysis with a weighted benefit-to-cost ratio of 0.48. Upgrading wavetraps on Hankinson to Wahpeton 230 kV can only address about 70 percent of its congestion. Although it shows a good benefit-to-cost ratio, it leaves a significant amount of the congestion unaddressed and the upgrade will most likely not be enough given the future wind development in the Dakotas and Minnesota border area. Neither of the two solutions was moved forward in the MTEP18 MCPS study cycle. Instead, MISO will continue to evaluate the congestion in this area in future MCPS cycles until MISO can find a more effective long-term solution.

Of the four solutions sought to address congestion on Wabaco to Rochester 161 kV, rebuilding Wabaco to Rochester 161 kV had the highest benefit-to-cost ratio to MISO and fully relieved the congestion. Therefore, it was identified as project candidate 1 (PC-1) and moved forward for further robustness analysis to help inform the project recommendation decision. The rest of the three solutions did not pass the present value analysis due to very high cost.

Contingency analysis was performed on PC-1 to identify any potential new flowgates that may be driven by the project. After selecting PC-1 as the most effective project to address Wabaco to Rochester area congestion, the project candidate went through the economic evaluation, reliability no-harm analysis, and scoping-level cost estimation. As a result of these analyses, PC-1 has been identified as the best-fit project to address Wabaco area congestion. This project fully relieved congestion on Wabaco to Rochester 161 kV while achieving a 6.79 benefit-to-cost ratio to MISO and 1.53 to local TPZ with an estimated cost of $11 million.

Also, various sensitivity analyses were performed to help inform the project's business case under different potential scenarios. A DPP wind sensitivity test evaluated the impact of modeling wind units in the queue with DPP status instead of Regional Generator Outlet Study/Regional Resource Forecast (RGOS/RRF) wind units in Iowa and Southern Minnesota. Under the sensitivity test, rebuilding Wabaco to Rochester 161 kV was shown to be robust and provide a benefit-to-cost ratio of 7.93 and 20-year present value benefit of $102.29 million.

The project of rebuilding the existing Wabaco to Rochester 161 kV is identified as a robust transmission solution and will be recommended as one of the three Economic-Other projects to be included in MTEP18.

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Iowa

In Iowa there were three identified top congested flowgates (Figure 5.3-5).

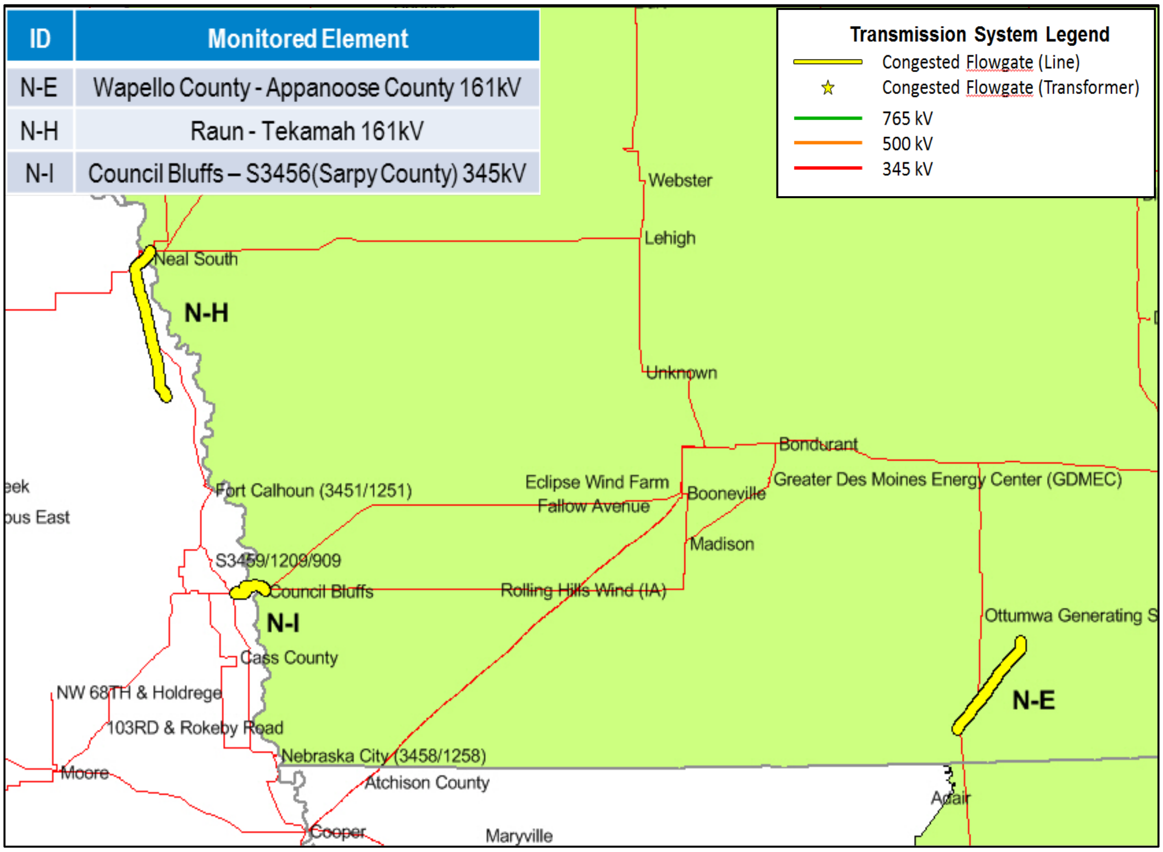

Figure 5.3-5: Iowa Top Congested Flowgates

The congestion in Iowa is due to the high amount of existing and future wind sited in Iowa and in southwestern Minnesota. The flowgates N-H and N-I are on the Iowa-Nebraska border and are aggregated by the power transfer out of Iowa that flows either south or southwest. Raun to Tekamah 161 kV (N-H) is one of lines in the north to south corridor. Existing and future wind generation located in the southwest corner of Minnesota (Split Rock, Buffalo area) increases north-to-south flow on the border. It shows heavy binding under the loss of the 345 kV line in the same flow corridor. In addition, existing and future wind generation located in central and southwest of Iowa flows southwest to the Iowa/Nebraska border through multiple 345 kV lines. Council Bluffs to S3456 (Sarpy County) 345 kV (N-I) shows binding under the loss of any other 345 kV lines in the corridor. Wapello County to Appanoose 161 kV (N-E) is a north-to-south flowgate near the border of Iowa and Missouri. It shows binding when another 345 kV line in the same corridor is out.

In the 2018 MCPS study, a total of 11 solutions were evaluated to address the congestion in Iowa. After the completion of screening and refinement, two out of those 11 solutions passed the initial screening and moved forward to present value analysis (Table 5.3-4).

During the present value analysis, only Council Bluffs–Sarpy County 345 kV terminal equipment upgrade passed 1.0 benefit-to-cost ratio. Although this solution provided high APC savings to MISO and fully relieved the congestion on flowgate N-I, the terminal equipment that will be upgraded is a non-MISO facility. It could be further evaluated in the next MISO and Southwest Power Pool (SPP) interregional study and will not move forward for further analysis in the MTEP18 MISO MCPS study.

Transmission Solution	Cost Estimate (2018-$M)	Benefit–to-Cost Ratios					20-year PV Benefit ($M)	% Congestion Relieved
		AFC	CFC	DET	LFC	Weighted		
New substation at the intersection Raun - Hoskins 345kV & Emerson - Bancroft 115 kV	18.0	1.56	0.01	0.54	0.21	0.50	11.11	N-H: 30%
Council Bluffs - Sarpy County 345 kV terminal equipment upgrade at Sarpy County	3.0	48.57	4.30	9.24	0.17	13.36	49.20	N-I: 100%

Table 5.3-4: Iowa Area Present Value Analysis Results

Therefore, no project will be recommended in Iowa area in MTEP18 MCPS. MISO will continue to monitor the congestion within this focus area in subsequent study efforts.

Wisconsin

In Wisconsin there were two identified top congested flowgates (Figure 5.3-6).

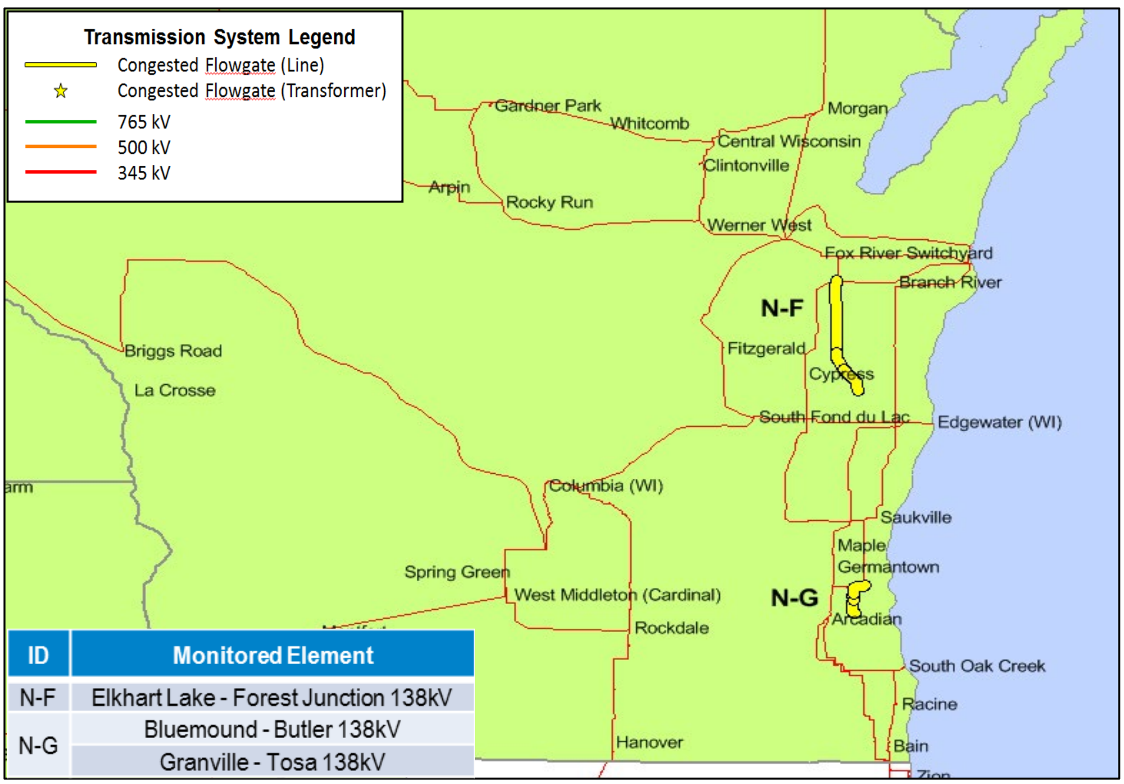

Figure 5.3-6: Wisconsin Top Congested Flowgates

The congestion in Wisconsin is caused by low-cost generation in the northern part of the state paired with retirements in the southern part of the state. Forest Junction to Elkhart Lake 138 kV (N-F, as shown in Figure 5.3-6) is one of the lines in the north-to-south flow corridor. It shows binding under the loss of any

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other parallel 345 kV lines. Bluemound to Butler 138 kV and Granville to Tosa 138 kV lines are in the north-to-south corridor between Edgewater and South Oak Creek substations, as well. This flow corridor becomes congested under loss of any 345 kV line allowing north-to-south flow.

A total of 10 solutions were submitted to address the congestion in Wisconsin. After the completion of screening and refinement, three out of 10 solutions passed the screening and moved forward for present value analysis (results as shown in Table 5.3.-5).

Transmission Solution	Cost Estimate (2018-$M)	Benefit-to-Cost Ratios					20-year PV Benefit ($M)	% Congestion Relieved
		AFC	CFC	DET	LFC	Weighted		
Move Elkhart Lake Load to Parallel 138 kV Circuit (Lyndon - Esker View)	1.5	7.77	(0.30)	1.27	2.08	2.30	4.24	N-F: 27%
Add Series Reactor on Elkhart Lake - Forest Junction 138 kV	***2.0****	***13.86***	***1.23***	***2.17***	***(0.53)***	***3.55***	***8.72***	***N-F: 89%***
Move Elkhart Lake Connection to Esker View - Lyndon 138 kV and add series reactor on Elkhart Lake	3	6.81	0.38	0.91	1.21	2.00	7.38	N-F: 76%

*Scoping-level cost estimation

Table 5.3-5: Wisconsin Area Present Value Analysis Results

During the present value analysis, all three solutions passed the 1.0 benefit-to-cost ratio. However, adding a series reactor on the Forest Junction to Elkhart Lake 138 kV line was moved forward as Project Candidate 2 (PC-2) because of the highest benefit-to-cost ratio and its ability to address the highest percentage of congestion on flowgate N-F.

Contingency analysis was performed on PC-2 to identify any potential new flowgates that may be driven by the project. After selecting PC-2 as the most effective project to address Forest Junction to Elkhart Lake area congestion, it went through the economic evaluation, reliability no-harm analysis, and scoping level cost estimation. As a result of these analyses, PC-2 has been identified as the best-fit solution to address congestion in the area. This project relieved 90 percent of the congestion on the line while achieving a 3.55 benefit-to-cost ratio to MISO and 5.62 to local TPZ with an estimated cost of $2 million.

In conclusion, the project of adding series reactor on Forest Junction to Elkhart Lake 138 kV will be recommended as one of the three Economic-Other projects to be included in MTEP18.

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Northern Indiana

There were three top congested flowgates identified in the Northern Indiana area (Figure 5.3-7).

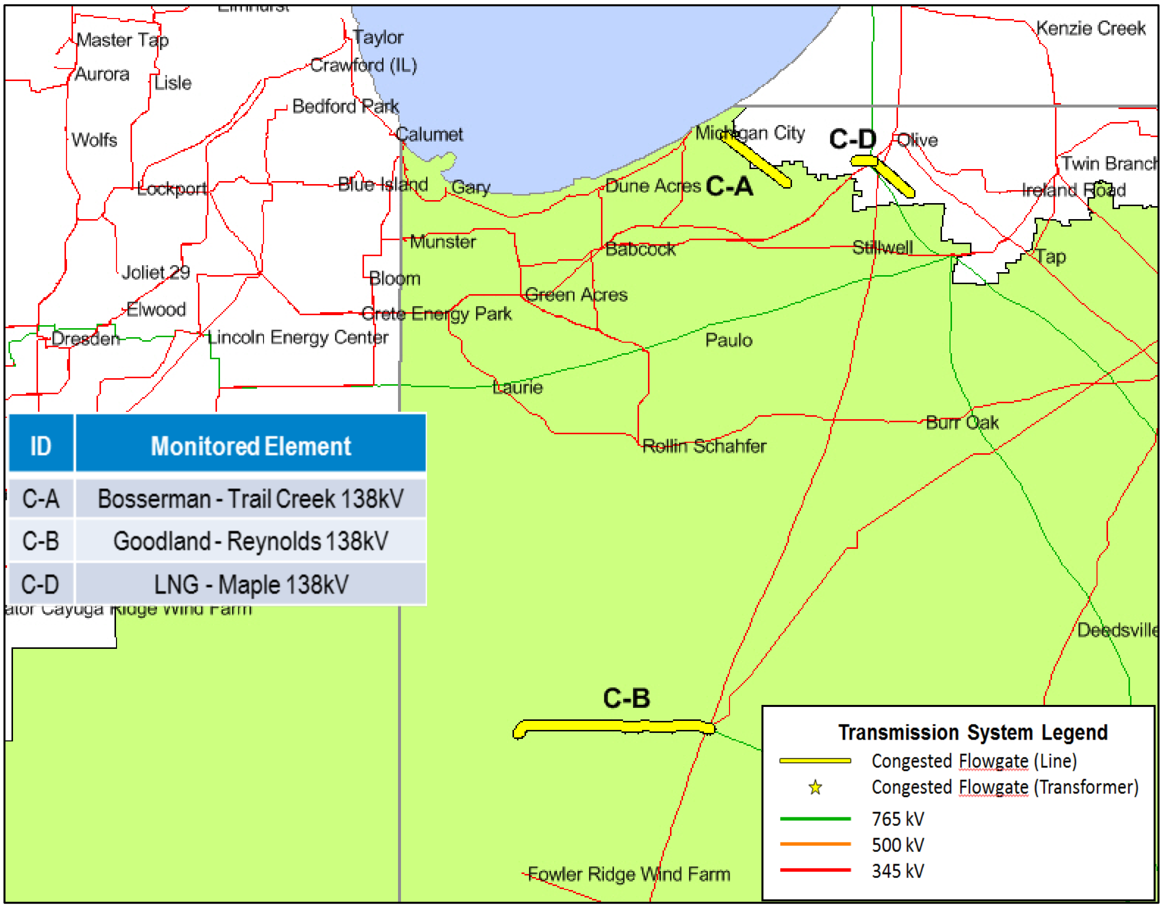

Figure 5.3-7: Northern Indiana Top Congested Flowgates

The main driver of congestion on Bosserman to Trail Creek 138 kV and LNG to Maple 138 kV is the increasing load in Michigan City area being served by generators located to the east and northeast. This leads to heavier east-to-west flows on the 138 kV system. The congestion on the Goodland to Reynolds 138 kV flowgate is driven by existing and future wind farms located west of the constraints and near the border of Illinois and Indiana.

A total of 20 solutions were evaluated in Northern Indiana area. Two out of 20 solutions passed the initial screening, both addressing congestion on Bosserman to Trail Creek 138 kV. Out of these two projects, the project to upgrade conductors on three lines (Michigan City to Trail Creek, Trail Creek to Bosserman 138 kV and LNG to Maple 138 kV) were selected as Project Candidate 3 (PC-3) and moved forward for robustness analysis. No projects near the Goodland–Reynolds 138 kV flowgate passed screening because the high costs of potential projects in the area outweighed the benefits.

Transmission Solution	Cost Estimate (2018-$M)	Benefit-to-Cost Ratios					20-year PV Benefit ($M)	% Congestion Relieved
		AFC	CFC	DET	LFC	Weighted		
Reconductor Michigan City - Trail Creek - Bosserman 138 kV and LNG - Maple 138 kV	8.5	1.43	1.84	1.33	0.92	1.40	15.29	C-A: 96% C-D: 100%
Duplicate Bosserman – Michigan City 138 kV	15.0	0.89	1.28	1.25	0.48	0.99	18.27	C-A: 100%

Table 5.3-6: Northern Indiana Area Present Value Analysis Results

In the robustness analysis phase, PC-3 would not be recommended because it does not provide benefits in excess of cost to the local transmission owner (Table 5.3-6). Therefore, no project will be recommended in the Northern Indiana area for Board of Director approval. MISO will continue to monitor the congestion within this focus area in subsequent study efforts.

Southern Indiana/Kentucky

There were three top congested flowgates identified and grouped as flowgate C-C in Southern Indiana (Figure 5.3-8).

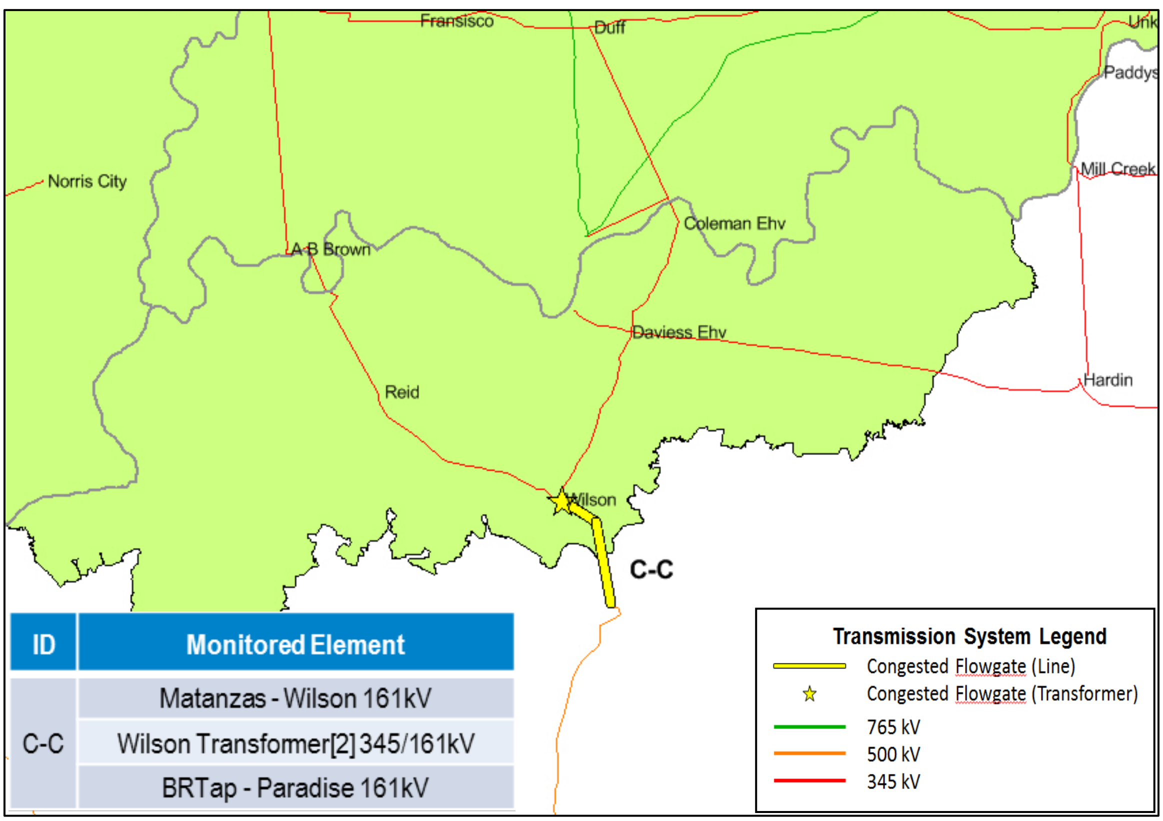

Figure 5.3-8: Southern Indiana/Kentucky Top Congested Flowgates

The congestion in Southern Indiana and Kentucky area is caused by the increased north-to-south flow between MISO and Tennessee Valley Authority (TVA). The flowgates listed above are on the border of MISO and TVA. This flow corridor becomes congested when higher north-to-south flow comes from MISO into TVA. Loss of one line or transformer causes congestion on other parallel flow paths near the seam. The congestion will be aggregated by retiring some generation in TVA area.

In the 2018 MCPS study, there were seven submitted solutions addressing the congestion in Southern Indiana and Kentucky area. Of those, four passed the screening (Table 5.3-7).

Transmission Solution	Cost Estimate (2018-$M)	Benefit-to-Cost Ratios					20-year PV Benefit ($M)	% Congestion Relieved
		AFC	CFC	DET	LFC	Weighted		
Wilson – BR Tap 161 kV, Reconductor BR Tap -Paradise 161kV and Remove BR Tap Switch	***16.0****	***4.26***	***2.53***	***5.04***	***1.65***	***3.28***	***61.60***	***C-C: 78%***
Wilson - Matanzas - Paradise 161 kV	45	1.41	0.84	1.57	0.49	1.05	55.34	C-C: 45%
Wilson - Paradise 161 kV	45	1.52	0.89	1.56	0.57	1.1	58.3	C-C: 50%
Wilson – BR Tap 161 kV, Reconductor BR Tap - Paradise 161 kV, Remove BR Tap Switch add 3rd Wilson 345/161 transformer	47.5	1.44	0.83	1.82	0.55	1.13	62.83	C-C: 100%

*Scoping-level cost estimation

Table 5.3-7: Southern Indiana/Kentucky Area Present Value Analysis Results

During the present value analysis, the first proposal was selected as Project Candidate 4 (PC-4). This proposal could fully address the congestion on Wilson to Matanzas and BR Tap to Paradise lines with the highest benefit-to-cost ratio among the four solutions.

Contingency analysis was performed on PC-4 to identify any potential new flowgates that may be driven by the project. After selecting PC-4 as the most effective project to address Wilson and BR Tap area transmission congestion, it went through the economic evaluation, reliability no-harm analysis and scoping level cost estimation. As a result of these analyses, PC-4 has been identified as the best-fit project to address congestion in the area. This project fully relieved congestion on Wilson to Matanzas and BR Tap to Paradise lines while achieving a 3.28 benefit-to-cost ratio to MISO and 1.73 to local TPZ with an estimated cost of $16 million.

In conclusion, the project of adding new Wilson to BR Tap 161 kV line, re-conductoring BR Tap to Paradise 161 kV, upgrading terminal equipment at Matanzas and removing switch at BR Tap will be recommended as one of the three Economic-Other projects to be included in MTEP18..

South Focus Areas

In the South region, the 10 identified top congested flowgates were split into four major focus areas by state. Those areas are: Texas, Louisiana, Arkansas and Mississippi. A total of 48 solutions were evaluated for the 10 identified flowgates (Table 5.3-8).

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2018 South MCPS Overview (Number of Solutions)	Texas	Louisiana	Arkansas	Mississippi
Evaluated	12	19	12	5
Passed one-year screening	0	5	0	0
Passed 20-year present value analysis	0	5	0	0
Project candidates identified	0	0	0	0

Table 5.3-8: MISO South top congested flowgates evaluated (by state)

Texas

There were two congested flowgates identified in the West of Atchafalaya Basin (WOTAB) and Western area of Texas (Figure 5.3-9). Congestion was driven by new generation as well as MTEP-approved projects shifting congestion in the area. After identifying economic congestion in the area, MISO worked with the local TO on modifications to MTEP17 Appendix A Project P12096. The withdrawal of P12096 (Dobbin Auto Project), replaced with P15105 (Dobbin 138 kV Line Breakers) and P15106 (Fish Creek–Ponderosa 138 kV Reconductor), reduced economic congestion within the Texas WOTAB/Western area. After the modification of the Appendix A project the flowgates in the Texas area would not have met the threshold for top congested flowgates.

There were 12 projects studied to address congestion on the flowgates in Texas. After the Appendix-A project modifications, congestion was not sufficient for the justification for the solutions received.

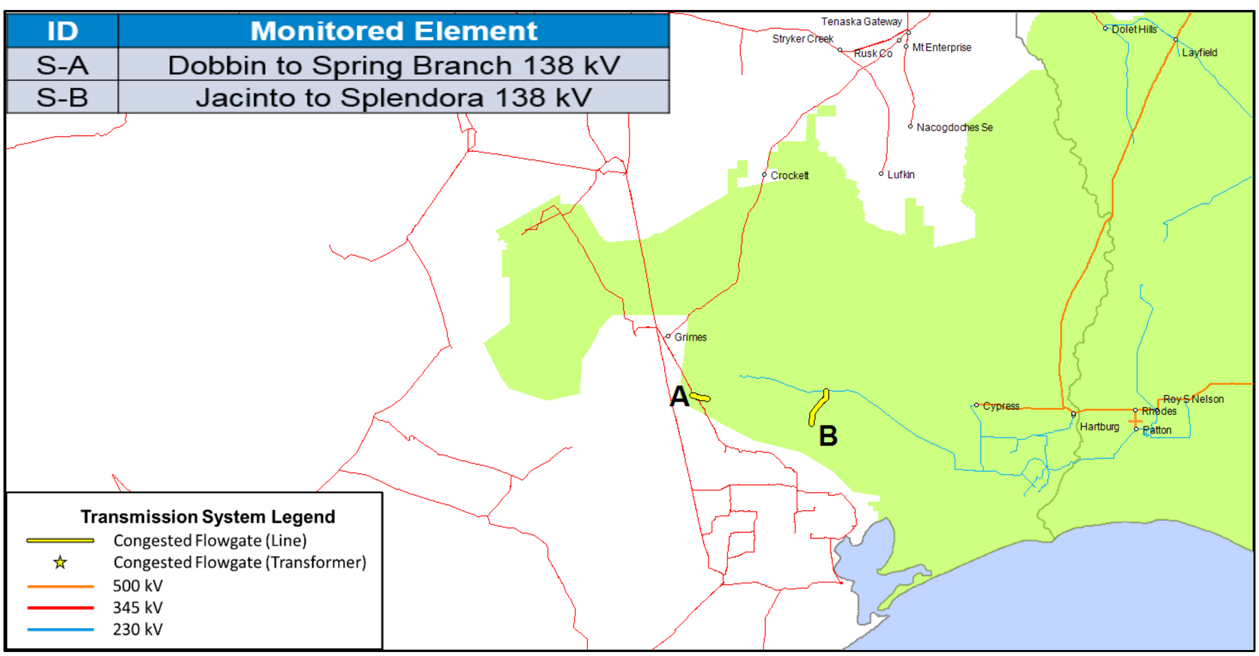

Figure 5.3-9: Texas Top Congested Flowgates

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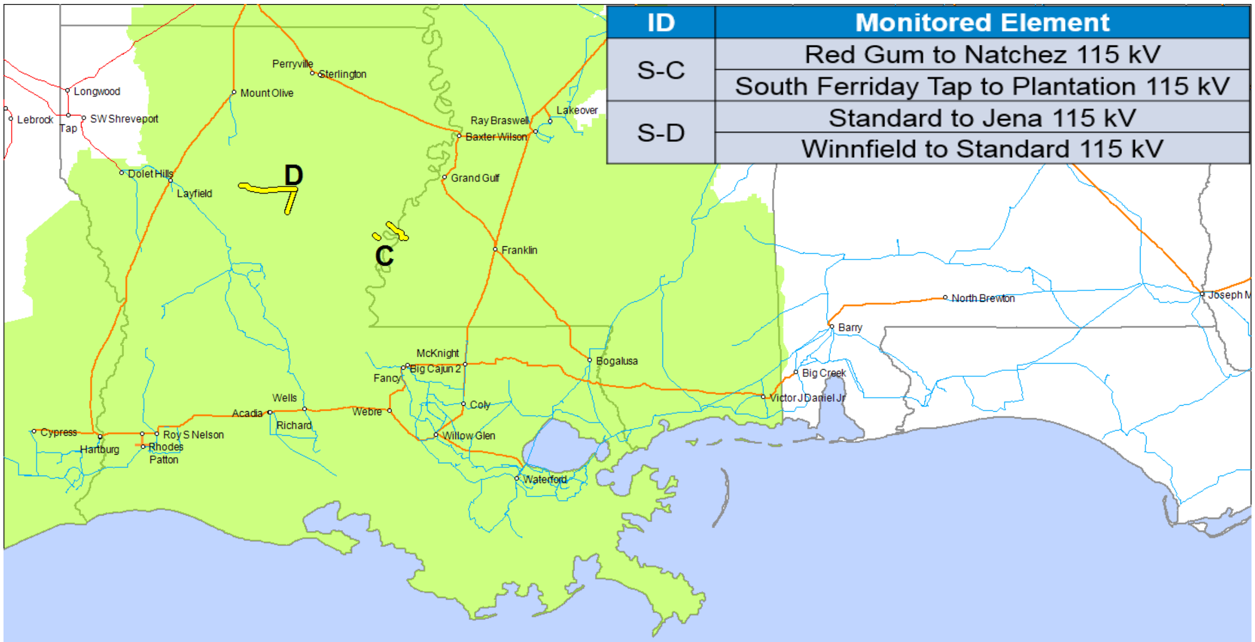
Louisiana

There were two congested flowgates identified in the state of Louisiana (Figure 5.3-10). Flowgate S-C —: Red Gum to Natchez and South Ferriday Tap to Plantation — are located on the Louisiana-Mississippi border. The identified congestion was influenced by the assumed retirements and replacement generation at Sterlington and Baxter Wilson substations in addition to high west (Perryville) to east (Baxter Wilson) transfers under contingent conditions. Flowgate S-D congestion levels were driven by the loss of the 500 kV system increasing congestion on the lower kV transmission system.



ID	Monitored Element
S-C	Red Gum to Natchez 115 kV
	South Ferriday Tap to Plantation 115 kV
S-D	Standard to Jena 115 kV
	Winnfield to Standard 115 kV

Figure 5.3-10: Louisiana Top Congested Flowgates

There were 19 projects studied to address congestion on the flowgates in Louisiana. Of those 19 projects five passed screening addressing flowgate S-C. The five solutions studied addressing this flowgate included a Target Appendix-A Baseline Reliability Project. After conducting robustness analysis on these five projects, the BRP rebuild of Natches SES – Red Gum was the most effective at resolving the reliability and economic congestion issues. While addressing both the reliability and economic congestion, this project did not meet the benefit-to-cost ratio of 1.25 and will therefore be categorized as a Baseline Reliability Project.

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Arkansas

There were four congested flowgates identified in the state of Arkansas (Figure 5.3-11). Flowgates were spread across the state with congestion showing up on flowgates on or close to the MISO seam. Congestion on the top flowgates in Arkansas are largely driven by retirements with limited replacement assumptions and are affected by contingencies for the heavy flows due to the loss of a nearby 500 kV transmission element.

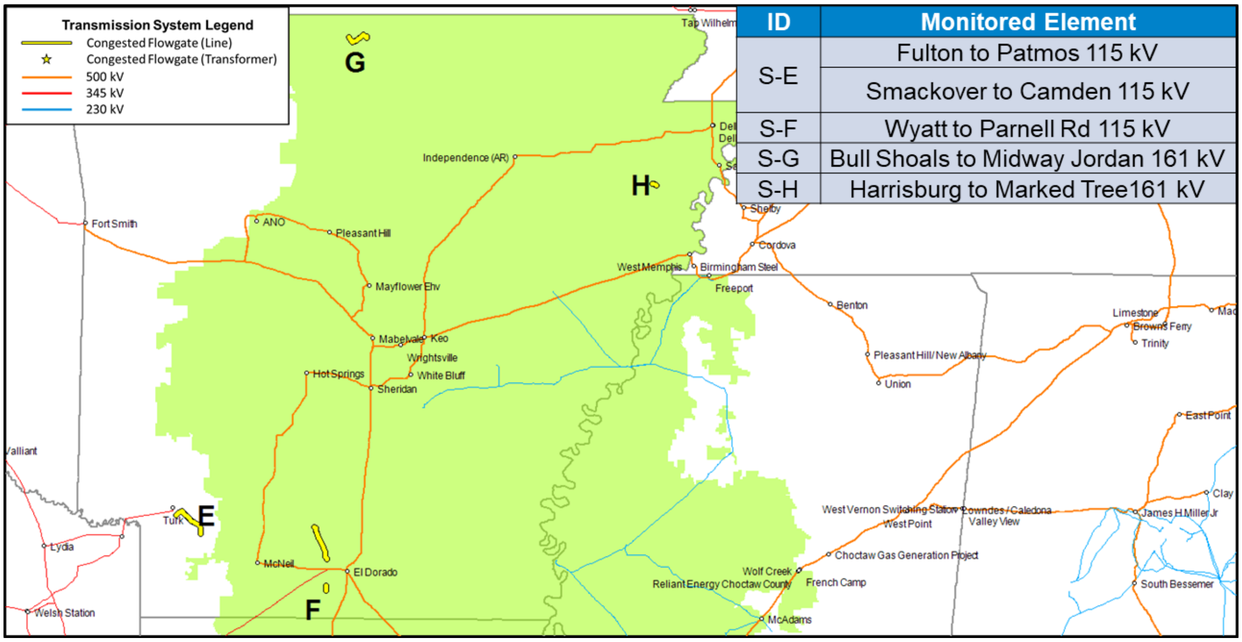

Figure 5.3-11: Arkansas Top Congested Flowgates

There were 12 projects studied to address congestion on the flowgates in Arkansas. Some of the projects aimed at rebuilding the congested flowgates with higher ratings while others had new area network upgrades that helped relieve congestion on the listed flowgates. There were also 500 kV project ideas close to the MISO-SPP seams that were studied. Though some of the projects did reduce congestion on the flowgates, none were cost effective enough to clear the 0.9 screening benefit-to-cost ratio threshold. Flowgates will be closely monitored for any change in congestion patterns in future MCPS cycles.

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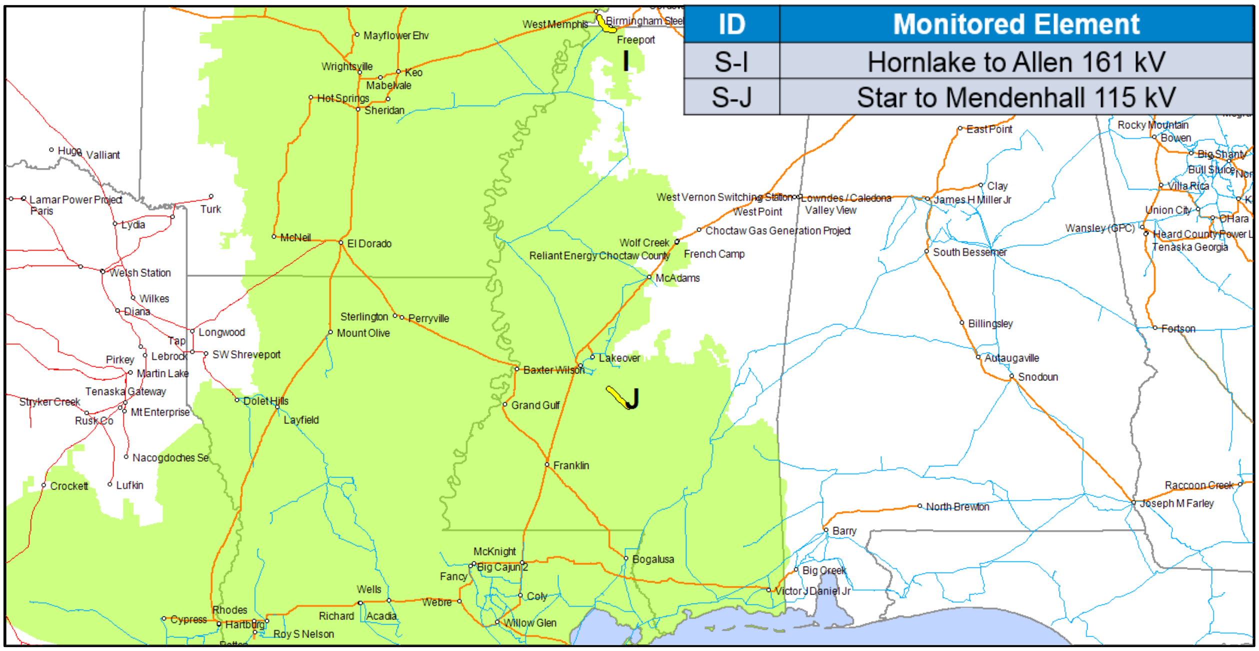
Mississippi

There were two congested flowgates identified in the state of Mississippi (Figure 5.3-12). Flowgates were along the MISO seam with TVA and SERC Reliability Corp. Congestion on the top flowgates in Mississippi are largely driven by retirements in TVA and cross-border flows into the SERC region due to load growth.



ID	Monitored Element
S-I	Hornlake to Allen 161 kV
S-J	Star to Mendenhall 115 kV

Figure 5.3-12: Mississippi Top Congested Flowgates

There were five projects studied to address congestion on the flowgates in Mississippi. Some of the projects aimed at rebuilding the congested flowgates with higher ratings while others had new area network upgrades that helped relieve congestion on the listed flowgates. There were also 500 kV project ideas close to the MISO-TVA and MISO-SOCO seams that were studied. Though some of the projects did reduce congestion on the flowgates, none were cost effective enough to clear the 0.9 screening benefit-to-cost ratio threshold. Flowgates will be closely monitored for any change in congestion patterns in future MCPS cycles.

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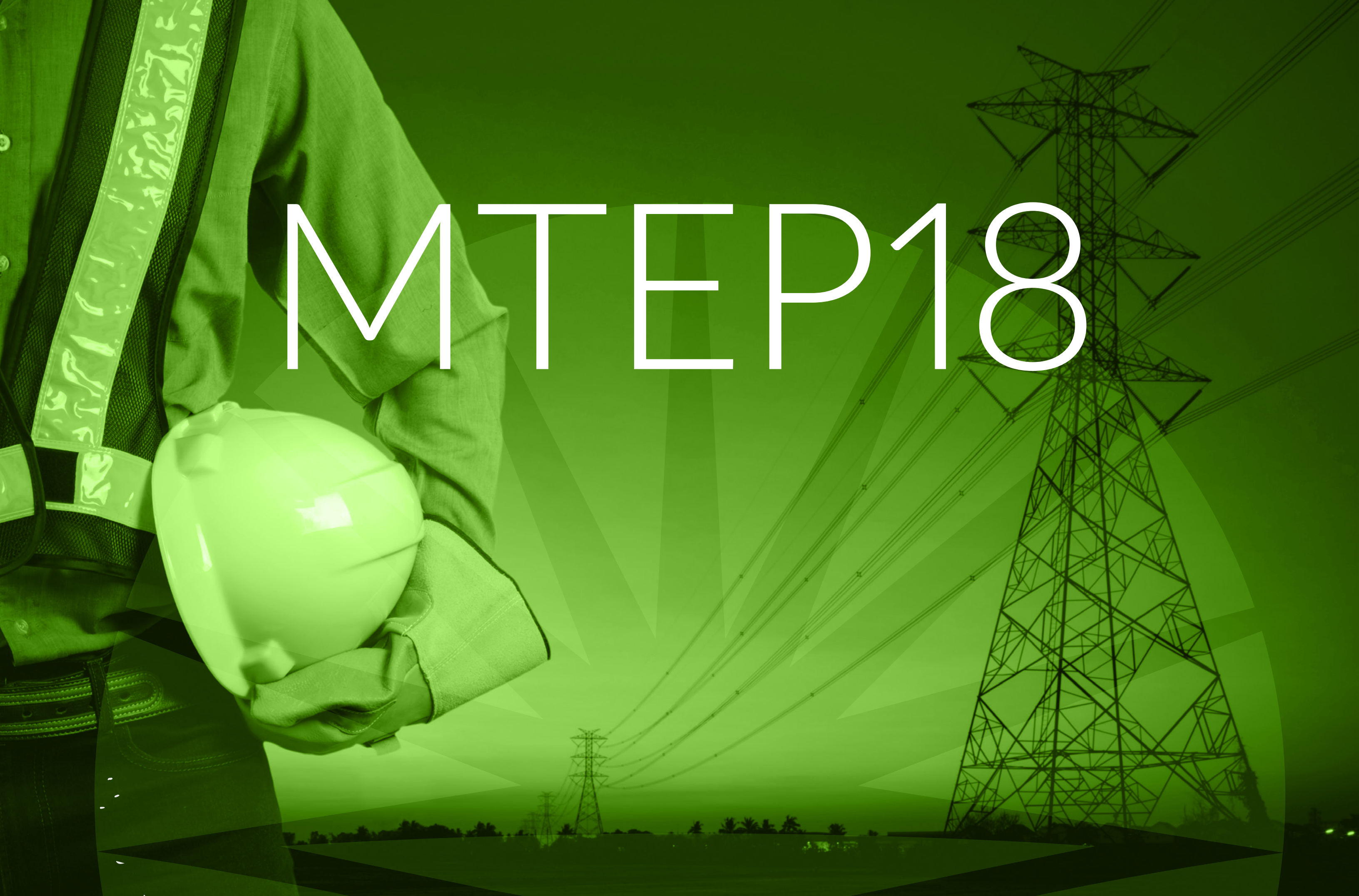

MTEP18

In this MISO Transmission Expansion Plan, MISO staff recommends $3.3 billion of new transmission enhancement projects for Board of Directors' approval.

BOOK 2

Resource Adequacy

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MTEP18
Resource Adequacy

Summary

Resource Adequacy requires enough capacity be available to meet the needs of all consumers in the MISO footprint to meet peak load serving needs. To achieve this, MISO supports its states and load-serving entities by providing projected risks and continuously works to improve transparency into near and long-term resource requirements.

A convergence of trends, including an aging generation fleet and growth of variable energy resources, has required MISO to look at existing processes to support states' and load-serving entities' efforts to satisfy their Resource Adequacy requirements. Improvements in MISO processes will benefit the system through ensuring sufficient energy is able to meet operational needs in all times of the year.

BOOK HIGHLIGHTS

- The footprint has sufficient resources to meet peak load for 2019. Risks exist in subsequent years as generation retires and is replaced by often lower-capacity resources like wind and solar, as well as Load Modifying Resources currently accessible only through the declaration of emergency operations.
- MISO is currently investigating how to ensure the efficient conversion of capacity cleared in the Planning Resource Auction into energy needed by real time operations through its Resource Availability and Need (RAN) effort

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Section 6: Resource Adequacy

6.0 Resource Adequacy Introduction and Enhancements

6.1 Planning Reserve Margin

6.2 Long Term Resource Assessment

6.3 Seasonal Resource Assessment

6.0 Resource Adequacy Introduction and Enhancements

MISO's ongoing goal is to support the achievement of Resource Adequacy — to ensure enough capacity is available to meet the needs of all consumers in the MISO footprint during all time frames and at just, reasonable rates. The responsibility for Resource Adequacy does not lie with MISO, but rather rests with load-serving entities and the states oversee them (as applicable by jurisdiction). MISO's role in resource adequacy is to support these entities and provide transparency into near- and long-term resource requirements. Additional Resource Adequacy goals include maintaining confidence in the attainability of Resource Adequacy in all time horizons, building confidence in MISO's Resource Adequacy assessments and providing sufficient transparency and market mechanisms to mitigate potential shortfalls.

Five guiding principles provide the framework necessary to achieve these goals:

1. Resource Adequacy processes must ensure confidence in Resource Adequacy outcomes in all time horizons
2. MISO will work with stakeholders to ensure an effective and efficient Resource Adequacy construct with appropriate consideration of all eligible internal and external resources and resource types and recognition of legal/regulatory authorities and responsibilities
3. MISO will determine adequacy at the regional and zonal level and provide appropriate regional and zonal Resource Adequacy transparency and awareness for multiple forward time horizons
4. MISO will administer and evolve processes in a manner that provides transparency and reasonable certainty, and that appropriately protects individual market participant proprietary information in order to support efficient stakeholder resource and transmission investment decisions
5. MISO's resource planning auction and other processes will support multiple methods of achieving and demonstrating Resource Adequacy, including self-supply, bilateral contracting and market-based acquisition

To date, the Resource Adequacy process has been a successful tool for facilitating and demonstrating Resource Adequacy in the near term, through such tools as the Loss of Load Expectation (LOLE) analysis, the Planning Resource Auction, and the Organization of MISO States (OMS) MISO Survey.

However, evolving market conditions at MISO have resulted in a resource portfolio with changed operational characteristics and less-certain available capacity. In the past, a Maximum Generation (MaxGen) Emergency occurred infrequently, with resource adequacy risk being focused on summer peak needs. In comparison, there have been more than 12 emergency events since the start of the 2016/17 Planning Year, occurring in all four seasons.

As a result, MISO began an effort to focus on the conversion of capacity to available energy, called Resource Availability and Need (RAN). The RAN effort will focus on:

1. Ensuring expected resource outages are matched with commitments
2. Examining, in close cooperation with state regulators, the characteristics of emergency only resources and their requirements in MISO processes
3. Committing capacity to meet resource needs throughout the year (Seasonal Resource Adequacy)
4. Ensuring resource attributes are sufficient to support reliability in light of the changing fleet characteristics (Essential Reliability Services)

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6.1 Planning Reserve Margin

The MISO Installed Capacity Planning Reserve Margin (PRM ICAP) for the 2018-2019 planning year, spanning from June 1, 2018, through May 31, 2019, is 17.1 percent, an increase of 1.3 percentage points from the 15.8 percent PRM set in the 2017-2018 planning year (Figure 6.1-1).

The PRM ICAP is established with resources at their installed capacity rating at the time of the system-wide MISO coincident peak load. The 1.3 percentage point PRM ICAP increase was the net effect of an increase in forced outage rates and reduction in load forecasts.

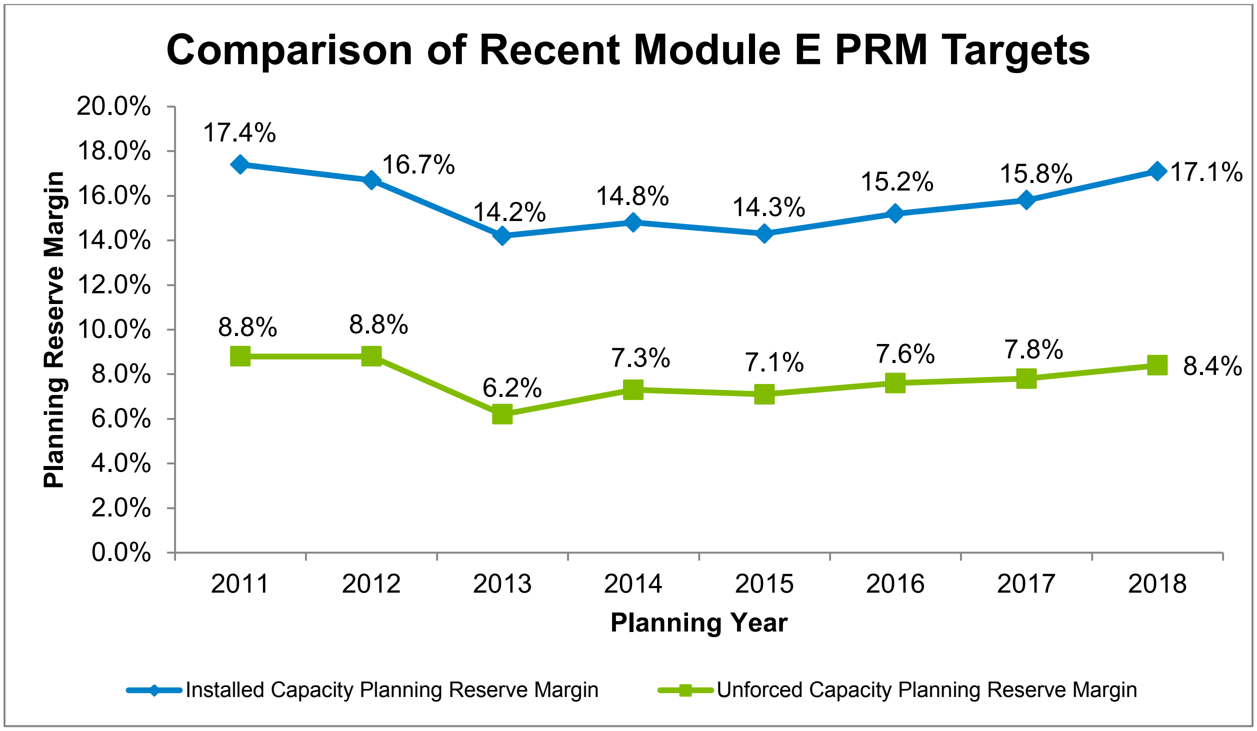

Figure 6.1-1: Comparison of recent PRM

As directed under Module E-1 of the MISO Tariff, MISO coordinates with stakeholders to determine the appropriate Planning Reserve Margin (PRM) for the applicable planning year based upon the probabilistic analysis of the ability to reliably serve MISO Coincident Peak Demand for that planning year. The probabilistic analysis uses a Loss of Load Expectation (LOLE) study that assumes no internal transmission limitations within the MISO region. MISO calculates the PRM such that the LOLE for the next planning year is one day in 10 years, or 0.1 days per year. The minimum amount of capacity above Coincident Peak Demand in the MISO region required to meet the reliability criteria is used to establish the PRM. The PRM is established as an unforced capacity (PRM UCAP) requirement based upon the weighted average forced outage rate of all Planning Resources in the MISO region.

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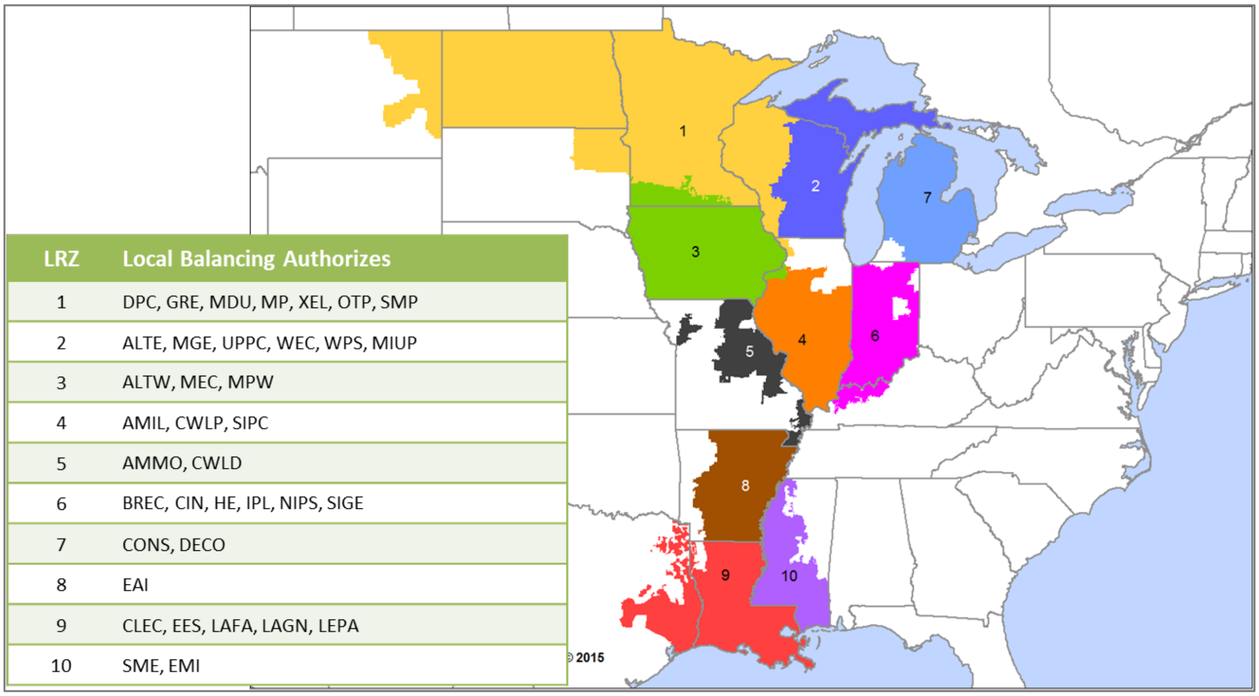
The LOLE study and the deliverables from the LOLE Working Group are based on the Resource Adequacy construct per Module E-1. MISO performs an annual LOLE study to determine the congestion-free PRM on an installed and unforced capacity basis for the MISO system. In addition, a per-unit zonal Local Reliability Requirement (LRR) for the planning year is determined for each Local Resource Zone (LRZ) (Figure 6.1-2), which is defined as the amount of resources a particular area needs to meet the LOLE criteria of one day in 10 years without the benefit of importing capacity. These results are merged with the Capacity Import Limit (CIL), Capacity Export Limit (CEL) and Wind Capacity Credit results to form the deliverables to the annual Planning Resource Auction.



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

Figure 6.1-2: Local Resource Zones (LRZ)

2018-2019 Deliverables to the Planning Resource Auction

The PRM deliverables are needed for the Planning Resource Auction (PRA). These deliverables include the PRM UCAP, a per-unit zonal LRR, and CIL and CEL values (Table 6.1-1).

The PRM UCAP[19] increased from 7.8 percent in the 2017-2018 LOLE report to 8.4 percent in the 2018-2019 LOLE report due to the modeling parameter changes. More information on the increase is available in the 2018 LOLE report[20]. Under the existing construct, the PRM UCAP is applied to the peak of each load-serving entity coincident with the MISO peak. A zonal CIL and CEL for each LRZ was calculated with the monitored and contingent elements reported (Tables 6.1-2 and 6.1-3; Figures 6.1-3 and 6.1-4). Adjustments were made to CIL based on a December 31, 2015, FERC order to reflect resources committed to non-MISO load. The ultimate PRM, CIL and CEL values for a zone could be adjusted within the PRA depending on the demand forecasts received and offers into the auction to assure that the

[19] PRM UCAP is the value accounting for the forced outage rate of capacity. More information on this calculation may be found in the LOLE report.
[20] Or: https://cdn.misoenergy.org/2018%20LOLE%20Study%20Report89286.pdf

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resources cleared in the auction can be reliably delivered. Most CIL values for the 2018-2019 Planning Resource Auction[21] were revised from the initial values calculated in the 2018 LOLE report to reflect changes in imports and exports submitted to the PRA (Table 6.1-1, Tables 6.1-2 and 6.1-3).

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Default Congestion Free PRM UCAP	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%
LRR UCAP per-unit of LRZ Peak Demand	1.148	1.186	1.152	1.216	1.239	1.144	1.153	1.267	1.127	1.489
Capacity Import Limit (CIL) (MW)	4,415	2,595	3,369	6,411	4,332	7,941	3,785	4,834	3,622	2,688
Capacity Export Limit (CEL) (MW)	516	2,017	5,430	4,280	2,122	3,249	2,578	2,424	2,149	1,824

Table 6.1-1: Deliverables to the 2018-2019 Planning Resource Auction (PRA)

LRZ	Tier	18-19 Limit (MW)[22]	Monitored Element	Contingent Element	Figure 6.1-3 Map ID	GLT Applied	Generation Redispatch (MW)	17-18 Limit (MW)
1	1&2	4,415	Sherman Street to Sunnyvale 115 kV	Arpin to Rocky Run 115 kV	1	No	0	3,531
2	1&2	2,595	Plano B to Electric Junction B 345 kV	Plano R to Electric Junction 345 kV	2	No	2,000	2,227
3	1&2	3,369	Sub 3458 to Sub 3456 345 kV	Sub 3455 to Sub 3740 345 kV	3	No	2,000	2,408
4	N/A	6,411	North Decatur West Bus 138 kV voltage	Clinton Generation	4	No	N/A	5,815
5	1&2	4,332	Joppa 345/161 kV	Shawnee 500/345 kV	5	No	2,000	4,096
6	1&2	7,941	Paradise to BRTAP 161 kV	Phillips Bend to Volunteer 500 kV	6	Yes	2,000	6,248
7	N/A	3,785	Hager 120 kV bus voltage	Wyane to Monroe 345 kV	7	No	N/A	3,320
8	1&2	4,834	Sterlington 500/115 kV #2	Sterlington to El Dorado 500 kV	8	No	2,000	3,275
9	1&2	3,622	Sterlington to Downsville 115 kV	Mt. Olive to El Dorado 500 kV	9	Yes	2,000	3,371
10	1	2,688	Henando to Coldwater 115 kV	Moon Lake to Batesville 230 kV	10	No	1,670	1,910

[21] Or: https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf
[22] The 18-19 Limit represents the limit after redispatch has been considered.

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Table 6.1-2: 2018-2019 Planning Year Capacity Import Limits

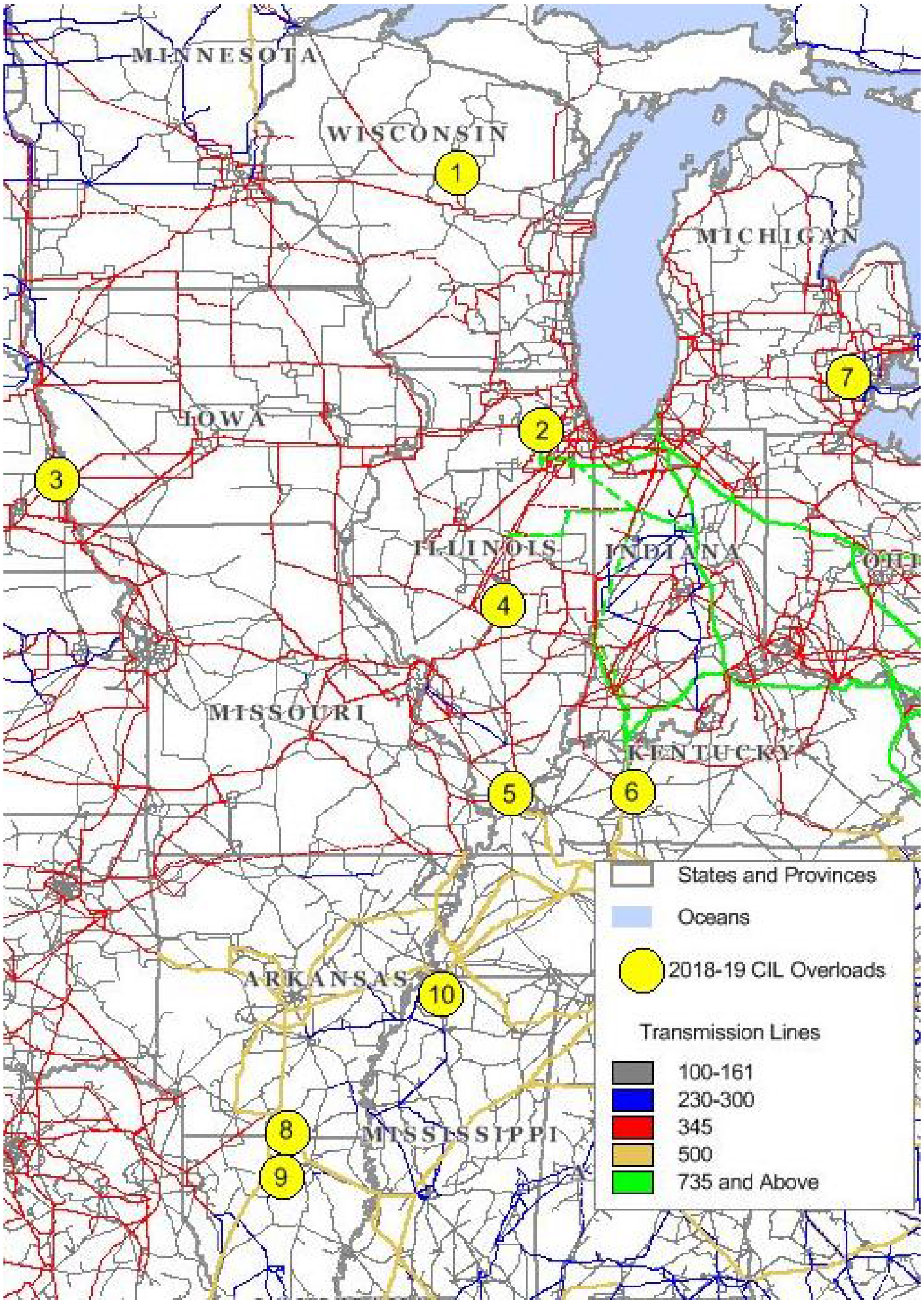

Figure 6.1-3: 2018-2019 Capacity Import Limit Map

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LRZ	18-19 Limit (MW)	Monitored Element	Contingent Element	Figure 6.1-4 Map ID	GLT Applied	Generation Redispatch (MW)	17-18 Limit (MW)
1	516	Lakefield to Dickson 161 kV	Webster to Kossuth 345 kV	1	Yes	1,685	686
2	2,017	Zion EC to Zion Station 345 kV	Zion to Pleasant Prairie 345 kV	2	Yes	950	2,290
3	5,430	Council Bluffs to Sub 3456 345 kV	Nebraska City Unit 2	3	Yes	1,111	1,772
4	4,280	Marion CT to Renshaw 161 kV	Marion Ct to Marion S 161 kV	4	Yes	0	11,756
5	2,122	Maywood to Spencer Creek 161 kV	System Intact	5	Yes	353	2,379
6	3,249	Wilson to Matanzas 161 kV	Green River to Wilson 161 kV	6	Yes	1,058	3,191
7	2,578	Monroe to Allendorf 345 kV	Lulu to Morocco to Milan 345 kV	7	Yes	0	2,519
8	2,424	Russelville South to Dardanelle 161 kV	Arkansas Nuclear to Fort Smith 500 kV	8	No	0	2,493
9	2,149	Clay to Aberdeen 161 kV	West Point to Clay 500 kV	9	No	2,000	2,373
10	1,824	Batesville to Tallahachie 161 kV	Choctaw to Clay 500 kV	10	No	1,534	1,747

Table 6.1-3: 2018-2019 Planning Year Capacity Export Limits

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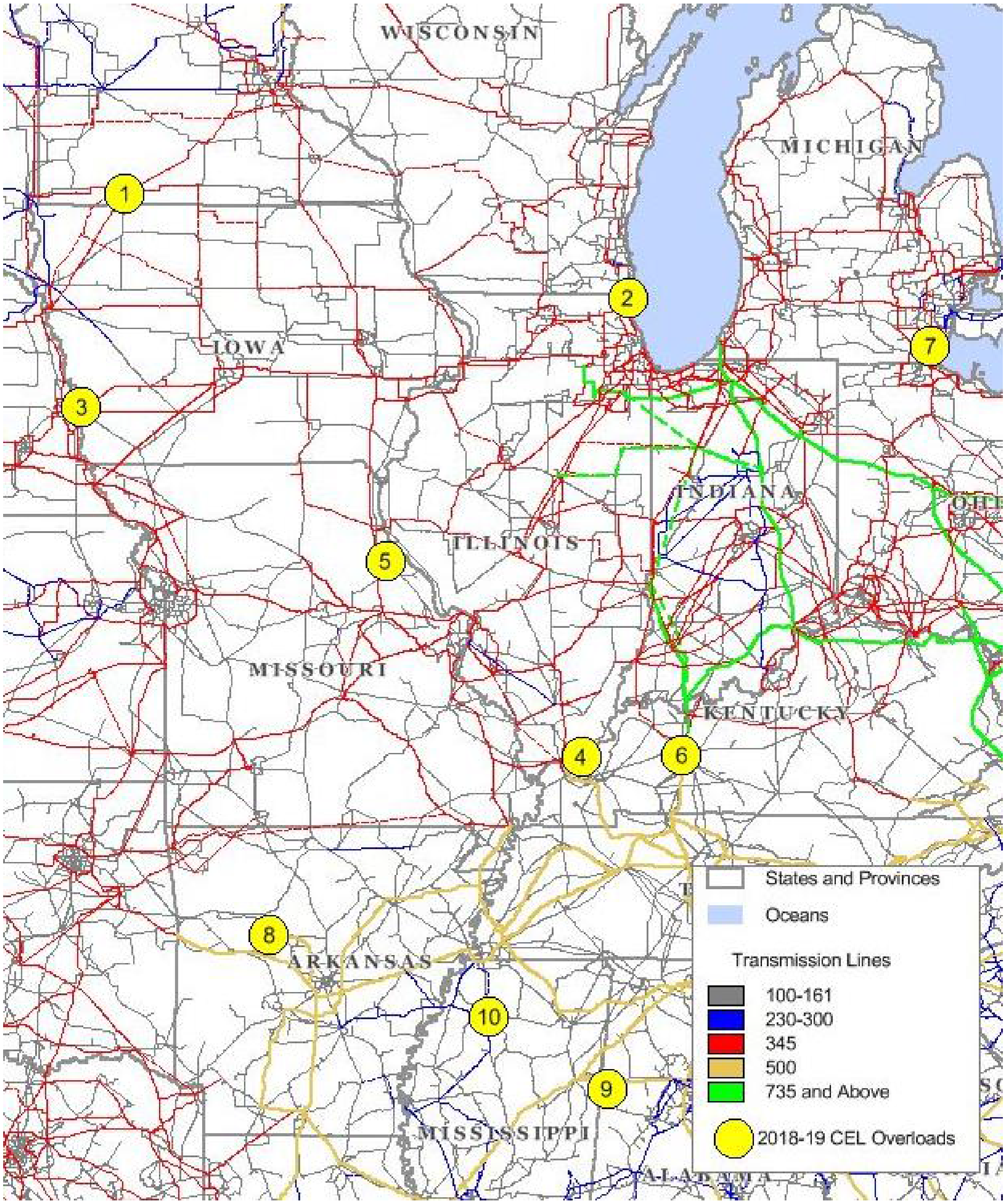

Figure 6.1-4: 2018-2019 Capacity Export Limit Map

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MTEP Projects and Capacity Import and Export Limits

The Capacity Import and Export Limits are deliverables to the PRA and, in combination with the Local Clearing Requirement (LCR), determine the maximum amount of imports or exports allowed for a zone. Constraints may occur in the PRA when the imports or exports are limited by the CIL, CEL and LCR. These constraints are considered in the development of the MTEP. Table 6.1-4 outlines projects impacting LCR, CIL or CEL that impact limits that have bound in the previous two Planning Resource Auctions.

LRZ	CEL or CEL	Monitored Element	MTEP Project ID	Target Appendix	Project Name	Min Expected ISD
1	CEL	Lakefield to Dickinson 161 kV Line	3205, 3213	A in MTEP11	Proposed MVP Portfolio 1: Lakefield Jct. – Winnebago – Winco – Kossuth County and Obrien County – Kossuth County – Webster 345 kV line and Proposed MVP Portfolio 1 – Winco to Hazleton 345 KV line	12/22/2015 – 9/4/2018, 8/14/2015 – 12/31/2019

Table 6.1-4: MTEP project impacting CEL, which has bound in the PRA

For full details of the LOLE study, refer to the Planning Year 2018 LOLE study report.

Wind Capacity Credit

A class-average wind capacity credit of 15.2 percent was established for the 2018-2019 planning year by determining the Effective Load Carrying Capability (ELCC) of wind resources. The wind capacity credit decreased from the wind capacity credit of 15.6 percent established in the 2017-2018 Planning Year (Figure 6.1-5). For more information, refer to the complete 2018-2019 Wind Capacity Credit Report[23].

[23] Or: https://cdn.misoenergy.org/2018%20Wind%20Capacity%20Report89288.pdf

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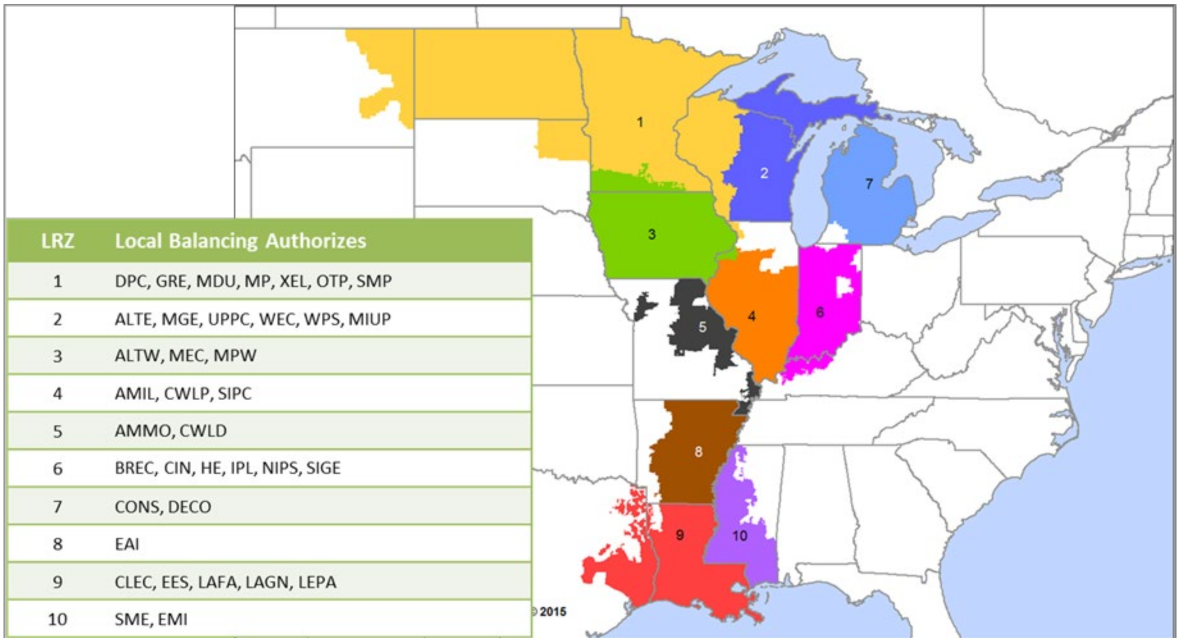

Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
Registered Max (MW)	16,761	4,779	734	8,450	644	282	1,872	0	0	0
UCAP (MW)	2,548	873	76	1,310	58	21	210	0	0	0
ELCC %	15.2%	18.3%	10.4%	15.5%	9.0%	7.4%	11.2%	0.0%	0.0%	0.0%
Wind CPNode Count	207	72	11	86	8	4	26	0	0	0

Figure 6.1-5: Wind Capacity Credit by Local Resource Zones (LRZ) for the 2018-2019 Planning Year

Solar Capacity Credit

A class-average solar capacity credit of 50 percent was established for the 2018-2019 planning year by estimating the peak period contribution from historical solar irradiance simulation data. New resources without summer operating history will receive this class average capacity credit until at least 30 consecutive days of summer performance data are available, at which time the resource's individual capacity credit will be based on its own operating history. More details can be found in the MISO BPM-011 in section 4.

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6.2 Long-Term Resource Assessment

The Long-Term Resource Assessment (LTRA) examines the balance between projected resources and the projected load. These resources are compared with Planning Reserve Margin Requirements (PRMR) to calculate a projected surplus or shortfall.

MISO forecasts sufficient capacity resources to meet expected demand and reserves for Planning Year 2019 above the Planning Reserve Margin Requirement (PRMR) of 17.1 percent. Beginning in 2020, MISO capacity is projected to fall below the PRMR and remain there for the rest of the assessment period (Table 6.2-1). MISO anticipates the projected margins will change significantly as load-serving entities and state commissions solidify future capacity plans.

In GW (ICAP)	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25	PY 2025/26	PY 2026/27	PY 2027/28	PY 2028/29
(+) Existing Resources	140.2	139.7	138.5	136.9	134.7	133.6	133.1	132.7	132.7	132.7
(+) New Resources	2.7	2.9	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6
(+) DRR	7.5	7.5	7.5	7.6	8.0	8.0	8.0	8.0	8.0	8.0
(+) BTMG	4.3	4.4	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8
(+) Imports	4.1	4.1	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
(-) Exports	3.4	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1
(-) Low Certainty Resources	5.2	6.1	6.0	5.6	5.8	6.2	6.9	7.8	8.1	8.1
(-) Transfer Limited	3.1	2.7	3.1	3.0	2.8	2.6	2.4	2.2	2.0	1.8
Available Resources	147.0	146.7	146.3	145.4	143.6	142.4	140.5	139.3	139.2	139.4
DPP Potential Resources	0.8	1.3	2.4	4.2	4.7	4.7	4.7	4.7	4.7	4.7
Demand	125.0	125.3	125.6	126.0	126.4	126.7	129.4	129.1	128.9	128.9
PRMR	146.4	146.7	147.1	147.5	148.0	148.4	151.5	151.2	151.0	151.0
PRMR Shortfall	0.6	0.0	-0.8	-2.1	-4.3	-6.0	-11.1	-11.8	-11.7	-11.5
Reserve Margin Percent (%)	17.6%	17.1%	16.5%	15.4%	13.7%	12.3%	8.6%	7.9%	8.0%	8.2%

Table 6.2-1: MISO projected PRMR details (cumulative)

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MISO projects a regional surplus for the summer of 2019, and then a continual decrease through the assessment period.

Operating at the reserve margin creates a new operating reality for MISO members where the use of all resources available on the system and emergency operating procedures are more likely. This reality will lead to a projected dependency in the use of Load Modifying Resources (LMR), such as Behind-the-Meter Generation (BTMG) and Demand Response (DR).

In 2019, MISO expects a total of 148,600 MW of Anticipated Capacity Resources to be available on peak

The conclusions from the long-term resource assessments are:

- Lower demand-growth forecasts across most zones in MISO
- The increase in committed resources from BTMG and Demand Response
- MISO projects that each zone within the MISO footprint will have sufficient resources within their boundaries to meet their Local Clearing Requirements or the amount of resource, which must be contained within their boundaries
- All zones within MISO are sufficient from a resource adequacy point of view in the near term, when available capacity and transfer limitations are considered. Regional shortages in later years may be rectified by the utilities; also MISO is engaged with stakeholders in a number of Resource Adequacy reforms to help rectify these out-year shortages.

Policy and changing generation trends continue to drive new potential risks to resource adequacy, requiring continued transparency and vigilance to ensure long-term needs.

MISO projects that reserve margins will continue to tighten over the next five years, approaching the reserve margin requirement.

Assumptions

At the end of 2013 MISO and Organization of MISO States (OMS) first conducted a Resource Adequacy survey of load-serving entities to help bridge the gap of limited visibility that exists between the annual Module E Tariff process and Forward Resource Assessment. MISO finished the fifth iteration of the OMS-MISO survey in June 2018, and it was instrumental in the development of the Long-Term Resource Assessment and the Resource Adequacy outlook for the MISO region.

Demand Growth

In 2019, MISO anticipates that the MISO Region's coincident demand will be 124,983 MW, which is a 50/50 weather-normalized load forecast.

In 2019, MISO anticipates that the MISO Region's coincident demand will be 124,983 MW, which is a 50/50 weather-normalized load forecast

Load-serving entities submit demand forecasts for the upcoming 10 years. MISO utilizes these forecasts to calculate a MISO business-as-usual load growth. Based on these forecasts, MISO anticipates a system-wide average growth rate of 0.3 percent for the period from 2019 to 2028.

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Resources

In 2019, MISO expects a total of 148,600 MW of Anticipated Capacity Resources to be available on peak.

MISO's current generation capacity (nameplate) of 170,500 MW steps down to Existing-Certain Capacity Resources of 140,200 MW by accounting for summer on-peak generator performance (including wind capacity at 15.2 percent of nameplate and solar at 50 percent of nameplate), transmission limitations and energy-only capacity (Existing-Other Capacity Resources). MISO only relies on 140,200 MW towards its PRMR to meet a loss-of-load expectation of one day in 10 years.

BTMG, Interruptible Load (IL), Direct Control Load Management (DCLM) and Energy Efficiency Resources (EER) are eligible to participate as registered LMRs. All of these are emergency resources available to MISO only during a Maximum Generation Emergency Event Step 2b per MISO's Emergency Operating Procedures. MISO assumes the 4,280 MW of BTMG increasing to 4,782 in 2023 and 5,990 MW of LMR DR that was qualified in the 2018 Planning Resource Auction to be available throughout the assessment period.

In the 2018 OMS-MISO Survey, resources that were identified to have a low certainty of serving load were not included (Figure 6.2-1).

Through the Generator Interconnection Queue (GIQ) process, MISO anticipates 3,646 MW of future firm capacity additions and uprates to be in-service and expected on-peak during the assessment period. This is based on a snapshot of the GIQ as of June 2018 and is the aggregation of active projects with a signed Interconnection Agreement.

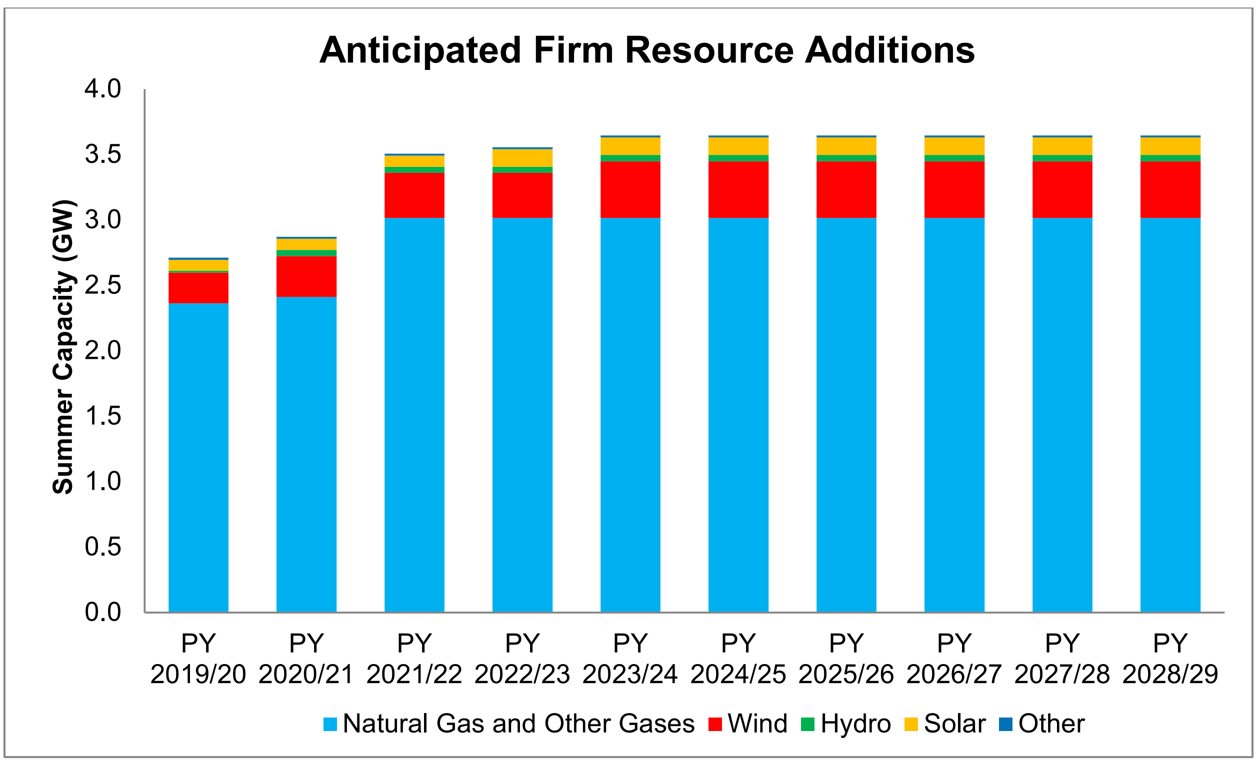

Figure 6.2-1: Anticipated Resource Additions and Uprates (Cumulative) of active projects with a signed Interconnection Agreement in the MISO Region

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Imports and Exports

MISO assumes a forecast of 4,064 MW of capacity from outside of the MISO footprint to be designated firm for use during the assessment period and cannot be recalled by the source transmission provider. This capacity was designated to serve load within MISO through the Module E process for summer 2018. It's assumed that the firm imports continue at this level for the assessment period. MISO assumes a forecast of 3,398 MW of firm capacity exports in year 2019. Exports are projected to decrease to 3,100 MW in 2020 and remain at that level for the rest of the assessment period.

When comparing reserve margin percent numbers between Figure 6.2-1 and the NERC LTRA, the percent for each planning year will be slightly lower in the NERC LTRA because of differences in the reserve margin percent calculation. MISO's resource adequacy construct counts DR as a resource while the NERC calculates DR on the demand side. While the percent will be slightly different, the absolute GW shortfall/surplus is comparable between the two.

6.3 Seasonal Resource Assessment

MISO has historically conducted seasonal resource assessments for the winter months of December, January and February, and the summer months of June, July and August. In 2018, MISO also conducted a spring assessment to capture risks during March, April and May. Seasonal assessments primarily evaluate the expected near-term system performance and prepare operators for the upcoming season. The MISO resource assessments coincide with NERC seasonal reliability assessments and MISO operational readiness workshops held prior to the assessment's season.

The 2017-2018 winter, 2018 spring and 2018 summer season findings show that the projected capacity levels exceed the Planning Reserve Margin Requirement, with adequate resources to serve load.

Seasonal Assessment Methods

MISO studies multiple scenarios at varying capacity resource levels, expected demand levels and forced outage rates. In order to align with the Sub-regional Export Constraint (SREC) from the Planning Resource Auction (PRA), only 1,500 MW above the MISO South load and reserve margin were counted toward aggregate margins at coincident peak demand in all of the projected scenarios for the 2018 Summer Assessment.

MISO coordinates extensively with neighboring Reliability Coordinators as part of the seasonal assessment and outage coordination processes, via scheduled daily conference calls and ad-hoc communications as need arises in real-time operations. There is always the potential for a combination of higher loads, higher forced outage rates and fuel limitations. In the summer, unusually hot and dry weather can lead to low water levels and/or high water temperatures. This can impact the maximum operating capacity of thermal generators that rely on water resources for cooling, leading to added deratings in real time and lowering functional capacity. MISO resolves these situations through existing procedures depending on the circumstances, and several scenarios are studied for each season to project the possible reserve margins expected.

Demand

Based on 22 years of historic actual load data, MISO calculates a Load Forecast Uncertainty (LFU) value from statistical analysis to determine the likelihood that actual load will deviate from forecasts. A normal distribution is created around the 50/50 forecast based on a standard deviation equal to the LFU of the 50/50 forecast. This curve represents all possible load levels with their associated probability of occurrence. At any point along the curve it is possible to derive the percent chance that load will be above or below a load value by finding the area under the curve to the right or left of that point. MISO chooses the 90th percentile for the High Load scenarios. For more information regarding this analysis, refer to the Planning Year 2018 LOLE Study.

Demand Reporting

MISO does not forecast load for the Seasonal Resource Assessments. Instead, Load-Serving Entities (LSEs) report load projections under the Resource Adequacy Requirements section (Module E-1) of the MISO Tariff. LSEs report their annual load projections on a MISO Coincident basis as well as their Non-Coincident load projections for the next 10 years, monthly for the first two years and seasonally for the remaining eight years. MISO LSEs have the best information of their load; therefore, MISO relies on them for load forecast information.

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For these studies, MISO created a Non-Coincident and a Coincident peak demand on a regional basis by summing the annual peak forecasts for the individual LSEs in the larger regional area of interest.

2017-2018 Winter Overview

For planning year 2017-2018, MISO's Planning Reserve Margin Requirement (PRMR) was 15.8 percent. For the 2017-2018 winter peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 35.7 percent, which far exceeds the PRMR of 15.8 percent. The winter scenarios project the reserve margin to be in the range of 28.3 to 37.3 percent (Figure 6.3-1).

MISO's 50/50 coincident peak demand for the 2017-2018 winter season was forecasted to be 103,407 MW including transmission losses, with 140,284 MW of capacity to serve MISO load during the 2017-2018 winter season. Excluded from the capacity are 3,906 MW of MISO South resources to align with the PRA SREC.

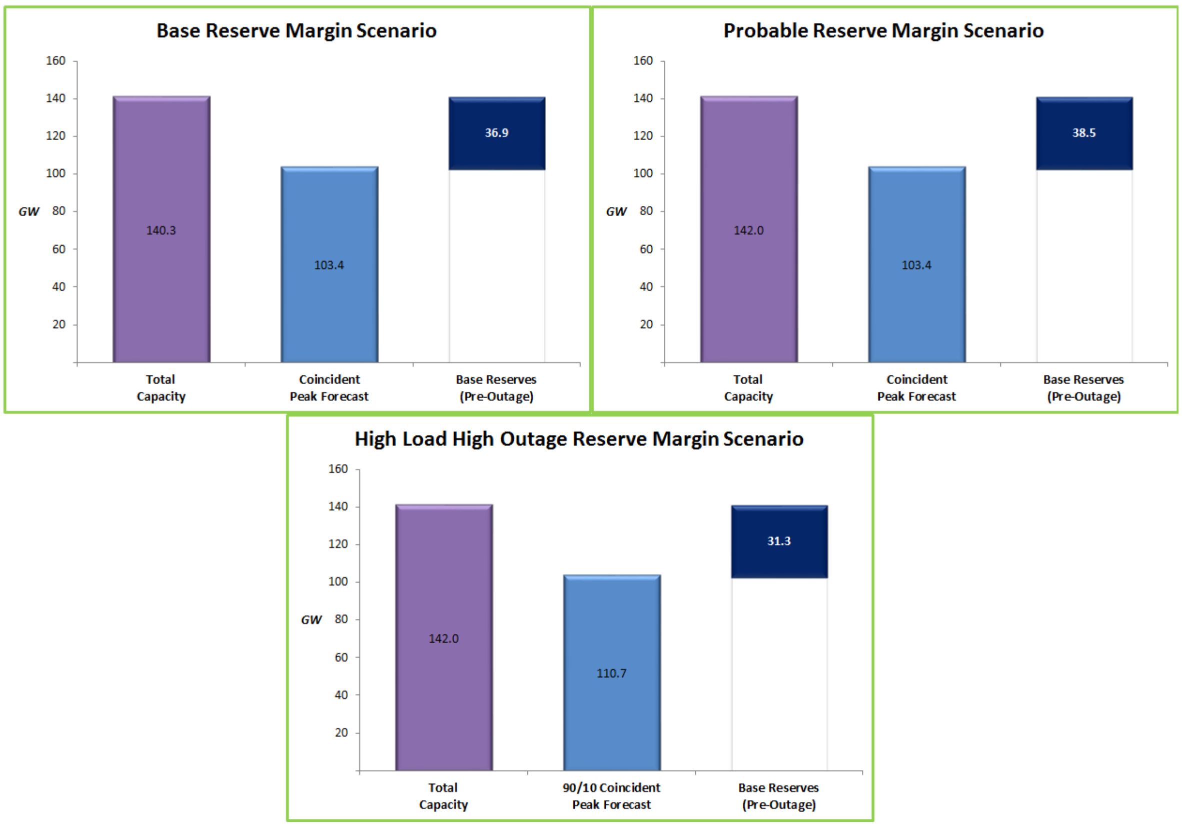

Figure 6.3-1: Winter 2017-2018 Projected Reserve Margin Scenarios (GW)

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2017-2018 Winter Rated Capacity

For the 2017-2018 winter season, MISO projected 140,284 MW of existing certain capacity to serve MISO load during the winter. The capacity includes 2,459 MW of Behind-the-Meter Generation (BTMG) and 3,593 MW of Demand Resource programs, with 871 MW of Net Firm Exports. MISO expected 2,326 MW of wind capacity to be available to serve load for the winter.

MISO arrived at the Winter Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations of 2,333 MW; thermal unit winter output reductions of 5,965 MW; and reductions due to the Effective Load Carrying Capability of wind resources of 13,905 MW based on available nameplate wind resources of 17,043 MW. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, it assumed that 1,500 MW of excess capacity transferred to the North/Central region of the footprint due to the estimated SREC for the PRA.

Winter Reserve Margin Scenarios

MISO's projected 2017-2018 MISO Winter Rated Capacity varies by scenario (Figures 6.3-2 through 6.3-5). MISO chose the 90^{th} percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 110,666 MW for the 2017-2018 winter.

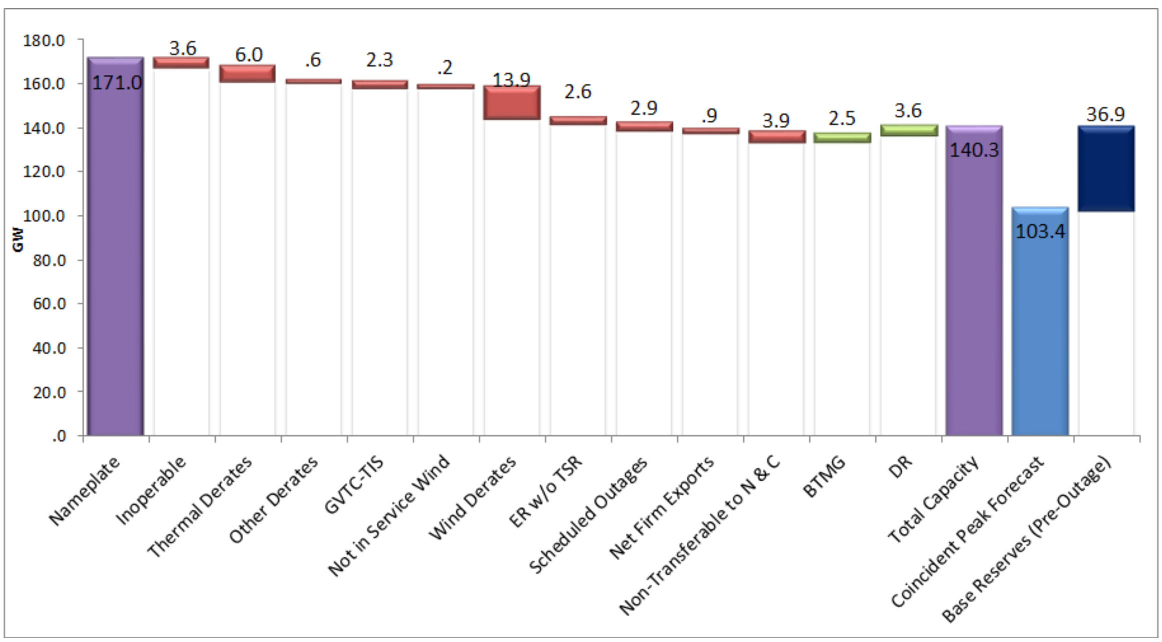

Figure 6.3-2: 2017-2018 Winter Rated Capacity Projected Base Scenario (GW)

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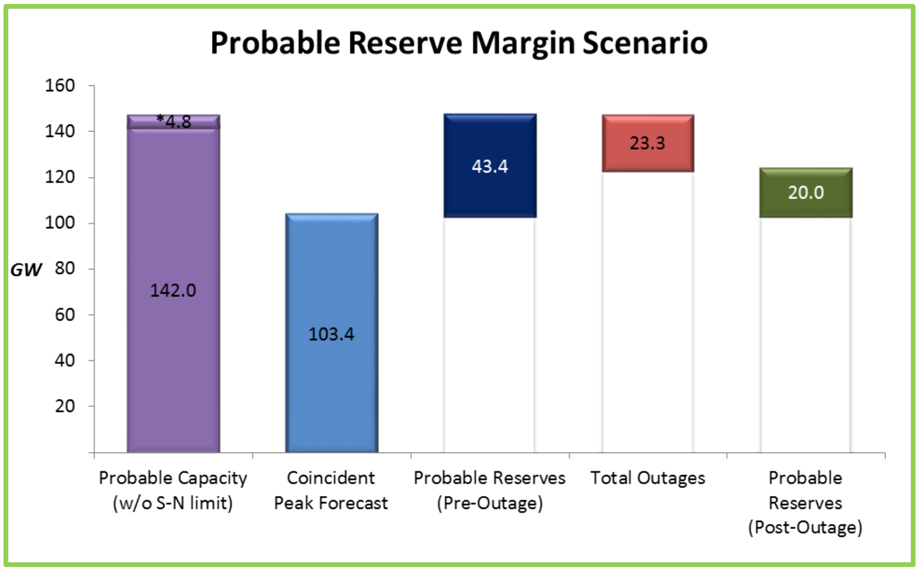
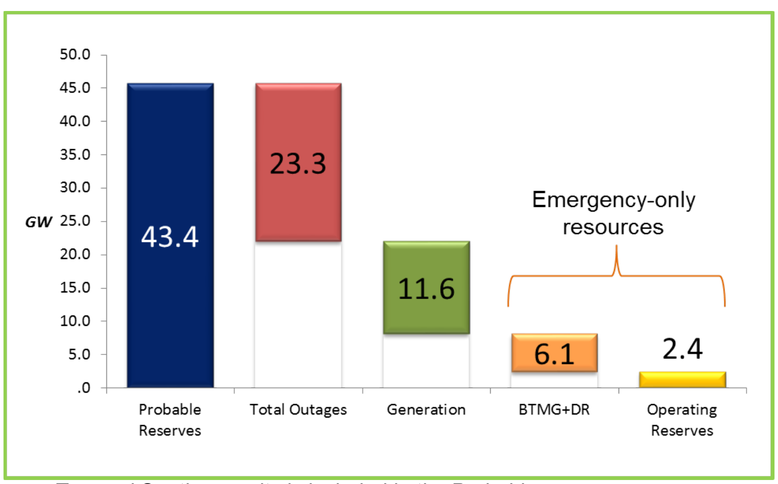
The Probable scenario contains additional assumptions (Figure 6.3-3). MISO expects that any energy resource without firm Point-To-Point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with the 1,500 MW SREC limitation for the 2017-18 Planning Year Auction.



Stranded South capacity is added to reserves to reflect outages seen by operations

Figure 6.3-3: 2017-2018 Winter Rated Capacity Probable Scenario (GW)

In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2017-2018 winter season was 2,400 MW, which is called on as a last resort before load shed (Figure 6.3-4). These reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.



Trapped South capacity is included in the Probable reserves

Figure 6.3-4: 2017-2018 Winter Rated Capacity Probable Scenario Reserves (GW)

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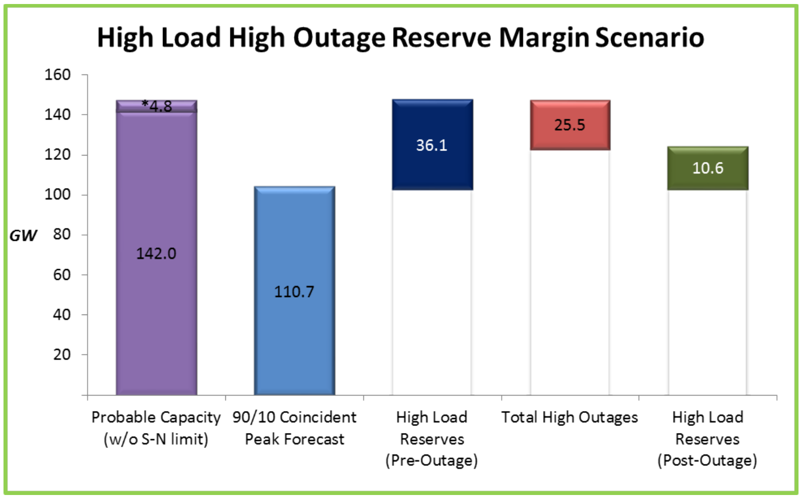
The High Load, High Outage scenario has added assumptions (Figure 6.3-5). Beginning with the anticipated reserves from the Probable scenario (Figure 6.3-3), the load increases to show the higher load from a 90/10 forecast. Higher than normal outages are assumed reflecting the highest seasonal average outages reported in GADS from 2012-2016. The extreme outages reflect the highest number of GADS reported outages seen on winter peak from 2012-2016.



Stranded South capacity is added to reserves to reflect outages seen by operations

Figure 6.3-5: Winter Rated Capacity Projected High Load, High Outage Scenario (GW)

2018 Spring Overview

For planning year 2017-2018, MISO's Planning Reserve Margin Requirement (PRMR) was 15.8 percent. For the 2018 spring peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 34.8 percent, which far exceeds the PRMR of 15.8 percent. The spring scenarios project the reserve margin to be in the range of 27.5 to 36.5 percent (Figure 6.3-6).

MISO's 50/50 coincident peak demand for the 2018 spring season was forecasted to be 103,407 MW including transmission losses, with 139,383 MW of capacity to serve MISO load during the 2018 spring season. Excluded from the capacity are 5,273 MW of MISO South resources to align with the PRA SREC.

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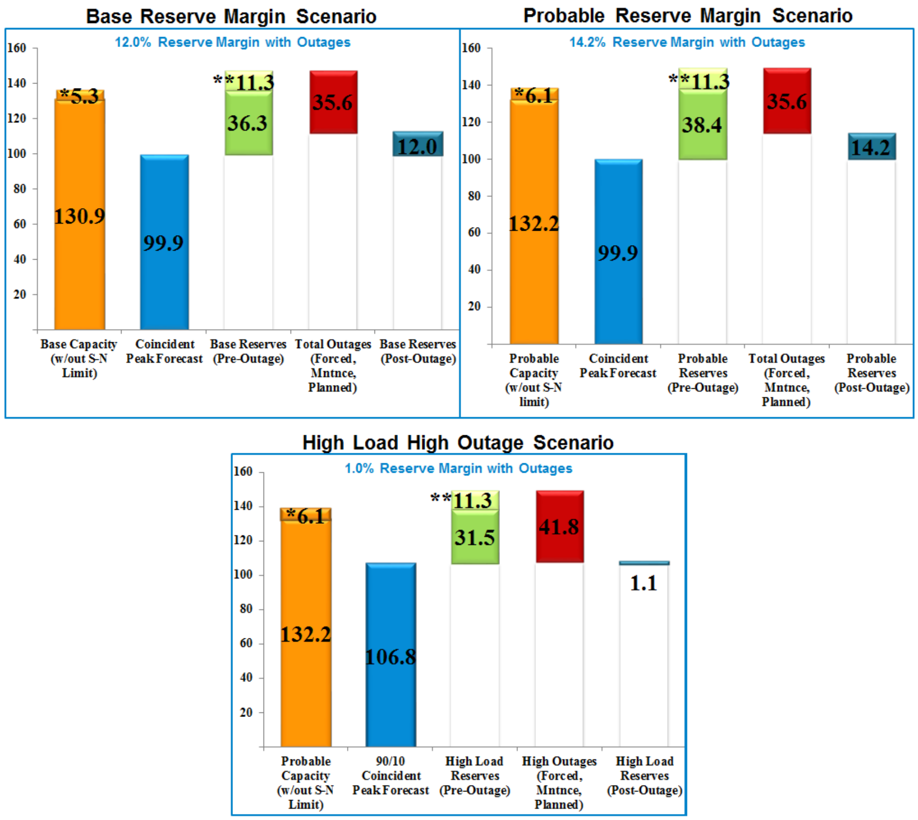


**Stranded South capacity is added to reserves to reflect outages seen by operations*
***Known planned outages added back to reserves before subtracting historic outages*

Figure 6.3-6: Spring 2018 Projected Reserve Margin Scenarios (GW)

2018 Spring Rated Capacity

For the 2018 spring season, MISO projected 139,383 MW of existing certain capacity to serve MISO load during the spring. The capacity includes 2,459 MW of Behind-the-Meter Generation (BTMG) and 3,593 MW of Demand Resource programs, with 871 MW of Net Firm Exports. MISO expected 2,345 MW of wind capacity to be available to serve load for the spring.

MISO arrived at the Spring Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations of 2,333 MW; thermal unit spring output reductions of 5,965 MW; and reductions due to the Effective Load Carrying Capability of wind resources of 13,905 MW based on available nameplate wind resources of 17,162 MW. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, it assumed that 1,500 MW of excess capacity transferred to the North/Central region of the footprint due to the estimated SREC for the PRA.

Spring Reserve Margin Scenarios

MISO's projected 2018 MISO Spring Rated Capacity varies by scenario (Figures 6.3-7 through 6.3-10). MISO chose the 90th percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 110,666 MW for the 2018 spring.

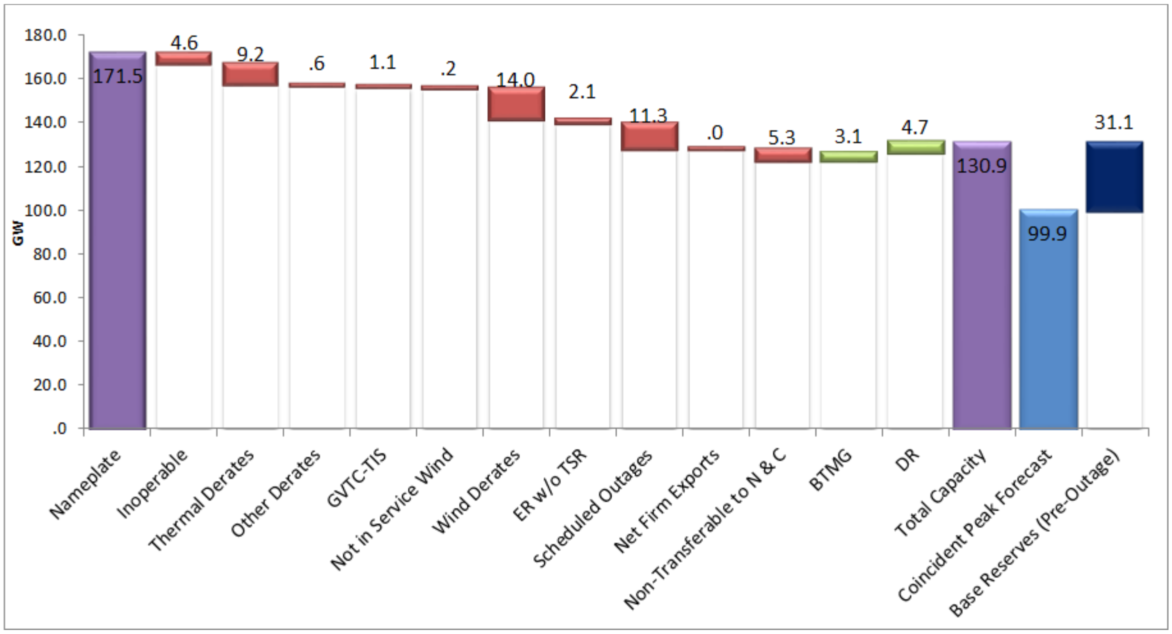
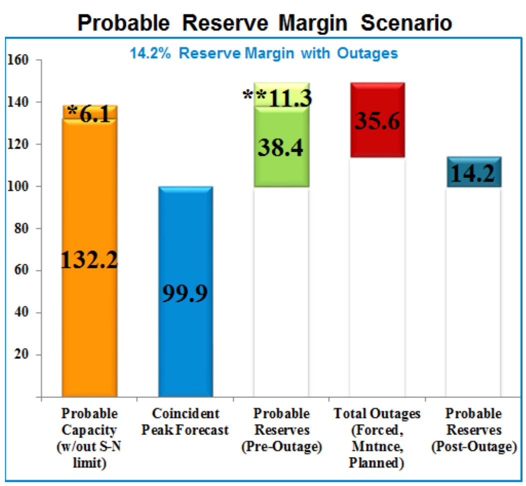


Figure 6.3-7: 2018 Spring Rated Capacity Projected Base Scenario (GW)

The Probable scenario contains additional assumptions (Figure 6.3-8). MISO expects that any energy resource without firm Point-To-Point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with the 1,500 MW SREC limitation for the 2017-18 Planning Year.



*Stranded South capacity is added to reserves to reflect outages seen by operations
**Known planned outages added back to reserves before subtracting historic outages

Figure 6.3-8: 2018 Spring Rated Capacity Probable Scenario (GW)

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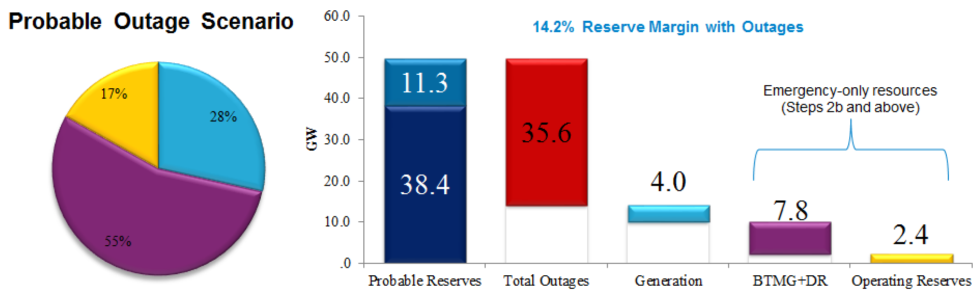
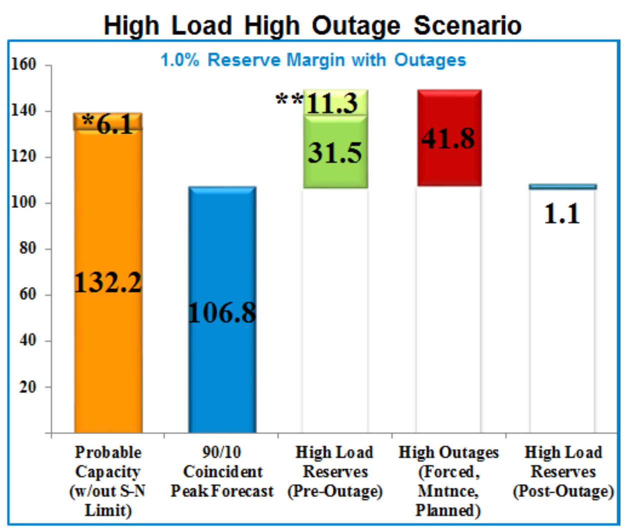
In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2018 spring season was 2,400 MW, which is called on as a last resort before load shed (Figure 6.3-9). These reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

The High Load, High Outage scenario has added assumptions (Figure 6.3-10). Beginning with the anticipated reserves from the Probable scenario (Figure 6.3-9), the load increases to show the higher load from a 90/10 forecast. Higher than normal outages are assumed reflecting the highest seasonal average outages reported in GADS from 2013-2017. The extreme outages reflect the highest number of GADS reported outages seen on spring peak from 2013-2017.



Trapped South capacity is included in the Probable reserves

Figure 6.3-9: 2018 Spring Rated Capacity Probable Scenario Reserves (GW)



**Stranded South capacity is added to reserves to reflect outages seen by operations*
***Known planned outages added back to reserves before subtracting historic outages*

Figure 6.3-10: Winter Rated Capacity Projected High Load, High Outage Scenario (GW)

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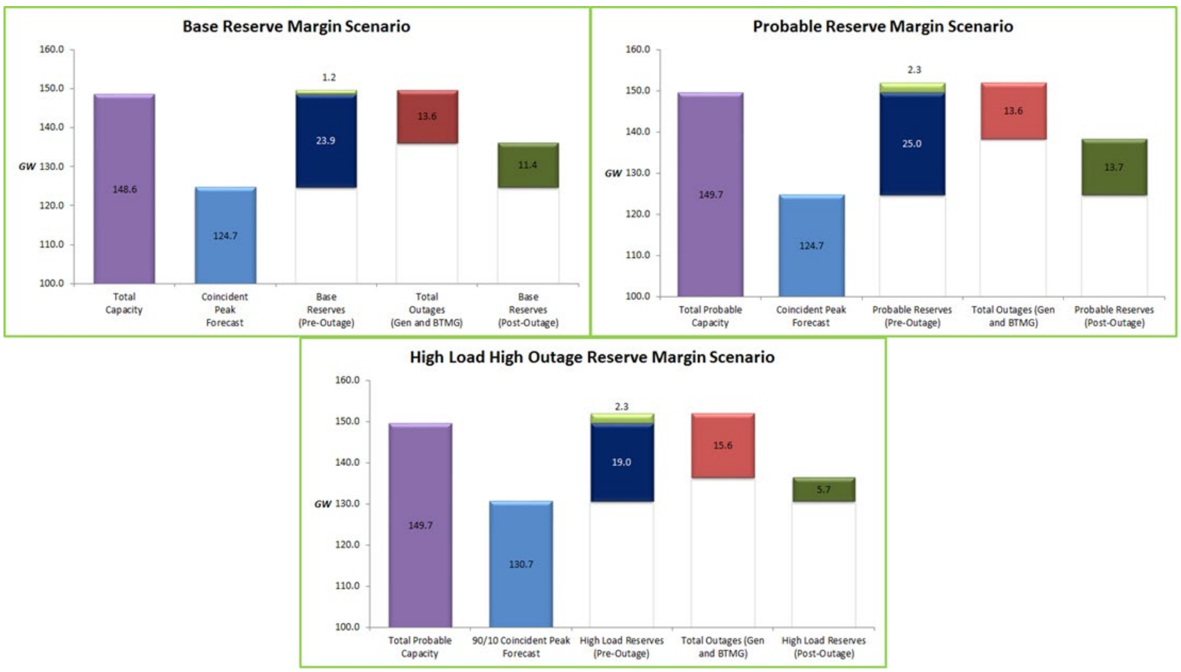
2018 Summer Overview

For planning year 2018-2019, MISO's summer PRM is 17.1 percent. During the 2018 summer peak hour, MISO expected adequate resources to serve load, with a NERC-reported base projected reserve margin of 19.1 percent, which exceeds the requirement of 17.1 percent by 2.0 percentage points. The summer scenarios project the reserve margin to be in the range of 14.5 to 20 percent (Figure 6.3-11).

MISO's 50/50 coincident peak demand for the 2018 summer season was forecasted to be 124,704 MW including transmission losses, with 148,553 MW of capacity to serve MISO load. Excluded from the capacity are 1,165 MW of MISO South resources to align with the 1,500 MW intra-RTO SREC.



**Stranded South capacity is added to reserves to reflect outages seen by operations*

Figure 6.3-11: MISO Summer 2018 Projected Reserve Margin Scenarios

2018 Summer Rated Capacity

For 2018, MISO projected 148,553 MW of capacity to serve MISO load during the 2018 summer season. The capacity includes 4,576 MW of BTMG and 7,137 MW of Demand Resource programs, while including 8 MW of Net Firm Exports. MISO expected 2,134 MW of wind capacity to be available to serve load this summer, after discounting wind capacity in the Commercial Model with pending interconnection agreements and capacity with Energy Resource Interconnection Service without a firm Point-To-Point Transmission Service Request. Capacity from the South, equal to its load and reserve margin requirement, was included in the regional total. Additionally, 1,500 MW of excess capacity was assumed as transferred to the North/Central region of the footprint.

MISO arrived at the Summer Rated Capacity value by reducing the Nameplate Capacity of its market footprint by multiple variables. The majority of the derates expected at-peak are due to resource interconnection limitations (1,704 MW); thermal unit summer output reductions (9,623 MW); and reductions due to the Effective Load Carrying Capability of wind resources (13,433 MW). Also, any MISO

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South capacity over the total of South Load, South reserve margin requirement, and 1,500 MW of SREC was not included in the regional value. This means that 1,165 MW of MISO South excess capacity was excluded from the calculation to align with 1,500 MW SREC limitation.

Reserve Margin Scenarios

MISO's projected 2018 MISO Summer Rated Capacity varies by scenario (Figures 6.3-12 through 6.3-16). MISO chose the 90th percentile of the normal distribution around a 50/50 load forecast for the High Load scenarios, which was 130,688 MW for the 2018 summer.

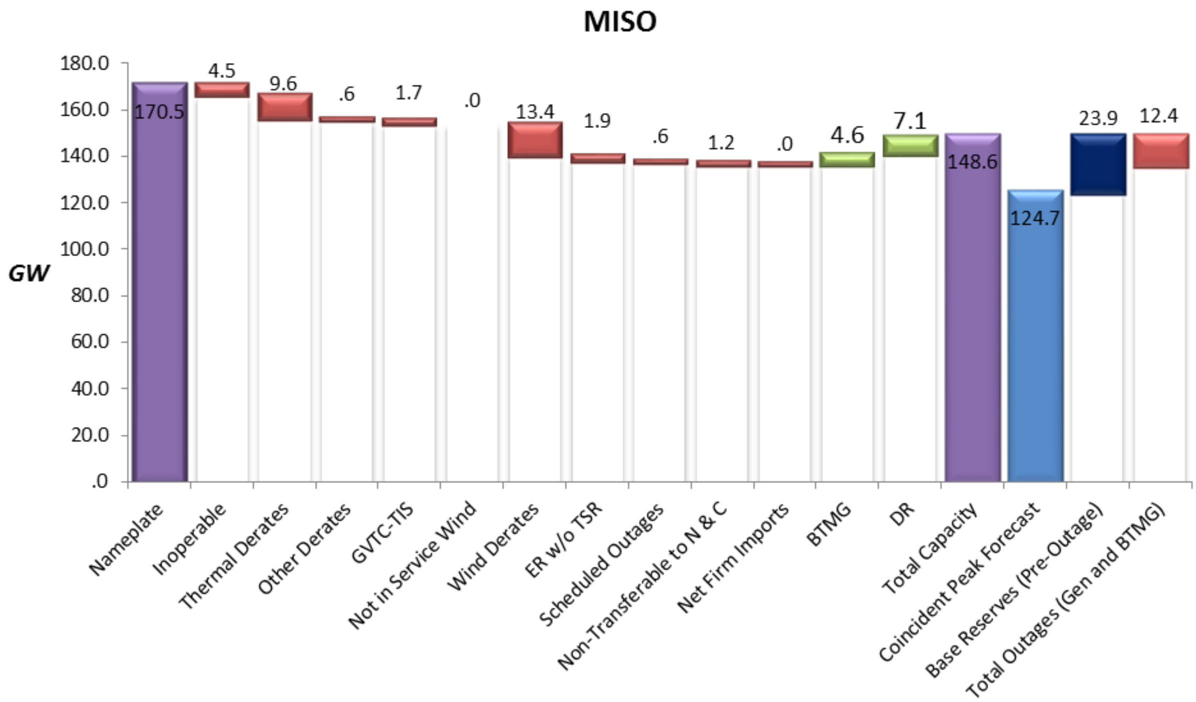

Figure 6.3-12: 2018 Summer Rated Capacity Projected Base Scenario (GW) showing the reduction of reserves from installed nameplate capacity, including derates and transmission-limited resources.

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The Probable scenario uses additional assumptions (Figure 6.3-13). MISO expects that any energy resource without firm Point-To-Point Transmission Service Rights will serve load locally, termed Energy Only. The portion of Energy Only from the MISO South region is excluded from the calculation to align with 1,500 MW SREC limitation. Additionally, any units designated as Under Study through the Attachment Y process are considered available.

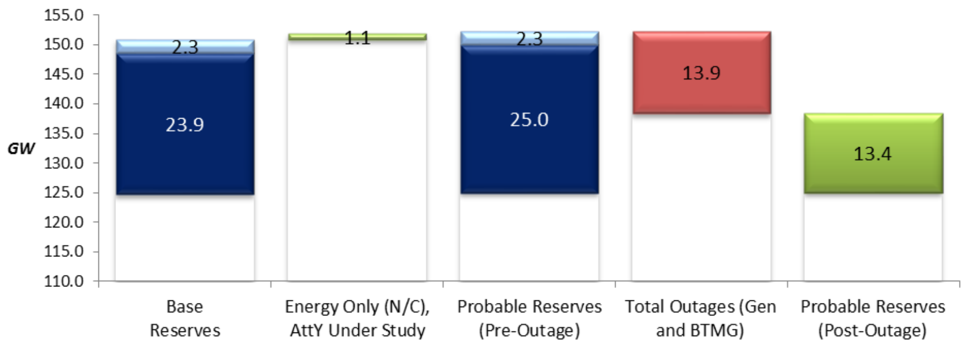

Figure 6.3-13: 2018 Summer Rated Capacity Projected Probable Scenario (GW)

The High Load, High Outage scenario has added assumptions (Figure 6.3-14). Beginning with the Probable reserves from the Probable scenario (Figure 6.3-13), the load is increased to show the higher load from a 90/10 forecast. Also a higher forced outage rate is assumed, using the highest historical forced outage rate applied to the capacity resources available.

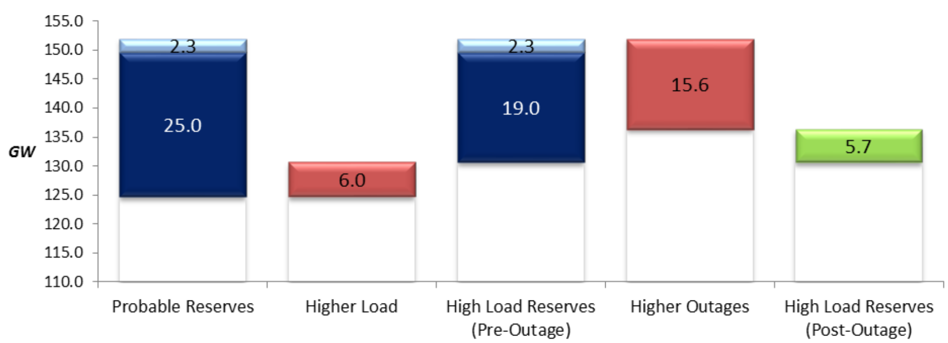

Figure 6.3-14: Summer Rated Capacity Projected High Load, High Outage Scenario (GW)

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2018 Summer Risk Assessment

MISO performs a probabilistic assessment on the region to determine the percent chance of utilizing Load Modifying Resources and Operating Reserves or having to curtail firm load. A risk profile is generated from this analysis (Figure 6.3-15).

It is always possible for a combination of higher loads, higher forced outage rates, fuel limitations, low water levels and other factors to lead to the curtailment of firm load. The Loss of Load Expectation (LOLE) model that MISO utilizes for PRMR takes into account the uncertainties associated with load forecasts (e.g., 50/50 versus 90/10) and generation outages (both forced and scheduled).

The chance of realizing an event is where the risk profile intersects the event range (Figure 6.3-10). As shown, the probabilistic analysis indicated a 79 percent chance of MISO calling a Maximum Generation Emergency Event Step 2b to access Load Modifying Resources; a 17 percent chance of initiating further steps to access Operating Reserves; and a 9 percent chance of curtailing firm load during the 2018 summer peak hour.

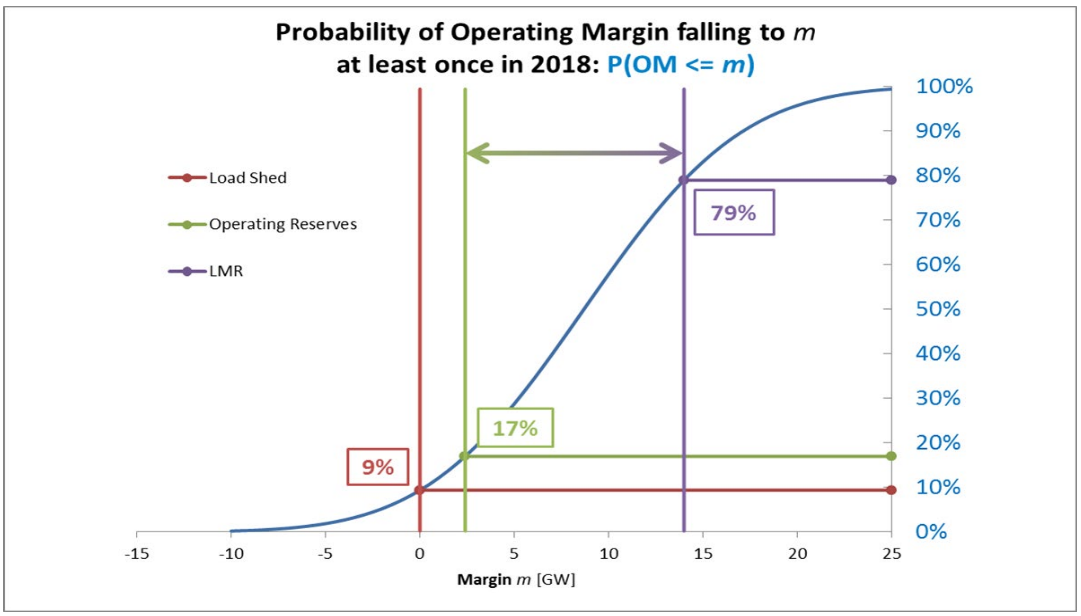

Figure 6.3-15: MISO 2018 summer chance of initiating Maximum Generation Emergency Step 2b or higher at forecasted Probable Reserve Margin

The reserves available in the Probable scenario are shown after forced, planned and maintenance outages are applied, showing the amount of Generation, BTMG, Demand Resource and Operating Reserves expected (Figure 6.3-16). In real-time, during normal operating conditions, MISO must carry Operating Reserves above load to maintain system reliability. The amount of Operating Reserves required to clear on a daily basis for the 2018 summer season was 2,400 MW, which is called on as a last resort before load shed. Operating reserves are made up of a combination of Regulating Reserves, Spinning Reserves and Supplemental Reserves.

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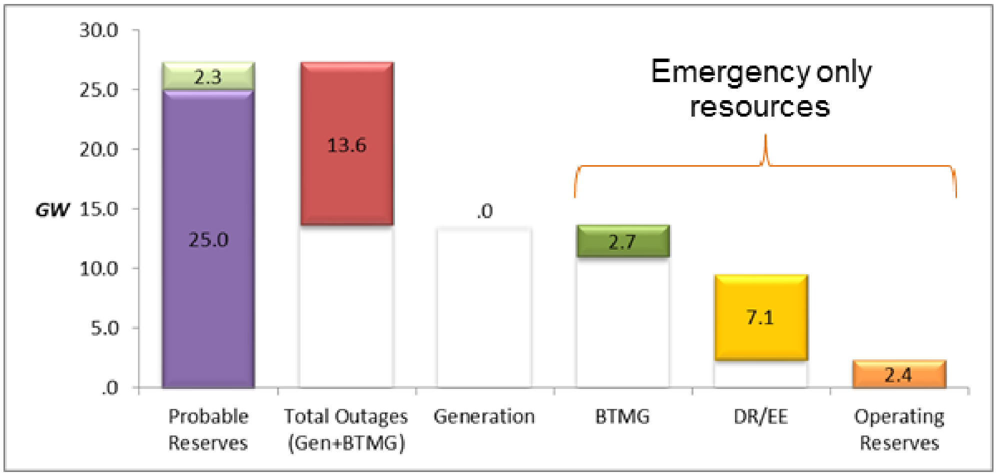

Figure 6.3-16: Summer Rated Capacity Projected Probable Reserves (GW)

MISO Summer Rated Capacity Methodology

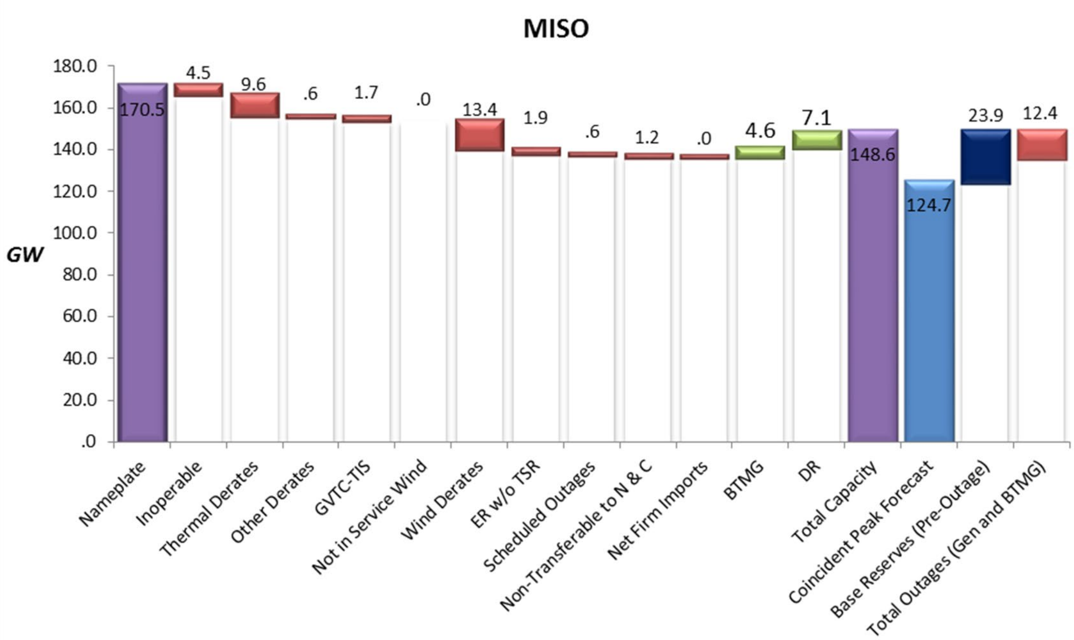

Figure 6.3-17: MISO 2018 Summer Rated Capacity Waterfall Chart — Base Scenario (GW)

The calculation of MISO Summer Rated Capacity resources separates into 13 parts (Figure 6.3-17). Separation of the Winter Rated Capacity is similar, with additional details found in the MISO 2017-2018 Winter Resource Assessment. The 13 parts include:

1. *Nameplate*: the summation of the maximum output from the latest commercial model. This reflects the amount of registered generation available internal to MISO.
2. *Inoperable:* the summation of approved mothballed or retired units determined through the Attachment Y process, which are still represented in the latest commercial model.
3. *Thermal Derates:* the summation of differences in unit nameplate capacities and the latest Generator Verification Test Capacity (GVTC) results, excluding inoperable resources.
4. *Other Derates*: the summation of differences in non-wind intermittent resource nameplate capacities and the resource averages of historical summer peak performance, excluding inoperable resources.
5. *Transmission-limited resources (GVTC-TIS)*: the summation of differences in GVTC and the unit's Total Interconnection Service (TIS) rights based on latest unit deliverability test results. Transmission-limited resources for wind are the summation of differences in nameplate capacity and TIS.
6. *Not-in-Service and provisional wind*: units that are registered in the latest commercial model, but are not in service yet; the wind units that are connected to the system but their interconnection process is not completed yet.
7. *Wind Derates*: the summation of the differences in wind unit Nameplate Capacities and the unit wind capacity credit, which is determined based on the Effective Load Carrying Capability of wind. This excludes Inoperable Resources and Transmission-Limited MWs.
8. *ER without TSR Energy-only:* resources with Energy Resource Interconnection Service (ERIS) without a firm Point-To-Point Transmission Service Right.
9. *Scheduled Outages*: Scheduled generator outages from June 1, 2018, through August 31, 2018, were pulled from MISO's Control Room Operator's Window (CROW) outage scheduler in March 2018. The data pulled met the following criteria: 1. Mapped to the latest commercial model; 2. Outage Request Status is equal to Active, Approved, Pre-Approved, Proposed, Study or Submitted; 3. Request priority is equal to planned; 4. Equipment request type is equal to Out of Service (OOS) or "Derated To 0 MW."

   In order to calculate the expected scheduled outages on peak, MISO calculates the amount of outages on a daily basis assuming that if a unit is out for as little as one hour, that unit will be out for that entire day. The highest amount of outages during the month of July is assumed to be equal to the amount of outage during summer peak conditions.

   This calculation amounts to an expected scheduled maintenance of 627 MW.
10. *Net Firm Exports:* MISO anticipated the net firm interchange to be exporting 8 MW for the 2018 summer.
11. *Non-Transferable to MISO North and Central*: 1,165 MW of MISO South resources were excluded from the available capacity to align with 1,500 MW SREC.
12. *Behind-the-Meter Generation (BTMG)*: the summation of approved and cleared load-modifying resources identified as Behind-the-Meter Generation through the Resource Adequacy (Module E) process. Based on the planning year 2018-2019 Planning Resource Auction, 4,576 MW of BTMG cleared to be available for the 2018 summer season.
13. *Demand Resource*: MISO currently separates contractual demand resource into two separate categories: Direct Control Load Management (DCLM) and Interruptible Load (IL).

    DCLM is the magnitude of customer service (usually residential) that can be interrupted at the time of peak by direct control of the applicable system operator. DCLM is typically used for "peak shaving." In MISO, air conditioner interruption programs account for the vast majority of DCLM during the summer months.

    IL is the magnitude of customer demand (usually industrial) that, in accordance with contractual arrangements, can be interrupted at the time of peak by direct control of the system operator (remote tripping) or by action of the customer at the direct request of the system operator. The amount of registered and cleared load-modifying resources identified as demand resource through the Resource Adequacy (Module E) process is 7,137 MW for the 2018 summer season.

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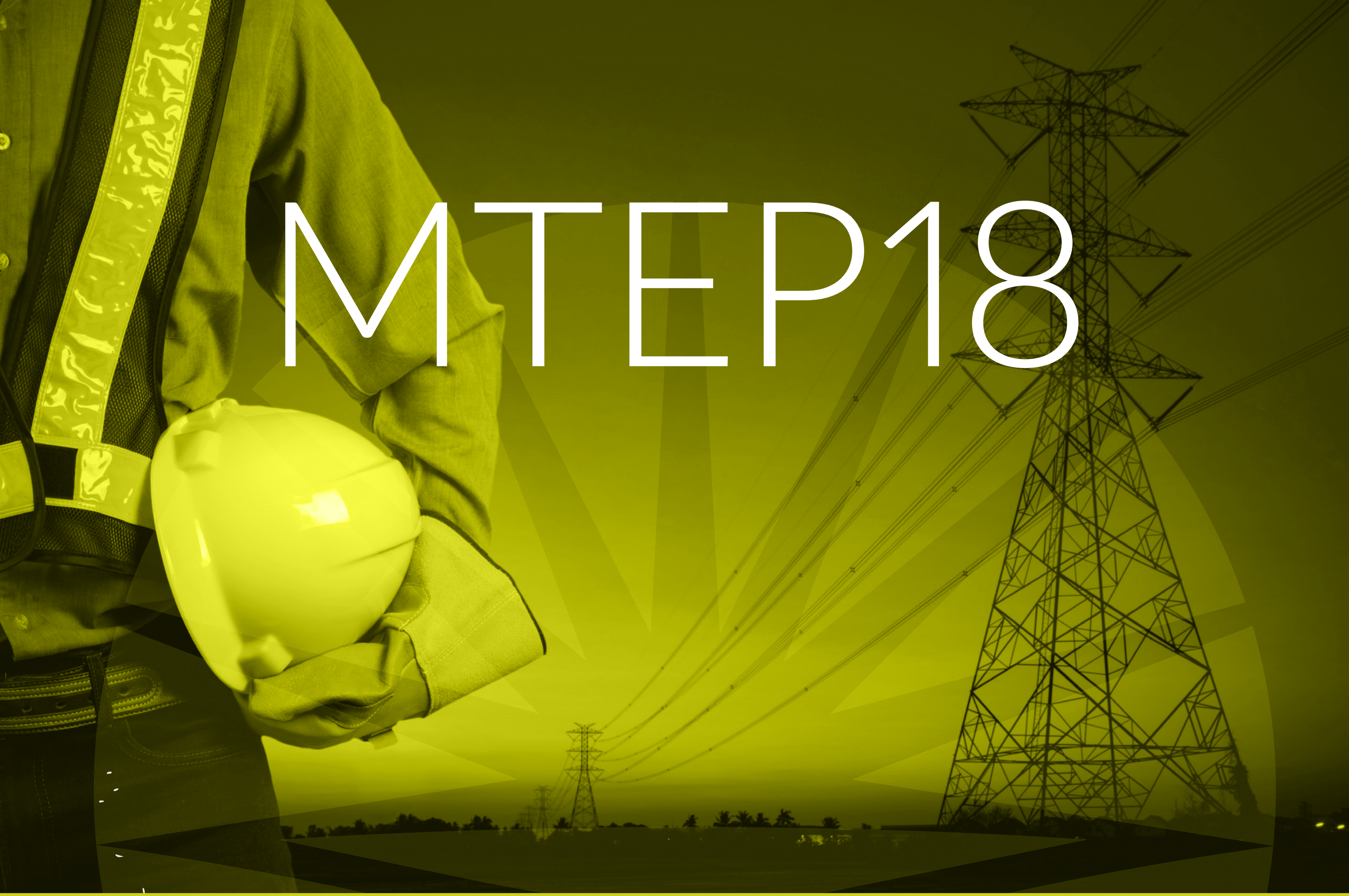
MTEP18



In this MISO Transmission Expansion Plan, MISO staff recommends $3.3 billion of new transmission enhancement projects for Board of Directors' approval.

BOOK 3

Policy Landscape

MISO

misoenergy.org

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MTEP18
Policy Landscape

Summary

MISO's generation fleet continues to evolve, and MISO is studying the impacts of increasing levels of renewable resources on the system. MISO also continues to follow federal and state policy as well as monitor industry trends. Additionally, interregional planning is critical to maximize the overall value of the transmission system and deliver savings for customers. Interregional studies conducted jointly with MISO's neighboring planning regions are based on an annual review of transmission issues at the seams. Depending on the outcome of those reviews, studies are scoped out and performed.

BOOK HIGHLIGHTS

- MISO and the Ontario-based Independent Electricity System Operator (IESO) have mutually agreed to updates of joint Transmission Planning Studies Instruction to guide future collaborative planning efforts
- MISO began a Renewable Integration Impact Assessment (RIIA) to methodically find system integration inflection points driven by increasing levels of renewable generation with focus areas of resource adequacy, energy adequacy and operating reliability
- Initial RIIA results indicate that as renewable penetration increases, risk of losing load compresses into a small number of hours and shifts to later in the day. As a result, the available energy from a combination of wind and solar decreases during the new high-risk window.
- The MTEP18 MVP limited review demonstrates that MVPs provide benefits in excess of costs, with a total benefit-to-cost ratio ranging from 2.0 to 3.1, and creates $8.9 to $40.6 billion in net benefits over the next 20 to 40 years. This is the fifth such review that reaffirms the business case established in 2011.
- MISO and PJM are making interregional process enhancement changes to the Joint Operating Agreement in a continuation of efforts to remove undue hurdles to interregional projects
- MISO and PJM are performing a two-part Coordinated System Plan Study for 2018-2019 consisting of a 2018 TMEP Study and a 2018-2019 IMEP Study
- MISO is proposing process improvements with SPP in the form of Joint Operating Agreement changes that include removing the interregional project criteria of $5 million, eliminating the joint model requirement and adding additional benefit metrics for all interregional project drivers. These changes should improve the interregional process with SPP and allow for more successful outcomes.

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Section 7: Regional Studies

7.0 Policy Landscape Overview

MISO's generation fleet continues to experience significant changes due to a combination of regulatory, political and economic factors resulting in an evolving resource mix that is moving from a historical reliance on coal-fired generation to an increased reliance on natural gas and renewable generation.

The possibility of federal carbon regulation has decreased notably since the 2017 Executive Order dismantling the Clean Power Plan. However, the abundance of low-cost natural gas, combined with decreasing capital costs and tax credits for renewable resources and legacy environmental regulations targeting emissions from coal-fired power plants, has put additional pressure on the traditional generation fleet as it ages. While coal-fired generation supplied 75 percent of MISO's electricity production as recently as 2011, that figure has fallen to less than 50 percent today. MISO estimates that age-related coal unit retirements within the MISO region could result in the retirement of about 17 percent of the MISO coal fleet over the next 15 years. Although discussions at the federal level about resilience raise the question of whether there could be future policy that may extend the life of some baseload generation units, no new federal policies have been enacted to date.

As coal generation retires and natural gas prices remain low, the percentage of MISO's energy supplied by natural gas generation will increase. While natural gas-fired generation supplied 6 percent of MISO's energy in 2011, that figure has increased to more than 20 percent today as a result of both fleet changes and the addition of the MISO South region. As MISO's reliance on natural gas units increases, MISO is focusing on gas-electric coordination to increase MISO's understanding of energy industry trends and the relationships between gas market drivers and bulk electric system dispatch.

MISO continues to see wind and solar resource additions trending above what is required to meet state renewable policies, in the form of Renewable Portfolio Standards or goals. Utility-scale wind and solar resources represent more than 85 percent of the more than 90,000 MW of requests currently[24] in MISO's generator interconnection queue (more than 42 GW of wind and more than 36 GW of solar). To get a sense of scale, consider that the total installed generation capacity in MISO today is 175,000 MW. Looking ahead, industry analysis predicts further reductions in capital costs for renewable resources, which would further drive the amount of wind and solar additions. Although the current Production Tax Credit and Investment Tax Credit for renewables are set to begin a phasedown in upcoming years, many utilities in MISO are developing long-term resource plans, which include increased levels of renewable energy.

Energy efficiency initiatives and demand-side programs that compensate customers for reducing their electricity use are growing in popularity, as are distributed-energy systems like rooftop-mounted solar panels that, in some cases, allow homeowners to generate their own energy and sell, or receive credits for, excess power delivered back to the grid. Additionally, new technologies impacting energy usage are emerging and are expected to become competitive or have increased levels of adoption, including energy storage and electric vehicles. MISO continues to monitor electric vehicle incentives, adoption and charging infrastructure. States around the country have begun to enact policies related to energy storage; however, this has not yet occurred in the MISO region. MISO is also studying trends of increasing distributed solar resources for future system impacts.

MISO will continue to follow federal and state policy as well as monitor fuel prices, plant retirements and announced member plans for any changing industry trends. The ability not only to meet peak demand,

[24] As of July 2018

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but to move bulk power from resource areas to load centers across the footprint in all hours of the day will be needed to maintain system reliability and improve efficiency with this new resource fleet. Regional planning solutions will play an essential role in optimizing the natural and geographic diversity of these resources.

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7.1 Renewable Integration Impact Assessment

Driven by economics, environmental regulations, technological innovation and aging infrastructure, the types of generating resources in the MISO region are changing in a profound way. Many of the legacy power plants that generated the bulk of the region's electricity for decades have retired in recent years, and have been replaced by natural gas-fired resources and renewable energy facilities such as wind and solar farms. Energy efficiency initiatives, demand-side programs, energy storage, and distributed energy systems are also growing in popularity. These changes represent a shift away from long-standing power system design and operational practices, and call for a detailed exploration of assumptions regarding the way the electrical grid will work in the future.

Renewable energy, namely wind and solar resources, is currently the fastest growing and most prominent class of resource in MISO. Under current practices, MISO uses these resources mostly for their energy production attributes. As they continue to replace existing assets, they will be expected to increase their contribution to grid reliability. Reliability is a fundamental component of the power industry. Additional analysis is needed to understand requisite resource performance on a regional scale as renewable penetrations reach new levels.

Given the current structure (physical infrastructure, operational practices, regulations, etc.) of the electric system in MISO and beyond, there may be limitations on the maximum penetration of renewable energy. The complexity of overcoming these limitations is dependent on the types and distribution of renewable resources, the current operational characteristics and locations of existing assets, and the actions of neighboring regions. Because the exact points of these limitations are not yet known, a framework is needed to examine renewable integration over a wide range of penetration levels, starting with the current system and examining penetration levels up to very high percentages of annual energy.

Because the exact points of these limitations are not yet known, a framework is needed to examine renewable integration over a wide range of penetration levels

The primary purpose of the Renewable Integration Impact Assessment (RIIA) is to methodically find system integration inflection points driven by increasing levels of renewable generation. Industry studies have shown that the complexity of integrating renewables escalates non-linearly with increasing penetrations of renewables. Over certain ranges of renewable penetration, complexity is constant when there is adequate transmission and generation capacity, but at specific penetration levels when this capacity is depleted, complexity rises dramatically. These are system inflection points, where the underlying infrastructure and/or system operations need to be modified to reliably achieve the next tranche of renewable deployment. This assessment aims to find those inflection points, and examine potential solutions to mitigate them.

RIIA comprises three main focus areas: resource adequacy, energy adequacy and operating reliability. These three focus areas include three separate models that use mostly common assumptions.

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Resource Adequacy Focus Area

A key component of MISO's transmission planning process is the resource adequacy analysis, as required by the North Electric Reliability Council (NERC). Standard BAL-502-RFC-02 requires planning coordinators to perform and document a resource adequacy study every year. The metric used to calculate the planning reserve margin (PRM) is the "one day in 10 years" metric, also known as the loss of load expectation (LOLE). The LOLE takes into account the forced and unforced outages and provides a probabilistic assessment of a given system.

The integration of higher levels of renewable resources into the MISO market has driven the need to quantify the effect of wind resources on the LOLE target. MISO has adopted the effective load carrying capability (ELCC), which uses an LOLE-type study, to quantify the capacity value of wind in the MISO system considering all hours of the year. For this analysis, the ELCC was measured for: each 10 percent renewable penetration level; each renewable technology being studied: wind, utility-scale photovoltaic (UPV) and distributed solar photovoltaic (DPV); the isolated collective solar technologies and the combination of all renewable technologies; and for each of the six different profile years studied (2007-2012). Figure 7.1-1 illustrates the effects of high levels of renewables on the average net load shape in MISO. Understanding the net load shape is helpful in interpreting the resultant ELCC values.

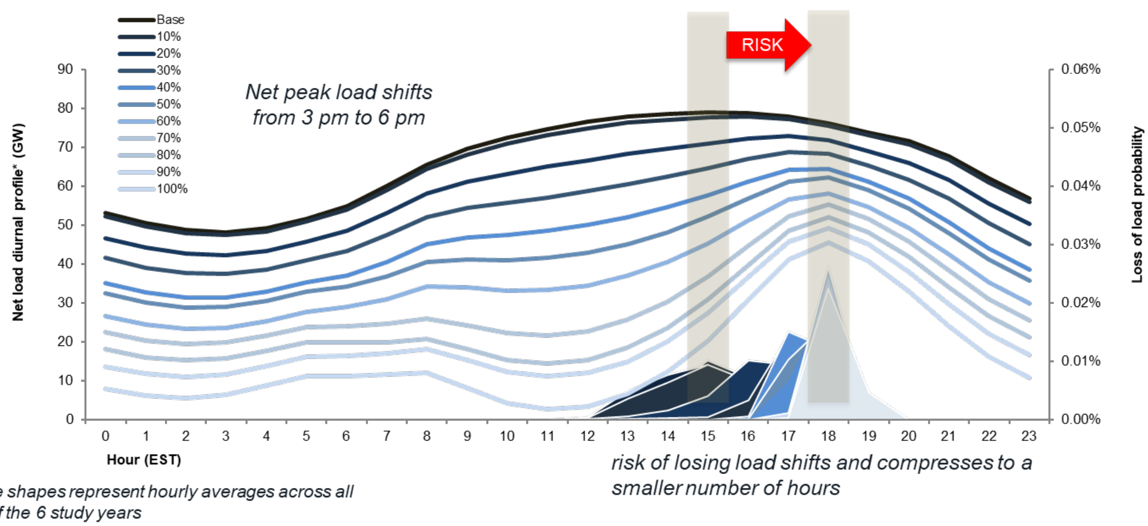

Figure 7.1-1: Effects of high levels of renewables on the average net load shape in MISO

Using this information, MISO observed these key takeaways for the resource adequacy focus area:

1. As renewable penetration increases, risk of losing load compresses into a small number of hours and shifts to later in the day.
2. As a result of the shift in risk of losing load, the available energy from a combination of wind and solar during high risk hours decreases.

With this change in load shape, the ELCC values for wind and solar are shown to decrease as penetration increases (Figure 7.1-2). Note that these curves are specific to the assumed capacity mix and the siting of new renewable units.

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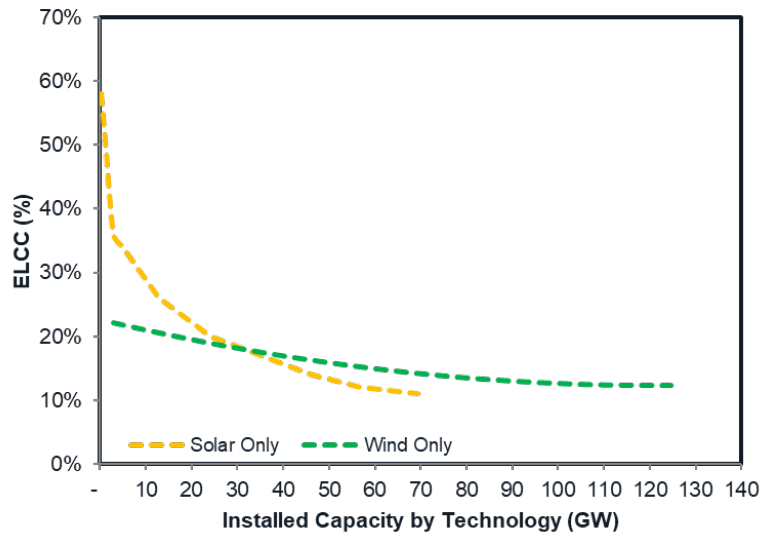

Figure 7.1-2: Effective Load Carrying Capability percentage for renewable penetration

Energy Adequacy Focus Area

Energy adequacy is defined as the ability of the system to operate continuously. The main goal of the energy adequacy focus area is to examine how the hour-by-hour system operating conditions could be affected by high levels of renewables. These conditions are determined by using an hourly production cost model to look at generation mix, operating reserves, system ramps, curtailment and congestion.

The study, thus far, assessed generation and capacity in the MISO region at four renewable penetration levels (Figure 7.1-3).

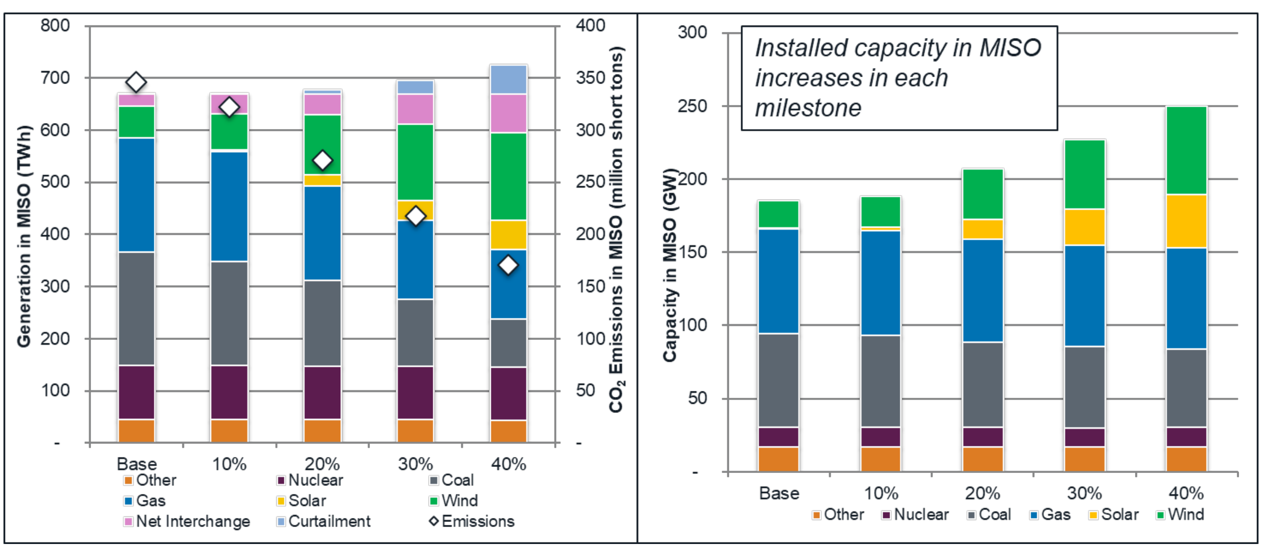

Figure 7.1-3: Renewable penetration impacts generation and capacity in the MISO region

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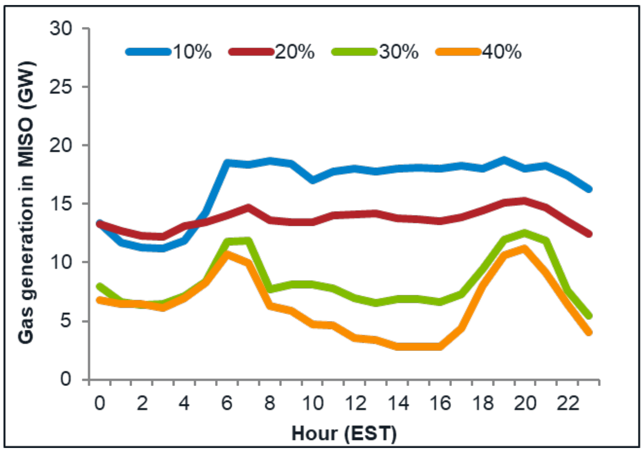
As renewable penetration levels increase, this assessment assumes conventional generation would retire at a rate that keeps the planning reserve margin constant. Because of the declining ELCC calculated for wind and solar, this leads to an increase in installed capacity in MISO. However, conventional generation remaining online still sees a decrease in average capacity factor as energy from renewable sources is dispatched. Not all renewable energy is dispatched – curtailment increases across each milestone as well. If the curtailment of renewables is high enough that the milestone percentage renewable penetration is not met, RIIA looks at ways to mitigate the curtailment as part of a solution development process.

Ramping behavior is another key metric examined as part of the energy adequacy focus area. The two graphs represent gas and coal unit behavior on days with the highest amount of renewable generation (Figure 7.1-4).



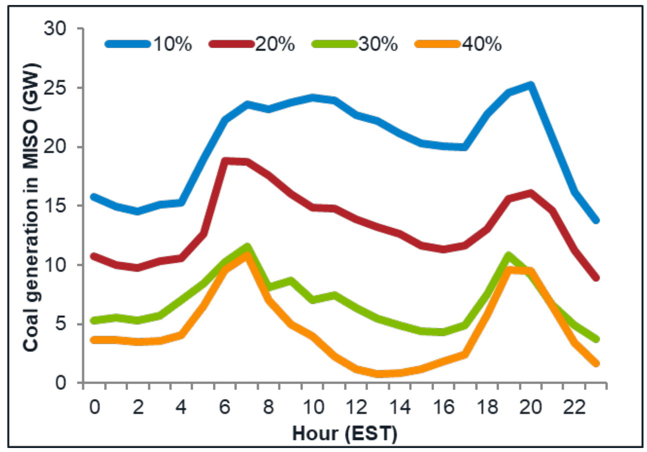


Figure 7.1-4: Ramping behavior of gas and coal units

As penetration levels increase, both gas and coal units see two significant ramps at the beginning and end of the day. Fuel price assumptions have coal and gas similarly priced in the model, leading to their similar behavior. The two ramps occur due the same behavior that reshaped the net load curve discussed in the resource adequacy focus area — the patterns of renewable resources and the gross load pattern.

Operating Reliability Focus Area

The RIIA operating reliability focus area investigates the steady-state thermal and voltage performance of the MISO Bulk Electric System (BES). This focus area looks at the impact of high levels of renewable penetration on voltage stability, transient stability and MISO's frequency response obligations. Study models are developed based on generation dispatch and loading level obtained from energy adequacy yearly production cost simulations.

Based on a combination of loading level and renewable penetration, three sets of stressful system conditions are selected for consideration in the AC contingency analysis: high renewable, high load and light load (Figure 7.1-5). The hour within each set with the highest renewable energy penetration is selected for further study.

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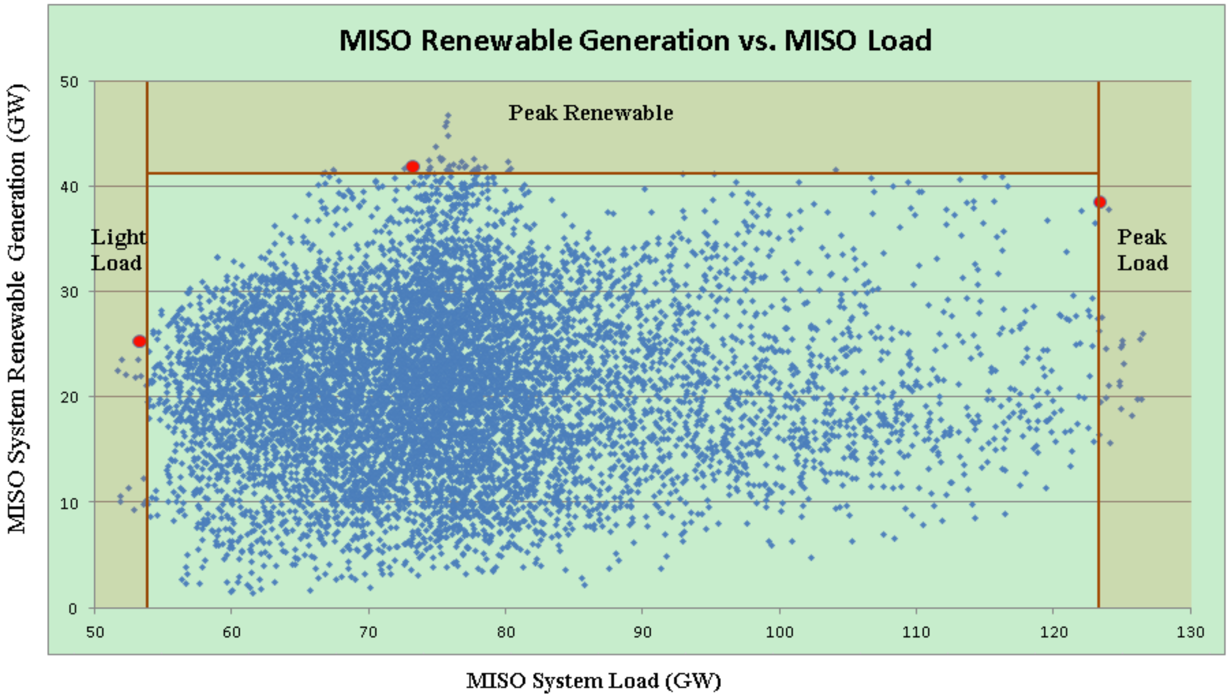
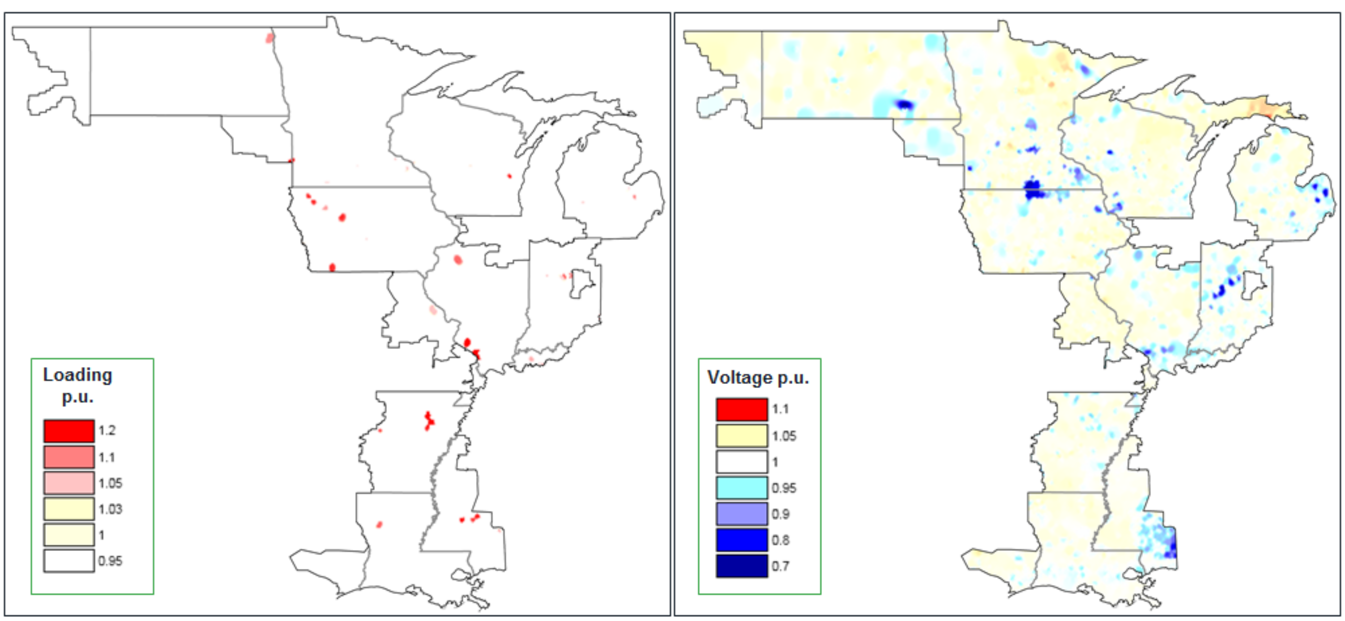


Figure 7.1-5: MISO renewable generation and load under 30 percent renewable energy penetration

By doing contingency analysis for selected NERC prescribed P0, P1, P2 events, MISO identified steady-state thermal and voltage issues (Figure 7.1-6).



(a) Thermal Loading (b) Voltage

Figure 7.1-6: Identified system thermal overload and voltage violations under 20 percent renewable penetration

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For identified system thermal overload and voltage violations, RIIA focuses on high-likelihood events that tend to cause severe reliability violations on the MISO system. The goal is to use a quick-fix approach to clear reliability issues observed, which reflects the traditional practice in industry to mitigate violations, rather than trying to find the optimal solutions. Integration complexity is reflected and approximated by the amount of transmission fixes needed to address identified issues. Figure 7.1-7 indicates that, although the complexity could be significant in certain areas like MISO West, it is generally relatively mild across the overall MISO study footprint under 20 percent renewable penetration.

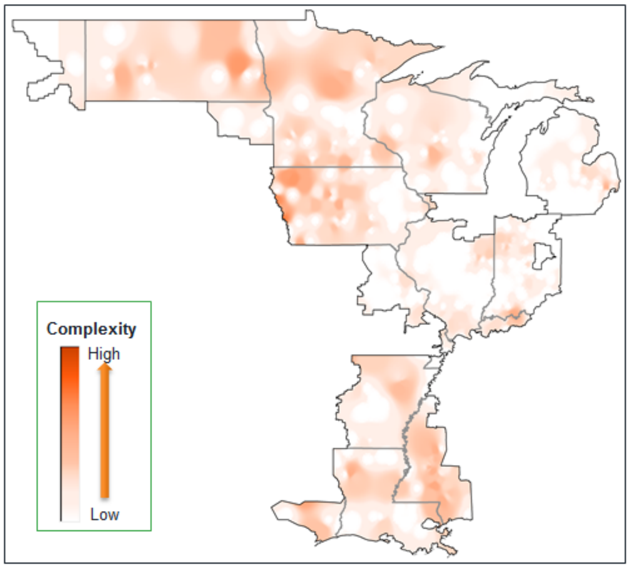

Figure 7.1-7: Integration complexity under 20 percent renewable penetration

The impact of renewable penetration on frequency response is being studied by evaluating MISO's performance per NERC BAL-00 during a 60-second dynamic model simulation. Through previous model validation efforts, MISO has observed that Eastern Interconnect-wide dynamic models are highly optimistic and do not capture system response realistically. MISO incorporates model updates such as modeling asymmetrical dead-bands in existing governor models with generic values, removal of governor models for any unit which remains non-response to frequency events, and withdrawal of frequency support by certain units to form a more realistic model. The base dynamic models are validated against actual system disturbances and response by utilizing Phasor Measurement Unit data (PMU).

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Next Steps

RIIA will continue to explore renewable energy growth in MISO and its effects on resource adequacy, energy adequacy, and operating reliability.

Due to the nature of the modeling, the resource adequacy focus area is fully complete in Phase 1 of RIIA (Figure 7.1-8). Phase 1 also looks at the 10 to 30 percent penetration levels and Phase 2 looks at the 40-50 percent penetration levels. Phase 3, likely to begin near at the beginning of 2019, will either continue along the renewable penetration arc, or run sensitivities to the 10 to 50 percent levels.

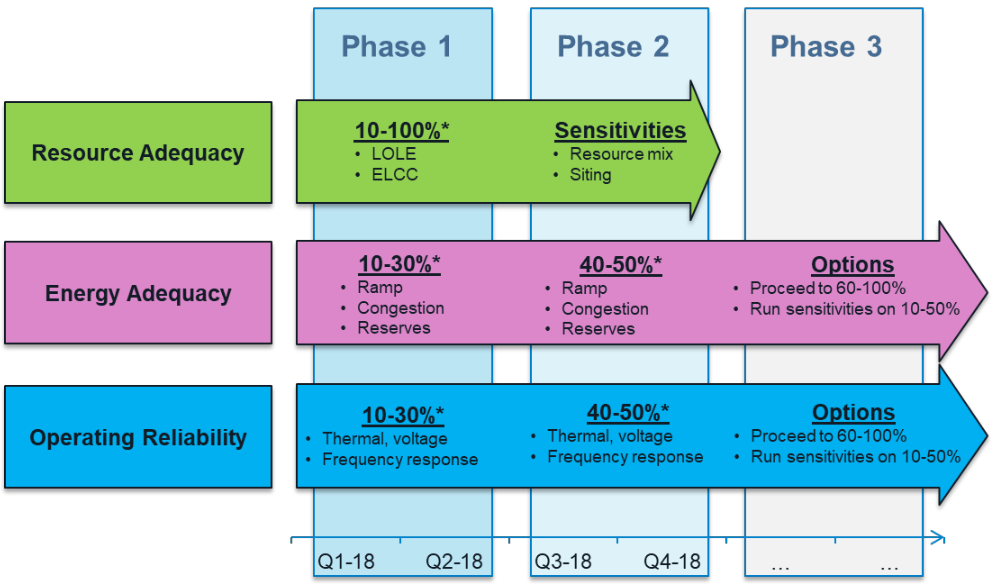

Figure 7.1-8: Percent penetration levels

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7.2 MTEP18 MVP Limited Review

The MTEP18 Multi-Value Project (MVP) Limited Review provides an updated view into the projected congestion and fuel savings of the MVP Portfolio. Consistent with the previous MVP reviews, the MTEP18 MVP Limited Review's business case is on par with the review of the original business case in MTEP11, providing evidence that the MVP criteria and methodology works as expected.

The MTEP18 results[25] demonstrate that the MVP Portfolio:

- Provides benefits in excess of its costs, with its total benefit-to-cost ratio ranging from 2.0 to 3.1; consistent with the 2.2 to 3.4 range calculated in MTEP17
- Creates $8.9 to $40.6 billion in net benefits (using MTEP17 benefits for all categories besides congestion and fuel savings) over the next 20 to 40 years

Benefit estimates are slightly lower compared to the MTEP17 Triennial Review due to lower fuel price assumptions and the removal of carbon cost adders from MTEP future scenario assumptions.

The fundamental goal of MISO's planning process is to develop a comprehensive expansion plan that meets the reliability, policy and economic needs of the system. Implementation of a value-based planning process creates a consolidated transmission plan that delivers regional value while meeting near-term system needs. Regional transmission solutions, or MVPs, meet one or more of three goals:

- Reliably and economically enable regional public policy needs
- Provide multiple types of regional economic value
- Provide a combination of regional reliability and economic value

MISO conducted its third limited MVP Portfolio review, per tariff requirement, for MTEP18. The MVP Review has no impact on the existing MVP Portfolio's cost allocation. MTEP18 Review analysis is performed solely for informational purposes. The intent of the MVP Review is to use the review process and results to identify potential modifications to the MVP methodology and its implementation for projects to be approved at a future date.

The MTEP18 results demonstrate that the MVP Portfolio provides benefits in excess of costs, with a total benefit-to-cost ratio ranging from 2.0 to 3.1, and creates $8.9 to $40.6 billion in net benefits over the next 20 to 40 years

Consistent with previous MVP Reviews, the MTEP18 MVP Limited Review uses the most currently available stakeholder vetted models, and assesses the benefits of the entire MVP Portfolio without differentiating between facilities currently in service and those still being planned. Because the MVP Portfolio's costs are allocated solely to the MISO North and Central regions, only MISO North and Central Region benefits are included in the MTEP18 MVP Limited Review.

[25] The detailed MTEP18 MVP Limited Review Business Case spreadsheet is posted under the Multi-Value Project Portfolio Analysis section of the MISO public website.

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Economic Benefits

MTEP18 analysis shows the MVP Portfolio creates $17.8 to $60 billion in total benefits[26] to the MISO North and Central regions (Figure 7.2-1). The decrease in benefits is due to a lower assumed fuel price forecast in MTEP18 compared to MTEP17, and the removal of a carbon cost adders from the MTEP18 future assumptions.

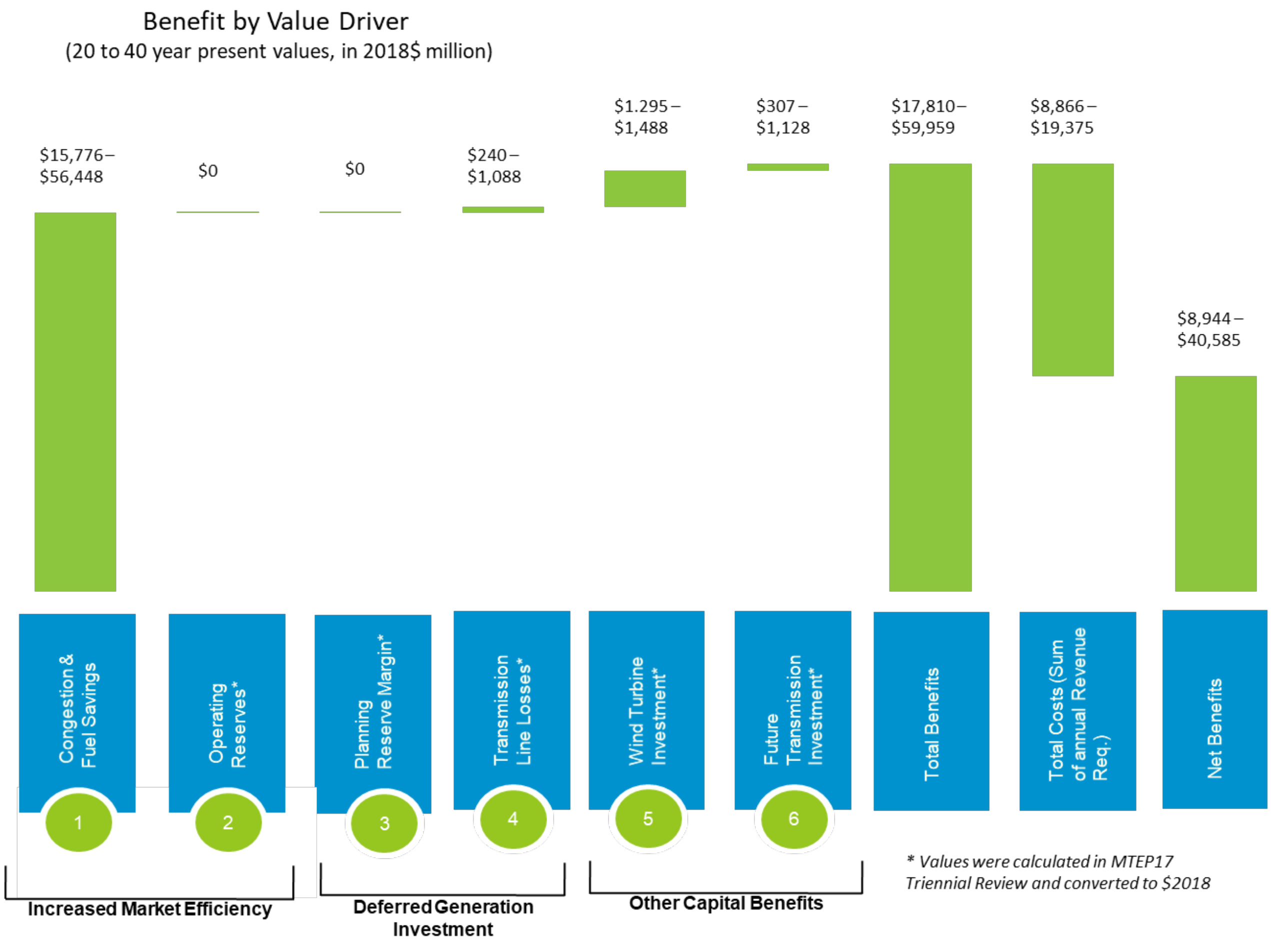

Figure 7.2-1: MVP portfolio economic benefits from MTEP18 MVP Limited Review with values from MTEP17 MVP Triennial Review

The MVP Portfolio continues to show economic benefits well in excess of costs. Total portfolio cost estimates have decreased slightly from $6.65 billion in MTEP17 to $6.58 billion in MTEP18, and annual charge rate assumptions have been reduced as a result of recent changes to the corporate tax rate. When the updated benefit projections are coupled with lower 20 and 40 year cost estimates, the results are MVP Portfolio benefit-to-cost ratios that are on par with the original business case studied in MTEP11.

[26] Benefits 2 through 6 are from the MTEP17 MVP Triennial Review. The next MVP Triennial Review is scheduled for MTEP20.

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Increased Market Efficiency

The MVP Portfolio allows for a more efficient dispatch of generation resources, opening markets to competition and spreading the benefits of low-cost generation throughout the MISO footprint. The MVP Review estimates that the MVP Portfolio will yield $15.6 to $56.4 billion in 20- to 40-year present value adjusted production cost benefits to MISO's North and Central regions.

The MVP Review estimates that the MVP Portfolio will yield $15.6 to $56.4 billion in 20- to 40-year present value adjusted production cost benefits to MISO's North and Central regions

The reduction in estimated congestion and fuel savings benefits relative to MTEP17 is primarily due to a decrease in the out-year fuel price forecast (Figure 7.2-2). The MVP Portfolio allows access to wind units with a nearly $0/MWh production cost and primarily replaces natural gas units in the dispatch, which makes the MVP Portfolio's fuel savings benefit projection directly related to the natural gas price assumption. Natural gas price assumptions were on average 9.5 percent lower in MTEP18 compared to MTEP17 (Figure 7.2-3).

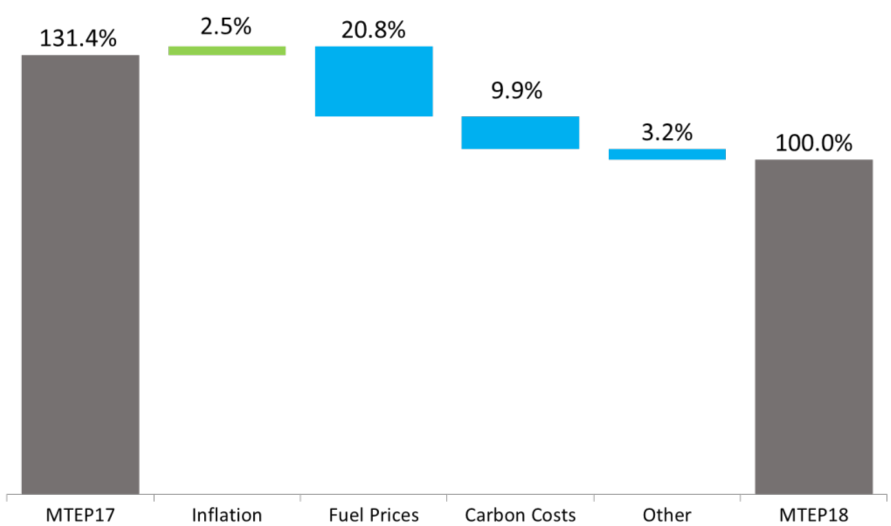

Figure 7.2-2: Breakdown of congestion and fuel savings decrease from MTEP17 to MTEP18

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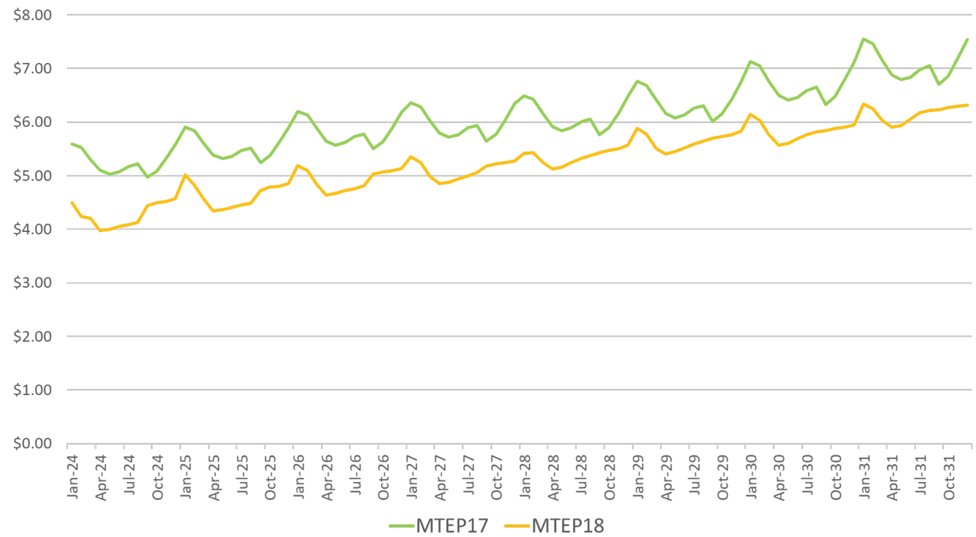

Figure 7.2-3: Henry Hub natural gas forecast difference between MTEP17 and MTEP18

The MTEP17 MVP Triennial Review assumptions also included a carbon dioxide emission adder priced at $5.80/ton. With this adder, the wind enabled through the MVPs would offset more expensive generation, because certain units would have included an additional carbon cost. The MTEP18 futures did not include this assumption, leading to a relative benefit decrease of approximately 10 percent in this review.

Distribution of Economic Benefits

The MVP Portfolio provides benefits across the MISO footprint in a manner that is roughly equivalent to costs allocated to each local resource zone (Figure 7.2-4). The MVP Portfolio's benefits are at least 1.5 to 2.6 times the cost allocated to each zone.

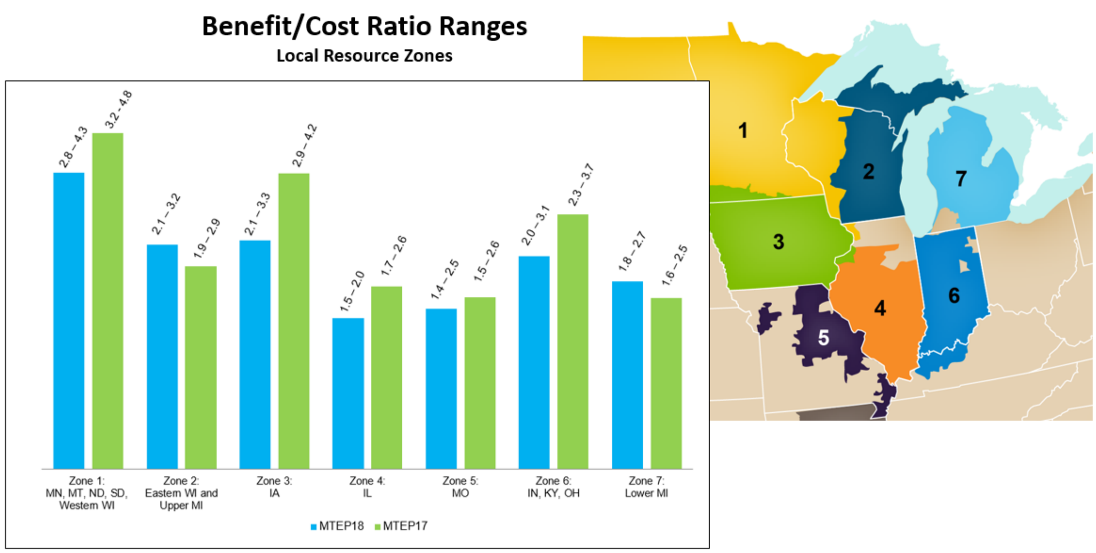

Figure 7.2-4: MVP Portfolio total benefit distribution by MISO North and Central Resource Zones

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Historical Data Review

MTEP17 marked the first cycle in which any MVP Review included historical market data for trend analysis. In accordance with Attachment FF, the MTEP18 Limited Review will continue this analysis with another quantitative and qualitative look into how the in-service MVPs impact the following Tariff-defined metrics[27].

- Congestion Costs
- Energy Prices
- Fuel Costs
- Newly Interconnected Resources
- Share of Energy Supplied

The prospective benefits quantified in the full MVP business case assume the entire MVP Portfolio is in-service over 20- and 40-year time-frames. As of the second quarter of 2018, eight of the 17 MVPs have gone into service (Table 7.2-1).

MVP #	Project Name	In-Service Date	MTEP Project ID
2	Brookings, SD - SE Twin Cities 345 kV	3/26/2015	1203
9	Maywood-Herleman-Meredosia-Ipava & Meredosia-Austin 345 kV Line	12/20/2017	3017
10	Pawnee to Pana - 345 kV Line	10/27/2017	3169
13	Michigan Thumb Wind Zone	12/31/2015	3168
14	Reynolds to Greentown 765 kV line	6/25/2018	2202
15	Pleasant Prairie-Zion Energy Center 345 kV line	12/6/2013	2844
16	Fargo-Sandburg-Oak Grove 345 kV Line	2/21/2018	3022
17	**Sidney to Rising 345 kV line**	**9/21/2016**	**2239**

Table 7.2-1: In-Service MVPs as of the second quarter 2018

Where available, data regarding each benefit metric for the previous five years[28] has been provided, along with contextual and qualitative discussion regarding the collection process, data sources and in-service MVP impact. Some correlations between targeted congestion areas and increasing renewable energy integration trends are observed, however, the small statistical sample size of in-service time does not provide any definitive conclusions.

Congestion Costs and Energy Prices

The 2018 MVP Review analysis of historical congestion costs and energy prices will focus solely on MVP 17: Sidney-Rising, which went into service in September 2016. Historical data for MVPs 9, 13, and 15 was analyzed in detail during the MTEP17 Triennial Review, and with less than a year of additional in-

[27] Planning Reserve Margin (PRM) is an additional metric in prior MVP Reviews that is no longer considered. A change in MISO's PRM methodology removed the congestion component from the calculation so the MVPs will not have a quantifiable impact on historical PRM values. For a detailed discussion of this change, refer to section 6.3 of the MTEP17 MVP Triennial Review.
[28] Sample period encompasses January 1, 2012-July 31, 2018

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service data, little to no substantive trend analysis can be performed. The remaining four MVPs are only recently energized and will be examined in the MTEP19 MVP Limited Review.

To evaluate congestion costs, constraints were identified based on economic planning and operational experience. First, the number of binding hours per year was collected from the Hourly MISO Day-Ahead (DA) market database for each identified constraint during the sample period (January 1, 2012 – July 31, 2018). These DA congestion hours were then matched with the congestion dollar amounts and congestion savings, quantified by constraint and year, for the project. Where congestion was present after the MVP in-service date, values are shown as negative. If no year is listed for a given constraint it means the binding constraint was not seen in the DA binding constraint database for that year.

Energy Prices are most commonly measured by the Day-Ahead Locational Marginal Price (LMP), but because changes in DA LMPs are driven to a large extent by variations in fuel prices (particularly natural gas prices), this is not a reliable metric for evaluating the impact of the MVPs. Instead, the binding constraints identified in the congestion cost analysis were evaluated for impact on energy price.

A binding constraint increases the prices at the raise-help nodes (where injecting power mitigates the flows creating congestion) by contributing to the Marginal Congestion Component (MCC). Each constraint and contingency was matched to the DA constraint and impacted Pnodes. DA shift factors for the significantly impacted (i.e. sensitivity of at least 5 percent) Pnodes were obtained along with Shadow Price of the constraints, and the energy price impact was calculated using the formula:

Average Price Impact for Most Significant Raise Help nodes = Average {Shift Factor * Shadow Price}

Finally, price impacts are compared before versus after the associated MVP in-service date.

MVP 17: Sidney – Rising (In Service September 2016):

The Sidney-Rising MVP, in conjunction with MVPs nine through 11, was designed to help alleviate historical West to East congestion through the state of Illinois. MVP 17 is primarily expected to help congestion in the region by creating better outlet for the Clinton generating station. Six constraints were identified for examination (Table 7.2-2).

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Year	Binding hours	DA Congestion Dollars
(1) 1998 NEWTON-ROBM 138 FLO NEWTON-CASEY W		
2012	1019	$19,482,797
2013	2298	$31,454,914
2014 Vortex	950	$18,440,904
2014 Non-Vortex	1736	$33,082,255
2015	2099	$21,841,973
(2) 254546 BUNSONVILLE-EUGENE FLO CASEY-W BREED		
2012	495	$1,775,427
2013	604	$2,038,907
2014 Vortex	327	$2,794,154
2014 Non-Vortex	599	$7,800,429
2015	576	$3,314,339
(3) 7RISING 348882 AMIL 4RISING 348883 AMIL		
2013	26	$182,129
2014 Non-Vortex	2	$2,896
2015	174	$655,766
2016	26	$204,325
(4) FG20032 Palmyra_345_161kV_XFMR		
2014 Non-Vortex	59	$2,050,623
2016	-161	-$229,281
(5) FG21278 Palmyra_345_161_KV_TR_BK_FLO_OTTUMWA_MONTEZUMA_345_KV		
2015	85	$552,215
2016	-50	-$69,036
(6) Rising 345/138kV Xfmr FLO Clinton - Brokaw 345kV		
2012	133	$5,692,642
2014 Vortex	414	17962709
2014 Non-Vortex	17	170721
2015	1761	$25,921,587
2016	10	$73,411
Total	13199	$195,196,806.00

Table 7.2-2: Congestion totals by constraint for MVP 17 for years 2012-2018

Because natural gas prices have such a significant impact on the congestion and energy data, the polar vortex weather event[29] of 2014 is separated from the yearly totals to avoid skewing aggregated results.

[29] Polar vortex period is assumed to be January 2, 2014 to March 31, 2014 for this analysis

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After removing the vortex period, an overall reduction in DA congestion costs is observed for the examined constraints, including no observed binding hours in years 2017 and 2018 (Table 7.2-3).

Year	Before In-Service Date		After In-Service Date	
	Number of Binding Hours	DA Congestion Amount	Number of Binding Hours	DA Congestion Amount
2012	1647	$26,950,866		
2013	2928	$33,675,950		
2014	2413	$43,106,925		
2015	4695	$52,285,880		
2016	75	$405,368	250	$425,948
Total	11758	$156,424,989	250	$425,948

Table 7.2-3: Congestion totals by year for MVP 17 for years 2012 – 2018 (with polar vortex period removed)

Similarly, when examining our constraints from an energy perspective, MISO observed that the average price impact before the MVP in-service start date is higher than the average price impact after the in-service date (Table 7.2-4). When a constraint is binding it increases the prices by contributing to the Marginal Congestion Component of LMP at the raise-help nodes, therefore the in-service MVP can contribute to price reductions by reducing the occurrence of congestion on the constraint. The overall average price impact for our examined constraints was $10.377/MWh before MVP 17 went into service, and $5.047/MWh afterwards — a reduction of approximately 49 percent.

Constraint	Before ISD: 1/1/2012 - 9/21/2016		After ISD: 9/21/2016 - 7/31/2018	
	Average MCC Impact ($/MWh)	Max Nodes Impacted	Average MCC Impact ($/MWh)	Max Nodes Impacted
7RISING 348882 AMIL 4RISING 348883 AMIL	1.924	41	4.608	55
FG20032 Palmyra_345_161kV_XFMR	15.872	61	6.063	81
FG21278 Palmyra_345_161_KV_TR_BK FLO_OTTUMWA_MONTEZUMA_345_KV	5.768	64	2.479	166
1998 NEWTON-ROBM 138 FLO NEWTON-CASEY W	14.606	7	0	0
254546 BUNSONVILLE-EUGENE FLO CASEY-W BREED	1.02	554	0	0
Rising 345/138kV Xfmr FLO Clinton - Brokaw 345kV	6.172	30	0	0

Table 7.2-4: Average energy price impact by constraint for MVP 17

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Fuel Costs

The fuel price indices associated with conventional generation in the MISO North and Central regions are the Chicago Citygates natural gas and Illinois Basin coal prices. No direct correlation is observed between the limited MVP data and historic fuel prices (Figure 7.2-5).

The main drivers for natural gas price changes are weather related. Sustained hot summer weather drives up demand for electric generators and sustained cold winter weather drives up demand for heating. Coal prices are more closely tied to electric power generation than gas, however price fluctuation is still mostly impacted a number of external factors not related to transmission including regulation, future stability, and competitive pressure of low gas prices. While a complete MVP Portfolio could potentially contribute to price pressures, the in-service MVPs on their own have most likely not resulted in any fuel price influence.

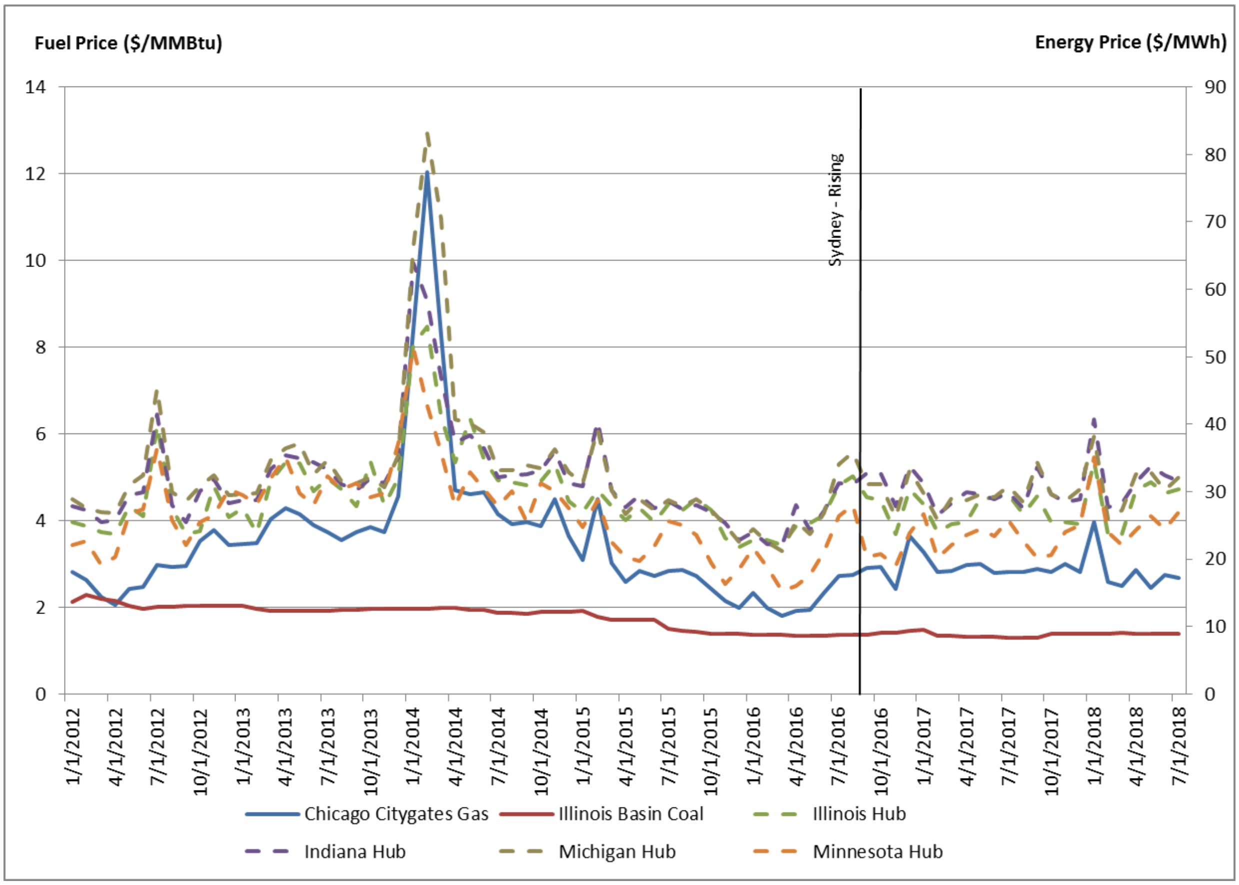

Figure 7.2-5: Fuel Prices 2012-2018 with MVP In-Service Dates

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Newly Interconnected Resources

A primary component of the MVP business case is the ability to reliably deliver wind energy to meet state renewable energy policy goals. To measure progress toward this objective, a review of completed Generator Interconnection Agreements (GIAs) from the MISO interconnection queue shows that over the five-year sample period, more than 6,000 MW of wind has been added to the MISO North and Central regions (Figure 7.2-6).

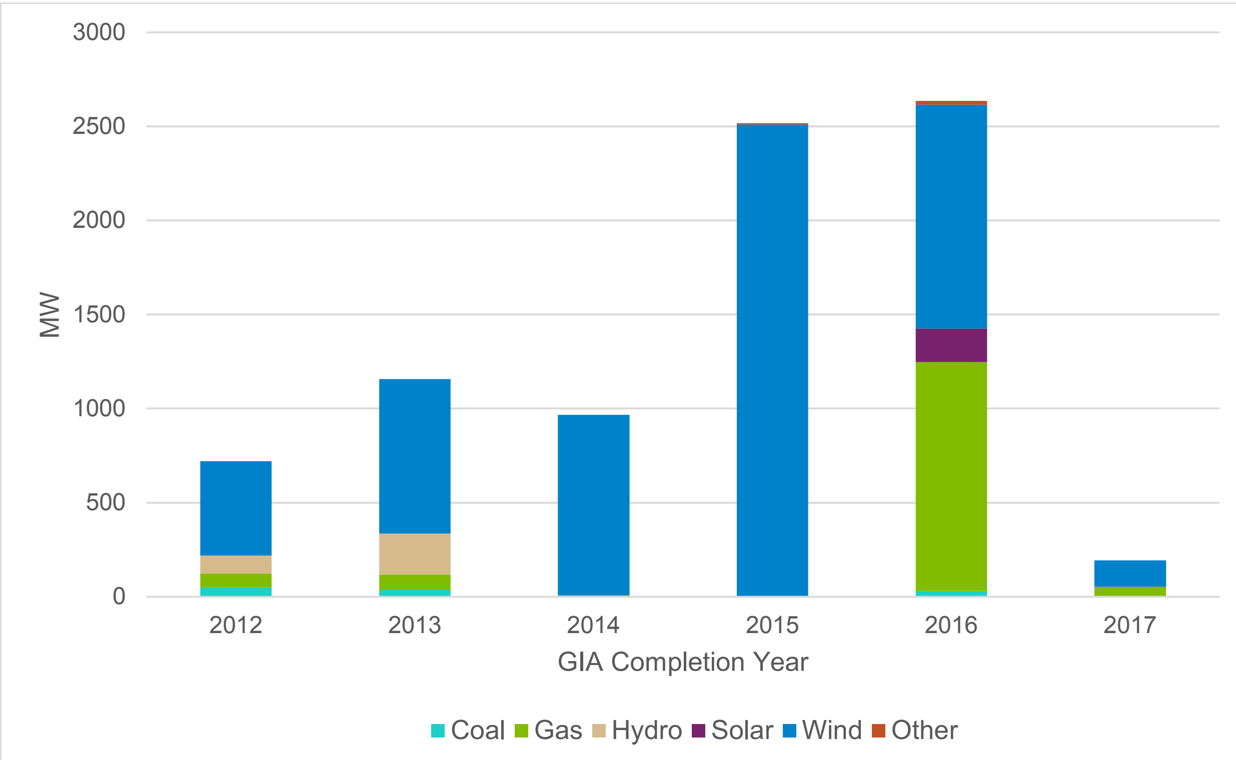

Figure 7.2-6: Completed Generator Interconnection Agreements (GIAs) with post-GIA status of "In Service" (MISO North/Central only)

Share of Energy Supplied

In addition to looking at what types of generation resources have been added to the MISO system, the share of energy supplied by resource type can also be measured using Real-Time settled generation market data (Figure 7.2-7). Some observed trends include a steady decline of coal from 2013-2017, while wind trends upward in each sample year correlating to more wind sources being added to the system. The settled gas generation largely correlates with gas price fluctuations discussed in in the previous section, while the remaining resource types stay generally level.

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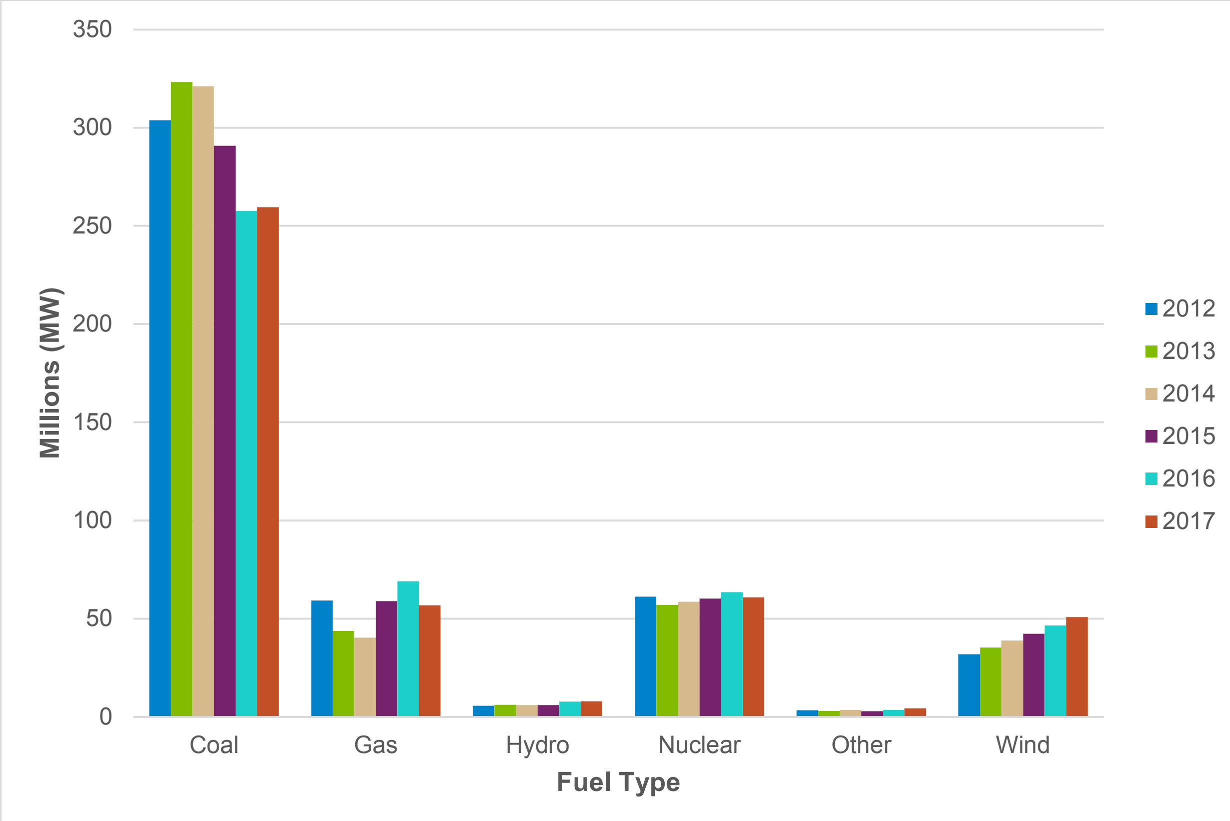

Figure 7.2-7: Sum of real-time hourly settled generation by ear (MISO North and Central)

Conclusions

All benefits assessed in the previous chapters of this review, and in the original MVP business case, are based on the MVP Portfolio in its entirety, without differentiating between individual projects. The MTEP18 review of historical market data shows similar trends to MTEP17, but because the in-service MVPs represent only a small portion of the entire portfolio (over a short time period), the tariff-required metrics discussed in this report may not yet be a reliable measure of MVP impacts. In future reviews, when a larger statistical sample of data becomes available, a more detailed analysis on the correlation between MVP system impacts and realized benefits can be performed.

Going Forward

MTEP19 will feature another limited review of the MVP Portfolio benefits, with an expanded look at historical data for several MVPs that recently went into service. The next full MVP Triennial Review is scheduled for MTEP20.

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Section 8: Interregional Studies

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8.1 PJM Interregional Study

MISO and PJM Interconnection, a Pennsylvania-based Regional Transmission Organization (RTO), focused their joint efforts in 2018 on a two year Coordinated System Plan Study, interregional process enhancements, and continued stakeholder interaction in the Interregional Planning Stakeholder Advisory Committee (IPSAC).

2018-2019 Coordinated System Plan Study

Following a March 30, 2018, IPSAC Annual Issues Review, MISO and PJM agreed to perform a Coordinated System Plan Study for 2018 and 2019. Included in the scope are both a 2018 Targeted Market Efficiency Project (TMEP) Study and a two-year, 2018-2019 Interregional Market Efficiency Project (IMEP) Study. The 2018 TMEP study is expected to conclude in October 2018 while the 2018-2019 IMEP Study will finish at the end of 2019.

2018 TMEP Study

In 2018, due to appreciable levels of Market-to-Market congestion — $500 million of Day-Ahead and Excess Congestion Fund (or “Balancing”) congestion on Market-to-Market flowgates from 2016 to 2017— MISO and PJM decided to continue their annual focus on resolving historical congestion and committed to a 2018 TMEP Study. This near-term study evaluates historical market-to-market congestion to find small but important fixes.

For the 2018 study, MISO and PJM analyzed historically congested market-to-market flowgates. Flowgates with significant congestion — Day-Ahead plus Excess Congestion Fund — in 2016 and 2017 were considered initially. MISO and PJM worked to identify valuable projects on their seams. A valuable project would accomplish four things: relieve known Market-to-Market issues, be completed in a relatively short time frame, have a quick payback on investment, and not be a greenfield project. MISO and PJM coordinated with facility owners to identify the limiting equipment and potential upgrades. Limited reliability and production cost analyses were used to confirm the projects’ effectiveness in relieving congestion.

MISO and PJM shared their 2018 TMEP study results and conclusions at an October 5, 2018, IPSAC. The RTOs identified two TMEPs (Table 8.1-1) for recommendation to their respective boards and for inclusion in MISO’s MTEP and PJM’s Regional Transmission Expansion Plan (RTEP).

M2M Facility	Upgrade	TO(s)	Benefit ($M)	Cost ($M)	Interregional Cost Split
Marblehead 161/ 138 kV Transformer	Terminal equipment (disconnect switch and bus conductor)	Ameren (IL)	12.4	0.18	100% MISO
Gibson - Petersburg 345 kV Line	Terminal equipment (switches, breakers, relays, bus work)	Duke/ IPL	19.5	4.3	93% MISO/ 7% PJM

Table 8.1-1: TMEP Projects

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2018-2019 Two-Year Coordinated System Plan Study

In 2018, MISO and PJM initiated a two-year study aimed at identification of IMEPs. This first year of study focused on issue identification, while 2019 will focus on project solicitation and evaluation.

MISO anticipates it will publish regional models and issues, for interregional project consideration, by the end of 2018. MISO will solicit interregional projects from stakeholders from January to February of 2019, running concurrent with PJM's regional project solicitation window. MISO and PJM will evaluate interregional project proposals submitted to both regional processes. Any projects satisfying the JOA IMEP criteria will be recommended for approval by the MISO and PJM Boards in December 2019.

Interregional Process Enhancements

In 2018, the MISO-PJM IPSAC continued its commitment to interregional metric and process enhancements. MISO and PJM worked with stakeholders to identify changes to lower or remove undue hurdles to approve interregional projects.

In the fourth quarter of 2018, MISO and PJM expect to file Joint Operating Agreement (JOA) changes with FERC to improve the interregional process and criteria. The JOA edits center on the IMEP process (removal of joint model references) and criteria (removal of the 5 percent generation-to-load distribution factor criterion), elimination of Cross Border Baseline Reliability Projects (CBBRPs) (replaced by Interregional Reliability Projects under Order 1000 changes), and clarification of the obligation to construct interregional projects solely in one RTO.

FERC Docket ER16-1969

By December 31, 2018, MISO will comply with the one remaining compliance directive stemming from the April 21, 2016, FERC Order EL13-88. Given two extensions, and assigned Docket ER16-1969, MISO will confirm, in a transmittal letter, that sub-345 kV IMEPs will use the prevailing regional cost allocation rules.

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8.2 Southwest Power Pool

MISO and Southwest Power Pool (SPP) kicked off 2018 by holding an Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting on February 27, 2018, at SPP's Little Rock, Ark., offices. This meeting served as the Annual Issues Review where MISO and SPP shared several stakeholder-submitted issues. The meeting focused primarily on Interregional Process Improvements and addressing historical Market-to-Market congestion. At the conclusion of the meeting, MISO, SPP and stakeholders decided to focus on process improvements in 2018 with no study conducted.

Following the February IPSAC meeting, MISO and SPP requested feedback regarding which process improvements should be implemented in the MISO-SPP interregional process. Stakeholder feedback was posted with the April 2018 Planning Advisory Committee (PAC) meeting materials. Stakeholders were largely split on the process improvements but MISO and SPP collaborated and agreed to focus on three main process improvements. Those improvements include:

- Remove the joint model requirement within the Joint Operating Agreement (JOA)
- Remove the $5 million threshold for interregional projects
- Additional benefit metrics for all interregional project drivers (Adjusted Production Cost and Avoided Cost)

MISO and SPP shared these improvement tasks with the IPSAC in July 2018 along with a work plan to implement these changes by the end of 2018.

Additionally, MISO and SPP continue to explore the possibility of implementing a planning process to address historical Market-to-Market congestion. MISO and SPP requested stakeholder feedback at the February 2018 IPSAC meeting, which was largely split. For the remainder of 2018, MISO and SPP plan on taking a deeper dive into the historical Market-to-Market data to better understand how an updated planning process may benefit all parties.

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8.3 Other Interregional Coordination Efforts

In addition to the joint planning efforts with SPP and PJM, MISO also coordinates with neighboring entities of the Southeastern Regional Transmission Planning (SERTP) organization and the Independent Electricity System Operator of Ontario (IESO). At the time of this report, no formal studies are underway with either neighbor, though MISO and these entities meet regularly to review interregional issues and possible areas of collaboration.

Southeastern Regional Transmission Planning Organization

The SERTP Region, with ties on both the western and southeastern seams of the MISO footprint, consists of 11 FERC-jurisdictional sponsors spanning 12 U.S. states. Coordination procedures with SERTP for compliance with FERC Order 1000 are dictated by Attachment FF, Section X of the MISO Tariff. These procedures include an annual exchange of regional transmission plans, powerflow models and associated data used in each region's planning processes, as well as annual and biennial coordination meeting requirements.

On April 5, 2018, MISO and SERTP met at the MISO offices in Metairie, La., for a biennial review of regional transmission plans and procedures. While no interregional projects were identified for joint evaluation during this planning cycle, MISO will continue to coordinate with SERTP as regional plans are finalized and new interregional issues arise.

Outside of the SERTP regional planning process, MISO works with individual SERTP sponsors on a wide variety of activities such as identifying system model improvements and coordinating reliability and economic assessments. This year MISO is working directly with TVA and LG&E on Market Congestion Planning Study project PC-4 to address congestion on the Southern Indiana/Kentucky border. For further details on this project and the economic planning process, refer to section 5.3 of this MTEP report.

Independent Electricity System Operator

IESO of Ontario, Canada, has interconnection paths into MISO through phase angle regulators in Michigan and Minnesota. While IESO and MISO do not have FERC Order 1000 coordination requirements, both parties still meet as needed to discuss reliability issues and coordinate ad hoc study efforts — most recently as a part of the exploratory Michigan Study in 2016. While no joint studies are currently underway, in May of 2018 both MISO and the IESO finalized revisions to the joint transmission studies operating instruction "A01," which will provide more clarity and guidance on future study efforts.

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8.4 Eastern Interconnection Planning Collaborative (EIPC)

Along with 19 other current NERC authorized Planning Coordinating members, MISO continues to participate in the voluntary Eastern Interconnection Planning Collaborative (EIPC) organization.

Originally formed independently in 2009 by more than two dozen planning coordinating regions, EIPC's purpose is to provide a broad-based planning dialogue with interested stakeholders; foster additional consistency and coordination in the Eastern Interconnection; and to provide policy makers with technically sound transmission planning information.

Recent EIPC activity includes:

- Performing analyses of the frequency response of the Eastern Interconnection to provide input to NERC's Long Term Reliability Assessments
- Development of an EIPC member peer reviewed production cost simulation model and tool
- Creation of reliability roll up cases and drafting a state of the electric grid report from the perspective of Planning Coordinators within the EIPC
- Continual review of transmission planning best practices
- Implementing a new, simplified approach to sharing CEII information for FERC Order 1000 and NERC MOD-032 purposes
- Exploring discussions with NERC to potentially become the modeling Designated Entity for MOD-32 compliance requirements

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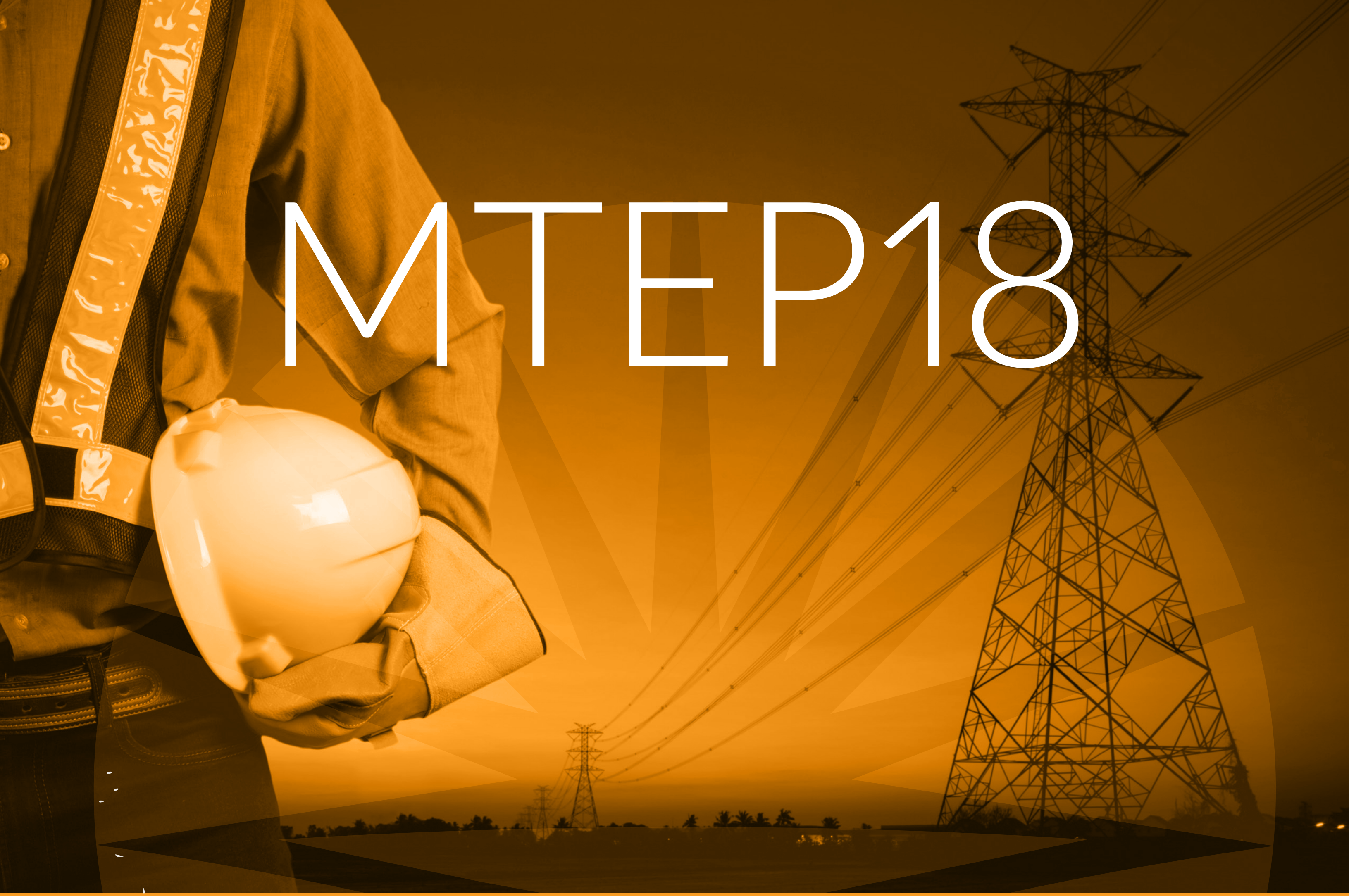

MTEP18

In this MISO Transmission Expansion Plan, MISO staff recommends $3.3 billion of new transmission enhancement projects for Board of Directors' approval.

BOOK 4

Regional Energy Information

misoenergy.org

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MTEP18
Regional Energy Information

Summary

The MISO footprint is not a monolithic area, but a dynamic region made up of different geographies, different generation mixes, varied pricing and conditions that affect load. Book 4 presents additional regional energy information to show a more complete picture of the regional energy system.

BOOK HIGHLIGHTS

- With its 50 Transmission Owner members, MISO has more than $37.9 billion in transmission assets under its functional control
- Planned generation additions and retirements in the U.S. from 2017 to 2021, separated by fuel type, shows the increased role natural gas and renewable energy sources will play in the future
- Load varies per time of year and geographic location. For calendar year 2017, the highest instantaneous peak load occurred on July 20 at 120,644 MW; the lowest load happened April 9 at 51,898 MW.

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Section 9: Regional Energy Information

9.1 MISO Overview

MISO is a not-for-profit, member-based organization that administers wholesale electricity and ancillary services markets. MISO provides customers a wide array of services including reliable system operations; transparent energy and ancillary service prices; open access to markets; and system planning for long-term reliability, efficiency and to meet public policy needs.

MISO has 51 Transmission Owner members with more than $37.9 billion in transmission assets under its functional control. MISO has 131 non-transmission owner members that contribute to the stability of the MISO markets.

MISO has 51 Transmission Owner members with more than $37.9 billion in transmission assets under MISO's functional control. MISO has 131 non-transmission owner members that contribute to the stability of the MISO markets.

The services MISO provides translate into material benefits for members and end users. The MISO's 2017 Value Proposition[30] affirms the company's core belief that a collective, region-wide approach to grid planning and management delivers the greatest benefits. MISO's landmark analysis serves as a model for other grid operators and transparently communicates the benefits in everything it does.

The value drivers are:

1. **Improved Reliability** - MISO's broad regional view and state-of-the-art reliability tool set enables improved reliability for the region as measured by transmission system availability.
2. **Dispatch of Energy** - MISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers by market participants.
3. **Regulation** – With MISO's Regulation Market, significantly less regulation is required within the MISO footprint. This is due to one centralized footprint regulation target rather than multiple non-coordinated targets across the footprint.
4. **Spinning Reserves** - Starting with the formation of the CRSG and continuing with the Spinning Reserve Market, the total spinning reserve requirement has been significantly reduced. Reduced requirement frees up low-cost capacity to meet energy market needs.
5. **Wind Integration** - MISO's regional planning enables more economic placement of wind resources in the North/Central region. Economic placement of wind resources reduces the overall capacity needed to meet required wind energy output.
6. **Compliance** - Before MISO, utilities in the MISO footprint managed their own FERC and NERC compliance. With MISO, many of these compliance responsibilities have been consolidated. As a result, member responsibilities decreased, saving them time and money.
7. **Footprint Diversity** - MISO's large footprint increases the load diversity allowing for a decrease in regional planning reserve margins from 22.15 percent to 15.80 percent. This decrease delays the need to construct new capacity.

[30] https://www.misoenergy.org/about/miso-value-proposition/

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8. **Generator Availability Improvement** - MISO's wholesale power market improved power plant availability in the North/Central region by 0.84 percent, delaying the need to construct new capacity.
9. **Demand Response** - MISO enables demand response through transparent market prices and market platforms. MISO-enabled demand response delays the need to construct new capacity.
10. **MISO Cost Structure** - MISO expects administrative costs to remain relatively flat and to represent a small percentage of the benefits.

MISO provides these services for the largest regional transmission operator geographic footprint in the U.S. MISO undertakes this mission from control centers in Carmel, Ind.; Eagan, Minn.; and Little Rock, Ark., with regional offices in Metairie, La., Little Rock, Ark., and Eagan, Minn. (Figure 9.1-1).

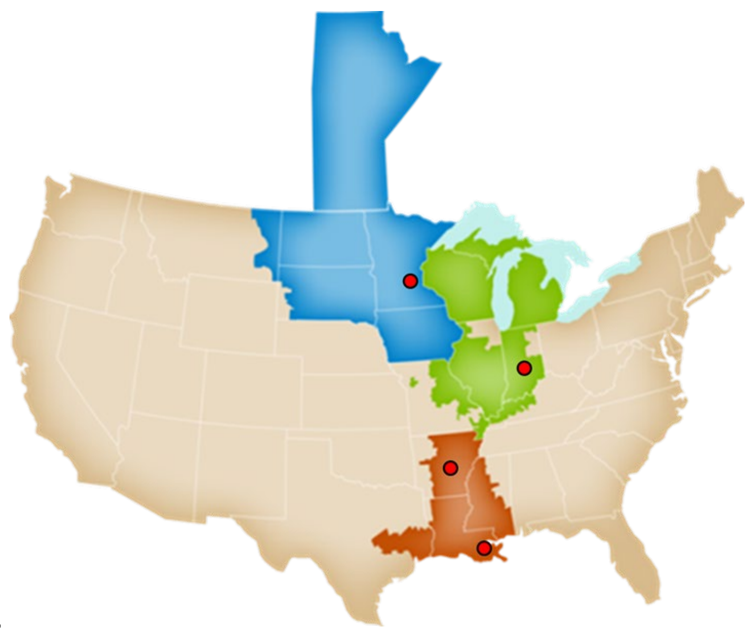

Figure 9.1-1: The MISO geographic footprint and office locations

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MISO by the Numbers

Generation Capacity (as of June 2018)

- 172,196 MW (market)
- 188,584 MW (reliability)[31]

Historic Summer Peak Load (set July 20, 2011)

- 127,125 MW (market)
- 130,917 MW (reliability)[32]

Historic Winter Peak Load (set Jan. 6, 2014)

- 109,336 MW (market)
- 117,903 MW (reliability)[33]

Miles of transmission

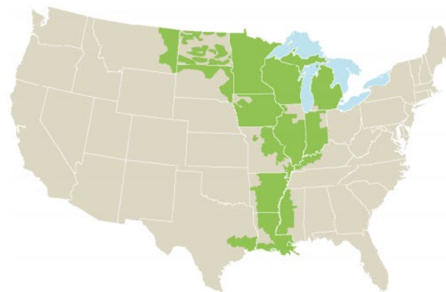
- 65,800 miles of transmission
- 383 approved new projects in MTEP17, representing $2.7 billion investment and 7,100 miles of new transmission

Markets

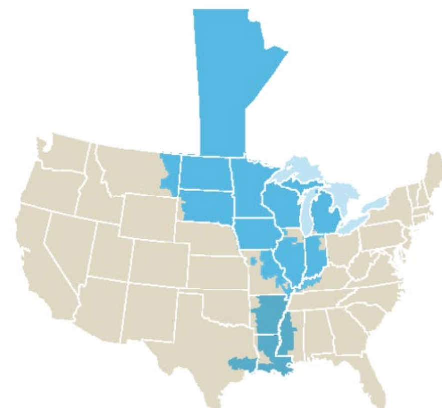
- $25.3 billion in annual gross market charges (2017)
- 453 Market Participants serving approximately 42 million people

Renewable Integration (June 2018)

- 17,117 MW Registered In-Service Wind Generation Capacity
- 18,204 MW Registered Wind Generation Capacity



MARKET AREA



RELIABILITY COORDINATION AREA

[31,3,4] MISO Fact Sheet

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9.2 Electricity Prices

Wholesale Electric Rates

MISO operates a market for the buying and selling of wholesale electricity. The price of energy for a given hour is referred to as the Locational Marginal Price (LMP). The LMP represents the cost incurred, expressed in dollars per megawatt hour, to supply the last incremental amount of energy at a specific point on the transmission grid.

The MISO LMP is made up of three components: the Marginal Energy Component (MEC), the Marginal Congestion Component (MCC) and the Marginal Loss Component (MLC). MISO uses these three components when calculating the LMP to capture not only the marginal cost of energy but also the limitations of the transmission system.

In a transmission system without congestion or losses, the LMP across the MISO footprint would be the same. In reality, the existence of transmission losses and transmission line limits result in adjustments to the cost of supplying the last incremental amount of energy. For any given hour, the MEC of the LMP is the same across the MISO footprint. However, the MLC and MCC create the difference in the hourly LMPs.

The 24-hour average day-ahead LMP at the Indiana hub over a two-week period highlights the variation in the components that make up the LMP for the first two weeks in 2018 (Figure 9.2-1). A real-time look at the MISO prices can be found on the LMP Contour Map[34] (Figure 9.2-2).

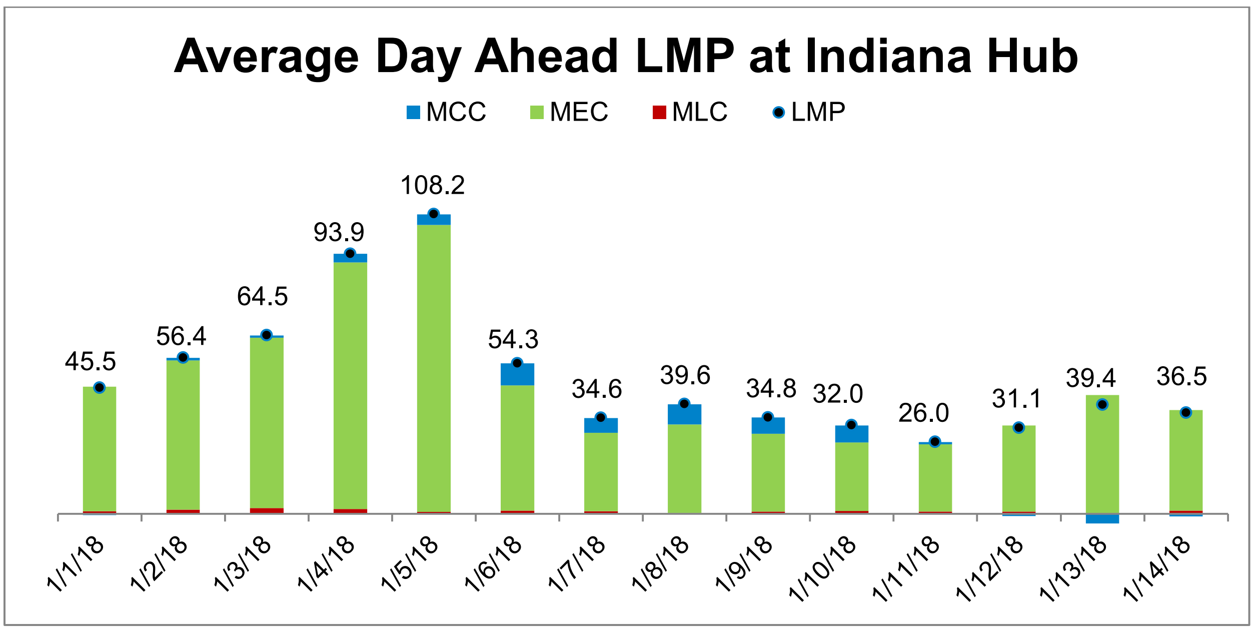

Figure 9.2-1: Average day-ahead LMP at the Indiana hub

[34] Markets and Operations Real-Time Displays: https://www.misoenergy.org/markets-and-operations/real-time-displays/

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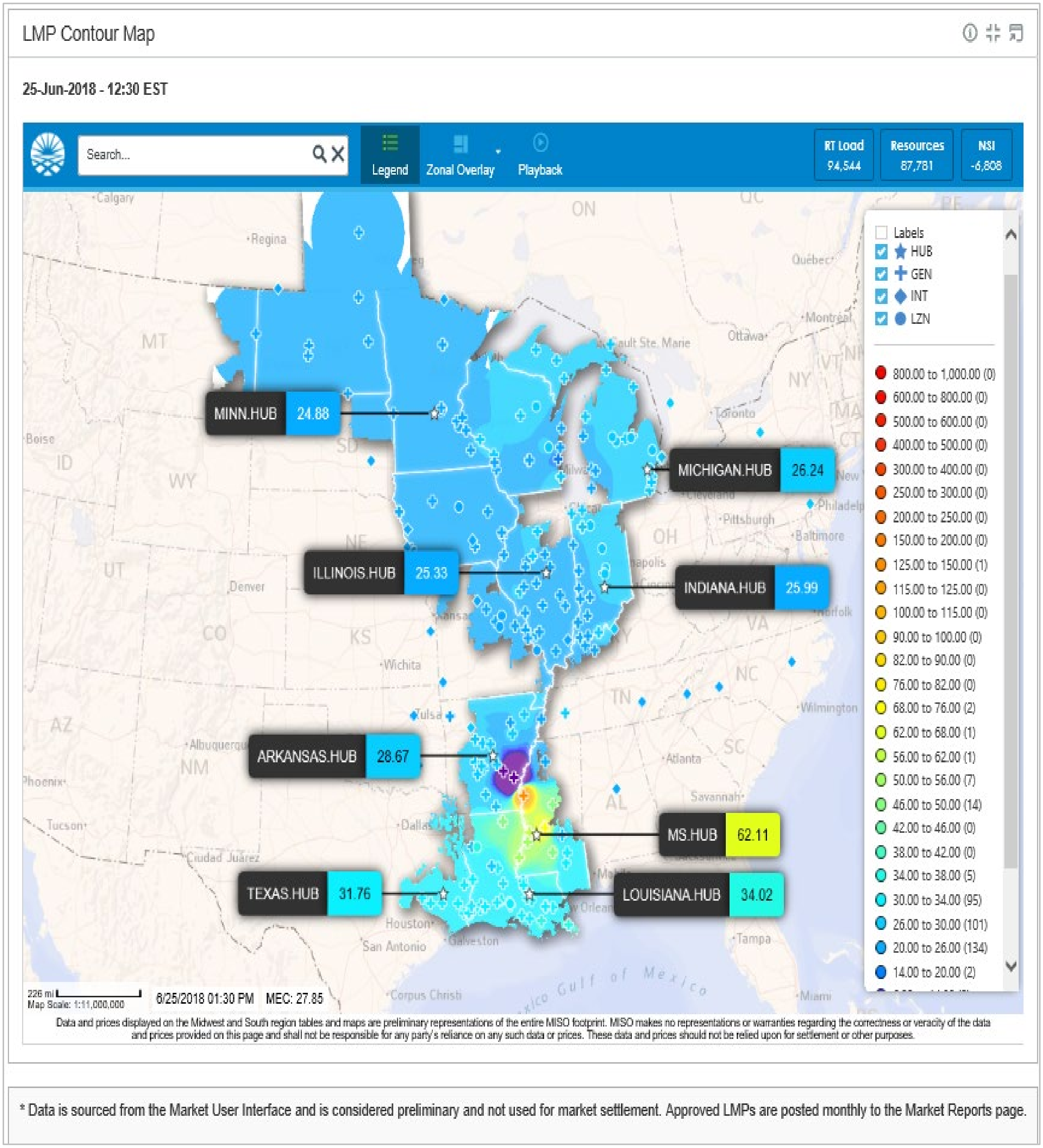

Figure 9.2-2: LMP contour map

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Retail Electric Rates

The MISO-wide average retail rate, weighted by load in each state, for the residential, commercial and industrial sector, is 9.12 cents/kWh, about 11 percent lower than the national average of 10.23 cents/kWh. The average retail rate in cents per kWh varies by 4.2 cents/kWh per state in the MISO footprint (Figure 9.2-3).

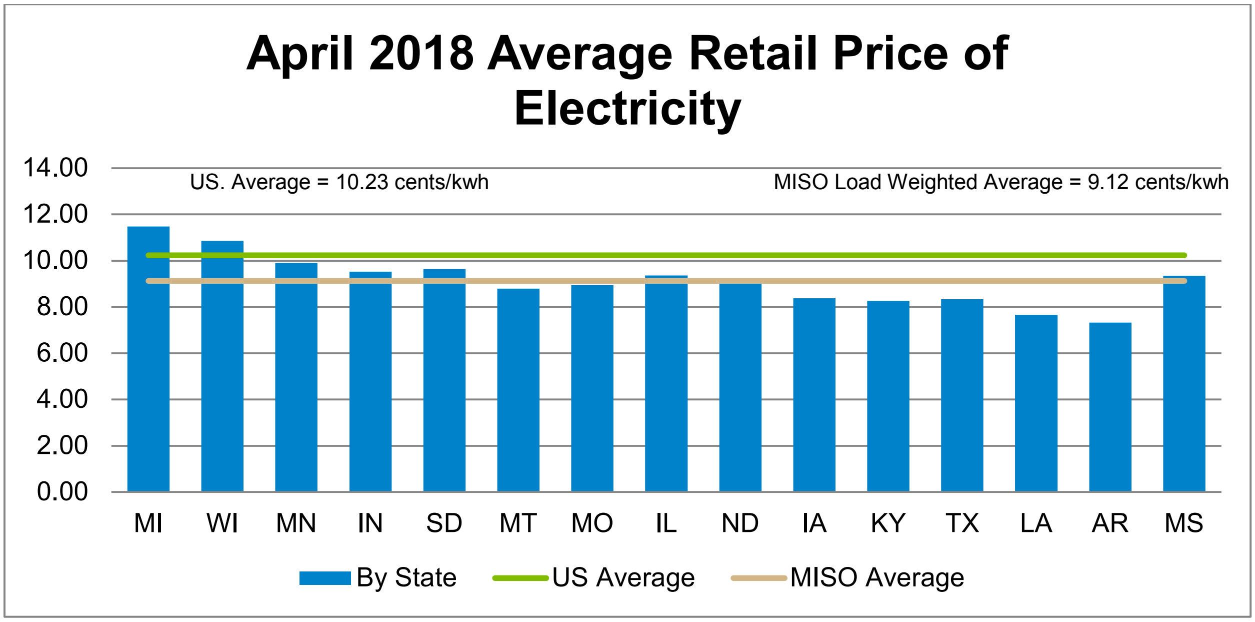

Figure 9.2-3: Average retail price of electricity per state[35]

[35] April 2018 EIA, Average Price of Electricity to Ultimate Customers by End-Use Sector, by State

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9.3 Generation Statistics

The energy resources in the MISO footprint continue to evolve. Environmental regulations, improved technologies and aging infrastructure have spurred changes in the way electricity is generated.

Fuel availability and fuel prices introduce a regional aspect into the selection of generation, not only in the past but also going forward. Planned generation additions and retirements in the U.S. from 2017 to 2021, separated by fuel type, shows the increased role natural gas and renewable energy sources will play in the future (Table 9.3-1).

	Planned Generating Capacity Changes, by Energy Source, 2017-2021					
Energy Source	Generator Additions		Generator Retirements		Net Capacity Additions	
	Number of Generators	Net Summer Capacity (MW)	Number of Generators	Net Summer Capacity (MW)	Number of Generators	Net Summer Capacity (MW)
Coal	2	292	76	19,049	-74	-18,757
Petroleum	22	33	52	948	-30	-915
Natural Gas	421	69,374	131	12,121	290	57,253
Other Gases	4	513	--	--	4	513
Nuclear	4	4,400	3	2,088	1	2,312
Hydroelectric Conventional	35	600	18	221	17	379
Wind	190	25,421	7	59	183	25,362
Solar Thermal and Photovoltaic	740	14,261	5	2	735	14,259
Wood and Wood-Derived Fuels	5	313	5	73	--	239
Geothermal	5	187	2	60	3	127
Other Biomass	47	202	23	14	24	188
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	45	567	--	--	45	567
U.S. Total	1,520	116,161	322	34,635	1,198	81,527

Table 9.3-1: Forecasted generation capacity changes by energy source[36]

[36] EIA: http://www.eia.gov/electricity/annual/html/epa_04_05.html

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The majority of MISO North and Central regions' dispatched generation comes, historically, from coal. With the introduction of the South region in December 2013, MISO added an area where a majority of the dispatched generation comes from natural gas. The increased fuel-mix diversity from the addition of the South region helps to limit the exposure to the variability of fuel prices. This adjustment to the composition of resources contributes to MISO's goal of an economically efficient wholesale market that minimizes the cost to deliver electricity.

The increased fuel-mix diversity from the addition of the South region helps limit the exposure to the variability of fuel prices

After the integration of the South region, the percentage of generation from coal units began to decrease as the amount of generation from gas units increased, as shown by trend lines (Figure 9.3-1).

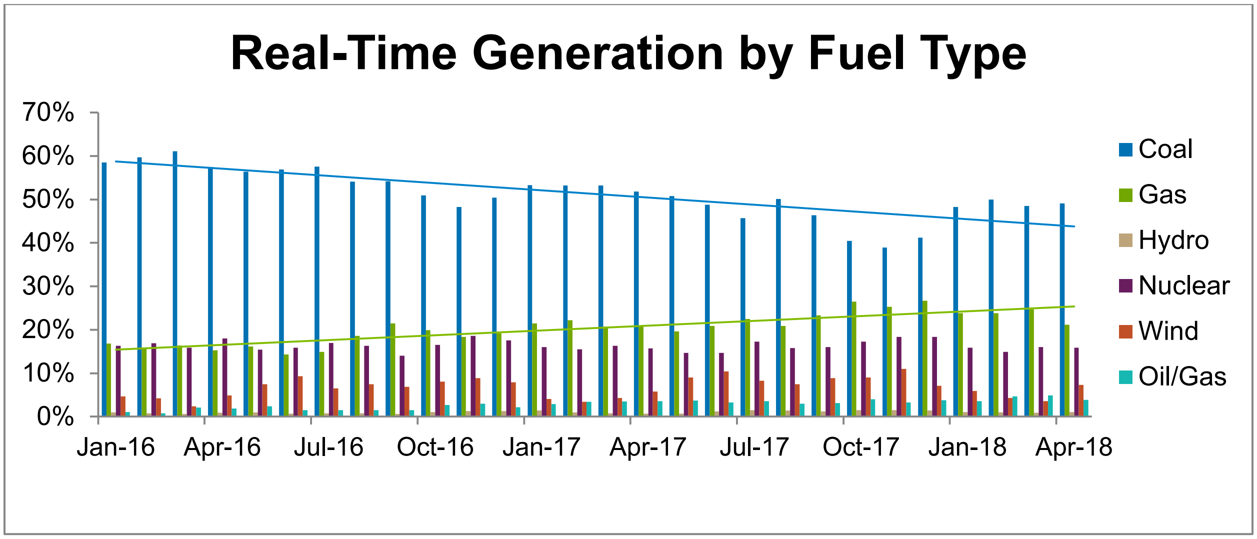

Figure 9.3-1: Real-time generation by fuel type

Different regions have different makeups in terms of generation (Figure 9.3-2). A real-time look at MISO fuel mix can be found on the MISO Fuel Mix Chart.[37]

[37] https://www.misoenergy.org/markets-and-operations/real-time-displays/

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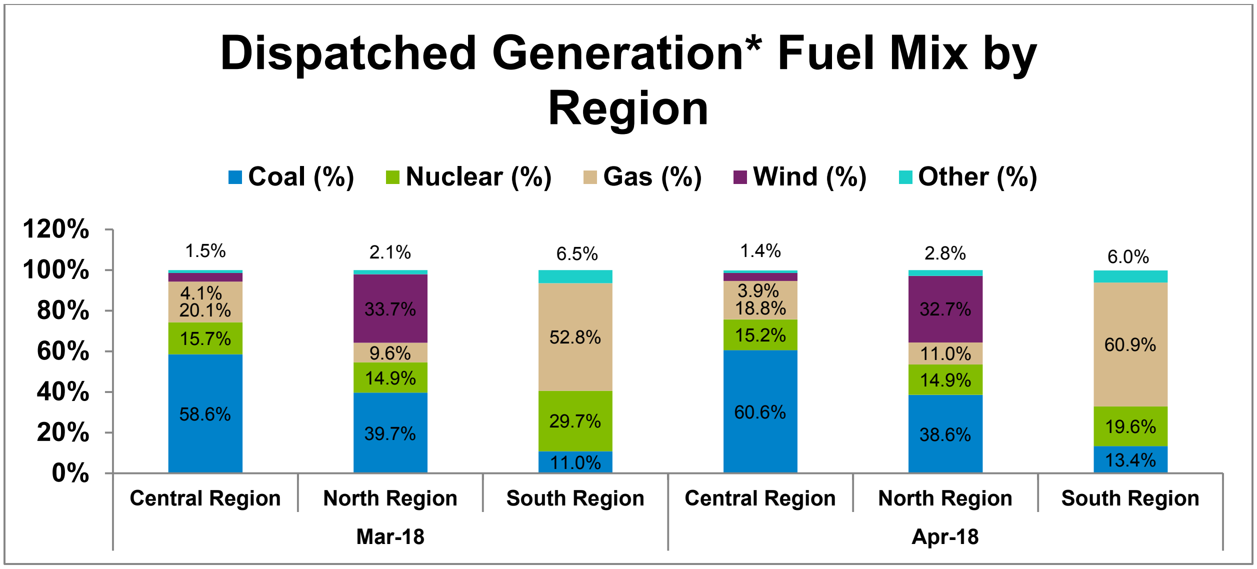

* Based on 5-minute unit level dispatch target

Figure 9.3-2: Dispatched generation fuel mix by region

Renewable Portfolio Standards

Renewable portfolio standards (RPS) require utilities to use or procure renewable energy to account for a defined percentage of their retail electricity sales. Renewable portfolio goals are similar to renewable portfolio standards but are not a legally binding commitment.

Renewable portfolio standards are determined at the state level and differ based upon state-specific policy objectives (Table 9.3-2). Differences may include eligible technologies, penalties and the mechanism by which the amount of renewable energy is being tallied.

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State	RPS Type	Target RPS (%)	Target Mandate (MW)	Target Year
Arkansas	None			
Illinois	Standard	25%		2025
Indiana	Goal	10%		2025
Iowa	Standard		105	2018
Kentucky	None			
Louisiana	None			
Michigan	Standard	15%		2021
Minnesota	Standard: all utilities	25%		2025
	Xcel Energy	30%		2020
	Solar standard – investor-owned utilities	1.5%		2020
Mississippi	None			
Missouri	Standard	15%		2021
Montana	Standard	15%		2015
North Dakota	Goal	10%		2015
South Dakota	Goal	10%		2015
Texas	Standard		10,000	2025
Wisconsin	Standard	10%		2015

Table 9.3-2: Renewable portfolio policy summary for states in the MISO footprint

Wind

Wind energy is the most prevalent renewable energy resource in the MISO footprint. Wind capacity in the MISO footprint has increased exponentially since the start of the energy market in 2005. Beginning with nearly 1,000 MW of installed wind, the MISO footprint now contains 17,071 MW of total registered wind capacity as of April 2018.

Wind energy offers lower environmental impacts than conventional generation, contributes to renewable portfolio standards and reduces dependence on fossil fuels. Wind energy also presents a unique set of challenges. Wind energy is intermittent by nature and driven by weather conditions. Wind energy also may face unique siting challenges.

A real-time look at the average wind generation in the MISO footprint can be seen on the MISO real time wind generation graph[38].

[38] https://www.misoenergy.org/markets-and-operations/real-time-displays/

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Data collected from the MISO Monthly Market Assessment Reports[39] determines the energy contribution from wind and the percentage of total energy supplied by wind (Figure 9.3-3).

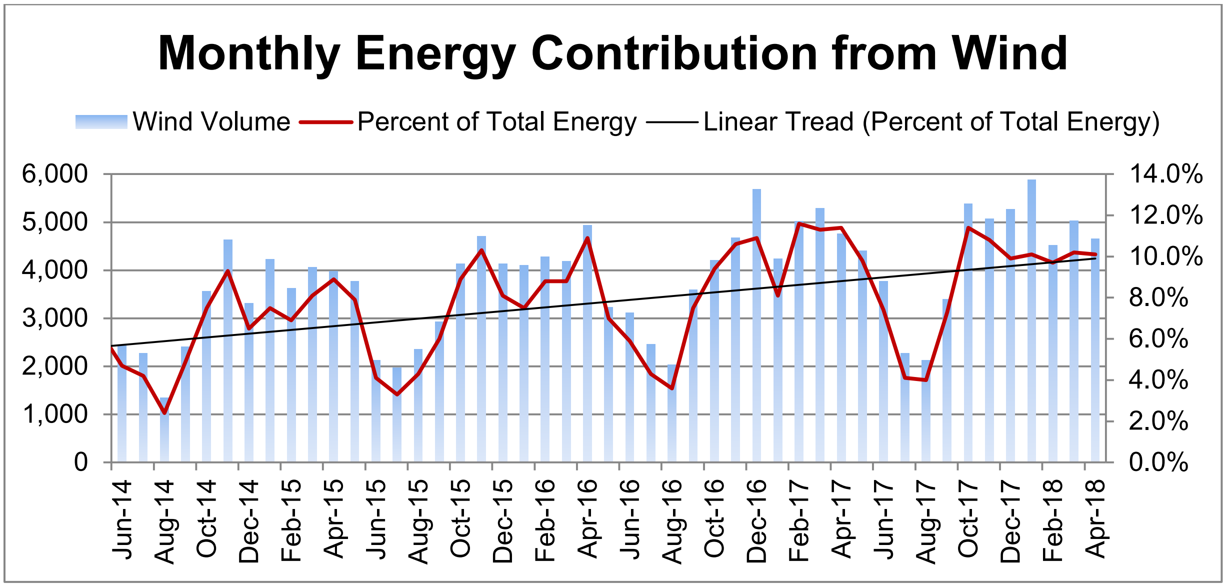

Figure 9.3-3: Monthly energy contribution from wind

Capacity factor measures how often a generator runs over a period of time. Knowing the capacity factor of a resource gives a greater sense of how much electricity is actually produced relative to the maximum the resource could produce. The graphic compares the total registered wind capacity with the actual wind output for the month. The percentage trend line helps to emphasize the variance in the capacity factor of wind resources (Figure 9.3-4).

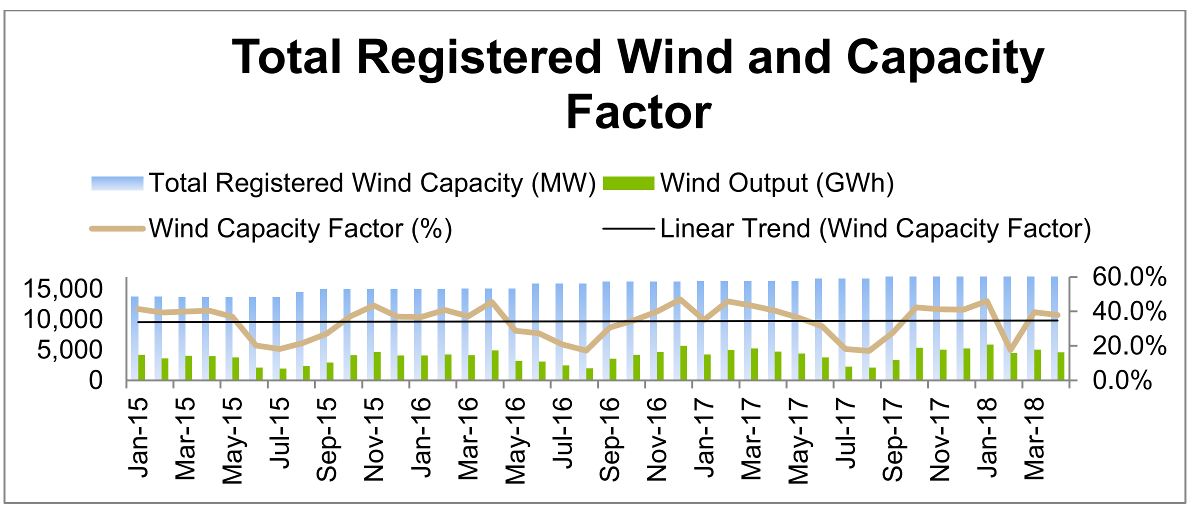

Figure 9.3-4: Total registered wind and capacity factor

[39] https://www.misoenergy.org/MarketsOperations/MarketInformation/Pages/MonthlyMarketAnalysisReports.aspx

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9.4 Load Statistics

The withdrawal of energy from the transmission system can vary significantly based on the surrounding conditions. The amount of load on the system varies by time of day, current weather and the season. Typically, weekdays experience higher load than weekends. Summer and winter seasons have a greater demand for energy than do spring or fall.

End-Use Load

It is a challenge to develop accurate information on the composition of load data. Differences in end-use load can be seen at footprint-wide, regional and Load-Serving Entity levels.

To keep up with changing end-use consumption, MISO relies on the data submitted to the Module E Capacity Tracking (MECT) tool. MECT data is used for all of the long-term forecasting including Long-Term Reliability Assessment and Seasonal Assessment as well as to determine Planning Reserve Margins.

The Energy Information Agency (EIA) Electric Power Monthly provides information on the retail sales of electricity to the end-use customers by sector for each state in the MISO footprint (Table 9.4-1).

April 2017 - Retail Sales of Electricity to Ultimate Customers by End-Use Customer							
State	Residential		Commercial		Industrial		All Sectors
	(Million kWh)	% of total	(Million kWh)	% of total	(Million kWh)	% of total	
Arkansas	1,128	33.0%	870	25.5%	1,417	41.5%	3,415
Iowa	1,050	26.9%	953	24.4%	1,901	48.7%	3,905
Illinois	3,046	30.0%	3,762	37.0%	3,305	32.5%	10,156
Indiana	2,262	30.7%	1,776	24.1%	3,336	45.2%	7,376
Kentucky	1,787	33.0%	1,392	25.7%	2,229	41.2%	5,408
Louisiana	1,810	27.8%	1,799	27.6%	2,904	44.6%	6,514
Michigan	2,467	31.6%	3,029	38.8%	2,317	29.7%	7,813
Minnesota	1,636	32.2%	1,768	34.8%	1,669	32.9%	5,075
Missouri	2,368	42.3%	2,323	41.5%	901	16.1%	5,594
Mississippi	1,126	32.2%	999	28.6%	1,368	39.2%	3,492
Montana	421	35.5%	401	33.8%	363	30.6%	1,185
North Dakota	407	25.6%	525	33.0%	658	41.4%	1,590
South Dakota	393	39.3%	389	38.9%	217	21.7%	1,000
Texas	8,745	31.5%	10,318	37.2%	8,665	31.2%	27,743
Wisconsin	1,633	30.3%	1,840	34.1%	1,916	35.6%	5,389
Total	30,279	31.7%	32,144	33.6%	33,166	34.7%	95,655

Table 9.4-1: Retail sales of electricity to ultimate customers by end-use sector, April 2017[40]

[40] http://www.eia.gov/electricity/annual

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Load

Peak load drives the amount of capacity required to maintain a reliable system. Load level variation can be attributed to various factors, including weather, economic conditions, energy efficiency, demand response and membership changes. The annual peaks, summer and winter, from 2007 through 2017, show the fluctuation (Figure 9.4-2).

Within a single year, load varies on a weekly cycle. Weekdays experience higher load. On a seasonal cycle, it also peaks during the summer with a lower peak in the winter, and with low-load periods during the spring and fall seasons (Figure 9.4-3). The Load Duration Curve shows load characteristics over time (Figure 9.4-4). Looking at all 365 days in 2017, these curves show the highest instantaneous peak load of 120,644 MW on July 20, 2017; the minimum load of 51,898 MW on April 9, 2017; and every day in order of load size. This data is reflective of the market footprint at the time of occurrence.

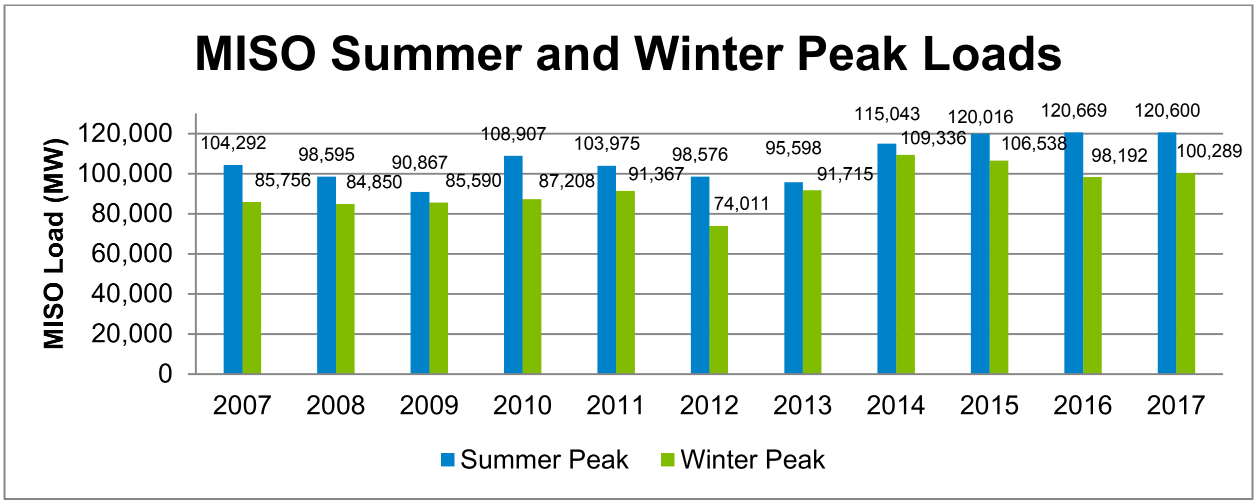

Figure 9.4-2: MISO Summer and Winter Peak Loads – 2007 through 2017[41]

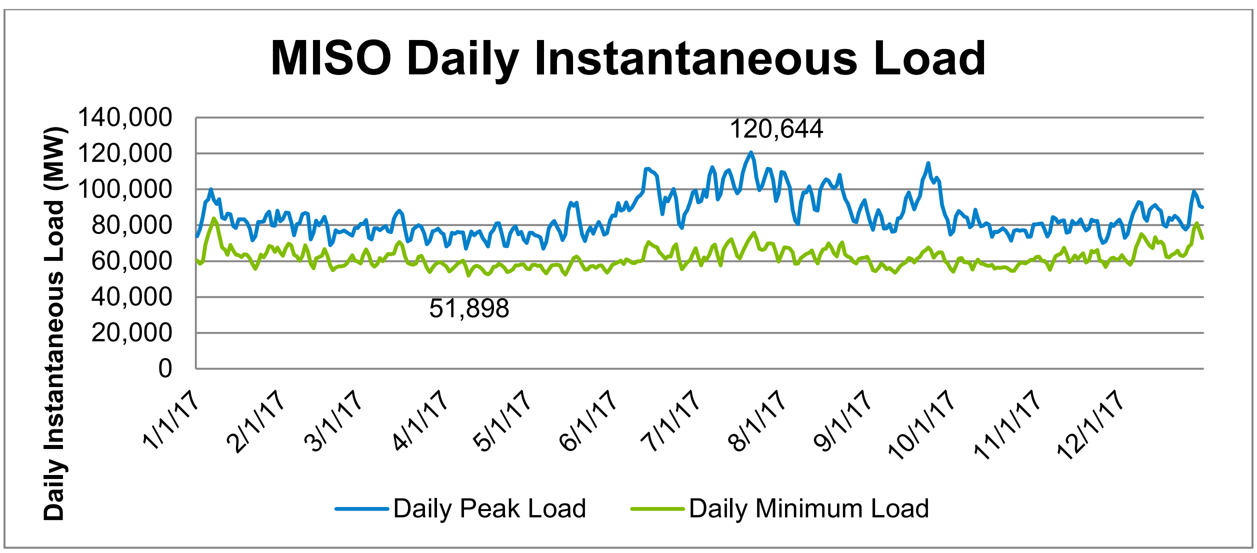

Figure 9.4-3: 2017 MISO - Daily Load[42]

[41] Source: MISO Market Data (MISO 2017 Summer and Winter Assessment Reports)

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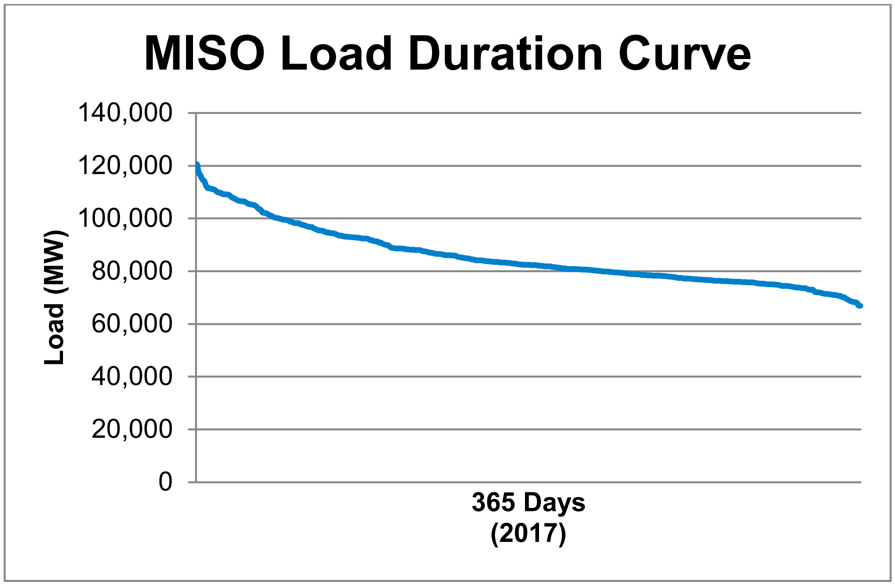

Figure 9.4-4: MISO Load Duration Curve – 2017[43]

[42] Source: MISO Market Data (2017)
[43] Source: MISO Market Data (2017)

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Appendices

Most MTEP18 appendices[44] are available and accessible on the MISO public webpage. Confidential appendices, such as D3 through D10, are available on the MISO MTEP18 Planning Portal. Access to the Planning Portal site requires an ID and password.

Appendix A: Projects recommended for approval
A.1, A.2, A.3: Cost allocations
A: MTEP18 Appendix A new projects and existing projects

Appendix B: Projects with documented need and effectiveness

Appendix D: Reliability studies analytical details with mitigation plan
Section D.2: Modeling documentation

Appendix E: Additional MTEP18 Study support
Section E.1: Reliability planning methodology
Section E.2: Futures development

Appendix F: MTEP18 Stakeholders Feedback

[44] https://www.misoenergy.org/planning/transmission-studies-and-reports/#nt=%2Freport-study-analysistype%3AMTEP%2Fmtepdoctype%3AMTEP%20Report%2Fmtepreportyear%3AMTEP18&t=10&p=0&s=&sd=

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Acronyms in MTEP18

ABB	ASEA Brown Boveri
AC	Alternating Current
AEG	Applied Energy Group
AFC	Accelerated Fleet Change
AMIL	Ameren Illinois
APC	Adjusted Production Cost
ARR	Auction Revenue Rights
BPM	Business Practices Manual
BRP	Baseline Reliability Projects
BTMG	Behind-the-meter Generation
CAGR	Compound Annual Growth Rate
CBBRP	Cross Border Baseline Reliability Projects
CFC	Continued Fleet Change
CT	Combustion Turbine
CEII	Critical Energy Infrastructure Information
CEL	Capacity Export Limit
CIL	Capacity Import Limit
CO_2	Carbon Dioxide
CP	Coincident Peak
CPCN	Certificate of Public Convenience and Necessity
CROW	Control Room Operator's Window
DCLM	Direct control load management
DET	Distributed and Emerging Technologies
DG	Distributed Generation
DPP	Definitive Planning Phase
DPV	Distributed Solar Photovoltaic
DR	Demand Response
EE	Energy Efficiency
EER	Energy Efficiency Resource
EGEAS	Electric Generation Expansion Analysis System
EIA	Energy Information Agency
EIPC	Eastern Interconnection Planning Collaborative
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency (U.S.)
ERAG	Eastern Reliability Assessment Group
FCA	Facility Construction Agreement
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GIA	Generator Interconnection Agreement
GIP	Generator Interconnection Projects
GIQ	Generator Interconnection Queue
GIS	Geographical Information System
GVTC	Generator Verification Test Capacity
IESO	Independent Electricity System Operator of Ontario
IL	Interruptible Load
ILF	Independent Load Forecast
IMEP	Interregional Market Efficiency Project
IPSAC	Interregional Planning Stakeholder Advisory Committee
JOA	Joint Operating Agreement
LBA	Local Balancing Authority
LCR	Local Clearing Requirements
LFC	Limited Fleet Change
LFU	Load Forecast Uncertainty
LG&E	Louisville Gas and Electric Co.
LMP	Locational marginal price
LMR	Load Modifying Resources
LOLE	Loss of Load Expectation
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
LTRA	Long-Term Resource Assessment
LTTR	Long-Term Transmission Rights
MATS	Mercury and Air Toxics Standard
MCC	Marginal Congestion Component
MCPS	Market Congestion Planning Studies
MEC	Marginal Energy Component (MEC)

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MECT	Module E Capacity Tracking
MEP	Market Efficiency Projects
MISO	Midcontinent Independent System Operator
MLC	Marginal Loss Component
MMWG	Multi-regional Modeling Working Group
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MVP	Multi-Value Projects
MW	Megawatt
NCP	Non-coincident Peak
NERC	North American Electric Reliability Corp.
NRIS	Network Resource Interconnection Service
OASIS	Open Access Same-Time Information System
OMS	Organization of MISO States
OOS	Out of Service
PAC	Planning Advisory Committee
PC	Project Candidate
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PRA	Planning resource auction
PRM	Planning Reserve Margin
PRM_{ICAP}	PRM installed capacity
PRM_{UCAP}	PRM uninstalled capacity
PRMR	Planning Reserve Margin Requirement
PSC	Planning Subcommittee
PV	Present Value
RAN	Resource Availability and Need
RE	Regional Entities
RECB	Regional Expansion Criteria and Benefits
RGOS	Regional Generator Outlet Study
RIIA	Renewable Integration Impact Assessment
ROW	Right of Way
RPS	Renewable Portfolio Standard
RRF	Regional Resource Forecast
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission operator
SERTP	Southeastern Regional Transmission Planning
SIS	System Impact Study
SOCO	Southern Colorado Transmission Co.
SPC	System Planning Committee
SPM	Subregional Planning Meetings
SPP	Southwest Power Pool
SREC	Sub-Regional Export Constraint
SSR	System Support Resource
SUFG	State Utility Forecasting Group
TDSP	Transmission Delivery Service Project
TIS	Total Interconnection Service
TMEP	Targeted Market Efficiency Project
TO	Transmission Owner
TPL	Transmission Planning Standards
TPZ	Transmission Planning Zone
TSR	Transmission Service Request
TSTF	Technical Study Task Forces
TVA	Tennessee Valley Authority
UNDA	Universal Non-disclosure Agreement
UPV	Utility-scale photovoltaic
WOTAB	West of the Atchafalaya Basin

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Contributors to MTEP18

MISO would like to thank the many stakeholders who provided MTEP18 report comments, feedback and edits. The creation of this report is truly a collaborative effort of the entire MISO region.

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Item 14) ***Provide a discussion of any impact that recent FERC rulings pertaining to the LG&E-KU wholesale pancaked transmission rates may have on BREC's continued ability to engage in off-system sales.***

Response) Big Rivers' understanding is that current transactions are grandfathered through their contractual termination date. If that understanding is correct, then there will be no impact on Big Rivers' transactions with Owensboro Municipal Utilities or the Kentucky Municipal Energy Agency.

For prospective transactions, Big Rivers believes that the rulings will increase the cost for load on the LGE/KU system to source supply within MISO. This result would eliminate a competitive advantage that MISO generators, such as Big Rivers, have over generators in other regional transmission organizations, such as PJM. The rulings should not affect Big Rivers' competitive position within MISO, however.

Witness) Mark J. Eacret

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Item 15) ***Explain whether any regional transmission changes could affect the ability to attract additional parties/partners in the projected NGCC plant, and if so, how.***

Response) The Wilson to BR Tap to Paradise 161 kV upgrade project, described in Big Rivers' response to Item 13 of the Office of the Attorney General's Initial Data Requests, is expected to reduce congestion along the Big Rivers/TVA/LG&E-KU interface near the Big Rivers' Wilson generating station. Reduced transmission congestion has the potential to make generation projects in the Big Rivers' service area more attractive.

Witness) Christopher S. Bradley

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Item 16) ***Explain whether BREC anticipates participating in any manner with the Southeast Energy Exchange Market, and if so: (i) how; and (ii) what benefits the Company hopes to achieve in doing so.***

Response) At this point, Big Rivers does not anticipate participating in the Southeast Energy Exchange Market.

Witness) Mark J. Eacret

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Item 17) ***Explain whether BREC has the ability to make off-system sales into the TVA service territory. If so confirmed, provide a discussion of whether recent changes in TVA's service territory, in particular the significant retirements of coal-fired generation, could create opportunities for off-system sales into that territory.***

Response) Big Rivers cannot make off-system sales into the TVA service territory.

Witness) Mark J. Eacret

Item 18) ***Explain how any idling, suspension, or retirement of the Green units will affect BREC's MISO reserve requirements.***

Response) Annual reserve requirements established by MISO are based on Big Rivers' load coincident with MISO's peak. Therefore, Big Rivers' reserve requirements would be impacted only to the extent such idling, suspension, or retirement of the Green units affects MISO's calculation of the annual Planning Reserve Margin Requirement.

Witness) Marlene S. Parsley

Item 19) ***Provide the most current projected retirement date of the Wilson unit, and explain whether: (i) the ELG Rule; and/or (ii) the Biden Administration's plan to require electric utilities to achieve carbon neutrality by 2035 will or could in any manner affect the projected retirement date.***

Response) Assuming Wilson Station continues to operate nominally as it has for the past thirty-seven (37) years, and parts are available for continued maintenance, Wilson's expected life span exceeds the full planning period covered by Big Rivers' 2020 IRP. Wilson Station will not be affected by the ELG Rule since it was equipped with the proper control equipment during initial construction. It is not possible to determine what impacts the Biden Administration's statement about carbon neutrality will have until such time as the United States Environmental Protection Agency (EPA), or other departments within the Administration, formulate draft rules addressing the topic.

Witness) Nathanial A. Berry

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Item 20) ***Explain whether the retirements of the HMPL, Coleman, Reid and/or Green units have created or will create any emissions allowance credits that could be "banked" for future use at Wilson.***

Response) Yes. Pursuant to federal regulations, once a generating unit has been inactive for a period of two (2) years it will continue to receive annual SO_2 and annual NOx allowance credits for a period of five (5) years from the start of the unit's inactivity. Therefore, Big Rivers continued to receive annual allowances related to Coleman through 2019 and Reid 1 through 2020; and Big Rivers will continue to receive allowances related to Henderson Municipal Power & Light's Station Two through 2022. Subject to United States Environmental Protection Agency regulations, these "banked" allowances are eligible for use at any Big Rivers facility.

Witness Michael S. Mizell

Item 21) ***Provide the total amount of dispatchable power that BREC either owned or had access to as of the date this IRP Plan was filed.***

a. ***Provide the amount of dispatchable power that BREC will either own or have access to as of the effective date of the retirements of the Reid coal unit and the Green units***

b. ***Confirm that the addition of 260 MW of power under the three solar power purchase agreements referenced in §§ 1.2.4 and 2.9 will not add any dispatchable power.***

c. ***Once the solar power purchase agreements referenced above are completed, provide the amount of dispatchable power that BREC will have available. Include in your response the projected date of the NGCC's commercial operation, and BREC's anticipated share thereof.***

Response) The table on the following page provides a breakdown of the 1,114 MWs total dispatchable power that Big Rivers owned, or had access to, as of the date it filed its 2020 IRP. Big Rivers' allocation of SEPA[1] hydropower is included due to Big Rivers' ability to schedule the power when needed within the terms of the contract. Since Big Rivers' Coleman units and Reid Unit 1 were officially retired on September 30, 2020, but were idled prior to their retirement they are not shown in the below table.

Big Rivers Electric Corporation Dispatchable Power (MWs)		
Unit	**As of September 2020**	**Following Retirement of Green Units**
Wilson Unit 1	417	417
Green Unit 1	231	-
Green Unit 2	223	-
Reid CT	65	65
SEPA (schedulable)	178	178
Total	1,114	660

a. Please see the table above. It includes the amount of dispatchable power that Big Rivers will have access to without the Green coal-fired units. On March 1, 2021, Big Rivers filed its plan to convert the two Green coal-fired

[1] SEPA = Southeastern Power Administration.

units to natural gas with the Commission.[2] If the Commission approves this plan, the Green natural gas units would provide another 414 MWs of dispatchable power beginning June 1, 2022.

b. Big Rivers confirms that the addition of 260 MWs of power under the three solar power purchase agreements will not add any dispatchable power.

c. Please see Big Rivers' response to sub–part a. for the amount of dispatchable power Big Rivers will have upon the commercial operation dates of the solar facilities, pursuant to the solar power purchase agreements. At this time, the commercial operation date of the NGCC is not known, nor is Big Rivers' anticipated share thereof.

Witnesses) Marlene S. Parsley (*a. and b. only)* and

Mark J. Eacret (*c. only*)

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[2] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing the Conversion of the Green Station Units to Natural Gas-Fired Units and an Order Approving the Establishment of a Regulatory Asset,* Case No. 2021-00079.

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Item 22) ***Provide a discussion of how much dispatchable power BREC will have in the event that: (i) the Biden Administration's plan of requiring electric utilities to achieve carbon neutrality by 2035 becomes a reality; and (ii) BREC is left with only renewable types of power generation.***

Response) Big Rivers is unable to determine what impact the Biden Administration's statement regarding carbon neutrality by 2035, will have on dispatchable power, until such time as the United States Environmental Protection Agency ("EPA") or other departments within the Administration formulate draft rules addressing the topic.

Witness) Nathanial A. Berry

Item 23) *Reference IRP Plan § 5.4. Confirm that MISO CEO Bear, appearing before the House Committee on Energy and Commerce, Subcommittee on Energy on October 30, 2019, indicated that maintaining grid reliability beyond the 40% renewable penetration level would become significantly more complex, and that above that level, advanced technologies would be required to balance the MISO system to reduce renewable curtailments and regional transmission reliability issues and keep the system stable.*

a. *Confirm also the statement: "Big Rivers believes that because of all of this change, there remains value in retaining our most efficient baseload resource and in identifying resources that will complement intermittent renewable resources in the future."*

b. *In light of the Biden Administration's plan to require electric utilities to achieve carbon neutrality by 2035, include in your response discussions of: (i) whether it will be possible to procure supply-side resources to complement and supplement the intermittent nature of renewable resources; and (ii) the "advanced*

technologies" that MISO would have to procure and deploy to reduce renewable curtailments and regional transmission reliability issues in order to maintain system stability.

Response) Big Rivers confirms the statement of Mr. Bear. For a copy of Mr. Bear's testimony, please see the attachment to Big Rivers' response to Item 29 sub – part a of the Commission Staff's First Request for Information.

a. As stated in Section 5.4 of its 2020 IRP, Big Rivers confirms the statement.

b.

i. Procuring supply-side resources to complement and supplement the intermittent nature of renewable resources will become increasingly difficult and expensive especially as older, less efficient resources are retired. On March 1, Big Rivers filed its plan to convert the Green Station coal units to natural gas the Commission.[1] That filing is one

[1] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing the Conversion of the Green Station Units to Natural Gas-Fired Units and an Order Approving the Establishment of a Regulatory Asset,* Case No. 2021-00079.

step in that direction. Extending the life of the Green units will provide more time to evaluate the effect of intermittent resources on the grid.

ii. Please see Big Rivers' responses to Item Nos. 18 and 19 of the Commission Staff's Initial request for Information in Case No. 2020-00183.[2] Also, see Big Rivers' response to Item 19 of the Office of the Attorney General's Second request for Information in Case No. 2020-00183. Those responses provide a detailed discussion of the topic.

Witness) Mark J. Eacret

[2] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of Solar Power Contracts*, Case No. 2020-00183. Application filed June 24, 2020.

Item 24) ***Explain how BREC will ensure reliability of services to its customers given: (i) the Company's increasing reliance on solar to meet its capacity load requirements; and (ii) the Biden Administration's plan to require electric utilities to achieve carbon neutrality by 2035.***

a. If BREC intends to insure reliability through MISO market purchases, include in the Company's explanation a discussion relating to MISO's on-going ability to meet its members' energy needs through market purchases.

Response) Big Rivers will continue to ensure reliability of services to its customers including the addition of solar to meet its capacity load requirements by participating in the MISO transmission expansion planning process and by complying with resource adequacy provisions of the MISO tariff. MISO annually studies proposed transmission and generation projects including transmission upgrades required to assure reliable service. Therefore, additional intermittent generation within MISO will be supported by sufficient transmission when it comes online.

Additionally, Big Rivers has filed a plan with the Commission to convert its Green coal units to natural gas,[1] extending the life of a more traditional generating resource. This provides time to evaluate the effect of the increasing level of intermittent resources on the grid.

a. Big Rivers does not anticipate the need to make large quantities of MISO market energy purchases to meet its Member–Owners' energy needs. In any case, such purchases represent more of a price risk than reliability issue. To the extent that Big Rivers does project the need for such purchases, Big Rivers will hedge its exposure in the bilateral markets to reduce the price volatility to which its Member–Owners are exposed.

Witness) Mark J. Eacret

[1] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing the Conversion of the Green Station Units to Natural Gas-Fired Units and an Order Approving the Establishment of a Regulatory Asset,* Case No. 2021-00079.

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Item 25) ***Given the reliability issues inherent with renewable energy sources such as solar and wind, explain how BREC's increased reliance on renewables will not lead to reliability issues for its members and end-use customers. Explain also how BREC will insure that its members and end-use customers do not experience blackouts, or rolling blackouts, as has happened in the past year in California, Texas and many other states that have increased their reliance on renewable energy.***

Response) Big Rivers' mission is to safely deliver competitive and reliable wholesale power and cost-effective shared services desired by its Members. Continuously and consistently focusing on each aspect of this mission, Big Rivers regularly reviews resource options in context of the dynamic electric utility industry and the uncertainty of the changing energy marketplace. Since its founding in 1961, Big Rivers has owned, operated, and maintained a predominantly coal-fired generating fleet. With access to low-cost and abundant Kentucky coal, such generating assets provided Western Kentucky with low-cost reliable electricity over the past 40+ years. As the Attorney General is aware, over the past few decades, environmental regulations have become more stringent thus eroding the cost advantage of coal-fired generation. An additional factor to Big Rivers' ability to provide low-cost wholesale power is its ability to obtain advantageous credit interest rates. A diversified generation portfolio with renewable energy sources is reviewed positively by the credit ratings agencies, whose credit reports greatly affect the interest rates Big Rivers will secure.[1] In response to these and other considerations, Big Rivers determined to diversify its resource mix, which currently includes hydroelectric power from the Southeastern Power Administration (SEPA), coal, and natural gas and will include solar.

As Big Rivers fully explained through Direct Testimony and responses to information requests in Case No. 2020-00183,[2] in which Big Rivers sought and received the Commission's approval of three solar power purchase agreements

[1] See. *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of Solar Power Contracts*, Ky.P.S.C. Case No. 2020-00183, Application Exhibit 5, Direct Testimony of Paul G. Smith at page 8.

[2] *Id.* Application Exhibit 4, the Direct Testimony of Mark Eacret at page 12 (June 24, 2020) and Big Rivers Electric Corporation's Response to the Commission Staff's Initial Request for Information dated August 5, 2020, at Big Rivers' Response to Item 19, (Aug. 14, 2020)

("PPAs") , and discussed in Big Rivers' Application in Case No. 2021-00079,[3] in which Big Rivers seeks relief including a certificate of public convenience and necessity to convert its two generating units at Green Station to natural gas-fired units, Big Rivers' plans to diversity its portfolio focuses on maintaining a "least cost" approach and avoiding reliability issues for its members and end-users.

John Bear, the Chief Executive Office of MISO, in his testimony before Congress cautioned that "at the 40% renewable penetration level becomes significantly more complex" and "in addition to the challenges described at the 30% level, we would encounter the need to balance the system over a very large area to reduce renewable curtailments and regional transmission reliability issues." While the MISO real-time fuel mix in 2020, was about 12% wind, and solar was not even presented separately, that was still quite lower than 30% to 40%. However, considering that more and more solar is being proposed for the grid and connection to Big Rivers' system, Big Rivers' proposal to keep to the Green Station's two large

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[3] *In the Matter of: Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing The Conversion of the Green Station Units to Natural Gas-Fired Units and an Order Approving the Establishment of a Regulatory Asset*, Ky. P.S.C. Case No. 2021-00079, Application Exhibit B, the Direct Testimony of Mark Eacret at page 15.

generators on the system, at a relatively low cost, is just one way Big Rivers continues to balance the goals of "least cost" and reliability.

Big Rivers' participation in MISO provides access to a large energy market with a diverse generation fuel mix. A robust transmission system with twenty (20) transmission interconnections to neighboring systems ensures Big Rivers' access to the MISO market and other external generation during a wide range of normal and emergency conditions. The transmission interconnections include seven (7) connections to the Tennessee Valley Authority ("TVA") with a combined rating of over 2,000 MVA; six (6) connections to other MISO members with a combined rating of almost 4,000 MVA; and seven (7) connections to Louisville Gas and Electric/Kentucky Utilities ("LG&E-KU") with a combined rating of over 3,800 MVA. Big Rivers has reliably served its Member-Owners and end-use customers under a wide range of generation dispatch scenarios. Big Rivers will continue to take steps internally and in coordination with its neighboring utilities to eliminate any barriers to reliable operations.

Witness) Christopher S. Bradley

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Item 26) ***Explain how locking in solar prices for a twenty-year period is beneficial for customers as opposed to obtaining solar power on the open market during the same twenty-year period.***

Response) The economic analysis presented in support of the Commission-approved solar power purchase agreements[1] demonstrated that the price paid for energy, capacity, and environmental attributes under the contracts is less than the projected cost of those commodities purchased separately. Additionally, the solar contracts fix the cost of the energy, capacity, and environmental attributes, which reduces the market volatility to which Big Rivers' Member-Owners would be exposed.

Witness) Mark J. Eacret

[1] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of Solar Power Contracts*, Case No. 2020-00183. Application filed June 24, 2020.

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Item 27) ***Confirm that Moody's has given BREC an investment grade rating.***

Response) Confirmed. Please see Big Rivers' response to Item 7 of the Commission Staff's First Request for Information in this case.

Witness) Paul G. Smith

Item 28) ***Reference the IRP Plan at pp. 40-42, regarding the impact of the Covid-19 crisis. Provide an update to these figures since the time the IRP Plan was filed.***

Response) The narrative on page 41 of Big Rivers' 2020 IRP included COVID impacts analyzed by Big Rivers' load forecast consultant, Clearspring Energy Advisors of Madison, Wisconsin, for March and April of 2020, and Big Rivers' internal analysis of April through June 2020.

While no particular analysis attributing load patterns changes to COVID were performed for the period, during the July to February 2021 timeframe, Rural load has continued lower, averaging a 7% demand reduction and 1% energy reduction from budget. Direct Serve load showed a 5% reduction in demand and 14% reduction in energy from budget for the period of July 2020 through February 2021. For additional information see Big Rivers' Member-Owners responses to the Commission's data requests in Case No. 2020-0085, with detailed information regarding the impact of the COVID-19 crisis experienced by the Member-Owners.[1]

Witness) Marlene S. Parsley

[1] *In the Matter of: Emergency Docket Related to the Novel Coronavirus COVID-19*, Ky. P.S.C. Case No. 2020-00085.

Item 29) ***Reference IRP Plan § 4.8, Conclusions for Demand Response, in particular p. 89 wherein it is stated that a residential peak time rebate (PTR) program would pass the TRC test.***

a. Confirm that Meade RECC and Kenergy either already have, or soon will have full deployment of AMI meters.

b. Explain whether Jackson Purchase RECC has AMI meters.

c. Explain whether any such PTR program would be premised on the three members' utilizing AMI meters, or whether such a program could be implemented and operated without AMI meters.

d. Provide the remaining useful lives of the AMI metering systems that BREC's members have installed.

Response)

a. Meade County RECC has proposed a full rollout of Advanced Metering Infrastructure ("AMI") to the Commission, and is awaiting the

Commission's decision.[1] If the Commission approves Meade County RECC's proposal, Meade County RECC expects to take about eighteen (18) months to fully deploy the AMI System. Kenergy Corp. currently has a fully-deployed AMI system.

b. Jackson Purchase Energy Corporation ("Jackson Purchase") currently has Power Line Carrier (PLC) AMI, which Jackson Purchase deployed in 2009.

c. A peak time rebate ("PTR") program would require the ability to document load impacts of end–use behavior and, therefore, would likely necessitate the use of AMI.

d. Generally, an electronic meter has an estimated life of fifteen (15) years. An AMI system would not have a specific useful life if properly maintained.

Witness) Russell L. Pogue

[1] *See In the Matter of: Electronic Application of Meade County Rural Electric Cooperative Corporation for a Certificate of Public Convenience and Necessity to Continue with the Full Deployment Installation of its Automated Metering and Infrastructure System*, P.S.C. Case No. 2020-00336.

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Item 30) ***Explain whether BREC and its members have considered utilizing the services of a demand response aggregator, pursuant to FERC Order 2222, to market any energy savings from potential demand response (DR) programs. If so, does BREC believe it will need to both address this issue through the IRP process, and seek permission of the Kentucky Public Service Commission before doing so?***

a. Reference the response to the question above regarding BREC's member systems' utilization of AMI meters. Explain whether utilization of AMI meters throughout BREC's footprint would or could make adoption of DR programs more feasible and cost-effective. Include in your response a discussion of whether DR programs could become more valuable in the years ahead, in light of the Biden Administration's plan to require electric utilities to achieve carbon neutrality by 2035.

Response) Big Rivers has neither approached nor been approached by a Demand Response ("DR") aggregator. Big Rivers is participating in the MISO Distributed

Energy Resources Task Force ("DERTF"), formed January 4, 2021, to develop MISO's compliance plan for FERC Order 2222 ("the Order"). MISO has submitted a motion for a limited extension of time to file the plan in compliance with the FERC Order's current filing deadline of July 19. Big Rivers has participated in the DERTF and monitored ongoing discussions to determine a number of Distributed Energy Resources ("DER") issues, including participation rules, and measurement and verification. Big Rivers' evaluation process of new DER opportunities will not necessarily be tied to an IRP process. Big Rivers currently does not know if DER participation in MISO would require the Commission's approval.

a. It is highly likely that AMI meters would be required for measurement and verification to participate in MISO's DER markets and, therefore, having the load data readily available would make a program more feasible and likely more cost effective. Big Rivers has not studied the potential impact of proposed regulation or legislation regarding carbon neutrality on DR programs.

Witness) Russell L. Pogue

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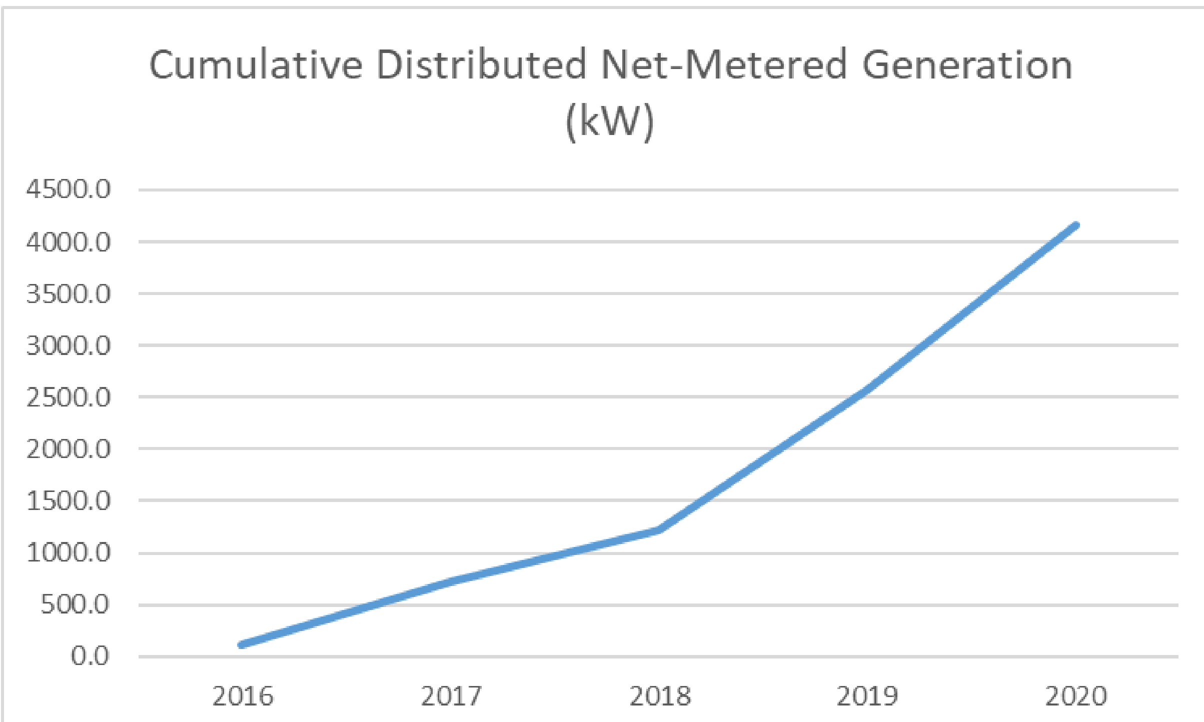
Item 31) ***Reference IRP Plan § 5.5.1, Net Metering Statistics. Confirm that in the last three years, net metering in BREC's service territory has grown from approximately 500 kW to in excess of 2.5 MW.***

a. Provide a breakdown of how many net metering customers are commercial, and how many residential.

Response) Net–metered renewable generation development among the retail members of Big Rivers' Member-Owners is shown annually in the graph on the following page. Since 2016, installed net–metered generation has grown from 113 kW to 4,161 kW.

Big Rivers Electric Corporation
Net-Metered Renewable Generation (kW)
Member-Owners' Retail Members



a. Two of Big Rivers' three Member-Owners track by account type. Of those, 51% of the installed capacity is commercial.

Witness) Russell L. Pogue