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AFFIDAVIT OF MR. JASON STANDING

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company for an Advance Determination of Prudence for the Proposed 345 kV Brookings County – Lyon County and Helena – Hampton Second-Circuit Project

Case No. PU-23-____

Exhibit 2 (JS-1)

STATE OF MINNESOTA)
IN THE)
COUNTY OF HENNEPIN)

I, Jason Standing, under oath, state:

I. Introduction

1. My name is Jason Standing. I am the Manager of Transmission Planning for Xcel Energy Services, Inc. (Xcel Energy).

2. My business address is 414 Nicollet Mall – MP8, Minneapolis, Minnesota, 55401.

3. Xcel Energy does business in Minnesota, North Dakota, and South Dakota through Northern States Power (NSP), a Minnesota corporation and utility operating company subsidiary of Xcel Energy.

4. I have worked for Xcel Energy since March 2004 in the area of transmission planning.

5. I have been in my current position as Manager of Transmission Planning since 2019.

6. I oversee a team of engineers and policy experts involved in the development of transmission planning policy and regional transmission plans in the Midcontinent Independent System Operator, Inc. (MISO), and Southwest Power Pool Regional Transmission Organizations, and the West Connect Order 1000 Transmission Planning organization.

7. Prior to my current position, I was a Transmission Analytics Engineer for Xcel Energy.

8. I was an engineer for different companies before joining Xcel Energy in roles involving distribution planning, system protection, substation design, field engineering, and project management.

9. My statement of qualifications is provided as Schedule 1.

10. I am providing this affidavit in support of the Advanced Determination of Prudence (ADP) filed by Xcel Energy to construct the Brookings County – Lyon County (Western Segment) and Helena – Hampton (Eastern Segment) Second-Circuit Project (collectively, the Project) in southwest Minnesota and southeast South Dakota. Mr. Tony Wendland provides a more fulsome description of the Project in his affidavit.

11. My affidavit addresses the economic prudence for the Project.

II. Congestion Analysis

A. Congestion Overview

12. The MISO electric transmission system currently has insufficient transmission capacity.

13. MISO operates day-ahead and real-time wholesale energy markets.

14. Curtailment of generation caused by transmission constraints creates inefficiencies in the wholesale energy market, making it more difficult to serve load in the most efficient manner.

15. Loading limits on certain transmission facilities prevent MISO from dispatching the most economic mix of generating resources.

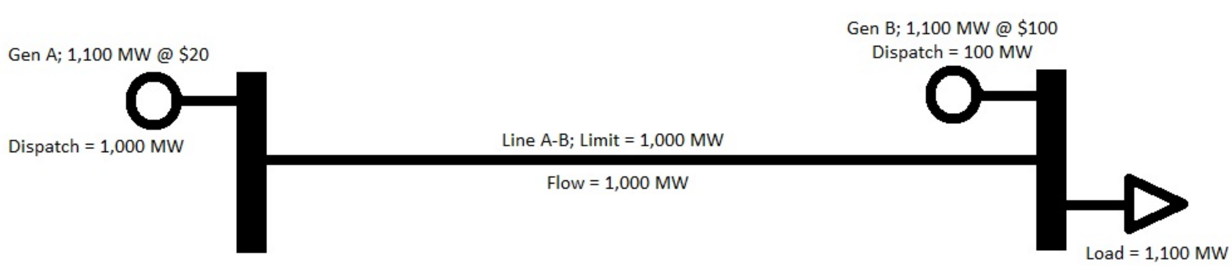
16. Without transmission constraints, MISO dispatches resources based on the resources that can serve load at the lowest marginal cost.

17. Transmission constraints require MISO to factor in the increased cost of transmitting the energy in making dispatch decisions, which may result in MISO dispatching resources with a higher marginal cost, leading to higher costs for customers.

18. Figure JS-1 illustrates how congestion affects the energy used and pricing in a single moment of time.

19. Figure JS-1 assumes an energy need of 1,100 megawatt (MW) that could be supplied by two potential generators, one at a marginal cost of $20 per and one at a marginal cost $100/MW.

Figure JS-1:
Congestion Illustration



20. Generator A has the generation capacity to serve the entire 1,100 MW needed at a marginal cost of $20/MW but cannot do so because of the 1,000 MW transmission capacity limit on Line A-B.

21. Generator A's dispatch is limited to 1,000 MW.

22. Generator B is called on to deliver the remaining 100 MW at a marginal cost of $100/MW.

23. If Generator A were able to deliver the entire 1,100 MW it can generate, the marginal energy cost to serve the entire load would be $22,000, assuming no energy is lost during transmission.

24. The marginal cost to deliver the entire 1,100 MW rises to $30,000 because 100 MW cannot be delivered due to system constraints and more expensive replacement energy is required from Generator B (1,000 MW X $20 for Generator A plus 100 MW X $100 for Generator B).

25. The congestion causes the marginal cost of energy to serve the 1,100 MW to increase $8,000 or 36 percent in this simplified example.

B. Congestion Charges

26. Transmission customers must pay congestion charges to transmit energy along constrained transmission paths.

27. Table JS-1 below provides actual figures and the forecasted 2023-24 amounts for Xcel Energy's MISO congestion charges.

Table JS-1:
Xcel Energy Congestion Charge by Year ($000s)

2020 Actual	2021 Actual	2022 Actual	2023 Approved	2024 Forecast
			TRADE SECRET DATA BEGINS	
$63,309	$230,065	$287,010		
			TRADE SECRET DATA ENDS	

C. Analyzing Congestion Relief Benefits of Transmission Projects

28. Xcel Energy uses PROduction MODeling (PROMOD) to analyze the economic impact of expanding transmission capacity. PROMOD is the industry standard market simulation software for economic transmission planning.

29. PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load.

30. PROMOD captures the effect of transmission constraints on the ability to flow power from generators to load.

31. The Company takes the data derived from PROMOD and inputs it into a program called "APC Reporter" to calculate future estimated costs of producing electricity, market congestion, and energy losses.

32. Economic transmission expansion projects can be evaluated based on whether they reduce the Company's estimated "Adjusted Production Cost" or "APC," which refers to the total production costs of a utility's generation fleet, including fuel,

variable operations and maintenance, startup cost, and emissions, adjusted to account for purchases and sales made in the wholesale energy market.

33. APC does not account for the capital costs of transmission projects, though APC savings can be compared to the capital cost of projects and revenue requirements to evaluate whether the investment is projected to lead to net savings.

D. Development of the Project

34. The Company evaluated transmission investments the Company could make to help relieve the transmission constraints in MISO Zone 1, which includes most of Minnesota and North Dakota.

35. The Company focused its evaluation on locations where serious transmission constraints exist and considered whether any projects could quickly and cost-effectively expand transmission capacity in those locations.

36. The Company identified the Project as a potential low-cost, low-impact means to reduce congestion because the Brookings County – Hampton 345 kV Transmission Line (Original Brookings Line) was constructed with double-circuit capable structures to accommodate future transmission needs.

37. Xcel Energy used PROMOD to confirm the Company's assumptions regarding the likely benefits of the Project.

38. This preliminary evaluation indicated net present values of 20 years of APC savings of $113.3 million for MISO as a whole and $44.3 million for NSP.

39. The initial modeling data and assumptions were lost due to unrelated computer hardware issues, the overall results were saved.

40. In August 2022, the Company submitted a request to MISO for expedited approval of the Project so the Project could be considered for approval as part of the 2022 MISO Transmission Expansion Plan (MTEP22).

41. The MISO Board of Directors approved the MTEP22 report and Appendix A, which included the Project, in December 2022, providing the necessary MISO approvals for the Project.[1]

42. Using PROMOD, the Company updated the 20-year present value APC savings after receiving MISO approval for the Project.

43. The Company estimated that the Project would result in APC savings of $75.05 million for MISO and $51.50 million for NSP.

III. Project Benefits

A. Analysis Assumptions

44. To analyze Project benefits, PROMOD requires various assumptions regarding future conditions.

45. MISO, in coordination with stakeholders, develops a variety of future scenarios or "Futures" under which to study potential transmission projects.

[1] The Project is listed as Project 23452 in both Appendix A and the main body of the MTEP22 report, which can be accessed at https://cdn.misoenergy.org/MTEP22%20Report627345.pdf.

46. Each Future contains different assumptions as to future demand and energy levels; fuel prices; generation retirements and additions; and potential environmental regulations.

47. The Company initially simulated the impact of the Project in PROMOD using Future 1 from the 2021 MISO Transmission Expansion Plan (MTEP21).

48. The assumptions included in the MTEP21 Future 1 scenario are described in the 2021 MISO Futures Report attached as Schedule 2.

49. The MTEP21 Future 1 input assumptions were established in September 2020 and represent MISO's projections at that time.

50. The Company evaluated the underlying assumptions of MTEP21 Future 1 to determine if the assumptions were consistent with the most current view of the future topography of the transmission system.

51. The Company concluded it should run a new PROMOD analysis using assumptions based on the Company's biennial resource planning process[2] and the results of recent resource procurements.

52. Schedule 3 provides the assumptions the Company input to PROMOD in its most recent economic analysis of the Project.

53. PROMOD provides results for a 20-year period.

[2] Filed as NDPSC Case No. PU-19-220.

54. 20 years is the period MISO typically uses to calculate APC savings for projects subject to regional cost-sharing. The 20-year period ensures the benefits used to justify the project are realized well before the end of the project's useful life.

55. The book life of the Project is approximately 63 years, and the Project should provide benefits to customers over that full life.

56. Using the trend-line from the 20-year APC data, the Company estimated the projected APC savings for the entire 63-year life of the Project.

B. APC Savings and Benefit-Cost Ratio

57. The Company estimated APC savings from the Project based on the resource and acquisition assumptions found in Schedule 3.

58. To Company calculated the benefit-cost ratio to evaluate the extent to which the APC savings exceeded the Project's capital investment costs.

59. The benefit-cost ratios assume an estimated Project cost of $102.0 million. Mr. Wendland's affidavit provides additional detail regarding the estimated Project costs.

60. The Company used a 6.36% discount rate for this analysis based on Xcel Energy's weighted average cost of capital.

61. The Company projects estimated NSP-specific APC savings over 63-years of $334.83 with a benefit-cost ratio of 2.53 if the Company owns the entire project.

62. The Company projects estimated MISO-wide APC savings over 63-years of $833.86 million and a MISO-wide benefit-cost ratio of 6.31.

63. The results of this analysis are reflected in Table JS-2.

64. Table JS-2 assumes NSP is assigned the full Project costs.

Table JS-2:
Forecasted APC Savings and Benefit-Cost Ratios

Timeline	APC Benefits/Benefit-Cost Ratio	NSP	MISO
20 Year Present Value	APC Benefits ($MM)	$149.00	$322.65
	Benefit-Cost Ratio	1.36	2.94
40 Year Present Value	APC Benefits ($MM)	$272.07	$655.84
	Benefit-Cost Ratio	2.11	5.08
63 Year Present Value	APC Benefits ($MM)	$334.83	$833.86
	Benefit-Cost Ratio	2.53	6.31

65. If the other owners of the Original Brookings Line[3] participate in the Project, the benefit-cost ratio increases to 3.29 because the costs of the Project are spread between the owners and the Company is assigned only $78.6 million of the Project costs.

66. Schedule 4 to my testimony provides estimated Project benefits assuming the other owners of the Original Brookings Line elect to participate in the Project.

C. LRTP Construction Related Outages

67. The capacity the Project provides will help reduce the cost of outages that will be necessary on the existing transmission lines between Alexandria and Monticello,

[3] The owners of the Original Brookings Line are NSP, Central Minnesota Municipal Power Agency, Great River Energy, Otter Tail Power Company, and Western Minnesota Municipal Power Agency

and Crandall and Wilmarth as part of construction of the Long-Range Transmission Plan (LRTP) Tranche 1 portfolio projects.

68. The Company used rough assumptions to estimate the scope of benefits the Project could provide in mitigating LRTP-outage impacts.

69. The Company estimates the Project will reduce the APC impacts of an outage on the Alexandria to Monticello line by approximately $11-12 million and on the Crandall to Wilmarth line by approximately $15 million.

D. Reliability Analysis

70. The Company conducted a reliability analysis separately from MISO's analysis to determine whether the Project would negatively impact the reliability of the transmission system.

71. This analysis included a comparison of the overloads both with and without the Project.

72. The results of the study showed no adverse reliability impacts resulting from the Project.

73. The analysis indicated that there would be fewer and less severe overloads on the transmission system in certain situations.

IV. Rate Impact

74. The Company conducted a high-level analysis of the potential rate impact of the Project based on the estimated APC savings and projected revenue requirements for the Project.

75. The Company conducted only a capital rate analysis because production-cost modeling models only production cost impacts. These APC savings generally cannot be reduced to impacts to fuel costs, dispatch costs, or other costs necessary to calculate sufficiently accurate net savings on a retail revenue basis.

76. Xcel Energy estimated the annual revenue requirement impact for the capital costs of the Project for a 20-year period. The Company concluded a longer period would be too speculative.

77. The revenue requirements projections do not account for future operation and maintenance expenses for the Project or fuel impacts.

78. The Company estimates nominal North Dakota revenue requirements in Year 1[4] of approximately $500,000 and in Year 20 of $296,000, assuming full NSP ownership.

79. Assuming shared ownership, the Company estimates nominal North Dakota revenue requirements in Year 1 of approximately $385,000 and in Year 20 of $228,000.

80. In Year 1 (2026), the Company estimates the nominal revenue requirement will be $7.6 million for both NSP and Northern States Power, a Wisconsin Corporation (collectively NSP Companies), assuming shared ownership.

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[4] Year 1 will be 2026, assuming a January 2026 in-service date.

81. The estimated APC savings for the NSP Companies is $8.3 million in Year 1.[5]

82. If only NSP owns the Project, estimated APC savings are expected to exceed the NSP Companies' annual revenue requirements by Year 6 (2031) and continue to exceed revenue requirements by increasing amounts thereafter.

83. Schedule 5 to my affidavit provides the revenue requirement calculations under both a shared ownership assumption and assuming NSP owns the entire Project.

V. Conclusion

84. The Company's economic analysis demonstrates that the Project is prudent because the APC savings exceed both the capital costs of the Project and revenue requirements of the Project.

[SIGNATURE PAGE FOLLOWS]

[5] Ownership percentages would not directly correlate to the benefits the Project provides to individual owners. That is, 60% ownership of the Project does not necessarily equate to 60% of the benefits. Rather, forecasted annual benefits result from the specific change to the transmission system and how the resulting increased capacity impacts each utility's overall mix of production throughout the year.

Further, Affiant sayeth not.

____
Jason Standing

Subscribed and sworn to before me
This 29th day of August, 2023

____
Notary Public

CHRISTOPHER C ROGERS
Notary Public
Minnesota
My Commission Expires
Jan 31, 2027

SCHEDULE 1:
STATEMENT OF QUALIFICATIONS
MR. JASON STANDING

Jason T. Standing

7614 Addisen Path
Inver Grove Heights, MN 55077
(651) 485-6427
jasonstanding@hotmail.com

SUMMARY

Degreed Electrical Engineer experienced in management in government, commercial, and utility markets. Capable of satisfying customer needs and expectations through creative engineering problem solving techniques and accurate communications.

PROFESSIONAL EXPERIENCE

Xcel Energy, Minneapolis, MN 2019-current
Manager Transmission Planning, NSP/NSPW

- Lead a team of transmission experts to develop long-term plans to ensure reliable transmission operations
- Coordination of diverse groups of contributors to develop regional and local plans
- Serve as expert witness in state permitting and regulatory process
- Develop future planning tools and processes to help with the grid of the future

Xcel Energy, Minneapolis, MN 2015-19
Principal Transmission Planning Engineer

- Lead Transmission Planning engineer for the Twin Cities area
- Responsible for training new Transmission Planning engineers
- Involved in local and regional policy with states and RTOs
- Develop computer programming skills and incorporate into Transmission Planning

Xcel Energy, Minneapolis, MN 2014-15
PROMOD Planning Engineer

- Provide Production Cost Modeling for the NSP area
- Evaluate transmission project impacts to generation
- Congestion analysis

Xcel Energy, Minneapolis, MN 2004-14
Senior Specialty Transmission Planning Engineer

- Responsible for leading and improving the Constructability I process for which all new transmission projects must be approved through
- Lead Technical expert for the Hiawatha Certificate of Need
- Lead the MISO MTEP process for NSP and NSPW areas
- Involved with neighboring and regional entities to create cost effective solutions to the regional and bulk transmission issues
- Work closely with MISO to ensure Xcel Energy's interests are being heard through multiple working groups

Wunderlich-Malec Systems, Minnetonka, MN 2002-2003
Project Manager
- Managed the design, electrical system analysis, and procurement for substation projects
- Responsible for delivering cost analysis to the customer, preparing equipment bids, while monitoring expenses
- Provided field support for the construction team to ensure that the substation was delivered on time and to the customer's satisfaction

Design Engineer
- Lead design engineer for the American Transmission Company's new 69 kV substation
- Lead engineer responsible for accurate settings of the system protection relays
- Responsible for ensuring the NEC codes were followed
- Created new drawing sets while updating old drawing sets to ensure accuracy for the customer

Sebesta Blomberg and Associates, Roseville, MN 2000-2002
Project Engineer
- Commissioning specialist whose duties included creating test sheets for various types of electrical equipment, field visits, overseeing testing specialists at the Pentagon and other commercial sites
- Design engineer who used creative problem-solving techniques to redesign customer's 230 kV and 115 kV breaker control panels.
- Developed load flow and system protection studies

Alliant Energy, Madison, WI 1999-2000
Distribution Systems Planner
- Responsible for running load flow analysis for the southern Wisconsin electrical distribution and transmission systems
- Involved in maintaining and updating existing computer models to reflect changes to the physical system
- Prepared cost analysis reports for management

EDUCATION

B.S. in Electrical Engineering, North Dakota State University, Fargo, ND 1999
MBA, University of Minnesota, Minneapolis, MN 2011
Profession Engineer Minnesota, PE 2012

COMPUTER EXPERIENCE

PSSE, PROMOD, Synergi, SKM Power Tools, Microsoft Office

SCHEDULE 2:
2021 MISO FUTURES REPORT

- Published April 2021 -

Updated December 2021

Highlights

- Electric utilities in the MISO region are responding to the energy industry's ongoing transition in different ways. At an aggregate level, there is a dramatic and rapid transformation underway of the resource mix in MISO's footprint.

- The three MISO Futures encompass scenarios that bookend the fleet resource mix over the next twenty years and are intended to be used for several years with minimal updates.

- Analysis of three scenarios allows for insights to the MISO system once it transforms to dual summer and winter peaking as renewable energy and projected demand increase.

- December 2021 updates include revised expansion results for Futures 2 and 3. Explanation and details of these results can be found in the September, October, and November 2021 PAC presentations in the Presentation Materials section of this report.

Executive Summary

MISO is tasked with delivering safe, reliable, and cost-effective power across 15 states and the Canadian province of Manitoba. Within MISO's diverse regional footprint, utility members are making future plans, committing to near and long-term retirements and investments, and announcing increasingly advanced decarbonization goals. Although MISO's role is to remain policy- and resource-agnostic, there is a clear fleet transition underway that has implications for system operations.

As the fleet transforms, the need to keep the system operating reliably and efficiently is driving what MISO refers to as a regional "Reliability Imperative." MISO, our member utilities, and state regulators all share the responsibility to address this Reliability Imperative. A key element of MISO's response to the Reliability Imperative is our Long-Range Transmission Planning (LRTP) initiative. The "Futures" defined in this document will be a key driver of those efforts and other elements of the Reliability Imperative.

How can MISO, as a regional grid operator, support its member utilities and state policy makers as they continuously refine how to serve the 42 million people in the MISO footprint? One tool at MISO's disposal is the use of forward-looking planning scenarios to provide outlooks of the future. These Future planning scenarios establish different ranges of economic, policy, and technological possibilities – such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas price, and generation capital cost – over a twenty-year period. This information is used to model a capacity expansion, which forecasts the fleet mix that meets MISO's planning reserve margin at the lowest cost while adhering to policy objectives. Using the range of resource generation modeled, MISO will then apply the Futures' expansion results to the development of transmission plans, the LRTP, and other MISO initiatives that ensure continued reliability and economic energy delivery.

This report captures an eighteen-month collaboration between MISO and stakeholders to develop three Future scenarios that bookend the uncertainty over the next twenty years. When carried forward into the transmission planning models, this set of Futures will enable the diverse goals and policies of MISO's states and utilities.

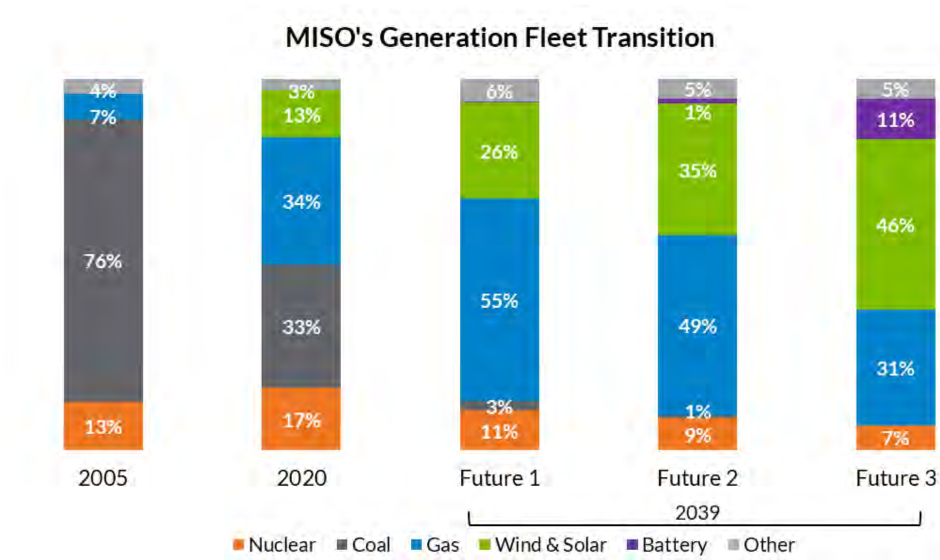


Figure 1: Overview of MISO's Generation Fleet Mix Transition [82]

Future 1 Assumptions – This Future reflects substantial achievement of state and utility announcements and includes a 40% carbon dioxide reduction trajectory.[1] While Future 1 incorporates 100% of utility integrated resource plan (IRP) announcements, state and utility goals that are not legislated are applied at 85% of their respective announcements to hedge the uncertainty of meeting these announced goals and respective timelines. Future 1 assumes that demand and energy growth are driven by existing economic factors, with small increases in EV adoption, resulting in an annual energy growth rate[2] of 0.5%.

Future 2 Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including a 60% carbon dioxide reduction. Future 2 introduces an increase in electrification, driving an approximate 1.1% annual energy growth rate.

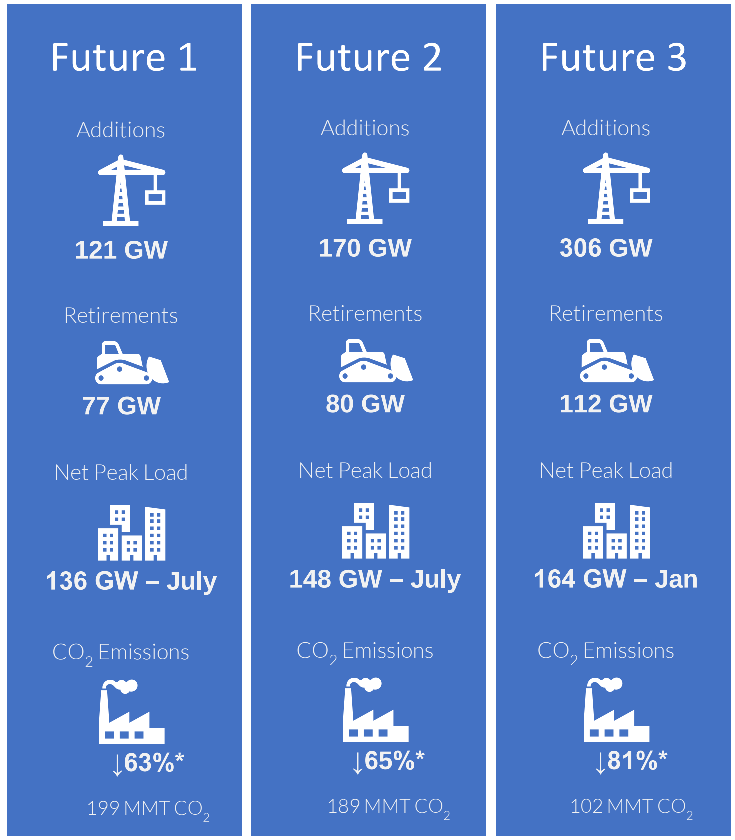


Figure 2: Summary of Future Scenario Impacts, 2039

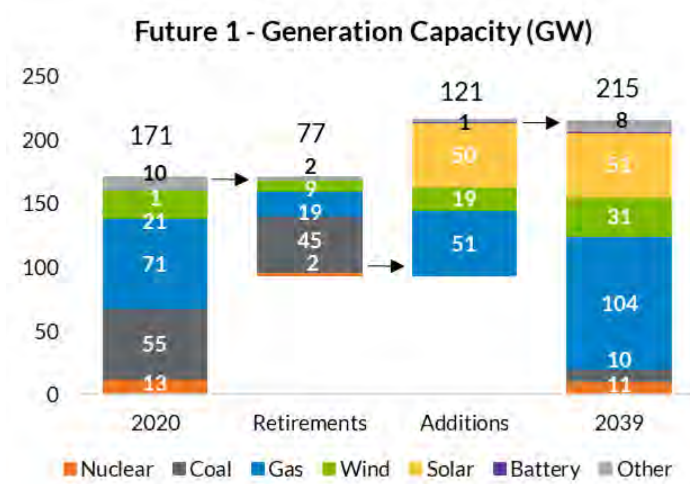
Future 3 Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including an 80% carbon dioxide reduction. Future 3 requires a minimum penetration of 50% wind and solar and introduces a larger electrification scenario, driving an approximate 1.7% annual energy growth rate.[82]

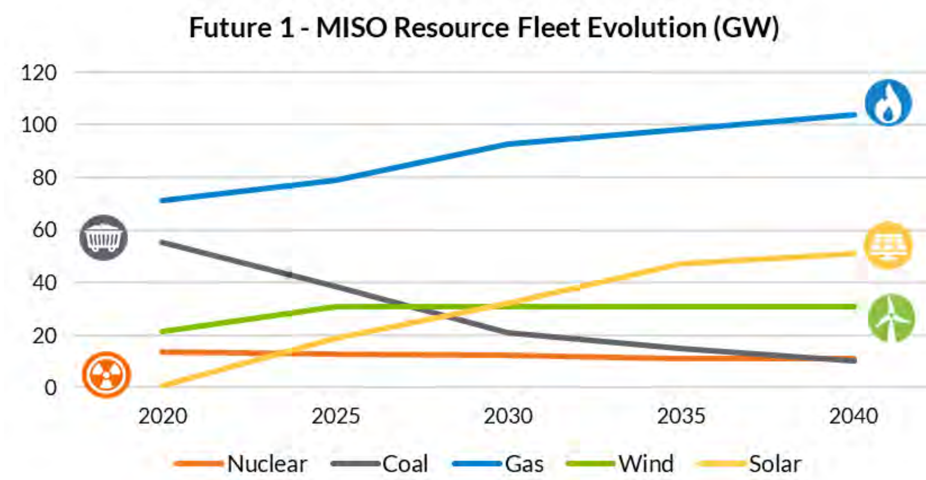
The Futures utilized announced goals and other input assumptions through September 2020 to represent a snapshot in time. Since the modeling of the Future scenarios, new announcements and updates to utility and state goals have been publicized. While the Futures Assumptions above summarize each scenario's inputs, Figure 2 details several key results of the modeling. For example, Future 1 included a 40% carbon reduction trajectory, and the model resulted in 63% carbon reduction. Additionally, "net peak load" results refer to peak load values, net of load modifying resources.

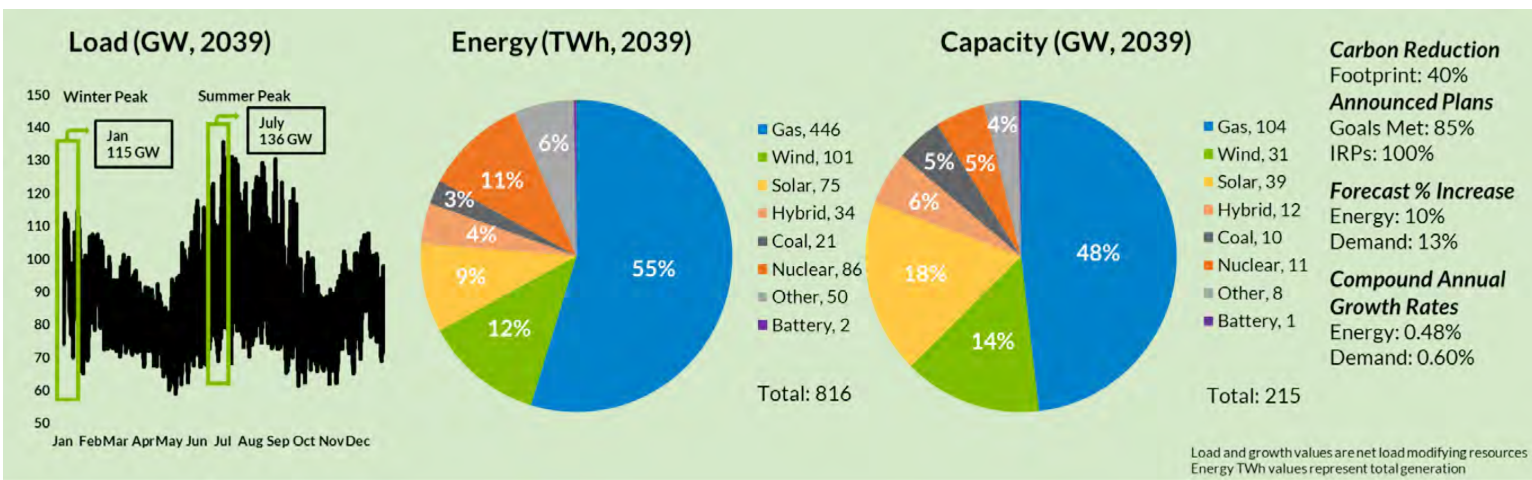
[1] Carbon emission reduction in Future scenarios refer to power sector emissions across the MISO footprint from a 2005 baseline.
[2] Futures energy growth rates are compound annual growth rates (CAGR).

Future 1 Results

This Future assumes demand and energy growth are driven by existing economic factors, with small increases in EV adoption. Modeling for Future 1 results in the retirement of 77 GW and the addition of 121 GW of resources to the MISO footprint.

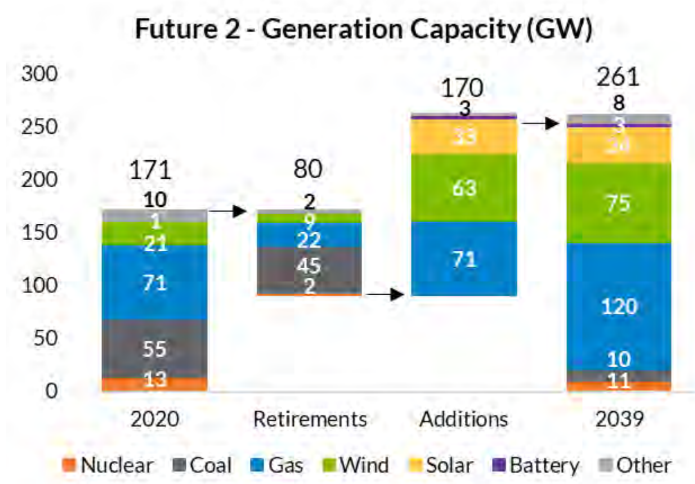


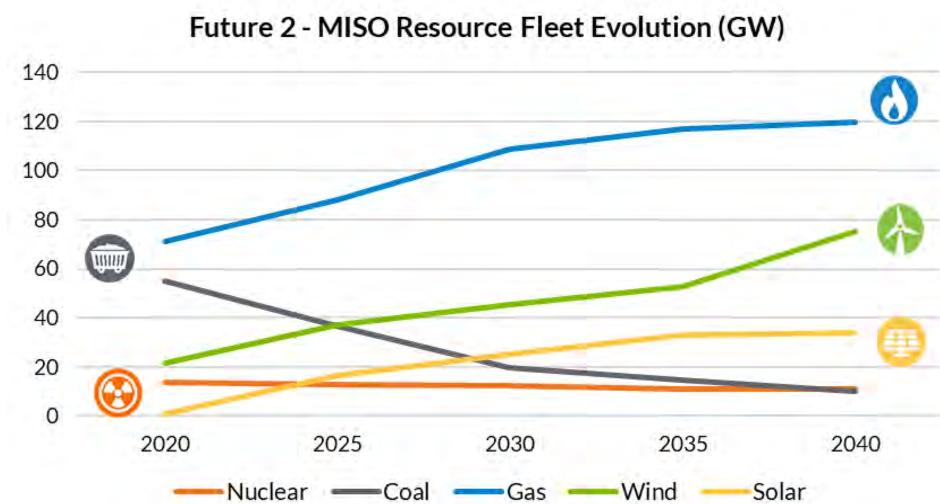


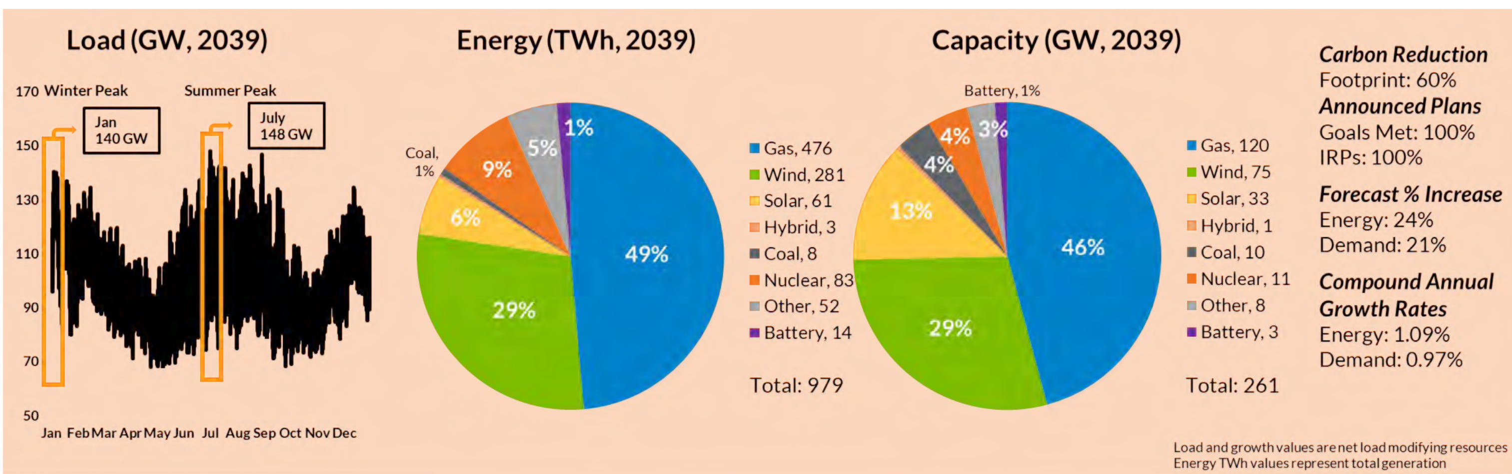


Future 2 Results

Due to retirements and increased electrification, moderate increases in demand and energy cause Future 2's load shape to have a larger peak in the summer but remain relatively dual peaking. Modeling of Future 2 results in the retirement of 80 GW and the addition of 170 GW of resources to the MISO footprint.

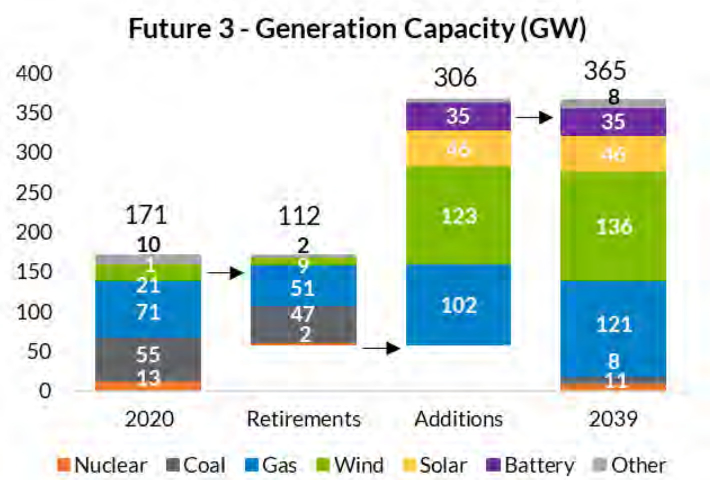


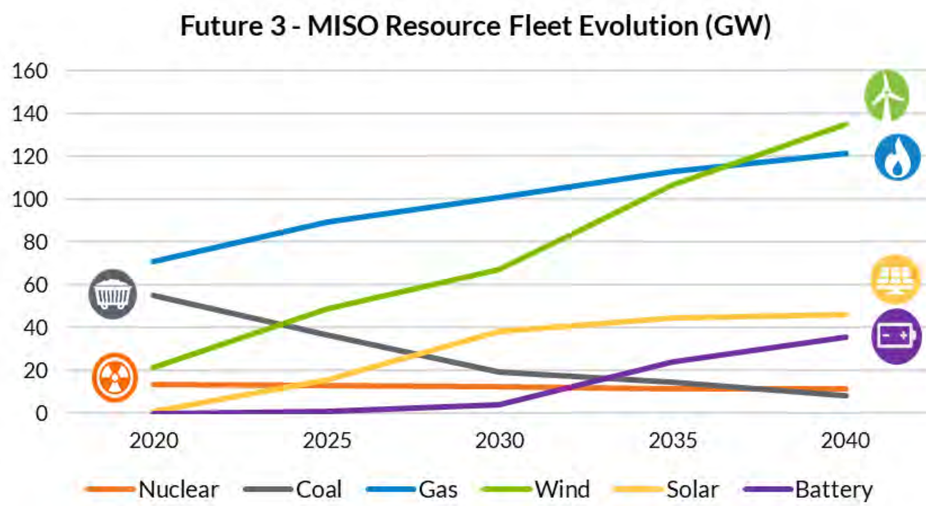


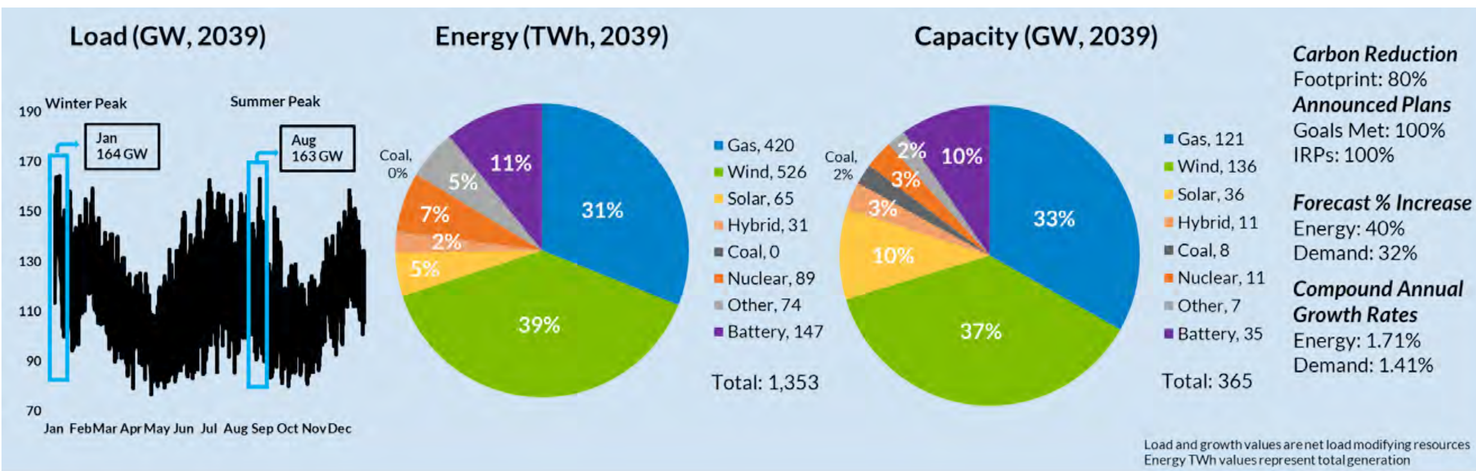


Future 3 Results

Due to retirements, decarbonization, and electrification, large increases in demand and energy produce a prominent dual peaking load shape in the later years of the study period. Modeling of Future 3 results in the retirement of 112 GW and the addition of 306 GW of resources to the MISO footprint.







MISO Futures Purpose and Assumptions

In order to perform analysis on the bulk electric system twenty years into the future, many assumptions must be made to bridge what is known about the system today to what it could be in the future. Complicating matters is the uncertainty of future developments.

A tool that MISO has developed to address this uncertainty is the use of multiple forward-looking scenarios to provide a range of future outlooks. Within MISO, the collection of assumptions defining these multiple forward-looking scenarios are called the "Futures". These Future scenarios establish different ranges of economic, policy, and technological possibilities – such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas price, and generation capital cost – over a twenty-year period.

One of the core components of analyzing the grid twenty years into the future is an understanding of what the electric generation resource fleet will be. Since MISO is not an integrated resource planner, MISO relies on its stakeholders, policy direction, and industry trends to bridge the gap between what the generation fleet is today and what it will be in the future. The Futures are used to hedge uncertainty by utilizing an economic resource expansion analysis, which forecasts the fleet mix that meets MISO's planning reserve margin at the lowest cost while adhering to policy objectives.

As the fleet transforms, the need to keep the system operating reliably and efficiently is driving changes within the Futures process, and throughout MISO more broadly as part of the Reliability Imperative. As the 2019 MISO FORWARD Report identified, three major trends that are changing the energy landscape have emerged – demarginalization, decentralization, and digitalization. Electric utilities in the MISO region are responding to the energy industry's ongoing transition in different ways. At an aggregate level, there is a dramatic and rapid transformation underway of the resource mix in MISO's footprint.

MISO received a clear message of urgency from its stakeholders including member utilities, policy makers, and large end-users asking MISO to move quickly from identifying high-level needs to providing solutions that allow states and utilities to reach their energy transition goals. In response, MISO initiated a public stakeholder process to update the Futures process to align with the ongoing rapid transformation and to better incorporate the plans of MISO's members and states, while also creating a bookended range of future scenarios that could be utilized in multiple study cycles. The public stakeholder process kicked off in August 2019, included thirteen different public stakeholder meetings, and concluded in December 2020.

MISO is not an integrated resource planner. The MISO Futures reflect resource plans announced by member utilities and states and forecast additional resources to meet forecasted energy demand, policy objectives, and reserve margins.

The Future scenarios in this document are a product of continued collaboration between MISO and its stakeholders. They represent challenges and compromises enabling member utilities to achieve significant fleet transition goals with diverse approaches or a more traditional resource portfolio. This report describes three Futures that are intended to be used as inputs for multiple MISO Transmission Expansion Plan (MTEP) cycles, the Long-Range Transmission Plan (LRTP) initiative, and other planning studies. These Futures will form the basis for all components of the Reliability Imperative, such that MISO and its stakeholders can plan to a consistent set of scenarios across transmission, markets, and operations.

Assumptions within the three Future scenarios vary to encompass reasonable bookends of the MISO footprint over the next twenty years. Future 1 represents a scenario driven by state and members' plans, with demand and energy growth driven by existing economic factors. Future 2 builds upon Future 1 by fully incorporating state and members' plans and includes a significant increase in load driven by electrification (discussed in the Electrification section of this report). In the final scenario analyzed, Future 3 advances from Future 2, evaluating the effects of large load increases due to electrification, 50% penetration of wind and solar, and an 80% carbon reduction across the footprint by 2039.

MISO conducted the Renewable Integration Impact Assessment (RIIA) to evaluate the impact of large installations of wind and solar to the system. This assessment found that managing MISO's grid, particularly beyond the 30% system-wide renewable level, will require transformational change in planning, markets, and operations. RIIA concludes that renewable penetration of at least 50% can be achieved through additional coordinated action. MISO members have continued to update their goals and look to MISO to help integrate these resources within the grid. With the analysis of the Future scenarios, wind and solar penetrations reach 26% in Future 1 and 46% in Future 3.[82]

Figure 3 shows the resulting wind and solar energy generation in each Future. Since load forecasts differ, the energy required of wind and solar to reach these penetrations is larger in each scenario. Futures 1, 2, and 3 reach maximum wind and solar penetrations of 26%, 35%, and 46% respectively.

Resulting Wind and Solar Penetration Levels

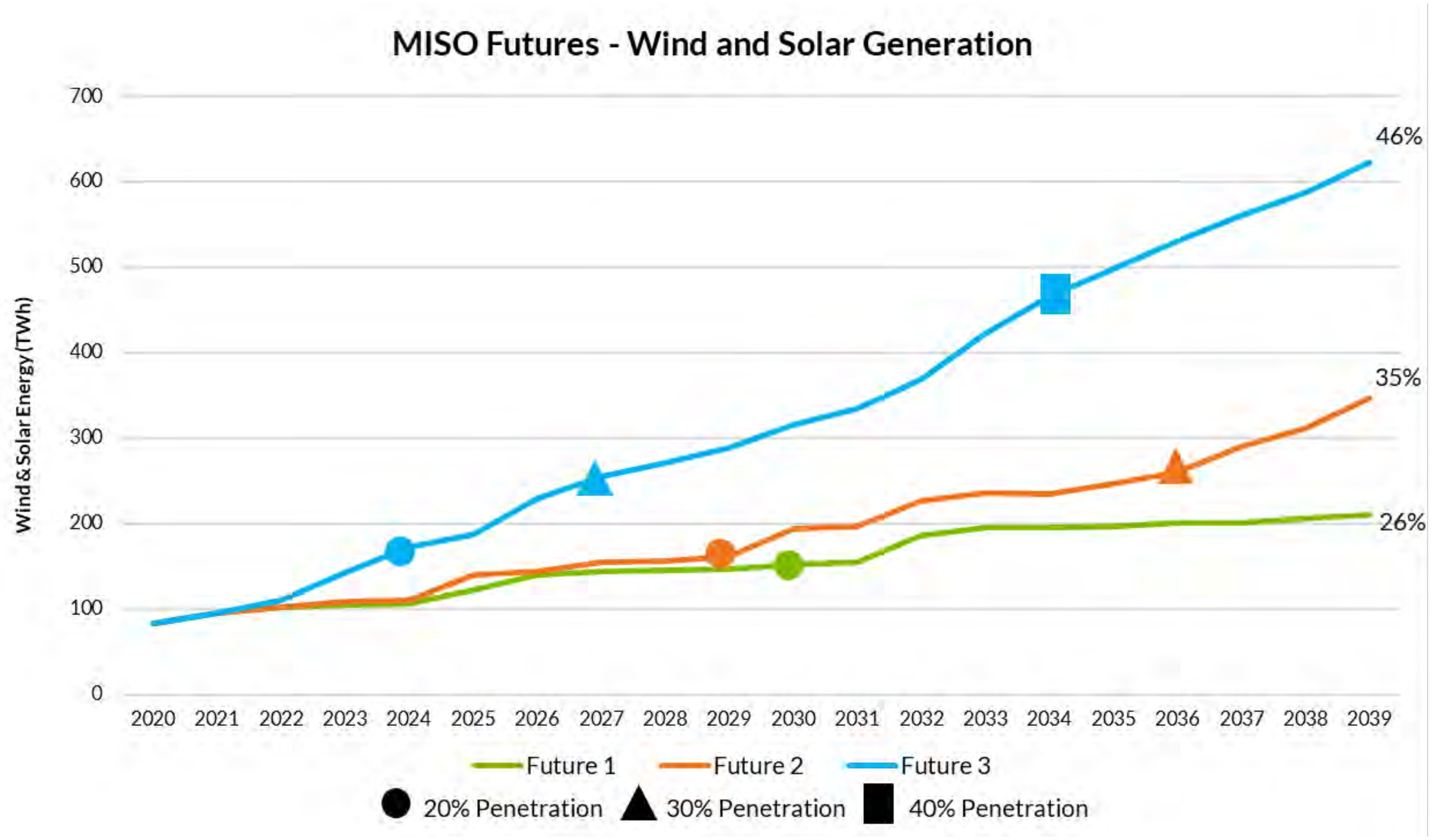


Figure 3: Wind and Solar Energy Generation Throughout Study[82]

Changing Energy Across MISO

Cities, states, large commercial and industrial corporations, and utilities are exploring and setting decarbonization goals that often include reaching 100% renewable energy supply or net zero carbon by 2050. Although not all states and utilities share these clean energy goals, a fleet transition of this magnitude will have implications on what resources will be needed across the MISO footprint to ensure reliability of the grid. The role of MISO is to remain resource-agnostic and to ensure a reliable and economic Bulk Electric System in an ever-changing energy, regulations, and economics environment.

Throughout the analysis of each Future scenario, MISO incorporated specific state and utility goals relative to carbon and renewable energy percentages into the models. Carbon was broken out into two segments per Future: a footprint-wide reduction applied to all resources and site-specific reductions applicable to carbon-emitting resources within states and utilities with announced carbon goals.

Renewable goals were modeled differently than those of carbon emissions. This was done by converting utility/state goals into relative percentages of MISO and taking the summation of these values to create footprint trajectories. As costs for wind and solar have decreased, the model surpassed these goals in Futures 1 and 2. Resources were assigned to their respective areas in the siting process.

Internal analysis indicates the MISO footprint has decarbonized by 29% since 2005. Early thermal retirements, public announcements, and evolving IRPs support MISO's preparation for a broad range of Future scenarios, enabling continual adaptation to the changing energy landscape while ensuring better grid reliability.

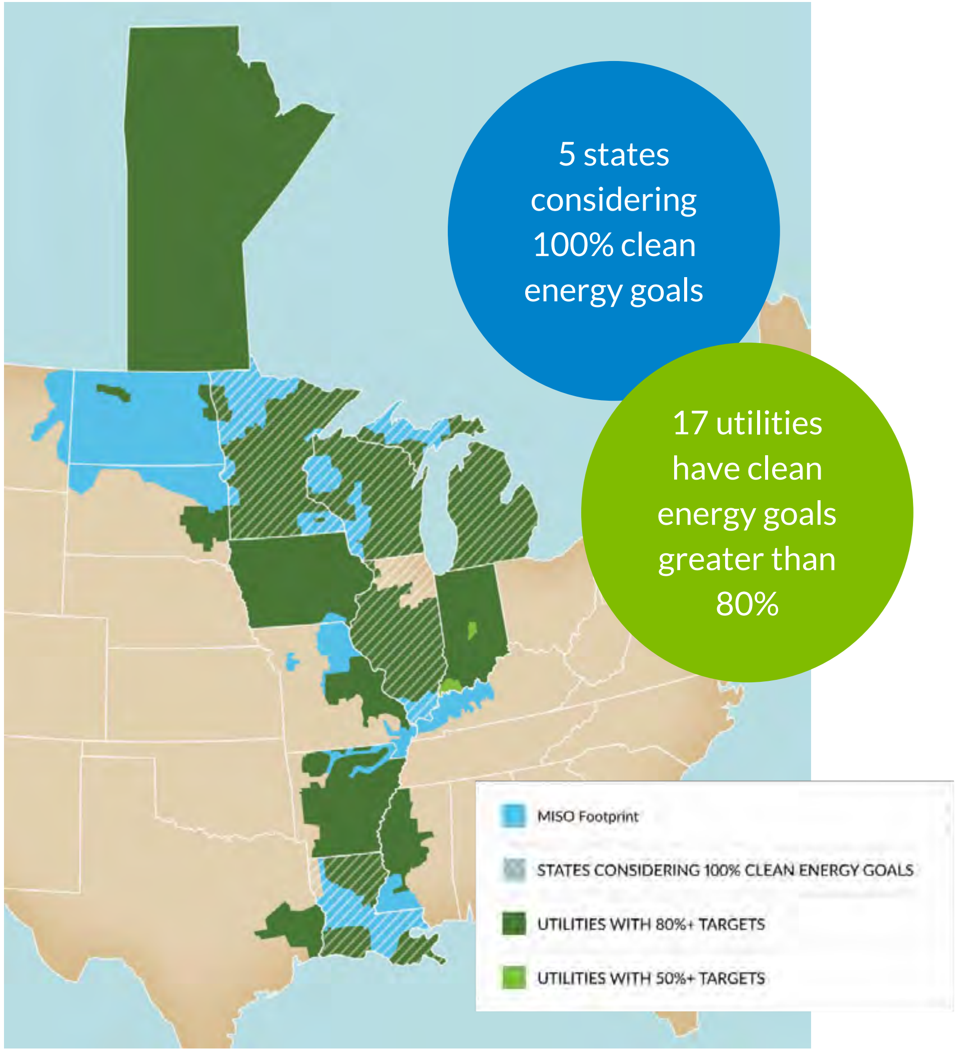


Figure 4: Clean Energy Goals above 50% Across Footprint[3]

State and Utility Clean Energy Goals

Today, state and utility policies and goals are changing rapidly and continued to do so during the Futures process, regarding carbon reductions, renewable energy targets, and unit retirement assumptions. To best account for these changes, MISO continuously updated these announced goals until the final Future scenario models were complete in October 2020. Since then, several members have updated or announced their plans, noted with asterisks in Table 1.

When collecting goal announcements, MISO staff examined companies' IRPs, state publications, and results from the MISO/OMS State Data Survey. (OMS refers to the Organization of MISO States). Once this information was compiled, MISO compared unit addition announcements with signed generation interconnection agreements (GIA) in its queue to ensure that these units would not be double counted. MISO then added IRP units into the base model to account for the announced goals of states and utilities. These units had a variety of fuel types and contained announced additions throughout the study period (2020-2039).

From Figure 4, it is apparent that much of the footprint has a clean energy goal greater than 50% (either from a carbon reduction or renewable energy target).[3] Some goals displayed in the table below were not included in the Futures analysis because their announcement came after the models were complete in October of 2020.[4,5] Table 1 displays state and utility goals within the model, overlapping by service area. In this analysis, MISO considered current trends but also had the opportunity to look beyond and plan for a range of Future scenarios to bookend plausible possibilities over the next 20 years.

[3] Utility goals are represented with green shading while state goals of 100% are given white stripes.

[4] Any goal denoted with an asterisk (*) was updated or announced following the modeling of the Futures.

[5] Entities who announced or updated their goals after Future scenario modeling was complete are listed here in their respective categories. Carbon reduction goals not modeled: Madison Gas, Vectren, Vistra, IPL, and OTP. Renewable energy targets not modeled: Alliant, CLECO, Vistra, IPL, and Entergy. Entities whose carbon reduction was modeled but a modification to the goal was made: Michigan (28% by 2025), Ameren (80% by 2050), and Minnesota Power (50% by 2021).

<table>
<tr><th>State Clean Energy Goals & RPS[6]
(source linked)</th><th>State</th><th>Utility</th><th>Utility Carbon Reduction Goals (2005 Baseline)[7]</th><th>Utility Renewable Energy Goals</th></tr>
<tr><td>RPS: 15% RE by 2021 (IOUs)</td><td>Missouri</td><td rowspan="2">Ameren</td><td rowspan="2">Net Zero by 2050*</td><td rowspan="2">100% by 2050</td></tr>
<tr><td rowspan="2">100% Clean Energy by 2050 (Governor)
RPS: 25% by 2025-2026</td><td rowspan="2">Illinois</td></tr>
<tr><td rowspan="2">MidAmerican Energy</td><td rowspan="2">-</td><td rowspan="2">100% by 2021</td></tr>
<tr><td rowspan="3">RPS: 105 MW (completed 2007)</td><td rowspan="3">Iowa</td></tr>
<tr><td>Alliant Energy</td><td>Carbon Free by 2050</td><td>30% by 2030*</td></tr>
<tr><td rowspan="2">Dairyland Power</td><td rowspan="2">-</td><td rowspan="2">29% by 2029</td></tr>
<tr><td rowspan="3">Carbon Free by 2050 (Governor)
RPS: 10% by 2020</td><td rowspan="3">Wisconsin</td></tr>
<tr><td>WEC Energy Group</td><td>Carbon Neutral by 2050</td><td>-</td></tr>
<tr><td>Madison Gas & Electric</td><td>Net Zero by 2050*</td><td>30% by 2030</td></tr>
<tr><td rowspan="3">Carbon Neutral by 2050*
RPS: 15% by 2021 (standard), 35% by 2025 (goal, including EE & DR)</td><td rowspan="3">Michigan</td><td>Consumers Energy</td><td>Net Zero by 2040</td><td>56% by 2040</td></tr>
<tr><td>DTE Energy</td><td>Net Zero by 2050</td><td>25% by 2030</td></tr>
<tr><td>Upper Peninsula Power</td><td>-</td><td>50% by 2025</td></tr>
<tr><td rowspan="4">Voluntary clean energy PS,
10% RE by 2025</td><td rowspan="4">Indiana</td><td>Duke Energy</td><td>Net Zero by 2050</td><td>16,000 MW by 2025</td></tr>
<tr><td>Hoosier Energy</td><td>80% by 2040</td><td>10% by 2025</td></tr>
<tr><td>Vectren</td><td>75% by 2035*</td><td>62% by 2025</td></tr>
<tr><td>NIPSCO</td><td>90% by 2028</td><td>65% by 2028</td></tr>
<tr><td rowspan="4">Carbon Free by 2050 (Governor)
RPS: 26.5% by 2025 (IOUs),
25% by 2025 (other utilities)</td><td rowspan="4">Minnesota</td><td>Xcel Energy</td><td>Carbon Free by 2050</td><td>100% by 2050</td></tr>
<tr><td>SMMPA</td><td>90% by 2030</td><td>75% by 2030</td></tr>
<tr><td>Minnesota Power</td><td>100% Clean Energy by 2050*</td><td>50% by 2021</td></tr>
<tr><td>Great River Energy</td><td>95% by 2023</td><td>50% by 2030</td></tr>
<tr><td>Net Zero GHG by 2050 (Governor)</td><td>Louisiana</td><td>Entergy</td><td>Net Zero by 2050
(2000 baseline)</td><td>12% by 2030*</td></tr>
</table>

Table 1: State & Utility Goals – Service Area Overlay

System-Wide Carbon Modeling

In addition to state and utility renewable goals, each Future scenario had a carbon emission reduction (CER) applied across the entire footprint. Carbon reduction trajectories were made from a total MISO 2005 CO_2 baseline, with linear reductions of 40%, 60%, and 80% (for Futures 1, 2, and 3, respectively) applied through the end of the study period. These trajectories were modeled within EGEAS (Electric Generation Expansion Analysis System). As well as the footprint-wide total CER for each Future, MISO also entered more specific trajectories for states and utilities as applicable.

[6] DR: demand response; EE: energy efficiency; GHG: greenhouse gas; IOU: investor-owned utility; PS: portfolio standard; RE: renewable energy; RPS: renewable portfolio standard

[7] Any goal denoted with an asterisk (*) was updated or announced following the modeling of the Futures.

All utility and state carbon trajectories used a 2005 CO_2 emissions baseline except for Entergy, which used a 2000 baseline in accordance with utility-specific goals. Each CER trajectory was given an approximate 2020 CO_2 starting value and then decreased to a target reduction percentage of the baseline. Consistent with Futures assumptions, CER trajectories reflected 100% of IRPs and 85% of other announced goals for Future 1, while trajectories for Futures 2 and 3 reflected 100% of both.

From analysis of the current fleet in 2005, MISO emitted 543 million (M) tons of CO_2. Figure 5 below illustrates CER for each Future scenario, displaying the tons of carbon emitted (bars) and the percentage of carbon reduction from the 2005 baseline (lines). The dotted line projects the historical trend of carbon emissions that MISO is assumed to have for comparison. From the trend of MISO, it is evident that the carbon emissions of the system will continue to decrease and will be accelerated as members' goals continue to change. Futures 2 and 3 emit more carbon than Future 1 in 2020 due to the increased load assumptions met by the existing fleet. The Future scenarios in this document allow for insights on how quickly carbon reduction across the footprint may occur. By the end of the study period, emissions reduced by 63% in Future 1, 65% in Future 2, and 81% in Future 3.

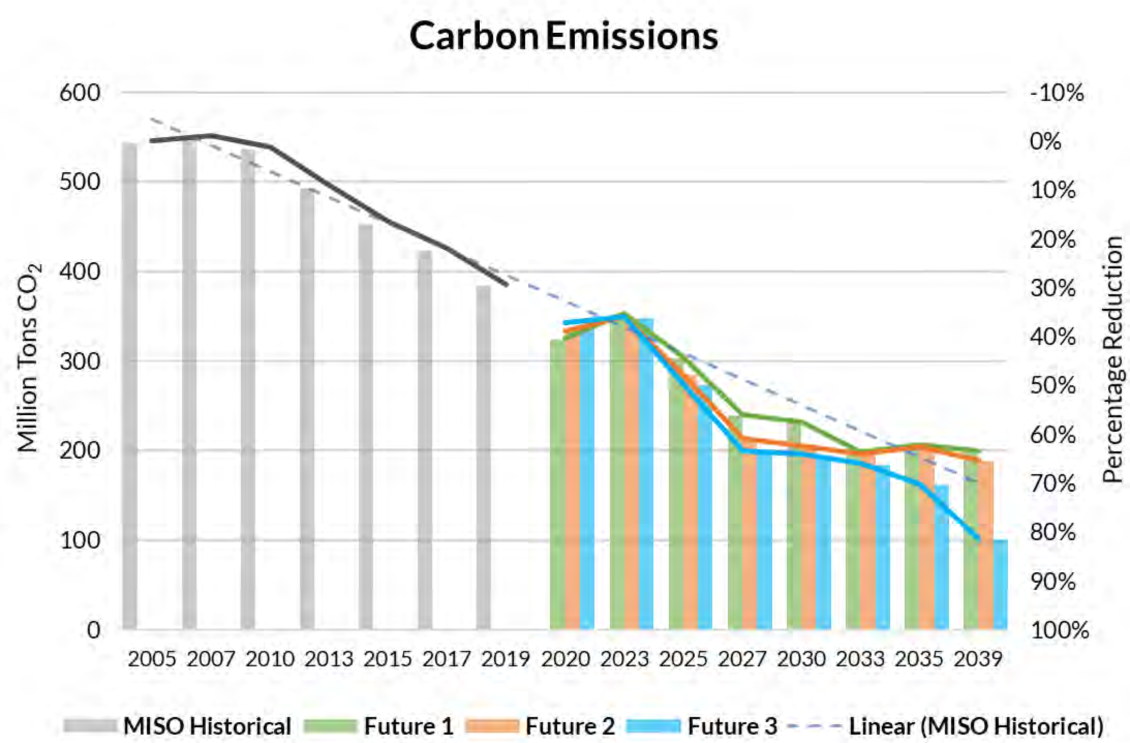


Figure 5: CO_2 Reduction Results (from 2005 Baseline)

Retirement and Repowering Assumptions

Base Retirement Assumptions

Nuclear and Hydroelectric –
Retirement of nuclear and hydroelectric units will occur when a unit has a publicly announced retirement plan or is listed to retire in an IRP. Otherwise, these units will remain active throughout the study across all Futures.

Age-Based Retirement Assumptions

Age-based assumptions will be applied to all the units that fall into any of the categories listed below. However, in cases where these assumptions cause older units in the MISO system to retire before the start of the study period (2020), units will be retired by 2025.

Coal –
Retirement ages of coal units progressively decrease with each Future. It is assumed that with changing policies and emission standards, coal usage will decline further. The coal retirement ages modeled in the three Futures respectively are: 46, 36, and 30 years. The Future 1 retirement age of 46 years is based on the average age of coal units noted by the Energy Information Administration (EIA).

- Coal retirements in each Future are approximately a 50/50 split between base and age-based retirement assumptions. The amount of coal retired results in similar capacity due to the average coal unit within the MISO fleet being 46 years of age.

Gas –
Retirements for gas units were split into two categories, Combined Cycle (CC) and Other-Gas (e.g., Combustion Turbine [CT], IC [Internal Combustion] Renewable, and Integrated Gasification Combined Cycle [IGCC]). Both unit types were given retirement ages that decreased across the Futures scenarios; retirement ages for CC gas units are: 50, 45, and 35 years and retirements for Other-Gas units are: 46, 36, and 30 years respectively.

Oil –
Retirement ages of oil units decrease across each Future scenario and are 45, 40, and 35 years respectively.

Wind and Solar –
Retirements for utility-scale wind and solar will occur once a unit reaches 25 years of age. However, wind units will be repowered within the same year of retirement. These will be replaced by a new 100m hub height wind turbine with the same capacity as the previous unit but will receive new wind profiles, dependent on location. New profiles have updated capacity factors that are higher than existing wind turbines.

	Future 1	*Future 2*	*Future 3*
Coal	46	36	30
Natural Gas – CC	50	45	35
Natural Gas – Other	46	36	30
Oil	45	40	35
Nuclear & Hydro	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
Solar – Utility-Scale	25	25	25
Wind – Utility-Scale	25	25	25

Table 2: Age-Based Retirement Assumptions

Figure 6 through Figure 8 display the results of differing retirement assumptions across each of the three Future scenarios. Retirement totals were calculated by applying age-based assumptions, announced retirements, and adjusting generation units per stakeholder feedback provided to MISO. Age-based assumptions are the product of Future-specific retirement assumptions, while base retirements are announced by the generator owner, stated in an IRP, or filed with MISO's Attachment Y.[8]

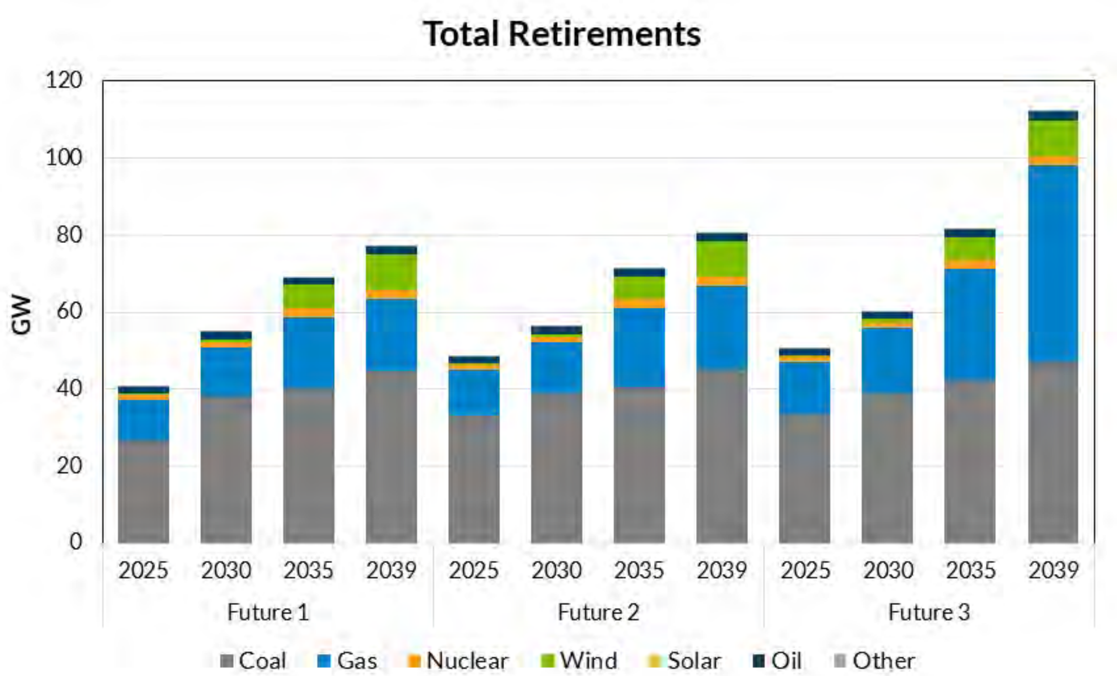


Figure 6: Total Retirements per Future (Cumulative by Year), Equal to Age-Based + Base

[8] MISO's retirement notification process

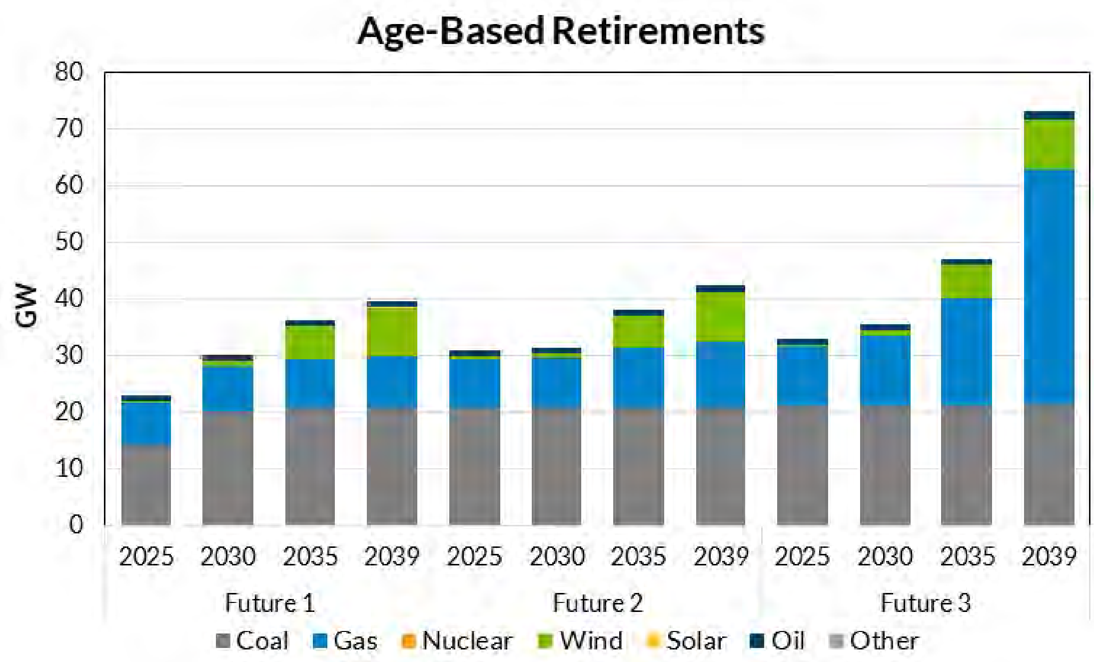


Figure 7: Age-Based Retirements per Future (Cumulative per Year)

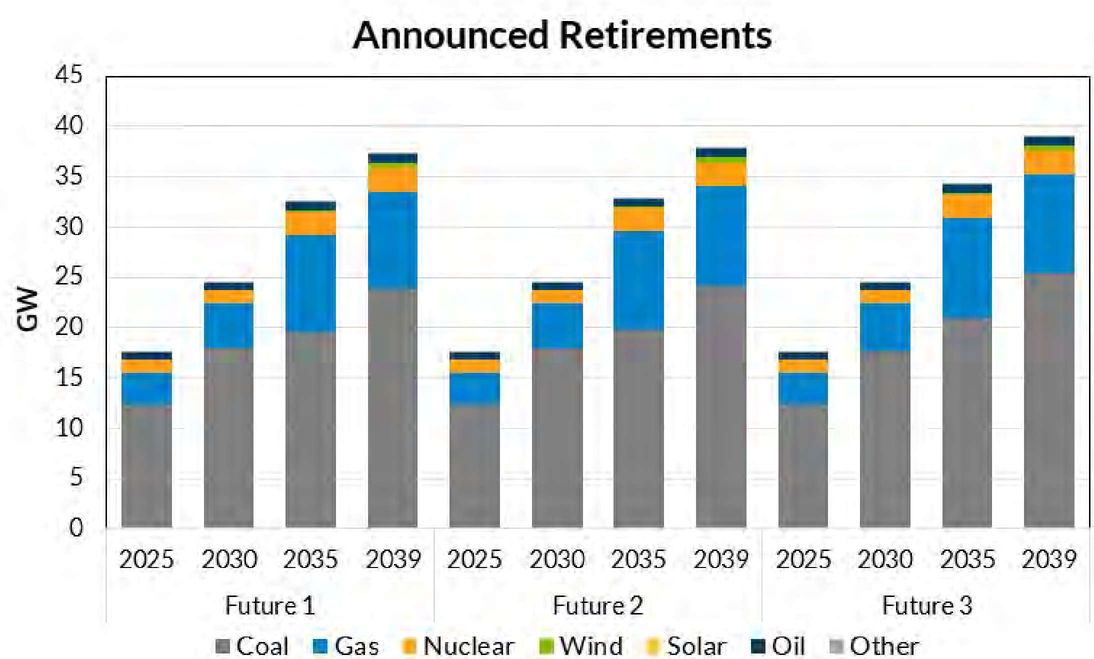


Figure 8: Base Retirements per Future (Cumulative per Year)

Figure 9 through Figure 11 display the results of the Future scenarios' retirement assumptions geographically throughout the MISO footprint. It is important to note that the wind units seen in these figures are assumed to be repowered with the same capacity, albeit with an updated profile that includes a higher capacity factor.

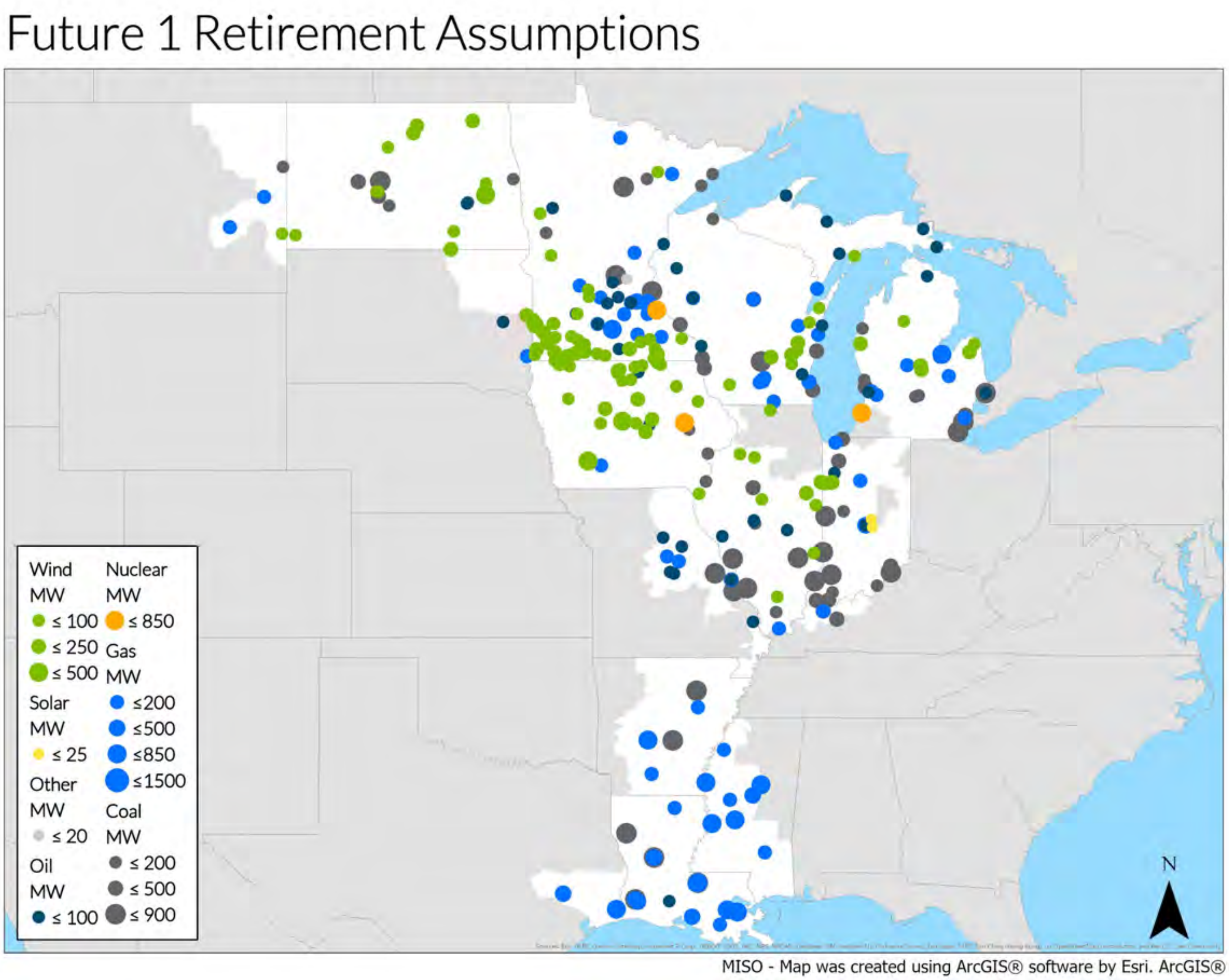


Figure 9: Future 1 Retirements by Fuel Type

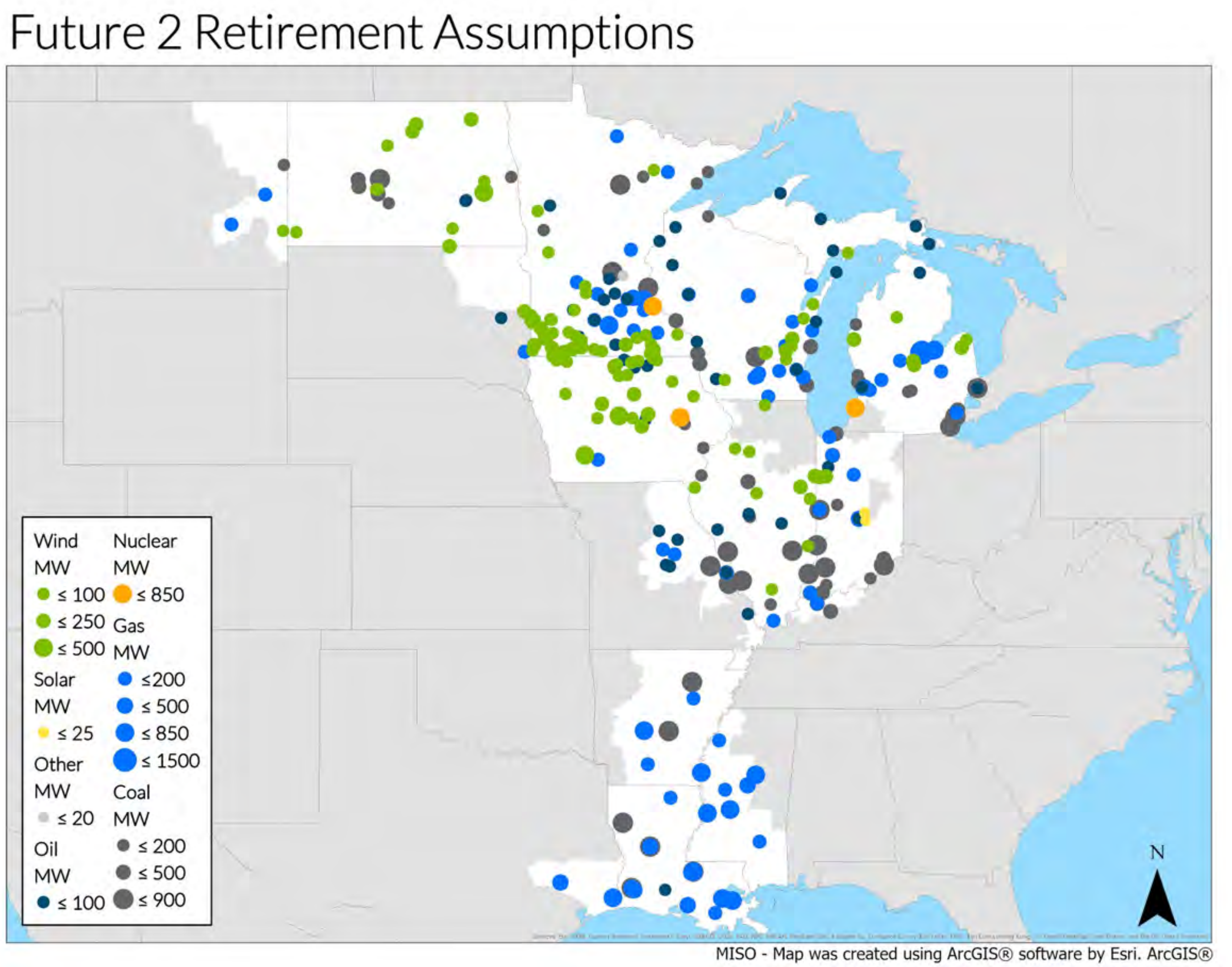


Figure 10: Future 2 Retirements by Fuel Type

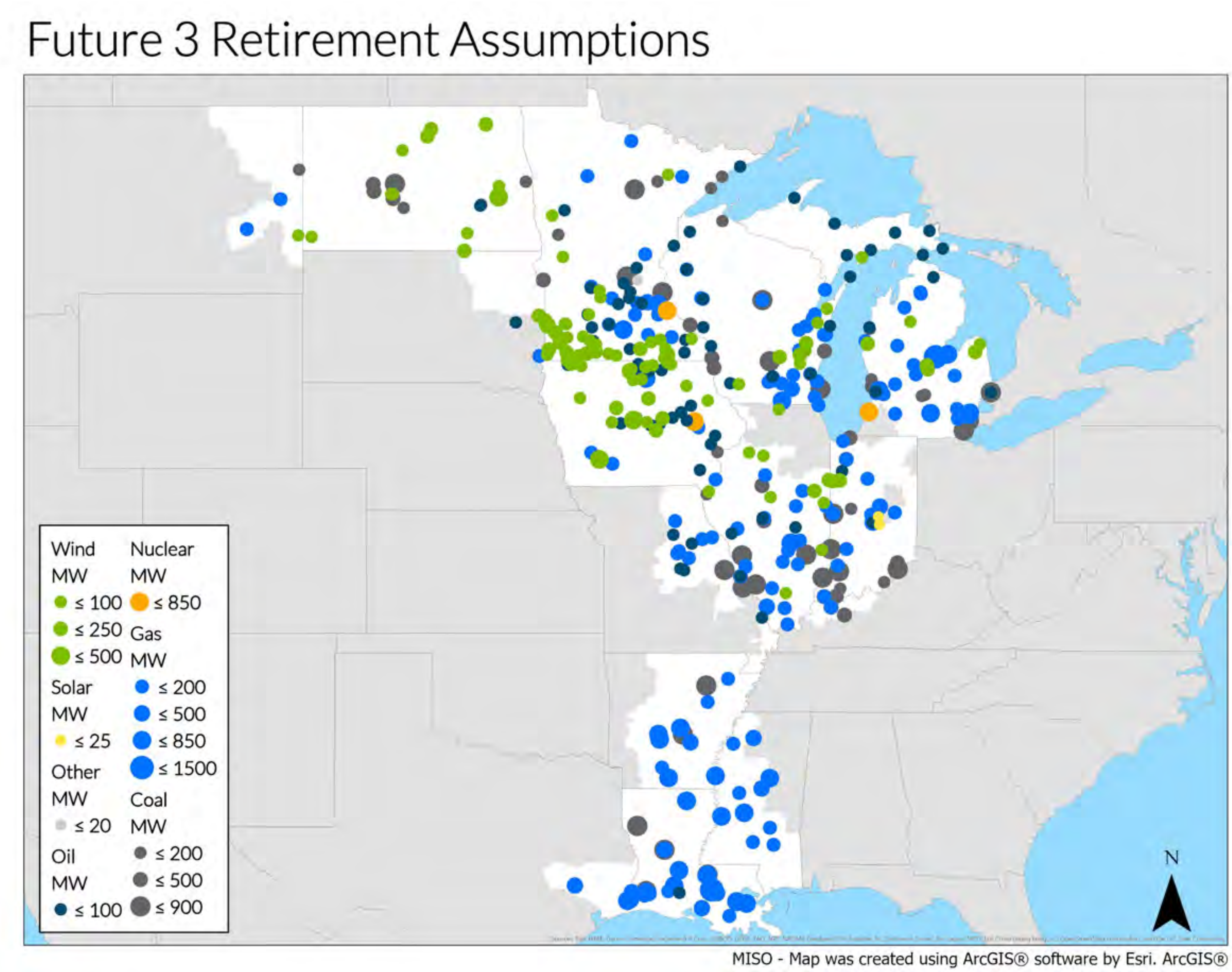


Figure 11: Future 3 Retirements by Fuel Type

Load Assumptions

To analyze what new generation and load modifying resources may be necessary 20 years into the future, assumptions were made regarding the load during that same 20-year period for each Future planning scenario. The three Futures each have differing assumptions representing a wide range of compound annual growth rates (CAGR) during the study period.

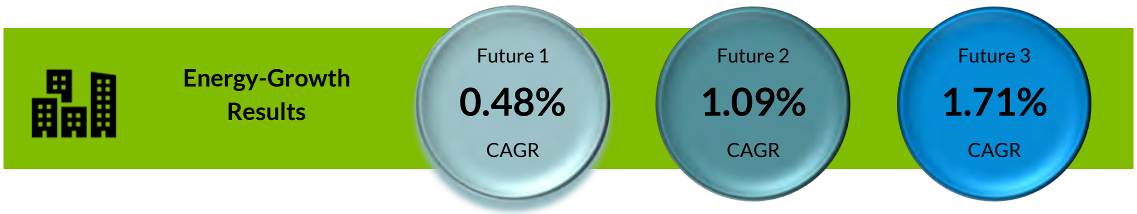


Figure 12: Annual Energy-Growth Rates

Future 1 assumed a load growth[9] consistent with recent trends; 0.48%, including currently low electric vehicle adoption as modeled by Lawrence Berkeley National Laboratory's (LBNL) 'Low' scenario projection.

Future 2 assumed an annual energy growth rate[9] of 1.09% to reach a targeted 30% energy increase by 2040, largely driven by electrification.

Future 3 assumed an annual energy growth rate[9] of 1.71% to reach a targeted 50% energy increase by 2040, driven by additional electrification.

A primary driver of load growth in Futures 2 and 3 is electrification. Electrification is the conversion of an end-use device to be powered with electricity, such that it displaces another fuel, (e.g., natural gas or propane). The increased energy assumptions of 30% and 50% were selected by MISO to create a wide but plausible range of growth scenarios. Although electrification drives the load increase in two of the Futures, it is not the sole source of each scenario's load growth. A more detailed discussion of each Future's load growth and electrification assumptions is provided below and in the Electrification Section of this report.

The resulting Future-specific Demand (MW) and Energy (GWh) forecasts are further detailed in the proceeding sections of this report.

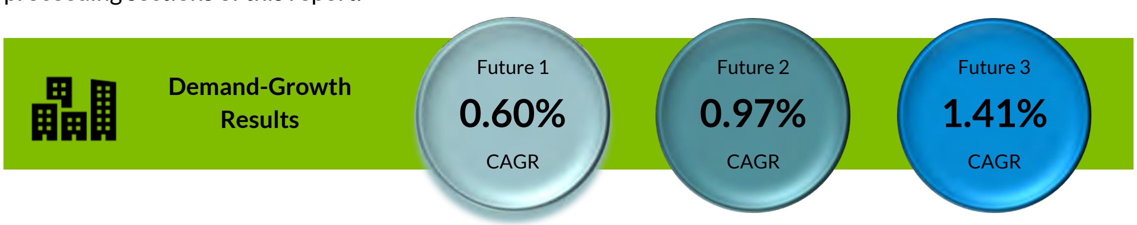


Figure 13: Annual Demand-Growth Rates

[9] Net annual energy and demand growth rates result from reducing the hourly load shape by the energy from energy efficiency (EE) programs.

MISO Forecast Development

The development of the EGEAS-Ready Coincident Peak (CP) Demand and Energy Forecasts for each Future began with MISO's load serving entities' 20-year demand and energy forecasts[10] and ended with the application of the various Future-driven assumptions, creating Future- and year-specific forecasts.

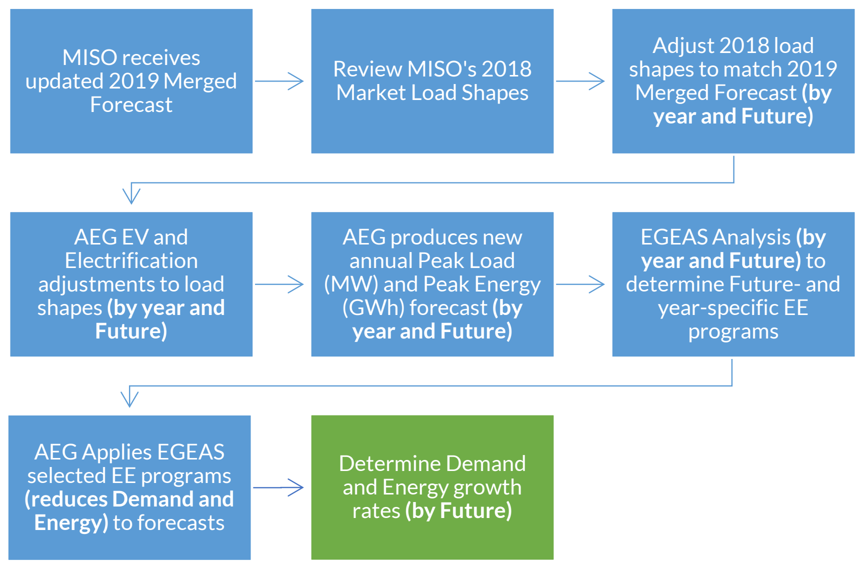


Figure 14: MISO's Forecast Development High-Level Process Flow Chart[11]

Base Forecast and Load Shapes

The 2019 Merged Load Forecast for Energy Planning forecast was reviewed for updates by stakeholders December 17, 2019 through January 10, 2020, and the updates received were incorporated. To accompany the forecast, MISO evaluated its 2018 load shapes for the impact of abnormal outages in operational load shape data due to weather anomalies. MISO evaluated the impact of Atlantic Tropical Cyclones which entered the MISO footprint according to the National Oceanic and Atmospheric Administration and determined that the 2018 shapes are suitable for MISO Futures.[12] MISO's 2018 load shapes also align with wind and solar shapes based on the most current data.

As a Futures process improvement, MISO used PROMOD to adjust each Load Balancing Authority's (LBA) 2018 load shape to meet Peak Load (MW) and Annual Energy (GWh) requirements set by the updated 2019 Merged Load Forecast for Energy Planning forecast. The benefit of this improvement was to create 20 years' worth of unique load shapes for the EGEAS analysis, as well to establish a common load shape for the EGEAS and Market Congestion Planning Studies (MCPS) analyses.

[10] If a particular MISO Load-Serving Entity (LSE) did not provide a 20-year demand and energy forecast, data from the State Utility Forecasting Group's Independent Load Forecast was used for it, creating the 2019 Merged Load Forecast for Energy Planning CP.

[11] Demand and Energy forecast process currently at box highlighted green.

[12] https://www.nhc.noaa.gov/data/tcr/index.php?season=2018&basin=atl

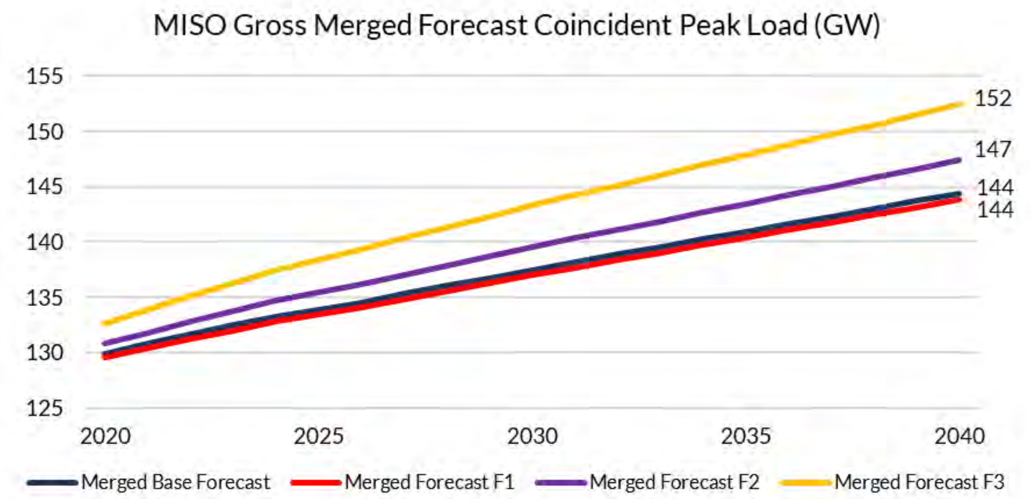


Figure 15: 2019 Merged Load Forecast Peak Load (GW)

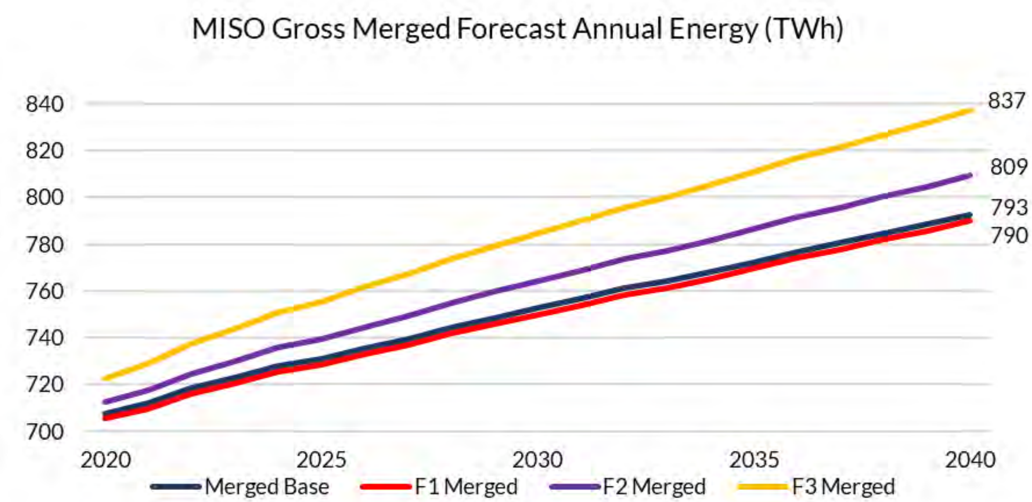


Figure 16: 2019 Merged Load Forecast Annual Energy (TWh)

Future-Specific Forecasts and Load Shapes

Applied Energy Group (AEG) used PROMOD-adjusted load shapes for their base input assumptions and then further modified these load shapes to achieve Future-specific electrification assumptions (EV growth and charging assumptions, residential electrification, and commercial and industrial electrification), ultimately creating 20 years of load shapes for each Future. A representation of the load shape modification is shown in Figure 24.

These Future-specific load shapes were used to calculate the associated Peak Load (MW) and Annual Energy (GWh) forecast for each year to be used in the EGEAS analysis. Refer to the following figures for MISO Footprint and Local Resource Zone (LRZ) representation of this forecast.

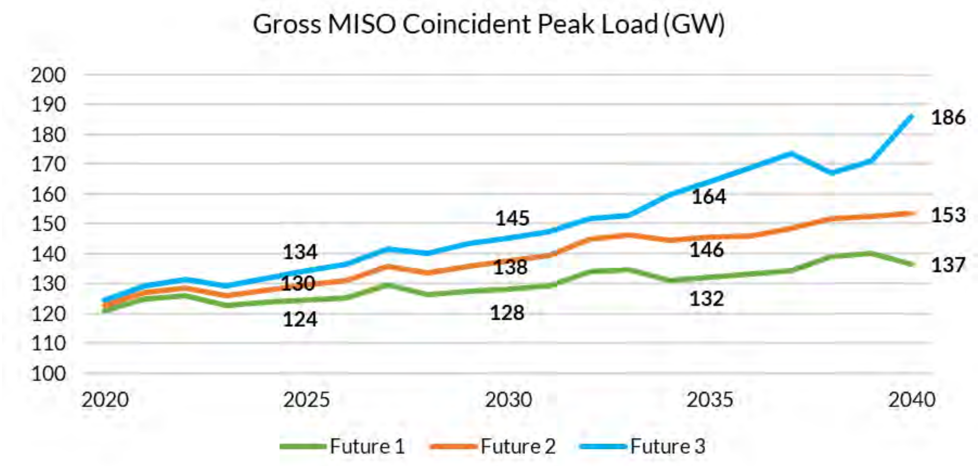


Figure 17: Final AEG Modified MISO Gross Coincident Peak Load (GW) Forecast by Future[13,14]

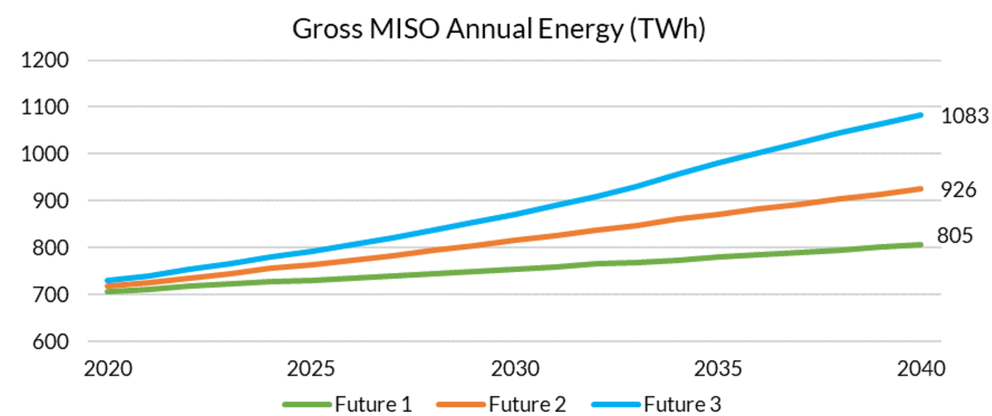


Figure 18: Final AEG Modified MISO Gross Annual Energy (TWh) Forecast by Future

[13] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[14] Dips in Future 3 are due to different peak times of reference, EV charging, and electrification load forecasts.

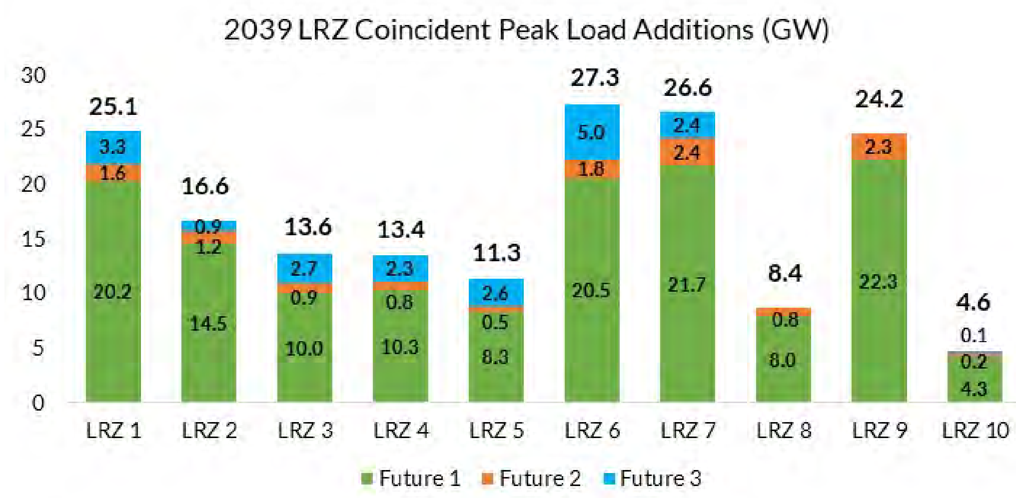


Figure 19: Final AEG Modified LRZ Coincident Peak Load (GW) Forecast[15,16]

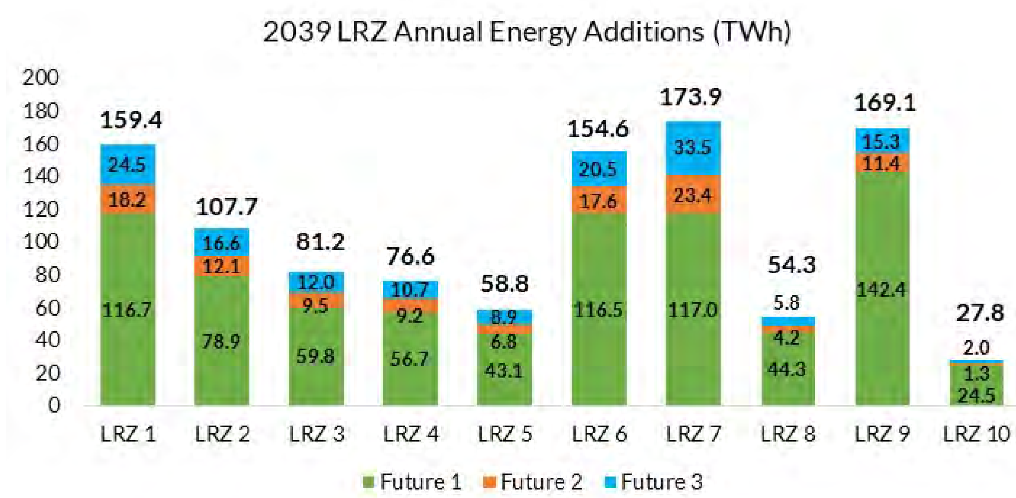


Figure 20: Final AEG Modified LRZ Annual Energy (TWh) Forecast[16]

[15] In LRZs 8 and 9, CP values decrease in Future 3, making the total shown less than the sum of values for Futures 1 and 2.

[16] Values shown do not include load and energy modifiers determined by EGEAS analysis.

Forecast Growth Assumptions

Demand and energy growth values are based on Futures assumptions and were determined once the analysis was finalized; EGEAS having selected hourly load (MW) and energy (GWh) modifiers and programs applied to each Future scenario's Coincident Peak forecast. The following figures represent compound annual growth rates (CAGR) and forecast increases pre- and post-analysis.

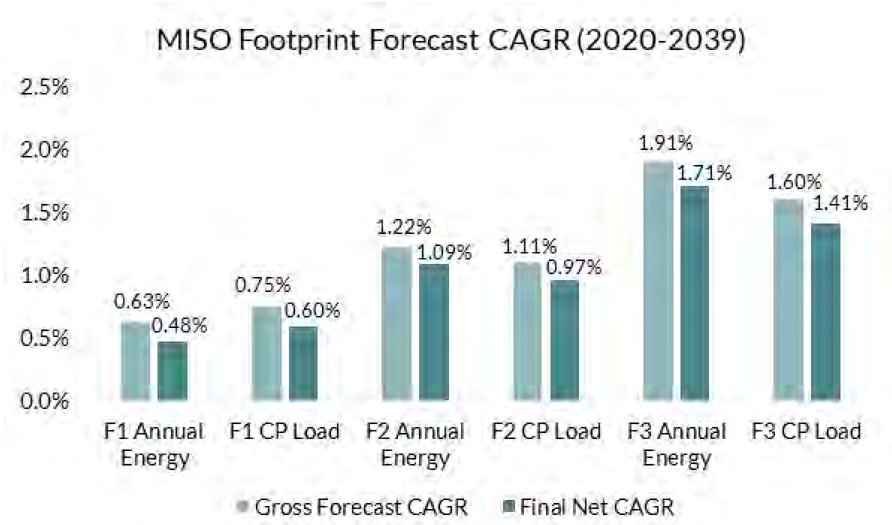


Figure 21: Final AEG Modified MISO Footprint Forecast Compound Annual Growth Rates (CAGR)

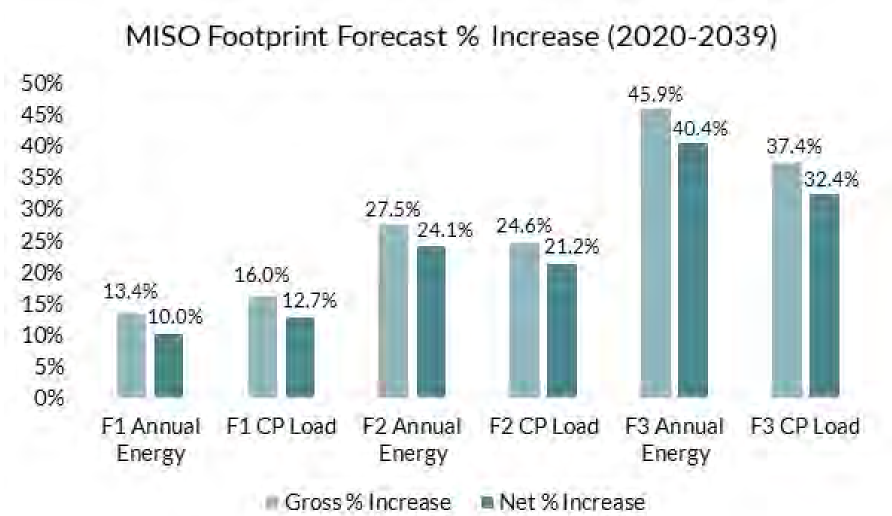


Figure 22: Final AEG Modified MISO Footprint Forecast % Increase[17]

[17] Gross values do not include load and energy modifiers determined by EGEAS analysis, while Net values include EE programs that were selected during modeling.

Forecast Evolution

To ensure the Futures update has effectively created broad and realistic bookends, especially with demand and energy assumptions as key drivers, MISO has compared the 2019 Merged Forecast (pre-application of EV and Electrification assumptions), MTEP21 Coincident Peak (CP) Future-specific forecasts (post-application of EV and Electrification assumptions), and MTEP19 Future forecasts.

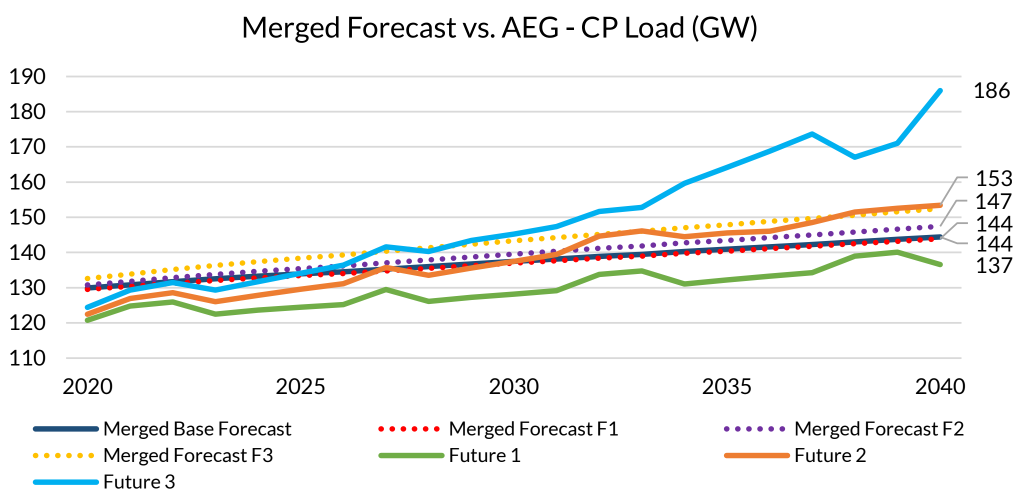


Figure 23: Merged Forecast vs. Future-Specific Adjustments – CP Load (GW)[18,19]

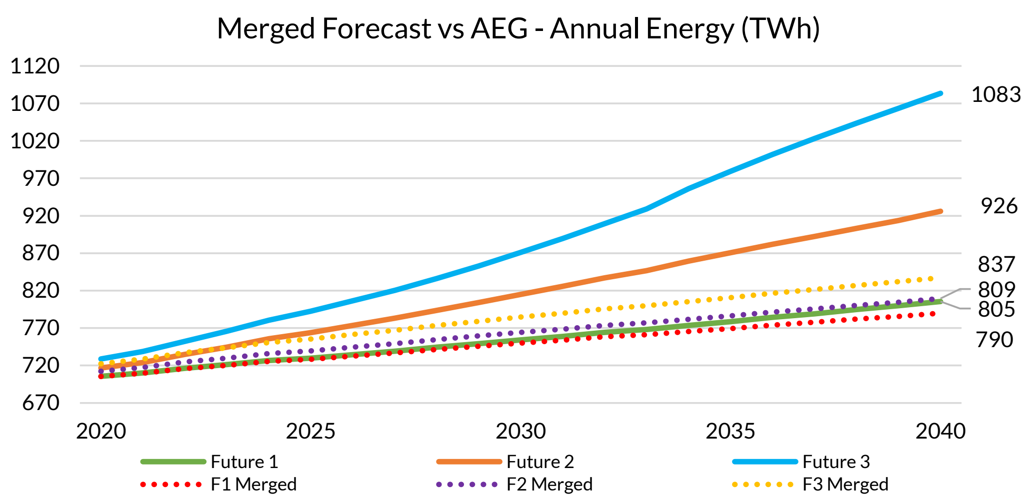


Figure 24: Merged Forecast vs. Future-Specific Adjustments – Annual Energy (TWh)

[18] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[19] Merged Forecast CP Load (GW) values are calculated from monthly peak data while the AEG Peak Load (GW) values are calculated from hourly data. This has the illusory effect of the Merged Forecast CP Load (GW) being reduced.

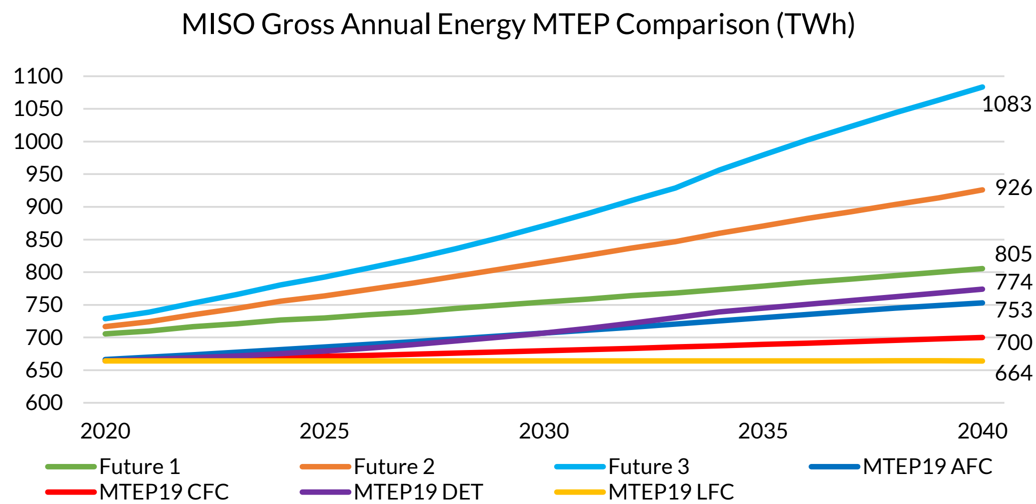


Figure 25: MTEP19 & MTEP21 MISO Annual Energy (TWh) Compare[20]

Final Load Shapes

Upon conclusion of the EGEAS analysis, MISO removed energy proportionate with selected energy efficiency programs in each Future scenario's load shape to produce final net load shapes. In Figure 27 through Figure 29, the evolution of each Future load shape is shown, starting with the initial 2020 load shape developed by SUFG,[21] the final input load shape for year 2039 from AEG that includes electrification assumptions, and then the 2039 load shape post modeling of each scenario that nets out EE programs selected. Figure 26 displays each Future scenario's post-modeling load shape in the final year of the study, for comparison.

[20] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[21] Purdue University's State Utility Forecasting Group

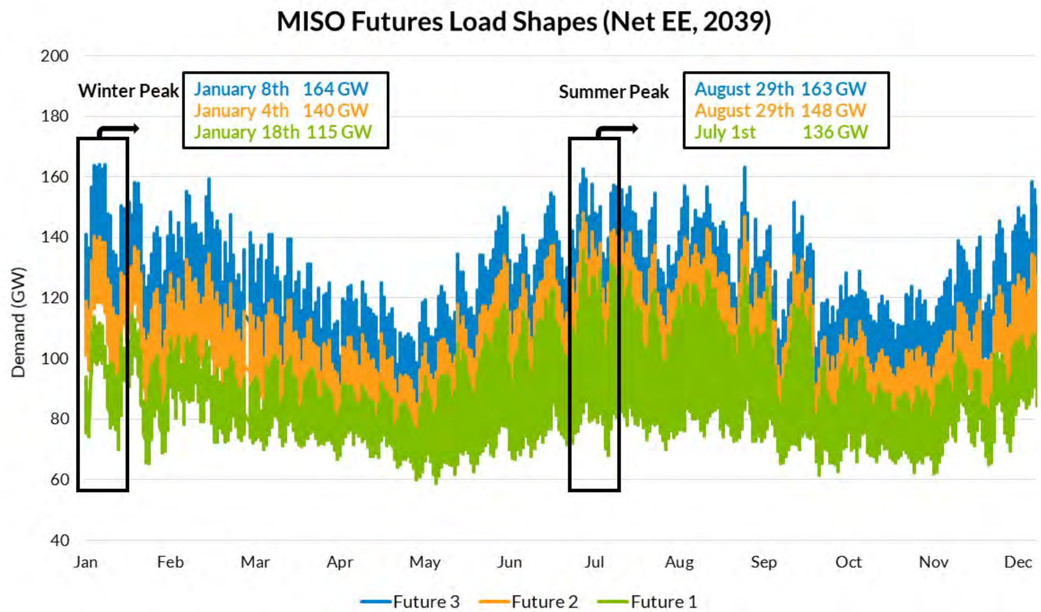


Figure 26: All Futures Final Load Shapes

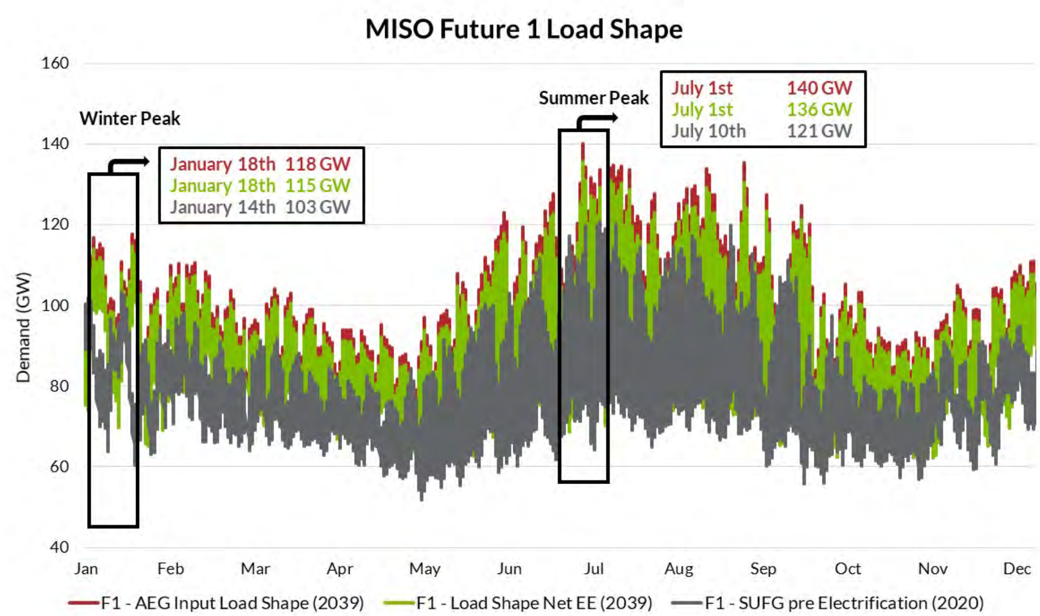


Figure 27: Future 1 Load Shape Evolution

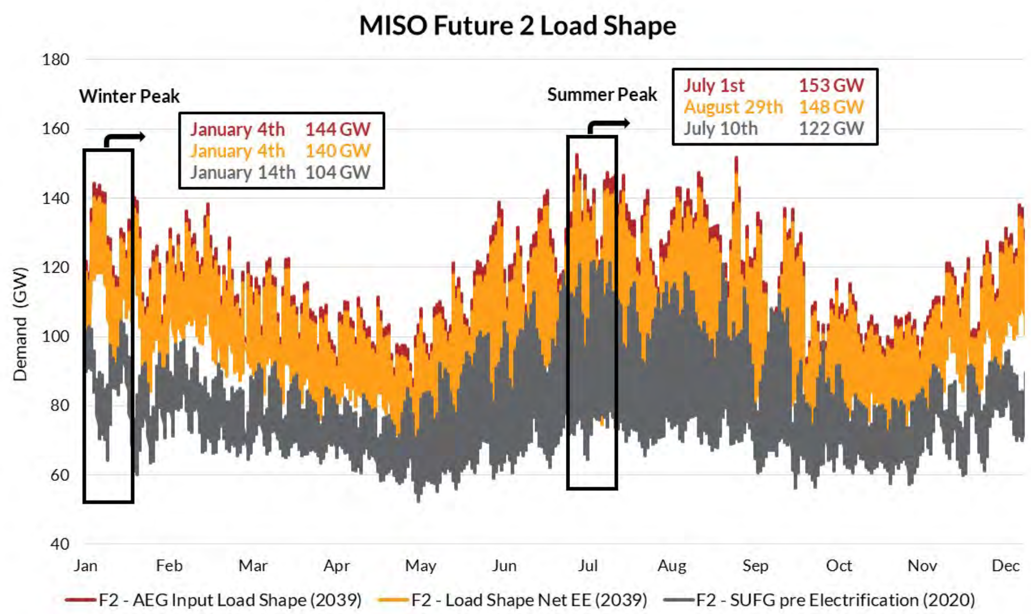


Figure 28: Future 2 Load Shape Evolution

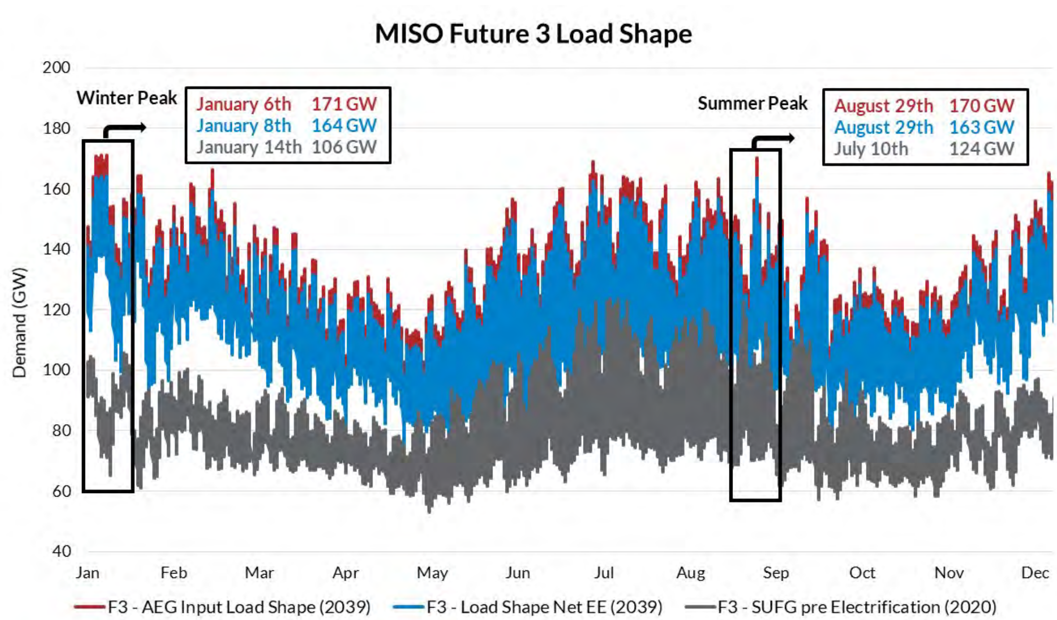


Figure 29: Future 3 Load Shape Evolution

Electrification

MISO contracted Applied Energy Group (AEG) to evaluate the MISO footprint on its potential to electrify. Electrification is the conversion of an end-use device to be powered with electricity, such that it displaces another fuel, (e.g., natural gas or propane). In this study, electrification is calculated as a percentage of technical potential that a given LRZ could achieve. The figure to the right shows the categories of electrification and what percentages of the technical potential they comprise. More details on the assumptions for the categories are included below.

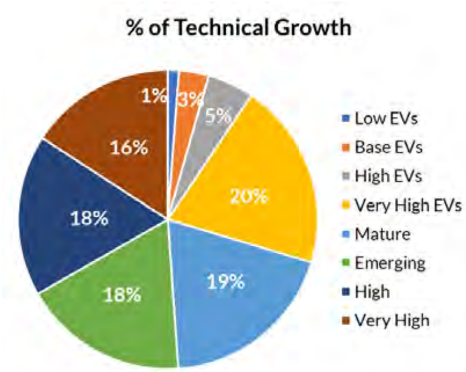


Figure 30: Electrification Categories

To estimate the available market for electrification, AEG started with the end-use load forecasting models developed for MTEP20 (previous set of MISO Futures), which include market data for each state in the MISO footprint. These market data included estimates of the penetration of many types of electric equipment. To estimate the total technical electrifiable load, AEG assumed that 90% of a particular end-use customer load was capable of being electrified, and then subtracted the electric equipment saturations (the load that is already electrified) from that value.

Electrification Categories

AEG identified each electrifiable technology and considered how likely or feasible it would be to be adopted before assigning it to one of four categories: mature technologies, emerging, high, and very high.[22] AEG considered how widespread the technology currently is, whether there are utility EE programs, and whether or not there are known market barriers. Since both mature and emerging versions of known technologies (e.g., traditional air-source heat pumps vs. cold-climate heat pumps) can coexist, AEG distributed the electrification potential for different technologies over more than one category. These are represented by the percentages below.

Additionally, AEG considered the certainty around each assumption. For example, industrial process loads are very customizable and would require a "bottom-up" approach to implementation, considering each industry and state individually. To capture this uncertainty, electrification of industrial process loads was assigned to higher electrification levels.

Each category is described below however, additional insights into the details of these categories may be found in MISO's Electrification Insights Report.

Mature Technologies

The "Mature Technologies" electrification category includes technologies that are widely available on the market today and are the most likely to electrify in the future. One example is an air-source heat pump, which is already found in many homes throughout the United States. Electric cooking equipment, such as induction ovens, is another example of an existing technology that is popular and relatively straightforward to install. Technologies in this category include:

- Air-Source Heat Pumps (50% of single-family [SF], 50% of multi-family [MF], 50% of Commercial and Industrial [C&I])
- Geothermal Heat Pumps (50% of SF, 50% of C&I)
- Heat Pump Water Heaters (50% of SF)
- Clothes Dryers

[22] AEG's 2019 Presentation on Electrification

- Dishwashers
- Stoves

To better understand how much of these technologies are being electrified in each category, it is best to give an example. For air-source heat pumps, this section is saying that 50% of single-family, multi-family, and commercial and industrial heat pumps that can electrify will be electrified in this category.

Emerging Technologies

The "Emerging Technologies" category represents electrification load that is beginning to become available or is more mature but limited by known market barriers. For example, while air-source heat pumps are a mature technology, they may not be easily installable without reconfiguring the ductwork. Gas forced-air furnaces provide hotter air and require smaller ducts, requiring an invasive modification to expand the ductwork to keep a home warm in the winter. Process loads also begin to appear in this category. Technologies in this category include:

- Air-Source Heat Pumps (50% of SF, 50% of MF, 50% of C&I)
- Geothermal Heat Pumps (50% of SF, 50% of MF, 50% of C&I)
- Heat Pump Water Heaters (50% of SF, 50% of MF, 50% of C&I)
- Industrial Process (25% of C&I)

High Electrification Scenario Technologies

This category represents the point where substantial market barriers exist or where technologies are new or still in development. An example is a large-scale air-source heat pump that would be necessary to replace a large gas boiler heating a hospital. These are not readily available—gas is the most common fuel source in large-scale applications. However, if high levels of electrification are to be achieved, electrification using these new and in-development technologies would need to take place. Technologies in this category include:

- Air-Source Heat Pump (50% of C&I)
- Geothermal Heat Pump (50% of MF, 50% of C&I)
- Heat Pump Water Heaters (50% of MF, 50% of C&I)
- Industrial Process (25% of C&I)

Very High Electrification Scenario Technologies

This category represents the highest levels of uncertainty in the analysis and is only applied in the highest-growth cases. As noted above, much of the industrial process electrification is present in this category. The only technology in this category is noted below:

- Industrial Process (50% of C&I)

Technologies Electrified

HVAC Heat Pumps - Air-source and geothermal heat pumps

- Lower-growth scenarios electrify many residential homes and some businesses, where this technology is already available (rooftop units and residential systems)
- Higher-growth scenarios assume large-scale replacements are available for technologies like gas boilers

Heat Pump Water Heaters - Efficient water heaters with a vapor-compression refrigeration cycle

- Lower-growth scenarios electrify tanks in both the residential and commercial sectors
- Higher-growth scenarios include the electrification of large-scale gas water heaters

Residential Appliances - Clothes dryers, dishwashers, and stoves

- Dishwasher electrification occurs when no existing dishwasher is present

Industrial Process - High growth potential, but only certain processes can be electrified

- Due to the complexity involved in electrifying industrial processes, AEG assumed that most of this occurs in the higher-growth scenarios
- Examples of technologies that may be electrified within industrial processes include ultraviolet (UV) curing and drying, machine drives, and process-specific heating and cooling
- Electric boiler, industrial heat pump, resistance heating industrial heat pump, induction furnace, etc.

LBNL PEV Forecasts[23] - All four forecasts were used in development of these scenarios

- These include combinations of uncontrolled and V2G versions of the: Low, Base, High, and Very High scenarios
- Merged PEV forecasts were selected for each growth scenario – adoption curves and load shapes specific to the selected forecast were used

Figure 32 through Figure 37 display the results of these electrification assumptions across each Future scenario in the MISO footprint. The charts present a detailed view of the results showing yearly cumulative increases in energy from electrification for the footprint, electrification totals for each Local Resource Zone for the entire study, and the proportion of electrification from each technology. Similar charts for external region electrification results are found in the Appendix, Figure 80 through Figure 87.

[23] Lawrence Berkeley National Lab EV Forecast Report

Electrification Potential Across MISO Footprint

This analysis was conducted at the state level in the MISO footprint then aggregated by LRZ. AEG's end-use forecasting and Demand-Side Management (DSM) potential model was used to conduct this analysis, providing estimates of electric equipment penetrations as well as consumption for MISO's fraction of each state. Since local weather and equipment penetration data were used in this analysis, each state will have different end-use consumption patterns and a different electrifiable load, as shown in Figure 31. These are high-level findings based on the end-use models and a result of the differences noted above. The three main drivers of technical potential for electrification are:

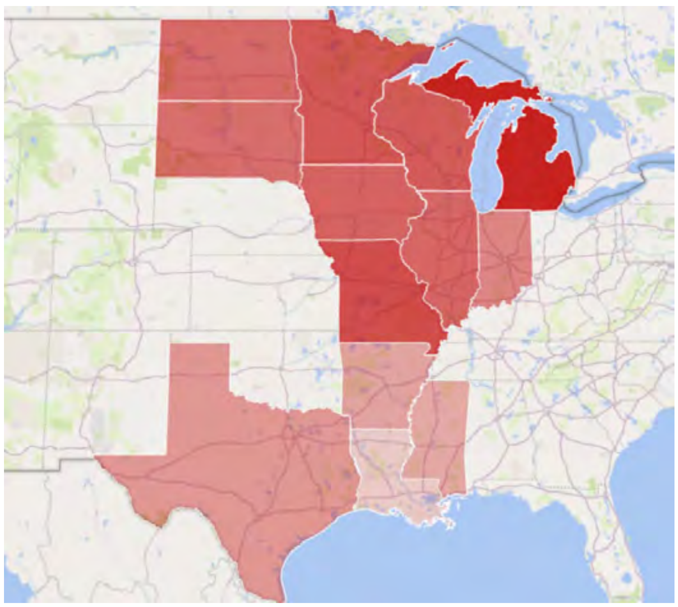


Figure 31: Electrification Potential by State

- **Latitude:** The northern states in the MISO footprint are generally colder than the southern states, resulting in larger space-heating loads. Since the heating end-uses represent some of the largest electrification potential, additional new loads are expected in the northern MISO states.
- **Gas Infrastructure:** Along with latitude, existing gas infrastructure heavily influences the electrifiable load. AEG utilized the state-level market data listed above to estimate gas equipment penetrations by state. If the load in a state is already mostly electric, there would be fewer non-electric units to convert, lowering potential.
- **Cooling Presence:** The final notable factor is the presence of existing cooling equipment. Similar to the gas infrastructure note above, high penetrations of existing cooling equipment limit electrification potential since the remaining non-electric market is smaller. In the warmer southern states, many homes already have cooling equipment installed, so their potential is lower.

Future 1 Electrification

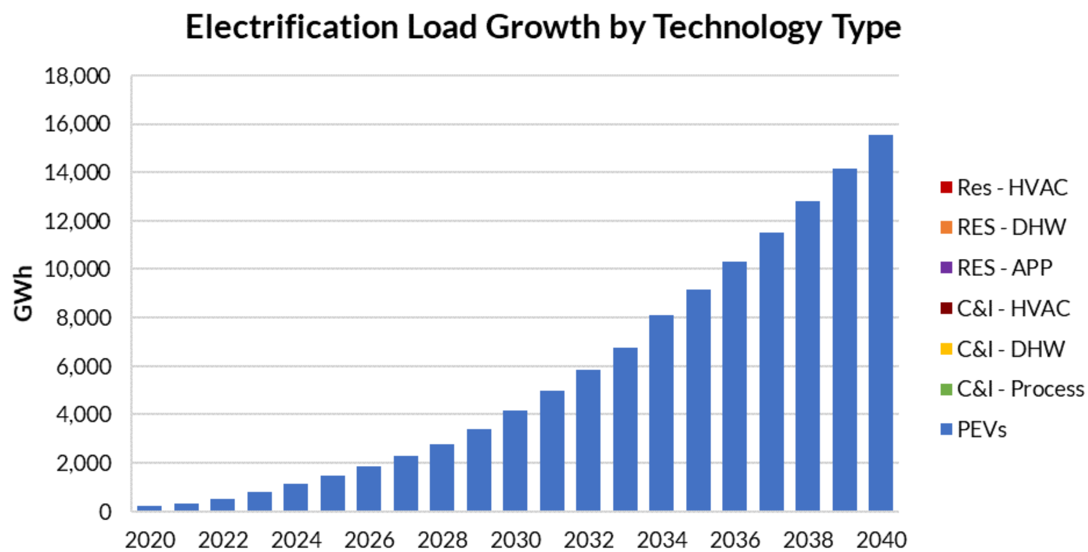


Figure 32: Future 1 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

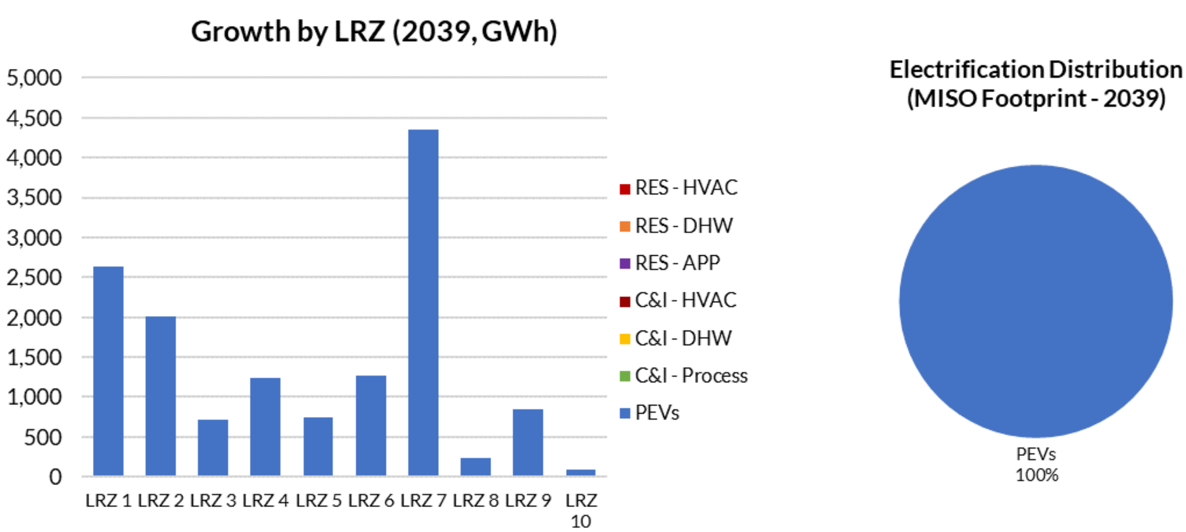


Figure 33: Future 1 Electrification Broken Down by End-Use

Future 2 Electrification

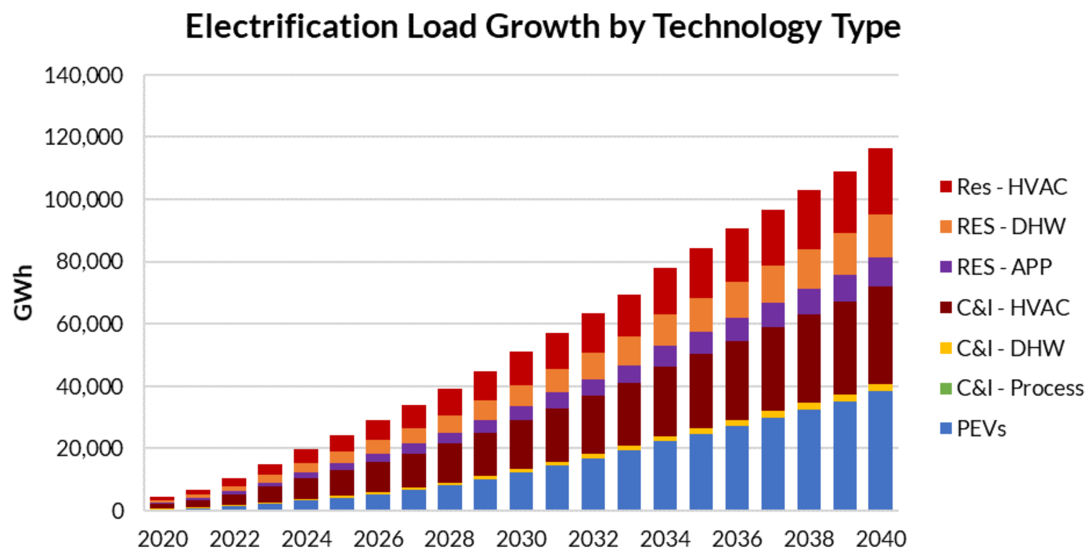


Figure 34: Future 2 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

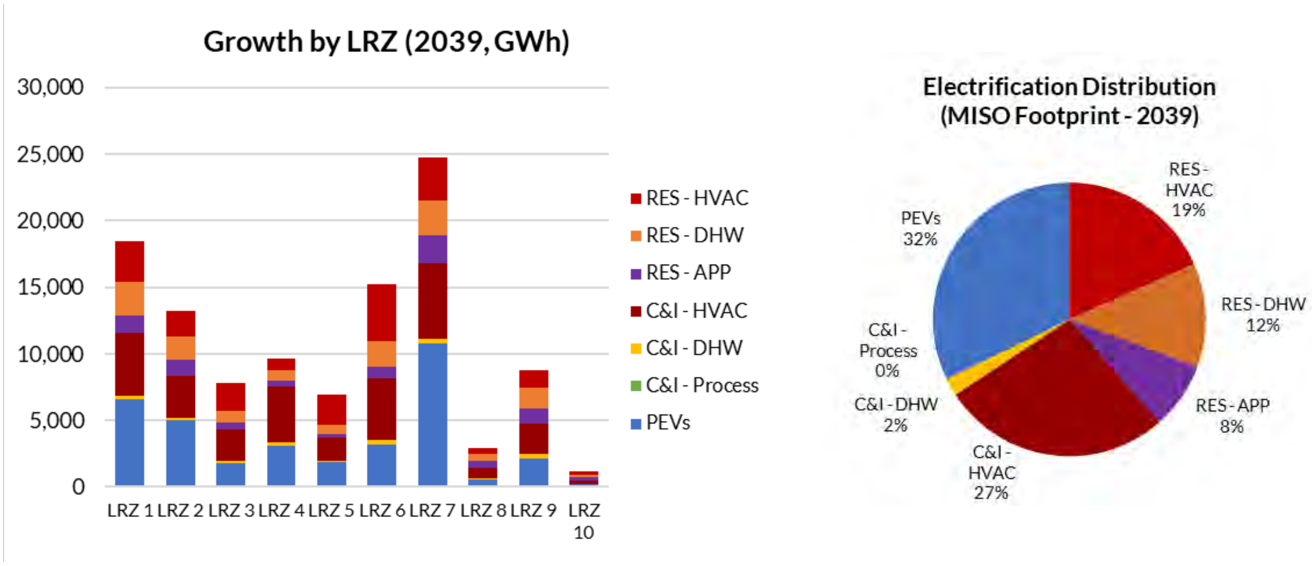


Figure 35: Future 2 Electrification Broken Down by End-Use

Future 3 Electrification

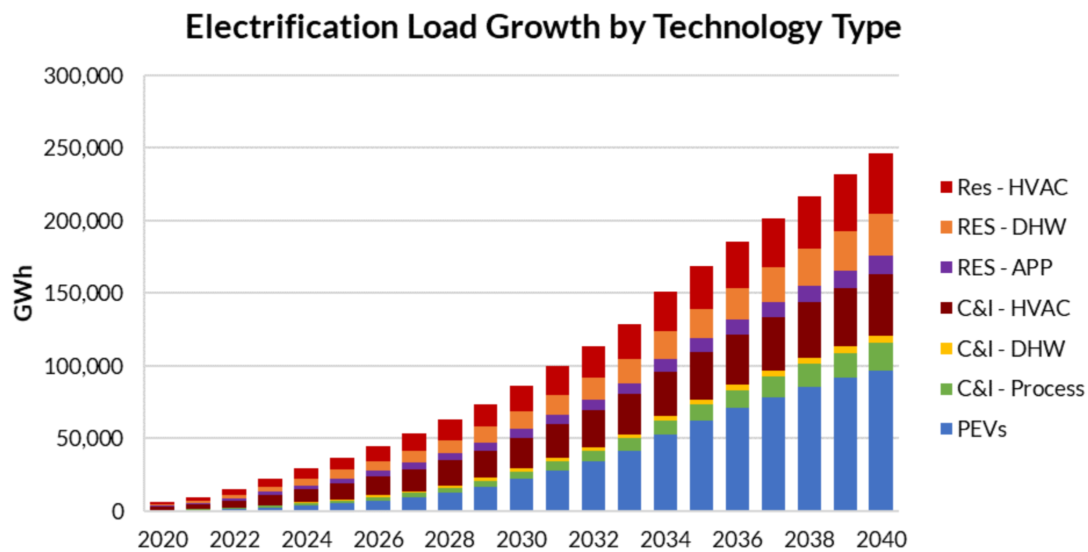
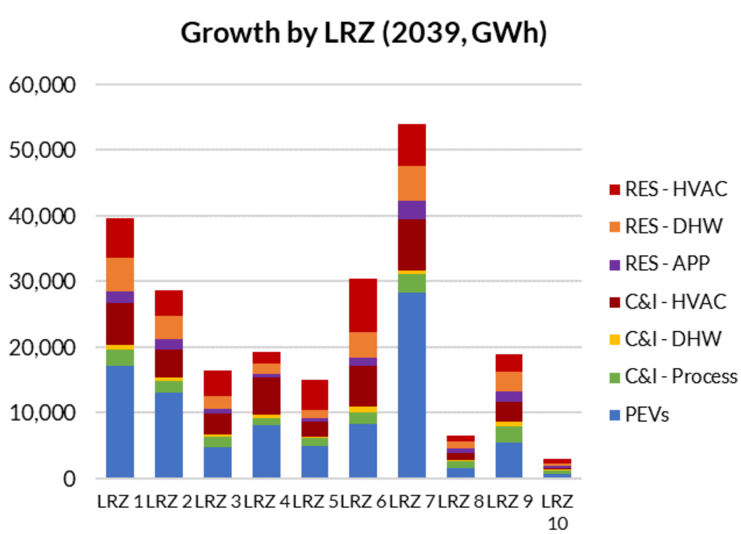


Figure 36: Future 3 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint



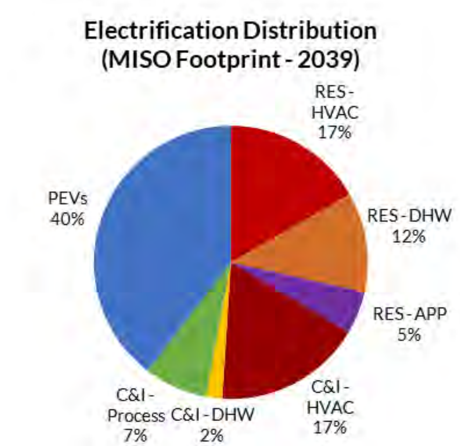
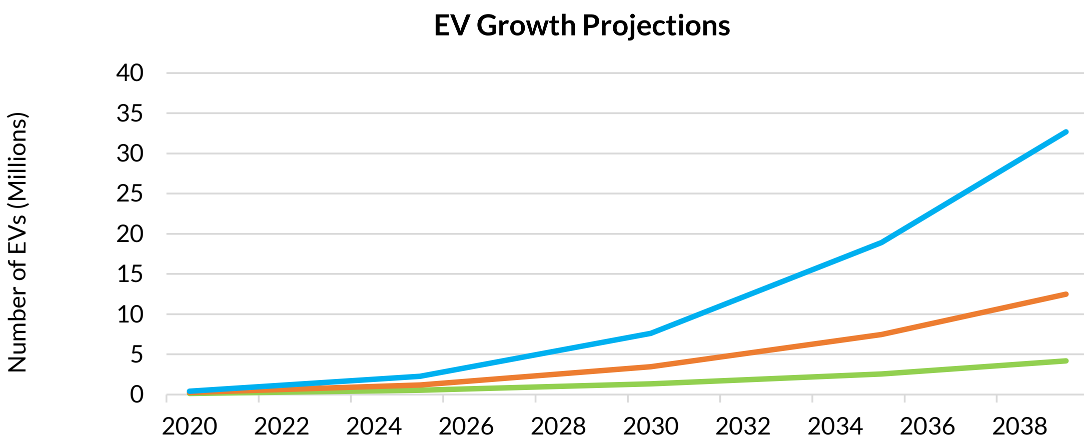


Figure 37: Future 3 Electrification Broken Down by End-Use

Electric Vehicle Forecasts

MISO collaborated with Lawrence Berkeley National Laboratory (LBNL) on a study to determine the potential for EVs within the MISO footprint. This study categorized the projected growth of EVs in into four scenarios: low, base, high, and very high. Each of the three Futures used merged forecasted EV growth scenarios to include different amounts of light-duty EVs. All Futures explored a variety of EV growth and charging scenarios within every LRZ across the 20-year study period.

Future 1 evaluated only uncontrolled charging methods, Future 2 included vehicle-to-grid (V2G) charging after 2035, and Future 3 incorporated V2G charging after 2030. Figure 38 through Figure 41 detail the number of EVs in each scenario, MISO footprint and LRZ.



	2020	2025	2030	2035	2039
Future 1	0.135	0.53	1.33	2.57	4.19
Future 2	0.26	1.205	3.47	7.455	12.49
Future 3	0.416	2.272	7.598	18.91	32.686

Figure 38: EV Growth per Future (MISO footprint)

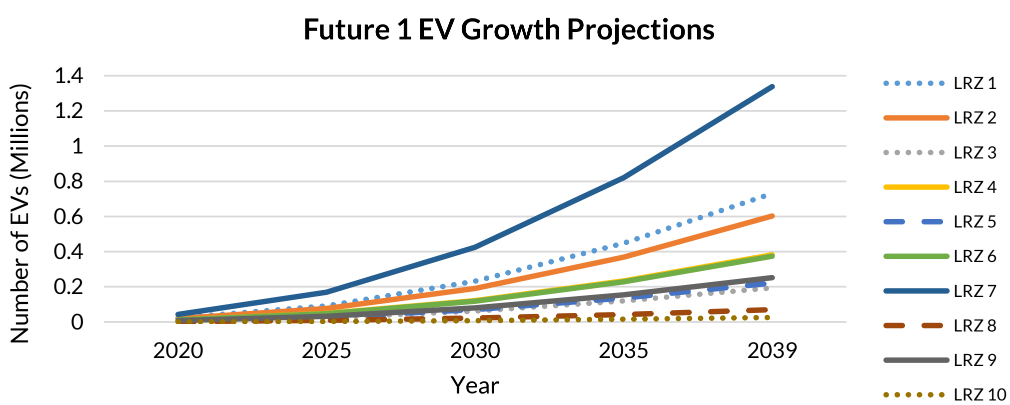


Figure 39: Future 1 EV Growth per LRZ

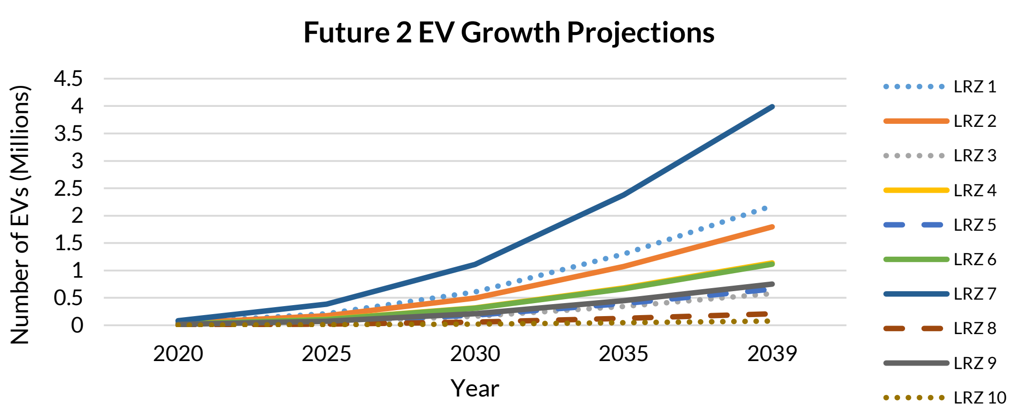


Figure 40: Future 2 EV Growth per LRZ

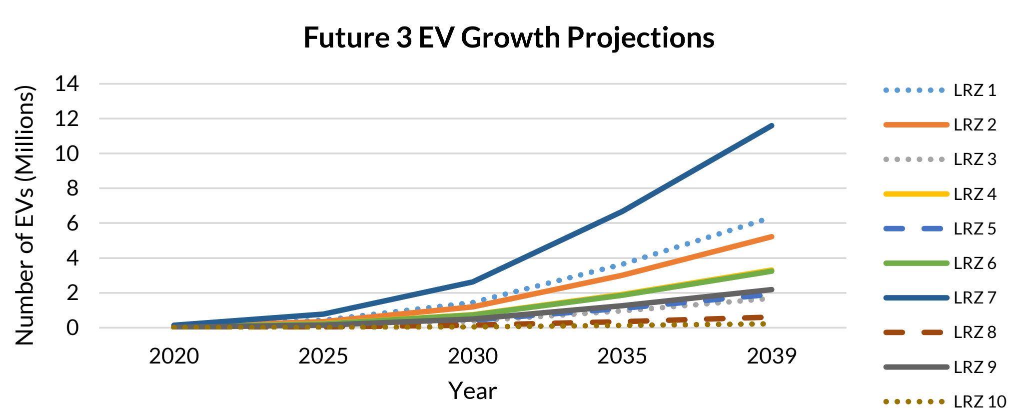


Figure 41: Future 3 EV Growth per LRZ

New Resource Additions

Regional Resource Forecast Units (RRF Units) are various resource types that are defined in and selected by MISO's capacity expansion tool, EGEAS, to achieve each of the Futures scenarios. The RRF units used in MISO Futures are discussed in further detail below.

Wind

Vibrant Clean Energy (VCE) 2018 hourly profiles were used as the base data. New RRF units were built at 100m hub height throughout the study period. Existing units used representative 80m hub height hourly profile and all wind units assumed 16.6% capacity credit.

Solar

Vibrant Clean Energy (VCE) 2018 hourly profiles were used as the base data. Existing units used a representative hourly profile and all solar units assumed 50% capacity credit at the beginning of the study period and decreased by 2% starting in year 2026, until the capacity factor reached a minimum of 30%.

Hybrid: Utility-Scale Solar PV + Storage

Hybrid solar profiles were created by modifying VCE 2018 hourly profiles for solar units. Hybrid units were modeled as a 1200 MW inverter attached to 1500 MW of solar panels, resulting in an over-panel of 25%. When solar output exceeded the inverter capacity, the battery charged. Once solar output reached 20% or lower of the max capacity (max capacity is 1500 MW making 20%, 300 MW), the battery discharged until empty. Hybrid units assumed a 60% capacity factor.

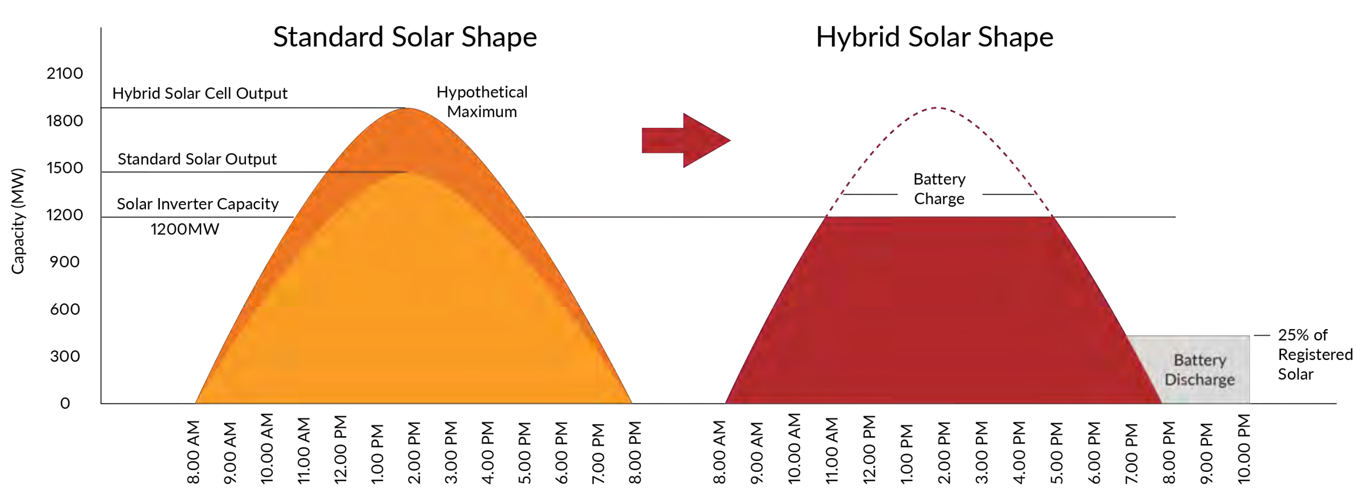


Figure 42: Solar + Storage Hybrid Profile

Storage: Lithium-Ion Battery (4-hour)

Batteries modeled in the capacity expansion were 4-hour duration lithium-ion batteries. Units were sited with a minimum capacity of 5 MW and a maximum capacity of 500 MW across all Future scenarios.

Distributed Energy Resources (DERs)

As in previous Futures cycles, MISO commissioned Applied Energy Group (AEG) to develop new DER technical potential. AEG developed estimates of DER impacts through survey of load-serving entities (LSE) and secondary research. Based on analysis for MTEP20, with updated utility information and Futures narratives for this cycle, technical potential represents feasible potential under each scenario. To support modeling, AEG compiled DER programs by type and cost into program blocks for EGEAS.

Previously referred to as demand-side additions or management (DSM), these resources were modeled as program blocks in three main categories: Demand Response (DR), Energy Efficiency (EE), and Distributed Generation (DG). Programs also fall into two sectors: Residential and Commercial and Industrial (C&I).

During the program selection phase for the models, each block was offered against supply-side alternatives to determine economic viability. For all three Futures, EGEAS selected the following program blocks, all within the C&I group: Customer PV, Utility Incentive PV, and Low-Cost Energy Efficiency. Additionally, Future 3 selected Residential Low-Cost Energy Efficiency. "Customer PV" indicates market-driven, naturally occurring solar panel adoption, whereas "Utility Incentive PV" indicates a utility incentive program for solar PV. Specific EE programs were grouped by cost into three tiers for C&I and two tiers for Residential. A complete list of detailed AEG programs mapped to EGEAS program blocks is below in Table 5.

Announced resources were included in Futures base assumptions. Several stakeholders submitted feedback detailing DERs they intend to add to their systems; these are also included in the totals below. Only selected programs and stakeholder additions were implemented in the Futures models. Table 3 and Table 4 show total DER technical potential and additions modeled in MISO by the end of the study period.

MTEP21 DERs Capacity (GW) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	5.2	0.9	5.9	0.9	5.9	0.9
Energy Efficiency (EE)	13.3	7.8	14.5	8.1	14.5	11.7
Distributed Generation (DG)	14.7	3.5	14.7	3.5	21.8	6.2

Table 3: DER Capacity (GW): 20-Year Technical Potential & Additions in MISO

MTEP21 DERs Energy (GWh) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	442	118	498	118	498	118
Energy Efficiency (EE)	86,886	30,801	94,313	31,393	94,313	49,145
Distributed Generation (DG)	26,119	5,709	26,119	5,709	36,934	9,837

Table 4: DER Energy (GWh): 20-Year Technical Potential & Additions in MISO

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response	C&I Price Response
DR	Residential Direct Load Control	Res. Direct Load Control
DR	Residential Price Response	Res. Price Response
EE	C&I High-Cost EE	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE*	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retro commissioning Low
EE	C&I Mid-Cost EE	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retro commissioning Mid
EE	Residential High-Cost EE	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE*	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV*	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV*	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

Table 5: EGEAS Program Block/Specific DER Program Mapping

* Program was selected as economically viable and utilized by EGEAS in the resource expansion.

Natural Gas Resources

Combined Cycle (CC) and Combustion Turbine (CT) were the two gas resource types modeled. Site priority levels for these units remained the same when selecting a site. However, CC units were given a higher priority over CT units.

CC + Carbon Capture Sequestration

Futures analysis modeled Combined Cycle plus Carbon Capture and Sequestration (noted as CC+CCS in report documentation) due to the need for a low-carbon resource with a high-capacity factor. This was found to be the case when modeling the high carbon reduction in Future 3 (80%) after 2035 and in 2039 of Future 2 (60%). While there are no large-scale CC+CCS plants in operation today, there are several states and utilities testing this resource.

In modified Futures studies to come, MISO will continue to investigate other forms of energy that could include small modular reactors (SMRs) and green hydrogen, for example. Recent announcements show that members are looking into SMRs and hydrogen resources for electricity production.[24,25,26] Due to such recent developments and MISO's role to remain resource-agnostic, MISO used CC+CCS units in modeling to serve as a proxy for a high-capacity factor, low-carbon-emitting resource.

New Resource Addition Siting Process

RRF unit siting processes were developed to help identify where future generation would likely be located. While different RRF unit types need their own siting processes, there are universal criteria that apply to each resource type's unique siting process. These universal siting criteria and resource-specific processes are discussed below.[27]

Universal Siting Criteria

To help improve siting measures, the following criteria underlie all resource-specific siting processes.

1. The same sites were used for each Future and site differences only occurred due to Future-specific renewable capacity needs. This included only using sites that were found in both the Year 5 and Year 10 MTEP Powerflow models.
2. Radial lines and associated buses were identified in the MTEP Powerflow models and excluded from potential resource sites.
3. Sited capacity could not exceed a site's N-1 capacity amount. This means the summation of all the transmission elements, excluding the highest rated capacity element, could not have a lower capacity than the resource capacity.
4. Units were only sited on MISO-owned transmission elements.

Wind and Solar PV

Resources of this type were modeled as a collector system, representing an aggregated capacity potential that can be installed within 10-30 miles of each site. These collector sites were identified by two methods:

1. Compilation of Generation Interconnection (GI) queue projects:
   - 80% of Future-determined capacity was distributed to GI sites.
   - GI projects were ranked based on GI queue status (projects further along in the GI study process were ranked higher) and grouped by project state location, creating a capacity by state penetration percentage.
   - GI projects within 10 miles of each other were identified and combined into a collector system.
   - The capacity by state penetration percentage was applied to the 80% capacity expansion results, creating a state-up siting processes driven by GI Queue activity.
2. Vibrant Clean Energy[28] (VCE) results:
   - VCE sites receive the remaining 20% of Future-determined capacity.
   - Collector buses represent a 20- to 30-mile aggregated capacity potential.

[24] Mitsubishi Power and Entergy Collaboration
[25] Xcel Energy and INL
[26] Xcel Energy
[27] All capacities referenced on this page are (MW).
[28] VCE Report

Utility-Scale Solar PV + Storage (Hybrid)

Hybrid units were sited the same as Solar PV units and utilized the GI Queue only. Due to low GI queue activity for hybrid units not all Hybrid capacity (MW) was able to be distributed. As a result, the remaining balance was sited at unutilized Solar PV GI sites for the respective Future.

Distributed Solar PV Generation (DGPV)

Distributed solar PV resources (DGPV) siting methodology utilized the National Renewable Energy Laboratory's (NREL) Distributed Generation Market Demand Model (dGen) and consisted of the following:

- Using dGen, identify top 25 counties by DGPV potential within each LRZ.
- Identify (up to) top 20 load buses for each county.
- Distribute county capacity using dGen results weighting.
- Use top 20 load buses' Load Ratio Share (LRS) to distribute dGen-weighted capacity to each bus.

Lithium-Ion Battery (4-hour)

Batteries were restricted to a minimum capacity of 5 MW and capped at a maximum capacity of 500 MW (PROMOD performance reasons) and sited in a way to create geographical distribution for each LBA. The geographical distribution process follows:

- Each LBA's LRS was determined using Future-specific forecast data; LRS was then used to determine each LBA's Battery Capacity (MW) allocation.
- Top load buses for each LBA were identified, and the nearest, highest N-1 capacity bus greater than 100kV was selected to site the capacity.
- If an LBA needed more than one battery site, the next bus selected would be at least 10-20 miles away from the previously used bus to maintain geographical distribution.

Combined Cycle and Combustion Turbine

Combined Cycle and Combustion Turbine siting largely remained the same as in past MTEP cycles with site rankings as follows:

- Combined Cycle units got higher priority sites over Combustion Turbine
- Priority 1: Active Definitive Planning Phase (DPP) Phase 1, 2, 3 Generator Interconnection Queue
- Priority 2: Brownfield – Existing and Retired Sites
    - Retired sites ranked by earliest commission date
    - Retired sites had to be 50 MW and greater
- Priority 3.1: SPA or Canceled/Postponed GI Queue
- Priority 3.2: Greenfield Siting Criteria

CC + Carbon Capture Sequestration

Combined Cycle plus Carbon Capture Sequestration (CC+CCS) sites were limited to sites suitable to this technology type. Desirable basins for these resources were determined using the results of the U.S. Geological Survey's (USGS) National Geologic CO_2 Storage Assessment. Potential sites were screened to ensure that their geographic location fell within the boundary of a geologic storage resource. Sedimentary basin locations were overlayed onto Priority Sites for Combined Cycle and Combustion Turbine. Priority sites were then ranked by suitability and reserved for CC+CCS resources.

MISO Expansion Results

While comparing the expansion results of the MISO footprint across each Future scenario, there are several key findings of note:

- All scenarios have relatively large amounts of gas additions; this is due to increasing amounts of coal and gas retirements and the system's need for base generation to replace retired units. CC and CT gas units emit approximately half the amount of CO_2 that coal units emit. Decarbonization and load growth allow for gas to comprise 40% of the total expansion in Future 1, while CC+CCS comprises 40% of the gas units built in Future 3's expansion, illustrating the model's need for a low-carbon, high-capacity factor proxy resource.
- Wind, solar, and hybrid resource expansion is largely driven by decarbonization and each underlying load shape. In Future 3 there is significantly more wind than the other two cases; this is primarily due to the increase in load, 80% carbon reduction, and dual peaking system.
- Battery installation is driven by increased load and decarbonization.
- Age-based retirement assumptions for nuclear, wind, solar, and "other" resources remain the same across all scenarios. Additionally, all retired wind is repowered and reflected in the resource addition totals.
- Distributed solar and energy efficiency (EE) resources are composed of both selected DER programs and specific member feedback. No demand response (DR) resources were selected in the model, but are present in the expansion due to member feedback.

Future Resource Additions (MW)												
	CC	CT	CC+CCS	Wind	Solar	Hybrid	Battery	Distributed Solar	Hydro	EE	DR	Totals
Future 1	37,126	14,094	0	18,704	34,696	12,000	600	3,475	82	7,824	939	129,540
Future 2	58,725	10,494	1,201	63,104	28,696	1,200	3,400	3,475	82	8,053	939	179,368
Future 3	41,923	17,695	42,001	123,104	28,696	10,800	35,400	6,168	82	11,722	939	318,530

Future Resource Retirements (MW)								
	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Totals
Future 1	44,827	18,627	2,359	1,996	9,223	21	36	77,089
Future 2	45,109	21,611	2,359	2,027	9,223	21	36	80,386
Future 3	46,963	51,368	2,359	2,295	9,223	21	36	112,265

Table 6: MISO Resource Additions and Retirement Totals

Figure 43 details the results from each Future scenario's resource additions as displayed in the table above. Solar resources are comprised of utility-scale solar PV, solar hybrid, and distributed solar resources. Wind totals include expansion wind units and repowered wind assumptions. The other resource categorey includes energy efficiency and demand side management programs selected within each future. Gas resources include both CC and CT units for Futures 1, while Future 2 and 3 additionally include CC+CCS expansion units. In Future 3, the CC+CCS resource proxy units (42 GW) are needed in the later years of the study period to serve base load with low CO_2 emissions.

Over the course of the following pages (Figure 44 through Table 12) the detailed expansion results of each Future scenario and the siting locations are displayed. Following the figures in each section are resource-specific additons and retirement (R&A) tables; each table details R&A capacities applicable for each LRZ and MISO per milestone year.

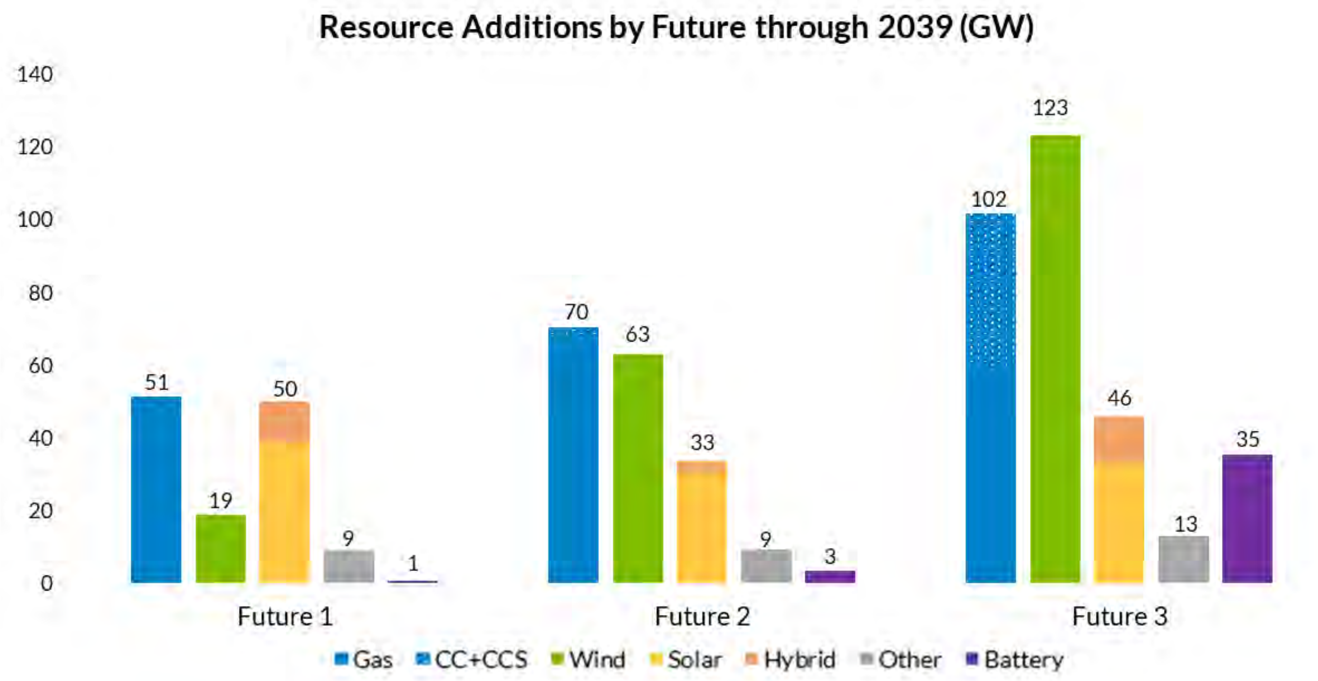


Figure 43: MISO Resource Addition Summary by Future

MISO – Future 1

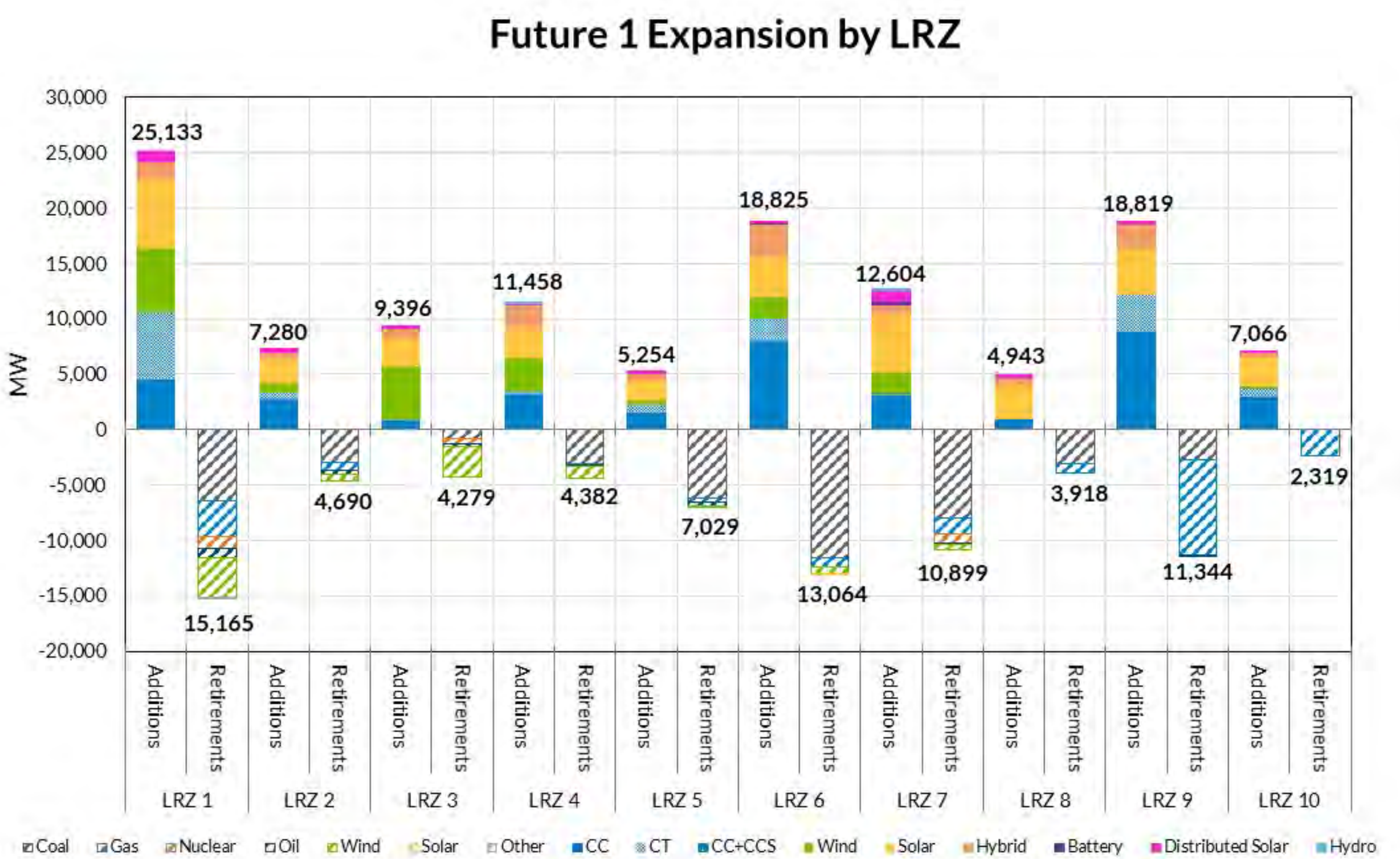


Figure 44: MISO Future 1 Resource Retirement and Addition Summary

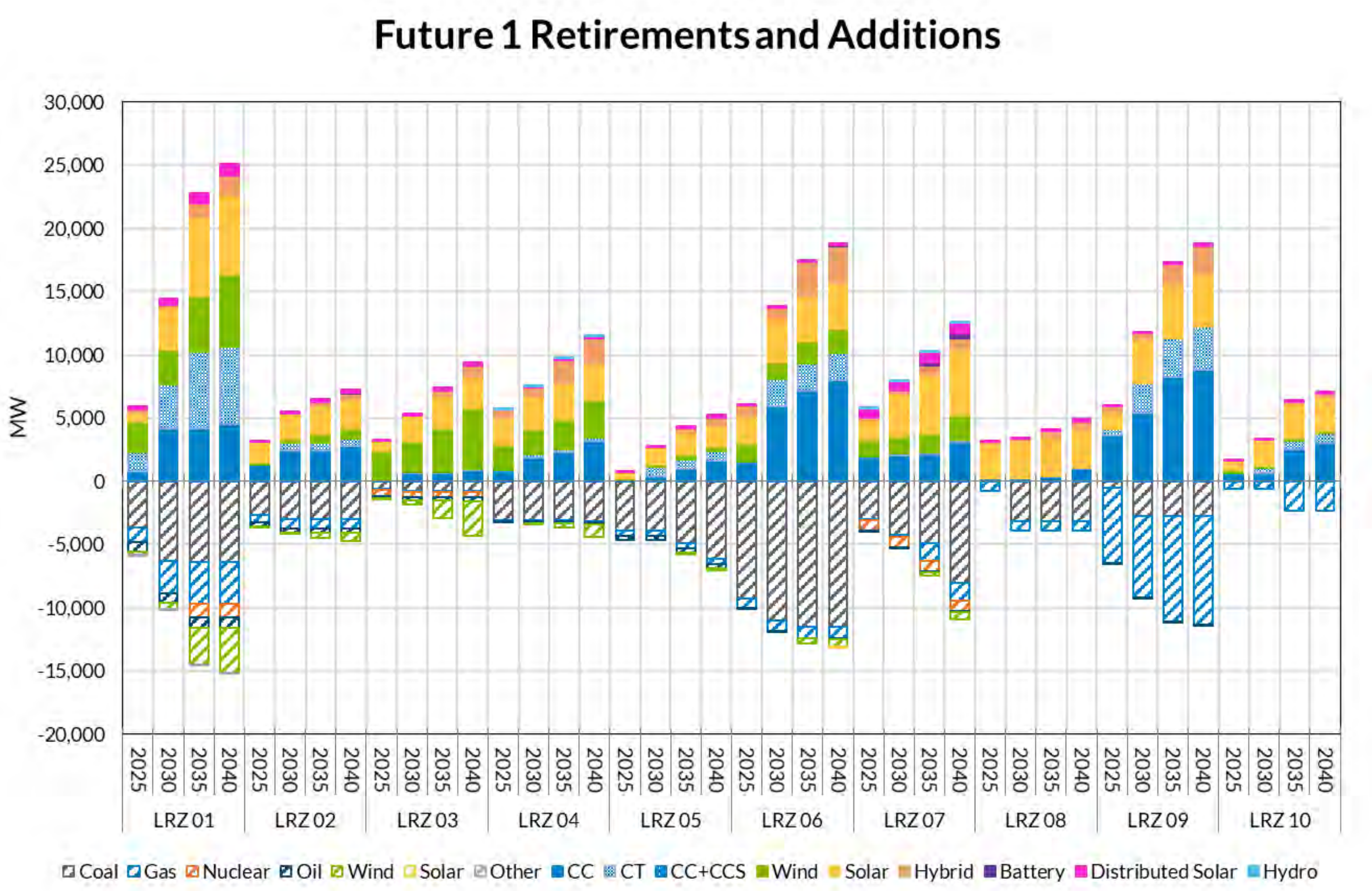


Figure 45: Future 1 Resource Additions per Milestone Year (Cumulative)

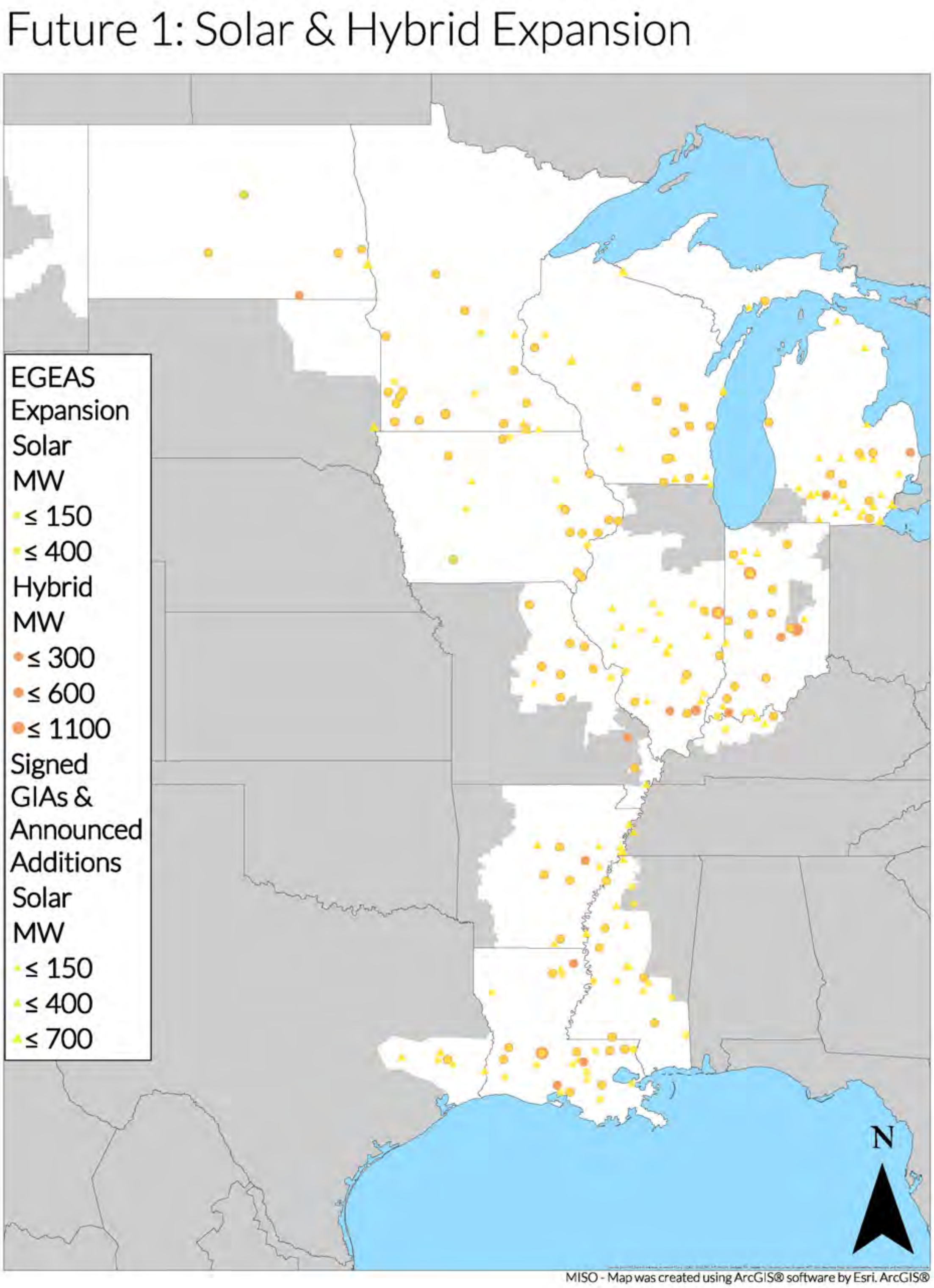


Figure 46: MISO Future 1 Solar and Hybrid Siting

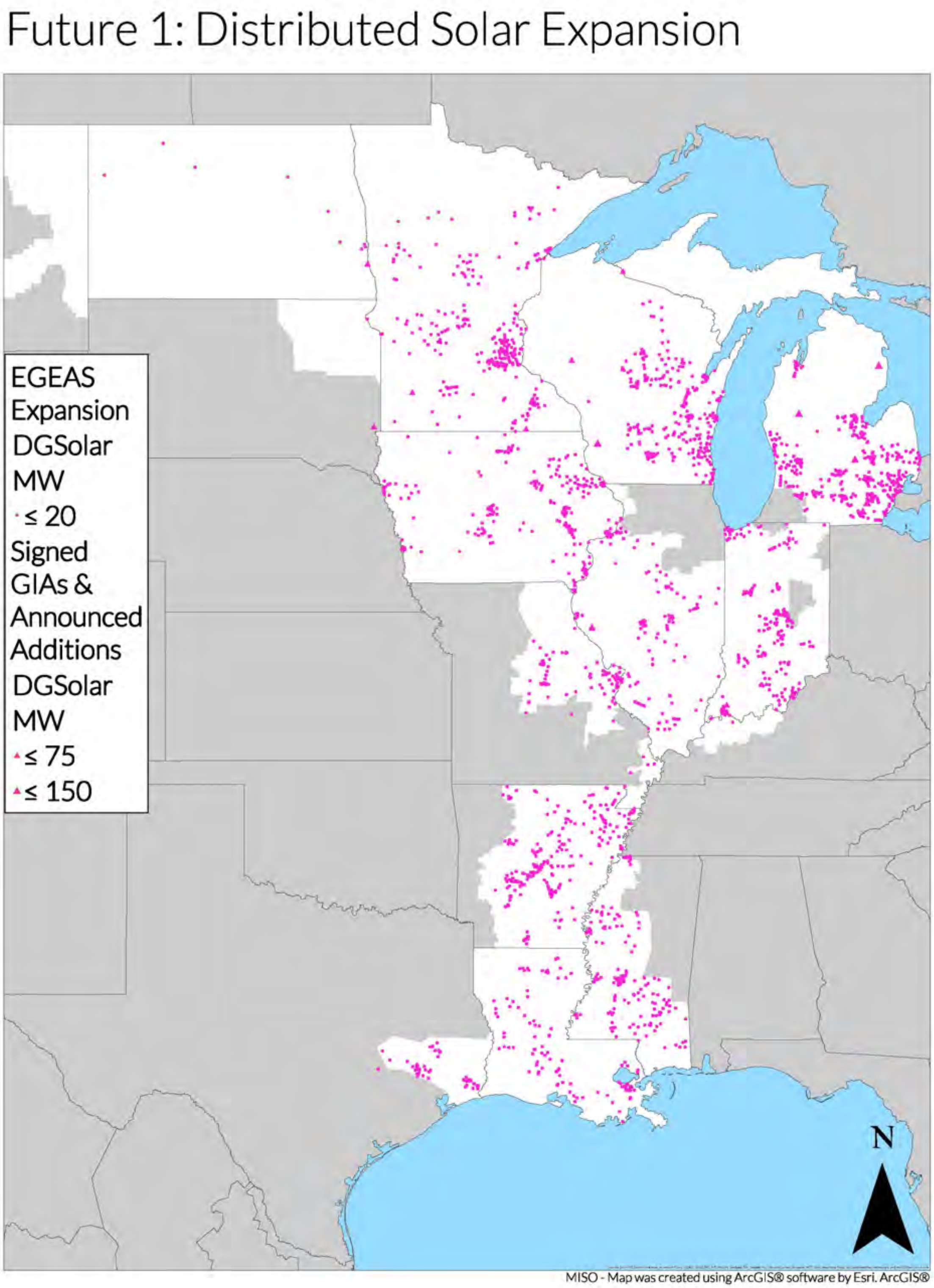


Figure 47: MISO Future 1 Distributed Solar Siting

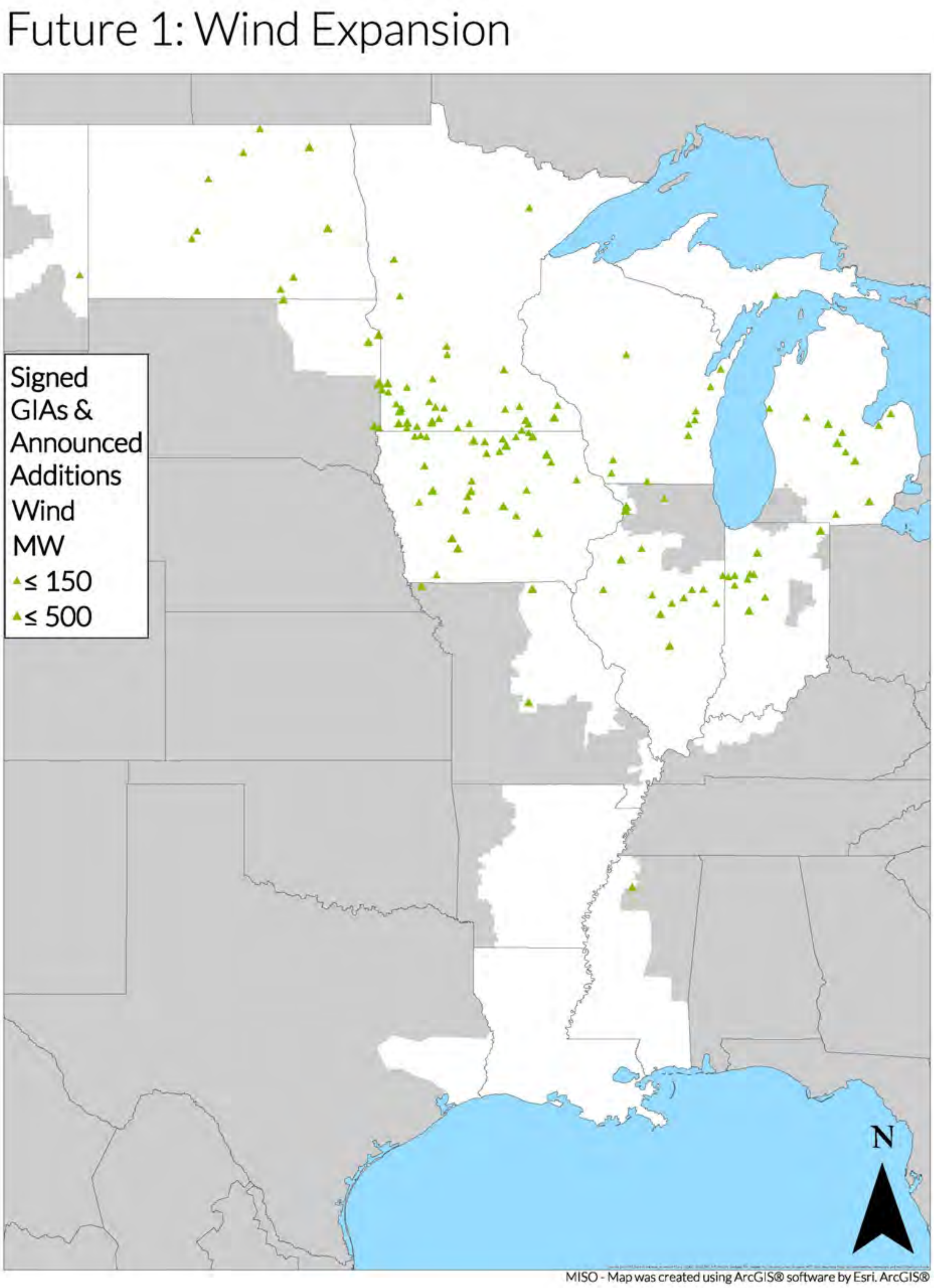


Figure 48: MISO Future 1 Wind Siting

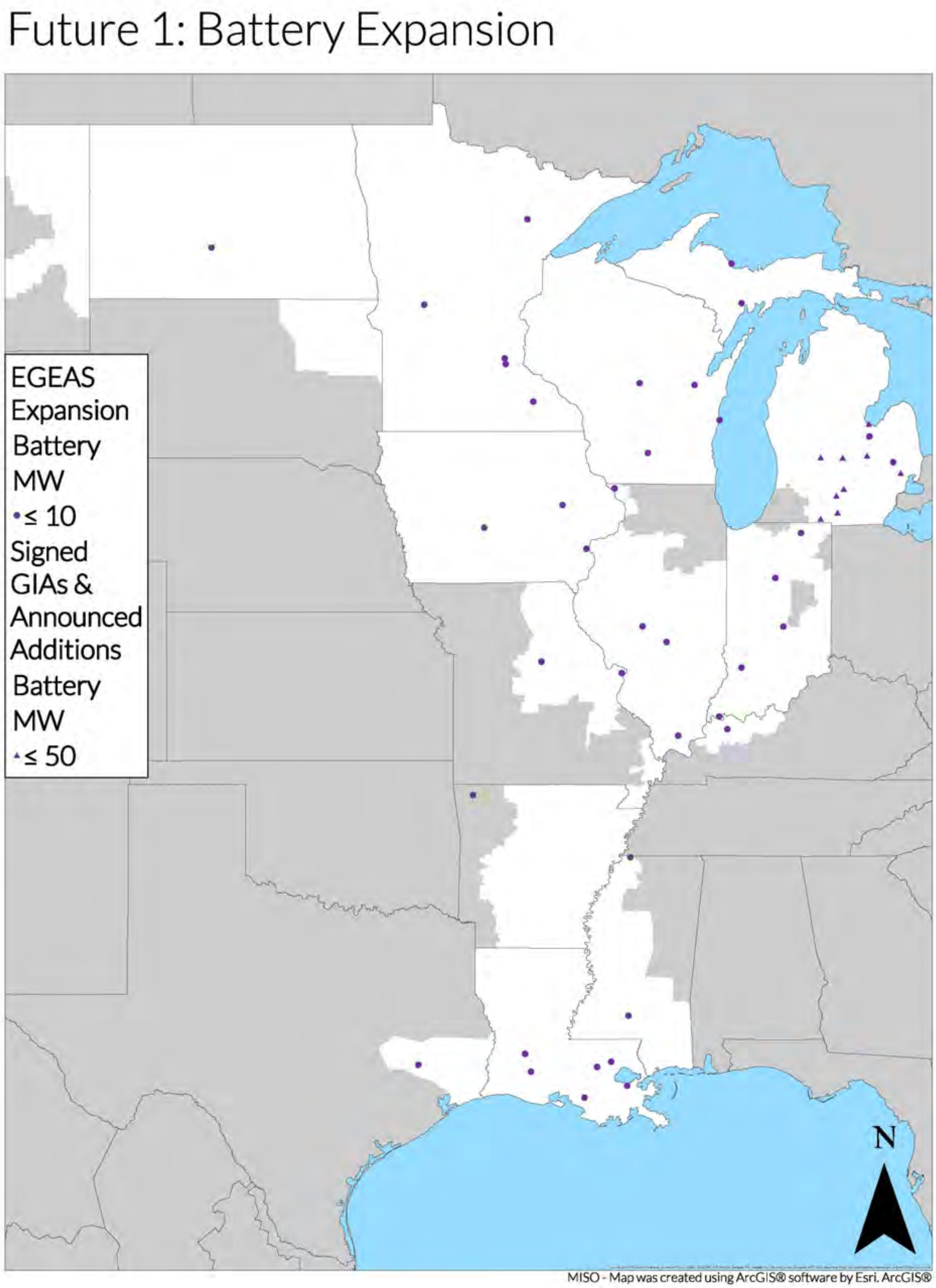


Figure 49: MISO Future 1 Battery Siting

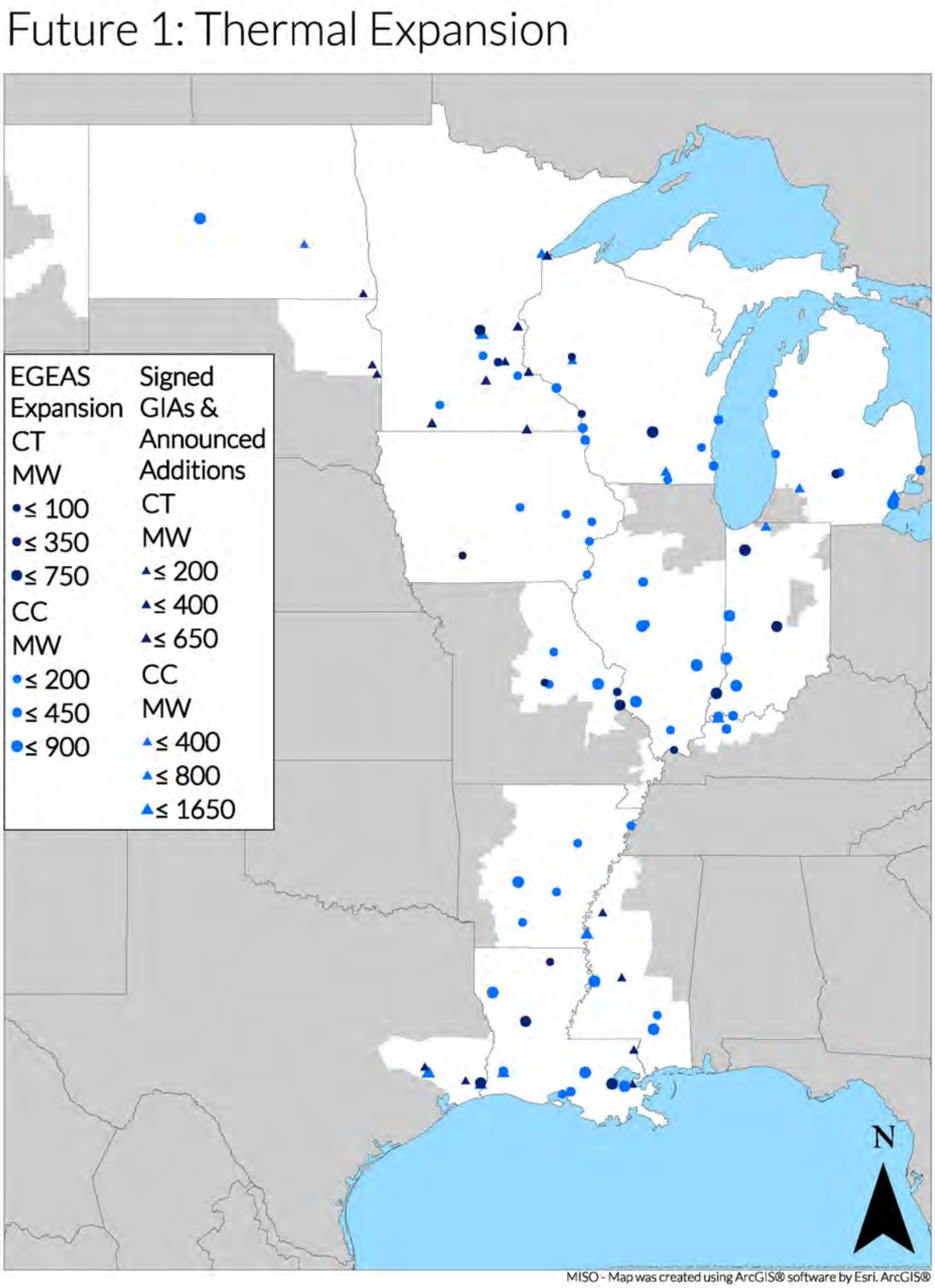


Figure 50: MISO Future 1 Thermal Siting

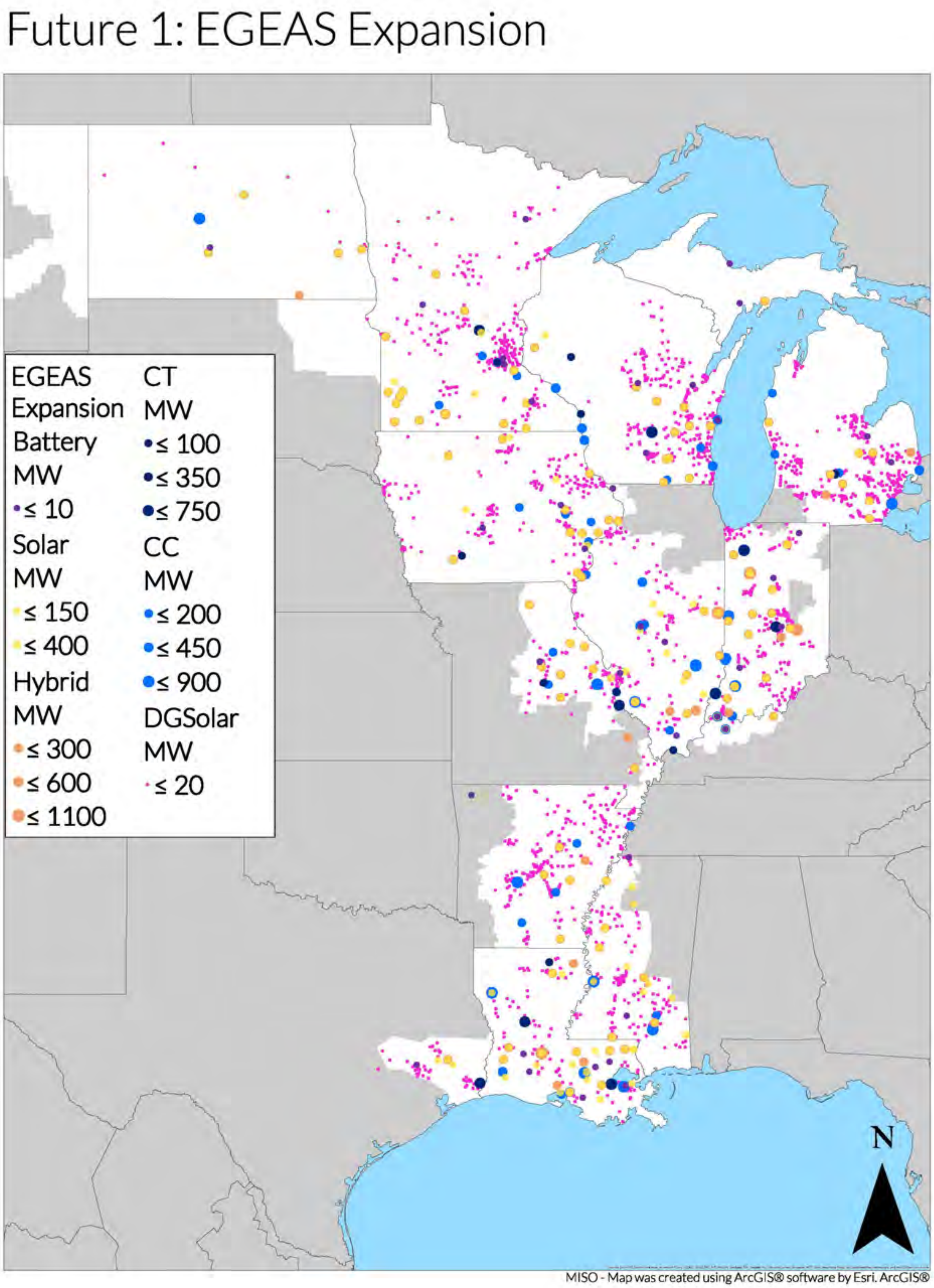


Figure 51: MISO Future 1 Complete EGEAS Expansion Siting

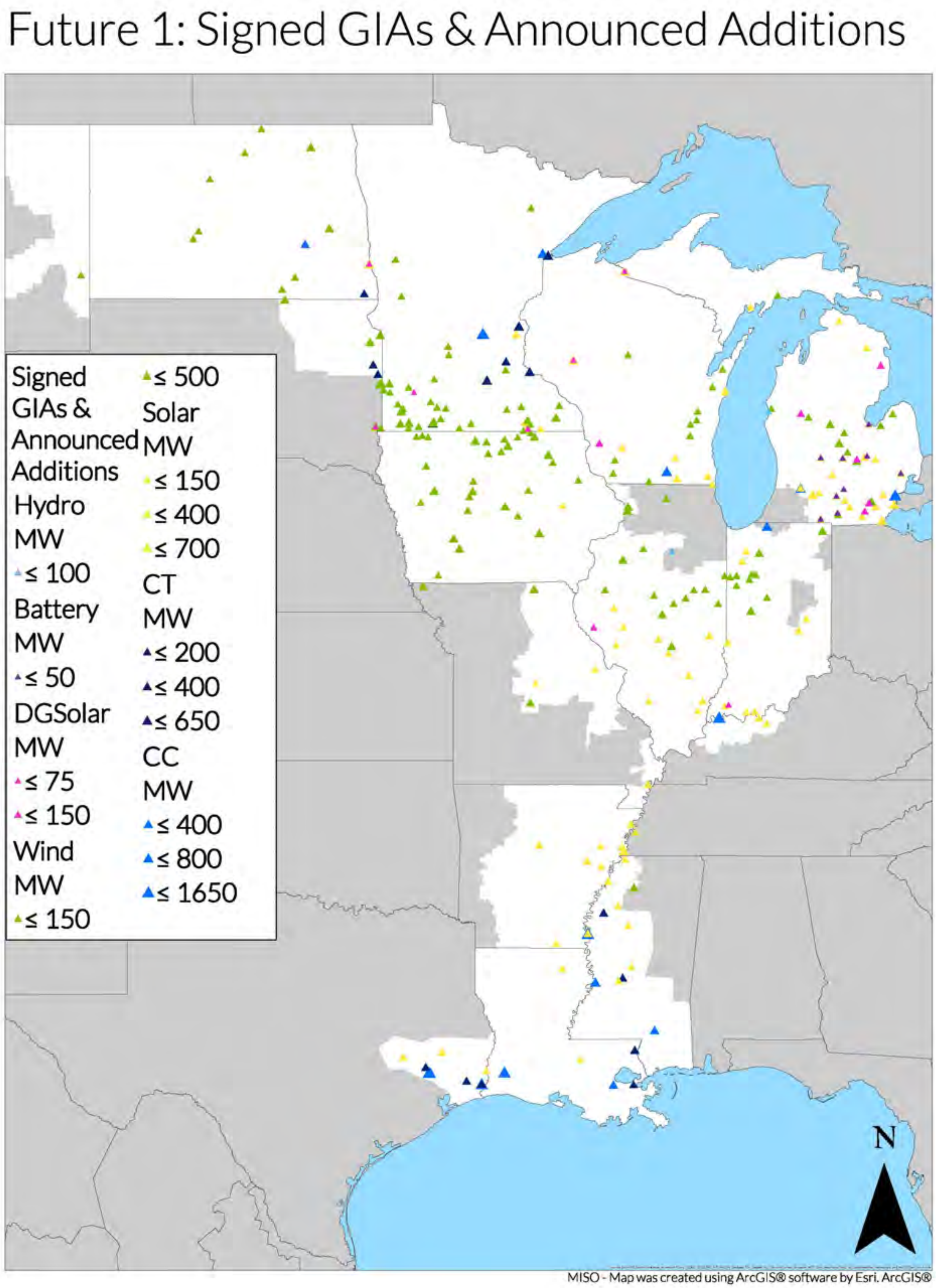


Figure 52: MISO Future 1 Non-EGEAS Expansion Siting

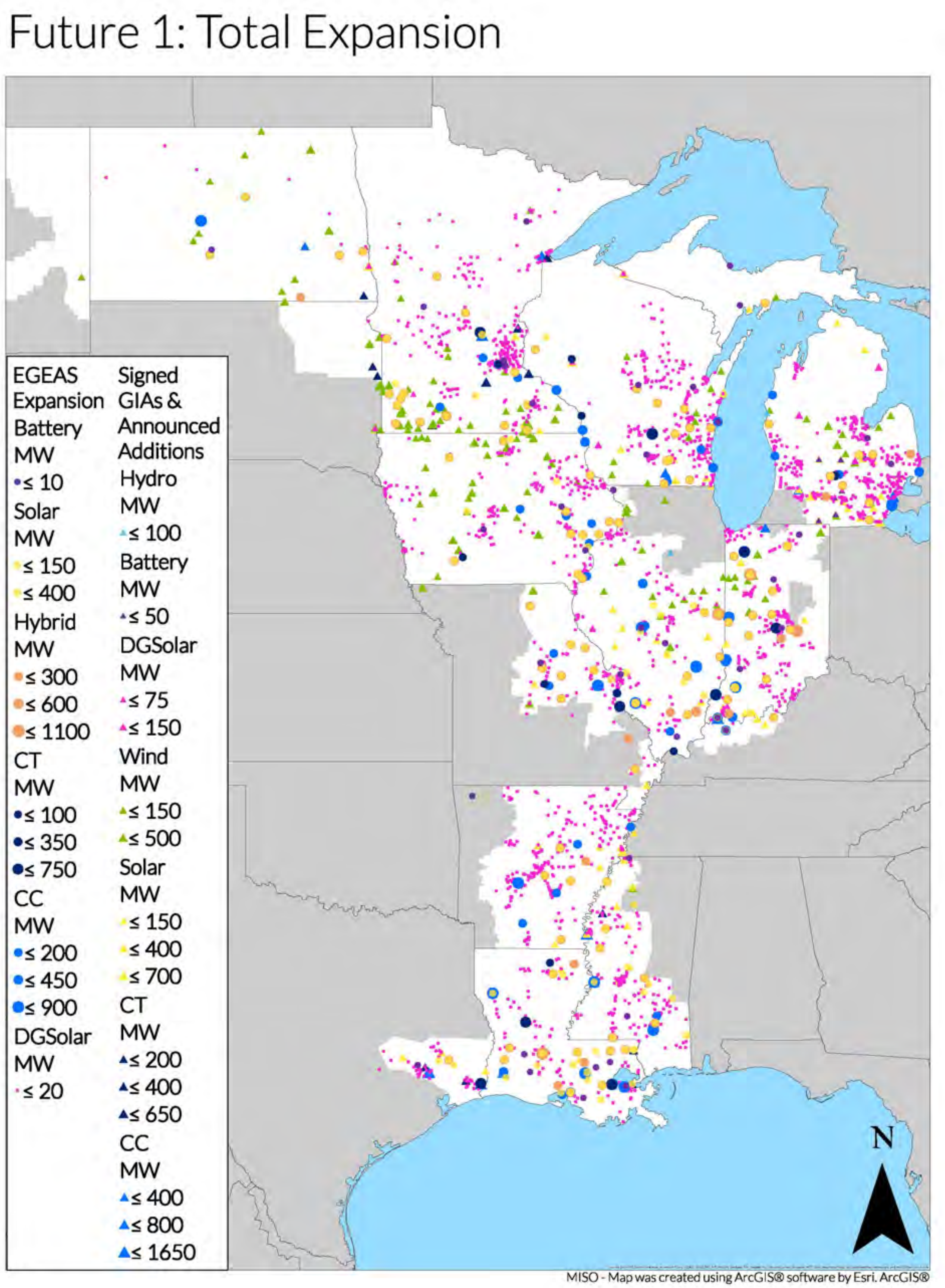


Figure 53: MISO Future 1 Non-EGEAS and EGEAS Expansion Siting

Future 1 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	850	1,453	0	2,402	771	198	0	283	0	5,957
	2030	4,171	3,520	0	2,669	3,384	198	0	499	0	14,442
	2035	4,171	6,088	0	4,379	6,225	1,129	0	772	0	22,764
	2039	4,560	6,088	0	5,734	6,225	1,547	36	942	0	25,133
LRZ 2	**2025**	1,268	0	0	240	1,585	0	0	38	0	3,131
	2030	2,432	572	0	270	2,099	0	0	122	0	5,495
	2035	2,484	572	0	636	2,304	242	0	246	0	6,484
	2039	2,795	572	0	846	2,304	422	30	311	0	7,280
LRZ 3	**2025**	150	0	0	2,198	875	0	0	33	0	3,256
	2030	608	92	0	2,424	2,103	0	0	104	0	5,331
	2035	608	92	0	3,510	2,522	475	0	210	0	7,417
	2039	881	92	0	4,783	2,522	838	15	265	0	9,396
LRZ 4	**2025**	900	0	0	1,966	2,152	628	0	52	10	5,709
	2030	1,868	240	0	1,986	2,693	628	0	80	10	7,504
	2035	2,285	240	0	2,345	2,871	1,839	0	120	10	9,710
	2039	3,231	240	0	2,979	2,871	1,971	15	141	10	11,458
LRZ 5	**2025**	64	0	0	200	500	0	0	25	0	789
	2030	382	747	0	200	1,381	0	0	80	0	2,790
	2035	979	747	0	369	1,755	322	0	162	0	4,333
	2039	1,596	747	0	369	1,768	560	10	205	0	5,254
LRZ 6	**2025**	1,594	0	0	1,325	2,282	853	0	69	0	6,123
	2030	5,956	2,136	0	1,325	3,466	853	0	103	0	13,839
	2035	7,189	2,136	0	1,702	3,685	2,626	0	153	0	17,491
	2039	7,989	2,136	0	1,907	3,685	2,899	30	179	0	18,825
LRZ 7	**2025**	1,954	0	0	1,322	1,550	189	0	749	72	5,835
	2030	2,051	153	0	1,322	3,421	189	0	781	72	7,988
	2035	2,116	153	0	1,551	4,715	638	200	829	72	10,274
	2039	3,156	153	0	1,887	5,315	755	412	854	72	12,604
LRZ 8	**2025**	250	0	0	0	2,688	155	0	26	0	3,119
	2030	250	0	0	0	2,985	155	0	83	0	3,473
	2035	384	0	0	0	3,059	536	0	168	0	4,147
	2039	1,038	0	0	0	3,059	628	5	212	0	4,943
LRZ 9	**2025**	3,601	493	0	0	1,465	378	0	28	0	5,965
	2030	5,439	2,328	0	0	3,540	378	0	91	0	11,776
	2035	8,287	3,020	0	0	4,238	1,640	0	184	0	17,369
	2039	8,833	3,366	0	0	4,238	2,113	37	232	0	18,819
LRZ 10	**2025**	672	0	0	200	730	0	0	16	0	1,619
	2030	672	350	0	200	2,070	0	0	52	0	3,345
	2035	2,531	700	0	200	2,709	153	0	106	0	6,399
	2039	3,046	700	0	200	2,709	267	10	134	0	7,066
MISO Total	**2025**	11,303	1,946	0	9,853	14,600	2,400	0	1,320	82	41,504
	2030	23,829	10,138	0	10,396	27,144	2,400	0	1,995	82	75,984
	2035	31,035	13,748	0	14,691	34,082	9,600	200	2,950	82	106,388
	2039	37,126	14,094	0	18,704	34,696	12,000	600	3,475	82	120,777

Table 7: MISO Future 1 Resource Additions by LRZ and Footprint

Future 1 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	3,619	1,214	0	698	240	0	36	5,807
	2030	6,303	2,567	0	698	519	0	36	10,123
	2035	6,413	3,281	1,092	771	2,946	0	36	14,539
	2039	6,413	3,281	1,092	771	3,572	0	36	15,165
LRZ 2	**2025**	2,650	599	0	351	11	0	0	3,611
	2030	2,981	736	0	351	41	0	0	4,109
	2035	2,981	741	0	351	427	0	0	4,500
	2039	2,981	741	0	351	617	0	0	4,690
LRZ 3	**2025**	596	92	448	196	122	0	0	1,454
	2030	757	92	448	196	348	0	0	1,841
	2035	757	92	448	196	1,434	0	0	2,927
	2039	757	92	448	275	2,707	0	0	4,279
LRZ 4	**2025**	3,056	134	0	90	0	0	0	3,281
	2030	3,056	134	0	117	20	0	0	3,327
	2035	3,056	134	0	117	379	0	0	3,686
	2039	3,118	134	0	117	1,013	0	0	4,382
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	384	0	345	169	0	0	5,796
	2039	6,132	384	0	345	169	0	0	7,029
LRZ 6	**2025**	9,268	788	0	50	0	0	0	10,106
	2030	11,002	853	0	50	0	0	0	11,905
	2035	11,537	853	0	50	377	0	0	12,816
	2039	11,537	853	0	71	582	21	0	13,064
LRZ 7	**2025**	2,956	155	819	45	0	0	0	3,974
	2030	4,223	161	819	59	0	0	0	5,261
	2035	4,878	1,444	819	59	230	0	0	7,429
	2039	8,013	1,444	819	59	565	0	0	10,899
LRZ 8	**2025**	0	788	0	0	0	0	0	788
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	788	0	0	0	0	0	3,918
	2039	3,130	788	0	0	0	0	0	3,918
LRZ 9	**2025**	515	5,919	0	7	0	0	0	6,441
	2030	2,746	6,438	0	7	0	0	0	9,191
	2035	2,746	8,361	0	7	0	0	0	11,114
	2039	2,746	8,591	0	7	0	0	0	11,344
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	2,319	0	0	0	0	0	2,319
	2039	0	2,319	0	0	0	0	0	2,319
MISO Total	**2025**	26,553	10,648	1,267	1,782	373	0	36	40,658
	2030	38,091	12,727	1,267	1,822	928	0	36	54,871
	2035	40,397	18,397	2,359	1,896	5,960	0	36	69,044
	2039	44,827	18,627	2,359	1,996	9,223	21	36	77,089

Table 8: MISO Future 1 Resource Retirements by LRZ and Footprint

MISO – Future 2

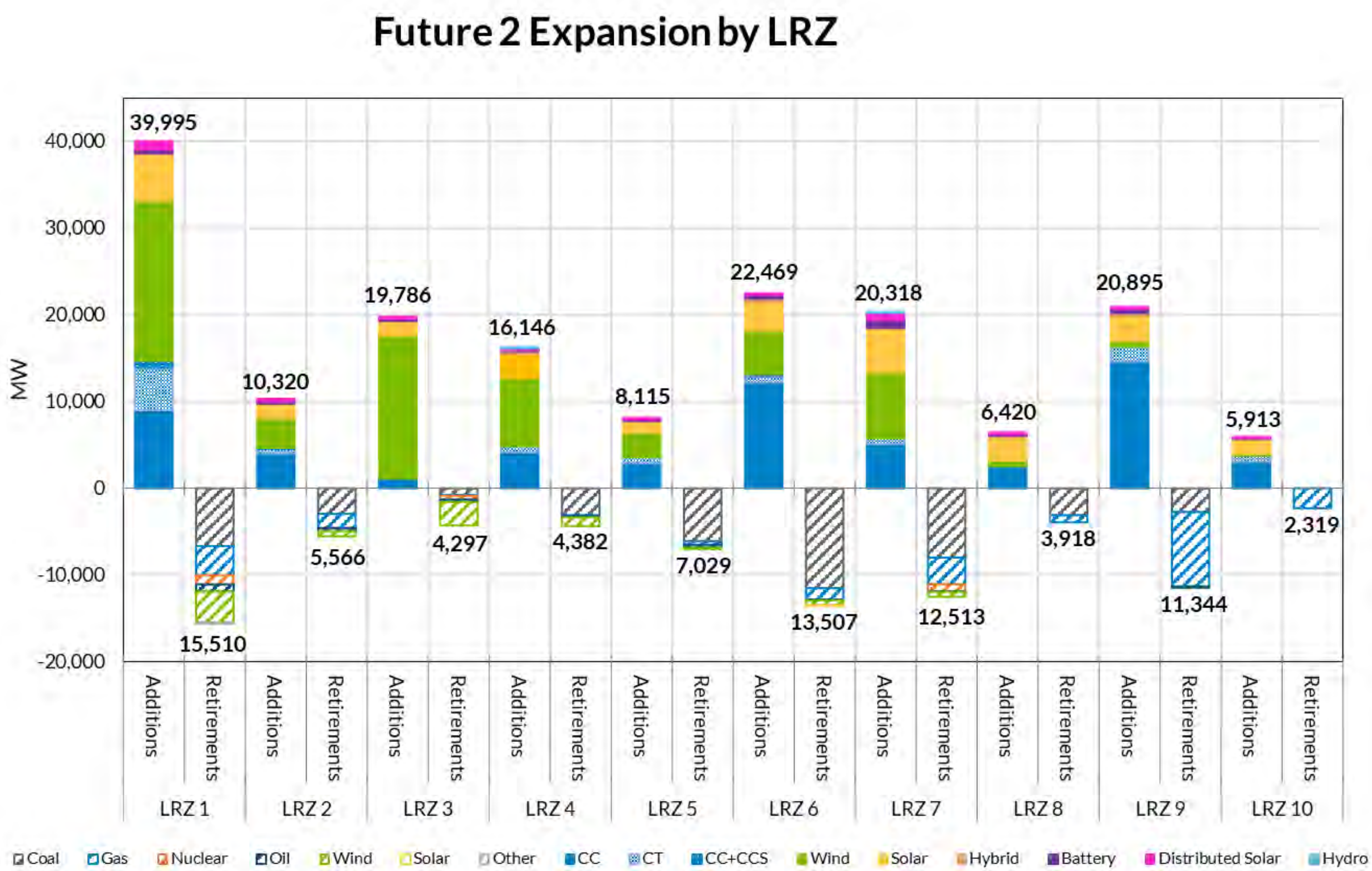


Figure 54: MISO Future 2 Resource Retirement and Addition Summary

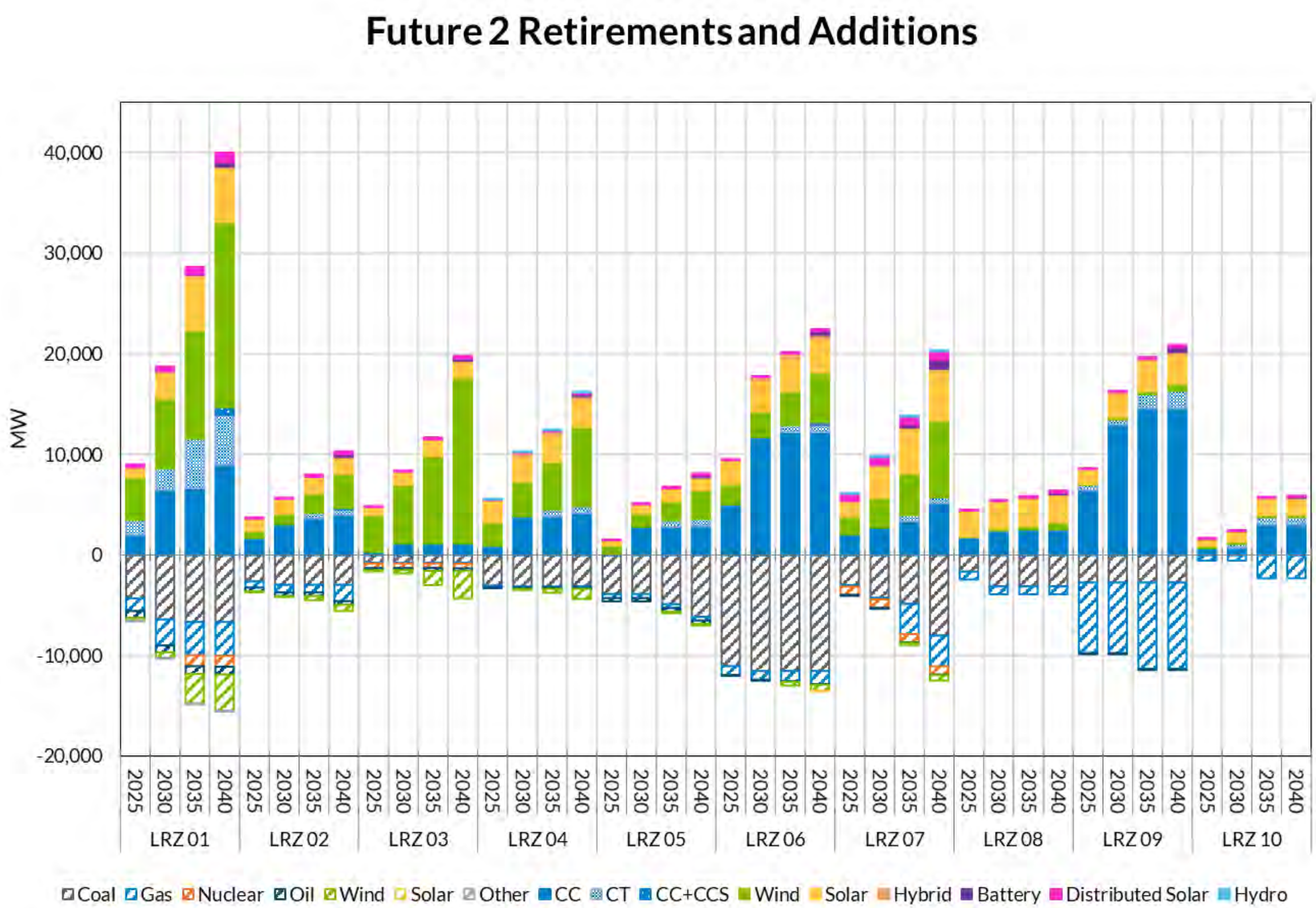


Figure 55: MISO Future 2 Resource Additions per Milestone Year (Cumulative)

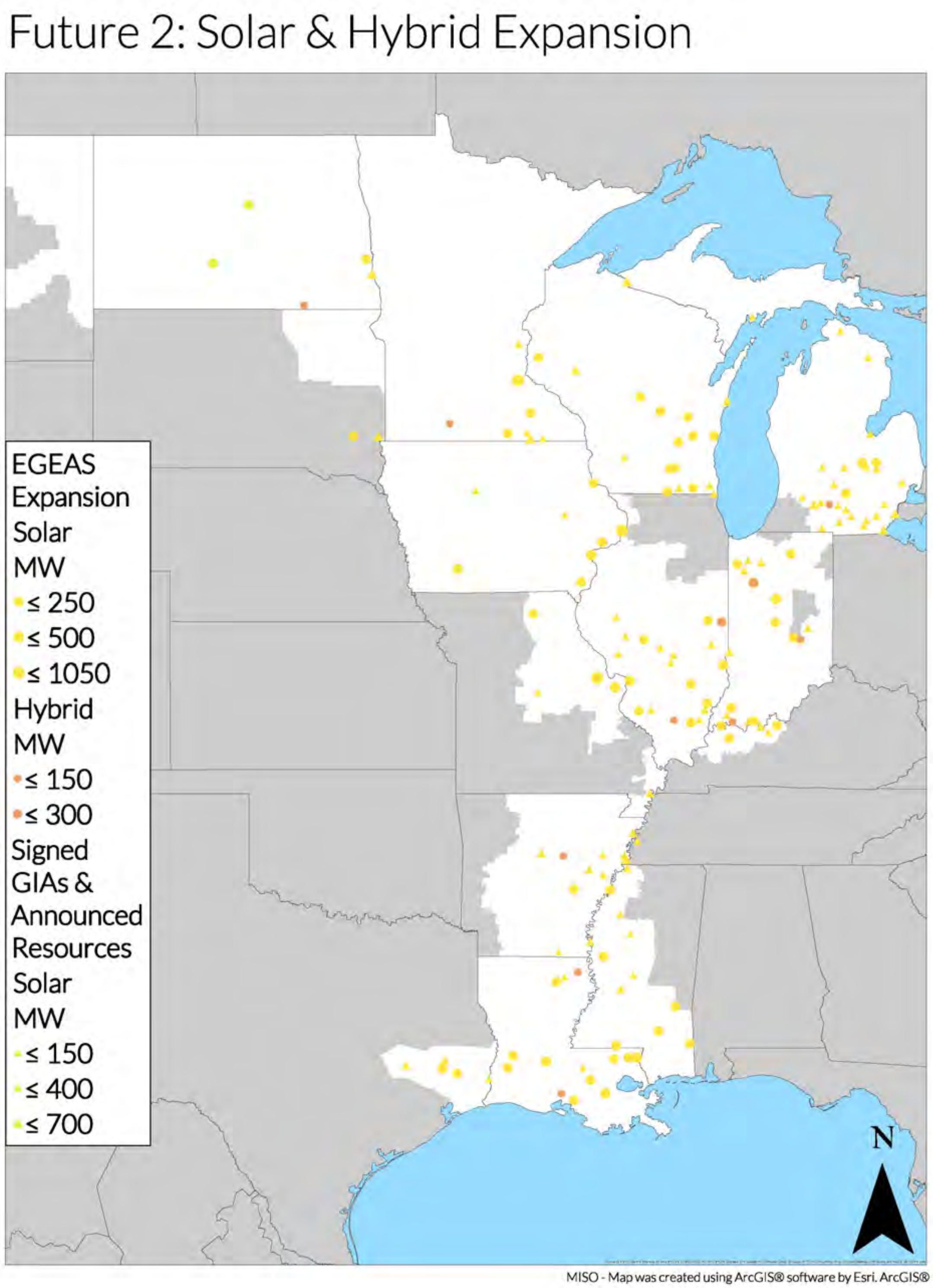


Figure 56: MISO Future 2 Solar and Hybrid Siting

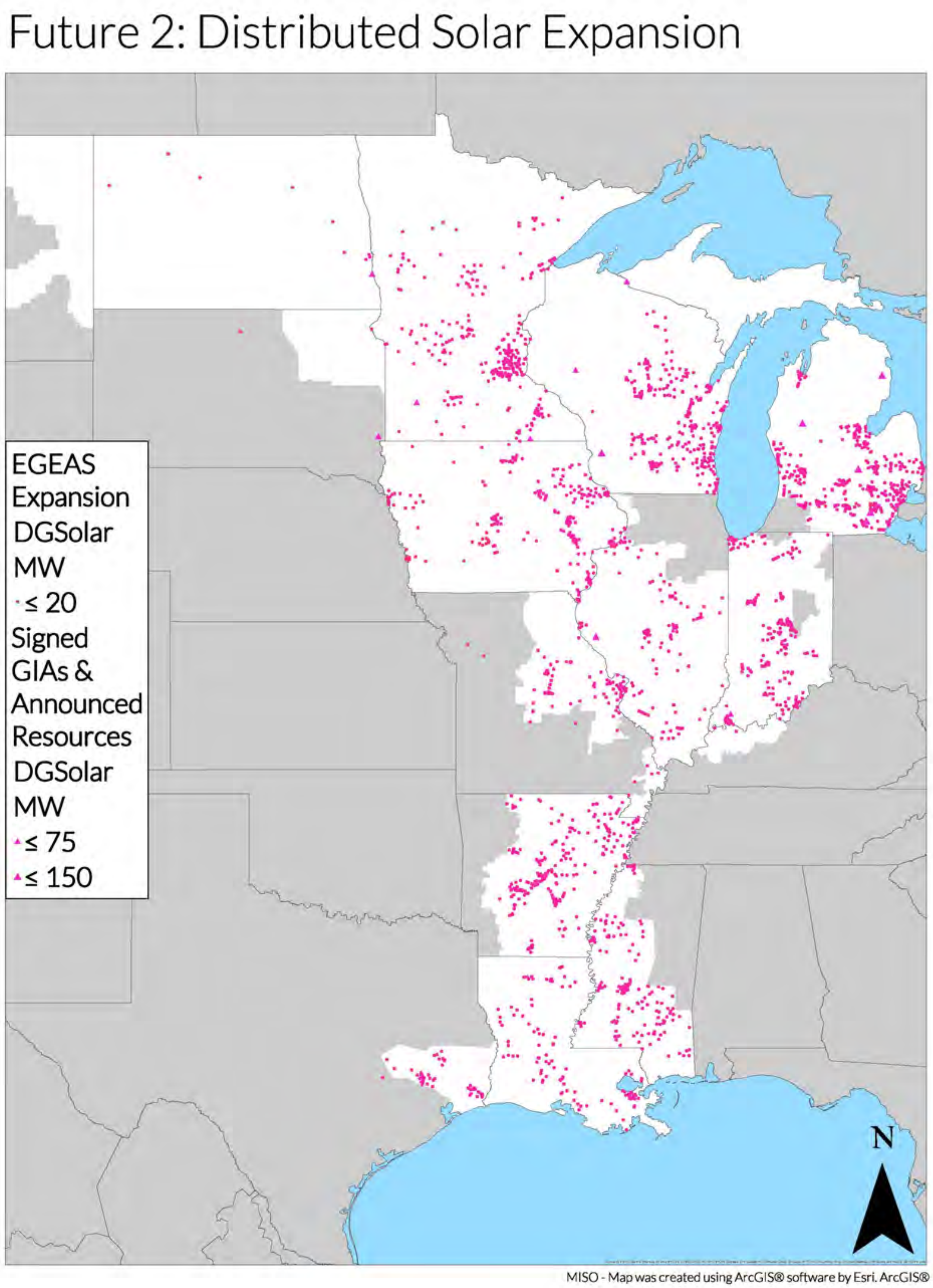


Figure 57: MISO Future 2 Distributed Solar Siting

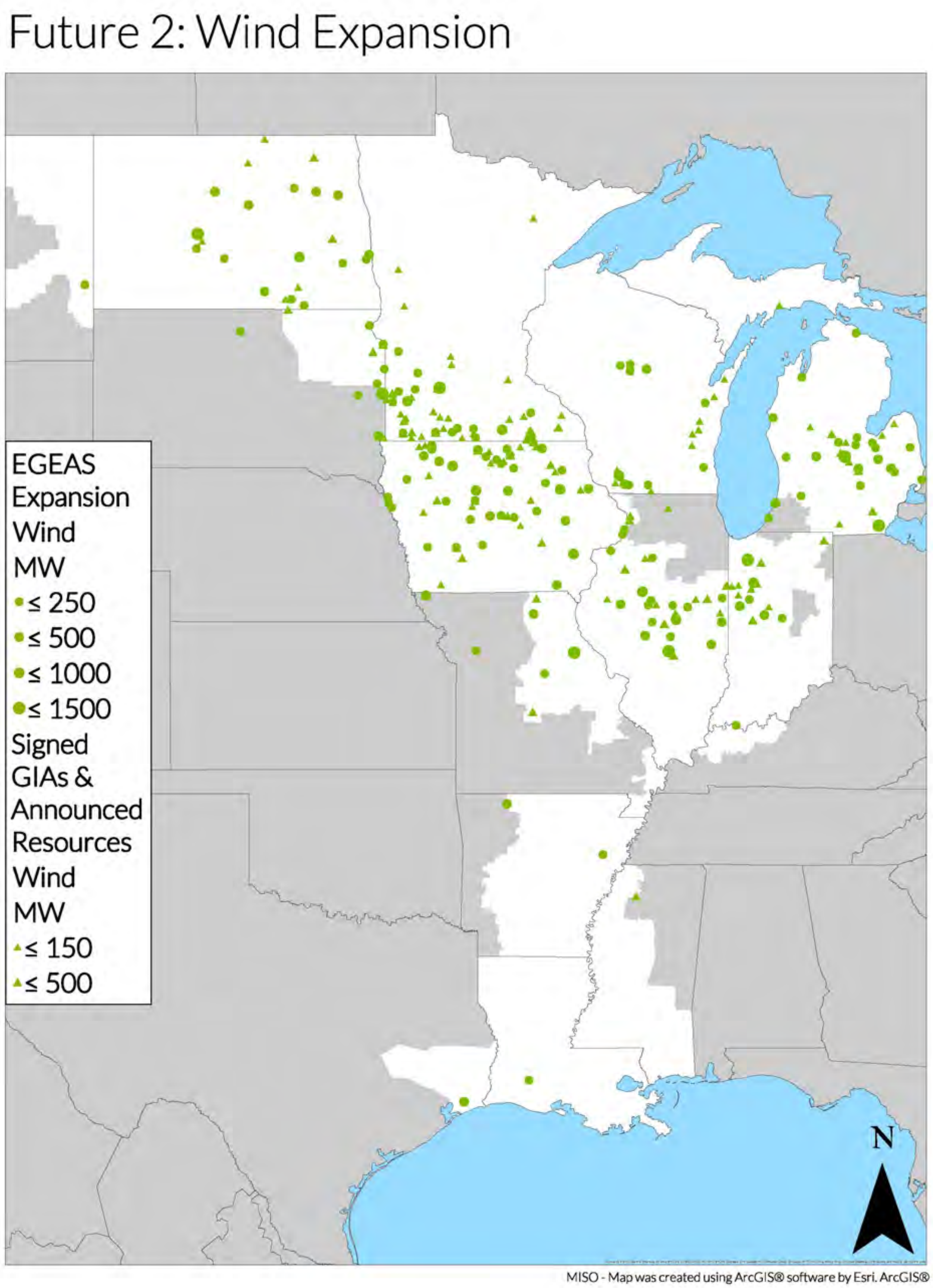


Figure 58: MISO Future 2 Wind Siting

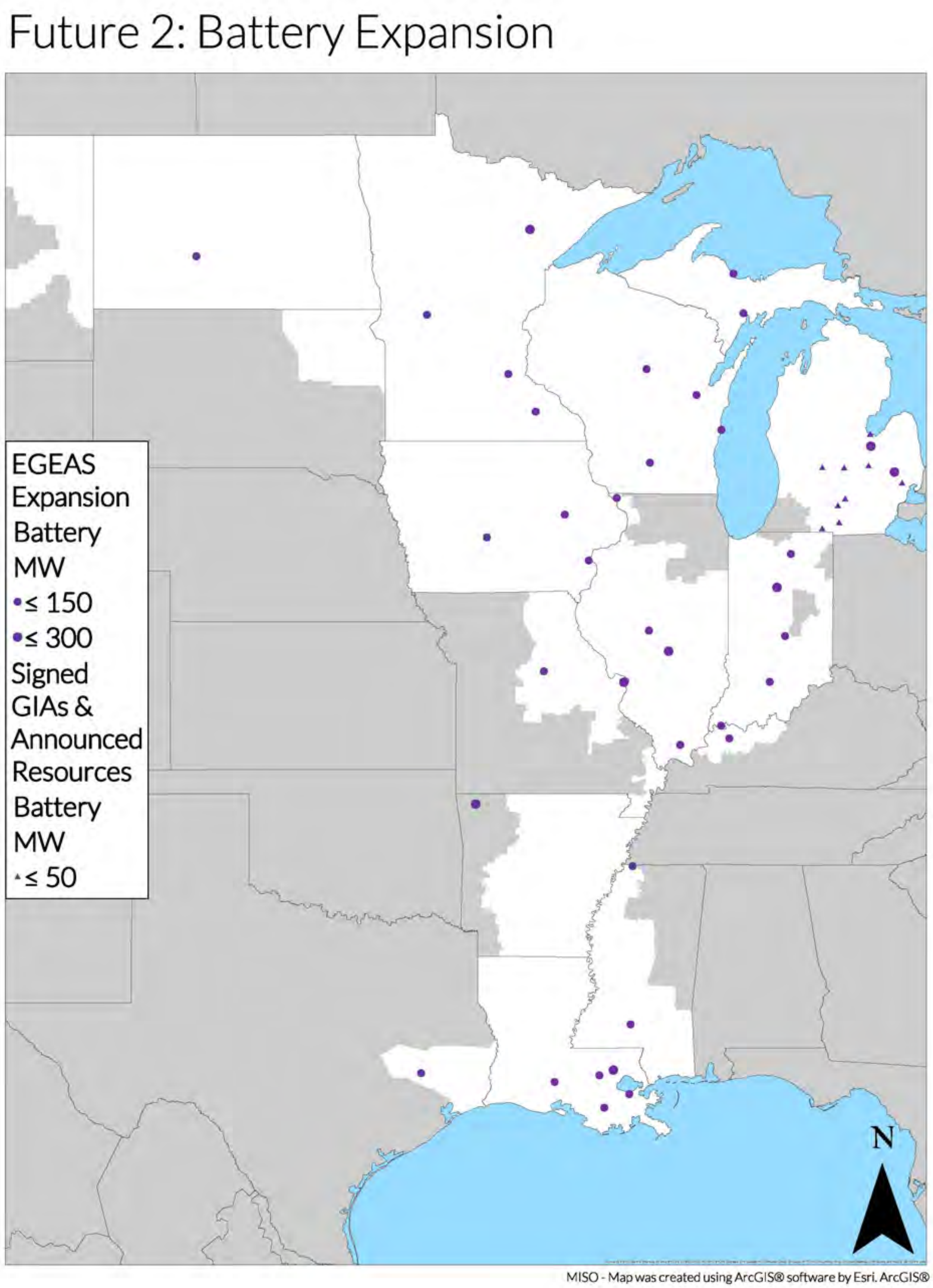


Figure 59: MISO Future 2 Battery Siting

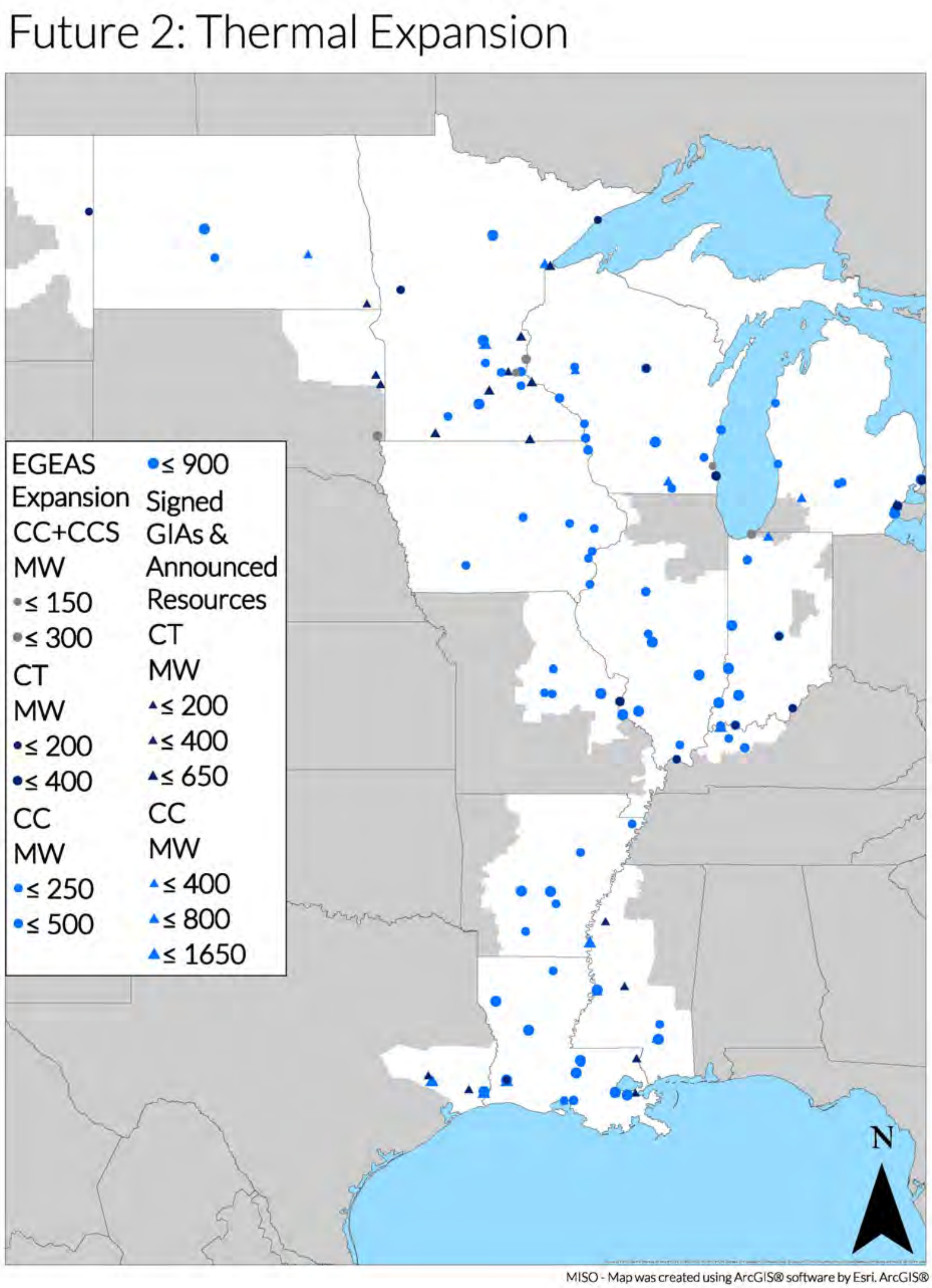


Figure 60: MISO Future 2 Thermal Siting

Future 2: EGEAS Expansion

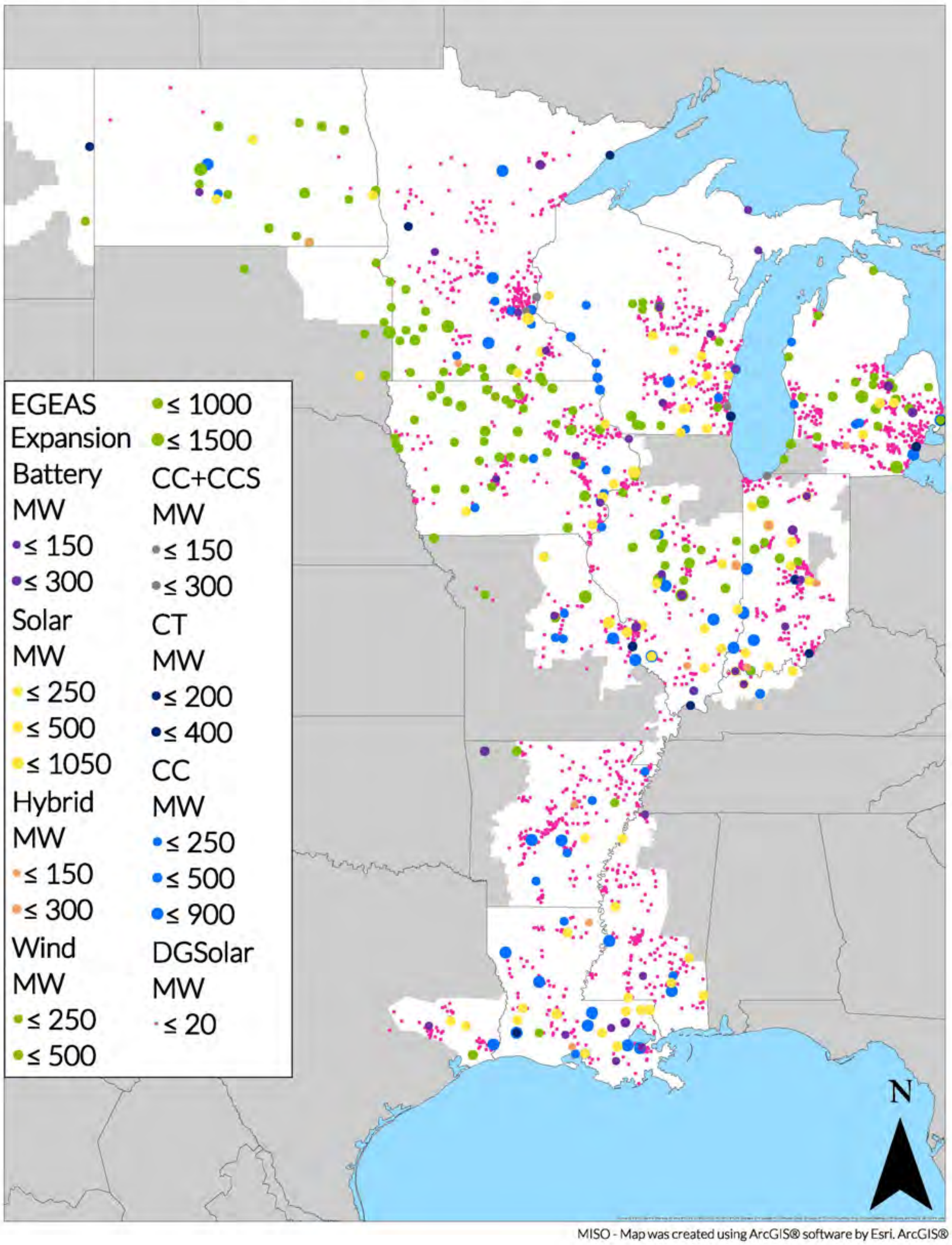


Figure 61: MISO Future 2 Complete EGEAS Expansion Siting

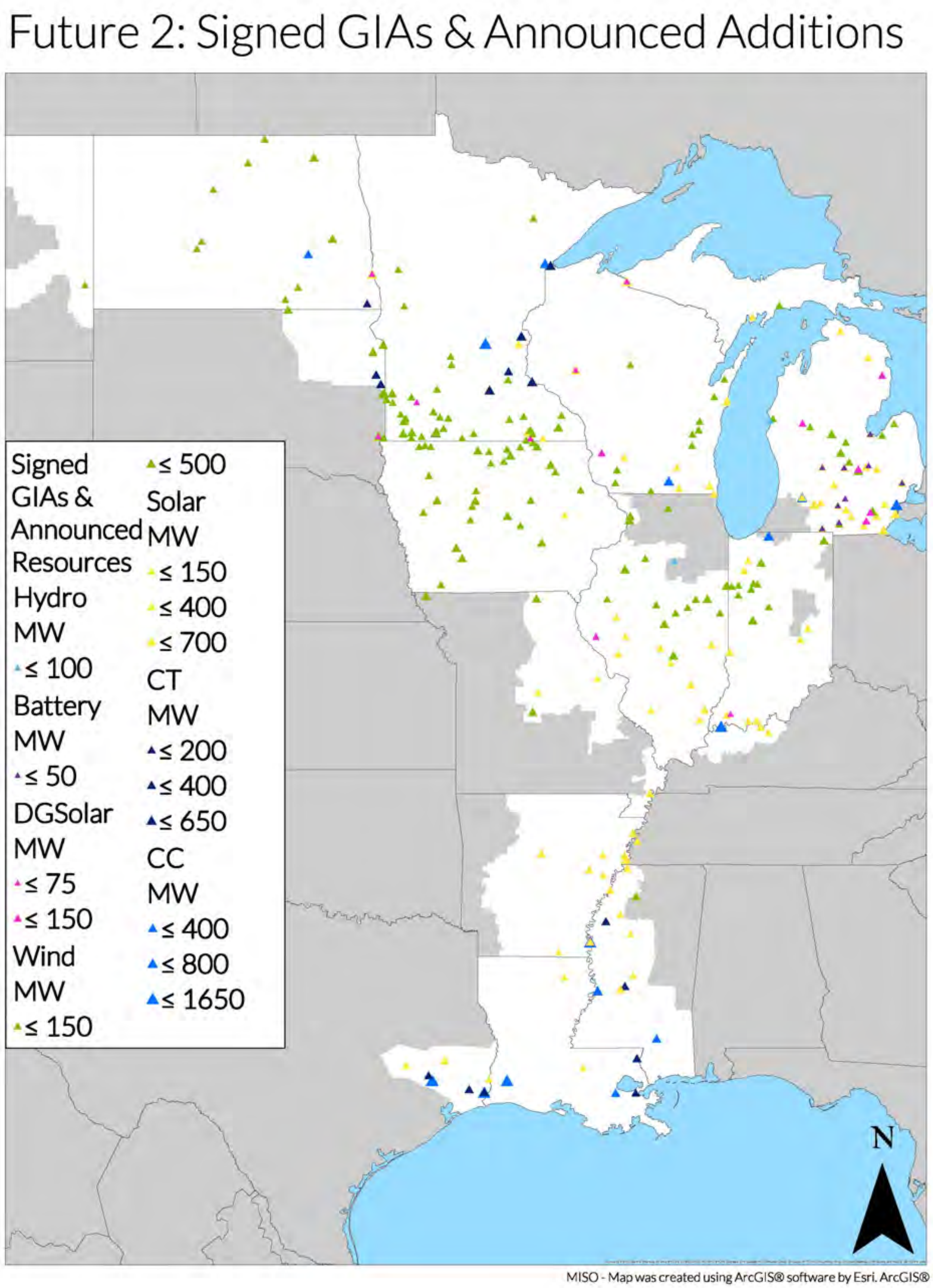


Figure 62: MISO Future 2 Non-EGEAS Expansion Siting

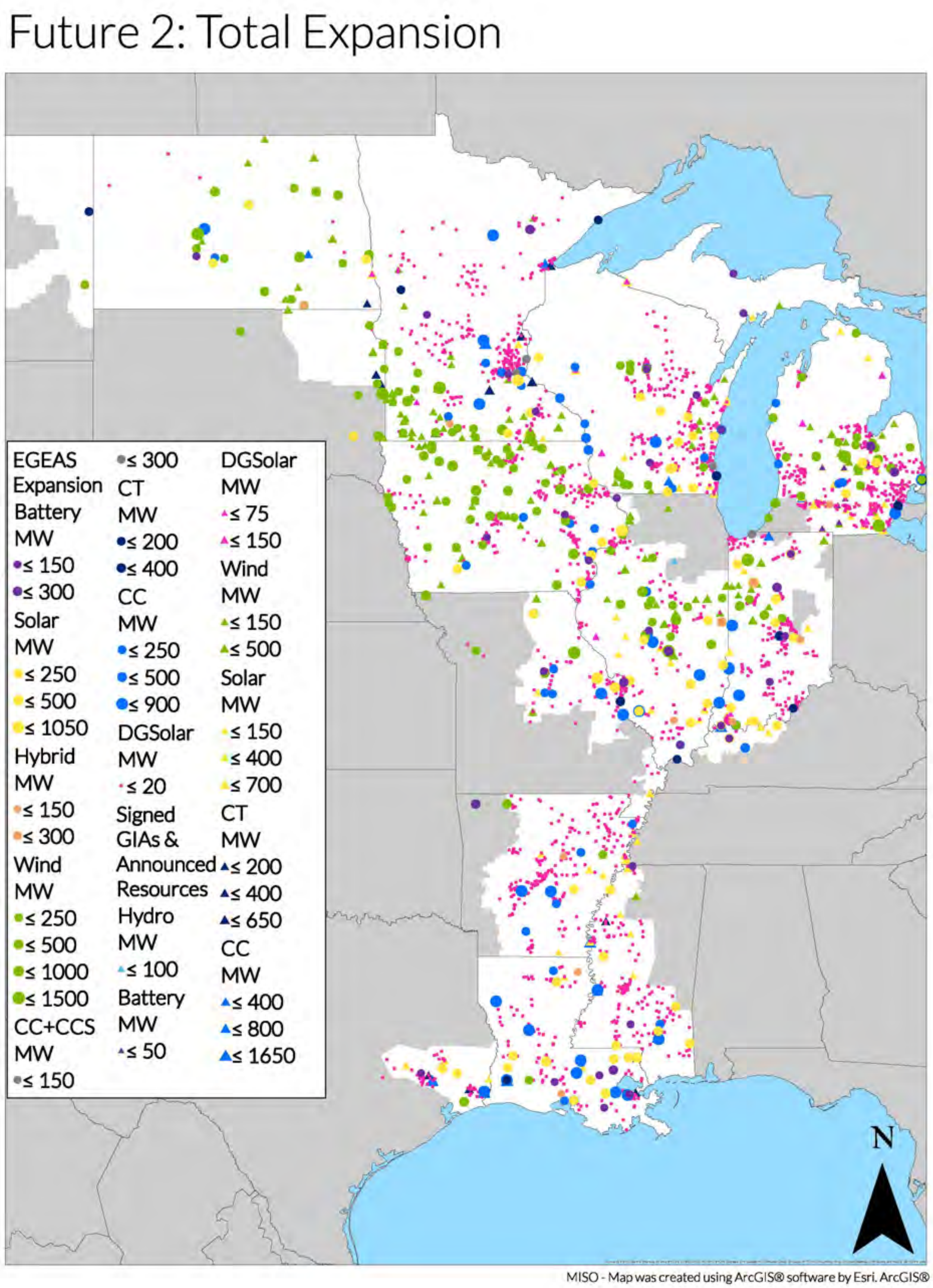


Figure 63: MISO Future 2 Non-EGEAS and EGEAS Expansion Siting

Future 2 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	2,020	1,453	0	4,219	1,032	0	0	283	0	9,007
	2030	6,491	2,095	0	7,006	2,550	99	0	499	0	18,740
	2035	6,641	4,928	0	10,797	5,380	99	33	772	0	28,650
	2039	8,986	4,928	774	18,435	5,380	99	451	942	0	39,995
LRZ 2	**2025**	1,686	0	0	657	1,270	0	0	38	0	3,650
	2030	3,056	0	0	1,041	1,471	0	0	122	0	5,689
	2035	3,673	511	0	1,903	1,680	0	0	246	0	8,012
	2039	4,004	511	138	3,408	1,680	0	268	311	0	10,320
LRZ 3	**2025**	311	0	0	3,630	821	0	0	34	0	4,796
	2030	1,134	0	0	5,850	1,295	0	0	109	0	8,388
	2035	1,134	0	0	8,682	1,666	0	0	220	0	11,701
	2039	1,134	0	0	16,484	1,666	0	224	277	0	19,786
LRZ 4	**2025**	900	0	0	2,328	2,225	0	0	51	10	5,514
	2030	3,850	0	0	3,424	2,557	314	0	75	10	10,230
	2035	3,850	668	0	4,671	2,771	314	0	111	10	12,396
	2039	4,184	668	0	7,862	2,771	314	207	129	10	16,146
LRZ 5	**2025**	64	0	0	881	498	0	0	25	0	1,468
	2030	2,783	0	0	1,358	901	0	0	80	0	5,122
	2035	2,783	660	0	1,905	1,273	0	0	162	0	6,783
	2039	2,909	660	0	2,879	1,287	0	174	205	0	8,115
LRZ 6	**2025**	5,009	0	0	2,002	2,410	0	0	69	0	9,490
	2030	11,699	0	0	2,552	3,027	426	0	103	0	17,807
	2035	12,209	699	0	3,384	3,309	426	0	153	0	20,180
	2039	12,209	699	289	4,935	3,309	426	423	179	0	22,469
LRZ 7	**2025**	2,051	0	0	1,758	1,537	0	0	749	72	6,166
	2030	2,718	0	0	2,937	3,211	94	0	781	72	9,813
	2035	3,378	601	0	4,106	4,498	94	267	829	72	13,845
	2039	5,133	601	0	7,576	5,098	94	889	854	72	20,318
LRZ 8	**2025**	1,734	0	0	93	2,578	0	0	26	0	4,431
	2030	2,400	0	0	222	2,681	77	0	83	0	5,464
	2035	2,522	0	0	334	2,750	77	0	168	0	5,851
	2039	2,522	0	0	686	2,750	77	172	212	0	6,420
LRZ 9	**2025**	6,457	493	0	86	1,512	0	0	28	0	8,577
	2030	12,965	493	0	207	2,360	189	0	91	0	16,305
	2035	14,597	1,381	0	310	3,031	189	0	184	0	19,692
	2039	14,597	1,727	0	638	3,031	189	481	232	0	20,895
LRZ 10	**2025**	672	0	0	200	718	0	0	16	0	1,606
	2030	731	350	0	200	1,091	0	0	52	0	2,425
	2035	3,046	700	0	200	1,723	0	0	106	0	5,776
	2039	3,046	700	0	200	1,723	0	109	134	0	5,913
MISO Total	**2025**	20,903	1,946	0	15,853	14,600	0	0	1,320	82	54,704
	2030	47,828	2,938	0	24,796	21,144	1,200	0	1,995	82	99,983
	2035	53,834	10,148	0	36,291	28,082	1,200	300	2,950	82	132,887
	2039	58,725	10,494	1,201	63,104	28,696	1,200	3,400	3,475	82	170,376

Table 9: MISO Future 2 Resource Additions by LRZ and Footprint

Future 2 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	4,324	1,255	0	698	240	0	36	6,553
	2030	6,413	2,584	0	698	519	0	36	10,250
	2035	6,676	3,281	1,092	771	2,946	0	36	14,802
	2039	6,676	3,332	1,092	803	3,572	0	36	15,510
LRZ 2	**2025**	2,650	2,650	0	351	11	0	0	5,663
	2030	2,981	741	0	351	41	0	0	4,114
	2035	2,981	741	0	351	427	0	0	4,500
	2039	2,981	1,617	0	351	617	0	0	5,566
LRZ 3	**2025**	757	92	448	196	122	0	0	1,615
	2030	757	92	448	196	348	0	0	1,841
	2035	757	92	448	275	1,434	0	0	3,006
	2039	776	92	448	275	2,707	0	0	4,297
LRZ 4	**2025**	3,056	134	0	117	0	0	0	3,307
	2030	3,118	134	0	117	20	0	0	3,389
	2035	3,118	134	0	117	379	0	0	3,748
	2039	3,118	134	0	117	1,013	0	0	4,382
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	384	0	345	169	0	0	5,796
	2039	6,132	384	0	345	169	0	0	7,029
LRZ 6	**2025**	11,068	853	0	50	0	0	0	11,970
	2030	11,537	853	0	50	0	0	0	12,439
	2035	11,537	1,008	0	71	377	0	0	12,992
	2039	11,537	1,296	0	71	582	21	0	13,507
LRZ 7	**2025**	2,991	161	819	59	0	0	0	4,029
	2030	4,258	168	819	59	0	0	0	5,303
	2035	4,878	2,973	819	59	230	0	0	8,958
	2039	8,013	3,059	819	59	565	0	0	12,513
LRZ 8	**2025**	1,647	788	0	0	0	0	0	2,435
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	788	0	0	0	0	0	3,918
	2039	3,130	788	0	0	0	0	0	3,918
LRZ 9	**2025**	2,746	7,013	0	7	0	0	0	9,766
	2030	2,746	7,013	0	7	0	0	0	9,766
	2035	2,746	8,591	0	7	0	0	0	11,344
	2039	2,746	8,591	0	7	0	0	0	11,344
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	2,319	0	0	0	0	0	2,319
	2039	0	2,319	0	0	0	0	0	2,319
MISO Total	**2025**	33,132	13,904	1,267	1,822	373	0	36	50,534
	2030	38,833	13,331	1,267	1,822	928	0	36	56,217
	2035	40,722	20,311	2,359	1,996	5,960	0	36	71,383
	2039	45,109	21,611	2,359	2,027	9,223	21	36	80,386

Table 10: MISO Future 2 Resource Retirements by LRZ and Footprint

MISO – Future 3

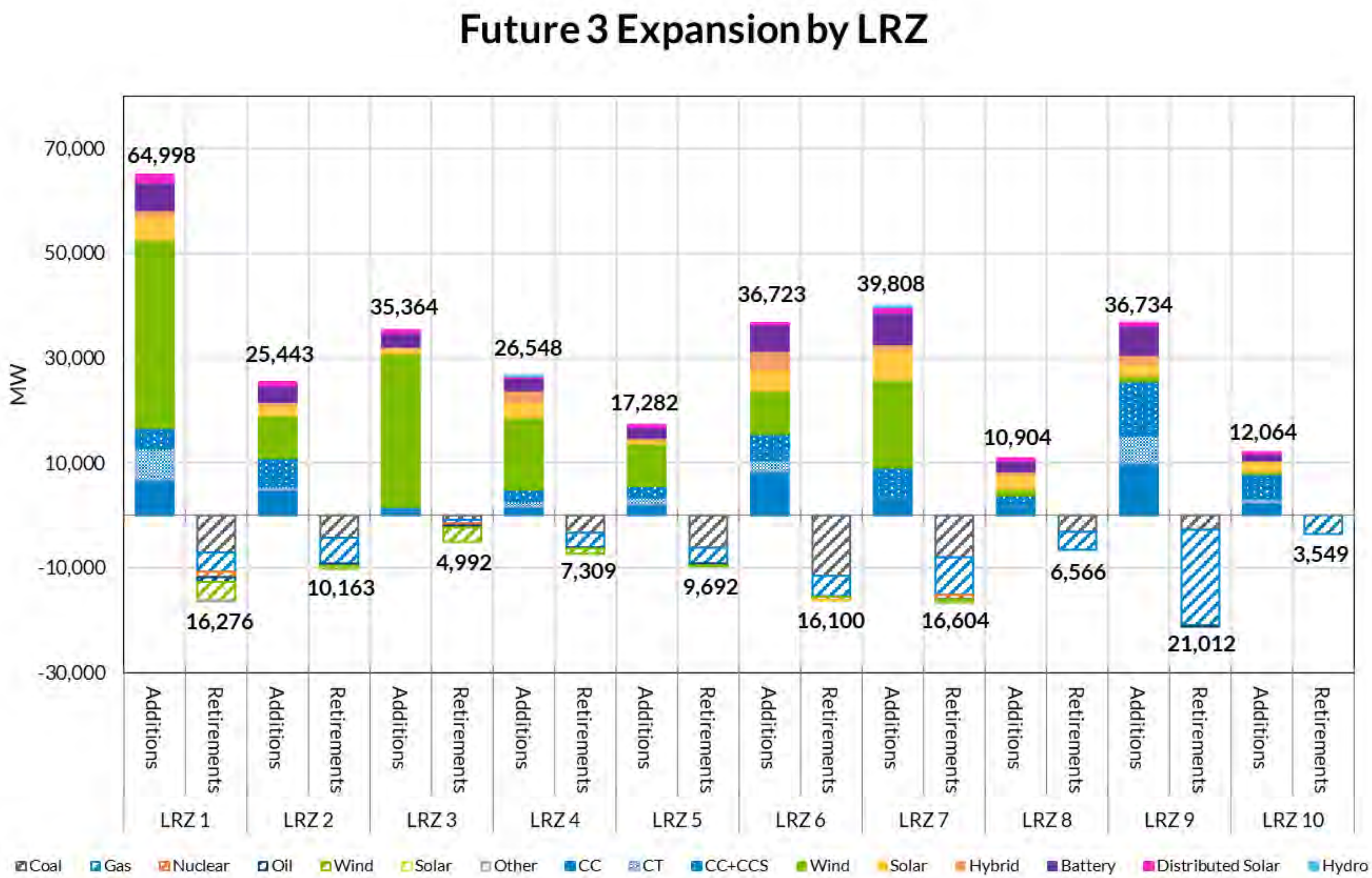


Figure 64: MISO Future 3 Resource Retirement and Addition Summary

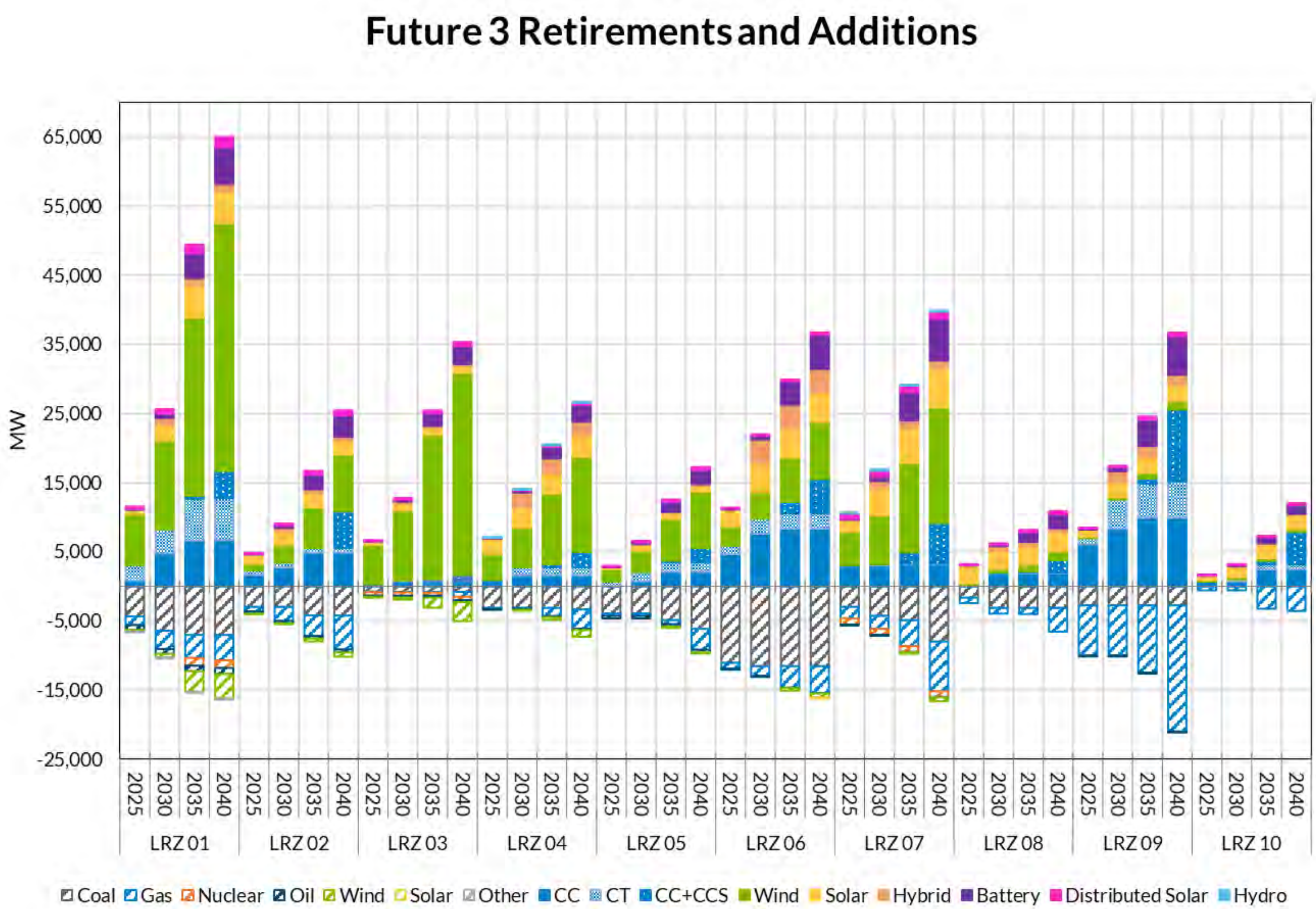


Figure 65: MISO Future 3 Resource Additions per Milestone Year (Cumulative)

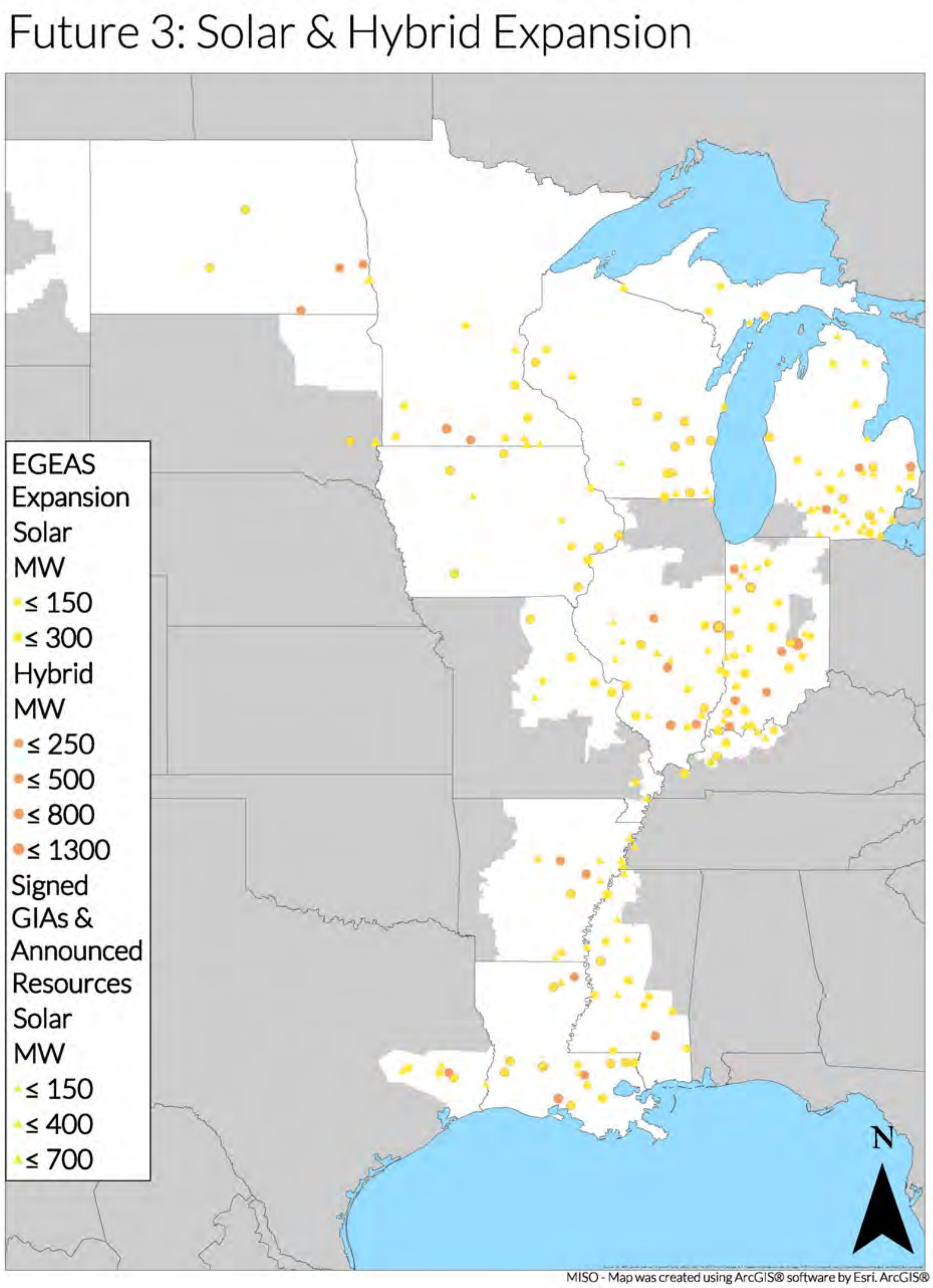


Figure 66: MISO Future 3 Solar and Hybrid Siting

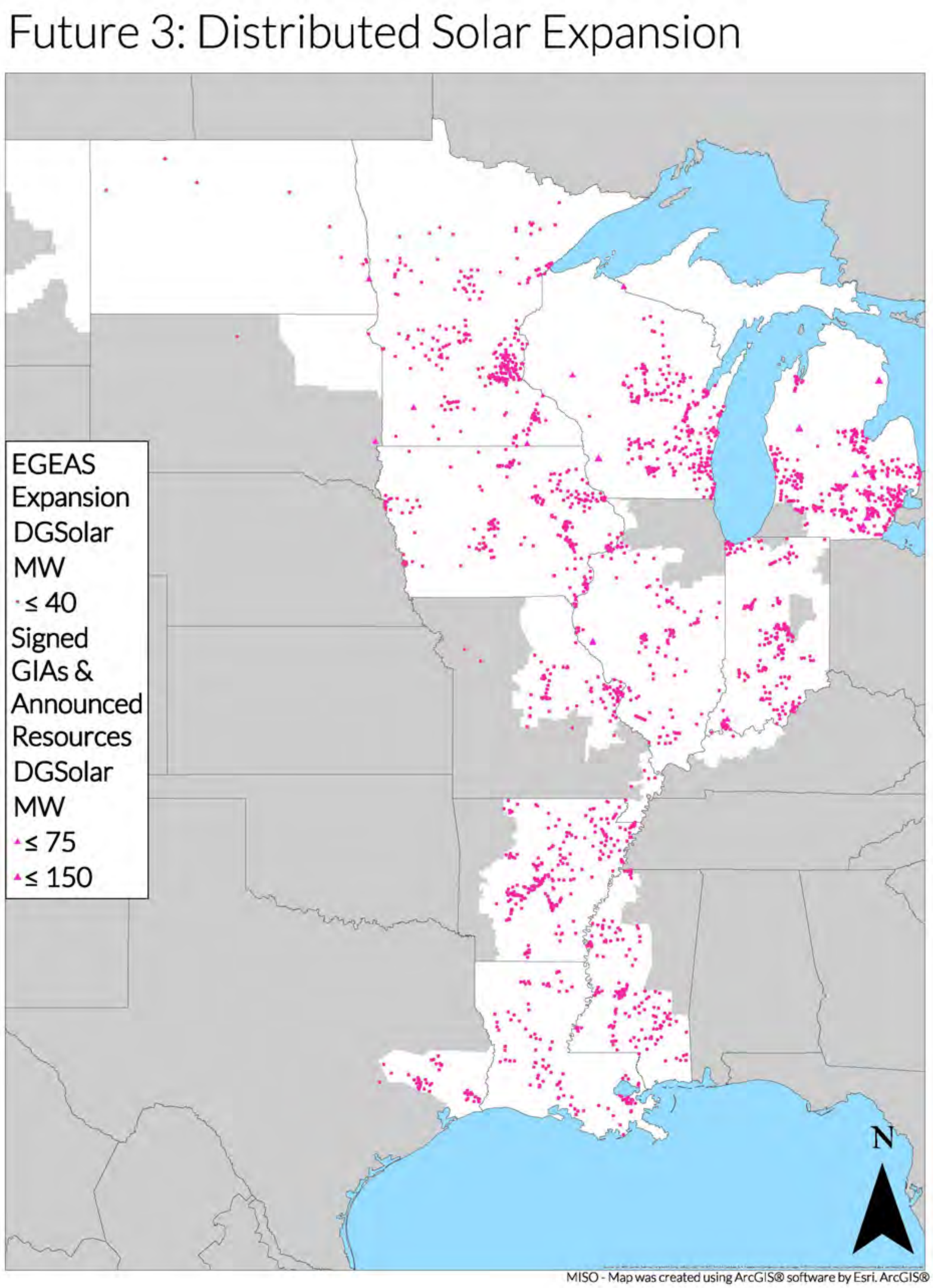


Figure 67: MISO Future 3 Distributed Solar Siting

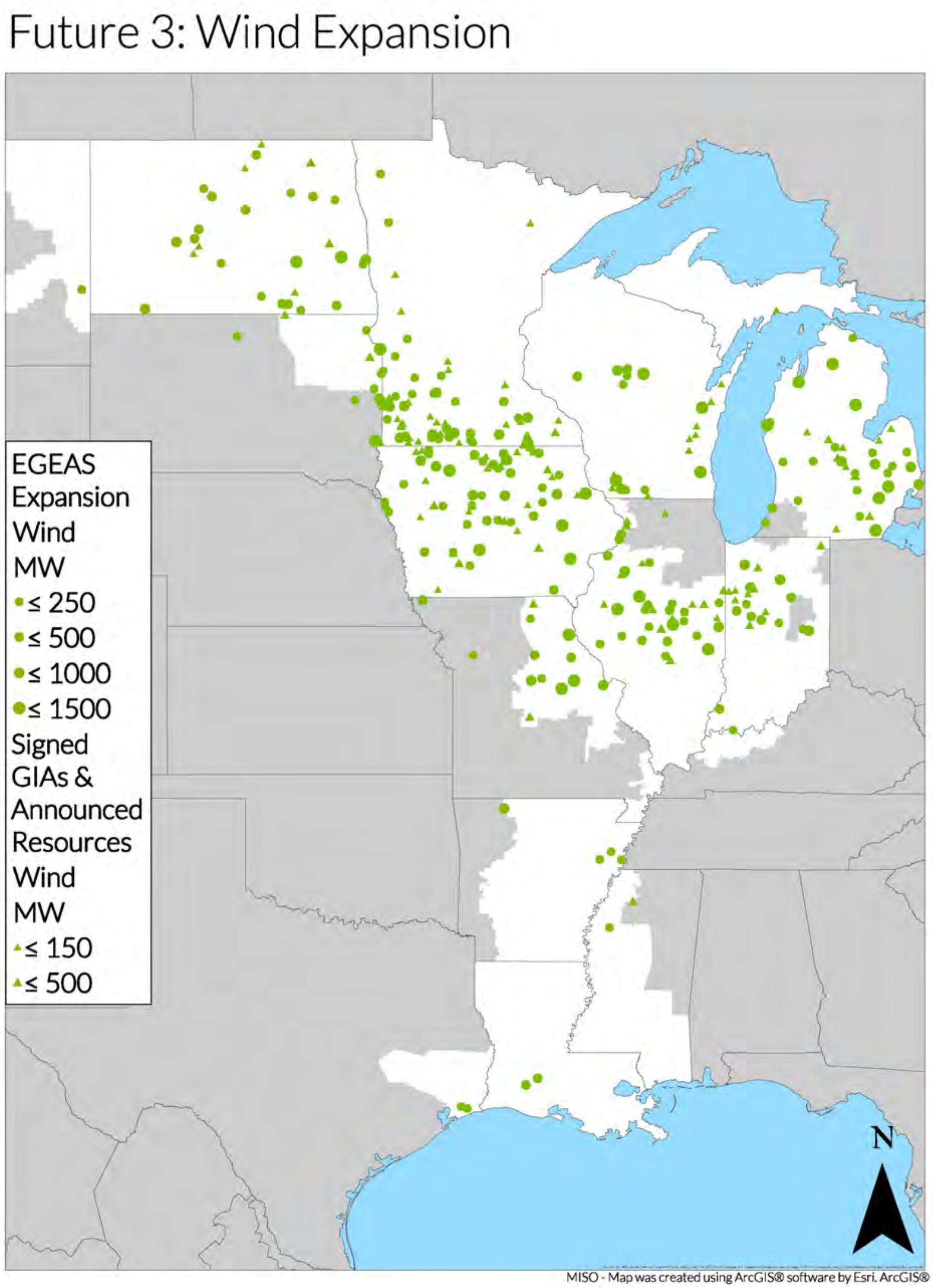


Figure 68: MISO Future 3 Wind Siting

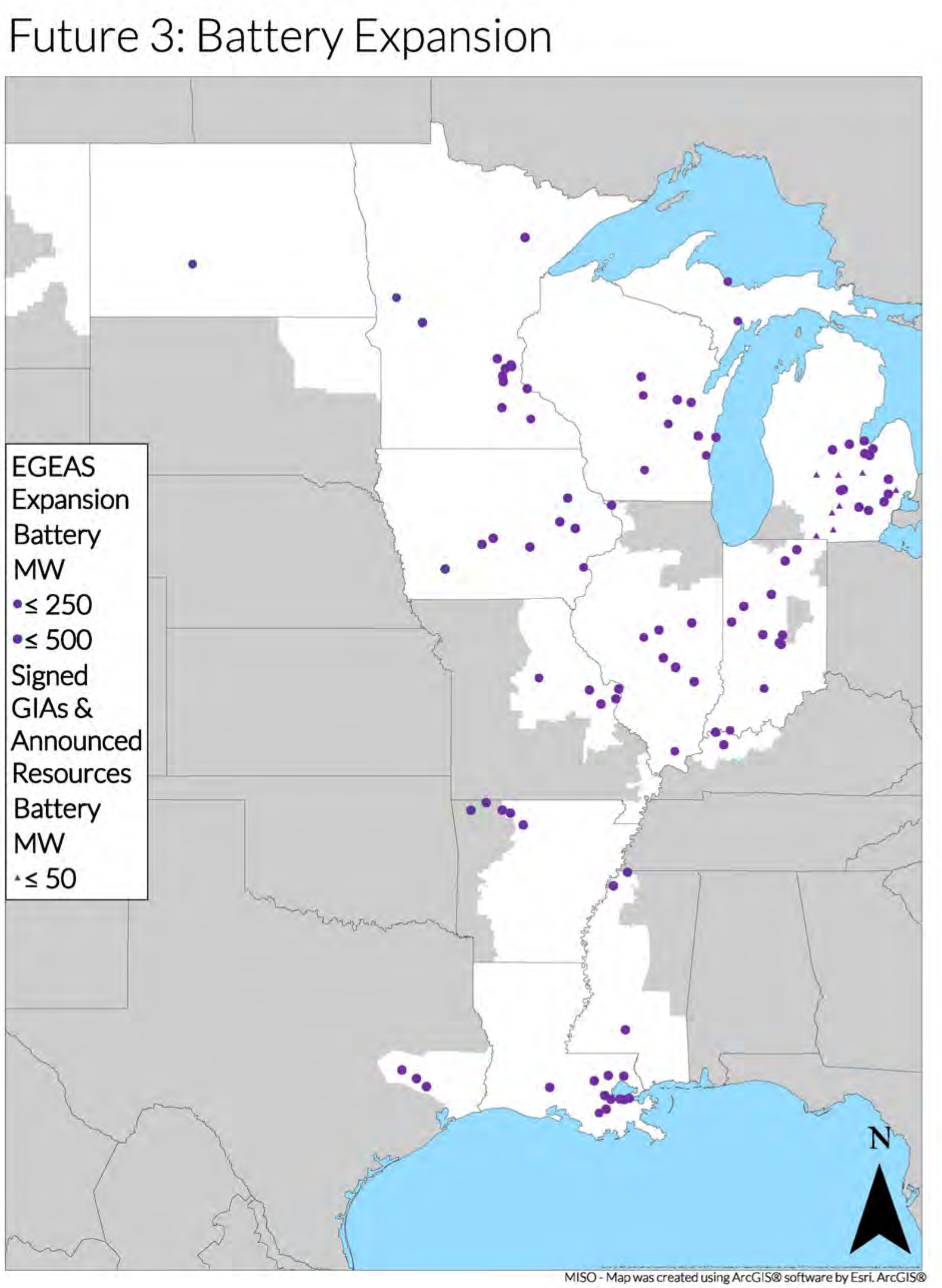


Figure 69: MISO Future 3 Battery Siting

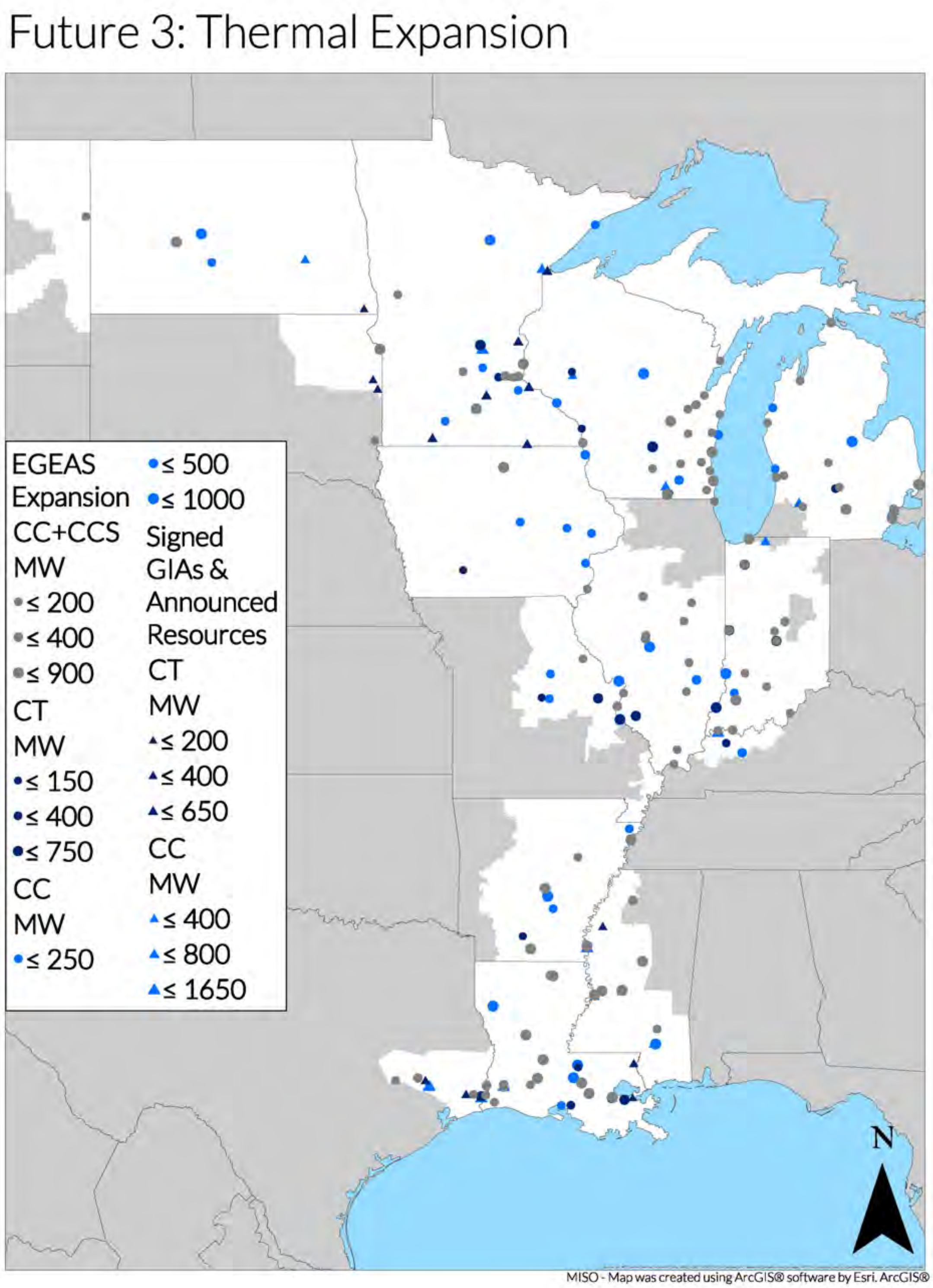


Figure 70: MISO Future 3 Thermal Siting

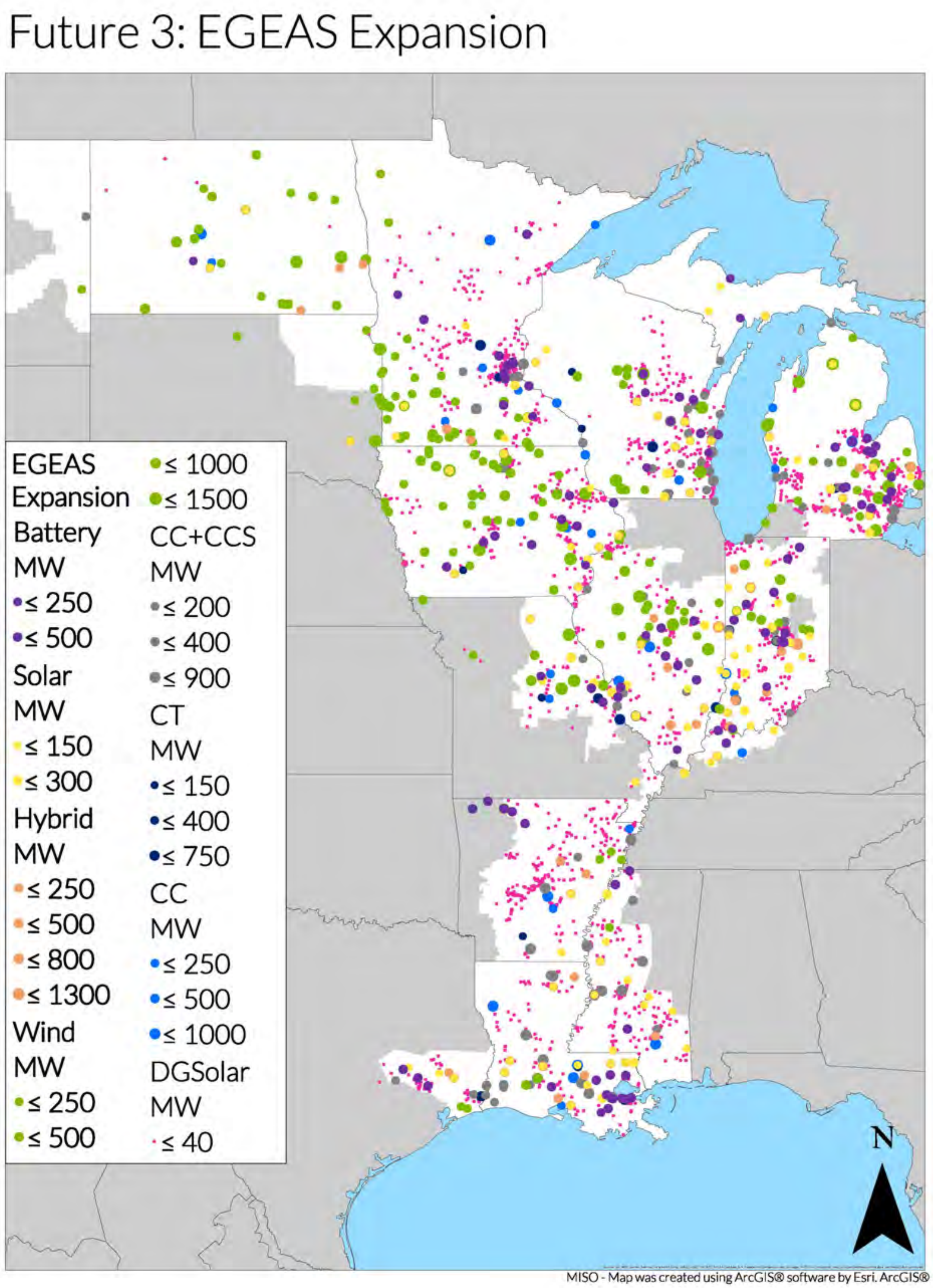


Figure 71: MISO Future 3 Complete EGEAS Expansion Siting

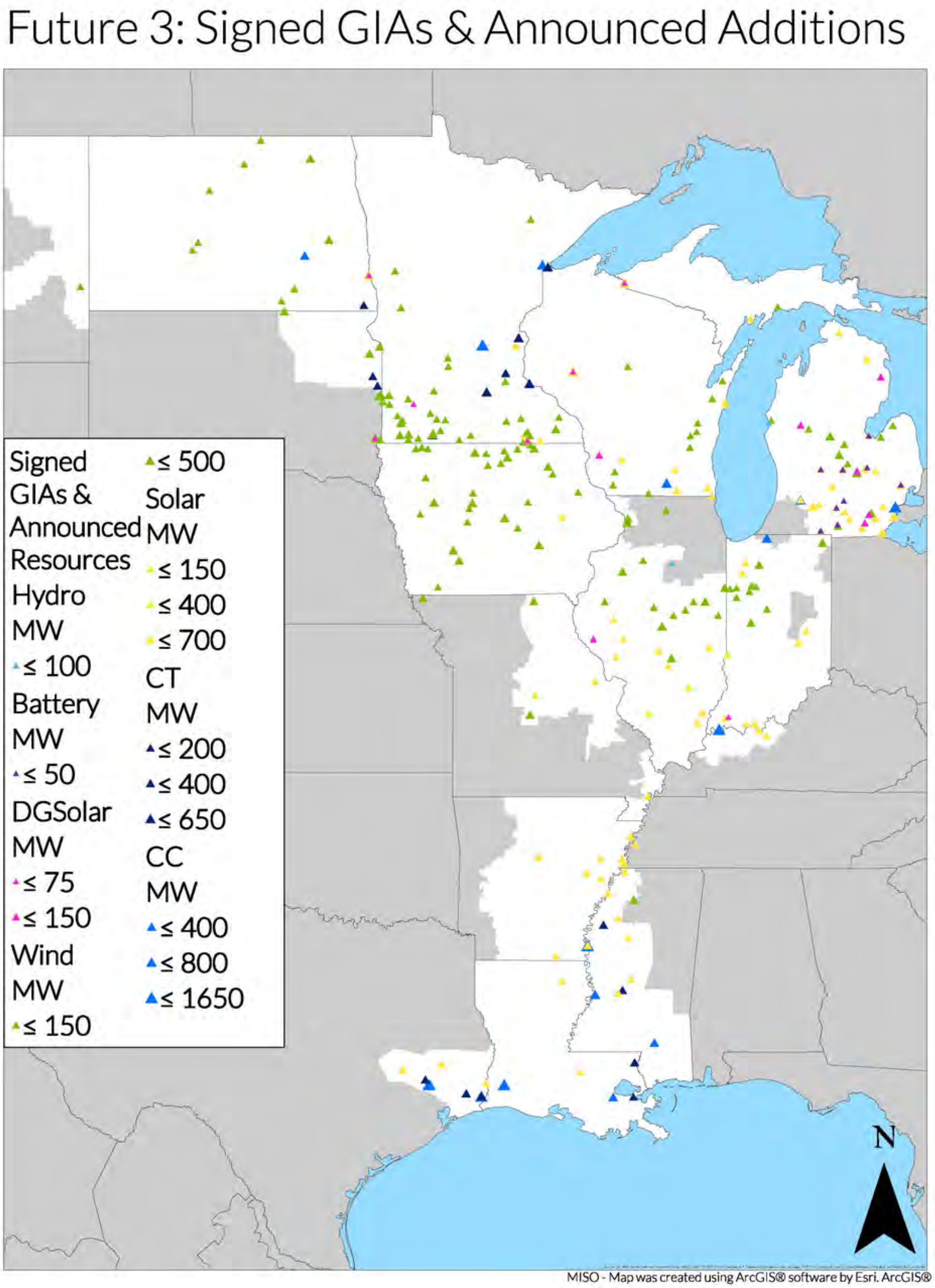


Figure 72: MISO Future 3 Non-EGEAS Expansion Siting

Future 3: Total Expansion

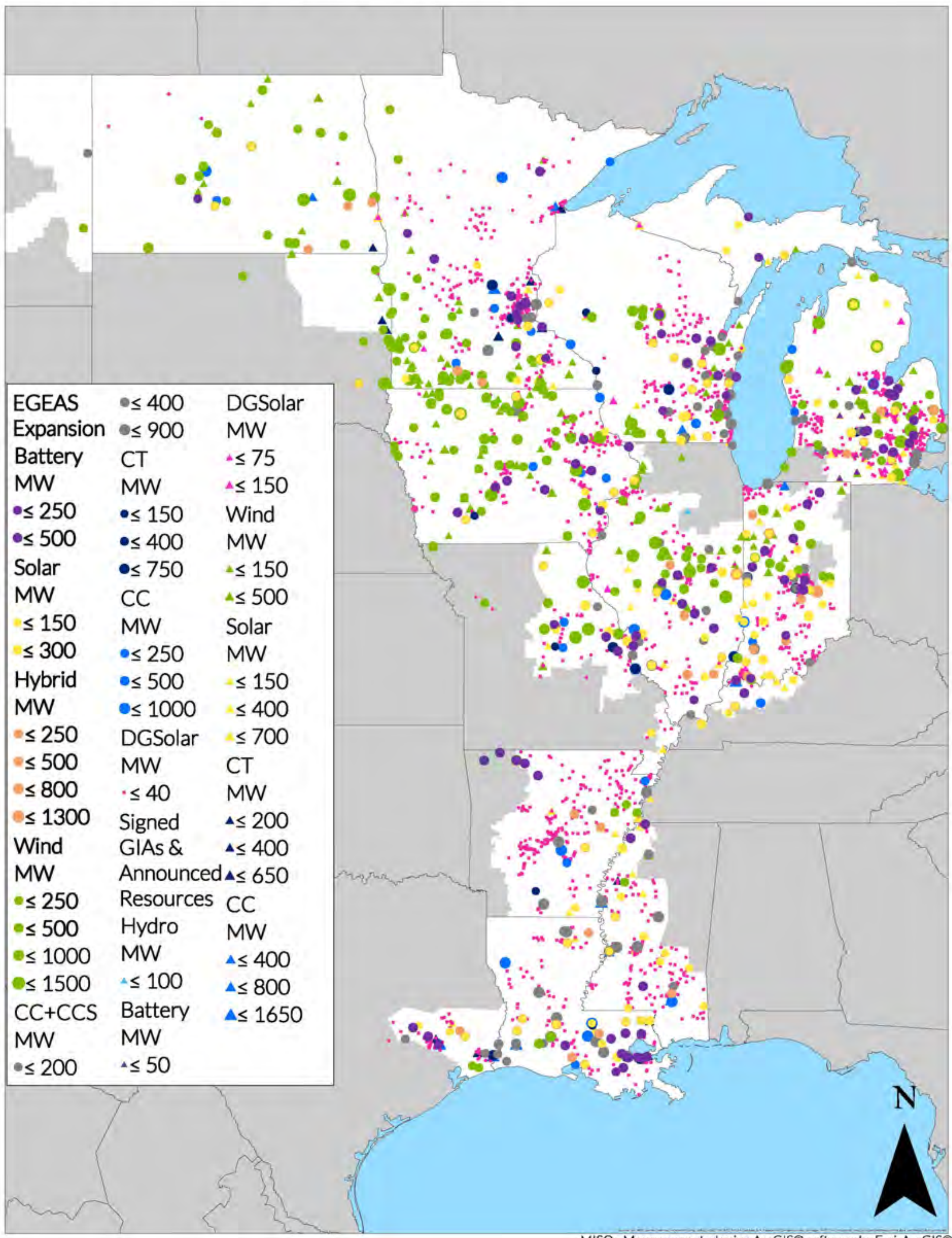


Figure 73: MISO Future 3 Non-EGEAS and EGEAS Expansion Siting

Future 3 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	850	2,179	0	7,398	640	0	149	350	0	11,565
	2030	4,766	3,486	0	12,897	2,228	969	606	712	0	25,664
	2035	6,641	6,054	409	25,786	4,728	969	3,635	1,202	0	49,425
	2039	6,731	6,054	3,881	35,848	4,728	969	5,302	1,486	0	64,998
LRZ 2	**2025**	1,686	620	0	949	1,332	0	91	86	0	4,764
	2030	2,762	673	0	2,532	1,991	516	356	275	0	9,105
	2035	4,880	673	0	5,898	2,066	516	2,133	556	0	16,722
	2039	4,880	673	5,363	8,132	2,066	516	3,111	703	0	25,443
LRZ 3	**2025**	311	0	0	5,669	513	0	74	74	0	6,640
	2030	769	92	0	10,102	1,019	264	298	235	0	12,779
	2035	769	92	200	20,874	1,019	264	1,786	475	0	25,479
	2039	769	92	766	29,249	1,019	264	2,605	600	0	35,364
LRZ 4	**2025**	900	0	0	3,768	2,240	0	72	68	10	7,059
	2030	1,612	1,134	0	5,745	2,957	2,122	278	130	10	13,988
	2035	1,612	1,134	459	10,219	2,957	2,122	1,668	221	10	20,403
	2039	1,612	1,134	2,203	13,808	2,957	2,122	2,432	269	10	26,548
LRZ 5	**2025**	64	609	0	1,793	283	0	62	57	0	2,868
	2030	748	1,344	0	3,091	728	251	234	181	0	6,577
	2035	2,114	1,344	266	6,029	791	251	1,402	366	0	12,565
	2039	2,114	1,344	2,117	8,143	805	251	2,045	463	0	17,282
LRZ 6	**2025**	4,659	1,223	0	2,765	2,467	0	142	89	0	11,345
	2030	7,629	2,158	0	3,805	4,259	3,401	566	164	0	21,982
	2035	8,375	2,158	1,661	6,410	4,259	3,401	3,398	277	0	29,940
	2039	8,375	2,158	4,988	8,251	4,259	3,401	4,955	336	0	36,723
LRZ 7	**2025**	3,051	0	0	4,837	1,722	0	159	767	72	10,609
	2030	3,051	153	0	7,079	3,936	1,054	648	841	72	16,832
	2035	3,120	153	1,642	12,888	5,136	1,054	4,087	949	72	29,100
	2039	3,120	153	5,870	16,730	5,736	1,054	6,068	1,006	72	39,808
LRZ 8	**2025**	250	0	0	227	2,544	0	57	59	0	3,137
	2030	1,897	134	0	454	2,753	571	229	188	0	6,226
	2035	1,897	134	122	954	2,753	571	1,377	379	0	8,187
	2039	1,897	134	1745	1,317	2,753	571	2,008	479	0	10,904
LRZ 9	**2025**	6,061	915	0	201	1,031	0	160	64	0	8,432
	2030	8,321	4,215	0	401	2,156	1,529	639	205	0	17,466
	2035	9,953	4,907	726	842	2,356	1,529	3,836	415	0	24,564
	2039	9,953	5,253	10,361	1,163	2,356	1,529	5,594	524	0	36,734
LRZ 10	**2025**	672	0	0	245	627	0	34	37	0	1,616
	2030	672	350	0	291	1,517	123	146	119	0	3,217
	2035	2,472	700	515	390	2,017	123	877	240	0	7,334
	2039	2,472	700	4,707	463	2,017	123	1,280	303	0	12,064
MISO Total	**2025**	18,503	5,546	0	27,853	13,400	0	1,000	1,650	82	68,034
	2030	32,228	13,739	0	46,396	23,544	10,800	4,000	3,049	82	133,837
	2035	41,833	17,349	6,000	90,291	28,082	10,800	24,200	5,081	82	223,719
	2039	41,923	17,695	42,001	123,104	28,696	10,800	35,400	6,168	82	305,869

Table 11: MISO Future 3 Resource Additions by LRZ and Footprint

Future 3 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	4,324	1,272	0	698	240	0	36	6,569
	2030	6,420	2,635	0	698	519	0	36	10,307
	2035	7,040	3,337	1,092	824	2,946	0	36	15,275
	2039	7,040	3,651	1,092	885	3,572	0	36	16,276
LRZ 2	**2025**	2,981	604	0	351	11	0	0	3,947
	2030	2,981	2,017	0	351	41	0	0	5,390
	2035	4,173	3,010	0	351	427	0	0	7,961
	2039	4,232	4,906	0	409	617	0	0	10,163
LRZ 3	**2025**	757	92	448	196	122	0	0	1,615
	2030	776	107	448	275	348	0	0	1,954
	2035	776	135	448	275	1,434	0	0	3,068
	2039	808	702	448	328	2,707	0	0	4,992
LRZ 4	**2025**	3,118	134	0	117	0	0	0	3,369
	2030	3,118	134	0	117	20	0	0	3,389
	2035	3,118	1,199	0	117	379	0	0	4,813
	2039	3,326	2,794	0	176	1,013	0	0	7,309
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	582	0	345	169	0	0	5,994
	2039	6,132	3,047	0	345	169	0	0	9,692
LRZ 6	**2025**	11,068	853	0	50	0	0	0	11,970
	2030	11,537	1,398	0	71	0	0	0	13,005
	2035	11,537	3,102	0	71	377	0	0	15,086
	2039	11,537	3,889	0	71	582	21	0	16,100
LRZ 7	**2025**	2,991	1,697	819	59	0	0	0	5,565
	2030	4,258	1,906	819	59	0	0	0	7,041
	2035	4,878	3,760	819	59	230	0	0	9,745
	2039	8,013	7,134	819	74	565	0	0	16,604
LRZ 8	**2025**	1,647	788	0	0	0	0	0	2,435
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	882	0	0	0	0	0	4,012
	2039	3,130	3,436	0	0	0	0	0	6,566
LRZ 9	**2025**	2,746	7,243	0	7	0	0	0	9,996
	2030	2,746	7,243	0	7	0	0	0	9,996
	2035	2,746	9,711	0	7	0	0	0	12,464
	2039	2,746	18,259	0	7	0	0	0	21,012
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	3,248	0	0	0	0	0	3,248
	2039	0	3,549	0	0	0	0	0	3,549
MISO Total	**2025**	33,525	13,640	1,267	1,822	373	0	36	50,663
	2030	38,858	17,185	1,267	1,922	928	0	36	60,196
	2035	42,297	28,965	2,359	2,049	5,960	0	36	81,665
	2039	46,963	51,368	2,359	2,295	9,223	21	36	112,265

Table 12: MISO Future 3 Resource Retirements by LRZ and Footprint

Appendix

EGEAS Modeling

Description

The Electric Generation Expansion Analysis System (EGEAS) is a program developed by EPRI which MISO uses to conduct its expansion analysis studies. The primary function of EGEAS is the creation of a generation expansion plan that meets system requirements specified by several inputs, assumptions, and constraints.

Modeling Procedure

The modeling process can be broken down into three main stages: definition of the model through inputs, computational analysis and solution processing, and consolidation of the results in the output file.

Inputs

Listed below are some of the key input parameters that EGEAS uses when selecting the optimal expansion solution. EGEAS allows users to input a variety of variables however, the inputs below include some of the more important parameters when setting up an economic expansion model.

- Hourly load shape files for the system and NDTs
- Projected peak yearly values of demand and energy
- Planning Reserve Margin (PRM) percentage requirement
- Renewable Portfolio Standard (RPS) percentage trajectories
- Decarbonization trajectories, may be input in short tons or $/short ton
- Existing unit data including planned additions and retirements
- Cost of unserved energy
- Available expansion resources and respective cost and emission data

Computational Analysis

To find the optimal resource expansion plan, EGEAS solves two objective functions:

1. Present value of the revenue requirements
2. The levelized average system rates ($/MWh)

The bulk of the work done by EGEAS is in solving these functions. It is an iterative process that progresses through the study year by year. Retaining only the feasible solutions each year, a single expansion plan that satisfies all input constraints and limitations over the study period is selected after the final year of study.

Output

The final report file is a text output file containing a report on the generic units EGEAS built to meet the system constraints in every year of the study. Metrics such as PRM, RPS, systemwide CO_2 emissions, resource generation, and cost data are also included in the report file.

From this information, MISO staff acquires its resource expansion and sites these resources throughout the footprint based on generator availability and other criteria discussed in the New Resource Addition Siting Process section of this report.

An important metric used in the Futures process is the RPS which EGEAS calculates as the ratio of Renewable Energy Generation (from wind, solar, and solar hybrid resources) to Net System Energy. In this calculation, net system energy is the sum of forecasted and storage charging energy minus energy from demand side management programs. While this may be how EGEAS calculated required contribution from renewable resources when defining an economic expansion, MISO displays these results differently so that energy generation from all resources may be seen. The calculation used by MISO is (Renewable Energy GWh / Total Generation GWh).

Shown below is an example of the EGEAS and MISO calculation to meet the RPS in Future 3 year 2039. MISO values appear less than EGEAS calculated values because total generation includes energy from DSM programs and curtailed renewable energy from low demand periods.

EGEAS Calculation

Forecasted System Energy (GWh)	Storage Charging (GWh)	DSM Energy (GWh)	Net System Energy (GWh)	Renewable Energy Generation (GWh)	RPS %
1,063,465	176,423	56,665	1,183,223	622,241	53%

$$\left(\frac{Renewable}{Forecasted + Storage - DSM}\right) \times 100 = RPS\%$$

$$\left(\frac{622{,}241}{1{,}063{,}465 + 176{,}423 - 56{,}665}\right) \times 100 = 52.59$$

MISO Calculation

Total Energy Generation (GWh)	Renewable Energy Generation (GWh)	RPS %
1,352,519	622,241	46%

$$\left(\frac{Renewable}{Total\ Generation}\right) \times 100 = RPS\%$$

$$\left(\frac{622{,}241}{1{,}352{,}519}\right) \times 100 = 46.01$$

Additional MISO Assumptions

Futures Assumptions Summary

Table 13 and Table 14 detail Future-specific input assumptions. Many of these variables were direct inputs to the model; however, selected DERs, retirements, and addition totals are results of the analysis.

Variables	Future 1	Future 2	Future 3
Gross Load[29] Total Growth	Low-Base EV Growth 94,275 GWh	30% Total Energy Growth by 2040 196,996 GWh	50% Total Energy Growth by 2040 334,692 GWh
Energy (CAGR) Input/*Result*	0.63% / *0.48%*	1.22% / *1.09%*	1.91% / *1.71%*
Demand (CAGR) Input/*Result*	0.75% / *0.60%*	1.11% / *0.97%*	1.60% / *1.41%*
Electrification Growth & Technologies Growth from Electrification	2% of Total Growth 14,147 GWh	15.2% of Total Growth 109,101 GWh	31.8% of Total Growth 231,513 GWh
Electrification Technologies	PEVs	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process
Selected DERs DR EE DG	0.94 GW 7.82 GW 3.47 GW	0.94 GW 8.05 GW 3.47 GW	0.94 GW 11.72 GW 6.17 GW
Carbon Reduction ***(2005 baseline)*** MISO Footprint currently at 29%	40% *63% realized in results*	60% *65% realized in results*	80% *81% realized in results*
Wind & Solar Generation Percentage[82]	Resulted in 26% with No Minimum Enforced	Resulted in 35% with No Minimum Enforced	46%
Utility Announced Plans	85% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met

Table 13: MISO Futures Assumptions

[29] Total Growth is based on 2039 values due to the study period ending on 12/31/2039.

Variables		Future 1	Future 2	Future 3
Retirement Age-Based Criteria	Coal	46 years[30]	36 years	30 years
	Natural Gas-CC	50 years	45 years	35 years
	Natural Gas-Other	46 years	36 years	30 years
	Oil	45 years	40 years	35 years
	Nuclear	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
	Wind & Solar - Utility Scale	25 years	25 years	25 years
Retirements	Coal	44.8 GW	45.1 GW	47 GW
	Gas	18.6 GW	21.6 GW	51.4 GW
	Oil	2 GW	2.03 GW	2.3 GW
	Nuclear	2.4W	2.4GW	2.4GW
	Wind	9.2 GW	9.2 GW	9.2 GW
	Solar	0.02 GW	0.02 GW	0.02 GW
	Other	0.04 GW	0.04 GW	0.04 GW
	Total	77.1 GW	80.4 GW	112.3 GW
Additions	CC	37.1 GW	58.7 GW	41.9 GW
	CT	14.1 GW	10.5 GW	17.7 GW
	CC+CCS	0 GW	1.2 GW	42 GW
	Wind[31]	18.7 GW	63.1 GW	123.1 GW
	Solar	34.7 GW	28.7 GW	28.7 GW
	Hybrid	12 GW	1.2 GW	10.8 GW
	Battery	0.6 GW	3.4 GW	35.4 GW
	Hydro	0.1 GW	0.1 GW	0.1 GW
	Total (Including DERs)	129.5 GW	179.4 GW	318.5 GW

Table 14: MISO Futures Assumptions and Expansion Results

[30] EIA Source for Coal Retirement Age, Future 1: https://www.eia.gov/todayinenergy/detail.php?id=40212

[31] All Futures include 9.2 GW of repowered wind and 9.5 GW of wind from signed GIAs.

Capital Costs

MISO used the 2020 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[32] to calculate the capital costs for all resources except for oil,[33] storage compressed air energy storage (CAES),[34] and internal combustion (IC) renewable[35] costs. MISO utilized moderate cost values within the 2020 ATB, which are in 2018 dollars. These values were converted to 2020 dollars and projected into the 20-year study period to create cost trajectories. For Hybrid unit costs, 2020 ATB Solar PV + Battery costs are included.

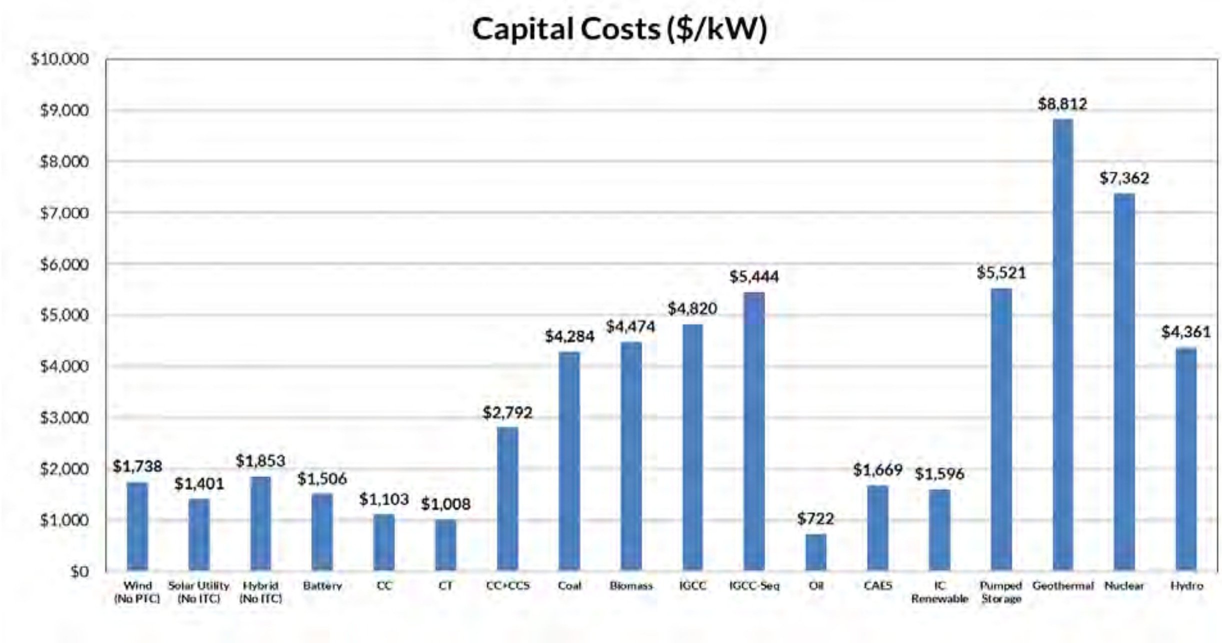


Figure 74: Annual Capital Cost Assumptions by Fuel Type

[32] NREL 2020 ATB: https://atb.nrel.gov/electricity/2020/data.php
[33] EIA costs were used and adjusted for 2020 dollars: https://www.eia.gov/electricity/generatorcosts/
[34] Costs from the DOE Energy Storage Technology and Cost Characterization Report of July 2019: https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf
[35] Costs from EIA Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

Production Tax Credits (PTC) and Investment Tax Credits (ITC)

Production Tax Credit (PTC) and Investment Tax Credit (ITC) effects on wind, utility-scale solar PV, and hybrid units are displayed below. Since the battery in the hybrid unit modeled is charged from solar resources 100% of the time, it may qualify for 100% of ITC benefits.[36,37]

Actual and Modeled Schedule of Wind and Solar Tax Credits

Consolidated Appropriations Act of 2016 PTC with 2020 Extensions	2016	2017	2018	2019	2020	2021	2022	2023 & onward
Utility Wind PTC	Full	80%	60%	40%	60%	0%	0%	0%
Utility Solar ITC	30%	30%	30%	30%	26%	22%	10%	10%
Model Representation	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023 & onward**
Utility Wind PTC	Full	Full	Full	Full	Full	Full	Full	0%
Utility Solar ITC	30%	30%	30%	30%	30%	26%	22%	10%
Hybrid ITC (Battery charged by solar 100% of the time)	30%	30%	30%	30%	30%	26%	22%	10%

Table 15: PTC and ITC Schedule

Accreditations of PTC and ITC benefits are seen for wind, solar, and hybrid units since extensions and changes were issued in the spring of 2020. The model representation differs due to the assumed construction time of each of these units, in order to ensure their safe harbor provisions. MISO used the values in the model representation section to build cost trajectories for these resources in EGEAS.

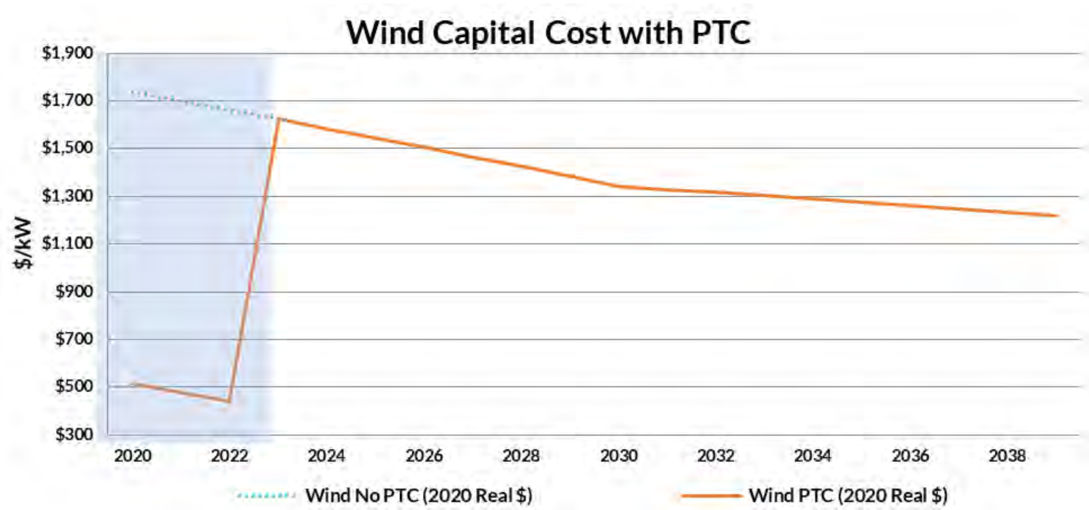


Figure 75: Wind with PTC

[36] Source for PTC and ITC for Wind & Solar PV: https://fas.org/sgp/crs/misc/R43453.pdf
[37] NREL - ITC accreditation for Hybrids: https://www.nrel.gov/docs/fy18osti/70384.pdf

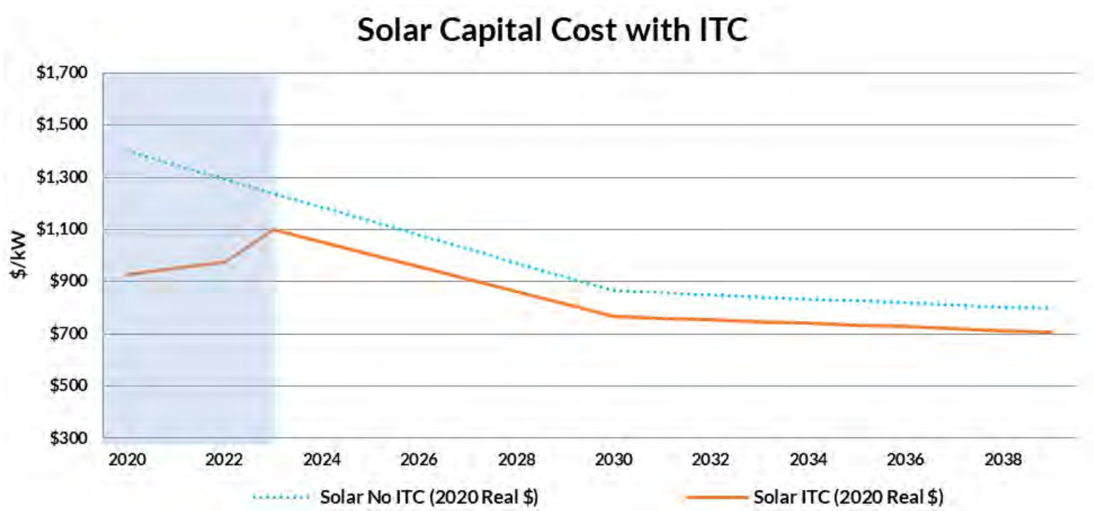


Figure 76: Solar PV with ITC

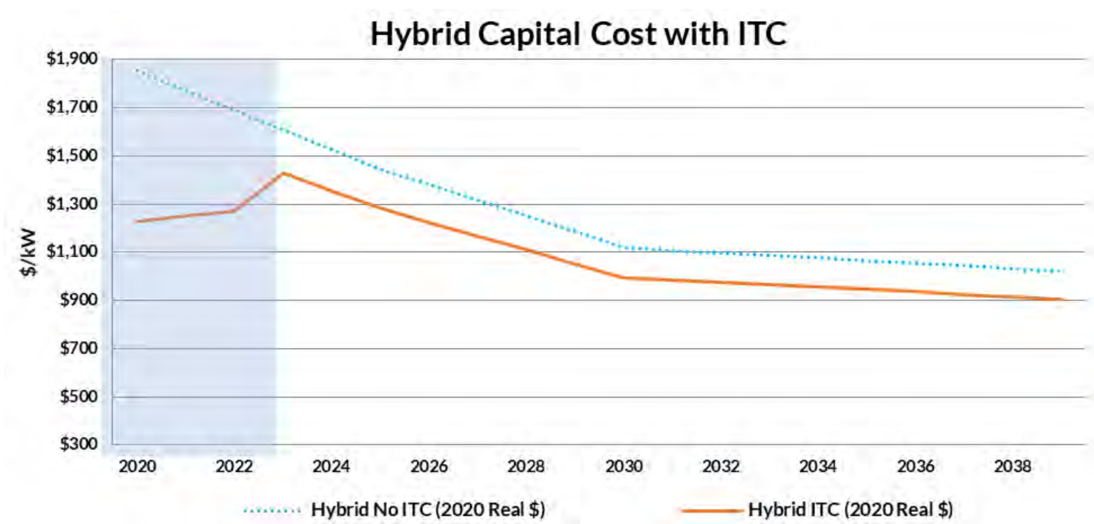


Figure 77: Hybrid with ITC

Electrification and Energy Growth Values

Although the energy growth in Futures 2 and 3 reaches 30% and 50% by 2040 respectively, not all growth is from electrification. Table 16 details the amounts of growth resulting from the reference forecast (SUFG) and electrification (AEG). By the end of the study period (12/31/2039), energy in Futures 1, 2, and 3 increases by 13%, 27%, and 46% respectively. On the following page, Table 17 presents the granular energy values for each technology that was electrified. These numbers represent the total energy growth from electrification in each Future scenario by LRZ.

Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	705,604	716,734	728,773
2039 Reference Growth	80,128	87,895	103,179
Electrification Growth	14,147	109,101	231,513
2039 Energy Forecast	799,879	913,730	1,063,465
Total Energy Increase, 2020-2039	**13%**	**27%**	**46%**
Energy Increase from Reference Forecast	11%	12%	14%
Energy Increase from Electrification	2%	15%	32%
Electrification Technologies	PEVs	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process

Table 16: Future-Specific Growth Assumptions (GWh)

Energy Growth by Technology Type from Electrification (GWh)								
F1	**RES_HVAC**	**RES_DHW**	**RES_App**	**C&I_HVAC**	**C&I_DHW**	**C&I_Process**	**PEVs**	**Total**
LRZ 1	0	0	0	0	0	0	2,636	2,636
LRZ 2	0	0	0	0	0	0	2,016	2,016
LRZ 3	0	0	0	0	0	0	719	719
LRZ 4	0	0	0	0	0	0	1,237	1,237
LRZ 5	0	0	0	0	0	0	747	747
LRZ 6	0	0	0	0	0	0	1,264	1,264
LRZ 7	0	0	0	0	0	0	4,352	4,352
LRZ 8	0	0	0	0	0	0	238	238
LRZ 9	0	0	0	0	0	0	851	851
LRZ 10	0	0	0	0	0	0	87	87
Total	0	0	0	0	0	0	14,147	14,147
F2	**RES_HVAC**	**RES_DHW**	**RES_App**	**C&I_HVAC**	**C&I_DHW**	**C&I_Process**	**PEVs**	**Total**
LRZ 1	3,108	2,556	1,266	4,711	307	0	6,542	18,489
LRZ 2	1,973	1,685	1,262	3,113	200	0	5,004	13,238
LRZ 3	2,076	945	451	2,425	137	0	1,784	7,818
LRZ 4	874	805	428	4,172	319	0	3,071	9,669
LRZ 5	2,307	654	332	1,686	129	0	1,855	6,962
LRZ 6	4,264	1,920	944	4,602	374	0	3,136	15,239
LRZ 7	3,265	2,574	2,085	5,710	316	0	10,802	24,751
LRZ 8	506	528	470	791	73	0	591	2,960
LRZ 9	1,330	1,540	1,114	2,276	387	0	2,112	8,760
LRZ 10	345	172	231	217	35	0	215	1,215
Total	20,048	13,378	8,584	29,702	2,277	0	35,112	109,101
F3	**RES_HVAC**	**RES_DHW**	**RES_App**	**C&I_HVAC**	**C&I_DHW**	**C&I_Process**	**PEVs**	**Total**
LRZ 1	6,005	5,289	1,723	6,411	594	2,573	17,078	39,673
LRZ 2	3,812	3,498	1,718	4,237	387	1,834	13,062	28,548
LRZ 3	4,012	1,967	614	3,300	264	1,662	4,657	16,476
LRZ 4	1,690	1,611	583	5,678	616	1,056	8,017	19,250
LRZ 5	4,457	1,334	452	2,295	249	1,303	4,842	14,931
LRZ 6	8,242	3,806	1,284	6,263	722	1,932	8,186	30,437
LRZ 7	6,308	5,301	2,838	7,771	611	2,878	28,198	53,905
LRZ 8	978	1,050	640	1,076	142	1,116	1,543	6,545
LRZ 9	2,570	3,043	1,516	3,098	749	2,340	5,513	18,829
LRZ 10	666	341	315	295	68	674	562	2,921
Total	38,741	27,240	11,683	40,423	4,400	17,368	91,658	231,513

Table 17: Quantification of Electrified Technologies (2020-2039)

Natural Gas Price Forecasting

MISO used the Gas Pipeline Competition Model (GPCM) base price forecast across the three Futures, instead of the Henry Hub price (HH) as in past cycles. GPCM outputs the gas price at a level of monthly granularity and produces unit-specific gas prices. The gas forecast per unit remained the same for all Futures modeled in EGEAS.

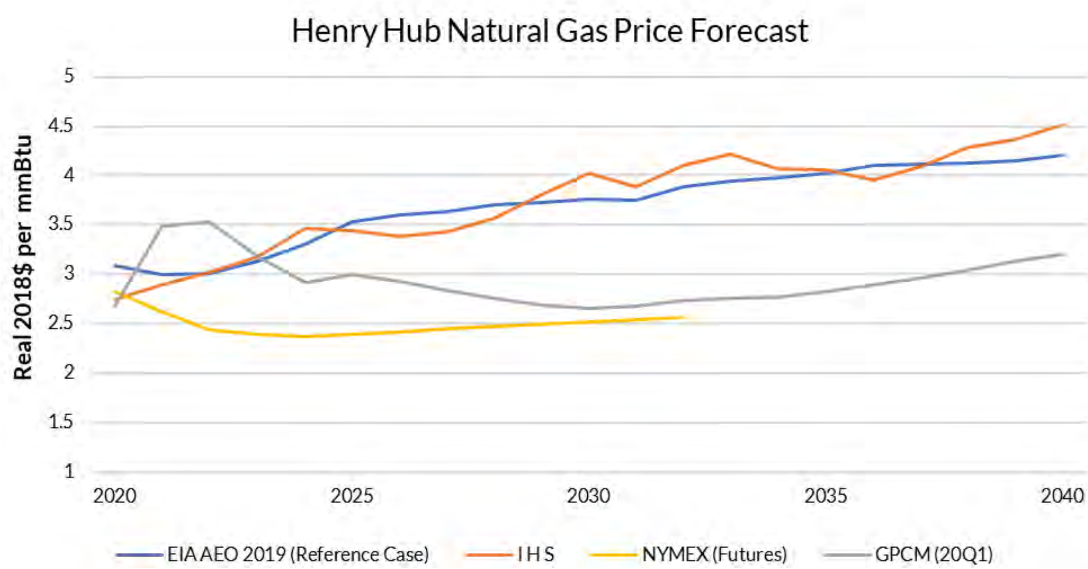


Figure 78: Henry Hub Natural Gas Price Forecast

General Assumptions

Study Period

The study period of the EGEAS resource expansion analysis is 20 years, beginning on 1/1/2020 and ending on 12/31/2039. An extension period of 40 years is added to the end of the simulation, with no new units forecasted during this time. This extension ensures that the generation selected in the last few years of the forecasting period (i.e., Years 15-20) is based on cost of generation spread out over the total tax/book life of the new resources (i.e., beyond Year 20) and does not bias to the cheapest generation in those final years.

Discount Rate

The discount rate of 7.22% is based upon the after-tax weighted average cost of capital of the Transmission Owners that make up the Transmission Provider Transmission System.

MISO Footprint Study Area

The study area for the updated MISO Futures continued to be the entire MISO footprint. However, the Local Clearing Requirement (LCR) for each zone was evaluated during the siting process to ensure each LRZ met their respective LCR as defined in the 2020/2021 Planning Resource Auction (PRA).

External Assumptions and Modeling

General Assumptions

External Footprint Study Area

From an external-to-MISO (External areas) perspective, MISO increased the EGEAS analysis granularity for External areas/pools represented in the MCPS[38] by increasing the number of representative models.

MISO-Created External Regional Model and Future Assumptions			
EGEAS Models	**Future 1**	**Future 2**	**Future 3**
PJM	Yes	Yes	Yes
SPP	No – Use SPP ITP Future 2 and Results[39]	Yes	Yes
TVA-Other *(includes Southeast, TVA, TVA-Other)*	Yes	Yes	Yes
Manitoba Hydro	No	No	No

Table 18: EGEAS External Model Representation

MISO realizes system flows depend on External areas' representations and the above improvements are intended to help align MISO Future assumptions to MISO's neighbors, as well as provide a Future (Future 1) that utilizes SPP Future assumptions. This Future will be used to help bookmark projected External system flows as decided by External Future assumptions.

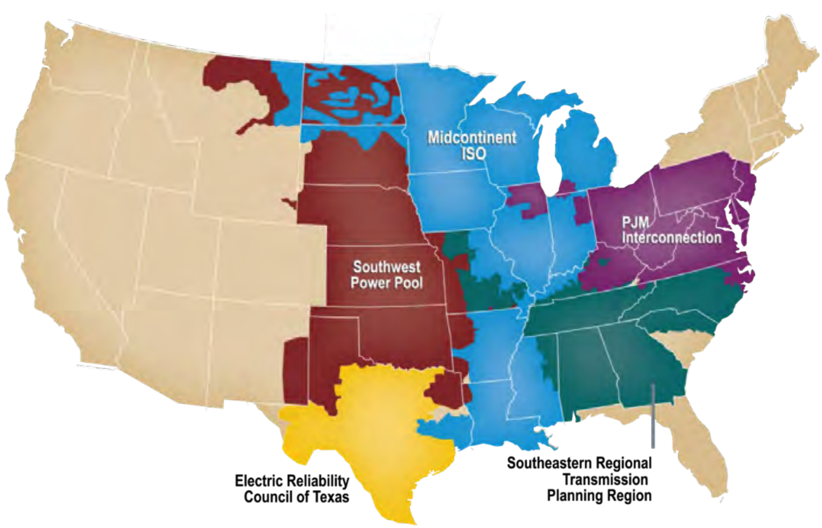


Figure 79: MISO Footprint & Neighboring Systems

[38] MISO Market Congestion Planning Studies (MCPS): https://www.misoenergy.org/stakeholder-engagement/committees/subregional-planning-meeting/market-congestion-planning-studies---south/

[39] https://www.spp.org/documents/61365/2021%20itp%20scope%20mopc%20and%20board%20approved.pdf

External Areas Forecasts Development

The 2019 Merged Load Forecast for Energy Planning forecast did not include External (non-MISO) companies' forecasts, so when available, External areas utilized respective regional model forecasts and when no regional forecast was available, the latest Multiregional Modeling Working Group (MMWG) model was used to create associated forecasts. External forecasts are defined in Table 19 and Future-specific adjustments will follow a similar process as shown in Table 18. Additionally, External areas utilized ABB's Velocity Suite 2018 load shapes.

Peak Load (MW) and Annual Energy (GWh)			
External Area (MCPS-Defined)	**Future 1**	**Future 2**	**Future 3**
PJM	PJM 2020 Long-Term Load Forecast (Base)	Base + Future-Specific Adjustments	Base + Future-Specific Adjustments
SPP	2021 ITP Future 2 Forecast (40% annual EV growth rate applied to energy only)	2021 ITP Future 1 Forecast + Future-Specific Adjustments	2021 ITP Future 1 Forecast + Future-Specific Adjustments
TVA-Other *(includes Southeast, TVA, TVA-Other)*	2019 MMWG Powerflow Model (Base)	Base + Future-Specific Adjustments	Base + Future-Specific Adjustments
Manitoba Hydro	MTEP20 CFC Forecast[40]	MTEP20 CFC Forecast	MTEP20 CFC Forecast

Table 19: External Area Demand & Energy Forecast Source

[40] 2020 MISO Transmission Expansion Planning (MTEP20): https://www.misoenergy.org/planning/planning/mtep20/

Electrification Assumptions

In addition to the electrification assumptions that were developed for the MISO footprint, a set of similar assumptions were made for External areas with the collaboration of AEG. The load growth in External areas came from electrification assumptions and reference load growth. Each area's growth is detailed in Table 20, electrification growth in Future 1 for SPP and PJM is reflected as zero due to this growth being incorporated in their reference load forecasts. Additionally, Figure 80 through Figure 87 detail the electrification of each technology within each External area.

PJM			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	939,546	946,602	949,301
2039 Reference Growth	111,347	111,347	111,347
Electrification Growth	0	172,086	353,105
2039 Energy Forecast	1,050,893	1,230,036	1,413,753
SPP			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	297,320	299,152	299,964
2039 Reference Growth	69,616	53,481	53,481
Electrification Growth	0	41,795	84,889
2039 Energy Forecast	366,936	394,428	438,334
TVA-Other (Southeast, TVA, TVA-Other)			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	698,962	702,206	703,821
2039 Reference Growth	78,303	75,059	73,444
Electrification Growth	7,553	76,817	163,373
2039 Energy Forecast	784,817	854,082	940,638
Electrification Technologies	PEVs (Included in reference forecast for PJM & SPP)	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process

Table 20: External Area Forecast Growth (GWh)

PJM Electrification

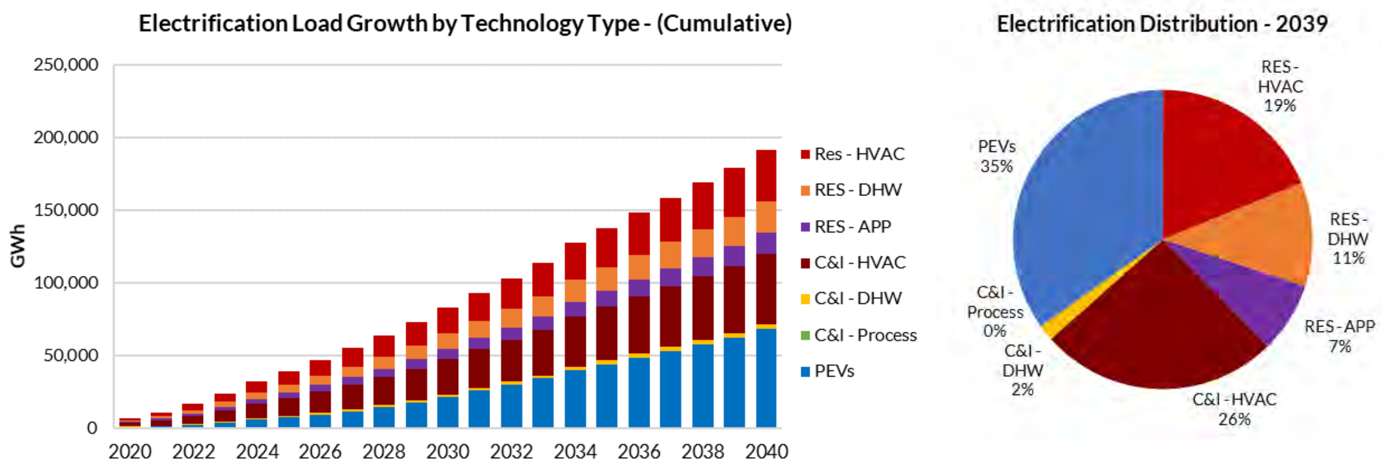


Figure 80: PJM Future 2 Electrification by End-Use

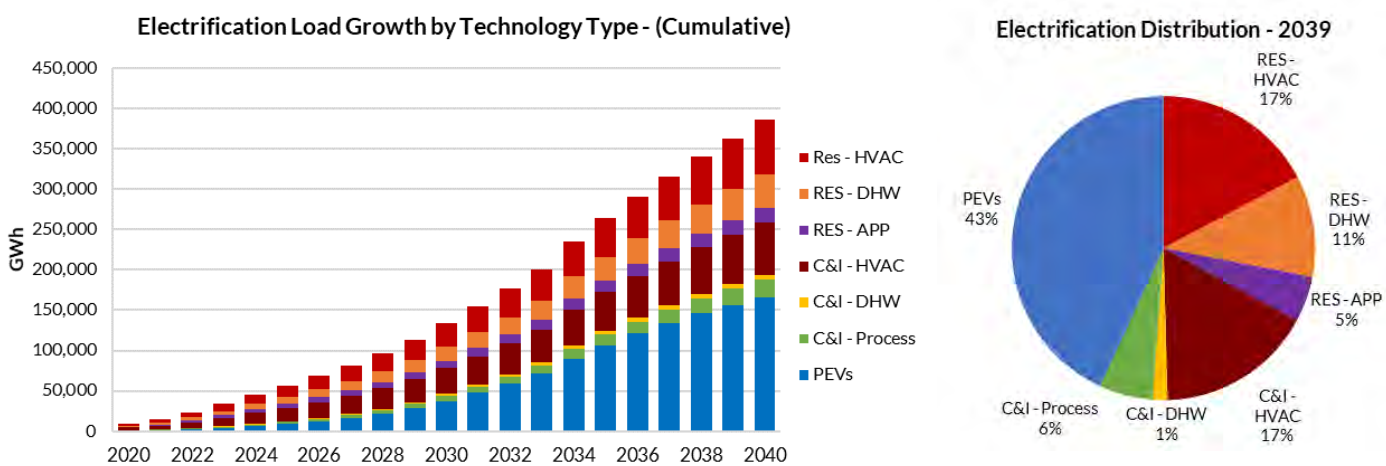


Figure 81: PJM Future 3 Electrification by End-Use

SPP Electrification

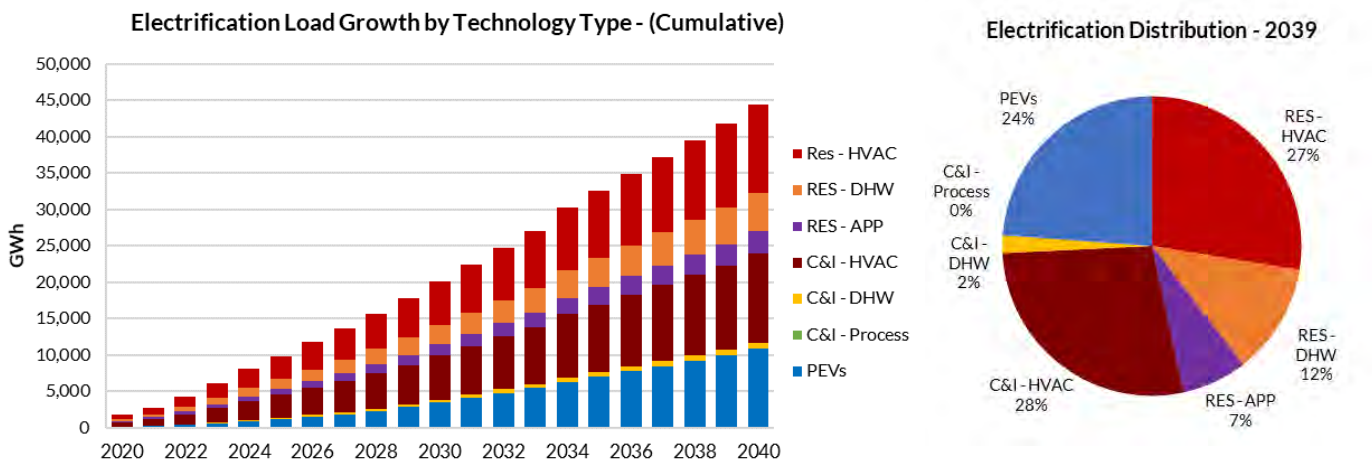


Figure 82: SPP Future 2 Electrification Broken Down by End-Use

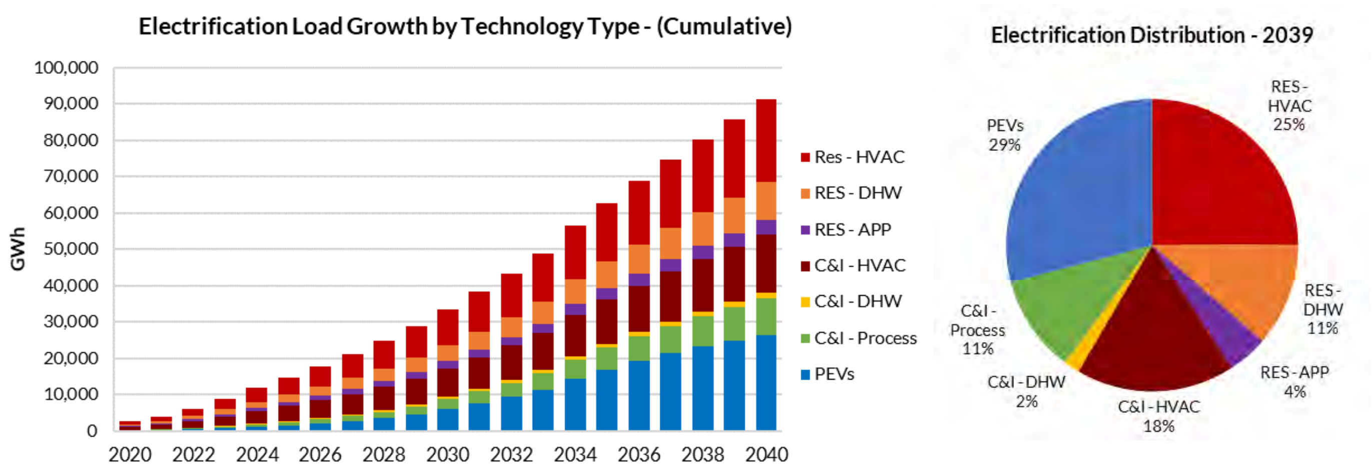


Figure 83: SPP Future 3 Electrification Broken Down by End-Use

TVA-Other Electrification

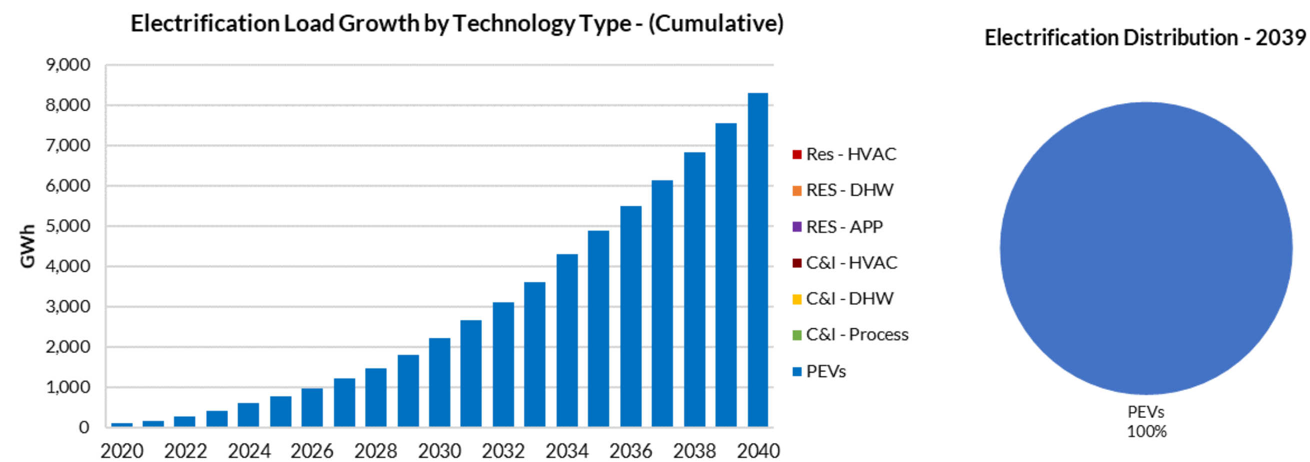


Figure 84: TVA-Other Future 1 Electrification Broken Down by End-Use

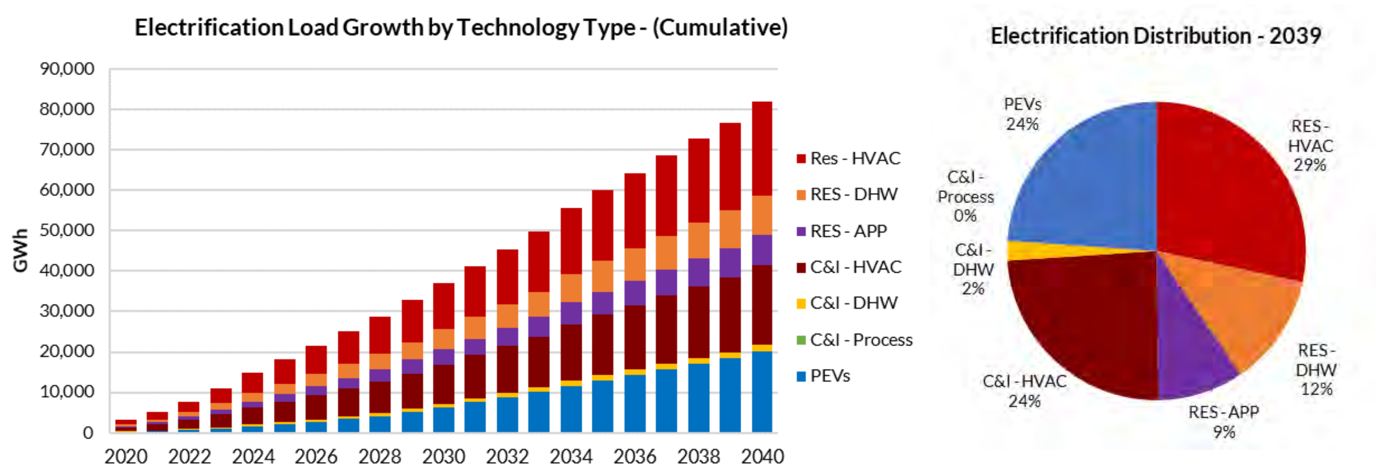
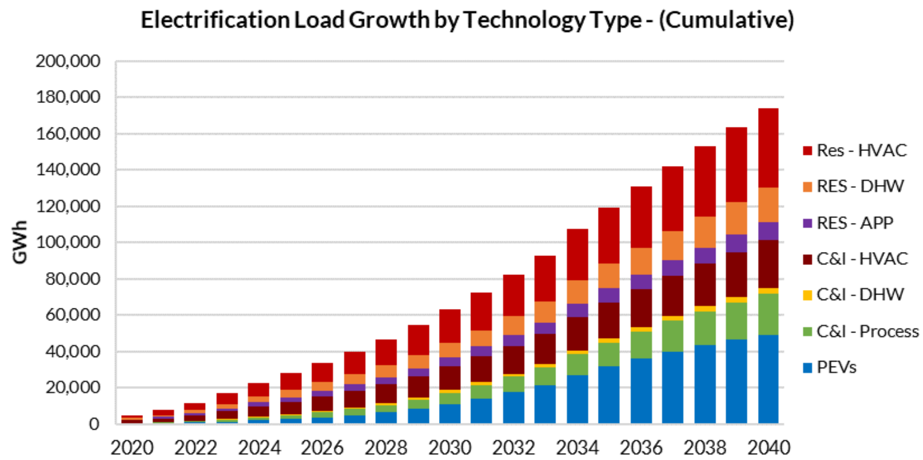


Figure 85: TVA-Other Future 2 Electrification Broken Down by End-Use



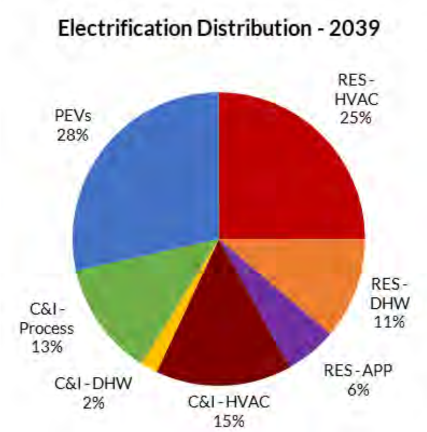


Figure 86: TVA-Other Future 3 Electrification Broken Down by End-Use

External Region Electrification Summary

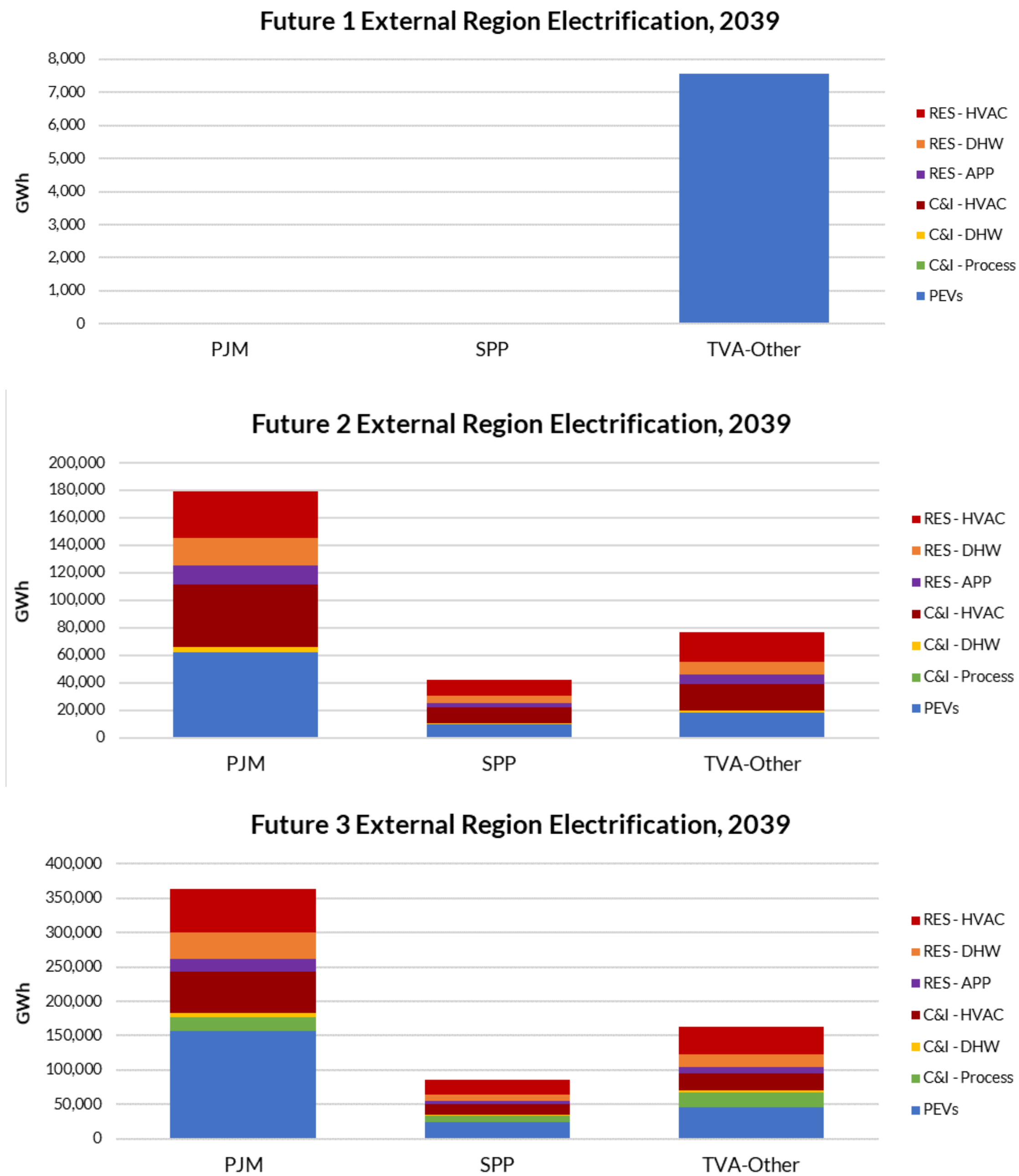


Figure 87: External Region Future Scenario Electrification[41]

[41] The only electrification in Future 1 happens in the external region TVA-Other due to SPP and PJM's Future 1 forecasts already including EVs.

External Expansion Results

While comparing the expansion results of the External regions across each Future scenario, there are several key findings of note:

- All scenarios have very different expansions; this is due to large contrasts among the regions with respect to geography, resource retirements, and current resource mixes.
- Wind, solar, and hybrid resource expansion is largely driven by decarbonization and each underlying load shape. In Future 3 there is significantly more wind than the other two cases; this is primarily due to the increase in load and 80% carbon reduction.
- Battery installation is driven by increased load and decarbonization.
- Age-based retirement assumptions for nuclear, wind, solar, and "other" resources remain the same across scenarios, with the exception of SPP Future 1. In this future, MISO incorporated retirement assumptions in SPP's Future 2. Additionally, all retired wind is repowered and reflected in the resource addition totals.
- In Future 3, the CC+CCS resource proxy units are needed in the later years of the study to serve base load with low CO_2 emissions, while maintaining a high capacity factor.
- Distributed solar (DGPV) and energy efficiency (EE) programs selected by EGEAS for TVA-Other (TVAO) remained the same across all scenarios. SPP Future 2 selected an additional EE program compared with Futures 1 and 3. Lastly, PJM's first two Futures both selected two DGPV and EE programs, while Future 3 selected one of each. A list of EGEAS-offered and selected programs for External regions is found below in Table 22.

Over the course of the following pages (Table 21 through Table 24) the detailed expansion results of each External Future scenario are displayed. Following the figures in each section are resource-specific additions and retirement (R&A) tables, each table details R&A capacities applicable for each region and milestone year.

Future Resource Additions (MW)											
Area	Future	CC	CT	CC+CCS	Wind	Solar	Hybrid	Battery	Distributed Solar	EE	Total
PJM	Future 1	14,400	21,600	0	6,641	3,600	10,800	0	2,954	35,919	95,915
	Future 2	25,200	18,000	0	42,641	21,600	21,600	2,000	2,954	38,110	172,106
	Future 3	21,600	7,200	32,400	175,841	3,600	79,200	20,000	295	17,291	357,427
SPP	Future 1	9,600	14,400	0	15,600	2,400	6,000	8,500	1,100	1,197	58,797
	Future 2	21,600	9,600	0	24,256	4,800	2,400	6,000	1,100	3,253	73,009
	Future 3	18,000	12,000	10,800	38,656	1,200	6,000	9,500	1,100	1,332	98,588
TVA-Other	Future 1	16,800	1,200	0	14,405	0	26,400	0	118	346	59,269
	Future 2	16,800	7,200	0	60,005	13,200	25,200	300	118	370	123,193
	Future 3	18,000	18,000	28,800	123,605	39,600	14,400	32,000	118	382	274,905

Future Resource Retirements (MW)									
Area	Future	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Total
PJM	Future 1	53,068	9,312	0	7,002	6,641	251	0	76,275
	Future 2	54,680	15,348	0	7,136	6,641	251	0	84,055
	Future 3	55,737	57,793	0	7,502	6,641	251	0	127,924
SPP	Future 1	18,361	5,631	0	1,260	0	0	0	25,252
	Future 2	19,842	13,205	0	1,361	9,856	50	0	44,314
	Future 3	20,524	24,516	0	1,392	9,856	50	0	56,337
TVA-Other	Future 1	42,295	7,350	0	1,910	1,205	165	276	53,201
	Future 2	43,840	9,117	0	1,910	1,205	165	276	56,513
	Future 3	45,040	55,246	0	1,990	1,205	165	276	103,922

Table 21: External Resource Additions and Retirements Summary

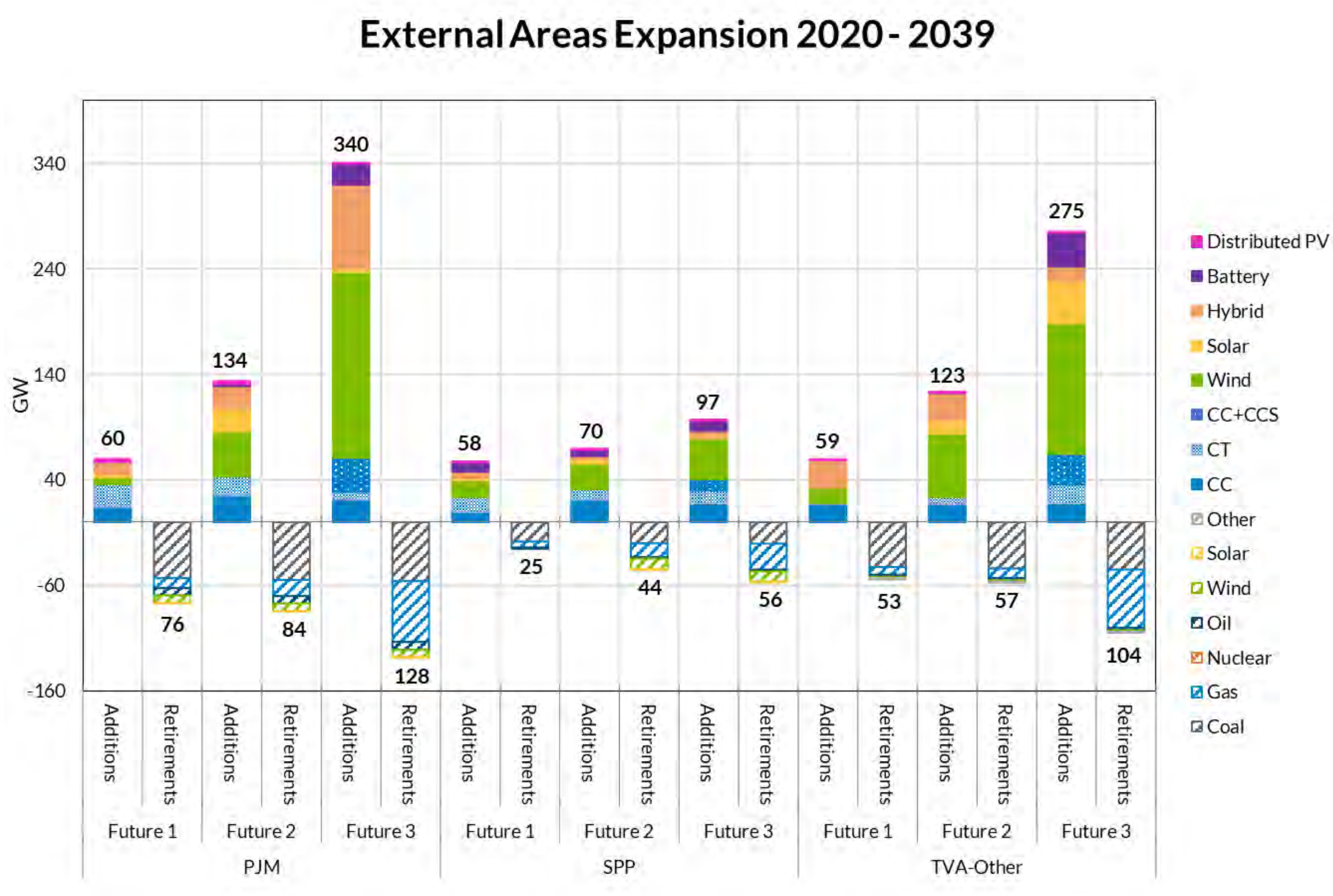


Figure 88: External Region Expansion Summary

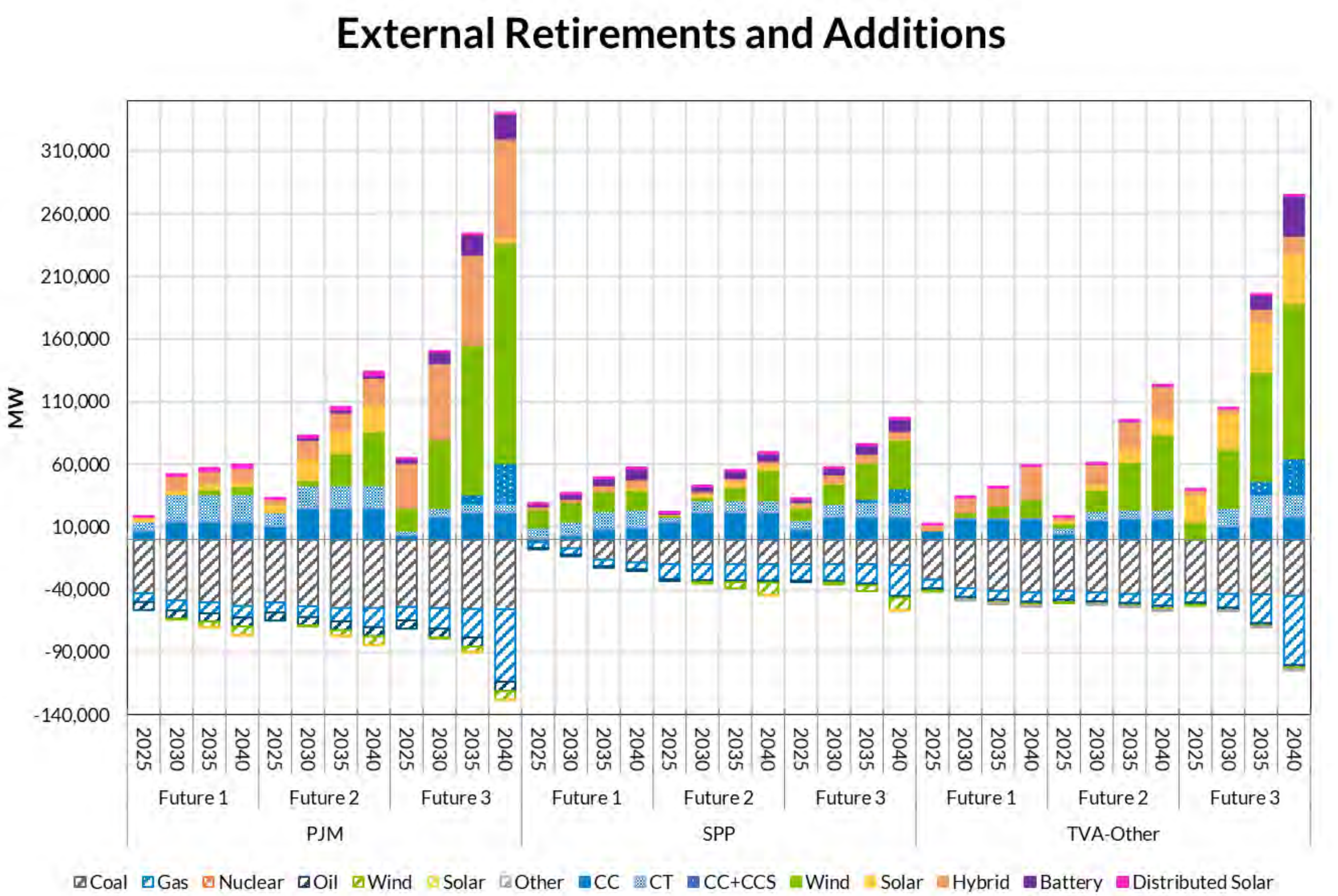


Figure 89: External Resource Additions and Retirements per Milestone Year (Cumulative)

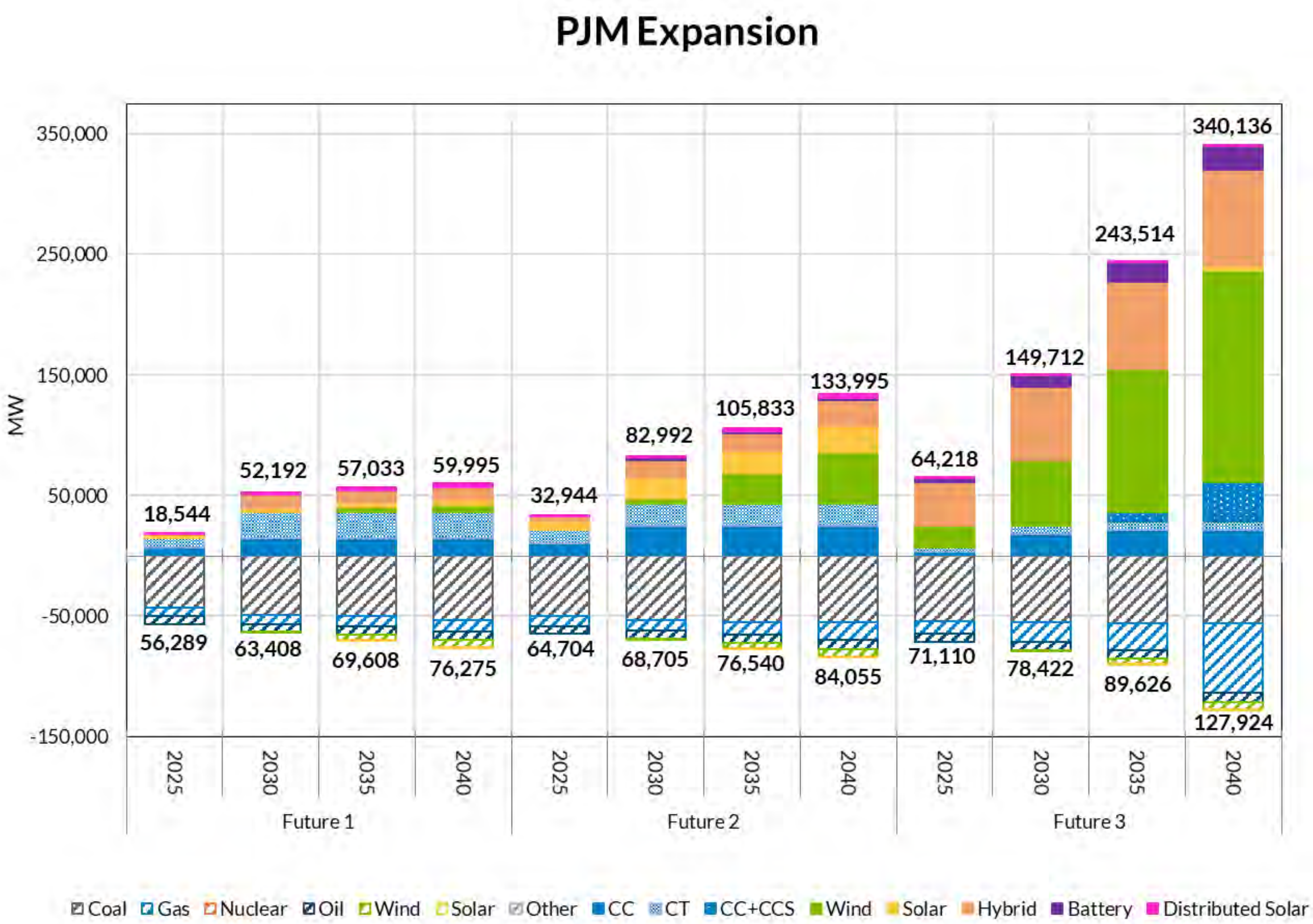


Figure 90: PJM Resource Additions and Retirements per Milestone Year (Cumulative)

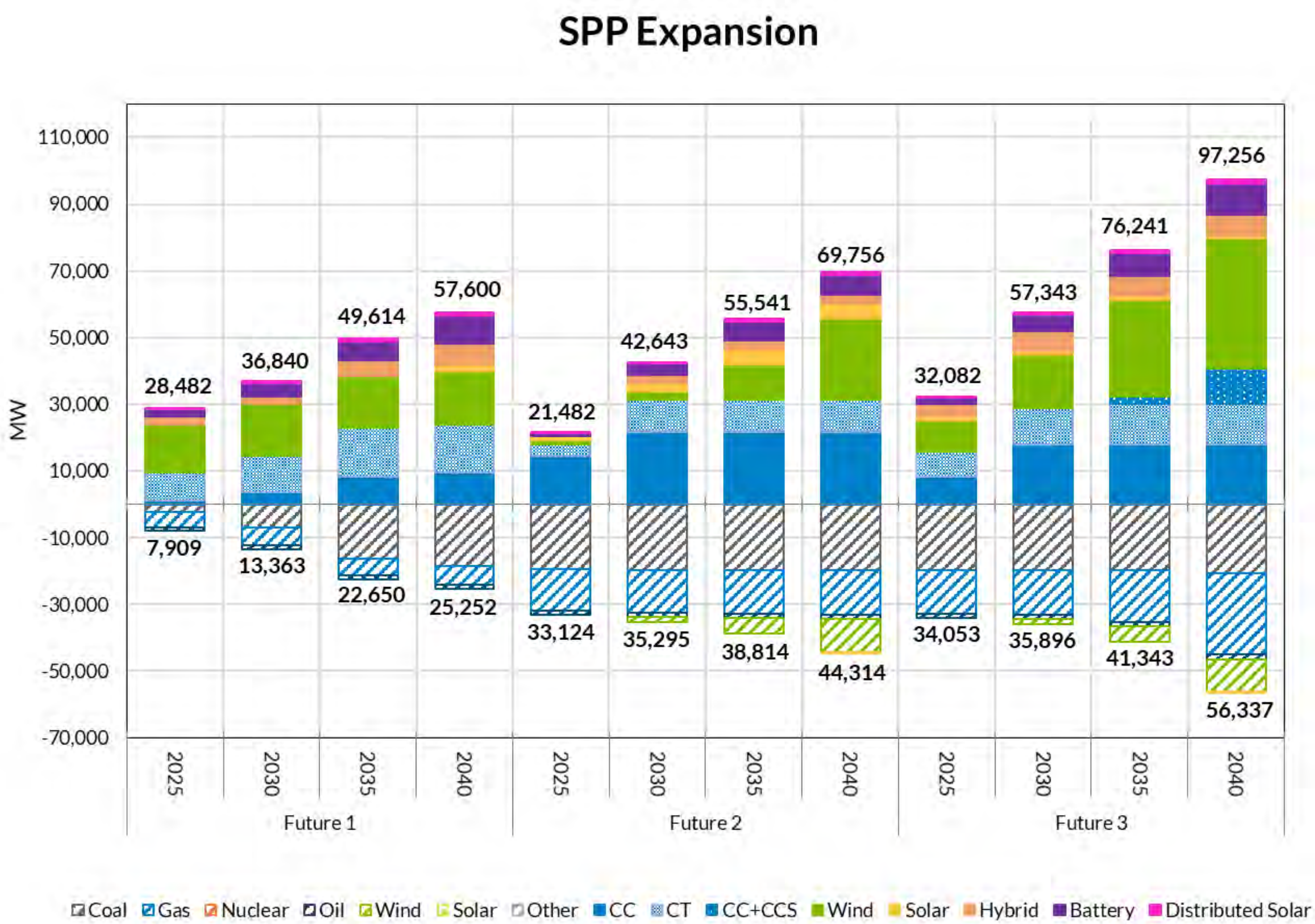


Figure 91: SPP Resource Additions and Retirements per Milestone Year (Cumulative)

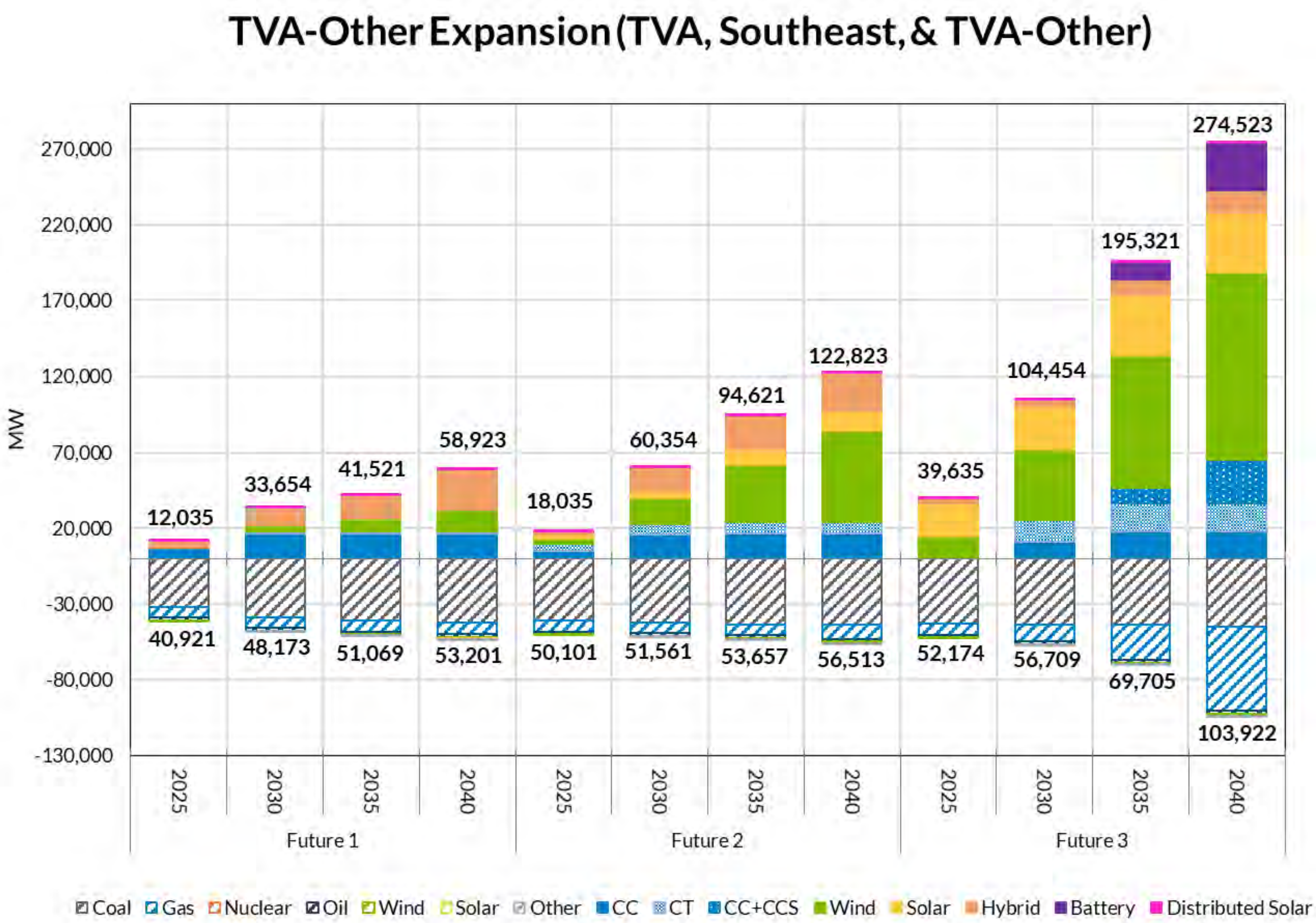


Figure 92: TVA-Other Resource Additions and Retirements per Milestone Year (Cumulative)

External DER Programs: Respective Offerings and Selections

DER Type	EGEAS Program Block	DER Program(s) Included	PJM	SPP	TVAO
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable	*Offered*	*Offered*	*Offered*
DR	C&I Price Response	C&I Price Response	*Offered*	*Offered*	*Offered*
DR	Res. Direct Load Control	Res. Direct Load Control	*Offered*	*Offered*	-
DR	Res. Price Response	Res. Price Response	*Offered*	*Offered*	-
EE	C&I EE	Custom Incentive, Lighting, New Construction, Prescriptive Rebate, Retro commissioning	F1, F2, F3	F2	F1, F2, F3
EE	Res. EE	Appliance Incentives, Appliance Recycling, Behavioral Programs, Lighting, Low Income, Multifamily, New Construction, School Kits, Whole Home Audit	F1, F2	F1, F2, F3	F1, F2, F3
DG	C&I Customer Solar PV	C&I Customer Solar PV	F1, F2	F1, F2, F3	F1, F2, F3
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Util Incentive Batt Storage	*Offered*	*Offered*	*Offered*
DG	C&I Utility Incentive Solar PV	C&I Utility Incentive Solar PV	F1, F2, F3	F1, F2, F3	-
DG	Res. Customer Solar PV	Res. Customer Solar PV	*Offered*	*Offered*	*Offered*
DG	Res. Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Util Incentive Batt Storage	*Offered*	*Offered*	*Offered*
DG	Res. Utility Incentive Solar PV	Res. Utility Incentive Solar PV	*Offered*	*Offered*	-

Table 22: External DER Program Mapping, with Respective Offerings and Selection by Future in EGEAS

External Area Resource Additions per Future (MW) - *Cumulative*										
Future/Area	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Total**
PJM Future 1	**2025**	7,200	7,200	0	0	3,600	0	0	544	18,544
	2030	14,400	21,600	0	245	3,600	10,800	0	1,547	52,192
	2035	14,400	21,600	0	4,129	3,600	10,800	0	2,504	57,033
	2040	14,400	21,600	0	6,641	3,600	10,800	0	2,954	59,995
PJM Future 2	**2025**	10,800	10,800	0	0	7,200	3,600	0	544	32,944
	2030	25,200	18,000	0	3,845	18,000	14,400	2,000	1,547	82,992
	2035	25,200	18,000	0	25,729	18,000	14,400	2,000	2,504	105,833
	2040	25,200	18,000	0	42,641	21,600	21,600	2,000	2,954	133,995
PJM Future 3	**2025**	3,600	3,600	0	18,000	0	36,000	3,000	18	64,218
	2030	18,000	7,200	0	54,245	0	61,200	9,000	68	149,712
	2035	21,600	7,200	7,200	119,329	0	72,000	16,000	185	243,514
	2040	21,600	7,200	32,400	175,841	3,600	79,200	20,000	295	340,136
SPP Future 1	**2025**	1,200	8,400	0	14,400	0	2,400	2,000	82	28,482
	2030	3,600	10,800	0	15,600	0	2,400	4,000	440	36,840
	2035	8,400	14,400	0	15,600	0	4,800	5,500	914	49,614
	2040	9,600	14,400	0	15,600	2,400	6,000	8,500	1,100	57,600
SPP Future 2	**2025**	14,400	3,600	0	1,200	1,200	0	1,000	82	21,482
	2030	21,600	9,600	0	2,703	2,400	2,400	3,500	440	42,643
	2035	21,600	9,600	0	10,727	4,800	2,400	5,500	914	55,541
	2040	21,600	9,600	0	24,256	4,800	2,400	6,000	1,100	69,756
SPP Future 3	**2025**	8,400	7,200	0	9,600	1,200	3,600	2,000	82	32,082
	2030	18,000	10,800	0	15,903	1,200	6,000	5,000	440	57,343
	2035	18,000	12,000	2,400	28,727	1,200	6,000	7,000	914	76,241
	2040	18,000	12,000	10,800	38,656	1,200	6,000	9,500	1,100	97,256
TVA-Other Future 1	**2025**	7,200	0	0	29	0	4,800	0	7	12,035
	2030	16,800	1,200	0	3,629	0	12,000	0	25	33,654
	2035	16,800	1,200	0	9,055	0	14,400	0	66	41,521
	2040	16,800	1,200	0	14,405	0	26,400	0	118	58,923
TVA-Other Future 2	**2025**	4,800	4,800	0	3,629	2,400	2,400	0	7	18,035
	2030	15,600	7,200	0	16,829	4,800	15,600	300	25	60,354
	2035	16,800	7,200	0	37,855	10,800	21,600	300	66	94,621
	2040	16,800	7,200	0	60,005	13,200	25,200	300	118	122,823
TVA-Other Future 3	**2025**	0	0	0	14,429	21,600	3,600	0	7	39,635
	2030	10,800	14,400	0	46,829	28,800	3,600	0	25	104,454
	2035	18,000	18,000	10,800	87,055	39,600	10,800	11,000	66	195,321
	2040	18,000	18,000	28,800	123,605	39,600	14,400	32,000	118	274,523

Table 23: External Resource Additions by Milestone Year

External Area Resource Retirements per Future (MW) - *Cumulative*									
Future/Area	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Total**
PJM Future 1	**2025**	43,061	6,829	0	6,400	0	0	0	56,289
	2030	48,723	7,981	0	6,460	245	0	0	63,408
	2035	50,263	8,569	0	6,604	4,129	43	0	69,608
	2040	53,068	9,312	0	7,002	6,641	251	0	76,275
PJM Future 2	**2025**	50,263	7,981	0	6,460	0	0	0	64,704
	2030	53,287	8,569	0	6,604	245	0	0	68,705
	2035	54,680	10,687	0	7,002	4,129	43	0	76,540
	2040	54,680	15,348	0	7,136	6,641	251	0	84,055
PJM Future 3	**2025**	53,819	10,687	0	6,604	0	0	0	71,110
	2030	54,680	16,495	0	7,002	245	0	0	78,422
	2035	55,469	22,703	0	7,283	4,129	43	0	89,626
	2040	55,737	57,793	0	7,502	6,641	251	0	127,924
SPP Future 1	**2025**	2,318	4,588	0	1,003	0	0	0	7,909
	2030	7,089	5,062	0	1,213	0	0	0	13,363
	2035	16,238	5,200	0	1,213	0	0	0	22,650
	2040	18,361	5,631	0	1,260	0	0	0	25,252
SPP Future 2	**2025**	19,563	12,329	0	1,232	0	0	0	33,124
	2030	19,842	12,649	0	1,301	1,503	0	0	35,295
	2035	19,842	12,938	0	1,307	4,727	0	0	38,814
	2040	19,842	13,205	0	1,361	9,856	50	0	44,314
SPP Future 3	**2025**	19,842	12,938	0	1,273	0	0	0	34,053
	2030	19,842	13,245	0	1,307	1,503	0	0	35,896
	2035	19,842	15,413	0	1,361	4,727	0	0	41,343
	2040	20,524	24,516	0	1,392	9,856	50	0	56,337
TVA-Other Future 1	**2025**	31,981	7,001	0	1,910	29	0	0	40,921
	2030	38,907	7,051	0	1,910	29	0	276	48,173
	2035	41,111	7,051	0	1,910	655	66	276	51,069
	2040	42,295	7,350	0	1,910	1,205	165	276	53,201
TVA-Other Future 2	**2025**	41,111	7,051	0	1,910	29	0	0	50,101
	2030	42,295	7,051	0	1,910	29	0	276	51,561
	2035	43,400	7,350	0	1,910	655	66	276	53,657
	2040	43,840	9,117	0	1,910	1,205	165	276	56,513
TVA-Other Future 3	**2025**	42,885	7,350	0	1,910	29	0	0	52,174
	2030	43,400	11,094	0	1,910	29	0	276	56,709
	2035	43,840	22,878	0	1,990	655	66	276	69,705
	2040	45,040	55,246	0	1,990	1,205	165	276	103,922

Table 24: External Resource Retirements by Milestone Year

Presentation Materials

Futures Workshops & MISO Stakeholder Presentations:

August 15, 2019: MTEP Futures Workshop – Purpose of MISO Futures

September 26, 2019: MTEP Futures Workshop – Drafting of Futures Assumptions

October 17, 2019: MTEP Futures Workshop – Walkthrough of Initial Strawman

December 5, 2019: MTEP Futures Workshop – Detailing Various Assumptions

February 13, 2020: MTEP Futures Workshop – Updated Assumptions

April 27, 2020: MTEP Futures Workshop – Final Assumptions

July 13, 2020: MTEP Futures Workshop – Siting Review

August 12, 2020: PAC Presentation – Draft Expansion and Siting Results

November 11, 2020: PAC Presentation – Final Expansion and Siting Results

September 22, 2021: PAC Presentation – Correction to Futures Resource Expansion

October 13, 2021: PAC Presentation – Revised Future 2 and 3 Expansion Results for MISO

November 10, 2021: PAC Presentation – Revised Futures Siting and External Expansion Results

Full Futures Evolution Material Available at: MISOEnergy.org

SCHEDULE 3:
RESOURCE ASSUMPTIONS

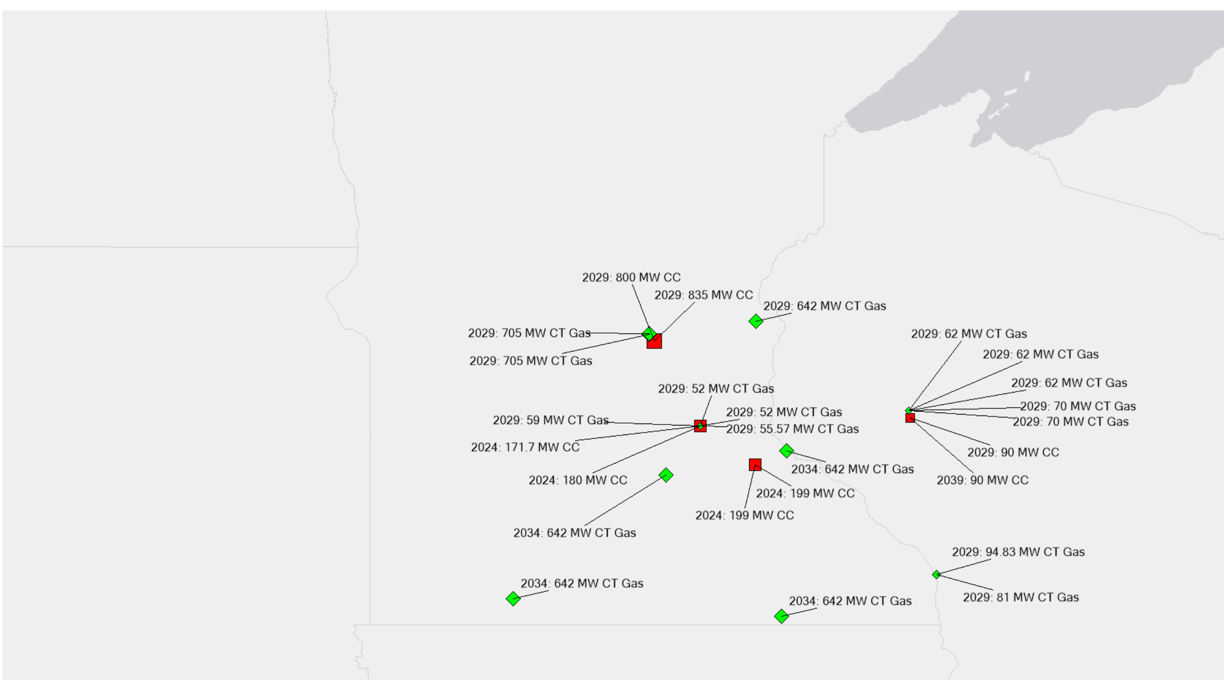
This schedule provides the assumptions that Northern States Power Company, a Minnesota corporation (NSP or Company), used in the economic analysis of Adjusted Production Cost (APC) savings for the Brookings County – Lyon County and Helena – Hampton Second-Circuit Project (Project)..

I. BACKGROUND

PROduction MODeling (PROMOD) was used to calculate the Project's APC savings. The economic benefits of the Project were initially evaluated with PROMOD using the MTEP21, Future 1 (Future 1), assumptions. Future 1 used announced state and utility goals, and other input assumptions through September 2020.

The Company completed its most recent resource planning process after the Future 1 assumptions were established.[1] Future 1 does not fully align with the Company's resource assumptions. Future 1 assumes that, by 2040, an additional 2,565 megawatts (MW) of combined cycle gas-powered generation (CC) and an additional 4,293 MW of combustion-turbine (CT) generation will be added to NSP and Northern States Power Company, a Wisconsin corporation's (NSP-W) system (NSP System). These additional CC and CT resources are depicted in **Figure 1, JS-1 (Sch. 3)**.

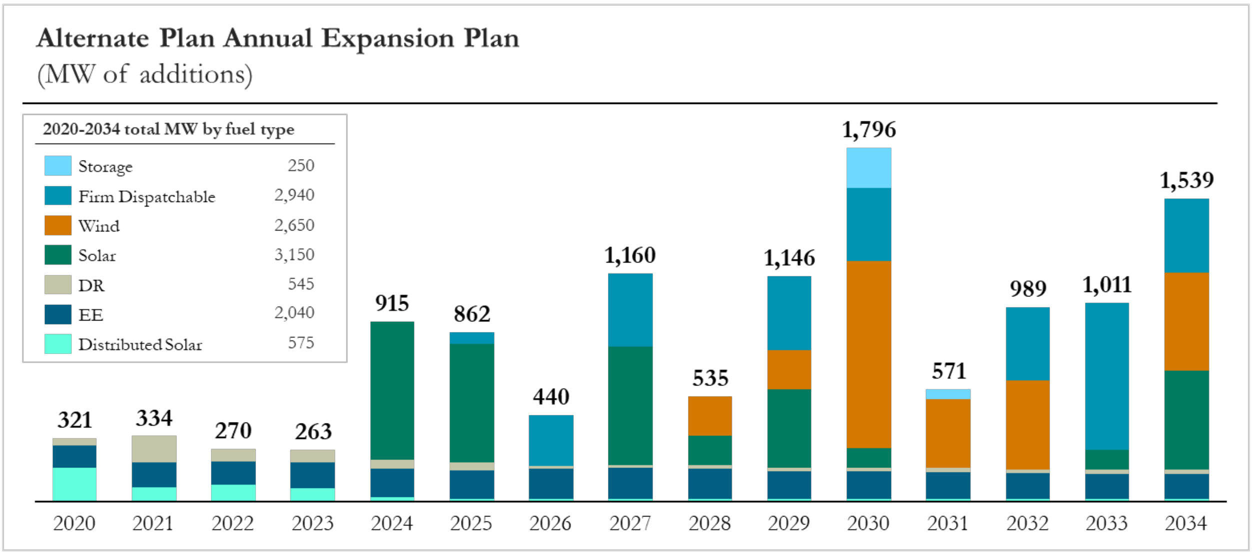
Figure 1, JS-1 (Sch. 3): Future 1 CC and CT Resources



[1] Reply Comments at fig. 4-4, Case No. PU-19-220 (June 28, 2021); Supplement to 2020-2034 Upper Midwest Integrated Resource Plan, Case No. PU-19-220 (June 28, 2020).

The Company's current resource assumptions anticipate 3,311 MW of new gas generation by 2040. The Company performed a second analysis using the PROMOD tool with assumptions that the Company believes more accurately reflect NSP's future generation mix.[2] These updated resource assumptions are shown, by fuel type, in **Figure 2, JS-1 (Sch. 3).**

Figure 2, JS-1 (Sch. 3): Upper Midwest Resource Plan, by Fuel Type[3]



The Company's planning period for new generation extends from 2020 to 2034. Generation beyond the planning period is also modeled to capture the "end effects" of the resource assumptions. End effects refer to the impacts outside the planning period of generation added within the planning period. The additional modeled years allowed the economic analysis for the Project to include anticipated generation through 2040. **Table 1, JS-1 (Sch. 3)**, reflects the new generation added in each year of the economic analysis by fuel type.

[2] Filed as NDPSC Case No. PU-19-220; 2020-2034 Upper Midwest Integrated Resource Plan, Case No. PU-19-220 (July 1, 2019); Supplement to 2020-2034 Upper Midwest Integrated Resource Plan, Case No. PU-19-220 (June 28, 2020); Reply Comments at fig. 4-4, Case No. PU-19-220 (June 28, 2021).
[3] Reply Comments at fig. 4-4, Case No. PU-19-220 (June 28, 2021).

Table 1, JS-1 (Sch. 3): Resource Plan, by Fuel Type

Plan Namplate (MW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Standalone Storage	-	-	-	-	-	-	-	-	-	-	200	50	-	-	-	-	-	-	100	100	650	1,100
Hybrid	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	200	200	950	350	450	-	500	600	200	400	-	300	750	4,900
Solar	-	-	-	-	700	600	-	600	150	400	100	-	-	100	500	-	200	550	100	450	-	4,450
Firm Peaking	-	-	-	-	-	60	259	374	-	374	374	-	374	748	374	-	-	-	-	374	-	3,311
CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SherCo CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distributed Resources	33	132	67	62	47	41	12	14	15	17	19	20	21	22	24	25	27	28	30	32	34	720
Energy Efficiency	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	(23)	(72)	(128)	(122)	(125)	(138)	1,433
Distributed Solar	173	72	87	68	25	16	15	15	15	15	15	15	15	15	15	15	15	15	14	14	14	662
Total	**33**	**132**	**67**	**62**	**747**	**701**	**271**	**988**	**365**	**991**	**1,643**	**420**	**845**	**870**	**1,398**	**625**	**427**	**978**	**230**	**1,256**	**1,434**	**19,881**

The economic analysis also updated Future 1 to include assumptions based on the results of NSP's recent resource procurement process. This process resulted in the planned procurements of 250 MW of new generation in the vicinity of the Company's Sherburne County generation facility site and a power purchase agreement for 100 MW of new generation in Polk County, Wisconsin.

The planned capacity additions are grouped into five-year increments in the economic analysis. **Table 2, JS-1 (Sch. 3)**, shows the total installed new capacity used in the analysis in each five-year period.

Table 2, JS-1 (Sch. 3): Resource Plan and Procurements

Nameplate (MW)	2025	2030	2035	2040
Standalone Storage	-	200	250	1,100
Hybrid	-	-	-	-
Wind	-	1,350	3,250	4,900
Solar	1,300	2,550	3,150	4,450
Firm Peaking	60	1,441	2,937	3,311
CC	-	-	-	-
SherCo CC	-	-	-	-
Distribute Resources	382	459	570	720
Energy Efficiency	781	1,524	2,017	1,433
Distributed Solar	440	515	589	662

PROMOD is typically used in MISO planning to provide forecasts over a 20-year period. The book life of the Project is approximately 63 years. The economic analysis was also updated to derive the present value of 63 years of APC savings. The updated assumptions are detailed below.

II. RESOURCE PLANNING ASSUMPTIONS

Updates were made to Future 1 in the economic analysis to align with NSP's future generation plans. Only NSP's generation resources were updated from the Future 1 assumptions. Generation owned by others remained in the analysis but was not modified from the Future 1 assumptions.

Both the capacity and location of NSP's generation resources were modified to reflect NSP's future generation plans. Reasonable assumptions were made regarding the siting of new resources. The Company attempted to spread changes to generation resources evenly across the NSP System. *With the exception of known resource procurements, the siting of the resources does not represent the location of NSP-planned resource additions*; they were simply reasonable assumptions necessary for conducting the analysis.

A. Battery Storage

Battery storage capacity consistent with the Company's current resource assumptions of 1,100 MW was added and all other battery storage capacity was removed to appropriately reflect the topology of the NSP System. **Table 3, JS-1 (Sch. 3)**, reflects the batteries added to PROMOD and their points of interconnection (POI). Each battery includes five or six POIs. The batteries were given multiple POIs to simulate a greater number of batteries than were actually added to the analysis. Each individual battery is simulated to charge and discharge at the same time and rate across the POIs. Separate batteries can charge and discharge at different times and rates in the analysis.

Table 3, JS-1 (Sch. 3): Battery Storage POIs

Resource	IRP BAT V1	IRP BAT V2	IRP BAT V3	IRP BAT V4
POIs	Inver Hills (MN)	Winona (MN)	Odel (MN)	Wilson (MN)
	North Rochester (MN)	Buffalo Ridge I (MN)	Roseau (MN)	Black Dog (MN)
	Stone Lake (WI)	Red Rock (MN)	Sherco (MN)	Lyon Co. (MN)
	Chisago (MN)	Gingles (WI)	Colvill (MN)	Hurley (WI)
	Crandall (MN)	Blue Lake (MN)	Franklin (MN)	Hazel Creek (MN)
	N/A	N/A	La Crosse (MN)	Minnesota Valley (MN)

Table 4, JS-1 (Sch. 3), provides the cumulative additional battery storage capacity added to the assumptions in five-year increments from a 2020 baseline.

Table 4, JS-1 (Sch. 3): Cumulative Newly Installed Battery Storage Capacity

Resource	Capacity by Year (MW)			
	2025	2030	2035	2040
IRP BAT V1	0	50	62.5	275
IRP BAT V2	0	50	62.5	275
IRP BAT V3	0	50	62.5	275
IRP BAT V4	0	50	62.5	275

B. Wind Generators

The analysis assumptions were updated to reflect the 4,900 MW of wind generation included in the resource assumptions and all additional wind generation from Future 1 was removed from the NSP System. Three simulated wind plants were created to represent wind sited in North Dakota, South Dakota, and southern Minnesota.

Table 5, JS-1 (Sch. 3), provides the POIs of those three wind resources. Each wind plant has multiple POIs to simulate wind plants sited at multiple locations. The energy output of each individual wind plant is evenly distributed between the POIs.

Table 5, JS-1 (Sch. 3): Wind Generation POIs

Resource	IRP Wind Dakota	IRP Wind SE Minnesota	IRP Wind SW Minnesota
POIs	Generator 302 and 503 (ND)	Crandall (MN)	Deuel (MN-SD Border)
	Prairie Rose (MN-SD Border)	Huntley (MN-IA Border)	Blazing Star (MN)
	Big Stone South (SD)	Adams (MN)	Stone Ray (MN)
	Generator 488 (SD)	Byron (MN)	Buffalo Ridge (MN)

Table 6, JS-1 (Sch. 3), provides the cumulative additional wind generation capacity in five-year increments from a 2020 baseline.

Table 6, JS-1 (Sch. 3): Wind Generation Capacity

Resource	Capacity by Year (MW)			
	2025	2030	2035	2040
IRP Wind Dakota	300	450	1083	1633
IRP Wind SE Minnesota	20	450	1083	1633
IRP Wind SW Minnesota	107	450	1083	1633

C. Utility-Scale Solar

The capacity of existing solar resources in the analysis was updated to reflect the 4,450 MW of new solar resources in NSP's resource assumptions. Two new solar resources were also added to represent the planned acquisition of 710 MW solar capacity to be interconnected at Sherco (Sherco 1, 2, and 3) and 100 MW to be interconnected at the Apple River Substation in Polk County, Wisconsin (Apple River Solar). No changes were made to the POIs of the existing utility-scale solar resources in Future 1. **Table 7, JS-1 (Sch. 3)**, reflects the added solar resources and updated capacity of the new utility-scale sources.

Table 7, JS-1 (Sch. 3): Utility Scale Solar Generation Capacity

Resource	Capacity by Year (MW)			
	2025	2030	2035	2040
IRP Solar Apple River	100	100	100	100
IRP Solar Sherco	230	710	710	710
RRF MISO PV: Minnesota - 1	37	57	57	57
RRF MISO PV: Minnesota - 6	37	57	57	57
RRF MISO PV: Minnesota - 7	37	57	57	57
RRF MISO PV: Minnesota - 8	147	165	165	165
RRF MISO PV: Minnesota - 9	37	57	57	57
RRF MISO PV: Minnesota - 10	37	57	57	57
RRF MISO PV: Minnesota - 15	37	57	57	57
RRF MISO PV: Minnesota - 16	70	78	78	78
RRF MISO PV: South Dakota - 1	113	126	126	126
RRF MISO PV: Tier 2 - 11	103	116	116	116
RRF MISO PV: Wisconsin - 8	57	64	64	64

D. Distributed Solar

The capacity of distributed solar resources was updated so that when combined with other distributed solar resources in Future 1, the total distributed solar in the analysis equaled 662 MW, the amount of distributed solar in the Company's resource assumptions. PROMOD does not model the distribution system. The distributed solar's profile and capacity in the analysis reflects the characteristics of rooftop and community solar. The in-service date of all the distributed solar resources the Company modified was accelerated to 2024 to align with the distributed solar capacity in the early years of the Company's resource assumptions. The updated capacity of the distributed solar resources are listed in **Table 8, JS-1 (Sch. 3)**.

Table 8, JS-1 (Sch. 3): Distributed Solar

Resource	Capacity by Year (MW)			
	2025	2030	2035	2040
DG Solar_IRP_2031_1	3.3	8.4	13.3	18.1
DG Solar_IRP_2031_2	3.3	8.4	13.3	18.1
DG Solar_IRP_2031_3	3.3	8.4	13.3	18.1
DG Solar_IRP_2031_4	3.3	8.4	13.3	18.1
DG Solar_IRP_2031_5	3.3	8.4	13.3	18.1
DG Solar_IRP_2033_1	3.3	8.4	13.3	18.1
DG Solar_IRP_2033_2	3.3	8.4	13.3	18.1
DG Solar_IRP_2033_3	3.3	8.4	13.3	18.1
DG Solar_IRP_2033_4	3.3	8.4	13.3	18.1
DG Solar_IRP_2033_5	3.3	8.4	13.3	18.1
DG Solar_IRP_2035_1	3.3	8.4	13.3	18.1
DG Solar_IRP_2035_2	3.3	8.4	13.3	18.1
DG Solar_IRP_2035_3	3.3	8.4	13.3	18.1
DG Solar_IRP_2035_4	3.3	8.4	13.3	18.1
DG Solar_IRP_2035_5	3.3	8.4	13.3	18.1

III. Gas Resources

Twenty-one CTs and CCs included in Future 1 were removed from the analysis. All CCs in Future 1 were removed because NSP's resource assumptions include no CCs. The capacity of six CTs from Future 1 were adjusted. These removals and adjustments were made so the firm peaking capacity on the NSP System equaled 3,790 MW. The capacity of CTs in the analysis exceeds the resource assumptions by around 500 MW. This additional firm peaking capacity was included as a reasonably conservative assumption in light of the new Midcontinent Independent System Operator, Inc., seasonal capacity construct and uncertainty around accredited capacity.

With the exception of the Lyon County CT, all the CTs and CCs in Minnesota were removed to recognize recent legislation requiring that electric utilities meet all Minnesota retail customers' electricity needs from "carbon-free energy technologies" by 2040.[4] The CT in Lyon County, Minnesota, was retained as a voltage support and potential capacity resource.

[4] *See* 2023 Minn. Laws ch. 7.

The CT and CC gas plants that the Company removed from the analysis are found in **Table 9, JS-1 (Sch. 3)**.

Table 9, JS-1 (Sch. 3): New NSP Generators Removed

Generator's PROMOD Name	Generator's PROMOD Name
CC_IRP_2026_2	RRF MISO CC: 012
CC_IRP_2027_1	RRF MISO CC: 013
CC_IRP_2030_1	RRF MISO CT Gas: 047
CC_IRP_2037_1	RRF MISO CT Gas: 057
CT_IRP_2029_1	RRF MISO CT Gas: 071
CT_IRP_2031_1	RRF MISO CT Gas: 072
CT_IRP_2033_1	RRF MISO CT Gas: 073
CT_IRP_2034_1	Wheaton: 1
CT_IRP_2035_2	Wheaton: 2
RRF MISO CC: 010	Wheaton: 3
RRF MISO CC: 011	Wheaton: 4[5]

Table 10, JS-1 (Sch. 3), provides the CTs whose capacities were adjusted and the POI[6] of those CTs.

Table 10, JS-1 (Sch. 3): CT Resources

Resource	POI	Capacity by Year (MW)			
		2025	2030	2035	2040
RRF MISO CT Gas: 058	Lyon County (MN)	374	374	374	374
RRF MISO CT Gas: 059	French Island (WI)	90	301	675	768
RRF MISO CT Gas: 062	Big Stone South (SD)	90	301	675	768
RRF MISO CT Gas: 066	Angus Anson (SD)	90	301	675	768
RRF MISO CT Gas: 067	Bison (ND)	374	374	748	842
Wheaton 2025[7]	Wheaton (WI)	270	270	270	270

IV. GAS ASSUMPTIONS

The natural gas-price forecasts were updated to match NSP's current resource assumptions. The gas-price forecasts in Future 1 were established in September 2020.

[5] Wheaton 1-4 represent the existing Wheaton CT units anticipated to be retired in 2025.
[6] The Company confirmed there were nearby gas transmission lines that could serve the CTs near these POIs.
[7] "Wheaton 2025" represents the Wheaton Repowering Project in Chippewa County, Wisconsin. NSP-W filed for a Certificate of Public Convenience and Necessity in Wisconsin for the Wheaton Repowering Project on May 12, 2023.[7] The shoulder season (spring and fall) nameplate capacity for Wheaton 2025 was used since that reflects the maximum output capacity.

The Company's resource assumptions rely on more updated gas-price forecasts developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term forecasts from Wood Mackenzie, Cambridge Energy Research Associates, and Petroleum Industry Research Associates.[8] The gas forecast reflects projected prices at the Ventura hub in northern Iowa. The forecasted monthly gas prices used in the Company's economic analysis for the Project are provided in **Table 11, JS-1 (Sch. 3)**.

[8] Reply Comments at 12, Case No. PU-19-220 (June 28, 2021).

Table 11, JS-1 (Sch. 3): Ventura Hub Resource Assumptions Gas Forecast

	January	February	March	April	May	June	July	August	September	October	November	December
2025	3.03	3	2.84	2.62	2.6	2.62	2.68	2.7	2.67	2.71	2.89	3.14
2026	3.27	3.25	3.06	2.81	2.72	2.74	2.77	2.78	2.85	2.98	3.15	3.36
2027	3.5	3.46	3.21	2.93	2.85	2.86	2.88	2.9	2.94	3.11	3.29	3.49
2028	3.58	3.55	3.4	3.09	3.02	3.03	2.96	2.98	3.08	3.3	3.51	3.68
2029	3.84	3.82	3.59	3.29	3.2	3.21	3.03	3.05	3.22	3.5	3.7	3.9
2030	4.05	4.04	3.83	3.48	3.4	3.43	3.44	3.47	3.54	3.69	3.89	4.09
2031	4.26	4.24	3.96	3.64	3.56	3.58	3.63	3.65	3.7	3.87	4.08	4.29
2032	4.4	4.32	4.13	3.79	3.72	3.75	3.79	3.82	3.88	4.01	4.26	4.42
2033	4.48	4.45	4.17	3.84	3.79	3.81	3.85	3.87	3.95	4.07	4.33	4.55
2034	4.68	4.6	4.29	3.95	3.87	3.89	3.94	3.97	4.02	4.12	4.43	4.66
2035	4.82	4.79	4.44	4.07	4	4.04	4.08	4.11	4.19	4.26	4.58	4.8
2036	4.94	4.84	4.55	4.17	4.13	4.16	4.22	4.25	4.31	4.4	4.7	4.95
2037	5.1	5.06	4.72	4.36	4.31	4.34	4.39	4.43	4.5	4.59	4.89	5.13
2038	5.3	5.27	4.94	4.56	4.53	4.56	4.61	4.66	4.69	4.78	5.1	5.34
2039	5.52	5.49	5.14	4.69	4.65	4.68	4.7	4.86	4.92	5	5.31	5.54
2040	5.78	5.59	5.31	4.92	4.9	4.93	4.99	5.03	5.08	5.17	5.4	5.58

V. CALCULATING APC SAVINGS OVER PROJECT BOOK LIFE

The initial analysis was simulated in five-year increments: 2025,[9] 2030, 2035, and 2040. A linear regression function was used to calculate APC savings over the entire book life of the Project between 2026 and 2088. For the non-simulated years between 2025 and 2040 (e.g., 2026, 2027, 2028, 2029, and 2031) and all the years after 2040, a regression function in Microsoft Excel referred to as "forecast.linear" was used to interpolate and extrapolate APC savings. The regression function predicts values along a line of best fit based on input data—here, the simulated APC values. The forecasted APC savings values can be found in **Schedule 4** of the Affidavit of Mr. Jason Standing.

[9] The Project is not anticipated to be fully in service until 2026. The Company simulated the APC savings, assuming the Project was fully in service during 2025. Including the 2025 simulation allowed the data to be interpolated more accurately for the first few years of the Project's operation. The 2025 APC savings data is not included in the total estimated APC savings.

SCHEDULE 4:
ADJUSTED PRODUCTION COST

MISO PV Analysis ($102,022,240 Cost)

63-Yr PV cost from the Service Year (M$):	$132.21
63-Yr PV of aggregated APC (M$):	$833.86
B/C Ratio:	6.31

Benefit (Positive is Saving) - $

Year	Project Year		Simulated Values	APC Benefit	PV Benefit
2026	1	Interpolated		11,150,144	8,711,891
2027	2	Interpolated		11,687,219	8,585,215
2028	3	Interpolated		12,224,295	8,442,514
2029	4	Interpolated		12,761,371	8,286,160
2030	5	**Simulated Value:**	13,298,447	13,298,447	8,118,296
2031	6	Interpolated		18,054,885	10,362,551
2032	7	Interpolated		22,811,324	12,309,217
2033	8	Interpolated		27,567,762	13,985,868
2034	9	Interpolated		32,324,200	15,417,846
2035	10	**Simulated Value:**	37,080,639	37,080,639	16,628,425
2036	11	Interpolated		43,486,457	18,334,367
2037	12	Interpolated		49,892,275	19,776,671
2038	13	Interpolated		56,298,093	20,980,777
2039	14	Interpolated		62,703,911	21,970,023
2040	15	**Simulated Value:**	69,109,729	69,109,729	22,765,807
2041	16	Extrapolated		66,401,740	21,873,754
2042	17	Extrapolated		70,387,184	21,799,446
2043	18	Extrapolated		74,372,627	21,655,737
2044	19	Extrapolated		78,358,071	21,451,199
2045	20	Extrapolated		82,343,514	21,193,625
2046	21	Extrapolated		86,328,958	20,890,091
2047	22	Extrapolated		90,314,401	20,547,019
2048	23	Extrapolated		94,299,845	20,170,227
2049	24	Extrapolated		98,285,288	19,764,978
2050	25	Extrapolated		102,270,732	19,336,024
2051	26	Extrapolated		106,256,175	18,887,652
2052	27	Extrapolated		110,241,619	18,423,722
2053	28	Extrapolated		114,227,062	17,947,699
2054	29	Extrapolated		118,212,506	17,462,692
2055	30	Extrapolated		122,197,949	16,971,479
2056	31	Extrapolated		126,183,393	16,476,538
2057	32	Extrapolated		130,168,836	15,980,074
2058	33	Extrapolated		134,154,280	15,484,040
2059	34	Extrapolated		138,139,723	14,990,162
2060	35	Extrapolated		142,125,167	14,499,957
2061	36	Extrapolated		146,110,610	14,014,754
2062	37	Extrapolated		150,096,054	13,535,708
2063	38	Extrapolated		154,081,497	13,063,820
2064	39	Extrapolated		158,066,941	12,599,948
2065	40	Extrapolated		162,052,384	12,144,821
2066	41	Extrapolated		166,037,828	11,699,054
2067	42	Extrapolated		170,023,271	11,263,155
2068	43	Extrapolated		174,008,715	10,837,539
2069	44	Extrapolated		177,994,158	10,422,536
2070	45	Extrapolated		181,979,602	10,018,400
2071	46	Extrapolated		185,965,045	9,625,315
2072	47	Extrapolated		189,950,489	9,243,407
2073	48	Extrapolated		193,935,932	8,872,743
2074	49	Extrapolated		197,921,376	8,513,347
2075	50	Extrapolated		201,906,819	8,165,196
2076	51	Extrapolated		205,892,263	7,828,231
2077	52	Extrapolated		209,877,706	7,502,360
2078	53	Extrapolated		213,863,150	7,187,462
2079	54	Extrapolated		217,848,593	6,883,390
2080	55	Extrapolated		221,834,037	6,589,975
2081	56	Extrapolated		225,819,480	6,307,031
2082	57	Extrapolated		229,804,924	6,034,356
2083	58	Extrapolated		233,790,367	5,771,732
2084	59	Extrapolated		237,775,811	5,518,934
2085	60	Extrapolated		241,761,254	5,275,726
2086	61	Extrapolated		245,746,698	5,041,865
2087	62	Extrapolated		249,732,141	4,817,103
2088	63	Extrapolated		253,717,585	4,601,189

NSP PV Analysis ($102,022,240 Cost) (NSP Sole Owner)

63-Yr PV cost from the Service Year (M$):	$132.21
63-Yr PV of aggregated APC (M$):	$334.83
B/C Ratio:	2.53

Benefit (Positive is Saving) - $

Year	Project Year		Simulated Values	APC Benefit	PV Benefit
2026	1	Interpolated		8,338,011	6,514,700
2027	2	Interpolated		7,919,036	5,817,177
2028	3	Interpolated		7,500,061	5,179,797
2029	4	Interpolated		7,081,086	4,597,861
2030	5	**Simulated Value:**	6,662,111	6,662,111	4,067,016
2031	6	Interpolated		9,318,372	5,348,253
2032	7	Interpolated		11,974,632	6,461,630
2033	8	Interpolated		14,630,893	7,422,646
2034	9	Interpolated		17,287,153	8,245,546
2035	10	**Simulated Value:**	19,943,414	19,943,414	8,943,415
2036	11	Interpolated		21,192,247	8,934,884
2037	12	Interpolated		22,441,080	8,895,362
2038	13	Interpolated		23,689,914	8,828,590
2039	14	Interpolated		24,938,747	8,737,969
2040	15	**Simulated Value:**	26,187,580	26,187,580	8,626,592
2041	16	Extrapolated		26,534,947	8,741,020
2042	17	Extrapolated		27,846,409	8,624,244
2043	18	Extrapolated		29,157,871	8,490,156
2044	19	Extrapolated		30,469,332	8,341,243
2045	20	Extrapolated		31,780,794	8,179,760
2046	21	Extrapolated		33,092,256	8,007,744
2047	22	Extrapolated		34,403,718	7,827,034
2048	23	Extrapolated		35,715,179	7,639,284
2049	24	Extrapolated		37,026,641	7,445,984
2050	25	Extrapolated		38,338,103	7,248,471
2051	26	Extrapolated		39,649,565	7,047,940
2052	27	Extrapolated		40,961,026	6,845,460
2053	28	Extrapolated		42,272,488	6,641,980
2054	29	Extrapolated		43,583,950	6,438,347
2055	30	Extrapolated		44,895,411	6,235,305
2056	31	Extrapolated		46,206,873	6,033,514
2057	32	Extrapolated		47,518,335	5,833,551
2058	33	Extrapolated		48,829,797	5,635,918
2059	34	Extrapolated		50,141,258	5,441,053
2060	35	Extrapolated		51,452,720	5,249,332
2061	36	Extrapolated		52,764,182	5,061,077
2062	37	Extrapolated		54,075,643	4,876,558
2063	38	Extrapolated		55,387,105	4,696,003
2064	39	Extrapolated		56,698,567	4,519,598
2065	40	Extrapolated		58,010,029	4,347,492
2066	41	Extrapolated		59,321,490	4,179,802
2067	42	Extrapolated		60,632,952	4,016,617
2068	43	Extrapolated		61,944,414	3,857,996
2069	44	Extrapolated		63,255,876	3,703,979
2070	45	Extrapolated		64,567,337	3,554,582
2071	46	Extrapolated		65,878,799	3,409,803
2072	47	Extrapolated		67,190,261	3,269,625
2073	48	Extrapolated		68,501,722	3,134,015
2074	49	Extrapolated		69,813,184	3,002,929
2075	50	Extrapolated		71,124,646	2,876,310
2076	51	Extrapolated		72,436,108	2,754,094
2077	52	Extrapolated		73,747,569	2,636,206
2078	53	Extrapolated		75,059,031	2,522,566
2079	54	Extrapolated		76,370,493	2,413,088
2080	55	Extrapolated		77,681,954	2,307,681
2081	56	Extrapolated		78,993,416	2,206,249
2082	57	Extrapolated		80,304,878	2,108,694
2083	58	Extrapolated		81,616,340	2,014,915
2084	59	Extrapolated		82,927,801	1,924,809
2085	60	Extrapolated		84,239,263	1,838,273
2086	61	Extrapolated		85,550,725	1,755,203
2087	62	Extrapolated		86,862,186	1,675,492
2088	63	Extrapolated		88,173,648	1,599,036

NSP PV Analysis ($78,607,353 Cost) (NSP Shared Owner)

63-Yr PV cost from the Service Year (M$):	$101.83
63-Yr PV of aggregated APC (M$):	$334.83
B/C Ratio:	3.29

Benefit (Positive is Saving) - $

Year	Project Year		Simulated Values	APC Benefit	PV Benefit
2026	1	Interpolated		8,338,011	6,514,700
2027	2	Interpolated		7,919,036	5,817,177
2028	3	Interpolated		7,500,061	5,179,797
2029	4	Interpolated		7,081,086	4,597,861
2030	5	**Simulated Value:**	6,662,111	6,662,111	4,067,016
2031	6	Interpolated		9,318,372	5,348,253
2032	7	Interpolated		11,974,632	6,461,630
2033	8	Interpolated		14,630,893	7,422,646
2034	9	Interpolated		17,287,153	8,245,546
2035	10	**Simulated Value:**	19,943,414	19,943,414	8,943,415
2036	11	Interpolated		21,192,247	8,934,884
2037	12	Interpolated		22,441,080	8,895,362
2038	13	Interpolated		23,689,914	8,828,590
2039	14	Interpolated		24,938,747	8,737,969
2040	15	**Simulated Value:**	26,187,580	26,187,580	8,626,592
2041	16	Extrapolated		26,534,947	8,741,020
2042	17	Extrapolated		27,846,409	8,624,244
2043	18	Extrapolated		29,157,871	8,490,156
2044	19	Extrapolated		30,469,332	8,341,243
2045	20	Extrapolated		31,780,794	8,179,760
2046	21	Extrapolated		33,092,256	8,007,744
2047	22	Extrapolated		34,403,718	7,827,034
2048	23	Extrapolated		35,715,179	7,639,284
2049	24	Extrapolated		37,026,641	7,445,984
2050	25	Extrapolated		38,338,103	7,248,471
2051	26	Extrapolated		39,649,565	7,047,940
2052	27	Extrapolated		40,961,026	6,845,460
2053	28	Extrapolated		42,272,488	6,641,980
2054	29	Extrapolated		43,583,950	6,438,347
2055	30	Extrapolated		44,895,411	6,235,305
2056	31	Extrapolated		46,206,873	6,033,514
2057	32	Extrapolated		47,518,335	5,833,551
2058	33	Extrapolated		48,829,797	5,635,918
2059	34	Extrapolated		50,141,258	5,441,053
2060	35	Extrapolated		51,452,720	5,249,332
2061	36	Extrapolated		52,764,182	5,061,077
2062	37	Extrapolated		54,075,643	4,876,558
2063	38	Extrapolated		55,387,105	4,696,003
2064	39	Extrapolated		56,698,567	4,519,598
2065	40	Extrapolated		58,010,029	4,347,492
2066	41	Extrapolated		59,321,490	4,179,802
2067	42	Extrapolated		60,632,952	4,016,617
2068	43	Extrapolated		61,944,414	3,857,996
2069	44	Extrapolated		63,255,876	3,703,979
2070	45	Extrapolated		64,567,337	3,554,582
2071	46	Extrapolated		65,878,799	3,409,803
2072	47	Extrapolated		67,190,261	3,269,625
2073	48	Extrapolated		68,501,722	3,134,015
2074	49	Extrapolated		69,813,184	3,002,929
2075	50	Extrapolated		71,124,646	2,876,310
2076	51	Extrapolated		72,436,108	2,754,094
2077	52	Extrapolated		73,747,569	2,636,206
2078	53	Extrapolated		75,059,031	2,522,566
2079	54	Extrapolated		76,370,493	2,413,088
2080	55	Extrapolated		77,681,954	2,307,681
2081	56	Extrapolated		78,993,416	2,206,249
2082	57	Extrapolated		80,304,878	2,108,694
2083	58	Extrapolated		81,616,340	2,014,915
2084	59	Extrapolated		82,927,801	1,924,809
2085	60	Extrapolated		84,239,263	1,838,273
2086	61	Extrapolated		85,550,725	1,755,203
2087	62	Extrapolated		86,862,186	1,675,492
2088	63	Extrapolated		88,173,648	1,599,036

OTP PV Analysis ($2,908,420 Cost)

63-Yr PV cost from the Service Year (M$):	$3.77
63-Yr PV of aggregated APC (M$):	$58.73
B/C Ratio:	15.59

Benefit (Positive is Saving) - $

Year	Project Year		Simulated Values	APC Benefit	PV Benefit
2026	1	Interpolated		2,144,105	1,675,244
2027	2	Interpolated		1,976,313	1,451,763
2028	3	Interpolated		1,808,521	1,249,026
2029	4	Interpolated		1,640,729	1,065,351
2030	5	**Simulated Value:**	1,472,937	1,472,937	899,183
2031	6	Interpolated		1,731,385	993,723
2032	7	Interpolated		1,989,833	1,073,734
2033	8	Interpolated		2,248,281	1,140,614
2034	9	Interpolated		2,506,729	1,195,648
2035	10	**Simulated Value:**	2,765,177	2,765,177	1,240,015
2036	11	Interpolated		3,277,639	1,381,889
2037	12	Interpolated		3,790,101	1,502,348
2038	13	Interpolated		4,302,562	1,603,449
2039	14	Interpolated		4,815,024	1,687,075
2040	15	**Simulated Value:**	5,327,486	5,327,486	1,754,956
2041	16	Extrapolated		4,727,005	1,557,148
2042	17	Extrapolated		4,933,785	1,528,031
2043	18	Extrapolated		5,140,566	1,496,824
2044	19	Extrapolated		5,347,346	1,463,882
2045	20	Extrapolated		5,554,126	1,429,524
2046	21	Extrapolated		5,760,906	1,394,038
2047	22	Extrapolated		5,967,686	1,357,681
2048	23	Extrapolated		6,174,466	1,320,685
2049	24	Extrapolated		6,381,246	1,283,256
2050	25	Extrapolated		6,588,026	1,245,579
2051	26	Extrapolated		6,794,807	1,207,816
2052	27	Extrapolated		7,001,587	1,170,114
2053	28	Extrapolated		7,208,367	1,132,600
2054	29	Extrapolated		7,415,147	1,095,387
2055	30	Extrapolated		7,621,927	1,058,572
2056	31	Extrapolated		7,828,707	1,022,242
2057	32	Extrapolated		8,035,487	986,470
2058	33	Extrapolated		8,242,267	951,320
2059	34	Extrapolated		8,449,048	916,844
2060	35	Extrapolated		8,655,828	883,089
2061	36	Extrapolated		8,862,608	850,091
2062	37	Extrapolated		9,069,388	817,880
2063	38	Extrapolated		9,276,168	786,481
2064	39	Extrapolated		9,482,948	755,912
2065	40	Extrapolated		9,689,728	726,185
2066	41	Extrapolated		9,896,508	697,310
2067	42	Extrapolated		10,103,289	669,290
2068	43	Extrapolated		10,310,069	642,127
2069	44	Extrapolated		10,516,849	615,819
2070	45	Extrapolated		10,723,629	590,361
2071	46	Extrapolated		10,930,409	565,744
2072	47	Extrapolated		11,137,189	541,960
2073	48	Extrapolated		11,343,969	518,997
2074	49	Extrapolated		11,550,749	496,841
2075	50	Extrapolated		11,757,530	475,479
2076	51	Extrapolated		11,964,310	454,895
2077	52	Extrapolated		12,171,090	435,072
2078	53	Extrapolated		12,377,870	415,993
2079	54	Extrapolated		12,584,650	397,639
2080	55	Extrapolated		12,791,430	379,992
2081	56	Extrapolated		12,998,210	363,034
2082	57	Extrapolated		13,204,990	346,745
2083	58	Extrapolated		13,411,770	331,105
2084	59	Extrapolated		13,618,551	316,096
2085	60	Extrapolated		13,825,331	301,697
2086	61	Extrapolated		14,032,111	287,890
2087	62	Extrapolated		14,238,891	274,655
2088	63	Extrapolated		14,445,671	261,973

GRE PV Analysis ($13,427,228 Cost)

63-Yr PV cost from the Service Year (M$):	$17.39
63-Yr PV of aggregated APC (M$):	$173.99
B/C Ratio:	10.00

Benefit (Positive is Saving) - $

Year	Project Year		Simulated Values	APC Benefit	PV Benefit
2026	1	Interpolated		2,543,384	1,987,210
2027	2	Interpolated		2,366,710	1,738,541
2028	3	Interpolated		2,190,037	1,512,514
2029	4	Interpolated		2,013,363	1,307,309
2030	5	**Simulated Value:**	1,836,690	1,836,690	1,121,243
2031	6	Interpolated		2,872,521	1,648,675
2032	7	Interpolated		3,908,351	2,108,985
2033	8	Interpolated		4,944,182	2,508,317
2034	9	Interpolated		5,980,013	2,852,319
2035	10	**Simulated Value:**	7,015,843	7,015,843	3,146,182
2036	11	Interpolated		8,648,041	3,646,109
2037	12	Interpolated		10,280,239	4,074,958
2038	13	Interpolated		11,912,437	4,439,443
2039	14	Interpolated		13,544,635	4,745,732
2040	15	**Simulated Value:**	15,176,832	15,176,832	4,999,482
2041	16	Extrapolated		13,920,767	4,585,715
2042	17	Extrapolated		14,771,757	4,574,925
2043	18	Extrapolated		15,622,746	4,549,014
2044	19	Extrapolated		16,473,736	4,509,828
2045	20	Extrapolated		17,324,726	4,459,049
2046	21	Extrapolated		18,175,715	4,398,204
2047	22	Extrapolated		19,026,705	4,328,679
2048	23	Extrapolated		19,877,694	4,251,731
2049	24	Extrapolated		20,728,684	4,168,497
2050	25	Extrapolated		21,579,673	4,080,005
2051	26	Extrapolated		22,430,663	3,987,181
2052	27	Extrapolated		23,281,653	3,890,860
2053	28	Extrapolated		24,132,642	3,791,793
2054	29	Extrapolated		24,983,632	3,690,654
2055	30	Extrapolated		25,834,621	3,588,045
2056	31	Extrapolated		26,685,611	3,484,504
2057	32	Extrapolated		27,536,601	3,380,509
2058	33	Extrapolated		28,387,590	3,276,486
2059	34	Extrapolated		29,238,580	3,172,810
2060	35	Extrapolated		30,089,569	3,069,811
2061	36	Extrapolated		30,940,559	2,967,781
2062	37	Extrapolated		31,791,548	2,866,972
2063	38	Extrapolated		32,642,538	2,767,602
2064	39	Extrapolated		33,493,528	2,669,861
2065	40	Extrapolated		34,344,517	2,573,909
2066	41	Extrapolated		35,195,507	2,479,881
2067	42	Extrapolated		36,046,496	2,387,892
2068	43	Extrapolated		36,897,486	2,298,034
2069	44	Extrapolated		37,748,476	2,210,381
2070	45	Extrapolated		38,599,465	2,124,990
2071	46	Extrapolated		39,450,455	2,041,906
2072	47	Extrapolated		40,301,444	1,961,156
2073	48	Extrapolated		41,152,434	1,882,761
2074	49	Extrapolated		42,003,424	1,806,726
2075	50	Extrapolated		42,854,413	1,733,050
2076	51	Extrapolated		43,705,403	1,661,723
2077	52	Extrapolated		44,556,392	1,592,728
2078	53	Extrapolated		45,407,382	1,526,040
2079	54	Extrapolated		46,258,371	1,461,632
2080	55	Extrapolated		47,109,361	1,399,467
2081	56	Extrapolated		47,960,351	1,339,510
2082	57	Extrapolated		48,811,340	1,281,717
2083	58	Extrapolated		49,662,330	1,226,046
2084	59	Extrapolated		50,513,319	1,172,448
2085	60	Extrapolated		51,364,309	1,120,875
2086	61	Extrapolated		52,215,299	1,071,276
2087	62	Extrapolated		53,066,288	1,023,600
2088	63	Extrapolated		53,917,278	977,794

SCHEDULE 5:
REVENUE REQUIREMENTS

Total Project Summary

Amounts in dollars

Line No.		Brookings - 2nd Circuit - 100% NSP Ownership			Brookings - 2nd Circuit - Shared Ownership of Lines		
		Line (A)	Subs (B)	Total	Line (A)	Subs (B)	Total
1	**All-in project revenue requirement**	**276,077,802**	**111,152,226**	**387,230,028**	**276,077,802**	**111,152,226**	**387,230,028**
2							
3	Less other ownership for Lines (32.2029% owned by other TOU's)	-	-	-	(88,905,058)	-	(88,905,058)
4							
5	**Project NSP Revenue Requirement**	**276,077,802**	**111,152,226**	**387,230,028**	**187,172,743**	**111,152,226**	**298,324,969**
6							
7	Estimated OATT Credit %	22.33%	22.33%		22.33%	22.33%	
8							
9	**TOTAL MISO OATT Credit**	61,660,557	24,825,278	86,485,835	41,804,069	24,825,278	66,629,347
10							
11							
12	Calculation to NSP loads:						
13		**Line (A)**	**Subs (B)**	**Total**	**Line (A)**	**Subs (B)**	**Total**
14	Total NSP Revenue Requirement	276,077,802	111,152,226	387,230,028	187,172,743	111,152,226	298,324,969
15	Less: NSP MISO OATT Credit	(61,660,557)	(24,825,278)	(86,485,835)	(41,804,069)	(24,825,278)	(66,629,347)
16	**Net cost - NSP Companies**	214,417,245	86,326,948	**300,744,193**	145,368,674	86,326,948	**231,695,622**
17							
18	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
19	Demand Allocator - ND Jurisdiction	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%
20							
21	**Net cost to ND Jurisdiction**	**10,900,986**	**4,388,867**	**15,289,854**	**7,390,553**	**4,388,867**	**11,779,420**

NOTE: Tax assumptions include 21% corp Fed tax rate

Project Summary - Year 1

Amounts in dollars

Line No.		Brookings - 2nd Circuit - 100% NSP Ownership			Brookings - 2nd Circuit - Shared Ownership		
		Line (A)	Subs (B)	Total	Line (A)	Subs (B)	Total
1	**All-in project revenue requirement**	**9,079,950**	**3,592,843**	**12,672,793**	**9,079,950**	**3,592,843**	**12,672,793**
2							
3	Less other ownership (32.2029% owned by other TOU's)	-	-	-	(2,924,007)	-	(2,924,007)
4							
5	**Project NSP Revenue Requirement**	**9,079,950**	**3,592,843**	**12,672,793**	**6,155,943**	**3,592,843**	**9,748,785**
6							
7	Estimated OATT Credit %	22.33%	22.33%		22.33%	22.33%	22.33%
8							
9	**TOTAL MISO OATT Credit**	**2,027,960**	**802,443**	**2,830,403**	**1,374,898**	**802,443**	**2,177,341**
10							
11							
12	Calculation to NSP loads:						
13		**Line (A)**	**Subs (B)**	**Total**	**Line (A)**	**Subs (B)**	**Total**
14	Total NSP Revenue Requirement	9,079,950	3,592,843	12,672,793	6,155,943	3,592,843	9,748,785
15	Less: NSP MISO OATT Credit	(2,027,960)	(802,443)	(2,830,403)	(1,374,898)	(802,443)	(2,177,341)
16	**Net cost - NSP Companies**	7,051,990	2,790,400	**9,842,390**	4,781,044	2,790,400	**7,571,444**
17							
18	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
19	Demand Allocator - ND Jurisdiction	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%
20							
21	**Net cost to ND Jurisdiction**	**358,524**	**141,864**	**500,388**	**243,069**	**141,864**	**384,933**

NOTE: Tax assumptions include 21% corp Fed tax rate

Total - Xcel Energy 100% Owner

Brookings - 2nd Circuit Line
66 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.7500%	45.8100%	2.1800%
Short Term Debt	4.3100%	1.6900%	0.0700%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.0600%	52.5000%	4.7600%
Required Rate of Return			7.0100%
Tax Rate	28.7420%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13
1	Project Spend														
2	Line	72,710,492													
3	Sub	29,311,748													
4	**Total**	102,022,240													
5															
	Revenue Requirement														
7	Line		9,079,950	8,843,087	8,573,100	8,319,908	8,081,833	7,857,475	7,642,727	7,431,059	7,219,298	7,007,536	6,795,775	6,584,013	6,372,252
8	Sub		3,592,843	3,501,797	3,397,397	3,299,767	3,208,232	3,122,226	3,040,095	2,959,206	2,878,278	2,797,351	2,716,423	2,635,496	2,554,568
9															
10	**Project Revenue Requirements - NSP**		12,672,793	12,344,884	11,970,497	11,619,676	11,290,065	10,979,701	10,682,822	10,390,265	10,097,576	9,804,887	9,512,198	9,219,509	8,926,820
11															
12	Less: NSP MISO OATT Credit on Line & Sub		(2,830,403)	(2,757,166)	(2,673,549)	(2,595,195)	(2,521,578)	(2,452,260)	(2,385,953)	(2,320,612)	(2,255,242)	(2,189,871)	(2,124,500)	(2,059,130)	(1,993,759)
13															
14	**Total Revenue Requirements - NSP**		9,842,390	9,587,718	9,296,948	9,024,481	8,768,487	8,527,441	8,296,869	8,069,652	7,842,334	7,615,016	7,387,697	7,160,379	6,933,061
15															
16	FERC Interchange Agreement allocator to NSPM		83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
17	Demand Allocator - ND Jurisdiction		6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%
18															
19	**Total Revenue Requirements - ND Jurisdiction**		500,388	487,440	472,657	458,805	445,790	433,536	421,813	410,262	398,705	387,148	375,591	364,034	352,477
20															
21															
22	**Discount Rate =**	0.06363305													
23															
24	**Present Value of Revenue Requirements - NSP**	115,162,397	11,914,628	10,911,975	9,948,021	9,078,764	8,293,490	7,582,974	6,936,546	6,342,961	5,795,497	5,290,837	4,825,817	4,397,501	4,003,161
25															
26															
27															
28			12.42%	12.10%	11.73%	11.39%	11.07%	10.76%	10.47%	10.18%	9.90%	9.61%	9.32%	9.04%	8.75%

Total - Xcel Energy 100% Owner

Brookings - 2nd Circuit Line
66 YEAR LIFE

Line No.	Rate Analysis	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Project Spend							
2	Line							
3	Sub							
4	**Total**							
5								
	Revenue Requirement							
7	Line	6,160,490	5,948,729	5,764,494	5,635,406	5,533,845	5,432,284	5,330,723
8	Sub	2,473,641	2,392,713	2,322,883	2,275,284	2,238,781	2,202,279	2,165,776
9								
10	**Project Revenue Requirements - NSP**	8,634,131	8,341,442	8,087,377	7,910,690	7,772,626	7,634,563	7,496,499
11								
12	Less: NSP MISO OATT Credit on Line & Sub	(1,928,389)	(1,863,018)	(1,806,274)	(1,766,812)	(1,735,976)	(1,705,140)	(1,674,305)
13								
14	**Total Revenue Requirements - NSP**	6,705,742	6,478,424	6,281,103	6,143,878	6,036,650	5,929,422	5,822,195
15								
16	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
17	Demand Allocator - ND Jurisdiction	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%
18								
19	**Total Revenue Requirements - ND Jurisdiction**	340,920	329,363	319,332	312,355	306,904	301,452	296,001
20								
21								
22	**Discount Rate =**							
23								
24	**Present Value of Revenue Requirements - NSP**	3,640,266	3,306,464	3,013,967	2,771,745	2,560,442	2,364,501	2,182,841
25								
26								
27								
28		8.46%	8.18%	7.93%	7.75%	7.62%	7.48%	7.35%

Total - Shared Ownership

Brookings - 2nd Circuit Line
66 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.7500%	45.8100%	2.1800%
Short Term Debt	4.3100%	1.6900%	0.0700%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.0600%	52.5000%	4.7600%
Required Rate of Return			7.0100%
Tax Rate	28.7420%		

Line No.	Rate Analysis		Year 1*	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13
1	Project Spend Less CIAC														
2	Line - Less CIAC	49,295,605													
3	Sub	29,311,748													
4	**Total**	78,607,353													
5															
	Revenue Requirement														
7	Line - 32.2029% owned by other TOU's		6,155,943	5,995,357	5,812,313	5,640,657	5,479,248	5,327,140	5,181,547	5,038,043	4,894,474	4,750,906	4,607,338	4,463,770	4,320,202
8	Sub		3,592,843	3,501,797	3,397,397	3,299,767	3,208,232	3,122,226	3,040,095	2,959,206	2,878,278	2,797,351	2,716,423	2,635,496	2,554,568
9															
10	**Project Revenue Requirements - NSP**		9,748,785	9,497,153	9,209,710	8,940,424	8,687,481	8,449,366	8,221,643	7,997,248	7,772,752	7,548,257	7,323,761	7,099,266	6,874,770
11															
12	Less: NSP MISO OATT Credit on Line & Sub		(2,177,341)	(2,121,140)	(2,056,941)	(1,996,798)	(1,940,304)	(1,887,123)	(1,836,262)	(1,786,144)	(1,736,004)	(1,685,864)	(1,635,724)	(1,585,584)	(1,535,445)
13															
14	**Total Revenue Requirements - NSP**		7,571,444	7,376,013	7,152,768	6,943,626	6,747,177	6,562,244	6,385,381	6,211,104	6,036,748	5,862,393	5,688,037	5,513,681	5,339,326
15															
16	FERC Interchange Agreement allocator to NSPM		83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
17	Demand Allocator - ND Jurisdiction		6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%
18															
19	**Total Revenue Requirements - ND Jurisdiction**		384,933	374,997	363,647	353,014	343,027	333,625	324,633	315,773	306,909	298,044	289,180	280,316	271,452
20															
21															
22	**Discount Rate =**	0.06363305													
23															
24	**Present Value of Revenue Requirements - NSP**	88,644,162	9,165,553	8,394,789	7,653,683	6,985,393	6,381,676	5,835,435	5,338,458	4,882,092	4,461,166	4,073,132	3,715,559	3,386,192	3,082,936
25															
26															
27															
28			12.40%	12.08%	11.72%	11.37%	11.05%	10.75%	10.46%	10.17%	9.89%	9.60%	9.32%	9.03%	8.75%

Total - Shared Ownership

Brookings - 2nd Circuit Line
66 YEAR LIFE

Line No.	Rate Analysis	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Project Spend Less CIAC							
2	Line - Less CIAC							
3	Sub							
4	**Total**							
5								
	Revenue Requirement							
7	Line - 32.2029% owned by other TOU's	4,176,634	4,033,066	3,908,160	3,820,642	3,751,786	3,682,931	3,614,075
8	Sub	2,473,641	2,392,713	2,322,883	2,275,284	2,238,781	2,202,279	2,165,776
9								
10	**Project Revenue Requirements - NSP**	6,650,274	6,425,779	6,231,043	6,095,925	5,990,568	5,885,210	5,779,852
11								
12	Less: NSP MISO OATT Credit on Line & Sub	(1,485,305)	(1,435,165)	(1,391,671)	(1,361,494)	(1,337,962)	(1,314,431)	(1,290,900)
13								
14	**Total Revenue Requirements - NSP**	5,164,970	4,990,614	4,839,371	4,734,432	4,652,605	4,570,778	4,488,952
15								
16	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
17	Demand Allocator - ND Jurisdiction	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%
18								
19	**Total Revenue Requirements - ND Jurisdiction**	262,587	253,723	246,034	240,699	236,539	232,379	228,219
20								
21								
22	**Discount Rate =**							
23								
24	**Present Value of Revenue Requirements - NSP**	2,803,845	2,547,114	2,322,157	2,135,889	1,973,400	1,822,709	1,682,985
25								
26								
27								
28		8.46%	8.17%	7.93%	7.75%	7.62%	7.49%	7.35%

Rev. Req. 2nd Circuit Line

Brookings - 2nd Circuit Line
66 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.7500%	45.8100%	2.1800%
Short Term Debt	4.3100%	1.6900%	0.0700%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.0600%	52.5000%	4.7600%
Required Rate of Return			7.0100%
Tax Rate	28.7420%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
1	Plant Investment		72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492
2	Depreciation Reserve		(1,596,043)	(3,192,087)	(4,788,130)	(6,384,173)	(7,980,216)	(9,576,260)	(11,172,303)	(12,768,346)
3	Removal Expense		-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(586,188)	(2,112,806)	(3,440,888)	(4,591,334)	(5,580,862)	(6,424,101)	(7,198,374)	(7,972,648)
5			70,528,261	67,405,600	64,481,474	61,734,985	59,149,414	56,710,132	54,339,815	51,969,498
6										
7	Average Rate Base		71,619,376	68,966,930	65,943,537	63,108,229	60,442,199	57,929,773	55,524,973	53,154,656
8										
9	Debt Return		1,611,436	1,551,756	1,483,730	1,419,935	1,359,949	1,303,420	1,249,312	1,195,980
10	Equity Return		3,409,082	3,282,826	3,138,912	3,003,952	2,877,049	2,757,457	2,642,989	2,530,162
11	Current Income Tax Requirement		788,870	(202,486)	(61,999)	61,202	170,933	268,985	291,779	246,270
12										
13	Book Depreciation		1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043
14	Annual Deferred Tax		586,188	1,526,618	1,328,083	1,150,446	989,528	843,239	774,274	774,274
15	ITC Flow Thru		-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		3,635,525	6,907,497	6,216,747	5,598,708	5,038,837	4,529,864	4,289,919	4,289,919
17	Tax Depreciation on Easements		-	-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-	-
21	Property Tax @ 1.497%		1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331
22										
23	Total Revenue Requirements - NSP		9,079,950	8,843,087	8,573,100	8,319,908	8,081,833	7,857,475	7,642,727	7,431,059
24										
25	Discount Rate =	0.06363305								
26										
27	Present Value of Revenue Requirements	99,268,321	8,536,731	7,816,643	7,124,632	6,500,567	5,936,777	5,426,653	4,962,558	4,536,450
28										
29	**Level Annual Revenue Requirement**	**6,426,319**								
30										
31	**66 Year Life LARR %**	**8.84%**								

Line No.	Rate Analysis	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
1	Plant Investment	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492
2	Depreciation Reserve	(14,364,390)	(15,960,433)	(17,556,476)	(19,152,519)	(20,748,563)	(22,344,606)	(23,940,649)	(25,536,693)
3	Removal Expense	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(8,749,012)	(9,523,286)	(10,299,649)	(11,073,923)	(11,850,287)	(12,624,560)	(13,400,924)	(13,558,693)
5		49,597,091	47,226,774	44,854,367	42,484,050	40,111,643	37,741,326	35,368,919	33,615,106
6									
7	Average Rate Base	50,783,294	48,411,932	46,040,570	43,669,208	41,297,846	38,926,484	36,555,122	34,492,012
8									
9	Debt Return	1,142,624	1,089,268	1,035,913	982,557	929,202	875,846	822,490	776,070
10	Equity Return	2,417,285	2,304,408	2,191,531	2,078,654	1,965,777	1,852,901	1,740,024	1,641,820
11	Current Income Tax Requirement	198,651	155,212	107,593	64,154	16,535	(26,904)	(74,523)	504,460
12									
13	Book Depreciation	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043
14	Annual Deferred Tax	776,364	774,274	776,364	774,274	776,364	774,274	776,364	157,770
15	ITC Flow Thru	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	4,297,190	4,289,919	4,297,190	4,289,919	4,297,190	4,289,919	4,297,190	2,144,960
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-
21	Property Tax @ 1.497%	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331
22									
23	Total Revenue Requirements - NSP	7,219,298	7,007,536	6,795,775	6,584,013	6,372,252	6,160,490	5,948,729	5,764,494
24									
25	Discount Rate =								
26									
27	Present Value of Revenue Requirements	4,143,511	3,781,352	3,447,696	3,140,428	2,857,585	2,597,346	2,358,016	2,148,286

Rev. Req. 2nd Circuit Line

Brookings - 2nd Circuit Line
66 YEAR LIFE

Line No.	Rate Analysis	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25
1	Plant Investment	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492
2	Depreciation Reserve	(27,132,736)	(28,728,779)	(30,324,822)	(31,920,866)	(33,516,909)	(35,112,952)	(36,708,996)	(38,305,039)	(39,901,082)
3	Removal Expense	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(13,099,959)	(12,641,224)	(12,182,489)	(11,723,754)	(11,265,020)	(10,806,285)	(10,347,550)	(9,888,815)	(9,430,081)
5		32,477,797	31,340,489	30,203,180	29,065,872	27,928,563	26,791,255	25,653,946	24,516,638	23,379,329
6										
7	Average Rate Base	33,046,452	31,909,143	30,771,835	29,634,526	28,497,218	27,359,909	26,222,601	25,085,292	23,947,983
8										
9	Debt Return	743,545	717,956	692,366	666,777	641,187	615,598	590,009	564,419	538,830
10	Equity Return	1,573,011	1,518,875	1,464,739	1,410,603	1,356,468	1,302,332	1,248,196	1,194,060	1,139,924
11	Current Income Tax Requirement	1,093,211	1,071,375	1,049,539	1,027,703	1,005,868	984,032	962,196	940,360	918,524
12										
13	Book Depreciation	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043
14	Annual Deferred Tax	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.497%	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331
22										
23	Total Revenue Requirements - NSP	5,635,406	5,533,845	5,432,284	5,330,723	5,229,162	5,127,601	5,026,040	4,924,478	4,822,917
24										
25	Discount Rate =									
26										
27	Present Value of Revenue Requirements	1,974,532	1,822,948	1,682,433	1,552,207	1,431,541	1,319,757	1,216,225	1,120,357	1,031,607

Line No.	Rate Analysis	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34
1	Plant Investment	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492
2	Depreciation Reserve	(41,497,125)	(43,093,169)	(44,689,212)	(46,285,255)	(47,881,299)	(49,477,342)	(51,073,385)	(52,669,429)	(54,265,472)
3	Removal Expense	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(8,971,346)	(8,512,611)	(8,053,876)	(7,595,142)	(7,136,407)	(6,677,672)	(6,218,937)	(5,760,202)	(5,301,468)
5		22,242,021	21,104,712	19,967,404	18,830,095	17,692,787	16,555,478	15,418,170	14,280,861	13,143,552
6										
7	Average Rate Base	22,810,675	21,673,366	20,536,058	19,398,749	18,261,441	17,124,132	15,986,824	14,849,515	13,712,207
8										
9	Debt Return	513,240	487,651	462,061	436,472	410,882	385,293	359,704	334,114	308,525
10	Equity Return	1,085,788	1,031,652	977,516	923,380	869,245	815,109	760,973	706,837	652,701
11	Current Income Tax Requirement	896,689	874,853	853,017	831,181	809,346	787,510	765,674	743,838	722,003
12										
13	Book Depreciation	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043
14	Annual Deferred Tax	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.497%	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331
22										
23	Total Revenue Requirements - NSP	4,721,356	4,619,795	4,518,234	4,416,673	4,315,112	4,213,551	4,111,990	4,010,428	3,908,867
24										
25	Discount Rate =									
26										
27	Present Value of Revenue Requirements	949,466	873,461	803,152	738,129	678,012	622,446	571,102	523,673	479,876

28

29 **Level Annual Revenue Requirement**

30

31 **66 Year Life LARR %**

Rev. Req. 2nd Circuit Line

Brookings - 2nd Circuit Line
66 YEAR LIFE

Line No.	Rate Analysis	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40	Year 41	Year 42	Year 43	Year 44	Year 45	Year 46	Year 47	Year 48	Year 49	Year 50	Year 51	Year 52	Year 53
1	Plant Investment	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492
2	Depreciation Reserve	(55,861,515)	(57,457,558)	(59,053,602)	(60,649,645)	(62,245,688)	(63,841,732)	(65,437,775)	(67,033,818)	(68,629,861)	(70,225,905)	(71,821,948)	(73,417,991)	(75,014,035)	(76,610,078)	(78,206,121)	(79,802,164)	(81,398,208)	(82,994,251)	(84,590,294)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(4,842,733)	(4,383,998)	(3,925,263)	(3,466,529)	(3,007,794)	(2,549,059)	(2,090,324)	(1,631,590)	(1,172,855)	(714,120)	(255,385)	203,349	662,084	1,120,819	1,579,554	2,038,288	2,497,023	2,955,758	3,414,493
5		12,006,244	10,868,935	9,731,627	8,594,318	7,457,010	6,319,701	5,182,393	4,045,084	2,907,776	1,770,467	633,159	(504,150)	(1,641,458)	(2,778,767)	(3,916,075)	(5,053,384)	(6,190,692)	(7,328,001)	(8,465,310)
6																				
7	Average Rate Base	12,574,898	11,437,590	10,300,281	9,162,973	8,025,664	6,888,356	5,751,047	4,613,739	3,476,430	2,339,121	1,201,813	64,504	(1,072,804)	(2,210,113)	(3,347,421)	(4,484,730)	(5,622,038)	(6,759,347)	(7,896,655)
8																				
9	Debt Return	282,935	257,346	231,756	206,167	180,577	154,988	129,399	103,809	78,220	52,630	27,041	1,451	(24,138)	(49,728)	(75,317)	(100,906)	(126,496)	(152,085)	(177,675)
10	Equity Return	598,565	544,429	490,293	436,158	382,022	327,886	273,750	219,614	165,478	111,342	57,206	3,070	(51,065)	(105,201)	(159,337)	(213,473)	(267,609)	(321,745)	(375,881)
11	Current Income Tax Requirement	700,167	678,331	656,495	634,659	612,824	590,988	569,152	547,316	525,481	503,645	481,809	459,973	438,137	416,302	394,466	372,630	350,794	328,959	307,123
12																				
13	Book Depreciation	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043
14	Annual Deferred Tax	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.497%	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331
22																				
23	Total Revenue Requirements - NSP	3,807,306	3,705,745	3,604,184	3,502,623	3,401,062	3,299,501	3,197,940	3,096,379	2,994,817	2,893,256	2,791,695	2,690,134	2,588,573	2,487,012	2,385,451	2,283,890	2,182,329	2,080,768	1,979,206
24																				
25	Discount Rate =																			
26																				
27	Present Value of Revenue Requirements	439,444	402,133	367,713	335,973	306,714	279,753	254,921	232,058	211,019	191,667	173,875	157,525	142,510	128,727	116,084	104,492	93,872	84,149	75,253
28																				
29	**Level Annual Revenue Requirement**																			
30																				
31	**66 Year Life LARR %**																			

Rev. Req. 2nd Circuit Line

Brookings - 2nd Circuit Line
66 YEAR LIFE

Line No.	Rate Analysis	Year 54	Year 55	Year 56	Year 57	Year 58	Year 59	Year 60	Year 61	Year 62	Year 63	Year 64	Year 65	Year 66
1	Plant Investment	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492	72,710,492
2	Depreciation Reserve	(86,186,338)	(87,782,381)	(89,378,424)	(90,974,467)	(92,570,511)	(94,166,554)	(95,762,597)	(97,358,641)	(98,954,684)	(100,550,727)	(102,146,770)	(103,742,814)	(105,338,857)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	32,628,365
4	Accumulated Deferred Taxes	3,873,228	4,331,962	4,790,697	5,249,432	5,708,167	6,166,901	6,625,636	7,084,371	7,543,106	8,001,840	8,460,575	8,919,310	0
5		(9,602,618)	(10,739,927)	(11,877,235)	(13,014,544)	(14,151,852)	(15,289,161)	(16,426,469)	(17,563,778)	(18,701,086)	(19,838,395)	(20,975,703)	(22,113,012)	0
6														
7	Average Rate Base	(9,033,964)	(10,171,272)	(11,308,581)	(12,445,889)	(13,583,198)	(14,720,506)	(15,857,815)	(16,995,123)	(18,132,432)	(19,269,741)	(20,407,049)	(21,544,358)	(11,056,506)
8														
9	Debt Return	(203,264)	(228,854)	(254,443)	(280,033)	(305,622)	(331,211)	(356,801)	(382,390)	(407,980)	(433,569)	(459,159)	(484,748)	(248,771)
10	Equity Return	(430,017)	(484,153)	(538,288)	(592,424)	(646,560)	(700,696)	(754,832)	(808,968)	(863,104)	(917,240)	(971,376)	(1,025,511)	(526,290)
11	Current Income Tax Requirement	285,287	263,451	241,615	219,780	197,944	176,108	154,272	132,437	110,601	88,765	66,929	45,093	(9,131,589)
12														
13	Book Depreciation	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043	1,596,043
14	Annual Deferred Tax	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	(458,735)	8,919,310
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	32,628,365
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.497%	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331	1,088,331
22														
23	Total Revenue Requirements - NSP	1,877,645	1,776,084	1,674,523	1,572,962	1,471,401	1,369,840	1,268,279	1,166,718	1,065,157	963,595	862,034	760,473	1,697,033
24														
25	Discount Rate =													
26														
27	Present Value of Revenue Requirements	67,120	59,692	52,911	46,729	41,097	35,971	31,312	27,081	23,245	19,770	16,628	13,792	28,935
28														
29	**Level Annual Revenue Requirement**													
30														
31	**66 Year Life LARR %**													

Rev. Req. 2nd Circuit Subs

Brookings - 2nd Circuit Subs
58 YEAR LIFE

Cost Assumptions

Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.7500%	45.8100%	2.1800%
Short Term Debt	4.3100%	1.6900%	0.0700%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.0600%	52.5000%	4.7600%
Required Rate of Return			7.0100%
Tax Rate	28.7420%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14
1	Plant Investment		29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748
2	Depreciation Reserve		(573,639)	(1,147,278)	(1,720,917)	(2,294,556)	(2,868,196)	(3,441,835)	(4,015,474)	(4,589,113)	(5,162,752)	(5,736,391)	(6,310,030)	(6,883,669)	(7,457,309)	(8,030,948)
3	Removal Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(256,364)	(891,843)	(1,447,286)	(1,931,119)	(2,350,081)	(2,710,070)	(3,042,257)	(3,374,444)	(3,707,473)	(4,039,660)	(4,372,689)	(4,704,876)	(5,037,905)	(5,370,092)
5			28,481,745	27,272,627	26,143,544	25,086,072	24,093,471	23,159,843	22,254,018	21,348,192	20,441,523	19,535,697	18,629,029	17,723,203	16,816,534	15,910,709
6																
7	Average Rate Base		28,896,747	27,877,186	26,708,086	25,614,808	24,589,772	23,626,657	22,706,930	21,801,105	20,894,857	19,988,610	19,082,363	18,176,116	17,269,869	16,363,621
8																
9	Debt Return		650,177	627,237	600,932	576,333	553,270	531,600	510,906	490,525	470,134	449,744	429,353	408,963	388,572	368,181
10	Equity Return		1,375,485	1,326,954	1,271,305	1,219,265	1,170,473	1,124,629	1,080,850	1,037,733	994,595	951,458	908,320	865,183	822,046	778,908
11	Current Income Tax Requirement		298,440	(100,250)	(42,661)	7,959	53,150	93,632	103,775	86,384	68,142	51,585	33,343	16,786	(1,456)	(18,013)
12																
13	Book Depreciation		573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639
14	Annual Deferred Tax		256,364	635,479	555,444	483,833	418,962	359,989	332,187	332,187	333,029	332,187	333,029	332,187	333,029	332,187
15	ITC Flow Thru		-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		1,465,587	2,784,616	2,506,154	2,257,005	2,031,304	1,826,122	1,729,393	1,729,393	1,732,324	1,729,393	1,732,324	1,729,393	1,732,324	1,729,393
17	Tax Depreciation on Easements		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.497%		438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738
22																
23	Total Revenue Requirements - NSP		3,592,843	3,501,797	3,397,397	3,299,767	3,208,232	3,122,226	3,040,095	2,959,206	2,878,278	2,797,351	2,716,423	2,635,496	2,554,568	2,473,641
24																
25	Discount Rate =	0.06363305														
26																
27	Present Value of Revenue Requirements	39,863,086	3,377,897	3,095,332	2,823,389	2,578,197	2,356,713	2,156,321	1,973,988	1,806,511	1,651,986	1,509,485	1,378,121	1,257,073	1,145,576	1,042,920
28																

Line No.		
29	**Level Annual Revenue Requirement**	**2,609,493**
30		
31	**58 Year Life LARR %**	**8.90%**

Rev. Req. 2nd Circuit Subs

Brookings - 2nd Circuit Subs
58 YEAR LIFE

Line No.	Rate Analysis	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	Plant Investment	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748
2	Depreciation Reserve	(8,604,587)	(9,178,226)	(9,751,865)	(10,325,504)	(10,899,143)	(11,472,782)	(12,046,421)	(12,620,061)	(13,193,700)	(13,767,339)	(14,340,978)	(14,914,617)	(15,488,256)	(16,061,895)	(16,635,534)	(17,209,174)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(5,703,121)	(5,786,777)	(5,621,902)	(5,457,026)	(5,292,151)	(5,127,276)	(4,962,400)	(4,797,525)	(4,632,649)	(4,467,774)	(4,302,899)	(4,138,023)	(3,973,148)	(3,808,273)	(3,643,397)	(3,478,522)
5		15,004,040	14,346,745	13,937,981	13,529,218	13,120,454	12,711,690	12,302,926	11,894,163	11,485,399	11,076,635	10,667,871	10,259,108	9,850,344	9,441,580	9,032,816	8,624,053
6																	
7	Average Rate Base	15,457,374	14,675,393	14,142,363	13,733,600	13,324,836	12,916,072	12,507,308	12,098,545	11,689,781	11,281,017	10,872,253	10,463,490	10,054,726	9,645,962	9,237,198	8,828,434
8																	
9	Debt Return	347,791	330,196	318,203	309,006	299,809	290,612	281,414	272,217	263,020	253,823	244,626	235,429	226,231	217,034	207,837	198,640
10	Equity Return	735,771	698,549	673,176	653,719	634,262	614,805	595,348	575,891	556,434	536,976	517,519	498,062	478,605	459,148	439,691	420,233
11	Current Income Tax Requirement	(36,255)	198,105	436,402	428,554	420,706	412,858	405,010	397,162	389,314	381,465	373,617	365,769	357,921	350,073	342,225	334,377
12																	
13	Book Depreciation	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639
14	Annual Deferred Tax	333,029	83,656	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	1,732,324	864,697	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.497%	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738
22																	
23	Total Revenue Requirements - NSP	2,392,713	2,322,883	2,275,284	2,238,781	2,202,279	2,165,776	2,129,274	2,092,772	2,056,269	2,019,767	1,983,264	1,946,762	1,910,260	1,873,757	1,837,255	1,800,752
24																	
25	Discount Rate =																
26																	
27	Present Value of Revenue Requirements	948,448	865,681	797,213	737,495	682,068	630,634	582,912	538,644	497,586	459,513	424,214	391,494	361,171	333,075	307,048	282,943
28																	
29	**Level Annual Revenue Requirement**																
30																	
31	**58 Year Life LARR %**																

Rev. Req. 2nd Circuit Subs

Brookings - 2nd Circuit Subs
58 YEAR LIFE

Line No.	Rate Analysis	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40	Year 41	Year 42	Year 43	Year 44	Year 45	Year 46	Year 47
1	Plant Investment	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748
2	Depreciation Reserve	(17,782,813)	(18,356,452)	(18,930,091)	(19,503,730)	(20,077,369)	(20,651,008)	(21,224,647)	(21,798,286)	(22,371,926)	(22,945,565)	(23,519,204)	(24,092,843)	(24,666,482)	(25,240,121)	(25,813,760)	(26,387,399)	(26,961,039)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(3,313,647)	(3,148,771)	(2,983,896)	(2,819,021)	(2,654,145)	(2,489,270)	(2,324,394)	(2,159,519)	(1,994,644)	(1,829,768)	(1,664,893)	(1,500,018)	(1,335,142)	(1,170,267)	(1,005,392)	(840,516)	(675,641)
5		8,215,289	7,806,525	7,397,761	6,988,998	6,580,234	6,171,470	5,762,706	5,353,942	4,945,179	4,536,415	4,127,651	3,718,887	3,310,124	2,901,360	2,492,596	2,083,832	1,675,069
6																		
7	Average Rate Base	8,419,671	8,010,907	7,602,143	7,193,379	6,784,616	6,375,852	5,967,088	5,558,324	5,149,561	4,740,797	4,332,033	3,923,269	3,514,506	3,105,742	2,696,978	2,288,214	1,879,451
8																		
9	Debt Return	189,443	180,245	171,048	161,851	152,654	143,457	134,259	125,062	115,865	106,668	97,471	88,274	79,076	69,879	60,682	51,485	42,288
10	Equity Return	400,776	381,319	361,862	342,405	322,948	303,491	284,033	264,576	245,119	225,662	206,205	186,748	167,290	147,833	128,376	108,919	89,462
11	Current Income Tax Requirement	326,529	318,681	310,833	302,985	295,137	287,289	279,441	271,592	263,744	255,896	248,048	240,200	232,352	224,504	216,656	208,808	200,960
12																		
13	Book Depreciation	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639
14	Annual Deferred Tax	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.497%	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738
22																		
23	Total Revenue Requirements - NSP	1,764,250	1,727,747	1,691,245	1,654,743	1,618,240	1,581,738	1,545,235	1,508,733	1,472,231	1,435,728	1,399,226	1,362,723	1,326,221	1,289,719	1,253,216	1,216,714	1,180,211
24																		
25	Discount Rate =																	
26																		
27	Present Value of Revenue Requirements	260,624	239,962	220,839	203,146	186,779	171,644	157,651	144,718	132,768	121,730	111,538	102,129	93,447	85,439	78,054	71,247	64,975
28																		
29	**Level Annual Revenue Requirement**																	
30																		
31	**58 Year Life LARR %**																	

Rev. Req. 2nd Circuit Subs

Brookings - 2nd Circuit Subs
58 YEAR LIFE

Line No.	Rate Analysis	Year 48	Year 49	Year 50	Year 51	Year 52	Year 53	Year 54	Year 55	Year 56	Year 57	Year 58
1	Plant Investment	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748	29,311,748
2	Depreciation Reserve	(27,534,678)	(28,108,317)	(28,681,956)	(29,255,595)	(29,829,234)	(30,402,873)	(30,976,512)	(31,550,151)	(32,123,791)	(32,697,430)	(33,271,069)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	3,959,321
4	Accumulated Deferred Taxes	(510,766)	(345,890)	(181,015)	(16,140)	148,736	313,611	478,487	643,362	808,237	973,113	0
5		1,266,305	857,541	448,777	40,014	(368,750)	(777,514)	(1,186,278)	(1,595,041)	(2,003,805)	(2,412,569)	0
6												
7	Average Rate Base	1,470,687	1,061,923	653,159	244,395	(164,368)	(573,132)	(981,896)	(1,390,660)	(1,799,423)	(2,208,187)	(1,206,284)
8												
9	Debt Return	33,090	23,893	14,696	5,499	(3,698)	(12,895)	(22,093)	(31,290)	(40,487)	(49,684)	(27,141)
10	Equity Return	70,005	50,548	31,090	11,633	(7,824)	(27,281)	(46,738)	(66,195)	(85,653)	(105,110)	(57,419)
11	Current Income Tax Requirement	193,112	185,264	177,416	169,568	161,720	153,871	146,023	138,175	130,327	122,479	(996,273)
12												
13	Book Depreciation	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639	573,639
14	Annual Deferred Tax	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	(164,875)	973,113
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	3,959,321
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.497%	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738	438,738
22												
23	Total Revenue Requirements - NSP	1,143,709	1,107,207	1,070,704	1,034,202	997,699	961,197	924,695	888,192	851,690	815,187	904,657
24												
25	Discount Rate =											
26												
27	Present Value of Revenue Requirements	59,198	53,880	48,987	44,486	40,348	36,546	33,055	29,851	26,912	24,217	25,267
28												
29	**Level Annual Revenue Requirement**											
30												
31	**58 Year Life LARR %**											

Northern States Power Company
State of Minnesota
OATT Credit Factor

		2023 Att O Filing*		
		Revenue Included in OATT Credit	**Revenue Excluded in OATT Credit**	**Total 2023**
Line No.	Description			
1	PTP Firm - Tsmn RTO	-	5,790,858	5,790,858
2	PTP Non-Frim - Tsmn RT	-	882,850	882,850
3	Network - Tsmn RTO	32,367,631	-	32,367,631
5	Sch 1. - Tsmn RTO	658,843	-	658,843
6	Sch 2 - Reactive Supply	8,451,378	-	8,451,378
7	Sch 24 - Bal Auth	1,279,088	-	1,279,088
8	Sch 26a-MVP NSP	-	74,452,948	74,452,948
9	Sch 26 Trans Exp Plan	-	70,635,129	70,635,129
10	Joint Pricing Zone - GRE*	42,232,761	-	42,232,761
11	Joint Pricing Zone - GRE Zone	5,864,668	-	5,864,668
12	Joint Pricing Zone - SMMPA	7,494,457	-	7,494,457
13	Joint Pricing Zone - MRES	6,113,924	-	6,113,924
14	Joint Pricing Zone - Sch 2 Reactive Supply	126,983	-	126,983
15	Contracts-SD State Pen	-	14,940	14,940
16	Contracts-WPPI Meter S	-	40,320	40,320
17	Contracts-UND	-	70,643	70,643
18	Contracts-Granite Fall	-	-	-
19	Contracts-E Grand Fork	-	-	-
20	Contracts-Sioux Falls	-	192,605	192,605
21	Self-Funding Network Upgrades	-	5,153,473	5,153,473
21	Marshall TOP Agreement	-	151,210	151,210
21	MMPA TOP Agreement	-	22,067	22,067
21	TOIF (Schedule 50)	-	290,393	290,393
22	Other (Kasota,Shakopee, St James)	46,888	-	46,888
23	**Total NSP Revenue**	**104,636,621**	**157,697,437**	**262,334,058**

Att O - Transmission charges for all transactions in divisor Line 36, Pg. 5	**104,636,621**
Att O - GROSS RR to be collected under Att) - Line 1, Pg. 1	**468,498,012**
OATT Credit Factor = Line 36 / Line 1	**22.3345%**

*Based on currently filed Att O on OASIS

Key Inputs

Line No	**Capital Structure**			
1				
2	Capital Structure	Cost	Ratio	WACC
3	Long Term Debt	4.7500%	45.8100%	2.18%
4	Short Term Debt	4.3100%	1.6900%	0.07%
5	Preferred Stock	0.0000%	0.0000%	0.00%
6	Common Equity	9.0600%	52.5000%	4.76%
7	**Required Rate of Return**			7.01%
8	Weighted cost of capital & ROE from settlement in Case No. PU-20-441			
9				
10	**Property Tax Rates**			
11	Property Tax Rate			1.497%
12				
13				
14	**Income Tax Rates**			
15	Composite Income Tax Rate			28.7420%
16				
17	**Allocators (Year 2023)**			
18	ND 12-month CP Demand (Electric Demand)			6.0613%
19	NSPM 36-month CP demand (Interchange Electric)			83.8765%
20	Jurisdictional Allocator			5.0840%
21				
22	**Book Depreciation Lives**			
23	Land			0.00
24	Line			65.70
25	Sub			58.38
26				
27	**Net Salvage %**			
28	Land			0.00%
29	Line			-44.21%
30	Sub			-14.24%
31				
32	**Book Depreciation Rates**			
33	Land			0.00%
34	Line			2.1951%
35	Sub			1.9570%