Appendix A

Certificate of Need Application Completeness Checklist

Certificate of Need Application
Completeness Checklist

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
Minn. R. 7829.2500, subp. 2	Brief summary of filing on separate page sufficient to apprise potentially interested parties of its nature and general content	Filing Summary
Minn. R. 7849.0200, subp. 2	Title Page and Table of Contents	Title Page and Table of Contents
Minn. R. 7849.0200, subp. 4	Cover Letter	Cover Letter
Minn. R. 7849.0220, subp. 3	Joint Ownership and Multiparty use	N/A
Minn. R. 7849.0240	Need summary and additional considerations	-
subp. 1	Summary of the major factors that justify the need for the proposed facility	Section 1.9
subp. 2	Relationship of the proposed facility to the following socioeconomic considerations:	Section 1.10
A.	Socially beneficial uses of the output of the facility	Section 1.10.1
B.	Promotional activities that may have given rise to the demand for the facility	Section 1.10.2
C.	Effects of the facility in inducing future development	Section 1.10.3
Minn. R. 7849.0260	Proposed LHVTL and Alternatives	–
A.	A description of the type and general location of the proposed line, including:	–
(1)	Design voltage	Section 2.1.1, Table 2.1
(2)	Number, sizes and types of conductors	Section 2.1.1, Table 2.1

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
(3)	Expected losses under projected maximum loading and under projected average loading in the length of the line and at terminals or substations	Exempt
(4)	Approximate length of the proposed line	Section 2.1
(5)	Approximate locations of DC terminals or AC substations on a map	Figure 2.1
(6)	List of likely affected counties	Section 2.1
B.	Discussion of the available alternatives including:	–
(1)	New generation	Section 4.6.1
(2)	Upgrading existing transmission lines	Section 4.6.2
(3)	Transmission lines with different voltages or conductor arrays	Section 4.6.3
(4)	Transmission lines with different terminals or substations	Section 4.6.4
(5)	Double circuiting of existing transmission lines	Section 4.6.5
(6)	If facility for DC (AC) transmission, an AC (DC) transmission line	Section 4.6.6
(7)	If proposed facility is for overhead (underground) transmission, an underground (overhead) transmission line	Section 4.6.7
(8)	Any reasonable combination of alternatives (1) – (7)	Section 4.6.9
C.	For the facility and for each alternative in B, a discussion of:	–
(1)	Total cost in current dollars	Section 2.2, Tables 2.2 & 2.3
(2)	Service life	Section 6.5

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
(3)	Estimated average annual availability	Section 6.6
(4)	Estimated annual O&M costs in current dollars	Section 6.5
(5)	Estimate of its effect on rates system wide and in Minnesota	Section 2.3, Appendices C & D
(6)	Efficiency	Exempt
(7)	Major assumptions made in subitems (1) – (6)	Chapter 4, Sections 6.5 & 6.6, Appendix E
D.	A map (of appropriate scale) showing the applicant's system or load center to be served by the proposed LHVTL	Exempt
E.	Such other information about the proposed facility and each alternative as may be relevant to determination of need.	Chapters 1, 2, 4, 6, Appendix E
Minn. R. 7849.0270	Content of Forecast	–
Minn. R. 7849.0270, subp. 1	Peak demand and annual consumption data	Exempt
Minn. R. 7849.0270, subp. 2	For each forecast year the following data:	–
A.	Minnesota forecast data	Exempt
B.	Estimates of the number of ultimate consumers and annual electrical consumption by those consumers:	–
(1)	Farm, excluding irrigation and drainage pumping	Exempt
(2)	Irrigation and drainage pumping	Exempt
(3)	Nonfarm residential	Exempt
(4)	Commercial	Exempt

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
(5)	Mining	Exempt
(6)	Industrial	Exempt
(7)	Street and highway lighting	Exempt
(8)	Electrified transportation	Exempt
(9)	Other	Exempt
(10)	Sum of subitems (1) – (9)	Exempt
C.	Estimate of the demand for power in system at the time of annual system peak demand	Exempt
D.	System peak demand by month	Exempt
E.	Estimated annual revenue requirement per kWh in current dollars	Exempt
F.	Estimated average weekday load factor by month	Exempt
Minn. R. 7849.0270, subp. 3	Forecast Methodology	–
	Detail of forecast methodology including:	–
A.	Overall methodological framework used	Exempt
B.	Specific analytical used	Exempt
C.	Manner in which specific techniques are related in producing the forecast	Exempt
D.	Where statistical techniques are used:	–

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
(1)	Purpose of the technique	Exempt
(2)	Typical computations	Exempt
(3)	Results of statistical tests	Exempt
E.	Forecast confidence levels for annual peak demand and annual electrical consumption	Exempt
F.	Brief analysis of methodology including:	–
(1)	Strengths and weaknesses	Exempt
(2)	Suitability to the system	Exempt
(3)	Cost considerations	Exempt
(4)	Data requirements	Exempt
(5)	Past accuracy	Exempt
(6)	Other significant factors	Exempt
G.	Explanation of discrepancies	Exempt
Minn. R. 7849.0270, subp. 4	Discussion of data base used for forecasts including:	–
A.	List of data sets including a brief description of each	Exempt
B.	Identification of adjustments made to raw data including nature, reason and magnitude	Exempt
Minn. R. 7849.0270, subp. 5	Assumptions and Special Information	–

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
	Discussion of each essential assumption including need and nature of assumption and sensitivity of forecast results to assumptions	Exempt
	Discussion of assumptions regarding:	–
A.	Availability of alternative sources of energy	Exempt
B.	Expected conversion from other fuels to electricity or vice versa	Exempt
C.	Future prices for customers and their effect on demand	Exempt
D.	Data requested in subp. 2 not historically available or generated by applicant for demand forecast	Exempt
E.	Effect of energy conservation programs on long term demand	Exempt
F.	Other factors considered when preparing forecast	Exempt
Minn. R. 7849.0270, subp. 6	Coordination of Forecasts with Other Systems	—
A.	Extent of coordination of load forecasts with those of other systems	Exempt
B.	Description of the manner in which those forecasts are coordinated	Exempt
Minn. R. 7849.0280	System Capacity	—
	Description of ability of existing system to meet demand forecast including:	—
A.	Power planning programs	Exempt
B.	Seasonal firm purchases and sales	Exempt
C.	Seasonal participation purchases and sales	Exempt

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
D.	For each forecast year load and generating capacity for:	Exempt
(1)	Seasonal system demand	Exempt
(2)	Annual system demand	Exempt
(3)	Total seasonal firm purchases	Exempt
(4)	Total seasonal firm sales	Exempt
(5)	Seasonal adjusted net demand	Exempt
(6)	Annual adjusted net demand	Exempt
(7)	Net generating capacity	Exempt
(8)	Total participation purchases	Exempt
(9)	Total participation sales	Exempt
(10)	Adjusted net capability	Exempt
(11)	Net reserve capacity obligation	Exempt
(12)	Total firm capacity obligation	Exempt
(13)	Surplus or deficit capacity	Exempt
E.	Summer and winter season load generation and capacity in years subsequent to application contingent on proposed facility	Exempt
F.	Summer and winter season load generation and capacity including all projected purchases, sales and generation in years subsequent to application	Exempt

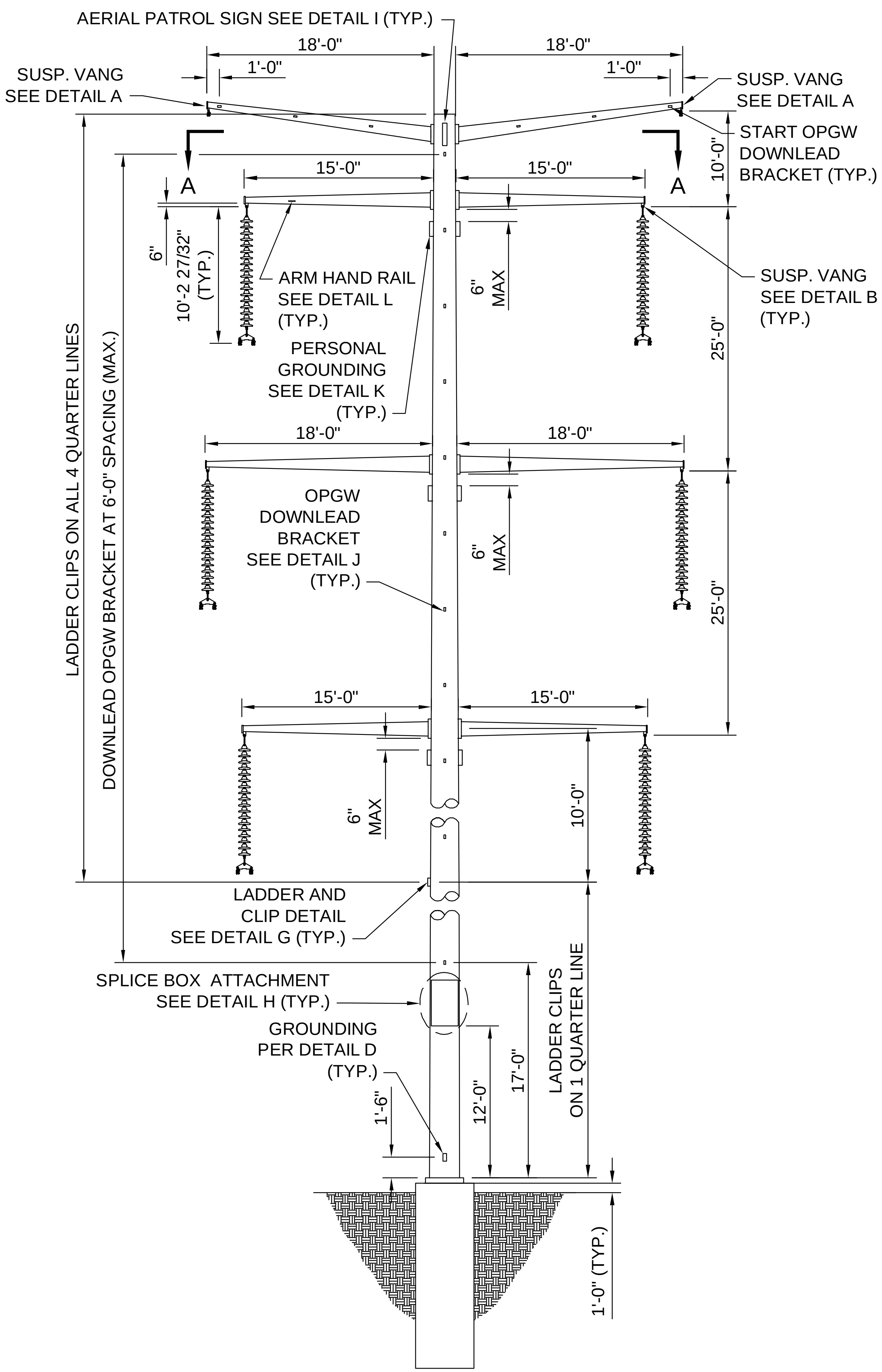
AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
G.	List of proposed additions and retirements in generating capacity for each forecast year subsequent to application	Exempt
H.	Graph of monthly adjusted net demand and capability with difference between capability and maintenance outages plotted	Exempt
I.	Appropriateness and method of determining system reserve margins	Exempt
Minn. R. 7849.0290	Conservation Programs	—
A.	Persons responsible for energy conservation and efficiency programs	Exempt
B.	List of energy conservation and efficiency goals and objectives	Exempt
C.	Description of programs considered, implemented and rejected	Exempt
D.	Description of major accomplishments in conservation and efficiency	Exempt
E.	Description of future plans with respect to conservation and efficiency	Exempt
F.	Quantification of the manner by which these programs impact the forecast	Exempt
Minn. R. 7849.0300	Consequence of Delay	Exempt
Minn. R. 7849.0310	Required Environmental Information	Chapter 7
Minn. R. 7849.0330	Transmission Facilities	—
	Data for each alternative that would require LHVTL construction including:	—
A.	For overhead transmission lines	—

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
(1)	Schematics showing dimensions of support structures	Appendix B
(2)	Discussion of electric fields	Sections 5.6.1 & 7.10
(3)	Discussion of ozone and nitrogen oxide emissions	Section 5.2
(4)	Discussion of radio and television interference	Section 5.4
(5)	Discussion of audible noise	Section 5.3
B.	For underground transmission facilities:	N/A
(1)	Types and dimensions of cable systems	N/A
(2)	Types and qualities of cable system materials	N/A
(3)	Heat released in kW per foot of cable	N/A
C.	Estimated right-of-way required for the facility	Table 2.1
D.	Description of construction practices	Section 6.3
E.	Description of O&M practices	Section 6.5
F.	Estimated workforce required for construction and O&M	Sections 2.4 & 6.3
G.	Description of region between endpoints in likely area for routes emphasizing a three-mile radius of endpoints including:	-
(1)	Hydrological features	Section 7.3
(2)	Vegetation and wildlife	Section 7.4

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
(3)	Physiographic regions	Section 7.2
(4)	Land use types	Section 7.6
Minn. R. 7849.0340	No-Facility Alternative	Exempt
Exemption Order		
Exemption Order	In lieu of Minn. R. 7849.0260 A(3) and C(6), requiring line-specific loss information, the Company provides system loss information.	Section 4.6.10 and Table 4.5
Exemption Order	In lieu of Minn. R. 7849.0260(D), requiring for a map showing the Applicant's system or load centers to be served by the Project, the Company provides a general map showing its service territory in Minnesota.	Figure 3.2
Exemption Order	In lieu of Minn. R. 7849.0270, subps. (1) through (6), requiring specific forecasting and capacity information, the Company provides provide substitute forecast information used in analyzing the need for the Project.	Chapter 4, Appendix E
Exemption Order	In lieu of Minn. R. 7849.0270, subp. 2(E), requiring an estimate of "the annual revenue requirement per kilowatt-hour of the system in current dollars," the Company provides general rate impact information regarding the Project.	Section 2.3, Appendices C & D
Exemption Order	In lieu of Minn. R. 7849.0290, requiring information related to conservation programs the applicant has in place and their effect on forecast information required by Minn. R. 7849.0270, the Company provides summary information related to its conservation programs in Minnesota, including how the Company considered conservation and energy efficiency in its evaluation of the Project.	Section 4.4, Appendices E & F
Exemption Order	In lieu of Minn. R. 7849.0300, requiring detailed information regarding the consequences of delay on three specific statistically based levels of demand and energy consumption, and Minn. R. 7849.0340, requiring a discussion of the impact on existing generation and transmission facilities at the three levels of demand specified in Minn. R. 7849.0300 for the no-build alternative, the Company provides the annual congestion-charge savings resulting from the Project.	Table 4.4

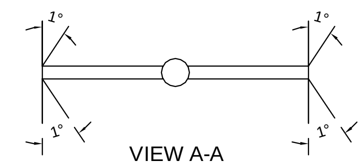
Appendix B

Technical Diagrams of Typical 345 kV Structures

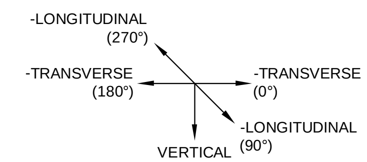


NOTES:

1. FOR GENERAL NOTES AND DESIGN LOADS REFER TO SHEET 1.
2. FOR ATTACHMENT DETAILS REFER TO SHEETS 2 - 6A.
3. FOR CLEARANCE PURPOSES USE 24"X24" ENERGIZED BOX.
4. ALL STRUCTURES WILL NOT HAVE A SPLICE BOX. REFER TO STRUCTURE LIST FOR THE STRUCTURES THAT WILL REQUIRE DOWNLEAD CLIPS AND SPLICE BOX ATTACHMENTS ETC.
5. MAXIMUM BOLT CIRCLE SHALL BE 6'-0".



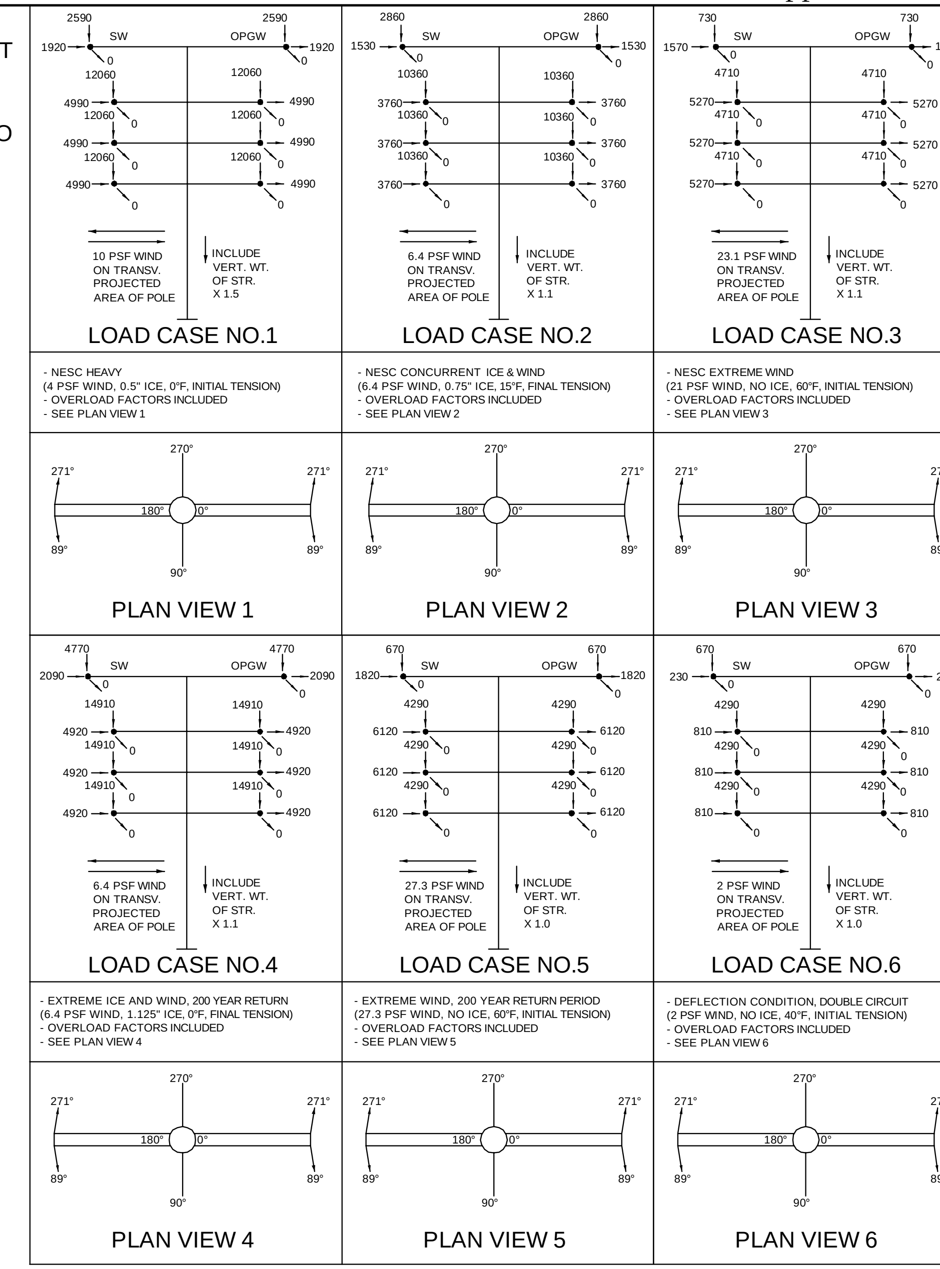
VIEW A-A



DIRECTION OF FORCES
(ALL FORCES EXPRESSED IN POUNDS)

DESIGN DATA:

LINE ANGLE: 2°
WIND SPAN: 1100'
WEIGHT SPAN: 1500'
RULING SPAN: 1000'
CONDUCTOR: 2-954 ACSS TW CARDINAL
SHIELD WIRE: DNO-8559, OPGW
3/8"-7 STRAND E.H.S.
VOLTAGE: 345KV/345KV



REFER TO SHEET 08 FOR ADDITIONAL LOAD CASES.

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REV NO	DATE	REVISION	REV BY	APPD BY
3	02/27/15	AS-BUILT W.O.#90972	MWB	LDK
2	08/26/13	ADDED ENGINEER'S SEAL	MWB	MFJ
1	07/15/13	LADDER CLIPS NOTE DELETED	RU	MFJ

Stanley Consultants INC.
8000 South Chester Street, Suite 500, Centennial, Colorado 80112-3520
www.stanleyconsultants.com

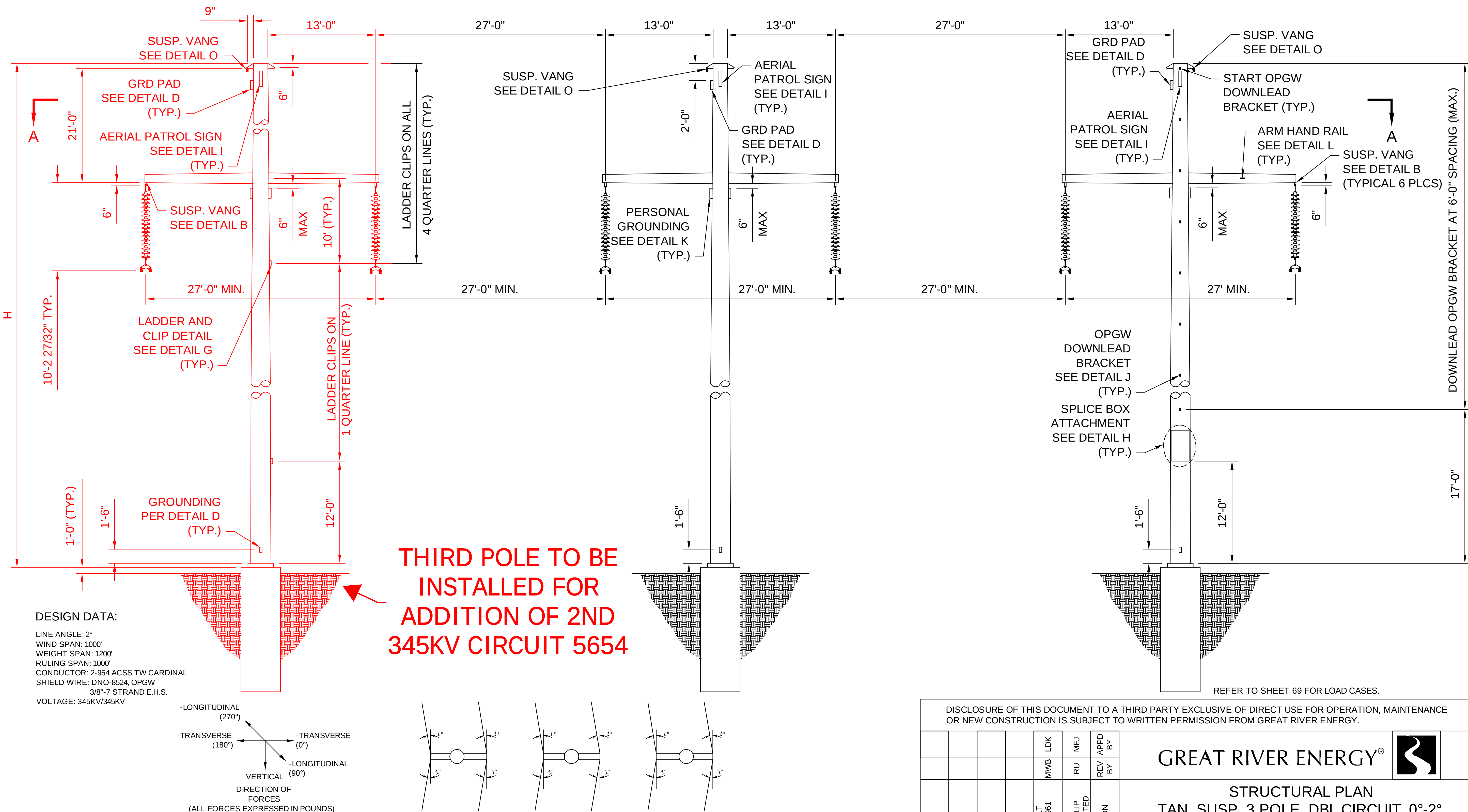
GREAT RIVER ENERGY®

STRUCTURAL PLAN
TAN, SUSP, DAVIT ARMS, DBL CIRCUIT, 0°-2°

345KV
CAPX
TS-DADC-345
0972

DATE:	03-29-2013	PROJECT NO	REVISION
SCALE:	NONE	0972	3
DWN BY:	BEC	DRAWING NUMBER	
CKD BY:	MWB	0972-35B	
CKD BY:	RU		
APPD BY:	MFJ	SHEET 07	

ACTIVE



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2. FOR ATTACHMENT DETAILS REFER TO SHEETS 2 - 6A.
3. ALL STRUCTURES WILL NOT HAVE A SPLICE BOX. THE STRUCTURES THAT WILL REQUIRE DOWNLEAD CLIPS AND SPLICE BOX ATTACHMENT ETC. WILL BE PROVIDED LATER.
4. THIS DRAWING IS FOR STR #'S 36, 37, 40 AND 41.

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REV NO	DATE	REVISION	REV BY	APPD BY
1	07/15/13	LADDER CLIP NOTE DELETED	RU	MFJ
1	01/30/15	AS-BUILT W.O.#90961	MWB	LDK

GREAT RIVER ENERGY®

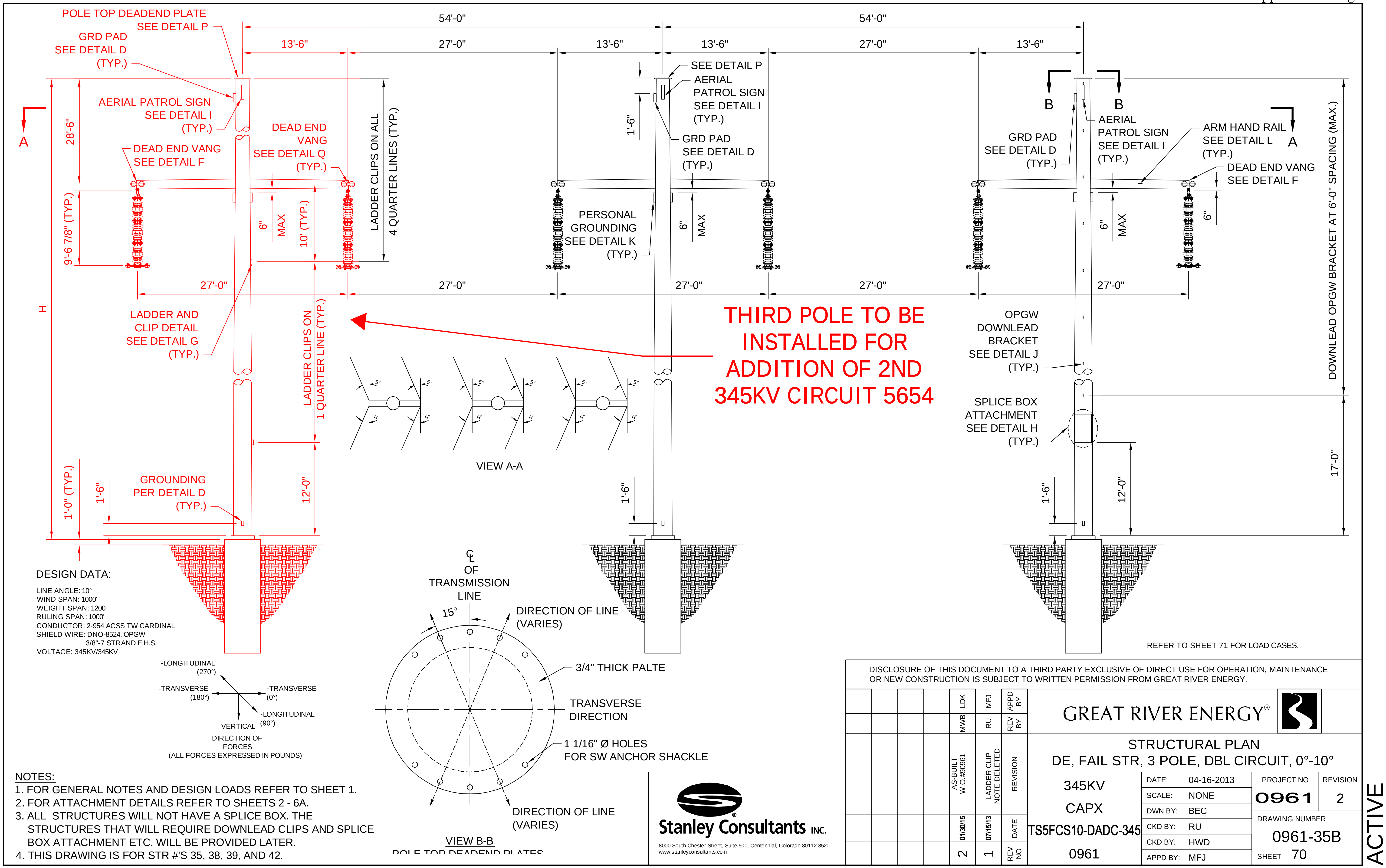
STRUCTURAL PLAN
TAN, SUSP, 3 POLE, DBL CIRCUIT, 0°-2°

345KV
CAPX
T3P-DC-345
0961

DATE: 04-16-2013
SCALE: NONE
DWN BY: BEC
CKD BY: RU
CKD BY: HWD
APPD BY: MFJ

PROJECT NO 0961
REVISION 2
DRAWING NUMBER 0961-35B
SHEET 68

ACTIVE


POLE TOP DEADEND PLATE
SEE DETAIL P
GRD PAD
SEE DETAIL D
(TYP.)
AERIAL PATROL SIGN
SEE DETAIL I
(TYP.)
DEAD END VANG
SEE DETAIL F
DEAD END
VANG
SEE DETAIL Q
(TYP.)
LADDER CLIPS ON ALL
4 QUARTER LINES (TYP.)
54'-0"
54'-0"
13'-6"
27'-0"
13'-6"
13'-6"
27'-0"
13'-6"
28'-6"
9'-6 7/8" (TYP.)
6"
MAX
10' (TYP.)
SEE DETAIL P
AERIAL
PATROL SIGN
SEE DETAIL I
(TYP.)
1'-6"
GRD PAD
SEE DETAIL D
(TYP.)
PERSONAL
GROUNDING
SEE DETAIL K
(TYP.)
B
B
A
A
AERIAL
PATROL SIGN
SEE DETAIL I
(TYP.)
ARM HAND RAIL
SEE DETAIL L
(TYP.)
DEAD END VANG
SEE DETAIL F
DOWNLEAD OPGW BRACKET AT 6'-0" SPACING (MAX.)
H
LADDER AND
CLIP DETAIL
SEE DETAIL G
(TYP.)
LADDER CLIPS ON
1 QUARTER LINE (TYP.)
THIRD POLE TO BE
INSTALLED FOR
ADDITION OF 2ND
345KV CIRCUIT 5654
OPGW
DOWNLEAD
BRACKET
SEE DETAIL J
(TYP.)
SPLICE BOX
ATTACHMENT
SEE DETAIL H
(TYP.)
17'-0"
12'-0"
VIEW A-A
GROUNDING
PER DETAIL D
(TYP.)
1'-0" (TYP.)
1'-6"
DESIGN DATA:
LINE ANGLE: 10°
WIND SPAN: 1000'
WEIGHT SPAN: 1200'
RULING SPAN: 1000'
CONDUCTOR: 2-954 ACSS TW CARDINAL
SHIELD WIRE: DNO-8524, OPGW
3/8"-7 STRAND E.H.S.
VOLTAGE: 345KV/345KV
-LONGITUDINAL
(270°)
-TRANSVERSE
(180°)
-TRANSVERSE
(0°)
-LONGITUDINAL
(90°)
VERTICAL
DIRECTION OF
FORCES
(ALL FORCES EXPRESSED IN POUNDS)
℄ OF
TRANSMISSION
LINE
15°
DIRECTION OF LINE
(VARIES)
3/4" THICK PALTE
TRANSVERSE
DIRECTION
1 1/16" Ø HOLES
FOR SW ANCHOR SHACKLE
DIRECTION OF LINE
(VARIES)
VIEW B-B
POLE TOP DEADEND PLATES
REFER TO SHEET 71 FOR LOAD CASES.
NOTES:
1. FOR GENERAL NOTES AND DESIGN LOADS REFER TO SHEET 1.
2. FOR ATTACHMENT DETAILS REFER TO SHEETS 2 - 6A.
3. ALL STRUCTURES WILL NOT HAVE A SPLICE BOX. THE STRUCTURES THAT WILL REQUIRE DOWNLEAD CLIPS AND SPLICE BOX ATTACHMENT ETC. WILL BE PROVIDED LATER.
4. THIS DRAWING IS FOR STR #'S 35, 38, 39, AND 42.
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GREAT RIVER ENERGY®
2 01/30/15 AS-BUILT W.O.#90961 MWB LDK
1 07/15/13 LADDER CLIP NOTE DELETED RU MFJ
REV NO DATE REVISION REV BY APPD BY
STRUCTURAL PLAN
DE, FAIL STR, 3 POLE, DBL CIRCUIT, 0°-10°
345KV
CAPX
TS5FCS10-DADC-345
0961
DATE: 04-16-2013
SCALE: NONE
DWN BY: BEC
CKD BY: RU
CKD BY: HWD
APPD BY: MFJ
PROJECT NO 0961
REVISION 2
DRAWING NUMBER 0961-35B
SHEET 70
ACTIVE

Appendix C

Revenue Requirements

Total Project Summary

		Brookings - 2nd Circuit - 100% NSP Ownership			Brookings - 2nd Circuit - Shared Ownership of Lines		
Line No.	Amounts in dollars	Line (A)	Subs (B)	Total	Line (A)	Subs (B)	Total
1	**All-in project revenue requirement**	**269,446,662**	**108,454,518**	**377,901,180**	**269,446,662**	**108,454,518**	**377,901,180**
2							
3	Less other ownership for Lines (32.2029% owned by other TOU's)	-	-	-	(86,769,639)	-	(86,769,639)
4							
5	**Project NSP Revenue Requirement**	**269,446,662**	**108,454,518**	**377,901,180**	**182,677,023**	**108,454,518**	**291,131,541**
6							
7	Estimated OATT Credit %	22.33%	22.33%		22.33%	22.33%	
8							
9	**TOTAL MISO OATT Credit**	60,179,526	24,222,759	84,402,285	40,799,973	24,222,759	65,022,732
10							
11							
12	Calculation to NSP loads:						
13		**Line (A)**	**Subs (B)**	**Total**	**Line (A)**	**Subs (B)**	**Total**
14	Total NSP Revenue Requirement	269,446,662	108,454,518	377,901,180	182,677,023	108,454,518	291,131,541
15	Less: NSP MISO OATT Credit	(60,179,526)	(24,222,759)	(84,402,285)	(40,799,973)	(24,222,759)	(65,022,732)
16	**Net cost - NSP Companies**	209,267,136	84,231,759	**293,498,896**	141,877,050	84,231,759	**226,108,809**
17							
18	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
19	Demand Allocator - MN Jurisdiction	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%
20							
21	**Net cost to MN Jurisdiction**	**153,274,493**	**61,694,256**	**214,968,748**	**103,915,661**	**61,694,256**	**165,609,917**

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**	**9,125,815**	**3,607,991**	**12,733,806**	**9,125,815**	**3,607,991**	**12,733,806**
2							
3	Less other ownership (32.2029% owned by other TOU's)	-	-	-	(2,938,777)	-	(2,938,777)
4							
5	**Project NSP Revenue Requirement**	**9,125,815**	**3,607,991**	**12,733,806**	**6,187,038**	**3,607,991**	**9,795,029**
6							
7	Estimated OATT Credit %	22.33%	22.33%		22.33%	22.33%	22.33%
8							
9	**TOTAL MISO OATT Credit**	**2,038,204**	**805,826**	**2,844,030**	**1,381,843**	**805,826**	**2,187,669**
10							
11							
12	Calculation to NSP loads:						
13		**Line (A)**	**Subs (B)**	**Total**	**Line (A)**	**Subs (B)**	**Total**
14	Total NSP Revenue Requirement	9,125,815	3,607,991	12,733,806	6,187,038	3,607,991	9,795,029
15	Less: NSP MISO OATT Credit	(2,038,204)	(805,826)	(2,844,030)	(1,381,843)	(805,826)	(2,187,669)
16	**Net cost - NSP Companies**	7,087,611	2,802,165	**9,889,776**	4,805,195	2,802,165	**7,607,360**
17							
18	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
19	Demand Allocator - MN Jurisdiction	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%
20							
21	**Net cost to MN Jurisdiction**	**5,191,212**	**2,052,402**	**7,243,614**	**3,519,491**	**2,052,402**	**5,571,893**

NOTE: Tax assumptions include 21% corp Fed tax rate

Total - Xcel Energy 100% Owner

Brookings - 2nd Circuit Line
63 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 (MN)	28.7400%		

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		9,125,815	8,885,272	8,611,607	8,354,736	8,112,980	7,884,940	7,666,510	7,451,159	7,235,714	7,020,270	6,804,825	6,589,381	6,373,937
8	Sub		3,607,991	3,515,680	3,410,017	3,311,125	3,218,325	3,131,055	3,047,659	2,965,504	2,883,312	2,801,119	2,718,927	2,636,734	2,554,542
9															
10	**Project Revenue Requirements - NSP**		12,733,806	12,400,953	12,021,625	11,665,861	11,331,306	11,015,995	10,714,169	10,416,663	10,119,026	9,821,389	9,523,752	9,226,115	8,928,478
11															
12	Less: NSP MISO OATT Credit on Line & Sub		(2,844,030)	(2,769,689)	(2,684,968)	(2,605,510)	(2,530,789)	(2,460,366)	(2,392,955)	(2,326,508)	(2,260,032)	(2,193,557)	(2,127,081)	(2,060,605)	(1,994,130)
13															
14	**Total Revenue Requirements - NSP**		9,889,776	9,631,264	9,336,657	9,060,351	8,800,517	8,555,629	8,321,215	8,090,155	7,858,994	7,627,832	7,396,671	7,165,510	6,934,349
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 - MN Jurisdiction		87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%
18															
19	**Total Revenue Requirements - MN Jurisdiction**		7,243,614	7,054,271	6,838,490	6,636,115	6,445,803	6,266,439	6,094,745	5,925,509	5,756,199	5,586,888	5,417,578	5,248,267	5,078,957
20															
21															
22	**Discount Rate =**	0.0636335													
23															
24	**Present Value of Revenue Requirements - NSP**	115,428,475	11,971,987	10,961,527	9,990,498	9,114,834	8,323,767	7,608,021	6,956,879	6,359,055	5,807,787	5,299,719	4,831,656	4,400,629	4,003,883
25															
26															
27															
28			12.48%	12.16%	11.78%	11.43%	11.11%	10.80%	10.50%	10.21%	9.92%	9.63%	9.33%	9.04%	8.75%

Total - Xcel Energy 100% Owner

Brookings - 2nd Circuit Line
63 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	6,158,492	5,943,048	5,755,127	5,622,349	5,517,095	5,411,841	5,306,587
8	Sub	2,472,349	2,390,157	2,319,060	2,270,193	2,232,421	2,194,650	2,156,878
9								
10	**Project Revenue Requirements - NSP**	8,630,841	8,333,204	8,074,188	7,892,542	7,749,516	7,606,491	7,463,465
11								
12	Less: NSP MISO OATT Credit on Line & Sub	(1,927,654)	(1,861,178)	(1,803,328)	(1,762,759)	(1,730,815)	(1,698,871)	(1,666,927)
13								
14	**Total Revenue Requirements - NSP**	6,703,187	6,472,026	6,270,859	6,129,783	6,018,702	5,907,620	5,796,539
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 - MN Jurisdiction	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%
18								
19	**Total Revenue Requirements - MN Jurisdiction**	4,909,646	4,740,336	4,592,994	4,489,665	4,408,305	4,326,946	4,245,586
20								
21								
22	**Discount Rate =**							
23								
24	**Present Value of Revenue Requirements - NSP**	3,638,857	3,303,178	3,009,031	2,765,367	2,552,810	2,355,788	2,173,203
25								
26								
27								
28		8.46%	8.17%	7.91%	7.74%	7.60%	7.46%	7.32%

Total - Shared Ownership

Brookings - 2nd Circuit Line
63 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 (MN)	28.7400%		

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		6,187,038	6,023,957	5,838,420	5,664,269	5,500,365	5,345,761	5,197,671	5,051,670	4,905,605	4,759,539	4,613,474	4,467,409	4,321,344
8	Sub		3,607,991	3,515,680	3,410,017	3,311,125	3,218,325	3,131,055	3,047,659	2,965,504	2,883,312	2,801,119	2,718,927	2,636,734	2,554,542
9															
10	**Project Revenue Requirements - NSP**		9,795,029	9,539,637	9,248,437	8,975,394	8,718,691	8,476,816	8,245,331	8,017,174	7,788,916	7,560,659	7,332,401	7,104,143	6,875,886
11															
12	Less: NSP MISO OATT Credit on Line & Sub		(2,187,669)	(2,130,629)	(2,065,591)	(2,004,608)	(1,947,275)	(1,893,253)	(1,841,552)	(1,790,595)	(1,739,614)	(1,688,634)	(1,637,654)	(1,586,674)	(1,535,694)
13															
14	**Total Revenue Requirements - NSP**		7,607,360	7,409,009	7,182,846	6,970,786	6,771,416	6,583,563	6,403,778	6,226,579	6,049,302	5,872,024	5,694,747	5,517,470	5,340,192
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 - MN Jurisdiction		87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%
18															
19	**Total Revenue Requirements - MN Jurisdiction**		5,571,893	5,426,614	5,260,965	5,105,645	4,959,619	4,822,029	4,690,349	4,560,562	4,430,718	4,300,874	4,171,030	4,041,186	3,911,342
20															
21															
22	**Discount Rate =**	0.0636335													
23															
24	**Present Value of Revenue Requirements - NSP**	88,844,841	9,209,026	8,432,335	7,685,858	7,012,703	6,404,589	5,854,377	5,353,823	4,894,240	4,470,427	4,079,806	3,719,925	3,388,501	3,083,419
25															
26															
27															
28			12.46%	12.14%	11.77%	11.42%	11.09%	10.78%	10.49%	10.20%	9.91%	9.62%	9.33%	9.04%	8.75%

Total - Shared Ownership

Brookings - 2nd Circuit Line
63 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	4,175,279	4,029,214	3,901,809	3,811,790	3,740,430	3,669,071	3,597,712
8	Sub	2,472,349	2,390,157	2,319,060	2,270,193	2,232,421	2,194,650	2,156,878
9								
10	**Project Revenue Requirements - NSP**	6,647,628	6,419,371	6,220,870	6,081,982	5,972,852	5,863,721	5,754,590
11								
12	Less: NSP MISO OATT Credit on Line & Sub	(1,484,714)	(1,433,733)	(1,389,399)	(1,358,379)	(1,334,006)	(1,309,632)	(1,285,258)
13								
14	**Total Revenue Requirements - NSP**	5,162,915	4,985,637	4,831,470	4,723,603	4,638,846	4,554,089	4,469,332
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 - MN Jurisdiction	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%	87.3%
18								
19	**Total Revenue Requirements - MN Jurisdiction**	3,781,497	3,651,653	3,538,736	3,459,730	3,397,651	3,335,573	3,273,494
20								
21								
22	**Discount Rate =**							
23								
24	**Present Value of Revenue Requirements - NSP**	2,802,713	2,544,558	2,318,350	2,130,988	1,967,549	1,816,039	1,675,615
25								
26								
27								
28		8.46%	8.17%	7.91%	7.74%	7.60%	7.46%	7.32%

Rev. Req. 2nd Circuit Line

Brookings - 2nd Circuit Line
63 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 (MN)	28.7400%		

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	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	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		(1,654,067)	(3,308,134)	(4,962,201)	(6,616,268)	(8,270,335)	(9,924,402)	(11,578,469)	(13,232,536)	(14,886,603)	(16,540,670)	(18,194,737)	(19,848,804)	(21,502,871)	(23,156,938)	(24,811,005)	(26,465,072)
3	Removal Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(569,471)	(2,079,307)	(3,390,621)	(4,524,311)	(5,497,094)	(6,323,598)	(7,081,141)	(7,838,685)	(8,598,319)	(9,355,863)	(10,115,496)	(10,873,040)	(11,632,674)	(12,390,218)	(13,149,851)	(13,290,934)
5			70,486,954	67,323,051	64,357,670	61,569,913	58,943,063	56,462,493	54,050,882	51,639,271	49,225,570	46,813,959	44,400,259	41,988,648	39,574,947	37,163,336	34,749,636	32,954,486
6																		
7	Average Rate Base		71,598,723	68,905,003	65,840,361	62,963,792	60,256,488	57,702,778	55,256,687	52,845,076	50,432,420	48,019,765	45,607,109	43,194,453	40,781,798	38,369,142	35,956,486	33,852,061
8																		
9	Debt Return		1,610,971	1,550,363	1,481,408	1,416,685	1,355,771	1,298,313	1,243,275	1,189,014	1,134,729	1,080,445	1,026,160	971,875	917,590	863,306	809,021	761,671
10	Equity Return		3,408,099	3,279,878	3,134,001	2,997,076	2,868,209	2,746,652	2,630,218	2,515,426	2,400,583	2,285,741	2,170,898	2,056,056	1,941,214	1,826,371	1,711,529	1,611,358
11	Current Income Tax Requirement		805,056	(187,022)	(47,335)	75,067	184,000	281,253	303,254	256,957	208,550	164,322	115,915	71,688	23,281	(20,947)	(69,354)	508,797
12																		
13	Book Depreciation		1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067
14	Annual Deferred Tax		569,471	1,509,836	1,311,314	1,133,690	972,783	826,504	757,544	757,544	759,634	757,544	759,634	757,544	759,634	757,544	759,634	141,083
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	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 @ 1.4828%		1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151
22																		
23	Total Revenue Requirements - NSP		9,125,815	8,885,272	8,611,607	8,354,736	8,112,980	7,884,940	7,666,510	7,451,159	7,235,714	7,020,270	6,804,825	6,589,381	6,373,937	6,158,492	5,943,048	5,755,127
24																		
25	Discount Rate =	0.0636335																
26																		
27	Present Value of Revenue Requirements	99,118,371	8,579,849	7,853,925	7,156,624	6,527,768	5,959,645	5,445,608	4,977,986	4,548,705	4,152,918	3,788,207	3,452,271	3,142,972	2,858,325	2,596,488	2,355,749	2,144,780
28																		
29	**Level Annual Revenue Requirement**	**6,439,362**																
30																		
31	**63 Year Life LARR %**	**8.86%**																

Rev. Req. 2nd Circuit Line

Brookings - 2nd Circuit Line
63 YEAR LIFE

Line No.	Rate Analysis	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	Year 31	Year 32	Year 33
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
2	Depreciation Reserve	(28,119,139)	(29,773,206)	(31,427,273)	(33,081,340)	(34,735,407)	(36,389,474)	(38,043,541)	(39,697,608)	(41,351,675)	(43,005,742)	(44,659,809)	(46,313,876)	(47,967,943)	(49,622,010)	(51,276,077)	(52,930,144)	(54,584,211)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(12,815,555)	(12,340,176)	(11,864,797)	(11,389,418)	(10,914,040)	(10,438,661)	(9,963,282)	(9,487,903)	(9,012,524)	(8,537,145)	(8,061,766)	(7,586,388)	(7,111,009)	(6,635,630)	(6,160,251)	(5,684,872)	(5,209,493)
5		31,775,798	30,597,110	29,418,422	28,239,734	27,061,046	25,882,358	24,703,669	23,524,981	22,346,293	21,167,605	19,988,917	18,810,229	17,631,541	16,452,853	15,274,164	14,095,476	12,916,788
6																		
7	Average Rate Base	32,365,142	31,186,454	30,007,766	28,829,078	27,650,390	26,471,702	25,293,014	24,114,325	22,935,637	21,756,949	20,578,261	19,399,573	18,220,885	17,042,197	15,863,508	14,684,820	13,506,132
8																		
9	Debt Return	728,216	701,695	675,175	648,654	622,134	595,613	569,093	542,572	516,052	489,531	463,011	436,490	409,970	383,449	356,929	330,408	303,888
10	Equity Return	1,540,581	1,484,475	1,428,370	1,372,264	1,316,159	1,260,053	1,203,947	1,147,842	1,091,736	1,035,631	979,525	923,420	867,314	811,209	755,103	698,997	642,892
11	Current Income Tax Requirement	1,096,713	1,074,085	1,051,457	1,028,829	1,006,201	983,573	960,945	938,317	915,689	893,061	870,433	847,805	825,177	802,549	779,921	757,293	734,665
12																		
13	Book Depreciation	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067
14	Annual Deferred Tax	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)
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 @ 1.4828%	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151
22																		
23	Total Revenue Requirements - NSP	5,622,349	5,517,095	5,411,841	5,306,587	5,201,333	5,096,079	4,990,825	4,885,571	4,780,316	4,675,062	4,569,808	4,464,554	4,359,300	4,254,046	4,148,792	4,043,538	3,938,284
24																		
25	Discount Rate =																	
26																		
27	Present Value of Revenue Requirements	1,969,943	1,817,416	1,676,088	1,545,166	1,423,910	1,311,632	1,207,692	1,111,494	1,022,484	940,146	864,000	793,600	728,532	668,409	612,872	561,587	514,246
28																		
29	**Level Annual Revenue Requirement**																	
30																		
31	**63 Year Life LARR %**																	

Rev. Req. 2nd Circuit Line

Brookings - 2nd Circuit Line
63 YEAR LIFE

Line No.	Rate Analysis	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	Year 48	Year 49	Year 50	Year 51
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
2	Depreciation Reserve	(56,238,278)	(57,892,345)	(59,546,412)	(61,200,479)	(62,854,546)	(64,508,613)	(66,162,680)	(67,816,747)	(69,470,813)	(71,124,880)	(72,778,947)	(74,433,014)	(76,087,081)	(77,741,148)	(79,395,215)	(81,049,282)	(82,703,349)	(84,357,416)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(4,734,114)	(4,258,736)	(3,783,357)	(3,307,978)	(2,832,599)	(2,357,220)	(1,881,841)	(1,406,462)	(931,084)	(455,705)	19,674	495,053	970,432	1,445,811	1,921,190	2,396,568	2,871,947	3,347,326
5		11,738,100	10,559,412	9,380,724	8,202,036	7,023,347	5,844,659	4,665,971	3,487,283	2,308,595	1,129,907	(48,781)	(1,227,470)	(2,406,158)	(3,584,846)	(4,763,534)	(5,942,222)	(7,120,910)	(8,299,598)
6																			
7	Average Rate Base	12,327,444	11,148,756	9,970,068	8,791,380	7,612,692	6,434,003	5,255,315	4,076,627	2,897,939	1,719,251	540,563	(638,125)	(1,816,814)	(2,995,502)	(4,174,190)	(5,352,878)	(6,531,566)	(7,710,254)
8																			
9	Debt Return	277,367	250,847	224,327	197,806	171,286	144,765	118,245	91,724	65,204	38,683	12,163	(14,358)	(40,878)	(67,399)	(93,919)	(120,440)	(146,960)	(173,481)
10	Equity Return	586,786	530,681	474,575	418,470	362,364	306,259	250,153	194,047	137,942	81,836	25,731	(30,375)	(86,480)	(142,586)	(198,691)	(254,797)	(310,903)	(367,008)
11	Current Income Tax Requirement	712,037	689,409	666,781	644,153	621,525	598,897	576,269	553,640	531,012	508,384	485,756	463,128	440,500	417,872	395,244	372,616	349,988	327,360
12																			
13	Book Depreciation	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067
14	Annual Deferred Tax	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)
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 @ 1.4828%	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151
22																			
23	Total Revenue Requirements - NSP	3,833,030	3,727,776	3,622,522	3,517,268	3,412,014	3,306,759	3,201,505	3,096,251	2,990,997	2,885,743	2,780,489	2,675,235	2,569,981	2,464,727	2,359,473	2,254,219	2,148,965	2,043,711
24																			
25	Discount Rate =																		
26																			
27	Present Value of Revenue Requirements	470,559	430,259	393,096	358,840	327,276	298,205	271,440	246,811	224,157	203,330	184,193	166,618	150,487	135,689	122,123	109,695	98,317	87,908
28																			
29	**Level Annual Revenue Requirement**																		
30																			
31	**63 Year Life LARR %**																		

Rev. Req. 2nd Circuit Line

Brookings - 2nd Circuit Line
63 YEAR LIFE

Line No.	Rate Analysis	Year 52	Year 53	Year 54	Year 55	Year 56	Year 57	Year 58	Year 59	Year 60	Year 61	Year 62	Year 63
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
2	Depreciation Reserve	(86,011,483)	(87,665,550)	(89,319,617)	(90,973,684)	(92,627,751)	(94,281,818)	(95,935,885)	(97,589,952)	(99,244,019)	(100,898,086)	(102,552,153)	(104,206,220)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	31,495,728
4	Accumulated Deferred Taxes	3,822,705	4,298,084	4,773,463	5,248,841	5,724,220	6,199,599	6,674,978	7,150,357	7,625,736	8,101,115	8,576,493	0
5		(9,478,286)	(10,656,975)	(11,835,663)	(13,014,351)	(14,193,039)	(15,371,727)	(16,550,415)	(17,729,103)	(18,907,792)	(20,086,480)	(21,265,168)	0
6													
7	Average Rate Base	(8,888,942)	(10,067,631)	(11,246,319)	(12,425,007)	(13,603,695)	(14,782,383)	(15,961,071)	(17,139,759)	(18,318,447)	(19,497,136)	(20,675,824)	(10,632,584)
8													
9	Debt Return	(200,001)	(226,522)	(253,042)	(279,563)	(306,083)	(332,604)	(359,124)	(385,645)	(412,165)	(438,686)	(465,206)	(239,233)
10	Equity Return	(423,114)	(479,219)	(535,325)	(591,430)	(647,536)	(703,641)	(759,747)	(815,853)	(871,958)	(928,064)	(984,169)	(506,111)
11	Current Income Tax Requirement	304,732	282,104	259,476	236,848	214,220	191,592	168,964	146,336	123,708	101,080	78,452	(8,780,614)
12													
13	Book Depreciation	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067	1,654,067
14	Annual Deferred Tax	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	(475,379)	8,576,493
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	-	31,495,728
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151	1,078,151
22													
23	Total Revenue Requirements - NSP	1,938,457	1,833,202	1,727,948	1,622,694	1,517,440	1,412,186	1,306,932	1,201,678	1,096,424	991,170	885,916	1,782,753
24													
25	Discount Rate =												
26													
27	Present Value of Revenue Requirements	78,392	69,700	61,768	54,535	47,947	41,952	36,502	31,554	27,068	23,006	19,332	36,576
28													
29	**Level Annual Revenue Requirement**												
30													
31	**63 Year Life LARR %**												

Rev. Req. 2nd Circuit Subs

Brookings - 2nd Circuit Subs
56 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 (MN)	28.7400%		

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		(593,578)	(1,187,157)	(1,780,735)	(2,374,314)	(2,967,892)	(3,561,471)	(4,155,049)	(4,748,627)	(5,342,206)	(5,935,784)	(6,529,363)	(7,122,941)	(7,716,520)	(8,310,098)
3	Removal Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(250,615)	(880,320)	(1,429,994)	(1,908,063)	(2,321,265)	(2,675,498)	(3,001,931)	(3,328,364)	(3,655,640)	(3,982,073)	(4,309,349)	(4,635,782)	(4,963,057)	(5,289,490)
5			28,467,554	27,244,272	26,101,019	25,029,372	24,022,591	23,074,779	22,154,768	21,234,756	20,313,902	19,393,891	18,473,037	17,553,025	16,632,171	15,712,160
6																
7	Average Rate Base		28,889,651	27,855,913	26,672,645	25,565,195	24,525,981	23,548,685	22,614,774	21,694,762	20,774,329	19,853,897	18,933,464	18,013,031	17,092,598	16,172,165
8																
9	Debt Return		650,017	626,758	600,135	575,217	551,835	529,845	508,832	488,132	467,422	446,713	426,003	405,293	384,583	363,874
10	Equity Return		1,375,147	1,325,941	1,269,618	1,216,903	1,167,437	1,120,917	1,076,463	1,032,671	988,858	945,045	901,233	857,420	813,608	769,795
11	Current Income Tax Requirement		303,998	(94,936)	(37,622)	12,723	57,639	97,846	107,717	90,055	71,543	54,715	36,202	19,375	862	(15,966)
12																
13	Book Depreciation		593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578
14	Annual Deferred Tax		250,615	629,704	549,674	478,069	413,202	354,233	326,433	326,433	327,276	326,433	327,276	326,433	327,276	326,433
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 @ 1.4828%		434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635
22																
23	Total Revenue Requirements - NSP		3,607,991	3,515,680	3,410,017	3,311,125	3,218,325	3,131,055	3,047,659	2,965,504	2,883,312	2,801,119	2,718,927	2,636,734	2,554,542	2,472,349
24																
25	Discount Rate =	0.0636335														
26																
27	Present Value of Revenue Requirements	39,780,311	3,392,137	3,107,602	2,833,874	2,587,066	2,364,122	2,162,413	1,978,893	1,810,350	1,654,869	1,511,512	1,379,385	1,257,657	1,145,558	1,042,370
28																
29	**Level Annual Revenue Requirement**	**2,613,954**														
30																
31	**56 Year Life LARR %**	**8.92%**														

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Brookings - 2nd Circuit Subs
56 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
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
2	Depreciation Reserve	(8,903,677)	(9,497,255)	(10,090,833)	(10,684,412)	(11,277,990)	(11,871,569)	(12,465,147)	(13,058,726)	(13,652,304)	(14,245,882)	(14,839,461)	(15,433,039)	(16,026,618)	(16,620,196)	(17,213,775)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(5,616,766)	(5,694,685)	(5,524,091)	(5,353,496)	(5,182,902)	(5,012,308)	(4,841,713)	(4,671,119)	(4,500,524)	(4,329,930)	(4,159,335)	(3,988,741)	(3,818,146)	(3,647,552)	(3,476,958)
5		14,791,306	14,119,808	13,696,824	13,273,840	12,850,856	12,427,872	12,004,888	11,581,904	11,158,920	10,735,936	10,312,952	9,889,968	9,466,984	9,044,000	8,621,016
6																
7	Average Rate Base	15,251,733	14,455,557	13,908,316	13,485,332	13,062,348	12,639,364	12,216,380	11,793,396	11,370,412	10,947,428	10,524,444	10,101,460	9,678,476	9,255,492	8,832,508
8																
9	Debt Return	343,164	325,250	312,937	303,420	293,903	284,386	274,869	265,351	255,834	246,317	236,800	227,283	217,766	208,249	198,731
10	Equity Return	725,982	688,085	662,036	641,902	621,768	601,634	581,500	561,366	541,232	521,098	500,964	480,829	460,695	440,561	420,427
11	Current Income Tax Requirement	(34,478)	199,593	437,601	429,481	421,361	413,240	405,120	397,000	388,880	380,759	372,639	364,519	356,398	348,278	340,158
12																
13	Book Depreciation	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578
14	Annual Deferred Tax	327,276	77,919	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)
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 @ 1.4828%	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635
22																
23	Total Revenue Requirements - NSP	2,390,157	2,319,060	2,270,193	2,232,421	2,194,650	2,156,878	2,119,107	2,081,335	2,043,564	2,005,793	1,968,021	1,930,250	1,892,478	1,854,707	1,816,935
24																
25	Discount Rate =															
26																
27	Present Value of Revenue Requirements	947,428	864,251	795,424	735,394	679,700	628,037	580,124	535,695	494,507	456,329	420,949	388,169	357,805	329,685	303,649
28																
29	**Level Annual Revenue Requirement**															
30																
31	**56 Year Life LARR %**															

Rev. Req. 2nd Circuit Subs

Brookings - 2nd Circuit Subs
56 YEAR LIFE

Line No.	Rate Analysis	Year 30	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
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	(17,807,353)	(18,400,931)	(18,994,510)	(19,588,088)	(20,181,667)	(20,775,245)	(21,368,824)	(21,962,402)	(22,555,980)	(23,149,559)	(23,743,137)	(24,336,716)	(24,930,294)	(25,523,873)	(26,117,451)	(26,711,030)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(3,306,363)	(3,135,769)	(2,965,174)	(2,794,580)	(2,623,985)	(2,453,391)	(2,282,796)	(2,112,202)	(1,941,608)	(1,771,013)	(1,600,419)	(1,429,824)	(1,259,230)	(1,088,635)	(918,041)	(747,447)
5		8,198,032	7,775,048	7,352,064	6,929,080	6,506,096	6,083,112	5,660,128	5,237,144	4,814,160	4,391,176	3,968,192	3,545,208	3,122,224	2,699,240	2,276,256	1,853,272
6																	
7	Average Rate Base	8,409,524	7,986,540	7,563,556	7,140,572	6,717,588	6,294,604	5,871,620	5,448,636	5,025,652	4,602,668	4,179,684	3,756,700	3,333,716	2,910,732	2,487,748	2,064,764
8																	
9	Debt Return	189,214	179,697	170,180	160,663	151,146	141,629	132,111	122,594	113,077	103,560	94,043	84,526	75,009	65,491	55,974	46,457
10	Equity Return	400,293	380,159	360,025	339,891	319,757	299,623	279,489	259,355	239,221	219,087	198,953	178,819	158,685	138,551	118,417	98,283
11	Current Income Tax Requirement	332,037	323,917	315,797	307,677	299,556	291,436	283,316	275,195	267,075	258,955	250,835	242,714	234,594	226,474	218,353	210,233
12																	
13	Book Depreciation	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578
14	Annual Deferred Tax	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)
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 @ 1.4828%	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635
22																	
23	Total Revenue Requirements - NSP	1,779,164	1,741,392	1,703,621	1,665,849	1,628,078	1,590,306	1,552,535	1,514,763	1,476,992	1,439,220	1,401,449	1,363,677	1,325,906	1,288,135	1,250,363	1,212,592
24																	
25	Discount Rate =																
26																	
27	Present Value of Revenue Requirements	279,548	257,243	236,608	217,520	199,870	183,553	168,473	154,540	141,671	129,789	118,822	108,702	99,368	90,762	82,830	75,522
28																	
29	**Level Annual Revenue Requirement**																
30																	
31	**56 Year Life LARR %**																

Rev. Req. 2nd Circuit Subs

Brookings - 2nd Circuit Subs
56 YEAR LIFE

Line No.	Rate Analysis	Year 46	Year 47	Year 48	Year 49	Year 50	Year 51	Year 52	Year 53	Year 54	Year 55	Year 56
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	(27,304,608)	(27,898,186)	(28,491,765)	(29,085,343)	(29,678,922)	(30,272,500)	(30,866,079)	(31,459,657)	(32,053,235)	(32,646,814)	(33,240,392)
3	Removal Expense	-	-	-	-	-	-	-	-	-	-	3,928,644
4	Accumulated Deferred Taxes	(576,852)	(406,258)	(235,663)	(65,069)	105,526	276,120	446,715	617,309	787,903	958,498	0
5		1,430,288	1,007,304	584,320	161,336	(261,648)	(684,632)	(1,107,616)	(1,530,600)	(1,953,584)	(2,376,568)	0
6												
7	Average Rate Base	1,641,780	1,218,796	795,812	372,828	(50,156)	(473,140)	(896,124)	(1,319,108)	(1,742,092)	(2,165,076)	(1,188,284)
8												
9	Debt Return	36,940	27,423	17,906	8,389	(1,129)	(10,646)	(20,163)	(29,680)	(39,197)	(48,714)	(26,736)
10	Equity Return	78,149	58,015	37,881	17,747	(2,387)	(22,521)	(42,656)	(62,790)	(82,924)	(103,058)	(56,562)
11	Current Income Tax Requirement	202,113	193,992	185,872	177,752	169,632	161,511	153,391	145,271	137,150	129,030	(981,310)
12												
13	Book Depreciation	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578	593,578
14	Annual Deferred Tax	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	(170,594)	958,498
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-	-	-	-	-	-	-	3,928,644
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635	434,635
22												
23	Total Revenue Requirements - NSP	1,174,820	1,137,049	1,099,277	1,061,506	1,023,734	985,963	948,191	910,420	872,648	834,877	922,102
24												
25	Discount Rate =											
26												
27	Present Value of Revenue Requirements	68,792	62,597	56,897	51,655	46,837	42,410	38,345	34,615	31,194	28,058	29,136
28												
29	**Level Annual Revenue Requirement**											
30												
31	**56 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			2023	
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	(Rates and Ratios from Settlement in Docket E002/GR-15-826)			
9				
10	**Property Tax Rates**			
11	Property Tax Rate			1.483%
12	(percentage based on last TCR filing in Docket No. E002M-21-814)			
13				
14	**Income Tax Rates**			
15	Federal Tax Rate			21.00%
16	StateTax Rate			9.80%
17	State Composite Income Tax Rate			28.7420%
18				
19	**Allocators (2018 Budget - Year 2022)**			
20	MN 12-month CP demand (Electric Demand)			83.8543%
21	NSPM 36-month CP demand (Interchange Electric)			87.3461%
22	Jurisdictional Allocator			73.2435%
23				
24	**Book Depreciation Lives**			
25	Land			0.00
26	Line			63.28
27	Sub			56.43
28				
29	**Net Salvage %**			
30	Land			0.00%
31	Line			-43.95%
32	Sub			-14.26%
33				
34	**Book Depreciation Rates**			
35	Land			0.00%
36	Line			2.2749%
37	Sub			2.0251%

Appendix D

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

Appendix E

2021 MISO Futures Report

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.

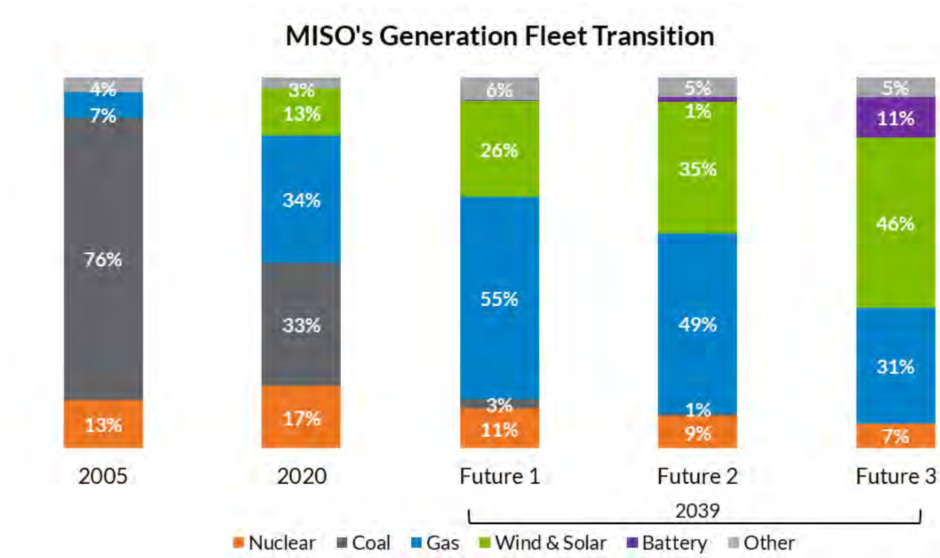


Figure 1: Overview of MISO's Generation Fleet Mix Transition [82]

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.

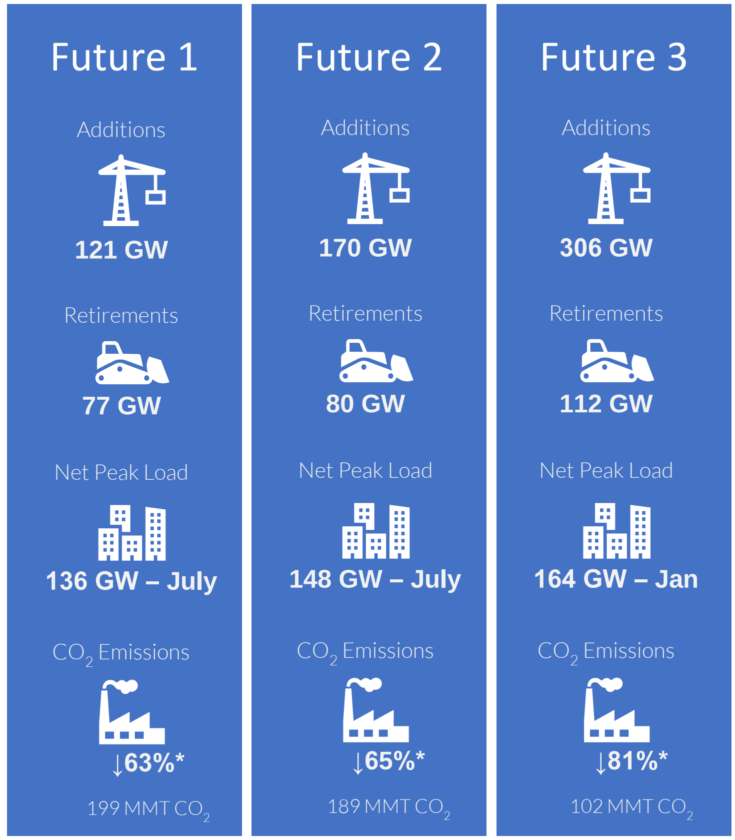


Figure 2: Summary of Future Scenario Impacts, 2039

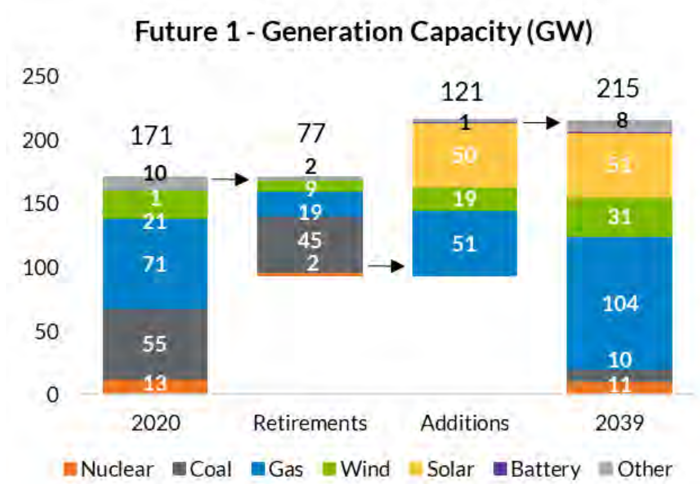
Future 3 Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including an 80% carbon dioxide reduction. Future 3 requires a minimum penetration of 50% wind and solar and introduces a larger electrification scenario,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

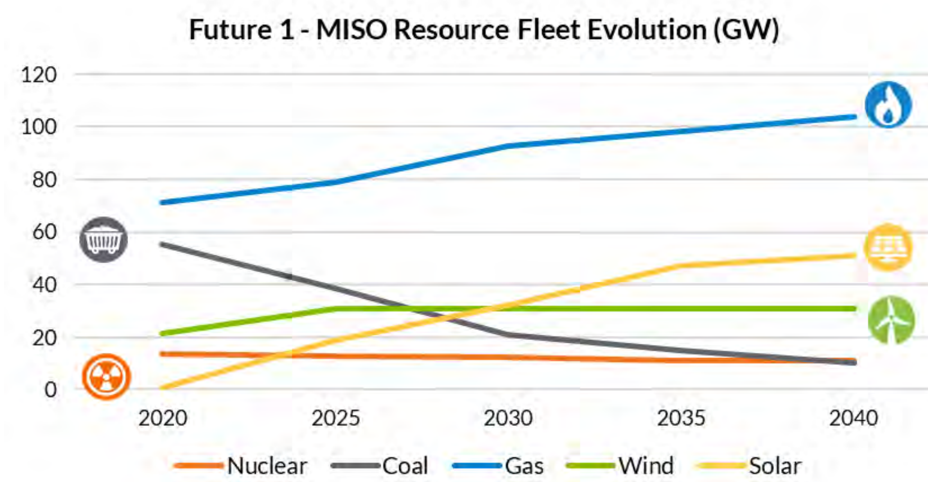
The Futures utilized announced goals and other input assumptions through September 2020 to represent a snapshot in time. Since the modeling of the Future scenarios, new announcements and updates to utility and state goals have been publicized. While the Futures Assumptions above summarize each scenario's 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.

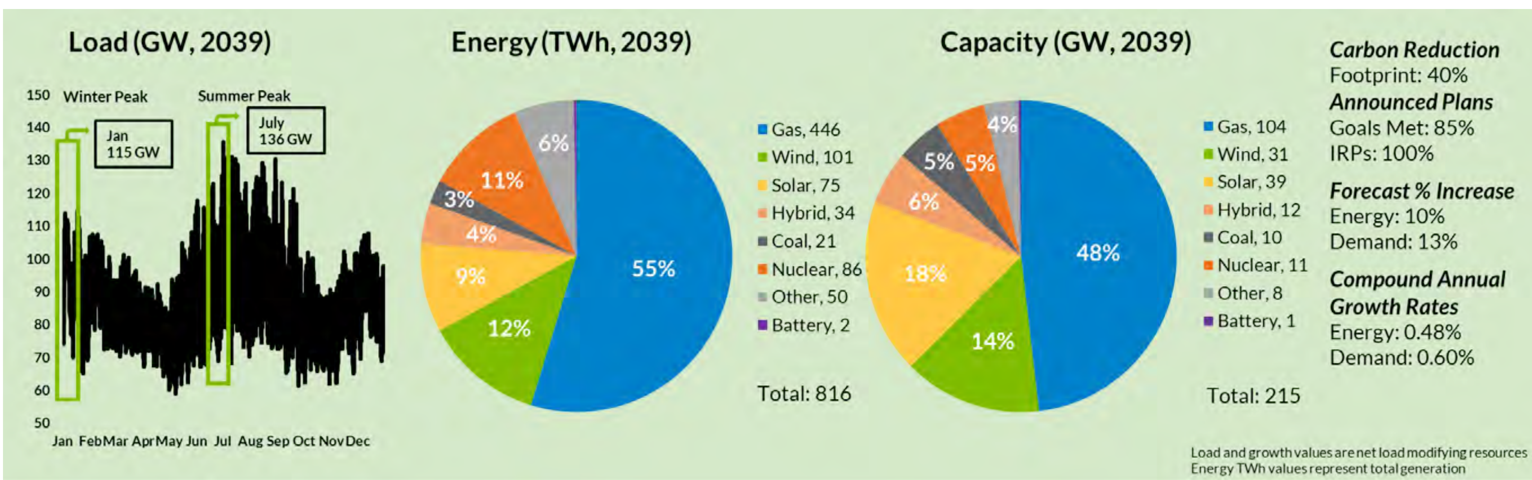
[1] Carbon emission reduction in Future scenarios refer to power sector emissions across the MISO footprint from a 2005 baseline.
[2] Futures energy growth rates are compound annual growth rates (CAGR).

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.

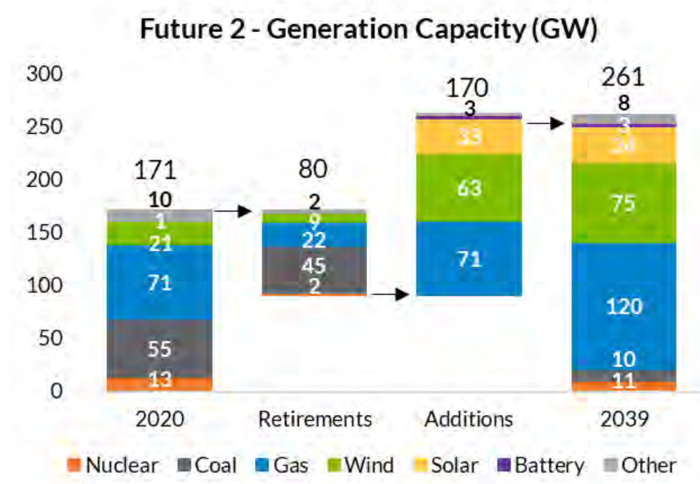


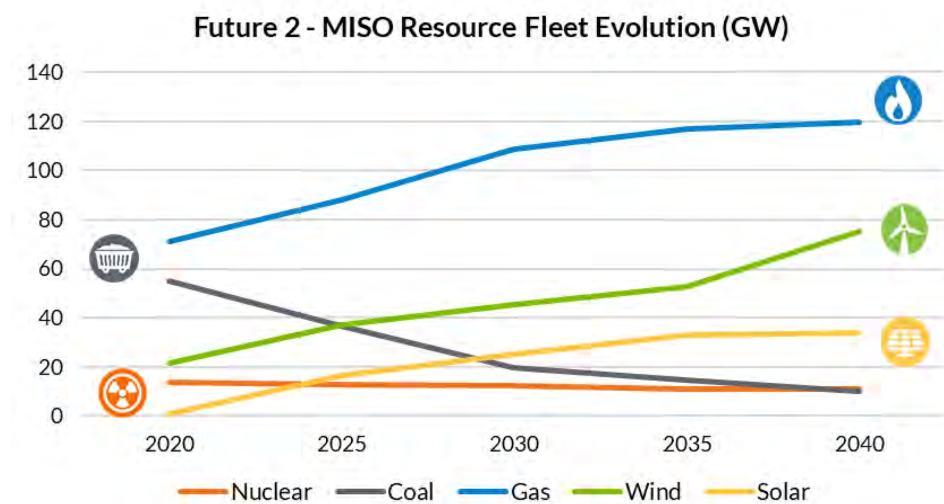


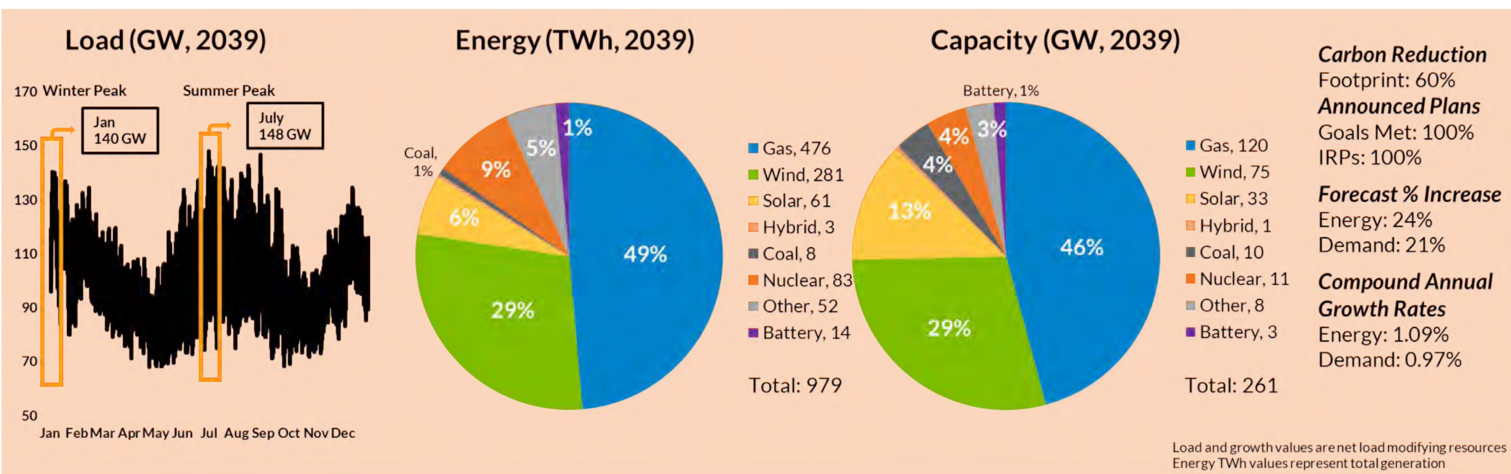


Future 2 Results

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.

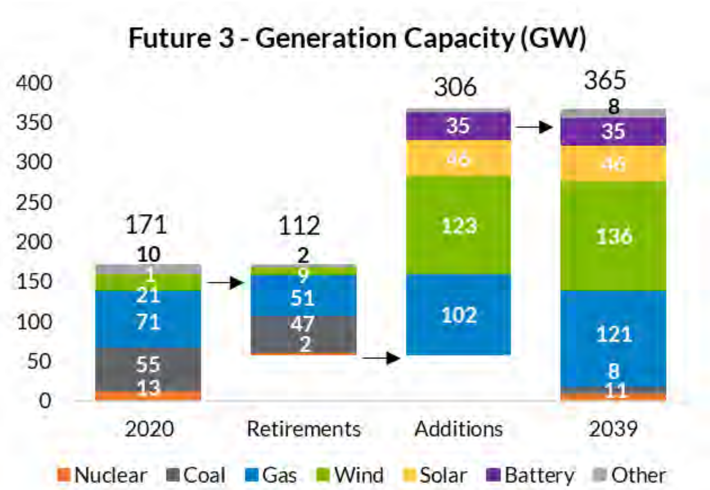


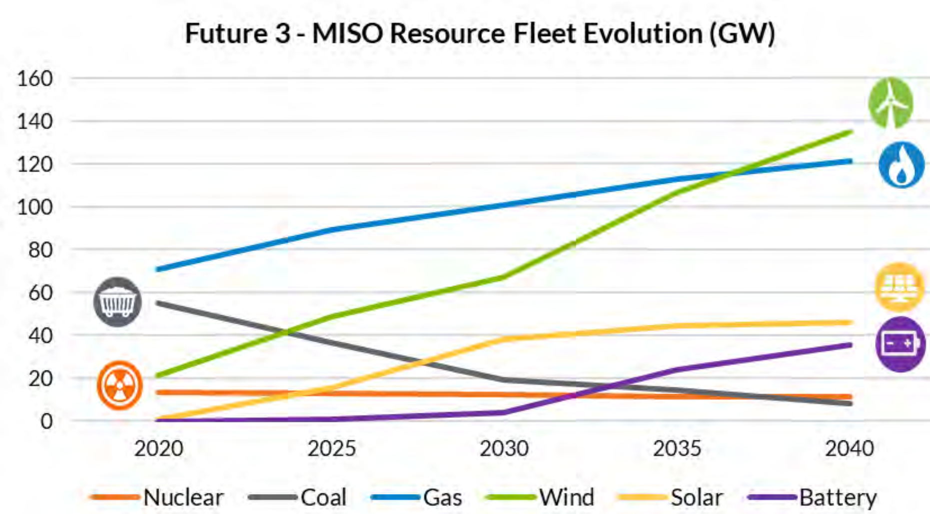


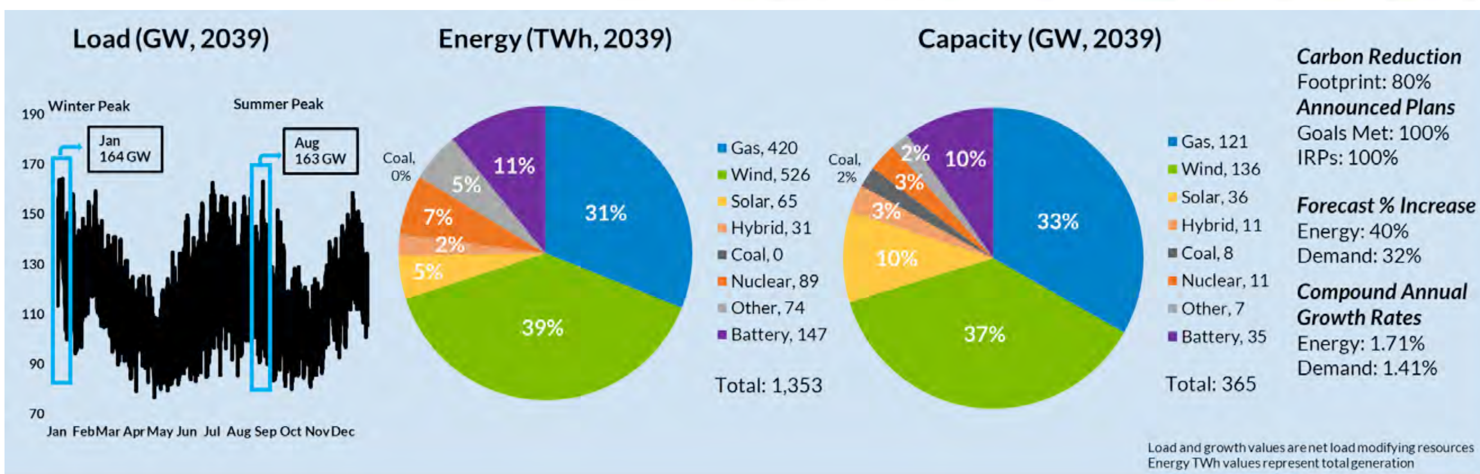


Future 3 Results

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

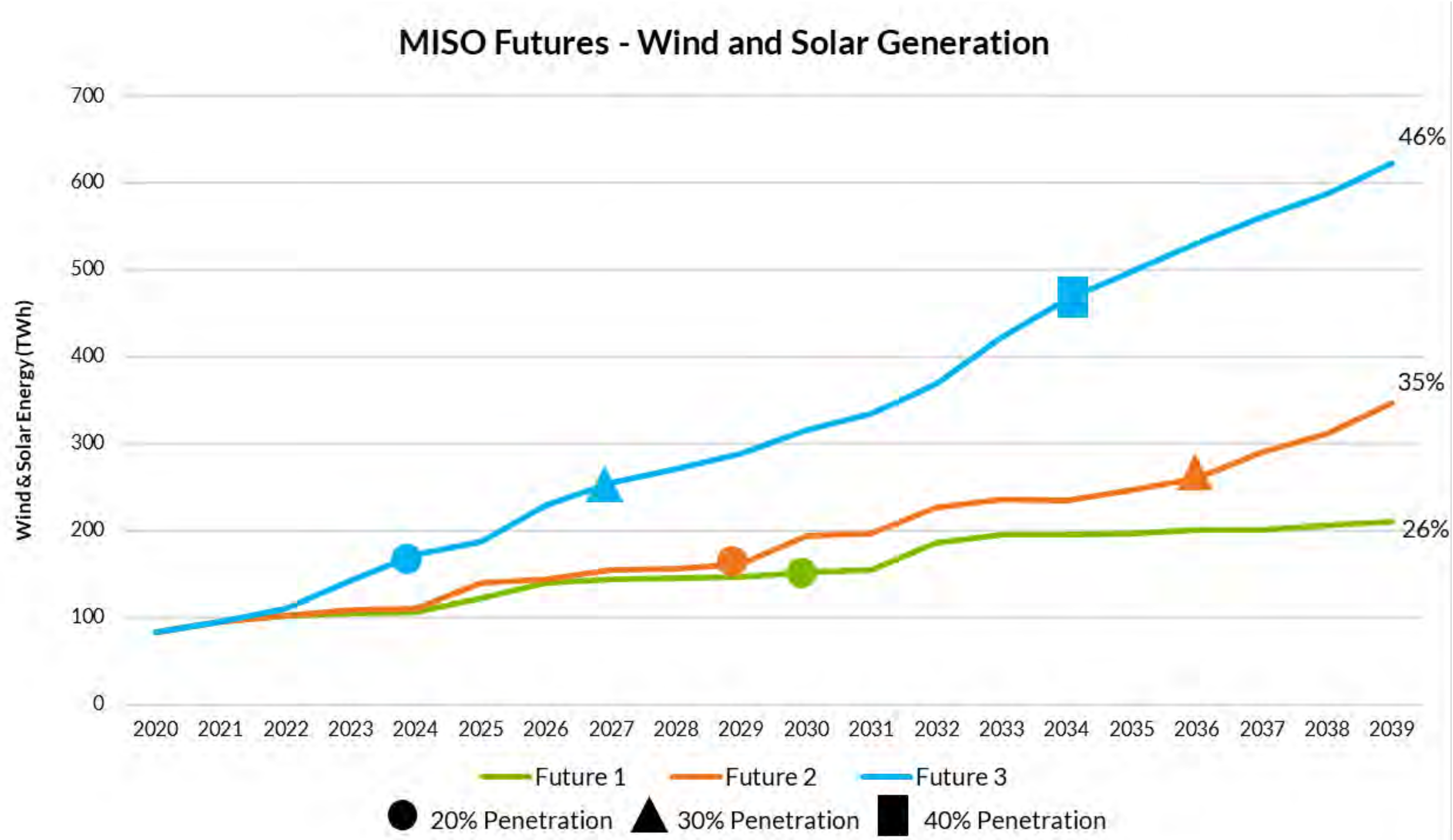


Figure 3: Wind and Solar Energy Generation Throughout Study[82]

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.

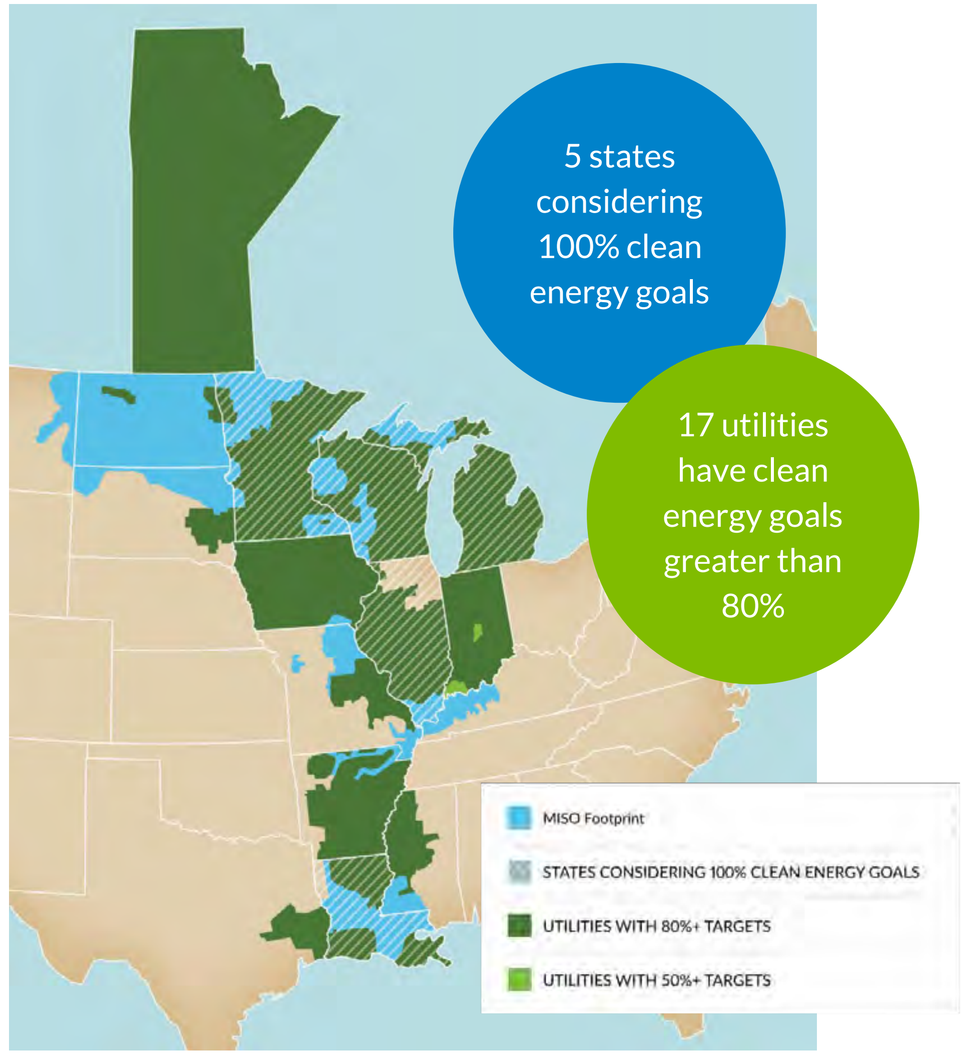


Figure 4: Clean Energy Goals above 50% Across Footprint[3]

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).

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

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.

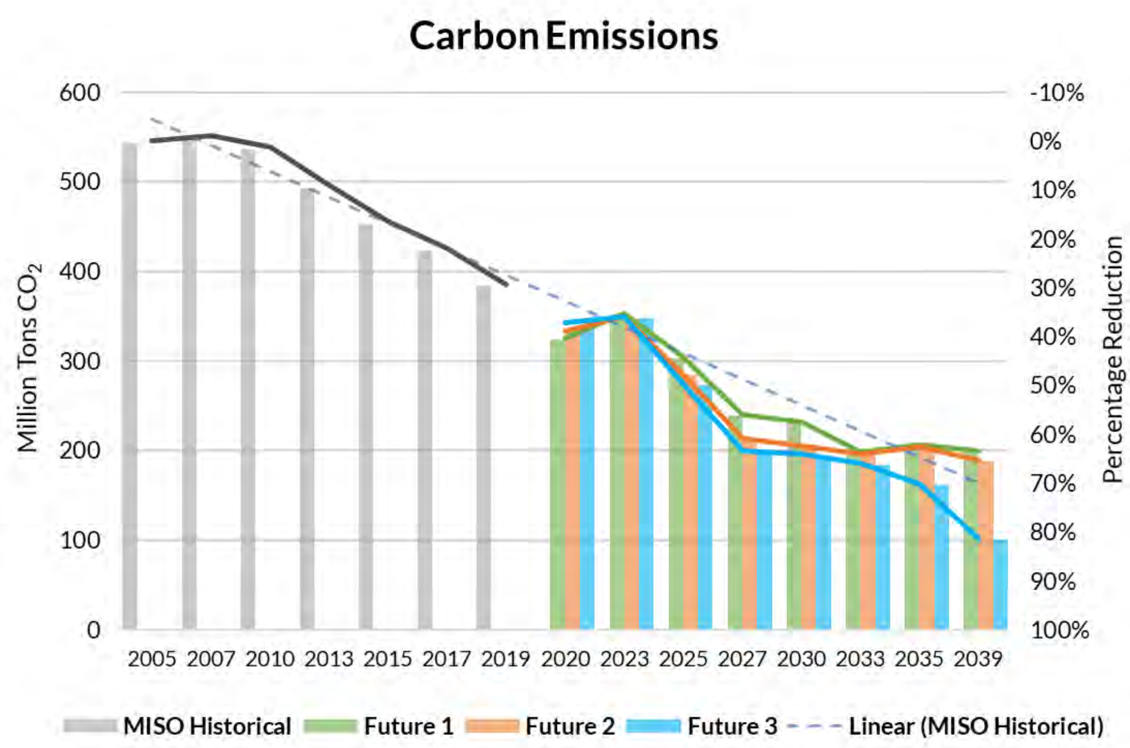


Figure 5: CO_2 Reduction Results (from 2005 Baseline)

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]

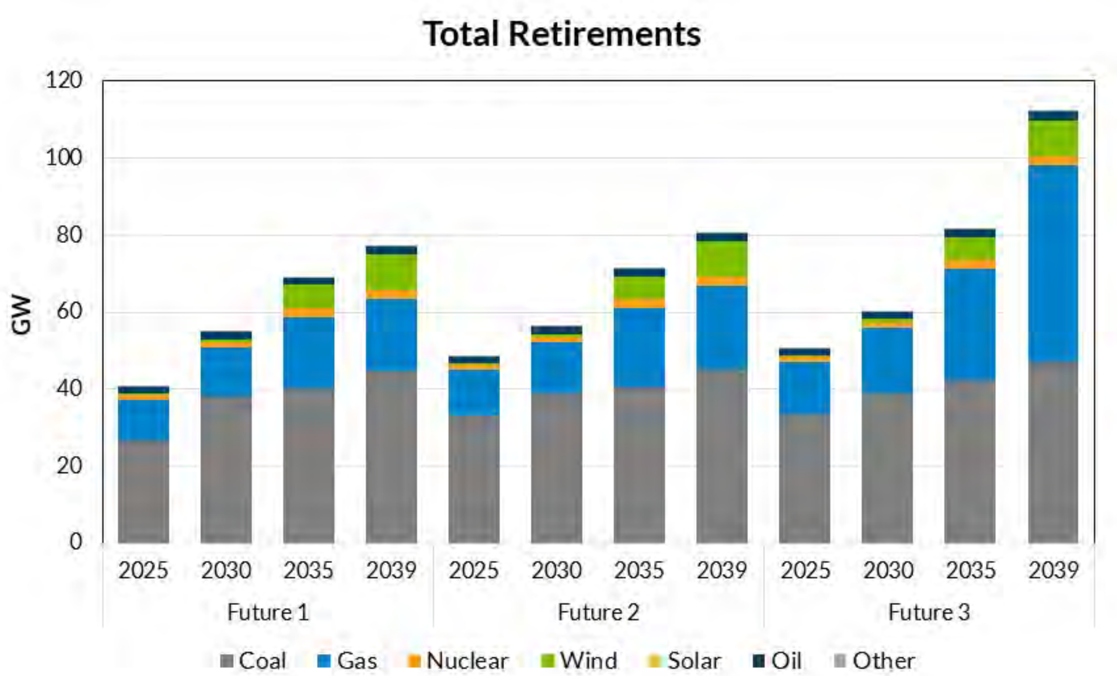


Figure 6: Total Retirements per Future (Cumulative by Year), Equal to Age-Based + Base

[8] MISO's retirement notification process

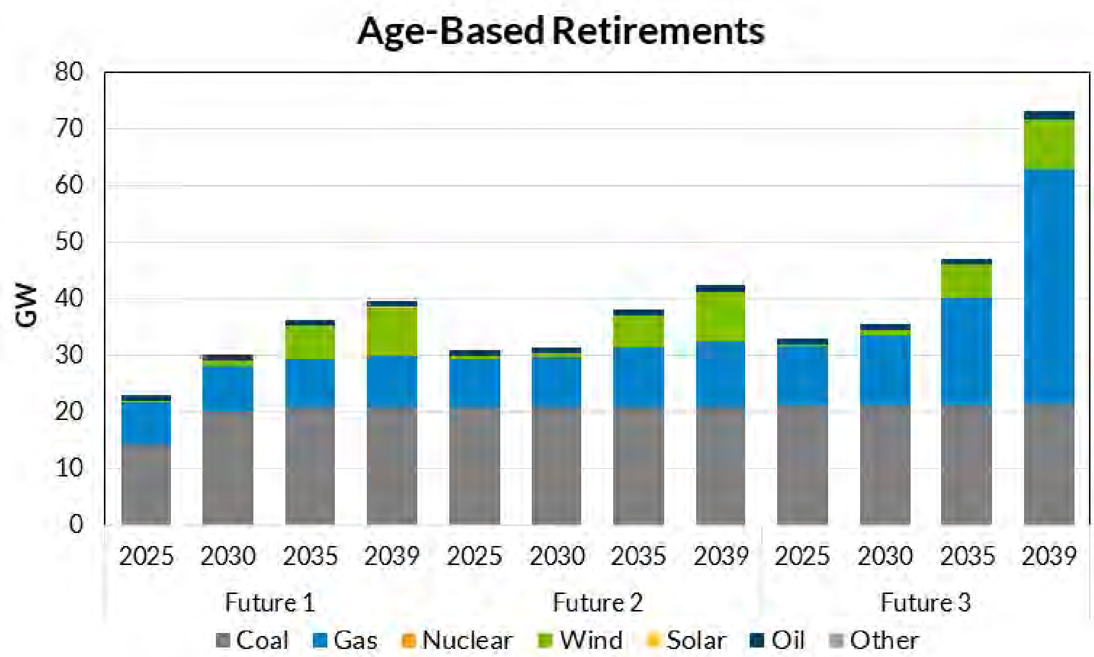


Figure 7: Age-Based Retirements per Future (Cumulative per Year)

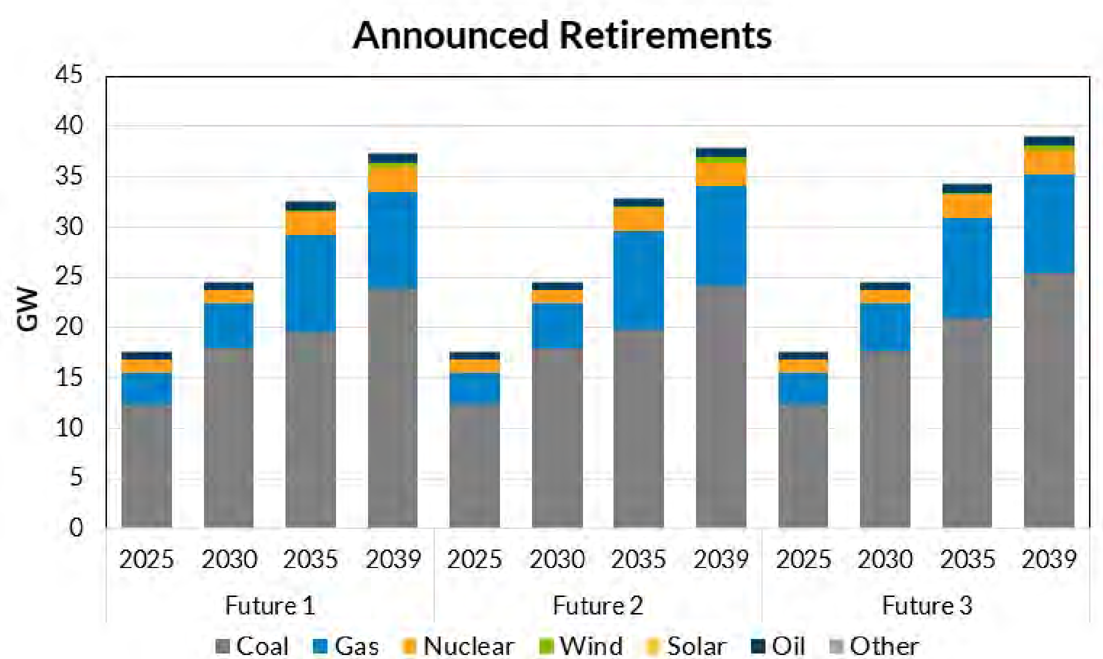


Figure 8: Base Retirements per Future (Cumulative per Year)

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.

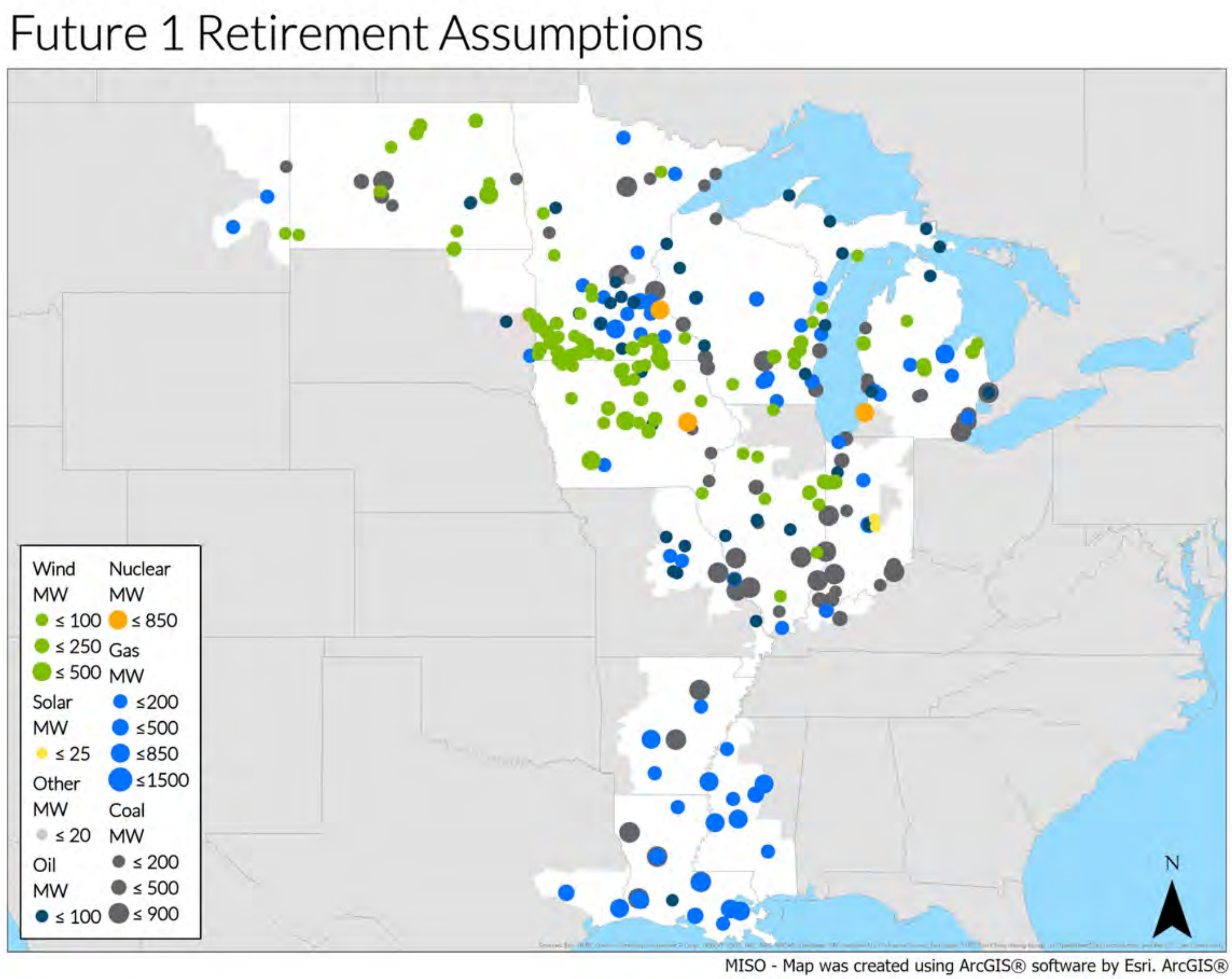


Figure 9: Future 1 Retirements by Fuel Type

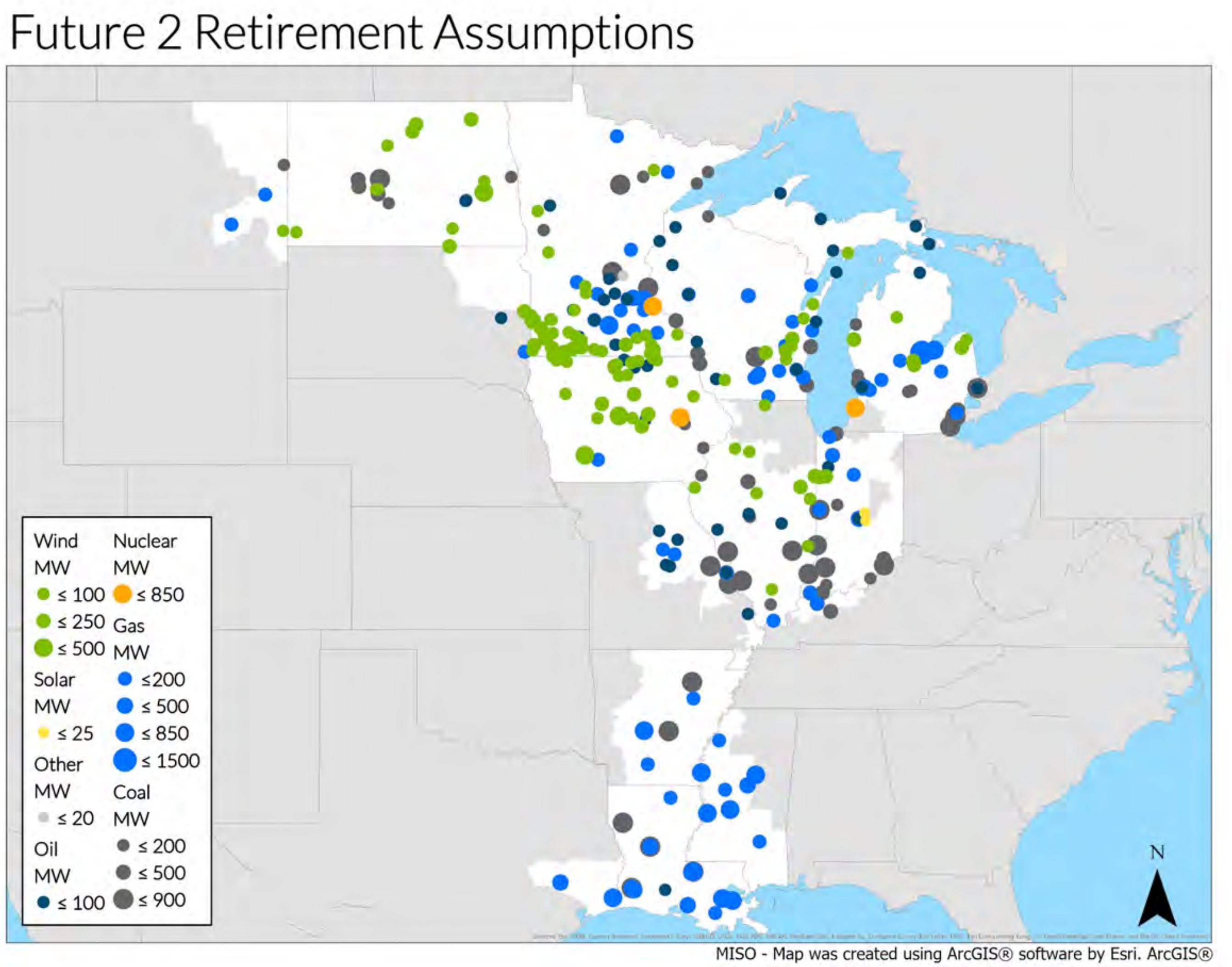


Figure 10: Future 2 Retirements by Fuel Type

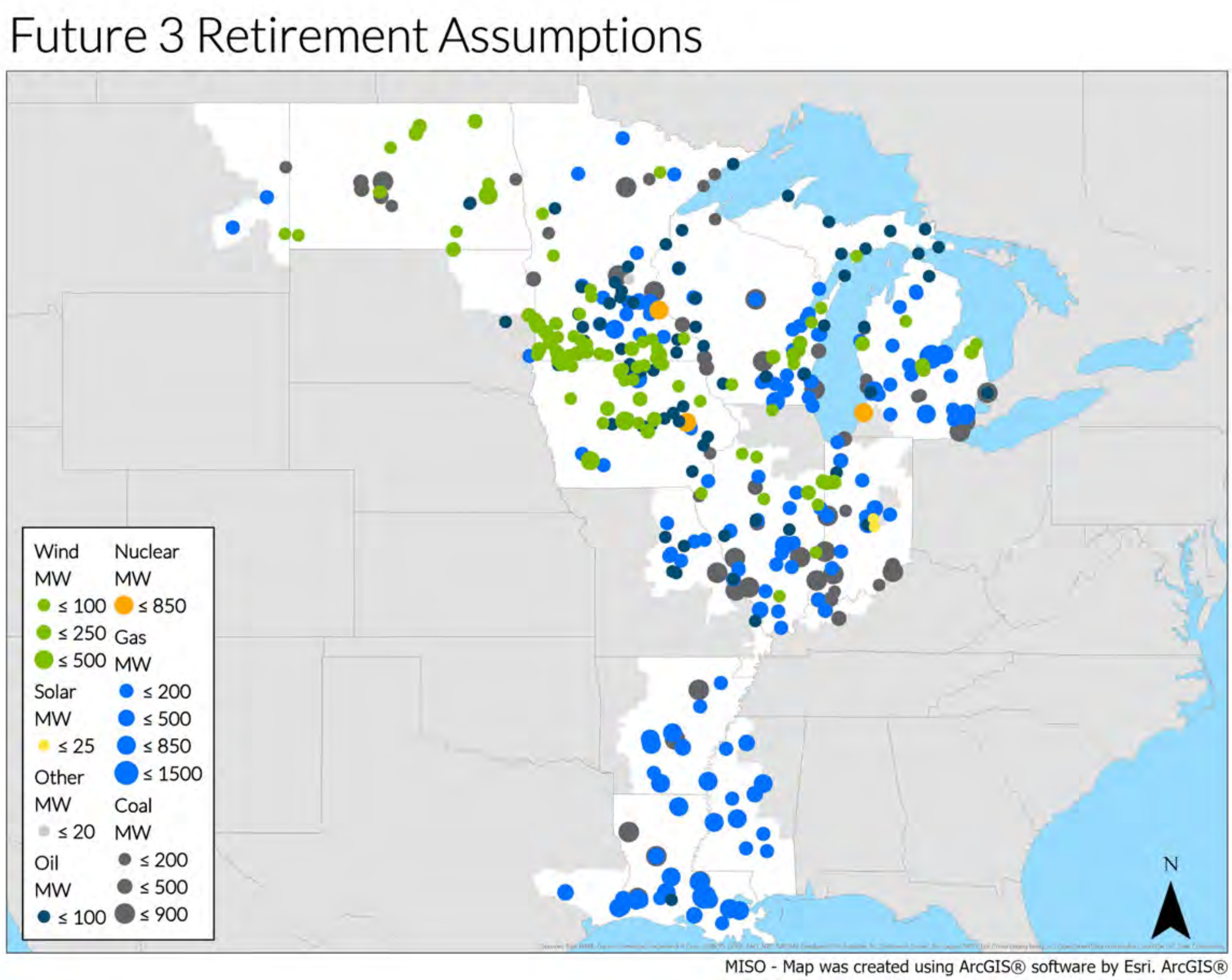


Figure 11: Future 3 Retirements by Fuel Type

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.

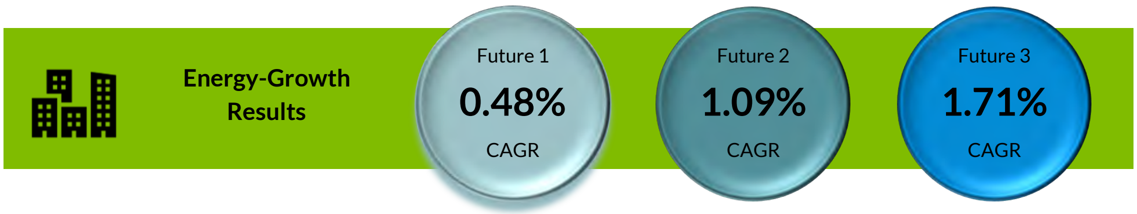


Figure 12: Annual Energy-Growth Rates

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.

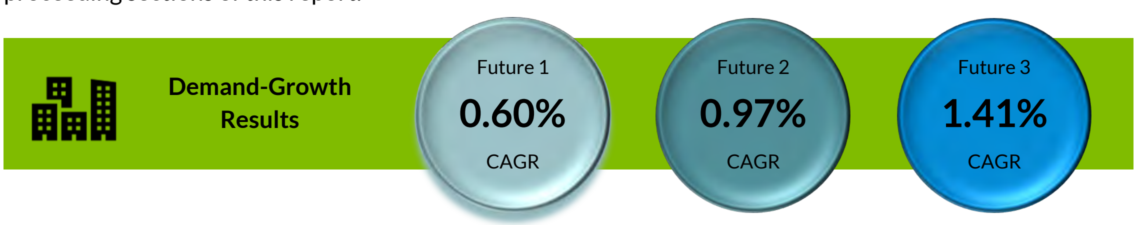


Figure 13: Annual Demand-Growth Rates

[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.

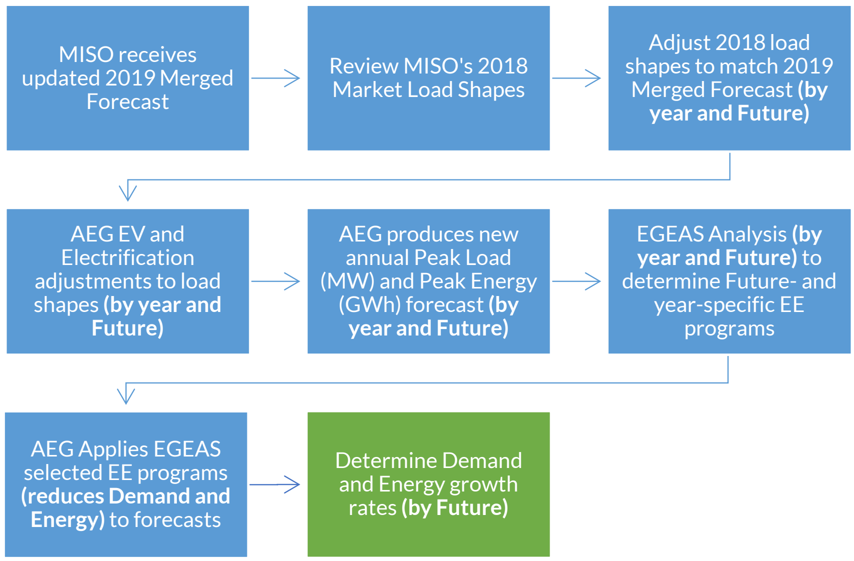


Figure 14: MISO's Forecast Development High-Level Process Flow Chart[11]

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

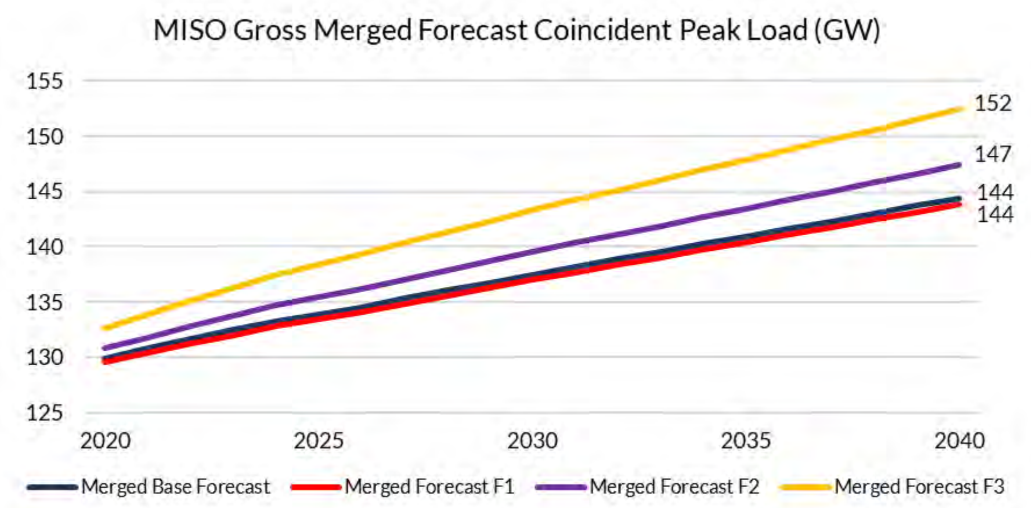


Figure 15: 2019 Merged Load Forecast Peak Load (GW)

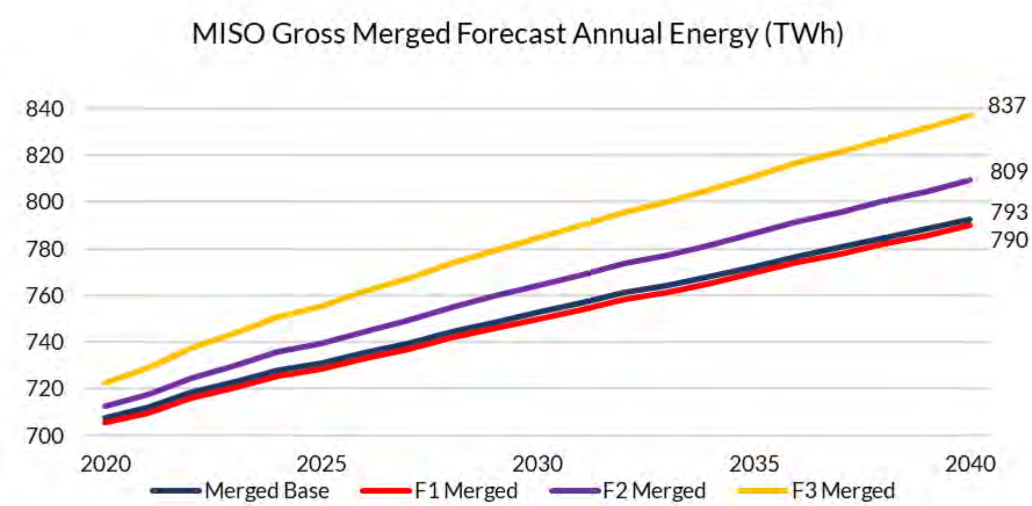


Figure 16: 2019 Merged Load Forecast Annual Energy (TWh)

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.

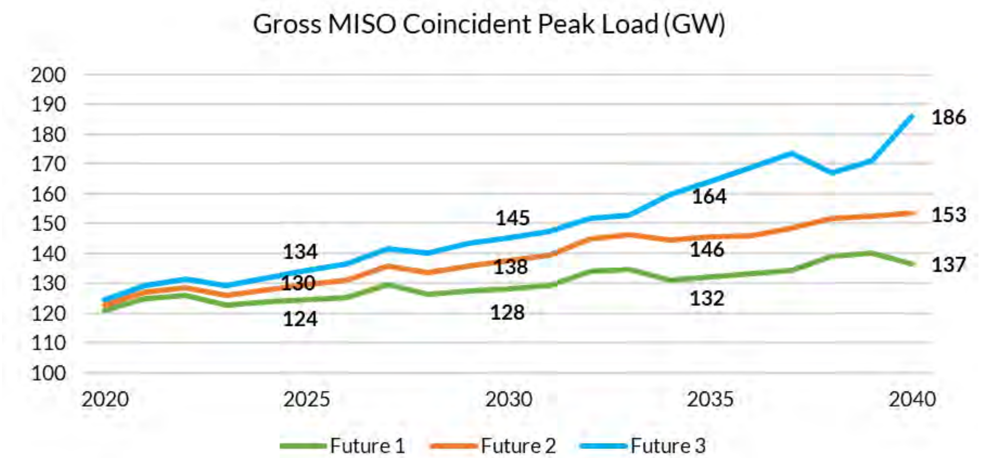


Figure 17: Final AEG Modified MISO Gross Coincident Peak Load (GW) Forecast by Future[13,14]

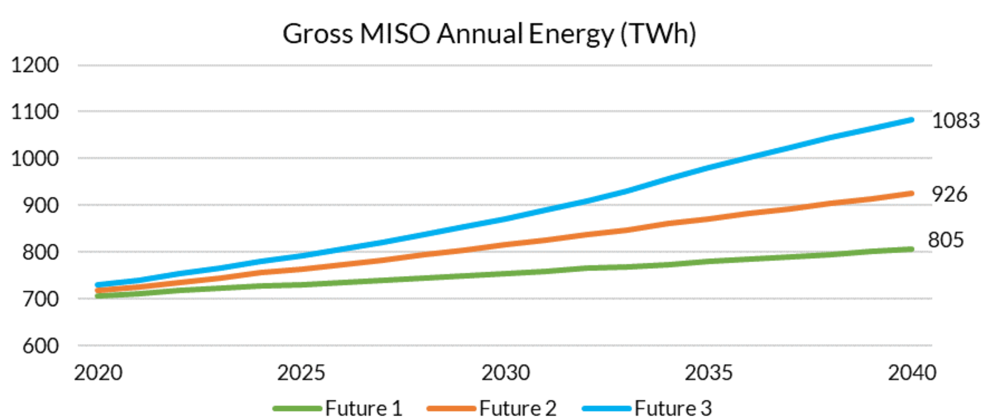


Figure 18: Final AEG Modified MISO Gross Annual Energy (TWh) Forecast by Future

[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.

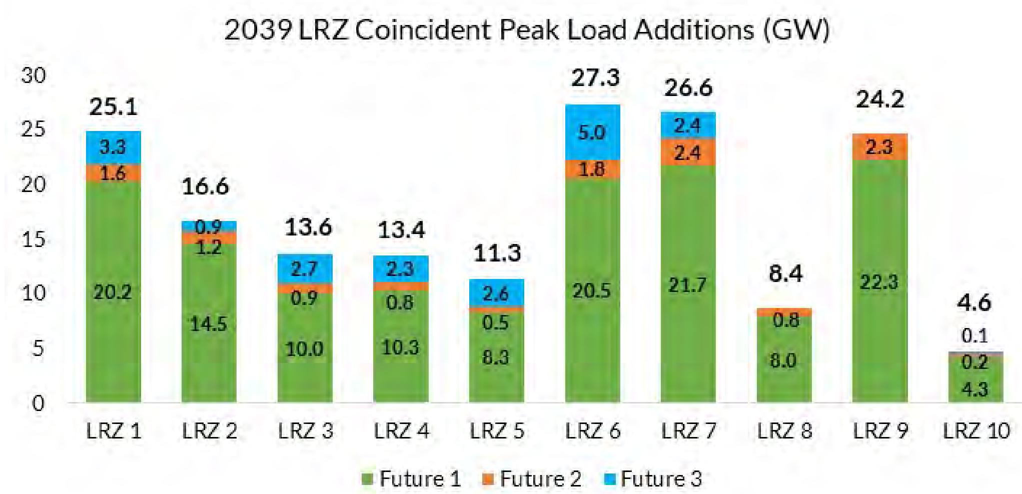


Figure 19: Final AEG Modified LRZ Coincident Peak Load (GW) Forecast[15,16]

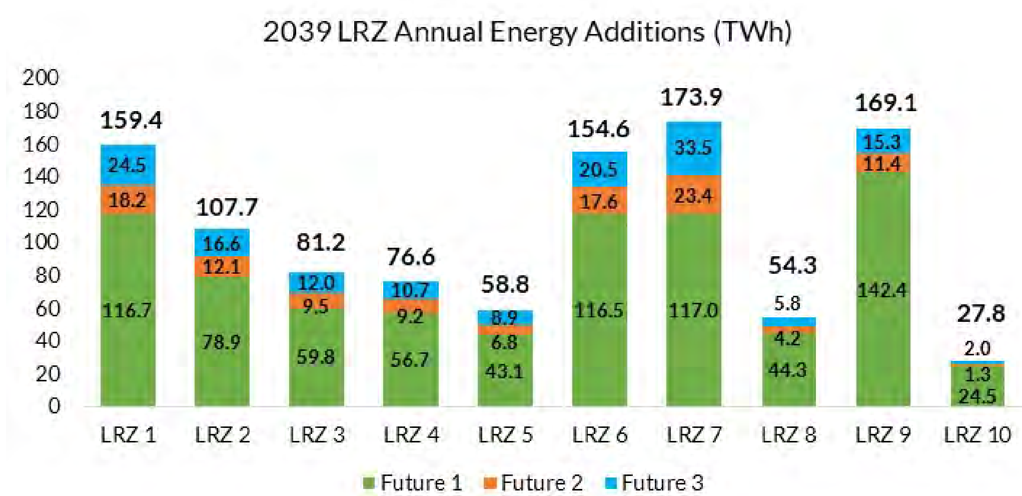


Figure 20: Final AEG Modified LRZ Annual Energy (TWh) Forecast[16]

[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.

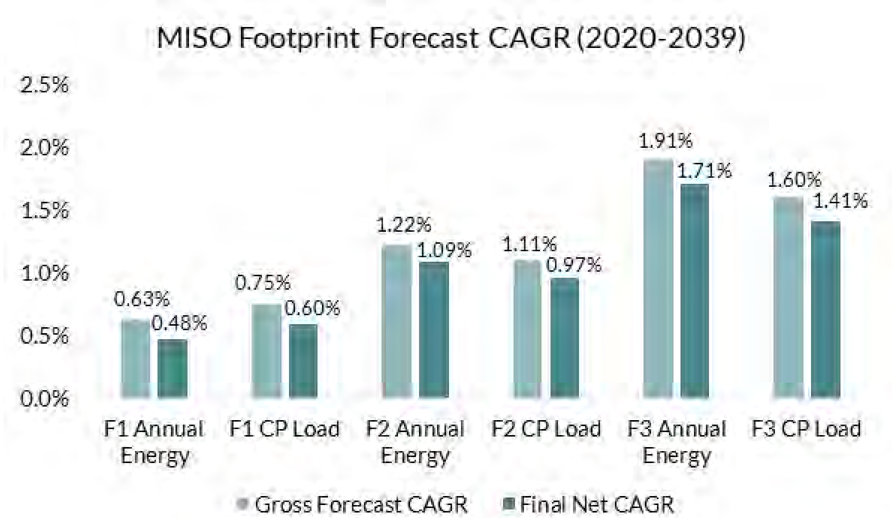


Figure 21: Final AEG Modified MISO Footprint Forecast Compound Annual Growth Rates (CAGR)

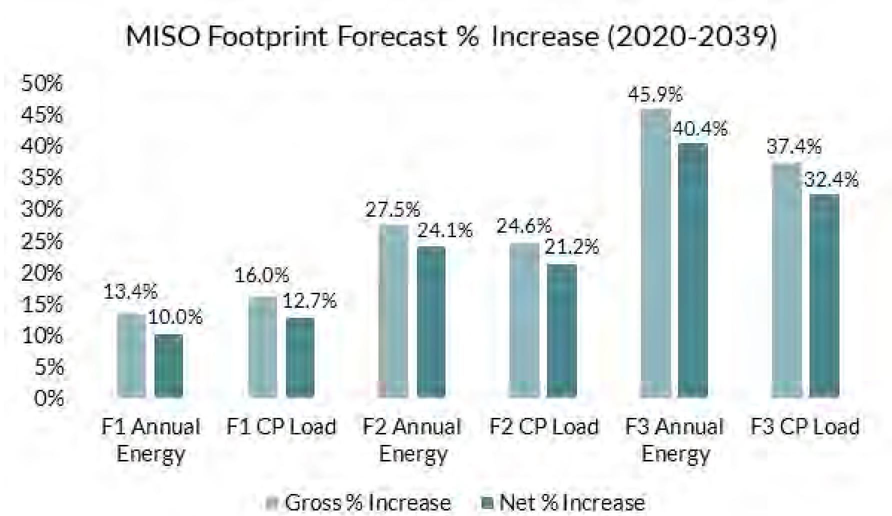


Figure 22: Final AEG Modified MISO Footprint Forecast % Increase[17]

[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.

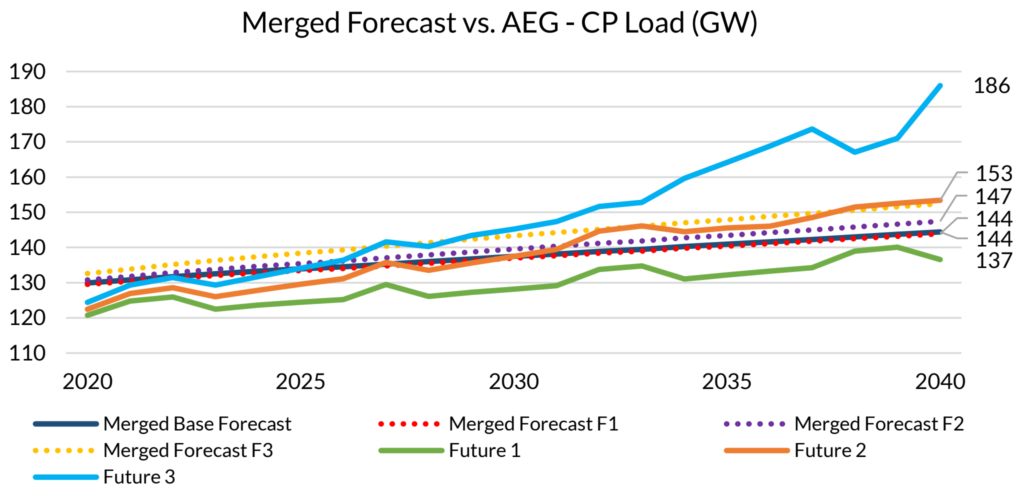


Figure 23: Merged Forecast vs. Future-Specific Adjustments – CP Load (GW)[18,19]

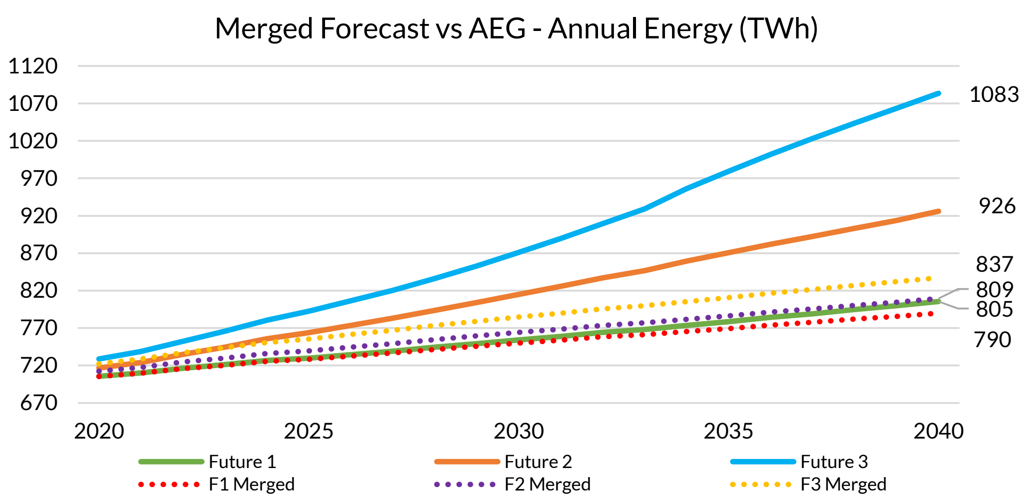


Figure 24: Merged Forecast vs. Future-Specific Adjustments – Annual Energy (TWh)

[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.

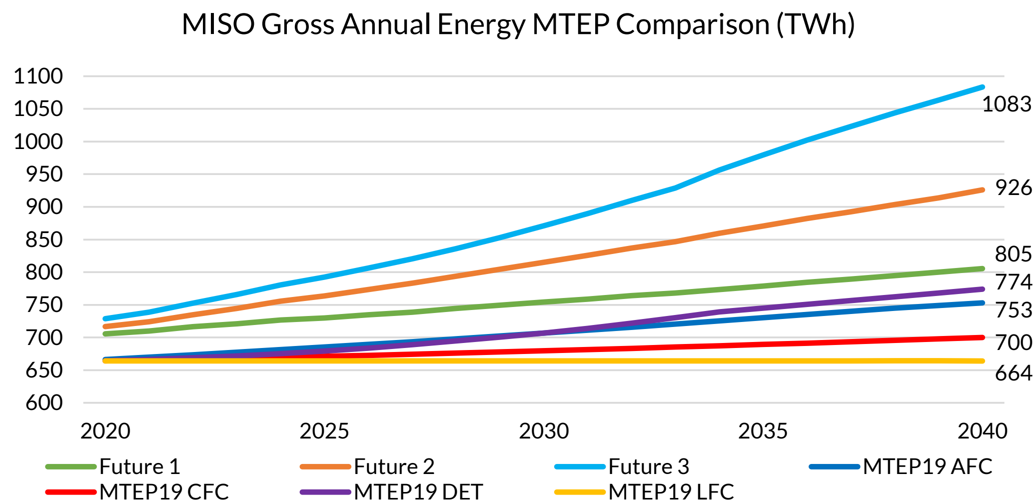


Figure 25: MTEP19 & MTEP21 MISO Annual Energy (TWh) Compare[20]

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

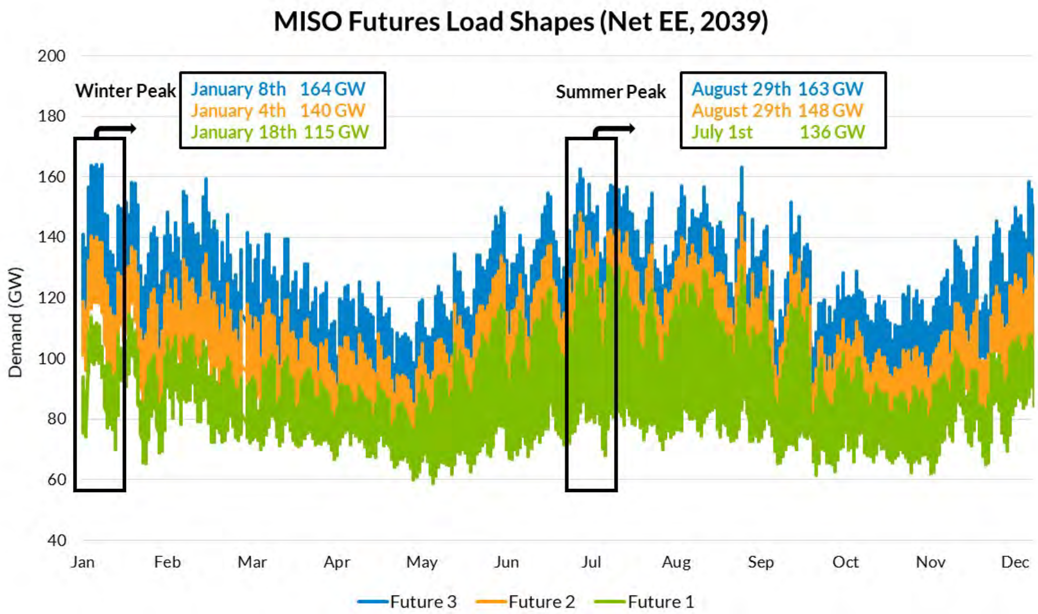


Figure 26: All Futures Final Load Shapes

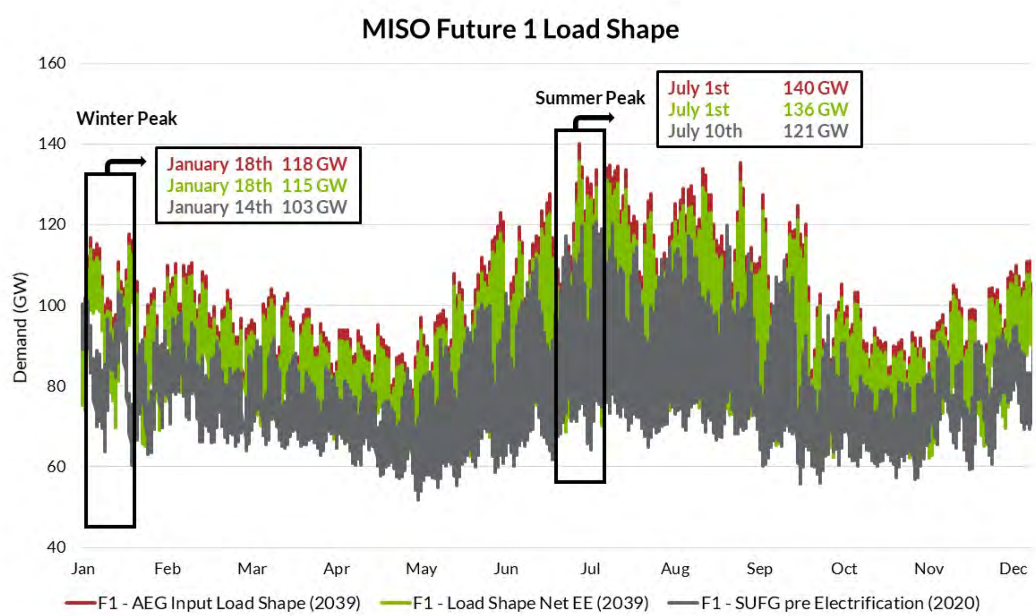


Figure 27: Future 1 Load Shape Evolution

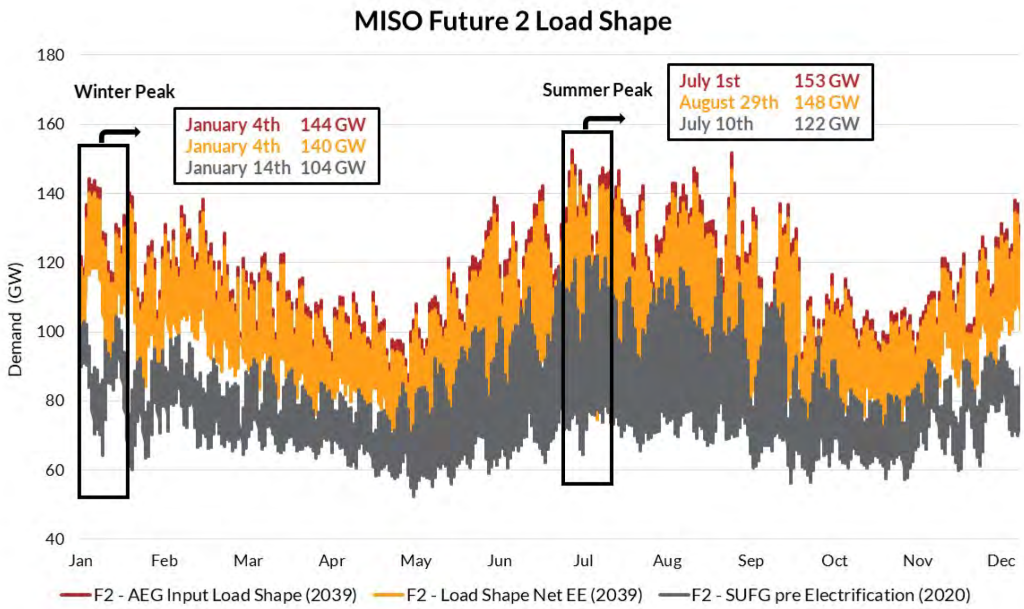


Figure 28: Future 2 Load Shape Evolution

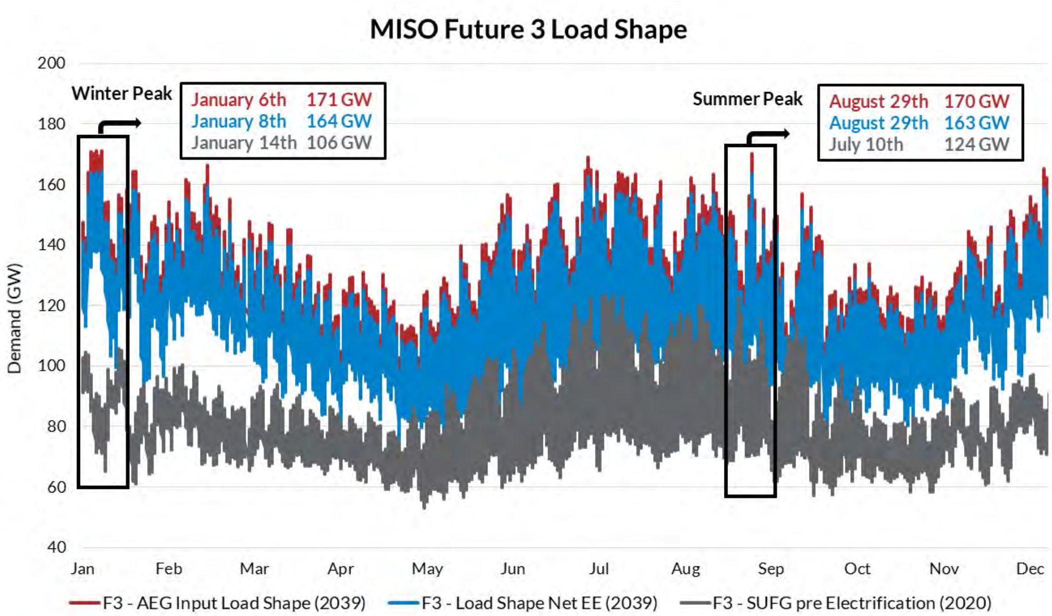


Figure 29: Future 3 Load Shape Evolution

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.

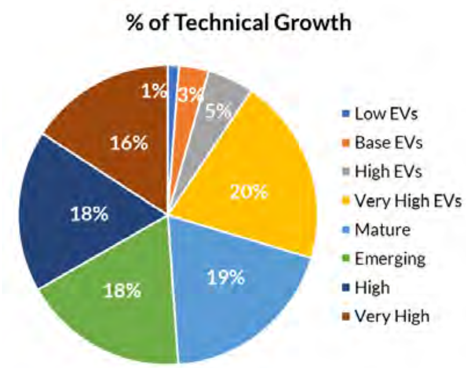


Figure 30: Electrification Categories

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:

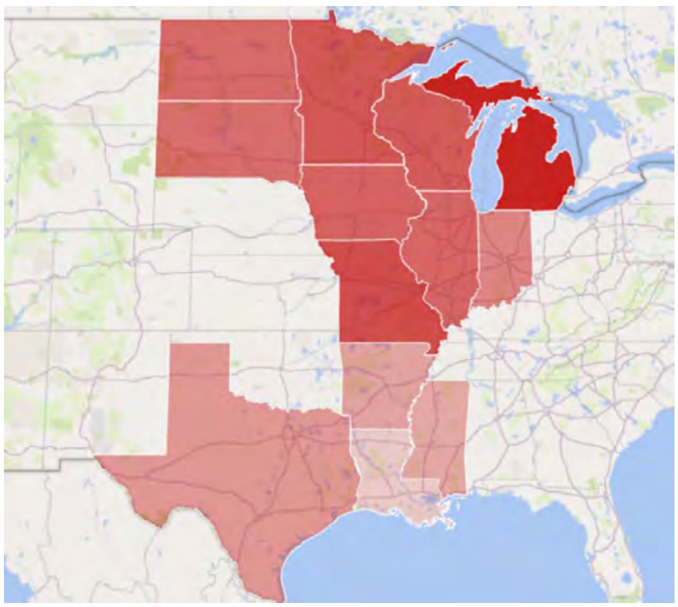


Figure 31: Electrification Potential by State

- **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

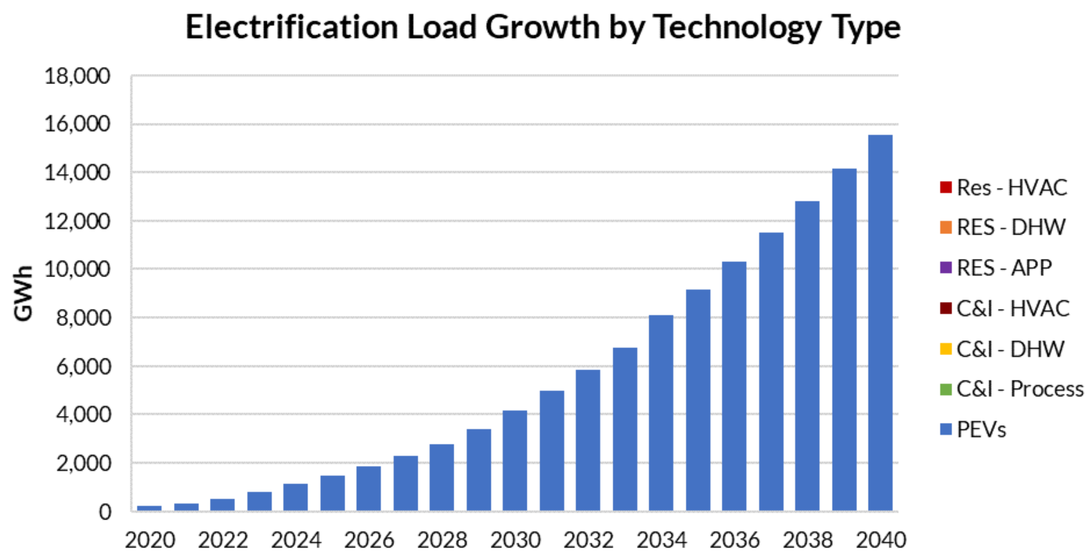


Figure 32: Future 1 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

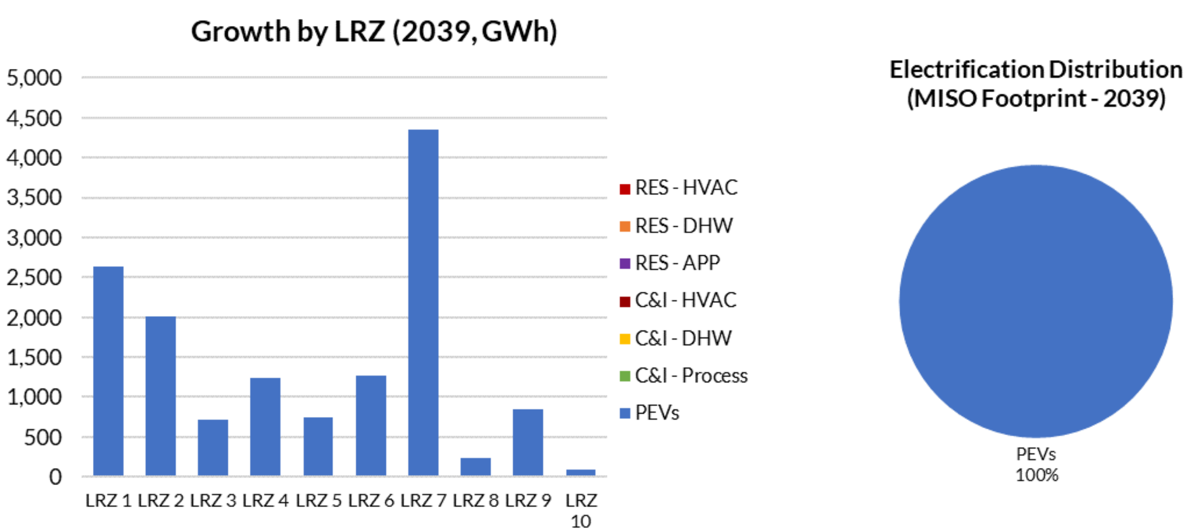


Figure 33: Future 1 Electrification Broken Down by End-Use

Future 2 Electrification

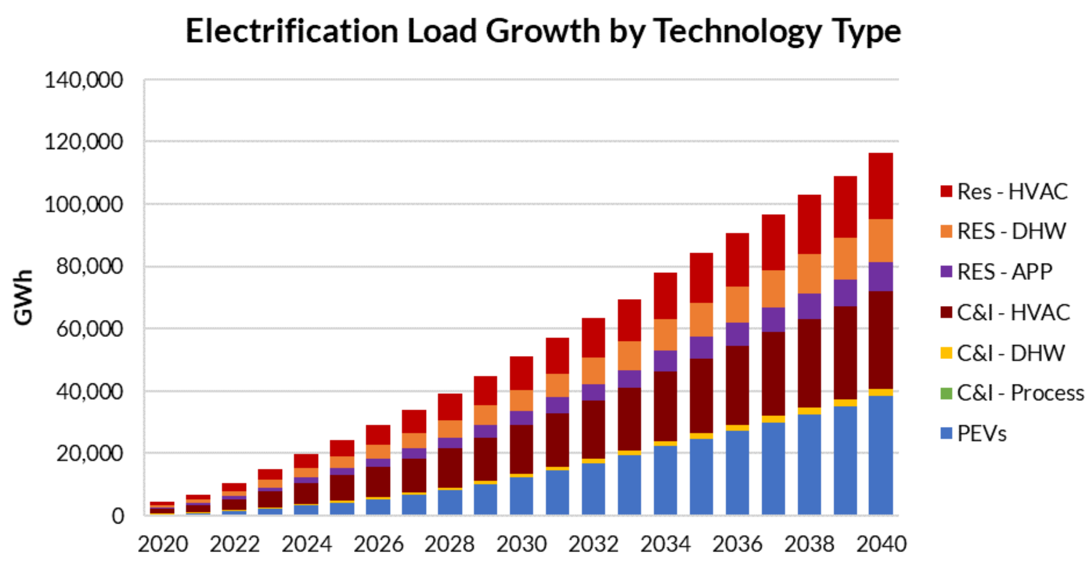


Figure 34: Future 2 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

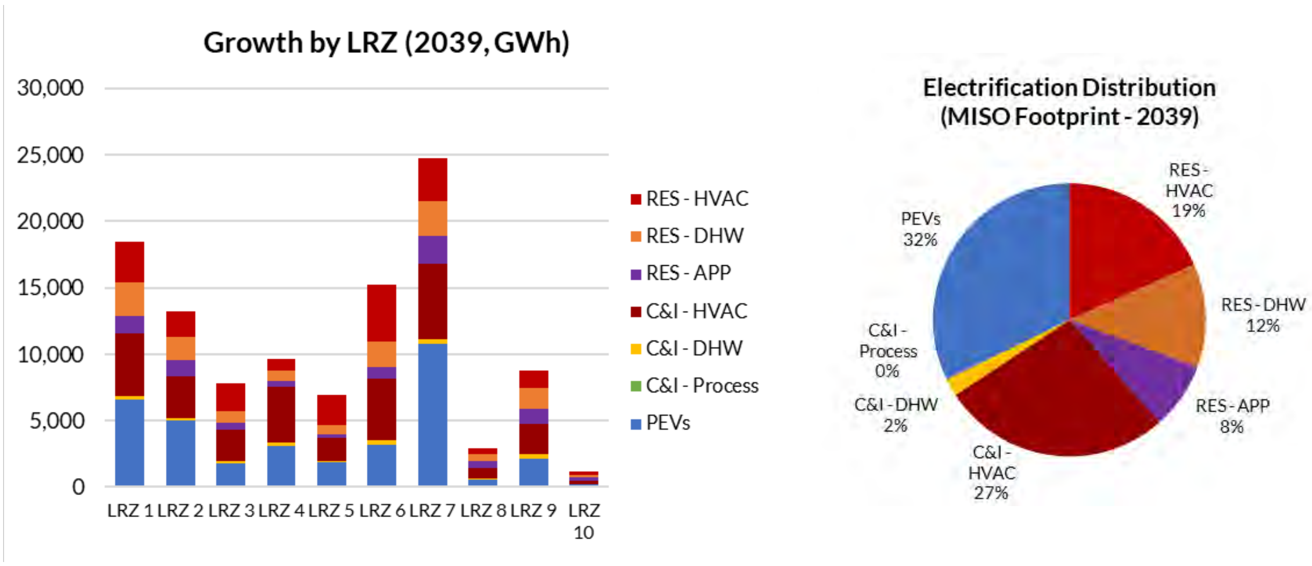


Figure 35: Future 2 Electrification Broken Down by End-Use

Future 3 Electrification

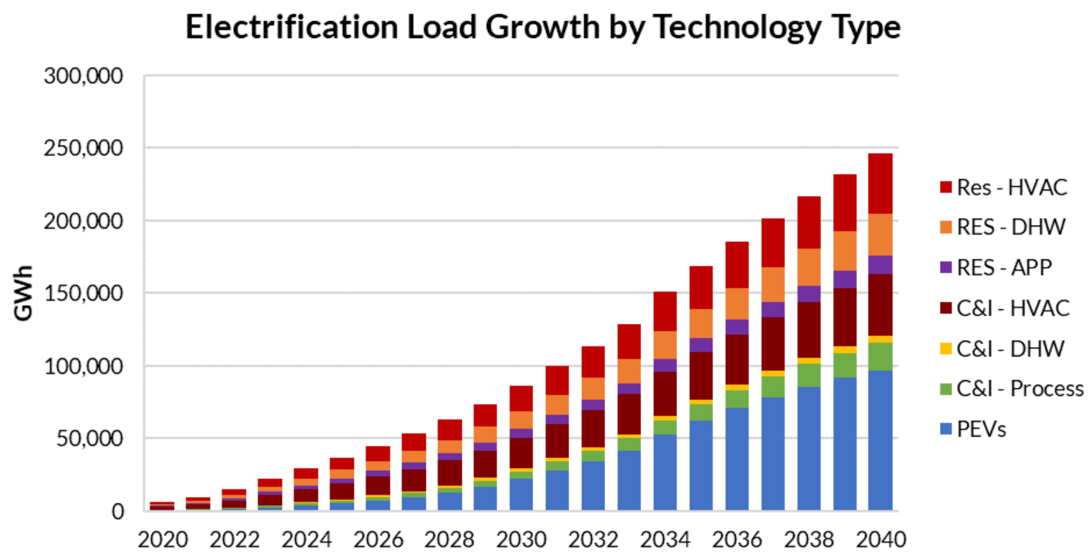
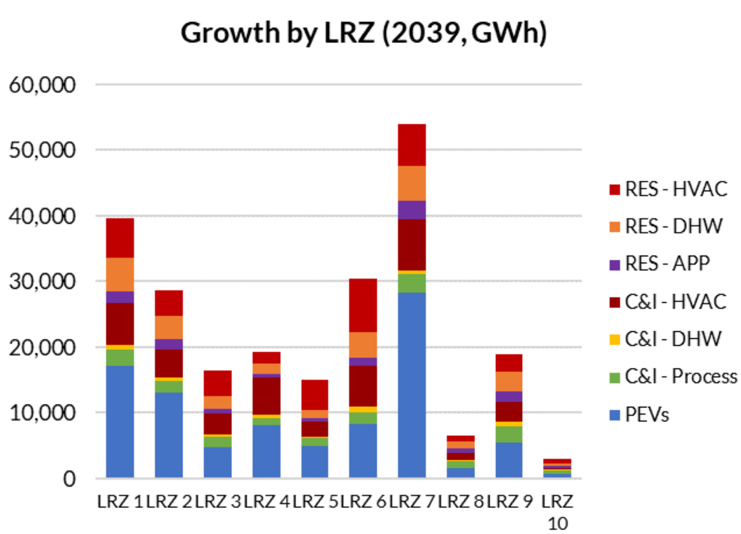


Figure 36: Future 3 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint



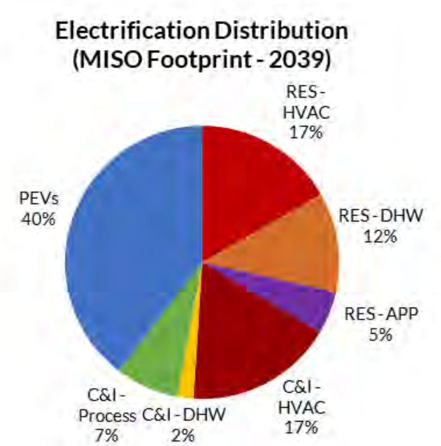
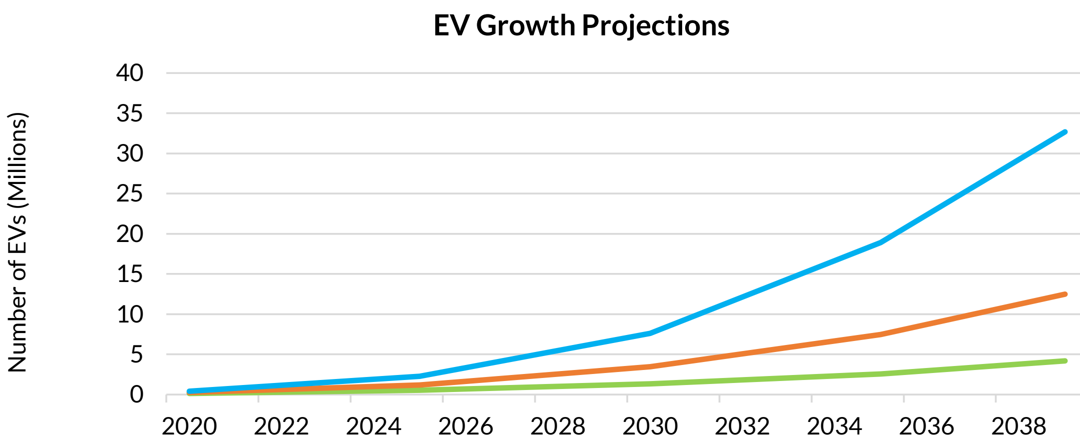


Figure 37: Future 3 Electrification Broken Down by End-Use

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)

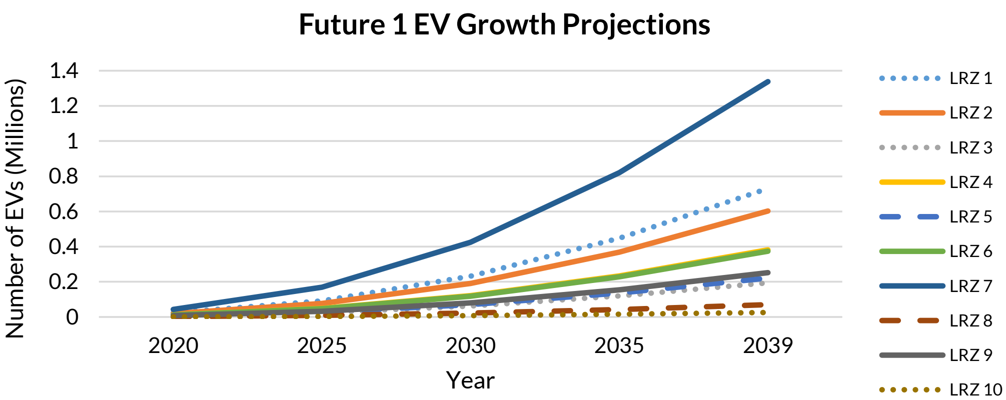


Figure 39: Future 1 EV Growth per LRZ

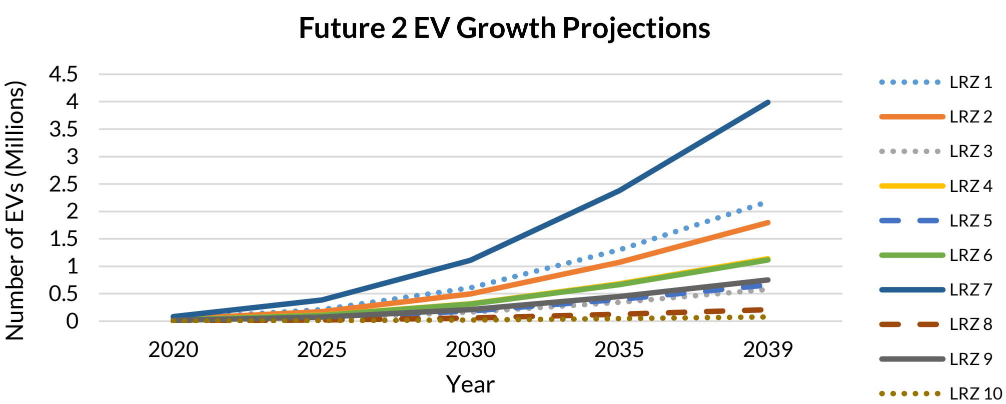


Figure 40: Future 2 EV Growth per LRZ

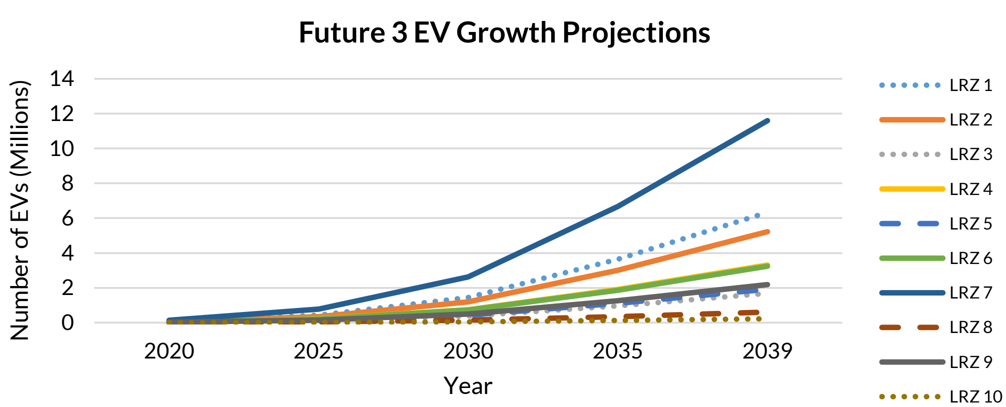


Figure 41: Future 3 EV Growth per LRZ

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.

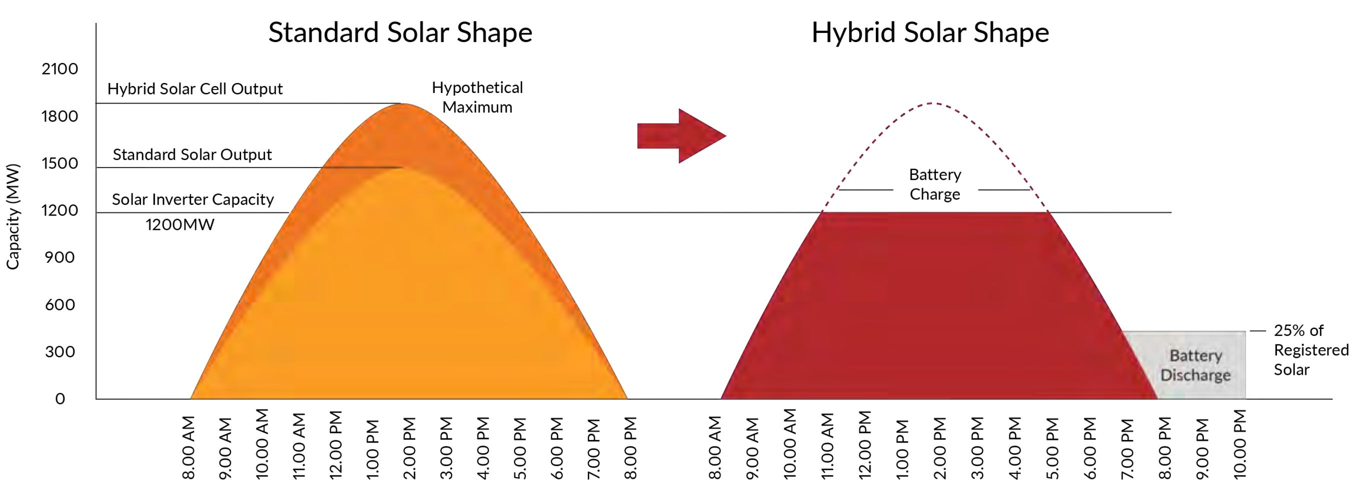


Figure 42: Solar + Storage Hybrid Profile

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.

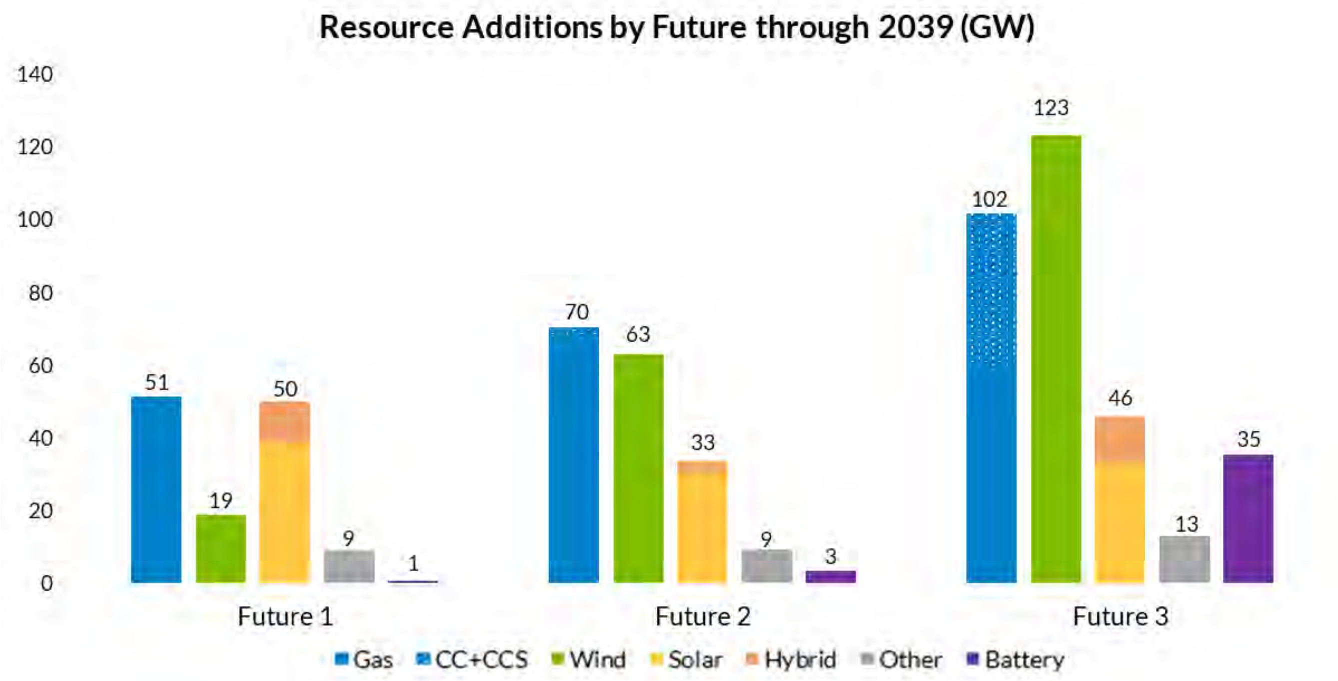


Figure 43: MISO Resource Addition Summary by Future

MISO – Future 1

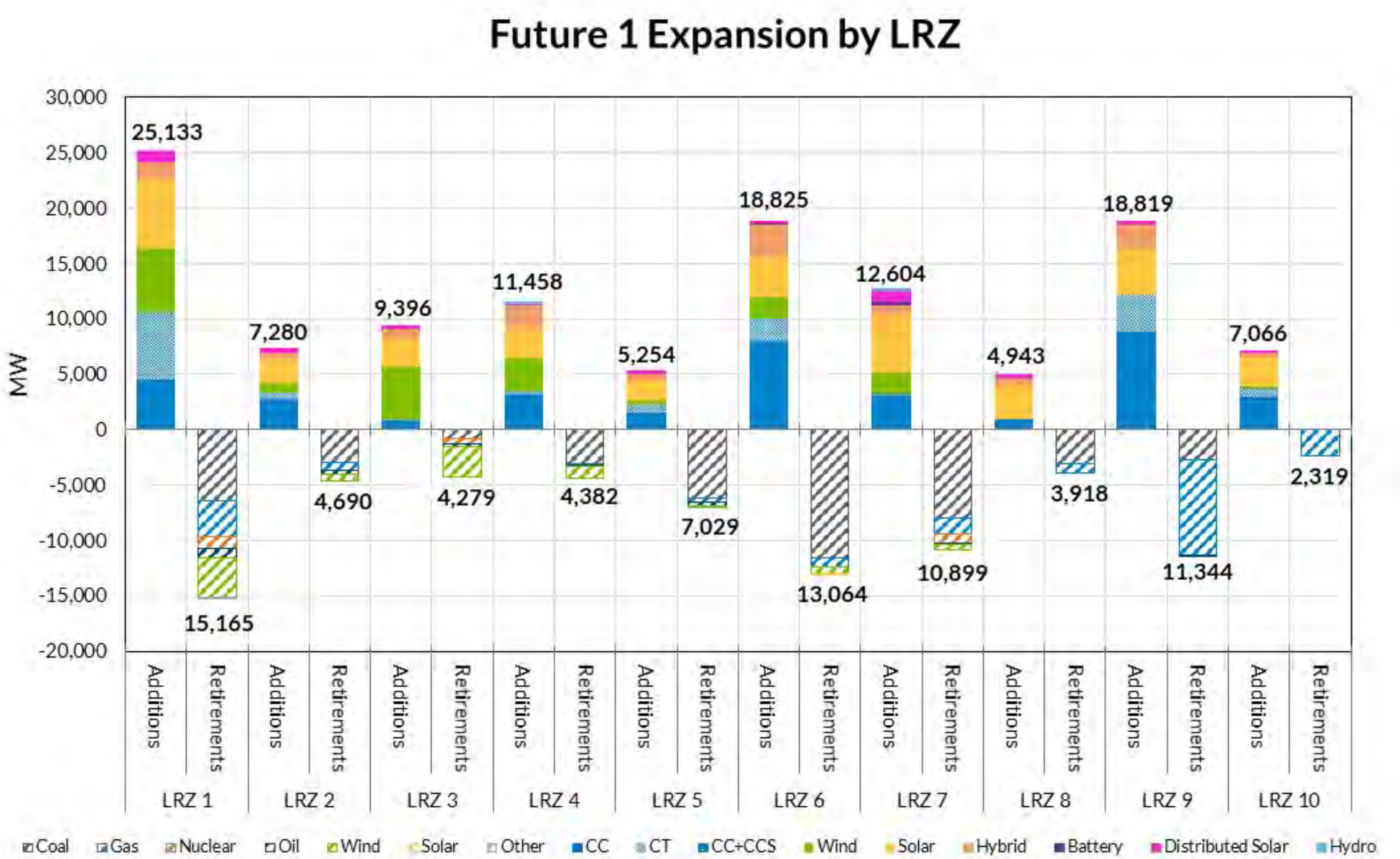


Figure 44: MISO Future 1 Resource Retirement and Addition Summary

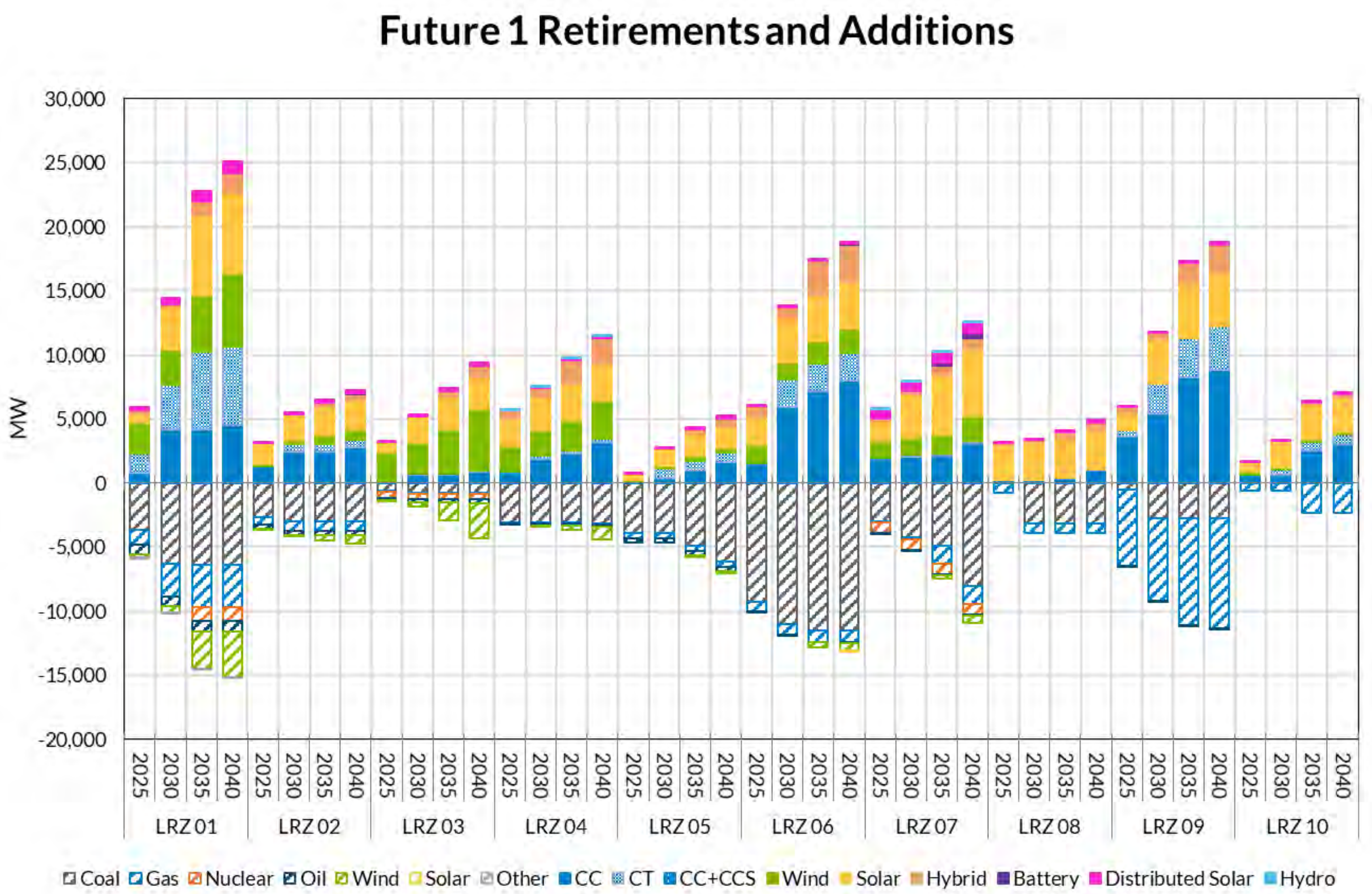


Figure 45: Future 1 Resource Additions per Milestone Year (Cumulative)

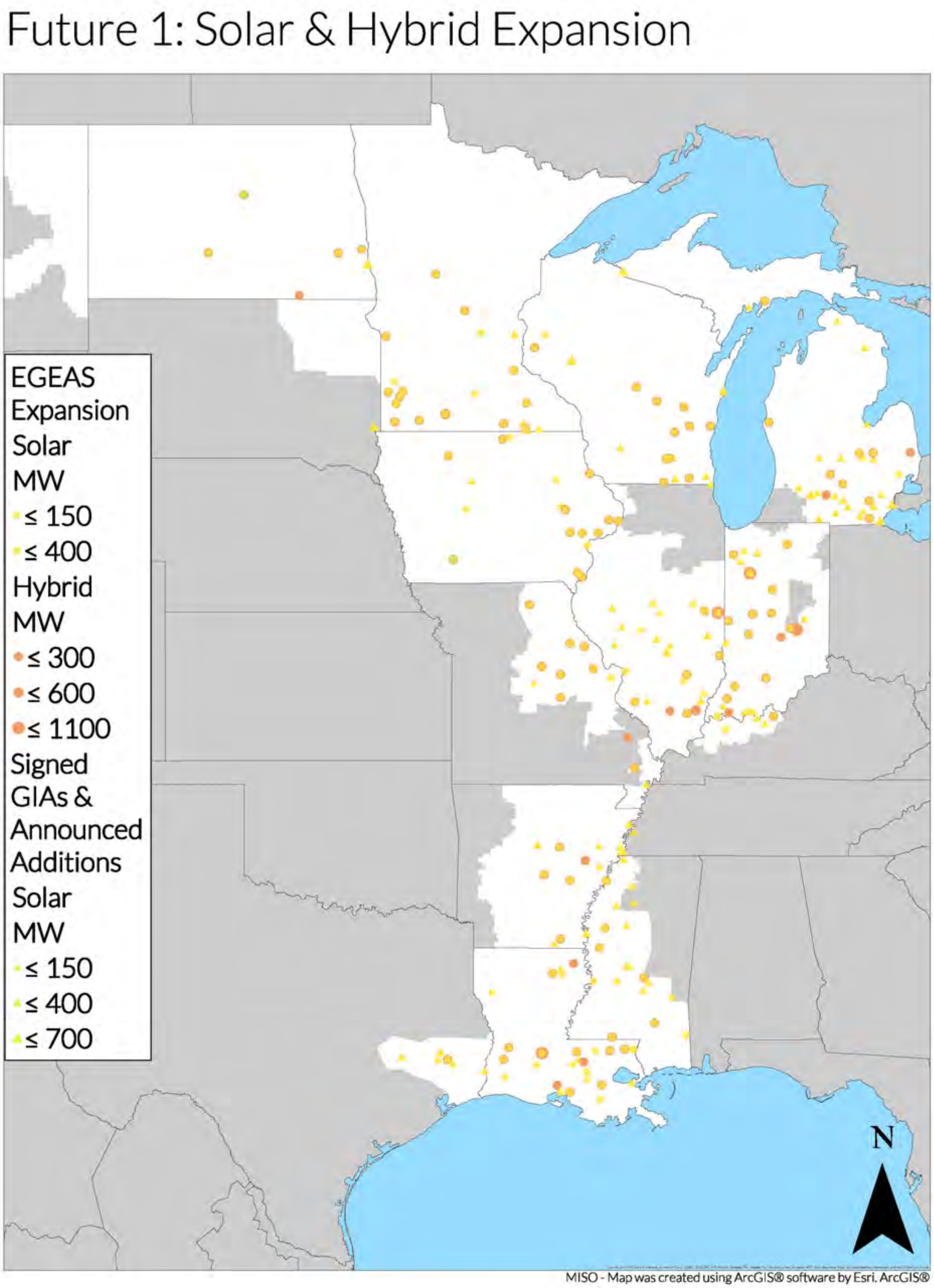


Figure 46: MISO Future 1 Solar and Hybrid Siting

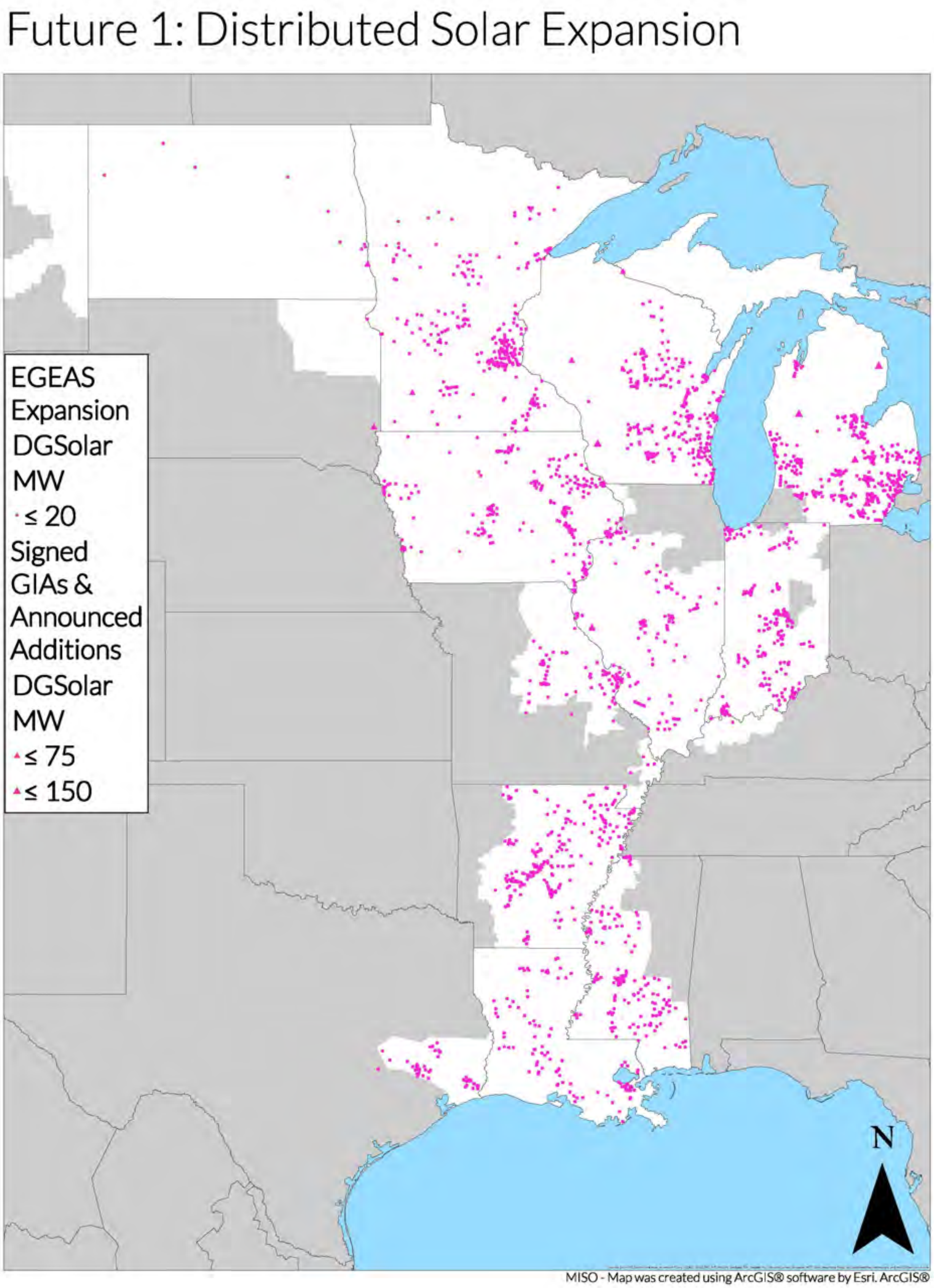


Figure 47: MISO Future 1 Distributed Solar Siting

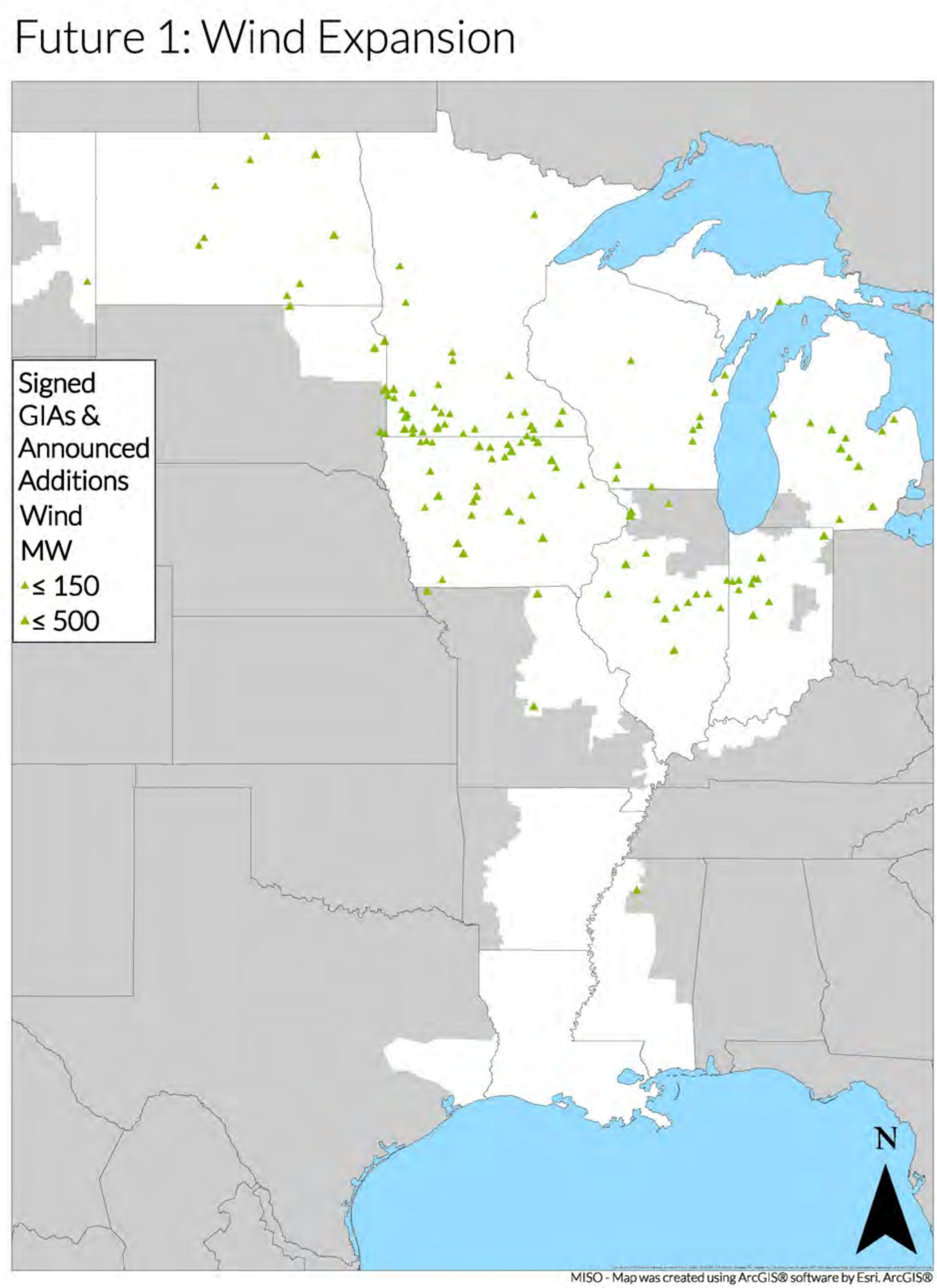


Figure 48: MISO Future 1 Wind Siting

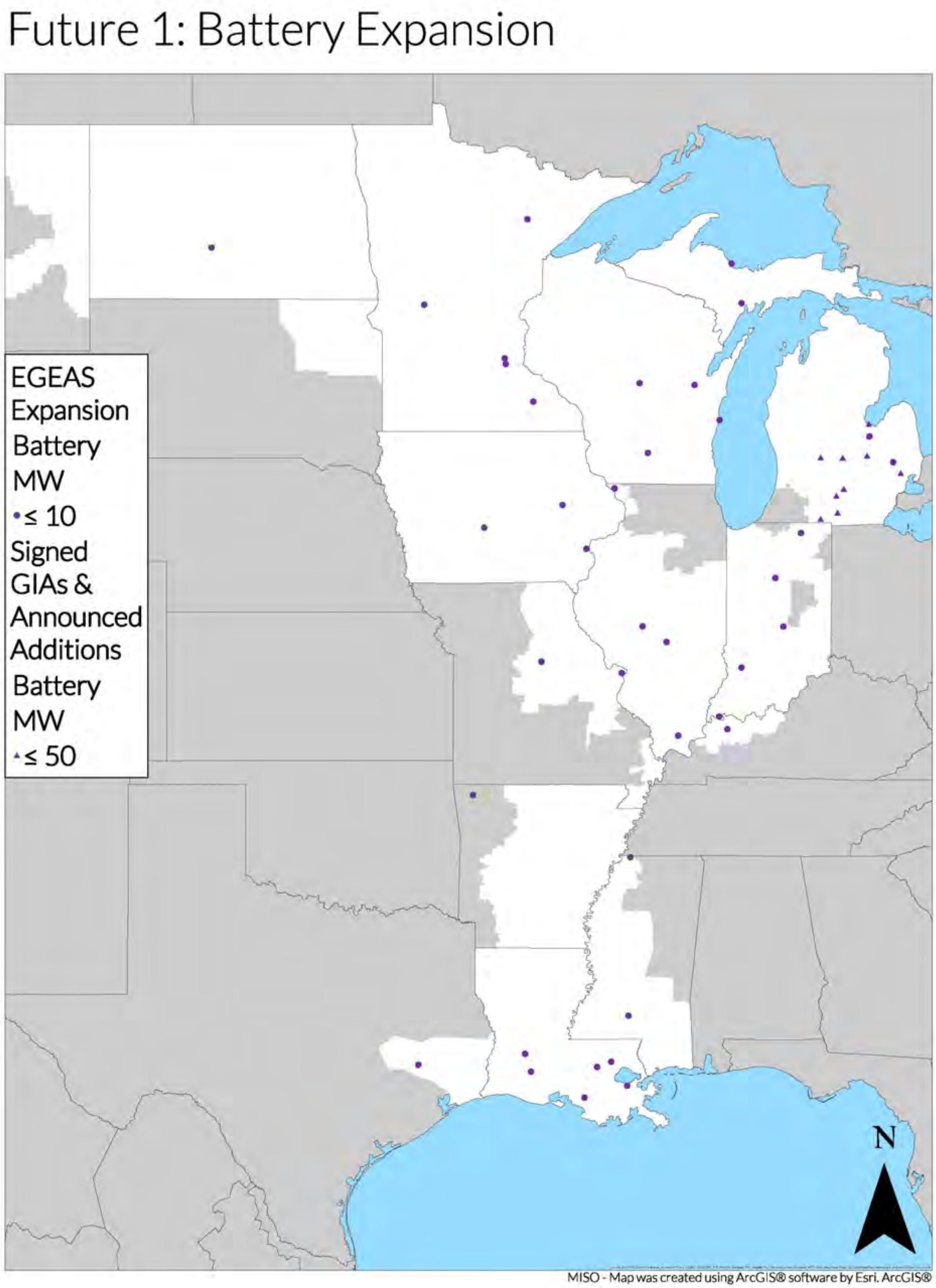


Figure 49: MISO Future 1 Battery Siting

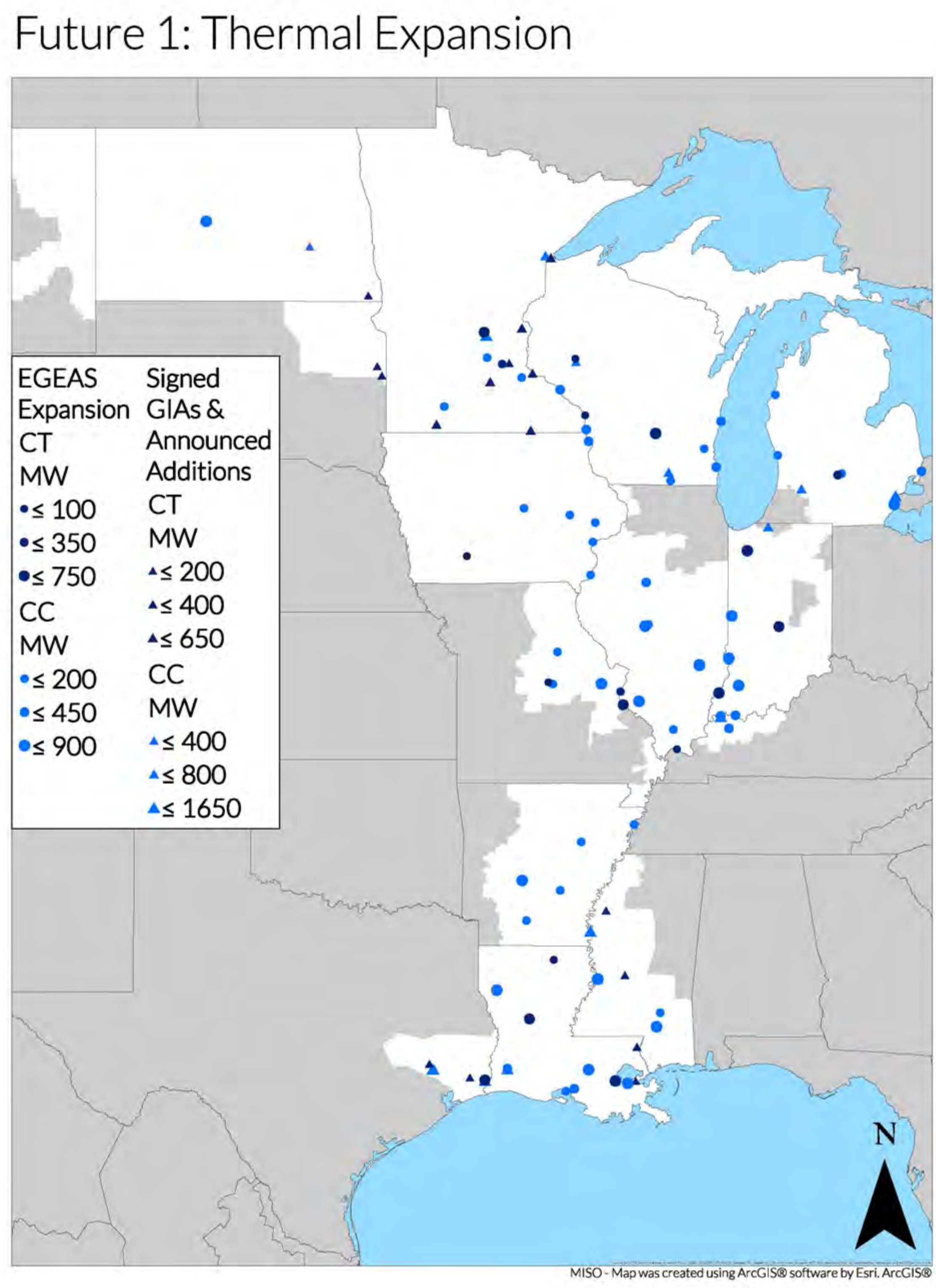


Figure 50: MISO Future 1 Thermal Siting

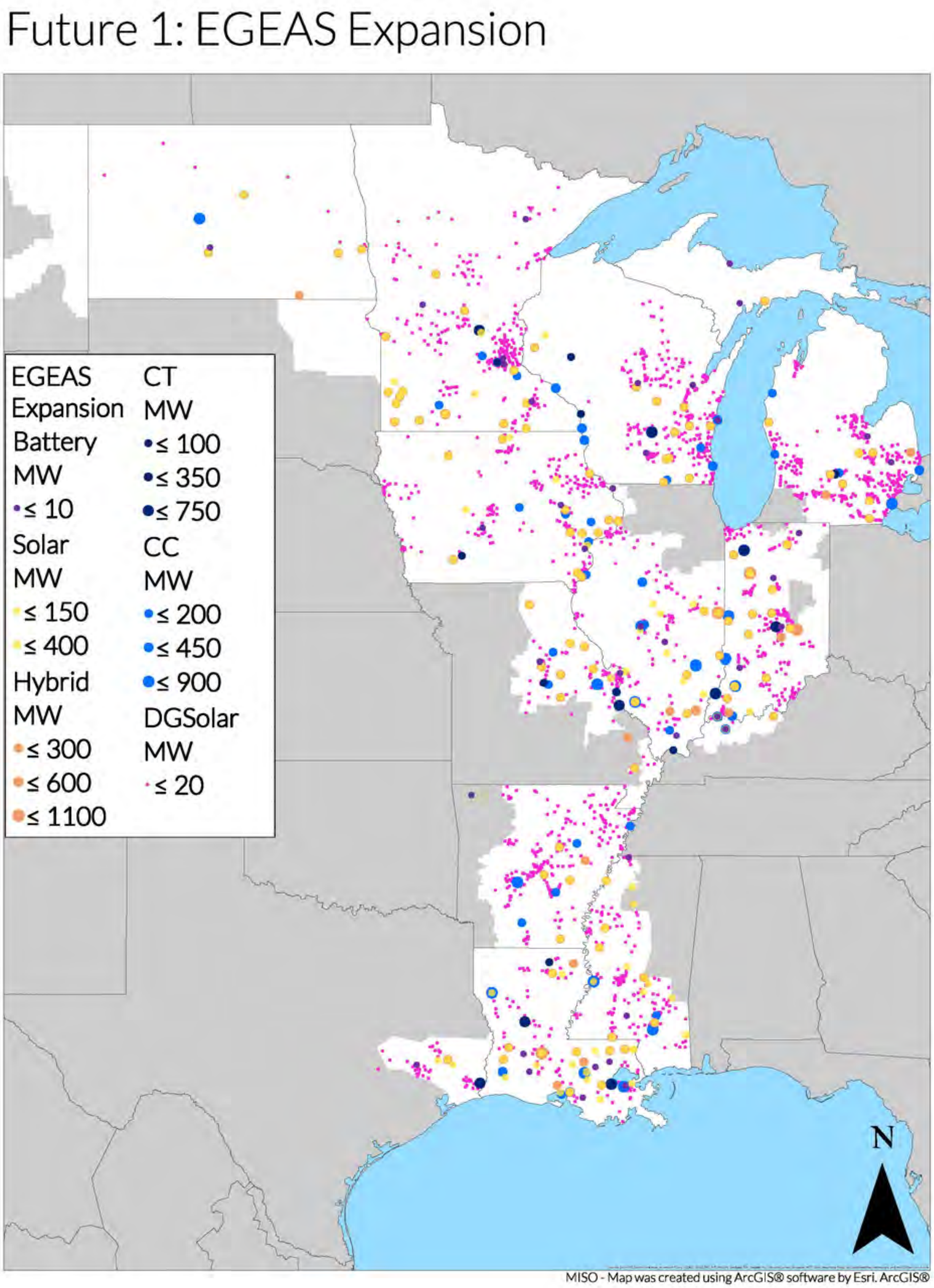


Figure 51: MISO Future 1 Complete EGEAS Expansion Siting

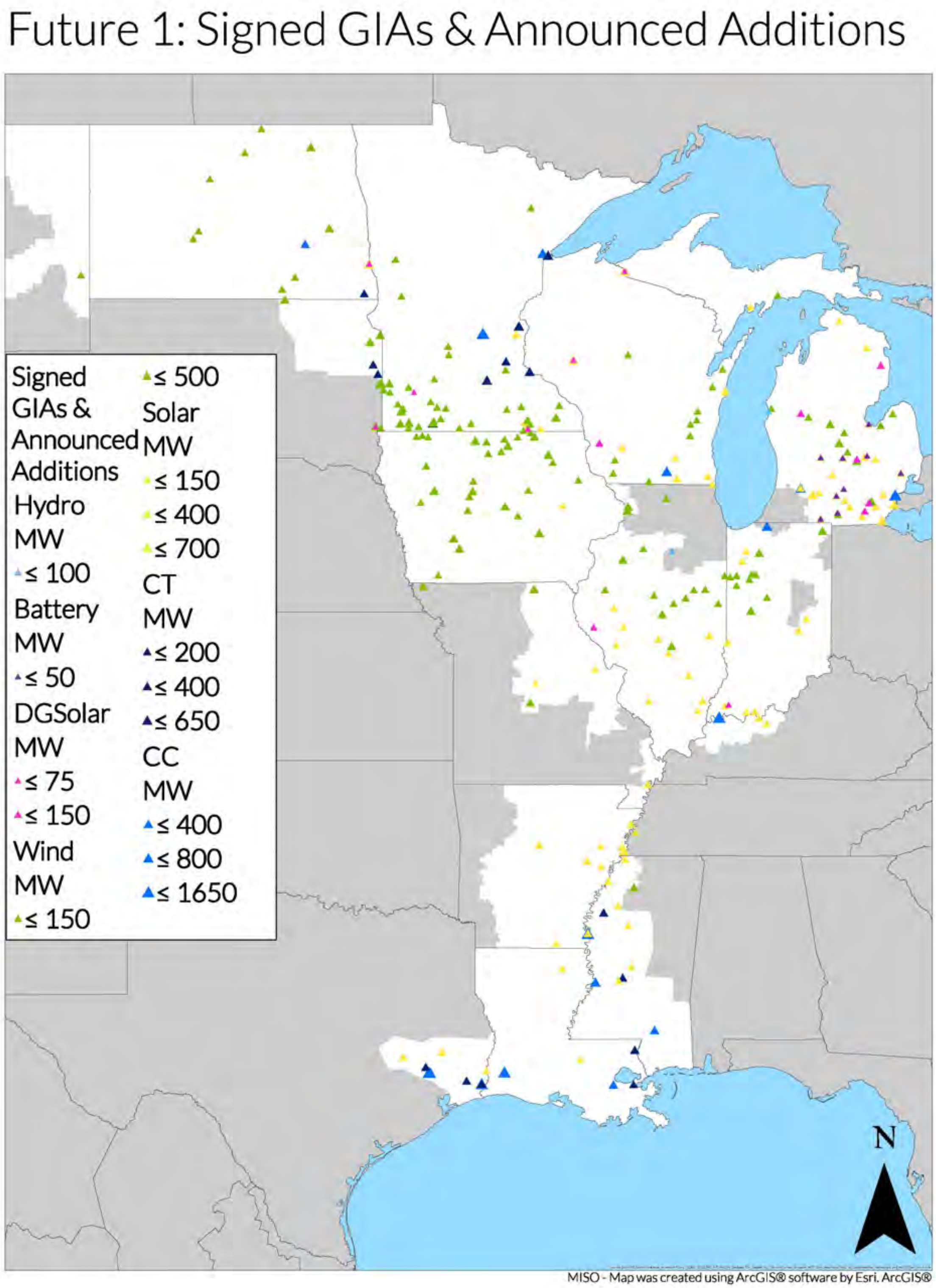


Figure 52: MISO Future 1 Non-EGEAS Expansion Siting

Future 1: Total Expansion

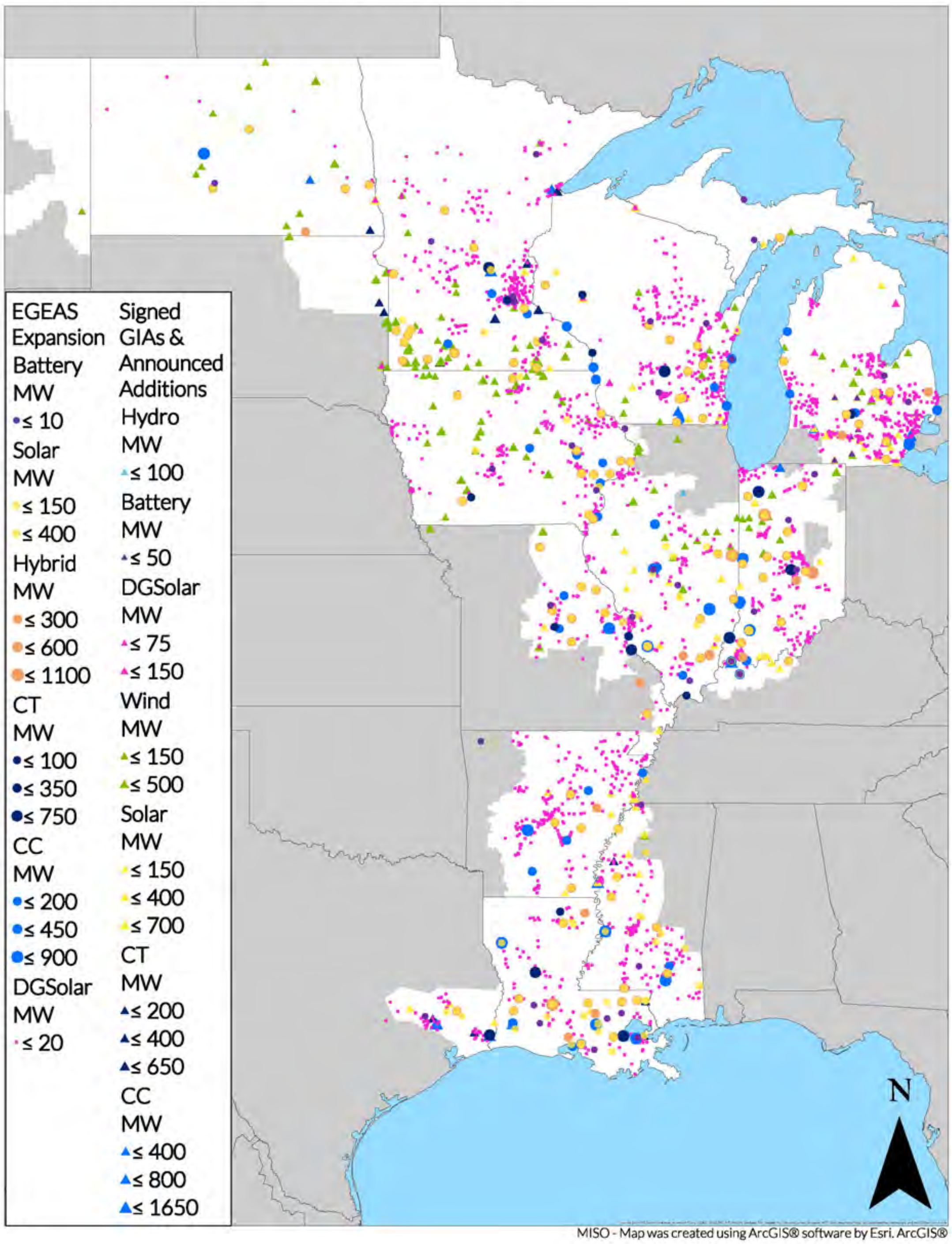


Figure 53: MISO Future 1 Non-EGEAS and EGEAS Expansion Siting

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

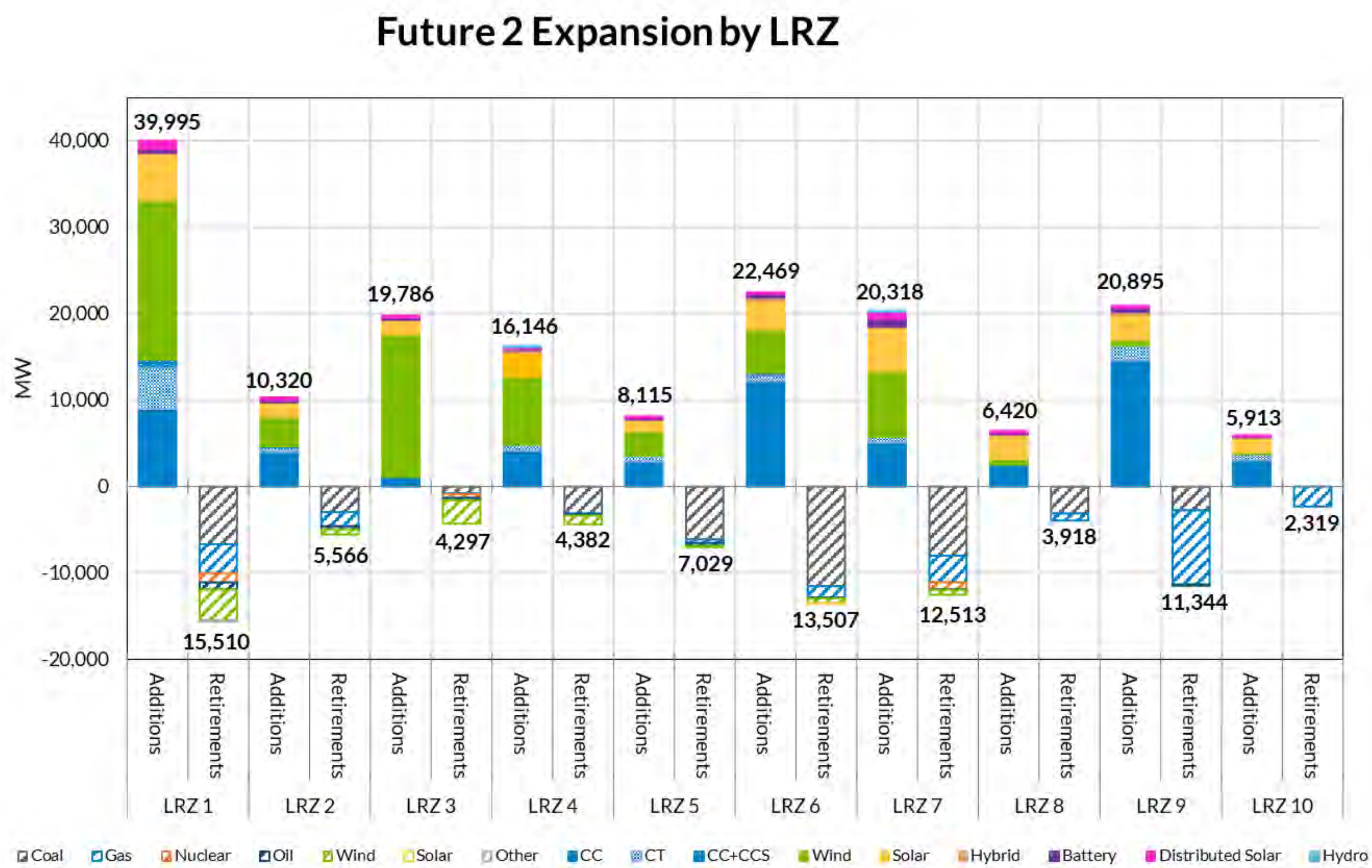


Figure 54: MISO Future 2 Resource Retirement and Addition Summary

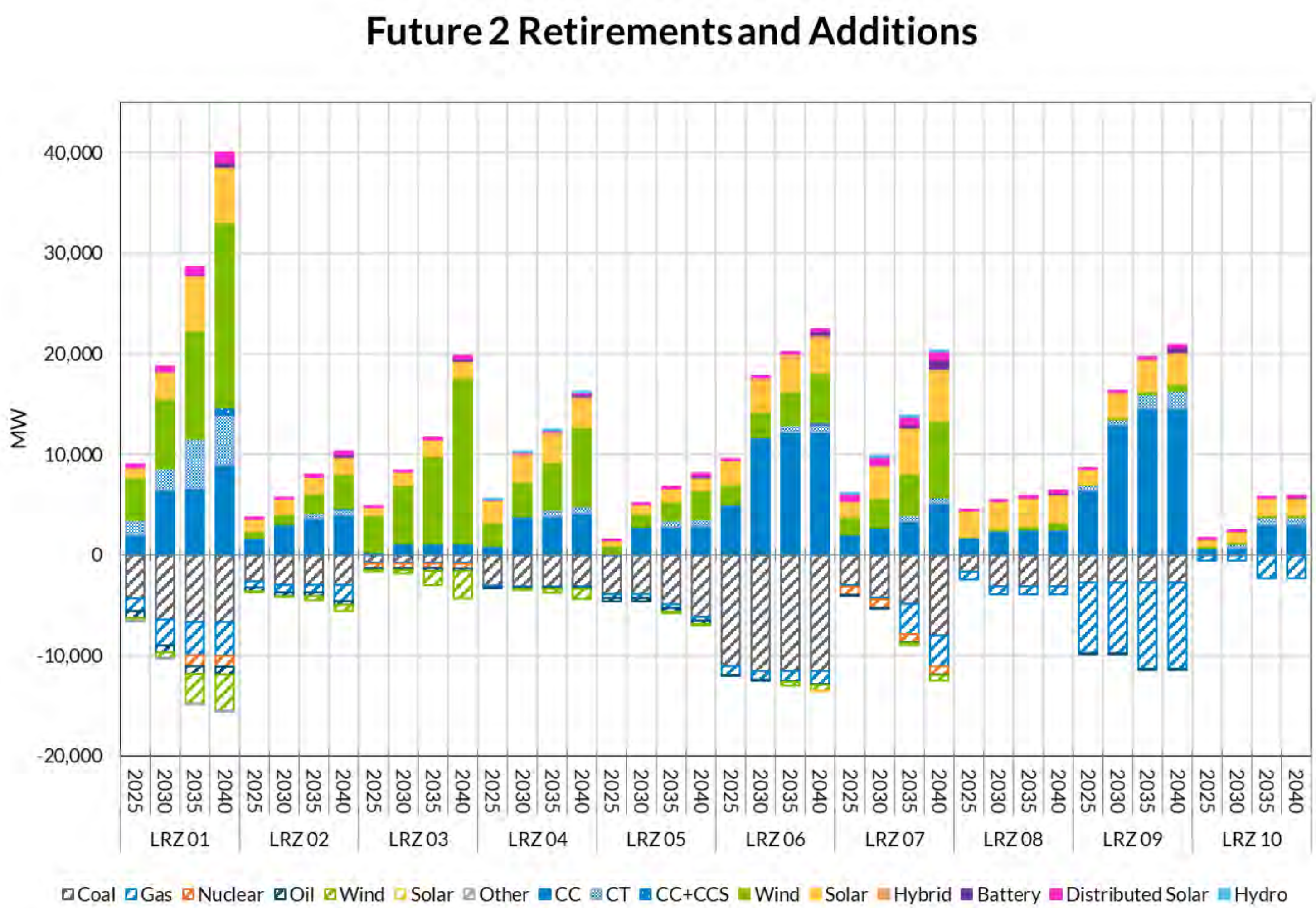


Figure 55: MISO Future 2 Resource Additions per Milestone Year (Cumulative)

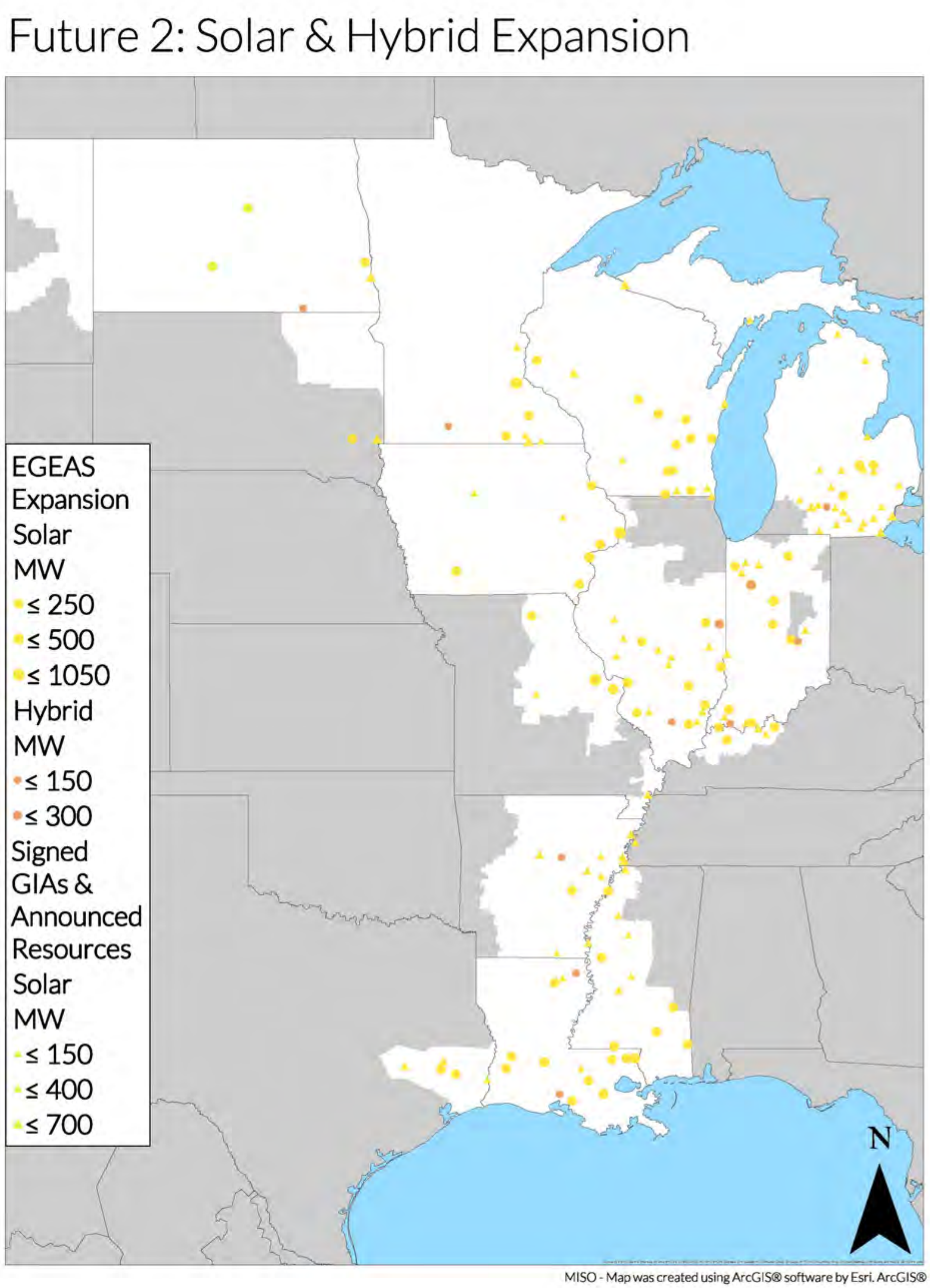


Figure 56: MISO Future 2 Solar and Hybrid Siting

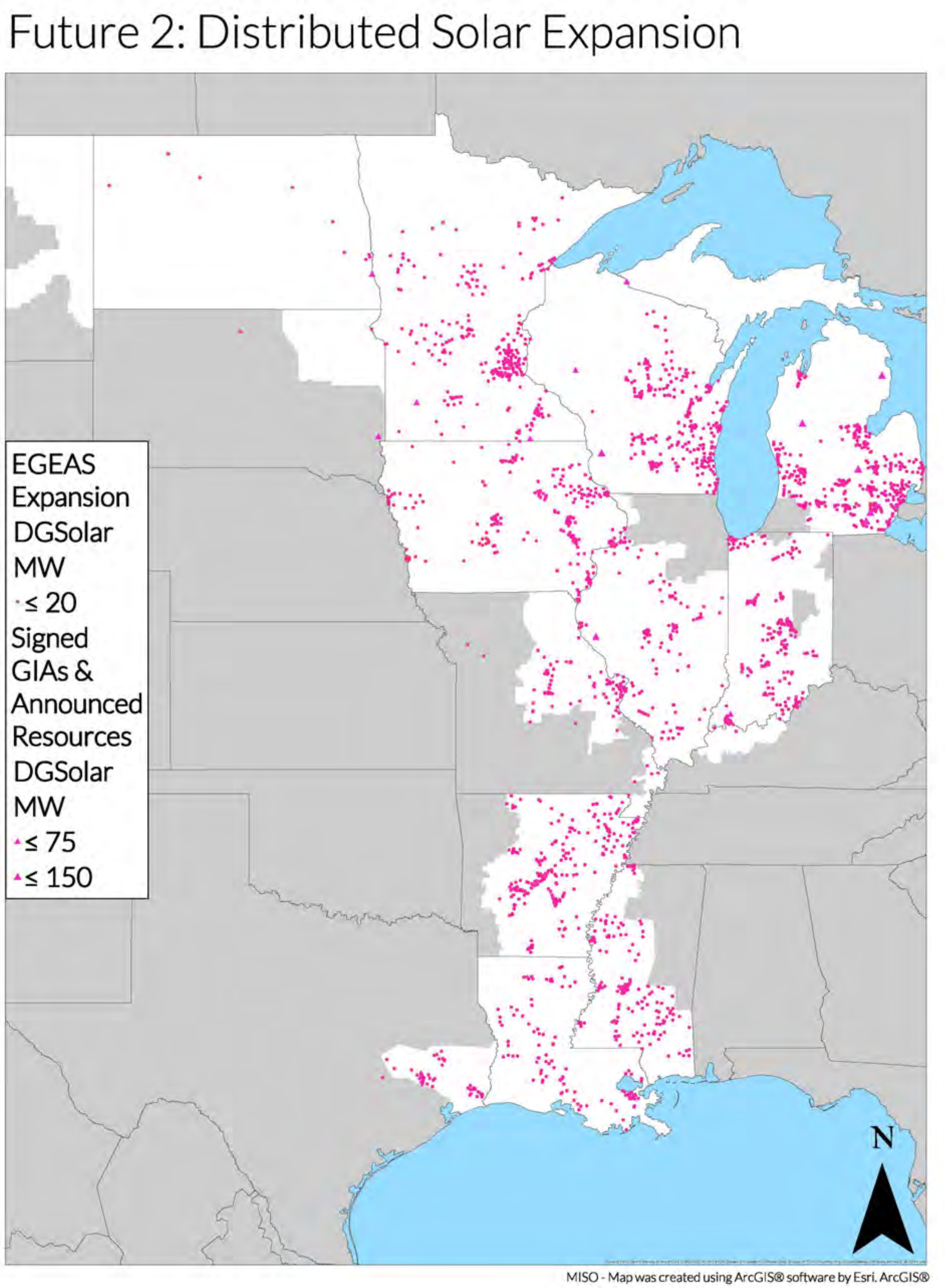


Figure 57: MISO Future 2 Distributed Solar Siting

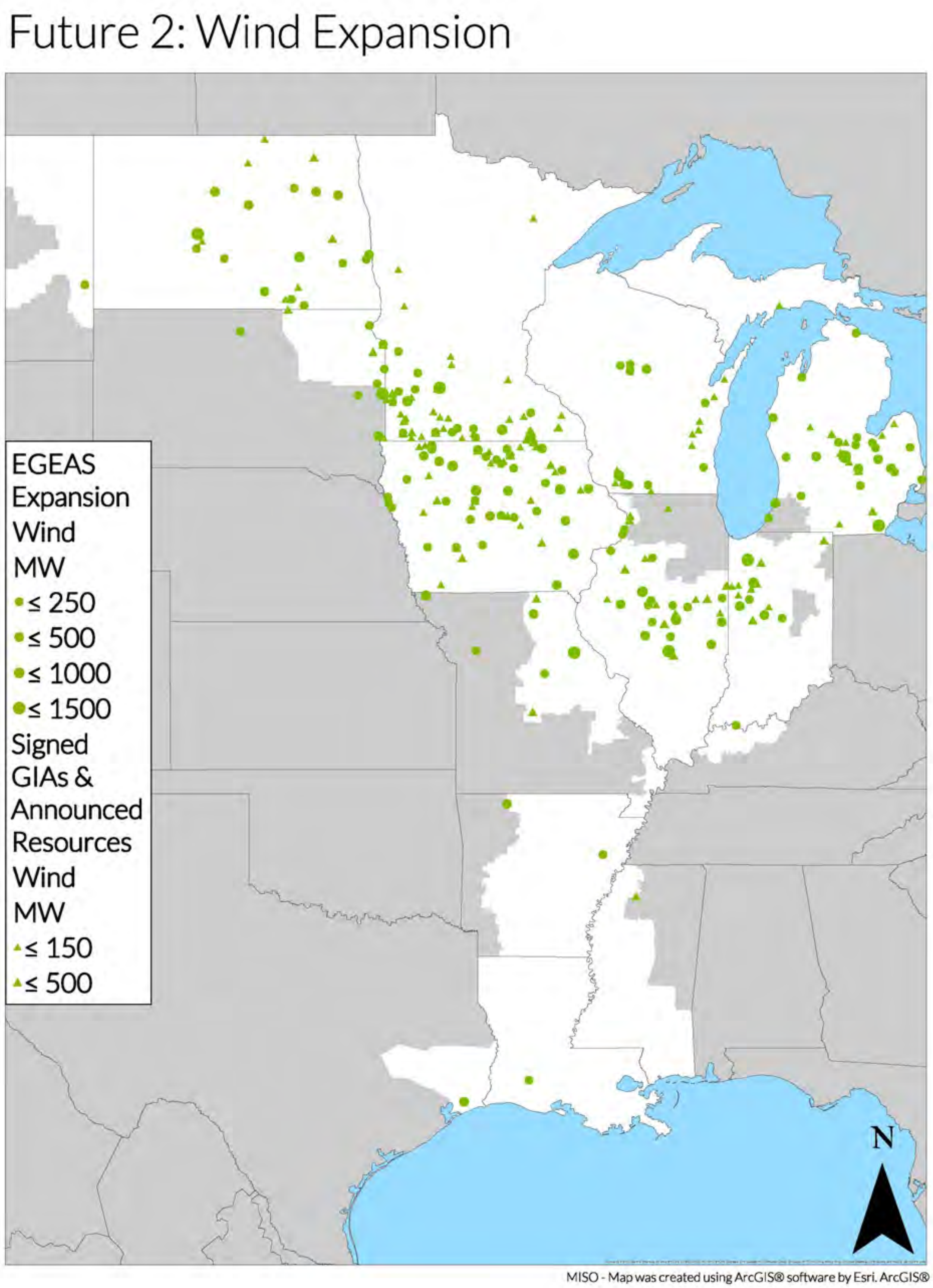


Figure 58: MISO Future 2 Wind Siting

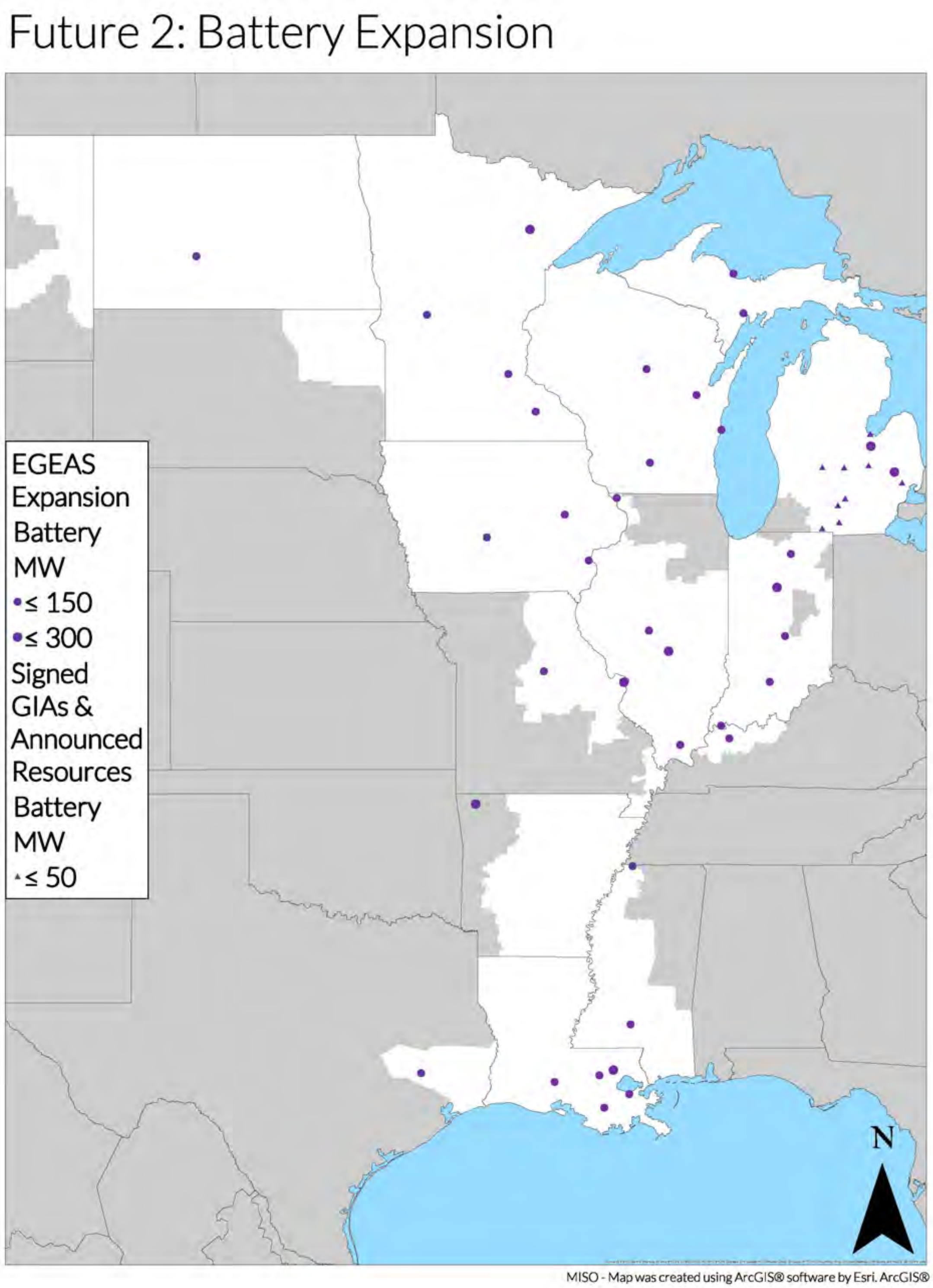


Figure 59: MISO Future 2 Battery Siting

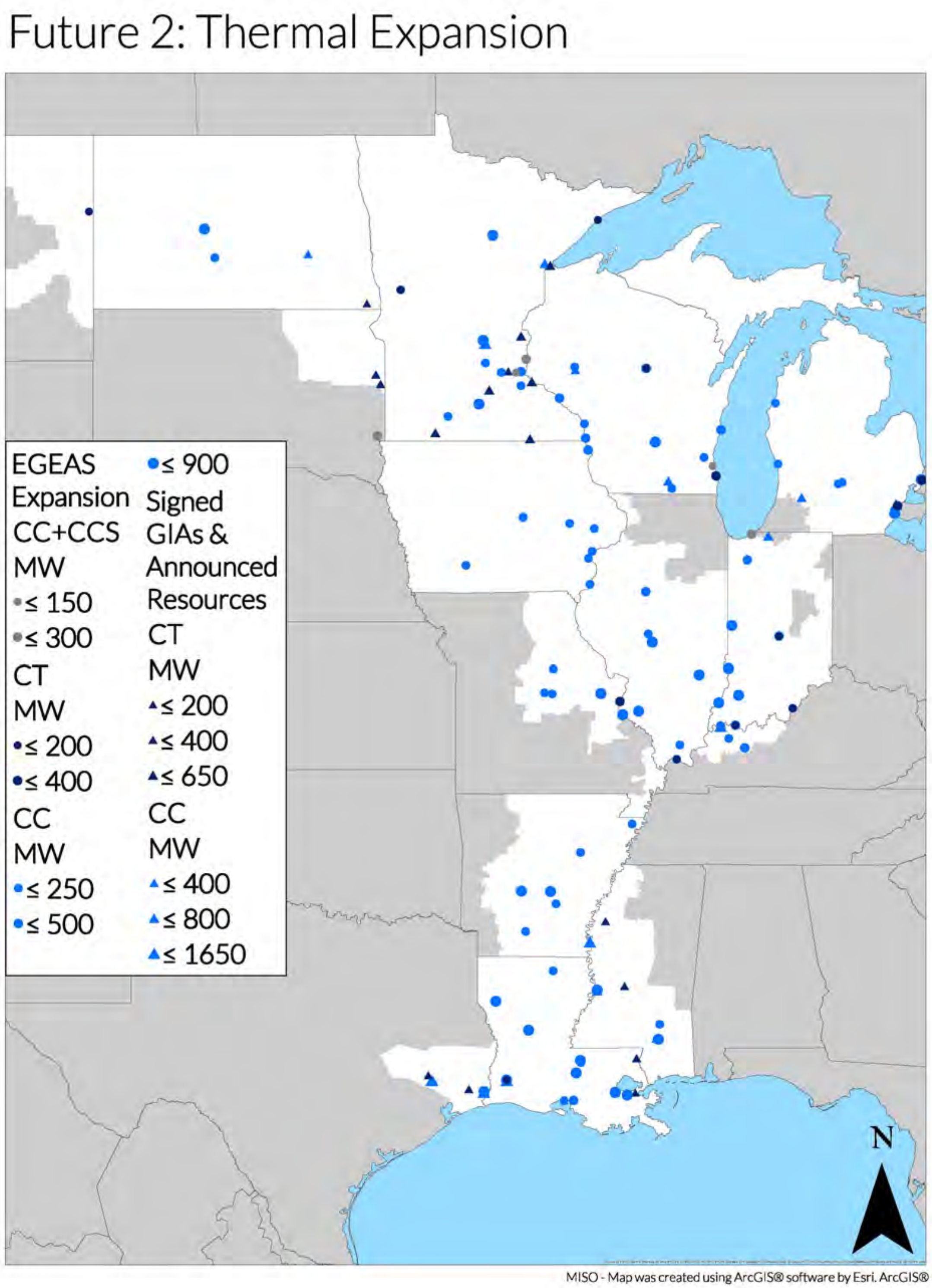


Figure 60: MISO Future 2 Thermal Siting

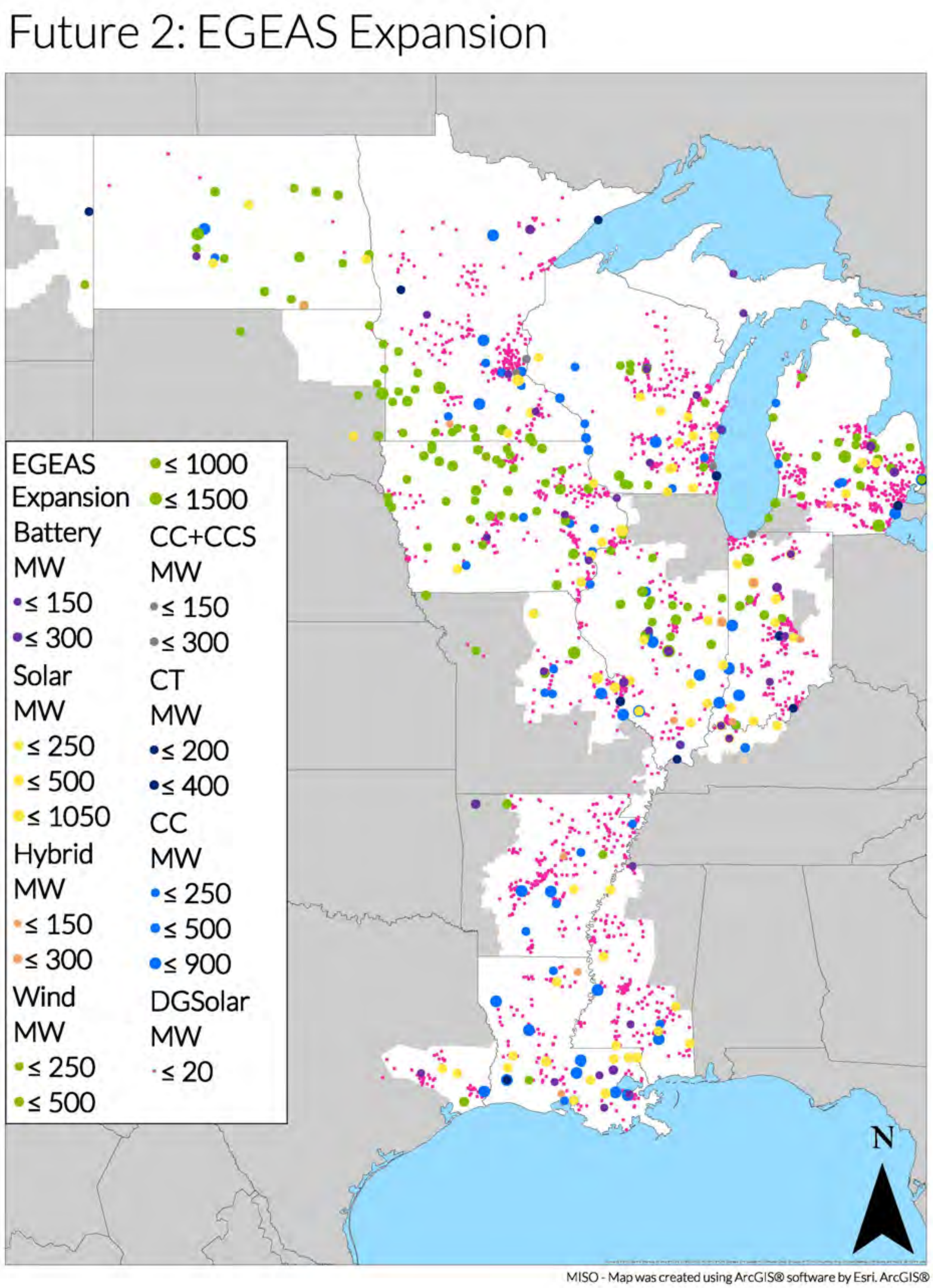


Figure 61: MISO Future 2 Complete EGEAS Expansion Siting

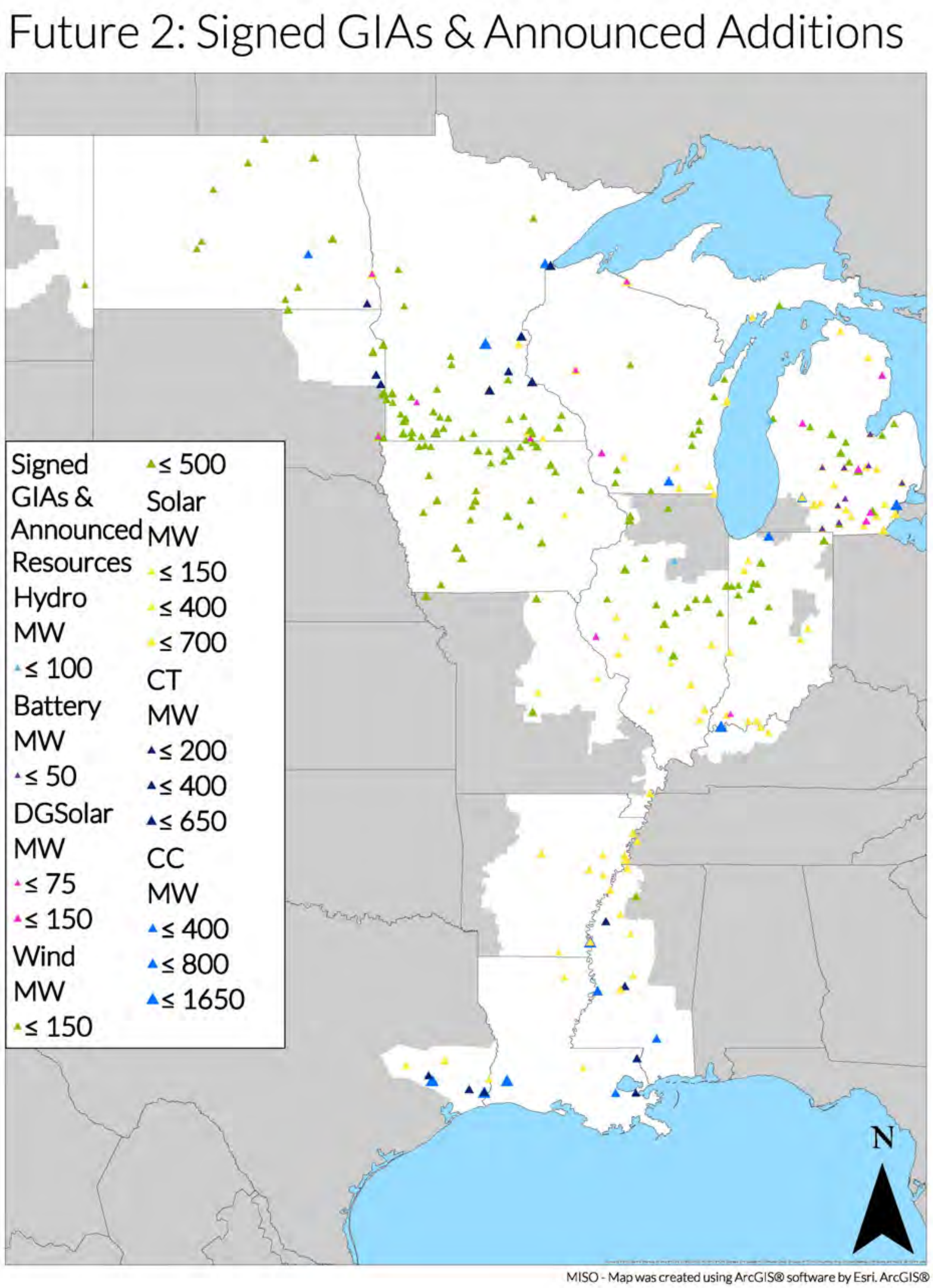


Figure 62: MISO Future 2 Non-EGEAS Expansion Siting

Future 2: Total Expansion

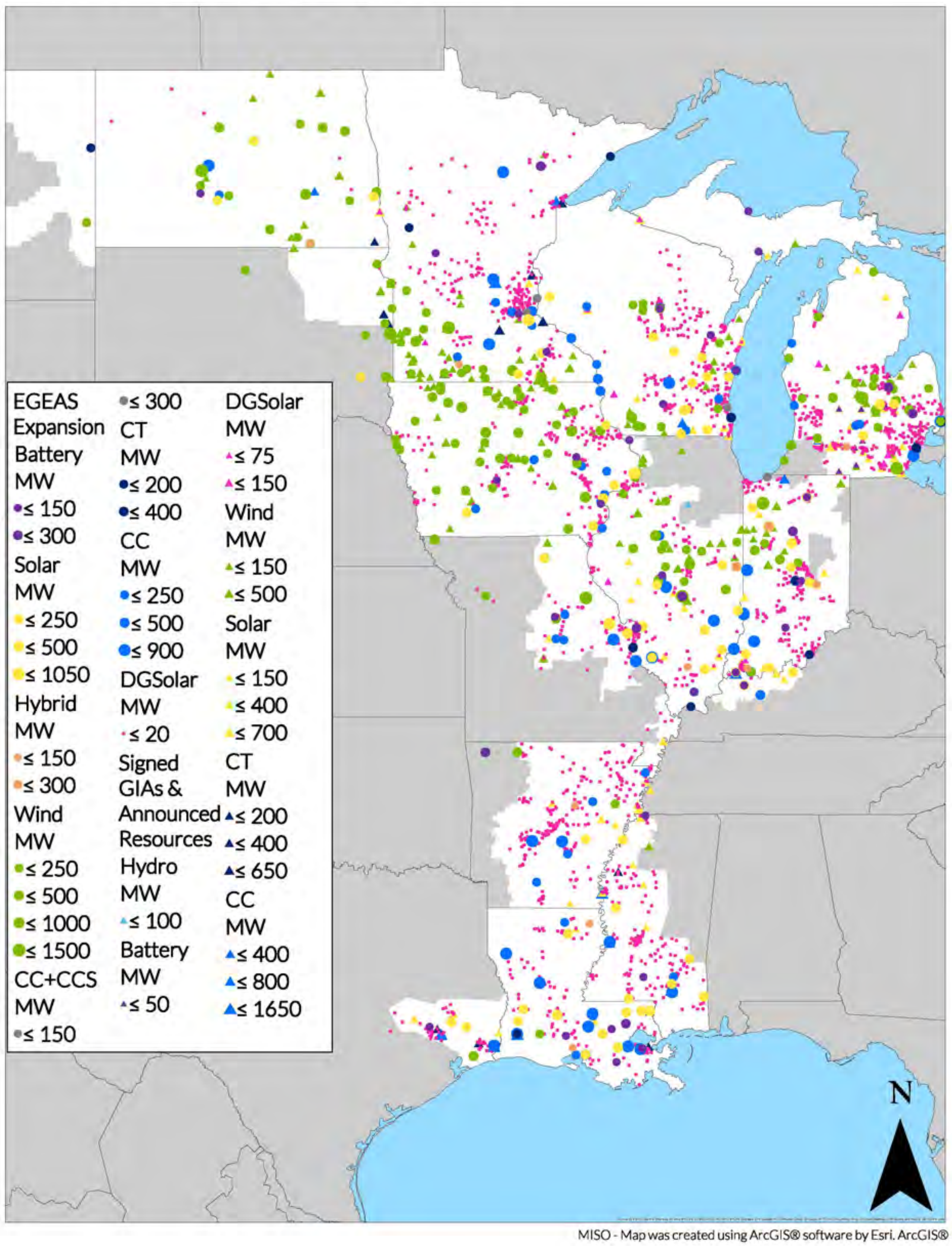


Figure 63: MISO Future 2 Non-EGEAS and EGEAS Expansion Siting

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

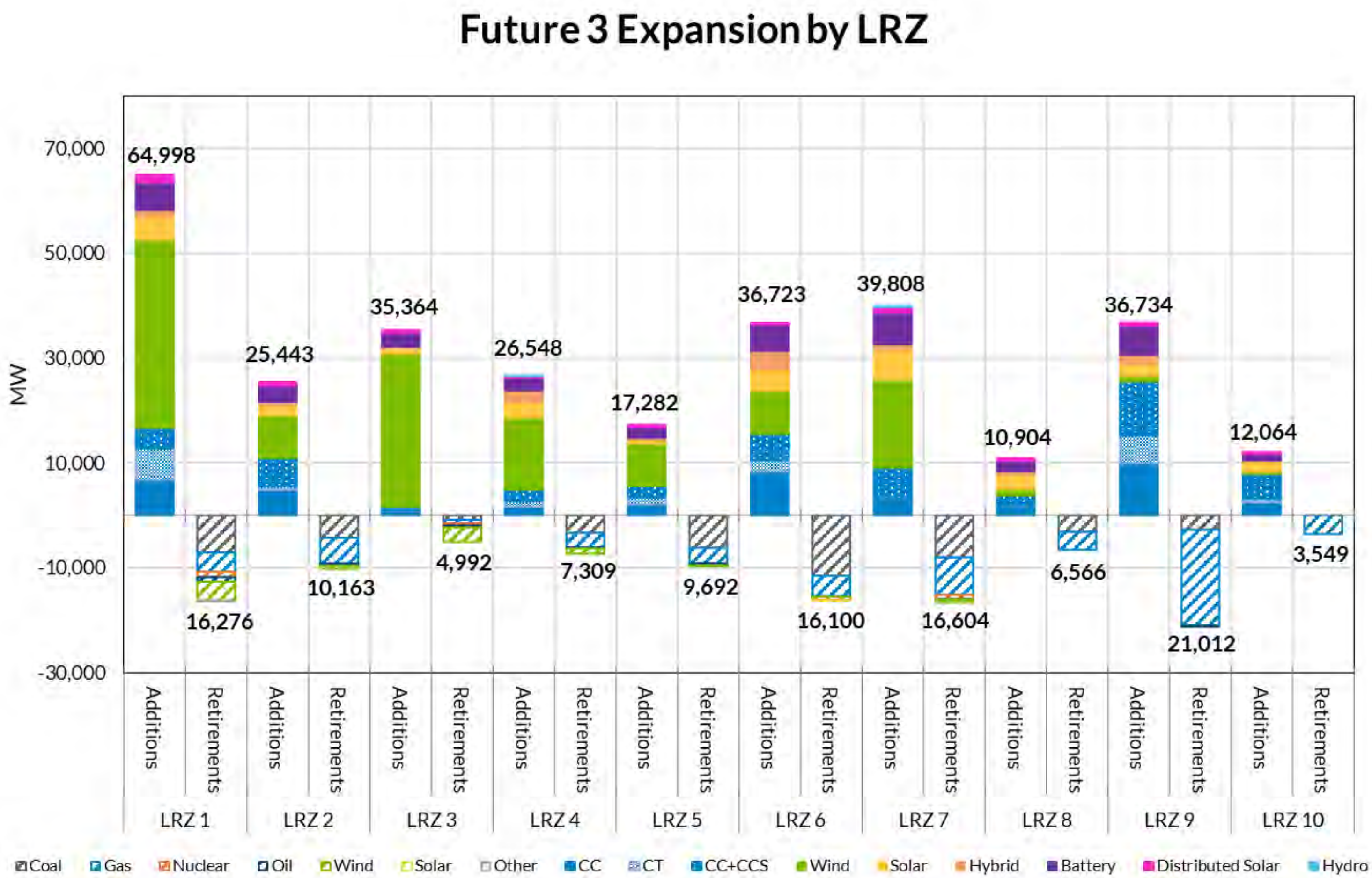


Figure 64: MISO Future 3 Resource Retirement and Addition Summary

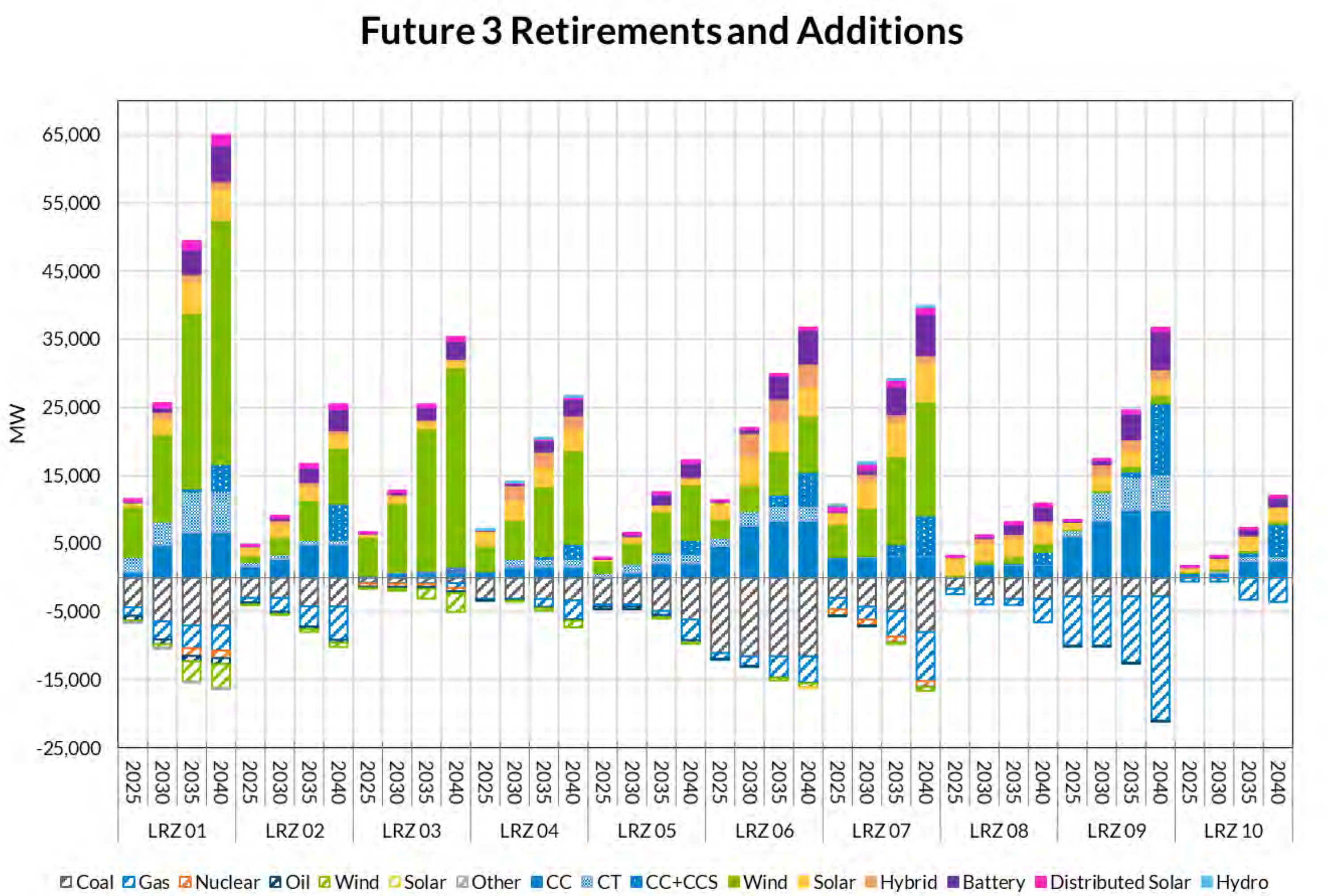


Figure 65: MISO Future 3 Resource Additions per Milestone Year (Cumulative)

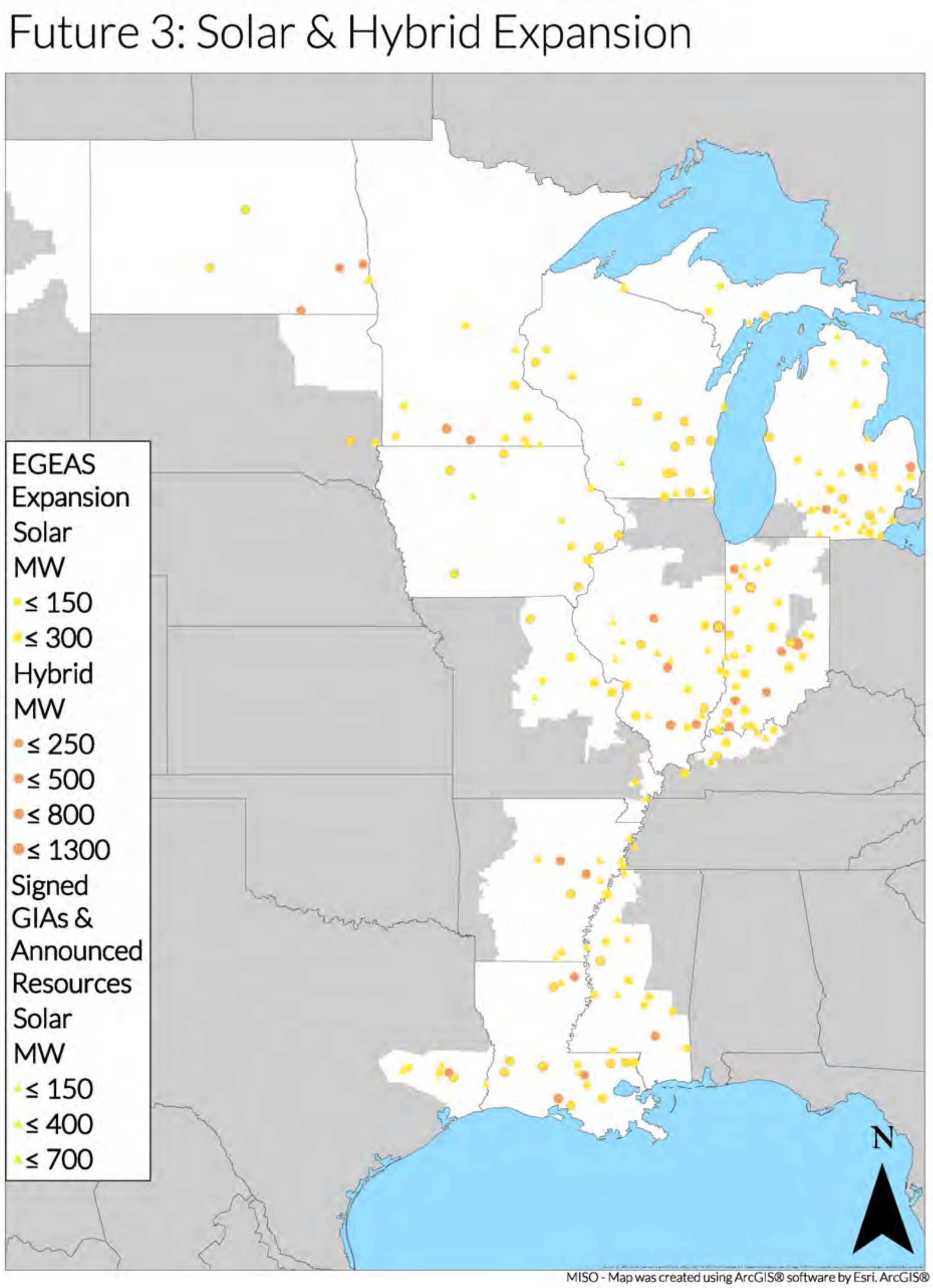


Figure 66: MISO Future 3 Solar and Hybrid Siting

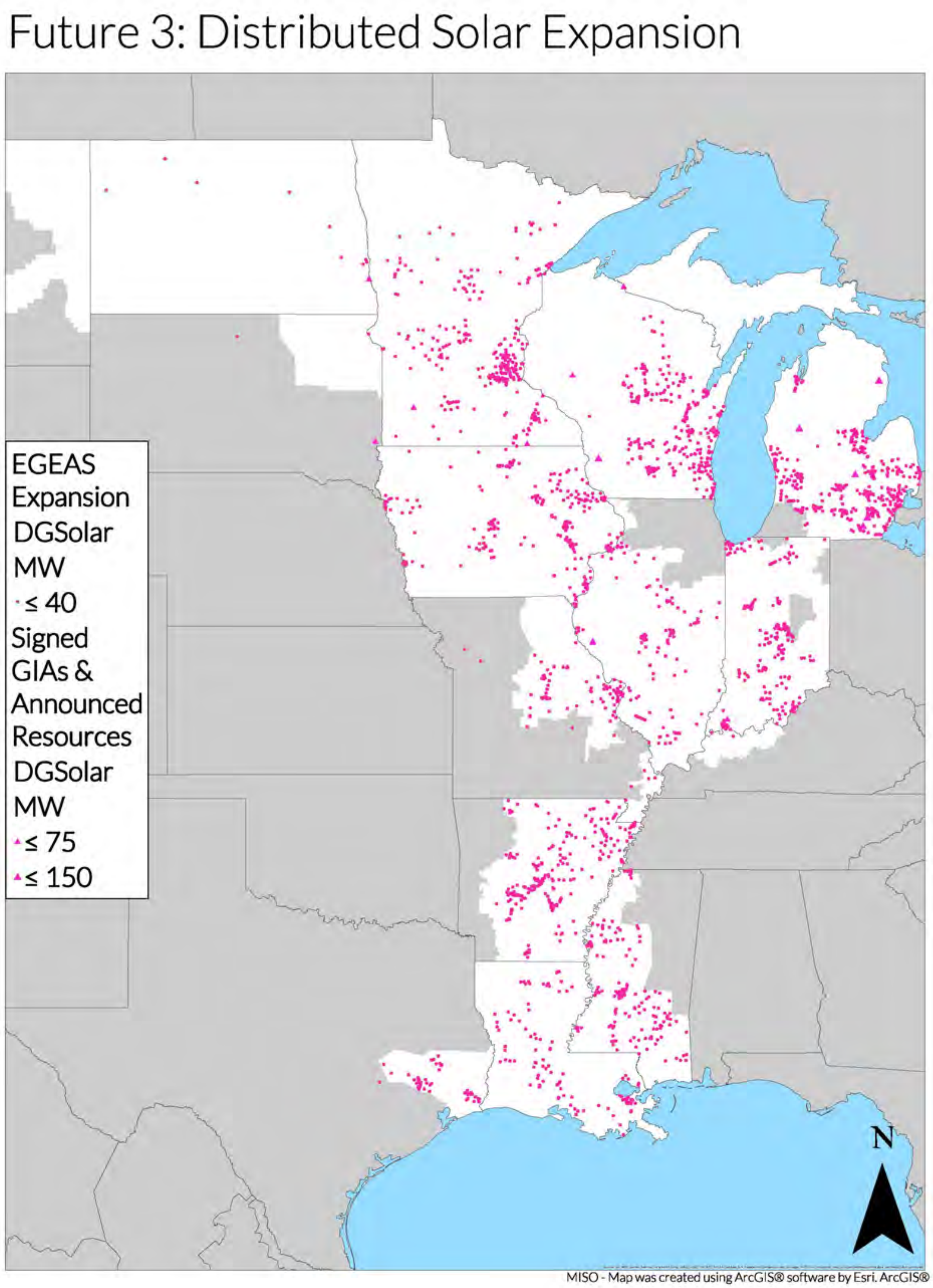


Figure 67: MISO Future 3 Distributed Solar Siting

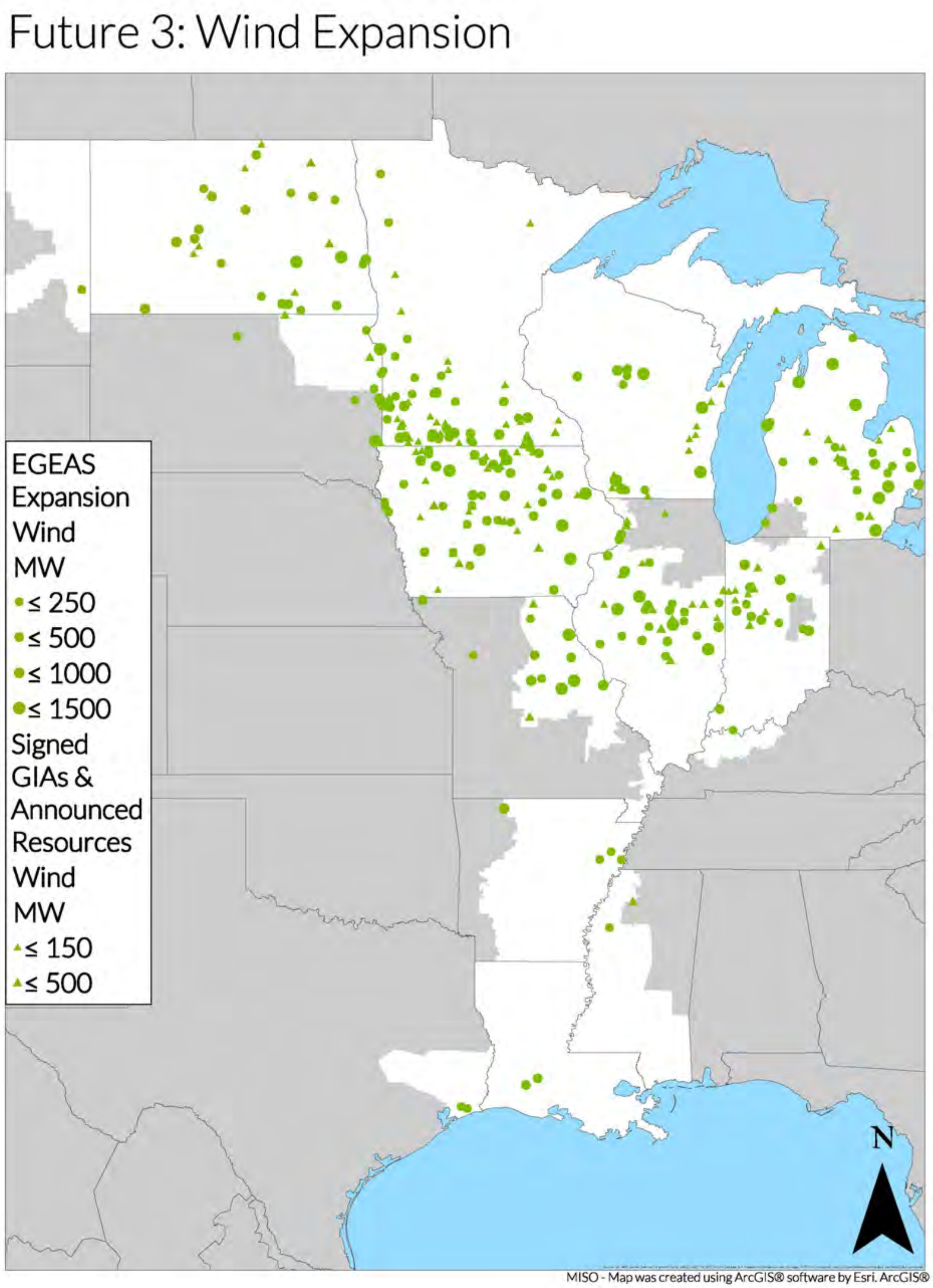


Figure 68: MISO Future 3 Wind Siting

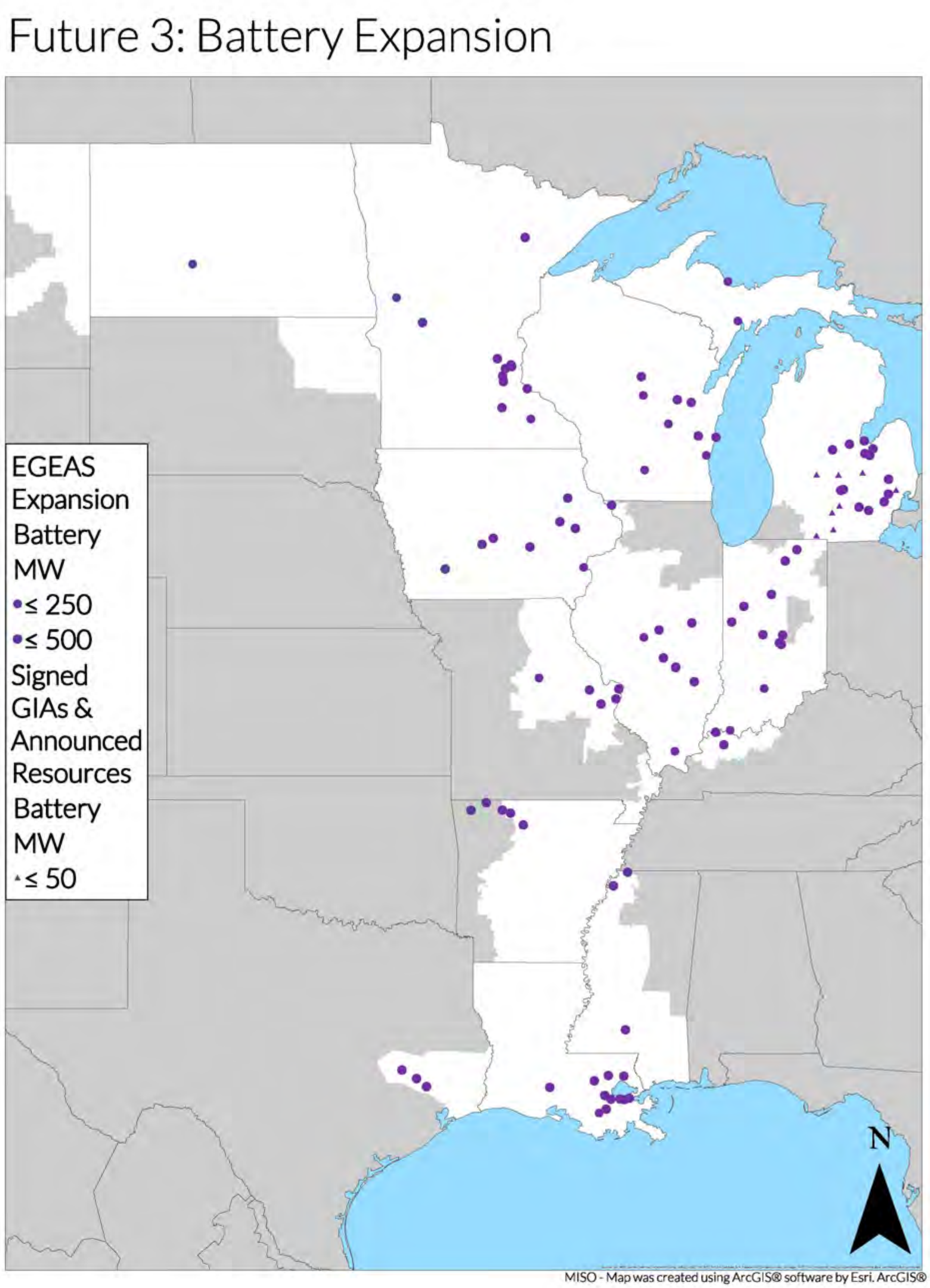


Figure 69: MISO Future 3 Battery Siting

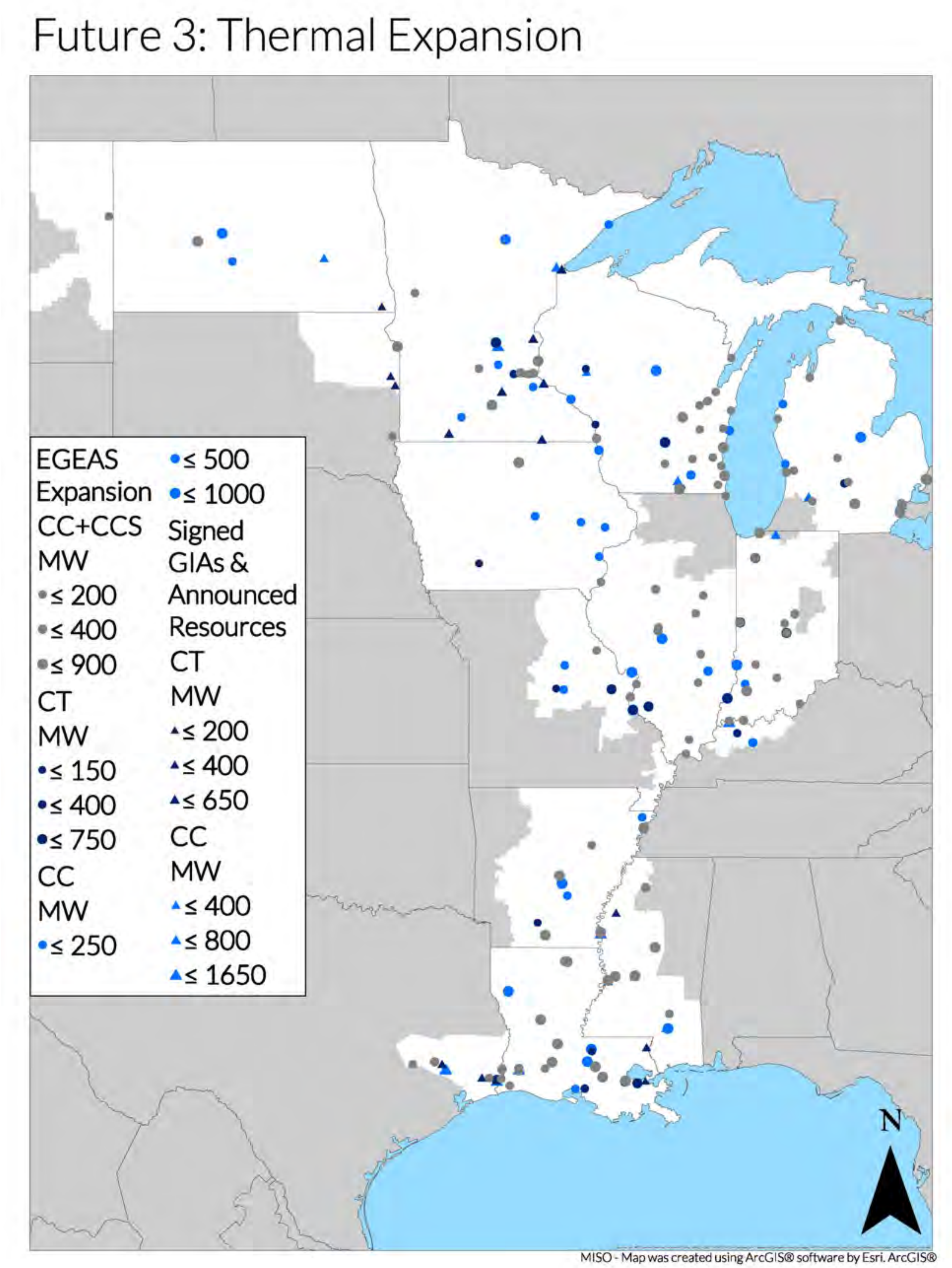


Figure 70: MISO Future 3 Thermal Siting

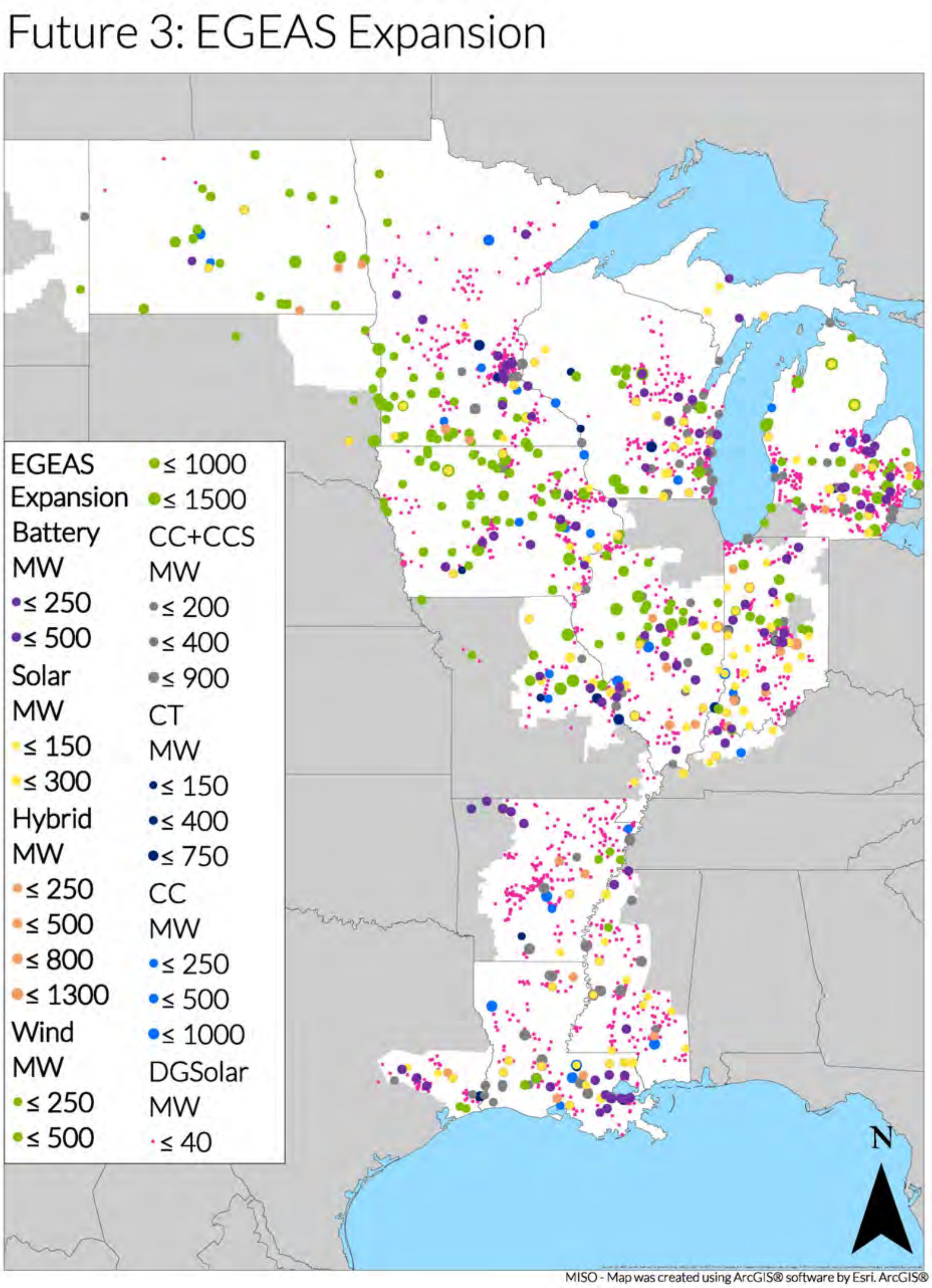


Figure 71: MISO Future 3 Complete EGEAS Expansion Siting

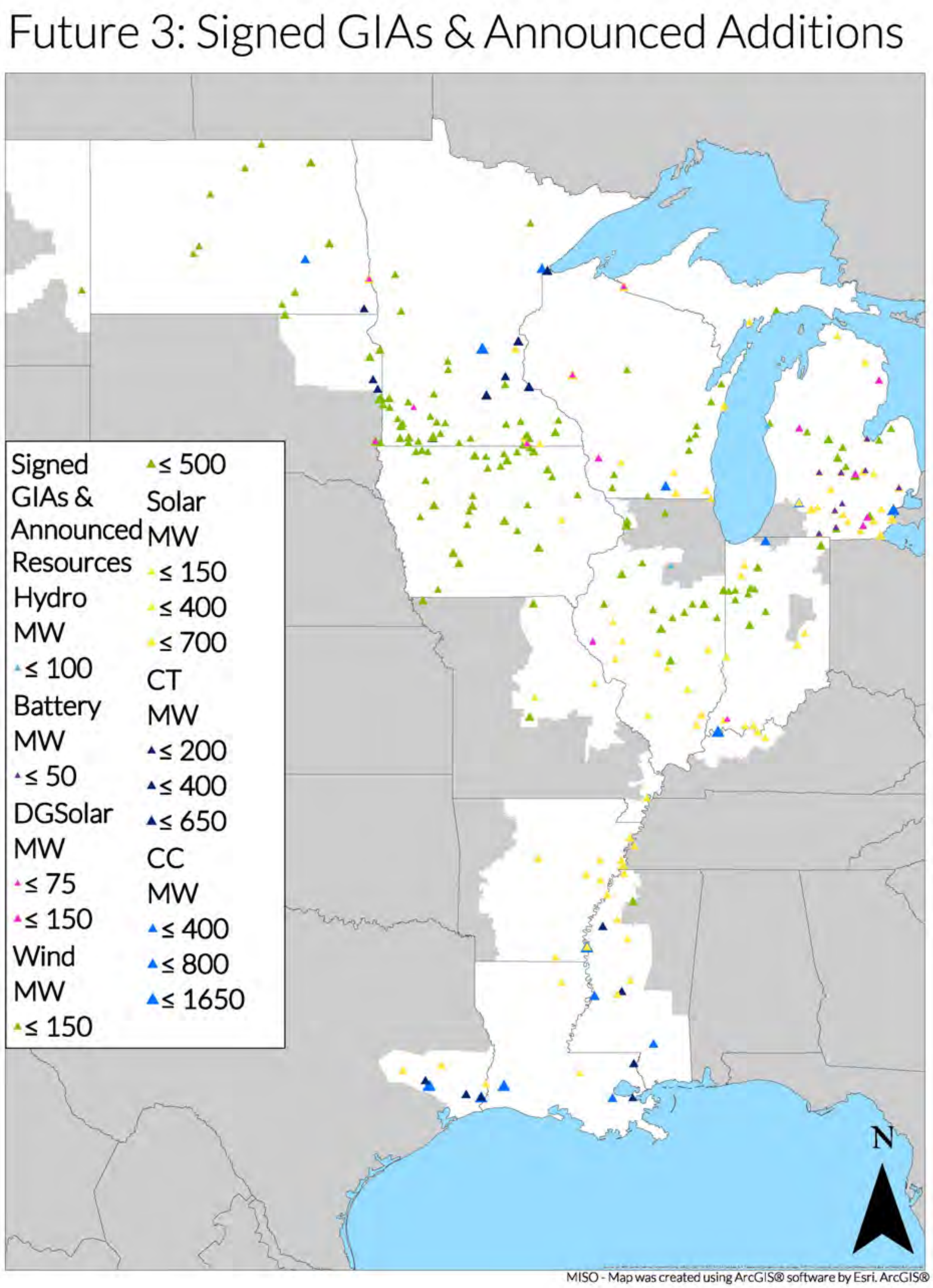


Figure 72: MISO Future 3 Non-EGEAS Expansion Siting

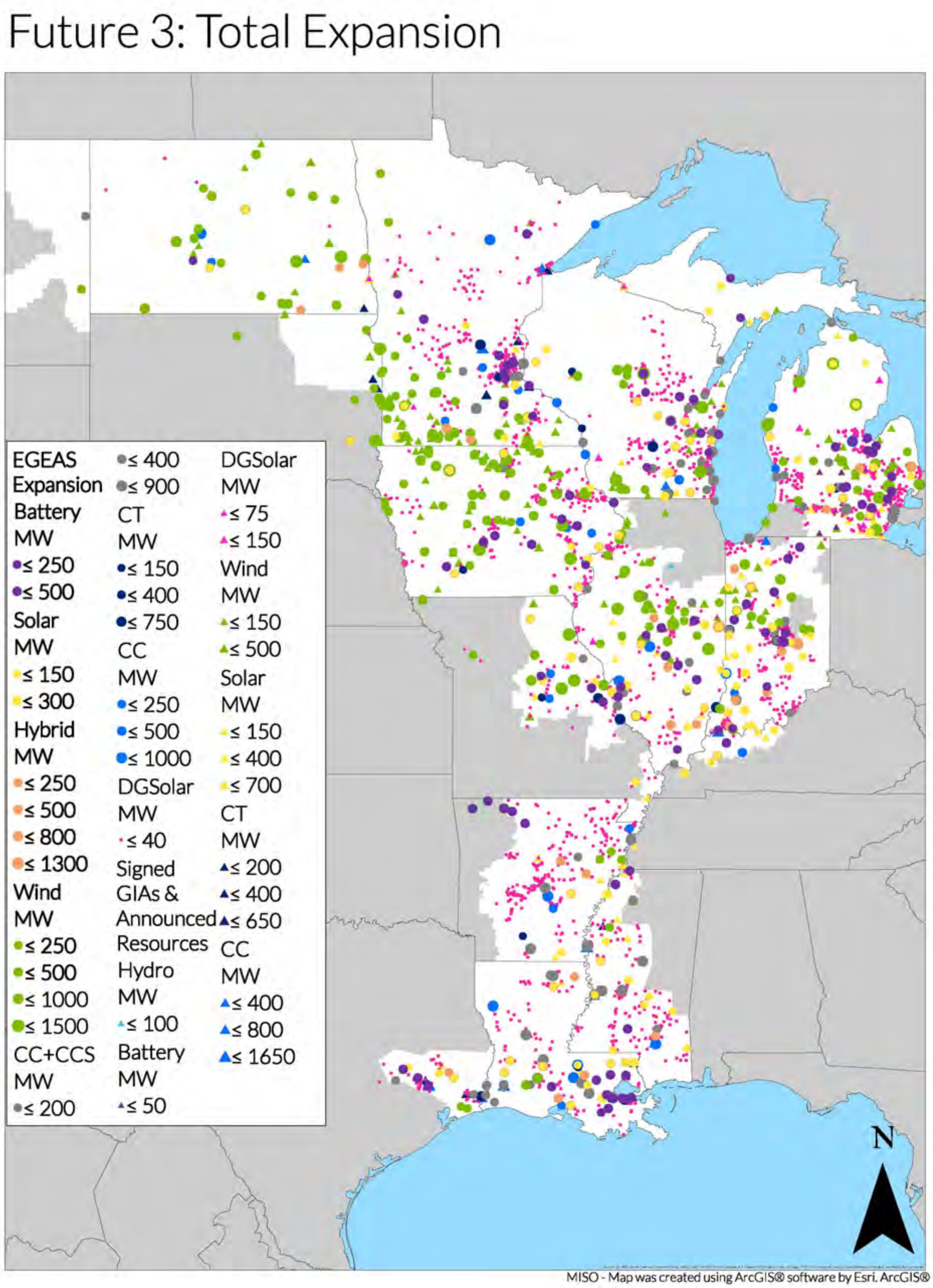


Figure 73: MISO Future 3 Non-EGEAS and EGEAS Expansion Siting

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]	Low-Base EV Growth	30% Total Energy Growth by 2040	50% Total Energy Growth by 2040
Total Growth	94,275 GWh	196,996 GWh	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	0.94 GW	0.94 GW	0.94 GW
EE	7.82 GW	8.05 GW	11.72 GW
DG	3.47 GW	3.47 GW	6.17 GW
Carbon Reduction *(2005 baseline)*	40%	60%	80%
MISO Footprint currently at 29%	*63% realized in results*	*65% realized in results*	*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.

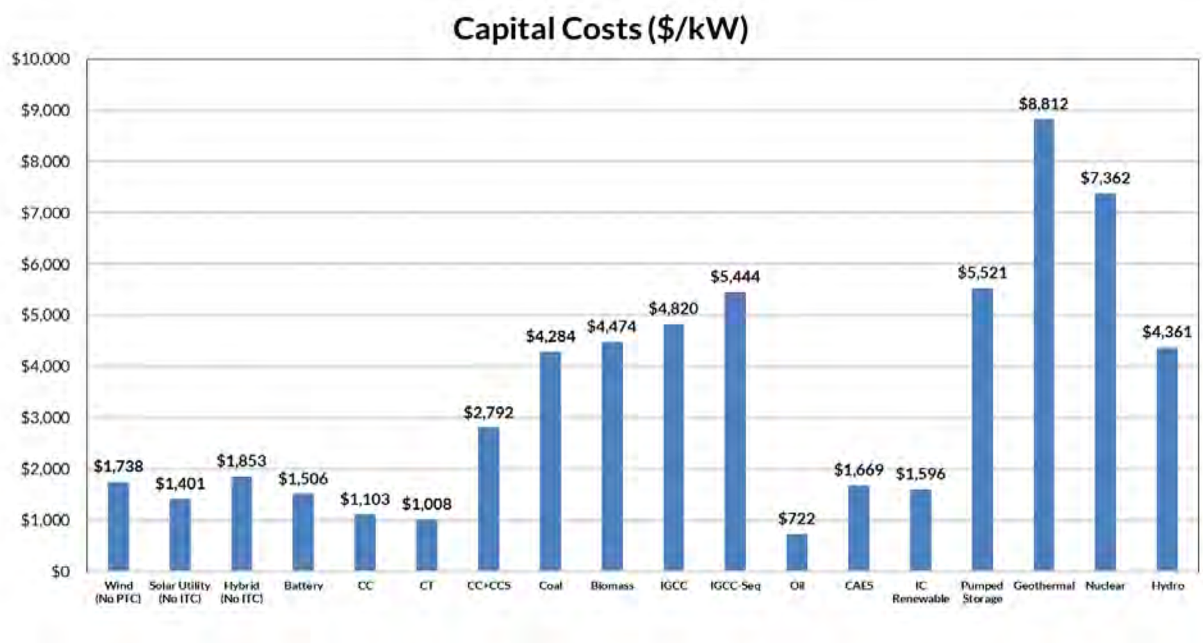


Figure 74: Annual Capital Cost Assumptions by Fuel Type

[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.

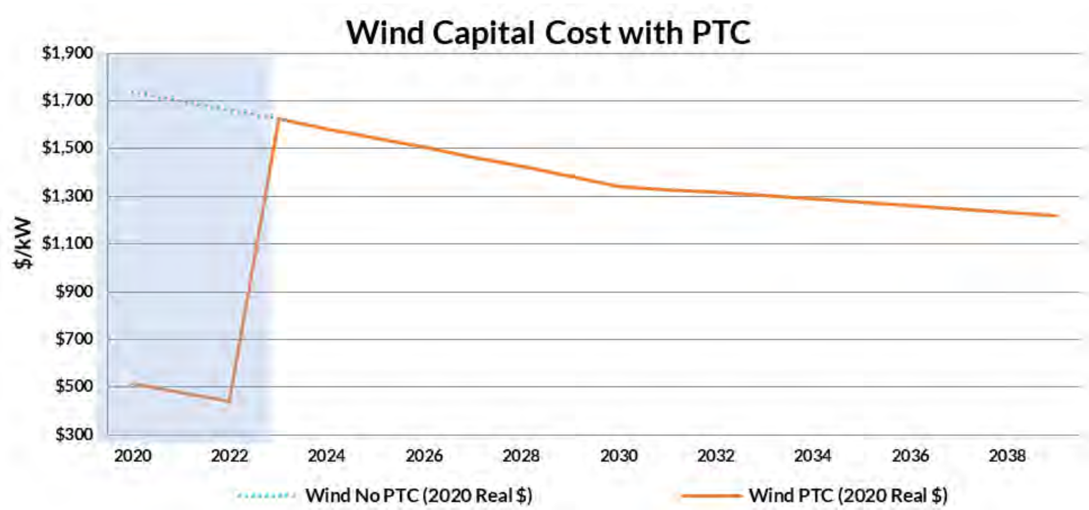


Figure 75: Wind with PTC

[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

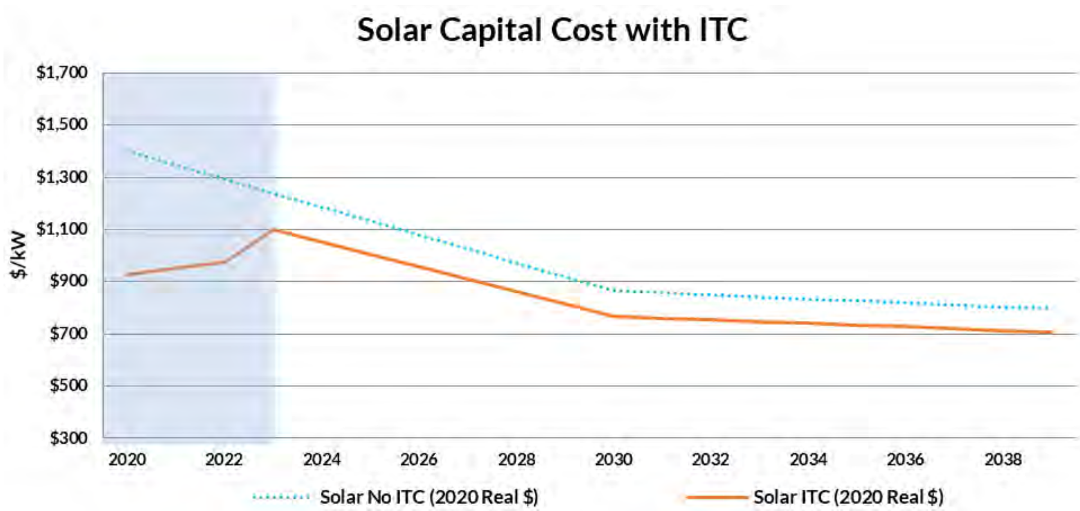


Figure 76: Solar PV with ITC

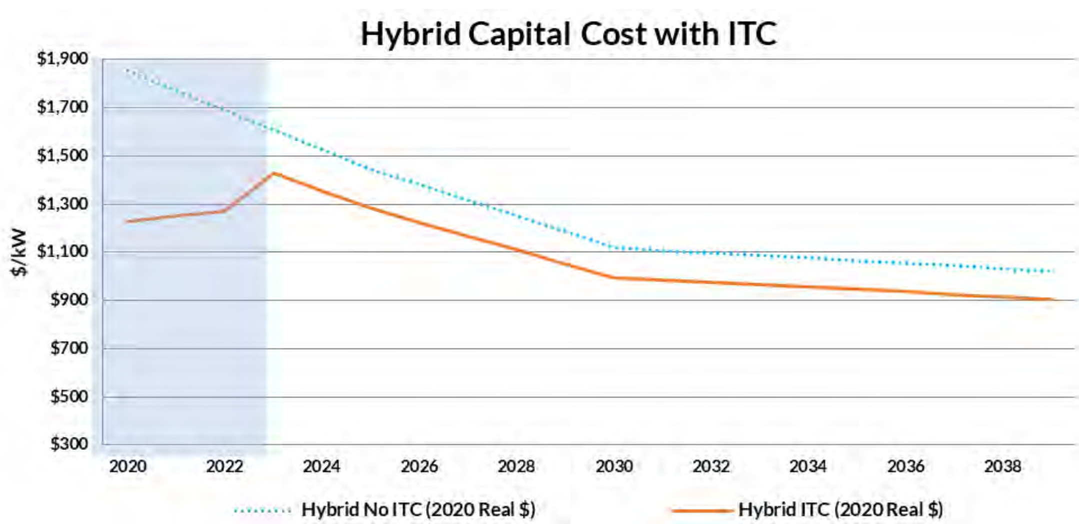


Figure 77: Hybrid with ITC

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.

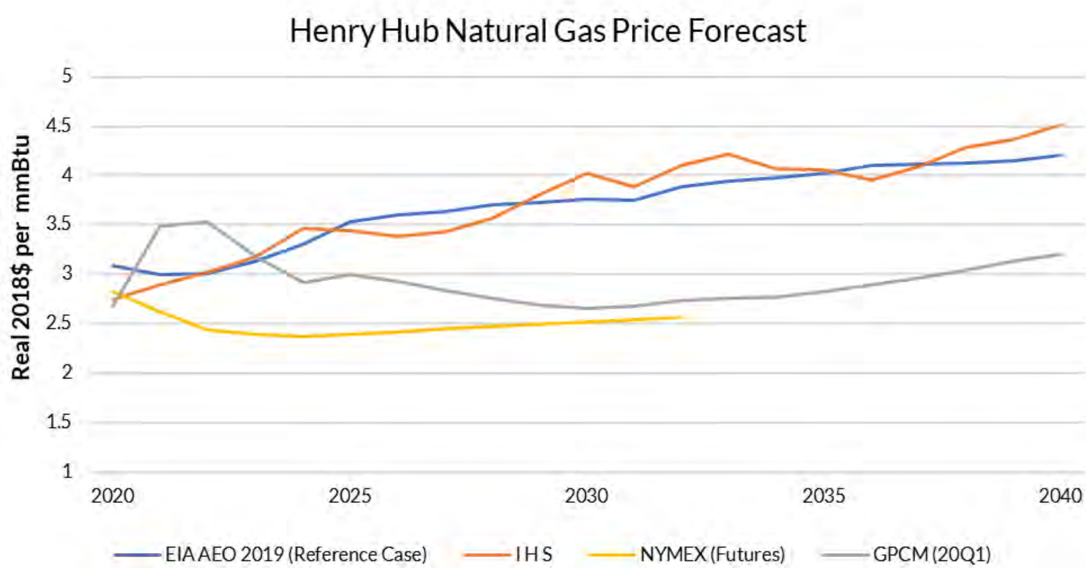


Figure 78: Henry Hub Natural Gas Price Forecast

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.

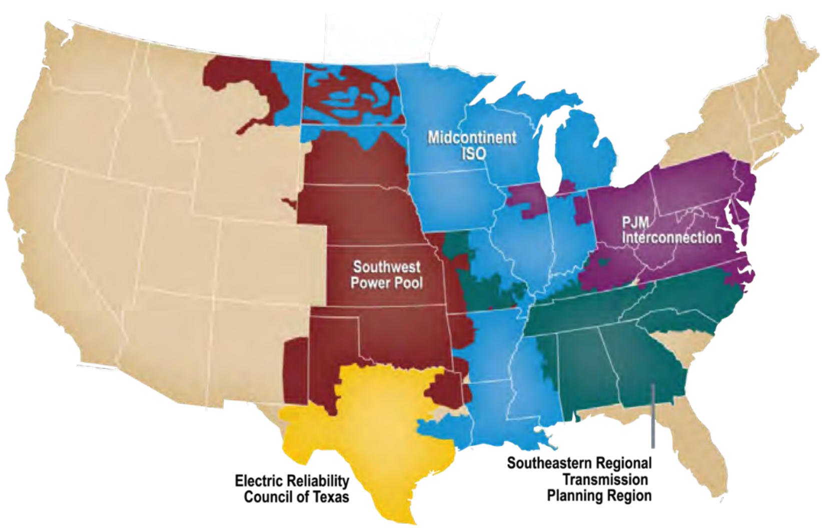


Figure 79: MISO Footprint & Neighboring Systems

[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

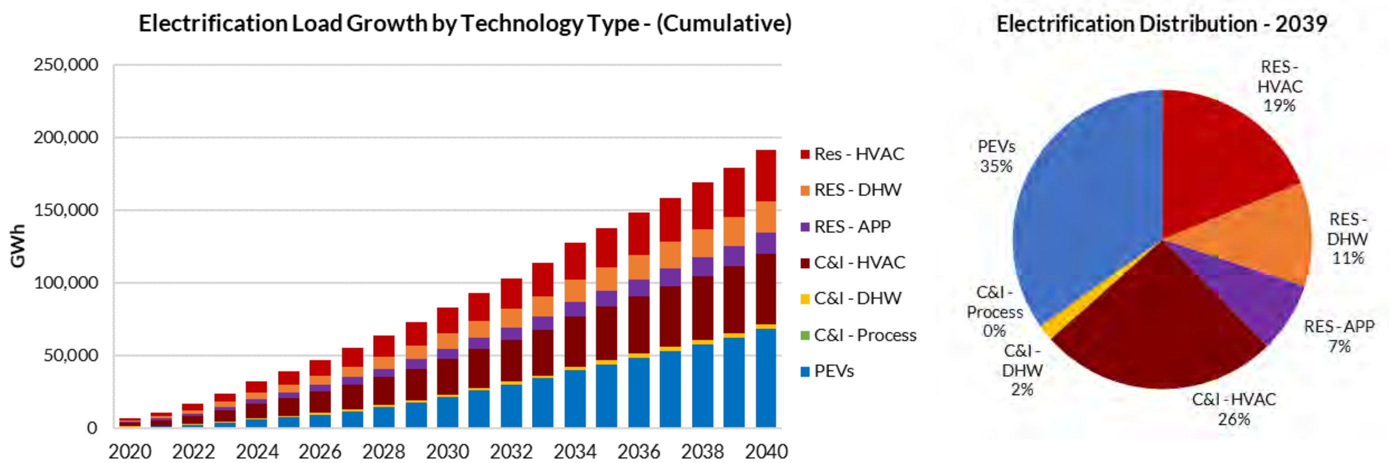


Figure 80: PJM Future 2 Electrification by End-Use

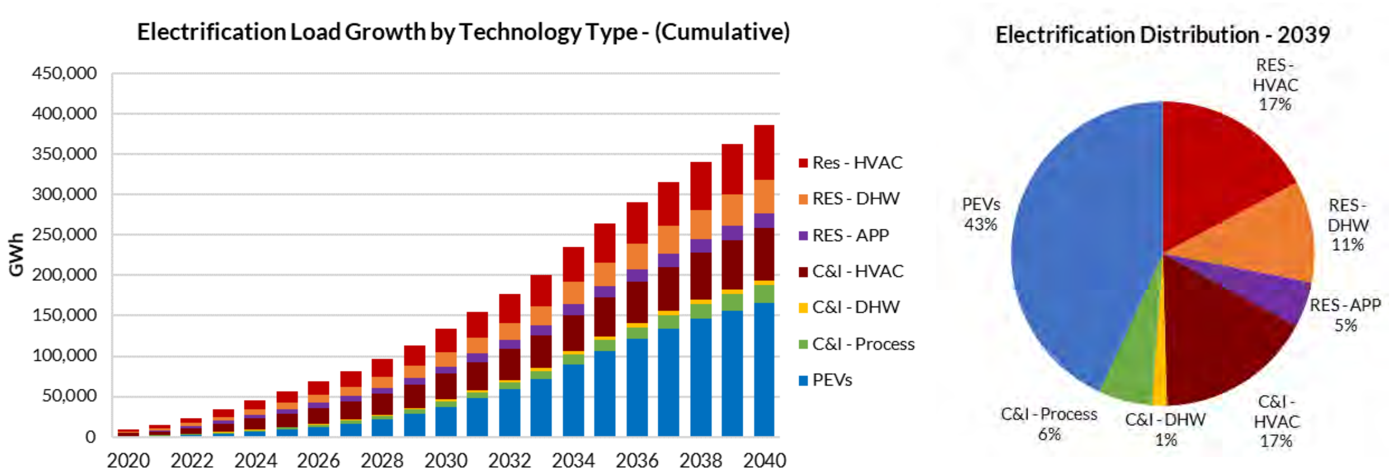


Figure 81: PJM Future 3 Electrification by End-Use

SPP Electrification

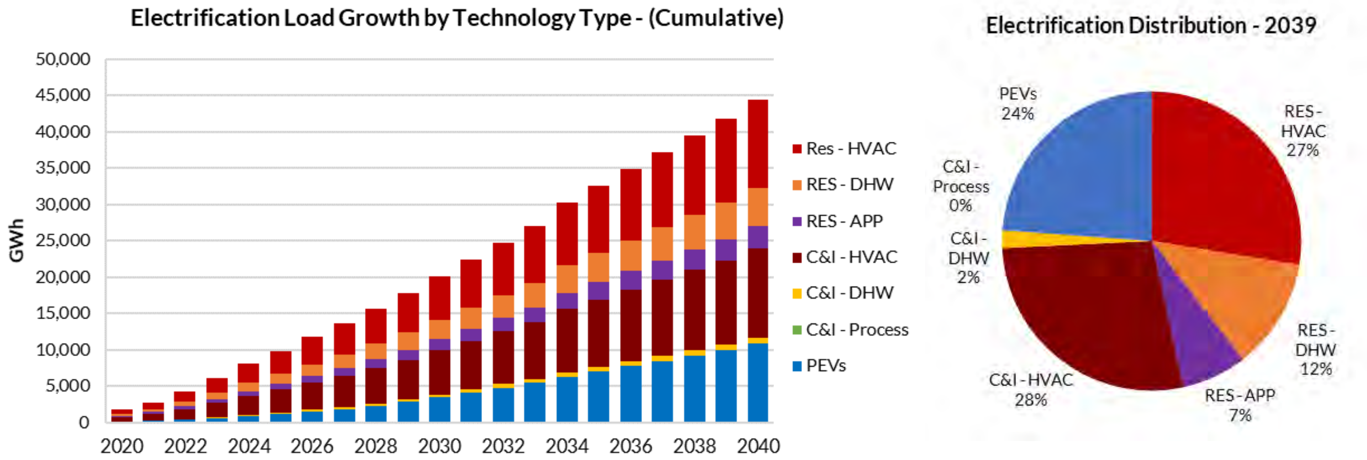


Figure 82: SPP Future 2 Electrification Broken Down by End-Use

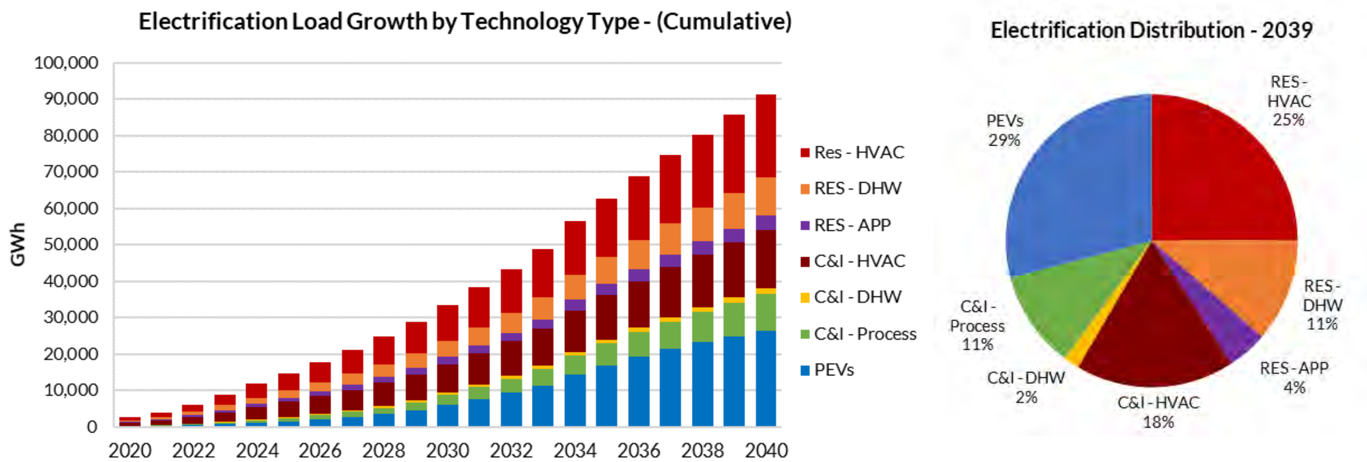


Figure 83: SPP Future 3 Electrification Broken Down by End-Use

TVA-Other Electrification

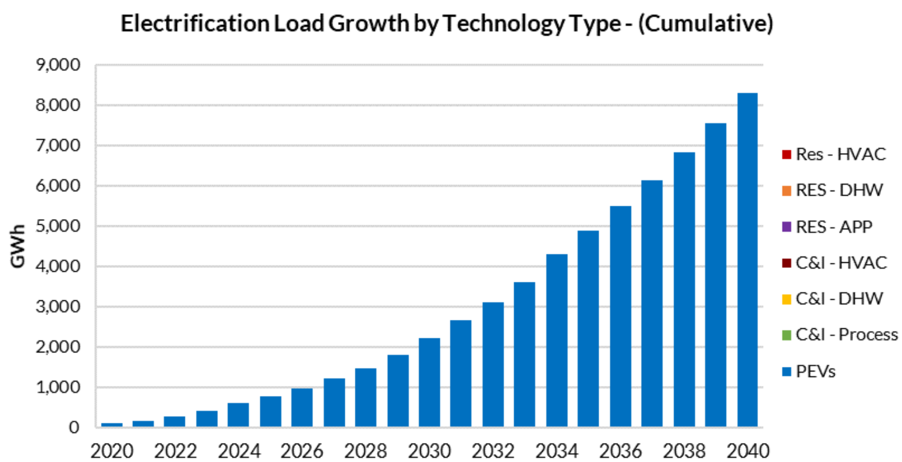
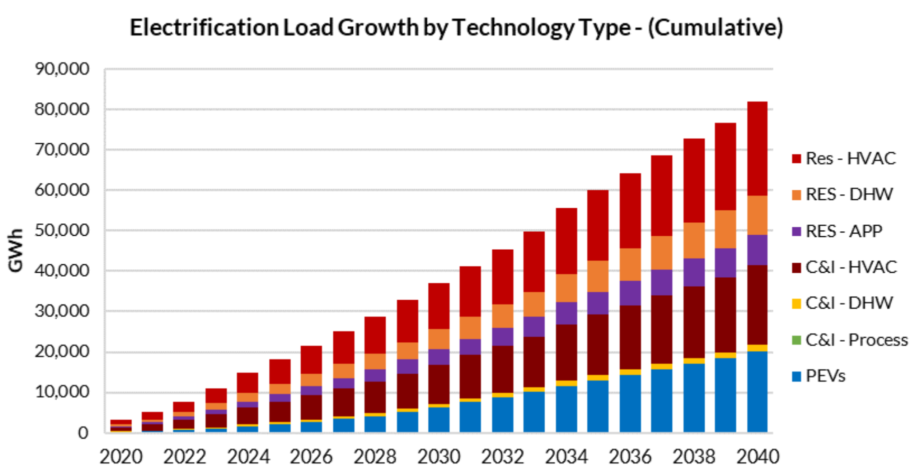


Figure 84: TVA-Other Future 1 Electrification Broken Down by End-Use



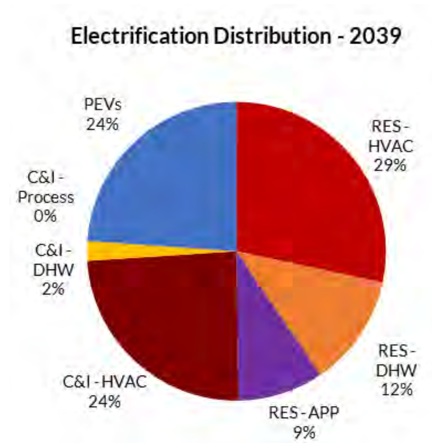


Figure 85: TVA-Other Future 2 Electrification Broken Down by End-Use

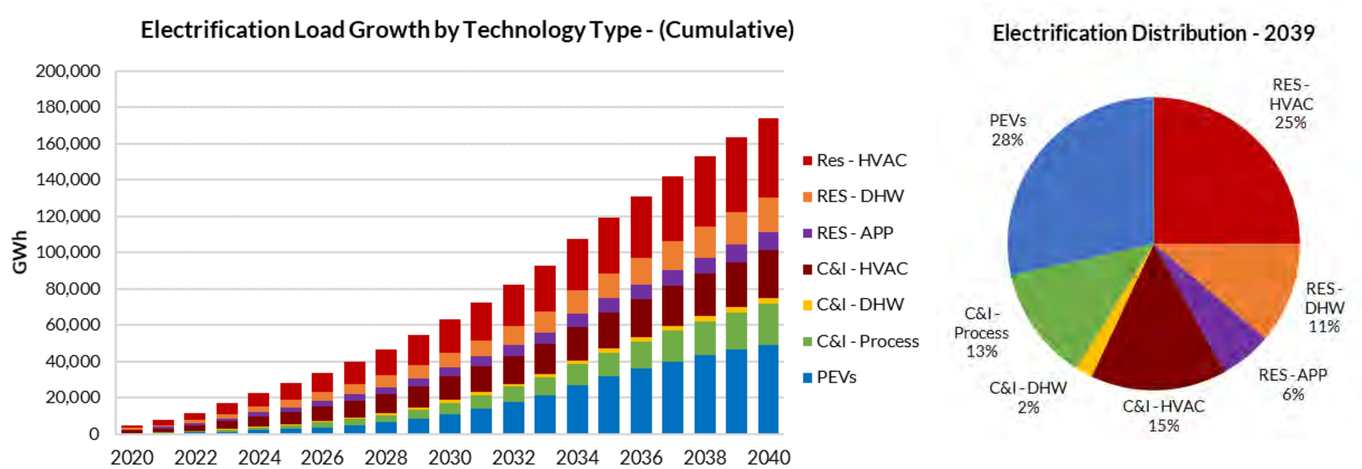
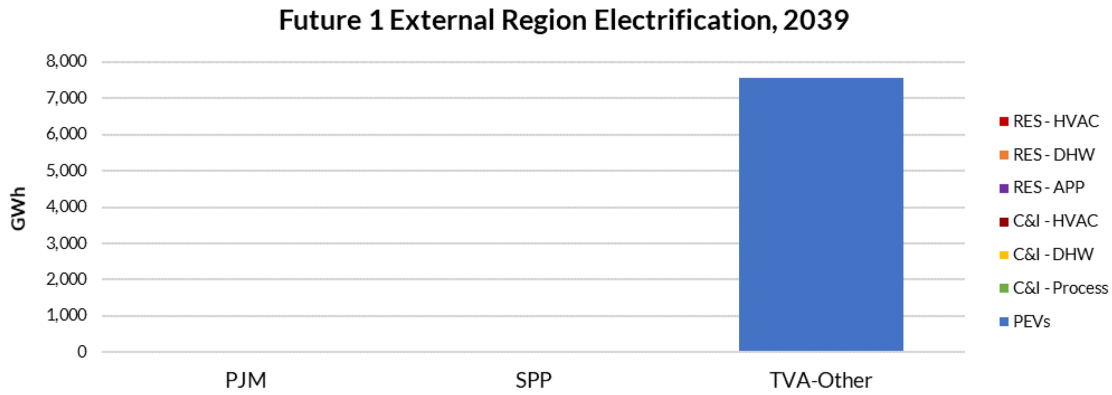
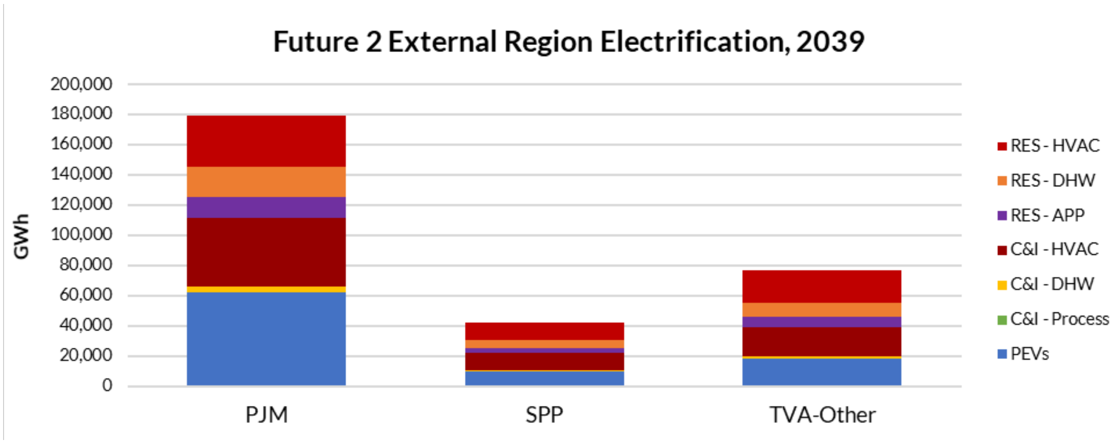


Figure 86: TVA-Other Future 3 Electrification Broken Down by End-Use

External Region Electrification Summary





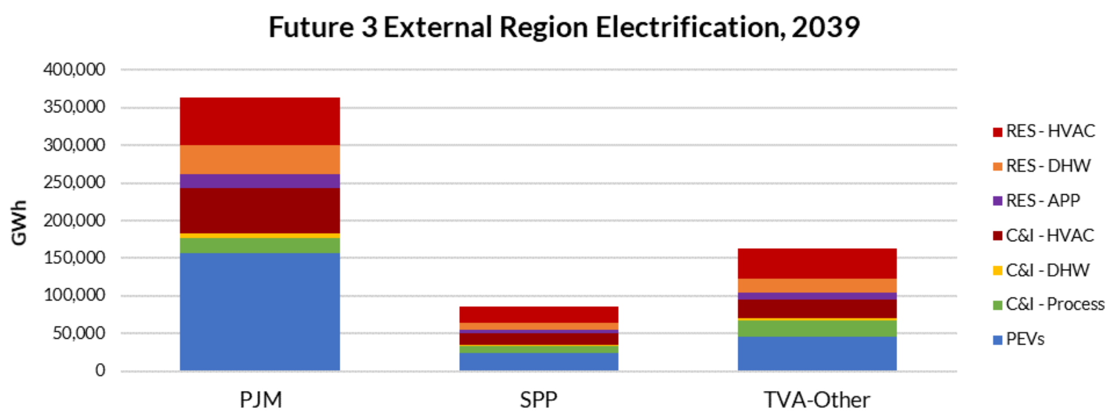


Figure 87: External Region Future Scenario Electrification[41]

[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

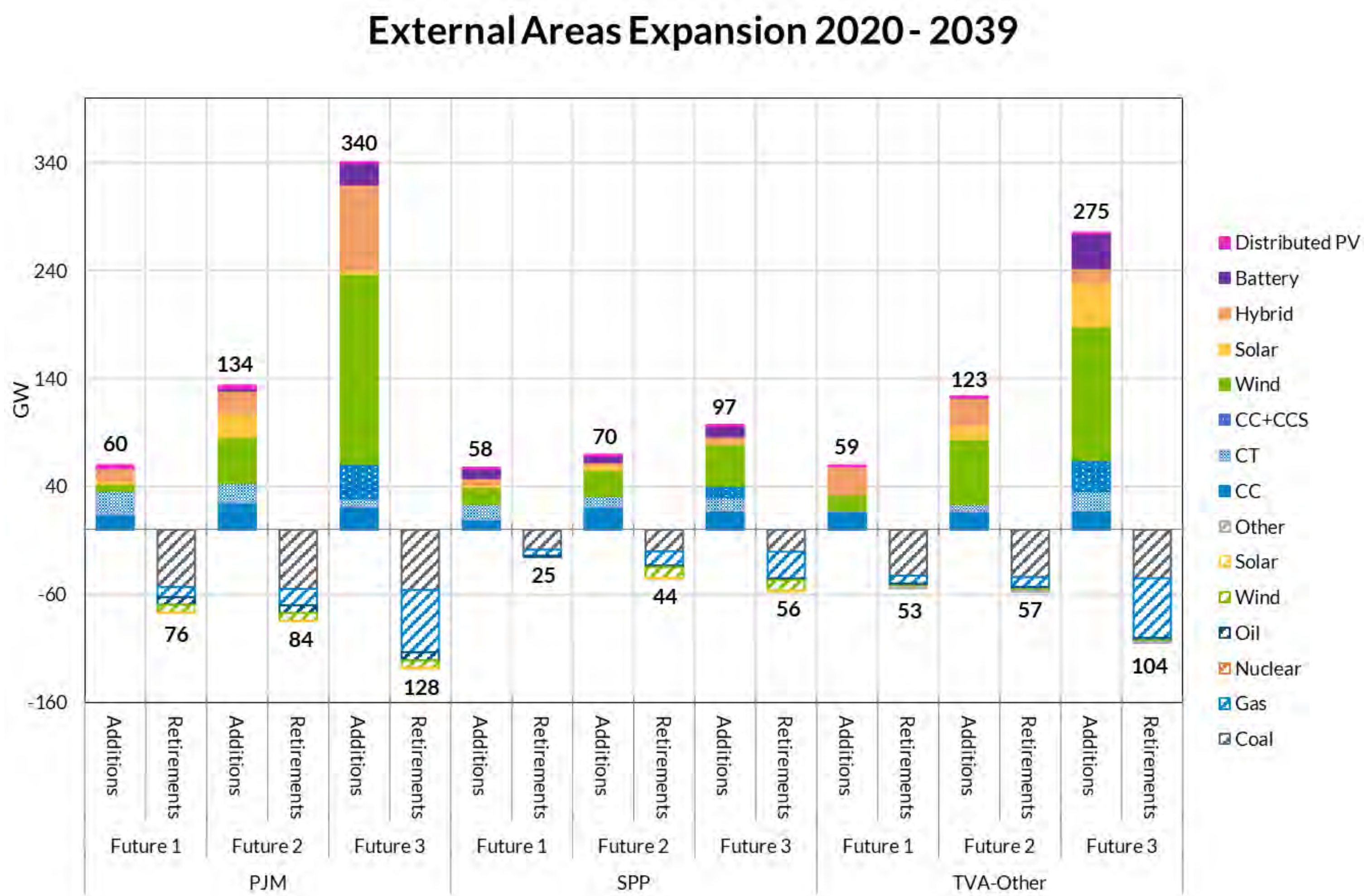


Figure 88: External Region Expansion Summary

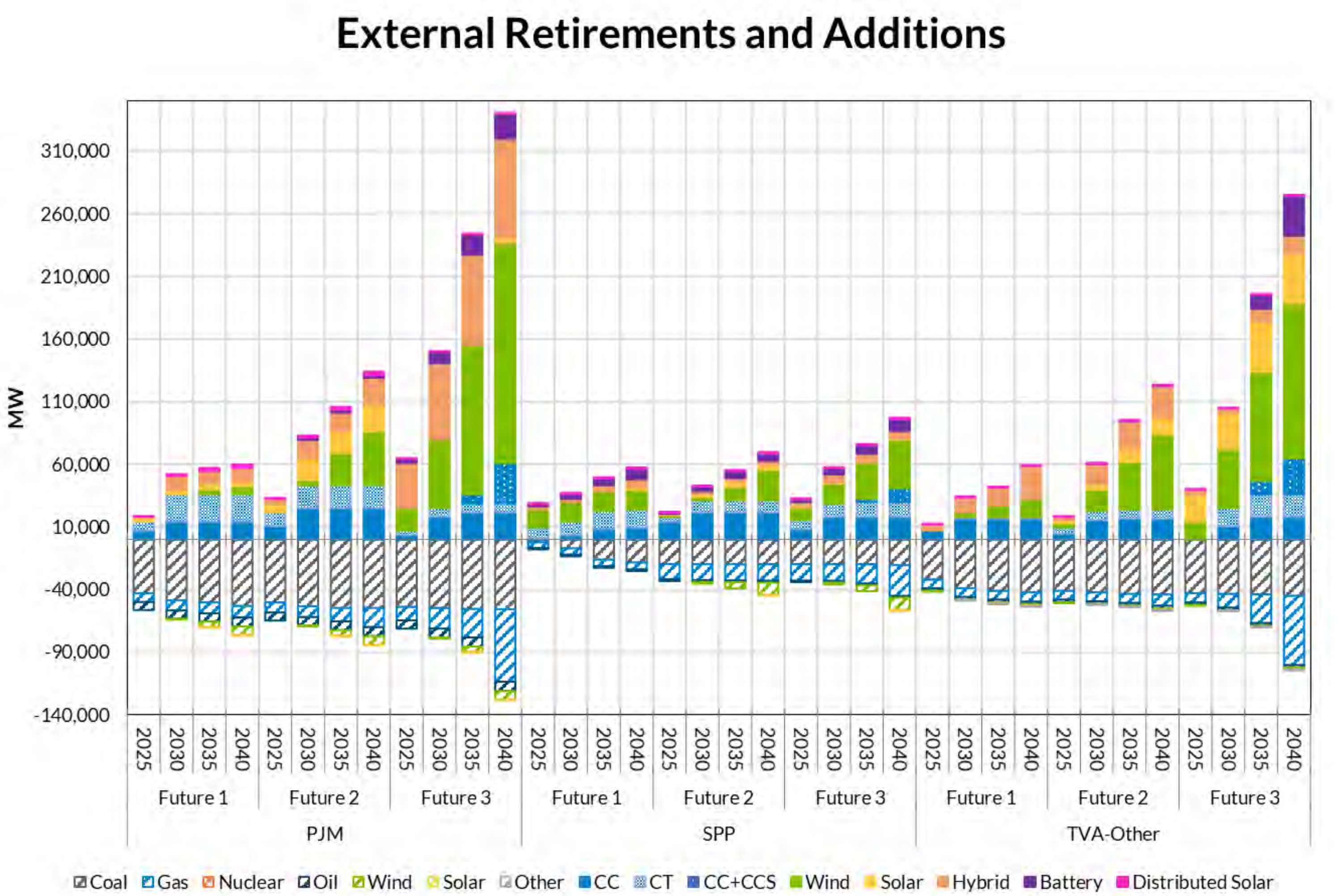


Figure 89: External Resource Additions and Retirements per Milestone Year (Cumulative)

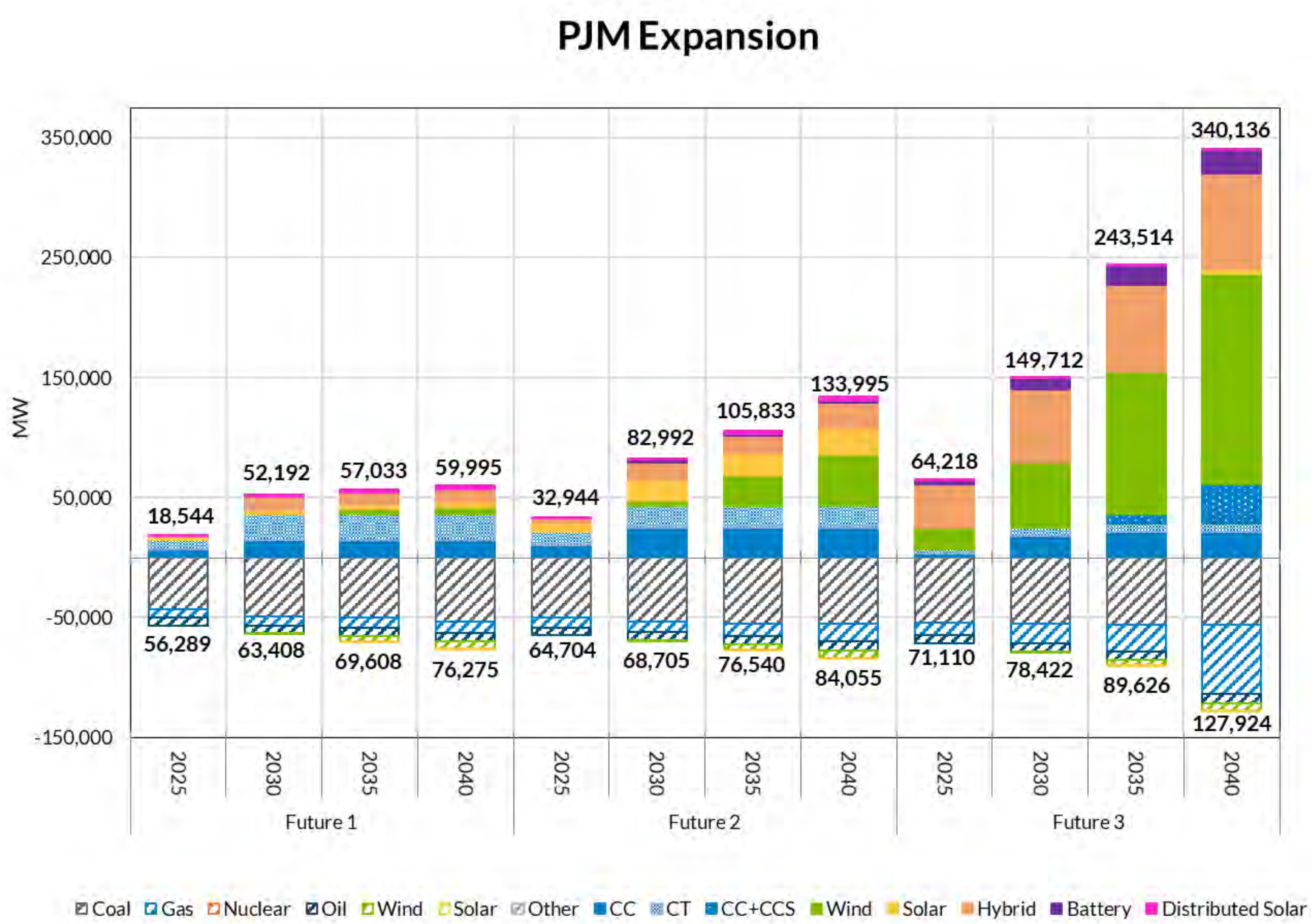


Figure 90: PJM Resource Additions and Retirements per Milestone Year (Cumulative)

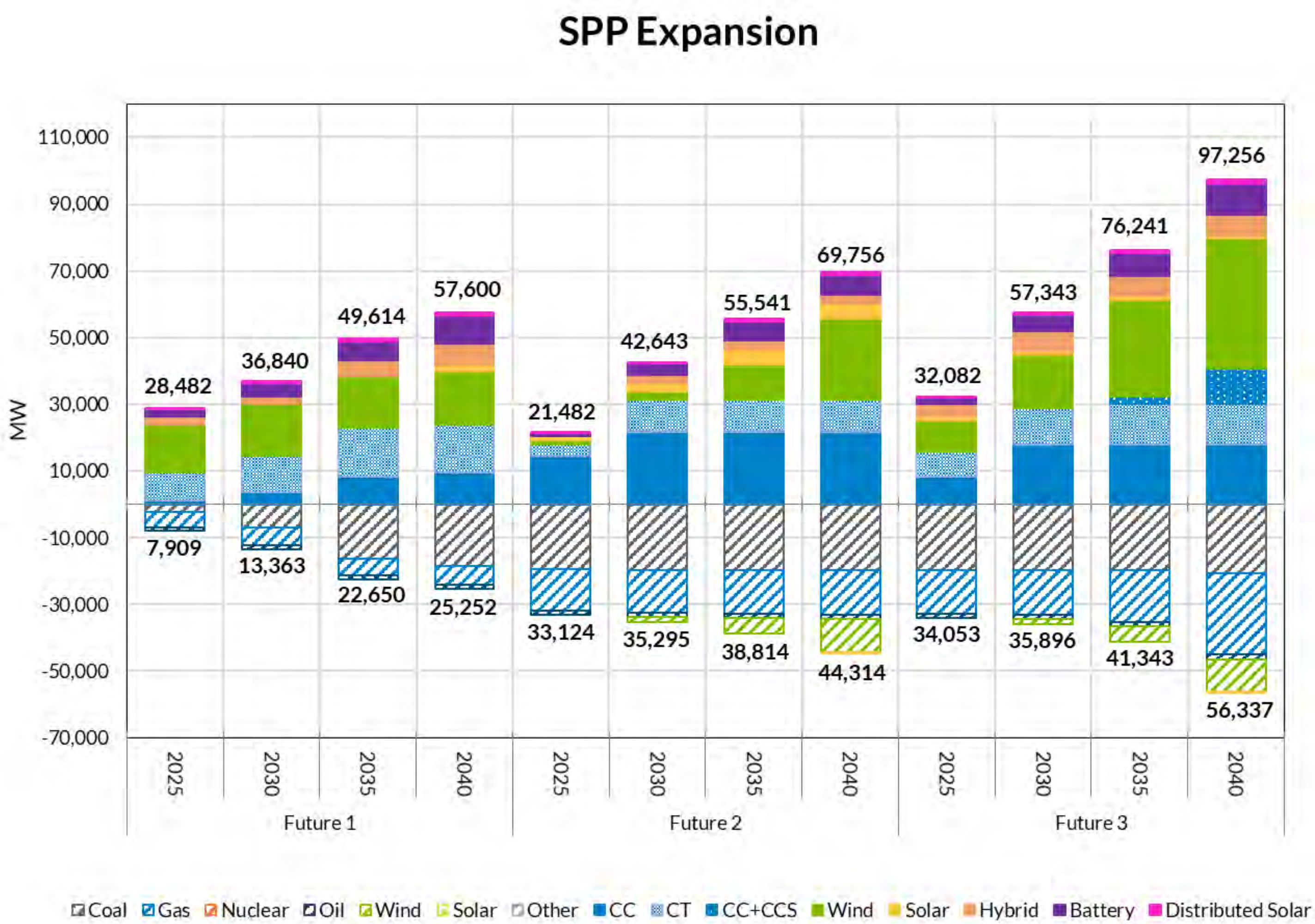


Figure 91: SPP Resource Additions and Retirements per Milestone Year (Cumulative)

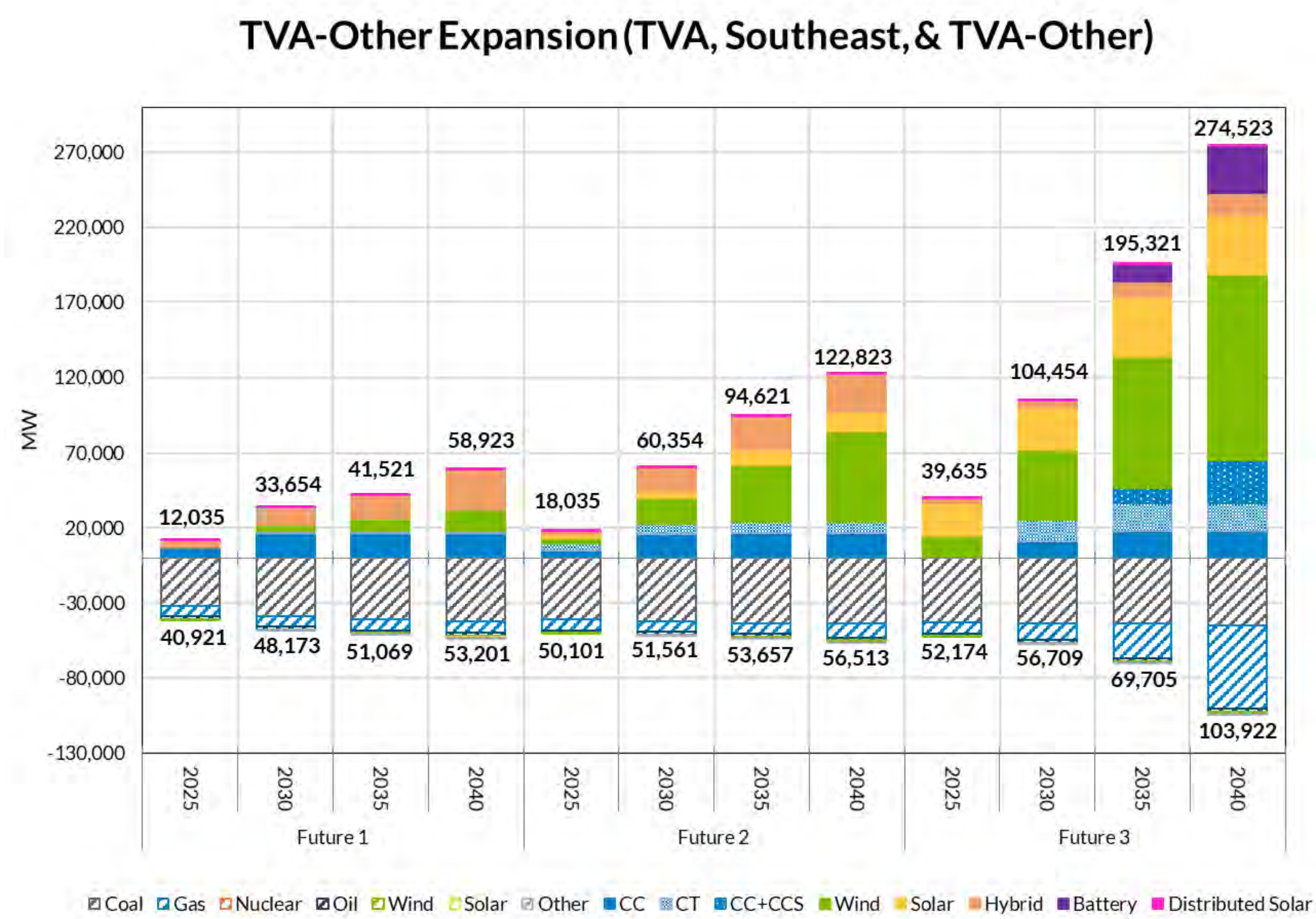


Figure 92: TVA-Other Resource Additions and Retirements per Milestone Year (Cumulative)

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

MISO

misoenergy.org

Appendix F

Conservation Program

Appendix F: Conservation Programs

Minnesota Rule 7849.0290 requires a Certificate of Need application to provide information related to an applicant's energy conservation and efficiency programs and a quantification of the impact of these programs on the forecast information required by Minn. R. 7849.0270. Within Xcel Energy, the Demand Side Management Policy and Strategy team is responsible for filing the Company's conservation and efficiency programs at Xcel Energy.

Xcel Energy requested an exemption from this content requirement. Xcel Energy explained that the development of renewable resources in southern Minnesota and South Dakota leading to congestion drives the need for this Project, not increased demand. The Commission approved Xcel Energy's requested exemption with the provision of the information the Company agreed to provide.[1] Accordingly, Xcel Energy provides this summary of Xcel Energy's conservation programs.

Nick Mark and Jessica Peterson, within the DSM Policy and Strategy team, are the individuals who submit these details to the Department of Commerce, Division of Energy Resources for approval. Xcel Energy's long-standing commitment in running cost-effective conservation and load-management programs places the Company among the nation's top utilities in terms of energy and demand saved and most innovative programs.[2] Indeed, between 1994 and 2022, the Company invested $2.2 billion (nominal) in energy conservation.[3] These investments resulted in 11,813 GWh of annual electric energy savings and 19.92 million Dth of natural gas savings. Xcel Energy's electric conservation improvement plan (CIP) portfolio has surpassed the statewide target every year since 2011, with electricity savings of 2.33 percent in 2022.[4]

Xcel Energy's 2024-2026 ECO Triennial Plan provides a description of specific energy conservation and efficiency programs the applicant has considered, including both those the Company adopted and those that the Company declined to adopt and why.[5] A list of specific energy conservation and efficiency programs implemented can be found in the Executive Summary of our CIP Status Reports[6] and the 2024-2026 ECO

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[1] Docket No. E002/CN-23-200, In the Matter of the Application of Xcel Energy for a Certificate of Need for the Proposed 345 kV Brookings County – Lyon County and Helena to Hampton Second-Circuit Project, *Letter Order* (July 12, 2023).
[2] Docket No. E,G002/CIP-23-92, 2024-2026 Minnesota Electric and Natural Gas Energy Conservation and Optimization Program (2024-2026 ECO Triennial Plan) at 3 (June. 29, 2023)..
[3] Triennial Conservation Plan at 2.
[4] *Id.*; Docket No. E,G002/20-473, 2022 Status Report & Associated Compliance Filings (2022 CIP Status Report) at 4 (Mar. 31, 2023).
[5] Triennial Conservation Plan at 69-237;*see also* Docket No. E,G002/CIP-20-473, 2021-2023 Xcel Energy CIP Triennial Plan Compliance Filling (Triennial Plan Compliance Filing) at 16-126 (Jan. 22, 2021).
[6] 2022 CIP Status Report; Docket No. E,G002/20-473, 2021 CIP Status Report (Apr. 4, 2022).

Appendix F: Conservation Programs

Triennial Plan. The Company provides these in detail on Xcel Energy's website.[7] In its 2024-2026 ECO Triennial Plan, Xcel Energy continues to strive to provide customers with a wide variety of options for saving energy. A review of ongoing new measures is conducted as new technologies are identified and reviewed compared to the cost effective analysis required by the Department of Commerce. Past programs reviewed and their approvals can be found in Docket No. E,G002/CIP-20-473 as required by the Department of Commerce through a "Modification Approval." Interested parties can follow the review of Xcel Energy's 2024-2026 ECO Triennial Plan at Docket No. E,G002/CIP-23-92. In the 2024-2026 ECO Triennial Plan, Xcel Energy continues to strive to provide customers with a wide variety of options for saving energy.

2024-2026 ECO Triennial Plan proposes ambitious goals of saving 1,869 GWh of energy and 3,950,998Dth of natural gas over the three-year period[8] and at a cost of $530 million.

Although the Department has not reviewed the 2024-2026 ECO Triennial Plan, in reviewing the 2021-2023 Triennial Plan, the Department concluded:

- "[B]usiness, residential, and low-income customers all appear to have opportunity to participate in the Company's CIP. . . . [T]he Company proposes a variety of program delivery approaches and measures that should provide participation opportunities across market segments."[9]
- "Xcel's 2021-2023 overall energy savings goals are generally aligned with the overall results from the 'Minnesota Energy Efficiency Potential Study.' "[10]
- "Staff recognize the positive efforts the Company has put forth to update its programs."[11]

The 2024-2026 ECO Triennial Plan notes that, for the 11th year in a row, the Company had exceeded the State of Minnesota's electric energy targets.[12] Specifically, in 2022, the electric portfolio met and surpassed the state's recently raised energy savings target of 1.75%,[13] achieving nearly 648 GWh of energy savings, representing 2.33% of sales.[14]

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7 https://www.xcelenergy.com/company/rates_and_regulations/filings/minnesota_demand-side_management
8 2024-2026 ECO Triennial Plan at 1.
9 Docket Nos. E,G002/CIP-20-473, G7034,E7032/CIP-20-483, G7036,E7035/CIP-20-480, E7030/CIP-20-485, G7033, E7031/CIP-20-481, Decision at 32 (Nov. 25, 2020).
10 CIP Decision at 35.
11 CIP Decision at 57.
12 2024-2026 ECO Triennial Plan at 2.
13 2022 CIP Status Report at 4. The ECO Act of 2021 updated the electric savings goal to 1.75 percent and the natural gas savings goal to 1.0 percent of annual retail energy sales.
14 CIP 2022 Status Report at 5.

Appendix F: Conservation Programs

Xcel Energy spent a total of $124 million to achieve the Company's savings results, including $104 million on electric programs and $20 million on natural gas programs.[15]

Likewise, Xcel Energy's initial IRP filing included energy efficiency (EE) and demand response (DR) investments, and the Supplemental Plan[16] and the Alternate Plan[17] continued to reflect those investments. Xcel Energy proposed to seek to achieve EE savings levels ranging from 2 to 2.5% annually, achieving average savings of over 780 GWh of energy in each of 2020-2034 and more than 800 MW of additional demand savings by 2034[18] when compared to the 1.5 percent level approved in the Company's prior IRP.[19] In addition, Xcel Energy is pursuing an incremental 400 MW of DR by 2023.[20]

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15 CIP 2022 Status Report at 5; *see also* 2024-2026 ECO Triennial Plan at 3.
16 *See* Docket No. E002/RP-19-368, 2020-2034 Upper Midwest Integrated Resource Plan (June 30, 2020).
17 *See* Docket No. E002/RP-19-368, 2020-2034 Upper Midwest Integrated Resource (Alternative Plan) (June 25, 2021). Docket No. E002/RP-19-368, Order Approving Plan With Modifications And Establishing Requirements For Future Filings at 10 (April 15, 2022).
18 Alternate Plan at 10.
19 Docket No. E002/RP-15-21, 2016-2030, Upper Midwest Resource Plan (Jan. 2, 2015); Docket No. E002/RP-15-21, Order Approving Plan With Modifications and Establishing Requirements For Future Resource Plan Filings (Jan. 11, 2017).
20 Alternate Plan at 10.