Appendix B

Appendix B contains the Congestion Study.

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Biennial Transmission Project Report – Congestion Study

Executive Summary

This congestion study is included in compliance with the Minnesota Public Utilities Commission's June 29, 2022 order which instructed the Minnesota Transmission Owners (MTO) to include a congestion study in future Biennial Transmission Project Reports.

Per the order, this Congestion Study which includes information on the following: 1) expected sustained HVTL or generation planned outages; 2) whether those outages are anticipated to have new or incremental congestion; and 3) whether those outages are anticipated to contribute to sustained incremental congestion. The MTOs shall include this information in Biennial Transmission Projects Reports. The goal is to understand the dynamic nature that outages (both planned and forced) have on congestion.

The study looked at congestion and outages the next four quarters, Q4 2023 through Q3 of 2024. Analysis compared market prices and congestion between a benchmark "System Intact" simulation without outages, a simulation with "Planned" outages taken from the Control Room Operating Window (CROW) as known at the time of the study, and a "Planned+Forced" outages simulation adding a proxy for future unknown forced outages (forced outages from 2021-2022 time-shifted to the study period).

The analysis found that in each quarter there were outages that significantly impacted average Locational Marginal Prices (LMPs) in the simulations. Specific outages contributing to the congestion are identified. The simulations do not include operating guides or system reconfigurations which may be planned to mitigate the congestion identified in this study.

Average LMP for Local Resource Zone 1 (LRZ1) areas during each quarter are shown in the tables below. Relatively small price differences ($0 to $2) do not indicate concern for any specific outages in the area.

DPC – Dairyland Power Cooperative
GRE – Great River Energy
MP - Minnesota Power
NSP – Northern States Power (Xcel)
OTP – Otter Tail Power
SMP – Southern Minnesota Municipal Power Agency

Table: Average LMPs

	2023 Q4				
Area	System Intact	Planned	Difference vs System Intact	Planned+ Forced	Difference vs Planned
DPC	$32.03	$35.36	+$3.33	$34.73	-$0.63
GRE	$29.00	$29.51	+$0.51	$28.14	-$1.37
MP	$29.19	$27.86	-$1.33	$26.65	-$1.21
NSP	$29.62	$31.82	+$2.20	$31.00	-$0.82
OTP	$28.70	$92.32	+$63.62	$90.28	-$2.04
SMP	$28.19	$27.64	-$0.55	$26.48	-$1.16

The LMP difference for OTP is driven by two outages: Donaldson to Drayton October 2-6, 2023, and Winger 115 kV outage November 13-24, 2023.

Table: Average LMPs

	2024 Q1				
Area	System Intact	Planned	Difference vs System Intact	Planned+Forced	Difference vs Planned
DPC	$32.92	$33.35	+$0.43	$32.28	-$1.07
GRE	$30.52	$32.15	+$1.63	$31.08	-$1.07
MP	$32.36	$63.43	+$31.08	$62.54	-$0.90
NSP	$30.77	$33.59	+$2.81	$33.62	+$0.04
OTP	$28.82	$28.75	-$0.07	$26.78	-$1.97
SMP	$26.72	$26.47	-$0.25	$24.69	-$1.78

The LMP difference for MP is driven by the outage of Ortman to Little Fork 230 kV January 1- March 9, 2024.

Table: Average LMPs

	2024 Q2				
Area	System Intact	Planned	Difference vs System Intact	Planned+ Forced	Difference vs Planned
DPC	$34.21	$34.83	+$0.62	$33.16	-$1.67
GRE	$28.47	$29.34	+$0.88	$28.34	-$1.00
MP	$30.45	$30.84	+$0.38	$29.08	-$1.75
NSP	$29.53	$30.33	+$0.81	$29.33	-$1.01
OTP	$27.98	$41.44	+$13.46	$48.65	+$7.21
SMP	$27.60	$27.88	+$0.28	$26.52	-$1.36

The LMP difference for OTP is driven by the outage of Forman 230/115 kV transformer and related outages May 1- August 30, 2024.

Table: Average LMPs

	2024 Q3				
Area	System Intact	Planned	Difference vs System Intact	Planned+ Forced	Difference vs Planned
DPC	$46.34	$45.58	-$0.76	$44.91	-$0.68
GRE	$42.70	$41.30	-$1.40	$42.61	+$1.30
MP	$43.42	$41.83	-$1.59	$39.87	-$1.96
NSP	$42.22	$40.84	-$1.39	$40.81	-$0.03
OTP	$48.95	$56.11	+$7.15	$63.28	+$7.17
SMP	$40.32	$38.56	-$1.76	$38.72	+$0.16

The LMP difference for OTP is driven by the outage of Forman 230/115 kV transformer and related outages May 1 - August 30, 2024.

Observations

- Congestion is typically highest in times with high wind around the morning or evening peak load.
- The system intact operating state has significant baseline congestion.
- The operating state with CROW outages increases congestion moderately.
    - Most outages have minimal impact, a few specific outages show potential for greater congestion impact.
- The operating state with CROW and a selected set of forced outages also increases congestion moderately.
- Patterns in all of the operating states show congestion between:
    - Wind generation areas in southwest Minnesota and the Twin Cities metro;
    - Minnesota and Wisconsin;
    - Twin Cities and northern Minnesota; and
    - Dakotas/far western Minnesota and the rest of Minnesota.

Model

Future congestion was simulated using PROMOD production cost modeling software. The source model for the simulation was MISO MTEP21 Future 1 2025 model adjusted to represent the system conditions for the four quarters from Q4 2023 through Q3 2024. The source model uses 2018 weather data for wind and solar output profiles representing a typical year and does not forecast 2022 weather, so a direct hour-by-hour comparison of results to actual congestion will be different due to weather patterns and other assumptions such as fuel price forecasts. The simulation calculates results on hourly timesteps.

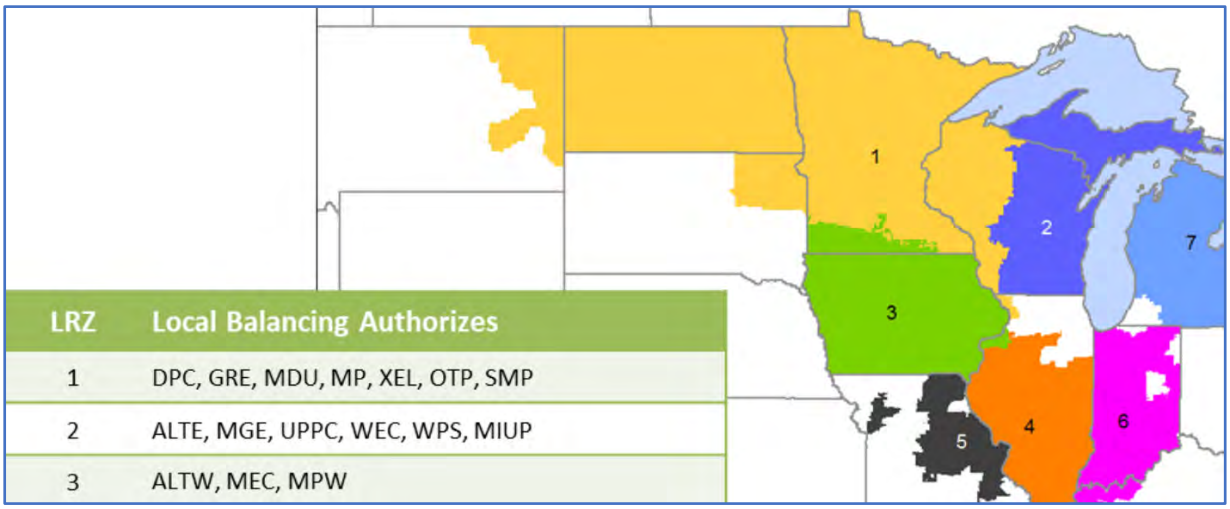
Three operating states of the electric grid were simulated:

- System Intact – Baseline with all transmission available.
- Control Room Operating Window (CROW) – Planned outages added.
- Forced Outages – Planned outages plus historical outages from 2021-2022 time-shifted forward to the study period.

Future forced outages are characteristically unpredictable, so the past events modeled are a proxy for unknown future forces outages and should not be viewed as a specific forecast of events, but as demonstration of wider scale trends due to forced outages.

Shadow price sums reported are a measure of the relative impact of constraints and do not represent to cost savings of fixing the constraint. Fuel mix and load is reported for MISO North in MWh. Constraints are reported for the LRZ1 (footprint as shown below).

The model may be overly sensitive to 69 kV constraints like Cleveland-Le Center and Spring Creek compared to recent historical constraints. Simulations with those constraints unenforced show similar impact in the results due to planned and forced outages.



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW

System Intact Congestion

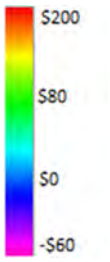
Similar congestion patterns appear in many hours throughout the simulation. Representative hours from the simulation were selected to show the typical conditions causing congestion. This section shows a map of LMPs and constraints for each representative hour and a pie chart of the MISO north generation fuel mix each hour. The table below shows the percent of time the facility is a constraint in the market and a sum of the Shadow Price, which is a measure of the marginal value of the constraint, not the savings if it were to be mitigated.

Table: Top Constraints Shadow Price Sum and Percent of Quarter Binding

Constraint	Map	Q4 2023	Q1 2024	Q2 2024	Q3 2024
ABDNJCT7 to ELLENDL7 #1	AE	$12253 (7%)	$3850 (2%)	$8843 (5%)	$2687 (2%)
ADAMS 5 to BVR CRK5 #1	AB			-$30586 (10%)	-$9711 (4%)
BIGSTON4 to BROWNSV4 #1	BB	-$13890 (3%)		-$35039 (9%)	-$81030 (12%)
BROWNSV4 to NEW EFFNGTN4 #1	BN	-$1563 (1%)	-$6576 (4%)		
BLCKBRY4 to GRE-SWTRX3A4 #1	BS			-$14277 (8%)	-$27859 (6%)
FORMN 7 to FORMAN 7 #1	FT	-$150111 (15%)	-$675665 (46%)	-$167422 (19%)	-$242468 (21%)
GRE-CHUBLAK3 to YBUS(GRE-CHUBLAK7_GRE-CHUBLAKT) #1	CT	$10682 (4%)	$39810 (18%)	$5429 (3%)	$2755 (2%)
GRE-CHUBLAK7 to YBUS(GRE-CHUBLAK3_GRE-CHUBLAKT) #1	CT	-$3119 (1%)	-$3788 (2%)	-$1175 (0%)	-$203 (0%)
GRE-CLVLAND8 to LECENTR8 #1	CL	-$138514 (10%)	-$465853 (31%)	-$172296 (16%)	-$199207 (11%)
GRE-SPRGCK15 to YBUS(GRE-SPRNGCK8_GRE-SPRNGC1T) #1	SC	-$136419 (5%)	-$111942 (7%)	-$39143 (1%)	-$45459 (1%)
HELENA 3 to SCOTTCO3 #1	HS	-$2002 (4%)	-$1153 (4%)		-$9 (0%)
HIBBARD7 to WNTR ST7 #1	HW	-$9383 (5%)	-$10831 (5%)	-$116555 (39%)	-$155900 (27%)
MINVALT4 to GRANITF4 #1	MG	$11635 (3%)	$1103 (0%)	$1702 (1%)	$2373 (1%)
RVT1BUS7 to GRE-MERRFLD7 #1	RM			-$251 (0%)	-$212686 (2%)
WILMART7 to SWAN LK7 #1	WS			-$9675 (2%)	-$12994 (3%)

Map Legend:

LMP in $/MWH



Pink Lines:

Constraints labeled with two letter code in table above

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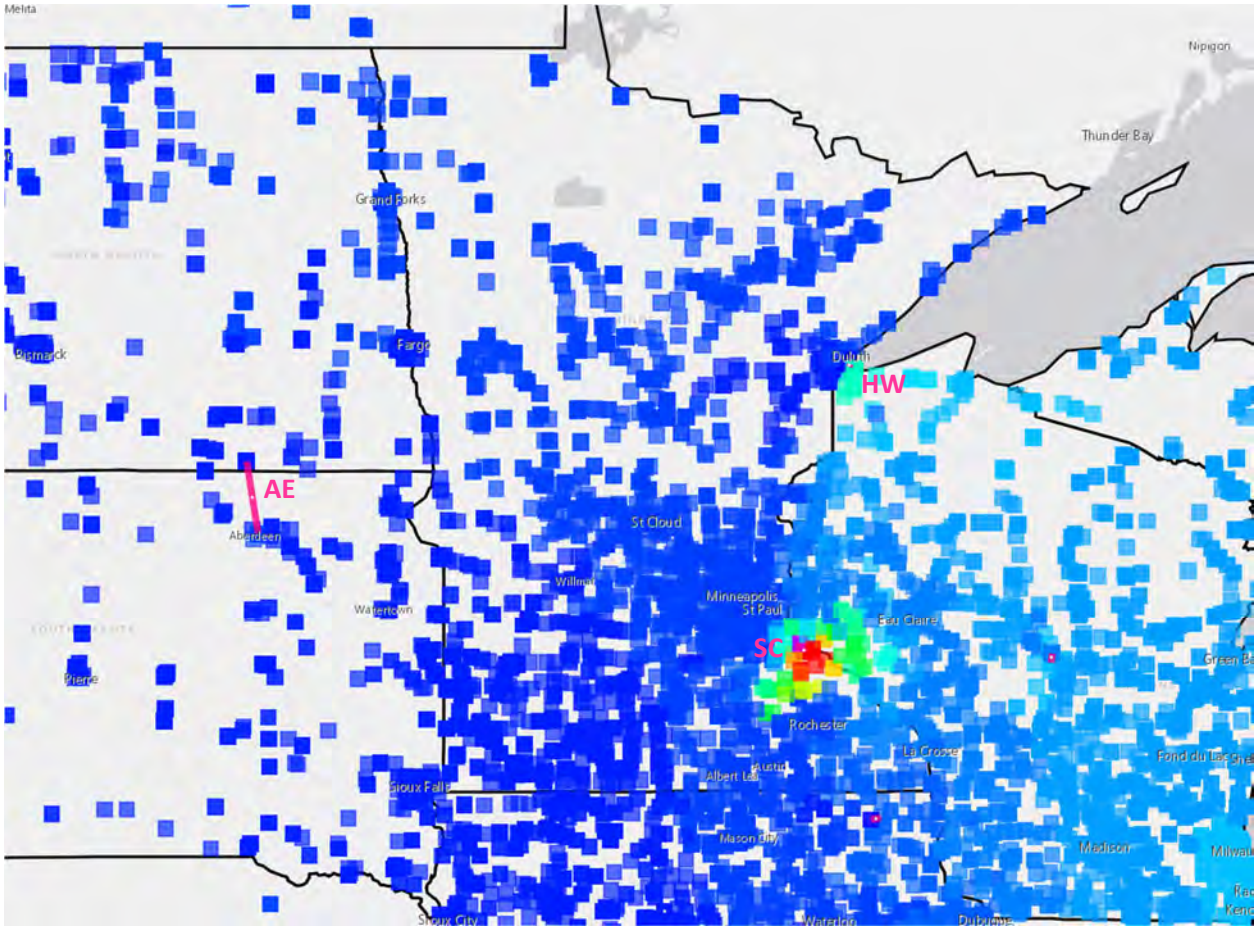

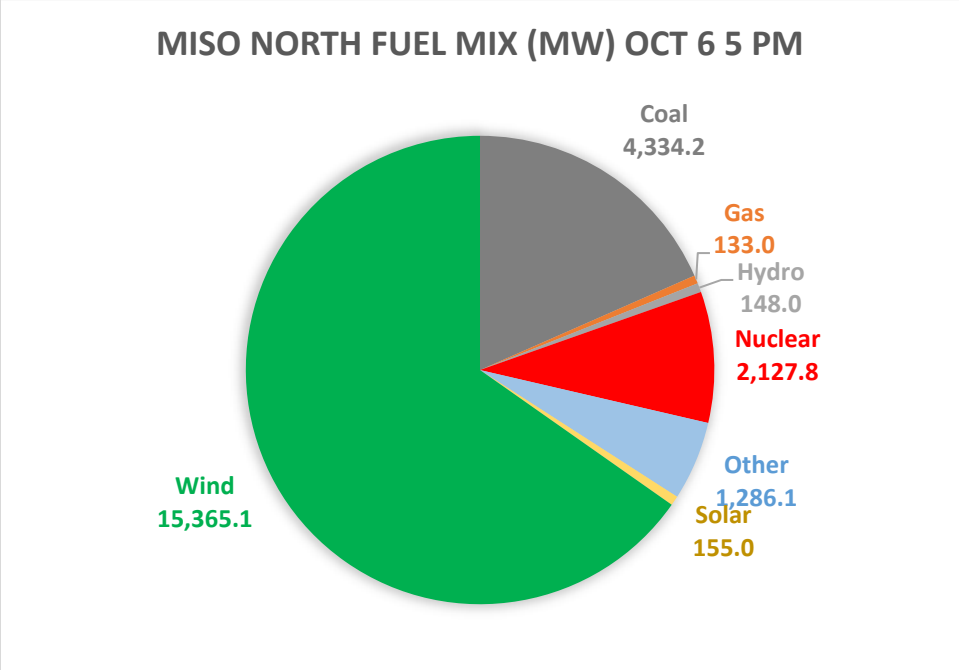

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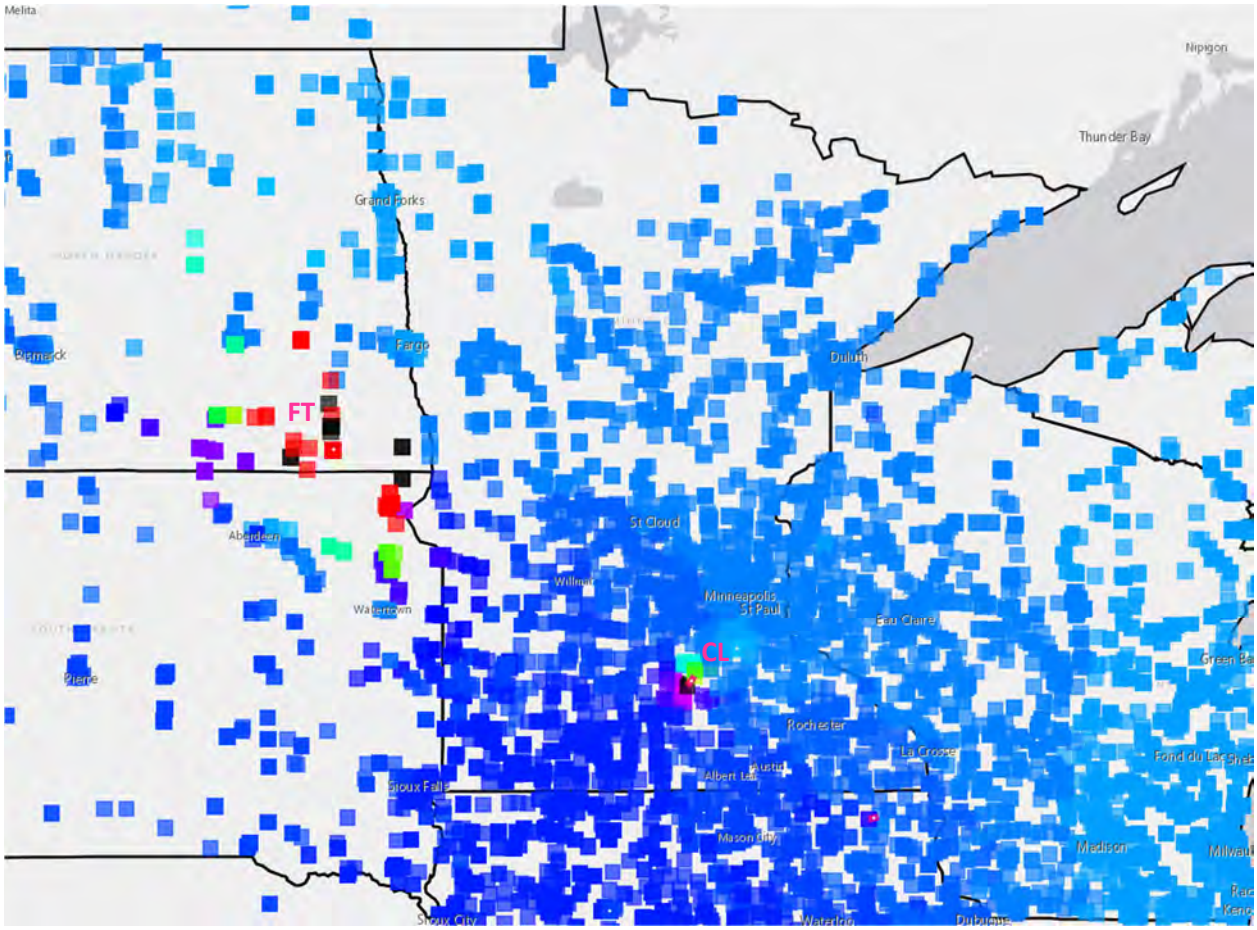

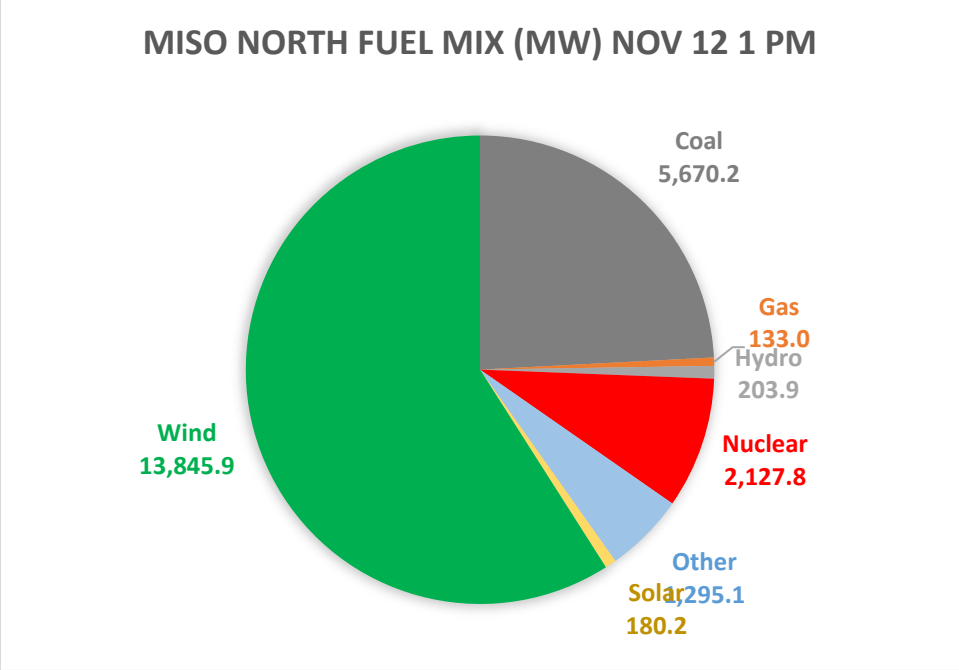

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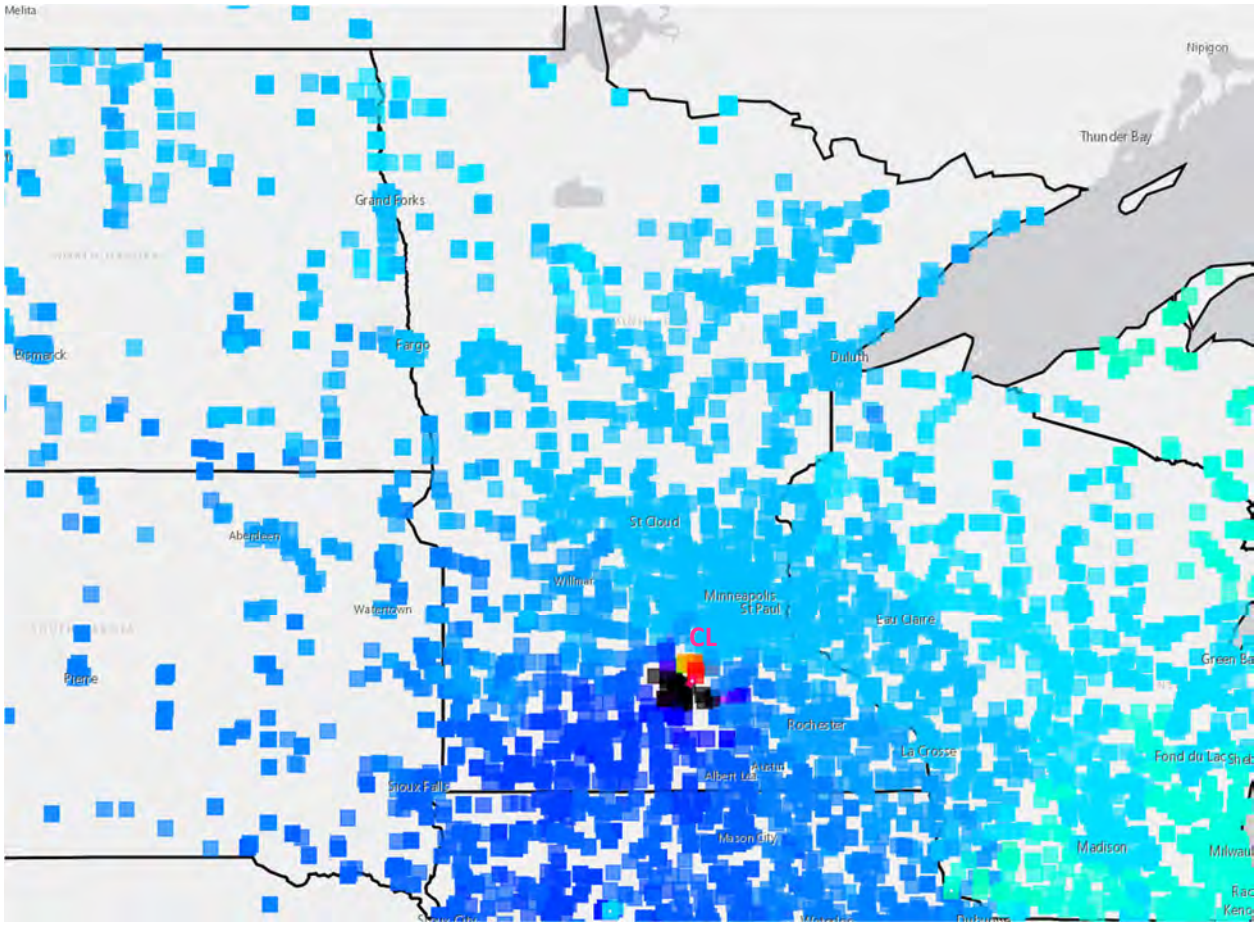

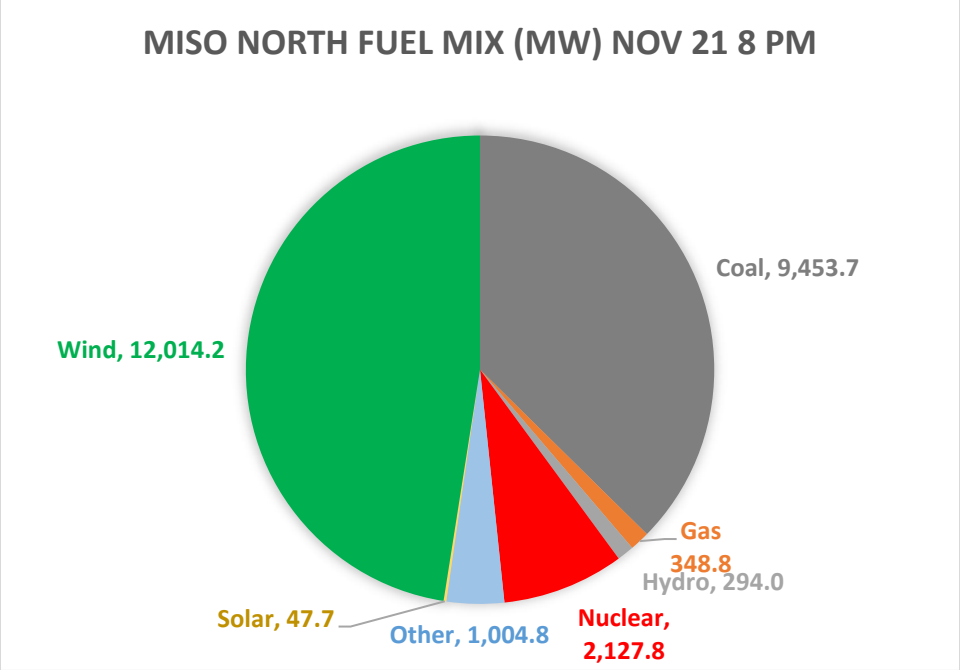

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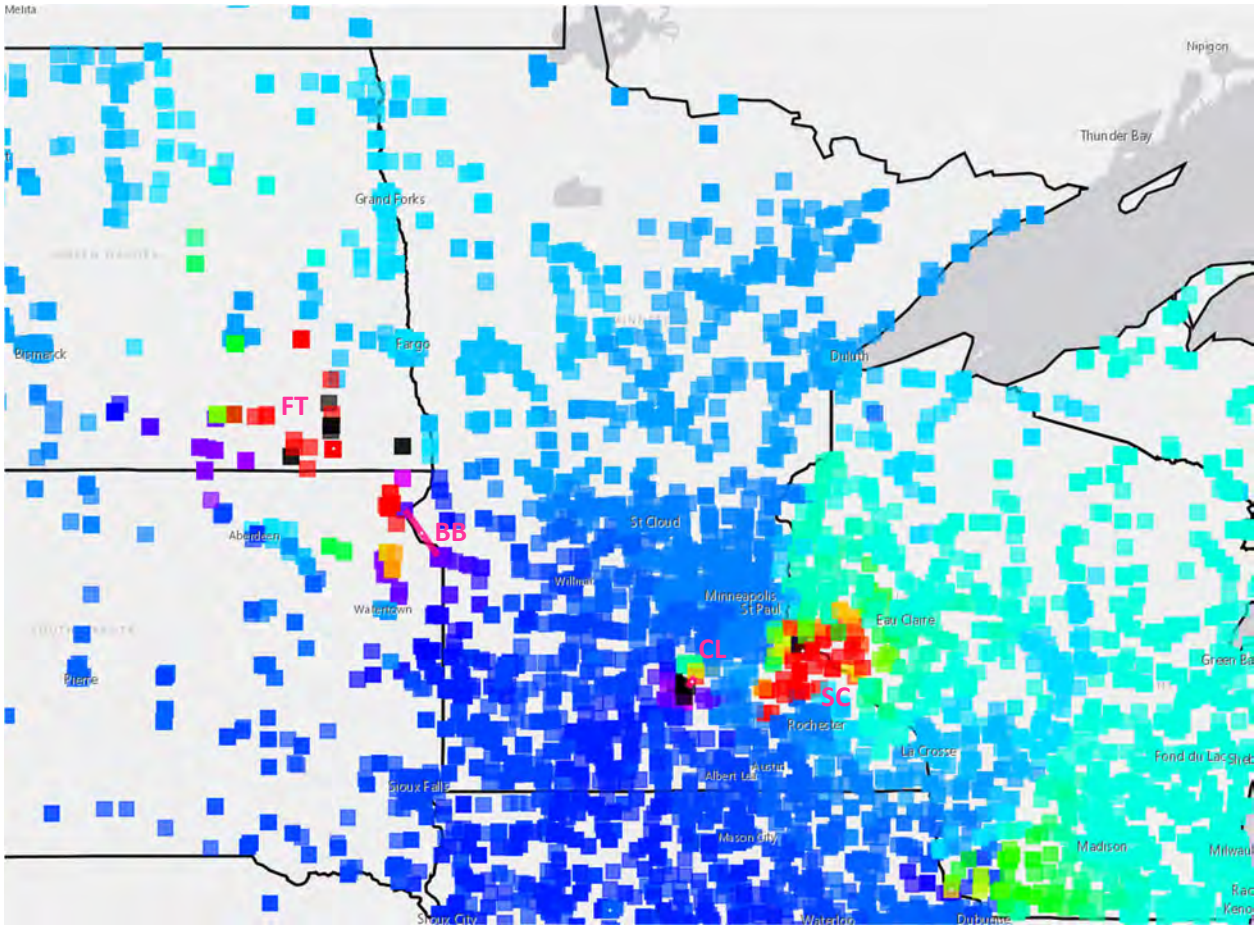

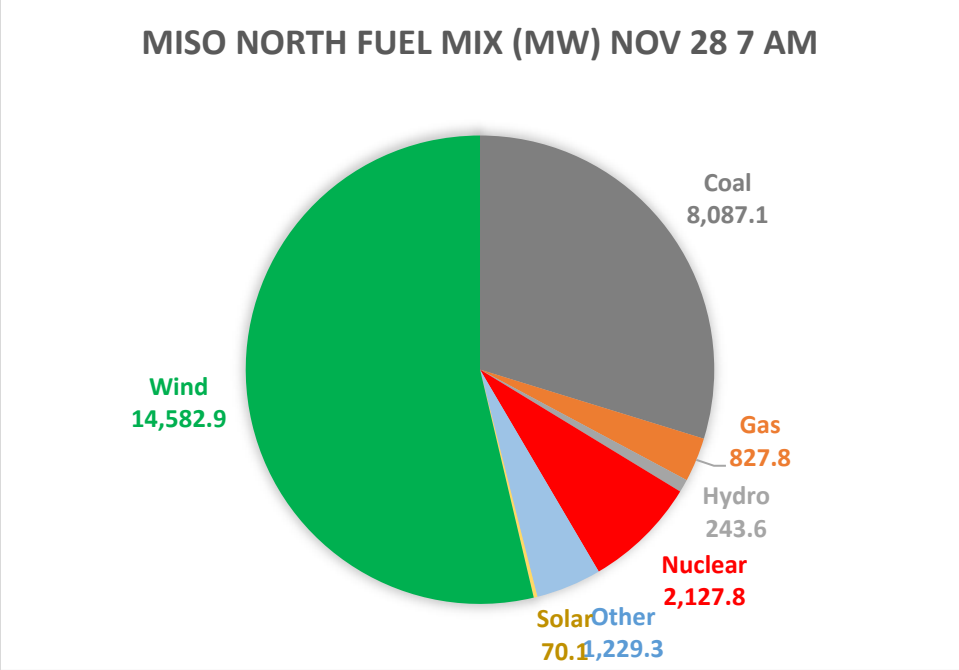

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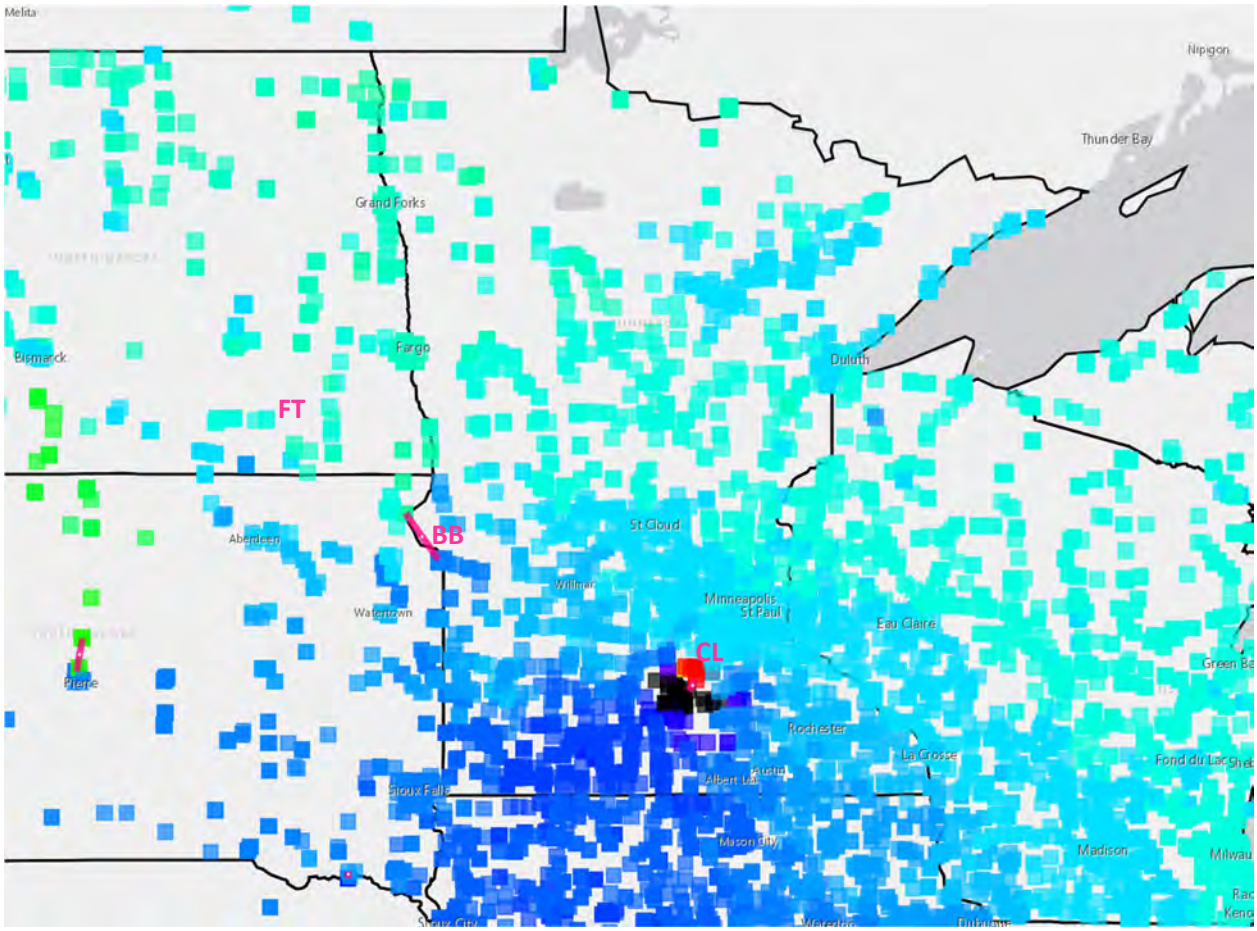

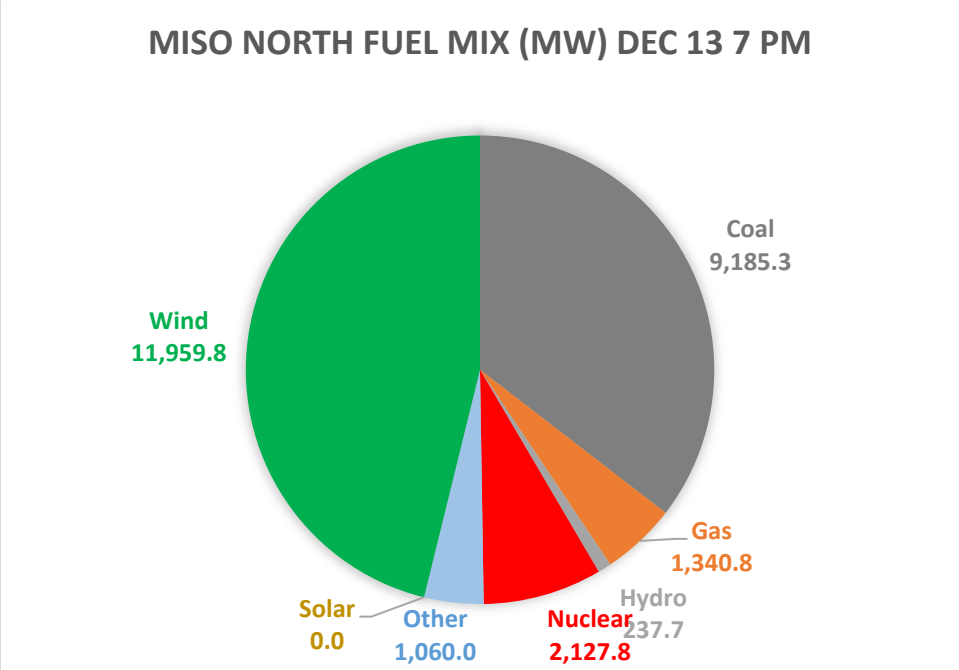

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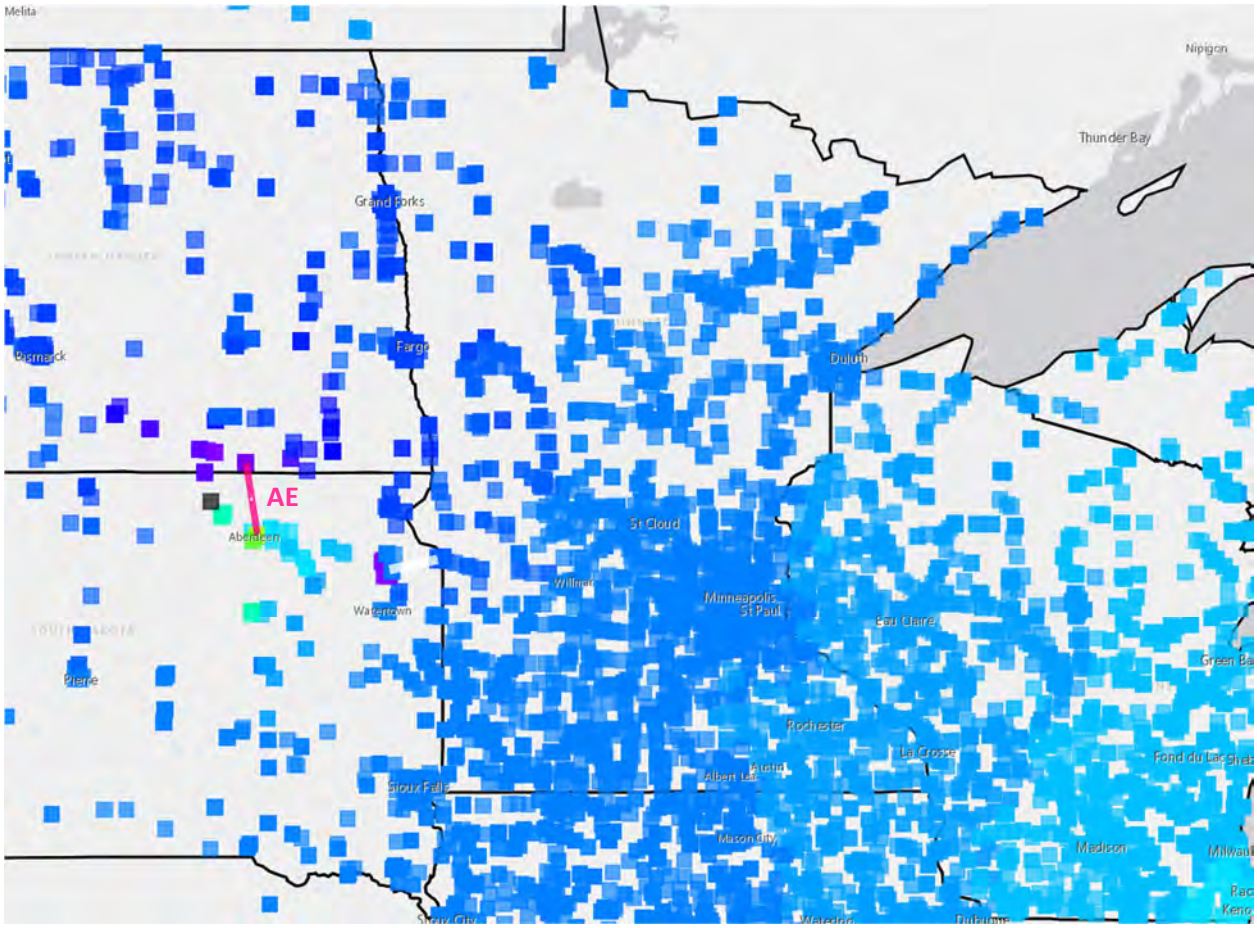

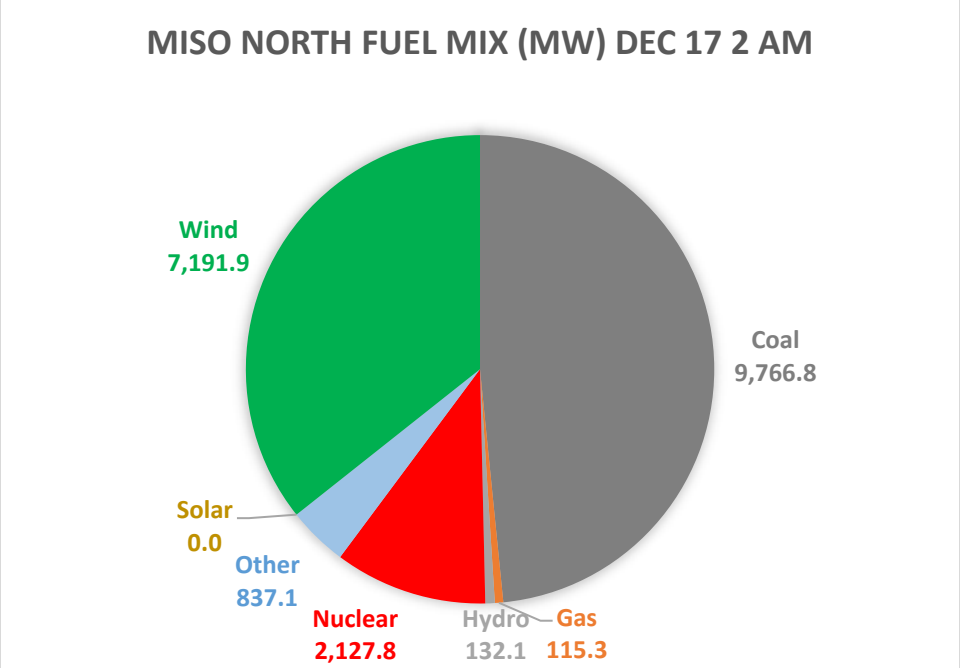

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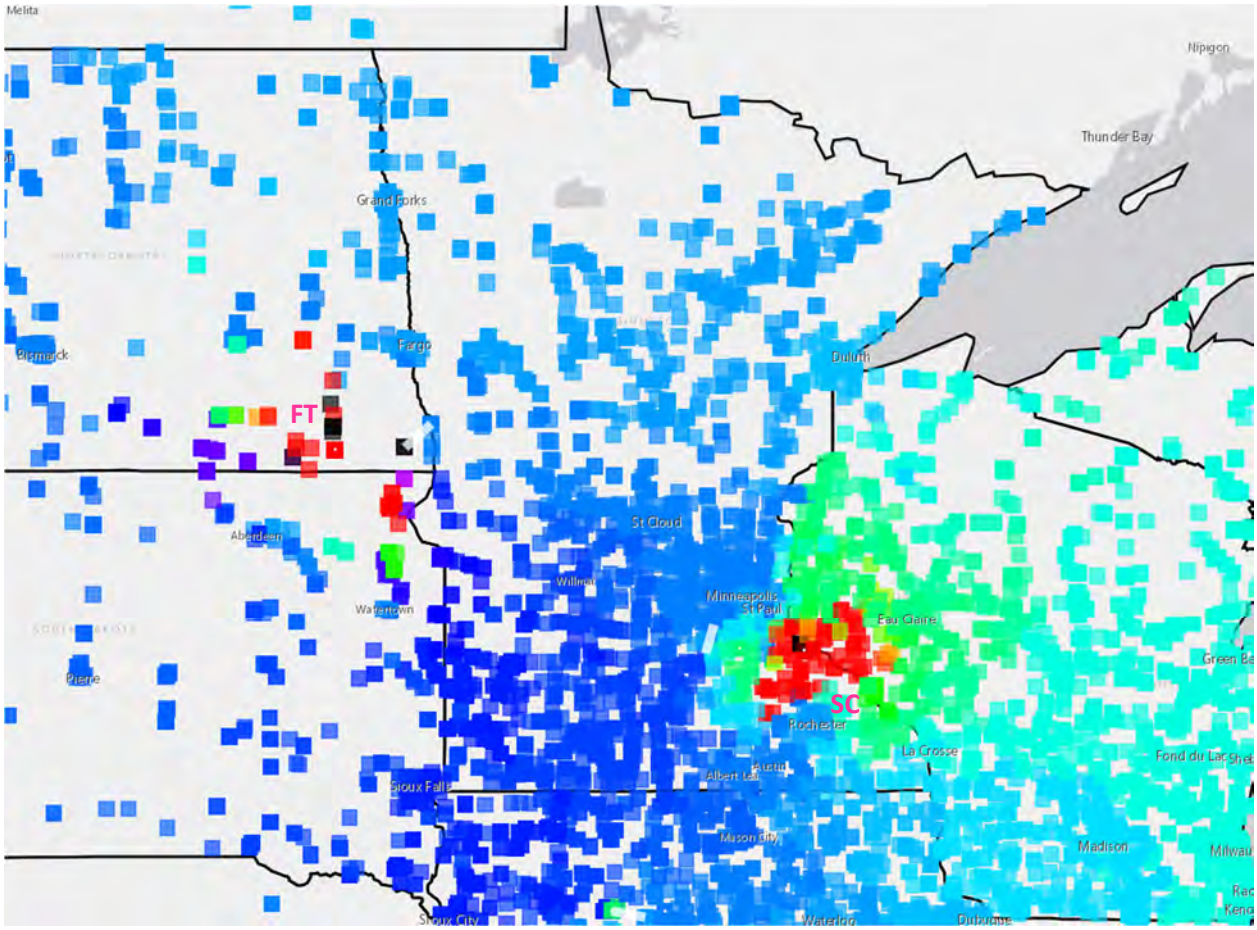

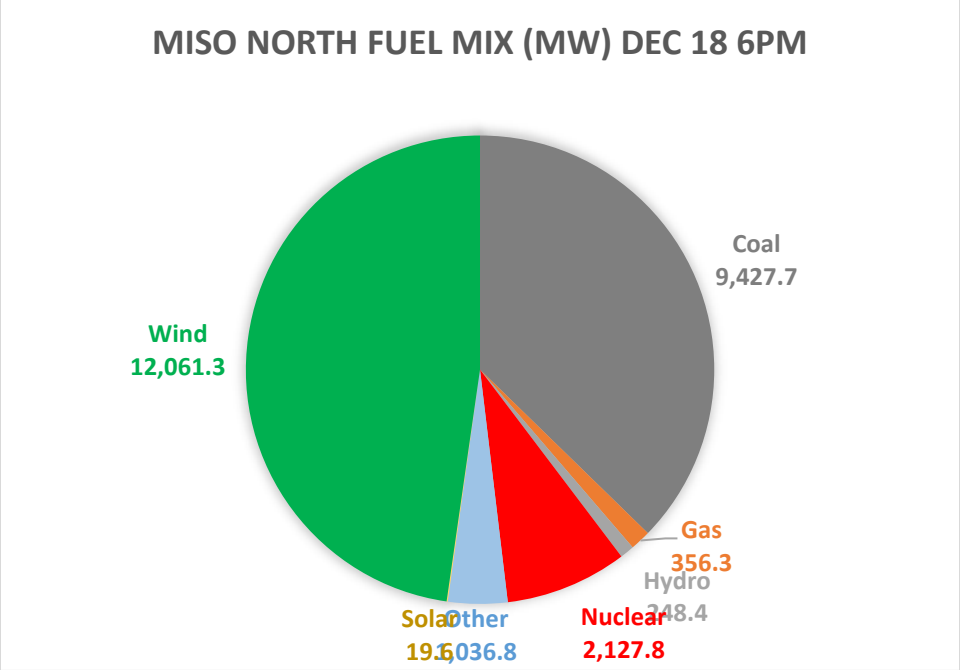

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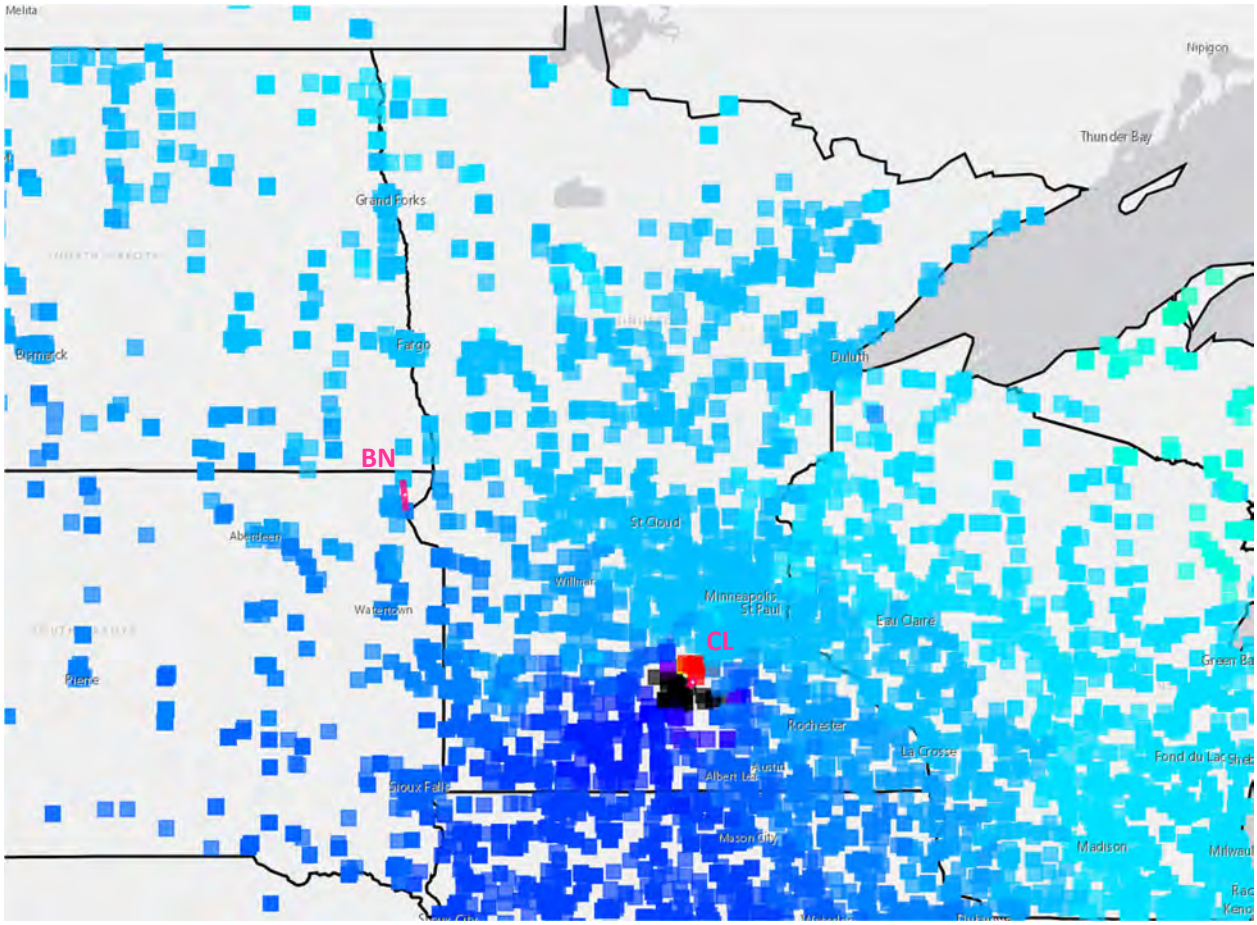

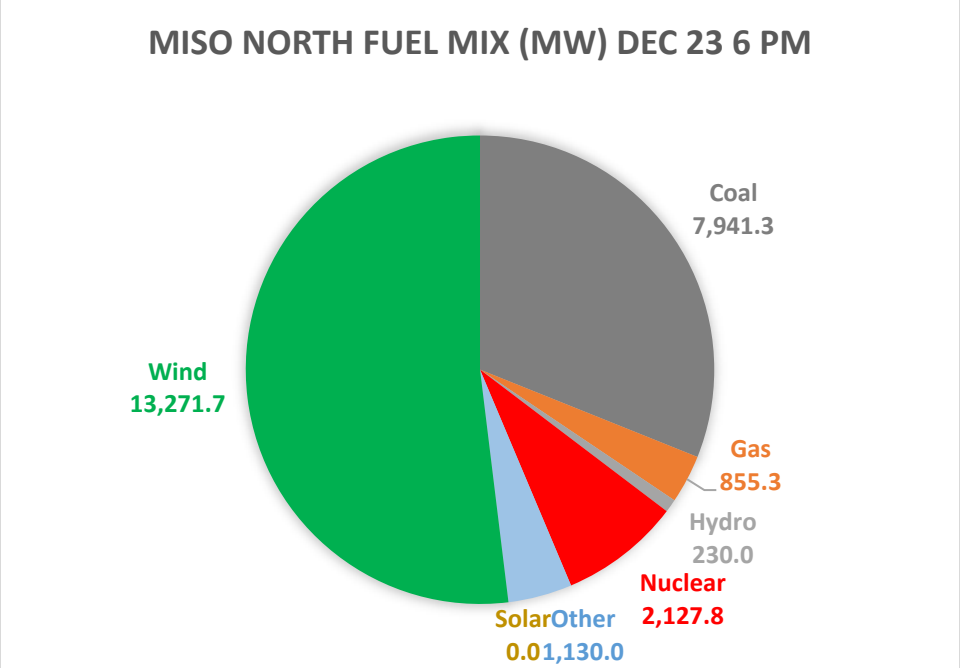

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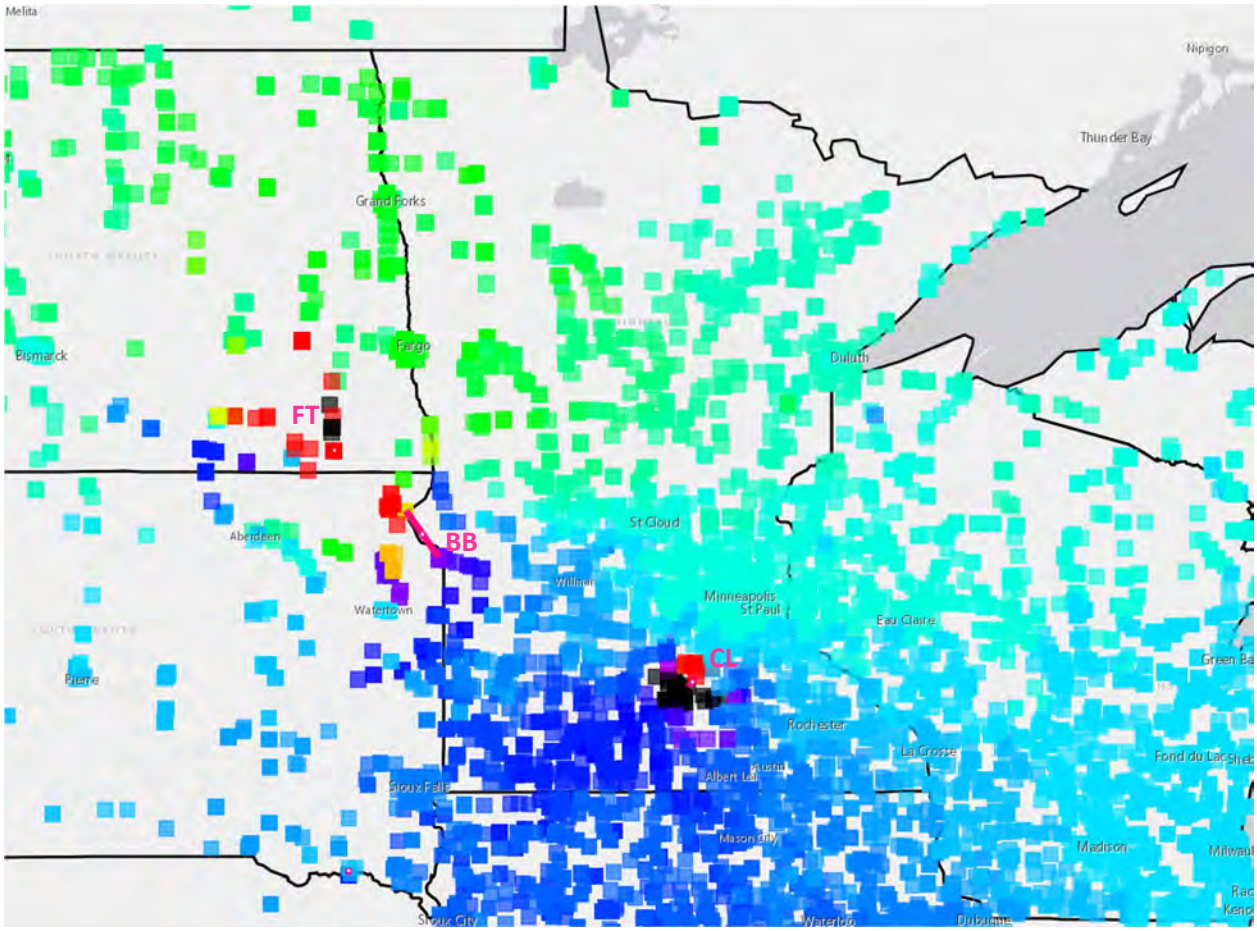

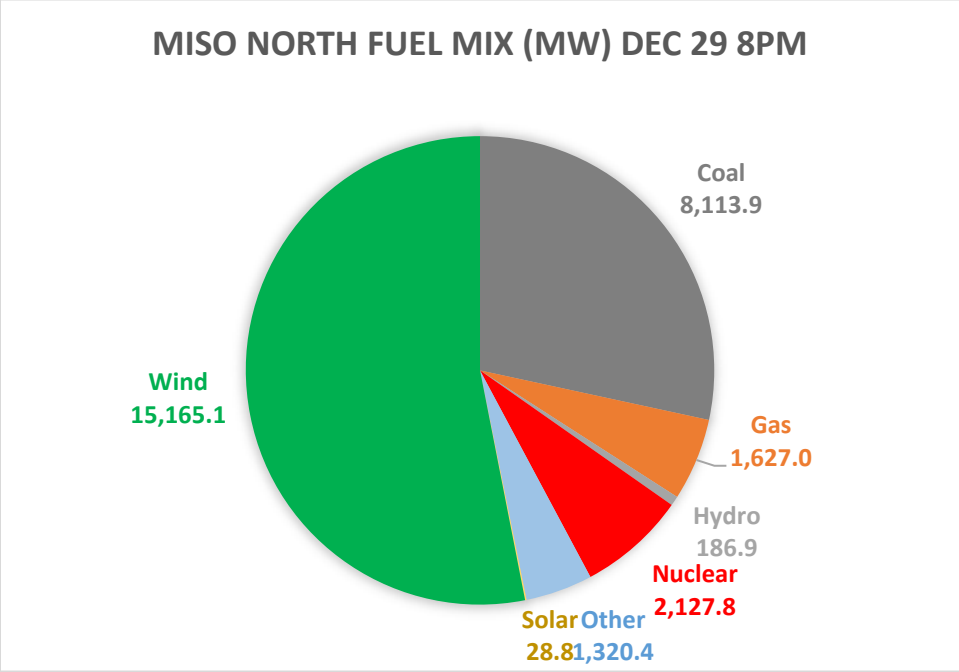

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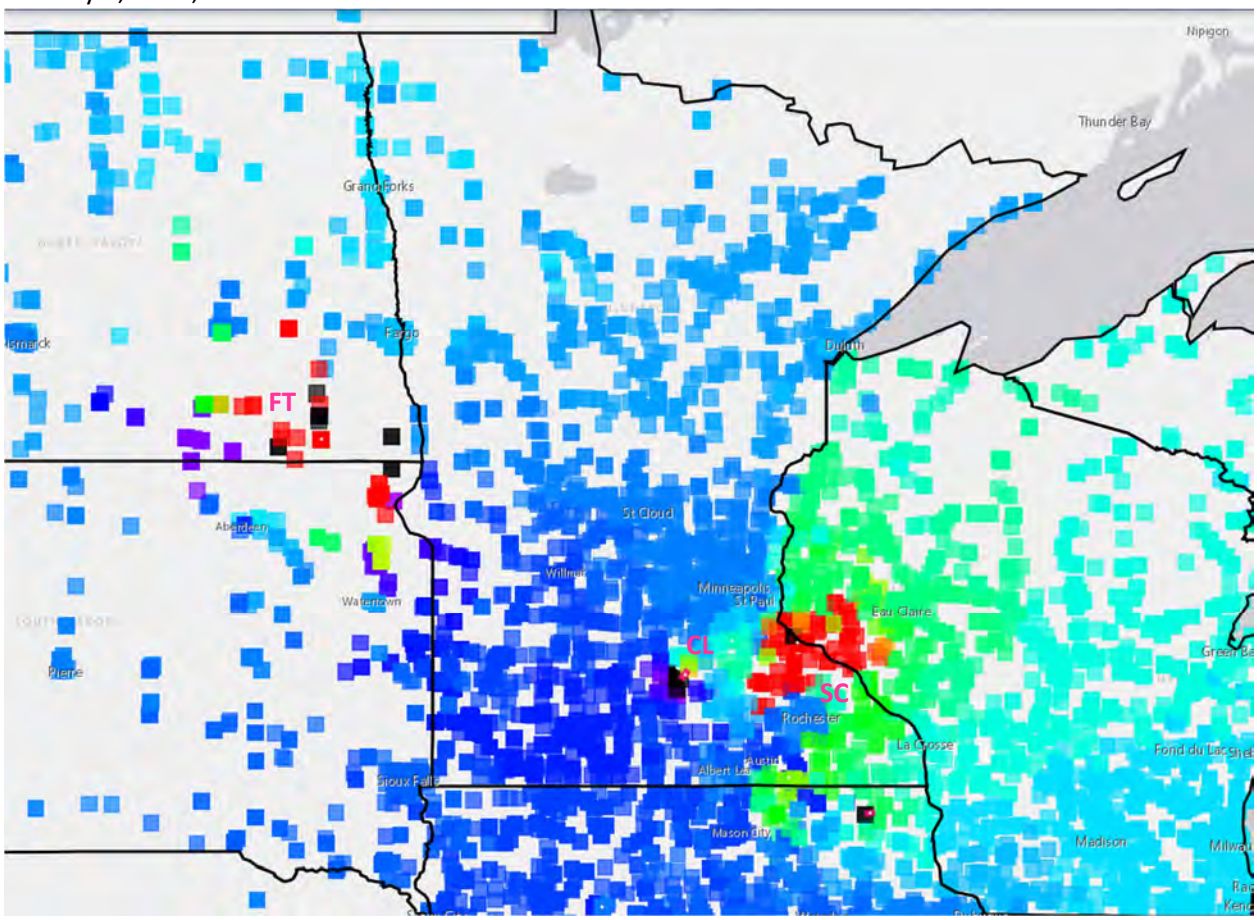

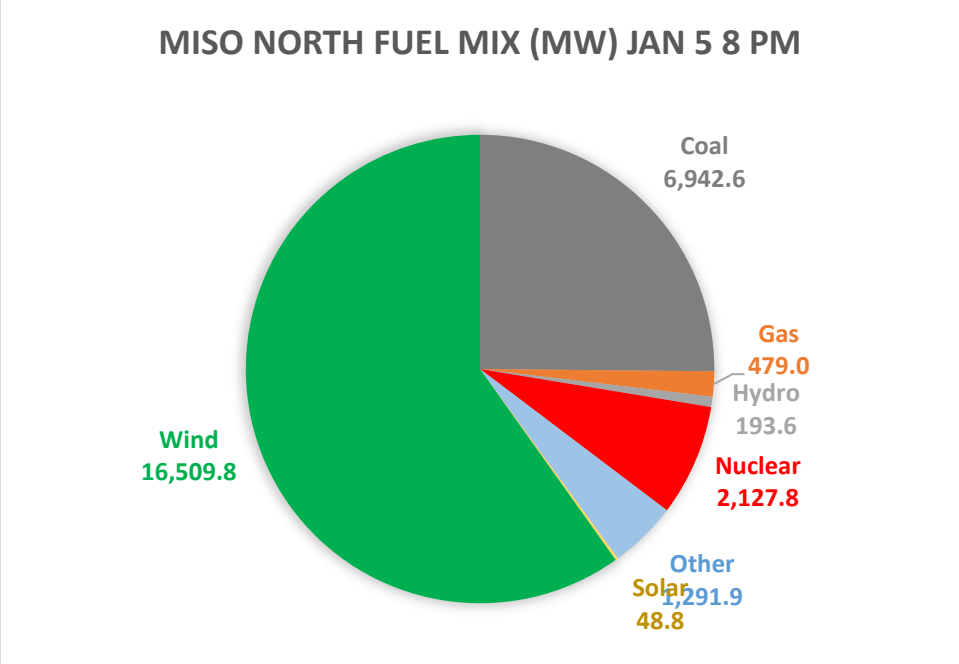

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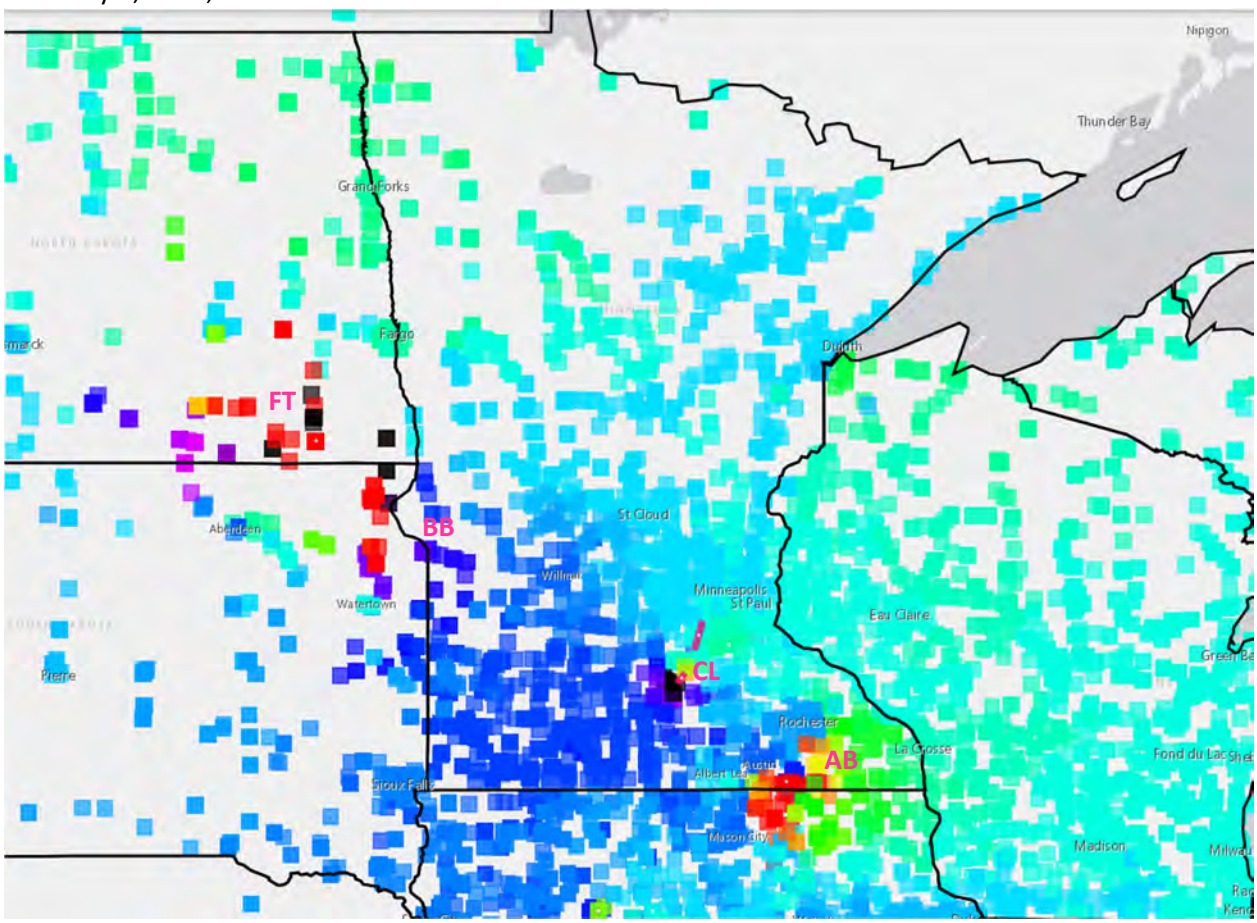

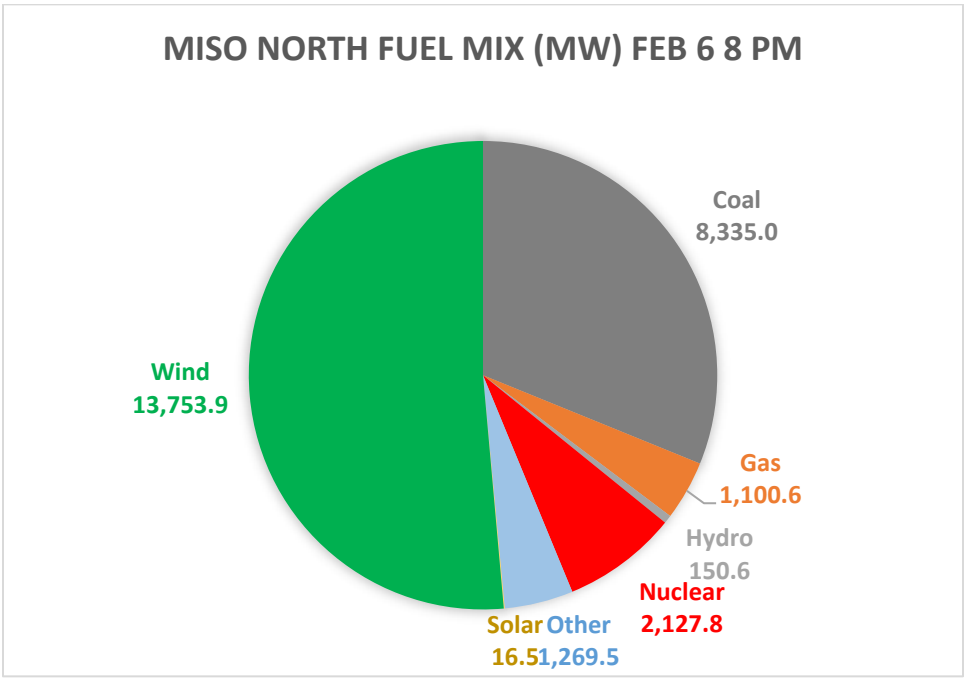

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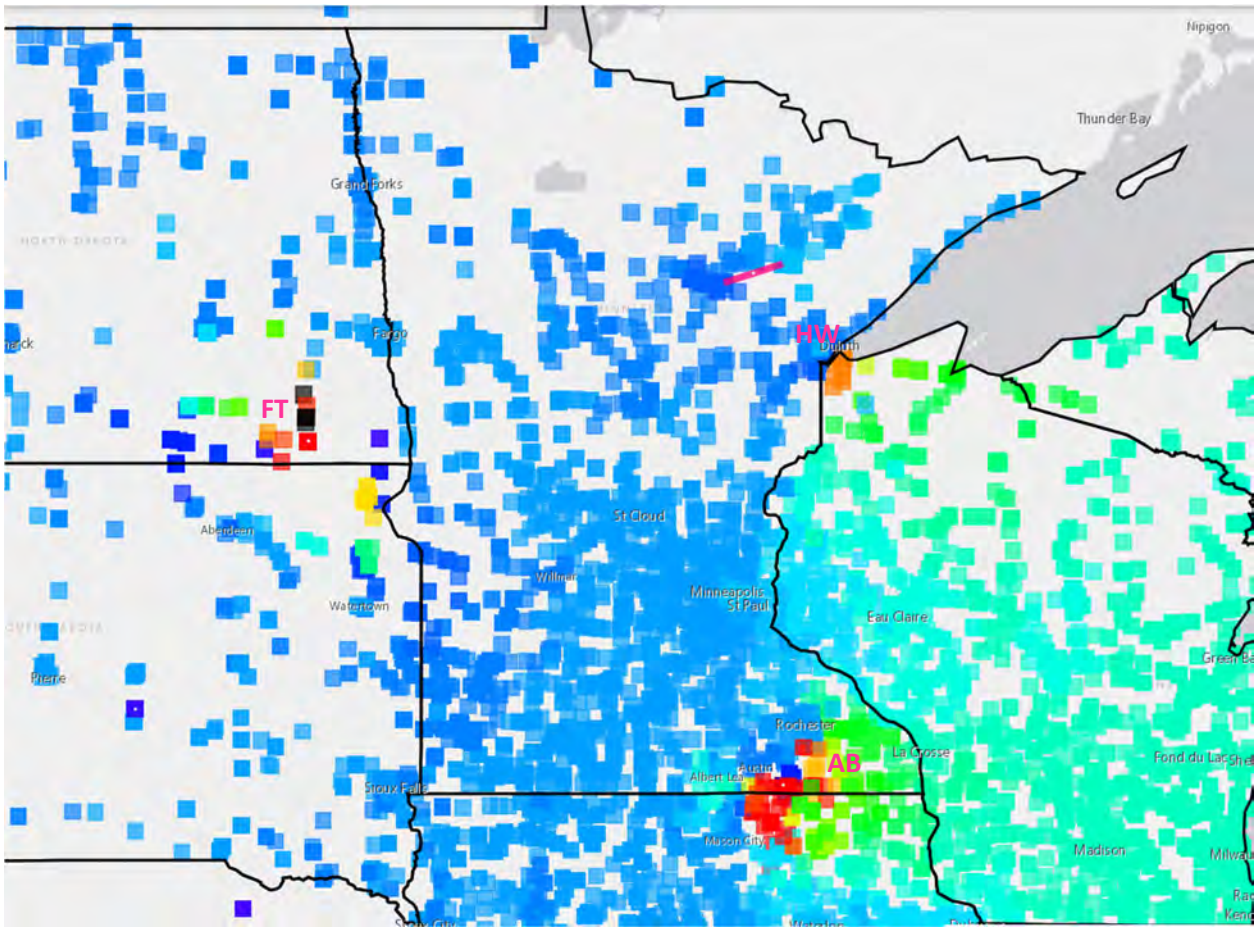

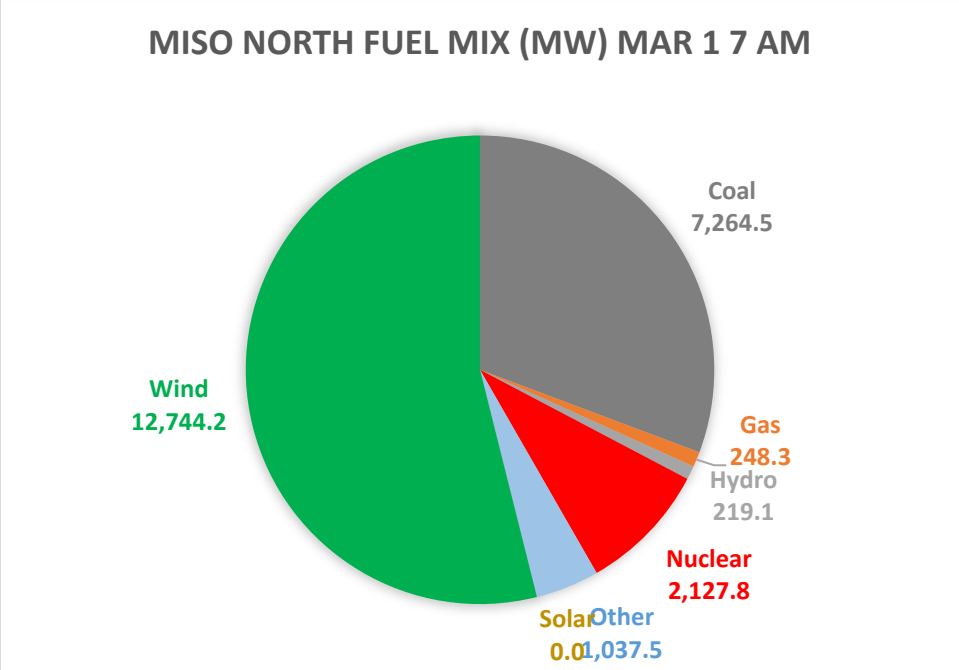

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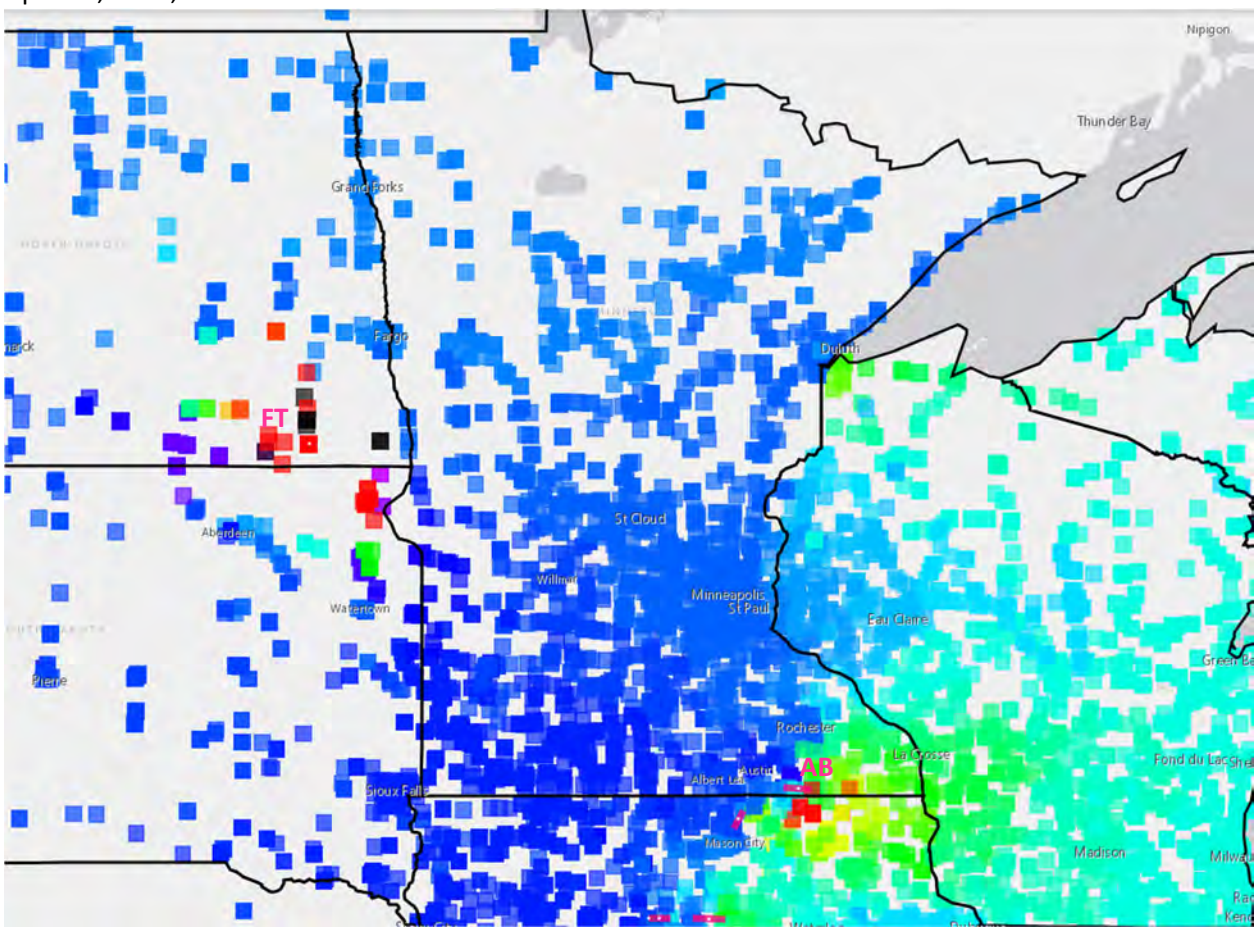

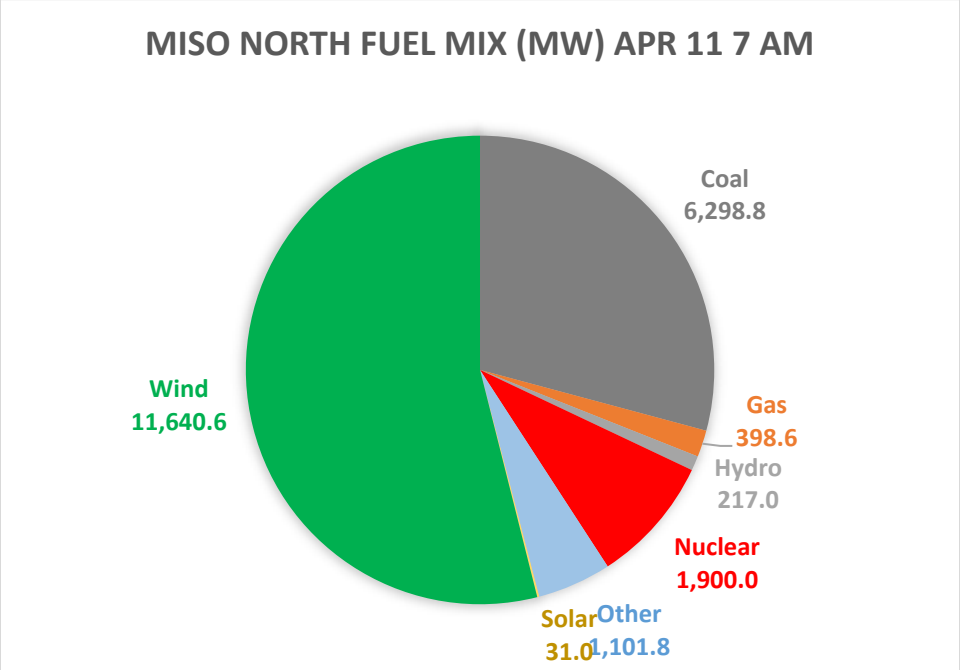

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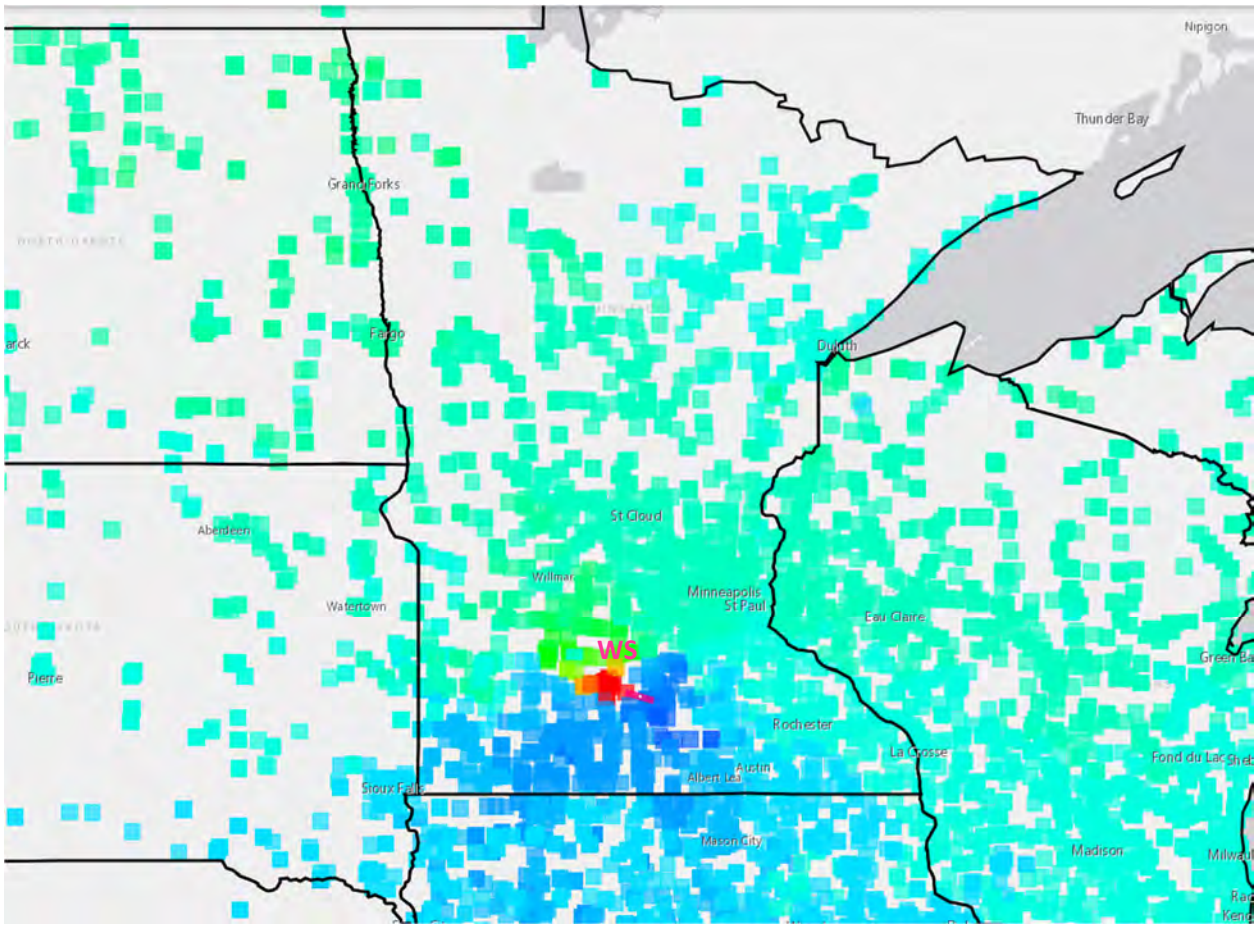

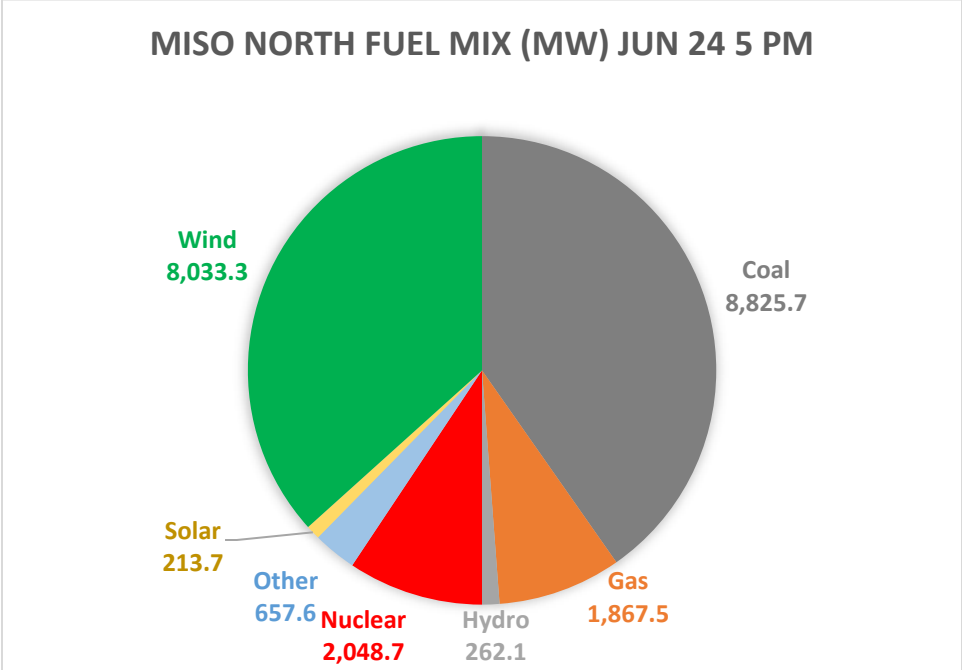

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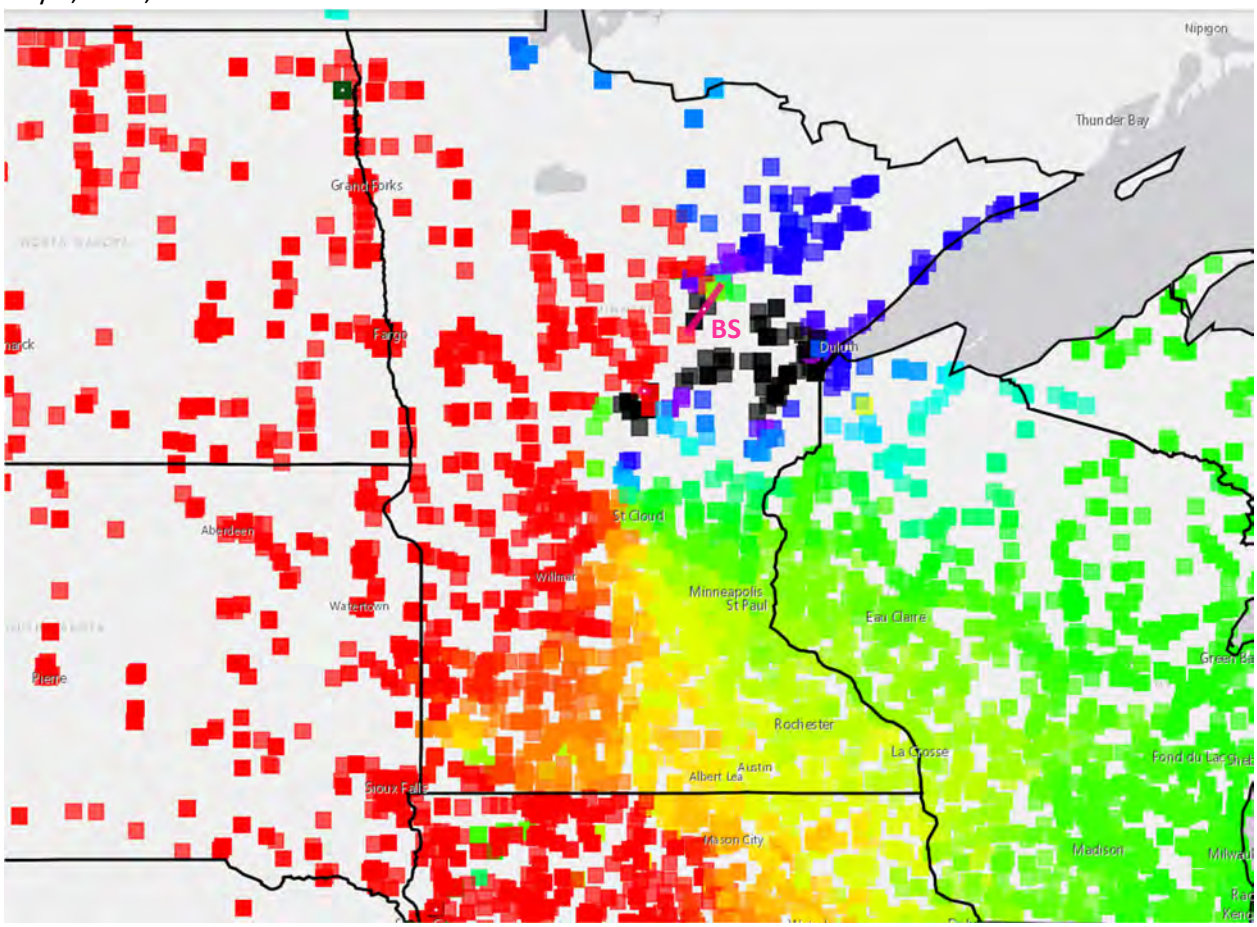

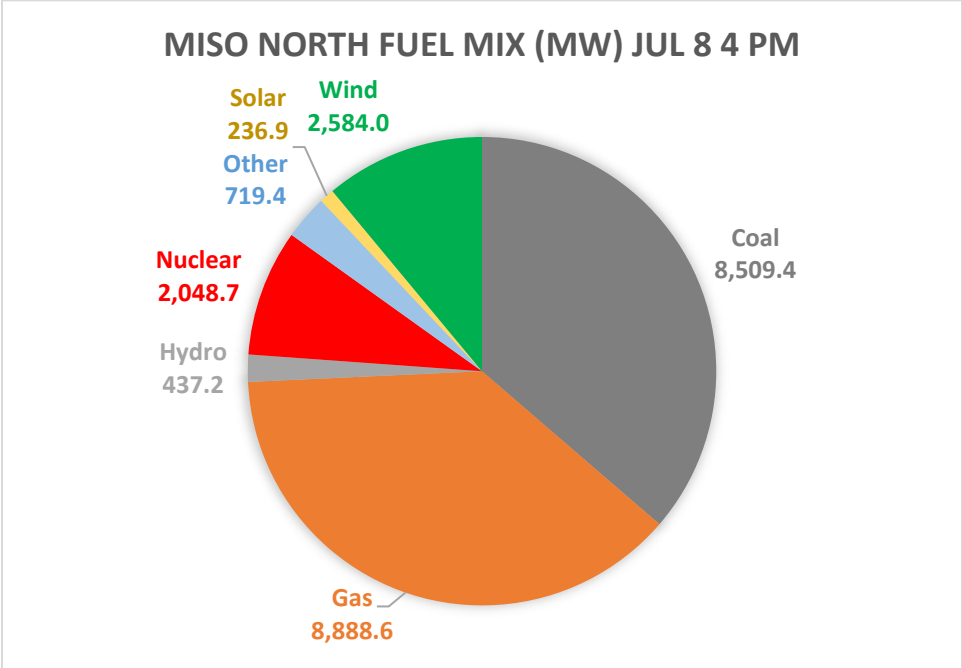

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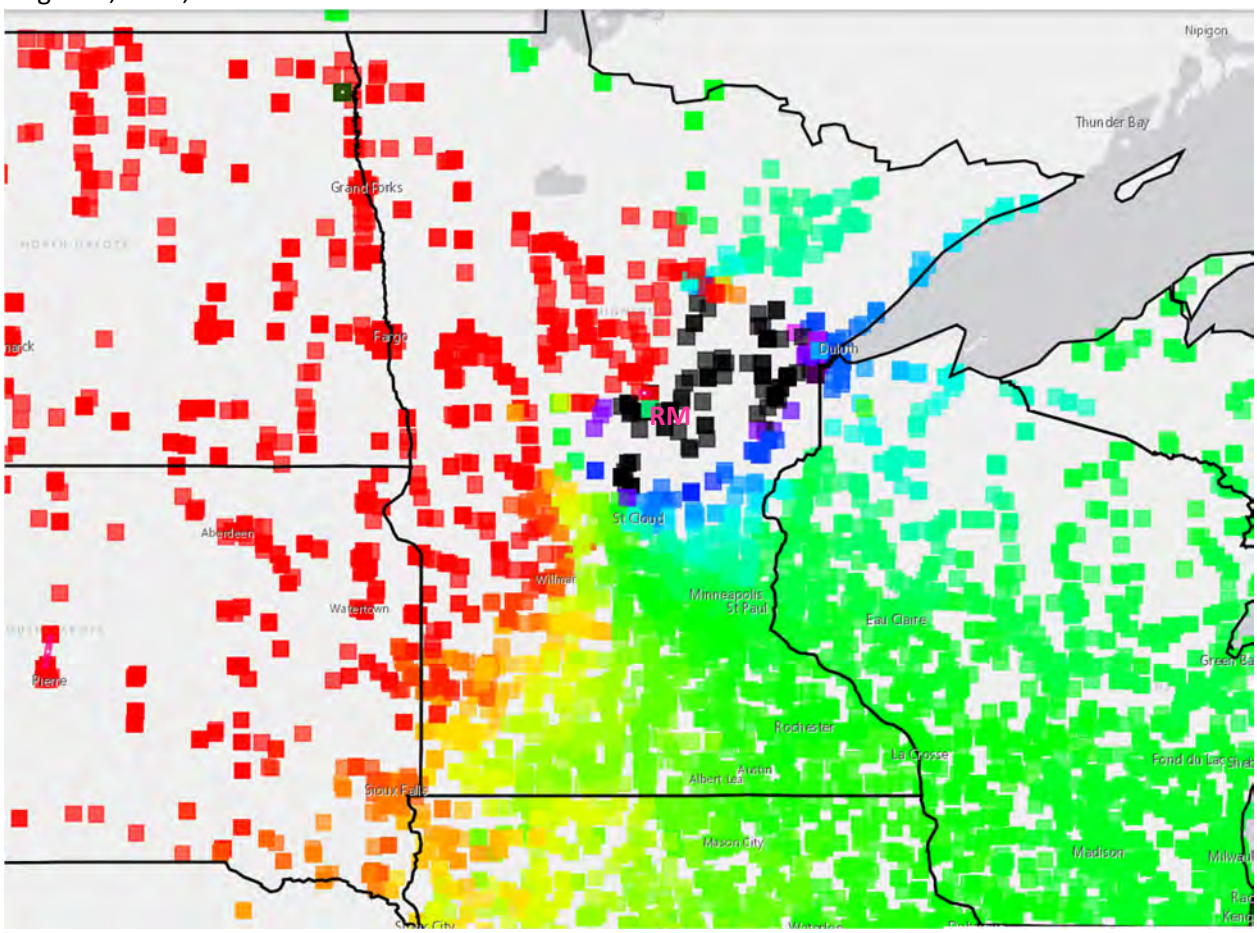
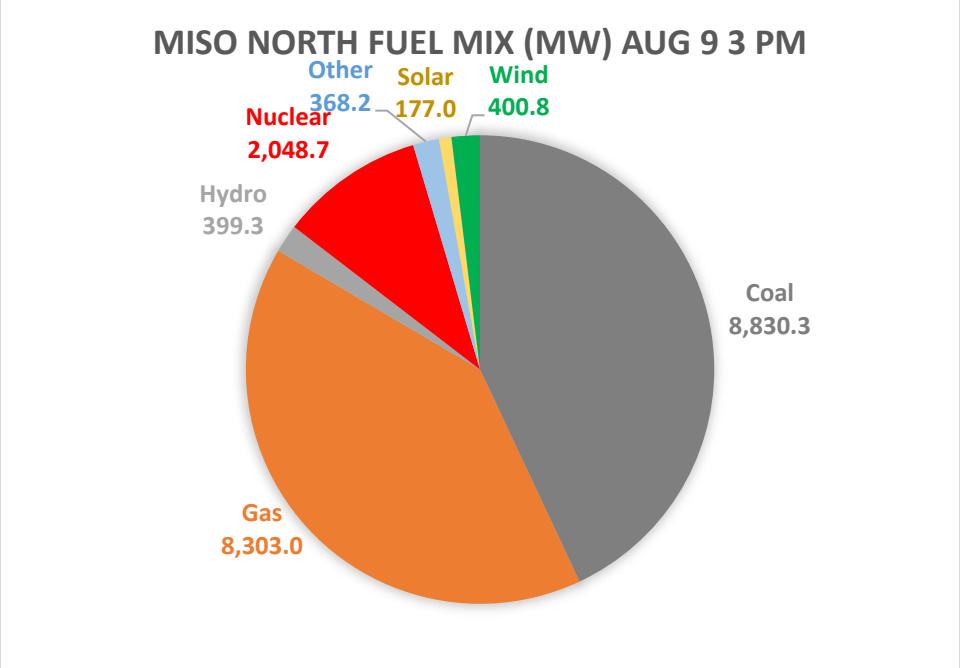
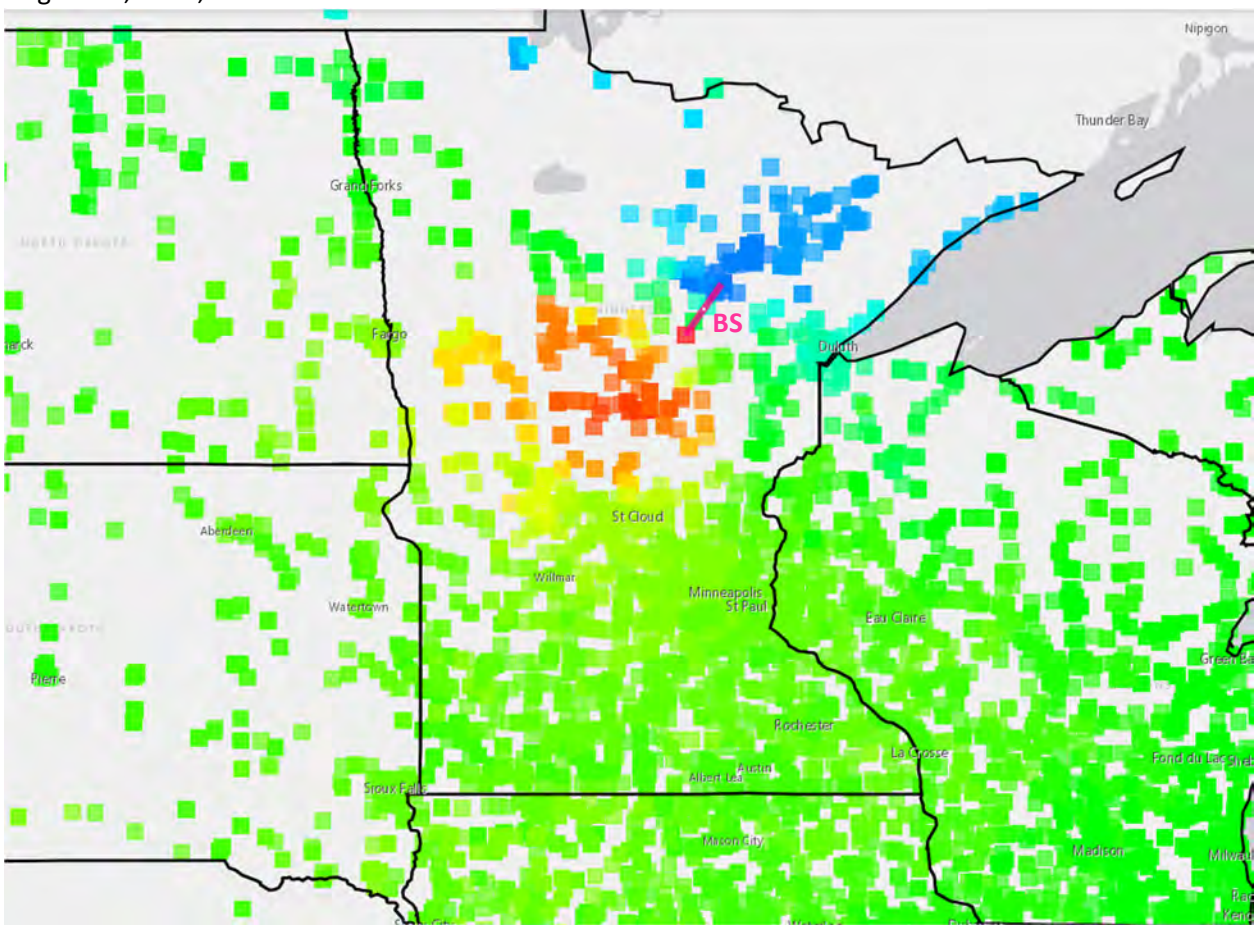
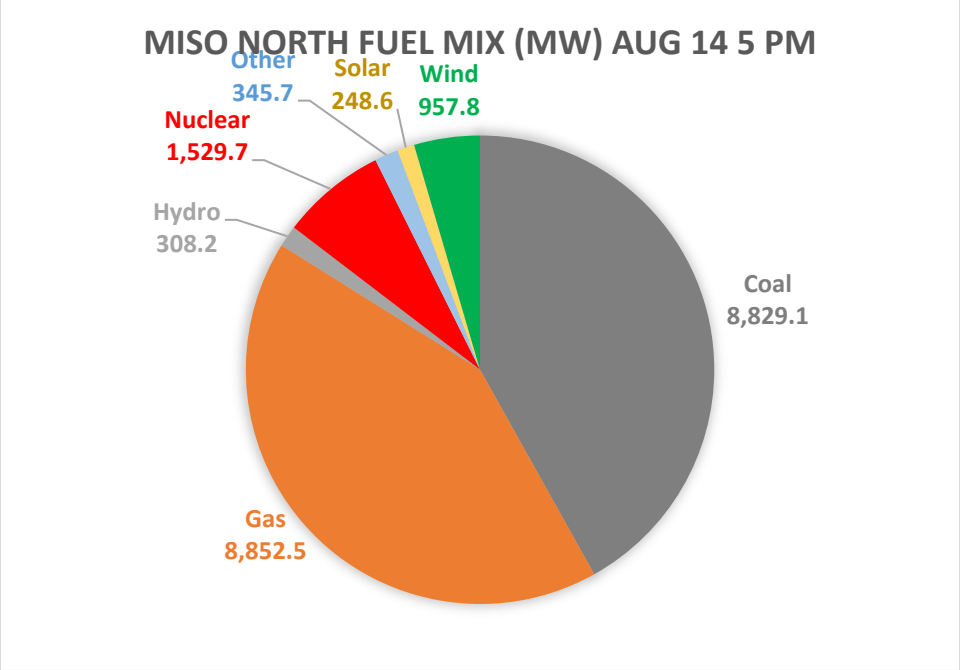




August 14, 2024, 5:00 P.M.





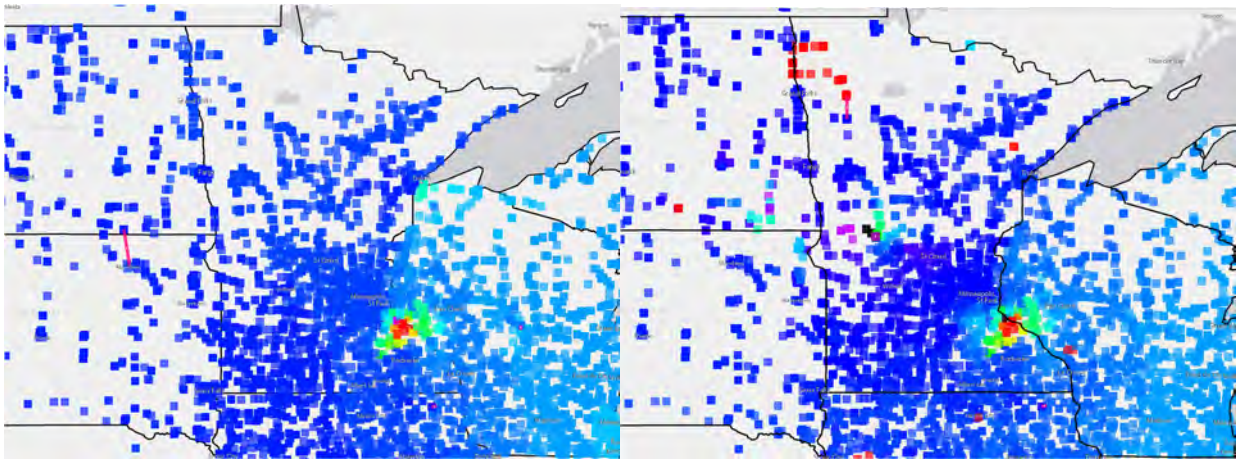
Impact of Planned and Forced Outages

The purpose of this study is to understand how planned and forced outages impact congestion. Outages can reduce congestion on one facility because it is masked by increased congestion on another facility, and not an indication of an overall reduction in congestion. In some cases, congestion due to outages can lower prices and appear favorable for Minnesota customers, while other customers in the MISO market have higher prices (see November 21, 2023, 8:00 p.m.). In general, the outage-congestion increase results in a reduction of MISO North generation, especially wind, replaced by imports from other regions.

Planned Outages

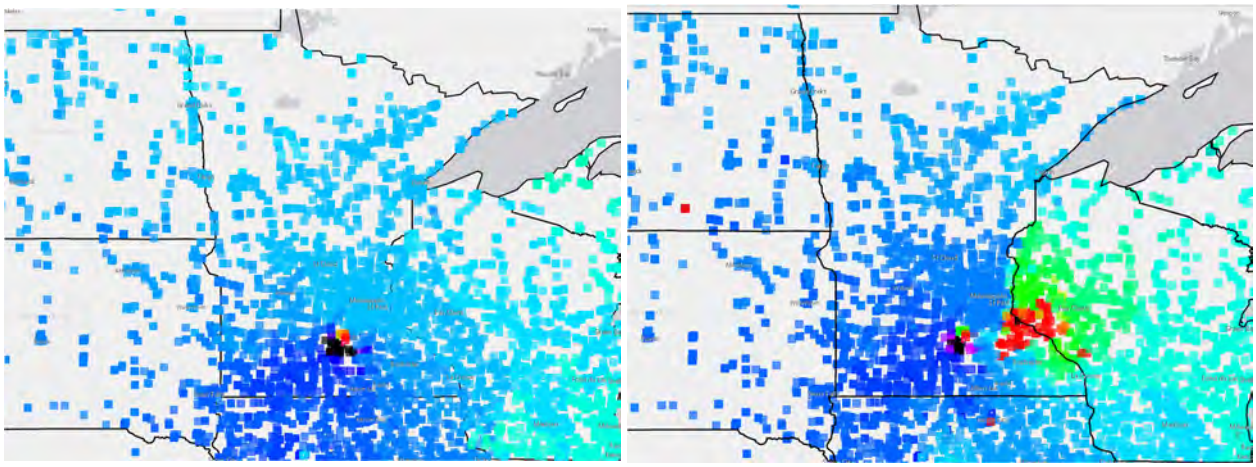
The following maps show side-by-side comparisons of LMPs from simulations before (left) and after (right) planned outages are included. Table show the impact on fuel mix for the representative hour.

October 6, 2023, 5:00 p.m. - Most Impactful Outage: Donaldson-Drayton



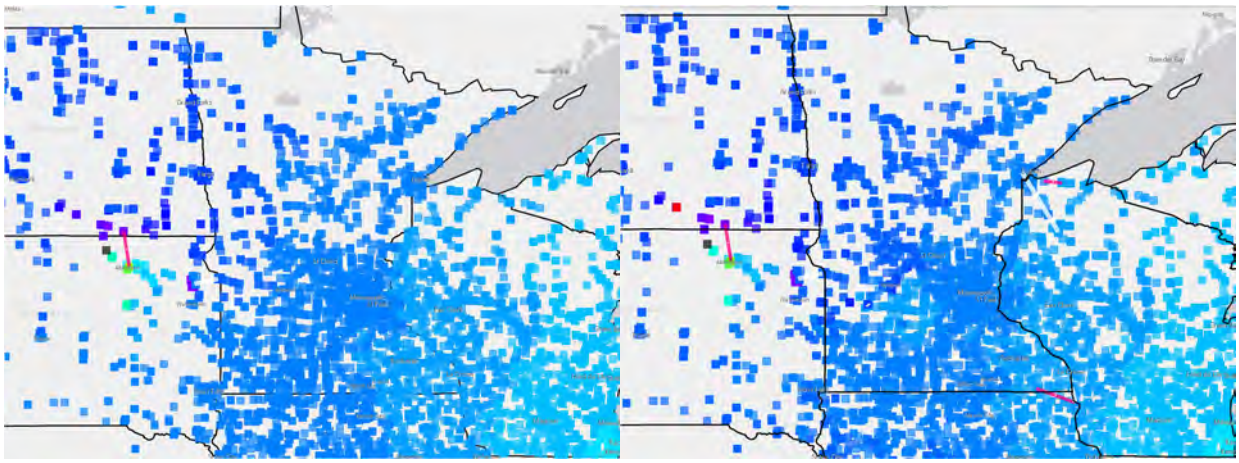
	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	4,334.2	133.0	148.0	2,127.8	1,286.1	155.0	15,365.1	23,549.2
Planned	4,646.9	133.0	148.0	2,127.8	1,288.3	112.5	13,423.0	21,879.6
Difference	+312.7	0.0	0.0	0.0	+2.2	-42.4	-1,942.1	-1,669.7

November 21, 2023, 8:00 P.M. – Most Impactful Outage: Winger



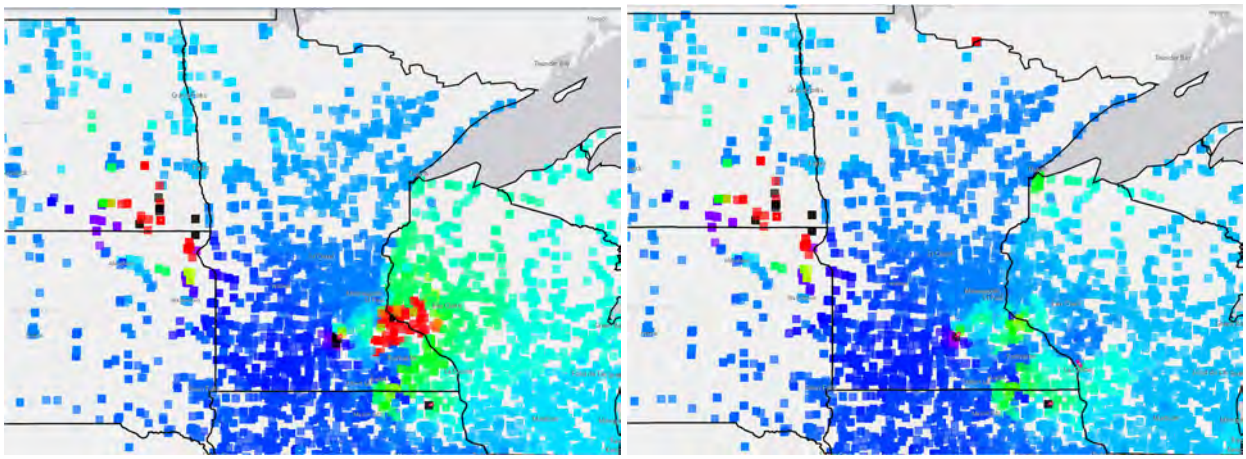
	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	9,453.7	348.8	294.0	2,127.8	1,004.8	47.7	12,014.2	25,290.9
Planned	9,389.9	248.3	317.8	2,127.8	1,008.1	47.7	11,659.8	24,799.3
Difference	-63.8	-100.5	+23.7	0.0	+3.4	0.0	-354.4	-491.6

December 17, 2023, 2:00 A.M. – Most Impactful Outage: Wishek



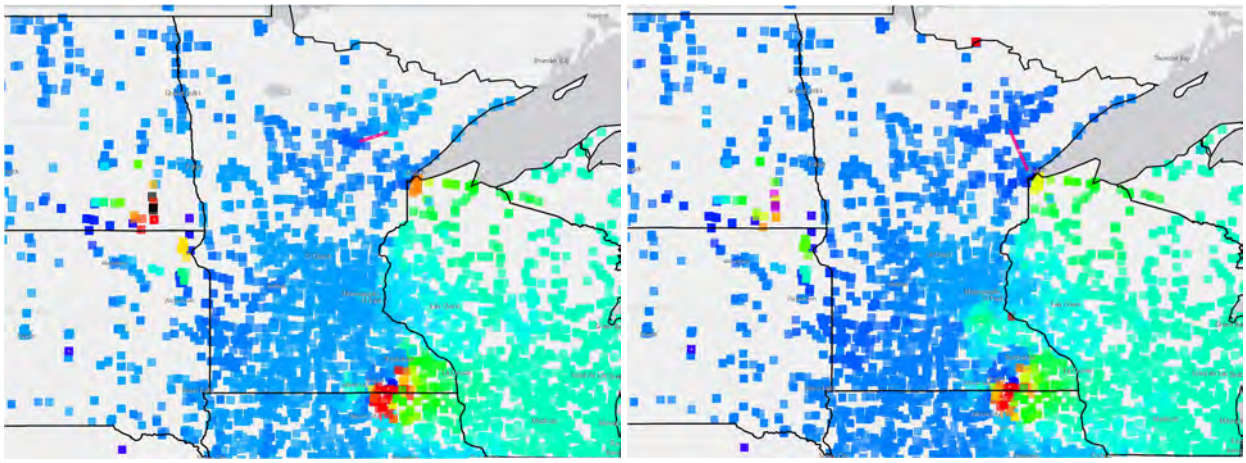
	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	9,766.8	115.3	132.1	2,127.8	837.1	0.0	7,191.9	20,170.9
Planned	8,768.0	115.3	132.1	2,127.8	842.6	0.0	7,180.9	19,166.6
Difference	-998.8	0.0	0.0	0.0	+5.5	0.0	-11.0	-1,004.3

January 5, 2024, 8:00 P.M. – Most Impactful Outage: Ortman-Little Fork



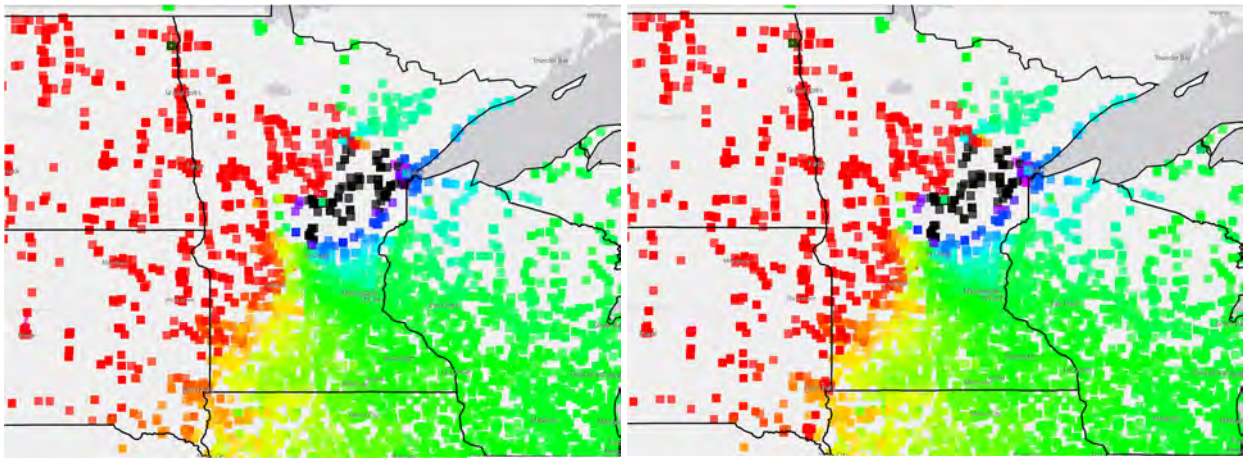
	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	6,942.6	479.0	193.6	2,127.8	1,291.9	48.8	16,509.8	27,593.4
Planned	6,817.4	449.4	172.1	2,127.8	1,291.9	48.8	15,537.8	26,445.0
Difference	-125.3	-29.6	-21.5	0.0	0.0	0.0	-972.1	-1,148.4

March 1, 2024, 7:00 A.M. – Most Impactful Outage: Ortman-Little Fork



	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	7,264.5	248.3	219.1	2,127.8	1,037.5	0.0	12,744.2	23,641.4
Planned	7,410.2	331.4	222.0	2,127.8	1,030.2	0.0	12,660.6	23,782.1
Difference	+145.6	+83.1	+2.8	0.0	-7.2	0.0	-83.6	140.7

August 9, 2024, 3:00 P.M. - Most Impactful Outage: Forman



	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	8,830.3	8,303.0	399.3	2,048.7	368.2	177.0	400.8	20,527.3
Planned	8,833.8	8,287.0	399.3	2,048.7	368.2	177.0	400.8	20,514.8
Difference	+3.5	-16.0	0.0	0.0	0.0	0.0	0.0	-12.5

Planned + Forged Outages

	Q4 2023		
Constraint	System Intact	Planned	Planned+Forced
ABDNJCT7 to ELLENDL7 #1	$12253 (7%)	$14336 (6%)	$8388 (4%)
ADAMS 5 to BVR CRK5 #1			
ALEXMRES7 to ALEXSWM7 #1		-$90013 (30%)	-$77053 (25%)
BRIGGS RD 5 to LAC TAP5 #1			
BIGSTON4 to BROWNSV4 #1	-$13890 (3%)	-$16189 (4%)	-$15147 (3%)
BROWNSV4 to NEW EFFNGTN4 #1	-$1563 (1%)	-$1771 (1%)	-$2576 (1%)
BLCKBRY4 to GRE-SWTRX3A4 #1		-$123 (0%)	-$92 (0%)
FORMN 7 to FORMAN 7 #1	-$150111 (15%)	-$178626 (21%)	-$154597 (21%)
GRE-CHUBLAK3 to YBUS(GRE-CHUBLAK7_GRE-CHUBLAKT) #1	$10682 (4%)	$14522 (5%)	$9734 (3%)
GRE-CHUBLAK7 to YBUS(GRE-CHUBLAK3_GRE-CHUBLAKT) #1	-$3119 (1%)	-$7547 (3%)	-$7231 (3%)
GRE-CLVLAND8 to LECENTR8 #1	-$138514 (10%)	-$220483 (15%)	-$368025 (20%)
GRE-JOHNJCT7 to MORRIS 7 #1			
GRE-SPRGCK15 to YBUS(GRE-SPRNGCK8_GRE-SPRNGC1T) #1	-$136419 (5%)	-$286554 (10%)	-$285925 (9%)
HELENA 3 to SCOTTCO3 #1	-$2002 (4%)		-$37 (0%)
HIBBARD7 to WNTR ST7 #1	-$9383 (5%)	-$7580 (4%)	-$6051 (4%)
LANSING L2 5 to HARMONY5 #1		-$4038 (14%)	-$3861 (14%)
MINVALT4 to GRANITF4 #1	$11635 (3%)	$17830 (8%)	$52904 (20%)
RVT1BUS7 to GRE-MERRFLD7 #1			
WILMART7 to SWAN LK7 #1		-$724 (0%)	-$3707 (1%)

	Q1 2024		
Constraint	System Intact	Planned	Planned+Forced
ABDNJCT7 to ELLENDL7 #1	$3850 (2%)	$3940 (2%)	$4224 (3%)
ADAMS 5 to BVR CRK5 #1			
ALEXMRES7 to ALEXSWM7 #1			
BRIGGS RD 5 to LAC TAP5 #1		-$10491 (8%)	
BIGSTON4 to BROWNSV4 #1			
BROWNSV4 to NEW EFFNGTN4 #1	-$6576 (4%)	-$7262 (5%)	-$5725 (4%)
BLCKBRY4 to GRE-SWTRX3A4 #1			
FORMN 7 to FORMAN 7 #1	-$675665 (46%)	-$669031 (46%)	-$631877 (48%)
GRE-CHUBLAK3 to YBUS(GRE-CHUBLAK7_GRE-CHUBLAKT) #1	$39810 (18%)	$30587 (13%)	$31942 (12%)
GRE-CHUBLAK7 to YBUS(GRE-CHUBLAK3_GRE-CHUBLAKT) #1	-$3788 (2%)	-$20225 (8%)	-$14853 (6%)
GRE-CLVLAND8 to LECENTR8 #1	-$465853 (31%)	-$414142 (32%)	-$715819 (38%)
GRE-JOHNJCT7 to MORRIS 7 #1			
GRE-SPRGCK15 to YBUS(GRE-SPRNGCK8_GRE-SPRNGC1T) #1	-$111942 (7%)	-$35398 (3%)	-$47758 (3%)
HELENA 3 to SCOTTCO3 #1	-$1153 (4%)	-$1005 (3%)	-$302 (1%)
HIBBARD7 to WNTR ST7 #1	-$10831 (5%)	-$20086 (10%)	-$7311 (4%)
LANSING L2 5 to HARMONY5 #1			
MINVALT4 to GRANITF4 #1	$1103 (0%)	$1843 (1%)	$23710 (7%)
RVT1BUS7 to GRE-MERRFLD7 #1			
WILMART7 to SWAN LK7 #1			

	Q2 2024		
Constraint	System Intact	Planned	Planned+Forced
ABDNJCT7 to ELLENDL7 #1	$8843 (5%)	$18897 (8%)	$13158 (7%)
ADAMS 5 to BVR CRK5 #1	-$30586 (10%)	-$21519 (7%)	-$9355 (2%)
ALEXMRES7 to ALEXSWM7 #1			
BRIGGS RD 5 to LAC TAP5 #1			
BIGSTON4 to BROWNSV4 #1	-$35039 (9%)	-$29059 (9%)	-$35056 (10%)
BROWNSV4 to NEW EFFNGTN4 #1			
BLCKBRY4 to GRE-SWTRX3A4 #1	-$14277 (8%)	-$14784 (9%)	-$14697 (9%)
FORMN 7 to FORMAN 7 #1	-$167422 (19%)	-$99569 (10%)	-$93178 (10%)
GRE-CHUBLAK3 to YBUS(GRE-CHUBLAK7_GRE-CHUBLAKT) #1	$5429 (3%)	$2095 (1%)	$2049 (1%)
GRE-CHUBLAK7 to YBUS(GRE-CHUBLAK3_GRE-CHUBLAKT) #1	-$1175 (0%)	-$1778 (1%)	-$1944 (1%)
GRE-CLVLAND8 to LECENTR8 #1	-$172296 (16%)	-$223586 (18%)	-$268606 (20%)
GRE-JOHNJCT7 to MORRIS 7 #1		-$14598 (2%)	-$26641 (3%)
GRE-SPRGCK15 to YBUS(GRE-SPRNGCK8_GRE-SPRNGC1T) #1	-$39143 (1%)	-$30891 (1%)	-$27621 (1%)
HELENA 3 to SCOTTCO3 #1			
HIBBARD7 to WNTR ST7 #1	-$116555 (39%)	-$152511 (42%)	-$118074 (35%)
LANSING L2 5 to HARMONY5 #1			
MINVALT4 to GRANITF4 #1	$1702 (1%)	$42514 (13%)	$33477 (10%)
RVT1BUS7 to GRE-MERRFLD7 #1	-$251 (0%)		-$297 (0%)
WILMART7 to SWAN LK7 #1	-$9675 (2%)	-$10807 (3%)	-$11907 (3%)

	Q3 2024		
Constraint	System Intact	Planned	Planned+Forced
ABDNJCT7 to ELLENDL7 #1	$2687 (2%)	$39746 (20%)	$45379 (27%)
ADAMS 5 to BVR CRK5 #1	-$9711 (4%)	-$8681 (3%)	-$8126 (3%)
ALEXMRES7 to ALEXSWM7 #1			
BRIGGS RD 5 to LAC TAP5 #1			
BIGSTON4 to BROWNSV4 #1	-$81030 (12%)	-$192813 (36%)	-$184256 (34%)
BROWNSV4 to NEW EFFNGTN4 #1			
BLCKBRY4 to GRE-SWTRX3A4 #1	-$27859 (6%)	-$30712 (6%)	-$36453 (8%)
FORMN 7 to FORMAN 7 #1	-$242468 (21%)	-$154458 (15%)	-$156740 (15%)
GRE-CHUBLAK3 to YBUS(GRE-CHUBLAK7_GRE-CHUBLAKT) #1	$2755 (2%)	$891 (1%)	$1047 (1%)
GRE-CHUBLAK7 to YBUS(GRE-CHUBLAK3_GRE-CHUBLAKT) #1	-$203 (0%)	-$1461 (1%)	-$1203 (1%)
GRE-CLVLAND8 to LECENTR8 #1	-$199207 (11%)	-$244317 (13%)	-$267809 (13%)
GRE-JOHNJCT7 to MORRIS 7 #1			-$252 (0%)
GRE-SPRGCK15 to YBUS(GRE-SPRNGCK8_GRE-SPRNGC1T) #1	-$45459 (1%)	-$75445 (2%)	-$68538 (3%)
HELENA 3 to SCOTTCO3 #1	-$9 (0%)		
HIBBARD7 to WNTR ST7 #1	-$155900 (27%)	-$141372 (27%)	-$109368 (23%)
LANSING L2 5 to HARMONY5 #1			
MINVALT4 to GRANITF4 #1	$2373 (1%)		$171 (0%)
RVT1BUS7 to GRE-MERRFLD7 #1	-$212686 (2%)	-$243067 (2%)	-$526918 (6%)
WILMART7 to SWAN LK7 #1	-$12994 (3%)	-$20287 (4%)	-$18400 (5%)