MISO's Response to Memphis Light, Gas & Water's Membership Assessment Request

Confidential and Proprietary

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1. Executive Summary

MISO is a member-driven organization, a 501(c)(4) non-profit that exists solely to serve the public good. In its pursuit to maximize value for its membership MISO periodically receives and responds to membership inquiries by various organizations. This document was drafted for Memphis Light, Gas & Water (MLGW) in response to its MISO membership inquiry as a part of its Integrated Resource Plan (IRP). MISO's responses herein are the product of a direct set of questions that were delivered to MISO from MLGW's IRP consultant, Siemens, along with a follow-up analysis considering a transmission-only option that was requested by MLGW.

This report covers many areas but is generally focused on the viability of MLGW's possible interconnection into MISO as a transmission owning member. As such it covers the areas of resource adequacy, transmission interconnection feasibility and cost, market impacts, membership application and cost, NERC functional requirements, and an overview of the interconnection process. For each study component MISO utilized either 2024 or 2025 depending on the available model framework to serve as the hypothetical year of integration. The results presented in this report are preliminary, based on the information MLGW and Siemens provided to MISO on MLGW's proposed generation and transmission additions and are subject to change based on future system conditions in MISO and MLGW. MISO looks forward to working with MGLW to further refine and enhance their MISO membership assessment with MLGW's input.

The ensuing report sections cover these topics in great depth. Additionally, the key takeaways are summarized below to provide MLGW with a focused view into the overall membership feasibility as studied by MISO in support of the MLGW IRP process.

- Under the base case proposal, the MLGW Capacity Import Limit (CIL) was estimated to be 2,579 MW with the Siemens' proposed transmission topology for the standalone case. This figure can be increased to approximately 2,783 MW if two 161 kV transmission lines are rebuilt to increase their contingent ratings.

- Siemens' proposed base capacity expansion plan would provide MLGW with sufficient local generation capacity to participate in MISO within the current Local Resource Zone (LRZ) 8 or as its own standalone zone, the hypothetical LRZ 11[1]. Additional transmission investments can be made to reduce the need for localized

[1] For Local Resource Zone (LRZ) 8 it was assumed that the Capacity Import Limit (CIL) would at least be equivalent to the current limit of 3,824 MW.

generation capacity, but this strategy may conflict with the identified reliability needs (highlighted in the third bullet below).

- If MLGW were to join LRZ 8 there would be mutually beneficial diversity benefits through the lowering of the Local Reliability Requirement (LRR) for both MLGW and the existing LRZ 8 footprint.

- MISO conducted a NERC TPL 001 planning assessment on the base generation and transmission expansion plan that validated the 2,400 MW transmission import capability during summer peak conditions. The only identified issues were due to rare NERC TPL 006 contingencies that can be mitigated through MISO South or MLGW internal redispatch.

- Based on the transmission interconnection analysis performed to date, MGLW would need to pursue all or most of the generation currently planned to facilitate redispatch during problematic P6 contingencies, which will avoid the need for load shed and ensure MISO South redispatch levels are reasonable.

- A second TPL-001 planning assessment was conducted on the transmission-only scenario. In this instance one additional transmission line (500 kV Dell – New Shelby) was added to the base transmission expansion plan. MISO analyzed a 3,200 MW transfer to accommodate MLGW's full load during all hours of the year. This analysis identified significant thermal, voltage, and stability issues that indicate that this would not be a reliable solution for MLGW. It is believed that many of these issues could be solved by siting some local generation in or around the MLGW service territory.

- The cost of the base transmission expansion proposal for new interconnections and reliability upgrades is projected to be $736.2 million ($2020) using MISO's transmission cost estimate guide. This figure is somewhat higher than the $630.0 million ($2018) total capital expenditure estimate provided to MLGW by Siemens due to inflation, differences in contingency assumptions, and the inclusion of a spare transformer at each site. Similarly, MISO's cost estimate for the transmission-only scenario was $1,127.5 million ($2020) which was higher than Siemens' estimate of $1,014.0 ($2018) due to the same factors. After adjusting for these differences the two cost estimates are very comparable.

- The market impact assessment identified annual production cost savings of $116.3 million in 2024 under Portfolio Option #1 increasing to as high as $345.2 million by 2034 under Portfolio Option #2. This is the result of MLGW developing its own local generation fleet and also participating in the larger MISO pool. The primary drivers of savings are the addition of low-cost renewable and gas-fired resources and access to more cost-effective purchases from the MISO wholesale energy market. A transmission-only scenario (Portfolio #3) where no incremental resources were added to the projected MISO fleet resulted in lower production cost savings than the scenario with local MLGW resources. Projected savings were estimated to be $55.9 million in 2024 and increasing to $117.2 million by 2034. Lastly, a hypothetical Portfolio #4 scenario was added that assumes that additional gas and renewable capacity are integrated into MISO as the direct result of a MLGW Power Purchase Agreement (PPA) solicitation. Similar to Portfolios #1-2 significant production cost savings are realized by MLGW due to the access that is provided to solar and gas-fired resources that have lower variable production costs. MISO's analysis did not evaluate the fixed costs associated with MLGW developing its own generation fleet. Only minor changes to congestion patterns were observed within the existing MISO footprint.

- Based on MLGW's projected energy sales in 2025 MISO estimates its annual administrative cost recovery fees to be approximately $6 million. MLGW would also be responsible for a portion of MISO's Schedule 10 FERC charges that would be an additional cost of roughly $730,000 per year.

2. Resource Adequacy Assessment

<u>Objective</u>: Analyze the feasibility and impact of MLGW joining MISO's existing Local Resource Zone 8 (Arkansas) or becoming its own standalone Local Resource Zone using the base capacity expansion plan. Additionally, MLGW requested that MISO analyze the viability of a transmission-only scenario in which MLGW participates in LRZ 8 while retaining no generation capacity to determine if sufficient resources inside and outside of LRZ 8 would be available to cover all of MLGW's resource adequacy needs. Lastly, evaluate the capacity available for purchase by MLGW that it would need to satisfy its resource adequacy requirement in MISO.

<u>MISO Conclusion</u>: It was determined that it is feasible for MLGW to join MISO and participate in the existing Local Resource Zone 8 or in the hypothetical standalone Local Resource Zone 11 under the current capacity expansion plan (i.e. proposed capacity in MLGW exceeds the local clearing requirement). However, if MLGW were to join LRZ 8 it appears that there would be mutually beneficial diversity benefits which is observed through a reduction in the Local Reliability Requirement (LRR) for both the existing LRZ 8 and MLGW. Incorporating MLGW into MISO's footprint also provides diversity benefits that results in a lowering of the overall Installed Capacity (ICAP) Planning Reserve Margin (PRM) from 18.2% to 17.9% and the Unforced Capacity (UCAP) PRM from 8.9% to 8.8%. The PRM and LRR calculated for the transmission-only scenario are very comparable to the results that were estimated for the base capacity expansion plan. As far as the availability of capacity for purchase, both the 2020-21 Planning Resource Auction (PRA) and the 2020 OMS-MISO survey indicate excess capacity in LRZ 8. The latter projects 0.9 – 1.8 GW of excess installed capacity in 2025. However, MISO is unable to anticipate changes that could occur based on future resource decisions and how that may impact how much capacity would be available for purchase by MLGW in 2025 and beyond.

<u>Loss of Load Expectations (LOLE) Analysis</u>:

MISO contracted with Astrapé Consulting to perform the base LOLE analysis to determine the MISO system-wide PRM with MLGW, and the per-unit LRRs of zonal peak demand, for MLGW stand-alone zone and LRZ 8 with MLGW. The analysis was built upon the 2020 MISO Loss of Load Expectation (LOLE) Study and used the 2025 out-year SERVM model to evaluate the impacts of MLGW on the MISO system.

<u>MLGW Modeling in SERVM</u>:

The following describes the approach Astrapé took in modeling MLGW within the MISO SERVM database. MLGW was added to the existing MISO SERVM database as a new region, LRZ 11. Using data provided by MLGW as well as publicly available load information, the load and resources for MLGW were modeled. Table 1 below shows the resources that were modeled for LRZ 11.

Table 1: Proposed Base MLGW Resource Mix

Resource	Summer MW	Winter MW	EFORd	Maintenance Rate
1x1 CCGT #1	-	-	5.70%	11.20%
Base	332	361	-	-
Duct Firing	82	89	-	-
1x1 CCGT #2	-	-	5.70%	11.20%
Base	332	361	-	-
Duct Firing	82	89	-	-
1x1 CCGT #3	-	-	5.70%	11.20%
Base	332	361	-	-
Duct Firing	82	89	-	-
7FA CT	216	237	4.65%	8.57%
Solar Facilities*	300	300	-	-
Total Capacity	1,758	1,887	-	-

*Represents an installed capacity of 1,000 MW at an Effective Load Carrying Capability (ELCC) of 0.3.

The solar facilities modeled were based on MLGW's current plan to add 600 MW of solar in 2025 and 400 MW of solar in 2026. For purposes of the study, both were assumed to be implemented in the Study Year (i.e., 2025) with an applied ELCC of 0.3 since additional capacity would be needed to meet the 0.1 MISO LOLE standard.

The unit, 1x1 CCGT #3, was listed as an optional unit. Therefore, the analysis considered the results with and without this unit.

Based on five years of hourly historical load pulled from FERC 714 forms for MLGW, load shapes were developed for each of the 30 weather years simulated (1989-2018). Table 2 below shows a 12x24 representation of the aggregate of the 30 load shapes.

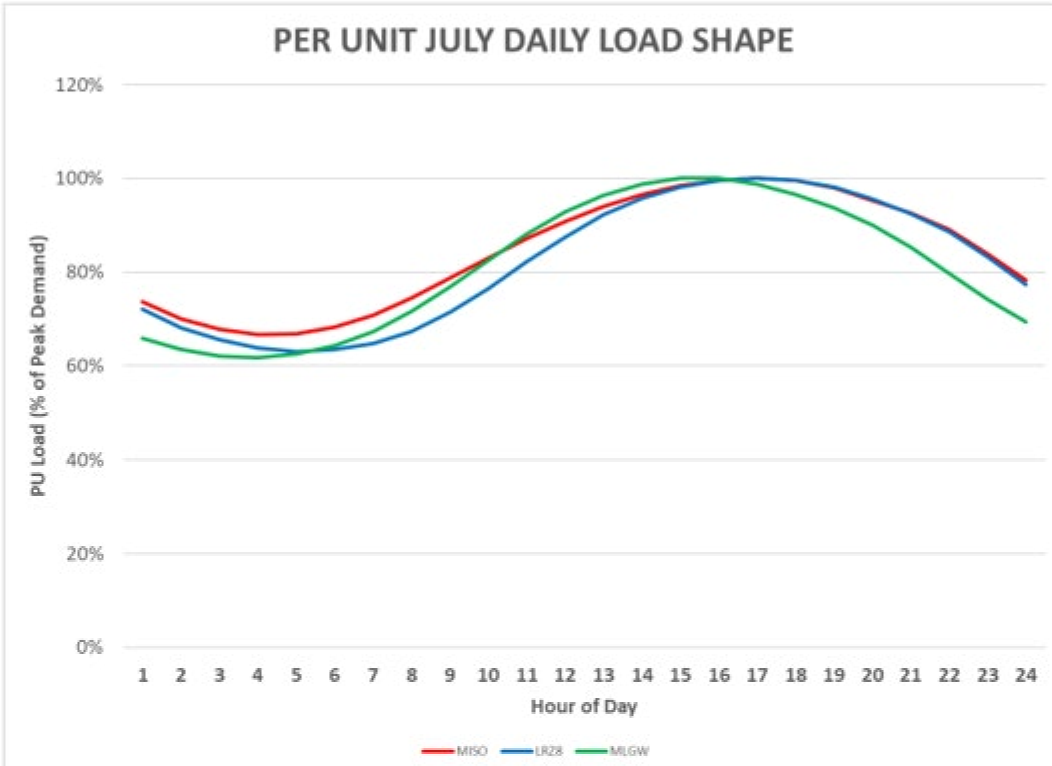
Table 2: MLGW Modeled Aggregate Load Shape

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	1,494	1,429	1,216	1,148	1,284	1,669	1,766	1,744	1,473	1,187	1,273	1,402
2	1,450	1,382	1,209	1,118	1,244	1,609	1,703	1,681	1,424	1,155	1,241	1,357
3	1,427	1,358	1,208	1,108	1,224	1,575	1,666	1,644	1,398	1,143	1,230	1,334
4	1,425	1,355	1,211	1,118	1,227	1,568	1,656	1,633	1,395	1,153	1,240	1,331
5	1,443	1,374	1,218	1,146	1,252	1,589	1,675	1,653	1,415	1,183	1,267	1,348
6	1,485	1,419	1,229	1,191	1,296	1,640	1,726	1,703	1,458	1,228	1,310	1,387
7	1,543	1,481	1,249	1,242	1,353	1,720	1,807	1,779	1,517	1,281	1,360	1,441
8	1,601	1,541	1,284	1,292	1,423	1,828	1,921	1,881	1,592	1,335	1,411	1,495
9	1,643	1,583	1,337	1,335	1,499	1,960	2,061	2,008	1,681	1,383	1,455	1,535
10	1,664	1,602	1,399	1,369	1,577	2,106	2,217	2,155	1,786	1,423	1,483	1,555
11	1,666	1,601	1,457	1,396	1,651	2,247	2,365	2,305	1,899	1,458	1,494	1,558
12	1,656	1,590	1,498	1,421	1,718	2,368	2,490	2,441	2,007	1,492	1,496	1,549
13	1,637	1,572	1,521	1,446	1,775	2,464	2,585	2,548	2,100	1,527	1,494	1,533
14	1,615	1,553	1,534	1,468	1,821	2,531	2,649	2,623	2,172	1,558	1,493	1,515
15	1,596	1,535	1,539	1,486	1,854	2,567	2,683	2,664	2,221	1,581	1,492	1,500
16	1,585	1,526	1,538	1,498	1,868	2,567	2,682	2,669	2,239	1,595	1,492	1,493
17	1,593	1,532	1,532	1,503	1,861	2,535	2,649	2,634	2,222	1,596	1,497	1,504
18	1,622	1,559	1,521	1,501	1,837	2,479	2,592	2,574	2,176	1,587	1,508	1,534
19	1,665	1,599	1,501	1,490	1,798	2,405	2,515	2,492	2,105	1,565	1,519	1,574
20	1,697	1,629	1,460	1,462	1,740	2,310	2,415	2,388	2,010	1,524	1,518	1,604
21	1,701	1,633	1,395	1,412	1,659	2,187	2,287	2,257	1,891	1,461	1,493	1,606
22	1,673	1,605	1,321	1,343	1,557	2,043	2,138	2,106	1,760	1,384	1,446	1,578
23	1,621	1,554	1,261	1,267	1,451	1,897	1,988	1,959	1,635	1,304	1,386	1,528
24	1,557	1,490	1,225	1,200	1,359	1,772	1,861	1,835	1,533	1,236	1,326	1,466

The table represents the average daily shape per month for all the 30 weather years modeled. As indicated in the additional figures below, MLGW tends to peak several hours earlier than either MISO or LRZ 8, creating potential opportunities for load diversity during the summer. However, it is the winter load shapes that create the greatest opportunities for load diversity. MLGW has a considerably lower relative winter load shape than either MISO or LRZ 8. The following figures illustrate these observations.

Figure 1 below shows the potential load diversity for the month of July between MLGW, the aggregated MISO, and LRZ 8 during the summer by showing the per unit July load shape for each. As the figure illustrates, MLGW peaks earlier than either MISO or LRZ 8.

Figure 1: MISO, LRZ 8, and MLGW Summer Load Shape Diversity



Likewise, Figure 2 below shows the potential load diversity for the winter between MLGW, MISO, and LRZ 8. As the figure illustrates, MLGW has much lower winter loads than the rest of MISO and LRZ 8 when examined on a per unit basis.

Figure 2: MISO, LRZ 8, and MLGW Winter Load Shape Diversity

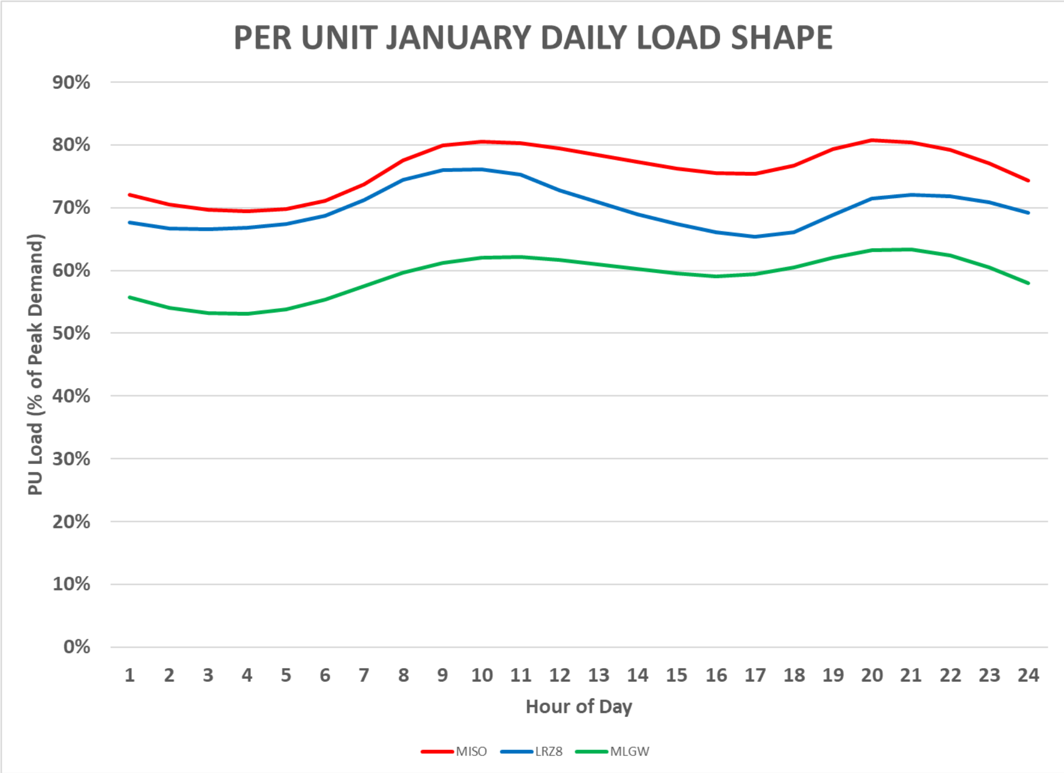


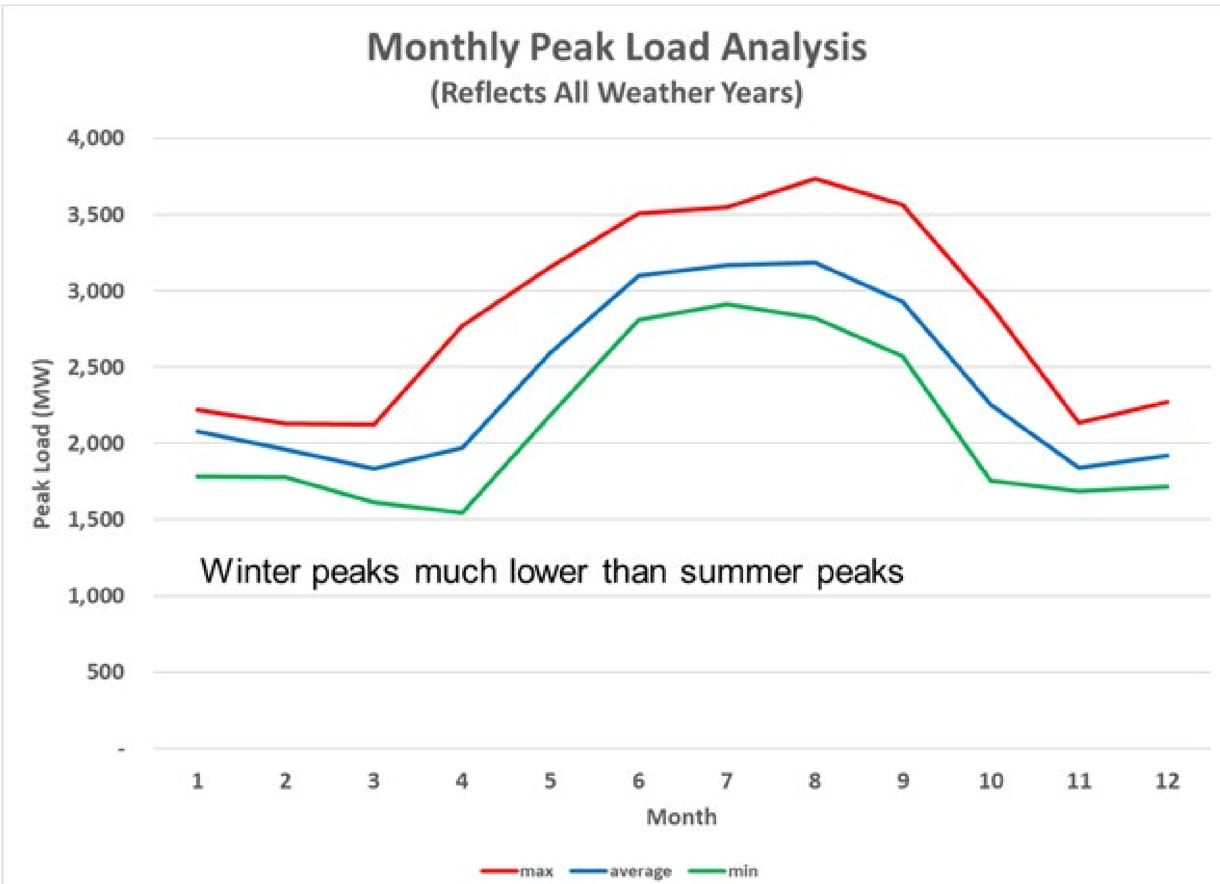
Table 3 below shows the monthly peak demand and energy forecasts used for the Study Year as provided by MLGW.

Table 3: 2025 Monthly Peak Demand and Energy Forecast

Month	Peak Demand (MW)	Total Energy (MWh)
January	2,087	1,087,107
February	1,963	943,512
March	1,841	967,194
April	1,983	931,655
May	2,606	1,140,181
June	3,112	1,412,151
July	3,177	1,534,660
August	3,197	1,497,591
September	2,942	1,235,031
October	2,273	1,003,987
November	1,846	938,792
December	1,929	1,042,692

Consistent with MISO's individual LRR analyses, the load shapes in SERVM were adjusted such that the average monthly peaks matched the monthly peak forecast. Figure 3 below shows the resulting modeled minimum, maximum, and average monthly peak loads.

Figure 3: MLGW Modeled Monthly Peak Loads



MISO System-Wide PRM Impact:

To determine the impact of integrating MLGW into MISO, a PRM analysis was performed on the combined MISO plus MLGW system in a manner consistent with the PRM analysis performed for the MISO system in the 2020 LOLE Study Report. Prior to making any adjustments for non-firm externals, the SERVM model of MISO (including MLGW) had a native reserve margin of 27.0%, which would have resulted in an LOLE significantly lower than 0.1 days/year. To determine the PRM at which LOLE would approximate 0.1 days/year, a Negative Adjustment Unit was placed at the "MISO Hub" and its capacity was iteratively adjusted until the combined MISO plus MLGW system reached 0.1 LOLE. Table 4 below shows the final PRM calculation on both an ICAP and UCAP basis, including an adjustment for non-firm externals of 2,987 MW. As indicated, the total negative adjustment required was 10,085 MW.

Table 4: 2025 PRM for MISO plus MLGW

MISO System Peak Demand (MW)	128,505	A
Installed Capacity (ICAP) (MW)	162,987	B
Unforced Capacity (UCAP) (MW)	150,599	C
Firm External Support (ICAP) (MW)	1,626	D
Firm External Support (UCAP) (MW)	1,572	E
Adjustment to ICAP (1d in 10yr) (MW)	(10,085)	F
Adjustment to UCAP (1d in 10yr) (MW)	(10,085)	G
Non-Firm External Support (ICAP) (MW)	2,987	H
Non-Firm External Support (UCAP) (MW)	2,331	I
ICAP PRM Requirement (PRMR) (MW)	151,541	J=B+D+F-H
UCAP PRM Requirement (PRMR) (MW)	139,755	K=C+E+G-I
MISO PRM ICAP	17.9%	L=(J-A) / A
MISO PRM UCAP	8.8%	M=(K-A) / A

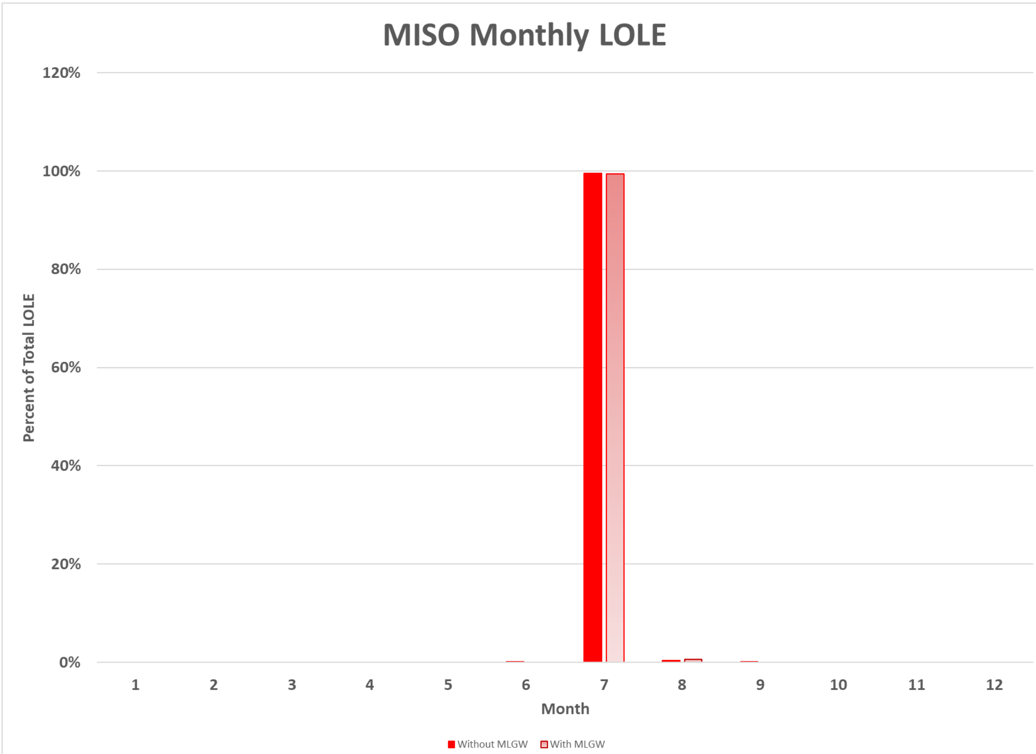
In accordance with MISO practice, the peak load used was the Summer coincident peak load for all of MISO including MLGW. The LOLE at 17.9% would be 0.10 days/year.[2] By comparison, without the addition of MLGW, the MISO 2020 LOLE Report calculated a PRM ICAP of 18.2% (PRM UCAP of 8.9%) to achieve 0.1 days/year LOLE. Figure 4 below shows the monthly LOLE for MISO with and without MLGW as a percent of total LOLE. Nearly 100% of the LOLE is concentrated in July. As indicated by the slightly lower PRM and as seen in the figure, there is a marginal benefit for MISO to add MLGW. For context, a table outlining the historical MISO Planning Reserve Margins is included below.

Table 5: Historical MISO Planning Reserve Margins

Historical PRM	14-15	15-16	16-17	17-18	18-19	19-20	20-21
PRM ICAP	14.8%	14.3%	15.2%	15.8%	17.1%	16.8%	18.0%
PRM UCAP	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%

[2] Astrapé notes that if the negative perfect unit were treated as load, the difference in PRMs would be much closer (i.e. 16.7% without MLGW and 16.7% with MLGW). The accounting method for the negative perfect unit slightly obfuscates the impact of the additional region.

Figure 4: Comparison of MISO LOLE with and without MLGW



MLGW as a Standalone Local Resource Zone 11:

Based upon the LRZ 11 SERVM model, the native reserve margin for MLGW (LRZ 11) is shown in Table 6 below.

Table 6: 2025 LRZ 11 Native Reserve Margin

Annual Peak Load (MW)	3,197	A
Total ICAP Resources (MW)	1,758	B
Total UCAP Resources (MW)	1,677	C
Reserve Margin ICAP %	-45.0%	(B-A) / A
Reserve Margin UCAP %	-47.5%	(C-A) / A

Consistent with MISO practice, this native reserve margin was calculated based on the highest monthly peak load for MLGW which was August.

A Local Reliability Requirement analysis was then performed for LRZ 11 using techniques consistent with how MISO performed such analyses for other LRZ's in the 2020 LOLE

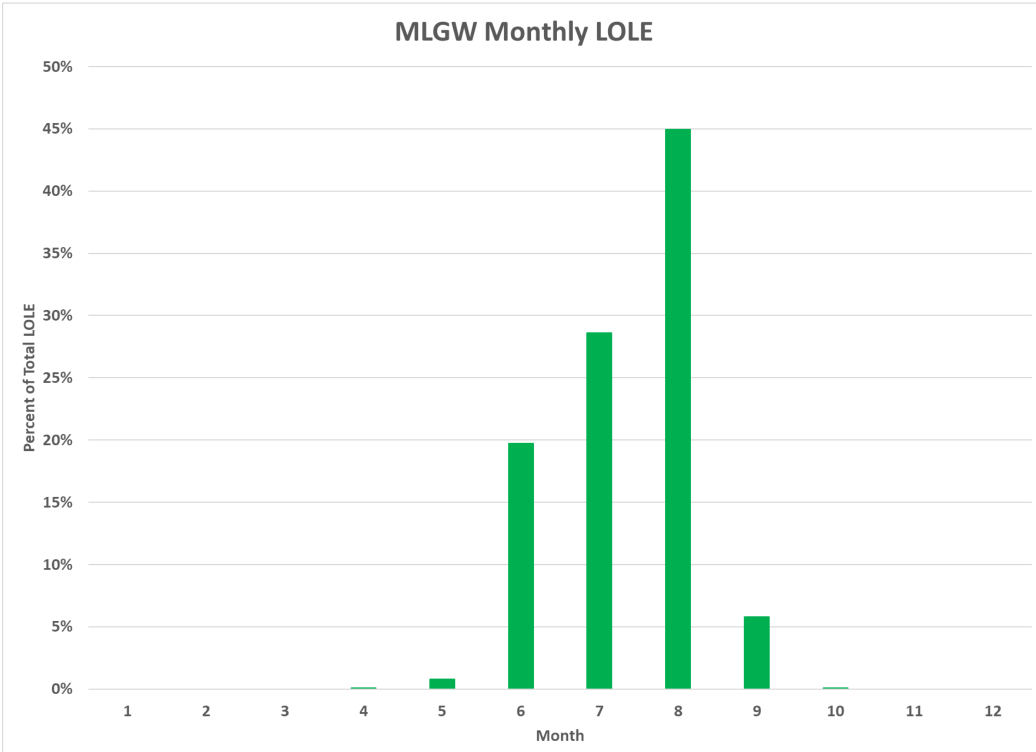
Study Report. Specifically, 160 MW "Adjustment Unit" CTs were added incrementally to LRZ 11 until the region reached an annual LOLE approximating 0.1 days/year. Based on this analysis, Table 7 below shows the stand-alone LRR calculations necessary for LRZ 11 to maintain the required 0.1 days/year LOLE criteria.

Table 7: 2025 LRZ 11 Standalone LRR Analysis

Installed Capacity (ICAP) (MW)	1,759	A
Unforced Capacity (UCAP) (MW)	1,677	B
Adjustment to UCAP (1d in 10yr) (MW)	2,351	C
LRR (UCAP) (MW)	4,028	D=B+C
Peak Demand (MW)	3,197	E
LRR UCAP per-unit of LRZ Peak Demand	**126.0%**	F=D/E

At 126% LRR UCAP, the total LOLE is 0.10 days/year. Figure 5 below shows the monthly breakdown of the LOLE as a percent of total LOLE. It should be noted that because the native reserve margin for LRZ 11 was already negative, MLGW would be short on capacity for meeting their LCR without all three combined cycle facilities. Therefore, Astrapé did not evaluate the stand-alone LRR for LRZ 11 without the optional 1x1 CCGT #3.

Figure 5: LRZ 11 Monthly LOLE



MLGW as a Part of Local Resource Zone 8:

To determine the impact of integrating MLGW into LRZ 8, an LRR analysis was performed on the combined LRZ 8 plus MLGW regions in a manner consistent with the LRR analysis performed in the MISO 2020 LOLE Study Report for LRZ 8 and as performed for LRZ 11 above. On a stand-alone basis, the SERVM Model for LRZ 8 had a native reserve margin of 48.2% and required approximately 655 MW of negative adjustment to achieve an LOLE of 0.1 days/year. However, because of the significantly negative native reserve margin for LRZ 11, the combined LRZ 8 plus LRZ 11 system required the addition of positive adjustment units to achieve the necessary 0.1 days/year. As with the LRZ 11 stand-alone analysis, this was accomplished through the iterative addition of 160 MW Adjustment Unit CTs until the combined system reached an LOLE of 0.1 days/year. Table 8 below shows the resulting LRR UCAP of the combined system.

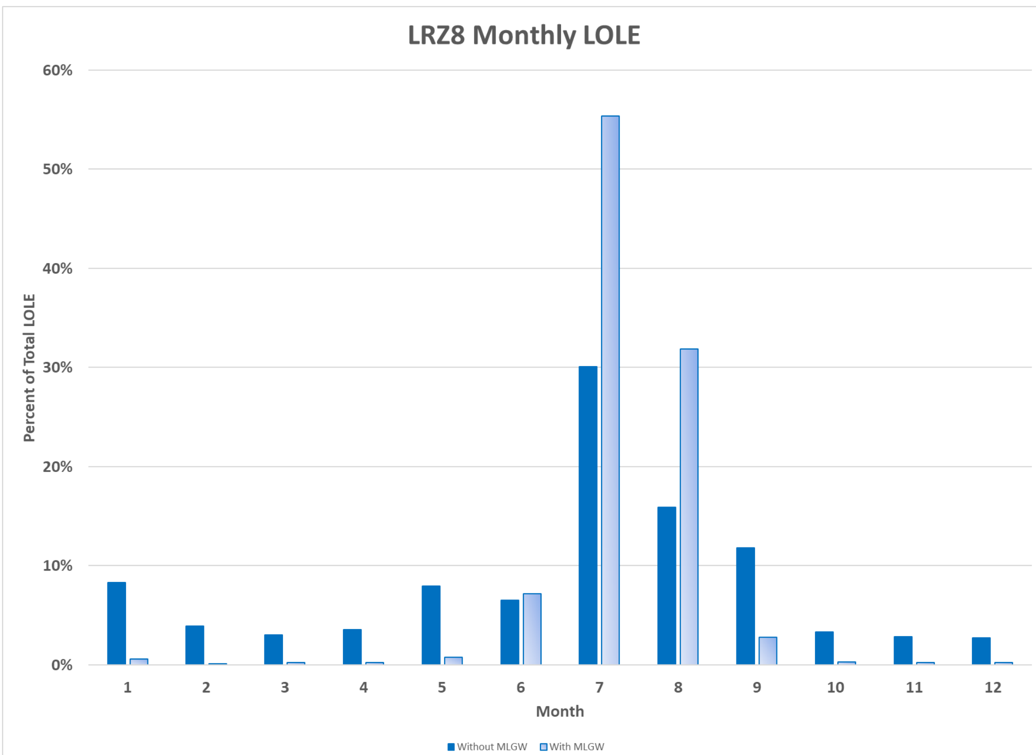
Table 8: 2025 LRR for LRZ 8 plus MLGW

Installed Capacity (ICAP) (MW)	13,525	A
Unforced Capacity (UCAP) (MW)	12,703	B
Adjustment to UCAP (1d in 10yr) (MW)	422	C

LRR (UCAP) (MW)	13,125	D=B+C
Peak Demand (MW)	10,884	E
LRR UCAP per-unit of LRZ Peak Demand	**120.6%**	F=D/E

In accordance with MISO practice, the peak load was based on the highest monthly peak load of the combined LRZ 8 plus LRZ 11 system, which turned out to be July. The resulting LOLE at 120.6% LRR UCAP would be 0.10 days/year. By comparison, the LRR UCAP at 0.1 days/year LOLE for LRZ 8 without MLGW according to the MISO 2020 LOLE study was 132.5%, which represents a substantial reduction in LRR for LRZ 8. This also represents a substantial reduction for MLGW (LRZ 11) on a stand-alone basis, which had an LRR of 126.0% (on a UCAP basis). Figure 6 below shows the monthly LOLE for LRZ 8 with and without MLGW as a percent of total LOLE.

Figure 6: Comparison of LRZ 8 Monthly LOLE with and without MLGW



As indicated by the monthly LOLE figure, the load and resource diversity afforded by adding MLGW to LRZ 8 resolves a significant portion of the non-summer LOLE. This creates an overall benefit for both regions, resulting in a significantly lower combined LRR than for either region individually.

Sensitivity Case Analysis:

Because the 1x1 CCGT #3 unit was considered optional, Astrapé performed a sensitivity in which it evaluated the LRR for the combined LRZ 8 plus MLGW system without this third combined cycle facility. The resulting LRR UCAP was 120.5%, which is not a substantial difference than the results including the third combined cycle facility.

Table 9: LRZ 8 Plus MLGW LRR with only Two Combined Cycles

Installed Capacity (ICAP) (MW)	13,111	A
Unforced Capacity (UCAP) (MW)	12,312	B
Adjustment to UCAP (1d in 10yr) (MW)	800	C
LRR (UCAP) (MW)	13,112	D=B+C
Peak Demand (MW)	10,884	E
LRR UCAP per-unit of LRZ Peak Demand	**120.5%**	F=D/E

Astrapé also performed a solar winter ELCC sensitivity on the combined LRZ 8 plus LRZ 11 regions. Currently, MISO gives solar the same ELCC value for solar in both summer and winter. Due to the amount of solar included in the two regions, a sensitivity was performed in which the ELCC for winter was decreased to 5%. The 5% assumption was modeled in December, January, and February. The LRR UCAP for the combined LRZ 8 plus LRZ 11 region increased slightly to 120.7%. The winter LOLE still remained low even with the lower solar capacity value modelled for the winter.

Table 10: LRZ 8 Plus MLGW LRR with 5% Winter Solar ELCC

Installed Capacity (ICAP) (MW)	13,525	A
Unforced Capacity (UCAP) (MW)	12,703	B
Adjustment to UCAP (1d in 10yr) (MW)	431	C
LRR (UCAP) (MW)	13,134	D=B+C
Peak Demand (MW)	10,884	E
LRR UCAP per-unit of LRZ Peak Demand	**120.7%**	F=D/E

Transmission-Only Scenario Results:

MISO ran one additional sensitivity which assumed that MLGW would join LRZ 8 but would rely exclusively on its transmission system to procure capacity from the current MISO footprint. In this scenario all of the proposed MLGW generation was removed from the model to identify the MISO-wide PRM as well as the LRR for the combined LRZ 8 plus MLGW region under this transmission-only sensitivity. This scenario did not result in a change to the PRM, however there was a slight reduction in the LRR due to the fact that the proxy units used to adjust the model to an LOLE of 0.1 are smaller than the proposed MLGW units. Multiple small units tend to increase reliability compared to fewer large units because the probability of losing several small units to forced outage simultaneously is lower than losing a single large unit. The results of this sensitivity are shown in the table below.

Table 11: 2025 PRM for MISO plus MLGW (Transmission Only)

MISO System Peak Demand (MW)	128,505	A
Installed Capacity (ICAP) (MW)	161,228	B
Unforced Capacity (UCAP) (MW)	148,922	C
Firm External Support (ICAP) (MW)	1,626	D
Firm External Support (UCAP) (MW)	1,572	E
Adjustment to ICAP (1d in 10yr) (MW)	(8,300)	F
Adjustment to UCAP (1d in 10yr) (MW)	(8,300)	G
Non-Firm External Support (ICAP) (MW)	2,987	H
Non-Firm External Support (UCAP) (MW)	2,331	I
ICAP PRM Requirement (PRMR) (MW)	151,567	J=B+D+F-H
UCAP PRM Requirement (PRMR) (MW)	139,863	K=C+E+G-I
MISO PRM ICAP	17.9%	L=(J-A) / A
MISO PRM UCAP	8.8%	M=(K-A) / A

Table 12: LRR for LRZ 8 plus MLGW (Transmission Only)

Installed Capacity (ICAP) (MW)	11,766	A
Unforced Capacity (UCAP) (MW)	11,026	B
Adjustment to UCAP (1d in 10yr) (MW)	2,061	C
LRR (UCAP) (MW)	13,087	D=B+C
Peak Demand (MW)	10,884	E
LRR UCAP per-unit of LRZ Peak Demand	**120.2%**	F=D/E

Conclusions:

The addition of MLGW added benefit to both MISO as well as LRZ 8. Table 13 below shows a summary of PRM calculations for MISO with and without MLGW.

Table 13: Summary of MISO System-Wide PRM Calculations

	MISO Without MLGW	MISO With MLGW	MISO With MLGW Transmission Only	
MISO System Peak Demand (MW)	125,600	128,505	128,505	A
Installed Capacity (ICAP) (MW)	161,228	162,986	161,228	B
Unforced Capacity (UCAP) (MW)	148,922	150,599	148,922	C
Firm External Support (ICAP) (MW)	1,626	1,626	1,626	D
Firm External Support (UCAP) (MW)	1,572	1,572	1,572	E
Adjustment to ICAP (1d in 10yr) (MW)	(11,360)	(10,085)	(8,300)	F
Adjustment to UCAP (1d in 10yr) (MW)	(11,360)	(10,085)	(8,300)	G
Non-Firm External Support (ICAP) (MW)	2,987	2,987	2,987	H
Non-Firm External Support (UCAP) (MW)	2,331	2,331	2,331	I
ICAP PRM Requirement (PRMR) (MW)	148,507	151,541	151,567	J=B+D+F-H
UCAP PRM Requirement (PRMR) (MW)	136,804	139,755	139,863	K=C+E+G-I
MISO PRM ICAP	18.2%	17.9%	17.9%	L=(J-A) / A
MISO PRM UCAP	8.9%	8.8%	8.8%	M=(K-A) / A

Table 14 below shows a summary of the LRR calculations for MGLW on a stand-alone basis as well as the combined region that includes LRZ 8 plus MGLW. The sensitivities assessing two combined cycles, winter solar ELCC, and a transmission-only scenario are included in the table but had a modest impact on the results.

Table 14: Summary of LRR Calculations

	MLGW	LRZ8	LRZ8	LRZ8	LRZ8	LRZ8	
	Stand Alone	Without MLGW	With MLGW (Base)	With MLGW 2 CCs	With MLGW 5% winter ELCC	With MLGW Transmission Only	
Installed Capacity (ICAP) (MW)	1,759	11,766	13,525	13,111	13,525	11,766	A
Unforced Capacity (UCAP) (MW)	1,677	11,026	12,703	12,312	12,703	11,026	B
Adjustment to UCAP (1d in 10yr) (MW)	2,351	(580)	422	800	431	2,061	C
LRR (UCAP) (MW)	4,028	10,446	13,125	13,112	13,134	13,087	D=B+C
Peak Demand (MW)	3,197	7,883	10,884	10,884	10,884	10,884	E

LRR UCAP per-unit of LRZ Peak Demand	126.0%	132.5%	120.6%	120.5%	120.7%	120.2%	F=D / E

Transfer Analysis:

MLGW contracted with Siemens to perform the base transfer analysis to determine the Capacity Import Limit (CIL) and Capacity Export Limit (CEL) for MLGW as a stand-alone zone. Siemens shared this work with MISO for inclusion in the resource adequacy analysis. Additionally, MISO is in the process of calculating a CIL for MLGW participating in LRZ 8 with no generation resources under a transmission-only scenario. The results of this analysis will not be complete until a later date and will be shared with MLGW at that time.

***Objective**: Determine constraints caused by the transfer of capacity to and from a Local Resource Zone (LRZ) as well as the associated transfer capability using MISO's criteria for CIL and CEL analyses. Perform CIL and CEL for MLGW assuming MLGW were to join MISO starting in 2025. Results will be used in determining whether MLGW can meet the MISO Resource Adequacy requirements under the base capacity expansion plan.*

***Conclusion**: Transfer analyses were performed to determine the CIL and CEL for MLGW assuming MLGW were to join MISO as early as 2025. The CIL was found to be 2,579 MW in out-year 2024-25 based on the study assumptions mentioned above. This limit can be further increased to 2,783 MW with the reinforcement of the FREEPORT #2 to MENDENHAL 161 kV line and the 5SE GATE 34 to 5SHADY GRV87 161 kV line. The constraints were found to be inside of MLGW's transmission system with no available redispatches to alleviate them. It is possible to achieve greater increased CIL levels by further upgrading MLGW's transmission facilities.*

The CEL, on the other hand, was found to be no limit. GLT was performed and no valid constraint was found either before or after GLT with a load and generation reduction of 50%.

These study results are a function of the assumptions used for the study. The analysis and results documented herein are based on the best available information, and the generation, load, and/or transmission topology associated with the study year at the time of the analysis. Any change to the study assumptions documented herein may result in alteration of the study results and require an update to the study. Several factors could potentially alter the study

results, including but limited to, the locations and capacity for MLGW's internal generation, actual system demand, the MISO out-year generation additions and retirements, and transmission topology. The goal of the IRP is to forecast the most likely future scenarios and help MLGW determine the most reliable and economical generation and transmission portfolio, however neither of which is considered final at the conclusion of the IRP.

Interconnection, Load and Generation Assumptions:

For MLGW to join MISO, it is assumed in this study that MLGW would have to build new transmission interconnections to MISO South, specifically:

1. A new 500 kV line from a new MLGW Shelby 500 kV substation to Entergy Arkansas's San Souci 500 kV substation
2. A new 500 kV line from a new MLGW New Allen 500 kV / 230 kV / 161 kV substation to Entergy Arkansas's West Memphis 500 kV substation
3. A new 230 kV line from a new MLGW New Allen 230 kV / 230 kV / 161 kV substation to Entergy Mississippi's Twinkletown 230 kV substation

In addition to the new interconnections, all existing transmission connections between MLGW and TVA are expected to be disconnected at the time of separation.

To complement the interconnections above, the internal MLGW transmission system will need to be reinforced to account for the changes in flows. Full reliability analyses were performed, and all necessary upgrades are assumed to be completed before the interconnection to MISO. These were modeled in the base powerflow case.

MLGW currently does not have any generation within its footprint that is not owned by TVA. In the Long-Term Capacity Expansion (LTCE) study of this IRP, new generation resources are expected to be added to the MLGW system. This study assumed three combined cycle gas turbines (CCGTs) 3x414 MW, one gas Combustion Turbine 1x215 MW, and up to 600 MW of solar PV capacity will be added to MLGW's system by 2025 (all in summer nameplate capacity).

The CIL/CEL study was carried out for summer peak conditions with MLGW's summer peak load of 3,197 MW. The base load forecast was provided by Siemens PTI IRP team.

Generation Pools:

To appropriately assess the MLGW's import or export capacity limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. MLGW is the sink subsystem when studied for the import limit and the adjacent MISO areas are the source subsystem. Tier-1 MISO areas where MLGW has direct transmission interconnections with are EES-EMI and EES-EAI and Tier-2 MISO areas are SMEPA, EES, CLECO, and LAGN. Import limit studies are analyzed first using Tier-1 generation only. If no constraint is identified, the source is expanded to Tier-2 and the transfer is retested. MLGW is the source subsystem when studied for the export limit while the rest of MISO is the sink subsystem.

Redispatch:

The base redispatch assumptions for CIL/CEL include:

- The use of no more than 10 conventional fuel units or wind plants
- Redispatch limited to 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- Intermittent resources are only ramped down

For import redispatch scenarios, all generation resources in the zone being studied and adjacent systems (Tier-1 or Tier-1 & 2) used for the transfer will be eligible to be ramped up. All MISO generation resources will be eligible to be ramped down. For export redispatch scenarios, only MISO generation resources within the zone being studies are eligible to be ramped up. All MISO generation resources are eligible to be ramped down.

Generation Limited Transfer for CIL/CEL:

When conducting transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g. there is not enough capacity for the transfer). If the LRZ experiences a GLT, MISO will adjust the base model based on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LRZ under study) MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will rerun the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after decreasing all generation within the source subsystem or dispatching all generation within Tier-1 & 2, MISO will adjust load and generation in the source subsystem. This increases the import capacity for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system supporting larger thermal transfers than would be available based on installed generation for some zones. However, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load.

If the GLT does not produce a limit for a zone(s), due to a valid constraint not being identified, or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

No GTL study was required for the CIL, but one was required for the CEL. Even with a load reduction of 50%, no valid constraint was found and the CEL is reported below as "No Limit Found".

<u>Voltage Limited Transfer for CIL/CEL:</u>

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the zone prior to the thermal limits determined by linear FCITC. LOLE studies may evaluate Power-Voltage curves for LRZs with known voltage-based transfer limitations identified through prior MISO or Transmission Owner studies. Such evaluation may also happen if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone.

It is not expected for MLGW's import or export capabilities to be voltage limited as there is adequate reactive power support provided by MLGW's internal generators and other generators in the surrounding areas.

Power Flow Models and Assumptions:

Software Tools:

Siemens PTI Power System Simulator for Engineering (PSS®E) and PowerGEM's Transmission Adequacy and Reliability Assessment (TARA) are used as transfer analysis tools.

Modeling Inputs:

MISO developed a subsystem file to monitor its footprint and seam areas. LRZ definitions were developed as sources and sinks in the study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above. Contingency files from MTEP reliability assessment studies and single-element contingencies in MISO/seam areas were evaluated.

Power Flow Models:

The MTEP19 summer peak 2024 with Appendix A and Target Appendix A transmission projects and out-year generation additions and retirements from the OMS-MISO survey was used as the base powerflow case. At the time of this study, the MTEP19 2024 was the best available model to analyze 2025 planning year which is the earliest year that MLGW could join MISO.

The modeling on MLGW's load, internal generation, and transmission interconnections with MISO and other system upgrades was provided by Siemens PTI's MLGW IRP team and was added to the base powerflow case (see Section Interconnection, load and generation assumptions)

System conditions such as load, generation dispatch, transmission topology and area/zone interchange have an impact on transfer capability. Siemens PTI's MLGW IRP team and MISO worked closely together to determine the most reasonable model configurations.

General Assumptions:

TARA was the main tool used to process the powerflow model and associated input files to determine the import and export limits. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred will be determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (equation shown below).

First Contingency Total Transfer Capability (FCTTC) = FCITC + Base Transfer

Results for CIL/CEL:

[redacted]

[redacted]

Table 15: Capacity Import Limit

LRZ	Tier	2025 CIL=ZIA (MW)	Monitored Element	Contingent Element	Base Transfer (MW)	FCITC (MW)	GLT Applied	Generation Redispatch (MW)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 16: Capacity Export Limit

LRZ	2025 CEL=ZEA (MW)	Monitored Element	Contingent Element	GLT Applied	Load Scaling (MW)	Generation Scaling (MW)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

Table 17: Capacity Import Limit with Reinforcements

LRZ	Tier	2025 CIL=ZIA (MW)	Monitored Element	Contingent Element	Base Transfer (MW)	FCITC (MW)	GLT Applied	Generation Redispatch (MW)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

It is beyond MISO's scope to make the capital investment decisions.

3. Transmission Interconnection Assessment

***Objective**: Review the adequacy of the proposed interconnections identified in the Siemens' transmission expansion plan and verify the 2,200 MW import limit. Additionally, a follow-up request was made to have MISO analyze the feasibility of MLGW pursuing a "transmission-only" option where MLGW pursues an expanded transmission expansion plan to interconnect with MISO without the development of any generating resources. For the second scenario MISO evaluated the viability of a 3,200 MW import limit to satisfy MLGW's full peak demand.*

***MISO Conclusion**: MISO's transmission expansion planning staff performed their analysis based on the NERC TPL 001 planning assessment. For the purposes of complying with this requirement MISO concluded that the generation and transmission proposal would be compliant. Furthermore, it was determined that a 2,400 MW transfer between MISO and MLGW would be feasible during the 2024 summer peak conditions. Under the transmission-only option MISO identified numerous thermal loading, stability, and voltage issues that could compromise the reliability of the MLGW system.*

Transmission Assessment of Siemens' Base Expansion Proposal

The key takeaways of the MISO evaluation of the Siemens proposal are as follows:

- Based on analysis to date, the Siemens connection proposal appears to be compliant with the NERC TPL-001 planning standards, but additional analysis is required.
- Based on analysis to date, the Siemens connection proposal appears to allow for a transfer limit from MISO to MLGW of 2,400 MW under first contingency conditions.
- Based on analysis to date, MLGW would need to pursue all or most of the generation currently planned to facilitate MLGW redispatch during problematic P6 contingencies, which will avoid the need for load shed and ensure MISO-South redispatch levels are reasonable.
- Additional study is needed to ensure the Siemens connection proposal is feasible, including steady state voltage analysis, angular stability analysis, voltage stability analysis and acceptable performance in winter peak, shoulder and light load cases.

MISO transmission expansion planning staff analyzed the proposed connection plan developed by Siemens to reconnect the MLGW transmission system from the TVA transmission system to the Entergy transmission system in Arkansas and Mississippi. The analysis was based on a NERC TPL 001 planning assessment where the system was analyzed under a full NERC TPL 001 contingency set (P0 to P7). The planning assessment was performed using the 2024 summer peak planning case and assuming a base transfer from MISO to MLGW of 2,400 MW. No allowable system adjustments were made in MLGW to hold the transfer level at 2,400 MW, which is above and beyond what is required for TPL compliance (i.e., actual TPL planning assessments would allow for system adjustments that reduce the transfer level into MLGW such as generation redispatch within MLGW).

The only identified issues were due to very rare NERC TPL P6 contingencies, which are N-2 conditions where the two outages do not occur simultaneously, and thus the NERC TPL standard allows for system adjustments after the first outage and prior to the second outage, and load shed after the second outage. Since the base transfers are fixed in the analysis, only MISO South generation was redispatched after the first outage and only MISO South load was shed after the second outage. All but three (3) identified issues under the 2,400 MW base transfer level were mitigated via MISO South generation redispatch and some allowable MISO South load shed. The three (3) identified issues that could not be mitigated by MISO South generation redispatch, were instead mitigated by MLGW redispatch. This is allowable under the NERC TPL 001 planning standards where there is no requirement to hold base transfers from MISO to MLGW constant if there is MLGW generation that is available and can be dispatched or committed after the first outage to mitigate the contingency via a reduction in the transfer level into MLGW prior to the second outage. Therefore, for the purpose of complying with the NERC TPL standards, all identified issues could be mitigated, most without load shed, given the currently proposed generation for the MLGW system. For this reason, based on analysis done to date, MISO believes that the Siemens connection plan would be compliant with NERC TPL-001 planning standards given the currently proposed generation system for MLGW. Furthermore, the analysis confirmed that an N-1 2,400 MW transfer level would be feasible for 2024 summer peak conditions.

It is important to note that the MISO studies focused on steady-state loading issues only. Steady state voltage analysis, angular stability analysis and voltage stability analysis has not yet been assessed. Furthermore, MISO did not study the proposed base transfer levels under winter peak conditions, shoulder peak conditions or light load conditions. MISO would be willing to perform a more detailed assessment in the future as a next step if requested to do so.

Analysis of Siemens Proposal under Base Transfer of 2,400 MW from MISO to MLGW. For a 2,400 MW base transfer level from MISO to MLGW, the MLGW generation dispatch would need to be 800 MW for a 3,200 MW peak summer load, and such dispatch could be obtained easily under a number of scenarios, including only CCGT dispatched, or some combination of CCGT dispatch and PV solar dispatch:

When the Siemens proposal was analyzed under 2024 summer peak load conditions with a base transfer from MISO to MLGW of 2,400 MW, the loading issues listed in Table 18 below were identified prior to system adjustments:

Table 18: 2024 Summery Case – 2,400 MW Base Transfer – Identified Loading Issues

Monitored Element	Contingent Element(s)	Contingency Type	Percent Loading
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Table 19: 2024 Summer Case – 2,400 MW Base Transfer – Monitored Elements with Identified Loading Issues

	Entergy Arkansas	Entergy Mississippi	MLGW	TVA	Total
[redacted]	[redacted]				[redacted]
[redacted]			[redacted]		[redacted]
[redacted]		[redacted]			[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]				[redacted]

[redacted]	[redacted]				[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Table 20: 2024 Summer Case – 2,400 MW Base Transfer – Summary of TPL P6 Contingencies Driving Identified Issues

Contingent Element 1	Contingent Element 2	Number of Issues
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]

[redacted]

Table 21: 2024 Summer Case – 2,400 MW Base Transfer – Summary of Overload Magnitudes

Overload Range	Number of Branches
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]

CERTAIN SECTIONS OF THIS REPORT ARE REDACTED IN COMPLIANCE WITH FEDERAL REGULATIONS.

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- [redacted]
- [redacted]

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[redacted]

- [redacted]
- [redacted]

[redacted]

Transmission Assessment of the Transmission-Only Proposal

At the request of MLGW, MISO analyzed an alternative transmission-only solution submitted by Siemens which assumed additional transmission would be installed above and beyond the original proposal, but no new generation would be installed by MLGW in the Memphis area. The alternative solution included all of the elements in the original

Siemens proposal plus an additional 500 KV line from the Dell Substation (owned by Entergy) to the Shelby-MLGW substation (to be owned by MLGW). The specific elements included in the transmission-only alternative solution proposed by MLGW and Siemens are shown in the table below:

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

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- [redacted]

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[redacted]

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[redacted]

[redacted]

[redacted]

Summary of the Transmission Only Analysis. It is important to note that MISO conducted the analysis by assuming all MLGW load would be served by available generation in MISO South. Based on these assumptions, there are a number of reliability issues that have been identified [redacted] A more thorough analysis that would include angular and voltage stability analysis as well as winter peak, shoulder peak and light-load analysis could uncover additional reliability issues.

MISO's analysis indicates that having resources interconnected to the MLGW 161 kV system could help to address the [redacted] thermal issues in the transmission only analysis. Such local resource capacity could also be used [redacted] to support local voltages and to mitigate or eliminate steady voltage issues and/or potential voltage collapse situations. As previously demonstrated, MISO believes that a substantial portion of the generation serving MLGW could be located at remote sites given the transmission expansion scenarios investigated to date, but that there is likely a minimum level of generation that should be located locally to the MLGW system, where such generation could either be owned and operated by MLGW and/or owned and operated by independent power producers who supply energy to MLGW through power purchase agreements.

Because of the identification of [redacted] voltage violations in general, MISO would suggest that MLGW and Siemens also study the benefits of adding reactive power compensation devices to the MLGW transmission system, with consideration given not only to traditional capacitor banks, but also to SVCs, STATCOMs and synchronous condensers.

4. Transmission Interconnection Cost Assessment

Objective*: Review the transmission cost estimate provided by Siemens for the base transmission expansion plan, system reliability upgrades, and generator interconnection for MISO to interconnect with MLGW under the worst-case scenario in which MLGW must completely isolate its system from TVA. Siemens estimated these costs to be approximately $630 million ($2018) under a base scenario with the caveat that the capital expenditure will vary depending on the final long-term capacity expansion portfolio that is selected. An additional scenario was evaluated that assumed MLGW would not develop a generation portfolio and would instead pursue a transmission-only strategy and increase its ties to the MISO footprint through a fourth transmission connection from Dell to New Shelby. Siemens estimates the costs associated with this scenario to be $1,014 ($2018).

MISO Conclusion*: MISO evaluated the project costs for the base transmission expansion plan, reliability upgrades, and the generator interconnections that were proposed by Siemens and summarized the associated project costs to be approximately $736.2 million ($2020). The source of the project cost differences can primarily be attributed to inflation, different contingency assumptions (MISO included 20% contingency in its cost estimate vs. 10% assumed by Siemens), and MISO including spare single-phase transformers at each substation site to account for the unknown availability of existing spare transformers in the transmission system. For the transmission-only scenario MISO estimated the total project costs to be $1,127.5 million ($2020). The variance from the Siemens cost estimate can be attributed to the same factors that were outlined under the base scenario. A full comparison of the MISO and Siemens transmission cost estimates are included in the table below.

Table 23: Comparison of MISO and Siemens Base Transmission Cost Estimates

Project scopes of work	MISO cost estimate	Siemens cost estimate		Difference	Notes of differences between MISO's and Siemens' cost estimates
	$2020 M	$2018 M	$2020 M*	$2020 M**	
Baseline Transmission Expansions	$362.9	$383.0	$402.4	-$39.5	MISO included a spare transformer on-site
Reliability upgrades	$172.1	$167.0	$175.5	-$3.4	
Generator Interconnection upgrades	$78.5	$80.0	$84.1	-$5.6	MISO included a spare transformer on-sites
Subtotal Total	$613.5	$630.0	$662	-$48.5	Same assumption used for AFUDC and Professional Services (17.5%)
Contingency	$122.7	$63.0	$66.2	$56.5	MISO (20%) vs. Siemens (10%)
Total Estimate Comparison	**$736.2**	**$693.0**	**$728.2**	**$8.0**	**Siemens' estimated $600 - $700 M (2018)**

Table 24: Comparison of MISO and Siemens Transmission-Only Cost Estimates

Project scopes of work	MISO cost estimate	Siemens cost estimate		Difference	Notes of differences between MISO's and Siemens' cost estimates
	$2020 M	$2018 M	$2020 M*	$2020 M**	
Baseline Transmission Expansions	$362.9	$384.5	$404.0	($41.1)	MISO included a spare transformer on-site
Reliability upgrades	$172.1	$167.3	$175.8	($3.7)	
Dell to Shelby 500kV	$204.5	$225.7	$237.1	($32.6)	MISO included a spare transformer on-site
Local 161 and 115 kV upgrades	$200.1	$144.5	$151.8	$48.3	MISO assumed rebuilds of existing transmission lines
Subtotal (before contingency)	$939.6	$922.0	$968.7	($29.1)	Same assumption used for AFUDC and Professional Services (17.5%)
Contingency	$187.9	$92.2	$96.9	$91.1	MISO (20%) vs. Siemens (10%)
Total Estimate Comparison	**$1,127.5**	**$1,014.2**	**$1,065.6**	**$61.9**	

MISO evaluated the base project costs for the scopes of work proposed by Siemens in their MLGW IRP Transmission Draft Memo, dated March 27, 2020 and the transmission-only scenario based on emails provided on June 8, 2020. The scopes of work are grouped in three categories: transmission expansion to provide connections from MISO to MLGW, reliability upgrades to reinforce the existing system as the result of the transmission expansion, and new generator interconnections. Siemens proposed to create a total of four (4) new interconnections as follows:

1. San Souci-MISO to Shelby-MLGW Interconnection consisting of:
   a. New 500 kV line from San Souci-MISO to New Shelby-MLGW; 3-954 ACSR, 3000 A, 2598/2598 MVA summer rating (approximately 26 miles), and

   b. New Shelby-MLGW 500/161 kV substation with two new 500/161 kV transformers, 1300 MVA each.

2. West Memphis-MISO to New Allen-MLGW Interconnection consisting of:

   a. New 500 kV line from West Memphis-MISO to New Allen-MLGW: 3-954 ACSR, 3000 A, 2598/2598 MVA summer rating (approximately 8.5 miles), and

   b. New 500/230/161 kV substation, New Allen-MLGW with two new 500/161 kV transformers, 1300 MVA each.

3. Twinkletown-MISO to New Allen-MLGW interconnection consisting of:

   a. New 230 kV line from Twinkletown-MISO to New Allen-MLGW; 2-1590 ACSS, 5000 A, 1991/1991 MVA summer rating (approximately 8 miles), and

   b. Two new 230/161 kV transformers, 1000 MVA each.

4. Dell-MISO to New Shelby-MLGW interconnection (transmission-only scenario) consisting of:

   a. Upgrade Dell substation for 1 additional 500 kV line position

   b. New 500 kV line from Dell-MISO to New Shelby-MLGW: 3-954 ACSR, 3000 A, 2598/2598 MVA summer rating (approximately 41 miles), and

   c. Upgrade New Shelby Substation for new 500 kV line position, 2-1300 MVA 500/161kV transformers, and 161 kV line positions

5. Reliability and local upgrades to reinforce the system

MISO assumed the above listed scope of work for its cost estimates provided. All of MISO's cost estimates are in $2020 and are based on its Transmission Cost Estimate Guide for MTEP20, which is a yearly publication MISO provides on its approach and cost data used to create cost estimates for new transmission infrastructure. Some of the transmission and substation equipment ratings identified by Siemens are higher than MISO typically assumes for similar scopes of work (MISO's Business Practice Manual 029 Tables 1, 2A, and 2B show the typical ratings MISO would assume). Higher than typical ratings on equipment may lead to less flexibility during operations and/or may require a more robust equipment arrangement as further study and design work are completed.

Table 25: Summary of Base Project Cost Estimates

Project	Project Implementation Cost Estimate ($2020)
New connection from San Souci-MISO to New Shelby-MLGW	$181.6M
New connection from West Memphis-MISO to New Allen-MLGW	$125.6M
New connection from Twinkletown-MISO to New Allen-MLGW	$73.6M
Reconnect TVA Allen Combined Cycle plant to its 500kV system	$54.7M
Reliability upgrades	$206.5M
Generator Interconnection	$94.2M
Total:	**$736.2M**

Table 26: Summary of Transmission-Only Project Cost Estimates

Project	Project Implementation Cost Estimate ($2020)
New connection from San Souci-MISO to New Shelby-MLGW	$181.6M
New connection from West Memphis-MISO to New Allen-MLGW	$125.6M
New connection from Twinkletown-MISO to New Allen-MLGW	$73.6M
New connection From Dell-MISO to New Shelby-MLGW	$245.4M
Reconnect TVA Allen Combined Cycle plant to its 500kV system	$54.7M
Reliability upgrades	$206.5M
Local 161kV and 115kV upgrades	$240.1M
Total:	**$1,127.5M**

New Connections:

a) New connection from San Souci (MISO) to New Shelby (MLGW). This project provides a 500 kV connection from a MISO substation (San Souci Substation) to a new substation in MLGW (New Shelby). The transmission line routing followed existing transmission line corridors and assumed steel poles due to being in a suburban area where it may be difficult to site steel lattice towers (which would be more cost effective). The substation provides an interconnection from 500 kV to 161 kV through two transformer banks. The transformer sizing could change based on further study work depending on the power flows on the circuit breakers, and industry available sizing. One spare single-phase transformer is included in the New Shelby Substation cost estimate. The cost estimate and design details are shown in the tables below:

Table 27: San Souci Substation (MISO)

Design Features	
Site:	Upgrade existing site
Primary voltage:	500kV
Primary voltage bus arrangement:	Breaker-and-a-half bus
Primary voltage positions:	1 transmission outlet
Cost estimate ($2020)	
Project management:	$0.2M
Engineering, environmental studies, and testing and commissioning:	$0.1M
Administrative & General Overhead (A&G):	$0.1M
Land acquisition, and regulatory and permitting:	$0.1M
Site work:	$0.6M
Access roads:	$0
Steel support structure material:	$0.3M
Steel support structure construction labor:	$0.4M
Substation foundations:	$0.4M
Electrical equipment material:	$1.4M
Electrical equipment construction labor:	$0.3M
Control enclosure:	$0
Relay panels:	$0.4M
Communication system:	$0
Control cable, conduit, and cable trench:	$0.2M
Contingency:	$0.9M
AFUDC:	$0.4M
Project Implementation Cost:	**$5.7M**

Table 28: San Souci (MISO) – New Shelby (MLGW) 500 kV Transmission Line

Design Features	
Number of circuits:	Single circuit
Voltage:	500kV
Structure type:	Steel pole
Line length:	~23 miles
Conductor:	3-954kcmil ACSR
Amp rating:	3000A
MVA rating:	2598MVA
Cost estimate ($2020)	
Project management:	$4.4M

Engineering, environmental studies, and testing and commissioning:	$2.4M
Administrative & General Overhead (A&G):	$1.2M
Right-of-Way, land acquisition, and regulatory and permitting:	$21.6M
Structure material:	$11.0M
Structure foundations:	$10.7M
Structure and conductor accessories:	$1.8M
Structure construction labor:	$27.5M
Conductor material:	$2.0M
Conductor construction labor:	$3.1M
OPGW, and/or shieldwire material:	$0.8M
OPGW and/or shieldwire construction labor:	$1.1M
Contingency:	$17.5M
AFUDC:	$8.8M
Project Implementation Cost:	**$113.1M**

Table 29: New Shelby Substation (MLGW)

Design Features	
Site:	New site
Primary voltage:	500kV
Primary voltage bus arrangement:	Ring bus
Primary voltage positions:	3 total positions: 1 transmission outlet 2 transformer positions
Transformer:	2-1300 MVA (2600MVA total) 500/161kV transformer bank
Secondary voltage:	161kV
Secondary voltage bus arrangement:	Breaker-and-a-half bus
Secondary voltage positions:	6 total positions: 4 transmission outlets 2 transformer positions
Cost estimate ($2020)	
Project management:	$2.4M
Engineering, environmental studies, and testing and commissioning:	$1.3M
Administrative & General Overhead (A&G):	$0.7M
Land acquisition, and regulatory and permitting:	$0.3M
Site work:	$4.4M
Access roads:	$1.1M
Steel support structure material:	$1.1M
Steel support structure construction labor:	$1.4M
Substation foundations:	$1.7M
Electrical equipment material:	$27.5M

Electrical equipment construction labor:	$1.4M
Control enclosure:	$1.1M
Relay panels:	$2.3M
Communication system:	$0.3M
Control cable, conduit, and cable trench:	$1.7M
Contingency:	$9.7M
AFUDC:	$4.4M
Project Implementation Cost:	**$62.7M**

b) New connection from West Memphis (MISO) to New Allen (MLGW). This project provides a 500 kV connection from a MISO substation (West Memphis) to a new substation in MLGW (New Allen). The transmission line routing followed existing transmission line corridors and assumed steel poles due to being in a suburban area where it may be difficult to site steel lattice towers (which would be more cost effective). The substation provides an interconnection from 500 kV to 161 kV through two transformer banks. The transformer sizing could change based on further study work depending on the power flows on the circuit breakers, and industry available sizing. One spare single-phase transformer is included in the New Allen Substation cost estimate. The cost estimate and design details are shown in the tables below:

Table 30: West Memphis Substation (MISO)

Design Features	
Site:	Upgrade existing site
Primary voltage:	500kV
Primary voltage bus arrangement:	Breaker-and-a-half bus
Primary voltage positions:	1 transmission outlet
Cost estimate ($2020)	
Project management:	$0.2M
Engineering, environmental studies, and testing and commissioning:	$0.1M
Administrative & General Overhead (A&G):	$0.1M
Land acquisition, and regulatory and permitting:	$0.1M
Site work:	$0.6M
Access roads:	$0
Steel support structure material:	$0.3M
Steel support structure construction labor:	$0.4M
Substation foundations:	$0.4M
Electrical equipment material:	$1.4M
Electrical equipment construction labor:	$0.3M
Control enclosure:	$0
Relay panels:	$0.4M
Communication system:	$0

Control cable, conduit, and cable trench:	$0.2M
Contingency:	$0.9M
AFUDC:	$0.4M
Project Implementation Cost:	**$5.7M**

Table 31: West Memphis (MISO) – New Allen (MLGW) 500 kV Transmission Line

Design Features	
Number of circuits:	Single circuit
Voltage:	500kV
Structure type:	Steel pole
Line length:	~9 miles
Conductor:	3-954kcmil ACSR
Amp rating:	3000A
MVA rating:	2598MVA
Cost estimate ($2020)	
Project management:	$2.2M
Engineering, environmental studies, and testing and commissioning:	$1.2M
Administrative & General Overhead (A&G):	$0.6M
Right-of-Way, land acquisition, and regulatory and permitting:	$11.0M
Structure material:	$4.3M
Structure foundations:	$4.3M
Structure and conductor accessories:	$0.8M
Structure construction labor:	$17.8M
Conductor material:	$0.8M
Conductor construction labor:	$1.2M
OPGW, and/or shieldwire material:	$0.3M
OPGW and/or shieldwire construction labor:	$0.4M
Contingency:	$9.0M
AFUDC:	$4.0M
Project Implementation Cost:	**$58.0M**

Table 32: New Allen Substation (MLGW)

Design Features	
Site:	New site
Primary voltage:	500kV
Primary voltage bus arrangement:	Ring bus
Primary voltage positions:	3 total positions: 1 transmission outlet 2 transformer positions

Transformer:	2-1300 MVA (2600MVA total) 500/161kV transformer bank
Secondary voltage:	161kV
Secondary voltage bus arrangement:	Breaker-and-a-half bus
Secondary voltage positions:	6 total positions: 4 transmission outlets 2 transformer positions
Cost estimate ($2020)	
Project management:	$2.4M
Engineering, environmental studies, and testing and commissioning:	$1.3M
Administrative & General Overhead (A&G):	$0.7M
Land acquisition, and regulatory and permitting:	$0.7M
Site work:	$4.0M
Access roads:	$1.1M
Steel support structure material:	$1.1M
Steel support structure construction labor:	$1.5M
Substation foundations:	$1.6M
Electrical equipment material:	$27.2M
Electrical equipment construction labor:	$1.2M
Control enclosure:	$1.1M
Relay panels:	$2.2M
Communication system:	$0.3M
Control cable, conduit, and cable trench:	$1.7M
Contingency:	$9.6M
AFUDC:	$4.3M
Project Implementation Cost:	**$61.9M**

c) New connection from Twinkletown (MISO) to New Allen (MLGW). This project provides a 230 kV connection from a MISO substation (Twinkletown) to a new substation in MLGW (New Allen). The transmission line routing followed existing transmission line corridors and assumed steel poles due to being in a suburban area where it may be difficult to site steel lattice towers (which would be more cost effective). The substation provides an interconnection from 230 kV to 161 kV through two transformer banks. The transformer sizing could change based on further study work depending on the power flows on the circuit breakers, and industry available sizing. One spare single-phase transformer is included in the New Allen Substation cost estimate. The cost estimate and design details are shown in the tables below:

Table 33: Twinkletown Substation (MISO)

Design Features	
Site:	Upgrade existing site

Primary voltage:	230kV
Primary voltage bus arrangement:	Breaker-and-a-half bus
Primary voltage positions:	1 transmission outlet
Cost estimate ($2020)	
Project management:	$0.09M
Engineering, environmental studies, and testing and commissioning:	$0.05M
Administrative & General Overhead (A&G):	$0.03M
Land acquisition, and regulatory and permitting:	$0.05M
Site work:	$0.3M
Access roads:	$0
Steel support structure material:	$0.13M
Steel support structure construction labor:	$0.17M
Substation foundations:	$0.15M
Electrical equipment material:	$0.42M
Electrical equipment construction labor:	$0.11M
Control enclosure:	$0
Relay panels:	$0.22M
Communication system:	$0
Control cable, conduit, and cable trench:	$0.13M
Contingency:	$0.37M
AFUDC:	$0.17M
Project Implementation Cost:	**$2.4M**

Table 34: Twinkletown (MISO) – New Allen (MLGW) 230 kV Transmission Line

Twinkletown (MISO) – New Allen (MLGW) 230kV Transmission Line	
Design Features	
Number of circuits:	Single circuit
Voltage:	230kV
Structure type:	Steel pole
Line length:	~10 miles
Conductor:	2-1590 kcmil ACSS
Amp rating:	5000A
MVA rating:	1991MVA
Cost estimate ($2020)	
Project management:	$1.2M
Engineering, environmental studies, and testing and commissioning:	$0.6M
Administrative & General Overhead (A&G):	$0.3M
Right-of-Way, land acquisition, and regulatory and permitting:	$6.5M
Structure material:	$3.2M

Structure foundations:	$2.1M
Structure and conductor accessories:	$0.6M
Structure construction labor:	$6.2M
Conductor material:	$0.9M
Conductor construction labor:	$1.3M
OPGW, and/or shieldwire material:	$0.3M
OPGW and/or shieldwire construction labor:	$0.5M
Contingency:	$4.8M
AFUDC:	$2.1M
Project Implementation Cost:	**$30.7M**

Table 35: New Allen Substation (MLGW)

Design Features	
Site:	New site
Primary voltage:	230kV
Primary voltage bus arrangement:	Ring bus
Primary voltage positions:	3 total positions: 1 transmission outlet 2 transformer positions
Transformer:	2-1000 MVA (2000MVA total) 230/161kV transformer bank
Secondary voltage:	161kV
Secondary voltage bus arrangement:	Breaker-and-a-half bus
Secondary voltage positions:	6 total positions: 4 transmission outlets 2 transformer positions
Cost estimate ($2020)	
Project management:	$1.6M
Engineering, environmental studies, and testing and commissioning:	$0.9M
Administrative & General Overhead (A&G):	$0.4M
Land acquisition, and regulatory and permitting:	$0.6M
Site work:	$3.6M
Access roads:	$1.1M
Steel support structure material:	$0.8M
Steel support structure construction labor:	$1.1M
Substation foundations:	$1.0M
Electrical equipment material:	$14.9M
Electrical equipment construction labor:	$0.9M
Control enclosure:	$1.1M
Relay panels:	$1.8M
Communication system:	$0.2M
Control cable, conduit, and cable trench:	$1.5M
Contingency:	$6.3M

AFUDC:	$2.8M
Project Implementation Cost:	**$40.5M**

d) New connection from Dell (MISO) to New Shelby (MLGW) **(**transmission-only scenario**)**. This project provides a 500 kV connection from a MISO substation (Dell) to an existing substation in MLGW (New Shelby). The New Shelby Substation is an existing substation created from the Shelby to San Souci transmission line, so it only needs to be expanded for this project. The transmission line routing followed existing transmission line corridors and assumed steel poles due to being in a suburban area where it may be difficult to site steel lattice towers (which would be more cost effective). The substation provides an interconnection from 500 kV to 161 kV through two transformer bank. The transformer sizing could change based on further study work depending on the power flows on the circuit breakers, and industry available sizing. One spare single-phase transformer is included in the New Shelby Substation costs estimate. The cost estimate and design details are shown in tables below:

Table 36: Dell Substation (MISO)

Design features	
Site:	Upgrade existing site
Primary voltage:	500kV
Primary voltage bus arrangement:	Breaker-and-a-half bus
Primary voltage positions:	1 transmission outlet
Cost estimate ($2020)	
Project management:	$0.2M
Engineering, environmental studies, and testing and commissioning:	$0.1M
Administrative & General Overhead (A&G):	$0.1M
Land acquisition, and regulatory and permitting:	$0.1M
Site work:	$0.6M
Access roads:	$0
Steel support structure material:	$0.3M
Steel support structure construction labor:	$0.4M
Substation foundations:	$0.4M
Electrical equipment material:	$1.4M
Electrical equipment construction labor:	$0.3M
Control enclosure:	$0
Relay panels:	$0.4M
Communication system:	$0
Control cable, conduit, and cable trench:	$0.2M
Contingency:	$0.9M
AFUDC:	$0.4M
Project Implementation Cost:	**$5.7M**

Table 37: Dell (MISO) – New Shelby (MLGW) 500 kV Transmission Line

Design features	
Number of circuits:	Single circuit
Voltage:	500kV
Structure type:	Steel pole
Line length:	~41 miles
Conductor:	3-954kcmil ACSR
Amp rating:	3000A
MVA rating:	2598MVA
Cost estimate ($2020)	
Project management:	$7.0M
Engineering, environmental studies, and testing and commissioning:	$3.8M
Administrative & General Overhead (A&G):	$1.9M
Right-of-Way, land acquisition, and regulatory and permitting:	$31.4M
Structure material:	$18.8M
Structure foundations:	$18.8M
Structure and conductor accessories:	$3.3M
Structure construction labor:	$42.1M
Conductor material:	$3.6M
Conductor construction labor:	$5.6M
OPGW, and/or shieldwire material:	$1.3M
OPGW and/or shieldwire construction labor:	$2.0M
Contingency:	$27.9M
AFUDC:	$12.6M
Project Implementation Cost:	**$180.1M**

Table 38: New Shelby Substation (MLGW)

Design features	
Site:	Existing site
Primary voltage:	500kV
Primary voltage bus arrangement:	Ring bus
Primary voltage positions:	3 total positions: 1 transmission outlet 2 transformer positions
Transformer:	2-1300 MVA (2600MVA total) 500/161kV transformer bank
Secondary voltage:	161kV
Secondary voltage bus arrangement:	Breaker-and-a-half bus
Secondary voltage positions:	6 total positions: 4 transmission outlets

	2 transformer positions
Cost estimate ($2020)	
Project management:	$2.3M
Engineering, environmental studies, and testing and commissioning:	$1.3M
Administrative & General Overhead (A&G):	$0.6M
Land acquisition, and regulatory and permitting:	$0.3M
Site work:	$4.0M
Access roads:	$0M
Steel support structure material:	$1.1M
Steel support structure construction labor:	$1.4M
Substation foundations:	$1.7M
Electrical equipment material:	$27.5M
Electrical equipment construction labor:	$1.4M
Control enclosure:	$0.5M
Relay panels:	$2.3M
Communication system:	$0.1M
Control cable, conduit, and cable trench:	$1.7M
Contingency:	$9.2M
AFUDC:	$4.2M
Project Implementation Cost:	**$59.6M**

e) Reconnect TVA Allen combined cycle plant to its 500 kV system. This project reconnects TVA's 500 kV system to its Allen combined cycle plant. The transmission line is assumed to be a relative short tap to facilitate this connection. The substation scope of work involves adding new equipment within an existing substation site. The transformer sizing could change based on further study work depending on the power flows on the circuit breakers, and industry available sizing. One spare single-phase transformer is included in the Allen combined cycle plant Substation cost estimate. The cost estimate and design details are shown in the tables below:

Table 39: 500 kV Transmission Line Tap

Design Features	
Number of circuits:	Double circuit
Voltage:	500kV
Structure type:	Steel lattice tower
Line length:	~1.3 miles
Conductor:	3-954 kcmil ACSR
Amp rating:	3000A
MVA rating:	2598MVA
Cost estimate ($2020)	

Project management:	$0.46M
Engineering, environmental studies, and testing and commissioning:	$0.25M
Administrative & General Overhead (A&G):	$0.12M
Right-of-Way, land acquisition, and regulatory and permitting:	$1.29M
Structure material:	$1.2M
Structure foundations:	$2.47M
Structure and conductor accessories:	$0.4M
Structure construction labor:	$2.59M
Conductor material:	$0.11M
Conductor construction labor:	$0.14M
OPGW, and/or shieldwire material:	$0.04M
OPGW and/or shieldwire construction labor:	$0.06M
Contingency:	$1.83M
AFUDC:	$0.82M
Project Implementation Cost:	**$11.8M**

Table 40: Allen Combined Cycle Plant Substation

Design Features	
Site:	Expansion of existing site
Primary voltage:	500kV
Primary voltage bus arrangement:	Breaker-and-a-half bus
Primary voltage positions:	4 total positions: 2 transmission outlets 2 transformer positions
Transformer:	2-650 MVA (1300MVA total) 500/161kV transformer bank
Secondary voltage:	161kV
Secondary voltage bus arrangement:	Straight bus
Secondary voltage positions:	2 transformer positions
Cost estimate ($2020)	
Project management:	$1.7M
Engineering, environmental studies, and testing and commissioning:	$0.9M
Administrative & General Overhead (A&G):	$0.5M
Land acquisition, and regulatory and permitting:	$0.4M
Site work:	$2.8M
Access roads:	$1.1M
Steel support structure material:	$0.9M
Steel support structure construction labor:	$1.2M
Substation foundations:	$1.5M
Electrical equipment material:	$16.5M
Electrical equipment construction labor:	$1.0M

Control enclosure:	$1.1M
Relay panels:	$1.9M
Communication system:	$0.3M
Control cable, conduit, and cable trench:	$1.6M
Contingency:	$6.6M
AFUDC:	$3.0M
Project Implementation Cost:	**$42.9M**

f) Reliability upgrades. Along with all of the transmission expansion, reliability upgrades to existing transmission infrastructure was identified as a need per Siemens' analysis. Costs were estimated below to rebuild 145 miles of existing 161 kV transmission lines, rebuild the Freeport to Twinkletown 230 kV transmission line, and to replacing limiting elements in 10 substations. For the transmission line reliability upgrades it was assumed no new land was required. The design features and cost estimates for the reliability upgrades are shown in the tables below.

Table 41: Rebuild 161 kV Transmission Lines

Design Features	
Number of circuits:	Single circuit
Voltage:	161kV
Structure type:	Steel pole
Line length:	145 miles
Conductor:	1-795 kcmil ACSS
Amp rating:	1650A
MVA rating:	460MVA
Cost estimate ($2020)	
Project management:	$6.9M
Engineering, environmental studies, and testing and commissioning:	$3.8M
Administrative & General Overhead (A&G):	$1.9M
Right-of-Way, land acquisition, and regulatory and permitting:	$0
Structure material:	$29.9M
Structure foundations:	$16.9M
Structure and conductor accessories:	$8.2M
Structure construction labor:	$50.0M
Conductor material:	$3.7M
Conductor construction labor:	$5.1M
OPGW, and/or shieldwire material:	$4.7M
OPGW and/or shieldwire construction labor:	$7.1M
Contingency:	$27.7M
AFUDC:	$12.4M

Project Implementation Cost:	**$178.4M**

Table 42: Rebuild Freeport to Twinkletown

Design Features	
Number of circuits:	Single circuit
Voltage:	230kV
Structure type:	Steel pole
Line length:	8.5 miles
Conductor:	1-795 kcmil ACSS
Amp rating:	1650A
MVA rating:	657MVA
Cost estimate ($2020)	
Project management:	$1.0M
Engineering, environmental studies, and testing and commissioning:	$0.5M
Administrative & General Overhead (A&G):	$0.3M
Right-of-Way, land acquisition, and regulatory and permitting:	$6.5M
Structure material:	$2.2M
Structure foundations:	$1.4M
Structure and conductor accessories:	$0.5M
Structure construction labor:	$5.8M
Conductor material:	$0.2M
Conductor construction labor:	$0.3M
OPGW, and/or shieldwire material:	$0.3M
OPGW and/or shieldwire construction labor:	$0.4M
Contingency:	$3.9M
AFUDC:	$1.8M
Project Implementation Cost:	**$25.1M**

Table 43: Replace Limiting Factor in 10 Substations

Site:	Upgrade of existing sites
Voltages:	115kV & 161kV
Substation sites:	10
Cost estimate per substation site:	$250k
Project Implementation Cost ($2020):	**$3.0M**

g) Local upgrades (transmission-only scenario). Along with all of the transmission expansion, local upgrades to existing transmission infrastructure was identified as a need per Siemens' analysis. Costs were estimated below to rebuild existing 161 kV and 115 kV transmission lines. For the transmission line reliability upgrades it was assumed no new land was required, and that no substation upgrades were required. The design features and cost estimates for the reliability upgrades are shown in the tables below.

Table 44: Rebuild 115 kV Transmission Lines

Design Features	
Number of circuits:	Single circuit
Voltage:	115kV
Structure type:	Steel pole
Line length:	10.1 miles
Conductor:	1-795 kcmil ACSS
Amp rating:	1650A
MVA rating:	329MVA
Cost estimate ($2020)	
Project management:	$0.6M
Engineering, environmental studies, and testing and commissioning:	$0.3M
Administrative & General Overhead (A&G):	$0.2M
Right-of-Way, land acquisition, and regulatory and permitting:	$0.0M
Structure material:	$2.0M
Structure foundations:	$0.9M
Structure and conductor accessories:	$0.5M
Structure construction labor:	$5.3M
Conductor material:	$0.3M
Conductor construction labor:	$0.4M
OPGW, and/or shieldwire material:	$0.3M
OPGW and/or shieldwire construction labor:	$0.5M
Contingency:	$2.3M
AFUDC:	$1.0M
Project Implementation Cost:	**$14.5M**

Table 45: Rebuild 161 kV Transmission Lines

Design Features	
Number of circuits:	Single circuit
Voltage:	161kV
Structure type:	Steel pole
Line length:	121.1 miles
Conductor:	2-954 kcmil ACSS

Amp rating:	3012A
MVA rating:	840MVA
Cost estimate ($2020)	
Project management:	$7.8M
Engineering, environmental studies, and testing and commissioning:	$4.2M
Administrative & General Overhead (A&G):	$2.1M
Right-of-Way, land acquisition, and regulatory and permitting:	$0M
Structure material:	$24.9M
Structure foundations:	$14.1M
Structure and conductor accessories:	$7.3M
Structure construction labor:	$66.8M
Conductor material:	$7.4M
Conductor construction labor:	$11.0M
OPGW, and/or shieldwire material:	$4.0M
OPGW and/or shieldwire construction labor:	$5.9M
Contingency:	$31.1M
AFUDC:	$14.0M
Project Implementation Cost:	**$200.6M**

Design Features	
Number of circuits:	Double circuit
Voltage:	161kV
Structure type:	Steel pole
Line length:	9.1 miles
Conductor:	2-954 kcmil ACSS
Amp rating:	3012A
MVA rating:	840MVA
Cost estimate ($2020)	
Project management:	$1.0M
Engineering, environmental studies, and testing and commissioning:	$0.5M
Administrative & General Overhead (A&G):	$0.3M
Right-of-Way, land acquisition, and regulatory and permitting:	$0M
Structure material:	$3.0M
Structure foundations:	$2.1M
Structure and conductor accessories:	$1.1M
Structure construction labor:	$8.0M
Conductor material:	$1.1M
Conductor construction labor:	$1.6M
OPGW, and/or shieldwire material:	$0.3M
OPGW and/or shieldwire construction labor:	$0.4M

Contingency:	$3.9M
AFUDC:	$1.7M
Project Implementation Cost:	**$25.0M**

h) Generator Interconnection: Aligning with Siemens memo, MISO assumed that MLGW would require 6 new generator interconnections. Each interconnection is sized at 450 MW and assumes that the new generators are able to meet voltage and frequency support requirements without additional substation equipment. MISO assumed new substation equipment needed (including a transformer with a spare single-phase unit) to interconnect into the existing system and assumed a 2-mile new transmission line to connect. The voltage classes, length of new transmission line, and transformer sizing would all be subject to further study and design considerations based on the site-specific characteristics of each generator interconnection site. The cost estimate and design details are shown in the tables below:

Table 46: New 161kV Transmission Line Tap

Design Features	
Number of circuits:	Single circuit
Voltage:	161kV
Structure type:	Steel pole
Line length:	2 miles
Conductor:	1-795 kcmil ACSS
Amp rating:	1650A
MVA rating:	460MVA
Cost estimate ($2020)	
Project management:	$0.2M
Engineering, environmental studies, and testing and commissioning:	$0.1M
Administrative & General Overhead (A&G):	$0.1M
Right-of-Way, land acquisition, and regulatory and permitting:	$1.2M
Structure material:	$0.7M
Structure foundations:	$0.4M
Structure and conductor accessories:	$0.1M
Structure construction labor:	$1.2M
Conductor material:	$0.2M
Conductor construction labor:	$0.3M
OPGW, and/or shieldwire material:	$0.1M
OPGW and/or shieldwire construction labor:	$0.1M
Contingency:	$1.0M
AFUDC:	$0.4M
Project Implementation Cost:	**$6.1M**

Table 47: Generator Interconnection Substation Upgrades

Design Features	
Site:	Expansion of existing site
Primary voltage:	230kV
Primary voltage bus arrangement:	Ring bus
Primary voltage positions:	1 transformer position
Transformer:	1-450MVA 230/161kV transformer bank
Secondary voltage:	161kV
Secondary voltage bus arrangement:	Ring bus
Secondary voltage positions:	1 transformer position
Cost estimate ($2020)	
Project management:	$0.37M
Engineering, environmental studies, and testing and commissioning:	$0.20M
Administrative & General Overhead (A&G):	$0.10M
Land acquisition, and regulatory and permitting:	$0.20M
Site work:	$1.19M
Access roads:	$0.00M
Steel support structure material:	$0.17M
Steel support structure construction labor:	$0.22M
Substation foundations:	$0.26M
Electrical equipment material:	$3.59M
Electrical equipment construction labor:	$0.26M
Control enclosure:	$0.00M
Relay panels:	$0.64M
Communication system:	$0.00M
Control cable, conduit, and cable trench:	$0.27M
Contingency:	$1.49M
AFUDC:	$0.67M
Project Implementation Cost:	**$9.6M**

Table 48: Total Generator Interconnection Cost

Generator Interconnection Cost Estimates	
Per site cost:	$15.7M
Number of sites:	6
Total cost:	$94.2M

5. Market Impact Assessment

***Objective**: Identify the expected MLGW production costs as a MISO member and evaluate any changes to regional congestion patterns that would result from MLGW, and its proposed generation portfolios, being integrated into the MISO footprint. Pinpoint any additional costs or long-term capacity expansion plan changes that would need to be made by MLGW in order to alleviate any identified issues.*

***MISO Conclusion**: MISO's Economic Planning team identified annual production cost savings under four potential portfolio options. The two base portfolios (#1-2) have MLGW developing their own thermal and renewable resources and procuring the remainder of their energy needs from the MISO market. Under these portfolios the average annual production costs savings are $116.3 million in 2024 (Portfolio #1) increasing to as high as $345.2 million in 2034 (Portfolio #2). In 2024 under these scenarios MLGW self supplies approximately 50% of its energy needs and procures the rest almost exclusively from the MISO wholesale market. As additional resources are added to the portfolio over time the amount of energy that MLGW self supplies increases to over 90% by 2034. MLGW's production cost savings go up significantly over time as additional low-cost resources are incorporated into the generation portfolio.*

Two additional sensitivities were simulated where MLGW does not develop its own resources. Portfolio #3 assumes no change to MISO's future portfolio assumptions and Portfolio #4 assumes that incremental gas and renewable resources are developed in response to a MLGW Power Purchase Agreement (PPA) solicitation. Portfolio #3 exhibits the lowest savings which are attributed exclusively to lower cost resources that exist in MISO's footprint relative to TVA's. These savings range from $55.9 million in 2024 to $117.2 million in 2034. Portfolio #4 exhibits comparable savings to Portfolios #1-2 in 2024 and 2029 but displays the highest savings by 2034 due to the large amount of gas and solar capacity that is incorporated, providing MLGW with access to resources that exhibit low variable production costs. Portfolio #4 savings range from $104.9 million in 2024 to $350.2 million in 2034. It is important to note that MISO's analysis did not evaluate the fixed costs associated with any of the portfolio options. None of the study cases evaluated resulted in a significant change in system congestion for existing MISO members.

Overview:

MISO's Economic Planning team performed production cost analysis using PROMOD® to analyze the scenarios provided by Siemens. In each "study case" scenario MLGW is disconnected from TVA, joins the MISO pool, and constructs new generation and transmission facilities. Four long-term capacity expansion options were evaluated and these portfolios are summarized in tables 49. These scenarios are contrasted with a "reference case" where MLGW is a part of the TVA pool. The results focused primarily on projected Adjusted Production Cost (APC) savings to MLGW between the four scenarios as well as shifts in economic congestion and capacity usage of the new interface and generation over the course of the years studied. MISO's studies look at four different potential futures: Accelerated Fleet Change (AFC), Continued Fleet Change (CFC), Limited Fleet Change (LFC) and Distributed Energy Technology (DET) futures. These four futures represent a collection of potential scenarios for what the system may look like in 5, 10 and 15 years. The MISO MTEP Futures scenarios are developed through a collaborative stakeholder process and are being leveraged for the MISO MTEP20 transmission planning cycle. Below is a brief description for each of the MTEP Future scenarios.

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

Continued Fleet Change (CFC) – The fleet evolution trends of the past decade continue. Coal retirements reflect historical retirement levels based on the average age of retirement. Renewable additions continue to exceed current renewable portfolio standard requirements as a result of economics, public appeal, and the potential for future policy changes. Natural gas reliance increases as a result of new capacity needed to replace retired coal capacity.

Limited Fleet Change (LFC) – The existing generation fleet remains relatively static without significant drivers of change. Some coal fleet reductions are expected as units reach the end of their useful life. Renewable additions are driven primarily by current renewable portfolio standards under low demand and energy growth rates.

Distributed Energy Technology (DET) – Fleet evolution trends continue, primarily driven by local policies and emerging technology adoption. State level policies reflect desires for local reliability and optionality. Mid-level coal retirements reflect economics and age limits. Increased renewable additions are driven by favorable economics resulting from technological advancements and state-level renewable portfolio standards and goals with targeted increases in distributed solar. Natural gas reliance increases as a result of new capacity needs driven by load growth largely attributed to electric vehicle adoption, the need to replace retired capacity and provide flexibility to support the integration of intermittent renewable resources.

Table 49: MLGW Long-Term Capacity Expansion Options

Year	Resource Type (MW)	Portfolio #1 (3 CC / 1 CT)	Portfolio #2 (2 CC / 2 CT)	Portfolio #3 All MISO	Portfolio #4 Generic PPAs
2024	MLGW CT	237	474	0	0
	MLGW CC	1,350	900	0	0
	MLGW Solar	600	600	0	0
	Arkansas CC	0	0	0	950
	Arkansas Solar	500	800	0	1,200
	Arkansas Wind	200	350	0	0
2029	MLGW CT	237	474	0	0
	MLGW CC	1,350	900	0	0
	MLGW Solar	1,000	1,000	0	0
	Arkansas CC	0	0	0	950
	Arkansas Solar	650	1,550	0	3,000
	Arkansas Wind	300	400	0	0
2034	MLGW CT	237	474	0	0
	MLGW CC	1,350	900	0	0
	MLGW Solar	1,000	1,000	0	0
	Arkansas CC	0	0	0	950
	Arkansas Solar	1,050	1,700	0	3,200
	Arkansas Wind	350	400	0	0

Table 50: MLGW Adjusted Production Cost (APC) Savings

Year	MTEP Future / APC Savings ($M)	Portfolio #1 (3 CC / 1 CT)	Portfolio #2 (2 CC / 2 CT)	Portfolio #3 All MISO Energy	Portfolio #4 Generic PPAs
2024	AFC	$172.7	$212.8	$108.5	$156.9
	CFC	$112.8	$143.1	$47.8	$97.2
	DET	$98.4	$128.6	$30.9	$81.4
	LFC	$81.5	$107.4	$36.3	$83.9
	AVG	**$116.3**	**$147.9**	**$55.9**	**$104.9**
2029	AFC	$254.6	$353.8	$174.7	$350.4
	CFC	$183.7	$255.4	$69.1	$243.7
	DET	$194.9	$260.7	$72.6	$245.2
	LFC	$171.3	$228.6	$69.8	$222.9
	AVG	**$201.1**	**$274.6**	**$96.6**	**$265.5**
2034	AFC	$313.9	$394.9	$179.4	$409.5
	CFC	$280.1	$346.7	$109.6	$353.7
	DET	$298.5	$354.7	$110.1	$350.4
	LFC	$237.7	$284.4	$69.7	$287.3
	AVG	**$282.6**	**$345.2**	**$117.2**	**$350.2**

APC is the summation of the cost of different sources of energy necessary to serve load. The following figure shows MLGW's APC and the source of energy broken up into component parts and averaged over the futures for simplification. Using this we can identify where the savings are coming from.

Figure 7: MLGW Adjusted Production Costs

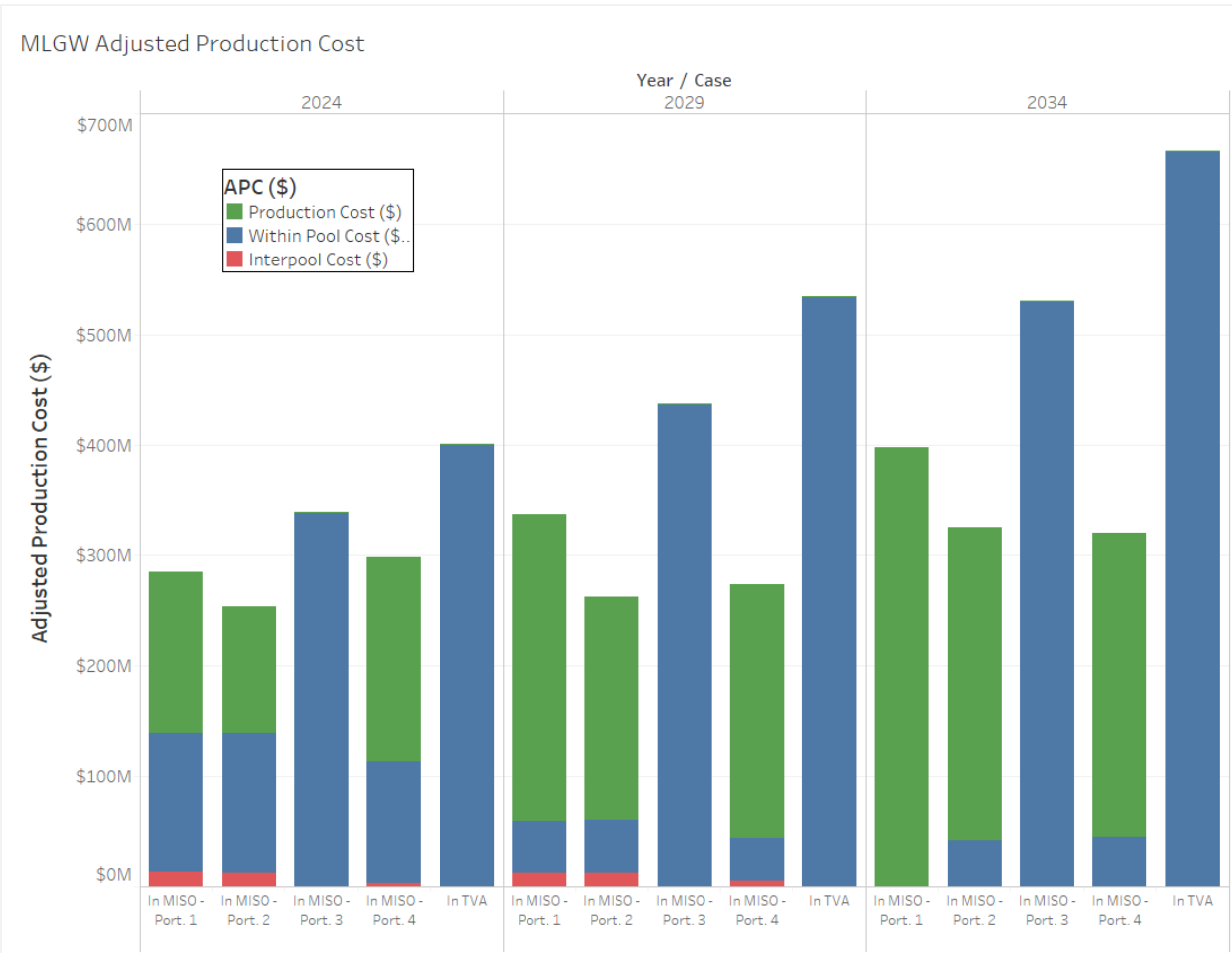
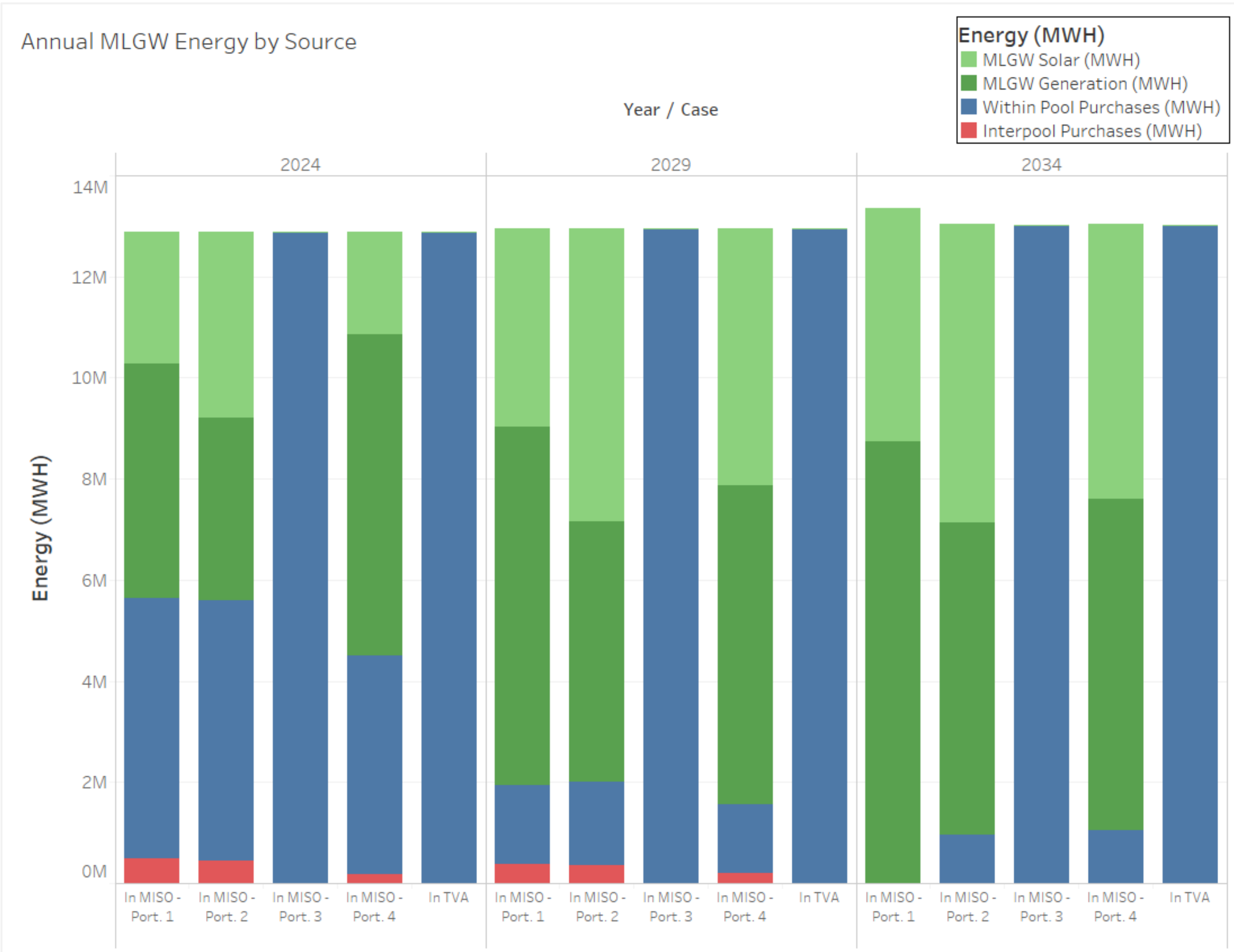


Figure 8: Annual MLGW Energy by Source



One of the primary drivers of savings are MLGW's average cost of purchasing energy between the MISO and TVA pools[4]. As the level of purchases decreases, so does the average cost of generation purchased from the pool.

The analysis shows that the cost of energy from MISO's market is less than TVA's by comparing the Within Pool categories. Over time all these values will increase with inflation and fuel price forecasts as shown below in table 51. These values would also decrease with lowered usage due to internal MLGW generation.

Table 51: MLGW'S Average Within Pool Purchase Price

	2024 ($/MWh)	2029 ($/MWh)	2034 ($/MWh)
Portfolio #1	$22.94	$27.54	$28.49
Portfolio #2	$24.00	$24.01	$36.69
Portfolio #3	$25.48	$24.44	$35.83
Portfolio #4	$27.01	$33.79	$42.20
TVA	$31.35	$41.24	$51.19

The MLGW Solar and MLGW Generation categories in Portfolio #1-2, which represent the new generation in MLGW's capacity expansion plan, provides for around 50% of their energy needs in 2024 and increases over time as unit economics change and additional resources are added to the portfolio.

Figure 9 shows the MW flows on each of the lines at the MISO-MLGW interface over time. The gray shaded region for each cell represents the line limits. We observe that each of the new lines are only about 25% loaded at normal max conditions. The interface as a whole has import and export limits as set by a reliability analysis. The maximum loading on this interface reaches about 70% of the limits found in this study but does not reach it.

[4] Estimated production cost savings are reliant on the MTEP 20 model assumptions for the specific attributes of external generating resources.

Figure 9: Flow Duration Curves for MISO-MLGW Interface (Portfolio #2)

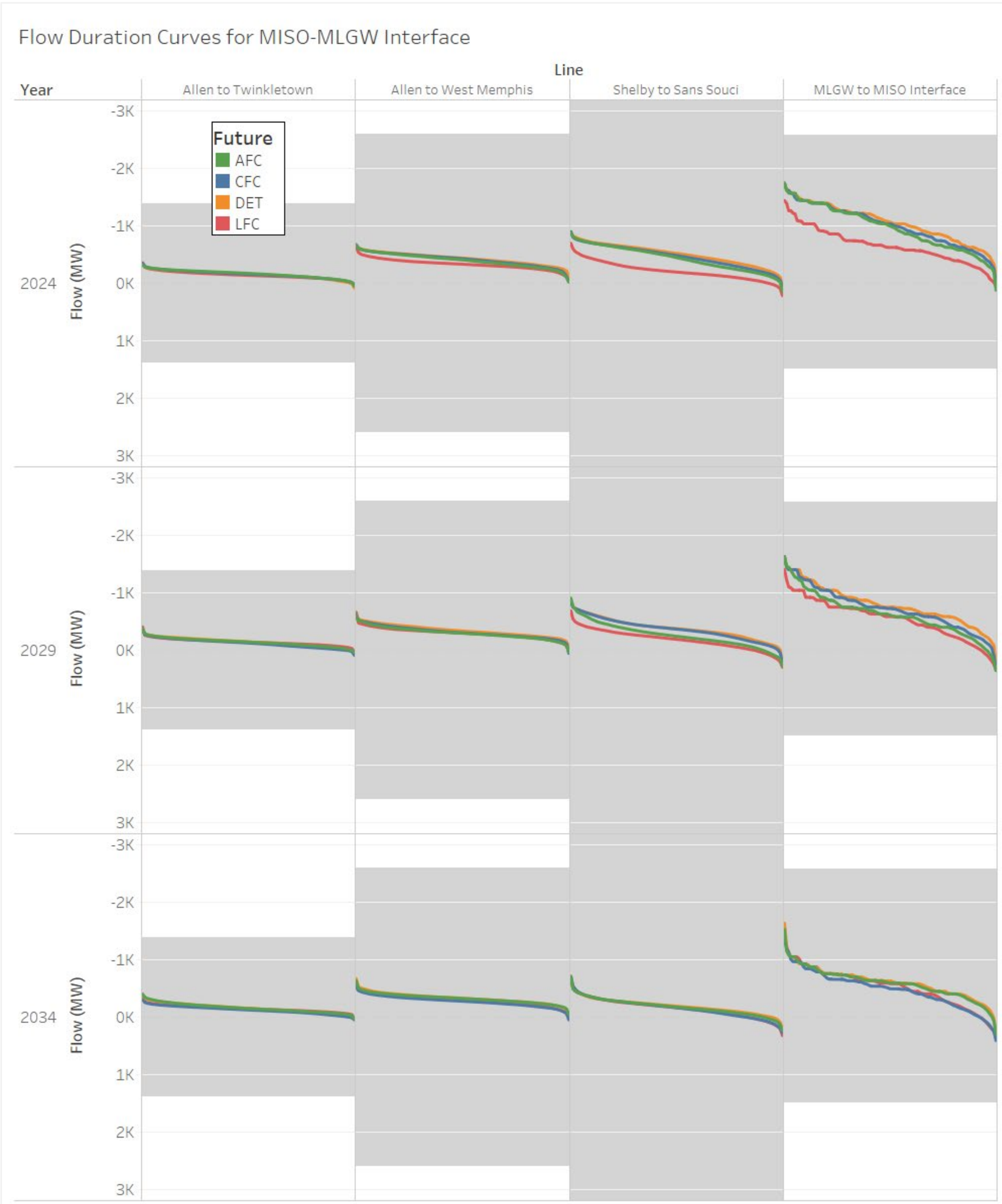


Figure 10 is a matrix of pie charts showing the capacity factor of each of the new generators being considered by year and technology type, under each future and year. The size of each circle represents the maximum capacity under each type. This illustrates the combined cycle facilities delivering increasingly high output while the combustion turbines and solar units produce an average of 1-4% and 17-19%, respectively, of their maximum annual energy in the MTEP20 models.

Figure 10: Average Capacity Factor by Generation Type

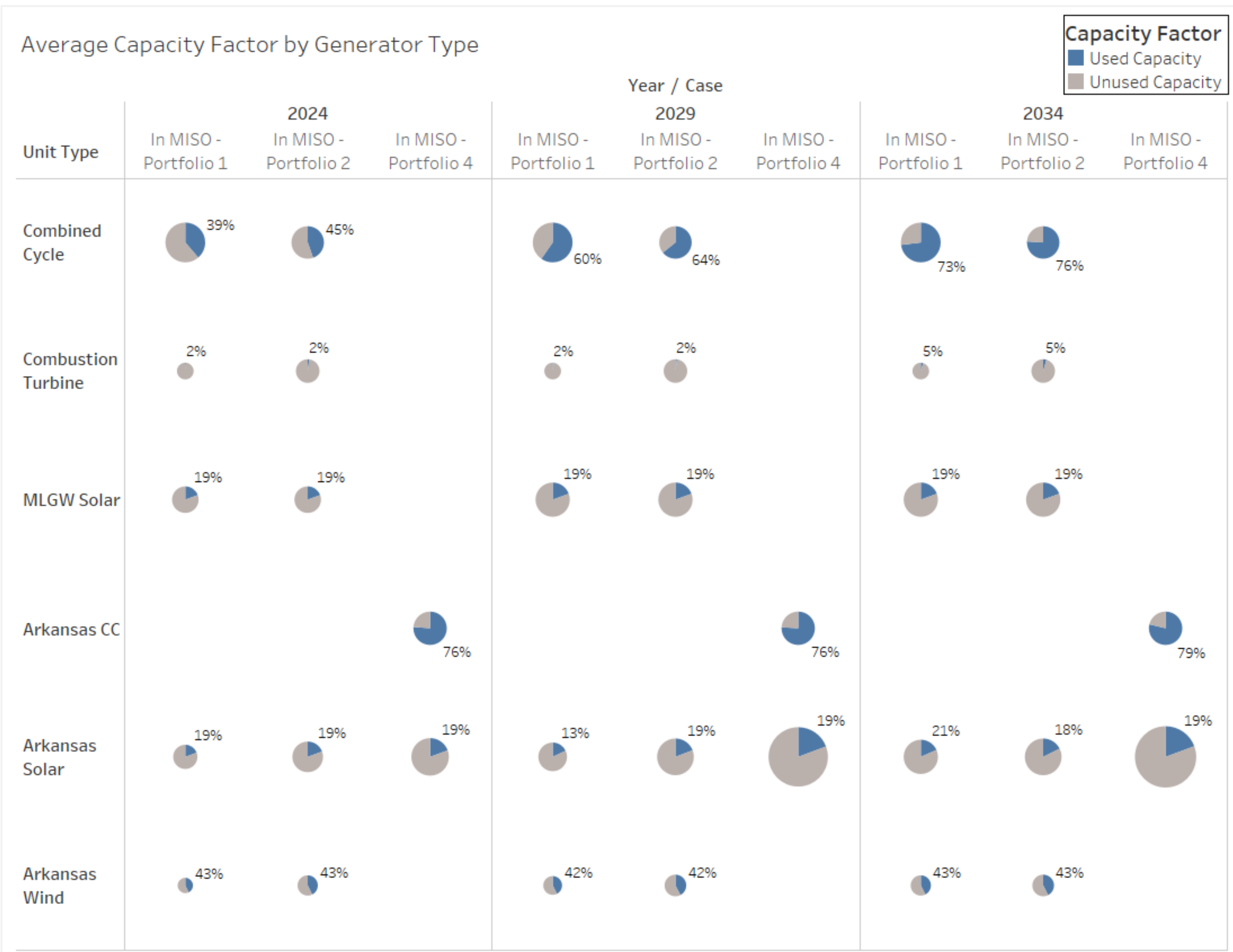


Figure 11 shows the notable impacts to congestion with the addition of the transmission projects, generation and integration of MLGW into MISO. The color of the lines indicates whether congestion was relieved (blue) or whether it has increased (red).

Table 52 shows the name of each of these impacted flowgates as well as how much they are now binding in each year, averaged over each future, and how much congestion increased due to the addition of the transmission projects, generation and joining of MLGW into MISO.

Figure 11: Congestion Pattern Changes (Portfolio #2)

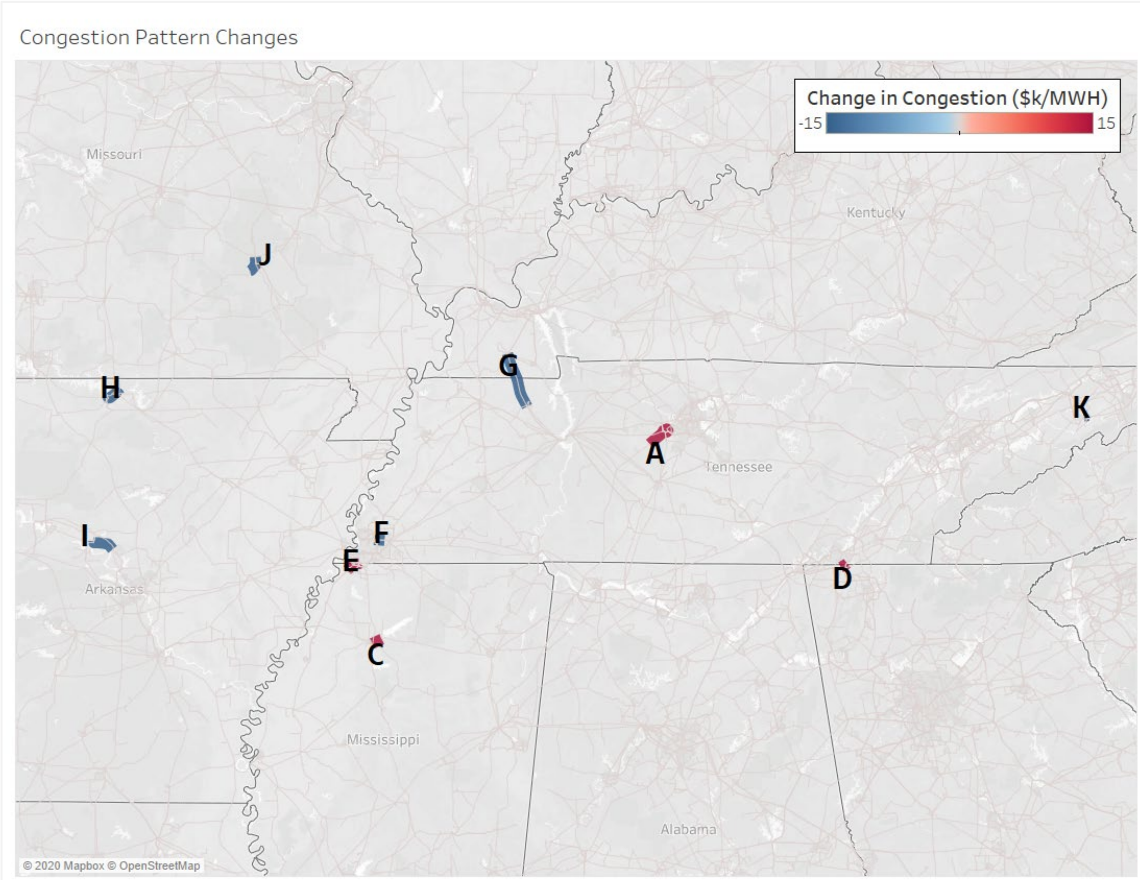


Table 52: List of Impacted Flowgates (Portfolio #2)

ID	Flowgate List	Congestion In TVA – Base			Change in Congestion In MISO – Port. 1			Change in Congestion In MISO – Port. 2		
		2024	2029	2034	2024	2029	2034	2024	2029	2034
A	Davidson – Davidson (TVA-TVA)	73	785	709	42	257	190	38	261	190
B	Haumesser – W Dekalb (COMED-COMED)	0	0	12	59	68	75	59	68	75
C	Batesville – Tallahachi (TVA-TVA)	17	29	72	6	20	35	8	22	40
D	Sequoyah – Concord (TVA-TVA)	157	66	365	18	13	45	16	16	42
E	Freeport – Twinkletown (EESMS-EESMS)	0	0	1	8	3	21	15	11	38
F	NE Gate – Shady Grv (MLGW-MLGW)	0	0	28	1	2	39	0	0	-19
G	Mayfield KY – Paris TN (TVA-TVA)	74	19	104	-18	-5	-65	-17	-5	-64
H	Midwy Jrdn – Bull Sh (EESARK-SPPC)	17	84	199	-1	-20	-74	-3	-27	-62
I	Morilton E – Gleason (EESARK-EESARK)	41	102	178	-12	-32	-53	-12	-29	-46
J	Fletch – Fletch XF (AECI-AECI)	128	171	294	-7	-33	-62	-12	-31	-50
K	Greenvl TP – W Greene TP (TVA-TVA)	117	482	563	-18	-39	-71	-17	-36	-68
L	Dixon – McGirr Rd (COMED-COMED)	95	107	136	-59	-70	-75	-59	-70	-75

Transmission congestion impacts are expressed in a $k/MWh shadow price. The study case does not result in a significant change in system congestion for MLGW or MISO.

In the area surrounding MLGW, congestion within TVA was observed to increase moderately, however, there is already projected system congestion in this area and the study scenario does not seem to be a significant factor in the overall congestion on these flowgates. It is important to note that MISO does not typically analyze or perform market congestion planning with TVA. The higher congestion observed in TVA is primarily in the out years (10 and 15) and is likely driven by assumptions in changes to the TVA generation portfolio that have not been reviewed by TVA or its stakeholders.

6. Membership Process & Cost

<u>Objective</u>**: Provide an overview of the MISO membership application process as well as the ongoing costs related to MISO's administrative cost recovery.**

<u>MISO Conclusion</u>**: Based on MLGW's forecasted 2025 energy sales and MISO's projected annual operating expenses MISO estimates MLGW's share of MISO administrative costs to be approximately $6 million annually. Additionally, MISO members are allocated its portion of FERC's annual budget. This cost is estimated to be an additional $730,000 annually for MLGW.**

<u>Membership Application Process:</u>

New members may join MISO upon submittal of an application in a form approved by the Chief Executive Officer and payment of the initial membership fee of $15,000. Action upon any application for membership shall be taken at the first meeting of the Board following submission of the application. Each year thereafter, each member shall pay an additional fee of $1,000 to MISO to retain its membership.

A new member may join as a transmission owner provided it:

- Owns, operates, or controls facilities used for the transmission of electricity in interstate commerce that are physically interconnected with the facilities of an existing owner; and
- Agrees to sign the MISO Transmission Owner's Agreement and to be bound by all its terms.

<u>Estimate of MLGW's MISO Administrative Costs</u>:

MISO's tariff authorizes it to charge fees designed to allow the full and complete recovery of MISO administration costs through the following formula rates.

<u>Table 53</u>: MISO Administrative Schedule Overview

Schedule 10 – ISO Cost Recovery Adder	• Reliability coordination • Operations planning • Maintenance coordination • Tariff administration
Schedule 16 – Financial Transmission Right (FTR) Cost Recovery Adder	• Coordination of FTR bilateral trading • Administration of FTR through allocation, assignment, auction or any other process accepted by the commission

Schedule 17 – Energy Market Cost Recovery Adder	• Market modeling and scheduling functions • Market bidding support • Locational marginal pricing support • Market settlements and billing

MLGW's MISO administrative costs are estimated to be approximately $5.97M annually. This estimate is based on a 2025 projection of MISO's annual operating expenses, expected load in the current MISO footprint, and the MLGW load projection. Table 54 below shows a summary of the projected MISO costs broken out by schedule. This detail is followed by a step-by-step analysis of how the MLGW annual MISO costs were calculated.

Table 54: 2025 Administrative Cost Projection

Administrative Cost Adder by Schedule	2025 Estimate
Schedule 10	$164,448,000
Schedule 16	$14,511,000
Schedule 17	$151,589,000
Total	$330,548,000
Billing Determinants	**2025 Estimate**
Schedule 10 MWh – Demand Based	1,060,000,000
Schedule 10 Adder MWh – Energy	750,000,000
Schedule 16 – FTR MW Volume	2,300,000,000
Schedule 17 – MWh (Load + Gen + Virtuals)	1,730,000,000
Administrative Cost per MWh of Schedule 10 Energy	**2025 Estimate**
Schedule 10	$0.22
Schedule 16	$0.02
Schedule 17	$0.20
Total Cost / MWh of Schedule 10 Energy	$0.44

Table 55: Step 1 - Estimate MLGW's Percentage of Post-Integration Billing Determinants:

Description	2018 (MWh)
MISO Load	716,070,890
MLGW Load	14,331,186
MLGW + MISO Load	730,402,076
MLGW / (MLGW + MISO)	1.96%

Table 56: Step 2 - Apply MLGW's Load Forecast to MISO Load Forecast to Establish Total:

Description	2025
MISO Estimated Operating Expenses ($ millions)	$330.5
MISO + MLGW Estimated Load (MWh)	750,000,000 + 13,795,598
Estimated Rate with MLGW Integrated ($/MWh)	$0.433

Table 57: Step 3 - Apply the Estimated Rate to MLGW's Billing Determinants:

Description	2025
MLGW Estimated Load (MWh)	13,795,598
Estimated Rate with MLGW Integrated ($/MWh)	$0.433
MLGW Estimated Annual Cost ($ millions)	$5.97

Estimate of MLGW's Schedule 10 FERC Charges:

- MLGW's Schedule 10 FERC charges are estimated to be approximately $731K (2025 MLGW load forecast x FERC Charge Recover Rate (FCRR)).
- Schedule 10 FERC charges are based on MISO's share of FERC's annual budget.

Table 58: FERC Schedule 10

Determinants	Annual Values
Estimated FERC Charge for FY 2020	$55,884,067
Invoiced FERC Charge for FY 2019	$54,098,807
Collected FERC Charge for FY 2019	$56,926,994
Estimated Total Transmission Service (MWh)	1,006,030,587
FCRR 2019-20 = $55,884,067 + (54,098,807 - $56,926,994) / 1,006,030,587 = $0.053/MWh	

7. Functional Responsibilities

***Objective*: Review NERC's designation of functional responsibilities for specific activities and assess what roles MISO and MLGW would assume if MLGW were to become a MISO member.**

***MISO Conclusion*: MISO's core reliability functions are to serve as the balancing authority, planning coordinator, reliability coordinator, and transmission service provider for its region. Additionally, it can take on additional compliance responsibilities for functions through Coordinated Functional Registration (CFR). In this manner MISO assumes some responsibilities associated with the role of resource planner, transmission operator, and transmission planner. MLGW would retain its existing functions and may take on the additional roles of generator owner/operator and resource planner.**

MISO is registered in three NERC Regions (MRO, RFC, SERC) for the following NERC Functional Entity areas:

1. Balancing Authority (BA)
2. Planning Coordinator (PC)
3. Reliability Coordinator (RC)
4. Resource Planner (RP)
5. Transmission Operator (TOP)
6. Transmission Planner (TP)
7. Transmission Service Provider (TSP)

MISO has taken on additional member compliance obligations under a Coordinated Functional Registration (CFR) for certain requirements in the following NERC functions: Transmission Operator, Transmission Planner, and Resource Planner. MISO is the Balancing Authority for the region, and for the legacy balancing authorities existing prior to becoming a MISO member they typically get reclassified as Local Balancing Authorities under the MISO Tariff. The Local Balancing Authorities do maintain some compliance obligations under a CFR with MISO. MISO has successfully undergone multiple NERC Organizational Certifications as well as NERC audits for these functions.

Based on MISO's review of the NERC registry we determined that MLGW is registered for the following NERC Functional Entity areas:

1. Distribution Provider (DP)

2. Transmission Owner (TO)

3. Transmission Operator (TOP)

4. Transmission Planner (TP)

If MLGW were to become a member of MISO, there would be a change in MLGW's ownership of some NERC Functional Entity requirements. Table 59, included below, shows by NERC Functional Entity those where ownership is by MISO and the ones that stay with MLGW. Also, we have indicated where there are typically CFRs entered into with the MISO member for a particular requirement under that NERC Function. For example, MISO enters into numerous CFRs with our members associated with the Balancing Authority NERC function.

Table 59: NERC Functional Responsibilities

NERC Functional Entity	MISO	MLGW
Balancing Authority (BA)	X	
Generator Owner (GO)		X
Generator Operator (GOP)		X
Planning Coordinator (PC)	X	
Reliability Coordinator (RC)	X	
Resource Planner (RP)	CFRs for certain requirements	X
Transmission Owner (TO)		X
Transmission Operator (TOP)	CFRs for certain requirements	X
Transmission Planner (TP)	CFRs for certain requirements	X
Transmission Service Provider (TSP)	X	
Load Serving Entity		X

Transmission Owner (TO):

Checklist for Incoming Transmission Owners (link to Appendix)

Overview of Transmission Owner Agreement and Governance:

MISO has two primary "governing" documents: (1) the "Agreement of Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., a Delaware Non-Stock Corporation" (TO Agreement)5; and (2) the Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff)[6]. These two agreements are on file with FERC. As discussed in more detail below, the TO Agreement outlines the rights and duties of the Transmission Owners and MISO, including terms and conditions for membership, board governance, stakeholder governance, operational control of transmission facilities, and entrance and exit fees. The Tariff addresses the terms and conditions under which MISO grants transmission service, consistent with or superior to FERC's pro forma Open Access Transmission Tariff, as well as the structures and rules for both the energy and ancillary services markets.

Importantly, both agreements originally were developed through the work of a diverse group of interested parties consisting of large and small investor-owned utilities, cooperatives, and municipalities. That type of input on changes to these agreements continues today through established and experienced stakeholder processes.

The TO Agreement establishes MISO as a legal entity, specifically a 501(c)(4) not-for-profit organization, as defined under the U.S. Internal Revenue Code, which requires MISO to be operated exclusively for the promotion of social welfare. Those social welfare aims include (1) non-discriminatory access to transmission facilities in a multi-state region at non-pancaked rates; (2) enhancement of regional reliability; and (3) maintaining independence from any undue influence by any party, including Transmission Owners or other Market Participants. In the TO Agreement the relationship of MISO to Transmission Owners and other stakeholders is described, including establishing the rights that remain exclusively with the Transmission Owners to set and alter transmission rates and revenue distribution. This provision is consistent with FERC's long-standing recognition that pricing and revenue requirement recovery are matters of particular importance to Transmission Owners. Also, only the Transmission Owners, not MISO, have the right to make modifications to the TO Agreement.

MISO's independent Board of Directors ensures fair treatment of all member interests. The MISO Board is comprised of qualified, non-partial Directors having no affiliation with any entity dealing with MISO. In other words, no employee of any of the MISO members

[5] MISO's TO Agreement can be found at the following link: https://www.misoenergy.org/Library/Repository/Tariff/Rate%20Schedules/Rate%20Schedule%2001%20-%20Transmission%20Owners%20Agreement.pdf

[6] MISO's Tariff can be found at the following link: https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx

may sit on the Board, as they have economic interests that may influence their voting. The MISO Board is elected by the MISO members. A MISO member is any eligible transmission customer (including Transmission Owners) who pays membership fees as specified in the TO Agreement. MISO's Board currently is comprised of nine Directors and the President and CEO of MISO, John Bear. The members elect the Directors from a slate of candidates chosen by an independent search firm. To ensure knowledgeable and effective administration, MISO's Directors are required to have specific expertise in varying areas such as corporate leadership, finance or accounting, engineering, or utility law or regulation.

A key part of MISO's governance includes the Advisory Committee, which is comprised of representatives from stakeholder groups ranging from Transmission Owners to public consumer groups and who provide information and advice to the Board. The Advisory Committee can provide recommendations to the Board but does not have any control over it or MISO. At the same time, the Advisory Committee, and its companion, the Steering Committee, oversee a robust stakeholder process that has recently been streamlined to facilitate thorough yet efficient review of strategic issues by stakeholders. The Advisory Committee meets regularly with the Board and MISO management and provides key insights that help to shape thinking on key policy issues such as transmission planning, markets, and resource adequacy.

MISO's independence is further assured by strict adherence of all Directors and MISO employees to standards of conduct. The standards ensure that no MISO employee has a financial interest in any MISO Transmission Owner or Market Participant. The standards of conduct contained in the TO Agreement also prohibit MISO employees from giving any preference to any Transmission Owner or Market Participant.

The TO Agreement also outlines the scope of control MISO has over transmission facilities. MISO controls the operations of 100 kV facilities and above, looped transmission facilities, and certain networked transformers. Control of lower voltage facilities that are considered "transmission" as determined using FERC's seven factor test also may be considered within MISO's functional control but not actually transferred to MISO.

MISO has a duty to protect the assets of the Owners, and to collect and distribute revenues to the Owners. The TO Agreement directs that MISO, its directors, officers and employees "shall have a custodial trust relationship."[7] Pursuant to the terms of the TO Agreement, MISO receives and holds such funds solely as agent or trustee for the MISO Transmission Owners pursuant to that custodial trust relationship. More specifically, the

[7] Article III, Section III, Paragraph A

funds MISO collects regarding transmission service do not belong to MISO. At all times, these funds belong to the owners of the transmission facilities and MISO acts merely as a collection and disbursement agent.

MISO also has a duty, pursuant to the TO Agreement, section III.D, to maximize transmission service revenues associated with "Transmission Services" as defined in the Tariff, so as to most efficiently use the Transmission System as it exists at any given time.

Finally, the TO Agreement also provides for procedures for independent market monitoring. Pursuant to these requirements, MISO has engaged an independent market monitor (IMM) that monitors the market behavior of the owners, generators, and other market players to see if there are any attempts to create transmission constraints to exclude competitors, or any other behavior that undermines the provision of transmission service and market operations.

<u>Effective Date, Termination, and Exit Fee:</u>

The effective date for any Transmission Owner under the TO Agreement is the date the TO Agreement is signed by the signatory, and thus subject to withdrawal fees and other obligations. MISO generally uses a contractual agreement with incoming Owners, which details anticipated costs that will be incurred by MISO to review facilities, make FERC filings, run studies and modify software and revise models to accommodate the applicant's participation in MISO. The agreement generally provides for recovery of these pre-integration costs separate from the withdrawal obligation of the TO Agreement, but also provides that if integration was completed, these costs would be waived in consideration of the future Schedule 10 charges to be paid by the new member.

Upon signing the TO Agreement, a Transmission Owner assumes the obligation to remain a member of MISO for five years, which begins at the time of executing the TO Agreement (as opposed to integration). Article Five of the TO Agreement allows a Transmission Owner unilaterally, upon written notice, to:

. . . commence a process of withdrawal of its facilities from the Transmission System. Such withdrawal shall not be effective until December 31 of the calendar year following the calendar year in which notice is given, nor shall any such notice of withdrawal become effective any earlier than five (5) years following the date that the Owner signed this Agreement except as provided for in Article Seven of this Agreement.

All financial obligations incurred by the withdrawing Transmission Owner prior to the effective date of the withdrawal will be honored, including the costs associated with transmission facilities that are allocated to the withdrawing Transmission Owner's load prior to the effective date of the withdrawal.

Any notice of withdrawal from the TO Agreement must be filed with FERC and FERC must approve or accept such notice, or otherwise allow the notice to become effective. Upon the effective date of the withdrawal all services provided by MISO to the withdrawing Transmission Owner will cease.

Transmission Operator:

MISO does not fulfill the role of transmission operator as defined by NERC. It relies on its transmission owner members to fulfill the following TOP responsibilities or to delegate that role to another NERC certified entity.

- Provide MISO with their respective System Operating Limits (SOLs).
- Provide MISO with generation facility ratings for the facilities within the Transmission Operator's system.
- Provide model data and the system topology for the facilities within the Transmission Operator's system.
- Submit the Transmission Operator's System Restoration Plan to MISO for review when it is updated or upon annual review.
- Submit the Emergency Operations Plan for MISO review.

Local Balancing Authority (LBA):

The Local Balancing Authority is an operational entity or a Joint Registration Organization which is (i) responsible for compliance to NERC for the subset of NERC Balancing Authority Reliability Standards defined in the Balancing Authority Agreement for their local area within the MISO Balancing Authority Area, (ii) a party to Balancing Authority Agreement, and (iii) shown in Appendix A to the Balancing Authority Agreement.

The responsibilities of the Local Balancing Authorities are outlined in Rate Schedule 03 - Amended Balancing Authority Agreement. Key Local Balancing Authority activities include the following:

- Maintain interconnection telemetry, metering, and associated accounting
- Send the area Net Actual Interchange (NAI) to the MISO Balancing Authority

- Establish equipment ratings and monitor their local system in real-time
- Implement emergency procedures including load shedding

Load Serving Entity (LSE) / Generation Operator (GOP):

LSEs and GOPs interact with MISO daily via the various markets. The most efficient method to learning more about the markets and the roles and responsibilities of MISO's market participants may be to start with reviewing the various training materials that are available on the customer training page on the MISO web site. Additionally, MISO provides business practice manuals that outline the key activities associated with many areas of the organization. A list of some of the foundational documents have been provided below. Additionally, MISO can make subject matter experts available for additional training or questions as needed.

- Level 100 – Energy and Operating Reserves Markets
- Level 100 – Auction Revenue Rights and Financial Transmission Rights
- Level 100 – Market Settlements
- BPM 001 – Market Registration

8. Interconnection Process

***<u>Objective</u>*: Outline MISO's current transmission and generation interconnection processes and how these would be applied during a potential period where MLGW is developing assets to facilitate MISO membership prior to integration.**

***<u>MISO Conclusion</u>*: Prior to potentially integrating into MISO, MLGW would have no transmission interconnection requirements. Development of new generating resources would need to be coordinated through TVA's generation interconnection queue or by MLGW on its own. In the latter case MISO can provide assistance to MLGW regarding study assumptions to facilitate a smoother integration.**

<u>Transmission Interconnection</u>:

MISO determines transmission requirements through its system planning processes, in particular, through its MTEP and Generation Interconnection process. These transmission facilities are owned by Transmission Owners in MISO. The only standalone Transmission Interconnection with MISO transmission is through a Merchant HVDC transmission connection as outlined in Attachment GGG of the MISO Tariff.

<u>Generation Interconnection</u>:

New Generation Interconnection Requests are processed in accordance with Attachment X to the MISO Tariff. Such a request must have a Point of Interconnection on the MISO Transmission System in order to be processed through the MISO Generation Interconnection Queue. Requests would not be processed in the MISO queue if the Point of Interconnection is to a MLGW facility prior to MLGW's integration to MISO.

Prior to integration with MISO, new Generation Interconnection Requests would be processed through other available means. If possible, one option would be to submit a request through the TVA queue. MISO would be committed to coordinating the study as an Affected System. Also, if possible, MLGW could assume responsibility to run their own interconnection queue. In this scenario, MISO would coordinate with MLGW on developing study assumptions to enable a more efficient transition upon MISO integration. In either case, existing generation or new generation processed outside of MISO's process would be subject to a market transition deliverability test upon MISO integration.

9. Appendix

Checklist for "Incoming" Transmission Owners

MISO provides this checklist to incoming Transmission Owners as general guidance for many of the steps needed to achieve Board approval and membership integration. Interested parties are encouraged to initially contact Transmission Owner Integrations (TOIntegrations@misoenergy.org), or Membership (membership@misoenergy.org) who will address various membership options with potential Members.

Membership Application and Supporting Documentation:

Membership Application. The incoming Transmission Owner is required to submit a fully executed Transmission-Owning Membership Application, which will be acted on by the MISO Board of Directors at a regularly scheduled Board meeting. Please forward via overnight delivery an originally executed copy of the Membership Application to Secretary, MISO Legal Department. Questions may also be directed to membership@misoenergy.org. The Membership Application can be accessed from MISO's website at the following link: Membership Information [scroll down and click on "Transmission Owners"].

Signature Page to Transmission Owners Agreement. The incoming Transmission Owner is required to submit a fully executed signature page to the "Agreement of Transmission Facilities Owners to Organize the Midcontinent Independent System Operator, Inc., A Delaware Non-Stock Corporation" ("Transmission Owners Agreement"). This signature page can be accessed from MISO's website at the above-referenced link. (Please forward via overnight delivery an originally executed copy to Secretary, MISO Legal Department.) Such signature page to the Transmission Owners Agreement will be reported to the Federal Energy Regulatory Commission ("FERC") in MISO's Electric Quarterly Report ("EQR").

Signature Page to Supplemental Agreement. The incoming Transmission Owner is required to submit a fully executed signature page to the Supplemental Agreement,[8] a multi-party contract, entered into by and between MISO, International Transmission Company and each of the MISO Transmission Owners ("Supplemental Agreement"). Pursuant to Section 3.5 of the Supplemental Agreement, any person or entity seeking to join MISO as a Transmission Owner shall, as a condition to being granted owner status, be required to sign the Supplemental Agreement and be bound by all of its terms and conditions. The signature page for the Supplemental Agreement can be accessed from

[8] *See*, *International Transmission Company, et al.*, 97 FERC ¶ 61,328 (2001).

MISO's website at the above-referenced link. (Please forward via overnight delivery an originally executed copy to Secretary, MISO Legal Department.) The signature page to the Supplemental Agreement will be reported to FERC in MISO's EQR.

Signature Page to Appendix G (Agency Agreement). The Transmission Owners Agreement defines "Non-transferred Transmission Facilities" (commonly referred to as "Appendix G" facilities) as the booked transmission facilities not identified in Appendix H[9] *(Transmission System Facilities)* of the Transmission Owners Agreement. If the incoming Transmission Owner owns transmission facilities below 100 kV, it is required to execute Appendix G (Agency Agreement) of the Transmission Owners Agreement, as such Agency Agreement provides for the MISO's use of the incoming Transmission Owner's Non-transferred Transmission Facilities (*i.e.,* facilities *below* 100 kV) to provide Transmission Service under MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"). (If applicable, please forward via overnight delivery an originally executed copy of Appendix G to Secretary, MISO Legal Department.) The Agency Agreement can be accessed from MISO's website at the above- referenced link. The fully executed Agency Agreement will be reported to FERC in MISO's EQR.

Signature Page to the Amended Balancing Authority Agreement. The incoming Transmission Owner may be required to submit a signature page to the Amended Balancing Authority Agreement, which delineates the responsibilities between MISO (as the Balancing Authority) and the Transmission Owners (as the Local Balancing Authorities) and providing for MISO's Tariff to be implemented. The signature page can be accessed from MISO's website at the above-referenced link. The incoming Transmission Owner should consult with MISO to determine if the incoming Transmission Owner meets the criteria of a Local Balancing Authority pursuant to MISO's Tariff. If appropriate, the incoming Transmission Owner is required to provide a signature page to the Amended Balancing Authority Agreement via overnight delivery to Secretary, MISO Legal Department.) Such signature page to the Amended Balancing Authority Agreement will be reported to FERC in MISO's EQR.

Settlement Agreement between Transmission Owners and MISO on Filing Rights ("Settlement Agreement").[10] The incoming Transmission Owner may become a signatory to the Settlement Agreement filed on November 30, 2004 in Docket No. RT01-87-010, resolving issues concerning the allocation of filing rights to MISO and the Transmission

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[9] Appendix H, regarding Transmission Facilities of the Transmission Owners that are committed to the operation of MISO pursuant to the Transmission Owners Agreement, must include: (i) all networked transmission facilities ***above 100 kV***; and (ii) all networked transformers where the two highest voltages qualify under the voltage criteria of item (i) above.

[10] *See,* Order Approving Settlement, *Midwest Indep. Transmission Sys. Operator, Inc.*, 110 FERC ¶ 61,380 (2005).

Owners (both individually and jointly) under Section 205 of the Federal Power Act within MISO.

Specifically, section 3 of the Settlement Agreement provides the basic understanding that (i) individual Transmission Owners should possess full and exclusive right to submit filings to establish their own revenue requirements, as well as the rate structures within their own Zone(s), provided other Transmission Owners are not impacted; (ii) the right to submit rate filings that impact multiple Transmission Owners should generally belong to owners collectively; (iii) certain types of filing rights, such as those relating to system-wide ancillary services, should belong to both Transmission Owners and MISO; and (iv) MISO should possess full and exclusive right to submit filings relating to the administration of its Tariff.

Once executed, the Transmission Owner's signature page to the Settlement Agreement will be filed at FERC in Docket No. RT01-87, commensurate with the effective date of integration. The incoming Transmission Owner should contact Wendy N. Reed, counsel for the Transmission Owners.

MISO Functional Control of Transmission Facilities

Transmission Facilities Review. To determine which facilities will be subject to FERC's open access requirements and which facilities will remain under the state's jurisdiction for purposes of retail stranded cost adders or other retail regulatory purposes, FERC developed a seven-factor test in Order No. 888[11] that determines which facilities are Local Distribution Facilities.

If applicable, the incoming Transmission Owner may be required to forward to TOIntegrations@misoenergy.org a copy of any order (from FERC or a state regulatory commission) concerning any determination of the classification of its facilities based on a seven-factor test. If the incoming Transmission Owner is not subject to regulation by a regulatory authority, it shall apply to MISO for a determination of the classification of its facilities pursuant to Article II.C.2 of Appendix C of the Transmission Owners Agreement, and MISO will conduct a test in order to determine which facilities are Transmission Facilities appropriate for inclusion in Appendix H of the common template referenced above, and which facilities are Non Transferred Transmission Facilities appropriate for

[11] *See, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC,* 535 U.S. 1 (2002).

inclusion in Appendix G of the common template referenced above. If the incoming Transmission Owner has any concerns on classification of its facilities as Transmission, the transmission review test should be completed before signing the Transmission Owners Agreement. The following information is required for any such transmission review:

a) Preliminary Functional Control and Non-Transferred Facility listing referenced above.

b) One-line diagrams (also called switching diagrams or operating diagrams) of the Transmission Facilities referenced above.

c) Geographic transmission map(s) of Transmission Owner's system.

Please see Transmission Determination Business Practice Manual 028 at the following link: Business Practice Manuals [scroll down and click on "BPM 028 – Transmission Determination Process"].

Listing of the incoming Transmission-Owning Member's (i) Transmission Facilities Transferred to MISO's Functional Control Pursuant to Appendix H (Transmission System Facilities) and (ii) Non-transferred Transmission Facilities that are subject to Appendix G (Agency Agreement) of the Transmission Owners Agreement. The criteria for facilities transferred under MISO's functional control is defined in the Transmission Owners Agreement, as follows:

"Transmission System. The transmission facilities of the Owners which are committed to the operation of MISO by this Agreement. These facilities shall include (i) all networked transmission facilities above 100 kilovolts (hereinafter "kV"); and (ii) all networked transformers where the two (2) highest voltages qualify under the voltage criteria of item (i) above. The facilities may also include other facilities that MISO directs the Owner(s) to assign to it subject to the procedures set forth in Appendix B to this Agreement."

See, Article One (Definitions) of the Transmission Owners Agreement.

The incoming Transmission Owner is required to provide a listing of its Transmission Facilities by means of a "common template," which is updated annually by the Transmission Owner. The common template is posted on MISO's website at the following link: Transferred Transmission Facilities.

Using the common template, the incoming Transmission Owner is required to list all networked Transmission Facilities above 100 kV on the top portion of the common template that fall under Appendix H (Transmission System Facilities) of the Transmission

Owners Agreement. The lower portion of the common template serves to identify the Non-transferred Transmission Facilities that fall under Appendix G (Agency Agreement) of the Transmission Owners Agreement. The Transmission Facilities Listing should specify all transmission lines meeting the above criteria, as well as (i) transformers and (ii) stations containing other transmission equipment (*e.g.*, capacitors, reactors, breakers, bus, etc.) meeting the above criteria. Please only report line miles that you own if you share jointly owned lines. Of special note, please do not include generation step-up facilities (*i.e.,* those facilities at a generator substation on which there is no flow when the generator is shut down) as generation step-up facilities are not reflected in Attachment O (Rate Formulae). The incoming Transmission Owner should forward via email its Transmission Facilities Listing to MISO's Manager of Expansion Planning for review and approval prior to posting such listing on MISO's website.

The incoming Transmission Owner will also be required to submit one-line diagrams and geographic transmission maps of the Transmission Facilities it is transferring to MISO's functional control to MISO's Manager of Expansion Planning. If applicable, please designate one-line diagrams and transmission maps as "Confidential and Non-Public" (pursuant to §301(b) of the FPA and 18 CFR § 388.112) and/or "Critical Energy Infrastructure Information" (CEII) (pursuant to 18 CFR § 388.113(c).

NERC Compliance

Review of Compliance Matters.

a. *Review whether a NERC registration, certification, or certification review is needed for the incoming Transmission Owner or for MISO*. Pursuant to NERC Rules of Procedure ("ROP"), Appendix 5A of the Organization Registration and Certification Manual, entities including Reliability Coordinator ("RC"), Transmission Operator ("TOP"), Balancing Authority ("BA"), Planning Authority ("PA"), Transmission Planner ("TP"), Transmission Service Provider ("TSP"), and Transmission Owner ("TO") are required to be registered and certified for their functions. Certification reviews may be required for the registered entity's footprint or other changes.

b. *Review whether NERC Coordinated Functional Registrations ("CFRs") need to be updated as a result of the incoming Transmission Owner*. A CFR is an arrangement between multiple entities to clearly identify compliance responsibilities. The incoming Transmission Owner may qualify to join existing NERC CFRs, which have the effect of reducing NERC audit scope for certain compliance functions that MISO performs on behalf of its members.

c. *Obtain Regional Entity and NERC committee approvals of updated MISO*

Reliability Plan, if applicable. MISO will update and obtain approval of its Reliability Plan for its footprint, member, or functional changes as necessary. Such Reliability Plan is used to communicate and coordinate any changes with neighboring seams.

Customer Training

Customer Training. From an introduction to MISO Markets to more in-depth learning on key MISO functions, MISO's courses offer new market participants and members an understanding of MISO business practices and market operations.

In addition to training, MISO's website also offers many Business Practice Manuals (BPMs), user guides, and policy documents. See below for a list of highlighted documents suggested for incoming Transmission Owners' review.

- Transmission Owners Agreement
- MISO Energy and Operating Reserves Tariff
- Self-Service Local Security Administrator (SSLSA) User Guide
- Local Security Administrator (LSA) Policy
- BPM 002 – Energy and Operating Reserve Markets
- BPM 012 – Transmission Settlements
- BPM 015 – Generation Interconnection
- BPM 019 – Monthly Transmission Billing
- BPM 020 – Transmission Planning
- BPM 021 – Transmission Pricing
- BPM 023 – Alternative Dispute Resolution

Tariff Filings with FERC

MISO eTariff Filing Guidelines for MISO Transmission Owners. Please refer to the MISO's eTariff Filing Guidelines, which are available at the following link: Filing Guidelines. Such guidelines document MISO's procedures and timeline requirements when it is necessary to coordinate with MISO's Legal Department regarding the submittal of Section 205 filings with FERC. Adherence to these guidelines ensures adequate time and resources are available to the Transmission Owner when it is necessary for MISO's Legal Department to submit, as Administrator of the MISO Tariff, any FERC filings on behalf of the Transmission Owner via MISO's eTariff software.

Pricing Zones. A determination will be made as to whether the incoming Transmission Owner will be part of an existing pricing Zone or a new pricing Zone. If the incoming Transmission Owner will be a separate pricing Zone or is joining an existing joint pricing Zone, MISO will coordinate with the incoming Transmission Owner to submit a Section 205 filing with FERC, amending Schedules 7, 8, 9 and 26 of MISO's Tariff to incorporate the new pricing Zone or amending the existing pricing Zone. Pursuant to the Transmission Owners Agreement,[12] pricing Zones may only be changed to:

- reflect the effectuation of a merger (or consolidating and reorganization),
- add a new Transmission Owner that operates a balancing authority area in existence on or before the "date of the initial filing with FERC to establish MISO,"[13] or
- reflect the withdrawal from MISO of an Owner or Owners.

Local Resource Zones (Attachment VV of MISO's Tariff). Attachment VV depicts a map of the Local Resource Zone boundaries contained within the MISO Region. MISO will, as necessary, develop new Local Resource Zones (LRZs) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within its Region to reliably meet Demand and resource adequacy requirements. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of LOLE studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers.

Cost Allocation Zones (Attachment WW of MISO's Tariff). The Zones identified in Attachment WW are used for allocating the costs of Market Efficiency Projects. Within the map, each Cost Allocation Zone is comprised of one or more Transmission Pricing Zones, and the map represents the approximate boundary of each of the Zones. The costs of Market Efficiency Projects are allocated as follows:

- Twenty percent of the Project Cost of the Market Efficiency Project is allocated on

[12] *See,* Appendix C of the Transmission Owners Agreement.

[13] The date of the initial FERC filing seeking authorization for the establishment of MISO was filed on January 15, 1998 in Docket No. ER98-1438-000. *See,* Order Conditionally Authorizing Establishment of Midwest Independent Transmission System Operator and Establishing Hearing Procedures, *Midwest Indep. Transmission Sys. Operator, Inc.*, *84 FERC § 61,231 (1998).*

a system-wide basis to all Transmission Customers and recovered through a system-wide rate.

- Eighty percent of the costs of the Market Efficiency Projects is allocated to all Transmission Customers in each of the Cost Allocation Zones, as defined in Attachment WW. The cost allocated to each Cost Allocation Zone is based on the relative benefit determined for each Cost Allocation Zone that has a positive present value of annual benefits over the evaluation period using the methodology for project benefit determination of Attachment FF, Section II.B.1.

Rate Structure Matters. If the incoming Transmission Owner intends to vary from the standard Attachment O (Rate Formulae), Attachment MM (MVP Charge), and Attachment GG (Network Upgrade Charge) template(s) for transmission services under MISO's Tariff, the incoming Transmission Owner shall coordinate with MISO, as Administrator of its Tariff, to file with FERC either new templates or revisions to Attachment O (Rate Formulae), Attachment MM (MVP Charge), and Attachment GG (Network Upgrade Charge) so as to amend such templates. A Transmission Owner's Attachment O should include its Transmission Facilities transferred to MISO's functional control, including Appendix G (Agency Agreement) facilities. However, Attachment O rates should not include any facilities considered to be Local Distribution Facilities or generation step-up facilities.

For assistance in populating the templates or the applicable revisions to the rate structure, including Attachment O of MISO's Tariff, please contact MISO's Transmission Rates Business Partner. See also, Item 11 above, which provides information relative to the Legal Department's eTariff Filing Guidelines and timing requirements for coordinating Section 205 filings with FERC.

As transmission billing and revenue distribution are key items that are often intertwined with rate structure issues, incoming Transmission Owners should review Appendix C of the Transmission Owners Agreement.

MISO has a link on its website for the Transmission Owner's Rate Data. A new link on MISO's website shall be created by MISO for each entity subject to MISO's Attachment O Formula Rate Protocols. Each entity submitting an Attachment O for rate recovery shall have public posting and notification requirements per the applicable Formula Rate Protocols.

MISO Transmission Expansion Plan:

- *Attachment FF-4 of MISO's Tariff (Transmission Owners Integrating Local Planning Processes into MISO's Planning Processes per Order No. 890)*. The incoming Transmission Owner will coordinate with MISO's Director or Manager of Expansion Planning so as to inform MISO planners if it intends to integrate its local planning processes into MISO's planning process by way of Attachment FF-4 of MISO's Tariff. If the incoming Transmission Owner intends to integrate its local planning processes by means of Attachment FF-4, such information will be jointly communicated by Client Relations and Expansion Planning personnel to MISO's Legal Department and MISO will submit a Section 205 filing with FERC to revise Attachment FF-4 of its Tariff so as to include reference to the new Transmission Owner in Attachment FF-4.

- *Attachment FF-5 of MISO's Tariff (Transmission Owners Retaining Separate Local Planning Processes per Order No. 890)*. If, however, the incoming Transmission Owner intends to retain the local planning provisions of its own tariff, such information will be jointly communicated by Client Relations and Expansion Planning personnel to MISO's Legal Department. Thereafter, MISO (as the Administrator of its Tariff) will coordinate with the incoming Transmission Owner in the submittal of a Section 205 filing with FERC to revise Attachment FF-5 of MISO's Tariff to include reference to the new Transmission Owner in Attachment FF-5, as well as the new Transmission Owner's local planning provisions in Attachment FF of MISO's Tariff.

Notices of Succession. If applicable, the incoming Transmission Owner shall coordinate with MISO, as the Administrator of MISO's Tariff, in the submittal of a Section 205 filing with FERC so as to assign Transmission Service Agreements from the Transmission Owner's tariff to MISO's Tariff as the provision of transmission and interconnection services may no longer be provided under the incoming Transmission Owner's tariff upon its effective integration into MISO. Such filing will contractually provide for any transactions that will continue flowing on the effective date of the incoming Transmission Owner's transfer of functional control to MISO.

Grandfathered Agreements

Grandfathered Agreements ("GFAs"). If applicable, MISO will coordinate with the incoming Transmission Owner in the submittal of a FERC Filing, amending Attachment P (Listing of Grandfathered Agreements) of MISO's Tariff to identify and classify the eligible GFAs to which the incoming Transmission Owner is a party. The incoming Transmission

Owner should contact MISO's Assistant General Counsel, to: (a) provide copies of any existing agreement(s) to be evaluated for potential eligibility for GFA treatment and (b) preliminarily discuss whether such agreement(s) would qualify for GFA treatment.

MISO's Tariff defines GFAs as follows:

- **1.126 Grandfathered Agreement(s) (GFA):** An agreement or agreements executed or committed to prior to September 16, 1998 or ITC Grandfathered Agreements that are not subject to the specific terms and conditions of this Tariff consistent with the Commission's policies. These agreements are set forth in Attachment P to this Tariff.

- **1.30a Carved-Out GFA(s):** Any Grandfathered Agreement(s) that the Commission has identified as "carved out" pursuant to Appendix B of the Commission's September 16, 2004 order, *Midwest Independent Transmission System Operator, Inc.,* 108 FERC ¶ 61,236 (2004) or that meet the criteria in Section 38.8.3(A).b, and set forth in Attachment P to this Tariff, as that Attachment may be amended from time to time.

The incoming Transmission Owner should also review Section 38.8.3(A) of MISO's Tariff with respect to the treatment of GFAs after September 16, 2004, as well as the following FERC Orders:

- September 16, 2004 *Order Addressing Treatment of GFAs in the Midwest ISO Energy Markets, and Establishing Hearing and Settlement Judge Procedures*, 108 FERC ¶ 61,236 (2004) in Docket Nos. ER04-691-000, ER04-106-002 and EL04-104-000 ("GFA Order").

- April 15, 2005 *Order on Rehearing and Compliance Filings Concerning the Treatment of GFAs in Midwest ISO Energy Markets*, 111 FERC ¶ 61,042 (2005) in Docket Nos. ER04-691-001, ER04-106-003 and EL04- 104-001, *et al*.

- December 15, 2009 *Order on Tariff Revisions and Complaint,* 129 FERC ¶ 61,221 at P 39 (2009), eliminating the availability of carved-out GFA status for existing agreements between the incoming Transmission Owner and its affiliates and/or owner-members, which is applicable to Transmission-Owning Members joining after December 15, 2009.

In addition, the incoming Transmission Owner is required to submit GFA templates to MISO's Client Relations Department for any agreements eligible to be classified as GFAs. The GFA template identifies, among other information, the following:

- The GFA Responsible Entity (or the billing entity, in the case of Carved- Out GFAs).
- The GFA Scheduling Entity (or the entity responsible for scheduling, in the case of Carved-Out GFAs).
- The source and sink points applicable under the GFAs.
- The maximum MW Capacity permissible under the GFAs
- The GFA termination date or any indication that the GFA is evergreen.

The incoming Transmission Owner and MISO shall coordinate on MISO's submittal of a Section 205 filing with FERC to update Attachment P of MISO's Tariff, notifying FERC of any newly listed GFAs and applicable GFA treatment option(s). Please refer to *MISO's eTariff* Filing Guidelines referenced above.

Newly added GFAs are afforded one of two treatment options (*i.e.*, Option A or Option C). Newly added GFAs can choose:

1. Option A or C treatment;
2. carved out treatment, provided they meet applicable criteria; or
3. conversion of the agreements to transmission service under Module B of the Tariff. *See,* April 15, 2005 *Order on Rehearing and Compliance Filings Concerning the Treatment of GFAs in Midwest ISO Energy Markets*, 111 FERC ¶ 61,042 at PP 104-106 and P 422 (2005).

Carved-Out GFAs are financially rather than "physically" carved-out of MISO's markets, in accordance with Section 38.8.4 of the Tariff. FERC has recognized that such GFAs cannot be physically carved out of the market as if they were operating wholly "outside" the market.[14] Carved-Out GFAs are financially exempt from congestion, losses and certain other charges directly linked to MISO's markets, but bear responsibilities concerning reliability-related coordination, scheduling and real-time energy imbalances,[15] and share in charges based on the system-wide reliability and efficiency benefits they

[14] *See, Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,236 at P 90 (2004) ("September 16, 2004 Order"), *order on reh'g*, 111 FERC ¶ 61,042 at P 406, 415 (2005) ("April 15, 2005 Rehearing Order"), *order on reh'g*, 112 FERC ¶ 61,311 (2005) ("September 19, 2005 Rehearing Order").

[15] September 16, 2004 Order at PP 90, 144 (scheduling); April 15, 2005 Rehearing Order at PP 358-60 (scheduling), PP 373-74 (real-time imbalances), P 415 (coordination and scheduling); September 19, 2005 Rehearing Order at P 38 (scheduling and cooperation).

receive from the existence and operation of the market.[16] In addition, Carved-Out GFAs can participate in certain benefits offered by MISO's markets. For example, parties to Carved-Out GFAs may use spot purchases and sales in the Energy Market,[17] rather than scheduling under the Carved-Out GFAs, to readily obtain replacement power in case of outages, or to more economically meet load requirements. Both Carved-Out GFA parties and other Market Participants benefit from such flexibility, which results in market participation and more efficient commitment and dispatch of the generation that may be used to serve Carved-Out GFA Load.

Allocation of FTRs / ARRs

Financial Transmission Rights ("FTRs")/Auction Revenue Rights ("ARRs"). Under MISO's Tariff, an Annual ARR Allocation year consists of the period beginning on June 1 of a given calendar year to May 31 of the following calendar year. When the incoming Transmission Owner's integration happens at mid- cycle, the Transmission Owner would not yet be able to participate fully in an Annual ARR Allocation. Accordingly, MISO's Tariff provides the procedure for a Partial-Year FTR Allocation that would give the incoming Transmission Owner (or Customers taking service under the Transmission Owner's tariff) a means to hedge congestion until the next Annual ARR Allocation year.

The Partial-Year FTR Allocation will be based on transmission rights arising from network, point-to-point and GFA transmission services in the incoming Transmission Owner's service area. The components of these transmission rights will need to be timely registered with MISO in four ways:

1. transmission assets on which the rights are based should be registered in time for inclusion in the Network Model and Commercial Model updates immediately preceding the integration date;
2. entities claiming transmission rights should register as Market Participants;
3. the transmission services on which the rights are based should be incorporated into MISO's Open Access Same-Time Information System ("OASIS"); and
4. the transmission rights must be recorded during a pre- integration, off-cycle ARR

[16] September 16, 2004 Order at PP 6, 297-98 (Schedule 17 charges); April 15, 2005 Rehearing Order at PP 174-181 (Schedule 10 and 17 charges), 419 (Schedule 18 charges); September 19, 2005 Rehearing Order at P 21 (Schedule 17 charges).

[17] April 15, 2005 Rehearing Order at P 179; September 16, 2004 Order at PP 101, 191 (FERC expressed its expectation that one party to GFA No. 308 "will register with the Midwest ISO as a market participant so that if it ever needs to purchase energy in the Midwest ISO market, for an emergency or otherwise, it will be subject to the TEMT for those transactions").

registration that will involve the preliminary gathering of data (relating to ARR Zone, Reserved Source Points, and transmission capacity), and the definition of ARR Entitlements that will form the basis for requests for FTRs in the Partial-Year FTR Allocation.

ARR Entitlements will be defined based on historical transmission usage during the Reference Year, which shall be the four full seasons before the integration date. As a part of this integration process, a Market Participant that has a sum total of baseload entitlement MWs below its baseload usage can invoke the supplemental rules to determine whether any new baseload entitlements can be created to fill the gap. The Partial-Year FTR Allocation will consist of a single round of nomination and allocation of FTRs, covering the peak and off-peak periods of each of the remaining seasons of the current Annual ARR Allocation period. The allocation of partial-year FTRs will be subject to the Simultaneous Feasibility Test ("SFT"). To the extent the paths of the partial-year FTRs may not coincide with actual usage, Market Participants may participate in the monthly FTR Auctions to reconfigure their FTR portfolio by selling and/or acquiring FTRs. Partial-year and monthly auction FTRs are also transferable on the FTR secondary market. For an incoming Transmission Owner, its "Year 1" of the allocation process will be the first full Annual ARR Allocation period that begins after the end of the partial year.

Capacity Market /Planning Resource Auction

Capacity Market/Planning Resource Auction Participation Requirements. Under the MISO Tariff, the annual Planning Resource Auction ("PRA") covers the MISO planning year period beginning on June 1 and running through May 31 of the following calendar year. Any Market Participant ("MP") serving load and/or providing generation within the MISO footprint must participate in the annual PRA to demonstrate resource adequacy. An incoming MP that functions only as a Transmission Owner has no requirements within the capacity market and thus can disregard this section. As detailed in MISO BPM-011, Section 7, an incoming Transmission Owner that serves load and/or provides generation and does not join MISO within the normal auction preparation window will be provided the opportunity to take part in a Transitional PRA.

The responsibilities of the incoming MP in the Transitional PRA process are to provide MISO with coincident and non-coincident peak forecasts covering the transitional period, and to ensure that they have sufficient resources to meet their coincident peak load forecast plus a Planning Reserve Margin. If the incoming MP will only be providing generation, they will have the opportunity to offer their output into the Transitional PRA.

Incoming MPs with generation will be asked to provide test data for units expected to offer output into the Transitional PRA. This data forms the basis of the capacity credit that each unit will receive in order to submit offers into the auction.

Other Agreements:

Miscellaneous Agreements. The incoming Transmission Owner is required to provide any must run agreements, operating guides and/or other operating agreements governing the operation of facilities within the incoming Transmission Owner's control area, to MISO's Regional Manager of Reliability Coordination & Engineering, who will coordinate further review of such agreements within MISO Operations.

In addition, the incoming Transmission Owner is required to provide any interconnection agreements to MISO's Resource Utilization Department to coordinate further review of such agreements within MISO Resource Planning.

Customer & Asset Registration

Market Participation. Please note that Market Participant status is not a requirement for membership status. Rather, Market Participant status is required in order to interact with MISO's Tariff (to buy and sell energy, bid and offer load and generation, participate in the FTR markets). This is substantially more involved than obtaining Membership status and requires establishing credit and executing a copy of Attachment W (Form of Market Participant Agreement) of MISO's Tariff, which is a contractual commitment to the terms of MISO's Tariff. If the incoming Transmission Owner also desires to be a Market Participant, it will be required to apply and register as such.

If the incoming Transmission Owner is not pursuing status as a Market Participant, it will be required to submit online a *Non*-Market Participant Application as discussed in Item 24(a). As a part of such application process, the Transmission Owner will designate various contacts, provide financial institution information, and provide a valid client-side Digital Certificate that will be registered to the Transmission Owner's Local Security Administrator ("LSA").

Portal Access and Entity Code Registration with OATI.

a. *Non-Market Participant Application*.

First, the incoming Transmission Owner should:

- obtain a Dun & Bradstreet D-UN-S Number (only if the entity does not already have one);
- obtain a digital certificate from one of the approved vendors listed on MISO's

website at https://www.misoenergy.org/globalassets/legal/tariff/final-miso-to-guidelines-for-etariff-08-21-2017.pdf and

- submit a Non-Market Participant Request for System Access form, which will provide the incoming Transmission Owner with access to the "*Non-Market Participant Registration*" online application.

Second, the incoming Transmission Owner must access MISO's secure Market Portal to submit a fully executed "Non-Market Participant Registration" application. As a part of such application process, the Transmission Owner will designate various contacts, provide financial institution information, and provide a valid client-side Digital Certificate that will be registered to the Transmission Owner's Local Security Administrator ("LSA").

b. *OATI webRegistry*. The incoming Transmission Owner will be required to register their entity with Open Access Technology International, Inc.'s ("OATI") webRegistry (https://www.naesbwry.oati.com/NAESBWRY/sys-index.wml) as an Operating/Security Entity and obtain an Entity Code that is not already in use by MISO systems. If the incoming Transmission Owner has not already obtained Market Participant status, then it must also register its OASIS entity code as a Purchase Selling Entity and associated tagging desk code with the NAESB webRegistry hosted by OATI in order to purchase transmission and schedule Energy in the MISO Energy and Operating Reserve Market or with any transmission provider or market. Please note that such registration with OATI webRegistry is separate and distinct from registering as a MISO Transmission Owner or Market Participant.

Once both (i) the Transmission Owner's Non-Market Participant Registration application has been received and processed by the Customer & Asset Registration Services Department and (ii) the Transmission Owner's Membership Application have been approved by MISO's Board of Directors, the Transmission Owner will be granted access to MISO systems. At that time, the LSA will be activated, resulting in the ability of the Transmission Owner to create portal user accounts with access to appropriate MISO Market Portal applications.

MISO OASIS / OASIS Postings

OATI Creation of a Link on MISO's OASIS for the incoming Transmission Owner. A new link shall be created by OATI on the MISO OASIS node for the incoming Transmission Owner. Each Transmission Owner has OASIS posting requirements by FERC, including the Transmission Owner's rate calculation related information. The incoming

Transmission Owner must first coordinate with OATI to register as a company in OATI OASIS (this registration in OASIS is separate and distinct from the webRegistry Entity Code registration referenced in Item 24(b) above). Thereafter, MISO will coordinate with OATI to coordinate the posting of OASIS information for the incoming Transmission Owner.

Transmission Owner OASIS Postings:

a. The incoming Transmission Owner is required to post rate calculation related information on MISO's website on the link (created by MISO) to its OASIS information. When posting such information, please contact MISO's IT Operations Center with the document(s) attached and include specific posting instructions. Please refer to the "Request for OASIS Postings documentation" located on the MISO OASIS at the following link:

https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Posting_to_OASIS.doc

b. *The incoming Transmission Owner will also post notice of any future Transmission Service that it is migrating to the MISO's Tariff.* Any Transmission Service from the incoming Transmission Owner's tariff should be posted on MISO's OASIS.

Operations Matters

MISO Model Updates. MISO maintains a Network Model in order to support various real-time and study network analysis functions used to maintain power system reliability, securely commit and dispatch generation, and operate the Day Ahead, Real Time, and FTR markets. The Network Model is populated with data provided by authorized Transmission Owners, Local Balancing Authorities, and Market Participants and provides a mathematical representation of the electric power system. All of MISO's Transmission Owners are obligated to provide transmission equipment modeling information to MISO in accordance with NERC Reliability Standard IRO-010 and MISO RTO-SPEC-006. New and incoming Transmission Owners are required to submit substation one-line diagrams and geographic transmission maps of the Transmission Facilities it is transferring to MISO's functional control to MISO's Manager of Operations Modeling. Additional modeling data in the form of Common Information Model (CIM) files or other model data files from various power system applications may also be required. For more information, MISO's BPM 010 for Network & Commercial Models and MISO's Network & Commercial Model Update Schedule can be found on the public website.

Inter-Control Center Communications Protocol (ICCP) Set-up: For real-time data requirements, MISO requires that an ICCP connection be established with the new

Transmission Owner or an entity that they designate. This entity is required to have the required ICCP infrastructure. MISO is responsible for building out the communication network required as well as the monthly maintenance costs. For more information, please contact the Manager of Networking.

See the ICCP Data Requirements Business Practice Manual 031 for more information: [BPM 031 – ICCP Data Requirements.]