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MEMO TO:	Memphis Light, Gas and Water IRP Team
FROM:	Siemens PTI IRP team
DATE:	March 12th, 2020
SUBJECT:	MLGW IRP Generation Technology and Resource Memo Update

This memo is an update to the generation Technology Costs and Performance Assumptions memo provided and approved in January 2020. The memo documents the methodology that Siemens Power Technologies International (Siemens) used to develop the cost and performance assumptions for all new build generation technologies for Memphis Light, Gas and Water (MLGW), with an update to the variable O&M of all gas fired technologies (Simple Cycle Gas Turbines and Combined Cycle). Additionally, as the Long Term Capacity Expansion (LTCE) was identifying that 1x1 combined cycle gas turbine (1 x1 CCGT) was part of the solution and that combustion turbines (CT) were also necessary, in this update we replaced the 350 MW 1x1 CCGT by a similar unit but with duct-firing for which we had detailed cost and performance characteristics. This offering has a winter capacity of 361 MW (without duct firing) and it increases to 450 MW with duct firing. The additional 89 MW are obtained at a very small additional cost and the efficiency of the duct-firing operation compares very favorably with respect to a CT.

The assumptions that are used in our long-term capacity expansion modeling are summarized by resource type. Furthermore, all of Siemens capital cost forecasts are compared with public forecasts as references.

This memo also discusses MLGW capacity needs (reserve) to meet MISO's resource adequacy requirements and become a MISO member as well as the requirements that would lead to its integration into an existing Local Recourse Zone (LRZ), rather than remaining as a separate zone.

Methodology

Siemens maintains a technology cost and performance database that includes all applicable studies, projects, and announcements from over fifty public and confidential client sources. All sources in the database are maintained to be within three years of the current year to sustain up-to-date assumptions. Key public sources include annual reports such as the NREL Annual Technology Baseline, the EIA Annual Energy Outlook, the Lazard Levelized Cost of Energy, and the Lazard Levelized Cost of Storage. In addition, key subscription sources such as ThermoFlow, S&P Global, Energy Velocity, and Greentech Media are included.

The Siemens team screens each source for equipment type, model, project scope and location to develop qualified samples. These qualified samples are then modified using variables including location adjustments, inflation adjustments and owner's interest rate to develop comparable national samples. Siemens then uses statistical analysis from the comparable national samples and expert opinion to determine likely cost ranges for each technology.

The technology database provides the foundation for our technology performance and costs forecasts. To develop longer term cost projections, Siemens considers a number of factors, including the recent and expected rates of technological improvements for existing technologies and new technologies that are under development. By varying assumptions (productivity, learning curves, technology obsolescence, cost escalations etc.), Siemens develops a distribution of values for each technology over time, which can help us develop high and low values for each of the technologies.

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Assumptions

For this analysis, generation options for the long term capacity expansion include advanced combined cycle gas turbine (CCGT), conventional CCGT-Fired, simple cycle advanced frame combustion turbine (CT), simple cycle conventional frame CT, simple cycle aeroderivative CT, supercritical coal with carbon capture and storage (CCS), single-axis tracking solar PV, lithium-ion battery storage, onshore wind, and small modular reactor (SMR).

Summarized Technology Comparison

This summary includes our national capital cost forecasts by technology class.[1] All of our capital cost assumptions are considered to be "All-In" capital costs which include EPC costs (engineering, procuring, construction), developer costs (land, permitting, employees, etc.), and financing interest during construction. However, these capital costs only include onsite costs up to the point of interconnection.[2]

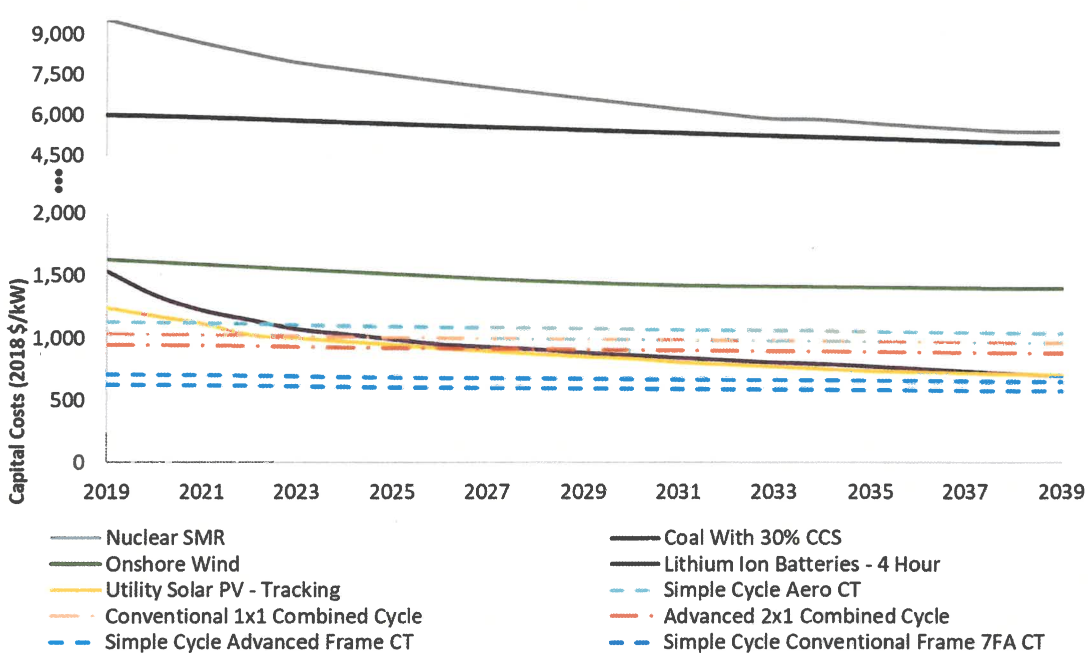
- Budgetary estimates of unit performance and cost was provided in the IRP. According to the American Association of Cost Engineers, this is a Class 4 estimate appropriate for a study with an expected accuracy range of Low: -15% to -30%, to High: +20% to +50%. That said, given the modularity and experience building most generation technologies, Siemens believes the cost estimates we provide are closer to Class 3 estimates and within a tighter band than AACE defines. Further, based on our research and experience, Siemens use different bands for each technology.
- The estimates are for typical units of a class (i.e. Advanced class CT = G, H, J, or HA CT models depending upon the vendor), the unit models presented are typical for the class, and do not necessarily the specific models used as a basis for the estimate. Specific units may be chosen during a procurement process when vendors provide unit performance and cost guarantees.
- Performance (e.g. heat rates) is based on ISO conditions as this is sufficient. Only in extreme cases (i.e. high elevations or exceptional temperatures) do we adjust performance estimates to locational specificity. We do adjust costs for locality
- The Capacity in our tables is provided for winter conditions. In the modeling winter to summer capacity are made with ratios of 0.92 for CCGT, 0.91 for SCCT, 0.99 for Coal, and 0.94 for Nuclear.
- Provided estimates are "inside-the-fence" estimates and account for all EPC and owners costs, including interest during construction, insurance and taxes. They do not include the cost of fuel, water, or waste pipelines, rail, or transmission upgrades since the location of the study plant is usually unknown. That said, we under transmission costs we add an estimation of the cost to interconnect and we can make estimates for gas delivery should those be requested.

[1] Regional capital cost forecasts are developed by applying regional multipliers from the EIA AEO to the Siemens national capital cost forecasts. A complete list of regional multipliers is included in Appendix A.
[2] Siemens "All-in" capital costs do not include additional transmission/interconnection costs past the busbar as these costs are highly variable dependent on project specific details.

- Estimates are based on other studies – some public and some private – to provide a range of potential performance and cost to account for unknown conditions which may impact unit cost or performance. No one estimate will exactly represent the performance of a given unit that a customer might procure for a specific site. Vendors will assess site conditions during a procurement process and develop a specific offer which guarantees both performance and cost.
- Vendors operate in a highly competitive space and thus continually improve unit performance and cost. As a result, a given turbine model (i.e. F-class) will perform better two to three years from now than today. Thus, the studies and tools used to develop the performance and cost estimates may not represent exactly the characteristics of a new unit purchased today, though the difference will be small. Even vendor websites often lag in presenting their latest performance.
- Even within given equipment model customers have choices which influence performance and cost, and those choices are not always apparent. They may select wet or dry cooling, add evaporative cooling, require on-site gas compression, or add a range of duct firing capability for example. This is a primary reason why we do not use project announcements – they generally lack scope and condition definition.

Exhibit 1 shows Siemens forecasted capital costs for each of the utility scale technologies to be considered for new development.

Exhibit 1: Siemens New Resource Capital Cost Assumptions by Technology, 2018$/kW



Source: Siemens

Siemens capital cost forecasts are assumed for the year of development as opposed to the year of commercial operation; thus, development timelines are considered for building new generation. Certain technologies achieve economies of scale or use different equipment dependent on the size of the projects. In addition, other cost and performance parameters such as operation and maintenance costs are required to develop levelized cost of electricity. Siemens uses the following cost and financial assumptions for each technology in the market shown in Exhibit 2. Note that two options are given for the CCGTs and three options are given for peaking generation to the long term capacity expansion plan (LTCE). Some of the new plants could be financed by MLGW, assumed at a weighted average cost of capital (WACC) of 6.16% to be consistent with other utility-financed new builds in SERC and MISO market.

Exhibit 2: Siemens New Resource Technology Cost and Financial Assumptions

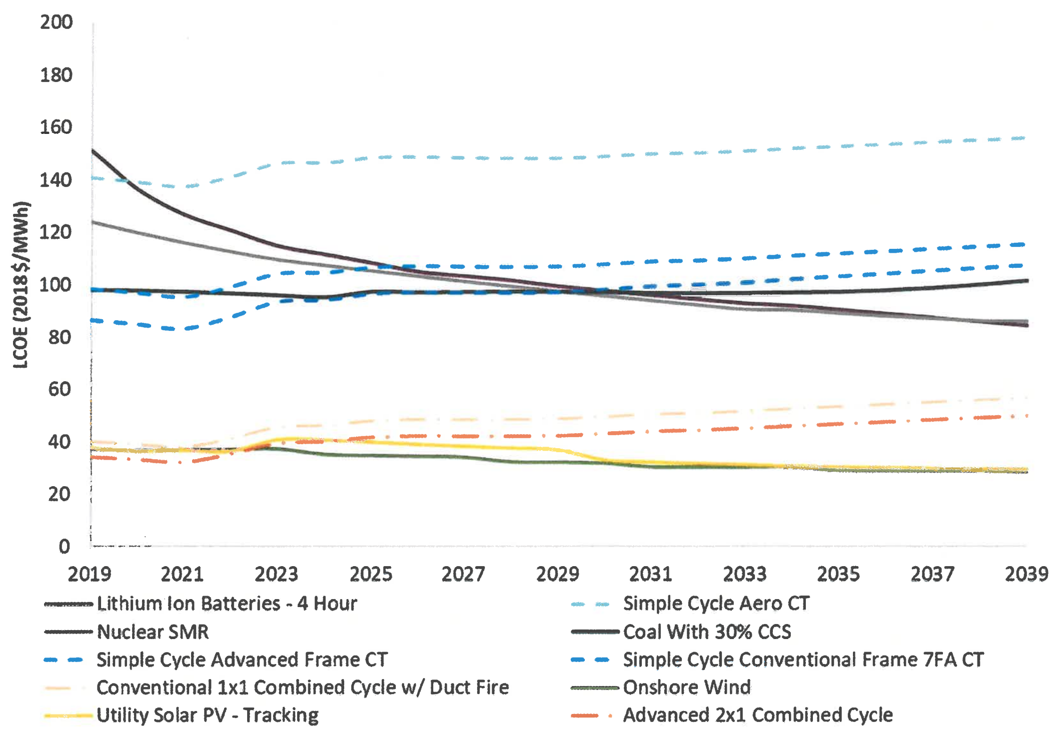
Technology	Advanced 2x1 CCGT	Conventional 1x1 CCGT, Fired	Simple Cycle Advanced Frame CT	Simple Cycle Conventional Frame 7FA CT	Simple Cycle Aero CT	Coal With 30% CCS	Utility Solar PV - Tracking	Onshore Wind	Lithium Ion Batteries (4 hrs.)	Nuclear SMR
Fuel	Nat. Gas.	Nat. Gas.	Nat. Gas.	Nat. Gas.	Nat. Gas.	Coal	Sun	Wind	Elec. Grid	Uranium
Construction Time (Yrs)	3	3	2	2	2	5	1	2	<1	7
Winter Capacity[3] (MW)	950	450 361 (Base) 89 (DF)	343	237	50	600	50	50	5 MW / 20 MWh	50-1,200
Average Heat Rate (Btu/kWh), HHV	6,536	7,011 (Base) 8,380 (Incr. DF)	8,704	9,928	9,013	9,750	N/A	N/A	N/A	N/A
VOM (2018$/MWh)	1.81	2.49	7.13	5.05	6.50	7.14	0.00	0.92	1.39	14.79
FOM (2018$/kW-yr)	15.90	17.41	9.53	4.39	15.70	73.45	20.70	36.56	32.21	165.42
Range of Capital Cost (2018$/kW)	947-874	1084-1003	711-652	626-578	1136-1041	6135-5027	1245-702	1636-1399	1534-693	9539-5365
Range of LCOE (2018$/MWh)	35-51	42-58	95-112	88-110	140-155	98-101	38-29	37-28	151-84	124-86
Book Life	30	30	30	30	30	40	30	30	15	40
Debt Life	20	20	20	20	20	20	20	20	10	20
MACRS Depreciation Schedule	20	20	15	15	15	20	5	5	7	15
Cost of Equity (Utility / Merchant)	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%
Cost of Debt (Utility / Merchant)	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%
Equity Ratio (Utility / Merchant)	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%
Debt Ratio (Utility / Merchant)	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%
After Tax WACC[4] (Utility / Merchant)	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%

Source: Siemens

[3] Winter to summer capacity adjustment ratio is 0.92 for CCGT, 0.91 for SCCT, 0.99 for Coal, and 0.94 for Nuclear.
[4] MLGW's new builds are assumed at generic utility's WACC of 6.16%.

Exhibit 3 shows Siemens forecasted levelized cost of energy assumptions for each technology.

Exhibit 3: Siemens New Resource Levelized Cost of Energy Assumptions by Technology, 2018$/MWh



Source: Siemens

Siemens notes that the levelized cost of energy determination for all thermal and storage technologies are highly dependent on capacity factor assumptions which are outputs of the production cost model scenarios. Thus, the levelized cost of energy forecasts above for these technologies are valid for the expected capacity factors and the exhibit below provides the selected values for the development of the chart above.

Exhibit 4: Assumed Capacity Factors

Technology	Advanced 2x1 Combined Cycle	Conventional 1x1 Combined Cycle	Simple Cycle Advanced Frame CT	Simple Cycle Conventional Frame 7FA CT	Simple Cycle Aero CT	Coal With 30% CCS	Utility Solar PV - Tracking	Onshore Wind	Lithium Ion Batteries - 4 Hour	Nuclear SMR
Assumed Capacity Factor (%)	60%	55%	10%	10%	10%	85%	23%	40%	15%	85%

However, to provide a view of the effectiveness of these resources at various capacity factors, Exhibit 5 illustrates the LCOE when they are operating at various capacity factors. As can be observed in the detail presented in Exhibit 6, for low capacity factors which as are expected for peaking services, the Simple Cycle Conventional and Advanced Frame CT have the lowest cost, followed by the CCGT's and the Aero CT. So, we would expect these first units to be selected, unless size requirements favor the smaller Aero CT. For base load services (higher capacity Factors), the lowest cost is observed for the Advanced 2x1 CCGT, followed closely by the Conventional 1x1 CCGT. For storage the capacity factor is determined by the number of cycles expected over the year.

Exhibit 5: Thermal & Storage Technology 2019 LCOE Assumptions by Capacity Factor, 2018$/MWh

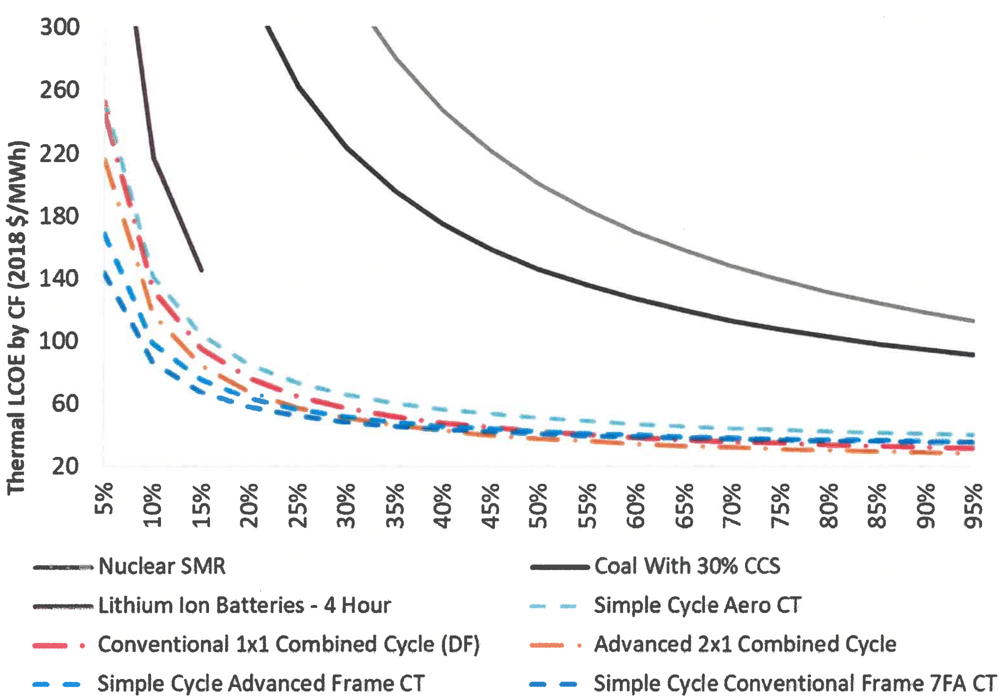
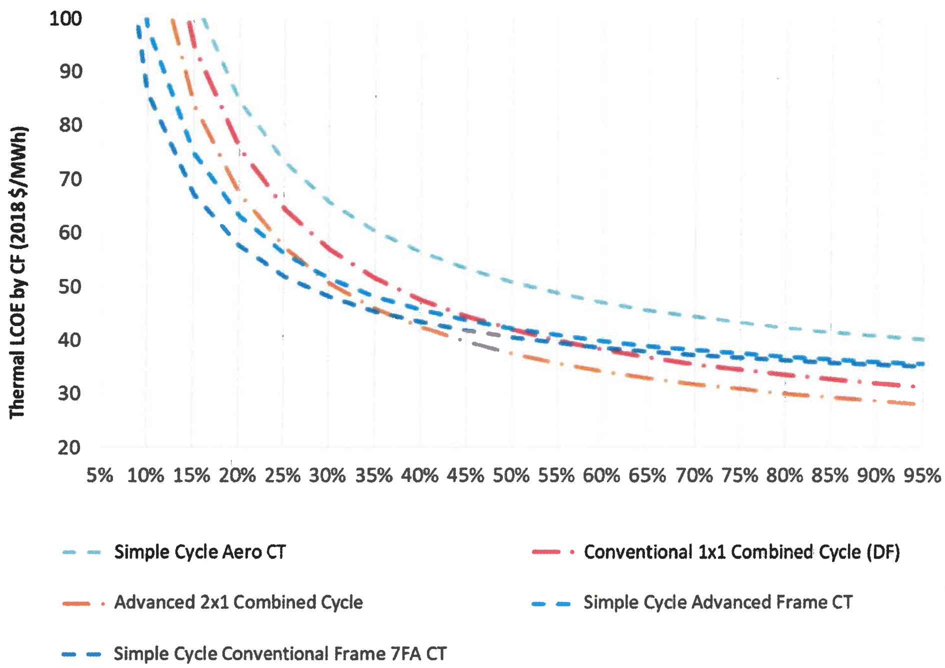


Exhibit 6: Thermal & Storage Technology 2019 LCOE Assumptions by Capacity Factor, 2018$/MWh



Source: Siemens

Combined Cycle Gas Turbine

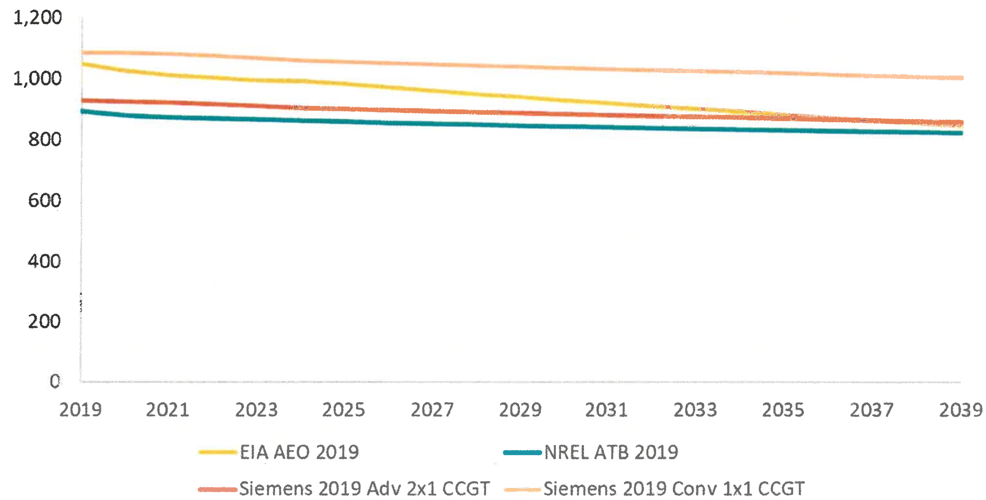
Combined cycle gas turbines (CCGTs) provide a reliable source of capacity and energy for relatively lower plant capital investment. CCGTs have slower ramp-rates to full power output than simple-cycle CTs, which make them less advantageous for integration of renewables in certain situations, although they can cycle daily facilitating the integration.

Advanced CCGTs now achieve operating efficiencies above 62 percent, compared to conventional generation technologies (including simple-cycle CTs) that range from 30 to 44 percent. Generally, CCGTs are good replacement options for less efficient, higher-emitting fossil fuel resources.
Favorable capital costs, operational flexibility, lower CO_2 emissions, and high plant efficiencies have allowed CCGTs to expand their role in power generation, serving as either baseload or intermediate generators.

Siemens compares our advanced frame 2x1 CCGT and conventional frame 1x1 CCGT capital cost assumptions to both NREL ATB and EIA AEO similar technologies in Exhibit 7.
On cost alone the LTCE would have selected the 2x1 CCGT (950 MW). However, this type of unit was not selected as its outage would create a large generation shortfall within MLGW. Considering that the peak load is expected to reach 3,200 MW, this unit would represent 30% of

the peak demand. Also considering that during high import conditions (e.g. 2,200 MW from MISO), there would be a local requirement of 1,000 MW and the 2x1 would be 95% of this requirement making its trip a critical contingency and forcing additional generation online. As discussed earlier in this document the initial offering of a 1x1 CCGT was optimized by adding duct firing (i.e. additional burners in the heat recovery steam generator or HRSG). The duct firing portion increases the unit capacity which contributes to local reliability, at a lower capital cost and better heat rate than a Simple Cycle Gas Turbine.

Exhibit 7: Advanced Combined Cycle Capital Cost Forecast, 2018$/kW



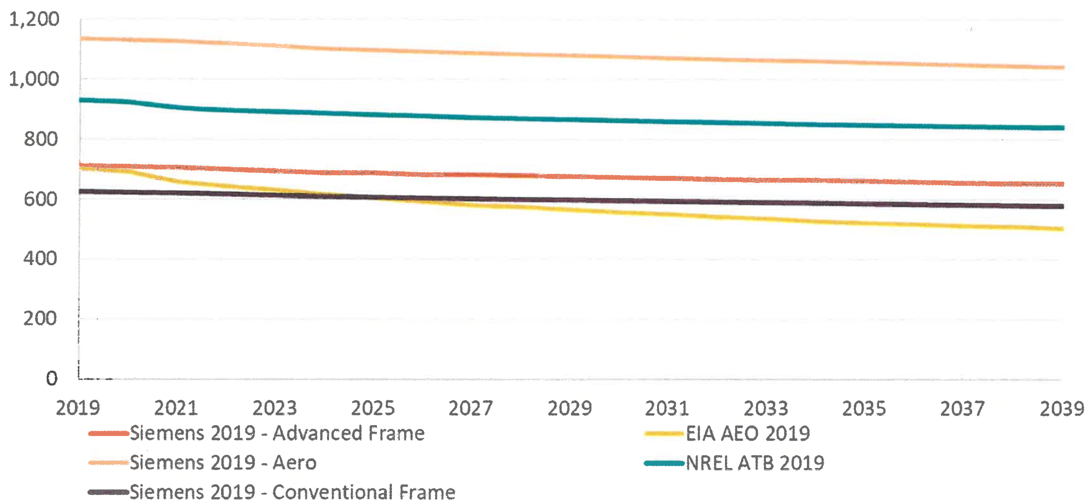
Source: Siemens

Simple Cycle Combustion Turbine

The high operating costs and low efficiency of CTs (around 40 percent) typically keep annual capacity factors below 10 percent and limit their primary use to load peaking purposes. However, CTs start up quickly and play a key role in grid stability, providing reserve capacity and ancillary services. The responsiveness of CTs make them viable candidates to manage intermittent resources on a broad scale. Historically, frame CTs have been used as peaking resources for utilities because of their lower operating costs and economies of scale; aeroderivative CTs are also used for peaking service applications where the smaller size makes them a better fit. Over the last decade, large frame CT generating efficiency has improved due to innovations across the industry. Newer frame CT models are designed for higher capacity (300 to 400 MW) and increased efficiency (heat rates of 8,000 to 8,500 Btu/kWh). Aeroderivative CTs have a wider range of efficiency (heat rates between 8,000 to 10,500 Btu/kWh) and have smaller size but are less cost-effective on a $/kW basis.

However, with an influx of intermittent energy resources and lower growth in load demand, the need for more flexible resources has brought increased interest in aeroderivative CT technologies as a peaking resource option. Newer models are designed for faster start up, higher ramp rates, and integration with other technologies, particularly battery energy storage. Siemens compares our simple cycle combustion turbine capital cost assumptions to both NREL ATB and EIA AEO similar technologies in Exhibit 8. It is important to note that NREL does not disclose the size or type (Frame vs Aero) for their combustion turbine assumptions in the ATB. For reference, Siemens presents our forecast for conventional frame (7FA technology) and advanced frame below.

Exhibit 8: Simple Cycle CT Capital Cost Forecast, 2018$/kW

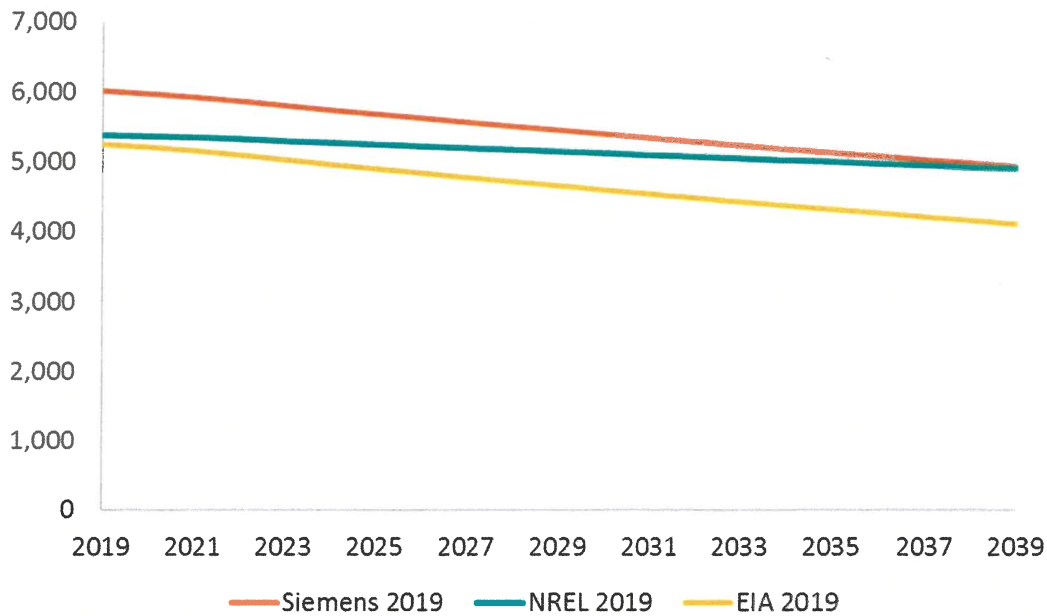


Source: Siemens

Coal with CCS

In a conventional coal plant, post-combustion carbon capture and storage (CCS) captures CO_2 from the exhaust gasses. Chemical solvents or other filtration separation techniques are used to absorb CO_2 from the exhaust which is heated to separate the CO_2 for storage. These processes are energy-intensive and expensive to implement. Typically, these facilities are most economic when the CO2 can be applied to industry needs such as enhanced oil recovery.
Siemens compares our supercritical coal with carbon capture and storage capital costs to both NREL ATB and EIA AEO similar technologies in Exhibit 9.

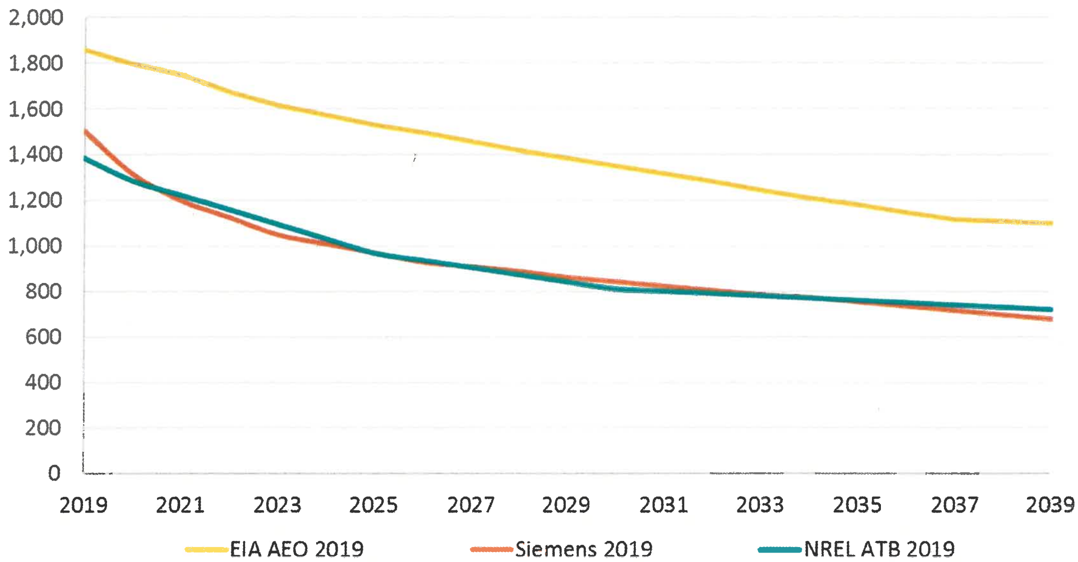
Exhibit 9: Supercritical Coal with CCS Capital Cost Forecast, 2018$/kW



Battery Storage

In recent years, battery energy storage has become more important as a utility-scale option to integrate non-dispatchable resources onto the energy grid. Lithium-ion (Li-ion) batteries are the most common type of storage used at the utility scale and can target location-specific applications unsuitable to pumped hydro or compressed air energy storage. Li-ion battery costs are rapidly declining as suppliers increase production, making them a popular choice for current energy storage needs. Manufacturing capacity should continue to grow to meet strong energy storage demand from mobile devices, medical devices, and electric vehicles. Li-ion batteries have accounted for 94 percent of all new energy storage capacity in the US since 2012, growing at an average rate of 55 percent per year. Most of the installed Li-ion capacity provides frequency regulation, but recent projects in the US have targeted alternative applications including peaking capacity, renewable integration (energy arbitrage), and peak shaving.
Siemens compares our four-hour duration lithium ion battery capital costs to both NREL ATB and EIA AEO similar technologies in Exhibit 9.

Exhibit 10: 4-Hour Lithium Ion Battery Capital Cost Forecast, 2018$/kW



Source: Siemens

In addition to capital costs, augmentation costs represent the additional battery equipment needed to maintain the usable energy capability to cycle the unit according to the usage profile in the particular use case, for the life of the system. Additional equipment is required in the following circumstances: (1) if the particular unit charges or discharges to a level less than its rated energy capacity (kWh) per cycle; (2) if the battery chemistry does not have the cycle-life needed to support the entire operating life of the use case; or (3) if the energy rating (kWh) of the battery chemistry degrades due to usage and can no longer support the intended application. This time-series of varying costs is then converted into a level charge over the life of the system to provide greater clarity for project developers. We assume a replacement of a third of the battery packs every eighth year, and battery packs are approximately 40% of the cost of the whole battery system. In total, the replacement battery cost is about 13% of the total battery system cost.

Solar PV

Solar PV generation has been rapidly expanding as a desirable form of renewable generation in recent years, with total US installed capacity reaching 62.5 GW through 2018.[5] Single-axis tracking PV systems require lower land commitments than fixed-tilt systems for the same energy output. Tracking-type solar installations now account for more than 50 percent of utility-scale solar PV in the US and are most common in the southwest.

Renewable energy incentives have played a critical role in supporting the development of solar PV, either in the form of renewable portfolio standards (RPS), feed-in tariffs, or tax credits. The investment tax credit is set to decline to 10% of capital investment in 2022, remaining available

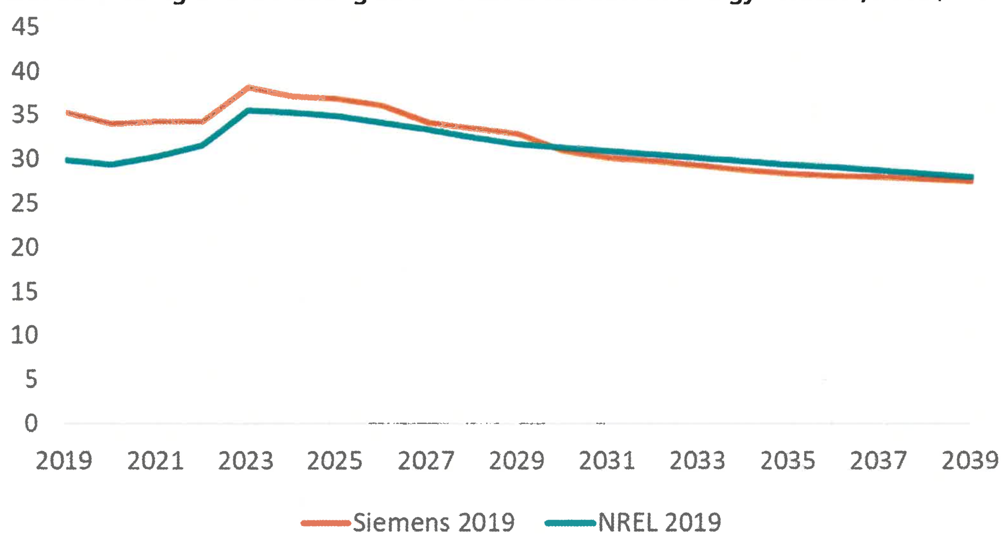
[5] SEIA US Solar Market Insight: Q2 2019

post 2021. Developers are able to "safe harbor" solar equipment for up to four years to qualify for the ITC, past the deadline.[6]

Siemens single-axis tracking solar technology forecast accounts for the increasing application of bifacial solar cells. While monofacial cells dominate the market today, bifacial cells are expected to comprise most solar cells sold by 2030. While bifacial cells cost slightly more than monofacial cells, they can deliver impressive generation gains over monofacial cells. Siemens forecasts accounts for a phasing in of bifacial technology.

Siemens compares our utility scale, single-axis, solar levelized cost of energy assumptions to NREL ATB[7] similar technologies in Exhibit 11. Note that we applied the same financial assumptions to both Siemens and ATB forecast using utility WACC. The faster reduction in LCOE in Siemens forecast is by a combination of reduction on capital costs and the phasing in of bifacial panels that result in higher capacity factors.

Exhibit 11: Single-Axis Tracking Solar PV Levelized Cost of Energy Forecast, 2018$/MWh



Source: Siemens

Siemens assumptions to derive our levelized cost of energy estimates are shown in Exhibit 12.

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[6] Siemens assumes two years of safe harboring in our LCOE calculations.

[7] NREL forecasts five LCOE scenarios based on different locations in the US. The most similar NREL reference case is located in Kansas City

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Exhibit 12: Single-Axis Tracking Solar PV Levelized Cost of Energy Assumptions Table

Year	Siemens Capital Cost (2018$/kW)	Siemens Capital Cost with Land Cost Adjusted (2018$/kW)	NREL Capital Cost (2018$/kW)	Capital Recovery Rate (%)	Siemens Fixed O&M (2018$/kW-yr)	NREL Fixed O&M (2018$/kW-yr)	Siemens Capacity Factor (%)	NREL Capacity Factor (%)	Siemens Variable O&M ($/MWh)	NREL Variable O&M ($/MWh)	Siemens LCOE (2018$/MWh)	NREL LCOE (2018$/MWh)
2019	1,245	1,343	1,096	4%	20	13	23%	22%	0	0	35	30
2020	1,180	1,278	1,076	4%	20	13	23%	22%	0	0	34	29
2021	1,119	1,217	1,054	4%	20	13	23%	22%	0	0	34	30
2022	1,028	1,126	1,032	5%	20	12	23%	22%	0	0	34	32
2023	1,001	1,099	1,010	6%	20	12	23%	22%	0	0	38	36
2024	975	1,073	988	6%	20	12	23%	22%	0	0	37	35
2025	950	1,048	966	6%	20	12	23%	22%	0	0	37	35
2026	921	1,019	945	6%	20	11	23%	22%	0	0	36	34
2027	897	995	923	6%	20	11	24%	22%	0	0	34	33
2028	874	972	901	6%	20	11	24%	22%	0	0	34	33
2029	853	951	879	6%	20	11	24%	22%	0	0	33	32
2030	837	935	869	6%	20	10	25%	22%	0	0	31	31
2031	808	906	860	6%	20	10	25%	22%	0	0	30	31
2032	790	888	850	6%	20	10	25%	22%	0	0	30	31
2033	772	870	840	6%	20	10	25%	22%	0	0	29	30
2034	753	851	830	6%	20	10	25%	22%	0	0	29	30
2035	735	833	821	6%	20	10	25%	22%	0	0	28	29
2036	728	826	811	6%	20	10	25%	22%	0	0	28	29
2037	720	818	801	6%	20	10	25%	22%	0	0	28	29
2038	711	809	791	6%	20	9	25%	22%	0	0	28	28
2039	702	800	782	6%	20	9	25%	22%	0	0	27	28

Source: Siemens

Land Constraints

One of the constraints associated with utility scale solar PV development that should not be ignored is the land availability. Siemens worked together with MLGW to identify local land availability for utility scale PV build in this IRP. The prospective land for solar PV is typically limited to agriculture and/or large commercial & industrial parcels that are generally flat and not prone to flooding. With current solar PV technology, it requires approximately 6.33 acres [8] of land for every MW of PV, i.e. a typical 100 MW PV project would require 633 acres of land. In addition, the solar project should be close to an existing transmission substation or transmission lines to minimize the need of building long gen-tie lines to interconnect the PV project to MLGW's transmission system. Shelby county is not only limited in the prospective land availability for utility scale PV, it would also be a tremendous challenge to successfully acquire all the usable land. Siemens working with MLGW identified prospective land in the order of 24,000 acres which in principle would accommodate 3,800 MW of PV if all the land was successfully acquired and met the minimum requirements with respect of flooding, which may not be the case.

Considering all these factors, it has been determined that a limitation of 1,000 MW combined local utility scale solar PV to be given to the LTCE program. This would require about 6,330 acres of land which is equal to about 1.3% of total land of Shelby county and implies approximately 25% success in acquiring the land above. Siemens is also considering land that is slightly outside of Shelby county as long as a short distance gen-tie transmission line is an option; i.e. not all PV has to be in Shelby county lowering the pressures on success in acquiring land within the county.

The cost of land was also reviewed in collaboration with MLGW for solar PV development in the specific region. Considering the land limitation, the cost of land in Shelby county is assumed to be higher than the national average. Siemens estimated the national average base cost of land

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[8] NREL ATB 2018

from NREL ATB 2018 data to be $5,000/acre. For the MLGW IRP, it has been determined that this cost should be adjusted to $17,000/acre. Based on the higher cost of land assumption applied to the NREL ATB data, the total capital cost is calculated to be about 6.6% higher than the base or $98/kw-ac more than the base in 2018. Siemens added the difference to the Siemens Solar PV capital cost in Exhibit 12, to be included as a candidate portfolio resource.

Onshore Wind

Due to significant growth over the past decade, wind generation has become the second largest source of carbon-free electric generation in the US, accounting for 6.3 percent of power produced in 2017. Wind generation has become well-established in the US, and capital and operating costs have dropped significantly over time. Over time, wind turbine design innovations have resulted in improved performance and energy output. Newer turbines are taller and have a larger rotor-swept area, allowing them to produce more energy across a wider range of wind speeds, which drives up average capacity factors.[9] The federal production tax credit (PTC) has made a significant impact on recent prices for wind power. However, the PTC is scheduled to phase out by 2020 which could affect near-term affordability for new wind resources. Developers are able to "safe harbor" wind turbine equipment for up to four years to qualify for the PTC past the deadline.[10]

Siemens compares our onshore wind levelized cost of energy assumptions to NREL ATB[11] similar technologies in Exhibit 13.

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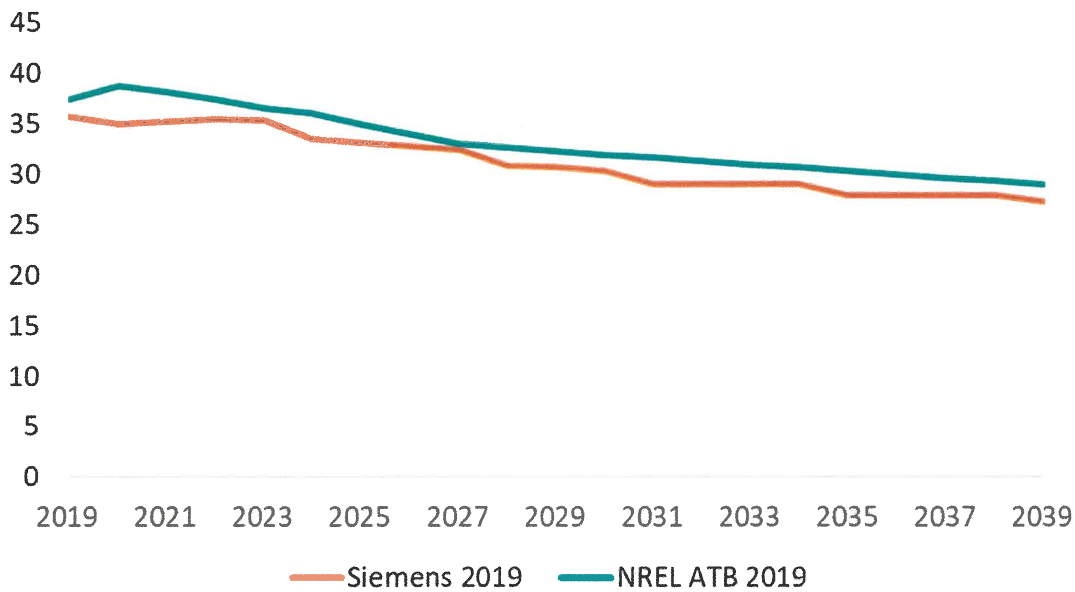
[9] Siemens assumes MLGW will be able to build or procure wind in the SERC reliability corporation / gateway region.

[10] Siemens assumes two years of safe harboring in our LCOE calculations.

[11] NREL forecasts ten Techno-Resource Groups (TRGs) to categorize types of wind projects across the US. The most similar NREL reference case for MLGW is TRG 6 due to wind speed ranges.

Exhibit 13: Onshore Wind Levelized Cost of Energy Forecast, 2018$/MWh



Source: Siemens

Siemens assumptions to derive our levelized cost of energy estimates are shown below.

Exhibit 14: Onshore Wind Levelized Cost of Energy Assumptions Table

Year	Siemens Capital Cost (2018$/kW)	NREL Capital Cost (2018$/kW)	Capital Recovery Rate (%)	Siemens Fixed O&M (2018$/kW-yr)	NREL Fixed O&M (2018$/kW-yr)	Siemens Capacity Factor (%)	NREL Capacity Factor (%)	Siemens Variable O&M ($/MWh)	NREL Variable O&M ($/MWh)	Siemens LCOE (2018$/MWh)	NREL LCOE (2018$/MWh)
2019	1,636	1,502	5%	37	44	40%	38%	0.90	0	37	38
2020	1,616	1,474	6%	37	43	44%	38%	0.90	0	36	40
2021	1,596	1,446	6%	37	43	44%	39%	0.90	0	36	39
2022	1,576	1,418	6%	37	43	44%	39%	0.90	0	36	38
2023	1,557	1,390	6%	37	42	44%	40%	0.90	0	36	37
2024	1,538	1,362	6%	37	42	46%	40%	0.90	0	34	37
2025	1,519	1,334	6%	37	42	47%	41%	0.90	0	34	36
2026	1,500	1,306	6%	37	41	47%	41%	0.90	0	34	35
2027	1,479	1,278	6%	37	41	47%	42%	0.90	0	33	34
2028	1,461	1,266	6%	37	40	49%	42%	0.90	0	31	33
2029	1,448	1,255	6%	37	40	49%	42%	0.90	0	31	33
2030	1,436	1,244	6%	37	40	49%	42%	0.90	0	31	33
2031	1,425	1,232	6%	37	39	51%	42%	0.90	0	30	32
2032	1,421	1,221	6%	37	39	51%	42%	0.90	0	30	32
2033	1,417	1,209	6%	37	39	51%	42%	0.90	0	30	32
2034	1,413	1,198	6%	37	39	51%	42%	0.90	0	30	31
2035	1,409	1,186	6%	37	38	52%	42%	0.90	0	29	31
2036	1,406	1,174	6%	37	38	52%	42%	0.90	0	28	31
2037	1,403	1,162	6%	37	38	52%	42%	0.90	0	28	30
2038	1,401	1,150	6%	37	37	52%	42%	0.90	0	28	30
2039	1,399	1,138	6%	37	37	53%	42%	0.90	0	28	30

Source: Siemens

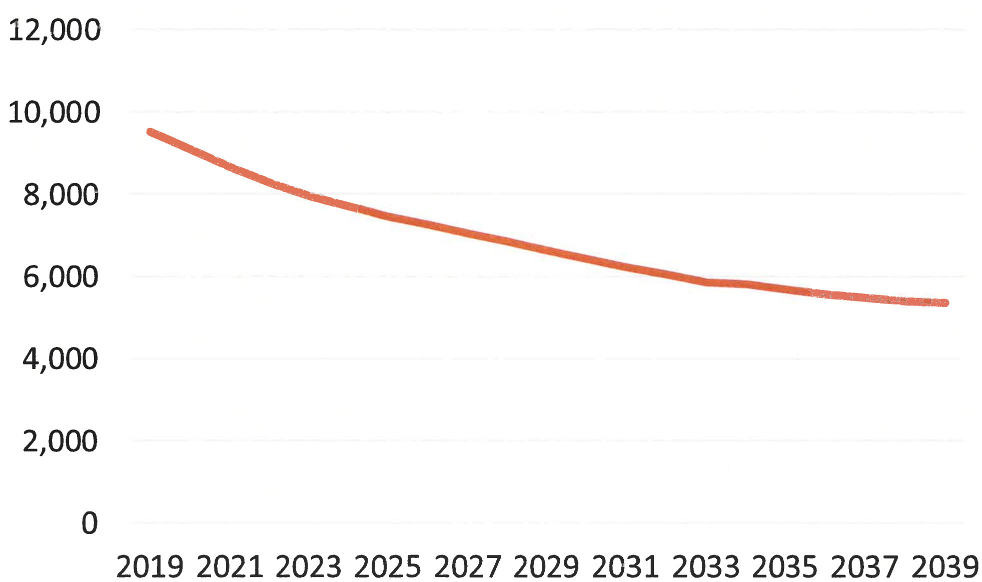
Small Modular Reactor

Small modular reactor (SMR) technology was initially developed for naval/shipping purposes and is being adapted for utility-scale generation; however, it has not yet demonstrated commercial viability in the US. SMRs can be scaled to meet load needs and delivered fully constructed. SMRs range in size from 10 to 300 MW compared to roughly 900 to 1,200 MW for conventional nuclear reactors. Some SMRs, by virtue of their smaller size and other operational features, can offer greater capability to conduct load following operations than larger nuclear power plants. SMRs have appeal as potential future carbon-free resources to complement renewable resources. Much of the key equipment for SMRs can be manufactured off-site, reducing plant construction time by 40 percent or more. They also provide potential improvements in safety from their underground containment designs and passive cooling systems. However, underground installations could make maintenance more challenging during a malfunction.

NuScale Power LLC is aiming to put an SMR into commercial operation in Utah, comprised of a dozen 50-MW reactors. It is the only company with an SMR design certification pending before the US Nuclear Regulatory Commission (NRC). The NRC is also reviewing two SMR pre-applications from BWXT mPower, Inc. and SMR Inventec, LLC.

As shown in Exhibit 15 the expected capital costs of the SMR put them at disadvantage with competing with other base load technologies on a cost in $ per MWh.

Exhibit 15: Small Modular Reactor (SMR), All-In Capital Cost, 2018$/kW



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River Flow Hydro

There are two forms of hydro generation which employ the energy from flowing river water to generate electricity, and neither are appropriate for the Mississippi river at this time.

A traditional Run of river hydro system diverts running water from a flowing river to turn a turbine, which drives a generator after which the water is returned to the river. Unlike traditional hydro systems, run of river systems do not dam the river to create a large reservoir. However, most will use a small dam, also known as a weir, to ensure sufficient water and use a small reservoir to store water for same-day-use only. Since run of river systems employ little storage, power generation is limited to and entirely dependent upon water flow. In dry seasons and droughts generation can become unreliable with degraded capacity factors impacting plant economics. These are most common in mountainous terrain where there is significant head to add potential energy to the flowing water.

The other option for extracting energy from flowing water is hydrokinetic technologies. These can be thought of essentially as propeller generators anchored to the river floor over which water flows. While there are a few projects in the U.S., the most notable of which is in the East River, high capital and operating costs have slowed development. A February 2019 FERC study for a 70kW system in Alaska estimated levelized energy costs could exceed other local options by $322/ MWh with a total system energy cost of $787/MWh[12]. Such high costs are driven by the novelty of the technology, as well as the need to protect the equipment from common river debris (i.e. logs, ice, etc.). Recognizing the potential of this technology, as well is the high current cost, in June 2019 the U.S. Department of Energy Advanced Research Projects Agency (ARPA) released a Request for Information (RFI) seeking industry insight into hydrokinetic technologies[13]. High current costs coupled with a nascent effort from a research agency to understand the technology suggests that economic application of hydrokinetic technologies remains out of reach for the immediate future.

Wet vs. Dry Cooled Condenser Application

Thermoelectric power plants boil water to create steam. Once steam has passed through a turbine, it must be cooled back into water before it can be reused to produce more electricity. Colder water cools the steam more effectively and allows more efficient electricity generation. Since wet-recirculating systems are generally more efficient and less expensive, they have been the traditional choice for cooling steam. These systems use cooling towers to expose hot water to ambient air to reduce the temperature with water loss resulting from evaporation.

Dry-cooling systems use air instead of water to cool the steam existing the turbine thereby reducing plant water use substantially. While air-cooled systems cost more than wet systems and reduce plant efficiencies more, they can be preferred where water is in short supply, expensive, or regulated in such a manner to incentivize minimizing its use. Siemens analysis indicates that plant capital costs are 2.8% higher, heat rates are 1.93% higher, and capacities are lower by 1.88% for 1x1 configuration combined cycle plants with air cooling.

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[12] https://www.ferc.gov/industries/hydropower/enviro/eis/2019/P-13511-003-EA.pdf
[13] https://arpa-e-foa.energy.gov/FileContent.aspx?FileID=e5f68776-98a0-4088-8086-06e8f9de87e5

Load Carrying Capability / Unforced Capacity.

The ISO's in general and MISO in particular, define the required reserve margin both as a function of the installed capacity (ICAP) and the unforced capacity (UCAP). The use of UCAP is becoming the preferred approach as this can be correlated directly with the load carrying capability of renewable resources, i.e. the level of perfectly reliably capacity that when added to the study results in the same level of reliability as when the renewable resource is model explicitly.

MISO studies indicate that for Solar the UCAP changes with the amount of the respective generation in the case[14]. For wind generation there is also a reduction, but it small and can be considered largely constant. Based on this the table below shows the factors for wind generation and solar generation used in this study to convert ICAP into UCAP, i.e. UCAP = Factor x ICAP:

Exhibit 16: Wind Turbine Generation and Solar PV adjustment Factors for UCAP

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Solar Factor	30%	29%	29%	28%	27%	26%	26%	25%	24%	24%	23%	22%	21%	21%	20%
Wind Factor	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%

For thermal the definition is Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – EFOR)
Where EFOR is Equivalent forced outage rate and assumed to be 2.5% in this study.

To calculate the UCAP for battery storage technology, Siemens researched the EFOR assumptions made by other entities in studies and resource plans. As a relatively new technology, there is little operating history. The research uncovered two sets of assumptions. One assumes an EFOR < 3% with a planned outage rate (POR) < 3%, and the other assumes EFOR + POR = (1- Unit Availability) < 2%. Both assumptions were developed by reputable engineering firms providing estimates for electric utility Integrated Resource Plans. Since the evidence suggests expected EFOR is between 1 and 3%, Siemens selected 2% for this assumption

Resource Adequacy

Background

If MLGW were to join MISO it would be subject to MISO's resource adequacy requirements. MISO, as the rest of the ISOs and Utilities in the US, defines its resource adequacy in terms of meeting a maximum Loss of Load Expectation (LOLE) of 1 in 10 years; this is defined as once every 10 years, due to a combination of generation outages and maintenance, there would not be enough resources to meet the load. The systems in the US have been planned with the criteria for a long time and it has resulted in an adequate balance of cost and reliability and it is mandated by NERC.

[14] [14] See Renewable Integration Impact Assessment (RIIA) Assumption Document V-6 December 2018, MISO

MISO, due to its geographical extension, assesses the adequacy of the resources of its members in terms of a MISO level Planning Reserve Margin (MISO PRM) and a Local Clearing Requirement (LCR).

The PRM is the required level of Unforced Capacity (UCAP) as defined earlier in this document, to achieve the LOLE of 1/10. As shown in Exhibit 17 this value is currently 8.9% that is the UCAP must exceed the MISO peak load at least by 8.9% and the PRM forecasted to stay in this level at least until 2029.

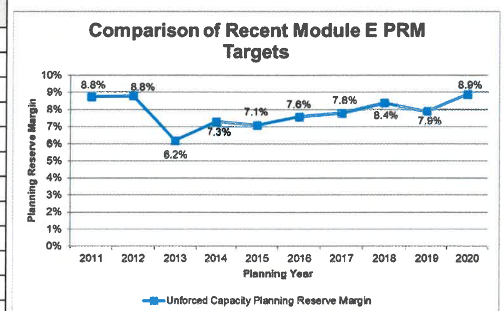
To account for its size, MISO is subdivided into ten Local Resource Zones (LRZ), which are geographically large areas with substantial internal load and adequate internal transmission (see Exhibit 19). The LCR is then the amount of capacity that must be **internal** to each LRZ to ensure that the LOLE of 1/10 is also met at the local level.

The above means that each zone must have enough capacity (designated or purchased via the Planning Resource Auction) to comply with the larger of the MISO PRM (8.9%) or its own LCR.

As shown in Exhibit 18 for all LRZ the MISO PRM is larger than the LCR and hence it defines the LRZ's individual PRM (LRZ PRM), which is met either by internal resources (LRZ 1 to 4 and 7 to 9) or by purchasing resources from other zones (e.g. LRZ-5,6 and 10). In all of them however, the internal UCAP is larger than the LCR meeting the second criteria.

Exhibit 17: MISO PRM Calculation

MISO Planning Reserve Margin (PRM)	2020/2021 PY (June 2020 - May 2021)	2023/2024 PY (June 2023 - May 2024)	2025/2026 PY (June 2025 - May 2026)	Formula Key
MISO System Peak Demand (MW)	124,625	125,308	125,600	[A]
Installed Capacity (ICAP) (MW)	156,426	160,125	161,228	[B]
Unforced Capacity (UCAP) (MW)	144,456	148,152	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)	-7,950	-11,000	-11,360	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-7,950	-11,000	-11,360	[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)	147,115	147,764	148,507	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	135,747	136,393	136,804	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	18.00%	17.90%	18.20%	[L]=([J]-[A])/[A]
MISO PRM UCAP	8.90%	8.80%	8.90%	[M]=([K]-[A])/[A]



Metric	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
ICAP (GW)	158.1	161.4	161.6	161.8	161.8	162.9	162.9	162.9	162.9	162.9
Demand (GW)	124.6	124.8	125.1	125.3	125.3	125.6	125.8	126	126.2	126.5
PRM_{ICAP}	18.00%	18.00%	17.90%	17.90%	18.20%	18.20%	18.10%	18.20%	18.20%	18.30%
PRM_{UCAP}	8.90%	8.90%	8.80%	8.80%	8.80%	8.90%	8.90%	8.90%	8.90%	8.90%

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Exhibit 18: MISO LRZ PRM / LCR assessment (2025 -2026)*

Formula Key	Local Resource Zone (LRZ)	LRZ-1	LRZ-2	LRZ-3	LRZ-4	LRZ-5	LRZ-6	LRZ-7	LRZ-8	LRZ-9	LRZ-10
		MN/ND	WI	IA	IL	MO	IN	MI	AR	LA/TX	MS
	2025-2026 Planning Reserve Margin (PRM) Study										
[A]	**Installed Capacity** (ICAP) (MW)	21,992	15,256	12,198	13,681	8,791	20,136	24,612	11,766	27,019	5,793
[B]	**Unforced Capacity** (UCAP) (MW)	20,854	14,392	11,612	12,372	7,878	18,694	22,527	11,026	24,783	4,794
[C]	**Adjustment to UCAP** {1d in 10yr} (MW)	410	554	-336	-507	1,774	1,774	2,241	-580	-100	2,283
[D]=[B]+[C]	**Local Reliability Requirement (LRR)** (UCAP) (MW)	21,264	14,946	11,276	11,865	9,652	20,468	24,768	10,446	24,683	7,077
[E]	**LRZ Peak Demand** (MW)	18,707	12,797	9,874	8,711	7,779	17,810	20,693	7,883	21,187	4,798
[F]=[D]/[E]	**LRR UCAP per-unit of LRZ Peak Demand**	**113.7%**	**116.8%**	**114.2%**	**136.2%**	**124.1%**	**114.9%**	**119.7%**	**132.5%**	**116.5%**	**147.5%**
[G]	**Zonal Import Ability (ZIA)**	3,747	1,713	2,813	5,210	5,013	6,924	3,211	4,185	3,631	3,792
[H]	**Zonal Export Ability (ZEA)**	3,379	979	4,664	5,332	2,122	1,577	1,358	5,328	2,224	1,721
[I]	**Forecasted LRZ Peak Demand**	18,707	12,797	9,874	8,711	7,779	17,810	20,693	7,883	21,187	4,798
[J]	**Forecasted LRZ Coincident Peak Demand**	18,041	12,341	9,522	8,401	7,502	17,176	19,956	7,602	20,432	4,627
[K]	**Non-Pseudo Tied Exports** UCAP **(ignored as not available)**	0	0	0	0	0	0	0	0	0	0
[L]=[F]x[I]	**Local Reliability Requirement** (LRR) UCAP	21,264	14,946	11,276	11,865	9,652	20,468	24,768	10,446	24,683	7,077
[M]=[L]-[G]-[K]	**Local Clearing Requirement** (LCR)	17,517	13,233	8,463	6,655	4,639	13,544	21,557	6,261	21,052	3,285
[N]=[1.089]X[J]	**Zone's System Wide PRM**	19,646	13,440	10,370	9,148	8,170	18,704	21,732	8,279	22,251	5,039
[O] = Higher of [M] or [N	**LRZ PRM (MW)**	19,646	13,440	10,370	9,148	8,170	18,704	21,732	8,279	22,251	5,039
[P] = [O]/[J]-1	**LRZ PRM %**	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%
[Q] = [M]/[I]	**LCR % of peak demand**	94%	103%	86%	76%	60%	76%	104%	79%	99%	68%
	MISO PRM	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%
	UCAP > LCR	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE
	UCAP > LRZ PRM	TRUE	TRUE	TRUE	TRUE	**FALSE**	**FALSE**	TRUE	TRUE	TRUE	**FALSE**

*The non-pseudo tied exports were not available at this time and were omitted. However, this would only reduce the LCR.

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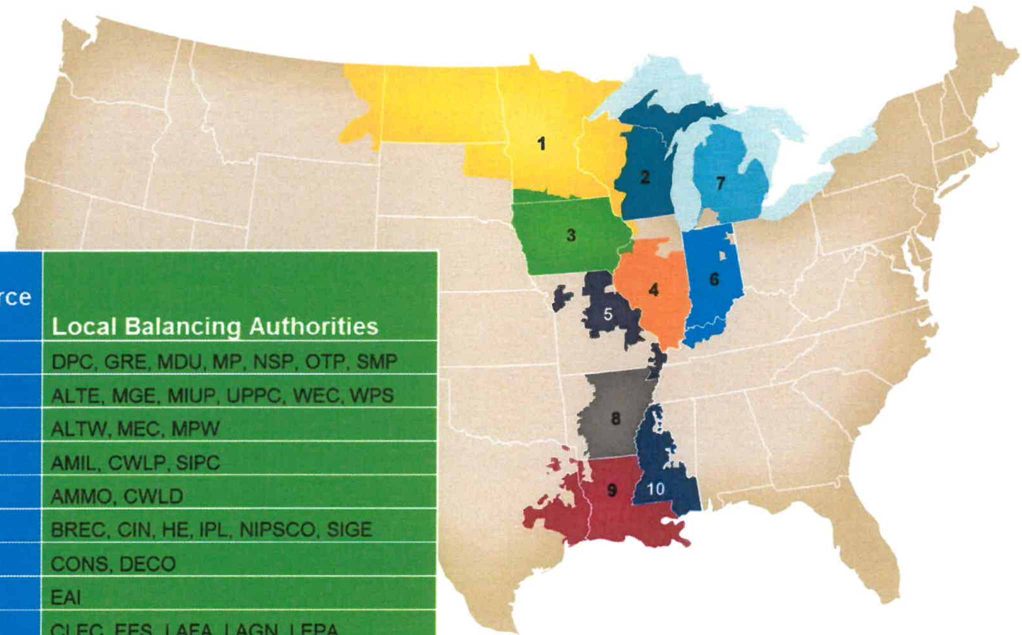
Exhibit 19: MISO Local Resource Zones (LRZ)



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

Considerations for MLGW

If MLGW were to join MISO and become part of LRZ-8, then it would only need to meet the MISO PRM with the combination of local resources within MLGW territory and acquired external resources. The reason for this is that in LRZ-8 the internal capacity (UCAP) is and is expected to remain larger than the zone's LCR, even after MLGW joins, as shown later in this memo. However, if MLGW joined as a stand alone LRZ, then the LCR would have to be met by local resources, which has important implications for the composition of the resources selected by the IRP in terms of installed capacity and contribution to the UCAP.

In this section we analyze the requirements that MLGW would have to meet to be part of the LRZ-8.

Size and level of interconnection

As indicated earlier the 10 LRZs are geographically large and each has substantial load. Geographical extension and substantial load favor the optimization of resources additions as there are fewer limitations on siting, size of the resource and the technology mix. As can be observed in Exhibit 19 all MISO areas cover large extensions and in generally more than one state and as can be observed in Exhibit 20 the average peak load by LRZ is just over 13 GW, being zone 10 the smallest with 4.8 GW.

The requirement of adequate LRZ internal transmission is also fundamental for allowing effective sharing of reserves within the LRZ unhindered by transmission limitations (bottling of reserves).

However, between LRZs there are transmission limitations and as can be in Exhibit 20, where each zone import ability (ZIA) is shown in MW and as a percentage the zone's peak load. In this exhibit we observe that the average ZIA is 39% of the peak load, with a maximum for LRZ 10 (79%) driven by its extensive border with LRZ 9 and LRZ 8 and the lowest in LRZ-2, which only borders LRZ-1.

Exhibit 20: MISO Local Resource Zones (LRZ) key forecasted 2025 Metrics and MLGW (2025) comparison

	Peak Demand MW	UCAP MW	ZIA MW	Largest Unit MW	ZIA/ Pk Demand	(ZIA+UCAP)/Demand	Largest Unit / Peak Demand
LRZ-1	18,707	20,854	3,747	632	20%	132%	3.4%
LRZ-2	12,797	14,392	1,713	670	13%	126%	5.2%
LRZ-3	9,874	11,612	2,813	866	28%	146%	8.8%
LRZ-4	8,711	12,372	5,210	1,115	60%	202%	12.8%
LRZ-5	7,779	7,878	5,013	1,246	64%	166%	16.0%
LRZ-6	17,810	18,694	6,924	630	39%	144%	3.5%
LRZ-7	20,693	22,527	3,211	1,215	16%	124%	5.9%
LRZ-8	7,883	11,026	4,185	1,073	53%	193%	13.6%
LRZ-9	21,187	24,783	3,631	1,214	17%	134%	5.7%
LRZ-10	4,798	4,794	3,792	1,554	79%	179%	32.4%
Average	**13,024**	**14,893**	**4,024**	**1,022**	**39%**	**155%**	**10.7%**
MLGW 1	3,200	1,601	2,200	414	69%	119%	12.9%
MLGW 2	3,200	1,601	2,720	414	85%	135%	12.9%
MLGW 3	3,200	1,812	2,510	414	78%	135%	12.9%

The observations above would favor MLGW to become part of LRZ-8.

a) It is geographically concentrated, and its load (3,200 MW forecasted for 2025) is significantly lower than the average in MISO and It would be the smallest of all LRZs if it were to become its own LRZ.
b) Even under the "No-Deal" condition, MLGW is expected to be well connected with LRZ-8 &10 with a minimum ZIA of 69% of the peak (2,200 MW) and as discussed later in this document it can be increased to 85% (2,720 MW) or more. This is shown as MLGW 1 and MLGW 2 in Exhibit 20.
c) Finally, MLGW is expected to acquire its external reserve requirements via bilateral contracts with well-defined source and firm point to point transmission, thus avoiding the risk of reserves not being able to be delivered to MLGW when required.

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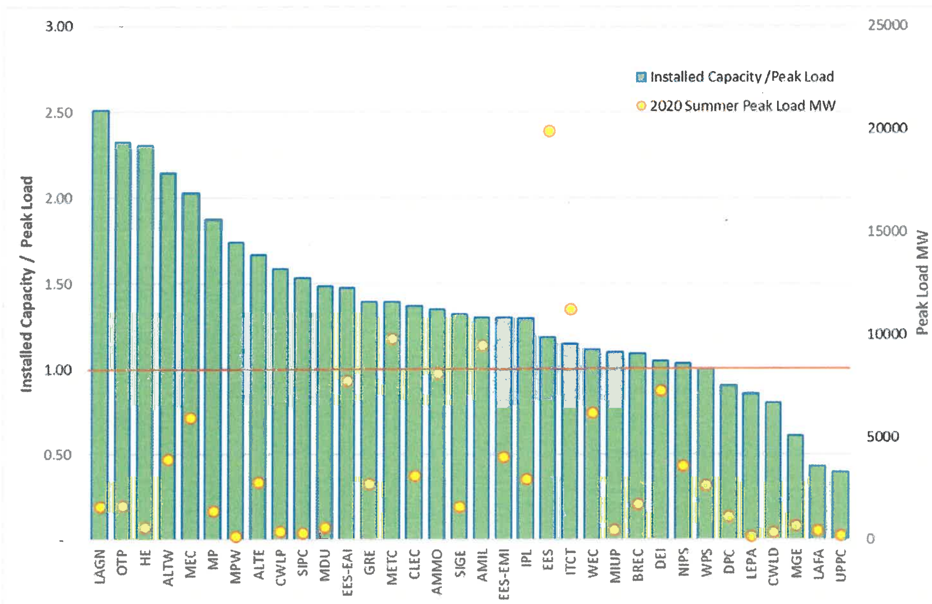
MLGW LOLE assessment

While the arguments above favor MLGW to become part of LRZ-8, MLGW does not have enough transmission to cover its entire load and it is not expected to have local generation to supply its capacity requirement, thus always depending on some level of MISO capacity purchases. This is not a typical situation, as most MISO members have substantial generation and in general the internal installed generation capacity is greater than the member's peak load as shown below for 2020 summer peak conditions.

Also, considering the ratio of the LRZ's UCAP + ZIA to the peak load as a proxy of adequacy, we observe in Exhibit 20 that on average this index is 155%, while for MLGW unless adjustments are made, the value can be much lower as shown in this document.

Exhibit 21: Installed Capacity / Peak Load and Peak Load in MW



Therefore, it is important to assess the conditions that would lead to MISO deciding that MLGW should stay as a separate LRZ and identify what adjustments would be necessary.

In the analysis below three conditions were assessed.

MLGW 1: This is based on the latest LTCE and has the local resources as shown below and assumes an interconnection capacity (ZIA) or 2,200 MW. CC= 450 MW x 3 =1,350 NW (414 MW x3 = 1242 NW Summer), CT=237 MW (216 MW Summer) and 600 MW solar PV.

Exhibit 22: MLGW 1: Base 2025 Internal resources.

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar
2025	0	237	1350	600

Local ICAP	2,058
Local UCAP	1,601

MLGW 2: This considers the same resources as in MLGW 1 but increases the import capability to 2,720 MW with transmission reinforcements into MLGW and avoiding overloads on TVA's or MISO's facilities.

MLGW 3: considers increases the import capability only to 2,510 MW but it adds one more CT to the resources to MLGW 1 and 2 as shown below

Exhibit 23: MLGW 3: Base 2025 Internal resources + 237 MW GT.

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar
2025	0	474	1350	600

Local ICAP	2,273
Local UCAP	1,812

As shown in Exhibit 20 MLGW 2 and MLGW 3 are closer to the average of the adequacy proxy index of (ZIA+UCAP)/demand, while MLGW 1 is below the lowest.

However, to complement this analysis we assessed what could be the LCR of MLGW to have a LOLE of 1/10 following MISO procedures.

MISO starts the analysis of each LRZ by assessing what would the local generation requirement if the LRZ were an island (i.e. no interconnections) and needed to meet the 1/10 LOLE requirement. This is called the Local Reliability Requirement (LRR) and it is shown as line [F] of Exhibit 18 as a percentage of the peak load. To determine this value for MLGW a LOLE study would be necessary, but we can produce an estimation considering that the LRR is closely correlated to the size of the largest unit with respect of the peak load. Using MISO's data, the Exhibit 24 below shows this correlation and based on it we estimate that the MLGW's LRR would be about 130% considering that the largest unit in the IRP is a 414 MW (450 MW Winter) CCGT which is 13% of the peak load. Also, we note that 130% is approximately the peak load + twice the largest machine.

However, to avoid underestimating the LRR **Exhibit 25** shows the LRR as a function of the peak load for the LRZ with the exception of LRZ-10 that would be an outlier considering that its largest unit (1,554 MW) is 32% of the peak demand forcing a large LRR. In this figure we observe that for MLGW's 3,200 MW an LRR of about 140% would be required.

Based on the above we estimated that MLGW's LRR could be 135% (average of both methods) and it is a conservative estimate since MLGW's generation should have higher availability because the units will be new.

Exhibit 24 LRR UCAP per-unit of LRZ Peak Demand

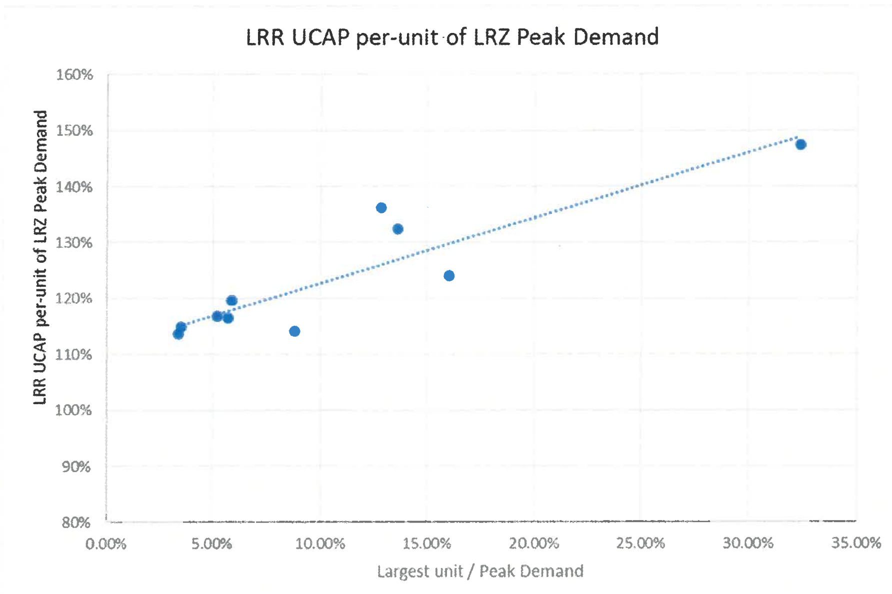
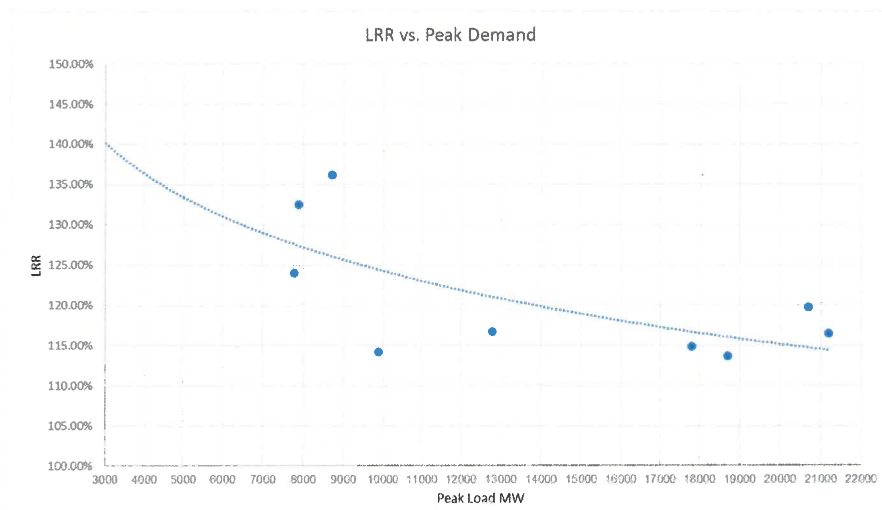


Exhibit 25 LRR vs. Peak Demand



The Exhibit 26 below shows the calculation of MLGW's LCR and PRM based on the LRR above for the three scenarios presented (MLGW 1, MLGW 2 and MLGW 3) along with the values of LRZ-8 and LRZ-8 + MLGW 1.

First, we note the combination of LRZ-8 + MLGW 1 results in an area that satisfies both the LCR and the PRM with local resources, so MLGW's addition would not result in a change or need to purchase external resources.

However, when MLGW 1 is considered a separate zone, the LCR, which is equal to the LRR less the ZIA, results in a requirement of 2,056 MW, much higher than the UCAP from the IRP of 1,601 and would require adding more local generation. This situation can be addressed by increasing the import ability (ZIA) to 2,720 MW, in which case, as shown below, the LCR drops to 1,600 MW, which is just less than the local UCAP.

Finally, under MLGW 3 a combination of adding a CT and enhanced transmission (2,510 MW) also addresses the LCR with local UCAP.

In summary, increasing the zonal import capability will result in better integration and enhanced likelihood of becoming one LRZ with LRZ-8.

Exhibit 26: MLGW LCR and PRM Determinations

Formula Key	Local Resource Zone (LRZ)	LRZ-8	MLGW 1	MLGW 2	MLGW 3	LRZ-8 + MLGW 1
		AR	TN	TN	TN	AR+TN
	2025-2026 Planning Reserve Margin (PRM) Study					
[A]	**Installed Capacity** (ICAP) (MW)	11,766	2,058	2,058	2,058	13,824
[B]	**Unforced Capacity** (UCAP) (MW)	11,026	1,601	1,601	1,812	12,627
[C]	**Adjustment to UCAP** {1d in 10yr} (MW)	-580	2,719	2,719	2,508	2,059
[D]=[B]+[C]	**Local Reliability Requirement (LRR)** (UCAP) (MW)	10,446	4,320	4,320	4,320	14,686
[E]	**LRZ Peak Demand** (MW)	7,883	3,200	3,200	3,200	11,083
[F]=[D]/[E]	**LRR UCAP per-unit of LRZ Peak Demand**	132.5%	135.0%	135.0%	135.0%	132.5%
[G]	**Zonal Import Ability (ZIA)**	4,185	2,200	2,720	2,510	4,185
[H]	**Zonal Export Ability (ZEA)**	5,328	1,500	1,500	1,500	5,328
[I]	**Forecasted LRZ Peak Demand**	7,883	3,200	3,200	3,200	11,083
[J]	**Forecasted LRZ Coincident Peak Demand**	7,602	3,200	3,200	3,200	10,688
[K]	**Non-Pseudo Tied Exports UCAP** (ignored as not available)	0	0	0	0	0
[L]=[F]x[I]	**Local Reliability Requirement** (LRR) UCAP	10,446	4,320	4,320	4,320	14,686
[M]=[L]-[G]-[K]	**Local Clearing Requirement** (LCR)	6,261	2,120	1,600	1,810	10,501
[N]=[1.089]X[J]	**Zone's System Wide PRM**	8,279	3,485	3,485	3,485	11,639
[O] = Higher of [M] or [N]	**LRZ PRM (MW)**	8,279	3,485	3,485	3,485	11,639
[P] = [O]/[J]-1	**LRZ PRM %**	8.9%	8.9%	8.9%	8.9%	8.9%
[Q] = [M]/[I]	**LCR % of Peak Demand**	79%	66%	50%	57%	95%
	MISO PRM	8.9%	8.9%	8.9%	8.9%	8.9%
	UCAP > LCR	TRUE	FALSE	TRUE	TRUE	TRUE
	UCAP > LRZ PRM	TRUE	FALSE	FALSE	FALSE	TRUE
	Indices					
	ZIA/ Demand	53%	69%	85%	78%	38%
	(ZIA+UCAP)/Demand	193%	119%	135%	135%	152%
	UCAP/ICAP	94%	78%	78%	88%	91%
	Largest unit	1073	414	414	414	1073
	Largest unit / Peak Demand	13.6%	12.9%	12.9%	12.9%	9.7%

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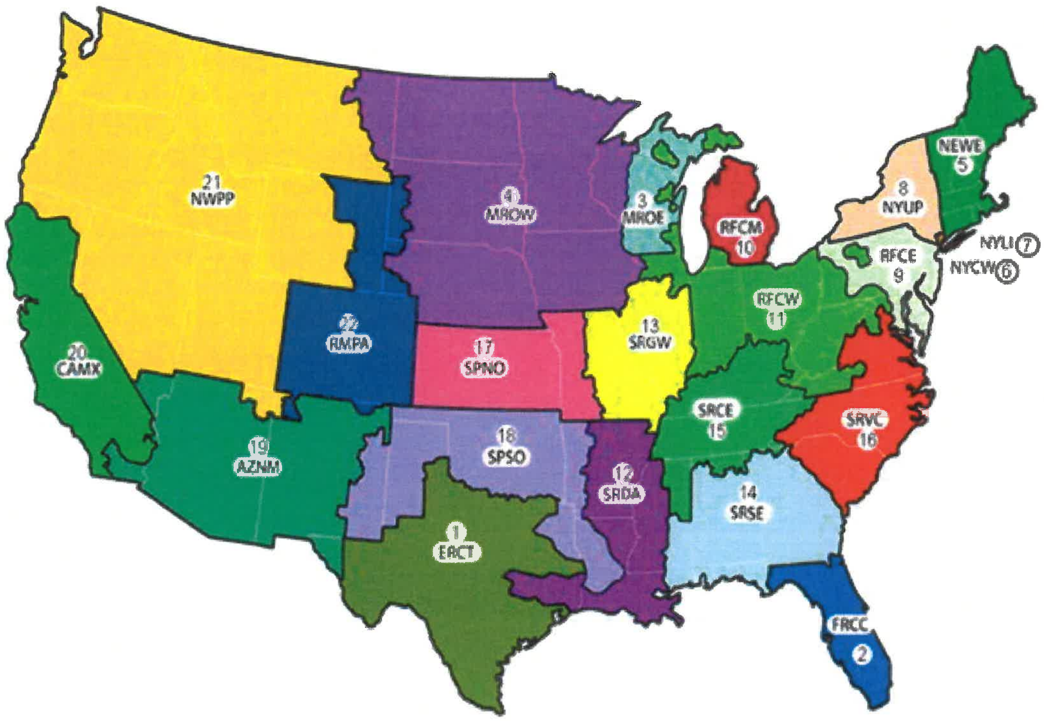
SIEMENS APPENDIX A - REGIONAL CAPITAL COST MULTIPLIER



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Technology	Advanced 2x1 Combined Cycle	Advanced Simple Cycle Frame CT	Small Aero Simple Cycle CT	Onshore Wind	Offshore Wind	Utility Solar PV Tracking	Batteries Li-ion
Average	1	1	1	1	1	1	1
ERCT	0.88	0.91	0.88	0.78	1.00	0.88	1.00
FRCC	0.90	0.94	0.91	N/A	1.00	0.94	1.00
MROE	0.87	0.90	0.87	1.07	N/A	0.98	1.00
MROW	0.91	0.93	0.91	0.88	N/A	1.01	1.00
NEWE	1.02	0.98	0.98	1.19	1.00	1.06	1.00
NYCW	1.39	1.33	1.40	N/A	1.00	N/A	1.00
NYLI	1.39	1.33	1.40	1.08	1.00	1.43	1.00
NYUP	1.03	0.97	0.97	1.08	N/A	1.00	1.00
RFCE	1.07	1.04	1.05	1.08	1.00	1.06	1.00
RFCM	0.91	0.93	0.91	1.07	N/A	1.01	1.00
RFCW	0.95	0.96	0.93	1.07	N/A	1.01	1.00
SRDA	0.88	0.92	0.89	0.98	1.00	0.91	1.00
SRGW	0.96	0.97	0.95	1.07	N/A	1.03	1.00
SRSE	0.90	0.94	0.93	1.16	1.00	0.90	1.00
SRCE	0.96	1.00	0.97	0.97	N/A	0.94	1.00
SRVC	0.86	0.89	0.87	1.16	1.00	0.86	1.00
SPNO	0.93	0.95	0.93	0.73	N/A	0.98	1.00
SPSO	0.91	0.93	0.91	0.67	N/A	0.94	1.00
AZNM	1.08	1.09	1.07	0.96	N/A	0.99	1.00
CAMX	1.17	1.08	1.09	0.96	N/A	1.14	1.00
NWPP	1.00	0.99	0.97	0.96	1.00	1.01	1.00
RMPA	1.12	1.13	1.30	0.73	N/A	0.96	1.00

Nelson Bacalao, Senior Consulting Manager

Print Name / Siemens Power Technology International

Signature
3/12/2020
Date

Alonzo Weaver, Senior Vice President & Chief Operating Officer

Print Name / Memphis Light, Gas and Water Division

3/17/2020 3/17/2020
Signature
Date