MISO Electrification Insights

APRIL 2021

Highlights

- Unprecedented electric demand from transportation, heating, and other end uses brings new opportunities and challenges for the MISO system.

- Electrification will shift the time of MISO's greatest electricity demand from summer to winter. Additionally, the average daily load pattern will begin to show steep changes in the morning and evening, suggesting benefits from flexible generation and load.

- Planning, markets, and operations must consider the simultaneous transformation of both generation and load to ensure system reliability over the coming decades.

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EXECUTIVE SUMMARY

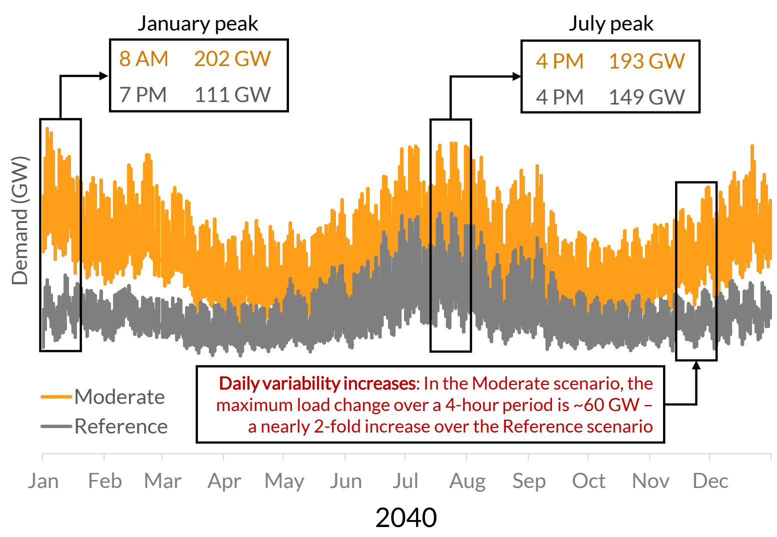
After many years of negligible load growth, electrification is poised to transform the future of electric utilities and the electric power system with increased and more variable demand. Electrification is the conversion of equipment powered by fossil fuels to equipment powered by electricity. Its impacts include increased and more variable load, changes in seasonal peak, and interactions between electrification and a decarbonizing grid. *Electrification Insights* documents anticipated load growth and possible impacts of electrification, outlining opportunities and challenges for which MISO and its stakeholders can prepare.

While the level and pace of change are outside of MISO's control, it is critical that MISO anticipate the impact of increased electrification in order to maintain reliability at a reasonable cost as the region evolves. Given that electrification is one of many trends (another is the changing resource mix) driving an unprecedented rate of change on the power system, MISO should understand the effect varying levels of electrification may have on its system in the coming decades. The overall goal of this report is to increase awareness of the potential reliability risks associated with electrification trends and to focus MISO and its stakeholders on working together toward solutions.

This report studies four electrification scenarios: Reference, Low, Moderate and High. The Reference scenario load growth follows recent patterns, with no electrification, corresponding to a 0.56% compound average growth rate (CAGR) of energy. The remaining three scenarios examine increasing levels of electrification assumed over a 20-year horizon with CAGR values ranging from 1.44% to 2.89% [1]. For comparison, the MISO Futures examine varying levels of electrification, with energy CAGR values spanning 0.63% to 1.91%. Furthermore, this report focuses on a system where only 20% of annual energy is generated from renewable resources, below the 30% inflection point identified by the Renewable Integration Impact Assessment (RIIA).

Key insights:

- Electrification has the potential to transform MISO system-wide demand from the traditional summer peak to a winter peak. The shift is predominantly driven by the electrification of heating loads in commercial and residential buildings. As a result, the time of system risk expands to winter mornings and widens over summer afternoons. This may require MISO and MISO members to further evolve processes such as resource adequacy, resource accreditation, system planning, and outage coordination.
- When examining net load [2], two daily power demand peaks now appear over nearly all months: one in the morning and one in the evening. This shape change is due to uncontrolled electric vehicle charging and daily heating and cooling loads. This may require both operational changes and changes to the time periods MISO selects for transmission planning.
- Electrification requires an increase in ramping services, as the average annual load increases and becomes more variable (right). The increased



[1] Scenarios do not consider responsive, flexible, or controllable load capabilities
[2] The expected output from all renewable generation is subtracted from the system load

ramping appears to be linked with uncontrolled charging patterns. This may require MISO and stakeholders to consider how to provide system ramping needs, and whether responsive, flexible, or controllable load should be a part of the strategy to manage ramping.

- Although the performance of responsive, flexible, or controllable loads was not included in the work for this report, research suggests that flexible loads have the potential to offset extreme ramps. Flexible load technologies include electric vehicles with vehicle-to-grid capability, water heaters, thermal energy storage, and space heating. This will require additional study and creative, collaborative problem solving with MISO stakeholders.
- Based on the current electrification landscape, some technologies will be adopted because they are cost-effective; others may depend on federal, state, and local policy related to decarbonization. Because electrification is expected to be a key lever for economy-wide decarbonization, this suggests assumptions related to power system decarbonization should continue to include electrification effects, as was done in the MISO Futures.
- A growing load with a decarbonizing generation fleet will require significant investment (generation and transmission) in the MISO system over the next 20 years. For example, the Low scenario would require around 160 GW of new generation, including more than 60 GW of wind and solar, if 20% of annual energy comes from renewable sources in 20 years.
- Economy-wide decarbonization is an important catalyst for electrification, so examining electrification only in the context of a low-renewable system may not identify all system performance risks.

The interplay between an evolving resource mix and electrification requires deeper study to ensure that MISO can continue to meet the Reliability Imperative. The four focus areas of the Reliability Imperative seek to ensure that markets, transmissions, operations, and systems — all of which will be directly impacted by electrification — are ready for the coming transition. Even moderate levels of electrification with low levels of renewables change the demand on the system — increasing overall energy demand, changing intra-day patterns, and changing annual patterns — and MISO needs to account for any changes in its planning, operations, and markets. The table below outlines considerations for different MISO processes.

MISO Process	Considerations
Planning	• Continuing to incorporate changing load shapes in long-term planning studies to ensure that all periods of system stress are captured.
	• Recognizing that shifting patterns of load growth could fundamentally shift flow patterns within MISO. By increasing the wintertime loads in the northern part of the footprint, electrification may contribute to new areas of system congestion and additional opportunities for economic transmission development.
	• Examination into how transmission supports flexible generation that can quickly change its output to provide system ramping needs.
Operations	• Monitoring seasonal load changes. Although the load shape changes result in higher summer and winter peaks, the load levels also increase across all seasons. With long-term maintenance outages traditionally taken in the spring and fall, higher “off-season” load may complicate outage scheduling. • Increased visibility into flexible, responsive, or controllable load.
Markets	• The possibility that the market may need to incentivize flexible, responsive, or controllable load as an alternative resource to provide system ramping.

As a result of continued electrification, consumers may rely more on electricity for heat and transportation. Recent disruptions such as the western heat wave in August 2020 or the cold weather event in February 2021 offer a stark reminder of the importance of the electric supply to consumers. Planning for a reliable system now and in the future remains imperative.

There is time to prepare for a future with high load growth, but it is not a time to be complacent. As large corporations with substantial presence in the MISO footprint begin their own electrification initiatives, the electrified future may arrive quickly. For example, several large automakers have announced commitments to phase-out gasoline-powered vehicles from their offerings over the coming decades. MISO and its stakeholders have a shared responsibility to maintain electric reliability by addressing the holistic needs of the system, including anticipated changes to system load.

1. INTRODUCTION

1.1 Background

Electrification is the process of converting fossil fuel-based equipment to electrical power. With the increased adoption of electric vehicles (EVs) and continued discussions of decarbonization, electrification is becoming an increasingly relevant topic of study. To reduce carbon emissions throughout the U.S. economy, electrification becomes an attractive strategy when more electric power is generated from resources with low emissions. In addition to economy-wide decarbonization, three other major trends enable electrification: increased and improved technologies available on the market; desires to encourage load growth to increase electricity sales and increase load manageability for electric utilities; and consumer preferences.

In California and Washington, cities are exploring regulations to limit the use of natural gas in new homes or even ban the use of natural gas for residential heating by the year 2040 [1], [2]. Within the MISO footprint, several companies have announced plans to facilitate EV adoption (Ameren [3], Detroit Edison [4], Xcel Energy [5], [6], and Entergy [7]). Furthermore, Entergy provides incentives to customers adopting certain electric-powered alternatives to fossil fuels through its eTech program [8].

Multiple electrical industry studies have recently examined electrification. The Electric Power Research Institute (EPRI) conducted the *U.S. National Electrification Assessment* to examine four core scenarios for efficient electrification, representing CAGR values of 0.6% to 1.2% [9]. The National Renewable Energy Laboratory (NREL) is also conducting the *Electrification Futures Study (EFS)* to explore the impacts of widespread electrification in all U.S. economic sectors and has released multiple technical reports examining CAGR values from 0.6% to 1.8% [10, 11, 12]. Both studies model EV adoption as a leading contributor to electric load growth, along with building and industrial electrification.

Electrification Insights differs from the national studies performed to date, as it:

- Studies the MISO system specifically with updated MISO load shapes for a range of electrification scenarios, supplied by Applied Energy Group Inc. (AEG)
- Studies scenarios that can serve as a time-agnostic snapshot of electrification impacts
- Offers additional value to MISO stakeholders by focusing on the challenges and opportunities provided by electrification specific to the MISO footprint

This report isolates the impacts of increasing levels of electrification and explores the unique characteristics of electrification on the MISO system, independent of other assumptions.

1.2 Trends and Impact

The 2019 MISO Forward report describes the system trends of de-marginalization, decentralization, and digitalization — the 3Ds — and their associated impacts on ***availability***, ***flexibility***, and ***visibility*** [13]. The 3Ds are trends seen in the power system, regardless of whether load remains flat or grows dramatically, but may interact with electrification.

- ***De-marginalization*** describes the effect of near-zero incremental cost of electricity: cheap electricity would increase the economic incentive to switch end-uses supplied by fossil fuels over to electricity supplied by renewable energy resources. A non-economic driver for electrification is a desire to reduce the carbon emissions of end-use, which could be achieved through a grid powered by renewables.

- *Decentralization* describes an increase in energy resources at end-use customer facilities: new responsive electric loads can participate as distributed energy resources (DERs), as demand response (DR), or through new market structures enabling time-of-use pricing at the distribution level.

- *Digitalization* describes changes in information and communications technologies: new electric end-uses will likely have advanced information and communications technologies built-in. This could allow for interactive management of new loads to reduce costs and support the grid.

Through MISO's exploration of the 3Ds, one of the main questions in ***availability*** is related to reliability metrics that capture the expected system performance during all hours. Electrification may require new reliability metrics due to the seasonal and diurnal shifts in system demand. Additionally, if electrified end-uses respond to grid conditions, they could add a new level of uncertainty to forecasts. For example, a decentralized "grid-friendly" appliance controller was developed by the Pacific Northwest National Laboratory (PNNL), which automatically starts and stops an appliance based on the grid frequency [14]. In this situation, loads are no longer passive, and it may be challenging to predict how millions of autonomous devices will respond to the grid once an algorithm replaces the "randomness" of individual consumer preferences.

Growing load and changing load patterns exacerbate the ***flexibility*** challenges that renewable generation already causes on the supply-side of the grid. However, new electric end-uses may provide a new source of flexibility if they have grid-responsive controls. The level of electrification will also determine the amount of new flexible load available to system operators, presuming flexibility is incentivized. However, if operators do not have ***visibility*** into the amount and capabilities of controllable or responsive loads, it will be difficult to take advantage of the capabilities of these new resources.

The potential interactions between the evolving resource mix and electrification warrant deeper study to ensure that MISO can continue to meet the Reliability Imperative. The four focus areas of the Reliability Imperative seek to ensure that markets, transmissions, operations, and systems — all of which will be directly impacted by electrification — are ready for the coming transition [15]. The insights contained in this report can inform the Reliability Imperative. With electrification already included in the Resource Availability and Need (RAN) Initiative and in the Long-Range Transmission Plan (LRTP) via the MISO Futures, it is important to understand the trends toward electrification, how electrification may impact MISO processes, and the reasons that electrification should continue to be included in future work.

1.3 Key Questions and Metrics Examined

This study addresses key questions about future electrification and MISO system impacts:

- What are different electrification technologies, and what is their level of commercial readiness?
- How are MISO members and states encouraging electrification?
- How does the electrified load shape differ from historical load shapes?
- What are the impacts on transmission and generation needs due to the different ways electrification could show up on the MISO system, specifically with respect to availability, flexibility, and variability?
- Does electrification impact flows between the MISO regions or between MISO and other regional transmission operators (RTOs)?

This report examines electrification trends, generation impacts, transmission impacts, and resource adequacy impacts (Figure 1).

Electrification Trends	• Technologies • Utility pilots, demonstration projects, and incentives • Policy trends • Academic and industry studies
Generation Impacts	• Generation expansion to address capacity needs • System production and capital costs • Energy production by fuel type • Total system emissions • Unit performance statistics
Resource Adequacy Impacts	• Load shape changes • Loss of load hours • Changes in seasonal risk
Transmission Impacts	• System congestion patterns • Locational marginal price impacts • Inter- and intra-regional flow patterns

Figure 1: Metrics for study evaluation

This report compares a Reference scenario to three different levels of electrification, chosen to capture a wide range of adoption regardless of cost. The Reference scenario assumes no electrification and has an energy CAGR of 0.6%, aligning well with the lowest growth scenarios evaluated by EPRI and NREL. This low growth rate also follows the historically low load growth seen over the last 15 years.

The Low scenario has an energy CAGR value of 1.4%, slightly above the highest electrification scenario evaluated in the EPRI study. The energy CAGRs of the Moderate and High scenarios are 2.2% and 2.9%, respectively, and both exceed the highest levels assumed in the NREL study. The technologies contributing to these growth levels are described in Sections 3.1 and 3.2 and the scenarios are detailed in Section 4.1.

Additionally, this report develops resource expansions for each of these scenarios for two different levels of annual energy from renewables (20% and 40%) by the final study year. This allows examination of interplay between a higher renewable system and the changing load due to electrification. To evaluate resource adequacy and transmission and generation performance, the case with 20% annual energy from renewables is examined because it falls below the 30% inflection point identified by RIIA.

2. MISO PROCESS INSIGHTS

High electrification within the MISO footprint will have significant impacts on the planning and operation of the MISO system. Thus, MISO should continue to include electrification in processes where it has already been incorporated and consider how it can be incorporated into additional system studies.

MISO Process	Considerations
Futures Development	Electrification should continue to be paired with assumptions related to decarbonization, as done in the MISO Futures
	The accelerated pace of technology adoption should continue to be incorporated into future studies
	Medium-duty and heavy-duty vehicle electrification should be included in future studies
	Future studies should consider potential new sources of load, such as indoor agriculture, and continue to account for energy efficiency initiatives.
Resource Integration	The past two years (2019 and 2020) were record years for completed Generation Interconnection Agreements with 10.8 GW and 9.9 GW, respectively. If electrification levels reach the Low scenario included in this study, while 40% of annual energy comes from renewables, the MISO system would need approximately 200 GW of new capacity to enter service over the next 20 years, an average of more than 10 GW per year.
	Recently, the interconnection queue shifted from being primarily wind to being predominately solar; with a winter-peaking system and relatively more demand from winter heating due to electrification, there may be a need for relatively more wind resources.
Markets and Resource Adequacy	New electrification technologies could enable responsive, flexible, and controllable loads. MISO should consider the value of flexible generation and load and whether it needs to be incentivized.
	Electrification shifts the time of system risk to winter mornings and widens the afternoon risk periods in the summertime. MISO should consider higher levels of electrification when evaluating changes to resource adequacy processes.
	Consumers rely more on electricity for heat and transportation as a result of electrification. MISO should consider evaluating the ability of the system to provide power during severe weather events
Transmission Planning	With load growth from electrification expected to be larger in the northern part of MISO due to heating, flow patterns throughout the footprint could fundamentally shift. Therefore, electrification should be included in any long-term transmission planning initiatives
	In a winter-peaking system, it remains important to evaluate the performance of transmission lines over many different seasons and operating conditions.
	Electrification increases system ramping needs. It will be important to explore how transmission can support flexible generation resources.
Operations	Without responsive, flexible, or controllable load, electrification will drive two large daily ramps in nearly all non-summer months. MISO should consider the operational challenges this may pose.
	Load growth across all seasons may complicate outage scheduling in the spring and fall. If responsive, flexible, or controllable load is available on the system, MISO should consider developing visibility requirements for outage scheduling and situational awareness.

3. ELECTRIFICATION LANDSCAPE INSIGHTS

The potential for electrification is highest in the northern part of the MISO footprint, due to heating loads. For the electrification scenarios in this report, most energy demand comes from light-duty EVs and heating, ventilation, and air-conditioning (HVAC). National policy trends and utility programs are beginning to lay the framework for greater electrification. Outside studies are also increasingly considering the impacts greater electrification will have on the power system.

3.1 Electrification Potential in MISO

EVs and HVAC loads contribute the most to electrification potential within MISO. As a result, the colder regions of MISO have great potential to electrify. Overall, MISO load could grow 70% larger compared to load growth without electrification.

The analysis of electrification technologies and their associated loads within the MISO footprint was performed by AEG [16]. This analysis used a top-down approach focused on identifying the upper technical limits of potential electrification and did not consider economics to determine those upper limits. AEG created load shapes covering a 20-year horizon and including increasing amounts of electrified load. The load shapes were developed starting with the 2019 MISO Transmission Expansion Plan (MTEP19) Reference Load forecast. Additional demand from EVs was added, sourced from the MISO EV study conducted by Lawrence Berkeley National Laboratory (LBNL) [17]. Finally, additional load growth from residential, commercial, and industrial electrification was added, based on AEG proprietary models.

To determine the mix of technologies adopted at the different electrification milestones, AEG considered the maturity of current technology and possible market barriers. Thus, lower levels of electrification include established and available technologies, while emerging technologies are added to create higher levels of electrification. At the upper limit of the study, AEG assumed that 90% of any particular end-use could be electrified, corresponding to a load growth of 70% compared to the Reference scenario by the end of the study period. The AEG load shapes were used as direct inputs to the analysis in this report. The High scenario corresponds to AEG's load profiles where the load due to electrification increases the energy in the final year by 60% compared to the Reference, while the Low scenario reflects a 20% higher annual energy.

AEG found three major drivers for a state's potential to electrify [16]:

a. Latitude — northern states have larger heating loads, providing more potential for electrification
b. Gas infrastructure — states with more existing natural gas heating infrastructure provide more potential for electrification
c. Cooling — states with higher cooling loads have less potential to electrify

The electrification potential of 13 states in the MISO footprint differs according to these three drivers (Figure 2). Although one might consider that states with existing gas infrastructure would be more likely to maintain natural gas heating, this analysis focuses on potential *without* detailed consideration of the economics. States with more existing gas infrastructure have more potential for the electrification of heating loads.

The highest milestone examined by AEG, "Technical," reflects a 70% increase in energy by 2040, compared to the Reference forecast. Figure 3 shows the system-wide energy growth according to the assumed level of electrification.

AEG analyzed the potential for electrification in the Residential (RES) sector and Commercial and Industrial (C&I) sectors. HVAC comprises heating, ventilation, and air conditioning. DHW refers to domestic hot water use, while APP refers to appliances, such as dishwashers, clothes dryers, and stoves. PEVs are plug-in electric vehicles. For C&I

loads, the “Other” category includes mostly process heating, for example heat curing and materials drying. The technical potential of C&I electrification, especially process heating, is the most uncertain (also noted in the EPRI and NREL electrification studies [9, 10, 11]). The AEG study attempted to consider the electrification effects without any efforts to mitigate the impact of growing load; therefore, no additional energy efficiency measures were applied beyond those already present in the reference forecast.

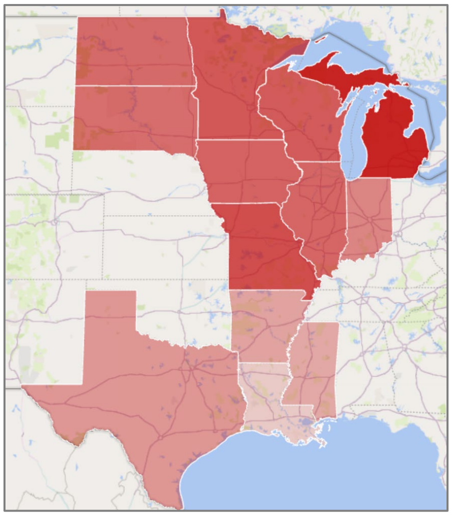


Figure 2: Electrification potential by state, developed by AEG. Darker red indicates greater potential for electrification. Source: MISO Electrification Load-Growth Assessment [16]

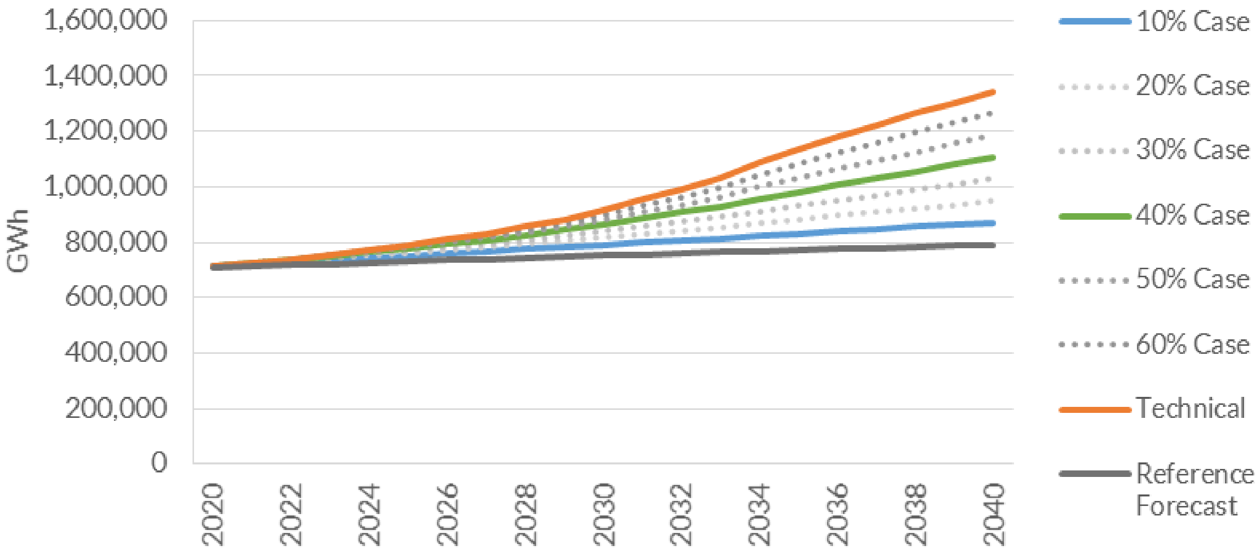


Figure 3: System-wide energy growth for each AEG electrification milestone. Source: MISO Electrification Load-Growth Assessment [16]

The AEG "40% Case," which corresponds to the MISO Moderate scenario (see Section 4.1), shows significant new load in all sectors (Figure 4). Section 4.2 provides further analysis of load shapes. Additional details of the AEG study are also available on the MISO website [16].

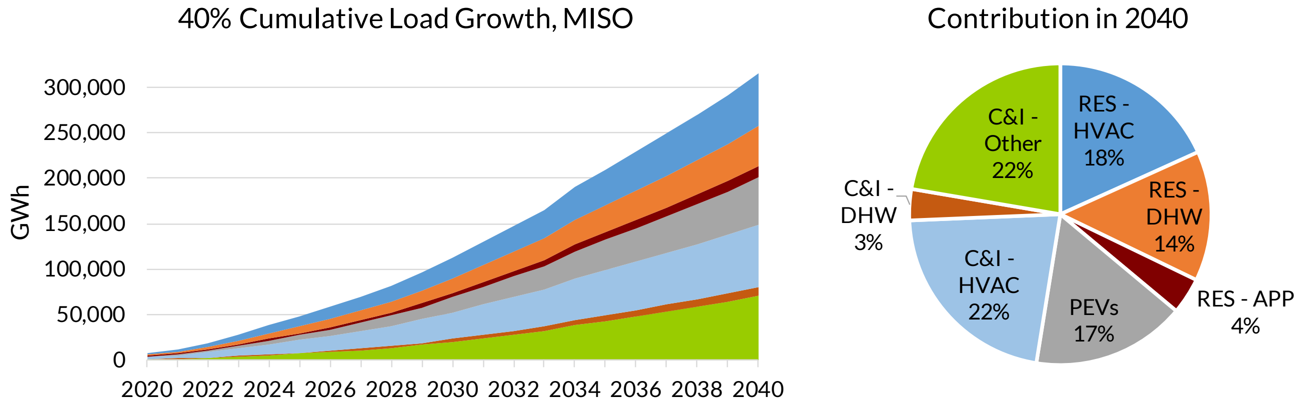


Figure 4: Moderate (40%) electrification scenario by end-use. Source: MISO Electrification Load-Growth Assessment [16]

Figure 5 breaks down the total new energy in 2040 by end-use technology for the scenarios examined in this report. The mix of end-use technologies assumed in the MISO Futures varies from the mixes shown below: by 2040, "C&I – Other" makes up only 7% of the annual energy in Future 3, and 0% in Future 2. An additional comparison of the different end-use technology categories by scenario is shown in Figure 6, where the amount of energy from residential loads is roughly the same between the Moderate and High scenarios. The biggest energy differences arise from PEVs, with smaller differences from C&I–Other and C&I–HVAC.

3.2 Technologies

Different electrification technologies are at different levels of maturity, and this section provides more context into the available technologies and recent developments.

3.2.1 Heat Pumps

Natural gas is the leading source of fuel for residential space heating in the U.S. and supplies nearly 60% of heating equipment in cold and very cold climates [18]. Electric air- or ground-source heat pumps provide an alternative technology to natural gas furnaces. Compared to natural gas furnaces, heat pumps are incredibly efficient. Many heat pumps provide 2.4 units of heating per unit of energy input, whereas natural gas furnaces provide less than 0.95 and electric resistance heating units provide 1.0 [19]. The coefficient of performance (COP) compares the total heating capacity to the electrical energy input [20]. For example, a heat pump with a 2.4 COP would provide 2.4 kWh of heat while consuming 1 kWh of electricity; electric resistance heating would provide 1 kWh of heat while consuming 1 kWh.

Heat pumps work by extracting heat from one substance (e.g., air or water) and transferring it to another (e.g., air or water). In heating mode, the heat pump circulates refrigerant to pull heat from cold outside air and transfers it inside the building. In cooling mode, the heat pump removes the heat from the inside air using the refrigerant, sending it outside, thereby cooling the internal spaces. The Department of Energy (DOE) website details the different types of heat pumps and recent technological advances in designs that improve performance [21].

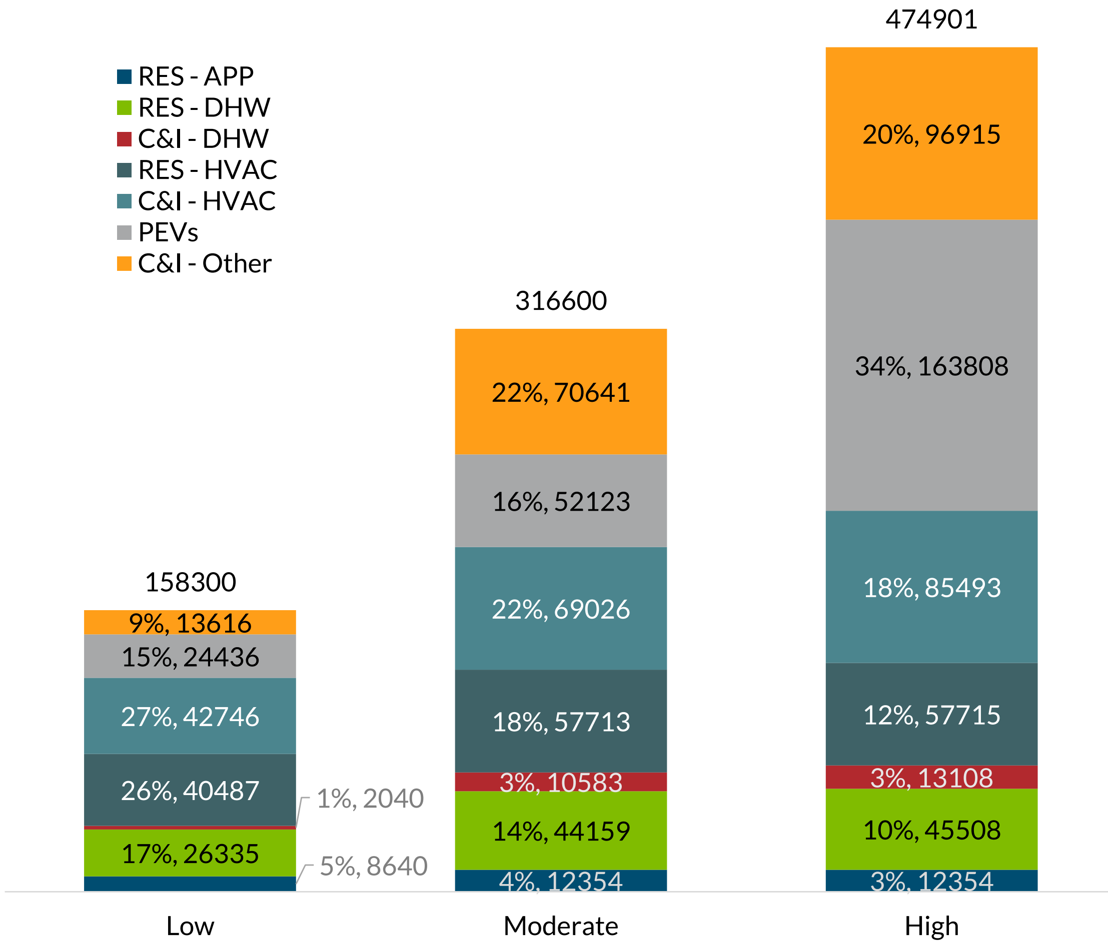


Figure 5: New energy (GWh) by end use for 2040 in each electrification scenario

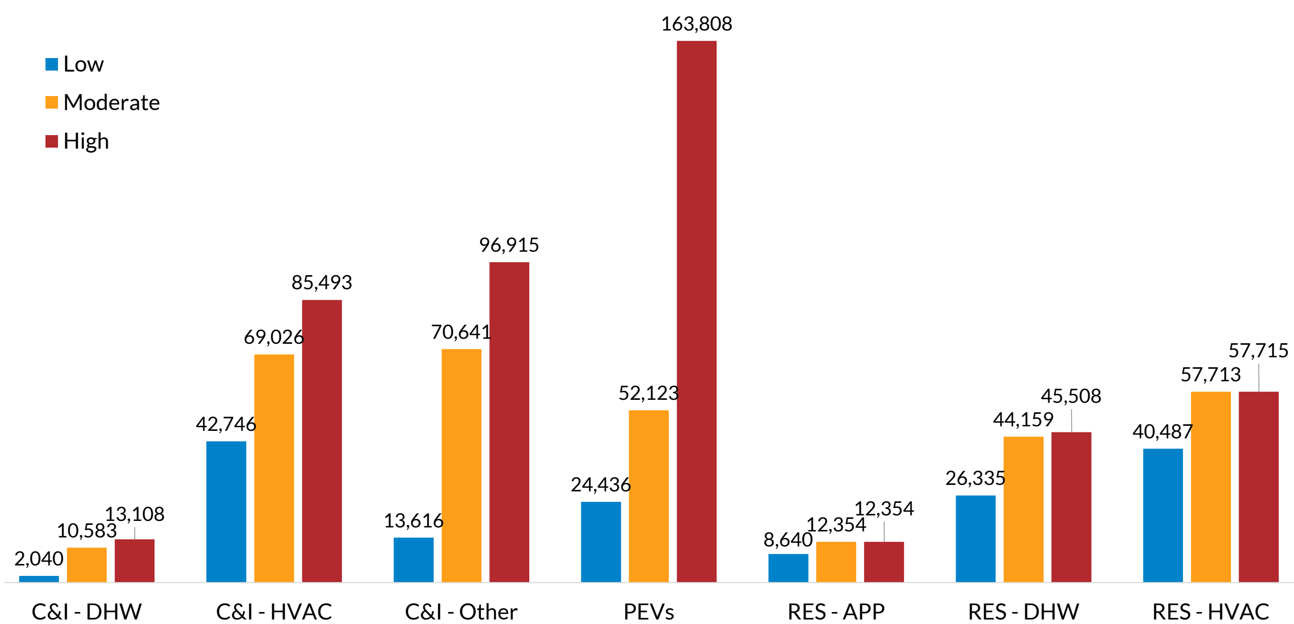


Figure 6: New end-use energy (GWh) in each electrification scenario by technology category in 2040

With the ability to both heat and cool, heat pumps would replace not just the furnace of a business or household, but also the air-conditioning unit. However, the installation cost of heat pumps can be larger than that of natural gas furnaces. Air-source heat pumps are cheaper than ground-source heat pumps, which are more efficient but require expensive drilling into the ground during installation. Converting a building from using a natural gas furnace to using a heat pump can also increase the installation costs, as some heat pump installations require different duct work than is used for a furnace. Ductless, wall-mounted heat pumps can avoid the cost of replacing or installing new ducts. A 2020 Wood Mackenzie Power and Renewables report estimated the cost of installation for a residential air-source heat pump system in the U.S. was between $5,000 and $14,000 [19].

Heat pumps are a mature heating and cooling technology. According to [18], in 2015, 12.1 million households in the U.S. used electric heat pumps, with most located in hot-humid and mixed-humid climate areas. In colder climates, there may be a need for a backup source of heat, due to the decreasing efficiency of air-source heat pumps at low temperatures. A Mitsubishi Electric air-source heat pump can provide 76% of its rated capacity at temperatures as low as -13°F [22], indicating that all but the coldest climates could depend on air-source heat pumps for their winter heating needs.

Ground-source (sometimes called "geothermal") heat pumps offer efficient heating and cooling across a wide range of temperatures but require a larger up-front investment. Current users of geothermal heat pump technologies include "schools, governments, senior communities and other long-term property owners capable of making a substantial investment with a payback period that could take a decade or more" [23]. Conventional ground-source heat pump systems can require multiple boreholes up to 250 feet deep. However, recent technological developments from researchers at the University of Minnesota could drastically reduce the required work by using wells connected to shallow aquifers to act as heat sources/sinks [23, 24]. The company promoting this technology predicts it could cut the payback period in half to five years [23, 24]. Several gas utilities in the Northeast are conducting pilots to create district geothermal systems, using their expertise with natural gas pipeline delivery to households [25].

3.2.2 Electric Vehicles

Announcements by auto manufacturers and large-fleet customers suggest that EV penetrations could increase rapidly. In 2020, Lyft pledged to have an all-electric fleet by 2030, including drivers' personal cars, the Lyft rental car program, and the autonomous vehicle program [26]. Amazon has also signaled a desire to have a large electric fleet of delivery vans and has partnered with Rivian on a bespoke delivery van design [27]. Amazon plans to have 10,000 vehicles on the road by 2022 and 100,000 on the road by 2030; their current on-road fleet is approximately 30,000 [28]. In January of 2021, General Motors announced that by 2035 it will no longer sell gasoline-powered sedans and sport utility vehicles, shifting its offerings to all-electric [29]. Over the next four years, General Motors plans to spend $27 billion on EVs and related investments [29]. In March 2021, Volvo announced that it will only sell EVs by 2030, with an intermediate milestone targeting half of 2025 sales to come from EVs and the other half from hybrid vehicles [30]. In 2020, the Governor of California issued an Executive Order banning sales of new gas-powered vehicles in California by 2035 [31].

BloombergNEF found that EVs in the US will achieve upfront cost parity with internal combustion engines in 2024 and an analyst wrote that "three market characteristics — the disappearance of the inexpensive new car, the high penetration of leasing for luxury brands, and the high true-market value for luxury vehicles — gives me reason to think that EV sales could move quickly" [32].

Using a consensus forecast, the Edison Electric Institute predicted in late 2018 that 9.6 million charge ports would be needed in the U.S. to supply the growth in EVs by 2030 [33].

"Three market characteristics — the disappearance of the inexpensive new car, the high penetration of leasing for luxury brands, and the high true market value for luxury vehicles — gives me reason to think that EV sales could move quickly."
- N. Bullard, BloombergNEF analyst

A McKinsey report from 2018 addressed the potential for EVs to impact load shapes in Germany [34]. The report suggested evening load impacts would be initially concentrated in the suburbs [34]. It further reported peak circuit loads would be increased by 30% once local EV penetration reaches 25% of neighborhood vehicles [34]. Further, the analysis suggests most of the required investment for distribution substations is needed at moderate levels of EVs [34]. In 2020, the Smart Electric Power Alliance (SEPA) released a report discussing best practices utilities should adopt to facilitate EV infrastructure deployment, highlighting the importance of having a cross-function transportation electrification team [35].

MISO collaborated with LBNL to study the expected penetration of EVs into the MISO footprint [17]. The potential amounts of EV penetration included only light-duty vehicles, specifically battery-only EVs and plug-in hybrid EVs. The LBNL EV forecasts were incorporated into the electrification load shapes developed by AEG for this study assume uncontrolled charging.

The LBNL study explored responsive charging regimes and found that unidirectional charging control can keep peaks at what they would have been without increased EV penetration [17]. The study also found vehicle-to-grid (V2G) operation could result in multi-day optimization of system load [17]. Both charging regimes were shown to be effective at achieving the control objectives in scenarios with lower and higher amounts of renewables. Specifically, for high renewable systems, it was found that controlled charging could be used to prevent the net load from becoming negative. Exploration of responsive charging in the context of electrification is reserved for future work.

There have been many pilots on V2G around the world, 50 of which were included in a 2018 report commissioned by the UK Power Networks and Innovate UK [36]. Although the technology for V2G has been around for about a decade, finding viable commercial models has been difficult [36]. Most of the projects reviewed in the report focused on technical issues, and many explored the ability of V2G to shift load in time, provide frequency response, and other distribution-level services [36].

A recent University of Chicago paper found that EV owners in California drove half as much as expected from the official EV driving estimates that are used in regulatory proceedings, suggesting several open questions related to widespread EV adoption: 1) are EVs currently being used as complements to rather than substitutions for gasoline vehicles? and 2) are early EV adopters substantially different from the population as a whole? [37].

3.2.3 Household Appliances

Many household appliances are already electrified, but there are also many that have not reached full market penetration. For example, stoves can be converted from gas-fired to electric. Clothes dryers that remain gas-powered could be replaced with dryers powered by electricity. Some households do not have dishwashers, an electrified appliance that is widely available and commercially mature. Dishwashers, stoves, and clothes dryers were all considered by AEG in their analysis [16].

Although not considered in the AEG analysis, there are further household energy uses that are increasingly electrified with the advent of powerful, rechargeable Lithium ion batteries. Electric lawnmowers are commercially available and offer several advantages over gas-powered mowers, including easy start, quiet operation, and no need to obtain and store gasoline. Commercially available electric snowblowers offer similar advantages.

3.2.4 Residential and Commercial Water Heating

Heat pump technology is not confined to space heating — it can also heat water. The NREL Electrification Futures Study reported heat pump water heaters have three to five times the efficiency of resistance-based water heaters [10]. Water heating in the commercial sector is dominated by fossil fuels; heat pump water heaters have the advantage of generating hot water and cool air simultaneously, so they can be particularly effective in applications where both are needed, such as restaurants, hotels, or laundries [10]. Both residential and commercial water heating are included as part of the AEG analysis of potential load growth in the MISO footprint [16].

3.2.5 Industrial Processes

Industrial processes represent the largest unknown in future electrification. Examples of technologies that may be electrified within industrial processes include ultraviolet (UV) curing and drying, machine drives, and process-specific heating and cooling. All of these were included in the NREL Electrification Futures Study [11]. Table 1 reproduces a breakdown of the industrial subsectors, end-use, and representative electrified technologies [11].

Industrial Subsector	End Use	Representative Electrotechnology
All manufacturing industries and agriculture	Building HVAC Machine drive	Industrial heat pump Electric machine drive
Food, chemicals, transportation equipment, plastics, and other manufacturing	Process heat	Electric boiler
Food	Process heat	Industrial heat pump
Chemicals	Process heat	Resistance heating Industrial heat pump
Glass and glass products	Process heat	Direct resistance melting (electric glass melt furnace)
Primary metals	Process heat	Induction furnace
Transportation equipment	Process heat	Induction furnace
Plastic and rubber products	Process heat	Resistance heating Infrared processing
Other manufacturing	Process heat	Resistance heating
Other wood products and printing and related support	Process heat: curing	Ultraviolet curing

Table 1: Electrification technologies (electrotechnologies) per industrial end use. Source: NREL Electrification Futures Study [10]

In the AEG analysis, most of the growth in the industrial sector was assumed to take place at higher levels of electrification load growth [16]. The AEG work suggests the total industrial process sector represents 175 TWh in 2040, representing about 30% of the total MISO electrification potential. In 2040, the Low (AEG 20%) scenario includes around 14 TWh of industrial process electrification (Figure 5), while the Moderate (AEG 40%) and the High (AEG 60%) scenarios include approximately 70 TWh and 97 TWh, respectively. The definitions of the Reference, Low, Moderate, and High scenarios are reviewed in Section 4.1.

3.2.6 Other Opportunities

Although this report does not consider medium- or heavy-duty vehicle electrification, work is ongoing to expand the analysis. MISO has partnered with Emerging Futures, LLC. to forecast medium- and heavy-duty truck electrification within the MISO footprint and is expected to release the analysis in Quarter 2 of 2021.

A 2020 Wood Mackenzie Power & Renewables report explores the economics of regional e-truck adoption by focusing on the Volvo-sponsored Low-Impact Green Heavy Transport Solutions (LIGHTS) demonstration project in and around the Port of Los Angeles [38]. This analysis suggests the total lifetime costs of an e-truck may be only 2% higher than a diesel truck, and 26% lower than a diesel truck with the application of all incentives available in California [38]. This area will likely grow rapidly as trucking companies gain more experience with e-trucks.

The North American Council for Freight Efficiency (NACFE) offers a primer for utility companies on commercial truck electrification, suggesting utilities get a head start on learning about the trucking industry [39]. In September 2021, NACFE will partner with the Rocky Mountain Institute for a three-week demonstration of electric trucks in everyday operation [40]. Mike Roeth of NACFE wrote in 2020, "For a time, trucking will be a multi-fuel industry, but in the end electricity will be the dominant power source for commercial vehicles" [41].

> *"For a time, trucking will be a multi-fuel industry, but in the end electricity will be the dominant power source for commercial vehicles."*
> *- M. Roeth, Executive Director of North American Council for Freight Efficiency (NACFE)*

Roeth predicts by 2040 the industry should expect "the absolute dominance of commercial battery electric vehicles from clean energy," because "battery electric powertrains are the most efficient use of energy for the purposes of transporting freight when viewed from well to wheel" [41].

Electric forklifts are an existing technology proven to have many benefits when electrified. Electric forklifts, rather than diesel or propane, can reduce indoor air and noise pollution when used in warehouses. Two-thirds of 2019's global forklift market ($49.6 billion) was electric, with further growth expected [42]. An EPRI calculator showed that over 72 months of operation (8 hours/day, 5 days/week), operations and maintenance costs for electric forklifts are $0.75 cheaper per hour than propane ($1.25/hour) or diesel ($2/hour) [43].

Up to this point, the discussion has focused on electrifiable technologies considered in the AEG analysis of electrification potential within the MISO footprint, except for medium- and heavy-duty truck electrification. AEG's analysis looked only at existing technologies and did not examine possible opportunities for electrifying new sectors of the economy.

One major new sector for load growth is energy-intensive grow lamps used for indoor agriculture. For example, the business of growing marijuana in states where it has been legalized can lead to new electric load [44]. Pacific Power attributed several distribution system outages in 2015 to increased load caused by grow houses [45]. Within the MISO footprint, Michigan and Illinois have legalized marijuana, and it is decriminalized or allowed for medical purposes in the remaining states [46].

Even in states without legalized marijuana, there remains the possibility of indoor agriculture for traditional crops, such as leafy greens. Indoor agriculture provides some advantages to traditional agriculture: it can use up to 95% less water, eliminates pesticide and fertilizer pollution in runoff, requires little to no soil, and does not require fossil-fuel-powered farm equipment, while being significantly more productive [47]. EPRI is working on a project using container farms across the U.S. to explore this growing industry and learn about consumption patterns and electricity demand [47].

The MISO footprint presents opportunities to demonstrate the feasibility of offshore electric technologies. The Mississippi River, running through the heart of the MISO area, carries 60% of the grain exported from the U.S. [48]. As MISO's footprint borders four of the five Great Lakes, any attempts to electrify maritime shipping within the

Great Lakes would likely impact MISO load. According to the Great Lakes Seaway Partnership website, ports within the MISO states of Minnesota, Wisconsin, Indiana, and Michigan handle more than 165 million tons of cargo each year [49].

3.2.7 Grid-Responsive Load Control

Although exploration of grid-responsive load control is reserved for future work, a brief discussion of the potential for these technologies is warranted. Controllable building loads could be used to change the daily load profiles to reduce ramps and better utilize solar and wind resources. Electrification may increase the amount of potentially controllable loads in buildings, such as heating and water heating, and may add new potentially controllable loads such as EV charging.

The majority of U.S. electricity consumption occurs in buildings: 36% in commercial buildings and 38% in residential (2019) [50, 51]. The majority of building electricity use is for HVAC, water heating, and refrigeration, comprising 74% of annual residential use and 61% of annual commercial use. Both HVAC and water heating are excellent candidates for control, allowing a building to act as a thermal battery. Building load control is not confined to new construction but could be added during a retrofit process.

During a New York State Energy Research and Development Authority Roundtable in 2019, panelists discussed policies and retail electric rate structures that would advance grid-responsive electric buildings [52].

A 2020 LBNL study focused "on the methods and practices for determining the economic value of demand flexibility provided by grid-interactive efficient buildings to electric utility systems," primarily through reduction in either generation costs or energy delivery cost [53]. The LBNL study defines a grid-interactive efficient building as one "equipped with one or more DERs that make the building both grid-interactive and energy-efficient, such as energy-efficient HVAC equipment, interactive electric water heaters, battery storage, or managed EV charging," allowing flexibility through "shedding or shifting load in response to price or other signals" [53]. To determine the economic value of grid-interactive efficient buildings, it is important to compare the services offered to an alternative that offers comparable service; these services depend on the response's timing, length, and location [53]. This economic value differs based on location but could include avoided generation expansion or avoided transmission and distribution costs [53].

A Brattle Group study estimates that 140 GW of new cost-effective load flexibility could be available nationally by 2030, mostly from smart thermostats and smart water heaters [54]. Approximately 60 GW of that estimate comes from the expansion of conventional programs, new load flexibility programs using smart thermostats, and the expansion of dynamic pricing to all customer segments [54]. The remaining 80 GW come from advanced metering infrastructure deployment, EV adoption, customer growth, and additional assumed value streams from transmission and distribution expansion and increased renewables adoption [54]. Most of the economic value of the flexibility is from avoided generation capacity [54].

An LBNL study found California could shift 2.5 GWh of building loads a few hours at costs less than battery storage by 2030 [55]. If the "shift" resource is used over the two hours of highest daily peak, it could reduce the peak by 1.25 GW [55]. Furthermore, if that energy was used to increase load in the two hours before peak, it could reduce the ramp by 2.5 GW. Most of the "shift" resource comes from HVAC in commercial buildings [55]. In the LBNL study, new building electrification does not contribute much to the "shift" resource by 2030 because of the assumed slow pace of electrification [55]. A forthcoming study from the US DOE Building Technologies Office will estimate the national-level demand reduction that could be achieved by controllable loads in commercial and residential buildings.

Additional work is needed to forecast grid services that could come from controllable building loads. More importantly, MISO should investigate the value those services can provide to the grid and how to incentivize availability and how to allocate payments for them. It may be difficult to allocate the value of avoided generation or transmission capacity.

3.3 Policy Trends and Utility Programs

In the mid-1950s, General Electric and Westinghouse co-sponsored a national campaign to promote the adoption of all-electric appliances [56]. At that time, all-electric houses were the wave of the future — and were tagged with the slogan of “Live Better Electrically” (Figure 7) [56]. Today, there is not a similar industry-wide campaign to encourage the adoption of electric technologies in the residential sector, but many utilities and states are supporting electrification through targeted programs and incentives.

Figure 7: Gold Medallion Home logo. Source: Washington State Department of Archaeology and Historic Preservation [55]

In early 2020, the Edison Electric Institute issued a joint statement with the Sierra Club and others in support of electric transportation [57]. This statement affirms electrifying transportation will provide widespread benefits, electric companies need to be involved to accelerate adoption, and efforts should be made to power that transportation with variable renewable, zero-emission generation resources. The Edison Electric Institute represents all U.S. investor-owned utility companies, including many MISO members [58].

In September 2020, four MISO members partnered with two non-MISO members to build a large interstate electric vehicle charging network [59]. Ameren Illinois, Ameren Missouri, Consumers Energy, and DTE are participating in this project, which aims to reduce range anxiety among consumers and spur adoption of EVs. All charging infrastructure is planned to be completed by the end of 2022.

President Joe Biden’s Climate Plan calls for the development of “rigorous new fuel economy standards aimed at ensuring 100% of new sales for light- and medium-duty vehicles will be electrified and annual improvements for heavy-duty vehicles” [60].

In February 2020, the Sacramento Municipal Utility District (SMUD) became the first utility in the U.S. to change its energy efficiency metric to incorporate “avoided carbon,” a change enabling investment in building electrification [61]. SMUD programs target the electrification of 80% of the buildings within its service territory, with expected customer savings of $300 to $700 annually [61, 62]. In September 2020, Wood Mackenzie released an in-depth analysis of SMUD’s plans for building electrification. The analysis expects the SMUD daily summer peak loads to decrease, due to increased efficiency of new heat pumps compared to legacy air conditioners, and two peaks will appear in the daily winter load shape, with the expected morning peak approximately equal to the typical daily summer peak [63].

Municipal gas bans in California require all-electric new construction. Berkeley was the first city to ban natural gas in new buildings in July 2019 and, in November 2020, San Francisco joined a list of 40 cities with similar bans in California [64]. By July 2020, the gas ban initiative had spread to cities in Massachusetts, where the cities of Arlington, Cambridge, Brookline, and Newton began to pursue banning natural gas in new construction [65]. In response, several states have introduced legislation to block such bans, including some MISO states (Minnesota, Missouri, Kentucky, and Louisiana) [63].

Instead of banning natural gas in new construction, Boulder, Colo., is pursuing a different approach: building performance standards. By limiting the maximum energy use per square foot of new construction, these standards can spur buildings toward all-electric construction [65]. In an S&P Global news article, a representative of the Institute for Market Transformation states "a building performance standard could drive very significant building electrification over a relatively short period. Buildings are a long-lived assets. They're an aircraft carrier. You can't turn them on a dime, but in building terms, you can move farther faster with a building performance standard than just about any tool to change your existing buildings" [65]. New York City is considering a building performance standard, while Washington state has already passed one [65].

"A building performance standard could drive very significant building electrification over a relatively short period. Buildings are a long-lived assets. They're an aircraft carrier. You can't turn them on a dime, but in building terms, you can move farther faster with a building performance standard than just about any tool to change your existing buildings"
- C. Majersik, Director of Market Transformation, Institute for Market Transformation

In New York and Massachusetts, both with aggressive decarbonization policies and large heating demand during the winter, district geothermal heating pilots are being proposed by gas utilities [25]. National Grid pilots have focused on customers who cannot access the existing gas infrastructure, burying pipes of water to act as the thermal source and sink for a neighborhood using geothermal heat pumps [25]. Con Edison is exploring projects that would remove old natural gas infrastructure and use the same rights-of-way to bury geothermal ground loops [25]. Massachusetts-based Eversource Energy won approval for a $10.2 million demonstration project with both commercial and residential buildings, which is "intended to test the viability of a non-gas thermal distribution model" [25].

3.3.1 Michigan

The city of Ann Arbor adopted a carbon neutrality plan that includes electrification of buildings and transportation as key focus areas [66]. This plan proposes to fully electrify 100% of city facilities, 30% of owner-occupied homes, and 25% of rental properties by 2030, including the expectation that all new residential and commercial buildings will be built to operate without using natural gas. Additionally, the plan includes the full electrification of public transit and city fleets, with programs to encourage public EV infrastructure and private EV adoption.

In 2019, DTE kicked off a pilot called "Charging Forward," which will last three years and cost approximately $13 million. The program offers rebates to encourage the installation of 1,000 public, Level 2 chargers and 32 direct current (DC) fast chargers along Michigan highways, as well as 2,800 residential in-home chargers [4]. The installed chargers will have the ability to communicate with the grid. DTE offers three different time-of-use rates to customers to encourage off-peak energy use [67]. Additionally, DTE is investing in transportation electrification using mainly electric buses in Wayne County, Mich. [68].

Consumers Energy has an ongoing rebate program, coupled with time-of-use pricing, called "PowerMIDrive" to encourage the adoption of EVs in its territory [4, 69]. This program will provide residential rebates of $500 for Level 2 chargers, $5,000 rebates for commercial customers installing a public Level 2 charger, and up to $70,000 for installation of a public DC fast charger.

3.3.2 Minnesota

In 2019, Minnesota regulators approved an Xcel Energy pilot supporting EV-sharing ($9.6 million) and electrification of government fleets ($14.4 million) [70]. In 2020, Xcel Energy announced a $300 million program to serve 1.5

million electric cars across its entire territory (Minnesota, Colorado, and Texas), corresponding to a 30-fold increase in EVs [71]. As part of this announcement, Xcel Energy expects 20% of all vehicles in its service territories to be replaced with EVs in the next decade. Furthermore, Xcel Energy plans to electrify all its sedans by 2023, all its light-duty vehicles by 2030, and 30% of its medium- and heavy-duty vehicles by 2030. Within Minnesota, Xcel Energy is partnering with Metro Transit in the Twin Cities on an electric bus pilot [72], and Metro Transit is working toward having all new buses be electric by 2022 [73].

Great River Energy (GRE) was a partner on an electric school bus pilot in 2017-2018 in Lakeville [74]. The company is also a partner on a housing development in Lakeville that will install 81 grid-responsive water heaters, along with EV chargers and energy efficient technologies (such as LED lighting) to evaluate the potential for load shaping [75]. GRE has a project with the University of Minnesota-Morris to evaluate net-zero dairy farming, including the feasibility of electrifying heating [75]. To explore the ruggedness and reliability of forklifts, GRE is partnering with EPRI to provide high-capacity forklifts that can move 11,000 pounds or more to a wood manufacturing plant [43]. The demonstration will collect data on the operations, battery performance, and energy use in a cold-weather environment as the forklifts are used to load railcars [43]. GRE is financially supporting a project that will test indoor agriculture by growing kale year-round in a shipping container, using techniques that could be adapted for any underutilized space [76]. The container is expected to produce approximately 100 pounds of produce per week, the same amount as one acre of land, according to a GRE spokesperson [76].

Currently, the Duluth Transit Authority has a $6.3 million pilot using seven electric buses on its routes [77].

Minnesota Power recently submitted a proposal to Minnesota regulators to explore the electrification of mining vehicles [78]. The project, partnering with Caterpillar, Komatsu, and Minnesota Power's mining customers, aims to evaluate the market for electrifying mining vehicles and to study ways to retrofit existing vehicles with electric equipment.

The Minnesota Solar Pathways project examined the potential of photovoltaic (PV) solar to provide 10% of energy by 2025 and of solar and wind together to provide 70% of energy by 2050 for both Minnesota [79] and MISO as a whole [80]. The Minnesota-specific study assumed electrification load increases from EVs, DHW, and HVAC, of which both DHW and EVs were assumed to be shiftable [79]. The study examined two electrification scenarios: low and high, which assumed full electrification of DHW and light-duty EVs and 50% electrification of single-family residential heating [79]. The study saw electrification of heating "altered the seasonality of Minnesota's load shape" and found "meeting future loads with electrified heating shifts the optimized wind/PV balance-point further toward wind" [80].

3.3.3 Missouri

In 2019, regulators approved an $11 million program by Ameren Missouri to support building EV charging infrastructure over three years, split between installing EV chargers along highway corridors and providing financial support for additional local EV charging station installation at local businesses and multifamily residences [81]. In 2020, Ameren Missouri installed 11 charging stations along highway corridors, part of an effort to ensure a state-wide network of chargers no more than 50 miles apart [82].

Ameren has a corporate focus on electrification. Its Vice President of Electrification and Sustainability, Gwen Mizell, was quoted in EPRI's Efficient Electrification newsletter in February 2020, supporting three areas of electrification: transportation, buildings and industry [83]. "Electrification is a key lever in this area, with huge potential benefits for our company, our customers, and society," Mizell said. "Although we don't control the entire electrification world, we can encourage our customers to adopt electrification, where it makes sense" [83].

"Electrification is a key lever in this area, with huge potential benefits for our company, our customers, and society. Although we don't control the entire electrification world, we can encourage our customers to adopt electrification, where it makes sense."
— G. Mizell, Vice President of Electrification and Sustainability, Ameren

Ameren's 2020 Sustainability report stated it spent 5% of its annual fleet budget on plug-in EVs for the last four years [84]. Ameren also committed to purchasing 150 electric forklifts over the next five years to completely replace all its combustion-powered forklifts.

St. Louis has enacted a building energy performance standard requiring existing buildings to meet energy use intensity requirements [85]. The standard applies to approximately 1,000 buildings in the city and the energy use intensity limits will be chosen such that 65% of the buildings will have to save energy [85]. As building electrification is one way to reduce energy use per square foot, it is expected electric end-use technologies will be a part of standard compliance [65].

3.3.4 Louisiana

Entergy began its eTech program more than five years ago with an initiative to electrify irrigation well pumps within its territory [86]. According to an EPRI Efficient Electrification newsletter, "Entergy emphasized the lower maintenance costs of electric pumps: electric motors have a longer service life than the typical diesel or gas pump and don't require oil changes or belts. Motor vibration is minimal, which is better for the pump and well" [86]. Now, the eTech program promotes electrifying forklifts, which are the most popular, fleets, rail or mining equipment, industrial welding, and marine and power equipment [86]. With the latter, Entergy has partnered in a joint project to demonstrate electrifying 10 marine vessels in Port Fourchon [87]. Alongside EPRI, Entergy is exploring electric technologies such as refrigerated transport, induction heating, induction melting, and infrared heating, drying, and curing [86]. Entergy is also partnering with five other major utilities to create the Electric Highway Coalition, whose stated goal is to offer convenient DC fast charging along major highway corridors within their footprints [7].

Furthermore, in August 2020, the Governor of Louisiana signed two executive orders to limit carbon emissions from the state; the goal is to reduce emissions 25% by 2025 and to achieve net-zero emissions by 2050. Although neither order directly addresses electrification, electrification is one method of achieving economy-wide emissions reductions.

3.4 Studies from Industry and Academia

EPRI's *U.S National Electrification Assessment* examined several electrification scenarios ranging from 24% ("Conservative") to 52% ("Transformation") electric load growth by 2050, representing CAGR values from 0.6% to 1.2% [9]. This study focused on what EPRI termed "efficient electrification," specifically "opportunities across the economy that yield a range of efficiencies — lower cost, lower energy use, reduced air emissions and water use, improved health and safety for customer's workers coupled with the opportunity for gains in productivity and product quality, and increased grid flexibility and efficiency." Key findings from this study indicate that, across many scenarios, electrification leads to reduced greenhouse gas emissions, reduced overall energy consumption, and a steady growth in electric load. The increased load drives an increase in natural gas generation and low-carbon electric generation (renewables and natural gas units outfitted with carbon capture and sequestration). With respect to planning, the EPRI study calls out the potential need to change assumptions in reliability planning, especially considering the coupling between the natural gas system and the electric system.

The *Electrification Futures Study* (EFS) from NREL is a multi-year study exploring many aspects of electrification. The second report (*Scenarios of Electric Technology Adoption and Power Consumption for the United States)* examines scenarios of technology adoption from Reference to High, corresponding to 21% to 67% energy growth by 2050 and CAGR values from 0.6% to 1.8%, respectively [11]. These scenarios are unique because they also account for a range of possible technology advancements and actual cost predictions, which were developed in the first study *(End-Use Electric Technology Cost and Performance Projections through 2050)* [10]. One key finding of *EFS: Scenarios of Electric Technology Adoption* is that electrification drives changes in load shape, particularly that the top 100 load hours of the year are spread across more months [11]. *EFS: Scenarios of Electric Technology Adoption* further found the biggest contributions of load growth from electrification come from the transportation sector, while the contributions of the building and industrial sectors is more limited and focus on space heating [11].

The third installment (*Methodological Approaches for Assessing Long-Term Power System Impacts of End-Use Electrification*) was released in July 2020 and explored methodologies for assessing the long-term impacts of electrification on the power system, mainly focused on implementing modeling assumptions related to electrification into a capacity expansion tool [12]. This publication finds:

1. Increasing correlation of the hourly loads in different local balancing authorities (LBAs) indicates it could become more difficult to take advantage of geospatial diversity in load profiles under high electrification scenarios
2. The price changes in natural gas demand driven by electrification are very difficult to model, but any examination considering only impacts from increasing demand within the power sector, without accounting for the declining demand in other sectors, is likely going to overestimate the gas price increases
3. Although there is uncertainty about the willingness of consumers to participate in flexible load programs, results show reduction in system costs if 10 to 15% of load (by energy) is flexible in the future, representing the upper limits on their assumed flexibility.

The Great Plains Institute (GPI) and the Midcontinent Transportation Electrification Collaborative (MTEC) partnered on a series of papers in 2018 and 2019 detailing road maps to decarbonizing the midcontinent [88]. The papers focused on pathways to decarbonizing the electricity system itself and on pathways to electrifying transportation. The GPI-MTEC report found transmission buildout can lower the cost of decarbonizing the electric system by 1% to 3%. Nevertheless, it expects energy efficiency and flexible demand to play an increasingly important role in electricity systems powered by low-carbon generation. The report highlights programs by three different MISO members (who are also members of MTEC) to electrify transportation [88]:

A. *Madison Gas and Electric* (MGE) has implemented a program including installation and maintenance of a smart charger with a monthly fee and no installation cost. With this program, MGE can view charging patterns and manage charging sessions remotely. MGE is also installing public charging stations and working with developers to have chargers at multifamily residential properties. The report further highlights MGE's customer outreach and education, partnership with City of Madison and the local transit group to start an electric bus program.

B. *GRE* is working on an electric bus pilot and is providing free wind energy to fuel EVs owned by cooperative members. GRE is also working on a project to develop an EV charging corridor along Interstate 35 between the Twin Cities and Duluth, with plans to extend into the Minnesota portion of the North Shore of Lake Superior.

C. *Xcel Energy* is working on several different pilots related to residential EV charging, public charging for multifamily properties, charging subscription services, smart charging, and new consumer tools. Xcel's partners include the cities of Minneapolis and Saint Paul, providers of EV analytics to inform fleet operators about EV conversions, and HOURCAR.

A January 2017 publication from the Brattle Group publication argues "a greening grid alongside rapid technological and other changes in transportation is providing the basis for a counter-narrative to the utility death spiral" [89].

"A greening grid alongside rapid technological and other changes in transportation is providing the basis for a counter-narrative to the utility death spiral."
— Brattle Group report

The authors write that transportation and heating currently account for 45% of greenhouse gas emissions and that, if those are converted to a 100% electric supply, utility sales could double [89]. To achieve an 80% reduction in greenhouse gas emissions from 1990 levels by 2050, the authors anticipate a CAGR of 1.9% and argue full electrification of transportation and heating is the simplest feasible path to such reductions [89]. In a report on "New Sources of Utility Growth," the Brattle Group suggests that controllable electric water heaters represent massive potential for flexible load, as they can act like thermal batteries; the 40% of water heaters fueled with electric resistance elements could provide 100 GW of controllable load throughout the U.S. [90].

In March 2019, the Brattle Group released another study focused on the transmission needs of a future grid with large amounts of electrification, sponsored by WIRES (a non-profit trade consortium) [91]. The report, titled "The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid," found that "$30–90 billion of incremental transmission investments will be necessary in the U.S. by 2030 to meet the changing needs of the system due to electrification, with an additional $200 to $600 billion needed from 2030 to 2050" [91]. The main drivers of the required transmission expansion were increasing peak demand and connecting additional renewable resources to the system [91]. Specifically, this report estimated that each kW of peak load growth requires $100 to $400 worth of transmission investment, while each kW of utility-connected renewable capacity requires $300 to $700 worth of transmission investment [91]. The report notes that a large challenge with planning transmission for electrification is that there remains a lot of uncertainty in the timing, location, and scale of electrification [91].

West Monroe conducted research on companies within six adjacent industries to MISO — transportation, industrial, high tech, buildings, fossil fuels, and retail — regarding energy procurement and decarbonization [92]. It concluded that "companies currently have the technical sophistication and software management tools to shift their load, but do not necessarily have the financial incentive or information to do so based on the data and price signals available to them" [92].

"Companies currently have the technical sophistication and software management tools to shift their load, but do not necessarily have the financial incentive or information to do so based on the data and price signals available to them."
— West Monroe report on MISO-adjacent industries

West Monroe reported on the use of advanced computation techniques, such as artificial intelligence and machine learning, to shift non-essential data center loads to periods of low carbon intensity [92]. Decarbonization is a primary concern for many end-users, and electrification is of great interest to them for its ability to lower end-use emissions and lower upstream emissions when coupled with a decarbonized electricity supply [92].

In September 2020, NGI Consulting released a report on "NextGen Highways," which proposed collocating transmission lines, electric vehicle charging infrastructure, and communications infrastructure along highway rights-of-way to facilitate the electric sector's and transportation sector's transitions to renewable energy and to zero-emission vehicles, respectively [93]. This paper further suggests that highway upgrades be combined with buried high-voltage DC (HVDC) lines to enable the creation of a national HVDC grid, which could increase resilience [93].

A 2020 PNNL study investigated resource adequacy in the face of widespread EV adoption in the Western Electricity Coordinating Council (WECC) footprint and found that resource adequacy in 2028 was likely to be sufficient [94].

A 2018 study by the Rocky Mountain Institute, "Economics of Electrifying Buildings," found that electrification of new houses will save money for residents in the long term [95]. However, existing houses with gas or other options of heating will face high upfront upgrade costs while paying more for the electricity (colder regions) or recovering too little from the reduced bill (warmer regions) [95]. To improve the viability of electrification, the report recommends reducing heat pump cost, increasing the benefits of owning smart electric devices that dynamically adjust electric usage based on the current market price, and adding carbon cost to the price of natural gas through policies or other methods [95]. To promote electrification, the report suggests [95]: 1) prioritizing upgrades for propane heater users, as they could immediately save money; 2) improving policy standards to bundle demand flexibility programs, new rate designs, and energy efficiency with electrification initiatives; and 3) updating energy efficiency resource standards and related goals.

In 2018, the American Gas Association released a report focused on the impacts of residential electrification [96]. The report found electrification would "increase the average residential household energy-related costs (amortized appliance and electric system upgrade costs and utility bill payments) of affected households by between $750 and $910 per year, or about 38 percent to 46 percent" [96]. It also concluded electrifying space and water heating would increase peak load demand and shift every U.S. region from a summer peaking system to a winter peaking system [96].

A 2020 Princeton study estimated that at least $2.5 trillion in additional capital investment into energy supply, industry, buildings, and vehicles is needed to achieve net-zero emissions by 2050 or sooner [97]. One of the pillars of reaching net-zero is to "improve end-use energy productivity — efficiency and electrification," and postulates that "electrification reduces fuel use and provides efficiency gains in road transport, heating of buildings, [and in] some industry, especially iron and steel" [97]. This study estimated that "even with flexible demand, distribution networks will likely need to accommodate ~5-10% increase in peak demand by 2030 and ~40-60% by 2050" due to electrification, totaling between $300 billion and $370 billion [97]. The study further lists electrification of transportation and buildings as a priority for the 2020s to meet net-zero by 2050.

Transpower, the owner and operator of the New Zealand transmission network, included "accelerated electrification" as its base system planning scenario through 2050, assuming that energy growth would increase 68% against its historic baseline, driven by transportation and process heat electrification [98]. Transpower's study combines electrification with a 100% renewable target and plans to supply the additional demand through expansion of wind, distributed solar, and utility solar [98]. Transpower notes "mandatory EV smart charging is a very good example of the need for an equitable approach… [and] will be critical because it will alleviate the risk that a group of less price sensitive consumers might choose to continue to charge their EVs during peak demand periods, despite higher prices" [98]. Meeting the accelerated electrification future will require 10 to 15 new transmission interconnections, including both grid backbone upgrades and regional transmission upgrades [98].

4. TECHNICAL INSIGHTS

The *MISO Electrification Insights* report findings are split into four focus areas: 1) analysis of electrified load profiles, 2) resource forecasting to meet the growing load, 3) resource adequacy impacts from electrification, and 4) generation and transmission performance with an electrified system.

The load profile analysis shows that the magnitude and variability of the load increases with increased electrification. Electrification increases the ramp requirements of the system. From the resource forecasting, it is seen that the change in annual shape to be winter peaking may result in a different mix of wind and solar being selected from the economic expansion analysis, all other assumptions being equal. Furthermore, it is seen that the resources added to the system will be dominated by natural gas units, in the absence of additional requirements on decarbonization.

Resource adequacy shows the periods of system risk shifting to the wintertime as electrification increases, aligning with system peak shift to winter. The analysis of generation and transmission performance validates the increased ramping needs identified through the load profile analysis and shows that they are met by all types of conventional units. Furthermore, changes to the system flow patterns are described.

4.1 Scenarios

Table 2 shows the four scenarios for analysis and the effective CAGRs for each level of electrification. The High electrification scenario assumes the annual energy has increased by 60% over the Reference by the end of the 20-year study period. The Low scenario does not represent a conservative assumption, however, as it reflects a much larger demand and energy growth than has been seen in recent decades. Figure 8 shows the total annual generation to serve load in the US for the last 70 years — and the generation is relatively flat over the past 20 years [99]. From 1990 to 2000, load growth was 2.7%, but dropped to 0.8% from 2000 to 2010 [9].

Scenario Name	Percent Increase in Energy (compared to Reference in 2040)	Energy CAGR	Peak Load CAGR
Reference	-	0.56%	0.53%
Low	20%	1.44%	1.20%
Moderate	40%	2.21%	2.06%
High	60%	2.89%	2.74%

Table 2: Electrification study scenarios

The CAGR levels explored in this study exceed the upper levels analyzed in both the EPRI *National Electrification Assessment* (1.2%) and the NREL *Electrification Futures Study* (1.8%). Both the EPRI and NREL studies accounted for economics, whereas this report captures the upper bookends of technical potential. Historically, the High scenario aligns with growth levels in the 1990s.

All three MISO Futures developed for MTEP21 and other MISO studies include some electrification as part of the future load growth through 2040 (Table 3). The assumptions in this study and the MISO Futures can be roughly mapped as follows: Future 1 maps to the Reference scenario; Future 2 represents a state between the Reference and Low scenarios; and Future 3 falls between the Low and Moderate scenarios. The Futures used base year 2018 to develop their load predictions, along with a revised Purdue load forecasting study, so the alignment is imprecise. By capturing the ranges of electrification assumed in the MISO Futures, this report distinguishes between results specific to electrification and results that could be attributed to other assumptions. Different technologies contribute to each end-use load in the three different scenarios (see Section 3.1). For more information on the technology mixes assumed in the MISO Futures, please see the final report.

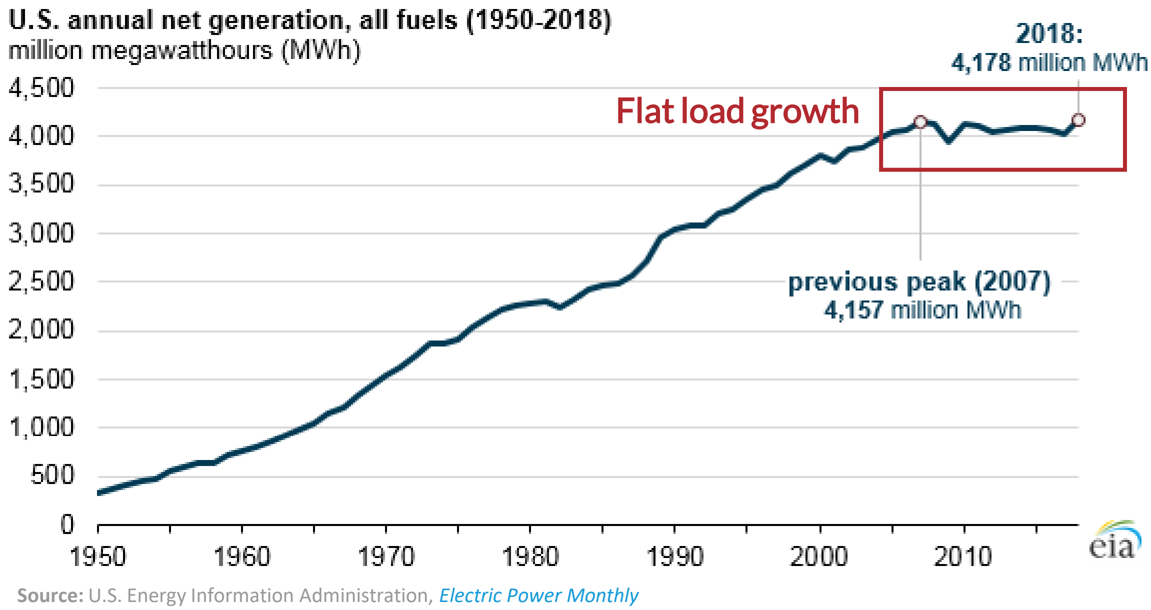


Figure 8: US annual generation for the past 70 years. Source: Today in Energy [99] (red text and box added)

Scenario Name	Increase in Energy from Electrification (compared to 2020)	Total Increase in Energy (compared to 2020)	Energy CAGR	Peak Load CAGR
Future 1	2%	14%	0.63%	0.59%
Future 2	16%	30%	1.23%	1.08%
Future 3	34%	50%	1.91%	1.93 %

Table 3: Load growth due to electrification in MISO Futures

4.2 Load Profile Analysis

The most important change in AEG load shapes for the final study year, 2040, (Figure 9) is that, with Moderate levels of electrification, the system becomes winter-peaking due to additional heating load. The winter peak occurs in the morning due to both heating and EVs charging. Figure 10 shows the regional differences in load growth due to electrification within the MISO footprint. The top part of the figure shows the load of local resource zones (LRZs) 1-3 (West) and LRZs 4-7 (East/Central), while the bottom shows that of LRZs 8-10 (South). LRZs 1-3 roughly correspond to Minnesota, North Dakota, Wisconsin, and Iowa, and the figure shows that the increase in winter load is higher than the increase in summertime load. A similar pattern is seen for LRZs 4-7. On the other hand, for the Southern LRZs, the increase in load is more-or-less even throughout the year. For comparison, MISO's historical summer peak as of 2019 was 127 GW and its historical winter peak was 110 GW; in the Reference scenario, the peak load is assumed to grow to 149 GW in the summer and 111 GW in the winter.

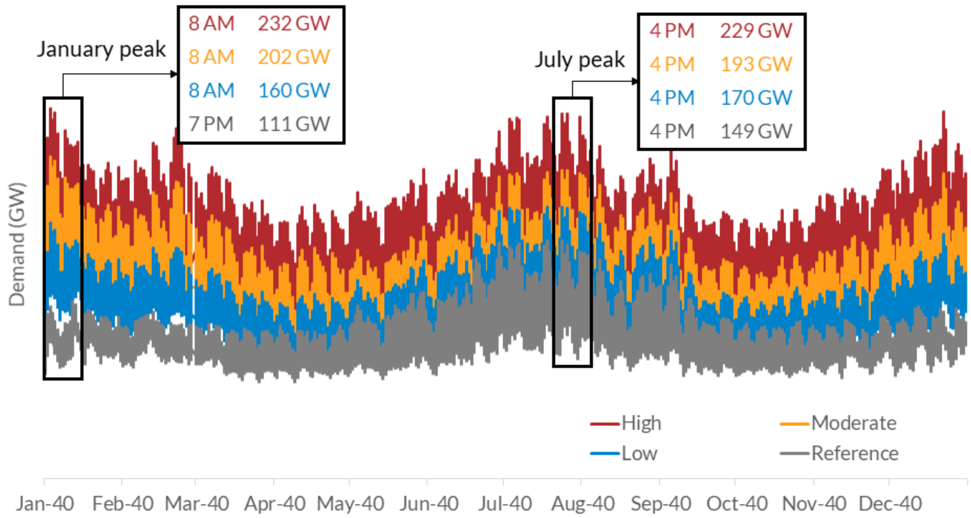


Figure 9: Change in composite load shape across electrification scenarios by 2040

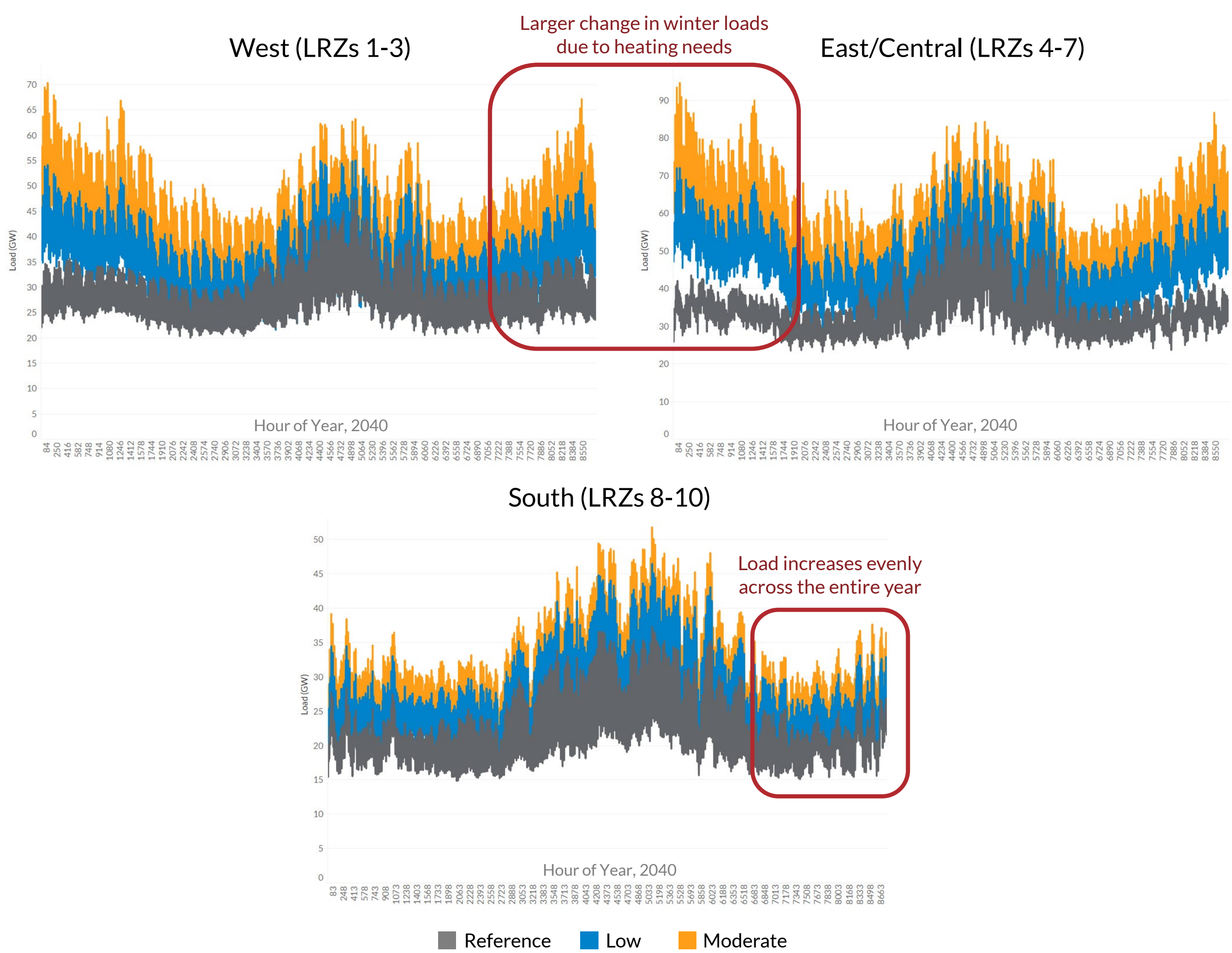


Figure 10: Regional differences in load growth due to electrification for the Reference, Low, and Moderate scenarios in year 2040. Note that y-axes have different scales.

To capture the load variability, box and whisker graphs for the year 2040 are shown in Figure 11, with the values in GW. In whisker charts, the "X" denotes the mean and the horizontal line in the box shows the median. The box shows the interquartile range (IQR), i.e. the middle 50% of values. Figure 11 clearly shows that increasing electrification increases both the annual minimum and annual maximum load. However, this figure also demonstrates that the load itself is more variable, with the middle 50% of load values spanning 38 GW in the High scenario, more than double the 17 GW span of the Reference scenario. Furthermore, the total range of load values increases from 60 GW in the Reference scenario, to 86 GW in the Low scenario, to 112 GW in the Moderate scenario, and more than 136 GW in the High scenario.

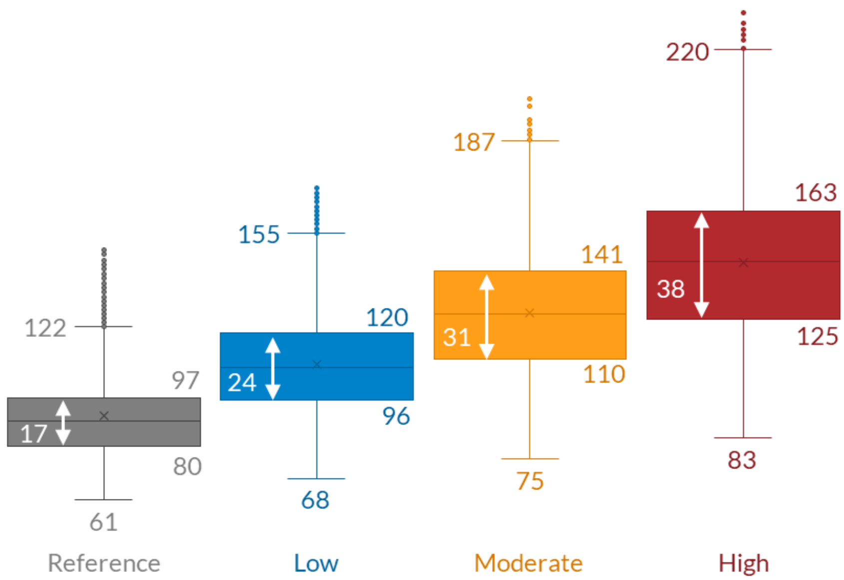


Figure 11: Whisker plot of load variability for all four scenarios; values are in GW. Each box and whisker shows the range of hourly loads in 2040 for each scenario.

Figure 12 compares the normalized load for the High scenario to the Reference case. The orange horizontal line indicates demand at 75% of annual peak load. In the Reference scenario, the demand stays well below the 75% level for most of the shoulder months when longer-term maintenance outages are normally scheduled (March, April, May, October, November). In the High scenario, the size of this seasonal window, when load levels are mostly below 75% of the annual peak, decreases. This suggests that individual generators could begin to cluster their outages into a shorter and shorter seasonal window, based on their in-house planning for cost-effective outage scheduling. This trend may be challenging for the MISO system and should be monitored as electrification levels increase.

The monthly diurnal load shapes also change with electrification. Figure 13 shows the monthly average daily load shapes for four representative months. In the High electrification scenario, large increases in load are seen daily between 6 a.m. and 8 a.m. These morning ramps are much steeper than those seen for the Reference scenario. The load shapes for the Reference and Low scenarios are smooth, while the Moderate and High scenario load shapes are jagged. The main driver of the jagged shape is PEVs, which are modeled with uncontrolled charging. Figure 14 shows the constituent parts of the daily load shape from different technologies. The figure shows that EVs tend to contribute a choppier shape in the Moderate scenario, whereas the contributions from building and industry are seen to vary smoothly throughout the day. Furthermore, the EV contribution spreads the average July load peak in the Moderate scenario over more hours.

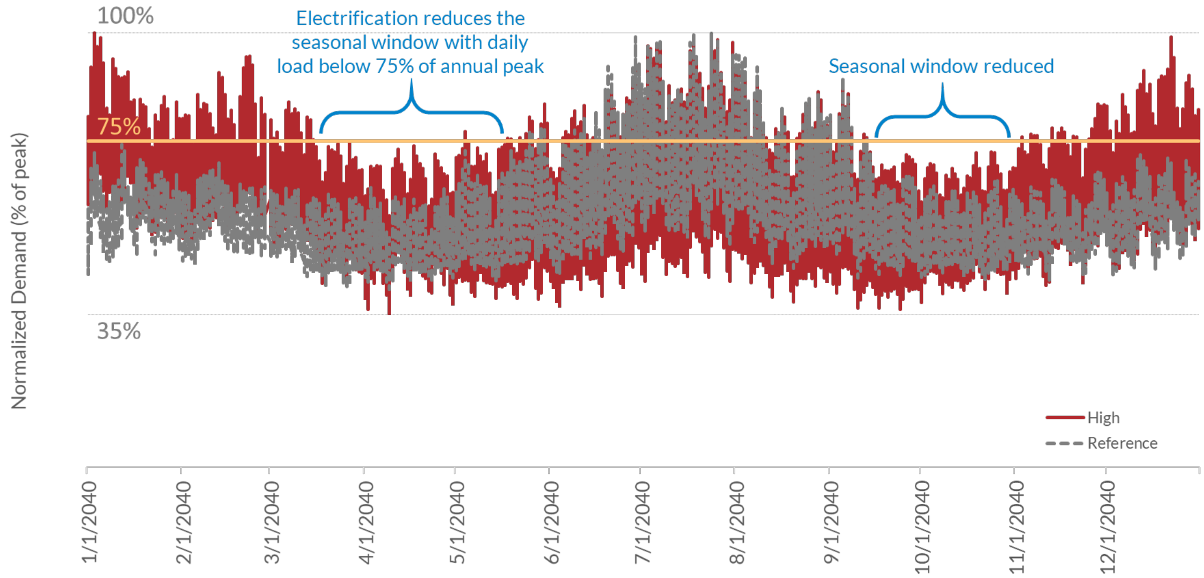


Figure 12: Annual load normalized based on annual peak for the Reference and High scenarios. The orange line corresponds to load values that are 75% of the annual peak.

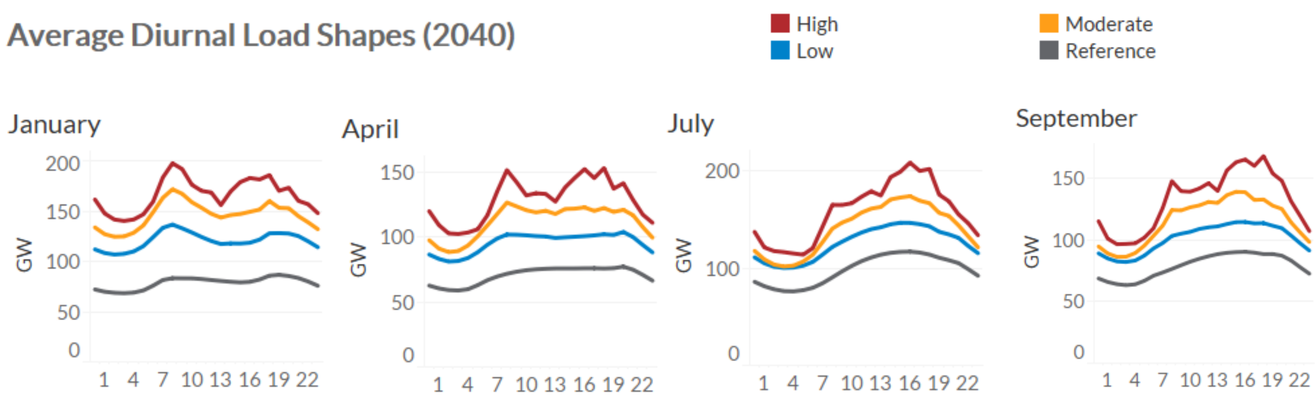


Figure 13: Average diurnal load shape for different levels of electrification during four indicative months; x-axis is load in GW, y-axis is hour of the day.

The monthly diurnal net load average load shapes are shown in Figure 15. In this example, "net load" refers to the daily load minus the renewable energy available at each hour based on a capacity expansion requiring 20% of annual energy to come from renewables (see Section 4.3: Resource Forecasting). This acts to exaggerate the patterns that were seen in the average diurnal load shape. The two daily net load peaks are accentuated in the winter months, and the two peaks appear in the shoulder months as well. Even the summer months (e.g. July) show a small additional morning peak not seen in other scenarios.

With clear patterns of increasing variation in load levels (Figure 11, Figure 13, and Figure 15), it is reasonable to consider what that means for ramping. Ramping is an important consideration for future system performance because existing generation sources have limited ramping capabilities — some generators can change their output power rapidly (quick ramping), while others change output slowly. Electrification increases the ramping required of system resources. Figure 16 shows the range of load ramping requirements over several different time periods. The Reference case shows one-hour ramps of between 2 and 10 GW. In the High scenario, those one-hour ramps reach

30 GW at the extreme, three times the extreme seen in the Reference scenario. In the Moderate scenario, the one-hour ramps are 15 GW in either direction. This pattern of increasing ramps continues across the different ramp durations examined. The maximum four-hour ramp in the High scenario is almost 80 GW; this represents two-thirds of MISO's historical summer peak (127 GW). And it's more than double the 30 GW four-hour ramp seen in the Reference scenario.

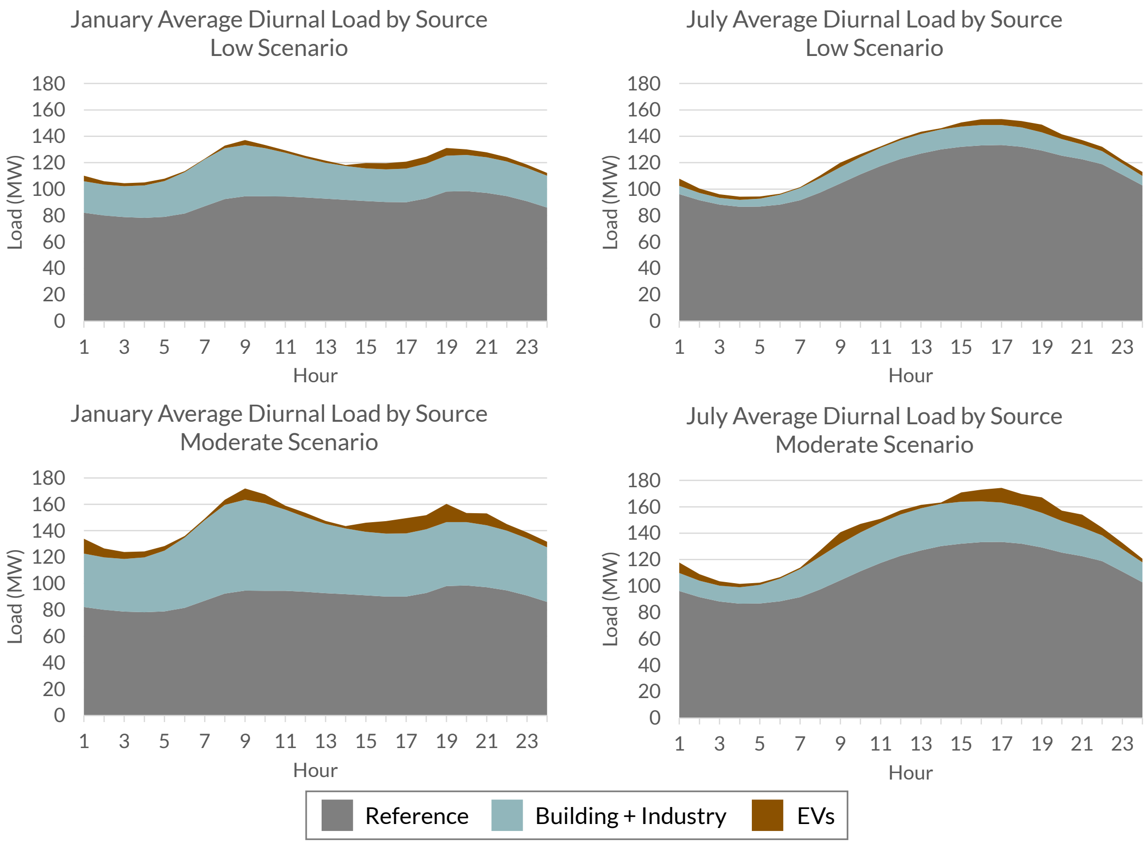


Figure 14: Average contributions to diurnal load in January and July (left and right) from different technology groups for the Low and Moderate scenarios (top and bottom).

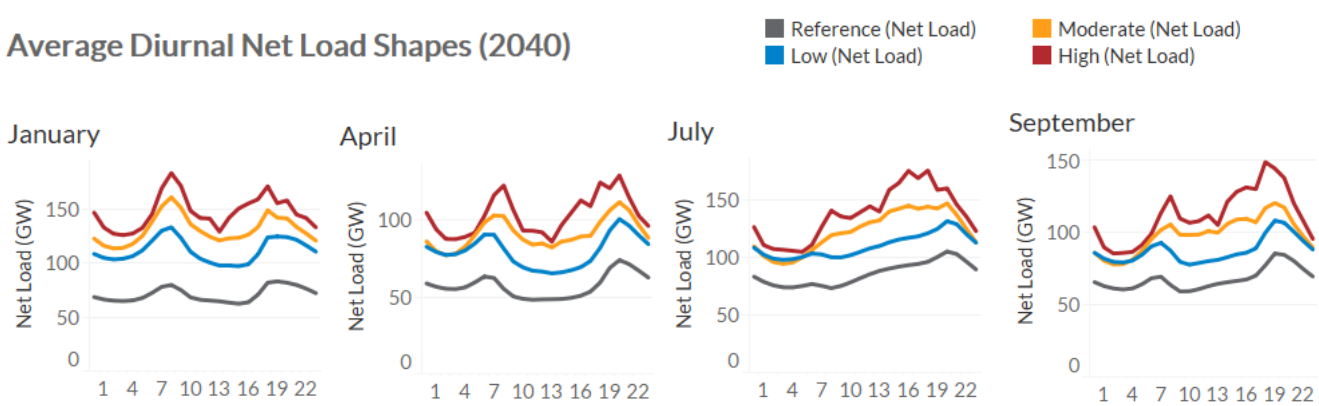


Figure 15: Average diurnal net load shape for different levels of electrification; x-axis is load in GW, y-axis is hour of the day. Net load subtracts the output of any renewable generation from the gross load.

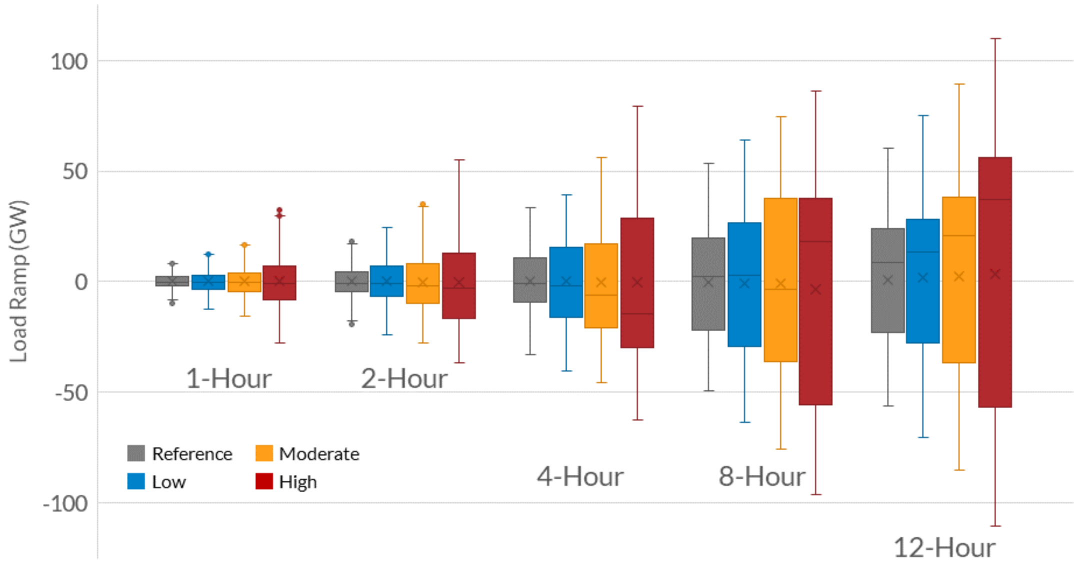


Figure 16: Load ramping requirements over several time periods for all electrification scenarios

The ramps are calculated as the step change in load; for example, a 4-hour ramp is calculated as Load(t+4) – Load(t), where t is the hour being analyzed. This definition means that positive ramps represent load increasing over time and negative ramps represent decreasing load. This analysis focuses on non-overlapping ramps to highlight the frequency of extreme ramps. Including overlapping ramps would overestimate the frequency of extreme ramp periods.

4.3 Resource Forecasting

The resource forecasting analysis, which does not include transmission and does not perform an hour-by-hour analysis, indicates that between 42 GW and 156 GW of extra generation will be required to meet the load growth due to electrification, depending on the amount of electrification and annual renewable energy requirements. The resource expansion was split between natural gas, wind, and solar generation; storage was not selected based on the cost assumptions.

4.3.1 Resource Expansion Requiring 20% Annual Energy from Renewables

More than half of the generation needed in each scenario comes from natural gas units, even when requiring 20% of annual energy be produced by renewable resources. As the amount of electrification increases, so does the proportion of new wind generation in the resource expansion. Figure 17 shows the expansion required for each scenario and only includes the new capacity (in GW) required to meet the electrification peak. The mix between natural gas units and wind and solar units is driven by the cost assumptions, see Appendix 8.3 for additional details.

The increasing amount of wind generation appears to be directly linked to two characteristics of electrification, in addition to the cost assumptions:

1) In the Moderate scenario, the system regularly peaks in winter by the end of the study period. Wind tends to be a more economic choice for winter-peaking systems, while solar contributes more to meeting the peak demand in the summertime. The profiles for the wind and solar units used in the expansion are shown in Figure 18, demonstrating this pattern.
2) The system energy increases at a greater rate than the peak demand as the electrification amount increases. When more energy is needed instead of capacity, wind tends to be chosen instead of solar. This point is not

related to the presence of winter peaks, but rather due to the overall increase in energy required. Averaging the profiles for wind and solar across the entire year provides a proxy for the energy contribution possible by each type of unit; it is seen that wind has an average profile (similar to capacity factor) of 43.6% of the installed capacity and solar has an average profile of 20.6%. Wind can contribute more to the needed energy supply per capacity installed, since it can produce energy at any hour of the year so long as there is wind, whereas solar units can only produce energy for a maximum of 12 hours a day, due to the earth's rotation.

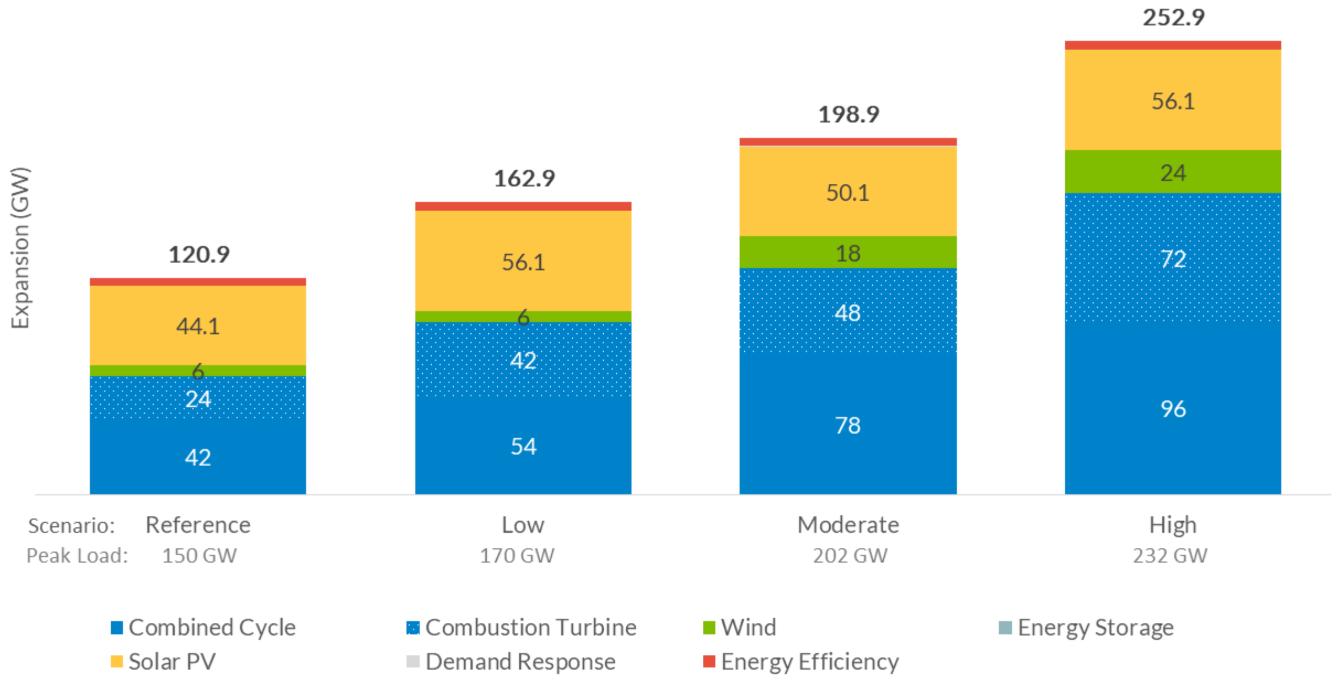


Figure 17: Resource forecast (GW) for all electrification milestones, requiring 20% of energy to be supplied by wind and solar. The total expansion for each scenario is marked bold.

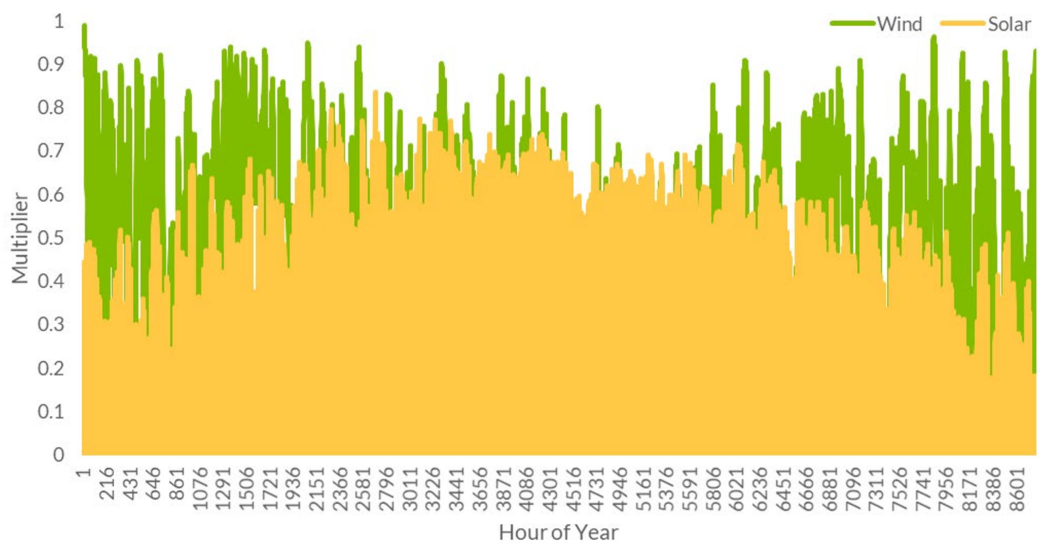


Figure 18: Wind and solar profiles used in resource expansion

To demonstrate the impact of the changing load shape on the resource expansion, a sensitivity run was performed where the annual load shape was held constant over all 20 years of study. The energy and demand increased while the system remained summer peaking (Figure 19). This sensitivity analysis confirmed that the main driver for increasing amounts of wind energy is the shift to a winter-peaking system, illustrated by the difference in the expansions for the Moderate and High scenarios. The shape changes appear to impact the selection of renewable resources, while the total capacity of natural gas units remains unchanged. When there is no shape change, the peak load increases more, leading to the selection of solar. With the shape change, the energy increases more than the peak, leading to more wind being selected.

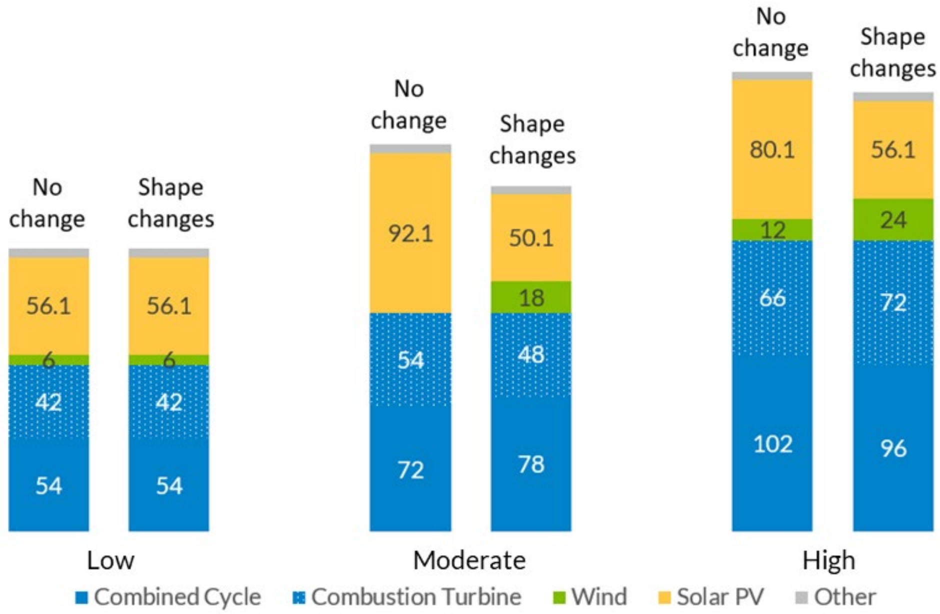


Figure 19: Expansion results (GW) for load shape sensitivity. At higher levels of electrification, the shift to a winter peaking load results in relatively more wind and less solar selected. Runs assumed that 20% of annual energy must be met by wind or solar.

Although the capacity of gas-fired units added to the system exceeds the capacity of the renewables added to the system, the overall emissions of the generation system decline throughout the study period in the Reference and Low scenarios, as older carbon-intensive units retire (Figure 20, left). With even more gas units added to the system to meet higher levels of electrification, the emissions from electricity production remain more-or-less constant over the study period. This stasis does not mean that overall economy-wide emissions do not decrease. In fact, one of the large drivers of electrification is the ability to reduce emissions over the entire economy. Despite the growing load and the fact that the electric system is responsible for winter heating, the intensity of carbon dioxide (CO_2) emissions for the electric system decreases over the 20 years of the study (Figure 20, right).

The total energy provided by different resources with increased electrification shows some variation. Figure 21 shows the estimated energy production by fuel source for the first year of the study, compared to the final study year for all electrification scenarios. The total annual energy is in bold at the top of the bars. The assumed coal retirements are the same for all scenarios, so the energy production from coal is the same in all scenarios, making up a smaller proportion of energy production, when transmission is ignored. With the expansion of gas combined cycle (CC) and combustion turbine (CT) units, the amount of energy produced by natural gas units increases with increased electrification, nearly doubling in the High scenario compared to the Reference scenario. All scenarios meet or exceed 20% of annual energy from renewables, except the Low scenario, which reaches 19%.

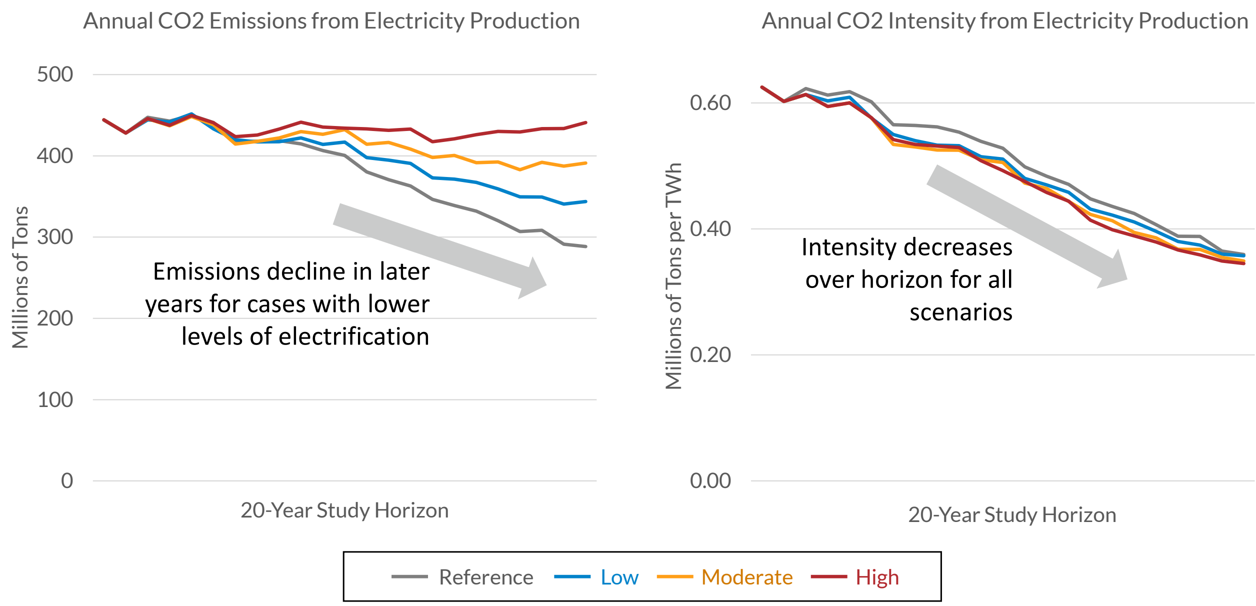


Figure 20: Electric system emissions for the resource forecasts at different levels of electrification, assuming 20% of annual energy comes from renewables. On the left is CO_2 emissions from electricity production for each year of the 20-year study horizon. On the right is carbon intensity of electricity production measured on an annual basis in millions of tons of CO_2 per TWh of electricity generated.

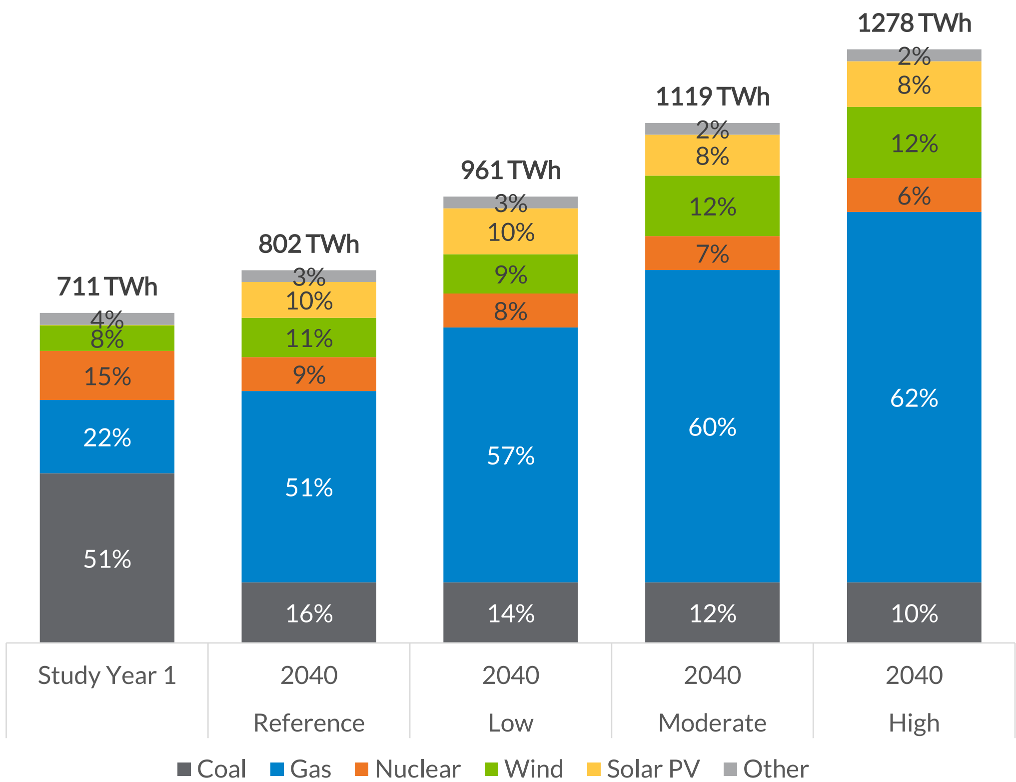


Figure 21: Estimated energy for first and last study years for the electrification scenarios. The amount of retired coal is consistent across all scenarios. All scenarios targeted 20% of annual energy from renewables.

4.3.2 Resource Expansion Requiring 40% Annual Energy from Renewables

When 40% of the annual system energy is required to come from renewables by 2040, the selected capacity expansion ranges from 145 GW in the Reference scenario to 300 GW in the High scenario (Figure 22). Requiring more energy to come from renewables results in a larger amount of wind being added to the system than in the case where only 20% of the annual energy needed to come from renewables. A direct comparison between the two expansions is shown in Figure 23, where five to 10 times the wind is added with the higher renewable energy requirement. This recalls the fact that wind in a favorable resource zone can provide more energy than solar for the same installation capacity (approximately 0.44 to solar's 0.21).

With more energy required to come from renewable resources, the carbon emissions decrease sharply for all electrification scenarios after study year 5 (Figure 24, left). For the rest of the study horizon, emissions from electricity production decrease for the cases with lower levels of electrification and hold steady for the High scenario. The carbon intensity of electricity production decreases for all scenarios across the study horizon (Figure 24, right).

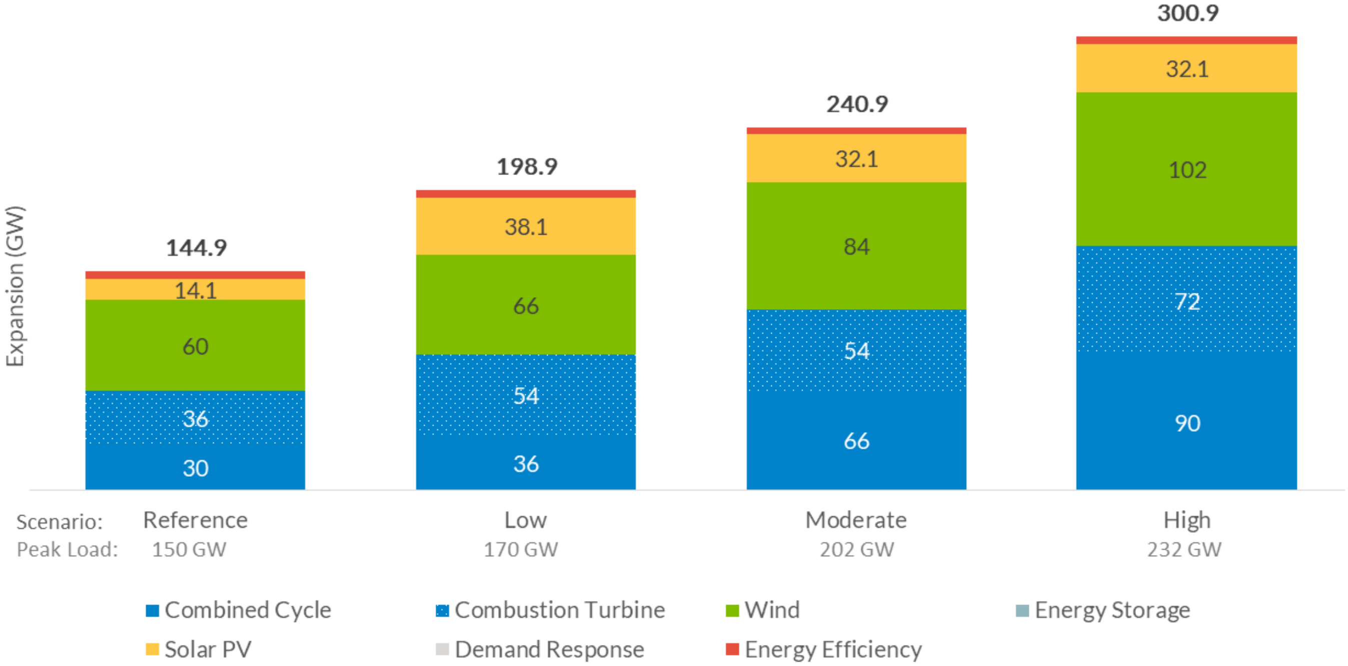


Figure 22: Capacity expansion for all electrification scenarios, if 40% of annual energy needs to come from renewables by the last year of the study horizon.

Requiring a higher proportion of energy from renewables results in a complementary decrease in the amount of energy from conventional fuels (coal, gas, nuclear) over the entire study horizon, even as the load grows. Figure 25 shows the change in annual energy production from the first year of the study to 2040 for each electrification scenario. The dark green portion of the bars represents "dumped" energy. The percentages are calculated based on the total annual energy, excluding the dumped amount, indicated by the bold numbers pointing to the point of annual energy. When simulating high renewable cases, there may be hours where the output of non-dispatchable resources, as wind and solar are classified in the resource expansion program, exceeds the system load. To ensure that the simulation can continue, there are a few different choices that can be made. For the purposes of this study, the option to dump excess energy was enabled.

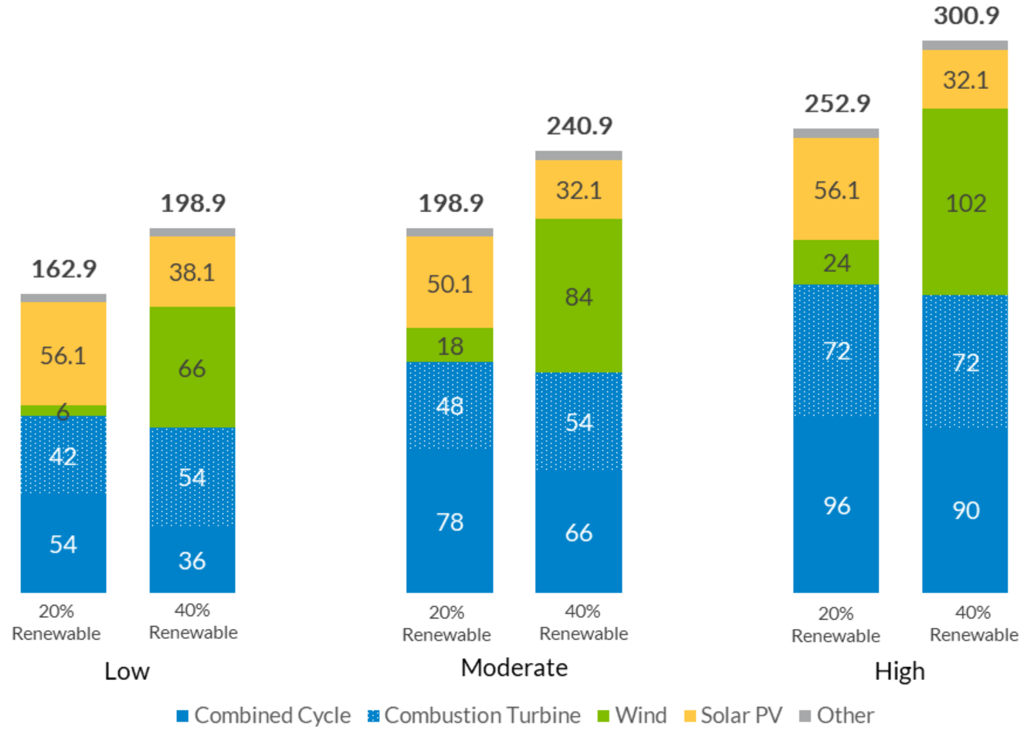


Figure 23: Comparison of resource expansions based on required energy from renewables for all electrification scenarios. Requiring 40% of annual energy be supplied by wind or solar resources results in a much larger expansion of wind.

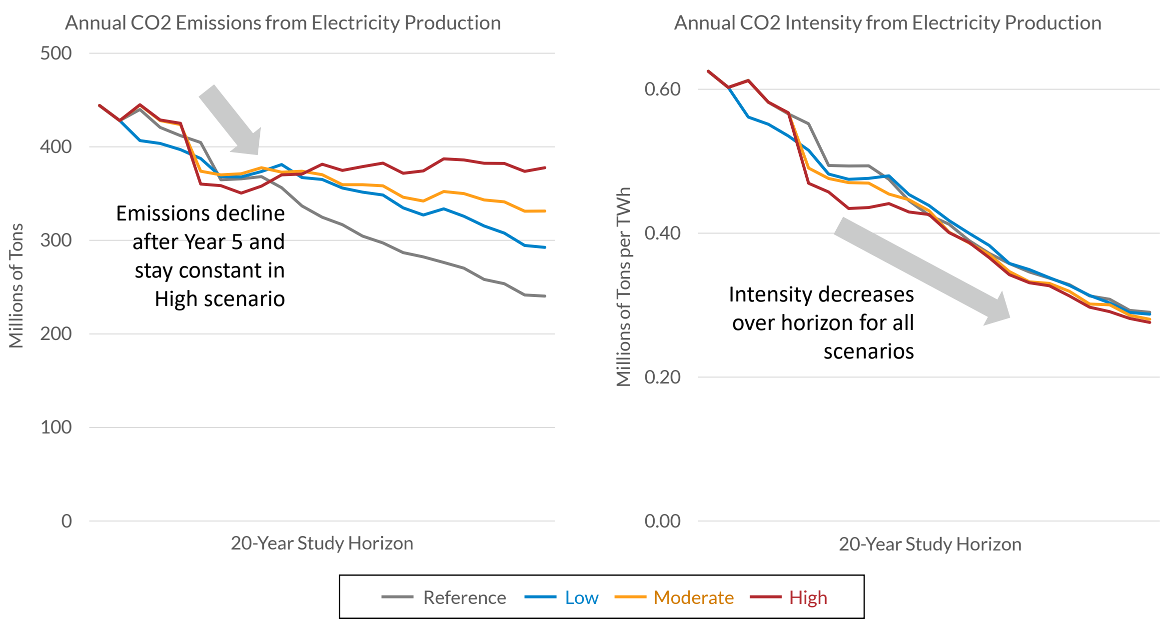


Figure 24: Electric system emissions for all electrification scenarios, assuming that 40% of annual energy comes from renewables by the last year of the study horizon. On the left is CO_2 emissions from electricity production for each year of the 20-year study horizon. On the right is carbon intensity of electricity production measured on an annual basis in millions of tons of CO_2 per TWh of electricity generated.

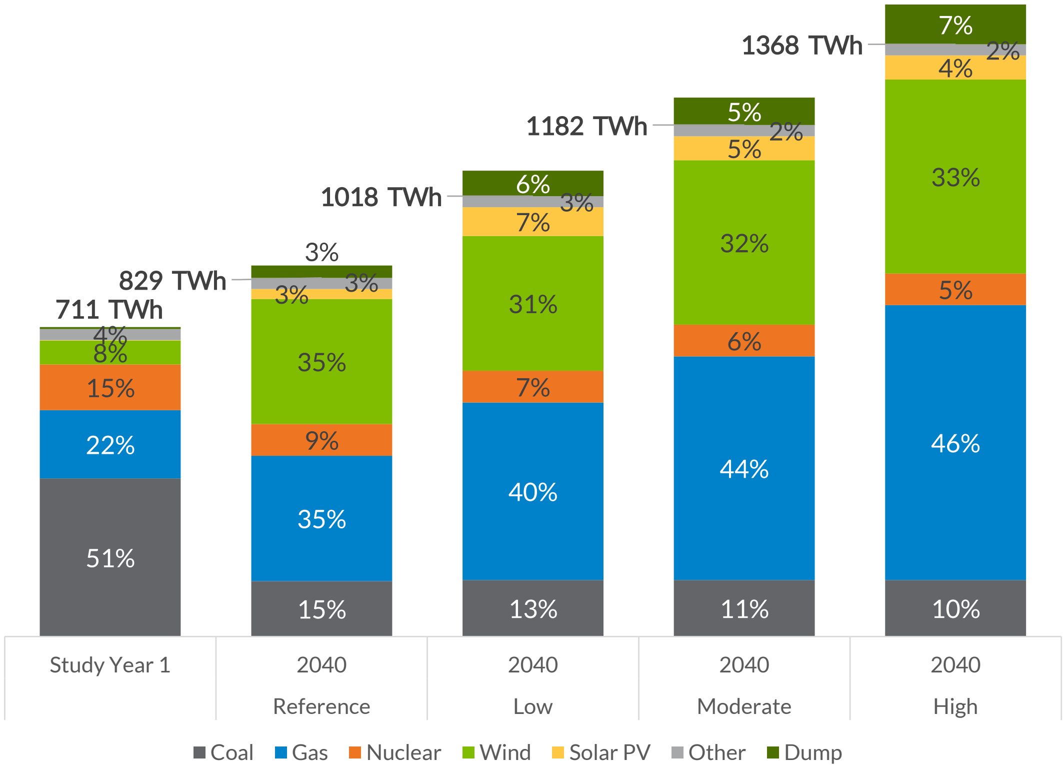


Figure 25: Estimated energy production in first and last study years for the electrification scenarios. The amount of retired coal is consistent across all scenarios. All scenarios targeted 40% of annual energy from renewables.

Dumping energy can be roughly considered as a form of curtailment. However, in the MISO operational realm, solar and wind have been enabled to be dispatchable. Thus, in practice, this dump energy could be reflected by time periods where wind and solar resources would be dispatched below their maximum possible output. Or, if adequate transmission is available, the excess energy could be exported to neighboring markets. Looking toward current and future technologies not considered in this study, the excess energy could also be used to charge battery storage or to produce hydrogen as a form of seasonal energy storage [100].

4.4 Resource Adequacy

Resource adequacy simulations, which only evaluate generation resources, help determine the diurnal and seasonal patterns of system risk. This analysis, which assumed that 20% of annual energy would come from renewables, shows that the shift to a winter peak creates a new risk period during January mornings. Heat maps of the average and maximum values of expected unserved energy (EUE) values are shown in Figure 26 for the Reference, Low, and Moderate scenarios. Risk is quantified by the patterns of non-zero EUE values. As electrification increases, the times of system risk expand from late evening in the summertime (Reference case) to include wintertime mornings (Moderate case).

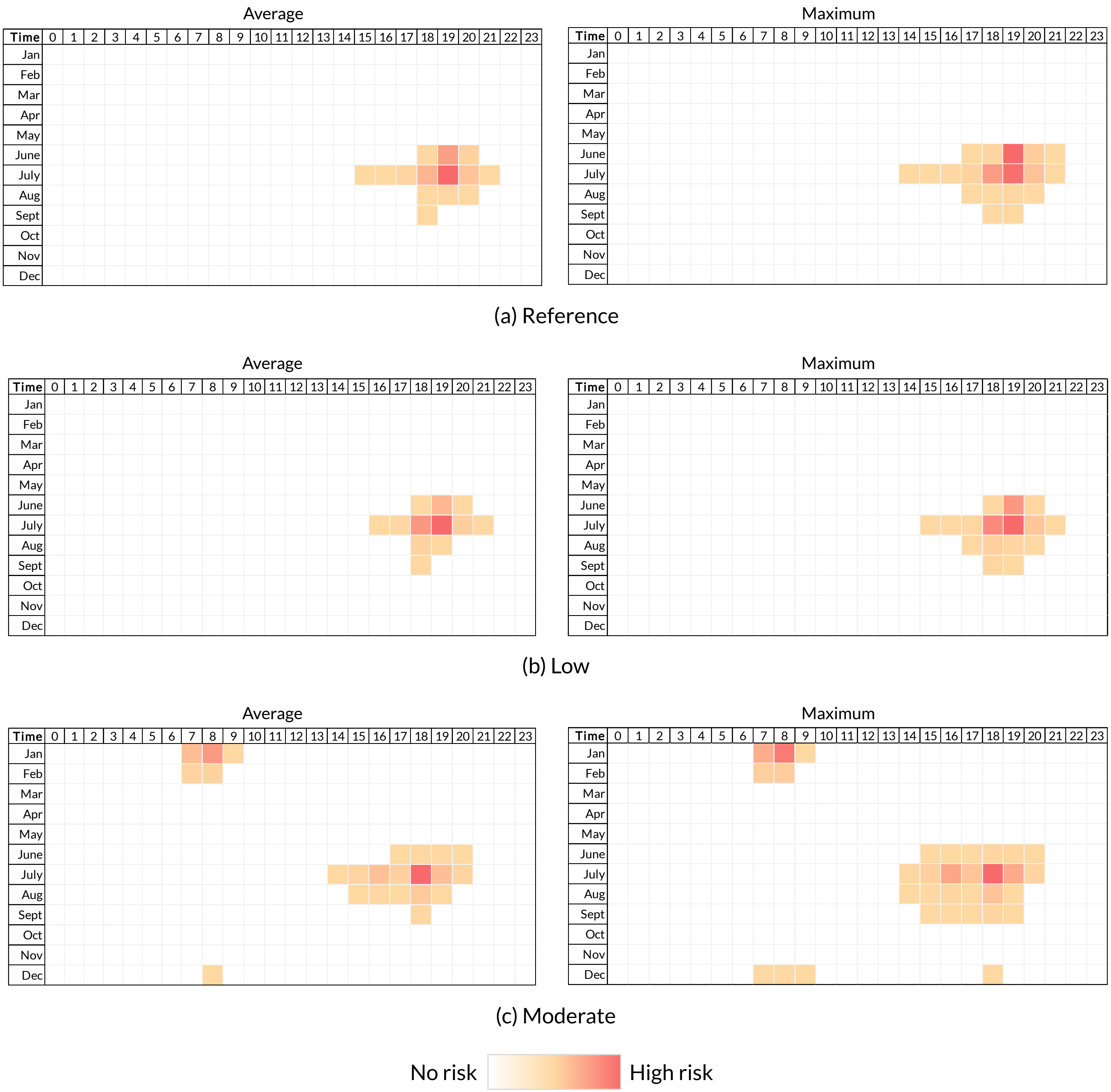


Figure 26: EUE heat maps for (a) Reference, (b) Low, and (c) Moderate electrification scenarios, based on weather year 2012. The left column shows the average EUE values, while the right column shows the maximum EUE values. Darker red indicates greater risk.

- The shift to wintertime mornings could be partially driven by increased reliance on solar generation (a pattern that was identified during the sensitivity analysis in RIIA [101]). However, all three scenarios achieve 20% energy from renewables, with the difference in solar capacity between the scenarios is a maximum of 12 GW, according to the expansion in Figure 17. The Low scenario is actually the expansion with the highest amount of solar (56 GW), while less solar was selected for the Moderate scenario (50 GW). The reasons for this were discussed in Section 4.3.

- The spread of summertime risk over more afternoon hours seems to be a direct result of the uncontrolled EV charging that was assumed (Figure 14). This is illustrated by the average diurnal net load shapes in Figure 15, where the July load for the Moderate scenario plateaus over the late afternoon, such that the net load is no longer focused at the end of the day.

EUE calculations are usually performed for a variety of years to capture annual variability in weather and uncertainty in consumption patterns. The load shapes supplied by AEG were based on weather year 2012. In order to estimate how different weather years might impact the EUE patterns described above, synthetic data was created for additional years. It was determined that the electrification hourly loads could be added to the loads of other years, adjusting for day of the week, without introducing unreasonable errors, based on an examination of the correlation between different electrification loads and the LRZ temperatures (see Section 8.4 in the Appendix). Nevertheless, the following results based on synthetic data should be used with caution. The EUE heat maps for the combined years of analysis (2007-2012 and 2014-2018 [3]) are shown in Figure 27, with the left column showing the average values and the right column the maximum values. These suggest that risk may begin to shift to winter mornings at lower levels of electrification than the load shape based on 2012 alone indicates. With periods of high net load directly related to EUE values, it is not surprising that winter morning risk appears in the Low scenario when other weather years are considered — the winter and summer peaks in the Low scenario based on 2012 are only 10 GW apart (Figure 9).

4.5 Analysis of Generation and Transmission Performance

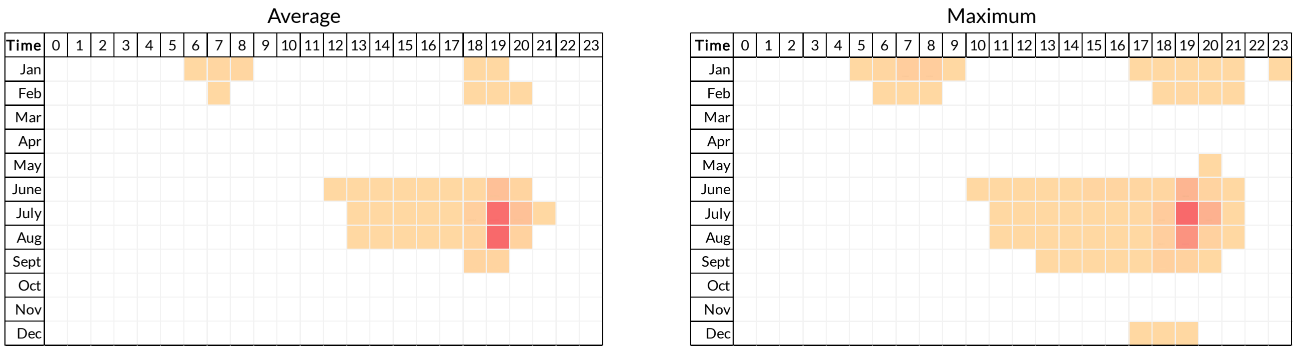
To examine generation and transmission operation in an electrified future, a chronological evaluation of the hourly system performance, while enforcing a variety of system constraints, was performed. These simulations were performed for the Reference, Low, and Moderate scenarios with 20% of annual energy from renewables, assuming a DC model of the transmission system where line flow limits are enforced. It is important to evaluate the performance of the electrified scenarios when transmission line flow constraints are enabled, as this provides a more complete picture of the deliverability of the energy throughout the MISO footprint. This analysis shows that electrification is associated with increases in average locational marginal prices (LMPs), changing system flow patterns, and conventional units serving not only more base load but also the daily load ramps.

This study did not explore the use of transmission to enable higher levels of electrification and the additional renewables that would be required to supply 20% of the annual energy from renewables. MISO's RIIA found that the complexity of renewable integration increased sharply at 30% of annual energy from renewables [101]; this study chose to examine the generation and transmission performance for a level below RIIA's inflection point. On an annual basis, the energy from renewables is within 2% of the 20% target — the Reference scenario has 22%, the Low scenario has 19.3%, and the Moderate scenario has 19.6%.

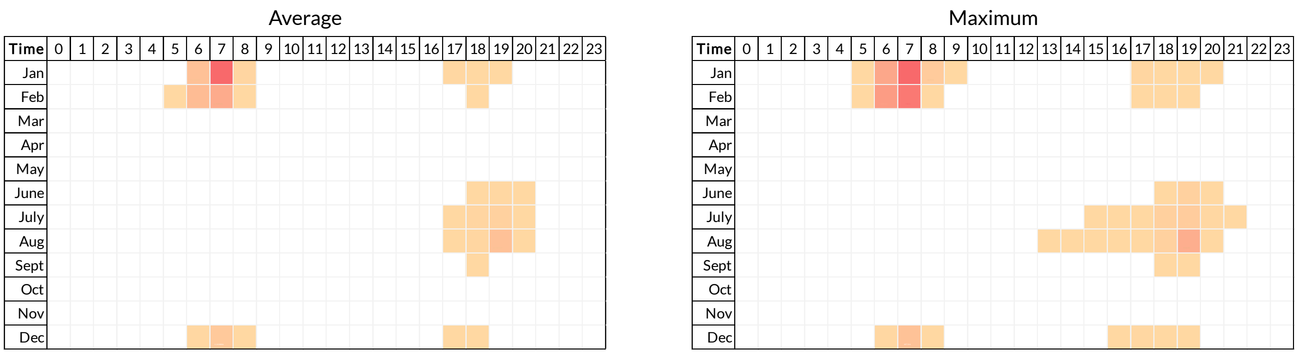
The monthly averages of LMPs, weighted by generator, are shown in Figure 28. Electrification increases the system LMPs throughout the whole year, but the impact is particularly pronounced in the winter months. In the Moderate electrification scenario, the July average LMP is substantially higher than those of the Reference and Low scenarios. This underscores a takeaway that is sometimes overshadowed by the focus on the shift to the winter peak: summer peak increase as well and, in the Moderate scenario, the summertime and wintertime peaks are within 10 GW of one

[3] Year 2013 was not evaluated because solar data was unavailable

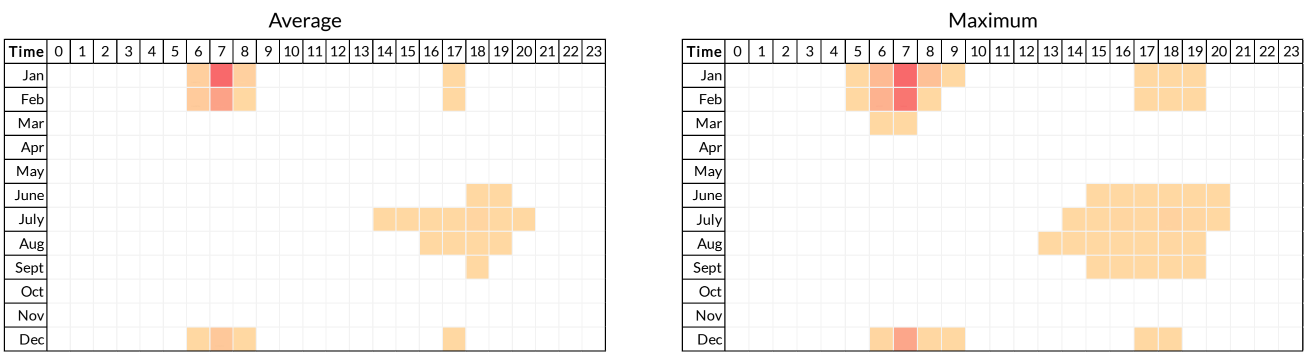
another (Figure 9). These LMP values are not intended to be a prediction of future values, but rather indicative of what may be expected with higher electrification.



(a) Reference



(b) Low



(c) Moderate

Figure 27: EUE heat maps for (a) Reference, (b) Low, and (c) Moderate electrification scenarios, calculated over 11 years of base data. The left column shows the average EUE values, while the right column shows the maximum EUE values. Darker red indicates greater risk.

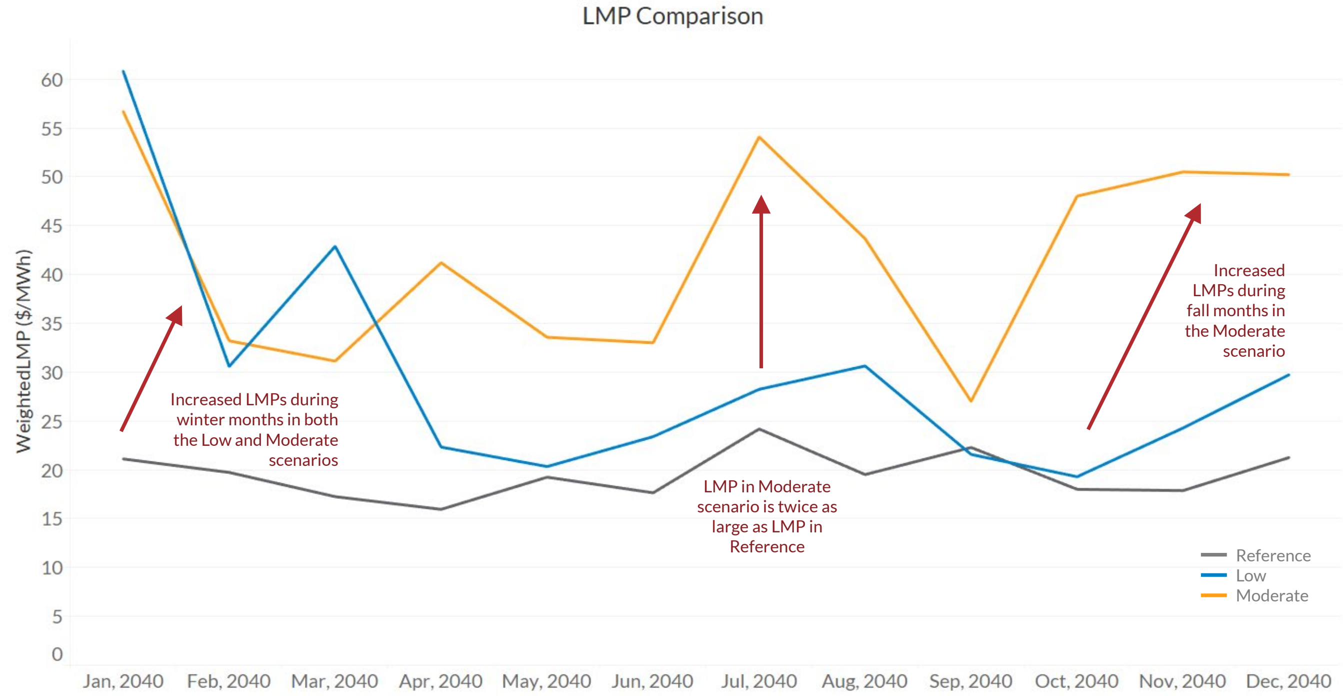


Figure 28: Monthly average weighted LMP values for the system at different levels of electrification

The calculated cost to load, which is calculated to be the cost paid by loads for energy purchases within the production cost model, is shown in Figure 29. The total cost of serving load increases as the load increases.

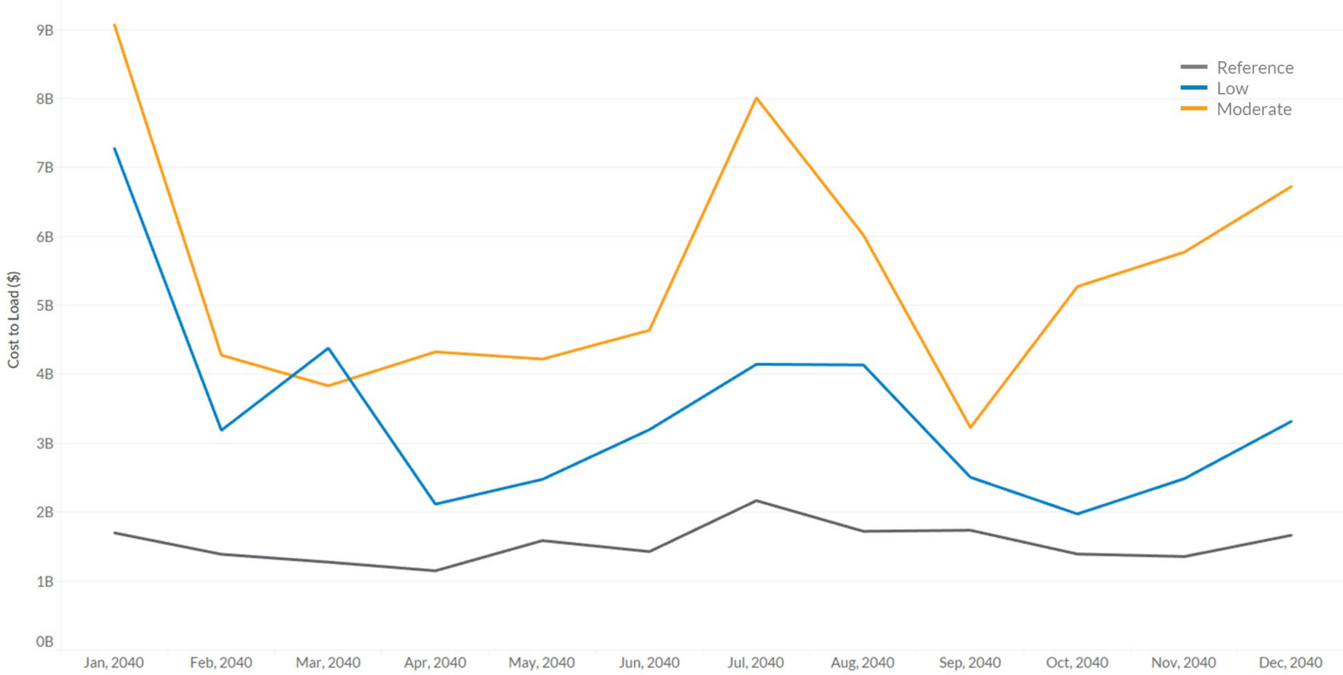


Figure 29: Monthly cost to load for the three electrification scenarios

The monthly energy production for each scenario is shown in Figure 30, along with the average LMPs. Increased coal generation with increased electrification is seen not just in winter months with higher load, but also in April and May, which are months with plentiful wind and solar resources. Figure 31 shows that more coal units are started in the spring and fall with the Low and Moderate scenarios than in the Reference scenario, with the effect much smaller in the winter and summer. Figure 32 shows the annual capacity factor for the coal units. Capacity factor is a ratio of the annual generation to the theoretical annual maximum generation (installed capacity multiplied by the number of hours in a year). Retirements were the same for all three scenarios, which means the coal fleet is the same for all three scenarios because no new coal generation was added to the system. The capacity factors show remaining coal units see higher usage with increased electrification.

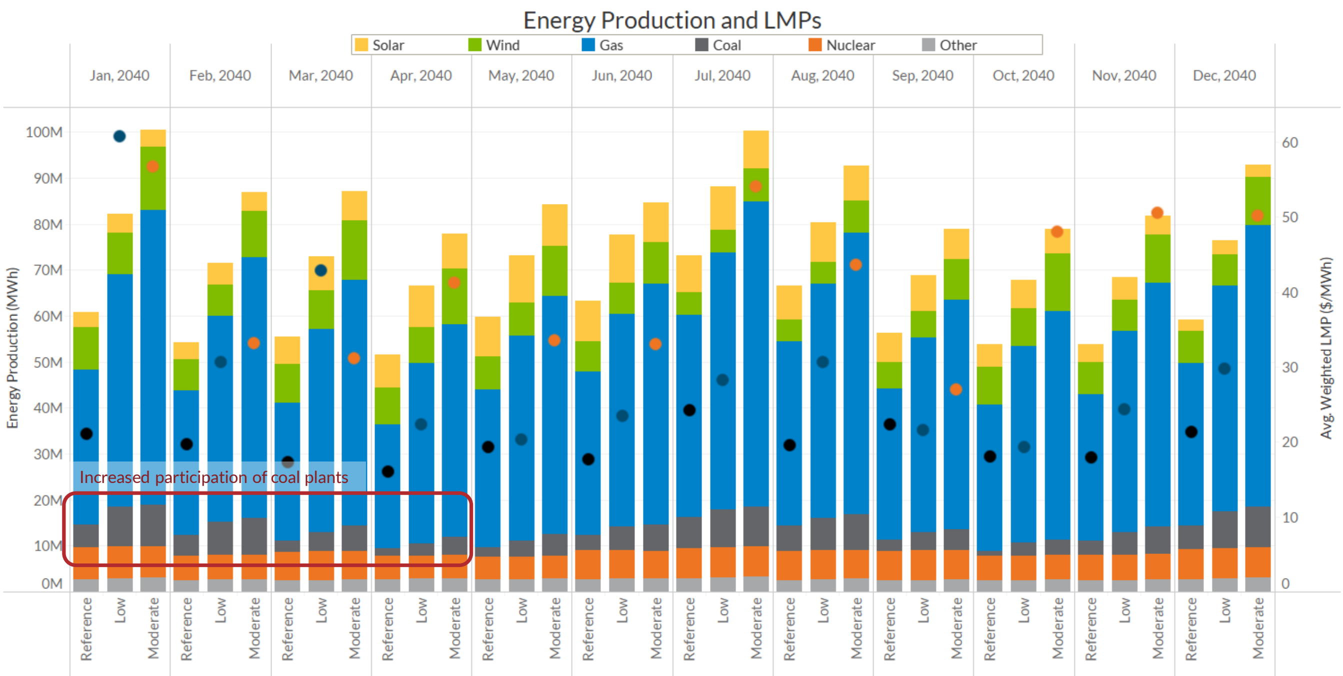


Figure 30: Monthly energy production and weighted LMPs

If the power grid does not itself decarbonize, switching end uses from fossil fuels to electricity may lead to increased emissions from the bulk power system. It is possible that these increased emissions may be more than offset by the reduced emissions in other sectors. However, there may be other reasons end uses electrify even in the absence of a clear decarbonization policy in the electric power sector, such as air quality concerns, convenience, or cheaper total cost of ownership.

Another way to compare the performance of the different scenarios is to look at the monthly average diurnal values (Figure 33). Unlike the previous figures, which show totals, this representation provides information about a "typical" day for any month. When compared to the Reference scenario, the Moderate scenario has higher LMPs in all months. Additionally, most months are shown to have an energy shortfall (white space between black load line and generation stack), noticeable in the winter months.

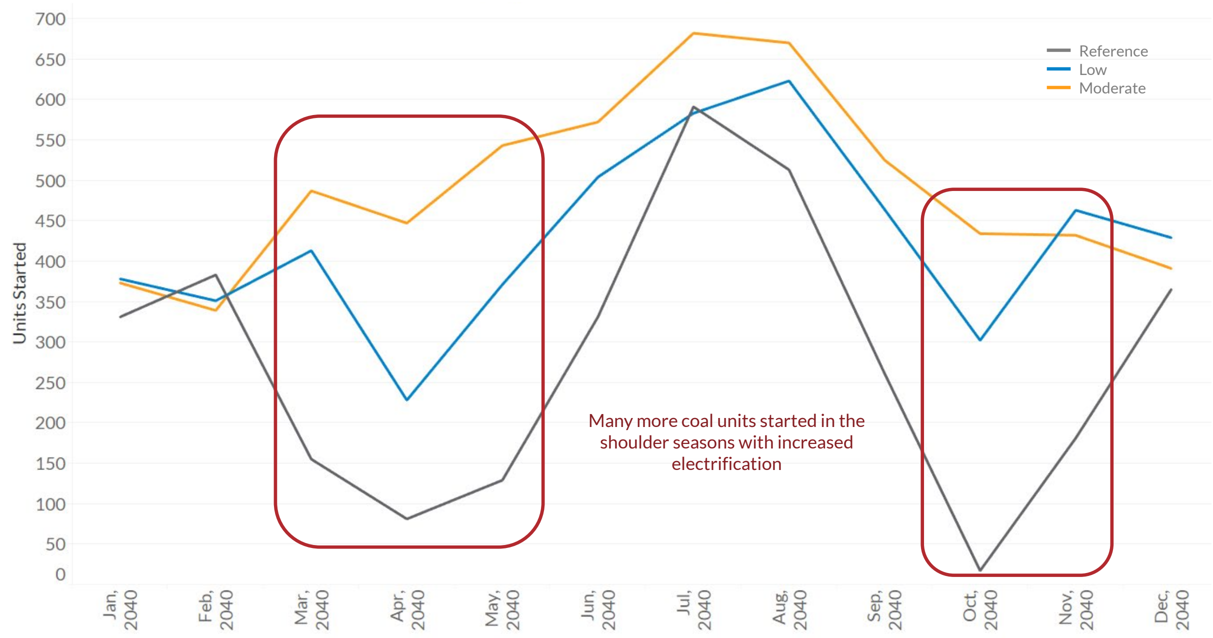


Figure 31: Number of coal units started during each month or the different electrification scenarios

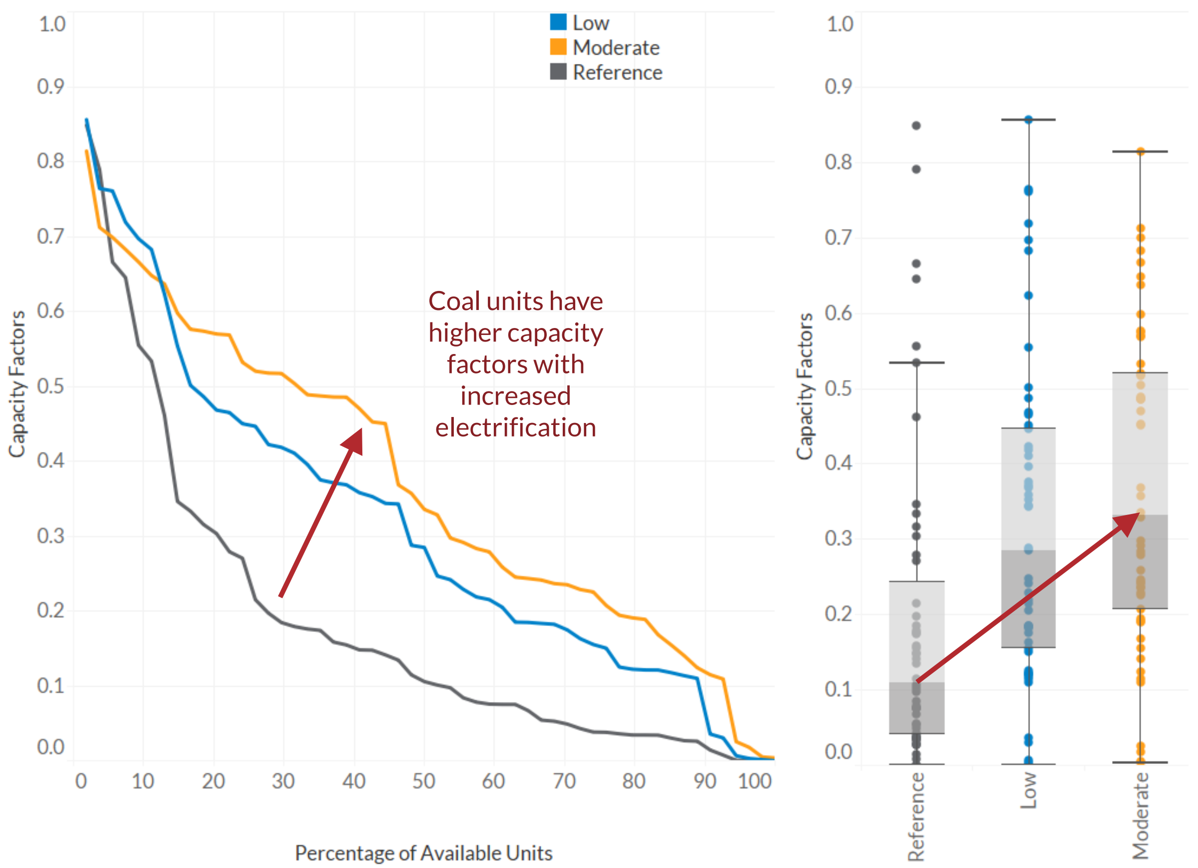


Figure 32: Capacity factors of coal units for the different electrification scenarios. In box-and-whisker plots, the box indicates the middle 50% of the data (first and third quartiles).

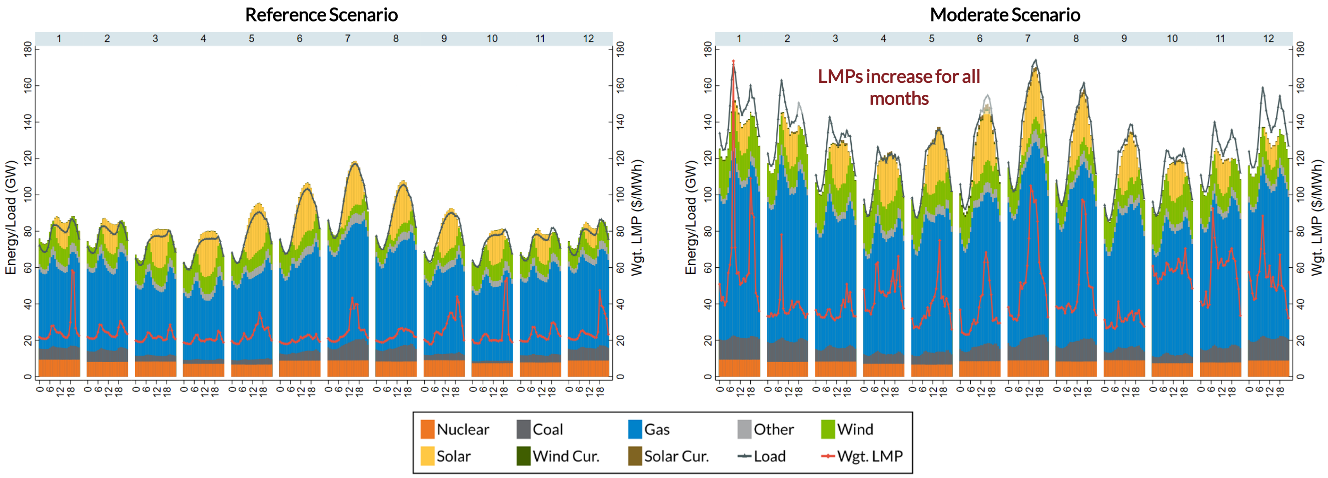


Figure 33: Monthly average diurnal load, fuel mix, and LMPs for the Reference scenario (left) and the Moderate scenario (right)

Ramping needs are increasingly covered by conventional units (Figure 34). This graph shows the annual generation versus the annual ramp for each type of conventional unit and the overall amount of ramping provided by all types of units increased. For most units, the trend shows that increased electrification leads to increased ramp duty, especially for coal and steam turbine (ST) gas units. This demonstrates the continued value that conventional units may provide in an electrified system. Because even serving additional EV load with gas units will decrease the total economy CO_2 emissions [9], considering the changing operation of conventional units is important if responsive, flexible, or controllable load is not available. It is possible that responsive, flexible, or controllable load could be used to mitigate ramping, as was demonstrated in [17] for EVs, though evaluating this possibility is reserved for future work.

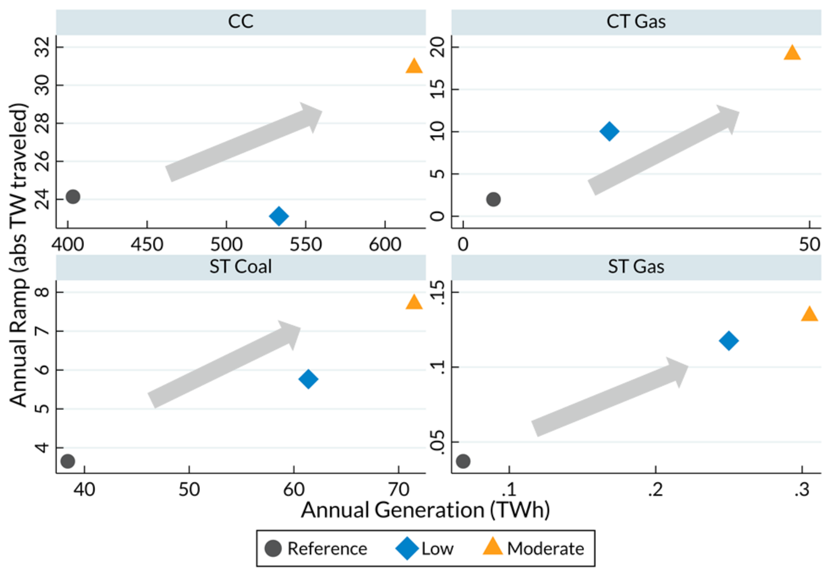


Figure 34: The needs for ramping grow with increasing electrification when transmission flow limits are considered. Conventional units are shown increasing their ramp contributions for the Reference, Low and Moderate electrification scenarios.

Certain interfaces, within the MISO footprint and between MISO and its neighbors, experience a wider range of expected flows under cases with increased load due to electrification, despite siting enough generation to meet the additional load. This behavior suggests that electrification may result in different usage of the transmission system. When planners are used to prevailing flows between regions falling within a certain range seasonally, the changes driven by electrification may result in unexpected planning outcomes.

Figure 35 shows three histograms of the interface between MISO North and South for different levels of electrification. The x-axis represents different flow levels and the y-axis is the number of hours in a year that the interface is at a particular flow level. For the Reference scenario, the flow on this interface is usually within a 1,000 MW range (standard deviation of the histogram). However, for the Low and Moderate scenarios, the distribution widens and the tails get longer. For the Low scenario, the range of flow on the interface increases by 500 MW; for the Moderate, it increases by 700 MW. This means that system conditions that would have been considered rare may become increasingly likely. The largest change in shape happens between the Reference and the Low scenarios, with limited changes due to additional increased electrification.

The MTEP19 MISO North-South Constraint Study explored the possibility of transmission projects to increase the contract path between the North and South regions [102]. Currently, the contract path is 1,000 MW, but MISO pays for the use of up to 2,000 MW of additional capacity between the two regions; the North to South transfer limit is 3,000 MW and the South to North transfer limit is 2,500 MW [102]. The North to South transfer limits are *not* enforced in this study, permitting flow values that exceed the existing transfer limits. The interface modeling in this report is representative, so unlike the planning study above, the flows here are only indicative. The histogram in Figure 35 for the Reference scenario comes close to staying within the current limits. The wider spread of the Low and Moderate scenarios, both of which exceed the current interface limits, suggests additional capacity across the North-South boundary could be beneficial to facilitate additional flow for a future with higher levels of electrification.

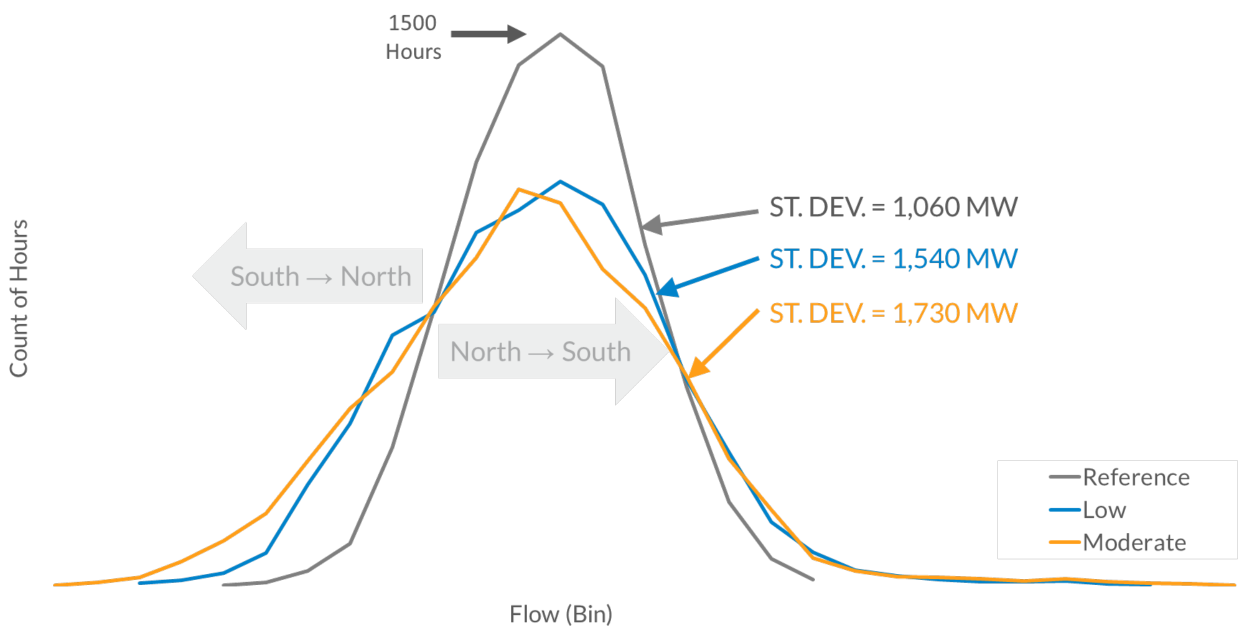


Figure 35: Histograms of the annual flows over the North-South Interface in 2040 for the Reference, Low, and Moderate scenarios. The histograms show a "flattening," indicating that MISO should prepare to plan for a wider range of flows as the system electrifies.

The flows between the regions in the North part of the MISO footprint are also affected by the growing electrification. Figure 36 shows a box and whisker plot of the quarterly flows between LRZs 1-3 (MISO West planning region) and LRZs 4-7 (MISO East/Central planning region). The quarters are broken up as follows:

- Q1 is January, February, and March
- Q2 is April, May, and June
- Q3 is July, August, and September
- Q4 is October, November, and December

The median of the boxes for the Reference case indicate that the flow is from West to East/Central (export) for at least half of the hours of the year. During quarters with colder weather (Q1 and Q4), it is seen that electrification shifts the middle 50% of the data points, so that there are more hours of flow from East/Central to West (import). This is likely driven by weather patterns; in the East/Central region, only LRZ 7 is at the same latitude as LRZs 1 and 2. Over the first three quarters, the overall range of flows widens with electrification compared to the Reference scenario.

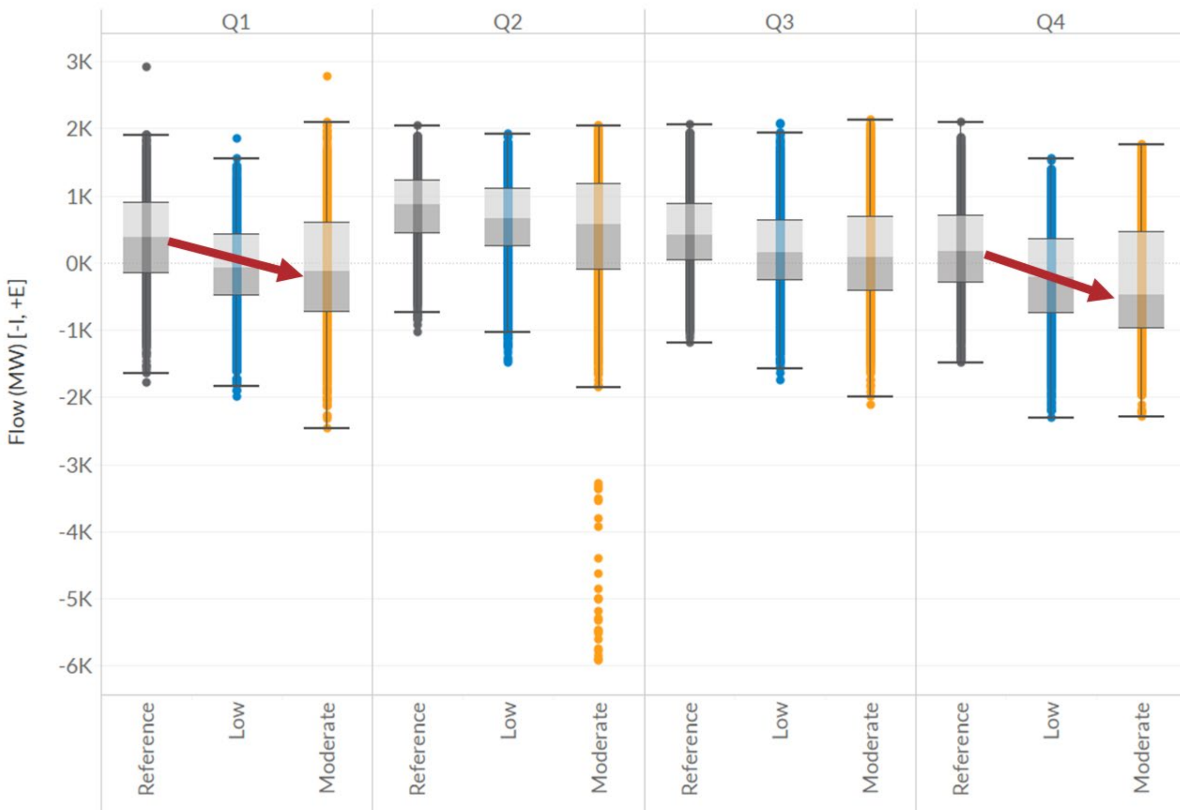


Figure 36: Intraregional flow between the West planning region (LRZs 1-3) and the East/Central planning region. (LRZs 4-7). Negative values indicate West is importing from East/Central.

This work did not assume any electrification-related load growth in neighboring regions, but it may be of interest to examine the interregional flows resulting from this assumption. The shifts in flow between MISO and its neighbors show seasonal dependence, but generally become more varied. For the purposes of this analysis, the interfaces between MISO and PJM, SPP, Southeast, and TVA were examined. A limited number of new gas CC and CT units were installed in PJM, SPP, and TVA, following the units sited for the MTEP19.

Figure 37 shows the range of interregional flows over each quarter. The seam between MISO and PJM shows an increased range of flows in all quarters, with imports increasing in the colder months in particular. The largest changes on the MISO-PJM seam happen between the Reference and Low scenarios. For the MISO-Southeast seam, the Low scenario shows the widest range of flows, increasing both imports and exports. The MISO-SPP and MISO-TVA seams both show increasing ranges of flows during the colder months.

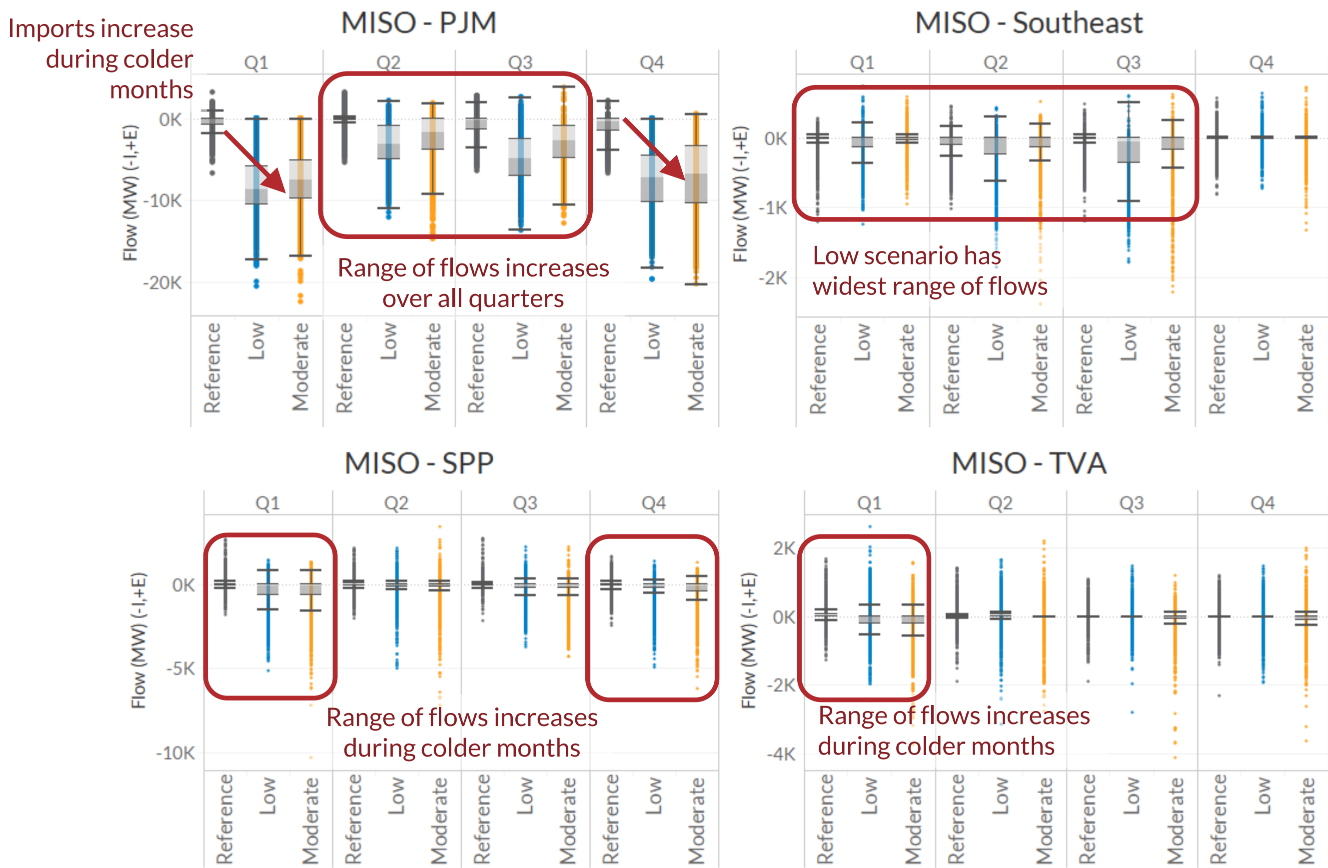


Figure 37: Quarterly interregional flows for different levels of electrification; note different y-axes scales

These preliminary results on transmission flow patterns may understate the magnitude of possible changes across MISO interface flows. In the models, the electrified load was distributed within LRZs according to historical loads. The nature of electrification means that the load locations will also change but, unfortunately, there was not enough data to make those assumptions.

5. ADDITIONAL CONSIDERATIONS

Risk is a measure of impact and likelihood. Figure 38 arranges the topics covered in this report into a framework of known and unknown magnitudes of impact and likelihood. From MISO's studies of high renewable systems, there is a good understanding of the impacts that diurnal shape changes and ramping will have on the system; addressing these changes is a key part of the Reliability Imperative. Electrification is likely to intensify the impacts by exacerbating the potential for diurnal shape changes. The locations and amounts of resources added to the system will change with electrification, seasonal shifts in the system peak will appear, and the patterns of flow within the transmission system will change. The magnitude of impact of these is currently unknown.

On the other hand, the timing of when electrification shows up on the system will have a large impact on planning the system, but there is not a good understanding of when specific amounts of electrification are likely to appear. Furthermore, academic studies demonstrate responsive, flexible, and controllable loads can have a large impact on the system's ability to cope with electrification. But it remains unknown how likely these technologies are to show up on the system when and where they are needed. Finally, there are always the unknown unknowns. What has been overlooked in this initial analysis of electrification on the MISO system?

		IMPACT	
		Known	Unknown
LIKELIHOOD	Known	Diurnal shape Ramping	Location Amount Flow patterns Seasonal shift
	Unknown	Timing Controllability	???

Figure 38: Known and unknown risks with respect to electrification

One reason that many of these qualities of electrification remain unknown is that the outcomes depend on the nexus of public policy, consumer choice, and utility promotion. How could market mechanisms affect the pace of electrification? Is it important to incentivize responsive, flexible, or controllable electrified loads? The widespread adoption of interactive electrified technologies may offer a change in paradigm to the day-ahead operations of power systems. One researcher suggests that dispatching load to meet the projected forecasts of wind and solar, along with a flat dispatch of conventional units, may result in a much more efficient system [103, 104]. What are optimal load profiles for MISO as the system evolves? Should MISO explore optimal load shaping/scheduling?

This report has focused on the technical potential and implications of electrification, but there remain non-technical political and economic considerations to the timing and impacts of electrification. For example, the upfront costs of EVs can be prohibitive for many lower-income consumers or charging infrastructure may not be available for renters. Adoption of EVs for these customers may depend on the buildout of public charging infrastructure or incentives encouraging property managers to install chargers. With respect to conversion from natural gas heating to electric heating, how will the economics be affected by changing demand patterns? How will the relative costs impact the rate of adoption? Many new types of technology exhibit an adoption plateau, and the plateau point may be different for different technologies — where is that point for electrification technologies?

Similarly, without proper incentives, it is difficult to spur energy efficiency and electrification investment in multi-family rental units. Georgia Power has implemented a "Pay as You Save" (PAYS) program to address some of these challenges with efficiency [105]. The PAYS program specifically targets low-income residents and renters by allowing Georgia Power to pay for energy efficiency improvements in a home and recover the costs as a part of the customer's monthly bill, while sharing a portion of the savings with the customer; once the investment is completely repaid, the customer then receives all of the savings [105]. Similar programs could be used to encourage adoption of domestic electrification technologies.

There may be an expectation that load growth due to electrification could be served locally by DERs, thus removing the need to consider electrification when planning the transmission system. However, this is not consistent with the current regulatory environment. As a result of FERC Order 747 and the NERC BAL-502-RFC-02 standard, MISO must analyze and plan for a system that serves gross system load in order to demonstrate that MISO satisfies the "one day in ten years" load criteria. It does not matter that net system load may be less than gross system load in almost all real-time operational scenarios. Thus, it is essential that known load growth due to electrification is incorporated into planning activities. Additionally, there remains uncertainty about the ability of distributed generation alone to match local load patterns without large amounts of on-site storage.

5.1 Future Directions

This report was unable to dive into analysis related to many other aspects of the evolving power system that are expected to impact and/or be interdependent with increased electrification. This list is not exhaustive but represents areas where further exploration could aid understanding how electrification will impact the MISO footprint:

- Electrified loads that are responsive, flexible, or controllable: Electrified loads may have new capabilities to respond to grid conditions. An overview of different residential load control methodologies is provided in a 2016 paper in the journal of Renewable and Sustainable Energy Reviews [106]. For example, the timing and mode of EV charging can be adjusted, or heating loads can act as thermal batteries. Does the responsiveness, flexibility, or controllability of the load mitigate supply-side challenges? If the load is more responsive, flexible, and controllable, how does the alignment of load and renewable energy production change?
- Low-carbon power sector: This study only performed resource adequacy and generation and transmission performance analysis for scenarios where 20% of annual energy was produced from renewables. Because economy-wide decarbonization is a driver of electrification, it is expected that the pace of electrification may be coupled to the rate at which the power sector decarbonizes. Therefore, it will be important to examine cases more like MISO Future 3, where electrification is combined with aggressive decarbonization goals.
- Electric vehicles
    - Correlation between cold weather and EV demand: Other studies have indicated that EVs consume more power in the winter months [9, 107]. The data used in this study did not account for any increased energy during cold weather and therefore may understate the winter peaking impacts of continued EV growth, if charging is not responsive, flexible, or controllable.

- Medium- and heavy-duty trucking: The initial MISO study into EVs, in concert with LBNL, did not consider the potential for electrified trucking and fleet vehicles. What is the impact of including trucking end-uses?

5.2 Open Questions

The Reliability Imperative is a call to action for the region, not just for MISO. The following items represent longer-term areas of investigation and stakeholder discussion related to electrification:

- Siting of increased loads: In the initial analysis, the increased load was apportioned to discrete locations based on the contribution of each location to the historical LRZ peak. With electrification of transportation and industrial processes, it is likely that the load will increase more near hubs of activity, e.g. near highways or industrial zones of cities. What is the impact of increasing the loading on a subset of likely locations within each LRZ? How are MISO stakeholders forecasting load change within their areas?
- Storage and hybrid participation: Increased loads could be coupled with on-site storage to mitigate some ramping impacts or flatten the demand pattern over the course of a day. Storage and hybrid units could also be used on the bulk electric system to support the reliable supply of energy. RIIA found that storage was somewhat more effective when located near renewable resources [101]. Could the growth and shift of load throughout the footprint impact the strategy for siting and sizing storage and hybrid units? How are MISO stakeholders thinking about the connections between electrification and generation expansion?
- CO_2 limits: One of the drivers for increased electrification is to reduce carbon consumption by the end-user. It is worth exploring the impacts of policies that limit the annual carbon emissions to a certain value or assign a price per ton to CO_2 emissions. How are stakeholders conceptualizing the interactions between electric system decarbonization and economy-wide decarbonization trends? What role could MISO play in tracking and data transparency?
- Natural gas system interactions: As heating demand for natural gas decreases, the price of natural gas may decrease. Or, with the increasing consumption from electric generation, the price may increase. The ways in which the existing natural gas system and market interact with electrification trends is unclear. How are MISO stakeholders considering the interdependencies between the natural gas supply and electrification of heating in resource planning?
- Treatment of external areas: If the load in MISO increased due to electrification, it is likely that the same drivers would cause the load in the neighboring areas to increase as well. In this report, the load in external areas was held constant. Would growing electrification in MISO's neighbors exacerbate the challenges the MISO system would experience? How do MISO stakeholders consider their electrification initiatives in the context of regional changes?
- DERs: Growing electrification will certainly drive DER adoption for business and residential electricity consumers as they seek to own the means of production. These consumers who produce electricity are sometimes called "prosumers." Most of these distributed resources will see the highest value by offsetting their load and participating in various retail programs. It is expected that high penetrations of DERs with increasingly dynamic control systems will provide an opportunity for DERs to provide wholesale "grid" services. FERC's Order 2222 anticipates this shift and instructs the RTOs/ISOs to remove barriers for wholesale market participation by aggregated DERs, where DER is defined as "any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but

are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment."

Estimating this growth is difficult, in part because there are no central planning authorities for distributed resources and local incentives vary widely. Further analysis could include the following research questions: What are the practical and economic limits on the amount of load which could be served by distributed generation? How much load can the geographic areas which are expected to see the most growth (residential, urban) and commercial and industrial areas physically support with distributed generation? For example, the amount of solar PV that a region can support is limited by the available land and roof area. For dense metropolitan areas, how much rooftop space is available for DER? How does the analysis change with widespread distributed storage options? For MISO operations, a critical issue is understanding the implications of the growing difference between gross load and net load, driven by adoption of distributed generation. How would this impact MISO transmission planning? How are MISO stakeholders preparing for responsive, flexible, or controllable load? What are the advantages and disadvantages of each in an RTO environment?

6. LIST OF ACRONYMS

3Ds	de-marginalization, decentralization, digitalization
AEG	Applied Energy Group
APP	appliances
CAGR	compound average growth rate (computed annually)
CC	combined cycle
CFC	Continued Fleet Change (MTEP19 future scenario)
C&I	commercial and industrial
COP	coefficient of performance
CO_2	carbon dioxide
CT	combustion turbine
DC	direct current
DER	distributed energy resource
DHW	domestic hot water
DOE	Department of Energy
DR	demand response
EFS	Electrification Futures Study (NREL)
EGEAS	Electric Generation Expansion Analysis System
EPRI	Electric Power Research Institute
EUE	expected unserved energy
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
GRE	Great River Energy
GPI	Great Plains Institute
HVAC	heating, ventilation, and air-conditioning
HVDC	high voltage DC
IQR	interquartile range
LBA	local balancing authorities
LBNL	Lawrence Berkeley National Laboratory
LED	light-emitting diode
LIGHTS	Low-Impact Green Heavy Transport Solutions
LMP	locational marginal price
LOLE	loss of load expectation
LOLP	loss of load probability
LRTP	Long-range Transmission Plan
LRZ	local resource zone
MGE	Madison Gas & Electric
MISO	Midcontinent Independent System Operator
MTEC	Midcontinent Transportation Electrification Collaborative
MTEP	MISO Transmission Expansion Plan
NACFE	North American Council for Freight Efficiency
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
PAYS	Pay as You Save (Georgia Power program for consumer energy efficiency)
PEV	plug-in electric vehicle
PNNL	Pacific Northwest National Laboratory
PV	photovoltaic
Q1	first quarter (January through March)
Q2	second quarter (April through June)
Q3	third quarter (July through September)
Q4	fourth quarter (October through December)
RAN	Resource Availability and Need

RES	residential
RIIA	Renewable Integration Impact Assessment
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SEPA	Smart Electric Power Alliance
SMUD	Sacramento Municipal Utility District
SPP	Southwest Power Pool
ST	steam turbine
TVA	Tennessee Valley Authority
UV	ultraviolet
V2G	vehicle-to-grid
WECC	Western Electricity Coordinating Council

7. CONTRIBUTORS

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8. APPENDIX

8.1 Simulation Methodology

All scenarios were run in an Electric Generation Expansion Analysis System (EGEAS) model to develop a generation capacity expansion plan, with new capacity sited within the MISO footprint following MTEP methodology. The capacity expansion was calculated through 2040 in the EGEAS model, with the intention that the results provide a snapshot of electrification impacts at the endpoint. PLEXOS was used to perform an analysis of generation and transmission performance, using production cost modeling, for the last year of study (2040). Although these electrification levels may not occur before 2040, the study results provide an indication of what may be expected whenever these electrification levels are eventually reached. These scenarios provide information that can inform planning for these potential impacts.

Figure 39 offers a flow chart of how the different study elements are linked. All three analysis techniques use the AEG load shapes and forecasts as an input. In this chart, red indicates study input, orange indicates study output, and bluish green denotes study analysis. The output of the EGEAS analysis acts as an input to the resource adequacy analysis and generation and transmission performance analysis.

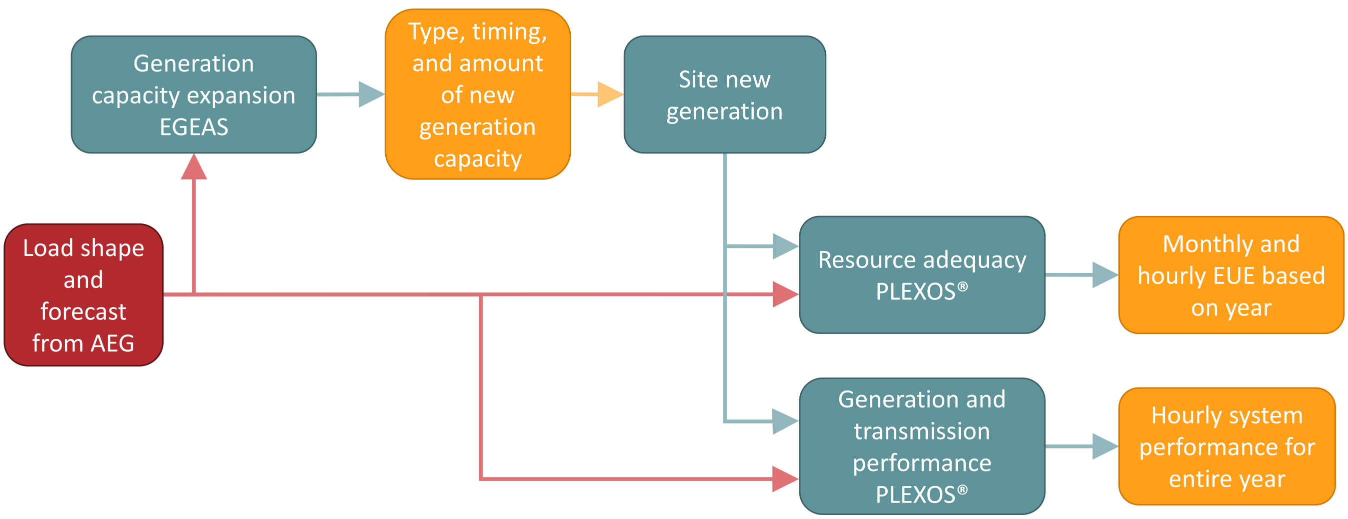

Figure 39: Flow chart of different study processes and information flow

The following topics are considered out-of-scope for this analysis:

- Responsive, flexible, or controllable load
- Additional improvements in energy efficiency
- Expansion of DERs
- Distribution system changes necessary to accommodate larger loads
- Transmission expansion

8.2 Load Duration Curve and Load Factors

The normalized load duration curves for the Reference, Low, Moderate, and High scenarios are shown in Figure 40, scaled by the annual peak. Currently, MISO defines the "shoulder" model for planning as 70 to 80% of the overall summer peak; this is intended to capture the peak load on a typical summer day [108]. With electrification, the assumptions related to shoulder models may need reassessment. If it is desired to look at a "typical" peak day, then there will be more peak days under electrification, and they may no longer occur in the summertime. From the normalized load duration curve, the number of hours where the load exceeds 70% of the peak value will nearly double in all electrification scenarios compared to the Reference scenario. The number of hours above 80% of the peak load will increase between 10% (High) and 17% (Low). However, the number of hours where the load exceeds 90% of the peak value decrease under electrification (seen in the Top 100 hours inset of Figure 40). The Reference scenario has 150 hours above 90%, where the Moderate scenario has 86 hours. However, the load level corresponding to 90% of peak is considerably larger in the Moderate scenario compared to the Reference scenario: 182 GW to 134 GW, respectively; this does not appear in the load duration curve because all values are normalized to a maximum of one. Figure 41 shows a compression of the daily peaks in the Moderate and High scenarios when viewed as a percentage of the annual peak and may explain the decrease in the Top 100 hours. The compression seems related to uncontrolled charging during the summer months (see Figure 14).

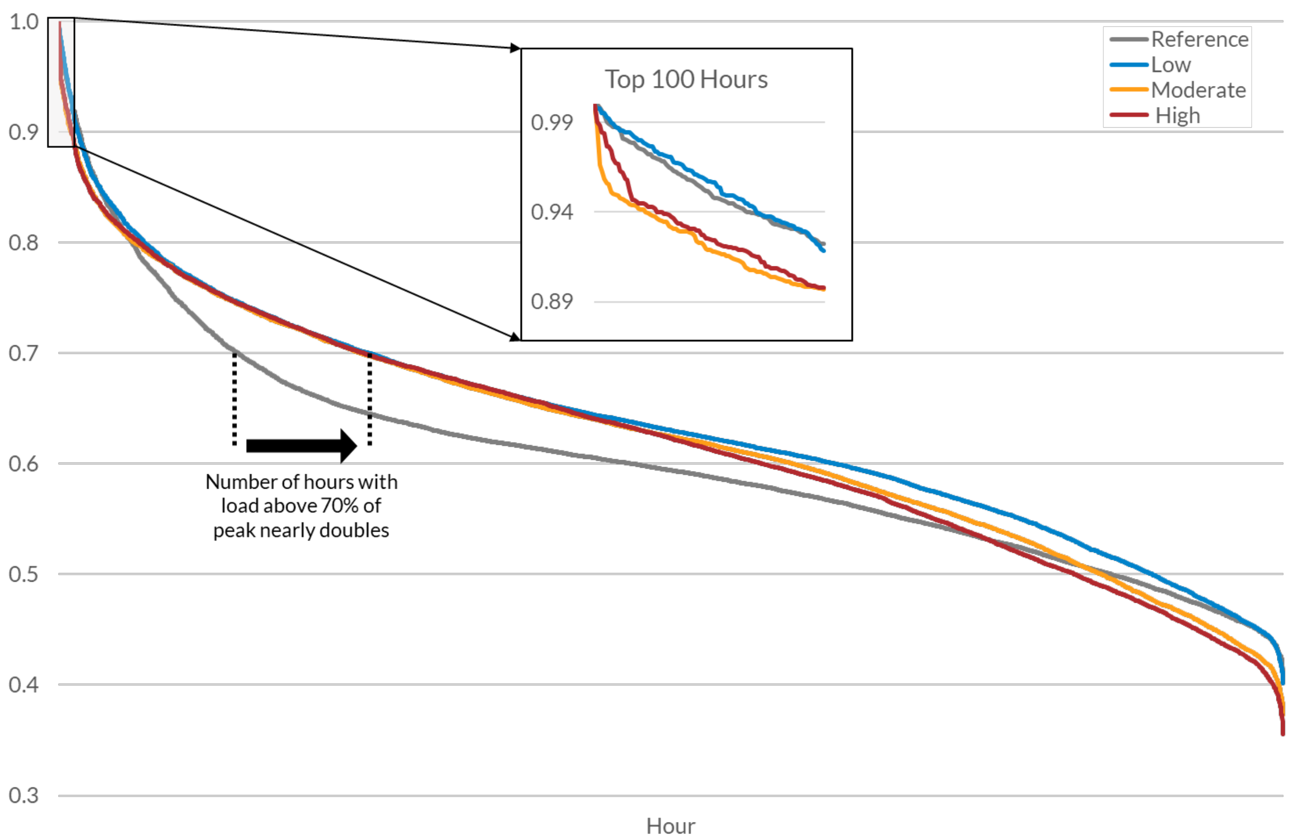

Figure 40: Normalized load duration curve for different electrification levels in 2040. Comparing the shapes shows a flattening of higher load hours in scenarios with higher electrification, suggesting that there will be more hours in a year where the load is above 70% of the maximum.

Load factor provides a way to measure system use. Load factor is defined as the energy divided by the peak load times the number of hours in the time period.

$$Load\ Factor = \frac{Energy}{Peak\ Load * Hours}$$

Load factor may be calculated on an annual or monthly basis. With a higher load factor, there are more hours where the system load is closer to the peak load for the time period being examined. When the load factor of the electrified load shapes is examined on an annual basis, it is seen that there is not much difference between the Reference scenario (63%) and the High scenario (62%). However, the monthly values tell a slightly different story (Figure 42).

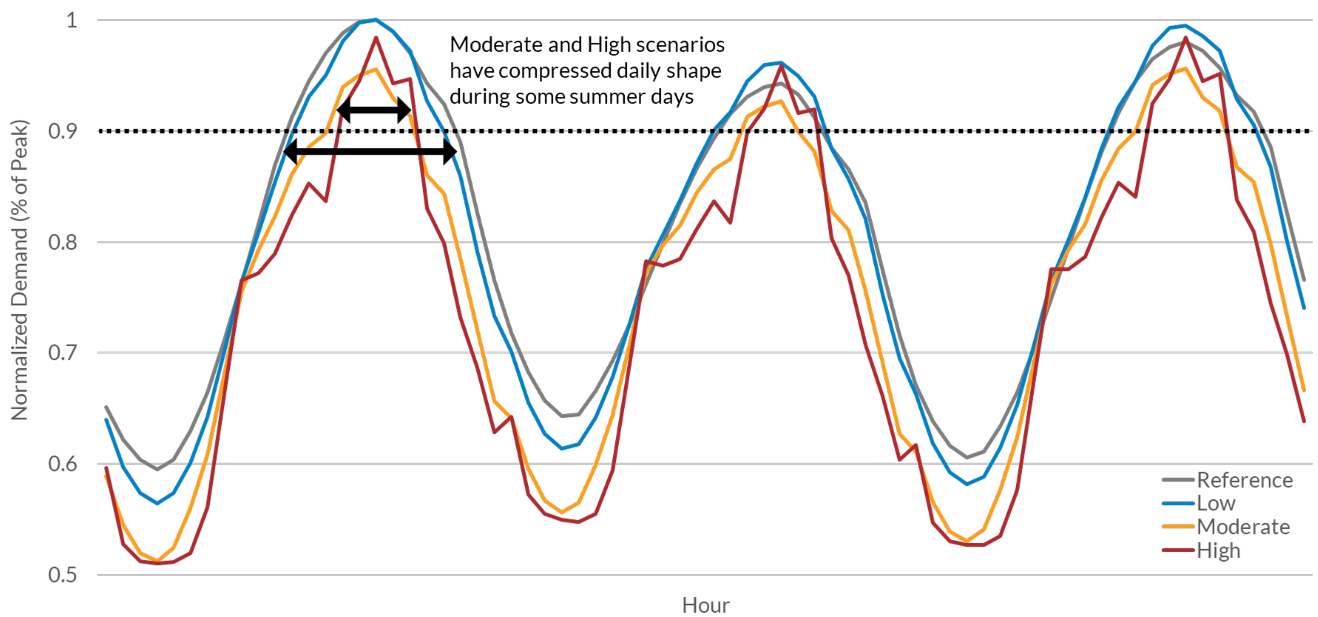

Figure 41: Normalized daily loads for July 24-26, 2040. Values are normalized based on the annual peak.

Figure 42 shows monthly load factors increasing in the winter months, from 60% in the Reference scenario to 72% in the High scenario for the month of January and increasing from 57% to 67%, respectively, for the month of December. The load factor for the summer peak month of July decreases from 75% in the Reference scenario to 68% in the High scenario. For the traditional shoulder months (March, April, October, and November), where many outages are planned for both the transmission and generation systems due to lower system load, the load factor increases by up to 7%.

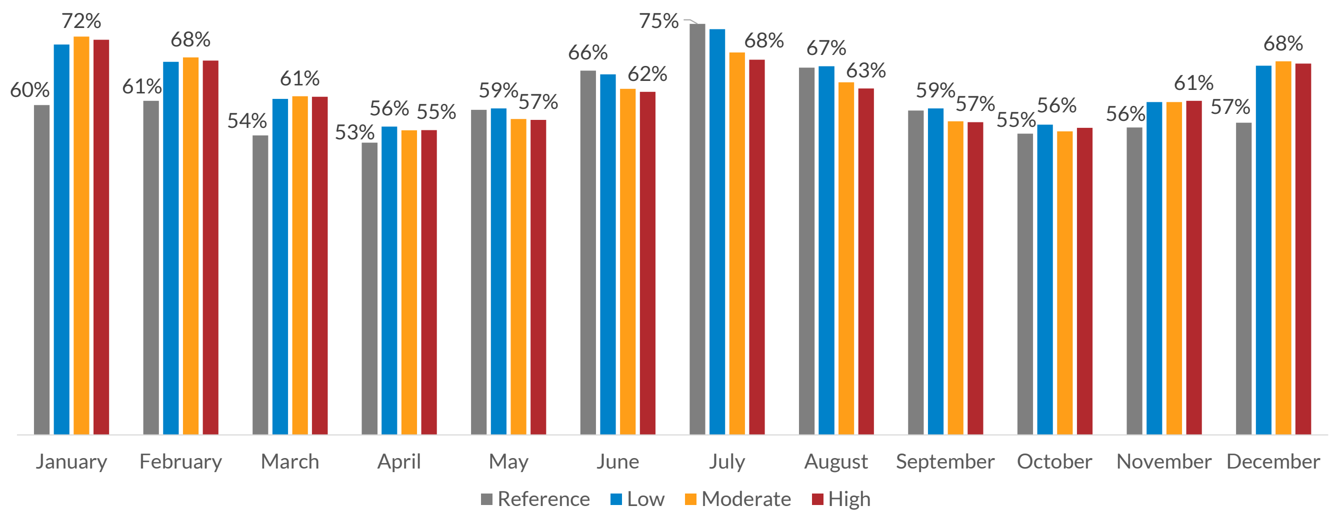

Figure 42: Monthly load factor calculation for the final year of study. Load factors increase for the winter months and decrease for the summer months.

8.3 Resource Forecasting using EGEAS

EGEAS is a tool originally developed by EPRI in the early 1980s. From the brochure, it is a "state-of-the-art modular production costing and generation expansion software package…for use by utility planners to develop and to evaluate integrated resource plans, avoided costs, and develop plant life management plans." The tool uses a nonlinear optimization algorithm to identify the least-cost resource expansion (new system generation), while meeting multiple user-defined constraints, such as the planning reserve margin, renewable portfolio standard requirements for the minimum energy from renewables in each year, or limits on system CO_2 emissions.

EGEAS does not consider the transmission system and is thus a copper-sheet model where all generation is available to meet all load, with no transfer limitations. Furthermore, EGEAS is not a production cost modeling tool, in that the analysis is performed on a load duration curve, ensuring that the peak plus reserve margin will always be supplied on an annual basis. It does not consider generation limitations, such as ramping or minimum up/down time, that are analyzed in a consecutive time simulation like production cost modeling. There are many inputs required by EGEAS, including load and energy growth curves, load shape, system generators and their characteristics, the characteristics of new generators, along with any constraint to be considered.

The EGEAS work used the MTEP19 Continued Fleet Change (CFC) model [109]. The CFC assumptions include base natural gas prices, retirements reflecting historical trends, and mid-level demand-side management program potential. The exceptions to this are demand and energy growth, load shapes, and renewable energy levels that were defined by the electrification scenario. No changes to the natural gas prices were assumed.

The CFC assumes that coal generation retires at the historical rate, slightly earlier than end of useful life, at 60 years; by 2033, 19 GW of coal units are retired and 16 GW of natural gas and oil-fired units are retired. The retirements were held constant across all scenarios, and total 73.6 GW over the study period for EGEAS simulations. This study further assumes that the growth in renewables exceeds the mandates set by Renewable Portfolio Standards (RPSs) and reaches 20% of annual energy by 2033. The capital cost assumptions for new generation options for EGEAS to select are included in Figure 43.

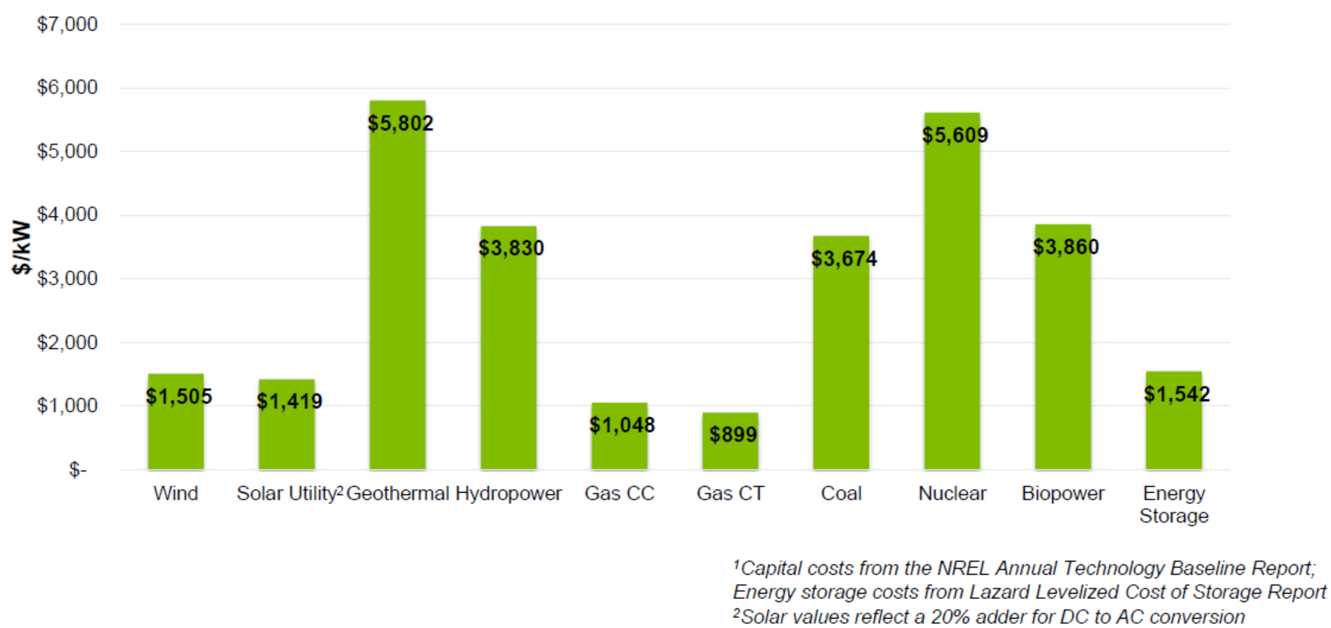

Figure 43: Capital cost assumptions for MTEP19 CFC. Source: MTEP19 Futures [109]

8.4 Correlation Between Temperature and Electrified Loads

To perform resource adequacy assessments, many years of load data and renewable generation output are required to ensure that conclusions are not biased toward one extreme weather year. However, AEG supplied load profiles based on one load year (2012). To create additional load profiles based on different weather years, it is necessary to determine the correlation between the weather and the incremental load due to electrification. At a minimum, this analysis aims to determine if weather correlation is a large effect in the data supplied by AEG.

To develop the load shapes, AEG began with the load shape for 2012. It was scaled to current annual energy and load levels. Then, increments were added for each hour reflecting electrification from EVs as well as electrification of buildings and industrial processes. The relative sizes of the increments were developed through sector-specific research and AEG's proprietary database of load characteristics for the U.S. power grid. To perform resource adequacy analysis, it is preferred to have many years of sample data so that several different weather years can be evaluated. Thus, MISO performed a correlation analysis using the Excel CORREL function to determine whether the same electrification increments could be applied to different base load years to construct multiple load shapes for different weather years.

It is important to determine whether the increments are correlated with temperature because they can make up a large percentage of the load at any given hour. For the Low scenario, the EV increment averages about 3% of the load at any given hour, making up a maximum of 8% of the load for a particular hour. In the Moderate scenario, it averages 5% of the load at any given hour, with a maximum contribution of 12% of the load for a particular hour. For the building and industry increment, the contributions are even larger. In the Low scenario, building and industrial electrification average 14% of the load at a particular hour, with a maximum contribution of 36% of the load for a particular hour. In the Moderate scenario, building and industrial electrified load contribute 23% of the load on average, with a maximum contribution of 49% of the load at a particular hour.

The initial hypothesis was that the building and industrial electrification increment would be correlated to temperature, due to the presence of heating loads as a large proportion of the demand, and that the EV electrification increment would likely not be correlated to the weather.

The correlation between temperature and EV load was found to be insignificant. Using year 2012, since that was the base year for the AEG analysis, the magnitude of correlation between the hourly average temperatures in each LRZ; the averages across all LRZs were 0.16 and 0.14 for the Low and Moderate scenarios, respectively, while the maximums were 0.18 and 0.15. Seasonally, the correlation for the EV increment was slightly more correlated in the summer than in the winter, with the average across all LRZs at 0.3, with a maximum of 0.37 for LRZ1 in the Moderate scenario. Correlation coefficients are included in Table 4.

Based on the lack of correlation between temperature and EVs, it was assumed that the portion of electrification coming from EVs could be added to the shape of other years' loads without introducing too much error, so long as the day of the week was matching for the appropriate season.

Correlation between EV demand and weather is expected once more operational experience has been achieved; however, it will not be considered for this study. Colder temperatures reduce the expected range of an EV, so to achieve the same number of miles driven, more charge would be required in winter months. The EPRI *U.S. National Electrification Assessment* includes predictions on how the seasonal load shape for EV charging alone might change seasonally in the Southeast U.S., due to lower temperatures, in a high electrification scenario [9]. Estimates of the actual impact of cold weather are available for the ISO-NE footprint. ISO-NE used data provided by Chargeport Inc. to develop their 10-year energy and load forecasts for EVs [107]. In the data collected from actual EV charging points through the ISO-NE footprint, it was seen that higher EV load was correlated with colder weather and the average daily charging energy increased by 25% from July to January (8.4 kWh compared to 12.1 kWh) [107]. The fact that the MISO electrification forecast does not include seasonal variations in EV demand indicates an area of future improvement.

(a) Correlation coefficients by LRZ calculated over the entire year

Annual	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
Low	0.15	0.13	0.16	0.17	0.17	0.15	0.13	0.18	0.17	0.18
Moderate	0.13	0.11	0.14	0.15	0.14	0.13	0.11	0.15	0.15	0.15

(b) Correlation coefficients by LRZ calculated over Q1

January-March	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
Low	0.17	0.13	0.15	0.16	0.18	0.14	0.12	0.18	0.17	0.18
Moderate	0.18	0.14	0.16	0.17	0.18	0.15	0.12	0.18	0.17	0.18

(c) Correlation coefficients by LRZ calculated over Q2

April-June	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
Low	0.25	0.20	0.26	0.28	0.27	0.23	0.20	0.24	0.23	0.24
Moderate	0.29	0.25	0.30	0.31	0.29	0.27	0.25	0.28	0.28	0.29

(d) Correlation coefficients by LRZ calculated over Q3

July-September	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
Low	0.35	0.28	0.31	0.32	0.31	0.28	0.27	0.30	0.24	0.23
Moderate	0.37	0.30	0.33	0.35	0.33	0.31	0.30	0.34	0.34	0.33

(e) Correlation coefficients by LRZ calculated over Q4

October-December	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
Low	0.17	0.17	0.20	0.21	0.22	0.20	0.17	0.27	0.26	0.27
Moderate	0.10	0.09	0.12	0.12	0.14	0.11	0.07	0.19	0.16	0.16

Table 4: Correlation coefficients for 2012 for the EV adder

For building and industrial uses the magnitude of correlation with temperature was greater than 0.5 for the North and Central regions (LRZs 1-7) of MISO. Technically, the values are anti-correlated, corresponding to reduced temperature causing increased load; this is indicated by a negative value of correlation. The Southern LRZs (8, 9, and 10) were less correlated, with the largest magnitude less than 0.35. With the building and industrial electrification portion showing correlation for the North and Central regions, more investigation was required to determine whether that portion could also be used for different weather years. The correlation between the building and industry increment and the hourly average temperature for the ten different LRZs for seven years was calculated.

Figure 44 shows the results for the Low scenario and Figure 45 shows the results for the Moderate scenario. The year 2012 is highlighted in blue and represents the correlation that has to be matched — i.e. if the temperatures of the other years correlate at approximately the same level, then the electrification supplied by AEG could be applied to other years. Based on calculations over the entire year, it appears that both the EV and building and industrial process electrification increments could be mapped to other weather years for use in resource adequacy analysis without introducing large errors. However, it is possible that the correlation coefficients may vary with the seasons. To simplify analysis, months were grouped into “warm” (June through September) and “cold” (November through

March) to calculate seasonal correlation coefficients between the incremental electrification and average LRZ temperature. For the warm season (Figure 46), the building and electrification increment shows similar correlation between 2012 and all other years for LRZs 1-7. In LRZs 8-10, the correlation in the base year is higher than when applied to other years, suggesting that error would be introduced by using other weather years. In the cold season (Figure 47), the results are ambiguous, with some years showing more correlation than the base year 2012 and others showing less. Correlation coefficients are included in Table 5.

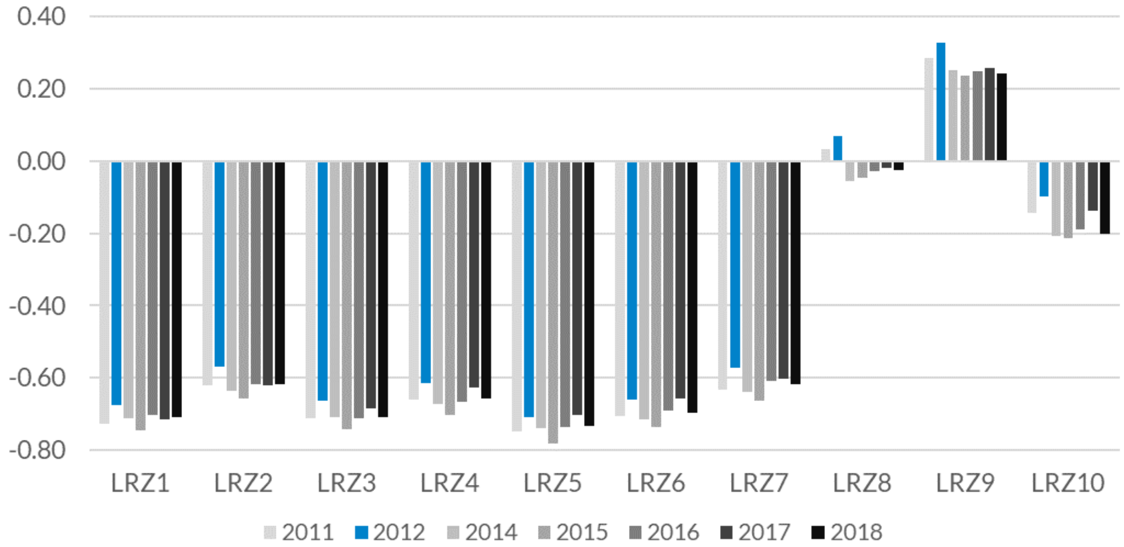

Figure 44: Correlation between average LRZ temperature and the contribution to load from building and industrial process electrification for the Low scenario. The original data from AEG was based on year 2012 (blue). The other weather years show comparable correlation levels to 2012 for all LRZs.

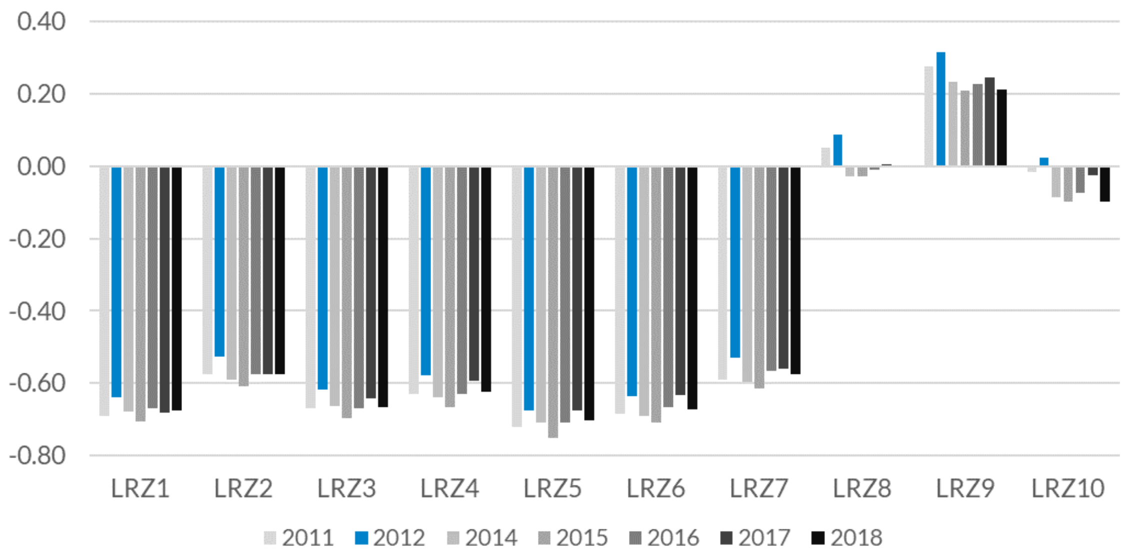

Figure 45: Correlation between average LRZ temperature and the contribution to load from building and industrial process electrification for the Moderate scenario. The original data from AEG was based on year 2012 (blue). The other weather years show comparable correlation levels to 2012 for all LRZs.

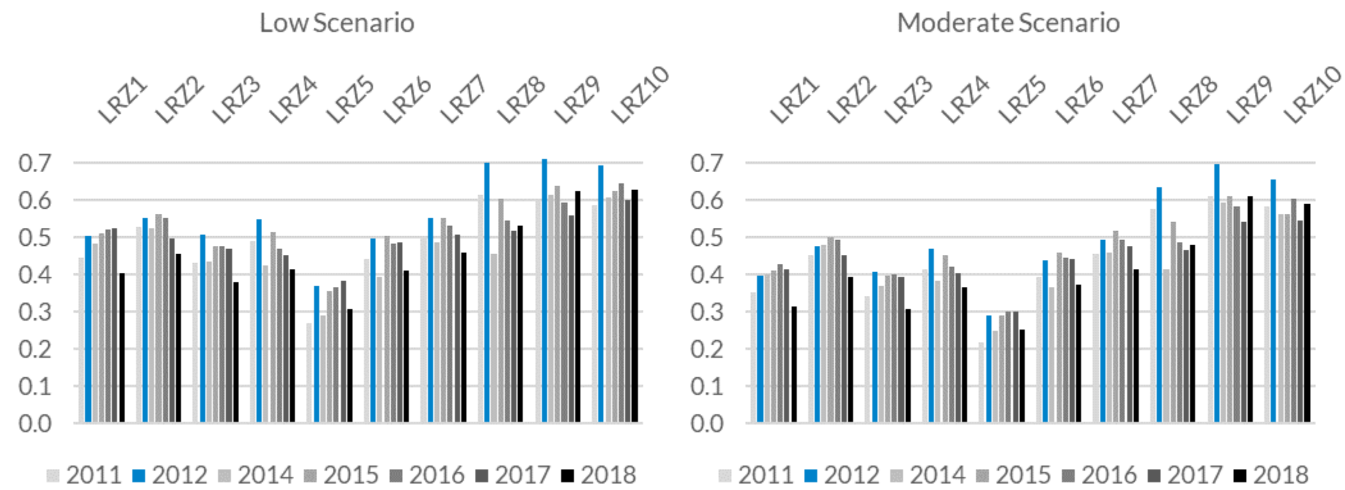

Figure 46: Correlation coefficients between average LRZ temperature and the contribution from building and process electrification for June through September. The graph on the left is the Low scenario, while the graph on the right is the Moderate scenario. Year 2012 shows the most correlation in LRZs 8-10, where for the other LRZs correlation is comparable across all years.

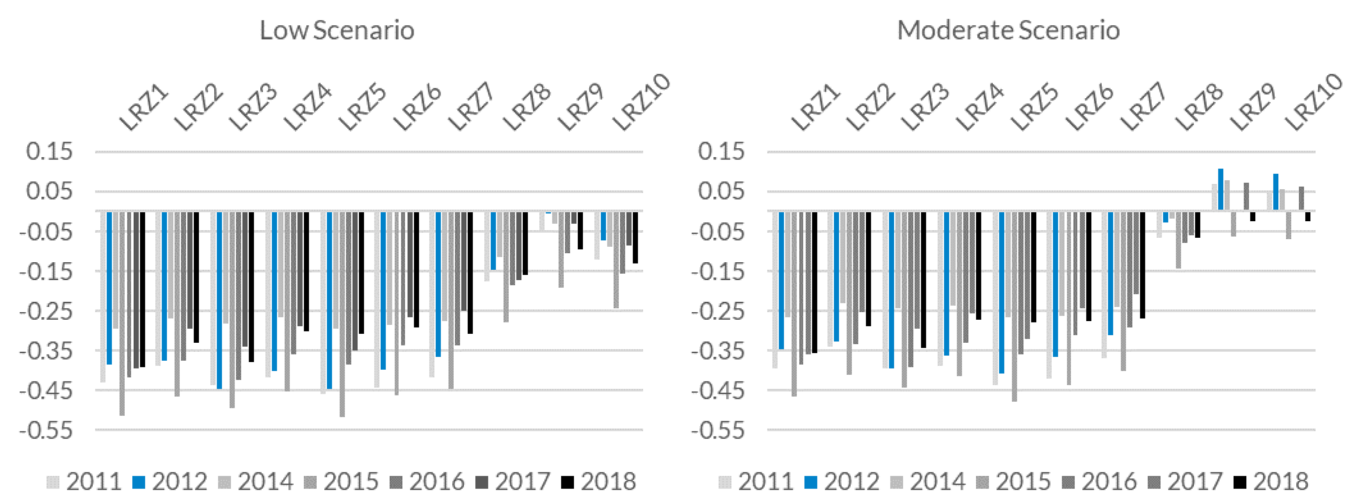

Figure 47: Correlation coefficients between average LRZ temperature and the contribution from building and process electrification for November through March. The graph on the left is the Low scenario, while the graph on the right is the Moderate scenario. Years 2011 and 2015 show comparable (or additional) correlation than the 2012 base year for most LRZs.

(a) Correlation coefficients by LRZ calculated over the entire year

Annual										
Low	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2011	-0.73	-0.62	-0.71	-0.66	-0.75	-0.71	-0.63	0.03	0.28	-0.14
2012	-0.67	-0.57	-0.66	-0.61	-0.71	-0.66	-0.57	0.07	0.33	-0.10
2014	-0.71	-0.63	-0.71	-0.67	-0.74	-0.71	-0.64	-0.06	0.25	-0.21
2015	-0.74	-0.66	-0.74	-0.70	-0.78	-0.73	-0.66	-0.05	0.24	-0.2
2016	-0.70	-0.62	-0.71	-0.66	-0.74	-0.69	-0.61	-0.03	0.25	-0.19
2017	-0.72	-0.62	-0.68	-0.63	-0.70	-0.66	-0.60	-0.02	0.26	-0.14
2018	-0.71	-0.62	-0.71	-0.66	-0.73	-0.70	-0.62	-0.02	0.24	-0.20
Moderate	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2011	-0.69	-0.58	-0.67	-0.63	-0.72	-0.68	-0.59	0.05	0.28	-0.02
2012	-0.64	-0.53	-0.62	-0.58	-0.68	-0.63	-0.53	0.09	0.32	0.02
2014	-0.68	-0.59	-0.66	-0.64	-0.71	-0.69	-0.59	-0.03	0.23	-0.09
2015	-0.70	-0.61	-0.70	-0.67	-0.75	-0.71	-0.62	-0.03	0.21	-0.10
2016	-0.67	-0.57	-0.67	-0.63	-0.71	-0.67	-0.56	-0.01	0.23	-0.07
2017	-0.68	-0.58	-0.64	-0.59	-0.67	-0.63	-0.56	0.01	0.25	-0.03
2018	-0.67	-0.57	-0.67	-0.62	-0.70	-0.67	-0.58	0.00	0.21	-0.10

(b) Correlation coefficients by LRZ calculated over the warmer months

Warm (June – September)										
Low	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2011	0.44	0.53	0.43	0.49	0.27	0.44	0.50	0.62	0.60	0.59
2012	0.50	0.55	0.51	0.55	0.37	0.50	0.55	0.70	0.71	0.69
2014	0.48	0.53	0.43	0.42	0.29	0.39	0.49	0.46	0.61	0.61
2015	0.51	0.56	0.48	0.51	0.36	0.50	0.55	0.61	0.64	0.63
2016	0.52	0.55	0.48	0.47	0.37	0.48	0.53	0.55	0.59	0.65
2017	0.53	0.50	0.47	0.45	0.38	0.49	0.51	0.52	0.56	0.60
2018	0.40	0.46	0.38	0.41	0.31	0.41	0.46	0.53	0.62	0.63
Moderate	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2011	0.35	0.45	0.34	0.41	0.22	0.39	0.46	0.58	0.61	0.58
2012	0.40	0.48	0.41	0.47	0.29	0.44	0.49	0.63	0.70	0.65
2014	0.40	0.48	0.37	0.38	0.25	0.37	0.46	0.41	0.59	0.56
2015	0.41	0.50	0.40	0.45	0.29	0.46	0.52	0.54	0.61	0.56
2016	0.43	0.50	0.40	0.42	0.30	0.44	0.49	0.49	0.58	0.60
2017	0.42	0.45	0.39	0.40	0.30	0.44	0.48	0.47	0.54	0.55
2018	0.32	0.39	0.31	0.37	0.25	0.37	0.42	0.48	0.61	0.59

(c) Correlation coefficients by LRZ calculated over the colder months

Cold (November – March)										
Low	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2011	-0.43	-0.39	-0.44	-0.42	-0.46	-0.44	-0.42	-0.18	-0.05	-0.12
2012	-0.39	-0.38	-0.44	-0.40	-0.44	-0.40	-0.36	-0.15	-0.01	-0.07
2014	-0.30	-0.27	-0.28	-0.27	-0.30	-0.28	-0.28	-0.12	-0.03	-0.09
2015	-0.52	-0.46	-0.50	-0.45	-0.52	-0.46	-0.45	-0.28	-0.19	-0.24
2016	-0.42	-0.38	-0.42	-0.36	-0.39	-0.34	-0.34	-0.19	-0.11	-0.16
2017	-0.40	-0.30	-0.34	-0.29	-0.35	-0.27	-0.25	-0.17	-0.03	-0.09
2018	-0.39	-0.33	-0.38	-0.30	-0.31	-0.29	-0.31	-0.16	-0.10	-0.13
Moderate	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2011	-0.39	-0.34	-0.40	-0.39	-0.44	-0.42	-0.37	-0.07	0.07	0.05
2012	-0.35	-0.33	-0.39	-0.36	-0.41	-0.37	-0.31	-0.03	0.11	0.09
2014	-0.27	-0.23	-0.24	-0.24	-0.27	-0.26	-0.24	-0.02	0.08	0.06
2015	-0.47	-0.41	-0.44	-0.41	-0.48	-0.44	-0.40	-0.15	-0.06	-0.07
2016	-0.39	-0.34	-0.39	-0.33	-0.36	-0.31	-0.29	-0.08	0.00	0.00
2017	-0.36	-0.25	-0.30	-0.26	-0.32	-0.24	-0.21	-0.06	0.07	0.06
2018	-0.36	-0.29	-0.34	-0.27	-0.28	-0.28	-0.27	-0.07	-0.03	-0.03

Table 5: Tables of correlation coefficients for the building and industry adder, with 2012 base year highlighted

8.5 Resource Adequacy using PLEXOS

PLEXOS is a market simulation software developed by Energy Exemplar. PLEXOS is considered a unified platform which consolidates different power system analyses in one tool, allowing the same tool to be used for resource forecasting, reliability studies for resource adequacy, and production cost modeling. PLEXOS can be customized by the user for many different scenarios, including customized constraints, conditional variables, physical elements, simulation horizon, duration of the simulation period, phases in the integration and model resolution. The PLEXOS simulator is a powerful tool for performing reliability studies on electric power systems and can calculate via convolution the standard metrics of loss of load probability (LOLP), loss of load expectation (LOLE), and EUE. Alternatively, PLEXOS can also use detailed chronological simulations to produce the same metrics via Monte Carlo.

The EGEAS capacities were added to the RIIA resource adequacy model to leverage previous work. This allowed the reuse of conventional units, with new resources, electrified loads, and retirements tailored to the electrification scenario. The resource adequacy simulations assume no transmission limitations, so there was no need to site the generation geographically for this part of the study. Because the original data from AEG was based on load year 2012, the Reference, Low, and Moderate scenarios were evaluated for one calendar year. The load of each case was increased to ensure that all three reached an LOLE of 0.1 day per year, or "one day in 10 years." This methodology matches that of RIIA and an explanation of the reasoning may be found in the RIIA final report [101]. In short, adding the load growth due to electrification requires expansion of generation resources. When the electrified load and new generation are added to the system, the LOLE value may not exactly match the 0.1 criteria. Additional load is added to bring the system LOLE to 0.1 for all cases and years, following the RIIA methodology, allowing an equivalent one-to-one comparison of the seasonality of loss of load risk. For the synthetic data years (2007-2011, 2014-2018), a similar procedure was followed.

8.6 Analysis of Generation and Transmission Performance using PLEXOS

The resource expansion from EGEAS simulations was sited into the production cost model. The siting of natural gas combined cycle (CC) and combustion turbine (CT) units followed the MTEP19 Future methodology, while the siting of wind and solar units followed the RIIA study methodology. The siting of the thermal units is shown in Figure 48, where priority was given to placing new units on sites where retirements have previously happened, as well as queue sites. Figure 48 shows siting layers — the Reference scenario generators show up on the top layer and, as sites were reused at higher and higher scenarios, the reader should assume that any grey dot without a larger colored dot beneath it (which would signal an increase in capacity at the same site) is also used in the cases with more generation sited. The sites are spread evenly throughout the MISO footprint.

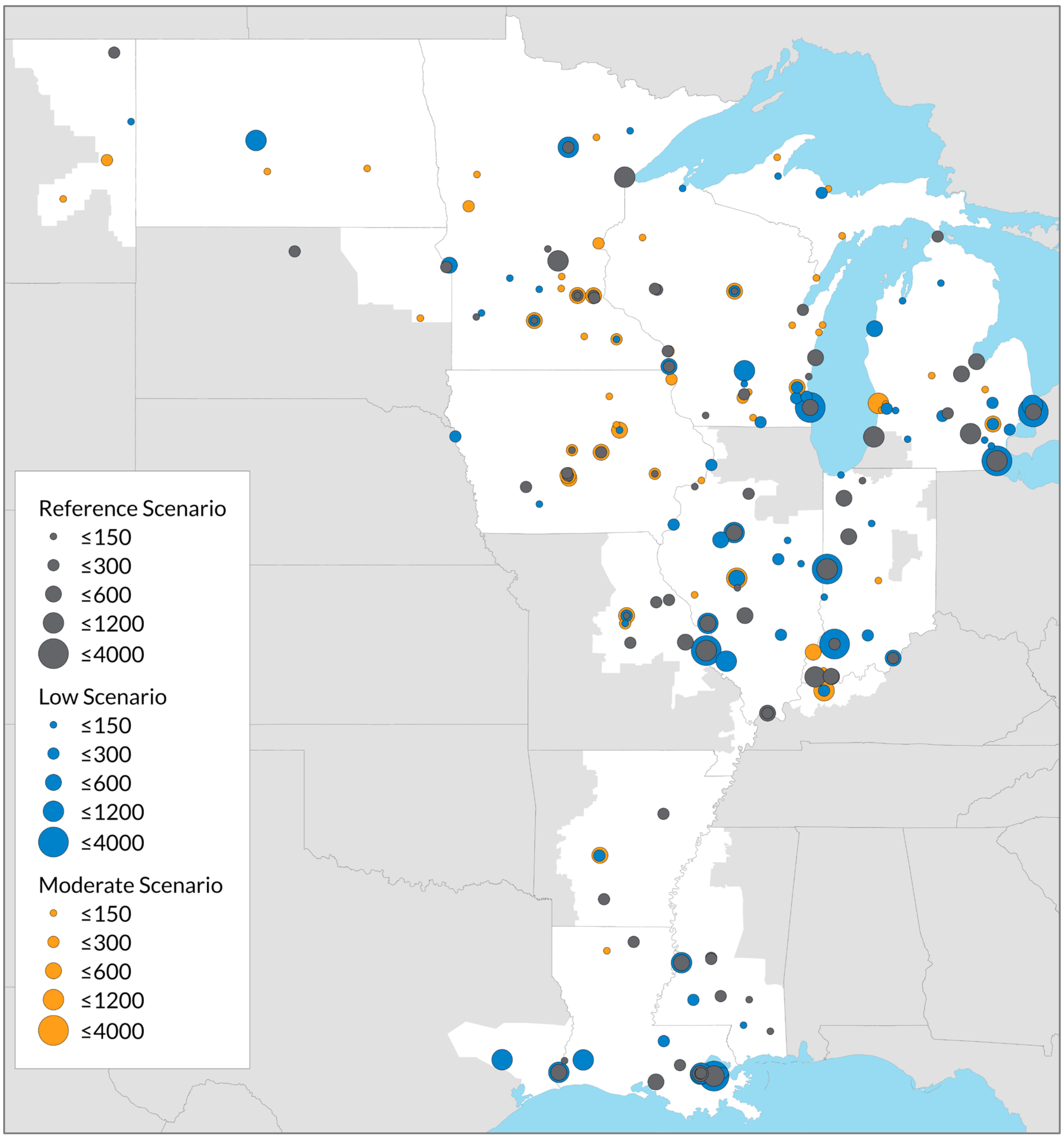

Figure 48: Siting of conventional units (natural gas CC and CT) for production cost model

When building the model in PLEXOS, several simplifying assumptions were made:

1) The transmission system for year 2023 in the MTEP17 model was used. This allowed this study to make use of the RIIA production cost models previously built for MISO study
2) No changes were made to the fuel price assumptions from the RIIA Phase II study. All new natural gas units were simply mapped to the Henry Hub prices
3) Fuel prices were not scaled
4) Non-MISO loads were not increased

The load profiles provided by AEG were for the whole MISO footprint and for each LRZ. To create the loads for the production cost model, which must be assigned to specific buses, the historical distribution of the total LRZ load across buses was used. Although this was the best assumption that could be made at the time of the study, it is an assumption that is incorrect and may introduce errors when examining specifics rather than directional trends. Electrification, by definition, is a shift in the types of loads that are being served. It is not valid to assume that new loads will be served from the transmission system at the same locations relative to one another as in the past. For example, it is likely that a shipping depot (i.e. a distribution center for a large online retailer) would have a larger impact on consumption near an airport to take advantage of the infrastructure, rather than equivalently across a metro area.

8.7 Generation and Transmission Performance under Stressed Conditions

The robustness of the generation and transmission performance can be probed by examining stressed cases, where the load growth due to electrification outstrips the generation expansion. To test the sensitivity of the system to increases in electrification without corresponding growth in generation, a series of stressed cases were examined:

- Low electrification with generation expansion from the Reference scenario
- Moderate electrification with generation expansion from the Reference scenario
- Moderate electrification with generation expansion from the Low scenario

The term "stressed" is used because each case is missing some amount of generation expansion. Through these stressed cases, it may be possible to explore the risk of not preparing adequately for electrification, which may move faster than transmission expansion or generation interconnection in a worst-case scenario.

Beginning with a comparison of the cost to load, Figure 49 demonstrates that a failure to site enough generation to meet growing load through electrification will cause an increase in the cost to load. The dark red line, which has the same load as the Moderate scenario combined with the generation expansion of the Reference scenario, has a cost to load that is higher than either scenario. The increase in cost to load is not as dramatic for the stressed case with the same load as the Low scenario combined with the generation expansion of the Reference scenario (lighter red line). Figure 50 shows a comparison between the Low scenario and the stressed case with the same load as the Moderate scenario and the same generation expansion as the Low scenario. As with the previous figure, the cost to load in the stressed cases is higher overall, but especially during the summer and winter months.

Figure 51 compares the monthly diurnal average load, fuel mix, and LMPs of the Reference scenario and the stressed scenario with the same generation expansion, but load levels aligned with the Moderate scenario. This figure shows a large generation shortfall during every month, suggesting that the MISO load would be relying more on imports to meet its load if adequate generation is not added to the system. Additionally, the figure shows LMPs in the stressed case are much higher in all months, and most months show exaggerated price spikes corresponding to the two daily peaks.

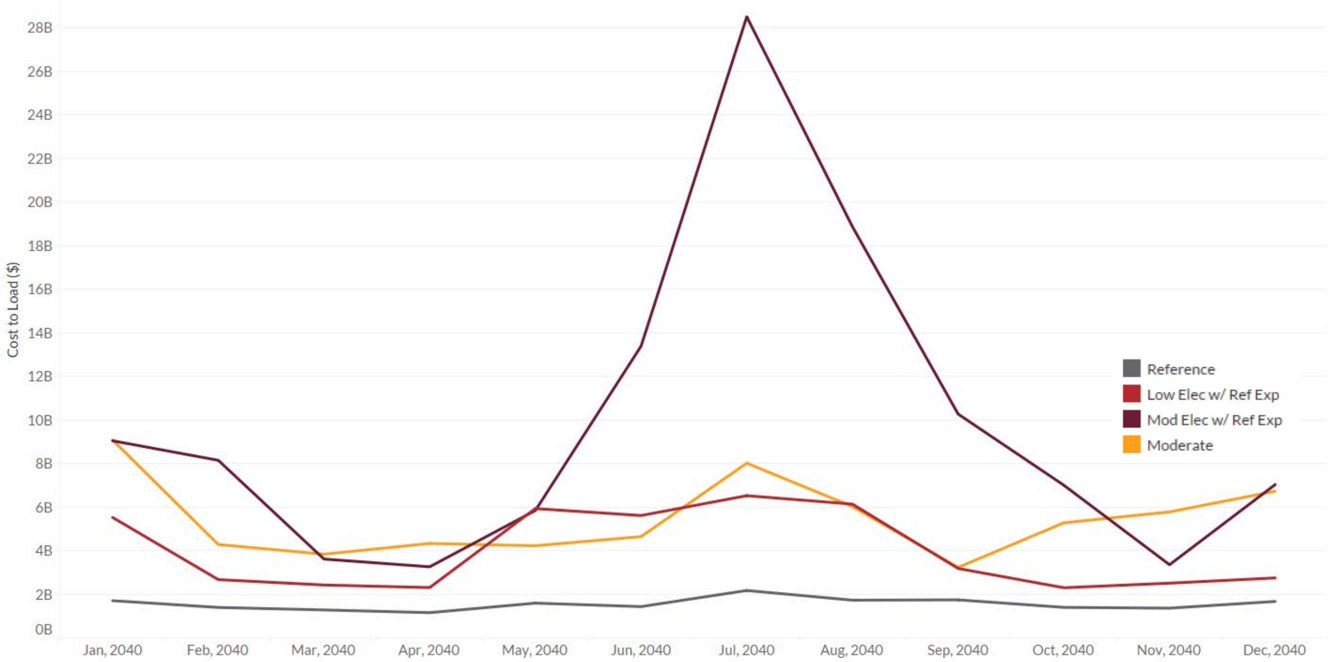

Figure 49: Cost to load for the Reference and Moderate scenarios, compared to stressed scenarios.

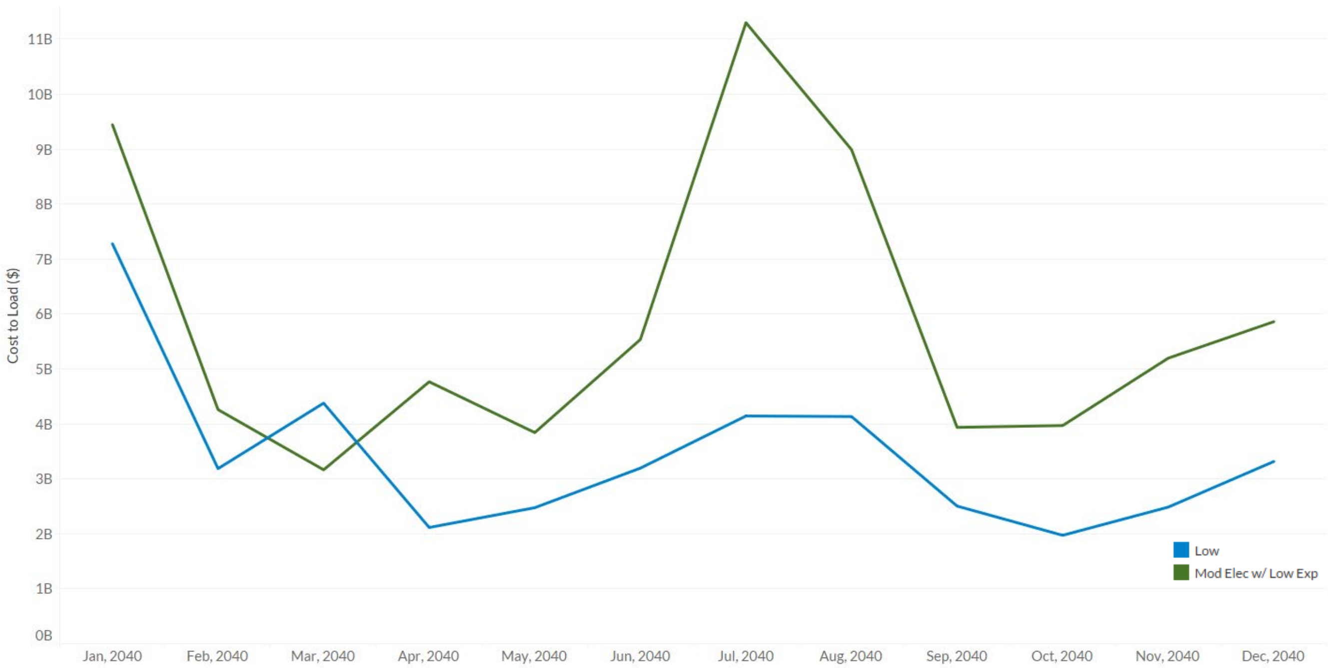

Figure 50: Cost to load for the Low scenario compared to a stressed case with a higher load, but the same generation expansion.

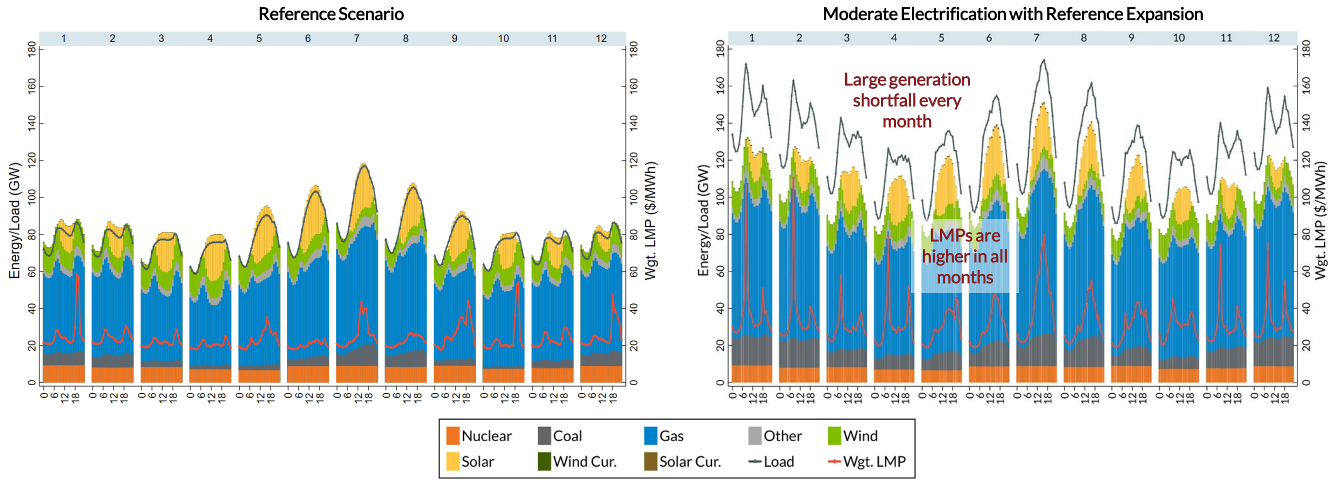

Figure 51: Monthly average diurnal load, fuel mix, and LMPs for the Reference scenario (left) compared to a stressed case (right) with the same generation but increased load due to electrification.

For CT gas units, ST coal units, and ST gas units, the annual ramping generally increases as the load increases due to electrification in the stressed cases (Figure 52).

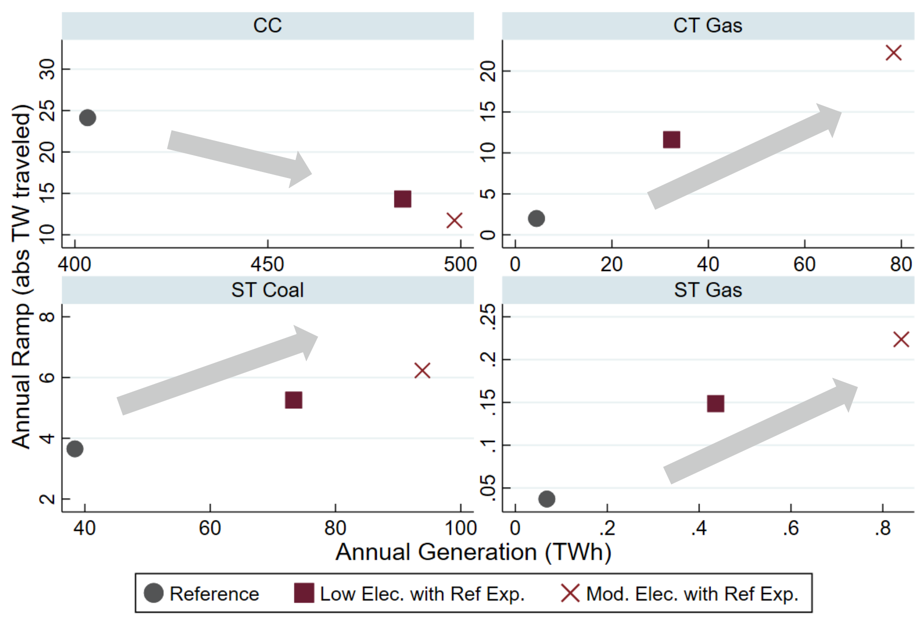

Figure 52: Annual ramp of conventional units for the Reference scenarios compared to cases with the same generation fleet, but increased load due to electrification.

Finally, delving into the interregional flows for the stressed cases, Figure 53 shows that the imports from PJM increase during all quarters. The behavior of the other seams is a bit more complicated — some quarters show increased export hours from MISO as the MISO generation shortfall increases (see arrows). Nevertheless, even along those seams, the number of hours where MISO imports power also increases. If the generation needed to supply electrification does not show up on the MISO system, MISO could need the capability to increase imports.

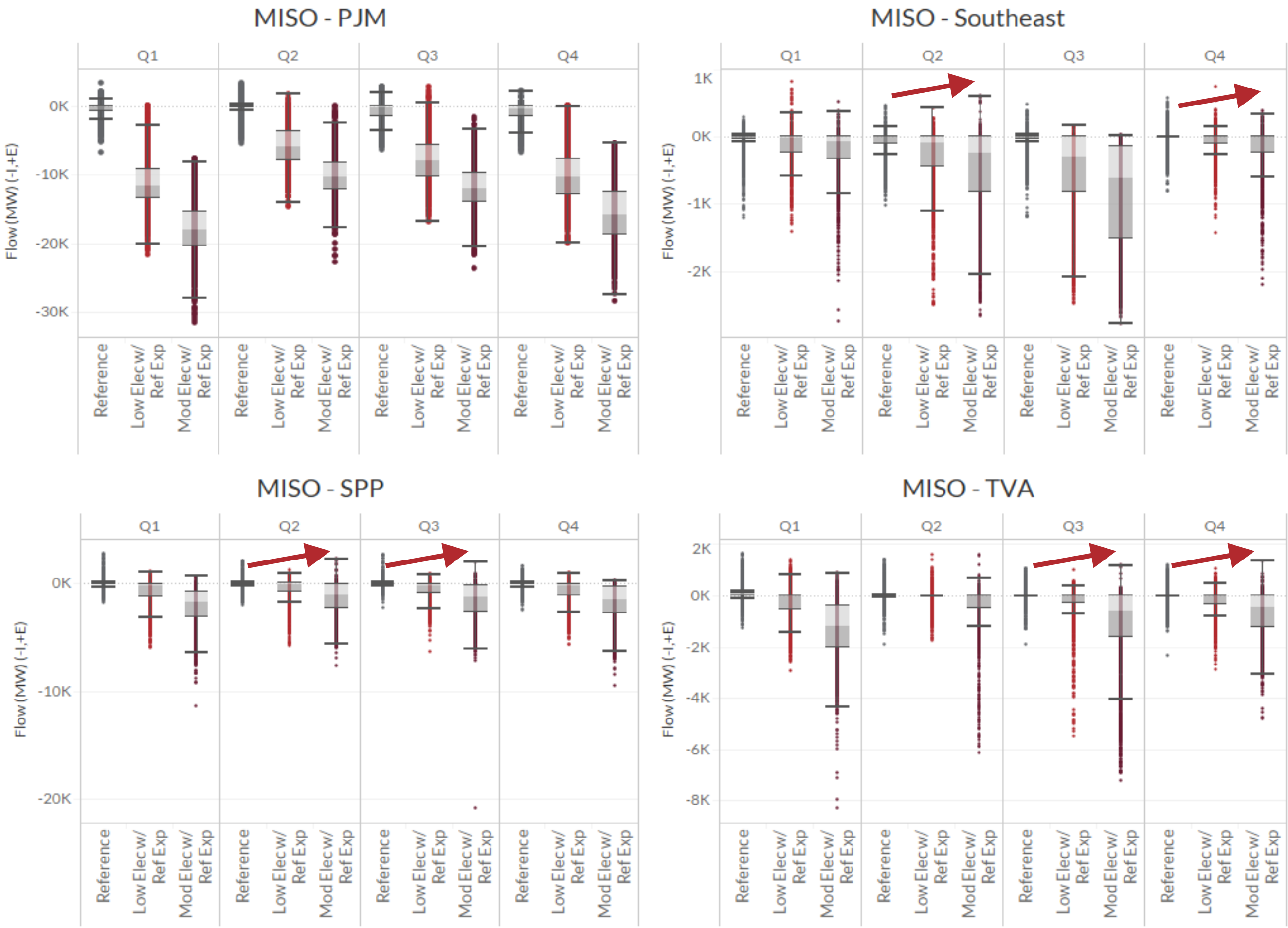

Figure 53: Interregional flows between MISO and its neighbors for the stressed cases, compared to the Reference scenario. Note different y-axis ranges.

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