Filling in the Gap: Added Value from Load Shifting from Avoided Cost and Emissions in the Midwest

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Abstract

As basic electric efficiency measures reach saturation in state energy efficiency programs - or are superseded by updated codes and standards - utilities need to fill the gaps with more advanced and often costlier measures. At the same time, due to the growth of renewable generation, utilities are beginning to place greater importance on measures that not only reduce overall energy but also shift the *time* of that energy use in a way that reduces cost and emissions without disrupting the grid. One major barrier that occurs through load shifting is the potential increase of overall energy use, which conflicts with energy efficiency policy and creates a potential load building incentive. Currently, regulators in Minnesota lack the geographically-specific information needed to assess the system value of load shifting to weigh these tradeoffs.

This research addresses this barrier by quantifying the economic, energy, and emissions impacts of measures that shift load with or without saving energy. The goal of the research is to identify how these measures may fit within a Midwestern state's energy efficiency program. We model multiple measures in a variety of future planning scenarios that include higher penetrations of renewable generation as well as increases in electrical load through electrification.

The paper's results will stress the impact of measures that shift load on avoided cost and emissions. We also highlight how this research builds a Midwest-focused foundation for consideration of load shifting impacts in utility energy efficiency programs.

Introduction and Background

As lighting and other basic efficiency measures reach saturation, utility energy efficiency programs need to fill the gap with more advanced and often costlier measures. At the same time, due to changing load shapes and generation mix, utilities are increasingly interested in measures that shift the *time* of energy use in addition to reducing overall energy use. Utilities in Minnesota offer incentives separately from energy efficiency programs that target this goal, such as demand response programs, but there is also overlap between energy efficiency and load shifting. Some energy efficiency measures have a demand reduction benefit and likewise some load shifting measures reduce energy. As renewable generation increases, increasing both the daily and yearly variation of emissions and avoided cost profiles, utilities are beginning to place greater importance on measures that not only reduce overall energy but also shift the *time* of that energy use. But one major barrier that occurs through load shifting is the increase of overall energy use, which conflicts with energy efficiency policy and creates a potential load building incentive.

Currently, regulators in Minnesota lack the geographically-specific information needed to assess the system value of load shifting to weigh these tradeoffs.

This area of work is especially valuable in Minnesota where the electricity supply mix is changing rapidly. Currently, Minnesota generates about 20% of its electricity production from non-hydroelectric renewable energy resources, and hydroelectricity adds an additional 1.6% (EIA 2018a). Like elsewhere, the state's large baseload coal generation is being retired. Xcel Energy, which delivers 45% of Minnesota's electricity sales (EIA 2018b), has plans to retire all coal-fired generation facilities by 2030, replacing the large majority with utility-scale wind and solar power (Northern States Power Company 2019). Great River Energy, the state's largest generation and transmission cooperative, also recently announced closure of their 1.1 GW Coal Creek power plant in 2022, one of the last remaining large coal facilities serving Minnesota (GRE 2020). While numbers have not been finalized in utility resource plans, we estimate that 50% of the statewide electricity production will come from wind and solar by 2035. Additionally, MISO's Transmission Expansion Plan process continues to show a need for peaking power plant resources, as well as energy efficiency and storage, in the short term (MISO 2018). If, as anticipated, wind and solar become the dominant generation resources in the region (Clean Power Research 2018), intermittent production and ever increasing differentials in marginal prices will be the new standard throughout a typical day in Minnesota.

Many electric utilities in the state have growing interest in activities that shift the timing of energy use in addition to, or instead of, reducing overall energy use. In addition, there are opportunities within Minnesota's current energy efficiency framework to design future programs that take advantage of load shifting as well as energy savings opportunities. Minnesota's Conservation Improvement Programs (CIPs) currently allow for load shifting measures that save energy (Minnesota Statutes, 2019). Beyond that, given that state policy is designed to correct the disincentive of decreased sales, efficiency programs that shift load while *increasing* energy use (e.g. thermal ice storage) are not eligible to be counted towards statewide energy efficiency resource standards. Consequently, there is a lack of robust data on the benefit in Minnesota of load shifting measures, especially looking ahead to Minnesota's changing grid. The load shapes that are used in technical reference manuals (TRMs), cost effectiveness calculations, and efficiency portfolio planning have not been maintained and were not initially developed with load shifting as a primary consideration. And the energy efficiency planning conducted by some utilities does not typically consider a broad spectrum of different future economic and emissions scenarios, and how the load shifting aspects of some measures could benefit the utilities – and their ratepayers – in those scenarios.

This research, funded through the Minnesota Department of Commerce's Conservation and Applied Research and Development grant, addresses these barriers by quantifying the Minnesota-specific economic, energy, and emissions impacts of measures that shift load with or without saving energy. The goal of the research is to identify how these measures may fit within the state's energy efficiency program. We model multiple measures in a variety of future planning scenarios that include higher penetrations of renewable generation.

The paper's results will stress the impact of measures that shift load on both avoided cost and emissions. We also highlight how this research builds a foundation in Minnesota for consideration of load shifting impacts in state and utility energy efficiency programs.

Methods

We began our research by engaging the primary stakeholders; largely utilities in the state which would directly benefit from the research, as well as other research institutions. The research team conducted a kick-off meeting to outline our approach and received feedback and suggestions for modifications. This stakeholder group then continued to play a role in providing feedback throughout the research.

To quantify the emissions, cost, and energy impact from load shifting measures, we developed hourly annual models (i.e., 8760 models) of energy, costs, and emissions for both present day and the future. Certain aspects of the model were constrained by the availability of data and the level of assumptions we needed to make. For example, the three grid regions in our analysis include a Midwestern electric utility, a statewide region, and the Midwest Independent System Operator (MISO); we procured energy and emission data for present day and future scenarios but not for all three grid regions. In this section, we provide background on the decision points for each element of the model. Figure 1 provides a simplified schematic that represents the key steps in both the development of our model and our ultimate analysis.

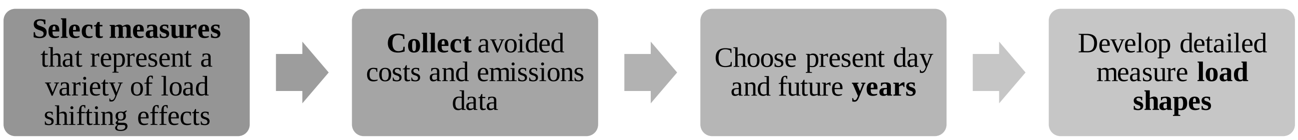

Figure 1: Methods summary: key steps in the development of the model

Measure Selection

To select measures, we identified a mix of residential and commercial measures as well as measures with various impacts on energy reduction and load shifting. We included a diverse set of measures that fit in *one* of the following categories:

(1) included in state efficiency program and has a potential to shift load,
(2) has the potential to save energy and shift load but not typically included in state efficiency programs,
(3) typically included in state efficiency programs and no shifting impact, or
(4) shifts load and may increase overall energy use.

We included two energy efficiency measures with no load-shifting potential to represent measures currently in state efficiency programs. Similarly, we included several purely load shifting measures to demonstrate the potential for cost and carbon savings even when no electricity is saved. We also categorized each of the measures based on the type of load shift: event-based, regularly-occurring shift, or pure energy efficiency with no shift. An event-based measure only shifts load on a select number of days, typically when demand is high, and utilities are near capacity. A measure categorized as a regularly-occurring shift can shift energy use each day from one period of the day to a different period of the day.

In Table 1, we provide the full set of measures developed for this study. For each measure, we include the sector, type of load shift, and baseline comparison shape. For purposes of this paper, we focus on three measures that represent a mix of the load shifting types: air source heat pump with demand response (event-based); controlled electric vehicle charging (regularly-occurring shift); and lighting efficiency and control (energy efficiency). These measures are italicized in Table 1.

Table 1. Summary of measures

Measure	**Sector**	**Type of load shift**	**Baseline**
Smart thermostats with DR	Residential	Event-based	SEER 12 AC with Current mix of programmable + smart Tstat
Air source heat pumps (ASHP) with demand response control	*Residential*	*Event-based*	*Electric resistance heat + SEER 12 AC*
Envelope measures (insulation, air sealing) combined with ASHP	Residential	Event-based	Baseline space conditioning + median SF in MN
Networked lighting controls with demand response	Commercial	Event-based	LED lighting
Strategic energy management with demand focus	Industrial	Event-based	Traditional industrial load
Critical peak pricing (behavior change)	Residential	Event-based	Typical consumer behavior
Phase change materials for space conditioning	Commercial	Regularly-Occurring Shift	Space conditioning (VAV – no PCM)
Phase change materials for refrigeration	Commercial	Regularly-Occurring Shift	Refrigeration
Active ice thermal storage	Commercial	Regularly-Occurring Shift	Space conditioning (VAV)
Electric water heater controls	Residential	Regularly-Occurring Shift	Electric resistance with no controls
Electric vehicles with charging controls	*Residential*	*Regularly-Occurring Shift*	*Level 2 uncontrolled charging*
Plug load controls	Commercial	Energy Efficiency	Typical office settings
Lighting efficiency and controls	*Commercial*	*Energy Efficiency*	*Fluorescent bulbs*

Air source heat pumps include controls which allows utilities to remotely adjust heating or cooling load (with some pre-cooling or pre-heating of the home prior to the event and a recovery period after the event). Electric vehicle charging is enrollment of participants in a managed controlled charging program that sets charging time between 9 pm and 5 am. Lighting efficiency and control is a typical LED retrofit along with daylighting, task tuning, and occupancy controls.

Avoided Cost and Emissions Data

The availability of cost and emissions data varies by grid region (utility, state, and independent system operator region) and timeframe of analysis (present day and forecast). Avoided costs include both avoided energy costs and avoided capacity, transmission, and distribution costs; and we collected costs that reflect present day, or the current market at both the ISO- and utility-level, and future energy costs from utility forecasts. Emissions data were derived from utility-specific forecasts (for present day and future estimates), statewide data (for present day and future estimate) and MISO fuel mix data (for present-day). Table 2 provides an overview of the hourly data available. In the case of state level costs, the data were not applicable because energy costs are not typically calculated for the area within one state's boundaries. This section explains the collection this cost and emissions data in more depth. Capacity costs are not listed in the table, though will be discussed further below.

Table 2. Summary of data source by scenario

		Timeframe			
		Current Year		Forecast	
		Costs	Emissions	Costs	Emissions
Grid Region	Utility	Midwestern IRP	Midwestern IRP	Midwestern IRP	Midwestern IRP
	State	*Not applicable*	EPA Hourly Emissions Data	*Not applicable*	EPA Hourly Emissions Data + Known Retirements
	ISO	MISO Market Data	MISO fuel mix + marginal plant data	*No available data*	*No available data*

Avoided Energy Cost

The primary source for present-day energy costs is MISO's publicly available market data. MISO provides day-ahead and real-time wholesale market prices for the Minnesota Hub, which encompasses all of Minnesota as well as parts of Iowa, Wisconsin, and the Dakotas. By comparing the average price profiles, we identified that the real-time and day-ahead prices correlate well with one another. As the real-time prices represents the most up-to-date market conditions, we chose to use real-time prices only in our analysis.

For future energy costs, we apply one Minnesota utility's forecasted energy prices to our analysis. While ideally our data would include multiple utilities for forecasted energy prices, using only one utility forecast still represents statewide effects since there is good correlation between current-day statewide and utility prices.

Avoided Capacity and Distribution Cost

As a number of these measures shift load from peak periods, avoided capacity and distribution is an important consideration. However, capacity cost data is much less refined than marginal energy cost data. For generation and transmission capacity, we collected yearly values ($ per kW-year) used by Minnesota utilities in their benefit cost analyses for integrated resource planning. As most utilities regard these costs as trade secret, we were again limited by the availability of data such that the capacity costs reflect only one utility in the state.

Avoided Emissions Data

For avoided emissions, we created an annual model representing hourly emissions rates for both the current generation mix and scenarios for the future generation mix where renewable energy and natural gas replace coal generation. One question we addressed is how results might vary depending on which grid region is assumed for the emissions footprint. We examined three distinct grid regions, each of which would make a reasonable assumption but carries distinct pros and cons:

- **Utility specific region:** In a vertically integrated state (like MN), this is the most direct way to evaluate how demand-side measures will change which type of generation gets built and operated. However, it often requires utility specific data, which is often proprietary.
- **Statewide Region:** This region (i.e. the Minnesota footprint) aligns with state specific policies, goals, and carbon tracking. However, given that there is no single statewide utility, it does not align with a natural planning or operational footprint. A statewide emissions footprint can also average out what might be large carbon variations across utilities.
- **ISO Region:** This reflects real time short-term dispatch decisions and is the closest to what would likely be the emissions outcome were these measures dispatched today. However, in a vertically integrated state, this loses the value of utility specific planning and has low forecast certainty.

For the ISO-level dataset, we used publicly available MISO fuel mix data. This dataset provides both the marginal plant fuel at a 5-minute increment and total generation by fuel type at a 1-hour increment for each of the three MISO subregions. As MISO covers a large geographic area, we only used MISO North, which covers Minnesota, Wisconsin, Iowa and parts of the Dakotas. However, MISO determines the marginal plant at each interval across its entire footprint, so we relied on data from the Central and South region when the marginal plant was located there to create a full dataset. Using these two datasets, we estimate both a marginal emissions factor per hour as well as an average emissions factor per hour.

For the state of Minnesota, we used EPA plant-level data which contains hourly generation data by plant. This source provides a more granular estimate of average emissions but does not allow for the calculation of marginal emissions. For future scenarios, we modeled hourly average emissions rates based on the future resource mix in existing approved integrated resource plans. This, therefore, accounts for planned fossil retirements and additions of renewable energy. The hourly dispatch of this future mix is based on replicating hourly patterns seen in historic data, in both the EPA and MISO data sets. That is, in every hour, renewable resources are taken if available, nuclear plants and a percentage of coal (if it still exists) are must-run, and natural gas plants will fill in any supply gaps. These methods are similar to those used by the EPA in their emission forecasting model, Avoided Emissions and Generation Tool (AVERT), though calculated for Minnesota only.

And finally, the utility-specific dataset is from a Midwestern utility's present-day hourly emissions factors. For future scenarios we used proprietary outputs from one Minnesota utility's Integrated Resource Plan. This allows us to compare results from a planning forecast that is utility specific versus for the entire state.

Future Year Selection

Based on the data collected for emissions and energy cost, we selected a set of future years to focus on in this analysis. We include years in this analysis that represent the variation in generation mix across various geographical footprints (i.e. different regions in the state vs. statewide vs. ISO-level) and variation across time.

The mid-term scenario represents year 2026 while the long-term scenario represents year 2034. We used 2034 for the long-term scenario as utilities in Minnesota currently forecast out to 2034 in the planning documents submitted to the state. The year 2026 then serves as the mid-point between the present-day scenario (2018), and the long-term scenario. Additionally, as these years fall before and after the large decommissioning of coal plants serving Minnesota in 2030, we are able to analyze the impact of little to no coal in the market and how increased renewable energy capacity changes the impact of load shifting measures. Table 3 illustrates these differences, showing the percent renewable capacity (primarily wind) in the present-day, mid-term, and long-term as well as across grid regions.

Table 3. Percent renewable energy capacity by grid region and year[1]

Grid Region	Present day (2018)	Mid-term (2026)	Long-term (2034)
Utility	25% renewable	45% renewable	59% renewable
State	27% renewable	40% renewable	54% renewable
MISO	13% renewable	*N/A*	*N/A*

Load Shape Development

For each of the 13 measures identified, we developed hourly load shapes that represent the change to system electricity at each hour. To collect the necessary data points for development of the load shapes, we relied on a mixture of empirical data from technology field tests conducted by our two organizations as well as secondary sources and research. As noted in other studies, it can be difficult to find geographically specific load shapes and technology-specific rather than end-use specific load shapes (Mims et al. 2017). Where empirical data was unavailable for a few measures, we combined Minnesota-specific assumptions with energy modeling to estimate the 8760 load shapes. Additionally, we relied on typical seasonal or weekday patterns to extend several load shapes into 8760 data.

Each of these load shapes were developed to be optimized around price, meaning that the shift or shed of energy occurred in the middle of the day when wholesale prices are high. Figure 2 illustrates this – showing that MISO prices, on average, are highest from around 5 am to 9 pm.

[1] Note that these renewable capacity projections do not include Great River Energy renewable additions announced in May 2020.

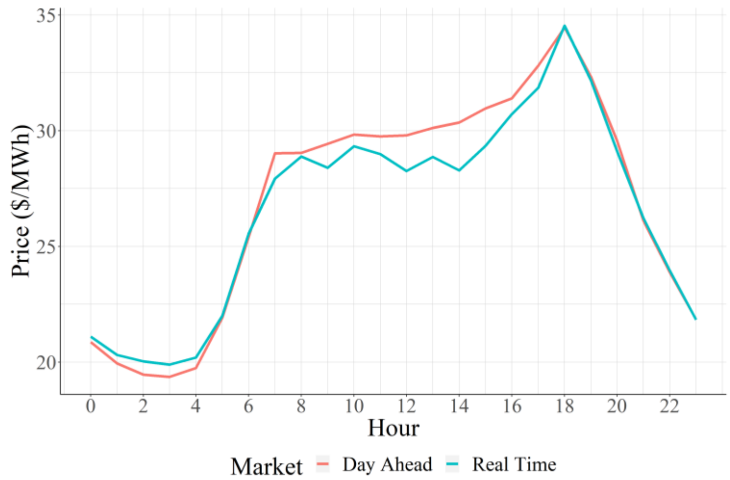

Figure 2. Hourly average prices - Minnesota Hub real-time vs day-ahead

For regularly occurring shifts, we ensured that modeled load shapes followed this pattern and the load shapes we were able to collect empirical data for naturally followed this pattern.

For each event-based load shape, we assumed a set number of called events within each year. As we had limited information on how utilities determine when to call events and the available data did not always link the event to an exact date, we used wholesale price data to determine when events occurred. To do this, we identified twenty days with the top wholesale hourly prices in a year and used the days as our events. This method also allowed us to use future price data to ensure events were called on days when prices were high. On the day of the event, we then used wholesale price data for that day as well as assumptions on technology or user acceptance restraints to model the exact pattern of the events. Due to differences in temperature or time of day when prices were high, each event had slight variations in its shed pattern.

We also developed a sensitivity analysis that instead optimized around emissions rather than prices for two of the measures, electric vehicles and air source heat pumps + demand response. For example, Figure 3 shows the hourly averages for the 2018 MISO marginal and average emissions datasets we created. The figure illustrates that the marginal emissions are typically lower in the middle of the day while the average emissions are typically lower in the middle of the night. The average emissions pattern correlates with the pattern for prices while the marginal emissions pattern is opposite. These patterns also differ when looking at future emissions scenarios, with some showing lower emissions in the middle of the day and others showing lower emissions in the middle of the night. For that reason, in addition to the load shapes that shift energy away from middle of the day, we also created load shapes that shift energy away from the middle of the night to run emissions scenarios against.

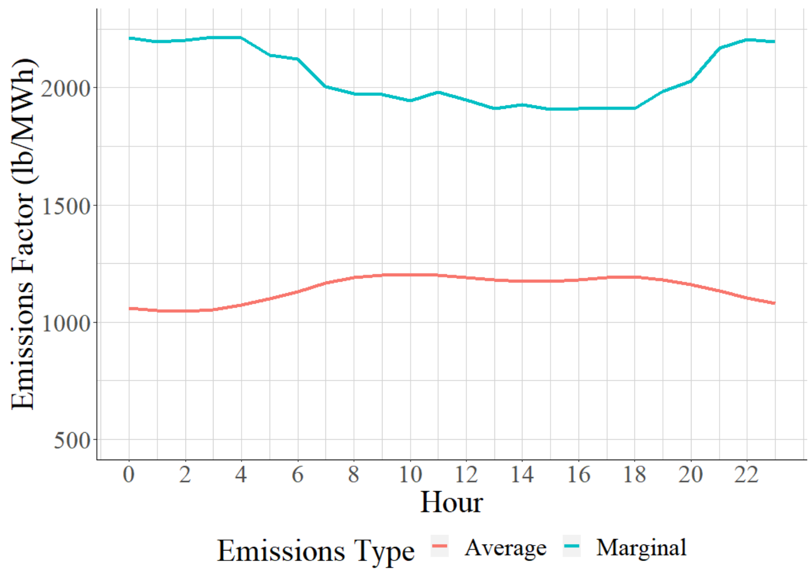

Figure 3. MISO marginal versus average emissions factor – hourly average

Lastly, in an effort to draw comparisons between types of measures, we scaled the extent of each measure to achieve 500 kW peak savings statewide. This method allows for a more direct comparison of time-varying impact as it lessens the influence from differences in the magnitude of savings among measures. To make this aggregation, we found the peak hourly kW savings for each measure using the 8760 load shapes we developed. We then divided 500 kW by that peak hourly kW value to estimate the number of customers necessary to hit 500 kW peak savings for each measure. Lastly, we multiplied the load shape by that number of participants. For measures with a higher kW savings value per participant, such as lighting efficiency and controls, it requires less participants to hit the 500 kW while measures, such as residential smart thermostats require significantly more. For example, Table 2 illustrates these numbers for the three measures highlighted in this paper – with the commercial measures having significantly less participants than the residential measures. This served as an alternative approach to estimating expected penetration rates for each measure.

Table 4. Measure load shape modeling assumptions

Measure	Baseline	Number of Participants for 500 kW demand reduction
Air source heat pumps with DR	Electric resistance heat + SEER 12 AC	341 single family residential homes
Electric vehicles	Level 2 uncontrolled charging	307 passenger vehicles
Lighting efficiency and controls	Fluorescent lighting	55 mid-sized offices

Figures 4 and 5 illustrate the differences in the four measures by showing the hourly average across the year of the baseline electricity usage of each end use compared to the hourly average of the electricity usage after the shift or efficiency measure is applied. Figure 6 shows the same for one event for the air source heat pump and demand response measure. The lighting efficiency measure reduces energy over the entire day, the electric vehicle measure shows reduced energy use during peak times and increased energy use during non-peak times, and air source heat pumps show a reduction in demand for the peak hours within a day.

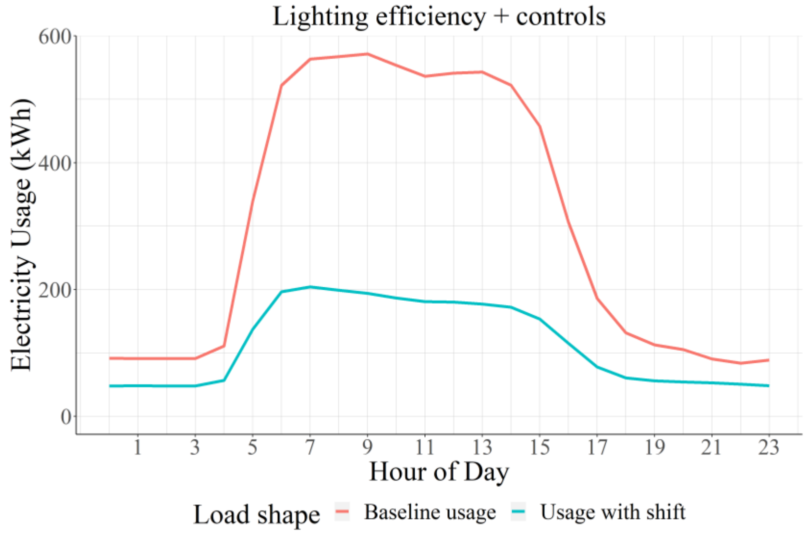

Figure 4. Commercial lighting hourly average electricity use before and after LED retrofit

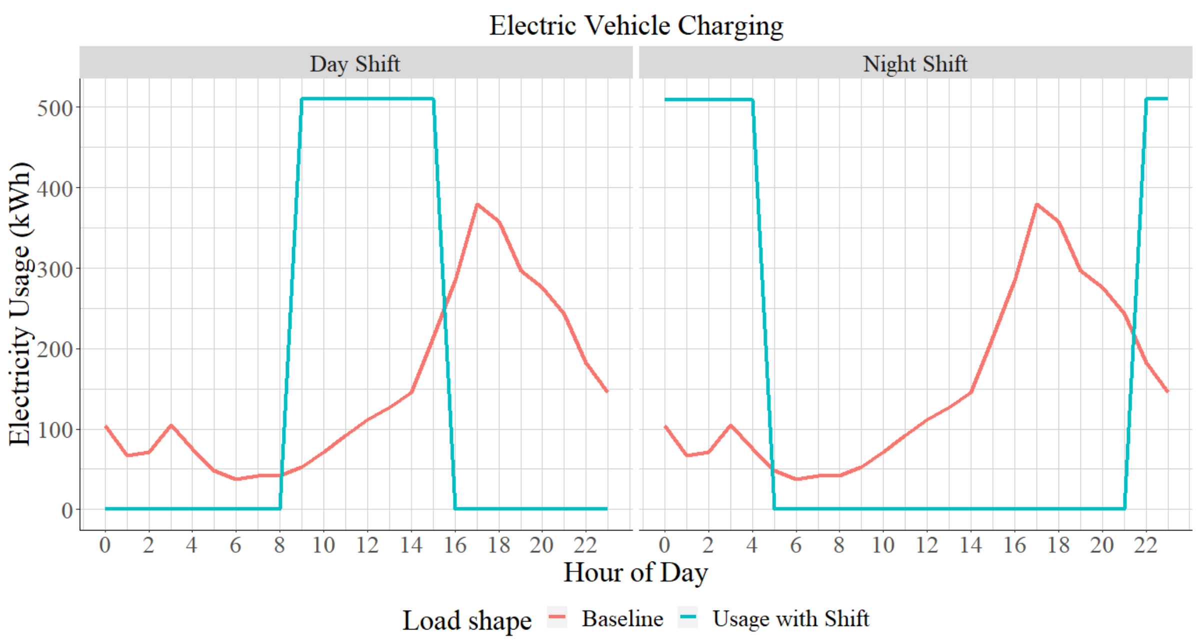

Figure 5. Electric vehicle-controlled charging vs. uncontrolled charging, average hourly use. Right shows shift to use energy during the day, left shows shift to use energy during the night

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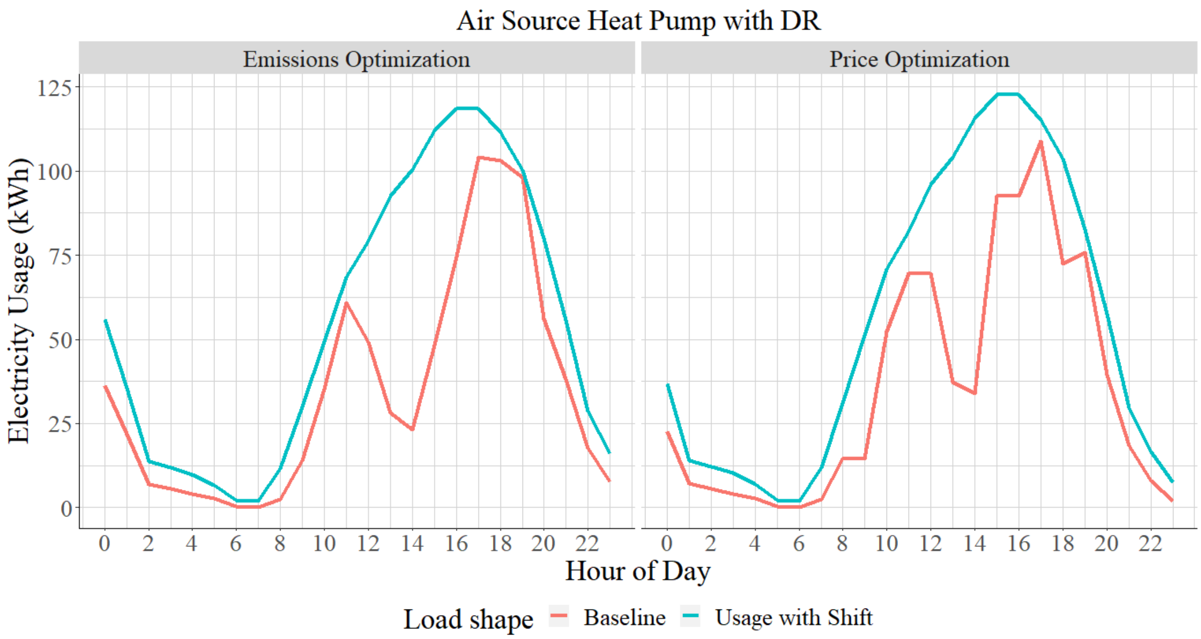

Figure 6. Air source heat pump with demand response hourly average electricity usage compared to SEER 12 AC

Results

Price Optimization

The results show a wide range of cost savings compared to the baseline load shape. Figure 7 shows the percent monetary savings compared to the baseline, which range from about 25 percent to over 60 percent. The results show that the efficiency (lighting efficiency + controls) measure has the highest percent cost savings over baseline. Additionally, it shows that measures that shift load and save no energy, such as electric vehicles, can still lead to moderate percent cost savings. This demonstrates the value of shifting load from high price times.

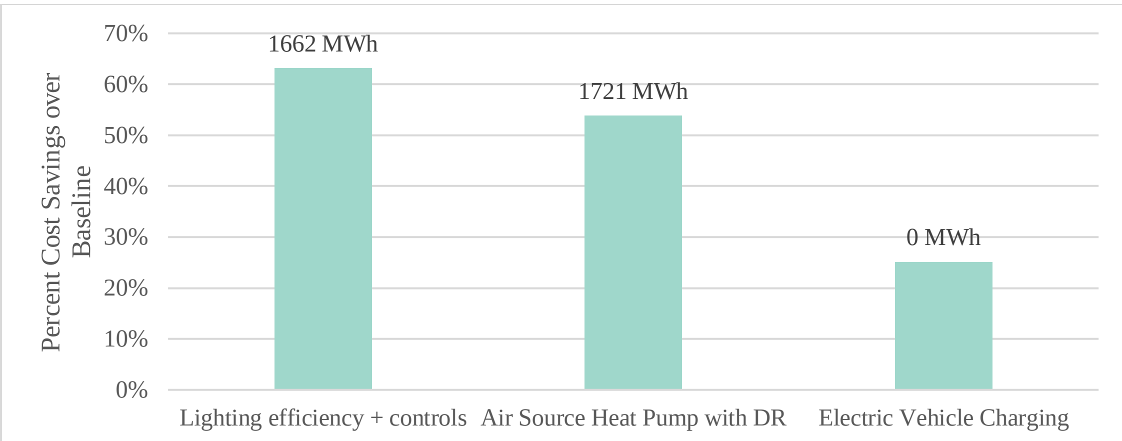

Figure 7. Percent cost savings over baseline using current day MISO prices. Labels on top of the bars show the cumulative energy savings across the year.

Over time, the monetary savings over baseline remain relatively constant for each of these measures. Figure 8 shows the changes from baseline for current prices, mid-term prices (2026), and long-term prices (2034). The shift measure, electric vehicles, show a small decrease in percent savings over baseline across time. This change is related to more renewables being online in future years, which results in the highest prices occurring in the middle of the day less frequently.

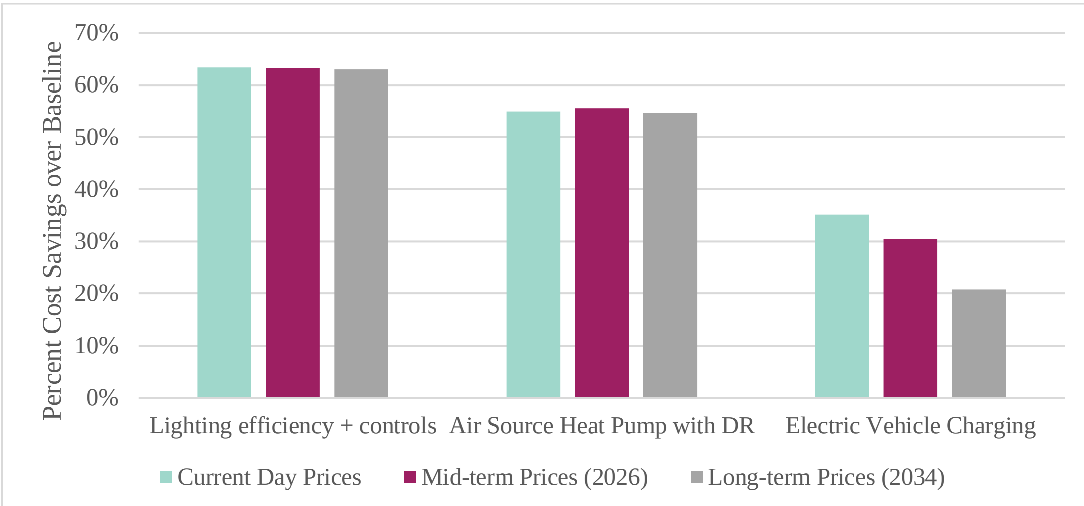

Figure 8. Percent cost savings over baseline over time for current day, mid-term, and long-term utility prices.

We also calculated the emissions implications from shifting load based on prices in the wholesale market. Figure 9 illustrates the percent savings over baseline for marginal and average emissions when we optimized for current-day MISO prices optimization. For all measures, optimizing on price leads to average emission savings as well, because our research suggests that the pattern of both prices and average emissions are highest in the middle of the day. Similarly, for two of the three measures presented here, the results from calculated changes in marginal emission show a similar pattern. However, for electric vehicle charging, which is just shifting energy use and not saving any energy, optimizing on price leads to higher marginal emissions compared to the baseline. This is mostly a result of the fact that marginal emissions exhibit a negative relationship with price.

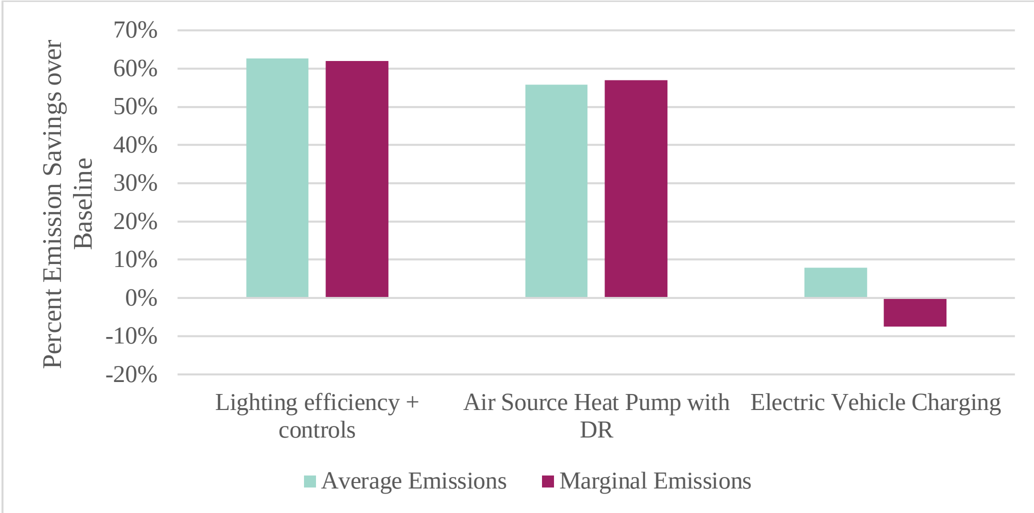

Figure 9. Percent emissions savings over baseline for cost optimization scenario – present day MISO average and marginal emissions

Capacity, Transmission and Distribution Cost Savings

The other benefit that load shifting provides is avoided capacity, transmission, and distribution costs. For each of the four measures, Figure 10 illustrates the breakdown of how energy cost savings, capacity cost savings, and transmission and distribution cost savings contribute to total cost savings. The figure illustrates how capacity savings comprise a much larger percentage of overall savings for load shifting measures. At the extreme, capacity savings make up 50 percent of total cost savings for electric vehicles and transmission and distribution savings add another 9 percent. This illustrates the added benefit of load shifting measures' ability to avoid energy use during peak times and help reduce constraints on the system.

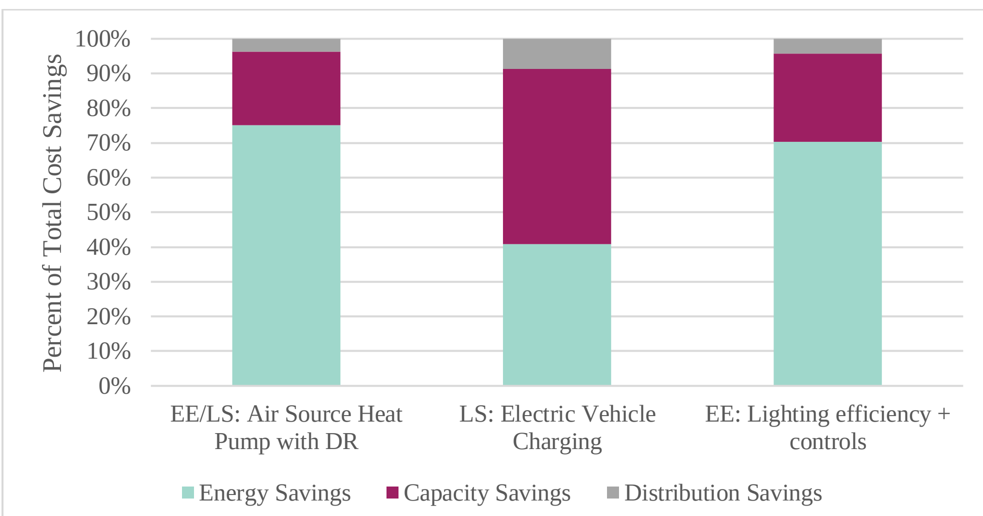

Figure 10. Breakdown of cost savings by energy, capacity, and transmission and distribution using current day values

Emissions Optimization

Analogous to price optimization, several emissions optimization scenarios calculated the carbon savings if loads were instead shifted to reduce energy use during times of highest emissions. While price and emissions are fairly correlated in the current MISO market, this analysis allowed us to examine the changing emissions dynamics of future years as the grid mix changes.

Our emissions analysis examined results across eight different emissions scenarios, which vary by year and by geographic footprint. In all scenarios except for one, we used the average emissions rate for a given hour. We analyzed the value of load shifting for two load shapes, listed below along with a reminder of the baseline to which they are compared, and the number of participants required to achieve a 500 kW demand reduction.

Measure	Baseline	Number of Participants for 500 kW demand reduction
Air source heat pumps with DR	Electric resistance heat + SEER 12 AC	341 single-family residential homes
Electric vehicles	Level 2 uncontrolled charging	307 passenger vehicles

The heat pump measure has the highest emissions savings over baseline, which is a result of the energy savings from switching from electric resistance heating. The incremental emissions savings from deploying demand response is on the order of 0.1%. This is largely because demand response events happen only a limited number of times per year, and the length of time available to shift these thermal loads in a typical Minnesota home is only 2-3 hours, which does not provide significant emissions changes.

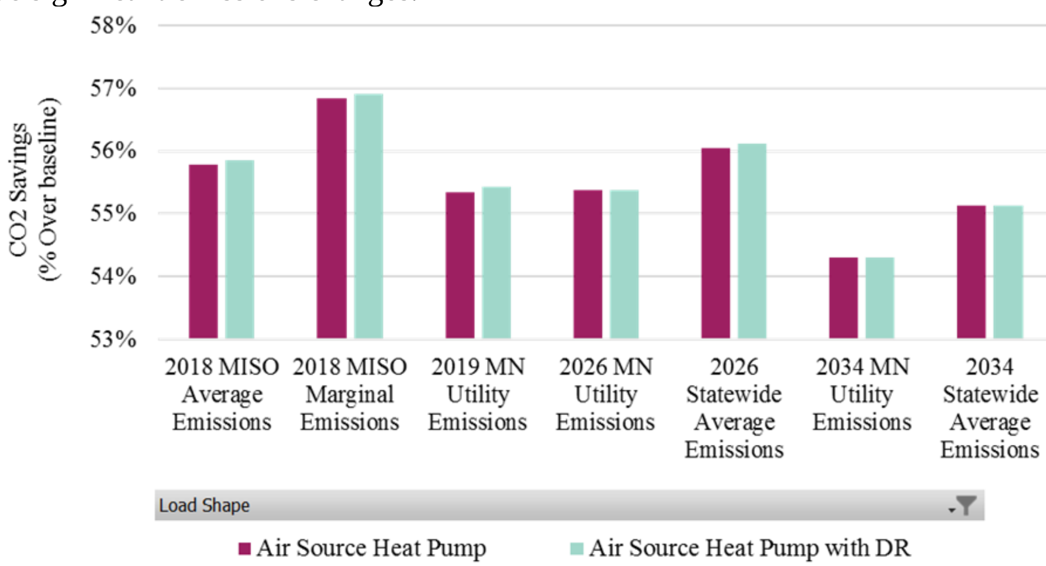

Figure 11. Air source heat pump carbon emission savings over baseline across 8 emissions optimization scenarios

Electric vehicle charging is the one exception where results show a high degree of variation based on emissions footprint. Since shifting EV charging times does not save energy, all of the carbon savings comes from time-of-day emissions variations. Nighttime charging shows higher emissions benefits than daytime charging with two exceptions: the current (2018) MISO marginal emissions, and the 2034 statewide emissions profile. This is for two very different reasons. In 2018, a large portion of MISO's nighttime marginal emissions are from must-run coal plants. In 2034, it is a result of high solar penetration during the day.

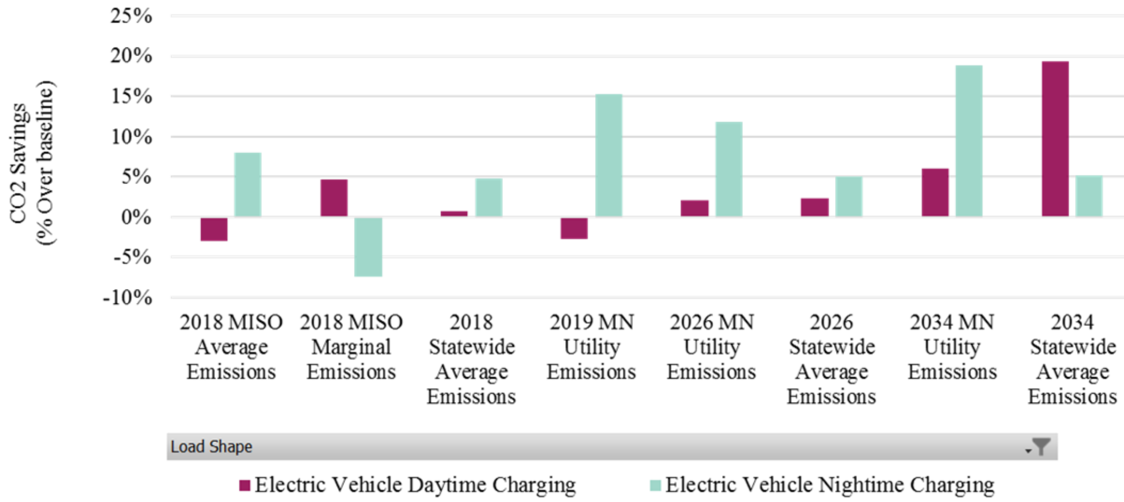

Figure 12. Electric vehicle carbon emission savings over baseline across 8 emissions optimization scenarios

Overall, optimizing load shifting around emissions provides very different results for these two measures, an indication that the baseline measure is a critical point of comparison, and in particular whether that baseline measure uses more energy. These limited results indicate that optimizing around emissions has minimal carbon benefit over optimizing around wholesale market price, in the near term. The variation from these three measures is 0-6%. However, since future prices were not available for this analysis, results for future years are uncertain. Finally, load shifting to daytime energy use has emissions benefits in the future years, as more solar comes online, especially if energy can be avoided during the early evening hours (as with electric vehicles).

Discussion and Recommendations

The results from this analysis show that load shifting measures can have a positive impact on both emissions and energy savings. Although this study's future scenarios show that absolute emissions impacts go down, these measures have the potential to have a sizeable impact on utilization of intermittent renewable resources. By shifting energy use to utilize renewables when they on the grid, these measures can help avoid curtailment of renewable energy resources when the demand is not there and reduce the use of fossil fuels during periods when renewable sources are not producing energy.

These results can directly inform state efficiency programs and offer evidence of the benefits of including non-traditional energy efficiency measures. Furthermore, our results show that there are typical load shifting measures that can also save energy, which would fit directly into the current regulatory framework. For example, the phase change materials measure included in this analysis saves energy while simultaneously providing the benefits from shifting energy use.

While there currently are not mechanisms in Minnesota programs for energy efficiency programs to prioritize low carbon measures, our results demonstrate that metrics can be calculated for carbon reduction. We recommend further discussion of how carbon fits into energy efficiency programs through stakeholder engagement

To continue to understand the impacts of load shifting measures on both cost and emissions, additional field research and monitoring efforts are needed to generate accurate and geographic-specific load shapes. This work is vital to further our understanding on how these measures can help utilities manage load, keep energy costs low for both utilities and consumers, and reduce carbon emissions. Additionally, further research on marginal emissions in the current grid and in future grid scenarios is needed. By shifting load, each of these measures impact the generating plant on the margin and a better understanding of which plant, and fuel, is being impacted will more accurately demonstrate the carbon benefits of these measures. Finally,, more advanced modeling into how the measures impact which plant on the margin can further our understanding of the total benefits and impacts on the system.

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