Brrrrr…! The Outlook for Beneficial Electrification in Heating Dominant Climates

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ABSTRACT

While energy efficiency and behind-the-meter renewables have contributed to flat sales in many regions, there are new opportunities to grow customer demand by electrifying existing loads, particularly thermal and transportation loads. But where is electrification really beneficial, from a systems perspective? Under what conditions does it lower carbon, especially when new electric loads vary by season and day, and are not necessarily in line with renewable production? These fundamental technical questions still need to be answered, and they vary greatly by region.

This paper explores these issues with a deep dive into Minnesota's current case for residential electrification. Minnesota is heating dominant, ranks 17th for overall carbon intensity of the energy sector, and variable wind generation is the state's dominant renewable. This paper uses results from a statewide air source heat pump study and electric vehicle (EV) performance data to model the economic and carbon implications of electrifying residential space heat and passenger vehicles under different electricity mix scenarios.

Defining Beneficial Electrification

After years of flat or declining electricity sales, many regions in the U.S. are seeing a return to growth. This new demand is largely attributable to the post-recession economic recovery and corresponding increase in housing and service sector jobs. But it also might foreshadow a dramatic new normal of electric expansion, brought on by the technology-driven transition to electrify transportation and heating loads.

All eyes are on this new growth as a huge environmental opportunity. With renewable portfolio standards (RPS) in place, grid-generated electricity does or will soon have lower emissions factors than direct natural gas in several parts of the country. Increased sales could allow further renewable energy and grid modernization investments without raising rates. And, deep decarbonization of the energy sector, reductions of 80% or higher, are only possible with significant electrification, storage, and shiftable loads to harness variable renewable generation. Given these potential benefits, the dominant framework for demand side management, focused on conservation, is being tested. A new framework is needed to determine when load growth is beneficial, when or if it should be incentivized, and how it aligns with existing energy efficiency policies.

Proposals to define beneficial electrification vary. The common thread is electrification that results in a net reduction in lifetime emissions (Dennis, Colburn, and Lazar 2016; Gowrishankar and Levin 2017; Weiss et al. 2017). However, changing generation resources make it hard to guarantee lifetime emissions, and further, the choice of which emissions factor to use varies by context.[1] Energy efficiency does not necessarily accompany beneficial

[1] Suggested methods include using the independent system operator, statewide generation portfolio, or individual utility footprint. This analysis uses statewide average emissions factors, for reasons described below.

electrification, the argument being that using *more* carbon-free energy is a benefit over using less energy that carries a higher carbon impact. Especially with fuel switching, others further argue that the focus on source energy reduction is no longer a reliable metric of benefit (Dennis 2015). Additional approaches to beneficial electrification note that it should reduce overall consumer costs (Hopkins et al. 2017) and that beneficial electrification should enable better load management to enhance grid performance (Colburn 2018).

Interestingly, few discussions of beneficial electrification focus explicitly on loads that will reduce (or at a minimum, not increase) peak electricity demand. However, while marginal costs decrease with increased renewables, capital infrastructure outlays become an increasing share of costs. Especially in the near term, electrical loads considered "beneficial" should complement underutilized grid capacity, and avoid unnecessary infrastructure. We therefore propose that a comprehensive systems definition of beneficial electrification should include:

- A net reduction in source energy use;
- A neutral or net reduction in coincident electricity demand;
- A net reduction in fuel-neutral customer energy costs; and
- A net reduction in lifetime carbon emissions.

This is a fairly conservative definition, and meeting each of these criteria may not be feasible for some technologies. Further, determining whether a technology meets these criteria is complex. Whereas energy efficiency analysis quantifies the magnitude of savings, beneficial electrification needs to assess both the magnitude *and* directionality of benefits, positive or negative. Fuel switching, the future makeup of the electricity grid, rapid technology advancement, and end use technology operation in the field are all important considerations. This paper tests these criteria for two emerging technologies: electric vehicles (EVs) and residential air source heat pumps (ASHPs), for the cold weather climate of Minnesota.

Minnesota's Electrification Context

Minnesota provides a unique and robust test case for assessing the system benefits of electrification. Minnesota is a vertically integrated state: sixty percent of the electric load is served by investor owned utilities, and the remaining 40% is served by municipalities and co-ops. Energy efficiency programs have existed for over 25 years, saved the state more than 100 million MWh and deferred over 2 GW of capacity. In 2005, comprehensive state legislation codified efficiency savings goals at 1.5% for electricity, established a renewable portfolio standard of 25% by 2025, and set carbon reduction goals of 30% by 2025 and 80% by 2050.[2] This is the leading comprehensive policy framework governing state decisions around carbon.

Minnesota's largest building energy end use is space heating. With an average of 7,500 heating degree days, Minnesotan's spend about $2 billion per year to heat their homes (US EIA 2014), and there is not widespread electric heat. The majority (60-65%) of heating systems are direct combustion - natural gas or liquid petroleum gas (LPG) - hence the electrification potential is immense. Twelve percent of households use delivered fuels (primarily LPG and fuel oil) for their heating systems.

[2] See Next Generation Energy Act

Wind energy is the upper Midwest's renewable energy powerhouse. In 2016, Minnesota produced 18% of its electricity from wind power, ranking 6th in the nation in total production.[3] Minnesota currently has 3.5 GW of installed renewables capacity, 25% of the statewide total. Solar energy makes up less than 0.5% of the state's production. However, significant growth is occurring, especially for utility-scale solar installations, and the state is on track to meet its 1.5% solar energy goal by 2025. Baseload renewables are minor contributors, with the only non-negligible source coming from hydro purchase agreements with Manitoba Hydro in Canada.

A Beneficial Electrification Calculator for Minnesota

Our team developed a scenario-based tool to quantify the various considerations of electrification technologies, given their anticipated trajectory over the coming decades. Scenarios are based on a range of assumptions around cost, the evolution of the electric grid, system performance under different temperature conditions, and choices in end-use equipment.

Emissions Assumptions

The model forecasts net electricity generation, emissions, and costs on a monthly basis. Our methodology is based on historical in-state generation by fuel type, using monthly generation data from the EIA (US EIA 2017). This approach aligns with the protocol for estimating statewide achievement of Next Generation Energy Act goals (Ciborowski and Claflin 2009), with one major exception. We include the Coal Creek Station, a 1.2 GW coal plant in North Dakota that exclusively serves Minnesota via a direct high-voltage, direct current transmission line.[4] Including Coal Creek's production increases emissions factors by 6 to 8%.

Figure 1 shows Minnesota's modified in-state electricity generation since 2003. The double peak in each year is characteristic of high demand in both winter (lighting and some electric heating) and summer (cooling). Electricity sales have been fairly constant over the past 10 years. Coal generation and imports have consistently decreased in favor of newer wind and natural gas generation, but coal still dominates the resource mix, and accounts for 90% of the emissions from the electricity sector. The seasonal wind production in Minnesota follows a consistent profile, peaking in the late winter and spring, and ebbing in late summer.

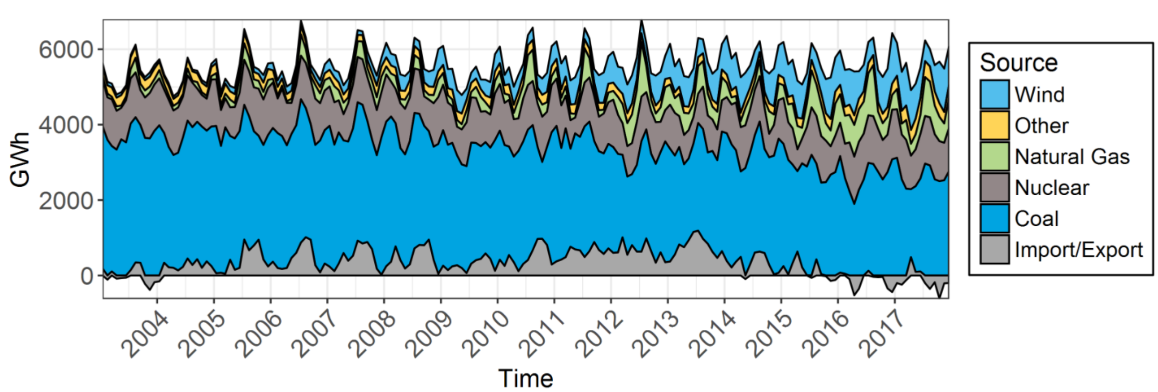

Figure 1: Results of historic monthly production by modified in-state plant

[3] American Wind Energy Association *U.S Wind Industry Annual Market Report* 2016.

[4] The generation from this plant is on the same order as net imports.

Emissions Forecasts

Minnesota's average emissions factor has declined by 30% over the last 15 years, with a low of 1.03 lb/kWh in October 2017.[5] But Minnesota's emissions future is highly dependent on the coal generation eligible for retirement between now and 2040, the future of the state's two nuclear generating plants, and the role of renewables versus natural gas as replacement fuels. Our model considers five plant retirement grid scenarios, described in Table 1. Data from the most recent Integrated Resource Plans (IRPs) are included for the four major utilities, which add 2.7 GW of wind and 1.9 GW of solar capacity by 2030. Coal retirements consider the scheduled retirement of six coal generators with 1.8 GW nameplate capacity ("Scheduled"), or add the retirement of 3.7 GW of remaining coal at their estimated depreciation date ("All Plants").

Table 1: Power Plant Scenarios through 2040

Grid Scenarios	Coal Retirement	Nuclear Retirement	Renewable Additions	Remaining Replacement
1. Current Grid	None	None	None	None
2. Existing Resource Plans	Scheduled	None	IRP	Natural Gas
3. Nuclear Retirements	Scheduled	2034	IRP	Gas / Wind / Solar
4. Coal and Nuclear Retirements	All Plants	2034	IRP	Natural Gas
5. Toward Zero Emissions	All Plants	2034	-	Wind / Solar

The resulting seasonal emissions factors are plotted in Figure 2.[6] The Current Grid scenario replicates the previous twelve months of monthly emissions factors as of October 2017. All other scenarios follow the IRP trajectory through 2026, and yield an emissions factor of 0.9 lb/kWh, a reduction of about 23% from the current annual average. The scenarios diverge in 2027 based on the assumptions around replacement fuel. In 2034, some scenarios see an emissions rebound resulting from the retirement of fossil-free nuclear generation.

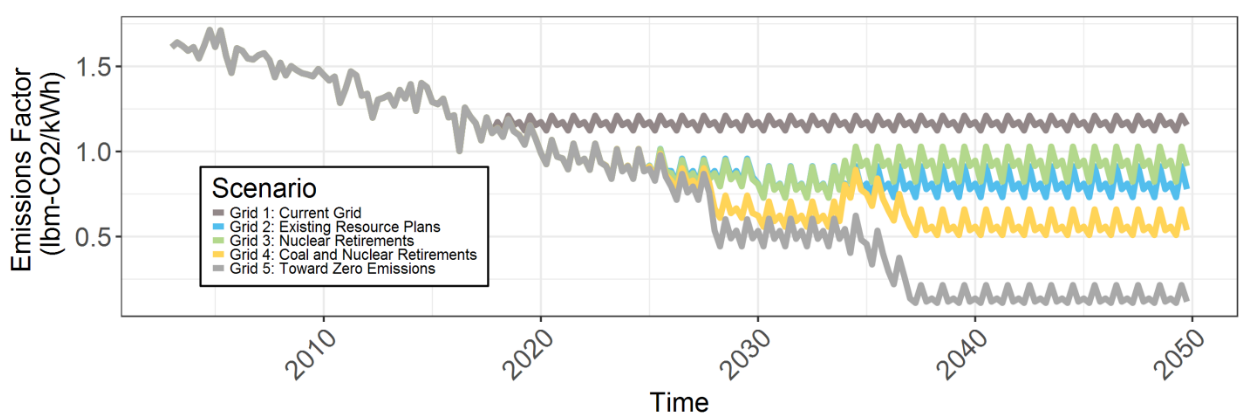

Figure 2: Average seasonal emissions factors in Minnesota for five power plant scenarios

[5] The average emissions factor is calculated as monthly emissions divided by the monthly generation. Plant-level emissions are from EPA's FLIGHT tool (US EPA 2017a).
[6] This is the average emissions factor per meteorological season.

In aggregate, these scenarios capture Minnesota's potential future and demonstrate the huge variability the state faces in terms of the emissions benefits of electrification. Key takeaways include:

- Current utility plans alone will reduce the emissions factor by 23% in the next 10 years.
- Beyond existing assets and current IRPs, new wind and solar development are not as essential as coal retirements for achieving deep cuts in Minnesota grid emissions.
- Current utility plans plus the replacement of all coal and nuclear generation with natural gas would yield an average annual emissions factor of 0.57 lb/kWh, a 51% reduction from the current value.[7]

Finally, a notable difference in the scenarios is the seasonal impact of wind generation. The Midwest wind resource peaks in spring and fall, when loads are low. This changes the forecasted 2037 emissions by 15-30% throughout the year, as shown in Figure 3. This has implications for winter electrification.

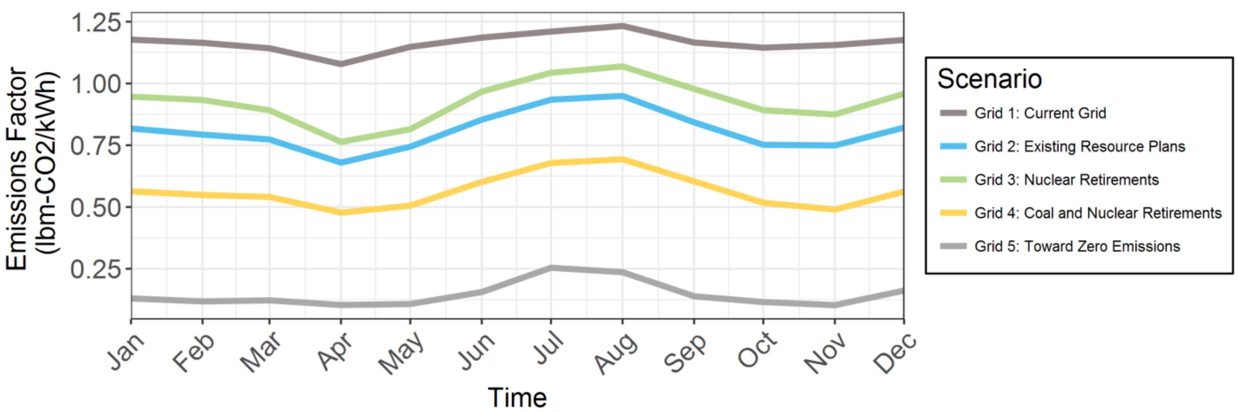

Figure 3: Monthly emissions profiles for five grid scenarios in 2037

Technology Results

Below we present the initial cost, energy, and emissions results from air source heat pumps and electric vehicles in cold climates. We use the grid methodology described above to calculate emissions impacts under the different generation portfolios.

Air Source Heat Pumps

The residential space heating systems compared in this analysis are shown in Table 2. Equipment efficiencies for space heating end-use equipment were developed from the Center for Energy and Environment's (CEE's) field performance measurements, and are accurate for the temperature ranges and usage profiles found in Minnesota (Schoenbauer, Bohac, and Kushler 2017). A large performance driver of measured heat pump COP is the system efficiency at low temperatures, and the operation of multi-fuel configurations (e.g. backup systems).

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[7] Emissions factors are an estimated 2.2 lb/kWh for coal and 1.0 lb/kWh for gas, but plant specific values can vary with a range of 20%.

Table 2: Residential space heating equipment scenarios

System	Fuel	Backup	Switchover	System Field Efficiency/COP
1) Condensing furnace	LPG	-	-	0.90
2) Condensing furnace	Natural Gas	-	-	0.90
3) ASHP (SEER 18/ HSPF 10)	Electric	LPG	10 °F	1.3[8]
4) ASHP (SEER 18/ HSPF 10)	Electric	Electric Resistance	Capacity Need	1.9

The annual site energy use for each system to meet a typical Minnesota residential space heating load is compared in Figure 4 for four state climate regions. Both propane and natural gas furnaces use similar site energy, between 90 and 120 MMBtu depending on region, and are represented by the natural gas furnace in the figure. The ASHP with LPG backup uses about 25% less site energy, and ASHP with an electric resistance backup uses 50% less than the conventional furnace.

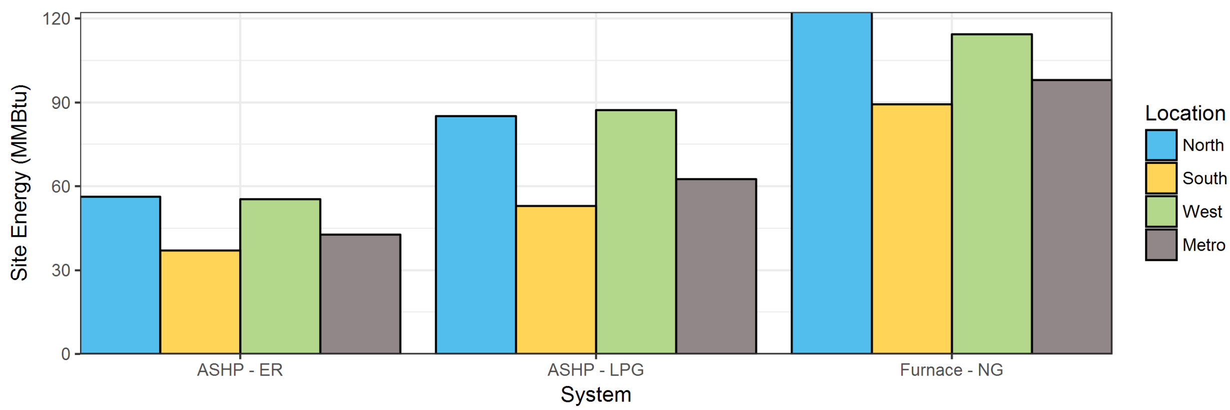

Figure 4: Annual site energy use for space heating of comparable systems

Source energy use depends on the makeup of the electrical grid. We use a "captured energy" approach to calculate source energy, which adjusts the site to source multiplier depending on the penetration of renewables.[9] The figures below compare heating system source energy under today's grid (Figure 5) and for the five grid scenarios in the year 2037 (Figure 6).[10] In 2018, both ASHP systems offer a slight reduction in source energy compared to direct combustion furnaces. In 2037, grid scenarios 2, 3, and 4 lower the source energy requirements for heat pumps by 10% or more. Scenario 5 demonstrates that 50% reductions in source energy are possible with aggressive renewable energy adoption. This is, again, with fairly conservative assumptions about ASHP performance in cold temperatures.

[8] The system 3 COP is lower than system 4 due to backup configuration. LPG backup is a conservative operational strategy and it yields lower than rated seasonal average efficiency, but reflects current practice in Minnesota.
[9] While renewables do have conversion losses, they don't pragmatically have the same apples-to-apples conversion losses as fossil based generation when compared to fossil site energy. Captured energy calculates the site to source conversion for renewables as 1, whereas fossil generation has a conversion factor of about 3 (DOE 2016).
[10] There are currently no forecasted generator changes (retirements or additions) in Minnesota beyond 2037.

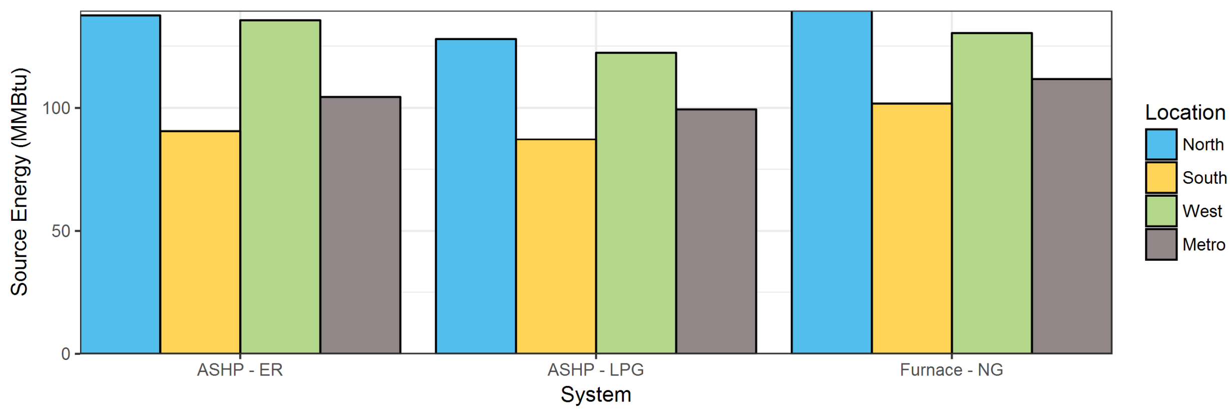

Figure 5: Source energy for comparable space heating systems in the current electrical grid 2018.

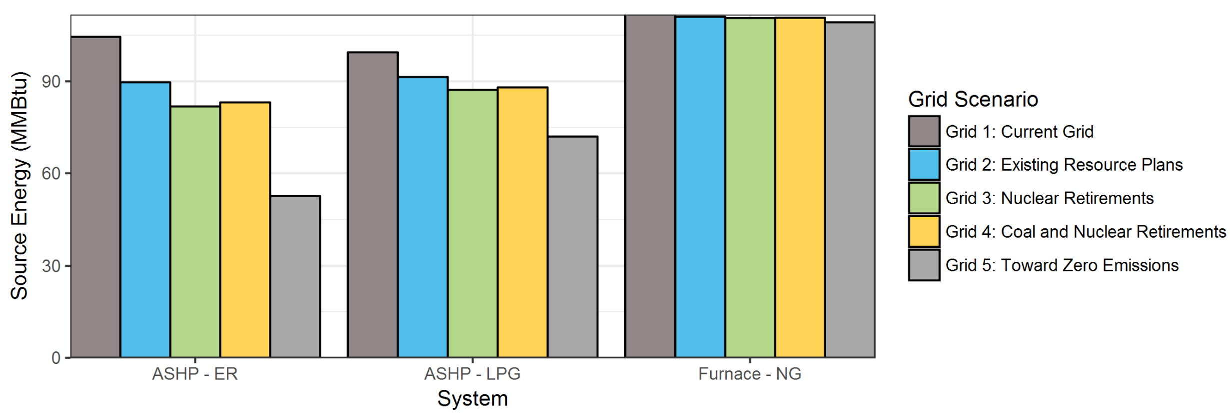

Figure 6: Source energy for different grid scenarios for the year 2037 (for the Metro region only).

Operating costs for heat pumps tell a more complex story. A natural gas furnace is still consistently cheaper to operate than heat pumps, for all regions of the state, given the low cost of natural gas.[11] On average the operating costs of an all-electric heat pump heating system are about twice those of a natural gas furnace. But for customers on delivered fuel, heat pumps can lower energy bills. The ASHP with LPG backup has lower operating costs than the LPG furnace in all climate regions. The ASHP with electric resistance backup has lower cost than the LPG furnace in South and Metro regions, and higher costs in North and West regions. These results reflect average rates, though residential retail rates vary substantially throughout the state.

[11] The operational costs are compared using average monthly residential pricing in 2017 for propane, natural gas, and electricity from Energy Information Administration. Average annual costs are $0.13/kWh for electricity, $1.57/gallon for LPG, and $0.95/therm for natural gas.

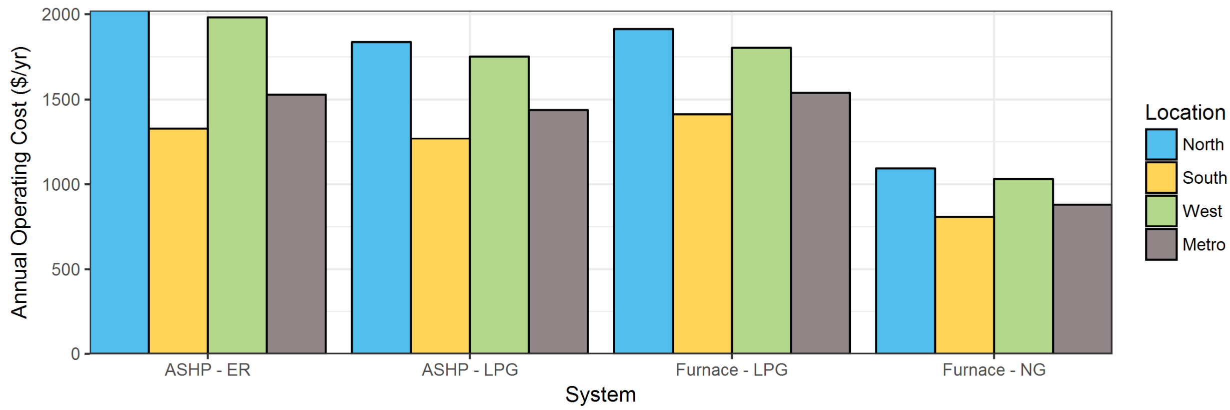

Figure 7: Current annual operating costs for comparable space heating systems

Emissions results are shown in Figure 8 for the current grid and the Coal and Nuclear Retirement case, which again follows current IRPs through 2027. The dashed lines show emissions from LPG and natural gas condensing furnaces. Currently, natural gas fired condensing furnaces yield the lowest annual emissions, and all-electric ASHP heating system produces the highest annual emissions, based on statewide averages. However, this system will see the most dramatic reductions in annual emissions. Within 2 years (2019), all-electric ASHPs are forecast to produce lower emissions than LPG-fueled furnaces and ASHP systems with LPG backup. Within 5 years (2023), according to approved IRPs, an all-electric ASHP will yield lower annual emissions than a high efficiency condensing furnace. In the case where the state retires its coal and nuclear fleet, even when natural gas is the dominant replacement fuel, the system will result in 40% lower emissions.

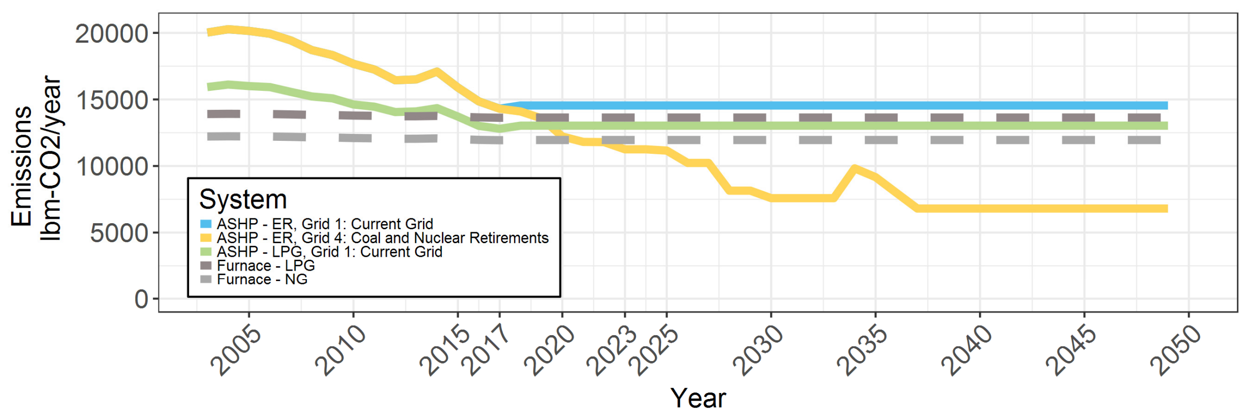

Figure 8: Annual emissions by technology type and grid scenario for the Twin Cities Metro area

Electric Vehicles

There are roughly 6,000 EVs in Minnesota today (MN PUC 2018).[12] This analysis focused primarily on the emissions implications of growing the passenger EV fleet compared to conventional internal combustion engine (ICE) vehicles. In terms of costs, EVs have generally higher lifetime costs than ICE vehicles, although this is expected to change and reach parity in

[12] Out of a total 2.6 million light duty trucks and 2.1 million light duty cars (US DOT 2017).

the future as battery prices continue to decline. In addition, it is generally shown that EVs have lower maintenance and energy costs than ICE counterparts (Hopkins et al. 2017). Our analysis found similar results in terms of fuel cost savings. Assuming an electricity cost of $0.13/kWh, a gasoline cost of $2.75, and the usage assumptions noted in the modeling below, driving an EV is roughly $190 less expensive than an ICE vehicle on an annual basis. However, the gasoline cost projections in EIA's 2018 Annual Energy Outlook and the historical change in electricity rates in Minnesota suggest this cost gap will widen in the future.

Our analysis used a weighted average efficiency for EVs and compared it to the performance of comparable new ICE vehicles (US EIA 2016a, 2016b). EV system efficiency degrades in cold temperatures, primarily because heating the vehicle cabin in the winter (without engine waste heat) nearly doubles energy consumption (Lohse-Busch et al. 2013). Figure 9 shows calculated vehicle efficiency and its correlation with outdoor air temperature (US DOE n.d.). ICE vehicles also have a performance hit in cold months due to idling and other issues, but these are more negligible. Note that if heat pump systems are integrated into electric vehicles, this will lessen the increase in EV emissions during winter months (Qi 2014). This analysis does not take into account these or other projected efficiency improvements to EV technology.

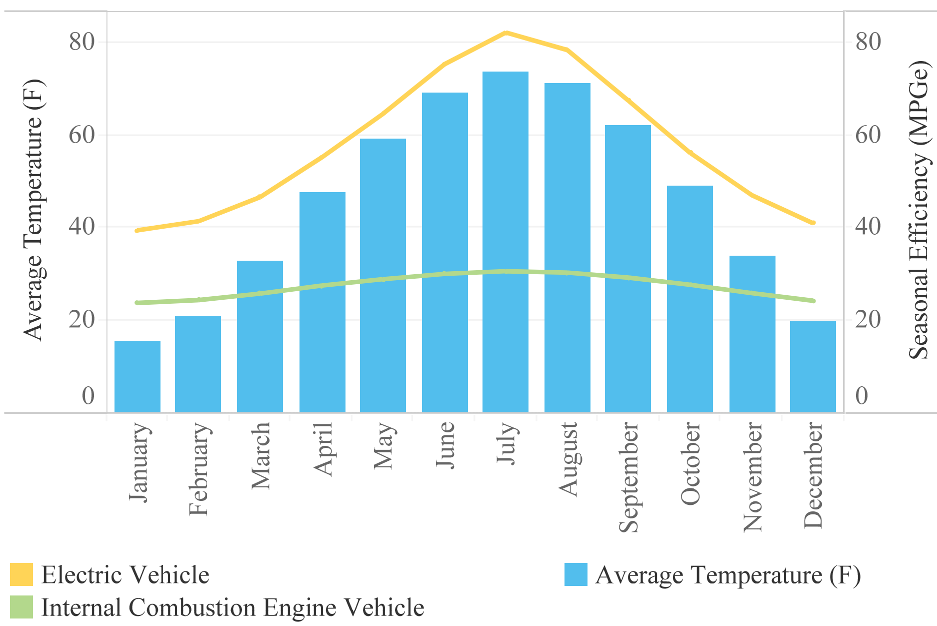

Figure 9: Seasonal efficiency estimations for EVs and ICEs

This analysis compared power plant emissions for EVs with tailpipe emissions for ICE vehicles.[13] Figure 10 below shows results under "Coal and Nuclear Retirement" (Scenario 4), which again follows IRPs through 2027, then replaces the coal and nuclear fleets with natural gas. EVs are projected to have lower emissions than ICE vehicles from 2018 onward, and almost half the emissions in 2040 under this scenario.

[13] This approach has known drawbacks in that it does not include the full lifecycle (upstream) emissions for gasoline, which can be significant (McFarlane 2016, 2017; Eleff 2016). A custom tailpipe emissions factor was created assuming 10% ethanol blended with gasoline, per Minnesota statutory requirement (MN DOA 2018).

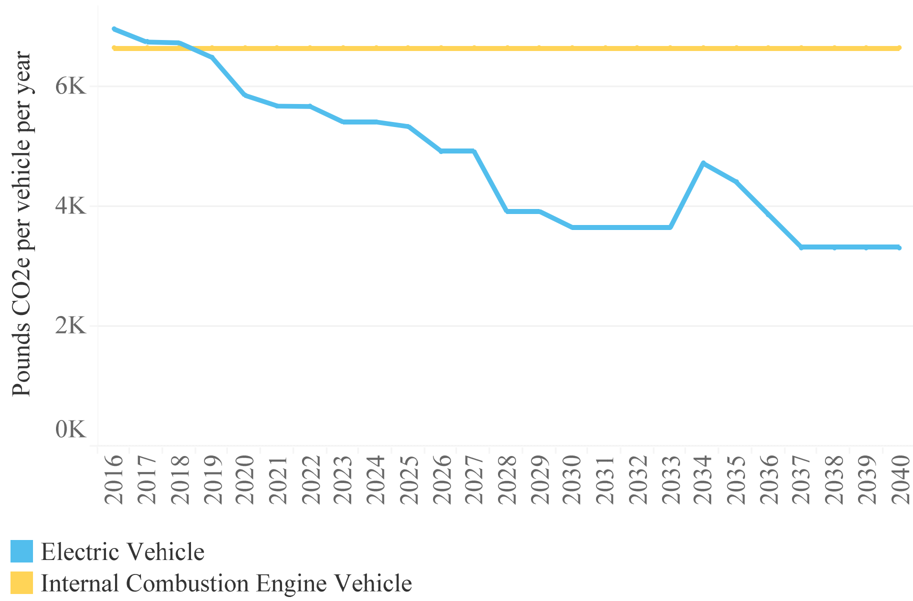

Figure 10: Forecasts of emissions from electric vehicles versus internal combustion emissions under the "Coal and Nuclear Retirements" scenario

EVs may be additionally beneficial since they can adjust the timing of their energy demand. We modeled the emissions impact of three different charging profiles, shown in Figure 11. To develop these profiles, we assumed the average passenger vehicle travels 26 miles per day (MN DOT 2018), and converted to kWh using the seasonal efficiency variation shown above. The uncontrolled charging profile is an estimation of a typical residential EV load unconstrained by costs or external controls, using level 2 charging (6.6 kW) demand profiles (Muratori 2017). The Off-Peak and Workplace/Public charging scenarios were assigned typical hours, and assumed to be flat over each hour.

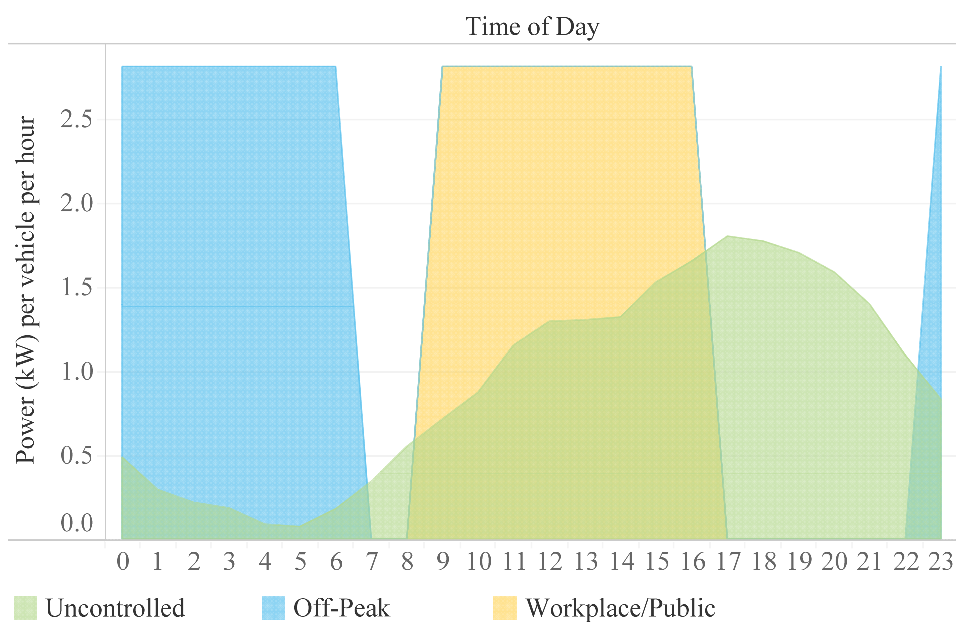

Figure 11: Electric vehicle charging scenarios

Hourly emissions factors were estimated for an entire year, using the 2017 electricity production data for the MISO North region. Figure 12 below shows the results of applying these hourly emissions factors to the three charging scenarios above. The Off-Peak charging scenario results in the lowest emissions. The relatively high percentage of wind in Minnesota's grid mix, and wind predominance overnight contributed to these results. However, as the grid evolves and the penetration of solar capacity increases, charging during the day could see a larger emissions benefit. Results also show that January emissions are nearly double those in June and July. Given the importance of seasonal variation of EV efficiencies, more research is needed to understand how these evolving technologies are performing in the field.

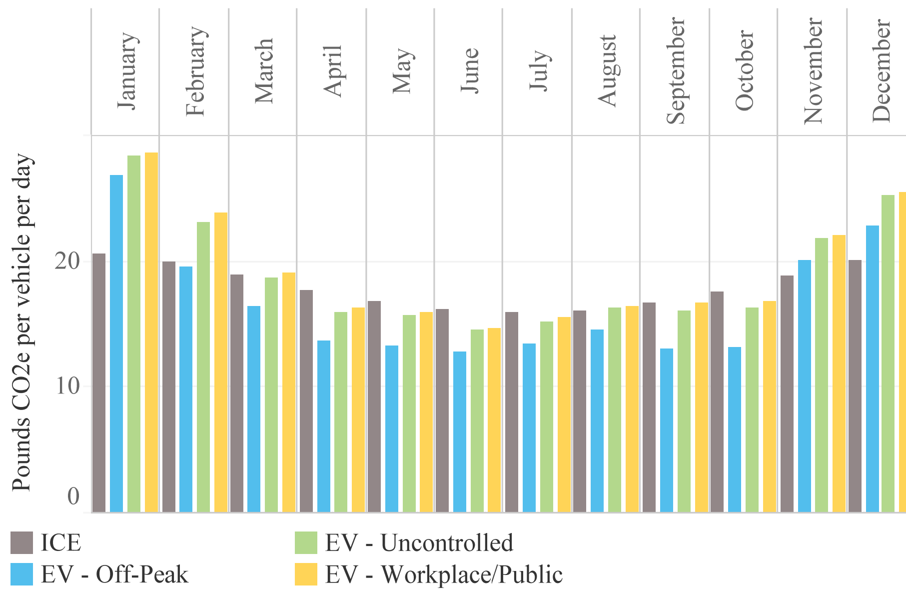

Figure 12: Daily average emissions for three EV charging scenarios

Implications and Discussion

This paper set out to test two emerging technologies against a fairly conservative definition of beneficial electrification, in the case of cold climate performance, to understand the conditions under which these technologies are beneficial. We looked at performance, climate, operational considerations, and the overarching question of Minnesota's future electricity generation mix, including the impact of seasonal variability on emissions and costs. Results are similar for both sets of technologies, despite being compared to different conventional fuels (gasoline, LPG, and natural gas).

Overall, both technologies will produce fewer net emissions over their lifetimes than their conventional counterparts. Unless there is a significant backtrack from current IRPs and associated coal retirements, technologies will hit emissions parity in the 2020-2023 timeframe. Lifetime emissions from electrification would be even lower if additional coal comes offline. Interestingly, with Minnesota's current renewable penetration, the state could replace all coal-fired generation with gas and these technologies would still have an emissions benefit, which reflects the large amount of coal on the system. While we present emissions at the state level, electrification would tell a very different story if considered on a utility-by-utility basis. Given the major utility-specific decisions on the horizon around fossil fuel and nuclear retirements, electrification should be considered in this context.

In all configurations of air source heat pumps, the partial or complete electrification of space heating over LPG and natural gas systems lowers site energy use. The source energy comparison is closer, but systems today are essentially at parity when compared to a natural gas furnace. This is the result of high heat pump efficiencies, as well as the current renewable mix on the grid. As the share of renewables grows, source energy benefits will increase.

Cost results for delivered fuel customers are generally beneficial today. However, the electrification of natural gas space heating loads is not cost effective and incurs approximately 50% higher heating costs. This is the largest barrier for a state heated 75% by natural gas. These results are highly sensitive to fuel prices. Current utility programs, state policies, and retail costs throughout the state cause the cost of electric space heating to vary by more than 50%.

While not a major focus of this modeling effort, a back of the envelope calculation using electrification loads shows that a full transition could dramatically alter Minnesota's grid needs. By 2040, adding air source heat pumps to 1.6 million single family homes would add a heating load that varies between about 1 GW (swing season) and 6 GW (winter peak). For comparison, Minnesota currently consumes about 6 GW of (average monthly) winter load. As for the cooling season, high-end ASHP technology performs better than code (SEER of 18 versus 13) and could result in lower summer demand if heat pumps displace less efficient cooling technologies. The net effect would be to even out the seasonal load profile. For transportation, registered vehicles in 2015 in Minnesota totaled 2.6 million light duty trucks and 2.1 million light duty cars (US DOT 2017). An uncontrolled charging profile for all of these vehicles combined would require 8.6 GW of capacity, peaking in the early evening.

Finally, part of the planning for future electrification can include lessons from current energy efficiency frameworks. For starters, a focus on efficiency opportunities for new loads, such as including electric vehicles in energy efficiency resource standards, will help manage the costs of new infrastructure. Further, these results show that technology performance is sensitive to installation and operation conditions, which can make the difference in the directionality of benefits compared to conventional technologies. As technologies proliferate, an emphasis on testing and field measurement will help support a systems understanding of beneficial electrification.

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