# A Simple Twist of Fuels: Demand Flexibility Opportunities in Cold Climates

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**ABSTRACT**

Space heating is the largest residential energy use in cold climates like Minnesota's, where low-cost natural gas dominates as a heating fuel but contributes to greenhouse gas emissions. Electrifying space heating is critical for decarbonization, especially as Minnesota mandates carbon-free electricity by 2040, a timeline aligned with the lifespan of heat pump systems installed today. Air source heat pumps (ASHPs) offer the most cost-effective electrification pathways for single-family homes. Dual fuel ASHPs may offer a near-term pathway to expand heat pump adoption while moderating operating cost and peak demand impacts.

A downside to ASHPs is their efficiency performance and capacity decline in cold temperatures, increasing electricity demand. At full penetration of cold climate ASHPs on distribution feeders, winter heating loads at design temperatures in MN may require over five times more power than current feeder-level cooling peaks, straining grid infrastructure. Even at 20% penetration on distribution feeders, heating loads may exceed cooling peaks during temperature extremes. As the share of cold climate ASHPs grows compared to AC, the peak load will continually shift to occur at lower ambient temperatures, requiring significant upgrades to generation and distribution capacities for high uptake of all-electric systems.

This paper examines residential dual fuel heat pump systems, how demand flexibility optimizes cost and grid impacts while maintaining comfort, and how industry standards such as AHRI 1380 can lower customer costs and grid emissions to support demand flexibility programs and rates.

## Introduction

Heat pumps move heat via the vapor-compression cycle rather than producing it through combustion. Since they are moving heat, they are more efficient than traditional systems burning fossil fuels. In addition, minimum cooling efficiency requirements for heat pumps are higher compared to air conditioners. Even the least-efficient legal heat pump outperforms the least-efficient legal AC (U.S. DOE 2026). Space heating is also the largest share of household energy use nationally and in cold-climate states like Minnesota (U.S. EIA 2020), so electrifying it yields significant efficiency and emissions benefits.

Utilities in MN have been able to increase rebates for ASHPs thanks to landmark legislation passed in 2021 that allows both gas and electric utilities to claim energy savings for efficient fuel-switching (Minnesota Office of the Revisor of Statutes 2025). Utility incentives, the former 25C tax credit, and market interventions such as training from the MN ASHP

Collaborative have significantly increased ASHP adoption in Minnesota.[1] Centrally ducted heat pumps compared to centrally ducted ACs have gone from being 4% of annual sales in 2020 to 17% of annual sales in 2025 (CEE 2026). However, the stock of ASHPs installed in Minnesota remains low relative to furnaces and ACs, and nationally, annual heat pump shipments still have not overtaken air conditioners, rising only from 42% to 47% of combined heat pump and AC shipments between 2023 and 2025 (AHRI 2026), underscoring that cost and operating barriers, not availability, constrain adoption. Regardless of the current deployment level, the state is on a trajectory to add significant beneficial load factor for electric utilities in the coming years as the share of ASHPs sold continues to grow.

In 2023, Minnesota lawmakers passed legislation that requires electricity to be generated from 100% carbon-free sources by 2040 (MN Department of Commerce 2026). Over the roughly 15-year life of a heat pump installed today, its efficiency benefits and the grid's decarbonization trajectory will significantly reduce carbon compared to a fossil fuel appliance. Through the Natural Gas Innovation Act, Minnesota utilities are exploring methods to decarbonize the gas system. However, there are limitations to the percentage of renewable energy that can be injected into the gas supply, so electrification remains critical to decarbonization (Rosa et al. 2025).

Heat pump efficiency and capacity, however, change with outdoor air temperature. With variable speed ASHPs, when it is very cold (e.g., <5°F) or very hot (e.g., >95°F), the heat pump increases its speed of operation to maintain heating or cooling capacity. This higher speed uses more energy and the efficiency of the system decreases. As outdoor temperatures fall below zero Fahrenheit, electric-resistance auxiliary heat supplies a growing share of the load, causing the system COP to approach one. A compounding problem with the relationship between outdoor air temperature and efficiency is the relative cost of fuels. Most homes in Minnesota heat their homes with natural gas via centrally ducted systems. Figure 1 shows on a per unit of heat delivered basis, the cost of natural gas compared to the cost of electricity in the past three heating seasons ranges between 3–6 times the cost of natural gas depending on the time of year (U.S. EIA 2026).

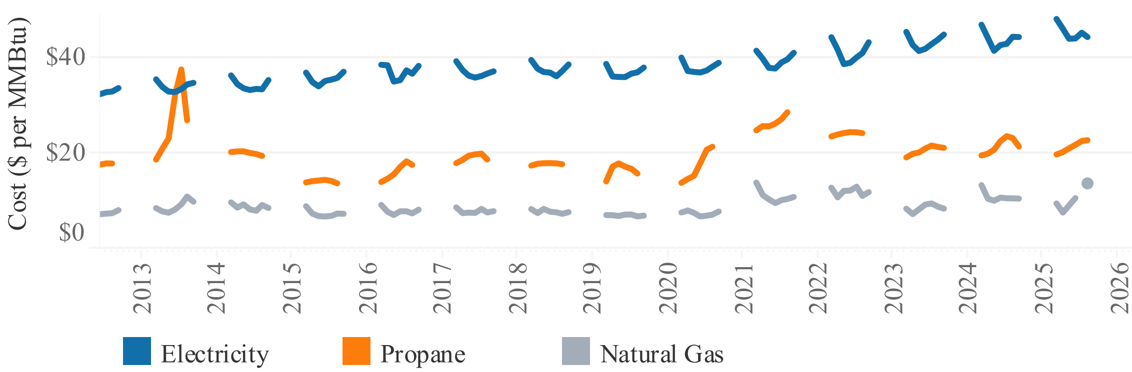


Figure 1. Cost per MMBtu non-summer monthly average heating fuel prices in Minnesota (October–April only)

Because of these relationships among efficiency, capacity, temperature, and the fuel cost ratio, all-electric ASHP systems pose a challenging proposition: both the incremental and

[1] This program is an initiative of Minnesota's Efficient Technology Accelerator (ETA), which is a partnership funded by the state's participating investor- and consumer-owned utilities, administered by the Minnesota Department of Commerce, Division of Energy Resources, and implemented by Center for Energy and Environment.

operating costs inhibit adoption. In many cases, an all-electric system could increase annual heating bills by hundreds of dollars for Minnesotans and Midwesterners alike (CEE 2023). In addition, multiple studies indicate that widespread adoption of all-electric, cold climate ASHPs in high electrification scenarios (with other measures) could double current generation peaks at the system level (deLeon et al. 2024).[2] Stakeholder modeling for Minnesota's natural gas end uses similarly identified an electrification-with-gas-backup pathway as the least-cost option for achieving significant emission reductions (GPI and CEE 2021). While these challenges may be addressed in the longer term, a near-term opportunity is to replace air conditioners with ASHPs and pair these with fossil fuel heating systems. This could save energy, carbon, and operating costs depending on electricity rates, equipment, design, and installation quality. When these systems are sized to 80% of the load and paired with weatherization measures and installation of heat pump water heaters, this can reduce household emissions by over 90% compared to the baseline in many cases (Douglas-May et al. 2026). This dual fuel approach could accelerate adoption far beyond current adoption levels in the near term, accelerating decarbonization compared to an all-electric strategy ignoring economic realities associated with up-front-costs, challenging efficiency barriers in low ambient temperatures, and fuel cost ratios.

## Residential HVAC Impacts on Bulk System Capacity

As space heating is electrified, system-level impacts differ from those at the site or distribution feeder level. At the feeder level, the combined effects of equipment capacity, efficiency, and outdoor air temperature can materially increase peak electric demand. To illustrate how electrification shifts feeder-level load shapes, Figure 2 presents modeled HVAC power curves for a representative Minnesota home across outdoor air temperatures in 5°F increments. These configurations—particularly all-electric versus dual fuel—translate into markedly different cold-weather power requirements. The curves were developed using the heat loss from a representative Minnesota home modeled in ResStock, with system performance based on CEE field-monitored ASHP data (Schoenbauer et al. 2024) and DOE Cold Climate Heat Pump Challenge results (Mendon et al. 2025).

The worst system for electric power consumption is electric resistance (COP of 1). A dual fuel heat pump in this example is composed of a moderately efficient variable speed system, which is a practical choice in terms of incremental cost compared to the AC baseline. So, the power consumption for the dual fuel ASHP is slightly higher than the cold climate ASHP when it is running. In this example, the dual fuel ASHP switches to its auxiliary fossil system at 20°F, significantly reducing the electric power demand in colder weather. However, with the cold climate heat pump, the power consumption continues to climb very high at low outdoor temperatures due to the declining efficiency and capacity of the system. The lowest electric power user is the furnace, which still uses electricity for its blower motor.

[2] Note that system peaks are composed of residential, commercial, and industrial loads, which affect the load profile, and so this value is different from the site-based peak discussed above.

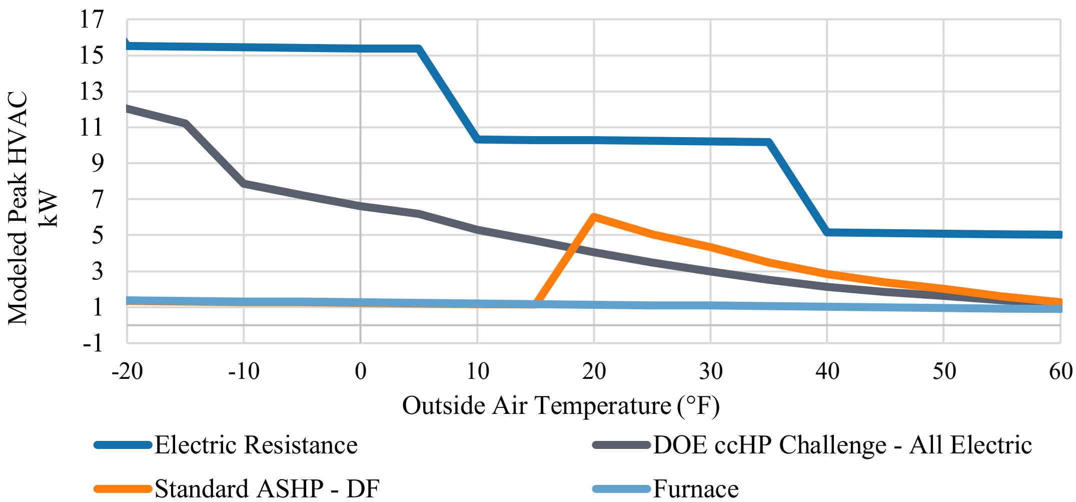


Figure 2. Modeled peak HVAC power required for a typical Minnesota home with various heating systems

The Midcontinent Independent System Operator (MISO) is the market and transmission operator serving Minnesota, as well as customers from Manitoba, Canada southward to Louisiana. This regional transmission organization (RTO), like many parts of the country, currently reaches peak load in the summer (OMS and MISO 2026), driven largely by air conditioning and other cooling-related end uses. However, as space heating becomes increasingly electrified, winter demand is expected to grow rapidly and, in some cases, surpass traditional summer peaks. Because local utility peaks may differ from the RTO peak, and because energy prices can spike during outages or weather events—adding energy-market arbitrage value to peak-reduction capacity value—peak-mitigation value may occur across a range of outdoor air temperatures.

The annual mean minimum dry-bulb temperature for the Twin Cities Metro Area, where the largest share of people live in Minnesota, is -15.6°F (ASHRAE 2025). Using the all-electric ASHP COP curve above, and assuming 20% penetration of all-electric cold climate ASHPs (excluding other home loads), the current cooling peak is exceeded by heating demand between -15°F and -20°F as shown in Figure 3, close to the ASHRAE annual mean minimum temperature.[3] As ASHP penetration increases, this crossover occurs at progressively warmer temperatures; at 50% adoption, the cooling peak is surpassed at 15°F, and at full adoption, feeders may experience winter peaks at the mean extreme temperature that are up to five times greater than current cooling peaks. When considering the moderately efficient dual fuel COP curve above, at 50% penetration, cooling peaks are surpassed at approximately 30°F—the median switchover temperature reported in Minnesota utility rebate data—highlighting the near-term relevance of this issue.

[3] This analysis, modeled in 5°F increments, assumes a peak cooling efficiency of 10 EER2 and an all-electric ASHP sized to the heating load with supplemental electric resistance heat. The model assumes a 4.5-ton ccASHP matching DOE challenge performance criteria. The ASHP supplies the entire heating load above -10°F. Below this temperature, the ASHP is supplemented by up to 20 kW of electric resistance heating elements in 5 kW stages, operating for as long as needed to address the total hourly load in tandem with the ASHP.

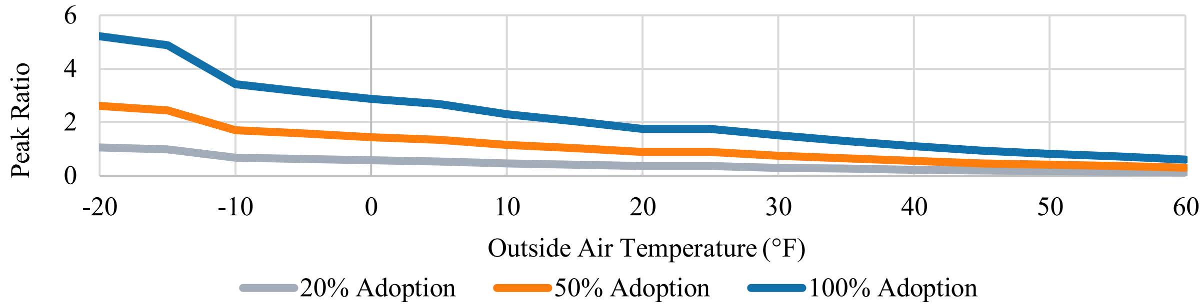


Figure 3. Peak load ratio compared to current cooling peak for a representative distribution feeder

## Existing Program and Equipment Capabilities

Dual fuel ASHPs provide a near-term pathway to mitigate winter peak demand by switching from electric to fossil fuel heating at a defined economic balance point. Contractor awareness of these operational dynamics continues to increase, driven in part by training efforts from the MN ASHP Collaborative. Since its launch in 2019, the Collaborative has trained hundreds of HVAC contractors annually on topics such as break-even COP and its role in determining optimal switchover temperatures (CEE 2026). These trainings help contractors weigh equipment performance against fuel costs to set switchover strategies that balance customer economics with decarbonization goals. Contractors who have participated in these trainings are also more likely to recognize and communicate the benefits of ASHP technologies compared to those without similar exposure (ETA 2025).

In the winter, load control with dual fuel ASHPs and water heating has long been a method used by consumer- and investor-owned utilities. These utility programs, which are offered as discounted electric rates, have been in place in Minnesota for decades and have scaled successfully. As Figure 4 shows, in the residential sector, Minnesota has the largest demand response resource in the country in terms of activated assets compared to the top 5 states (U.S. EIA 2025).[4]

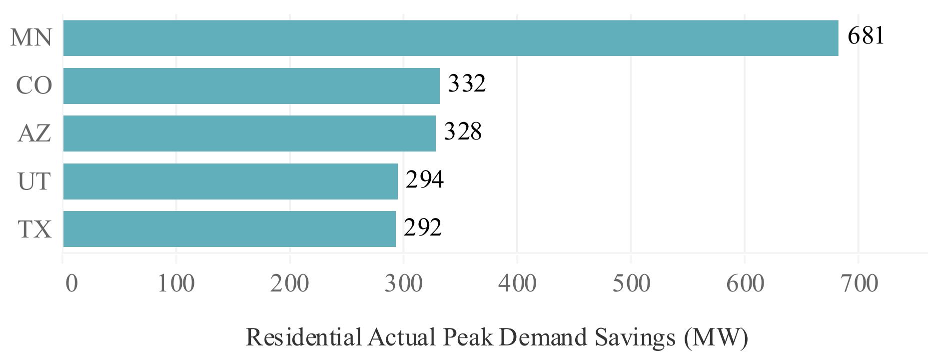


Figure 4. Actual peak demand savings by top 5 states (U.S. EIA 2025)

Minnesota utilities' long history of dual fuel and interruptible space-heating tariffs serves as a template for modern dual fuel ASHP load management related to cost parameters, customer

[4] Much of the current fleet of these assets are direct load control methods receiving a radio or cellular signal and activating a relay switch to turn off loads with a significant amount of electric resistance water heating and direct load control of ACs within this capacity figure.

benefits, and equipment requirements. These programs typically require an electric heating system paired with a non-electric backup that can carry the full load during control events. In exchange for the right to interrupt electric heat for a set number of hours per day or season, the utility offers a discounted off-peak dual fuel rate.

Their high enrollment shows utilities can reliably shift coincident peak demand from electric to non-electric fuels on cold days while maintaining comfort, establishing utility, regulatory, and customer-acceptance precedents for dual fuel ASHP programs that integrate with distributed energy resource management systems (DERMS) and modern demand-flexibility protocols.

## DERMS and Utility Control of Dual Fuel ASHPs

Aggregators and DERMS provide the coordination layer that turns disparate dual fuel ASHPs into a system-level winter capacity resource. Conceptually, DERMS maintain an inventory of controllable assets and their attributes, optimize dispatch at the distribution, system, or bulk-system level, and interface with assets through standards-based protocols to send event signals and receive telemetry. As non-wires alternatives, for example, DERMS can capture locational benefits from distributed energy resource (DER) assets—delivering customer value rather than the shareholder returns of the traditional build-and-rate-base model.

In a dual fuel context, there are two primary DR control paradigms for ASHPs today: direct load control (DLC) of the dual fuel system using two-wire relays or thermostatic control. With DLC, a utility or aggregator sends a command that overrides equipment operation—cycling the compressor in summer (e.g., 15 minutes on, 15 off) or, in winter, switching it off or to standby so the auxiliary system meets calls for heat. DLC provides predictable, immediate load relief: the operator ensures the compressor is off or limited during events while the non-electric backup carries the load. For example, Xcel Energy has roughly 400,000 residential customers enrolled in its DLC AC program called Saver’s Switch. In combination with their smart thermostat program, which pre-cools and adjusts the setpoint temperature during summer peak events, this amounts to 1,117 MW of potential capacity (Xcel Energy 2026). Unlike summer programs with setpoint adjustment or condenser unit cycling, since non-electric heat is a requirement for program enrollment, participants in a dual fuel program do not experience comfort impacts, so these resources can be called upon more often with less risk of attrition.

Most Minnesota utility customers have access to some interruptible dual fuel ASHP program via DLC, but significant barriers remain: these programs require HVAC systems compatible with two-wire load management receivers, which sharply limits inverter-driven ASHP eligibility. As a short-term solution, the Collaborative created a qualified products list to highlight which manufacturers offer these solutions and links to wiring diagrams to assist contractors in correctly wiring these systems (MN ASHP Collaborative 2025).

Manufacturers are also reticent to develop two-wire compatibility for a load control method that may be retired in favor of the thermostatic control described below. Some utilities also require a separate meter (separate billing) or submeter (subtractive billing) to enroll; where the customer bears this cost, it can exceed $2,000 to install, further straining the ASHP value proposition. To address this, utilities such as Otter Tail Power recently began incentivizing this cost for a second meter and now offer a rebate for installation (Otter Tail Power Company 2025). These metering costs may be lower in some cooperative utility territories and supported by programs that build on existing DLC infrastructure.

Despite the barriers, there are major advantages to choosing compatible equipment with established interruptible, dual fuel rate programs. The electric rates offered by utilities with these tariffs are highly discounted, which helps mitigate the challenging value proposition of ASHPs. A customer with propane can save hundreds of dollars with a cold climate system displacing most of their heating load and agreeing to have the system switch to auxiliary fossil fuel heating during times of high electricity bulk system costs or grid constraints. These dual fuel programs even make these systems cost-competitive in areas served by natural gas thanks to steeply discounted electric rates as it relates to the fuel cost ratio. This allows savvy contractors to size systems to the economic balance point, which is a lower temperature with these programs, and the added up-front cost is offset by a cold climate rebate tier (as opposed to an AC replacement tier). Correctly sized systems and lower switchover temperatures equate to more energy and carbon savings. Despite potentially lowering energy costs, a high level of control (e.g., 1,000 hours) could limit the efficiency and decarbonization benefits of an ASHP compared to a traditional furnace and AC, especially as the grid approaches the 2040 carbon-free standard. Figure 5 compares heating and cooling costs across system and rate types for a natural gas customer in an example MN utility territory: a baseline (AC + furnace), an all-electric cold-climate system (ccASHP + electric auxiliary), and four dual fuel scenarios (ccASHP + furnace) with different rates and switchover temperatures. This modeling shows that a dual fuel natural gas system on an interruptible, dual fuel rate can operate to a much lower economic switchover temperature (5°F) compared to the traditional solution.

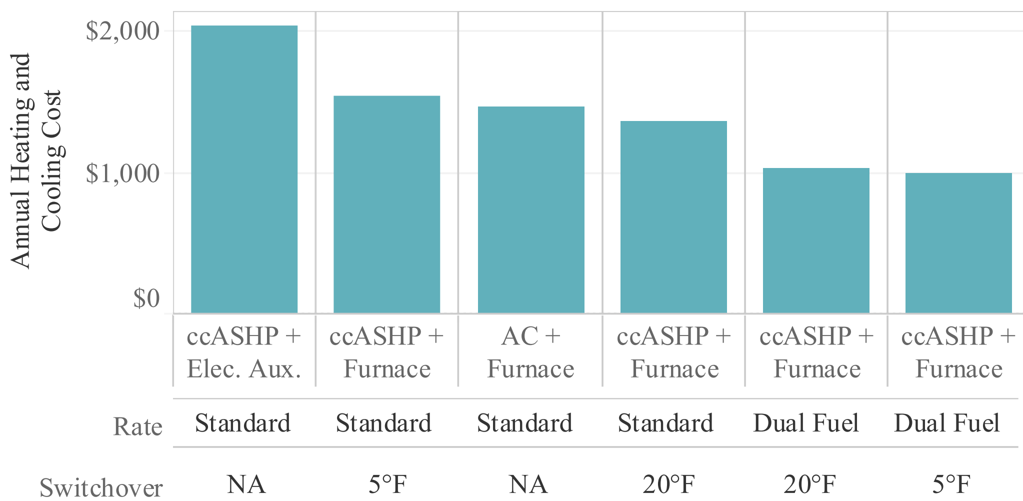


Figure 5. Comparison of annual heating and cooling costs among application types for a typical residential customer with natural gas service in East Central Energy territory

## Grid Integration of Dual Fuel ASHP DERs

Across much of the United States, utilities participate in bulk electric systems that balance supply and demand and keep the grid within critical physical limits such as thermal ratings, frequency, and voltage. To support these functions, wholesale electricity markets create value for reliability and system balance, with demand-side resources playing an important role. In MISO, load modifying resources (LMRs) are a primary mechanism for demand response to participate in the capacity market. LMRs are treated as capacity and emergency resources, helping load-serving entities meet planning reserve margins while providing load reduction during system stress events.

Some utilities may use their programs as an LMR in MISO and monetize the capacity value at the bulk system. Others may operate their assets more frequently as a method of price arbitrage. As noted, off-peak interruptible dual fuel rates can fall well below the standard rate because the assets can be called frequently, within program bounds, with control events typically unnoticeable to the customer. If a utility is long on capacity, they could bid their excess generation capacity into the wholesale market during high price periods to reduce rate pressure for their customers. A real-world precedent exists in Quebec, where utility modeling found that converting gas-heated customers to dual fuel rather than full electrification reduced the added winter electric capacity requirement from roughly 2,070 MW to 63 MW while lowering projected rate impacts for both the electric and gas utilities; Hydro-Québec compensates Énergir through an annual payment for the winter capacity its gas system provides (Séguin and Bigouret 2023).

Table 1 compares, by MISO season, the number of hours when the locational marginal price (LMP) exceeded $100/MWh from May 31, 2021 to May 31, 2026. The quantity of events is greatest in the summer above the threshold. In the winter, there are a similar, but slightly lower amount of hours, a much lower median temperature, and a much higher maximum LMP. These high-price periods and their median temperatures illustrate price-arbitrage value for gas systems on discounted rates or propane systems on standard rates, which may operate at colder temperatures set by the economic balance point. The frequency and temperature when thresholds are met may increase soon, as will be discussed further.

Table 1. Summary of hours above $100/MWh by MISO season and associated temperatures

| Season | Total hours ≥$100/MWh | Percentage of hours ≥$100/MWh | Median temp. at ≥$100 hours (°F) | Max LMP ($/MWh) | Temp. at max LMP (°F) |
|---|---|---|---|---|---|
| Summer, Jun–Aug (2021–2025) | 513 | 3.29% | 83°F | $396 | 83°F |
| Fall, Sep–Oct (2021–2025) | 106 | 1.05% | 81°F | $230 | 85°F |
| Winter, Nov–Mar (2021/22–2025/26) | 507 | 1.76% | 1°F | $670 | -7°F |
| Spring, Apr–May (2021–2026) | 11 | 0.10% | 83°F | $156 | 87°F |

*Source*: Ex Ante LMP at MINN.HUB (MISO 2026) and MSP Airport weather (NOAA 2026).

In 2020, the Federal Energy Regulatory Commission (FERC) issued Order Number 2222 to enable more demand flexibility and distributed energy resources (DERs) in wholesale electricity markets. This order removes barriers by allowing participation of aggregations of DERs or other grid services resources that can be grouped and bid into regional organized wholesale markets to compete in "organized capacity, energy and ancillary services markets run by regional grid operators." While mainly affecting large distribution utilities, there is a small utility opt-in measure. This specifically means that MISO does not need to accept bids from

DERS in utility service territories below the threshold of 4,000,000 MWh unless the utility opts in (FERC 2020). For utilities above this threshold — in Minnesota, only Xcel Energy and Minnesota Power (U.S. EIA 2024) — participation is the default; for all smaller utilities (the state's many cooperative and municipals), the relevant retail regulatory authority must opt in. (FERC 2020).

The implementation of Order No. 2222 is a year-long process within MISO's footprint. FERC Docket ER22-1640 contains the compliance proceedings to implement this order for DER aggregations in MISO's markets. Simply put, DERs will be able to participate in various markets when implemented in 2030. First, MISO proposed using the existing DRR-Type I construct as a transitional measure, which FERC rejected; the dedicated DEAR model is planned for the 2030 timeframe (FERC 2025).

Going a level further below FERC and MISO, at the distribution level, utilities are beginning to prepare for these market changes. Xcel Energy is planning for FERC 2222 through a staged approach. The "Capacity*Connect" battery electric storage pilot is beginning this journey via "grid DERMS." The next stage, "Aggregator DERMS" will be launched in a following phase after system capabilities are determined with battery systems. Lastly, "enterprise DERMS" will be deployed to operate all DERs (Xcel Energy 2025).

At a local distribution level, some investor-owned utilities (IOUs) are already peaking in winter such as Minnesota Power (Minnesota Power 2025). Others, such as the largest investor-owned utility in Minnesota, Xcel Energy, projects 50% of their distribution feeders will transition from summer to winter peaking "between the mid-2040s and the early 2050s" (Xcel Energy 2025). Although this system-wide transition is decades away, regulators increasingly emphasize collaboration "to address intensifying reliability risks, particularly as seasonal challenges, especially in winter, grow increasingly complex" (OMS and MISO 2026). This indicates that in the near term, utilities may find increasing value in load shifting for wholesale price arbitrage in the winter.

To illustrate this point, Figure 6 displays LMP over multiple years. Prices have spiked during the last three winters consecutively and summer price spikes are intensifying. Over the last two heating seasons, a second wave of price spikes has occurred in late February and March. During shoulder seasons, dual fuel systems can activate auxiliary, non-electric heat when their load is curtailed. This temperature range is also more likely to experience realized power reduction during events as it is more likely to be higher than the switchover setting determined by the economic balance point of ASHPs. Conversely, some of the highest-value hours occur in extreme weather when the heat pump may not be operating—for example, gas-served homes that have switched to gas for economic reasons. All-electric homes with tight, well-insulated envelopes could pre-heat or pre-cool ahead of a price event.

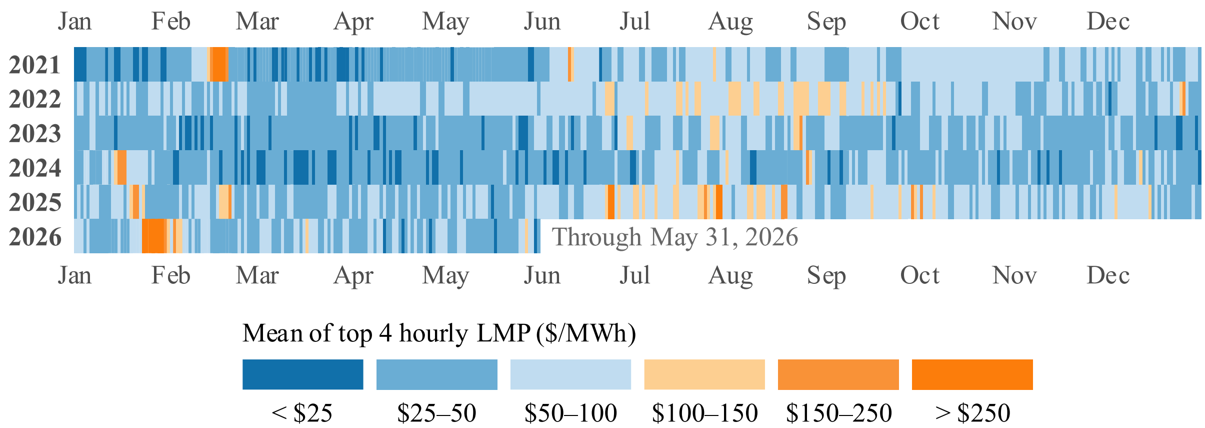


Figure 6. Peak electricity prices: daily top-4 hourly LMP at MISO MINN.HUB (MISO 2026)

## Piloting and Improving ASHP DERs

In the context of controlling electric heating load in cold climates, Pacific Northwest National Laboratory tested the concept of shifting all-electric ASHP loads in Cordova, Alaska, using CTA-2045. Though CTA-2045 is uncommon in HVAC products today relative to OpenADR or proprietary protocols, the pilot verified key factors such as resource availability, capacity, and operational considerations (e.g., acceptable setpoint adjustments). The study pointed to issues related to event fatigue and risk of attrition during extreme cold weather curtailment and load shifting/shedding. In addition, the study pointed to the need for more data related to the realized saving potential and modeling this asset to be used predictably, such as in the DERMS context (Nambiar 2024).

In the dual fuel context with ASHPs, the National Rural Electric Cooperative Association explored demand flexibility with ASHPs utilizing two-wire load management receivers. The study primarily focused on identifying opportunities for load management with ductless, inverter-driven products. However, there were results from two centrally ducted sites in terms of capabilities for load shifting at various outdoor air temperatures (Hamilton, Dayem, and De Fouw 2025). The realized kW reduction values per nominal ton across varying outdoor air temperatures in this study were relatively modest compared to modeled power reductions discussed, so further field studies are needed to better understand actual on-site performance and savings. This may reflect the study's heavy emphasis on non-ducted systems, as well as natural variation in cycling due to the diversity of loads across study participants.

Beyond price signals, additional control frameworks could add customer value. In Figure 7, above a price threshold (e.g., $100/MWh) the emissions factor and bulk-system price are highly correlated, so emissions become inconsequential as a separate variable. Dual fuel programs could instead optimize on both retail price and emissions, depending on utility and customer interests. Most customers, even eco-conscious innovators, are primarily driven by cost, though the smaller innovator segment weights environmental benefits more heavily (CEE and BIT 2024). In 2025, a record was set in terms of the percentage of Americans concerned about climate change posing a serious threat. This figure has nearly doubled since 1997 — 48% of Americans are now concerned (Saad 2025). Innovative program design could operate with cost-neutrality and prioritize carbon savings, resiliency, and flexibility depending on the customer segment.

As seen in Figure 7, there are many points in time when there are low electricity bulk system prices, but high carbon intensity. If the cost to operate the fossil auxiliary system is lower than the heat pump (either at the bulk system or the retail rate level), choosing to operate the auxiliary system during these times of high grid marginal emissions and low costs could provide customer and decarbonization benefits. Where marginal emissions correlate with time-of-use (TOU) periods, the control logic can key off time rather than emissions—much as TOU rates group hours to pass through the cost of expensive peaking resources, which are often also high-emitting. Xcel will offer residential time-of-use rates in 2026 (MPUC 2026); comparing MISO marginal-emissions data from that period against currently available 2024 data will show whether this correlation holds. Such rate-and-emissions interactions warrant study and could be encouraged through control specifications as HVAC controls evolve.

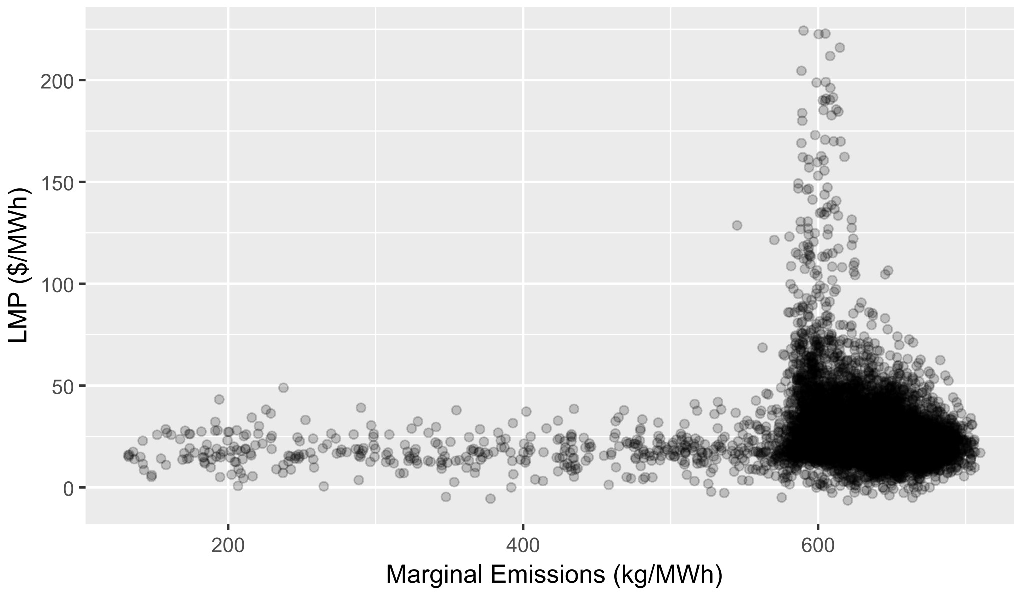


Figure 7. Comparison of 2024 Ex Ante LMP versus marginal emissions for MINN.HUB node in MISO (MISO 2026, WattTime 2026)

AHRI 1380-2019[5] standardizes demand response control methods for variable capacity ASHP systems. This includes multistage systems and variable speed ASHP systems. The current standard does not address dual fuel methodology, nor does it include updated or proprietary communication protocols such as OpenADR 3 and Home Connectivity Alliance (AHRI 2019). An effort is currently underway to update the AHRI standard to 1380-202x, with the "x" likely to be changed to a 6 when the standard is released for public review in 2026 (ANSI 2023). This update creates opportunities for dual fuel demand flexibility program operation. Updated communication protocols such as OpenADR 3.0 will enable a simpler code structure compared to OpenADR 2.0, as well as allow for better incorporation of "price to device" types of operation. It will also allow integration with greenhouse gas data streams (Nordman et al. 2024), enabling the operational logic described above.

Although OpenADR 3, AHRI 1380-202x, aggregator DERMS, and FERC 2222 will roll out over the coming months and years, there are near-term opportunities to demonstrate this

[5] The last four numbers indicated the year the standard was published.

control framework. For example, field studies and program pilots could deploy price control logic for the purposes of price arbitrage to control compressor operation (reduced speed or off) for systems with OpenADR 2 capabilities.

## Conclusion

When replacing heating and cooling equipment, ASHPs offer significant site-energy efficiency improvements and, on a decarbonizing grid, emissions reductions, though the source-energy advantage narrows at extreme cold. All-electric ASHPs face significant barriers related to up-front and operational costs across the US as it relates to their net present value (Wilson et al. 2024). Dual fuel systems can bridge the gap between electrification goals and the challenges with the value proposition described to accelerate adoption. AHRI shipment data show that there is still a major challenge across the U.S. to replace standard ACs with heat pumps, not to mention furnaces (AHRI 2026). The share of ASHPs compared to furnaces fell four points from 57% in 2024 to 53% in 2025, potentially highlighting the operational cost challenges with all-electric systems compared to furnace baselines. The 25C Tax Credit, eliminated after 2025 for ASHPs, contributed to meaningful levels of adoption, but nowhere near what is needed to fully transform the replacement of ACs with ASHPs, potentially because the high efficiency level was mismatched from the baseline technology price. Despite layering the tax credit with utility rebates, from 2023 through 2025, the share of heat pumps compared to ACs only climbed from 42% to 47%. This growth is real, but program and academic goals of installing the most efficient systems often collide with the realities of higher incremental and operating costs. Electrification and dual fuel are complementary pathways that should advance together (GPI and CEE 2021); could prioritizing pragmatic, flexible, and cost-effective dual fuel solutions now—while continuing toward full electrification as the grid decarbonizes—help us decarbonize faster than treating full electrification and furnace replacement as the only near-term path?

Load flexibility programs can monetize the available capacity created from dual fuel systems with minimal customer awareness of events. Originally designed to use low-cost coal rather than to decarbonize, these load control programs have succeeded in Minnesota for decades with single-stage heat pumps and now capture low-cost renewables while avoiding costly fossil peaking generation. Updates to load control standards via AHRI 1380-202x in concert with the implementation of aggregator DERMS and FERC 2222 will create new market opportunities for dual fuel ASHPs.

These opportunities can help close the DLC equipment-compatibility gap, especially for variable-speed, communicating systems. Depending on program value, a new era of dual fuel programs could encourage or require lower switchover temperatures, reflecting an economic balance point reduced by the capacity and price-arbitrage value these systems provide.

Beyond controlling system operation for bulk system price arbitrage, there may be additional opportunities to control based on marginal emissions, especially for customers wishing to decarbonize further with their dual fuel ASHP system. For example, a program control framework could choose to optimize based on the lowest emissions secondary to operational economics. As efficiency programs face headwinds—rising equipment costs, shrinking federal incentives, and a persistently high fuel cost ratio—updated program design and expanded DER frameworks offer major near- and medium-term energy, cost, and emissions savings.

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