Memorandum

TO: FEDERAL ENERGY REGULATORY COMMISSION

FROM: ASA S. HOPKINS, PHD

DATE: APRIL 21, 2021

RE: INFRASTRUCTURE IMPLICATIONS OF ELECTRIFICATION

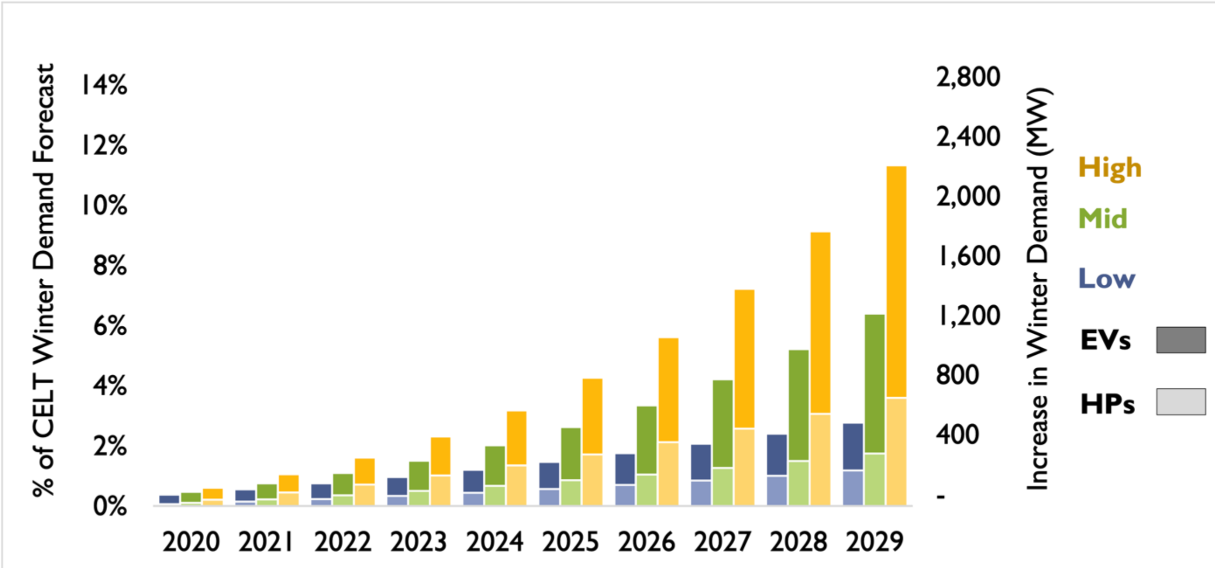
Thank you very much for the opportunity to join a panel in your April 29, 2021 Technical Conference on Electrification and the Grid of the Future. In advance of my participation, I would like to share six simple points that inform and frame my comments.

1. Electrification will arrive slowly enough that we can plan for it

While the remainder of my comments are focused primarily on building electrification, the first point applies across all sectors. Most end-uses that consume substantial amounts of energy are driven by infrastructure or equipment with many-year lifespans. Vehicles typically spend more than a decade on the road, while heating systems commonly last two decades. This means that even very rapid changes in market share for electric alternatives to incumbent fossil fuel technologies would not result in rapid changes in electric loads. The deployed stock of electric equipment is what drives electric loads.

This effect can be seen in my Synapse colleagues' analysis of the potential impact of electrification on the regional load in ISO New England. Figure 1 shows the increase in winter peak load in ISO New England—relative to the ISO New England *2020 Capacity, Energy, Loads, and Transmission* (CELT) forecast—from our independent forecast of electric vehicle and heat pump adoption across the region, driven by adopted state policies (as of mid-2020). While there is uncertainty regarding the uptake of new electric loads, even the highest-load case with unmanaged EV charging shows winter peaks that remain well below the region's current summer peaks. This indicates there is at least a decade to plan for transmission-level grid impacts from winter peaks in New England. While local distribution peaks could develop sooner if electric technologies are adopted unevenly, careful load monitoring and market awareness by distribution utilities should allow appropriate planning.

Figure 1. Winter demand impacts on New England's electric grid from heat pumps and EVs with unmanaged charging



Source: Goldberg et al. 2020. New England Electrification Load Forecast. Prepared for E4theFuture by Synapse Energy Economics. Available at https://e4thefuture.org/wp-content/uploads/2020/06/New-England-Electrification-Load-Forecast.pdf. (Figure 20 in original)

The slow pace of stock turnover, even if market shares were to shift rapidly, is a double-edged sword. It means there is time to plan for the impacts of electrification on grid infrastructure (and on the fossil fuel infrastructure left behind), but it also means that aggregate emissions impacts from electrification (including greenhouse gas emissions as well as particulates and other criteria pollutants) are similarly slow. Efforts to reach net zero greenhouse gas emissions by 2050, for example, imply a need for rapid market share changes within the next decade or so (depending on the lifetime of the equipment in question).

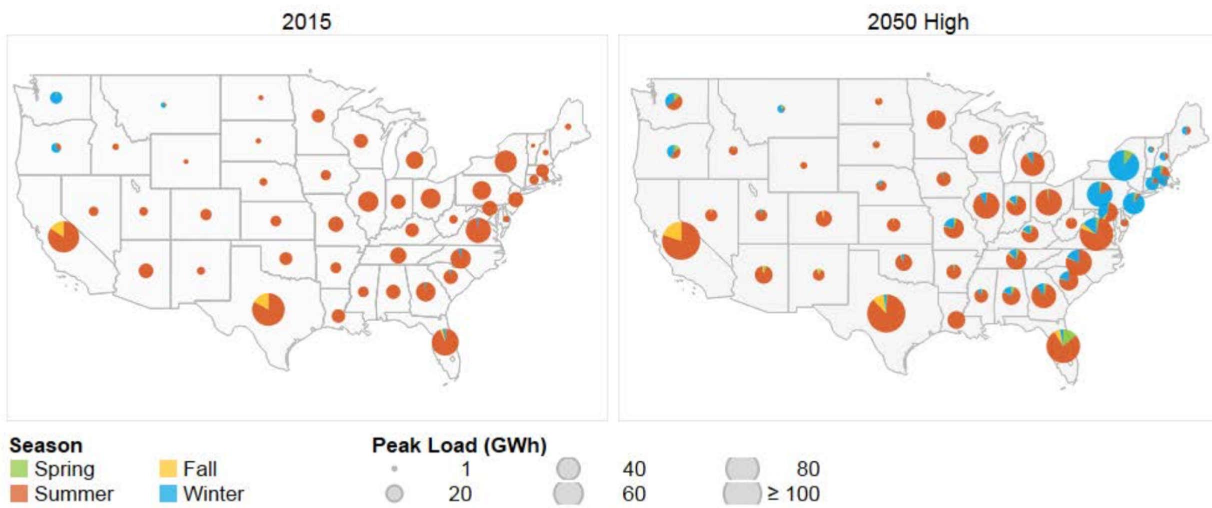
One caveat regarding the pace of change: the aggregate energy and emission impacts could be achieved much faster if high-emitting buildings and vehicles were electrified more rapidly (especially if that electrification were to happen outside of the normal replacement cycle). Our analysis of Massachusetts homes and commercial buildings, for example, indicates that only about 22 percent of homes are responsible for half of on-site greenhouse gas emissions from space heating. Emissions and fossil fuel use are even more concentrated among the state's commercial buildings, where one-quarter of floor space produces between two-thirds and three-quarters of non-electric-sector emissions. Even a relatively small market share for electrification technologies, therefore, could increase electric consumption (and reduce emissions) most of the way to a fully electrified building stock if that market share were focused in high-emitting buildings.

2. Electric system demands will shift to the winter in many places

If space heating for buildings is completely or mostly electrified, electric system peaks will shift to the winter. While the New England analysis I discussed above showed winter peaks remaining below summer levels over the next decade, further electrification in the 2030s would bring winter peak loads above summer peaks. Several other recent analyses show this effect in different regions, and show how it varies by region and climate. In a 2018 analysis, we showed that Pacific Gas and Electric's system would become winter peaking under normal weather if half of buildings in its Northern California service territory electrify space and water heating.[1] However, CAISO as a whole would not typically see a winter peak.

In cold climates, a shift to winter peaking is all but assured unless most or all electrically heated buildings retain combustion-based (that is, non-electric) backup systems. The National Renewable Energy Laboratory's *Electrification Futures Study* showed a shift to winter peak hours across the country, with the most pronounced shifts in the Mid-Atlantic and Northeast. The High scenario, shown on the right in Figure 2, corresponds to electrification of the majority of residential space and water heating, and commercial space heating, dominated by growth in heat pumps.

Figure 2. NREL Electrification Futures Study: Estimated peak load magnitude and seasonal timing by state for 2015 (left) and 2050 in the High scenario (right)



Source: Mai, et al. 2018. Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71500. *https://www.nrel.gov/docs/fy18osti/71500.pdf.*

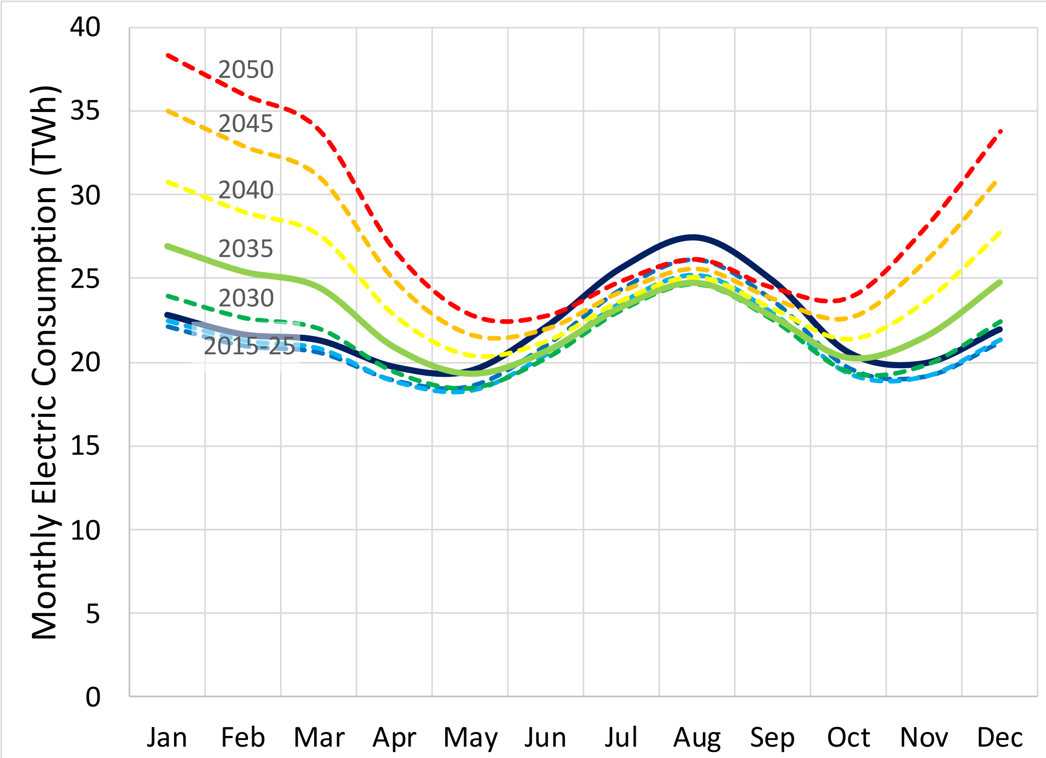
[1] Hopkins, et al. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for Natural Resources Defense Council. www.synapse-energy.com/sites/default/files/Decarbonization-Heating-CA-Buildings-17-092-1.pdf.

To bookend the range of possible peak effects, we examined a polar vortex event across the northern tier of states in a world with complete building electrification. In this case, the peak load would more than double the current winter load and be far in excess of the current summer peak.[2] However, if such an extreme winter peak occurred on the grid in 2050 or later, the annual implied growth in peak load over the next 30 years would be comparable to historical rates of peak load growth in the second half of the 20th century. Therefore, with careful planning and cost-effective mitigation (see the next section), reliably meeting new winter peaks is achievable.

Winter peak loads are not the only aspect of electrification that would have electric infrastructure implications. Even before new peak loads arise, increased off-peak energy demand in the winter would change the energy resources required. Figure 3 shows a “butterfly chart” of the growing winter demand in New York and New England under a “plausibly optimistic” electrification scenario as part of a path to 80 percent greenhouse gas reductions by 2050 (including strategic electrification of both vehicles and buildings). Monthly energy consumption in January exceeds August’s level by 2035, driven by a combination of summer energy efficiency and increased heating demand. By 2050, even April’s energy requirements exceed mid-summer’s needs. As these states plan to increase the proportion of their energy supplies that come from renewable sources, the alignment (or lack thereof) of this seasonal shape to the different sources of renewable energy will have a strong impact on what generation resources are built. Offshore wind, with its strong winter performance, is likely to be a key part of the answer, as will connections to Canadian hydroelectricity (which may eventually operate as a kind of seasonal storage for the Northeast United States and Eastern Canada). Legacy combustion plants may be needed for low-wind winter weeks, although they are likely to have low capacity factors unless substantial amounts of zero-carbon fuels are available.

[2] Hopkins, A., K. Takahashi, and S. Nadel. 2020. “Keep Warm and Carry On: Electrification and Efficiency Meet the ‘Polar Vortex.’” Proceedings of the 2020 ACEEE Summer Study on Energy Efficiency in Buildings 6: 96–108. Washington, DC: ACEEE. www.synapse-energy.com/sites/default/files/Keep_warm_carry_on_polar_vortex_ACEEE.pdf.

Figure 3. Monthly Northeastern electric energy demand under a "plausibly optimistic" electrification scenario to achieve approximately 80 percent greenhouse gas emission reductions by 2050



Source: Hopkins et al., 2017. "Northeastern Regional Assessment of Strategic Electrification. Synapse Energy Economics and Meister Consultants Group for Northeast Energy Efficiency Partnerships. https://neep.org/sites/default/files/media-files/se_report_neep.pdf.

3. Winter electric system peaks can be mitigated

The extent and size of new winter peaks from electrification will depend on how well energy efficiency and load flexibility are harnessed to mitigate those peaks. Electric vehicles, heat pump water heaters and (to a lesser extent) heat pumps for space heating can all be used to increase electric load flexibility.[3] In this way, electrification comes packaged with solutions to some of the problems it could create.

Following a successful and cost-effective path toward electrification will require coordination and trust between policymakers, grid planners, utilities, and demand-side-management program implementers. Policymakers interested in emissions reductions will drive the adoption of the new technologies, while utilities (through rate design) and demand-side program implementers (through program requirements and coupled measures like buildings shell improvements and fostering high-efficiency technologies) can simultaneously mitigate the peak load impacts of these changes. Grid planners need to understand the

[3] Shipley, J., Hopkins, A., Takahashi, K., & Farnsworth, D. 2021. Renovating regulation to electrify buildings: A guide for the handy regulator. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/renovating-regulation-electrify-buildings-guide-handy-regulator/.

technology adoption as well as the mitigating actions and plan for the actual resulting loads. When determining cost-effectiveness of end-use efficiency measures, program implementers should account for the avoided grid investments (in both wires and generation capacity) that would result from doing their jobs well.

Two recent studies have evaluated the winter peak mitigating effects from demand-side measures. First, the polar vortex modeling mentioned above[4] examined not only the unmitigated peak loads but also the impact of various mitigating measures. Where unmitigated building electrification added 411 GW to the winter peak across MISO, PJM, NYISO, and ISO-NE, a combination of building shell improvements, thermostat demand response, and use of ground-source heat pumps in the coldest part of the region (i.e., the upper Midwest) reduce the new peak load to only 130 GW. While this new winter peak would still exceed the summer peak, the savings from avoiding about 300 GW of peak load capacity, transmission, and distribution could be staggering.

A recent study by ACEEE reinforces the message that peak impacts from electrification can be mitigated.[5] Specian et al. examine demand-side measures in equipment efficiency, building envelopes, smart thermostats, lighting, and managed EV charging. The authors identify model existing programs for each of these measures addressing winter peaks. The study shows that portfolios of these measures could be constructed that are cost-effective compared with the cost of electricity during winter peak periods—without even counting avoided transmission, distribution, or capacity costs—and states and programs are actively working towards further cost reductions for more expensive measures (like deep energy retrofits).

4. Equity can and should be central to electrification and mitigation planning

Any transition risks leaving people behind, and the transition to electrification is no different. Those most likely to be left behind are households without access to capital (to buy electric options, which can be more expensive up front) and renters (who do not control the capital systems, like HVAC, in their homes and may not have a place to charge an EV). Low-income and renting households on the gas utility system are most vulnerable, because the cost of the gas system will fall heavier and heavier on customers whose gas use remains unchanged while wealthier homeowners electrify. To increase energy justice and mitigate energy burdens, programs and policies encouraging electrification and associated mitigation measures (like retrofits to improve building shells, comfort, and indoor air quality) should be directed, early and with strength, toward assisting low-income households and renters (and their landlords).

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[4] Hopkins, A., K. Takahashi, and S. Nadel. 2020. "Keep Warm and Carry On: Electrification and Efficiency Meet the 'Polar Vortex.'"

[5] Specian, M., C. Cohn, and D. York. 2021. Demand-Side Solutions to Winter Peaks and Constraints. Washington, DC: ACEEE. www.aceee.org/research-report/u2101.

5. To manage electrification, the natural gas and electric systems must coordinate at a wide range of timescales

In infrastructure-intensive energy systems like electricity and natural gas, planning, operation, and system design occur over a wide range of timescales—from less than a second through many years. The electric and gas systems interact on many of these timescales. As we saw in Texas this February, the gas system supplies both power plants and buildings, and when supplies are short the buildings get preferential supply. However, when power plants are not reliably available (due to the lack of fuel or other causes) the buildings do not have electricity to run their gas heating systems (and the gas system itself can suffer from power outages). During winter events, coordination between gas supplies (and the markets that allocate those supplies) and the electric markets and assets is therefore critical. As buildings and transportation electrify, the nature of this event-based coordination will change. While electricity is already essential to heating, the amounts of energy required from each fuel in buildings will change, with implications for market design, firm commitments, and infrastructure.

Gas and electric systems will need to coordinate distribution infrastructure investments. Increased electric loads to meet winter demand on the electric system will correspond to reductions in need for gas infrastructure. It may make sense, for example, to accelerate electrification in buildings served by an aging spur of the gas system. This would allow distribution companies to retire that gas asset instead of paying to replace it for a limited and low-use future. Where a single utility provides both fuels, coordinating system investments and design is likely to be easier than in the cases where the two systems are separately owned. Distribution planning timescales are typically on the order of one to three years, so this kind of coordination can be accomplished on a quarterly basis (as opposed to the hourly or faster basis required during winter events).

On even longer timescales, planning for gas and electric transmission assets and resource adequacy will also need to adjust and be coordinated between the electric and gas systems. Firm capacity on gas transmission may need to shift from serving local distribution companies, toward serving power plants (with that power plant use shrinking over time to those limited times when combustion is required to supplement renewable resources).

6. Electrification is happening in the midst of other transformations, and planning is essential for managing the combined effects

Electrification of transportation and buildings is just one of many simultaneous transformations occurring in the energy and electric systems. Variable renewable generation is a rapidly growing portion of the electric supply portfolio, with implications for grid planning and operations. Energy storage costs are falling rapidly, and deployment is accelerating as storage becomes the cost-effective solution to a wider range of challenges. And distributed resources—both generation and flexibility from controllable load—are becoming part of the baseline expectation for customers, regulators, and utilities alike.

In this context, electrification interacts with, mitigates, and exacerbates different aspects of the concurrent transformations. Electric vehicles depend on the same progress in battery technology as is driving utility deployments; they represent a potential grid resource that dwarfs the direct utility deployment of batteries on the grid. Electric water heaters can provide similar grid services. In higher-performing building shells, pre-heating and pre-cooling with heat pumps can shift comfort loads by a few hours. But, as discussed above, building electrification will also create new winter supply and peak demand challenges.

It is essential that grid planners, policymakers, and utilities plan for all of these transitions at the same time, while recognizing their different drivers and timescales. Customer adoption of electric technologies depends on a complex mix of upfront and ongoing costs, services provided, and marketing. Planners should be cognizant of the risks of placing too many costs on electric bills, because actions that raise effective electric rates can impede electrification. State-level policy leadership has been a primary driver here, and I expect it will remain the primary driver given state regulatory authority over most of the relevant processes. But federal actions (from transmission planning and siting to tax policy to offshore wind permitting) will also shape the outcomes.

Thank you for the opportunity to raise these few points with you in advance of the Technical Conference. I look forward to the discussion.