Right Place, Right Time: How Modernizing Load and DER Forecasting Practices can Help Utilities Prepare their Systems for Electrification

Ahmed Hanafy, Dunsky Energy + Climate Advisors
Amara Slaymaker, Dunsky Energy + Climate Advisors

ABSTRACT

Decarbonization towards net-zero pathways is largely driven by electrification. Utilities are critical in this transition, responsible for delivering reliable, and affordable electricity. To play their role effectively, utilities must understand the pace and magnitude of electrification and its impacts on their generation, transmission, and distribution systems. They must also evolve their consideration of distributed energy resources (DERs) not as load modifiers, but as critical resources to maintaining affordable and reliable power.

Leveraging learnings from our work supporting load forecasting and modernization efforts for several utilities, this paper aims to empower utilities with insights as they prepare for and accommodate wide-spread electrification, including:

- **View load growth holistically.** New electric loads will not just be passenger EVs or residential heat pumps. A full system outlook that captures the combined impacts of multiple sectors/technologies is critical to understanding how system fundamentals may evolve (transition to winter-peaking regime, load pattern changes)
- **Load impacts will not be homogenous throughout the system**. Technology uptake and consumption patterns will vary across sub-regions of the service territory and result in a non-homogeneous distribution of load impacts regionally (municipal level to individual substations and feeders);
- If **unmitigated, the pace and magnitude of load impacts will trigger significant** investments system-wide and in localized hot spots, however, DERs should be explicitly considered to assess their potential and **cost-effectiveness for avoiding/deferring these impacts.**

The paper highlights recommendations for utility planners, program administrators, and service providers on appropriate assessment of load impacts as well as unlocking the full potential of DERs to minimize ratepayer impacts.

Introduction

The race to net-zero is on, and the deep decarbonization required to achieve net-zero targets necessitates a fundamental transformation of our energy system. At the heart of this transformation lies the pivotal role of electrification, which drives the displacement of fossil fuels across all key sectors. While forecasts and estimates vary, there is growing consensus that wide-spread electrification of transportation, buildings, and industry aligned with a net-zero pathway will grow electricity demand by 2 – 3x current levels.

Central to this transition are utilities, entrusted with the critical task of delivering reliable and affordable electricity to customers while adapting and expanding their systems and infrastructure to decarbonize electricity supply and accommodate the expected growth in electrification. Understanding the pace and magnitude of electrification, along with its implications for generation, transmission, and distribution systems, is paramount for utilities to fulfill their mandate effectively.

In addition to electrification, the accelerating trend of decentralization is also reshaping traditional modes of electricity generation, distribution, and consumption. As the traditional lines between producers and consumers shift, utilities must evolve their approach to distributed energy resources (DERs), recognizing them not merely as load modifiers, but as indispensable resources that contribute to the resilience and flexibility of the grid.

Drawing upon insights from our work supporting load forecasting and modernization efforts for utilities and planners across North America, this paper aims to provide utilities with actionable insights as they prepare for and accommodate widespread electrification. Through a comprehensive examination of key considerations and emerging trends, we delve into these insights, and synthesize our findings into proposed practices for utility planners, program administrators, and service providers to assess load impacts effectively and unlock the transformative potential of DERs.

Methodology

The results and key findings presented in this paper are highlights from load forecasting projects conducted by Dunsky for multiple clients across North America. These load forecasts were developed using a proprietary modelling approach developed by Dunsky, which consists of four key steps (Figure 1) further described below.

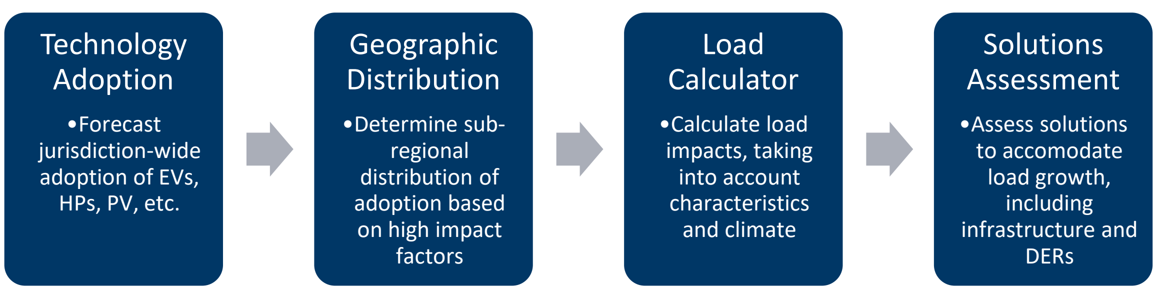

Figure 1. Overview of modelling approach

Technology adoption forecasts are conducted leveraging Dunsky's proprietary in-house models, including EVA™ (Electric Vehicle Adoption Model), HEAT™ (Heating Energy Decarbonization Model), and SAM™ (Solar Adoption Model). While each of these models has characteristics unique to the technologies and end-uses being assessed, at the core of these models is the adoption engine, which projects technology uptake considering market barriers, customer economics, and a range of program and policy options aimed at reducing barriers and accelerating adoption.

Geographic distribution of jurisdiction-wide technology adoption results is based on analysis of key high-impact factors that impact propensity for adoption within a given region. This analysis disaggregates jurisdiction-wide results to each sub-region considered in the analysis. The granularity of sub-regions is flexible (e.g., municipality, neighborhood, substation, or feeder-level), and depends on both client needs as well as data availability. The studies have typically relied on a combination of utility customer and load data, census data, and other supporting datasets (e.g. municipal tax records, vehicle registration), and uses Geographic Information Systems (GIS) tools to consolidate the data into a uniform dataset that characterizes each market adequately.

Three key factors are used in the propensity models developed to disaggregate jurisdiction-wide results into each sub-region:

1. **Market size** and composition. Evidently, sub-regions with a larger market size are more likely to exhibit greater adoption of the technologies considered. Composition (e.g., proportion of residential vs. non-residential buildings) is also a key factor as adoption behavior can vary between different segments of the market.
2. **Market saturation** also plays an important role in driving sub-regional adoption patterns. Sub-regions with a higher existing penetration of a technology (e.g., EVs) are likely to experience greater uptake due to networking effects.
3. **Market characteristics** correlated with adoption propensity are the third key factor analyzed. These factors may vary by technology but may include income levels, housing type (e.g., the proportion of single-family vs. multi-family), occupant type (e.g., the proportion of owner-occupied vs. renter-occupied homes) and driving distances (in the case of EVs).

The load calculator is specific to each end-use, but overall, considers the forecasted technology adoption (jurisdiction-wide and for each sub-region), local characteristics (e.g., annual driving distance per market segment) and climate, technology performance, and diversified technology- and segment-specific load profiles in order to determine hourly energy needs, which are then scaled by the adoption to determine overall load impacts.

The calculation includes nuanced considerations specific to each end-use. For example, for electric vehicles, the analysis considers assumptions regarding the distribution of different types of charging events (e.g., home charging, workplace charging, public charging, depot charging) and chargers (e.g., level 1, level 2, and direct-current fast charging), and adjusts consumption based on temperature.

For heating electrification, the load calculator leverages HEAT™'s detailed hourly simulations of heat pumps in order to determine energy and load impacts, and also takes into account the impacts of differing system configurations (e.g., hybrid heat pump systems with a fuel back-up vs. all-electric heat pump systems with an electric resistance back-up). The baseline systems are also taken into account in order to determine incremental impacts (for example, if a customer switches from electric baseboards).

The assessment of solutions that can either accommodate or mitigate the forecasted load impacts is the final step of the analysis. There are two phases to this assessment:

- **Initial Impact Assessment:** This phase considers the load forecast developed through the previous three steps, as well as data relevant to the assets evaluated (e.g., rating, lifetime, archetypal costs) in order to determine an asset upgrade or replacement schedule, including early replacement, as well as associated infrastructure costs.
- **Alternative Solutions Assessment:** This phase considers the load forecast and initial impact assessment, as well as multiple DER solutions and key parameters (e.g., managed EV charging, stationary battery storage, smart thermostats, expected penetration/participation rates, program costs, and impact to load shape and peak), in order to determine appropriate non-wire alternatives and assess their potential and cost-effectiveness.

Key Findings

This section presents the key insights gleaned from our support of utilities, planners, and program administrators across North America in electrification load forecasting and DER assessments. While the specific nuance of each study and jurisdiction result in varying results, there are a number of consistent insights that have emerged from these explorations.

Insight #1 - Holistic Assessment of Load Growth Is a "Must-Have"

Forecasts that focus on a single technology in isolation are akin to attribution exercises and do not provide a robust and full system outlook that captures the combined impacts of multiple sectors, segments, and technologies, which is critical to understanding how system fundamentals may evolve – for example, a transition to a winter-peaking regime, or shifts in load patterns, such as a change in peak hour.

Load growth from electric vehicles, and particularly personal electric vehicles, is often top of mind for utility planners, driven by the increase in EV sales observed in recent years – for example in California, where battery electric vehicles (BEVs) have increased from 5.8% to 21.4% of annual vehicle sales in just three years (2020-2023) (CNCDA 2024), and strengthening of policies driving transportation electrification, such as zero-emission vehicle (ZEV) mandates, as seen in jurisdictions including California (CARB 2024), New York[1], and Canada (Transport Canada 2024).

However, the electrification of other key end uses – such as heating – is also expected to play a significant role in the mid- to long-term, particularly for jurisdictions in colder climates. Several jurisdictions across North America are implementing or considering policies that will

[1] Senate Bill S2758 (An act to amend the environmental conservation law, in relation to providing that one hundred percent of in-state sales of new passenger cars and trucks shall be zero-emission by two thousand thirty five). 2021.

strengthen heating decarbonization efforts and drive increased electrification, such as bans on new gas connections (City of Montreal 2023), clean heat standards (State of Vermont PUC 2024), and building performance standards which set energy efficiency and emissions requirements for buildings (City of New York 2022).

Results from an analysis (Figure 2) conducted for a utility serving a large urban region (IECC climate zone 6-7) that predominantly relies on gas-based heating reaffirms that principle. Our analysis identified that the forecasted EV uptake is expected to increase system peak by nearly 40% by 2040 (from 3.2 GW to 4.4 GW). However, the combined unmitigated impacts of both forecasted EV and heating electrification loads were forecasted to nearly double the system peak to 6 GW.

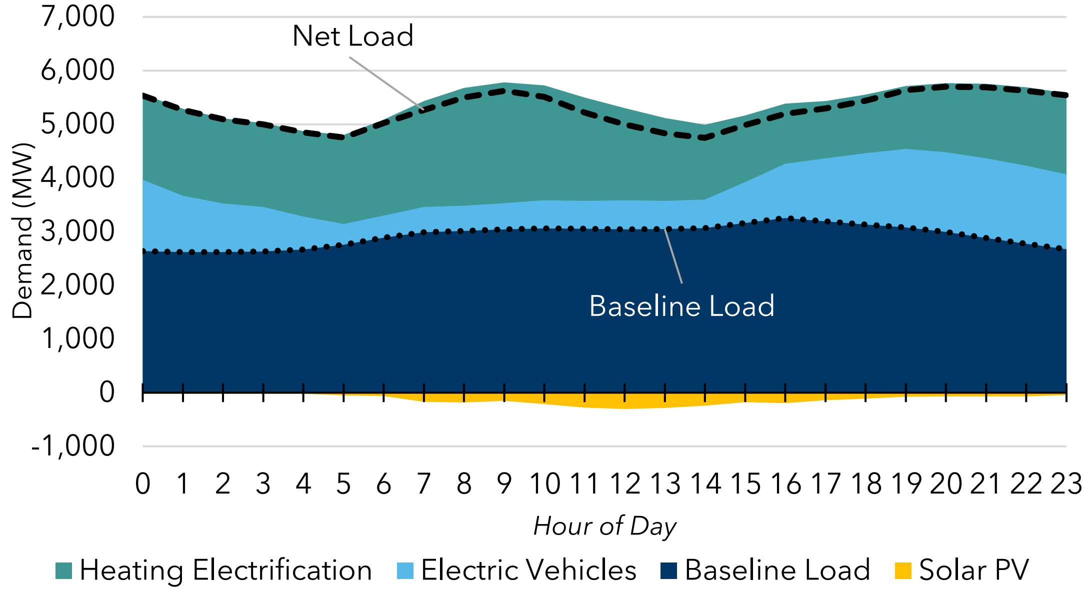

Figure 2. Forecasted jurisdiction-wide winter peak demand impacts (2040) of electrification of transportation and heating and adoption of solar PV.

In addition to the more nuanced magnitude of load growth, the results also highlight more nuanced patterns around the system dynamics. Notably, the combined impacts of unmitigated EV and heating electrification loads highlighted a shift from a summer-peaking to a winter-peaking regime as early as 2029 (Figure 3). If the effects of heating electrification were not considered, this transition would have only been expected four years later, in 2033. Additionally, the peak load patterns observed (Figure 2) also highlight shifts in the window and duration of system peak events, which has significant operational implications on the system.

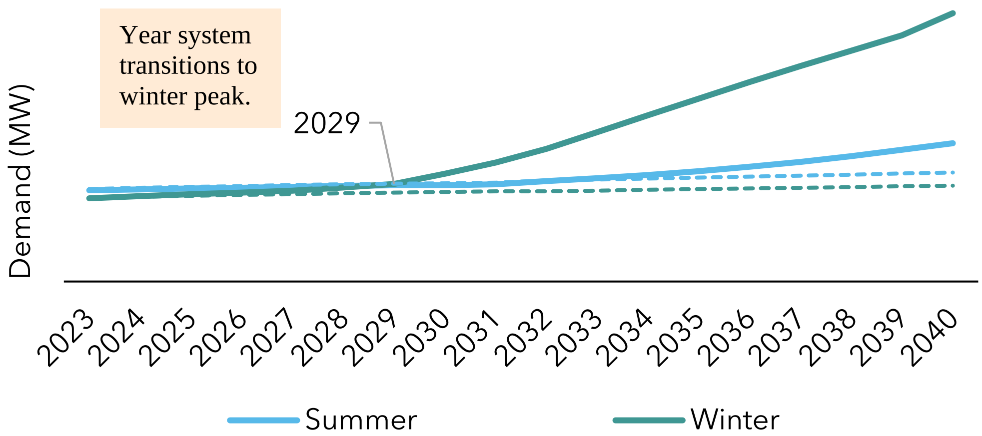

Figure 3. Jurisdiction-wide summer and winter peak demand forecast for 2023-2040.

Considering the combined impacts of multiple technologies and end-uses is equally critical in summer-peaking systems, and in jurisdictions in warmer climates which may be expected to remain summer-peaking despite heating electrification. An often-missed impact of heat pump adoption is that they typically displace less efficient air conditioning systems. For example, our analysis for a western Canadian utility identified that the combined load reductions from efficiency gains associated with heat pumps displacing air conditioning coupled with the load reductions from solar PV were comparable, and almost fully offset the load growth associated with EVs (Figure 4). Further, in the example considered, these combined effects shift the summer peak to later in the evening. This could also contribute to an increasing pace of transitioning to a winter-peaking regime.

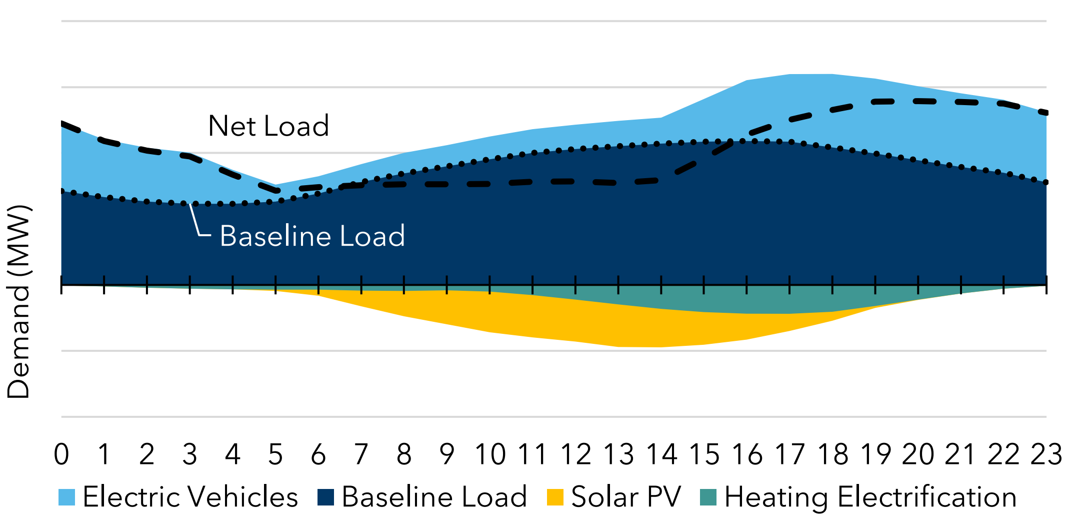

Figure 4. Forecasted jurisdiction-wide summer peak demand impacts (2040) of electrification of transportation and heating and adoption of solar PV.

This underscores the importance of holistic load forecasting which provides comprehensive information regarding the full spectrum of electrification impacts. By understanding these dynamics, planners can make informed decisions and proactively adapt their plans and investments to meet evolving demands, ensuring that utilities can continue to serve their customers reliably in an era of rapid transition.

Insight #2 – Load Growth from Electrification Will not be Homogenous.

Understanding territory-wide load impacts is only part of the picture. Our studies have consistently identified significant regional variations in technology uptake and load impacts of emerging technologies within a utility's service territory. Rather, technology uptake and consumption patterns will vary across sub-regions, creating varying shifts in dynamics within the system's secondary networks. This has the potential to drive more imminent impacts in pockets of the distribution system and accelerate the need for interventions. Understanding localized impacts provides valuable insights into infrastructure needs as electrification may accelerate investment requirements in sub-regions with greater uptake, or where existing infrastructure is already nearing capacity limits.

Local demographics and market characteristics will drive non-homogeneous impacts, driven by the three factors used in our disaggregation model ; market size, market saturation and market characteristics (described in further detail in Methodology section).While population centers, such as cities, often experience higher overall load impacts due to their larger market sizes, factors such as market saturation, concentration of residential vs. non-residential loads and other characteristics drive differences at a more granular level. For example, in Figure 5a, greater load impacts are clustered in population centers. However, when zooming in on a given population center (Figure 5b), there is still significant variation between feeders. Feeders in neighborhoods with a higher average annual income and a greater proportion of homes occupied by owners (as opposed to renters), for example, are expected to see greater technology uptake and, subsequently, greater peak impacts. Similarly, the characteristics of customers in a certain sub-region may have an impact on the load impacts to be observed. For example, the load impacts observed in areas that serve commuters / drivers with longer than average driving distance will be higher than areas with lower vehicle ownership / use.

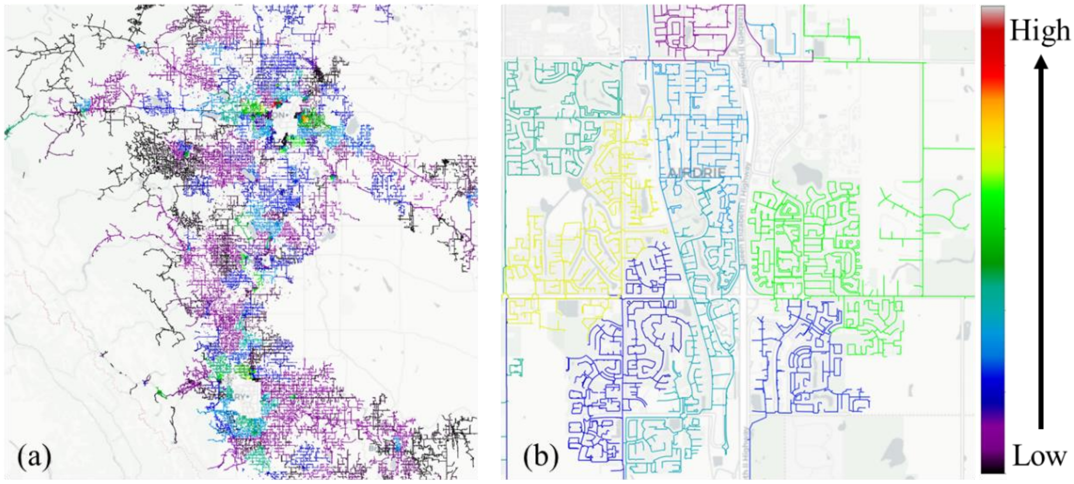

Figure 5. Winter peak load impacts (MW) in 2040 by feeder for an entire jurisdiction (a) and a single population center (b)

This analysis can highlight not only where utility planners should target actions and investments, but also the timing and magnitude of the needs.

Figure 6 presents the results of an analysis conducted for a utility client in western Canada, showing the forecasted loading on 20 substations without and with EV relative to their rates capacity. The highlighted example illustrates three cases for how different segments of the system will be impacted by EVs:

- For Substation 4, the substation is expected to reach its rated capacity by 2024 both with or in the absence of EV loads, so there is no acceleration in the need for investment, however, the forecasted load growth indicates that the investment must be future-proofed to accommodate 30% higher loading in the future due to electrification.
- Substation 5, on the other hand, shows a significant acceleration in the need for investment by 7 or more years, which was previously not expected to experience any load growth over the next decade.
- Substation 16 shows a subtle increase in substation loading, that does not result in a need for accelerated or future-proofed investments during the period considered.

Forecasted Loading with and without Evs

Below Rated Capacity | Above Rated Capacity

Peak Load (MW)	Substation 1		Substation 2		Substation 3		Substation 4		Substation 5	
	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs
2021	92.1	92.2	32.1	32.1	91.4	91.4	60.0	60.0	80.9	80.9
2022	92.8	93.1	33.3	33.3	91.5	91.5	61.3	61.4	83.5	83.5
2023	93.6	94.0	34.6	34.6	91.6	91.6	62.6	62.7	84.9	84.9
2024	94.4	95.1	35.8	35.9	91.7	91.8	63.9	64.1	84.9	84.9
2025	95.1	96.3	37.0	37.2	91.7	91.9	65.2	65.5	93.6	93.6
2026	95.9	97.6	38.2	38.8	91.8	92.1	66.4	66.9	93.6	93.6
2027	96.7	99.2	39.5	40.4	91.9	92.2	67.7	68.3	94.5	94.6
2028	97.5	101.0	[illegible]	[illegible]	[illegible]	[illegible]	68.9	69.8	94.5	94.6
2029	98.2	103.3	[illegible]	[illegible]	92.1	[illegible]	70.0	71.3	94.5	94.6
2030	99.0	106.1	43.3	46.1	92.2	92.9	71.2	76.4	94.5	94.6
2031	101.8	111.4	[illegible]	[illegible]	[illegible]	[illegible]	72.3	80.6	94.5	94.7
2032	102.6	115.5	[illegible]	[illegible]	[illegible]	[illegible]	73.4	85.8	94.5	94.7
2033	103.4	122.2	47.3	51.7	92.5	94.1	74.4	92.0	94.5	94.8
2034	104.2	127.8	48.6	58.3	92.6	[illegible]	75.4	99.1	94.5	94.8
2035	105.0	134.0	49.6	62.0	92.7	95.1	76.4	107.2	94.5	94.9

Peak Load (MW)	Substation 6		Substation 7		Substation 8		Substation 9		Substation 10	
	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs
2021	62.5	62.5	121.6	121.6	58.6	58.6	76.6	76.7	65.6	65.6
2022	62.9	63.1	121.7	121.8	59.0	59.2	76.9	77.0	65.6	65.8
2023	63.8	64.1	121.8	122.0	59.5	59.7	77.1	77.3	65.7	65.9
2024	64.0	64.6	122.0	122.2	60.0	60.4	77.3	77.6	65.7	66.1
2025	64.3	65.2	124.0	124.3	60.4	61.1	77.6	78.0	68.7	69.3
2026	64.6	65.9	124.1	124.6	60.9	61.9	77.8	78.4	68.7	69.7
2027	64.8	66.7	124.2	124.9	61.4	62.8	78.1	78.9	68.8	70.1
2028	65.1	67.8	124.4	125.4	61.9	63.8	78.3	79.5	68.8	70.7
2029	[illegible]	[illegible]	[illegible]	126.0	62.4	65.1	78.6	80.2	68.9	71.4
2030	65.5	[illegible]	124.6	[illegible]	62.9	66.6	78.8	81.1	68.9	72.4
2031	65.8	72.9	124.7	[illegible]	63.4	68.5	79.0	82.1	69.0	73.7
2032	[illegible]	[illegible]	[illegible]	128.9	63.9	70.7	79.3	89.5	69.1	75.3
2033	66.2	78.5	125.0	130.2	64.4	73.1	79.5	92.7	69.1	77.1
2034	66.4	81.9	125.1	131.8	64.9	75.8	79.8	96.3	69.2	79.1
2035	66.7	85.7	125.3	133.4	65.4	78.8	80.0	100.3	69.2	81.2

Peak Load (MW)	Substation 11		Substation 12		Substation 13		Substation 14		Substation 15	
	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs
2021	54.7	54.8	17.7	17.7	87.0	87.1	62.2	62.3	16.7	16.7
2022	55.2	55.3	17.8	17.9	87.4	87.6	64.5	64.8	17.2	17.2
2023	55.6	55.8	18.0	18.0	88.3	88.7	66.8	67.3	17.7	17.7
2024	56.0	56.4	18.1	18.2	88.7	89.3	69.0	69.8	18.1	18.2
2025	56.5	57.1	18.3	18.3	89.1	90.0	72.2	73.4	18.6	18.7
2026	56.9	57.9	18.4	18.5	89.5	90.8	74.4	76.2	19.1	19.3
2027	57.4	58.7	18.5	18.7	89.9	91.7	76.5	79.1	19.5	19.8
2028	57.8	59.7	18.7	18.9	90.3	92.8	78.6	82.3	20.0	20.3
2029	58.3	61.0	18.8	19.1	90.7	94.0	[illegible]	[illegible]	[illegible]	[illegible]
2030	58.8	62.5	18.9	19.3	91.1	95.6	82.6	90.2	[illegible]	[illegible]
2031	60.2	65.3	19.5	20.0	91.5	97.5	84.5	95.0	21.2	22.0
2032	60.6	67.4	19.6	20.2	91.9	99.7	86.4	100.5	21.6	22.6
2033	61.1	69.8	19.7	20.5	92.4	103.3	88.2	106.5	22.0	23.2
2034	61.6	72.4	19.8	20.8	92.8	107.3	90.0	114.5	22.4	23.8
2035	62.1	75.0	19.9	21.0	93.2	111.5	91.7	121.7	22.8	24.5

Peak Load (MW)	Substation 16		Substation 17		Substation 18		Substation 19		Substation 20	
	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs	w/o EVs	w/ EVs
2021	133.8	133.9	58.1	58.2	96.1	96.3	131.5	131.5	62.2	62.2
2022	135.9	136.0	58.4	58.4	100.2	100.7	131.6	131.7	62.3	62.4
2023	[illegible]	[illegible]	58.7	58.8	106.3	107.1	131.7	131.8	62.3	62.5
2024	136.9	137.1	59.0	59.1	110.4	111.5	135.1	135.3	62.4	62.7
2025	137.9	138.3	59.3	59.4	114.3	116.0	139.7	139.9	63.0	63.4
2026	138.0	138.7	59.5	59.7	118.2	120.6	139.8	140.1	63.0	63.7
2027	138.2	139.1	59.8	60.0	122.1	125.3	142.7	143.2	63.1	64.1
2028	138.3	139.6	60.4	60.6	125.8	130.2	142.8	143.5	63.2	64.5
2029	139.3	141.2	60.4	60.8	129.4	135.3	142.9	144.0	63.3	65.4
2030	139.5	142.1	60.5	60.9	142.0	149.8	143.1	144.6	63.3	66.3
2031	139.6	143.2	60.5	61.2	145.4	155.9	143.2	145.3	63.4	67.5
2032	139.7	144.5	60.6	61.4	148.8	162.3	143.3	146.0	63.5	74.9
2033	139.8	146.0	60.6	61.7	152.1	169.1	143.5	146.9	63.6	78.2
2034	140.9	148.6	60.7	62.0	155.3	178.9	143.6	147.8	63.7	82.0
2035	141.0	150.4	60.8	62.9	158.4	186.7	143.7	149.9	63.7	85.6

No acceleration in investment, but substation must be future-proofed to accommodate 30% higher loading

Investment accelerated by 7+ years

Modest growth in EV load has limited imapcts

Figure 6. Forecasted substation-level peak demand impacts (MW) from 2021-2035.

Granular load impact results can inform utilities' investment decisions by assessing the pace and magnitude of infrastructure needs compared to the baseline or "business-as-usual" scenario. By leveraging these insights, utilities can better anticipate infrastructure requirements and allocate resources strategically, targeting investments at the right time, and in the right place, in order to support the transformation of our energy system.

Insight #3 – DERs offer a Cost-Effective Solution to Mitigating Load Impacts

Unmitigated load impacts associated with net-zero aligned decarbonization pathways will be significant, as seen in Figure 2. The costs associated with investments in infrastructure needed to accommodate this growth, as well as the pace of build-out required, may also be barriers to utilities as they seek to prepare for and accommodate increasingly widespread electrification.

However, heat pumps, EVs, storage-paired solar PV, and other emerging technologies driving electrification across various economic sectors and end-uses are flexible resources that can be controlled, managed, and leveraged as DERs, both on their own and when paired with additional technologies (e.g., smart thermostats and smart chargers). Leveraging the potential of DERs to reduce the magnitude of load impacts, through the use of managed charging of EVs and customer participation in demand response (DR) programs targeting heating electrification, brings significant opportunities to bring benefit to the generation, transmission and distribution systems as well as customers.

A study led by Dunsky for the Independent Electricity System Operator (IESO) in Ontario to identify the technical, economic and achievable potential for DERs identified that there was sufficient technically feasible and cost-effective DER potential to meet Ontario's emerging seasonal peak needs associated with electrification (IESO 2022). As shown in Figure 8 and Figure 8, under all scenarios there is sufficient technically feasible and cost-effective DER potential to meet Ontario's emerging seasonal peak needs. Despite the significant economic potential, less than a third of it is achievable over the next decade under existing market conditions. However, modeled market, policy and technology changes under the Accelerated scenarios can increase achievable capacity reductions to 3.6 - 4.3 GW of peak reductions by 2032 (equivalent to 9%-14% reduction in peak).

The identified DER Potential offers numerous system benefits, including contributing system resource adequacy needs, serving as non-wire alternatives (NWAs) that can avoid and/or defer transmission and distribution (T&D) infrastructure upgrades, as well as support the integration of intermittent renewable generation through energy shifting, balancing services and avoiding curtailment. Tapping into this high-potential, high-value resource brings considerable system cost reductions and long-term value to ratepayers through avoiding costly infrastructure investments. For example, the DER potential identified through our study for the IESO referenced earlier identified that in a net-zero aligned future, DERs are estimated to bring a net-benefit to the system of $40B. This corresponds to nearly a 10% reduction in the $400B cost estimated by the system operator for the sector to meet net zero by 2050.

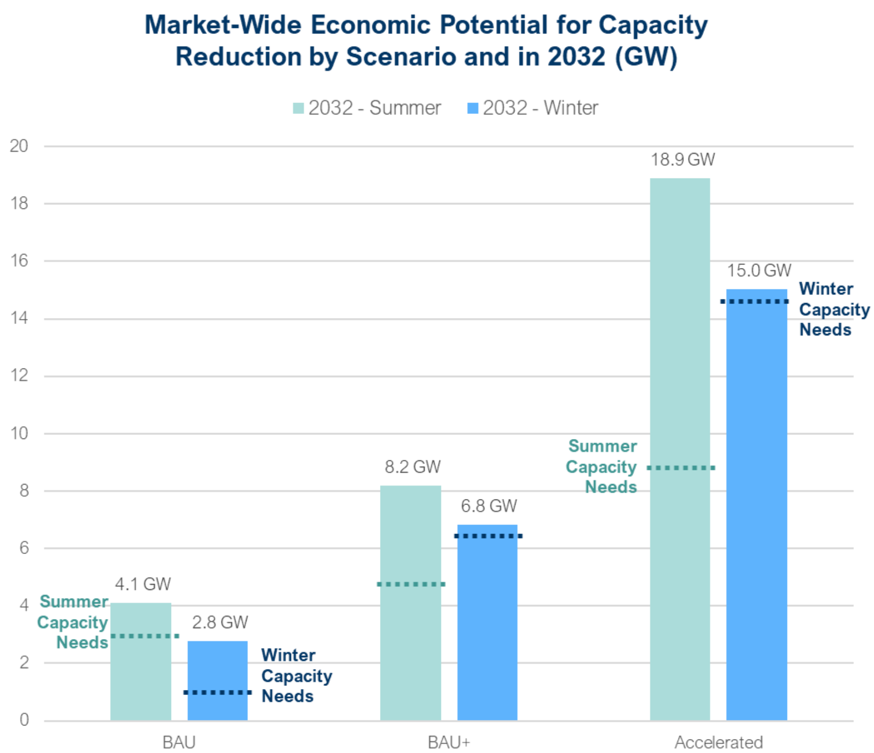

Figure 7. Forecasted economic potential for peak demand reductions from DERs

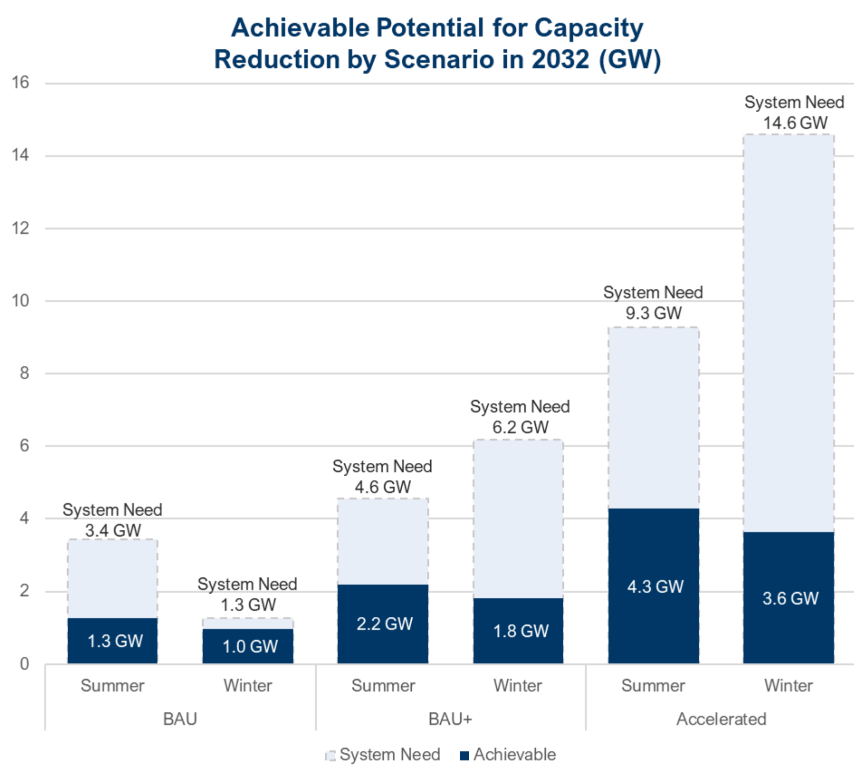

Figure 8. Forecasted achievable potential for peak demand reductions from DERs

Leveraging the potential of DERs to reduce the pace at which utilities must expand and upgrade infrastructure to accommodate load impacts is another key role that these cost-effective resources can play in this transition. This can be of particular relevance when long lead times and supply chain constraints can lead to significant timelines for infrastructure buildout. Lead times for procuring and installing a new transformer can range from several months to over two years (Wood Mackenzie 2021), and the wait times for building new substations or upgrading existing ones can extend to several years, further exacerbating the challenges associated with electrification. Beyond deferral opportunities which may be short-lived, DERs offer a long-term opportunity to right-size future investments when they eventually take place.

Within this context, DERs offer a not only cost-effective but scalable and quick-to-deploy solution to effectively address emerging demands on the system. This value is widely recognized by numerous utility DR and NWA initiatives. One recent example that captures the magnitude of the opportunity is that of Hydro Québec, the electric utility in Québec, Canada, which offered free demand response packages (including a smart hub, smart plug-in switches, and up to 20 smart thermostats) to residents in a community experiencing infrastructure overloading (Hilo 2024).

Conclusion

The central role of electrification in net-zero pathways presents both challenges and opportunities to utilities as they navigate this transition. Our work supporting utilities, system planners, and program administrators across North America underscores the importance of modernizing load forecasting practices through 1) taking a holistic view of load growth, 2) recognizing and accounting for the regional variations in load impacts and how this may impact investment needs, and 3) capturing the central role of DERs as a key cost-effective resource for utilities, which can mitigate both the pace and magnitude of load impacts, avoiding and/or deferring investment needs.

As demonstrated by examples presented in the paper, embracing these three principles is critical to ensuring utilities have robust outlooks for their systems in order to continue to fulfill their mandate of delivering safe, reliable service while stepping into a new role as key enablers of decarbonization and the net-zero transition. The insights from these forecasts allow utilities to select cost-effective solutions and target their investments at the right time, and at the right place, as they prepare for and accommodate widespread electrification.

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