Proactive Grid Investment Assessment

Medium-and Heavy-Duty Vehicle Transportation Electrification

Prepared for

Environmental Defense Fund

November 6, 2024

BLACK & VEATCH

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About the Contributors

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Executive Summary

Electric utility demand growth is poised to increase significantly in the coming years given the expected adoption of electric vehicles, trucks, and buses driven by a range of factors that support accelerated fleet electrification. Most notably, the Advanced Clean Trucks (ACT) regulation adopted in several states addresses greenhouse gas emissions and pollution from medium- and heavy-duty vehicles (M/HDVs) by imposing requirements on vehicle manufacturers to sell zero-emission vehicles as an increasing percentage of annual M/HDV sales. Since 2020, 18 states have signed a memorandum of understanding (MOU) to address pollution from M/HDVs, and 11 states have adopted the ACT rule. Furthermore, in 2022, the United States joined 16 nations by signing a global MOU on zero-emission M/HDVs that commits to a goal of 100% zero-emission truck and bus sales by 2040, with an interim goal of 30% new sales by 2030.

Electric utilities across the country will need to make significant investments in the electric grid to support accelerated electric vehicle (EV) sales and will be tasked to provide service in shorter timelines than done historically. Utilities will face multiple considerations to successfully forecast, plan, and deploy infrastructure to support M/HDV charging in a reliable, affordable, sustainable, and equitable way. This study seeks to inform these considerations by examining the potential costs, benefits, and risks associated with proactively developing the grid in anticipation of M/HDV electrification, through the lens of the utility, EV fleet owner, and rate payers' perspective.

Utility investments in grid infrastructure have historically been made following a process of forecasting load growth based on historical usage and adjusted for factors, such as economic and weather data and established expansion plans of major commercial and industrial customers. Accommodating forecast growth, which increasingly includes M/HDV electrification load, is done on a sequential basis, where least cost (expenditure) grid upgrades are determined following the customer request. This sequential approach is largely born from concern that anticipatory utility construction might lead to underutilized assets if the expected load does not materialize, yielding increased financial burden on rate payers.

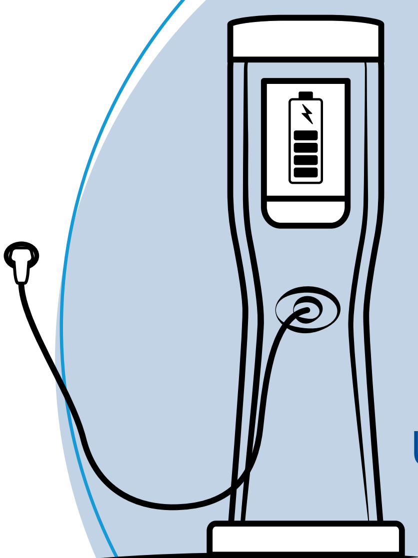
This study seeks to test this concern through high-level modeling of the cost and risk impacts of proactive construction in two utility service territories: one in New York (Con Edison) and one in Texas (CenterPoint Energy Houston). For the purposes of this study, a proactive approach is defined as planning for and implementing grid upgrades to support growth beyond the minimum required, as identified through traditional forecasting approaches. Key examples of proactive planning include the following:

- Building a new substation to address new load rather than deferring the substation by first transferring load, and then transferring it back after the substation is built, or to avoid upgrading a transformer,
- Building a new substation sized for load growth anticipated for a longer design horizon than typical, e.g., 20 years, in anticipation of higher levels of growth, or
- Connecting load to higher feeder voltages via a new, higher voltage substation; multi-voltage transformer upgrade; or a voltage conversion.

Reform to grid planning processes and regulatory frameworks may be supported by providing evidence that proactive grid investments result in long-term cost savings for the utility and ratepayers and direct benefits to the fleets when compared to traditional, sequential planning. This study aims to provide utilities and regulators with tools and strategies to support proactive grid planning for M/HDV distribution grid upgrades.

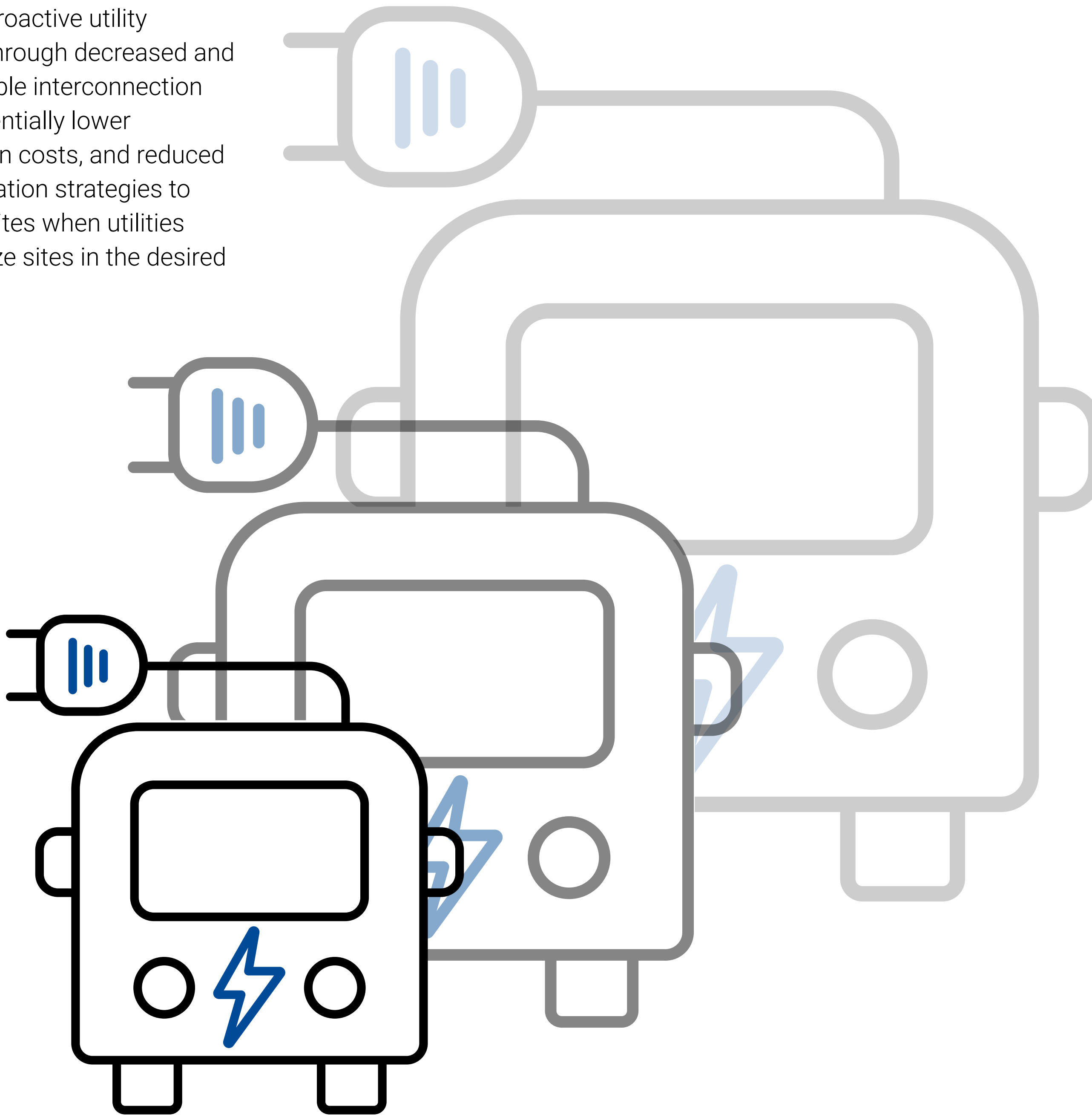
The key findings of this Proactive Grid Investment Study include the following:

- Load growth due to vehicle electrification, including M/HDV trucks, can be a significant driver of grid infrastructure needs and should be considered in grid planning processes.
- Grid forecasting, planning and the consideration of grid solutions should be evaluated in the long-term (greater than 20 years) to better characterize the long-term need and quantify the costs and benefits for a given grid solution.
- Proactive planning for M/HDV electric load can result in capital expenditure (CAPEX) savings in the long run due to reduced need to upgrade the same station to accommodate load growth into the future, when compared to sequential planning approaches. Certain planning conditions provide indication that proactive planning will be more cost effective, including:
    - Proactive planning approaches are generally more cost-effective in instances when load growth is forecasted to achieve substantial growth over the asset planning horizon.
    - Sequential planning approaches are generally more cost-effective in instances when overall load is not expected to continue at the current growth rate over the asset planning horizon.
    - The costs and benefits related to adopting a proactive planning approach over a sequential one is largely dependent of the level of oversizing employed with a proactive approach and the associated costs, which varies by planning specifications and jurisdiction.
- The lowest cost planning approach identified through the study involves employing a mix of proactive and sequential planning methods, determined on a case-by-case basis for each substation. Furthermore, overall results show that leveraging proactive planning approaches generally yields lower cost outcomes than a sequential approach. Utilities should favor proactive planning where there is uncertainty in EV load forecasts as a proactive approach generally yields lower cost outcomes when compared to a sequential approach.

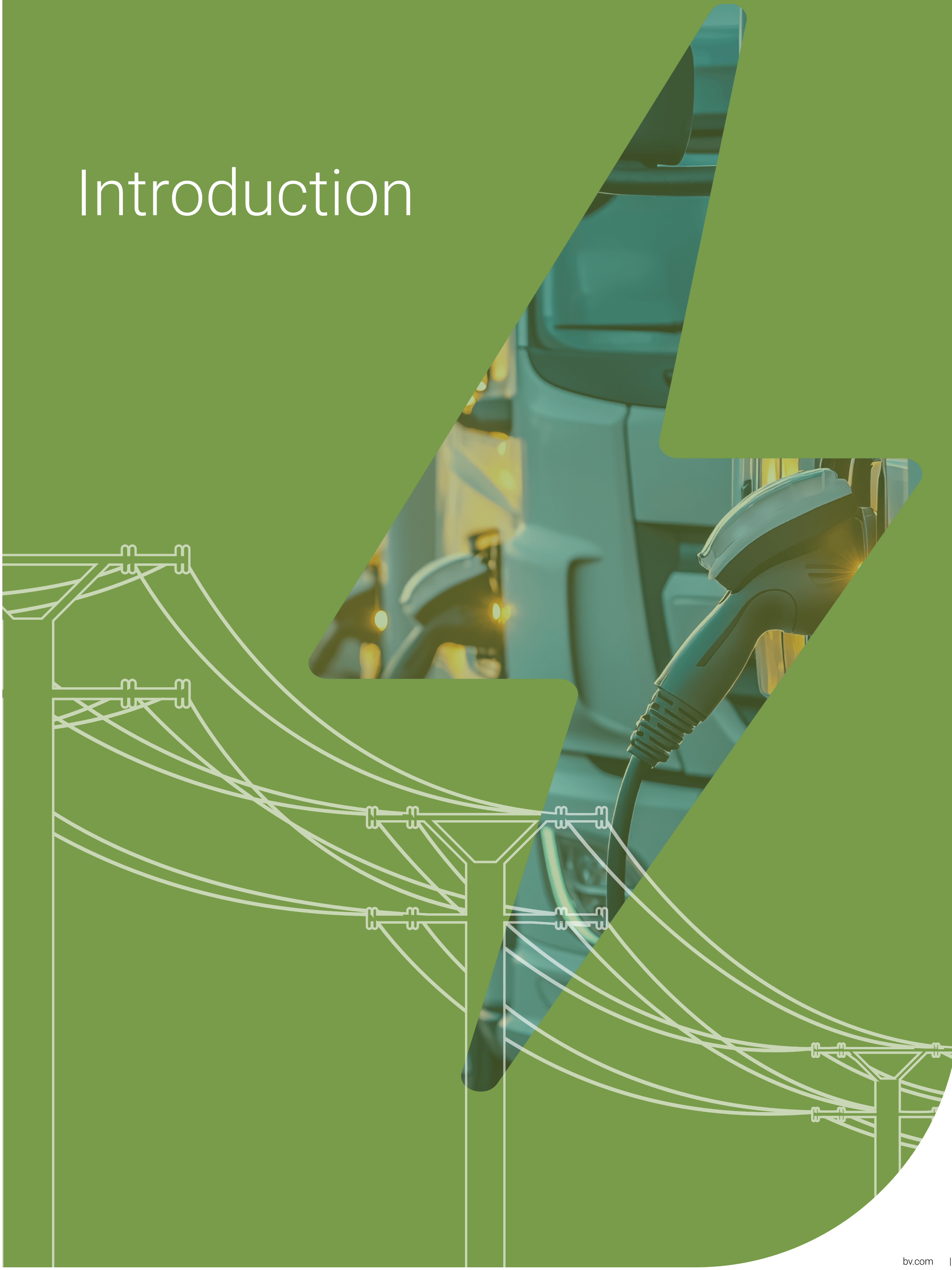


Utilities should favor proactive planning when there is uncertainty in EV load forecasts.

- While vehicle electrification load is a driver in load growth, changes to overall load growth is critical when determining whether proactive investments are more cost-effective than sequential approaches. New trends that will likely contribute to load growth in the future beyond historical drivers, such as building electrification and data centers, will, if realized, further improve the economics of adopting proactive planning approaches.
- Managed charging initiatives can also deliver significant cost savings in the long run, though the impact is dependent on the effectiveness of the initiatives at modifying charging behavior.
- The cost of identified substation upgrades through the study period is relatively minor when evaluated against the anticipated load realized onto the system (i.e., on an average cost per kWh basis).
- Fleet owners and operators can benefit from proactive utility investments through decreased and more predictable interconnection timelines, potentially lower interconnection costs, and reduced need for mitigation strategies to commission sites when utilities cannot energize sites in the desired time frame.



Introduction



Electricity System Planning

The objectives of utility electricity system planning process are to ensure secure, reliable, affordable, and sustainable electric service. This involves forecasting future electricity demand, determining the optimal mix of generation sources that will meet demand, and designing the grid to deliver electricity reliably while minimizing costs, customer electricity rates, and environmental impacts.

The planning process can be complex and challenging, particularly considering the rapidly changing energy landscape. Utilities must consider a range of factors in their planning process, including changing energy demand behaviors, the availability of new technologies, and evolving environmental regulations. They must also balance the need for new investment in power supply and infrastructure with the need to keep electricity rates affordable for customers.

Utility Challenges

Uncertainty. 1
The energy landscape is rapidly changing, and utilities must plan for a future that is uncertain. Factors such as changes in technology, customer demand, and government policies can be difficult to predict, making it challenging for utilities to plan effectively.

Aging Infrastructure. 2
The US electric grid is aging, and many utilities are struggling to keep up with the need to upgrade their infrastructure. This can lead to reliability issues and increased costs for customers.

Regulatory Complexity. 3
The regulatory environment for electric utilities is complex and constantly evolving.

Financing. 4
Upgrading the electric grid can be expensive, and utilities must find ways to finance these investments while keeping rates affordable for customers.

Planning – including making investments in anticipation of future conditions – is a critical way in which utilities approach these challenges. Current utility planning processes include the development of system needs and infrastructure upgrades based on load forecasts that typically incorporate historical demand, economic and weather trends, and large announced projects. These planning processes are performed on a routine, periodic basis (often annually) to identify potential problems that forecasted load conditions may place on the system, develop solutions to implement before such problems become exigent.

Utilities determine upgrades based on a range of factors, including security, reliability, cost, regulatory requirements, and customer demands, and must carefully balance these considerations to ensure that they are providing secure, safe, reliable, and affordable electricity to their customers. While utility regulations are designed to give Investor-Owned Utilities (IOUs) the opportunity to achieve a reasonable rate of return on investments, they are limited to distribution cost recovery only if investments are considered efficient and prudent by regulatory authorities. Subsequently, utilities often take a more conservative approach in planning by waiting to make necessary distribution grid upgrades until they receive individual customer requests for grid capacity or are certain expected load growth proposed investments would serve will materialize, e.g., by focusing on the next 5 to 10 years only.

Current utility planning for transportation electrification serves to illustrate this more conservative approach. Some utilities across the country incorporate anticipated load growth from light-duty vehicle electrification in this process, but few incorporate expectations around growth of large, electric M/HDV loads over time. Discrete large customer loads are often not incorporated as a part of routine planning unless utilities receive a load request from the customer. These types of load requests typically come from large, greenfield facility projects with long lead times, providing the utility with time to make the necessary grid upgrades to support service. The emergence of brownfield M/HDV charging sites with significant load needs introduces new challenges for utilities, as site preparation and equipment procurement generally do not have the same long lead-times, and charging operators are often wanting to energize their sites on a faster timeline than a utility can always support.

Utility commissions are understandably hesitant to forward-looking cost recovery for grid assets built in a proactive manner, outside of traditional grid planning approaches, given the risks associated with potentially over-investing in the system leading to rate base increases from unrealized load creating underutilized, ‘stranded’ assets. Stranded utility assets are those considered to be significantly underutilized and as such, prevent the utility from recovering full asset investment costs which ultimately leads to negative financial impacts for both the utility and its customers. Alternatively, under-investing in grid upgrades and not having enough capacity to serve customers can result in significant risks including delays in connecting new load, associated regulatory compliance issues, reduced competitiveness, increased costs, and delayed realization of environmental and public health benefits of electrification.

Risks of Under-investing in Grid Infrastructure

Costs - Interconnection delays resulting in consumers investing in BTM assets, which lead to erosion of utility market share, and higher consumer costs.

Reduced Competitiveness - Inability to provide reliable and affordable electricity may result in loss of business to competitor utilities and BTM solutions.

Regulatory Compliance - Inability to meet required compliance with federal, state, and local regulations resulting in fines or other penalties.

Fleet Electrification Challenges

The electrification of M/HDV fleets presents additional and unique planning challenges for utilities. M/HDV electrification presents large electric loads relative to their geographic concentrations; however, this load can be highly flexible in certain circumstances. Additionally, M/HDV load requests are expected to increase over time based on policy objectives, customer preferences for electrification, and positive economics as the cost of batteries falls – resulting in an ‘s-curve’ of demand that can deviate from traditional utility planning process. Furthermore, the electrification of fleets can, at times, occur in a phased approach. As a result, load growth from M/HDV electrification may not be easily, prudently, or efficiently managed through a traditional planning approach that relies on specific load applications over a relatively short, 5- to 10-year planning horizon. Furthermore, load requests submitted by fleets today may not meet the needs of the operator’s fully electrified fleet.

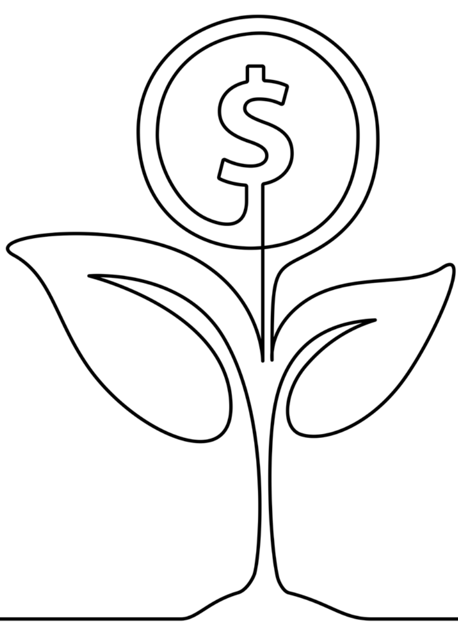
Moving from traditional planning approaches to a more proactive planning approach requires a longer planning time horizon, a more sophisticated forecasting method, and a higher level of forecasting accuracy that better captures future loads. Accurately forecasting M/HDV load spatially requires a new approach for several reasons. As a new technology, historical electricity growth data cannot provide insights to M/HDV electrification. Additionally, M/HDV fleets are not distributed evenly and often concentrated in commercial and industrial areas within a utility's service territory. Although utilities know where their commercial and industrial customers are, they typically lack crucial information from fleet operators required to develop accurate future M/HDV charging load forecasts such as fleet size and makeup, operational characteristics, or fleet electrification plans and timelines. Improved data, analytics, and engagement with fleet operators and charging providers will be critical to develop accurate forecasts and implement necessary grid upgrades in a proactive manner to facilitate accelerated fleet electrification deployments across the country.

Electric M/HDV fleet owners and charging operators can be faced with lengthy interconnection lead times that do not align with corporate EV procurement or policy timelines. Once a load request is received, the necessary distribution grid upgrades required to energize M/HDV charging sites can take 18 months to 8 years to complete, depending on level of complexity and other factors. In contrast, it may only take 6 months to a year for fleets to procure EVs and chargers and complete make-ready construction. This misalignment can generate financial stress for fleet operators through unused asset depreciation, potential regulatory compliance penalties, and increased operational costs to develop mitigation strategies such as leveraging off-site public charging or hiring third parties to provide temporary or permanent power solutions. Furthermore, M/HDV transition plans can span many years through phased procurements. Managing M/HDV electric load requests in a sequential manner can lead to duplicative or increased rework to utility investments as future phases are pursued.

Fleet Electrification Investment Scenarios

This study evaluates the potential costs and benefits generated from proactive grid planning and policies compared to conventional, sequential approaches to serve anticipated transportation electrification load by examining utility service territories in New York and Texas.

Utilities traditionally plan and invest in necessary grid upgrades sequentially, once an electric fleet or charging operator has submitted the site load request or as part of a 5–10-year, trend-based forecast. For the purposes of this study, a proactive approach is defined as investing in grid upgrades that increase capacity beyond the minimum defined under the sequential approach. Under the conditions where load



Proactive investment strategies for connecting new M/HDV loads can include building a substation earlier or larger or connecting the load at a higher voltage. Where there are no existing high voltage feeders in the area, utility voltage upgrade strategies typically include the following:

Converting a substation to a higher voltage – This is usually the highest cost option, as all the primary distribution feeders must be upgraded as well.

Upgrading a distribution transformer to a higher voltage – This may be lowest cost option, achieved with a multi-voltage transformer, providing more capacity overall, and higher voltage feeders for the MD/HD load.

Building a new substation at the higher voltage – **Also known as an overlay network, this may become the preferred voltage for new connections, with existing connections converted.**

This study explores whether investing in larger capacity options is cost-effective, and under which circumstances implementing proactive planning will yield cost savings. While many potential grid solutions can be applied under a proactive planning approach, the key solution investigated with this analysis is **substation voltage upgrades** due to data availability and the significantly lower unit cost of additional capacity[3]. Importantly, upgrading distribution voltages is a complex endeavor, with local conditions, constructability and operational considerations that may dominate decision-making over realized costs and benefits, and therefore may not be a suitable option in all applications.

Study utility partners, Con Edison Company of New York (Con Edison) and CenterPoint Energy Houston Electric (CenterPoint), provided real-world data to test various planning strategies and assumptions and determine the associated costs and benefits. Spatial forecasts for EV charging provided by the Electric Power Research Institute (EPRI) in their EVs2Scale2030 dataset were also used, which reflects data collected in collaboration with utilities, major EV truck manufacturers, fleet operators, charging

[3] *Oversizing assets without a significant decrease in unit costs is unlikely to result in positive economics or savings.*

providers, telematics companies, government agencies, and regulators. The impact of vehicle electrification on the distribution grid for both utilities were modeled under varying load management and grid planning approaches from 2025 through to 2070.

For this study, initial voltage upgrades are assumed to occur at the same time as the alternative, sequential investment, i.e., year before the asset is forecasted to experience its first thermal overload. Since assets are sized differently depending on the scenario they fall under, subsequent asset upgrades due to later thermal overloads will occur at different times based on the scenario parameters but will always occur the year before the thermal overload. This set of study parameters provides the foundation for quantifying and comparing costs and impact against the sequential utility approach for distribution grid investments.

In addition to evaluating proactive and sequential planning approaches, the analysis aims to understand the impacts of managed charging and the resulting benefits that may be realized through influencing the charging behavior of EV fleet owners.

Utilities can encourage load management through specialized managed charging rates, programs, and incentives. Implementation of managed charging strategies[4] can help mitigate the impact of charging demand on connected grid infrastructure, potentially resulting in lower and deferred grid upgrade needs and costs. Managed charging is assumed to reduce EV peak demand by 10% and 30% for Con Edison and CenterPoint's service territory, respectively. Per guidance from Con Edison, a 10% value was used for Con Edison based on the potential constraints resulting from their dense urban service area, including significant on-street parking and the ultra-high density parking at depots. A 30% value was used for CenterPoint following the findings from the U.S. Department of Energy's Multi-State Transportation Electrification Impact Study[5].

The four scenarios evaluated in the utility case studies are shown on Figure 1. Each scenario is a unique combination of a grid planning strategy (i.e., proactive or sequential) and charging strategy (i.e., unmanaged or managed).

Figure 1 – Scenarios Evaluated in the Utility Case

Scenario Parameters

Sequential Investment Strategy • New distribution substation added 1-year prior to a foecasted thermal overload • Upgrade is sized to accommodate forecast grid needs 20-years into the future • Cost of new distribution substation is equal to historical $/MW provided by the utility for previous substations	**Proactive Investment Strategy** • New distribution substation added 1-year prior to a forecasted thermal overload • Upgrade is sized to accommodate forecast grid needs 20-years into the future + voltage upgrade oversize • Cost of voltage upgraded distribution substation is based on research
Unmanaged Charging Strategy • Vehicles are charged without any external control, scheduling intervention or rate pressure	**Managed Charging Strategy** • Vehicles are charging is influenced by managed charging systems, schedules and/or rate • Managed charging coincident peak demand impact assumption vary between the utilities

Scenario Modeled

Sequential, Unmanaged Charging Scenario	Proactive, Unmanaged Charging Scenario
Sequential, Managed Charging Scenario	Proactive, Managed Charging Scenario

The following sections discuss the key study findings related to load growth and the cost effectiveness of each planning and load management strategy.

[4] *Managed charging strategies include active (e.g., software) or passive (e.g., time-of-use incentives) methods to effectively control or influence EV charging behavior thereby, reducing peak demand.* [5] *U.S. Department of Energy's Multi-State Transportation Electrification Impact Study*

Utility Impacts

Summary of Findings

- Load growth due to vehicle electrification, including M/HDV trucks, can be a significant driver of grid infrastructure needs and should be considered in grid planning processes. The potential impact varies as a function of the size of the asset studied, and the relative size of the expected transport electrification load.
- Planning and investing in a proactive manner, where voltage upgrades are pursued to expand capacity beyond anticipated load needs, can be more cost-effective than planning in a sequential manner under certain conditions, e.g., where load growth is forecast to require an additional capacity expansion in the next 30 to 40 years.
- The lowest cost planning approach identified through the study involves employing a mix of proactive and sequential planning methods, determined on a case-by-case basis for each substation. Furthermore, overall results show that leveraging proactive planning approaches generally yields lower cost outcomes than a sequential approach. Utilities should favor proactive planning where there is uncertainty in EV load forecasts as a proactive approach generally yields lower cost outcomes when compared to a sequential approach.
- The ability to accurately forecast EV load can impact whether proactive investment is the most cost-effective solution for a given substation. Forecasts that underestimate load growth will result in fewer proactive planning solutions constructed than would be cost-effective, while forecasts that overestimate load growth will result in more proactive planning solutions constructed than cost-effective.
- Managed charging initiatives can lead to significant cost savings in the long run, though the impact is dependent on the effectiveness of the initiatives at modifying charging behavior. The impact of managed charging on peak is modeled at 10% for the Con Edison case and 30% for the CenterPoint case, and notable differences in cost impact between both cases are observed.
- The overall cost of identified substation upgrades through the study period is relatively minor when evaluated against the anticipated load realized onto the system (i.e., on a cost per kWh basis).
- While these utility case studies focused on distribution substations, downstream upgrades will likely be required to accommodate EV load growth (e.g., distribution feeders and customer transformers and equipment). To get a total estimated grid infrastructure cost associated with different planning scenarios, these downstream upgrade costs will need to be factored.

Con Edison Case Study

Con Edison delivers electricity to an estimated 3.6 million customers across New York City and Westchester County. New York State has identified EVs as a crucial part of its path to reducing 85% of its greenhouse gas emissions by 2050 from its 1990 benchmark[6] . New York State has adopted multiple initiatives, including the Advanced Clean Truck rule, zero-emission school bus legislation and the Multi-State Medium and Heavy-Duty Zero Emission Vehicle MOU.

The study evaluated the impact of EVs and upgrade costs in seven network areas within Con Edison's service territory, identified as likely geographic EV hotspot areas, at the network area substation level[7]. Network area substation peak demand, peak demand timing, and necessary system upgrades between 2024 and 2042 were identified from Con Edison's Preliminary Area Substation and Subtransmission Feeder Twenty-Year Load Relief Program for the seven networks. Forecasted EV load from 2024-2030 was provided by EPRI's EVs2Scale and was extrapolated

[6] New York's Climate Leadership and Community Protection Act aims to achieve 85% carbon reduction in greenhouse gas emissions by 2050, compared to 1990 levels. [7] Con Edison's network areas are geographical regions that are served by a network or meshed distribution grid.

to 2070 with an assumed 80% EV penetration by 2050 for each network area. Notably, the load forecasts and system upgrades outlined in Con Edison's Twenty-Year Load Relief Program includes some electrification adjustments associated with EV load. This study removed Con Edison's electrification adjustments to peak demand to allow the inclusion of EPRI's forecasts. This study incorporated the load relief projects detailed for modeling purposes through 2042 and, following which, assumed substation capacity for the remaining study period of 2043 to 2070 remained unchanged at 2042 levels.

The Con Edison case study analysis finds that, outside of those upgrades identified in Con Edison's Preliminary Area Substation and Subtransmission Feeder Twenty-Year Load Relief Program, the forecasted vehicle electrification begins to impact substation peak demand post 2032. The impact of EV charging on area substation peak across the seven area networks is depicted in Figure 2. The observed declines in peak demand for these substations are based on planned load transfers contained within Con Edison's plans Preliminary Area Substation and Subtransmission Feeder Twenty-Year Load Relief Program; and do not indicate reductions in system demand.

Of the seven network areas evaluated in Con Edison's territory, three substations are forecasted to experience overload conditions in the study period under both the unmanaged and managed charging scenarios beyond the load relief projects identified by Con Edison.

Figure 3 and Figure 4 report on the forecast headroom available at area substations, if current load relief projects are assumed to be implemented, and depicts three substations reaching overloads during the study period: Sub B overloading in 2045 and again in 2066, Sub D in 2054, and Sub E in 2068. Upward shifts in headroom are a result of load transfers or asset upgrades that are detailed through 2042. In other words, the load relief plans described in Con Edison's Twenty-Year Load Relief Program are found to appropriately accommodate the incremental EV loads for the network area substations examined and based on the inputs and assumptions made for this study.

Figure 2 – Con Edison Area Substation Total Annual Peak per Charging Scenario

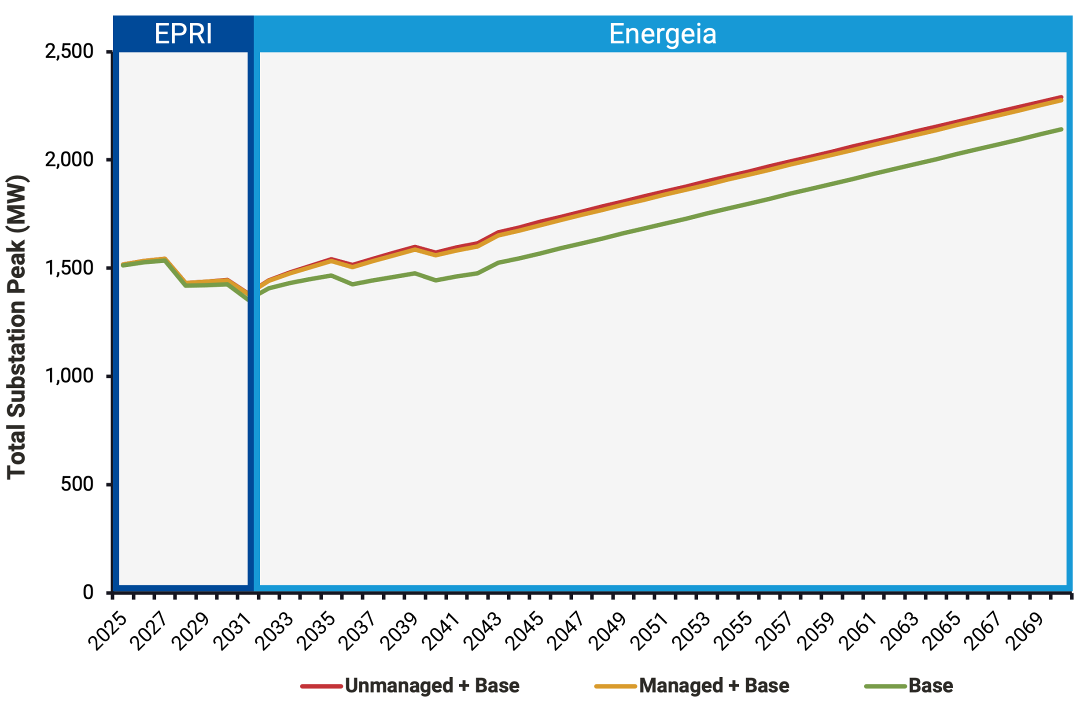
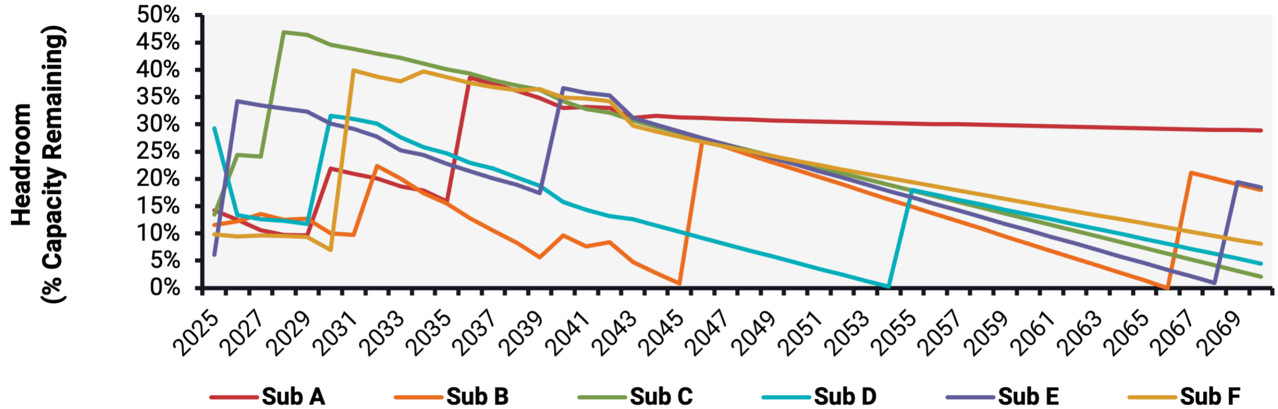


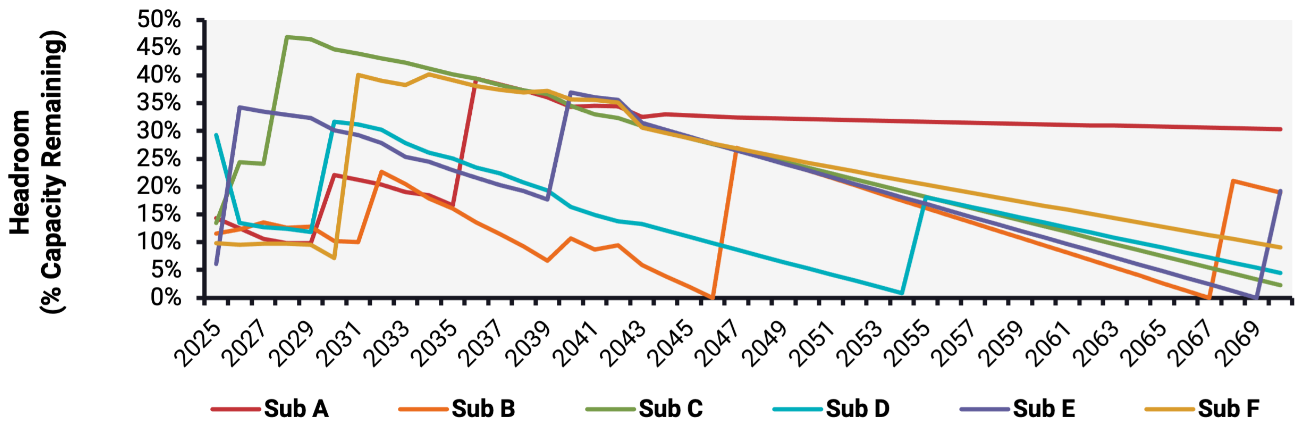
Figure 3 – Con Edison Remaining Headroom Forecast Under the Unmanaged Charging Strategy



Because of the relative size of charging load compared to overall load, and the assumed 10% impact of managed charging on charging demand, adjusting for charging behavior under a managed charging scenario only delays the overloads for Sub B and E by 1 year, as shown on the Figure 4.

As detailed in the technical methodology in Appendix 6.0, analysis modeling relieved the above thermal overloads on a sequential and proactive basis. The sequential basis sized a substation to relieve the overload that was able to meet 20 years of trended growth, while the proactive approach considered building a larger (200%) capacity, higher secondary voltage substation instead[8].

Figure 4 – Con Edison Remaining Headroom Forecast Under the Managed Charging Strategy



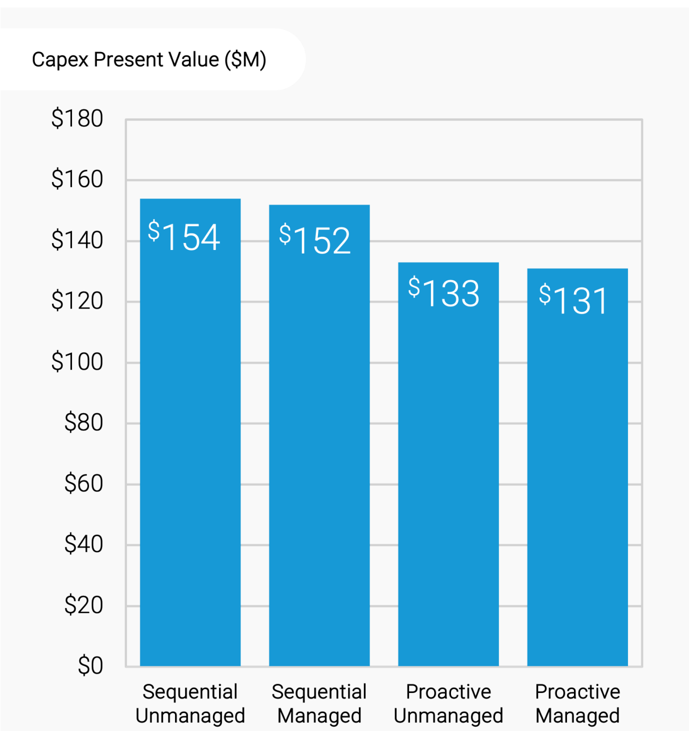
The results of the analysis show that a proactive approach to planning yields a lower cost when the higher costs paid for the larger, higher voltage substation sufficiently defers or avoids the need for an additional investment that would be required under a sequential investment strategy. This ultimately depends on the load trajectory, with strong growth over the period supporting proactive oversizing of the substation. As the load forecast varies for each substation, the lowest cost outcome is one in which a proactive or sequential approach is employed on a case-by-case basis, at each substation, referred to in this study as the optimized proactive approach. As shown on Figure 5, the analysis finds

8 *The technical appendix provides the oversizing, costing, and brownfield integration costs assumptions.*

that proceeding on an optimized proactive approach results in a $21 million Present Value (PV) cost savings under an unmanaged charging scenario when compared to the sequential grid planning approach, and a $20 million PV cost savings under the managed charging scenario, based on the assumptions and conditions that were leveraged for this study.

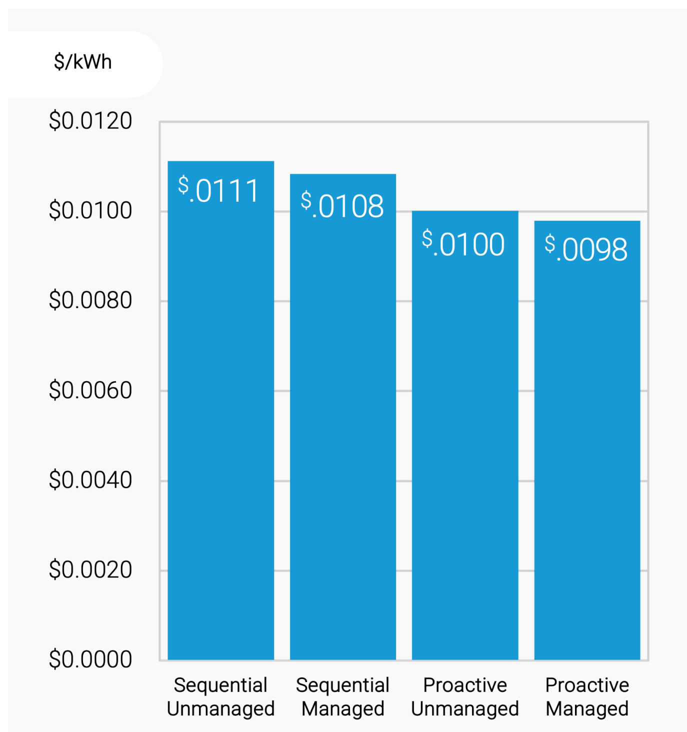
The impact of load management on Net Present Value (NPV) costs is approximately $3 million for the sequential scenario and approximately $2 million for proactive scenario. A key driver of the relatively small impact of EV load management in this analysis is due to the lower fraction of EV loads compared to total load based on this study's forecasted EV growth assumptions, the load relief plans assumed to occur prior to 2042, and the assumed 10% impact value that managed changing was assumed to have on peak demand.

Figure 5 – Con Edison Area Substation CAPEX by Scenario



The relative impact of the grid upgrades costs resulting from vehicle electrification is determined by dividing the present value of forecasted total expenditures (TOTEX; capital expenditures plus annualized operating expenditures) by the forecasted EV load across Con Edison's entire service territory. In all scenarios, the cost per kWh of incremental EV load remains around 1 cent per kWh as depicted in Figure 6. This calculation is not intended to be a reflection of rates, nor does it incorporate impacts associated with revenues, including any new EV revenues . This analysis scales the directly modeled assets to account for unmodeled infrastructure costs. The modeled substations are assumed to represent around 10% of the TOTEX across the business to accommodate additional EV hosting capacity[9,10].

Figure 6 – Con Edison Marginal PV Cost ($/kWh) Impact of EV Load



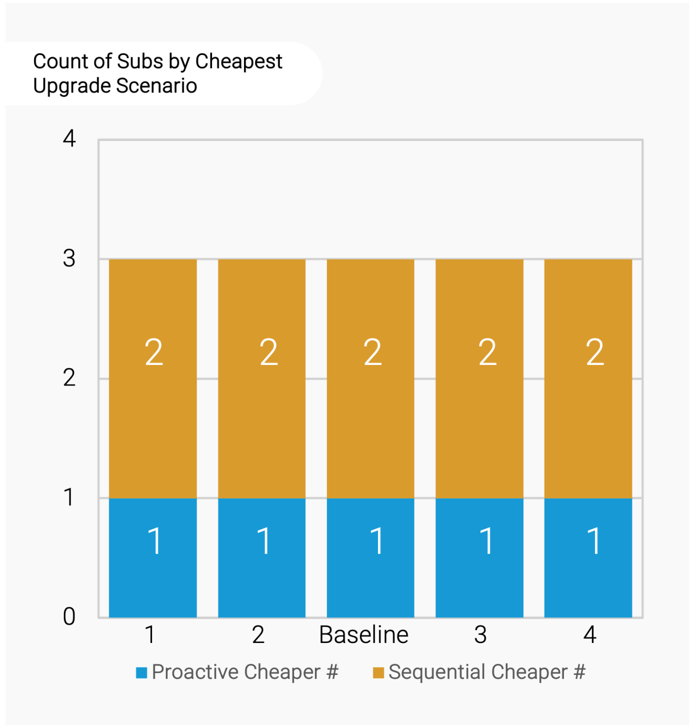
[9] Con Edison's provided 10% number is derived from actual performance and results from their current managed charging program. [10] Data on the actual historical CAPEX ratios of area substations to other asset classes was not available.

Con Edison Sensitivity Analysis

A sensitivity analysis was performed to consider the risk associated with EV load forecasting; namely, the extent to which actual EV loads must vary before the economics of proactive versus sequential planning approaches are impacted. Forecast sensitivities were run at (1) 25%, (2) 50%, (3) 200% and (4) 400% of the baseline forecast, to identify the number of substation upgrades that are more cost-effective under a sequential or proactive planning approach under different EV load assumptions, with results shown on Figure 7.

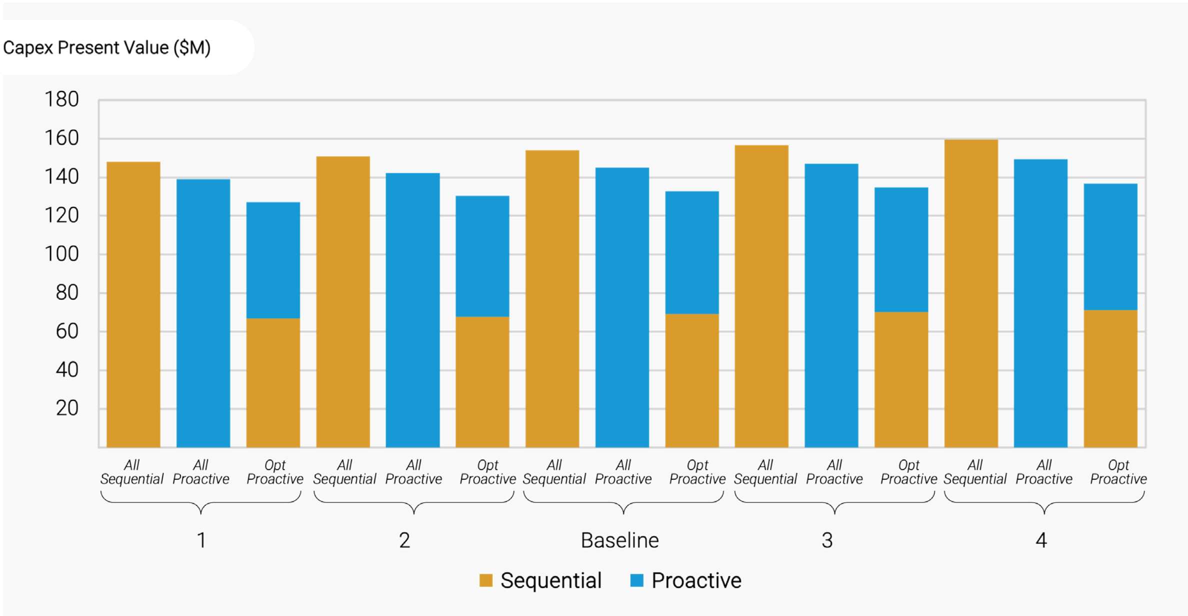
The analysis finds, across all EV sensitivities analyzed, three overloads are identified, in which one overload is most economically addressed through a proactive planning method and two are most economically addressed through a sequential planning method. This similar result across all sensitivities is mainly caused by the low forecasted impact of EV load relative to total load at the sub-transmission level, as this study focused on area substations. Variations in EV load across the sensitivities studied do not significantly impact the most economic planning approach nor the number of substation overloads identified when the load relief plans outlined in Con Edison's Twenty-Year Load Relief Program have been included.

Figure 7 – Con Edison Number of Substation Overloads and Lowest Cost Planning Approaches by Sensitivity (Unmanaged Scenario)



The PV CAPEX values over the study period were calculated for each forecast sensitivity. Figure 8 indicates the price comparison for each sensitivity, where PV CAPEX is indicated based on three planning approaches: (1) All Sequential: planning using only sequential approaches, (2) All Proactive: planning using only proactive approaches, and (3) Optimized Proactive: planning using a mix of sequential and proactive approaches, optimized for each substation. The results show that the long-term optimized planning method where proactive and sequential planning approaches are pursued based on anticipated load growth at each substation yields the lowest cost outcome across all sensitivities. Overall results also show that leveraging proactive planning approaches generally yields slightly lower cost outcomes than a sequential approach for all substations, across all sensitivity cases. This would indicate that utilities should favor proactive planning when there is uncertainty in EV load forecasts as the proactive approach generally yields lower cost outcomes when compared to a sequential approach.

Figure 8 – Con Edison CAPEX PV by Planning Approach and Sensitivity (Unmanaged Scenario)



CenterPoint Case Study

CenterPoint delivers electricity to an estimated 2.8 million customers across most of Harris and Fort Bend Counties. CenterPoint's service territory includes commercial and industrial parks in and around the Houston area. The significant freight movement in these areas indicate CenterPoint's service territory may be well poised for load growth due to M/HDV electrification.

CenterPoint provided data sufficient to evaluate the EV charging impacts and upgrade costs by scenario for 217 distribution substations. CenterPoint provided distribution substation peak demand forecasts without EV load from 2024 – 2033 and distribution substation capacities in 2023. Forecasted EV load from 2024-2030 was provided by EPRI's EVs2Scale and was extrapolated to 2070 with an assumed 80% EV penetration by 2050 for each distribution substation[11]. Although planned grid upgrades in 2024 were provided, the area substation capacity for the modeled period was assumed to remain at 2023 levels for the analysis.

The resulting sum of the forecast non-coincident peak demand across the 217 distribution substations in the CenterPoint case study are shown on Figure 9, which covers close to 100% of CenterPoint demand and distribution substations.

[11] *While there is not yet a carbon reduction mandate in Texas, New York's Climate Leadership and Community Protection Act is applied in the CenterPoint under the assumption that the economics for EVs in Texas may ultimately lead to strong EV adoption.*

Figure 9 – CenterPoint Distribution Substation Total Annual Peak Demand per Charging Scenario

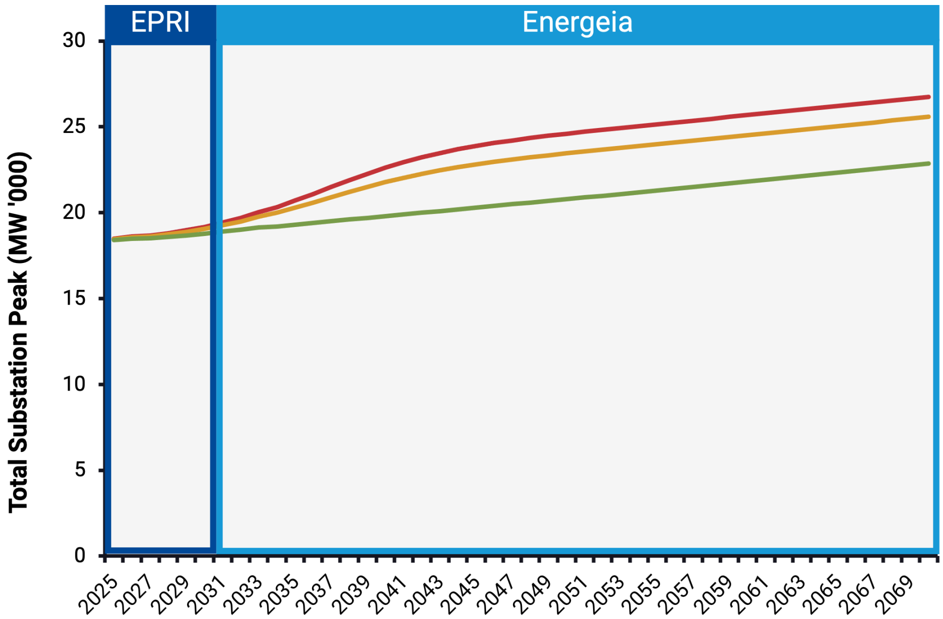
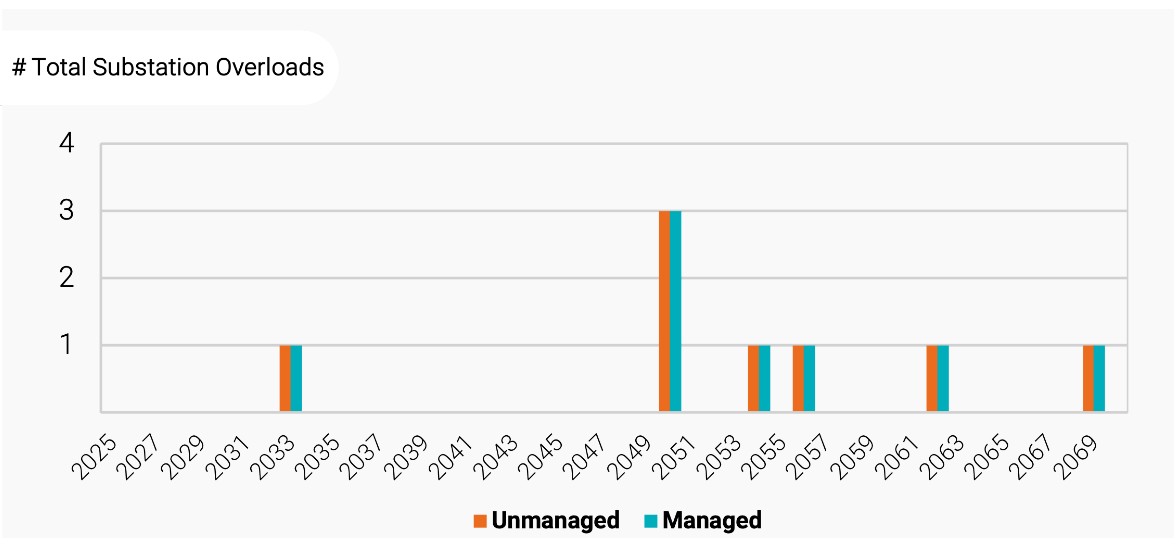


Figure 10 shows forecasted substation overloads without EV load. The results indicate that eight overloads would result from forecasted load growth based on historical growth trends and existing substation loading provided by CenterPoint over the study period.

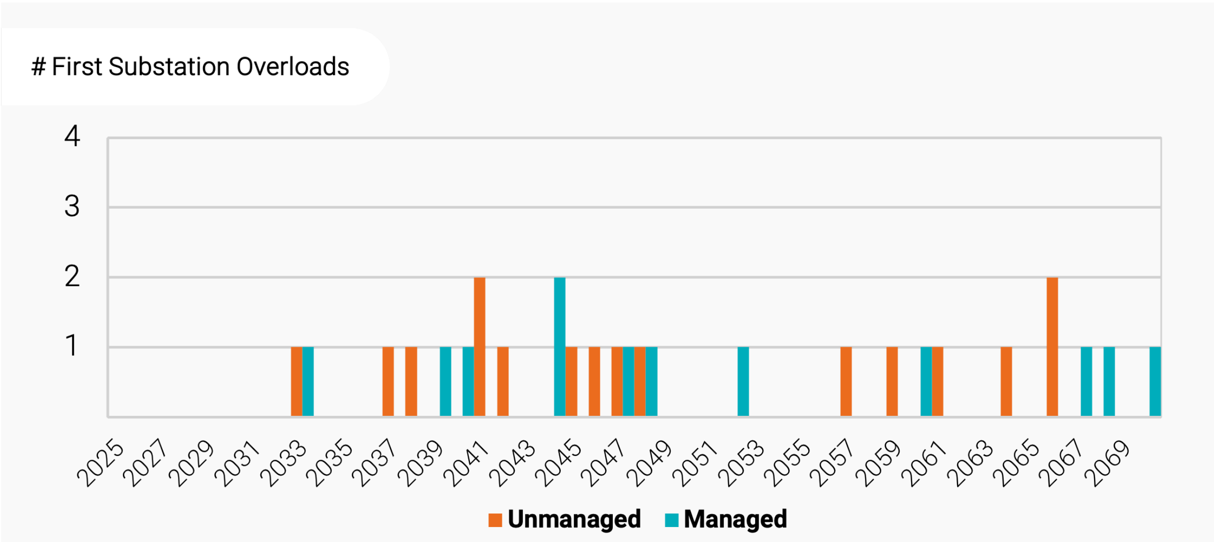
Figure 10 – CenterPoint

Distribution of Initial Substation Overloads by Year Without EV Load Considered



Conversely, when EV load is applied to the load forecasts, 16 distribution substations out of a total of 217 are forecasted to experience an overload by 2050 under the unmanaged charging strategy while only 12 are forecasted to experience an overload by 2050 under the managed charging strategy. The number of overloaded substations per year under the unmanaged and managed charging strategies are shown on Figure 11.

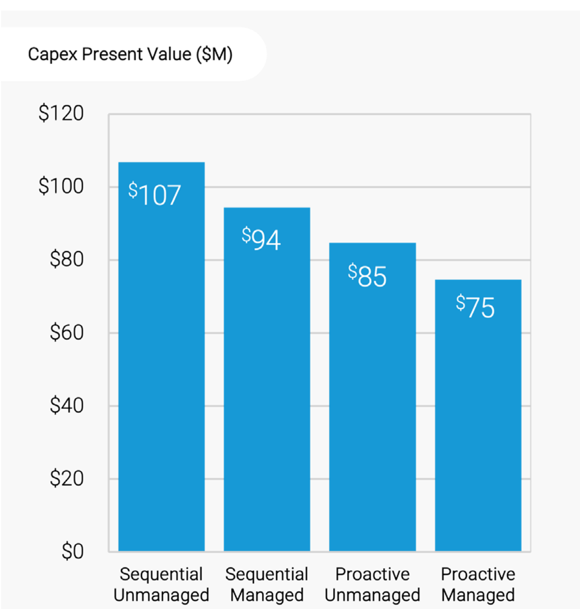
Figure 11 – CenterPoint Distribution of Initial Substation Overloads by Year and Charging Strategy



The results of the analysis again show that an optimized proactive planning approach yields the lowest cost outcome. As shown on Figure 12, the analysis finds that proceeding on an optimized proactive approach results in a $22 million PV cost savings under an unmanaged charging scenario when compared to the sequential grid planning approach, and a $19 million PV cost savings under the managed charging scenario, under CenterPoint's assumptions and conditions.

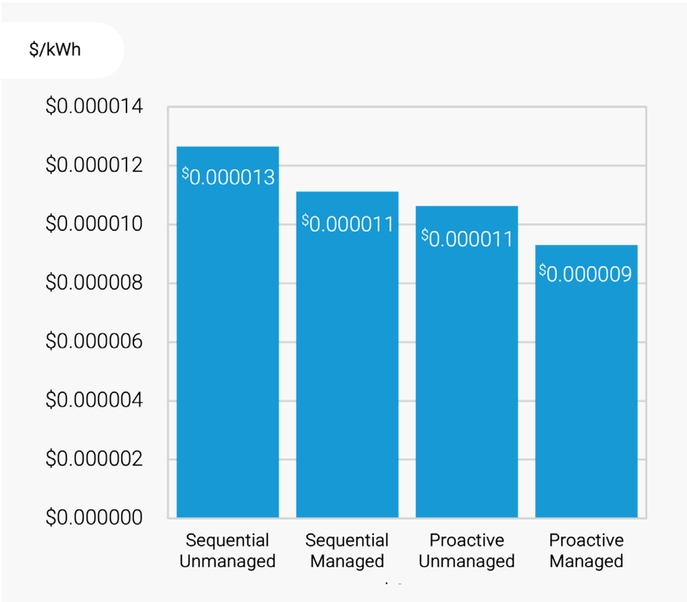
The analysis also shows managed charging saving $13 million under the sequential scenario, and $10 million under the proactive planning scenario. This reflects a 30% impact from managed demand, compared to the 10% impact assumed in the Con Edison analysis. In addition, this analysis is at the distribution substation level, which are relatively smaller assets compared to Con Edison, and EV load is therefore more likely to represent a significant portion of it, making EV load management relatively more valuable.

Figure 12 – CenterPoint Distribution Substation CAPEX per Scenario



The relative impact of the grid upgrades costs resulting from vehicle electrification is estimated by dividing the forecasted TOTEX by the forecasted load from EV's across CenterPoint's entire service territory. Total marginal TOTEX from the substation asset class modeled was again scaled up by 90% to reflect the total expected TOTEX across the remaining but not modeled asset classes to accommodate increased demand. The results of the marginal cost of load per kWh by scenario is shown on Figure 13.

Figure 13 – CenterPoint Estimated Marginal $/kWh Investment Impact of EV Load

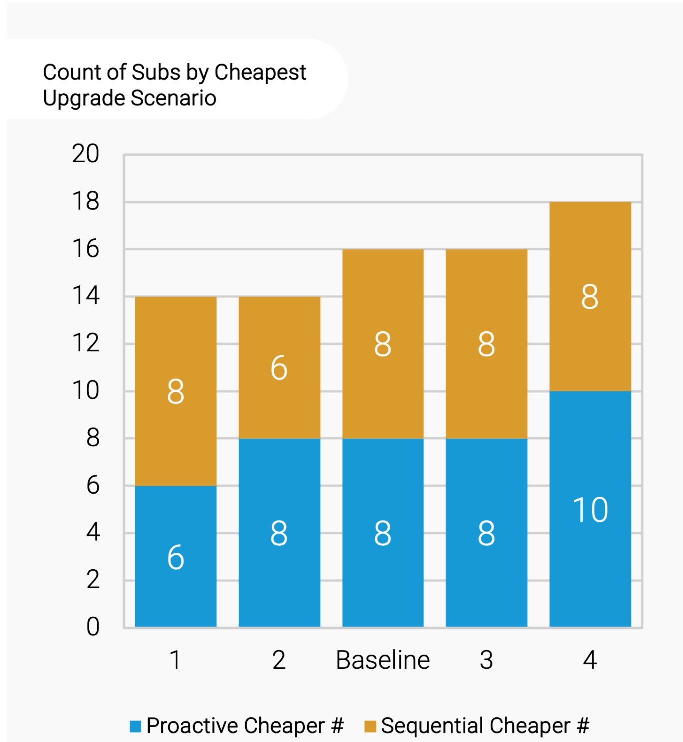


CenterPoint Sensitivity Analysis

The CenterPoint analysis also considered EV load forecasting risk; namely, the extent to which actual EV loads would need to vary before it changed the economics of proactive versus sequential planning approaches. Forecast sensitivities were run at (1) 25%, (2) 50%, (3) 200% and (4) 400% of the baseline forecast, to identify the number of substation upgrades that are more cost-effective under a sequential or proactive planning approach under different EV load assumptions, with results shown on Figure 14.

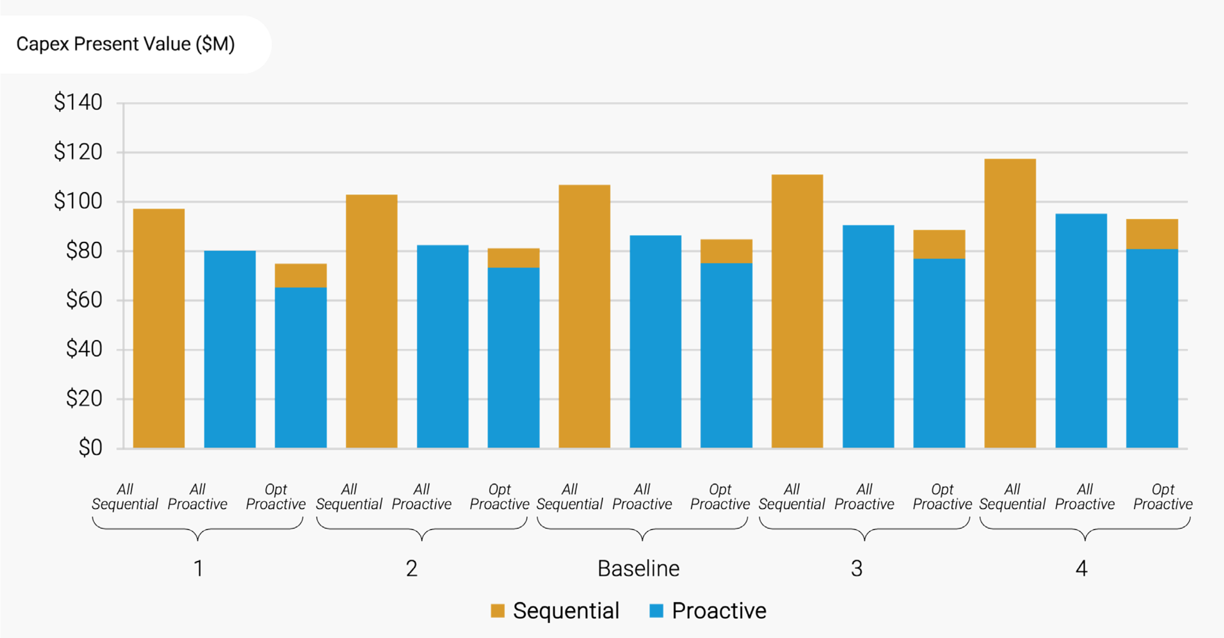
The forecasting sensitivity analysis shows that when EV forecasts underestimate the load growth realized, the number of overloaded substations would be higher than originally planned, and the number of substations that would have benefited from a proactive planning approach would also increase from the original plan. Conversely, when EV forecasts overestimate the load growth that is eventually realized, the number of overloaded substations would be lower than originally planned, and the number of substations that would have benefited from a sequential planning approach increase.

Figure 14 – CenterPoint Substation Count of Overloads and Lowest Cost Planning Approaches by Sensitivity (Unmanaged Scenario)



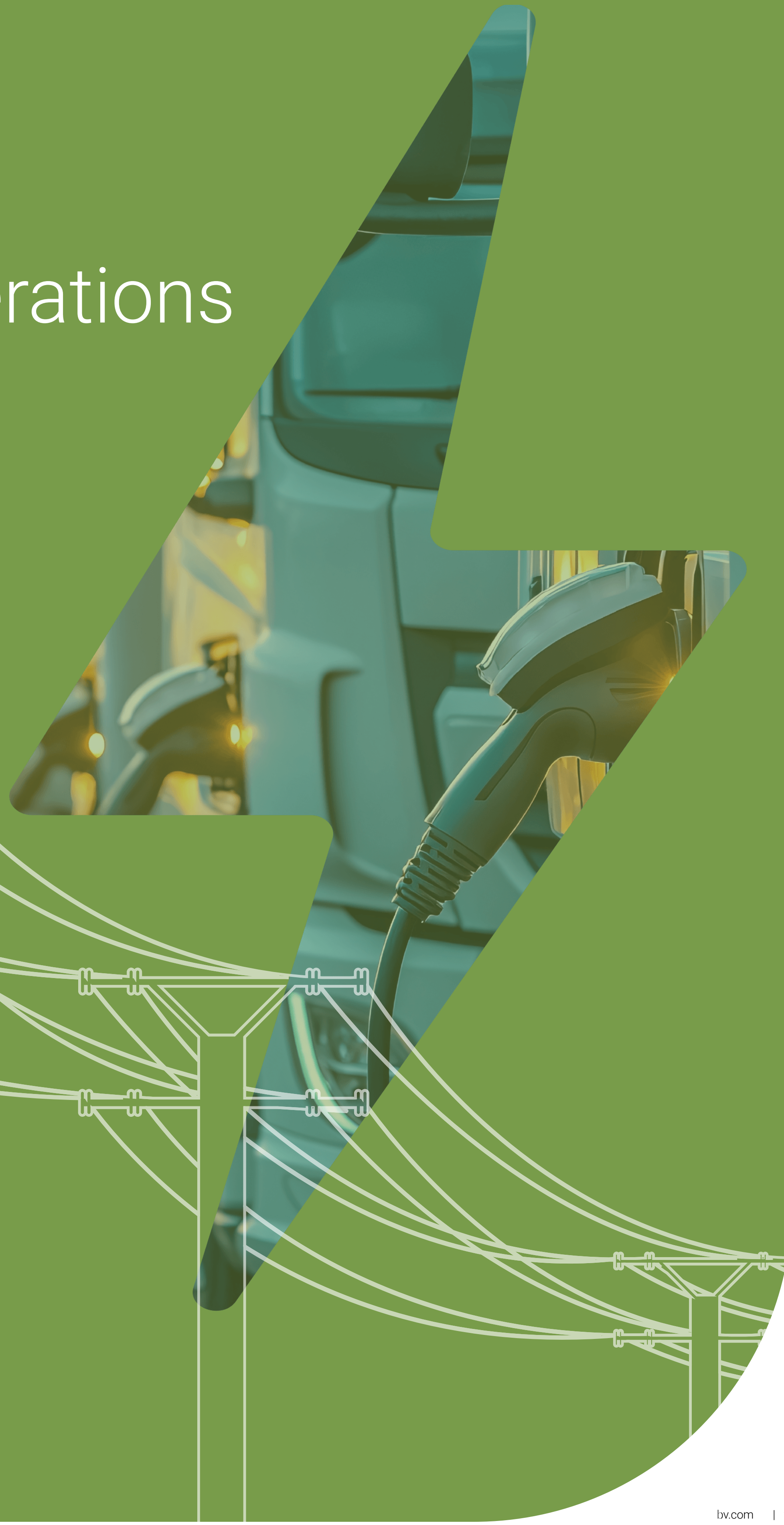
The PV CAPEX values over the study period were calculated for each sensitivity. Figure 15 indicates the price comparison for each sensitivity, where CAPEX PV is indicated based on three planning approaches: (1) planning using only sequential approaches, (2) planning using only proactive approaches, and (3) planning using a mix of sequential and proactive approaches, optimized for each substation. The results show leveraging a long-term optimized planning method where proactive and sequential planning approaches are pursued based on anticipated load growth at each substation yields the lowest cost outcome. Overall results also show that leveraging proactive planning approaches generally yields lower cost outcomes than a sequential approach for all substations, across all sensitivity cases. This would indicate that utilities should favor proactive planning when there is uncertainty in EV load forecasts as the proactive approach generally yields lower cost outcomes when compared to a sequential approach.

Figure 15 – CenterPoint PV CAPEX by Planning Approach and Sensitivity (Unmanaged Scenario)



Study suggests proactively building modeled assets could yield roughly $20M in savings for Con Edison and about $10-13M for CenterPoint.

Fleet Considerations



Logan Bus Case Study

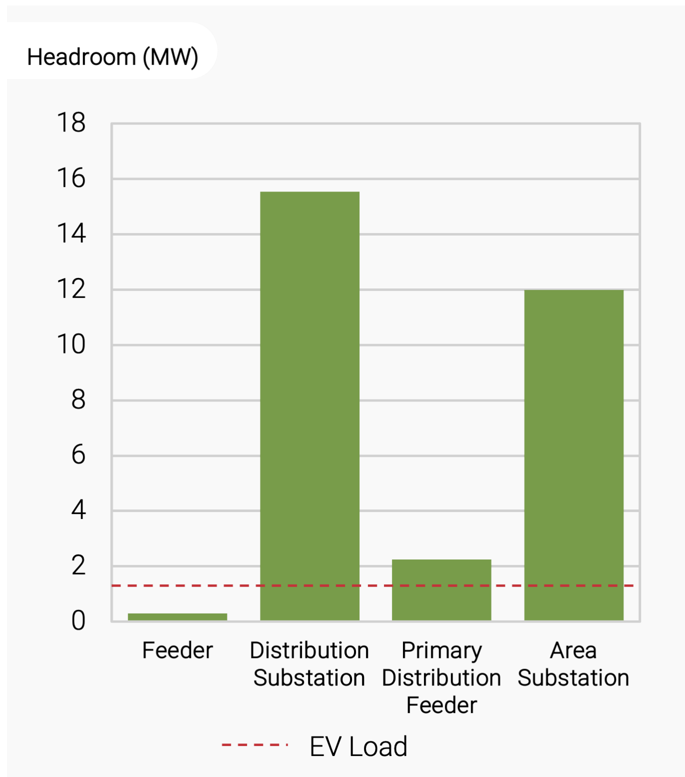
Logan Bus Co., Inc. & Affiliates (Logan Bus) is the largest privately owned school bus company in the state of New York, with facilities in Queens, Bronx, Brooklyn, and Nassau County. According to the New York legislation, 100% of its school bus fleet must be electric by 2035 and as such, Logan Bus is building its electric bus procurement plan around governmental assistance programs, subsidies, and grants. While Logan Bus does not have a strict procurement policy in place to reach 100% electrification, it is committed to meeting New York's state and legislative goals by 2035 and is actively pursuing EV grants to support its impending transition.

Logan Bus operates 190 buses out of the Bronx facility within Con Edison's service territory, 21 of which are vans while the remaining 169 are full buses. On average, the Bronx facility buses drive about 20 miles per day and operate 180 days per year for normal school operations with 10 to 20% of the fleet providing support for summer school resulting in an additional 30 days in operation per year. Buses at the Bronx facility dwell overnight with some opportunity for mid or intra-day charging during lunch. Additionally, as New York experiences harsh winters, electric bus heating loads are factored into the bus charging requirements and utilization analyses.

A 19.2 kW AC single-port charger (16.6 kW actual output) for each vehicle, assuming a 1:1 vehicle to port ratio, would be necessary to meet the operational needs for the electrification of the Logan Bus fleet. This charger configuration results in a total 3,154 kW of maximum site capacity required to support electric fleet transition. The maximum site capacity assumes no energy management strategies are implemented and all buses would charge concurrently at maximum output. Under a managed charging scenario, the minimum estimated site capacity of the Bronx facility is reduced to 1,300 kW site capacity to support a minimum daily (winter) site load of 24,707 kWh from full fleet electrification. If Logan Bus were to use faster, DCFC units, the maximum site capacity would be higher than those used in this analysis.

Study analysis of Logan Bus Bronx facility in Con Edison's service territory identified both customer distribution feeder and the primary, 4 kV feeder as likely to require upgrades to accommodate the minimum expected fleet electrification load by 2035. Refer to Figure 16.

Figure 16 – Con Edison Headroom by Asset versus Expected Logan Bus EV Load in 2035 (MW)



Driven by New York regulatory requirements, Logan Bus is working to develop concrete fleet electrification plans across all facilities, however, may not yet be ready to engage the respective utilities with site-specific requests to support. As Logan Bus is currently pursuing grants to support vehicle procurements, it is possible their imminent plans come to fruition quickly resulting in urgent load requests. The expected load (minimum) of the Bronx Logan Bus facility is relatively large and produces load impacts on the distribution system resulting in required upgrades to support. With this information, the utility (in this case Con Edison) could in theory begin planning for this expansion now to ultimately reduce overall project costs in the long-term.

Furthermore, the Bronx facility is in an industrial cluster in proximity to other transportation facility yards including Pioneer Transportation Corporation, Total Transportation Corporation, Boro Transit Bus Company, and Consolidated Bus Transit. Given regulatory requirements and economic factors, this area is likely to produce significant new load requests over the next 10 to 15 years to support fleet electrification transitions. Proactively building in this area would likely generate long-term cost savings for Con Edison and enable quicker interconnection timelines to service nearby fleets, including Logan Bus, and mitigate delayed interconnection cost impacts to fleet operators.

Maersk Case Study

A.P. Moller-Maersk (Maersk) is a Danish shipping and logistics company involved in port operation, supply chain management, and warehousing with operations in 130 countries across the world. Maersk is aiming to reach net zero emissions by 2040 across the entire business with new technologies, new vessels, and green fuels. Since 2022, Maersk North America has placed orders for hundreds of electric Class-8 trucks to replace diesel trucks and achieve net zero goals.

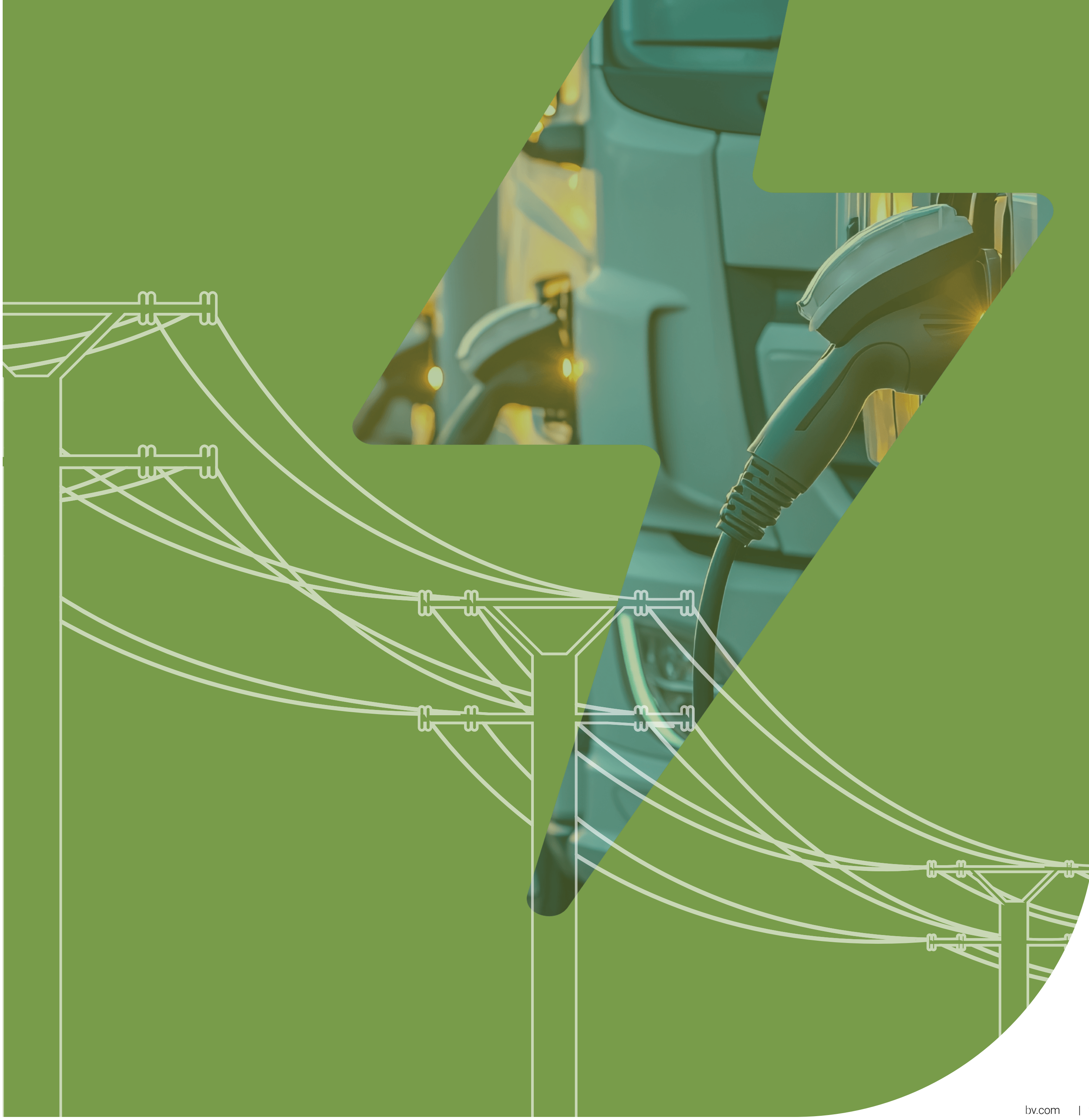
At one location near the Port of Houston and within CenterPoint's service territory, Maersk operates a large distribution center with 212 Class-8 trucks, 20 of which are owned and operated by Maersk, while the remaining 192 are third party, owner-operator trucks. Owner-operator trucks face many challenges when transitioning to electric given vehicle cost premiums and inability to control access to public or private charging infrastructure. However, Maersk plans to electrify at least 15 of their company-owned trucks at this location before 2030. Maersk's trucks are expected to drive an average 60-miles round trip performing one to two turns per day, 260 days per year. Maersk's trucks dwell overnight at the distribution center and are assumed to charge overnight.

Assuming each vehicle will have a dedicated charging port, deploying eight 60 kW dual-port chargers (16.6 kW of actual output) to support the 15 electric trucks results in a total 480 kW of maximum site capacity required. The maximum site capacity assumes no energy management strategies are implemented and all trucks would charge concurrently at maximum output. Under a managed charging scenario, the minimum estimated site capacity of Maersk owned trucks is reduced to 277 kW site capacity to support a daily site load of 6,647 kWh from 75% fleet electrification.

Study analysis of the selected Maersk distribution center in CenterPoint's service territory identified adequate headroom available on the associated distribution substation; therefore, no substation upgrades are required to accommodate the minimum expected fleet electrification load from this site.

Considering the selected Maersk distribution center has 212 trucks owned and operated by independent companies or contractors, it is likely that significantly more electric load may be required to support operations sometime in the future. However, this load is dependent on the owner-operators' decision to procure electric trucks and their ability to access reliable charging. Owner-operators typically manage long-haul trucking applications driving anywhere from 200 to 500 miles in a day and do not employ a "return to base" model, meaning trucks do not dwell in a single location each night. As such, owner-operator trucks will likely rely on public or semi-public charging within proximity to the distribution centers or customers they serve.

Conclusions & Considerations



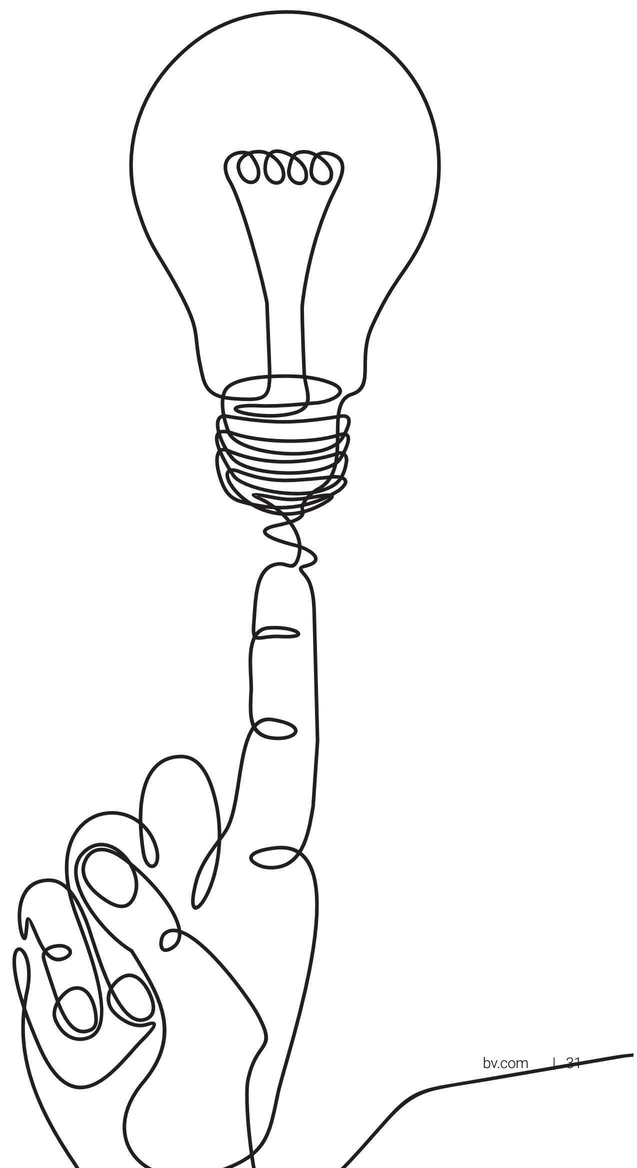
Load growth caused by vehicle electrification, including M/HDV trucks, can be a significant driver on grid infrastructure needs and should be considered in grid planning processes. The results of this study lend support to updating utility grid planning to consider proactive approaches for load growth, including from vehicle electrification, and to consider proactive investments such as voltage upgrades to address capacity constraints. Although limited in scope and depth of analysis, this study identified situations where utility investment that provide additional capacity beyond the minimum required can make economic sense while, at the same time, mitigating the risk of delayed interconnection faced by M/HDV fleet operators to facilitate their fleet transition plans.

The study also confirmed that managed charging programs have the potential to significantly reduce utility costs over time depending on the program's ability to effectively modify or manage charging behavior. Managed charging solutions include both active and passive strategies to optimize EV charging to benefit grid operations by maximizing value of local generation, decreasing equipment upgrade requirements, and allowing customers to pay lower electricity rates. Utilities should explore implementation of active strategies such as use of software to directly control a customer's charging and passive strategies such as offering EV tariff rates, time-of-use incentives, or demand response notifications. In turn, fleet owners and operators may also implement managed charging for their vehicles by participating in utility offered programs, leveraging charge management software, developing optimized charging schedules, and planning routes to maintain optimal vehicle battery state-of-charge.

A key risk identified by study for utilities and regulators to tackle will be the ability of utilities to accurately forecast the amount, timing and geospatial location in which vehicle electrification will be realized. Sophisticated analytical tools, such as EPRI's EVs2Scale2030 data, can support forecasting needs. Utility forecasting capabilities will require continuous testing, validation, and improvement over time to support the changing policy, customer preferences, and technology advancements related M/HDV electrification. It will be important to be able to identify where load growth will continue at the same trend, and when growth is likely to taper off due to saturation of vehicle electrification. Importantly, the potential for other anticipated demand growth drivers, such as building electrification and data centers, should also be factored when performing proactive planning analysis. Anticipated load growth through drivers other than and in addition to vehicle electrification, if sufficiently significant, would also support proactive grid planning. Importantly, the study sensitivity analysis indicates that proactive investment approach is favorable even under a range of load forecast uncertainties and will, generally result in cost savings when compared to a business-as-usual, sequential approach.

Utilities will be better prepared to meet the needs of fleet owners and operators electrifying their fleets through continuously improving their forecasting and grid planning processes, thus supporting an accelerated clean transportation transition. By proactively planning for EV load growth, the associated risks of long interconnection lead times may be relieved making fleet electrification a more attractive option for customers. Fleet customers are encouraged to engage with their utilities as early as possible to enable utilities to identify fleet cluster areas considering electrification to incorporate the anticipated aggregated EV load into their grid planning processes. Large fleet customers should also share insights around their fleet electrification transition plans and operational characteristics of their site with their utilities. This early engagement can help to minimize the risk of duplicative grid investments, streamline interconnections, and provide assurances to the utility that EV load in these clusters will manifest.

While this study investigated proactive planning through the lens of voltage upgrades to expand capacity beyond minimum requirements, other proactive investment options may also yield similarly favorable results in applications where voltage upgrades are impracticable. Other potential proactive investment approaches include transformer upgrades, development of a new substation, or changes in investment timing. Due to variations in utility grid conditions and data availability, this study did not analyze the full range of distribution grid conditions or potential proactive investment approaches. Given the estimated savings from proactive voltage upgrades, future studies should be developed to investigate the range of proactive investment approaches and the subsequent costs and benefits of each approach. Further investigation will enable utilities to develop comprehensive investment strategies encompassing a mixture of the proactive options that will enhance the grid planning process, improve grid readiness for vehicle electrification, and maximize cost savings.



Proactive Grid Investment Assessment

Technical Appendix Modeling Methodology

Prepared for

Environmental Defense Fund

November 6, 2024

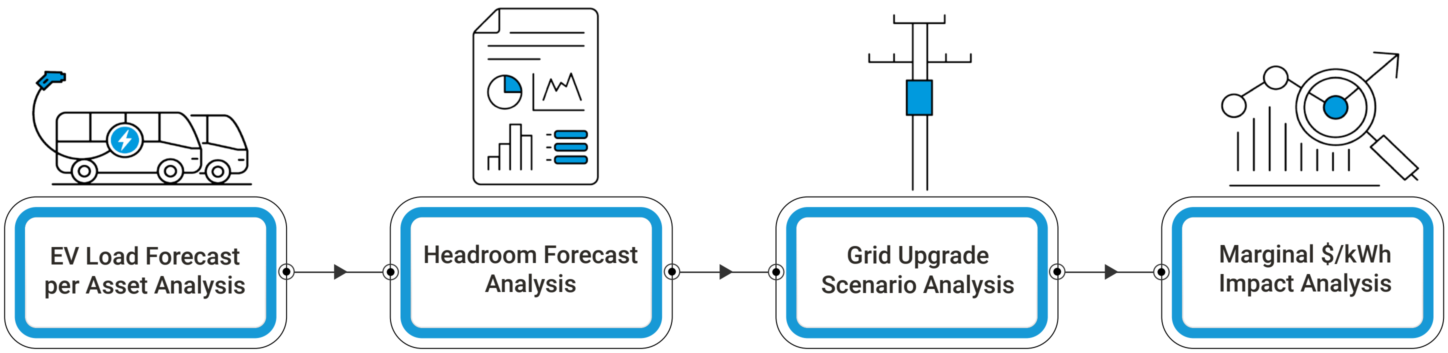
BLACK & VEATCH

Table of Contents

Technical Appendix | Modeling Methodology

The modeling and analysis methodology used in this study is summarized on Figure 1.

Figure 1 – High-Level Utility Case Study Analysis Methodology

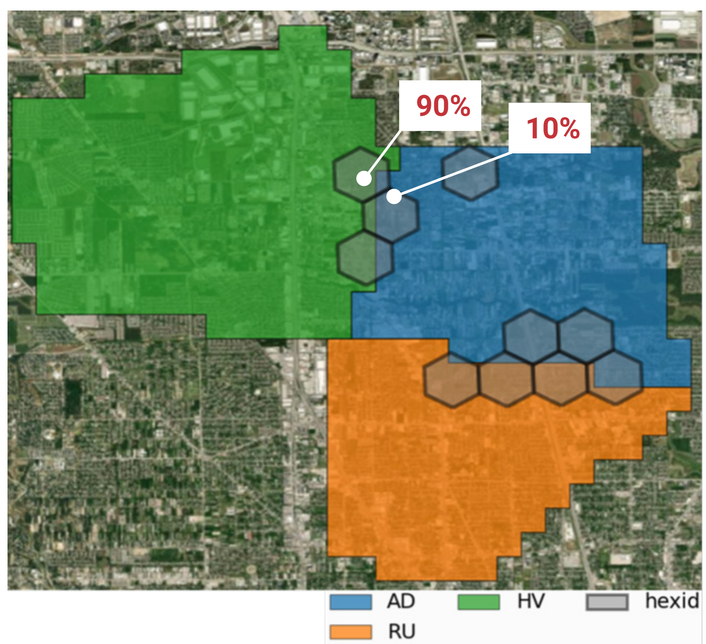


EV Load Forecast per Asset Analysis

The Electric Power Research Institute (EPRI) EVs2Scale2030 data set brings together data collected in collaboration with utilities, major EV truck manufacturers, fleet operators, charging providers, government agencies, and regulators to provide expected future EV charging deployments and load growth to help utilities plan and proactively build the grid upgrades needed. EPRI's EVs2Scale average kWh/day load forecast provided the basis for forecasting EV load per substation. EPRI's data breaks down EV load into light duty (LD) and M/HD vehicle categories and forecasts consumption within 0.28 mi² hexagonal areas (hexes) for the period of 2024-2030. Spatially joining hexes to the areas substations serve enabled precise assignment of EV consumption to each substation, assuming substations serve the connections closest to them. Hexes partially overlapping a substation's service area are pro-rata scaled based on the percentage overlap.

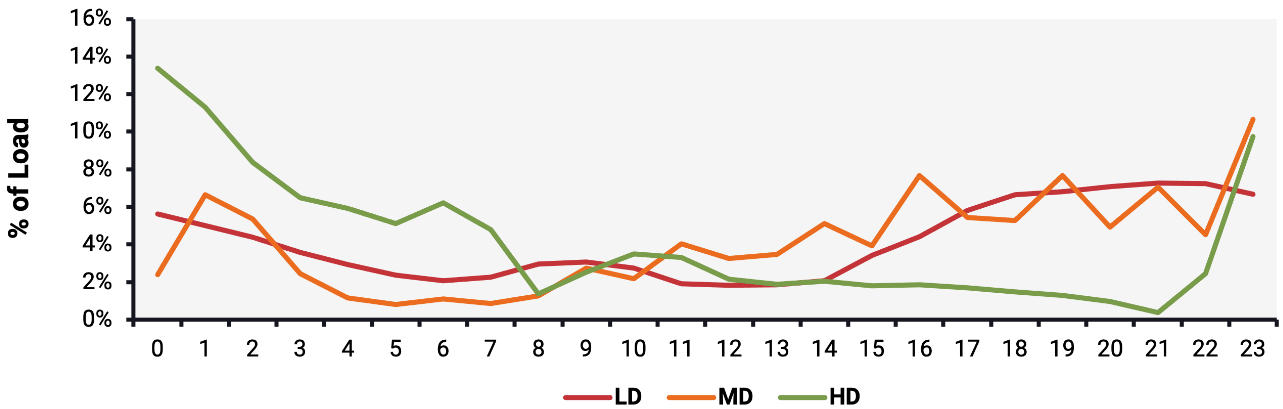
Figure 2 illustrates the allocation of EPRI's EV load hexes to distribution assets (Note: Colors = substation areas, Grey = EPRI hexagons).

Figure 2 – Illustrative Example Spatial Allocation of EPRI Load to Substations



EVs2Scale provides combined load forecasts for M/HDV. To apply differentiated charging behavior and load shapes, state truck and truck tractor registration data, as reported by the Federal Highway Administration (FHWA), informed the share of EV kWh/day load for each vehicle class. For purposes of the study, the medium duty (MD) and heavy-duty (HD) vehicle shares of M/HDV load is assumed to remain constant throughout the forecast period.

Figure 3 – Average Hourly LD, MD, and HD EV Charging ProfilesSubstations

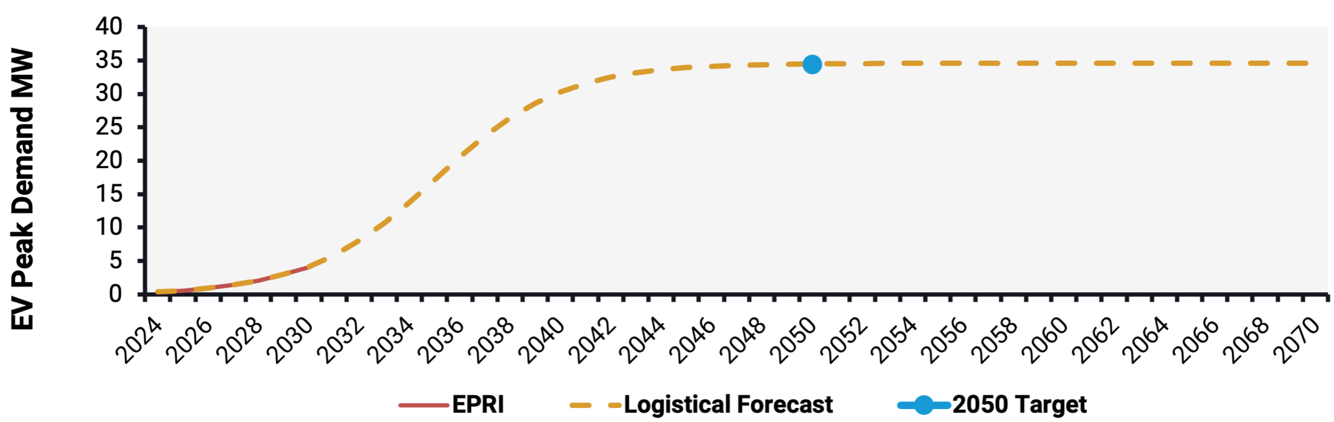


To evaluate the impact of EV load on substation capacity, EV kWh/day metrics are converted into MW/hour demand profiles using load shapes from National Renewable Energy Laboratory's EVI-Pro tool (LD vehicles) and Berkley Lab (MD and HD vehicles). These load shapes represent unmanaged charging EV profiles. Figure 3 illustrates the normalized load shapes utilized as unmanaged charging profiles for LD, MD, and HD vehicles, where the y-axis represents the percent of daily charging load, in MW per hour.

EV coincident peak demands are identified by assessing the EV load coinciding with each distribution asset's historical peak hour. For the managed charging strategy, a 10–30% reduction in peak demand, varying by utility, is assumed.

This study extended EPRI's 2030 forecast to 2070 by fitting a logistic curve to the 2024-2030 coincident peak demand forecast. The curve fitting process ensured that the resulting logistical curve per substation best fit the EPRI forecast by minimizing the sum of squared errors between them and projected the EV load to reflect an 80% EV penetration by 2050[1] assumption. Figure 4 illustrates the coincident peak demand forecast for a sample distribution asset where the Logistical Forecast portion is derived. Both unmanaged and managed charging scenarios incorporate this logistical curve fitting process.

Figure 4 – Illustrative Example of EV Coincident Peak Demand for 2024-2050 for a Given Asset

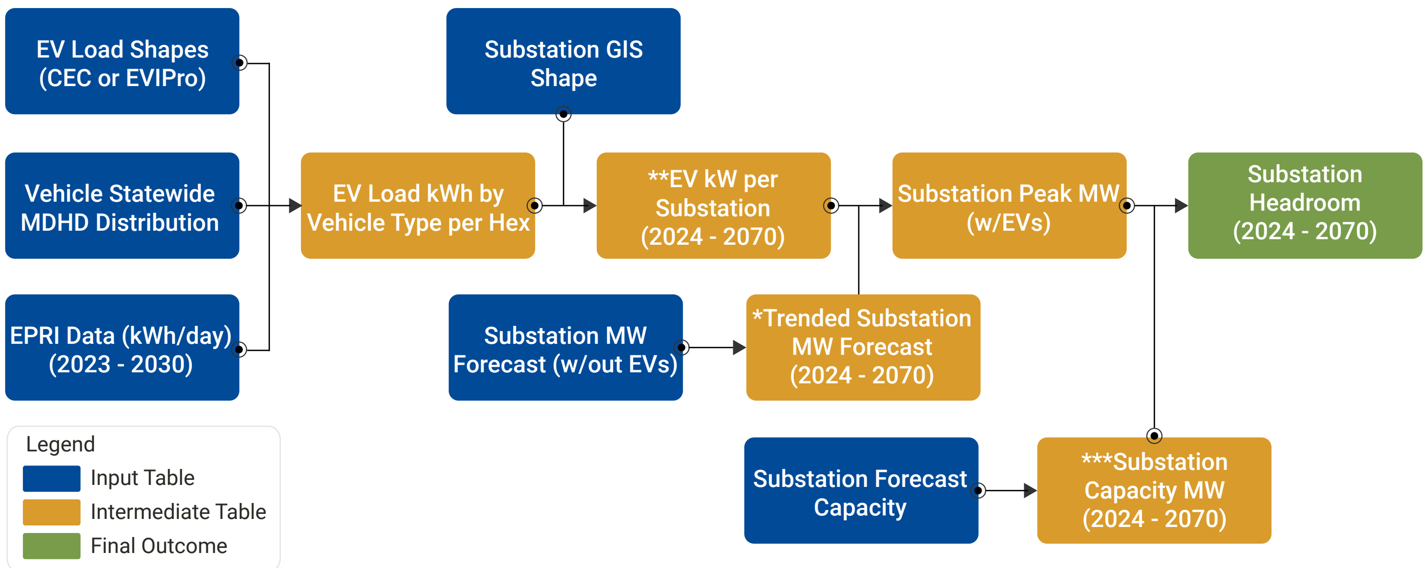


1 Assumption informed by New York's Climate Leadership and Community Protection Act aims to achieve 85% carbon reduction in greenhouse gas emissions and applied in both utility case studies under the assumption that economics for EVs in Texas will ultimately lead to strong EV adoption.

Headroom Forecast Analysis

EV coincident peak demand (MW) from 2024-2070, combined with utility-provided forecast substation peak demand (excluding EV load), generated total future peak demand projections per asset[2]. Available headroom for each year is determined by comparing peak demand forecasts to substation capacity forecasts. Two headroom values are produced for each substation: one for the unmanaged charging strategy and one for the managed charging strategy. Figure 5 outlines this headroom calculation process and includes the EV coincident peak demand calculations.

Figure 5 – Headroom Forecast Analysis Methodology

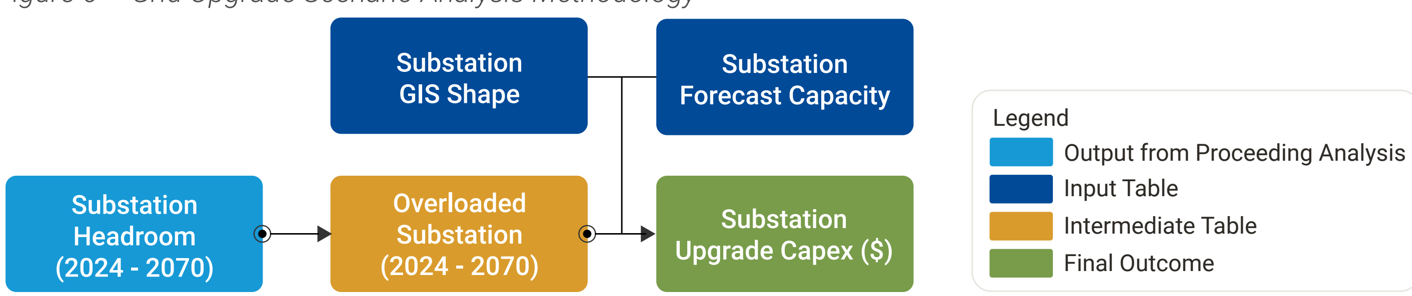


* = Trended using linear forecast of historical data.
** = 2024-2070 EV per substation based on EPRI, 2031-2070 EV load forecasted from EPRI by fitting logistical curve to 2024-2030 data and specifying the 80% by 2050 target EV penetration.
*** = Any future year without an assigned capacity was assumed to have the same capacity as the last year of data provided.

Grid Upgrade Scenario Analysis

For each substation forecasted to experience overloads, upgrade sizing and costs are calculated based on scenario parameters, yielding a present value (PV) of the required CAPEX.

Figure 6 – Grid Upgrade Scenario Analysis Methodology



[2] *This approach assumes no change in the timing of peak demand.*

Figure 6 summarizes the grid upgrade scenario analysis methodology, beginning with the substation headroom forecast identification of overloads, which are relieved by either the proactive or sequential investment strategy and associated sizing and cost assumptions. The output of this analysis is total expenditures in PV terms for each overloaded substation.

The key difference between the proactive and sequential scenarios is the approach taken to receive the substation overload. For sequential scenarios, substations are assumed to be sized to accommodate 20 years of growth before needing an additional investment, such as adding a substation to a spare bay. For the proactive scenarios, higher secondary voltage substations were incorporated.

The example on Figure 7 shows a proactive versus sequential investment for the same CenterPoint substation load forecast, which reflects the unmanaged EV charging scenario. In this case, the proactive investment in 2041 is more cost-effective, as it avoids the need for the second substation investment in 2061, given the assumed oversizing and costs of the higher voltage substation.

Figure 7 –Proactive Grid Upgrade as the Lowest Cost Example (CenterPoint, Unmanaged Scenario)

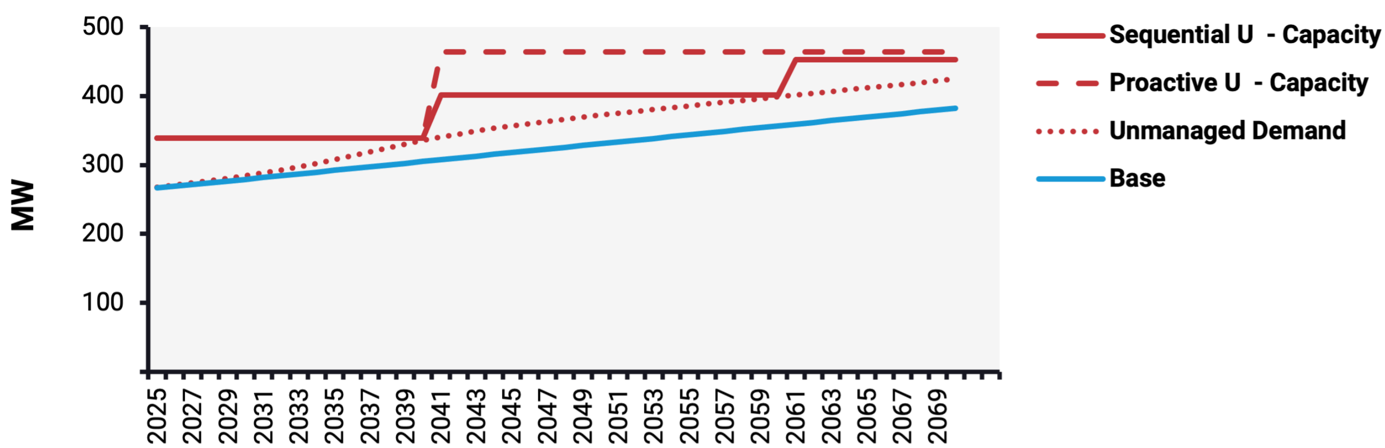


Figure 8 –Sequential Grid Upgrade as the Lowest Cost Example (CenterPoint, Unmanaged Scenario)

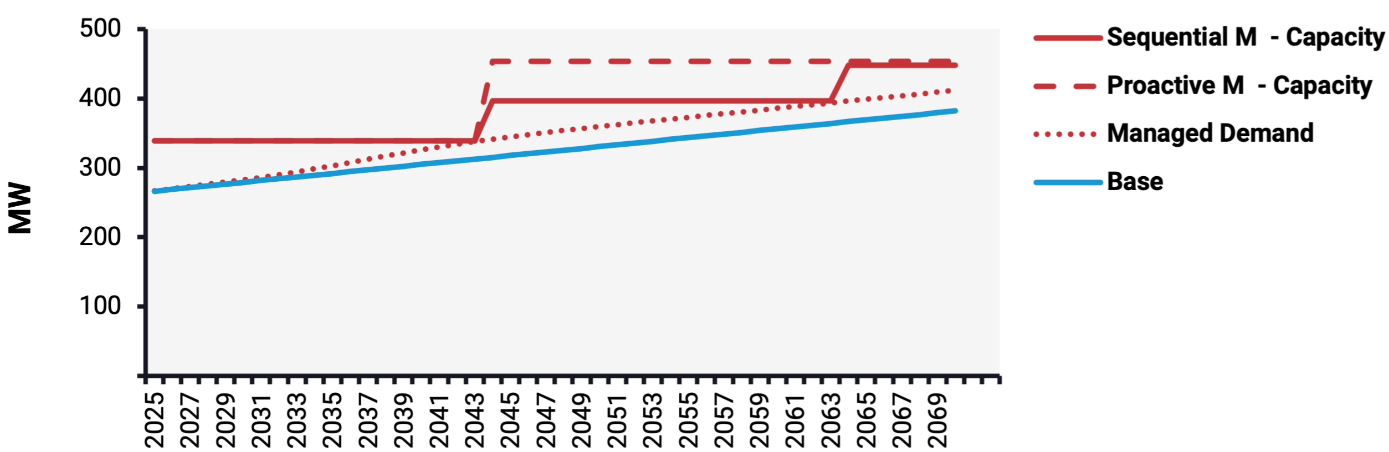


Figure 8 displays a different CenterPoint substation, where the forecasted unmanaged load curve stabilizes over the study period. Under these conditions, a sequential investment is the more cost-effective approach. The rapid increase in demand due to EV charging leads to oversizing of the upgrade under the proactive scenario. As a result, the sequential scenario yields the lowest cost option in this case.

While the relative costs of different voltages are relatively well understood, voltage upgrade integration costs are not widely available in the public domain. Voltage upgrades typically occur over time, as higher voltages become the standard, but it is less common to convert voltages, unless there is a specific trigger, usually cost and/or capacity. Based on the IEEE analysis[13], it is assumed a higher secondary voltage primary distribution voltage would deliver a 41% lower cost per MW overall but require 100% larger substations on average; in other words, building ahead of need but at a lower cost per MW.

Importantly, upgrading distribution voltages is a complex endeavor, with specific local conditions dominating the actual costs and benefits. Given data availability limitations, IEEE assumptions are used to estimate relative costs and sizing. In practice, each utility will need to assess the costs and benefits of specific opportunities for themselves.

The PV CAPEX values over the study period were calculated to evaluate each scenario. PV CAPEX was determined based on three planning approaches: (1) All Sequential: planning using only sequential approaches, (2) All Proactive: planning using only proactive approaches, and (3) Optimized Proactive: planning using a mix of sequential and proactive approaches, optimized for each substation.

Grid Upgrade Sensitivity Analysis

The study analyzed a range of sensitivities to validate the results based on a wide range of substation demand forecasts, which are outlined in the table below. The sensitivities represent a scaling of the EPRI forecast, which yielded different levels of EV adoption in 2050, which was then functionally carried through to 2070. All other assumptions and model inputs were held constant.

Sensitivity	EPRI 2024-2030 Scaler (%)	2050 EV Penetration (%)
1	25%	60%
2	50%	70%
Baseline	100%	80%
3	200%	90%
4	400%	100%

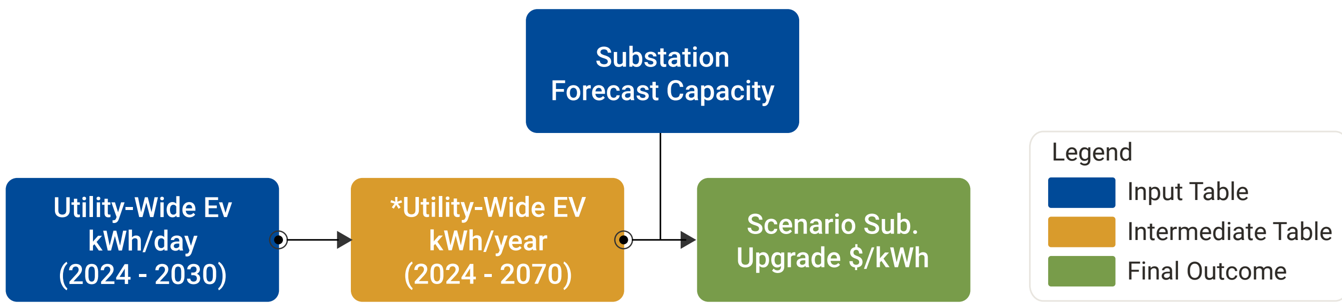
[3] *EEP - Electrical Engineering Portal, and Edvard Csanyi. "Primary Distribution Voltage Levels." EEP - Electrical Engineering Portal, 26 August 2017*

Marginal Cost Impact Analysis

To estimate the cost of upgrades over the period in $/kWh terms, the PV of total expenditures (TOTEX) is scaled based on its expected percentage (10%) of systemwide total expenditures and divided by the projected total EV consumption (MWh) by year. To the degree this $/kWh value is lower than current rates, it implies that overall costs per kWh would be reduced over the period. An overview of the $/kWh analysis methodology is shown on Figure 9.

EV demand is only a fraction of the demand being modeled, so the study analysis likely overstates the cost of connecting EV load to the grid; however, the study provides indicative results.

Figure 9 – Marginal $/kWh Impact Analysis Methodology



* = Forecasted years generated by fitting logistical curve to 2024-2030 data and specifying 2050 end point
** = TOTEX is equal to CAPEX + annualized OPEX

Con Edison Case Study

Con Edison's transmission and sub transmission systems feed area (aka distribution) substations, which in turn feed distribution feeders that either serve network customers or non-network customers. Network customers reside within network areas, which are specific geographic zones (primarily in dense urban regions), where they are served by an underground grid designed to provide high reliability. This system uses multiple feeders that allow electricity to flow from several directions, ensuring that even if one feeder fails, power can still be maintained to minimize disruptions. In contrast, non-network (radial) customers are served by a simpler, one-way system, typically using overhead lines, which may be more vulnerable to outages. A majority of the load distributed by Con Edison supplies network customers (87%), while the other 13% supplies non-network customers.

The study evaluated the impact of EVs and upgrade costs in seven network areas[4] within Con Edison's service territory, identified as likely geographic EV hotspot areas at the network area substation level.

Assumptions

Con Edison provided EV contribution to network area peak demand (MW) coincident with upstream area substation peak timing from 2024-2042 for seven network areas. Con Edison's EV peak demand out to 2070 for each network was estimated by fitting a logistical function or "s-curve" to it that achieved 80% penetration by 2050.

The area substation peak demand forecasts from

[4] *Con Edison's network areas are geographical regions that are served by a network or meshed distribution grid.*

Con Edison's Preliminary Area Substation and Subtransmission Feeder Twenty-Year Load Relief Program includes some electrification adjustments that account for EV load. Con Edison's assumed EV contribution to network area peak demand was removed to add EV load forecasted in EPRI's EVs2Scale data and logistical forecasting process to 2070 (as shown on Figure 2). Area substation capacity for 2043-2050 is assumed to stay at 2042 levels.

Con Edison provided data from previous proactive planning work that included estimated asset upgrade costs by asset type. This data is leveraged with the relative costs between different investment types from other utilities to derive a $/MW CAPEX estimate for new area substation installations, resulting in an assumed area substation installation cost of $918,836/MW.

Lastly, Con Edison provided a managed charging assumed peak demand reduction impact of 10%.

CenterPoint Case Study

The CenterPoint transmission system feeds distribution substations, which then feed primary distribution feeders that in turn feed downstream transformers and customer circuits. CenterPoint's transmission system is unique in its configuration and operation as it is the largest in the United States with over 3,000 miles of transmission lines and 265 substations.

For this case study, CenterPoint provided data sufficient to evaluate the EV impact and upgrade costs of the outlined scenarios for 217 distribution substations.

Assumptions

CenterPoint provided distribution substation peak demand forecasts without EV load from 2024-2033. Con Edison's EV peak demand out to 2070 for each network was estimated by fitting a logistical function or "s-curve" to it that achieved 80% penetration by 2050.

Along with the distribution substation peak demand forecasts, distribution substation capacities as of 2023 were provided. Distribution substation capacities are assumed to remain unchanged over the forecast period, unless a forecasted overload is identified and an upgrade, in accordance with the scenario analysis, is planned.

CenterPoint provided budgets for 2024 planned distribution system upgrades, which were used to calculate a $/MW installation cost for new distribution substations. The average project $/MW for new substations taken forward in the modeling was $140,000/MW. A value of $93,432/MW was provided by CenterPoint for a higher voltage substation, which is close to the differential identified from the IEEE dataset, net of the 31% brownfield integration cost estimate.

A 30% managed charging impact on peak demand was assumed in the CenterPoint modeling, following the findings from the U.S. Department of Energy's Multi-State Transportation Electrification Impact Study[5].

[5] U.S. Department of Energy's Multi-State Transportation Electrification Impact Study