Assessment of Infrastructure Needs to Support Regulatory Requirements for Light-, Medium-, and Heavy-Duty Zero-Emission Vehicles: Grid Impact Assessment

Introduction

This technical memorandum is an extension of the main report[1], named "Assess the Battery-Recharging and Hydrogen-Refueling Infrastructure Needs, Costs and Timelines Required to Support Regulatory Requirements for Light-, Medium-, and Heavy-Duty Zero-Emission Vehicles", with the purpose of evaluating the impact of electric vehicle (EV) charging approaches on the power sector. The main report examined the cost and time required to install sufficient charging and refueling infrastructure to support the number of EVs required to fulfill existing and proposed vehicle regulations for light-duty (LD) and medium/heavy-duty (MDHD) vehicles. Following the development of the main report, the project team has also investigated how altering LD fleet technology mix can affect the required supporting infrastructure and associated costs in an accompanying memorandum with this study, named "Assessment of Infrastructure Needs to Support Regulatory Requirements for Light-Duty Vehicles: Sensitivity to Technology Mix" (hereinafter referred to as sensitivity analysis). The EV penetrations from both the main report and the sensitivity analysis were utilized to design four scenarios that differ in transportation demand as well as EV charging patterns to assess the potential impact of the charging profiles on electric peak demand requirements and identifies the additional capacity required to meet the increased demand due to electric vehicle loads.

Background and Assumption

This study assessed a total of four scenarios to understand the impacts of various EV deployment scenarios and charging profiles on the electric demand and the supply required to meet the resulting demand. Three out of the four scenarios modeled use the same EV penetration rates as the main report (also referred to as the baseline scenario in the sensitivity analysis), with varying charging profiles:

- Base Scenario: In the base scenario, vehicles charge immediately upon plugging in at home or the workplace at the maximum rate available. Peak loads occur between 6 pm - 9 pm as most vehicles are plugged in when drivers return home from work, coinciding with high grid loads as appliance and heating/cooling loads increase upon returning home. ZEV adoption includes a mix of BEV, PHEV, and FCEV to meet the regulatory requirements outlined in the main report.**Error! Bookmark not defined.**
- Managed Scenario: In the managed scenario, vehicles charge immediately upon being plugged in, but charging is slower and spread over more hours to reduce load peaks, rather than at the maximum speed.
- Bidirectional Vehicle-Grid Integration (VGI) Scenario: The bidirectional VGI scenario assumes that vehicles are capable of returning electricity back to the grid. To reduce the peak load, the bidirectional vehicles charge throughout the day (usually at work) and return energy back to the grid between 6 pm-

[1] Assess the Battery-Recharging and Hydrogen-Refueling Infrastructure Needs, Costs and Timelines Required to Support Regulatory Requirements for Light-, Medium-, and Heavy-Duty Zero-Emission Vehicles, available at https://crcao.org/wp-content/uploads/2023/09/CRC_Infrastructure_Assessment_Report_ICF_09282023_Final-Report.pdf

9 pm (usually upon returning home)[2]. Since bidirectional VGI is only in its nascent stage, it is assumed to only play a significant role after the 2030 timeframe.

The last scenario, the high BEV scenario, differs from the base scenario in that it assumes that 100% of ZEV regulatory requirements are fulfilled with BEVs (rather than a mix of BEVs, PHEVs, and FCEVs), which increases the number of BEVs deployed in California and other Clean Car States[3]. This shift in fleet technology increases total on-road BEV stock from 84 million in the base scenario to 91 million in the high BEV scenario and in turn increases the total electric demand by 10 TWh in 2035[4]. More details of this modeling scenario are listed below:

- High-BEV Scenario: The high-BEV scenario relies on the base scenario charging pattern but assumes that 100% of regulatory requirements are fulfilled with BEVs. In California and Clean Car States, where the regulatory requirements are electric vehicle sales targets, this leads to higher electric loads due to an increase in BEVs. In non-Clean Car States, the regulatory requirements are achieved through emission reduction targets, and therefore the shift to compliance through 100% BEVs increases the relative share of BEVs to PHEVs, but the overall reduction of emissions and electric vehicle miles traveled (VMT) is consistent and therefore the electric load is not impacted.

The managed and bidirectional VGI scenarios vary the LD charging profiles from the base scenario to mitigate peak impacts relative to the base scenario. Figure 1 summarizes the LD charging profiles of the base, managed, and bidirectional VGI scenarios and the MDHD charging profiles by vehicle types and applications, which remain consistent across all scenarios.

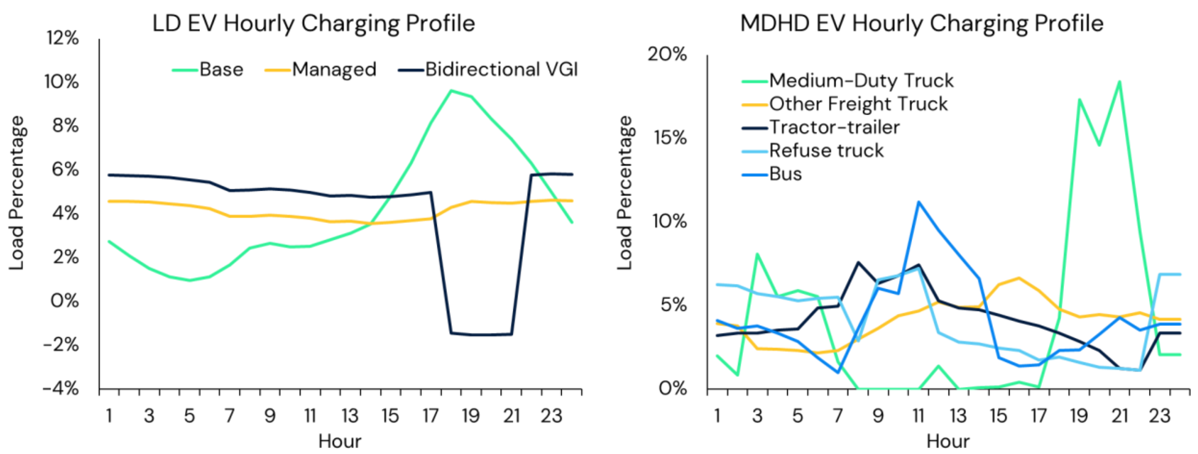

Figure 1. Hourly load profiles of LD EV charging (left) and MDHD EV charging (right).

The base and managed LD charging profiles were developed using the National Renewable Energy Laboratory's (NREL) Electric Vehicle Infrastructure Projection Tool (EVI-Pro)[5]. Each of these profiles corresponds to a set of charging parameters that influence both the timing and the type of charging, as

[2] Post-EV peak hours primarily occur between 6-9 pm. VGI scenario EV discharge assumptions were tailored to reduce overall system peak in the baseline scenario.
[3] This study adopted the same terminologies used in the main report to classify LD ZEV sales groups by states: California, Clean Car States, and Non-Clean Car States. California: adopted ACCII and sells LD FCEVs; Clean Car States: states that have adopted (or are expected to adopt) ACCII rules and do not sell LD FCEVs; Non-Clean Car States: states that follow EPA's proposed LD Multi-Pollutant Emissions Standards. More details can be found in Figure 6 of the main report.
[4] Detailed fleet modeling results can be found in Figure 6 and Table 1 of the sensitivity analysis.
[5] Available at https://afdc.energy.gov/evi-pro-lite

listed in Table 1. The impact on hourly load distribution by charger type is also illustrated in Figure 2 for both base and managed charging scenarios.

Table 1. Charging parameters to determine the LD base and managed charging profiles using EVI-Pro.

Parameters	Base	Managed
Average Daily Miles Traveled per vehicle	35	35
Plug-in Vehicles that are All-Electric	0.75	0.75
Plug-in Vehicles that are Sedans	0.5	0.5
Mix of Workplace Charging	20% Level 1 and 80% Level 2	50% Level 1 and 50% Level 2
Access to Home Charging	100% (50% Level 1)	100% (80% Level 1)
Preference for Home Charging	80%	60%
Home Charging Strategy	Immediate - as fast as possible	Immediate – as slow as possible (even spread)
Workplace Charging Strategy	Immediate - as fast as possible	Immediate – as slow as possible (even spread)

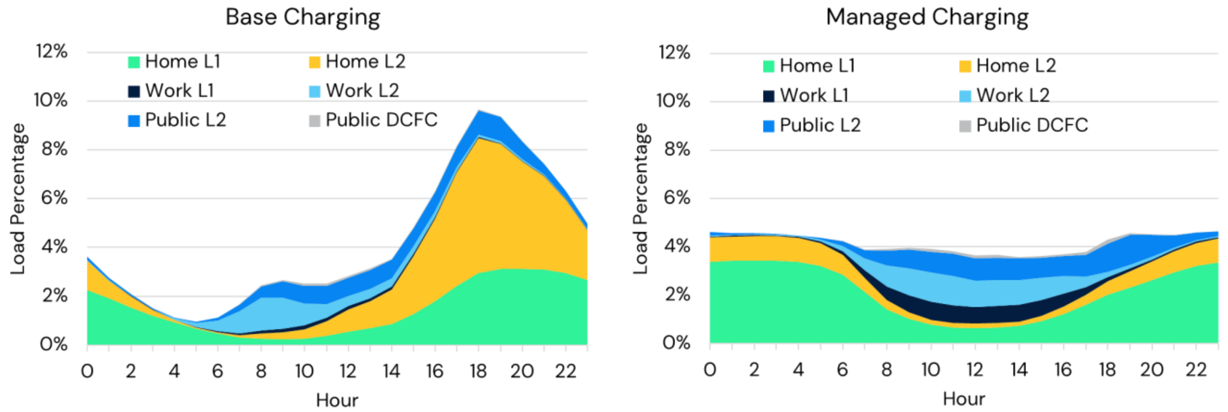

Figure 2. Light-duty charging load distribution by charger types based on EVI-Pro parameters. These profiles correspond to the green (base) and yellow (managed) lines of Figure 1: LD EV Hourly Charging Profile, respectively.

The bidirectional VGI profile was derived from the managed scenario, and assumes that EVs will charge throughout the day and then discharge to the electric grid between 6 pm - 9 pm. Currently, bidirectional VGI is only in its nascent stage, with a few pilot programs led by utilities, such as the Vehicle-to-Everything (V2X) pilot program by the Pacific Gas and Electric Company (PG&E)[6]. While some states like California[7] are planning to require all EVs to be bi-directional capable in the near future, due to the long lead time to establish processes and programs such as the establishment of interconnection agreements[8], the exclusion of bidirectional charging in electric vehicle supply equipment (EVSE) warranties[9], and the overall

[6] More information available at https://www.pge.com/en/clean-energy/electric-vehicles/getting-started-with-electric-vehicles/vehicle-to-everything-v2x-pilot-programs.html

[7] SB-233 Battery electric vehicles and electric vehicle supply equipment: bidirectional capability, more information available at https://legiscan.com/CA/text/SB233/id/2797556#:~:text=This%20bill%20would%20require%20that,vehicles%20sold%20in%20California%20be

[8] The X in V2X Matters: Energization versus Interconnection of Bidirectional Charging Systems, available at https://sepapower.org/knowledge/the-x-in-v2x-matters-energization-versus-interconnection-of-bidirectional-charging-systems/

[9] Nissan Approves Fermata Energy's Bidirectional Charger as First for Use with Nissan LEAF in the U.S., available at https://fermataenergy.com/article/nissan-release-nissan-approves-first-bi-directional

lack of large-scale utility programs and regulatory guidance, bidirectional VGI is assumed to only play a significant role after the 2030 timeframe.[10]

Load profiles as assumed in the Medium- and Heavy-Duty Electric Vehicle Infrastructure Load, Operations, and Deployment Tool (HEVI-LOAD), developed by the Lawrence Berkeley National Lab (LBNL), were applied to estimate load impacts resulting from MDHD electrification.[11] Considering that the charging behavior of commercial trucks are mainly driven by their duty cycles, and there is not enough data available to examine the impact of managed vs. un-managed charging, only one set of charging profiles for these vehicles was considered (shown in Figure 2). In other words, the four charging scenarios only vary by LD loads, while the same MDHD hourly loads were applied to all.

Methodology

Vehicle fleet modeling was conducted at the state level to calculate the projected on-road ZEVs by fuel technologies, and energy demand modeling was done at the regional level to project future demand growth and capacity expansion. The U.S. EPA's Motor Vehicle Emission Simulator (MOVES) was used to establish the baseline national vehicle fleet mix. LD ZEV penetration was then modeled through three sales curves, for California, Clean Car States, and non-Clean Car States, respectively. Clean Car States in this analysis include New York, Massachusetts, Vermont, Maine, Connecticut, Rhode Island, Washington, Oregon, New Jersey, Maryland, Colorado, Minnesota, Nevada, Virginia, and New Mexico. The California (LD) and Clean Car States sales curves reflect the ACCII regulation, which leads to 100% ZEV for passenger cars and trucks by 2035. The Non-Clean Car State sales curve assumes the ZEV penetration rates for passenger cars and trucks from the Proposed EPA Rule: Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles[12]. California's ACCII technology mix assumptions were applied for BEV and PHEV technologies across the country in the base, managed, and bidirectional scenarios, while FCEVs are only considered in California. For MDHD vehicles, similar fleet modeling and sales curve categories were utilized, with more details available in the main report.[13]

The combination of EV load shapes for LD and MDHD, combined with the expected penetration of EVs, allow for the development of load shapes that reflect the various scenario charging assumptions and projected EV penetration. Each scenario profile is characterized as a 24h shape that is distinct for weekdays and weekends and year, reflecting the growth in EV loads over time, and, as applicable, the scenario specific charging parameters.

The EV load shapes created through the process above were then merged with electricity sector load shapes and modeled in the Integrated Planning Model (IPM)® to assess the impact of increased EV adoption on electric sector capacity expansion and generation. IPM is a capacity expansion and dispatch model that projects for electricity capacity and generation based on assumptions such as electric demand, electricity sector policies, and commodity forecasts such as natural gas prices. IPM includes a representation of the existing grid supply and determines the least-cost supply mix to meet the growing demand, drawing on options such as retirement or adjustments to dispatch of existing grid facilities and additions of new facilities. Characteristics of existing and new facilities, such as the cost to add capacity or dispatch existing plants, vary regionally. For example, wind additions in the Midwest feature higher

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[10] It was assumed that under the bidirectional VGI scenario, the hourly load shape will incrementally change from the managed charging load shape in 2025 to the bidirectional VGI load shape in 2035.
[11] Electric Vehicle Charging Infrastructure Assessment - AB 2127, more information available at https://www.energy.ca.gov/data-reports/reports/electric-vehicle-charging-infrastructure-assessment-ab-2127
[12] https://www.epa.gov/regulations-emissions-vehicles-and-engines/proposed-rule-multi-pollutant-emissions-standards-model
[13] For more detail on these ZEV technology penetration rates and sales curves, please refer to the Appendix I of the main report and the sensitivity analysis.

outputs per MW of installed capacity due to the quality of the wind resources, whereas solar output in California is higher compared to New England. For each region, the supply of resource accounts for the costs and performance of all available resources to meet demand.[14]

The projections for electric sector capacity are based on assumptions that include electric demand forecasts to capture the expected growth of electric demand across the country. This analysis relied on electric demand projections from a range of industry sources. Whenever possible, demand forecasts are based on the projections published by the system operators of the regional electricity grid. This includes the Pennsylvania New Jersey Maryland Interconnection LLC (PJM), the New York Independent System Operator (NYISO) and the Independent System Operator of New England (ISONE) in the Mid-Atlantic and Northeasters US, the Electricity Reliability Council of Texas (ERCOT), the California Energy Demand study by the California Energy Commission (CEC), and the Mid-Continent Independent System Operator (MISO) in the Midwest. For the parts of the country where ISO forecasts are not available, the Electricity Supply and Demand projections (ES&D) from the North American Electric Reliability Corporation (NERC) were used.

ISO forecasts may already include EV forecasts based on the expectations of the system operators and to assess the impacts of the forecasts developed for this study, these ISO-derived electric vehicle load forecasts were removed from the electric demand projections used for the grid impact assessment. This process results in a load forecast that reflects electric load growth assumptions without transportation electrification and forms the basis for a non-EV electric grid forecast. As a second step in the grid impacts assessment, the scenario-specific EV loads and load shapes are added to this non-EV load forecast, and an alternative grid forecast is modeled for each of the four EV charging scenarios. Reported from the grid impact assessment is the incremental peak demand driven by EVs as well as the incremental grid capacity required to meet the EV demand of each of the scenarios.

Results

Figure 3**Error! Reference source not found.** below shows the incremental increase (in percent) of 2035 peaks by region when comparing the EV charging scenarios to the non-EV case. The base and high BEV scenarios yield the highest impacts on 2035 peak demand, producing peak loads that increase between 6% in the least impacted region (ERCOT) and up to 44% in the most impacted region (CAISO), a region with higher EV adoption. By comparison, the managed and bidirectional VGI scenarios yield more moderate impacts on peak demand, capping out at 26% increases in CAISO. In Figure 4**Error! Reference source not found.**, these results are superimposed on a U.S. map to illustrate the geographical distribution of regions and peak impacts.

The EV charging scenarios yield regional 2035 peaks that are 6-44% higher than the non-EV case. Regions with relatively minimal EV impacts (ERCOT, WECC, FRCC, SERC) exist predominantly in Texas, the Southeast, and the West (excluding California), where incremental EV impacts on 2035 peaks are no greater than 13% in any EV charging scenario. More impacted regions, including CAISO, ISONE, MISO, and PJM, are more geographically diverse, spanning regions of the Northeast, Mid-Atlantic, Midwest, and West Coast. These regions experience incremental peak increases between 18-44% in the base and high BEV scenarios and between 9-26% in the managed and bidirectional VGI scenarios. As a result, these more heavily impacted regions experience 2035 peak increases that are no less than 9% greater than the non-EV case peaks.

[14] For more information on IPM, please refer to EPA's documentation of its latest IPM Reference Case: https://www.epa.gov/power-sector-modeling/post-ira-2022-reference-case

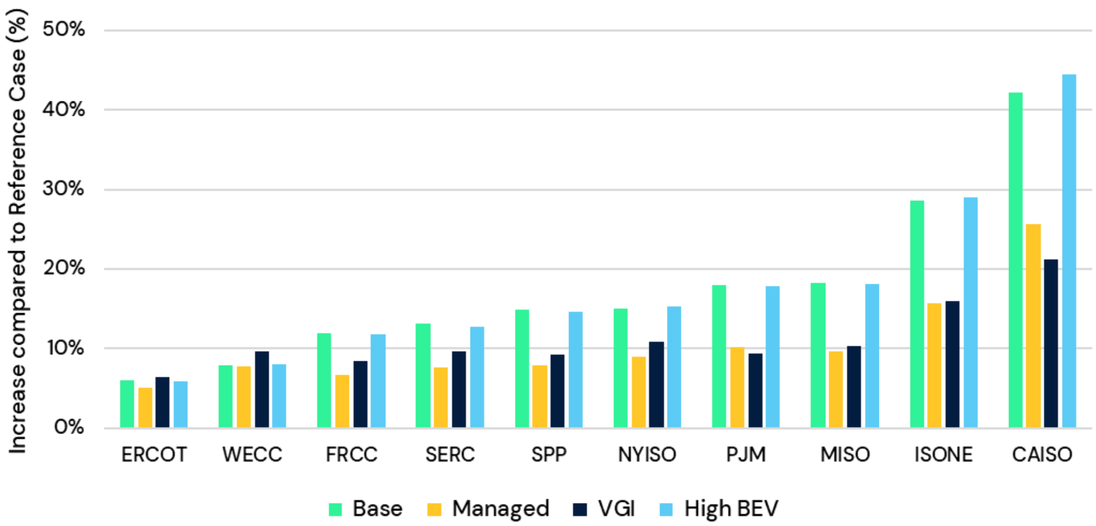

Figure 3. Incremental increase in 2035 peaks by region and EV charging scenario.[15]

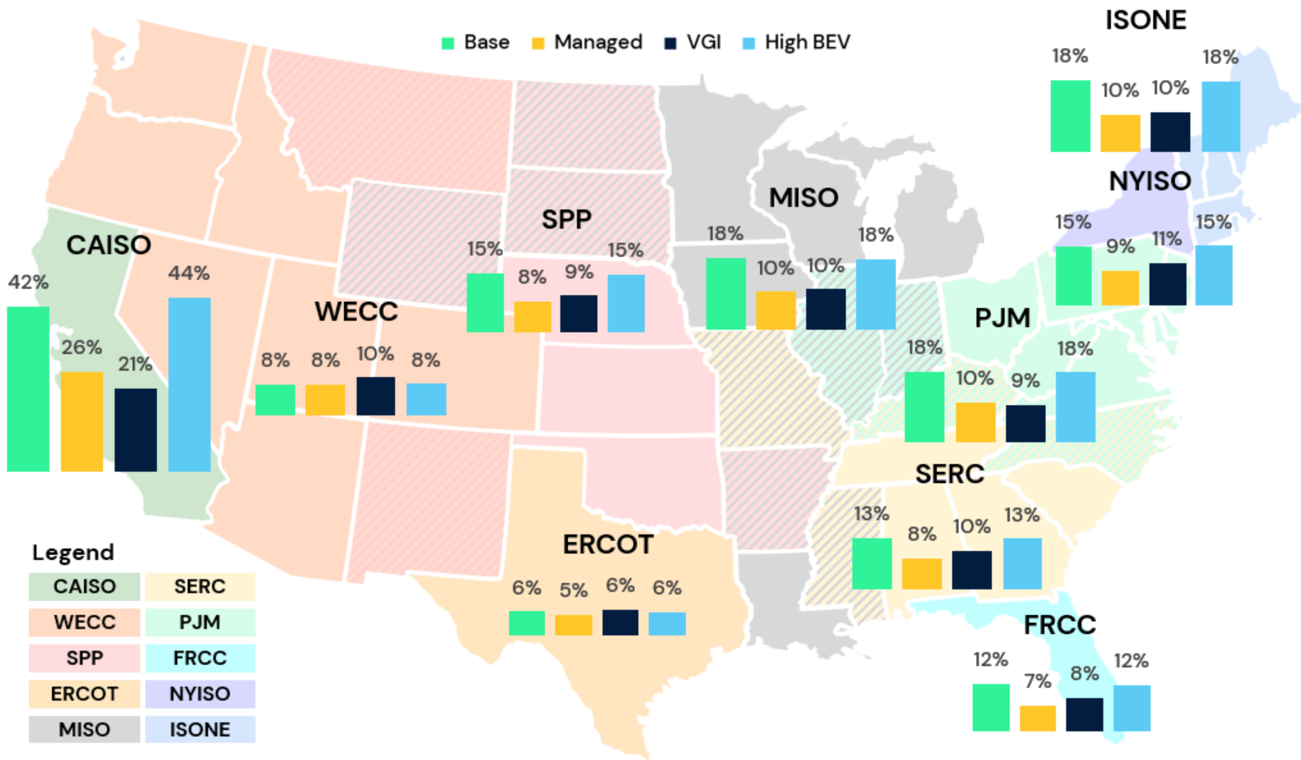

Figure 4. Map of incremental increase (%) in 2035 peaks by region and EV charging scenario.[16]

Table 2 shows the percent increase in U.S. generating capacity from the non-EV load case to each of the four scenarios in 2035. The larger load requirements of the modeled transportation electrification scenarios lead to increases in total generating capacity compared to the non-EV load case by 2035. The base and high BEV scenarios result in the largest increase in generating capacity of 13%, which is driven both by increases in peak demand and the types of technologies that are deployed to meet demand.

[15] The definition of region acronyms can be found in the List of Acronym table on page 14.
[16] Regional boundaries do not follow state lines and are therefore simplified in the map above. Crosshatched shading denotes states that are partially covered by 2 or more regions.

More detailed discussions of the generating capacity technologies are included in the Discussion section below.

Table 2. United States percent change in electric generating capacity (%) from non-EV load case in the base, managed, bidirectional VGI, and high BEV scenarios in 2035.

Year	Base	Managed	Bidirectional VGI	High BEV
2035	13%	9%	10%	13%

Impacts of electrification of the transportation sector varies by region, as seen in**Error! Reference source not found.** Table 3 and Table 4**Error! Reference source not found.**. To further investigate scenario impacts, four states across the U.S. — California, Texas, Florida, and Ohio — are examined below.

Table 3. Percent increase in peak demand by region and scenario in 2035.

Region	Base	Managed	Bidirectional VGI	High BEV
CA	42%	26%	21%	44%
TX	7%	5%	7%	7%
FL	12%	7%	8%	12%
OH	35%	21%	17%	35%

Table 4. Percent increase in generating capacity by region and scenario in 2035.[17]

Region	Base	Managed	Bidirectional VGI	High BEV
CA	23%	14%	16%	24%
TX	13%	12%	12%	13%
FL	8%	3%	6%	8%
OH	17%	16%	16%	17%

Table 3 shows the percent change in peak demand and Table 4 shows the percent change in generating capacity in California, Texas, Florida, and Ohio in 2035 in the four scenarios compared to the non-EV case. The base scenario leads to higher peaks, 7-42% (Table 3) as well as a 8-23% (Table 4) increase in generating capacity. At the U.S. or regional level, the increase in load in the high BEV scenario is masked by the fact that EV demand is only assumed to increase in 15 states in this scenario. Looking specifically at one of those 15 states, California's peak load increases about 44%, only slightly higher than what is seen in the base scenario. Compared to the base, the high BEV scenario has no additional impact, on both peak and generating capacity, in states like Texas, Florida, and Ohio since the overall energy demand in Non-Clean Car States does not change.

Table 3 also indicates that the managed and bidirectional VGI scenarios increase in peak load ranges from 5-26% compared to the non-EV case. The lower peak loads in the managed and bidirectional VGI scenario are achieved by spreading the EV load over the course of the day, away from peak hours in the afternoon and evening. The benefits related to peak load between the managed and high BEV scenario are regionally dependent and is explored further below. Total generating capacity in these two scenarios increases

[17] Changes in total capacity refer only to changes in regional capacity and do not include potential capacity transfers that may occur from neighboring regions to supply the growing EV demand, subject to existing transmission constraints.

between 3-16% compared to the non-EV case. Compared to the base and high BEV scenarios, there are also smaller increases in total generating capacity in these scenarios.

California

Figure 5**Error! Reference source not found.** shows the load shape for the peak day in California in 2035 for the four scenarios modeled. The addition of transportation demand leads to an increase in California's peak across all modeled scenarios relative to the non-EV load case. By 2035, the high BEV scenario showcases the highest peak impact of 44%, as shown in **Error! Reference source not found.**. The bidirectional VGI scenario has the lowest peak impacts of 21%, and the managed scenario increases peak by 26%.

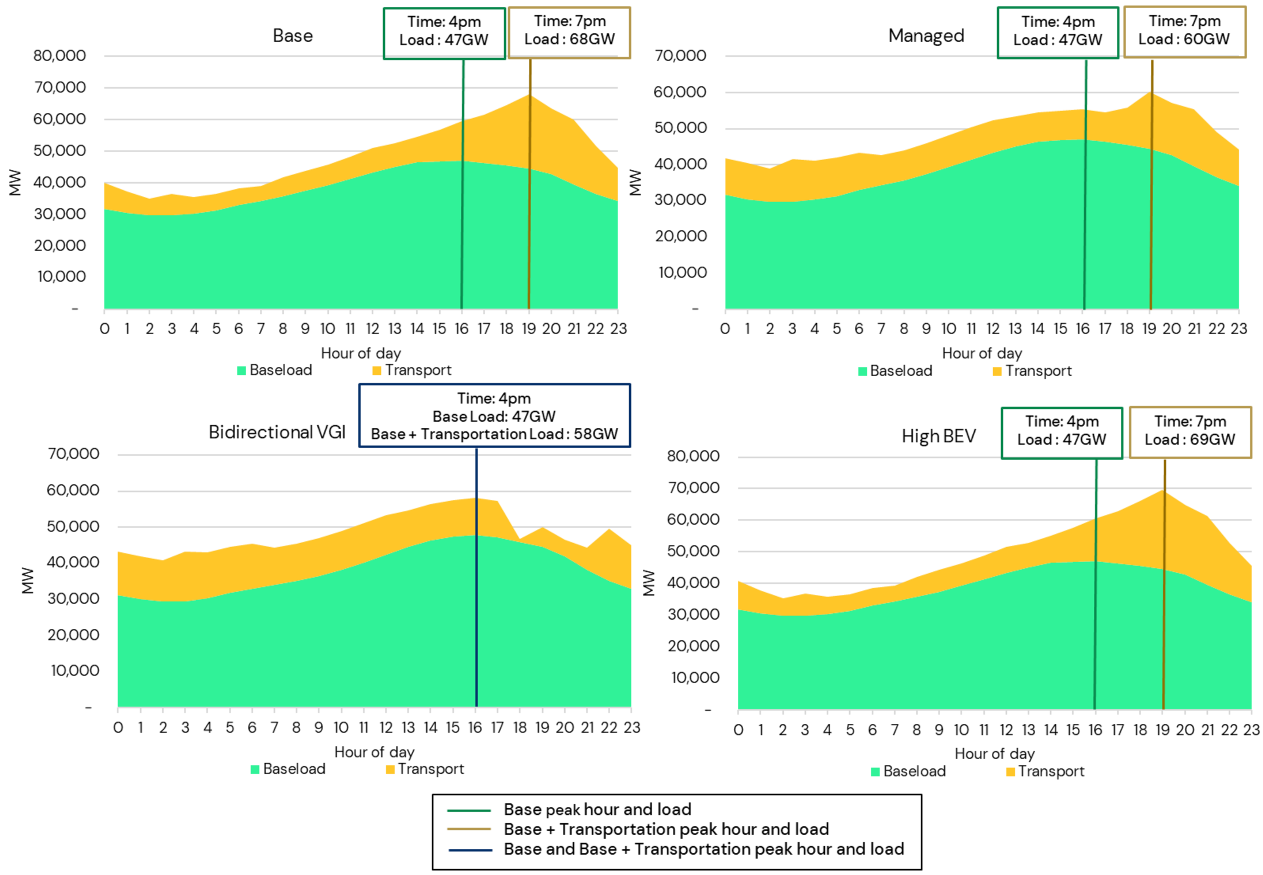

Figure 5. Load profiles for California including transportation electrification in 2035.

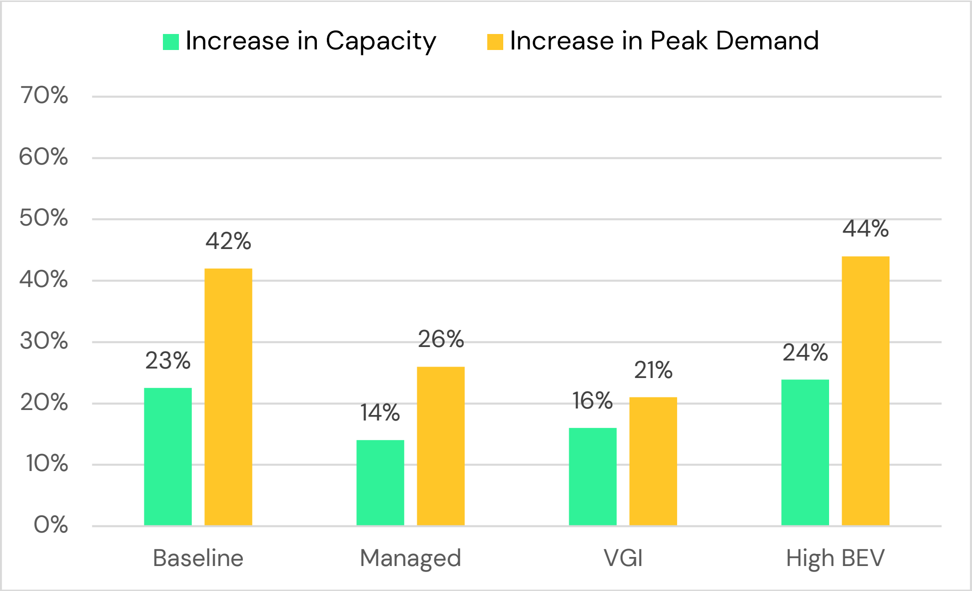

*Figure 6**Error! Reference source not found.** shows the increase in 2035 total generating capacity in California for each scenario from the non-EV load case. The larger load requirements of the scenarios lead to increases in total generating capacity. This increase is the largest in the high BEV scenario, with the highest peak demand and EV load, leading to an increase of 24% in generating capacity by 2035. The managed scenario leads to the lowest levels of incremental capacity, with an additional capacity of 14% by 2035.*

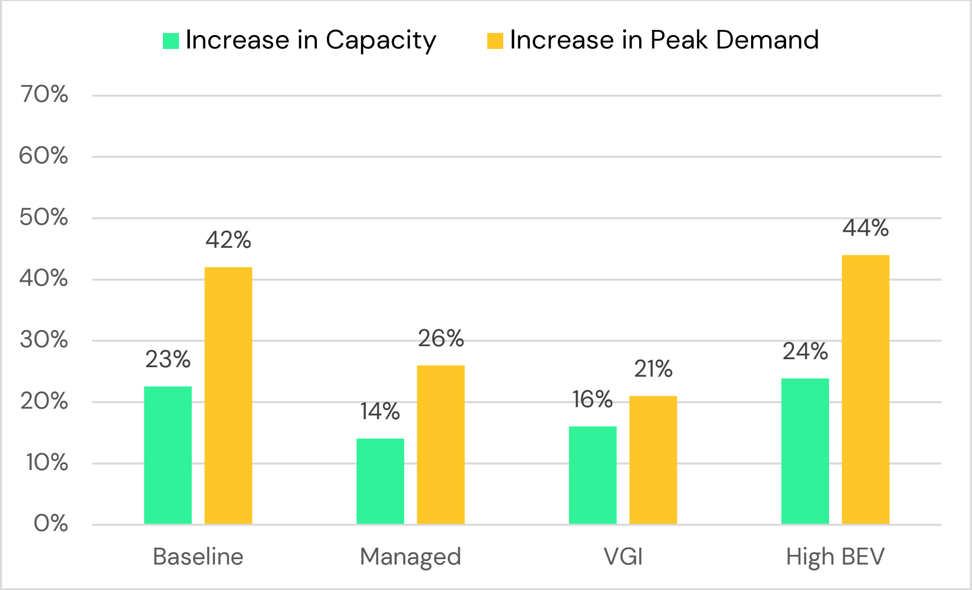

Figure 6**Error! Reference source not found.Error! Reference source not found.** also shows that while increases in peak load leads to increases in generating capacity, these increases are not necessarily linear. For example, while the bidirectional scenario has the lowest peak in California of the four scenarios, there is a slightly larger capacity build out, as there are more renewables that come online compared to the managed scenario. The factors driving overall capacity levels are not exclusively peak demand levels, but also capacity transfers with neighboring regions, the type of capacity added as each capacity type contributes different percentages of capacity to peak demand, and the overall load profile over the course of the day.

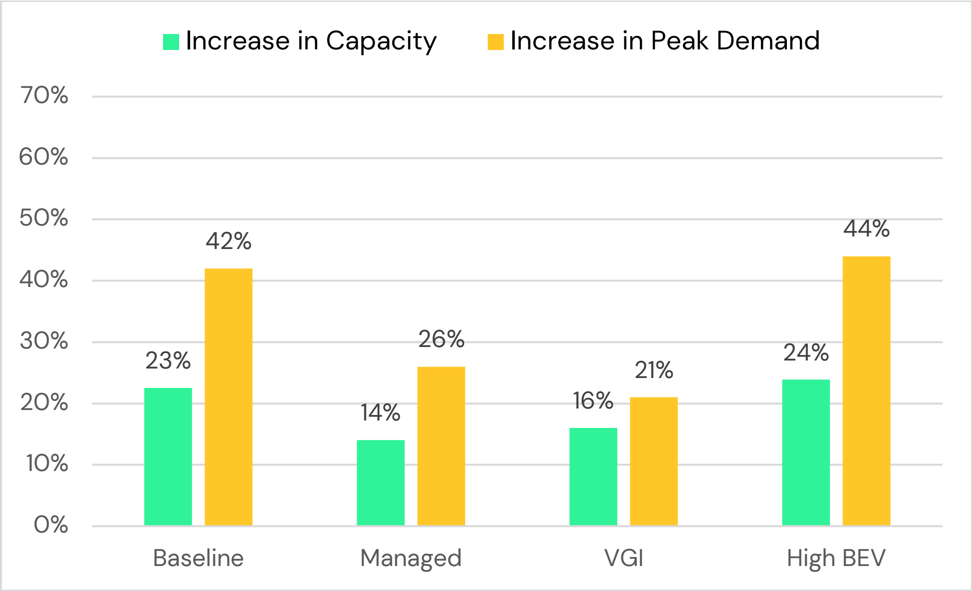

Figure 6. California Incremental Capacity Additions and Peak Demand Compared to non-EV case in 2035.

Texas

Figure 7**Error! Reference source not found. Error! Reference source not found.**shows the peak day load shape in 2035 in Texas for the four scenarios modeled. The demand increase from transportation electrification leads to a 7% increase in peak demand in 2035 in the base and high BEV scenarios (Table 5**Error! Reference source not found.**). Since Texas is a Non-Clean Car State, the base and high BEV scenarios are the same. The managed and bidirectional VGI scenarios exhibit peak increases of 5-7%, respectively. Both the managed and bidirectional VGI scenarios lower peak demand by spreading the EV charging load over the course of the day, shifting load from the evening period to the hours between 12 am and 3pm. In Texas, the peak demand occurs outside of the 6 pm-9 pm window, meaning that the bidirectional VGI as defined is not effective in reducing peak, and as the bidirectional VGI scenario increases load outside of 6 pm – 9 pm, it also increases the grid load relative to the managed scenario in the peak hour. This is shown in **Error! Reference source not found.** below and leads to a higher peak in the bidirectional VGI scenario compared to the managed scenario.

Table 5. Incremental Texas peak demand (%) by scenario in 2035.[18]

Base	Managed	Bidirectional VGI	High BEV
7%	5%	7%	7%

Table 6 shows Texas's incremental generating capacity (in percent) in 2035. Since the electricity demand from transportation is the same in the base and high BEV scenarios, they have the same increase in generating capacity at 13%. The lower peaks in the managed and bidirectional VGI scenarios lead to a 12% increase in generating capacity compared to the non-EV load scenario, about 1% below the higher peak impact scenarios. In addition to the absolute peak demand, factors such as transfer of capacity to and from neighboring regions, the type of capacity added to the system and their contribution of each

[18] Table 5 and Table 6 are both expressed in percentage terms off different metrics. 1% peak demand change is not the same MW figure as 1% change in electric generating capacity as resource types contribute different amounts to peak demand. Same apply to the pair of tables for other states.

resource type to peak demand and the shape of the underlying load all contribute to shaping the system response to increases in peak demand.

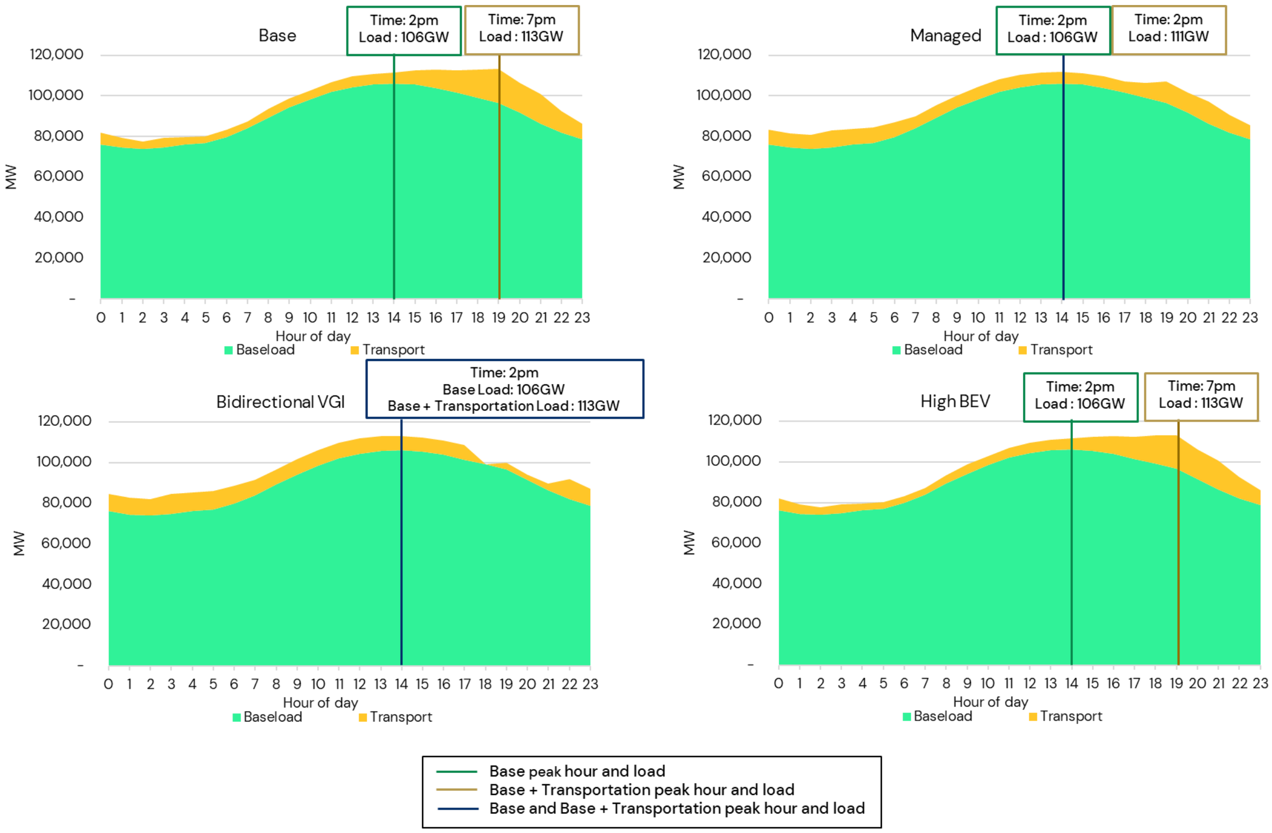

Figure 7. Peak day load profiles for Texas including transportation electrification in 2035.

Table 6. Texas incremental electric generating capacity (%) by scenario in 2035.

Base	Managed	Bidirectional VGI	High BEV
13%	12%	12%	13%

Florida

Florida is a Non-Clean Car State and as such, the peak load increase of the managed and high BEV scenarios is the same with 12% (Figure 8 and Table 7**Error! Reference source not found.**). The managed scenario has the lowest increase in peak impacts of 7%. The grid peak occurs outside of the 6 pm – 9 pm window, resulting in the bidirectional VGI scenario reducing demand in non-peak hours, and increasing it during peak hours.

Table 7. Incremental Florida peak demand (%) by scenario in 2035.

Base	Managed	Bidirectional VGI	High BEV
12%	7%	8%	12%

Table 8. Florida incremental electric generating capacity (%) by scenario in 2035.

Base	Managed	Bidirectional VGI	High BEV
8%	3%	6%	8%

As shown in Table 8, Florida's generating capacity expands by 3-8% across the four modeled scenarios. Consistent with peak demand increases, the base and high BEV scenarios showcase the highest increase in generation capacity, with 8% incremental capacity in the form of additional battery storage and thermal generating capacity. The managed scenario capacity additions are primarily thermal capacity additions, as well as shifts in capacity transfers with neighboring regions, leading to a lower in-state capacity required to meet peak demand growth of 7%.

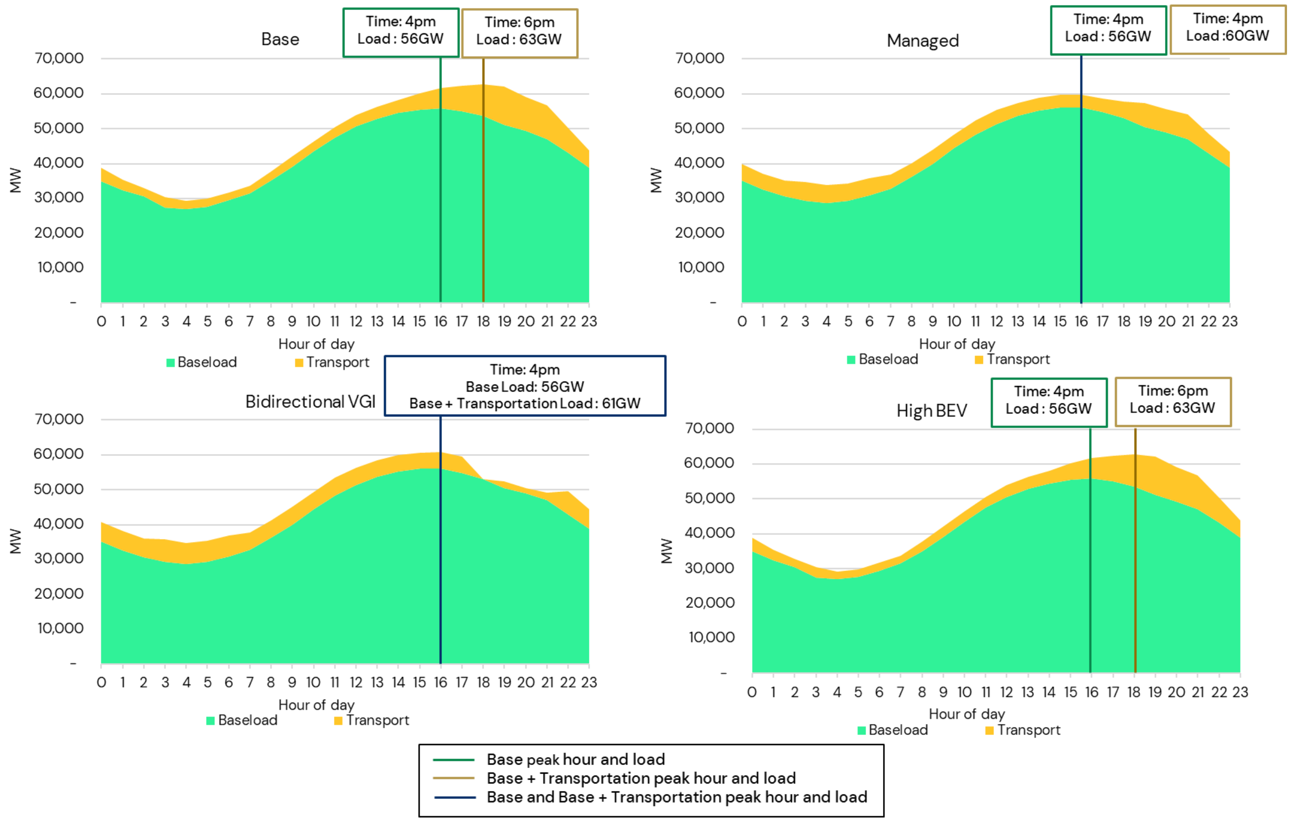

Figure 8. Peak day load profiles for Florida including transportation electrification in 2035.

Ohio

As a Non-Clean Car State, Ohio sees a 35% increase in peak load occurring in both the base and high BEV scenarios, as shown in Table 9 and Figure 9**Error! Reference source not found.Error! Reference source not found.**. The managed scenario, which spreads the additional EV load over the course of the day, results in a 21% increase in peak compared to the non-EV case. Like the base and high BEV scenarios, the peak hour still occurs at 7 pm. Of the four scenarios, the bidirectional VGI scenario has the lowest increase in peak demand compared to the non-EV scenario at 17%. This scenario reduces peak impact of EVs the most as the additional transportation load moves the peak hour to the 6 pm - 9 pm window in the managed scenario which the bidirectional VGI scenario is based on. As the bidirectional VGI scenario reduces load from 6 pm - 9 pm, it reduces this 7 pm system peak.

Across the various charging patterns of the scenarios, Ohio has a similar increase in capacity in each scenario, about 16-17%, as summarized in Table 10. In addition to in-state expansion of capacity, transfers from neighboring regions help meet peak demand. Across all the scenarios, the additional load from EVs leads to the deployment of technologies that primarily provide peaking capacity, like combined combustion, to meet changes in demand.

Table 9. Incremental Ohio peak demand (%) by scenario in 2035.

Base	Managed	Bidirectional VGI	High BEV
35%	21%	17%	35%

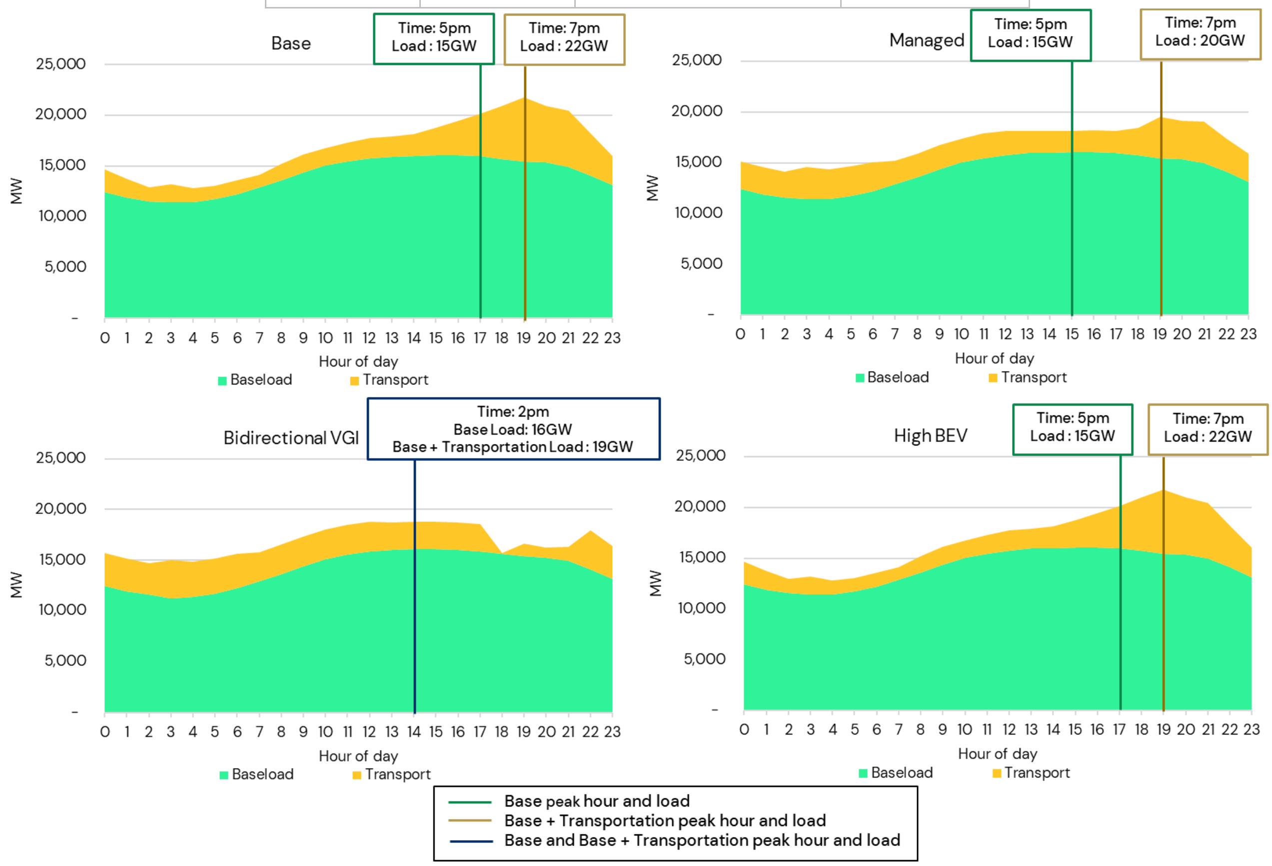

Figure 9. Peak day load profiles for Ohio including transportation electrification in 2035.

Table 10. Ohio incremental electric generating capacity (%) by scenario in 2035.

Base	Managed	Bidirectional VGI	High BEV
17%	16%	16%	17%

Discussion

Electric Grid Changes from Transportation Electrification

Electricity demand is expected to grow over the next 10 years and questions remain regarding how EVs may impact demand during peak hours and how much generating capacity is needed to meet this new demand. This study analyzes four different transportation electrification scenarios to provide insights into these questions at the U.S. and state level for California, Texas, Florida, and Ohio. Across all scenarios, transportation electrification leads to increases in peak load and in electric generating capacity.

In the base and high BEV scenarios, peak demand accounting for EV loads generally occurs during the 6 pm - 9 pm window. EV demand also results in the peak hour shifting for some regions. For example, without the additional EV load, California and Florida have a peak hour of 4 pm; however, with the additional EV load, the peak hour shifts to 7 pm and 6 pm respectively. Changes in the peak hour may be important considerations for areas with high renewable penetration or economy-wide decarbonization goals. A region that has a peak shift from 5 pm to 8 pm and also has high solar photovoltaics (PV) penetration may see greater ramping requirements for their system since solar PV starts coming offline before the new 8 pm peak, shortening supply while demand increases. The challenge of high renewable penetration leading to greater ramping needs has already been visible in California, where the net load shape (the load shape after accounting for non-dispatchable generation such as solar PV) has been coined as a "duck curve" due to the steep decline in net load due to the renewable penetration during the mid-day when solar output is high and the steep increase in net load due to the increase in evening demand and in particular solar facilities reducing output to the grid as the sun sets. Planning for a potential change in peak hour and the types of generating sources available during that time is an important factor in maintaining reliability and meeting increases in demand due to EVs or other forms of electrification. In addition to absolute peak loads, ramping requirements are evolving into more prominent planning requirements, and system operators such as the California ISO have specific processes to address ramping needs. CAISO's Flexible Capacity Needs Assessment identifies the flexible capacity needs to ensure enough flexible capacity is available to meet ramping requirements. In 2020, CAISO projected a flexible capacity need of 17,476 MW[19], which has grown to a forecast of 26,405 MW in 2026 (as per the 2024 capacity needs assessment)[20], an increase of 50% over just 6 years, highlighting the growth in ramping requirements.

Additional forms of electrification in the building and industrial sectors could further shift the peak hours. The base and high BEV scenarios are examples of how this additional load, if unmanaged, may impact the electric grid and influence peak periods of the day. Coincidence of these new peak demand hours with either supply side considerations (shape of solar supply) or other demand-side considerations (building or industrial electrification) have not been examined in this report but will be an important aspect when developing the solutions for how the demand on the grid can be met with various supply-side resources.

Managing Peak Load from Transportation Electrification

The managed and bidirectional VGI scenarios reduce the peak transportation load seen in the evening hours of the base and high BEV scenarios by spreading the evening peak load over the course of the day. In this study, these strategies have the potential to help lower the peak hour up to 16% in the states analyzed, which can support electric system cost reductions of up to 8%.

[19] Flexible Capacity Needs Assessment for 2020, available at https://www.caiso.com/Documents/Final2020FlexibleCapacityNeedsAssessment.pdf

[20] Flexible Capacity Needs Assessment for 2024, available at https://www.caiso.com/InitiativeDocuments/Final-2024-Flexible-Capacity-Needs-Assessment-v2.pdf

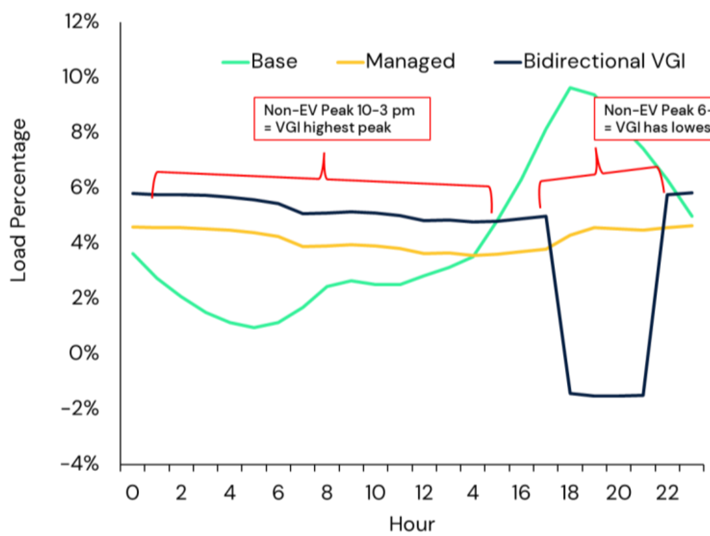

Figure 10. Hourly load profiles of LD EV charging.

Figure 10**Error! Reference source not found.** shows the EV load shape between scenarios. The increase in load relative to the base is largest in the bidirectional VGI scenario between 10 pm – 3 pm (next day) and lowest between 6 pm – 9 pm when EVs are discharging to the grid. The design of the bidirectional VGI leads to higher peaks in regions where the peak occurs in the 10 pm – 3 pm window because:

a) The base and high BEV load shape is lowest prior to 2 pm and lower than the bidirectional VGI shape before 3 pm and after 10 pm.

b) The managed shape is generally lower than the bidirectional VGI, except for 6 pm - 9 pm. Since that window is not relevant for the regions in this example, the managed shape leads to lower peak increases.

For regions that have a peak load in the 6 pm - 9 pm period, the bidirectional VGI scenario will therefore result in the lowest peak. However, if the peak occurs outside of the 6 pm - 9 pm period, the benefits of bidirectional VGI are not fully realized. Bidirectional VGI can have the highest peak of the four scenarios if a region's non-EV peak occurs in the 10 pm - 3 pm period. An example of this can be seen in Figure 11**Error! Reference source not found.**, where the WECC region has a 10% increase in peak demand in the bidirectional VGI scenario compared to an 8% increase in the other scenarios.

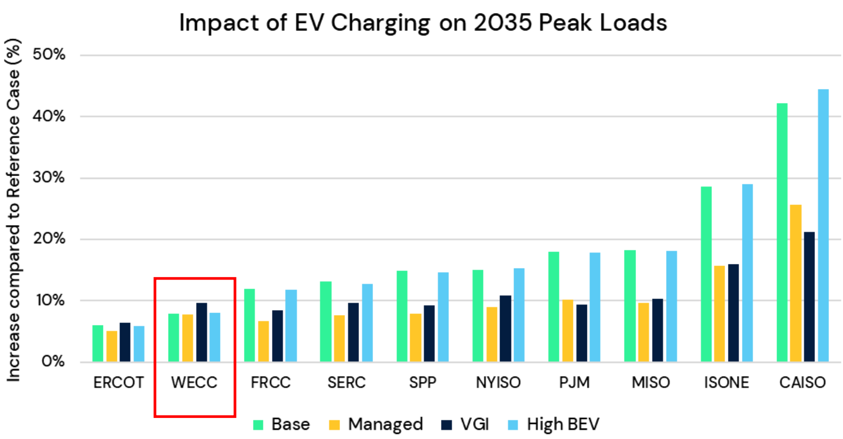

Figure 11. Highest 2035 peaks are evident in WECC in the bidirectional VGI scenario.

An additional example of this effect can be seen in how spreading the load over the course of the day may change when the peak hour occurs and therefore affect the effectiveness of bidirectional VGI. Prior to transportation electrification Ohio and Florida have peak hours of 5 pm and 4 pm respectively. As shown in Figure 12**Error! Reference source not found.**, the additional transportation load in the managed scenario peaks at 7 pm in Ohio. This peak is then reduced the most in the bidirectional VGI scenario, which shows the lowest peak increase of the four scenarios of 17%. In Florida, however, the managed load scenario maintains the 4 pm peak. Since the managed peak occurs prior to when the bidirectional VGI scenario is effective, the managed scenario ultimately has a slightly lower peak (about 1% less) than the bidirectional VGI scenario shifts 4 pm peaks higher to compensate for the reduction in EV loads prior to the VGI window from 6 pm – 9 pm.

These examples highlight that the benefits of bidirectional VGI are dependent on when the peak hour occurs, both prior to and after transportation electrification. Additionally, the ability to structure bidirectional VGI charging hours to align with grid peak demands may be limited as vehicle owners will either be at work or using their cars to get home prior to that time period. The regional differences in load shapes and how changes in demand may impact the peak hour emphasize that there is not necessarily a 'one-size fits all' approach to designing charging patterns and incentive structures that mitigate peak loads. Approaches to managed charging and bidirectional VGI are shown in this assessment to have the potential to reduce peak demand impacts from EV loads, and this ability will depend on the design of the respective programs, the ability to convert incentive structures to actual load shifts, and the hours in which the underlying grid is peaking. Programs that align electricity pricing with periods of demand can incentivize consumption patterns with the objective of reducing peak demand. Additionally, incentive mechanisms may also provide opportunities to incentivize electricity consumption during periods of high renewable output that may otherwise end up curtailed. Especially in high-renewable output regions, mechanisms to incentivize load shifting may not just target peak reductions, but also maximizing existing resource utilization or minimizing grid emissions. One-size-fits-all approaches may not account for these nuances and the success of such programs will depend on their abilities to adjust for local and regional grid conditions.

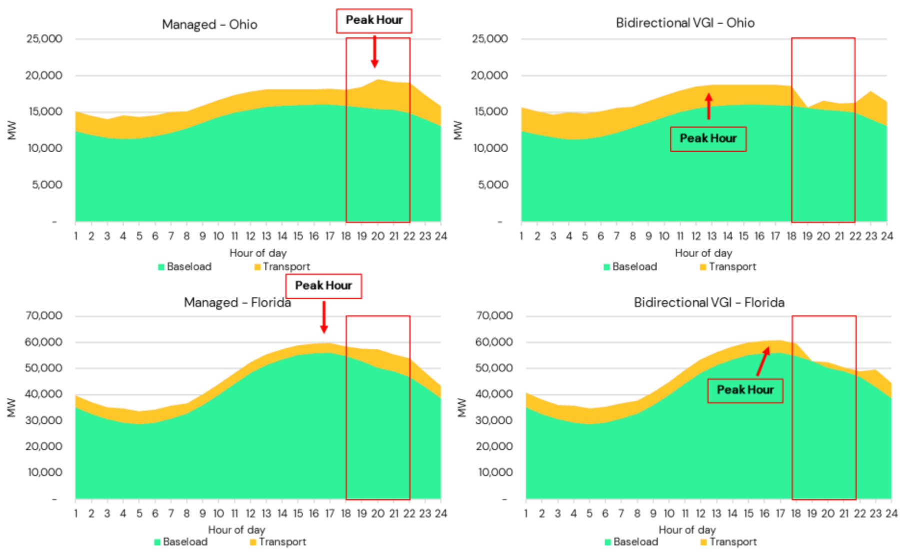

Figure 12. Load profiles for the managed and bidirectional VGI scenarios in 2035 in Ohio and Florida.

Additions in Generating Capacity

In the non-EV case, US generating capacity grows by 21% and peak demand increases by 7%. The additional demand from transportation electrification leads to further increases in total generating capacity. While changes in peak between the scenarios is one driver of capacity growth, this relationship is not linear, with other factors such as the types of technologies deployed, capacity transfers between regions, and the changing load shape also playing a role in these differences. For example, Texas's peak load increases between 5-7% compared to the non-EV scenario, whereas Florida's peak increases between 7-12%. However, Texas has a larger increase in total generating capacity, 12-13%, compared to Florida's 3-8%, when compared to the non-EV case. This can be in part driven by the finding that Texas builds more renewables, such as solar PV, wind, and battery storage to meet the additional demand stemming from transportation electrification, whereas Florida builds more thermal capacity. Due to the lower peak contribution of renewables, total capacity expansion in Texas is higher compared to other states that rely on resources with higher reserve contributions. In California, the bidirectional VGI scenario has a larger capacity increase of 16% compared to the non-EV case than the managed scenario with 14%, despite having a peak that is 3% lower than the managed scenario. This too is driven by a range of factors, including more renewable capacity coming online compared to the managed scenario, which instead relies on resources with a higher peak contribution, as well as differences in capacity transfers with neighboring regions. Solar may also be slightly more advantageous in the bidirectional VGI scenario because of the higher load during the sunny hours of the day.

Conclusions

Electrification of the transportation sector, the associated demand increase for energy and peak demand, and how this additional demand is managed, leads to a variety of nuanced impacts on the electric grid. Increases in peak demand and capacity to meet that additional energy consumption are expected. However, the potential for the peak hour to be managed proactively and the ability of EVs to be active contributors through bidirectional VGI is an important planning consideration that could influence regions differently. Benefits from changes in charging patterns, to encourage charging outside the evening period, can vary region to region. While the bidirectional VGI and managed scenario has the potential to reduce peak demand, this can be further facilitated by taking into consideration their regional demand patterns. Finally, capacity increases are not only a result of increased peak demand from transportation electrification, but also from the types of technologies that are deployed to meet the additional demand.

List of Acronyms

Acronym	Description
BEV	Battery Electric Vehicle
CAGR	Compound Annual Growth Rate
CAISO	California Independent System Operator
CEC	California Energy Commission
EIA	Energy Information Administration
ERCOT	Electricity Reliability Council of Texas
ES&D	Electricity Supply and Demand projections
EVI-Pro	Electric Vehicle Infrastructure Projection Tool
FRCC	Florida Reliability Coordinating Council
HD	Heavy-Duty
HEVI-LOAD	Medium- and Heavy-Duty Electric Vehicle Infrastructure Load, Operations, and Deployment Tool
IPM	Integrated Planning Model
IRA	Inflation Reduction Act
ISO	Independent System Operators
ISONE	Independent System Operator of New England
LBNL	Lawrence Berkeley National Laboratory
LD	Light-Duty
MD	Medium-Duty
MDHD	Medium- and Heavy-Duty
MISO	Mid-Continent Independent System Operator
NERC	North American Electric Reliability
NYISO	New York Independent System Operator
PG&E	Pacific Gas and Electric Company
PJM	Pennsylvania New Jersey Maryland Interconnection LLC
PV	Photovoltaics
SB	Senate Bill
SCE	Southern California Edison
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
U.S.	United States
VGI	Vehicle-Grid Integration
WECC	Western Electricity Coordinating Council
ZEV	Zero Emission Vehicle

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