EnergyHub

From obstacle to opportunity:

How managed charging can mitigate the distribution impacts of EV charging

Contents

Introduction

EV load is coming

Electric vehicle adoption is accelerating rapidly. Last year, the Edison Electric Institute forecast the number of electric vehicles (EVs) on the road in the US could reach 26.4 million by 2030 — nearly 10 percent of all light-duty vehicles.[1] The Biden administration's proposed new emissions limits would further accelerate transportation electrification, with EVs making up more than 60 percent of all new passenger vehicle sales by the end of this decade.[2] A recent ICCT study suggests that medium and heavy-duty electric vehicles will follow suit, with class 4-8 EVs comprising ten percent of the total stock by 2030.[3]

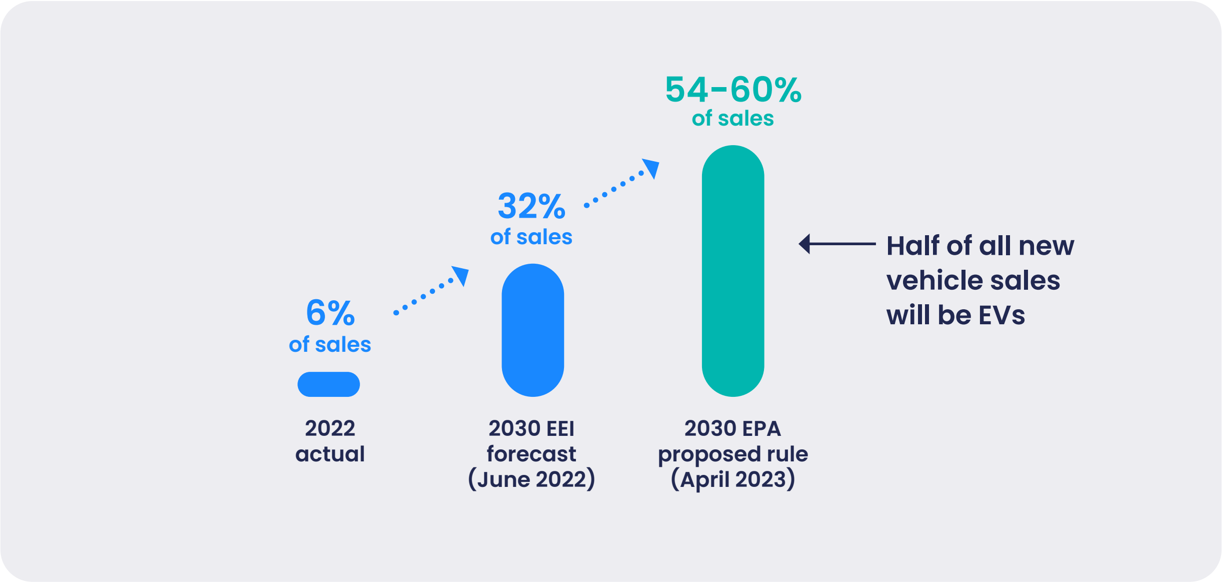


Figure 1: Percentage of vehicle sales rapidly shifting to EVs through 2023+

While charging these additional electric vehicles will require substantial amounts of electricity, the country's power system, or bulk grid, is relatively well-positioned to supply the energy needed to meet rising electricity demand.

Our aging distribution infrastructure, on the other hand, is less prepared to deliver electricity where and when it is needed. EV charging affects the distribution network in several ways that could significantly increase the need for costly new infrastructure.

Fortunately, most EVs only charge a few hours per day. That means it's possible to use managed charging to minimize the new infrastructure needed to support EV-driven electricity demand.

In this white paper, EnergyHub describes the distribution challenges that will emerge in the coming years, and how **managed residential charging can help solve these problems** and become an essential part of future grid operations.

Distribution vs. bulk grid impacts

Electric vehicles consume a lot of electricity when they are charging. A standard Level 2 home charger consumes around seven kilowatts (kW) at its peak, which is about five times higher than the average home load in the US.[4] Newer home charging stations can use as much as 19 kW. However, the typical EV only needs to charge a few hours a day, and charging behaviors vary widely.

These behaviors average out to produce a consistent, predictable load pattern when analyzing thousands of vehicles, but small groups of 10 vehicles do not see this same consistency. As a result, there is an enormous difference between the hourly average charging load per vehicle from a group of many EVs, and the same hourly average from a small group of cars. To illustrate this point, the figure below shows the average load per vehicle for a large group and a small group.

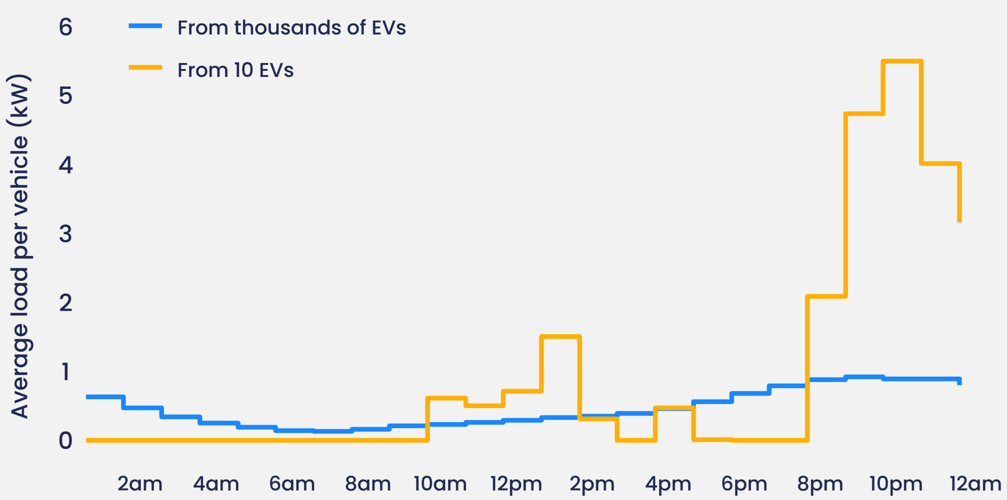


Figure 2: The average uncontrolled charging load per vehicle from thousands of vehicles (blue) and the load per vehicle from a group of 10 (orange). The average from the large group is 0.46 kW, with around 0.9kW during the evening hours and 0.1-0.2 kW in the early morning hours. The load from the small group has a much higher peak value, with load patterns that vary enormously from one day to the next. Data from EnergyHub programs.

The difference between the average load per vehicle from large groups and small groups has important implications for how EV charging will impact the bulk grid (centralized generation and large transmission lines) and distribution networks (the poles, wires, and transformers that connect homes and businesses to the bulk grid). When we are estimating the impact of EVs on the bulk grid, it is reasonable to focus on the average load from EVs, with some adjustments for the time of day. In the worst case, without any load shifting, the additional bulk grid capacity needed per vehicle will be less than the "thousands of EVs" values from **Figure 2**, i.e., less than 0.9 kW of capacity per vehicle. When we are estimating the impact of EVs on the distribution network, we need to plan for the highly variable nature of EV loads, where the impact can be much larger.

EV charging's effect on the bulk grid is manageable

In order to further understand the bulk grid impacts, let's consider a typical EV. An electric vehicle driven 13,476 miles a year with an efficiency of four miles per kilowatt-hour will consume 3,369 kilowatt-hours (kWh) each year. US electricity consumption in 2022 was 4.05 trillion kWh according to the U.S. Energy Information Administration. As a result, converting 50 percent of US light duty vehicles to EVs (about 150 million new EVs) would add 12 percent to national electricity consumption, or about 60 GW of average power demand.

But the more important question is how much EVs will add to peak loads, which in turn will determine how much bulk generation and transmission capacity is needed. From the data in **Figure 2** we see that during peak evening hours the load per vehicle is around 0.9 kW, which implies that we need 135 GW of additional bulk grid capacity to electrify 50% of cars. However, it is relatively easy to shift load to off-peak periods using time-of-use (TOU) rates or managed charging programs, so the additional peak impact is likely to be less than half of this amount, or about 60 GW.

Adding 60 GW of new load during peak hours would increase the need for bulk grid capacity by a mere eight percent, which is less than the 10 to 20 percent capacity reserve margins common in the US.[7] Given that this new load will be added gradually, we estimate that EVs will increase peak loads **on the bulk grid** by less than one percent per year. If utilities and customers broadly adopt incentive programs that shift EV load to off-peak periods, the peak-load (bulk grid) impact from EVs may be even smaller.

In short: **With fairly modest improvements to the bulk grid, the US generation and transmission system can support a very large number of EVs.** Increasing peak loads by a few percentage points is not the main concern.

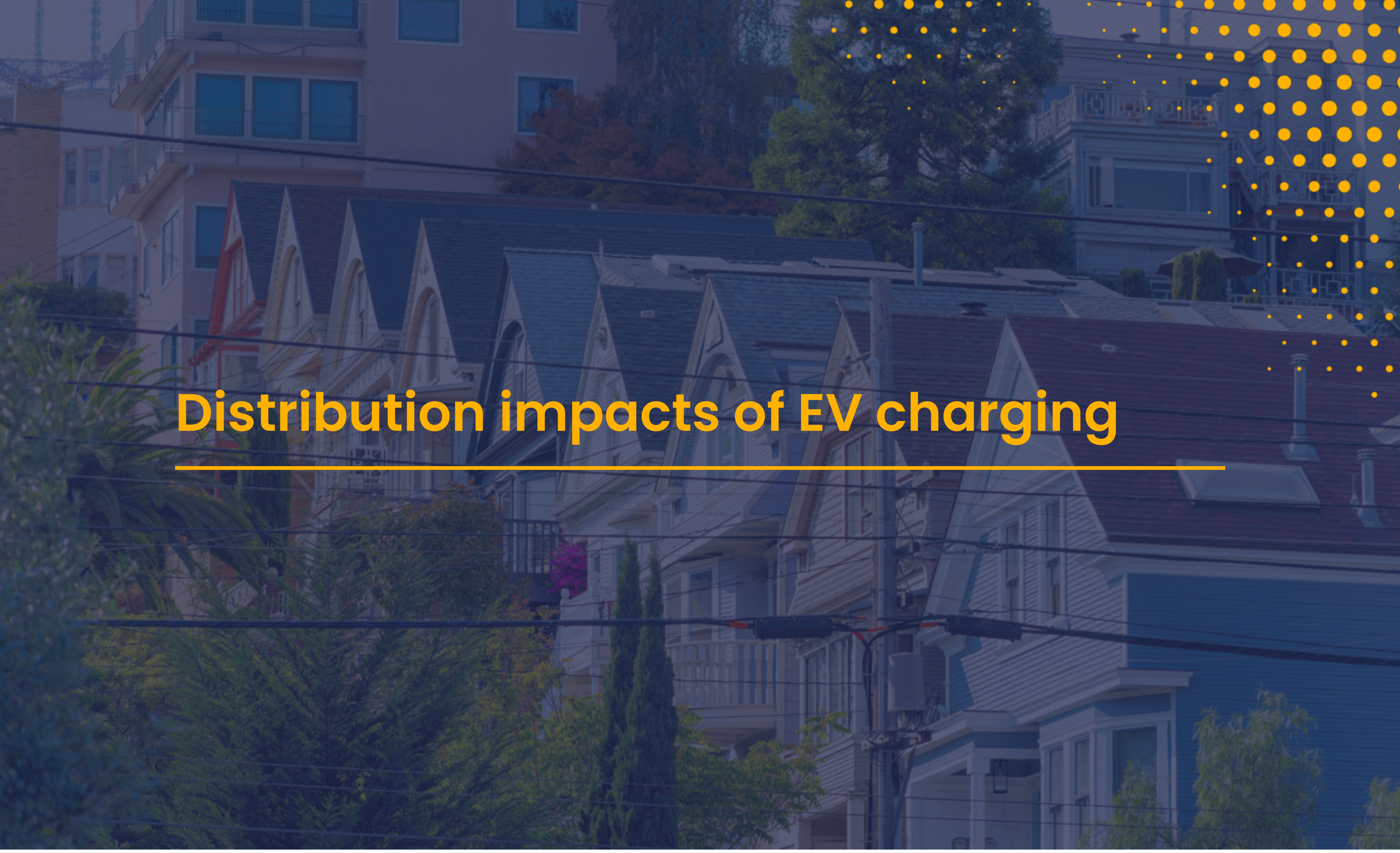
EVs present challenges for aging distribution infrastructure

While the bulk grid is relatively well-prepared for transportation electrification, **peak load from EVs will be a major stressor on distribution networks.** As previously mentioned, an AC Level 2 home charger will use between seven and 19 kW. Four EVs simultaneously charging at seven kW will easily overload a typical 25 kilovolt-amp (kVA) distribution service transformer. A DC fast-charging station can use between 50 and 350 kW.

When estimating the bulk grid impacts from EVs, we can ignore the maximum load from EV charging because the irregular load patterns from many EVs average out. From a bulk grid perspective, the most important thing to look at is the average power consumption of EVs in a particular hour of interest.

However, the aggregated load from a small number of EVs is highly dependent on the maximum load of each charger. This difference can be clearly seen in **Figure 2**, where the small group of cars produces a very spiky load pattern not seen in the larger group.

This has important implications for distribution network management. Distribution network elements, such as transformers, will be stressed by highly variable loads from small numbers of EVs at the local level. The next section of the paper outlines the portions of the distribution network that are most likely to be impacted.



Distribution impacts of EV charging

EV charging will have **differing impacts** on distribution network elements.

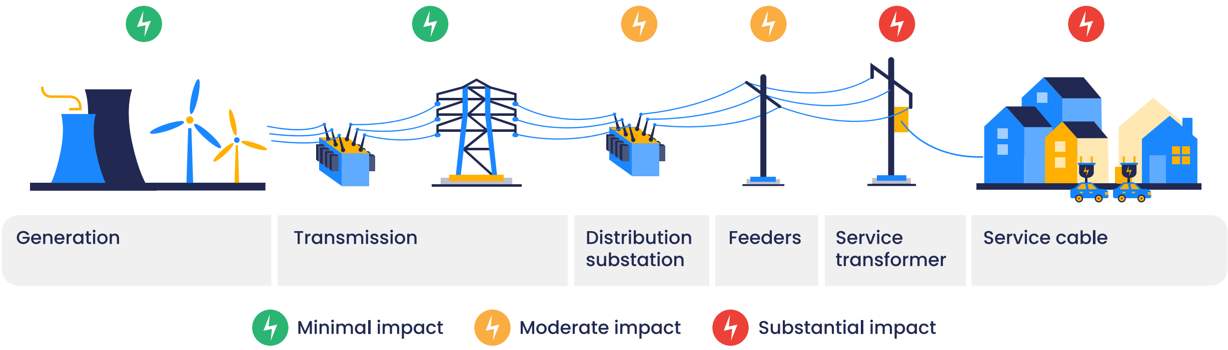


Figure 3: EVs will impact individual parts of the power grid differently. Generation and transmission systems will require incremental changes. Distribution substations and feeders may require significant upgrades in certain locations. Service transformers, cables, and panels will almost certainly require changes. **Managed charging technology will be essential to keeping upgrade costs reasonable.**

Time-of-use rates and distribution networks

Before we outline how EV charging will impact elements of the distribution network, let us first consider how TOU rates and similar programs that optimize for bulk system benefits impact distribution networks.

Programs of this sort are very effective at shifting load away from peak periods. So effective, in fact, that utilities must manage the downstream impacts of these rates. TOU rates essentially eliminate the variability from a naturally diverse load pattern and can inadvertently create another larger, more costly problem.

As seen in **Figure 4**, TOU rates that encourage EVs to charge during off-peak times create a timer peak that can increase the risk of thermal damage to distribution elements like transformers.

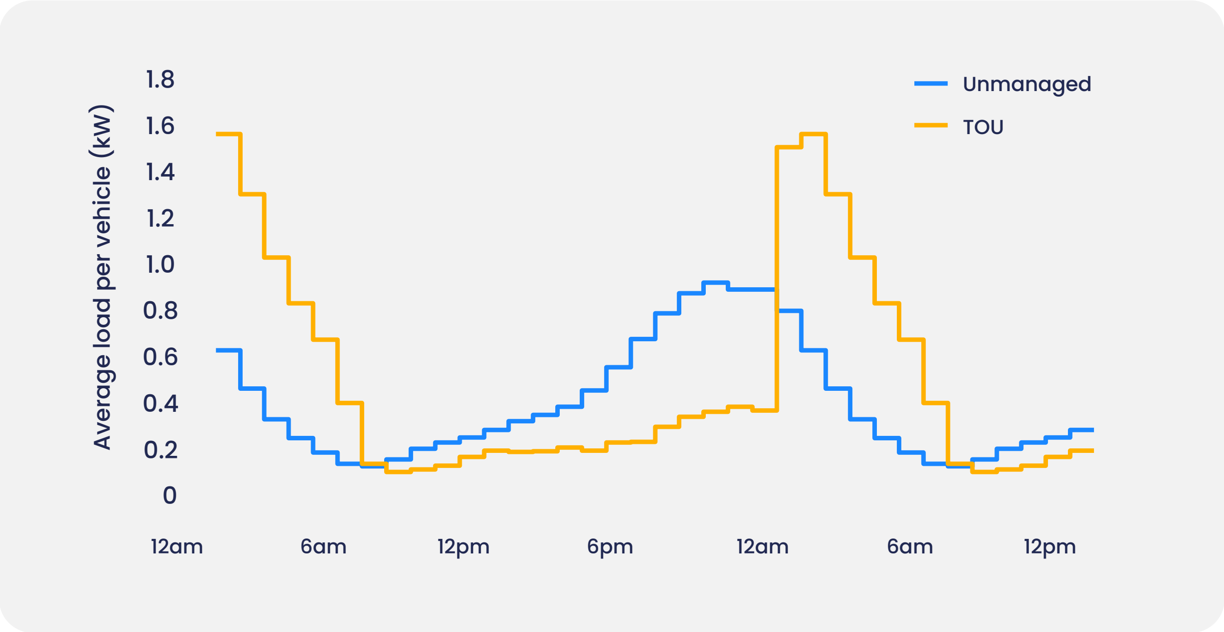


Figure 4: Comparison of the hourly average load per vehicle for an unmanaged (blue) and a managed (orange) fleet of vehicles. Time-of-use rates effectively shift EV loads away from peak hours, but also create a new "timer peak" at the end of the peak period. Data from EnergyHub programs.

As EV adoption grows, **managed charging** programs that can shift load dynamically based on real-world conditions **do a far better job of managing the risk of service transformer failure than TOU rates.**

Early and unplanned failure of service transformers

Simultaneous charging from several EVs behind a distribution service transformer can lead to thermal overloads. 25 kVA transformers can overload when three or four EVs charge simultaneously. Many utilities still have some 10 kVA transformers in their network that will overload when just two EVs charge concurrently.

TOU rates can have a particularly acute impact on service transformers. The greatest danger comes when the transformer is still hot from daytime load and then multiple EVs begin to charge simultaneously. One study[8] found that a TOU-style program that resulted in vehicles charging after midnight would cause service transformers to fail faster than uncontrolled EV charging.

Given that there are more than 40 million service transformers in the US, and that replacing each transformer costs thousands of dollars, this is a significant concern. With supply-chain challenges for transformers mounting, this problem becomes even more pressing.

Damage to substation transformers

While replacing a service transformer can be done in a day and costs between $5,000 and $20,000, replacing a distribution substation transformer costs millions of dollars and typically requires a multi-year purchasing and replacement process. In much of the aging U.S. grid, substations are already approaching their load limits, making it particularly important that EV loads do not overtax the grid in these locations. As with service transformers, managed charging can intelligently shift loads when substations approach their limits.

Voltage and power quality issues

Simultaneous, unmanaged charging can result in localized under-voltage events, causing devices like electronics and motors to operate improperly. When voltages dip too low, motors may stall, potentially damaging expensive systems like air conditioners. When voltages are too high, sensitive electronics may be damaged. The risk of over-voltage events can increase as a result of TOU rates, as those rates encourage a large number of EVs to begin charging simultaneously, creating a new peak (see **Figure 4**).

Increased costs due to energy losses

Transmission and distribution losses are generally small, averaging around five percent.[9] However, increased load from electric vehicles can exacerbate loss rates, because power losses in wires increase with the square of the current. For example, if you double the electric load in a distribution feeder, losses will increase by a factor of four. Losses are particularly high for older distribution networks that have lower feeder voltages, such as four-kilovolt (kV) systems.

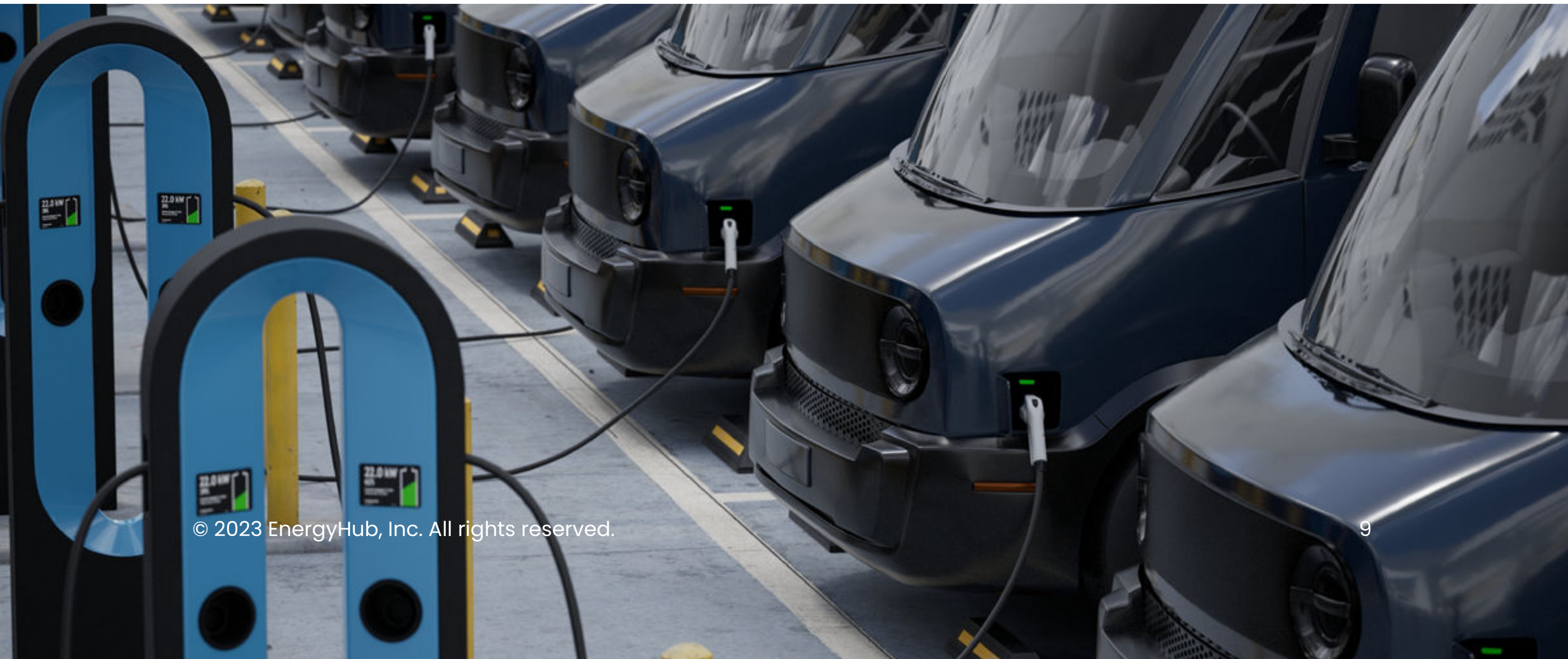
A study published by the Institute of Electrical and Electronics Engineers (IEEE)[10] suggests that distribution losses are the largest additional cost associated with increasing EV charging load.

Fleet charging and required network upgrades

The majority of distribution feeders have capacity to add a new grocery store with only modest upgrades. But there are few, if any, parts of the nation's distribution infrastructure that can support a shipping company that wants to build charging capacity for 50 commercial trucks without at least some upgrades.

Connecting large new commercial fleets to the grid will require significant upgrades to power distribution systems.[11] Upgrades of this sort often require millions of dollars and years of planning; executing them rapidly is challenging. Ultimately this new load is helpful for the electric power industry, since utilities can expect to recover their investment over time, but it will require proactive planning.

As EV fleets become more common, utilities will need to develop strategies to manage the cost of network upgrades. Here again, managed charging programs can help — potentially in combination with energy storage installations — by spreading out EV charging loads over time. With the right combination of managed charging and energy storage, the additional distribution capacity needed to support a new EV fleet can be reduced by more than half.



Other impacts

While voltage issues, energy losses, early transformer replacements, and network upgrades necessitated by commercial fleets are the most important distribution system effects resulting from unmanaged EV-induced load, there are other challenges to watch for.

In some locations, underground distribution feeders are already operating near their thermal load limits. Underground cables are expensive to replace, adding another compelling reason for utilities to plan ahead for the management of EV charging. Overhead feeders may also reach their limits, but these are less costly to replace. Whether above or below ground, managed charging programs are an effective means of managing feeder impacts.

One significant impact that charge management will not be able to address is overloading of older service drop cables and electrical panels that are not large enough to support an EV. These will need to be replaced as EVs arrive on the grid.[12]

Bring it back to revenue

The good news about EVs for the electric power industry is that, as with all electrification, new load results in new revenue. The question is how to invest to ensure that the grid can support affordable and reliable electrification.

In some cases, infrastructure upgrades are the only way to service increased load safely. Here, utilities can amortize costs over time and use the new revenue from EV charging to cover upgrade costs, rather than charging customers for upgrades up front.

In other cases, utilities can defer or avoid the need for additional infrastructure by actively managing EV charging load. In the next section we outline how managed charging can address distribution network challenges.

The essential role of managed charging

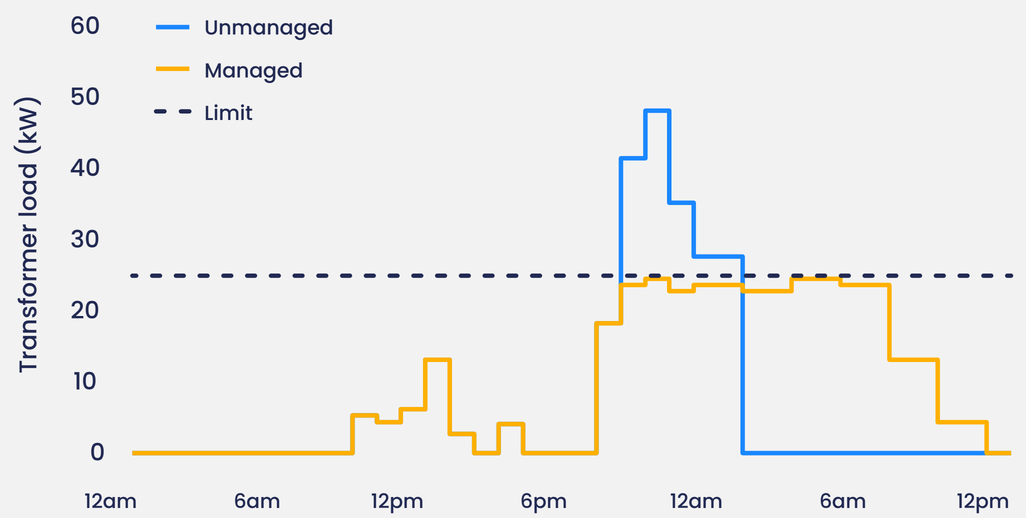


Figure 5: Data for a group of 10 vehicles operating without any charge management (blue) and data showing the impact of a managed charging algorithm (orange) designed to ensure that vehicles get the charge they need, while also keeping the aggregate load under 25 kW.

Addressing EV impacts on aging infrastructure will require data to guide strategic investments in grid elements, ensuring the scale and timing of upgrades are right-sized for anticipated load growth. However, relying solely on replacing grid components with bigger ones is prohibitively costly. The electric power industry must also be forward-thinking about how loads are managed on the distribution network.

Today, simple system-wide EV demand response (DR) programs are a step in the right direction, but can have the same effect as EV TOU rates (see previous section, **Early and unplanned failure of service transformers**): if every vehicle charges at the same time following a DR dispatch, the immediate increase in load on service transformers in locations with multiple EVs could lead to rapid failures, producing outages for customers and emergency replacement costs for utilities. TOU and DR programs provide valuable insights into the flexibility of EV loads, but are unlikely to address most grid issues, including distribution constraints.

Fortunately, supplementing grid infrastructure upgrades with **intelligent managed charging solutions** helps utilities achieve reliability goals at a reduced total cost, while ensuring customers get the charge they need.

Managed charging to the rescue

A recent study[13] for the California Energy Commission concludes that "rates alone are no longer the silver bullet for where and when generation capacity needs diverge from the where and when of distribution capacity needs." Instead, what is needed is a "form of congestion management for responsive demand where the distribution networks are somehow taken into account." Intelligent managed charging solutions enable utilities to take advantage of these advanced grid services.

Instead of focusing solely on peak reduction, utilities should explore value-stacking opportunities for managed charging programs that add load shifting and distribution capacity benefits to peak load reduction values. Managed charging can reduce energy procurement costs via load shifting and help utilities defer or avoid grid upgrades, which recent studies suggest could be worth several thousand dollars per EV compared to an unmanaged scenario. This approach provides a more holistic accounting of the value EV-based virtual power plants can deliver.

From the customer perspective, managed charging is simple. Rather than time-varying rates that require the customer to remember a schedule and stop and start charging sessions to comply, they receive an easy-to-understand incentive for participating in their utility's managed charging program and the vehicle's charging schedule is automated.

At the time of enrollment, customers choose a time by which their vehicle must be charged each day, and no further customer action is required. A typical electric vehicle needs to charge two to three hours a day, but is plugged in for up to 12 hours. It doesn't matter when that charging occurs, so long as the driver has the charge they need when it's time to leave their home. Enrolling in managed charging ensures that a customer's car will be fully charged when they need it, while supporting grid needs over the course of those 12 hours.

From the utility perspective, managed charging creates opportunities to meet EV owners' needs with low-cost electricity that doesn't overload grid infrastructure.

Consider the following plausible future scenarios:

Scenario 1: Substation transformer optimization

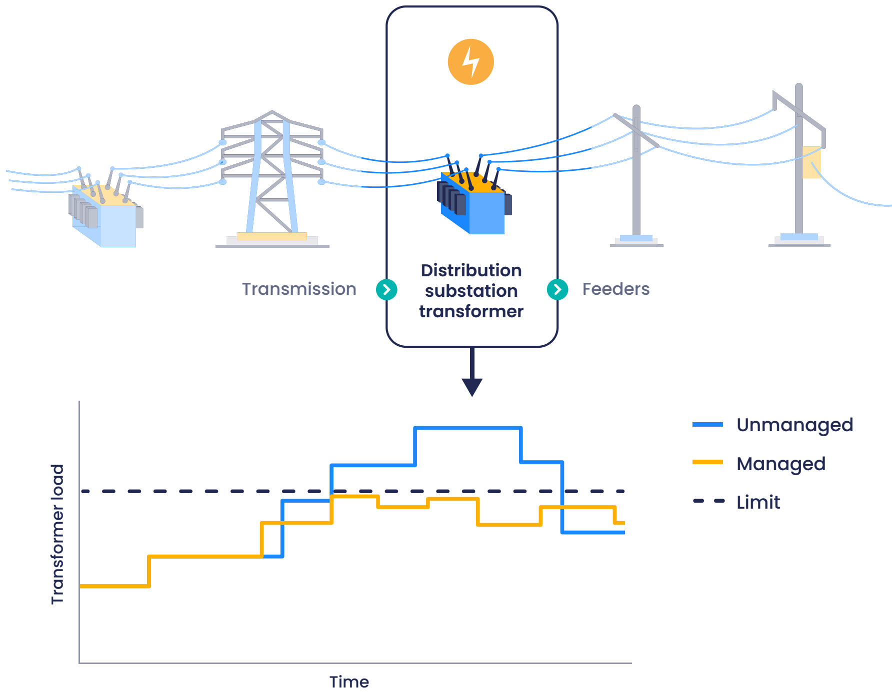


Figure 6: Illustration of the impact of managed charging on a distribution substation. Before managed charging (blue), the transformer was overloaded. After charge management (orange), loads operate under their limit.

A utility has a managed charging program for 10,000 EV customers. One afternoon, the utility expects to see high load in the early evening, which will lead to significant loads on substation transformers and high market prices. Later in the evening, a weather front increases the supply of wind power, driving down market prices for electricity. The utility's distributed energy resource management system (DERMS) forecasts the baseline EV load and ingests price forecasts from market software. With this information, the DERMS creates an EV charging schedule that pushes most of the EV charging to around 1:00 am as the weather front moves in.

A small number of EVs start charging earlier than 1:00 am, because they have nearly empty batteries and need to begin charging sooner in order to meet customer-set charging perameters. However, the DERMS also receives information from utility software systems that a substation transformer in one portion of the grid will approach its apparent power limit at 1:00 am if all EVs charge simultaneously. Therefore, the DERMS updates the schedule so that the EVs served by that transformer adjust their charging and avoid overloading the transformer. Every vehicle gets the charge needed, and the utility is able to minimize loading on the transformer, reducing losses and defer ing the need for replacement. Repeating this process day in and day out will produce significant customer savings.

Managed charging spreads charging load during periods of high demand, providing the utility with valuable non-wires alternatives to extensive infrastructure upgrades.

Scenario 2: Service transformer optimization

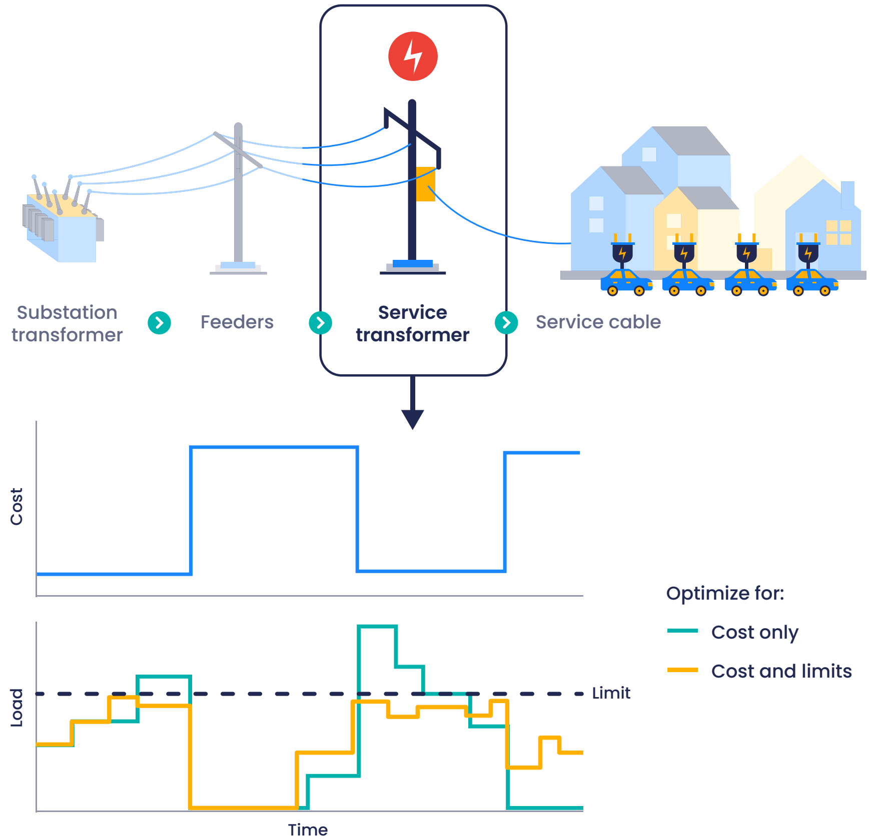


Figure 7: Comparison of managed charging for cost-optimization only (green) and for joint optimization of cost and service transformer limits (yellow). Purely optimizing for the customer rate or wholesale costs alone will likely lead to transformer overloads. Joint optimization keeps costs low, while preserving grid assets.

In one neighborhood, four homes served by a single 25 kVA service transformer have recently purchased electric vehicles and Level 2 EV chargers. While four cars charging at the same time is rare in practice, theoretically the event would cause the transformer to exceed its load limit. The transformer can easily serve two vehicles at a time.

Knowing this, the DERMS schedules the four vehicles to break their charging sessions into multiple time periods, ensuring that no more than two vehicles are charging at once, and that all four vehicles get the charge that they need by the drivers' preferred start time.

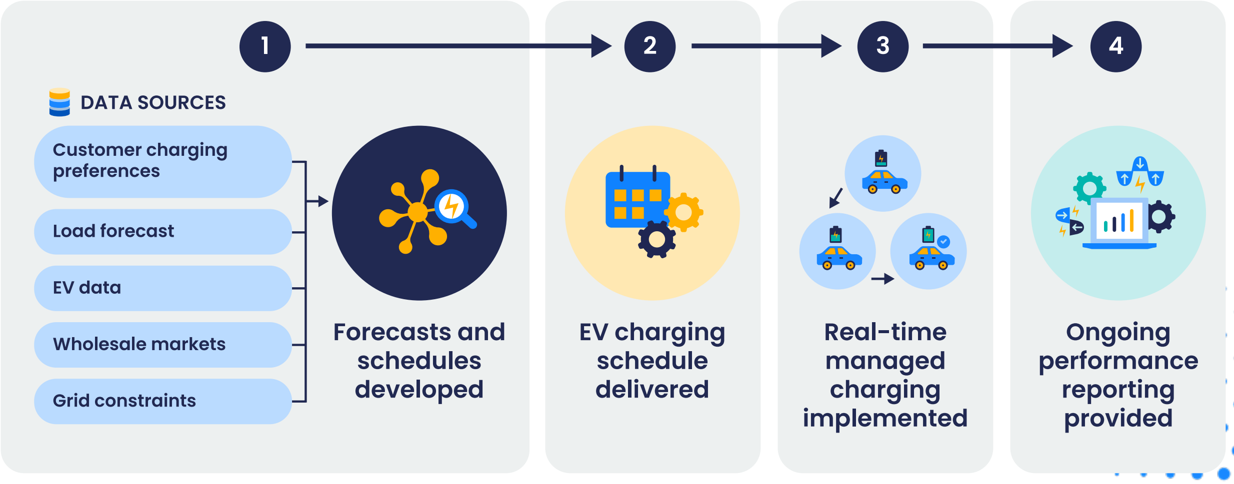
Managed charging ensures that EVs spread their load throughout the typical evening-through-night charging period to minimize costs while meeting customer requirements.

The cost objective for the program can be calibrated to minimize wholesale energy costs by optimizing according to locational marginal prices for a particular location, or to minimize customer costs if customers have time-varying rates. EnergyHub managed charging programs will be able to co-optimize for both customer and utility cost objectives. In either case, the algorithm keeps loads under the specified load limit, giving the utility time to upgrade services transformers in a systematic, strategic manner, rather than all at once.

In the ideal state for both scenarios, the managed charging program provides the following services:

1. **Each hour, the utility's DERMS produces or ingests four types of information:**
    - It ingests customer charging preferences, which drivers enter using a mobile app where they set a desired charging schedule and percent charge.
    - It forecasts the baseline load from EVs and other DERs and the potential flexibility of that baseline load, based on historical data.
    - It uses data from the wholesale market and other utility software systems to forecast the cost per hour, and eventually per minute, of serving the EV load.
    - It ingests forecasts of network constraints from energy management systems (EMS), advanced distribution management systems (ADMS), or other software systems.
2. **With these forecasts, the DERMS produces an EV charging schedule.** This optimal schedule ensures that EVs get the charge they need by their scheduled departure time, at the lowest possible cost to the utility, without violating grid constraints.
3. **The DERMS coordinates the EVs to meet this schedule,** updating the schedule in real-time as new data is ingested. This step requires the use of advanced coordination algorithms, such as those provided by EnergyHub EV, which randomly stagger when an EV will begin charging.
4. **Finally, the DERMS reports on the performance of the system** so that utilities can understand the impact of managed charging from both operating cost and network management perspectives.

The result is a more strategic, fiscally responsible approach to grid infrastructure improvements that defrays costs for utilities and customers and improves customer satisfaction.



Start your managed charging program now

The power of managed charging is here today. Everything described in this white paper can be achieved using existing one-way smart charging (V1G) technology.

Utilities and consumers can benefit from V1G managed charging programs now, while gaining valuable data about how they will operate bi-directionally in the years to come, as we prepare for a fully electric future.

Learn more about EnergyHub EV and schedule a demo.

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Or learn more at energyhub.com

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Helping over 60 utilities unlock value from DERs at the grid edge.

Endnotes

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[7] This analysis aligns with that of *Prospects for electric vehicle deployment – Global EV Outlook 2021 – Analysis* - IEA. (n.d.). IEA. https://www.iea.org/reports/global-ev-outlook-2021/prospects-for-electric-vehicle-deployment. Note that there are some regions of the US that approach their bulk capacity limits (particularly during plant outages or low wind conditions). The 10-20% represents the average amount of long-term bulk grid capacity reserves, not the amount for any particular region.

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