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# Heavy-duty truck electrification and the impacts of depot charging on electricity distribution systems

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**Major technological advancements and recent policy support are improving the outlook for heavy-duty truck electrification in the United States. In particular, short-haul operations (≤200 miles (≤322 km)) are prevalent and early candidates for plug-in electric vehicles (EVs) given their short, predictable routes and return-to-base applications, which allows vehicles to recharge when off shift at their depots. Although previous studies investigated the impacts of added electrical loads on distribution systems, which included light-duty EVs, the implications for heavy-duty EV charging are underexplored. Here we summarize the causes, costs and lead times of distribution system upgrades anticipated for depot charging. We also developed synthetic depot charging load profiles for heavy-duty trucks from real-world operating schedules, and found that charging requirements are met at common light-duty EV charging rates (≤100 kW per vehicle). Finally, we applied depot charging load profiles to 36 distribution real-world substations, which showed that most can accommodate high levels of heavy-duty EV charging without upgrades.**

Plug-in electric vehicles (EVs) reduce petroleum dependency, improve the driving experience with fast accelerations and less noise, eliminate tailpipe pollutants and provide a pathway to greatly reduce greenhouse gas emissions, especially when recharged with low-carbon electricity. Driven by rapid technological progress and supportive policy and regulations, EVs are becoming increasingly affordable and popular worldwide, particularly in the small two- and three-wheeler, light-duty passenger and bus segments[1,2].

Electrifying medium- and heavy-duty vehicles, which accounted for over 20% of national transportation energy use in 2019[3], is a critical step to decarbonize the transport sector in the United States[4]. Heavy-duty trucks (that is, Class 7–8 semi-trucks with gross vehicle weight >26,000 lbs (>11.8 tonnes)) are responsible for ~15% of total U.S. transportation energy use and GHG emissions[3]. Commercial heavy-duty trucking operations are highly sensitive to operating costs[5], which makes battery EVs an attractive option given their reduced maintenance (which minimizes costs and downtime) and lower fuel costs from higher power-train efficiencies and cheap electricity[6–8]. Fuel costs alone make up half the total cost of ownership for Class 8 diesel trucks[9].

The opportunity for battery EVs in commercial medium- and heavy-duty operations, however, is highly debated. Historically, EVs were not considered viable alternatives to diesel trucks, even in ambitious emissions reduction scenarios, due to their high capital costs, limited range and low battery-energy densities[10–15]. Although stationary EV charging methods are sufficient for small urban commercial vehicles, overhead catenary, in-road charging or hydrogen fuel cell technologies are often thought to be required for heavy-duty vehicles[16]. Some studies estimate that the batteries required for long-haul operations will be so heavy as to limit the payload capacity compared with that of diesel trucks, which increases operational costs[10,17,18]. Weigh-in-motion data reveal, however, that ~90% of on-road heavy-duty trucks in operation in the United States weigh <73,000 lb (<33.1 t), which indicates that most operations are volume, route or time constrained, not weight constrained[19]. In addition, there is currently a nationwide 2,000 lb (~0.9 t) exemption for electric trucks (towards 80,000 lb (~36.3 t), the maximum roadway gross vehicle weight for conventional trucks in the United States, although several state exceptions exist)[20].

Vehicle range is often cited as the greatest barrier for battery electric trucks, but daily range requirements vary, and many trucks in the United States are not driven over long distances. Figure 1 shows the 2019 total US stock and annual energy consumption for medium-duty (Classes 3–6) and heavy-duty (Classes 7 and 8) freight trucks from the US Energy Information Administration's *Annual Energy Outlook*[3]. Values are disaggregated by operating range based on the 2002 *Vehicle Inventory and Use Survey* (VIUS)[21], the most recent year conducted. VIUS data show that just ~10% of heavy-duty trucks require an operating range of 500 miles (805 km) or more, whereas ~70% operate within 100 miles (~161 km). Although the total energy consumption for heavy-duty trucks is skewed towards long-range operations, ~40% is attributed to trucks that operate within 100 miles (~161 km). Moreover, recent industry trends (for example, the rise of e-commerce and low driver retention) produced a shift away from interregional and national hauls in favour of decentralized hub-and-spoke distribution models, which culminated in a 37% decrease in the average length of haul from 2000 to 2018[22] (not factored into Fig. 1). Figure 1 shows that, although medium-duty trucks outnumber heavy-duty trucks by more than 3:2, the annual energy consumption (and greenhouse gas emissions) is much greater for heavy-duty trucks due to the higher annual vehicle miles travelled (VMT) and lower fuel efficiencies.

EV trucks gained further momentum in June 2020 with the announcement of the California Air Resources Board's Advanced

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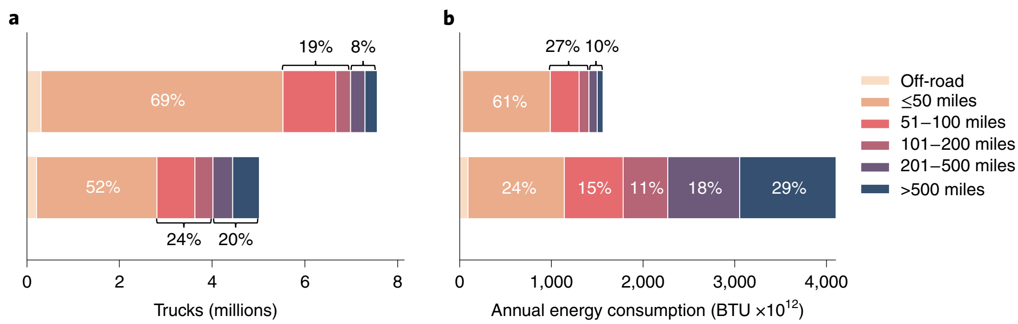


**Fig. 1 | US truck stock and energy consumption disaggregated by primary operating range. a**, Classes 3–6 (top) and Classes 7 and 8 freight truck stock disaggregated by the VIUS primary operating range. **b**, Classes 3–6 (top) and Classes 7 and 8 annual energy consumption disaggregated by the VIUS primary operating range. Data are from the US Energy Information Administration's 2019 *Annual Energy Outlook*[3] and the 2002 VIUS[21]. VIUS defines 'primary range of operation' as the typical trip mileage for trucks that operate from a home base (that is, depot) or the average range of operation for those that do not. A low operating range, although an imperfect proxy for electrification potential because it does not account for atypical long trips or operations with many short trips per day, can be suggestive of trucks that are more easily electrified without an extensive high-power charging network.

Clean Trucks regulation—a zero-emission commercial truck mandate to start in 2024 that requires 100% zero-emission truck sales within the state by 2045[23]. Soon after, 15 states (which included California) and the District of Columbia signed a memorandum of understanding that committed that 30% of new medium- and heavy-duty vehicle sales will be zero-emission vehicles by 2030 and 100% by 2050[24]. Original equipment manufacturers are responding to the emerging opportunity and, although only four zero-emission Class 7–8 and truck models (all battery EVs) are currently available in North America[25], 16 more (11 battery EVs and 5 hydrogen fuel cell EVs) are expected by 2023, and include models from new market entrants (such as Tesla and Nikola[26,27]) and traditional original equipment manufacturers (which include Freightliner, Kenworth, Volvo and Mercedes-Benz[28–31]). This momentum, combined with rapidly declining battery costs, has led multiple recent studies to anticipate a much greater opportunity for EVs in commercial operations, including long haul—a particularly challenging segment to electrify for its long routes and heavy payloads[32–37]. Experts now project US electric truck sales to grow exponentially in the coming years[1,9,38,39]. Wood Mackenzie, for example, reports that the total US stock will exceed 54,000 units (from ~2,000 units in 2019) by 2025[40].

The short-haul trucking segment, characterized by routes <200 miles (<322 km) (ref. [41]), is an early candidate for electrification due to its limited range requirements, fixed routes, consistent shift schedules and tendency to operate out of one (or several) depot locations[32,42]. The total cost of ownership for short-haul battery electric trucks can be competitive with that of diesel trucks today, provided financial incentives, and costs are predicted to be lower by 2030 without such incentives[43]. Short-haul operations (≤200 miles (≤322 km)) represent ~50% of heavy-duty and ~60% of total truck energy use and greenhouse gas emissions in the United States (Fig. 1). Short-haul trucks often have long and predictable off-shift dwell periods (usually overnight) at a central location, such as a depot, warehouse or vehicle yard, where they can recharge. As a result, these vehicles are not expected to rely on an extensive network of high-power public charging infrastructure, as is required for long-haul operations. Ideally, fleets could perform all charging at their depots, where it is convenient, inexpensive and easily controlled. However, depot charging can substantially increase the electricity demand at these locations and may require costly and time-consuming upgrades to distribution systems.

Given the current status of the technology and the increasing policy support, relevant stakeholders—which include fleet managers, utilities, original equipment manufacturers and policymakers—are exploring opportunities for heavy-duty-fleet electrification. However, there is a lack of information on the expected magnitude and timing of electrical loads introduced by heavy-duty EV charging. Additionally, the required electricity distribution system upgrades—which include associated costs and lead times—are not well understood.

Here we combined recent public cost data and industry knowledge to summarize the typical causes, costs and timelines for the distribution system upgrades anticipated with depot charging. We also developed synthetic fleet depot charging load profiles under various charging strategies from real-world operating data, and found that the power requirements are met at the current light-duty EV charging levels (≤100 kW per vehicle). Finally, we applied these load profiles to distribution substations in the Oncor electric delivery company's service territory (Texas), which showed that, despite local variability in grid conditions, most substations can supply 100 electric trucks with 100 kW per vehicle charging without upgrades.

## Electricity distribution system upgrades for depot charging

There has been substantial research on the impacts of added electrical loads on distribution systems, which includes those for light-duty passenger EV charging (Supplementary Note 1). However, the implications of heavy-duty electric truck charging, with higher power requirements and more concentrated loads, are not well understood and the expected costs and lead times for distribution system upgrades associated with heavy-duty electric truck charging are uncertain.

Figure 2 illustrates a typical secondary electricity distribution system, and includes distribution substations, distribution feeders and on-site equipment. We leveraged multiple sources, which included public cost data, project reports, existing research and industry expert elicitation, to summarize the types of upgrades required for depot charging at each stage of the distribution system (Table 1). In addition to the causes and typical costs for upgrades, we also estimated project lead times, which are often overlooked.

In general, we found that as the charging loads increase, the likelihood for upgrades further upstream in the distribution system (that is, distribution feeders and/or substations) also increase. These are generally more expensive and time-consuming and require considerable planning to accommodate. Approaches for cost allocation between utilities and consumers vary, but it is common for utilities to cover the cost of off-site system expansion, with expected recovery over time through increased revenues from electricity sales.

## Fleet-charging load profiles

To model realistic duty cycles for short-haul trucking operations, we used vehicle drive cycle (1 Hz speed) data from three real-world Classes 7 and 8 delivery fleets in the National Renewable Energy

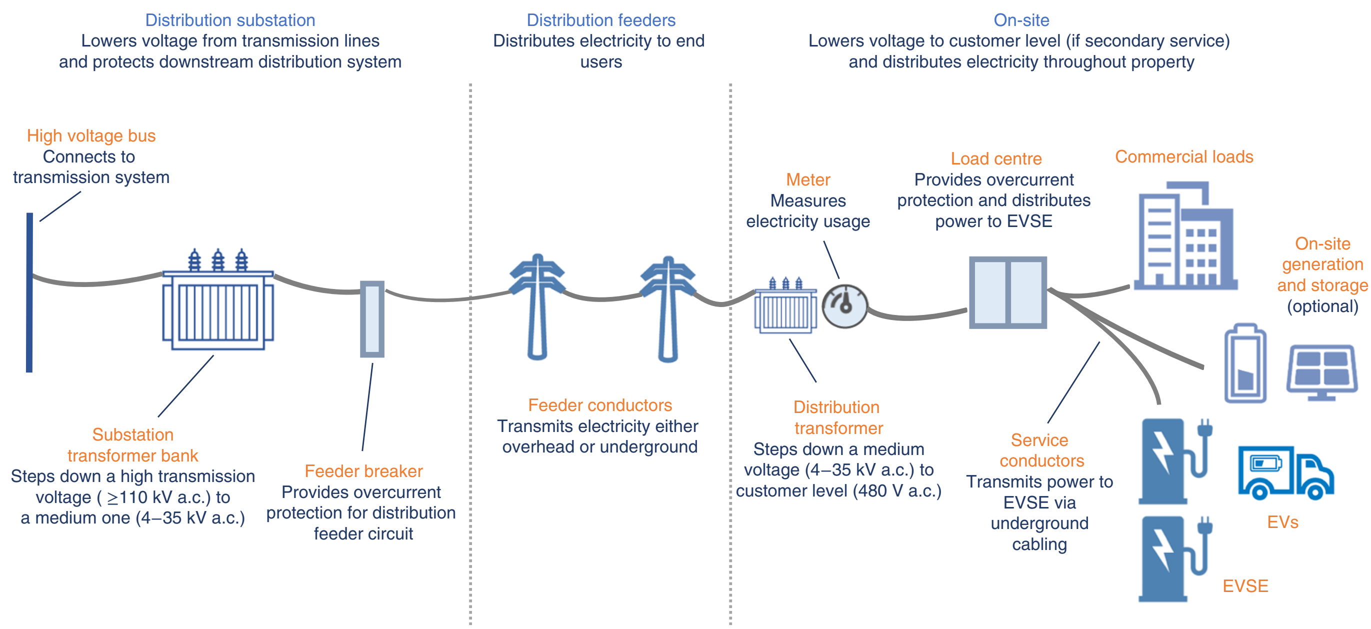


**Fig. 2 | Typical secondary electricity distribution system with depot charging.** High-voltage electricity from transmission lines (≥110 kV) are reduced to medium voltage (4–35 kV) at a distribution substation and transferred via feeders either directly to end users (primary voltage customers) or to a distribution transformer that reduces the voltage to secondary customer levels (480 V). For EVSE, additional on-site service conductors and equipment are needed to deliver power to each charging station.

**Table 1 | Summary of electricity distribution system upgrades for depot charging**

| Component category | Upgrade | Typical cause for upgrade | Typical cost[a] | Typical timeline (month)[a] |
|---|---|---|---|---|
| Customer on-site | 50 kW DCFC EVSE | EVSE addition | Procurement, U$20,000–36,000 per plug; installation, U$10,000–46,000 per plug[b] | 3–10 |
| | 150 kW DCFC EVSE | | Procurement, US$75,000–100,000 per plug; installation, US$19,000–48,000 per plug[b] | |
| | 350 kW DCFC EVSE | | Procurement, US$128,000–150,000 per plug; installation, US$26,000–66,000 per plug[b] | |
| | Install separate meter | Decision to separately meter | US$1,200–5,000 | |
| Utility on-site | Install distribution transformer | 200+ kW load | Procurement, US$12,000–175,000 | 3–8 |
| Distribution feeder | Install/upgrade feeder circuit | 5+ MW load[c] | US$2–12 million[d] | 3–12[e] |
| Distribution substation | Add feeder breaker | 5+ MW load[c] | ~US$400,000 | 6–12[f] |
| | Substation upgrade | 3–10+ MW load[g] | US$3–5 million | 12–18 |
| | New substation installation | 3–10+ MW load[g] | US$4–35 million | 24–48[h] |

[a]Cost and timeline ranges include procurement, engineering, design, scheduling, permitting and construction and installation; estimates are project-specific and vary greatly. [b]Costs reflective of 2019 and expected to continue to fall in future years; EVSE installation includes upgrading or installing service conductors and load centres; per-unit installation costs are reduced as the number of installed units increase. [c]Feeder extensions or upgrades (including new feeder breakers) are typically required for new loads >5 MW, especially for voltages <20 kV; new loads >12 MW may require a dedicated feeder. [d]Feeder extensions or upgrades tend to be more expensive in urban areas than in rural areas. [e]Timeline for feeder extensions includes jurisdictional permitting for construction, obtaining easements and right-of-way, and procurement lead times. [f]Timeline for adding a new feeder breaker depends on substation layout and the time required to receive clearance for construction. [g]The decision to upgrade an existing substation versus to build a new one is largely dependent on the layout of the existing substation and whether there is sufficient room for expansion. [h]Additional time may be required for regulatory approval for the transmission line construction. DCFC, direct current fast charging.

Laboratory's (NREL's) Fleet DNA database[44]. Each fleet is a return-to-base operation with moderate daily VMT and extended off-shift dwell periods for vehicles to charge (Fleet 1, beverage delivery; Fleet 2, warehouse delivery; Fleet 3, food delivery). The data collection period spans 20–59 days, depending on the fleet, and thus any seasonal operational variations may not be represented. However, previous studies suggest that heavy-duty tractors exhibit fewer seasonal usage variations than those of other vehicle types[45]. The fleets selected for this study are summarized in Supplementary Table 1.

Figure 3 shows daily VMT and off-shift dwell-time distributions. For Fleets 1 and 2, the maximum daily VMT is well within the expected range of battery electric trucks coming to market, at 130 and 194 miles (~209 and ~312 km), respectively. The maximum daily VMT is considerably greater for Fleet 3 (546 miles (~879 km)); however, most vehicle days require <300 miles (<483 km) (89%)

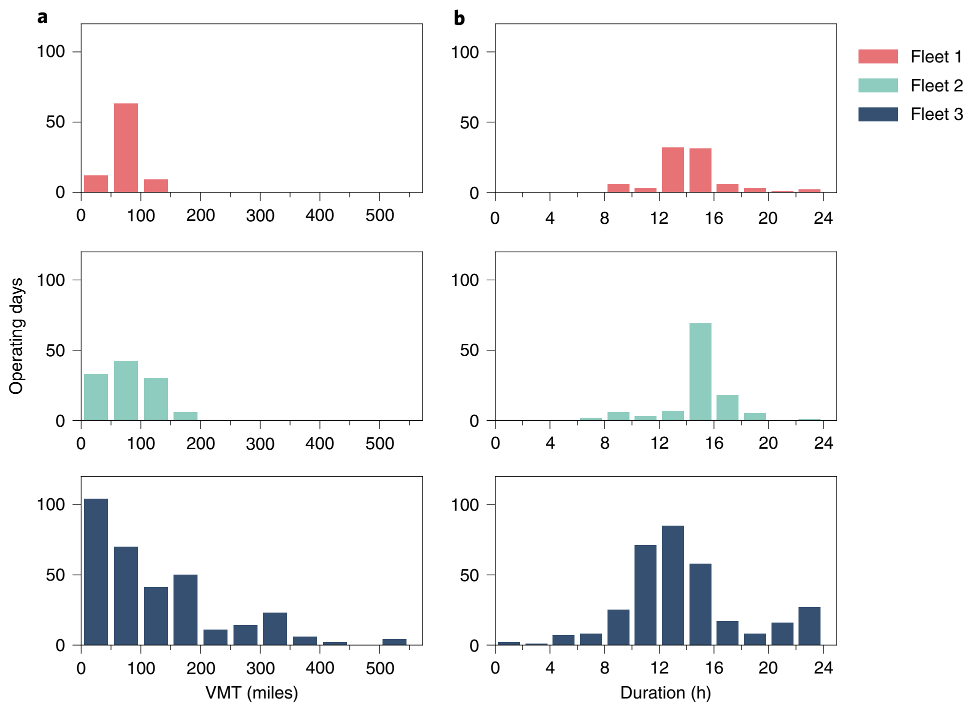


**Fig. 3 | Daily fleet driving mileage and off-shift dwell distributions. a**,**b**, Daily driving distances (**a**) and daily off-shift dwell durations (**b**) for the fleets studied. The daily off-shift dwell duration indicates the maximum available time window for charging.

and nearly all require <500 miles (<805 km) (99%). In all three fleets, trucks have ample opportunity for depot charging, with an average of 14.1 off-shift dwell hours (Fleet 1 = 14.2, Fleet 2 = 15 and Fleet 3 = 13.8) per day. For reference, assuming an average energy consumption of 2 kWh mile$^{-1}$ (~1.3 kWh km$^{-1}$), it takes ~6 hours for an electric truck to add 300 miles (~483 km) of range charging at 100 kW. Off-shift dwell hours are >12 for 74% of days and >6 for 98% of days.

Fleets with consistent operating schedules and long off-shift dwells can manage their charging to lower their energy bills and mitigate grid impacts[46,47]. We modelled three charging strategies to demonstrate this potential, illustrated in Fig. 4.

The first strategy is referred to as '100 kW immediate' with uncoordinated 100 kW per vehicle charging beginning once a shift ends and continuing until either the battery is fully recharged or a subsequent shift begins. The second is '100 kW delayed', which demonstrates the extent to which charging loads can be postponed by delaying the 100 kW per vehicle charging to the extent possible to fully recharge the vehicle's battery prior to a subsequent shift. The final strategy is 'constant minimum power', which leverages the entire off-shift period to charge at the minimum power required to fully recharge the vehicle's battery prior to a subsequent shift. This strategy minimizes the peak load for each vehicle (but not necessarily the fleet), and demonstrates the potential to flatten the load profile by charging at lower power levels.

We also modelled higher-power (250 kW per vehicle) charging strategies to explore the impact of increased charging rates (Supplementary Note 2).

Daily individual EV charging load profiles were aggregated into fleet load profiles through a bootstrap sampling procedure (Methods, Simulating fleet EV charging). The average fleet load profile was representative of a given fleet, fleet size (that is, number of EVs) and charging strategy. In addition, the sample profiles with the highest and lowest peak loads were selected as worst-case 'peak day' and best-case 'min day' scenarios, respectively. In total, 81 load profiles (27 average, 27 peak day and 27 min day scenarios) were produced for each fleet, fleet size (10, 50 and 100 EVs) and charging strategy (100 kW immediate, 100 kW delayed and constant minimum power) combination (the load profiles generated for this study are publicly available (Data availability). The average fleet profiles are shown in Fig. 5. In addition, the peak day profiles are shown in Supplementary Fig. 3.

The shape and magnitude of the load profiles for Fleets 1 and 2 are very comparable. These fleets operate similarly (Fig. 3), and their fixed routes and consistent operating schedules led to high peak loads (472–654 kW for 10 EVs) in the 100 kW per vehicle charging strategies because most vehicles charge concurrently. If charging is not managed (100 kW immediate), peak load coincides with the typical system-level summer peak period (17:00–21:00)[48], which adds load when the system is most stressed. To delay charging as much as possible (100 kW delayed) shifts the peak load into the early morning (6:00–10:00), which overlaps with the typical winter peak period on the grid. This strategy, however, demonstrates the extent to which charging loads can be shifted through managed charging, and the roughly three hour duration of the fleet's peak demand period can move anywhere between the apexes of these two profiles (that is, 18:00–7:00). The constant minimum power strategy effectively flattens the fleets' load profiles, which produces a >80% reduction in the peak demand. This is accomplished by charging at substantially lower power levels—4.5–15.3 kW per vehicle for Fleet 1 and 2.7–22.8 kW per vehicle for Fleet 2 (Supplementary Fig. 4). These rates are much lower than is generally assumed for heavy-duty trucks, and the electric vehicle supply equipment (EVSE) capable of supplying them is already commercially available for light-duty EVs[7,49].

Fleet 3's load profiles differ due to earlier start times and more variable operating schedules (Fig. 3). Despite the higher vehicle energy requirements, staggered shifts produce lower aggregate peak loads with unmanaged charging (324 kW for ten EVs) because fewer vehicles are likely to be at the depot at any time. Another result of

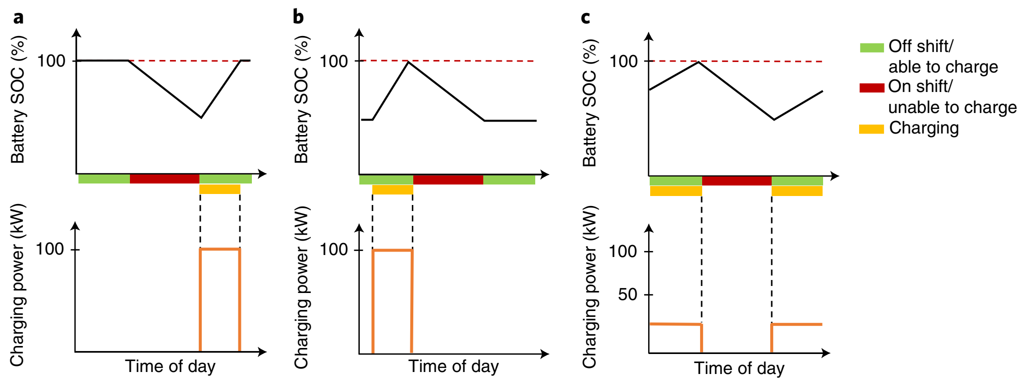


**Fig. 4 | Depiction of EV load profiles for the modelled charging strategies. a–c**, Charge at 100 kW immediate (EVs charged as soon as possible) (**a**), at 100 kW delayed (EVs charged as late as possible) (**b**) and at constant minimum power (EVs charged as slowly as possible) (**c**) showing the vehicle operating schedule (top row) and EV load profile (bottom row). SOC, state of charge.

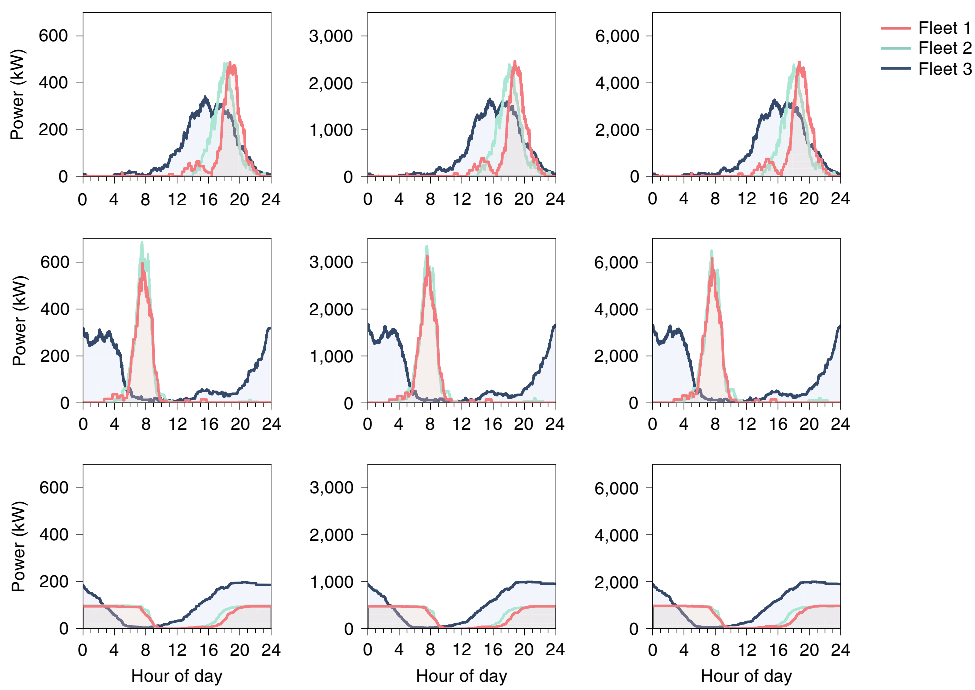


**Fig. 5 | Average daily depot load profiles for multiple scenarios.** Each scenario represents a combination of fleet, fleet size (10, 50 and 100 EVs charging (left, centre and right columns, respectively)) and charging strategy (100 kW immediate, 100 kW delayed and constant minimum power (top, middle and bottom rows, respectively)).

schedule variation is that the peak demand period is approximately twice as long, which limits the opportunity to load shift. The constant minimum power charging strategy produces a more modest but still substantial reduction in peak load (~40%) . Under this strategy, charging power levels vary greatly, 1.7–103 kW per vehicle, depending on the day (Supplementary Fig. 4), but are still in line with that of current light-duty EVSE technology.

Fleet managers, motivated to reduce operating costs, and distribution system operators, driven to enhance reliability, are concerned with the magnitude and timing of peak loads for depot charging. Figure 6 shows the normalized per-truck contribution to the depot peak load for all the fleets and charging strategies studied (Supplementary Fig. 5 shows the average and range of absolute peak load values for different scenarios). In addition, the min day (that is, minimum peak load) and peak day (that is, maximum peak load) profiles are presented to bound these estimates. Note that per-vehicle contributions to the peak depot charging load are lower than the individual vehicle charging power levels due to the asynchronous charging behaviours from multiple vehicles. Slower charging (constant minimum power strategy) led to much lower peak loads (<10 kW per vehicle for Fleets 1 and 2, and 20 kW per vehicle for Fleet 3), which mitigates electricity demand charges and enables the use of less expensive EVSE. In addition, the daily variance in peak load is reduced when vehicles are charged at slower rates, which results in an improved predictability for both utilities and fleet managers.

The charging load profiles presented here are generated with an assumed average energy consumption rate of 1.8 kWh mile$^{-1}$ (~1.1 kWh km$^{-1}$) (Methods, Developing EV charging schedules). However, the energy consumption for battery electric trucks in

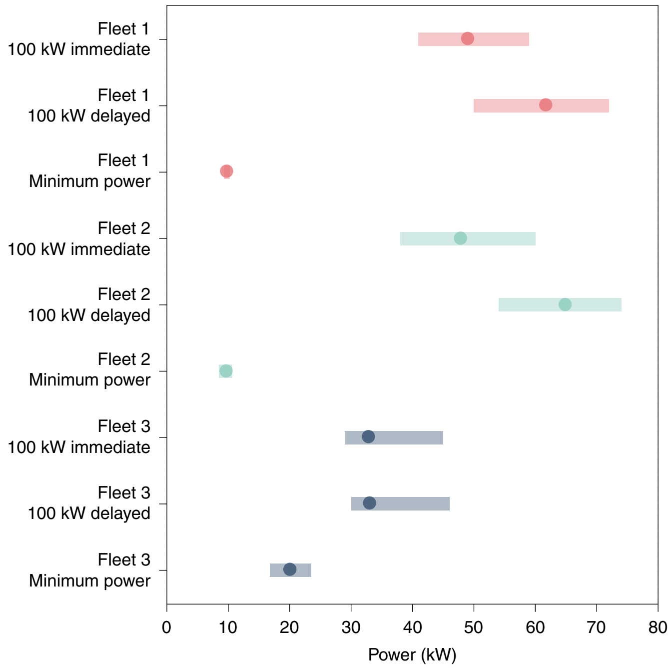


**Fig. 6 | Peak depot charging load normalized per vehicle.** Variation (bars) in per-vehicle contribution to peak depot charging load for each fleet and charging strategy with the average profile values overlayed (dots).

real-world operations is uncertain, given limited empirical data, and variable due to multiple factors (for example, ambient temperature and payload; Supplementary Note 3). We explored the sensitivity of the results to variations in the energy consumption rate parameter by establishing 'optimistic' and 'pessimistic' bounding cases from non-definitive estimates for the combined effects of factors presented in Supplementary Fig. 2: 1.5 kWh mile$^{-1}$ (~0.9 kWh km$^{-1}$) ('high efficiency') to 2.8 kWh mile$^{-1}$ (~1.7 kWh km$^{-1}$) ('low efficiency'). In the high-efficiency case, the EV charging power requirements decrease by 13–19% compared with the baseline, whereas in the low-efficiency case, requirements increase by 50–57%.

### Substation load integration case study

We performed a load integration study for 36 substations within the Oncor electric delivery company's service territory (Texas) to determine the likelihood that heavy-duty depot charging loads necessitate upgrades to distribution substations (Methods, Substation load integration study). We assessed 24 unique load profiles from Fleets 1 and 3, considering both low and high EV adoption levels (10 and 100 EVs, respectively), three charging strategies (100 kW immediate, 100 kW delayed and constant minimum power) and both average and peak day load profiles. Figure 7 shows the share of substations that required upgrades for the peak day profile in each simulated scenario.

The results suggest that the magnitude of the depot charging loads is more indicative of the likelihood for substation upgrades than is the timing. For both 100 kW per vehicle charging strategies with 100 EVs, Fleet 1's peak load is greater than Fleet 3's (Fleet 1 = 5,900 kW (immediate) and 7,200 kW (delayed); Fleet 3 = 4,500 kW (immediate) and 4,600 kW (delayed)); thus, more upgrades are required. From Table 1, substation upgrades cost between US$400,000 (feeder breaker) and US$35 million (new substation), which take six months to four years to complete and potentially result in higher electricity costs and delayed fleet electrification. Unsurprisingly, increased charging loads from a higher EV adoption more frequently necessitate expensive and time-consuming upgrades. We limit the study to fleets with 100 EVs, as short-haul delivery fleets with >100 trucks are exceedingly rare in the United States[50,51]; however, this trend is expected to persist with larger fleet sizes. Given local variabilities in system conditions and operations, some upgrades are difficult to avoid. For both fleets, we found that charging 10 EVs at 100 kW per vehicle (peak load ~700–900 kW) requires upgrades to ~6% of substations and one new substation installation. Nonetheless, the majority (78–86%) of the substations studied are capable of supplying 100 battery electric trucks with 100 kW per vehicle charging without upgrades, and 89–92% can handle 100 trucks charging at their slowest possible rates (constant minimum power strategy).

### Discussion and conclusions

In this study, we explored the potential to electrify short-haul (that is, a ≤200 mile (≤322 km) operating range) heavy-duty trucks and the electricity distribution system impacts of depot charging. We considered three real-world short-haul fleet operations, and found that each can be served by battery electric trucks coming to market in the near future with depot charging alone and at power levels in line with current light-duty charging equipment (<100 kW per vehicle). We generated a set of synthetic fleet depot charging load profiles, estimating that each EV requires an average of 137–235 kWh day$^{-1}$ and contributes an ~10–74 kW peak load to the system depending on the fleet and managed charging strategy. Given the uncertainty around the average energy consumption rate of heavy-duty electric trucks in real-world operations, we explored the sensitivity of our results when this parameter was varied between 1.5 and 2.8 kWh mile$^{-1}$ (~0.9–1.7 kWh km$^{-1}$) (baseline, 1.8 kWh mile$^{-1}$ (~1.1 kWh km$^{-1}$)), which shows that the daily energy requirements vary between 114 and 365 kWh per vehicle per day over this range, depending on the fleet. Finally, we assessed a substation load integration case study, and found that, despite local variability in grid conditions, most (78–86%) substations studied can supply 100 battery electric trucks with 100 kW per vehicle without additional upgrades, and ~90% can accommodate 100 trucks if charged at their slowest possible rates (constant minimum power strategy). This finding is consistent with research on light-duty residential EV charging and concludes that most distribution substations are capable of accommodating moderate-to-high EV penetrations, particularly if the charging is managed[52–54].

The opportunity for managed charging of heavy-duty electric trucks depends on the fleet's duty cycles. In general, as daily VMT requirements decrease and dwell times at the depot increase, fleet managers have a greater opportunity to shift demand temporally and/or reduce peak demand to minimize charging costs. For fleets in this study, we observed ample opportunity for managed charging, with an average charging window of 14.1 h day$^{-1}$. By charging each vehicle at its slowest rate (constant minimum power strategy), the fleet's peak charging load is substantially reduced (~40–80% compared with 100 kW per vehicle charging, depending on the fleet). There is a financial benefit to low-power charging for fleets and utilities alike. For utilities, it produces lower peak demand requirements and a smooth and predictable load profile that is less likely to require costly and time-consuming system upgrades. Fleet managers save on the capital costs of EVSE when electing for lower-power charging (the purchase and installation of 50 kW EVSEs are 62–81% cheaper than 350 kW EVSE; Table 1). In addition, fleets can save on electricity costs from reduced demand charges, if present. For Fleets 1–3, we found that, respectively, 16, 23 and 103 kW per vehicle charging power levels were sufficient for electric trucks to fully recharge when off shift, all much lower than is generally assumed[55–57].

In this study, we showed that there is a high variance in heavy-duty fleet electrification outcomes depending on multiple fleet characteristics and grid conditions. First, operating requirements for heavy-duty trucks vary depending on their vocation.

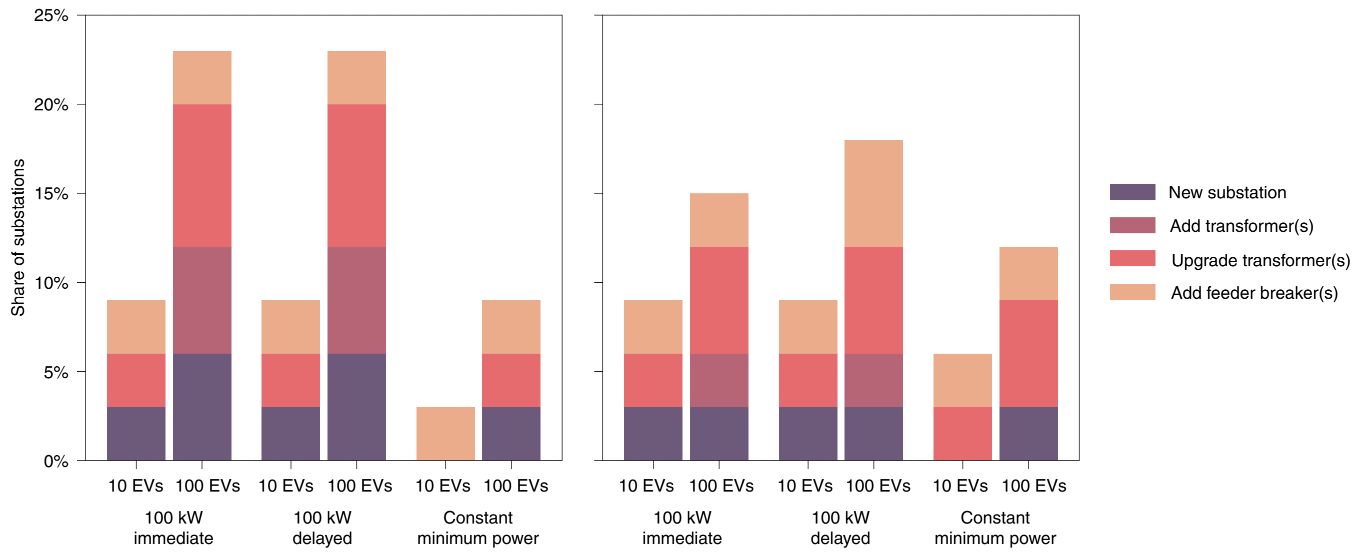


**Fig. 7 | Likelihood of substation upgrades required for peak day fleet depot charging.** The likelihood that added heavy-duty electric truck depot charging loads require specific upgrades to real-world distribution substations, including new feeder breaker(s), transformer upgrade(s), new transformer(s) and a new substation. The peak day load profiles for Fleet 1 (left) and Fleet 3 (right) are added to each substation transformer's respective 2019 single-day peak demand profile for combinations of fleet size (10 and 100 EVs charging) and charging strategy (100 kW immediate, 100 kW delayed and constant minimum power).

This study focused on short-haul delivery operations; however, we found that even within this segment, operating schedules and daily mileage requirements vary, which resulted in different fleet-charging power requirements and load profiles. Second, fleet managers have the opportunity to apply managed charging strategies to shift or flatten their fleet's load profile, such as save money on electricity by taking advantage of EV-friendly tariffs (for example, off-peak time-of-use pricing). We show that depot charging for short-haul operations is flexible given the low mileage requirements and extended dwell periods and demonstrate how managed charging can substantially modify a fleet's load profile (Fig. 5), and even avoid major impacts to upstream power systems (Fig. 7). Third, additional demand from heavy-duty electric truck charging must be met by electricity distribution systems with a variable capacity by location and time. In some cases, added demand exceeds the available capacity of a particular system component, which initiates upgrades. The summaries provided in Table 1 are useful to anticipate the upstream effects of electrification and provide order-of-magnitude cost and timeline estimates for upgrades; however, detailed load integration studies are required for individual cases. Finally, the costs (including cost share) and timelines for upgrades vary and can be affected by delays in permitting, regulatory approval and obtaining right-of-way easements. This list demonstrates the potential complexity of integrating heavy-duty electric trucks with the electrical grid, and stresses the importance that fleet managers who consider EVs engage early with their utilities to establish a feasible power-delivery schedule.

This study fills several research gaps on heavy-duty electric truck charging and its impact on electricity distribution systems; however, substantial work remains to be done. We focused on short-haul heavy-duty trucks because they are early candidates for electrification, but future research should consider other segments (for example, last-mile delivery vans and regional/long-haul operations) with different charging behaviours and energy requirements. Additionally, opportunities for electrification should be assessed economically, comparing the total cost of fleet ownership for electric trucks (including the cost of electricity and charging infrastructure) to that for diesel trucks or other alternatives across multiple operational segments and for various charging strategies. Although we consider current real-world operations, vehicle electrification might also induce changes in how vehicles are operated to facilitate charging. Retail electricity tariff designs should also be assessed for their ability to provide low-cost electricity for heavy-duty EV charging (for example, by aligning charging with excess cheap renewable electricity) and limit impacts on distribution systems while supporting bulk power-system planning and operations. Lastly, the trade-offs for high-power (>350 kW per vehicle) charging, which is more expensive but enables greater flexibility, should be thoroughly researched for heavy-duty electric trucks.

## Methods

**Summary of electricity distribution system upgrades.** The value ranges presented in Table 1 are an attempt to generalize the typical causes, costs and timelines expected for distribution system upgrades related to heavy-duty fleet depot charging. In total, ten separate data and literature sources were used[7,49,58–65]. It is important to clarify that the costs and timelines in Table 1 may not be additive because soft costs are often spread across several phases of a project and multiple upgrades can be performed concurrently. Also, note that the available EV hosting capacity and charging loads are highly variable, depending on the time of day, season, location and fleet-charging schedules. This variability is not fully captured in Table 1, and a detailed load integration study is required for values specific to any individual project. We only consider upgrades to the electricity distribution system; however, high-enough concentrations of heavy-duty electric truck charging may require upgrades to the bulk power system (that is, the generation and transmission infrastructure), which are not studied here.

**Developing EV charging schedules.** Daily operating schedules are derived from 1 Hz vehicle drive cycle data, with the assumption that vehicles idle for ≥3 h consecutively are 'off shift' and available to depot charge. Idle periods lasting <3 h are considered 'on-shift' (for example, loading or unloading); at these times, vehicles are not assumed to be available for charging. Operating schedules segment days into on- and off-shift time periods, in which each shift has an associated VMT, and vehicles are only available for depot charging when they are off shift.

A reduced set of vehicle operating schedules was used to develop synthetic EV charging load profiles for each of the three fleets. The first and last days of each data collection period were removed to avoid modelling incomplete operating days because trucks are often instrumented/de-instrumented midday. We removed 24 days (2 from Fleet 1 and 22 from Fleet 3) with a daily VMT less than 10 miles (~16 km) and 4 days from Fleet 3 for which the daily VMT exceeded 500 miles (805 km). In total, 412 operating days were used in this analysis—76 for Fleet 1, 100 for Fleet 2 and 236 for Fleet 3.

The daily VMT was positively skewed in the fleets considered (Fig. 3a), with an average of 107 miles (~172 km) (Fleet 1 = 74 miles (~119 km), Fleet 2 = 82 miles

(~132 km) and Fleet 3 = 123 miles (~198 km)) per vehicle day. Assuming 260 operating days per year, the extrapolated annual VMT range is from ~19,000 (Fleet 1) to ~32,000 (Fleet 3) VMT per year (~30,500 to ~51,500 VKT per year), which marks the 44–55th percentile of annual mileages for heavy-duty trucks reported in VIUS[21]. Fleet 3 has more heterogeneous daily operations than Fleets 1 and 2, with more-variable daily VMT requirements ($\sigma_3$ = 109 miles (~175 km) versus $\sigma_1$ = 23 miles (~37 km); $\sigma_2$ = 42 miles (~68 km) for Fleets 1 and 2) and daily off-shift dwell periods ($\sigma_3$ = 4.4 h versus $\sigma_1$ = 2.6 h; $\sigma_2$ = 2.3 h for Fleets 1 and 2).

Fleet-charging behaviours were modelled under the assumptions: (1) operating schedules collected from conventional trucks were not adjusted as a result of the electrification; (2) short-haul battery electric trucks had an average energy consumption rate of 1.8 kWh mile$^{-1}$ (~1.1 kWh km$^{-1}$), the average of an empty and fully loaded battery electric truck (that is, assuming an average load factor of 50% (ref. [66])); (3) total daily energy consumption (kWh) was estimated as the product of the total daily VMT and the average energy consumption rate (1.8 kWh mile$^{-1}$ (~1.1 kWh km$^{-1}$), that is, energy consumption = VMT × 1.8); (4) each truck has a dedicated EVSE plug at its depot (that is, trucks do not queue for a limited plug supply); (5) trucks are charged at constant power with no tapering given the relatively modest charging power levels modelled compared with the battery capacities (that is, low *C* rates)[67] and (6) trucks are unavailable to charge for 15 min immediately preceding or following a shift, which accounts for the time taken to plug and unplug the vehicle.

**Simulating fleet EV charging.** Daily individual EV charging load profiles were selected for aggregation into fleet-charging load profiles through a bootstrap sampling procedure. Bootstrapping is a statistical resampling method in which objects are repeatedly randomly selected with replacement to produce a set that approximates the sampling distribution. Specifically, for a fleet of size *n*, we randomly selected (with replacement) the set of vehicle load profiles ($\mathbf{v}_1$, ..., $\mathbf{v}_n$) from the sample of available vehicle load profiles *V*. Each daily individual EV load profile, $\mathbf{v}_i$, is represented by the 1 Hz time-series vector:

$$\mathbf{v}_i = \langle p_{t=1}, \ldots, p_{t=86,400} \rangle \quad (1)$$

where each entry $p_t$ corresponds to the charging power (kW) at time *t*—the total number of seconds from the start of the day. Bootstrapping allows the generation of multiple synthetic fleet-charging load profiles as combinations of *n* daily individual EV charging load profiles. For each bootstrap sample, we calculated a single synthetic fleet-charging load profile $\mathbf{f}_i$ from:

$$\mathbf{f}_i = \sum_{i=1}^{n} \mathbf{v}_i \quad (2)$$

We resampled and repeated equation (2) 49 times to produce a set of 50 sample fleet profiles. This set estimated the sampling distribution, which we used to calculate the average fleet-charging load at each second of the day. Specifically, the average fleet-charging load profile $\bar{\mathbf{f}}$ was calculated from:

$$\bar{\mathbf{f}} = \sum_{i=1}^{50} \frac{\mathbf{f}_i}{50} \quad (3)$$

The average fleet-charging load profile represents the expected electricity demand required for a specific fleet, fleet size (number of EVs) and charging strategy. Extreme load profiles (maximum energy demand, or worst-case scenarios), however, are often used for system reliability planning and assessments. Thus, we also identified and provided the sample fleet profiles with the maximum peak load requirements (peak day). Finally, we selected the sample fleet profile with the minimum peak load requirement (best-case scenario) to fully bound the analysis. This process was repeated for combinations of the three fleets, three fleet sizes and three charging strategies considered, which totalled 81 separate load profiles.

Resampling methods, such as bootstrapping, make economical use of the limited sample data to improve estimates for population parameters and provide an approximation of the sampling distribution[68]. Our sample was limited by the total number of vehicle days in the original dataset; thus, bootstrapping enabled the simulation of fleet sizes and vehicle days (from limited empirical information) that would not otherwise be possible. A key assumption made here is that vehicle days are independent of each other. Although this may not always be the case, the sampling distribution provides a range of outcomes for analysis in which we also selected the sample with the peak load (which represents highly aligned charging schedules) for comparison.

Supplementary Figs. 6–8 show the variation in daily fleet-charging load profiles (50 sample days) from random sampling for the three fleets studied.

**Substation load integration study.** Oncor is the largest energy delivery company in Texas, and serves over 98 counties in the east, west and north-central regions of the state, which include the Dallas–Fort Worth metropolitan area. We performed a load integration analysis for select substations within Oncor's service territory to determine the likelihood that added heavy-duty electric-truck-charging loads require certain upgrades to real-world distribution substations. First, Oncor identified >300 locations within a large contiguous area of their service territory as probable vehicle depots or other sites at which heavy-duty EV fleets are anticipated. For each potential site, the three closest substations within a 5 mile radius were considered (average distances to the three nearest substations are 1.3, 2.3 and 2.9 miles (2.1, 3.7 and 4.7 km, respectively) for the sites considered). A total of 36 substations (from >850 within Oncor's service territory) were selected for the study. Nearly 90% have multiple transformers and ~85% have 15 kV transformers; the remaining have 25 kV transformers. A majority (~85%) of the substations selected serve metropolitan, suburban areas with mixes of residential, commercial and industrial loads, and the remaining ~15% serve the fringe of metropolitan areas (exurbs) with both residential and commercial loads.

Fleet-charging load profiles were averaged over 15 min intervals and added to each substation transformer's respective 2019 single-day 15 min peak demand profile. Substation component-level capacity constraints were used to determine which upgrades (if any) were required to accommodate the added loads. Upgrades were assessed at the substation level only and include: (1) adding new feeder breaker(s) only, (2) upgrading one or more transformers with higher-rated units, (3) adding one or more new transformer(s) to an existing substation or (4) building a new substation in a separate location.

We assessed 24 fleet demand profiles from Fleet 1 (beverage delivery) and Fleet 3 (food delivery), and considered low and high levels of EV adoption (fleets of 10 and 100 EVs, respectively), the three charging strategies (100 kW immediate, 100 kW delayed and constant minimum power) and both the average and peak day (that is, sample day with the highest peak load) profiles. A complete summary of the results for this study are available online (Data availability). Note that we excluded Fleet 2 (warehouse delivery) from this study to limit the number of simulations required because its charging load profiles are so similar to those of Fleet 1.

The results are representative of locations within the Oncor service territory in which heavy-duty EV fleets are expected to operate and recharge. By selectively analysing substations that already serve commercial and industrial loads, the results may be generalized—to an extent—to other regions that meet this description. However, distribution system characteristics and their EV hosting capabilities vary, and utility collaboration is needed to access the detailed infrastructure data required for a comprehensive analysis. The time-resolved (15 min) load profiles generated in this study are publicly available (Data availability) and can be used to perform detailed load integration studies in other areas.

## Data availability

The fleet depot charging load profiles and EV load integration results generated in this study are available through the NREL Data Catalog at https://data.nrel.gov/submissions/162. The vehicle drive cycles used in this study contain business-sensitive geographical information and thus are not publicly available; however, anonymized data summaries and visualizations are available through the Fleet DNA website at https://www.nrel.gov/ transportation/fleettest- fleet-dna.html.

## Code availability

Derived fleet-charging availability schedules, daily vehicle mileage and energy requirements, and the code developed to produce, study and visualize fleet load profiles, are open source and available at https://github.com/NREL/hdev- depot-charging-2021.

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## Author contributions

M.M. and B.B. conceptualized the study. M.M., B.B., M.G., D.W. and T.C. provided the methodology. B.B. and D.W. created the software and carried out the formal analysis and visualization. All the authors performed data curation and took part in consultation. The original draft was written by B.B., M.M., M.G. and D.W., with review and editing by B.B. and M.M. Funding acquisition was by M.M., who supervised the study.

## Competing interests

D.W. and W.M. are employees of Oncor Electric Delivery Co. and T.C., A.I., H.G. and C.M. are employees of Southern Company. The other authors declare no competing interests.

## Additional information


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