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Powering Electric Trucks: Impacts and Optimization of Charging Patterns

Chase LeCroy, Jon Gordon, Shuhan Song, Alise Crippen, Derek Ichien,

CALSTART, clecroy@calstart.org, jgordon@calstart.org, ssong@calstart.org, acrippen@calstart.org, dichien@calstart.org

Summary

This paper reviews two recent extensive deployments of medium- and heavy-duty battery-electric vehicles (BEVs), charging infrastructure, solar canopies, and battery storage systems. In-depth data collection and analysis offers insight into best practices for medium and heavy-duty BEVs charging under different utility rate structures. A case study on one fleet's experience with integrating solar energy and energy storage is also described. This real-world data informed the design of a new tool to assist fleets in optimizing BEV infrastructure deployment. The tool helps plan charging schedules while minimizing energy costs, project future costs, and right-size solar and energy storage systems.

Keywords: EV infrastructure, power management, solar energy, energy storage, heavy-duty

1 Deploying Battery-Electric Vehicle Infrastructure

1.1 Background

As part of its plan to meet climate goals, the State of California has taken aggressive action to transition medium- and heavy-duty (MHD) vehicles to zero-emission (ZE) models.[1] In December 2018 California adopted the Innovative Clean Transit Rule (ICT), which requires public transit agencies to gradually convert to 100% ZE bus models by 2040 [1]. Then in July 2020, California implemented the Advanced Clean Trucks (ACT) regulation, mandating that original equipment manufacturers (OEMs) must sell an increasing percentage of ZE heavy-duty trucks, beginning with the 2024 model year [2]. By 2035, 40% of tractor sales and 75% of straight truck sales must be ZE [3]. To offset the costs of transitioning to ZE vehicles, in 2009 the California Air Resources Board (CARB) started the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP), providing point-of-sale vouchers to both public and private fleets [4]. HVIP made $430 million available to fleets in the March 2022 iteration. CARB recently supplemented HVIP's vehicle-side purchase incentives with the EnergIIZE Program (Energy Infrastructure Incentives for Zero-Emission Commercial Vehicles), a $347 million program that offers funding to help finance commercial charging and hydrogen fueling infrastructure [5].

The market for MHD and off-road ZE vehicles is thus growing rapidly but there has been little real-world research into managing these vehicles' energy use. This lack of data is a challenge at a time when battery-electric vehicle (BEV) deployments are ramping up due to increasingly stringent regulations and growing

[1] Medium-duty is defined under the American system as 10,001-26,000 lbs or 4,536-11,793 kg Gross Vehicle Weight Rating; heavy-duty is >26,001 lbs or >11,794 kg

fleet demand. Forward-thinking fleets are now deploying some of the first commercialized MHD BEVs off the assembly line along with the accompanying charging and energy management infrastructure.

Transitioning from combustion engines to BEVs is a big shift for fleets and requires adequate planning. Installing charging infrastructure requires investment and coordination among multiple entities including utilities, manufacturers, infrastructure providers, and third-party contractors. Even with high-powered charging equipment, significant operational changes are often necessary. Charging must be carefully managed to optimize energy efficiency, infrastructure usage, and cost. Complicated utility rate structures must be deciphered in concert with an understanding of vehicle charging patterns. Demand charges further complicate the picture.[2] With all these obfuscating factors, it is challenging for fleets to determine whether the benefits of BEVs are being realized. Orchestrating these variables to achieve peak performance is not straightforward.

In 2018, CARB launched the Zero- and Near-Zero Emission Freight Facilities (ZANZEFF) program, awarding more than $200 million dollars to projects showcasing the performance of MHD BEVs and infrastructure (including chargers, solar arrays, and energy storage systems (ESSs)) at locations across the state [6]. ZANZEFF projects include comprehensive data collection and analysis to demonstrate real fleet operations and reduce reliance on assumptions or unrealistic test conditions. This analysis offers a unique look into the electrification efforts the freight transport sector will need to achieve in coming years.

The goal of this paper is to share findings and lessons learned from three fleets deploying BEV equipment across two ZANZEFF projects to support the accelerated adoption of these technologies. Each project demonstrates BEV technology across multiple platforms in daily operations to quantify the benefits they provide in emissions and energy savings. The first project is the Volvo Low Impact Heavy Transport Solutions (LIGHTS) Project. Volvo LIGHTS involves two fleets conducting port drayage operations and regional deliveries in Southern California [7]. Fleet A demonstrated battery-electric (BE) HD trucks and BE off-road equipment in drayage duty cycles between the Port of Los Angeles and its Ontario, CA facility. Fleet B also used drayage routes to their facility in Chino, CA. The second project involves Fleet C, located in California's Central Valley, which is converting nearly all transportation equipment at a 500,000 ft^2 manufacturing facility to ZE or near-ZE.

1.2 Technology Deployment Overview

In total, 69 BEVs along with the associated charging and energy management infrastructure were deployed. A and B deployed BE heavy-duty (HD) on-road trucks alongside BEV yard tractors. Fleet C deployed medium-duty (MD) Class 6 BEV box trucks on shorter-range deliveries as well as BEV yard tractors. Fleets A and C also installed solar canopies and ESSs. Table 1 summarizes the infrastructure deployed.

Table 1: Energy infrastructure; parentheses denote peak power capability or energy storage capacity

	Fleet A	Fleet B	Fleet C	Manufacturers
Heavy-duty Truck Chargers	2 (150 kW)	2 (150 kW)	6 units, 12 ports (125 kW)	ABB, ChargePoint
Yard Tractor Chargers	2 (22 kW)	2 (10 kW)		Orange EV, Transpower
Solar Canopy	1 (864 kW)	-	1 (1.08 MW)	Solar Optimum, Tesla
Energy Storage System	1 (130 kWh)	-	1 (696 kWh)	CPS, Tesla

2 Data Collection

Multiple data sources were used in the analysis. Data from BEV chargers came from software platforms tracking energy output during each charge event. This was compared with vehicle-side charging data to ensure consistency. Charger data and utility bills were also cross referenced with results validated by the fleet managers. Cost values were taken directly from utility bills or estimated by applying BEV charger data to the local utility's rate structure. Various fleet charging strategies were tested, including manual and automated approaches, providing a unique look at how different practices may affect results across multiple facilities. The solar and ESS data was collected via online software platforms connected to each system. The impact of

[2] Demand charges are fees assessed by the electricity provider based on the highest power draw in kilowatts (kW) during the previous month; this is in addition to the energy consumed in kilowatt-hours (kWh) that month

solar arrays and ESS systems was analyzed to explore cost savings, estimate return on investment, and identify best practices for utilizing this technology. BEV charger, solar array, and ESS data were incorporated with information from fleets on their plans to continue electrifying their vehicles over time, allowing the impacts and opportunities associated with scaling MHD BEV fleets to be modeled.

3 Vehicle Charging Strategies

3.1 Time-of-Use Rates

Utility rate plans based on time-of-use (TOU) apply different prices per kWh throughout the day and year. Avoiding the highest rates (on-peak) is one strategy that can lead to significant cost savings. Importantly, this utility currently has a demand charge waiver in place and will thus not assess these fees for BEVs until 2024. Table 2 below contains the TOU rates at Southern California Edison (SCE), the utility for Fleets A and B (note that mid-peak summer rates were only charged on weekends when Fleet A did not operate).

Table 2: SCE TOU rates [8]

	Summer ($/kWh)	Winter ($/kWh)
On-Peak	0.59521	-
Mid-Peak	0.35999	0.40046
Off-Peak	0.15808	0.16777
Super-Off-Peak	-	0.09772

The BEV yard tractors and HD trucks at Fleets A and B charged on the rate plan above. Figure 1 shows the average energy charged per hour by Fleet A yard tractors and Figure 2 shows how that energy consumption compared to charging cost per TOU period.

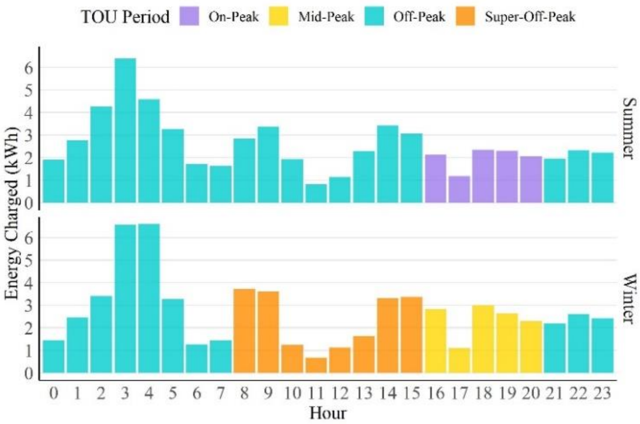

Figure 1: Average energy charged per hour for yard tractors at Fleet A

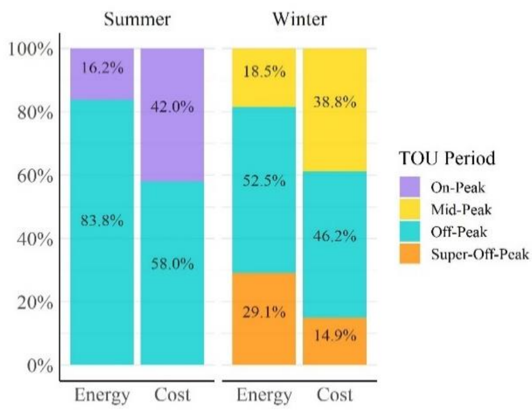

Figure 2: Percent of total energy and cost by TOU period for yard tractors at Fleet A

In Figure 1, we see BE yard tractor charging peaked at approximately 3-4 am, with smaller peaks at 8-9 am and 2-3 pm. The fleet attempted to minimize charging during on-peak rate periods (4-9 pm). Work was usually lighter earlier in the day during non-peak hours (8 am-4 pm) so drivers were instructed to plug in yard tractors during that time. This helped ensure that yard tractors charged during super-off- or off-peak periods and avoided charging during on- or mid-peak periods. Fleet A's standard work schedule and the fact that the yard tractors had resting periods allowed for charging to be effectively managed, even without the availability of smart charging software.

Despite these efforts, Figure 2 shows that a hefty portion of the energy cost was assessed during the most expensive charging periods. The relatively small amount of energy charged in the late afternoon/early evening comprised a disproportionate amount of the total cost: 16-19% of the total energy charged was during on- or mid-peak hour but this generated 42-46% of the costs. Eliminating charging during 4-9 pm could save

Fleet A about $2,400 annually.[3] Fleet B experienced the same trend; they charged their yard tractors whenever possible with the goal of maximizing time in service and thus were largely unable to avoid on-peak pricing. In the summer, 38% of their energy use was on-peak amounting to 70% of the cost. Shifting charging to avoid on-peak hours (4-9 pm) could save the fleet $4,000 annually, about half of the total cost. The fleet manager suggested adjusting charging times might be possible if they had more BEV yard tractors or larger battery capacities.

Class 7 and 8 BEVs consumed more energy and as a result showed more extreme results, as shown for Fleet A in Figure 3 and Figure 4 below.

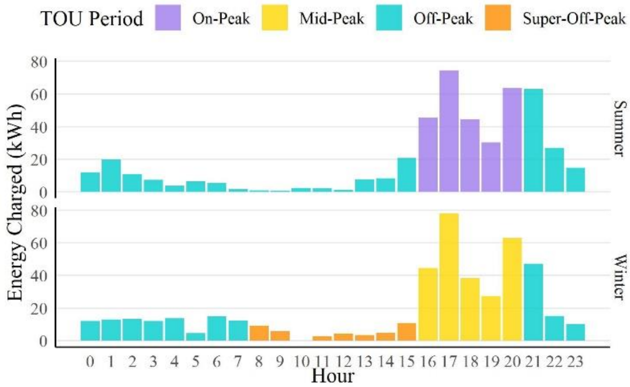

Figure 3: Average energy charged per hour for Class 7 and 8 trucks at Fleet A

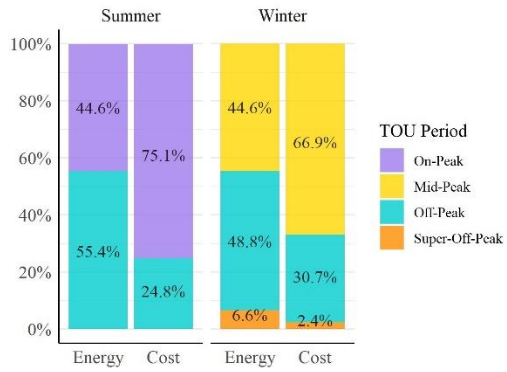

Figure 4: Percent of total energy and cost by TOU period for Class 7 and 8 trucks at Fleet A

These BEV tractors had a very consistent schedule making energy management more difficult. They completed 45% of their charging during on-peak pricing, comprising 67-75% of the cost. The fleet could save $18,000 annually if they avoid on-peak charging altogether. Although this may not be possible, their charging peaks occurred right at the beginning and end of the highest rates so starting an hour or two earlier and ending an hour later could still be effective. Fleet B again showed a similar pattern, as depicted in Figure 5 and Figure 6 below (data was only available for the winter utility rates).

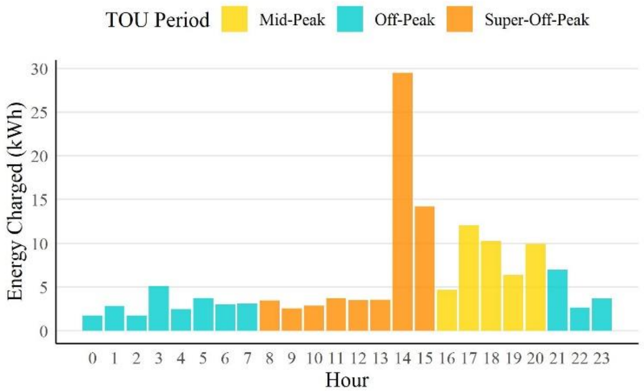

Figure 5: Average energy charged per hour for Class 8 trucks at Fleet B

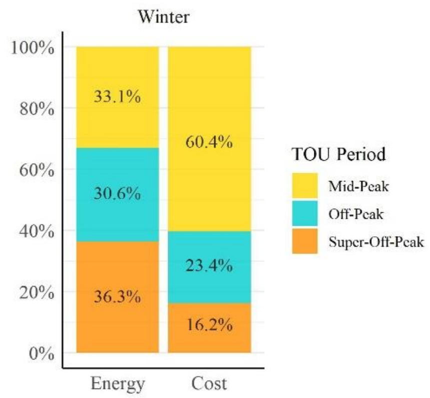

Figure 6: Percent of total energy and cost by TOU period for Class 7 and 8 trucks at Fleet B

The high-cost TOU periods again comprise a disproportionate amount of charging cost, with mid-peak representing twice as large a proportion of cost compared to energy. Luckily, their primary charging peak occurs at 2-3 pm, just before mid-peak begins. It is unlikely that the fleet would be able to shift charging times enough to move this peak into a lower rate period, but some of the evening charging around 7-9 pm could perhaps be moved to after 9 pm for off-peak pricing.

3 Annual savings calculated by shifting on-peak energy charging data to mid-peak and applying energy consumption to the rate structure in Table 2

To summarize, fleets on TOU utility rates can cut their charging bills dramatically by avoiding on-peak hours. This can be achieved manually by carefully planning their charging or automatically by utilizing smart chargers that can be programmed to avoid on-peak charging. Charging practices will vary with the business needs of each fleet's particular duty cycle but avoiding on-peak charging should be made a priority.

3.2 Managed Charging and Demand Charges

Unlike the other fleets, Fleet C's utility did not use a TOU rate. Instead, the rate structure charged a flat fee per kWh with an additional fee per kW of peak power demand (the demand charge) each month (Table 3).

Table 3: Utility rate structure for Fleet C when charging BEVs [9]

Summer (May – September)	Winter (October – April)
Fixed Monthly $45.00	Fixed Monthly $45.00
Demand (per kW):	Demand (per kW):
Over 20 kW $10.31	Over 20 kW $10.31
Electric Usage (per kWh):	Electric Usage (per kWh):
First 20,000 kWh $0.1304	First 20,000 kWh $0.1065
Over 20,000 kWh $0.1019	Over 20,000 kWh $0.0813

BE yard tractors and BE box trucks charged on this rate plan via a shared bank of 12 charging ports. The box trucks began their routes at 1-2 am, returning to the facility and plugging in around noon. Because they only ran one route per day, there was plenty of time to recharge before the next day. In contrast, the yard tractors had nearly 24-hour duty cycles, so they had to charge throughout the day. An opportunity charge strategy was used where the yard tractors were plugged in at every break for short sessions (a median of 45 minutes each).

Charging behavior at the site was unrestricted from October – December 2020 with charging occurring as needed. However, demand charges were identified as a key challenge because simultaneous charging by multiple vehicles caused a peak demand of over 400 kW and a fee of nearly $4,000 per month. To moderate this, different control strategies were implemented via the chargers' demand management software, as described in Table 4.

Table 4: Demand management strategies used at Fleet C and the resulting average charge rate by vehicle type

Phase	Timing	Strategy	Class 6 average charge rate (kW)	Yard tractor average charge rate (kW)
1	Jan-Mar 2021	Unrestricted charging for both vehicle types	47	82
2	Mar-Jul 2021	Overall maximum of 200 kW; yard tractors charge at full power (~100 kW)	28	71
3	July-on 2021	Overall maximum of 180 kW; box truck rate capped at 50 kW, dropping to 5 kW if yard tractor also connected	18	73

With a goal of reducing the maximum power draw but a need to keep yard tractors running on their constant 24/7 duty cycle, Phase 2 was implemented. This prioritized yard tractors; if box trucks were also plugged in, yard tractors received full power (around 106 kW) until fully charged or unplugged and overall power demand was capped at 200 kW. In Phase 3, this strategy was modified by limiting box trucks to 50 kW in general or 5 kW if a yard tractor was also connected. Figure 7 below helps visualize the effects.

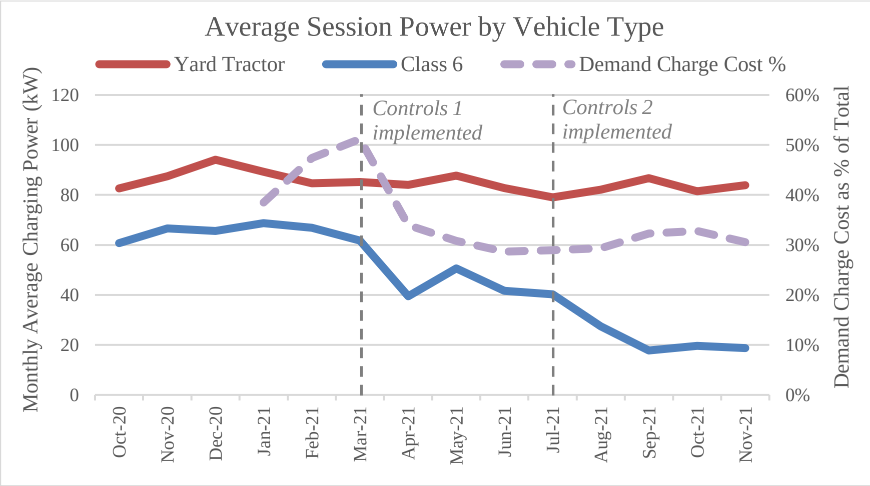

Figure 7: Monthly average charging power for BEV yard tractors and box trucks and corresponding demand charge as a percent of monthly electricity cost

The fleet was able to prioritize keeping their yard tractors charged while decreasing maximum power draw and keeping total energy consumption relatively constant. The average power draw from the yard tractors remained steady while box trucks decreased from over 50 kW to below 20 kW. The first controls swiftly brought down the peak demand and associated fees, which dropped by just over half and saved over $24,000 annually. The proportion of the total cost from demand charges dropped from 54% to 38%. The second controls did not appreciably affect the demand charge fraction but did continue to noticeably reduce the average power draw per session for the box trucks. It should be noted that Fleet C was able to limit their box truck charging rate because they operated shorter routes each day with about 12 hours of downtime, providing flexibility. Fleets subject to demand charges should attempt to limit their BEVs' maximum power draw either by using smart charging software or manually staggering charging times.

4 Solar and ESS Case Study

An 864 kW photovoltaic (PV) system and a 130 kWh ESS were installed at Fleet A. The process of selecting providers, construction, and energizing the system took nearly two years. Delays were caused by slow response times for support, communications with the utility, and system testing. The solar PV system was intended to supply renewable energy to the charging stations for Fleet A's BEV yard tractors, trucks, and workplace chargers. Approximately half of the solar panels were generating energy at the time of this analysis, with the others having wiring and inverter issues. Although the system was not fully operational, it generated more energy than the BEV trucks and equipment consumed (a total of two yard tractors and four HD trucks, as well as 12 forklifts). Table 5 below describes energy production for the PV system.

Table 5: Fleet A solar PV system metrics, May 7 to August 7, 2021 in Ontario, CA

Average Daily Energy Generation (kWh)	4,124
Max Daily Energy Generation (kWh)	5,326
Average Hours of Generation per Day (hrs)	12.8

Solar energy production was four to five times higher than BEV energy usage (aside from an eight-day maintenance outage in June). The maximum recorded daily energy use by the chargers (1,306 kWh) was covered by the PV system with 68% of the generation leftover. Excess energy generated was fed back to the grid and produced energy credits for the fleet through the utility's net energy metering program. Solar credits are calculated as the net total of energy production and consumption each month. For example, if 10,000 kWh is generated and 5,000 kWh consumed, -5,000 kWh multiplied by the delivery rate of $0.0227 results in $113.50 of excess energy credits. These credits can be used within a 12-month period to offset energy costs. The energy surplus during this analysis offset all consumption so that essentially, the fleet did not have to pay for their electricity use. Average monthly savings were $5,413 or about $65,000 annually. Fleet A is expected to remain a net energy producer for several more years. Until they adopt enough BEVs for energy demand to exceed production (or demand charges begin in 2024), Fleet A is only expected to pay for non-bypassable fees.[4] Figure 8 shows the relative energy use of the BEV chargers versus solar energy production.

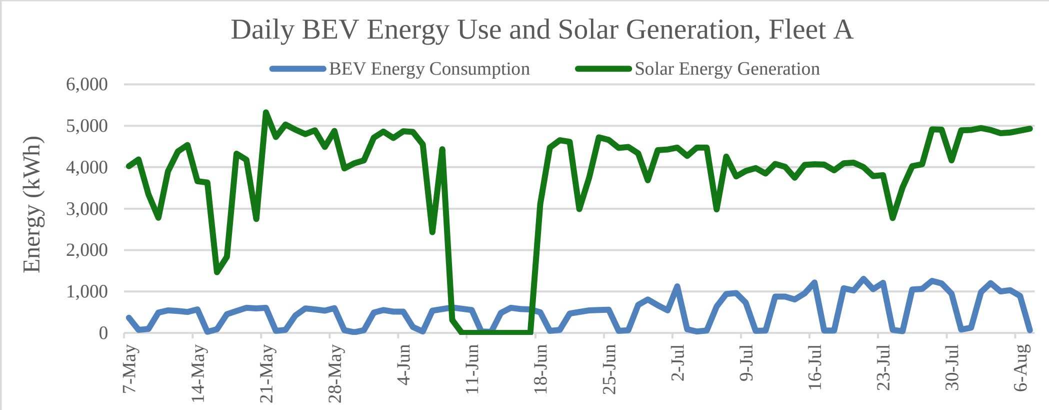

Figure 8: Fleet A daily BEV energy draw and solar generation

The overall financial impact of the PV system was estimated by accounting for capital and ongoing costs. The fleet also estimated the pace of conversion for the rest of their vehicles from combustion vehicles to BEVs based on their business needs and regulations. Annual energy consumption for this growing fleet of BEVs was estimated with an assumed increase in battery efficiency of 1% each year to account for technology advancements. Total demand was then translated to dollars under scenarios with no solar power, 50% capacity (current case), and 100% capacity (after repairs are made). Figure 9 below displays the results.

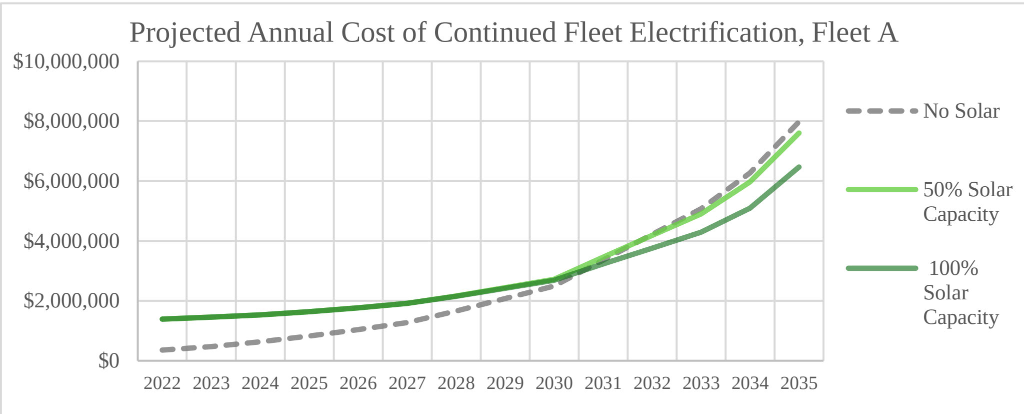

Figure 9: Annual cost of further fleet electrification with scenarios based on level of solar power capacity

The PV system, which came with a ten-year warranty and 30 year expected lifetime, is expected to produce a return on investment in 10-12 years. The fleet would start saving money in 2031 at full solar generation capacity with a cumulative savings of over $1.5 million by 2035. At 50% capacity, the break-even point is pushed out one year to 2032 and total savings by 2035 decreases to about $300,000. With an average of 4,124 kWh produced daily, Fleet A's PV system offsets 364,574 kg CO_2 and 7.53 kg NO_x each year, or 11,000 metric tons of CO_2 and 226 kg NO_x over its 30-year lifetime. This is equivalent to driving 27,485,231 miles in an average gasoline passenger vehicle [10].

The 130 kWh ESS was programmed for TOU arbitrage, meaning charging when costs are lowest and discharging when highest. Free energy via solar power generally charged the battery from 8 am-3 pm. This energy was discharged to supplement BEV charging during high rate periods and when solar power was not generated, generally from 6-9 pm. If there was no demand from the BEVs such as on weekends, energy would be sold back to the grid. Disregarding the fact that the PV system covered nearly all electricity costs, the ESS's energy (130 kWh) and power rating (60 kW) were too small to significantly affect cost. The ESS

[4] "Non-bypassable fees" are costs levied by utilities meant to cover the baseline cost for being connected to the grid and other costs that are not impacted by renewable energy generation or energy consumption

discharged about 75 kWh per day, virtually its entire usable capacity. However, the BEVs consumed nearly ten times as much energy on average. The BEV meter regularly drew nearly 300 kW from the grid, five times the ESS's maximum discharge rate. If used for TOU arbitrage, the ESS would save the fleet a maximum of only $30-45 per day but closer to $12 based on actual charging practices. ESSs can instead be used to offset demand charges by supplementing grid power when demand is highest (known as "peak shaving"), lowering the monthly fee. The ESS's hypothetical impact on demand charges was estimated by applying the rate structure at Fleet C (with demand charges) to Fleet A's energy consumption. With their current ESS, Fleet A's maximum demand charge reduction would only be $60 from a $3,000 monthly fee. The ESS would need to discharge at close to 300 kW and have a capacity of at least 600 kWh to offset peak grid demand. As fleets deploy more BEVs, they should scale their ESS to ensure peak shaving is possible. This is especially true under net metering plans where PV energy production can reduce total energy costs (kWh) but cannot mitigate demand charges (kW), while ESS can.

5 Modeling Fleet Electrification Scenarios

Understanding BEV infrastructure power demands and right-sizing this technology are concerns expressed across the industry. Current models or tools focus on technical sizing and financial modeling for microgrid design, [11, 12] fuel savings calculators, [13] and total cost of ownership estimators for BEV users [14]. Few models consider changes in peak demand or energy consumption over time resulting in a lack of understanding of the true value an optimized energy infrastructure system can provide, especially as a fleet converts large numbers of vehicles to BEVs. To address this specific yet universal question, a modeling tool was developed to help fleets explore possible scenarios and optimize operations when it comes to scaling their BEV deployments and energy infrastructure. The tool uses inputs of current infrastructure capacity (i.e., rated solar power, ESS size, and charger power), vehicles and daily duty cycle, utility rates, and planned expansion to model energy consumption, peak power demand, and costs. The effects of phasing-in demand charges, projected fluctuations in fuel costs, and BEV technology improvements are included as well. The primary objective of the model is to assist fleets with visualizing their charging patterns and estimating maximum demand charges. By revealing when and why costs are projected to be highest, fleets can experiment with adjusting charging practices or energy infrastructure capacities to minimize these costs.

5.1 Fleet Duty Cycle and Charging Schedule

Duty cycles influence charging duration and schedule which in turn impact cost. The model uses duty cycle data and charger specifications for each vehicle type to estimate how many hours of charging each vehicle needs and when this might occur. Using Fleet A as a case study, charging data was analyzed for each vehicle type over a typical day (Figure 10) and the corresponding energy demand represented visually (Figure 11).

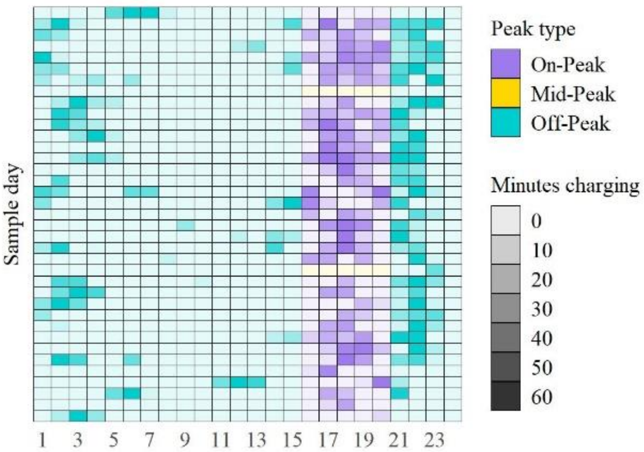

Figure 10: Heatmap showing amount of charging time needed for Class 7 box trucks each hour of the day (columns) on sampled summer days (rows)

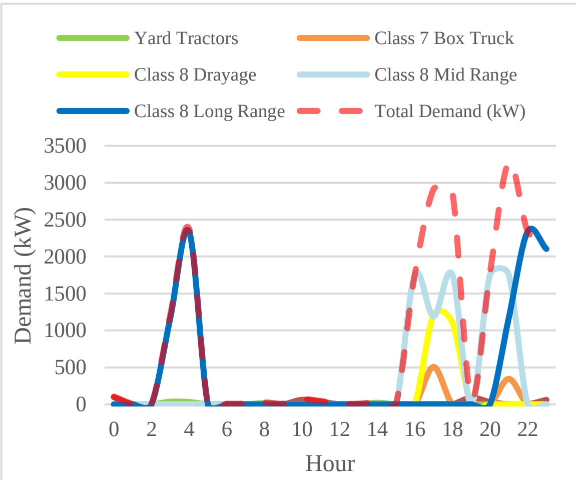

Figure 11: Visualized energy demand based on heatmap in Figure 10

Figure 11 depicts power demand per vehicle and in aggregate for a hypothetical fleet with a variety of BEVs including Class 8 trucks which cover three different range categories daily. Charging schedules need to be carefully planned to keep energy costs under control. As shown in the figures above, the highest power was drawn between 4-6 pm and 8-10 pm through a combination of simultaneous Class 8 truck and box truck charging. Because utility rates are highest between 4-9 pm, the fleet could consider waiting until 9 pm to begin their charging. If demand charges applied, the fleet could also consider staggering charging times to help minimize the maximum power draw.

The highest power draw for most fleets will be HD trucks because they usually have the largest battery capacities and highest charging rates. Planning HD truck charging will be crucial for fleets seeking to minimize costs. The more details a fleet can gather on their vehicles' duty cycles and charging schedules, the better they can plan for an electrified future. The tool can use a fleet's charging schedule and expected adoption rate of BEVs to estimate peak electricity demand into the future as shown in Figure 12 below.

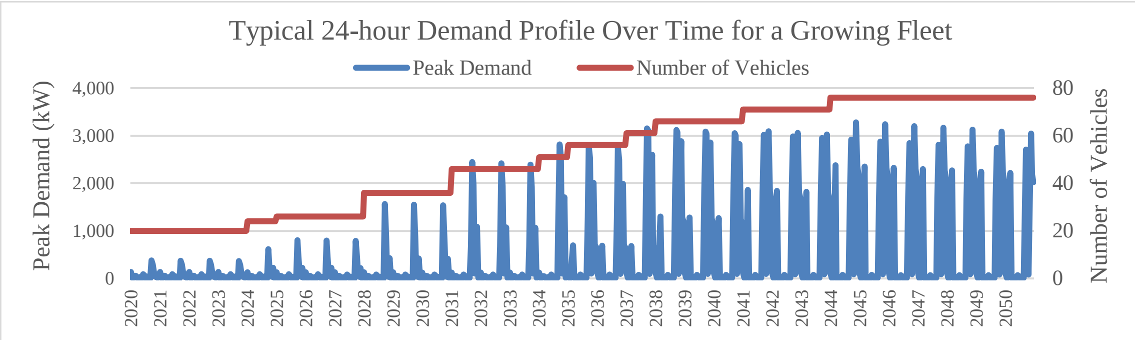

Figure 12: Peak demand throughout each hour of a typical day for each year through 2050 as a fleet adopts more BEVs

In the modeled scenario, there is a steady increase in peak demand as additional trucks are deployed. Halfway through this expansion, demand charge costs already approach $30,000 per month if we assume demand charge rate equal to what Fleet C was subjected to. The model assumes that vehicles of the same type will be charged following the same schedule due to duty cycle constraints such as needing to run routes in the morning and charging in the evening. This is often a reality for commercial fleets, but it means that the demand charges estimated are a cost ceiling. The model can be rerun using updated charging schedules to assess the resulting effects.

5.2 Projected Energy Cost Scenarios

Projecting energy costs under different BEV fleet growth scenarios is a key feature of the model. Figure 13 compares the total energy costs for a fleet and its facility from 2020-2050 under three scenarios: continuing diesel vehicle operations, BEV deployment, and BEV deployment with on-site energy infrastructure.

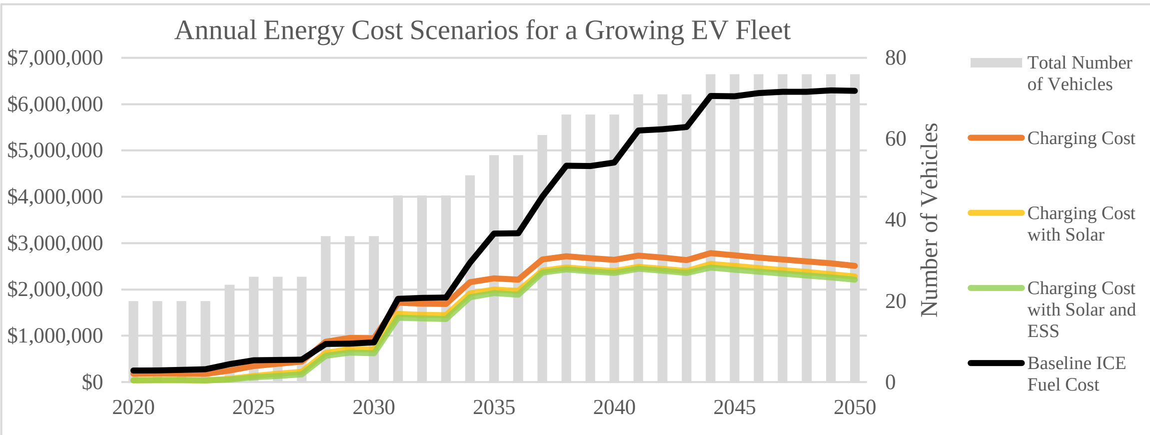

Figure 13: Annual total number of vehicles (equivalent for diesel and BEV) and fleet energy costs modeled with and without PV solar and an ESS[5]

[5] This model includes BEV charging costs from demand charges, assuming a phase-in approach from 2024-2030 as is expected in this

In this scenario, solar power is rated at 450 kW and the ESS is 200 kWh. Solar production efficiency is assumed to be 65% to account for seasonal variation, weather, and other incidents. The on-site ESS is modeled to offset demand charges, which were assumed to begin in 2024, while solar is modeled to offset electricity cost. The stepwise increase in energy cost is coupled with the addition of more BEVs over time.

Deploying a solar energy system was found to decrease energy costs significantly, with the ESS providing a further marginal decrease. The solar system itself saved an estimated $3M versus the baseline diesel scenario by 2050. This is reduced to $1M including installation costs. This projection shows the benefit over time of maximizing energy infrastructure to lead to lower operating costs in a fleet of growing BEVs.

5.3 Planning Solar and ESS Capacity

Calculating the appropriate size for a fleet's solar array and ESS is one of the most important determinants of energy cost saving. An ESS helps reduce monthly peak demand ("peak shaving") and associated demand charges. However, as a fleet continues to add BE trucks, this benefit can be overtaken. Figure 14 and Figure 15 show how peak shaving would evolve for a growing BEV fleet with a single ESS of 200 kWh.

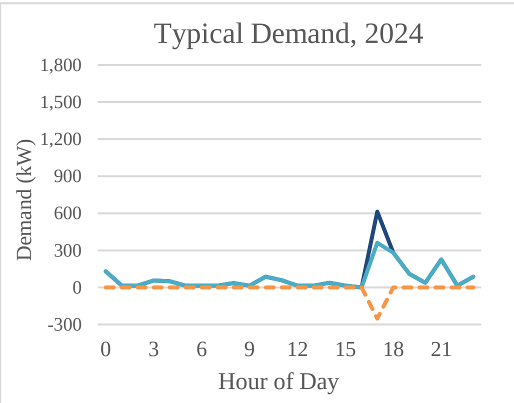

Figure 14: Peak demand shaving using an ESS for a fleet with 24 BE trucks in 2024

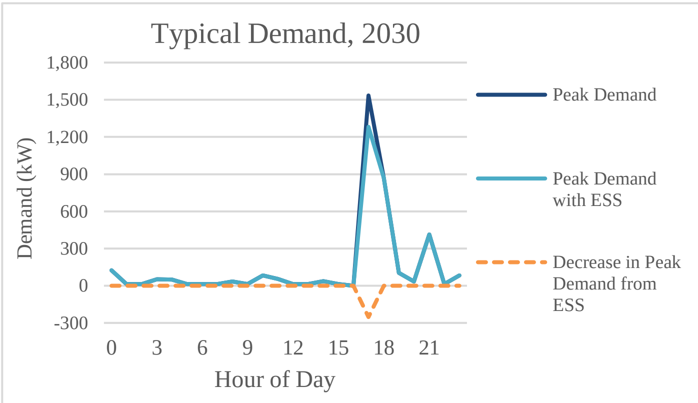

Figure 15: Peak demand shaving using an ESS for a fleet with 36 BE trucks in 2030

In 2024, peak demand is about 600 kW, incurring about $6,000 monthly in demand charge fees before peak shaving. A 200 kWh ESS reduces the peak demand to around 400 kW, saving $2,000 or 33%. When the fleet has 36 BEV trucks in 2030, the same ESS offers the same $2,000 per month savings but the demand charge balloons to over $15,000. A fleet intending to deploy more BEVs should plan ahead and install a larger ESS than what is needed today. A large solar array should be paired with the ESS to prevent demand charges from charging the ESS itself. Deploying a large solar array and ESS before it is needed can provide a fleet with more predictable benefits versus growing their systems over time. The best plan will be unique to each particular fleet.

Fleets' energy costs are closely tied to their dependency on the grid. Projecting a fleetwide energy consumption profile allows for estimating when a planned energy management system would be overwhelmed by demand. Planning for further electrification and infrastructure expansion is then possible. If starting with small solar and ESS capacity, a fleet's energy needs could quickly exceed their infrastructure. Figure 16 and Figure 17 compare the energy demand of a growing BEV fleet with a small

utility's territory, as well as energy consumption costs. Electricity starts at $0.12/kWh and remains relatively constant through 2050. Diesel prices begin at $5.46/gal in 2020 [13] and reach $8/gal by 2050. Future price changes come from EIA projections [14].

(450 kW) versus large (2,000 kW) solar system.

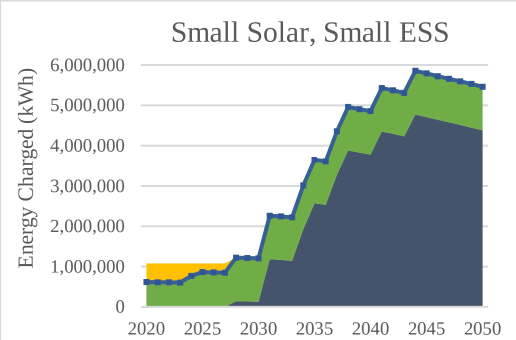

Figure 16: Energy consumption for a hypothetical growing BEV fleet with a small ESS (200 kWh) and small solar array (450 kW) installed in 2020

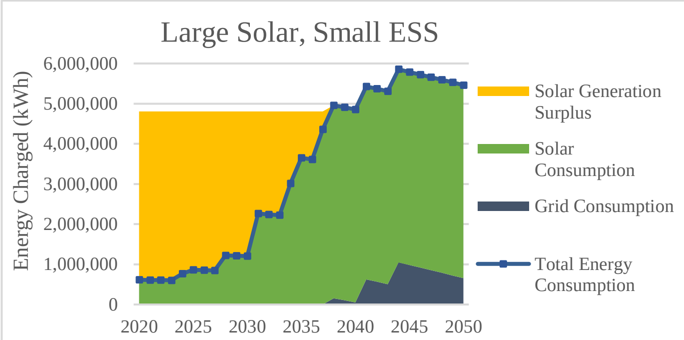

Figure 17: Energy consumption for a hypothetical growing BEV fleet with a small ESS (200 kWh) and large solar array (2,000 kW) installed in 2020

By 2027, the fleet in Figure 16 with a small solar array and small ESS has exhausted their solar capacity and starts to increasingly rely on grid energy, peaking at over 4.75 million kWh in 2044. Annual electricity cost rises to more than $1,600,000 per year based on the fleet behavior modeled. Alternatively, a fleet investing in a large solar array maintains a surplus through 2037 and a manageable level of grid consumption afterwards (maxing out at $100,000-$250,000 annually). Under this scenario, the fleet would save more than $1 million on energy costs by investing in a large solar system. A long-term BEV adoption plan can ensure fleets that their infrastructure investments will continue to pay off for years to come. CALSTART will be developing this tool further and it should become available for public use within the next year.

6 Conclusion

The goal with this discussion is to share lessons learned from early deployments of MHD BEVs and the accompanying energy infrastructure. Freight stakeholders currently lack real-world data performance data that is critical in planning fleet electrification and optimization. These two projects offer unique insight into the current state of this technology. The variety of advanced BEV equipment deployed and analyzed provides a look at what the near future brings. Results show the impacts of different management strategies and their effects on fleet operations, which can be useful as more fleets plan their clean energy transitions.

A few key lessons are clear. Monitoring and continually optimizing the energy flow at freight facilities will be crucial for fleets to realize the benefits of transitioning to electrified operations. Under TOU utility rates, fleets are advised to plan BEV charging for off-peak hours. This can be done manually with a little planning and the cost savings can be significant. Under rate structures with demand charges, peak power demand can be minimized manually through staggered charging or with smart charging software if available. Vehicles that consume the most energy generally charge at the fastest rate and thus require the most consideration. Each fleet's optimal solution will be determined by their specific technology deployed, operating schedules, and utility policies.

An electrification scenario modeling tool has been developed to help fleets explore their options. This includes adjusting charging times to minimize costs, projecting costs under different BEV and infrastructure adoption scenarios, and right-sizing solar energy and ESSs. The modeling tool accounts for these complex variables so that fleets can easily get an estimation of possible outcomes and observe the effects of different technology and operational choices. The tool is being developed into a public, web-based resource for launch in the coming year.

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Presenter Biographies

Chase LeCroy is a Technical Program Manager responsible for leading data collection and analytics strategy on CALSTART's Validation & Assessment Team, overseeing a team working on several large-scale data synthesis projects including the two described above. He has worked on various medium- and heavy-duty clean transportation projects across many sectors. Chase has a Bachelor of Science in Earth Science from Rice University and a Master of Environmental Science and Management from the University of California, Santa Barbara.

Jon Gordon is a Technical Project Manager II for CALSTART's Validation & Assessment Team. In three years with the organization, he has supported and managed numerous projects including the two case studies described above. His specific experience extends to several other heavy-duty and offroad electrification demonstrations, commercialization studies, and policy efforts. Jon has a Bachelor of Science in Civil and Environmental Engineering from the University of California, Davis.