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Abstract

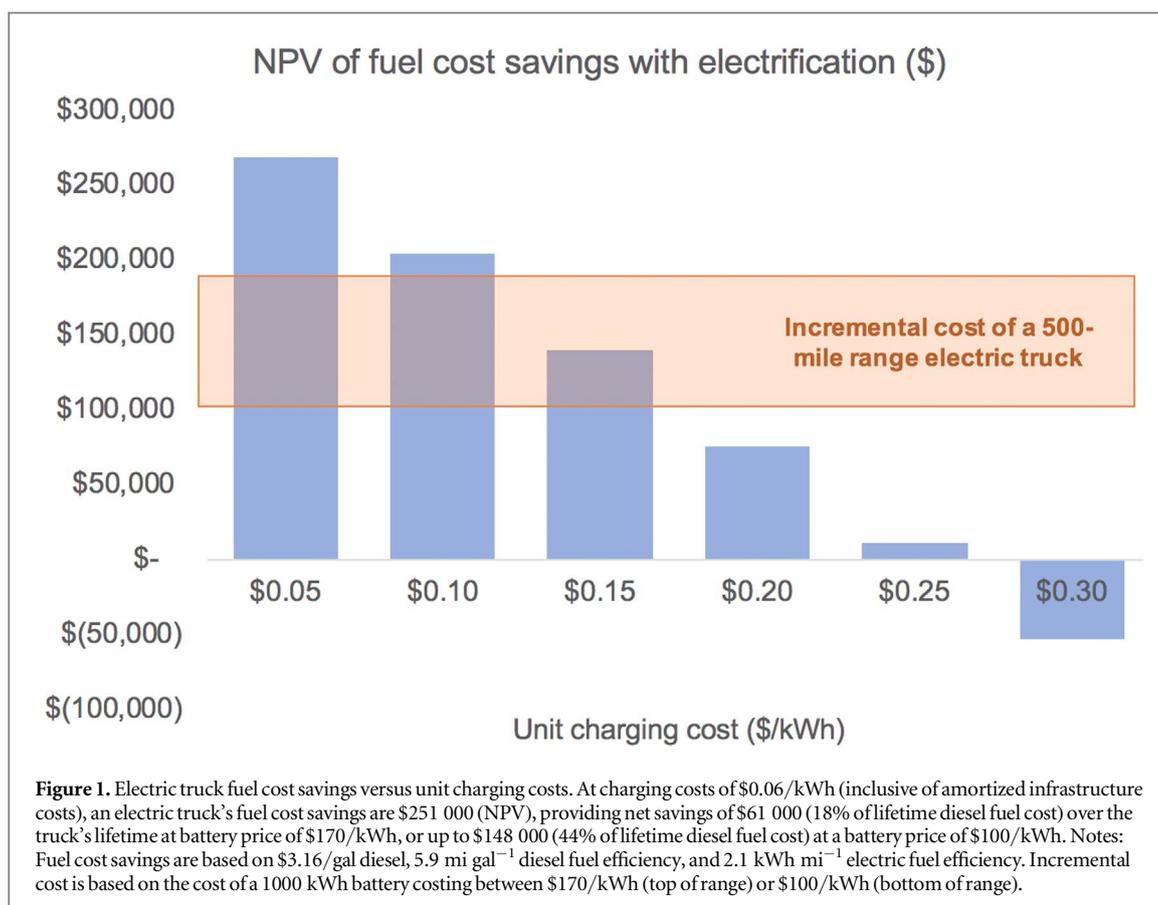
The imperative to decarbonize long-haul, heavy-duty trucking for mitigating both global climate change as well as air pollution is clear. Given recent developments in battery and ultra-fast charging technology, some of the prominent barriers to electrification of trucking are dissolving rapidly. Here we shed light on a significant yet less-understood barrier, which is the general approach to retail electricity pricing. We show that this is a near term pathway to \$0.06/kWh charging costs that will make electric trucking substantially cheaper than diesel. This pathway includes (i) reforming demand charges to reflect true, time-varying system costs; (ii) avoiding charging during a few specific periods (<45 h in a year) when prices are high; and (iii) achieving charging infrastructure utilization of 33% or greater. However, without reforming demand charges and low utilization of charging infrastructure, charging costs more than quadruple (to \$0.28/kWh). We also illustrate that a substantial share of current trucking miles within select large regions of the United States can be reliably electrified without constraining electricity generation capacity as it exists today. Using historical hourly electricity price and load data for last 10 years and future projections in Texas and California, we show that electricity demand is at least 10% lower than yearly peak demand for at least 15 h on any given day. In sum, with electricity rates that closely reflect actual power system costs of serving off-peak trucking load, we show that electric trucks can provide overwhelming cost savings over diesel trucks. For reference, at diesel prices of \$3.16/gal and charging costs of \$0.06/kWh (inclusive of amortized charging station infrastructure costs), an electric truck's fuel cost savings are \$251 000 (NPV), providing net savings of \$61 000 (18% of lifetime diesel fuel cost) over the truck's lifetime at battery price of \$170/kWh, or up to \$148 000 (44% of lifetime diesel fuel cost) at a battery price of \$100/kWh (figure 1).

1. Introduction

The imperative of decarbonizing long-distance, heavy-duty trucking to mitigate global climate change and reduce air pollution is clear. For instance, medium- and heavy-duty trucking—almost entirely diesel-based—contributes 23% of U.S. transportation-sector greenhouse gas (GHG) emissions (US EPA 2015); heavy-duty trucking is expected to contribute a third of transportation NO_x emissions by 2025 (US EPA 2018). In developing countries, this sector has an even larger impact—for example, of India's transportation emissions, heavy-duty trucking contributes 41% of the CO₂

and 55% of the NO_x (Guttikunda and Mohan 2014). However, technological constraints and economic conditions have generally suggested that electrifying this sector is challenging.

The emerging reality is different. Two recent developments suggest that two widely understood barriers to electrification of long-distance trucking have diminished substantially. One is the reduced cost of battery storage. By the end of 2017, lithium-ion battery costs had fallen more than 80%—to \$176 per kilowatt-hour (kWh)—relative to their cost in 2010 (Goldie-Scot 2019). Costs are expected to continue falling; a cost of \$100/kWh is expected by 2026 according to BNEF



(Curry 2017), and by 2020 according to Tesla (Holland 2018). The other development is the dramatically lower cost of electricity generation due in part to solar and wind technologies that are now at parity with or cheaper than coal generation on a levelized cost basis. While declining natural gas prices have played a larger role than renewables in depressing wholesale energy prices (Wiser *et al* 2017), high penetrations of renewables are expected to drive substantial drops in wholesale prices in the future (Seel *et al* 2018). These changes—coupled with the fact that several large automakers are developing multiple long-range electric truck models, and ultra-fast charging technologies are being commercialized—suggests that truck electrification is not unrealistic in the near to medium term.

However, the presumed need for electric trucks to charge via direct-current fast charging (DCFC) would likely incur significant electricity demand charges, which could make electric trucks uneconomical. Electric utilities commonly employ demand charges, which charge customers on a \$/kW basis for their maximum instantaneous consumption in a given period. The justification for demand charges is that the utility must maintain adequate generation, transmission, and/or distribution capacity to serve the customer at all times (Wood *et al* 2016). Yet non-peak-coincident demand charges are levied regardless of whether an individual customer's peak coincidences with system peak and imposes additional costs on the grid. As stated by

economist Severin Borenstein, 'the single highest consumption hour of the billing period is not the only, and may not even be the primary, determinant of the customer's overall contribution to the need for generation, transmission, and distribution capacity.' Instead, 'time-varying price schedules... can easily be designed to more effectively capture the time-varying costs that a customer imposes on the system' (Borenstein 2016).

Given this context, the focus of this paper is twofold. First, we illustrate that it is feasible for trucks to avoid charging during peak demand hours, when the power system is truly constrained. For example, using historical hourly electricity price and load data for the last 10 years and future projections in Texas and California, we show that the demand is at least 10% lower than the yearly peak demand for at least 15 h on any given day. Further, we show that a substantial share of total annual trucking miles within select US regions can be electrified using the current grid configuration with little or no impact on grid generation capacity, and thereby little impact on generation cost to current electricity consumers. We demonstrate this through a detailed analysis of available system capacity during each hourly interval from 2010–2018 for Texas and California independent system operator (ISO) regions, as well as under alternative future scenarios with substantial renewable electricity generation.

Second, we estimate the achievable cost of electric truck charging to illustrate the importance of appropriate electricity prices to making electric trucks economically

Table 1. Unit charging cost model. Capital costs and \$/MW costs levelized over 20 year lifetime and baseline 33% capacity utilization (with sensitivity of 10% utilization) using 7% cost of capital^a.

Cost component	Estimation method for customer in ERCOT	Estimation method for customer in SCE territory within CAISO	Estimation method for direct-access customer in CAISO
	Modeled as the unit charging cost for a retail customer able to access wholesale energy prices in ERCOT territory. Realistic under current regulation.	Modeled as the unit charging cost for a retail customer on SCE's real-time pricing program. Realistic under current regulation.	Modeled as the unit charging cost for a retail customer able to access wholesale energy prices in CAISO territory, but (1) paying the same T&D charges as in ERCOT, and (2) not paying for resource adequacy. Not realistic under current regulation; modeled to understand the impact of not paying for capacity expansion if charging exclusively off-peak.
Electricity Generation	Modeled as the price a retail electric provider would pay to pass through the real-time price to a retail customer: \$27/MWh ^b	Modeled as the price a large customer connected at the transmission level would pay on SCE's 2017 real-time price tariff: \$38/MWh ^c	Illustratively modeled as the price an energy service provider would pay to pass through the real-time price to a direct-access customer, not including resource adequacy payments: \$34/MWh ^d
T&D	Modeled as the T&D charges paid by a transmission-connected customer in Oncor service territory, charging only at non-critical-peak times: \$2/MWh ^e	Modeled as the price of a large customer connected at the transmission level on SCE's 2018 real-time price tariff: \$49/MWh ^f	Illustratively modeled as the T&D charges paid by a transmission-connected customer subject to critical peak pricing, charging only at non-critical-peak times: \$2/MWh ^g
Infrastructure			
Electrical equipment	Modeled as the average of best-case electric vehicle supply equipment (EVSE) costs, taken to be (1) the balance of system (BOS) costs of grid-tied storage, and (2) industry-projected EVSE costs: \$18/MWh ^h		
Grid connection cost	Modeled as the average U.S. grid connection cost for utility-scale solar photovoltaic (PV) projects: \$5/MWh ⁱ		
O&M cost	Modeled as the cost of (1) inverter maintenance for a PV plant, (2) preventive maintenance and inspection, averaged for both an existing electric bus charging station and the electrical/wiring inspection costs of a PV plant, and (3) estimated structural maintenance: \$5/MWh ^j		
Installation cost	Modeled as the installation costs associated with grid-tied storage plus land costs in California and Texas: \$8/MWh ^k		

^a Based on recent California IOU rates of return (CPUC 2018).

^b Number modeled based on ERCOT energy prices from 2011–2018 (ERCOT 2018), ERCOT day-ahead market clearing prices for capacity (ERCOT 2019), SCID monthly fee from CAISO (California ISO 2018), conversations with ERCOT staff, and industry interviews.

^c Number modeled based on SCE 2017 rate schedule TOU-8-RTP (Southern California Edison 2017), using 2017 Los Angeles temperature data.

^d Number modeled based on CAISO real-time prices from 2012–2018 (LCG Consulting 2018), California RPS standards (CPUC, n.d.), REC prices (Pinko and Weinrub 2013), and CAISO fees (California ISO 2018).

^e Number modeled based on Oncor retail delivery tariff (Oncor 2017).

^f Number modeled based on T&D charges in SCE 2017 rate schedule TOU-8-RTP (Southern California Edison 2017).

^g Number modeled based on Oncor retail delivery tariff (Oncor 2017).

^h Number modeled based on utility-scale solar+storage BOS costs (Fu *et al* 2018), inverter lifetime (Enbar *et al* 2015), and industry interviews.

ⁱ Number modeled based on US utility-scale solar grid connection costs (IRENA 2016).

^j Number modeled based on wiring/electrical inspection costs for PV plants (Enbar *et al* 2015), inverter O&M costs (Enbar *et al* 2015), PMI costs from Foothill Transit, and industry interviews.

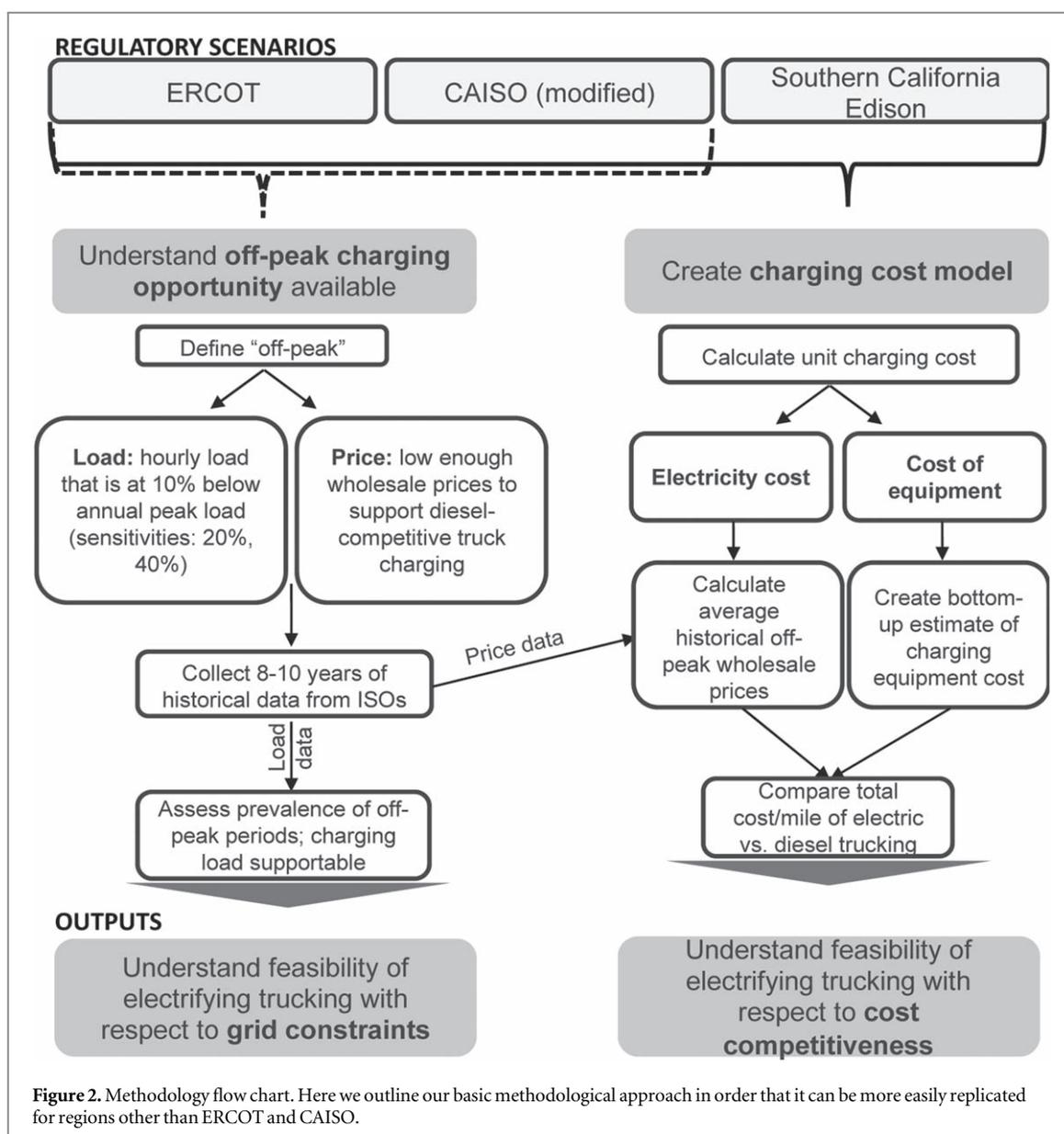
^k Number modeled based on the average price of existing truck stops in California and Texas (Interstate Frontage 2018) and grid-connected storage cost of installation labor and equipment, EPC overhead, and interconnection (Fu *et al* 2018).

competitive. Specifically, we show why it is essential to align a retail consumer's electricity prices with wholesale energy market prices and with their true contribution to buildout of system-wide generation capacity. We do this by modeling scenarios with access to dynamic energy and T&D pricing (in ERCOT and CAISO) and scenarios without (in Southern California Edison territory) (see table 1). We argue that, if trucks can avoid charging when the system is truly constrained, they should realize much lower electricity costs because they are not incurring the cost of

building additional generation capacity. We do not consider prices on environmental externalities in this analysis. We also show how pricing is negatively interrelated with low average utilization of charging infrastructure.

2. Methods and data

We investigate the cost of DCFC and the feasibility of off-peak charging under different regulatory regimes.



We compare (1) an Electricity Reliability Council of Texas (ERCOT) direct-access customer, and (2) a full-service customer within the Southern California Edison (SCE) utility territory. We also envision (3) an illustrative CAISO direct-access customer with modified delivery charges (table 1). We chose Texas because ERCOT is among the most liberalized US electricity markets (Stoft 2002): it is the only US ISO with both an energy-only wholesale market and full retail competition. We selected California because it is a leader in clean energy technology and policy, has vertically integrated utilities, and its policies will likely encourage the adoption of electric trucks. By comparing two different states and two different regulatory regimes (i.e. regulated utilities versus direct-access customers), we highlight how differences in electricity policy and regulation affect the economics of truck charging. See figure 2 for a schematic depiction of our approach.

First, we explain our analysis of historical price and load data to determine the opportunities for off-peak charging (section 2.1). Separately, we present our basic economic model for the cost of electrified trucking. This model consists of calculating the unit charging cost (section 2.2) and integrating it with the incremental cost of truck electrification (section 2.3) to obtain an overall cost per mile for truck electrification.

2.1. Off-peak price and demand analysis

We analyze data on demand and wholesale energy prices in ERCOT and CAISO to understand the prevalence of off-peak periods that would support truck charging. Various definitions exist for the term 'off-peak'; in this paper, we use it to indicate hours with low demand relative to yearly peak demand (i.e., hourly demand at least 10% below yearly peak demand), and hours with low enough wholesale energy prices to support competitive truck charging.

In terms of demand, this use of the term off-peak aligns with the concept of critical peaks—that is, analyzing off-peak periods relative to truly extreme system conditions rather than daily peaks that may not reflect true system constraint.

We analyze historical demand and price data. Determining if adequate off-peak demand windows exist is the most fundamental question regarding tariff design, to see if truck charging can avoid incurring new generation capacity buildout on the electricity system. Separately, determining if off-peak price periods consistently exist is important for determining if low energy prices are available even on hot days with extreme price spikes.

We also analyze hourly demand and price projections for the year 2030 for both ISOs. The projection we analyze was built on a scenario of each ISO achieving 40% variable renewable energy (VRE) penetration with balanced amounts of wind and solar (Seel *et al* 2018). In this paper, we do not attempt to predict how the electricity system will evolve in response to higher EV penetrations; we instead use historical and forecasted scenarios as baselines to see where additional EV load could fit in.

We only analyze price and demand in wholesale markets and not within SCE territory because (1) on the demand side, we want to examine the capacity of the larger system, and not artificially constrain our understanding of available capacity, and (2) on the pricing side, SCE's fixed hourly real-time price offering is determined annually and does not necessarily reflect actual grid conditions.

2.2. Charging cost model

Unit charging cost is principally a function of the levelized cost of charging equipment and the cost of electricity:

$$\text{Unit charging cost} = \text{Levelized cost of equipment} + \text{Cost of electricity.} \quad (1)$$

The levelized cost of equipment is the minimum price per unit of energy delivered (kWh) that a charging service provider should charge consumers to break even on the investment in charging equipment and grid interconnection. The levelized cost is a function of (1) the useful service life of the charging equipment, and (2) the utilization rate in terms of average kWh/day delivered to consumers. Utilization rate is defined as the fraction of time trucks spend charging per day (i.e. a 33% utilization rate means a station is fully utilized for 8 h out of 24). A higher utilization rate implies a lower levelized cost per kWh for the equipment. In this paper, we assume that utilization rate is constant throughout the project lifetime.

The cost of electricity is a function of the cost of generation (i.e. energy production) and the cost of transmission and distribution (T&D). Both generation

and T&D have fixed and variable cost components.

$$\text{Cost of electricity} = \text{Cost of generation} + \text{Cost of T\&D.} \quad (2)$$

Generation costs consist of the variable cost of producing a unit of electricity and the fixed cost of having adequate generating capacity on hand. The recovery of these costs varies significantly by territory. In ERCOT, both the fixed and variable costs of generation are intended to be recovered in the energy-only market. In CAISO, the energy market covers variable generation costs, but separate capacity contracting (for resource adequacy) covers fixed capacity costs. In SCE's territory, customers pay different tariffs that cover generation costs; large customers can access a 'real-time' volumetric energy price that varies between fixed levels hourly depending on the time of day and the temperature.

Recovery of T&D costs also differs from one market to another. Typically, a portion of T&D costs is recovered through energy prices, and a portion is recovered through demand charges. In ERCOT, T&D costs are largely recovered through a critical-peak pricing scheme in which customers pay for their peak use during four 15 min critical-peak demand periods per year. Eighty percent of a customer's use during these windows determines their demand charges for each other month of the year; this is called the '80% ratchet.' In CAISO, both direct-access customers in SCE's territory and full-service SCE customers pay a non-coincident monthly peak demand charge and a per-kWh charge (called an 'energy charge') for T&D.

To analyze unit charging cost, we model a transmission-connected 9.4 MW DCFC station that can simultaneously charge five trucks to a 75% state of charge in 30 min. The size of the truck battery pack—1000 kWh—is estimated based on a 500 mile range semi with a fuel efficiency of 2 kWh mi⁻¹, which current market trends suggest is a reasonable efficiency⁴; however, the modeled per-kWh charging costs would be the same for smaller trucks. We model a baseline station utilization rate of 33%⁵ with a sensitivity of 10%. Truck charging is scheduled during the hours of the day with lowest-cost electricity. The model is based on long-range combination trucks charging at public truck stops; grid-connection and land cost values reflect this scenario.

Table 1 summarizes the methods and data used to estimate each of these unit charging cost components.

⁴ Tesla gives 2 kWh mi⁻¹ as the upper bound for the efficiency of the Tesla Semi (Tesla 2019). Burns & McDonnell, in an analysis of the electricity infrastructure of the Port of Oakland, cite manufacturers of Class 8 trucks as claiming less than 2 kWh mi⁻¹ (Burns & McDonnell Engineering Company, Inc., 2019); California ARB also supports a roughly 2 kWh mi⁻¹ estimation based on dynamometer testing and in-use data (California ARB 2019).

⁵ Upper bound based on utilization rate of 30%–40% assumed for fueling stations in scenario of 100% conversion of long-haul freight trucking to natural gas (Tong *et al* 2019).

Table 2. Inputs to per-mile fuel cost estimation.

	Inputs: electric		Inputs: diesel
Fuel efficiency	0.48 mi kW ⁻¹ h ⁻¹ (California ARB 2019)	Fuel efficiency	5.87 mi gal ⁻¹ (California ARB 2019)
Battery capital costs	\$100/kWh (Curry 2017) and \$170/kWh (Goldie-Scot 2019)	Diesel price	\$3.16/gal (national), \$2.81/gal (TX), \$4.20/gal (CA)
Battery cycles	2000/lifetime (Miles 2018)	Miles/lifetime	1 000 000 (California ARB 2014)
Battery depth of discharge	75% (Miles 2018)		
Miles/year	68 000 (Alternative Fuels Data Center, n.d.)		

It should be noted that diesel price, truck mileage, grid connection cost, and other variables each have a high degree of variability and uncertainty, although point estimates are used in representative calculations.

2.3. Per-mile cost of electric trucking

After calculating unit charging cost, we compare the total cost per mile of electric and diesel trucking. We assume that the incremental cost of an electric truck relative to a diesel truck is simply the cost of the battery (minus the cost of the diesel engine and transmission, plus the difference in costs of diesel and electric drivetrains), and we treat the battery as an asset that depreciates at a constant level per mile⁶. This is consistent with Sripad *et al.*, who use a detailed model of total cost of ownership to show that battery replacement costs and electricity price are the top two critical determinants of the payback to electrification (Sripad and Viswanathan 2019). Our model explicitly accounts for both of those factors and complements the analyzes of Sripad *et al.* We ignore maintenance costs, although this only makes our estimate more conservative, because electric vehicles are expected to realize lower maintenance costs relative to internal combustion engine vehicles (Sripad and Viswanathan 2019).

Diesel fuel cost is a function of diesel price and the fuel efficiency of diesel trucks. Electric fuel cost is a function of the unit charging cost, the fuel efficiency of electric trucks, and the per-mile battery depreciation cost. We compare diesel and electric fuel costs as follows:

$$\begin{aligned} \text{Fuel cost per mile (Diesel)} \\ = \text{Diesel fuel price} / \text{Fuel efficiency diesel}, \end{aligned} \quad (3)$$

$$\begin{aligned} \text{Fuel cost per mile (Electric)} \\ = \text{Unit charging cost} / \text{Fuel efficiency EV} \\ + \text{Battery depreciation cost}. \end{aligned} \quad (4)$$

Under our approach, a lower fuel cost per mile automatically translates into a lower total lifecycle cost of ownership per mile, because the total cost of all other truck components is assumed to be identical and

thus accounted for. In other words, a lower fuel cost per mile for electric trucks implies a negative incremental cost on a lifecycle cost-of-ownership basis.

We incorporate three assumptions on diesel price into our modeling: a national average price of \$3.16/gal (EIA 2019), a Texas price of \$2.81/gal, and a California price of \$4.20/gal (AAA 2019). (Both Texas and California prices are current as of June 2019 and do not attempt to project state-specific diesel prices into the future.) We analyze incremental cost of electrification using both a state-specific and a national average diesel price in order to capture savings that are possible for both intrastate and interstate trucking. This paper primarily relies on the national average price to facilitate comparison between different electrification scenarios.

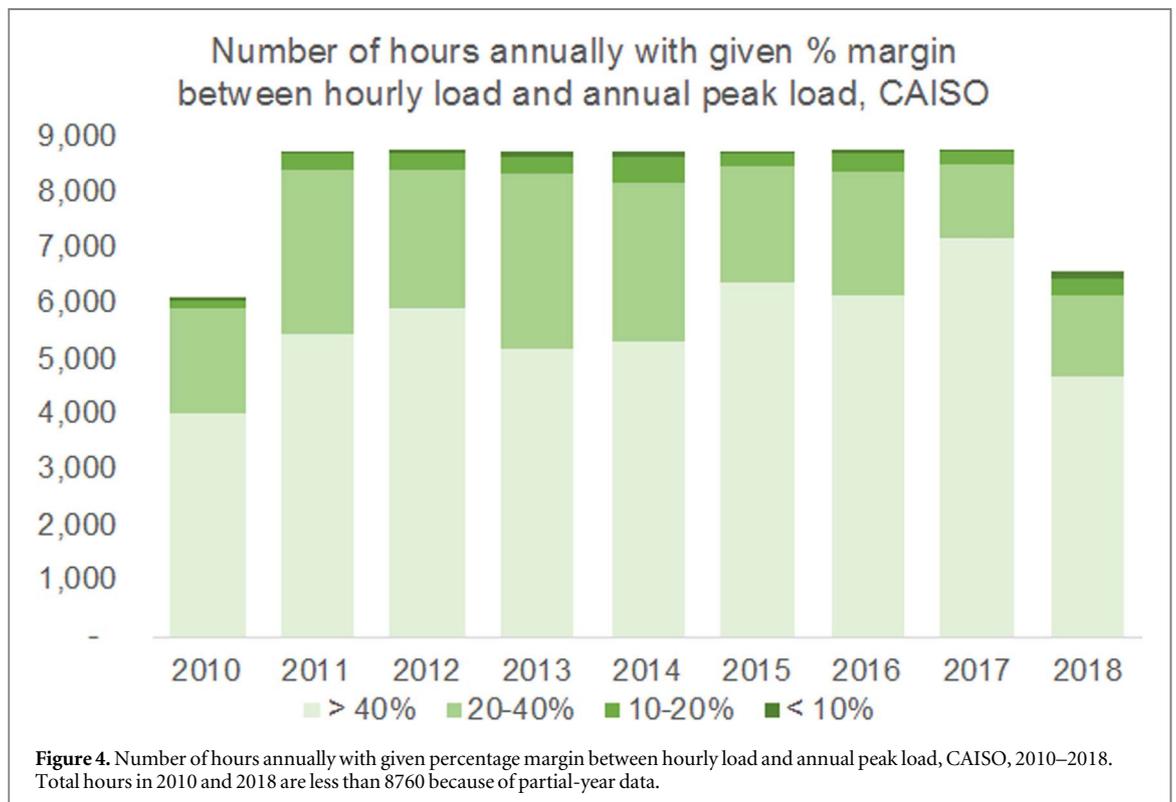
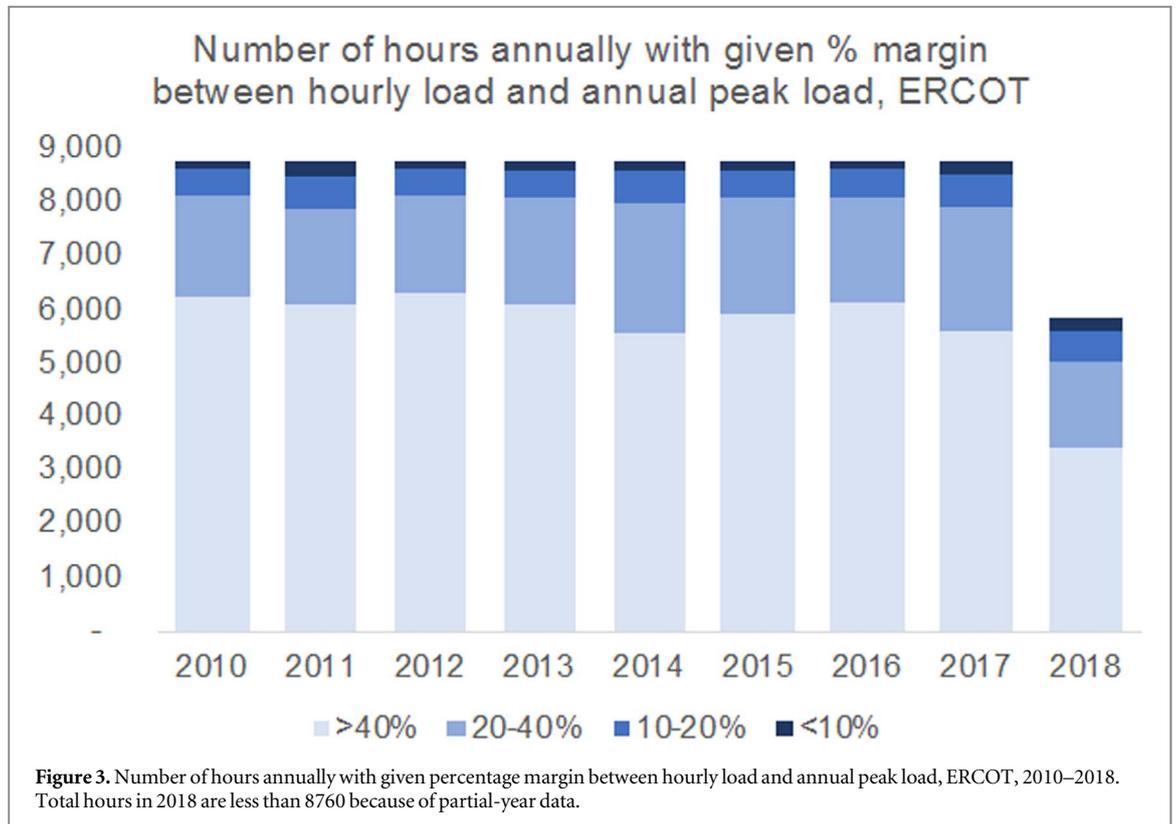
Table 2 outlines the basic inputs underlying our fuel cost per mile estimates, with the exception of unit charging cost, which varies based on the scenario used in our analysis.

3. Results

Our analysis of historical and projected demand and price data suggests that the current CAISO and ERCOT electricity systems have abundant non-critical-peak opportunities for trucks to charge in terms of both price and demand. Most hours of the year offer opportunities for trucks to charge without contributing to peak demand and, thus, to the need for additional generation capacity. Since 2010, the vast majority of hours in ERCOT (98% of hours) and CAISO (99% of hours) have provided a greater than 10% margin between hourly load and annual peak; in fact, fully 91% of hours in ERCOT and 96% of hours in CAISO have had a greater than 20% margin (figures 3 and 4).

While maintaining a 10% margin between hourly load and annual peak, 724 000 truck-charges/day, at 750 kWh/charge (or 272 million truck-miles/day) could be delivered on average in ERCOT, and 489 000 truck-charges/day (or 183 million truck-miles/day) could be delivered on average in CAISO. An average of 23 h/day in ERCOT, and 24 h/day in CAISO, offer opportunities for truck charging while maintaining a 10% margin.

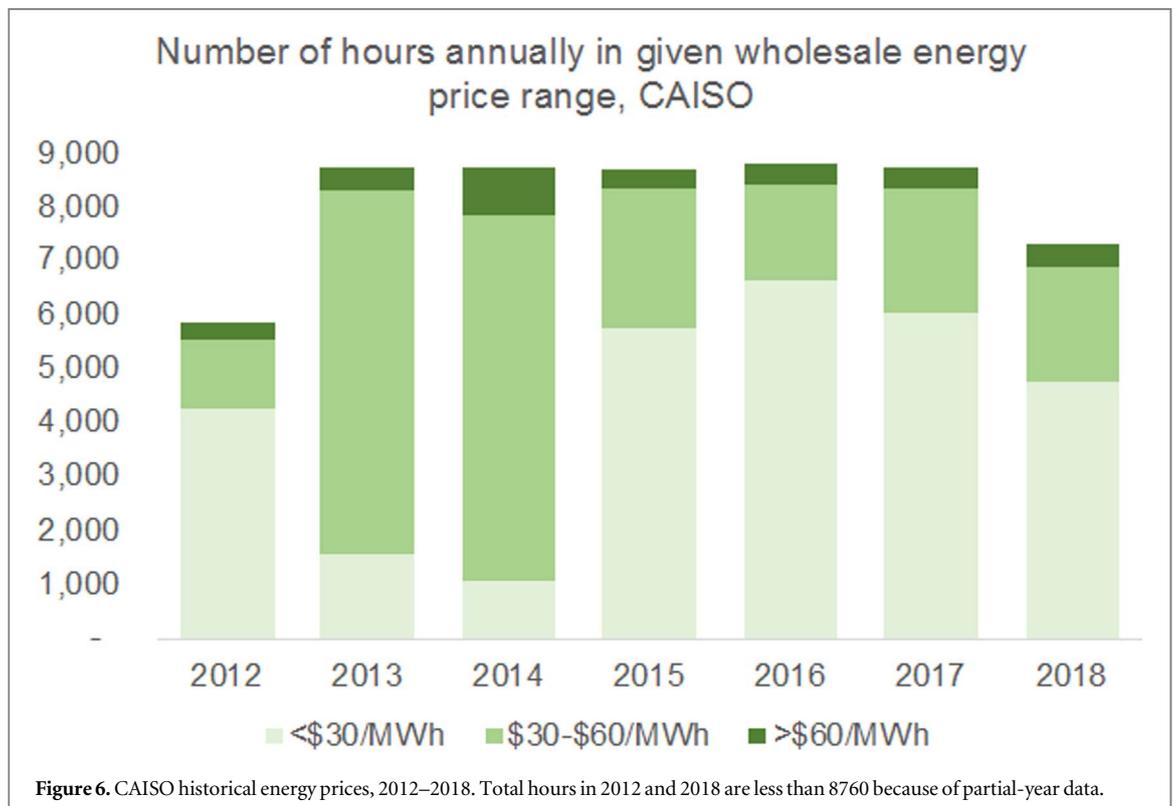
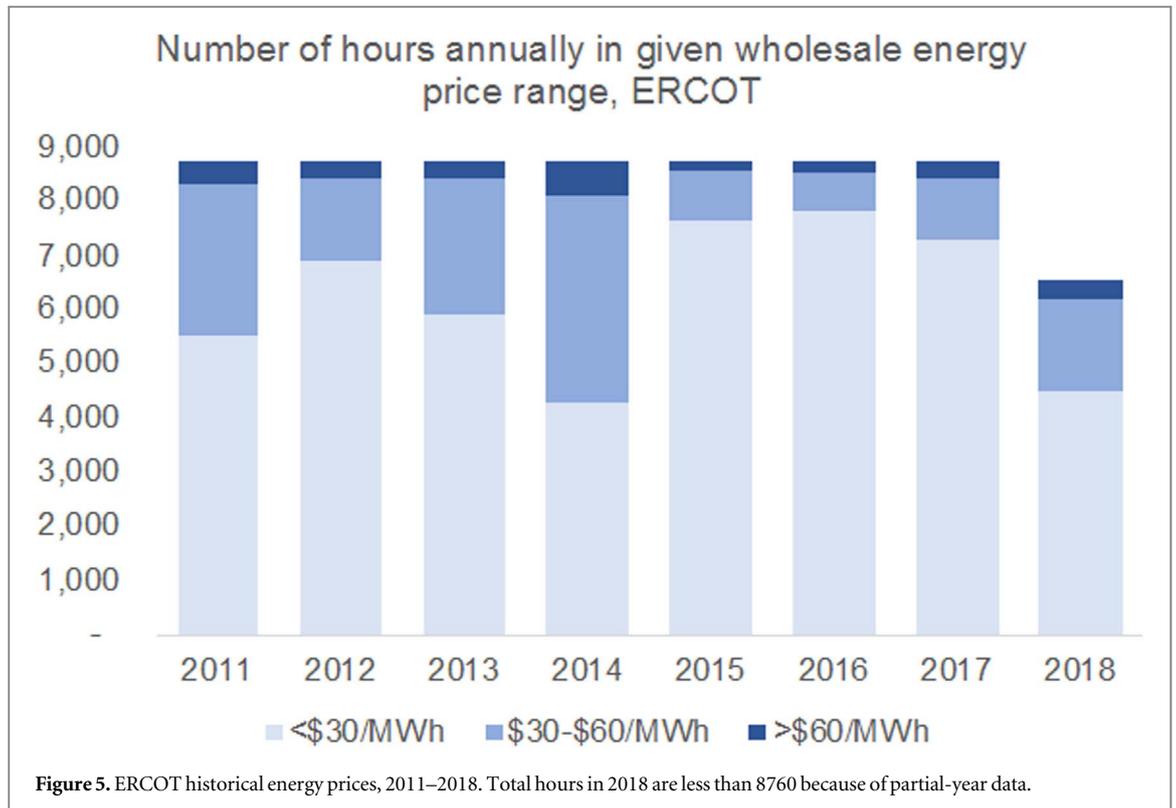
⁶ This treatment of batteries differs from the analysis in (Sripad and Viswanathan 2019), which included battery replacement costs rather than treating batteries as assets that depreciate per mile. We find the battery-as-an-asset approach to be particularly appropriate from a fleet owner perspective.



At worst (i.e. on a single day in the 9 years of data analyzed), to maintain a 10% margin between hourly load and annual peak, 15 h are available for charging. Only 239 000 truck-charges (89 million truck-miles) would be available in ERCOT, and 177 000 truck-

charges (67 million truck-miles) would be available in CAISO.

During at least 8 h of every day in ERCOT and CAISO over the past 7–8 years, wholesale energy prices have been low enough to support diesel-competitive



truck charging (figures 5 and 6)—and 8 low-price hours could enable 33% utilization of charging infrastructure. (The energy price required to support diesel-competitive charging varies slightly by ISO, but ranges from ~\$65/MWh at high battery prices to ~\$127/MWh at low battery prices).

In this period, 53% of hours in CAISO and 74% of hours in ERCOT have had average prices of \$30/MWh or less, while 95% of hours in CAISO and 96% of hours in ERCOT have had average prices of \$60/MWh or less. On average, the 8 cheapest hours in ERCOT from 2011–2018 had a price of \$20/MWh. In CAISO, the 8 cheapest hours

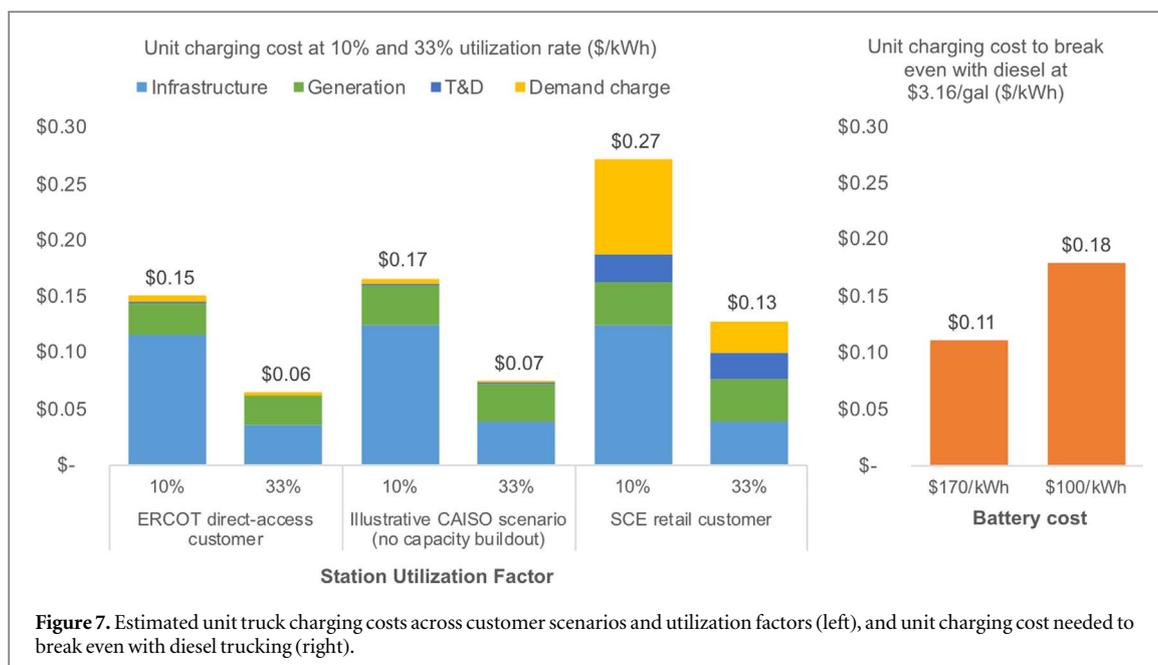


Figure 7. Estimated unit truck charging costs across customer scenarios and utilization factors (left), and unit charging cost needed to break even with diesel trucking (right).

Table 3. Historical and projected (2030) hourly load patterns in ERCOT and CAISO.

	Historical		Projected	
	ERCOT (2011–2018)	CAISO (2012–2018)	ERCOT (2030)	CAISO (2030)
% of hours with >10% margin between hourly load and annual peak load	98%	99%	98%	99%
% of hours with >20% margin between hourly load and annual peak load	91%	96%	91%	93%
Average number of 750 kWh truck-charges available per day	724 000	489 000	839 000	503 000
Number of 750 kWh truck-charges available on the most constrained day	239 000	177 000	231 000	175 000

Table 4. Historical and projected (2030) wholesale energy price patterns in ERCOT and CAISO

	Historical		Projected	
	ERCOT (2011–2018)	CAISO (2012–2018)	ERCOT (2030)	CAISO (2030)
% of hours ≤\$30/MWh	74%	53%	87%	16%
% of hours ≤\$60/MWh	96%	95%	98%	90%
Average price of 8 cheapest hours (\$/MWh)	\$20	\$27	\$16	\$31
Average price of 8 cheapest hours on the most expensive day (\$/MWh)	\$58	\$78	\$30	\$56

from 2012 to 2018 had an average real-time price of \$27/MWh. Even on the most expensive days, low-cost truck charging opportunities exist: in ERCOT, the most expensive day had 8 h averaging \$58/MWh. In CAISO, the most expensive day had 8 h averaging \$78/MWh. Electric trucking is still competitive with diesel at these prices.

These demand and price trends hold in a projection to the year 2030 under high wind and solar penetration. In CAISO demand projections, 99% of hours maintain a greater than 10% margin between hourly load and annual maximum load, although only 93% maintain a

greater than 20% margin, down slightly compared with historical data (table 3). The average amount of charging available at a 10% margin increases modestly, to 503 000 truck-charges/day (3% greater than historical), and the amount of charging available on the most constrained day decreases slightly (by 3%). In ERCOT demand projections, 98% of hours maintain a greater than 10% margin, and 91% maintain a greater than 20% margin (same as historical). However, the average truck-charges/day available at a 10% margin increase to 839 000 (16% greater than historical).

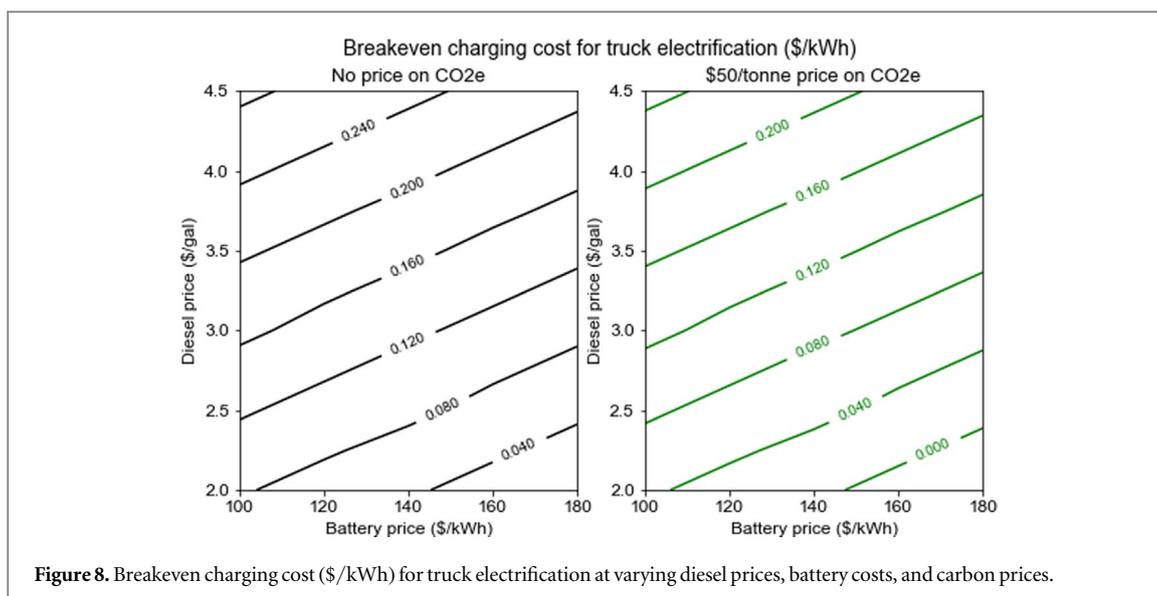


Figure 8. Breakeven charging cost (\$/kWh) for truck electrification at varying diesel prices, battery costs, and carbon prices.

Table 5. Net savings with electrification, as dollar figure and as percentage of lifetime diesel fuel costs.

Scenario	ERCOT		CAISO		SCE		
	\$0.06		\$0.07		\$0.13		
Charging cost (\$/kWh)							
Diesel price (\$/gal)	\$2.81	\$3.16	\$4.20	\$3.16	\$4.20	\$3.16	
Battery price (\$/kWh)	\$100	\$111 000 38%	\$148 000 44%	\$246 000 56%	\$137 000 41%	\$175 000 40%	\$65 000 20%
	\$170	\$24 000 8%	\$61 000 18%	\$159 000 36%	\$49 000 15%	\$88 000 20%	(\$22 000) -7%

In ERCOT price projections, 87% of hourly prices are projected at \$30/MWh or less, and 98% at \$60/MWh or less; even the most expensive day demonstrates an average price of only \$30/MWh over the 8 cheapest hours (table 4). Projected prices are higher in CAISO than in ERCOT, with only 16% of hours at \$30/MWh or less. However, 90% of hours are at \$60/MWh or less, and the average price over the 8 cheapest hours of the most expensive day is only \$56/MWh.

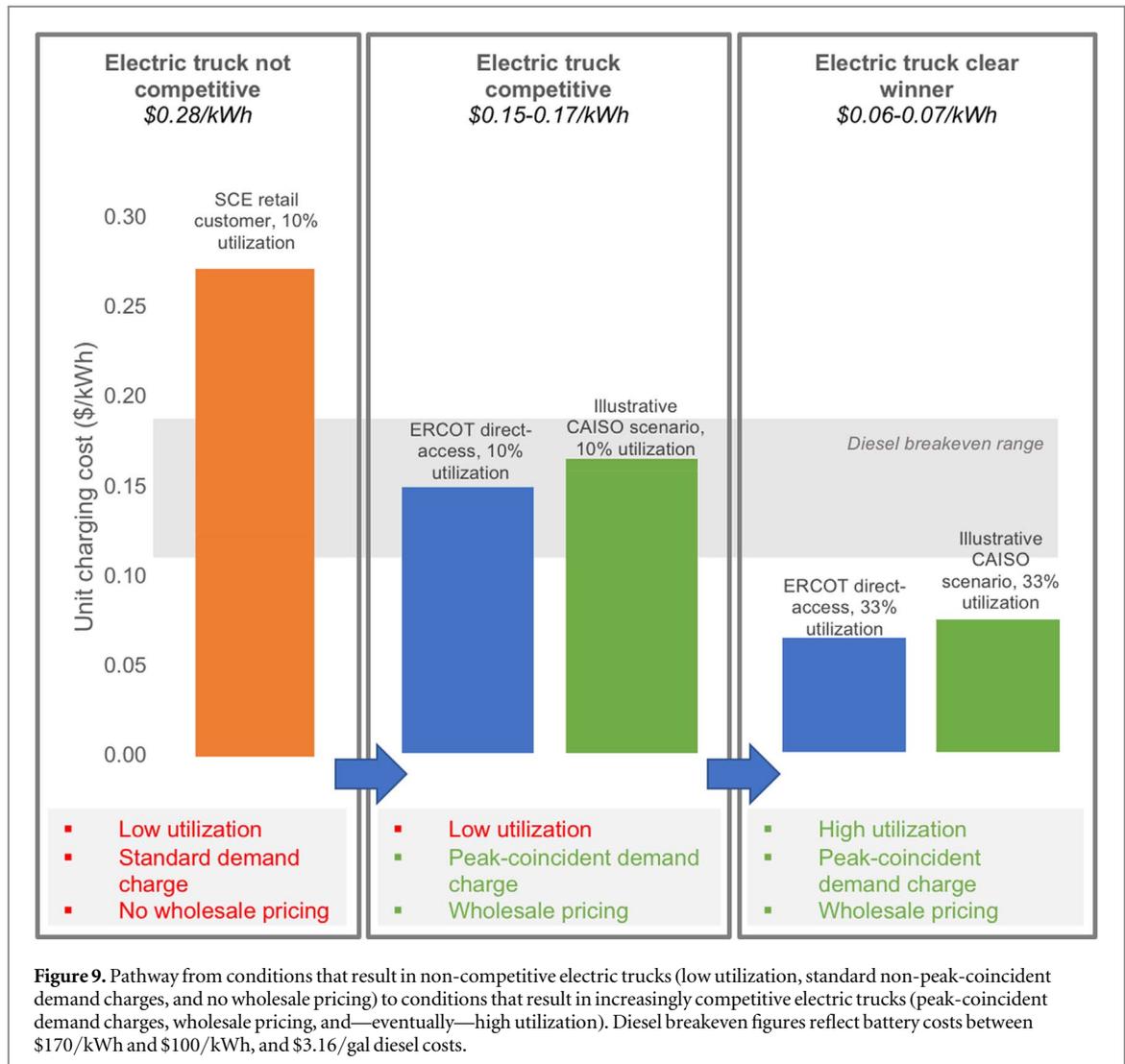
It should be noted that these figures address average prices. Price spikes are highly dependent on hourly variations in electricity demand and supply and thus are difficult to predict into the future. Similarly, in our analysis of forecasted demand, we only analyze average patterns rather than hourly extremes.

Given the opportunity for trucks to charge off-peak and at low-cost hours, we estimate that truck charging can be delivered at a lowest unit charging cost of about \$0.06/kWh (figure 7, left). At this cost, electric trucking demonstrates substantial cost savings over diesel (figure 7, right). Including infrastructure costs and assuming 33% station utilization, \$0.06/kWh charging is achievable in ERCOT, \$0.07/kWh is achievable in the illustrative no-capacity-buildout CAISO scenario, and \$0.13/kWh is achievable in SCE territory. However, at 10% station utilization, charging costs rise to \$0.15/kWh in ERCOT, \$0.17/kWh

in the CAISO scenario, and \$0.28/kWh in SCE territory.

The economics of truck charging vary significantly based on demand-charge design and charging station utilization. With a peak-coincident demand-charge design, truck charging can still be competitive with diesel at low utilization, assuming trucks charge off-peak. This competitiveness could in turn increase the utilization of truck charging stations and further reduce costs by spreading charging station costs over more kWh sold.

The breakeven point for and net savings from electrification vary depending on assumed battery cost and diesel price (see figure 8). (While this work largely avoids any pricing on environmental externalities, we have included a scenario with a \$50/tonne tax on carbon emissions in figure 8 as well). Where diesel prices are lower and battery costs higher, breakeven charging cost is lower. However, almost all scenarios demonstrate net savings over diesel trucking (see table 5)—in ERCOT, the maximum benefit from electrification of a truck amounts to 44% savings (\$148 000) over the truck’s lifetime diesel costs; in the illustrative CAISO scenario, the maximum benefit is 56% savings (\$246 000). The only scenario in which truck electrification leads to net financial losses is in SCE



territory, which has the highest charging costs, when diesel prices are low and battery prices are high.

4. Discussion

Our modeling identifies a near-term pathway to charging costs that would make the lifetime cost of electric trucks substantially lower than the lifetime cost of diesel trucks, even before accounting for additional benefits of electrification from mitigating environmental externalities. In the illustrative pathway depicted in figure 9, the left panel shows conditions resulting in non-competitive electric truck economics, corresponding to our highest-cost scenario: standard non-peak-coincident demand charges (which account for about a third of the unit charging cost), retail electricity prices, and 10% charging infrastructure utilization. In the center panel are conditions resulting in competitive truck economics, still featuring 10% utilization but now assuming policies that improve electric truck economics: a critical-peak demand charge (based on demand coincident with the year's highest-demand hours) and access to wholesale

electricity prices. If such policies successfully promote electric truck deployment, charging station utilization would rise as depicted in the right panel (33% utilization), in which case electric trucks become clear economic winners over diesel trucks. (If high utilization could be achieved independent of demand-charge reform and wholesale price access, the economics of truck charging would still improve, but the pathway described should provide a smoother path to favorable economics). Achieving this pathway might establish a positive feedback loop, with lower charging costs driving increasingly higher electric truck deployment and station utilization, which would reduce costs further. Low-cost financing appropriate to the long lifetimes of truck charging infrastructure would also help reduce costs.

Revising or replacing demand charges in electricity rate structures is particularly crucial to electric truck economics, particularly in the early stages of electrification when station utilization is low. For example, off-peak charging in ERCOT avoids critical-peak demand charges and makes electric trucking competitive even at low station utilization, whereas non-coincident demand charges

in SCE drive electric trucking to be non-competitive with diesel, comprising 31% of the charging cost stack⁷. Today, California's IOUs have some of the country's highest demand charges. ERCOT comes closest to tariffs reflecting true system costs with its energy-only market and low fixed T&D charges. However, its '80% ratchet' essentially extends demand charges through the rest of the year at an 80% level.

Instead of non-coincident demand charges, time-varying rates reflecting the time-varying system costs that customers incur—higher on-peak and lower off-peak—are a more economically efficient approach to cost recovery. As the Regulatory Assistance Project states, 'Rate design should make the choices the customer makes to minimize their own bill consistent with the choices they would make to minimize system costs' (Linville 2018). Aligning incentives to shift trucking off-peak will be increasingly important as high levels of renewable energy depress wholesale prices further, especially during the day. Texas, California, and other states that want to level the playing field for electric trucking should reevaluate their use of demand charges.

Some utilities, especially those in California, are responding to vehicle electrification by developing EV-specific electricity tariffs. For example, PG&E has created a subscription rate plan with a basic TOU structure; SDG&E is working with 'dynamic adders,' which are similar to critical peak pricing; and SCE is granting a five-year demand charge holiday for EV charging (Pyper 2018). However, SCE will be phasing demand charges back in over the course of five years, and the demand charge on SCE's large-customer EV tariff is still over 90% as high as the demand charge for other large customers, with no time-varying component. In fact, unit charging cost as modeled using SCE's EV tariff is marginally higher than the cost using SCE's generic large customer tariff. Although it is encouraging to see utilities addressing EV rate design, further work is needed to design cost-reflective tariffs.

With beneficial electricity rate structures in place, electric trucks would still need to charge at off-peak times to realize the full economic benefits of electrification. Fortunately, off-peak charging periods are abundant. We demonstrate that a minimum of 89 (24) million miles of charge can be delivered daily in ERCOT, and 67 (35) million in CAISO, such that maximum demand remains below 10% (20%) of each ISO's annual peak. For reference, in 2017 Texas's highway system saw 43 million miles/day of combination truck travel and California's saw 24, suggesting that even when the electricity grid is most constrained, Texas's and California's heavy-duty truck charging needs could be met (Federal Highway Administration 2017). Furthermore, there are more than enough

low-priced hours to enable high levels of station utilization: on average, fewer than 45 h/year in both ERCOT and CAISO have charging costs greater than \$4/gallon diesel equivalent. Even on the most expensive days, there are several hours in which energy prices are significantly lower than peak prices. In addition, trucks could lock in prices on day-ahead electricity markets to mitigate fuel price uncertainty.

In conclusion, our analysis shows that institutional innovations, such as electricity tariff reform, are needed to exploit the economic advantages of electric trucking that have emerged from advances in battery and fast-charging technologies. Although we explore the potential in CAISO and ERCOT, utilities and grid operators nationwide are experiencing similar trends that could support trucking electrification, including low wholesale electricity prices and stronger diurnal electricity price profiles—both driven in part by increasing renewable energy penetrations (Seel *et al* 2018). This analysis can be replicated for other regions using this methodology, depicted in figure 2. Valuable future research might include estimating the achievable utilization of charging stations based on the rate of trucking electrification, station siting practices, and vehicular autonomy. In addition, expanding on our hourly demand and price analysis by examining load-zone-specific data instead of ISO-wide averages would provide a better picture of inter-zonal variability in grid conditions. Finally, in this paper we focus on reforming electricity rates to account for the fact that trucking can be electrified without incurring new generation build; an important area for future research is to assess the extent to which truck electrification would or would not incur new build on either the transmission or the distribution system.

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Data availability statement

The data that support the findings of this study are openly available.

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⁷ For a low-utilization, transmission-connected SCE customer, demand charges account for about \$0.10/kWh of unit charging cost, whereas the cost per kWh of transmission for IOUs from 1960 to 2014 is only \$0.0047/kWh.

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