Technology Solutions to Mitigate Electricity Cost for Electric Vehicle DC Fast Charging

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ABSTRACT

Widespread adoption of alternative fuel vehicles is being hindered by high vehicle costs and refueling or range limitations. For plug-in electric vehicles, direct-current fast charging (DCFC) is proposed as a solution to support long-distance travel and relieve range anxiety. However, DCFC has also been shown to be potentially more expensive compared to residential or workplace charging. In particular, electricity demand charges can significantly impact electricity cost for fast charging applications. Here we explore technological solutions that can help reduce the electricity cost for electric vehicle fast charging. In particular, we consider thousands of electricity rates available in the United States and real-world vehicle charging load scenarios to assess opportunities to reduce the cost of DCFC by deploying solar photovoltaics (PV) panels and energy storage (battery), and implementing a co-location configuration where a DCFC station is connected to an existing meter within a commercial building. Results show that while the median electricity cost across more than 7,000 commercial retail rates remains less than $0.20/kWh for all charging load scenarios considered, cost varies greatly, and some locations do experience significantly higher electricity cost. Co-location is almost always economically viable to mitigate fixed cost and demand charges, but the relative benefit of co-locating diminishes as station size and utilization increase. Energy storage alone can help mitigate demand charges and is more effective at reducing costs for “peaky” or low-utilization loads. On the other hand, PV systems primarily help mitigate energy charges, and are more effective for loads that are more correlated with solar production, even in areas with lower solar resource. PV and energy storage can deploy synergistically to provide cost reductions for DCFC, leveraging their ability to mitigate demand and energy charges.

1. INTRODUCTION

The majority of plug-in electric vehicles (PEVs) recharging is currently performed at owners’ residences [1], [2]. However, a network of nonresidential electric vehicle supply equipment, or charging stations, is necessary to provide charging opportunities for those who cannot reliably recharge at home, enable long-distance travel, and to cope with range anxiety issues. Generally, public electric vehicle supply equipment is intended to provide electric vehicle drivers with mobility opportunities that are comparable to those offered by conventional gasoline vehicles. In particular, direct-current fast charging (DCFC), which typically supplies 50 kW of power or more, can quickly replenish a vehicle's battery by adding about 50 miles or more of range in 20 minutes [3]. To further reduce refueling time, extreme fast charging is currently being studied [4]. Extreme fast charging is defined as charging at up to 400 kW, which can provide 200 miles of range in about 10 minutes [4].

The network of DCFC stations in the United States has been expanding in line with increased adoption of PEVs. As of April 2018, there were 2,305 DCFC stations (6,688 plugs) in operation in the United States, including 402 Tesla proprietary superchargers [5]. Several more DCFC stations are being planned [6]–[10]. However, previous literature has shown that DCFC stations can incur high electricity costs, particularly for low-utilization cases [11], [12]. This mainly stems from retail electricity fixed and demand charges that heavily impact total electricity cost when small amounts of electricity are consumed in each billing period (in terms of kilowatt-hour purchased). Fixed charges, measured in dollars per month, are independent of power consumption. Demand charges, measured in dollars per kilowatt, are proportional to the maximum power consumption during any billing period and are independent of how much energy is used in total. For example, in the summer of 2016, costs related to demand charges for a low-utilized EVgo DCFC station (SDG&E Freedom Station, Las Americas) reached $1.96/kWh, which represented more than 90% of the total monthly electricity bill [13]. Muratori et al. [12] shows that the cost of electricity for DCFC in the United States can vary widely, ranging from less than $0.10/kWh to more than $2.00/kWh, depending on station design, and use that is characterized by high uncertainty [12]. These costs are significantly more than current residential electricity cost. State-average residential electricity cost in 2015 varied from $0.09/kWh in Louisiana, $0.20/kWh in Connecticut, to ($0.27/kWh in Hawaii. The national average was $0.13/kWh [14].

While consumers might be willing to pay a premium for electricity recharged at DCFC stations, higher electricity costs are detrimental to the business case for DCFC, and in turn PEVs. A recent report by the Rocky Mountain Institute (RMI) analyzed charging events at 230 EVgo DCFC stations in California during 2016 and identified the high cost of demand charges as a significant barrier to development of viable business models for public DCFC network operators [13].

High electricity cost for DCFC can be mitigated using market mechanisms, such as restructuring retail electricity pricing, or with technology solutions. For example, Southern California Edison proposed new optional PEV rates that include a five-year introductory period during which demand charges will be waived to incentivize early market low-utilization stations [15]. This paper provides a thorough analysis to assess the value of using technology solutions to mitigate electricity cost for DCFC focusing on the cost-saving opportunities achievable by deploying a DCFC station in conjunction with solar photovoltaics (PV) panels, energy storage (battery), and implementing a co-location configuration where the DCFC station is connected to an existing meter within a commercial building. In particular, the National Renewable Energy Laboratory REopt optimization model [16] is used to find the least-cost DCFC station configuration, including the three options above, across more than 7,000 commercial electricity retail rates currently available in the United States (and associated solar resource at representative locations) for four charging load scenarios based on empirical DCFC and gasoline station use.

Results show that the median electricity cost across all rates considered for a one-plug 50 kW DCFC station at low utilization is about $0.19/kWh. As DCFC station size and utilization increase, the electricity cost decreases. Overall, for the majority of the sites and loads considered in this paper, purchasing electricity from the grid is the least-cost option. There is, however, a great variability in electricity cost and PV and energy storage technologies can reduce electricity costs in many cases for which grid-purchase is more expensive. In particular, energy storage systems help mitigate high electricity demand charges. Deployment of such systems is fairly insensitive to DCFC load, even though cost savings decrease for larger, higher-utilization charging loads. On the other hand, PV systems primarily help mitigate energy charges, and are more effective for loads that are more correlated with solar production. Moreover, batteries and PV can be deployed synergistically to provide cost reductions for DCFC, leveraging their ability to mitigate demand and energy charges. For most sites, co-location is economically preferable, as it reduces fixed cost and cost related to demand charges. The median savings from co-location increase as DCFC utilization increases, but relative savings decrease as fixed and demand charges become a smaller portion of total costs. Overall, deployment of technologies and/or co-location can help reduce DCFC electricity cost for sites that would otherwise experience very high electricity cost. Technologies can help keep electricity cost for DCFC application less than $0.20/kWh, except for one-plug 50-kW stations that consistently experience low utilization.

2. METHODS

2.1. Literature Context

PV, energy storage, and co-location with an existing load are explored in detail to determine their potential to reduce retail electricity costs for DCFC. Previous studies have shown that energy storage can be used to effectively reduce electricity cost for both consumers and utilities, especially by providing energy arbitrage and peak shaving [17–19]. That is, using energy storage to align electricity demand with supply can provide significant system benefits [20]. Several studies have shown that for an industrial customer with a properly-sized battery, an energy storage system can reduce electricity cost by shaving peak demand and reducing demand charges [21, 22]. Moreover, energy storage could also provide additional value by providing grid services, such as ancillary services or demand response [23, 24], prevent capacity expansion by limiting peak demand [25], limit distribution infrastructure cost such as transformer replacement or upgrade [26, 27], or exploit vehicle-to-grid opportunities [28] and facilitate the integration of renewable and distributed energy sources [29]. Distribution system value and electricity market integration are not considered in this paper, to the extent that those are not included in the retail electricity rates.

Use of PV has also been shown to reduce PEV charging costs and reduce PEV charging impact on the grid [30–33]. Most of these studies consider energy storage (battery) to be deployed in conjunction with PV, to account for solar intermittency. Tulpule et al. [34] shows that a PEV charging station located in a workplace parking garage and coupled with PV would provide benefits to the vehicle owner as compared to home charging, and that the garage owner will be able to achieve profit within the life of the PV panels. Mouli et al. [35] assesses the deployment of PV and battery storage for PEV charging in the Netherlands showing that PV needs to be oversized and that local battery storage improves but does not eliminate the grid dependence, especially due to seasonal variations in insolation. Azuara Grande [36] shows that in Spain a DCFC station with PV and storage is economically cost competitive and can provide electricity at 0.4 €/kWh between 8 and 11 a.m. and 3 and 7 p.m., and 0.25 €/kWh between 11 a.m. and 3 p.m.

This paper complements the existing literature by assessing the value of different technology solutions to reduce electricity cost for PEV DCFC considering multiple real-world charging load scenarios for more than 7,000 electricity rates currently available in the United States for commercial and industrial applications. A variety of techniques have been used in the literature to model electricity costs for PEV charging. Some studies focus more on sizing and location of infrastructure and either assume a flat electricity cost [37, 38] or no electricity cost for islanded operation [39]. Other studies focus on integration with time-varying wholesale electricity prices rather than assessing retail electricity cost [40]. Electric vehicle DCFC infrastructure that purchases electricity, however, will most likely be enrolled on commercial or industrial retail electricity rates, as opposed to participation directly in the wholesale markets. As a result, a more realistic way to calculate electricity costs is to represent the complete retail rate structure, including different cost components (that is, fixed charges, demand charges, and energy charges). This study considers thousands of commercial electricity retail rate structures and improves the state-of-the-art by optimizing DCFC station design using multiple technology solutions for each of the rates considered. In addition, current studies in the literature focus on a limited region. For this paper, more than 7,000 commercial electricity retail rates were explored, which expands the coverage across the entire United States making the results more general (and applicable to other regions with similar electricity rate structures and solar resource). Moreover, charging profiles produced from actual charging data are used to provide up-to-date and realistic insights on the technical opportunity for DCFC cost mitigation. With many cities and states in the early stages of electric vehicle charging infrastructure rollout, a realistic understanding of current electricity costs and technological options for reducing those costs will help inform early-market strategies and future planning.

2.2. REopt Model

REopt is a techno-economic decision support model used to optimize energy systems for buildings, campuses, communities, and microgrids [16]. The primary application of the model is for optimizing the integration and operation of behind-the-meter energy assets. Formulated as a mixed-integer linear program, REopt solves a deterministic optimization problem to identify the optimal selection, sizing, and dispatch strategy of technologies chosen from a candidate pool such that electric loads are met at every timestep at the minimum life-cycle cost. Select equations from the model are shown below as they were applied to find the optimal PV/storage size for the DCFC station design optimization problem.

Indices and sets

$h \in H$ *set of timesteps*

$d \in D$ *set of demands*

$t \in T$ *set of technologies*

$r \in R$ *set of demand ratchets*

$m \in M$ *set of months*

Parameters

c_t *capital cost for technology t*
c_r^D *demand cost for ratchet r*
c_m^{Dm} *demand cost for month m*
c^{bkWh} *battery cost ($/kWh)*
c^{bkW} *battery cost ($/kW)*
c_t^{om} *O&M cost for technology t*
f_{dt}^p *production factor for technology t and demand d*
b_{dh}^p *maximum bound on load d in timestep t*

Variables

X_t^σ *System size of technology t*
W_r^D *Peak demand in ratchet r*
W_m^{Dm} *Peak demand in month m*
W^{bkWh} *Battery size (capacity)*
W^{bkW} *Battery size (power)*
X_t^{Uc} *Fuel cost for technology t*
$\hat{X}_{dth}^q$ *Rater power for technology t, demand d and timestep t*
$X_h^{\hat{b}}$ *Power from battery in timestep t*
$X_h^{\check{b}}$ *Power to battery in timestep t*
X_h^b *Energy in battery in timestep t*

For this analysis, REopt determines the optimal combination, size, and dispatch of PV, lithium-ion batteries, and grid-purchased electricity to minimize the life-cycle cost of electricity consumption for a given DCFC station load, a utility tariff, and solar resource. The objective function (Equation 1) minimizes the sum of non-battery capital costs, battery capital costs, operation and maintenance costs, demand costs, and fuel costs (which includes volumetric grid purchases).

$$min \sum_{t \in T} c_t \cdot X_t^\sigma + W^{bkWh} \cdot c^{bkWh} + W^{bkW} \cdot c^{bkW} + \sum_{t \in T} c_t^{om} \cdot X_t^\sigma + \sum_{r \in R} W_r^D \cdot c_r^D + \sum_{m \in M} W_m^{Dm} \cdot c_m^{Dm} + \sum_{t \in T} X_t^{Uc} \quad (1)$$

This analysis considers capital cost for batteries and PV (see **Error! Reference source not found.** for cost assumptions) used to mitigate electricity cost, but capital and operation and maintenance cost for DCFC stations are not considered, since they do not impact electricity cost and investment in those assets is not a decision assessed in this analysis. Grid purchases, including fixed, demand, and energy charges, are assessed according to the utility tariff under consideration. Utility tariffs are pulled into the model programmatically from the Utility Rate Database [41].

Net present value (NPV) of the recommended technologies is calculated by taking the difference between the optimal solution and the "base case," namely a case in which all electricity is purchased from the grid. The sum of electricity generated from all technologies, including purchases from the grid, and discharged from the battery has to be greater than or equal to the load of the DCFC in each timestep (Equation 2).

$$\sum_{t \in T, u \in U} f_{dt}^p \cdot \hat{X}_{dthu}^q + X_h^{\hat{b}} \geq b_{dh}^p \; \forall \, h \in H \quad (2)$$

REopt uses the National Renewable Energy Laboratory's PVWatts application to determine the electricity production of installed solar PV systems [42]. By default, REopt assumes fixed-tilt arrays oriented due south with a tilt angle equal to the latitude of the site location. The amount of energy supplied by a technology across all loads in any given timestep must be less than or equal to the system size (Equation 3). PV generation can either offset the onsite (DCFC station) load, charge onsite energy storage, or be exported to the grid. Grid exports were assumed to have zero value for this analysis (no net metering).

$$X_t^{\sigma} \geq \sum_{d \in D} \hat{X}_{dth}^{q} \; \forall\, t \in T, \forall\, h \in H \quad (3)$$

REopt utilizes a reservoir model for energy storage, where energy can be moved from one timestep to another, subject to a total roundtrip efficiency and minimum state of charge. The energy and capacity of energy storage devices are costed and sized independently. The power supplied to the battery in any timestep cannot exceed the power of the battery, and the energy stored in the battery in any timestep cannot exceed the capacity of the battery (Equations 4-6). Both the power and energy in any timestep, and the power and energy size of the battery are decision variables in the model.

$$X_h^{\check{b}} \leq W^{bkW} \; \forall\, h \in H \; (4)$$
$$X_h^{\hat{b}} \leq W^{bkW} \; \forall\, h \in H \; (5)$$
$$X_h^{b} \leq W^{bkWh} \; \forall\, h \in H \; (6)$$

The combination of the constraints outlined here (Equations 2-6) ensure that capital cost of assets, including power and energy components for energy storage, is considered in conjunction with the hourly decision variables around dispatch of the PV and storage assets to meet the key requirement of meeting the load in each timestep at a minimum cost for the site (as defined in Equation 1).

The model was also used to calculate the difference in life-cycle cost of electricity between a case where a DCFC station load and a commercial building load are metered on two separate meters compared to the case where the combined load is metered behind a single meter (co-located) to evaluate if there are opportunities for cost savings by co-locating DCFC infrastructure with commercial building loads.

2.3. Charging Load Scenarios

To explore a wide range of DCFC applications, four DCFC load scenarios were developed based on empirical DCFC and gasoline station use and in line with scenarios informed by subject experts and reported in Muratori et al. [12]. The profiles, reported in Figure 1 for a one-week sample, consist of hourly charging loads for an entire year for four scenarios:

A. One plug at 50 kW assuming low utilization

B. One plug at 50 kW assuming high utilization

C. Four plugs at 150 kW each for a total station capacity of 600 kW

D. Twenty plugs at 400 kW each for a total station capacity of 8,000 kW .

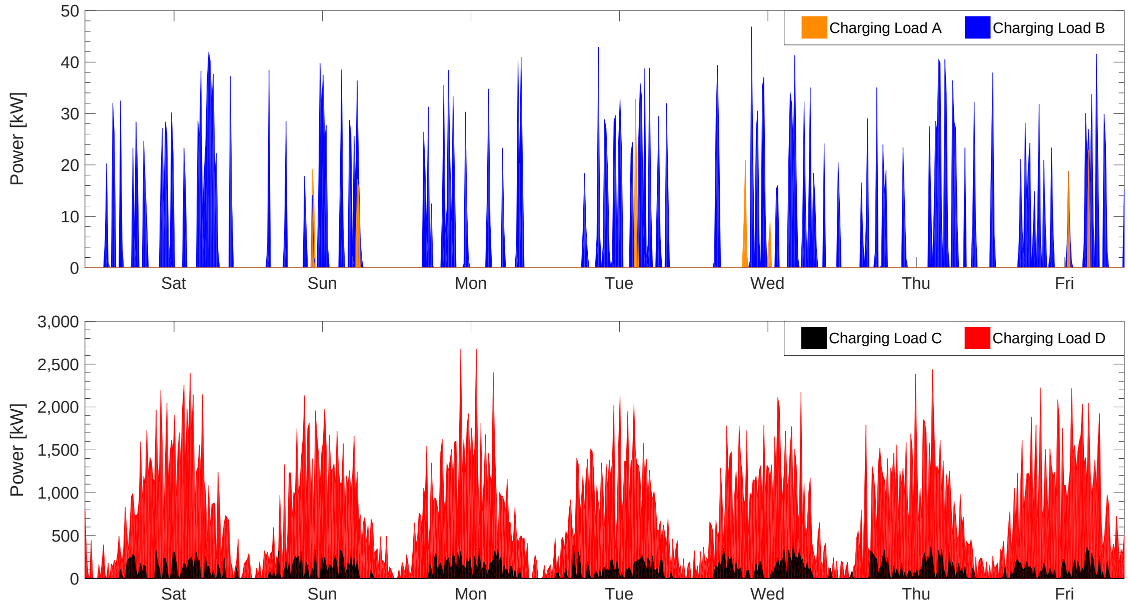

Figure 1. DCFC load scenarios (sample week).

The DCFC charging load profiles for Scenarios A and B are representative of the range of use seen by DCFC stations today and are based on data collected from two 50-kW DCFC stations between November 2014 and October 2015 [43]. DCFC station utilization in these data ranges from approximately one to two charges per day (Scenario A) to almost 17 charges per day (Scenario B), and the typical energy use was 8.2 to 9.2 kWh per recharging event (by PEV with 20 to 24 kWh of onboard energy storage capacity).

Scenarios C and D consider future high-power DCFC stations. In particular, Scenario C, which has four plugs each rated at 150 kW, represents future (2020 to 2025) intermediate DCFC stations that satisfy growing charging demand and meet BEV drivers' expectations in terms of charging time. Station utilization is based upon data received throughout 2017 from a highly-used EVgo station in Fremont, California, with four co-located 50-kW fast chargers. This paper assumes that longer range PEVs and faster charging will not have a significant effect on the charging start time. It also assumes that a typical PEV in Scenario C will have a battery capacity of 60 kWh, in line with Muratori et al. [12]. For this reason, the energy delivered per charge event is based on data received from more than 9,000 charging events performed on EVgo fast chargers, which have battery packs rated at 60 kWh, by Chevrolet Bolts.

Scenario D represents an upper-bound future case in which a large, high-power DCFC station operates similarly to a gasoline station and has 20 plugs rated at 400 kW each (extreme fast charging). This paper assumes that in this scenario, PEV drivers will have recharging experiences in line with current gasoline refueling. Charge start times are based on data available on the usage of gas stations, which includes hourly, daily, and seasonal variations [44, 45]. This paper also assumes that a typical PEV in Scenario D will have a battery capacity of 100 kWh, in line with Muratori et al. [12]. Since these vehicles will have driving ranges similar to those of many gasoline vehicles, the energy delivered per charge event is based on data collected on the volume of fuel purchased by real gas station patrons via in-person observations (see Supplemental Information for additional details).

In the absence of empirical time-resolved data on DCFC events at more than 50 kW, the power profiles for Scenarios C and D are based on charge start times and energy need distributions for a typical 50-kW DCFC session [46]. In particular, probability distribution functions were created to approximate the distribution of energy needs for charging events in each scenario. The energy transferred during each individual charging event was then randomly determined using inverse transform sampling. The hourly power profile of each event was then determined by scaling an empirical 50-kW charging session [46], namely increasing the maximum power and decreasing the charge duration to respect the energy needs of each individual charging event.

A key difference between these load scenarios is the utilization or station's load factor, which is calculated by dividing the total energy consumed by the maximum amount of energy that could be delivered during the same time period (assuming that all plugs can deliver full power simultaneously). The load factor for Scenarios A through D is 1.1, 11.7, 13.7, and 10.5%, respectively. As shown in the results, utilization has a dramatic impact on the charging cost and is a key challenge for new and early market stations.

2.4. Sites Evaluated

Utility rate structures and solar resource both vary geographically, impacting the operating cost and optimal technology configuration. In this analysis, we did not consider specific locations (that is, certain city or highway locations), but instead a set of sites was defined by the combination of all commercial electricity rates available as of January 2018 in the Utility Rate DataBase (URDB) and the solar resource associated with the centroid of each utility territory to cover all possible rate/solar resource combinations in the United States. We considered 7,336 commercial and industrial electricity rates available as of January 2018 in the URDB covering 2,172 utility service territories [41], based on filtering reported in Muratori et al. [12]. Some of these service territories span multiple solar resource levels, and thus the service territories were subdivided to capture the variability in solar resource within each service territory. The resulting unique electricity rate-solar resource combinations resulted in 9,781 total "sites."

2.5. Technology Configuration Cases

REopt was used to assess opportunities for electricity cost savings under two alternative cases comparing a proposed solution with the base case (a case in which all electricity is purchased from the grid) for each case:

1. Technologies: The potential technology configurations include adding PV only, adding energy storage only, adding PV and storage, or continuing to purchase all electricity from the grid.
2. Co-locating: Results show whether it is cost effective to co-locate the DCFC station with a commercial building load.

In total, we explore four load scenarios and four technology cases (base cases and proposed cases for the two alternatives) for each of the 9,781 sites, resulting in 156,496 REopt runs.

In this analysis, we assume direct purchase for PV/storage systems with a discount rate of 8% and an analysis period of 20 years (assuming the battery would be replaced in year 10 of the analysis). System costs and incentives assumed are reported in **Error! Reference source not found.** in the Supplemental Information. We assume that all electricity produced by the PV must be consumed by the DCFC station or curtailed/exported at no value (no net metering). Solar resource is taken from the National Solar Radiation Database multi-year physical solar model (v2.0.1) [47]. The building load represents the load of a strip mall from the Department of Energy commercial reference building data set [48] and it is adjusted for 16 climatic zones to reflect different building designs based on climatic factors.

3. RESULTS

The REopt model finds the optimal DCFC station design, including size of the different technologies available in each case, minimizes electricity cost for DCFC (that is, optimal technology sizing to minimize cost of electricity based on retail rates from the URDB) for the four DCFC load scenarios and the two configuration cases considered.

3.1. Deploying Technologies to Mitigate DCFC Electricity Cost

The base case to assess if technologies are effective at mitigating DCFC electricity cost considers fixed charges (dollars per month, independent of the power consumption), demand charges (dollars per kilowatt, proportional to the monthly peak demand), and energy charges (dollars per kilowatt-hour, proportional to the monthly cumulative electricity consumption), for each site assuming that the load is met entirely by grid purchases. Figure 2 shows that the median electricity cost across all rates, levelized on a dollars per kilowatt-hour basis, for a one-plug 50-kW DCFC station at low utilization (load Scenario A) is about $0.19/kWh (ranging from $0.02 to $2.00/kWh). The median electricity cost decreases as utilization of a DCFC station and the total load size increase. This reduction is driven by a relative decrease in demand and fixed charges since these charges are spread over a much larger amount of energy (number of kilowatt-hour consumed). These results are consistent with findings in Muratori et al. [12]. By individual component, the median fixed charges for Scenario A are $0.07/kWh compared to $0.01/kWh for load Scenario B, and less than $0.001/kWh for Scenarios C and D. The median demand charges for Scenario A are $0.05/kWh compared to $0.01/kWh for Scenario B. The median energy charges are $0.08/kWh across all four loads.

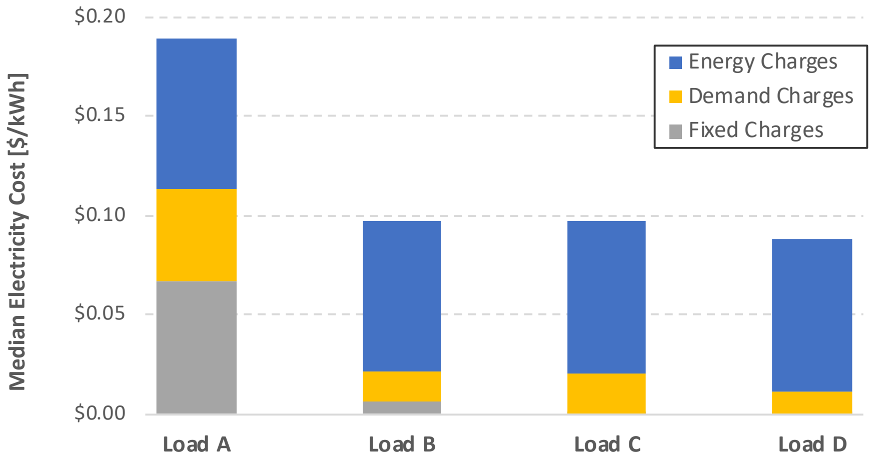

Figure 2. Base case (load met by only grid purchases) median electricity cost by load scenario.

While the median electricity cost shown in Figure 2 is fairly low, some sites experience significantly higher electricity cost. Figure 3 shows the least-cost technology configuration identified by REopt to minimize life-cycle DCFC station electricity cost. PV and storage technologies can be deployed in conjunction with DCFC to reduce electricity costs at many of the sites evaluated in this analysis, but the number of technology recommendations, as well as the mix of technologies, varies with the load scenario. In Scenario A only 11% of sites can achieve cost savings by deploying technologies compared to 18, 34, and 39% for Scenarios B, C, and D, respectively. Across all scenarios, the increase in technology deployment is primarily due to increased deployment of PV. Since PV mainly mitigates energy charges and we assume that the electricity produced from PV cannot be net metered, PV deployment increases with a higher DCFC utilization factor and as the correlation between DCFC load and PV-produced electricity increases (that is, as less PV-generated electricity needs to be curtailed). PV is only deployed at 6% of sites (with or without storage) in Scenario A compared to 34% of sites in Scenario D. The deployment of storage is driven largely by savings in demand charges. The savings is more a function of the utility tariff and the shape of the DCFC load rather than the utilization factor. Storage is deployed at 11% of sites in Scenario A (with or without PV) compared to 16% of sites across Scenarios B, C, and D. Only 5,086 of the 9,781 sites have demand charges, which reduces the number of sites that are likely to install storage. As with PV, all sites only install storage if it is economically beneficial, so while 52% of the rates include demand charges, not all of those rates will result in sites that add storage on account of the magnitude of the demand charge and the cost of storage.

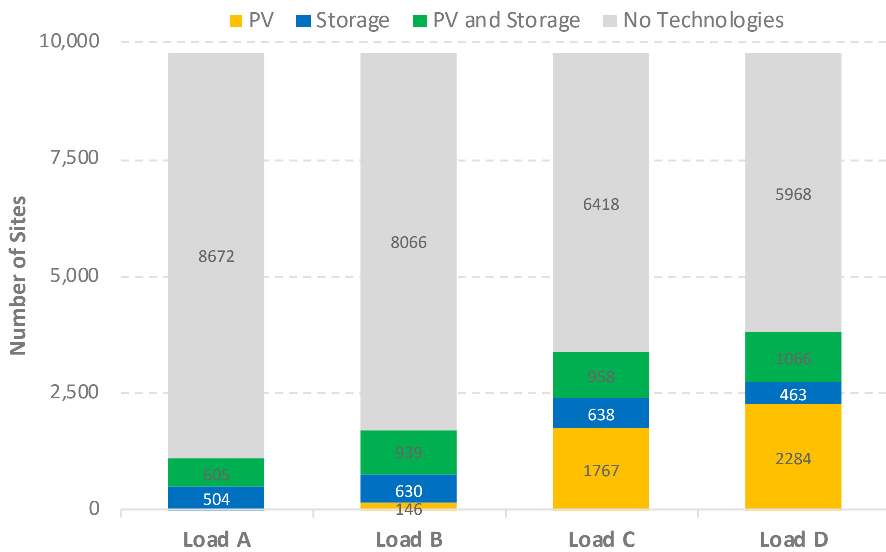

Figure 3. Least-cost technology option for DCFC at each site by load scenario.

The size of the PV and energy storage systems deployed increase as more energy is used by the DCFC station. Figure 4 shows the optimal sizing of PV and batteries: the median PV size for Scenario A is 2 kW compared to 23 kW, 332 kW, and 2.8 MW for Scenarios B, C, and D, respectively; the median battery size is 10 kW for Scenario A, compared to 13, 128, and 509 kW for Scenarios B, C, and D, respectively. For each of the four load scenarios, the absolute value of the savings (NPV) increases as system sizes increase, but the NPV relative to the size of the system deployed decreases. This results in greater lifetime value to the project; however, the increased upfront costs will have to be evaluated by DCFC station developers when considering whether to deploy additional technologies with the DCFC system. The relative life-cycle cost savings (NPV as a fraction of life-cycle cost) decreases with utilization from a median of 5% for Scenario A to 3% for Scenario B. Also, as the utilization increases, the relative size of the storage systems compared to the size of the PV systems decreases. While a similar number of systems benefit from storage across all scenarios, low-utilization chargers can benefit from larger storage systems more than higher-utilization chargers. This is driven by demand charge reduction potential and the capacity of storage that is required to achieve the maximum reduction.

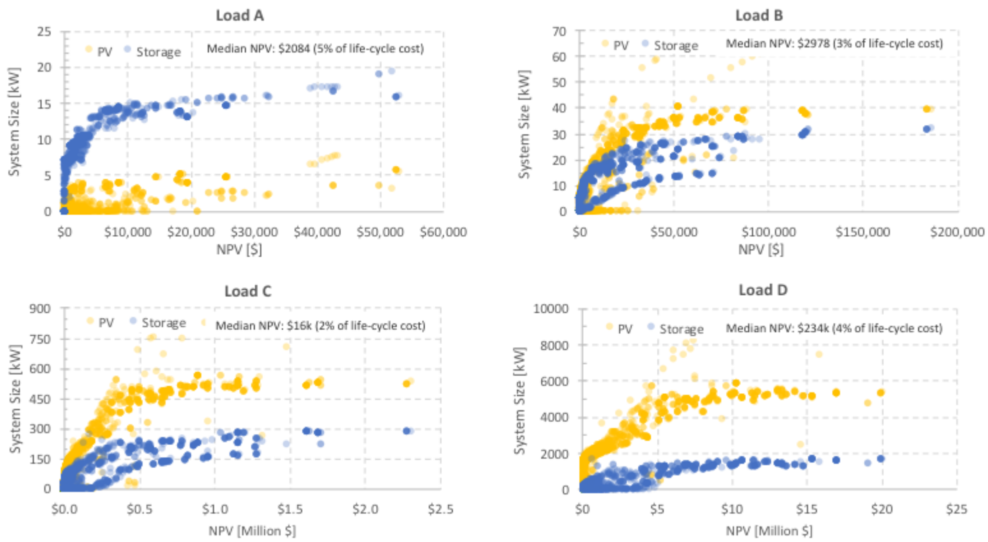

Figure 4. Technology sizing and NPV by load scenario.

Figure 5 shows the median fixed, demand, and energy charges at sites where PV and/or storage were deployed before (left-most bar) and after (right-most bar) technology deployment for each of the four load scenarios, along with cost reductions in energy and demand charges in a waterfall format. These values are different from the base case values (shown in Figure 2) because they represent only the subset of sites where technologies were deployed.

In Scenario A, for the1,109 sites where technologies are deployed, the median energy charge is reduced by $0.041/kWh from a baseline of $0.12/kWh (a 34% reduction); the median demand charge is reduced by $0.46/kWh for a baseline of $0.77/kWh (a 60% reduction). Scenarios B, C, and D see a median reduction in energy charges of $0.16, $0.18, and $0.041/kWh from a baseline of $0.25, $0.25, and $0.12/kWh, respectively (64, 72, and 34%), and a median reduction in demand charges of $0.056, $0.039, and $0.016/kWh from a baseline of $0.088, $0.062, and $0.042/kWh, respectively (64, 63, and 38%). While the median energy and demand charges savings (on a dollars per kilowatt-hour basis) decrease as the DCFC load increases, larger loads consume larger amounts of electricity. Moreover, PV and batteries are effective at reducing electricity costs for more sites as DCFC load increases and technologies are typically deployed at larger scales for larger loads, especially PVs. Note that for each load, the median electricity fixed charge is the same before and after technology deployment since neither PV nor energy storage deployment can mitigate fixed charges.

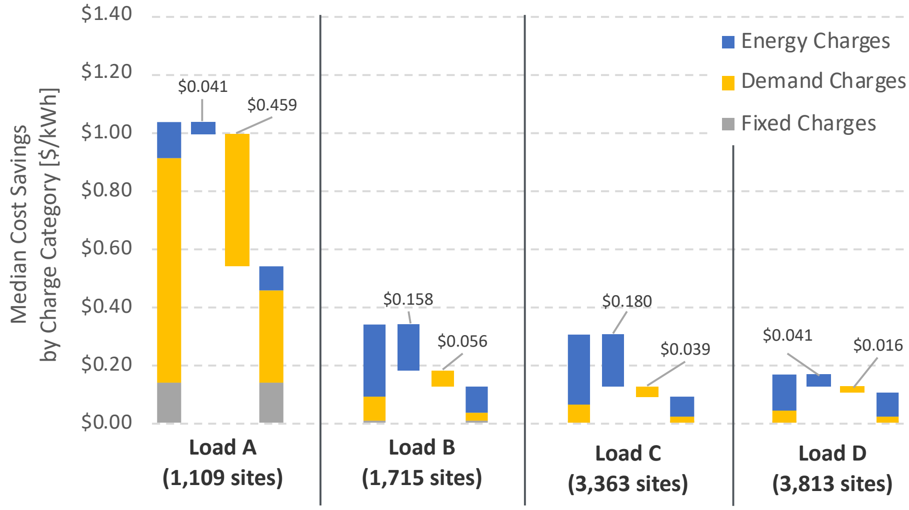

Figure 5. Median cost savings by charge category across load scenarios for all sites where PV and/or storage were deployed. For each load scenario, the left bar shows median electricity cost when all electricity is purchased from the grid, the right bar shows the median cost achieved with technology deployment, and the waterfall bars (the two bars in the middle) highlight savings by charge category.

Figure 6 maps the variation of energy and demand charges, as well as the technology recommendation for load Scenario B. Energy charges shown in these maps are the total annual energy cost divided by total annual electricity use, averaged across all rates available in a site; demand changes shown are total annual demand costs divided by monthly peak demand (also averaged across all rates available). Results show that high energy charges are the main driver of PV deployment, even in areas with fewer solar resources (such as Vermont), though high solar resource (in combination with moderate energy charges) are driving some deployment in the southwest. High demand charges are the primary drivers of energy storage deployment. While intuitive, the maps in Figure 6 illustrate the variability of energy and demand charges for Scenario B (similar results apply for other load scenarios as well) and the geographic distribution of technology deployment to mitigate DCFC electricity cost.

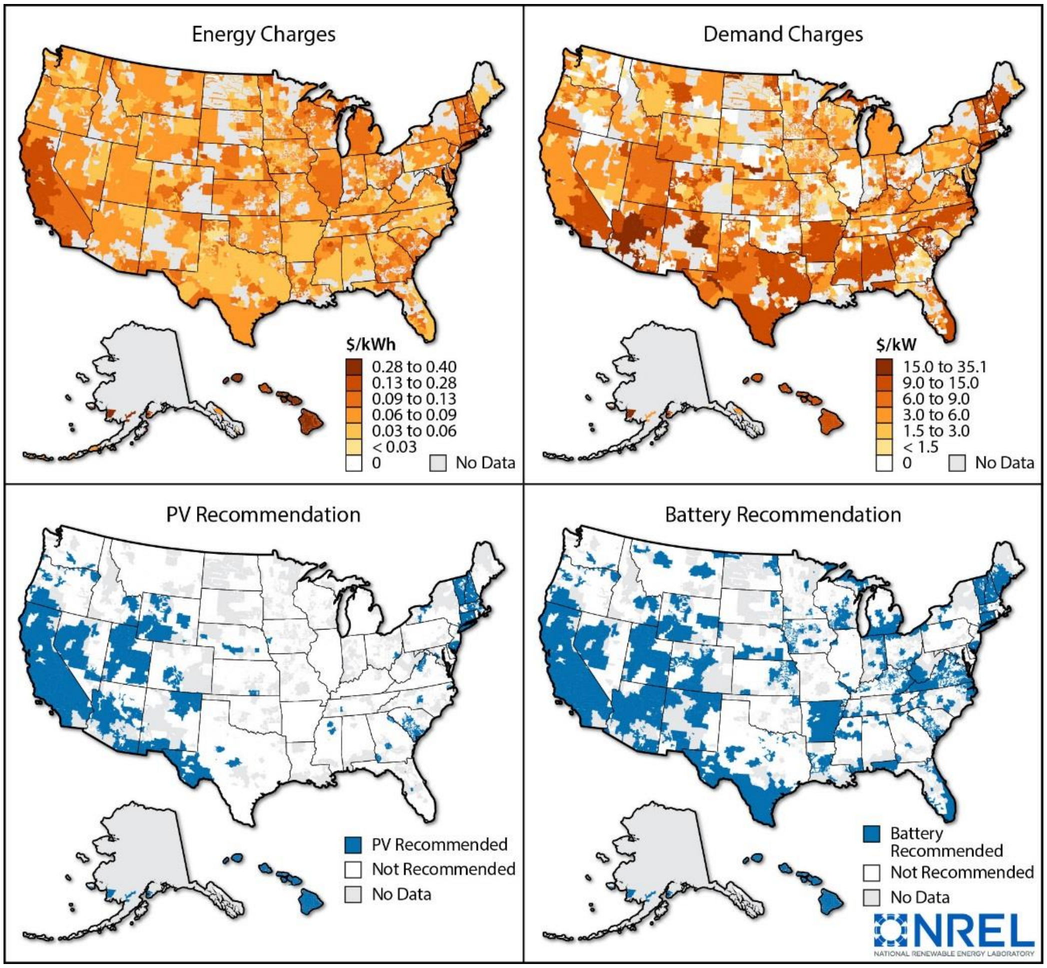

Figure 6. Geographic distribution of energy and demand charges, as well as the technology recommendation, for Scenario B.

4. CO-LOCATING WITH A COMMERCIAL BUILDING TO MITIGATE DCFC ELECTRICITY COST

Comparing the cost savings opportunities of co-locating DCFC with a building load versus stand-alone DCFC stations require a base case for the stand-alone DCFC station and building. The base case is the life-cycle cost of electricity of the DCFC station and the building loads billed under two separate meters. The co-location case considers both DCFC and building loads behind the same meter, thus splitting fixed charges and possibly impacting demand and energy charges based on peak coincidence and tiered pricing structures. Results show that for most sites (around 90% for all four load scenarios), co-location is economically preferable, as it reduces fixed cost and cost from demand charges (when the two loads do not have coincident maximum peaks). In the remaining cases, reversed-tiers (that is, increasing charges for higher electricity consumption or power demand levels) make co-location more expensive. The median savings from co-location increase as the DCFC utilization increases (from $708/year for load Scenario A to $5,343/year for Scenario D), but relative savings decrease as fixed and demand charges become a smaller portion of total costs. Co-location provides cost reductions that are higher than 20% for DCFC in Scenario A, offering significant cost saving opportunities for small stations characterized by low utilization. Savings become relatively less for Scenarios B, C, and D, as illustrated in Figure 7.

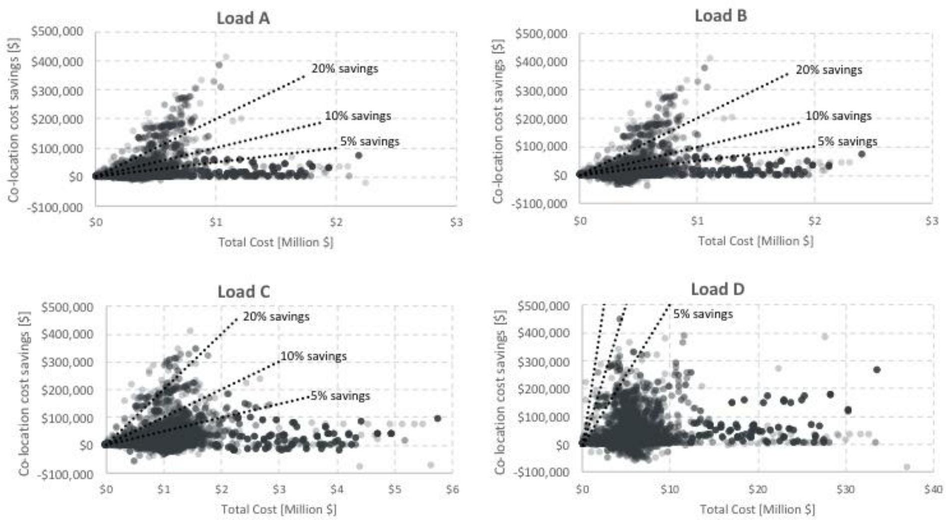

Figure 7. Co-location cost saving and total project costs by load scenario.

Deployment of PV and energy storage was also evaluated for the co-location case. When co-located with a commercial building, PV is deployed at about 35% of sites across all load scenarios, a significant increase in deployment for Scenarios A and B, indicating that PV can still be deployed cost-effectively at charging stations with low utilization when co-located with another load (mainly due to the magnitude of the building load). Deployment of energy storage did not change significantly with co-location.

5. DISCUSSION AND CONCLUSIONS

This paper explores the use of technology solutions to mitigate electricity cost for DCFC. While many previous studies assume a flat electricity cost or focus on time-varying wholesale electricity prices, this paper represents the complete retail structure for more than 7,000 commercial electricity retail rates, including different cost components (that is, fixed charges, demand charges, and energy charges), and improves the state-of-the-art by optimizing DCFC station design using multiple technology solutions for each of the rates considered. Moreover, charging profiles produced from actual charging data are used to provide up-to-date and realistic insights on the technical opportunity for DCFC cost mitigation.

Results show that the median electricity cost for different DCFC load scenarios is fairly low, approximately $0.19/kWh for a one-plug 50-kW DCFC station at low utilization (load Scenario A) and less than $0.10/kWh for larger or higher utilized stations. Electricity cost, however, varies greatly and some locations do experience significantly higher electricity cost that can be mitigated by using technologies. This is particularly important in the near-term as the customer base and charging station business cases evolve. The technology focus is on deploying a DCFC station in conjunction with PV panels, energy storage (battery), and co-located on the same meter as a commercial building. Significant cost savings can be achieved depending on location, including variations in electricity rates available and solar resources, as well as use and size of DCFC stations. Generally, the most valuable strategy is to co-locate DCFC infrastructure with an additional load. Co-location is almost always economically viable to mitigate fixed cost and demand charges, but the relative benefit of co-locating diminishes as station size and utilization increase. Therefore, the most benefit can be realized when smaller or less-utilized stations are co-located. Co-location with buildings increases the potential sites that could benefit from installing PV even for low charging station utilizations on account of the ability to leverage the greater building demand.

Energy storage alone can help mitigate demand charges and is more effective at reducing costs for "peaky" or low-utilization loads. However, results show that the decision of deploying energy storage alone is fairly insensitive to DCFC load, even though cost savings decrease for larger, higher-utilization charging loads. On the other hand, PV systems primarily help mitigate energy charges, and are more effective for loads that are more correlated with solar production. High energy charges are the main driver of PV deployment, even in areas with lower solar resource. PV and energy storage can deploy synergistically to provide cost reductions for DCFC leveraging their ability to mitigate demand and energy charges.

In general, technology solutions are effective at reducing electricity cost for DCFC at locations with high energy and/or demand charges, reducing overall average cost of electricity for DCFC applications. With many cities and states in the early stages of electric vehicle charging infrastructure rollout, a realistic understanding of current electricity costs and technological options for reducing those costs will help inform early-market strategies and future planning. This paper considers existing electricity rates and does not speculate on possible future electricity rates targeting DCFC that could provide lower electricity cost. Moreover, DCFC stations can pursue additional revenue streams that are not considered here, including provisions of grid services with PV or energy storage and credits for producing a renewable fuel or exporting renewable electricity with the PV panels.

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SUPPLEMENTAL INFORMATION

Variable	Assumption
Technologies	Solar PV, Li-Ion batteries, co-location with commercial buildings
Objective	Minimize lifecycle cost (cost-effective projects)
Ownership model	Direct purchase for PV/storage systems (also, we do not account for capital cost of DCFC stations)
Analysis period	25 years
Discount rate	8%
Utility cost escalation rate	Energy Information Administration utility cost escalation rates
Inflation rate	Energy Information Administration general inflation rate
Incentives	PV: 30% federal ITC and 5-year MACRS (no state/local) Storage: 7-year MACRS Combination: PV same as above; storage depends on PV deployment/charging
Net metering limit	No net metering
Electricity sellback over net metering	$0/kWh
Technology costs	PV: Installed: $2.465/W; operation and maintenance: $18/kW/year; replacement: none [NREL ATB] Storage: Installed $500/kWh plus 1,000 $/kW; operation and maintenance: none; replacement: $200/kWh plus $200/kW in year 10 [DG Hub Survey, 2015 & RMI, 2015]
Solar resource	National Solar Radiation Database TMY data
Electricity rate	~7,500 nationwide rates from the URDB, including fixed, energy, and demand charges (no ratchets, no coincident demand charges)

Table 1. Key analysis assumptions.

Gas Station Data Collection

As a part of this work, Idaho National Laboratory researchers performed in-person data collection on fuel purchases at seven gasoline stations throughout the United States (two stations in Eastern Idaho, two stations in the Charlotte, North Carolina, area, and three stations in the San Francisco bay area). Among the data collected was the volume of fuel purchased by each patron, their general class of vehicle, and the times at which they arrived and departed the fuel pump. A summary of the collected data can be found in **Error! Reference source not found.**.

Vehicle Type	Vehicles Observed	Average Fuel Purchase (gal)	Average Time Spent at Pump (min)

Small car	777	8.8	5.5
Large car	450	9.5	5.6
Small SUV	526	10.7	5.6
Large SUV	232	12.7	6.2
Van/truck	615	15.0	6.8

Table 2. Summary of data collected via in-person observation by vehicle type.