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Electricity Rate Tariff Options for Minimizing Direct Current Fast Charger Demand Charges

Final Report

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Electricity Rate Tariff Options for Minimizing Direct Current Fast Charger Demand Charges

Final Report

Prepared for:

New York State Energy Research and Development Authority

Albany, NY

Adam Ruder
Program Manager

Prepared by:

Energetics Incorporated

Utica, NY

Russell Owens, PE
Technical Team Lead

Michael Dwyer
Transportation Engineer

Notice

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Acronyms and Abbreviations List

A	Amps
AC	Alternating Current
BEV	Battery Electric Vehicle
DC	Direct Current
DCFC	Direct Current Fast Charger
IOU	Investor-Owned Utility
kW	Kilowatt
kWh	Kilowatt-hour
PEV	Plug-in Electric Vehicle
PHEV	Plug-in Hybrid-Electric Vehicle
PSC	Public Service Commission
SOC	State-of-Charge
VAC	Volts Alternating Current

1 Problem Statement and Approach

Direct current (DC) fast chargers (DCFCs) are anticipated to play an important role in the wider market acceptance of plug-in electric vehicles (PEVs). PEVs include battery electric vehicles (BEV) and plug-in hybrid-electric vehicles (PHEV).

DCFCs provide a convenient method to quickly extend the electric range of PEVs and helps to alleviate drivers' and fleet managers' "range anxiety" concerns. DCFCs have real-world potential for supporting both personal and commercial fleet markets. DCFCs require high input power levels (25-120 kilowatts [kW]) which can result in high "demand charges" from the utility associated with these high peak power levels. When DCFC utilization rates are very low, demand charges can account for up to 80-90% of a station's monthly bill. This bill results in a poor, or negative, business case, which can prevent DCFC infrastructure growth at this early stage in the market development for PEVs. This lack of DCFC infrastructure may limit PEV adoption, especially as the customer base expands to include occupants of multi-dwelling units and others who do not have regular access to vehicle charging. These customers might be expected to rely more on DCFC as a regular part of their driving experience.

As described later in this study, in the most basic terms, utilities use demand charges to pay for power capacity-related costs that include the wear-related grid components, both upstream (e.g., distribution station, distribution feeder, transmission line, generation) and downstream (e.g., transformers, distribution cabling, and utility poles). Demand charges are not a penalty, rather a method for utilities to distribute these costs evenly across their customers. To ensure demand charges do not prevent deploying DCFCs that enable widespread PEV use, options must be developed to mitigate the financial impact of demand charges to bridge the gap from the current low-utilization to when the normal usage is economically viable using conventional rates.

Several approaches can be used to accomplish the goal of eliminating/significantly mitigating the large demand charges DCFC stations experience, including (but not limited to):

- Technology approaches such as onsite energy storage (i.e., battery) or onsite power generation (e.g., solar, wind, or natural gas).
- System control and scheduling approaches can be used to schedule a 20-minute session to have the first 10-minutes be in demand charge Session 1 and the last 10-minutes be in Session 2 (as an illustrative example).
- Tariff approaches using existing and newly developed alternative electricity tariffs to eliminate or significantly mitigate demand charges.

- A combination of all approaches.

Technology, system control, and system scheduling approaches have been, or are being, investigated by market participants, so these are not addressed in this study. This report focuses on regulatory and rate-making aspects affecting DCFC operator costs.

This DCFC tariff option study conducted a literature review and industry expert interviews, with electric utility industry technology and policy advocacy organizations (e.g., Edison Electric Institute and the Electric Power Research Institute). Interviews were also conducted with utilities and public service commissions outside New York State, especially progressive utilities in areas where EV adoption and DCFC use is further along than in New York State. The study's initial goal was to identify and summarize tariffs, programs, and alternative approaches that have been implemented, or are under development, by other utilities specifically intended to minimize demand charges for DCFCs, or that apply more broadly to similar high-power loads. The study's second target was to identify new and potentially better approaches that have not yet been implemented but are under consideration or being developed by utilities, public service commissions, or industry advocacy groups. The study examines if these alternative approaches are currently in use and whether they are economically feasible for the New York State Public Service Commission and New York State utilities to consider for implementation.

2 Summary of Interviewed Organizations

The list of organizations to be interviewed was developed with the intent of providing a broad perspective from utilities, public service commissions, and industry advocacy groups at the forefront of PEV adoption and DCFC usage. The list of interviewed organizations was not intended, however, to be a comprehensive sample of the entire industry. The interviewed organizations included:

- Progressive large non-New York State PEV-supporting electric utilities and states they support
 - Investor-owned utilities – 1) Southern California Edison (CA), 2) Pacific Gas & Electric Company (CA), 3) PacifiCorp (UT, OR, WY, WA, ID, and CA), 4) Eversource Energy (CT, MA, and NH), 5) Baltimore Gas and Electric Company (MD), and 6) Pepco (MD and DC).
 - Municipal utilities/public power utilities – 1) Sacramento Municipal Utility District (CA) and 2) the City of Palo Alto (CA).
- Electric utility and electric vehicle industry advocacy groups – 1) the Edison Electric Institute, which represents investor-owned utilities and 2) the Electric Power Research Institute.
- DCFC equipment manufacturers – 1) AeroVironment and 2) Efacec USA.
- Public utility commissions / public services commission – 1) California Public Utilities Commission and 2) New York State Public Service Commission.
- New York State electric utilities and power authorities – 1) the New York Power Authority and 2) PSE&G Long Island.

A number of additional utilities and industry advocacy groups were contacted to be included in the study, but did not respond.

3 Background

3.1 Direct Current Fast Chargers

DCFCs quickly charge PEVs (includes battery electric vehicles [BEV] and plug-in hybrid-electric vehicles [PHEV]), typically in less than 30 minutes. A representative installed cost for DCFC units is approximately \$90,000. The maximum DCFC power output and installation complexity impact the final cost.¹ They are anticipated to play an important role in public charging as PEV adoption increases. DCFCs can be used to provide charging for residents of multi-dwelling unit family housing and in neighborhoods that have non-assigned street or communal parking, as well as for consumers at retail locations, city centers, and other venues. Installing DCFCs along heavily travelled corridors can also increase the driving range of PEVs to make replacing a conventional vehicle more feasible for consumers and fleets.

DCFCs have output power ratings between 25 and 120 kW, but 50 kW is typical. DCFCs use an alternating current (AC) input of between 208-600 volts AC (VAC) (480 VAC is common) and between 70-200 amps (A). The vehicle recharging time varies based on the vehicle's battery energy capacity (measured in kilowatt-hours [kWh]), the DCFC output power (kW), and the percentage change in the state-of-charge (SOC). The charge time for a typical 25 kWh EV using a 50-kW DCFC that receives an 80% SOC is typically between 10 and 30 minutes. Similarly, an 85-kWh capacity Tesla Model S charging using a 120-kW charger needs approximately 40 minutes for an 80% charge and 75 minutes for a full charge.²

3.2 New York State Electric Utilities

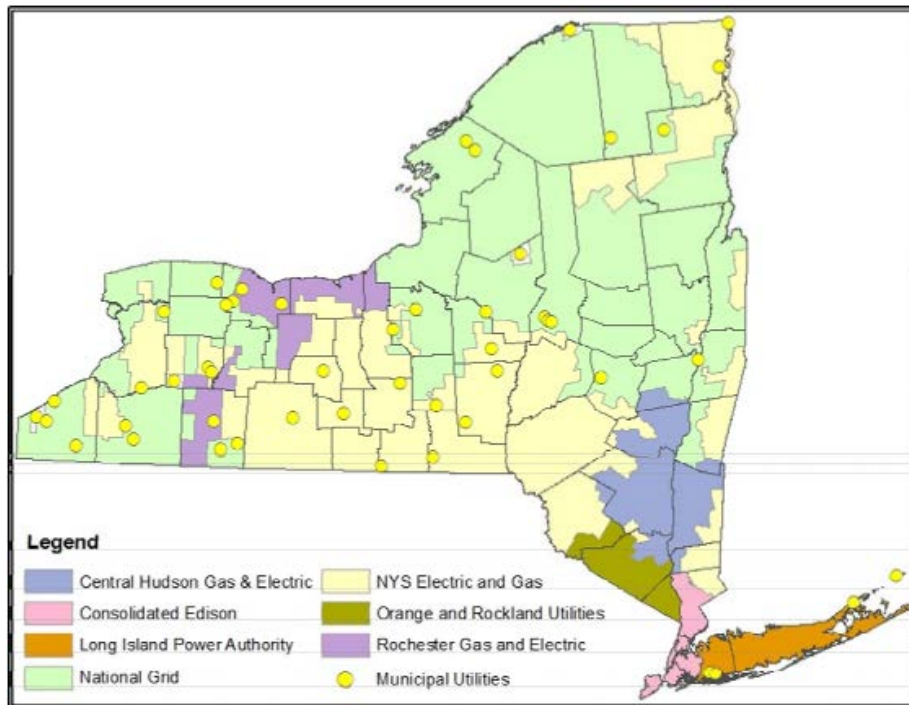
New York has six investor-owned utilities (governed by the New York Department of Public Services), approximately 36 municipal utilities³ (members of the New York Municipal Power Agency and Municipal Electric Utilities Association of New York State), and five (5) electric cooperatives (part of the New York State Rural Electric Cooperative Association). Figure 1 shows the service territories for all New York State electric utilities as of 2012.

¹ Nigro, N., & Frades, M. (2015). Business Models for Financially Sustainable EV Charging Networks. Center for Climate and Energy Solutions.

² Tesla Supercharger Network. <http://www.teslamotors.com/supercharger>

³ New York Municipal Power Agency (NYMPA). <http://nympa.org/>

Figure 1. New York State Electric Service Territories (DPS, 2012)



3.3 Types of Utilities

The ratemaking process, and the tariff development flexibility, differs between utilities. These differences can be generalized based on utility ownership, which falls into three types: 1) investor-owned utilities, 2) municipal power/public power companies, and 3) electric utility cooperatives.

3.3.1 Investor-Owned Utility

Investor-owned utilities, as the name implies, are owned by shareholders, so they operate to generate a profit. These utilities are regulated by the public utility commission/public service commission (PSC) in the state whose customers are served (i.e., the New York State Public Service Commission). The PSC requires investor-owned utilities to develop rates that fairly charge all customers in the same rate class for the service they receive. According to the Electric Power Research Institute, investor-owned utilities will never accept losses from non-economic tariff structures because they are for-profit companies. So, even if regulations force them to lose profit in one area, they will increase rates elsewhere to make up the costs to ensure that the company does not lose money. One utility offered an example of the basic steps necessary to implement a new rate. The process starts with a utility proposal to the PSC for review. If approved, the proposal is sent to the state legislature for further review. The Maryland State Legislature session is only three months long, which is an extremely short time for the utility to educate the legislative

representatives and complete the process. If the tariff rate structure is deemed to be cost-based and fair to all of the ratepayers (meaning that it benefits all customers in the rate class who will pay for it), the tariff is approved and passed into law. The process differs slightly for electric utilities in New York State. The utility proposal is submitted to the New York State Public Service Commission, which assembles a team to review and develop a response. An Administrative Law Judge is assigned to preside over the case, and is able to make recommendations to the PSC for the final decision after reply briefs are filed between the PSC and relevant utility. The PSC holds open and public meetings to complete deliberations, and releases a written order that resolves the final amount to charge customers.

3.3.2 Public Power/Municipal Utility

According to the American Public Power Association, the service and advocacy group for public power utilities, “public power utilities are operated by local governments to provide communities with reliable, responsive, not-for-profit electric service. Public power utilities are directly accountable to the people they serve through local elected or appointed officials.”⁴ The association states that “in general, a utility’s governing body (city council or independent utility board, for example) has authority over a public power utility’s retail rates, but in some states – and in certain circumstances – a state regulatory commission may have jurisdiction.”⁵ In cases where municipal utilities’ service territories appear to overlap with other utilities, the municipal utility takes precedence inside the service territory border.

3.3.3 Electric Cooperative

According to National Rural Electric Cooperative Association, the service and advocacy group for electric utility cooperatives, “electric cooperatives are: 1) private, independent, non-profit electric utilities, 2) owned by the customers they serve, 3) incorporated under the laws of the states in which they operate, 3) established to provide at-cost electric service, and are 4) governed by a board of directors elected from the membership which sets policies and procedures that are implemented by the electric utility cooperatives’ management.”

⁴ American Public Power Association - About Public Power and About APPA.
<http://www.publicpower.org/about/index.cfm?navItemNumber=37583>

⁵ American Public Power Association - References for State Rate Regulation of Public Power Utilities.
http://www.publicpower.org/files/Resources/Rate_reg_of_PP_by_PUC_-_Statutes_6_19_2014_update.pdf

3.4 Demand Charges

DCFCs are more often installed in commercial locations, so the electricity usage charge is based on commercial utility customer rates and tariffs. Commercial customer tariffs are comprised of several components: 1) a fixed monthly account charge, 2) the energy charge (based on the amount of electrical energy consumed [kWh]), 3) the demand charge (based on the peak electrical power demand [kW]), and 4) other miscellaneous taxes and fees.

Utilities define *demand charges* in slightly different ways. In the most basic terms, demand charges are power capacity-related costs that cover all of the wear-related grid components, both upstream (e.g., distribution station, distribution feeder, transmission line, generation) and downstream (e.g., transformers, distribution cabling, and utility poles). DCFCs impact the local downstream grid infrastructure much more than the large-scale upstream components. Demand charges recover the cost of utility infrastructure investments that depreciate due to grid use. This cost includes purchases of new equipment (e.g., transformers, distribution cabling, and utility poles), maintenance of existing equipment, and replacement of equipment. Utilities develop demand charge rates based on the cost of the hardware required to satisfy the peak electrical power load (kW). Infrastructure applies to all segments of electricity delivery (i.e., generation, transmission, and distribution), but the demand charge is mostly attributable to the distribution-level. Utilities recover these infrastructure costs over a long period of time (e.g., 30-40 years for a transformer and 25 years for a utility pole). Demand charges are designed to spread the relevant infrastructure costs evenly and fairly across all similar commercial ratepayers included in the same class of customers. If transmission and distribution services are provided by different entities there may be separate demand charges for each entity.

Not all utilities use the “energy plus demand charge” structure. Interviews revealed that this practice is primarily used on the West Coast (California, Oregon, and Washington) and in the Northeast. Even so, AeroVironment, the DCFC hardware developer and network charging service provider for the West Coast Electric Highway, said that most of the Oregon and Washington utilities with whom they worked for the West Coast Electric Vehicle Highway do not have demand charges.

Utilities that do not charge demand charges incorporate the equipment wear and tear, maintenance, and replacement costs in their tariff structures in other ways (e.g., additional fees or higher energy rates).

For the most part, the utilities interviewed develop their demand charge rates regardless of the load. One IOU utility in the Northeast said that its conventional demand charge rates are developed under the assumption that all electrical devices operating on the rate plan will have a typical load factor between 20-60%, with a 40% average. “Load factor” is defined as the ratio of average power to peak power. The frequency at which the peak load occurs is also generally not factored into the demand charge calculation because the electrical supply equipment must be sized for the peak power load regardless of how often it is reached.

Demand charges are calculated on a dollar per peak power basis (\$/kW), where the power is the average over a specified time interval (15 minutes is common). This peak power level determines the demand charge for the billing period, or in some cases the entire billing year. So, for example a 50-kW average peak demand at \$10/kW equates to a \$500 monthly demand charge. Demand charges can also vary by time of year. For example, the demand charge in the summer may be higher than in winter due to high air-conditioning loads.

Another approach used by some utilities is to implement a “ratchet” demand charge. This demand charge ratchet approach tracks the customer’s rolling annual peak power demand (i.e., the maximum monthly power demand experienced during the past 12 monthly billing cycles) to create a minimum required monthly demand charge (i.e., floor). If the example customer from the previous paragraph has a peak power demand of 50 kW in December on a rate schedule with a 60% ratchet, their minimum bill (regardless of their power demand) for the next 11 months will be \$300 (i.e., $60\% \times 50 \text{ kW} \times \$10/\text{kW}$). However, the ratchet will reset at a higher price if the peak demand increases above 50 kW during this period.

Several IOU and municipal western utilities have an installation charge that covers the upfront infrastructure investment (hardware and labor). The amount depends on the location of the service being installed. In some cases the new load could “tip the scale” and require a large infrastructure upgrade in that portion of the grid. In others, the new load could have a negligible impact on that branch of the grid. In some cases, the demand charge covers generation, transmission, and distribution, while the upfront cost only covers distribution and transmission. For others, the upfront cost covers all new equipment and installation, while the billed monthly demand charge covers only wear and tear on the grid. AeroVironment mentioned that the 22 utilities within whose territories they have installed DCFCs

required an upfront charge of \$8,000-25,000 for each DCFC installation. (Each location has one DCFC, requiring three-phase service, and one Level 2 charger.) For those 22 utilities, less than half offer commercial customer rate tariffs without some form of demand charges. The minority of these utilities that apply demand charges argue that the rates would not be cost-based and the utility would either lose money, or the demand-related hardware maintenance/replacement costs would be distributed unfairly among customers without demand charges.

The utilities interviewed were all interested in supporting EVs, but are very apprehensive about creating “non-economic” rates or rates specific to a single application. This apprehension is especially true of investor-owned utilities because all tariffs must be approved by a public service commission.

Some utilities argue that simply eliminating demand charges for DCFCs, even though they support EVs, is also not a logical option. It is not logical because utilities, and states in general, are working hard to reduce peak energy demand, so removing demand charges runs counter to this initiative and discourages developing the most energy and cost-efficient approaches. The Hawaiian Electric Company pilot rate program that eliminates EV charger demand charges (Level 2 and DCFC) is a case study that counters the above logic.

Based on the information gained from the interviews in this project, the tariff approval process for municipal utilities and cooperative utilities seems to be more amenable to alternative approaches that incentivize DCFCs (and help PEV drivers) because these organizations operate as nonprofits and tariffs are reviewed and approved by a board that represents the utility’s customers who will benefit from the rates.

Table 1 summarizes the range of demand charges available on commercial rates that apply to DCFCs for the interviewed utilities, for all New York State investor-owned utilities, and for a couple New York State electric cooperatives and municipalities. The charges are presented as a range that includes small and large commercial rates that can accommodate a single standalone DCFC, multiple standalone DCFCs, and DCFCs integrated into existing accounts.

Table 1. Estimated Demand Charge Ranges for Interviewed and New York State Utilities

Utility Type	Utility Name	New York State	Demand Charge (\$/kW)
IOU	Baltimore Gas and Electric Company	No	\$0 - \$3.69 ^a
Municipal	City of Palo Alto	No	\$3.23 - \$20.54 ^b
IOU	Eversource Energy	No	\$0 - \$19.14 ^c
IOU	PacifiCorp	No	\$3.29 - \$5.03 ^d
IOU	Pepco	No	\$0 - \$4.53 ^e
IOU	Pacific Gas & Electric Company	No	\$0 ^f
IOU	Southern California Edison	No	\$0 - \$13.20 ^g
Municipal	Sacramento Municipal Utility District	No	\$7.14 ^h
IOU	Consolidated Edison Company of New York	Yes	\$28.98-\$33.58 ⁱ
IOU	PSE&G Long Island	Yes	\$3.84 - \$44.78 ^j
IOU	National Grid	Yes	\$0 - \$10.86 ^{k,l}
IOU	New York State Electric & Gas Corporation	Yes	\$8.93 ^m
IOU	Rochester Gas & Electric Corporation	Yes	\$10.26 - \$15.69 ⁿ
IOU	Central Hudson Gas and Electric	Yes	\$8.42 ^o
Municipal	Village of Akron	Yes	\$1.53 ^p
Municipal	Village of Fairport	Yes	\$0 - \$3.12 ^{q,r}
Municipal	Massena Electric	Yes	\$6.50 ^s
Cooperative	Delaware County Electric Cooperative	Yes	\$7.00 ^t
Cooperative	Steuben Rural Electric Cooperative	Yes	\$13.35

^a General Service Large - Electric Schedule GL. (n.d.). Retrieved September 20, 2015, from http://www.bge.com/myaccount/billsrates/ratestariffs/electricservice/Electric_Services_Rates_and_Tariffs/P3_SCH_GL.pdf

^b Monthly Retail Electric Rate Charges. (n.d.). Retrieved September 20, 2015, from <http://www.cityofpaloalto.org/civicax/filebank/documents/48623>

^c Small General Electric Service - Rate 30. (n.d.). Retrieved September 20, 2015, from <https://www.eversource.com/Content/docs/default-source/rates-tariffs/rate30.pdf?sfvrsn=2>

^d Rates & Regulation (by State). (n.d.). Retrieved September 20, 2015, from <https://www.pacificpower.net/rates>

^e General Service Low Voltage (Demand or Non-Demand). (n.d.). Retrieved September 20, 2015, from <http://www.pepco.com/my-business/choices-and-rates/district-of-columbia/rate-schedules/>

^f Small General Service (<75 kW). (n.d.). Retrieved September 20, 2015, from http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHS_A-1.pdf

^g General Service - Demand GS-2. (n.d.). Retrieved September 20, 2015, from <https://www.sce.com/NR/sc3/tm2/pdf/ce30-12.pdf>

^h General Service - Demand GS-2. (n.d.). Retrieved September 20, 2015, from <https://www.sce.com/NR/sc3/tm2/pdf/ce30-12.pdf>

ⁱ Service Rates (Pgs. 59-81). (n.d.). Retrieved September 20, 2015, from <http://www.coned.com/documents/elecPSC10/SCs.pdf>

^j 2015 Common Commercial Electric Rates. (n.d.). Retrieved September 20, 2015, from https://www.psegliny.com/files.cfm/rates_comm.pdf

^k Small General (SC-2). (n.d.). Retrieved September 20, 2015, from https://www.nationalgridus.com/niagaramohawk/business/rates/5_elec_sc2.asp

^l No demand charge for monthly usage under 2,000 kWh

^m Electric Rates Summary (Leaves 128-153). (n.d.). Retrieved September 20, 2015, from <http://www.nyseg.com/MediaLibrary/2/5/Content%20Management/NYSEG/SuppliersPartners/PDFs%20and%20Docs/120v99.pdf>

ⁿ Electric Rates Summary. (n.d.). Retrieved September 20, 2015, from http://www.rge.com/MediaLibrary/2/5/ContentManagement/RGE/SuppliersPartners/PDFs_and_Docs/RGE_Electric_Rate_Summary.pdf

^o Summary of Proposed Monthly Electric Base Delivery Rates (pg. 277). (n.d.). Retrieved September 20, 2015, from <https://www2.dps.ny.gov/ETS/jobs/display/download/5722422.pdf>

^p Electric Rates Summary. (n.d.). Retrieved September 20, 2015, from <http://www2.erie.gov/akron/index.php?q=electric>

^q Fairport Electric. (n.d.). Retrieved September 20, 2015, from <http://www.village.fairport.ny.us/electric.html>

^r No demand charge for monthly usage under 7,500 kWh

^s Commercial and Industrial Rates. (n.d.). Retrieved September 20, 2015, from <http://www.massenaelectric.com/businesscustomer/nonresidentialrates.htm>

^t Small Commercial - Rate Schedule 3. (n.d.). Retrieved September 20, 2015, from http://dce.coop/sites/dce.coopwebbuilder.com/files/service_rules_regulations_2015august25_approved_0.pdf#page=15

Demand charges currently apply only to commercial and industrial customers. Several of the interviewed utilities are considering expanding this rate approach to residential customers. Europe also uses this structure. None had a definite plan for introducing residential demand charges.

The earlier monthly demand charge example of a 50-kW average peak demand at \$10/kW results in a \$500 monthly demand charge. As a point of comparison, Car Charging Group charges \$6.99 for a single DCFC session on its Blink network. It would take 72 DCFC charge sessions per month just to cover the station's demand charge cost in this example. This cost does not cover all of the other costs such as: the energy cost, the land lease/rental, any charging network fees, etc. AeroVironment said that a positive DCFC business model does not exist with low charger utilization (rural, corridor stations), even in the Pacific Northwest with a high EV population. Even when all DCFC equipment (hardware and installation) was grant-funded (mainly through the American Reinvestment and Recovery Act of 2009 and the U.S. Department of Transportation's Transportation Investment Generating Economic Recovery program), the DCFC station income currently only covers roughly one-third of the operating costs, absent outside incentive programs (i.e., from automotive original equipment manufacturers [OEMs]). So, eliminating demand charges improves the business case, but does not make it economically viable. Improving the business case requires increased utilization. DCFCs are essentially part of a chicken and egg scenario with EV adoption and DCFC use.

4 Interview Results

4.1 Utility Perception of DCFC Load

All of the utilities and organizations interviewed were interested in supporting PEVs. Interviewees were asked how DCFC installations are perceived from their grid operator's viewpoint. For example, are DCFCs viewed simply as a "black box" drawing power like any electrical load, or are they a unique load that should be treated differently? Most utilities stated that they view DCFCs as just another electrical load, but with a specific and unique load profile and power draw. The DCFC's location (i.e., urban, suburban, or rural) did not seem to impact how utilities deal with DCFCs. Rather, the local grid load and capacity conditions where the DCFC is installed determine the potential impact. One municipal utility commented that the DCFC load profile is significantly different than that of an average commercial customer. An IOU agreed, adding that DCFCs are just a high power load, but they have a much lower average power/peak power ratio than most other applications.

One large Mid-Atlantic IOU noted that they do not like unpredictable large loads at peak times, a category that can include DCFCs. They also commented that DCFCs really need to be installed in the most affordable location to minimize installation costs. The utility is in the best position to know where this affordable location is based on network power capacity. However, several organizations, including the Electric Power Research Institute, noted that DCFCs are viewed as a "bad" load, because: 1) they have an extremely low load factor (approximately 2% according to Edison Electric Institute and several utilities) and 2) they have a load profile that has the potential to occur during on-peak hours (specifically after work during the evening commute). Edison Electric Institute highlighted that a DCFC's full load rating is generally on the same order as a typical standalone commercial account at maximum load. A few large IOUs in the Northeast and Northwest stated that they did not view DCFCs as being different than any other high load service. However, they pointed out that the critical factor is the *combination* of: 1) what the load is and 2) specifically where on the network it is being added, and how it will affect that portion of the network. AeroVironment mentioned a University of Nevada-Reno modeling study done in collaboration with Sierra Pacific Power (now part of NV Power) that investigated DCFC effects on

distribution loops (both 13.3 kV and 26 kV) that had multiple DCFC units installed.⁶ The study investigated both end-of-the-line and midline connections and found no issues even if there were eight 250 kW DCFCs in use (equivalent to 40 standard 50 kW DCFCs).

Other similar loads and/or load profiles to DCFCs that utilities deal with were mentioned, including: 1) flash/on-demand water heaters, 2) commercial arc welders, and 3) rock crushers. None of these applications operate precisely as DCFCs do.

One California municipal utility was the exception. This utility viewed DCFCs as more of a threat due to their unpredictable and uncontrollable load profile. Every DCFC must get a permit, and each installation must be evaluated by the utility, to determine whether a grid upgrade is needed. This is discussed more in the next section.

4.2 DCFCs May Be Unique

Certain aspects of DCFCs' use may be sufficiently different from other types of electrical loads to justify different treatment. More research is needed to fully understand DCFC use and existing tariff structures to see how actual use may be similar to or different from other, more traditional loads.

4.2.1 DCFC May Cause Reduced Transformer Wear

One large Northeastern IOU commented that transformers can be safely overloaded, and can handle loads quite a bit past their rated capacity. Transformer life decreases in relation to the length and frequency with which they are overloaded, because of heat buildup from continuous/mostly continuous use. This heat buildup degrades the windings and oil, which leads to a shorter operating life and increased capital expense to replace the transformer (parts and labor) more frequently. So at low utilization (the current case for DCFCs), a 50-kW transformer for a 50-kW DCFC that is used for one 15-minute period per hour does not represent high stress for that transformer. Several interviews with IOU and municipal utilities hypothesized that DCFC use *may* lead to a slower transformer wear rate compared to the base case assumptions used to develop standard electrical equipment tariffs. This potentially slower wear rate could be attributed to DCFCs' load factor and load profile, because even though they require high power over a short time, there are long rest periods between charge sessions, including likely very low overnight usage.

⁶ Etezadi-Amoli, M., Choma, K., & Stefani, J. (2010). Rapid-Charge Electric-Vehicle Stations. *IEEE Transactions on Power Delivery*, 25(3), 1883-1887.

This ability to maintain a lower average operating temperature may decrease transformer wear. If the transformer has less wear, then theoretically the transformer life may be extended. If true, this could require a lower cost recovery rate, and thus lead to a smaller demand charge. This decreased wear advantage decreases as the DCFC load factor increases. One interview with a Northeastern IOU indicated that even in the long-term they did not expect DCFC load factor to reach 20%. If so, the reduced wear logic discussed here may continue to hold true in the long-term.

A cost study analyzing DCFCs' wear and tear on the electricity grid infrastructure, especially for local transformers, is necessary to determine whether DCFCs operate differently enough to warrant a new unique rate structure. One Northeastern IOU interviewed for the project was collecting usage data to conduct this type of cost study at the time they were interviewed.

4.2.2 DCFC Load Timing Impact and Controllability

Several utilities conveyed concern over unpredictable and uncontrollable DCFC load profiles. Drivers will use DCFCs whenever they need to quickly charge their vehicles, like they do with a conventional gasoline car. The resulting local grid impact increases with the number of DCFCs installed at a location. The ultimate DCFC usage profile is not known, but it is logical to assume that drivers may charge on their way home from work, which coincides with the afternoon air-conditioning peak in warm months. Because of this activity, the charging load cannot be scheduled to take place outside of peak demand periods.

One utility stated that they do not have any DCFCs in its service territory, but stated that it wants to prevent future DCFCs from further stressing the grid at peak load times. They suggested that this could be accomplished perhaps through the use of price signals to step down the DCFC power output (potentially even disabling it) during high demand. Another IOU said they have a small number of DCFCs installed in its service territory. This utility said it would likely never allow a customer-owned DCFC to be installed that the utility could not control the power output via signals (i.e., curtailment and demand response functionality) because of peak system demand concerns to ensure system reliability. One potential solution would be that the curtailment function would only be implemented on a limited number of "energy action days" per year, typically occurring in the summer.

Edison Electric Institute suggested that a higher demand charge could be developed to be higher during peak times because of the coincident peak. This approach would likely need to be applied to *all* loads, not just DCFCs. They suggested that utilities could send a price signal to the DCFCs to allow them to alert the consumer about the higher cost to charge (or not allow the vehicle to be charged) during peak hours.

Demand response functionality was a common thread in the discussions with each utility. All of the interviewed utilities want, or would require, the DCFCs to be controlled. Control could be performed directly by the utility, by the charge network provider, or by an independent DCFC site to respond to demand and/or pricing signals to ramp down/up power output. This output power controllability is implemented via different combinations of communications protocols such as: 1) Smart Energy Profile (SEP) 2.0, 2) Open Charge Point Protocol, 3) OpenADR (typically a utility DR communication), or 4) other proprietary communication protocols. The output power control could be done via the charging network back-office, or directly with the DCFC unit.

4.3 Comments on Utility Engagement

Interviewees indicated that municipalities/public power companies and utility cooperatives, both community/customer-owned, are more flexible to consider rate options such as lower/temporarily suspended demand charges. Cost recovery was not as big a concern for the utilities interviewed as for IOUs. The rate approval process varies by company, but was described as usually being simpler than for investor-owned utilities.

AeroVironment found that, while installing its West Coast Electric Highway network, electric utility cooperatives were much more receptive and willing to discuss unique rates and fees than investor-owned utilities. For example, the company proposed to one electric cooperative to eliminate demand charges for DCFCs. The company reported that it was a relatively easy proposal/approval process since DCFCs support EV adoption and use, which supports its customers' values. The process took approximately two months from the initial meeting to propose the approach to the implemented decision. This solution will likely be rare solution in New York State because municipal utilities and rural co-operatives do not hold a large portion of the State's electricity market. In contrast, AeroVironment has also worked for the past two years with an IOU and reports slow, but forward progress to a demand charge solution.

4.4 DCFC Infrastructure Ownership

The largest network of DCFCs is privately owned and operated by Tesla. This straightforward business model focuses on providing Tesla customers the peace of mind that they can travel long distances and have the ability to charge at convenient, predictable intervals. Other automotive OEMs such as Nissan and BMW have programs that incentivize either infrastructure installation or EV driver charge sessions.

Several organizations suggested the concept of utility-owned DCFCs (or any public-access electric vehicle charging stations, including Level 2) where the cost is spread out over all ratepayers in the service area. Utilities argue that because the biggest cost of DCFCs is the charger device and installation costs, not the network, that utilities are best suited to install and own the infrastructure. Utilities' long cost-recovery timeframe makes them well-suited. They are able to spread the cost recovery over a much longer period of time than would be required for a private company's business case. One large Mid-Atlantic IOU stated that they feel this approach eliminates much of the overhead from the equation because the utility, not the station operator, owns the charger, other electrical equipment, and the systems required for customer payment. This utility felt that this model also avoids the need for the DCFC units to be restricted to operating on an EV charging network (e.g., ChargePoint). This model would enable EV drivers to use any DCFC, not just ones in the EV charging network to which they belong. In this model, the utility would install and maintain the hardware and payment network. Third-party companies could own and operate the payment systems. If utility-owned EVSE (including DCFCs) were allowed by the PSC, transactions could be processed similarly to how automated teller machines access bank accounts for multiple banks. The utility felt that utility-owned infrastructure also solves the problem of charging infrastructure companies that go bankrupt and leave stranded hardware and customers because the DCFC hardware operation could be taken over by another operator or the utility. Utilities argue that this model would result in a more affordable service for the EV-driving customer.

This IOU also felt that large financial incentives will be needed to jumpstart DCFC infrastructure development if utilities are not paying for installation and operation. Utility-owned DCFCs also enable the utility to have complete control over its operation and could optimize (e.g., reduce) its power output. This model would be beneficial for the utility during peak hours, but customers may not accept it if the output power is reduced and the charge takes longer than expected. Further study will be required to

answer this question. Other utilities argue that the business model for privately-owned charging stations of all types, but especially DCFC, is not profitable. Therefore, the third-party companies will underinvest, which will lead to a market failure. This ultimate projected market failure is used as an argument that the need for charging stations to be incorporated into socialized cost via utility-ownership makes sense.

Utility-owned DCFC is a relatively controversial topic with respect to existing regulations, which prevent utilities from owning and operating EV charging equipment in some states. The California Public Utilities Commission explained that it decided in 2011 to not allow utility-owned charging stations. More recently, in comments regarding the California Public Utilities Commission's 2013 proceedings that again brought up whether utility-owned charging stations should be allowed, large private sector EVSE network providers argued against utility-owned charging stations primarily due to issues with unfair market competition.^{7,8} These companies argue that utility-owned infrastructure is not the best approach for maximizing innovation, cost reduction, customer choice, and customer ownership of EVSE. Other groups have suggested that it is risky for utilities to invest in DCFCs at this early stage because the final market-accepted DCFC technology solution (e.g., peak output power and voltage level) have not been determined.

The EV and DCFC industry is still evolving, so there is still more than one set of standards. This multiplicity creates a risk of stranded assets for the utility, just as it would for private companies. Some are also concerned that utilities do not have the required experience to provide electricity as a driver's fuel (e.g., facilities, amenities, and customer interaction/relationship). It should be noted that the perspectives of these private corporations are in constant flux depending on the state of evolving EV and EVSE markets. In 2014, reversing its prior position, the California Public Utilities Commission ruled that utility-ownership of EVSE is acceptable, but determinations on whether it will be allowed will be decided on a case-by-case basis. CA PSC began accepting applications from utilities in 2014 requesting approval to install and own charging infrastructure and will make approval decisions on a case-by-case basis. Two utilities (Pacific Gas & Electric and San Diego Gas & Electric) submitted proposals to install utility-

⁷ Reply to Comments of NRG Energy, Inc. on Order Instituting Rulemaking. (2013, November 14). Retrieved May 12, 2015, from ftp://ftp2.cpuc.ca.gov/PG&E20150130ResponseToA1312012Ruling/2013/12/SB_GT&S_0117484.pdf

⁸ Comments of Chargepoint, Inc. on Order Instituting Rulemaking to Consider Alternative-Fueled Vehicle Programs, Tariffs, and Policies. (2013, November 14). Retrieved May 12, 2015, from ftp://ftp2.cpuc.ca.gov/PG&E20150130ResponseToA1312012Ruling/2013/12/SB_GT&S_0125507.pdf

owned EV charging infrastructure, which for Pacific Gas & Electric includes DCFCs. Southern California Edison proposed instead to install the utility-side infrastructure up to the DCFC connection point; the DCFC units would be purchased by the station owner or operator.

Other utility commissions, such as the State of Oregon Public Utility Commission, have ruled against allowing utility-owned DCFCs because it would have decreased market competition. For the proposal to have been approved, utilities needed to show there would be a net benefit to all customers. The State of Washington recently passed legislation allowing utility ownership of EV charging infrastructure.

4.5 DCFC Locations

Demand charges vary by the region of the country and by the utility provider. The demand charge amount also varies depending on the load and service type. Utilities know what portions of their networks have sufficient capacity and will be the most affordable to install DCFCs. In an ideal world, utilities would want to select the DCFC station's location based on the location of existing infrastructure (e.g., distribution wires) and available local capacity. DCFC station owners and operators, however typically require the site to be located where it best fits the needs of their EV driver customers, such as proximity to major travel routes for visibility and customer convenience. The result may be higher installation costs to extend/upgrade service and more required utility-side power management of the local power grid to ensure reliability.

The interviewed utilities consistently distinguished between standalone DCFC installations and DCFC installations that were added onto an existing larger facility (e.g., a supermarket or shopping mall). Standalone DCFCs are a bigger challenge because the peak load and demand charge are wholly attributed to the DCFC. Adding a DCFC to an existing large commercial account may avoid, or limit, the need for a transformer upgrade and reduce the installation cost. This option is preferred because the required electrical infrastructure is already in place and the overall site power demand could potentially be managed to accommodate all of the loads. These large customers already pay demand charges, so the DCFC impact could be less. Some respondents also felt that locating the DCFC at an existing facility, instead of a remote separate location, may be a better option for security and property damage reasons because there will be more activity to deter vandalism.

5 Existing Utility Tariff Approaches

Edison Electric Institute explained that utilities operate in unique ecosystems (consisting of their governing board, PSC, local government, state government, etc.), so the issue of how to address DCFC demand charges must be approached on a region-by-region, or utility-by-utility, basis. Two potential alternative approaches were suggested by interviewees for electric utility tariffs that can reduce demand charges for DCFC infrastructure. Most utilities suggested that existing rate structures could accommodate DCFCs with some variations. A few utilities developed special programs with unique rate structures. All of the interviewed utilities agreed that the high demand charge and low utilization is a relatively short-term barrier that must be briefly overcome while utilization is low. Once DCFC utilization increases past a tipping point, standard electricity rate structures will be cost-effective both for the customer and the utility.

Most of the interviewed utilities felt that an existing tariff fit the DCFC application and load profile well, so developing a new DCFC-specific rate was not needed. AeroVironment noted that 50% of the Oregon/Washington State utilities whose service territories they installed DCFCs in for the West Coast EV Highway had suitable tariffs available that did not include a demand charge. Several interviewed utilities have power thresholds higher than a single DCFC, so the demand charges do not come into play. Neither of these options are available in New York State.

Utilities used to have a number of more specific, different rates for different customers, but now the customer generally prefers fewer and simpler-to-understand options. One large Western US IOU mentioned two specific reasons for its avoidance of load-specific rates for different end users. First, the utility is disinclined to develop specific rates for different end users (e.g., DCFC) because it needs to be fair and consistent to all customers. Second, the utility cannot be certain what device is drawing power. If rates for specific applications were implemented, enforcement and monitoring would be required to ensure only allowable loads were being powered. The utility has a residential EV rate that seems to disprove this logic. The rate is really a rebranded, existing time-of-use rate that also worked for charging EVs. The utility has also considered developing a transitional rate with a higher energy charge and a reduced demand charge that would be suitable for DCFCs, but would be available to any load. The utility is also considering a rate with several power thresholds (e.g., 15, 30, 50, and 200 kW). Both rate concepts could accommodate DCFC.

A large IOU in the Northeast commented that their existing rates are fairer to customers on a month-to-month basis because they charge for the service that was actually used. A few large IOUs mentioned that DCFCs as a population are not a large enough subclass, and likely never will be, to warrant the utility developing a DCFC-specific rate. The utilities stated that developing a DCFC-specific rate to be used as a temporary measure is very risky. The utilities' experience shows that customers become accustomed to the lower rate, so are not very accepting when the rate expires. Utilities have approved cost-based rates that recover the revenue equally and fairly from ratepayers, and they are hesitant to work outside of this structure. The utility interviews identified three basic rate structures, as discussed in the following three sections.

The research and interviews conducted for this study identified that only three DCFC-specific tariffs have been implemented. These tariffs are discussed in the next section. Most of the interviewed organizations have discussed internally how to address DCFCs. Because DCFC users are such a small class of customers and impact, priority to develop DCFC-specific rates and programs is low relative to other utility initiatives. Utilities' current preferred approach is to work with DCFC operators to select the existing rate that best fits the DCFC site's projected load profile and will minimize its monthly bill.

5.1.1 Energy-Only Rate with a Monthly Energy Consumption Threshold

This rate schedule type uses a monthly energy threshold (e.g., 2,000; 3,000; 5,000; and 8,000 kWh were identified). Demand charges do not apply if monthly usage is maintained below this level. The energy charge (\$/kWh) for this type of rate is higher than for a standard rate that includes demand charges (\$/kW) because the demand charge has been converted into an energy charge (\$/kWh). This concept could be considered a "Lumped Energy Charge" because some demand costs are included in the rate. This type of rate benefits the customer because the monthly bill is lower than it would have been using a standard type rate schedule when the DCFC utilization is low. However, the utility may not receive the same amount for demand charge-related costs. Research for this study revealed that some utilities offer this rate type. A non-exhaustive search located two utilities in New York State. One large IOU lets customers who use less than 2,000 kWh per month choose to either be on the demand or non-demand rates.⁹ One New York State municipality offers a similar option but with a 7,500 kWh monthly energy threshold.¹⁰

⁹ PSEG Long Island, 2015 Common Commercial Electric Rates. https://www.psegliny.com/files.cfm/rates_comm.pdf

¹⁰ Village of Akron Electric Rates Summary. <http://www2.erie.gov/akron/index.php?q=electric>

A rough calculation for a vehicle with a 25-kWh battery pack, such as a Nissan Leaf, that needs an 80% charge (so, 20 kWh per charging session), would need 100, 150, and 250 charges per month respectively to reach the 2,000, 3,000, and 5,000 kWh energy thresholds. This usage is much higher than DCFC units currently have. Monthly usage at or above this limit reaches the point where using a standard demand charge is lower cost for the customer.

The California Public Utilities Commission noted that they decided to move away from allowing energy thresholds because it determined that the tariffs were not cost-based and did not result in customers evenly paying for the utility service they were provided. Two large IOUs, one from the Northwest and one from the Mid-Atlantic, were concerned about costs shifting to other customers if DCFC utilization remains low, noting that it would be unfair to offer such a rate.

5.1.2 Energy-Only Rate without a Monthly Energy Consumption Threshold

This rate type is very similar to the previous option. It also converts the demand charge (\$/kW) into the energy charge (\$/kWh), but without a kWh threshold limit. As with the previous rate type, the energy charge in this case is higher than for a rate that includes demand charges separately. Many utilities offer this rate type, so it is not a “special rate.”

5.1.3 Hybrid Rates or Other Approaches

The previous options are typically combined with a peak power threshold (e.g., 50, 60, 75, 100, or 200 kW). Peak power use above the threshold moves the customer into the established “Large Commercial” class of rates. Some utilities use rate steps (by increasing peak power thresholds) before the Large Commercial rate level is reached (generally entails exceeding a minimum monthly energy consumption or peak power). Many of the interviewed utilities have peak power thresholds above 50 kW. A single DCFC would fall below this threshold, so demand charges would not apply if the DCFC were separately metered. It may be cost-effective to establish separate accounts for each charger, or a group of chargers, to stay below the kW threshold. This approach would require a monthly account fee for each DCFC or group of DCFCs.

However, utilities may not allow this approach because it could be viewed as a way to sidestep paying demand charges. It is unclear whether this would be allowed by New York State utilities. If allowed, the site owner would need to compare the costs for this approach versus using a single conventional account with the most favorable rate schedule to determine the most cost-effective option.

6 DCFC-Specific Tariffs

The research conducted for this study identified only three utilities that have implemented DCFC-specific rate structures. All three programs are short-term (approximately three years) and are intended to either gain more understanding of the effects that DCFCs will have on the grid and/or to encourage electric vehicle adoption as a service to the public.

Interviewed utilities cautioned that they have found, from previous non-DCFC programs, that it is difficult (or impossible) to move customers back to a standard rate after the pilot ends. Edison Electric Institute agreed with this statement, adding that incentivized rates will promote DCFC network growth, but customers will get used to the subsidy and view the lower rate structure as a “right.” This view conflicts with utilities’ long-term cost-recovery needs.

6.1 Pilot Programs that Eliminate Demand Charges

Two implemented DCFC-relevant rate options eliminate demand charges for DCFC stations (Hawaiian Electric Company and Connecticut Light & Power). Hawaiian Electric Company did not respond to interview requests, but the DCFC-relevant rate is available online.¹¹ The rate eliminates demand charges for EV charging facilities drawing less than 100 kW. (This number includes both DCFCs and Level 2 chargers.) The rate has no power-based demand charge, but the energy cost is nearly double the conventional rate that includes demand charges as previously described in a “Lumped Energy Charge.” Facilities using the rate must use a separate meter, which only the DCFC (and 5 kW of ancillary equipment) can operate on. The Hawaii State Energy Administration said that the rates are a “positive step in meeting the state’s clean energy objectives,”¹² which includes reducing the State’s dependency on imported oil. The rate is currently limited to 100 accounts, but may be increased if needed.

¹¹ Commercial Public EV Charging Facility Service Pilot - EV-F. (2013, July 3). <https://www.hawaiianelectric.com/vcmcontent/StaticFiles/FileScan/PDF/EnergyServices/Tariffs/HECO/HECORatesEV-F.pdf>

¹² Hawaiian Electric Companies offer new rates for public EV charging. (2013, July 10). http://www.hawaiianelectric.com/heco/_hidden_hidden/CorpComm/Hawaiian-Electric-Companies-offer-new-rates-for-public-EV-charging

Connecticut Light & Power's parent company, Eversource Energy, shared background information regarding how and why the Electric Vehicle Rate Rider Pilot program was developed. Because DCFCs have a very low load factor, Eversource felt that the typical equipment wear and rate design calculations used to develop demand charges for this application may not be accurate. A large amount of DCFC usage data were needed to conduct the robust analysis needed to more fully understand the DCFC application. So Eversource proposed the Electric Vehicle Rate Rider Pilot program to the State of Connecticut Public Utilities Regulatory Authority to incentivize increased DCFC installations and use in its service territory.

Like with the Hawaiian Electric Company program, the pilot rate does not simply eliminate demand charges, rather, it was developed assuming a 40% load factor.¹³ This concept was converted to an energy charge and then added to the standard energy charge to result in the pilot program's rate,¹⁴ similar to the previously described "Lumped Energy Charge" approach. The program will allow the utility to "gather data more quickly regarding issues surrounding public charging stations, including their use levels, rates, and technology." The program was approved and went into effect on July 1, 2014 and will remain in place for two years.¹⁵ The pilot rate is available to any DCFC site or provider willing to share anonymized usage data.

Eversource Energy will use the collected data to conduct a cost of service study to evaluate DCFC impacts and costs on the grid. The results will be used to determine whether the current rate development process is accurate for DCFCs, or whether an alternative approach could be used to develop a DCFC-specific rate. If it is determined that DCFCs do affect the grid differently than conventional loads, one potential result could be developing a rate that is higher during peak demand periods and lower during off-peak periods to incentivize off-peak use. In this case, a controllable DCFC that lowers its output power during peak periods could be used to allow DCFC operators to lower their monthly costs (if customers accepted this idea).

¹³ Eversource Energy's current tariffs assume a load factor of between 20-60% (40% average) when developing rates.

¹⁴ The Eversource Energy Rate Engineering group mentioned in the interview that this will not fully pay back the utility's costs.

¹⁵ State of Connecticut, Public Utilities regulatory Authority, Docket Number 13-12-11, "Request of CL&P for Approval of Electric Vehicle Rate Rider Pilot", June 4. 2014.

6.2 Rate Limiter

The third DCFC program identified is a “rate limiter” program offered by Southern California Edison. The tariff was initiated to enable Foothills Transit to decrease the operating costs for the fleet to fast charge its battery electric buses. However, any government-owned transit agency can apply for the rate to use for DCFCs for battery electric buses.

The rate limiter is not a new tariff, but rather a limit is placed on the maximum allowable rate that customers can be charged. The “advice letter” process Southern California Edison used for this instance resulted in the California Public Utilities Commission allowing a temporary rate change, not an indefinite change to the rate. Using this approach, the customer’s bill is calculated normally, but there is a “cap” set on the overall average energy charge (\$/kWh).^{16,17} In the case where there is only one bus charging session per month, there would only be about 50 to 100 kWh of energy provided with 500 kW worth of demand charge. This example would equal an energy charge of over \$50/kWh. The California Public Utilities Commission defined a rate limit of approximately \$0.18/ kWh. This approach allows the utility to keep relatively normal rates so the transit agency and other customers are not be tempted to try to retain artificially low rates.

Southern California Edison and California Public Utilities Commission both acknowledge that this approach does not allow for fully recovering the demand charges, but it does show the user what the full-scale operating costs would be. Neither organization wanted to set the rate limiter too low, because that would discourage the customer from using other demand charge mitigation strategies and operating efficiently. The key is to set the rate just above the current energy rate. This strategy encourages users to implement energy efficiency measures to reduce their consumption and bill. The rate limiter is a three-year temporary program that expires at the end of 2015. The concept is that by the time the program expires the number of electric buses and the charging frequency will be past the point where the rate limiter comes into play and it will be less expensive to use the conventional rate. Southern California Edison is collecting and analyzing the usage data, performing a cost of service study, and working to develop a new rate for the buses. The rate limiter approach could be a long-term solution; however it would have to go through the full California Public Utilities Commission proposal and approval process.

¹⁶ This is a similar approach as Southern California Edison’s EV-4 rate used, with an exception for DCFCs to use up to 500 kW.

¹⁷ General Service TOU EV Charging Rate. (n.d.). <https://www.sce.com/NR/sc3/tm2/pdf/ce141-12.pdf>

7 Conclusions and Future Needs

- Absent outside incentive programs (e.g., from automotive OEMs), DCFC station income currently covers roughly one-third of the monthly operating costs. Eliminating demand charges improves the business case, but does not make it economically viable. Increased utilization is needed.
- Utilities use demand charges to achieve two key goals: 1) to recover utility equipment capital and operating costs and 2) to encourage customers to shift grid power loading to off-peak times to maximize grid reliability and lower consumer costs. Eliminating, or reducing, demand charges goes against IOU cost-based rate requirements and energy-saving measures.
- Several relatively common rates that reduce demand charges are currently used by some utilities in both New York State and across the county. The rates are not DCFC-specific. The categories are described as: 1) energy charge-only rate with a monthly energy consumption threshold, 2) energy charge-only rate without a monthly energy consumption threshold, and 3) a rate limiter. These rates are not offered by all utilities, but could be considered by New York State utilities because they were developed as cost-based rates and have been implemented by other utilities.
- Many of the interviewed utilities noted that because the DCFC population is currently very low, detailed discussions of how to address DCFCs have not been a high priority. Most of the interviewed utilities felt that an existing tariff rate fit the DCFC application and load profile well, so developing a new DCFC-specific rate was not needed.
- Several utilities noted that they have internally discussed how DCFCs impact grid equipment infrastructure, but do not have sufficient available data (e.g., quantified equipment wear and tear data, accurate load profile, potential DCFC population) to make an informed decision on whether or not developing DCFC-specific rates and tariffs is needed or warranted.
- DCFC loads (high power and a very low load factor) appear to be unique compared to all other electrical loads (often lower power with a higher load factor), so further investigation is needed. A thorough cost analysis of DCFC-specific transformer wear is needed to understand how DCFCs affect the grid (especially the transformer) and whether they should be treated differently than standard electrical loads. A few studies are being performed by utilities outside of New York State.
- Demand response functionality to control the DCFC output power was a common thread in the discussions with each utility. All of the interviewed utilities want, or will likely require, the DCFCs to have controllable output power. This could be performed directly by the utility, by the charge network provider, or by an independent DCFC site to respond to demand and/or pricing signals to ramp down/up power output. This output power controllability is implemented via different combinations of communications protocols

- Several utilities mentioned the topic of utility-owned EVSE infrastructure (including DCFCs). Utilities argue that their long cost-recovery timeframe makes them well-suited for owning the infrastructure because they can spread the cost recovery over a much longer period of time than would be required for a private company's business case. Private EV charging system providers are not in favor of utility-owned charging stations primarily due to issues with unfair market competition. These companies also raised concerns of whether it would be too risky for utilities to invest in DCFC since the technology is still being developed and will likely change. Another EV charging system provider concern was that utilities are not experienced in providing electricity as a driver's fuel (e.g., facilities, amenities, and customer interaction/relationship, etc.). PSCs offered a similar conclusion, generally deciding against utility-owned EV infrastructure and waiting to re-address the topic in the future.

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**New York State
Energy Research and
Development Authority**

17 Columbia Circle
Albany, NY 12203-6399

toll free: 866-NYSERDA
local: 518-862-1090
fax: 518-862-1091

info@nyserdera.ny.gov
nyserdera.ny.gov



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