Lessons Learned – The EV Project DC Fast Charge - Demand Charge Reduction

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List of Acronyms

AC	Alternating Current
APS	Arizona Public Service
ARRA	American Recovery and Reinvestment Act
BMS	Battery Management System
DC	Direct Current
DCFC	DC Fast Charge
DOE	U.S. Department of Energy
ESS	Energy Storage System
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
GCV	Grid-Connected Vehicle
kW	Kilowatt
kWh	Kilowatt-hour
PEV	Plug-in Electric Vehicle
PHEV	Plug-in Hybrid Electric Vehicle
SOC	State of Change
TOU	Time-of-Use
U.S.	United States

1 Company Profile

ECOtality, Inc. (NASDAQ: ECTY), headquartered in San Francisco, California, is a leader in clean electric transportation and storage technologies. Its subsidiary, Electric Transportation Engineering Corporation (eTec) dba ECOtality North America (ECOtality), is the leading installer and provider of charging infrastructure for electric vehicles (EVs). ECOtality has been involved in every major EV or plug-in electric vehicle (PEV) initiative to date in North America and is currently working with major automotive manufacturers, utilities, the United States (U.S.) Department of Energy (DOE), state and municipal governments, and international research institutes to implement and expand the presence of this technology for a greener future.

ECOtality designed and currently manages the world's largest EV infrastructure demonstration - The EV Project. With a budget of over $230 million, The EV Project will deploy and study Level 2 alternating current (AC) electric vehicle supply equipment (EVSE) stations for residential use, Level 2 AC EVSE stations for commercial and direct current (DC) fast charge (DCFC) stations. This represents thousands of field assets, utilized in concert with the deployment of Nissan LEAF™ vehicles and Chevrolet Volt® vehicles.

The EV Project is a public and private partnership administered by the DOE through a federal stimulus grant, made possible by the American Recovery and Reinvestment Act (ARRA) and by the private investment of ECOtality and its partners.

The EV Project is an infrastructure study. The EV Project will deliver to ECOtality, the Government and the general public a wealth of directly-applicable technical and professional experience for jumpstarting regional EV adoption and replicating business models that lead to sustainable, market-based charge infrastructures.

One purpose of The EV Project is to identify potential barriers to the widespread adoption of EVs and the deployment of EVSE to support them. This process identifies topics of national interest in the early deployment of EV charging stations in order to facilitate discussion and resolution. This paper documents the issues associated with and The EV Project's approach to the reduction of the demand charges.

2 Statement of Need

The first objective of The EV Project is to collect usage data from deployed EVSE to understand the charging behavior and habits of users. The second objective is to elucidate the motivations and hindrances to EVSE ownership. To achieve this second objective, it is important to consider the various factors that a prospective EVSE owner will weigh when deciding to purchase and install an EVSE unit.

One such factor that arises with EVSE ownership is the application of “demand charges”. These are charges levied by the utility, typically for commercial properties, for the peak power used during a billing cycle, regardless of the amount of energy drawn at this power rate. These demand charges can add significantly to the utility bill for an EVSE host, and can make EVSE hosting cost prohibitive. While demand charges are incurred for the AC Level 2 EVSE hosts, and the methods for demand charge reduction apply to both EVSE types, the DCFC hosts’ demand charge costs are likely to be more significant because of the much higher power draw by a DCFC. Thus, the methods for demand charge reduction are more likely to be applied in the DCFC case, and this white paper will focus on DCFCs.

This paper identifies issues associated with electric utility demand charges for power drawn by DCFC units and discusses opportunities for demand charge avoidance. These opportunities will become a part of the Micro-Climate™ process, the planning activity utilized by ECOtality North America to facilitate EVSE installation. The opportunities will be discussed with prospective EVSE hosts where appropriate, and steps will be taken to reduce or eliminate demand charges if necessary.

The following sections discuss the issue of demand charges more explicitly, and outline the various methods for demand charge reduction. Subsequently, there is a section on a case study in which the methods are applied to a specific hypothetical EVSE installation. Finally, a concluding section is included to summarize the study findings.

3 Background

The demand charge incurred by a customer is related to the peak power used during a billing cycle. In contrast to the total energy usage that is the more familiar utility charge, a demand charge is incurred for a one-time occurrence of an elevated power level and is not a cumulative-type charge. Demand charge rates are specified in $/kW, and are usually incurred when the peak power used during a billing cycle rises above a specified threshold, but are sometimes incurred for any power level above zero. Certain utilities even levy a yearly peak power demand charge. Demand charges are the method by which utilities dis-incentivize power use during high demand periods and high peak demands.

For most U.S. utilities, the peak power for a given billing cycle is determined by calculating the average power in consecutive 15-minute intervals (from start to finish of the billing cycle) and extracting the highest average from the entire cycle of intervals. Some utilities will impose a demand charge for every kW of usage; others will impose no demand charge until a specified power threshold is surpassed. In some of the latter cases, the demand charge is calculated by subtracting the demand charge threshold power level from the highest average power from the set of intervals, and then multiplying the remainder by the demand charge rate. In other cases where a threshold exists, any incursion over the threshold will result in a demand charge for the entire average power level, not just the amount above the threshold. Since the power is averaged over the interval, it is possible for the power demand during an interval to exceed the threshold and still incur no demand charge, as long as the average power over the interval is below the threshold.

Demand charges can become quite significant, and can in fact dominate a utility bill in certain circumstances. A generic example of the effect of demand charges on a utility bill is shown below in Table 3-1, where the bills for a varying number of charged GCVs are shown, along with the cost per vehicle charged. In this example, the basic meter charge is $200 (regardless of the power and energy drawn by the EVSE); the demand charge is $10/kW, a typical commercial value; and the energy charge is $0.11/kWh, also a typical commercial value. Each GCV that is charged is assumed to use the full 60 kW available from the Blink DCFC for 20 minutes, for a total energy usage of 20 kWh per vehicle. A further assumption is that there is no other load on this particular meter. Implicit in this assumption is that this means that a new utility service is installed for the EVSE, and that the additional costs associated with a new service for the EVSE are ignored.

Table 3-1 Demand Charge Scenarios

Scenario	Number of Vehicles Charged/ Month	Meter Charge	Demand Charge	Energy Charge	Monthly Total	Cost per Vehicle
1	0	$200	$0	$0	$200	N/A
2	1	$200	$600	$2.20	$802.20	$802.20
3	10	$200	$600	$22	$822	$82.20
4	100	$200	$600	$220	$1,020	$10.20
5	250	$200	$600	$550	$1,350	$5.40
6	500	$200	$600	$1,100	$1,900	$3.80

As shown in the table, the demand charge remains constant regardless of the number of vehicles charged, and that it becomes proportionally less of the bill as the number of vehicles charged increases. Furthermore, as the number of vehicles charged increases, the overall cost per vehicle falls dramatically. If a sufficiently large number of vehicles use the EVSE to charge, the demand charge becomes less of a concern. However, since the number of vehicle customers cannot be estimated with any precision and the site owners may be unwilling to incur large demand charges, strategies to reduce or eliminate these charges must be developed. The number of GCVs, and hence the number of EVSE users, will be low at first, but are expected to grow gradually. The demand charges incurred from hypothetical DCFC installations in EV Project areas can also be examined. The rates are taken from the schedules presented in Appendix A (the rates highlighted in yellow were selected). For this analysis, a particular duty cycle will be assumed. The duty cycle involves three vehicles charging from 30-90% and 7 vehicles charging from 30-60% per day, all at the maximum rate of 60 kW. The vehicles will all be assumed to be Nissan LEAFs, each with a useable energy storage system (ESS) capacity of approximately 20 kWh. Thus, the three vehicles will each receive 12 kWh and the seven vehicles will receive 6 kWh for a total of 18 kWh per day. The DCFC will again be assumed to be the only load on the meter.

Some of The EV Project utility partners do not impose any demand charges for the power and energy demand of a DCFC installation:

1. Tucson Electric Power
2. Alameda Municipal Power
3. Silicon Valley Power
4. Pacific Gas and Electric
5. City of Palo Alto Utilities

The three utilities within The EV Project with the highest demand charge rates are all in California (these are given as the highest possible demand charge; demand charges may be lower at other times of the year and/or at other times of the day):

1. Los Angeles Department of Water and Power: $9.00 per kW (high peak demand charge) plus $5.00 per kW (Facilities charge), for a total of $14.00 per kW.
2. Southern California Edison: $17.05 per kW (summer demand charge) plus $12.18 per kW (Facilities charge), for a total of $29.20 per kW.
3. Burbank Water and Power: $9.86 per kW (Billing Demand Charge), $11.18 per kW (Special Demand Charge), for a total of $21.04 per kW.

The demand charges for a representative sample of utilities in The EV Project are presented in Appendix B. It should be noted that the Tennessee utilities only impose demand charges above 50 kW, so if the DCFC was the only appliance on the circuit and the maximum AC power was 50 kW, there would be no demand charge.

Using the base and energy rates from Appendix A for the high demand charge utilities along with the demand charge rates, the monthly (30.4 days) bill for a DCFC installation with the assumed duty cycle could reach:

- Los Angeles Department of Water and Power: $28.00 (base) + $25.60 (energy) + $840 (demand), for a total of $893.60. The demand charge would be 94% of the total monthly bill.
- Southern California Edison: $134.17 (base) + $12.13 (energy) + $1752 (demand), for a total of $1898.30. The demand charge would be 92% of the total monthly bill.
- Burbank Water and Power: $15.99 (base) + $62.22 (energy) + $1052 (demand), for a total of $1130.21. The demand charge would be 93% of the total monthly bill.

It is clear from these examples that devising solutions to the demand charge problem associated with fast charging GCVs is imperative in order to prevent the hindrance to growth of this industry. The purpose of this white paper is to discuss the various options available for reducing or eliminating the demand charge for EVSE installations. It is unlikely that one method will be optimal for each specific location, and so all options should be considered on a case-by-case basis.

4 Demand Charge Reduction Options

In order to determine the method for reducing the demand charge, the first step is to determine the following parameters for a given location:

a) What is the expected peak demand of the site owner in a billing period? Over how much of the 15-minute interval does the peak demand span?
b) What is the average site demand?
c) What is the utility rate structure? Is there a yearly maximum average power demand charge in addition to the billing cycle maximum average power demand charge?
d) What is the demand charge tolerance?

Once these parameters are specified, the next step is to choose from the possible methods for reducing the demand charge. The six methods that have been identified are:

1. Never allow the overall site power demand to exceed a specified value.
2. Attempt to ensure that the average power over the interval is less than or equal to a specified value.
3. Attempt to recoup the demand charge cost through structured pricing for EVSE charging.
4. Add an ESS that buffers the EVSE unit from high power demands during charging.
5. Aggregate demand among multiple EVSE installations into one demand charge calculation, taking advantage of the diversity that may exist in individual unit usage.
6. Provide demand response capability to the utility to either offset or circumvent demand charges.

The first option is more conservative in that demand charges will be less likely to be incurred. The second option allows more flexibility, higher EVSE power levels and is useful when the expected site peak demand (without the EVSE contribution) is much larger than the average site demand. Ensuring that the average site power does not exceed the specified value can be accomplished in two ways: (1) using a combination of historical data for peak and average power, the EVSE power is de-rated, and (2) using only the historical average demand data, allow full EVSE power but only for a portion of the 15-minute interval. The third option can ensure that the EVSE owner is compensated for the demand charges incurred, but the cost per charge may become prohibitive for the average vehicle owner or DCFC host. These three options are discussed in more detail in the following sections.

The fourth option can provide certainty that the demand charges are minimized, but only up to a certain number of vehicles, and the complexity and cost of the overall system will necessarily increase. The fifth and sixth options offer demand charge reduction opportunities, but they both involve substantial negotiations with the electric utility. The fifth option would require the utility to allow the EVSE network operator to aggregate all of the deployed EVSE into one demand. The sixth option, which is known as interruptible service and is offered already by some utilities, would require an agreement between the operator and utility on the value of the network providing demand response capabilities. The complexities of these last three methods warrant separate discussions in future white papers and the three are not discussed further in this paper.

4.1 Demand Charge Reduction Method 1: Peak Site Demand-Dictated Approach

The first method for demand charge reduction (or elimination) is to ensure that the peak output of the EVSE never exceeds the value that is the difference between the demand charge tolerance and the expected peak demand of the site owner. This is depicted below in Figure 4-1, where the blue line is the billable power over the interval (the sum of the site power demand and EVSE power demand), the red line is the demand charge tolerance (*T*), the orange line is the EVSE power demand (*X*), and the green line is the site peak power demand (*P*) without the EVSE contribution. Even though the expected peak demand without the EVSE contribution may not extend over the entire interval, in order to ensure the total demand never exceeds the threshold, the peak expected demand is assumed to last the entire interval.

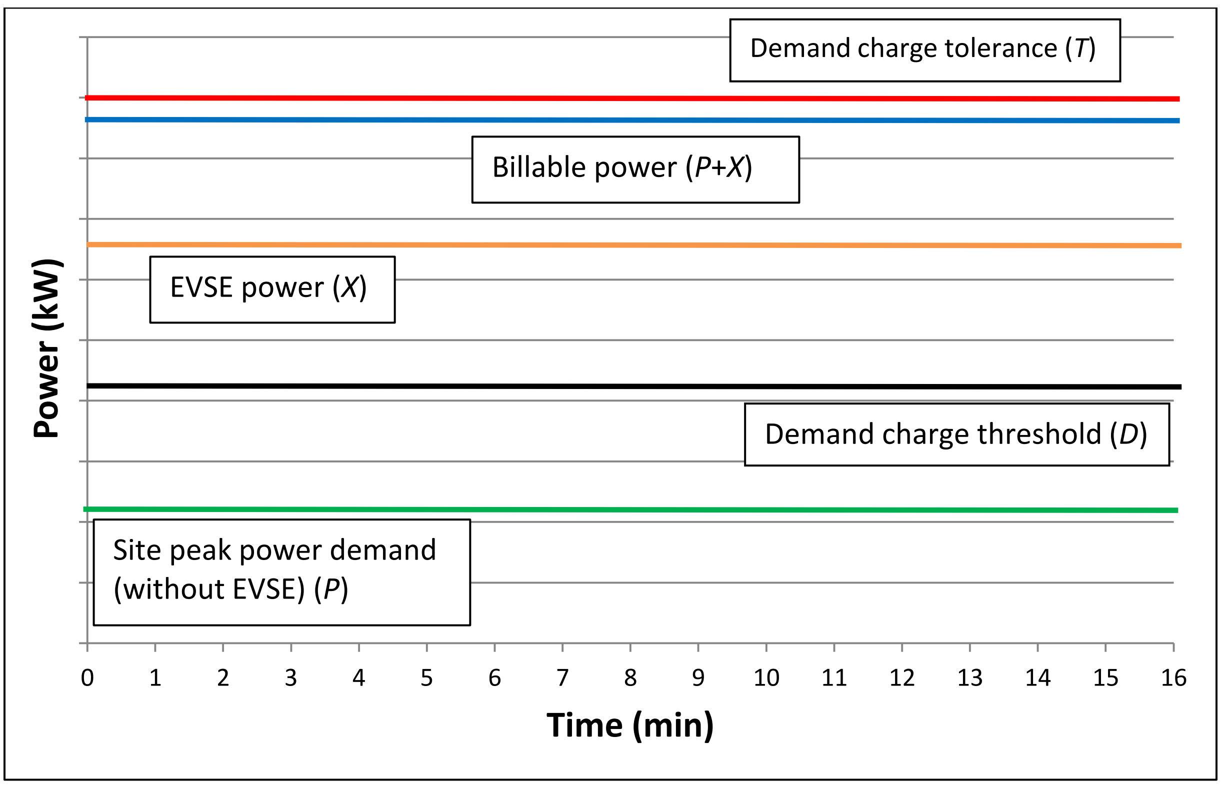

Figure 4-1 Billable Power Never Exceeds the Demand Charge Tolerance

To capture this strategy in a formula, the following variables are assigned:

- Let *D* be the threshold above which there is a demand charge (in kW); *D* is known from the published utility rate structure
- Let *P* be the expected peak site demand without the EVSE over the 15-minute interval (in kW)
- Let *X* be the peak power of the EVSE over the 15-minute interval (in kW)
- Let *T* be the demand charge tolerance (in kW, is zero when total demand charge avoidance is desired); *T* will be a function of the demand charge rate structure and demand charge threshold *D*

The equation that governs the relationship is then:

$$P + X \leq T \qquad (1)$$

or billable power is less than or equal to the demand charge tolerance. The variable *T* is defined by the customer's preference and published utility rate structure. The expected peak site demand can be obtained from historical usage data and so the peak power allowable for the EVSE (*X*) to obtain a desired demand charge can be calculated from Equation (1). The DCFC can then be electrically limited at the time of installation.

4.2 Demand Charge Reduction Methods 2a and 2b: Exceeding the Demand Charge Tolerance Approach

Methods 2a and 2b for demand charge reduction (or elimination) involves allowing the sum of the peak site demand and EVSE power to exceed the value of the demand charge tolerance, but only for a short period of time. The power sum for the rest of the 15-minute interval must be sufficiently low that the average power demand over the interval does not exceed the demand charge tolerance.

4.2.1 Method 2a

Method 2a is depicted below in Figure 4-2 for when the site peak power demand duration is well defined. A crucial aspect of this method is that reliable historical data on the site peak demand duration must exist and the average site power value must be relatively stable for the time outside of the peak site demand. If the peak demand timeframe is unknown or if the average site power has a large standard deviation, Method 2a cannot be used with any confidence that the demand charge will be reduced or eliminated. This method is complicated by the fact that even if the peak demand timeframe is known, the 15-minute interval begins at an unknown time. Therefore, the 15-minute interval with the highest peak and average site demand should be used in order to conservatively determine the highest allowable EVSE power.

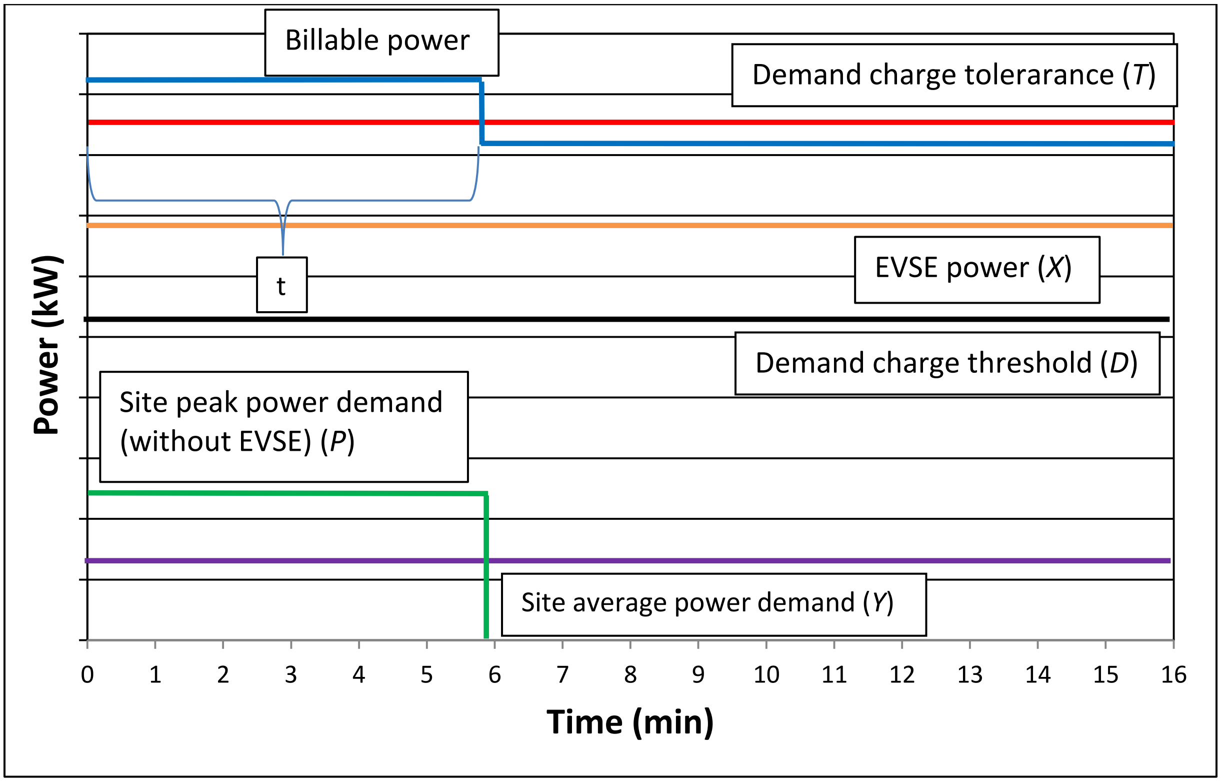

Figure 4-2 Billable Power Exceeds the Demand Charge Threshold for Duration *t* due to Site Peak Power Demand

For Method 2a, two more variables must be assigned:

- Let *Y* be the average site power demand
- Let *t* be the amount of time over which the site peak power demand (*P*) occurs (in min, is less than or equal to 15 min)

The formula relating these variables for this strategy is then:

$$\frac{(P+X)t+(Y+X)(15-t)}{15} \leq T \qquad (2)$$

As before, the variable *T* is defined by the customer's preference and published utility rate structure. The expected peak site demand (*P*) and average site power (*Y*) are obtained from historical usage data, as is the peak site demand period (*t*) and so the peak power allowable for the EVSE (*X*) to obtain a desired demand charge can be calculated from Equation (2). The DCFC can then again be electrically limited at the time of installation.

4.2.2 Method 2b

It should be noted that experience to date indicates that nearly all commercial sites that are subject to utility demand charges already have a load management system in place that controls site loads to maintain a consistent average site power demand that is below the host's demand charge tolerance. Method 2b is then implemented, where the duration of the EVSE charge is controlled to allow for full EVSE power, but only for a shortened duration such that the average power demand over the interval does not exceed the demand charge tolerance, as shown below in Figure 4-3, Equation (2) is therefore modified.

$$\frac{15Y + Xt}{15} \leq T \tag{3}$$

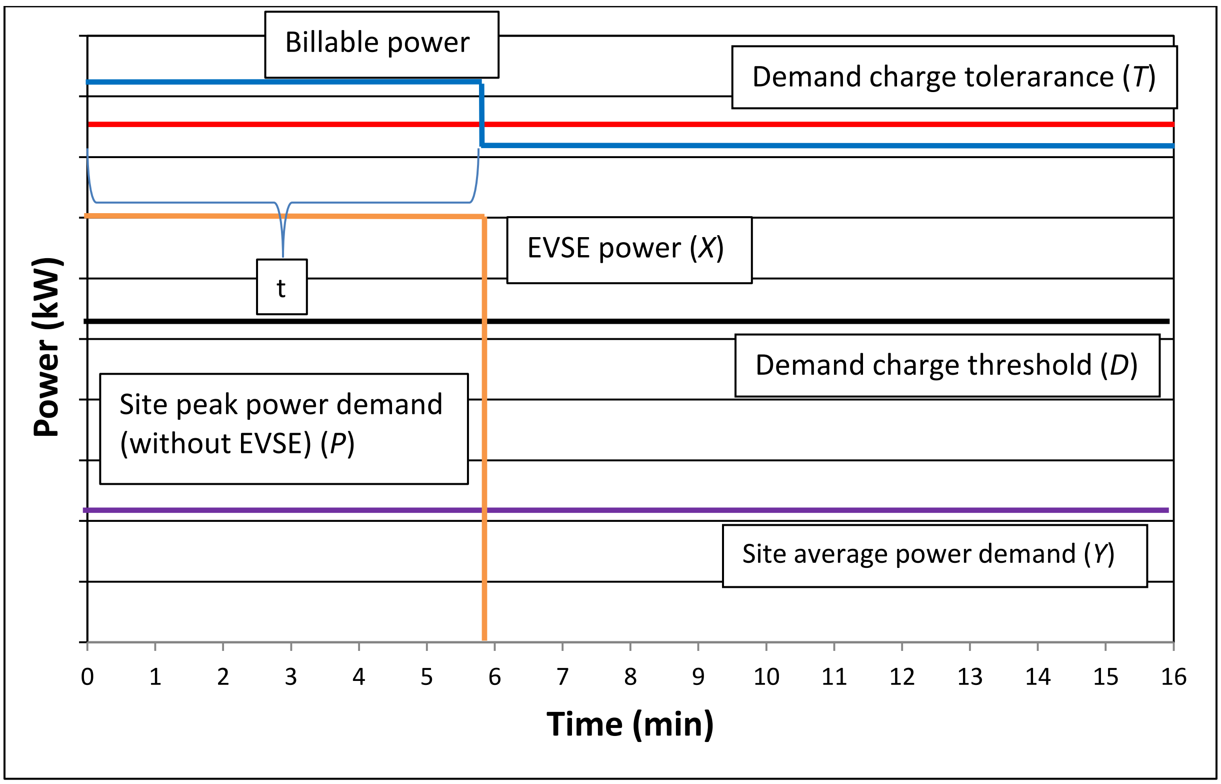

Figure 4-3 Billable Power Exceeds the Demand Charge Threshold for Duration *t* due to EVSE Power

Limiting the EVSE charge to a portion of the 15-minute interval may be a viable method until the number of vehicles increases to the point that demand charges are amortized over a large number of charges per month. This strategy may also be advantageous in that the user can be notified that the charge is done for the 15-minute interval and can perhaps be given the choice to disconnect. However, depending on the site data, the energy provided to the GCV may be lower with Method 2b, creating GCV owner dissatisfaction.

4.3 Demand Charge Reduction Method 3: Selective User Charge Rates Approach

The third method for reducing or eliminating the demand charge for EVSE usage is for the user to be allowed to select different charge rates, e.g., "premium", "regular", and "economy", with costs differences for each rate. For example, the premium rate for the DCFC might be the maximum allowable power of the unit (60 kW), while the other rates can be any combination that is deemed commercially beneficial. The advantage of this method is that any power schedule that is the EVSE owner's preference can be used. The disadvantages include potentially pricing EVSE usage out of the range of the average user as well as uncertainty because the number of users selecting each tier will affect the amount that must be assessed for each vehicle. Also, this approach may cause legal problems since charging at different power levels may contravene the legal requirement that only utilities can legally sell power. It is important to note that even though a user may select a given charge power rate, the battery management system (BMS) of the battery on board the vehicle will ultimately control the flow of electricity to the battery and may not allow the power rate chosen. The strategy in the BMS will take several factors into account, including temperature and SOC, and also potentially battery characteristics such as total Ah throughput.

5 Case Study

This section outlines case studies for demand charge reduction using the three methods outlined in Section 4 for the DCFC case. Unlike the previous examples, this case study considers a DCFC installation that will be additional to a building service, not a stand-alone service.

One of the building meters at ECOtality North America headquarters was instrumented with measurement equipment that captured power and energy usage data at a sampling frequency of once per minute. The data were captured over a three day period from 8:35 am, August 8, 2011 to 7:47 am, August 11, 2011. The resultant data were then analyzed and the 15-minute interval with the highest average power was determined. The peak site demand of 16.6 kW was the highest from the three-day collection period. The data from this interval are presented below in Table 5-1.

Table 5-1 ECOtality North America Site Demand Data for 15-Minute Interval

Statistic	Value
Peak Site Demand	16.6 kW
Time at Peak	2 min
Average Site Demand	14.6 kW
Site Demand Std. Dev.	4.2 kW

The local utility is Arizona Public Service (APS), and the commercial rates for an Extra Small location are used for this case study:

- Energy usage rate: $0.10403 per kWh for the first 200 kWh; $0.06083 per kWh for all additional
- Demand charge rate: $9.675 per kW for the first 100 kW; $5.146 per kW for all additional

While the interval with the highest average and peak demand is considered for the demand charge, the energy charge is calculated using the entire three-day period data. The electrical energy consumed over the three-day period was 512.02 kWh. Extrapolating this demand over a month (30.4 days) of energy usage and using the energy use rate from above results in an energy charge of $489.65. The demand charge tolerance for the DCFC is assumed to be equal to the cost for the energy portion of the site bill, i.e., T is assumed to be $489.65 divided by the demand charge rate of $9.675/kW, or 50.6 kW.

The case study will include the same duty cycle from Section 2 for charging of GCVs. The costs for Methods 1, 2a, and 2b will be the same since the charging energy is constant and the demand charge threshold is set. The only difference will be the charge times associated with each method. Method 3 will be considered separately. The total bill not is determined; only the additional costs associated with the DCFC operation will be calculated.

5.1 Demand Charge Reductions Using Methods1, 2a and 2b

The total monthly bill for these three methods would be: $20.43 (base) + $41.93 (energy) + $489.56 (demand), for a total bill of $551.92. The demand charge would be 89% of the total bill. The cost per vehicle is $1.82 if all charges are considered equal. If value of the charge from 30-60% is considered to be one-half of the 30-90% charge, the costs per vehicle would be $2.79 (30-90%) and $1.40 (30-60%).

The demand charge reduction for Method 1 is determined by using Eq. (1), and the maximum allowable DCFC charge would be 34.0 kW. The amount of energy that could be provided during any single 15-minute charge period would be 8.5 kWh. Thus, all seven of the vehicles charging from 30-60% could be fully charged within the 15-minute interval, while the three vehicles charging from 30-90% would require nearly 22 minutes each.

The demand charge reduction for Method 2a is determined using Eq. (2) and the maximum allowable DCFC charge would be 35.7 kW. The amount of energy that could be provided during any single 15-minute charge period would be 8.9 kWh. All seven of the vehicles charging from 30-60% could be fully charged within the 15-minute interval, while the three vehicles charging from 30-90% would require over 20 minutes each.

The demand charge reduction for Method 2b is determined using Eq. (3), and the DCFC can charge a vehicle at its full 60 kW capacity for 9 minutes. After the 9 minutes elapse, the DCFC power output would have to drop to zero in order to prevent the demand charge threshold from being exceeded; the charge could resume at the start of the next interval. The amount of energy that could be provided during any single 15-minute interval would be 9.0 kWh. All seven of the vehicles charging from 30-60% could be fully charged within the 15-minute interval, while the three vehicles charging from 30-90% would require 18 minutes each.

The EVSE site host could be more confident that the demand charges would not be larger than the specified value by using Method 1 and Method 2b over Method 2a. Method 2a appears to be the inferior of the three since *a priori* knowledge of peak power values and durations will be difficult to obtain. Method 2b is likely the superior of the three methods since it allows for the highest energy transfer at the maximum DCFC charge rate; Method 1 could pay a penalty in customer satisfaction because of the lower charge power. However, Method 2b could also result in customer dissatisfaction because the charge will terminate and cannot begin again until the next 15-minute interval begins.

5.2 Demand Charge Reduction Using Method 3

For Method 3, it is assumed that the three tiers, “premium”, “regular”, and “economy”, are available to the customer. The power levels for the three tiers are assumed to be 60 kW, 40 kW, and 20 kW, respectively. The charging component of the demand charges associated with the three tiers are therefore $580.50, $387.00, and $193.50. Adding the base and charging energy costs ($20.43 (base) + $41.93 (energy)) from the duty cycle charging results in total costs of charging for the three tiers to be $642.86, $449.36, and $255.86, respectively. The required costs for different combinations of charge rates are presented below in Table 5-2 Method 3 Scenarios and Costs per Vehicle. The demand charge will always be associated with the maximum tier for a given billing cycle, e.g., if there are any vehicles charged at the "premium" rate, the $642.86 charge will apply as shown in the last entry in the table. The prices will follow the relative differences in power of the tiers for this analysis, although that is not necessarily required; this assumption means that the "premium" charge rate costs three times that of the "economy" rate. The duty cycle of 10 cars charging per day is used again for each scenario has been made so that a comparison with the results from Methods 1, 2a, and 2b can be made. However, the demand charge tolerance, which was held constant for the other methods, is not fixed in Method 3, and this makes a direct comparison difficult.

Table 5-2 Method 3 Scenarios and Costs per Vehicle

Scenario	Premium	Regular	Economy	Required Cost Per Premium Vehicle	Required Cost Per Regular Vehicle	Required Cost Per Economy Vehicle
1	304	0	0	$2.11	-	-
2	0	304	0	-	$1.48	-
3	0	0	304	-	-	$0.84
4	104	100	100	$3.15	$2.10	$1.05
5	204	50	50	$2.53	$1.69	$0.84
6	50	204	60	$3.17	$2.11	$1.06
7	50	50	204	$4.25	$2.83	$1.42
9	1	0	303	$6.30	-	$2.10

It is apparent that the fewer Premium selections for a given number of overall cars to be charged, the higher cost that must be assigned to both the premium and regular vehicle prices in order to amortize the demand charge.

It should also be noted that using the three tier power levels, the time required to charge from 30-60% at each tier is 6 minutes (Premium), 9 minutes (Regular) and 18 minutes (Economy), and from 30-90%, the charging time at each tier is 12 minutes (Premium), 18 minutes (Regular), and 36 minutes (Economy).

6 Conclusion

Several conclusions can be reached through the analysis of the three methods presented for reducing demand charges as well as the case study. First, for two out of the three methods, it is imperative that reliable historical energy use data are available for any prospective DCFC site. If the site's demand data without the DCFC contribution are not entirely reliable, a margin of error should be maintained to prevent inadvertent exceeding of a demand charge threshold that could vastly increase the cost of operation. Each site must be vetted thoroughly for appropriateness for DCFC deployment, including the obvious permitting and installation costs and complexities, but also from the standpoint of site demand data reliability and uniformity: If the data are unavailable or the demand varies widely, the site may not be a suitable for a DCFC unit. This decision must be made on a case-by-case basis, and will largely depend on the tolerance of the DCFC host to large and varying demand charges.

The various methods represent different approaches and philosophies to demand charge reduction. The peak demand-dictated approach of Method 1 is very conservative, especially if the assumed peak demand is conservatively chosen with a margin of error. The maximum demand charge can be made to be very predictable. However, the user may be forced to accept a lower charge rate, and this may result in dissatisfaction with the DCFC experience.

The exceeding the demand charge tolerance approach of Method 2a is less conservative, and will allow for higher charge rates. This will increase user satisfaction, but the host may incur larger demand charges as a result. The reliability and invariability of the site demand data is even more important for this method. Method 2b is likely to be no less conservative than Method 1 (whereas Method 1 relies on the historical site peak demand, Method 2b relies on the historical site average demand) and the full power of the DCFC is available; however, since the charge time must be truncated within the 15-minute interval, customer dissatisfaction may result from having to wait for the next interval to occur, with potentially prolonged periods with a connected vehicle but no charging.

If the pricing scheme of Method 3 is used, the objective is to compensate the host for demand charges, rather than attempting to reduce the incurrence of demand charges. In this case, the site demand data is largely irrelevant, but reliable data on user tier preferences and on user numbers are crucial to the pricing scheme settings in order to maintain the satisfaction of the DCFC host. The larger the number of users, the lower the price can be per charge for the customers. Furthermore, the more users that choose the higher-priced charge rate, the lower the price can be for all tiers.

It should be noted once again that the three methods described in detail in this paper are not the only ways that demand charges can be reduced. Further study will be conducted, and white papers will be released, to devise additional methods which may provide more flexibility, options, and cost-reduction certainty for the DCFC host. In particular, an approach in which the DCFC is paired with a ground energy storage system that could accept power during periods of low demand (and during periods of low time-of-use (TOU) rates to reduce energy charges) and release power during periods of high demand to reduce the peak demand value should be investigated fully. ECOtality North America is currently conducting such a study. Alternatively, the EVSE network operator could negotiate with the local utility whereby instead of a demand charge is incurred for each DCFC unit, the demand can be aggregated into a single demand charge to help lower the overall cost and remove the burden from EVSE hosts. Finally, the EVSE network operator could agree to classify the EVSE units as interruptible service units so that the utility could direct the EVSE to stop charging whenever warranted by excessive overall grid demand. In this case, demand charges would still be incurred, but the charges would be offset by compensation for interruptible service provision.

On a broader scale, some comments on demand charges themselves are warranted. The basic rationale for demand charges is that they will reduce peak power demands by financially impacting behavior regarding the use of electrical power. This assumption is based on the premise that utilities should reduce peak demand, which will reduce the need for additional generation facilities by using existing plants more efficiently, and will also reduce the need for the inherently inefficient usage of spinning reserve plants. This premise remains appropriate in the absence of smart grid technologies and distributed energy storage. However, utilities may be able to substitute these two paradigm-shifting additions in the electricity sector for new generation capacity since the additions allow for much more utility control over the electricity demand. Eliminating demand charges, at least in certain circumstances, in exchange for more utility control, may be in the public interest for a number of reasons, including the advancement of GCVs. GCVs offer the possibility of distributed energy storage, interruptible service provision, in addition to additional revenue from increased electricity demand that can be shifted to off-peak times. Imposing burdensome demand charges may stunt the nascent introduction of GCVs by limiting the attractiveness of DCFC deployment, and this may be against the interest of utilities as well. While demand charge reduction using the methods outlined in this document for the current rate structures should be undertaken, the issue and indeed the concept of demand charges should be revisited in the context of GCVs and DCFCs to determine what steps can be taken to address the needs of all stakeholders.

Appendix A- Utility Rates[1]

Utility Rates for Seattle, Washington

Utility	Seattle City Light		
Base Rate	**(Up To 50 kW Max Demand) Schedule SMD: Small General Service Network:** Minimum Charge: $0.27 per meter per day, **Schedule SMC: Small General Service City:** Minimum Charge: $0.27 per meter per day	**(50 kW - 1,000 kW Max Demand) Schedule MDD: Medium General Network Service:** Minimum Charge: $0.71 per meter per day, **Schedule MDC: Medium General Service City:** Minimum Charge: $0.71 per meter per day	**Schedule LGD: Large Network General Service: (max demand is greater than or equal to 1,000 kW)** $33.15 per meter per day. **Schedule LGC: Large Standard General Service: City: (max demand is greater than 1,000 kW, but less than 10,000 kW)**: $33.15 per meter per day
Energy Charge	**SMD:** $0.0669 per kWh, **SMC:** $0.0669 per kWh	**MDD:** $0.0669 per kWh, **MDC: $0.0569 per kWh**	**LGD: Peak**: $0.0720 per kWh, **Off-Peak**: $0.0485 per kWh; **LGC: Peak**: $0.0648 per kWh, **Off-Peak:** $0.0438 per kWh
Demand Charge?	No	Yes	Yes
Utility Definition of Demand Charge		Classification of new customers will be based on the Department's estimate of maximum demand in the current year.	
When Does It Take Effect?		All kW of maximum demand is charged a specific rate per kW	
Cost of Demand Charge		**MDD:** All kW of maximum demand at $1.89 per kW, **MDC**: All kW of maximum demand at$1.22 per kW	**LGD: Peak**: $1.99 per kW, **Off-Peak**: $0.25 per kW; **LGC: Peak**: $0.95 per kW, **Off-Peak**: $0.25 per kW
Contact Info	(206)-684-3000 (Customer Service)		

[1] These rates are as of the date of this paper and to the best of our knowledge.

Utility Rates for California

Utility	Burbank Water and Power	Glendale Water and Power	
Base Rate	<u>**Schedule D: Medium General Service (20 - 250 kW)**</u>: **1-Phase:** $10.67 per meter; **3-Phase:** $15.99 per meter	**Small/Medium Business Standard Service Rate LD-2A**: $3.60 per meter per day	Large Business Standard Service Rate PC-1-A: (less than 500 kW of demand): Customer Charge: $30.00 per meter per day
Energy Charge	All kWh/mo. $0.1137	**July through October per kWh**: $0.07; **November through June per kWh**: $0.065	July - October: $0.0600 per kWh, Nov. - June: $0.0500 per kWh
Demand Rate?	Yes	Yes	Yes
Utility Definition of Demand Charge	**Billing Demand:** kW of measured max demand, but not less than 70% of the highest demand established in billings for the preceding months of July, August, September, and October, with meters read on and after July 1. **Special Demand:** applies to devices and equipment that produce highly intermittent demands of short duration.	see below	
When does it take affect?	Billing demand shall be defined as the kilowatts of measured maximum demand, but not less than 70% of the highest demand established in billings for the preceding months of July, August, September, and October, beginning with meters read on and after July 1.	Maximum kW reading for last 12 months	
Cost of Demand Charge	Min: $87.96 per month; All kW of Billing Demand: $9.86 per kW;	**Small/Medium Business:** **July through October** Max kW reading for last 12 months: $0.32; **November through June** Max kW reading for last 12 months: $0.22	July - October: $0.3200 per kWh; November - June: $0.2200 per kWh
Additional Monthly Charges	Special Demand Charge: $11.18 per kW. Special Demand Charge applies to devices and equipment that produce highly intermittent demands of short duration. EV mileage credit: $0.0138 per mile		Fuel Adjustment Charge: $0.0448 per kWh
Contact Info		Linda Umeda (PEV) 818-551-3043 lumeda@ci.glendale.ca.us	

Utility	Los Angeles Department of Water and Power		Southern California Edison	
Base Rate	**Small General Service A1:** Service Charge $6.50	**Primary Service Schedule A2a:** Service charge $25.00 per month; **Schedule A2b: TOU Rate Schedule**: $28.00 Service Charge per month (Rate plan B required if max demand (over 30 kW) is reached 3 out of 12 months, or 2 times during high season billing months	**Schedule GS-1: Demand Should Not Exceed 20kW:** **Customer Charge**: $0.733 per meter per day, **3-Phase**: $0.032 per day	**Schedule GS-2:** **(Demand) 20kW-200kW**: Customer Charge: $134.17 per meter per month
Energy Charge	**High Season, June - September**: $0.06558 kWh; **Low Season, October - May**: $0.04268 kWh	**Schedule A2a: High Season, June- September:** $0.03645 per kWh; **Low Season, October - May:** $0.02995 per kWh; **Schedule A2b TOU Rate: June-September: High Peak**: $0.04679, **Low Peak:** $0.03952, **Base**: $0.01879; **Oct. - May: High Peak**: $0.04045, **Low Peak**: $0.04045, **Base**: $0.02252	$0.06353 per kWh per meter per day for both Summer and Winter months	$0.02216 per kWh per meter per month for both Summer and Winter months
Demand Rate?	No	Yes	No	Yes
Utility Definition of Demand Charge		**Demand:** based on max demand recorded at any time during billing month. **Facilities Charge**: based on highest demand recorded in last 12 months, but not less than 30 kW.		**Time Related Demand:** a per kW charge applied to greatest amount of registered demand during each summer season billing period. **Facilities Related Demand:** a per kW charge applied to greatest amount of registered demand during each billing period.
When does it take affect?	Plan is based on a less than 30 kW monthly load	Based on the Maximum Demand recorded at any time during billing month. Plan is intended for loads greater than 30 kW.	Plan is based on a less than 20 kW monthly load	Only during Summer, it is the max demand for each billing period
Cost of Demand Charge		**Rate A: High Season, June- September:** $9.00 per kW; **Low Season, October - May:** $5.50 per kW **Rate B:, June- Sept. High Peak**: $9.00 per kW, **Low Peak**: $3.25 per kW; **Oct. - May High Peak**: $4.00 per kW		**Time-Related Demand: 17.05 per kW in the summer. Facilities Related Demand Charge: $12.18 per kW.** Facilities related demand charge shall be for the kW of Maximum Demand recorded during the monthly billing period, year round.
Additional Monthly Charges	**Facilities Charge: $5.00 per kW** Facilities Charge is based on highest demand recorded in last 12 months, but not less than 4 kW.	**Facilities Charge: $5.00 per kW** : Facilities Charge is based on highest demand recorded in last 12 months, but not less than 30 kW.		
Contact Info	Aviva Raskin (Rates) aviva.raskin@ladwp.com John Romero (Major Accounts) john.romero@ladwp.com		Chris Vournakis (PEV or Rates Group) 626-302-7319, christopher.vournakis@sce.com	Kelly Garcia (Major Accounts Group) 714-895-0335, kelly.garcia@sce.com

Utility	Pacific Gas and Electric		City of Palo Alto Utilities	
Base Rate	**Schedule A-1: 1-Phase**: $0.29569 per meter per day **Poly-Phase**: $0.44353 per meter per day **(Includes both Summer and Winter)**	**Schedule A-10**: $3.94251 per meter per day	**E-2: Small Business Electric Service (no demand),** less than or equal to 6,000 kWh a month	**E-4: Medium Commercial Electric Service:** max demand is less than 1,000 kW per month. **TOU Rate Schedule:**
Energy Charge	**Summer:** $0.19712 per kWh, **Winter**: $0.14747 per kWh	**Secondary Voltage:** **Summer:** $0.13666 per kWh, **Winter**: $0.10643 per kWh **Primary Voltage:** **Summer:** $0.13007 per kWh, **Winter:** $0.10142 per kWh; **Transmission Voltage:** **Summer:** $0.11470 per kWh, **Winter**: $0.09101 per kWh	**Summer Period per kWh**: $0.14045, **Winter Period per kWh:** $0.12661	**Summer Period per kWh**: $0.08171, **Winter Period per kWh**: $0.07318; **TOU Rate Schedule: Summer: Peak**: $0.14526, **Mid**: $0.07561, **Off**: $0.05837, **Winter: Peak**: $0.09620, **Off**: $0.05722
Demand Rate?	No	Yes	No	Yes
Utility Definition of Demand Charge		Max load expressed in kW placed on PG&E's system by the customer's equipment as recorded over a specific interval of time, normally 15 minutes.		**Max Demand:** average power in kW taken during any 15 min interval, City may use a 5 min interval in cases of violent fluctuations; **Billing Demand**: actual max demand in kW for the month
When does it take affect?		Based on highest level of kW required by a customer during a billing period		All kW over 1,000 kW per month; max demand in any month will be the max average power in kW taken during any 15 minute interval in the month
Cost of Demand Charge		**Secondary Voltage:** **Summer**: $11.05 per kW, **Winter**: $7.02 per kW **Primary Voltage:** **Summer**: $10.39 per kW, **Winter:** $6.49 per kW; **Transmission Voltage:** **Summer:** $7.96 per kW, **Winter:** $4.58 per kW		**Summer Period**: $20.54 per kW, **Winter Period:** $13.84 per kW; **TOU Rate: Summer: Peak**: $12.08, **Mid:** $7.64, **Off:** $4.39; **Winter: Peak:** $7.87, **Off**: $4.43
Additional Monthly Charges		**Optional Meter Data Access Charge:** $0.98563 per meter per day		
Contact Info	Reiko Takemasa (PEV) 415-973-5742 r1t6@pge.com		Shiva Swaminathan 650-329-2465 shiva.swaminathan@cityofpaloalto.org	

Utility	San Diego Gas and Electric		
Base Rate	**Schedule A- General Service (less than 20 kW per month)**: $9.56 per month	**Schedule AL-TOU: (loads greater than 20 kW automatically placed on this plan): (0-500 kW): Secondary:** $58.22 per month	**Schedule A6-TOU (max demand is greater than or equal to 500 kW): Basic Fee: Primary:** $232.87, **Primary Substation:** $16,630.12, **Transmission**: $1,270.44
Energy Charge	**Summer:** **Secondary**: $0.09804 per kWh, **Primary:** $0.09170 per kWh; **Winter**: **Secondary:** $0.08516, **Primary:** $0.08010	**Summer: On-Peak:** Secondary: $0.01312 per kWh, **Semi**: Secondary: $0.01046 per kWh, **Off-Peak**: Secondary: $0.00970 per kWh; **Winter: On-Peak:** Secondary: $0.01209 per kWh, **Semi:** Secondary: $0.01046 per kWh, **Off-Peak**: Secondary: $0.00970 per kWh,	**Summer: On-Peak: Primary:** $0.00936, **Primary Substation& Transmission:** $0.00930, **Semi-Peak: Primary:** $0.0083, **Primary Substation/Transmission:** $0.00825, **Off-Peak: Primary:** $0.00796, **Substation/Transmission**: $0.00795; **Winter: On-Peak: Primary:** $0.00897, **Substation/Transmission**: $0.00885, **Semi Peak: Primary:** $0.0083, **Substation/Transmission**: $0.00825, **Off-Peak: All**: $0.00796 (all per kWh)
Demand Rate?	No	Yes	Yes
Utility Definition of Demand Charge	Monthly demand is the 15 min interval in which average electricity consumption is greater than any other 15 min interval for the month		Non-Coincident Demand: The Non-Coincident Demand Charge shall be based on the higher of the Maximum Monthly Demand or 50% of the Maximum Annual Demand.
When does it take affect?	Less than 20 kW per month	**Non Coincident Demand Charge** is based on the higher of the Maximum Monthly Demand, or 50% of the Maximum Annual Demand. **On-Peak Demand Charge** is based on the Max On-Peak Period Demand.	Maximum Demand at the Time of System Peak. The Maximum Demand at the Time of System Peak will be based on the kW of Maximum Demand measured at the time of system peak occurring during each billing period during the on-peak period.
Cost of Demand Charge		**Non Coincident:** Secondary: $13.57 per kW, Primary: $13.71 per kW, Transmission: $4.99 per kW; **Max On-Peak:** **Summer:** Secondary: $7.65 per kW, Primary: $8.03 per kW, Transmission: $1.50 per kW; **Winter:** Secondary: $5.22 per kW, Primary: $5.34 per kW, Transmission: $0.32 per kW	**Non-Coincident Demand: Primary:** $14.85, **Primary Substation**: $6.18, **Transmission**: $6.12; **Max Demand at Time of System Peak: Summer: Primary:** $9.31, **Primary Substation:** $2.07, **Transmission**: $2.10; **Winter: Primary**: $6.10, **Primary Substation** $0.40, **Transmission** $:0.39 (all per kW)
Additional Monthly Charges			
Contact Info	**Phone:** 800-411-SDGE		

Utility	Alameda Municipal Power			Hercules Municipal Utility		
Base Rate	A-1 General Service (kW is less than 500 kW a month for any 6 out of 12 months) Customer Charge: $10.00	A-2 General Service - Demand Metered: (equals or exceeds 8,000 kWh, demand is less than 500 kW for 6 of 12 months): Customer Charge: $90.00	A-3 Medium General Service - Demand Metered (demand is equal to or exceeds 500 kW for any 6 out of 12 months): Customer Charge: $290.00	E-5: Small Commercial Electrical Service (demand is less than 50 kW for 3 consecutive months, or use less than 100,000 kWh per year) Customer Charge: $16.93 per month	E-10 Medium Commercial Electrical Service (demand is between 50 kW and 399 kW, but has not exceeded 399 kW for 3 consecutive months) Customer Charge: $93.75 per month	E-19: Industrial Electrical Service (billing demand has exceeded 399 kW for at least 3 consecutive months): Customer Charge: $2.85 per meter per day
Energy Charge		$0.10898 per kWh	$0.10316 per kWh	$0.2253 per kWh	$0.1526 per kWh	$0.1249 per kWh
Demand Rate?		Yes	Yes	No	Yes	Yes
Utility Definition of Demand Charge						
When does it take affect?		The Metered Demand is the maximum average power taken per meter during any 15-minute interval in the month			The demand charge is based on the highest 30-minute average usage measured in kW during the monthly billing period	Demand will be averaged over 30-minute intervals for customers whose maximum demand exceeds 399 kW. "Maximum demand" will be the highest of all the 30-minute averages for the billing month. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month
Cost of Demand Charge		$9.00 per kW of Metered Demand	$9.00 per kW of Metered Demand		Summer: $7.54 per kW of max demand per month, Winter: $1.86 per kW of max demand per month	Summer: $5.75, Winter: $3.25 per kW of max demand per month
Additional Monthly Charges						Install Charge: $443.00, one time charge per meter
Contact Info						

Utility	Silicon Valley Power		
Base Rate	**Schedule C-1: General Service (less than 8,000 kWh per month): Customer Charge**: $3.14 per meter per month **(same for TOU Rate Option)**	**Schedule CB-1 (energy exceeds 8,000 kWh, demand is less than 4,000 kW)** Customer Charge: $57.12 per meter per month **(same for TOU Option)**	**Schedule CB-3: Large General Service Demand Metered (Billing Demand exceeds 4,000 kW):** Customer Charge: $57.12 per meter per month **(same rate for TOU Option)**
Energy Charge	**First 800 kWh:** $0.15136 per kWh, **Over 800 kWh:** $0.13742 per kWh; **TOU Peak: First 800 kWh:** $0.16473, **Over 800 kWh**: $0.15078, **Off-Peak: First 800 kWh:** $0.14044, **Over 800 kWh**: $0.12648 per kWh.	**All kWh:** $0.09176 per kWh; **TOU Rate: Peak**: $0.10513, **Off Peak**: $0.08084 per kWh	$0.08451 per kWh; **TOU Rate: Peak**: $0.09786, **Off-Peak:** $0.07357 per kWh
Demand Rate?	No	Yes	Yes
Utility Definition of Demand Charge			
When does it take affect?		All kW of Billing Demand	All kW of Billing Demand
Cost of Demand Charge		$6.91 per kW; **TOU Rate: Peak**: $6.91, **Off-Peak:** $0.00	$9.21 per kW; **TOU Rate: Peak:** $9.21 per kW, **Off-Peak:** $0.00 per kW
Additional Monthly Charges			
Contact Info			

Utility Rats for Arizona

Utility	SRP	Tucson Electric Power		
Base Rate	**E-36: General Service Price Plan: Total Monthly Service Charge:** $14.61	**Schedule GS-10: General Service: Single Phase Service (min)**: $8.00 per month, **Three Phase Service (min)**: $14.00 per month	**Schedule LGS-13: Large General Service: (Min demand is 200 kW)** Customer Charge: $371.88 per month	**Schedule LGS-85N Large General Service "Powershift" TOU Program (min demand is 200 kW): Customer Charge**: $371.88 per month
Energy Charge	**First 350 kWh: Summer:** $0.0911 per kWh, **Summer Peak:** $0.1098 per kWh, **Winter:** $0.0790 per kWh; **Next 180 kWh: Summer:** $0.0908 per kWh, **Summer Peak:** $0.1095, **Winter:** $0.0787 per kWh	**Base Power Supply Charge: Summer:** $0.031550 per kWh; **Winter:** $0.024222 per kWh	**Base Power Supply Charge: Summer:** $0.032554 per kWh; **Winter**: $0.025054 per kWh	**Base Power Supply Charge: Summer: Peak:** $0.059253 per kWh, **Shoulder Peak**: $0.033588 per kWh, **Off-Peak**: $0.025299 per kWh; **Winter: Peak:** $0.036088 per kWh**,** **Shoulder Peak**: N/A, **Off-Peak**: $0.027799 per kWh
Demand Charge?	Yes	No	Yes	Yes
Utility Definition of Demand Charge	Billing demand is the max 15 minute integrated kW demand occurring during the billing cycle			
When does it take affect?		Monthly load must be less than 200 kW	The maximum 15 minute measured demand in the month, but not less than 50% of the maximum demand used for billing	
Cost of Demand Charge	**Summer**: $4.21 per kW, **Summer Peak**: $4.21 per kW, **Winter**: $2.46 per kW		$10.362 per kW	**Summer: Peak**: $11.869 per kW, **Off-Peak**: $8.239 per kW; **Winter: Peak**: $8.908 per kW, **Off-Peak:** $6.418 per kW
Additional Monthly Charges		**Delivery Charge: First 500 kWh: Summer**: $0.056236 per kWh, **Winter:** $0.051252 per kWh; **Remaining kWh: Summer:** $0.085145 per kWh, **Winter:** $0.080145 per kWh	**Delivery Charge: Summer**: $0.025656 per kWh; **Winter:** $0.023910 per kWh	**Delivery Charge: Summer: Peak:** $0.059253 per kWh, **Shoulder-Peak**: $0.033588 per kWh, **Off-Peak**: $0.025299 per kWh; **Winter: Peak**: $0.036088 per kWh, **Shoulder-Peak**: N/A, **Off Peak:** $0.027799 per kWh
Contact Info	**(602)236-8833 (Customer Service)**	**(520)623-7711 (Customer Service)**		

Utility	TRICO Electric Cooperative		
Base Rate	**GS2: General Service Plan (10 kW to 200kW)** **Single Phase Service:** $18.00 per month, **Three Phase Service:** $26.00 per month	**GS3: General Service less than 12,000 kW):** **Single phase:** $18.00, **Three-phase**: $26.00	**GS-TOU:** **Single-phase:** $24.00, **Three-phase:** $32.00
Energy Charge	$0.1380 per kWh	$0.0830 per kWh	$0.06375 per kWh
Demand Charge?	Yes	Yes	
Utility Definition of Demand Charge	**Demand:** the rate at which power is delivered during any specified (15 minutes) period of time. **Coincident Demand Charge:** applied to the customer's monthly measured demand as recorded by a suitable metering device at the time of the AEPCO peak		
When does it take affect?	First 10 kW: no charge; Each kW over 10 kW	$16.65 per kW	$5.95 Coincident Demand Charge: $29.50
Cost of Demand Charge	$4.50 per kW over 10 kW		**This utility's service rules are very vague (see TOU): http://www.trico.coop/index.php?option=com_content&view=article&id=113&Itemid=114**
Additional Monthly Charges			
Contact Info	Customer Service: (520)744-2944		

Utility	APS					
Base Rate	**E-32S: Small General Service (21 kW- 100 kW): Self Contained Meters:** $0.672 per day, **Instrument-Rated Meters:** $1.324 per day, **Primary Voltage:** $3.415 per day	**E- 32S-TOU: Self Contained Meters**: $0.672 per day, **Instrument-Rated Meters:** $1.324 per day, **Primary Voltage:** $3.415 per day	**E-32M: Medium General Service (101 - 400 kW) Self Contained Meters**: $0.672 per day, **Instrument-Rated Meters:** $1.324 per day, **Primary Voltage:** $3.415 per day, **Transmission Voltage**: $26.163 per day	**E-32M-TOU: Self Contained Meters**: $0.672 per day, **Instrument-Rated Meters:** $1.324 per day, **Primary Voltage**: $3.415 per day, **Transmission Voltage:** $26.163 per day	**E-32L: Large General Service (over 400 kW): Self Contained Meters**: $1.068 per day, **Instrument-Rated Meters:** $1.627 per day, **Primary Voltage**: $3.419 per day, **Transmission Voltage:** $22.915 per day	**E-32l-TOU**: **Self Contained Meters:** $0.710 per day, **Instrument-Rated Meters:** $1.324 per day, **Primary Voltage**: $3.415 per day, **Transmission Voltage**: $26.163 per day
Energy Charge	**Summer**: $0.10403 per kWh for first 200 kWh, plus $0.06083 per kWh for all additional kWh; **Winter**: $0.08689 per kWh for first 200 kWh, plus $0.04369 for all additional kWh	**May-Oct.: Peak**: $0.07291 per kWh, **Off-Peak:** $0.05794 per kWh; **Nov. - April: Peak:** $0.05586 per kWh, **Off-Peak**: $0.04089 per kWh	**May- Oct.: 1st 200 kWh:** $0.10320 per kWh, **additional kWh**: $0.06034 per kWh, **Nov. - April: 1st 200 kWh:** $0.08619 per kWh, **additional kWh:** %0.04334 per kWh	**May - Oct: Peak**: $0.07233 per kWh, **Off-Peak**: $0.05748 per kWh; **Nov. - April: Peak:** $0.05542 per kWh, **Off-Peak:** $0.04057 per kWh	**May - Oct: First 200 kWh:** $0.10093 per kWh, **Additional**: $0.05902 per kWh; **Nov. - April: First 200 kWh:** $0.0843 per kWh, **Additional:** $0.04239 per kWh	**May- Oct.: Peak**: $0.07076 per kWh, **Off-Peak:** $0.05623 per kWh; **Nov. - April: Peak**: $0.05421 per kWh, **Off-Peak:** $0.03968 per kWh
Demand Charge?	Yes	Yes	Yes	Yes	Yes	Yes
Utility Definition of Demand Charge	Average kW used during the 60 min period of max use during the on-peak hours of the billing month.					
When does it take affect?	Separate costs between first 100 kW and any additional kW used					

Utility	APS					
Cost of Demand Charge	**Primary**: $8.976 per kW for first 100 kW, plus $4.448 per kW for all additional kW; **Secondary**: $9.675 per kW for first 100 kW, plus $5.146 per kW for all additional kW	**Secondary: Peak:** $14.322 per kW for the first 100 on-peak kW, plus $9.725 per kW for all additional on-peak kW, **Off-Peak**: $5.492 per kWh for the first 100 off-peak kW, plus $3.059 per kW for all additional off-peak kW; **Primary: Peak**: $13.863 per kW for the first 100 on-peak kW, plus $9.657 per kW for all additional on-peak kW, **Off-Peak**:$4.916 per kW for the first 100 off-peak kW, plus $2.979 per kW for all additional off-peak kW	**Secondary: 1st 100 kW:** $9.597 per kW, **Additional**: $5.105 per kW, **Primary: 1st 100 kW**: $8.905, **Additional:** $4.412 per kW; **Transmission: 1st 100 kW:** $6.942 per kW, **Additional:** $2.45 per kW	**Secondary:** $14.209 per kW for the first 100 on-peak kW, plus $9.649 per kW for all additional on-peak kW, $ 5.449 per kWh for the first 100 off-peak kW, plus $3.034 per kW for all additional off-peak kW; **Primary:**$13.753 per kW for the first 100 on-peak kW, plus $9.581 per kW for all additional on-peak kW, $4.877 per kW for the firs 100 off-peak kW, plus $2.955 per kW for all additional off-peak kW; **Transmission**: $12.938 per kW for the first 100 on-peak kW, plus $9.300 per kW for all additional on-peak kW, $4.232 per kW for the first 100 off-peak kW, plus $2.849 per kW for all additional off-peak kW	**Secondary: 1st 100 kW:** $9.384 per kW, **Additional**: $4.993 per kW; **Primary: 1st 100 kW**: $8.703 per kW, **Additional:** $4.315 per kW; **Transmission: 1st 100 kW:** $6.788 per kW, **Additional:** $2.396 per kW	**Secondary:** $13.901 per kW for the first 100 on-peak kW, plus $9.439 per kW for all additional on-peak kW, $ 5.331 per kWh for the first 100 off-peak kW, plus $2.969 per kW for all additional off-peak kW; **Primary**: $13.455 per kW for the first 100 on-peak kW, plus $9.373 per kW for all additional on-peak kW, $4.771 per kW for the firs 100 off-peak kW, plus $2.891 per kW for all additional off-peak kW; **Transmission:** $12.658 per kW for the first 100 on-peak kW, plus $9.098 per kW for all additional on-peak kW, $4.140 per kW for the first 100 off-peak kW, plus $2.787 per kW for all additional off-peak kW
Additional Monthly Charges						
Contact Info						

Utility Rates for Oregon

Utility	Pacificorp	
Base Rate	**Schedule 28: General Service, Large Non-Residential (31 kW - 200 kW)** **Primary: (Less than 50 kW per month):** $17.00, **(52 kW - 100 kW per month):** $29.00,	**Schedule 28: General Service, Large Non-Residential (31 kW - 200 kW)** **Secondary: (Less than 50 kW per month):** $15.00, **(51 kW - 100 kW per month):** $28.00,
Energy Charge	$0.0325 per kWh	$0.619 per kWh
Demand Rate?	Yes	Yes
When Does It Take Effect?	15 minute period of greatest use during month, but not less than 15 kW.	
Utility Definition of Demand Charge	**Special Demand:** In the event of loads with large short-period fluctuations, Pacificorp reserves the right to employ special demand determinations	
Cost Of Demand Charge	$4.16 per kW	$4.39 per kW
Additional Monthly Costs	**Load Size Charge: Loads less than 50 kW**: $0.95 per kW, **Loads 51 - 100 kW:** $0.80per kW	**Load Size Charge: Loads less than 50 kW**: $0.95, **Loads 51- 100 kW:** $0.75
Contact Info		

Utility	Portland General Electric		
Base Rate	**Schedule 32: Small Non-Residential (up to 30 kW):** **Single-Phase:** $12.00 per month, **Three-Phase:** $16.00 per month	**Schedule 38: Medium and Large Non-Residential (up to 200 kW):** **Single-Phase:** $20.00, **Three-Phase:** $25.00	**Schedule 83: Large Non-Residential Standard Service (31 kW - 200 kW):** **Single-Phase:** $20.00, **Three-Phase**: $30.00
Energy Charge	**Total**: $0.10186 per kWh for first 5,000 kWh, then $0.07674 per kWh over 5,000 kWh	**Total On Peak:** $0.11912 per kWh, **Total Off Peak:** $0.10662 per kWh	$0.06993 per kWh
Demand Rate?	No	No	Yes
When Does It Take Effect?	Greater than 30 kW twice will result in removal from schedule		Separate Charges for first 30 kW of demand, and all kW over 30 kW
Utility Definition of Demand Charge			Demand: Measure the highest average usage over a 30 minute period.
Cost Of Demand Charge			**Facilities Charge:** **First 30 kW**: $2.38 per kW, **Over 30 kW:** $2.08 per kW,
Additional Monthly Costs			**Transmission and Related Services Charge:** $0.82 per kW of monthly demand; **Distribution Charge:** $1.76 per kW
Contact Info	1-800-743-5000 (Customer Service)		

Utility Rates for Tennessee

Utility	Middle Tennessee Electric (MTEMC)		Duck River Electric Membership Corporation	
Base Rate	**Schedule GSA1-40 (Less than 50 kW, Less than 15,000 kWh)**: $16.60 per month	**Schedule GSA2-50 (51- 1,000 kW, Greater than 15,000 kWh)**: $45.33 per month	**General Service Rate: GSA-1 (loads less than 50 kW)**: $20.00 per month	**GSA-2 (50 kW- 1,000kW):** $175.00 per month
Energy Charge	$0.09226 per kWh	**First 15,000 kWh**: $0.09593 per kWh; **Additional kWh:** $0.05545 per kWh	$0.10349 per kWh	**Summer:** **First 15,000 kWh**: $0.10159 per kWh, **Additional kWh**: $0.06281; **Winter:** **First 15,000 kWh:** $0.10147 per kWh, **Additional kWh**: $0.06281 per kWh; **Transition:** **First 15,000 kWh**: $0.10083 per kWh, **Additional kWh:** $0.06281 per kWh
Demand Charge?	No	Yes	No	Yes
Utility Definition of Demand Charge		Demand is determined by the higher of the following calculations: metered demand at 100%, kVA at 85%, contract demand at 30%, or 12 month high demand at 30%		
When Does It Take Effect		Over 50 kW		Anything over 50 kW results in a demand charge
Cost of Demand Charge		**First 50 kW**: $0.00; **Excess over 50 kW:** $12.07		**Summer:** $13.79 per kW, **Winter:** $26.00 per kW, **Transition:** $13.00 per kW
Additional Monthly Costs	**TVA Fuel Cost Adjustment:** $0.00864 per kWh per month	**TVA Fuel Cost Adjustment:** **First 15,000 kWh**: $0.00864 per kWh per month, **Additional kWh**: $0.00855 per kWh per month		
Contact Info	Russell Lane **Email:** rlane@mtemc.com **Phone:** (615)453-3078		Steve Lyne **Email:** slyne@dremc.com **Phone:** (931)728-7547 x.5402	

Utility	Harriman Utility Board		Athens Utilities Board	
Base Rate	**Small Commercial (less than 50 kW):** $27.60 per month ($16.60 if 300 kWh or less per month)	**Large Commercial (Greater than 15,000 kWh, 50 kW)**: $109.94 per month	**GSA Part 1 (less than 50 kW, 15,000 kWh):** $31.93 per month	**GSA Part 2 (50 kW - 1,000 kW, greater than 15,000 kWh):** $162.74 per month
Energy Charge	$0.10986 per kWh	$0.11012 per kWh (first 15,000 kWh); $0.06398 per kWh (over 15,000 kWh)	$0.07074 per kWh	**Summer:** **First 15,000 kWh:** $0.06960 per kWh **Over 15,000 kWh:** $0.03489 per kWh; **Winter:** **First 15,000 kWh:** $0.06686 per kWh, **Over 15,000 kWh**: $0.03227 per kWh **Transition:** **First 15,000 kWh:** $0.06515 per kWh, **Over 15,000 kWh:** $0.03120 per kWh
Demand Charge?	No	Yes	No	Yes
Utility Definition of Demand Charge				
When Does It Take Effect		Anything over 50 kW results in demand charge		Anything over 50 kW results in demand charge
Cost of Demand Charge		$0.00 (first 50 kW), $15.36 (over 50 kW- 1,000 kW)		**First 50 kW**: $0.00, **51 kW - 1,000 kW:** **Winter:** $13.34 per kW, **Summer:** $12.53 per kW, **Transition:** $12.53 per kW
Additional Monthly Costs				
Contact Info	Wayne Jenkins **Email:** gmelhorn@hub-tn.com **Phone:** (865)607-4058		Kent Wilson **Email:** kwilson@aub.org **Phone:** (423)745-4501	

Utility	Cookeville Electric Department		Cleveland Utilities	
Base Rate	**Schedule GSA Part 1 (0-50 kW, 0-15,000 kWh) Class 40:** $20.00 per month	**Schedule GSA Part 2 (51- 1,000 kW, greater than 15,000 kWh) Class 50:** $50.00 per month	**Schedule GSA-1 (up to 50 kW, and up to 15,000 kWh):** $15.41 per month	**Schedule GSA-2 (51 kW - 1,000 kW, or greater than 15,000 kWh):** $46.22 per month
Energy Charge	$0.10225 per kWh	**First 15,000 kWh:** $0.10287 per kWh, **Additional;** $0.06234 per kWh	$0.08372 per kWh per month	**First 15,000 kWh per month:** $0.08372 per kWh, **Additional:** $0.04299 per kWh
Demand Charge?	No	Yes	No	Yes
Utility Definition of Demand Charge				
When Does It Take Effect		Anything over 50 kW results in demand charge		Anything over 50 kW results in demand charge
Cost of Demand Charges		**0-50KW**: $0.00 **1- 51-1,000kW**: $11.85 per kW		**First 50kW**: $0.00 per kW **Excess over 50kW per month:** $12.26 per kW
Additional Monthly Costs				
Contact Info	Jeff Peek **Email:** jpeek@cookeville-tn.org **Phone:** (931)526-7411		David Tyner **Email:** dtyner@clevelandutilities.com **Phone:** (423)478-9323	

Utility	Nashville Electric Service		EPB Chattanooga	
Base Rate	**GSA-1 (0- 50kW, 0-15,000 kWh):** $25.38 per month	**GSA-2 (51 - 1,000 kW, Greater than 15,000 kWh)**: $156.87 per month	**GSA-1 (Less than 50 kW, less than 15,000 kWh)**: $9.90 per month per delivery point (account)	**GSA-2 (50 kW - 1,000 kW, greater than 15,000 kWh)**: 9.90 per month per delivery point (account)
Energy Charge	**Summer:** $0.10974 per kWh per month **Winter:** $0.10700 per kWh per month, **Transition:** $0.10529 per kWh per month	**Summer:** **First 15,000 kWh per month:** $0.10974 per kWh**,** **Additional**: $0.06564 kWh; **Winter**: **First 15,000 kWh per month:** $0.10700 per kWh, **Additional:** $0.06564; **Transition**: **First 15,000 kWh per month:** $0.10529 per kWh, **Additional**: $0.06564	$0.08072 per kWh	**First 15,000 kWh**: $0.08072 per kWh, **Additional kWh over 15,000 kWh**: $0.03355 per kWh
Demand Charge?	No	Yes	No	Yes
Utility Definition of Demand Charge				
When Does It Take Effect		Anything over 50 kW results in demand charge		Anything over 50 kW results in demand charge
Cost of Demand Charge		**Summer:** **Over 50 kW:** $12.22 per kW; **Winter:** **Over 50 kW:** $11.43 per kW; **Transition:** **Over 50 kW**: $11.43 per kW		**First 50 kW:** $0.00 per kW, **Over 50 kW**: $14.04 per kW
Additional Monthly Costs				
Contact Info	David McDannald **Email:** dmcdannald@nespower.com **Phone:** (615)747-3384		Melvin Baumgardner **Email:** Baumgardnermr@epb.net **Phone:** (423)648-3524	

Utility	Lenoir City Utility Board		Volunteer Electric Co-Op	
Base Rate	**GSA-1 (less than 50 kW, less than 15,000 kWh)**: $15.26 per month	**GSA-2 (51 kW - 1,000 kW, greater than 15,000 kWh):** $61.29	**GSA Part 1 (Does not exceed 50 kW/Does not exceed 15,000 kWh)**: $14.00 per month	**GSA Part 2 (Greater than 50 kW, but not to exceed 1,000 kW/Greater than 15,000 kWh):** $25.00 per month
Energy Charge	$0.09674 per kWh	**First 15,000 kWh:** $0.09618 per kWh, **Additional kWh over 15,000 kWh:** $0.05899 per kWh	**Summer:** $0.07889 per kWh, **Non-Summer:** $0.07849 per kWh	**Summer: First 15,000 kWh per month**: $0.07889 per kWh, **Additional kWh per month**: $0.03648 per kWh; **Non-Summer**: **First 15,000 kWh per month**: $0.07849 per kWh per month, **Additional kWh per month**: $0.01930 per kWh per month
Demand Charge?	No	Yes	No	Yes
Utility Definition of Demand Charge				
When Does It Take Effect		Anything over 50 kW results in demand charge		Anything over 50 kW results in demand charge
Cost of Demand Charge		**Between 51 - 1,000 kW:** $11.23 per kW		**Summer: First 50 kW**: $0.00 per kW, **Over 50 kW:** $13.10 per kW; **Non-Summer: First 50 kW:** $0.00 per kW, **Over 50 kW:** $12.50 per kW
Additional Monthly Costs				
Contact Info	Jay Hines **Email:** pcterry@lcub1.com **Phone:** (865)483-4730 x1730		Mark Evans **Email:** mevans@vec.org **Phone:** (931)484-3527 x7241	

Utility	Murfreesboro Electric		Sequatchee Valley Electric Cooperative	
Base Rate	**GSA-1 (0 - 50 kW):** $24.86 per month	**GSA-2 (51 -1,000 kW, or less than 15,000 kWh):** $49.00 per month	**GSA Part 1 (0 - 50 kW):** $20.56 per month	**GSA Part 2 (51 kW - 1,000 kW, or less than 15,000 kWh)**:$146.84 per month
Energy Charge	$0.07539 per kWh per month	**First 15,000 kWh per month:** $0.07648 per kWh per month, **Additional kWh per month:** $0.03679 per kWh per month	$0.07975 per kWh per month	**First 15,000 kWh per month**: $0.07858 per kWh, **Additional kWh:** $0.03936 per kWh
Demand Charge?	No	Yes	No	Yes
Utility Definition of Demand Charge				
When Does It Take Effect		Anything over 50 kW results in demand charge		Anything over 50 kW results in demand charge
Cost of Demand Charge		**Excess over 50 kW per month:** $11.71 per kW		**Excess over 50 kW:** $11.92 per kW
Additional Monthly Costs		**FCA: First 15,000 kWh per month**: $0.02770, **Additional kWh per month**: $0.02742	**TVA Total Monthly Fuel Cost**: $0.02872 per kWh	
Contact Info	Mark Kimball **Email:** Mkimball@murfreesboroelectric.com **Phone:** (615)494-0424 or Chris Barns **Email:** cbarns@medtn.com **Phone:** (615)494-0428		Randy McClure **Email**: rmcclure@svalleyec.com **Phone:** (423)837-8605	

Utility	Knoxville Utility Board		Maryville		Fort Loudoun Electric Cooperative	
Base Rate	**GSA-1 Electric Rate (0-50 kW)**: $15.00 per delivery point per month	**GSA-2 Electric Rate (50 kW - 1,000 kW):** $50.00 per delivery point per month	**GSA-1 General Power Rate (0- 50 kW):** $16.06 per month	**GSA-2 General Power Rate (50 kW - 1,000 kW):** $53.50 per month	**GSA-1 (0 - 50 kW):** $27.75 per month	**GSA-2 (50- 1,000 kW)**: $135.00 per month
Energy Charge	**Summer Period**: $0.10097 per kWh per month; **Winter Period:** $0.10056 per kWh per month; **Transition Period:** $0.10056 per kWh per month	**Summer Period**: First 15,000 kWh per month at $0.10303 per kWh, Additional kWh per month at $0.06339 per kWh; **Winter Period**: First 15,000 kWh per month at $0.10262 per kWh, Additional kWh per month at $0.06339 per kWh; **Transition Period:** First 15,000 kWh per month at $0.10262 per kWh, Additional kWh per month at $0.06339 per kWh	**All kWh is at** $0.10001 per kWh	**First 15,000 kWh per month:** $0.10182 per kWh, **Additional kWh per month** : $0.06636 per kWh	**All kWh at:** $0.09871 per kWh	**First 15,000 kWh at** : $0.09763 per kWh, **Additional kWh at:** $0.06739 per kWh
Demand Charge?	No	Yes	No	Yes	No	Yes
Utility Definition of Demand Charge						
When Does It Take Effect		Any usage over 50 kW results in demand charge		Any usage over 50 kW results in demand charge		Any usage over 50 kW results in demand charge
Cost of Demand Charge		**Summer Period (over 50 kW per month):** $11.59 per kW; **Winter Period (over 50 kW per month):** $10.80 per kW; **Transition Period (over 50 kW per month):** $10.80 per kW		**First 50 kW:** No Charge **Over 50 kW:** $11.68 per kW		**First 50 kW**: No Charge **Over 50 kW:** $15.27 per kW
Additional Monthly Costs]						
Contact Info			http://www.maryvillegov.com/uploads/8/2/6/7/8267180/electric.pdf			

Appendix B- Utility Demand Charges[2]

Washington

Seattle City Light: $61.00

California

1. Burbank Water and Power: $1052.00
2. Glendale Water and Power: $16.00 (July through October); $11.00 (November through June)
3. Los Angeles Department of Water and Power: $250+$450=$700 (June-Sept, high peak); $250+$162.50=$412.50 (June-Sept, low peak);$250+$212.50=$462.50 (Oct-May)
4. Southern California Edison: $1460.00
5. Pacific Gas and Electric: None
6. City of Palo Alto Utilities: None
7. San Diego Gas and Electric : $678.50 (Non-Coincident);$382.50 (Max On-Peak, Summer); $237.50 (Max On-Peak Winter)
8. Alameda Municipal Power: None
9. Hercules Municipal Utility: $377.00(Summer); $93.00 (Winter)
10. Silicon Valley Power: None

Arizona

1. SRP: $210.50 (Summer); $123.00 (Winter)
2. Tucson Electric Power: None
3. TRICO Electric Cooperative: $180.00
4. APS: $483.75 (Secondary); $448.00 (Primary)

Oregon

1. Pacificorp: $213.00 (Secondary); $216.00 (Primary)
2. Portland General Electric: Schedule 38- None; Schedule 83: $71.40+$41.60=$113.00 (Facilities) + $41.00 (Transmission and Related Services Charges) + $88.00 (Distribution Charge) =$242.00
3. Eugene Water and Electric Board: Primary: No charge for first 300 kW; Secondary: $306.50
4. Lane Electric Co-Op: None (cut-off at 50 kW exactly)

Tennessee

1. Middle Tennessee Electric: None (cut-off at 50 kW exactly)
2. Duck River Electric Membership: None (cut-off at 50 kW exactly)
3. Harriman Utility Board: None (cut-off at 50 kW exactly)
4. Athens Utility Board: None (cut-off at 50 kW exactly)
5. Cookeville Electric Department: None (cut-off at 50 kW exactly)
6. Cleveland Utilities: None (cut-off at 50 kW exactly)

[2] These calculations use the rates of Appendix A, are as of the date of this paper, and are correct to the best of our knowledge.

7. Nashville Electric Service: None (cut-off at 50 kW exactly)
8. EPB Chattanooga: None (cut-off at 50 kW exactly)
9. Lenoir City Utility Board: None (cut-off at 50 kW exactly)
10. Volunteer Electric Co-Op: None (cut-off at 50 kW exactly)
11. Murfreesboro Electric: None (cut-off at 50 kW exactly)
12. Sequachee Valley Electric Cooperative: None (cut-off at 50 kW exactly)
13. Knoxville Utility Board: None (cut-off at 50 kW exactly)
14. Maryville: None (cut-off at 50 kW exactly)
15. Fort Loudoun Electric Cooperative: None (cut-off at 50 kW exactly)
16. Memphis Light Gas and Water Division: None (cut-off at 50 kW exactly)

Washington D.C

1. PEPCO: Schedule GS-LV (low voltage) (First 25 kW: no charge): Summer: $193.25, Winter: $192.00; Schedule GS-3A (Primary Service, Higher Voltage) (First 25 kW: no charge): Summer: $202.00, Winter: $200.75