DOCKETED

Docket Number:	19-IEPR-04
Project Title:	Transportation
TN #:	228787-38
Document Title:	NREL - Workplace Charge Management with Aggregated Building Loads - 2018
Description:	N/A
Filer:	Wendell Krell
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	6/19/2019 9:22:42 AM
Docketed Date:	6/19/2019

Workplace Charge Management with Aggregated Building Loads

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***Abstract*—This paper describes a workplace charge management system developed to control plug-in electric vehicle charging stations based on aggregated building loads. A system to collect information from drivers was also developed for better charge management performance since the present AC charging station standard does not provide battery state of charge information. First, simulations with uncontrolled charging data were conducted to investigate several scenarios and control methods, and then one method with the most power curtailment during peak load was selected for verification tests. This paper illustrates load reduction test results for 36 charging stations and real-time campus net load data.**

I. INTRODUCTION

As the number of plug-in electric vehicles (PEVs) grows, needs for more electric vehicle charging stations, or electric vehicle supply equipment (EVSE) increase to relieve PEV range anxiety. The availability of workplace charging can encourage commuters to use PEVs more to travel to their work and can promote penetration of PEVs. However, charging stations can impact building peak load and thereby can increase electricity costs to employers. This paper investigates saving costs by managing workplace charging depending on building load.

There has been some recent work on coordinated and managed charging to minimize distribution system losses [1], to minimize power losses and improve voltage profiles [2], to minimize load variance [3], and to minimize peak power demand by demand response [4]. However, most previous results focus on simulations, and there are very few studies that have investigated real-world test results. This paper analyzes cost saving by charge management with the data collected from the charging stations on the National Renewable Energy Laboratory (NREL) campus and from NREL employees who commute using PEVs.

NREL has developed a smart charge control system to aggregate PEV charging that reduces the cost of electricity for the rate payer at workplace or commercial facilities. In some cases, the electricity for these facilities is billed for the energy consumed (in kilowatt-hours) or for the energy charge and a demand charge, which is the peak power (in kilowatts) or rate at which energy is consumed during the billing period.

The demand charge portion is used to separately reflect the infrastructure cost associated with serving peak load periods. As a result, energy charge rates are less for commercial facilities with demand charges than those without demand charges in the same service territory. An analysis of workplace charging at NREL has shown that reduced charging during critical periods could decrease the annualized average cost of charging from about 7¢/kWh to as low as 3.8¢/kWh. This reduction is possible because the peak net load for the rest of the NREL load behind-the-meter tends to occur in either the early morning or the late afternoon. This smart charging control system can reduce the volatility of the marginal demand charge, shown in Fig. 1, by leveraging the flexibility of when PEVs charge. These demand charges totaled $4,500, which could have been avoided through peak load management.

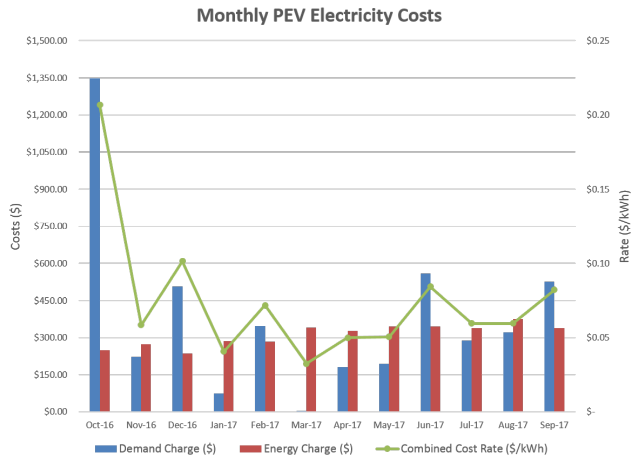

Fig. 1. Monthly electricity cost of workplace charging at NREL where demand charges are on the margin for charging demand.

II. SYSTEM ARCHITECTURE

NREL's charge management system consists of electricity meters and servers located both on campus and outside the campus that are connected by a communication network. The overall system structure is illustrated in Fig. 2. Our charge management algorithm uses information provided by the drivers about how much energy should be delivered to their vehicles and by what time. The SAE J1772 standard for AC charging stations does not provide battery state of charge

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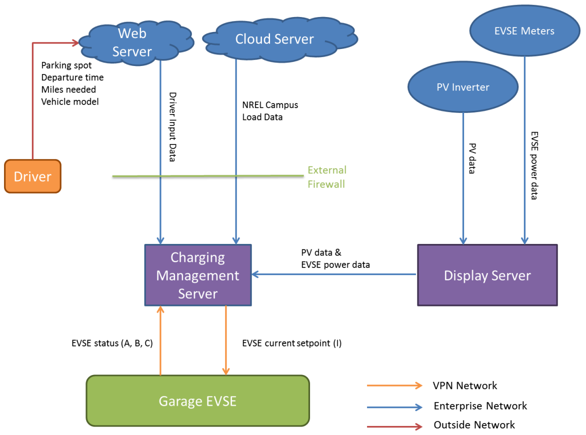

Fig. 2. Architecture of NREL charge management system

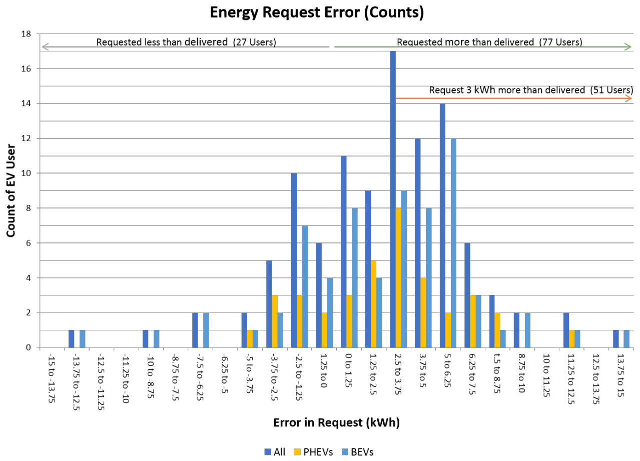

Fig. 3. Average energy request error for 6 months of collected data.

data and thus does not give information to the charger about how much energy is needed to fully charge the battery [5]. Further, it may not be necessary to fully charge every vehicle if a reduced capacity can meet the transportation requirement of the driver. Therefore, each user is requested to enter a charging request using the web site for the charge management system. The requested information is: 1) the miles needed for the following trips until the driver reaches a charging opportunity, 2) charging station number, and 3) expected departure time. The PEV model of each user is stored in a database with the username of each user and is automatically populated when the user logs into the system. With this information and the energy efficiency data of the PEV, the amount of the energy that should be delivered by the departure time is calculated.

NREL's parking garage has 18 dual-port charging stations. The original stations did not have communication and remote control function. The original control boards of the charging stations have been replaced by new controllers with the capability to control charging current remotely. They have a ModBus TCP interface for communication. There are other communication protocols used for remote control of charging stations in the market. The Open Charge Alliance developed an open communication protocol called Open Charge Point Protocol (OCPP) for communication between charging stations and a central system. Another communication protocol available for remote control of charging stations is Smart Energy Profile (SEP) 2.0. This protocol is not just for charging stations but is also used for home energy networking.

III. CHARGE MANAGEMENT ALGORITHM

We analyzed the user information data to compare the energy amount that users requested with what was actually delivered. The analysis showed that the data provided by the users were not always reliable. For example, some users requested more energy than the amount needed to fully charge the battery or more than could be delivered before the departure time when considering the onboard charger power capability of the vehicle. A plot of error statistics between the requested energy amount and the actual delivered energy is shown in Fig. 3. The average energy for users who requested less energy than delivered is known as the system continues to charge vehicles beyond the requested energy during the 6-month data collection period.

For load management, the charge management server calculates how much charging power each station can curtail when the total building load reaches a threshold value. The algorithm should guarantee that each station delivers the requested energy amount by the departure time with this adjusted charging power. The algorithm calculates a new adjusted power value for EV charging as follows:

- Find a list of charging stations $k \in \{1, 2, \cdots, n\}$ that can provide more than the requested energy amount by the departure time.
- For each k, calculate a new adjusted charging value $\tilde{P}$:

$$\tilde{P}_k(t) = \frac{E_{req,k} - E_k(t)}{T_{dep,k} - t} \tag{1}$$

  where t is current time, $E_{req,k}$ is the energy amount requested by the user of the charging station k, $E_k(t)$ is the energy amount provided to charging station k until time t, and $T_{dep,k}$ is the departure time provided by the user of charging station k.

Notice that the more stations are in the list, the more power that can be reduced by charge management. If there is no charging station in the list, there is no power reduction possible by charge management.

The peak demand value is set to 4.5 MW on the first day of each month and the system starts charge management if the total building load exceeds the threshold, which is set to 4.5 MW less a preassigned tolerance value (0.2 MW was used in the tests). If the total building load exceeds the peak demand value even with charge management, a new peak demand value is set for the total building load and a new threshold value that triggers charge management becomes the new peak value less the tolerance. The flowchart of the algorithm is illustrated in Fig. 4.

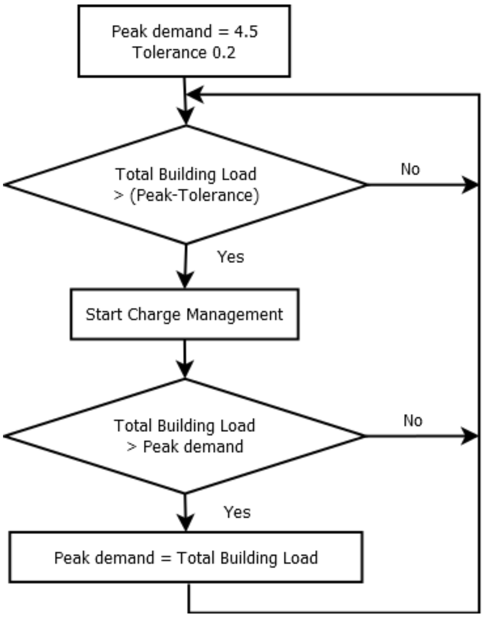

Fig. 4. Flowchart of charge management

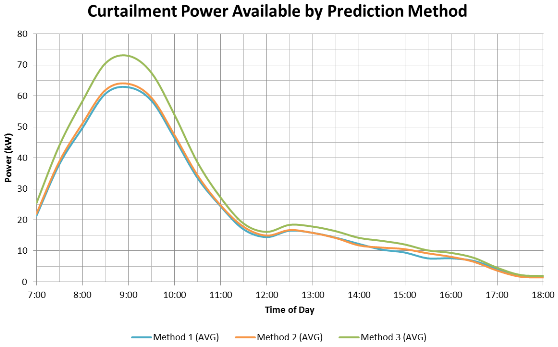

Fig. 5. Curtailment power available by prediction method

TABLE I
DEMAND CHARGES PER KW

Distribution Demand	\$3.86
Generation & Transmission Demand	\$9.55
Transmission Cost Adjustment	\$0.51
Demand Side Management Cost	\$0.54
Purchase Cap Cost Adjustment	\$1.29
Clean Air Clean Jobs Act	\$1.04
Total Demand Charge	\$16.79

IV. SIMULATIONS

The charge management algorithm described in Section 3 can provide more EVSE load reduction if there are more charging stations that can deliver the requested energy amount by the departure time. However, we can observe from Fig. 3 that typically half of the users (51 out of 104 users) request 3 kWh more than what is delivered. Unreliable data provided by the users can reduce the performance of the charge management system. Three different methods to determine an accurate value for requested energy are examined in the simulation. The value for each method is determined as follows:

- Method 1: Energy request provided by the user
- Method 2: The historical average energy actually provided to the user
- Method 3: Energy request by user (Method 1) if user-provided error is typically less than 3 kWh; otherwise the average energy actually delivered (Method 2).

Building load data for July 2017 were used for the simulations. An artificial demand event was injected into each 30-minute time window from 7:00 AM to 6:00 PM to examine how much power is available for curtailment in each time slot. The simulation results are shown in Fig. 5 as an average of every time window for all days within the month. The simulation shows that Method 3 provides more curtailment power throughout all time windows. It also shows that charge management will have more peak load reduction if a peak occurs around 9:00 AM. This is due to the immediate charging nature of the vehicles, which were not controlled, in combination with the arrival times of the vehicles.

The charge management system adjusts charging power so that it can deliver the requested energy amount by the departure time. However, the requested energy amount cannot be delivered if drivers depart earlier than the departure time they provided. We analyzed the error of the delivered energy amount when drivers actually left with charge management and without management for the case in July 2017 with Method 3. The average number of daily users is 44. The average number of cases that drivers left with less energy with a 30-minute demand response event is 0.43 cases per day, and the average difference in energy delivered is 0.0895 kWh. This error is due to the use of the historic average value, but it shows that drivers can get the expected energy amount even with charge management in most cases.

V. TEST RESULTS AND ANALYSIS

It is not straightforward to measure the amount of power reduced by charge management because the power provided by the charging stations without charge management cannot be measured if charge management is active. Therefore, we estimate the amount of curtailed power from charge management by two power values—the total EVSE power demand before the charge management is active and the total managed EVSE power demand when the charge management is active. For example, if charge management becomes active at time T, the sampling time is Δt, and the total demand by the charging station before charge management is $P(T-\Delta t)$, then the curtailed power by the charge management system at time T is $P(T-\Delta t)-P(T)$. If charge management is active from time T through $T+n\Delta t$, then an estimated average curtailed power is

$$\frac{\sum_{k=0}^{n}\left(P(T-\Delta t)-P(T+k\Delta t)\right)}{n+1}. \tag{2}$$

For February 2018, the monthly peak of 4,559.777 kW occurred at 8:45 AM on February 22. The demand charge

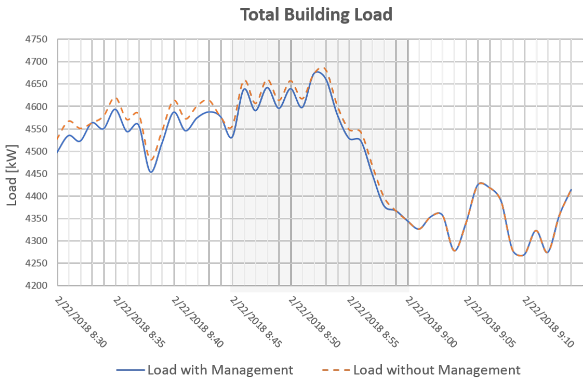

Fig. 6. Total building load with and without charge management on February 22, 2018.

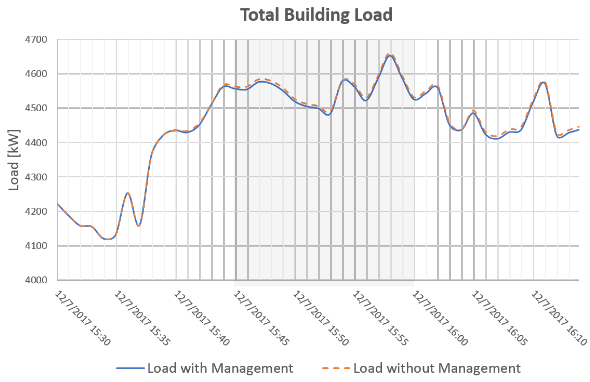

Fig. 7. Total building load with and without charge management on December 7, 2017.

per kW is about $17. The detailed items for demand charge are shown in Table I. The peak value is calculated as a 15-minute average from 8:45 AM to 8:59 AM. The plots of the total building load with and without charge management around the monthly peak period are shown in Fig. 6. The 15-minute average curtailed EVSE load is about 20 kW, which would have been added to the total campus load, resulting in a monthly campus peak of 4,580 kW had charge management not been operational. The 15-minute average load reduction of 20 kW contributes to a $332 saving. This is less than the amount reduced in the simulations shown in Fig. 5, which is more than 70 kW around 8:45 AM when Method 3 is used.

As shown in Fig. 5, the amount of available curtailment power is large in the morning and small in the afternoon. As a comparison, the monthly peak in December 2017 occurred in the afternoon. The plots of the total building load with and without charge management around the monthly peak period are shown in Fig. 7. The curtailed EVSE demand on December 7, 2017, is about one-third of the curtailed amount on February 22, 2018, resulting in a similar cost saving reduction ($117 vs. $332).

The charge management algorithm described in Section III guarantees users should receive the requested energy amount upon departure. On February 22, 2018, a total of 41 users used the charging stations. Six users left on that day without their batteries fully charged, and the other 35 PEVs had full batteries upon departure. The requested energy, actual delivered energy, provided departure time, and actual departure time for those six users are shown in Table II. User A departed at the provided departure time with more energy than requested. Four users (Users B, C, D, and F) received less energy than requested, but they departed earlier than their provided departure time. User E left after the provided departure time and received less energy than requested; however, the average energy delivered to User E from the historical data is 12.08 kWh. Since User E typically provides requests with more than 3 kWh of error, the charge management system used 12.08 kWh, not 18 kWh, as a value for the energy amount that should be provided by the departure time, and User E received more than 12.08 kWh upon departure.

TABLE II
COMPARISON OF REQUESTED ENERGY, ACTUAL DELIVERED ENERGY, PROVIDED DEPARTURE TIME, AND ACTUAL DEPARTURE TIME FOR THE USERS WITHOUT THEIR BATTERIES FULL UPON DEPARTURE ON FEBRUARY 22, 2018

User	Requested Energy (kW)	Delivered Energy (kW)	Provided Departure	Actual Departure
User A	8.4	19.67	4:00 PM	3:57 PM
User B	27	4.74	6:00 PM	12:10 PM
User C	6.25	1.06	2:00 PM	12:22 PM
User D	3.7	2.65	5:00 PM	11:30 AM
User E	18	13.90	12:00 PM	12:48 PM
User F	18	6.13	7:30 PM	5:50 PM

In February 2018, we had eight days with active charge management, and a total of 1,192 minutes of active charge management. The total energy consumption by the charging stations in this month was 7,578 kWh, which cost $285.84 in energy consumption charges (at $0.03772/kWh). The marginal demand of the charging stations during the monthly peak period (from 8:45 AM to 8:59 AM on February 22, 2018) was 46.28 kW, which cost $777.04 in demand charges. This corresponds to $1,062.88 in total electricity cost for the charging stations and is a combined cost of about $0.14/kWh. This is higher than the residential Schedule R Winter season electricity rate ($0.05461/kWh) for the surrounding service territory [6]. The marginal demand has not been eliminated because we cannot predict when the monthly peak will occur, and the charge management system does not turn off charging station power completely as the power curtailment is calculated assuming the peak demand event continues until departure. If the control knew when the monthly peak would occur and completely turned off charging station power during only the monthly peak period, we could have saved $777 demand charge (or $0.03772/kWh).

VI. CONCLUSION

This paper describes a workplace charge management system we developed. The system is integrated with campus building meters and utilizes real-time building load for charge management. While the system interacts with users to collect the necessary information for charge management, the control algorithm uses statistics of actual user usage to account for incorrect information provided by users. The charge management algorithm was validated through simulations first and verified that it performs well with very little error in energy delivery when user statistics are used. The charge management system has been validated with actual charging stations and real-time building load.

The lessons we learned from real-world tests are: 1) the information provided by users is not always correct, 2) better prediction for peak load period and/or user energy needs provide better charge management performance and more cost savings. Machine learning might be one approach for better prediction of user energy needs if enough user data is collected. Building peak load prediction is dependent on the types of buildings. If a building has low PV generation and load is mostly determined by heat and air conditioning, building peak load will closely synchronized with the temperature. If a building has high PV generation like at the NREL campus, the building peak load is quite dependent on PV generation and not easy to predict. PV generation is mostly determined by local weather conditions like small local cloud covering or local wind speed/direction that control cloud movement as well as solar irradiation. Thus, a local weather forecast with high resolution and a short time window should be incorporated to predict the peak load periods for such buildings.

ACKNOWLEDGMENT

This work was supported by the U.S. Department of Energy under Contract No. DE-AC36-08GO28308 with the National Renewable Energy Laboratory. Funding provided by the U.S. Department of Energy's Vehicle Technologies Office. The authors would specifically like to thank the Grid and Infrastructure R&D Program Manager Lee Slezak for his guidance.

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