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Distribution System V1G PEV Charging Impacts Report

January 2018

R.M. Pratt L.E. Bernal

U.S. DEPARTMENT OF ENERGY
Prepared for the U.S. Department of Energy
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Abstract

Plug-in Electric Vehicles (PEVs) are a clean form of transportation that will require a new control paradigm between the energy supply and the transportation sectors as PEV adoption continues to grow. Meeting the projected PEV energy demands will require implementing PEV / grid integration methods beyond charging PEVs at incentivized times. MATLAB was used to simulate the daily vehicle trip demands and charging processes of hundreds of PEVs. The National Household Travel Survey (NHTS) data was used as the source of vehicle travel data, and EV Project provided measured PEV charging data to calibrate the PEV population models. GridLAB-D analyses used a prototypical feeder and PEV population models to evaluate residential PEV V1G (unidirectional) charging in multiple locations, V1G PEV distribution feeder impacts, Time-Of-Use (TOU) rate effects on PEV charging, and charging control methods. The key findings were: optimized charging using California TOU rates could result in savings of over $20 per month for non-TOU program participants; non-TOU participants consume 30-40% of PEV charging energy; about 50% of PEV drivers have their transportation fuel bill reduced by $50 per month; 6.6kW charging will cause distribution transformer power limits to be exceeded on prototypical feeders if the household PEV adoption rate reaches 0.75 PEVs per home; distribution feeder loading is proportional to PEV charging rate; a method was devised to remotely identify when residential transformer overloads occur using changes in PEV charging rate; and the low-cost TOU period is composed of a distribution of PEVs needing small, medium and larger energy needs that can be more effectively shifted as groups to mitigate the TOU peak power and enable a higher PEV adoption rate per household without overloading distribution transformers.

Summary

Pacific Northwest National Laboratory (PNNL) used MATLAB and GridLAB-D to investigate the distribution system-level impacts of plug-in electric vehicles (PEVs) for various PEV penetration levels and charging rates. The PEV charging models were calibrated using measured charging data obtained from Idaho National Laboratory (INL) and the EV Project. The MATLAB simulations combined the PEV charging models with the daily trip demand and charging processes of hundreds of PEVs using National Household Travel Survey (NHTS) data as the source of vehicle travel data for evaluating Time-Of-Use (TOU) rate effects on PEV charging and to develop methods for implementing charging control. GridLAB-D simulations were used to analyze residential PEV V1G (unidirectional) charging locations and V1G PEV distribution feeder impacts.

The key findings identified in this report are:

1. Optimized charging using California TOU rates could result in up to $20 per month savings for non-TOU participants. The reasons why 30-40% of the PEV charging energy delivered to the EV Project participants was not during the lowest-cost TOU periods are not understood, but understanding these reasons would be important in developing effective policies and supporting technologies.
2. About 50% of PEV drivers have their transportation fuel bill reduced by $50 per month when compared to petroleum fuel.
3. PEVs require either autonomous control or fast communications to implement V1G regulation services, but could result in an additional ~$20/month/PEV for an aggregated group whose owners have flexibility in the PEV mobility due to longer charging times while engaged in regulation services.
4. In regions using TOU rates, distribution transformer power limits will be exceeded on prototypical feeders if the household PEV adoption rate reaches ~0.75 PEVs per home for 6.6kW charging. Customer responses to TOU rate structures induce significant increases in load when the low-rates periods begin, but overall TOU rates do enable the utility to supply additional PEVs/home before transformer power limits are exceeded. Distribution transformer upgrades are very capital intensive projects and deferring upgrades by using flexible PEV charging requirements could provide significant short-term economic value to PEV owners.
5. Distribution feeder loading is directly proportional to PEV charging rate. It was anticipated that as battery sizes continue to increase to enable longer PEV travel ranges that the PEV charging rates needed to support larger batteries will also increase. At 19.2kW charging rates, the PEV adoption rate reduces to only 0.25 PEVs per home before the distribution transformer limit was exceeded.
6. Experimental test results showed that residential transformer overload conditions can be sensed by measuring the A.C. line voltage at locations such as the power meter, Electric Vehicle Supply Equipment (EVSE), PEV, electric water heaters, electric dryers or an A.C.

line voltage sensor at a single point supplied by that transformer in the facility. A.C. line voltage changes were found to correlate with PEV charging power changes and methods were developed to implement the transformer loading measurement method using firmware upgrades in the EVSE charging rate controller. This capability can be used to reduce the degree and frequency of residential transformer overload conditions by adjusting PEV charging rate while loads such as HVAC are being supplied.

7. NHTS and EV Project travel data was analyzed to show that the low-cost TOU period is composed of a distribution of PEVs needing small, medium and larger energy needs that can be temporally shifted to mitigate the TOU peak power and enable a higher PEV adoption rate per household without overloading distribution transformers. Entities that have access to the PEVs State-Of-Charge (SOC) and charging times can easily shift charge start times, maintain PEV availability for transportation and ease grid integration issues.
8. From a business perspective where communication and control technology deployments should have a one-year positive Return-On-Investment (ROI), a product that generates $20/month of revenue could cost the customer up to $240 to install or upgrade. The product cost must a fraction of this cost to manufacture and ship to generate sustaining business profit margins.

Acknowledgments

This report and the work described were sponsored by the U.S. Department of Energy (DOE) Vehicle Technologies Office (VTO) under the Energy Efficient Mobility Systems (EEMS) Program Systems and Modeling for Accelerated Research in Transportation (SMART) Mobility Laboratory Consortium. The following U.S. Department of Energy Office of Energy Efficiency and Renewable Energy (EERE) officials and managers played important roles in establishing the project concept, advancing implementation, and providing ongoing guidance: Mr. Lee Slezak and Mr. David Anderson.

Acronyms and Abbreviations

AC	Alternating Current
CAISO	California Independent System Operators
DC	Direct Current
DER	Distributed Energy Resources
DOE	Department of Energy
DR	Demand Response
EPRI	Electric Power Research Institute
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
HAN	Home Area Network
INL	Idaho National Laboratory
ISO	International Organization for Standardization
IVC	Intelligent Vehicle Charging
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt
MWh	megawatt-hour
OEM	Original Equipment Manufacturer
PNNL	Pacific Northwest National Laboratory
PEV	plug-in electric vehicle
PJM	Pennsylvania, New Jersey, Maryland Interconnect
RTO	Regional Transmission Organization
SAE	Society of Automotive Engineers
TOU	Time-Of-Use
V1G	Vehicle to Utility Grid – one-way
V2G	Vehicle to Utility Grid – bidirectional
VGI	Vehicle Grid Integration
XFC	Extreme Fast Charging

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1.0 Introduction

This report presents an investigation of the distribution system-level impacts of plug-in electric vehicles (PEVs) for various PEV penetration levels and charging rates, as well as methods PEV owners could gain additional economic value from PEV charging. Previous analysis showed that a controlled and aggregated group of bi-directionally charged (V2G) PEVs approximates the economic value associated with a similarly sized stationary energy storage battery system [Pratt, 2014]. The economic value from stationary energy storage included the value from grid services including arbitrage (purchase power at a low price and sell at a higher price), regulation services, Transmission & Distribution (T&D) deferral, outage mitigation, and peak shaving as a part of an energy storage system size and site selection process [Wu, 2013]. The dominant economic factors were grid capacity and reliability-related concerns (i.e., T&D deferral and outage mitigation). The regional economic variations in bi-directional PEV charging (V2G) grid services, particularly regulation services, are also a significant factor [Pratt, 2014].

This report assesses the distribution feeder impact of residential, unidirectional PEV battery charging (V1G where the PEV receives power from the grid, but does not supply power to the grid). Evaluating the economic potential for V1G is also important as there have been over 170,000 V1G PEVs sold in California as of January 2016, and there are projected to be over 400,000 PEVs sold by 2022 in California [DeShazo, 2012]. Monetizing the economic value from PEV-provided V1G services could provide additional incentives for vehicle owners to purchase PEVs and enhance the PEV adoption rate.

Expanding PEV adoption has other benefits and causes other challenges. The benefits of electrifying vehicle fleets include increasing the overall energy efficiency of vehicles and decreasing the use of petroleum as a fuel. Transitioning to a light-duty fleet of HEVs and PEVs could reduce U.S. foreign oil dependence by 30-60 percent and vehicle emissions by 30-45 percent, depending on the exact mix of technologies. However, an increasing adoption rate may lead to significantly higher loads on residential distribution feeders during periods of heavy PEV charging [VTO, 2015].

This report will use measured data, simulations and analysis to address four key questions associated with expanding the PEV adoption rate:

1. Do the PEV charging tariff / rate structures cause additional strain on the distribution feeders?
2. Is there additional economic value available to PEV charging that is currently lost to PEV owners subscribing to time-of-use (TOU) tariffs?
3. What are potential economic impacts of implementing controlled or managed charging beyond current PEV charging tariff / rate structures?
4. What approach might be used to evaluate whether or not a residential transformer is being overloaded by PEV charging?

This report will contribute to: the development of Vehicle Grid Integration (VGI) business models through PEV charging simulation results; provide analytical results needed to articulate managed PEV charging benefits to Original Equipment Manufacturers (OEMs), PEV owners, utilities and policy makers; and identify simulation and demonstration areas and capabilities needing additional research and development. In addition, this report provides a detailed description of the economic optimization methods used and identifies several use cases worthy of additional analysis.

2.0 PEV Charging Analysis

Determining both the potential PEV charging economic value to the PEV owner, and the PEV battery charging effects on the distribution feeder, requires a simulation tool that enables analysis of many aggregated PEV batteries and charging events. This simulation tool should also maximize the use of existing data sets to improve the accuracy of the analysis results. The Charging Analysis simulation tool was developed to perform this analysis using MATLAB software. The simulation tool obtained PEV travel information, including travel distances, destinations, and times, from the National Household Travel Survey [NHTS, 2009] data set. This data was analyzed to generate temporal PEV charging power values for each PEV and incorporate vehicle charging availability. The temporal PEV charging power values were calibrated to enable the aggregated population's response to very closely match the EV Project measured charging power data. Regional variations in driving style, geographical terrain, traffic, and weather were incorporated by adjusting the simulated PEVs battery energy to distance traveled conversion ratio (kWh/mile) using the actual battery energy consumed as measured by the EV Project and the NHTS reported miles traveled to determine an average value for the kWh/mile conversion factor.

2.1 Temporal PEV Charging Time

Determining the PEV charging economic value requires PEV availability and charging energy data as inputs. The data needed was obtained from the following sources and several constraints applied:

1. 2009 National Household Travel Survey data [NHTS, 2009] is a comprehensive data base containing travel and transportation patterns in the United States. Its data includes travel times, travel durations, distances traveled and vehicle availability at the residence. This data was used to develop a representative population sample of times vehicles are available for charging and provides vehicle distance traveled data.
2. The Idaho National Laboratory team compiled measured PEV charging data for the 4th quarter of 2013 in the EV Project Charging Infrastructure Summary Report [EV Project, 2013] used to calibrate the MATLAB analysis. The EV Project's residential Level 2 chargers measured power versus time and the data was used to verify simulation results and develop a basis to scale PEV populations.

3. The MATLAB analysis assumed that the charging rate was 3.3kW and the vehicle population was composed of Nissan LEAFs which was the vehicle model used in the EV Project's power versus time data used to calibrate the Charging Analysis simulations.
4. When evaluating the accuracy of the Charging Analysis against EV Project data, the input data set was limited to only include vehicles that traveled less than 80 miles per day to more closely mimic Nissan LEAF capabilities.

The PEV Charging Times used in the Charging Analysis were determined by assigning each PEV charging times that met the PEV's traveling constraints and transportation energy requirements using the following steps:

1. A city was selected for analysis (e.g., Seattle, San Diego, Los Angeles, San Francisco)
2. The EV Project Summary Report for the selected city provided the number of residential charging units and the measured charging power versus time data. The black line in Figure 1 is the 50% median charging power line for weekday PEV charging data measured in San Francisco. The red line represents the minimum weekday charging power and was significantly affected by the Thanksgiving and Christmas holidays during this period.

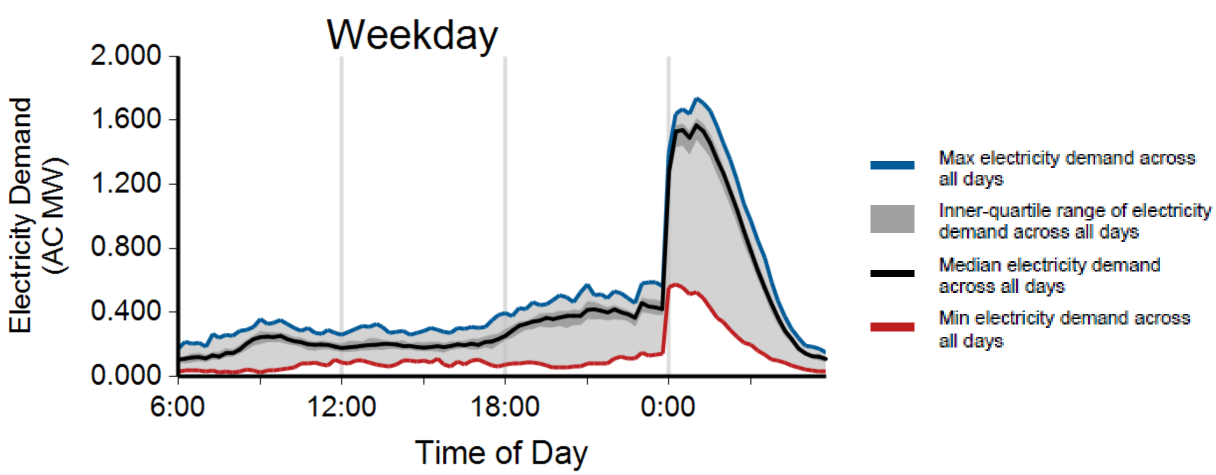

Figure 1 - San Francisco Weekday Aggregate Electricity Demand versus Time of Day – EV Project 4th Quarter 2013

3. The 2009 NHTS data base was randomly searched for the same number of vehicles used in the selected city's EV Project report data that had traveled less than 80 miles (Nissan LEAF conservative travel range).
4. The individual vehicle distance traveled data was converted to charging energy requirements by dividing the average total energy delivered (area under the black line in Figure 1) by the distance traveled by the selected vehicles to determine a measured value for kWh / mile conversion factor.
5. The charging time simulation used a single 24-hour period that forced each PEV battery to be at identical charge states at the beginning and end of the simulation.

6. Charging was conducted only when the vehicle was home and the PEV owner's battery range was inadequate for transportation needs
7. As simulations were performed, the base condition was determined such that the aggregated charging power and charging times match the EV Project measured data. This approach enables each PEV's temporal energy needs to be individually determined and made available for use cases that incorporate the effects of observed customer PEV charging behaviors (e.g., TOU rates, geographic location, etc.). The base condition was determined for each vehicle by:
   a. Determining energy required by converting vehicle miles traveled to kWh
   b. Determining the charging time required by dividing kWh by the charging power
   c. Finding the peak power time window(s) in the EV Project data that matches times and durations when charging power was needed.
      i. Continuously apply 3.3kW charging rate until required energy was delivered
      ii. In the event that not all energy was delivered while a particular vehicle was connected, the non-delivered kWh was converted to miles and added to the next time window that the vehicle was connected.
      iii. Store the vehicle's temporal charging power
      iv. Subtract the power used to charge each vehicle from the EV Project measured data at time span it was charged
   d. Repeating until all vehicles are fully charged or the average power load from EV Project data was exceeded

In order to verify that the analysis approach using NHTS vehicle travel data accurately represents the EV Project energy consumption of 1132 vehicles, 1132 PEV were randomly selected from the 2009 NHTS data then run through the Charging Analysis simulation a hundred times. The minimum, average, and maximum simulated charging power were plotted against EV Project data as shown in in Figure 2.

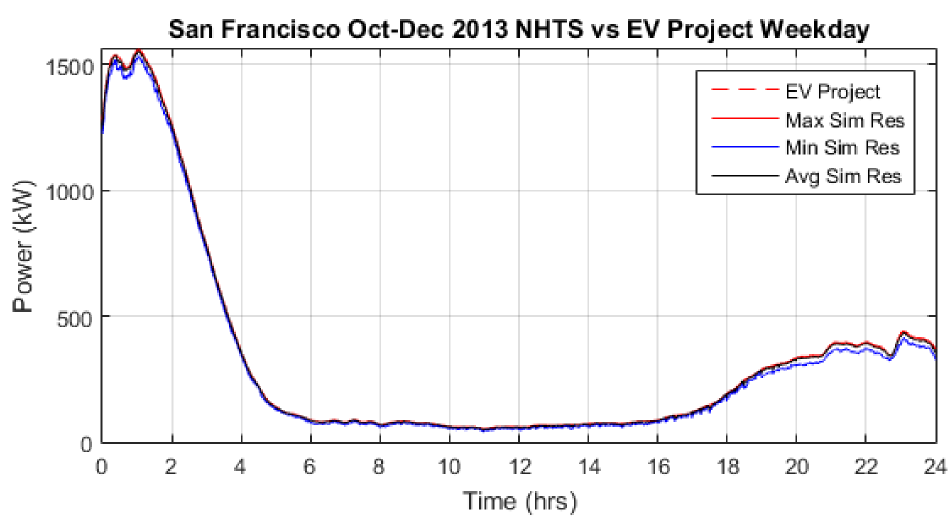

Figure 2: San Francisco 4th Quarter 2013 EV Project Aggregated Weekday Data

The simulation using NHTS-based vehicle availability and travel distance results were compared to the San Francisco EV Project data to evaluate the simulation error. The results had an average error of 2% and an error band of 0.67%-8% relative to the 50% median values. These values were well within the range between the measured 50% and 75% median values (which differ by 13% on average). Therefore, the measured PEV charging data can be closely approximated using Charging Analysis simulation system's use of NHTS data.

2.2 PEV Charging Economic Analysis Sources

An economic analysis was performed using Time of Use (TOU) rates for three California locations and Seattle, WA was used as a non-TOU case. The economic value was reported as the savings between the base case and the use case charging approach. The TOU rates for Los Angeles, San Francisco and San Diego were acquired from the following sources:

1. Los Angeles Electric Rates [LADWP, 2008] is an ordinance approving the rates fixed by the Department of Water of Power of the City of Los Angles and charged for electrical energy distributed and for service supplied by the Department to its customers. This ordinance from 2008 is currently active as of June 2, 2016 and defines the TOU rates active during the EV Project period. An EV discount of 2.5 cents is listed for the base period.
2. Pacific Gas & Electric (PG&E) provides historical electricity price data on their website [PG&E 2013]. The residential TOU rates spanning October 1, 2013 – December 31, 2013 were used for this analysis to match the EV Project period. The summer TOU rates were used since it provides the greatest opportunity of economic savings than the winter rates. The month of October is considered part of the summer period.
3. San Diego TOU rates were taken from the EV Project Residential Charging Behavior in Response to Utility Experimental Rates in San Diego April 2013 report [INL-2015]. The EV TOU rates were established by San Diego Gas & Electric Utility.
4. The Seattle electricity rate was taken from Seattle City Light power utility. Seattle does not offer TOU rates to EV customers [Seattle, 2014]. Seattle City Light has two rates, a lower rate for less than 10kWh/day that approximately doubles for energy demands in excess of 10kWh / day.

The monthly cost was determined by multiplying the temporal EV charging data by the TOU rates corresponding to the time period of the day. The total cost for each PEV was calculated on daily basis for a weekday. The monthly cost was obtained by multiplying the daily cost by 20.

3.0 Additional Economic Value for TOU Subscribers

The potential additional economic value for residential TOU subscribers used the methods described in Section 2 to graphically present the temporal PEV charging power and electricity rate schedules. This approach revealed PEV owner charging behavior and provided insight into opportunities to gain additional value from PEV charging.

3.1 San Francisco

San Francisco EV Project PEV charging data, TOU rate schedules, and NHTS driving profiles were used to develop Figure 3. Figure 3 shows the aggregated San Francisco EV Project power data collected from October 2013 to December 2013 plotted with the San Francisco TOU rate schedule. The aggregated temporal PEV charging data plot on Figure 3 was labeled as "Simulation" in the figure. The EV Project data and the aggregated plot are in very close agreement, which indicates that the process used to obtain the temporal PEV charging data was a very close approximation to the original EV Project data and can be used to provide realistic spatial and temporal distribution of charging events.

The first observation from Figure 3 was that most of the charging energy was delivered during low TOU rate periods, but a significant percentage of the charging power was supplied at other times. By analyzing the data, it was determined that of the 7,925kWh of charging energy delivered, 68% of San Francisco PEV charging energy was supplied during the low TOU rate periods. During the median rate time, approximately 16% of the charging energy was supplied. Approximately 16% of the charging energy was supplied during the high rate period (see Table 1). In addition, the slowly increasing charging demand from 4PM until 9PM occurred during the high TOU period was coincident with the time period many people typically return home from work. The power profile has three inflections at the same times as the electricity rate changes: 9PM, 11PM, and midnight which are indicators of the degree of customer price sensitivity.

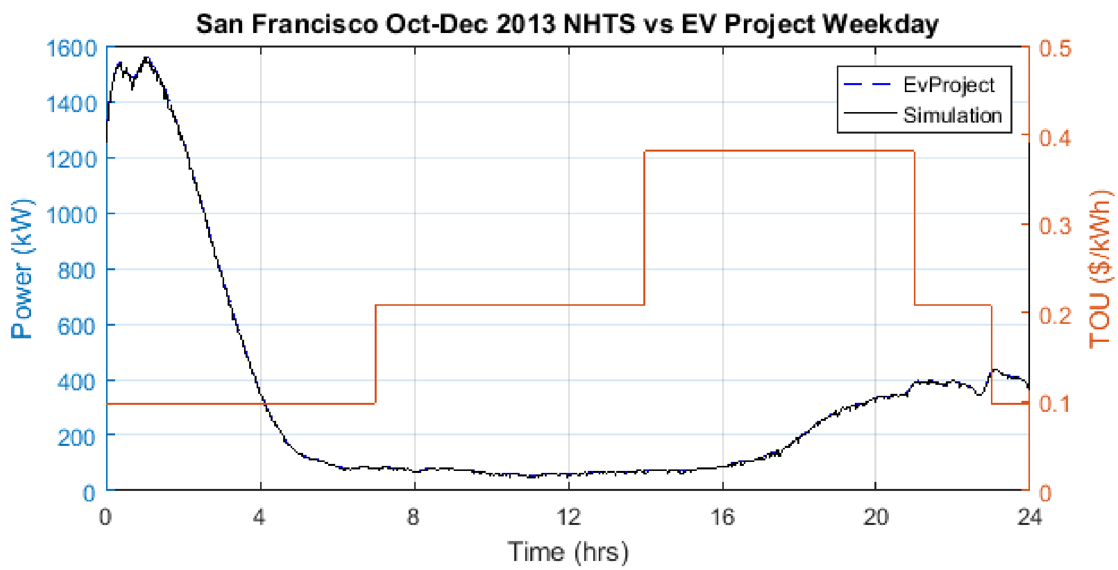

Figure 3: San Francisco EV Project Data

Low TOU Rates	Median TOU Rates	High TOU Rates
68.5%	15.6%	15.9%

Table 1: San Francisco PEV Charging Energy Delivery Periods

Using the simulated PEV temporal charging data, the total daily cost can be computed for each PEV. This was done by taking the time periods when the car was being charged, multiply each time period by the charging rate to calculate kWh, and finally multiply again by the time of use rate for each charging period. The total cost was summed up for each PEV and then multiplied by 20 to get the monthly cost based only weekday use. The results are summarized by the Figure 4 histogram.

The distribution of the monthly energy costs of driving a PEV in San Francisco on a weekday basis are shown in Figure 4. About 60% of PEV drivers pay less than a $1 a day or $20 a month for the 2013 TOU electricity cost in San Francisco. The median charging cost was $15.24 per month. But, over 1/3 of the PEV drivers pay more than $1/day, with a few heavy users paying more than $80 per month.

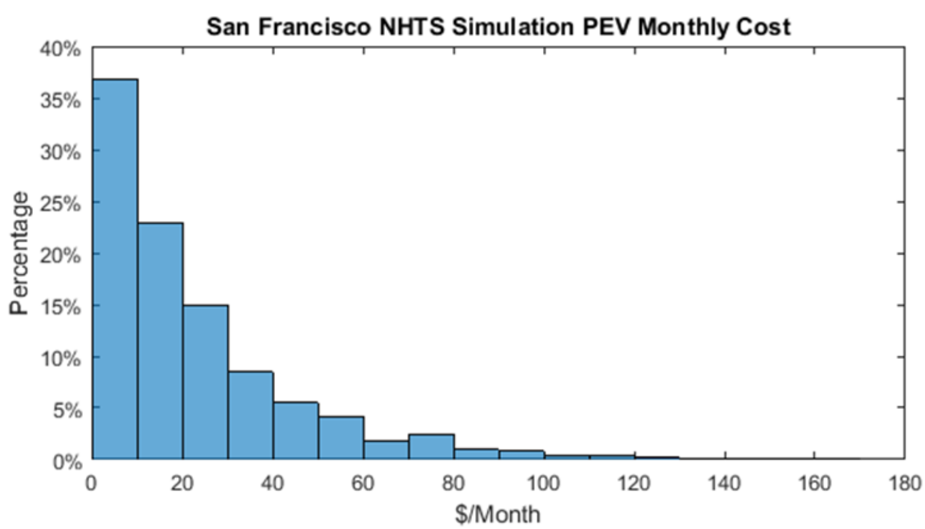

Figure 4: San Francisco PEV Monthly Cost Distribution versus Percent of Customers

Assigning additional economic value for TOU rate subscribers must include the possibility that not all PEV energy consumption shown in Figure 3 and Figure 4 was influenced by the TOU rate schedules. Table 2 provides the potential monthly value per customer to those who charged their vehicles outside of the low TOU period. Those San Francisco PEV customers charging at the high TOU rate periods could save up to $20.68 / month.

TOU Rate	Median	High
Monthly Value	$7.28	$20.68

Table 2: Potential Average Additional Monthly San Francisco PEV Customer Value

The PEV modeled in the simulations was a Nissan LEAF. An estimate of its fuel savings over a comparably-sized U.S. light duty vehicle with a gasoline fuel consumption rate of 21.6mph [DOT-2016] and the average gasoline price of $3.75/gal [EIA - 2016] in San Francisco from October 2013 to December 2013 are shown in Figure 5. The median fuel (gasoline costs – electricity cost) savings was $44.56/month. The range was from $2.35/month to $227/month. The savings were significant for the majority of PEV drivers, especially at longer ranges.

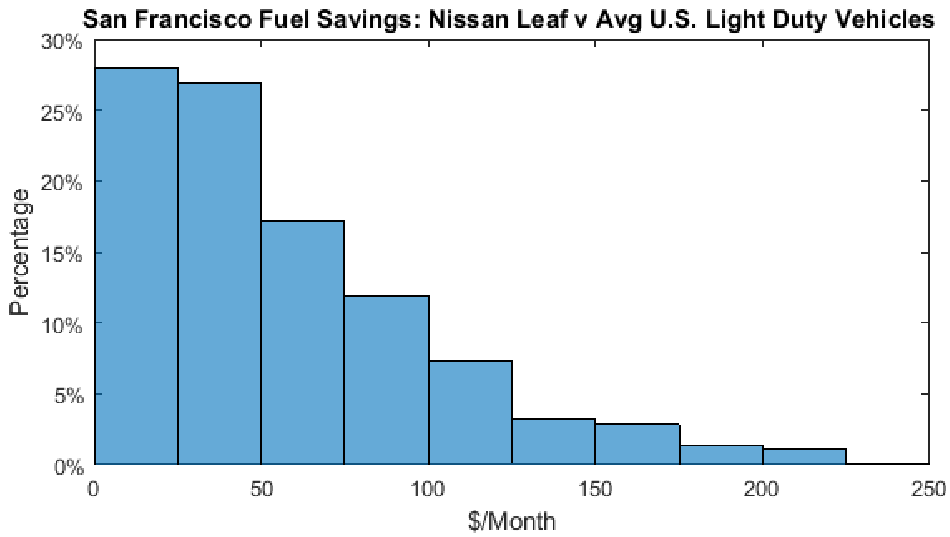

Figure 5: San Francisco 2013 Monthly Fuel Savings Distribution versus Percent of Customers - Nissan Leaf EV vs the Average U.S. Light Duty Vehicle

3.2 San Diego

The potential economic value analysis was applied to residential TOU subscribers using EV Project data from San Diego, and similar results to San Francisco were obtained. The San Diego temporal power data and TOU rate schedule is shown in Figure 6. A significant percentage of the San Diego energy dispensed for charging EVs also occurred at times other than the low TOU rate periods, as shown in Table 3. From the Figure 6 data, it was determined that of the 4,595kWh of charging energy delivered, only 63% of San Diego charging energy was supplied during the low TOU rate periods. A slowly increasing charging rate occurs during the high TOU period from noon to 7PM, which was coincident with the time period many people return home from work, and 11% of the charging energy was delivered during the highest rate periods. The power profile from 6PM until midnight shows a slightly decreasing PEV charging power demand, indicating some additional PEV charging events throughout the period.

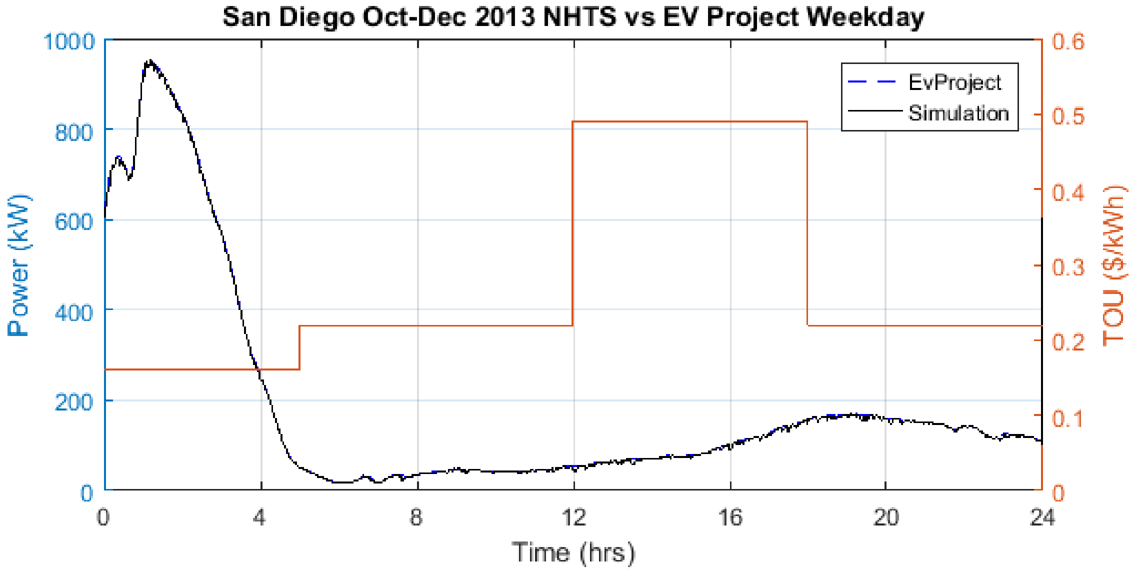

Figure 6: San Diego EV Project Data

Low TOU Rates	Median TOU Rates	High TOU Rates
63.6%	24.8%	11.5%

Table 3: San Diego PEV Charging Energy Delivery Periods

In terms of TOU monthly weekday cost, 45% of the San Diego PEV drivers pay less than $20 a month for electricity charging expenses. About 25% have charging costs between $20 and $40. PEV drivers in San Diego pay higher electricity costs than San Francisco. The median charging cost was $23.56 per month. The monthly TOU charging cost distribution is shown in Figure 7.

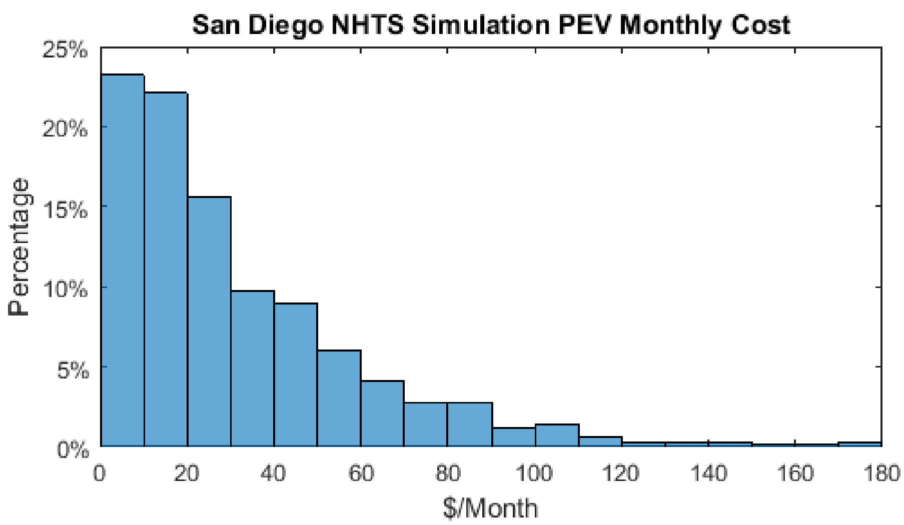

Figure 7: San Diego Distribution of Monthly Weekday TOU cost for PEVs

Assigning additional economic value for TOU rate subscribers must include the possibility that not all PEV energy consumption shown in Figure 6 was influenced by the TOU rate schedules. Table 4 provides the average potential monthly per customer value to those who charged their vehicles outside of the low TOU period for both the residential and TOU rates. The relatively high TOU rates for the high rate period would enable those San Diego PEV customers not participating in the TOU program up to $21.79 / month.

TOU Rate	Median	High
Monthly Value	$5.70	$21.29

Table 4: Potential Additional Monthly San Diego PEV Customer Value

The average gasoline price in San Diego from October 2013 to December 2013 was $3.64 per gallon. When compared to the TOU electricity cost, the savings over gasoline are shown in Figure 8. The median fuel savings was $38.08 per month. The savings were significant for the majority of PEV drivers, especially at longer travel ranges.

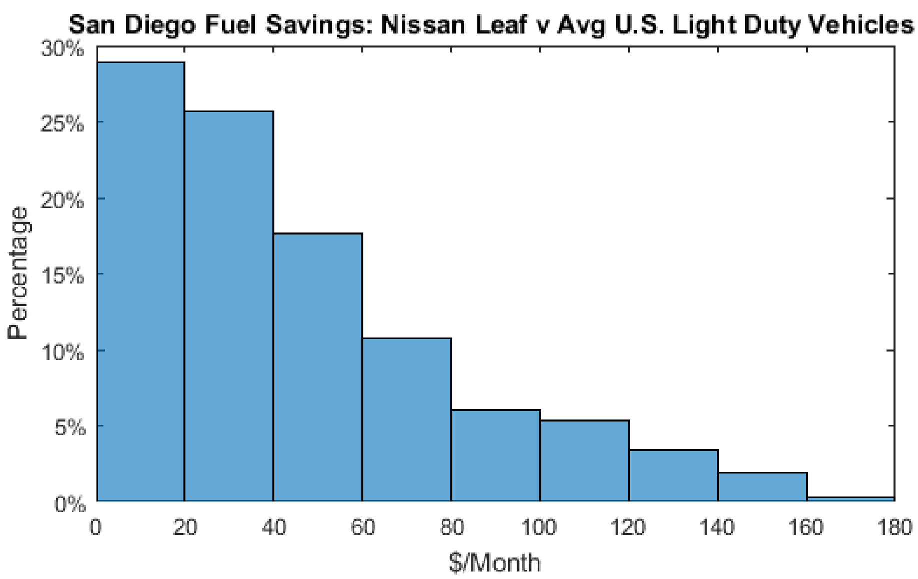

Figure 8: San Diego 2013 Monthly Fuel Savings Distribution versus Percent of Customers - Nissan Leaf EV vs the Average U.S. Light Duty Vehicle

3.3 Los Angeles

The potential economic value analysis was applied to residential TOU subscribers using EV Project data from Los Angeles, with results shown in Figure 9. The Los Angeles temporal charging power curve does show strong responsiveness to the TOU rate schedules. From the Figure 9 data, it was determined that of the 3,360kWh of charging energy delivered, only 63% of the Los Angeles charging energy was supplied during the low TOU rate periods. Significant populations of PEV owners start charging when they return home as shown by the continual charging power increase between 4PM and 8PM, and over 6% of the energy delivered was during the highest cost TOU rate period (see Table 5). The dramatic increase in charging rate at 8PM indicates the sensitivity of PEV owners to price.

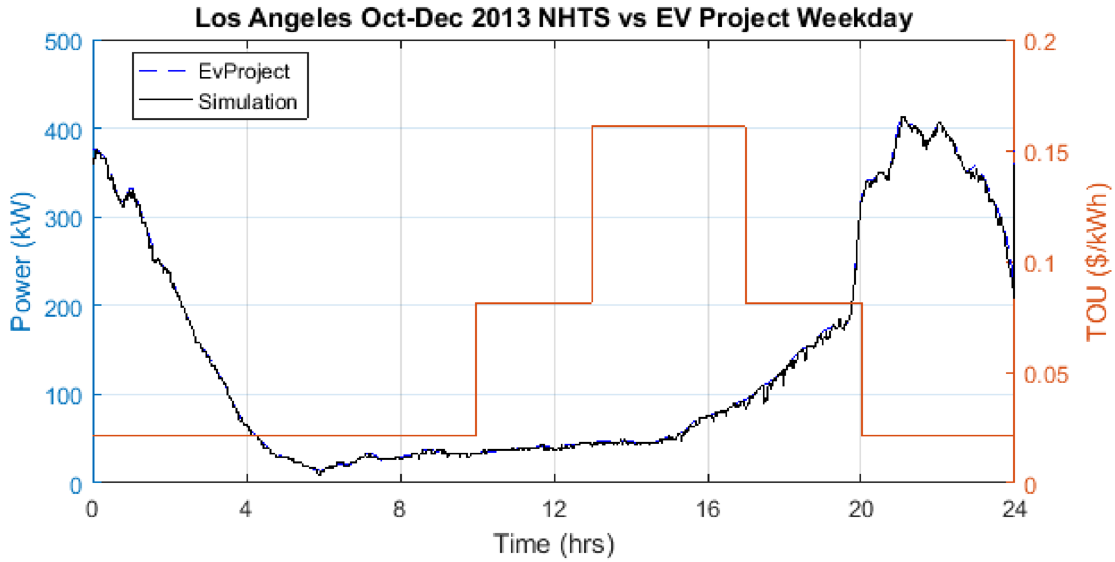

Figure 9: Los Angeles EV Project Data

Low TOU Rates	Median TOU Rates	High TOU Rates
62.9%	30.5%	6.6%

Table 5: Los Angeles PEV Charging Energy Delivery Periods

Assigning additional economic value for TOU rate subscribers must include the possibility that not all PEV energy consumption shown in Figure 9 was influenced by the TOU rate schedules.

Electricity charging costs in Los Angeles are significantly less than San Francisco or San Diego. 63% of PEV drivers pay less than $5 a month. The median monthly TOU cost is $3.78 per month. Less than 10% of drivers pay more than $15 a month for TOU costs. Figure 10 shows the monthly cost distribution.

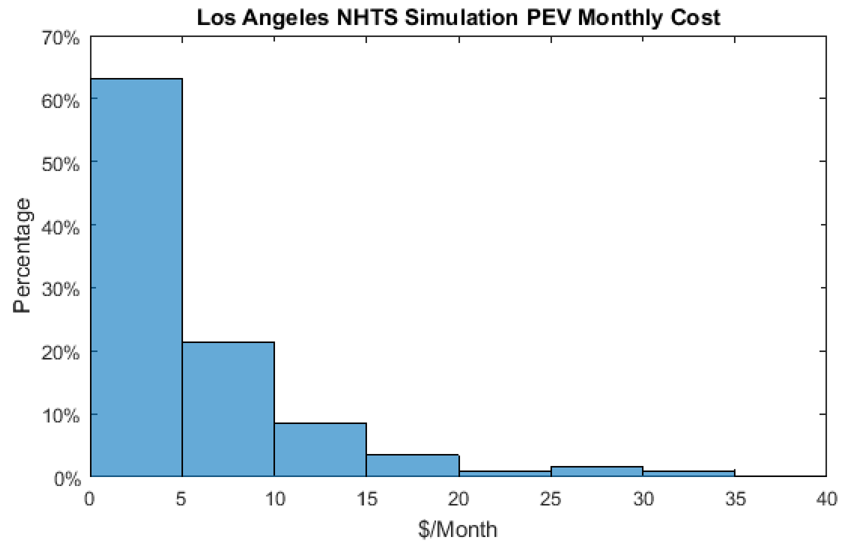

Figure 10: Los Angeles Distribution of Monthly Weekday TOU Cost for PEVs

Table 6 provides the potential monthly per customer value to those who charged their vehicles outside of the low TOU period for both the residential and TOU rates.

TOU Rate	Median	High
Value	$3.26	$6.24

Table 6: Potential Additional Monthly Los Angeles PEV Customer Value

The relatively low TOU rates in Los Angeles significantly reduced the potential PEV customer value from participation in these programs. However, even with the low value associated with TOU charging, Figure 9 clearly shows that charging behavior is dramatically affected by the TOU rate schedule.

The average gasoline price in Los Angeles from October 2013 to December 2013 was $3.73 per gallon. When compared to the TOU electricity cost, the savings over gasoline are shown in Figure 11. The median fuel savings for Los Angeles was $54.58 per month. This is because Los Angles has the lowest PEV charging cost than the other cities in California and about the same gasoline costs during the last quarter of 2013.

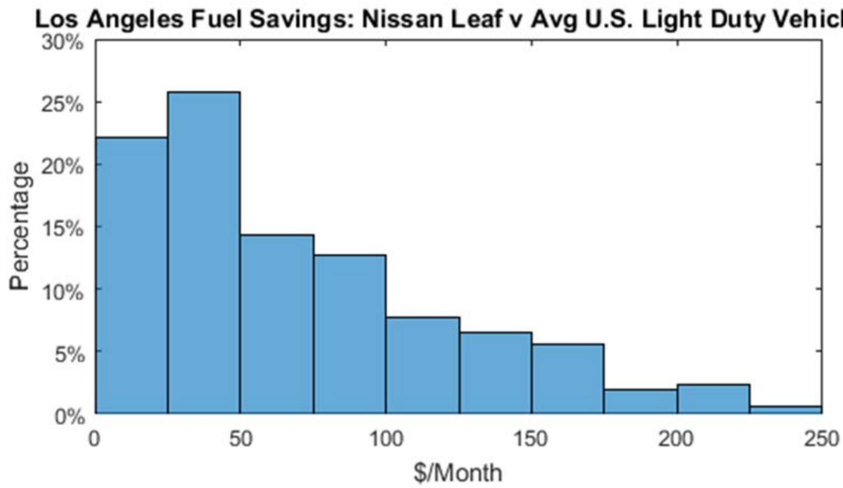

Figure 11: Los Angeles 2013 Monthly Fuel Savings Distribution versus Percent of Customers - Nissan Leaf EV vs the Average U.S. Light Duty Vehicle

3.4 Additional Economic Value Summary Analyses

The TOU Charging Energy Delivery Period Summary, Table 7, clearly shows that the energy delivery times are strongly influenced by TOU pricing, but there is a significant amount of energy delivered during higher cost TOU periods. This charging behavior is not directly associated with TOU prices, but could be related to "range anxiety", PEV owner transportation schedules, not participating in TOU rate programs, "behind the meter" charging at a residence equipped with a PV-array, or participating on a net metering plan. An alternative to a purely economic PEV charging motivation includes exhortations to reduce the susceptibility of the grid to electricity service interruptions during peak demand periods [Kurani, 2013].

Region	Low TOU Rates	Median TOU Rates	High TOU Rates
Los Angeles	62.9%	30.5%	6.6%
San Diego	63.6%	24.8%	11.5%
San Francisco	68.5%	15.6%	15.9%

Table 7: TOU Charging Energy Delivery Period Summary

Table 8 shows that in each city, PEV customers that do not participate in TOU programs could reduce their PEV charging bills by $5 to $20 per month by participating in the utility offered TOU programs.

Monthly TOU Savings by City	Median	High
San Francisco	$7.28	$20.68
San Diego	$5.70	$21.29
Los Angeles	$3.26	$6.24

Table 8: Potential Additional Monthly PEV Customer Value Summary

The effectiveness of TOU rates on shifting PEV driver charging behavior can be seen in Figure 12. The source data used to develop Figure 12 was directly developed by the EV Project, where the power data for San Diego, Seattle, and Los Angeles were scaled to represent the same number of vehicles as the San Francisco data. If the Seattle PEV charging response (purple) curve was used as a reference (lacking a TOU rate), both San Francisco (blue) and San Diego (green) show high PEV charging time sensitivity to TOU rates.

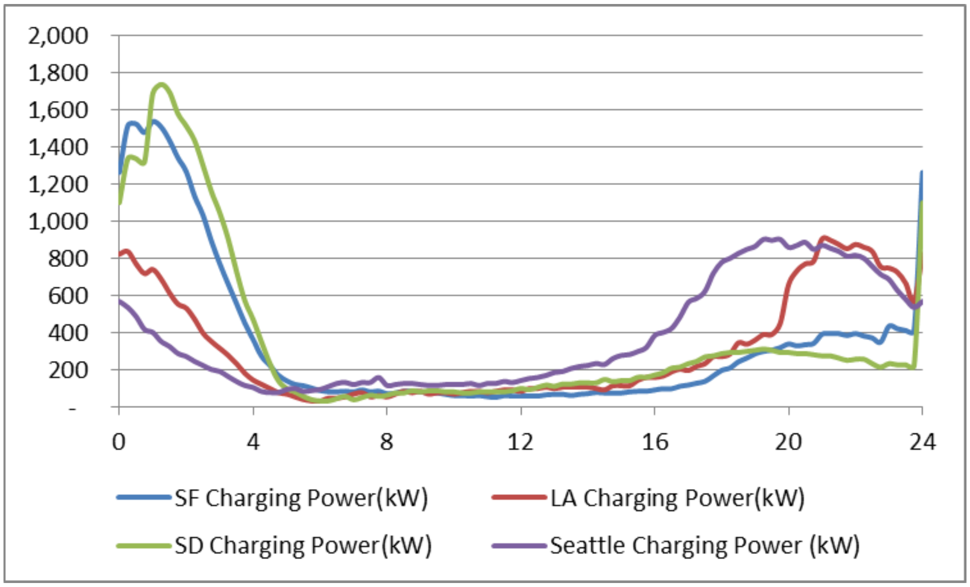

Figure 12: TOU Rate Impacts on PEV Charging Times

However, the Los Angeles charging response (red) is significantly closer to the Seattle response. One contributor to these similarities could be the low peak TOU rate in Los Angeles of 15¢/kWh, but San Francisco and San Diego peak TOU rates are in excess of 38¢/kWh.

3.5 Charging Time Analysis with no TOU Rates (Seattle)

The simplest and most broadly used charging method is called uncontrolled charging. Uncontrolled charging implements no incentives or delays to the charging process. The PEV simply charges until it is unplugged or fully charged. Seattle does not have Time of Use (TOU) rates that could influence the times when PEV drivers would charge their vehicles. The EV Project collected PEV charging data from 632 vehicles in Seattle. In order to understand uncontrolled charging impacts and to verify that using NHTS vehicles could accurately represent PEV energy consumption, the same number of vehicles was randomly selected from the 2009 NHTS data then run through the Charging Time Analysis simulation one hundred times. From this, a minimum, median, and maximum charging power were plotted against EV Project data collected from an equivalent number of PEVs, as shown in Figure 13.

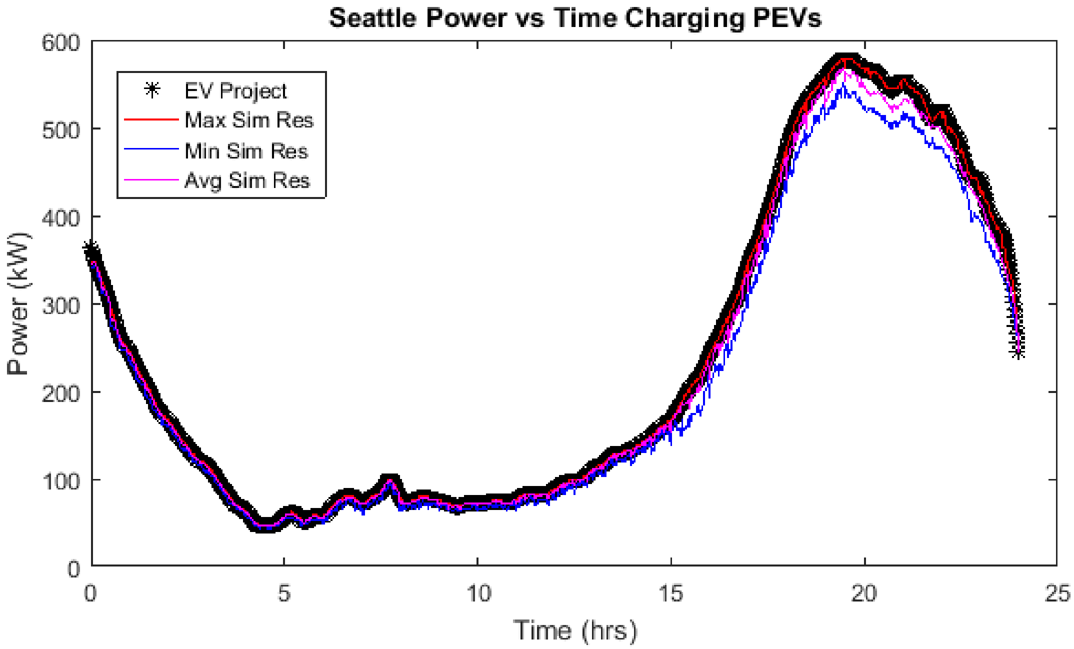

Figure 13: Seattle 4th Quarter 2013 EV Project Aggregated Weekday Data

The aggregate Seattle Weekday charging power versus time data shows that there are only minor differences between uncontrolled charging (where the PEV is charged as soon as it arrived) and the measured Seattle EV Project data collected from October 2013 to December 2013. Therefore, the measured EV Project PEV charging data can be closely approximated using NHTS data.

Figure 14 shows that about 40% of the Seattle PEV drivers pay less than $10 a month for charging their electric vehicles. 37% have charging costs between $10 and $20. PEV drivers in Seattle pay lower electricity costs than San Francisco, but higher than Los Angeles. The median PEV charging cost was $12.17 per month. The monthly flat rate charging cost distribution is shown in Figure 14.

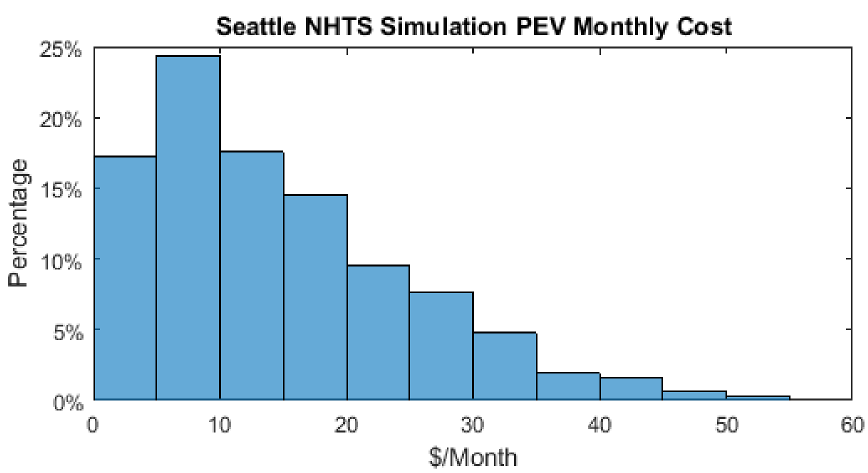

Figure 14: Seattle Distribution of Monthly Weekday PEV Charging Cost versus Percent of Customers

The average gasoline price in Seattle from October 2013 to December 2013 was $3.47 per gallon. When compared to the charging electricity cost, the savings over gasoline are shown in Figure 15. The median fuel savings was $48.56 per month.

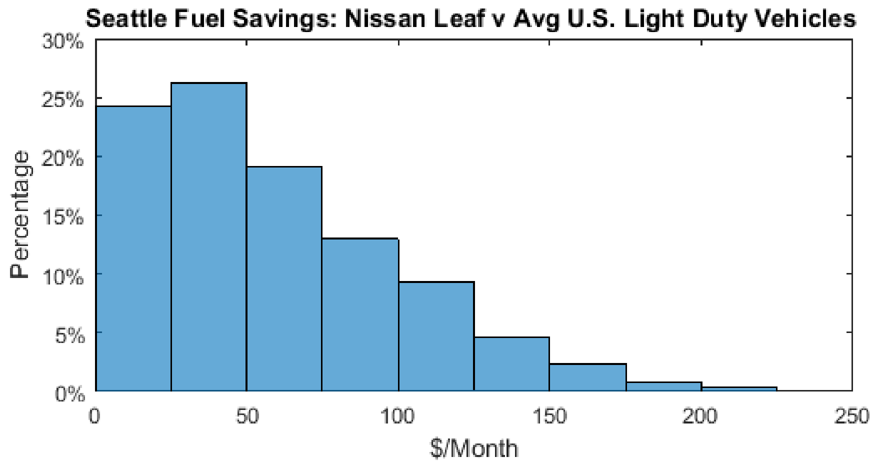

Figure 15: Seattle 2013 Monthly Fuel Savings Distribution versus Percent of Customers - Nissan Leaf EV vs the Average U.S. Light Duty Vehicle

Table 9 summarizes the information from Figure 5, Figure 8, Figure 11 and Figure 15, which shows the percentage of vehicle owners in each city that could realize a $25/month and $50/month reduction in transportation fuel cost using PEVs.

Monthly Fuel Cost Savings by City	$25/mo.	$50/mo.	Median Savings
San Francisco	28%	55%	$44.56/mo.
San Diego	29%	54.5%	$38.08/mo.
Los Angeles	22%	47.5%	$54.58/mo.
Seattle	24.5%	50%	$48.56/mo.

Table 9: Potential Percentage of PEV Owners Receiving $25/mo or $50/mo Monthly Fuel Cost Savings

3.6 Vehicle Participation Needed for Grid Services Markets

Regional grid services markets currently include regulation services and demand response. Some markets allow 100kW aggregated loads to participate, while others require participation levels of 500kW or 1MW. These power-based participation requirements result in a few questions including: how many PEV’s are required to meet the minimum power requirement; can the PEV population on one distribution feeder support participation; and what is the potential additional value available?

An evaluation of the number of PEV’s required to participate in a regulation services program could use any of these three alternatives:

1. Using an idealistic approach to quantify the number of PEVs needed, the 100kW load level can be achieved by using the average charging power (assume 3.3kW) of a number of PEVs. This approach neglects vehicle and battery capacity availability and assumes the connected batteries always need to be charged.
2. Using the TOU graphs shown in Figure 3 (San Francisco) and Figure 6 (San Diego) and taking into account the number of vehicles enrolled in the EV Project, the average charging power is about 1kW/vehicle during the early morning hours. This approach incorporates statistical variation in PEV availability and usage, but there is a limited time window for vehicles participating in TOU programs to meet the minimum of 100kW except during the early morning hours.
3. Using the "uncontrolled charging" graphs shown in Figure 13 (Seattle) and taking into account the number of vehicles enrolled in the EV Project, the average charging power is about 750W/vehicle during the afternoon hours. This approach incorporates statistical variation in PEV availability and usage, but shows a limited time window that PEV charging could meet the 100kW minimum.

These three alternatives have significant availability gaps during daytime hours when PEVs could be at a work location and rely on statistical methods to predict adequate resource availability to participate in the regulation services market. EMotorWerks (recently acquired by Enel's U.S.-based subsidiary EnerNOC) consolidates distributed grid demand resources and offers dynamic demand response capability to utilities. EMotorWerks is partnering with French utility, EDF, to tie its JuiceNet software into EDF's grid management network [CleanTechica, 2017].

An alternative to the three approaches above that would maximize usage of existing infrastructure, minimize technology implementation costs, not depend on statistical data, and expand the business opportunities for Vehicle Manufacturers (OEMs) or third-party businesses with access to PEV information is described below. Implementation of this alternative requires the customer be presented information to help make PEV charging decision, but could use the following approach.

1. Contracts are developed between the OEM and utility, as well as between the OEM and PEV owner, to formalize participation in an enhanced owner value program (e.g., regulation services, TOU, RTP, CPP, or Demand Response).
2. EVSE availability is provided to the PEV driver and coordinated geographically and temporally to maximize the program value. The PEV owner is presented with timely charging options to enable him to decide to charge using existing TOU rates at home or delay charging until a more preferable location or time is available.
3. PEV availability: The vehicle GPS information coupled with battery SOC and driver's destination are used to reserve or identify potential EVSEs that are participating in the enhanced owner value program and their availability to charge the PEV.

4. One conceptual PEV Charging control implementation follows: Once the contractual agreements are in place, a PEV owner can interactively identify when and where to charge using a cell phone app or potentially use messages on the PEV info screen presenting EVSE availability. Coupled with this EVSE availability is an incentive indication that would encourage PEV customers to preferentially select usage of a given EVSE. The incentive could be an indication of savings using a particular EVSE and charging schedule or grid service.

Estimating the potential customer value in these programs has a significant assumption: that the customer's travel schedule can tolerate extended charging times while participating in the regulation services market. V1G regulation services value is based on the change in vehicle charging rate. If the current PEV charging rate is 3.3kW and the maximum charging rate is 6.6kW, the vehicle is capable of providing 3.3kW REG-UP services and 3.3kW REG-DN services for a total of 6.6kW. The regulation services price value can be from 4¢/kWh to 10¢/kWh for as long as the battery is NOT fully charged [Kempton, 2008].

$$(6.6kW\ charging\ rate\ ) * \ (4¢/\mathrm{kWh}) * \ time\ plugged\ in\ (8h) = \sim\$1/day$$

V1G regulation services only charges the PEV at rates below the normal charging rates allowed by the PEV / battery type, but this approach does delay the vehicle's availability for transportation, since the battery may not be charging at the maximum rate while plugged-in.

3.7 PEV Travel Efficiency

A key parameter used throughout the economic value analysis converts vehicle miles traveled to kWh. The vehicle miles per kWh parameter was calculated by taking the total vehicle distance traveled sampled from the NHTS survey dataset and dividing it by the total charging energy delivered from the EV Project charging data. This value was computed from the average of a 100 simulations per city since the total vehicle distance traveled varies slightly per simulation run. Table 10 presents these values and shows regional differences associated with regional driving conditions, travel speed, climatic and topographic conditions.

Region	Los Angeles	San Francisco	San Diego	Seattle
Miles / kWh	3.29 – 3.52	3.21 – 3.39	3.03 - 3.25	2.54 – 2.73

Table 10: Observed Regional PEV miles/kWh

4.0 TOU Rate Impacts on Distribution Feeders

The temporal power data for each PEV being charged can be used to estimate the overall distribution transformer loading by adding the transformer base and PEV charging temporal loads. A more detailed analysis at the feeder's component level can also be done by assigning each PEV to a different location in a distribution system simulator (e.g., GridLAB-D) to assess the PEV charging impacts. The impact of TOU PEV loads on a typical suburban California feeder can be assessed. The GridLAB-D analysis of a prototypical feeder found that at 1.75 PEVs/home and 3.3kW charging rate, the total PEV charging and base load exceeded the substation transformer limits. Simulations were run for San Francisco, San Diego, Los Angeles, and Seattle.

4.1 GridLAB-D Distribution Transformer Analysis

The plots in Figure 16 were obtained by using a prototypical suburban California distribution feeder with 1000 homes that is supplied by a distribution transformer rated to deliver up to 5.3 MVA and has a typical base load shown by the no PEV load line. The analysis assumes a 3.3kW PEV charging rate and a scaled version of the 2013 EV Project PEV energy requirements used in Figures 3 (San Francisco), Figure 6 (San Diego), Figure 9 (Los Angeles) and Figure 13 (Seattle) were used to display the substation transformer loading from 500 (½ PEV/home), 1000 (1 PEV/home), 1500 (1½ PEV/home), 2000 (2 PEVs/home) and 2500 (2½ PEVs/home) PEVs charging using that city's PEV charging profile.

This analysis showed that TOU rates have a positive impact on delaying when distribution transformers would be overloaded. Seattle will exceed the distribution transformer limits with 1 PEV/home during the evening hours. Los Angeles will also exceed the distribution transformer limits during the evening hours, but it takes 1.5PEV/home. The TOU rates also biased both San Francisco and San Diego customers to shift PEV charging to the early morning hours where over 1.5PEV/home are required to exceed a distribution transformer load limit. This is a longer-term problem since there are 6.8M Single Family Homes [Census, 2011] in California and there are projected to be 400K PEVs in California by 2022 (~6%) which is only 0.06 PEV/home when averaged over the entire state's single family homes.

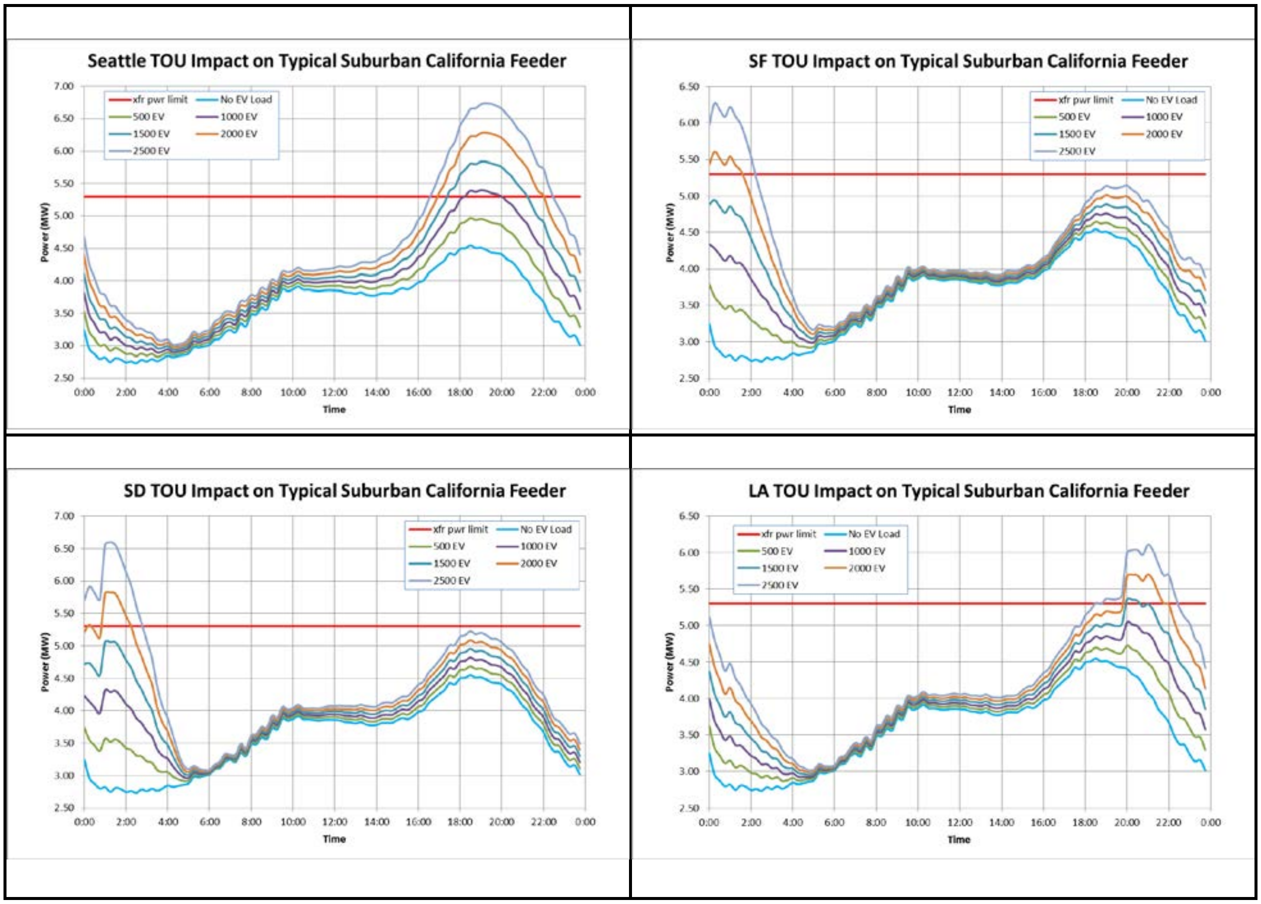

Figure 16: Comparison of Projected Distribution Feeder Impacts by PEV Charging

However, in 2013 Nissan LEAF battery charger was upgraded from 3.3kW to a 6.6kW charger. Each vehicle with this larger battery charger has the same effect on the distribution transformer as doubling the number of PEVs being charged. As battery technology continues to improve, battery size is anticipated to also increase. Higher power charging systems are anticipated to be needed for these larger batteries, which has a direct impact on the distribution feeder. Most Level 2 EVSEs are capable of supplying charging power at 19.2kW. One PEV charging at this higher rate would be the same as six current generation PEVs charging at 3.3kW. Broad adoption of these higher power charging stations would rapidly shift the distribution transformer loading situations, at least in localized distribution feeder situations.

The anticipated expense associated with new Extreme Fast Charging (XFC) PEV charging technology would limit its physical locations to more commercial settings, but the substation transformer impact of the XFC chargers would add to existing PEV charging and normal system loads. But the XFC charging short duration and high power (~350kW) may require local battery storage to absorb power system transients and to disperse impacts of multiple simultaneous charging events.

4.2 Adoption Forecast

Using data from Electric Drive [EDTA, 2016], the PEV (BEV + PHEV) adoption rate has continued to increase with a projected 1M PEVs sold in early 2019. Approximately 40% of the sales are in California.

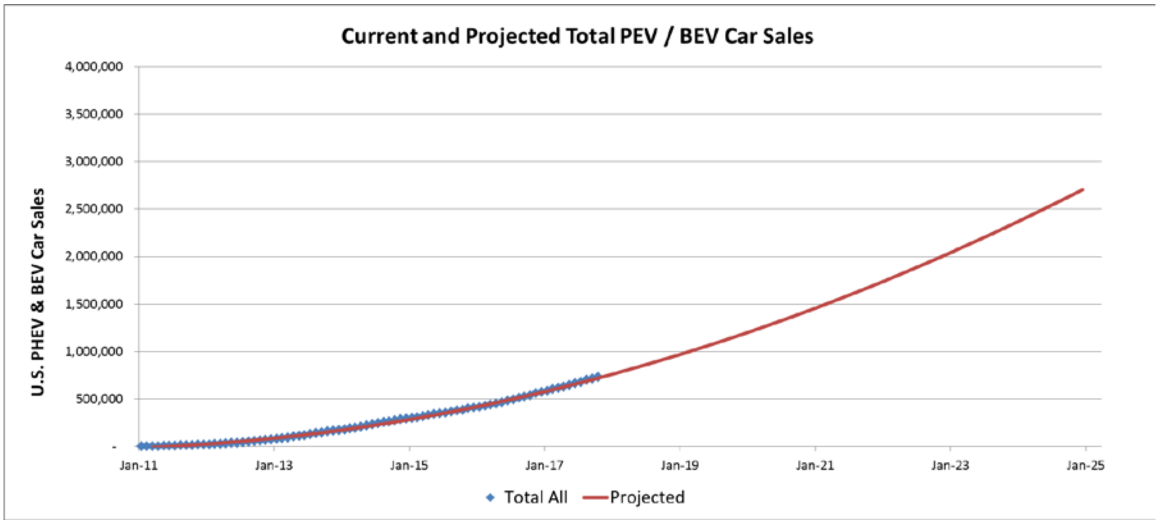

Figure 17: U.S. PEV Adoption Rates

With 3.3kW chargers and non-clustered PEVs, the PEV charging impacts on most distribution transformers would probably be minimal based on the need for over 1 PEV/home on the distribution feeder to have an impact. However, it has been observed that PEV owners might live in the same neighborhood resulting in local concentrations of PEVs that enable the 1 PEV/home level to be met. This local effect has primarily affected residential transformers, but not distribution transformers.

The PEV population size and vehicle miles traveled also has a direct effect on transportation oil consumed and associated gaseous emissions. In 2013, EV Project reported that 6,474 vehicles consumed 17,552.6MWh of energy [EV Project, 2013]. If each PEV uses 0.32kWh/mile instead of 25 miles/gallon of gasoline, this equates to 340 gallons of gasoline per vehicle per year not used. From Figure 17, in 2020 an estimated 560,000 PEVs will be operating. This equates to 190.4 million gallons of gasoline not used. The joint EPA / Department of Transportation rule states that 8,887 grams of CO_2 emissions per gallon of gasoline (8.887×10^{-3} metric tons CO_2/gallon of gasoline) [EPA, 2016] which calculates to be 1.7 million metric tons of CO_2 not released during the year with the aggregated impact increasing in significance.

5.0 Potential Economic Impacts of Controlled Charging

The controlled charging approach presented utilizes the flexible and dispatchable nature of PEV charging. These capabilities would be used to enable utilities or aggregators to integrate these loads into demand response or regulation service agreements.

5.1 Development of Low-Cost Charging Control Methods

Identification of low-cost and practical methods that maximize PEV transportation availability and minimize PEV charging electricity costs is critical to promoting PEV adoption. One step in achieving this objective is to determine if a population of PEV charging energy events fit into a predictable response curve. For example, does a significant population of PEVs have small energy requirements and a small population has larger energy requirements? This question was initially answered using the San Francisco EV Project charging power data and vehicles randomly selected from the NHTS data set and limited to 80 miles traveled in a weekday to match the Nissan Leaf's range. The data was processed to collect the number of vehicles whose charging events required 1 kWh, 2 kWh, etc. and then plotted by the percentage of vehicles whose charging events required different amounts of energy.

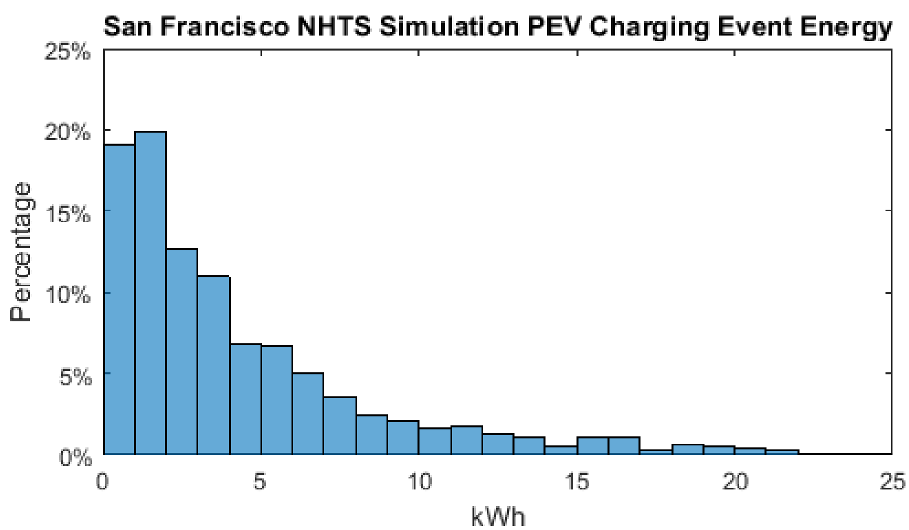

Figure 18: Energy Distribution of San Francisco PEV Charging Events

Figure 18 shows the distributions of charging events in the NHTS simulation for San Francisco for all vehicles. There are multiple instances of 0-1 kWh charging events in the NHTS simulation. This is due to the system not meeting trip energy requirements for a one trip because of PEV limited availability due to mobility needs when there was not enough time to charge in a single session. Instead the energy demand was met through multiple charging events to work around PEV availability and PEV travel requirements. Most charging events are under 4 kWh (70%). Using a 3.3kW charging rate, these events would last less than 1 hour and 13 minutes.

Less than 5% of charging events exceed 15kWh. The maximum charging event consumed 21kWh for this particular simulation. A 2016 Nissan leaf's battery pack capacity is 24-30kWh [Nissan, 2016].

The PEV Charging Energy Distribution for San Diego (Figure 19) and Los Angeles (Figure 20) are very similar to the San Francisco PEV Charging Energy Distribution. They all have a majority of charging events under 4kWh: 61% for San Diego, 66% for Los Angeles, and 62% for San Francisco. When evaluating the charging periods that consumed less than 2kWh, they made up 40% of San Francisco charging events, 39% for San Diego and 41% for Los Angeles.

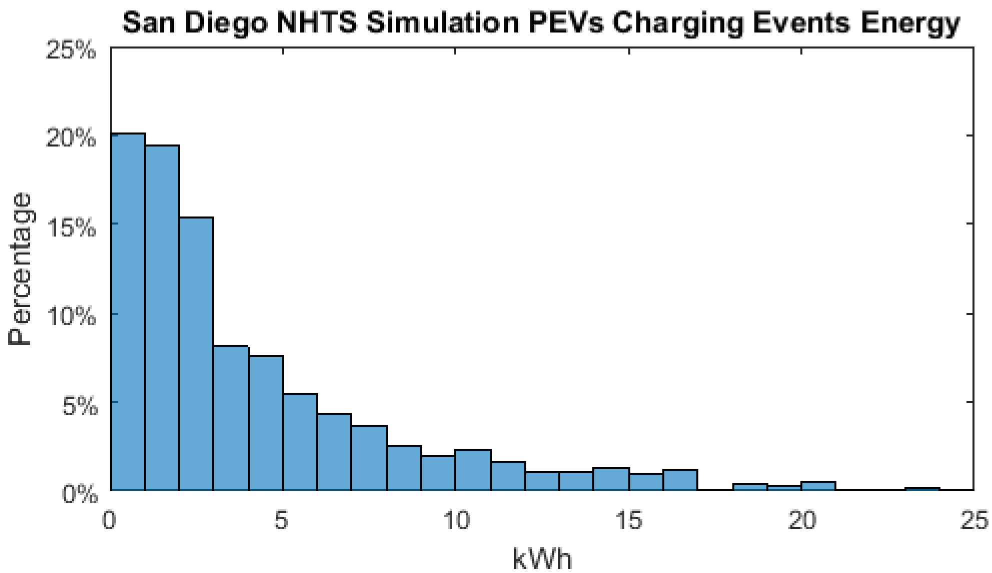

Figure 19: Energy Distribution of Charging Events of PEVs at San Diego

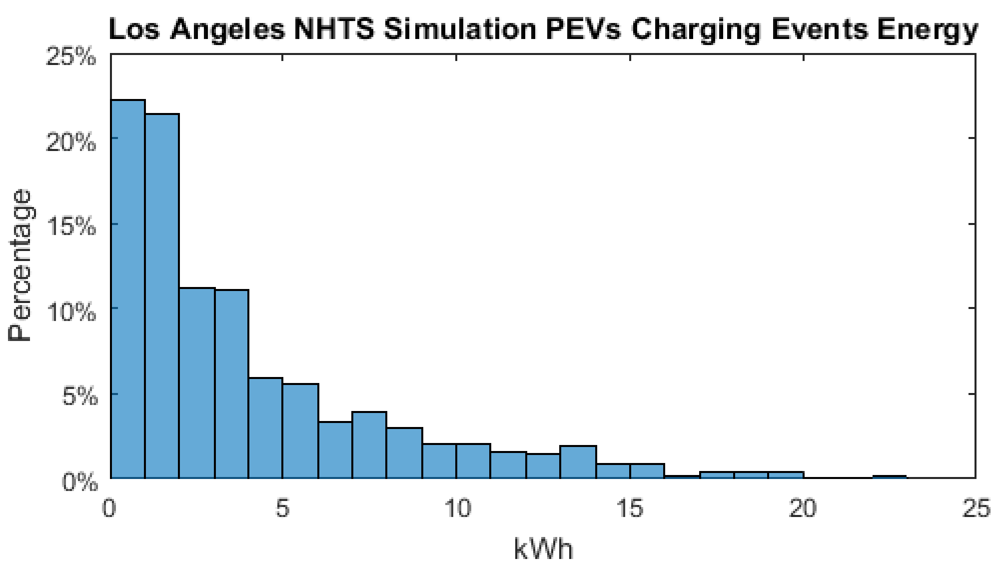

Figure 20: Energy Distribution of Charging Events of PEVs at Los Angeles

Seattle's PEVs charging event energy distribution has a noticeable difference in that only about 32% of events are less than 2 kWhs compared to the other cities (40%).

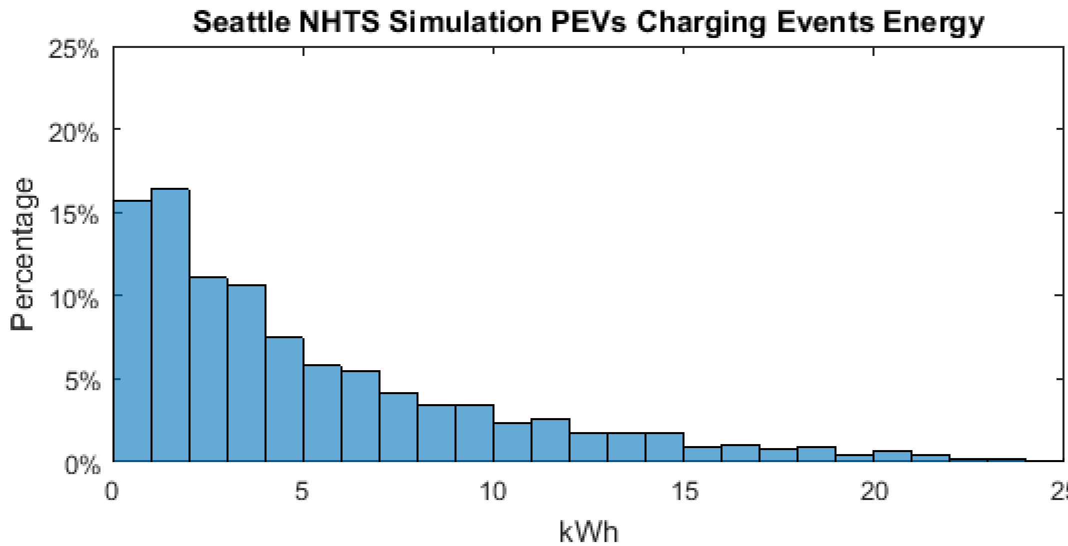

Figure 21: Energy Distribution of Charging Events of PEVs at Seattle

5.2 Required Energy Profiles

When the pool of PEV users was divided into subsets according to their required energy needs, it clearly stood out that a significant population had smaller energy needs. Further analysis divided the population into two groups of PEV users. One group is the low energy demand drivers that have short commutes of less than 12kWh (~40 miles) in a weekday (most under this group is below 4kWh), and the other group contains the large energy demand drivers whose weekday requires 12kWh and longer charging sessions.

An interesting observation concerning customer charging behavior was revealed when the San Francisco PEV simulated temporal charging data was aggregated into two subsets, the high energy demand PEVs charging and the low energy demand PEVs charging. Figure 22 shows three curves using the San Francisco EV Project and NHTS data. The NHTS San Francisco Simulation PEV load curve that matches the EV Project San Francisco data is shown by the green dashed line. The blue line shows the NHTS travel data simulation results from the San Francisco PEV drivers that commuted less than 40 miles and needed less than 12kWh to charge. The red line shows the NHTS travel data simulation results from the San Francisco PEV drivers that commuted more than 40 miles and needed more than 12kWh to charge. The figure shows that PEVs with the lowest energy needs also have the highest aggregate charging power. These PEVs have shorter duration charging events which could be flexibly moved within the charging period to mitigate peak loads and yet maintain high availability for transportation.

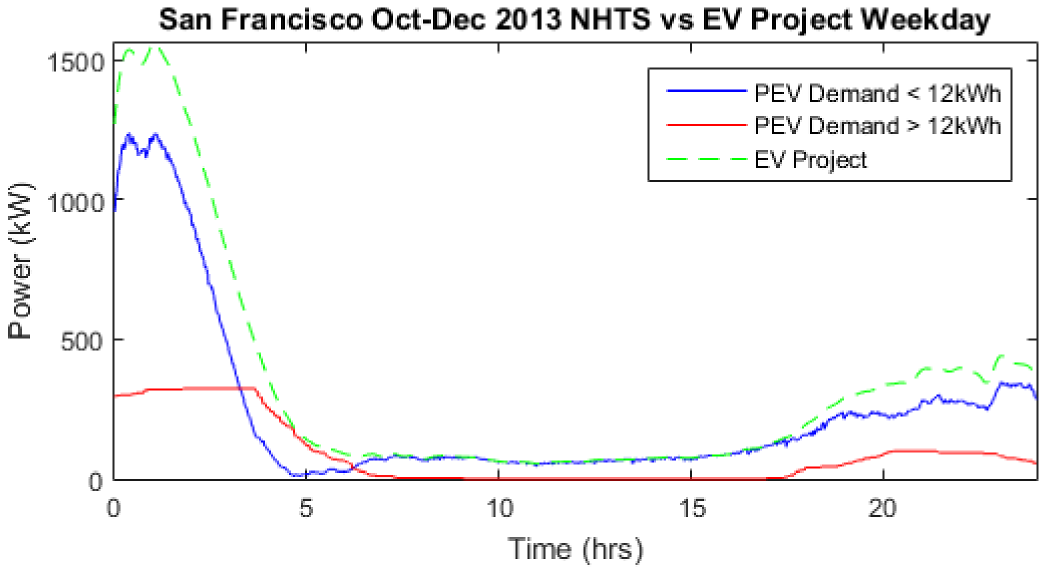

Figure 22: San Francisco Loads for High Demand and Low Demand PEV

The simulation load profile for high demand PEV drivers jumps at midnight and is almost level from midnight to 4AM, then tails off until the high demand PEVs are the primary vehicles being charged at 5AM. Around 9AM until 5PM, the high demand PEV load is either at or near zero. In contrast, the simulation load profile from the low energy demand PEV drivers makes up most of the power demand in the middle of the day. The low energy charging events always use greater aggregate charging power than the high demand except for the hours of 4AM to 6AM. This observation indicates significant potential for peak load shifting using just the low demand PEV charging events.

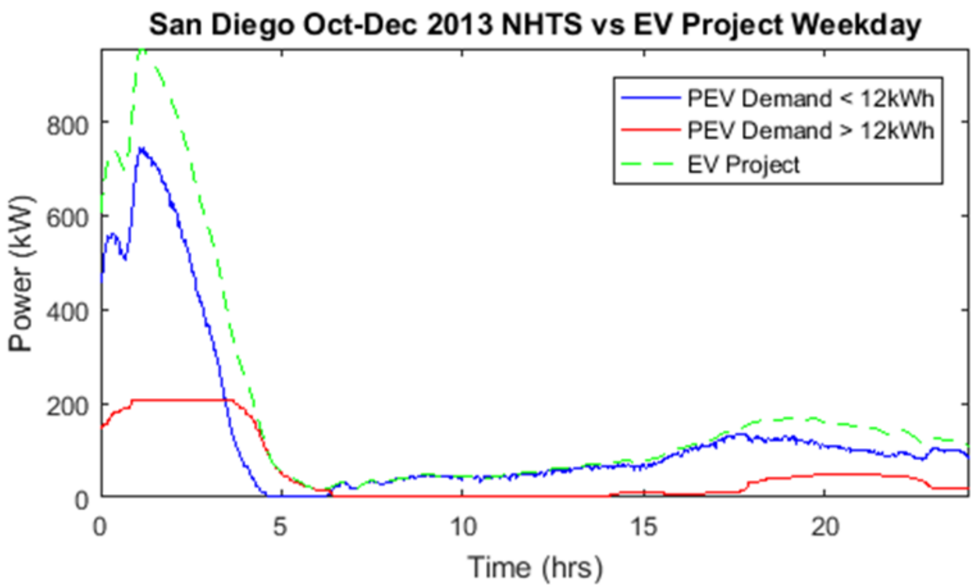

Figure 23: San Diego PEV Loads for High Demand and Low Demand PEV

San Diego features similar PEV charging load profiles as San Francisco. The simulation shows that the high PEV demand can be met in the morning from midnight to 4AM, is at or almost zero during the middle of the day, and increases slightly in the afternoon from 5PM to 11PM.

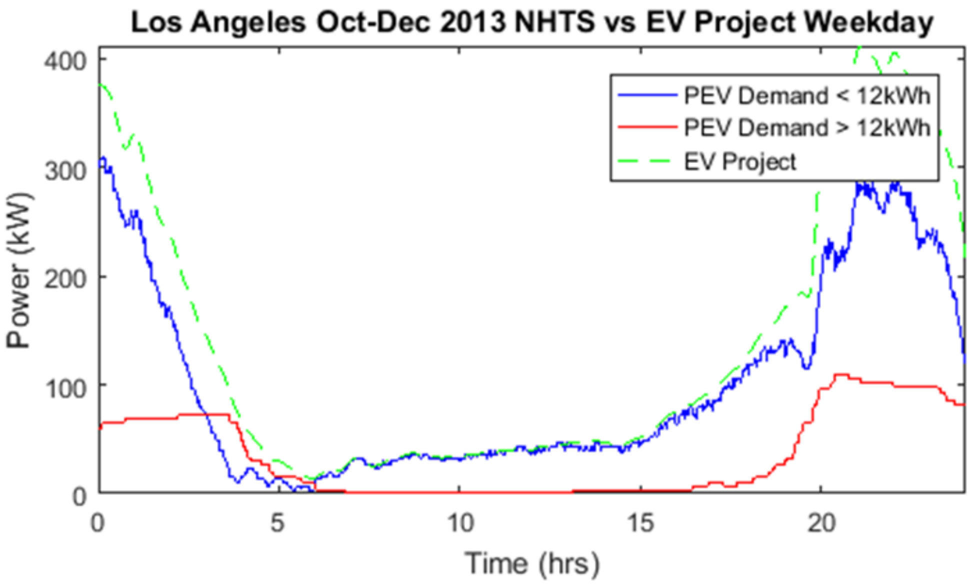

Figure 24: Los Angeles PEV Loads for High Demand and Low Demand PEV

In contrast, the Los Angeles PEV charging demand is highest in the evening starting at 8PM due to the TOU schedule shifting to the low rates at that time. Just like San Diego and San Francisco, the simulation shows that the high demand PEV load can be met from the time the low rate period begins to 4AM, and then levels off to zero at 6AM. Although the power demand differs during this timeframe, the starting and ending time are the almost the same for this charging behavior.

Seattle PEV charging behavior (Figure 25) is similar to Los Angeles, despite not incorporating a TOU rate schedule. The PEV charging demand is higher in the evening than the other cities and has a similar population that completes charging before the morning commute. But Seattle does not have the pronounced charging power peak at midnight like San Francisco and San Diego.

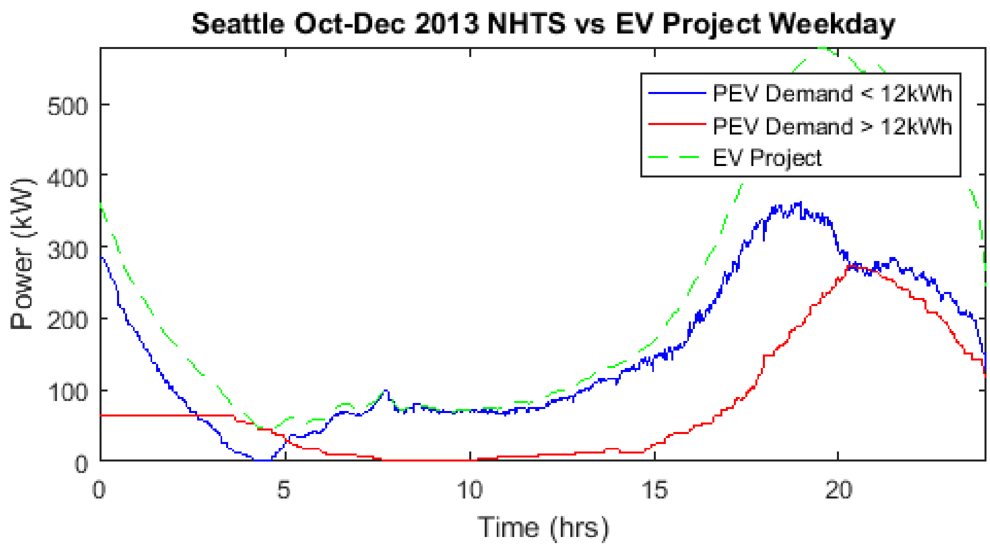

Figure 25: Seattle PEV Loads for High Demand and Low Demand PEV

5.3 Energy Shifting Function

A charging energy shift function was designed to reduce the peak PEV aggregate load by only shifting the charging times of the low energy demand vehicles. This is accomplished by delaying the charging of vehicles when the load is at its highest. Only PEVs with energy needs of 6kWh (~18 miles) or lower are delayed. Assumptions associated with this model are as follows:

- PEV user would denote the time they will need their PEV available for driving. It was assumed that all PEVs with energy needs of 6kWh or less in the morning were plugged between midnight and 4:30AM.
- The utility in coordination with a car manufacturer or a third party aggregator was able to change charging time set points based on PEV location and TOU rate period. These could be updated at a monthly rate assuming the home charging location hasn't changed.
- A decentralized control approach would be used that minimizes communication requirements using telematics generated by the vehicle and GPS coordinates.

Peak demand can be a burden on power system assets such as transformers and substations. One negative side effect of PEVs on TOU rate schedules is that there will be a sudden increase of PEVs charging at TOU transients, such as San Diego going from the mid-rate to the base rate at midnight, causing a 500kW jump for a 616 PEV population.

The demand shifting function aims to lessen these problems by smoothing out the peak, and spreading out the charging in the morning period. Instead of PEVs flipping the switch simultaneously to charge at midnight, the energy shift function will implement a scheduled process of charging based on battery energy needs that will randomize and delay the starting charging time for PEVs with 6kWh or less energy needs.

It was found through experimentation that there should be three energy distribution subsets to optimize the demand shifting of PEV load in the San Francisco case. Table 11 shows the charging time required for specific amounts of energy required to charge the battery to meet the daily trip total demand. These quantities of energy define three charging energy ranges of PEVs that will have their charging time adjusted. Recall in section 5.1, about 40% of the PEV charging sessions were between 0 to 2kWhs, 25% were between 2 to 4kWhs, and 15% were between 4 to 6kWhs for San Francisco.

Energy Required	Charging Time @ 3.3kW
2 kWh	36 min
4 kWh	73 min
6 kWh	110 min

Table 11: Charging time required to meet specific energy demands

Using the Table 11 charging times and a desired charging completion time of ½ hour prior to the end of the low TOU period, each of the Table 11 energy windows were assigned different charging windows. For PEVs that need to charge 2kWh or less, the period to randomly start charging is shown by the green rectangle timespan in Figure 26. The PEV has to start charging by 3:53AM to have enough time to fully charge the battery by 4:30AM. Only 75% of PEVs under this energy need distribution had their charging times controlled and randomized. Furthermore, a similar approach was done for PEVs needing 2kWh to 4kWh, as shown in Figure 27, and PEVs needing 4kWh to 6kWh, as shown in Figure 28. For these subsets, only 50% of the PEVs under the corresponding distributions were affected by delay and randomization charging control.

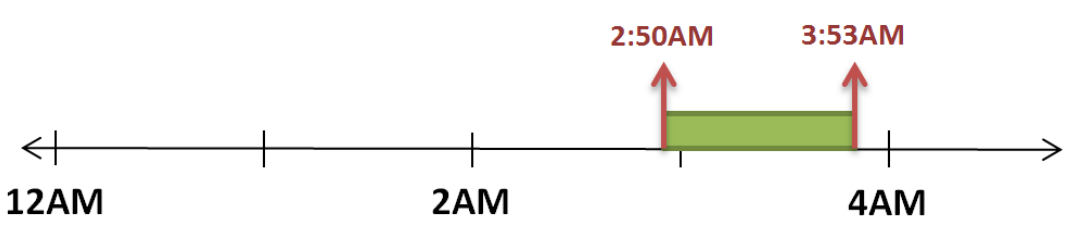

Figure 26: PEV Charging Start Period with Energy Needs between 0kWh and 2kWh

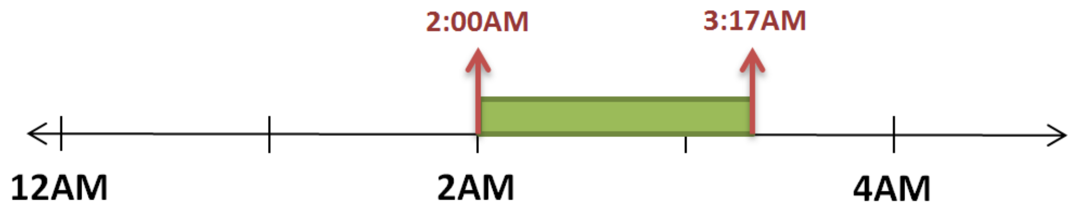

Figure 27: PEV Charging Start Period with Energy Needs between 2kWh and 4kWh

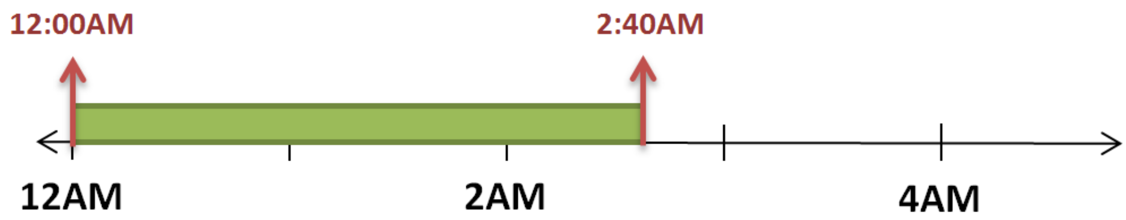

Figure 28: PEV Charging Start Period with Energy Needs between 4kWh and 6kWh

The exact starting time for each PEV was randomized within the green interval for each energy range. When applied to San Francisco, the results of a 100 simulation runs of the energy shifting function are shown in Figure 29 below. In average, 346 out of the 1132 PEV's (31%) had their charging times moved. Peak demand was originally at 1559kW before the demand shift. It was lowered to 1300kW in average – a 17% peak load power reduction. The maximum peak was 1383kW and the minimum peak was 1251kW out of the 100 simulation runs.

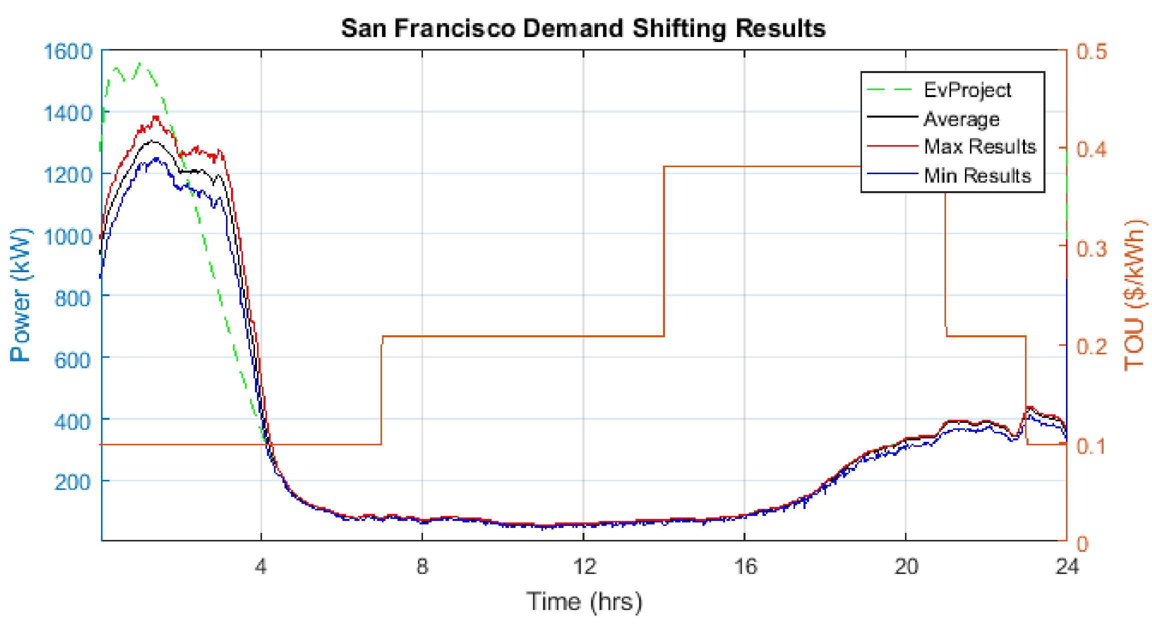

Figure 29: Peak power reduction by delaying PEV charging times and randomizing charge start time in San Francisco.

The average results were used to examine the demand shifted San Francisco TOU impact on a typical suburban California feeder for San Francisco. As mentioned in Section 4.1, 1.5 PEV/household would overload the transformer in San Francisco. Using the PEV demand shifting, that number increases to about 2.3 PEV/household, meaning the transformer can handle a larger PEV penetration than before, as shown in Figure 30.

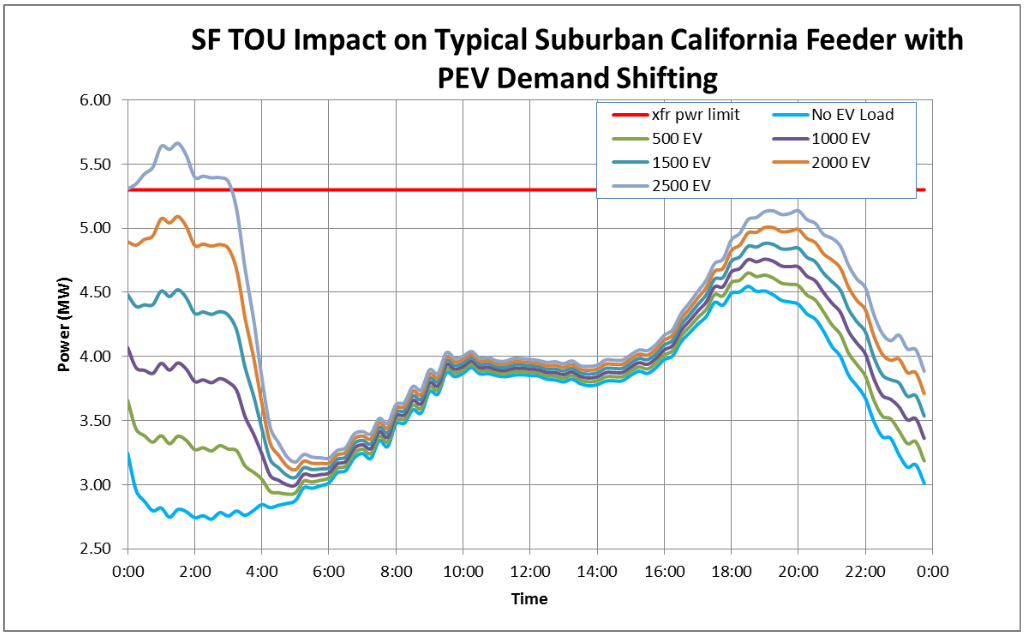

Figure 30: Projected Distribution Feeder Impacts with PEV Demand Shifting for San Francisco

The peak of the maximum results for San Diego was 861.3kW, the peak of the average result was 807.1kW, and the peak of the minimum result was 768.9kW. EV Project peak was 956.2kW. The average number of cars used in demand shifting process was 189.43 out of 616 or 30.8% of the PEV population. The demand shifting function reduced the peak by 16%, as shown in Figure 31, if the average results are used.

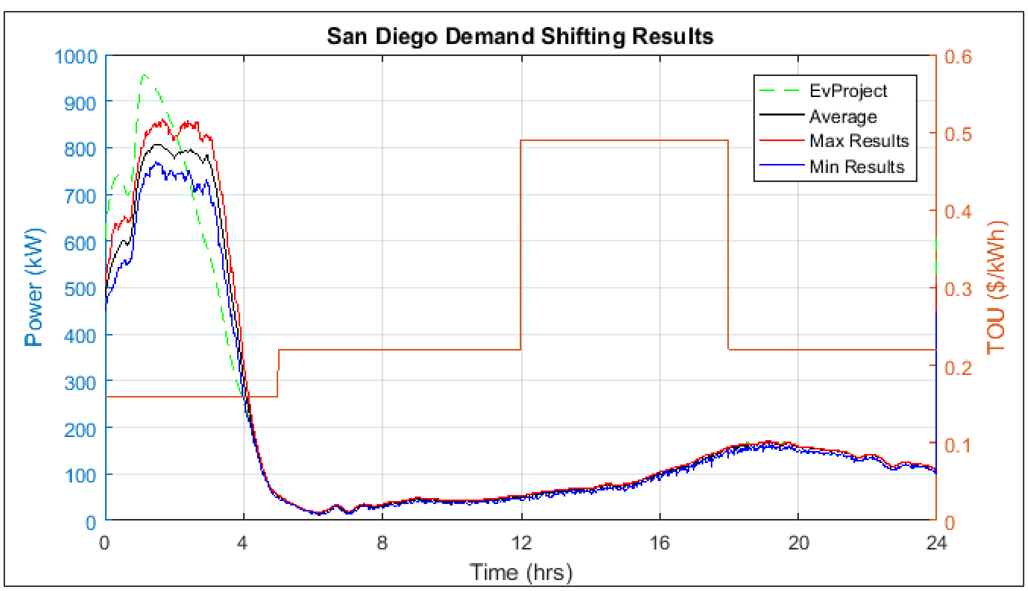

Figure 31: Peak Power Reduction by Delaying PEV Charging Times and Randomizing Charge Start Time in San Francisco

Finally, the average results were used to examine the demand shifted TOU PEV charging impact on a prototypical suburban California feeder for San Diego. As mentioned in Section 4.1, 1.5 PEV/household overloads the transformer. Using the PEV demand shifting, the PEVs/household needed to overload the transformer increases to about 1.8 PEV/household, meaning the transformer can handle a larger PEV penetration than before. This is shown in Figure 32.

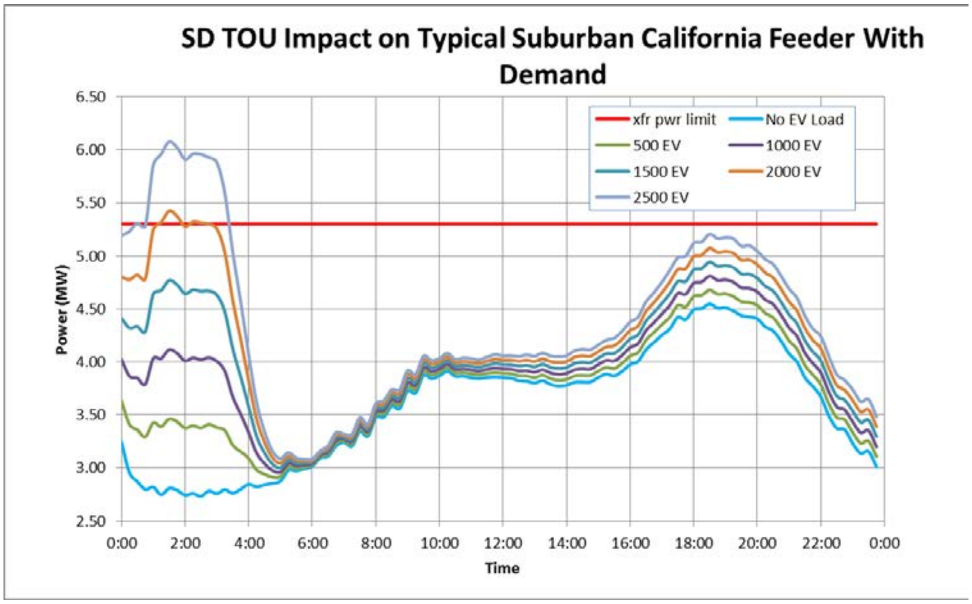

Figure 32: Projected Distribution Feeder Impacts by PEV Charging with PEV Demand Shifting for San Diego

6.0 Additional Economic Value beyond TOU Rates

Identifying potential areas where new technology could increase customer economic value requires that the installation and maintenance of the new technology results in a profitable solution to both the customer and the service provider. In the areas where new electrical markets or rate structures are created, additional impacts such as grid reliability, resilience, and security need to be considered. As shown by the EV Project data from Los Angeles, San Francisco, and San Diego, customer response to new rate structures (e.g., TOU rates) is difficult to predict.

6.1 Observed TOU Charging Behaviors

This report found that about 35% of the PEV charging energy was delivered at times when TOU rates were not the minimum. The reasons for this behavior are probably varied, but can be summarized by stating this group of PEV owners people did not find between $5/month and over $20/month an adequate incentive to shift their PEV charging practices.

Data from the EV Project shows that the majority of PEV owners do respond to price differences in the electricity rates. The majorities of PEV owners voluntarily respond to the lower TOU rates and charge predominantly during off-peak periods. However, the degree to which consumers respond may depend on the level of the peak versus off-peak rate differential. Charging behaviors by EV Project participants demonstrate that consumers in regions without TOU rates choose to begin charging upon returning home from the daily commute. PEVs charging during the off-peak TOU periods have been shown to cause significant load ramping in the distribution feeders and potentially have regional balancing impacts. The large spike in demand occurs precisely when the off-peak rates go into effect strains the distribution infrastructure and may require infrastructure upgrades or enhanced managed charging techniques, such as randomized PEV charging start times [Letendre, etal., 2013].

6.2 Regulation Services

Section 3.6 described a commercial entity that is currently developing the information basis needed to enable PEVs to participate in the regulation services market with a per-vehicle value of ~$20/month. This section also described a method for OEMs to utilize existing telematics communications to enable PEVs to gain access to the regulation services market. However, participation in the regulation services market has the potential to limit the vehicle availability for transportation since the PEV average charging rate is lower and the charging time is extended.

6.3 Low Carbon Fuel Credits

In 2007, California enacted the Low Carbon Fuel Standard (LCFS) designed to enable a 10% greenhouse gas reduction from transportation fuels by 2020. LCFS uses a system of credits that can be bought or sold to enable entities to meet their emissions reduction goals. One credit is equivalent to one metric ton of CO_2-equivalent emissions avoided[1]. The value of these credits varies. Table 12 shows illustrative Low Carbon Fuel Credit (LCFC) values[2].

Table 1: Estimated 2016 credit revenue generated

Typical EV Types	EERs	Credit Revenues (per KWh) LCFS Credit Price $50*	$100*	$150*
Light/Medium Duty EVs	3.4	¢4.01	¢8.03	¢12.04
Electric Buses	4.2	¢5.66	¢11.33	¢16.99

* Credit prices used here are for illustration proposes only.

Table 12: Illustrative 2016 LCFC Values

[1] https://avt.inl.gov/sites/default/files/pdf/EVProj/HowManyLCFScreditsWereGeneratedByTheUseOfEVPcharginginfrastructures.pdf

[2] http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/03082016regguidance_16-04.pdf

In 2013, EV Project reported that 6,474 vehicles consumed 17,552.6 MWh of energy [EV Project, 2013] which is equivalent to an average PEV consuming 225 kWh/month and creating LCFCs worth $9/month at 4¢/credit.

6.4 Workplace Charging

Although this report is primarily focused on V1G PEV / Grid Integration opportunities for residential charging, workplace charging provides two other sources of economic value. The first involves implementing PEV charging control adequate to minimize demand charges to businesses. To provide an estimate of potential demand charge impact of workplace charging, the Seattle distribution transformer impact curve from Section 4.1 can be used. Throughout the day, an additional average 300kW to 1000kW is consumed by approximately 2000 PEVs (see dark blue curve in Figure 33). If the 1000kW PEV charging load shared by 2000 PEVs is scaled to be located at a single business with 50 PEVs, then the business's peak power would be 25kW. If demand charges are assessed at $10/kW, the business would have $250/month of demand charges. But the Figure 33 data is average data and the monthly peak demand could be almost twice as high[3] or nearly $500/month. Business's need to be aware of their rate structure as the rate structure varies by utility across the country.

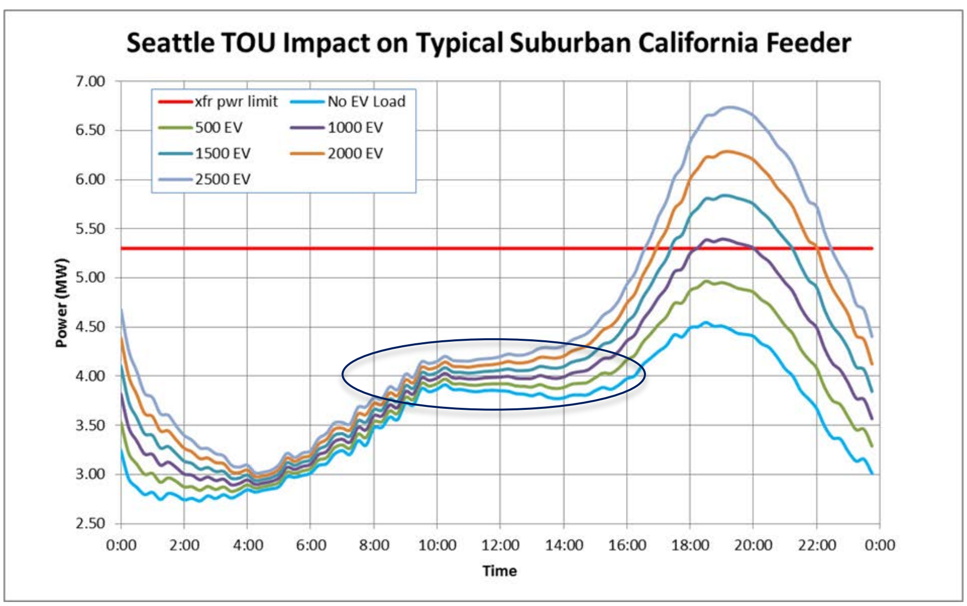

Figure 33: Seattle Workday Charging

[3] http://www.eia.gov/todayinenergy/detail.cfm?id=15051

6.5 Transmission and Distribution Deferral

Transmission and Distribution systems may need to be upgraded over time. Delaying or deferring these upgrades is called T&D Deferral. Section 4 describes the potential for PEV charging to contribute to distribution transformer overloading. This is a significant high-value opportunity that the existing telematics communication infrastructure available to OEMs could be used to gain access to this revenue stream through Demand Response (DR) platforms like the Open Vehicle Grid Integration Platform (OVGIP). OVGIP is the result of collaborations between EPRI and OEMs that enables a unified common interface between utilities and the PEVs [EPRI – 2013]. The OVGIP system's proof of concept demonstration was conducted at Sacramento Municipal Utility District, SMUD, in October 2014 with seven OEM PEVs responding to a DR signal.

Studies like [Hu, 2012] and others have also proposed that increasing market penetrations of PEVs will impact the electricity system infrastructure. Impacts will begin initially at residential transformers, and then begin affecting the grid at the distribution transformer or neighborhood level as PEV market penetration continues to grow. These studies used uncoordinated charging models to show that distribution transformers will be loaded too heavily and cause outages, infrastructure upgrades will be required, voltage tolerances will be exceeded and harmonic distortion will exceed limits. These studies typically recommend that a form of coordinated or managed PEV charging must be used to diversify the energy consumption and minimize large transformer loads. It is expected that these mitigation strategies will be generally be effective, but older neighborhoods and areas with very high PEV concentrations could require infrastructure upgrades. For the foreseeable future, no issues are anticipated on the bulk grid from PEV charging.

6.6 Battery Size and Charging Power

As battery sizes, and therefore PEV ranges, increase, charging power will also increase to keep charging times and the vehicle's availability for transportation high. The value of grid services from PEVs will also increase. Specifically, the value of regulation services is directly proportional to charging power and larger batteries extends the time period that regulation services can be made available. These higher charging power levels can have negative and positive consequences including:

1. Increasing the battery size will increase the vehicle range and potentially reduce range anxiety.
2. For the same size battery, doubling the charging rate will result in the car being fully charged in about ½ the time.

3. Doubling the charging rate (e.g., from 3.3kW to 6.6kW) is similar to having twice as many 3.3kW charging rate vehicles charging on the distribution feeder or at the workplace.
4. Workplace charging Demand Charge effects could also double.
5. The Level 2 EVSE design can provide up to 19.2kW of charging power which increases the impacts listed above.
6. XFC systems can have a 100x larger power impact than 3.3kW chargers on the distribution system, but simultaneous XFC charging events would proportionally increase the impact further.

6.7 Renewables Integration

Another key value proposition for PEVs is their use in aiding the integration of renewable generation sources. In particular, PEVs have potential in photovoltaic renewable energy systems for voltage support and cloud transient suppression. Some considerations of that proposition are:

1. PEV and PV can operate synergistically in a distribution system. PEV charging can provide additional load under high feeder voltage conditions to reduce the excess voltage. PV resources provide an additional power injection, mitigating overload conditions on secondary transformers under high PEV assumptions [Tuffner, 2012]. An interesting predisposition of EV adopters was that approximately 25% of the EV Project participants in San Diego also had installed PV arrays [Cook, 2014].
2. The PEV charging policy proposed in a voltage support study considers transmission and distribution integration issues and reacts to market signals. Their recommendation was that the PEV should make economic charging decisions every 5 minutes, while performing one-second interval adjustments to voltage support. Simulation results indicate voltage support may be provided at low cost ($5 - $50 per year / PEV) as an alternative to installing or upgrading distribution networks and tap-changers [Foster, 2013].
3. PEV potential for wind renewable energy systems includes the capabilities of frequency regulation and load shifting. A study found that if about 13% of the existing light-duty vehicle fleet (about 2.1 million vehicles) was PHEVs with a 33-mile electric range and charging managed at home and at work, ALL of the balancing requirements of 10GW additional wind generation could be provided. [Tuffner, 2011].

6.8 Additional Economic Value Summary

A summary of grid service and other economically viable options available to PEV customers is shown in the Table 13 below:

Service	Value	Comments
Transformer Overload	$200 - $2000 transformer cost	New concept and no existing market
Fuel Cost	$50 / month	Simulations show about 50% of the customers could receive this amount
TOU Rates	$5 - $20 / month	Available to customers not participating in TOU program
Regulation Services	$20 / month	V1G Regulation Services reduces the average charging rate and delays transportation availability
Low Carbon Fuel Credits	$9 / month	Average PEV consumes 225 kWh/month and creating LCFCs worth $9/month at 4¢/credit
Demand Charge Mitigation	$33 - $66 / month	At $10/kW, a 3.3kW PEV could cause demand charges to be assessed at $33 / month and a 6.6kW PEV at $66 / month
Ramp Rate Reduction	No explicit market	The rapid response of PEV charging rate to changes in solar power generation is realistic
Demand Response	$10/MWh	3.3kW vehicles that delay charging for 3 hours would be eligible to receive $0.10
Renewables Integration	$5 - $50 per year / PEV	Delay upgrading distribution networks and tap-changers

Table 13: Summary Value Proposition

7.0 Residential Transformer Overload Predictive Concept

The detection of overload conditions in residential or distribution transformers has high value to utility companies and during an outage and even higher value to affected customers. Reduction of outages can be achieved if controllable loads could be shifted to times where the transformer loading was within the transformer's operating limits. Patents have been written to detect distribution transformer overload conditions by comparing stored voltage and current measurements with present conditions[4]. However, the potential for controllable PEV charging to externally measure the transformer loading using measured residential A.C. voltage under controlled variable load conditions has not been investigated. The investigation's first step was collect A.C. line voltage and A.C. power meter data during the controlled charging of three 3.3kW PEVs. The A.C. voltage data was collected using a PNNL-developed device called the Grid Friendly Appliance connected to the 120VAC line. Figure 34 below shows the data collected.

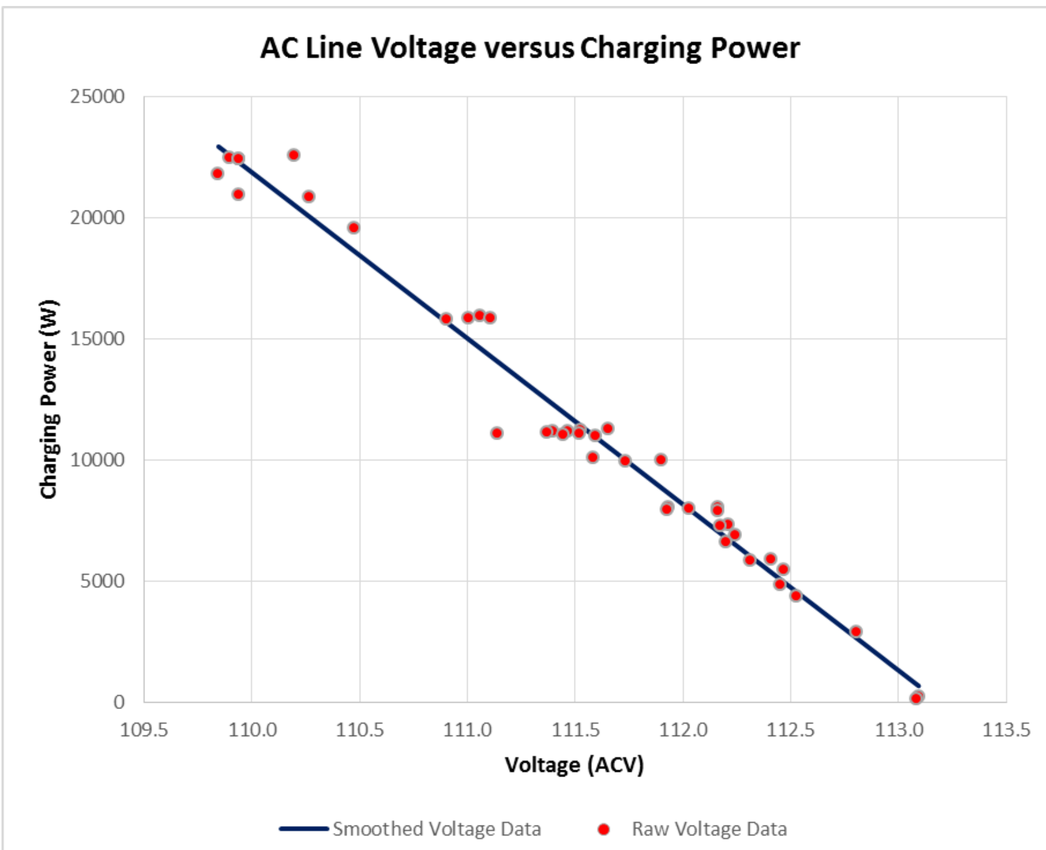

Figure 34: A.C. Line Voltage versus Charging Power

[4] US7701357 B2 - https://www.google.com/patents/US7701357

The slope of the A.C. voltage versus A.C. power curve is ~7000W/VAC using the voltage measured at a 120VAC outlet in the facility. The residential transformer that supplied the facility is a 25kVA pole-mounted transformer. The cause of this voltage drop with changing PEV charging power is due to the small series impedance in the transformer. The data shows that a Chevy Volt or pre-2013 Nissan LEAF with ~3.3kW chargers could change the A.C. voltage by ~0.5VAC when changing from full charge rate to OFF. A 2013 and newer Nissan LEAF could cause a ~1.0VAC change when changing from a full charge rate (6.6kW) to not charging.

Background information on residential pole-mounted transformers, as shown in Figure 35, is provided to help frame the proposed approach. These transformers are typically mineral oil-filled and are used to reduce the 7.2kV-13.6kV distribution system voltages to 240VAC[5] and, depending on the vendor and features, cost in the \$200 - \$2000 range. The transformer ratings typically require continuous operation at rated kVA without exceeding either a 65^{o}C average temperature rise or an 80^{o}C hot spot temperature rise. There are three electrical characteristics specified in transformer designs: core losses, winding losses, and percent impedance (~1.6 – 3.0%)[6]. These characteristics can also be specified as No Load Losses and Full Load Losses. Typical transformer losses increase with load from 95W (no load) to 512W at full load and typical impedance values are R=1.6%, X=2.29% and Z=2.7%[7].

Figure 35: 25kVA Pole Mount Transformer

The coil loss in the transformer model evaluated is specified to increase from 246W at 25^{o}C to 512W at 135^{o}C[4]. Transformer temperature is the primary metric for assessing transformer life, but the transformer secondary voltage can also be influenced by variations in the distribution system (e.g., loads, solar generation, tap changer settings, etc.). Equation 1 is a form of the classical relationship between power, current and impedance (e.g., Power = Current^2 * Impedance). When Equation 1 is solved for a 246W coil loss (no temperature effects), the transformer impedance is calculated to be 0.0227 Ohms, which equates to reducing the transformer secondary voltage by 2.36VAC at full load. When Equation 1 is solved for a 512W coil loss (includes temperature effects), the transformer impedance is 0.0472 Ohms. Therefore, the difference between the 512W full load impedance and the 246W no load impedance is 266W or 0.0245 Ohms, which equates to the secondary voltage changing 2.55VAC due purely to the transformer temperature change.

$$Transformer\ Power\ = \frac{Base\ Power\ (W)}{Base\ Voltage\ (VAC)} * \frac{Base\ Power\ (W)}{Base\ Voltage\ (VAC)} * Impedance\ \ (Eq.1)$$

[5] http://www.powerpartners-usa.com/wp-content/uploads/2016/01/single-phase_product_spec_sheet.pdf?x30412
[6] https://www2.dteenergy.com/wps/portal/dte/bizBuild/buildersContractors/details/electric%20service/transformer%20impedances
[7] https://www.fs.fed.us/database/acad/elec/greenbook/10_shortcalc.pdf

The measured data from Figure 34 shows that a 7kW change in PEV charging rate causes a 1VAC change measured in the 120VAC outlets (or equivalently 2VAC measured across 240VAC). Equation 2 is a form of the classical relationship between voltage, current and impedance (e.g., Voltage = Current * Impedance). Solving Equation 2 for Impedance using a 6600W change is 0.61 ohms which is the PEV charging impedance.

$$Measured\ Voltage\ Drop = \frac{Delta\ Charging\ Power\ (W)}{Voltage\ (VAC)} * Impedance\ \ (Eq.2)$$

An equivalent electrical circuit representing the transformer, PEV charger and other facility loads would be as shown in Figure 36. The values calculated above are included for the transformer base impedance, the load / temperature dependent transformer impedance, the PEV charging impedance (assuming 7kW load), the A.C. voltage measurement point (TP1 – available in the EVSE, the PEV, and power meter), and the location of other loads that could potentially interfere with the measurement.

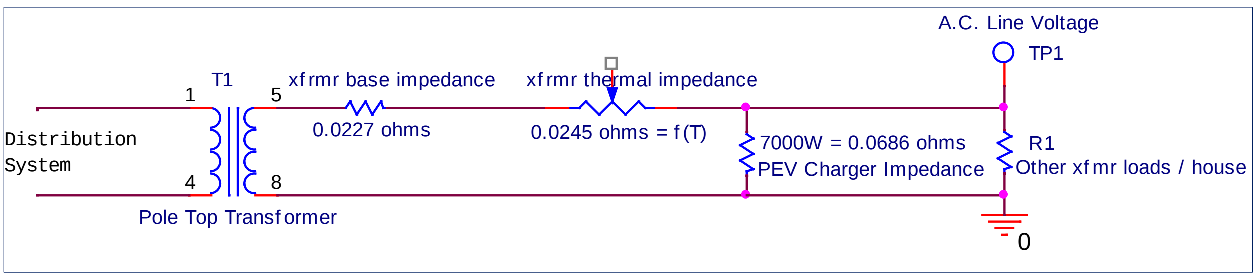

Figure 36: Residential Transformer Overload Measurement Equivalent Circuit

Figure 37 show the response of the TP1 voltage at several charging rates and home loads using the impedance values for the transformer base and thermal impedance, the equivalent charging impedance, and assuming no additional facility loads. The thermal impedance of 0.0245 Ohms was equally divided into five temperature areas, T0 (no thermal impedance) to T5 (0.0245 Ohms thermal impedance). The broad red line shows the calculated voltage where the transformer reaches its maximum output power.

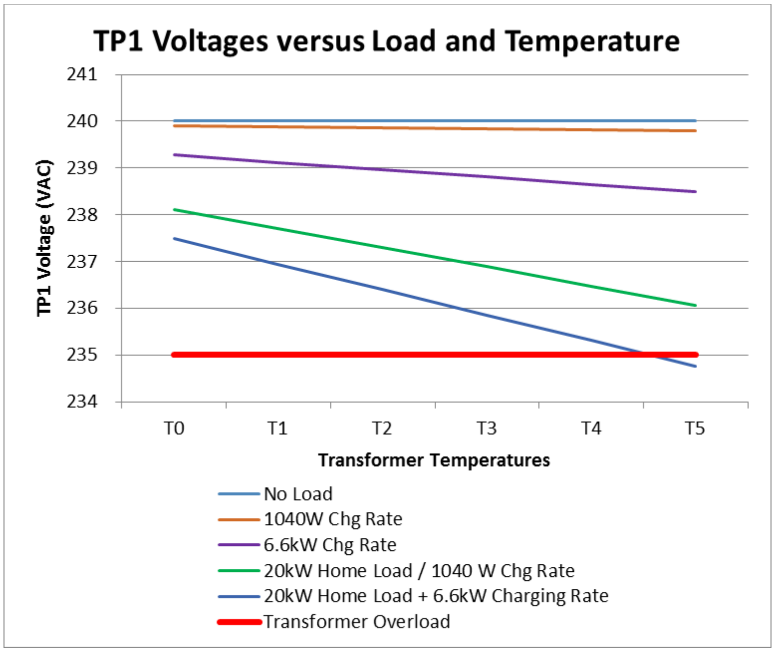

Figure 37: TP1 Voltages versus Load and Temperature

When the TP1 voltage reached 235VAC, the transformer would approach an overload condition if the no load secondary transformer voltage was 240VAC. But from the PEV or EVSE, the facility A.C. power data is not available, only the A.C. line voltage. It would be ideal if a direct A.C. voltage measurement is needed to provide an adequate indication of transformer overload conditions, especially in locations with roof-top solar or changes in the distribution system tap changer. This no-load voltage can be periodically determined in a three step process: (1) maintain a history of the A.C. Line voltage while the loads normally cycle ON / OFF; (2) during those times with the maximum A.C. Line voltage (minimum load) command the system to temporarily reduce the charging rate to the minimum; (3) and at minimum charging rate and maximum A.C. voltage use the change in A.C. power and change in A.C. line voltage to extrapolate the no load A.C. line voltage value for use in determining the transformer's loading state.

This concept of using different PEV charging rates to determine the residential or small commercial transformer loading condition is unique, a PNNL invention disclosure was submitted, and a prior art process has begun as part of the patent application process. The process to calculate the transformer load condition is described in the steps below:

1. Identify the transformer's full load core loss value (watts)
2. Identify the transformer's base load (e.g., 25kVA) and secondary voltage (e.g. 240VAC)
3. Use equation 1 to calculate the full load transformer impedance
4. Use the transformer base current and calculated full load impedance to determine the maximum transformer voltage drop before exceeding the transformer power limit
5. Implement a periodic A.C. line voltage measurement and control capability (e.g., 240VAC) that records the line voltage and minimizes the PEV charging rate during relative high A.C. voltage times to determine a second A.C. line voltage value.

6. The two A.C. voltage and power values are then used to calculate a no-load transformer voltage. This no-load A.C. voltage estimate can be used to verify that transformer voltage remains above its minimum voltage.
7. These controls take into account variations in no-load line voltage and can be as simple as a short-term (e.g., ~one-hour) history of the highest line voltage as most residential loads cycle within that time period.

8.0 Future Research

1. The distribution system impact of varying populations of 3.3kW and 6.6kW EVSEs on the distribution feeder is shown in Figure 16. The projected impact of multiple 250kW to 400kW extreme fast charging (XFC) stations on distribution feeders has already limited installation and availability of XFC electric public bus charging locations by several utilities. An area of study would be to evaluate the options of local energy storage (e.g., batteries), communications and charging rate control, local power delivery availability, preferable XFC station location attributes on the distribution system (e.g., line losses and impacts on other loads), and transportation energy requirements needed to expand electrified public transportation.
2. Identify the PEV charging behaviors that cause PEV owners to charge during high TOU periods.
3. Evaluate and test measurement and control methodology needed to mitigate residential and workplace demand charges.
4. Perform an economic analysis of grid services in regions that show large growth in PEV sales including San Diego, Los Angeles, San Francisco, Seattle, Detroit, PJM-area, and New York City. This economic analysis should use an enhanced Battery Evaluation Tool that incorporates Li-ion battery degradation costs, regional values for retail electricity prices and grid services, and NHTSA driving pattern impacts. This analysis will be done for aggregate residential and fleets of 20, 100 and 500 vehicles using V1G. This regional analysis would seek to identify the concentration of PEV's; their V1G capabilities and services (deferment, outage mitigation, balancing, and arbitrage); and electrical power market environment needed to start aggregation businesses.
5. Perform technical modeling analyses of regional distribution systems to determine impacts of off-peak charging ramp events when the off-peak rate takes effect and provide mitigation strategies to address this issue.
6. Integrate the transactive control capabilities developed by the LBNL / ORNL / PNNL VOLTTRON Buildings Technology Office-funded projects with controls needed to perform V1G charging to identify and demonstrate the increased value stream potential enabled by PEV charging.
7. Develop and test the transformer loading / overload detection methodology in additional applications to determine the approach's range of applicability beyond residential pole-mounted transformer installations to include XFC applications.
8. Perform GridLAB-D XFC charging impact assessment on prototypical distribution feeders.

9.0 Conclusion

MATLAB and GridLAB-D analyses and literature reviews identified several distribution system-level impacts of plug-in electric vehicle (PEV) charging rates for various PEV penetration levels and charging rates, as well as economic drivers needed to sustain PEV adoption rates. The key findings identified in this report are:

1. About 50% of PEV drivers have their transportation fuel bill reduced by $50 per month
2. Optimized charging using California TOU rates could result in up to $20 per month for 30-40% of PEV energy dispensed. The reasons why 30-40% of the EV Project participants did not follow the lowest-cost TOU rate schedule are not understood, but understanding these reasons would be important in developing effective policies and supporting technologies.
3. PEVs will require either autonomous control or fast communications to implement V1G regulation services that could result in an additional ~$20/month/PEV for an aggregated group whose owners have flexibility in the PEV mobility due to longer charge times.
4. In regions using TOU rates, distribution transformer power limits will be exceeded on prototypical feeders if the household PEV adoption rate reaches ~0.75 PEVs per home for 6.6kW charging. Customer responses to TOU rate structures induce significant increases in load when the low-rates periods begin, but overall TOU rates do enable the utility to supply additional PEVs/home before transformer power limits are exceeded. Distribution transformer upgrades are very capital intensive projects and deferring upgrades by using flexible PEV charging requirements could provide significant short-term economic value to PEV owners.
5. Distribution feeder impacts are directly proportional to PEV charging rate. It was anticipated that as battery sizes continue to increase to enable longer PEV travel ranges that the PEV charging rates needed to support larger batteries will also increase. At 19.2kW charging rates, the PEV adoption rate reduces to only 0.25 PEVs per home before the distribution transformer limit was exceeded.
6. Residential transformer overload conditions can be sensed at the power meter, EVSE, PEV, water heater, resistive HVAC system, or using an additional A.C. line voltage sensor at a single point supplied by that transformer. The capability to implement load control actions using data from that single point A.C. voltage sensor can reduce the degree and frequency of residential transformer overload conditions.
7. The low-cost TOU period is composed of a distribution of PEVs needing small, medium and larger energy needs that can be shifted to mitigate the TOU peak power and enable a higher PEV adoption rate per household without overloading distribution transformers. Entities that have access to the PEVs State-Of-Charge (SOC) and charging times can easily shift charge start times, maintain PEV availability for transportation and ease grid integration issues.

8. The effect of XFC charging on distribution feeders has two impacts: the short-duration, high-power charging event and the potential for multiple simultaneous XFC charging events to occur on the same distribution feeder.
9. From a business perspective where communication and control technology deployments should have a one-year positive Return-On-Investment (ROI), a product that generates $20/month of revenue could cost the customer up to $240 to install or upgrade. The product cost must a fraction of this cost to manufacture and ship to generate sustaining business profit margins.

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