ELECTRIC POWER RESEARCH INSTITUTE

Open Standards-Based Vehicle-to-Grid

Value Assessment

2019 TECHNICAL REPORT

Open Standards-Based Vehicle-to-Grid: Value Assessment

Value Assessment

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Final Report, June 2019

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ABSTRACT

This report describes the valuation aspects of plug-in electric vehicles (PEVs) that are vehicle-to-grid (V2G) capable. The foundational technology implementation based on open standards-based communication and control protocols provided the necessary validation of the assumptions used in this techno-economic analysis. This project is the first end-to-end system implementation, demonstration, and application of the standards suite from the Society of Automotive Engineers that addresses distribution and localized integration of V2G-capable vehicles. A distinguishing feature of this project was participation of mainline automotive manufacturers, including Fiat Chrysler Automobiles and Honda Motor, who provided vehicles equipped with on-vehicle grid-tied bidirectional power conversion systems. Established, credible electric vehicle supply equipment (EVSE) developer and manufacturer AeroVironment Inc. also participated. EPRI designed a Transformer Management System that constrains monitoring and control of V2G operation to the local transformer and facility distribution service drop. The overall project focused on use cases, including facility demand management, local and macro distribution system supply balancing, and reverse power flow applications. V2G use cases addressed primarily peak shaving and renewables ramping support. The team developed and deployed various distribution and macro level valuation tools to create a comprehensive valuation assessment of the broad penetration of V2G-capable vehicles on the California distribution system. The project identified the limitations of the regulatory interconnection requirements and provides recommendations for accommodating this new class of distributed energy resources on the California distribution system. The valuation analysis, based on CPUC practice manual and other established practices, proves that V2G technology, if implemented at scale, has the value that is 2X to 3X the value obtainable through managed charging, even when constrained by battery cycle life. As EV batteries continue to improve, this picture will continue to improve.

Keywords

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Distributed energy resources
Distribution operation
Plug-in electric vehicles
Value of Vehicle to Grid (V2G

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PRIMARY AUDIENCE: Utility Program planners, regulators

SECONDARY AUDIENCE: Technology developers, automotive OEMs, equipment manufacturers

KEY RESEARCH QUESTION

Millions of plug-in electric vehicles (PEVs) are likely to be deployed in the near-term future. To support utility system operations, a low-cost storage mechanism can provide benefits to the grid and ratepayers via vehicle-to-grid (V2G) capabilities. To take advantage of this resource, utilities need a way to assess the value to the grid of V2G-capable vehicles, translate this value to program definitions, and verify the value through pilot implementation.

RESEARCH OVERVIEW

This report describes the valuation methodology for distribution-system-constrained vehicle-to-grid services, through developing a distribution circuit analytic approach and feeder loading profiles, abstracted and fed into the valuation model that applies the value stacking and dispatch principles per CPUC standard practice manual and associated models, and creates a range of forecasts for managed charging versus V2G services. Methodology for Quantification of tariff effects on benefits is also discussed.

KEY FINDINGS

- This report provides insight on use cases that include facility demand management, local and macro distribution system supply balancing, and reverse power flow applications. The use cases primarily address peak shaving and renewables ramping support. These use cases were implemented and demonstrated over open standards-based, cybersecure and interoperable systems in a field demonstration
- The project team developed and deployed various distribution and macro level valuation tools to create a comprehensive valuation assessment of the broad penetration of V2G-capable vehicles on the California distribution system.
- Through participation of two mainline automotive manufacturers, this project is the first step in establishing rules for interoperability of communications and control, as well as integration of the power system at the point of common coupling. The results of this project are informing rulemaking for CPUC Rule 21 for V2G interconnection as a DER.
- The research found that there is significantly more value to employing V2G capable vehicles toward distribution grid support – as high as 2X to 3X the value as compared to managed charging. The process of integrating these EVs as a resource class therefore has merit.

WHY THIS MATTERS

Among the next developments in "greening the grid" will be the need for storage that enables further adoption of renewable power generation. Given typical vehicle driving patterns, approximately 85-90% of total vehicles are expected to be parked at any given point in time. Furthermore, PEVs are expected to constitute a significant portion of total automobiles in service by the end of the next decade. Hence, a significant number of EVs will be connected to the electric grid and available for dispatch. The available energy associated with such a large aggregate source represents a potential resource from which to support utility system operations.

HOW TO APPLY RESULTS

Section 5 of this report describes an approach to quantifying the potential grid and ratepayer benefits of distribution-aware V2G compared to smart charging and unmanaged charging. Section 6 describes how to use the EPRI StorageVET® tool to calculate the revenue that PEVs generate in providing ancillary services and capacity (resource adequacy) to the grid. Section 7 describes the process of translating the quantified grid benefits into incentive and tariff structures that can be deployed to reward or incent participating customers and PEVs.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- Vehicle-to-grid technology deployment and integration in a variety of operational scenarios, is a well-funded research area at Program 18, consisting of integration projects that span microgrid, building energy management systems, PV, Storage, flexible loads and other types of EVs. Contact Sunil for more details on how to engage
- Other interested parties include members to EPRI Programs 94, 174, 161, 170, 204 and possibly 182 and 200. Also, standards organizations (IEEE, SAE), equipment manufacturers, automotive OEMs, third-party software providers and aggregators

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PROGRAM: Electric Transportation, P18

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ACRONYMS AND ABBREVIATIONS

AS	ancillary services
BEV	battery electric vehicle
CAISO	California Independent System Operator
CEC	California Energy Commission
CONE	cost of new entry
CPUC	California Public Utility Commission
CTCC	combustion turbine combined-cycle
CZ4	Climate Zone 4
DSO	distribution system operator
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
ESS	energy storage system
EV	electric vehicle
EVSE	electric vehicle supply equipment
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GIR	grid integration rate
HE	hour ending
IEPR	Integrated Energy Policy Report
IOU	investor-owned utility
IRP	integrated resources planning
ITQM	incentive and tariff quantification methodology
LMP	locational marginal price
LNBA	local net benefits analysis

MMT	million metric tons
MRTU	Market Redesign and Technology Upgrade
NHTS	National Household Travel Survey
NPV	net present value
OASIS	Open Access Same-Time Information System
OEM	original equipment manufacturer
PEV	plug-in electric vehicles
PG&E	Pacific Gas & Electric
PHEV	plug-in hybrid electric vehicle
pmf	probability mass function
PV	photovoltaics
RA	Resource Adequacy
RECC	real economic carrying cost
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SOC	state of charge
SOH	state of health
TOU	time-of-use
UCSD	University of California, San Diego
V2G	vehicle-to-grid
ZEV	zero emission vehicle

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BACKGROUND AND PROCESS

Among the next developments in "greening the grid" will be the need for storage that enables further adoption of renewable power generation. The most significant obstacle to current grid storage solutions is their cost. Given typical vehicle driving patterns, approximately 85-90% of total vehicles are expected to be parked at any given point in time. Furthermore, electric vehicles (EVs) are expected to constitute a significant portion of total automobiles in service by the end of the next decade. Hence, a significant number of EVs will be connected to the electric grid and available for dispatch. The available energy associated with such a large aggregate source represents a potential resource from which to support utility system operations. With hundreds of thousands of plug-in vehicles deployed in the near-term future, a low-cost storage mechanism is possible with V2G capabilities.

The analysis conducted in this project addresses these issues by applying a systems approach to an existing/upcoming distributed non-stationary energy storage asset—the plug-in electric vehicle (PEV). A key enabler of this approach is PEV use as a distributed storage device (see Figure 1-1).

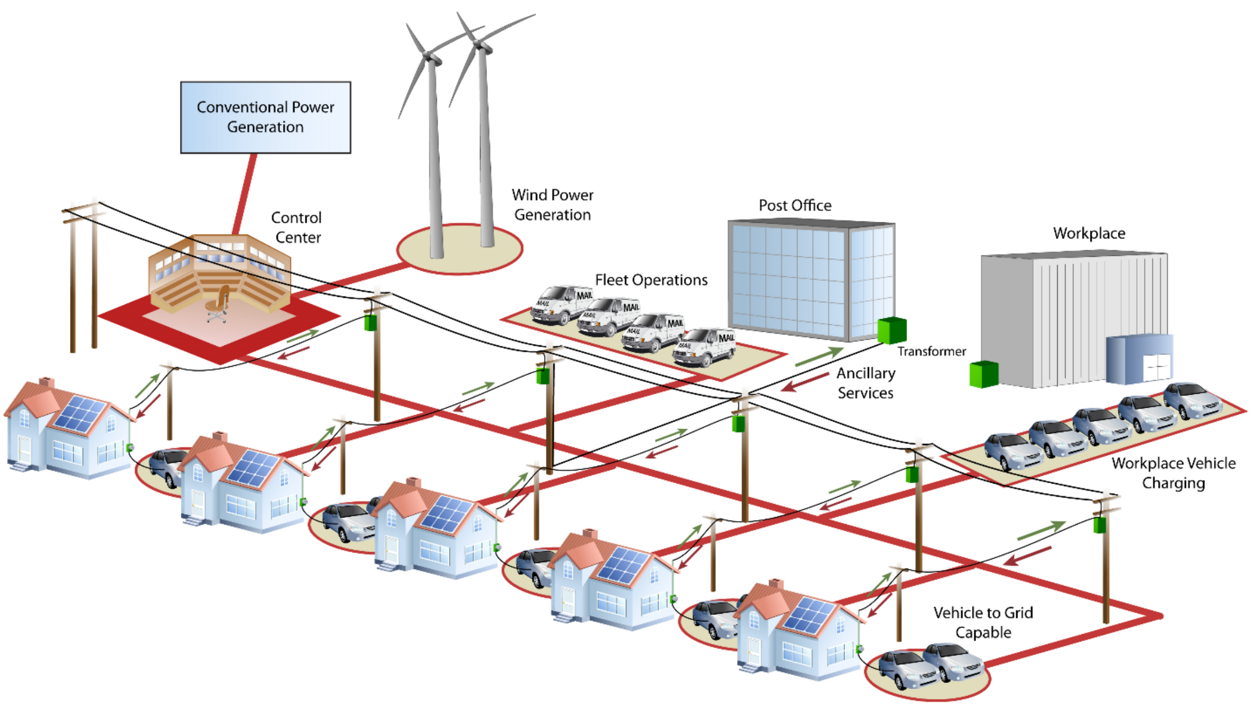

Figure 1-1
System overview PEV as a distributed resource

Grid operators use ancillary services to reliably operate the power system. The Federal Energy Regulatory Commission (FERC) defines ancillary services [1] as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." Load following, for example, is the balancing of generation to normal time-varying changes in load. Another ancillary service is operating reserves in the form of spinning and non-spinning reserves, which are called into service to provide system reliability in the event of a major grid disturbance such as the loss of a generator or transmission line. In all, ancillary services account for 5-10% of the total cost of electricity, which equates to approximately $12 billion per year in the U.S. [2].

Ancillary services focus on reducing these deviations at different timescales. The system flexibility/reliability functions and ancillary services that are required can be grouped into the following categories:

- Inertial response (cycles to 1-2 seconds)
- Primary frequency response (cycles to 5-10 seconds)
- Regulation (10 seconds to several minutes)
- Load following/ramping (several minutes to few hours)
- Dispatchable energy (sub-hourly and hourly)
- Contingency spinning reserve
- Contingency non-spinning reserve (within 10 minutes)
- Replacement or supplemental reserve (30 to 60 minutes)
- Voltage support
- Load leveling and standby power (typically in the timeframe of minutes to hours)
- Energy peak shifting (typically in the timeframe of hours)

PEV Charging and Discharging Assessment

As customer adoption of PEVs continues to grow, so does the potential for adverse consequences to distribution system operations and assets. These concerns are amplified considering that geographical clustering of PEV adopters within particular neighborhoods or socioeconomic regions can lead to significant concentrations of PEVs on particular feeders, even though overall adoption may be limited.

Recognizing the unpredictability in identifying specific customer adoption, vehicles types, and charging patterns, a proactive risk mitigation strategy is recommended to mitigate system-wide and localized risk to the distribution system. The strain on power delivery systems requires adjustments in asset management, system design practices, or even application of advanced controls that properly account for the particular nature of the newly emerging load.

PEV electrical charging characteristics have quickly evolved since the initial offerings in 2010. The first mass-produced PEVs charged at relatively low rates (up to 3.7 kW), traveled between 35 and 75 miles per charge, and suffered from limited public infrastructure. Over the course of the first few years, a host of additional PEV models had been introduced, including a battery electric vehicle (BEV) offering a range of up to 265 miles, as well plug-in hybrid electric vehicle (PHEV) offering an electrical range of 10-15 miles.

Charging rates in new vehicle models have also increased dramatically from 3.7 kW to upper ranges between 7.0–19.2 kW. In order to provide context for these demands, Figure 1-2 compares several PEV charging rates against average peak summer demand of typical household appliances.

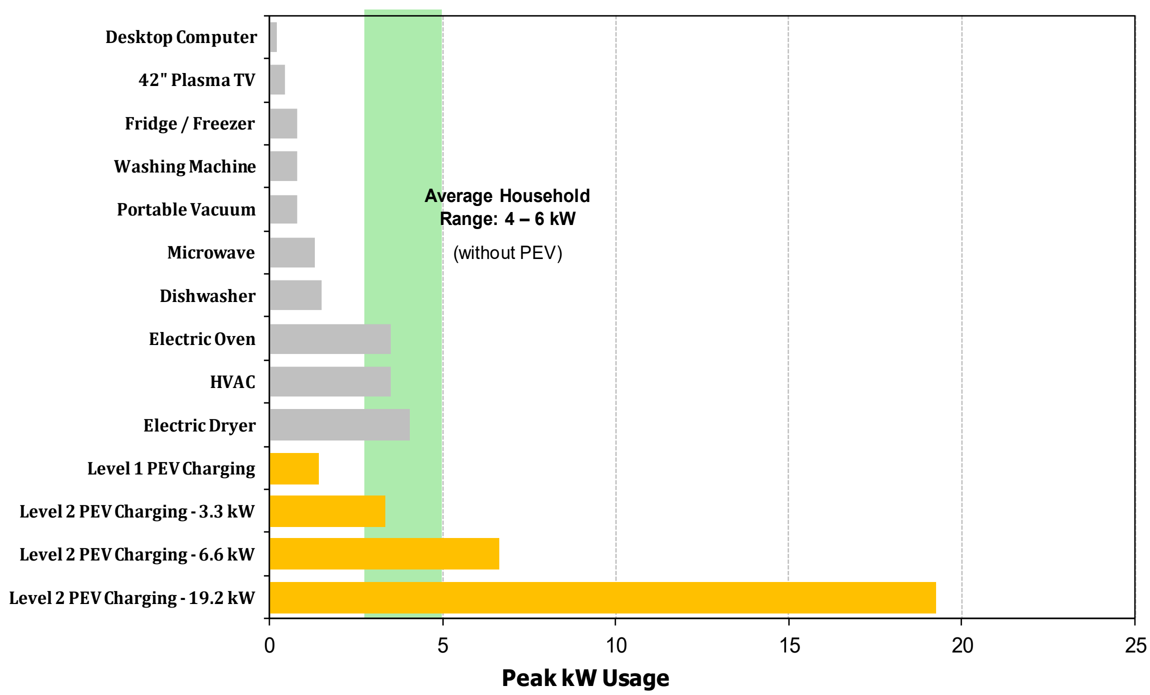

Figure 1-2
PEV load comparisons with typical household appliance loads

Accordingly, increased customer adoption of PEVs on the distribution system has raised a variety of potential system impact concerns, as well as the need for future advanced operations, such as controlled charging strategies, V2G (discharging), and provision of ancillary services.

Customer Charging Habits

The project team modeled PEV demand based on likely customer behavior. The team derived likely customer charging behavior from U.S. driving pattern data from the 2001 National Household Travel Survey [3]. Assuming customers with no incentive to do otherwise will plug-in the vehicle when arriving at their residences, residential customer home arrival time data is used to generate PEV interconnection time probabilities. The resulting customer PEV charge time probability distribution used for the stochastic analysis is shown in Figure 1-3. The analysis examines a simple case, charging once per day at home, as soon as the driver arrives home. This represents the arrival time for the longest dwell time and does not account for multiple home arrival times per day. General features of this distribution to note include:

- Customers arrive at home throughout the day, although the highest rates of home arrival (12%) unsurprisingly occur during the peak hours of residential electricity use between 5-6 pm.
- Over 70% of vehicles arrive at home by 8 pm, and nearly 50% of home arrivals occur between 3-7pm.
- The probability distribution contains a 14% chance that vehicles remain stationary (are not driven) during the day. Hence, the cumulative frequency in Figure 1-3 does not reach 100%.

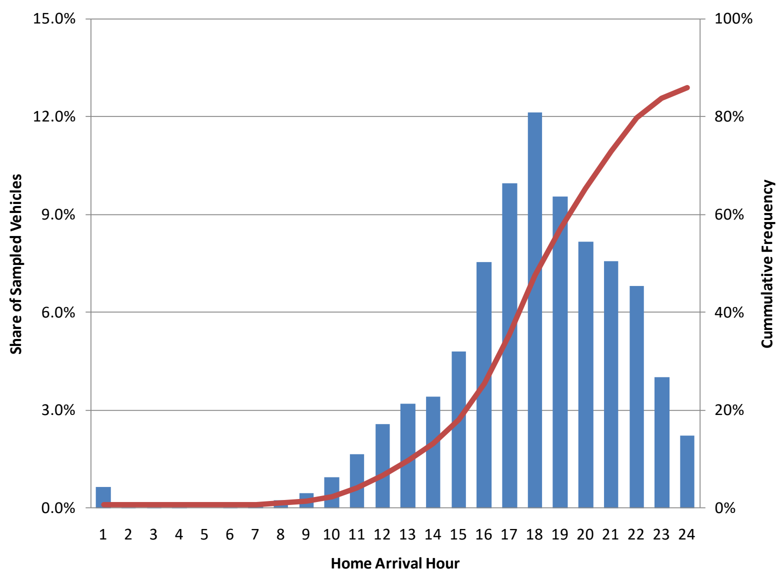

Figure 1-3
Customer home arrival times

Battery State of Charge

The team also obtained typical daily driving distances from the National Household Travel Survey. For each possible home arrival time, a joint probability is derived for the associated miles driven that day. Assuming a fixed depletion rate and battery size, the amount of energy required to recharge the battery is tied to the associated miles driven. The probability distribution in Figure 1-4 shows the relationships between projected home arrival times and miles driven. General features of this distribution to note include:

- Early morning arrival times coupled with long miles are unlikely.
- Seventy-four percent of trips are less than 40 miles a day.
- Thirty-six percent of vehicles are driven less than 20 miles per day.

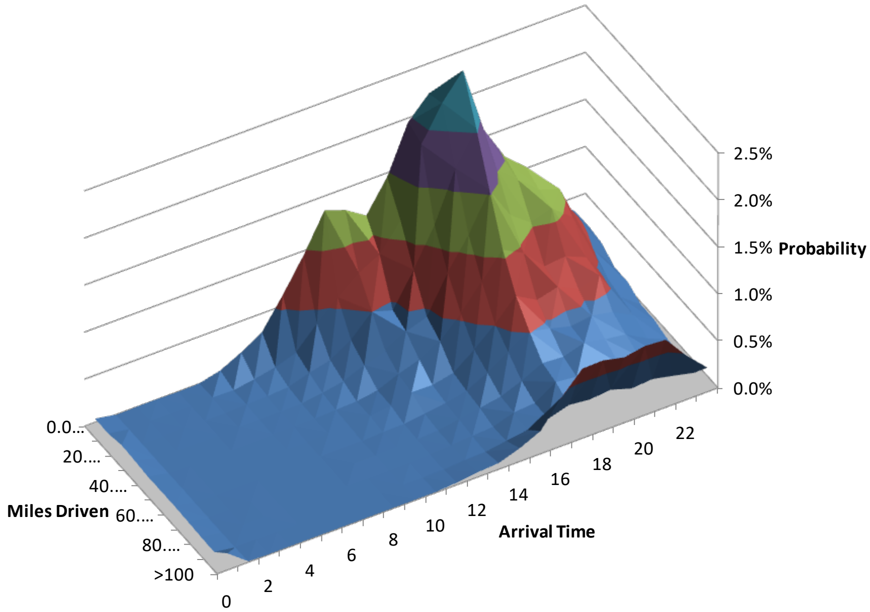

Figure 1-4
Joint probability relationship between arrival time and miles driven

PEV Demand Characteristics and Projection Sensitivity Evaluations

In this subsection, probabilistic examinations of PEV demand are performed to gain a further understanding of the temporal and spatial diversity inherent to PEV load. The evaluations also demonstrate the potential application of a probabilistic approach for future impact evaluations.

General findings for this section include:

- Home arrival time (considered to be the uncontrolled charging start time) has the largest influence on the total and worst-case PEV demands.
- The maximum total PEV demand may be between 0.43 - 0.94 kW/PEV, depending on the makeup of the PEV fleet.
- The worst-case PEV demand, for assets serving less than 30 customers, is more sensitive to the charge level than overall PEV penetration.

Demand for a Single PEV of Unknown Type

Given the complexity of the factors influencing the PEV load profiles—both probabilistic as the physical characteristics—the team used a Monte Carlo analysis to determine the probability distribution of the demand from a single PEV of unspecified type. To achieve an acceptable estimate of the distribution, 30,000 random daily charging profiles were generated and used to create histograms for the PEV charging at each hour of the day. A large number of simulations were required to ensure that a sufficient number of non-zero charging values were generated across each hour. Note that weekdays and weekends or seasonality is not represented. Similar analyses could be performed for these cases through the specification of associated vehicle usage probability functions.

Letting the random variable *B* be the demand per PEV, the probability distribution for the demand for a single PEV—of unknown type—at hour *h* is designated $p(b; h, n = 1)$. Unless otherwise noted, the analysis examines the results only for the peak hour (hour 17 or 5 pm), and the variable "*h*" will be subsequently dropped from the notation.

In this analysis, the home arrival and miles driven data presented in section 3 is assumed in the analysis, along with the distribution for the various vehicular charging levels and battery sizes detailed in Table 1-1.

Table 1-1
Vehicular mix (10/40/40/10) distribution

Vehicle Type	p(Vehicle Type)
120 V – 12 A – 4 kWh	10%
240 V – 15 A – 8 kWh	40%
240 V – 30 A – 8 kWh	40%
240 V – 30 A – 24 kWh	10%

The calculated probability mass function (pmf) is provided in Figure 1-5. A few characteristics of note for the distribution are:

- Non-Gaussian
- $E[B; N=1] = \mu = 0.74$ kW/PEV
- $P(B = 0; N=1) = 0.78$
- $P(B \geq 3.6; N=1) = 0.171$

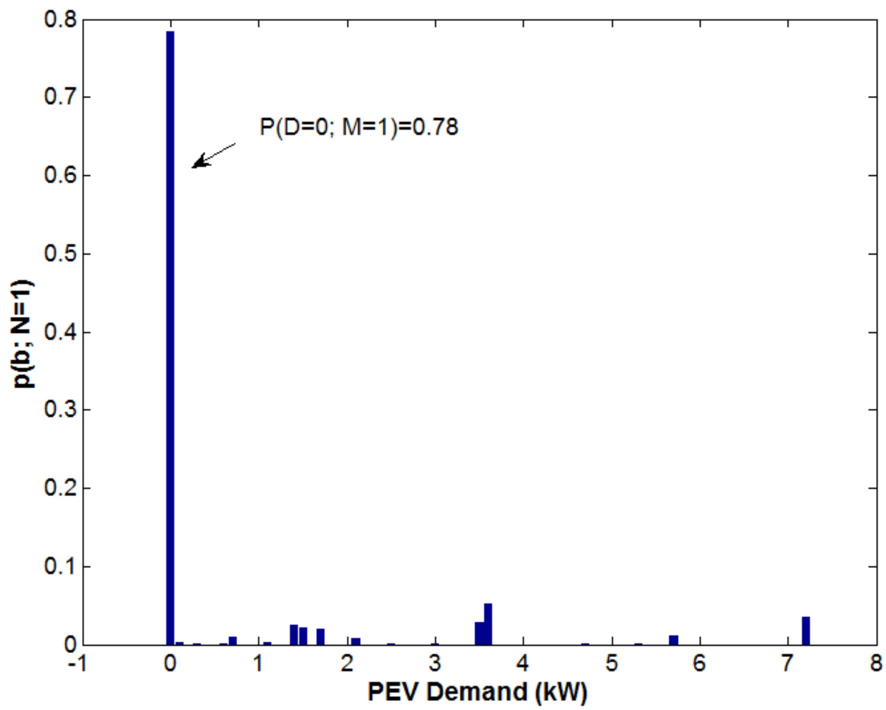

Figure 1-5
Probability mass function for single PEV demand

Given this set of PEV characteristics assumptions, approximate 20% of PEVs charge during hour 17 (typically assumed to be the peak hour for most circuits). This finding served as the basis for the conservative assumption, used in the asset analysis portion of the study, that there is a 30% probability that a PEV charges during the peak hour.

Demand for Fixed Number of PEVs

The total demand for n PEVs can be found by n summations of B as in Equation 1-1. Note that the calculation of B_n is also normalized by n to keep the variable in terms of demand “per” PEV.

$$B_n = \left(\sum_{1}^{n} B\right)/n$$

Equation 1-1

The associated probability mass function, $p(b;n)$, can therefore be determined for increasing numbers of PEVs through recursive convolutions as shown in Equation 1-2.

$$p(b;n) = p(b;n-1) * p(b;1)$$

Equation 1-2

The probability functions of $p(b;n)$ for increasing order of magnitude values of n are illustrated in Figure 1-6. It can be shown that the mean remains constant for the normalized distribution for all values of n. However, the variance decreases linearly with increasing values of n. Additionally, following the central limit theorem, the distribution takes on a Gaussian shape with sufficiently large values of n. Thus for large numbers of PEVs, the likely demand during the peak hour can be reasonably approximated using the distribution mean. Thus, for the example assumption set, the total PEV demand at the head of a feeder can be reasonably approximated using 0.74 kW/PEV.

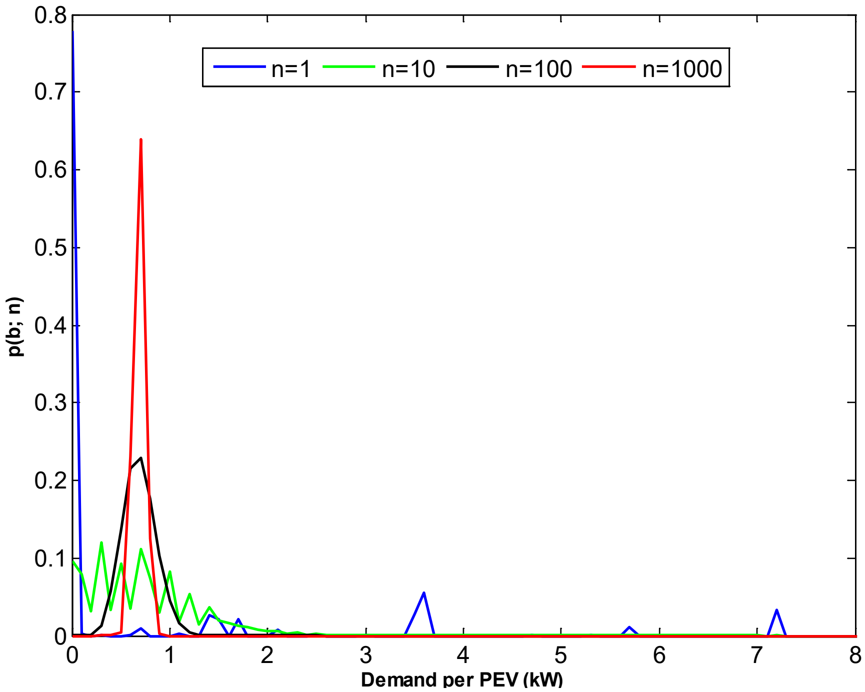

Figure 1-6
Demand per PEV probability mass functions for sample values of *n*

Instead of the variance, a common ηth percentile metric is used to examine the impact of increasing n on the nature of the distributions. High percentiles values, greater than 95%, are selected to compare conservative estimates of the maximum PEV demand expected for each n.

Percentile lines plotted in Figure 1-7 indicate the potential worst-case demand/PEV that would be expected for η^{th} percent of the cases. Note that the lines converge—along with the variance—towards the mean value as n is increased. Thus, the average demand is a useful statistic when evaluating the expected demand for a large number of PEVs, and the η^{th} percentile provides a bound for the worst-case estimates.

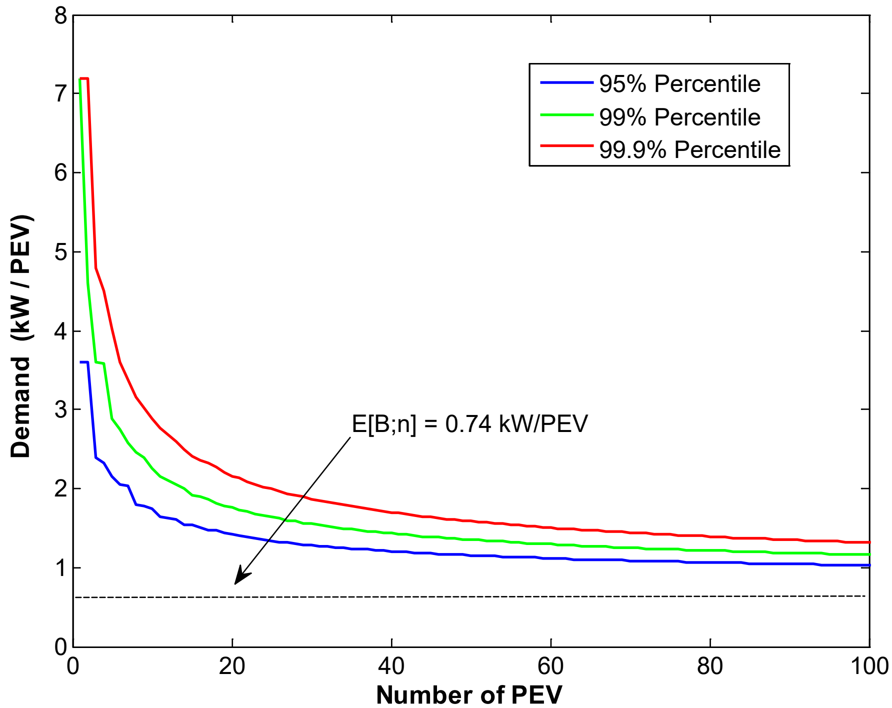

Figure 1-7
Demand per PEV percentiles

PEV Demand for a Single Residence

Letting x again denote the number of PEVs per residence and d represent the demand per residence, the probability function describing the total PEV demand for a single residence is given by:

$$p(d|x) = p(b; N = x) = \begin{cases} p(b; N = x - 1) * p(b; N = 1), & X \geq 1 \\ 1, & X = 0, D = 0 \\ 0, & otherwise \end{cases}$$

Equation 1-3

The joint probability mass function for d and x is then defined by Equation. Note that the distribution p(x) was derived in Equation 1-3, and values used in this section were taken from the example distributions provided in Table 4-1.

$$p(d, x) = p(d|x) \cdot p(x)$$

Equation 1-4

The probability mass function for d is therefore the marginal probability, where M denotes the number of residences:

$$p(d; M = 1) = \sum_{j} p(d, X = j)$$

Equation 1-5

The resulting PEV demand per residence probability distribution, assuming 8% market penetration, is plotted in Figure 1-8. As shown, the probability that a randomly selected household will have a PEV charging during the peak hour is very low. Note that this assumes no knowledge of the number of PEVs at the residence or any other indicating factors. As the probability that a residence has zero PEVs is relatively high at 8% penetration, the resulting probability that any random residence will have a PEV charging at the peak hour drops to less than 3%. A summary list of the probability distribution characteristics for the example market penetration is provided in Table 1-2.

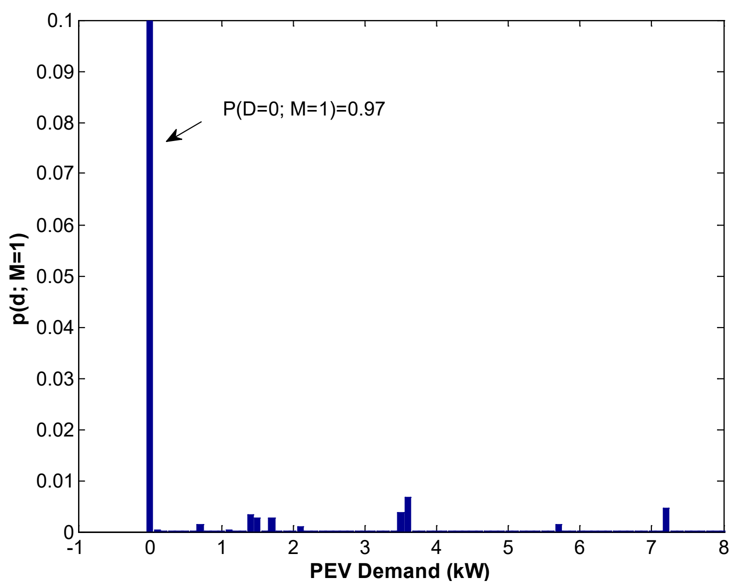

Figure 1-8
Probability mass function for PEV demand for a single residence p(b; M=1) (8% market penetration)

Table 1-2
Sample *p*(*d*; *M*=1) characteristics

Market Penetration	μ (kW)	σ	*P*(*D*=0)	*P*(*D*>3.6)
2%	0.025	0.336	0.993	0.002
4%	0.049	0.475	0.985	0.007
8%	0.099	0.671	0.971	0.013

PEV Demand for Fixed Number of Residences

For m residences, the total PEV demand per number of residences, D_m, is simply another summation of the random and normalized variables, as was done for B_n.

$$D_m = \left(\sum_{i=1}^{m} D_i \right) / m$$

Equation 1-7

The probability mass function for D_m can then be determined for every possible number of households served in the circuit (i = 1, 2, 3,…, m) through recursive iterations of the convolution of p(d) or

$$p(d; m) = p(d; m - 1) * p(d; 1)$$

Equation 1-8

As was done for the demand per PEV distributions, p(b; n), the percentiles for increasing values of m are calculated from each p(d;m). The resulting percentiles indicators are shown in Figure 1-9. These lines indicate the worst-case PEV demand per number of residences based on the level of confidence of the likelihood of occurrence. Recall that p(D=0, M=1) was 97.1% for the 8%penetration level, which accounts for the zero value shown for the 95 percentile line at m = 1. More importantly, this figure indicates that assets serving few customers have to potential to see relatively high PEV demands per residence, even though the probabilities of this occurring may be fairly low.

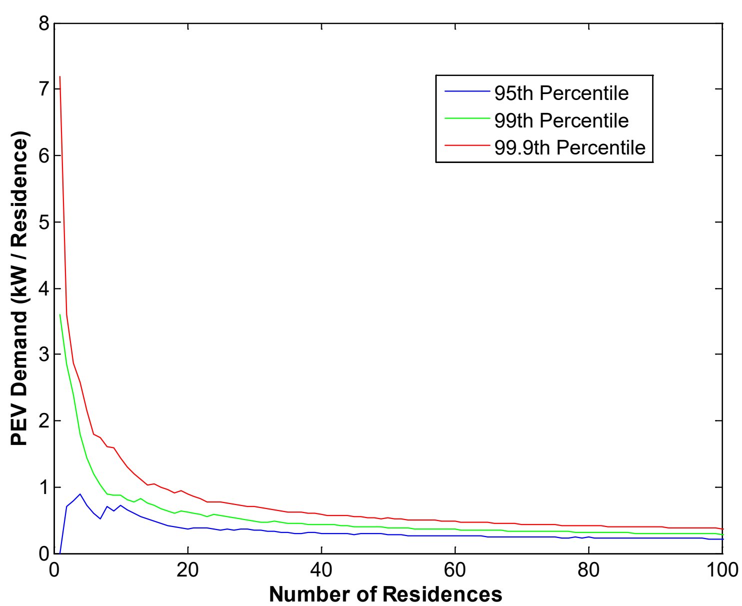

Figure 1-9
PEV demand per residence percentiles (8% penetration)

Peak Hour PEV Demand Projection Sensitivities

The change in the projected worst-case demand (specifically for the 99.9th percentile demand) given increasing PEV market penetration, is illustrated in Figure 1-10. As shown, the largest deviation in projected demands for these market penetrations occurs within the 1 < m <30 band.

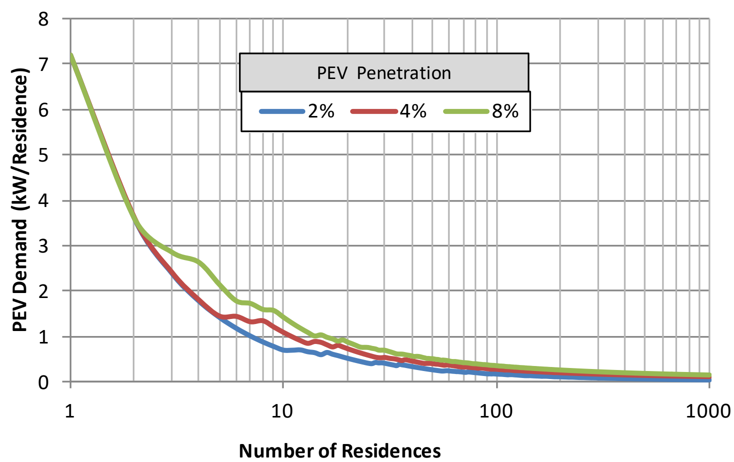

Figure 1-10
99.9th percentile PEV demand per residence at various penetrations

In Figure 1-11, the sensitivity of the percentile lines to assumed PEV type distribution is shown. In this case, 99.9th percentile lines were calculated assuming the PEVs are composed of only a single type—with a line for each potential charging rate/battery combination—or a diverse mix as previously defined by the distribution in Table 1-1. As expected, vehicles with the faster charging rates can result in higher projected PEV/residence demands for assets that serve a relatively small number of customers. In contrast, little difference can be noticed in the expected assets serving more than 100 customers, given the benefits from diversity in the charging times and durations.

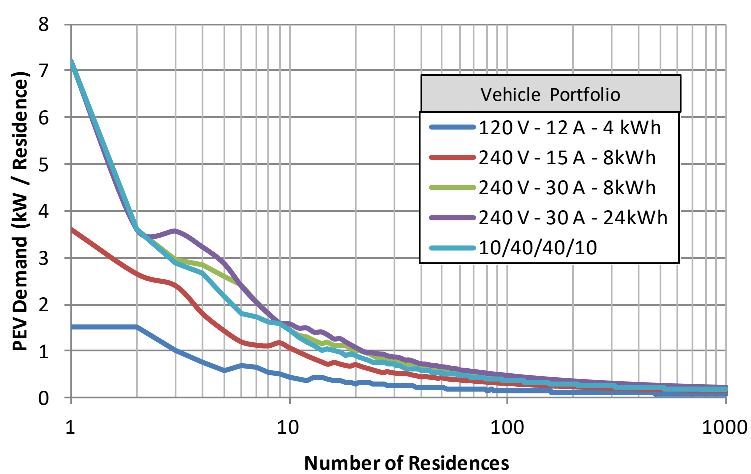

Figure 1-11
99.9th percentile for varying vehicle portfolios (8% market penetration)

Note that the assumed vehicle charging rate had a much larger influence on the 99.9th percentile projected demands in Figure 4-10 than the resulting changes across the examined penetration levels (Figure 4-9). This indicates the potential diversity benefits from lower charging rates on system impacts. For example, for assets serving between 2 to 10 residential customers, the "240V-15A-8kWh" percentile line at 8% penetration level shows a similar maximum demand projection as the mixed distribution at 2% penetration.

The projected 99.9th percentile demand lines using the full set of probabilities is compared in Figure 1-12 to the simplified projection model (used in the asset analysis and detailed elsewhere) and the projection utilizing Gaussian tables. The conservative nature of the simplified model is clearly shown by estimates that are more than twice the full diversity model projection. Additionally, the inaccuracy in the estimates when assuming the PEV demand probabilities are Gaussian is clearly shown. Conversely, the Gaussian assumption provides a reasonable and quick approximation when examining the additional loading expected on assets serving a larger number of customers, such as the substation transformer.

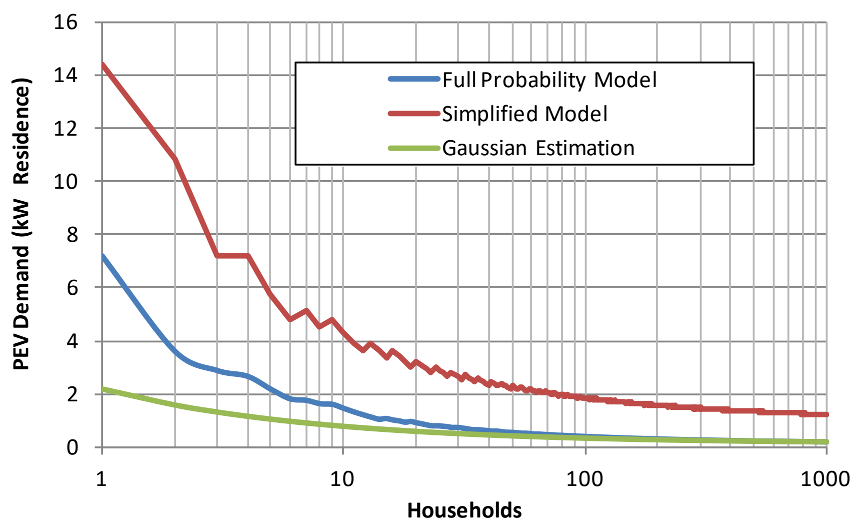

Figure 1-12
99.9th percentile demand estimate comparisons (8% market penetration)

PEV Hourly Demand Sensitivities

As EV charging is not limited to the peak hour alone, it is worthwhile to similarly examine the probabilistic projections and the associated sensitivities at other hours. The various distributions and figures developed for the peak hour can be summarily determined for other hours using the previously outlined calculations and assumptions.

The probability distributions for the demand for a single PEV are plotted in Figure 1-13 for each hour of the day. Here h is again used to represent the particular hour of the day. For example, the probability distribution for the peak hour demand for 5 pm used in the previous sections is therefore p(b; h=17, N=1). Note that the probabilities here are for a single PEV of unspecified type, but assuming the probabilistic mix case.

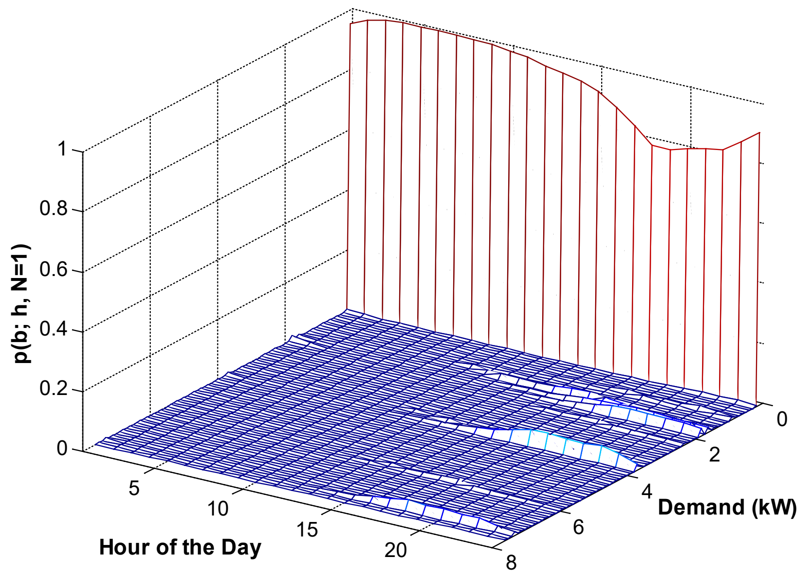

Figure 1-13
Example distributions for *p*(*b*; *h*, *N*=1)

The 99.9th percentile for each hour of the day for an increasing number of residences is plotted in Figure 1-14. As shown, the 99.9th percentile is relatively constant between 3 pm and midnight. Thus, worst-case PEV demand does not significantly change during these hours. Given residential loads are already high during these hours, adjustments to charging behavior—via charging start times and/or charging rates—are desirable in order to reduce or shift these additional worst-case demands. For example, limiting the charging to 3.6 kW—by assuming the entire fleet is of the 240V-15A-8kWh type—the resulting 99.9th percentiles, shown in Figure 1-15, display a much lower PEV demand but spread across a wider section of hours.

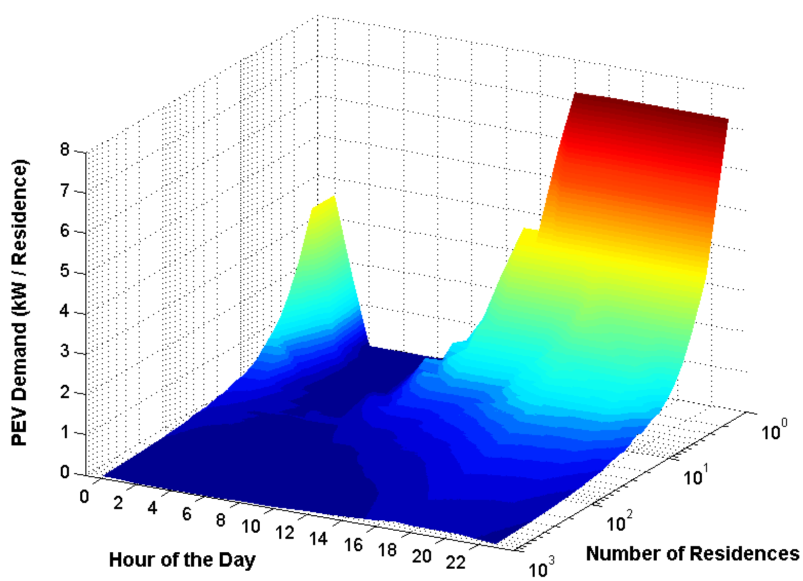

Figure 1-14
99.9th percentile PEV demand per residence and hour (8% penetration and mixed PEV portfolio)

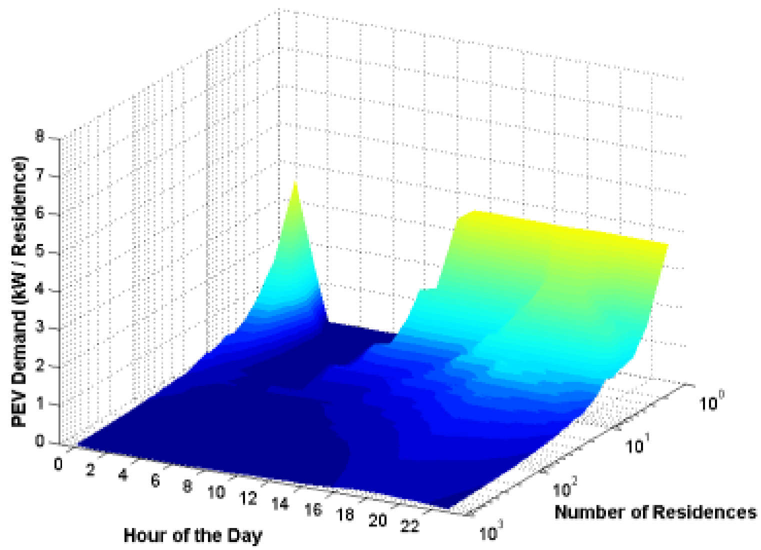

Figure 1-15
99.9th percentile PEV demand per residence and hour
(8% penetration and all 240V-15A-8kWh PEV portfolio)

While the extremes of the distribution do not change dramatically during these evening hours, as indicated by the 99.9th percentiles, the average demand per PEV exhibits much larger variations, as shown in Figure 1-15. Recall that the normalization of the probability distributions results in the mean being constant as the number of residences increases. Thus, the average demand "per residence" can be plotted independently of the number of residences, as in Figure 1-16. The average demand for m residences can then be quickly determined by scaling the results in Figure 1-16. As indicated, the majority of the uncontrolled demand is projected to occur during the later afternoon to evening hours.

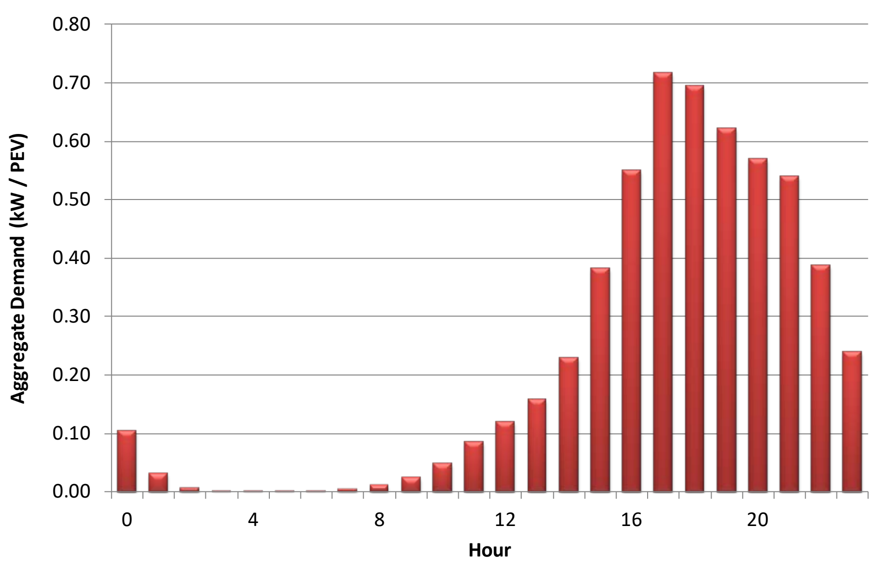

Figure 1-16
Average demand per PEV for each hour of the day (10/40/40/10 mix)

Up to this point in the estimates, a PEV portfolio consisting of a 10/40/40/10 mix (as summarized in Table 1-1) is assumed. To evaluate the sensitivity to vehicular types, the average hourly demand was calculated and plotted in Figure 1-17 for each vehicle type. Clearly, the projected average demand is also significantly influenced by battery size. Consequently, the maximum demand is expected to range between 0.43 and 0.94 kW/PEV given the selected vehicle types.

Home arrival time primarily drives the hourly variation in the average demand. While longer duration charging profiles can skew the peak PEV demand slightly, due to the overlapping of multiple PEV charging profiles, the projected peak demand is expected to be skewed only by an hour or so from the peak in home arrival times. Finally, doubling the charging rate (15 to 30A) for the 8-kWh battery size is shown to increase the average peak demand by 100 watts/PEV, or approximately 14%.

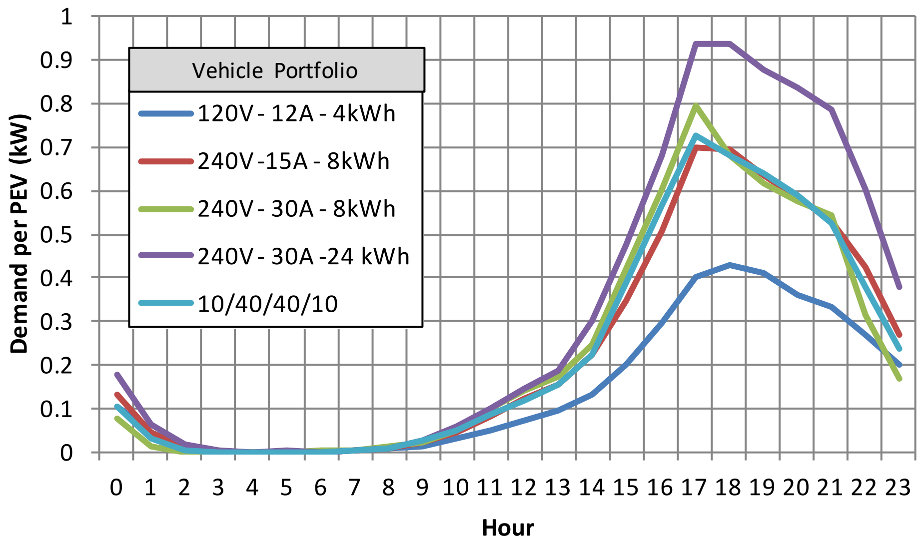

Figure 1-17
Average hourly demand per vehicle type

In Figure 1-18, the probabilities of a single PEV charging at each hour are plotted for each vehicle type, as well as assuming the vehicle mix. Note that the shorter the expected charging duration, the closer the correlation of the probability with the home arrival times as shown in Figure 1-3.

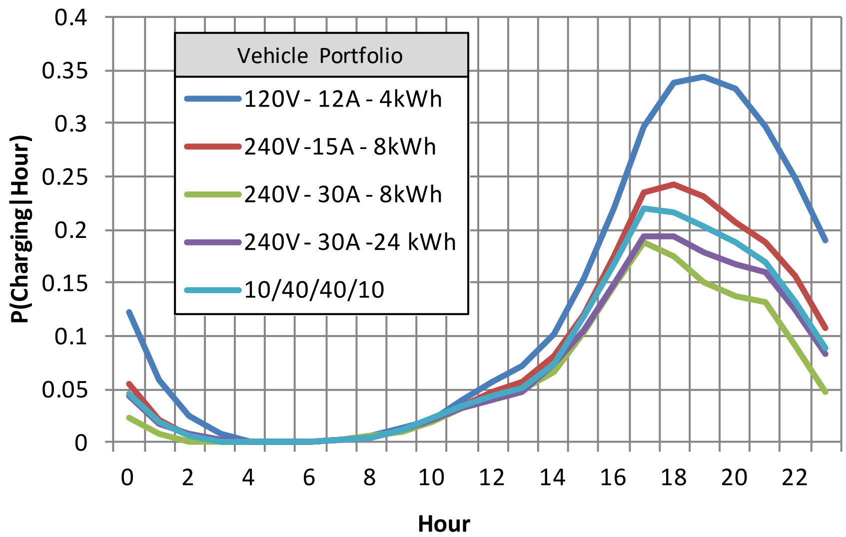

Figure 1-18
PEV charging for given hour probability mass function

For uncontrolled PEV charging, customer behavior undoubtedly has a significant impact on the expected PEV demand. While home arrival times (charging start times) and miles driven can vary somewhat between regions, small variations are expected to result in small changes to the projected demand and should be analyzed in context of the particular impact study.

In contrast, much larger changes to these values—through "smart charging" controls or other means—can have significant impacts. The team evaluated an example time-of-use (TOU) case that delays any PEV arriving home between the hours 16-20 to charging at hour 21. The bearing of this program on the worst-case loadings is illustrated in Figure 1-19. As shown, the TOU rate has the intended effect of shifting the demand, but also significantly increases the worst-case PEV loading during hours 21 and 22. The TOU rate also influences the projected average loading in a similar fashion as shown in Figure 1-20, where the maximum expected PEV demand is shown to increase over 300%—however now at hour 21. The influence of TOU and PEV are evaluated further in section 9.

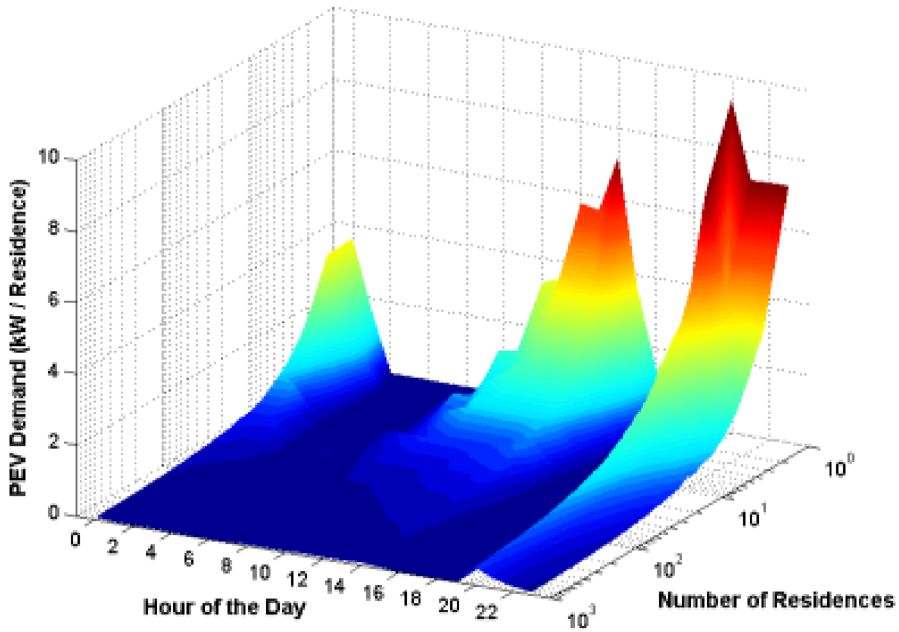

Figure 1-19
99.9th percentile PEV demand per residence and hour (TOU example case)

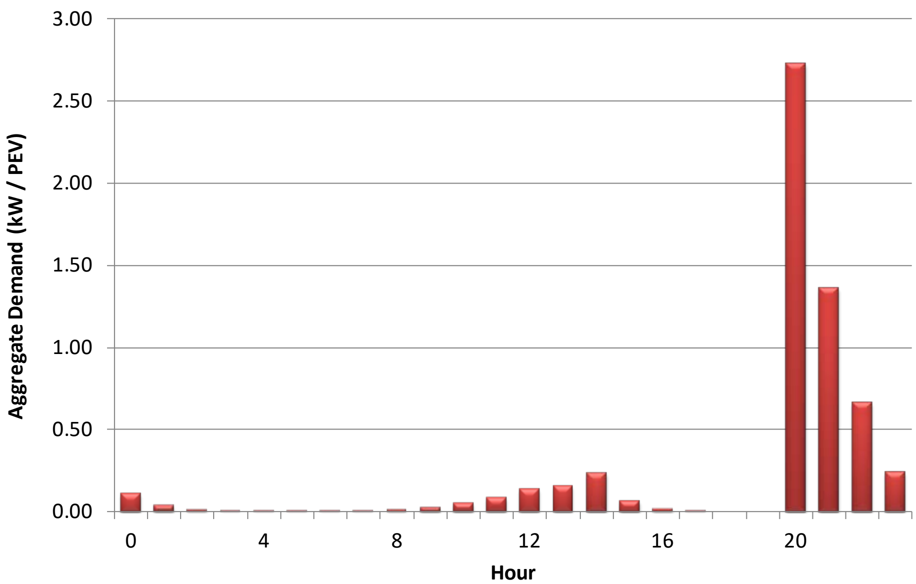

Figure 1-20
Average hourly demand per PEV for an example TOU case

2
PROBABILISTIC DEMAND PROJECTION

Using the probability distribution calculated in Equation 2-1, the probability that PEV demand for a given number of residences exceeds a specified amount can be readily calculated.

$$P(D \geq kW;\ m) = 1 - F(d; m)$$

Equation 2-1

Hence, a table of probabilities across a combination of residences and potential PEV demand can be derived, as shown in Figure 2-1, and used as a lookup table to determine the probability of PEV demand exceeding an asset's thermal ratings—given the assets available capacity and number of connected residences. In this manner, a probabilistic assessment of the potential impacts across a wide section of system assets can be determined.

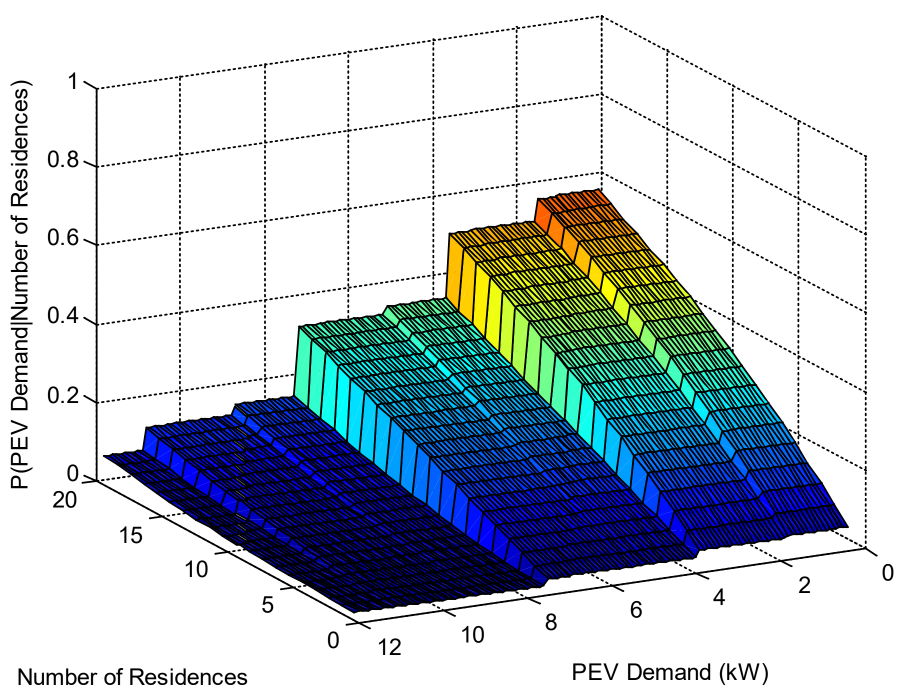

Figure 2-1
Example *P*(*D* ≥ kW; *m*) matrix

Overview of Avoided Cost Methodology

DER can either positively or negatively impact local T&D costs, depending on its location on the distribution grid as well as the timing and direction of its effect on net load. In general, DER provides benefits by reducing the loads on the T&D system at times of peak demand, thereby allowing the deferral or avoidance of T&D capacity additions. In some cases, where there are high amounts of uncontrolled distributed generation on the local system, additional DER could exacerbate the reverse flow problems in the area and trigger or accelerate the need for capacity or protection additions to accommodate the reverse flow. While this methodology discussion focuses on the deferral case, the methodology is equally applicable to the acceleration case.

3

PROJECT DEFERRAL VALUE

The deferral value of DER is the difference between the net present value of any T&D capacity projects before and after DER installation. The project costs include project upgrade capital costs ($DefValCap$), ongoing O&M costs ($DefValOM$), and impacts on losses ($DefCostTransLosses$ and $DefCostDistLosses$).

$$DefValTot[a] = DefValCap[a] + DefValOM[a] - DefCostTransLosses[a] - DefCostDistLosses[a]$$

Equation 3-1

Deferral Value of a Capital Project

$DefValCap[a]$ is the present value of capital deferral savings at the DER installation in year y. The savings are for all projects, p, that are affected by DER installed in area a.

$$DefValCap[a] = \sum_{p \in P} DefValCap[p, a]$$

Equation 3-2

where P is the set of projects that can be deferred by DER in location a

To calculate the deferral value for a single project deferred by DER in location a ($DefValCap[p, a]$), the capital cost of the project is first converted to revenue requirement costs based on the revenue requirement multiplier. The revenue requirement adjustment reflects cost increases from factors such as corporate taxes, return on and of investment, property taxes, general plant, and administrative costs. Levelized revenue requirement costs in real terms are then calculated based on the real economic carrying cost (RECC). Finally, deferral values are calculated based on the number of years deferred and the levelized revenue requirement costs.

$$DefValCap[p, a] = \sum_{yr=1}^{deferral\ years[p,a]+1} \frac{RECC[p] \times RRC_y[p]}{(1 + disc_{real}[inv])^{yr-1+OriUpgradeYr[p]- DERinstalledYr}}$$

Equation 3-3

$$RRC_y[p] = Capital_{costyr}[p] \times RRMultiplier[inv] \times Einf[inv]^{y-costyr}$$

Equation 3-4

$$RECC[p] = \frac{disc - Einf[inv]}{1 + disc} \times \frac{(1 + disc)^{blife[p]}}{(1 + disc)^{blife[p]} - (1 + Einf[inv])^{blife[p]}}$$

Equation 3-5

$$disc_{real} = \frac{1 + disc}{1 + Einf[inv]} - 1$$

Equation 3-6

where:

- $DefValCap[p, a]$ = net present value (NPV) of the deferral values in the DER installation year
- inv = investment equipment types for the project
- $Capital_{costyr}[p]$ = the capital investment in the cost year specified by users for project p
- $RRMultiplier[inv]$ = revenue requirement multiplier that adjusts the engineering cost estimate for the capital project to total revenue requirement cost levels for the types of investment. The adjustment reflects cost increases from factors such as corporate taxes, return on and of investment, property taxes, general plant, and administrative costs.
- $Einf[inv]$ (%/yr) = equipment inflation rate
- $RRC_y[p]$ = revenue requirement costs in the DER installation year y for the project p
- $RECC[p]$ = real economic carrying charge for the project p. RECC converts capital cost into an annual investment cost savings, resulting from a discrete period of deferral.
- $disc$ = nominal discount rate
- $blife[p]$ = book life of the upgrade project p
- $disc_{real}$ = discount rate net of project inflation (%/yr)
- $OriUpgradeYr[p]$ = original upgrade year for the project p
- $deferral\ years[p, a]$ = number of years that the project p can be deferred due to DER installed in the location a = deferred upgrade year–original upgrade year

Deferral Value of Avoided Incremental O&M

In addition to deferral capital investment, the deferred O&M costs also contribute to the total deferral value. $DefValOM[a]$ is the net present value of the O&M deferral saving for all projects p that are affected by DER installed in area a.

$$DefValOM[a] = \sum_{p \in P} DefValOM[p, a]$$

Equation 3-7

$$DefValOM[p,a] =$$

Equation 3-8

where:

- $DefValOM[p,a]$ = NPV of deferred O&M cost at the DER installation year
- $OMFctr[inv]$ = O&M factor for the investment type (O&M factor is the ratio of annual O&M costs to project capital costs)
- $OMesc[inv]$ = O&M escalation rate for the investment type

Deferral Cost of Transmission Losses

Finishing a new T&D upgrade project generally reduces electrical losses, generating savings from reduced energy consumption. When a T&D project is deferred, these savings are foregone. The formulae below define the cost of foregoing the efficiency improvements of T&D projects in an area a.

$$DefCostTransLosses[a] = \sum_{p \in P} DefCostTransLosses[p,a]$$

Equation 3-9

$$DefCostTransLosses[p,a] = \sum_{yr=1}^{deferral\ years[p,a]+1} \frac{AvoidedTransLosses[p, yr + OriUpgradeYear]}{(1 + dist[inv])^{yr-1+OriUpgradeYr[p]-\ DERinstalledYr}}$$

Equation 3-10

$$\begin{aligned} AvoidedTransLosses[p,y] &= AreaMWh[p,y] \times WeightedEnergyAC[y] \times \Delta LossMWh\%[p] \\ &+ AreaMW[p,y] \times AGCC[y] \times 1000 \times \Delta LossMW\%[p] \end{aligned}$$

Equation 3-11

$$WeightedEnergyAC[y] = \frac{\sum_{t \in T} EnergyAC[t,y] \times SystemLoad[t,y]}{\sum_{t \in T} SystemLoad[t,y]}$$

Equation 3-12

where:

- T = set of time steps in the year y
- $AvoidedTransLosses[p,y]$ = nominal avoided costs ($) for transmission losses at year y after the project p upgrade
- $AreaMWh[p,y]$ = energy consumption in the transmission area affected by the project p upgrade
- $EnergyAC[t,y]$ = energy avoided cost at the time step t

- ΔLossMWh%[p] = baseline area average annual loss factor minus average loss factor after the project p is completed.
- AreaMW[p, y] = the peak MW for the affected area
- AGCC[y] = the avoided generation capacity cost in $/kW
- ΔLossMW%[p] = baseline area peak loss factor minus peak loss factor after the project p is completed
- $SystemLoad[t, y]$ = system load at the time step t

Deferral Cost of Avoided Distribution Losses

Similar to transmission system losses, the team modeled energy losses on the distribution system that would be avoided with the deferred upgrade project using the following formulae.

$$DefCostDistLosses[a] = \sum_{p \in P} DefCostDistLosses[p, a]$$

Equation 3-13

$$DefCostDistLosses[p, a] = \sum_{yr=1}^{deferral\ years[p,a]+1} \frac{AvoidedDistLosses[p, y]}{(1 + dist[inv])^{yr-1+OriUpgradeYr[p]-\ DERinstalledYr}}$$

Equation 3-14

$$\begin{aligned} AvoidedDistLosses[p, y] &\\ = AreaMWh[p, y] \times WeightedEnergyAC[y] \times \mathit{\Delta} LossMWh\%[p] &\\ + AreaMW[p, y] \times (AGCC[y] + ADC[a, y]) \times 1000 \times \mathit{\Delta} LossMW\%[p] & \end{aligned}$$

Equation 3-15

$$WeightedEnergyAC[y] = \frac{\sum_{t \in T} EnergyAC[t, y] \times DistLoad[t, y]}{\sum_{t \in T} DistLoad[t, y]}$$

Equation 3-16

where:

- $DefCostDistLosses[p, a]$ = NPV deferral values at the DER installation year
- T = set of time steps in the year y
- $AvoidedDistLosses[p, y]$ = nominal avoided costs ($) for distribution losses at year y after the project p upgrade
- $AreaMWh[p, y]$ = energy consumption in the distribution area affected by the project p upgrade
- $EnergyAC[t, y]$ = energy avoided cost at time step t on year y

- $\Delta LossMWh\%[p]$ = baseline area average annual loss factor minus average loss factor after the project p is completed.
- $AreaMW[p, y]$ = peak MW for the affected area
- $AGCC[y]$ = avoided generation capacity cost in $/kW
- $ADC[a, y]$ = avoided distribution cost in $/kW for location a
- $\Delta LossMW\%[p]$ = baseline area peak loss factor minus peak loss factor after the project p is completed
- $SystemLoad[t, y]$ = distribution load at the time step t

4
ATTRIBUTION OF DEFERRAL VALUE

T&D Topology

DER systems located at location a might have impacts on multiple capacity projects located electrically upstream from location a. Flow factors and location-specific loss factors are needed to identify the impacts of DER systems on the surrounding potential upgrade projects.

Flow Factors

Flow factors represent the impact percentage of the DER project to the T&D upgrade project located in the upstream locations. For example, in Table 4-1 shows that for the DER systems installed in DPA2, 100% of its load reduction affects the T&D upgrade in DPA2. However, only 90% and 50% of its load reduction would affect the T&D upgrade projects in DPA 1 and DPA3.

Table 4-1
Flow factors: Impact of DER installation location on T&D upgrade projects

		DER installation location (a) -->		
	Flow Factors	**DPA1**	**DPA2**	**DPA3**
<--Affected T&D project (p)	DPA1	1	0.9	0.8
	DPA2	0.8	1	0.5
	DPA3	0.8	0.5	1

Loss Factors

Loss factors indicate the T&D losses between DER installation location and the potential T&D upgrade location. Note that 10% losses are entered as a 1.10 loss factor (see Table 4-2).

Table 4-2
Loss factors: Impact of DER installation location on T&D upgrade projects

		DER installation location (a) -->		
	loss factors	**DPA1**	**DPA2**	**DPA3**
<--Affected T&D project (p)	DPA1	1.1	1.12	1.15
	DPA2	1.12	1.05	1.1
	DPA3	1.15	1.1	1.05

The load impact on T&D upgrade project p by the DER systems at location a at time t is:

$$LoadReduction[p,a,t] = \frac{LoadReduction[a,t] \times FF[p,a]}{LF[p,a]}$$

Equation 4-1

Contribution of DER to Peak Load Reduction

The reduction in peak load for project p due to DER in area a, $PeakReduction[p,a]$, is given by the following formulae.

$$Peak\_after\_DER[p,a] = Max_t\left(Load[p,t] - \frac{DERNetDischarge[a,t] \times FF[p,a]}{LF[p,a]}\right)$$

Equation 4-2

$$Peak[p] = Max_t(Load[p,t])$$

Equation 4-3

$$PeakReduction[p,a] = Peak[p] - Peak\_after\_DER[p,a]$$

Equation 4-4

where:

- $Load[p,t]$ = project load at time t
- $Peak\_after\_DER[p,a]$ = project p peak load after the effects of DER in area a
- $Peak[p]$ = original peak load for project p
- $PeakReduction[p,a]$ = reduction in project p peak load due to DER in area a

Allocation of Deferral Project Value to a DER

Deferral value attributed to DER located in area a is based on expected reductions during peak load times. This method assumes that deferral is achieved for a project, and that DER in each area contributes to the deferral. Given the full value of a deferral project ($DefValTot[p]$), the value allocated to DER in area a ($DefValTot[p,a]$) is proportional to the ratio of DER peak reduction provided by DER in area a for project p to the total reduction needed for project p, such that $DefValTot[\ a] = \sum_p DefValTot[p,a]$.

$$DefValTot[p,a] = DefValTot[p] \times \frac{PeakReduction[p,a]}{kWNeeded[p]}$$

Equation 4-5

where:

- $DefValTot[p]$ = total deferral value of a project p
- $kWNeeded[p]$ = peak load reduction needed to successfully execute the deferral project p

5
GRID AND RATEPAYER BENEFITS OF DISTRIBUTION-AWARE V2G

Introduction

The project team analyzed the potential benefits of distribution-aware V2G for the electric grid and California ratepayers. This section describes the approach used to quantify the potential benefits of V2G compared to smart charging (V1G) and unmanaged charging and summarizes the findings and policy recommendations. The benefits are calculated based on the demonstration of a fleet of vehicles at the University of California, San Diego (UCSD) campus.

One of the team members, E3, has developed a Solar + Storage dispatch optimization and valuation tool for the California Energy Commission (CEC) under Electric Program Investment Charge (EPIC) project EPC-17-004. The Solar + Storage tool quantifies the value of solar, storage, and other DER, including local distribution system benefits with the local net benefits analysis (LNBA) approach developed for utilities to use in the California Public Utility Commission (CPUC) Distribution Resource Plans Proceeding R.14-08-013[1]. The V2G benefit analysis is performed by representing a fleet of PEVs as a dispatchable resource in the Solar + Storage tool (modeling approach). The PEVs are modeled with three dispatch approaches: unmanaged charging, smart charging (V1G), and V2G under a variety of use case scenarios. The use case scenarios range from simpler cases, where the PEVs provide only system and distribution capacity grid services, to more involved cases that also engage in energy arbitrage and ancillary services. Both base and high values are modeled for each use case, and the PEVs are modeled as dispatched either to maximize utility grid benefits or reduce customer bills (dispatch behavior or price signals).

The benefit values are developed using the 2018 Avoided Cost Calculator (developed by E3 for the CPUC,) most recently updated in June 2018 [4]. The technology to enable smart charging and V2G is nascent and rapidly developing, and costs are not yet well established. Therefore, the results presented here are the potential benefits of V2G for the electric grid and California ratepayer. The net benefits are calculated as the net of the market revenues and grid benefits minus the costs of delivered energy to charge the PEVs for each use case. No costs for PEV, EVSE, or V2G enabling technology are included. The results are summarized as the incremental net benefits of smart charging relative to unmanaged charging, and of V2G relative to smart charging (net benefits of V2G). The potential benefits are scaled up for the forecasted California PEV population in 2030 to estimate potential benefits for all California ratepayers (benefits to

[1] More information on Local Net Benefits Analysis (LNBA) for distribution resources plans available at: https://drpwg.org/sample-page/drp/

California ratepayers). Findings and policy recommendations are presented in the final section (conclusions and recommendations).

Modeling Approach

Randomized EV Driving Patterns

The CEC Solar + Storage model used for the analysis takes one year of hourly or sub-hourly time series data as an input for driving behavior, consisting of vehicle location and the energy discharged from the battery during driving. This one-year driving activity profile is then used for all years through the modeling period. When and where an EV is available to connect to the grid strongly impacts the potential costs and benefits of V2G or smart charging technology. It is therefore crucial that driving patterns used to simulate V2G charging and discharging are representative of typical commuting behavior. Finding a complete year of historical data for a real driver that provides a reasonable representation of the wider driving population is challenging. This is further complicated when modeling vehicle fleets where multiple such datasets are needed and diversity in driving patterns is important. Furthermore, given the impact of driving patterns on the results, the ability to perform sensitivity analysis by systematically tweaking driving pattern input data is important. Therefore, a randomized EV driving pattern algorithm was developed that uses probability distributions to generate the required time series input data.

The EV driving pattern algorithm was used to generate location and driving power discharge data for all five EVs at 15-min intervals for an entire year. The probability distributions used for random generation were garnered from the National Household Travel Survey (NHTS) (ref - 2017 NHTS https://nhts.ornl.gov/). The NHTS dataset was collected from 129,112 household surveys from all 50 states across the U.S. (pg. 4 dataset guide) and includes 923,572 trips. These trips were filtered depending on the analysis. For example, to obtain probability distributions for the time of leaving home for work, only trips by car from home to work were analyzed. Figure 5-1 provides a visual representation of how the algorithm operates and its built-in probability distributions.

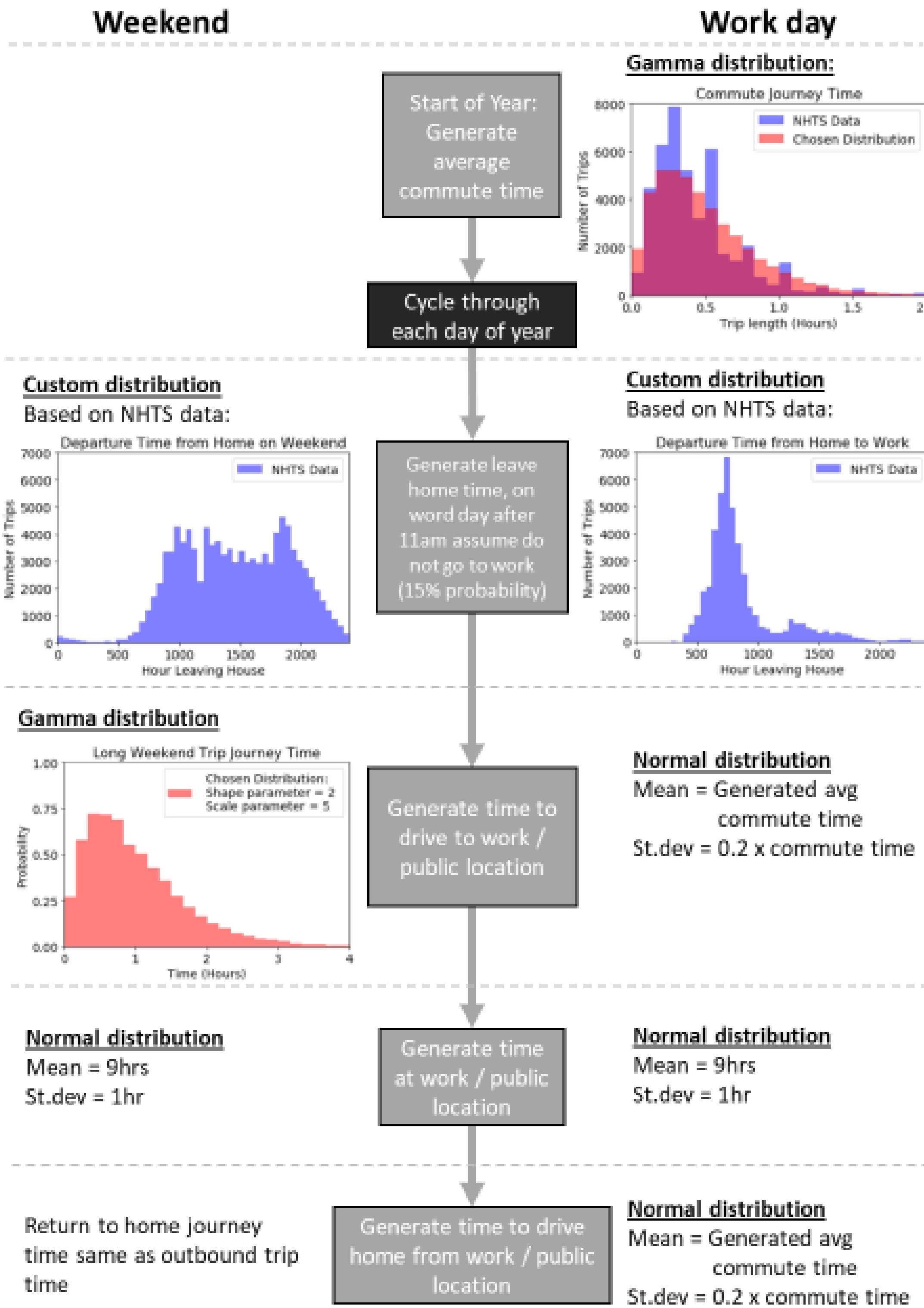

Figure 5-1
Visual representation of the random EV driving pattern algorithm

Using a randomized approach rather than real historical driving patterns requires some simplifying assumptions. Each day is modeled separately, which means that drivers will always be at home by midnight of that day. Drivers only travel to work on weekdays and spend 9 hours on average per day at work. Drivers that do not leave the house before 11am on a weekday stay at home all day, which based on NHTS data, has a 15% probability of occurring. Weekday trips involve only commutes to and from work, so no other trips are modeled. On weekends, 1–2 long trips are simulated to a public location with no charging rather than many smaller individual trips. No public holidays or vacations are included. The power discharged from the battery to the engine when driving, or "driving discharge" time series, is created by assigning an average power value to each 15-minute time step when driving. This average power value is the same for every time step and assumed not to vary based on driving distance, style, terrain, etc.

Table 5-1 provides high-level statistics for each of the five EV profiles generated.

Table 5-1
Summary of driving activity profiles for each EV

	EV 1	EV 2	EV 3	EV 4	EV 5
Total Hours at Home	6,105	6,204	6,334	5,521	5,559
Total Hours at Work	1,981	1,951	1,849	1,954	2,022
Total Hours Driving	333	265	233	949	841
Total Energy Consumed by Driving (kWh)	3,324	2,644	2,325	9,461	8,383
Average commute time - one way (hrs)	0.39	0.27	0.17	1.58	1.34
Average time spent at work (hrs)	8.93	8.79	8.34	8.81	9.11

The main difference in behavior across each of the EVs is the commute length, which causes the broad variation in total energy consumption seen across the fleet. The impact of charging behavior and the relative benefits and costs of V2G is discussed later in the report.

Avoided Cost Methodology

The benefits of V2G are calculated using the 2018 CPUC avoided costs. The avoided costs include the six components shown in Table 5-2.

Table 5-2
Components of electricity avoided cost

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy
Generation Capacity	The costs of building new generation capacity to meet system peak loads
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads
Monetized Carbon (cap and trade)	The cost of cap and trade allowance permits for carbon dioxide emissions associated with the marginal generating resource
GHG adder	The difference between the CPUC-adopted total value of CO_2 and the cap and trade value of CO_2.
Avoided RPS	This component has been set to zero.

Each of these avoided costs is determined for every hour of the year. The hourly granularity is obtained by shaping forecasts of the average value of each component with historical day-ahead and real-time energy prices and actual system loads. Table 5-3 summarizes the methodology applied to each component to develop this level of granularity.

Table 5-3
Summary of methodology for electricity avoided cost component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Forward market prices and the $/kWh fixed and variable operating costs of a combustion turbine combined-cycle (CTCC)	Historical hourly day-ahead market price shapes from Market Redesign and Technology Upgrade (MRTU) Open Access Same-time Information System (OASIS)
Generation Capacity	Residual capacity value a new simple-cycle combustion turbine	RECAP model that generates outage probabilities by month/hour and allocates the probabilities within each month/hour based on 2017 weather
Ancillary Services	Percentage of generation energy value	Directly linked with energy shape
T&D Capacity	Marginal T&D costs from utility ratemaking filings.	Hourly 2017 temperature data by climate zone

Table 5-3 (continued)
Summary of methodology for electricity avoided cost component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Monetized Carbon (cap and trade)	CO_2 cost forecast from revised 2017 the CEC Integrated Energy Policy Report (IEPR) mid-demand forecast, escalated at inflation beyond 2030	Directly linked with energy shape with bounds on the maximum and minimum hourly value
Greenhouse Gas (GHG) Adder	Difference between total value of CO_2 and monetized carbon cost in the energy market prices	Same as monetized carbon
Avoided Renewable Portfolio Standard (RPS)	Set to zero to be consistent with GHG adder	NA

Figure 5-2 shows a three-day snapshot of the avoided costs by component in Climate Zone 4. As shown, the cost of providing an additional unit of electricity is significantly higher in the summer afternoons than in the very early morning hours. This chart also shows the relative magnitude of different components in this region in the summer for these days. The highest peaks of total cost shown in Figure 5-2 of over $20,000/MWh are driven primarily by the allocation of generation and T&D capacity to the peak hours (because of high demand in those hours), but also by higher energy market prices during the late afternoon and early evening.

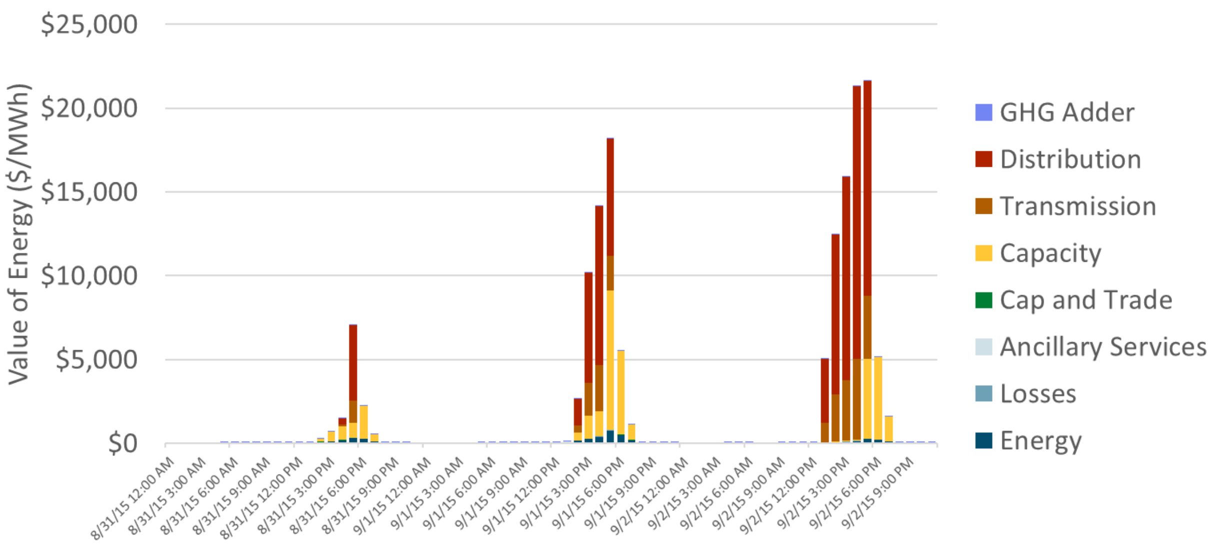

Figure 5-2
Three-day snapshot of energy values in Climate Zone 4 (CZ4) in 2015 (Pacific Standard Time)

Figure 5-3 shows the average monthly value of electricity reductions, revealing the seasonal characteristics of the avoided costs. The energy component dips in the spring, reflecting low energy prices due to increased hydro supplies and imports from the Northwest. The energy component peaks in the summer months when demand for electricity is highest. The value of capacity—both generation and T&D—is concentrated in the summer months and results in significantly more value on average in these months.

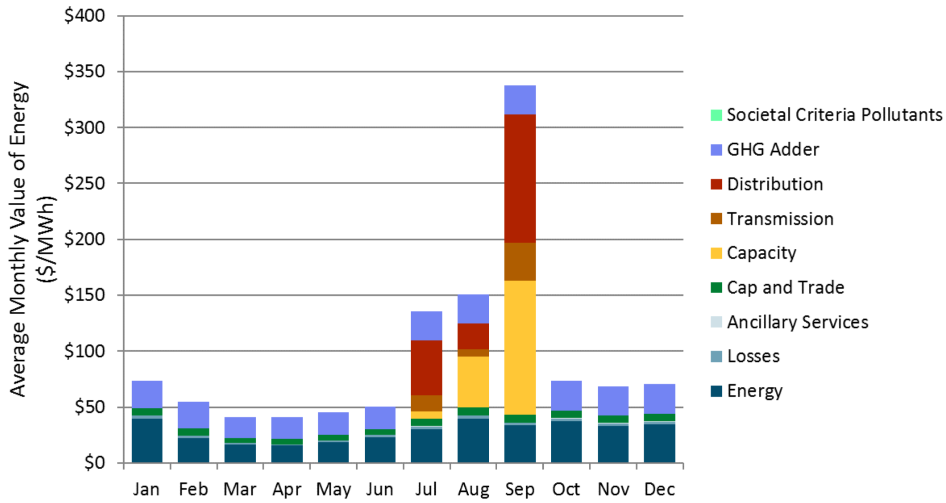

Figure 5-3
Average monthly avoided cost in CZ4 in 2018 (societal criteria pollutants have zero value, consistent with the 2017 update)

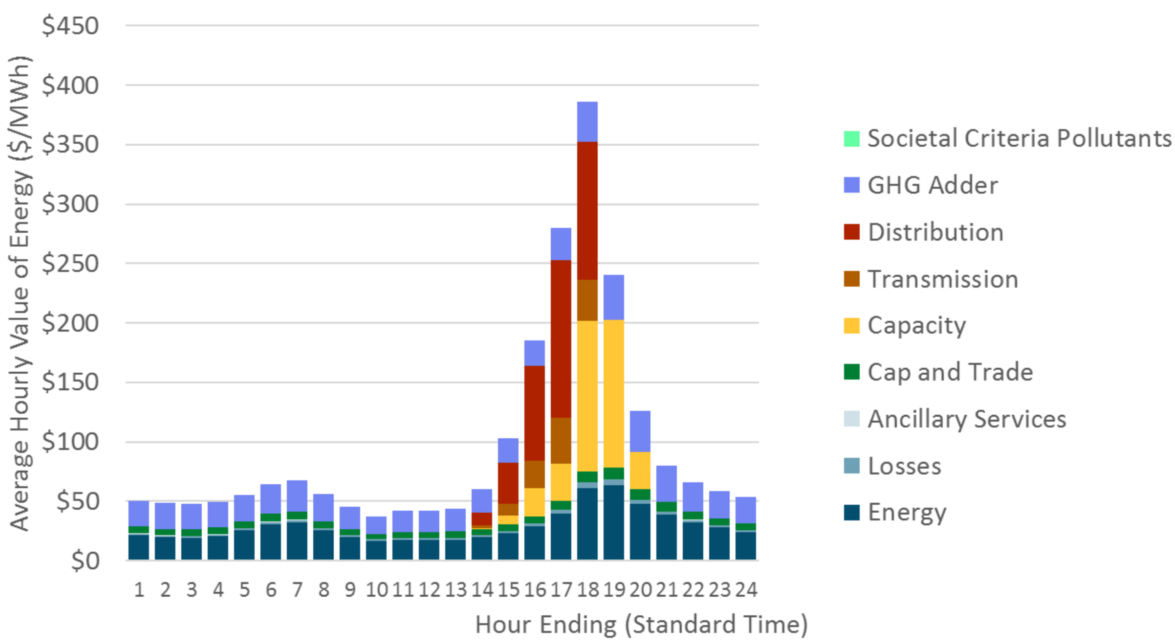

Figure 5-4
Average monthly avoided cost in CZ4 by hour of the day in 2018 (societal criteria pollutants have zero value, consistent with the 2017 update)

CAISO Energy and Ancillary Service Market Revenues

In place of the energy prices from the 2018 Avoided Cost Calculator Update, system planning cases from the CPUC Integrated Resources Planning (IRP) proceeding are used to develop hourly energy and ancillary service prices. With resource portfolios from the IRP cases, the AuroraXMP production simulation model is used to produce energy and ancillary service prices for a base and high value case for V2G. The reference plan designed to limit statewide GHG emissions to 42 million metric tons (42 MMT) is used for the base case (see Figure 5-5). Cases with more aggressive GHG and RPS targets produce more volatile market prices that provide higher revenues for flexible resources such as energy storage and V2G-enabled PEVs. A CPUC IRP scenario achieving an 80% RPS is used to develop hourly prices for the high value case (see Figure 5-6).[2] Note that the negative prices during the middle of the day and the high prices in the evening compensate flexible resources for reducing the evening ramp.

	Hour																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	54.55	53.91	54.76	54.70	54.23	54.32	55.54	55.98	55.93	50.54	50.16	50.92	50.25	47.47	42.92	49.01	51.92	52.89	55.94	54.64	54.19	54.41	55.96	55.39
2	51.67	52.02	52.01	51.55	51.60	51.83	53.87	54.15	52.10	43.31	39.58	39.03	39.10	39.95	37.07	40.50	49.67	50.90	53.08	53.40	52.29	51.04	52.86	51.50
3	48.43	47.91	47.61	47.63	47.41	47.87	49.10	49.01	37.50	33.93	30.38	20.97	19.35	27.16	28.61	34.70	44.12	47.98	48.98	49.50	49.65	49.49	48.85	48.13
4	42.35	42.91	42.97	42.70	42.40	43.14	43.69	36.22	27.46	23.45	20.36	4.09	-2.32	11.41	24.31	32.02	37.81	44.13	46.73	46.54	46.47	46.56	46.41	43.83
5	42.15	42.57	42.44	42.44	42.45	42.86	41.66	31.41	21.33	20.21	17.26	16.05	16.96	18.10	24.73	31.22	34.32	42.16	45.06	45.87	45.66	46.49	46.76	43.48
6	45.15	45.93	45.98	45.90	45.14	45.15	43.20	38.85	30.47	28.79	26.33	21.45	22.31	24.90	32.23	34.95	42.26	48.10	50.12	48.42	47.35	49.71	49.60	45.47
7	49.38	49.86	50.59	50.31	51.60	52.87	48.33	44.28	38.90	36.17	35.61	35.44	34.72	35.22	41.21	44.10	47.59	51.18	53.84	53.42	50.89	52.72	51.86	50.41
8	53.44	53.09	52.51	51.42	52.14	52.25	50.87	44.99	38.58	37.64	37.01	36.29	37.48	37.01	43.42	46.16	49.10	54.80	56.96	54.62	51.93	53.97	53.80	52.25
9	52.61	52.31	51.28	50.12	50.51	51.22	50.32	45.33	39.61	38.39	35.85	36.48	36.50	38.03	43.22	47.12	50.07	55.03	54.94	53.82	54.99	55.30	53.88	52.94
10	49.41	49.14	48.40	47.90	48.07	49.05	50.66	49.81	39.49	39.51	34.44	34.23	34.37	36.71	40.92	45.72	49.15	50.85	52.71	53.36	52.29	52.89	51.44	49.54
11	50.74	50.87	51.70	51.61	51.44	51.33	52.04	50.98	45.54	43.55	43.10	40.24	39.31	38.56	40.92	47.23	50.26	50.85	52.20	51.67	51.38	52.23	52.14	51.37
12	54.77	54.62	54.04	53.46	53.45	53.04	54.35	54.87	55.22	52.71	53.53	51.31	48.50	46.95	44.02	49.76	50.81	53.44	55.59	54.94	55.45	54.35	55.46	55.16

Figure 5-5
Average hourly energy prices in 2030—base case

	Hour																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	42.26	42.65	44.15	45.26	45.88	46.92	44.20	45.59	50.18	36.22	22.99	19.80	20.50	20.27	24.99	35.29	41.22	41.00	40.26	39.33	39.75	40.02	40.79	42.30
2	42.19	42.86	44.01	44.42	44.90	44.32	44.58	43.22	38.69	26.16	-0.17	-7.78	-8.07	-8.56	-8.32	20.98	36.97	37.85	38.49	38.91	38.86	41.08	42.65	42.60
3	37.14	37.94	37.91	37.52	36.71	36.01	34.59	35.18	15.95	0.53	-28.74	-30.00	-30.00	-30.00	-30.00	-17.12	25.71	32.14	33.55	34.93	34.57	35.03	36.99	37.17
4	31.40	30.43	31.19	31.20	29.66	30.89	26.57	19.79	0.58	-24.58	-30.00	-30.00	-30.00	-30.00	-30.00	-30.00	14.60	20.26	29.52	28.67	31.48	33.33	36.46	34.42
5	30.01	30.01	28.27	26.91	26.39	24.63	25.40	10.12	-1.49	-13.75	-14.67	-24.44	-22.88	-16.91	-9.36	-1.57	23.03	23.42	33.48	30.48	30.85	36.80	42.87	34.74
6	39.43	38.03	38.68	38.62	38.63	38.04	34.96	28.01	16.61	-0.11	-8.55	-16.69	-21.32	-22.23	10.58	19.66	28.80	30.46	40.77	42.29	37.66	40.51	45.99	40.80
7	46.48	47.44	47.84	47.89	47.80	48.79	42.31	34.50	20.17	18.27	17.55	9.41	0.28	6.70	28.47	37.61	43.38	53.65	69.86	64.66	54.89	51.13	52.89	47.58
8	52.62	52.21	52.34	51.59	51.12	51.25	48.87	36.59	21.26	19.60	7.74	-5.96	-7.01	2.40	30.41	43.01	44.40	64.91	82.78	75.45	60.48	62.87	62.23	51.45
9	54.22	52.46	49.61	46.70	47.38	48.33	49.81	35.89	20.28	12.84	-2.06	-6.09	-7.51	-3.49	25.09	37.51	48.83	78.91	75.23	63.94	64.11	58.06	57.81	54.96
10	47.01	46.90	45.81	45.12	43.01	44.49	52.31	42.04	13.29	-0.05	-22.96	-25.67	-25.85	-18.75	20.61	37.70	54.40	71.15	79.24	67.13	56.06	52.97	48.31	48.79
11	43.81	43.42	43.25	43.31	43.59	43.80	46.82	46.48	26.54	16.28	-3.50	-13.00	-6.97	-2.71	25.09	38.58	44.28	44.17	43.90	43.09	45.52	47.51	48.79	44.30
12	42.92	43.35	44.12	45.57	45.58	45.32	42.94	45.15	45.34	36.75	28.50	27.39	27.29	30.21	34.07	40.56	45.41	46.20	44.24	43.77	42.25	42.73	44.70	43.41

Figure 5-6
Average hourly energy prices in 2030—high value case

The relationship of frequency regulation prices to energy prices are illustrated by season in Figure 5-7 and Figure 5-8. For the base case, these relationships are based on current market conditions when fossil fuel plants are often on the margin. For the high value case, the team envisions a regime where energy storage is the dominate resource for frequency regulation. This substantially reduces the potential market revenues from ancillary services relative to energy markets.

[2] Details on the 42 MMT reference plan and additional sensitivities, including the 80% RPS case are available at: http://cpuc.ca.gov/irp/proposedrsp/

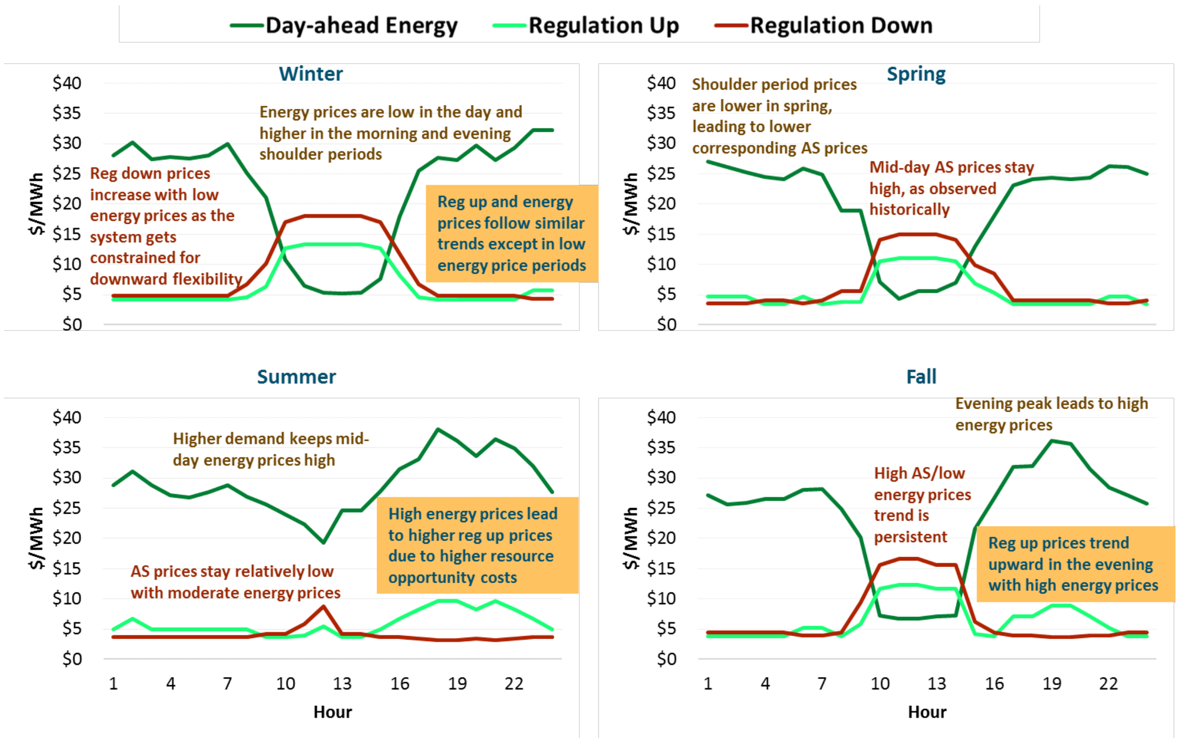

Figure 5-7
Relationship of energy and frequency regulation prices (base case)

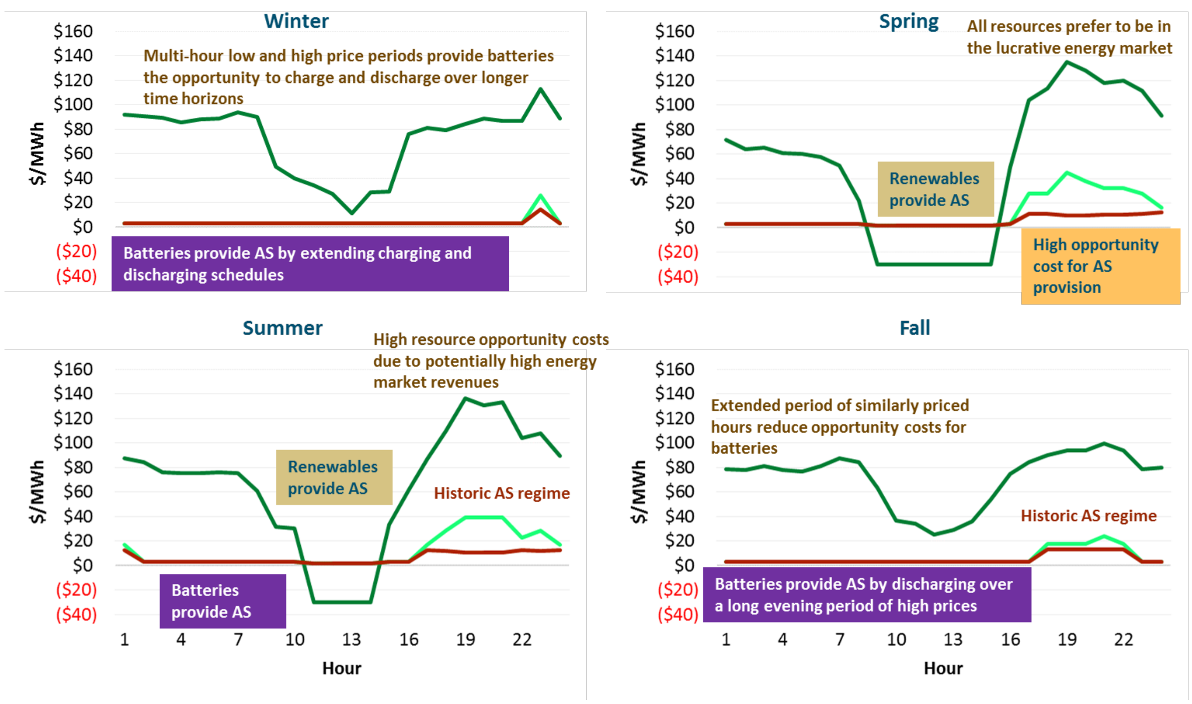

Figure 5-8
Relationship of energy and frequency regulation prices (high value case)

System Capacity Value

The CPUC Avoided Cost Calculator sets the resource balance year to 2018 by default. This represents the capacity value as the full cost of new entry (CONE) for a new combustion turbine starting in 2018. This is done to reflect the position of energy efficiency and demand response as first in the CEC "loading order" for energy resources. For the base case, the resource balance year is set to 2040. This is reflective of the actual market today, in which RPS driven procurement of renewable generation has resulted in a large planning reserve margin and relatively low prices for resource adequacy -- $36/kW-yr. for 2016-2020 [5]. Thus, for the base case, the system capacity value starts at $76/kW-yr. in 2018 and rises to $121/kW-yr. in 2030. For the high value case, with the resource balance year set at 2018, the capacity value starts at $124/kW-yr. in 2018 and rises to $144/kW-yr. in 2030.

Distribution Value

Distribution avoided costs are highly location specific. Figure 5-9 shows distribution avoided costs by planning area for the three investor-owned utilities (IOUs). A limited number of locations have a high value above $100/kW-yr., whereas most locations have a value below $50/kW-yr. For the base case, a lower value of $20/kW-yr. is used for distribution avoided cost. In the high value case, $120/kW-yr. is used.

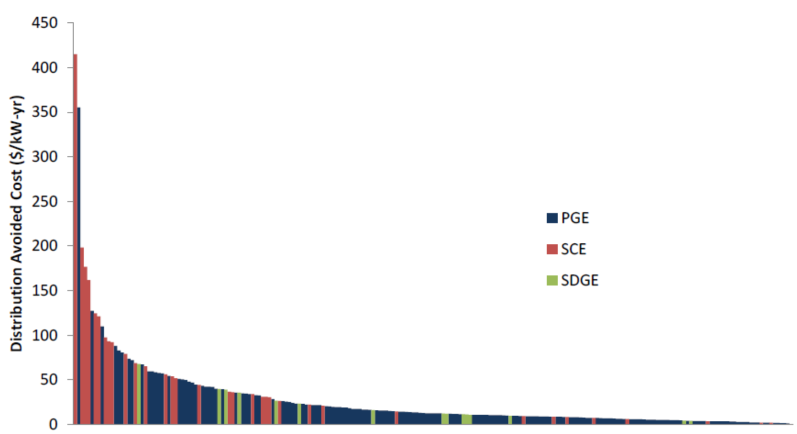

Figure 5-9
Distribution avoided costs by planning area

SDG&E Rates

Under "customer control" mode, San Diego Gas & Electric (SDG&E) rates rather than utility avoided costs are used as a price signal for EV dispatch. The SDG&E EV-TOU rate was used as the signal for home dispatch, and the SDG&E TOU-M rate was used for the work dispatch.

Vehicle and Charging Equipment Assumptions

The analysis of benefits is simplified by modeling a fleet of five PEVs using Chevy Volt (BEV) vehicle characteristics. The vehicles are assumed to have an energy of 60 kWh and a charging capacity of 6.6 kW, which is set by the capacity of an L2 charger. Vehicles have access to L2 charging at both a work location and a home location, but have no access to public charging.

Apart from the unconstrained case, EVs were modeled with a degradation factor of $0.052 / kWh discharged, which served as a deterrent to EVs taking advantage of energy arbitrage or bidding into regulation markets at any given opportunity. This served as a constraint to ensure that EVs were only discharging when the effective export rate was greater than a $0.052 / kWh degradation penalty. In addition, EVs were penalized for leaving a pre-set state of charge (SOC) range of 30–95%. The unconstrained EV case could run without any of these penalties, leading to high battery mileage, but increased revenues.

Overview of V2G Benefits

V2G grid services can provide a variety of benefits, but four benefit categories provide the bulk of the potential value.

- System capacity: Reducing net load during system peak hours
- Distribution capacity: Reducing net load during distribution peak load hours
- Load shifting: Shifting load to periods of lower cost energy and to reduce system operational costs
- Ancillary services: Providing ancillary services in California Independent System Operator (CAISO) markets

Price Signals and Dispatch Behavior

The Solar + Storage dispatch optimization and valuation tool is used to generate EV daily dispatch behavior. The PEVs are modeled with three dispatch approaches: unmanaged charging, smart charging (V1G), and V2G under a variety of use case scenarios. The use case scenarios that were modeled are listed in Table 5-4 and Table 5-5, and the dispatch charts presented later in this section highlight the differences in the three dispatch approaches under different use cases.

Table 5-4
Dispatch approaches and base cases run

Unmanaged Charging	V1G	V2G
Base Case	V1G Base Case	V2G Base Case
	Base Case + Distribution Deferral	Base Case + Distribution Deferral
		Base Case + Distribution Deferral + Ancillary Services
		Unconstrained Case

Each case provided an additional revenue stream for each of the dispatch approaches. For example, in the V2G cases, the model ran with a base case with energy arbitrage and capacity benefits as its primary revenue streams. The second case added access to distribution deferral as a revenue stream, while the third case included access to the ancillary services market. The final case was an unconstrained case where the EV had access to all of the above revenue streams and was dispatched without limitations on battery degradation or SOC.

Table 5-5
Dispatch approaches and high cases run

Unmanaged Charging	V1G	V2G
High Case	V1G High Case	V2G High Case
	High Case + Distribution Deferral	High Case + Distribution Deferral
		High Case + Distribution Deferral + Ancillary Services
		Unconstrained Case

A set of high value cases were run, with a set of more optimistic projections for capacity value, distribution deferral value, ancillary service, and energy prices. In addition, these cases were run in both customer control mode (i.e., EVs were dispatching for bill reduction), and utility control mode (i.e., EVs were dispatching to minimize utility avoided costs).

Distribution Peak Reduction

One of the primary benefits of smart charging is the ability to optimize dispatch for peak reduction. Figure 5-10 demonstrates the differences in dispatch behavior between unmanaged charging, V1G, and V2G in a high renewable world during a day with solar overgeneration and a distribution peak. The V2G case clearly provides the most value to the utility, with a net benefit of $46 relative to the unmanaged charging case and a net benefit of $35 relative to the managed charging case. The bulk of these benefits originate from peak reduction that is unique to V2G vehicles.

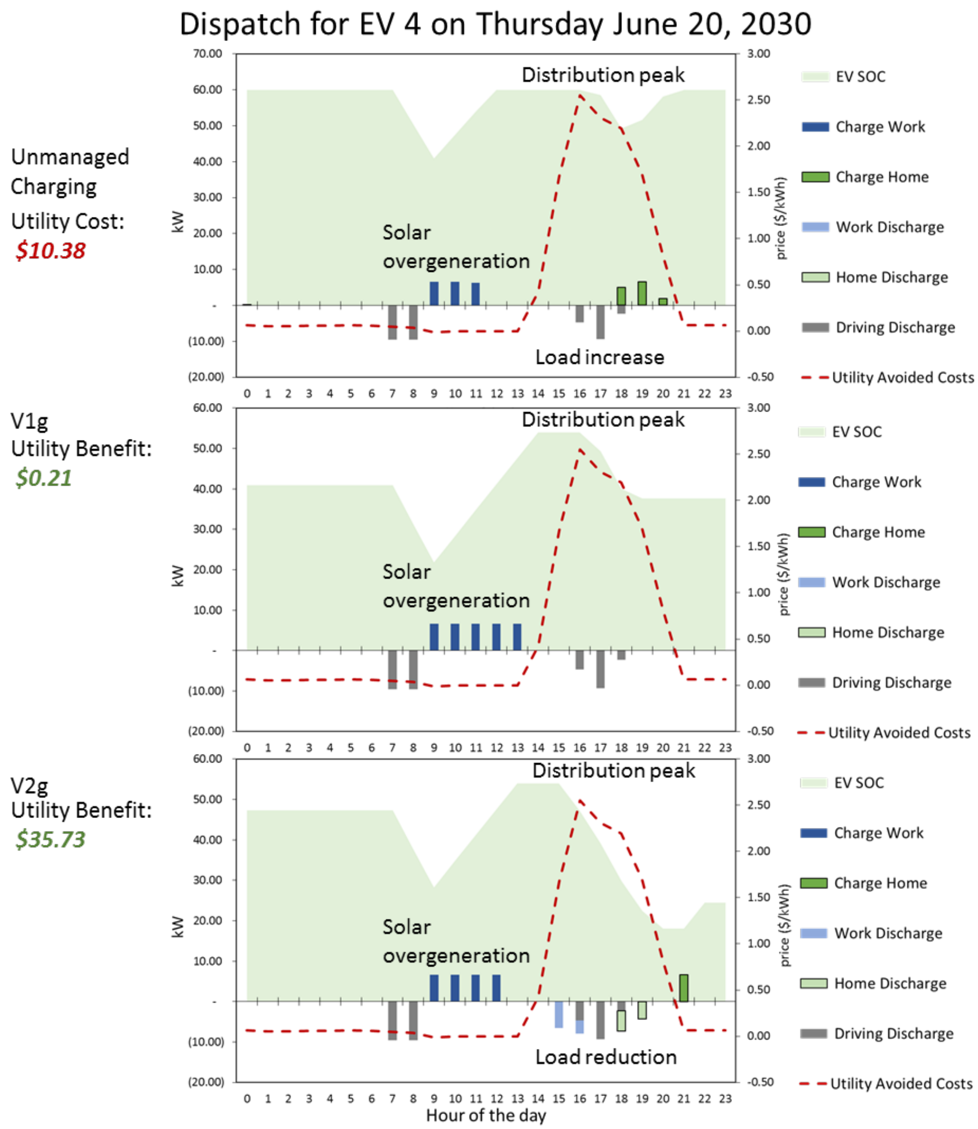

Figure 5-10
Illustrative PEV dispatch for a single day

The unmanaged EV is modeled to charge whenever a charger is available, until its maximum SOC is reached. Unmanaged charging represents an increase in utility costs on this day, as the driver charges their vehicle upon returning from work at 6 PM, which adds load to the monthly distribution peak.

The V1G case is modeled to try to charge during hours of low utility avoided costs. In the V1G case, the smart charging EV can take advantage of negative prices during solar overgeneration, resulting in a net utility benefit of $0.21. In addition, the smart EV does not charge during distribution peak hours 18–20, which is when the unmanaged vehicle provides a load increase. However, it does not provide any additional benefit over the unmanaged case in hours 15–17 because the unmanaged vehicle is not charging from the grid during these hours.

The V2G case provides the highest benefit to the utility, as it is the only vehicle that can discharge during the entire distribution peak from hours 15 - 20. During the distribution peak, the vehicle cannot provide load reduction when driving home from work, but it attempts to discharge as much as it can whenever it is connected to the grid. This results in a net utility benefit of $35.73.

Solar Overgeneration

During days with solar overgeneration and corresponding negative prices, V2G vehicles can generate significant benefits relative to V1G vehicles by discharging before the overgeneration hours. As shown in Figure 5-11, this morning discharge gives V2G vehicles more “space” than V1G vehicles to charge during solar overgeneration (33 kWh versus 4.2 kWh).

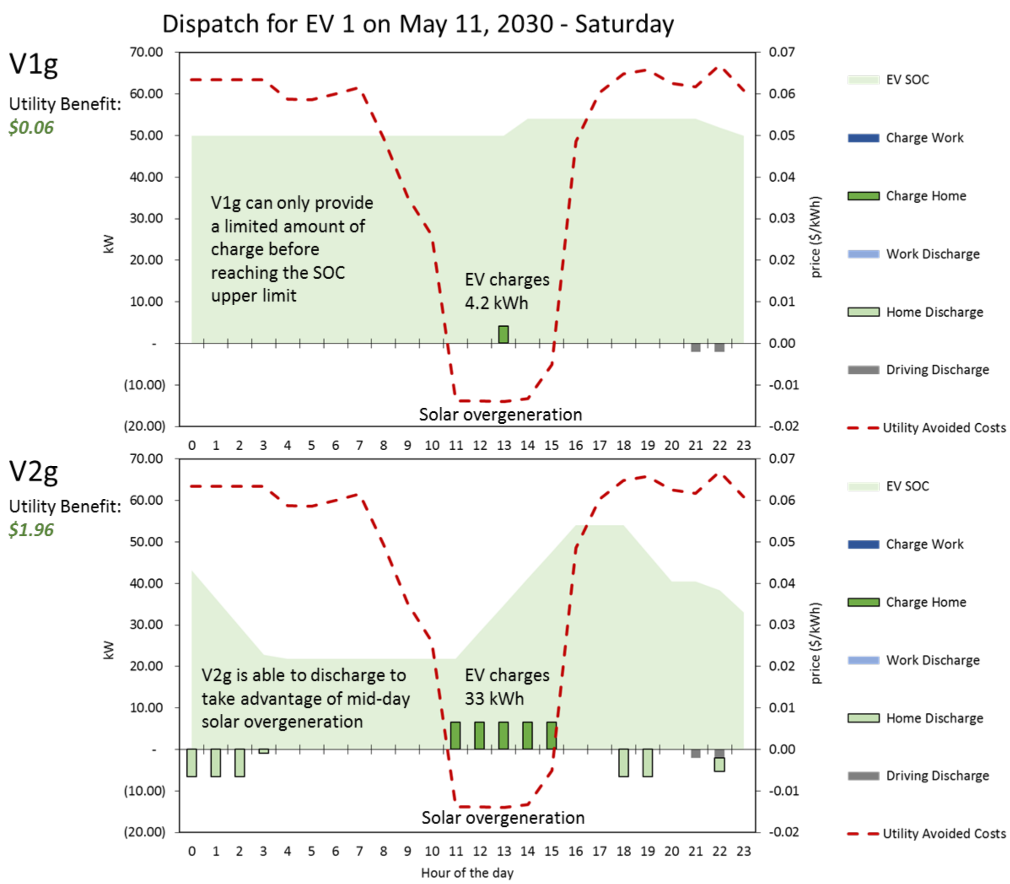

Figure 5-11
PEV dispatch during solar overgeneration

This behavior primarily occurs when V1G vehicles have short commutes or begin their day with a high SOC. Because V1G cars can only impact their SOC in one direction, if a V1G vehicle begins the day with 90% SOC, it will only be able to provide 10% of its SOC for load during solar overgeneration hours. On the other hand, in this case the V2G vehicle discharged to 35% SOC so that it could provide 33 kWh of charging during solar overgeneration hours.

It is important to note that the benefits provided from V2G solar overgeneration days are small relative to the benefit achieved on peak capacity days (net benefit $1.90). In addition, situations like the one shown in Figure 5-10 do not occur at a high frequency throughout the year. Generally, V1G EVs have enough "space" to provide more charge than in this case.

Unconstrained and Constrained Frequency Regulation

Figure 5-12 demonstrates the differences in dispatch behavior between an EV with SOC constraints and one that can dispatch freely.

As discussed earlier, EVs in the constrained cases were subject to battery cycling and SOC limits.

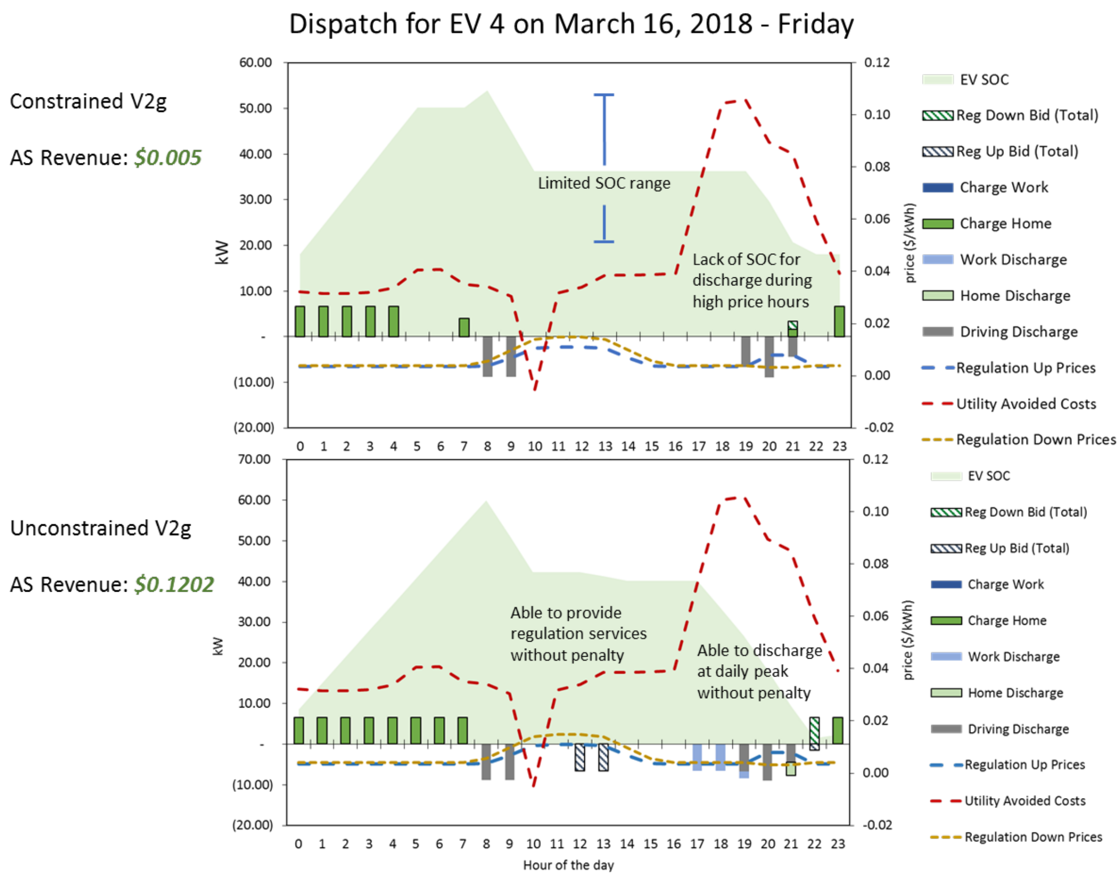

Figure 5-12
Constrained and unconstrained EV dispatch

Due to the SOC limitations of the constrained V2G case, there was no opportunity for the EV to discharge during high price hours, because any discharge would incur a penalty for falling below 30% SOC. In addition, the benefit of participating in the regulation market in hours 12 and 13 was lower than the degradation of the cost of the battery, so there was no regulation up bid for the constrained case. In contrast, the unconstrained case discharged at the daily peak and provided regulation services freely to reduce utility costs over the course of the day by $0.60.

Net Benefits of V2G

For each case that was run, the Solar + Storage valuation tool compiles the results of the daily dispatch to generate total levelized costs and benefits for each dispatch approach. Real levelized cost benefits for EVs across the EV lifetime are shown in Figures 5-13 through 5-16.

Grid Benefits—Utility Control

Figure 5-13 presents a breakdown of the costs and benefit streams associated with an EV for the three different dispatch approaches under the base case assumptions. The results presented are shown in real annual levelized dollars for a single EV. Smart charging provides a 62% cost reduction from the unmanaged case, due to the ability to shift load growth away from peak hours. However, the $155 in cost reduction gained by moving from unmanaged to managed charging pales in comparison to the $407 in benefits gained by moving from V1G to V2G. As shown in the daily operations charts, this is primarily because V2G vehicles are uniquely able to provide peak reduction, capture ancillary service revenue, and to a lesser degree provide energy arbitrage during solar overgeneration.

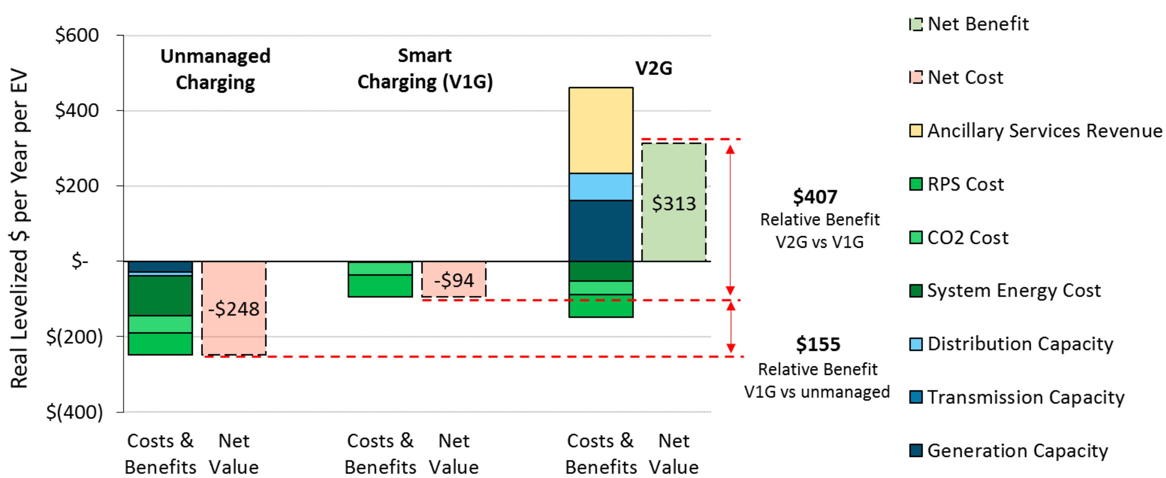

Figure 5-13
Levelized costs and benefits for base case PEV

The cost and benefit streams for all vehicle dispatch approaches under the base case are shown in Figure 5-14 There is a consistent progression in benefits from unmanaged charging to V2G charging with ancillary services market access. Under the base case scenario, the ability for EVs to access ancillary services market results in an annual benefit of $70 per EV.

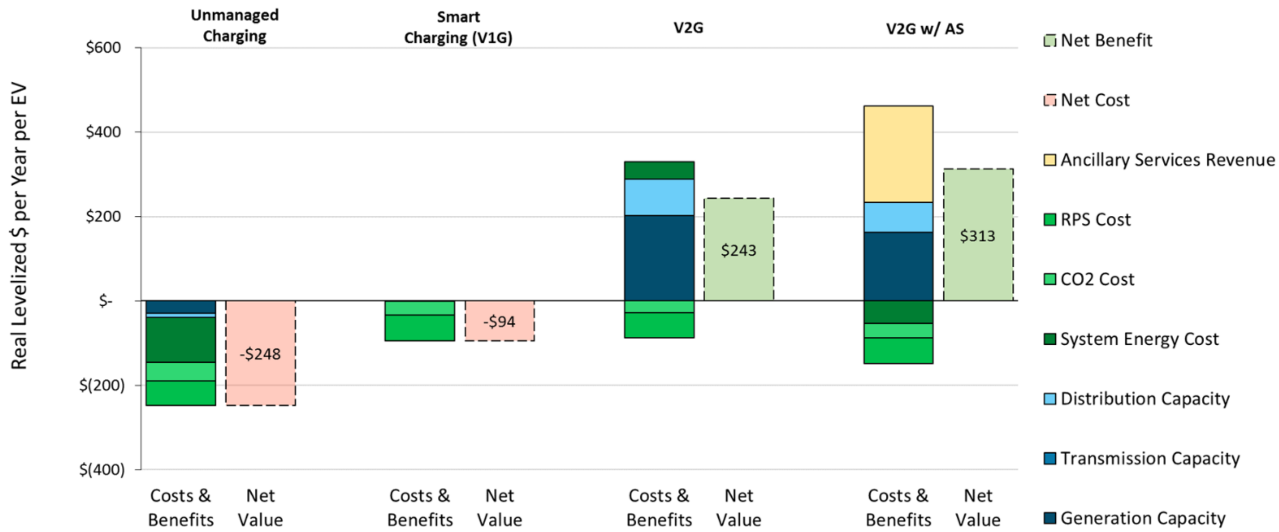

Figure 5-14
Levelized costs and benefits for base case with ancillary services (AS)

Figure 5-15 summarizes the cost and benefit streams associated with an EV under different dispatch approaches using the high case assumptions. This high case assumes a high renewable future with higher system and distribution capacity values.

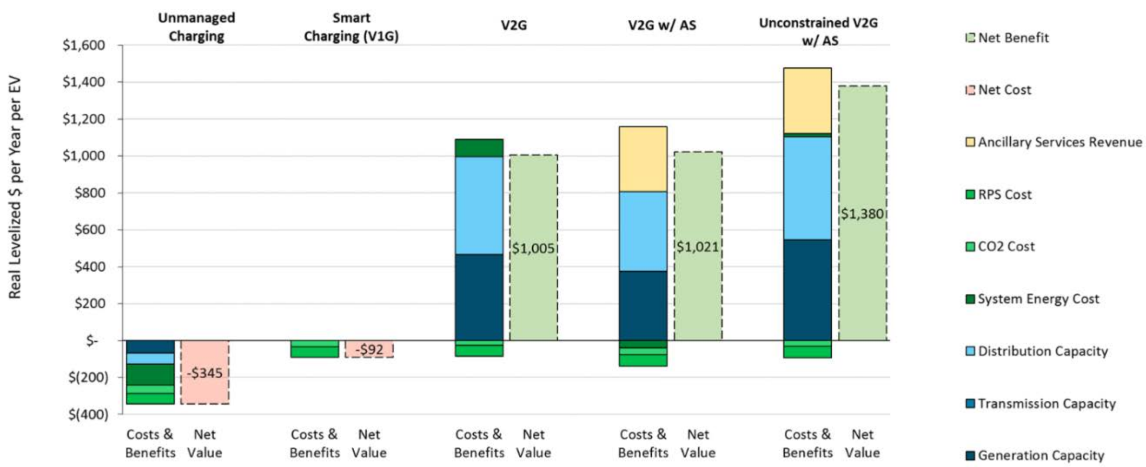

Figure 5-15
Levelized costs and benefits under high case

The high case values amplify the effects seen in the base case, with much of the benefits coming from V2G capacity reduction. The net benefit from the high value V2G case is more than three times larger than the benefit from V2G in the base case.

When EVs gain access to the ancillary services market in the high value scenario, the dispatch trades off energy arbitrage and capacity reduction opportunities to capture ancillary service revenues during high value hours. The incremental benefit associated with access to the AS markets is smaller than the base case due to the higher values attributed to system and distribution capacity. Due to degradation and SOC penalties, the additional benefit is small ($16) when the EV has access to the AS market, as shown in the daily dispatch operations. However, if the EV can participate in the AS market with no constraints on battery degradation or SOC, there is a significant annual benefit of $1725 per EV relative to the unmanaged case. This is the highest potential benefit that an unconstrained EV can provide to the grid.

Customer Benefits—Customer Control

Figure 5-16 represents cost and benefit streams when EVs are dispatched against utility time-of-use (TOU) rates in "customer control" mode. The SDG&E EV-TOU rate was used as the signal for home dispatch, and the SDG&E TOU-M rate was used for work dispatch. The case was run under the base case assumptions shown in Figure 5-10.

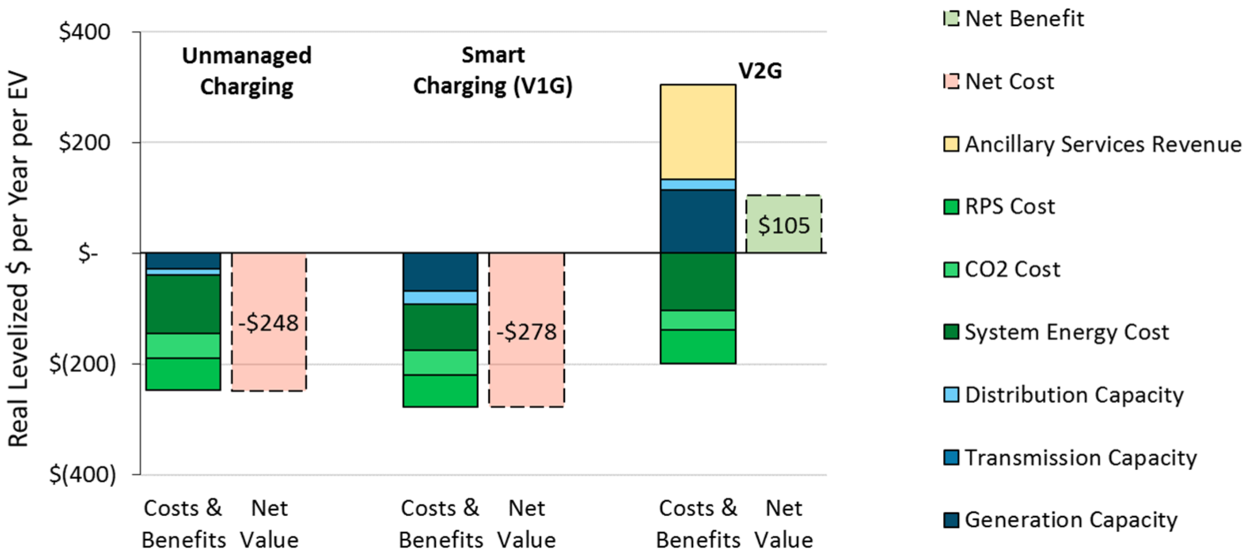

Figure 5-16
Customer control cost and benefits under base case assumptions

The fact that utility rates are not aligned with the utility costs of serving electricity leads to lower V1G and V2G benefits relative to the case where EVs were dispatched against utility avoided costs. As EV adoption increases, alignment of EV rates with true utility avoided costs will be important to prevent situations like the one shown in Figure 5-16, where smart charging leads to larger capacity costs than an unmanaged charging profile.

Table 5-6
Summary of net grid value

		Net Grid Value			Battery Use	
Case	**Dispatch**	**Un-managed**	**V1G**	***V2G***	**Battery cycles**	**Discharge Energy (kWh)**
Unconstrained High Value V2G	Utility	($345)	($92)	$1,380	251	15,051
High Value V2G	Utility	($345)	($92)	$1,021	164	10,225
High Value V2G w/o AS	Utility	($345)	($92)	$1,005	133	7,969

Table 5-6 (continued)
Summary of net grid value

		Net Grid Value			Battery Use	
Base V2G Case	Utility	($248)	($94)	$313	158	9,454
Base V2G Case w/o AS	Utility	($248)	($94)	$243	105	6,322
Base V2G Bill Optimized Case	Customer	($248)	($278)	$105	155	9,325

Note: Net grid value are the grid benefits – the cost of delivered energy for PEV charging. Cost for the PEV, EVSE, V2G equipment and enabling technology are not included.

Table 5-7
Summary of incremental benefit of V2G

		Incremental Benefit	
Case	**Dispatch**	**V1G v Unmanaged**	**V2G v V1G**
Unconstrained High Value V2G	Utility	$253	$1,472
High Value V2G	Utility	$253	$1,113
High Value V2G w/o AS	Utility	$253	$1,097
Base V2G Case	Utility	$154	$407
Base V2G Case w/o AS	Utility	$154	$337
Base V2G Bill Optimized Case	Customer	($30)	$383

Note: Incremental benefits are the grid benefits – the cost of delivered energy for PEV charging. Incremental costs for the PEV, EVSE, V2G equipment and enabling technology are not included.

Benefits for California Ratepayers

The potential benefits of V2G to California ratepayers are calculated using the base case annual benefits of V2G relative to smart charging (V1G) of $407 per PEV in Table 6-8. The medium PEV forecast reaches 3.3 million PEVs in California by 2030, whereas the high forecast is 5.0 million. Assuming 50% of the PEVs are V2G enabled, the potential annual benefits are approximately $670 million in the medium forecast and $1,020 million in the high forecast. Note that these are very rough estimates that do not account for market price impacts of many PEVs participating in energy and ancillary service markets. These are an estimate of potential benefits only and do not include any PEV, EVSE, or enabling technology costs to provide V2G services.

Table 5-8
Potential ratepayer benefits in 2030

	Medium PEV forecast	High PEV Forecast
Million PEVs in 2030	3.3	5.0
Percent V2G Enabled	50%	50%
Base Case Annual Value per PEV	$407	$407
$ Million Annual Benefit	$671	$1,018

Conclusions and Recommendations

The potential grid benefits of V2G PEVs are calculated using CPUC avoided costs updated in June 2018. The avoided costs are supplemented with energy and ancillary service price forecasts developed based on CPUC IRP planning cases. The 42 MMT reference plan is used for the base case, and the 80% RPS portfolio is used for the high value case.

The driving patterns for a fleet of five PEVs (Chevy Bolts) are modeled with probability distributions developed from the 2017 National Household Travel Survey. While the PEVs are plugged in, both at home and at work, the CEC Solar + Storage tool is used to optimize the charging and discharging of the PEVS to minimize costs and maximize revenues. Three cases are modeled: unmanaged charging, smart charging (V1G), and bi-directional charging (V2G). The benefits for the three cases are calculated for both a base case and a high value scenario.

In the base case, the levelized annual benefits of V2G over smart charging are $407 per PEV. The potential benefits are grid benefits minus the cost of delivered energy for PEV charging. No costs for PEV, EVSE, or V2G enabling technology are included. Based on these results, if V2G capability can be enabled for less than $407 per PEV, V2G could provide net benefits for California. For a limited number of congested locations with both high system and distribution capacity value, the potential benefits of V2G could be as high as $1,100 per PEV.

Three factors result in a significant incremental benefit for V2G over managed charging:

- PEVs with shorter commutes (less eVMT) arrive with a relatively full battery, which limits the benefits that can be realized with smart charging alone.
- Once the PEV is fully charged, no grid services can be provided with managed charging.
- Smart charging provides significant system and distribution capacity benefits only to the extent PEV charging is occurring during peak load hours.

In contrast, with V2G, the PEV can be fully utilized independent of the SOC when arriving and when the PEV is charging. The battery can be fully utilized (within operating constraints) even if the battery is nearly full upon arrival. The ability to discharge to the grid effectively doubles the kW capacity available for peak load reduction, and the discharge can be effectively timed to be coincident with peak loads independent of when the PEV would have been charging. These factors lead to significantly higher system and distribution capacity benefits with V2G relative to V1G.

The value of providing ancillary services with V2G is much lower in the high value case than the base case. The base case (42 MMT) has less volatile energy prices and less curtailment than the high value case (80% RPS). Thus, the frequency regulation market provides more revenue opportunity in the base case. Frequency regulation revenues provide a net increase of $70 per PEV. In the high value case, frequency regulation prices are lower due to the entry of energy storage. There is a greater opportunity cost in lost energy market revenues to provide frequency regulation, and the increase in net benefits is only $16 per PEV. The total size of the frequency regulation market in California is relatively small -- approximately 350 MW each for regulation up and regulation down. With Level 2 charging at 6.6 kW, this market could theoretically be serviced by just over 100,000 PEVs. Even triple that number is still less than 6% of the California Governor's goal of 5 million ZEVs by 2030. These findings suggest that capacity value (both system and distribution) and load shifting could be the most valuable markets for V2G, without the complications of bidding behind-the-meter resources into CAISO ancillary services markets.

Smart charging dispatched to reduce customer bills reduces grid benefits relative to unmanaged charging. This is a result of relatively broad TOU periods not being precisely aligned to the hours with the highest value to the grid. Similar results have been shown for the energy storage in the Self-Generation Incentive Program evaluations [6]. The grid benefits of V2G dispatched to customer rates is $105 per EV, compared to $313 in the base case under utility dispatch. For V2G to provide benefits to the electric grid and California ratepayers, utility dispatch signals or more dynamic rate designs reflective of the hourly grid value will be required.

Caveats

There are several caveats for this analysis:

- The impact of increased cycling on battery life is not well understood, and additional constraints on operation may be required to maintain battery health.
- V2G services may void original equipment manufacturer (OEM) and battery manufacture warranties.
- This analysis is based on a small fleet of a single PEV type.
- Several variables may significantly alter the relative benefits of V2G over smart charging:
- Driving patterns and total eVMT for the PEVs
  - The length of time the PEVs are plugged in
  - The PEV battery size
  - The charging level

For example, larger batteries and more eVMT could increase the benefits achieved with smart charging alone, and potentially reduce the incremental benefit of V2G.

6
VEHICLE TO GRID EXTENSION OF ENERGY STORAGEVET®

StorageVET® Overview

The revenue that PEVs generate in providing ancillary services and capacity (resource adequacy) to the grid is calculated using the EPRI StorageVET® tool [7]. The primary capability of StorageVET® is to support the understanding of energy storage project operations and economics. The tool has been designed with caveats to capture policy or market-related rules, commercial decisions (by a range of actors) and constraints, along with infrastructure planning and research. StorageVET® provides a range of technical results such as battery dispatch, SOC, and state of health (SOH) profiles, and financial results such as pro forma and net present value (NPV).

When the storage system can provide many such services, the various revenue streams are stacked on top of each other to achieve the total value for the project. StorageVET® also provides the flexibility to prioritize the different services selected, based on which the final technical and financial results are computed.

The compatibility of the different services provided are dictated based on several factors.

Location of the Storage System

The energy storage system (ESS) can participate in certain services only if it is located at certain locations. For instance, a customer-sited system can only perform customer bill reduction, demand response, and backup power reservation. Similarly, a distribution-level connected system may offer wholesale services, but only after reserving a certain amount of power and energy capacity for distribution-level services. In other words, the distribution-level services will always hold a higher operational priority compared to other wholesale market services.

Time-Related Operation

Distribution-level services generally have a time-series requirement of power and energy reservations. In such a case, the power and energy requirements for these services are translated into a time-series constraint profile, based on which the storage system’s operational schedule is compiled.

Prioritization in Selection Among Applications

Some of the use cases have certain primary services that always hold a higher priority compared to secondary services. For instance, in one case, the primary service that the storage system is expected to perform is phase balancing. However, the phase balancing requirement is not prevalent throughout the year. Hence, during the times with no phase balancing needs, the storage system can offer other secondary non-distribution level services, such as participating in the day-ahead market by providing resource adequacy and ancillary services.

StorageVET® has been designed as a model that has perfect foresight of the various data that are provided as input. This applies to the various aspects of the tool's operation described above.

Typically, energy storage technologies can be integrated to the grid at three possible locations: the transmission system, the distribution system, and the customer's premises. In this analysis, each EV is assumed to be an individual storage system of a uniform power and energy capacity. These PEVs are then aggregated together by accounting for the number of PEVs.

Grid Services Overview

This subsection provides a brief description of the services the storage system can offer.

Ancillary Services

The ESS offers ancillary services in the day-ahead market based on the ancillary services price. The ancillary services include frequency regulation, spinning reserves, and non-spinning reserves.

Frequency Regulation

The CAISO uses frequency regulation to follow the real-time imbalance of electricity supply and demand between 5-minute economic dispatch instructions. The CAISO dispatches a frequency regulation signal and manages separate products for frequency regulation up and frequency regulation down.

The ESS is assumed to follow sample regulation signals that the CAISO has published. StorageVET® does not explicitly model the regulation dispatch. Rather, this is an external calculation that is translated into an energy usage associated with the regulation operations and requiring energy charging to make-up for efficiency losses. StorageVET® determines the amount of energy absorbed and injected, as well as the impact on storage degradation following the customized signals.

Spinning Reserves and Non-Spinning Reserves

Spinning reserves and non-spinning reserves are employed primarily to protect the system against contingencies -- particularly unplanned outages of major facilities, such as transmission lines or generators. Spinning reserves are acquired from units that are synchronized and can provide full awarded capacity in 10 minutes. On the other hand, non-spinning reserves must be started (if needed) and synchronized with the full award available in 10 minutes. When dispatched, these two types of resources must be capable of sustaining its awarded capacity for 30 minutes.

In StorageVET®, an ESS offering spinning reserve and non-spinning reserve service is modeled to reserve its awarded capacity for the awarded hours. Moreover, it is also assumed that the CAISO market allows spinning and non-spinning reserve service commitment during scheduled charging hours. From a technical standpoint, spinning and non-spinning reserves are contingency resources, so they can reduce load and discharge energy. In a way, if the reserves can stop charging, this equates to added generation. For instance, a 1-MW ESS can provide 1 MW of spinning/non-spinning reserve and 1 MW of added generation (by stopping charging), thus effectively providing 2 MW of reserve response.

StorageVET co-optimizes the ancillary services offered along with the wholesale energy price. This wholesale energy price is usually the locational marginal price (LMP) for a specific node. However, since the EVs are distributed across California, a flat energy price of $40/MWh was assumed as the energy price for the co-optimization.

For the V2G analysis, the ancillary services were offered based on the CAISO ancillary services market clearing price for 2015, as shown in Figure 6-1.

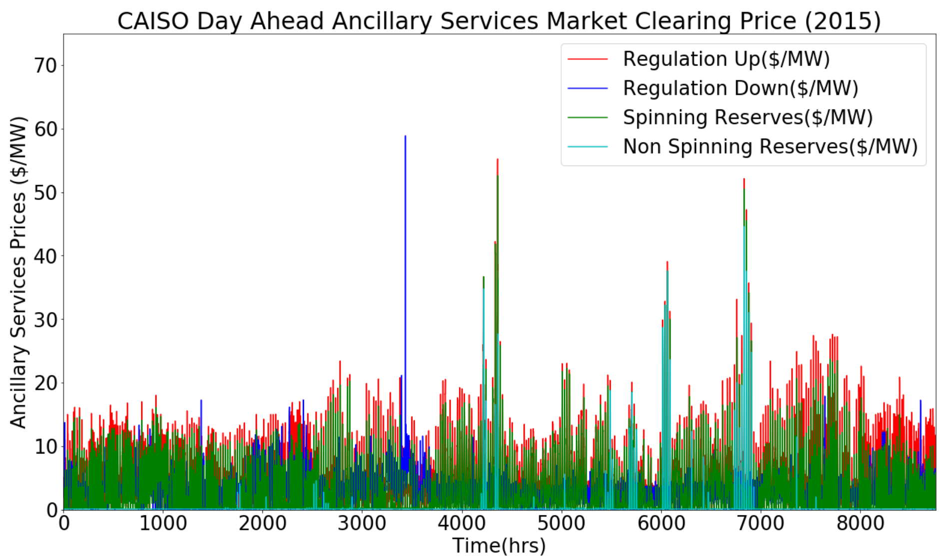

Figure 6-1
CAISO ancillary services clearing price (2015)

Resource Adequacy

Resource adequacy is a reliability requirement that ensures there are sufficient generation and non-generation resources available to meet the forecasted peak load along with reserve requirements, generally one to three years ahead. In California, to qualify for system or local area resource adequacy, a storage resource is rated at the maximum output that can be sustained for at least 4 consecutive hours and be available for at least 3 consecutive days.

In StorageVET®, a storage asset eligible to provide resource adequacy receives the monthly capacity payments and either reserves the capacity or is dispatched for the designated hours on the designated days. Based on the 2015 Resource Adequacy (RA) Report that the CPUC publishes, the monthly payment for resource adequacy is set at $3/kW-month. The storage asset is fully charged up to the capacity eligible for resource adequacy prior to the designated hours. It was also assumed that the minimum bidding increment for resource adequacy is 0.1 MW for a duration of four hours.

Input Data Summary

Based on the various grid services described in the previous section, the input data required for performing the services are summarized in Table 6-1.

Table 6-1
Input data summary

Data	Services Associated
Day Ahead Wholesale Energy Price	$40/MWh (Flat Value)
CAISO Ancillary Services Market Clearing Price (2015)	1. Frequency Regulation 2. Spinning Reserves 3. Non-Spinning Reserves
Monthly Capacity Payment (Resource Adequacy)	$3/kW-month (CPUC's 2015 RA Report)

Vehicle to Grid StorageVET® Analysis

The impact of employing PEVs to offer grid services is analyzed using StorageVET.

ISO Level Analysis

This impact is analyzed from the macroscopic level (i.e., from the perspective of the ISO). This is briefly described in the flow chart in Figure 6-2.

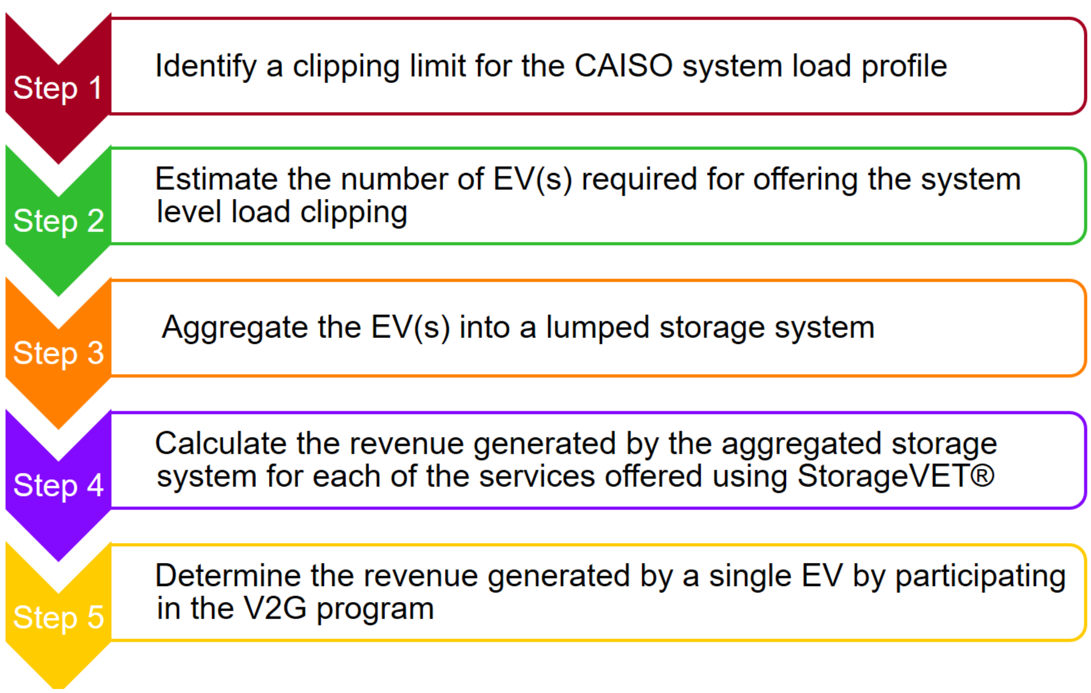

Figure 6-2
ISO level analysis flowchart

A clipping limit of 750 MW was identified as the target for the aggregated storage system. Two cases were modeled separately based on the capacity (power and energy) reservation made by a single EV. The capacity reservation values were 3 kW/6 kWh, and 6 kW/30 kWh, respectively. Based on these numbers, the number of EVs required to provide a 0.75 GW clipping was estimated at 250,000 for the 3 kW/6 kWh case, and 125,000 for the 6 kW/30 kWh case, respectively.

For both cases, 10% of the vehicles were assumed to be capable of providing frequency regulation as a service along with spinning and non-spinning reserves. The remaining 90% of the vehicles were assumed to be capable of providing only spinning/non-spinning reserves.

Based on these assumptions, the summary of number of EV(s) required is presented in Table 6-2.

Table 6-2
Electric vehicle summary

Capacity of One EV	Number of EV(s)		Total
	Frequency Regulation + Spin/Non-Spin	Spin/Non-Spin	
3 kW, 6 kWh	25,000	225,000	250,000
6 kW, 30 kWh	12,500	112,500	125,000

The next step was to aggregate the capacity of the EVs into a single storage system and then model the system in StorageVET® to calculate the revenue of offering each service (see Table 6-3).

Table 6-3
EV aggregated capacity

Capacity of One EV	Aggregated Capacity	
	Frequency Regulation + Spin/Non-Spin	Spin/Non-Spin
3 kW/6 kWh	75 MW, 150 MWh	675 MW, 1350 MWh
6 kW/30 kWh	75 MW, 375 MWh	675 MW, 3375 MWh

Financial Results Summary

The financial results for the two cases of the analysis are summarized in Table 6-4 and Table 6-5.

Table 6-4
Revenue summary for 3-kW/6-kWh reservation

Annual Revenue Generated ($)	Regulation + Spin/Non-Spin		Spin/Non-Spin	
	Overall	Per Vehicle	Overall	Per Vehicle
Frequency Regulation	$5,809,000	$232.36	N/A	N/A
Spinning Reserve	$373,400	$14.94	$20,000,000	$88.89
Non-Spinning Reserve	$9,330	$0.37	$340,100	$1.51
Total	$6,191,730	$247.67	$20,340,100	$90.40

Table 6-5
Revenue summary for 6-kW/30-kWh reservation

Annual Revenue Generated ($)	Regulation + Spin/Non-Spin		Spin/Non-Spin	
	Overall	Per Vehicle	Overall	Per Vehicle
Frequency Regulation	$6,271,074	$501.69	N/A	N/A
Spinning Reserve	$533,670	$42.69	$23,750,000	$211.11
Non-Spinning Reserve	$18,161	$1.45	$459,500	$4.08
Total	$6,822,904	$545.83	$24,209,500	$215.20

Impact on the California Duck Curve

The analysis of the employment of EVs to provide capacity support to the grid was also performed on a macroscopic level to study the impact on the California "Duck Curve." The key steps involved in this analysis are summarized in Figure 6-3.

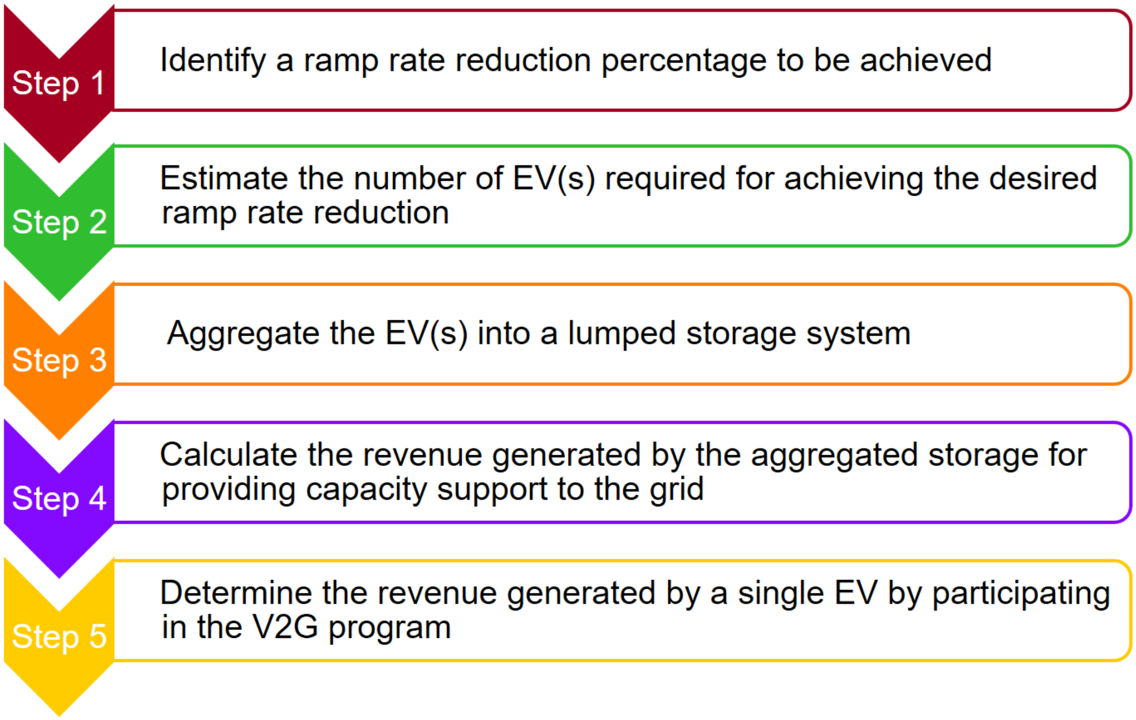

Figure 6-3
Ramp rate mitigation flowchart

As a first step, a ramping reduction of 35% was assumed as a target reduction value. Assuming that the capacity reserved for the service, is 6 kW/30 kWh per EV, the number of EVs required to provide a 35% reduction in ramp rate was estimated at approximately 58,333. The impact of providing capacity to the grid is represented graphically in the form of two duck curves (see Figure 6-4).

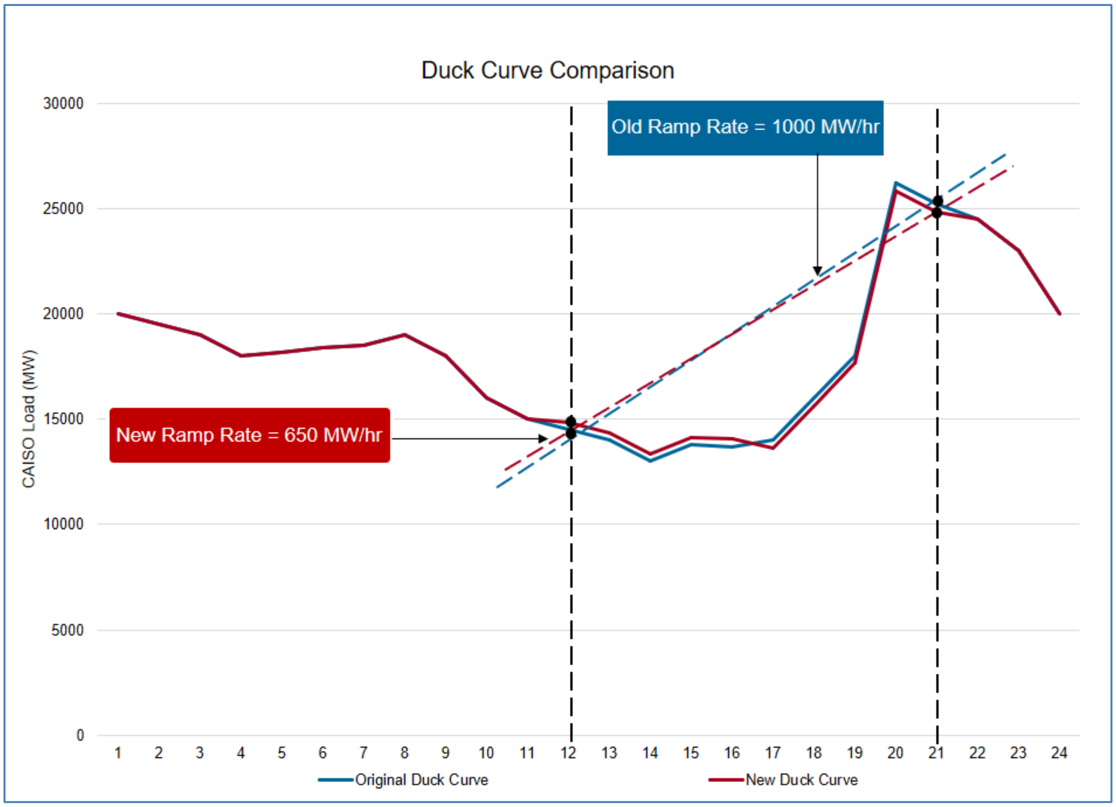

Figure 6-4
Duck curve ramping mitigation

Since the charge/discharge duration of one EV is 5 hrs, the EV was assumed to charge from hours 12 to 17, where there was surplus photovoltaics (PV) generation and net load was low. From hours 17 to 22, the EV was assumed to discharge when the PV generation started to drop and load started to spike up. Based on the assumptions made above, the ramp rate is calculated as:

$$Original\ Ramp\ Rate = \frac{(24{,}500\ MW - 14{,}500\ MW)}{(22{:}00\ - 12{:}00)} = 1{,}000\ MW/hour$$

Equation 6-1

$$New\ Ramp\ Rate = \frac{(24{,}150\ MW - 14{,}850\ MW)}{(22{:}00\ - 12{:}00)} = 650\ MW/hour$$

Equation 6-2

$$Change\ in\ Ramp\ Rate = 1 - \frac{(650\ MW/hour)}{(1000\ MW/hour)} = \mathbf{35.00}\%$$

Equation 6-3

Based on the assumption that the value of providing capacity support is \$3/kW-month [8], the approximate revenue that each EV would generate is about \$216 per year.

Assuming that approximately 308,333 EVs sign up for the V2G program, the average revenue that one EV generates is approximately $126.91 (see Table 6-6)

Table 6-6
Revenue summary for cumulative services

	3-kW/6-kWh reservation		Capacity Participation	Total
	Regulation + Spin/Non-Spin	Spin/Non-Spin		
Number of EVs	25,000	225,000	58,333	308,333
Revenue ($)	$6,191,370	$20,340,100	$12,599,928	$39,131,398
Revenue per EV ($)	$247.67	$90.40	$216.00	$126.91

Increasing PV Penetration along a Feeder

A bottom-up approach can also be utilized to evaluate EVs as a resource to increase PV integration on a feeder. However, this requires feeder-level impact analysis information on the type of customers on the feeder, the number of potential EVs that could be utilized at those locations, including customer load profiles and generation profiles. This analysis also involves applying a probabilistic approach to integrate the different parameters. Once an individual feeder analysis is complete, the results could be rolled up for a system-level assessment, with an assumption on the number and type of similar feeders. This was beyond the scope for this analysis.

7 SUMMARY AND RECOMMENDATIONS

Scope and Key Findings

This project involved simultaneous evaluation of the technology, value and planning aspects of systematics integration of on-vehicle Vehicle-to-Grid (V2G) capable Plug-in Electric Vehicles, based on open, interoperable standards and technologies, involving mainline automotive OEMs and an industry-first implementation of the SAE standards implementing grid/vehicle communications. It also implemented transformer-based monitoring and control technologies to help identify and impose distribution system constraints to the V2G operation, synthesizing the grid services via the use cases around EV charging, local and macro-distribution system level energy and demand management. Reverse power flow applications such as peak shaving and ramping support were implemented in technology and incorporated in the dispatch strategy for valuation assessment.

There are other companion publications that address technology and planning aspects of V2G capable PEVs. This publication focuses on the valuation aspects of the V2G technology. Putting upper and lower bounds on the value of V2G services is important to drive the regulatory, scaled pilot investments related discussion forward and investment decisions forward within automotive industry to make the bidirectional power inverter / charger technology available on-vehicle. The work performed in this part of the project assessed valuation of the grid services provided by V2G capable PEVs, based on the realistic results that were obtained through the technology development and demonstration part of the project. Following sections outline key conclusions that can be drawn from this effort, as well as how to move this technology forward in terms of making V2G capable PEVs available for grid and owner benefits, while maintaining their viability for the automotive manufacturers.

Distribution System Modeling Methodology

Given the distribution system focus of this project, the first task in the process was to model a prototypical distribution system feeder over an entire year with baseline (non-EV-related) and EV-impacted loading profiles. The idea behind this was to identify segments of the feeder where there was excessive loading (‘hotspots’). These could be seen as the bottlenecks to increasing the active power throughput of the distribution feeder (also sometimes referred to as ‘Hosting Capacity’). If these hotspots are mitigated by applying selective mitigation that is location-specific, to the loads (and DERs) present there, that would result in a system-wide benefit. Similar analyses have been performed on ‘static i.e., ’non-mobile’ assets present on the distribution system (PV, storage etc). While these are time-varying and a growing class of asset, an attribute shared by EVs, EVs present additional complexity by being mobile, or discharging/charging only at a specific rate, and available only while plugged in as well as customer’s mobility need being the highest priority, reflected in this project as a ‘reserve’ battery capacity not to be used for grid services purposes. The last constraint on the EV batteries is the charge/discharge power cycling, impacting their cycle life.

The analysis created forecasts for a growing share of EVs with higher energy and power capabilities on a distribution system feeder to create prototypical profiles for loading at different locations. This methodology can be incorporated broadly in the Interconnection Capacity Analysis (ICA) as a part of Distribution Resource Planning. If managed properly, EV charging can serve as a PV hosting capacity mitigation measure. The key findings from this portion of the analysis were:

- Distribution system modeling is complex but an essential ingredient to understanding EV impacts as well as the hotspots, which help ascertain the avoided costs through charging and discharging power management
- Sine each distribution system is different, in the past, utilities have identified 'at-risk' feeders for subjecting them to these analyses. This narrows down the scope of this work, although with the increasing penetration, the scope of the analysis will have to grow.
- While spatial and temporal variations of individual EV charging are known, their cumulative effect needs to be studied through at-scale pilots that allow statistically significant experiments to be conducted with real customers participating. These will have the additional benefit of creating datasets that can be used for future modeling and forecasting efforts.

Distribution System Avoided Cost Estimation Methodology

Randomized data from NHTS published by ORNL was used to create trip-level data for EVs in order to determine charging patterns. This charging pattern data was used as a dispatchable resource in estimating avoided costs for distribution system upgrades. CPUC standard practice manual was used to formulate the avoided costs and using the standard terminology defined therein to produce the value stack. Given the uncertainty in the cost side of the technology, only the benefits were estimated. Benefits net of costs to implement V2G on vehicle and on EVSE (As well as at the utility) would provide the net benefits estimation.

This methodology was used in conjunction with a dispatch strategy and also the tariffs that are applicable, to determine cumulative effect of avoided costs, on-bill and other regulatory benefits (LCFS credits etc) were utilized. The use cases implemented in this project were incorporated in the forecasts for value assessment, to produce base case, charging only and V2G related benefit estimates. The following tables summarize the business-as-usual, realistic and best case scenarios for value with impact on batteries also identified qualitatively.

Table 8-1
Summary of Estimated Range of V2G Grid Services Benefits

		Incremental Benefit	
Case	**Dispatch**	**V1G v Unmanaged**	**V2G v V1G**
Unconstrained High Value V2G	Utility	$253	$1,472
High Value V2G	Utility	$253	$1,113
High Value V2G w/o AS	Utility	$253	$1,097
Base V2G Case	Utility	$154	$407
Base V2G Case w/o AS	Utility	$154	$337
Base V2G Bill Optimized Case	Customer	($30)	$383

When applied across the state of CA fleet under a varying set of overall installed base scenarios, the cumulative benefits to ratepayers can be calculated. A summary of the results are shown in the table below:

Table 8-2
Summary of California Ratepayer Benefits from V2G Technology

	Medium PEV forecast	**High PEV Forecast**
Million PEVs in 2030	3.3	5.0
Percent V2G Enabled	50%	50%
Base Case Annual Value per PEV	$407	$407
$ Million Annual Benefit	$671	$1,018

Caveats

There are several caveats for this analysis:

- The impact of increased cycling on battery life is not well understood, and additional constraints on operation may be required to maintain battery health.
- V2G services may void original equipment manufacturer (OEM) and battery manufacture warranties.
- This analysis is based on a small fleet of a single PEV type.
- Several variables may significantly alter the relative benefits of V2G over smart charging:
- Driving patterns and total eVMT for the PEVs
  - The length of time the PEVs are plugged in

- The PEV battery size
- The charging level

For example, larger batteries and more eVMT could increase the benefits achieved with smart charging alone, and potentially reduce the incremental benefit of V2G

Benefit Estimation Specifically to Exploit Reverse Power Flow Capability

EPRI team modified the StorageVET analysis tool to estimate the value of reverse power flow capability primarily for two key use cases: Peak Shaving and Ramping Support. Ramping support relates directly to avoided peaker capacity at the time during which net demand ramps up rapidly at sunset time when PV generation is declining at the same time the AC load is picking up in hot summer evenings as EV drivers reach home. For simplification purposes, EVs were aggregated on feeders and across ISO as an equivalent storage capacity so they can be analyzed efficiently. The results are shown below in terms of per-vehicle per year and for California ratepayers per year in cumulative terms in the table below:

Table 8-3
Revenue summary for cumulative services

	3-kW/6-kWh reservation		Capacity Participation	Total
	Regulation + Spin/Non-Spin	Spin/Non-Spin		
Number of EVs	25,000	225,000	58,333	308,333
Revenue ($)	$6,191,370	$20,340,100	$12,599,928	$39,131,398
Revenue per EV ($)	$247.67	$90.40	$216.00	$126.91

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A
VEHICLE TO GRID INCENTIVES AND TARIFF QUANTIFICATION METHODOLOGY

Background

V2G services can be designed to deliver grid benefits at local (facility), distribution system, and ISO levels. Owing to the vehicles' ability to send and receive power to and from the grid, V2G-capable vehicles have the flexibility to perform services both on the load and supply side. This section describes the process of translating the quantified grid benefits into incentive and tariff structures that can be deployed to reward or incent participating customers and PEVs. In developing this incentive and tariff quantification methodology (ITQM), industry-standard practices, such as the one described in the CPUC Standard Practice Manual [9] and Bonbright's Principles on rates [10], were used. The CPUC recently held a zero-emission vehicle (ZEV) Rate Design Forum [11] that addressed enhanced PEV adoption through appropriate rate structures. One discussion topic was "key concepts underlying electric rate design" [12]. This presentation elaborated on ten key principles of effective rate design that can be adopted to EV-related tariffs.

- **Electricity as a basic necessity**. Universal access to electricity that is especially affordably to economically- or health-disadvantaged individuals, may place the burden of subsidizing electricity on utilities.
- **Marginal cost basis**. Rates should be designed based on marginal cost.
- **Cost causation.** Rates should be aligned and correlated with the cost drivers. What costs more should be priced higher.
- **Conservation and energy efficiency**. Progressive tariffs reward energy savings.
- **Peak demand consideration**. Rates should discourage both coincident and non-coincident peak demand.
- **Stable, understandable, and enabling customer choice.** This is self-explanatory.
- **Avoid cross-subsidies.** In following the principle of fairness, one class of customers should not bear the burden of paying for consumption of another class of customers. If societal good is the driving principle for the subsidies, then the costs of implementation of such subsidies should be more broadly spread.
- **Explicit and transparent Incentives.** Incentives should be directly correlatable to incentive-deserving customer choices and should be obvious (e.g., customer did X and hence received incentive Y, etc.).
- **Encourage economically efficient decision making.** For example, load shifting via off-peak charging shifts energy consumption during hours of inexpensive electricity. Similarly, energy consumption during the excess supply (belly of the "duck") period can receive similar subsidies.

- **Customer education.** An educated customer is an informed customer and a better consumer of electricity.

This section describes a methodology to correlate the incentives and rates that are attributable to the participating PEVs as utility assets to compensate for their participation in the value-added grid services. Energy services enabled by V2G-capable PEVs are comprised of two types:

- Load shifting by explicit or tariff mechanisms
- Market-oriented grid services, where PEVs offer services by participating in the ISO market

In general, charging pattern modification to better utilize grid capacity results in a variety of savings. These can be incentivized based on marginal cost principles. Table A-1 illustrates this principle.

Table A-1
Marginal cost as incentive driver [12]

Type of Marginal Cost	Basis for Allocation	Incentive Units
Energy	Generation	Cents/kWh or $/MWh
Capacity	Generation, Distribution	$/kW or $/kW/year
Customer	Final Line Transformer, Service Drops, Meters, Billing, Customer Service	$/customer/year or $/customer/month

Tying incentives to marginal costs is the best way to reward causality directly. Rewarding grid-friendly behavior also promotes energy conservation, and consequently, economically efficient decision making. The CPUC recently announced a decision that allows time of use tariff revision that incentivizes specific grid-friendly energy use behavior [13]. This effectively correlates the rate or price of each kWh consumed at different times of the day with the costs associated with serving that kWh at that time (i.e., a temporal correlation between the rates and costs). The most important principle of the rate design has been the concept of "equal percent marginal costs," [14], which effectively enables equitable allocation of rates against cost drivers for each class of customers and individual customers.

Incentives and Tariff Quantification Methodology Process Flowchart

Figure A-1 identifies the steps necessary to translate macro-level cumulative system benefits to per-vehicle, per-year incentives that can be rolled out in terms of a variety of compensation mechanisms for the participating PEVs in utility programs. Each of the steps in this process is described in the ensuing paragraphs.

Estimate System Level Grid Benefits on a Per-Vehicle Basis

Previous sections discuss a variety of methods and approaches to estimating grid-level benefits on an ISO-wide, distribution system operator (DSO)-wide, and per-vehicle basis for the use cases that are implemented and relevant to V2G-capable vehicles randomly located and mobile across distribution systems. These use cases assume the vehicles to be either at home or at work, plugged in, and available for extended periods of time. These grid level benefits are calculated through one of the following mechanisms

- Avoided or deferred capacity upgrades
- Avoided or deferred generation procurement
- Avoided or deferred distribution system overvoltage mitigation costs

These avoided costs are assessed at

- Local facility level
- Distribution feeder level
- DSO/ISO level

Through a variety of co-optimization and dispatch algorithms employed in the valuation models, value-stacking of these benefits computes their cumulative value.

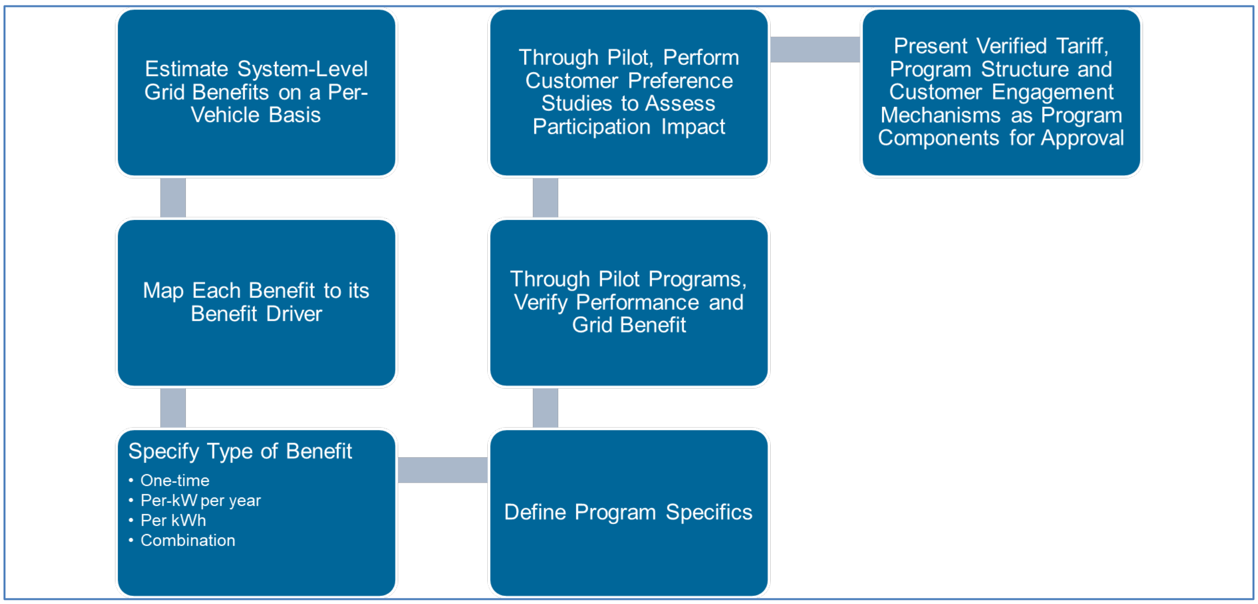

Figure A-1
Incentives and tariff quantification methodology flowchart

Map Each Benefit to its Value Driver

When value-stacking is applied, each stack of value has a value-driver among the drivers described above. At this step, the ordered pairs of value-driver and value are compiled so that the nature of the benefit (one-time or recurring) can be assessed. Once the nature of the benefit is assessed (e.g., one-time, per-kW, per-kWh, or a combination), an appropriate incentivization method can be assessed.

Specify Type of Benefit

Depending on the type of grid service, the type of benefit may be different. To each program-specific service, assign an appropriate type of incentive. Incentive types could be one-time, per availability, or per event, in the form of per-kW, per-kWh, or one-time lump-sum benefit per year.

Define Incentive Program Specifics

Based on the highest value-drivers (or the ones that the utility wants to address), incentive program specifics can be defined. For example, if only availability is being incentivized for spinning or non-spinning reserves, then a per-kWh value may be applied. If the resource is utilized for a service-like peak shaving, then a per-kW value can be assigned for incentivization, etc. This incentive program then needs to undergo technology and market tests. Depending on the size of the sample, PUC approval may be required. When setting up pilot program incentive structures, also keep in mind the popularly offered incentives and allow as much diversity of incentive structures as possible to collect customer participation data for analysis purposes.

Through Pilot Programs, Verify Technology Performance and Grid Benefits

Conduct a technology pilot (such as this project, on a larger sample size), gather data, and verify the performance of the technology according to the program requirements. Use the data gathered through the pilot to assess how closely the data resembles the assumptions used to create the valuation model. If needed, modify the valuation model to refine the assessed benefits.

Conduct Customer Preference Studies

Conduct customer preference studies applying discrete choice experimentation and similar statistical analytical methods. The aim is to identify which specific incentive mechanisms generate superior participation from the customers. Given that all of the incentive programs are designed to encourage consumers to modify their EV charging and discharging behavior, the focus is to identify the most promising approaches to maximize participation.

Determine Effective Consumer Program Structure

If previously designed steps are implemented effectively, the process helps identify the following:

- Type of programs and corresponding grid services
- Incentive structures
- Consumer engagement strategies
- Program implementation blueprint
- Measurement and verification strategy
- On- and off-vehicle technology components
- Interconnection guidelines

These become the incentive program packages for utilities' further consideration for engaging V2G-capable vehicles for grid services.

TOU Rates versus Marginal Costs

CPUC avoided costs developed for DER represent the marginal cost of delivering energy in each hour, including an allocation of system, transmission, and distribution capacity costs to peak load hours. Figure A-2 shows the average hourly CPUC avoided costs for DER overlayed with the Southern California Edison (SCE) TOU periods in 2016. Figure A-3 shows revised TOU periods that SCE proposed in the CPUC Residential Rate Reform Proceeding and CPUC avoided costs for 2030, reflecting higher penetrations of renewable generation [15].

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
1	$43	$41	$33	$38	$38	$39	$42	$44	$45	$47	$52	$53
2	$42	$39	$32	$36	$37	$38	$41	$42	$43	$45	$51	$52
3	$41	$38	$31	$35	$36	$38	$40	$41	$42	$44	$50	$51
4	$41	$38	$32	$37	$37	$38	$40	$42	$43	$46	$51	$52
5	$42	$40	$35	$43	$41	$40	$42	$44	$46	$49	$54	$54
6	$47	$46	$40	$48	$43	$42	$42	$46	$48	$53	$60	$62
7	$51	$49	$42	$46	$40	$41	$42	$46	$48	$54	$65	$69
8	$52	$49	$38	$37	$33	$38	$42	$44	$46	$50	$59	$71
9	$47	$45	$33	$30	$29	$40	$43	$45	$46	$47	$51	$59
10	$44	$41	$31	$29	$30	$41	$44	$46	$47	$48	$48	$53
11	$44	$40	$31	$31	$30	$43	$45	$48	$49	$49	$47	$48
12	$43	$39	$31	$32	$31	$45	$48	$51	$51	$51	$48	$47
13	$42	$39	$31	$32	$30	$46	$51	$53	$53	$52	$47	$46
14	$41	$38	$32	$32	$31	$48	$53	$77	$538	$54	$47	$46
15	$42	$39	$32	$33	$31	$50	$56	$289	$910	$58	$49	$47
16	$44	$41	$35	$36	$34	$54	$60	$530	$1,266	$72	$52	$55
17	$55	$46	$40	$41	$38	$55	$60	$596	$1,166	$72	$65	$67
18	$66	$56	$46	$50	$46	$60	$61	$331	$1,899	$87	$85	$87
19	$66	$65	$54	$58	$52	$62	$62	$521	$1,175	$76	$77	$84
20	$61	$58	$50	$62	$59	$60	$60	$157	$327	$65	$68	$76
21	$58	$56	$45	$53	$53	$54	$56	$55	$55	$58	$65	$72
22	$54	$51	$41	$48	$46	$48	$51	$52	$51	$55	$60	$66
23	$50	$47	$38	$43	$42	$44	$48	$48	$49	$52	$57	$62
24	$46	$44	$34	$41	$39	$41	$45	$46	$47	$48	$52	$57

Figure A-2
2016 SCE TOU periods and average hourly CPUC avoided costs for DER in 2016 (Pacific local time, hour ending) [16]

There are two key challenges for TOU rates with respect to incentivising V2G dispach. The first is properly aligning the TOU periods for peak loads net of PV generation that are occurring later in the evening. The second challenge, with respect to V2G, is that TOU rates provide an on-peak price that is averaged over a relatively broad period of six to eight hours in the day over four to six summer months, without special emphasis on the highest system peak load hours.

Hour	Jan 1	Feb 2	Mar 3	Apr 4	May 5	Jun 6	Jul 7	Aug 8	Sep 9	Oct 10	Nov 11	Dec 12
1	$105	$106	$98	$100	$97	$97	$100	$103	$101	$107	$116	$112
2	$102	$101	$95	$95	$93	$95	$98	$95	$97	$102	$113	$110
3	$100	$99	$94	$93	$90	$93	$95	$93	$95	$101	$111	$107
4	$100	$97	$98	$99	$94	$94	$96	$94	$97	$104	$113	$109
5	$104	$102	$108	$118	$105	$100	$100	$102	$106	$113	$119	$114
6	$117	$123	$127	$134	$111	$105	$102	$108	$112	$122	$135	$128
7	$128	$131	$137	$126	$102	$102	$101	$107	$112	$124	$144	$148
8	$129	$132	$120	$97	$14	$95	$99	$99	$103	$113	$129	$152
9	$118	$119	$100	$14	$14	$99	$102	$101	$103	$108	$113	$122
10	$109	$106	$14	$14	$14	$15	$106	$107	$107	$110	$105	$111
11	$107	$102	$14	$14	$14	$18	$110	$112	$113	$115	$102	$99
12	$105	$101	$14	$15	$15	$22	$114	$118	$117	$118	$105	$98
13	$102	$99	$14	$15	$15	$24	$121	$124	$123	$121	$102	$95
14	$100	$99	$15	$17	$15	$29	$129	$132	$133	$126	$103	$95
15	$102	$101	$15	$17	$15	$33	$137	$138	$306	$135	$107	$98
16	$110	$107	$108	$18	$16	$142	$147	$154	$1,347	$145	$115	$112
17	$135	$122	$127	$112	$17	$145	$151	$576	$2,883	$239	$146	$144
18	$171	$154	$152	$139	$121	$158	$154	$501	$2,851	$214	$195	$189
19	$172	$182	$183	$165	$139	$162	$153	$664	$1,584	$185	$177	$183
20	$156	$160	$166	$174	$160	$160	$147	$256	$520	$154	$155	$164
21	$150	$152	$146	$150	$141	$142	$137	$126	$130	$138	$147	$152
22	$133	$137	$131	$132	$122	$121	$126	$122	$121	$129	$134	$142
23	$124	$123	$118	$118	$108	$113	$112	$116	$117	$117	$125	$133
24	$114	$116	$103	$110	$101	$104	$105	$108	$109	$110	$116	$120

Figure A-3
Proposed SCE TOU periods and average hourly CPUC avoided costs for DER in 2030 (Pacific local time, hour ending)

Modifying TOU periods to account for excess solar generation during the day and peak net loads that occur later in the evening is under active consideration in the CPUC Residential Rate Reform Proceeding. Shifting the TOU period to later in the day will capture more of the high system marginal costs hours (e.g., hour ending 19 and 20 in August and September) that fall outside the current on-peak TOU period. SCE has also proposed a super off-peak period in the winter between hour ending (HE) 9 and HE 16 when excess renewable generation is most likely to occur.

Broad TOU rate periods, however, do not harness the potential for highly flexible resources such as V2G and energy storage to support the grid during those specific hours with the highest marginal costs. Figure A-4 shows an example Pacific Gas and Electric (PG&E) TOU rate (E19S) compared to the 2016 CPUC avoided costs in Fresno for three summer days. On the first day, high system capacity value is concentrated in the three hours between 5 and 8 pm, but the TOU rate provides an equal incentive for AES Corporation to discharge beginning at noon. The next day, local T&D capacity costs drive a significantly higher value concentrated between 4 and 6 pm. Focusing V2G discharge in just those two hours based on local system conditions would maximize the value to the grid. For the last day, the difference between on- and off-peak marginal costs is relatively small. Charging PEVs off-peak and discharging on-peak reduces the customer bill, but provides limited value to the grid on this particular day.

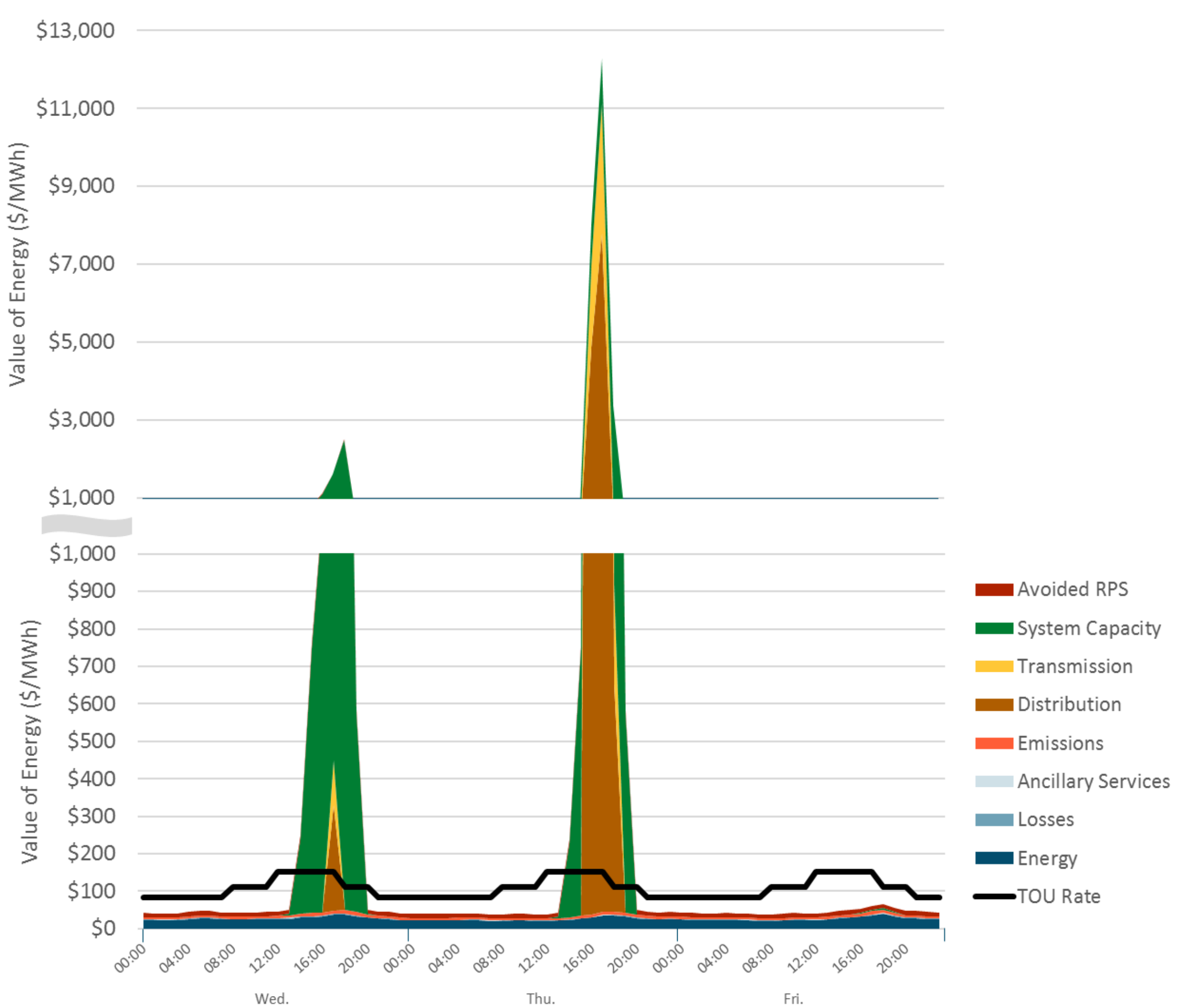

Figure A-4
Three-day snapshot of PG&E TOU rates and CPUC avoided costs in 2016 [17]

SDG&E Grid Integration Rate

- The grid integration rate (GIR) consists of an hourly base rate plus the CAISO day-ahead hourly price (see Figure A-5).
- There are also two dynamic capacity adders—one for the top 150 system hours, and the other for the top 200 circuit hours.
- The GIR rate was proposed as part of SDG&E's SB350 Transportation Electrification.

Diagram 5-4: Commercial GIR[24]

Grid Integration Charge	
(kW)	($/Mo.)
0-20	522.37
20-50	882.55
50-100	1,458.85
100-200	2,539.41
200-300	3,980.15
300-400	5,420.90
400-500	6,861.64
500+	up to 160K

+

Hourly Base Rate	
	(¢/kWh)
Base Rate	9.690
+	
CAISO Day Ahead Hourly Price	

+

Dynamic Adders	
	(¢/kWh)
System Top 150 Hours	50.535
Circuit Top 200 Hours	18.656

Figure A-5
Commercial GIR [18]

An analysis performed for the SGIP evaluation of energy storage is also instructive for the value of more dynamic rates for V2G.

- Six customers from SDG&E were selected, encompassing a variety of building types and battery sizes (see Figure A-6).
- AES systems were dispatched in price taker optimization model. Resulting utility avoided costs, customer bill savings, and CO_2 emission savings were quantified.
- The GIR pilot rate was modeled against existing rates.
- VGI and TOU-DR-E3 rates were also analyzed, with similar results.

CUSTOMER SAMPLE SUMMARY

RTE	Customer IDs	Existing Rate	kW Size	Type	Online Date	Effective kW
84%	SD-SGIP-2014-0684	ALTOU_CPP_Hybrid	400	Industrial	5/1/2016 0:00	268
91%	SD-SGIP-2013-0537	ALTOU_CPP_hybrid	60	Mining	2/1/2016 0:00	55
84%	SD-SGIP-2013-0555	ALTOU	30	Food/Liquor	1/1/2016 0:00	30
81%	SD-SGIP-2013-0557	ALTOU	30	Food/Liquor	1/1/2016 0:00	30
84%	SD-SGIP-2015-0758	ALTOU	2000	Industrial	5/1/2016 0:00	1339
81%	SD-SGIP-2015-0757	ALTOUCP2	1600	Industrial	5/1/2016 0:00	1071

Figure A-6
Customer sample summary

Operating under the GIR rate tends to improve the $/kW of energy storage utility avoided costs over the existing rate. Across the sample, the GIR rate has average $/kW savings of $14.80/kW, versus $5.83/kW for the existing rate (see Figure A-7).

Figure A-7
$/kW avoided costs

2016 Avoided Costs

Super Off Peak / Summer / Off Peak / Super Off Peak / On Peak / Super Off Peak

	1	2	3	4	5	6	7	8	9	10	11	12
0	0.087	0.063	0.031	0.040	0.049	0.072	0.069	0.059	0.044	0.044	0.039	0.047
1	0.073	0.054	0.030	0.042	0.051	0.069	0.066	0.060	0.043	0.043	0.038	0.045
2	0.059	0.047	0.030	0.040	0.050	0.061	0.059	0.056	0.043	0.042	0.038	0.044
3	0.051	0.042	0.031	0.037	0.049	0.052	0.054	0.051	0.044	0.044	0.038	0.044
4	0.049	0.040	0.034	0.038	0.048	0.043	0.051	0.048	0.046	0.047	0.040	0.045
5	0.050	0.039	0.040	0.042	0.047	0.042	0.048	0.046	0.049	0.054	0.045	0.050
6	0.053	0.043	0.044	0.041	0.040	0.040	0.043	0.046	0.048	0.058	0.051	0.056
7	0.052	0.042	0.036	0.016	0.010	0.030	0.041	0.043	0.043	0.047	0.046	0.058
8	0.044	0.036	0.020	(0.010)	(0.001)	0.019	0.039	0.043	0.039	0.039	0.038	0.050
9	0.041	0.032	(0.001)	(0.017)	(0.006)	0.017	0.034	0.044	0.039	0.035	0.030	0.044
10	0.039	0.030	(0.002)	(0.020)	(0.010)	0.022	0.038	0.046	0.047	0.032	0.027	0.039
11	0.038	0.027	(0.007)	(0.018)	(0.008)	0.029	0.043	0.048	0.052	0.038	0.029	0.038
12	0.037	0.026	(0.008)	(0.019)	(0.008)	0.032	0.046	0.051	0.058	0.042	0.028	0.035
13	0.037	0.027	(0.006)	(0.017)	(0.008)	0.037	0.053	0.058	0.104	0.078	0.035	0.037
14	0.039	0.033	0.001	(0.011)	(0.003)	0.043	0.058	0.069	0.130	0.099	0.038	0.042
15	0.041	0.036	0.010	0.003	0.006	0.049	0.065	0.087	0.166	0.125	0.045	0.048
16	0.047	0.040	0.037	0.021	0.020	0.056	0.064	0.085	0.162	0.114	0.057	0.058
17	0.062	0.050	0.043	0.042	0.043	0.062	0.068	0.083	0.132	0.108	0.071	0.071
18	0.061	0.056	0.051	0.051	0.048	0.066	0.071	0.073	0.087	0.079	0.062	0.068
19	0.065	0.050	0.047	0.054	0.057	0.062	0.064	0.064	0.079	0.066	0.056	0.064
20	0.075	0.047	0.042	0.045	0.048	0.053	0.058	0.056	0.069	0.059	0.053	0.061
21	0.091	0.052	0.039	0.041	0.041	0.047	0.059	0.051	0.052	0.052	0.049	0.056
22	0.108	0.061	0.035	0.037	0.038	0.052	0.064	0.048	0.048	0.048	0.045	0.052
23	0.107	0.062	0.033	0.035	0.044	0.065	0.069	0.050	0.045	0.045	0.042	0.049

Showing TOU periods adopted in SDG&E Revenue Allocation and Rate Design Proceeding D. 17-08-012 (A. 15-01-012)

SDG&E GIR*

Super Off Peak / Summer / Off Peak / Super Off Peak / On Peak / Super Off Peak

Month

	1	2	3	4	5	6	7	8	9	10	11	12
0	0.187	0.171	0.128	0.165	0.148	0.187	0.156	0.173	0.124	0.125	0.120	0.127
1	0.169	0.169	0.111	0.163	0.147	0.186	0.156	0.173	0.124	0.124	0.119	0.126
2	0.169	0.151	0.111	0.163	0.147	0.184	0.155	0.172	0.124	0.123	0.119	0.125
3	0.168	0.151	0.112	0.165	0.148	0.185	0.139	0.172	0.124	0.125	0.119	0.125
4	0.137	0.152	0.115	0.119	0.150	0.137	0.139	0.158	0.127	0.128	0.121	0.126
5	0.140	0.120	0.120	0.123	0.153	0.139	0.140	0.127	0.130	0.150	0.126	0.131
6	0.145	0.124	0.124	0.122	0.150	0.121	0.140	0.127	0.129	0.153	0.132	0.137
7	0.146	0.123	0.117	0.113	0.130	0.120	0.122	0.124	0.124	0.144	0.127	0.139
8	0.141	0.117	0.110	0.106	0.112	0.120	0.123	0.124	0.120	0.120	0.119	0.131
9	0.122	0.114	0.108	0.104	0.112	0.121	0.125	0.125	0.120	0.119	0.113	0.125
10	0.119	0.112	0.107	0.105	0.113	0.123	0.127	0.127	0.135	0.120	0.112	0.120
11	0.119	0.112	0.107	0.105	0.113	0.125	0.130	0.129	0.137	0.122	0.113	0.118
12	0.118	0.112	0.107	0.105	0.113	0.127	0.132	0.131	0.139	0.135	0.114	0.116
13	0.118	0.113	0.113	0.106	0.113	0.129	0.135	0.146	0.191	0.173	0.116	0.118
14	0.120	0.114	0.114	0.109	0.114	0.134	0.139	0.162	0.231	0.181	0.119	0.122
15	0.122	0.117	0.116	0.111	0.116	0.136	0.168	0.190	0.253	0.227	0.126	0.129
16	0.128	0.121	0.121	0.115	0.118	0.138	0.144	0.198	0.252	0.206	0.138	0.139
17	0.143	0.131	0.129	0.123	0.124	0.142	0.148	0.180	0.241	0.196	0.151	0.152
18	0.157	0.137	0.132	0.132	0.129	0.146	0.152	0.158	0.175	0.165	0.142	0.148
19	0.151	0.131	0.128	0.135	0.138	0.143	0.144	0.145	0.167	0.154	0.137	0.145
20	0.165	0.128	0.123	0.126	0.129	0.134	0.153	0.137	0.160	0.148	0.134	0.142
21	0.194	0.158	0.120	0.122	0.122	0.144	0.147	0.132	0.144	0.133	0.130	0.137
22	0.208	0.174	0.116	0.118	0.135	0.175	0.160	0.129	0.128	0.129	0.126	0.133
23	0.205	0.171	0.114	0.149	0.150	0.189	0.158	0.159	0.126	0.126	0.123	0.130

*Calculated using 2016 CAISO and DER avoided cost data

Figure A-8
2016 avoided costs and SDG&E GIR

Summary

Previous sections have described a variety of approaches to assess the value of V2G-capable vehicles to the grid through a variety of mechanisms. These sections summarized how to translate this macro or per-vehicle value into program definitions and verify them through pilot implementation so the technology and market acceptance of a variety of approaches can be evaluated for effectiveness in terms of technology performance and customer engagement.

Program:

Electric Transportation

3002014771

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