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Developing Strategies for
Plug-in Electric Vehicle and
Smart Grid Integration in California:
A Qualitative Analysis of Expert Opinions

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Abdulkadir Bedir
Joan M. Ogden
Thomas T. Turrentine

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Abdulkadir Bedir*, Joan Ogden, and Thomas Turrentine

*Institute of Transportation Studies
University of California, Davis*

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Abstract

This empirical study first identifies vehicle-grid integration (VGI) strategies as discussed by stakeholders in California, then, provides a feasibility assessment for these strategies focusing on technical and market challenges. VGI strategies presented in this paper include four components; (1) plug-in electric vehicle (PEV) load identification and tracking, (2) choosing a load management strategy, (3) deployment of enabling technologies, and, finally, (4) providing grid services and compensating participants. The assessment is performed based on a qualitative analysis of expert opinions gathered by a series of stakeholder interviews. These interviews were conducted between March 2013 and June 2014, including representatives of 18 organizations from the government, electric utility, and PEV sectors. The participants expressed their opinions about potential VGI strategies based on personal or company experiences. The qualitative data is analyzed under three categories of load management, which include dynamic pricing, demand response, and energy storage. The results show that both, technical and market challenges exist in each of the load management strategies, except the most basic dynamic pricing strategy. This strategy, which provides special time-of-use rates for PEV-owner households, is currently being implemented by all major utilities in California. The findings also feature a list of technical and market challenges that need to be taken into consideration by stakeholders in VGI-related decision-making.

Keywords: Plug-in Electric Vehicles; Vehicle-Grid Integration; Feasibility Assessment; Expert Opinion Analysis

* Corresponding Author: abedir@ucdavis.edu

1. INTRODUCTION

Deployment of plug-in electric vehicles (PEVs) presents several benefits to the transportation economy and environmental sustainability. According to a group of energy regulators in California (Governor's Office, 2013) these benefits can be classified into the following five categories: (1) decreasing cost of transportation fuel, (2) improving air quality – locally and globally, (3) increasing energy independence, (4) supporting the clean technology sector, and, finally, (5) supporting the electricity grid through PEV-based grid services. Among these benefits, supporting the electricity grid is becoming an important issue due to rapid increase in renewables. Especially in California, the share of renewables is expected to reach 50% of the electricity generation mix by 2030 (Olson et al., 2015). The amount of electricity generated by renewables can be hard to predict based on environmental conditions. This situation brings challenges in grid operations. The uncertainties caused by renewables make the grid vulnerable to large imbalances between demand and supply, and, therefore, higher frequency and voltage spikes. These challenges motivate energy planners in California to consider PEV-based grid services, which have significant potentials for integrating renewables, improving grid reliability and, also, mitigating negative impacts of the growing PEV load on the grid infrastructure (Ryan and Lavin, 2015).

Enabling PEV-based grid services, on the other hand, requires developing appropriate technology and policy frameworks, known as *vehicle-grid integration* (VGI). Our previous study (Bedir et al., 2015) showed that the feasibility of incorporating VGI enabling technologies into the grid has been one of the major barriers in policy-making in California. This empirical study first identifies potential VGI strategies as considered by the stakeholders in California, then, provides a feasibility assessment for these strategies focusing on technical and market challenges. VGI strategies presented in this study included four major components; (1) identification of PEV load, (2) choosing a load management strategy, (3) deployment of enabling technologies, and, finally, (4) providing grid services and compensating participants. This study especially focused on the load management strategies to address the questions related to how PEVs on the grid should be tracked, communicated, managed, and compensated based on their benefits to the grid system. The analysis is performed based on a set of qualitative data from VGI stakeholder interviews. These interviews were conducted between March 2013 and June 2014, including representatives of 18 organizations from the government, electric utility, and PEV sectors. The organizations in California are chosen because of the State's experience in developing VGI technologies and policies. The participants evaluated feasibility issues associated with potential VGI strategies based on personal or company experiences. The stakeholder opinions are compared and contrasted for issues on which they were divided.

The following section provides the necessary technical background on major grid operations, smart grid and VGI. The methodology for data gathering and analysis is described in detail in Section-3. In Section-4, the qualitative data is analyzed under three categories of demand side management, which include dynamic pricing, demand response, and energy storage.

II. TECHNICAL BACKGROUND ON VGI

Recent developments in information technologies led grid operators toward the vision of a *smarter grid* system where intelligent and prompt control systems are implemented over the complex grid infrastructure enabling reliable, cleaner, and efficient electricity delivery. These communication and control systems have different implications at the electricity supply and demand sides. Figure-1 presents some key components of the smart grid, including generation, transmission, and distribution systems with end-users including industrial, commercial and residential customers. Among the components shown in Figure-1, the system operator, also called the independent system operator (ISO) has a critical role in balancing demand and supply through direct regulations or various market measures. Utility companies are mostly responsible to deliver electricity through their distribution infrastructure. The distribution infrastructure includes substations and distribution transformers, which provide a safe way of power delivery to customers from high or medium-voltage electricity lines. For residential areas, distribution transformers are usually called neighborhood transformers. Note that, in Figure-1, the cylinder-looking neighborhood transformers are located on the poles presented in the distribution system.

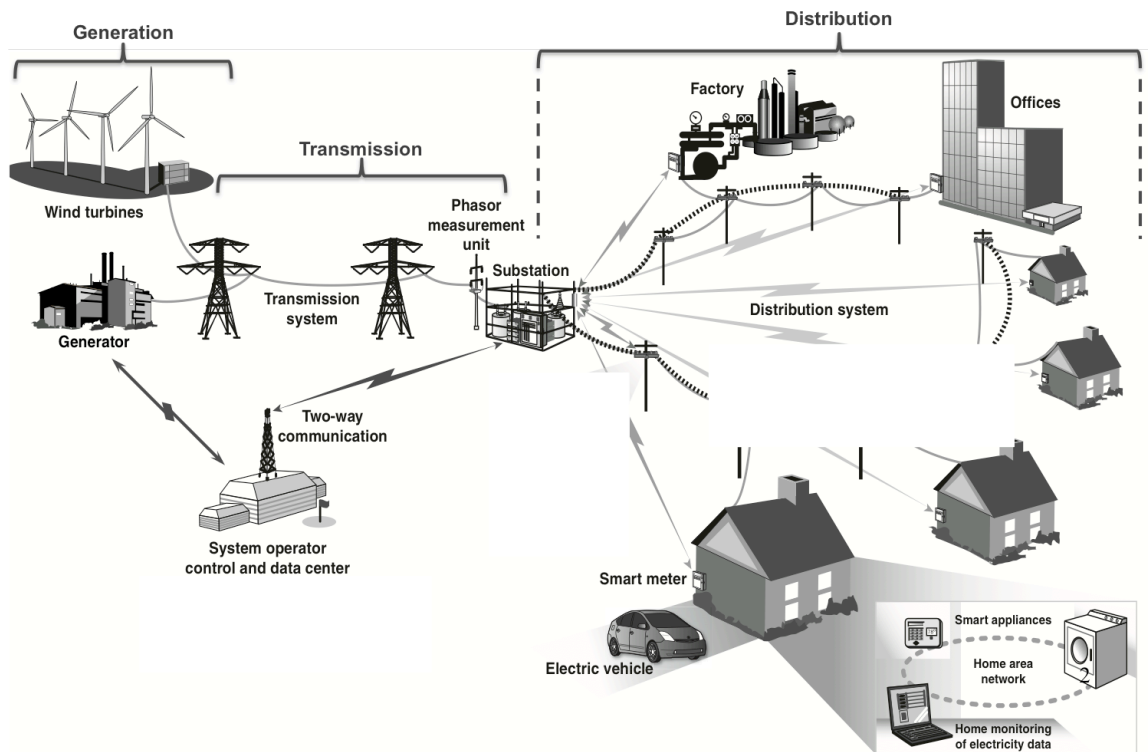


Figure-1. Illustration of a smart grid system (as adapted from GOA, 2011).

On a smart grid, the emerging technologies enable consumer control of electricity consumption. For instance, new telemetry technologies are being used to communicate with consumers and encourage them to adjust their consumption during critical times. Such applications on the grid bring prospects toward advancing *demand-side*

management (DSM) programs in order to improve better utilization of the generation assets, and prevent increases in peak electricity demand. In particular, preventing increases in peak electricity demand is very important for stakeholders in the electricity sector as they plan the generation, and transmission infrastructure based on the peak demand—often occurring during summer heat storms in California.

Recently, DSM is becoming more important due to increased renewable electricity generation, especially from solar and wind-based generation (Williams et al., 2012). The electricity generation through renewables can be hard to predict based on environmental conditions. Such situations create high uncertainty in the system. Additionally, distributed generation such as residential PVs can create technical difficulties in the distribution system such as voltage sags and so-called backfeeding problems (Lewis, 2011). Figure 2 shows several hourly load curves for the California ISO (or CAISO) between the years 2012 through 2020. These curves are based on future estimates in the demand and electricity generation mix, and represent a load profile for an average day in CAISO territory. Net load is the difference between forecasted load and expected electricity production from renewables. As seen on Figure-2, these curves produce steep reductions in the mid-afternoon that quickly ramps up to produce an “arch” in the evening. These conditions on the grid system create needs for new resources with specific operational capabilities. For instance, these resources need to have short and steep ramp capability in the case when CAISO must start or shut down generation resources in order to meet an increasing or decreasing electricity demand over a short period of time. In this regard, some DSM strategies present potential low-cost solutions that meet the required operational flexibility described above.

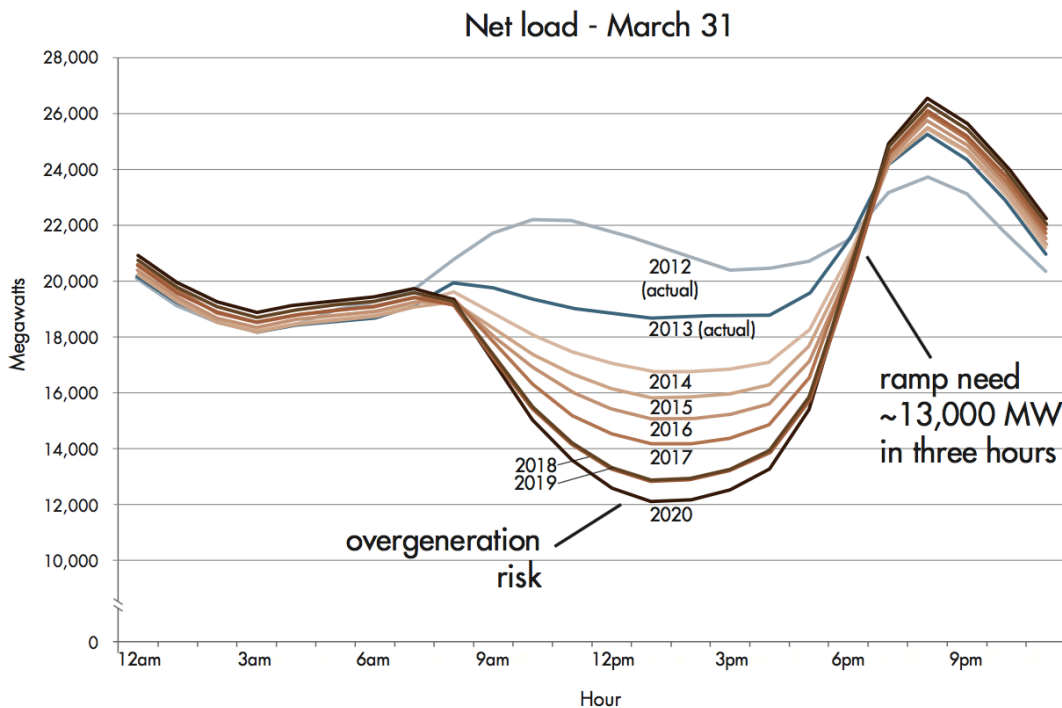


Figure-2. The estimated net load curves show steep ramping needs and overgeneration risk after increased renewable generation in CAISO territory (CAISO, 2013)

The DSM strategies discussed in this paper include energy storage systems (ESS), demand response programs, and, most basically, dynamic pricing programs such as time-of-use (TOU) and real-time pricing (RTP) rates. TOU rates follow a fixed schedule of prices that vary by time of the day and season. The rates reflect historical patterns of daily demand. RTP is a variable price per kWh that reflects real-time changes in the wholesale market price of electricity. The dynamic pricing programs target long-term changes in consumer behavior, however, they may not provide urgent load curtailment solutions during critical periods such as peaking generation capacity and transmission capacity. In such emergency cases, demand response programs and ESS can provide solutions for the load curtailment.

In demand response programs, usually administrated by independent system operators or utilities, electricity consumers (traditionally large-industrial customers) participate through so-called *direct-load control* (DLC) programs. DLC refers to demand response programs in which the participant's consumption is temporarily limited by an automated management system during a demand response request (Leo et al., 2012). Due to these arrangements, DLC-based demand response programs require telemetry devices and official agreements between program participants and the program providers.

In California, the grid system operator, CAISO, manages DR programs, in which participants can enroll and receive compensation based on several performance measures, including the amount of electricity they curtail during a DR request. Based on CAISO terminology, DR and ESS *resources* can ramp-up or ramp-down the net load curve and can provide energy and/or ancillary services to the grid. Therefore, these resources can participate in wholesale markets, which include real-time and day-ahead markets. The ancillary grid services market includes reserve and frequency regulation markets. This scope of market measures (energy, reserves, and frequency regulation) target minimizing the gap between supply and demand optimally in real-time (also called load balancing). Resources that provide ancillary grid services need to operate faster, and in some cases, be automated directly by the system operator. In this regard, demand response and ESS are considered low-cost and reliable options for ancillary grid services.

The market measures described above provide incentives for utilities to participate in load balancing as well. Through a mix of the DSM programs (e.g. dynamic-pricing, DR, or ESS), utilities may buy electricity at a lower cost during off-peak hours, protect their infrastructure from overloads, and be compensated by their system operator if they participate in CAISO-level DR programs. Recently, utility-administrated residential DR is becoming popular for the air conditioning load, especially during summer heat waves (Mathieu et al., 2015). Utilities limit the use of air conditioners through a device installed in participants' homes, and participants are compensated by annual bill credits as a financial incentive.

The DSM strategies described above such as dynamic pricing, demand response, and energy storage can be applied to PEVs. In the following sections, these load management strategies will be evaluated for PEVs from technical and market feasibility perspectives. The technical feasibility assessment will include PEV metering, telemetry, and the use of

bidirectional chargers (BC), which enable two-way (bidirectional) power flow between PEV battery and the grid. The market feasibility assessment will include limitations and concerns from the perspectives of consumers and the wholesale electricity market.

III. METHODOLOGY

The data for this empirical study is collected through stakeholder interviews. These interviews were conducted between March 2013 and June 2014. As seen in Table-1, the participants are the representatives of various stakeholder organizations from the utility and PEV sectors. The interview invitations were sent to a sample of 20 organizations that were active participants in the VGI roadmap workshops. Table-1 provides a list of participants from policy, utility and PEV sectors. The PEV sector consists of representatives from original equipment manufacturers (OEMs), PEV supply equipment (EVSE), and service provider (EVSP) companies. Twelve of the 18 interviews were conducted in-person at the participants’ workplaces. The rest of the interviews were conducted by phone. The participants are full-time employees who hold administrative or senior staff positions in a PEV-related department or working group.

Table-1: The stakeholders that participated in VGI stakeholder interviews

	STAKEHOLDER ORGANIZATION	DATE
1	California Independent System Operator	03.21.13
2	San Diego Gas & Electric (SDGE)	03.25.13
3	Southern California Edison (SCE)	03.25.13
4	Sacramento Municipality Utility District	04.03.13
5	ChargePoint	04.04.13
6	Pacific Gas and Electric (PG&E)	04.05.13
7	Nissan North America	04.08.13
8	AeroVironment	04.10.13
9	Ford	04.12.13
10	Los Angeles Department of Water and Power	04.18.13
11	ECotality	04.25.13
12	California Public Utilities Commission	11.20.13
13	Sacramento EV Buyers Association	12.10.13
14	Former Senator Christine Kehoe	12.20.13
15	GM/OnStar Alliance	01.08.14
16	California Energy Commission	04.24.14
17	Governor's Office	04.30.14
18	BMW North America	06.11.14

During the semi-structured interviews, stakeholders were asked questions related to four major topics; (1) their perception of the technical and economic value of VGI; (2) their preferences regarding technology and policy framework; (3) their relations with other stakeholders; (4) and lastly, their visions on consumer engagement. The participants evaluated feasibility issues associated with potential VGI strategies based on personal or company experiences. The qualitative data is coded as key VGI technologies such as PEV metering, submetering and telemetry, and load management concepts such as TOU rates, RTP, and DLC.

This study presents qualitative data as the expert opinions to develop a basis for understanding current and future issues related to feasibility assessment for VGI. As discussed by Dennis (2015), a feasibility assessment for a technology or project may include several measures such as technical feasibility, economic feasibility, market or marketing feasibility, resource feasibility and operational feasibility. These feasibility measures may exist in different levels based on the topic that is being evaluated. In the case of VGI, stakeholders mostly focused on the technical and market challenges. Therefore, the feasibility assessment in this study focused on the identification of technical and market feasibility issues as the primary target areas.

The use of stakeholder interviews as expert opinions is discussed by several studies in the literature. For instance, Hirschey (2008) discussed that the opinions of experts carry a lot of weight in many professions, if they consist of unbiased and informed opinions. On the other hand, Knudson and Morrion (2002) presented the weaknesses of using expert opinions in empirical research. The authors discussed that the expert opinions are subjective and they may conflict and often change about key points of an issue. Additionally, the stakeholder organizations are usually also interest groups, especially in the area of energy policy. Therefore, the survey participants may express opinions that carry some level of their personal or company interest. These aspects of the expert opinions are considered as the major limitations in this study.

IV. ANALYSIS

This section provides a feasibility assessment for VGI strategies based on the qualitative data collected from stakeholder interviews. The stakeholders mostly discussed four major stages regarding VGI. These stages are conceptually presented in Figure-3. As seen on the figure, the first stage for VGI is identified as the PEV load identification. By the identification of PEV load, stakeholders can understand the potential for VGI. This is currently being done by so-called utility notifications (CPUC, 2010a). Utility representatives work with automakers and consulting companies to gather location-specific PEV ownership data in their territories (interview). After understanding the VGI potential, interested parties need to set specific goals for the types and amount of PEV-based grid services that they can utilize through PEV load management strategies. The second stage of VGI is the design of a particular PEV load management strategy that will incentivize consumer participation. The PEV load management strategy can be based on one or more of the DSM programs such as dynamic pricing, demand response, or energy storage. This stage requires complicated system assessments to evaluate proposed load management programs that can be implemented, considering market realities. Through these assessments, stakeholders can compare the potential load management programs based on the technical feasibility and economic value, and make decisions on the execution before spending resources on enabling technology and marketing.

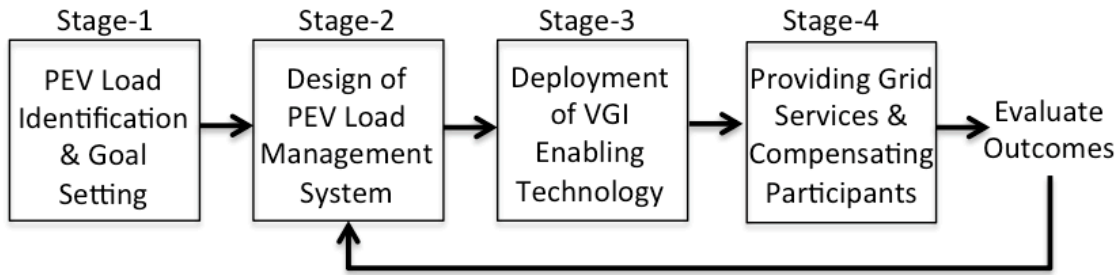


Figure-3: Conceptual representation of four-major stages involved in VGI

The third and fourth stages of VGI involve the execution of the chosen PEV load management strategy. The enabling technology, such as a communication infrastructure, should be provided to PEV owners and the participants of the load management such as PEV buyers, utilities or service providers who manage the PEV telemetry, should be compensated by the electricity market mechanisms. Finally, by evaluating outcomes of the adopted PEV load management strategy, stakeholders can understand the successes and failures, and consider changes in the design of their load management strategy.

The following analysis identifies major VGI-related technical and market challenges, which decision-makers should consider in their feasibility assessments. As discussed in Section-2, the major load management strategies for PEVs are identified as (1) dynamic pricing, (2) demand response, and (3) energy storage. Each load management strategy should address the questions such as how the PEV load should be identified/included, communicated, managed, and compensated. As also discussed in Section-2, some load management strategies may be considered differently. Table-2 presents a list of load management strategies currently being implemented or evaluated by the stakeholders in California. In the following paragraphs, each of the strategies will be evaluated from technical and market-feasibility perspectives based on the expert opinions gathered from the survey data.

Table-2: PEV load management strategies considered by stakeholders in California

PEV Load Management	Description
Dynamic pricing: PEV Household-TOU	Special TOU rates for those households who own a PEV. This program has higher on-peak rates and lower off-peak rates compare to regular rates.
Dynamic pricing: PEV-TOU	Special TOU rates, for the PEV charging only, which have higher on-peak rates and lower off-peak rates compare to previous program (PEV Household-TOU).
Dynamic pricing: PEV-RTP	RTP rates, for the PEV charging only, where price signals represent the real-time changes in the wholesale electricity prices and/or renewable electricity generation.
Demand Response: Direct Load Control (DLC)	Demand response programs where PEV load is aggregated, and being monitored and managed by a 3 rd party agent who participates in a DR program managed by the utility or system operator.

Energy Storage: Vehicle-to-Grid (V2G)	PEV battery represents an ESS that can be used for load shifting, residential PV integration, and a back-up power by the household.
Energy Storage: Vehicle-to-Home (V2H)	PEV battery represents an ESS that can sell power back to the grid when PEV owner participates in an ESS program managed by the utility or ISO.

4.1 Dynamic Pricing for PEVs

Stakeholders, especially utility representatives, discussed dynamic pricing strategies as the most basic form of load management strategy for PEVs. Utilities in particular have experience adopting TOU rates for PEV owner households (PEV Household-TOU). This strategy is already implemented by the five largest electric utilities in California. Through these programs, the households owning a PEV can enroll in a special electricity rate program, which typically has cheaper electricity rates during off-peak demand hours and higher prices during on-peak demand hours. The timing and amount of PEV household TOU rates change seasonally. Among the PEV household TOU rate options in California, the cheapest rates were provided by LADWP as 6 cents/kWh for winter off-peak, while most expensive rates were provided by PGE as 37 cents/kWh for the super-peak hours in summer (interview). This pricing scheme shows that the cost of PEV charging can be six times more expensive in California based on the location and time that a PEV is being charged.

Through the PEV household TOU rates, utility representatives were agreement that they receive satisfactory behavioral change from consumers. For instance, an SDGE representative mentioned, “*For now, TOU prices (are) good enough; eighty percent of charging happens at night*” (interview). Such an outcome is very favorable for the utilities because these programs do not require a separate utility meter or a particular grid communication system to be implemented. By using existing smart meters, utilities can provide a special TOU rate for households that own a PEV. On the other hand, these utilities also currently provide another dynamic pricing option for PEV consumers, where a separate utility meter is installed in the PEV owner’s house for billing PEV charging only (also called “PEV metering”). Through this separate smart meter, utilities can provide PEV-only TOU rates. Although these rates are usually more complicated as compared to the PEV household TOU rates, they better represent daily patterns of the wholesale electricity market.

There are two types of configurations that can be applied to the additional PEV meter (CPUC, 2010b). The first configuration is called a series meter, which is installed under the same electricity panel and on the same electricity line where household smart meter is connected. This option is cheaper as compared to a parallel configuration where a meter is installed onto a separate electricity panel. However, the cheaper series configuration requires more complicated data management. In general, there was a concern that the use PEV-only dynamic pricing may not be convenient for consumers due to the additional cost paid to the supplementary smart meter, panel upgrades, labor and permits. The cost of installing a separate utility meter was estimated at \$2,000, according to the ChargePoint representative (interview). Stakeholders also consider use of customer-

owned submeter for billing PEV load. This customer-owned submeter can be located in the EVSE or in PEV itself. On the other hand, such a system requires electricity regulators to develop standards and procedures, where the 3rd party (submeter manufacturer) will be responsible for certification, accounting, and billing data produced by their submeter (CPUC, 2012). A utility representative voiced his concerns on the reliability and compliance issues of using non-utility metering for billing purposes (interview). This issue is currently a policy discussion in the CPUC's AFV agenda. A roadmap for adapting PEVSP was released in Jan 2012 (CPUC, 2012).

Utilities currently do not offer RTP rates for the PEV consumers. The utilities agreed that the RTP rates might be difficult for the consumers to follow, with the exception of the workplace charging (interview). At the time of the interview, SDGE started their workplace RTP program where the prices reflect the day-ahead electricity market (interview). The SDGE's workplace pilot program includes 35 workplace charging station located in the utility campus.

4.2 PEV-Based Demand Response

Dynamic pricing programs target long-term behavioral changes in the ways that PEV buyers charge their cars, however, these programs do not provide solutions for urgent grid issues such as real-time balancing of supply and demand. Grid services that are being used for real-time balancing of supply and demand are becoming more important with the rapid increase of renewable electricity generation. Advanced load management options, such as demand response and energy storage, are being considered to allow PEVs participate in major grid services. As discussed in Section-2, demand response programs can be designed for PEVs in the form of direct load control (DLC) where a third-party agent manages a group of PEVs collaborating with the utility or CAISO. In this regard, stakeholders mostly discussed the implementation of a telemetry system for DLC, which will allow PEV-grid communication and PEV charge control. PEV-grid communications refer to the PEV charging systems where a two-way data communication exists between PEV buyer and utility (or a third party company on behalf of the grid operators).

Enabling communication between PEV and grid systems is a major technical challenge that raises data management issues similar to PEV metering. On the other hand, it is critical to build a telemetry system to integrate PEVs with other smart grid systems. If enabled, the PEV-grid communications can be used in the management of PEV load, aggregated or individually, to provide energy, non-spinning reserves, and frequency regulation services. Currently, there are several communication technologies available for PEV-grid applications including cellular networks, satellites, power line carriers, and household WiFi. OEMs and EVSE companies may adapt one of these technologies to connect PEVs into their network. When it comes to manage PEV charging, OEM representatives expressed their concerns about an EVSE-based communication system. From an OEM perspective, the EVSE involvement in PEV-grid communication is an “*intervention*” because PEVs are already equipped with the cellular network (interview).

Additionally, EVSEs may not provide advanced charging algorithms since they cannot receive signals from PEVs regarding the battery's state of charge. On the other hand, EVSE-based communications provide some advantages in the shared charging environment, such as public charging and workplace charging, where the EVSE can provide spatial data regarding the locations of PEV load (interview). From a utility's perspective, whether communication solutions are provided by EVSE or OEM does not matter—it is all about the cost, “*whichever provides the cheapest option—that one is better (interview).*” Representatives from PG&E and SMUD seemed to be very interested in working with communication providers to learn about the cost of adapting a particular infrastructure and data management system. Related to this topic, the ChargePoint representative estimated that they pay about \$10/year per charger for the cellular connection installed in their 15,000 PEV charge stations (interview). He added that the cost of \$10/year is very sensitive to the amount of data being used by a particular charger.

Representatives from both utility and automaker companies mentioned Electric Power Research Institute (EPRI)'s effort to create a so-called *open integration platform* for PEVs. EPRI leads a group called Infrastructure Working Council, which includes 8 automakers and 15 large-scale utilities across the US (EPRI, 2014). Utilities agreed that standardization among the PEV manufacturers would be helpful in accelerating VGI (interview). On the other hand, current regulations in the state of California do not allow the adoption of mobile systems (such as cars) for the use of load metering and utility billing (CPUC, 2012). Stakeholders first need to wait for the Division of Measurement Standards (under California Department of Food and Agriculture) to develop procedures for certifying mobile meters. Once this is accomplished, stakeholders need to address how these mobile submitters will be associated to the master (household) meters, and be managed when the PEVs are being charged in a different utility jurisdiction.

Besides the technical challenges mentioned above, stakeholders also discussed several market challenges related to the PEV participation in demand response. These market challenges exist on both sides—consumers and the wholesale electricity market. In the wholesale market, CAISO DR, called proxy demand resources, participants should provide load curtailment at the minimum 100 kW for the energy market and 500 kW for the non-spinning reserve market (CAISO). Smaller loads that are aggregated to meet the minimum requirements should be located in one of the 24 CAISO-defined areas, which do not include SMUD and LADWP territories. Besides the location and minimum load requirements, DR participants above 10 MW are required to have a telemetry system in compliance with NERC standards. This amount would correspond to a fleet of 3030 PEVs, considering a level-II (at 3.3 kW) charging scenario. Considering these telemetry and location requirements, a CAISO representative postulated that the existing DR program by CAISO might be difficult to adopt for PEVs in the near-term.

Additionally, representatives from PGE and CPUC mentioned that the regulation market in CAISO is relatively small and may not be attractive for PEVs. Although, PEVs can be a low-cost solution, PEV consumers, especially those who own a small battery, may not receive significant revenue from the regulation market. As a CPUC representative mentioned, “*if you have 100,000 EVs, they will saturate the frequency regulation*

market—the price will be zero (interview).” This observation is supported by a scientific study Leo et al (2012). The researchers found that there is a negligible revenue opportunity for aggregators and end consumers, totaling only \$8 per PEV annually, considering a high PEV adoption scenario in California. In contrast to the case in California, some stakeholders discussed that market conditions for the grid services vary among regions. Therefore, frequency regulation may have a potential value for different regions in the US, especially some regions on the East Coast (interview).

Finally, the issue of consumer engagement has been discussed. Most of the stakeholders mentioned that they have had very limited experience so far when it comes to consumer engagement. The initial thought about the potential consumer profile is that environmentally motivated consumers are most likely to participate if they have large battery capacity (interview). OEM representatives generally expressed a more consumer-focused approach toward VGI. He was concerned that PEV buyers may have difficulty understanding PEV-based grid services. As the GM/OnStar representative explains (interview):

“We are very much advocates of making sure the utilities have some of the fundamental relationship with the customers across the board. So it is very easy to say customers are [going to] find out VGI activities, but the truth is that the market is struggling even explaining PEV-TOU rate options.”

OEM representatives also expressed their concerns over the DR programs with automated load control. For instance, one Nissan representative mentioned that they have *“a huge concern that somebody else having control on DR will effect [consumers’ PEV experience] negatively* (interview).” From an OEM perspective, it is either the consumer or the OEM that should be the one to control charging. In summary, OEMs expect that if grid operators engage with PEV-based grid services, they should make it simple for the PEV consumers, and *“do not over-control* (interview).”

Despite the technical and market challenges described above, demand response is a hot topic among the stakeholders. In particular, participants from utility and automaker companies discussed their demonstration and pilot projects on PEV demand response. For instance, representative from SCE described their pilot project in their workplace. They were planning to install 180 chargers in 17 facilities with the goal of evaluating DR potential. Additionally, SMUD representative mentioned SMUD’s interest in automated load control programs during the summer heat storms (interview). At the time of the interview, SMUD was starting a pilot program, where the utility limits the level of PEV charging during the critical peak hours in summer.

4.3 PEVs as Energy Storage Systems

Finally, stakeholders discussed the use of PEV battery as energy storage for the grid in the form of vehicle-to-grid (V2G) or vehicle-to-home (V2H), which is a more isolated way of using PEV battery to reduce total electricity demand. This advanced load management strategy requires dealing with several technical challenges in addition to the challenges described in previous sections such as enabling PEV metering, telemetry, and

wholesale market challenges. The use of PEV battery for energy storage requires adopting bidirectional chargers, which is a type of PEV charger that permits two-way power flow between the PEV battery and the grid (or only the building into which the PEV is plugged).

Related to the use of PEVs in energy storage, interviewees first discussed the technical feasibility of the use of bidirectional chargers (BCs). Several OEM representatives mentioned that long-term impacts of frequent charge/discharge of the battery are unknown. As the Nissan representative mentioned, they do not have enough experience to know how bidirectional charging affects battery chemistry, “*different battery chemistry lends itself to different behavior and degradation* (interview)”. Therefore, the representative from Nissan concluded, “*the battery warranty issue is a totally unknown area* (interview).” Such ambiguity creates skepticism among the stakeholders about the future of PEV-based grid services that require BC technology.

Besides the concerns over battery, stakeholders also expressed concerns about the grid infrastructure. For instance, two utility representatives mentioned some technical limitations for V2G on the distribution side. These limitations include PEVs creating voltage sags and so-called *backfeeding* problems (interview). As utilities consider grid reliability as their primary responsibility, the participants from the utility sector mostly agreed that, “*V2G is a long time away,*” especially to be considered a widely available resource for the grid system (interview).

On the other hand, utilities were very interested to see consumers adopting vehicle-to-home (V2H) or vehicle-to-building (V2B) systems in their household or workplace. These systems require a complete isolation between PEVs and the grid when PEV is being used as a power resource. Therefore, these systems require a separate electric panel that is connected in parallel to the main electric panel that carries power from the utility. Despite the anticipated high cost, some utility representatives suppose that consumers might be interested in V2H to use as back-up power or for better utilization of their solar panels (interview). Additionally, V2H does not require any agent to be involved since the PEV owner has complete control over the system.

Finally, stakeholders, especially policy-makers, discussed the use of V2G applications for vehicle fleets. A CAISO representative highlighted the V2G potential in fleets including trucks or busses with higher and more stationary batteries compared to light-duty vehicles. Consistent with this idea, CEC representatives mentioned that V2G could be of value on military campuses, where vehicles stay idle for long periods of time during the year (interview). Participants from CEC, CPUC and Aeroenvironment described a large-scale V2G demonstration project on two air force bases in Southern California (interview). The Los Angeles PEV and V2G demonstration project includes the first federal PEV fleet of 42 vehicles, which makes up 100% of the general-purpose fleet in that military base (Marnay et al., 2014). This demonstration project aims to utilize up to 700 kW of power capacity on the grid collaborating with SCE as the local utility company.

V. CONCLUSIONS

In this study, the industry experts from electricity and PEV sectors evaluated feasibility issues related to VGI strategies, focusing on technical and market challenges. The qualitative data is analyzed under three categories of demand side management strategies, which include dynamic pricing, demand response, and energy storage. Although, they are presented as completely separate strategies, some of these load management strategies can be implemented at the same time. For instance, at the time of the interview, SMUD were starting their VGI pilot program where they were experimenting feasibility of PEV-TOU rates and a DLC together in the same program. Table-3 presents a summary of the technical and market challenges as discussed by the stakeholders.

As seen in Table-3, both, technical and market challenges, exist in each of the load management strategies, except providing special time-of-use rates for the PEV owner households (PEV household-TOU). This strategy is currently being implemented by all major utilities in California. The following three conclusions are some of the highlighted results from the qualitative analysis in Section 4:

- Stakeholders from utility and automaker sectors were highly skeptical about the near-term feasibility and economic value from V2G. Fleet vehicles have been mentioned as the only near-term application of such system;
- Financial prospects of VGI on grid operations created a competition between OEMs and EVSP companies over being the primary service provider for PEV metering and PEV-grid communications;
- OEM representatives expressed concerns over the consumer engagement with PEV-based grid services. They are concerned that the complicated VGI programs by the utilities, and control of PEV charging by third parties may impact consumer experience from PEVs negatively.

Table-3: A summary of technical and market feasibility issues as discussed by the VGI stakeholders

PEV Load Management Strategies	Technical Challenges	Market Challenges
Dynamic Pricing	<ul style="list-style-type: none"> • Separate utility meters are costly. • Submetering systems for PEVs currently cannot be used in utility billing. 	<ul style="list-style-type: none"> • Implementation of real-time rates can be difficult for consumers to follow.
Demand response: Direct Load Control (DLC)	<ul style="list-style-type: none"> • Managing telemetry between PEVs and the grid system brings additional cost and data liability issues. • PEV-grid communication standards are under development. 	<ul style="list-style-type: none"> • DLC programs may limit consumers' control over the PEV charging, and have a negative impact on consumers' PEV experience.
Energy Storage	<ul style="list-style-type: none"> • The battery impacts of frequent charge and discharge are not totally understood. • The power from V2G creates reliability problems in the distribution system. • Installment of a separate electricity panel is costly. 	<ul style="list-style-type: none"> • The regulation market in CAISO currently does not have a significant potential for PEVs. • CAISO's telemetry and minimum load requirements will be difficult to apply on PEVs.

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