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The authors also thank Kelsey Johnson, who was instrumental in the operation and success of the INVENT Project.

PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable and advanced clean generation, energy-related environmental protection, energy transmission and distribution, and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The CEC and the state's three largest investor-owned utilities—Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emissions in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Intelligent Vehicle Integration is the final report for the INVENT Project (EPC-16-061) conducted by Nuvve Corporation. The information from this project contributes to the Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at ERDD@energy.ca.gov.

ABSTRACT

Electric vehicles can function as aggregated power plants, demand response resources, energy storage devices, and backup power systems. Yet there remains a lack of consensus regarding the role these functions will play as well as their value, technical readiness, and near- and long-term commercial viability. The Intelligent Electric Vehicle Integration Project (INVENT) demonstrated how vehicle-to-grid technology bidirectional electric vehicles combined with unidirectional electric vehicles and a third-party intelligent collection and control platform can benefit utility customers. Benefits increase by managing demand charges in response to retail electric prices, coordinating with rooftop solar energy production, responding as a virtual power plant to frequency regulation signals from the California Independent System Operator, and engaging in aggregated demand response bids. The project included a variety of commercially available electric vehicles and charging stations using several different communications protocols and power capacities in multiple locations distributed across the University of California, San Diego microgrid to represent a commercial rollout scenario. INVENT intentionally included drivers with diverse use and charging patterns to allow the research team to assess the appropriateness of the use cases being analyzed. The aggregation platform successfully coordinated and controlled electric vehicle charging and discharging to provide demand charge, renewable energy optimization, frequency regulation, and demand response services while meeting the mobility needs of drivers. The project assessed existing values and compensation opportunities for the provided services. The project identified gaps in current rules and unintentional disincentives that policy makers can mitigate to unlock the potential of electric vehicles as distributed energy resources.

Keywords: Demand Response, Frequency Regulation, Demand Charge Management, Renewable Energy Time Shift, On-Peak

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California has adopted a broad and comprehensive set of policies to remove carbon from its electricity sector, including electrifying the transportation sector. The two sectors are intertwined because electric vehicles use electricity and can store electricity. Intelligent electric vehicle charging technology is emerging alongside heightened customer awareness and expectation, as well as a growing number of zero emissions vehicles in California that is expected to reach 8 million [1].

In addition to legislation focused on reducing greenhouse gas emissions and increasing electrifying transportation, a series of new laws and regulatory proceedings have concentrated on electric charging station rollout, emergency backup power, and more. There remains, however, uncertainty among industry and policymakers regarding the role of electric vehicles: will they create a problematic, unpredictable new electric load or provide a new grid asset of unparalleled potential? What will be the value of the services plug-in electric vehicles can provide and who will benefit from that value?

Project Purpose

The Nuvve Holding Corporation lead a team to validate actual use cases in as-close-to-world conditions as possible to show stakeholders that vehicle-grid integration technologies are mature and should warrant development of supporting legislation and policy. The project included technical and practical customer-focused studies of selected transmission, distribution, and behind-the-meter applications to demonstrate the feasibility of vehicle-to-grid applications using commercially available technology and a variety of electric vehicles from multiple manufacturers.

The Intelligent Electric Vehicle Integration Project (INVENT) explored these uncertainties by measuring the value of the ways electric vehicles can act as distributed energy resources (DER). The project results will contribute to developing an integrated vehicle-grid market by:

- Demonstrating vehicle-grid integration technology with bidirectional (two directions) and unidirectional (single direction) vehicles.
- Demonstrating how electric vehicles deliver grid services through software aggregation.
- Showing available value streams and potential values that remain inaccessible to vehicle owners and aggregators.
- Assessing the evolving market and policy landscape.
- Analyzing existing gaps and barriers slowing adoption of these technologies.
- Recommending actual steps to move the industry forward.

Project Approach

[1] California Energy Commission. 2021. “Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment (Revised Staff Report)” https://efiling.energy.ca.gov/getdocument.aspx?tn=238032

The INVENT project required real-time communication and coordination between Nuvve's platform and drivers, cars, charging stations, and energy markets. The team used Nuvve's Grid Integrated Vehicle platform (GIVe™) software aggregation platform for the vehicle-grid integration services. This software creates a virtual power plant from multiple electric vehicle batteries linked to either bidirectional or unidirectional electric vehicle supply equipment chargers. The services and values explored were:

- Demand charge management
- Renewable energy time-shifting (focused on co-sited solar PV)
- Frequency regulation
- California Independent System Operator (ISO) demand response via the investor-owned utility Demand Response Auction Mechanism

Project implementation was in three phases:

- In Phase One, the researchers installed and tested the first tranche of a mix of unidirectional and bidirectional charging stations in selected locations around the University of California, San Diego (UCSD) campus for use by the university employees. The charging stations were integrated with the GIVe™ aggregation platform to enable second-by-second communication and control.
- In Phase Two, the project team recruited more drivers to participate, completing the project fleet with electric vehicle models from Nissan, Mitsubishi, Honda, and BMW. Vehicle charging schedules were analyzed to determine when it was beneficial for an electric vehicle to pause charging (unidirectional chargers) or discharge its battery (bidirectional chargers).
- Phase Three of INVENT combined unidirectional and bidirectional vehicle chargers on Nuvve's aggregation platform to demonstrate increasingly sophisticated grid services. Also, Nuvve aggregated electric vehicles with UCSD's 5 megawatt-hour (MWh) stationary battery to participate in the Demand Response Auction Mechanism. Strategen Consulting quantified the potential benefits of each use case at the individual site and grid levels.

The INVENT team formed a technical advisory committee that included representatives from BMW, the California ISO, City of San Diego Economic Development, the National Renewable Energy Laboratory, San Diego Gas and Electric Company, SunSpec Alliance, and Honda. The committee members supported the project throughout, assisting in achieving project goals, providing advice when barriers were encountered, and identifying paths forward when roadblocks were met.

Project Results

The INVENT project team successfully met its technical goals, including use case testing of remote fleet coordination and control, economic value analysis, and participation in external markets. The team successfully used forecasting and individual charging optimization to coordinate electric vehicle charging and discharging with building energy use and solar output, allowing assessment of existing rates and tariffs as facilitating mechanisms. The team gained access to the California ISO day-ahead energy market and bid the stationary battery's aggregated capacity and a subset of project electric vehicles, ultimately participating in the grid-wide effort to mitigate the August 2020 heat wave, during which the California ISO instituted rotating electricity outages to alleviate severe grid congestion and maintain safety.

This project results identified the need to integrate electric vehicles more aggressively into existing and planned policy and market frameworks. Simply adding new policies focused on electric vehicles will not address the policy and regulatory limitations that already exist. As increasing numbers of electric vehicles are added to the grid, their participation in grid services, and integration with other customer loads and resources, are limited by current electric vehicle, DER, and market frameworks.

Market design and the INVENT project were confined within a microgrid; this made identifying and accessing value streams a challenge. The outcome, however, was a rare if not unique demonstration of a microgrid resource participating in day-ahead energy markets and contributing to the statewide curtailment response to the August 2020 heat wave.

Retail rate structures, modeled to approximate the use case experience outside the microgrid, were not a perfect match, because retail rates do not yet contemplate bidirectional electric vehicles. When considering the renewable energy time-shifting use case, the project team discovered no rate structures that consider an electric vehicle, co-sited with solar, at a commercial building. Ultimately, the team chose a standard demand-metered commercial rate, thereby ignoring both the electric vehicles and the solar. While this decision may currently be the most efficient way to meter this configuration, the project highlights a gap for the California Public Utilities Commission (CPUC) to examine as more and more buildings have both solar resources and electric vehicles at the same site.

The project team suggests further research on retail rate innovation that would incentivize customers to use their electric vehicles in the use cases explored in this project. New rate structures that compensate for export by DER and operationalize aggregation for resource adequacy are required. Rate structures should recognize the value of flattening the "duck curve", a steep late-afternoon rise in system load that coincides with declining solar generation.

Technology/Knowledge Transfer Summary

Nuvve and UCSD hosted an INVENT seminar and site tour at the 2019 Energy Storage North America Conference, presenting accomplishments and next steps at the halfway point of the project to attendees from around the country.

Nuvve, with Leapfrog Power as the scheduling coordinator, identified a pathway to include electric vehicles in the UCSD campus microgrid's participation in the Demand Response Auction Mechanism. The microgrid consequently contributed 8 megawatts (MW) of curtailment during the August 2020 heat wave via this mechanism. The university will continue to use the forecasting methods, market participation pathways, and partnerships that resulted from INVENT to continue contributing to the California grid's stability, reliability, and resilience going forward after the project ends.

During the project, the INVENT team collaborated with the Advanced Research Projects Agency–Energy (ARPA-E) Network Optimized Distributed Energy Systems (NODES) team at UCSD to demonstrate frequency regulation with electric vehicles.

Nuvve continues to use INVENT experience and results as input for comments on California energy and mobility policy in venues such as vehicle-grid integration working groups, Assembly Bill 841 (Ting, CHAPTER 372, Statutes of 2020)[2] comments, Senate Bill 676 (Bradford, CHAPTER 484, Statutes of 2019)[3] implementation comments, the CEC's Integrated Energy Policy Report and Assembly Bill 2127 (Ting, CHAPTER 365, Statutes of 2018) [4]assessment, and the CPUC's proceedings on microgrid and resiliency (Rulemaking 19-09-009). and emergency reliability (Rulemaking 20-11-003).

Expected Scope of Commercial Technology Rollout

Though INVENT has shown that vehicle-to-grid-capable electric vehicles and electric vehicle supply equipment, under the control and optimization of Nuvve's GIVe™ vehicle-to-grid platform, are technically capable of providing services to a wide range of customers, vehicle-to-grid technology and services will likely be applied to select segments before they become widely used. Fleets and individual units with regular routes, such as school buses, and fleets with long parking times, such as delivery vehicles, will likely be first adopters of vehicle-to-grid technology. The appropriateness of workplace charging varies depending on employee schedules. However, daytime parking presents an important opportunity to coordinate charging and discharging with solar output in the near- to medium-term. Residential applications will depend on introducing affordable residential bidirectional chargers and on streamlining interconnection, making the timeline uncertain. Mainly for these reasons, multiunit dwellings also remain a challenge for any type of electric vehicle charging application; vehicle-to-grid is no exception.

Benefits to Ratepayers

According to the project findings, managed charging of the electric vehicles reduced carbon dioxide by an average of 12.9 kilograms (kg) per vehicle per year compared to unmanaged charging. Adding onsite solar PV resulted in a 20-fold increase in greenhouse gas savings (258.6 kg) per vehicle annually compared to only electric vehicle demand charge management. The savings from these CO_2 reductions were $1.37 per electric vehicle per year for managed charging alone, and $26.17 for managed charging paired with onsite solar PV.

Managed charging improves grid reliability by controlling the power delivered to individual vehicles in a fleet that are being charged simultaneously. Compared to unmanaged charging, which could have multiple vehicles charging simultaneously at maximum power, managed charging also reduced demand charges. This project's demonstration of managed charging achieved an annual cost savings of $888 per year per vehicle.

This project lays the groundwork for expanding vehicle-grid integration in the emerging markets for this technology. The project results also provide a reference for lawmakers to consider vehicle-to-grid, not only when creating new legislation and associated regulations, but also to modernize existing legislation that currently limits vehicle-grid integration.

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[2] Ting. 2020. "AB 841 Energy: transportation electrification: energy efficiency programs: School Energy Efficiency Stimulus Program. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201920200AB841

[3] Bradford. 2019. "SB-676 Transportation electrification: electric vehicles: grid integration." California Legislative Information. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200SB676

[4] Ting. 2019. "AB 2127 Electric vehicle charging infrastructure: assessment. California Legislative Information. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB2127

CHAPTER 1: Introduction

Project Purpose, Context, Scope, and Goals

When electric vehicle supply equipment (EVSE) is equipped with a bidirectional inverter, the system is referred to as vehicle-to-grid (V2G) direct current (DC) (V2G-DC), because DC power flows from the electric vehicle (EV) to the EVSE where the inverter is located to convert the DC power to alternating current (AC). To interconnect in California, a V2G-DC system must complete the investor-owned utility's (IOU) Rule 21 process to ensure the system meets all safety and reliability requirements for interconnection to the distribution grid. Currently, the Rule 21 interconnection process is not streamlined and represents a significant misalignment with the customer experience. For example, a customer purchasing an EV and EVSE system in hopes of interconnecting under the current Rule 21 would not be able to charge from the grid until the interconnection process is complete.

The first V2G-capable production model EV, the Nissan LEAF, became available in 2013. Other automotive manufacturers have since explored various bidirectional implementations, but new commercially available models have yet to appear at scale in the market. The California Energy Commission's (CEC) school bus replacement program has brought a new market segment into the V2G space. Many automotive manufacturers have signaled their intentions to explore or include V2G capability in future models.

EVs can function as demand response resources, energy storage devices, and backup power systems. And yet, there remains uncertainty regarding what role these functionalities will play, their value will be, where they are in terms of technical readiness, and their near and long-term commercial viability. Standards (for example, communications, automotive and electrical) and regulatory frameworks exist but are evolving. Technical and business model pathways for vehicle-grid integration (VGI) and V2G in California remain challenging as a result. Automakers and utilities alike remain interested but are slow to examine the real-world usefulness of V2G applications. Despite progress in Rule 21 interconnection procedures, continuing regulatory uncertainty has left automakers with no guarantee that V2G-capable EVs will be able to interconnect and function as designed and intended. This has slowed introduction, and the consequent lack of V2G market formation has decreased the urgency of regulatory reform initiatives to enable it fully.

To break this cycle, the Intelligent Electric Vehicle Integration Project (INVENT) set out to demonstrate the technical capabilities of V2G to participate in real-world services and the potential value streams associated with those services when performed by EVs in different contexts. INVENT addressed these barriers by demonstrating technical feasibility, including real-world experience of working with drivers and vehicle availability and potential value streams to answer some of the questions and address barriers that are delaying action required to propel V2G rollout in California. INVENT used commercially available first-run vehicles and infrastructure to show they work, proved EVs can provide the services while meeting individual drivers' needs, explored the complexities around different driver classes and use cases, and put forward values to the driver and society.

Overview of Project Architecture

Description of the University of California, San Diego Microgrid

UCSD has a premier research and development microgrid focused on maximum integration of renewable resources. The microgrid's generation resources power the college campus, which covers 1,200 acres and serves a community of about 45,000 faculty members and students living and working in 450 buildings. The UCSD campus hosts the submetered and controllable loads, renewable energy resources (3 megawatts [MW] of photovoltaic [PV] and a 2-8 MW fuel cell), a cogeneration plant (a natural gas-fired plant with two 13.5 MW turbines and 3 MW steam turbine), and a 2.2 MW/3.6 megawatt-hour (MWh) battery energy storage system (BESS). UCSD meets most of its energy needs at a cost lower than the utility's power cost, leading to significant savings per year. UCSD is a "connected" microgrid so the remaining power requirements are supplied by the local utility, San Diego Gas & Electric Company (SDG&E). INVENT adds coordination and control of EVs parked inside the microgrid. UCSD has permitting authority within the microgrid, allowing new types of resources and experimentation that may not be possible in IOU territories.

Project Assets

INVENT specifically set out to include a mix of commercially available EVs and charging stations using a variety of communications protocols and power capacities in multiple locations distributed across the UCSD microgrid to better represent a commercial rollout scenario. The charging stations were a mix of uni- and bidirectional stations charging and discharging at or below 10 kilowatts (kW). The EVs were privately-owned and university assets, and brands included Nissan, Chevrolet, BMW, Ford, Daimler, Mitsubishi, and Honda.

Refer to Appendix C for a detailed list of INVENT equipment.

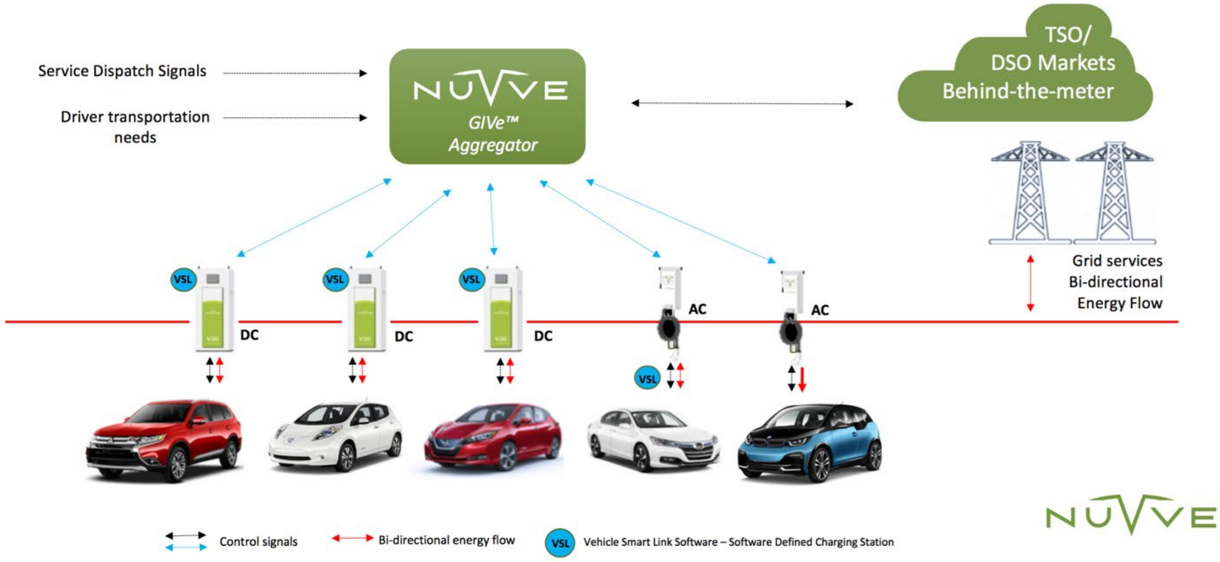
Electric Vehicle Drivers

INVENT intentionally recruited drivers with diverse use patterns, enabling the research team to assess various characteristics of the use cases being analyzed. Drivers included individual university employees who used their EV for workplace commuting and agreed to participate in the project. The project also monitored and controlled the charging behavior of two on-campus "fleets." The first fleet was comprised of EVs used in the university's "Triton Rides" program, a nighttime free shuttle service available to students, staff, and faculty that is staffed by volunteer drivers. The UCSD campus police department provided the second fleet. Each driver was given access to Nuvve's mobile app to set schedules, check their state of charge, and trigger an immediate charge in case of an unforeseen trip. The EVs were also fitted with Fleet Carma devices to enable the project team to access more live data about the EV and assist in troubleshooting.

Nuvve GIVe™ Aggregator

Nuvve's Grid Integrated Vehicle platform (GIVe™) transforms EVs into grid assets when those vehicles are charging while guaranteeing the expected level of charge at the time the owner or driver needs it for transportation (Figure 1). The aggregation of parked and plugged-in EVs into a virtual power plant using the GIVe™ platform allows Nuvve to provide EV drivers with benefits while also participating in electricity markets with a power capacity and capability comparable to traditional generators. INVENT seeks to explore how V2G and a platform such as Nuvve's can benefit utility customers by responding to retail price signals, coordinating with solar production, receiving signals from the California California ISO, and by engaging in aggregated demand response.

Figure 1: Nuvve GIVe™ Aggregator



Source: Nuvve Holding Corporation

Use Cases and Services Studied

INVENT explored services behind the meter and in response to external price signals. The services and values explored were:

- Demand charge management.
- Renewable energy time-shifting (focused on co-sited solar PV).
- Frequency regulation.
- California ISO demand response via IOU Demand Response Auction Mechanism.

The researchers chose these services to represent a broad range of applications that could be implemented in the near or medium term. Multiple types of EVs and chargers were included to simulate real-world conditions of fleets or parking lots. The V1G and V2G technologies were included in each use case to compare their relative contributions to value created and demonstrate that the two slightly different resource types could be coordinated within a single aggregation to provide coherent and appropriate responses to service requirements and price signals.

Demand charges are a well-known element of commercial and industrial electric bills in California and across the country. How EVs impact customer usage, and the generator capacity requirements and transmission and distribution infrastructure that serves them, is a topic of much discussion by the industry. INVENT shows how V1G and V2G can avoid increasing electricity bills and mitigate them.

Coordinating EV charging (and discharging) with the daily shape of California's solar-influenced "duck curve"[5] of demand is well-documented but INVENT set out to examine how EVs can

[5] Department of Energy. 2017. "Confronting the Duck Curve: How to Address Over-Generation of Solar Energy" https://www.energy.gov/eere/articles/confronting-duck-curve-how-address-over-generation-solar-energy

optimize co-located solar resources and how that may be reflected on customer electric bills. Every geography that embraces solar will have its version of the duck curve, and INVENT contributes to the state, national, and international efforts of planning demand to match supply, mitigating the need for traditional generators to ramp up as solar resource fall off at the end of the day, and coordinating usage to maximize greenhouse gas avoidance.

Demand response capabilities are becoming increasingly important to the California electric grid. INVENT tested how EVs can participate in existing mechanisms and how new resources inside microgrids might do the same. Indeed, this project's timing enabled it to participate live in the emergency mitigation efforts the California ISO triggered to address the heat wave in August 2020. The new Emergency Load Reduction Program (ELRP) that sprang from this incident now includes V2G as a qualifying technology to respond and compensate for grid emergencies.

INVENT project results contributed to system operators' understanding of how EVs can participate in a range of existing and planned services. This in turn will help system operators to design markets that incorporate EV participation as they work through compliance with the Federal Energy Regulatory Commission's (FERC) Order 2222 to open markets to distributed resources. Nuvve, with experience providing frequency regulation using EVs in Europe and PJM territory, was well-positioned to build on previous studies in the California ISO territory and thereby was able to meet qualification requirements to participate and remain in the California ISO market.

These studies have significant influence beyond California and depict the broader impact EVs will have in evolving energy ecosystems worldwide. The aim is for INVENT to provide sufficient proof of technical viability and to inform policymakers as to the best structure for rates, markets, and system-level coordination to enable true grid integration of EVs and V2G.

CHAPTER 2: Renewable Energy Time Shift

2.1. Overview of Use Case

2.1.1 Solar and Demand Charge Optimization Objectives

This study showcased the smart charging method by reducing the Gilman Parking Structure's demand charges, a facility with associated solar PV resources. The electricity costs consisted of volumetric charges (energy consumption) and demand charges (maximum power consumption). The method considers only the demand charge cost since the energy supplied is expected to be the same (ignoring minor differences due to roundtrip efficiency losses when discharging and later recharging for V2G). The demand charge is specified per the SDG&E AL-TOU tariff schedule,[6] which has two components:

1. The noncoincident charge, which is computed as the maximum 15-min power consumption in a month and charged at c_1 = $24.48/kW
2. The onpeak charge, which is the maximum 15-minute power consumption in the month between 4 p.m. and 9 p.m., and is charged at c_2= $19.14/kW in the summer and $19.23/kW in the winter[2]

The EV forecast consisted of a set of predictions for the arrival and departure times of the cars based on historical data for cars at the same building. Different possible scenarios were obtained by drawing from the observed distributions of the parameters for previous charging events in the dataset using an inverse sampling method. For more detail on the sampling, forecasting, and modelling of the renewable energy time shift (RETS) and demand charge management (DCM) optimization, see Appendix B section B2.1.2.

Optimization of the future day or future hours required a load forecast and an EV forecast (for layover time and initial state-of-charge). Ensemble forecasts (several forecasts that describe the range of uncertainty) addressed the considerable uncertainty in each forecast that allows the EV charging operator to choose an operating strategy based on risk preference.

The load forecast was based on historical load data from the building. The prediction was created using a decision tree algorithm to deliver different scenarios based on percentiles. The prediction considered seasonality (weekdays in school session, weekdays in school breaks, holidays/weekends) and five years of historical load data.

The solar energy forecast was a prediction of the solar power that would be generated during the next day by the rooftop PV system. Solar irradiance data was obtained from the operational North American Mesoscale Model (NAM) forecast and transformed into power for the building's PV installation specifications using a model output statistics (MOS) correction.[7]

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[6] San Diego Gas & Electric. 2020. "Electric Vehicle Plans." https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans

[7] Mathiesen, P., Kleissl, J., "Evaluation of numerical weather prediction for intra-day solar forecasting in the continental United States", Solar Energy, Volume 85, Issue 5, 2011, pp. 967-977, https://doi.org/10.1016/j.solener.2011.02.013

Additional scenarios for the solar forecast were obtained using the analog ensemble technique, which selected matching days in the past.[8]

2.2. Phase 1 Implementation (April 2019 – Mar 2020)

2.2.1 Assets Used

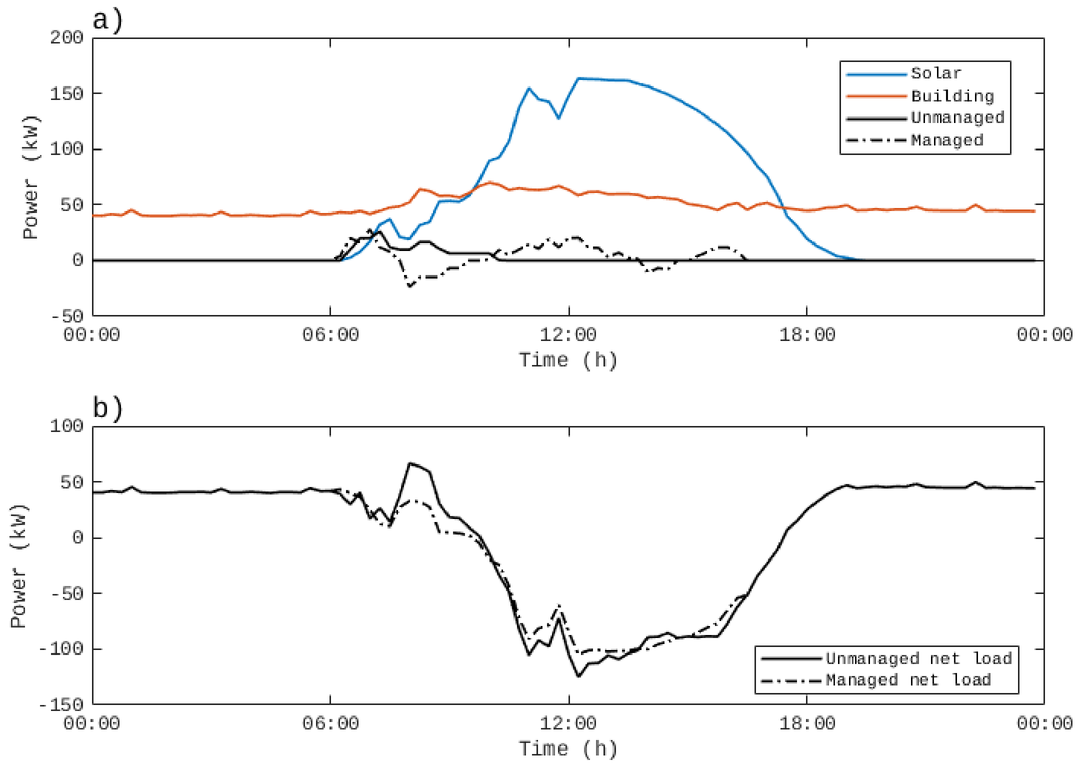
The building considered for DCM was the UCSD Gilman Parking Structure, a 302,000 square foot ($ft^{2)}$ parking structure with a 5,800 ft^2 bank office and a 3,700 ft^2 UCSD transportation services office. Because of the mixed-use, the typical load in this building had a stable baseline load overnight and increased consumption during business hours. A 195 kW solar power plant was located on the top floor. The EV fleet changed during 2020; in January, a fleet of four cars was available, then in April, three cars with bidirectional chargers were added to the fleet. On average, 5 of the 7 cars were fully operational each month. See Appendix C for a list of project chargers and vehicles.

2.2.2 Evaluation Metrics

The optimal dispatch framework results were evaluated by comparing the actual performance of the EV car charging — denoted here as managed charging — to a simulated unmanaged charging scenario. For the unmanaged charging scenario, cars are assumed to charge at full capacity as soon as they arrive until cars have charged the same energy that they consumed. Figure 2 shows an example of the unmanaged charging time series. The solid black line in Figure 2a shows how the unmanaged charging occurs earlier and is always positive/uni-directional, varying only because different cars arrive at different times. In contrast, managed charging (black dot-dashed line) distributes charging throughout the day by first charging and then discharging during the building load peak to result in a lower net load (Figure 2b).

[8] Delle Monache, L., Eckel, F. A., Rife, D., Nagarajan, B., Searight, K. "Probabilistic weather prediction with an analog ensemble", Monthly Weather Review 141 (10), 2013, pp 3498-3516.

Figure 2: RETS Results for May 11, 2020



Results for May 11, 2020, at the Gilman Parking Structure. (a) All building net load components: solar generation, building load, and managed and unmanaged charging power. Unmanaged charging occurs only in the morning when the cars arrive while managing charges and discharges during the day. (b) Net load = building load - solar generation + EV charging for the managed and unmanaged cases. Managed charging reduces the morning peak in the unmanaged case by discharging the cars around 0800 h. The net load is negative between 10 am and 5 pm due to excess solar PV generation.

Source: Nuvve Holding Corporation

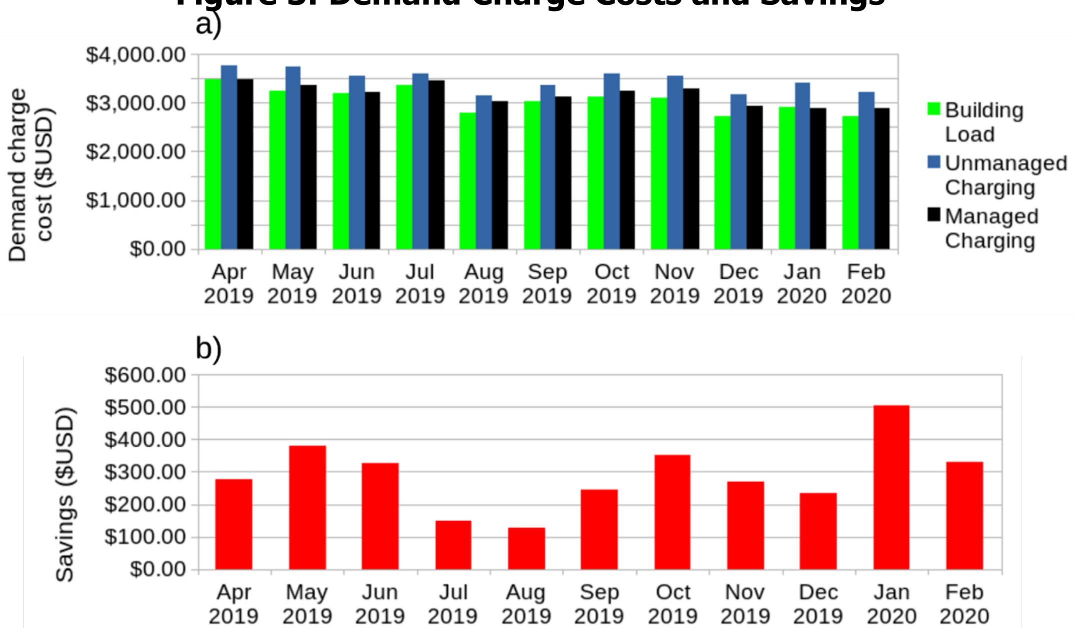
The total demand charge cost is calculated from the maximum non-coincident and on-peak power readings in the month for the managed and unmanaged charging time series, and then applying the appropriate tariffs, plus a 5.78 percent franchise fee for San Diego. The DCM savings are the difference between the unmanaged and managed charging demand charges.

2.3 DCM Phase 2 at the Gilman Parking Structure

Figure 3a shows the demand charge costs for the year 2020 at the Gilman Parking Structure. Peak demands for January through March were identical between managed and unmanaged charging. All non-coincidental peaks occurred before 8 am when no cars were available. Therefore, these data are not shown in the figure. Starting March 16, the parking structure was largely empty, and the office space was vacant. Therefore, office and elevator electric demand and associated demand peaks were reduced, and the building load was mostly flat throughout the day. EVs were plugged in all day, but realistic EV demand was created by assuming EVs to be available in a fixed timeframe from 8 am to 4 pm starting April 7th. Managed charging resulted in a reduced demand compared to the unmanaged charging case and the original building net load. This means that the addition of V2G chargers helped reduce the demand charge bill even compared to having no cars at the building. November and December showed no savings since the peaks occurred on cloudy days and at times where no cars were available.

Figure 3b shows the demand charge savings for April to October (November and December were zero), computed as the difference between the managed and unmanaged demand charges. April yielded the smallest savings, which can be attributed to the lowest demand during the mandatory stay-at-home orders at the beginning of the pandemic when all offices were closed, and very few employees traveled to campus. From May until December 2020 the average savings were $450 per month which translates to $90 per car per month.

Figure 3: Demand Charge Costs and Savings



Demand charge (a) costs and (b) savings between managed and unmanaged charging for the year 2020 at the Gilman Parking Structure.

Source: Nuvve Holding Corporation

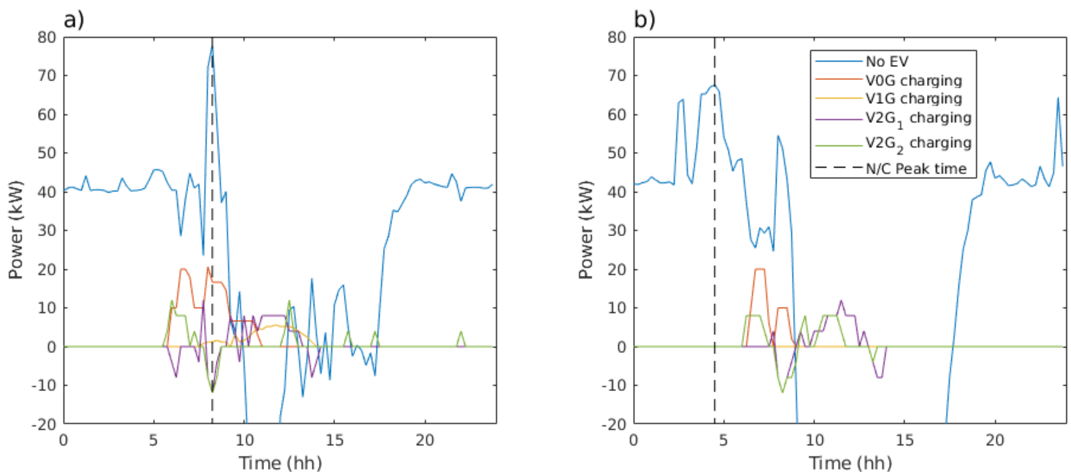
2.3.1 V2G Contribution to Demand Charge Reduction at the Gilman Parking Structure

Lower demand charges result from a reduction in the peak demand. With a fleet of V1G and V2G chargers, there are two ways to reduce the demand: (i) not charging a V1G car or (ii) discharging a V2G car. The breakdown of these two contributions to the demand charge costs each month can be quantified by analyzing each car's contributions to the change of the peak demand (Non-coincident and On-peak) between the unmanaged and managed charging scenarios and attributing it to V1G and V2G cars.

Since the managed charging peaks usually occur on a different day in the month than the unmanaged peaks, the net reduction between the unmanaged and managed charging peak can be less than at the original peak. As an example, consider Figure 4, where the non-coincidental peak occurred on July 1, 2020 for the unmanaged case and on July 14 for the managed case. 94.47 kW of peak demand on July 1 were reduced to 47.07 kW, with V2G contributing by discharging 32.00 kW and V1G contributing by 15.40 kW. But on July 14, the managed peak was 67.61 kW, larger than the new peak demand on July 1. So, the net reduction is 94.47 - 67.61 = 26.86 kW, which is less than the actual discharging of 32 kW on July 1. The whole 26.86 kW reduction is attributed to V2G discharging because if the V2G discharge had not happened, the reduction would not have been possible. The breakdown of

V2G/V1G contributions to demand charge savings each month is shown in Figure 5. V2G has a large contribution in reducing demand charges for the Gilman Parking Structure, averaging $351.8 between April and December, while the V1G average contribution is $98.2. There were no savings for November and December.

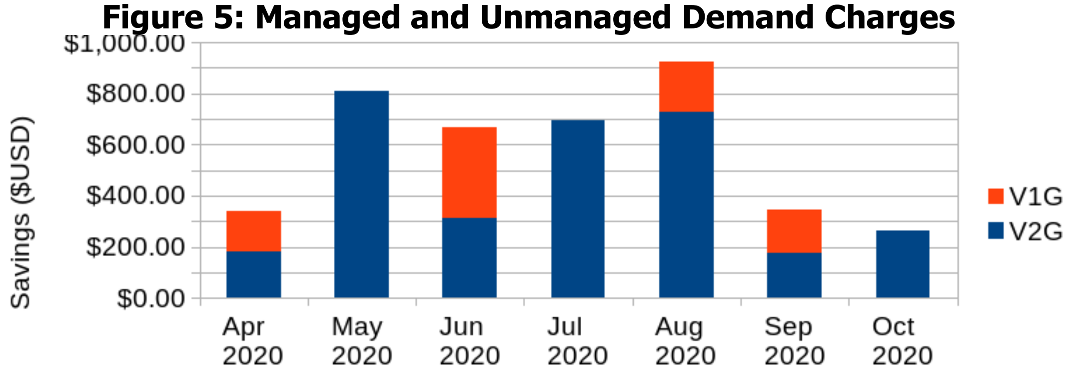
Figure 4: Non-Coincident Peak Contributions



Breakdown of V1G and V2G contributions for the original NC peak for unmanaged charging (V0G) on (a) July 1 and the new NC peak for the managed charging on (b) July 14 for the Gilman Parking Structure. V0G represents a) 4 EVs or b) 3 EVs, V1G represents a) 2 EVs or b) 1EV, and the two separate V2G chargers are shown as V2G1 and V2G2.

Source: Nuvve Holding Corporation

Figure 5: Managed and Unmanaged Demand Charges



Attribution of demand charge savings for managed versus unmanaged charging to V1G and V2G for the Gilman Parking Structure.

Source: Nuvve Holding Corporation

2.3.2. Evaluation Metrics

The optimization is set to minimize demand charges and not to maximize the GHG savings. GHG savings are therefore incidental but are still elevated because larger solar power production leads to reduced net load, creating opportune times for charging EVs without causing demand peaks. Large solar generation often leads to negative net load when the demand charge optimization preferentially schedules EV charging, therefore saving GHG emissions. Between 10 a.m. and 5 p.m. for May 11, 2020, all the energy consumed in the building and the EVs is provided by the solar system, with zero marginal greenhouse gas emissions. During the rest of the day, when the net load is positive, energy is purchased from SDG&E, with an associated GHG emissions factor of 0.241MTCO_2/MWh[9]. The total GHG emissions for the month are then the energy consumed when the net load (building + EV - solar) is positive times the SDG&E emissions factor. The GHG savings are the difference between the emissions for the unmanaged charging and the optimal dispatch.

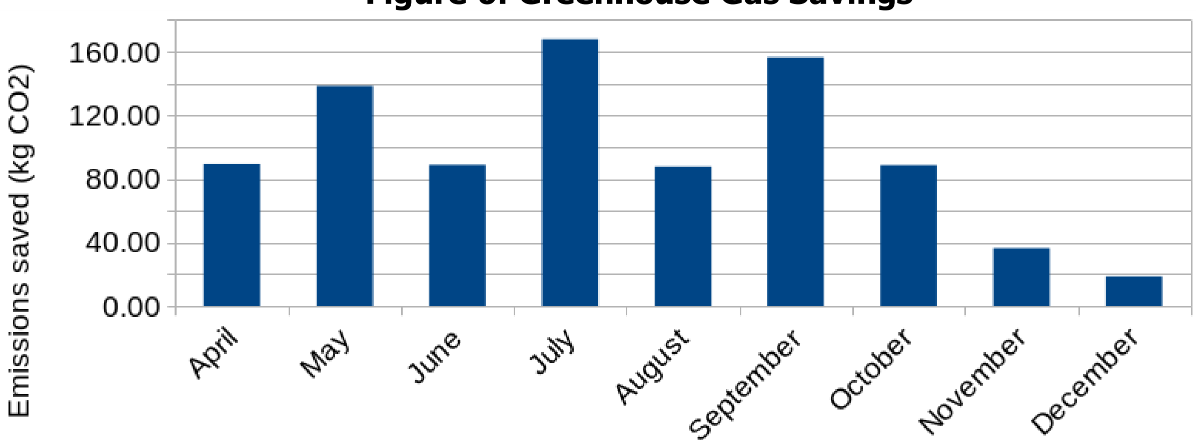
2.4 Results

2.4.1 Renewable Energy Time Shift Results at the Gilman Parking Structure

Figure 6 shows the GHG emissions saved by managed charging compared to the emissions associated with the unmanaged charging reference case. The behavior of these savings is directly related to the annual changes in solar power. The power generated diminished during winter months, as the hours of sunshine are less than in summer. During winter days, this translates to a reduced period where solar power provides the energy to charge the cars at zero GHG emissions and an extension of the times when the peak demand can occur. This annual variability explains the larger GHG emissions savings during summer. June and August see lower savings for two reasons: both months had a lower monthly solar production than July due to the greater presence of marine layer clouds; and during August one car was inoperable, reducing the energy consumed by the fleet and therefore the opportunity for emissions savings.

GHG reductions for nine months of EV charging at a building with solar power averaged 96.9 kg CO_2 per month with a summer peak of 167.94 kg CO_2. For workplace charging at buildings where solar power generation dominates the net load profile, there are opportunities for substantial GHG emissions savings by charging from local solar energy with zero marginal GHG emissions during midday instead of grid power in the morning. Opportunity for EV demand charge savings diminish on buildings with solar, as building peak loads shift to the early morning or evening when EVs may not be available.

Figure 6: Greenhouse Gas Savings



GHG emissions savings for the year 2020 at Gilman Parking Structure for the Renewable Energy Time Shifting service.

Source: Nuvve Holding Corporation

[9] Annual average factor for 2018. Personal communication with SDG&E.

CHAPTER 3: Demand Charge Management

3.1 Overview of Use Case

Demand charge management (DCM) refers to scheduling when EVs are charged and discharged to reduce demand charges. Demand charge management with EVs for a building with solar power is more challenging. Since solar energy peaks in the middle of the day, the net load is reduced during this time frame. Consequently, net load peaks tend to occur either in the early morning or in the evening, outside of typical EV layover times.

This chapter presents the common framework and a summary of the operational results for the DCM service. The same method is then applied in the following chapter to buildings without solar power, but both use cases apply a single optimization.

3.1.1 Rationale for Picking – Context in California Landscape

Charging electric vehicles (EVs) at stations connected to the electric meter of a building can increase building demand charges, which are calculated based on the largest energy consumption in a 15-minute interval of the month multiplied by the demand charge rate in $ per kW. Demand charges typically make up about half of the electric bill. Therefore, reducing monthly load peaks through flexible loads, stationary batteries, or EV discharging has potential for utility bill savings or both. Demand charge management (DCM) refers to scheduling when EVs are charged and discharged to reduce demand charges.

The previous chapter presented a common framework for optimally scheduling an EV fleet's charging in a building with associated solar energy production. This chapter presents results of the same method applied to EV fleets parked at buildings without solar power and describes the forecast components and procedures for a day-ahead and real-time optimization.

3.1.2 Demand Charges and Optimization Objectives

This study showcases the smart charging method by reducing the demand charges of the Hopkins Parking Structure. The electricity costs consist of volumetric charges (energy consumption) and demand charges (maximum power consumption). The demand charge cost is only considered since the energy supplied is expected to be the same (ignoring minor differences due to roundtrip efficiency losses when discharging and later recharging for V2G). The demand charge is specified per the SDG&E AL-TOU tariff schedule[10], which has two components:

1. The non-coincident charge, which is computed as the maximum 15-minute power consumption in a month and charged at c_1=$24.48/kW

[10] San Diego Gas & Electric. 2020. "Electric Vehicle Plans." https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans

2. The on-peak charge, which is the maximum 15-minute power consumption in the month between 4 p.m. and 9 p.m. and it is charged at c_2=$19.14/kW in the summer and $19.23/kW in the winter.[11]

As previously noted, this demand charge management study uses the same optimization described in section 2.1.1 of the previous chapter, with the solar generation $S_k = 0$.

3.1.3 Forecast Components: Load Consumption and Electric Vehicle Availability

The future day or future hours' optimization requires a load forecast and an EV forecast (for layover time and initial state-of-charge). Ensemble forecasts address the considerable uncertainty in each forecast, allowing the EV charging operator to choose an operating strategy based on their risk preference. The load forecast is based on historical load data from the building. The prediction is created using a decision tree algorithm to deliver different scenarios based on percentiles. It considers seasonality (weekdays in school session, weekdays in school breaks, holidays/weekends) and five years of historical load data.

The EV forecast consists of a set of predictions for the arrival and departure times of the N different cars in the fleet, t_a and t_d, and an estimated initial state of charge, SOC_0. The EV forecast is based on historical data for the cars at the same building. Different possible scenarios are obtained by drawing from the observed distributions of the parameters for previous charging events in the dataset using an inverse sampling method. The cumulative distribution function of the arrival time ta of a car is obtained from its historical records. The optimization picks a random number R between 0 and 1 to retrieve a corresponding arrival time with a cumulative frequency of $F(t_a)=R$. This sampling technique is performed for the three variables and multiple times to create different scenarios.

3.1.4 Day-Ahead Optimization

All forecasts for the next day are generated at 4 p.m., and an initial day-ahead optimization is performed. Since the set of forecasts provides different scenarios, the optimization is performed for each scenario, and the EV charging schedule will be an ensemble created from the scenarios. For example, a low risk/conservative option is to solve the scenario with the 90th percentile of the maximum net load. The optimization is run on the previous day primarily for situational awareness for the charging operator.

3.1.5 Real-Time Optimization

During the day and generally, after the first EV arrives, the optimization and charging instructions will be updated automatically every 15 minutes through a receding horizon approach. The load and EV status are observed continuously during the day. The current state of the system will be obtained by scraping load readings from UCSD, and EV state-of-charge (SOC) readings from Nuvve. These observations allow removing unrealistic EV scenarios as well as updating/correcting all forecasts used in the optimization. For example, if an EV has arrived in reality, then the optimization generates new scenarios that only match the observed behaviour with the fixed (past) arrival time but unknown departure time.

[11] San Diego Gas & Electric. 2020. "Electric Vehicle Plans." https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans

Since the optimization is run at discrete time intervals every 15 minutes, rapid changes in the building demand could be missed. To avoid associated demand charge events, a real-time control that instantly corrects charging power in response to the building load can maintain net load below the demand charge threshold. In other words, if the net load increases, the optimization would decrease the charging power (or increase discharging power) by the same amount. And if the load reverts to the forecasted value, the optimization will return to the original charging decision. All charging schedules were based on day-ahead optimization.

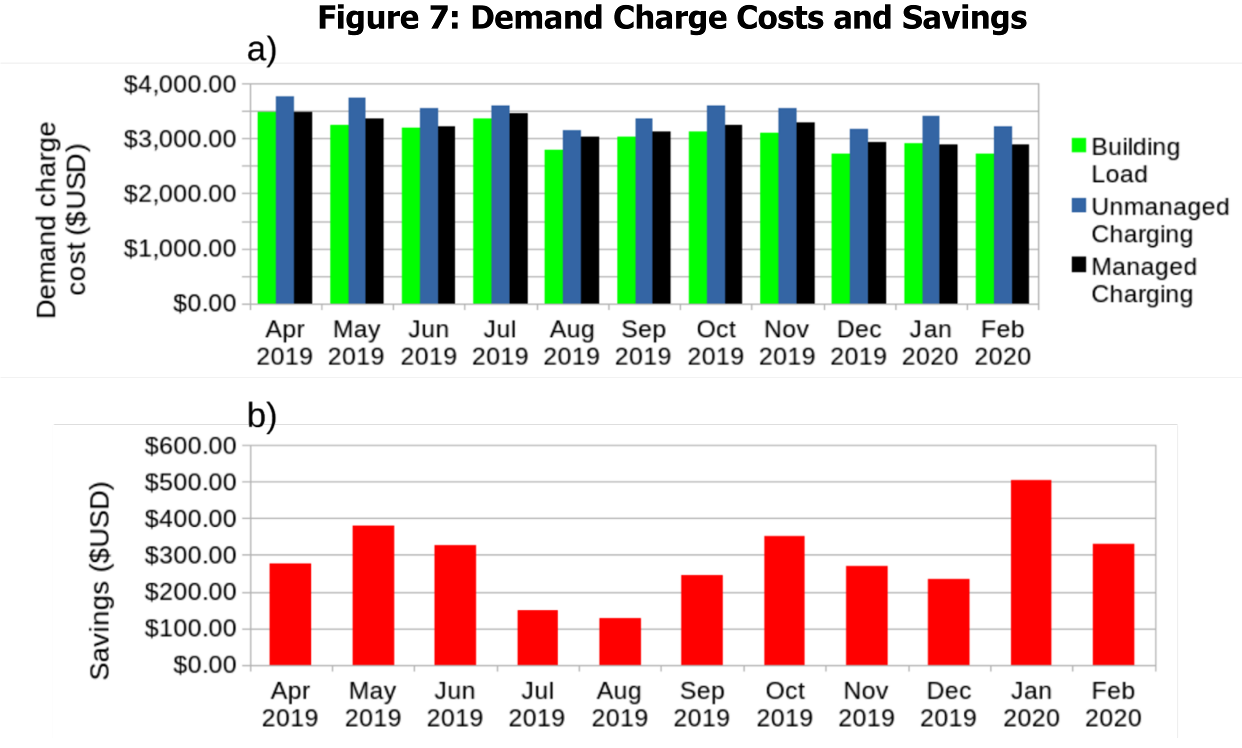
3.1.6 Hopkins Site

The UC San Diego Hopkins Parking Structure is a 446,000 ft^2 parking structure with a small 1,600 ft^2 office for UC Transportation Services. The building has a stable baseline load overnight and increased consumption during business hours. The EV fleet varied: In April 2019 three cars (each with 6.6 kW unidirectional chargers) were available; in August 2019 a fourth car with a 10 kW bidirectional charger was added; in March 2020 a fifth car with a 10 kW bidirectional charger was added. See Appendix C for a list of project chargers and vehicles.

3.1.7 Historical Load Peak Times

From April 2019 until early March 2020, operations at the Hopkins Parking Structure were based on discharging during historical load peak times. Operations were supposed to switch to optimized dispatch during March 2020, but COVID impacts resulted in the discontinuation of operations at the Hopkins Parking Structure. For that reason, only results for April 2019 to February 2020 are included in Figure 7. For the Hopkins Parking Structure, managed charging always has lower costs than unmanaged charging, but it was never lower than the building load. This is because the number of V2G chargers was smaller than at the Gilman Parking Structure, and — given the absence of solar power — the timing of the load peaks was less predictable and less aligned with EV availability.

Figure 7: Demand Charge Costs and Savings



Demand charge (a) costs and (b) savings between unmanaged and managed charging for the Hopkins Parking Structure using dispatch based on historical load peaks.

Source: Nuvve Holding Corporation

Savings varied during the year. The temporal availability of cars impacted the potential to reduce the costs. The average savings for Hopkins were $290 per month or $80 per car per month. The V2G chargers did not contribute to the DCM savings at all during 10 of the months. Only during January and November, V2G contributed by reducing the NC peak by 4 kW each.

3.1.8 COVID Implementation Adjustments and Challenges

In response to the COVID pandemic, effective March 16, 2020, UCSD closed its campus for instruction and non-critical operations, which prevented some EV drivers from commuting to campus, and left some EVs that were usually driven on campus to remain parked at the buildings for the whole day. The day-ahead optimization was performed, with certain modifications: the training dataset was modified to include only COVID days, and seasonality adapted to only distinguish between weekdays and weekends, as the school session and breaks were similar.

Since the EVswere not driven and remained parked at the buildings 24/7, the optimization simulated car availability between approximately 8 a.m. and 4 p.m., with EVs being discharged at dawn to recreate an initial state of charge of approximately 50 percent for all cars at 8 a.m., consistent with typical office buildings. With this new configuration, an EV forecast is not needed, and dispatch errors are solely a consequence of errors in the load forecasts.

3.2 Phase 2 Implementation (April 2020 – July 2020)

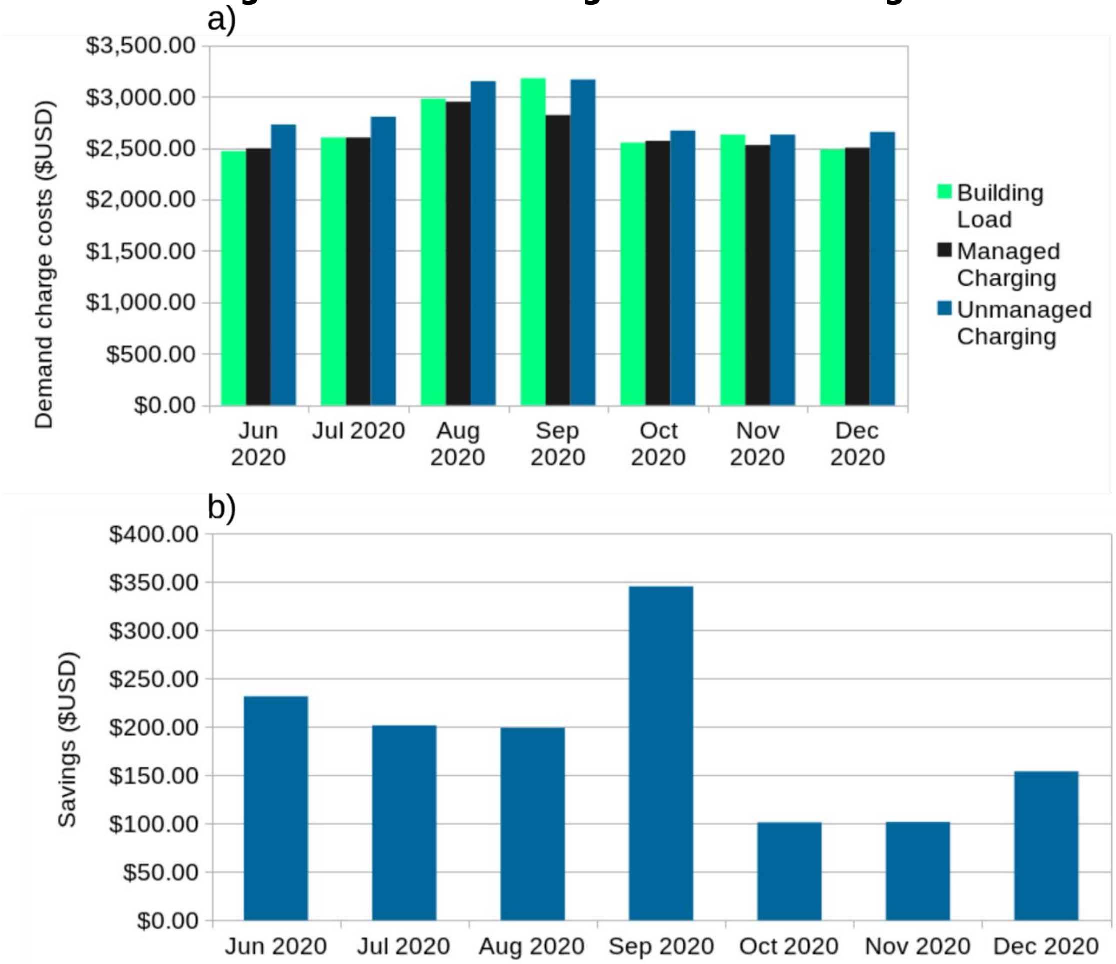
3.2.1 Assets Used / Impacts of COVID-19

Since the pandemic resulted in a flat load profile at the Hopkins Parking Structure, in June 2020 the DCM operation was transferred to the 14,600 ft2 Police Department building, which stayed operational and had daytime load peaks. The fleet for the Police Department consisted of 4 cars, with one 6.6 kW unidirectional charger, two bidirectional 10 kW chargers, and a bidirectional 6 kW charger. See Appendix C for a list of project chargers and vehicles.

3.2.2 Demand Charge Management Phase 2 at the Police Department

DCM was implemented following the optimized dispatch method. Since the fleet had 3 V2G chargers, it managed charging demand charges that sometimes were lower than the original building load demand charges without EVs. The average savings were $191 per month or $52 per car per month. As shown in Figure 8 below, savings were lower in October since one car in the fleet was not operational.

Figure 8: Demand Charge Costs and Savings



Demand charge (a) costs and (b) savings between managed and unmanaged charging for the Police Department using optimized dispatch.

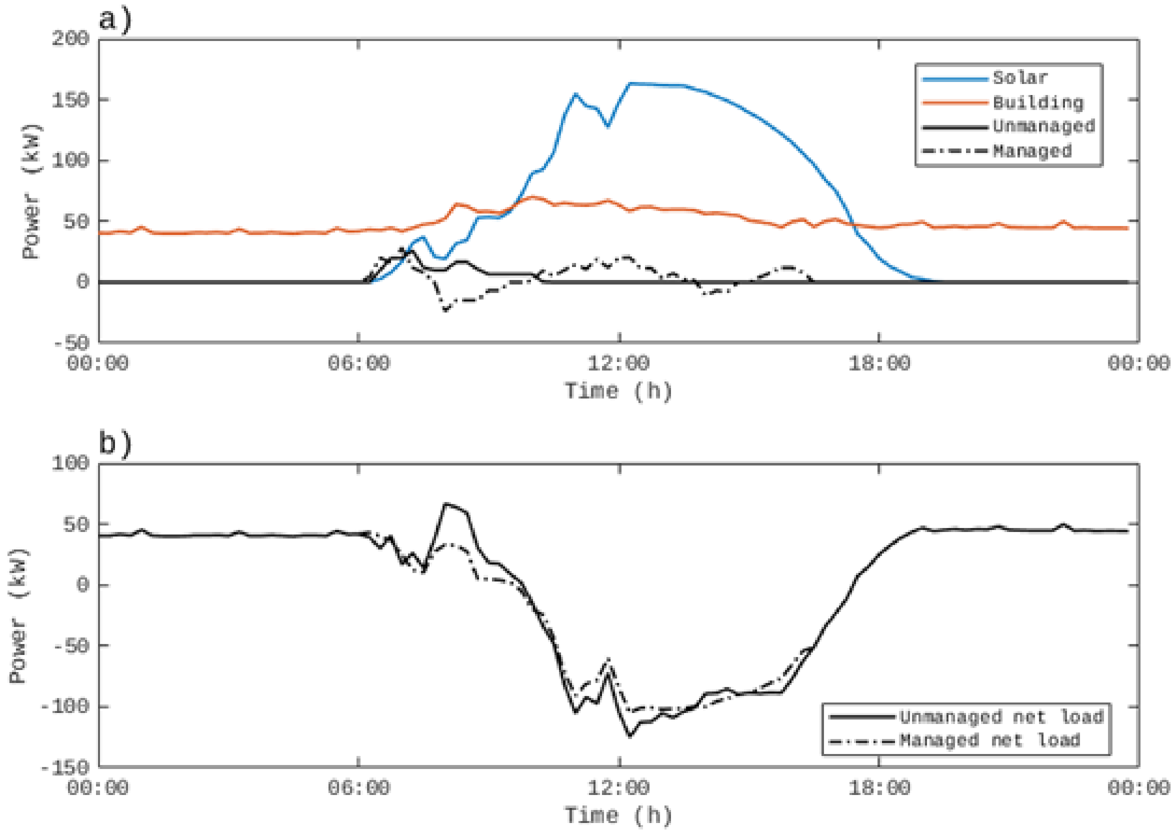
Source: Nuvve Holding Corporation

3.3 Results

3.3.1 Evaluation Metrics

Results of the optimal dispatch framework are evaluated by comparing the actual performance of the EV car charging — denoted here as managed charging — to a simulated unmanaged charging scenario. For the unmanaged charging scenario, cars are assumed to charge at full capacity as soon as they arrive until cars have charged the same energy that they actually consumed. The solid black line in Figure 9a shows how the unmanaged charging occurs earlier and is always positive, varying only because different cars arrive at different times. In contrast, managed charging (black dot-dashed line) distributes charging throughout the day by first charging and then discharging during the building load peak to result in a lower net load (Figure 9b).

Figure 9: Results for May 11, 2020 at the Gilman Parking Structure



(a) All components of the building net load: solar generation, building load, and managed and unmanaged charging power. Unmanaged charging occurs only in the morning when the cars arrive, while managed charging charges and discharges during the day. (b) Net load = building load - solar generation + EV charging for the managed and unmanaged cases. Managed charging reduces the morning peak that occurs in the unmanaged case by discharging the cars around 0800 h. The net load is negative between 10 am and 5pm due to excess solar PV generation.

3.4 Summary

The common methodology produced optimal EV charging dispatch for demand charge management at UCSD campus buildings without solar resources during 2019 and 2020. Charging optimization can reduce the demand charges associated with peak power consumption in a building by either avoiding charging V1G EVs during the building peak load or by discharging V2G EVs. Data collection was performed in three buildings for 7, 9, and 11 months to evaluate the demand charge savings compared to a simulated unmanaged charging scenario. The managed charging resulted in monthly demand charge savings of $80 per car for the Hopkins Parking Structure and $52 per car for the Police Department (or total savings of $290 and $191 per building). Fleets installed with bidirectional EVSEs can reduce the demand charges compared to a building without electric vehicles.

CHAPTER 4: Frequency Regulation

4.1 Frequency Regulation Market Overview

Power grid operation is a complex act of continuously balancing supply and demand. Here, demand is the amount of energy customers are using, and supply is the energy being generated at any given moment. When demand exceeds supply, the frequency at which electricity is traveling on the grid drops, and the system operator requests that generators increase production to restore the frequency to normal. When supply exceeds demand, the frequency rises, and the system operator requests that generators decrease their production.

Maintaining grid frequency close to its nominal operating frequency (60±0.3 Hz in the US) is critically important for the stable operation of the grid. Small frequency deviations are tolerated by the system and are usually restored through automated frequency control measures as described above. However, large frequency deviations can lead to cascading failures and need intervention from system operators to decrease the power imbalance manually.

The Federal Energy Regulatory Commission (FERC) has issued a series of orders over the last decade to revise markets designed around assumptions that participants would be traditional centralized generation, including Order 755[12] compensating for performance in frequency regulation markets, Order 841 adjusting markets to make a level playing field for energy storage, and Order 2222 integrating DER and behind the meter assets to the same markets. The ability of battery energy storage systems (BESS) to ramp quickly for charging and discharging has allowed being successfully employed for frequency regulation services and compensated for fast performance.

While EVs have successfully participated in frequency regulation markets in Pennsylvania-New Jersey-Maryland Interconnection (PJM) and Europe, every market is different and the California ISO is currently in the process of compliance with FERC's orders. Against this changing landscape, INVENT set out to show that EVs could respond to real California ISO signals and meet the minimum performance requirements to participate in the California ISO's frequency regulation market, giving the California ISO an updated look at how EVs can fit into its operations.

The analysis presented in this chapter is the continuation of prior efforts[13] to demonstrate the technical capabilities of an aggregation of V2G EVs in a workplace setting to provide regulation up and down to the California ISO's frequency regulation and ancillary services market.

[12] Frequency Regulation Compensation in the Organized Wholesale Power Markets, FERC Stats. & Regs. ¶ 31,324 (2011) (Order 755), 138 FERC ¶ 61,123 (2012) (Order 755-A).

[13] Kelsey G. Johnson et al., Electric Vehicle Storage Accelerator (EVSA), Nuvve Corporation, September 2019.

4.1.1 Motivation and California Context

The grid and ratepayer benefits of distribution-aware Vehicle-Grid Integration (VGI) have been explored,[14] highlighting the enormous possibility of smart charging (V1G) and vehicle-to-grid (V2G) technology participating in Ancillary Services and, in particular, frequency regulation markets. Though EVs are well suited for this participation due to their fast ramp rates and response times compared to other resources, EV coalition Frequency Regulation market participation is still under research in the California ISO due to uncertainty that this type of resource can viably and reliably meet market requirements. This study aims at collecting and analyzing data for the participation of the EV fleet in the frequency regulation market through emulated AGC signals to build a better understanding among relevant stakeholders of the frequency regulation opportunity for EVs in California.

4.2 Implementation

4.2.1 Electric Vehicle Coalition Set-up

The EV coalition is formed by nine vehicles of four different types, using the two types of EV Supply Equipment (EVSE) on UCSD's campus for charging and discharging. The two types of EVSE are the Nuvve PowerPort EVSE, a V1G AC charger with a rated capacity of 6.6 kW, and the Hitachi EVSE, a V2G DC charger with a rated capacity of 6 kW. The total rated capacity of the fleet is 55.2 kW. See Appendix C for a list of project chargers and vehicles.

4.2.2 Frequency Regulation Signal and Assignment to Electric Vehicles

A recorded California ISO Automated Generation Control (AGC) signal from the Los Angeles Air Force Base (LAAFB) V2G project[15] is scaled to the total rated capacity of the EV coalition. The Nuvve GIVe™ aggregation software platform simulated participation in the California ISO regulation up and down markets by sending the scaled AGC signal as 'power requested' to the charging stations while the vehicles were plugged in. The summed power output of the coalition is recorded as 'power provided' in response to the AGC signal. The temporal resolution of the recorded data is one second.

4.2.3 Data Collection

Data collection in the frequency regulation use case was impacted by hardware challenges and COVID-19 in a way that limited the period in which data could be collected.

The Hitachi EVSEs had a limitation that prevented the stations from engaging when connected to an EV below 30 percent state of charge (SOC). Drivers were instructed to return the cars above 30 percent SOC. When they were not able to do so, they were instructed to initiate charging manually. Manually initiation of charging would ensure that the vehicle reached 100 percent SOC but prevented the station from connecting to the aggregator, which prevented data collection.

[14] Distribution System Constrained Vehicle to Grid Services for Improved Grid Stability and Reliability [EPC-14-086]. https://www.energy.ca.gov/2019publications/CEC-500-2019-027/CEC-500-2019-027.pdf.

[15] Los Angeles Air Force Base Vehicle-to-Grid Demonstration – https://vehicle-grid.lbl.gov/project/los-angeles-air-forcebase-vehicle-grid.

To keep the chargers online and collecting data, the stations needed to be power cycled daily once the vehicles reached a minimum of 30 percent SOC. This required a Nuvve employee to be onsite each morning for 30-45 minutes while all the EVs reached 30 percent SOC. The employee would then restart the Hitachi chargers and get them reconnected to the aggregator. This took place daily for two months leading up to the Frequency Regulation data collection period.

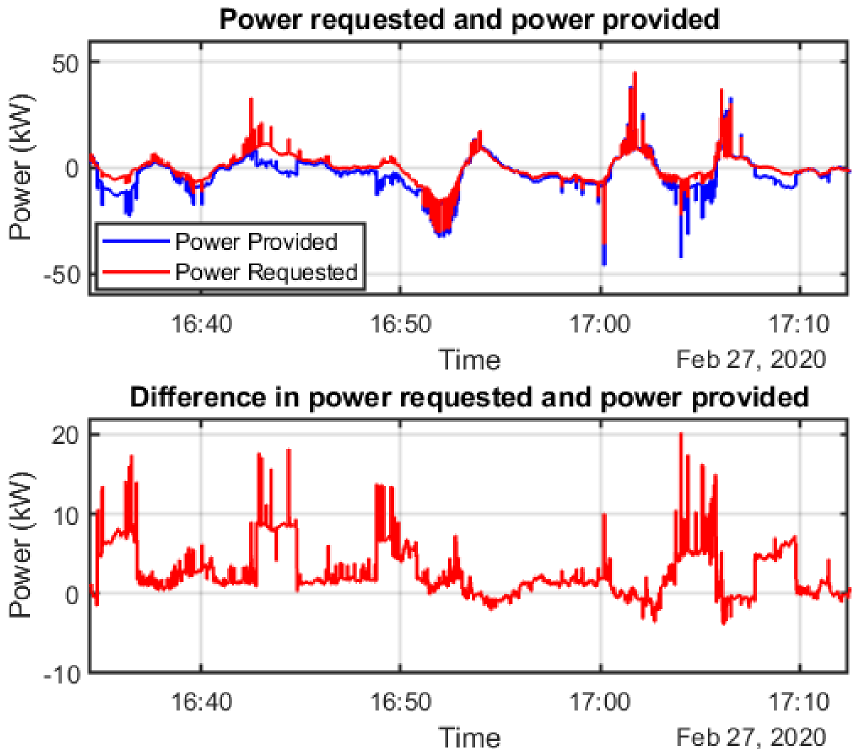
Initially, the testing was planned for a complete month in March 2020. However, the arrival of COVID-19, and the subsequent stay-at-home orders, prevented the required manual intervention to keep the Hitachi stations online and operational. This decreased the availability of the vehicle fleet starting in the second week of March 2020. Therefore, data was collected only for a period of two weeks from February 27, 2020, at 2 a.m. to March 11, 2020, at Midnight, before the university was locked down. The first two hours on February 27 were dropped due to data abnormalities resulting in a sharp rise or fall in performance accuracy.

After the frequency regulation data collection ended, the Hitachi chargers' inclusion in other use cases was limited due to the complexity of keeping them operational.

The collected data of provided power in response to the requested power is used to calculate the performance accuracy and accrued mileage as per the California ISO settlement process. The Python script written by the E3 for the EVSA project is customized and used for the calculation of the performance accuracy mileage for regulation up and regulation down commands. Both the dispatch operating point (DOP) and the point of preferred operation (POP) are set to zero for the analysis. The frequency regulation market bidding process is not considered in the test as the EV coalition did not actually participate in the frequency regulation market. Therefore, for simplicity the bid capacity is assumed to be the same as the 'power requested' in the calculations. The analysis presented is based on the settlement calculations outlined in the California ISO's Business Practice Manuals[16]. The results of the frequency regulation testing are presented in Figure 10.

[16] Business Practice Manual, California ISO – http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx

Figure 10: Frequency Regulation Data



Sample data for frequency regulation on 33 minutes of February 27, 2020. The upper subplot shows power requested and power provided by the EV coalition. The lower subplot shows the difference between the requested and the provided power.

Source: Nuvve Holding Corporation

4.2.4 Performance Accuracy Results

Performance accuracy (PA) is a metric from 0 to 1, which measures how closely the power provided follows the requested power. PA is calculated following the California ISO business manual. For regulation-up commands, PA is calculated using Equation (1), and an analogous equation is used for calculating PA for regulation down commands. During the analysis period from February 27 to March 13, 2020, the 15-minute averaged performance accuracy ranges from 37.02 percent to 69.21 percent for regulation up and 27.48 percent to 56.73 percent for regulation down commands. As shown in Figure 10, the rolling 15-minute averaged performance accuracy is always above the minimum threshold of 25 percent dictated by the California ISO. The average performance accuracy for regulation up and down is 56.86 percent and 48.58 percent, respectively.

$$CU_{r,i} = \frac{\max\left[0, \sum_{j\in S_i}(AIU_{r,j} - |AIU_{r,j} - ATU_{r,j}|)\right]}{\sum_{j\in S_i} AIU_{r,j}} \quad (1)$$

where,

$CU_{r,i}$: Performance accuracy for regulation up for resource r in interval j

i : 15-min interval

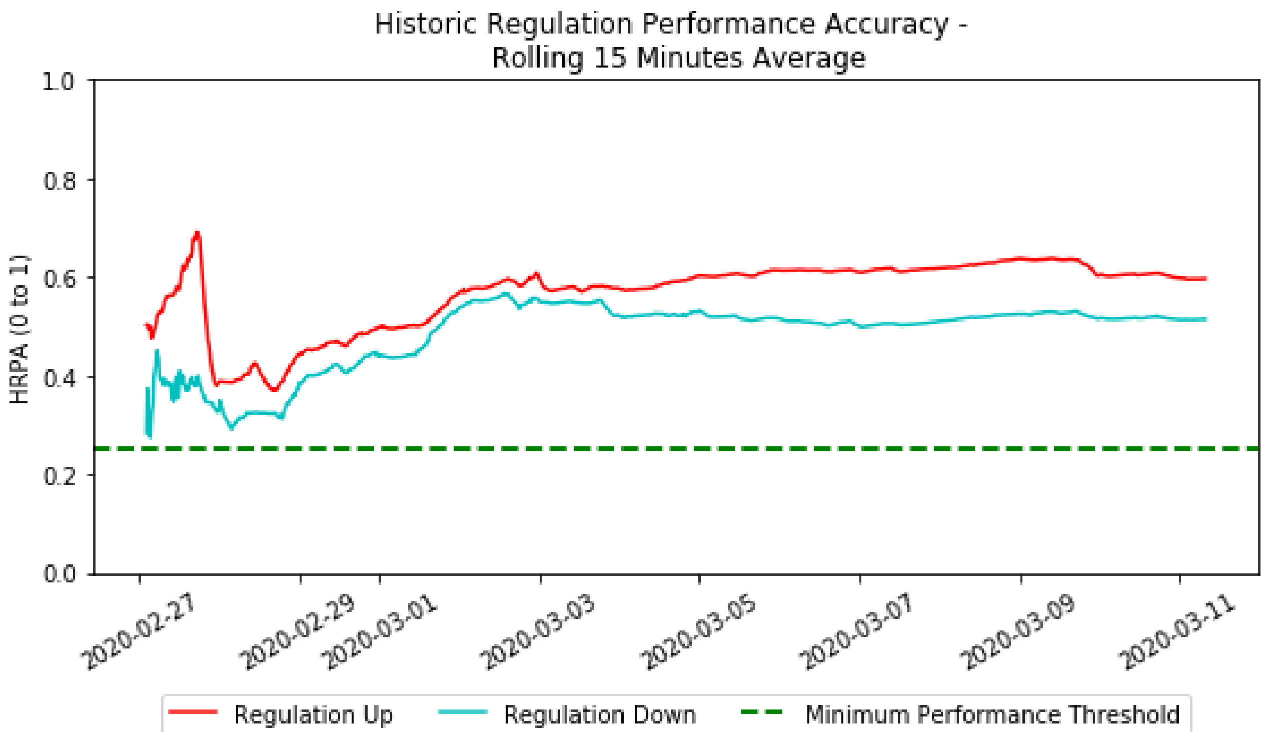
S_i: Set of configurable periods j in interval i

$AIU_{r,j}$: Average instructed regulation up for resource r in period j

$ATU_{r,j}$: Average telemetric regulation up for resource r in period j

The coalition of EV batteries generally performed better when responding to regulation-up instruction, suggesting that the signals directing the coalition to discharge were easier to follow. The possible reasons behind this could be the use of a historical AGC signal. Without a live signal, dispatch requests were not adjusted in real-time to account for the EV state of charge as they would have been by the California ISO during live market participation.

Figure 11: Historic Regulation Performance Accuracy



Rolling 15-minute averaged performance accuracy for the entire two-week test period reported separately for regulation up (red, upper line) and down (cyan, lower line).

Source: Nuvve Holding Corporation

4.2.5 Daily Instructed Mileage

The instructed mileage for each day is shown in Figure 12. The highest mileage of 14.32 MW for regulation up occurred on March 9, 2020, while the lowest mileage of 2.56 MW occurred on March 11, 2020. The total regulation up mileage for the duration of the analysis is 114.73 MW, averaging 8.20 MW per day. Similarly, the highest and lowest regulation down mileage was observed to be 12.07 MW on 2 March 2 and 1.82 MW on March 11, respectively. The total regulation down mileage is 90.95 MW with an average of 6.50 MW per day.

Figure 12: Daily Instructed Mileage

Source: Nuvve Holding Corporation

4.3 Conclusions

This analysis confirms that the coalition of electric vehicles successfully participated in the frequency regulation ancillary services market, achieving a performance accuracy well above the minimum threshold and on the upper end of the California ISO system average (30 percent – 60 percent[17]) for regulation up and regulation down. This should serve as a starting point for the California ISO to consider the place of EVs in not just the frequency regulation market but other fast-reacting services that may depend on frequency or similar live signals.

[17] Frequency Regulation Compensation in the Organized Wholesale Power Markets, FERC Stats. & Regs. 31,324 (2011) (Order 755), 138 FERC 61,123 (2012) (Order 755-A). https://www.caiso.com/Documents/Jul31_2014_Order755MarketDesignReport_ER12-1630_ER14-971.pdf.

CHAPTER 5: Demand Response

5.1 Overview of Use Case

The demand response use case under INVENT was implemented in two phases. The first phase occurred during the first half of the project and focused on leveraging INVENT project assets to provide voluntary demand response load reduction during California ISO Flex Alerts and SDG&E Reduce-Your-Use events that took place during August 2018. The second phase developed through conversations with UCSD starting in June 2019. UCSD approached Nuvve and the INVENT project with interest in leveraging a stationary storage battery located on the campus microgrid to access the California ISO wholesale markets and provide grid services.

5.2 Phase 1

During the summer of 2018, three California ISO Flex-Alerts and SDG&E Reduce-Your-Use events were called. The project team took the opportunity to discharge the project assets that were installed and operational at the time. See Appendix C for a list of project chargers and vehicles.

Table 1 lists the vehicles and EVSEs used.

Table 1: Load Reduction Event Results in Summer 2018

Date	Alert Type	Time	Energy
July 24th, 2018	Flex-Alert	17:00-21:00	63 kWh
July 25th, 2018	Flex-Alert	17:00-21:00	76 kWh
August 7th, 2018	Reduce-your-Use	17:00-21:00	75 kWh

5.3 Phase 2

The goal of Phase 2 was to register the BYD battery as a capacity resource to access and provide services to the California ISO wholesale markets. To participate in the California ISO wholesale market, Nuvve and UCSD together had to decide what wholesale market participation model to pursue, find and sign on with a demand response provider and scheduling coordinator, qualify and implement metering and settlement processes, and design a forecasting and bidding strategy.

5.3.1 Market Participation

UCSD and Nuvve together decided the proxy demand response (PDR) market participation model was optimal for wholesale market participation by the UCSD battery storage resource.

Under current California ISO market design rules, there are two wholesale market participation models to enable wholesale market access for an energy storage resource — the non-generating resource (NGR) participation model and the PDR participation model. The PDR participation model enables third parties to bid demand response for load curtailment into the

California ISO wholesale market.[18] PDR does not allow for or compensate energy injection to the grid.

The NGR participation model enables energy storage resources to inject and withdraw energy from the grid or more actively participate in the California ISO wholesale market. However, NGR participation requires a wholesale distribution access tariff (WDAT) interconnection. The WDAT interconnection process comes with higher fees and a longer timeline than the Rule 21 interconnection process but also requires that there be no retail loads on the same metered account. This removed NGR as an option for a resource inside a microgrid.

PDR is the main wholesale market participation model for behind-the-meter (BTM) resources. To qualify as a PDR resource, the resource must have a Rule 21 Interconnection agreement with the local distribution company and sign a Demand Response Provider Agreement with the California ISO. The resource submits settlement quality meter data (SQMD) to the California ISO through their scheduling coordinator (SC).

PDR participation also requires the establishment of a resource load baseline. This baseline load value is compared to the resource's actual load during a market dispatch or demand response event to measure resource performance and calculate market compensation (settlement) for the market participant. PDR resources can participate in the day-ahead (DA) and real-time (RT) energy markets. PDR resources can also participate in ancillary service products spin and non-spin reserve markets once they have telemetry.

5.4 Implementation

See Appendix D for the timeline of market access and implementation.

5.4.1 Technical Integration

One of the key components of enabling this use case was the need for the Nuvve aggregation platform to integrate with the BYD battery's communication interface for Nuvve to control the battery for dispatching. The development and testing of the interface integration took five months of consistent collaboration between Nuvve and UCSD. Testing of the interface started in July 2020, but due to several challenges, the Nuvve aggregator was not able to take control of the battery until mid-October. These challenges included:

- Limited technical documentation from the battery manufacturer (BYD).
- Limited technical support from battery manufacturer (BYD).
- Conducting testing with COVID-19 precautions.
- Navigating the UCSD IT department, identifying appropriate personal and troubleshooting remotely due to COVID.

Prior to mid-October, UCSD and Nuvve were still able to participate in the Demand Response Auction Mechanism (DRAM) and dispatch the battery according to UCSD's existing manual process as well as the dispatch forecast algorithm developed by UCSD under INVENT. The most significant challenge listed was the limited involvement and documentation from the

[18] California Independent System Operator. PDR-DERP-NGR Summary Comparison Matrix. 2021 http://www.caiso.com/Documents/ParticipationComparison-ProxyDemand-DistributedEnergy-Storage.pdf

battery manufacturer. It is imperative for efficient technical development and integration to have the manufacturer of an asset involved to provide accurate and clear documentation, feedback and troubleshooting assistance.

5.5 Market Access

Nuvve and UCSD together decided to use Leapfrog Power as the demand response provider (DRP) and scheduling coordinator (SC) for the UCSD battery storage resource.[19]

Selecting companies that provide DRP and SC services is a key step in accessing the California ISO wholesale energy market as a demand response resource. The DRP and the SC enable access to wholesale market participation and handle settlement of market participation results with the California ISO as well as with SDG&E, the utility distribution company for the area.

Every wholesale market participant, including those in demand response programs, must use an ISO-certified SC to act on behalf of the resource. SCs submit bids into the market, receive energy market awards, and handle market settlement information for a given resource.

Leapfrog Power also acted as the SC for the UCSD battery resource. Leapfrog Power, Nuvve, and UCSD worked together to understand PDR market bidding for a resource and resource baselining, to develop a bidding strategy. Bidding into the California ISO wholesale market was new for Nuvve and UCSD so it was important to understand how to bid the battery into the DA market, how to respond to a dispatch, implications for under or over-performance, how deviations from the market dispatch would settle, how to baseline the resource, and what factors impact the baseline.

5.5.1 Dispatch Forecast Development

The battery is used primarily for demand charge management (DCM) and is otherwise idle most of the time. The purpose of this project is to generate additional revenue from the battery operation by participating in demand response markets.

An economic model including DCM and demand response auction mechanism (DRAM) feeds a control algorithm for the BYD battery.

The model downloads historical data of utility imports, onsite generators output, PV output, and BYD battery dispatch from the UCSD metering system website. These inputs allow calculating the adjusted baseline, utility imports, and adjusted demand. For DCM, thresholds (including the peak-demand threshold and the non-coincident demand threshold) are used to trigger battery discharge for demand charge reduction when the load is higher than the threshold. In addition to historical data, the model also took in forecasted utility import and forecasted adjusted demand and forecasted day-ahead LMP as revenue from DRAM dispatch is based on both prices.

5.5.2 Metering and Settlement

Metering and settlement are necessary elements for any resource participating in the California ISO wholesale market. Resource metering provides the SC and California ISO data for baselining and settlement. Settlement is ultimately provided by the California ISO to pay

[19] Leapfrog Power, Inc. 2021. https://leap.energy/index.html.

resources for their in the wholesale market. Metering and quality of metering are important because meter data is necessary for calculating the demand response customer baseline as well as the basis for settlement with the California ISO. The customer baseline establishes a method for setting a customer's baseline load, an estimate of how much electricity a customer would have used had it not reduced its use in response to DA and RT prices or awards or both.

The metering of a resource can determine how a resource is settled. Metering was an important consideration as the team worked through the market access process under INVENT. PDR resources have the option of leveraging the meter generation output (MGO) performance methodology developed under the California ISO's Energy Storage and Distributed Energy Resources (ESDER) stakeholder initiative and implemented in 2019. And, upon initial evaluation, the project team saw a clear advantage in leveraging the MGO performance method under PDR (PDR/MGO pathway) for the UCSD microgrid battery storage resource. Using MGO would enable the battery storage resource (1.8 MW) to be separated out and metered separately from the overall UCSD microgrid load (42 MW) as is illustrated in Figure 13 (option A).

The ability to meter specifically from the battery storage resource made it very attractive to pursue the PDR/MGO wholesale market participation pathway, but the PDR/MGO pathway also had concerns. Metering from the battery meter would allow the battery to be removed from the noise of the campus microgrid so the team invested significant effort in trying to use the MGO method.

However, as the INVENT project progressed, the team discovered that the battery meter was not utility certified (nor utility-owned since it is on the microgrid). Because UCSD is its own microgrid, they have assets (meters and generation) that are not owned and operated by the utility. To implement a non-utility owned meter for MGO, the SC must register the meter themselves, which is time and capital-intensive.

The other option for developing a baseline beyond the MGO methodology is the 10-in-10 non-event method.[20] In this case, performance is determined through a pre-defined baseline calculation using the last 10 similar nonevent days with a lookback window of 45 days and a bidirectional morning adjustment capped at 20 percent.

While the 10-in-10 method seems reasonable, because of the battery meter non-certification and without using the MGO performance method, the UCSD battery storage resource presented a unique challenge in that the 10-in-10 would need to be based on the upstream retail campus meters for baselining the battery instead of the battery meter. This presented new challenges including the difficulty of using baselining to accurately discern the battery activity among a diverse load profile and the prohibited resources which exist on the UCSD microgrid. Figure 13 (option B) illustrates this scenario.

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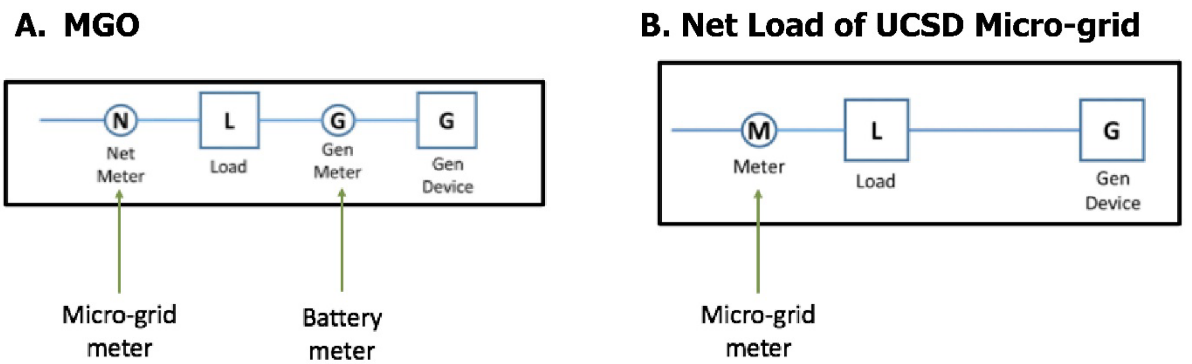
[20] California ISO DR Baseline BPM see 5.4.

Figure 13: Baseline and Settlement Options A and B



Source: Nuvve Holding Corporation

5.5.3 Capacity

While not part of the initial INVENT project scope, the new baselining method opened the DRAM as an option that would not have been available under the MGO model. The California ISO and CPUC oversee resource adequacy (RA), which is California's "capacity" paradigm. LSE capacity procurement is to ensure generation capacity, or the potential to generate exceeds the system needs across the year. An RA commitment obligates a generation resource to must offer obligations for energy bids, typically 24 hours a day, into the DA and RT markets for the given month of the RA commitment. A resource gets compensated for that RA commitment, and the capacity payment can make a real difference for a resource.

To open up the benefit of capacity revenue to smaller demand response programs, the CPUC issued a rule in 2014 which obligated PG&E, SCE, and SDG&E to design and implement a capacity procurement method for small demand response programs via the DRAM. Each utility has designed and administers its own DRAM program. Resources receiving a DRAM capacity payment also have a must offer obligation between the hours of 4 p.m. to 9 p.m. with some exceptions. And, the resource must demonstrate they are providing load reduction, and they do this through 'event' performance in the market.

5.6 Results: Impact on Overall Market Trends

The INVENT project participated in seven months of DRAM 2020 (June - December 2020). Table 2 details results for each month. The team did not submit DRAM bids in November and December to allow scheduled maintenance and complete technical integration, but resumed market participation in January 2021 and will continue as a partnership after the close of the project. See Appendix D for demand response event participation.

Table 2: Demand Response Auction Mechanism 2020 Revenues Under INVENT

Month	June	July	August	Sept	Oct	Nov	Dec
Capacity - Base	$15,660	$39,161	$28,710	$15,660	$9,486	$7,830	$5,220
Capacity - Bonus	N/A	$18,281	$21,290	$30,000	N/A	N/A	N/A
Energy	N/A	$925	$8,226	$10,631	$754	N/A	N/A
Demonstrated Capacity (MW)	1.8	3.4	4.6	8.2	1.6	N/A	N/A

Source: LEAPFROG POWERPartner Payment Summary

5.7 Discussion

The INVENT team encountered a number of issues that constitute barriers to entry for DERs into wholesale energy markets.

5.7.1 Onerous Wholesale Market Rules

Wholesale market rules are onerous, which limits the ability for new/small companies to compete and bring new resources to market. DER participation in wholesale markets would benefit from simpler and easier-to-understand rules. Wholesale markets are difficult to understand and lack transparency, and this can be a barrier to entry for small DERs or new entities looking to enter the market. Complex market rules are published in tariff and business practice manuals (BPMs), which can be confusing and hard to decipher. Also, it is difficult to know exactly where information is housed unless one is a tariff expert. For example, the INVENT project team discovered they couldn't use the MGO method after months of designing and working towards wholesale market participation. When it became clear the meter was not certified in the fashion needed to provide settlement quality meter data, the team went with the next best option of the 10-in-10 baseline methodology. DER participation would benefit from a clearer description and/or tool to illuminate and calculate a resource baseline. The baseline is paramount to assessing performance, which results in either payment of financial penalties. For the INVENT project, the baseline was of even greater concern and increased ambiguity because the battery was metered at the microgrid level.

DER participation would benefit from a centralized document outlining the market requirements and compliance criteria for the DRAM program. While each investor-owned utility has its own DRAM program, there are commonalities, such as market bidding obligations and test event measurement, that could be published in one place, making it much simpler for small entities to understand. DER participation could benefit from some outline of whom to work with on what when it comes to moving through the process of registering and preparing for wholesale market participation. Again, unless someone has a consultant or market expert, either of which is costly for a small resource, it is hard to know exactly what is needed for resource registration and whom to work with. At a minimum, a new registering entity is working with the Load Serving Entity (LSE), Utility Distribution Company (UDC), Local Regulatory Authority (LRA), and the California ISO.

5.7.2 Limited Ecosystem of Vendors and Companies

There is a limited ecosystem of vendors and companies supporting DER market participation. DER wholesale market participation would benefit from a larger ecosystem of companies serving DERs and BTM resources. DERs and BTM resources are at a disadvantage because of the small ecosystem service them and this limits wholesale market access.

While there are many SCs listed on the California ISO SC list, the reality is only a few offer services to small resources and aggregators. Nuvve searched to find multiple SCs in an effort to evaluate options. Nuvve found Leapfrog Power and Olivine to be the only companies offering SC services to a small resource like the UCSD battery. Leapfrog Power provided valuable services, insights, and strategy and was a valuable partner in this project.

5.7.3 Distributed Energy Resources in Multiple Applications

DERs must manage co-optimization of multiple applications (peak management, Self Generation Incentive Program [SGIP]). When setting up a resource there are considerations such as the ramp rate of the resource, daily cycles, and bidding strategy. The battery was originally added to the UCSD microgrid to serve the needs of the microgrid and campus and falls under the SGIP, which has requirements on how many times the battery must cycle. As with many distributed resources, wholesale market participation becomes one of a handful of objectives. In the case of the UCSD battery this meant managing campus peaks and reducing non-coincident peak charges as well as creating revenue. Also, it is paramount for resource ownership to understand how a resource is dispatched/paid in the wholesale market and what a DA award means, and how it is settled in the RT market for any performance imbalances.

It is clear that microgrids and the resources situated inside them can participate, if allowed, as significant actors in the California electric system. Baselining, metering methods and market access processes can all be revised to facilitate integrating microgrids as essential components of distributed grid management and resilience.

CHAPTER 6: Market Opportunities and Challenges for Vehicle-Grid Integration in California

This chapter summarizes the VGI Market Development Report that assesses the extent to which value streams at the site host, distribution, and wholesale levels are accessible to EVs. See the full VGI Market Development Report in Appendix A.

6.1 Electric Vehicle Operator / Electric Vehicle Support Equipment Site Host Value Streams

Chapter 3 of the VGI Market Development Report provides overviews of the four categories of EV operator / EVSE site host value streams, as well as discuss market development recommendations to improve the ability of VGI technology to provide value in each category. It is important to note the EV operator (that is the driver or fleet manager) can be the same or different as the EVSE site host. The two are included together because the value streams available to both are largely the same.

6.1.1 Time-of-Use Bill Management

Time-of-use (TOU) electricity rates offer price signals that differ throughout the day, with higher rates during times of peak electricity demand and lower rates during off-peak or low-demand hours. If designed in accordance with best practices in utility rate design, this time-varying rate structure can offer electricity customers an opportunity to take advantage of lower energy prices and save money on their monthly utility bill. Utility customers with EVSE, for example, residential customers with wall-mounted chargers or commercial workplaces, can leverage well-designed TOU rates to save on EV charging costs by shifting when an EV charges. Other time-varying price signals, such as rebates for charging during off-peak times and critical peak pricing rates, can also enable EVSE site hosts to save on their monthly utility bills. The current and pending commercial EV TOU rate structures are relatively flat compared to their residential counterparts. Peak periods for EV-specific and general commercial and industrial TOU rates generally fall between 2 p.m. and 9 p.m., a longer peak than the period of residential TOU rates.

6.1.2 Bidirectional Charging for Time-of-Use Bill Management

In addition to saving money by charging during off-peak times, both residential and commercial customers could generate additional revenue by offsetting on-site consumption of energy from the grid during peak times. This would require an EV or EVSE equipped with a bi-directional inverter capable of serving the on-site load. While both bi-directional EV and EVSE technologies exist, only the latter method has an available interconnection pathway in California.

6.2 Market Development Recommendations

Overall, the TOU value stream is currently accessible to VGI technology and monetizable to build a business case around. However, there are areas for improvement to increase the value VGI further can bring to stakeholders.

6.2.1 Encourage Dynamic Rate Design

Time-varying rates such as SDG&E's are a type of dynamic price signal that better reflects the cost of energy generation and could lead to more impactful shifts in charging behavior to reduce peak demand. Retail EV charging rates, whether for residential or commercial customers, could be more reflective of the cost of energy generation, delivery, GHG emissions, and any other relevant value streams through the use of more granular time- and location-specific price signals. Widespread implementation of such rates would require optionality, with both simple, existing TOU and more complex, dynamic rates being made available to customers.

6.2.3 Demand Charge Management

Commercial customers are typically subject to demand charges, a $/kW charge that is included alongside the $/kWh volumetric bill component. In California, demand charges are applied to a customer's demand, which is based on the maximum average amount of energy used in a 15-minute interval in a month. Stationary energy storage has been shown to help commercial customers limit their peak demand up to 25 percent and reduce their monthly electricity bills[21]. VGI resources can also capture the demand charge management value stream: V1G solutions can shift charging load away from peak periods and bi-directional solutions can further reduce demand charges by discharging the EV to meet on-site peak loads.

While the three California IOUs all offer commercial rates across various load sizes and rate structures (including demand and energy charge components), only PG&E and SCE currently have EV-specific rates for C&I customers that begin to specifically address EV demand rather than focusing on volumetric, $/kWh rate time-of-use periods.

6.3 Market Development Recommendations

The demand charge management value stream is also accessible and monetizable for VGI technology. However, challenges remain and are similar to those seen for TOU bill management.

Similar to TOU bill management, offering optional, more dynamic rate structures, such as average daily demand, can help ensure commercial EVSE site hosts are continually incentivized to manage charging. This alternative would base monthly billing demand on the average of the peak intervals for each day within the month, rather than the single maximum highest 15-minute period. This price signal could better reward customers who monitor and adjust their EV charging load daily.

6.3.1 Increased Photovoltaic Self-Consumption

EVSE site hosts with on-site solar photovoltaic (PV) generation behind the meter can leverage managed charging solutions to increase the amount of self-generation that is consumed on-site. For example, a customer's rooftop PV panels generate electricity at effectively zero marginal cost, and an EVSE site host may implement a VGI solution to ensure that EV charging adds to on-site load when solar PV generation is at its peak. Office buildings, college

[21] Gagnon et al. 2017. "Solar + Storage Synergies for Managing Commercial-Customer Demand Charges." Berkeley Lab. https://emp.lbl.gov/publications/solar-storage-synergies-managing.

campuses, and residential customers may be particularly interested in capturing this value stream, as EV driving patterns for these customers often lead to EVs being parked during times of high solar generation.

6.3.2 Net Energy Metering and Self Generation Incentive Program Compensation

Another pathway for EVSE site hosts with onsite PV to capture value is through net energy metering (NEM) tariff options. NEM compensates commercial and residential customers with solar PV (less than 1 MW) for kWh generated onsite that offsets onsite kWh consumption. The NEM bill credit for onsite generation that offsets site load is equal to the full retail electricity rate. NEM customer offsets are assessed annually and any NEM exports that exceed the annual site load are compensated at a lower wholesale rate. Leveraging V2G-capable EVs under a NEM set-up is more challenging due to the need to prove all energy used by the vehicles charge or discharged comes from the on-site, solar installation.[22]

V2G systems may qualify for compensation for exporting power through California's SGIP, a $/kWh rebate intended to encourage GHG reductions, peak demand reductions, and DER market development. Another action that could alleviate this barrier would be to implement a new, separate incentive or retail price signal specific to VGI resources to leverage bidirectional functionality.

6.3.3 Non-Net Energy Metering Increased Self-Consumption

In the NEM case, the opportunity cost of not consuming a kWh generated by on-site solar is equal to the difference between the retail rate and the net surplus compensation (NSC). In the case where on-site generation is not "oversized" (that is, when solar output does not exceed site load), increasing PV self-consumption by using VGI technologies could also help lower EV charging costs. This depends on the exact configuration of a customer's system. However, charging EVs directly from solar PV could offer an alternative to paying for EV charging from the grid. PV self-consumption can also have a GHG reduction benefit as well. By shifting charging load to capture midday on-site solar generation, an EV customer is potentially shifting load away from fossil fuel electricity generators.

6.4 Market Development Recommendations

The increased PV self-consumption value stream can be captured through accessible and monetizable pathways, although there are potential market development actions that could be taken to strengthen the economics of this value stream.

6.4.1 Implement "Reverse Energy Efficiency"-Style Rebates

These rebates provide incentives for consumption during the midday hours of peak solar output. Such a policy can also be used to integrate renewables more generally (that is, not just self-generation), as incentives can be crafted to shift further charging towards times of peak solar supply.

6.4.2 Expand Net Energy Metering

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[22] Definition of customer-generator in RPS Eligibility Guidebook, published April 27, 2017 states, "storage may be considered if…[it] is capable of storing only energy produced by the facility." Source: https://efiling.energy.ca.gov/getdocument.aspx?tn=217317.

Expanding customer-generator NEM eligibility to include and address bidirectional EVs could ensure V2G resources are compensated for exporting power to the grid. However, as noted previously, it is critical to address, track and potentially audit the source of charging and discharging energy to ensure the spirit of NEM is maintained. Overall, NEM tariff options or any successor DER compensation mechanisms can be thoughtfully enhanced to enable VGI, specifically focusing on leveling the playing field for DERs, as solar-paired stationary energy storage is currently eligible for NEM if it meets relevant conditions.

6.4.5 Backup Power and Resiliency

While commonly referred to as V2G, bi-directional applications can also provide power to entities other than the grid. Vehicle-to-building (V2B) applications can allow site hosts to use bi-directional EV and EVSE systems to provide backup power to all or some on-site load. This value stream may be particularly useful for California customers considered vulnerable to planned power shutoffs, unplanned outages, or other emergencies. This value stream presents an entirely new category of value for customers. Currently, customers seek backup power from diesel generators or stationary energy storage systems.

6.4.6 Allocate Funding for Resiliency Projects

Currently, the backup power use case is theoretically permitted if the EVSE is certified under the relevant standards and the system is compliant with Rule 21 for interconnection. However, the process of safely islanding the facility and how exactly the critical load panels would be wired in relation to the EVSE is not standardized or clear. However, providing public funding for projects could support such applications and serve as a "proof of concept" in a priority area of public policy focus (SB 1339, Stern 2018). The Backup Power and Resiliency value stream will become more practical from a customer perspective in mid-2021 when residential V2G EVSEs become commercially available.

6.5 Utility Value Streams

This section will review the three categories of utility value streams identified in Table 3 and identify market development recommendations for each. Utilities can capture value streams from distributed DERs by aggregating them into a portfolio of resources used to meet bulk power sector needs. Several VGI applications in this utility value streams chapter and the following grid operator value streams chapter may be inapplicable to individual VGI resources and require aggregation due to the small capacity (kW) of individual resources.

Table 3: Electric Vehicle Operator/Electric Vehicle Supply Equipment Site Host Value Streams Market Development Summary

Value Stream	Accessible	Monetizable	Potential Action Topics
TOU Bill Management	✓	✓	Rate Design Interconnection
Demand Charge Management	✓	✓	Rate Design Interconnection
Increased PV Self-Consumption	✓	✓	Rate Design Interconnection

Value Stream	Accessible	Monetizable	Potential Action Topics
Backup Power & Resiliency	✓	✗	Interconnection Resiliency Funding

6.5.1 Transmission and Distribution Deferral

Transmission and distribution (T&D) upgrades need to occur when electricity transmission lines, substations, and other equipment lack the capacity to handle increases in peak demand and ensure reliability. Alternatively, VGI technology could provide the necessary bandwidth to handle peak demand and can be deployed as an alternative to investing in new infrastructures such as feeder lines and substations. If EV charging load is not included in load forecasts, then the ability to defer a T&D investment through leverage VGI technology to shave local peak charging load will not be valued. V2G, however, may be able to provide distribution deferral even if the EV load is not adequately accounted for in the load forecast.

Location-specific rates could be a lever to defer T&D upgrades indirectly, but previous efforts to conduct the locational net-benefit analyses required to design such rates have proven unsuccessful.

6.5.2 Resource Adequacy (RA)

RA is the procurement process undertaken by utilities to ensure sufficient generation capacity is contracted to meet peak demand. The RA framework was instituted in 2004 to guarantee the reliable operation of California's electric grid to evaluate the systemwide, local, and flexible capacity needs and direct CPUC-jurisdictional LSEs to procure enough capacity to match their requirements. Several types of capacity can be procured to meet RA requirements; DR is one of them. DR programs offer an incentive to customers to reduce their consumption during certain peak pricing hours or reliability events. DR programs work by notifying customers to reduce consumption during an event.

VGI solutions may be able to meet LSEs' RA requirements, and utilities are looking for zero-carbon RA contracts as gas peaker plants around the state get shuttered to support the state's 100 percent carbon-free electricity goals. V1G strategies, when implemented through aggregations of EVs, could provide RA through a contract with a utility to reduce charging load, especially during peak times. V2G technologies can also provide RA by exporting power to the grid to provide capacity.

6.5.3 Supply-Side Demand Response

DRAM and the Capacity Bidding Program (CBP) are examples of DR programs that procure supply-side DR as RA resources and allow third-party aggregators to bid into the wholesale market, subject to contractual testing, dispatch, and performance requirements. DRAM is open to DER aggregations, including VGI resources. Therefore, a version of the RA value stream can is accessible and monetizable. However, as with all behind the meter resources, traditional resource adequacy remains inaccessible.

Baseline usage is challenging to determine with high levels of accuracy due to the inherent volatility of load. The 10-in-10 baselining methodology is the simplest of the four options, although it is still a troublesome method for fairly evaluating VGI resources. The unique load patterns and metering configurations of EVSE necessitate a well-designed framework to assess the "business as usual" or counterfactual load. As detailed in the Time-of-Use Bill Management and Demand Charge Management sections, several EV rates require separate metering, which can make finding a true baseline used to fundamentally value and compensate the VGI resource for DR events incredibly challenging. This represents a significant barrier for VGI market development, as it restricts the stacking of several economically appealing value streams spanning all stakeholders.

6.5.5 Distribution Voltage Support

As DER penetration increases and more power is exported to the distribution grid, the need for voltage support increases. New "smart inverter" capabilities offer methods for managing the impact of these DERs, and the IEEE 1547 standard sets specific requirements for smart inverters. IEEE 1547 outlines "modes" to support voltage regulation by quickly controlling a representative component of electrical current known as reactive power.

While the technical capabilities for this value stream will be in place for all Rule 21 compliant inverters, there is currently no monetization pathway corresponding to the value stream.

Table 4 summarizes this chapter's conclusions regarding the three Utility value streams covered.

Table 4: Utility Value Streams Market Development Summary

Value Stream	Accessible	Monetizable	Potential Action Topics
T&D Deferral	✓	✗	•Distribution Investment Deferral Framework •Rate Design
Resource Adequacy	✓	✓	•Supply-Side Demand Response •Utility Demand Response Programs
Voltage Support	✗	✗	•Interconnection •Distribution Planning

Source: California ISO, 2020

6.6 Grid Operator Value Streams

The VGI value streams that exist at the wholesale market level generally mimic grid services identified in the original RMI wheel for stationary energy storage. Energy arbitrage, spin / non-spin reserves, frequency regulation, and transmission voltage support are all value streams that could be made available to VGI solutions. Grid operator value streams are most applicable to aggregations of EV and EVSE systems that behave like systems large enough to participate under a grid operator's market rules, specifically minimum capacity (kW) thresholds.

6.6.1 Resource Classifications and Aggregations

EVs and EV aggregations can currently participate in the California ISO proxy demand resource (PDR) load curtailment products for energy, spin, and non-spin value streams at a facility/utility line of service aggregation level. The reliability demand response resource (RDRR) is also an available participation mechanism, but this classification cannot submit ancillary services bids.

California ISO rules also theoretically allow EVs to be aggregated as non-generator resources (NGR) through a DER provider (DERP). The DERP-NGR framework allows for the provision of all California ISO market products, allowing DERs to capture the energy arbitrage, spin/non-spin reserves, and frequency regulation value streams. However, there exists a requirement that NGR resources be available for market participation 24 hours per day, a prohibitive requirement for a multi-use DER like EVs that are needed for transportation. Additionally, as distribution-level resources, DERs applying for DERP-NGR participation will go through the utility/distribution level interconnection request (for example, SCE Wholesale Distribution Access Tariff (WDAT)), study, and agreement process (unless interconnecting at high voltage) to become assets on the grid. Additionally, the administrative burden associated with achieving and maintaining a DERP agreement is prohibitively high for many aggregators, as evidenced by the small list of DERPA holders. Given the multiple and complicated barriers currently in place for the DERP-NGR model, it offers a theoretically accessible but not monetizable pathway to access any grid operator value stream.

Table 5 summarizes which value streams DERs can access through the three different California ISO resource classifications. A more detailed investigation into each market product can be found in Appendix A.

Table 5: Summary of Currently Available California Independent System Operator Resource Classifications for Distributed Energy Resources

Grid Operator Value Stream	Distributed Energy Resource Provider: Non-Generator Resource (DERP-NGR)	Proxy Demand Resource (PDR)	Reliability Demand Response Resource (RDRR)
Energy	✓	✓	✓
Spinning Reserve	✓	✓	✘
Non-Spinning Reserve	✓	✓	✘
Frequency Regulation	✓	✘	✘
Voltage Support	N/A	N/A	N/A

Source: California ISO, 2020

6.6.2 Capturing Value Streams Through Demand Response

Proxy Demand Resource

A resource capable of providing demand response can participate more fully in California ISO markets via the PDR framework through DRAM and other contracting mechanisms. A resource can either participate directly in the wholesale energy market and receive energy payments, or it can participate via a RA capacity contract with a utility (like DRAM) which includes payment for performance in the energy market and an additional capacity payment. Therefore, the PDR model offers accessible and monetizable value streams for energy and spin/non-spin (if aggregation is larger than 0.5 MW).

Spinning Reserves

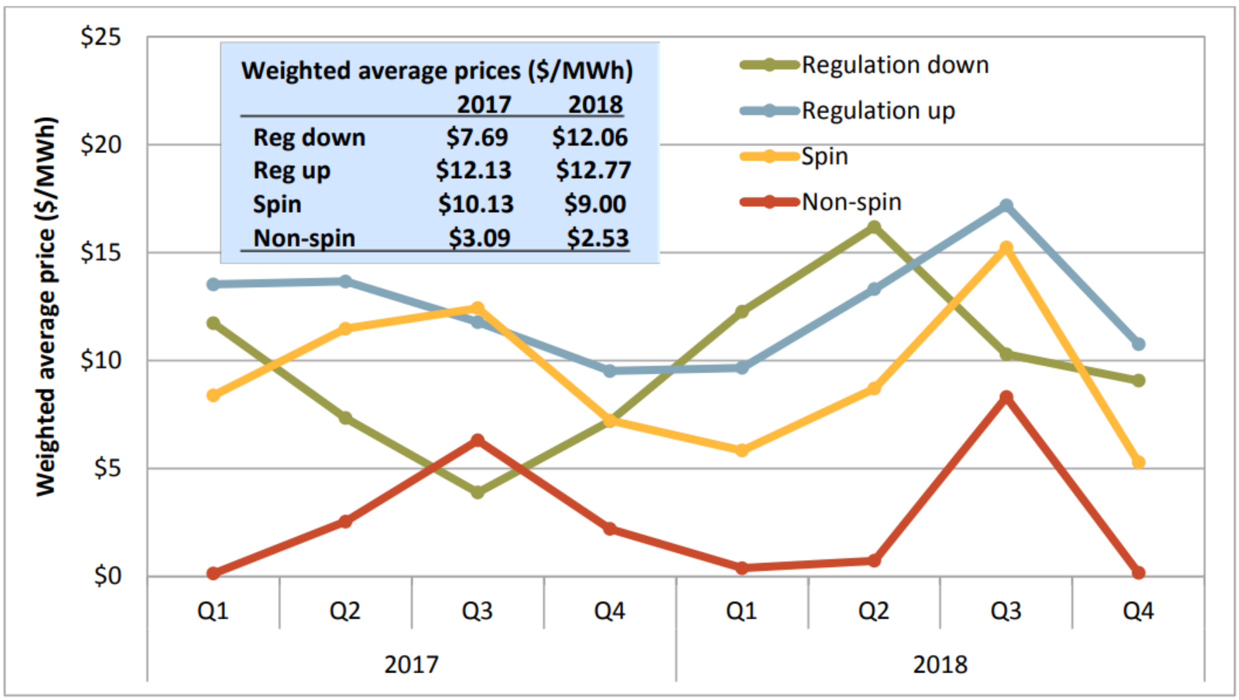
Spinning reserves refer to the immediate capability of a resource to contribute power to the grid. Traditionally, this refers to generators that are already grid-connected, producing below-rated power, and immediately ready to produce additional power. It is procured in the Day-

Ahead Market for each hour in a bid stack of resources and has a low likelihood of dispatch for any given hour. Resources can receive spinning reserve payments simply by being synchronized to the grid (the EVSE inverter is grid-connected and therefore synchronized to the grid). Therefore, the spinning reserve is a market easily bid into by multi-use DERs like EVs and offers an accessible and monetizable value stream for VGI technology.

Non-spinning Reserves

In contrast, non-spinning reserves allow for some delay in generating resources to synchronize to the grid before responding to a grid signal with a power dispatch. This is helpful for resources that need such synchronization time, such as generators that are not normally grid-connected. Overall, the regulation of non-spinning reserves is very similar to that of spinning reserves, except for an allotted time of synchronization following notification. However, it is a much less valuable resource, as shown in Figure 14. In 2018, the weighted average price of the non-spinning reserve was $2.53/MWh, compared to $9.00/MWh for spinning reserves.

Figure 14: Weighted Average Price for Ancillary Services by Quarter, 2017-2018



Source: California ISO 2018 Annual Report on Market Issues & Performance.

Given that grid-connected inverters are always qualified to be spinning reserves and that non-spinning reserves are less valuable than spinning reserves, spinning reserves should a higher priority value stream than the non-spinning reserves market.

Frequency Regulation

Frequency regulation allows participating entities to respond to California ISO signals to raise or lower grid frequency (nominally 60 Hz in the U.S.) via frequency up or down signals, respectively. Frequency regulation in California is predominately regulation down, a result of solar PV ramping up in the morning and down in the evening. The regulation-down requirement is consistently greater than the regulation-up and exhibits peaks in the morning and evening. This revenue stream is currently not accessible via PDR and therefore comes under the realistically inaccessible DERP-NGR framework.

Table 6 summarizes the grid operator value streams and whether they are theoretically accessible (those available through DERP-NGR) and monetizable (those available through PDR). It also identifies potential high-level areas of market development action. The regulatory barriers chapter goes into more depth.

Table 6: Grid Operator Value Streams Market Development Summary

Value Stream	Achievable Monetization Pathway	Practical Monetization Pathway	Potential Action Topics
Energy Arbitrage	✓	✓	PDR Enhancements
Spin / Non-Spin Reserves	✓	✓	PDR Enhancements
Frequency Regulation	✓	✗	PDR Enhancements NGR Enhancements

Source: California ISO, 2020

CHAPTER 7: Vehicle-Grid Integration Regulatory Barriers

7.1 Current California Regulations

As policymakers and regulators around the world develop programs and policies to accelerate transportation electrification, there is a growing need to share and prioritize the most effective strategies. As other geographies make progress in demand response, localized flexibility, and DER aggregation, California could potentially lead the world in VGI and, specifically, V2G policy. It will, however, require a commitment to a coherent vision of EVs as DERs that permeates through transportation electrification (TE) programs, rate design, and development of new markets. Without such a change, California may meet TE goals but will fail to leverage the extraordinary potential of EVs as flexible DERs to support a fast-changing grid and meet its broader decarbonization goals.

It is tempting to focus on widespread TE as itself the ultimate and only goal of VGI policy. This framing fails to capitalize on the unparalleled potential of EVs as a flexible resource to minimize distribution grid upgrade costs, increase charger site connection use, encourage localized and system-level renewable energy, facilitate the "pro-sumer" model, increase the affordability of EVs, enhance grid reliability and resiliency, and, ultimately, support broader decarbonization goals.

Experts and decisionmakers around the world are working diligently to advance decarbonization solutions, including in two of the largest GHG-contributing sectors: electricity generation and transportation. Decarbonization is the ultimate goal, so to effectively combat climate change, policies and markets must coordinate and co-optimize decarbonization efforts that are currently focused on each system individually. Synchronizing clean energy and transportation policy can also foster a positive feedback loop in which EVs support the integration of renewable generation, which in turn reduces transportation emissions. EVs represent an available and valuable tool to support the evolving grid through managing load and/or exporting power and, ultimately, to achieve our climate goals. EVs are more flexible than other loads and can control the timing of energy charged from the grid, discharged to the grid, and the provision of other grid services (for example, voltage control, frequency regulation). However, a self-sustaining market allowing today's commercially available VGI technology to support the broader decarbonization effort can only be facilitated by a suite of practical policies and programs.

EVs can become a new type of DER, optimized at the distribution level with distributed solar, stationary energy storage, and co-located loads, and available at the transmission level for large-scale load shifting and duck curve mitigation, but not without coordinated and immediate change to the status quo. EV deployment and related program and infrastructure investments – or "TE" – and VGI implementation cannot occur sequentially, or even in parallel, but rather must be a single, coordinated effort if it is to play a facilitating role in the ongoing evolution of the electric grid. An examination of the INVENT use cases reveals the disincentives and barriers to VGI present in California's current and potential policy development practices. A common element among these barriers seems to be that while there is broad agreement on what VGI is, there seems to be less focus and agreement on the essential function of VGI. VGI critically situates TE in the broader decarbonization project, showing the "why" of electrifying transportation, rather than simply the "what."

It may first be useful to review what VGI refers to in this report. In accordance with SB 676, California's regulators define it as follows:[23]

- For purposes of this section, "electric vehicle grid integration" means any method of altering the time, charging level, or location at which grid-connected electric vehicles charge or discharge, in a manner that optimizes plug-in electric vehicle interaction with the electrical grid and provides net benefits to ratepayers by doing any of the following:
  - Increasing electrical grid asset use and operational flexibility.
  - Avoiding otherwise necessary distribution infrastructure upgrades and supporting resiliency.
  - Integrating renewable energy resources.
  - Reducing the cost of electricity supply.
  - Offering reliability services consistent with the resource adequacy requirements established by Section 380 or the Independent System Operator tariff.[24]

It is difficult to imagine how the requirements of SB 676 can be met, according to this definition, if these strategies are to be applied retroactively and if charger installation and distribution grid build-out fail to take these strategies into account. INVENT's use cases, which fit nicely into the definition of VGI, the project shines a light on the unintentional disincentives to VGI in current TE efforts in California, which create an environment that is not conducive to later revision or adjustment.

7.1.1 INVENT Use Cases Are Not Incentivized Under the Current Policy Framework

INVENT set out to technically demonstrate a range of unidirectional (V1G) and bidirectional (V2G) services and to quantify potential values and stakeholder benefits of those services. The team explored TOU rate optimization, renewable energy time-shifting (RETS), demand charge management, frequency regulation, and demand response. These use cases represent a cross-section of near-term opportunities that leverage technologies in use either in California or in other geographies. The project team explored technical feasibility and estimated the potential value proposition, to the individual EV owner and to society. This chapter explores the likelihood that without an immediate and bold change of direction, most of the VGI applications included in the INVENT project are at risk of being shut out of California.

7.1.2 Renewable Energy Time-Shifting

For example, in the stakeholder benefits chapter the retail rate used for analysis in the RETS use case is SDG&E's AL-TOU schedule, a standard (that is, non-EV specific) TOU rate schedule. Why did the analysis not use an EV rate or acknowledge that much of the rooftop solar in California qualifies to be compensated under NEM tariff? The answer is evident across

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[23] SB-676 Transportation electrification: electric vehicles: grid integration. Bradford, 2019. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200SB676

[24] California Public Utilities Code Section 740.16(b).

several different rates, tariffs, and ratepayer-funded programs: EV rates require that no other loads or resources be metered with the EV; ratepayer-funded TE programs generally require an EV rate and an entirely separate service for the EV; solar NEM tariffs cannot accommodate a bi-directional EV configuration. These constraints diminish the pool of potential customers for V2G-plus-solar to those who want neither an EV rate nor a NEM account for their solar panel nor funding assistance from a TE program. This effectively situates the V2G-plus-solar use case, which could bring considerable environmental and ratepayer benefits as a direct competitor to the programs intended to advance. Despite these facts, the V2G-plus-solar use case is highlighted in California VGI policy documents, such as the 2020 VGI Working Group Final Report as a near-term, high-value opportunity.[25]

7.1.3 Frequency Regulation

EVs can and do provide frequency regulation in other geographies, and there is investigative and industry interest in enabling this use case in California. The LA Air Force Base study in Southern California Edison territory and the Electric Vehicle Storage Accelerator in SDG&E/at UCSD identified a range of barriers to be addressed, and the Department of Energy-funded "Bus to Grid" in Rialto, California is currently exploring metering configurations with the help of Southern California Edison. INVENT has demonstrated that a V2G system can follow a California ISO signal with sufficient fidelity to remain in the market. Recent federal regulatory directives[26] do go some distance toward clearing the way for behind-the-meter resources such as EVs to participate in wholesale markets, including California's. However, the California ISO may implement changes to be in perfect compliance with these federal directives and still see zero V2G resources in frequency regulation markets if California regulators do not modify retail rate structures accordingly. CPUC can investigate changes to interconnection categories, a new multiple-use application proceeding, compensation for export, and rules around Resource Adequacy procurement to begin to integrate EVs as system-level resources fully.

7.1.4 Demand Charge Management

The 2020 VGI Working Group Final Report highlighted other behind-the-meter opportunities such as demand charge management, Time-of-Use rate optimization, and demand response[27]. Demand charges are, other than for pilot purposes, generally only found at Commercial and Industrial accounts. If customers take advantage of TE funding, the separate service drop needed to receive TE funding will separate their EVs from the building load and put them on a volumetrically focused Time of Use rate. This decreases the opportunity to focus on demand and connection size as a stabilizing metric for EV loads. If encouraging the flexibility EVs afford and developing pro-sumer configurations are indeed priorities, a departure from volumetric-heavy rates in favour of a capacity-focused charge based on connection size is worth exploring. The commercial EV rates the IOUs have begun to implement are targeted at and

[25] Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group https://gridworks.org/wp-content/uploads/2020/07/VGI-Working-Group-Final-Report-6.30.20.pdf. (June 30, 2020) at 32, Table 5. "V2G Use Cases Appearing in High-Scoring Subsets."

[26] FERC Orders 841 and 2222.

[27] Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group https://gridworks.org/wp-content/uploads/2020/07/VGI-Working-Group-Final-Report-6.30.20.pdf (June 30, 2020)

appropriate for a very specific and particularly inflexible use case. VGI rate development should consider the flexibility of EVs and acknowledge the fact that many EVs will ultimately be co-sited with solar PV.

7.1.5 Demand Response

The demand response use case seems promising according to the results of the INVENT project, particularly in the context of the increasing need for flexibility in extreme weather events such as the August 2020 heat wave blackouts that inspired California regulators to take swift action to procure incremental reliability resources. However, non-residential EV-based demand response does not currently have a clear path to widespread implementation. The fleet of EVs at a Commercial or Industrial location whose owners took advantage of TE program assistance will have no other non-EV loads to help establish a baseline usage against which to measure demand response. While V2G resources may be capable of discharging during a demand response event, demand response programs do not compensate for net generation measured at the retail meter (that is, exports). Therefore, V2G systems isolated at a separate account on an EV rate will not be compensated for discharging in a demand response event. The emergency reliability proceeding in autumn 2020 and winter 2021 began to acknowledge and address this with a situational, energy-only opportunity for compensated export for EVs. This is a start but does not constitute a business case for V2G. The next step will be to seriously consider how V2G can qualify for Resource Adequacy or similar capacity-based payments, how interconnection will need to take these use cases into account, and if current multiple use applications rules are sufficient for this scenario.

These four examples – RETS, frequency regulation, demand charge management, and demand response – demonstrate that current regulatory development is not accounting for the cross-disciplinary nature of VGI in general and V2G specifically, thereby creating barriers to market development. If California continues its current path, EVs will remain responsive but unpredictable loads rather than essential components of a flexible network of resources.

California is encouraging transportation electrification at every level of state and local government and attacking the VGI project from multiple angles. The transportation electrification landscape in the state, and indeed the VGI landscape, has changed considerably since the INVENT project began. California now has the basis for the interconnection of bi-directional EVs in its distributed generation rules ("Rule 21").[28] A variety of proceedings and funding efforts are considering how EVs could be used for emergency backup power, how they will fit into microgrids, how they will communicate with utilities, how they will be metered, how they will participate in markets, and more. However, implementations of related policies are not laying the adequate groundwork for these forward-looking VGI proceedings to build on. California's proposed transportation electrification framework, the 2020 VGI working group, the microgrids and resiliency strategies proceeding, and DER interconnection revisions all take important conceptual steps forward, but they build on the incompatible legacy frameworks that undergird TE programs while hamstringing VGI. This is not to say that TE programs should not be funded. Rather, agencies should revisit funding programs to assess opportunities to enable VGI and increase decarbonization potential in the near term.

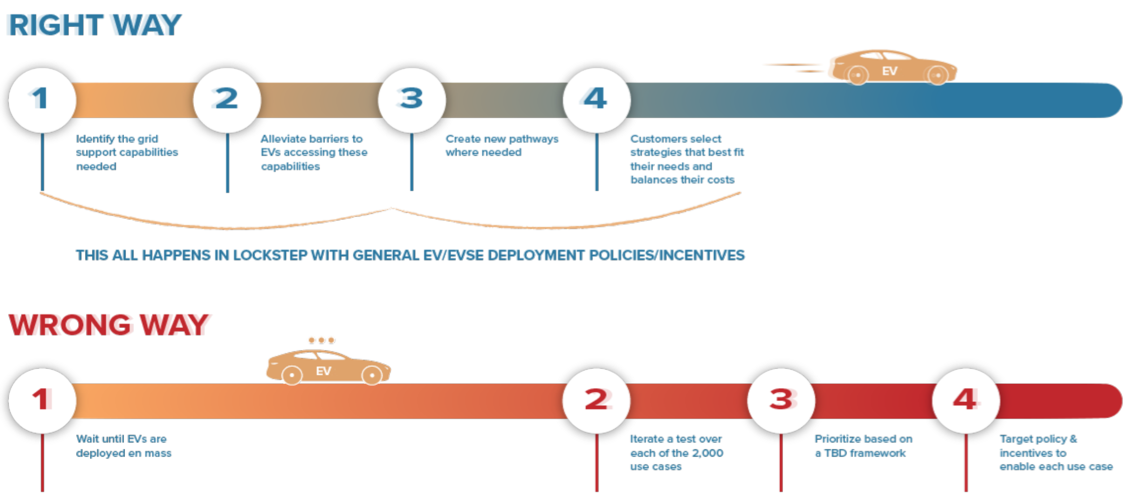
[28] California Public Utilities Commission. 2021. Rule 21 Interconnection. https://www.cpuc.ca.gov/Rule21/.

7.2 Coordinating Vehicle-Grid Integration and Transportation Electrification Policy

7.2.1 Vehicle-Grid Integration and Transportation Electrification Policy Need to Happen in Lockstep

Rather than introducing VGI policies after broader TE policies, state agencies should aim to implement VGI together with broader EV/EVSE deployment strategies (Figure 15). By enabling fair access to value streams and delivering solutions to overcome technical barriers, this approach is fundamentally centered on the idea that VGI is not merely a tool to accelerate TE but rather a desirable outcome for the grid and the broader energy ecosystem. To develop VGI markets, the focus must remain on removing disincentives and expanding access to value streams. However, existing value streams for DERs may not be a perfect fit for EVs right away, meaning effective market development depends on regulatory bodies, grid operators, and other decision-makers to take decisive action to update the rules of the market to spur the nascent VGI market meaningfully.

Figure 15: Policy Implementation



Source: Nuvve Holding Corporation

Implementing VGI policies from the start of TE programs enables a growing number of EVs to behave as nodes on an increasingly flexible grid, in turn enabling and encouraging more renewables and system resiliency. This virtuous cycle can also place downward pressure on rates, lead to GHG savings from offsetting miles traveled with an internal combustion engine, and reduce environmental and health benefits associated with fossil fuel electricity generation. To reach this future, California needs frameworks that correctly conceptualize the suite of EV capabilities.

The core principle of incorporating VGI into TE program development should be to ask how can EVs that modulate/stop charging load and - if asked - begin discharging, be incentivized to meet grid needs. This reframes EVs as DERs for grid operators conceptually to accurately assess the potential EVs to serve their changing needs and functionally for the design of appropriate requirements and technical standards.

It is important to note that, while similar to other DERs, VGI market development sometimes demands new, dedicated policies and programs. This assessment of the California VGI market through INVENT use cases has revealed that most existing DER policies and programs are not well-suited for the unique opportunity of VGI based on their current rules.

7.2.2 Leverage Rates to do More than Shift Load

Rate design can be an effective tool to help accelerate TE overall. In California, EV rates are mostly designed to focus on the projected usage patterns of the EV as a separate load.[29] As a result, these rates are not designed to integrate EVs through any mechanism other than time-of-use price signals that shift charging load to off-peak hours. They separate EVs from other resources such as solar panels and stationary energy storage and make determining a baseline for load reduction difficult in the absence of other loads. In contrast, outcome oriented VGI rates can lower the total cost of ownership by reducing charging costs, provide a revenue stream to third-party aggregators, and provide incentives for bi-directional vehicles to remain plugged in allowing for dispatch to response to the grid needs. VGI rate design should follow a consistent set of assumptions, developed to harmonize well with existing rate design principles:[30]

1. The EV will respond to the best available price signal. This may be a retail TOU rate or an external price signal (for example, DR).
2. The EV may discharge in a manner similar to stationary energy storage placed behind a retail meter. This is most relevant when considering the eligibility of EVs as a generating / exporting resource (for example, decoupling eligible renewables from battery under NEM, value of DER tariffs, and so on).
3. The EV may be co-located and able to optimize energy flows with a variety of resources and loads such as solar or stationary energy storage.
4. The EV customer may be allowing a third-party aggregator or automotive manufacturer to control how and when their EV charges or discharges. Do not assume a customer will need to manually and personally decide how and when to react to price signals.

Specific enhancements can be made to existing TOU EV rate options to increase the reward to customers of shifting load to charge. Additionally, a retail TOU rate is likely to be an insufficient price signal to truly take advantage of the flexibility and response time of a properly configured EV when compared to a rate with finer temporal granularity. Ultimately, retail rates will also need to be adjusted to consider the possibility of layered price signals, per assumption #2.

Assumption #4 addresses one of the most common pitfalls in DER rate design, as concerns that a VGI rate could be overly complicated or require active management of an EV that is beyond the interest or capabilities of the average car owner ignores the potential of third-party aggregators to coordinate charging. Third-party aggregators can coordinate charging to meet driver needs while also potentially filling requests for demand response or controlling load to

[29] SDG&E 2020. POWER YOUR DRIVE FOR WORK & HOMES. https://www.sdge.com/sites/default/files/LoveElectric_Update_092220_FINAL%20%281%29.pdf.

[30] California Public Utilities Commission. Electric Rates. 2021. https://www.cpuc.ca.gov/electricrates/.

avoid grid upgrades. While such an entity may not always be necessary, it is a mistake to assume all charging decisions would be made manually and in real-time by each individual driver going forward.

7.2.3 Unlock Pathways for Electric Vehicle Supply Equipment Submetering and Electric Vehicle Telematics to Reduce Costs and Promote Vehicle-Grid Integration

The dedicated metering requirement of residential and commercial EV rates offered by California's three major investor-owned utilities creates a threshold issue for many customers, as expensive new metering infrastructure can deter participation. From a VGI enablement perspective, onerous metering requirements effectively isolate the EV from other resources or loads and make it unrealistic to respond to external price signals such as demand response requests. To remedy this would require a complete redesign of EV rates focused on allowing EVs at a separate service to engage in VGI activities.

There is a less costly alternative approach that depends on commercially available and widely deployed technologies that can be implemented across the full spectrum of VGI applications. EVSE submetering or advanced EV telematics interval data can allow for the implementation of advanced rate or bill credit options and facilitate participation in non-rate price signals without resorting to expensive new metering infrastructure that could deter customer participation. These approaches have been proposed and implemented in other jurisdictions as a means for calculating bill credits. Furthermore, EVs capable of discharging can provide benefit to behind-the-meter and grid-related stakeholders, and submetering is an important accounting tool to correctly classify and allocate these benefits by reconciling retail and wholesale settlements. There is a clear trend among jurisdictions moving toward this submetering approach, for example. This is one critical area in which other jurisdictions have leaped ahead of California in terms of market development.

7.3 Facilitate Participation of Behind-the-Meter Resources in Wholesale Markets

There is also a need to remove existing disincentives to V2G operations, specifically as they relate to participating in wholesale markets per the intent of recent federal regulatory directives[31,32]. Similar to stationary energy storage, V2G systems should be allowed to participate in retail and wholesale markets such that they are not double-paying and able to be compensated for functioning as storage. It is imperative that a standard compensation model be established and widely implemented for energy exports. Notably, this issue is not unique to V2G resources but rather impacts behind-the-meter DERs broadly, including stationary energy storage systems. For example, energy storage assets capable of responding to a wholesale frequency regulation market signal or arbitraging wholesale energy prices are locked out of the

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[31] FEDERAL ENERGY REGULATORY COMMISSION. 2018. FERC Order No. 841: Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. https://www.ferc.gov/media/order-no-841.

[32] FEDERAL ENERGY REGULATORY COMMISSION. 2020. FERC Order No. 2222: A New Day for Distributed Energy Resources. https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet.

market due to onerous metering requirements/requirements to pay retail rates to charge while settling energy exports at the wholesale energy rate. While this is not the only barrier to wholesale market participation, it must be addressed to unlock the full potential of multi-use DERs like V2G resources or stationary energy storage.

Until these resources gain equal access to participate in the wholesale markets, V2G market development can be kickstarted by developing pathways to compensate V2G exports for their environmental benefits and approximate avoided costs. A V2G rate could take the form of a NEM tariff that decouples NEM from existing qualifying energy generation resources (or that defines V2G resources as a qualifying NEM resource), a separate feed-in-tariff, or a V2G export bill credit that is not simply based on volumetric retail rates. To promote V2G market development in the early days of the market, policy makers could first consider V2G export bill credits that are large enough in value to spur customer adoption and familiarity with V2G technologies meaningfully.

Jurisdictional boundaries between the distribution and transmission levels cannot preclude cooperation and coordination between the independent system operators and the regulatory agencies that monitor them.

7.4 Align Transportation Electrification and Distributed Energy Resource Incentives

In addition to rates, nonrate programs can be a powerful tool to either promote or disincentivize beneficial EV charging and discharging. Existing TE programs, which require separate service drops to isolate EVs on their own meter and electrical connection to the grid, do little to allow VGI functionalities to support grid flexibility, reliability, and resilience. As demonstrated in the INVENT use case discussion, requirements for separate metering and separate service connections – and dedicated EV rates – isolate rather than integrate EVs. TE programs must foresee VGI- and V2G-capable EVs and EVSEs, both in implementation and in funding structures. VGI installation and incentive programs may have more in common with existing DER programs than with TE programs and policy makers should be bold as they reconsider what an EV is to the system, and how EVs can open opportunities for flexibility. Adopting this issue into guiding principles for existing and new TE and DER programs can help identify and guide critical program areas where a mechanism may promote or disincentivize VGI.

7.5 Conclusion

VGI should not just be viewed as a way to leverage EVs to support the grid. Customers can take advantage of VGI market opportunities to automatically lower charging costs, keep the lights on, and earn additional revenue, and OEMs and EVSPs have a unique and critical role in easing the customer experience. As stakeholders continue to come together on VGI market development efforts, VGI should be viewed not solely as a means to accelerate TE and not solely as an asset to support the grid. If done right, policies enabling VGI strategies will support the decarbonization goals of both systems and meaningfully contribute toward broader climate goals. If kept in separate silos, VGI may seem like a complex burden for policy makers, utilities, and grid operators to address after TE is implemented. Similarly, there is a risk of framing VGI as an impediment to a smooth customer experience when promoting general EV adoption. There is an important opportunity to use VGI as a powerful tool to accelerate EV adoption, support an evolving grid, and, ultimately, combat climate change.

CHAPTER 8: Stakeholder Benefits

8.1 Use Cases

The stakeholder benefits discussion focuses on the RETS and DCM use cases for VGI. The costs of the EVs and the EVSE installation are not included in the analysis, as those will be considered sunk costs. Rather, the focus is on the incremental costs of moving from unmanaged charging to managed charging. Analysis of frequency regulation is excluded from this chapter as well, because stakeholder feedback indicated that the INVENT project should focus on testing California ISO performance requirements for frequency regulation rather than quantifying value streams for that use case. In addition, frequency regulation does not currently have a viable pathway for retail and wholesale settlement that would enable a viable business model in California. Please see Chapter 7 for additional detail.

8.2 Electric Vehicle Fleet

The RETS use case included the 150 kW Gilman Solar Array; four Nissan LEAFs, two BMW i3s, and one Chevy Bolt; four PowerPort V1G chargers; and three Princeton Power V2G chargers. Vehicle charging was optimized to lower demand costs from the ratepayer's perspective.

The DCM use case was implemented at the Hopkins parking structure, a 1,395-space parking garage on the UCSD campus with an average building load between 40-80 kW. Vehicle charging was optimized to lower demand charges incurred to meet the charging load of the parking structure and the EV fleet. The parking structure is within the UCSD microgrid, so a tariff with a demand charge was simulated. For the DCM use case, the project used two Nissan LEAFs, two BMW i3s, and one Ford Fusion as well as five PowerPort V1G chargers and two Princeton Power V2G chargers.

The composition of the EV fleet varied during the implementation of the project, with several changes resulting from the COVID-19 pandemic and subsequent changes in commuting patterns. This report quantifies data up to October 2020 for the Gilman RETS use case and up to March 2020 for the Hopkins DCM use case. The pandemic caused the load profile of the Hopkins parking structure to fall flat during the day, so the DCM operation was transferred to the Police Department building, which remained operational and thus had a load profile with greater consumption during the day. See Appendix C for a list of project chargers and vehicles.

8.3 Demand Charge Management

VGI can deliver benefits on multiple fronts, but value stacking is not always possible. The use cases implemented within INVENT and investigated in this analysis pursued bill savings based on the demand charge components of a simulated tariff. Thus, energy cost savings and environmental or other benefits could have occurred but were not pursued, and the results should be evaluated within this context.

Based on the preceding discussion – and before embarking on the quantification of the INVENT benefits – it is useful to understand the context of the INVENT charge scheduling. According to the EV charge scheduling report, charge was scheduled with the objective of minimizing demand charges both in the RETS and DCM cases. The two tariff components that were simulated include the noncoincident charge and the on-peak charge. Energy cost savings were not targeted in any of the cases, and there was no assumption of a NEM tariff in the RETS case. Environmental benefits were not targeted in the DCM case but were assumed to occur due to the reduction of solar curtailment. This reduction was only simulated, as solar energy would be used within the microgrid even if vehicles were not charging. Furthermore, present a NEM tariff charge, scheduling might have resulted in significantly different charging behavior.

This analysis addresses the energy cost savings and related environmental benefits that, although not pursued, could have occurred, and found them to be very low. This finding does not imply that such savings could not be achieved, but that they were not based on the pilot implementation.

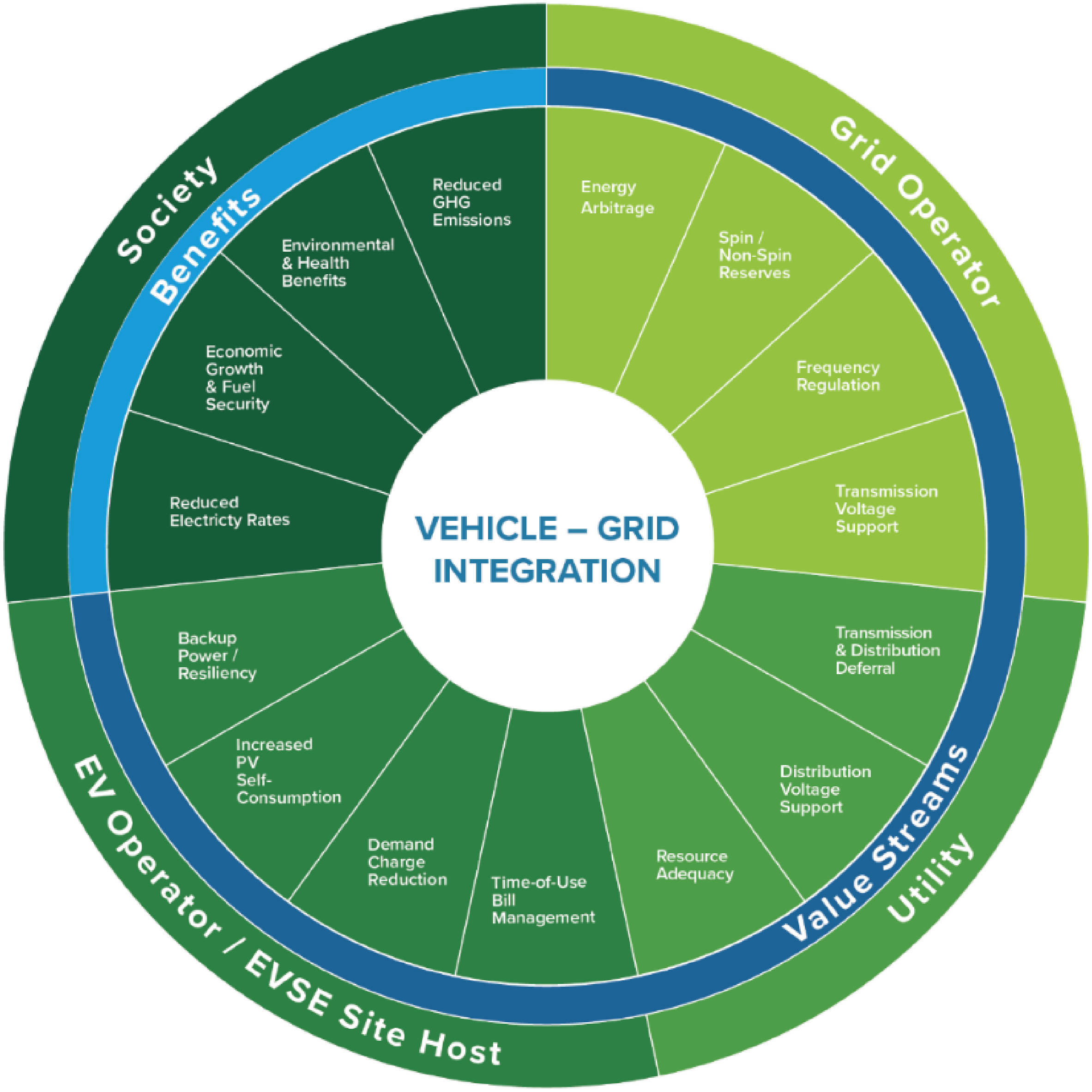
The charge scheduling was based on two components of the demand charge per the SDG&E AL-TOU tariff as this was shared by the utility to UCSD:

- The non-coincident charge, which is computed as the maximum 15-minute power consumption in a month and charged at $24.48/kW.
- The on-peak charge, which is the maximum 15-min power consumption between 4 p.m. and 9 p.m. in a month, at $19.14/kW in the summer and $19.23/kW in the winter.

8.4 Cost-Benefit Analysis of Vehicle-Grid Integration Value to the Grid

Benefits can accrue to different stakeholders depending on the business model and regulatory framework in which VGI is implemented. Figure 16 shows the array of VGI value streams and benefits, mapping each to one of the four main stakeholder groups.

Figure 16: Vehicle-Grid Integration Value Streams



Source: Strategen Consulting, 2020

This chapter focuses primarily on the societal perspective, because this analysis attempts to quantify the change in the total resource costs to society as a whole rather than only costs to the participants, the utility, or its ratepayers. The quantification of benefits also contains externality costs of power generation not captured by the market system.

In taking society's perspective, it is important to distinguish between system benefits and monetizable services; the set of benefits that VGI can provide to a system and the services that can be monetized do not fully intersect. It is crucial to discern between the value provided to the system or society by VGI and by generally deploying more DERs, and the value that certain stakeholders receive, which comes directly from the revenue streams that VGI resources can obtain within a certain regulatory and market framework. Those revenue streams might not be able to capture all the benefits derived from VGI. At the same time, not all the revenue streams provided to VGI are directly reflective of actual system benefits. For example, reducing the demand charge of a customer may create system value by potentially lowering the need for a distribution system upgrade, but it also may have no direct impact on reducing such a need. Avoiding infrastructure costs is the real system value; reducing the customer's bill is only a money transfer between stakeholders that incentivizes the creation of such value. Such bill reduction is therefore an indirect proxy for value creation rather than direct compensation for the creation of actual system value. The money transfer, although not an incremental benefit to society, is of crucial importance: the societal value that can be generated by a new technology is a function of deployment, and deployment depends on stakeholders' incentives and monetizable revenue streams.

The stakeholder economic benefits analysis is a cost-benefit analysis that leverages both actual data collected under INVENT as well as industry research to quantify the costs and benefits of VGI technology. The analysis is conducted based on a societal perspective, including the benefits of VGI technology at the system/grid level regardless of how these are monetized and who collects those monetary streams. Benefits also include environmental impacts such as carbon emissions reduction. In contrast, UCSD has quantified the monetizable benefits from the EV driver / site owner perspective in the form of savings due to DCM and RETS (Zamora & Kleissl). The comparison of the societal and participant values can provide useful insights to inform both future deployment levels of VGI and necessary policy tools to achieve them.

Like any technology, VGI comes at a cost, particularly because the technology is still very new. However, it is important to separate the costs of vehicle charging in general and those of VGI. For example, the cost of EVs should not be included in the economic analysis of VGI as they would be incurred even without VGI. Thus, the report only contains the incremental costs of moving from unmanaged to managed charging. These costs include only EVSE hardware, installation, and operational costs that are incremental to the unmanaged charging use case.

8.4.1 Benefits and Costs within the INVENT Project

This chapter quantifies the following benefits:

- Avoided energy costs (time-shifting & curtailment reduction): VGI allows EVs to charge and store energy when it is least expensive. V2G capabilities further allow EVs to use the stored energy to offset customer demand or export power to the grid during peak demand when prices are highest. Vehicle-to-building (V2B) can use the stored energy to power site load. From a system-wide perspective, VGI also helps avoid renewable curtailment when there is insufficient demand by charging during periods of peak renewable production and using that energy when more expensive, non-renewable energy sources dominate the grid.
- Avoided capacity costs: By shifting charging load to occur during periods of low demand and – in the case of V2G operations – discharging during peak demand to power system needs, VGI uses existing resources to meet capacity requirements. Demand management reduces the need for system upgrades and can help defer or avoid investments in generation, transmission, and distribution infrastructure.
- Avoided carbon cost: VGI helps maximize the usage of renewable energy and reduces the need to use energy sources powered by fossil fuels by charging when solar and wind output are the highest and – when V2G capabilities are enabled – discharging when they are the lowest. This leads to an overall reduction in GHG emissions and results in environmental and health benefits.

This list of benefits is not exhaustive. However, the benefits could be quantified with the data collected throughout the INVENT project. This analysis refrains from evaluating other benefits that were or could be generated but for which there was no data available from project implementation. Nevertheless, it is important to recognize that additional benefits occur when VGI is deployed. A more detailed list can be found in Chapter 6.

All "avoided cost" categories listed as benefits were calculated by comparing the actual operational data from V1G and V2G service implementation under INVENT with a simulated unmanaged baseline of vehicle and charging station operation. The unmanaged charging baseline was created by taking the project vehicles' actual plug-in time, starting state of charge, and maximum charge rate and simulating what the vehicle charge profile would have been if it had not been managed (the vehicle plugs in and starts charging at a constant rate until the vehicle battery is full). A detailed description of the calculation of the unmanaged charging time series can be found in the EV charge scheduling report. This unmanaged baseline can then be directly compared to the actual managed V1G and V2G scenarios to determine the avoided costs for grid capacity and energy, retail bill cost, and avoided CO_2 emissions.

Furthermore, it should be noted that because the vehicles and stations were part of the UCSD microgrid, data on marginal cost of energy and emissions were not available. Even if they were, they would not necessarily be representative of the benefits that could be achieved in SDG&E's system, as the microgrid's resource mix differs from that of SDG&E. For both reasons, the analysis was conducted as if the vehicles were included in SDG&E's system directly.

8.4.2 Avoided Energy Costs

VGI can reduce system costs for energy generation by shifting energy consumption from hours when energy cost is high to lower-cost hours. The cost differential should be high enough to justify the efficiency losses of storing and, in the case of V2G, discharging energy.

However, as mentioned above, the charging scheduling in the INVENT project did not consider any price differential in the energy rates, and as such, did not shift energy consumption to lower-cost hours based on that rationale. Specifically, the vehicle charge was scheduled to maximize bill savings based on demand charge management in the DCM and RETS use cases. Co-optimizing for demand and energy charges could lead to a different schedule with higher energy cost savings. Managing charging to minimize demand charges could result in either higher or lower energy costs compared to the unmanaged case.

Before quantifying this change in energy costs, it is important to differentiate the avoided energy cost as calculated from a grid perspective from that of the end consumer's perspective, as calculated based on the tariff schedule. From the grid perspective, the avoided energy costs represent the costs that would not occur to generate the energy in the electricity system, while from the customer perspective, avoided costs represent the bill charges that would not have to be paid. The former calculation is based on the system energy cost differential during the day (using as a proxy the locational marginal price [LMP]), while bill savings are based on the retail rate differential. Theoretically, the two values should be close as the actual value is the cost avoidance of energy generation, while bill savings are a simple (partial) transfer of that value. Although, the division of that value among stakeholders (and consequently the provision of incentives to generate it in the first place) depends on the regulatory framework.

In reality, however, the societal and participant values can differ significantly. Although the LMP varies throughout the hours of the day, as does the retail rate, the hourly variation can be more or less pronounced in the rates.

For example, the marginal system cost of generation per hour according to the California ISO wholesale LMP for the UCSD node (UCM_6_N001) exhibited differences of over $110/MWh on average during a day for the summer months of 2019. On the other hand, the energy charges on the simulated tariff schedule show a lower differential in Table 7:

Table 7: Simulated San Diego Gas & Electric Company Tariff – Energy Charges

	Summer	Winter
On-Peak Energy ($/kWh)	$0.11957	$0.09955
Off-Peak Energy ($/kWh)	$0.10008	$0.08835
Super_Off-Peak Energy ($/kWh)	$0.07487	$0.07594

Source: SDG&E simulated tariff

The maximum LMP difference over the course of a day can never be fully captured given that retail tariffs are not real-time price signals. However, low differences in the TOU levels might result in under-deployment compared to the societally optimal level.

There are tariff schedules in SDG&E and other utilities that present cost differentials an order of magnitude higher than this tariff. Under such tariffs, the charging scheduling and subsequent energy savings could look different. For example, PG&E's EV-B tariff includes much steeper differences.

The reason for such steep differences between the on- and off-peak rates is that incentivizing optimized consumption leads to additional benefits, such as transmission & distribution deferral opportunities which are not captured by the grid energy cost analysis through the LMP. Furthermore, incentivizing EV and VGI adoption adds an externality of learning by doing (future costs are projected to fall significantly) while benefits will increase, providing net benefits to society. Although, these benefits can only be enabled if early adoption is incentivized. This positive externality is not captured by any stakeholder unless included through policy intervention. The PG&E EV-B tariff includes transmission and distribution components and is more reflective of the overall value that energy time-shifting could provide to the grid.

In addition to not optimizing vehicle charging based on energy rates, the energy cost savings calculation presents another challenge and does not fully account for the benefits that VGI could achieve under different circumstances. Specifically, the vehicles in the project were used by UCSD staff who plugged the vehicles into the chargers when they were on campus but then returned to their residences. This means that the presence and participation of the vehicles in the project were not consistent during the months the project was implemented. More importantly, the vehicles were also charging off-campus, and thus, their energy needs were not entirely met by the project chargers. For this reason, charging data exhibits discrepancy, which is to be expected based on this vehicle use. This discrepancy makes the benefits' quantification more difficult but does not interfere with whether those savings are indeed technically achievable or incentivized within the larger regulatory and market framework.

For example, the avoided energy cost results for the vehicles charging at Hopkins are presented in Table 8.[33] During April-December 2019, three to four vehicles were participating in the project at that location.

Table 8: Energy Cost of Unmanaged & Managed Charging (Hopkins Location)

	Grid Cost for Managed Charging ($)	Grid Cost for Unmanaged Charging ($)	Savings of Managed Charging ($)
Apr-19	$16	$22	$6
May-19	$14	$22	$8
Jun-19	$10	$16	$6
Jul-19	$14	$17	$3
Aug-19	$23	$29	$6
Sep-19	$35	$44	$9
Oct-19	$32	$38	$6
Nov-19	$33	$45	$12
Dec-19	$48	$34	$-14
Jan-20	$41	$47	$6
Feb-20	$33	$38	$5
Mar-20	$29	$33	$4
Apr-20	$4	$4	$0

Source: Strategen Consulting 2021

The avoided energy cost savings captured by the INVENT project either in the Gilman or Hopkins locations were not substantial. The small magnitude is a result of the small fleet size, the fact that charging was not optimized to maximize energy savings, and that the managed and unmanaged charging data were impacted by the fact that vehicles also interacted with the grid outside of INVENT's chargers.

8.4.3 Avoided Capacity Costs

Demand is one of the key drivers of electricity costs. From a societal perspective, reducing demand can result in lower generation capacity, transmission, distribution, and customer-related costs. Unfortunately, not all those costs can be captured from a behind the meter installation, as is the case for EVs and VGI. From an EV owner/driver perspective, the benefits of VGI depend on the utility's tariff.

Two types of demand charges can be found in SDG&E's tariffs. Each of these charges is meant to capture a different avoided cost element.

- Non-coincident: This applies to the highest kW demand peak in any 15-minute interval in the billing month, or 50 percent of the highest peak in the last 11 months. Non-coincident demand can occur any time, day or night, on-peak, off-peak, or super off-peak. On-peak: This applies to the highest kW demand in a 15-minute interval that occurs during the on-peak time period. The on-peak period varies by summer and winter seasons (Summer: June 1 to October 31; Winter: November 1 to May 31). A

[33] S&P Market Intelligence Platform. 2021. https://www.spglobal.com/marketintelligence/en/solutions/market-intelligence-platform

component of the UDC Total Rates, the on-peak demand charge recovers SDG&E's cost of building out the electric infrastructure (for example, transmission and distribution substations, lines) in support of non-generation-related costs necessary to meet peak demands.

- Generation: This applies to the highest kW demand in a 15-minute interval that occurs during the on-peak time periods, which vary by winter and summer seasons (Summer: June 1 to October 31; Winter: November 1 to May 31) and recovers the generation costs of meeting energy demands on-peak. The generation demand charge is similar to the on-peak demand charge but, as shown in Table 9, is a component of the Electric Energy Commodity Cost (EECC).

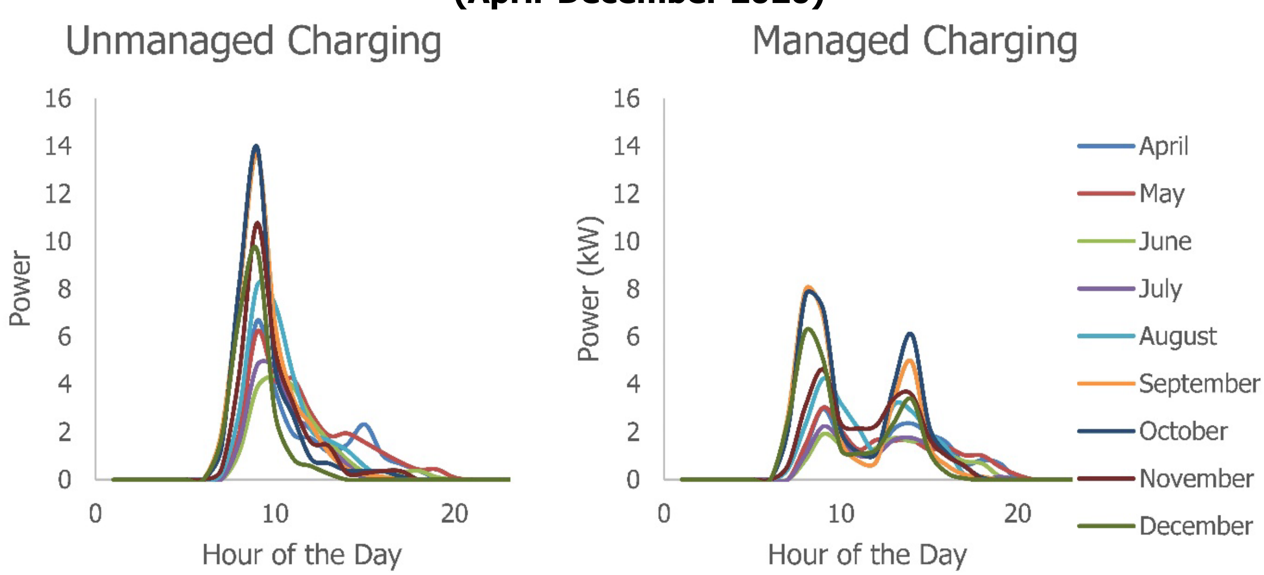
Table 9: Simulated San Diego Gas & Electric Company tariff - Demand Charges

UDC Rates	Value	Commodity Cost	Value
Non-Coincident Demand	$24.48	--	--
On-Peak Demand Summer	$19.14	On-Peak Demand Summer	$9.78
On-Peak Demand Winter	$19.23	--	--

Source: SDG&E simulated tariff

Figure 17 illustrates the rationale behind the charging scheduling. The unmanaged charging graph shows the average charging load in the absence of VGI (vehicles start charging as soon as they arrive and stop charging once full). Unmanaged charging peaks in the morning. The managed charging has significantly lower peaks as some of the charging needs are shifted to later in the day. The exact shape also depends on the availability and trip considerations (for example, charging could not be shifted to night hours when the vehicle was not dwelling at Hopkins site).

Figure 17: Unmanaged and Managed Charging for the Hopkins Use Case (April-December 2020)



Source: Strategen Consulting, 2021

As previously discussed, the benefits that the EV driver/owner receives do not necessarily reflect the grid benefits. To calculate the avoided capacity benefits from a societal perspective, estimations of the costs the utility incurs to serve individual customers (such as the cost of transformers located at a customer's site), the cost of building out the electric infrastructure (for example, transmission and distribution substations, lines), and the generation costs of meeting energy demands on-peak should be included.

According to the EV charge scheduling report, the bill savings based on the demand charge mitigation in the DCM use case at the Hopkins building (April 2019 - April 2020, three to five cars) are approximately $4,200 for the duration of the INVENT project, while the bill savings for the RETS use case at the Gilman building (April 2020 – October 2020, five cars) are $4,050. All those benefits stem from the reduction of the non-coincident demand which recovers the costs SDG&E incurs to serve individual customers, such as the cost of transformers located at a customer's site, sized to a customer's specific load requirements.

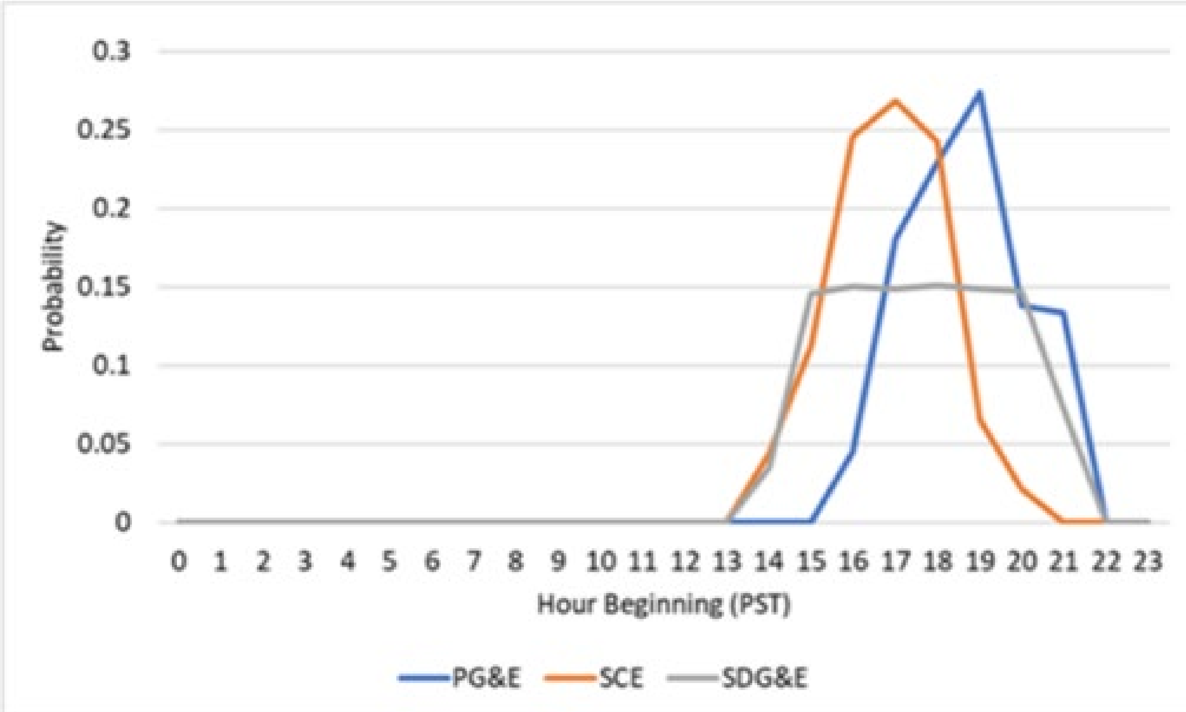
In addition to these bill savings, additional avoided capacity costs could be achieved when avoiding generation, transmission, and distribution capacity costs. Due to the scheduling being based on the simulated tariff's non-coincident demand component, no demand reduction was achieved during the on-peak window between the managed and unmanaged charging cases. Thus, no additional savings, other than the ones reported by UCSD, can be attributed to the INVENT project. Potential savings of VGI following the California Public Utility Commission's avoided cost calculator (ACC) method are discussed.[34]

8.4.4 Generation Capacity

Although a generation demand charge was included in the tariff, this component was not included in the optimization of the charge schedule. Given that the charge management was driven only by the noncoincident demand charge, charging was flattened from morning peaking to a double peak as shown in Figure 18 with some charging occurring in the early on-peak hours (starting at 4 p.m.). Consequently, managed charging resulted in higher on-peak demand from vehicles compared to the unmanaged charging case, and no avoided generation capacity savings can be attributed to the INVENT project.

[34] 2020 Distributed Energy Resources Avoided Cost Calculator Documentation, For the California Public Utilities Commission https://bit.ly/3g1ZL6l

Figure 18: Distribution of Peak Capacity Allocation Factors by Hour



Source: ACC documentation

Following the ACC method, the proxy for new capacity is a battery storage resource. The cost and configuration of the battery storage resource were taken from California's Integrated Resource Plan (IRP). Specifically, the RESOLVE capacity expansion modeling in the IRP uses a battery storage resource with a 4-hour duration and 20-year useful life (with augmentation costs) for a capacity resource. Using the cost of new entry for new battery storage resources, the ACC calculated the marginal generation capacity cost to be at $195/kW-yr. In addition to the capacity price outlined above, the ACC used the E3 RECAP model to allocate generation capacity values to the hours of the year with the highest system capacity need creating hourly capacity allocation factors. These factors cannot be applied in the present analysis as, in reality, the system does not peak at the exact same hours as the modeled version. Still, these marginal generation capacity costs are allocated during summer on-peak hours. The $195/kW-year divided by five months that belong to the summer period as defined in the tariff (June 1 – October 31) results in a $39/kW-month avoided cost, which is not fully reflected in the generation demand charge of the AL-TOU tariff that SDG&E shared with UCSD (even though the generation demand charge was not simulated). This difference can be explained because the rates are based on costs already embedded in the system and not marginal costs (which would be higher), and the ACC's marginal cost assumption is on the higher end. Still, this difference can result in under-compensated services and consequently under-deployment.

8.4.5 Transmission Capacity

Avoided transmission capacity costs represent the potential cost impacts on the utility's transmission investments from changes in peak loadings on the utility system. Reductions in peak loadings via customer demand reductions, distributed generation, or storage could reduce the need for some transmission projects and allow for deferral or avoidance of those projects. The ability to defer or avoid transmission projects would depend on multiple factors, such as the ability to obtain sufficient dependable aggregate peak reductions in time to allow prudent deferral or avoidance of the project, as well as the location of those peak reductions in the correct areas within the system, to provide the necessary reductions in network flows.

According to the ACC, SDG&E's annual marginal transmission capacity cost in 2020 is $14.44/kW-yr. The marginal cost was calculated based on a projected $21.85 million in investment costs to accommodate 185 MW of projected load growth between 2021-2024. Using an annual transmission inflation rate of 2.06 percent, SDG&E's projected marginal transmission capacity cost is shown in Table 10.

Table 10: Projection of San Diego Gas & Electric Company's Marginal Transmission Capacity Cost (2020-2024)

Year	Marginal Costs ($/kW-year)
2020	14.44
2021	14.74
2022	15.04
2023	15.35
2024	15.67

Source: ACC Documentation

Since the need for transmission capacity varies between the hours of each day, the ACC also calculates the hourly allocation of transmission avoided capacity cost. The calculation used the peak capacity allocation factor (PCAF) method to allocate capacity costs to the hours where the utility system is most likely to be constrained and therefore more likely to require upgrades. For SDG&E, those hours highly coincide with the on-peak window (4 p.m. – 10 p.m.).

Similar to the generation capacity costs, as no demand reduction was achieved from the INVENT project during the hours that have a strictly positive PCAF for SDG&E, no avoided transmission capacity costs can be attributed to the INVENT project.

8.4.6 Distribution Capacity

Differing methods were used by the ACC to calculate the near-term (2020-2024) and long-term (2027 and beyond) marginal distribution capacity cost with a linear transition applied between the near- and long-term for 2025 and 2026, resulting in significant differences in pricing during these three periods. For the near term, the ACC used data from the utilities' distribution deferral opportunity report, and grid needs assessment filings and calculated the marginal distribution capacity cost to be $3.66/kW-year (in 2019 dollars). For the long term, the ACC leveraged utility general rate case (GRC) data and calculated marginal distribution capacity cost to be $100.02/kW-year (in 2016 dollars). Applying a 2.0 percent/year annual distribution escalation rate, the marginal distribution capacity cost in SDG&E territory from 2020 to 2029 is shown in Table 11.

Table 11: Projection of San Diego Gas & Electric Company's Marginal Distribution Capacity Cost (2020-2029)

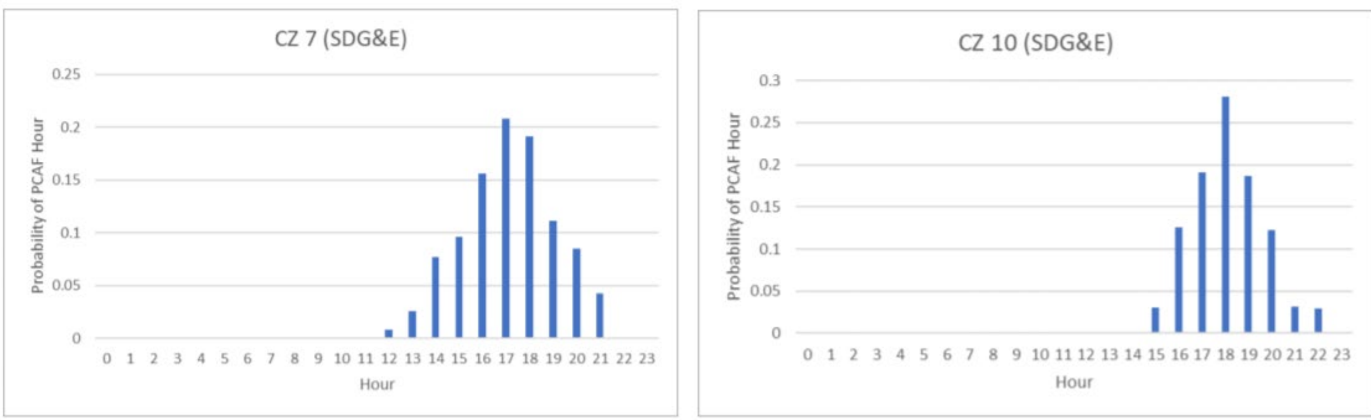
Year	Period	Marginal Costs ($/kW-yr)
2020	Near Term	$3.73

Year	Period	Marginal Costs ($/kW-yr)
2021	Near Term	$3.81
2022	Near Term	$3.88
2023	Near Term	$3.96
2024	Near Term	$4.04
2025	Transition	$44.15
2026	Transition	$84.26
2027	Long Term	$124.36
2028	Long Term	$126.85
2029	Long Term	$129.39

Source: ACC Documentation

To reflect the time-varying need for distribution capacity, the ACC also calculated the hourly allocation of avoided distribution capacity costs using the PCAF method. For SDG&E, this calculation is based on distribution-level power flow data provided by the utility (Figure 19).

Figure 19: Example San Diego Gas & Electric Company Climate Zone Peak Capacity Allocation by Hour of the Day



Source: ACC documentation

Again, positive PCAFs highly coincide with the on-peak window of the tariff and no savings can be reported for the INVENT project. However, the dramatic increase of marginal distribution costs in a few years indicates the value that VGI could deliver to the system.

8.4.7 Avoided Greenhouse Gas Emissions

In addition to the capacity and energy avoided cost savings, managed charging in VGI could also result in lower carbon emissions. However, it is also possible that storage dispatch management could result in increased emissions depending on how charge scheduling is optimized. For example, a tariff that has on-peak pricing in the middle of the day could result in shifting energy consumption away from those hours. However, during those exact hours the grid marginal emissions could be low or even zero with significant solar generation. Thus, optimizing for economics is not necessarily the same as optimizing for carbon emissions. This has also been witnessed in the Self-Generation Incentive Program (SGIP) in California during which emissions storage sometimes resulted in increased emissions until the program was reformed to include a GHG price signal.[35] A carbon intensity signal or a carbon cost integrated in the retail rate could be used in the future to shift energy consumption to hours with lower carbon emissions.

For this report, there are two separate quantification analyses in terms of GHG emissions reduction. First, for the RETS use case that shifted energy consumption better to capture the generation of the local solar array, the quantification is straightforward and consists of the multiplication of the SDG&E marginal emissions rate and the increased solar consumption. The UCSD analysis adopts the assumption that solar energy would otherwise be curtailed as it exceeds the building needs. While this local perspective is reasonable for the benefits calculation in the EV charge scheduling report, in reality, there are other factors that should be taken into account: first, within the microgrid context, this energy could still be used somewhere else, and not necessarily be curtailed, and second, if outside the UCSD microgrid, the solar could be subject to a NEM tariff and being exported to the grid, instead of being curtailed.

Based on a 0.241 MT Co2e/MWh emissions rate in the SDG&E system, the CO_2 savings are calculated and are presented in Table 12.[36]

Based on the RESOLVE GHG shadow price from the CA IRP ($96.42/ton CO_2), the cost reduction associated with the emissions savings is $41.55.

The 2020 ACC updated the method for the price of CO_2 emissions. Instead of calculating CO2 price as the cost of cap-and-trade allowances plus a GHG adder like in the 2019 ACC, the new methodology uses GHG values on IRP RESOLVE outputs, discounted by the weighted average cost of capital. The resultant CO2 prices are similar to those calculated by the 2019 methodology for the 2020-2030 period but then scale up beyond 2030 and are represented by the red line in Figure 20. The increase of that price in future years indicates the increased value that VGI could deliver to the grid.

Table 12: Monthly San Diego Gas & Electric Company Carbon Dioxide Savings for Gilman Use Case

Month	Emissions Savings (kg CO_2)
January	2.98
February	17.07
March	24.80
April	89.31
May	138.43
June	88.77
July	167.94

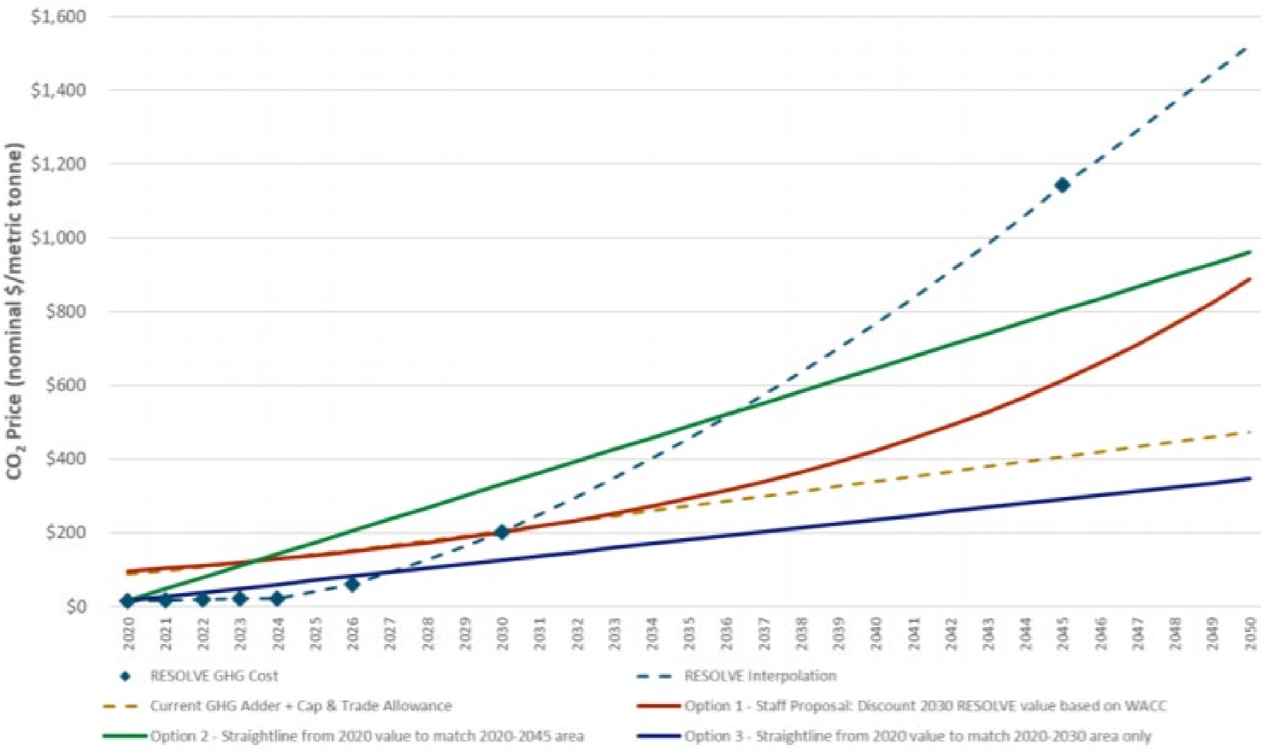
[35] 2018 SGIP Advanced Energy Storage Impact Evaluation https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/SGIP%20Advanced%20Energy%20Storage%20Impact%20Evaluation.pdf

[36] Lyons, Chrostopher. 2018 ELECTRIC PROCUREMENT REVENUE REQUIREMENT FORECASTS AND GHG-RELATED FORECASTS . 2018. https://www.sdge.com/sites/default/files/SDGE%2520Application.pdf SDG&E

Month	Emissions Savings (kg CO_2)
August	87.59
September	156.47
October	88.53

Source: EV Charge Scheduling Report

Figure 20: Price of Avoided Greenhouse Gas Emissions



Source: ACC documentation

For the Hopkins use case, the quantification of carbon emission reduction differs as there is no local renewable resource. Thus, charge management does not necessarily result in lower curtailment at the local level, but the impact that energy shifting has on grid emissions could be examined. In this case the emissions intensity (MTCO2e/MWh) from SDG&E's annual electric procurement revenue requirement forecasts report for 2018 would not be helpful as it has no hourly variation. For this reason, the report relies on the California average grid electricity used as a transportation fuel in California report, part of the low carbon fuel standard annual updates to lookup table pathways published by the California Air Resources Board. This report includes a table with normalized marginal emission rates for California grid average electricity for 2020 that can be used to translate the annual emissions intensity to hourly values. Those values multiplied with the managed and unmanaged charge level time series for Hopkins were the basis for the calculation of the grid-level emissions reduction. Results for the Hopkins use case for the first four months of 2020 are shown in Table 13.

Table 13: Carbon Dioxide Emissions under Unmanaged and Managed Charging Scenarios for the Hopkins Use Case

	Unmanaged Charging (kg CO_2)	Managed Charging ((kg CO_2)
January	48.13	39.54

	Unmanaged Charging (kg CO_2)	Managed Charging ((kg CO_2)
February	48.40	38.67
March	28.55	25.26
April	10.02	10.10

Source: Strategen Consulting, 2021

8.4.8 Total Benefits

Avoided energy, capacity, and emissions costs can be aggregated to reflect the value added to the system by VGI. However, the benefits observed during the INVENT project comprise only a subset of VGI benefits. Furthermore, vehicle charging was optimized for specific use cases and the benefits captured are not necessarily reflecting the maximum value that could be provided to the system. For example, in the Hopkins case, vehicle charging was optimized to reduce the demand charge of the parking structure, so energy savings were not maximized. Co-optimizing energy arbitrage based on a TOU tariff, including a demand charge could result in even higher savings. Co-optimization could but would not necessarily result in benefits equal to the sum of the savings achieved under specific use cases; the use of a battery for a specific use case could make it unavailable for another use case. Overlapping requests or conflicting requests for a resource may raise compensation or incrementality issues, making it unsuitable for stacking value.

8.5 Costs

For this analysis, no vehicle cost was identified. Specifically, the EVs themselves are not included in the costs as they are not an incremental expense. Vehicle costs are considered sunk costs because the vehicles used under INVENT were already capable of V1G and V2G charging, and the incremental cost to manufacture a bi-directional EV versus a uni-directional EV is not currently available in a publicly distributable format.

Regarding the electric vehicle supply equipment (EVSE) hardware, this analysis examines three different types of charging stations – unmanaged EVSEs, managed, unidirectional EVSEs (V1G), and managed, bi-directional EVSEs (V2G). The incremental cost differences between the three types are used to quantify the EVSE hardware costs.

The charging stations used in the project were the first product lines and are now at end of life. When the project was kicked off in October 2017, there were four charging station manufacturers that produced bidirectional products, all of whom INVENT worked with in some capacity. The 10kW bidirectional CHAdeMO charging station price was in the range of $7,500 - $20,000 in 2017. Today, a more populated market exists with around 30 charging station original equipment manufacturers (OEMs) producing or in the process of producing 10kW bidirectional charging stations with a price range of $4,000 - $10,000.

Installation costs are one-time expenses and can vary significantly from site to site, thus this project's installation costs are excluded from this chapter. Factors influencing the installation costs include the power capacity of the charging stations, the location of the charging stations, the distance to the nearest electrical panel, and the potential need for infrastructure upgrades depending on the total capacity being installed. In addition, for V2G-capable EVSEs, the cost to interconnect with the local distribution utility must also be considered. SDG&E's interconnection application cost is $800, in addition to the additional labor required to complete an interconnection application. Although installation costs will continue to be highly variable, there is potential for costs to decrease as it becomes more common for sites to use load management software to avoid the need to upgrade distribution infrastructure, potentially also making costs more predictable and streamlining interconnection approval.

8.6 Business Models Explored Under the INVENT Project

Business models for behind-the-meter energy management, meant to monetize b revenue and avoided cost value streams for third parties who help customers take advantage of relevant price signals, are already generally established, coming under the general heading of energy as a service (EaaS). The question we address here is how well EaaS models, adjusting to include or combine with mobility as a service (MaaS) as EVs become part of customer capital expenses, operating expenses, and load profiles.

- Adjusting EaaS models for an EaaS/MaaS hybrid service percent share of revenue (DR):
    - For a revenue-based service, where a response to an external price signal yields an actual payment from a grid actor such as the TSO, third parties can contract to receive a cut of any revenues. This type of contract, of course, needs to be structured to ensure the third party weighs costs to the customer and driving needs as constraints for market bidding strategies, bidding only in a manner that is a net financial benefit for the customer. The "mobility" piece must be prioritized, and any market participation is opportunistic based on natural availability of EVs when parked. The "energy" piece must also be considered: Time-of-Use price signal constraints may limit market participation opportunities.
    - Transportation electrification programs, and now SB 841, that place EVs behind their own separately metered account may determine whether such a model is viable. Without other loads or resources against which to measure decreases in usage and lacking compensation for export on retail bills and in-demand response compensation, EVs in transportation programs are currently not incentivized to participate in demand response (see section 7.1.1 in CHAPTER 7: Vehicle-Grid Integration Regulatory Barriers). That said, EVs at commercial and industrial demand metered accounts, co-mingled with building loads, can certainly access this value stream as it exists today. EV submetering may also provide a way to allow IOUs to charge EV-only rates while combining EV loads with other loads and resources a customer may have at their main account.
- Flat price for monthly management:
    - This "subscription model" is an existing model for capturing avoided-cost value streams behind retail meters. In general, a third party providing EaaS in this way may guarantee a specified level of savings on a monthly bill equal to or greater than the subscription fee. If the promised savings do not accrue, the third party provides a refund to cover the shortfall. Adding the "mobility" piece here increases the complexity for the third party and requires some modeling of use in the absence of the service to determine what level of use is attainable to set the subscription fee.
    - While this service is possible to provide under a transportation electrification program framework and all the specifications that imply as explained, it likely makes more sense when EVs are comingled with other loads and resources.
- Percent share of monthly bill savings:

- This model includes a subscription fee that is not only a flat rate but rather a smaller base rate with an additional sliding scale of compensation for the third party based on the customer's bill savings. Again, the "mobility" piece must be prioritized, and contracts need to ensure that the customer's energy and mobility needs are considered constraints within which to work to minimize operating costs and contracts must reflect that.

8.6.1 Service Descriptions

The following future business models are outside the scope of INVENT but represent applications of near- to medium-term interest to stakeholders. This is a high-level assessment of the potential viability of related business models.

Frequency Regulation

In general, the prospects for EVs to provide frequency regulation are similar to those of other behind-the-meter resources. The viability of V2G frequency regulation generally depends on the resolution of the questions regarding the measurement of response in load curtailment scenarios, settlement of retail bills and wholesale payments between the distribution and transmission-level system operators in case, and reconciling the needs and operational expectations of those same stakeholders.

Resiliency

The authors use the term resiliency in this context to mean EVs providing emergency backup power in islanded situations when the customer is separated from the grid in case of a blackout or other reason. This application is technically possible. There is clearly an interest and a need in California as fire season extends, public safety power shutoffs become longer and more widespread, and "extreme weather events" such as extended regional heat waves strain the system.

Distribution Deferral

EVs in general and V2G specifically are a promising use case for customer-level dynamic load control mechanisms. The distribution deferral case, if addressed correctly, has the potential to introduce new efficiencies into distribution buildout practices. "Automated Load Management Software" (ALMS) is in commercial use in other countries and states and is technically viable today.

Stakeholder Revenue Sharing

Benefits of these use cases and business models can accrue directly and indirectly to retail customers, utilities, CCAs, the California ISO, ratepayers, the energy system more broadly, and third-party service providers. INVENT has addressed potential value streams and limitations. However, identifying the equitable or optimal division and distribution of value, how much and to whom, is the project of industry, and of those who propose to provide these services. If the exact service structure, level of investment recovery by third-party service providers, and expected value for each customer type is agreed upon in advance, we have simply extended the regulated utility model. Those who successfully answer these questions in a manner that covers operating costs while incentivizing customers to participate will form this industry.

CHAPTER 9: Results and Recommendations

Project Results

VGI and V2G capabilities have not yet been integrated into distribution buildout, transportation electrification, or DER-related rate making in any appreciable way beyond Time-of-Use compliance. The first real progress appears to be taking place in the SB 676 implementation, during which there has been discussion of the impacts automated load management capabilities can have on connection procedures for new EVSE installations. By identifying the rates and proceedings on ratepayer-funded mechanisms that need to account for VGI capabilities in updates, INVENT seeks to ensure EVs and VGI are a central consideration not just in mobility-related policy making but in ratemaking more generally.

Significant monetary and emissions savings were achieved by the use cases in the INVENT project. In the DCM use case, average demand charge savings of $888 per EV per year was achieved. Charging optimization can reduce the demand charges associated with peak power consumption in a building by either avoiding charging V1G EVs during the building peak load or by discharging V2G EVs.

By managing electric vehicle charging to prioritize monetary savings, greenhouse gas emissions can be saved as well. According to our research, managed charging saves on average an additional 12.9kg CO_2 per vehicle per year over unmanaged charging. The addition of on-site solar PV resulted in a 20X increase in greenhouse gas savings compared to EV demand Charge Management alone. According to data collected in the RETS use case, prioritizing renewable energy consumption with on-site solar PV increases CO_2 savings to 246kg CO_2 per vehicle per year.

Based on the RESOLVE GHG shadow price from the CA IRP ($96.42/ton CO_2), the total monetary savings of these reductions would be $1.37 per EV per year for managed charging alone and $26.17 for managed charging paired with on-site solar PV.

This project sets the groundwork for the expansion of VGI implementation in the emerging markets for this technology. It can serve as a reference for regulators and policy makers to take V2G into consideration, not only when creating new legislation but to update existing laws and regulations that currently address VGI in limited ways.

In the RETS use case, workplace charging at buildings where solar power generation dominates the net load profile, there are opportunities for substantial GHG emissions savings by charging from local solar energy with zero marginal GHG emissions during midday instead of grid power in the morning. But opportunities for EV demand charge savings diminish on buildings with solar, as building peak loads shift to the early morning or evening when EVs may not be available. That said, the DCM plus solar use case showed a savings of $90 per car per month at Gilman Parking Structure, or $450 total savings for the building.

It was determined that DCM without solar resulted in significant monthly demand charge savings of $80 per car per month for the Hopkins parking structure and $52 per car for the police department (or $290 and $191 per building). Fleets with more bidirectional chargers can reduce the demand charges compared to a building without electric vehicles.

In the frequency regulation use case, coalitions of electric vehicles successfully participated in the frequency regulation ancillary services market. The EVs achieved performance accuracy well above the minimum threshold and on the upper end of the California ISO system average (30 percent – 60 percent) for regulation up and regulation down. This should serve as a starting point for the California ISO to consider the place of EVs in not just the frequency regulation market but other fast-reacting services that may depend on frequency or similar live signals.

Challenges

Hitachi, Princeton Power, and PowerPort stations were able to perform their functions, but using first-of-its-kind bidirectional EV charging stations presented some complications throughout the project. A lesson learned is that engineering support from the manufacturer is key during experimentation, and integration with the charging station may be preferable in commercial operation. Since the start of INVENT, new, smart inverter standard-compliant bidirectional EVSE models have been introduced in the US and Europe and will likely be more user-friendly and more affordable for consumers.

Beyond the previously mentioned interconnection standard and market access barriers, COVID-19 presented the most significant challenge. The UCSD campus mostly shut down along with the rest of the state. Commuting drivers began working from home, and on-campus vehicles were driven significantly less. Load profiles of buildings and the microgrid overall changed drastically. The project EVs either were not on campus or were parked constantly with no driving and use patterns to work with when studying use cases. Driving schedules were simulated in instances that vehicles were stationary for long periods of time.

Recommendations

This study shows definitively that V2G-capable EVs can respond with both the speed and accuracy necessary to participate in ancillary services. With technical capability proven, it should now be possible to consider how EVs can be integrated into system-wide services. The California ISO can address telemetry requirements, the remaining complications in the NGR/DERP model, and collaborate with the CPUC to address the remaining uncertainty around FERC Order 2222 compliance at the distribution level, including settlement, interconnection, multiple-use applications, aggregation, and resource adequacy.

The DCM, RETS, and DR use cases demonstrate that EVs, both in V1G and V2G mode, can optimize co-located loads and resources. Transportation Electrification programs should acknowledge this and allow EVs to connect at existing accounts when appropriate. Rate design should also include consideration of the increasingly likely "EV plus solar" configuration. In this study, the same optimization was viable for both DCM alone and RETS plus DCM demonstrating a linkage and synergy in the two use cases. This type of natural value stacking should be explored more. The fact that NEM cannot include V2G and that EV rates cannot include resources such as solar leave this case in a gray area. If there are, in fact, existing rates that can allow for optimization of smart charging uni-directional EVs with solar or can be adjusted to include V2G and solar on the same account, they should be publicized. It is possible that addressing coordination of EVs and solar at the system level is more efficient, but customers should have an option to choose.

The highly distributed, grid-edge location of many EVs will make behind the meter and system-level applications a natural combination. As stated in Chapter 7, EVs broadly and V2G specifically will gain clarity from new multiple-use applications proceeding to clarify their potential roles.

The demand response use case demonstrates the potential for microgrids to contribute to resilience, day-ahead energy markets, resource adequacy, and emergency grid events. PPAs, revision of baselining methods, interconnection, multiple-use applications, and coordination of capacity resources between distribution and transmission system operators should all focus on and seek to facilitate the potential role of microgrids and the resources they contain going forward.

Finally, while the CPUC and CEC have made real progress on considering and integrating V2G into their programs, there remains work to be done. The Rule 21 acknowledgment of V2G as a storage resource and the CEC encouragement of V2G research and development in school buses, for example is groundbreaking. INVENT seeks to point the way to the next steps these agencies can take to ensure their previous actions lead to the formation of a new industry in California rather than to yet another pilot and yet another report. V2G is cross-disciplinary and cross-jurisdictional. This can lead to regulatory and programmatic pitfalls in utility and governmental structures as transportation electrification staff, resources, and rules remain siloed. The agencies can continue to encourage V2G and VGI by examining their existing programs for subtle (or obvious) barriers or contradictions that will exclude V2G resources from programmatic inclusion or customer contact. INVENT has shown the capability of these technologies, and it is up to the state of California to continue to create an environment for innovation to move toward its renewable energy and transportation electrification goals as quickly as possible to lead the worldwide effort to address and avert climate change.

GLOSSARY AND LIST OF ACRONYMS

Term	Definition
DRAM	Demand Response Auction Mechanism
DAM	Day-ahead Market
DCM	Demand Charge Management
Distributed Energy Resources (DER)	Distributed energy resources are smaller sources of energy (or in some cases energy storage) that are located at the distribution level of the grid instead of the transmission level or centrally located. Examples would be home solar installations or residential batteries.
EPIC (Electric Program Investment Charge	The Electric Program Investment Charge, created by the California Public Utilities Commission in December 2011, supports investments in clean energy technologies that benefit electricity ratepayers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.
LMP	Locational Marginal Price
NBT	Net Benefit Threshold
NCD	Non-coincident Demand
NPR	UCSD Generator Nameplate Rating, 31,956 Kw
PD	Peak Demand
PJM	Pennsylvania-New Jersey-Maryland Interconnection LLC
RTM	Real-time Market
Variable	Definition and Units
Vehicle-grid integration (VGI)	How electric vehicles integrate into the grid and can possibly provide grid services
V1G	The term refers to the unidirectional flow of power enabling EVs to flexibly and intelligently charge from the grid
V2B	The term refers to the bidirectional flow of power enabling EVs to charge from the grid and to discharge back to the grid
V2G	The term refers to the bidirectional flow of power enabling EVs to charge from the grid and to discharge back to the grid
c_{bid}	Bidding Price [$/MWh]
c_{energy}	Flat Rate for UCSD Direct Access Energy Purchases, 0.068 $/Kw
$c_{\text{LMP,DAM}}$	Day-ahead Market Locational Marginal Price [$/MWh]
$c_{\text{LMP,RTM}}$	Real-time Market Locational Marginal Price [$/MWh]
c_{NCDC}	Non-coincident Demand Charge [$]
c_{PDC}	Peak Demand Charge [$]
$E_{\text{BYD,Max}}$	Battery Maximum Energy Capacity [Kw]
$FNL_{\text{AnnualMax}}$	Maximum UCSD Total Campus Load In the Past Year
$P_{\text{BYD,actual}}$	Actual BYD Battery Discharging Power
$P_{\text{BYD,fc}}$	Forecasted BYD Battery Discharging Power
$P_{\text{BYD,Max}}$	Battery Maximum Charging / Discharging Power [Kw]
E_{DR}	Submitted Energy Bid of Utility Import Demand Reduction Compared to The Adjusted Baseline at The Trading Hour [KWh]

Term	Definition
$P_{DR,actual}$	Actual Demand Response Power, THAT IS Actual Utility Import Compared to The Adjusted Baseline at The Trading Hour [KWh]
$P_{DR,bid}$	Bid Demand Response Power [MWh]
$P_{DR,fc}$	Forecasted Available Demand Response
$P_{DR,full}$	Full Nominated Capacity of The Month [MW]
P_{import}	Imported Power Value Read by The Utility Meter, THAT IS Campus Net Load
$P_{import,actual}$	Actual Utility Imports
$P_{import,base}$	Adjusted Baseline of Utility Imports [Kw]
$P_{import,base,actual}$	Actual Adjusted Baseline of Utility Imports
$P_{import,base,fc}$	Forecasted Adjusted Baseline of Utility Imports
$P_{import,fc}$	Forecasted Utility Imports
P_{NCD_Max}	Power Used for Non-coincident Demand (NCD) Charge Calculation = Maximum NCD of the Month or Half of Maximum NCD of the Past Year, Whichever Is Greater
P_{NCD_th}	Threshold of Non-coincident Demand of The Month
P_{OG}	Total Power Generated by UCSD Onsite Generators
P_{PD_Max}	Power Used for Peak Demand (PD) Charge Calculation = Maximum PD of the Month or Half of Maximum PD of the Past Year, Whichever Is Greater
P_{PD_th}	Threshold of Peak Demand of The Month
P_{PV}	Power Generated by PV Systems on Campus
$r_{capacity}$	Monthly Capacity Rate [$/MW]
r_{NCDC}	Non-coincident Demand Charge Rate, 15.40 $/Kw/Mo.
r_{PDC}	Peak Demand Charge Rate, 3.02 $/Kw in Summer And 0.63 $/Kw in Winter
$R_{capacity}$	DRAM Capacity Payment [$]
R_{energy}	DRAM Energy Payment [$]
R_{over}	Extra Revenue of Energy Payment [$]
R_{loss_BYD}	Battery Operation Cost [$]
$R_{penalty}$	DRAM Penalty [$]
$x_{BYD}(t)$	Normalized Battery Charging / Discharging Signal [-]
η_{eff}	On Campus BYD Battery Round-trip Efficiency [%]
EPIC	Electric Program Investment Charge

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APPENDIX A: Vehicle-Grid Integration Market Development Report

A-1: Energy Market and Policy Context

Vehicle-Grid Integration Overview

The transportation sector in California was responsible for 41 percent of statewide emissions in 2017, making it the single largest contributor of greenhouse gas (GHG) emissions in the state (California Energy Commission [CEC] 2019). In pursuit of a decarbonized transportation sector, California has set a goal to reach 1.5 million zero-emission vehicles (ZEV) by 2025 (Office of Governor Brown 2012) and 5 million by 2030 (Office of Governor Brown 2018). Meaningful progress has been made towards these goals, as the state is currently home to nearly 50 percent of ZEVs in the U.S. and 90 percent of total U.S. clean transportation investment (California Energy Commission 2019).

The accelerated deployment of electric vehicles (EV) – the predominant ZEV – and resulting increase in EV charging demand pose challenges and opportunities for the electricity grid. New EV load could increase peak demand, which would trigger investments in new peaking power plants, as well as transmission and distribution systems upgrades. Together these infrastructure investments could increase costs for electric utilities and their customers. Fortunately, EVs are more flexible than other types of load, as the timing of charging and discharging can be controlled, as can the provision of grid services. Additionally, widespread EV charging will increase sales of energy (kWh), which has the potential to benefit all electric utility customers by putting downward pressure on electricity rates.

Opportunities stemming from new EV load are likely to outweigh the challenges if the necessary strategies are intelligently enabled and implemented at scale. Managed charging, or the shift or modulation of an EV's one-way charging in response to retail rates and incentives, is one such strategy. Managed charging can be used to either limit the charging level (for example, lower the rate of charge from the common 6.6 kW to some lower rate) or temporarily stop all flow of power into the EV (for example, lower the rate of charge from 6.6 kW to 0 kW). EV charging can also adjust to provide dispatchable grid services through programs designed to meet local or system-wide grid needs. These applications are commonly referred to as V1G.

EV batteries can store several times more energy than the average California home consumes in a day. For example, the battery capacity for one of the most common EVs in California is 75 kWh (KBB 2020), while the average California home consumes about 18 kWh per day (EIA 2019). EVs – as well as the EV supply equipment (EVSE) that connect them with the grid – exist at the grid edge and can be deployed with the technological capabilities to discharge the stored energy, sharing many of the same characteristics as other distributed energy resources (DER), such as stationary energy storage. It is therefore logical to consider EVs as DERs in addition to their use as a mode of transportation. The ability for EV batteries to leverage bi-directional power flow and, if needed, export energy to the grid is known as vehicle-to-grid (V2G).

Vehicle-grid integration (VGI) can be roughly defined as the array of V1G and V2G solutions. VGI's role as an important tool in the decarbonization toolkit is highlighted by the enactment of Senate Bill 676 (Bradford 2019), which provides the following definition for VGI:

> "any method of altering the time, charging level, or location at which grid-connected electric vehicles charge or discharge, in a manner that optimizes plug-in electric vehicle interaction with the electrical grid and provides net benefits to ratepayers by doing any of the following:
>
> - Increasing electrical grid asset use.
> - Avoiding otherwise necessary distribution infrastructure upgrades.
> - Integrating renewable energy resources.
> - Reducing the cost of electricity supply.
> - Offering reliability services consistent with Section 380 of the Independent System Operator Tariff."

For this report, VGI also includes a unique and potentially high-value set of use cases in which EVs provide backup power to a building or section of the grid that is islanded from the larger grid, or microgrid. While the building or microgrid may not always be grid-connected, these use cases still fall within the V2G concept of bi-directional power flow that leverages the energy stored in EV batteries. This topic is explored in greater detail in the Backup Power and Resiliency section.

California Energy Market Context

The VGI market in California exists within the state's partially deregulated electric power sector, wherein bilaterally procured generating resources bid their capabilities in a competitive wholesale electricity market. Load-serving entities (LSE), such as the state's three major investor-owned utilities (IOU) and several municipal (publicly-owned) utilities, satisfy their capacity planning requirements to provide power to end-use customers. Since 2006, California has also seen the rise of 21 community choice aggregators (CCA), a type of LSE uniquely focused on procuring clean and/or local alternatives to IOU-procured power (California Energy Commission 2019).

Another important stakeholder in shaping California's energy system is the California Independent System Operator (California ISO). California ISO is a nonprofit entity tasked with balancing supply and demand on the bulk electric grid, ensuring reliability, and optimizing energy and ancillary services through various market mechanisms. While energy market participation rules are actively evolving, the general trend of wholesale electricity markets throughout much of the U.S., including California ISO, is towards allowing a greater number of resource types, as well as smaller and more diverse resource aggregations, to participate. This trend has implications for VGI market development because the limited capacity of most EV batteries, especially passenger or light-duty vehicles (LDV), does not meet the minimum participation requirements needed to qualify for direct participation in wholesale markets. Aggregating diverse resource types, whether a collection of VGI-capable EVs or a mix of EVs and other DERs, allows for participation in California ISO's various market mechanisms.

VGI technology has emerged alongside heightened customer awareness, expectation, and interest in distributed and decarbonized energy systems. This trend, paired with declining costs for DER technologies, has led to consistently increasing deployments of DERs over the past decade (California Energy Commission 2019). Through innovative policy and market levers, policymakers, regulators, California ISO, and the LSEs have begun to lay the foundation for a future grid scenario with higher penetration of DERs. This influences VGI market development by providing existing market products, compensation mechanisms, and business models that can be leveraged or updated to harness the potential of EVs as grid assets.

Statewide Decarbonization Goals

The California Air Resources Board (CARB) ZEV Regulation, part of its Advanced Clean Cars program, encourages automotive original equipment manufacturers (OEM) to sell ZEVs in California by administering a ZEV credit mandate. CARB sets a number of credits that OEMs must meet through either selling ZEVs or acquiring credits from other automakers. While the ZEV credit requirement is set to increase to 8 percent of EV sales by 2025, OEMs are well ahead of schedule to comply with the ZEV regulation. OEMs can also carry over excess credits from earlier years. Additionally, CARB's ZEV regulation has been adopted in eleven other states (Vermont Department of Environmental Conservation 2020), and OEMs are permitted to transfer credits between states, helping them comply in markets exhibiting slower growth.

In support of the CARB ZEV Regulation, Governor Jerry Brown issued an executive order in 2012 that set a near-term goal to reach 1.5 million ZEVs on California roads by 2025 (Office of Governor Brown 2012). In 2018, Executive Order B-48-18 added the goal of 5 million ZEVs by 2030 and set a target for the deployment of 250,000 charging stations by 2030, including 10,000 direct current fast chargers (DCFC).

A suite of other state policies enacted in 2018 and 2019 supplement these core policy drivers by supporting specific areas of EV deployment and VGI market development. For example, SB 1000 (Lara 2018) requires an assessment of the extent to which charging infrastructure is equitably distributed across high-, medium-, and low-income neighborhoods and communities of color, as underserved neighborhoods are also the most likely to be subject to increased air pollution and in turn most in need of EV-enabling infrastructure. The bill also authorizes the use of public funds if the assessment finds EV charging infrastructure is disproportionately distributed. AB 2127 is another notable piece of legislation that requires the CEC assess the need for charging infrastructure to achieve 1.5 million EVs by 2025. Executive Order N-19-19 directs CARB to develop new criteria for clean vehicle incentive programs, propose new strategies to increase demand for ZEVs, and consider holistically strengthening or adopting new regulations to achieve the necessary GHG reductions from within the transportation sector (Newsom 2019).

California has also adopted a broad and comprehensive set of policies to decarbonize the electricity sector, which closely interact with transportation electrification goals. The two sectors are inherently and necessarily intertwined, as EVs store and use electricity.

Senate Bill 100 – the 100 Percent Clean Energy Act of 2018 – established a state policy to increase California's renewable portfolio standard (RPS) to 50 percent renewables by 2026, 60 percent renewable energy by 2030, and 100 percent carbon-free electricity by 2045. Renewable energy such as solar and wind are not dispatchable like traditional fossil fuel generators. For example, solar panels generate the most energy during the middle of the day and, unless there is a way to store those electrons, the assets are not able to provide power to the grid at night. Similarly, the energy generated by wind turbines varies with fluctuations in wind speed. Decarbonizing the grid through higher penetration of renewable energy will therefore require the deployment of assets, such as stationary energy storage or VGI-enabled EVs, that can provide essential grid reliability services.

The Clean Energy and Pollution Reduction Act, or SB 350 (De León 2015), requires California to reduce its GHG emissions to 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050. SB 350 also requires CARB, the California Public Utilities Commission (CPUC), and Energy Commission (CEC) direct IOUs to file applications for programs and investments to accelerate widespread transportation electrification (TE). TE programs and investments are required to maximize benefits and minimize costs, and VGI solutions offer additional levers for benefit and cost optimization within IOU TE programs and investments. In 2018, Governor Brown built upon these carbon emissions goals by issuing Executive Order B-55-18, which set a statewide goal to achieve carbon neutrality by 2045 (Office of Governor Brown, 2018).

The potential use of VGI technologies to serve as a cost-efficient strategy for transportation sector decarbonization is explicitly supported in SB 676, which aims to broadly advance VGI in the state (Bradford, 2019). SB 676 requires the CPUC establish strategies and quantifiable metrics by December 31, 2020 to maximize the use of feasible and cost-effective VGI. Following CPUC implementation, LSEs would be required to report on progress towards VGI strategies in accordance with CPUC direction. SB 676 also requires publicly-owned utilities that serve more than 700 GWh of annual electric demand to consider establishing VGI strategies in their integrated resource plans (IRP).

Federal Policy and Regulatory Context

The Energy Improvement and Extension Act of 2008 ushered in federal tax credits for new EVs, ranging from $2,500 to $7,500 per EV. The American Recovery and Reinvestment Act of 2009 ensured that this credit, known as the Qualified Plug-In Electric Vehicle Tax Credit, was made available until each OEM sells 200,000 qualified vehicles, at which point the credit is phased out for that OEM over the next year and half. Tesla and General Motors have reached their cap, with Nissan and Ford Motor Company on track to reach their cap in the coming years (Kane 2020). This federal EV tax credit has provided critical support for EV market growth over the past decade (Congressional Research Service 2019) and is likely a contributing factor in the observed cost declines of lithium-ion batteries, which have fallen 85 percent in volume-weighted average battery pack price (Goldie-Scot 2019).

The Federal Energy Regulatory Commission (FERC), the federal agency tasked with regulating transmission and wholesale electricity markets that involve interstate commerce, issued Order 841 on February 15, 2018 (Federal Energy Regulatory Commission 2018). Order 841 directed the development of market participation models for DERs in wholesale electricity markets. In April of 2018, FERC convened a technical conference to address DER aggregation and more broadly discuss DER participation in wholesale markets. While many details still need to be determined to make DER participation in wholesale markets economically and operationally efficient, these FERC efforts signal a fundamental recognition that DERs have a strong value proposition and role to play within wholesale electricity markets. Order 841 did not address or provide direction to system operators, such as California ISO, on the integration of EVs, but it did set the stage for the potential participation of EVs as demand response or mobile energy storage resources within the context of wholesale electricity markets.

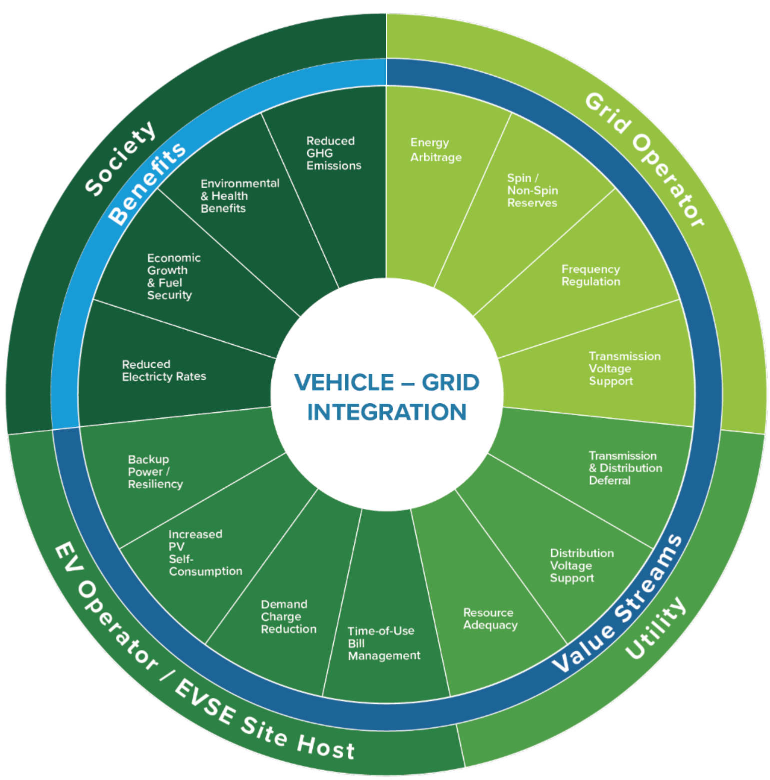
A-2: Framework for Assessing Vehicle-Grid Integration Value Streams

VGI-enabled EVs can provide services beyond mobility to a range of different stakeholders. The four key stakeholder groups considered in this assessment are EV customers / EVSE site hosts, utilities, grid operators, and society as a whole. These groups span the depths of the grid, from customer retail rate interaction and utility distribution system operation to the California ISO's bulk electric grid operation and broad societal perspective.

VGI technology is not only capable of providing value and benefits to several stakeholders, but also can capture multiple value streams and benefits simultaneously, a concept known as value stacking. Other DERs use value stacking, most notably stationary energy storage, to maximize net benefit and improve project economics by capturing more value. As multi-use DERs, EVs and stationary energy storage both use power to serve customer end-use needs, for example through transportation in the case of EVs and backup power in the case of stationary energy storage. The similarity in characteristics of VGI-enabled EVs and stationary energy storage provides an opportunity to leverage an existing framework in support of the VGI value market development assessment.

The foundation for assessing VGI value streams in this report is based on a concept introduced by the Rocky Mountain Institute (RMI) (Fitzgerald 2015) originally intended to show the range of grid services that stationary energy storage could provide to various stakeholders. By leveraging the RMI concept, Figure A-1 maps VGI value streams and benefits to one of the four main stakeholder groups.

Figure A-1: Vehicle-Grid Integration Value Streams



Source: Strategen Consulting, 2020

The identified value streams and stakeholder categorization serves as the foundation for the VGI market development assessment framework addressed in this report. The VGI value streams and benefits identified above could be captured by EVs through leveraging VGI capabilities to respond to price signals or participate in programs related to each value stream. Value streams are defined based on overarching VGI capabilities that are not specific to the California market. This ensures that the assessment represents VGI applications beyond those currently enabled in California, setting an appropriately broad baseline for the assessment. Each value stream is then assessed to determine whether it is:

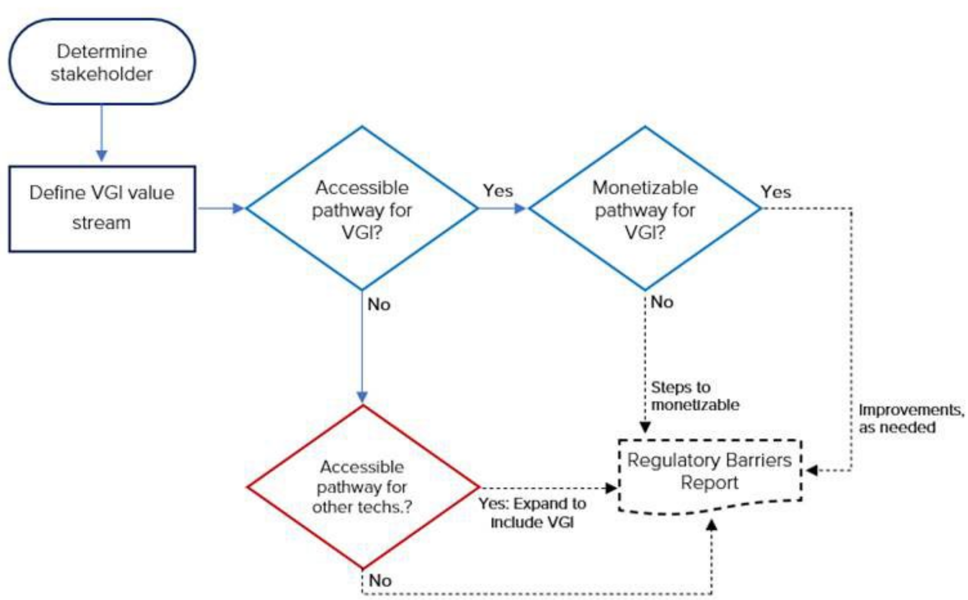
- Accessible – An accessible value stream is available to VGI technologies today based on current market rules, regulations and /or tariffs.

If a value stream is Accessible, it is then assessed to determine whether it is also:

- Monetizable – A monetizable value stream is accessible and can also be leveraged by VGI service providers to build a viable business case.

Insights from this assessment are used to outline a portfolio of possible actions to evolve value streams from Accessible to Monetizable, improve access to Monetizable value streams, and open Monetizable value streams that may exist but are closed to VGI technologies. These high-level actions are not collectively exhaustive but do follow existing trends and narratives in several ongoing policy forums, including California's Joint Agency VGI Working Group. These potential market development actions should be surveyed for ease and timing of implementation, cost-efficiency compared to alternative pathways, and any double-counting considerations. A deeper dive into specific regulatory gaps and potential steps to alleviate them will be investigated in greater detail in the INVENT VGI Regulatory Barriers Report. Figure A-2 shows the assessment process described above as well as the relationship between the INVENT Market Development and Regulatory Barriers reports.

Figure A-2: Assessment Process



Source: Strategen Consulting, 2020

A-3: Electric Vehicle Operator / Electric Vehicle Supply Equipment Site Host Value Streams

This section provides overviews of the four categories of EV Operator / EVSE Site Host Value Streams previously identified, as well as discuss market development recommendations to improve the ability of VGI technology to provide value in each category. It is important to note the EV Operator (that is the driver or fleet manager) can be the same or different as the EVSE Site Host. The two are included together because the value streams available to both are largely the same.

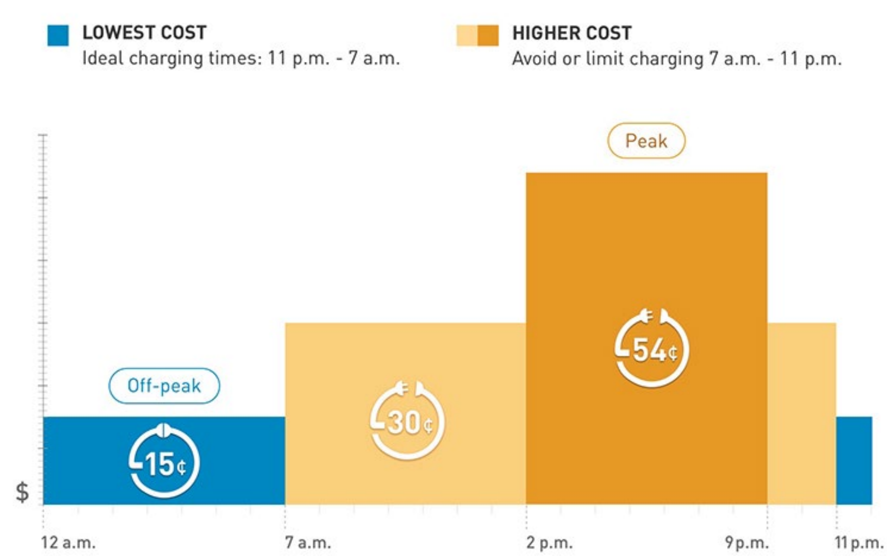
Time-of-Use Bill Management

Time-of-use (TOU) electricity rates offer price signals that differ throughout the day, with higher rates during times of peak electricity demand and lower rates during off-peak or low demand hours. If designed in accordance with best practices in utility rate design, this time-varying rate structure can offer electricity customers an opportunity to take advantage of lower energy prices and save money on their monthly utility bill. Utility customers with EVSE, for example residential customers with wall-mounted chargers or commercial workplaces, can leverage well-designed TOU rates to save on EV charging costs by shifting when an EV charges. Other time-varying price signals, such as rebates for charging during off-peak times and critical peak pricing rates, can also enable EVSE site hosts to save on their monthly utility bills.

TOU Bill Management for Residential Customers

All three of California's major IOUs currently offer TOU rates to residential customers with EVs. The rates differ in their exact structure and price, although each IOU has the same peak period of 4 p.m. – 9 p.m. Figure A-3 shows the specific rate structure for PG&E's EV-B rate, including the 4 p.m. – 9 p.m. peak period applicable across the three major IOUs.

Figure A-3: PG&E EV-B Rate



Source: Pacific Gas and Electric, 2020

Residential EV customers in SCE service territory can enroll in the TOU-D-PRIME rate for their home and EV, which means that every kWh consumed on their premises, whether for EV charging or another end-use, will be billed according to the $/kWh prices in the TOU-D-PRIME rate. SDG&E and PG&E's EV-driving residential customers have more choice in selecting their TOU rate. Customers in these service territories can decide whether to measure their home and EVSE on the same electricity meter – similar to the "whole-house" TOU rate offered by SCE – or to install a separate, dedicated meter for their EVSE. Compared to the whole-house TOU rate options, SDG&E and PG&E's separately-metered "EV-only" rates offer relatively larger price differentials between peak and off-peak periods. This peak/off-peak differential is a major factor in the amount of value a customer could capture by shifting their consumption patterns, including EV charging behavior. SDG&E and PG&E customers face an important tradeoff when deciding which rate is best for them, as the installation costs for a dedicated EVSE meter are around $2,000 but can cost up to $8,000, depending on the specific configuration of the customer's home (Pacific Gas & Electric 2020). Customers looking to reduce the total cost of ownership for their EV should weigh the installation costs for a separate meter against the added benefit they expect to achieve from choosing the EV-only rate and charging in response to the price signals.

VGI technologies can play a key role in capturing the value stream created by well-designed TOU rates. Managed charging software and tools that enable "charge-by" services (that is, charge by the morning to drive to work), which co-optimize for customer needs and TOU price signals, can offer a simple and no-hassle pathway for EV customers to save money on their home charging costs.

Peak/off-peak price differentials can be hard to get right. An optimal price signal would incentivize charging behavior that simultaneously benefits customers and the grid, a concept fundamental to VGI as detailed in the Vehicle-Grid Integration Overview section. Reducing charging costs is important for customers, but if the peak/off-peak differential is too low, customers may not exhibit an adequate response to the price signal. A differential that is too low also limits the opportunity to reduce peak demand and save on grid costs incurred by meeting that peak demand.

The price differential can also be set too high, which risks lower customer enrollment in the rate due to customers' expectations and perceived ability to respond to the price signal. SDGE's whole-house EV-TOU-5 rate offers the highest peak/off-peak differential of the three IOU's EV rates, with a summer super off-peak rate of $0.09/kWh and a summer peak charge of $0.50/kWh (San Diego Gas & Electric 2020). Table A-1 compiles the differentials between key rate components of currently open residential TOU EV rates among the three major IOUs. There is a wide range of rate differentials among the rate offerings, but it is important to note rates with low differentials may inadequately incentivize altered charging behavior.

The TOU bill management value stream for residential customers can be captured with an achievable monetization pathway, for example by adopting VGI strategies to shift charging load towards off-peak times. However, setting optimal peak/off-peak differentials could provide a more practical monetization pathway for VGI strategies to capture the TOU bill management value stream for residential customers.

Table A-1: Current IOU Residential EV TOU Rate On-Peak / Off-Peak Differentials

Rate	On-Peak	Off-Peak	Differential
PG&E EV-B, summer	$0.53525	$0.14189	$0.39336
PG&E EV-B, summer	$0.37322	$0.14521	$0.22801
PG&E EV2-A, summer	$0.48179	$0.16928	$0.31251
PG&E EV2-A, winter	$0.35468	$0.16928	$0.18540
SCE TOU-D Option Prime, summer	$0.39314	$0.13577	$0.25737
SCE TOU-D Option Prime, winter	$0.35943	$0.12932	$0.23011
SDG&E EV-TOU, summer	$0.55279	$0.19319	$0.35960
SDG&E EV-TOU, winter	$0.30540	$0.19392	$0.11148
SDG&E EV-TOU-2, summer	$0.55279	$0.19319	$0.35960
SDG&E EV-TOU-2, winter	$0.30540	$0.19392	$0.11148
SDG&E EV-TOU-5, summer	$0.50411	$0.08558	$0.41853
SDG&E EV-TOU-5, winter	$0.25672	$0.08631	$0.17041

Source: PG&E, SCE and SDG&E, 2020

TOU Bill Management for Commercial Customers

Currently, only SCE and PG&E offer open TOU EV rates applicable to commercial customers with separately-metered EVSE. If the EVSE is on the same meter as the site host load, the commercial EVSE site host will be on the default commercial TOU rate, which is not designed with EV charging behavior in mind. As is the case with residential TOU rates, a well-designed price signal could incentivize customers operating fleets or otherwise managing EV charging to encourage consumption during off-peak times and reduce their monthly electricity bill. VGI technologies can be used to capture this value stream for commercial customers.

The current and pending commercial EV TOU rate structures are relatively flat compared to their residential counterparts. Peak periods for EV-specific and general C&I TOU rates generally fall between 2 p.m. and 9 p.m., a longer peak than period than the residential TOU rates. Table A-2 shows the peak/off-peak differentials for current and pending commercial EV rates, which are lower on average than the residential peak/off-peak differentials.

Commercial EVSE site hosts can leverage VGI strategies to capture the TOU bill management value stream, making it both an achievable and practical monetization pathway. However, the potential size of the TOU bill management value stream for commercial customers is relatively limited compared to the demand charge management value stream, as the opportunity to save on the $/kW or "demand charge" component of a commercial bill using DERs is typically much higher than the opportunity for TOU bill management (Gagnon et al. 2017). This idea is detailed further in the Demand Charge Management section.

Table A-2: Current and Pending IOU Commercial EV TOU Rate On-Peak / Off-Peak Differentials

Rate	On-Peak	Off-Peak	Differential
PG&E BEV-1	$0.32858	$0.10991	$0.21867
PG&E BEV-2 S	$0.34490	$0.10840	$0.23650
PG&E BEV-2 P	$0.33694	$0.10540	$0.23154
SCE TOU-EV-7, summer	$0.41056	$0.14839	$0.26217
SCE TOU-EV-7, winter	$0.31791	$0.08496	$0.23295
SCE TOU-EV-8, summer	$0.49738	$0.12710	$0.37028
SCE TOU-EV-8, winter	$0.29831	$0.07865	$0.21966
SCE TOU-EV-9 (<2kV), summer	$0.44227	$0.10703	$0.33524
SCE TOU-EV-9 (<2kV), winter	$0.25703	$0.06890	$0.18813
SCE TOU-EV-9 (2-50kV), summer	$0.40891	$0.09854	$0.31037
SCE TOU-EV-9 (2-50kV), winter	$0.23603	$0.06493	$0.17110
SCE TOU-EV-9 (>50kV), summer	$0.30422	$0.07972	$0.22450
SCE TOU-EV-9 (>50kV), winter	$0.15389	$0.05749	$0.09640

Source: PG&E, SCE and SDG&E, 2020

While SDG&E does not currently offer an open commercial EV rate, it is important to note that the utility has been piloting a VGI rate for customers participating in the Power Your Drive (PYD) program. The VGI pilot rate offers EV drivers a day-ahead hourly dynamic rate based on California ISO energy prices. As of July 31, 2019, 254 workplace, residential multi-unit dwelling (MUD), fleet, and school EVSE sites contracted with SDG&E and were enrolled in the VGI pilot rate. SDG&E has filed an application with the CPUC for a PYD 2 plan that would expand PYD efforts from pilot scale to mass market.

Table A-3: Commodity Component of SDG&E VGI Pilot Rate

Commodity Rate	$ / kWh
Commodity Base Rate	0.06385
California ISO day-ahead hourly price	Updated daily, day-ahead
VGI day-ahead C-CPP Hourly Adder	0.52695
California ISO day-of hourly adjustment for surplus energy	Updated daily, same day

Source: SDG&E, 2019

Bidirectional Charging for TOU Bill Management

In addition to saving money by charging during off-peak times, both residential and commercial customers could generate additional revenue by offsetting on-site consumption of energy from the grid during peak times. This would require an EV or EVSE equipped with a bi-directional inverter capable of serving the on-site load. While both bi-directional EV and EVSE technologies exist, only the latter method has an available interconnection pathway in California.

When the EVSE is equipped with the bi-directional inverter the system is referred to as V2G-Direct Current (V2G-DC) because DC power flows from the EV to the EVSE, where the inverter is located to convert the DC power to alternating current (AC). To interconnect, a V2G-DC system would need to navigate the IOUs' Rule 21 process to ensure the system meets all safety and reliability requirements for interconnection to the distribution grid. Currently, the Rule 21 interconnection process is not streamlined and represents significant misalignment with the customer experience. For example, a customer purchasing an EV and EVSE system in hopes of interconnecting under Rule 21 would not be able to charge from the grid until the interconnection process is complete.

Bi-directional systems where the inverter is onboard the EV are referred to as V2G-AC because AC power leaves the vehicle. Currently, there is no pathway to interconnect V2G-AC systems, although meaningful progress was made in the CPUC's V2G-AC Interconnection Technical Subgroup (California Energy Storage Alliance 2019).

Market Development Recommendations

Overall, the TOU value stream is currently accessible to VGI technology and monetizable to build a business case around. However, there are areas for improvement to further increase the value VGI can bring to stakeholders.

- Encourage dynamic rate design. Time-varying rates such as SDG&E's are a type of dynamic price signal that better reflect the cost of energy generation and could lead to more impactful shifts in charging behavior to reduce peak demand. Retail EV charging rates, whether for residential or commercial customers, could be more reflective of the cost of energy generation, delivery, GHG emissions, and any other relevant value streams through use of more granular time- and location-specific price signals. Widespread implementation of such rates would require optionality, with both simple, existing TOU and more complex, dynamic rates being made available to customers.

  More dynamic rates create the opportunity for more dynamic responses in charging load, increasing the opportunity for customers to use VGI technologies to save on their monthly electricity bills. For customers on EV-specific or whole-house TOU rates, more dynamic rate designs could be explored to ensure rates better reflect cost of supplying power at that time, reduce peak demand, incorporate GHG goals, and achieve any other identified policy goals. Critical peak pricing rates and programs can be powerful levers to change customer behavior and could be explored to further leverage VGI technologies to shift load and provide benefits to customers and other grid stakeholders. Within TOU rate design, the differential between on-peak and off-peak rates can be selected optimally to maximize the customer and grid-related benefits from off-peak charging.

- Consider price signals to incentivize behind-the-meter discharging. Under California's current net energy metering (NEM) tariff options, customers with stationary energy storage paired with less than 1 MW of solar generation are incentivized to offset on-site load by exporting power to the grid. These customers, known as Customer-Generators, are compensated with a monthly bill credit equal to the full retail rate of electricity for every kWh exported to the grid. If the amount exported exceeds on-site consumption on an annual basis, the customer is compensated at a lower rate. The current iteration of NEM requires that customers be on TOU rates, which means the TOU bill management value stream can currently be captured by stationary energy storage paired with solar PV. If V2G systems were eligible as Customer-Generators, then customers with on-site solar and EVs (not on separate meters) would be able to capture the TOU bill management value stream to a much larger extent than they can now when only V1G resources have an achievable monetization pathway.

For V2G systems that are not paired with solar, compensation for exporting power could come through California's Self Generation Incentive Program, a $/kWh rebate intended to encourage GHG reductions, peak demand reductions, and DER market development. Another action that could alleviate this barrier would be to implement a new, separate incentive or retail price signal specific to VGI resources in order to leverage bi-directional functionality.

Demand Charge Management

Commercial customers are typically subject to demand charges, a $/kW charge that's included alongside the $/kWh volumetric bill component. In California, demand charges are applied to a customer's demand, which is based on the maximum average amount of energy used in a 15-minute interval in a month. Stationary energy storage has been shown to help commercial customers limit their peak demand up to 25 percent and reduce their monthly electricity bills (Gagnon et al 2017). VGI resources can also capture the demand charge management value stream: V1G solutions can shift charging load away from peak periods and bi-directional solutions can further reduce demand charges by discharging the EV to meet on-site peak loads.

The demand charge management value stream is of great importance to commercial EVSE site hosts subject to demand charges, such as companies or transit authorities charging fleets of EV buses, shuttles, or delivery vehicles or premises hosting "destination chargers," such as workplaces, shopping centers, or community centers. This section will focus on this set of EVSE site hosts. However, it should be noted that public direct current fast charging (DCFC) EVSE site hosts face their own unique set of challenges in managing demand charges. The demand charge management value stream becomes much more complex for DCFC site hosts, as charging is unpredictable and simultaneous at times resulting in higher likelihood of an increased contribution to peak demand. Additionally, the DCFC business model aims to provide reliable charging services to customers, and customer expectations may make it difficult for VGI strategies may to be viable.

One-way EVSE site hosts leverage V1G technologies to mitigate demand charges for their site load is by purchasing fleet management services from EVSPs. Transit authorities and delivery fleets, for example, may wish to co-optimize vehicle charging for demand charge reduction and the unique needs of the organization using an EVSP's managed charging software, services, and tools.

While the three California IOUs all offer commercial rates across various load sizes and rate structures (including demand and energy charge components), only PG&E and SCE currently have EV-specific rates for C&I customers that begin to address this peak demand challenge.

Pacific Gas & Electric (PG&E) Demand Charges

The PG&E Commercial Electric Vehicle (CEV) rates, approved by the CPUC in October 2019, are constructed around a unique subscription charge model. The majority of the site host's EVSE bill will be comprised of peak, off-peak, or super off-peak volumetric energy charges. However, each site host will also purchase blocks of power to meet their estimated peak demand each month, shown below in Table A-4.

Table A-4: Estimated Peak Demand of Site Hosts

Rate	CEV-S	CEV-L-S	CEV-L-P
Subscription Charge per Kilowatt (KW) of Peak Demand	\$21.17/10 kW block	\$167.75/50 kW block	\$153.41/50 kW block
Peak Energy Charge	\$0.32166/kWh	\$0.33410/kWh	\$0.32611/kWh
Off-Peak Energy Charge	\$0.12966/kWh	\$0.12086/kWh	\$0.11723/kWh
Super Off-Peak Energy Charge	\$0.10299/kWh	\$0.09760/kWh	\$0.09457/kWh

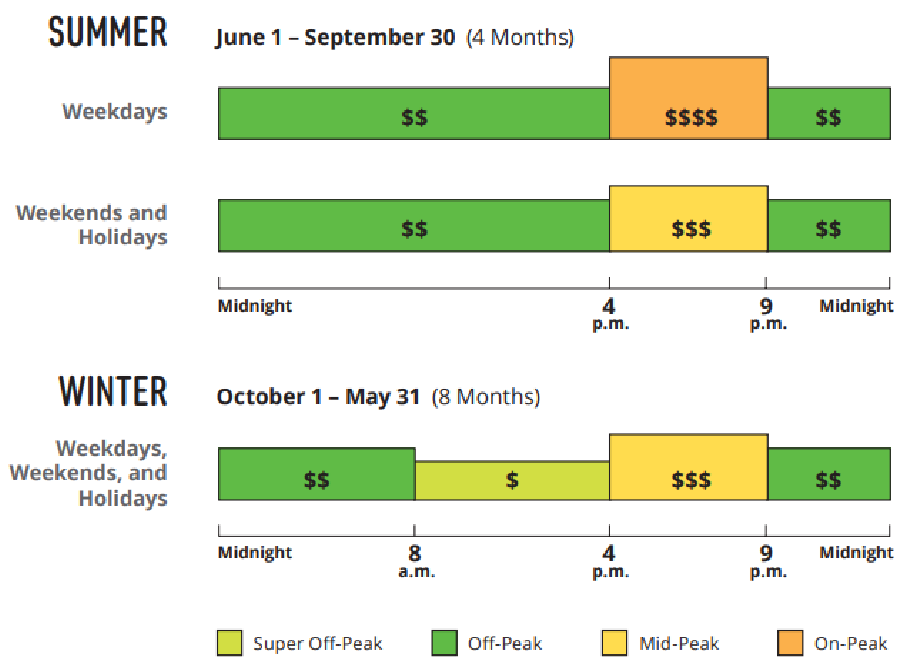
Source: PG&E, 2019

For customers with peak demands of 100 kW and less, blocks of 10 kW each are available for purchase at a rate of \$21.17 per block. The CEV peak period is 4 p.m. – 9 p.m. and super off-peak is 2 a.m. – 9 a.m. This rate requires the EV to be on a separate meter, which may already be the case for some EVSE site hosts, such as publicly-accessible sites. As discussed in the Time-of-Use Bill Management section, installation costs for a separately-metered EVSE depend on the exact configuration and layout of the site, which vary from site to site. Some EVSE site hosts may be more impacted than others by the requirement to separately meter EVSE depending on exact project economics. This reality of EVSE project development can limit the enrollment in an EV-only commercial rate such as PG&E's CEV subscription rate. However, commercial customers unable to enroll in the CEV rates as a result of the separate-meter requirement may still leverage VGI strategies to capture the demand charge reduction value stream as it relates to their whole-premise demand rate.

Southern California Edison (SCE)

The SCE C&I EV rates are listed as TOU-EV-7, TOU-EV-8, and TOU-EV-9, and are meant to service small (<20kW), medium (20-500kW), and large (>500kW) customers, respectively (Southern California Edison, 2019). While the previous versions (TOU-EV-3, TOU-EV-4, and TOU-EV-6) included demand charges, the current rates only include time-of-use energy charges. The elimination of demand charges is set to last until 2024, at which point demand charges will be re-introduced incrementally. The period of times without demand charges is known as a demand charge holiday, as shown in the Summer section in Figure A-4.

Figure A-4: SCE Time-of-Use EV Rate Structure



Holidays are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas. When any holiday falls on a Sunday, the following Monday will be recognized as a holiday. However, no change will be made for holidays falling on a Saturday.

Source: SCE, 2019

Like the PG&E CEV rates, these SCE rates all require the EVSE to be on a separate meter from the rest of the site host load. For qualifying C&I customers with EVSE on a separate meter, the demand charge reduction value stream is not achievable as the rates eliminate demand charges altogether.

Market Development Recommendations

The Demand Charge Management value stream is also accessible and monetizable for VGI technology. However, challenges still remain and are similar to those seen for TOU Bill Management.

Encourage dynamic rate design. Similar to TOU Bill Management, offering optional, more dynamic rate structures, such as average daily demand, can help ensure commercial EVSE site hosts are continually incentivized to manage charging. This alternative would base monthly billing demand on the average of the peak intervals for each day within the month, rather than the single maximum highest 15-minute period. This price signal could better reward customers who monitor and adjust their EV charging load on a daily basis. This contrasts with a traditional demand charge, where there is little incentive to manage charging for the remainder of the month once a peak demand threshold is reached.

For commercial customers on EV-specific or whole-premise TOU rates, more dynamic rate designs could be explored to ensure rates better reflect cost of supplying power at that time, reduce peak demand, incorporate GHG goals, and achieve any other identified policy goals. Critical peak pricing rates and programs can be powerful levers to change customer behavior and could be explored to further leverage VGI technologies to shift load and provide benefits to customers and other grid stakeholders. Within TOU rate design, the differential between on-peak and off-peak rates can be selected optimally to maximize the customer and grid-related benefits from off-peak charging.

Streamline interconnection for V2G-DC Systems. Bi-directional EV and EVSEs systems can also provide demand charge management on a standard commercial rate by discharging power to meet on-site peaks, thereby reducing the observed peak for the entire site. However, this requires interconnection, which is a possible, but lengthy process available to V2G-DC systems. Use of V2G technologies to capture this value stream will require further refinement as V2G technology scales across California.

Consider the full costs of separately metered EV-rates on EV Operators / EVSE Site Hosts. The demand charge management value stream is currently practical for V1G EVs and EVSEs on standard commercial rates, with no metering requirements. However, if a site host has access to a separately-metered, EV-only rate there is a need to evaluate the tradeoffs and value between the EV-only rate and a standard commercial rate with demand charges. Although the new commercial EV rates eliminate demand charges (either through a subscription structure or a demand charge holiday), the required metering entails additional installation costs and also limits the customers' ability to leverage their EVs to stack other value streams that require connection to site load, such as demand response or bi-directional discharge to meet site load.

Increased PV Self-Consumption

EVSE Site Hosts with on-site solar photovoltaic (PV) generation behind-the-meter can leverage managed charging solutions to increase the amount of self-generation that is consumed on-site. For example, a customer's rooftop PV panels generate electricity at effectively zero marginal cost, and an EVSE Site Host may implement a VGI solution to ensure that EV charging adds to on-site load when solar PV generation is at its peak. Office buildings, college campuses, and residential customers may be particularly interested in capturing this value stream, as EV driving patterns for these customers often lead to EVs being parked during times of high solar generation.

A benefit associated with this value stream but not directly captured by EVSE Site Hosts is the potential to lower overgeneration in regions with high penetration of solar PV. Peak solar PV production hours may result in higher output (supply) than is required by the grid (demand), resulting in a problem of overgeneration. In addition, the quick ramp down in solar generation as the sun sets necessitates an equally as quick ramp up of other resources to meet demand in the evening hours. As more solar PV is deployed, the rate of the ramp increases, meaning grid operators require greater flexibility to respond to ramps and adjust production to meet sharp changes in net demand. Leveraging EV and EVSE with bi-directional capabilities to discharge during ramps can further benefit the grid during these ramp times by exporting power.

Net Energy Metering (NEM) Compensation

Another pathway for EVSE Site Hosts with on-site PV to capture value is through net energy metering (NEM) tariff options. NEM compensates commercial and residential customers with solar PV (less than 1 MW) for kWh generated on-site that offsets on-site kWh consumption. The NEM bill credit for on-site generation that offsets site load is equal to the full retail electricity rate. NEM customer offsets are assessed annually and any NEM exports that exceed annual site load are compensated at a lower wholesale rate. This lower rate is called the net surplus compensation (NSC) rate and tends to be about $0.02-$0.04 per kWh. Assuming a PV customer generates more than they consume on-site, the opportunity cost of not increasing self-consumption is therefore relatively high, equal to the difference between the retail and NSC rates. NEM customers with EVs on the same meter as the on-site generation and load can use V1G technologies to increase self-consumption to capture the full retail rate rather than ending up with positive net exports that get compensated according to the NSC rate.

The current NEM tariff options require customers to be on TOU rates, which means the credit for on-site consumption from solar PV will be higher during peak hours than during off-peak hours. For savvy EV operators and EVSE site hosts, or those leveraging EVSPs, the high opportunity cost creates an incentive to shift on-site EV charging load to periods of peak on-site solar production rather than end up with an annual net surplus. Depending on utility service territory and peak TOU periods, the mid-late afternoon could provide both high solar output and high on-peak bill credits, which enhances the value proposition for V1G strategies to increase self-consumption.

Leveraging V2G-capable EVs under a NEM set-up is more challenging due to the need to prove all energy used by the vehicles charge or discharged comes from the on-site, solar installation.37 This is possible if the EVs only charge at one location, like in a fleet application and if there is an adequate accounting process in place to track generation and consumption. There are still additional discussions that need to be had at the CPUC and elsewhere to formalize this nuance. Therefore, this value stream can only be captured by V1G resources because of NEM eligibility and because the value stream is built upon increasing positive load, rather than the V2G capability to discharge power. For a V1G resource, NEM compensation provides a monetizable pathway for capturing the increased PV self-consumption value stream.

Non-NEM Increased Self-Consumption

In the NEM case, the opportunity cost of not consuming a kWh generated by on-site solar is equal to the difference between the retail rate and the NSC. By comparison, customers with on-site solar but not on a NEM tariff could benefit even more from self-consumption because the opportunity cost is equal to the full retail rate since any generation in excess of site load would not be compensated.

In the case where on-site generation is not "oversized" (that is when solar output does not exceed site load), increasing PV self-consumption by using VGI technologies could also help lower EV charging costs. This depends on the exact configuration of a customer's system, however charging EVs directly from solar PV could offer an alternative to paying for EV charging from the grid. PV self-consumption can also have a GHG reduction benefit as well. By shifting charging load to capture midday on-site solar generation, an EV customer is potentially shifting load away from fossil fuel electricity generators. The GHG reduction can be monetized by claiming renewable energy credits (RECs) for the on-site solar generation and pairing them with Low Carbon Fuel Standard (LCFS) credits generated from the EV charging. The pairing makes the LCFS credits have zero carbon intensity ("zero-CI") and therefore increases the LCFS credit value.

[37] Definition of customer-generator in RPS Eligibility Guidebook, published April 27, 2017 states, "storage may be considered if…[it] is capable of storing only energy produced by the facility." Source: https://efiling.energy.ca.gov/getdocument.aspx?tn=217317

Market Development Recommendations

The increased PV self-consumption value stream can be captured through both accessible and monetizable pathways, although there are potential market development actions that could be taken to strengthen the economics of this value stream.

Implement "reverse energy efficiency"-style rebates that incentivize consumption during the midday hours of peak solar output. Such a policy can also be used to integrate renewables more generally (that is, not just self-generation), as incentives can be crafted to further shift charging towards times of peak solar supply.

Expand NEM customer-generator eligibility to include and address bi-directional EVs. Expanding eligibility could ensure V2G resources are compensated for exporting power to the grid. However, as noted previously, it is critical to address, track and potentially audit the source of charging and discharging energy to ensure the spirit of NEM is maintained. Overall, NEM tariff options or any successor DER compensation mechanisms can be thoughtfully enhanced to enable VGI, specifically focusing on leveling the playing field for DERs, as solar-paired stationary energy storage is currently eligible for NEM if it meets relevant conditions.

Backup Power and Resiliency

While commonly referred to as V2G, bi-directional applications can also provide power to entities other than "the grid." Vehicle-to-building (V2B) applications can allow site hosts to use bi-directional EV and EVSE systems to provide backup power to all or some on-site load. This value stream may be particularly useful for California customers considered vulnerable to planned power shutoffs, unplanned outages, or other emergencies. For example, a residential customer could charge their EV before a power shutoff and then use bi-directional equipment to power critical loads in their home. Another important example could be an electric school bus helping provide backup power to community or evacuation centers and other priority sites during an extreme weather event or other emergency in which the vehicle's primary transportation purpose may not be needed. An EV's inherent mobility is a key characteristic that demonstrates their value as emergency backup power supply compared to other backup power resources.

This value stream presents an entirely new category of value for customers. Currently, customers seek backup power from diesel generators or stationary energy storage systems. EVs are multi-use assets, and the ability to capture several value streams and stack benefits is advantageous for customers from an economics customer perspective when compared to dedicated backup power resources.

The backup power values stream is not necessarily expected to have a monetization pathway, as backup power is service that is difficult to quantify and compensate. Since bi-directional EVSE can interconnect under Rule 21, there is an accessible pathway to capture the backup power value stream. However, the interconnection process is not streamlined, a concept detailed in the and Demand Charge Management sections of this Chapter. Therefore, the Backup Power and Resiliency value stream is impractical from a customer perspective and not monetizable at the time of writing. However, this can quickly change in mid-2021 when residential V2G EVSEs become commercially available.

Market Development Recommendations

Allocate Funding for Resiliency Projects. Currently, the backup power use case is permitted if the EVSE is certified under the relevant standards and the system is compliant with Rule 21 for interconnection. However, providing public funding for projects could support such applications and serve as a "proof of concept" in a priority area of public policy focus (see SB 1339, Stern 2018).

Grant funding for specific projects could also be used for V2G applications where "the grid" is a microgrid or mini-grid that is islanded from the larger grid. For example, EV school buses could provide capacity and other services to microgrids when the microgrid is islanded. EV-powered microgrids could be tested at community centers in vulnerable communities to mitigate the adversity and hardship many communities face during the California wildfire season.

Streamline Bi-directional VGI Interconnection Pathways. The high probability of more public safety power shutoffs (PSPS) and other emergency events requiring backup power in the future adds a level of urgency to streamlining the interconnection process for V2G-DC systems and opening an interconnection pathway for V2G-AC systems.

There may also be a separate pathway to capture this value stream that does not require interconnection of the V2G system under Rule 21. For example, commercially available meter socket switches could be installed by utilities to enable the utilities to intentionally island customers before a PSPS so that they can use backup power devices to power their building (California Energy Storage Alliance 2020). This opportunity is currently being explored under the CPUC's Micro-grid proceeding 19-09-009.

Overall, the lengthy interconnection pathway for V2G-DC systems represents a barrier not only to Backup Power and Resiliency, but to realizing the full potential to almost all value streams discussed in this report. Table A-5 provides a high-level summary of the four value streams examined in section A-3 and whether they are accessible and also monetizable. Section A-4 will conduct a similar analysis for the VGI value streams utilities can capture.

Table A-5: EV Operator / EVSE Site Host Value Streams Market Development Summary

Value Stream	Accessible	Monetizable	Potential Action Topics
TOU Bill Management	✓	✓	Rate Design Interconnection
Demand Charge Management	✓	✓	Rate Design Interconnection
Increased PV Self-Consumption	✓	✓	Rate Design Interconnection
Backup Power & Resiliency	✓	✘	Interconnection Resiliency Funding

Source: California ISO, 2019

A-4: Utility Value Streams

This section will review the three categories of Utility Value Streams identified in Figure 1 and identify market development recommendations for each. Utilities can capture value streams from distributed DERs by aggregating them into a portfolio of resources used to meet bulk power sector needs. A DER aggregation may consist of multiple of the same resource type or a portfolio of different types of resources, therefore, widespread deployment and aggregation of DERs will require innovative approaches to market design as well as new tools and software to harness the capabilities of the collective resources. Several VGI applications in this Utility Value Streams chapter and the following Grid Operator Value Streams chapter may be inapplicable to individual VGI resources and require aggregation due to the small capacity (kW) of individual resources.

Transmission and Distribution Deferral

Transmission and Distribution (T&D) upgrades need to occur when electricity transmission lines, substations, and other equipment lack the bandwidth to handle peak demand and ensure reliability. These T&D upgrades are expensive to develop and require a time-intensive, multi-year planning and permitting process. Alternatively, VGI technology could provide the necessary bandwidth to handle peak demand and can be deployed as an alternative to investing in new infrastructure such as feeder lines and substations. Leveraging VGI technology over direct T&D upgrades is referred to as T&D upgrade deferral and may represent a more efficient deployment of capital to meet evolving grid needs.

Competitive procurements for alternatives to traditional infrastructure solutions are issued to allow DERs to capture this value stream. Although not technically prohibited from bidding in these procurements, DERs are at a disadvantage given the short time period over which these procurements occur (<one year). For DER aggregators, including EVSPs, this means this value stream is accessible but not monetizable.

The evaluation of opportunities for DERs to defer or avoid traditional distribution infrastructure projects is done under the Distribution Investment Deferral Framework (DIDF), which is informed by load forecasts. If EV charging load is not included in these forecasts than the ability to defer a T&D investment through leverage VGI technology to shave local peak charging load will not be valued. V2G, however, may be able to provide distribution deferral even if the EV load is not adequately accounted for in the load forecast, however the barriers related to interconnection pathways for bi-directional EV and EVSE systems remain key challenges.

TOU rates and utility programs can be designed to shift load away from peak times, which may reduce transmission congestion and defer the need for T&D investment. These rates are not location-specific and therefore are unlikely to contribute meaningfully to opportunities for T&D deferral. Location-specific rates could be a lever to indirectly defer T&D upgrades, but previous efforts to conduct the locational net-benefit analyses required to design such rates have proven unsuccessful.

Resource Adequacy

Resource Adequacy (RA) is the procurement process undertaken by utilities to ensure sufficient generation capacity is contracted to meet peak demand. The RA framework was instituted in 2004 to guarantee the reliable operation of California’s electric grid. The RA program evaluates the systemwide, local, and flexible capacity needs and directs CPUC-jurisdictional LSEs to procure enough capacity to match their requirements. Several types of capacity can be procured to meet RA requirements; demand response (DR) is one of them. Demand response programs offer an incentive to customers to reduce their consumption during certain peak pricing hours or reliability events. DR programs work by notifying customers to reduce consumption during an event.

VGI solutions may be able to meet LSEs' RA requirements, and utilities are looking for zero-carbon RA contracts as gas peaker plants around the state get shuttered to support the state's 100 percent carbon-free electricity goals. V1G strategies, when implemented through aggregations of EVs, could provide RA through a contract with a utility to reduce charging load, especially during peak times. V2G technologies can also provide RA by exporting power to the grid to provide capacity.

Supply-Side Demand Response

The Demand Response Auction Mechanism (DRAM) and the Capacity Bidding Program (CBP) are examples of DR programs that procure supply-side DR as RA resources and allow third-party aggregators to bid into the wholesale market, subject to contractual testing, dispatch, and performance requirements. DRAM is open to DER aggregations, including VGI resources, therefore the RA value stream can is accessible and monetizable.

While DRAM is a monetizable value stream, certain enhancements could be made, as the current iteration of the program presents some challenges for market participants. As of 2019, the DRAM program employs different baselines to assess the overall impact on load provided by DR resources. In general terms, baselines provide a counterfactual level of load representative of the electrical consumption that would have been perceived by grid operators had a DR resource not been dispatched. Thus, the use of baselines provides information essential to properly value and settle the load modification provided by DRAM-participating resources. Following approval by FERC, the CPUC has adopted four baselining methodologies for DRAM resources: (1) day-matching customer load 10-in-10 baseline with a day-of adjustment cap of +/-20 percent to account for temperature differences between the event and historical data; (2) weather-matching baseline with a 40 percent cap; (3) baselining by the use of control groups; and, (4) a 5-in-10 day baseline (Aceves 2019).

Baseline usage is challenging to determine with high levels of accuracy due to inherent volatility of load. The 10-in-10 baselining methodology is the simplest of the four options, although is still a troublesome methodology for fairly evaluating VGI resources. The unique load patterns and metering configurations of EVSE necessitate a well-designed framework to assess the "business as usual" or counterfactual load. As detailed in the Time-of-Use Bill Management and Demand Charge Management sections, several EV rates require separate metering, which can make finding a true baseline used to fundamentally value and compensate the VGI resource for DR events incredibly challenging. This represents a significant barrier for VGI market development as a whole, as it restricts the stacking of several economically-appealing value streams spanning all stakeholders. For example, TOU bill management, RA through DRAM, and grid operator value streams through the Proxy Demand Resource (PDR) model can all be improved by enhancements to baselining and/or alternatives to separate metering requirements.

VGI-Specific Utility Demand Response

Utility DR programs can provide another monetization pathway for VGI solutions that can respond to a DR event signal to reduce load. The PG&E BMW i ChargeForward Pilot (Kaluza 2017), SCE Workplace Charging Pilot (SCE 2016), and SCE Smart Charging Pilot (SCE 2016) are past utility pilots that tested DR for EVs, offering economic incentives and price signals for customers.

However, utility DR programs designed for VGI are limited to these three pilot programs, and the lack of variety and scale in available VGI DR programs represents a major gap for this value stream. While utility DR programs may be accessible for VGI market participants, they are not at the scale required to make them practical for market participants to build business models around. A more robust portfolio of RA-focused VGI programs could include utilities procuring VGI resources to meet their RA requirements through utility DR programs.

Valuing V2G Capacity for Resource Adequacy

V2G resources capable of supplying RA, whether through supply-side DR, utility DR, or another RA procurement framework, could be enabled by streamlined or open interconnection processes. Wholesale market participation for V2G resources is explored in further detail in the Grid Operator Monetization Pathways chapter.

In summary, the RA value stream for VGI resources can be captured through the accessible and monetizable DRAM value stream, although market opportunities for this pathway could be enhanced through changes to baselining methodologies. Additionally, utility DR programs would need to be expanded at scale to provide a monetizable pathway. This expansion could include scaling up existing DR programs or implementing new DR programs at a larger scale.

Distribution Voltage Support

Traditionally, utilities regulate distribution system voltage through load tap changers, line regulators, and capacitors. As DER penetration increases and more power is exported to the distribution grid, the need for voltage support increases. New "smart inverter" capabilities offer methods for managing the impact of these DERs, and the IEEE 1547 standard sets specific requirements for smart inverters. IEEE 1547 outlines "modes" to support voltage regulation by quickly controlling a representative component of electrical current known as reactive power.

DERs interconnecting under California's Rule 21 process will follow the IEEE 1547 standard and be technically capable of supporting voltage regulation through the IEEE 1547 modes. Bi-directional EVSE, or V2G-DC systems, can interconnect under Rule 21, making these systems well suited to support voltage needs on the distribution grid. While the technical capabilities for this value stream will be in place for all Rule 21 compliant inverters, there is currently no monetization pathway corresponding to the value stream. Voltage control can improve the lifetime of electrical equipment and even reduce load and consumption, saving utility customers money. However, there is no mechanism for DERs to be compensated for this essential grid service. Widespread deployment of these new smart inverter capabilities within DERs also raise many questions around exactly how these smart inverters should be used and coordinated, a topic requiring further discussion within the relevant policy forums. This is a particularly critical topic for electric vehicles given their potential to be dual usage as both a transportation asset and DER.

Given the implementation of smart inverter standards throughout California and several other jurisdictions, the technical capabilities for EVs to provide grid services in response to signals from a managing entity, or to adjust automatically in response to the real-time physics of the grid, are expected to proliferate at the grid edge. This will provide ample opportunity for EVs to provide valuable grid support at scale. The growing EV stock and widespread implementation of new, standardized smart inverter capabilities creates a pressing need for new policies and regulatory structures that adequately leverage EVs as DERs. While distribution planning processes and technological capabilities may need to advance before the value stream of automated grid services can become available to market participants, a key barrier which should first be alleviated is related to the interconnection of EVs under these new standards. This topic will be explored further in the INVENT Regulatory Barriers Report.

Table A-6 summarizes this chapter's conclusions regarding the three Utility value streams covered.

Table A-6: Utility Value Streams Market Development Summary

Value Stream	Accessible	Monetizable	Potential Action Topics
T&D Deferral	✓	✗	Distribution Investment Deferral Framework Rate Design
Resource Adequacy	✓	✓	Supply-Side Demand Response Utility Demand Response Programs
Voltage Support	✗	✗	Interconnection Distribution Planning

Source: California ISO, 2019

A-5: Grid Operator Value Streams

The VGI value streams that exist at the wholesale market level generally mimic grid services identified in the original RMI wheel for stationary energy storage. Energy arbitrage, spin / non-spin reserves, frequency regulation, and transmission voltage support are all value streams that could be made available to VGI solutions. Grid Operator value streams are most applicable to aggregations of EV and EVSE systems that behave like systems large enough to participate under a grid operator's market rules, specifically minimum capacity (kW) thresholds.

Resource Classifications and Aggregations

EVs and EV aggregations can currently participate in the California ISO Proxy Demand Resource (PDR) load curtailment products for energy, spin, and non-spin value streams at a facility/utility line of service aggregation level. The Reliability Demand Response Resource (RDRR) is also an available participation mechanism, but this classification cannot submit ancillary services bids.

California ISO rules also allow EVs to be aggregated as Non-Generator Resources (NGR) through a DER Provider (DERP). The DERP-NGR framework allows for the provision of all

California ISO market products, allowing DERs to capture the energy arbitrage, spin/non-spin reserves, and frequency regulation value streams. The DERP-NGR framework allows bi-directional EVs to export power, enabling V2G solutions. Table A-7 shows a summary of which value streams DERs can access through the three different California ISO resource classifications.

Table A-7: Summary of Currently Available California ISO Resource Classifications for DERs

Grid Operator Value Stream	Distributed Energy Resource Provider: Non-Generator Resource (DERP-NGR)	Proxy Demand Resource (PDR)	Reliability Demand Response Resource (RDRR)
Energy	✓	✓	✓
Spinning Reserve	✓	✓	✗
Non-Spinning Reserve	✓	✓	✗
Frequency Regulation	✓	✗	✗
Voltage Support	N/A	N/A	N/A

Source: California ISO, 2020

At the national level, FERC Order 841 reduced the minimum size requirement for electric storage in ISO/RTO wholesale markets from 0.5 MW to 0.1 MW (Federal Energy Regulatory Commission 2018). California ISO, in its filing for compliance with Order 841, stated that "The California ISO also offers distributed resources—including storage resources—the ability to aggregate into a single virtual resource to meet the California ISO's minimum capacity requirements. The California ISO tariff refers to these as Distributed Energy Resource Aggregations. These aggregations can participate in the California ISO markets as NGRs." (California Independent System Operator 2018). DERs and aggregations of only 0.1 MW (100 kW) in size can participate under NGR classification or as a PDR. However, PDR resources or aggregations between 0.1 MW and 0.5 MW can only bid energy and cannot participate in ancillary services market products.

Capturing Value Streams Through Demand Response

Reliability Demand Response Resource (RDRR)

RDRR may not submit ancillary services bids and are only called in reliability scenarios. RDRR participation is contracted through utilities for load that would only rarely respond to demand response calls. This "merchant" DR participation only yields an energy payment for avoided load, which is a very small payment compared to other market access opportunities. This likely does not result in net profit, as a resource will likely consume that load later and pay the energy price at that time. Ultimately, it is not financially attractive for DER operators to participate via the RDRR pathway because it does not allow access to other market products and is low in value. Therefore, although RDRR is accessible, it is not a practical monetization pathway to be leveraged in a business case.

Proxy Demand Resource (PDR)

A resource capable of providing demand response can participate more fully in California ISO markets via the PDR framework, through DRAM and other contracting mechanisms. A resource can either participate directly in the wholesale energy market and receive energy payments, or it can participate via a RA capacity contract with a utility (like DRAM) which includes both payment for performance in the energy market as well as an additional capacity payment. Therefore, the PDR model offers both accessible and monetizable value streams for energy and spin/non-spin (if aggregation is larger than 0.5 MW).

However, enhancements to PDR could be made to increase the opportunity to capture these value streams. As detailed in the Supply Side Demand Response section in Chapter 4, the 10-in-10 baselining method combined with EV rate metering requirements present significant challenges for VGI market participants. Additionally, the PDR model is not meant for bi-directional power flows, and, therefore, does not allow power to be exported beyond the customer meter, effectively closing the opportunity to fully capture the value streams across all accessible California ISO products under PDR.

Given the limitations of the RDRR and PDR mechanisms, the market for demand response is bifurcating in California between load-modifying programs (utility-run) and supply-side mechanisms (California ISO integration). While DRAM tests third-party aggregation of DR services, the IOUs are also acting as the aggregator and scheduling coordinator for their own supply-side DR programs, such as those discussed in the VGI-Specific Utility Demand Response section.

Load-modifying programs such as DRAM will continue to exist to support very localized issues, such as emergency demand response for distribution-level contingencies. Ultimately, the demand response market seems to be shifting toward "supply-side" demand response as the dominant model for demand response service. As this shift continues, a major gap will persist as VGI solutions remain subject to conflicting TOU-rate metering requirements and DR baselining requirements.

Bidirectional Participation in Wholesale Market

Under the California ISO NGR classification, resources can participate in all markets that they are physically capable of providing market products for. As NGRs can be treated as any other wholesale market resource, NGRs submit charge and discharge bids at wholesale Locational Marginal Price (LMP) and can set the price at the LMP. The NGR classification could be a model for an aggregated fleet of EVs under the DERP-NGR framework, as it affords access to all of the wholesale market services and the energy arbitrage, frequency response, spin/non-spin value streams. However, several barriers exist that prevent VGI solutions from capturing grid operator value streams using NGR.

There exists a requirement that NGR resources be available for market participation 24 hours per day, an onerous requirement for a multi-use DER like EVs that are needed for transportation. Additionally, as distribution-level resources, DERs applying for DERP-NGR participation will go through the utility/distribution level interconnection request (for example, SCE Wholesale Distribution Access Tariff (WDAT)), study, and agreement process (unless interconnecting at high voltage) to become assets on the grid.

Overall, the DERP-NGR framework is unpopular among market participants because of the complexities of coordinating transmission and distribution dispatch, charging costs, and interconnection of resource aggregations that export beyond the meter. Additionally, the administrative burden associated with achieving and maintaining a DERP Agreement (DERPA) is prohibitively high for many aggregators, as evidenced by the small list of DERPA holders. Given the multiple and complicated barriers currently in place for the DERP-NGR model, it offers an accessible, but not monetizable pathway to access any grid operator value stream.

Energy Arbitrage

Using the price of energy throughout the day, VGI resources can perform energy arbitrage: buying energy when the price is low and selling it when the price is high. For VGI resources, only a V2G-capable EV and EVSE system could fully capture this value stream. At its core, energy arbitrage is a straight-forward strategy for participating on the wholesale market. In California, there are no signals from California ISO that the resource must respond to or any penalties for incorrectly dispatching to grid. This opportunity is currently the most promising option for immediate participation on the wholesale market.

Figure A-5 shows the day-ahead pricing heatmap for a single node in California, color-graded with red cells indicating low prices, and green cells indicating high prices.

Figure A-5: Sample Day-Ahead Pricing Nodal Heatmap

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
0	$ 33	$ 27	$ 23	$ 23	$ 30	$ 32	$ 37	$ 38	$ 34	$ 33	$ 29	$ 35	
1	$ 30	$ 24	$ 17	$ 19	$ 27	$ 29	$ 34	$ 34	$ 31	$ 31	$ 25	$ 32	
2	$ 29	$ 22	$ 14	$ 16	$ 25	$ 25	$ 31	$ 32	$ 30	$ 29	$ 24	$ 31	
3	$ 28	$ 20	$ 12	$ 13	$ 23	$ 23	$ 30	$ 31	$ 29	$ 28	$ 23	$ 30	
4	$ 28	$ 20	$ 13	$ 13	$ 23	$ 24	$ 29	$ 30	$ 29	$ 28	$ 23	$ 29	
5	$ 29	$ 24	$ 18	$ 19	$ 26	$ 25	$ 28	$ 30	$ 30	$ 29	$ 25	$ 31	
6	$ 34	$ 30	$ 30	$ 31	$ 33	$ 29	$ 30	$ 32	$ 33	$ 33	$ 30	$ 35	
7	$ 41	$ 39	$ 40	$ 43	$ 38	$ 30	$ 31	$ 35	$ 35	$ 39	$ 36	$ 42	
8	$ 46	$ 40	$ 40	$ 35	$ 29	$ 24	$ 29	$ 33	$ 35	$ 42	$ 35	$ 44	
9	$ 38	$ 28	$ 22	$ 19	$ 19	$ 19	$ 25	$ 30	$ 31	$ 33	$ 28	$ 37	
10	$ 33	$ 24	$ 9	$ 12	$ 17	$ 19	$ 26	$ 29	$ 30	$ 28	$ 26	$ 33	
11	$ 31	$ 21	$ 6	$ 9	$ 15	$ 20	$ 28	$ 31	$ 30	$ 27	$ 25	$ 31	
12	$ 28	$ 20	$ 4	$ 7	$ 15	$ 23	$ 31	$ 32	$ 31	$ 28	$ 25	$ 30	
13	$ 26	$ 18	$ 4	$ 5	$ 15	$ 24	$ 33	$ 33	$ 32	$ 29	$ 24	$ 27	
14	$ 26	$ 18	$ 5	$ 5	$ 17	$ 27	$ 36	$ 35	$ 33	$ 29	$ 24	$ 28	
15	$ 28	$ 18	$ 6	$ 7	$ 20	$ 29	$ 38	$ 39	$ 35	$ 30	$ 24	$ 30	
16	$ 33	$ 22	$ 8	$ 8	$ 22	$ 32	$ 42	$ 44	$ 37	$ 32	$ 29	$ 35	
17	$ 40	$ 31	$ 15	$ 11	$ 26	$ 39	$ 45	$ 50	$ 40	$ 35	$ 39	$ 44	
18	$ 53	$ 45	$ 28	$ 19	$ 30	$ 43	$ 49	$ 57	$ 44	$ 44	$ 53	$ 57	
19	$ 53	$ 54	$ 47	$ 37	$ 46	$ 59	$ 59	$ 72	$ 52	$ 58	$ 49	$ 53	
20	$ 48	$ 46	$ 54	$ 56	$ 65	$ 80	$ 70	$ 74	$ 55	$ 57	$ 42	$ 50	
21	$ 45	$ 42	$ 44	$ 52	$ 64	$ 59	$ 53	$ 54	$ 47	$ 46	$ 39	$ 47	
22	$ 41	$ 37	$ 36	$ 41	$ 46	$ 44	$ 47	$ 45	$ 40	$ 40	$ 35	$ 42	
23	$ 37	$ 32	$ 29	$ 31	$ 35	$ 36	$ 40	$ 41	$ 37	$ 37	$ 32	$ 38	**Yearly Average**
Range	**$ 27**	**$ 36**	**$ 50**	**$ 51**	**$ 50**	**$ 61**	**$ 44**	**$ 45**	**$ 26**	**$ 30**	**$ 30**	**$ 30**	**$ 40**

This heatmap shows that day-ahead pricing follows the "duck curve", where an over-abundance of solar PV during the day drives prices down, while prices increase when demand is still significant but not supported by solar PV output (for example in the morning and evening). This means that intra-day trading is an effective means of generating revenue. Intra-day energy arbitrage suits VGI as it does not require a large energy capacity to participate in.

This intra-day arbitrage affords considerable opportunity on a $/MWh basis. For the node above, the intra-day range in price is between $26/MWh and $61/MWh, with an average range of $40/MWh.

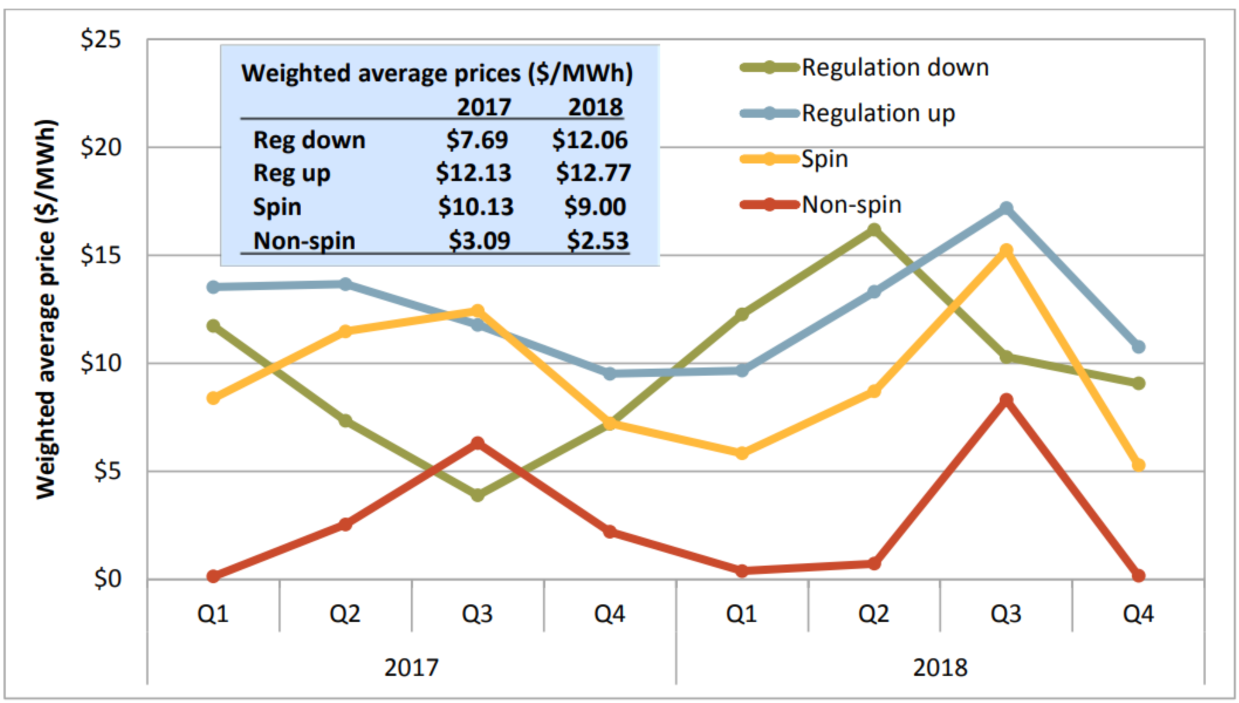
Spinning Reserves

Spinning reserves refers to the immediate capability of a resource to contribute power to the grid. Traditionally, this refers to generators that are already grid-connected, producing below rated power, and immediately ready to produce additional power. It is procured in the Day Ahead Market for each hour in a bid stack of resources and has a low likelihood of dispatch for any given hour. Resources can receive spinning reserve payments simply by being synchronized to the grid (the EVSE inverter is grid-connected and therefore synchronized to the grid). Therefore, spinning reserve is a market easily bid into by multi-use DERs like EVs and offers an accessible and monetizable value stream for VGI technology.

Non-Spinning Reserves

In contrast, non-spinning reserves allow for some delay for generating resources to synchronize to the grid before responding to a grid signal with a power dispatch. This is helpful for resources that need such synchronization time, such as generators that are not normally grid-connected. Overall, the regulation of non-spinning reserves is very similar to that of spinning reserves with the exception for an allotted time of synchronization following notification. However, it is a much less valuable resource, as shown in Figure A-6. In 2018, the weighted average price of non-spinning reserve was $2.53/MWh, compared to $9.00/MWh for spinning reserves.

Figure A-6: Weighted Average Price for Ancillary Services by Quarter, 2017-2018



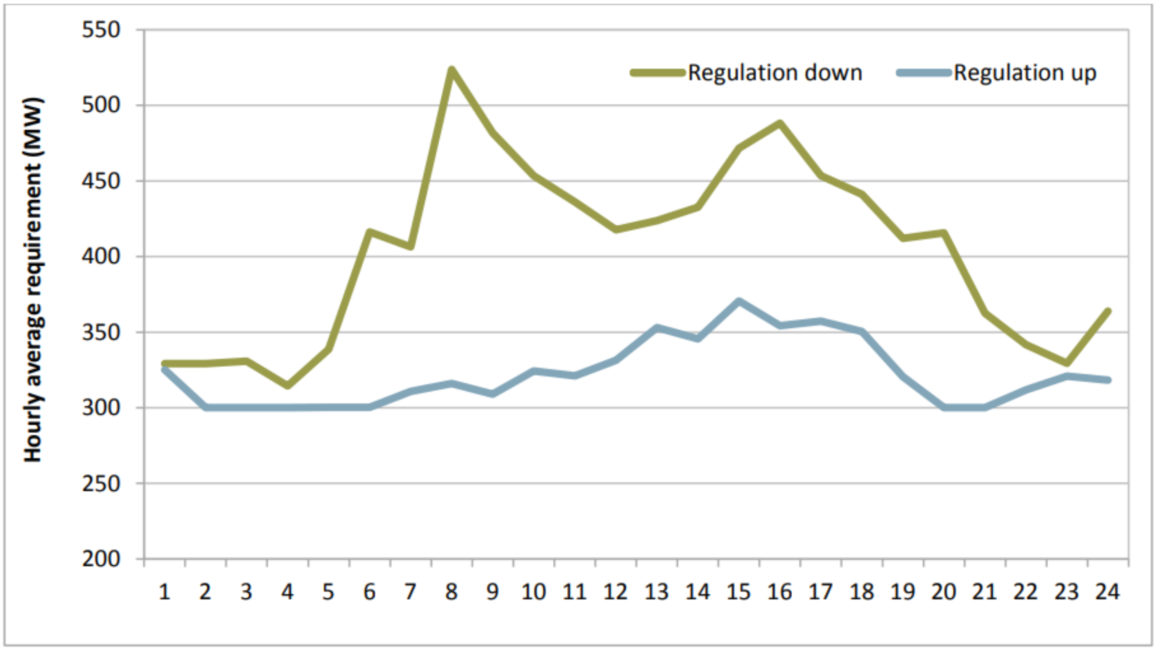
Source: California ISO 2018 Annual Report on Market Issues & Performance.

Given that grid-connected inverters are always qualified to be spinning reserves, and that non-spinning reserves are less valuable than spinning reserves, spinning reserves should a higher priority value stream than the non-spinning reserves market.

Frequency Regulation

Frequency regulation allows participating entities to respond to California ISO signals to raise or lower grid frequency (nominally 60 Hz in the U.S.) via frequency up or down signals, respectively. Frequency regulation in California is predominately regulation down, a result of solar PV ramping up in the morning and down in the evening. Figure A-7 shows this pattern, as the regulation-down requirement is consistently greater than the regulation-up and exhibits peaks in the morning and evening.

Figure A-7: Hourly-Averaged Frequency Regulation Requirements



Source: California ISO Annual Report on Market Issues & Performance, 2018

Table A-8 summarizes the grid operator value streams and whether they are accessible (that is, those available through DERP-NGR) and also monetizable (that is, those available through PDR). It also identifies potential high-level areas of market development action. The challenges with accessing and monetizing wholesale-level value streams in California will be covered in greater depth in the INVENT Regulatory Barriers report.

Table A-8: Grid Operator Value Streams Market Development Summary

Value Stream	Achievable Monetization Pathway	Practical Monetization Pathway	Potential Action Topics
Energy Arbitrage	✓	✓	PDR Enhancements
Spin / Non-Spin Reserves	✓	✓	PDR Enhancements
Frequency Regulation	✓	✗	PDR Enhancements NGR Enhancements

A-6: Societal Benefits

VGI technology can also create value streams for stakeholders beyond those discussed in this report who are not directly participating in VGI applications. For example, VGI can have environmental and health benefits, as VGI reduces the total cost of EV ownership, in turn driving EV adoption over more polluting and greenhouse gas-emitting internal combustion engine (ICE) vehicles.

VGI can also shift charging to times where electricity generation is cleanest, such as times of high solar PV output during the middle of the day, further reducing the overall greenhouse gas emissions (GHG) of the electricity generation fleet while enabling future deployment of renewables. Utility customers can benefit from improved health due to local particulate and pollution reduction, an especially strong benefit in the case of electrifying medium and heavy-duty vehicles.

Deployment of VGI solutions represents a benefit to all utility customers since EV charging can result in downward pressure on rates. VGI can accelerate EV deployment, resulting in increased kWh consumption as more drivers fuel their vehicles from the grid. The increase in kWh consumption provides a larger number of sales over which to distribute utility fixed costs. This benefit can be further bolstered by enabling VGI services that reduce the need for infrastructure and the resulting fixed costs that require recovery through retail electricity rates.

VGI solutions can also spur economic growth through job creation and the expansion of local tax bases from resulting private investment into the EV supply chain, EVSE, and related infrastructure. To the extent VGI accelerates the transition away from ICE vehicles, it also helps ensure fuel security by insulating customers from fossil fuel price and supply uncertainty.

Realizing Societal Benefits

The assessment of societal benefits remains separate from the exploration VGI value streams in the previous three chapters. Rather than one-to-one mapping of accessible and monetizable value streams, VGI's societal benefits can be realized through VGI market development more broadly. There is one specific policy that provides incentives for VGI's societal benefits but does not directly capture any one specific VGI value stream: the Low Carbon Fuel Standard (LCFS). LCFS is a cap-and-trade program for transportation fuels implemented as a result of AB 32 (Nunez 2006). Fuel producers, distributors, and suppliers are subject to the regulation, which sets an average carbon-intensity allowance for each regulated firm and creates an open market to trade credits to achieve compliance. Beginning in 2020, California's three major IOUs must pass about two-thirds of their LCFS credit revenues through to EV-owner customers through a point-of-sale rebate. The remaining credits must be used for certain priority policy goals aimed to reach under-developed corners of the EV market and return the credit through strategic investments in transportation electrification programs and infrastructure.

Each societal benefit can be realized through any policy that advances EV adoption and further uses VGI strategies. The key barriers standing in the way of faster EV adoption include total cost of ownership (TCO), a value proposition that may not be compelling enough for customers when compared to internal combustion engine (ICE) vehicles, limited strategic prioritization of EVs from automotive original equipment manufacturers (OEM), and insufficient transportation electrification infrastructure. Each of these barriers can be addressed with VGI strategies, contributing to a positive feedback loop for EV adoption.

Table A-9 connects the results of the stakeholder-by-stakeholder market development assessment.

Table A-9: VGI Market Development Assessment Summary

Stakeholder	Value Stream	Achievable Monetization Pathway	Practical Monetization Pathway	Potential Action Topics
EV Operator and EVSE Site Host	TOU Bill Management	✔	✔	Rate Design Interconnection
	Demand Charge Management	✔	✔	Rate Design Interconnection
	Increased PV Self-Consumption	✔	✔	Rate Design Interconnection
	Backup Power & Resiliency	✔	✘	Interconnection Resiliency Funding
Utility	T&D Deferral	✔	✘	Distribution Investment Deferral Framework Rate Design
	Resource Adequacy	✔	✔	Supply-Side Demand Response Utility Demand Response Programs
	Voltage Support	✘	✘	Interconnection Distribution Planning

Stakeholder	Value Stream	Achievable Monetization Pathway	Practical Monetization Pathway	Potential Action Topics
Grid Operator	Energy Arbitrage	✓	✓	PDR Enhancements
	Spin / Non-Spin Reserves	✓	✓	PDR Enhancements
	Frequency Regulation	✓	✗	PDR Enhancements NGR Enhancements
Society	Reduced GHG Emissions	VGI market development broadly leads to these societal benefit streams.		
	Reduced Electricity Rates			
	Environmental & Health Benefits			
	Economic Growth & Fuel Security			

Appendix A Glossary

Term	Definition
EPIC (Electric Program Investment Charge)	The Electric Program Investment Charge, created by the California Public Utilities Commission in December 2011, supports investments in clean energy technologies that benefit electricity ratepayers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.
Vehicle-grid integration (VGI)	How electric vehicles integrate into the grid and can possibly provide grid services
V1G	The term refers to the unidirectional flow of power enabling EVs to flexibly and intelligently charge from the grid
V2G	The term refers to the bidirectional flow of power enabling EVs to charge from the grid and to discharge back to the grid
V2B	How electric vehicles can charge from a building or discharge back to a building
Distributed Energy Resources (DER)	Distributed energy resources are smaller sources of energy (or in some cases energy storage) that are located at the distribution level of the grid instead of the transmission level or centrally located. Examples would be home solar installations or residential batteries.

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APPENDIX B: Value Stacking – Application to University of California San Diego Campus with Real-World Operation

Table B-1: Nomenclature with Technical Terms and Variables

Acronym	Description
DRAM	demand response auction mechanism
DAM	day-ahead market
DCM	demand charge management
LMP	locational marginal price
NBT	net benefit threshold
NCD	non-coincident demand
NPR	UCSD generator nameplate rating, 31,956 kW
PD	peak demand
RTM	real-time market
Variable	Definition and Units
c_{bid}	bidding price [$/MWh]
c_{energy}	flat rate for UCSD direct access energy purchases, 0.068 $/kW
$c_{\text{LMP,DAM}}$	day-ahead market locational marginal price [$/MWh]
$c_{\text{LMP,RTM}}$	real-time market locational marginal price [$/MWh]
c_{NCDC}	non-coincident demand charge [$]
c_{PDC}	peak demand charge [$]
$E_{\text{BYD,Max}}$	battery maximum energy capacity [kW]
$FNL_{\text{AnnualMax}}$	maximum UCSD total campus load in the past year
$P_{\text{BYD,actual}}$	actual BYD battery discharging power
$P_{\text{BYD,fc}}$	forecasted BYD battery discharging power
$P_{\text{BYD,Max}}$	battery maximum charging / discharging power [kW]
E_{DR}	submitted energy bid of utility import demand reduction compared to the adjusted baseline at the trading hour [kWh]
$P_{\text{DR,actual}}$	Actual demand response power, that is actual utility import compared to the adjusted baseline at the trading hour [kWh]
$P_{\text{DR,bid}}$	bid demand response power [MWh]
$P_{\text{DR,fc}}$	forecasted available demand response
$P_{\text{DR,full}}$	full nominated capacity of the month [MW]

P_{import}	imported power value read by the utility meter, that is campus net load
$P_{import,actual}$	actual utility imports
$P_{import,base}$	adjusted baseline of utility imports [kW]
$P_{import,base,actual}$	actual adjusted baseline of utility imports
$P_{import,base,fc}$	forecasted adjusted baseline of utility imports
$P_{import,fc}$	forecasted utility imports
P_{NCD_Max}	power used for non-coincident demand (NCD) charge calculation = maximum NCD of the month or half of maximum NCD of the past year, whichever is greater
P_{NCD_th}	threshold of non-coincident demand of the month
P_{OG}	Total power generated by UCSD onsite generators
P_{PD_Max}	Power used for peak demand (PD) charge calculation = maximum PD of the month or half of maximum PD of the past year, whichever is greater
P_{PD_th}	threshold of peak demand of the month
P_{PV}	power generated by PV systems on campus
$r_{capacity}$	monthly capacity rate [$/MW]
r_{NCDC}	non-coincident demand charge rate, 15.40 $/kW/mo.
r_{PDC}	peak demand charge rate, 3.02 $/kW in summer and 0.63 $/kW in winter
$R_{capacity}$	DRAM capacity payment [$]
R_{energy}	DRAM energy payment [$]
R_{over}	extra revenue of energy payment [$]
R_{loss_BYD}	battery operation cost [$]
$R_{penalty}$	DRAM penalty [$]
$x_{BYD}(t)$	normalized battery charging / discharging signal [-]
η_{eff}	on campus BYD battery round-trip efficiency [%]

Dispatch Forecast Development

Overview

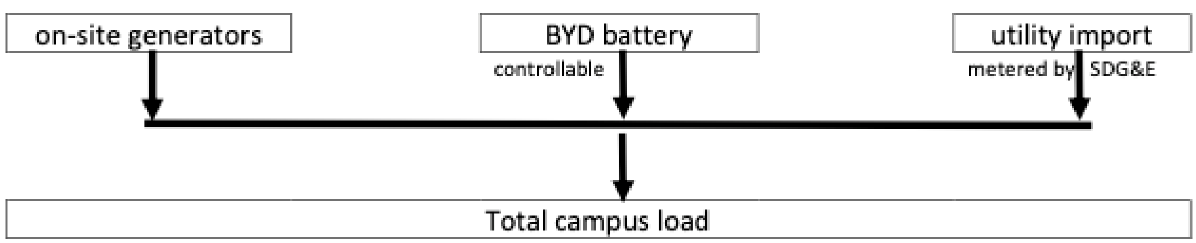
UCSD has purchased a BYD battery (battery specifications of P_{BYD_Max} = 1,800 kW, E_{BYD_Max} = 3,600 kWh) as an energy storage system. The battery is used primarily for demand management (DCM) and is otherwise idle (that is the majority of the time). The purpose of this project is to generate additional revenue from the battery operation by participating in demand response markets.

An economic model including both DCM and demand response auction mechanism (DRAM) feeds a control algorithm for the BYD battery. Market revenue analysis of real-world operation indicate that, using our novel economic model and control algorithm, the average monthly net benefit in year 2020 is <>. With this work, the potential of including more energy storage systems in energy markets can be further evaluated.

Method

In Figure B-1, total campus load is the sum of the power input from on-site generators, BYD battery dispatch, and the utility imports. The utility import is the variable bid into DRAM, as it is the only variable metered by San Diego Gas & Electric (SDG&E). Yet, the BYD battery is the only controllable demand response resource on campus and therefore the economic only optimizes the BYD battery dispatch. The difference in magnitude between the microgrid load averaging 18 MW and the 1.8 MW rated power of the battery is a risk factor in demand response market participation.

Figure B-1: Conceptual Campus Load Chart



A conceptual chart showing the contributions to the total microgrid load: the on- site generators, the controllable battery, and the metered utility import.

In the following, first the revenue or objective function is defined. Then a rule-based control algorithm for battery dispatch is presented. Finally, inputs and outputs to the model are described including automatic data scraping and processing, load and price forecasting, and decision making.

1) Objective function

The revenue function is:

$$max\{Net\ revenue\} = \max\left\{\begin{array}{c} DRAM\ revenue +\ DRAM\ penalty \\ +Savings\ from\ demand\ charge\ management \\ -loss\ due\ to\ battery\ round\text{-}trip\ efficiency \end{array}\right\}. \quad (1)$$

1.1) Demand response auction mechanism (DRAM)

The California ISO offers a wholesale market demand response participation platform, the demand response auction market (DRAM) which is only active during the peak load period from 4pm to 9pm daily. DRAM includes a real-time market (RTM) and a day-ahead market

(DAM). The RTM, with a trading interval of 5 minutes, is not ideal for UCSD since the resolution of the data is 15 minutes and lead times are shorter requiring an efficient computation and decision-making framework. Participation in the RTM may be implemented in the future. During the INVENT project, the UCSD-Nuvve team participated in the DAM DRAM market from July to December 2020. DRAM consists of capacity and energy payments. The capacity payment, $R_{capacity}$ [\$], is given by:

$$R_{capacity} = r_{capacity} \times P_{DR\_full}, \tag{2}$$

where $r_{capacity}$ [\$/MW] is the monthly capacity rate, and P_{DR_full} [MW] is the full nominated capacity of the month. Another revenue source is the energy payment, R_{energy}, given by:

$$R_{energy} = \begin{cases} c_{LMP\_DAM} \times P_{DR\_bid} + c_{LMP\_RTM} \times (P_{DR\_actual} - P_{DR\_bid}), & if\ P_{DR\_actual} \geq P_{DR\_bid} \\ c_{LMP\_RTM} \times (\max\{P_{DR\_actual}, 0\} - P_{DR\_bid}), & otherwise \end{cases}, \tag{3}$$

where c_{LMP_DAM} [\$/MWh] is the DAM Locational Marginal Price (LMP), and E_{DR} [kWh] is the submitted energy bid. Note that the DAM uses hourly intervals; thus, energy terms in kWh equal power terms in kW. The demand response power P is calculated as the difference between utility imports and the adjusted baseline. Since the goal of demand response is load reduction compared to normal ("non-event") operations, the energy bid is calculated with respect to a baseline. The baseline is designed to approximate the energy use in any given hour, based on recent load history during non-DRAM periods ("non-event days"). The adjusted baseline of the utility import at hour t of day d, P_{Import_base}, is calculated as:

$$P_{Import\_base}(t)_d = \frac{\left(\sum_{n=2}^{n=4} P_{Import}(t-n)_d\right)/3}{\left[\sum_{m=1}^{m=\bar{d}} \left(\sum_{n=2}^{n=4} P_{Import}(t-n)_{d-m}\right)/3\right]/\bar{d}} \times \frac{\left(\sum_{m=1}^{m=\bar{d}} P_{Import}(t)_{d-m}\right)}{\bar{d}}, \tag{4}$$

Where n is the number of time steps prior to hour t. $\bar{d}$=4if d is a weekend day, and $\bar{d}$=10 if d is a weekday, meaning that the adjusted baseline is calculated based over the past 4 or 10 non- event days for weekends or weekdays, respectively. A non-event "day" is actually a non-event hour, that is the same hour of the day on a prior day without DRAM participation. For instance, if there was no DRAM participation during hours 17, 18, and 19, but there was DRAM dispatch at hours 20 and 21, the adjusted baseline calculation on non-event days will include hours 17, 18, and 19 and exclude hours 20 and 21. The bid submission for each trading hour includes the demand response power, P_{DR_bid} [MWh], and the price, c_{bid} [\$/MWh] (see Section **2**). If the bid price is less or equal to the market price (that is $c_{bid} \leqq c_{LMP\_DAM}$), the bid will be awarded. On the trading day, if the bid is awarded and the bidder overperforms, that is the actual demand response power is more than the demand response power that was bid (that is $P_{DR\_actual} \geqq P_{DR\_bid}$), the bidder will receive additional energy payment revenue, R_{over}, which is:

$$R_{over} = c_{LMP\_RTM} \times (P_{DR\_actual} - P_{DR\_bid}), \tag{5}$$

where c_{LMP_RTM} [\$/MWh] is the RTM LMP, and P_{DR_actual} [kWh] is the actual utility import demand response (adjusted baseline minus actual imports) at the trading hour. On the other hand, if the bid is awarded but the bidder underperforms, the bidder will be assessed a penalty, $R_{penalty}$ as:

$$R_{penalty} = c_{LMP\_RTM} \times (max\{P_{DR\_actual}, 0\} - P_{DR\_bid}). \tag{6}$$

Eq. 6 means that the bidder has to make up for underperformance by purchasing the missing demand response power in the real time market. $max\{P, 0\}$ indicates that the actual demand response power cannot be less than zero, that is if the actual utility import is larger than the baseline, then no additional penalty will be assessed for the actual demand response power than exceeds the baseline.

1.2) Demand charge management

There are two kinds of demand charges: (a) the non-coincident demand charge, c_{NCDC}, is based on the larger value of either the maximum adjusted demand of the current month or half of the maximum annual adjusted demand of the past year, and (b) the peak demand charge, c_{PDC}, is based on the larger value of either the maximum utility imports of the month or half of the maximum annual imports of the past year during the peak period from 4 pm to 9 pm. The monthly savings from DCM is R_{DCM}:

$$R_{DCM} = c_{NCDC} \times (P_{NCD\_Max} - P_{NCD\_th}) + c_{PDC} \times (P_{PD\_Max} - P_{PD\_th}), \tag{7}$$

$$c_{NCDC} = r_{NCDC} \times (P_{NCD\_Max} - P_{NCD\_th}), \tag{8}$$

$$\text{and } c_{PDC} = r_{PDC} \times (P_{NCD\_Max} - P_{NCD\_th}), \tag{9}$$

where r_{NCDC} is the non-coincident demand charge rate (r_{NCDC} = 15.40 \$/kW), and r_{PDC} is the peak demand charge rate (3.02 \$/kW in summer and 0.63 \$/kW in winter). P_{NCD_Max} and P_{PD_Max} are the maximum non-coincident demand and peak demand of the month without battery, respectively, and P_{NCD_th} and P_{PD_th} are the (reduced) thresholds of non-coincident demand and peak demand of the month resulting from discharging of the battery, respectively.

Demand charges are calculated on a monthly basis. Since the UCSD microgrid includes generators, NCDC and PDC are assessed on different variables: NCD is based on adjusted demand while PD is based on utility imports. Adjusted demand is calculated from the utility imports as:

$$\mathrm{P_{Standby}} = \min\{\mathrm{NPR}, \mathrm{FNL_{AnnualMax}}\}, \tag{10}$$

$$\mathrm{P_{ForcedOutage}} = \mathrm{P_{Standby}} - \mathrm{P_{OG}} - \mathrm{P_{PV}}, \tag{11}$$

$$\text{and } \mathrm{P_{AdjustedDemand}} = \mathrm{P_{Import}} - \mathrm{P_{ForcedOutage}}, \tag{12}$$

where NPR is the UCSD generator nameplate rating (31,956 kW), and $FNL_{AnnualMax}$ is the maximum UCSD total campus load in the past year. P_{OG} is the power generated by all UCSD onsite generators (excluding PV), P_{PV} is the power generated by the UCSD onsite PV systems, and P_{Import} is the imported power read by the SDG&E meter.

In summary, the maximum hourly savings from DCM is 1800 kW x (15.40 $/kW + 3.02 $/kW), as per Eq. (7) (that is $33,156) while the maximum hourly DRAM revenue from battery dispatch during one hour is 1800 kW x 1 $/kW per Eq. (3) (that is $1,800). Since DRAM savings are an order of magnitude smaller than the DCM savings during any given hour, the battery dispatch priority goes to DCM. The maximum hourly loss due to round-trip efficiency is 20% x 0.068 $/kWh x (10/9) x (1800 kWh/2) per Eq. (13) (that is $13.60), which is two orders of magnitude smaller than the maximum hourly revenue from DRAM. Therefore, the minimum DRAM price for us to make profit will be $13.60 / 1.800 MWh, that is, 7.556 $/MWh. That is, it is profitable to dispatch battery for DCM and for DRAM participation when the LMP is higher than 7.556 $/MWh.

1.3) Battery round-trip efficiency

The round-trip efficiency, η_{eff}, of the campus BYD battery is assumed to be 80%, meaning that 20% of the energy flow from the grid is lost. The battery costs due to this 20% energy loss, R_{loss_BYD}, is:

$$R_{loss\_BYD} = -(100\% - \eta_{eff}) \times c_{energy} \times \left(\frac{10}{9}\right) \times \left(\frac{\sum_{t=1}^{n} \left| P_{BYD\_Max}(t) \times x_{BYD}(t) \right|}{2}\right), \tag{13}$$

where c_{energy} is the average of the annual energy costs for UCSD direct access energy purchases, c_{energy} = 0.068 $/kWh. Note that while actual energy costs vary hour-by-hour based on market prices, the actual prices are only made available to UCSD at the end of the year and therefore cannot be included in the operational economic model. $P_{BYD\_Max}(t)$ [kW] is the battery maximum charging / discharging power at hour t, and $x_{BYD}(t)$ [-] is the normalized battery charging / discharging signal at hour t. When $x_{BYD}(t) = -1$, the battery discharges at maximum power rate at time t. Since the meter of battery power flow is on the battery side instead of the grid side of the inverter, the original power flow from the grid before energy loss is the metered power flow multiplied by 10/9. The battery constraints are:

$$P_{BYD}(\mathrm{t}) \leq P_{BYD\_Max}, \tag{14}$$

$$SOC(t+1) = SOC(t) - \frac{P_{BYD}(\mathrm{t})}{E_{BYD\_Max}} \times 100\%, \tag{15}$$

$$\text{and } 0\% \leq \mathrm{SOC(t)} \leq 100\%, \tag{16}$$

where SOC is the state of charge of the battery.

2) Risk-constrained strategic DRAM bidding

DRAM participants must successfully show the full nominated capacity at least three times (for three hours) in a month to receive DRAM capacity and energy payments. Given operational challenges and load forecast uncertainties, ten (instead of three) self-scheduling battery dispatch events are planned per month. The events are planned for hours when the forecasted utility imports are much lower than the forecasted adjusted baseline. At the end of the month, three out of ten events with full nominated capacity performance are reported to CAISO. The forecasted available demand response power, P_{DR_fc}, is:

$$P_{DR\_fc} = \left(P_{Import\_base\_fc} - P_{Import\_fc}\right) + P_{BYD\_fc}, \qquad (17)$$

where $P_{Import\_base\_fc}$ is the forecasted adjusted utility import baseline (also called forecasted adjusted baseline), P_{Import_fc} is the forecasted utility import, and P_{BYD_fc} is the forecasted BYD battery discharging power. At the trading hour, the actual demand response, $P_{\_DR\_actual}$, is:

$$P_{DR\_actual} = \left(P_{Import\_base\_actual} - P_{Import\_actual}\right) + P_{BYD\_actual}, \qquad (18)$$

where $P_{Import\_base\_actual}$ is the actual adjusted utility import baseline, P_{Import_actual} is the actual utility import, and P_{BYD_actual} is the actual BYD battery discharging power. Due to forecasting errors and the limited control over the utility import power, the higher the forecasted adjusted baseline with respect to the forecasted utility import, the smaller the risk of failing to perform at full nominated capacity in real-time. For instance, the nominated capacity is the maximum BYD battery discharge rate (that is P_{BYD_fc} = 1800 kW). If $P_{Import\_base\_fc}$ - P_{Import_fc} = 3000 kW when the forecast underestimates the import, the total available demand response will be 4800 kW.

However, if at the trading hour the import is 2000 kW higher than the forecasted value, then the actual available demand response will be P_{DR_actual} =2800 kW, which is still much higher than the required capacity; thus, the self-schedule event is successful, and – if three such events occur in the month - we will receive the capacity payment per Eq. (2).

If three capacity performance events are completed successfully, participants are eligible for energy payments. To receive energy payments, DRAM participants are required to submit a bid for price and demand response power. The bid price and demand response must be submitted for at least four out of five trading hours from 4 pm to 9 pm daily, excluding national holidays. During the trial phase, the project aimed to reduce the number of successful bids and reduce the risk of penalties for not meeting the forecasted available bidding power. Accordingly, a low-risk bidding strategy of bidding demand response power and bidding price is (Figure B-2):

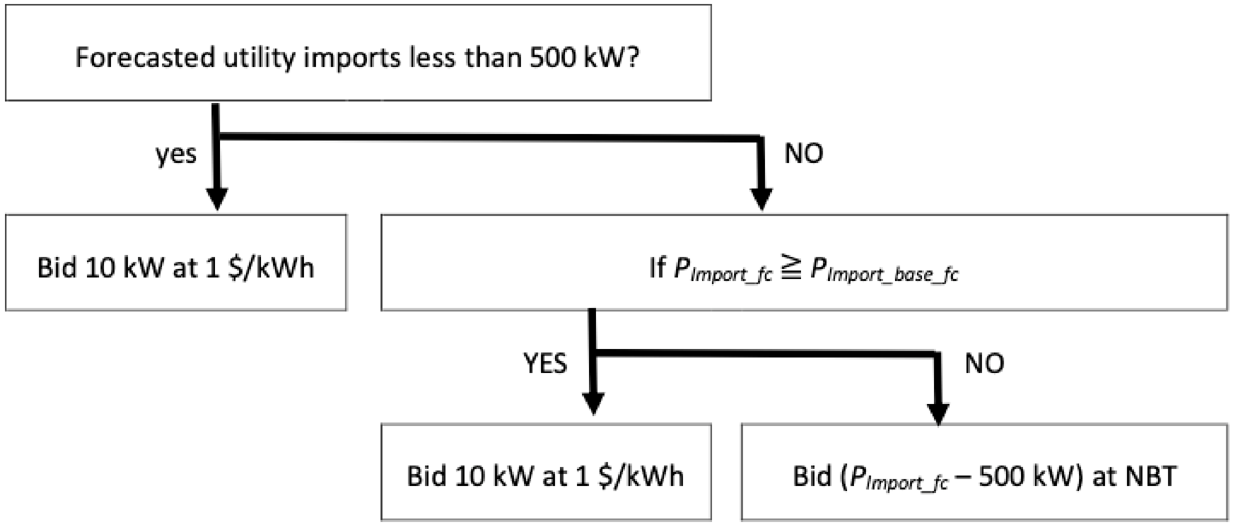
$$P_{DR\_bid} = \min\left(P_{BYD\_Max}, \max\left(10\ kW, \left(P_{Import\_fc} - 500\ kW\right)\right)\right) \qquad (19)$$

$$\text{and } c_{bid} = \begin{cases} 1\ \$/\text{kWh}, if\ P_{Import_{fc}} \geq\ P_{Import_{base_{fc}}} \\ \text{NBT}\ \$/\text{kWh}, \qquad otherwise \end{cases}. \qquad (20)$$

Eq. (19) is designed to restrict the bidding demand response to be no higher than the maximum battery discharging rate and no lower than 10 kW, which is the minimum bidding demand response power. The interconnection agreement with SDG&E does not permit UCSD to export power to the grid at any time. To avoid the risk of "negative imports" (that is exports) when the battery dispatches during low utility demand periods, the demand response bid is set at the DRAM minimum of 10 kW if the forecasted imports are less than 500 kW. As

DRAM participants are required to bid at most trading hours, the bidding price is decided based on the load forecast to reduce the risk of penalties per Eq. (6). During unfavorable hours with forecasted imports higher than or equal to the forecasted baseline (that is $P_{DR\_fc} \leqq P_{BYD\_fc}$), bids are submitted at the highest DRAM price, 1 $/kWh. During favorable hours with forecasted imports lower than the forecasted adjusted baseline (that is $P_{DR\_fc} > P_{BYD\_fc}$) per Eq.(17), the lowest bid price, which is the floor price of the monthly net benefit threshold (NBT) test published by California ISO, is submitted per Eq. (20). The process of determining the bid is shown in Figure B-2.

Figure B-2: The Process of Determining Bid Price and Power



The process of determining bid price and power.

That the final submission of demand response energy is also restricted by the battery energy capacity, which will be explained in the following section.

3) Optimal battery scheduling

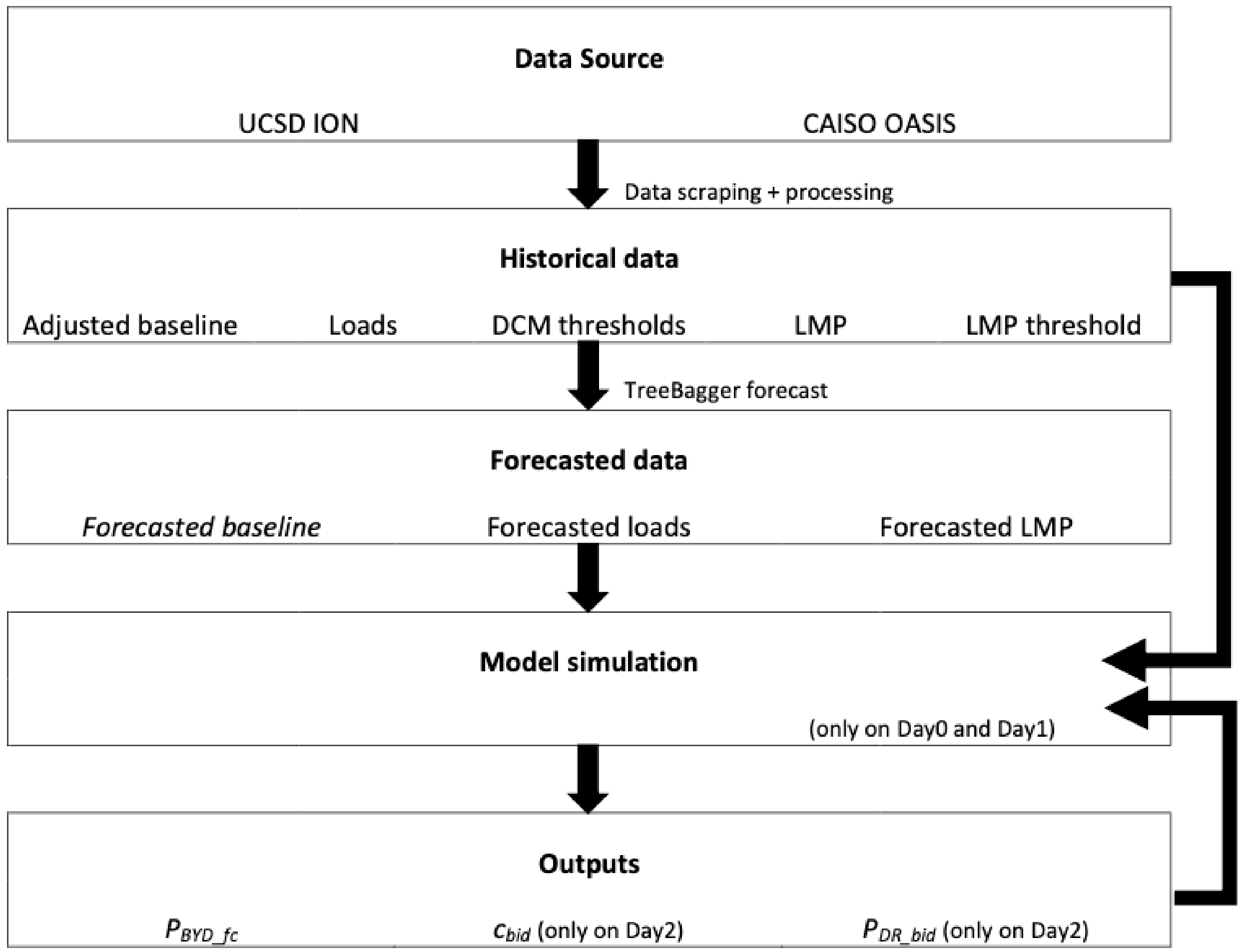
To optimize battery scheduling, a model simulation with automatic data processing, load and price forecasting, and decision making is applied. In this section, the model inputs / outputs, the automatic data processing, forecasting, and model simulation are first described. Then, the timeline of the energy market and the simulation time points are presented. Lastly, battery dispatch criteria considering DCM/DRAM participation are explained.

3.1) Process flow chart

As shown in Figure B-3, the model downloads historical data of utility imports, onsite generators output, PV output, and BYD battery dispatch from the UCSD metering system website. These inputs allow calculating the adjusted baseline (Eq. *(4)*), utility imports, and adjusted demand (Eq. (10)-(12)). For DCM, thresholds (including the peak-demand threshold and the non-coincident demand threshold) are used to trigger battery discharge for demand charge reduction when the load is higher than the threshold. Since demand charges apply to the maximum load in the month, the thresholds are adjusted (increased) over the month. The starting DCM threshold value of the month is half of the maximum annual load peak in the past year, due to how the demand charge is calculated (see section '**1.3 Demand charge management**'). The threshold will be updated when actual load values set a new high record. The LMP includes day-ahead and real-time locational marginal price, as revenue from DRAM dispatch is based on both prices per Eq. (*3*)).

The LMP threshold is the lowest bid price published by California ISO in the monthly demand response net benefits test results report. The price threshold applies to those demand response market participants having prohibited resources. Besides historical data, the model also takes in forecasted data, including '*Fc load'* (that is forecasted utility import and forecasted adjusted demand) and '*Fc LMP*' (that is forecasted day-ahead LMP). All forecasts are generated by the TreeBagger forecast method, which is described in section 'forecast of loads and LMP'.

Figure B-3: Bid Parameters and Battery Dispatch Flowchart



Flowchart of automatic data processing, forecasting, and model simulation to obtain the bid parameters and battery dispatch.

3.2) Timeline of the energy market along with inputs/ outputs of the model simulation

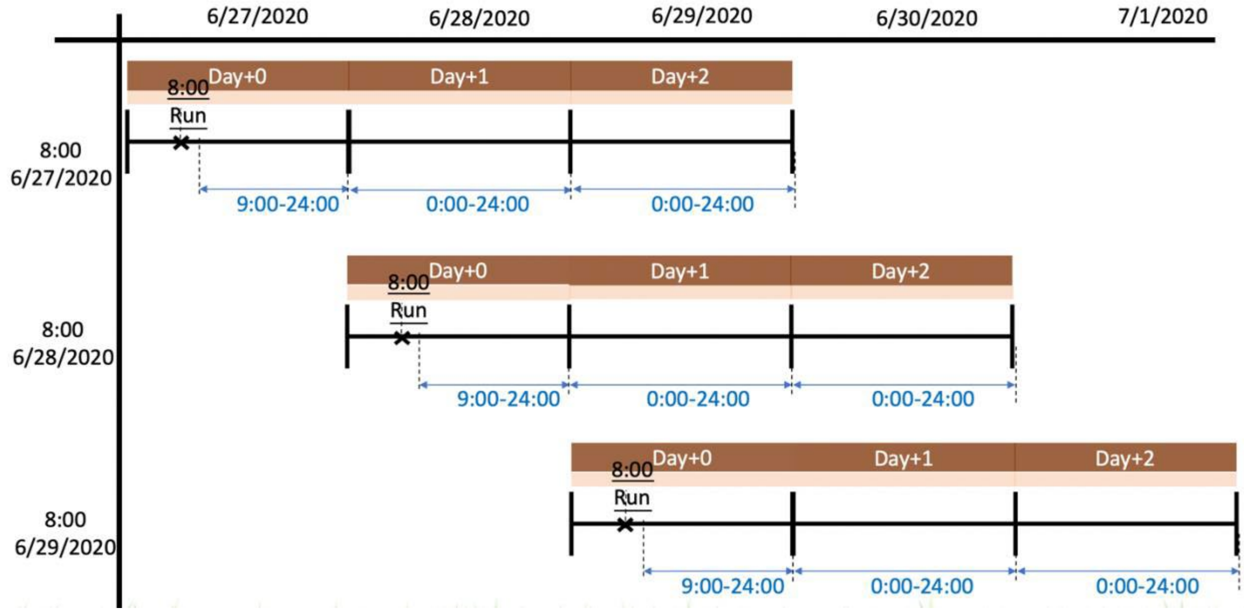
The timeline of automatic simulation and DRAM operation is presented in Figure B-4. The simulation runs at 8 am daily. As an example, consider 6/29/2020, where the simulation time horizon is 63 hours, including 'today' (Day+0), 'tomorrow' (Day+1), and 'the day after tomorrow' (Day+2). The inputs and outputs for each day are listed in Figure B-5.

On 6/29, the trading day (Day+2) of DRAM is 7/1, and the bidding price and the bidding demand response power, which are the outputs "c_{bid} from 6/29 (Day+2)" and "P_{DR_bid} from 6/29 (Day+2)," for the trading day (Day+2) should be submitted two days prior to the day. Likewise, the 6/29 (Day+0) inputs, "c_{bid} from 6/27 (Day+2)" and "P_{DR_bid} from 6/27 (Day+2)," are the trading day (Day+2) bid outputs from 6/27.

Figure B-4: Inputs and Outputs of Automatic Simulation and DRAM Operation

	Inputs	Outputs
6/29 (Day+0) = (6/29)	Adjusted baseline Forecasted loads DCM thresholds (Day-1) LMP LMP threshold c_{bid} from 6/27 (Day+2) P_{DR_bid} from 6/27 (Day+2)	P_{BYD_fc} of 6/29 (Day+0) DCM threshold (Day+0)
6/29 (Day+1) = (6/30)	Forecasted adjusted baseline Forecasted loads Forecasted DCM thresholds (Day+0) c_{bid} from 6/28 (Day+2) P_{DR_bid} from 6/28 (Day+2)	P_{BYD_fc} of 6/29 (Day+1) DCM threshold (Day+1)
6/29 (Day+2) = (7/1)	Forecasted adjusted baseline Forecasted loads Forecasted DCM thresholds (Day-1) Forecasted LMP	c_{bid} of 6/29 (Day+2) P_{DR_bid} of 6/29 (Day+2) P_{BYD_fc} of 6/29 (Day+2) DCM threshold (Day+2)

Figure B-5: Timeline of Automatic Simulation and DRAM Operation



The bid price and power output from 6/27 Day+2 is inputs to the 6/29 Day+0 run.

After data acquisition, the TreeBagger forecast function processes the data into the forecasted adjusted baseline and the forecasted load.

3.3) Optimal battery scheduling

The battery charging / discharging criteria are discussed separately in three different periods of the day: (a) before DRAM, from 0:00 to 16:00, (b) during DRAM, from 16:00 to 21:00, and (c) after DRAM, from 21:00 to 24:00.

(3.3a) Before DRAM

The battery is usually recharged in the early morning, and the SOC will be 100% before 8 am. As a result, the starting SOC at 9 am on Day+0 is set to be 100%. For Day+1 and Day+2, if there is no need for demand charge reduction and SOC is lower than 100%, the battery is recharged back to full capacity immediately after 00:00 h. The battery will be discharged only when the forecasted adjusted demand is higher than the NCD threshold.

(3.3b) During DRAM

During DRAM hours, DRAM participation, PD reduction, and NCD reduction are all considered for battery dispatch. The battery is discharged prioritizing DCM, and no recharging is allowed during this time period to avoid the risk of creating demand peaks. When no DCM is needed, and the suggested DRAM dispatch is more than two hours, the two hours with the highest forecasted LMP will be chosen for battery dispatch.

(3.3c) After DRAM

After DRAM hours, the battery will discharge only if there is need for NCD reduction, which is extremely rare during this nighttime period. Also, the battery will not be recharged in this time period, since recharging costs are typically lower in the 00:00 to 06:00 window due to lower direct access market prices.

APPENDIX C: Project Assets

Table C-1: Overview of EVs

Make/Model	Location
Nissan LEAF (11 EVs)	1 at Gilman Parking Garage 2 at Hopkins Parking Garage 1 at UCSD Police Department 2 at Rady School of Management 3 at P703 Parking Lot 1 at Trade Street Logistics Center 1 at Center Hall
Chevy Bolt (2 EVs)	1 at Gilman Parking Garage 1 at Scripps Institute of Oceanography
BMW i3 (3 EVs)	2 at Gilman Parking Garage 1 at Hopkins Parking Garage
Ford Fusion (1 EV)	1 at Hopkins Parking Garage
Daimler Smart (1 EV)	1 at UCSD Police Department
Mitsubishi Outlander (3 PHEVs)	2 at P703 Parking Lot 1 at UCSD Police Department
Honda Accord (2 PHEVs)	2 at P703 Parking Lot

Table C-2: Overview of charging stations

EVSE ID	Make Model	Coalition Names/ Transitions	Location	Use Case	Power Capacity	Comms Protocols
Hitachi-0001	Hitachi Bidirectional DC EVSE	INVENT1, EVSA	Rady	DR	6kW	CHAdeMO
Hitachi-0002	Hitachi Bidirectional DC EVSE	INVENT1, EVSA	Rady	DCM	6kW	CHAdeMO
Hitachi-0003	Hitachi Bidirectional DC EVSE	INVENT1, EVSA	P703	DCM/FR	6kW	CHAdeMO
Hitachi-0004	Hitachi Bidirectional DC EVSE	INVENT1, EVSA	P703	FR	6kW	CHAdeMO
Hitachi-0005	Hitachi Bidirectional DC EVSE	INVENT1, EVSA	P703	FR	6kW	CHAdeMO
Hitachi-0006	Hitachi Bidirectional DC EVSE	INVENT1, EVSA	P703	FR	6kW	CHAdeMO
Hitachi-0007	Hitachi Bidirectional DC EVSE	INVENT1, EVSA	P703	FR	6kW	CHAdeMO
Hitachi-0008	Hitachi Bidirectional DC EVSE	INVENT1	Scripps	DR	6kW	CHAdeMO
Hitachi-0009	Hitachi Bidirectional DC EVSE	EVSA, PD	Police Department	DCM/FR	6kW	CHAdeMO

EVSE ID	Make Model	Coalition Names/ Transitions	Location	Use Case	Power Capacity	Comms Protocols
PP-0001	PrincetonPower Bidirectional DC EVSE	EVSA, INVENT1, SOLAR, PD	Police Department	DCM/RETS	10kW	CHAdeMO
PP-0002	PrincetonPower Bidirectional DC EVSE	EVSA, INVENT1, HOPKINS, PD	Scripps	DCM	10kW	CHAdeMO
PP-0003	PrincetonPower Bidirectional DC EVSE	EVSA, INVENT1, HOPKINS, SOLAR	Hopkins	DCM/RETS	10kW	CHAdeMO
PP-0004	PrincetonPower Bidirectional DC EVSE	EVSA, INVENT1, SOLAR	Trade Street	RETS	10kW	CHAdeMO
PP-0005	PrincetonPower Bidirectional DC EVSE	EVSA, INVENT1, SOLAR	Center Hall	RETS	10kW	CHAdeMO
PP-0006	PrincetonPower Bidirectional DC EVSE	EVSA, INVENT1	Hopkins	DCM	10kW	CHAdeMO
F00062	Nuvve PowerPort	INVENT, HOPKINS	Hopkins	DCM	6.6kW	J1772 Type 1
F00065	Nuvve PowerPort	INVENT, SOLAR	Gilman	RETS/DCM	6.6kW	J1772 Type 1
F00067	Nuvve PowerPort	INVENT, EVSA, PD	Police Department	DCM/FR	6.6kW	J1772 Type 1
F00070	Nuvve PowerPort	INVENT, EVSA	Scripps		6.6kW	J1772 Type 1

EVSE ID	Make Model	Coalition Names/ Transitions	Location	Use Case	Power Capacity	Comms Protocols
F00071	Nuvve PowerPort	INVENT, SOLAR	Gilman	RETS/DCM	6.6kW	J1772 Type 1
F00073	Nuvve PowerPort	INVENT, SOLAR	Gilman	RETS/DCM	6.6kW	J1772 Type 1
F00074	Nuvve PowerPort	INVENT, HOPKINS	Hopkins	DCM	6.6kW	J1772 Type 1
F00075	Nuvve PowerPort	INVENT, HOPKINS	Hopkins	DCM	6.6kW	J1772 Type 1
F00076	Nuvve PowerPort	INVENT, SOLAR	Gilman	RETS/DCM	6.6kW	J1772 Type 1
M00031	Nuvve PowerPort	INVENT, EVSA	P703	DR	2kW	J1772 Type 1
M00041	Nuvve PowerPort	INVENT, EVSA	P703	DR	2kW	J1772 Type 1

APPENDIX D: Demand Response Supporting Tables

Demand Response Timeline

Summer 2018
Participated in voluntary DR events – CAISO Flex Alert + SDG&E Reduce-Your-Use with V2G EVs / EVSEs

Fall 2018 – Winter 2019
Evaluated available and accessible market access pathways for INVENT vehicles to provide demand response:

1. Energy via Proxy Demand Resource (PDR) mechanism (CAISO)
2. Demand Response Auction Mechanism (DRAM) (CPUC/IOUs)
3. ~~Capacity Bidding Program (CBP) (IOUs)~~
4. ~~Base Interruptible Program (BIP) (IOUs)~~

SDG&E determined 3 and 4 were not possible to do with assets from within the UCSD micro-grid.

June 2019
UCSD approached Nuvve with opportunity to leverage 2.5 MW / 5 MWh BYD battery for market participation.

Summer 2019
After evaluation, the team (Nuvve, 33 North and UCSD) determined the most viable market access pathway was PDR.

Oct 2019
Nuvve secured a Scheduling Coordinator (SC) / Demand Response Provider (DRP) to enable market access via the PDR mechanism, Leapfrog Power (aka Leap).

Nov 2019
Due to the size and variability of the UCSD micro-grid, further evaluation indicated we should pursue use of CAISO's recently released baselining methodology – ***meter generation output (MGO)*** – in order to separate the battery behavior from the rest of the grid for baselining and settlement.

Jan 2020
Leap concluded they would not be able to execute the MGO methodology due to additional meter data verification requirements for a non-utility owned meter. However, they would be able to support DRAM.

Decision Point:
1) Evaluate DRAM
2) Recruit another SC / DRP that could do PDR with MGO
3) Discontinue pursuit of DR market access

Feb – April 2020
INVENT Project Team evaluated DRAM participation.

Evaluation included:
- Modeling of the battery in conjunction with the UCSD micro-grid load
- Discussions with SDG&E
- Discussions with CPUC
- Discussions with CAISO
- Discussions with Project TAC (4/21/20) and Jeffrey Sunquist + Qing Tian (4/23/20)

May 2020
Leap identified the main issue of the BYD Battery participating in DRAM from within the UCSD micro-grid was the other "Prohibited Resources" (i.e. fossil fuel generators) that are present on the micro-grid.

After several conversations with the CPUC and SDG&E, Leap identified a path forward – for UCSD to sign an attestation stating that it has Prohibited Resources that operate as baseload but would not use those resources purposefully to contribute to a load reduction event.

May 21, 2020
UCSD signed attestation and submitted to SDG&E.

May 29, 2020
SDG&E (the utility distribution company) and Univ. of California Office of the President (UCOP) (the load serving entity) approved the resource location in CAISO's Demand Response Registration System (DRRS).

June 1, 2020
The resource went "live" in the 2020 DRAM, with a nominated capacity of 1.8 MW

Demand Response Event Tables

Table D-1: July – December 2020 DRAM Test and Market Events – July 2020

Test Events		
Date	**Time**	**Capacity (kW)**
7/22/20	4-6pm	3600
Market Events		
Date	**Time**	**Capacity (kW)**
7/24/20	4-9pm	10
7/27/20	4-5pm	310
	5-6pm	430
	6-9pm	10
7/28/20	4-5pm	310
	5-6pm	430
	6-9pm	10
7/31/20	4-5pm	310
	5-6pm	430
	6-9pm	1

Table D-2: July – December 2020 DRAM Test and Market Events – August 2020

Test Events		
Date	**Time**	**Capacity (kW)**
8/17/20	6-8pm	1800
8/27/20	4-6pm	1800
8/28/20	4-6pm	1800
8/29/20	7-9pm	1800
8/30/20	7-9pm	1800
Market Events		
Date	**Time**	**Dispatch Capacity (kW)**
8/8/20	4-5pm	310
	5-6pm	410
	6-9pm	10
8/9/20	4-5pm	310
	5-6pm	410
	6-9pm	10
8/14/20	4-6pm	10
	6-8pm	610
	8-9pm	10
8/16/20	4-9pm	10
8/18/20	4-5pm	310
	5-6pm	910
	6-7pm	1510
	7-8pm	1510
	8-9pm	310
8/19/20	6-8pm	1800

Table D-3: July – December 2020 DRAM Test and Market Events – September 2020

Test Events		
Date	**Time**	**Capacity (kW)**
9/5/20	7-9pm	1800
9/7/20	7-9pm	1800
9/23/20	7-9pm	1800
Market Events		
Date	**Time**	**Capacity (kW)**
9/6/20	5-6pm	430
	6-9pm	10

Table D-4: July – December 2020 DRAM Test and Market Events – October 2020

Test Events		
Date	**Time**	**Capacity (kW)**
10/3/20	6-8pm	1800
10/25/20	6-8pm	1800