Ancillary Service Revenue Opportunities from Electric Vehicles via Demand Response

Better Place Master's Project Team

Mark Leo, Kripal Kavi, Hanns Anders, Brian Moss

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Faculty Advisor:
Dr. John M. DeCicco

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1 Executive Summary

Driven by a variety of factors including falling costs, environmental impacts, and state mandates, the integration of renewable energy on the U. S. electrical grid is increasing. While studies have shown that the existing electric grid system can absorb this load with the addition of considerable transmission and distribution infrastructure over the next few decades, the effect that intermittent solar and wind resources may have on the operational flexibility of the grid are less known. This poses a unique challenge for the Regional Transmission Organizations (RTO), Independent System Operators (ISO), and other grid operators that are responsible for procuring and coordinating ancillary services that support and maintain the reliable operation of the interconnected transmission system. As additional renewables are added to the system, they must secure enough services to account for small disparities between the quantity and quality of the energy output of these variable sources and those of the dispatchable resources responsible for the majority of electricity generation. In certain regions, these organizations not only determine the existence, definition, and pricing of these ancillary services, but also enable a range of generation, transmission, system control, and distribution system stakeholders to trade these products on open markets.

Perhaps the most promising, but least proven, providers of ancillary services are electric energy storage (EES) technologies such as flywheels and advanced batteries. These devices store and release electric energy on demand and are prized for their fidelity and rapid response functionality. However, high costs associated with the operation of EES assets have prevented their deployment at a meaningful scale. The large-scale adoption of electric vehicles (EVs) presents an opportunity to overcome this barrier. Recent advancements in demand response, vehicle-to-grid (V2G), and battery technologies suggest that networks of aggregated battery EVs may soon be a reality. Research suggests these networks could provide EES-based ancillary services at a competitive price.

The purpose of this project is to provide a technical and economic analysis of the ability of EV networks to deliver ancillary services associated with the integration of renewables within the California Independent System Operator (CAISO) market area, and identify which ancillary services are best suited for EES. The California ISO region was selected for three reasons. Firstly, California is predicted to contain the highest concentration of early EV adopters in the US. Secondly, state regulators generally maintain a progressive stance towards renewable energy and EES. Finally, research suggests a causal relationship between increased renewable energy penetration and increased demand for two primary types of ancillary services within the CAISO region: frequency regulation and operating reserves.

This report examines the potential impact of renewables on the ancillary service market under the CAISO, and focuses on the ability of EVs to provide such services via demand response and V2G. The document also presents a revenue model that incorporates potential scenarios regarding EV adoption, electricity prices, and driver behavior. The output of the model determines the overall revenue opportunity for aggregators who plan to provide DR-EV. While EVs and renewable energy technologies are often mentioned in the same breath as cornerstones of a low-carbon future, the relationship between the two technologies remain nebulous. Our hope is that the conclusions herein will facilitate the transition to a sustainable transportation system by highlighting important synergies and related potential business opportunities.

In order to color our analysis and inform our assumptions, we relied on a number of private and public sector organizations. When considering the integration of renewables, we turned primarily to the California Public Utility Commission and the CAISO. To understand ancillary services and their markets, we relied on ORNL and EPRI reports and personnel. Similarly, we used published reports to model EV adoption rates and patterns. We also interviewed EV, EES, and renewable energy experts from the

University of Michigan to determine the capabilities and limitations of these technologies. Finally, the team met with experts from numerous advanced battery, utilities, and other industry stakeholders to collect supplementary information.

During our study we created a simulation model and used primary and secondary research to examine the relationships between electric vehicles, renewable energy, and the electric grid. We found that increased penetration of renewables in the electricity grid does increase the demand for ancillary services. Also, while vehicle to grid technology is technically feasible, because actual commercialization is not likely in the near to medium term, this technology is not a viable source for providing ancillary services. However, electric vehicles when managed by an aggregator can participate in the ancillary services market through a demand response function. The summary of the findings with respect to Ancillary Services are presented below:

Service	Supply Duration	Directional Shifts	Response Rate	Service Duty	Suitable for DR-EV?
(Frequency) Regulation	10–15 min	High	<1 min	Continuous	Yes
Spinning Reserves	10 min–2 hours	Low	<10 min	Intermittent	Yes
Supplemental Reserves	10 min–2 hours	Low	<10 min	Intermittent	Yes
Replacement Reserves	2 hours	Low	<30 min	Intermittent	Yes
Voltage Control	-	-	-	-	No
Load Following	1–10 hours	Medium	<1 hour	Intermittent	No
System Control	NA	NA	NA	Continuous	No
Real Power Loss Replacement	1–10 hours	Low	<10 min	Continuous	No

Despite there being a significantly large market for these services, the limited revenue opportunity for aggregators on a per car basis is unlikely to be compelling enough to justify a business model.

2 Project Introduction

This project was conceived by four University of Michigan MBA/MS students who have a strong interest in the intersection of renewable energy, smart grid technology, and electric vehicles. Better Place, a global electric vehicle infrastructure and services company, was targeted by the project team as a sponsor for our project based on its revolutionary business model which encompasses all areas of our interests. The scoping for this project was a collaborative and iterative process between the company, the project team, and our project advisor.

As an advocate of global sustainability, one of Better Place's goals is to contribute to ending the world's reliance on fossil fuels and to help control carbon dioxide and other emissions. Accordingly the company expressed to the project team its concern regarding the reliance of the U. S. electricity grid on coal, and the implications if EVs were largely powered by this source. This brought up questions about how the company interacts with renewable energy and to what extent it could be quantified.

Ultimately the goal of the project is to identify the ways the EVs, renewable energy, and the electricity grid interact, and how an aggregator such as Better Place fits in. At the same time we attempted to quantify the benefits to aggregators and end users in terms of revenue opportunities from the markets that demand response via electric vehicles (DR-EV) participates in.

This report begins by explaining the basic concepts behind EVs and EV Infrastructure, Vehicle-to-Grid technology, Demand Response, Electric Vehicle Electric Energy Storage, and renewable energy and its effects on the grid. We then move on to discuss EV adoption projections, and explain how our simulation model uses our research data to predict revenue opportunities. Finally, we examine the outputs of our model and make general conclusions.

3 Electric Vehicles and Energy Infrastructure

3.1 Introduction to Vehicle-to-Grid (V2G)

The vehicle-to-grid (V2G) concept links two large and independent systems – electrical power generation and light-duty vehicle transportation – for the first time. It accomplishes this linkage through integrating these systems via the bi-directional transfer of electricity over the "smart" grid. In other words, V2G conceptualizes that electric vehicles can facilitate both power inflow, which is stored in the vehicle's battery, and power outflow, which feeds power back out onto the traditional power grid whenever the vehicle is plugged in to a charging station.

The current light-duty vehicular transportation system is based on individual fossil fuel-powered units. These units sit idle over 90% of each day and, in aggregate, are used in highly predictable patterns[i]. The electrification of the light duty fleet opens the door for V2G because the battery in each EV represents a mobile (distributed) storage opportunity for electricity generated by the grid[ii]. Under the vision of V2G proponents, this means that electricity can be stored easily and cheaply during times of excess production and returned to the grid at a later time, when demand is greater. This effectively allows electricity to be produced in the most cost-effective manner and serves to alter the traditional demand for energy and generation capacity requirements during any given day to promote efficiency in production and consumption.

One central tenet of the practical application of V2G is the aggregation of electric vehicles into a resource that has the appropriate size and resource capability to become a meaningful player at the ISO-level electricity market (>1MW capacity). Storage capacity and grid support capability at the individual vehicle level are too small to impact the grid in a meaningful way – for example, in 2011 the most popular electric vehicle models (Chevrolet Volt and Nissan Leaf) utilize batteries that range in size from 16 to 24 kWh, although due to the nature of lithium ion batteries not all of this capacity is available to be used by V2G. However, by combining hundreds or thousands of electric vehicles into a consolidated entity through V2G software and technology, electric vehicles can overcome their inherent individual limitations[iii]. Thus, large vehicle fleets are an attractive option for early deployment and testing of V2G[iv].

A V2G-enabled electric vehicle must contain each of the following three components:

(1) A physical connection to the grid for electrical energy flow
(2) A connection device that enables two-way communication with the grid operator, and
(3) Controls and metering capability integrated into the vehicle's electrical system[v].

3.2 V2G Feasibility

It is important to note that despite widespread popularity in the press, V2G is currently still in the conceptual planning stages. Requisite V2G enabling technology – power grids that with remote control over bi-directional energy flows, widespread adoption of "smart" vehicle charging stations, power grid infrastructure upgrades and the development of grid standards, and electric vehicles with V2G-enabled communications software capabilities are not currently available to the general public at the requisite scale. Most estimates conclude that it will be several more years before any practical applications of V2G technology become widely adopted[vi].

3.3 V2G Challenges

On the surface, V2G appears to be a promising development to those seeking to maximize the efficiency of the electric grid using existing grid resources. However, despite solid theoretical underpinnings, V2G has several challenges to overcome.

To enable V2G to operate efficiently, the electricity grid must be re-developed to permit the bi-directional flow of power and power-related data between utilities, consumers, OEM onboard computers, and charging infrastructure providers, among others. The result of this complexity in energy and data flow is the need for the development of standards along each piece of the V2G value chain. These standards will enhance the speed of development of a smart-grid enabled V2G system in the United States while ensuring and seamless and safe transition for consumers, utility workers, OEMs, and other relevant parties. These standards include both physical infrastructure as well as virtual standards involving communication, safety, data security, and information-sharing between stakeholders.

As seen in the development process of many new, complex, multi-party systems, the current stage of smart grid deployment has been slowed by the proliferation of multiple independent stakeholders advocating for the adoption of proprietary technologies to be adopted as industry standards. The recent partnership between Nissan-Renault and Better Place to develop an EV battery that can be removed and replaced at a "swap" station is one example of private stakeholders developing a standard that they hope will be adopted by other vehicle OEMs in the future. However, as of April 2011 practically none of the smart-grid V2G standards have been officially formalized[vii,viii].

As of early 2011, under authorization from the Energy Independence and Security Act (EISA) of 2007, the National Institute of Standards and Technology (NIST) convened a Vehicle-to-Grid Working Group to address the development of smart grid and V2G standards at the national level. This group, which includes state and national regulators, academics, and representatives from private industry, has been tasked with identifying "the service interfaces and standards needed. . . [and to] then prepare an action plan for addressing the interoperability issues that stand in the way of achieving the desired smart grid future", including V2G. The goal of this working group is to produce a national set of V2G standards that will be able to support one million EVs by the year 2015[ix].

4 Demand Response via Electric Vehicles

4.1 Introduction to Demand Response

While the bi-directional flow of electricity between EVs and the grid may be years away from commercialization at scale, networked EVs promise nearer term benefits as a result of demand response (DR). FERC defines DR as:

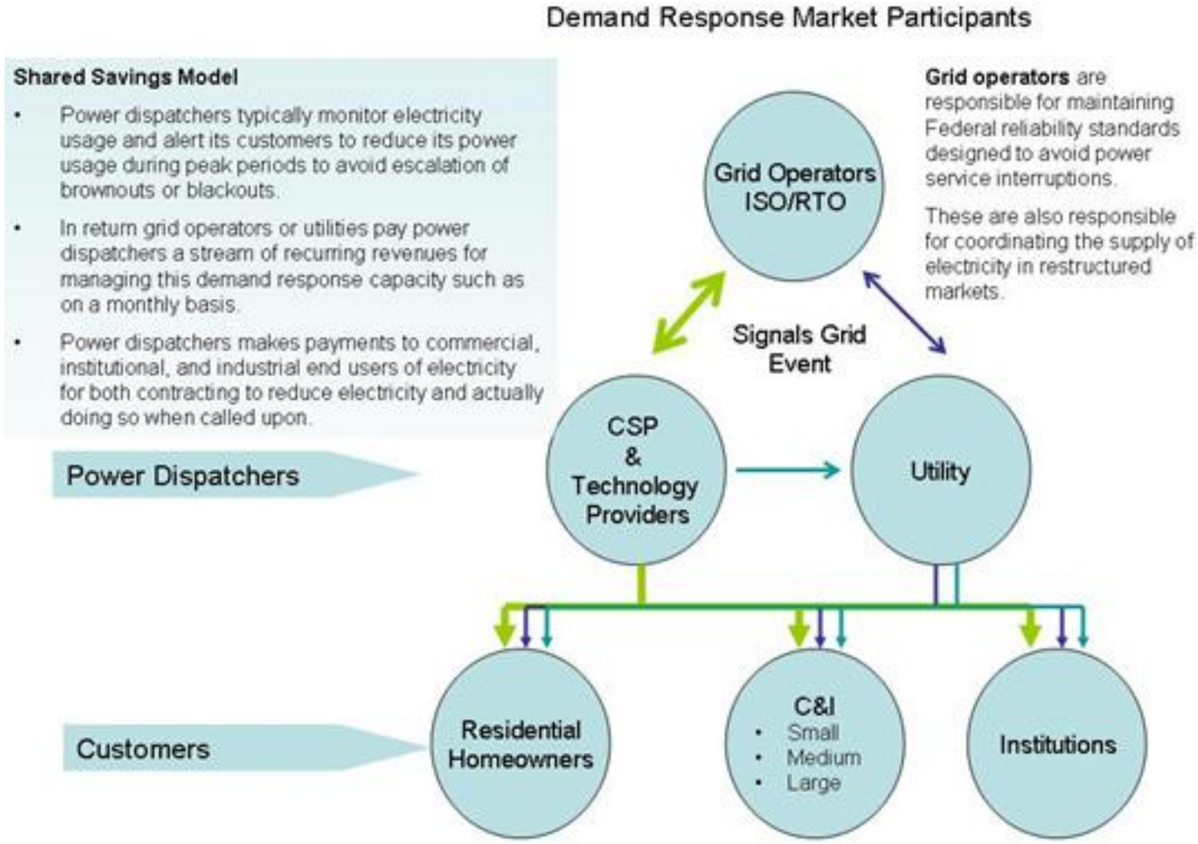
> *Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*

DR programs fall under a larger umbrella of initiatives known as demand-side management (DSM) – the planning, controlling, and monitoring activities used by power dispatchers to manage supply and demand by encouraging consumers to modify their electricity usage[x]. Whereas energy efficiency focuses on reducing the amount of energy consumed by a particular good or service, DR exploits price signals and monetary incentives to impact consumption patterns, often in lieu of peaking generation and/or transmission and distribution (T&D) capacity[xi]. As a result, DR facilitates grid optimization, long-term planning, and certainty during emergency situations, while simultaneously realizing cost savings for T&D owners, grid operators, and end-users. Payment is conferred regardless of whether the services are called on or not. For additional background on DR, please reference **Appendix 1**.

4.1.1 DR Market Participants

The DR market encompasses a number of entities and roles (**Figure 1)**. Amongst this tangled web of market participants, power dispatchers such as curtailment solution providers (CSPs) play a vital role by managing the exchange of data and the notification process amongst balancing authorities, utilities, and end-users in restructured markets. First, dispatchers weigh the consumption patterns and needs of electricity customers against tariff structures and variable electricity prices to establish curtailment plans. They also sign contracts with end-users to assume direct control of specific energy assets. They then aggregate this information to create portfolios of load reduction commitments – schedules which are provided to grid operators in exchange for recurring compensation related to the amount of capacity involved. In the event of a system emergency or requirement, operators require the aggregator to reduce or "dispatch" a portion of its contracted portfolio. In return, dispatchers receive additional compensation that may take the form of rate discounts, incentive payments, and bill credits. Finally, dispatchers take a profit of the total revenue collected before splitting the remaining revenue amongst their own customers. Utilities or other technology providers may take the place of the DR dispatcher and deal with the ISO/RTOs and customers directly. They may also act as a go-between between the dispatcher and grid operator.

Figure 1: DR Market Participants and Roles[xii]

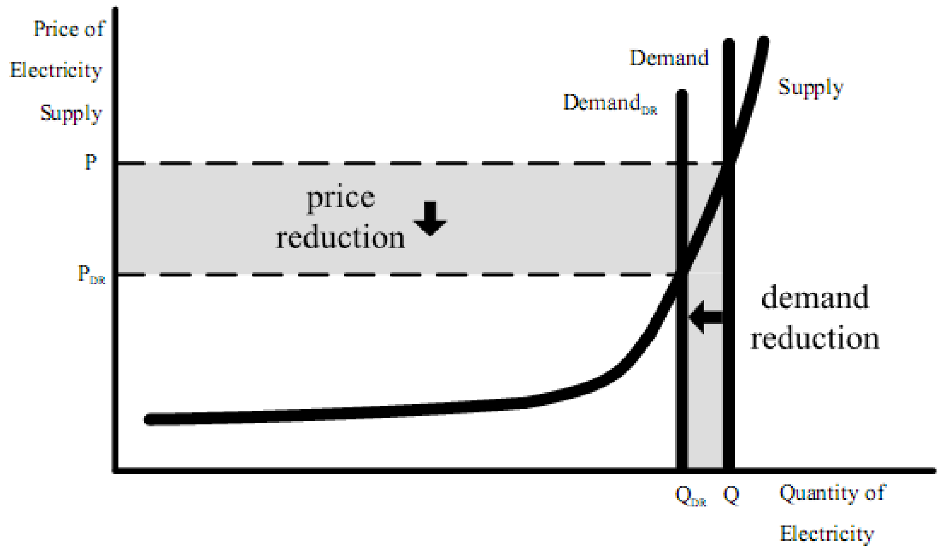


4.1.2 DR Compensation

The methods used to determine and award compensation for DR varies considerably amongst the RTO/ISO markets. Generally, DR payments are awarded in two pieces: contracted capacity and dispatched energy. While this distinction will be explored in greater detail later in the report, it is important to note that the protocols that govern DR compensation are set to change dramatically.

On March 15, 2011, FERC ruled to amend the Federal Power Act and ensure that DR is compensated on par with traditional energy products and services. Under the revised compensation rules, the full market price for energy, also known as the locational marginal price (LMP), must be awarded to DR resources that: 1.) balance supply and demand as an alternative to generation and 2.) pass a net benefit test. A net benefit is said to exist as long as dispatching the DR reduces the LMP by more than the cost of dispatching and paying the LMP for the DR[xiii]. The basic premise behind this reduction is shown in Figure 2. According to FERC, payments made below the LMP in the real-time and day-ahead RTO/ISO markets for DR violates the Commission's goal of "just and reasonable" energy prices. The Commission hopes the ruling will "encourage new entry and innovation in energy markets, and spur the deployment of new technologies[xiv]."

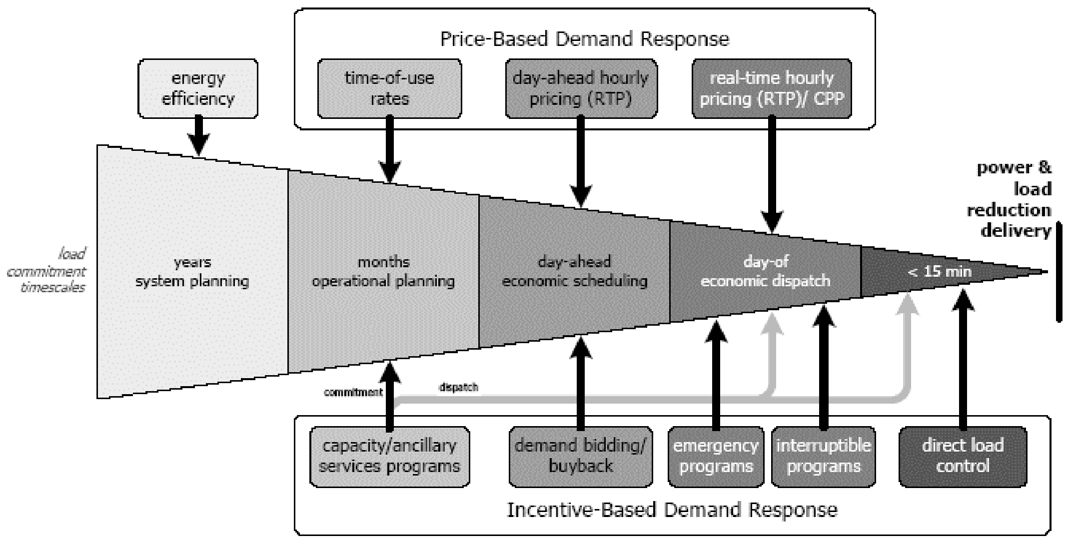
Figure 2: Supply and Demand Curve of Electricity[xv]



4.1.3 DR Programs

DR programs often encompass a spectrum of demand side management products and services, as well as a variety of functions between wholesale and retail entities[xvi]. Despite the best efforts of the DOE, FERC and market participants, classifying DR programs by type remains a challenge due to a lack of uniformity around market definitions and practices. As a result, DR programs are often organized by timescale, compensation, customer, and functionality (Figure 3). This report differentiates between time-based DR and incentive-based DR, while assuming that electricity customers may participate in all markets regardless of their size and current market rules. This presumption is based on recent regulatory activity.

Figure 3: DR Program Types[xvii]



Although the electric power industry has employed DR for over a decade, these resources have primarily included interruptible, capacity, and bidding programs for commercial and industrial (C&I) customers with a load profile of more than 200 kW[xviii]. Operators continue to source the majority of their DR resources from large C&I through interruptible tariffs, capacity, and demand bidding programs. However, industry regulators and market participants have recently begun to broaden the scale and scope of DR markets and applications. CSPs and power dispatchers have expanded their programs to include not only small (< 20 kW) to medium (20-200 kW) C&I customers, but also residential customers.

According to FERC, residential customers represent the most untapped potential for demand response and offer the largest per-customer contribution under pricing programs. SBI Energy and Frost and Sullivan believe residential DR programs will play a substantial role over the next five years, but admit that residential DR remains in the pilot and evaluation phase despite receiving most of the market's attention since 2007[xix]. An example of successful residential programs is Florida Power and Light (FP&L) Company's "On Call" initiative that boasts the ability to shed ~1,000 MW while employing more than 900,000 load control transponders across more than 750,000 enrolled customers[xx].

4.1.3.1 Price-based DR

Price-based DR programs require advanced metering infrastructure (AMI) such as smart meters that are able to convey dynamic rates and record usage over shorter periods of time than traditional technologies.

Time-of-Use Pricing Rates

Time-of-use (TOU) rates vary by intra-day periods, day of the week, and season to reflect the average cost of generating and delivering power during that period[xxi]. TOU rates are typically conveyed well in advance and based on static peak and off-peak rates that reflect the average cost of generating and delivering power during those periods. Their inability to reflect operating conditions has led FERC to exclude TOU rates from its own DR Assessments[xxii].

Dynamic Pricing

Dynamic pricing encourages customers to adjust their consumption patterns to capture savings based on dynamic electricity rates that change on a day-ahead or real-time basis. These rates fluctuate according to the cost of providing electricity at a particular time, which is directly related to load levels, reliability concerns, and critical events. Peak periods command a premium as a result of the higher-than-average cost of generation, while off peak hours see lower prices due to lower-than-average costs.

Dynamic rates include the following initiatives and additional incentives[xxiii]:

- **Real-time prices (RTP) -** fluctuate hourly to mirror the wholesale price of electricity and are typically conveyed on a day-ahead or hour-ahead basis.
- **Critical peak prices (CPP) -** blend TOU and RTP features by maintaining TOU under normal operating conditions and a higher price under predefined conditions such as when system reliability is compromised or fuel prices jump.
- **Peak time rebates -** reward demand reductions rather than penalize consumption during specific periods.

Dynamic rates are further broken down into dispatchable and non-dispatchable resources[xxiv]:

- **Dynamic Pricing with Enabling Technology (Dispatchable) -** rely on control and communications technologies to automatically reduce consumption. Customers program their preferences based on their needs and desired cost savings into automated systems. Technologies such as programmable thermostats and large automated building control systems are driving the implementation of these programs into residential and commercial applications respectively[xxv].
- **Dynamic Pricing without Enabling Technology (non-Dispatchable) -**passive programs rely on the end-user to reduce consumption manually based on individual preferences and dynamic rates. Customers may curb or reschedule certain activities such as laundry or dishwashing to realize lower rates. Non-dispatchable DR capacity is expected to be more difficult to estimate given the inevitable unknowns associated with behavior-based solutions.

4.1.3.2 Incentive-Based DR

Direct Load Control (DLC)

DLC authorizes grid dispatchers to cycle the end-use devices (HVAC systems, water heaters, etc.) of residential and C&I customers on and off to maintain reliability in exchange for cost savings. These programs rely on programmable technologies and switches to cycle conventional devices and may well be one of the first DR technologies applied to EVs due to the low cost of implementation and high degree of certainty that it affords.

Interruptible Load (Tariffs)

Interruptible load programs reduce consumption to pre-approved levels for C&I customers during periods of grid instability. Compensation for interruptible load events is provided in the form of rate discounts or bill credits. CSPs may provide notice before curtailment pending the specifics of each contract.

Capacity Bidding

Capacity programs employ DR resources to displace or supplement traditional generation or delivery resources during planning and operation. Operators signal to CSPs and other dispatchers when curtailment is required and penalize those that are unable to provide the contracted capacity. Contract terms include a maximum level of DR over a defined period of time. Since FERC's first proposal to allow DR to participate in organized capacity markets in 2008, DR providers have bid into capacity markets in PJM ISO region and ISO-NE. Only regulated utilities can bid into these programs.

Demand Bidding & Buyback

Demand programs allow DR providers to set desired prices for a set amount of load, or a particular amount of load curtailment at a specific price.

Ancillary Services

Grid operators have also begun to accept load curtailments from aggregators and grid dispatchers through the ancillary services markets – competitive markets that allow dispatchers and other participants to buy and sell reliability products and services at competitive rates. Currently, CSPs and other aggregators may bid curtailment capacity into the market at market rates. If these resources are called on, they also receive the spot-market price for energy. Although DR resources have yet to participate in ancillary services markets at a meaningful scale, widespread changes in the way DR is sourced and paid for are set to change the process.

4.1.4 California & DR

Since implementing TOU pricing for all large C&I customers in 1978, California has led the charge in pursuing DR resources. For example, following the energy crisis of 2000-2001, the state approved a resource loading order that placed DR behind energy efficiency, but ahead of renewable energy resources and conventional generation[xxvi]. While this designation does not favor demand resources in the energy mix, it is used to guide energy policies and decisions. As a result, the state has pursued programs like the 2003/2004 Statewide Pricing Pilot (SPP), which indicated that despite concerns of sustained consumption impacts, residents and small C&I customers will support dynamic CPP rates with statistical significance.

Over the past year, FERC has conditionally accepted the following CAISO compliance filings related to the provision of ancillary services via DR as outlined by FERC Order No. 719 (

Table 1):[xxvii]

Table 1: CAISO Compliance Filings & Implications

FERC Approval Date	Description of Filing	Implication
June 2010	Outlines the implementation and need for a Scarcity Pricing Mechanism (SPM) – a mechanism to apply pre-determined prices in the day-ahead and real-time markets for energy and ancillary services markets associated with the procurement of regulation and reserves. Prices are based on demand curves drawn by administrators in each region[xxviii].	By allowing prices to rise during times of scarcity and compensating demand-side ancillary services resources accordingly, CAISO aims to more accurately reflect the value of such services during operating shortages.
July 2010	Permits an aggregator or DR provider to bid directly into CAISO's day-ahead and real-time energy service and ancillary service markets on behalf of retail customers through a mechanism known as Proxy Demand Resource (PDR). Proxy Demand Resources includes load or aggregated loads that are capable of measurable and verifiably reducing demand when prompted by CAISO dispatch instructions. Resource performance is to be verified against baselines built off historical metered-demand[xxix].	This basic rule change allows retail customers to participate in organized markets, including those related to ancillary services, via aggregators. At the time of implementation, only the non-spinning reserve market will be available to PDR.
September 2010	Includes tariff revisions that target the equal treatment of demand and supply resources in the ancillary services markets[xxx].	

4.2 DR via EVs (DR-EV)

4.2.1 Potential DR-EV Products and Services

According to FERC's annual assessment of DR, the residential market for DR remains largely untouched and holds the most potential for growth[xxxi]. Within this end-consumer market, the ISO/RTO Council (IRC) has identified a number of scenarios where EVs may be managed as demand-side assets (**Appendix 1**). While the specifics of how these DR-EV methods are most likely to be deployed at scale remain unknown, DR-EV has the potential to provide the following products and services.

4.2.1.1 Enhanced Aggregation (EA)

Aggregating EVs would provide the scale, control, and flexibility required to participate in energy markets and impact grid operations. In order to increase the efficacy of this consolidation, EA will most likely be deployed along with dynamic and TOU pricing programs to predict with some degree of certainty how a particular set of customers may react. Similar to the way that traditional DR programs reduce loads across a large number of customers, EV aggregators should be able to monitor individual charging profiles to model expected supply and adjust load across a network of vehicles based on actual demand.

4.2.1.2 Dynamic Pricing (DP)

Dynamic pricing generally refers to any variable pricing scheme that reflects current supply and demand factors through "time-based rates". The goal of such programs is to influence end-users to reduce or delay consumption by charging higher prices during peak periods or critical events and lower prices when demand is lower. In the case of an EV user, dynamic rates would most likely be used to incent drivers to charge their vehicles at night, when demand for electricity is less. Unfortunately, consumer behavior is difficult to predict and the impact of such rates continues to be debated. As a result, despite FERC's assessment that universal and mandatory dynamic pricing could achieve peak demand reductions of 20% of peak by 2019 and considerable attention from utilities, startups, and data management companies like Google and IBM, the use of variable rates remains limited[xxxii]. Furthermore, of the few states that have approved such plans, most have only adopted rebate plans that reward customers for reducing demand on only the most critical hours of particular days. In contrast, California has adopted a critical peak pricing tariff as its default rate for commercial and industrial customers. It should be noted that dynamic pricing does not include time-of-use programs, which set rates for particular blocks of time during the day, but are otherwise static.

4.2.1.3 Emergency Load Curtailment (ELC)
The quick-response functionality of EVs indicates they are particularly well suited to provide reliability-based DR through the emergency load curtailment (ELC) of charging. Moreover, the mechanisms associated with this service charging are expected to be relatively simple and inexpensive to implement, increasing the likelihood that ELC will be one of the earliest DR-EV to reach the market. For the purposes of this report, ELC is not being considered as it is an emergency service, not a market-based ancillary service.

4.2.2 Drivers of DR-EV
Since FERC advocated for the widespread adoption of DR in the Energy Policy Act of 2005 (EPAct 2005), a variety of policy, market, and technology innovations have sought to unlock the DR market. The size and scope of DR programs are expected to increase substantially over the next decade, particularly in regards to the residential market, which is expected to include EVs.

4.2.2.1 Smart Control and Communication Technologies
Enabling technologies such as advanced metering infrastructure (AMI), home networks, and interoperability standards are expanding the number of appliances and systems available to DR. Programs have already begun incorporating DR-enabled space heaters, HVAC systems, washing machines, dishwashers, pool pumps, and lighting installations into their DR offerings. As the pace of innovation quickens and prices fall, policy makers and DR providers hope to apply DR to devices that can manage demand and control power flows in and out of storage devices.

Meanwhile, mobile applications are changing the way information is delivered. Although some researchers are skeptical that real-time price signals will provide enough financial motivation to drive customers to save[xxxiii], other studies and pilot programs such as California's Statewide Pricing Pilot indicate that transparent feedback is critical. Moreover, studies have also shown that frequent information delivered through interactive tools increases the likelihood of achieving real savings. [xxxiv]With more than half a million smart phones sold every day, consumers are increasingly using powerful handheld communications platforms and applications. By transmitting and receiving dynamic information such as geography, electricity prices, and usage preferences, these tools are expected to dramatically change the way customers view their energy consumption[xxxv].

Finally, EV load control and aggregation demands sophisticated software and hardware, in addition to on and off-board communications technologies and infrastructure (Table 2)[xxxvi].

Table 2: Complementary Technologies & Implications

Enabling Technology	Implication
Low-latency, Moderate-bandwidth Communication Networks	Affordable broadband and other local communication networks are expected to be widely available over the next decade. According to a paper authored by Google engineers, many of the networks currently being rolled out by the utilities for other smart grid applications are not able to support DR[xxxvii].
Software	Sophisticated algorithms and communication protocols are required to handle the telemetry associated with regulation and reserves[xxxviii].
Advanced Batteries	Cheaper and more efficient battery technologies are also essential to enable grid applications for EVs. Experts from the IRC and Taratec expect PEV and battery manufacturers to limit warranties to normal driving conditions, or a maximum 2-10 second cycle between charging and non-charging state. For example, in order to provide grid services, EVs will most likely require a higher rate of charge/discharge than if they were being used for transportation exclusively[xxxix].
Charging Infrastructure	Based on the IRC's assessment of traditional DR products and services, current charging infrastructure must improve if EVs are to ever meet market requirements[xl]. For example, manufacturers have recommended a maximum cycling rate of 15-seconds, while most DR products and services require a faster response time[xli]. In addition, charging infrastructure must be able to measure customer usage over short intervals to capture dynamic rates and services.

4.2.2.2 Saturation of C&I

Secondly, the C&I DR market is increasingly saturated. Publicly held DR providers have already tapped their largest customers and are constantly seeking additional growth opportunities. The size of the average C&I load means these individual users require fewer controls and are cheaper and easier to automate. However, as traditional C&I DR systems achieve market saturation, CSPs are expected to target residential consumers, which have been estimated to represent 60% of peak load[xlii].

4.2.2.3 Standardization

The standardization of charging infrastructure such as communication networks, metering and electric flow control, and plug interfaces is expended to expedite the use of EVs for grid services[xliii]. In addition, any ISO/RTO products will require interoperability standards so that aggregators and balancing authorities can collect, validate, and settle transactions, while simultaneously determining individual EV performance[xliv].

4.2.2.4 Policy

Since the Energy Policy Act of 2005, FERC has pursued a series of orders, assessments, and reports to ensure that DR remains competitive while simultaneously preserving system reliability, the accuracy of reliability assessments, and the standardization of reporting and evaluation[1]. Regulators have repeatedly

[1]Under the reliability provisions of EPAct 2005 and subsequent rulings, FERC has established the rules governing the formation and operation of an independent self-regulatory agency known as the Electric Reliability Organization (ERO). As the United States ERO since 2006, the North American Electricity Reliability Council (NERC) has sourced, reviewed, and approved the Reliability Standards that govern electric utilities and ensure the reliability of the bulk power system. These planning and operating rules must be "just and reasonable, not unduly preferential, and in the public interest. " The NERC Standards Committee, comprised of representatives from across the electric industry, submits proposed standards to FERC for final approval.

praised the rapid response and capital efficiency of DR while taking steps to ensure that providers of these resources are compensated fairly in both wholesale and ancillary service markets. In addition to outlining DR scenarios and recommending general policy actions through a National Action Plan on Demand Response, FERC has also passed highlighted the ability of DR to supply ancillary services in restructured markets[xlv].

FERC Order No. 719

FERC Order No. 719 attempts to put demand response on par with other resources in ancillary services markets and increase the likelihood that DR will be deployed. [xlvi]In order to comply with the rulemaking, ISO/RTOs must:

- Accept bids from DR in ancillary service markets on a basis comparable to other resources
- Remove charges normally incurred during system emergencies when buyers in the energy markets call on less electricity in the real-time market than purchased in the day-ahead markets
- Allow aggregators of retail customers to bid DR directly into organized energy markets as an agent of the customers
- Modify market rules to allow the market-clearing price to fluctuate during times of operating-reserve shortage such that it rebalances supply and demand, maintains reliability, and provides sufficient provisions for mitigating market power

Comparable Treatment

Most recently, the Commission has taken steps to ensure the comparable treatment of demand resources with supply resources in RTO/ISO markets. On March 18, 2010 FERC proposed that ISO/RTOs with DR rate provisions must compensate CSPs and other DR providers at the market price for energy in wholesale markets at all times. While this ruling does not directly impact the ancillary services markets, it opens the door for DR to scale at the residential level, potentially driving the adoption of DR-EV[xlvii].

4.2.2.5 Networkable

Aggregating EVs to provide DR products and services is advantageous for a number of reasons. Firstly, it provides certainty. Just as the consumption patterns of individual residents and C&I vary considerably by time and customer, the driving patterns of individual drivers fluctuate. Assuming that compatibility requirements are met across vehicles, one of the best ways to overcome such variability is to cluster EVs into networks of distributed EES assets. In addition, aggregation allows potential aggregators such as utilities, automakers, and 3rd party operators to meet minimum requirements for participation in energy markets. Finally, aggregation has the potential to drive cost savings through scale efficiencies, particularly around the regulatory, administrative, and legal challenges associated with operating modular electricity resources such as EVs[xlviii]. This project assumes an aggregator is able to network EVs together by coordinating their operation without sacrificing personal convenience.

4.2.2.6 Low Capacity Factor

The relatively low capacity factor of EVs for transportation indicates that the majority of vehicles are available for secondary functions even during periods of peak usage. Research indicates that primary use is limited to just 4%, which leaves 96% of the day for secondary usage. This is in stark contrast to traditional generation units, which are defined by much higher capacity factors as a result of their high capital costs.

4.2.2.7 Dispatchable

Similar to most generation, storage, and load-controlled resources, EVs represent dispatchable load assets – energy resources whose output may fluctuate according to real-time control and price signals.

4.2.3 Barriers to DR-EV

4.2.3.1 Shared State and Federal Jurisdiction

The sharing of jurisdiction between states and federal authorities is a potential problem for DR-EV. Retail markets are regulated on a state-by-state basis while wholesale markets and transmission are under FERC jurisdiction. Because of this disconnect there are many instances where different regulatory bodies may enact opposing policies which prevent the cooperation necessary to make demand response an efficient solution[xlix]. This is especially relevant in the EV application since by their nature, vehicles are mobile, can cross-regulatory borders, and be charged in different locations. Aggregators and regulatory bodies must cooperate in order to overcome these challenges.

4.2.3.2 Program Design and Network Effects

Because of the nature of the DR-EV program design, network effects are a potential challenge. As with any other network-based service, a critical mass of users is required before any benefits can be derived. If there are insufficient numbers of users in each aggregator network, or if the participation rates of the users within networks are too low, aggregators may not be able to participate in ancillary service markets. At the same time this limits benefits to end users and therefore raises the cost of EVs, further perpetuating a negative cycle.

4.2.3.3 Lack of Sufficient Financial Incentives to Induce Participation

DR-EV programs will include voluntary participation from end users. In order for DR-EV to be successful, aggregators must confer enough financial incentive to their users in order to induce participation levels that will produce enough capacity to bid into ancillary service markets. Participation in DR-EV reduces costs for users, but also decreases flexibility and convenience in the use of vehicles to some extent. In addition, EV owners must weigh the value of potential DR revenues against any negative effects on battery life associated with providing such resources. Depending on the cost of operation of DR-EV systems, aggregators may or may not be able to offer compelling financial incentives to induce necessary participation levels.

4.2.3.4 Driver Behavior & Uncertainty

The variability inherent in the operation of EVs is a significant impediment to their participation in the electricity markets, which require demand scale and certainty. The idea of range anxiety is particularly hard to overcome and forecast. While one driver may be comfortable driving with a low state of charge, another may prefer to be at near full charge as often as possible.

4.2.3.5 Cost

While many of the automation and communications technologies required for EV-DR may piggy-back on existing systems such as WI-FI or utility smart grid build-outs, the sheer cost of aggregation infrastructure and implementation may be prohibitive.

4.2.3.6 Over-Supply of Ancillary Services

As of 2011, the CAISO market for ancillary services is abundantly over-supplied. According CAISO representatives, there is currently ten times the necessary capacity to serve the ancillary service market[l]. A market with this level of over-capacity would not usually be considered a favorable business to enter. However, DR-EV may be a low cost option as a result of a low marginal cost. For example, it is possible that the outlays associated with the installation and operation of EV charging infrastructure may be considered towards the cost of providing charging services. DR may simply be an additional service with a difficult to determine, but low marginal cost. If this is the case, then it is likely that DR-EV will be cost competitive with other ancillary service providers.

5 Electric Vehicle Electric Energy Storage (EV-EES) Applications

5.1 Introduction to EV-EES

This section covers the various potential applications of Electric Energy Storage (EES) that can potentially be provided by electric vehicles. In theory, there are a wide range of grid related applications for storage technology. However, due to various reasons – technology, cost, scalability, etc. – storage technology is suitable for a small section of these applications. This section of the report attempts to describe the various categories of applications, identify selection criteria for their suitability with EV-EES and then finally explore the current available market potential for the services deemed suitable.

Table 3: Categories of Energy Storage Applications

Energy Storage Applications
Category 1 – Electricity Supply
1. Electric Energy Time Shift 2. Electric Supply Capacity
Category 2 – Ancillary Services
1. Regulation 2. Spinning Reserves 3. Supplemental Reserves 4. Replacement Reserves 5. Load Following 6. Voltage Control 7. System Control 8. Real Power Loss Replacement
Category 3 – Grid System Support
1. Transmission Support 2. Transmission & Congestion Relief 3. Transmission & Distribution Upgrade Deferral 4. Substation on-site Power

5.1.1 Capacity Applications versus Energy Applications

When considering grid related applications for storage, it is important to distinguish between the so-called *energy* applications and *capacity* applications. The nature of these two application segments presents very different costs structures to potential service providers and regulatory implications for utilities.

Energy Applications: This typically involves the storage of a significant amount of energy by the EES system. This stored energy offsets energy that would otherwise need to be purchased from and generated by the grid. Due to the nature of these applications, service providers need to account for costs due to energy losses from storage, EES degradation costs and the cost of energy consumed when charging the EES system. Investor Owned Utilities treat purchases or generation of energy as an expense, which under the revenue requirement regulatory structure should be passed on to consumers directly without any mark-up.

Capacity Applications: Here, the presence of EES systems decreases, by some amount, the addition of generation and transmission capacity for an investor owned utility. In other words, the presence of the EES system alone is a form of service that enables utilities to avoid capacity additions. Since significant amounts of energy are not transferred during the provision of these services, providers do not need to worry as much about degradation costs or energy losses. And more importantly, capacity additions are treated as an investment, off which utilities are allowed to earn a rate of return (profit). In theory, this allows service providers some pricing flexibility when providing these services.

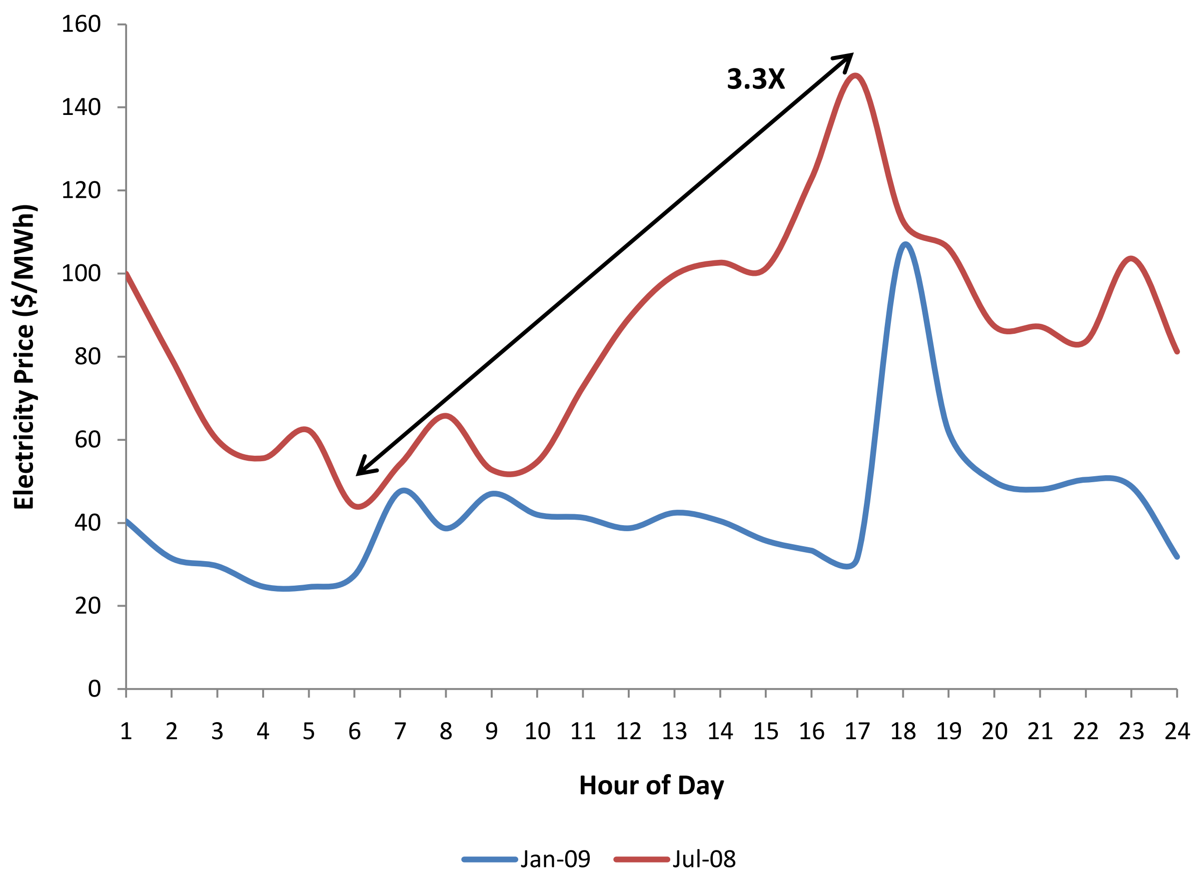
5.2 Categories of EES applications

5.2.1 Electricity Supply

5.2.1.1 Electric Energy Time-shift

This application involves purchasing electricity when prices are low, typically during periods of low demand, and selling the charged energy when prices are more favorable. According to current regulations, both utility and non-utility merchants can engage in this service provision. As **Figure 4** indicates, intra-day electricity prices can vary significantly – sometimes by as much as 400%. Service providers can take advantage of these large price swings to charge their EES systems when prices are low (say at 5AM) and then sell this energy back to the grid when prices are higher (say at 5 PM).

Figure 4: Hourly Electricity Prices in California[li]



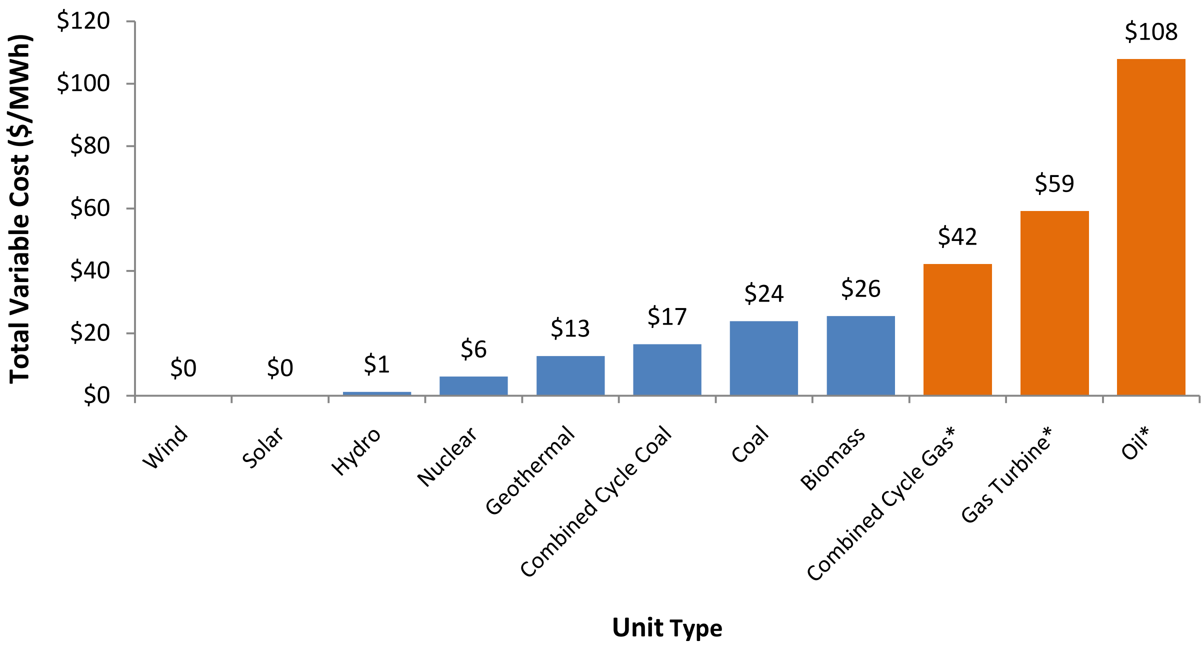
However, as this becomes more prevalent in the long run, prices will gradually begin to level out between the high demand and low demand periods. As this is a typical *energy application*, service providers will need to consider charging electricity, storage loss and degradation costs when making provisioning decisions.

5.2.1.2 Electric Supply Capacity

EES could be used to defer and/or reduce the need to purchase new generating capacity in wholesale electricity markets. In the United States, most generating plants that are used for *peaking* purposes are natural gas fired combined-cycle power plants. Utilities pass these capacity addition costs on to consumers by allocating them to each unit of energy generated. These allocated costs depend on the nature of capacity being added, and are broadly categorized into installation and fixed operations and maintenance costs.

More often than not, these peak load plants are left idle because their operation costs are higher than for base load generation sources such as coal and nuclear. These plants are operated only during peak demand, when electricity prices are high enough to support a positive marginal contribution from their operation. As seen below in Figure 5, peak load plants are economically feasible only when the price of electricity is greater than $42 per MWh. When the price of electricity drops below this level (as a result of falling demand), these plants are idled and amount to excess generating capacity on the grid.

Figure 5: Variable Generation Costs by Unit Type[lii] [2]



* Denotes critical peak plant

EES systems can reduce the need for peaking plants by providing previously stored electricity during periods of high demand. Consequently, utilities and power generators can reduce the fixed cost they incur

[2] Brattle Group unit-specific data, Michigan team Analysis; includes Variable Operating & Maintenance Costs and Fuel Costs in real 2010 USD. Fuel costs ($/MMBtu): Coal – 1.63, Natural Gas – 5.82, Oil – 10.59, Biomass – 1.95, Uranium – 0.42

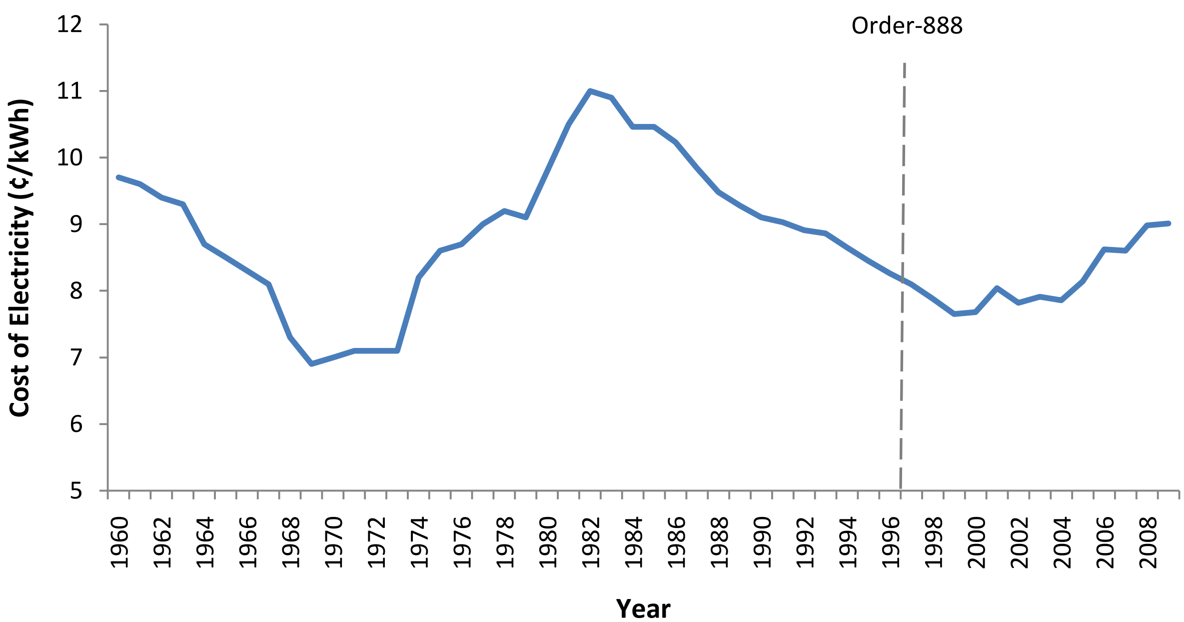
when building out peak capacity. This is a typical capacity application, where service providers are compensated for every unit of excess capacity they take off the grid for the specified period of time.

5.2.2 Ancillary Services

5.2.2.1 Regulatory Background

In 1996, the Federal Energy Regulatory Commission's (FERC's) landmark decision (Order no. 888) to functionally separate generation and transmission exposed the array of bulk-power functions called ancillary services. Unbundling these two functions did not create the services themselves, as investor owned utilities had to provide these services in order to maintain the stability of the grid. However, in the wake of the decision, customers paid a single rate for both electricity and ancillary services, as opposed to before when the price of ancillary services was coupled with the cost of producing electricity. FERC determined that this vertically integrated structure where utilities were responsible for generation, transmission and distribution resulted in a higher cost of electricity to the consumer. Theoretically, unbundling these different functions and employing a market-based mechanism to provide these services would lower the cost of electricity to the consumer and reduce price volatility.

Figure 6: Retail Price of Electricity in the United States (1960 – 2008)[liii] [3]



As Figure 6 shows, after the order was passed in 1996, the retail price for electricity has fluctuated, but the volatility is markedly lower[4]. Also, studies have suggested that in aggregate, the prices of ancillary services are highly correlated with the price of electricity. This suggests that the embedded-cost tariffs that were being used by the utilities before Order-888 did not properly account for the costs incurred in providing these services[liv]. Thus, unbundling them and allowing efficient markets to provide them should set prices more accurately.

5.2.2.2 Introduction to Ancillary Services

The Federal Energy Regulatory Commission defines ancillary services as those "necessary to support the

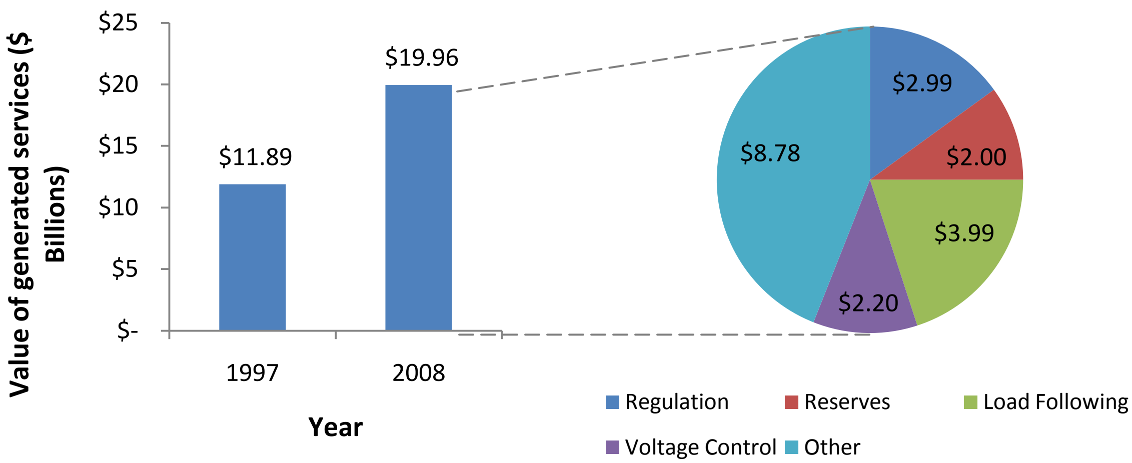
[3] All values in constant 2005 USD

[4] Standard deviation before 1996 = 1.11¢/kWh, after 1996 = 0.45¢/kWh

transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system"[lv]. In other words, they are the activities and functions that enable the produced electricity to reach end consumers reliably.

According to research by the Oak Ridge National Laboratory, these services cost consumers approximately $12 billion per year at an approximate price of $4/MWh. Given the increase in annual generation and accounting for the increase in the general price of electricity itself, our team estimates that the ancillary services market for the United States was worth approximately $20 billion at the end of 2008, most of which was provided by typical generator-type sources.

Figure 7: Projected Ancillary Services Market and Breakdown[lvi] [5]



5.2.2.3 Description of Ancillary Services

As
Figure 7 shows, ancillary services can be broadly classified into the following categories.

Load following

Load following is the use of online generation equipment to track the Inter–hour changes in customer loads[lvii]. Unlike minute-to-minute fluctuations, which are generally uncorrelated among customers, the hourly and diurnal changes in customer loads are generally correlated with each other.

Frequency regulation

Frequency Regulation (often called Regulation) is the use of online generating units that are equipped with governors and automatic generation control (AGC) and that can change output quickly (MW/minute) to track the moment-to-moment fluctuations in customer loads and unintended fluctuations in generation[lviii]. In so doing, regulation (along with spinning reserve) helps to maintain interconnection frequency, minimize differences between actual and scheduled power flows between control areas, and match generation to load within the control area. This service can be provided by any appropriately equipped generator that is connected to the grid and electrically close enough to the local control area that physical and economic transmission limitations do not prevent the importation of this power. This is called extremely often (400 times per day). Of critical importance, is the "dispatch–to–contract ratio"

[5] Michigan Team Analysis

which measures the amount of energy dispatched to the (contracted capacity * duration in hours). That is empirically found to be 0.08 – 0.10.

Spinning Reserves

Spinning reserve is the use of generating equipment that is online and synchronized to the grid that can begin to increase output immediately in response to changes in interconnection frequency and that can be fully available within ten minutes to correct for generation/load imbalances caused by generation or transmission outages[lix]. Most "calls" to the spinning reserve systems are between the duration of 10 minutes to two hrs. Contracts limit the number of calls to typically around 20 per year.

Non-Spinning

Supplemental reserve is the use of generating equipment and interruptible load that can be fully available within ten minutes to correct for generation/ load imbalances caused by generation or transmission outages[lx]. Supplemental reserve differs from spinning reserve only in that supplemental reserve need not begin responding to an outage immediately. This service may also include replacement reserves, the provision of additional generating capacity that must be fully available within thirty or sixty minutes (the exact time depends on the rules of the regional reliability council) and can then be maintained until commercial arrangements can be made (e.g., for two hours) to "back up" the normal supply for the load (operating reserves).

The primary cost for these reserves is traditionally the opportunity cost of holding some generating capacity off the market and available for emergency use. Given that the units providing these reserves need not be operating (as with spinning reserve), their costs would normally be less than that for spinning reserves. If the spinning reserve market clears first, however, it may use the cheapest resources. Supplemental and replacement reserves might then be more expensive, in a competitive market, than spinning reserves. The charges for operating reserves, both spinning and supplemental, will reflect primarily the capacity assigned to these services each hour, captured in a $/MW-hour charge.

Voltage control

Voltage control is the use of generating and transmission-system equipment to inject or absorb reactive power to maintain voltages on the transmission system within required ranges[lxi]. FERC decided that the costs of voltage control provided by transmission equipment [e.g., through capacitors, tap-changing transformers, condensers, reactors, and static VAR compensators (SVCs)] should be incorporated into the basic transmission tariffs, and not charged for separately. FERC decided that voltage control provided by generators should be a separate service. (In general, generators can change their production and absorption of reactive power much more rapidly than can transmission-related voltage-control equipment). Because reactive-power losses are much greater than real-power losses, voltage-control equipment must generally be dispersed throughout the system and located close to where the voltage support is needed.

Real Power Loss Replacement

Real-power-loss replacement is the real-time provision of energy and capacity to compensate for losses in the transmission system. As with energy imbalance, the cost factors for loss replacement are the same as those for the basic energy service. Loss replacement will also likely be priced in $/MWh and charged on the basis of the current hourly spot-market price with the amount of service consumed computed hourly.

In the next section, we will discuss the various selection criteria employed to filter this list of services to determine which are most suited to be provided by storage devices in a distributed network of EVs.

5.2.2.4 Selection criteria for compatibility with EV EES

While most ancillary services can theoretically be provided for by storage, those that can be provided successfully by EV EES are far more limited. Based on research conducted by NREL and interview with subject matter experts, the team has developed a set of criteria with which to filter the list of services that can be successfully provided by EV EES. They are:

- Supply Duration
- Directional Shifts
- Response Rate
- Service Duty

Supply Duration

This is the period of time for which the service is called on at every instance. Depending on the service, it ranges from a few minutes to a more than ten hours. Most EV EES resources are expected to be variants of the Lithium-Ion (Li-Ion) technology. While there may be some cases of Nickel-Metal-Hydride (NiMH) batteries used in traditional grid-free hybrid vehicles, they are slowly being phased out due to their low energy density and high cost. Lithium-Ion is significantly more energy-dense than the other technologies available, but it is also one of the most expensive. Thus, services that have a large supply duration require larger Li-Ion batteries (due to the longer energy drain), which in turn drive costs higher. Supply durations ranging from a few minutes to a few hours are ideal for EV EES.

Directional Shifts

Both, electricity supply and demand, shifts are bi-directional. That is, loads ramp up and down depending on consumer usage, and supply ramps up and down depending on generator performance, outage and utilization. Some services are extremely volatile, undergoing shifts in both directions rapidly (multiple times within a minute). Other services ramp in only a single direction for prolonged periods of time (few hours). To minimize asset degradation during bi-directional shifts, short and volatile services are more suited to EV EES. Unidirectional shifts for long periods of time are not particularly suited to EV EES due to the degradation effects on the assets. The results are summarized in Figure 8.

Figure 8: Directional Shift Suitability of EV EES

Direction of Shift	Frequency of Shifts: High	Frequency of Shifts: Low
Up	Yes	No
Down	Yes	Yes

Response Rate

This is the time within which the resource providing the ancillary service needs to initiate service. Depending on the nature of the event, response times for various ancillary services range from less than one minute up to one hour. The base response rate requirements for the services are set by the Federal Energy Regulatory Commission. Local Independent System Operators add regional requirements depending on region-specific characteristics such as generation mix, outage frequency, etc. Traditional providers of ancillary services need fairly long ramp up times. In order to provide the rapid response services, generators tend to keep plants idling but operational so that they can ramp up rapidly in the case of an emergency. This increases costs due to continued fuel consumption even though the service is not being actively demanded. However, the advantage that EV EES provides is that it can ramp up or down rapidly without requiring to be idled, thereby potentially providing higher response times at reduced costs.

Service Duty

Service duty refers to the nature of consumption of the ancillary services. Some service such as Spinning and Supplemental Reserves, are called on only in the case of a previously unforeseen event – a plant outage or a sudden unplanned increase in load. Other services such as Regulation and Voltage Control are required virtually around the clock. While EV EES can technically provide both services, it is more suited to intermittent services that enable the asset to be charged while it is not providing the service.

5.2.2.5 Suitability of EV EES to Ancillary Services

Applying the four criteria outlined above to the list of ancillary services, the team has determined that there are primarily four ancillary services that can have high potential for provision by EV EES. These results have been verified qualitatively by experts from organizations such as ORNL and EPRI.

Table 4: Ancillary Services EV EES Compatibility Matrix

Service	Supply Duration	Directional Shifts	Response Rate	Service Duty	Suitable for DR-EV?
(Frequency) Regulation	10–15 min	High	<1 min	Continuous	Yes
Spinning Reserves	10 min–2 hours	Low	<10 min	Intermittent	Yes
Supplemental Reserves	10 min–2 hours	Low	<10 min	Intermittent	Yes
Replacement Reserves	2 hours	Low	<30 min	Intermittent	Yes
Voltage Control	-	-	-	-	No
Load Following	1–10 hours	Medium	<1 hour	Intermittent	No
System Control	NA	NA	NA	Continuous	No
Real Power Loss Replacement	1–10 hours	Low	<10 min	Continuous	No

5.2.3 DR-EV Ancillary Services

Just as AMI is expected to open the residential market to DR, smart-charging infrastructure promises to expand load-shedding capabilities to include EVs. Aggregators will assume the role of CSP to suspend charging across a network of vehicles based on consumer usage, preferences, and location – providing the certainty to handle an emergency or meet demand for ancillary services.

5.3 Grid System Support

Energy storage can be used in a number of applications in support of the transmission grid. Broad categories of storage include transmission support, transmission congestion relief, transmission and distribution upgrade deferral, and substation on-site power. In theory, with large number of electric vehicles being aggregated and managed, it may technically be possible to supply these services with DR-EV. However, because the necessary penetration rates are not likely within the scope of this report, and because there is no current regulatory mechanism for DR-EV to participate in these markets, they have been excluded from this study. See **Appendix 2** for more detail on these applications[lxii].

6 Notable Developments Affecting Prospects for EV EES

6.1 Renewable Energy and the Electric Grid

In recent years there has been much study and speculation about how the increase penetration of intermittent renewables will affect the operation and stability of the electricity grid. While EVs do not directly interact with renewable energy resources, one of the goals of this study is to examine the energy delivery system as a whole and investigate the possible influences that EVs and renewables may have on each other. In order to introduce and illustrate the conditions under which these two may affect each other, this section will briefly review the drivers and effects of renewable energy on the grid.

6.1.1 Drivers of Renewable Energy

6.1.1.1 Cost

Due to the extremely complex nature of the energy business, many factors are considered when determining what type of generation a particular producer will invest in. However, one of the key drivers of these decisions is cost. Because different generating technologies vary widely in terms of initial capital costs, fuel costs, and operation and management costs, many managers use the Levelized Cost of Electricity (LCOE) method in order to obtain an apples-to-apples comparison.

6.1.1.2 Levelized Cost of Electricity

The levelized cost of electricity (LCOE) is generally viewed as an accurate measure of competitiveness among different generating technologies. The LCOE for a given technology represents the present value of the construction and operation of an energy-producing asset over its total useful life. The LCOE includes overnight capital costs, fuel costs, fixed and variable operation and maintenance costs, and is based on a utilization rate specific to each asset. It should be noted that some inputs such as fuel costs must be estimated during these calculations, and are subject to commodity price fluctuations that can alter competitiveness of a given technology. In addition, various incentives and subsidies are available for renewable and other technologies that are not taken into account in these calculations. LCOE, along with other factors such as projected utilization rate, existing resource mix, capacity values, and portfolio diversification are taken into account when making investment decisions.

Table 5 on the following page shows the U. S. Average Levelized Costs for plants entering service in 2016:[lxiii]

Table 5: Levelized Cost of Energy

Plant Type	Capacity Factor (%)	U.S. Average Levelized Costs (2009 $/megawatthour) for Plants Entering Service in 2016				
		Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System Levelized Cost
Conventional Coal	85	65.3	3.9	24.3	1.2	94.8
Advanced Coal	85	74.6	7.9	25.7	1.2	109.4
Advanced Coal with CCS	85	92.7	9.2	33.1	1.2	136.2
Natural Gas-fired						
Conventional Combined Cycle	87	17.5	1.9	45.6	1.2	66.1
Advanced Combined Cycle	87	17.9	1.9	42.1	1.2	63.1
Advanced CC with CCS	87	34.6	3.9	49.6	1.2	89.3
Conventional Combustion Turbine	30	45.8	3.7	71.5	3.5	124.5
Advanced Combustion Turbine	30	31.6	5.5	62.9	3.5	103.5
Advanced Nuclear	90	90.1	11.1	11.7	1.0	113.9
Wind	34	83.9	9.6	0.0	3.5	97.0
Wind – Offshore	34	209.3	28.1	0.0	5.9	243.2
Solar PV[1]	25	194.6	12.1	0.0	4.0	210.7
Solar Thermal	18	259.4	46.6	0.0	5.8	311.8
Geothermal	92	79.3	11.9	9.5	1.0	101.7
Biomass	83	55.3	13.7	42.3	1.3	112.5
Hydro	52	74.5	3.8	6.3	1.9	86.4

On a levelized-cost basis traditional technologies are more competitive than most renewable sources, particularly intermittent sources such as solar and wind. Excluding hydro (which is not an intermittent source), wind is by far the most cost competitive renewable energy source. Despite their lack of cost competitiveness, solar and wind installations are steady being built across the US. This is due to other considerations, the most import of which being regulatory policy.

6.1.1.3 Renewable Energy Regulatory Policy

The electric utilities industry is one that has historically had tremendous influence and oversight from regulatory bodies at the Federal, State and Municipal levels. This continues to be the case today. In the case of renewable energy, regulatory policy has almost complete control over the rate at which new technologies are integrated into generation portfolios. As we have seen above, renewable technologies cannot currently compete with traditional technologies on price alone. Policy is therefore perhaps the single most important driver of renewable in the US today and for the next five to ten years, or until the cost of renewable energy becomes competitive with traditional technologies.

6.1.1.4 Renewable Portfolio Standards

A key driver of renewable energy adoption from the state level is the renewable portfolio standard (RPS). Table 6 below outlines the renewable goals of each state:[lxiv]

The differences in RPSs across states represent different goals and objectives of lawmakers. This is a result of many factors including differences in priorities as well as regional variations in resources and climate. Overall, RPS is generally used to define minimum renewable resources be used for a specified portion of electricity generation, subject to requirements such as timing, technology and resources, and other policies. These standards are key drivers of renewables because they influence investor confidence. Strong RPS policies allow developers and investors to recover their capital investments and result in the development of strong markets.

Federal RPS

Currently there is no federal RPS in place. However, in recent years there have been several proposals by lawmakers to enact legislation that would mandate a renewable energy policy across the entire country. While many states have already enacted legislation to require renewable generation above what is proposed at the federal level, a federal RPS is generally seen by advocates as the only effective way of requiring non-participating states to incorporate renewables into their portfolios. Such legislation is unpopular in many areas and may be extremely difficult to pass due to perceived inequities such as differing renewable resources by geographical area.

Table 6: RPS by State

State	Target RPS (%)	Target Year (yyyy)
Arizona	10.50%	2025
California	33.00%	2020
Colorado	10.00%	2020
Connecticut	20.00%	2020
Delaware	21.50%	2027
District of Columbia	19.60%	2020
Hawaii	40.00%	2030
Illinois	18.75%	2025
Iowa		2000
Kansas	20.00%	2020
Maine	30.00%	2017
Maryland	18.00%	2022
Massachusetts	19.09%	2020
Michigan	10.00%	2015
Minnesota	25.00%	2025
Missouri	14.70%	2021
Montana	15.00%	2015
Nevada	23.50%	2025
New Hampshire	16.00%	2025
New Jersey	17.88%	2021
	5,316 GWh	2026
New Mexico	10.00%	2020
New York	20.70%	2015
North Carolina	11.53%	2021
Ohio	12.00%	2024
Oregon	25.00%	2025
Pennsylvania	10.00%	2021
Rhode Island	14.00%	2019
Texas	10000 MW	2025
Washington		
Wisconsin	15.00%	2020
North Dakota	**10% by 2015**	**voluntary**
Oklahoma	**15% by 2015**	**voluntary**
South Dakota	**10% by 2015**	**voluntary**
Utah	**20% by 2025**	**voluntary**
Vermont	**20% by 2015**	**voluntary**
Virginia	**15% by 2025**	**voluntary**
West Virginia	**25% by 2025**	**voluntary**

6.1.1.5 Renewable Energy Credits

Renewable Energy Credits (REC) are tools to represent the attributes of renewable energy generation that have inherent value that is separate from the actual commodity electricity. They are used both in the voluntary and compliance markets. As rules and regulations vary by state and region, they may also be known as renewable energy credits, green tags, or tradable renewable energy certificates. The main function of RECs is to monetize the value of attributes separately from the electricity. Doing so helps to mitigate challenges with intermittency and load matching. This separation allows RECs to avoid transmission constraints of electricity and creates markets where they can be traded and sold across geographic boundaries without losses that would have been associated with transmission over long distances. In addition, they allow consumers to choose to support renewable energy even if their providers don't offer it as an option. [lxv]

6.2 California Focus

Based on the RPS table and the variable nature of renewable markets across the US, it is clear that there is no single way to characterize the renewable adoption portfolio of the country as a whole. Of all states and ISO/RTO's across the nation, California is by far the leader in terms of favorable regulatory environment for the adoption of renewable energy[lxvi]. As of 2009, the state had nearly 14% of its generation produced from renewable sources. Of all the states it also has the most aggressive RPS of 33% by 2020. Because California and its regulatory bodies have historically been on the cutting edge of energy policy, and because it is by far the most progressive in this area, it is clear that the issues that this report focuses on will first manifest themselves in California. From an intermittent renewable perspective, it is the only state that has begun to seriously consider the consequences of high penetration rates and their implications for the grid. This report will therefore focus on the California market and regulatory environment.

Table 7: 2009 California In-State Power Generation Mix

2009 California In-State Power Generation		
Fuel Type	In-State Generation (GWh)	Percent of California In-State Power
Coal	3,735	1.8%
Large Hydro	25,094	12.2%
Natural Gas	116,716	56.7%
Nuclear	31,509	15.3%
Oil	67	0.0%
Other	7	0.0%
Renewables	28,567	13.9%
Biomass	5,685	2.8%
Geothermal	12,907	6.3%
Small Hydro	4,181	2.0%
Solar	846	0.4%
Wind	4,949	2.4%
Total	**205,695**	**100.0%**

6.2.1 Integration Effects on the Grid

As of 2010, approximately 14% of California's generation was being produced from renewable sources[lxvii]. In order to meet the 2020 California RPS goal of 33%, total generation from renewable needs to more than double. Based on technology costs and resource availability, it is likely that most of this generation will be supplied by a combination of wind and solar energy. The variability of these sources is by far the greatest of all available renewables. The resulting variable generation from these resources is predicted to cause four specific operational challenges for the California energy provision market:[lxviii]

1. The magnitude of hourly overall ramping requirements
2. Intra-hour variability
3. Over-generation issues (particularly wind)
4. Large, near-instantaneous production ramps (particularly solar)

These challenges are the product of both the wind and solar components of the forecasted portfolio. Each technology has specific advantages and disadvantages with regard to their variability and load profiles.

6.2.1.1 Wind

As a relatively low cost source of renewable energy, wind is the largest component in most renewable portfolios. According to CAISO, wind is very likely to continue to be the dominant source of renewable energy, with up to 4,200 MW to meet the 20% RPS[lxix].

6.2.1.2 Variability

As the amount of wind energy on the grid increases, so does the variability that it causes. Generally speaking, wind tends to blow stronger during the night than during the daytime hours. It also has significant variation from day-to-day, as well as season-to-season. See **Appendix 3**: Renewables Profiles and Forecast

Figure 29 for a profile of typical wind loads. Interestingly, variability over large areas (e. g. entire state footprints) may not significantly increase with increased renewable penetration because of the impact of temporal averaging, geographic diversity and wide-area aggregation. However, on the local and regional levels the added variability can range from minor to extreme. Even with temporal and spatial averaging, little or no increase in overall variability does not eliminate the extreme outliers on the tails of the distribution, which are the hours that tend to create the most operational challenges.

6.2.1.3 Forecasting

The variable nature of wind naturally calls for an increase in forecasting capabilities of utilities and regulators. On the load side, even with extremely precise weather forecasts, small variations in weather temperature can cause massive swings in load. On the supply side, despite recent improvements in forecasting capabilities, the average day ahead forecasting error for wind is approximately 20%[lxx]. In fact, some system operators will ignore renewables, particularly wind, in the day-ahead operation due to the lack of confidence in the forecast[lxxi]. These two margins combine to cause a significantly increased need for flexibility in resources. These inaccuracies compromise reliability, increase operating costs, and require greater ancillary service procurement.

6.2.1.4 Wind Over-Generation

Wind over-generation is a phenomenon that occurs when the electricity that is being generated exceeds the load and cannot be reduced. Often this results when weather fluctuates in a region with heavy wind resources and causes sudden increase in wind turbine sourced energy on the market. Because wind generators qualify for production tax credits they are always incentivized to produce energy no matter how low the current market rate of electricity may be. The situation can often be exacerbated because these conditions tend to happen in the night hours when demand for electricity tends to be low.

6.2.1.5 Solar

Solar energy is generally broken out into two categories: distributed and utility scale. Distributed systems are generally solar photovoltaic (PV) systems that tend to be smaller and regionally located. Utility scale solar generation includes PV, concentrated solar, as well as solar thermal installations. Though distributed solar is generally not considered to cause as many integration problems due to its distributed nature, in fact it can cause problems similar to those of utility scale. In addition, both types of solar suffer from some of the same challenges of wind, namely intermittency and forecasting difficulties.

However, the main challenge across all types of solar is large nearly instantaneous ramps caused by fluctuations in cloud cover. In general, solar production follows demand since it peaks during the middle of the day. However with increasing penetration of solar in the grid it is possible to experience a change in output of +/- 50% over 90 seconds and up to +/-70% in five to 10 minutes[lxxii]. Because of its high cost relative to wind, solar energy is generally predicted to account for approximately 15% of the total renewable portfolio. For example, if a given region has 35% renewables, 5% will be solar with the rest being sourced from wind.

6.2.1.6 Mix of Wind and Solar

From a variability perspective, in many cases it appears that regions which include both wind and solar are better off than those including large amounts of a single resource. With the varying load production profiles of wind and, the two resources can often complement each other because they peak at different times of the day. Specifically, solar peaks near the middle of the day, while wind tends to peak during the evening or night time hours. However, at the same time it is also possible for areas to experience situations where the two are not complementary such as when wind ramps down before solar ramps up. As with all intermittent resources, it is difficult to predict when these conditions will occur. Furthermore, additional complexity is added to the balancing challenge as geographical locations and the distributed/non-distributed nature of the resources must be considered as well.

6.2.2 Implications on the Grid / Ancillary Services

Because of the complex nature of the electricity grid, variability from region to region, differing policies and structures of various regulatory bodies, and intermittent nature of wind and solar; to date there do not exist any studies that have been able to quantify the relationship between the increased solar and wind penetration in the grid and the amount of ancillary services necessary to support them. Experts do agree, however, that a positive correlation does exist and that each region must manage it on a case-by-case basis. One approximation for the baseline required spinning reserves for a given area is three percent of total load. Recent reports, such as the 2010 NREL Western Wind and Solar Integration study, suggest one possible strategy where in addition to the baseline requirement for ancillary services, spinning reserve requirements should be increased proportional to the day-ahead wind forecast. However, in high wind hours the necessary increases would be on the order of 25% of the wind forecast. This would be an expensive strategy.

6.2.2.1 The 3+5 Rule

In general, there is no commonly accepted quantitative rule for maintaining reserves to handle increased load variability. However, the NREL report referenced above explores a simple and somewhat conservative heuristic rule: 3% of load plus 5% of forecasted wind. This means that in addition to the normal ancillary services requirement of 3% of load, 5% of actual or short-term forecasted wind generation (not 5% of installed nameplate MW) governs the commitment of additional reserves. The study claims that while outliers always exist, the 3+5 rule usually provides the necessary coverage. It is conservative at the study footprint level, i.e. assuming control areas cooperate for intra-hour balancing. In contrast, the performance of individual areas ranges from good coverage of the reserve requirements to frequent violations. This suggests that in practice, customized reserve rules for individual areas are likely to be necessary. As our revenue analysis shows, we have made conservative projections as to the total future demand for ancillary services, around which we will demonstrate sensitivity analysis. This 3+5 rule will be used as a proxy in our analysis.

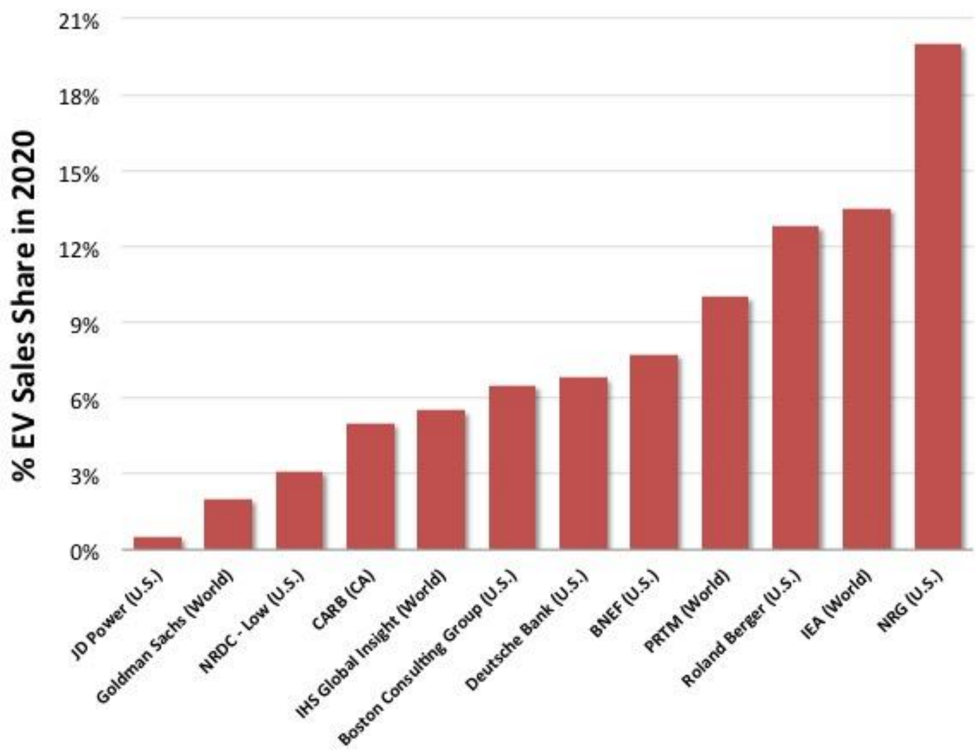
7 Electric Vehicle Adoption

Many organizations, including consultants, banks, and OEM vehicle manufacturers have produced studies in the last few years that forecast the adoption of electric vehicles domestically and globally. Not surprisingly, these estimates vary widely based on assumptions and intended purpose.

Many organizations - including vehicle OEMs, banks, consultants, and research organizations - have recently published reports that project the domestic and global adoption of electric vehicles over the next five to ten years. These forecasts are highly sensitive to a host of important drivers, including assumptions related to the future of fossil fuel price volatility, demand for vehicle ownership, consumer appetite for range limitation, Li-ion battery technology *and* costs, population growth, and availability of EV support infrastructure, to name just a few.

A sample of the range of EV adoption forecasts can be seen in Figure 9[lxxiii].

Figure 9: EV Adoption Rate Forecasts, 2020



7.1 EV Adoption Drivers and Barriers

While there are a number of potential factors that will impact EV adoption in the US, the following are of critical importance:

- **Stability of grid infrastructure**: as currently configured, the US electric grid cannot handle transmission and distribution of the volume of energy that will be required by a sudden mass adoption of EVs by consumers. This problem is particularly acute at the street and individual home level of the grid. For example, some physical grid components are designed to cool off during evening hours to prevent breakage caused by overheating during the day. Because much of the appeal of an electric vehicle is the ability to charge it at home, utilities and regulators must ensure that the grid infrastructure can handle the increased load that EVs will place on the grid[lxxiv].

- **Sales Price**: As with any other large and expensive consumer purchase, cost will play an important role in the speed of EV adoption in the US. Currently, a significant percentage of the total manufacturing cost for electric vehicles is contained in the battery itself. Technological improvements and economies of scale will continue to improve battery quality while reducing production costs; however, it is unclear how fast these advances will occur. Moreover, many studies indicate that early adopters of EVs will incur first-mover cost penalties relative to conventional ICE hybrid vehicles, even if cost reductions in lithium batteries occur as forecast. Financial incentives, including various federal and state tax credits, will reduce the overall cost to consumers and therefore will encourage faster EV adoption rates.

- **Fossil Fuel price level and volatility**: At the current average prices of oil and electricity in the US, the lifetime total cost of ownership for EVs is greater than equivalently sized ICE vehicles. However, industry analysts have predicted that when gasoline prices reach just over $5/gallon, electric vehicles will cost less than ICE vehicles to own and operate. While a break-even point for gasoline price varies based on other factors such as cost of electricity, government rebates, and battery technology, our conclusion remains the same: as gasoline prices increase it will make increasing economic sense for consumers to make the switch to electric vehicles, which may lead to progressively greater adoption[lxxv].

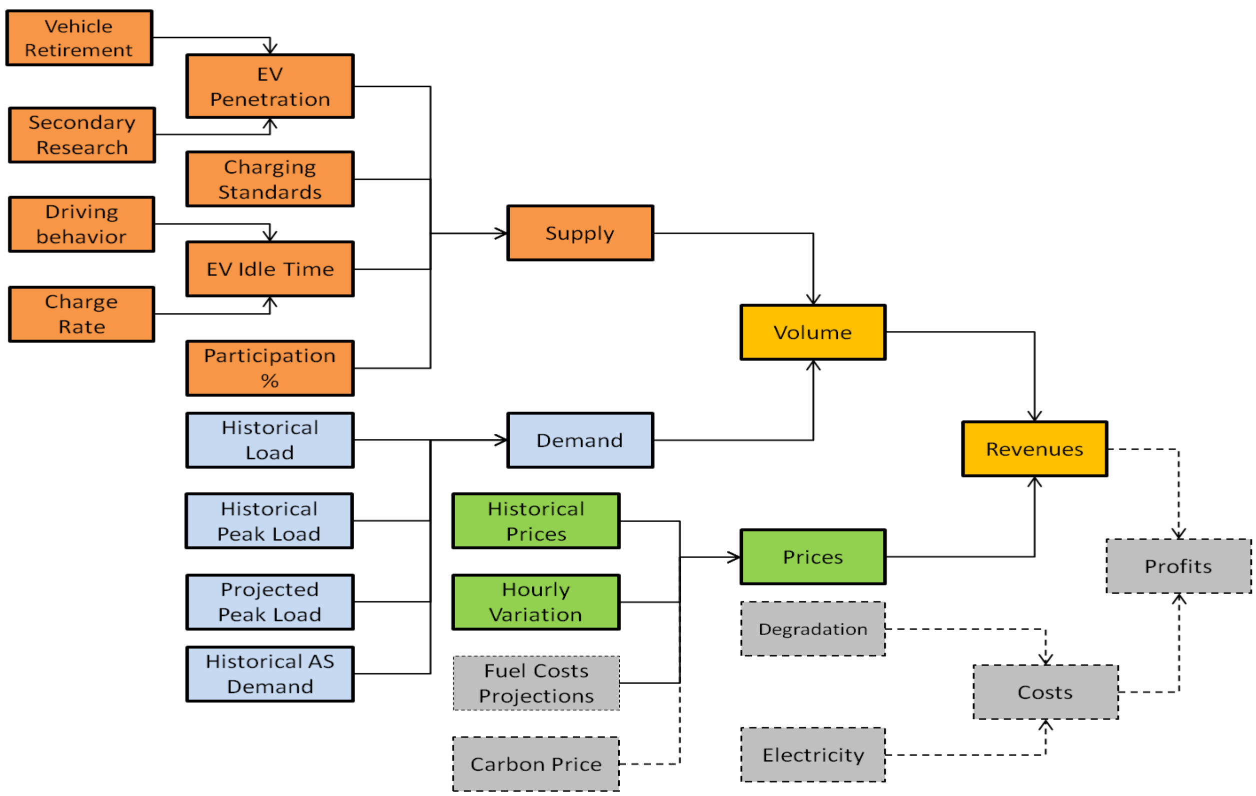
Based on these and the numerous other factors that can impact the economic case for electric vehicles, tremendous uncertainty exists with regard to the speed of EV penetration. However, because of this uncertainty, any additional value that can be generated by EV-DR can only help improve the economic value proposition for EVs and will therefore help speed adoption.

8 DR-EV Ancillary Services Revenue Opportunity

8.1 Introduction to Revenue Model

The Demand Response Electric Vehicle (DR-EV) model attempts to project the demand for ancillary services and potential revenue opportunity for aggregators that provide these services (**Figure 10**). The model uses extrapolation and discrete summation techniques implemented by Visual Basic macros to execute the simulation. While this specific version of the model is limited to the California Region, it can be extrapolated to other regions of the United States by using locally specific data. The data required for the model is tracked by most, if not all, Independent System Operators and should be easily available. Primary sources for all non EV-specific data were the California ISO, US Energy Information Administration, and The National Household Travel Survey. The model is designed to generate projections from year 2011 to year 2030, and provides projections for all the primary ancillary services. It should be noted however, that there is significant ambiguity over the nomenclature for certain ancillary services. However federal oversight through the Federal Energy Regulatory Commission ensures that the underlying definitions of these four ancillary services are consistent across various ISOs.

Figure 10: Outline of DR-EV Ancillary Services Model



The advantages of our model are:

- Easy to use
- Use of Visual Basic allows easy enhancements
- Simple and easily available inputs
- Straightforward financial outputs by year
- Allows highly tailored inputs
- Provides aggregate output and hourly level output

However, as with all models, ours too suffers from certain limitations. The most significant ones are:

- Prices used are 2010 hourly prices
- Does not differentiate between BEVs and PHEVs
- Only covers four ancillary services
- Significant uncertainty in certain inputs (e. g. EV penetration rates)
- Does not account for change in generation mix

8.1.1 Technology assumptions

8.1.1.1 Charge Rate

The model assumes that the energy rating supported by EV-chargers is 19.2 kW-h. This is the accepted standard across the industry for a Level-II charger (J1772)[lxxvi]. However, since this is also an input variable, future developments can be accounted for by changing this input variable accordingly at the time of use of the model.

8.1.1.2 Recharge Profile of Discharged Batteries

The model assumes that EV batteries that have been discharged (partially or completely) due to vehicle use are recharged linearly in time[6] so that the vehicle is fully charged by the time of the next trip. Also, it is assumed that the aggregator can vary the rate of charge instantaneously by controlling the flow of current through the charging station. Finally, we have also assumed that demand response technology being absent, drivers would like their cars charged at the fastest rate possible.

8.1.1.3 Generating Mix is Constant

The projections for ancillary services do not account for a changing generating mix in California. Also, since the current state of research has not identified a clearly quantifiable relationship between Ancillary Services and generating mix, we have not included this as an input parameter. In other words, the hourly generating mix for 2010 was assumed to stay constant going forward. This assumption forces our projections to be on the conservative side as increased renewable penetration will increase the demand for ancillary services. However, the relationship is not readily quantifiable due to the wide range of factors affecting this relationship and the significant variation in these factors from region to region.

8.1.1.4 EV Energy Efficiency

Our model assumes an energy efficiency of 3 miles/kWh. This number was determined through the secondary research that our team conducted and by looking at the energy efficiency of currently available EVs such as the GM Volt, Nissan Leaf and the Tesla Roadster (**Figure 11**)[7]. Since this assumption is an input variable, future improvements in EV drive-train technology can be accounted for by varying the relevant input variables.

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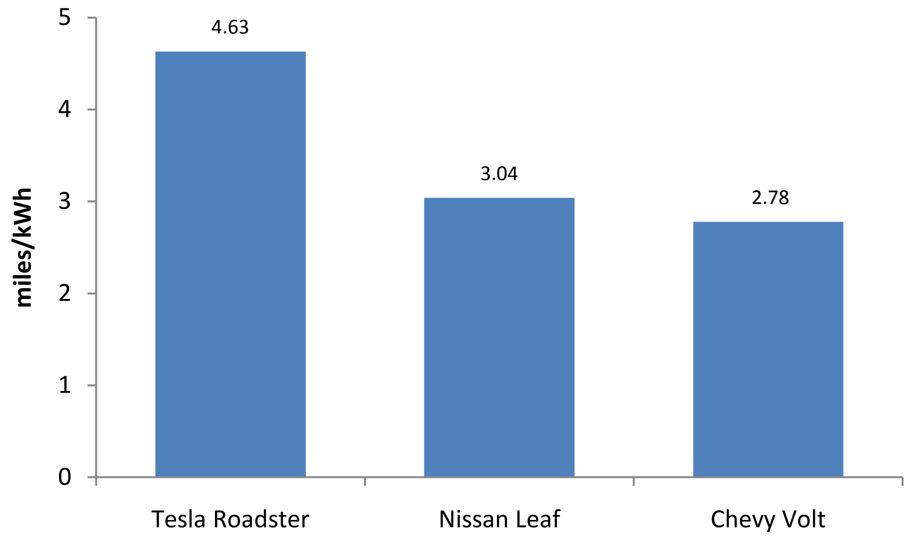
[6] The team concluded that on average, drivers will be indifferent to the actual charging pattern over time as long as the vehicle is charged fully by the time the vehicle is needed again. As a result, to simplify modeling requirements, the team assumed a linear recharge profile.

[7] Current Energy Efficiency of vehicles

Figure 11: Energy Efficiency of Battery Electric Vehicles[lxxvii]



8.1.2 Market assumptions

8.1.2.1 Constant 2010 Prices

The team has not attempted to project future prices for Ancillary Services. This is due to the fact that Ancillary Service prices in California have varied significantly in previous years, decreasing by as much as 55% from 2005 to 2009 for certain services (**Figure 12)**. Our team does not believe that this is a sustainable trend. And due to the fact that there is limited pricing data available (few years) and there is high variability on an hourly basis, we have decided against projecting future prices. Instead, hourly Ancillary Service prices for year 2010 have been used as an hourly constant for future years.

Figure 12: Average Price for Regulation-Up Service in California[lxxviii]

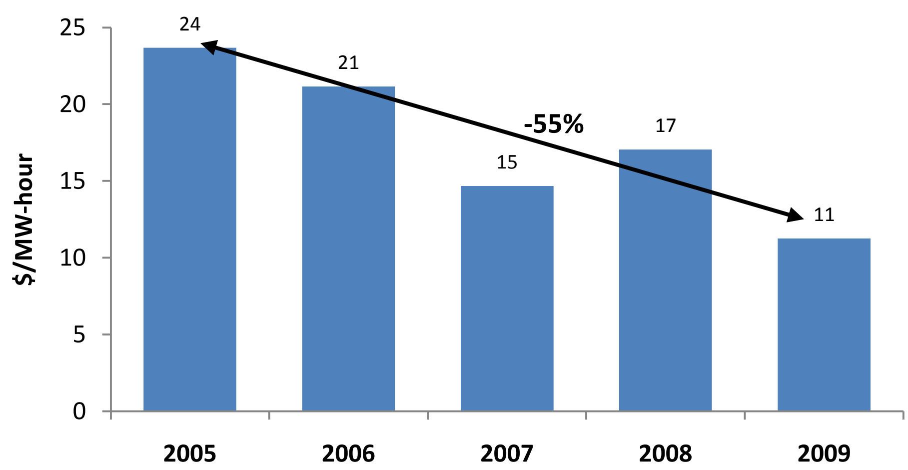
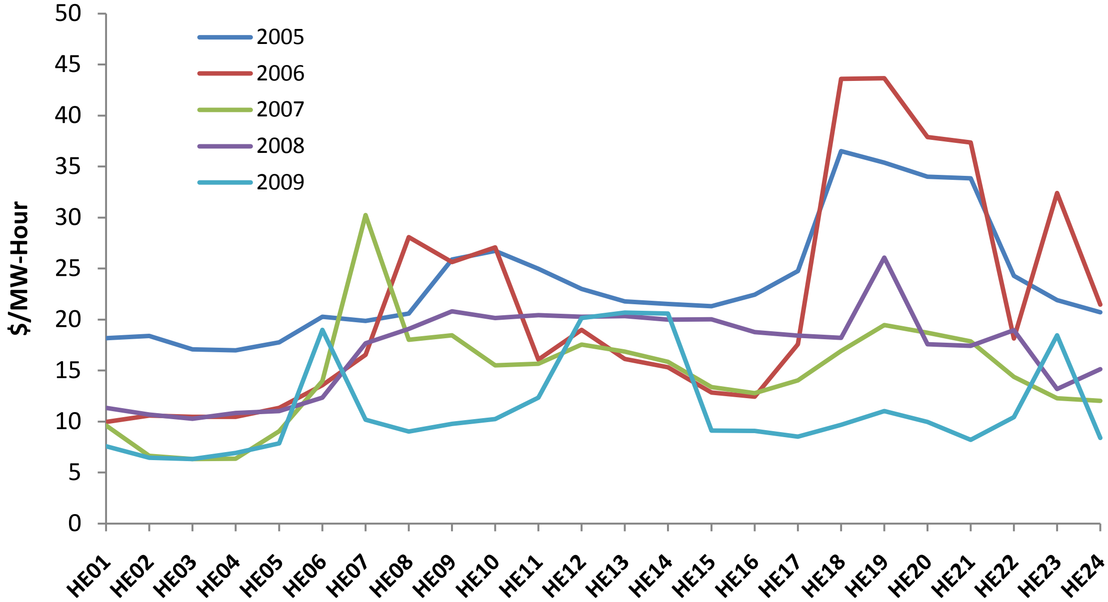


Figure 13: Average Hourly Price for Regulation-Up Service in California[lxxix]



8.2 Parameters

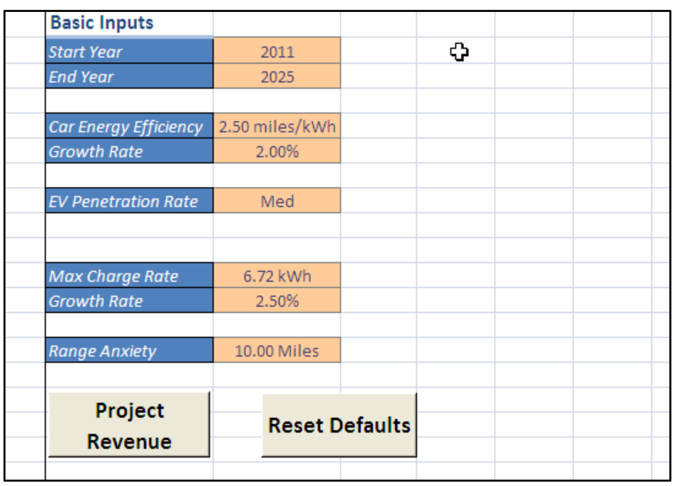
8.2.1 Inputs

The model employs five sets of input variables:

- Projection Timeline
- Car Energy Efficiency
- Maximum Charge Rate
- Range Anxiety
- EV Penetration Rate

While the model is preset with certain default values for California, users may modify these values as desired (**Figure 14**).

Figure 14: Screenshot of "Inputs" tab for the model



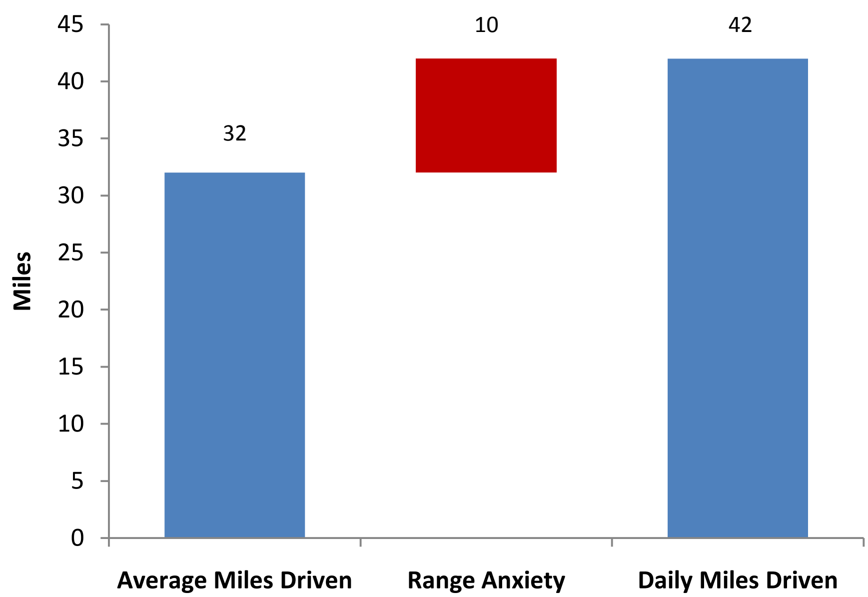
8.2.1.1 Projection Timeline (years)
The model can project information from year 2011 up to year 2030. Projections beyond 2030 are extremely uncertain and all of the relevant technologies are at such a nascent stage currently that projections beyond 2030 will be extremely unreliable.

8.2.1.2 Car Energy Efficiency (miles/kWh)
This is the distance that the EV can travel on a single kilowatt-hour expressed in the form of miles/kWh. While the team has assumed a default value of 3.04 miles/kWh, the user of the model is free to change this (and the trend for future years) as he/she sees fit[lxxx].

8.2.1.3 Maximum Charge Rate (kWh)
The model assumes a constant maximum charge rate of 19.2 kW-h[8]. As explained above, this is the rate of the generally accepted industry standard for EV chargers – SAE J1772. While this is the default value, the user of the model is free to change this (and the trend for future years) as he/she sees fit.

8.2.1.4 Range Anxiety (miles)
Given that drivers will be risk averse to ensure that they have a charged car for their driving needs, we have decided to include a variable to account for this. This is to be interpreted as the number of miles of buffer that an average driver will want the aggregator to maintain when adjusting the charge rates and resultant demand response capacity. According to research, the average Range Anxiety for drivers is approximately 20 miles[lxxxi].

Figure 15: Implementation of Range Anxiety

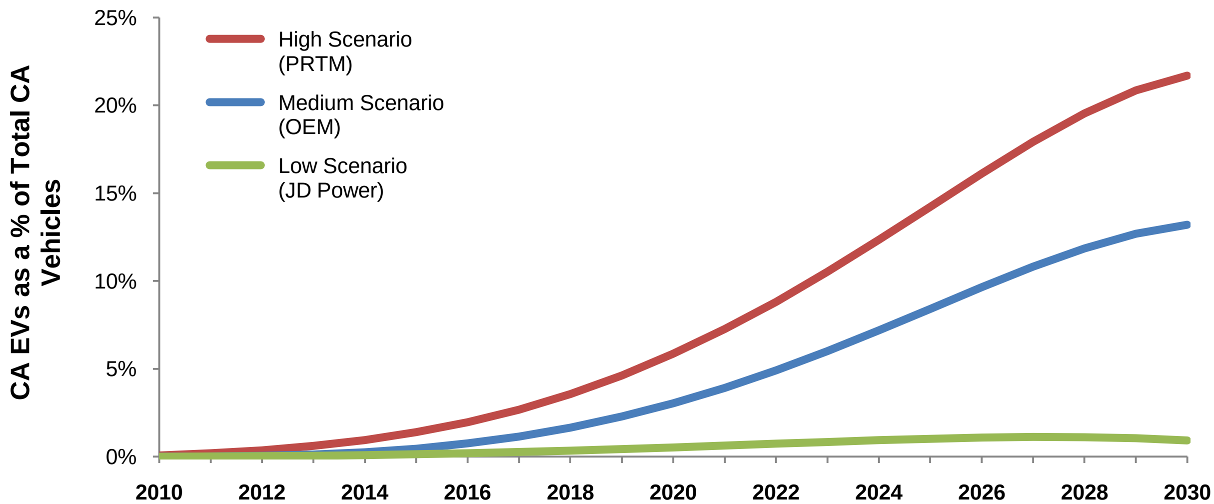


8.2.2 EV Adoption Forecast
The aggregation of mass-adopted EVs represents a significant amount of DR capability. However, as demonstrated in **Figure 9**, present day forecasts of EV adoption rates in 2020 vary significantly based on assumptions about the impact of various adoption drivers and barriers. Therefore, in an effort to capture the impacts of the various assumptions made in forecasting EV adoption, this model will consider

[8] The default settings of the model include a CAGR of 2.5%. However, for the scenarios executed, our team set the growth rate to 0%, resulting in a constant maximum charge rate over the projection timeline

multiple EV adoption scenarios – Low, Medium, and High - based on data from what we consider to be representative forecasts of each scenario. See **Figure 16** below for a visual representation of these scenarios.

Figure 16: High, Medium, and Low California EV Forecast Scenarios



These scenarios were generated by applying several assumptions to data collected during the course of our research. While we believe that the assumptions made as part of this exercise are reasonable, the project team does not take a position on which scenario(s) is/are more or less likely to occur. These scenarios are intended to be used as illustrative, rather than predictive, examples of EV adoption trends over the next 20 years based on the variety of forecasts currently available. See **Appendix 4:** Results of EV Scenario Forecastingfor full results from our scenario forecasting.

8.2.2.1 General EV Adoption Assumptions for Model

In order to convert published global and national EV forecasts into the appropriate input format for the model, the project team made several assumptions (outlined below):

General EV Adoption Assumptions:

1. **Total Domestic Vehicle registrations 2010-2030**: Using historical growth trend data from Bureau of Transportation Statistics (BTS) from 1990-2008, we made assumptions regarding the total number of domestic vehicle registrations from 2011-2030[lxxxii].
2. **New Vehicle Sales**: Using data from the National Automobile Dealers Association (NADA) and a Boston Consulting Group vehicle sales forecast, we assumed a linear growth curve for domestic new vehicle sales from 2011-2030[lxxxiii,lxxxiv].
3. **California New Vehicle Sales**: Using data from BTS and the California New Car Dealers Association (CNCDA), we have assumed that 12% of new car sales occur in California each year[lxxxv,lxxxvi].
4. **California Total Vehicle Population**: Using BTS state vehicle registration data for 2009, we have assumed that 15% of the total US vehicle population is located in California[lxxxvii].

5. **California Share of EV Market**: Using historical hybrid vehicle adoption rates as well as EV forecast data for California published by the Center for Automotive Research, we have assumed that a constant 24% of domestic EV sales will occur in California[9].
6. **Electric Vehicle Survivability Forecast**: Using data published by the National Highway Traffic Safety Administration (NHTSA), we estimated EV retirement rates using historical ICE vehicle survivability rates as a proxy[lxxxviii].

8.2.2.2 Low Scenario

This scenario was generated using data published in a 2010 special report by JD Power and Associates. This report takes a relatively pessimistic view of EV adoption rates over the coming decade, citing low consumer acceptance of battery technology, low fossil fuel prices, and global regulatory policy as three of the most significant barriers that will impact EV adoption rates over the coming decade and beyond.

According to this report, 107,000 EVs are projected to be sold in the US in 2020, which represents a 0. 5% share of total 20. 7 million new light vehicle sales projected for that year[lxxxix].

Methodology used to generate Low Scenario forecast:

1. Using data from the report, we assumed a linear trend for EV sales projections from 2010-2020 and extrapolated this data to 2030 using the same linear trend[xc]
2. We then applied the assumed 24% factor for California EVs to results from #1 to estimate the volume of EVs sold in California each year
3. We then applied NHTSA survivability statistics to results from #2 to generate a retirement schedule for EVs produced during 2011-2030
4. Next, we subtracted retired EVs (#3) from total EVs on the road (#2) for each year between 2011-2030
5. Then we estimated the total number of vehicles on the road in California each year from the BTS sales forecast and a California vehicle registration rate of 15% (from assumption #4 above)
6. Finally, we computed the yearly ratio of EVs on the road in California to total vehicles registered in California between 2011-2030

Key assumptions (Low Scenario): Linear trend of EV adoption from 2011-2030; EV survivability will approximate historical ICE survivability trends; a constant 24% of EV sales in the US will occur in California over the next 20 years; a constant 15% of US vehicles will be registered in California.

8.2.2.3 Medium Scenario

This scenario was generated using actual vehicle OEM EV production forecast data that was collected and published by Frost & Sullivan in March 2009. We filtered the database to obtain relevant forecast data based on the following pivot-table options:

- OEMS: (All)
- OE Type: (All)
- OE Model: (All)
- Vehicle Type: (All)
- Vehicle Segment: (All)
- EV Segment: (Extended-Range EVs (eREV), High-Performance EVs (HPEV))
- Region: North America
- Country: USA

[9] For more on California Electric Vehicle adoption figures, see: Hill, Kim and J. Cregger. *Deployment Rollout Estimate Of Electric Vehicles 2011-2015.* Center for Automotive Research (CAR), Ann Arbor, 2011.

The database provided aggregated OEM EV production data for the years 2011-2015[xci].

Methodology used to generate Medium scenario forecast:

1. Using the EV production forecast data for 2011-2015, we extrapolated the results to 2030 by fitting a polynomial trend line (r^2=. 9964)
2. We then applied the assumed 24% factor for California EVs to results from #1 to estimate the volume of EVs sold in California each year
3. We then applied NHTSA survivability statistics to results from #2 to generate a retirement schedule for EVs produced during 2011-2030
4. Next, we subtracted retired EVs (#3) from total EVs on the road (#2) for each year between 2011-2030
5. Then we estimated the total number of vehicles on the road in California each year from the BTS sales forecast and a California vehicle registration rate of 15% (from assumption #4 above)
6. Finally, we computed the yearly ratio of EVs on the road in California to total vehicles registered in California between 2011-2030

Key Assumptions (Medium Scenario): EV survivability will approximate historical ICE survivability trends; a constant 24% of EV sales in the US will occur in California over the next 20 years; a constant 15% of US vehicles will be registered in California.

8.2.2.4 High Scenario

This scenario was generated using global EV forecast data from a report published in 2010 by PRTM, a consulting firm focused on strategy and innovation. In this report, PRTM takes a relatively optimistic view of EV adoption projections, citing growing concern over climate change, anticipated increases in fossil fuel prices, financial incentives offered by governments, and increasing levels of urban pollution caused by ICEs as the primary drivers of EV adoption through 2020.

The data provided by PRTM includes global EV production as a percentage of global vehicle sales from 2011-2020[xcii].

Methodology used to generate High Scenario forecast:

1. Generated yearly forecast estimates for the volume of EVs sold in the US (based on global production averages) and then extrapolated this data to 2030 by fitting a polynomial trend line (r^2=. 99993)
2. We then applied the assumed 24% factor for California EVs to results from #1 to estimate the volume of EVs sold in California each year
3. We then applied NHTSA survivability statistics to results from #2 to generate a retirement schedule for EVs produced during 2011-2030
4. Next, we subtracted retired EVs (#3) from total EVs on the road (#2) for each year between 2011-2030
5. Then we estimated the total number of vehicles on the road in California each year from the BTS sales forecast and a California vehicle registration rate of 15% (from assumption #4 above)
6. Finally, we computed the yearly ratio of EVs on the road in California to total vehicles registered in California between 2011-2030

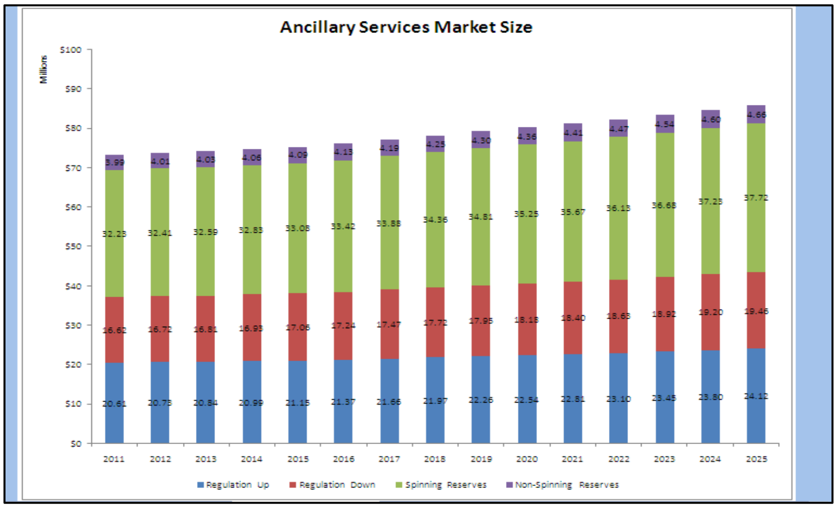
Key Assumptions (High Scenario): US EV sales will be proportional to the number of EVs sold globally; EV survivability will approximate historical ICE survivability trends; a constant 24% of EV sales in the US will occur in California over the next 20 years; a constant 15% of US vehicles will be registered in California.

8.2.3 Outputs

8.2.3.1 Market Size for Ancillary Services

The model projects the market size for Regulation Up, Regulation Down, Spinning Reserves and Non-Spinning Reserves by year for the entire California region expressed in $-Millions. A sample screenshot of the output is shown in **Figure 17**. Actual output from the model runs are explained and discussed in the following "Results" section.

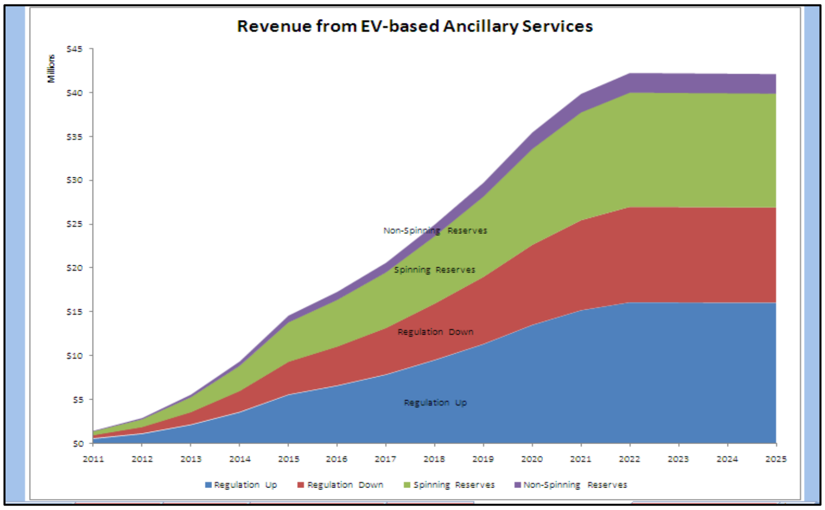
Figure 17: Sample Screenshot of the Market Size Output



8.2.3.2 Revenue Opportunity from DR-EV provided Ancillary Services

The model projects the potential revenue that an aggregator (or aggregators) could generate by providing the four ancillary services using DR-EV. The projections are annual and are expressed in $-Millions (**Figure 18**).

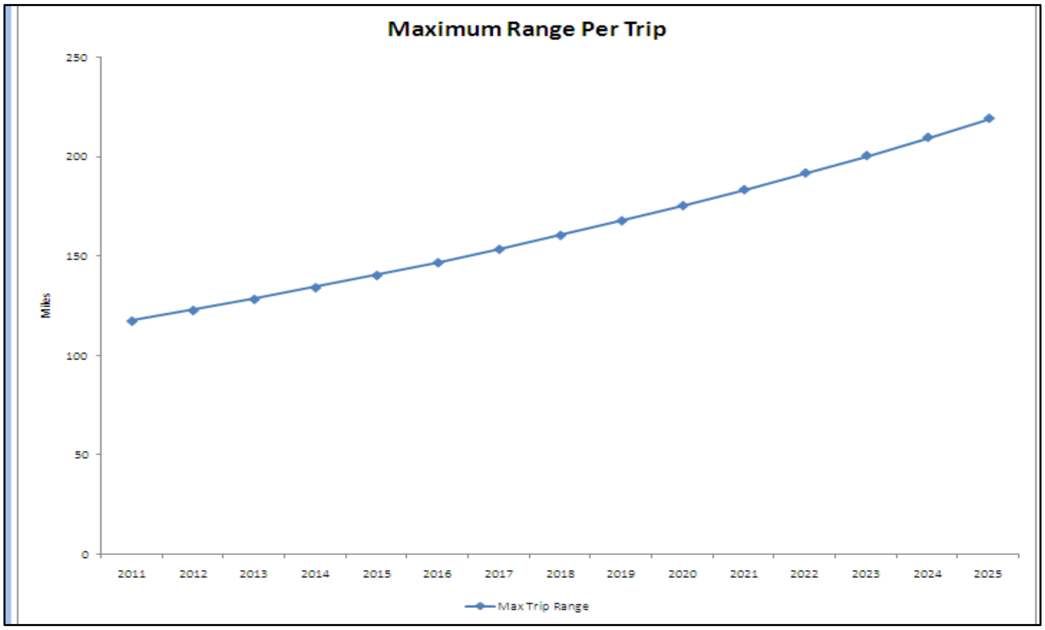
Figure 18: Sample Screenshot of the Revenue Opportunity Output



8.2.3.3 Maximum Trip Range

This output presents the limiting factor for trip distance as a result of the assumptions and input variables. This is to be understood as the maximum length of a trip allowed for the results of the model to hold (**Figure 19**). This is expressed in miles[10].

Figure 19: Sample Screenshot of the Maximum Trip Range Output



8.3 Model Results

The ancillary services market in California is an annual multi-million dollar market. The following section attempts to quantify the value of that market and the revenue that an aggregator of electric vehicles could generate by providing these services.

8.3.1 Ancillary Services Market in California

The ancillary services market in California alone is worth about $1.65 B from year 2010 to 2030, growing at a compounded annual growth rate of about 0.70%. The most lucrative service in terms of market size is the Spinning Reserve service, closely followed by the Regulation Up service (**Figure 20**). However, despite that Spinning Reserves present the greatest revenue opportunity for demand response aggregators, they should focus on the Regulation Up service due to its higher value proposition ($/MWh).

[10] The range of the Tesla Roadster is 221 miles per single charge (Source: Tesla Motors, US EPA)

Figure 20: Market Size for Ancillary Services in California by Service

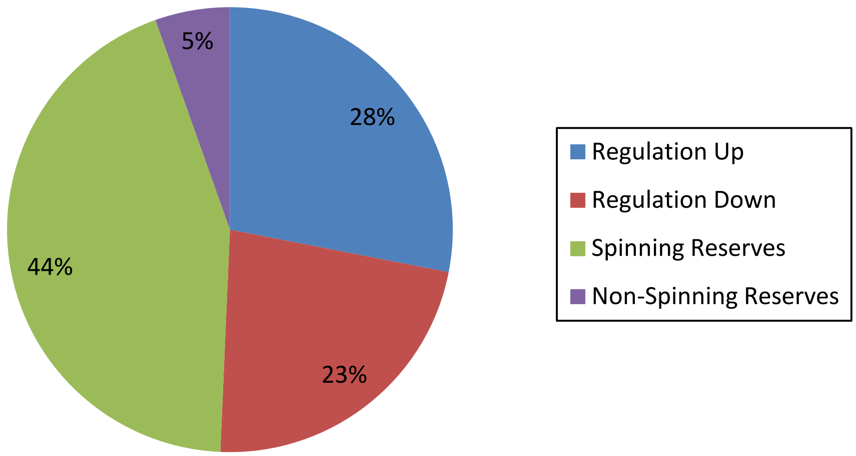
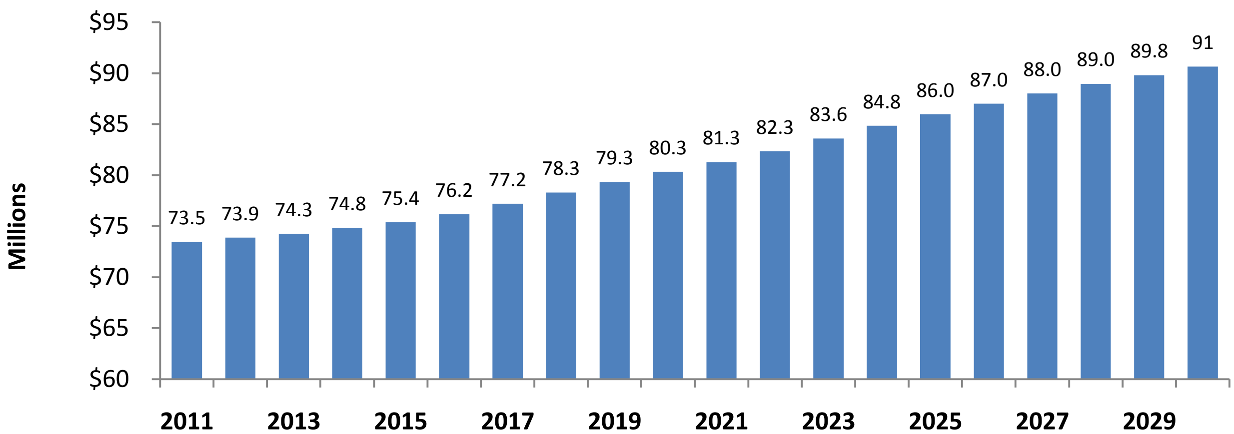


Figure 21: Ancillary Services Market in California, by Year



8.3.2 Ancillary Service Revenue Opportunity for DR-EV in California

To examine the revenue opportunity for provision of Ancillary Services by DR-EV, we ran three scenarios on our model – low, medium and high. Three inputs (Timeline, Energy Efficiency and the Maximum Charge Rate) were maintained constant across all three scenarios, while two (Range Anxiety and EV Penetration) were varied. The results, along with the respective inputs are summarized below.

8.3.2.1 Low Scenario Results

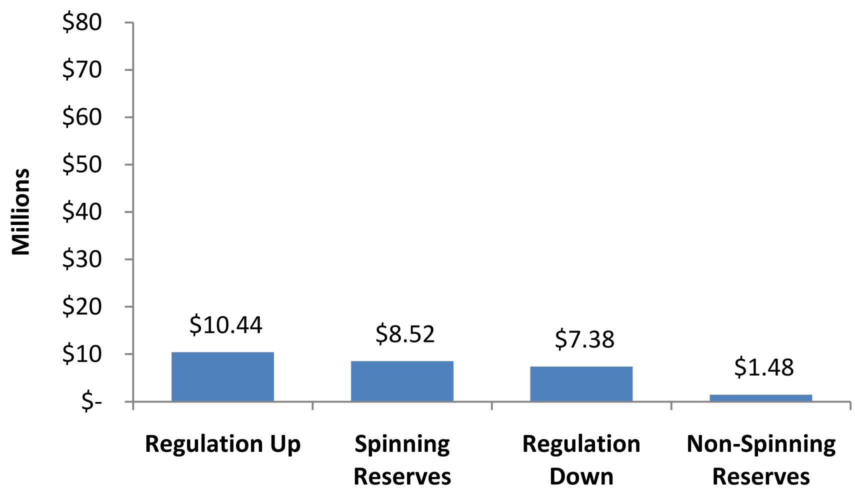
This scenario uses the following values for the input variables:

- Timeline: 2011 to 2030
- Vehicle Energy Efficiency: 3.04 miles/kWh
- Maximum Charge Rate: 19.2 kW-h

- Range Anxiety: 30 miles
- EV Penetration: Medium

The total revenue opportunity is $27.8 M with the Regulation Up service being the most lucrative (**Figure 22).**

Figure 22: Revenue Opportunity from DR-EV based Ancillary Services (2011 – 2030): Low Scenario



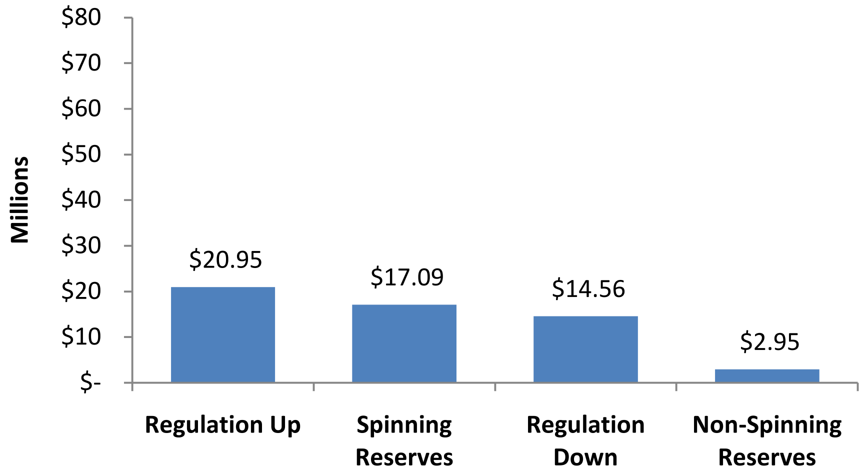
8.3.2.2 Medium Scenario Results

This scenario uses the following values for the input variables:

- Timeline: 2011 to 2030
- Vehicle Energy Efficiency: 3.04 miles/kWh
- Maximum Charge Rate: 19.2 kW-h
- Range Anxiety: 20 miles
- EV Penetration: Medium

The total revenue opportunity is $55.6 M with the Regulation Up service being the most lucrative (**Figure 23**).

Figure 23: Revenue Opportunity from DR-EV based Ancillary Services (2011 – 2030): Med Scenario



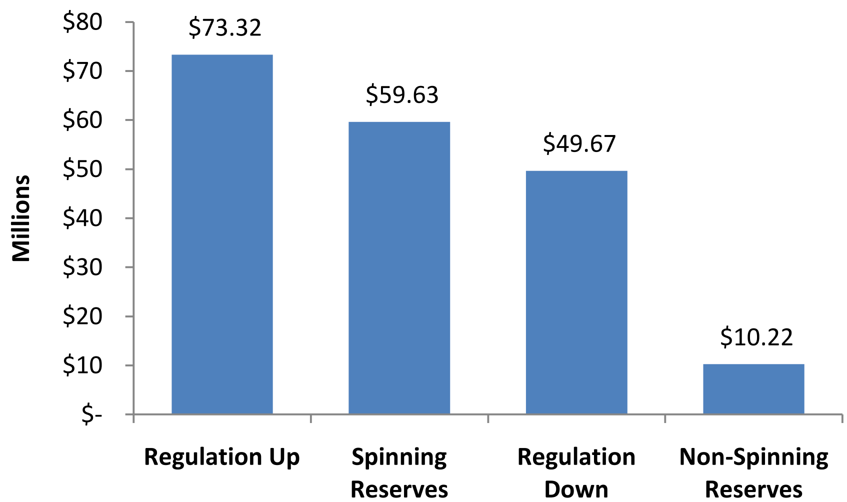
8.3.2.3 High Scenario Results

This scenario uses the following values for the input variables:

- Timeline: 2011 to 2030
- Vehicle Energy Efficiency: 3.04 miles/kWh
- Maximum Charge Rate: 19.2 kW-h
- Range Anxiety: 10 miles
- EV Penetration: High

The total revenue opportunity is $192.8 M with the Regulation Up service being the most lucrative (**Figure 24**).

Figure 24: Revenue Opportunity from DR-EV based Ancillary Services (2011 – 2030): High Scenario



8.3.3 Sensitivity of Model

Of all the input variables, the model is most sensitive to the following parameters (**Figure 25**):

- EV Penetration Rates (highly sensitive): A higher number of EVs on the road will result in increased demand response capacity that the aggregator can draw on to provide to the grid.
- Range Anxiety (moderately sensitive): The higher this variable is, the more frequently the aggregator needs to actually "top-up" or recharge the EV. As a result, demand response capacity will be reduced.
- EV Energy Efficiency (moderately sensitive): The higher this is, the lower the battery discharge for a given mile. Since the aggregator capacity is directly proportional to the discharge of the battery (i. e. the amount by which the battery needs to be charged again), this results in decreased revenue opportunity.

Since the charging rate for recharge stations is not a sensitive parameter, the capabilities of the SAE Level-II charger should be more than adequate for use by the aggregator(s).

Figure 25: Sensitivity of Ancillary Services Revenue to Input Parameters

Increase in …	Results in …
Penetration rate of EVs	↑
EV energy efficiency	↓
Charging rate limitations	↔
Driver range anxiety	↓

9 Conclusions and Key Takeaways

The overarching impetus for the commissioning of this study was a desire to examine the interactions among EVs, the energy grid, and renewable energy sources in the CAISO market.

Due to very limited empirical evidence, there is currently a great deal of uncertainty around the extent to which increasing levels of wind and solar energy will destabilize the electricity grid. However, various studies have generally confirmed that increased intermittent resources require some level of infrastructure upgrades, and specifically tend to increase the demand for stabilizing resources such as ancillary services.

9.1 Demand Response vs. V2G

A common topic of discussion among supporters of EVs is the potential to leverage EV's battery assets and high percentage of plug-in time to provide distributed storage resources to the grid. This technology, commonly known as V2G, theoretically allows EVs to be charged during off peak periods and discharged back onto the grid during peak hours in order to provide stabilization services and take advantage of price arbitrage opportunities. Studies predict that as EVs become more pervasive, they could help support penetration of renewable energy sources by meeting the increase in demand for stabilization services that such intermittent sources require. However, our primary and secondary research has determined that the commercialization and mass adoption of V2G systems is not realistic in the short to medium term. This is due to a number of technical challenges that will likely take many years to overcome. However, primary research has found that EVs that are managed by an aggregated system do in fact have the potential for providing ancillary services to the grid by means of a demand response function (DR-EV). We believe that the four services are that are best suited to DR-EV are Frequency Regulation, Spinning Reserves, Supplemental Reserves and Replacement Reserves.

Service	Supply	Directional	Response	Service	Suitable for

	Duration	Shifts	Rate	Duty	DR-EV?
(Frequency) Regulation	10–15 min	High	<1 min	Continuous	Yes
Spinning Reserves	10 min–2 hours	Low	<10 min	Intermittent	Yes
Supplemental Reserves	10 min–2 hours	Low	<10 min	Intermittent	Yes
Replacement Reserves	2 hours	Low	<30 min	Intermittent	Yes
Voltage Control	-	-	-	-	No
Load Following	1–10 hours	Medium	<1 hour	Intermittent	No
System Control	NA	NA	NA	Continuous	No
Real Power Loss Replacement	1–10 hours	Low	<10 min	Continuous	No

9.2 Markets are increasingly being opened to DR

In researching the market for ancillary services, it was found that in CAISO (as well as most other ISO's and RTO's) there is currently over-supply (approximately 10x of demand) of ancillary service capacity bidding into the market. This was a somewhat surprising finding given the fact that the total amount of ancillary services required to serve the CAISO market are increasing due to renewables integration. Despite the over-supply of ancillary service capacity, it was determined that there is still room for DR-EV in the market due to its expected low costs (e. g. zero fuel costs) and short response times, as well as favorable regulatory conditions which have explicitly opened these markets to DR.

9.3 Revenue Opportunity is minimal, at best

Based on forecasts of ancillary service markets and EV penetration rates, we have built a simulation model to predict revenue opportunities for aggregators in this market. Our model predicts that in our medium range scenario there is a total revenue opportunity of $42 M for EV aggregators in the California region alone. Because this revenue number is based on approximately 5.3 M cars spread out over 20 years, it is clear that there is a negligible revenue opportunity for aggregators and end consumers. This figure is based on historical market clearing prices and represents the total revenue opportunity for all DR-EV players in the market, and is exclusive of operation costs for aggregators.

The results of our scenario analysis show that the overall revenue opportunity is most sensitive to the penetration rate of EVs as well as the range anxiety of their users. In addition, because the relationship between the actual increase in ancillary service demand and renewable penetration has not been quantified, our model uses the very conservative assumption that ancillary services will increase at the same rate as load. However, because we expect the need for ancillary services to increase at a greater rate with the addition of intermittent renewables, the total revenue opportunity will expand as California fulfills its RPS. In addition, our model excludes energy payments which if included would also marginally increase these revenue projections.

Interestingly, the results of this study suggest the relationship between EVs and renewable energy is decidedly different than what is commonly believed. The increased demand in ancillary services caused by increasing renewable penetration in California is easily met by existing resources, and requires no capacity additions. While it is fair to argue that as renewables drive an increase in demand for ancillary services, the revenue opportunities for EV aggregators increase, the overall revenue opportunities do not appear to be compelling. Therefore, the revenue opportunities from this market are unlikely to be large enough to significantly improve either the economics of EV ownership or the business case for intermediaries in the grid.

10 Appendices

10.1 Appendix 1: Demand Response Additional Information

10.1.1 ISO/RTO DR-EV

1.) EV Charging-only Management & Reliability Assets
    - Simple: dynamic pricing
    - Complex: aggregators assemble predictable blocks of load
2.) Charging and Discharging Reliability Assets – V2G and bi-directional flow of electricity
3.) Price-Sensitive Demand Resources – Aggregators play in ISO/RTO markets by relaying price signals and collecting information regarding willingness to pay
4.) EVs as Ancillary Market Assets – complex two-way charging and communication capabilities allow EVs to participate in AS markets

The ISO/RTO Council has already begun to outline the steps necessary to integrate DR-EV into its existing markets and systems and has identified a number of products and services to be of the highest priority (**Figure 26**). In addition the council has outlined potential business models for services such as DR-sourced regulation services or DR Regulation Resource (DRR) (**Figure 27**).

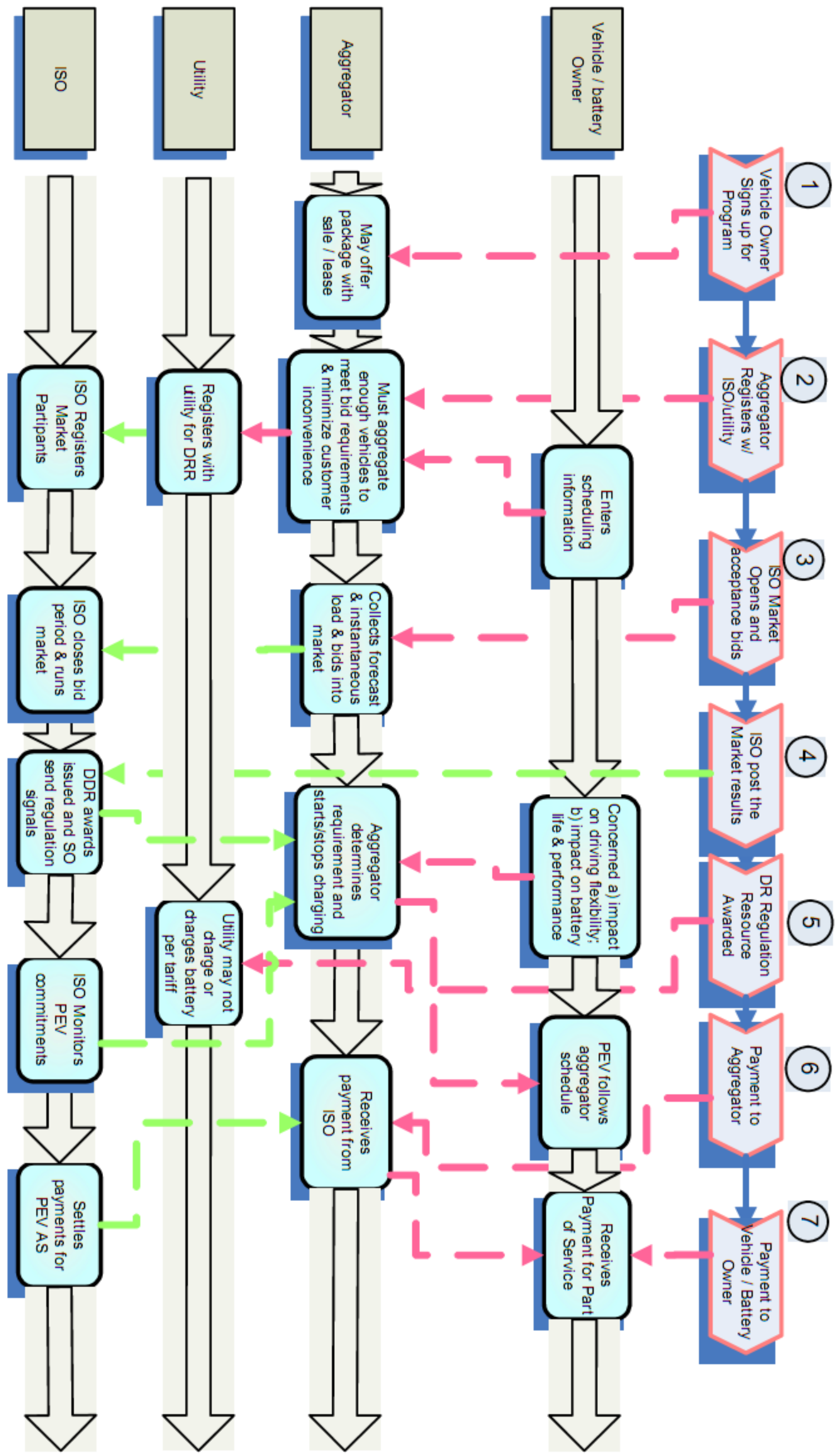
Figure 26: Potential DR-EV Products and Services[xciii]

Services Provided by PEVs	Description of Service Requirements	Map to existing ISO/RTO Products/Services	PEV Possibilities	Complexity 1-easy 5-complex
Reserves	• An aggregator providing reserves shall be able to reduce its charging level by SR kW near-instantaneously (with SR/sec) on receipt of a control signal. Note also that a PEV not capable of modulated charging or pulsed charging is nonetheless able to provide reserve by simply stopping charging • An aggregator which responds to a reserve actuation signal must remain "off" for the minimum of SRM minutes or until the reserve signal is rescinded • An aggregator which sells reserves from its PEV base is responsible to have sufficient PEV response available to reduce load by the reserve amount offered above and beyond response offered for regulation services • An aggregator must be able to deliver that reserve from PEV response within SRS sec when requested. • An aggregator shall have sufficient governor response available to demonstrate compliance to the obligation	There are existing reserve products/services at most ISO/RTOs: • Obligation-based (allocation of reserve requirement) and/or market-based awards • ISO/RTO issues calls if more/less reserves are needed • Telemetry measurement requirements on the resources (MW) Existing services may need modifications to accommodate PEVs	PEVs could provide reserves (and other reserve products) by simply interrupting charging in response to a signal from an aggregator. The aggregator might have to limit SR sales in the final hours of the night, for instance, in order to meet commitments to PEV owners of a full charge overnight. The requirement that SR be provided for at least one hour is typical of ISO/RTOs today.	3
Emergency Load Curtailment (ELC)	• Aggregators which are not providing reserves or regulation but which are scheduled to be charging may be able to provide load shed capabilities • Such PEVs must accept a signal to stop charging in response to a load shed signal from the grid operator • An aggregator providing load shed service to the grid operator must have scheduled charging available in excess of regulation and reserve so as to be able to reduce aggregate load by the load shed amount	Similar to the demand response energy services and will require adaptation to accommodate PEVs. Telemetry will be required.	The ability to accomplish fast demand response as a form of emergency load shed at a level below the distribution feeder is interesting. This would vary from many existing DR products in that the ISO/RTO, via an aggregator, would be able to accomplish the emergency load shed rapidly and with certainty. This is a kind of second- stage reserve.	3

Services Provided by PEVs	Description of Service Requirements	Map to existing ISO/RTO Products/Services	PEV Possibilities	Complexity 1-easy 5-complex
Scheduled Energy	• An aggregator providing scheduled energy shall be able to reduce its charging level by "Scheduled Energy schedule" • An aggregator with an accepted energy bid must reduce its aggregate PEV load by the scheduled amount for the period of the award • An aggregator which sells energy from its PEV base is responsible to have sufficient PEV response available to reduce load by the scheduled amount offered, above and beyond response offered for market products or services • An aggregator must be able to deliver that energy scheduled from PEVs' response and adhere to the required ramp rates • An aggregator shall have sufficient governor response available to demonstrate compliance to the obligation, if required	There are existing scheduled energy products/services at most ISO/RTOs • Obligation-based bilateral contracts: and/or market-based awards • ISO/RTO opens the market for scheduling • Telemetry measurement requirements on the resources (MW) Existing services may need modifications to accommodate PEVs	PEVs could provide scheduled energy by simply interrupting charging in response to a signal from an aggregator. The aggregator might have to limit sales in the final hours of the night, for instance, in order to meet commitments to PEV owners for a full charge the next day.	3
Regulation	• An aggregator providing regulation service shall be capable of adjusting its charge rate up or down by an amount equal to the regulation amount offered • An aggregator providing regulation must be able to adjust its charge rate by the regulation amount at a rate of R kW/minute. Its rate of change in %/sec must be sufficient to meet regulation service response requirements • An aggregator providing regulation service shall provide a sustained kW contribution (up or down) for RM minutes • An aggregator shall have sufficient regulation service response available to demonstrate compliance to the obligation	There are existing regulating products/services at most ISO/RTOs: • Obligation-based (allocation of Reg requirement) and/or market-based awards • ISO/RTO issues signals for Req Up or Reg Down via telemetry (2-6 sec range) • Typically resource-specific • Telemetry measurement requirements on the resources (MW, Status) Existing services may need modifications to accommodate PEVs	Battery makers are unsure what level of modulation the battery charging can support. Initial feedback is that a roughly 15-second rate is the best they would agree to. Thus PEVs could not provide regulation without very sophisticated algorithms and vehicle-unique communications via an aggregator that ensured this constraint was met. A simple broadcast signal would not suffice unless the regulation signals used were adjusted to avoid more rapid cycling.	3

Services Provided by PEVs	Description of Service Requirements	Map to existing ISO/RTO Products/Services	PEV Possibilities	Complexity 1-easy 5-complex
Balancing Energy	▪ An aggregator capable of altering PEV charging on a real-time basis may offer changes in total PEV charging load into the balancing energy/real-time dispatch market ▪ The aggregator must be able to adjust PEV aggregate charging load down (selling energy) or up (buying energy) in response to dispatch signals ▪ The aggregator must be able to affect PEV charging and respond in aggregate on time scales identical to that of conventional generation.	Some components of this service are similar to existing services but will require modifications to accommodate PEVs. Telemetry will be required.	Conceivably this is a good fit for PEVs at periods when the balancing demands are "balanced" up and down as opposed to long periods when all balancing is in one direction only (such as when the load forecast is off). Hourly schedule transitions are an example of this in many markets and cause balancing price spikes especially at nodes where generation is restricted. PEVs' ability to provide this service could be valuable.	4

Figure 27: Business Model for DR Regulation Resource (DRR) via DR-EV[xciv]



10.1.2 Dispatching DR-EV

Depending on the communications and control technologies available, EV charging may take two forms:

- **Simple (Pulse) Charging** – limits charging to a simple on and off signal. This scenario includes the following definitions[xcv]:
    - Normal charging rate: average charge rate of pulsed on and off control signal.
    - Charge cycle duty: % of time the vehicle is charging while it is connected to the grid.
    - Duration: time it takes to charge an EV at the normal charging rate.
    - Maximum charge rate: rate of inherent charge, absent a control signal.
    - Minimum charge rate: zero.
    - Rate of charge: maximum rate of change in the charging rate (in %/sec).
    - Maximum charge energy: duration multiplied by normal charge rate

- **Modulated Charging** – adjusts the rate of charge over time
    - Normal charging level: charge rate absent of control signal (between max and min rates).
    - Duration: time required to reach full charge at normal charge rate
    - Maximum charge rate: highest rate possible given signals and capabilities
    - Minimum charge rate: lowest rate possible given signals and capabilities, assumed to be zero
    - Rate of change: maximum rate of change in the charging rate (in %/sec).
    - Maximum charge energy: duration multiplied by normal charge rate

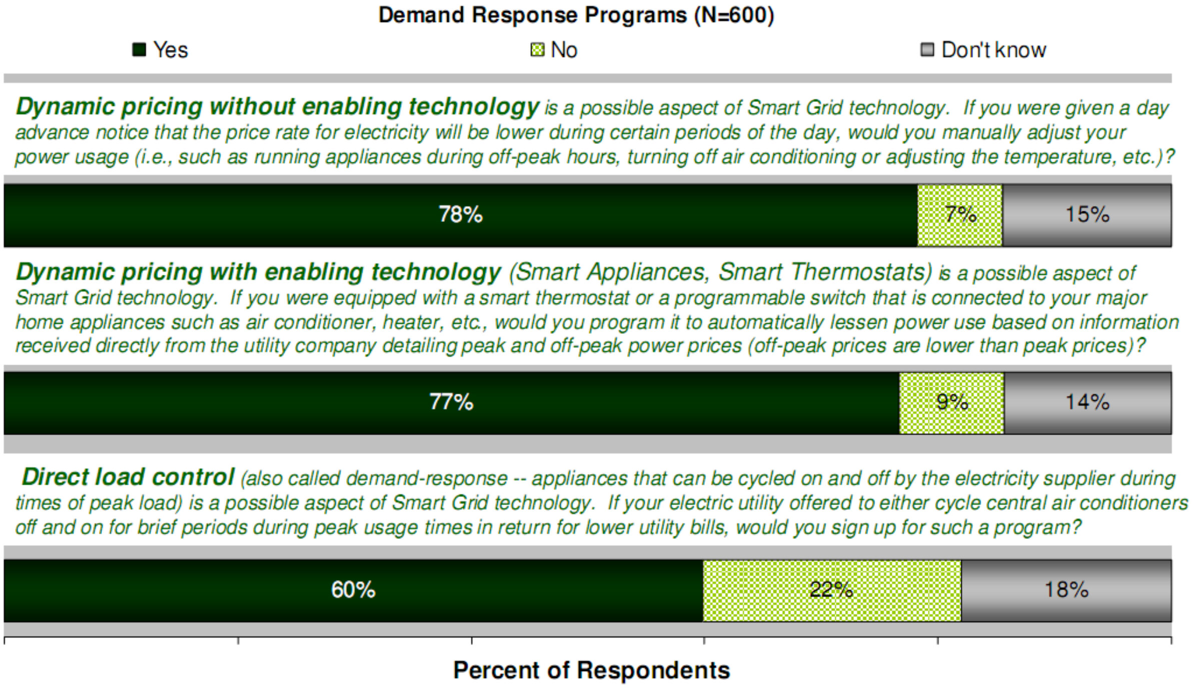
Theoretically, pulsed charging can be treated as modulated if the pulse rate is approximately four times faster than the control signal.

10.1.3 DR & Behavior

All DR programs are designed to reflect the preferences and behavior of users. While most large electricity customers enrolled in incentive programs must decide whether and when to allow power dispatchers to cycle their devices on and off, smaller consumers participating in dynamic pricing programs, must weigh prices against needs to make daily decisions regarding consumption.

In an effort to determine the likelihood that residential energy consumers will change their habits and/or participate in DR programs, Frost and Sullivan interviewed 600 homeowners from around the country with some insight into their electricity bills. Respondents were generally supportive of DR programs, with a large majority in favor of dynamic pricing programs and a slightly less percentage interested in direct load control (**Figure 28**). Despite these findings, the price elasticity and behavior of residential consumers remains a chief concern for many dispatchers, utilities, and system operators.

Figure 28: Adoption Probability by Demand Response Program[xcvi]



10.2 Appendix 2: Grid Support Services

10.2.1 Transmission Support

Transmission support generally improves transmission and distribution systems by correcting problems such as voltage sag, unstable voltage, and sub-synchronous resonance. The compensation provided by the energy storage system broadly improves the system stability and electrical performance. However, the actual benefits vary on a case-by-case basis and are site and situation specific. **Table 8** below outlines the main types of transmission support:

Table 8: Primary Modes of Transmission Support[xcvii]

Transmission Support Mode	Description
Transmission Stability Damping	Increase load carrying capacity by improving dynamic stability.
Sub-Synchronous Resonance	Increase line capacity by allowing higher levels of series compensation by providing active real and/or reactive power modulation at sub-synchronous resonance modal frequencies.
Voltage Control and Stability	1. Transient Voltage Dip Improvement: Increase load carrying capacity by reducing the voltage dip which follows a system disturbance. 2. Dynamic Voltage Stability: Improve transfer capability by improving voltage stability.
Under-frequency Load Shedding Reduction	Reduce load shedding needed to manage under-frequency conditions which occur during large system disturbances.

For energy storage to be viable for these services, the source must be capable of sub-second response, partial state-of-charge operation, and have numerous charge-discharge cycles. In addition, the source must be able to provide real and reactive power, and the discharge duration must be between one and 20 seconds. The resource is also not likely to have the ability to be used concurrently with other application unless it is only used for peak demand or peak congestion periods.

10.2.2 Transmission Congestion Relief

Due to increasing demand and an aging infrastructure, many areas of the grid have a lack of adequate transmission capacity. During periods of peak demand, these capacity shortfalls result in higher cost of capacity supply and capacity charges for users who pay fees to access this capacity. These regional differences in capacity availability are the underlying conditions that lead to locational marginal pricing (LMP). To avoid abnormally high charges, storage resources can be installed downstream from areas that tend to become congested, and discharged during peak periods in order to decrease congestion and the associated premiums during peak. For this application to be viable is generally necessary to have resources with standard discharge durations of four hours. Resources used in this function will likely be compatible with other energy storage applications.

10.2.3 Transmission and Distribution Upgrade Deferral

Transmission and distribution upgrade deferral refers to the installation of energy storage devices in transmission systems which allow the deferral or complete avoidance of large capital outlays associated with such system upgrades. These applications are most commonly done in systems that are at or near their load carrying capacity. As with congestion relief, these systems would typically be installed downstream from an area with overloaded capacity. The key aspect of this application is that these deferrals can usually be accomplished with relatively small amounts of energy storage resources. It can therefore be significantly more cost effective to make these small investments in lieu of the large capital expenditures which would be necessary to upgrade capacity with the traditional methods. The end result of these deferrals provide advantages such as lower rates for end users, higher utilization rates of the existing assets, and lower risk profile for the entity which would be responsible for making large capital investments.

Standard discharge duration of this application is from three to six hours. These systems will also require considerable design considerations and cooperation between energy system engineers and utility engineers. This application also has potential synergies with several other energy storage applications.

10.2.4 Substation On-Site Power

There are currently approximately 100,000 battery storage substations in locations scattered throughout the US[xcviii]. The role of these storage facilities is to provide backup power to substation components when the grid is not energized, including switching components, control equipment, and communication devices. Currently, the most common technology in place is lead-acid batteries. Users of these resources are generally satisfied with current solutions that are in place, however the following considerations would be critical when choosing alternate technologies:

- Improved reliability
- Metrics or measurement tools that can provide an easy and effective way to track assets remaining useful life and maintenance needs
- DC power capabilities

The requirements for these resources vary by the amount of voltage they are required to provide:

Voltage Required	Battery Rating
< 69 KV	1. 6 KVA
Between 69 KV and 169 KV	2. 9 KVA
>169 KV	8. 5 KVA

Typical resources have a standard value of 2.5 kW and a discharge range from eight to 16 hours. These resources can also be used for other applications but must not interfere with the primary function.

10.3 Appendix 3: Renewables Profiles and Forecast

Figure 29: Renewable Production Profiles[xcix]

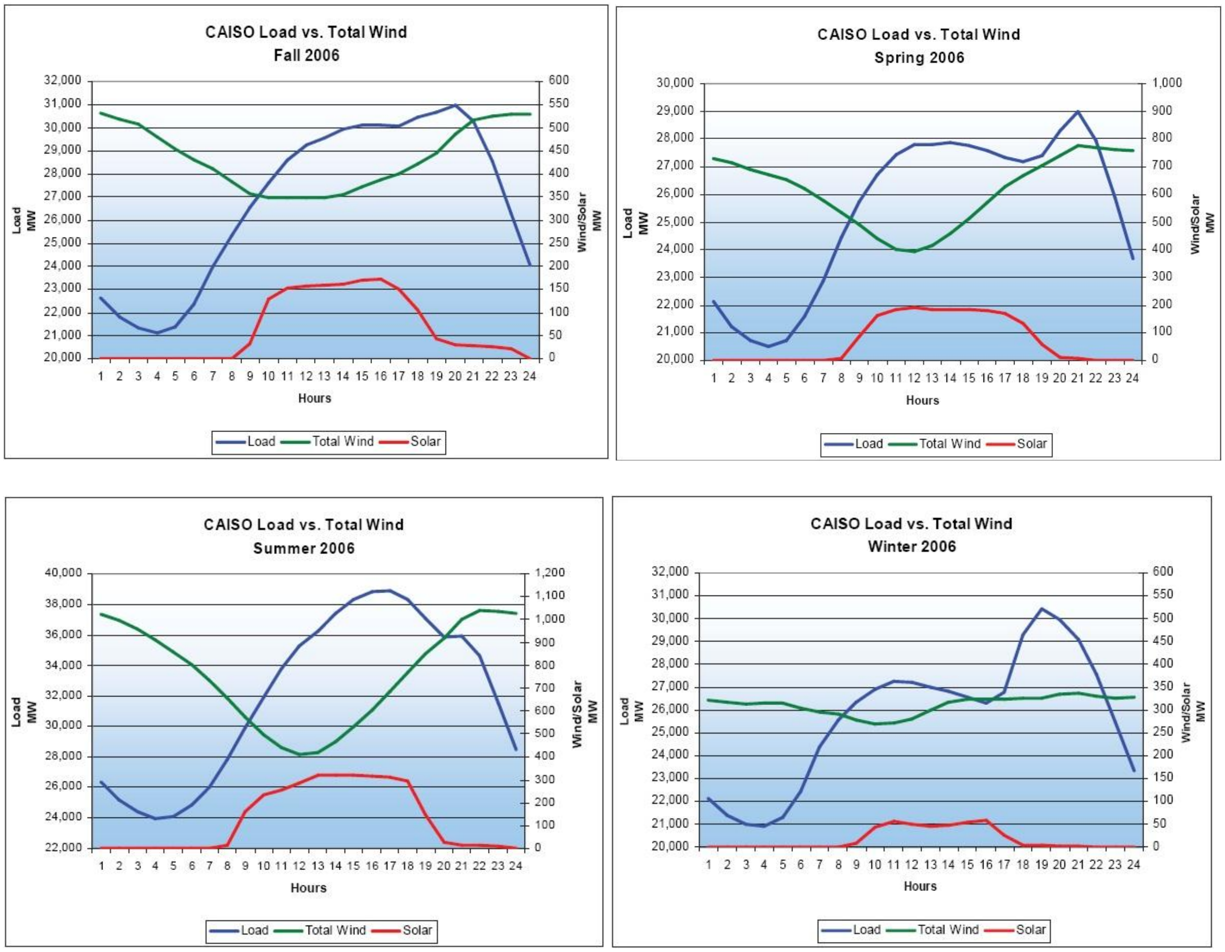
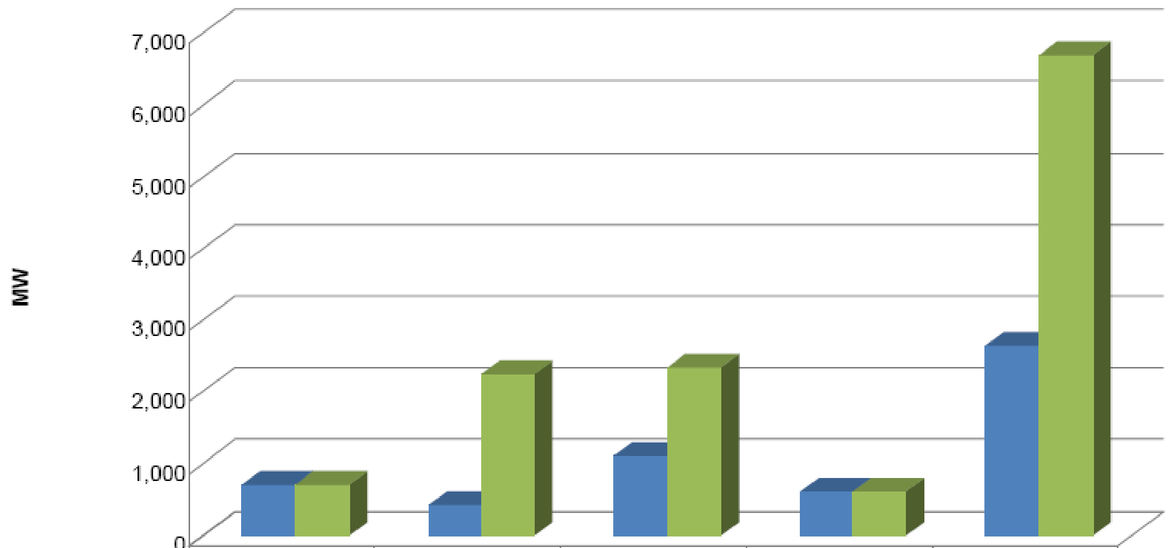


Figure 30: Renewable Resource Forecast[c]



	Biomass/BioGass	Solar	Geothermal	Small Hydro	Wind
2006	701	420	1,101	614	2,648
2012 (expected)	701	2,246	2,341	614	6,688

Renewable Resource Capacity (MW) in 2006 and 2012 (expected)

10.4 Appendix 4: Results of EV Scenario Forecasting

Year	Total Registered Passenger Vehicles (US)	Total Registered Passenger Vehicles (CA)	New Vehicle Sales (US)	New Vehicle Sales (CA)	Low Scenario: Total EV Sales (CA)	Low Scenario: EVs retired per year (CA)	Low Scenario: Net EVs on the road (CA)	Low Scenario: Net EVs on the road as a % of total vehicles in CA	Medium Scenario: Total EV Sales (CA)	Medium Scenario: EVs retired per year (CA)	Medium Scenario: Net EVs on the road (CA)	Medium Scenario: Net EVs on the road as a % of total vehicles in CA	High Scenario: Total EV Sales (CA)	High Scenario: EVs retired per year (CA)	High Scenario: Net EVs on the road (CA)	High Scenario: Net EVs on the road as a % of total vehicles in CA
2011	138,515,216	20,127,642	12,330,000	1,439,546	1,555	16	1,539	**0.0%**	3,264	33	3,231	**0.0%**	0	488	37,913	**0.2%**
2012	138,914,533	20,185,667	13,260,000	1,548,125	3,344	60	4,823	**0.0%**	7,040	126	10,145	**0.1%**	2	1,166	73,176	**0.4%**
2013	139,313,850	20,243,691	14,190,000	1,656,704	5,368	153	10,038	**0.0%**	14,627	354	24,418	**0.1%**	12	2,390	123,266	**0.6%**
2014	139,713,166	20,301,716	15,120,000	1,765,283	7,626	322	17,343	**0.1%**	26,520	838	50,100	**0.2%**	43	4,451	191,959	**0.9%**
2015	140,112,483	20,359,741	16,050,000	1,873,861	10,119	605	26,857	**0.1%**	44,640	1,773	92,967	**0.5%**	123	7,734	282,603	**1.4%**
2016	140,511,800	20,417,766	16,980,000	1,982,440	12,846	1,050	38,654	**0.2%**	63,861	3,393	153,435	**0.8%**	290	12,758	399,159	**2.0%**
2017	140,911,117	20,475,790	17,910,000	2,091,019	15,808	1,718	52,744	**0.3%**	87,699	6,041	235,093	**1.1%**	606	20,211	546,909	**2.7%**
2018	141,310,434	20,533,815	18,840,000	2,199,598	19,005	2,684	69,065	**0.3%**	115,348	10,166	340,276	**1.7%**	1,145	28,367	732,126	**3.6%**
2019	141,709,750	20,591,840	19,770,000	2,308,177	22,435	4,036	87,464	**0.4%**	146,810	16,334	470,752	**2.3%**	2,000	45,923	951,929	**4.6%**
2020	142,109,067	20,649,864	20,700,000	2,416,756	26,101	5,873	107,693	**0.5%**	182,085	25,249	627,588	**3.0%**	3,273	66,887	1,211,304	**5.9%**
2021	142,508,384	20,707,889	21,630,000	2,525,335	30,001	8,354	129,340	**0.6%**	221,172	37,864	810,896	**3.9%**	5,065	95,973	1,502,717	**7.3%**
2022	142,907,701	20,765,914	22,560,000	2,633,914	34,136	11,708	151,768	**0.7%**	264,072	55,404	1,019,564	**4.9%**	7,451	135,593	1,830,429	**8.8%**
2023	143,307,018	20,823,939	23,490,000	2,742,492	38,505	16,186	174,086	**0.8%**	310,784	79,378	1,250,970	**6.0%**	10,458	188,480	2,190,448	**10.5%**
2024	143,706,335	20,881,963	24,420,000	2,851,071	43,108	22,052	195,142	**0.9%**	361,309	111,684	1,500,595	**7.2%**	14,023	257,788	2,576,146	**12.3%**
2025	144,105,651	20,939,988	25,350,000	2,959,650	47,946	29,572	213,517	**1.0%**	415,646	154,656	1,761,585	**8.4%**	17,962	347,141	2,977,797	**14.2%**
2026	144,504,968	20,998,013	26,280,000	3,068,229	53,019	39,014	227,522	**1.1%**	473,795	210,947	2,024,433	**9.6%**	21,936	460,609	3,382,122	**16.1%**
2027	144,904,285	21,056,037	27,210,000	3,176,808	58,326	50,639	235,209	**1.1%**	535,757	283,402	2,276,789	**10.8%**	25,433	602,831	3,771,726	**17.9%**
2028	145,303,602	21,114,062	28,140,000	3,285,387	63,868	64,706	234,371	**1.1%**	601,532	375,093	2,503,228	**11.9%**	27,786	779,029	4,124,512	**19.5%**
2029	145,702,919	21,172,087	29,070,000	3,393,966	69,644	81,470	222,546	**1.1%**	671,119	489,265	2,685,082	**12.7%**	28,224	994,935	4,413,175	**20.8%**
2030	146,102,235	21,230,112	30,000,000	3,502,545	75,655	101,182	197,019	**0.9%**	744,519	629,292	2,800,309	**13.2%**	25,987	1,256,809	4,604,668	**21.7%**

10.5 Appendix 5: List of Abbreviations

AGC – Automatic Generation Control
AMI – Advanced Metering Infrastructure
BEV – Battery Electric Vehicle (i.e. Nissan Leaf)
BTS – Bureau of Transportation Statistics
CAISO – California Independent System Operator
C&I – Commercial and Industrial
CSP – Curtailment Solution Providers
DR – Demand Response
DLC - Direct Load Control
DRR – Demand Response Regulation Resource
DSM – Demand Side Management
EA – Enhanced Aggregation
EES – Electrical Energy Storage
ELC - Emergency Load Curtailment
EPRI – Electric Power Research Institute
eREV – Range Extender Electric Vehicle (i.e. Chevy Volt)
EV – Electric vehicle (for the purposes of this report, "EV" includes BEV, PHEV, and eREV)
FERC – Federal Energy Regulatory Commission
ISO – Independent System Operator
kW – kilowatt (1,000 watts)
LCOE - Levelized Cost of Electricity
LMP – Locational Marginal Pricing
MW – megawatt (1,000 kW)
NHTSA – National Highway Traffic Safety Administration
NREL – National Renewable Energy Laboratory
ORNL – Oak Ridge National Laboratory
PHEV – Plug-in Electric Vehicle (i.e. Prius Plug-In)
REC – Renewable Energy Credits
RPS – Renewable Portfolio Standard
V2G – Vehicle-to-Grid

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