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Value to the Grid from Managed Charging based on California's High Renewables Study

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***Abstract*—Managed charging of electric vehicle (EV) loads has the potential to use renewable energy more effectively, shave peak demand, and fill demand valleys while serving transportation needs. However, the potential value to the grid from managed charging has not been fully quantified. This paper adopts the tools used in the National Renewable Energy Laboratory's California Low Carbon Grid Study to quantify value to the grid from managed charging by using three levels of managed loads for 13 terawatt-hours of annual load from three million EVs in a 2030 California grid scenario. Simulation results show that management of the EV fleet's aggregate load from unmanaged to 100% managed results in savings between $210 million and $660 million annually in generation system costs, depending on grid conditions. The simulation results also suggest that targeted EV supply equipment (EVSE) deployments at workplaces and other mid-day parking locations will be needed to support managed charging in a high-renewables California and enable the identified value to the grid. Although the value of generation to the grid from managed EV load paired with high renewables seems substantial, we estimate that the installed cost of an EVSE must be between $1,000 and $3,000 for a 10-year life to be cost neutral, depending on grid conditions.**

***Index Terms*—Smart charging, electric vehicles, renewables**

I. Introduction

CALIFORNIA Executive Order S-03-05 targets a reduction in greenhouse gas emissions within or attributable to the state of California to 80% below 1990 levels by 2050 [1]. References [2–4] conclude that the electricity sector plays a crucial role in achieving this target. The Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California includes electrification of the transportation sector as an element in achieving the long-term emission target [2]. Electric vehicles (EVs) present demand that is potentially flexible and controllable [5-7]. Managing a controllable EV load may benefit the utility by shaving peaks, filling valleys, and allowing more efficient and effective use of excess energy produced by renewable energy resources [8-11].

DiUS Computing Pty Ltd has demonstrated that managed EV charging at the network level will not only defer costly infrastructure upgrades through peak demand management, but may deliver better returns on existing investments through improved asset utilization [12]. Grid-integrated smart charging technology would deliver these benefits and avoid creation of a second peak in electricity demand as drivers individually defer charging to the off-peak period. The outcome from these improvements will be lower cost for all electricity consumers, not just those who drive EVs. The *California Transportation Electrification Assessment Phase 2: Grid Impacts* report [13] quantified the costs and benefits of plug-in EVs (PEVs) for utilities, their customers, and the state of California. The report from the California Air Resource Board and the California Public Utilities Commission (CPUC) shows that PEVs reduce rates for utility customers and provide net economic and societal benefits for California. In [14], a detailed unit commitment model of the Texas electric power system is developed to estimate the potential cost savings from using different sizes of plug-in hybrid EV (PHEV) fleets. The authors conclude that flexibility in the timing of PHEV charging can provide an opportunity to improve power system efficiency and reduce costs of power systems by providing ancillary services and reducing the need to reserve conventional generator capacity. The simulation results in [15] further demonstrate that flexibility in the timing of PHEV charging can result in significant generation efficiency gains by shifting load to more efficient generators, and thus reduce transportation-related emissions beyond currently reported estimates.

To further the quantification of the value to the grid from managed charging on California's high renewable future grid, we use tools from the 2030 Low Carbon Grid Study (LCGS) and consider three levels of managed load for 13 terawatt-hours (TWh) of annual EV load from 3 million EVs. The major contribution of this paper is two-fold: 1) we analyze how managed charging affects annual production costs, peak load, curtailment, and annual carbon dioxide (CO_2) emissions, and 2) we investigate how managed charging may shape future electric vehicle supply equipment (EVSE) deployment strategies and cost requirements.

II. Method

A. California Low Carbon Grid Study

The National Renewable Energy Laboratory (NREL) performed the LCGS to analyze the impacts of many scenarios that achieve a 50% reduction in carbon emissions of California's electric power sector by the year 2030 [2]. The grid impacts are characterized based on several key operational and economic metrics, including production costs, emissions, curtailment, imports, and impacts on the operation of gas generation. The LCGS adopts the PLEXOS Integrated Energy Model [16, 17] to simulate the hourly unit commitment and dispatch of generation fleet in the western United States for 23 different scenarios, which include a variety of assumptions regarding the generator portfolios, storage, and grid flexibility [2].

The future electricity system is expected to bear a larger burden of total end use energy of the transportation sector through EV market growth. Due to flexibilities of PEVs in terms of their energy consumption rates and use schedules, the

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TABLE I
ASSUMPTIONS OF GRID CONDITIONS [2]

Assumption	High Solar, Conventional Grid Flexibility	Diverse Portfolio, Enhanced Grid Flexibility
Renewable resource portfolio	High in-state solar PV generation (California load is supplied by 28% PV, 16% wind, and 12% others)	Diverse renewable resource profile (more solar thermal power with thermal energy storage, biomass, and geothermal than the conventional flexibility scenario) (California load is supplied by 21% PV,18% wind, and17% others)
Import requirements	70% of out-of-state (California-entitled) renewable, nuclear, and hydro generation must be imported in every hour	Only physical limitations on imports and exports
Minimum local generation requirements	25% of generation in California balancing authorities must come from local fossil-fueled and hydro sources	No minimum generation requirements
Storage buildout	1.5-GW battery storage to meet CPUC requirement	1.5-GW battery storage to meet CPUC requirement, plus 1 GW pumped hydro, and 1.2 GW out-of-state compressed air energy storage
Ancillary service provision	In addition to physical limitations on ancillary service provision, capacity of hydro and pumped storage that can provide ancillary services are limited	The capacity of hydro and pumped storage that can provide ancillary services is doubled from conventional assumptions
Annual total load	320 TWh	320 TWh
EV load (3M EVs)	13 TWh, about 12.4 kWh/day/EV	13 TWh, about 12.4 kWh/day/EV

EV load has the potential to be a flexible resource to enhance the operation of the electricity system [14, 18, 19]. To quantify the value of managed charging to the grid under various grid flexibilities, we adopted two portfolios in this study. These two portfolios, shown in Table I, have 56% renewable penetration to achieve the goal of 50% carbon reduction, but represent different trajectories for achieving the carbon reduction goal. These two portfolios capture the full spac The high solar portfolio with conventional grid flexibility emphasizes more photovoltaic (PV) and less wind as well as a more inflexible grid. It represents a continuation of current procurement trends (prioritization of in-state resources with lower upfront capital costs) and current operational practices. The diverse portfolio with enhanced grid flexibility uses a diverse mix of renewable resources with 2.2 gigawatts (GW) of additional storage. It also has no limitation on the import requirements and no minimum local generation requirements, which represents a future with more flexible grid operation in California. The diverse portfolio with enhanced grid flexibility increases California's ability to export California-entitled energy, shut down gas generation to make room for renewables, and use storage to reduce curtailment and peak-load energy needs. The detailed assumptions of resources in these scenarios are described in [20]. To save space in the following paragraphs, we will use enhanced diversity (ED) to denote diverse portfolio grid condition with enhanced grid flexibility. Conventional solar (CS) is used to denote a high solar grid condition with conventional grid flexibility. Fig. 1 compares the net load profiles of two grid flexibility portfolios in 2030. The original load is the total demand from all sources. The net load is defined as the system load minus contributions from variable generation sources (wind and solar) and indicates the load that must be met by the rest of the dispatchable generator fleet. The PV generation creates low net load in the middle of the day and high ramp in the morning and evening due to sunrise and sunset, and a late afternoon peak. Although both grid conditions in Table I have 56% renewable penetration, CS has even lower net loads and higher ramps than ED, but has the same peak generation period.

Although it is not a key component of the study, the LCGS assumes that 3 million EVs will be on the road in California by the study year of 2030. As Table 1 shows, each EV requires 12.4kW per day, leading to annual increase of 13 TWh of electricity (about 4% of total load). The study assumes that half of these vehicles exhibit a fixed charging profile (i.e., charging at a constant time each day) while half of these vehicles are charged at the optimal times from the standpoint of the utility. This assumption is further discussed in the following section.

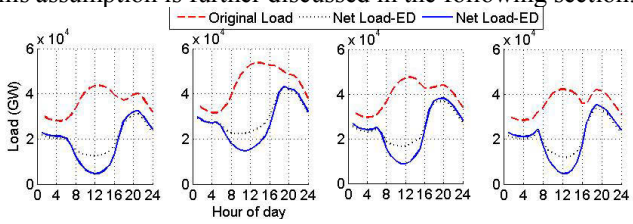

Fig. 1. Net load profiles in 2030, where both grid conditions have 56% renewable penetration.

B. *Review of LCGS PLEXOS Model*

The primary goal of the LCGS was to understand the operation and economics of the power system with low-carbon portfolios in the state of California under a range of assumptions. The complete assumptions for this simulation were summarized in [2, 20]. However, we discuss key assumptions and background that are related to the conclusions of this paper.

The model in this paper aims to analyze and understand the key drivers for the metrics of interest (e.g., production cost, curtailment, emissions, imports, and gas fleet utilization) with managed charging. To quantify these drivers, we use the PLEXOS by Energy Exemplar software [17]. PLEXOS uses mixed integer programming to determine the unit commitment decisions of all generating units, and uses linear programming to determine the least cost dispatch for all committed generators. The model is formulated as an optimization problem to minimize fuel cost, startup costs, variable operations and maintenance costs, and emissions costs under many constraints. These constraints include electricity demand, generator operating characteristics, transmission grid topology, and renewable energy output. Every generating unit in the Western

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Interconnection of North America is captured, with part-load heat rate curves, start costs, and transmission network topology derived from the planning organization of the Western Electricity Coordinating Council [21]. PLEXOS is a commercial model and thus not open-sourced. However, the model has been widely accepted and validated externally, and is used by utilities and researchers alike [22, 23, 16].

The optimal DC power flow inside of California is represented at a nodal resolution but only a zonal resolution outside of California. This means that full nodal power flow was simulated, but individual line constraints are not enforced; only the 67 WECC paths are constrained. This simplification keeps run time reasonable.

To handle renewable supply uncertainty, the LCGS models day-ahead, intra-day, and real-time operations [23]. Both day-ahead and intra-day simulations include day-ahead and four-hour-ahead forecasts for renewable generation, respectively [23]. The day-ahead simulation commits the long-start generators and fixes the hydro and storage dispatches [20]. The intra-day simulation also fixes the commitment of natural gas combined-cycle units [23]. Real-time dispatch uses generation based on estimated wind speeds after considering errors in forecasts for wind and solar generators [23]. Emissions are calculated in post processing. The time resolution of the simulations was generally hourly while a 5-minute resolution was employed in some cases to analyze the sub-hourly operation. A detailed description of the inputs and outputs of the LCGS PLEXOS model can be found in [23].

C. Managed Charging Components

In this paper, we consider two types of vehicle charging regimes: unmanaged charging and managed charging. The following paragraphs define both vehicle charging regimes.

1) Unmanaged Charging

Unmanaged charging (also called 0% managed) assumes that charging would take place on a predetermined schedule [24, 25]. It represents a typical charging method in which an EV is charged immediately after it is plugged in. The vehicle keeps charging until complete or until another trip begins. Unmanaged charging ignores grid conditions and charges the EV according to the EV user's schedule. For this study, two charging profiles are adopted from [26, 27]. The charging profiles were based on the detailed vehicle simulation using second-by-second vehicle speed and trip profile characteristics collected using on-board GPS unites. In "home dominant" case, EV is plugged in and charge at 120V as soon as the vehicle ends the last trip for the day. In "opportunity" case, charging infrastructure is assumed ubiquitous and the consumer will choose to plug-in and charge at 240V any time the vehicle is parked regardless of stop duration. The total electric energy consumed is limited by the size of the battery and travel behavior. The average daily charging energy per EV is 12.4 kWh, and the daily driving distance is around 40 miles. Sixty percent of the unmanaged charging profile vehicles would follow a "home dominant" charging pattern. The other 40% of unmanaged charging-profile vehicles follow an "opportunity" charging pattern. Fig. 2 illustrates the charging profiles that compose the unmanaged EV charging grid load. This type of charging takes place at the same time each day, regardless of the underlying grid conditions. Unmanaged charging-profile indicates that EV users are not incentivized or equipped to change the timing of their EV demand. To simplify the simulation, we assumed that each day in the entire year has the same daily aggregate EV profile shown in Fig. 2.

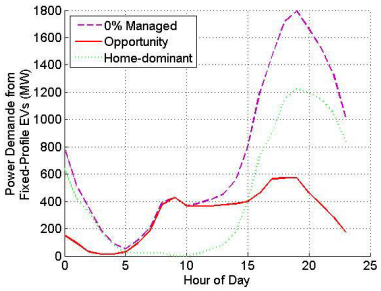

Fig. 2. Aggregated EV charging patterns from the unmanaged charging profile EV fleet in 2030 [13]

2) Managed Charging

Managed charging considers EV load as a resource for the utility, and charging occurs when it is most advantageous from the utility's perspective. Instead of starting to charge an EV based on the EV user's schedule, the managed charging schedules the EV's energy needs and charging pattern according to the best time to integrate with grid operations. From a modeling standpoint, managed charging represents a daily load (12.4kWh per vehicle) that may occur at any point during the day. There is no constrains on when it must be met, however, the charging rate varies by time of day. The maximum charging rate at night is 1kW per vehicle, which means that most vehicles will be charged on a standard household 120-volt outlet. Only a fraction of vehicles will be plugged in at any time. EVs are assumed to be charged at workplaces or public charge station with 240-volts services during daytime, leading to 2kW maximum charging rate per vehicle. From a practical standpoint, this may be achieved via implementation of a central control signal from the grid, time-of-use electricity pricing, or other response influence methods. The charging profiles for the managed charging vehicles are determined by the model. In contrast to the unmanaged-profile EVs shown in Fig. 2, the charging profiles for managed charging are an output of the grid model rather than an input. For instance, the optimization within the PLEXOS model determines when the EV load should occur, at the minimum cost to the system. As in the case of Fig. 2, all EV load was scheduled during the day. Our results in [28] simulate the managed charging with consideration of driving patterns and simulation results indicate that managed charging can shift most EV loads to mid-day while meeting the EV charging demand. This result is further discussed in the following section.

III. Simulation Setup and Results

A. Simulation Setup

To study the impacts of different percentages of managed

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charging on the potential value to the grid, we adopted three levels of managed charging: 0% managed (unmanaged) charging, 50% managed charging, and 100% managed charging. The unmanaged charging represents the worst case in 2030, where no vehicle charging is managed. The 50% managed charging represents a 2030 case with conditions that enable half of the EV load to be aligned with grid needs. The 50% managed case was used as the primary assumption for EV loads in the California LCGS [2]. The 100% managed charging represents a case that all vehicles participate in managed charging, which is used to determine the maximum benefits achievable from managed charging. For comparison, we also use cases with no EV as baselines. Given the two grid conditions, eight simulations are adopted in this study, which are listed in Table II. No EV means all EV load is removed from the utility load.

TABLE II
CASES NAMING CONVENTIONS

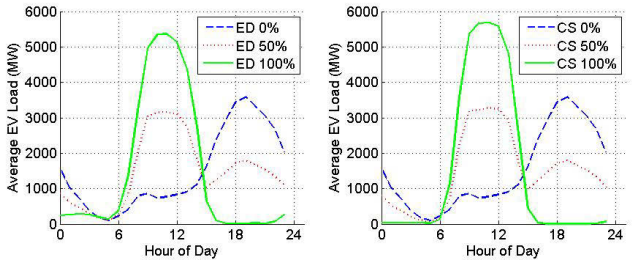
EV Load\ Grid Conditions	Diverse Portfolio, Enhanced Grid Flexibility	High Solar, Conventional Grid Flexibility
No EV (all EV load removed)	ED, No EV	CS, No EV
Unmanaged EVs	ED 0%	CS 0%
50% Managed EVs	ED 50%	CS 50%
100% Managed EVs	ED 100%	CS 100%

ED: Diverse Portfolio, Enhanced Grid Flexibility; No EV: all EV load removed; CS: High Solar, Conventional Grid Flexibility

B. Simulation Results

1) EV Load profile

Fig. 3 compares the average EV load profile of the three managed charging cases. In the unmanaged case, charging takes place based on the driver's charging profile. The EV load peak is nearly aligned with the typical grid peak shown in Fig. 1 and further exacerbates peak load and ramp rate challenges while the renewable energy generation in the middle of the day is not fully utilized. The managed charging shifts EV loads from evening to mid-day. In the 100% managed cases, the EV load drops off completely before the evening peak. The grid conditions rarely affect the EV charging profile as shown in Fig. 3. The average difference of average load under both grid conditions is very small. The profiles of home-dominated and opportunity charging go to half for 50% managed charging case and are completely removed for the 100% managed case.



(a) Diverse portfolio with enhanced grid flexibility (ED) condition

(b) High solar portfolio with conventional flexibility (CS) condition

Fig. 3. EV load profiles in 2030, where both grid conditions have 56% renewable penetration

2) Value to Grid from Managed Charging

a) Production Cost Reduction

Table III summarizes the total production cost, including generation cost and net import cost (including purchases of electricity from out of state and sales of electricity). Since the grid needs to generate more energy to charge vehicles, unmanaged EV load could increase between $810 million and $960 million in production cost, which represents between 9.4% and 13.2% incremental in overall costs. However, managed charging reduces the production cost associated with EV load. More production cost savings are achieved as the percentage of managed vehicles increases. Changing the EV fleet from unmanaged to 100% managed could save between $210 million and $660 million annually in generation costs. This represents 2.9%–7.6% reduction in overall costs. This also represents a 22%–81% reduction in the total costs of EV charging.

TABLE III
CALIFORNIA ANNUAL ELECTRICITY PRODUCTION COSTS

Cases	Annual Costs ($B)	Average Price ($/MWh)	Cost reduction Compared to No EV Case (%)
ED, No EV	7.10	23.1	0.0
ED 0%	8.04	25.1	13.2
ED 50%	7.95	24.8	12.0
ED 100%	7.83	24.5	10.3
CS, No EV	8.61	26.9	0.0
CS 0%	9.42	29.5	9.4
CS 50%	9.05	28.3	5.1
CS 100%	8.76	27.4	1.7

Table IV compares the annual production cost by component. The largest share of costs in California comes from fuel cost, which is used to buy natural gas to fuel the generator fleet. Other large contributions in cost reduction come from emissions costs and imported power purchases. Carbon price for computing emission costs in California is $32.44 per metric ton based on the California Energy Commission (CEC) "low" forecast and extrapolated to 2030 [29]. The carbon price commensurate with their threat levels to the environment is essential to rapidly reduce fossil fuel consumption and transition to using renewables in a market economy [30]. The most effective broad-based measure is a significant, steadily rising carbon fee. EV load increases each component of production cost. However, changing the EV fleet from unmanaged to 100% managed could save between 3% and 5% in fuel costs and emission costs. One hundred percent managed EV charging reduces start costs to less than the start costs for pure system load. This is because flexible EV loads enhance the flexibility of utility load. The managed charging reduces variable operations and maintenance costs (VO&M). The managed charging effectively utilizes the generated energy from solar and reduces net import costs about 20% for the CS grid condition. Since a diverse portfolio with enhanced flexibility already maximizes the load flexibility to reduce production cost, imported power is needed to support vehicle

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charging. Managed charging also effectively utilizes the import power to reduce overall production cost with EV load for the ED grid condition.

TABLE IV
CALIFORNIA ANNUAL ELECTRICITY PRODUCTION COSTS BY COMPONENT ($M)

Cases	Fuel Cost	Start Cost	VO&M Cost	Emissions Cost	Net Import Cost
ED, No EV	4,580	250	214	1,190	450
ED 0%	5,030	300	224	1,300	770
ED 50%	4,940	250	223	1,280	830
ED 100%	4,860	210	222	1,260	860
CS No EV	5,600	260	176	1,420	850
CS 0%	5,980	300	185	1,520	1,130
CS 50%	5,820	270	183	1,480	980
CS 100%	5,690	240	181	1,450	880

VO&M = Variable operations and maintenance

b) Seasonal Costs for Charging Vehicles

Table V compares seasonal cost of each component for charging vehicles under CS grid condition. In this comparison, the total production costs without any EV load are assumed as baselines. The cost for charging vehicles is added production cost from EV load, which is equal to the difference between the total production cost with EV load and the baseline. Managed charging reduces the seasonal cost of each component for charging vehicles, especially from fuel cost and net import cost. The cost of charging on the grid depends on the season. In the spring, the total cost of adding load is reduced. Since the total load is lower, the resource cost is lower, and lower cost generation technologies, including curtailed wind and solar, can be used to charge EVs.

TABLE V
CALIFORNIA SEASONAL COMPONENT PRODUCTION COSTS COMPARED TO BASELINE (NO EV) FOR CHARGING VEHICLES UNDER CS CONDITION ($M)

Quarter	Scenario	Emissions Cost	Fuel Cost	Start & Shutdown Cost	VO&M Cost	Net Import Cost
Spring	CS 0%	26	105	16	2	78
	CS 50%	18	75	5	2	109
	CS 100%	11	48	-5	1	119
Summer	CS 0%	31	123	9	3	90
	CS 50%	30	118	-4	3	80
	CS 100%	29	113	-14	3	69
Fall	CS 0%	27	100	7	2	105
	CS 50%	23	86	-5	2	112
	CS 100%	19	69	-15	2	118
Winter	CS 0%	28	121	11	2	49
	CS 50%	21	91	1	2	81
	CS 100%	14	60	-11	1	101

Table VI shows the total California seasonal component production costs for charging vehicles from various resources under the ED grid condition. Managed charging reduces the costs of each component for all seasons with the exception of the net import cost. Since diverse resource generation and grid flexibility still cannot meet the need for EV charging, some energy still needs to be imported to support EV charging. Managed charging is more effective in reducing each component of charging cost in non-summer seasons.

TABLE VI
CALIFORNIA SEASONAL COMPONENT PRODUCTION COSTS COMPARED TO BASELINE (NO EV) FOR CHARGING VEHICLES UNDER ED CONDITION ($M)

Quarter	Cases	Emissions Cost	Fuel Cost	Start & Shutdown Cost	VO&M Cost	Net Import Cost
Spring	ED 0%	19	79	14	2	57
	ED 50%	10	41	5	2	29
	ED 100%	2	10	-2	1	5
Summer	ED 0%	23	94	8	3	98
	ED 50%	15	61	2	2	58
	ED 100%	10	39	-6	1	21
Fall	ED 0%	25	95	12	3	75
	ED 50%	15	57	3	2	34
	ED 100%	7	25	-4	2	7
Winter	ED 0%	27	115	14	2	50
	ED 50%	16	68	7	2	13
	ED 100%	7	26	-2	1	0

c) Peak Load Reduction

Table VII summarizes the peak load reduction achieved through managed charging. The managed charging of EVs can effectively lower the peak load by a substantial margin, 1.2 – 1.8 GW. Utilities generally contend with peak load by procuring additional generation capacity. This capacity is often expensive, especially due to its low utilization. The ability to manage EV charging to reduce system peaks can provide substantial economic value to the system by offsetting the cost of new generator capacity. For its modeling, the CPUC uses a short-run cost of capacity (the avoided cost of contracting for resource adequacy capacity) of $30/kW-year and a long-run cost of capacity (the avoided cost of a new gas combustion turbine) of $153/kW-year [31]. Based on the CPUC's cost assumptions, avoided capacity costs could add $36 – $180 million in annual reserve margin value for the CS grid condition and $54 – $270 million for the ED grid condition. Capacity benefits are not currently included in this paper as the methods for valuing are complex, and we focus instead on operational value. However, capacity benefits may provide another economic incentive to deploy managed EV charging and are an area for future work.

TABLE VII
MANAGED CHARGING IMPACTS ON SYSTEM PEAK LOAD

Cases	CA Peak Load (GW)	CA Peak Load Reduction (GW)	Percentage of CA Peak Load Reduction (%)
ED 0%	65.5	0	0.0
ED 50%	64.4	1.1	1.7
ED 100%	63.7	1.8	2.8
CS 0%	66.0	0.0	0.0
CS 50%	65.0	1.0	1.5
CS 100%	64.8	1.2	1.8

d) Curtailment

Curtailment is renewable energy that is available from variable resources like solar and wind, but which cannot be absorbed into the system, mainly due to operational limitations of resources and the alignment of loads with generation. Curtailment is a measure of system stress [4]. Table VIII compares impacts on renewable curtailment under several managed charging scenarios. In the ED grid condition, changing charging from unmanaged to 100% managed decreases curtailment from 0.26% to 0.22%. This equals to 70 gigawatt-hours (GWh) more renewable energy in the ED 100%

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case compared to the ED 0% case. The EV load only reduces curtailment by a small amount because curtailment in the ED condition is already minimal due to more flexible conditions, In the CS condition, changing from unmanaged to 100% managed reduces curtailment from nearly 12.83% to 7.27%. This equates to 7,400 GWh more renewable energy in the CS 100% case compared to the CS 0% case. Curtailment reduction is valuable for a few reasons. Currently, California is obligated to supply a certain fraction of its load from renewable energy. Curtailed renewable energy does not count toward this goal. In addition, wind and PV resources do not have any marginal costs because they do not require fuel, and therefore curtailment represents a lost opportunity to use zero-marginal cost (and carbon) energy.

TABLE VIII
RENEWABLE CURTAILMENT INFLUENCES DUE TO MANAGED CHARGING

	Curtailment (%)	Saved energy (GWh)
ED, No-EV	0.29	-
ED 0%	0.26	0
ED 50%	0.24	30
ED 100%	0.22	70
CS, No-EV	12.83	-
CS 0%	11.71	0
CS 50%	9.31	4000
CS 100%	7.27	7400

e) CO_2 Emissions

Table IX summarizes annual CO_2 emissions from the electricity sector in California. EV loads increase annual CO_2 emissions by requiring more electricity generation. However, managed EV charging (versus unmanaged profile charging) can save between 1.3 and 2.4 million metric tons (MMT) of CO_2 annually. These equate to a 2.93% – 4.65% reduction in CO_2 from the electrical sector.

TABLE IX
ANNUAL CO_2 EMISSIONS FROM ELECTRICITY SECTOR IN CALIFORNIA

Scenarios	Annual CO_2 Emissions (MMT)	Annual CO_2 Emissions Reduction Compared to Unmanaged Case (%)
ED, No EV	40.5	-
ED, 0%	44.3	0
ED, 50%	43.7	1.35
ED, 100%	43.0	2.93
CS, No EV	48.4	-
CS, 0%	51.6	0
CS, 50%	50.3	2.52
CS, 100%	49.2	4.65

Table X compares average CO_2 emissions by contrasting the CO_2 emissions for the No EV case with the three levels of managed charging. Managed charging fully utilizes renewable energy to charge vehicles, and reduces CO_2 emissions. Compared with ED grid condition, the CS grid condition generates more renewable energy from solar but has less grid flexibility, which enhances effectiveness of managed charging on reduction of CO_2 emissions. Managed charging can reduce CO_2 emissions to half for CS 50% managed vehicles and one fourth for CS 100% managed vehicles.

TABLE X
CO_2 EMISSIONS FROM CHARGING EVS (MMT)

Cases	ED 0%	ED 50%	ED 100%	CS 0%	CS 50%	CS 100%
CO_2 (MMT)	3.774	3.117	2.429	3.218	1.922	0.868

C. *Energy Throughput*

Managed charging generally shifts the EV demand to a lower net load period. Existing grid conditions have the lowest net load at night and peak load in the middle of the day, so managed charging strategies will attempt to shift the EV load to nighttime. A high penetration of PV generation lowers the net load in the middle of the day as shown in Fig. 1. The change in the lowest net load period also affects the EVs' load for managed charging as shown in Fig. 3. The EVs will be charged in the middle of the day when they are mainly parked at workplaces. Fig. 4 compares the energy distribution of the EV load under unmanaged as well as 50% and 100% managed charging cases. Unmanaged charging uses 65% of energy to charge EVs at home, which is a home-dominated charging case. The 50% managed charging case moves 32% of charging from evening to mid-day, which is likely to be at workplace and public stations and results in 67% of energy to charge EVs. The 100% managed charging case uses 95% of energy to charge EVs at workplace and public stations, which is the upper limit for shifting energy from evening to mid-day through managed charging. This result suggests more EVSE deployment at workplace to maximize the potential value to the grid.

Moving managed EV charging from home to the workplace is beneficial by full utilization of metering and other implementation for large industrial and commercial customers, which is typically costly to implement at home [32]. In addition, direct load control strategies by using non-price-based signals can be implemented at a workplace aggregator by reusing existing infrastructure to enable fast, predictable control opportunities, especially for the provision of ancillary services such as regulation and contingency reserves [33].

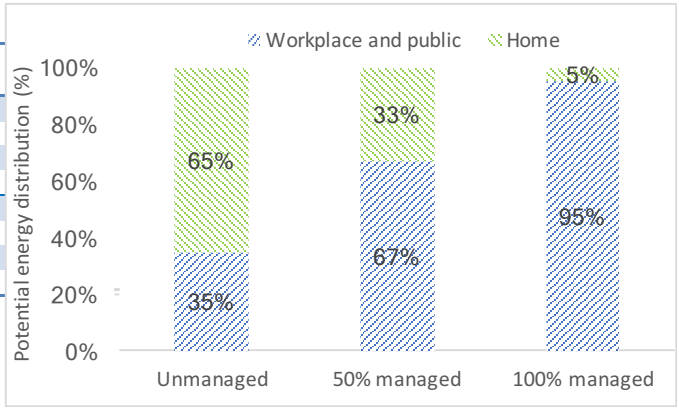

Fig. 4. Potential energy distribution scenarios of EV loads under unmanaged, 50% managed, and 100% managed charging cases

D. *Additional Investment of EVSE to Support Grid Value-focused Charging*

1) *Additional EVSE Investment to Support Managed Charging*

To support managed charging, a sufficient number of EVSEs should be deployed to shift the EV charging load from evening to mid-day. The additional EVSEs to support managed charging are mainly used to shift EV peak power to mid-day. The number

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of EVSEs to support managed and unmanaged charging is determined by the peak power in the mid-day and evening.

Table XI summarizes EV peak power by unmanaged and managed charging. EV peak loads are very close under both ED and CS grid conditions though they vary by day, and so the values in Table IX are the worst case for both conditions. Compared with unmanaged charging, 50% managed charging adds an additional 2,600-megawatt (MW) power of EV load in mid-day and reduces EV peak load in the evening to half. The 100% managed charging adds 5,700-MW load in mid-day and reduces peak load in the evening to almost zero.

TABLE XI
SHIFTED EV POWER PEAK IN MID-DAY AND EVENING (MW)

		Opportunity (60% Unmanaged)	Home dominated (40% Unmanaged)	Managed
Unmanaged	Mid-Day	200	700	0
	Evening	1,100	2,700	0
50% Managed	Mid-Day	100	350	2,600
	Evening	600	1,300	0
100% Managed	Mid-Day	0	0	5,700
	Evening	0	0	200

According to [34], the average EVSE utilization time during workplace and public stations is 6 hours per day at the lowest utilization rate. Given an eight-hour work day, the utilization rate is around 75%. Adding EVSEs to support managed charging may reduce the charging rate, but the future grid may use new policies and/or time-of-use rates to encourage more EV owners to charge during low net load periods. We adopt 75% of the EVSE utilization rate in the following grid savings analysis.

The number of EVSEs is determined by the average EVSE power, peak power of EV loads, and EVSE utilization rate. That is, the approximate number of EVSEs is a division of the peak power of the EV load by average EVSE power and EVSE utilization rate. Based on the simulation, the average EV charge power is 2 kW in mid-day and 1 kW in the evening. The EVSE average power is assumed the same as the average EV charging power. Given the above EVSE utilization rate, average EVSE power, peak power in TABLE XI, the total numbers of EVSEs are summarized in Table XII. Total numbers of EVSEs for unmanaged charge as well as 50% and 100% managed charges are 4.39 million, 3.89 million, and 3.82 million, respectively. To support managed charging, an additional 1.73 million EVSEs are required to support 50% managed charging, and 3.8 million EVSEs are required to support 100% managed charging.

TABLE XII
NUMBER OF EVSES BASED ON THE EV LOADS (MILLION UNITS)

Method	Time	Opportunity (60% unmanaged)	Home-dominated (40% unmanaged)	Managed	Total
Unmanaged	Mid-Day	0.13	0.93	0.00	5.39
	Evening	0.73	3.60	0.00	
50% Managed	Mid-Day	0.01	0.02	1.73	3.89
	Evening	0.40	1.73	0.00	
100% Managed	Mid-Day	0.00	0.00	3.80	3.82
	Evening	0.00	0.00	0.02	

Considering the EVSE investment, the value of generation to the grid from managed charging over the life of the EVSE is the difference between the total grid savings and additional EVSE investment to support managed charging during the life of the EVSE. To evaluate the EVSE investment, we take the annual production cost savings results, which represent a year of avoided generation costs, and then apply it over the whole lifetime of the EVSE equipment. This simple payback calculation leaves out many important factors, such as uncertainty about future avoided generation costs and rate of return on investment, and therefore the calculation represents a simplified analysis of EVSE investment.

Table XIII summarizes the potential savings for the grid from managed charging under CS grid condition. For the CS 50% case, a positive value of generation to the grid from managed charging can be achieved (green highlight) when the EVSE lifetime cost including installation, operation and capital costs is less than $3,000 for a 10-year life, $4,000 for a 15-year life, and $5,000 for a 20-year life. For 100% managed charging, a positive value of generation to the grid from managed charging can be achieved (green highlight) when the EVSE lifetime cost is less than $2,000 for a 10-year life, $3,000 for a 15-year life, and $4,000 for a 20-year life. One-hundred percent managed charging requires all PEV connected to EVSEs during parking, and thus needs much more EVSE investigation to enable managed charging. The high percentage of managed charging requires a low-priced EVSE to make the benefits cost-neutral.

TABLE XIII
TOTAL GRID SAVINGS FROM MANAGED CHARGING UNDER CS GRID CONDITION ($MILLION)

Managed EV %	Life /EVSE Costs ($)	1,000	2,000	3,000	4,000	5,000
50% Managed	10 years	1,970	240	-1,490	-3,220	-4,950
	15 years	3,820	2,090	360	-1,370	-3,100
	20 years	5,670	3,940	2,210	480	-1,250
100% Managed	10 years	2,800	-1,000	-4,800	-8,600	-12,400
	15 years	6,100	2,300	-1,500	-5,300	-9,100
	20 years	9,400	5,600	1,800	-2,000	-5,800

Table XIV summarizes the potential savings for the grid from managed charging under ED grid conditions. A positive value of generation to the grid from 50% and 100% managed charging can be achieved (green highlight) when the EVSE lifetime cost is less than $1,000 for an EVSE life of 10 and 15 years or $1,500 for an EVSE life of 20 years. A diverse portfolio and enhanced grid flexibility enhance grid flexibility, which requires a low price of EVSEs to support managed charging.

TABLE XIV
TOTAL GRID SAVINGS FROM MANAGED CHARGING UNDER ED GRID CONDITION ($MILLION)

Managed EV	Life \ EVSE Costs	$500	$1,000	$1,500
50% Managed	10 years	35	-830	-1,695
	15 years	485	-380	-1,245
	20 years	935	70	-795
100% Managed	10 years	200	-1700	-3,600
	15 years	1,250	-650	-2,550
	20 years	2,300	400	-1,500

Future grid conditions are expected to be between the CS and ED conditions presented here. The estimated EVSE prices under both grid conditions provide a range to guide future

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EVSE design. The price range should be between $1,000 and $3,000, depending on grid conditions and EV charging management methods.

2) Current EVSE Installed Cost

There is a gap between the current EVSE installed cost and the required cost for managed charging. Table XV lists investor-owned utilities' proposals to the CPUC for PEV charger installations [35]. These plans are for installing 35,550 EVSEs between 2016 and 2021. These proposals can be used to help understand the current cost of EVSE installation. With the caveat that not all costs in these proposals are directly attributable to EVSEs, the average EVSE cost seems to be between $11,800 and $18,000.

TABLE XV
INVESTOR-OWNED UTILITIES' PROPOSALS TO THE CPUC FOR PEV CHARGER INSTALLATIONS [19]

	San Diego Gas& Electric	Southern California Edison
Charge Points	5,550 L1/L2	30,000 L1/L2
Timeline	2016–2021	2016–2021
Targeted Areas	Multi-user domains and workplaces	Locations considered to have long "dwell times"
Cost	$103 M	$355 M
Average Cost	$18K/EVSE	$11.8K/EVSE

The Rocky Mountain Institute [36] studies EVSE installation cost. Installation is the major contributor to the cost of public stations. The distance to the breaker box is usually the most important factor in determining the installation cost. The average EVSE cost can be reduced if a multi-port station or multiple stations are installed at the same time. Cost is reduced mainly because a single trench/bore, conduit, and wire can be used to service adjacent stations. Comparing the current costs in the California utilities' proposals and those from the Rocky Mountain Institute field study to the requirements determined from the present study suggests that further work is needed in reducing costs of EVSE to effectively unlock potential grid value in a high-renewable generation grid. Curbside installation needs more conduits to connect EVSEs to the infrastructure, which increases the total cost.

IV. CONCLUSIONS

We adopted the LCGS model to quantify the value to the grid from managed charging. According to the simulation, three million EVs with 50% managed charging could generate $90–$370 million in grid savings, reduce electricity cost around by 1%–4%, reduce peak demand by 1.5%, reduce renewable curtailment by 0.04%–4.3%, and reduce grid CO_2 emissions by 1%–4%. These outcomes are achieved by moving the energy demands of EVs to align better with the generation of solar energy in mid-day.

Future grid conditions are expected to be between the CS and ED conditions presented here. The estimated EVSE prices under both grid conditions provide a range to guide future EVSE design. The ranges of each item when EV fleet load management changes from unmanaged to 100% managed are listed below.

- Production cost savings: Changing charging from unmanaged to 100% managed results in production cost savings between $210 million and $660 million annually in generation costs. This represents 2.9%–7.6% reduction in overall production costs. This also represents a 22%–81% reduction in the total cost of EV charging.
- Curtailment: Changing charging from unmanaged to 100% managed decreases curtailment from 0.26% to 12.83%. This equals 70 GWh to 7,400 GWh more renewable energy.
- Peak Shaving: The managed charging of EVs can effectively lower the peak load by a substantial margin, 1.2 – 1.8 GW. Based on the CPUC's cost assumptions, avoided capacity costs could add $36 – $180 million in value for the CS grid condition and $54 – $270 million for the ED grid condition. Capacity benefits are not currently included in the results of this paper as the methods for estimating them are complex, and we focus instead on operational value. However, capacity benefits may provide another economic incentive to deploy managed EV charging and are an area for future work.
- CO_2 Emission: Changing charging from unmanaged to 100% managed can save between 1.3 and 2.4 MMT of CO_2 annually, which equates to a 2.93%–4.65% reduction in CO_2 from the California electric sector in these low carbon grid scenarios.
- Energy throughput for charging: The managed charging shifts EV load from evening to mid-day. In the 100% managed cases, the EV load drops off completely before the evening peak. The EV charging profiles under both grid conditions are mainly determined by the high solar generation. The average loads under both grid conditions have little difference. The 100% managed charging case uses 95% of energy to charge EVs at workplace and public stations.

To enable smart charging, future research should focus on the following areas:

- EVSE manufacturers should reduce EVSE costs and/or extend EVSE life. The breakeven EVSE lifetime cost should be between $1,000 and $3,000 for a 10-year life, depending on grid conditions. If the emission cost is not considered, the breakeven EVSE life time cost would be lower. This is a simple payback calculation, when in reality more factors would be taken into account. Certain assumptions about rate of return on investment may low the price range of the EVSE.
- EVSE manufacturers should enhance interoperability of EVSEs and enable accurate voltage, current, and power management to support managed charging. EV and EVSE communication should be enhanced to support vehicle charging information (such as departure time and required energy) to assist in grid control of EV charging rates.

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- More EVSEs should be deployed at workplaces in a high-renewables grid condition to provide more opportunities to allow EVSE plug-in during periods of high-renewable generation to support peak shifting of the EV load. Workplace and public charging should be emphasized in future EVSE deployment plans.
- Utility companies should develop new control strategies such as direct load control strategies, especially for the provision of ancillary services such as regulation and contingency reserves at the workplace. This will allow for the aggregation of more EVs during periods of high-renewable generation to maximize grid savings.

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