CUSTOMER DISTRIBUTED ENERGY RESOURCES GRID INTEGRATION STUDY

DER Grid Impacts Analysis

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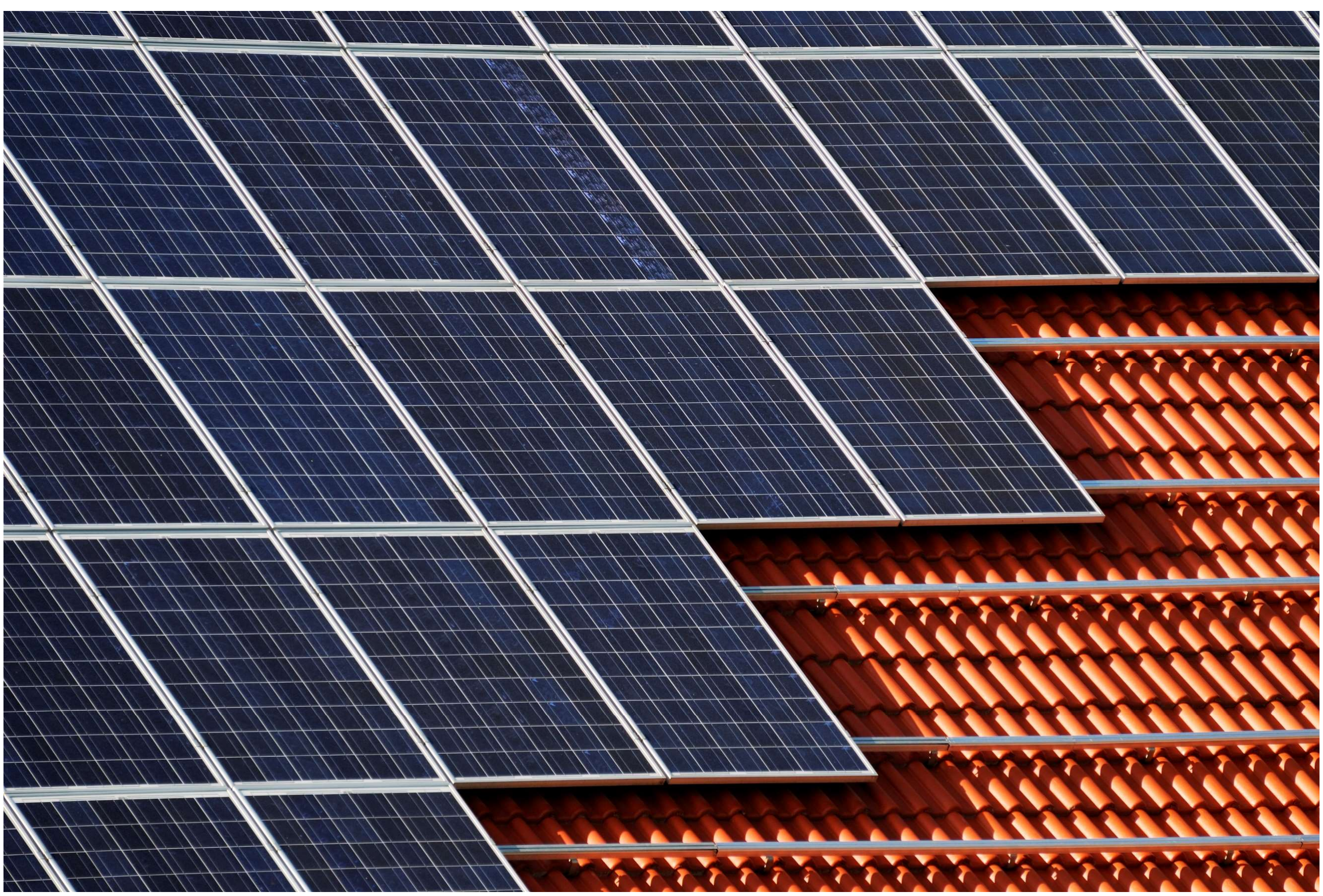

Legislative Report on Customer Distributed Energy Resources Grid Integration Study
California Public Utilities Commission

Prepared for:
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List of abbreviations

Abbreviation	Meaning
CAISO	California Independent System Operator
CEC	California Energy Commission
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DER	Distributed Energy Resources
DER-CAM	Lawrence Berkley National Lab's Distributed Energy Resources Customer Adoption Model
DNV GL	KEMA Inc. (DNV GL)KEMA Inc
DR	Demand Response
DRP	Distributed Resource Plan
ES	Energy storage
EV	Electric vehicles
GIS	Geographic Information System
GW	GigaWatts
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Plan
kW	KiloWatts
LTC	Load Tap Changer
LTPP	Long Term Procurement Plan
PG&E	Pacific Gas and Electric Company
PV	Solar photovoltaics
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
VO&M	Variable Operation and Maintenance

DISCLAIMER & LIMITATIONS

Disclaimer

The study analysis for this report was drafted in 2017 and covers the period from 2017 to 2026. The conclusions and intent of this study reflect regulatory and stakeholder concerns and questions raised at the time of the study. The evaluation of the costs and benefits of a high DER scenario/portfolio does not represent a supported CPUC policy direction rather this evaluation is an attempt to understand the impacts of DER growth and determine methods to reduce the integration costs associated with DER growth.

Limitations of the Study

It is important to note that this study is for research purposes only. Even though some of the topics addressed in this study are similar to those under consideration in the Integrated Resource Plan (IRP) proceeding, this study is not meant to influence or draw similar conclusions as the IRP proceeding.

This study and IRP both analyze the optimal resources portfolios under multiple Distributed Energy Resource (DER) scenarios. However, this study and the IRP diverge on their focus and data inputs. IRP focuses on optimizing a diverse candidate pool of bulk system resources as well as several DER types, including behind-the-meter (BTM) solar photovoltaic (PV) and shed demand response (DR), whereas this study focuses on analyzing integration costs of different levels of DERs and their associated bulk system savings. Lawrence Berkeley National Lab's Distributed Energy Resources Customer Adoption Model (LBNL's DER-CAM) is a customer economics model that optimizes for customer benefits, while IRP considers costs more holistically from both the utility and customer's perspective. Moreover, the IRP proceeding drives bulk resource procurements, whereas DER investment decisions are mainly driven by individual customers who may consider California Public Utilities Commission (CPUC) incentives and other policies.

Since one of the study's primary objectives is to demonstrate a methodology to analyze DER impacts on the grid, including an estimate of the extent of costs impacts at different DER penetration levels, the consultant who developed the study took a simplified approach. We list these simplifications below:

- To develop the high DER scenario, the LBNL DER-CAM analysis takes a simplistic approach of finding maximum DER bundles for generic customers from a sample of building types.
- The DER bundles, which are a combination of cost effective solar and storage per customer premise, are developed mainly based on costs. They do not take into account any technical limitations, such as roof suitability or space availability for DER installations.
- When calculating grid integration costs, we used 75 sampled feeders to represent California's distribution system which has over 10,000 feeders.

When a draft of this report was completed in 2017, the EV forecast from California Energy Commission Integrated Energy Policy Report (CEC-IEPR) did not constitute a large enough electric vehicle (EV) population to affect distribution integration costs. However, in 2018 Governor Brown set a goal of 5 million zero-emission vehicles (ZEVs) on the road in California by 2030 that significantly increased the EV forecast. As a result, DNV GL has completed a separate analysis of EV integration costs in the Addendum A.

One of the scenarios modelled in the study assumes that solar could be placed anywhere in the three large California investor-owned utility (IOUs) territories. In theory, there is sufficient available hosting capacity across the three IOU distribution circuits to accommodate all of the forecasted PV generation without any further grid integration costs. However, realistically, since DER adoption is driven by personal investment decisions of customers, that scenario is not particularly realistic without significant policy and rate reforms.

FOREWORD

By CPUC's Energy Division

Introduction to Customer Distributed Energy Resources Grid Integration Study

As Distributed Energy Resources (DERs) proliferate in California, the state is interested in evaluating the impacts and maximizing the potential of DERs.

Assembly Bill (AB) 578 (Blakeslee,2008)[1] required the California Public Utilities Commission (CPUC) to submit a biennial report to the Legislature on "the impacts of distributed energy generation on the state's distribution and transmission grid" including reliability issues related to connecting distributed energy generation to the local distribution networks.

AB 327 (Perea, 2013) requires utilities to file Distributed Resource Plan (DRP) proposals by July 1, 2015 to identify optimal locations for the deployment of DERs. Approved DRPs should minimize overall system costs and maximize ratepayer benefit from investments in DERs. Utilities must propose any spending on distribution infrastructure necessary to accomplish the DRP in its GRC. Spending may be approved if ratepayers would realize net benefits and costs are just and reasonable. Public Utility (PU) Code Section 769 defines DERs as energy efficiency (EE), demand response (DR), renewable distributed generation (DG), electric storage (ES), and electric vehicles (EV).

In 2013, the CPUC contracted Black & Veatch to prepare the "Biennial Report on Impacts of Distributed Generation"[2] for the first AB 578 report, and Itron to prepare an Impact Evaluation of CPUC's Self Generation Incentive Program (SGIP).[3]

In 2015, the CPUC contracted Kema Inc. (DNV GL) to assist the CPUC with understanding the current and future impacts that Customer-Side DER would have on the California Investor Owned Utility (IOU)[4] owned electric transmission and distribution systems, and describing and quantifying the impact of different levels of DER penetration. A second AB 578 legislative report "Impacts of Distributed Energy Generation on the State's Distribution and Transmission Grid" was sent to the legislature on January 1, 2016.[5] Subsequently, a third legislative report "Residential Zero Net Energy Building Integration Cost Analysis" was sent on February 1, 2018.[6]

This report serves as the fourth biennial DER impact study to comply with AB 578.

[1] Public Utilities Code Section 321.7(a)(1).
[2] http://docs.cpuc.ca.gov/publisheddocs/published/g000/m096/k207/96207286.pdf
[3] http://www.cpuc.ca.gov/general.aspx?id=5935
[4] The IOUs that are the subject of this study are Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and Pacific Gas and Electric (PG&E).
[5]http://www.cpuc.ca.gov/uploadedfiles/cpuc_public_website/content/about_us/organization/divisions/office_of_governmental_affairs/legislation/2016/legislative%20report%20on%20impacts%20of%20distributed%20energy%20generation%20submitted%20january%201%202016.pdf
[6]http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislative%20Report%20on%20Residential%20ZNE-Building%20Integration%20Costs%20Analysis.pdf

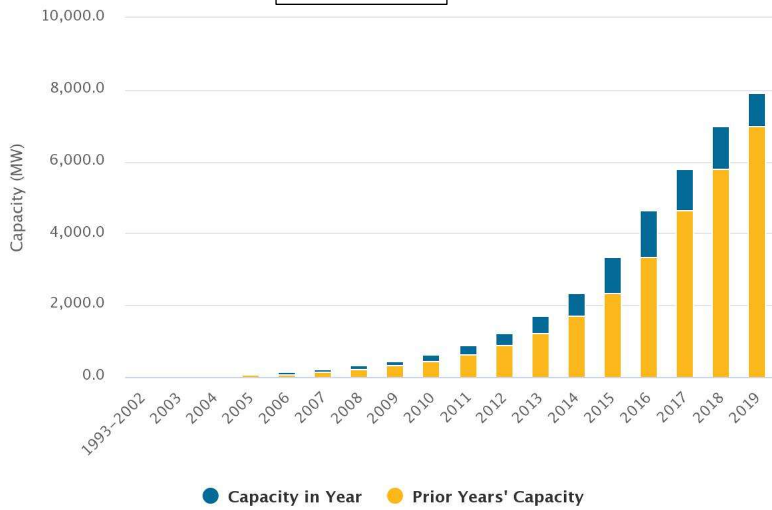
Rapid Growth of DER Programs and Deployment

California's DER programs and other incentives have fostered steady growth in DERs on California's grid. The primary programs and drivers of California's rapid expansion include:

- **Self-Generation Incentive Program (SGIP)** that is aimed at reducing customer energy demand and reducing greenhouse gas (GHG) emissions by providing incentives to support existing, new, and emerging distributed energy resource. On January 16, 2020, in response to Senate Bill 700 (Weiner, 2018), the CPUC reauthorized SGIP from 2020 to 2024 through extended program collections of $166 million annually from the three California IOUs.
- **Net Energy Metering (NEM)** program and its 2016 "2.0" version that continues to provide compensation for residential and commercial solar generation at retail rates.
- **The Federal Investment Tax Credit (ITC)** that started in 2005 and allows investors to deduct 30% of the cost of residential or commercial solar energy systems and some storage systems from their federal taxes. This program expires in 2022.
- **Revised CEC Building Code Requirements** that require all new residential buildings built on or after 2020 to include solar power generation on site unless otherwise exempted to achieve zero net energy status. These requirements are referred to as Title 24 Building Codes.
- **Electric Vehicle (EV) 2030 Goal** established in 2018 through a Governor Executive Order that set a goal of 5 million EVs on the road by 2030. This EV goal is supported with $2.5 billion in Cap-and-Trade program funding over eight years. The previous goal was 1.5 million EVs on the road by 2025.
- **Assembly Bill 2514 (AB 2514)** (Skinner, 2010) **Energy Storage Systems** legislation that resulted in customer side energy storage targets for the three California IOUs, which are 85 megawatts (MW) in both the PG&E and SCE's service areas and 30 MW in SDG&E's service area.
- **Senate Bill 100 (SB 100)** (de León, 2018) **Carbon-Free Resources by 2045** legislation that requires 100 percent of all the state's retail electricity sales to come from renewable or carbon-free resources by 2045. Additional growth in DER procurement is expected.

To illustrate this DER growth, Table 1. provides the NEM capacity growth data from the three California IOUs (Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas and Electric).

Table 1.

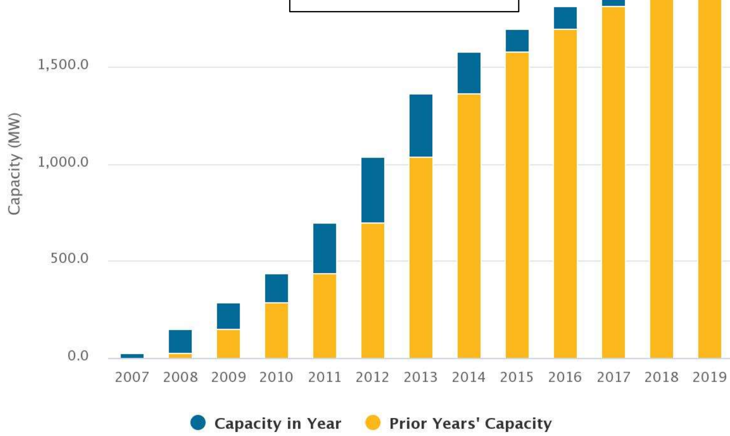


In 2003 there was less than 30 MW of NEM capacity in California, and in 2019 there was an estimated 7,919 MW of NEM capacity on the grid.

California Solar Initiative (CSI) capacity has also grown from less than 30 MW in 2007 to an estimated 1,895 MW in 2019. This estimate includes the total MW capacity from the CSI General Market, Single-Family Affordable Solar Homes (SASH) and Multifamily Affordable Solar Housing (MASH) programs. The CSI General Market and MASH programs are now closed. The combined MW target for these programs was 1,940 MW.[7,8]

Table 2. provides the CSI capacity growth from 2007 to 2019 amongst the three California IOUs.

Table 2.



Challenges of High DER Penetration

California Distributed Generation Statistics reports that there is 8,739 MW of distributed generation installed on the California grid. As a result of this growth in new renewables on the grid including DER, the CAISO

[7] https://www.californiadgstats.ca.gov/charts/nem
[8] 2019 California Solar Initiative Annual Program Assessment, June 2019, California Public Utilities Commission, p. 16.

grid is experiencing steep increases in demand when the sun goes down and oversupply during the middle of the day at certain times of the year.[9]

Both the CEC and the CAISO predict that increased penetration of DG, specifically solar generation, will cause operational challenges for the grid.[10,11,12] Further, with additions of more central and distributed solar generation in California and the region, the CAISO states there is the potential that California's energy resources plus imports will not meet the extended energy demand ramps.[13]

With respect to planning for where and when DER should be installed, the state's DER programs currently allow for growth to happen where it is desired by customers. With all ratepayers sharing in some of the costs of new DER deployment, it is important to evaluate the impact of DERs and determine if greater benefits can be provided and at reduced costs.

For this reason, the objective of this biennial impact analysis is to evaluate a high DER portfolio to identify impacts and methods to reduce integration cost that are cost-effective for ratepayers. This impact analysis specifically considers the benefits of locating DERs such as solar photovoltaics (PV) and energy storage where hosting capacity exists on the distribution system and co-locating energy storage with renewables to reduce integration costs.

High DER Grid Integration Analysis

In order to determine the impact of higher DER penetrations due to the expected growth in DERs, the CPUC's Energy Division requested its consultant KEMA, Inc. (DNV GL) to develop a method to quantify the impact of different levels of DER penetration on the distribution system. This study covers the period from 2017 to 2026. DNV GL analyzed PV, storage, combined heat and power, and demand response to minimize distribution grid integration costs under different scenarios. The analysis considers the impact of customer-driven growth of behind-the-meter (BTM) solar generation, and the resulting solar exports, on constrained utility distribution feeder capacity. The analysis then assesses the customer cost of increasing installations of BTM storage to absorb increasing solar exports to mitigate utility distribution and transmission level capacity constraints. This cost is considered relative to the utility cost of upgrading distribution feeder capacity to accommodate increased solar exports. Then the results of high BTM DER and distribution integration costs are combined to investigate their effect on the distribution system. This report validates the importance of distributed resource planning and demonstrates a method to quantify the cost impact of DERs for the entire State.

The report also provides supplemental information and insights for a significant number of current CPUC programs and proceedings in addition to SGIP and NEM, which are the main programs driving BTM solar and storage installations. These include:

- Distributed Resource Plan (DRP), which develops tools, processes, and investment frameworks that enable IOUs to better integrate DERs into grid operations and the annual distribution planning process.

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[9] https://www.caiso.com/Documents/ManagingAnEvolvingGrid-FastFact.pdf

[10] Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California, May 2009, California Energy Commission, p. 89.

[11] https://www.caiso.com/informed/Pages/ManagingOversupply.aspx

[12] https://www.caiso.com/Documents/MatchingTimeOfUsePeriodsWithGridConditions-FastFacts.pdf

[13] CAISO Chief Executive Officer Report to the ISO Board Governors, December 11, 2019, p. 2.

- Integration Capacity Analysis (ICA), which calculates available circuit hosting capacity to accommodate additional DERs;
- Locational Net Benefit Analysis (LNBA), which determines optimal locations for DER deployment based on opportunities for DERs to cost-effectively defer or avoid traditional distribution (and transmission) system investments, and provides indicative avoided costs of DER solutions for candidate distribution investment deferral opportunities;
- Interconnection (Rule 21), which consist of the process and timeframes for reviewing interconnection requests, the technical standards for equipment and operations, rules for allocating interconnection upgrade costs, and the process for resolving disputes;
- Zero Net Energy Buildings, which combines the use of on-site renewable distributed generation, energy efficiency, and storage to achieve zero net energy (ZNE) impacts from all new residential construction starting in 2020,[14] and all new commercial construction by 2030;[15,16] and
- Zero-Emission Vehicles (ZEV) which include pure battery plug-in electric vehicles, plug-in hybrid electric vehicles, and hydrogen fuel cell electric vehicles.

Highlights of Study Findings:

- Following on the results from 2018 AB 578 report entitled the *Residential Zero Net Energy Building Integration Cost Analysis*, which reported that PV integrations costs could range between $196 million to $2.35 billion, this 2020 AB 578 analysis demonstrates that DER integrations costs can be reduced if new solar PV locations are based on system hosting capacity. Specifically, if the expected growth in solar PV installations[17] is distributed around a circuit in increments of up to 100 kilowatts (kW) versus 'lumped" at the at the end of the circuit furthest from the substation, the integration costs could be significantly reduced in the Pacific Gas and Electric Company (PG&E) and Southern California Edison (SCE) service areas. This is because PG&E and SCE have sufficient available capacity on their distribution systems to accommodate the amount of PV generation forecasted for these systems.[18]

- The analysis reveals that there is insufficient available capacity to accommodate all of the PV generation forecasted for the San Diego Gas and Electric (SDG&E) system without additional upgrades even if the new solar PV growth is distributed around the circuit.

- Customer-sited energy storage can have a significant impact on the total grid integration cost of high penetration DER scenarios, reducing the incremental grid integration costs between 2017 and 2026 by 4% in the worst case in the SDG&E service area, and by up to 33% in the best case in SCE service area.
- The use of Smart Inverters can further reduce PV integration costs, especially in the cases where PVs are located in a clustered fashion at the end of a feeder.
- If new DERs are distributed according to available hosting capacity across PG&E, SCE, and SDG&E service territories then there is sufficient available hosting capacity across the three California IOUs' distribution circuits to accommodate all the forecasted PV generation. This generation can be

[14] 2019 Building Energy Efficiency Standards for Residential and Nonresidential Buildings for the 2019 Building Energy Efficiency Standards, Title 24, Part 6, and 11, effective January 1, 2020, California Energy Commission.
[15] ibid
[16] Draft 2019 Integrated Energy Policy Report, November 2019, California Energy Commission, p.4.
[17] Solar PV installation are expected to continue to increase in the State due to the revised Title 24 requirements and other CPUC expanded solar PV programs.
[18] This conclusion assumes solar PV growth due the 2019 Title 24 Building Efficiency Standards.

accommodated without any further grid integration costs, provided that it is distributed in the optimal manner. While a useful theoretical finding in practice this is not a likely to happen as all three IOUs experience robust growth of BTM DERs and the locations are determined by customer preference without regard to system costs.

- Under the high DER scenario, 8 gigawatt (GW) of new gas fired generation between the 2017 and 2026 timeframe could be deferred through DER customer load reductions. This gas generation deferral is estimated at an average of 51-terawatt hour (TWh)/year (yr) and would have an average annual decrease of 22 Metric ton (Mton)/yr in CO_2 emissions. This gas generation deferral estimate is not directly comparable to the current modeling in the IRP-LTPP due to resource attributes not considered.
- With the high DER scenario, the difference in investments in gas-fired generation capacity is around $1 billion for the entire 10-year period of 2017 to 2026. The average annual reduction in gas production costs is $2.76 billion/yr, leading to a cumulative difference of $2.76 billion for the ten years between 2017 to 2026. This gas generation deferral estimate is not directly comparable to the current modeling in the IRP-LTPP due to resource attributes not considered.
- The EV impact study results suggest that placing the EV charging facility close to the substation would minimize grid integration costs as voltage drop is minimized, and any re-conductoring required would be limited to the distance between the substation and the EV charging facility.
- Since the effects of co-located EV charging stations and PV generation could cancel each other out (if EV charging could be incentivized to reliably occur during times of high PV output), EVs also have the potential to reduce PV integration costs as well.

In Staff's view, the primary study conclusions for the CPUC are:

1. There is significant variation in the DER integration costs amongst the three California IOU service areas. This complicates modeling DERs in the IRP because locational specific integration challenges cannot be factored at this time.
2. Building on the 2016 *Impacts of Distributed Energy Generation on the State's Distribution and Transmission Grid* report conclusion that the solar in the southeast portion of the State generates higher quality power, the optional location for new solar PV growth may be in the SCE service area. This is because SCE's circuit design can also accommodate expected DER growth without upgrades if this growth is distributed optimally.

Hence, future DER policies that seek to optimize DER costs and benefits should consider these conclusions.

Study limitations that should be considered before drawing policy conclusions from this study include:

- Analyses were performed on individual representative distribution feeders as a proxy for the whole distribution system. Analysis on the sub-transmission system would require modeling of the transmission system, and all connected feeders at a given transmission bus.
- The full transmission system was not modelled, but instead DNV GL used a production cost model to study the bulk system, which has a simplified transmission model to capture inter-regional transfer limitations.
- The study does not capture the full benefits of energy storage.   DNV GL included energy storage only with respect to how they affect the impact of PV generation on the circuit. Energy storage was factored into the analysis as one of the potential solutions to mitigate the integration costs

of PV by reducing PV's export to the grid. However, in practice there are other potential benefits of energy storage systems beyond mitigating PV impacts.

- The study analysis does not consider energy storage operating and maintenance costs.
- Energy Efficiency also is not optimized in this study but is accounted for as low-load energy profiles. This is because modern homes are expected to be more energy efficient than the older ones.
- This study did not take into consideration the customer costs to procure the BTM equipment in the bulk power system simulation.
- To the extent possible, DNV GL used the latest publicly available data for all its assumptions. When the data was unavailable, DNV GL used its best judgement. These best judgements include cost declines of DERs, rate increases, consumption changes, and EV charging patterns.
- The DER scenarios are hypothetical and would require major regulatory changes to realize. For example, either solely lumping DERs at the end of a feeder or evenly distributing them are unlikely forecast of future build-out states, but they were devised as scenarios to study best and worst-case costs of DER placement. Likewise, it is not realistic to allocate DERs across IOUs or the state to fully minimize integration costs. But the scenarios provide an approximate value the State could maximally achieve by improving locational valuation and compensation of DERs.
- Although the study includes EVs as a static load, EVs were not included as part of the customer cost-effectiveness optimization. This is because when the study began in 2015, forecasted EV penetration was not significant. However, EVs are now expected to play a prominent role in the current energy environment. As a result, an Appendix was included in this study to address how the increased EV load would impact the power flow and trigger infrastructure upgrades (and therefore EV integration costs). As mentioned, the study finds that EV charging and PV generation can have cost reductions if paired and that additional integration cost reductions can be achieved if EV charging stations are located in close proximity to substations.
- The report does not factor in the full costs of EVs. DNV GL factored EVs into the analysis because they likely increase the peak and minimum loads on a feeder, thereby changing the allowable PV penetration levels. DNV GL did not consider dynamic pricing of EV charging in this study due to the low penetration forecast of EVs at the beginning of the study.

CPUC should take into consideration all the assumptions behind this study before using it as the basis for future policy decisions impacting DER grid integration or optimization. Further research areas that would be beneficial to help the CPUC understand the optimal location and value of DER include:

- Increasing the number of representative distribution and transmission circuits in future electric grid modelling;
- Accounting for all energy storage potential benefits in optimization;
- Revisiting the energy efficiency assumption in future analysis;
- Accounting for customer costs to procure BTM equipment in the bulk power system simulation; and
- Applying the latest assumptions and policy requirements.

EXECUTIVE SUMMARY

Introduction

As distributed energy resources proliferate in California, the California Public Utilities Commission (CPUC) is interested in better understanding the potential impacts that customer-side distributed energy resources (DER) will have on the transmission and distribution systems. Currently, a commercial tool that optimizes DER deployment on the distribution and transmission system does not exist. The CPUC hired DNV GL to conduct a study to illustrate a method to develop a high penetration DER scenario that minimizes system costs. This study is also an attempt to develop a new and comprehensive approach to quantifying DER impacts on the grid.

For this study, we examine a high DER portfolio that assumes the maximum growth of distributed generation programs such as energy efficiency (EE), solar photovoltaic (PV), energy storage, combined heat and power (CHP), demand response (DR), and electric vehicles (EV) to better understand the potential benefits and costs of a high DER growth scenario under the current planning paradigm.

In support of these objectives, the study:

1. Demonstrates a methodology of quantifying DER impacts on the grid, and calculates the potential distribution integration costs and bulk system savings from different DER scenarios in California;
2. Provides an estimate of the extent of DER integration costs savings when they can be optimally located; and
3. Validates the importance of developing policies and regulations with DER integration costs in mind.

Although the study has some similarities to CPUC's Integrated Resource Plan-Long Term Procurement Planning (IRP-LTTP) process formerly referred to as the Long-Term Procurement Plan (LTPP) before 2017,[19] and Distribution Resources Plan (DRP) efforts, the primary objective of this study is to estimate the potential grid impacts of DERs under different theoretical DER penetration scenarios. Additionally, while the study validates the importance of the work done under the 2016 LTPP and DRP proceedings, we do not provide any specific recommendations for the IRP-LTTP or DRP proceedings. In short, the results from this study are independent from the work done under the IRP-LTPP and DRP proceedings.

Method

DNV GL developed the high DER portfolio in three steps at different locations of the grid: behind-the-meter customer side, distribution system, and the bulk system. Table ES-1 provides an overview of the methodology. The light blue boxes describe the scenario development, analysis steps, and data sources, while the dark blue boxes describe the output results.

[19] Per Senate Bill 350 Clean Energy and Pollution Reduction Act of 2015, which was finalized in 2016 CPUC's Long-Term Procurement Planning Proceeding is now referred to as the Integrated Resource Plan (IRP). The first year of the IRP was 2017.

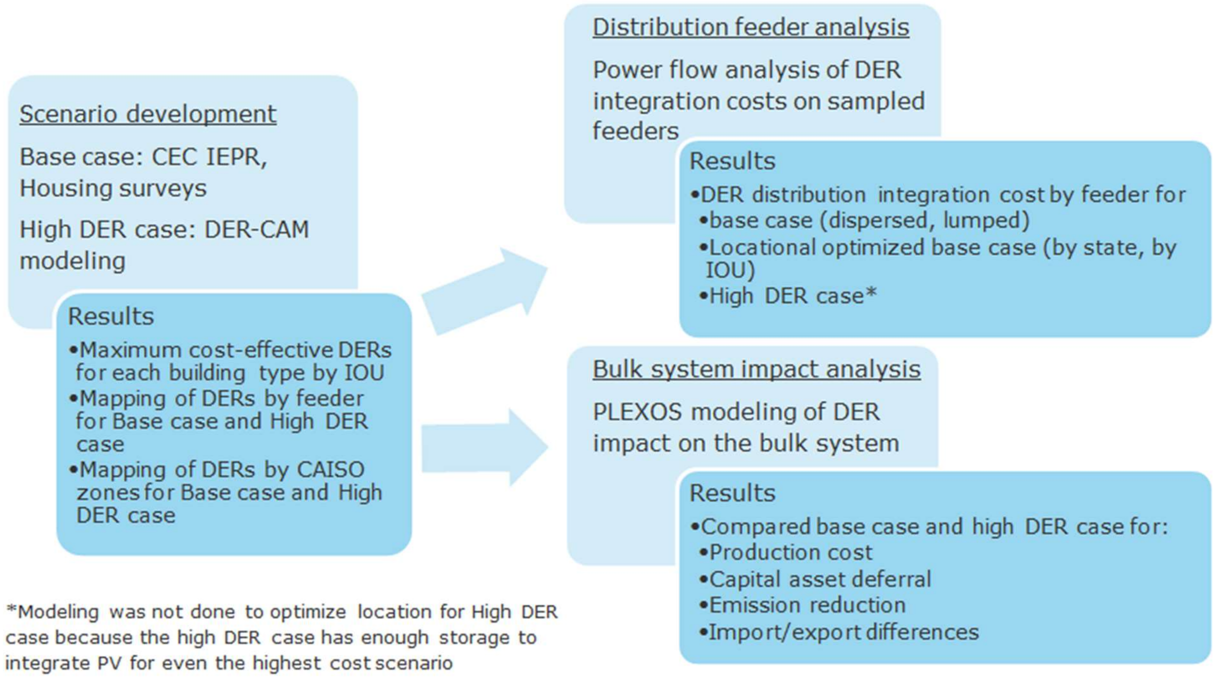

Figure ES- 1 Methodology Overview

Scenario development

For the first step, DNV GL constructed the study scenarios by mapping DER forecast data from the most recent California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) mid-demand scenario and a high DER scenario based on the maximum amount of DERs that are considered cost-effective from the customer's perspective. We completed the cost-effectiveness analysis using Lawrence Berkeley National Laboratory's (LBNL) Distributed Energy Resources Customer Adoption Model (DER-CAM)[20] optimization tool for 18 different customer types for each of the three major investor owned utilities (IOU) in California, which a Pacific Gas and Electric Company, Southern California Edison and San Diego Gas and Electric. IOUs in the year 2026. We assigned each customer type an optimal bundle of DERs that were cost-effective to them based on their load profiles, tariffs, equipment costs, and payback period.[21] The bundles included PV, storage, combined heat and power, and DR. We did not include EVs as part of the optimization instead EVs are included in the study as a static charging load per building type. Energy efficiency (EE) was also not part of the optimization, but we accounted for EE by using low energy profiles in the optimization.

Distribution grid integration cost analysis

For the second step, DNV GL determined the distribution integration costs for two main scenarios: The CEC IEPR mid-demand scenario and the high DER scenario based on all the cost-effective DER bundles from the

[20] DER-CAM is a decision support tool to help in investment and planning of DER in buildings and decentralized energy systems such as microgrids. It is an economic optimization model which finds the most cost-effective mix of energy supply technologies and dispatch to minimize costs and CO_2 emissions. More information regarding the tool can be found here: https://building-microgrid.lbl.gov/projects/der-cam.

[21] In this study, we assumed that the costs taken on by customers who are installing DER technologies are not socialized or rebated through utility incentives, which often result in increased costs to other customers who may not necessarily purchase the same equipment.

DER-CAM analysis. Since PV is the primary DER technology that affects grid integration costs due to its ability to export to the grid, this analysis focused on the cost of integrating PV. We included energy storage and EVs only with respect to how they affect the impact of PV generation on the circuit. Storage was factored into the analysis as one of the potential solutions to mitigate the integration costs of PV by reducing PV's export to the grid. We factored EVs into the analysis because they likely increase the peak and minimum loads on a feeder, changing the PV penetration levels. We did not consider dynamic pricing of EV charging in this study due to the low penetration forecast of EVs at the time we started the study. Since the writing of this report, EV forecasts have drastically increased; as a result, DNV GL subsequently added an analysis of EV impacts as an addendum to this report.

DNV GL sampled 75 feeders across the three IOUs (see previous reports for PG&E,[22] SCE,[23] and SDG&E,[24] for descriptions of sampling methodologies), and analyzed typical reliability criteria for these IOUs: static voltage, transient voltage, thermal loading, and reverse power flow. The same reliability criteria were used for all three IOUs. The analysis investigated the penetrations of distributed generation at which the technical criteria would be exceeded and identified suitable mitigation measures and related costs that would be required at each stage. The outcome is an integration cost function for each representative feeder that depends on penetrations of PVs. PV penetrations were forecasted for each feeder in each IOU, and each feeder was mapped to one of the representative feeders. The integration cost function for the mapped representative feeder (in terms of dollars vs PV penetration) was then combined with the forecasted PV penetration for the feeder to determine the integration cost in dollars.

We then mapped the base and high levels of DERs to feeders for integration costs analysis. We modelled a total of six cases for the integration costs analysis. Five cases were under the base scenario and one case under the high DER scenario.

For first two cases modelled are two different PV dispersal cases. The purpose of modeling the dispersal cases was to identify the best- and worst-case scenarios, with the expectation that the real result would lie somewhere in the middle. We describe the two primary dispersal cases below:

1. **"Lumped" dispersal base case**: The new PVs were placed at the end of the circuit furthest from the substation. This represents a worst-case condition for most circuits—we refer to this as the "lumped" dispersal case. Given that 2019 Title 24 standards require all new homes to have PVs and new homes are likely to be located at the end of a feeder, the "lumped" dispersal case may not be too far from a realistic representation of future PV locations.
    a. **"Lumped" dispersal case with reactive power priority on smart inverters**: We also ran an additional case to study how smart inverters with reactive power prioritized could mitigate integration costs in this "lumped" dispersal case. Prioritizing reactive power means that, when a volt/var curve is implemented, the inverter prioritizes providing the required amount of reactive power, rather than providing reactive power if there is available capacity given the active power output.

[22] Navigant Distributed Solar Photovoltaic Transmission and Distribution Impact Analysis
[23] Characterization & Modeling of Representative Distribution Circuits in GridLAB-D, California Solar Initiative Project, Advanced Distribution Analytic Services Enabling High Penetration Solar PV
[24] CPUC, 2017. *Residential Zero Net Energy Building Integration Cost Analysis.* Document No.: 10007451-HOU-R-02-D. October 18, 2017

2. **"Distributed" dispersal base case**: The new PVs were distributed around the circuit in increments of up to 100 kilowatts (kW). This normally represents a more favorable condition for integration of distributed generation—we refer to this as the "distributed" dispersal case.

We place hypothetical future generation on the system in accordance with the two cases described above. The size of the hypothetical generator is increased incrementally such that the penetration of distributed generation on the circuit increases from 0 percent to 160 percent in 10 percent increments. For each of these increments, we carried out static and quasi-static load flow studies and identified any technical violations. For each analysis, we assumed the generator output to be at 100 percent of total rated output during the peak load and then at 100 percent output during the minimum daytime load on the circuit. Where technical violations occurred, we identified the appropriate mitigation options and selected the cheapest option. For example, if there is a high voltage violation due to high PV output, the following options are available:

- Enable reactive power priority and volt/var control on inverter: $0;
- Install additional line regulator: $150,000;
- Install energy storage system: Depends on size and the required size would increase with PV capacity. $150,000 would be enough for a 61-kW system. A system larger than this would be more expensive than the line regulator option.

The normal process in this case would be to implement volt/var control with reactive power priority on the inverter first. This may be effective and allow the PV penetration to be increased until some level is hit where the volt/var control is no longer effective. At this point, the options would be a new regulator or an energy storage system. The new regulator may mitigate the voltage problem and allow a large increase in PV capacity. The energy storage system would need to increase in size in line with any increases in PV penetration, and the costs would therefore quickly exceed those of the regulator. The initial choice here would likely be to add a new line regulator. This is reflective of a reactive approach to mitigation. A proactive approach would attempt to forecast PV penetrations on a feeder and establish what mitigation would ultimately be required. In this case, the PV penetration on the feeder may ultimately increase to the point where energy storage is required anyway. For example, to mitigate a voltage variation problem which cannot be mitigated by the regulator due to its time delay. In this case, given that energy storage is going to be required anyway, the proactive approach would forego the line regulator in favour of the energy storage system, rather than ending up with energy storage as well as a redundant line regulator.

Energy storage effectively reduces the next generation output on each feeder. This is based on the assumption that the energy storage system would be used to reduce the net export of energy to the grid when the PV system's output is high and to smooth the output of the PV system to prevent voltage fluctuation issues. When energy storage is not already installed by customers as part of their cost-effective DER bundles, the full costs of energy storage systems were attributed to mitigation of the PV impact on the grid. However, in practice there are several potential benefits of energy storage systems beyond mitigating PV impacts. This distribution side of the study is a cost analysis only, but a more complete picture would be obtained by quantifying the benefits of energy storage systems.

We calculated the integration cost estimates for each feeder and summed the estimates for each IOU in the 'lumped' dispersal case, the 'distributed' dispersal case, and the smart inverter sensitivity study.[25]

Under the base DER scenario, we also studied two additional generation placement cases. The objective of these hypothetical cases is to estimate the extent of integration costs savings that could be achieved under optimal DER placements. Realistically, since DER adoption is driven by personal investment decisions of customers, there needs to be significant rate reform or institutional/infrastructure changes to achieve these scenarios.[26]

1. **IOU separated placement under base scenario.** In the first of these cases, we re-distributed PV generation and energy storage systems within each IOU to find the lowest possible integration cost. The objective of this was to deploy PV generation more on feeders that had higher hosting capacities, while maintaining the same total capacities within each IOU (i.e., a facility was allowed to move within an IOU, but not between IOUs).
2. **IOU combined placement base scenario.** In the second case, we re-distributed PV generation and energy storage systems across the three IOUs to find the lowest possible integration cost. In this case, we maintained the same total capacities across the three IOUs but allowed the capacities within each IOU to change (i.e., a facility was allowed to move within an IOU, and between IOUs). Placement of generation in these studies was done automatically, prioritizing feeders with the largest available hosting capacity first. In all of these studies, we assumed generation to be on the distribution system and behind the meter.

High DER scenario. Finally, we analyzed the distribution integrations for the high DER scenario from the DER-CAM analysis. The DER-CAM model analyses the optimal cost-effective DER bundles for each customer type based on their hourly load, tariffs, and DER costs. The model result shows that cost-effective energy storage added between 2017 and 2026 exceeds the added PV capacity. It is possible to use the energy storage capacity to mitigate any technical problems caused by PV, provided that the energy storage systems can be used to limit net export from the facilities at critical times. Therefore, even in the worst dispersal case, the integration cost is zero, so no additional cases were studied under the high DER scenario.

DER impacts on the bulk system

In the third and final step, we analysed the different DER scenarios to see their effects on the bulk system. We aggregated the DERs from each feeder to the zonal level for wholesale market modeling using PLEXOS LT Plan. The PLEXOS LT module optimizes total fleet operation over a future time horizon. Over the selected future years, the LT simulates the WECC system while minimizing both long term capacity costs and short-term variable costs. Based on all the cost options, the model then selects the best capacity expansion options.[27] We modelled two scenarios: the base scenario with trajectory DERs and the high DER case based

[25] The smart inverter study concerned potential savings that could be made by implementing the default volt/var controls for new inverters on PV projects in California. This has the potential to reduce voltage problems caused by PV generation. See CPUC, 2017. *Residential Zero Net Energy Building Integration Cost Analysis.* Document No.: 10007451-HOU-R-02-D. October 18, 2017 [note to DNV: CPUC adopted default volt/var controls in Q1 2018, some revisions needed]

[26] Addendum B "Distribution System Operator Model" of this report explores some of these alternative scenarios.

[27] PLEXOS LT Plan allows the user to create multi-year plans for generation and transmission expansion. This module is a higher-level model than the more commonly used ST Model, which is the hourly production cost model. Rather than solving for hourly conditions, the LT Plan model slices the load duration curve into segment and solves for gradations of high, medium, and low load system conditions. In this module, binary variables can be activated and deactivated allowing the user to input generation and transmission proposed projects. The model then commits to mid to long term generation and transmission projects that are economical and reduce the overall production cost. While the ST Model only minimizes

on maximum quantity of DERs that are cost-effective from the DER-CAM analysis.[28] The two scenarios are based on the California Independent System Operator's (CAISO's) LTPP 2026 model and E3's RESOLVE model. CAISO uses the LTPP 2026 to do transmission planning and CPUC uses RESOLVE for its Integrated Resource Planning (IRP) proceeding. The two scenarios have the same bulk existing resources, new candidate resources, and transmission limits. The only variation is the zonal loads. The base scenario uses the default load in RESOLVE, but the high DER scenario reduces the load based on the maximum cost-effective DERs from the customer's perspective. The goal is to find out how the bulk system resource mix, market costs, emissions quantity, and transmission capacity change as a result of the high levels of DERs. It is important to note that the PLEXOS is a zonal production cost mode and does not include a full transmission model. There are benefits and costs of DERs in the transmission system that is not fully examined.

Results

DNV GL found that the penetration of DERs pose both costs and benefits. The costs are mainly from distribution interconnection costs of PV systems.[29] However, customer-sited storage can reduce as much as 33% of the PV integration costs. In addition, the use of smart inverters can further reduce PV integration costs, especially in the cases where PVs are located in a clustered fashion at the end of a feeder.

DNV GL modelled the costs of PV integration assuming that they could be placed anywhere in California. In theory, there is sufficient available hosting capacity across California distribution circuits to accommodate all of the forecasted PV generation without any further grid integration costs. If forecasted PVs have to be placed within their own forecasted IOU territory, the results show that there is sufficient available hosting capacity across the PG&E and SCE distribution systems to accommodate the amount of PV generation forecasted for those systems, while there is insufficient available capacity to accommodate all of the PV generation forecasted for the SDG&E system without additional upgrades. Realistically, since DER adoption is driven by personal investment decisions of customers, there needs to be significant rate reforms or institutional/infrastructure changes to achieve these scenarios. Addendum B explores some of these alternative scenarios that could encourage more optimally placed DERs.

In the high DER scenario, due to the high level of storage, it is possible to use the energy storage capacity to mitigate any technical problems caused by PV, provided that the energy storage systems can be used to limit net export from the facilities at critical times. In this case, the incremental integration cost between 2017 and 2026 for all PV could be reduced to zero.

On the bulk system side, DNV GL found that the high DER scenario avoids investment of 8 GW in gas-fired generation capacity. Additionally, it reduces annual production costs and CO_2 emissions, and changes CAISO from a net importing region to a net exporting region. The reduction in load for the transmission network allows low-cost electricity from wind, solar, and nuclear to be exported to other regions.

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the short-term variable production cost, the Plexos LT Plan minimizes both the fixed capacity costs and the variable production cost. Capacity costs are applicable for mid to long term system planning in a 5-30 year ahead horizon.

[28] We initially planned a third scenario that consists of maximum cost-effective DERs in the optimal distribution grid locations (i.e., feeders with high hosting capacities or utilities with high hosting capacities). However, the distribution integration costs analysis revealed that this scenario is unnecessary, because the amount of cost-effective storage for each customer can already integrate all of their cost-effective PVs. Therefore, this reduced distribution integration cost to $0 and negated the need to redistribute the PVs to minimize grid integration costs.

[29] The study does not include DER installed cost since these costs are not socialized across ratepayers.

Table ES-1 summarizes the costs and benefits of DERs:

Table ES-1 Summary of Costs and Benefits (in 2016 dollars)

Scenarios	Distribution integration costs	Bulk system benefits compared to base case
Base (PV lumped)	$1,627 million	$0
Base (PV lumped) with smart inverters	$574 million	
Base (PV dispersed)	$128 million	
Optimal location base (IOU separated)	$342 million	
Optimal location base (all CA)	$0	
High DER case	$0	Capital investment savings: $1,000 million in 10 years Production cost savings: $27,662 million in 10 years

Distribution integration cost

The results of the studies with the forecasted distribution of DER systems on the IOUs' distribution circuits show that the customer-sited energy storage can have a significant impact on the total grid integration costs, reducing the incremental costs between 2017 and 2026 by 4% in the worst case and up to 33% in the best case. There are large differences between the three IOUs, and these are largely related to circuit design. SCE has, on average, significantly shorter circuits than PG&E or SDG&E. This leads to higher hosting capacities as shorter circuits are less prone to voltage problems. Circuits with voltage problems, especially due to voltage variation, are more likely to require energy storage at lower PV penetrations, which is what drives the majority of the integration cost. In this case, the difference between customer-sited and utility-owned is that the utility-owned storage would be rate-payer funded, whereas customer-sited energy storage would not (the majority of its use would be for the customer's benefit, with the utility using it at critical times to mitigate potential problems caused by PV generation). It is assumed in this study that the energy storage can provide the same mitigation functionality whether it is customer-owned or utility-owned. below shows that use of customer-sited (and customer-owned) energy storage systems—rather than utility-owned energy storage systems—can reduce integration costs by up to 33% for SCE, up to 8% for PG&E, and up to 4% for SDG&E in the lumped dispersal case.

Table ES-2 Grid integration costs with and without customer-sited energy storage – lumped dispersal of base case

Utility	SCE	PG&E	SDG&E
2017 Grid Integration Costs without Customer-Sited ES	$ 73,300,000	$ 361,640,000	$ 173,170,000
2026 Grid Integration Costs without Customer-Sited ES	$ 215,070,000	$ 1,900,100,000	$ 863,200,000
Incremental cost from 2017 to 2026 without Customer-Sited ES	**$ 141,770,000**	**$ 1,538,460,000**	**$ 690,030,000**
2017 Grid Integration Costs with Customer-Sited ES	$ 67,060,000	$ 328,200,000	$ 140,680,000
2026 Grid Integration Costs with Customer-Sited ES	$ 161,580,000	$ 1,756,660,000	$ 799,720,000
Incremental cost from 2017 to 2026 with Customer-Sited ES	**$ 94,520,000**	**$ 1,428,460,000**	**$ 659,040,000**

Table ES-3 below shows that use of customer-sited (and customer-owned) energy storage systems—rather than utility-owned energy storage systems—can reduce integration costs by up to 8% for SCE, up to 7% for PG&E, and up to 6% for SDG&E in the distributed dispersal case.

Table ES-3 Grid integration costs with and without customer-sited energy storage – distributed dispersal of base case

Utility	SCE	PG&E	SDG&E
2017 Grid Integration Costs without Customer-Sited ES	$ 9,610,000	$ 22,230,000	$ 21,610,000
2026 Grid Integration Costs without Customer-Sited ES	$ 49,390,000	$ 111,310,000	$ 76,460,000
Incremental cost from 2017 to 2026 without Customer-Sited ES	**$ 39,780,000**	**$ 89,080,000**	**$ 54,850,000**
2017 Grid Integration Costs with Customer-Sited ES	$ 8,210,000	$ 20,660,000	$ 19,490,000
2026 Grid Integration Costs with Customer-Sited ES	$ 45,400,000	$ 102,610,000	$ 71,110,000
Incremental cost from 2017 to 2026 with Customer-Sited ES	**$ 37,190,000**	**$ 81,950,000**	**$ 51,620,000**

Table ES-4 below shows that use of customer-sited (and customer-owned) energy storage systems can reduce integration costs by up to 11% for SCE, up to 13% for PG&E, and up to 6% for SDG&E in the lumped dispersal case with smart inverters.

Table ES-4 Grid integration costs with and without customer-sited energy storage – smart inverter study of base case

Utility	SCE	PG&E	SDG&E
2017 Grid Integration Costs without Customer-Sited ES	$ 44,750,000	$ 172,430,000	$ 43,700,000
2026 Grid Integration Costs without Customer-Sited ES	$ 127,040,000	$ 729,930,000	$ 290,110,000
Difference 2017-2026 without Customer-Sited ES	**$ 82,290,000**	**$ 557,500,000**	**$ 246,410,000**
2017 Grid Integration Costs with Customer-Sited ES	$ 42,650,000	$ 158,320,000	$ 33,290,000
2026 Grid Integration Costs with Customer-Sited ES	$ 116,050,000	$ 645,050,000	$ 265,020,000
Difference 2017-2026 with Customer-Sited ES	**$ 73,400,000**	**$ 486,730,000**	**$ 231,730,000**

For the high DER studies,

Table ES-5 presents the results for the "IOUs separated" case. The results here show that there is sufficient available hosting capacity across the PG&E and SCE distribution systems to accommodate the amount of PV generation forecasted for those systems, while there is insufficient available capacity to accommodate all of the PV generation forecasted for the SDG&E system without additional upgrades.

Table ES-5 IOUs separated results for base case

	SDG&E	PG&E	SCE
Total 2017 hosting capacity (kW)	471,000	6,094,000	17,804,000
Total 2017 Available Capacity (kW)	309,000	4,935,000	16,867,000
PV to add to 2026 (kW)	761,000	3,591,000	3,656,000
ES to add to 2026 (kW)	36,000	93,000	244,000
Total 2017 Integration Cost	$ 173,170,000	$ 361,640,000	$ 73,300,000
Total 2026 Integration Cost	$ 424,760,000	$ 361,640,000	$ 73,300,000
Additional Integration Cost	$ 251,590,000	$ -	$ -

Table ES-6 presents the results for the "IOUs combined" case. These results have a similar explanation to the explanation for Table ES-5 above—there is sufficient available hosting capacity across the three IOUs' distribution circuits to accommodate all of the forecasted PV generation without any further grid integration costs, provided that it is distributed in the optimal manner.

Table ES-6 IOUs combined results for base case

Utility	SDG&E	PG&E	SCE
Total 2017 hosting capacity (kW)	471,000	6,094,000	17,804,000
Total 2017 Available Capacity (kW)	309,000	4,935,000	16,867,000
PV to add to 2026 (kW)	761,000	3,591,000	3,656,000
ES to add to 2026 (kW)	36,000	93,000	244,000
Total 2017 Integration Cost	$ 173,170,000	$ 361,640,000	$ 73,300,000
Total 2026 Integration Cost	$ 173,170,000	$ 361,640,000	$ 73,300,000
Additional Integration Cost	$ -	$ -	$ -

DNV GL conducted an additional study using a high DER forecast through LBNL's DER-CAM optimization tool. In this study, we used a different set of assumptions for the DER forecast on the feeders.

Table ES-7 presents the PV, Energy Storage, and Electric Vehicle capacities in 2017 and 2026. This table shows that the additional energy storage capacity installed between 2017 and 2026 exceeds the PV capacity installed in that period for all three IOUs.

Table ES-7 High DER scenario forecast by technology

	SDG&E	PG&E	SCE
2017 PV Capacity (kW)	292,000	1,532,000	1,209,000
2026 PV Capacity (kW)	4,650,000	24,260,000	20,461,000
2017 ES Capacity (kW)	41,000	72,000	121,000
2026 ES Capacity (kW)	6,112,000	30,515,000	54,617,000
2017 EV Capacity (kW)	176,000	1,081,000	1,295,000
2026 EV Capacity (kW)	6,112,000	30,515,000	54,617,000

Table ES-8 presents the integration costs with the customer-sited energy storage capacities identified above. As the energy storage added between 2017 and 2026 exceeds the PV capacity, it is possible to use the energy storage capacity to mitigate any technical problems caused by PV, provided that the energy storage systems can be used to limit net export from the facilities at critical times. In this case, the incremental integration cost between 2017 and 2026 for all PV could be reduced to zero.

Table ES-8 High DER scenario integration cost results

	SDG&E	PG&E	SCE
2017 Grid Integration Costs without Customer-Sited ES	$ 173,170,000	$ 361,640,000	$ 73,300,000
2026 Grid Integration Costs without Customer-Sited ES	$ 2,524,570,000	$ 10,598,650,000	$ 1,133,480,000
Difference 2017-2026 without Customer-Sited ES	$ 2,351,400,000	$ 10,237,010,000	$ 1,060,190,000
2017 Grid Integration Costs with Customer-Sited ES	$ 140,680,000	$ 328,200,000	$ 67,060,000
2026 Grid Integration Costs with Customer-Sited ES	$ 140,680,000	$ 328,200,000	$ 67,060,000
Difference 2017-2026 with Customer-Sited ES	$ -	$ -	$ -

When a draft of this report was written in 2017, the preliminary EV forecast from the CEC IEPR did not constitute a large enough EV population to affect distribution integration costs. Since then Governor Brown set a goal to increase EVs to 5 million by 2030 in 2018, which represents a significantly increased. As a result, DNV GL has completed a separate analysis of EV integration costs in the Addendum A. The analysis shows that

1. Circuits with a larger margin between their peak load and circuit rating are less likely to require mitigation. This is because the worst case involves adding the EV capacity to the circuit peak load. Once the summed load exceeds the rating of conductors or other equipment on the circuit, mitigation (likely re-conductoring) will be necessary;
2. Shorter circuits are likely to have lower mitigation costs if equipment ratings are exceeded. This is because there is a shorter distance between the substation and the EV facility which limits the re-conductoring cost;
3. Circuits which have conductors with lower impedance are less likely to exhibit low voltage problems at higher EV charging capacities. This is because voltage drop is reduced with reduced impedance.

Wholesale energy system cost

For the wholesale energy system, DNV GL investigated the impact of DER by performing a capacity expansion and dispatch optimization of bulk generation assets within the Western Electricity Coordinating Council region (WECC) with a detailed focus on the CAISO region. We simulated two cases: the base case with trajectory DER, and a high DER case with all economically viable DERs. The results show that additional gas-fired capacity generation is added to CAISO system due to the increase in load within the CAISO region; however, the high DER scenario avoids investment of 8 GW in gas-fired generation capacity and an average of 51 TWh/year in gas-fired generation.

Table ES-9 shows that the total production costs in the high DER case are lower compared to the base case. This is a result of reduced investments in new gas-fired generation capacity and less gas-fired generation. The difference in investments in gas-fired generation capacity is roughly $1 billion for the entire 10-year period. The average annual reduction in production costs is $2.766 billion per year, leading to a cumulative difference of $27.662 billion through 2026 in favor of the high DER case. The increase of costs and emissions from 2025 to 2026 under the High DER case for Tables ES-9 and ES-10 is due to generating unit retirements across WECC, and the resultant increase in California's natural gas-based electricity production.

Table ES-9 Sum of annual generation costs and annualized investment costs (in millions of dollars)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base case	5,053	5,182	5,410	5,611	5,735	5,941	6,112	4,278	4,532	5,560
High DER	3,971	3,270	2,807	2,479	2,201	2,026	1,923	1,732	1,739	3,605
Difference	-1,081	-1,912	-2,603	-3,132	-3,534	-3,915	-4,189	-2,546	-2,793	-1,955

Table ES-10 shows that there is an average annual decrease of 22 Mton/yr in CO_2 emissions. In several years, the emission reduction reaches nearly 78% of the annual emissions in the base case. The emission reduction is due to the reduction in gas-fired generation.

Table ES-10 Annual CO_2 emissions from bulk power generation within CAISO region (Mton)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base Case	37	38	40	42	42	44	45	28	30	40
High DER	29	23	18	15	13	11	10	8	9	25
Difference	-8	-15	-22	-27	-29	-33	-35	-20	-21	-15

The additional DER in the high DER case changes the import/export balance of the CAISO region from a net importing region into a net exporting region (see Table ES-11). The reduction in load for the transmission network allows low-cost electricity from wind, solar, and nuclear to be exported to other regions. This increase in exporting and the associated increase in generation (including DER sources) lowers the impact of the additional DER on the production costs and the emissions savings. If CAISO were to keep the same import/export balance (the same net importing position) as in the base case, the reduction of production costs and emissions would be larger.

Table ES-11 Net export of CAISO (negative means net importing) (TWh/yr)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base case	-49	-52	-54	-56	-60	-65	-70	-118	-119	-106
High DER	-47	-46	-41	-35	-27	-18	-8	0	11	53

Since PLEXOS simulation is a wholesale market study, there are both benefits and costs DER integration into the transmission system that are not fully examined. It is noted that DER resources in transmission constrained areas such as Southern California decrease congestion on the transmission and distribution system. Another benefit not measured is the reduction in system losses due to DER integration.

1 INTRODUCTION

As distributed energy resources proliferate in California, the California Public Utilities Commission (CPUC) is interested in better understanding the potential impacts the customer-side distributed energy resources (DER) will have on the transmission and distribution systems. The CPUC hired DNV GL to conduct a study to estimate the grid impacts of trajectory DER growth, and to develop a high penetration DER scenario that minimizes system costs.

For this study, we examines methods to a achieve a the high DER scenario that: (1) is cost-effective to customers according to current tariffs and incentive programs as calculated by LBNL's DER-CAM tool; (2) minimizes distribution integration costs; and (3) maximizes wholesale market benefits. The DER resources analyzed for the study include solar photovoltaic (PV), energy storage, combined heat and power, demand response (DR), energy efficiency (EE) and electric vehicles (EV).

2 METHODOLOGY

The overall approach consists of three main steps:

1. **Scenario development**
    a. **DER allocation for the base scenario.** Create a base case from the forecasts in California Energy Commission's 2016 Integrated Energy Policy Report (IEPR).[30] The base case consists of IEPR's mid-demand forecast of DERs that are mapped to each utility's feeder.
    b. **Customer-driven high DER scenario.** Determine the maximum amount of DERs that are considered cost-effective from the customer's perspective. We completed this analysis for 18 different customer types for each of the three California IOUs. Each of the customer type has an optimal bundle of DERs (PV, storage, or combined heat and power) that are cost-effective to them based on their load profiles, applicable tariffs, equipment costs, and payback period.[31]
2. **Distribution integration cost analysis**. Based on circuit analysis of representative feeders, DNV GL determines the optimal amount of cost-effective DERs that could go on each feeder for the base scenario and maximum cost-effective DER scenarios.
3. **Wholesale market simulation.** The DERs from each feeder are aggregated to the zonal level for wholesale market modeling. The objective of this modeling exercise is to find the impact of high levels of DERs on the wholesale market and their impacts on transmission lines loading capacity.

Figure 2-1 provides an overview of the methodology. The light blue boxes describe the scenario development, analysis steps, and data sources, while the dark blue boxes describe the output of results.

[30] The DER forecasts are mainly from CEC's 2016 IEPR. The electric vehicle forecasts are from CEC's preliminary forecasts provided to DNV GL in early November 2017. It is noted that CEC's revised forecast was significantly higher than the preliminary forecast but DNV GL was not able to use the updated forecast due to the timing of the study.
[31] Costs taken on by the customer who is installing DER technologies are not socialized or otherwise passed on to other customers through utility incentive programs. Additionally, this modeling exercise does not take into account factors such as a customer's personal preference or financial viability and serves to provide a simple overview of DER penetration based on physical potential in California.

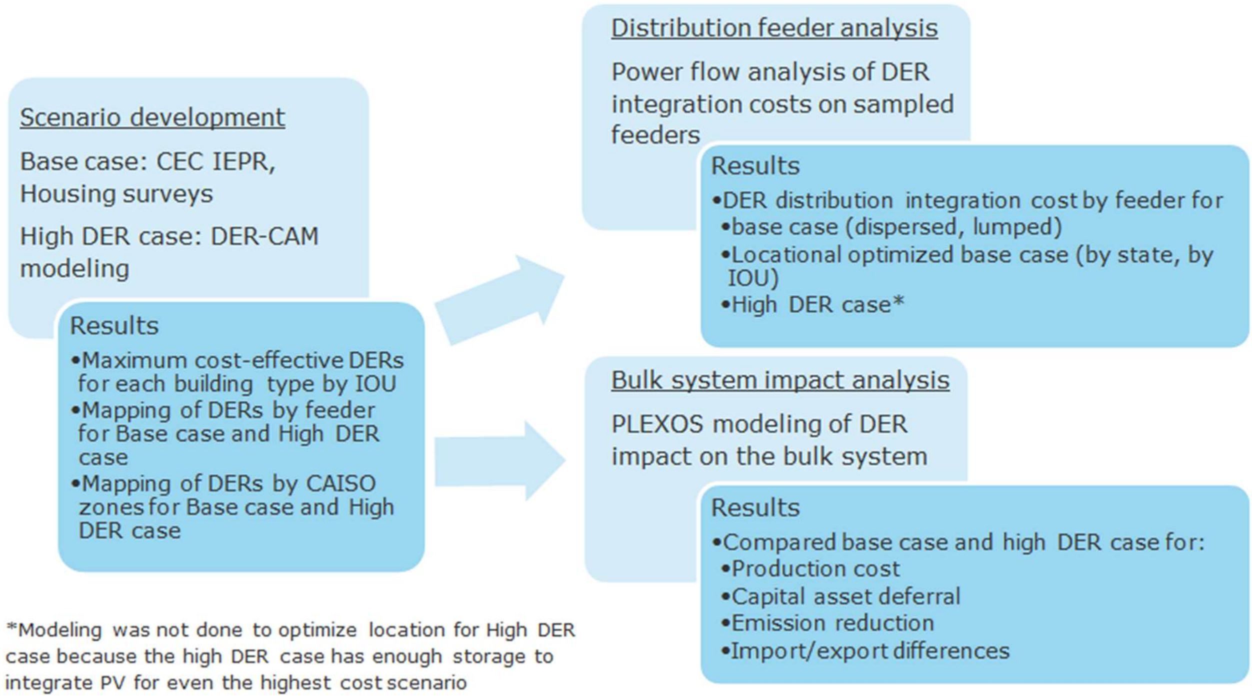

Figure 2-1: Methodology Overview

The sections below provide a detailed description for each of the three steps.

2.1 Step 1a: DER allocation for Base Scenario

The purpose of this step is to create a base scenario that represents trajectory, non-optimized DER distribution across California based on public data sources. The analysis consisted of four main elements:

- Estimate residential PV capacities by feeder, including existing PV on existing homes in 2015, a forecast of new PV installed on existing homes from 2016-2026, and a forecast of new PV installed on new homes from 2016 to 2026
- Estimate the number of commercial building on each distribution feeder by building type in 2015.
- Forecast cumulative commercial PV and other DER capacity, by technology, on each distribution feeder for 2017 and 2026.
- Forecast the cumulative number of electric vehicles by distributions feeder for 2017 and 2026.

DNV GL assumes DER capacity and electric vehicle growth follow the IEPR mid-demand forecasts. The feeder-level forecasts allocate the IEPR forecasts, which are at the forecast zone level, to feeders within each forecast zone. DNV GL layered the following data onto the California map to create the basis for the various forecasts:

- Existing distribution feeders from Geographic Information System (GIS) maps provided by the IOU;

- Existing homes from the American Community Survey;[32]
- Count and consumption of commercial electricity customer accounts,[33] by North American Industry Classification System (NAICS)[34] code;
- Cumulative commercial DER capacity forecasts based on CEC IEPR forecast for 2017 and 2026; and
- Cumulative electric vehicle forecasts based on CEC IEPR forecast for 2017 and 2026.

Since the forecast data from IEPR are by forecast zones, DNV GL applied several analytical methods to break out the forecast at the feeder level described. For EVs, DNV GL used a bottom-up analysis based on Census block group-level household counts. For commercial DER, we used a Census block-group-level analysis of commercial electricity consumption. These methods are described in more details in Sections 2.1.1 to 2.1.5 below.

2.1.1 Residential building and DER Forecast

The residential baseline forecast has three main elements: (1) allocating existing PV on existing homes; (2) new PV on existing homes; and (3) new PV on new homes.

2.1.2 Allocate existing and new PV on Existing Homes

To allocate new PV across existing homes, we reviewed the literature on drivers of PV adoption. The primary driver of PV adoption is the potential for monetary savings,[35] which correlates strongly with the size of a household's electricity bill. Since getting billing data was not feasible, we used data from the American Community Survey as predictors of high energy bills: income, number of people per household, and number of rooms (home size). The higher these metrics, the higher we estimated the adoption rate to be for the associated Census block group.

In addition to these proxies for the size of the energy bill, we looked at the percent of owner-occupied households by Census block group; we examined the share of owner-occupied households under the assumption that a building owner would be more inclined to install PV if it would reduce their own electricity bill as opposed to only reducing a tenant's bill. When we applied our estimated adoption rates, we estimated the pool of potential adopters to include all owner-occupied households plus 10% of all non-owner-occupied households.

We mapped the estimated adoption rates and owner-occupied rates from the Census block group level to a grid of 1 kilometer square blocks covering California that we developed for this study to facilitate mapping between feeders and other geographic data. We refer to this common mapping grid as a "fishnet grid" and the 1-km-square blocks as "grid cells."

The mapping was an approximation. Some grid cells overlapped two or more census block groups, while in other cases our GIS approach produced no matching block group for a fishnet grid cell. In the former case,

[32] United States Census Bureau / American FactFinder. "B11001 : Housing: Basic Count/Estimate." 2007 – 2011 American Community Survey. U.S. Census Bureau's American Community Survey Office, 2017. Web. March 21, 2017 <http://factfinder2.census.gov>.
[33] Utility datasets obtained under the 13-15 CPUC EM&V contract, used for this project with CPUC permission
[34] North American Industry Classification System is system used by Federal statistical agencies to classify businesses when reporting statistical data for the commercial and industrial sectors. DNV GL used the NAICS coding in the billing data to group customers into the specific building types being analyzed in this study.
[35] Agarwal, Anish, 2015. *A Model for Residential Adoption of Photovoltaic Systems.* California Institute of Technology.

we pulled household characteristics from just one of the Census Block Groups; in the latter, we assigned the average values for the feeder associated with that fishnet grid.

This process produced estimates of existing (2015) PV and a forecast of new PV to existing homes by fishnet grid cell. We aggregated the fishnet grids data to the forecast climate zone level. These first-cut estimates were not yet calibrated to the PV capacity forecasts at the forecast climate zone level (our targets). Essentially, we had estimated relative levels of adoption among feeders within a climate zone, but up to this point had ignored the overall average expected adoption rate.

To calibrate our first-cut estimates to align with the forecast-zone-level targets, we developed calibration factors by year and forecast zone and applied them to our fishnet-grid-level estimates. After calibration, our estimates aligned closely with the targets for both 2015 existing capacity and forecast new PV capacity. We then aggregated the calibrated forecasts up to the feeder level.

2.1.2.1 Allocate New PV on New Homes

We took a different approach to the analysis of new homes. The CEC forecasts new housing starts by year and climate zone as part of their regular forecasting process. This project required analyzing grid impacts at a local scale (i.e. feeders). DNV GL developed the process below for allocating the CEC forecasts to local levels. The process uses regional planning concepts, such accessibility, to allocate new homes. Due to schedule and budget constraints, our process did not attempt to incorporate county or municipal development plans. Our forecasts approximated how local development occurs from a regional perspective. The forecasts are not suitable as an alternative to detailed regional or local land use forecasts.

The process for developing housing forecasts was as follows, starting with the 1-kilometer (km) x 1 km grid discussed earlier:

1. Overlaid land use data onto the fishnet grid cells. We categorized land as either (1) developed urban land, (2) open space preserved against development, or (3) potentially developable land. The last category includes farmland and other land not following into the first two groups. This step results in partitioning the area of each grid cell into one or more of these development categories.
2. Overlaid U.S. Census data of housing onto the grid cells. As Census boundaries cross grid cell boundaries, we allocated houses to grid cells proportional to the amount of urban area in the grid cells.
3. Calculated the capacity for new housing development. We assumed that new development density in each grid cell would be at the same density as currently exists near the grid cell.
4. Created 50-mile buffers by climate zone.
5. For each climate zone, we step through the following by year:
    a. Calculated a measure of attractiveness (υ_i) for development of each grid cell as $\sum_j e^{\propto d_{ij}+log(h_j)} + \gamma p_i$ where:

        α is a calibration parameter, set to -0.5?
        d measures the distance between grid cells *i* and *j*
        h is the number of homes in grid cell *j*
        β is a dampening factor, set to 0.5
        p is a shadow price

        This expression makes grid cells in close proximity development appear more attractive to development than grid cells without developed neighbors.

b. Calculated the probability of development in a grid cell as $\frac{e^{u_i}}{\sum_j e^{u_j}}$. This expression is known as a multinomial logit model.
c. Allocated the CEC forecasts of new houses (in groups of 25) to grid cells using a Monte-Carlo simulation. Grid cells with higher accessibility are more likely to get allocated new homes than grid cells with low accessibility.
d. Calculated the implied space requirements, assuming the development densities in step 3.
e. Calculated a shadow price as the $log\left(\frac{capacity)}{allocation}\right)$ for each zone where the new allocation of houses is greater than the development capacity.
f. Repeated steps a through e until all no grid cell is over capacity.
g. Updated grid cell housing and land categorization values and moved to the next forecast year in step 5.

This process produced a forecast of where we expect new homes, both single-family and multifamily, to be constructed. We then turned our focus to determining PV adoption among those new homes.

For the base scenario new homes capacity forecast, we began with a forecast-climate-zone-level forecast of PV to new homes. We evaluated a couple approaches for allocating this capacity to feeders. One was to use the remaining PV hosting capacity of each feeder to constrain PV growth on the feeder, essentially saying that PV growth will occur only on feeders that have available hosting capacity. This only makes sense if the utilities refuse to integrate new PV beyond a certain point, or interconnection costs are prohibitively high for interconnecting on feeders with low hosting capacity. However, we decided that it made sense to model more organic (demand-based) growth of PV.

Unlike existing homes, where we had data on household characteristics, we had no way to model drivers of PV adoption for new homes in the base scenario, beyond what is already embodied in the climate zone forecast. We therefore simply took the forecast-zone-level PV forecast and allocated it to feeders in proportion to the share of new homes.

2.1.3 Commercial Building Stock and Consumption Forecast

A commercial building stock breakout by building type and feeder provided the basis for DER optimization. The corresponding estimates of commercial consumption fed into the DER forecasts discussed below in section 2.1.4.

DNV GL used utility datasets obtained under the 2013-15 CPUC EM&V contract to develop customer counts and consumption estimate by building type. Then, customer accounts were mapped to the following building types[36] using NAICS coding and consumption data (to break out buildings by size) from the billing data:

- Full-service restaurant
- Hospital
- Industrial
- Large hotel (>720,000 kWh)
- Large office (>1,300,000 kWh)

[36] Note that the analysis excludes agriculture, mining, and the transportation, communications, and utilities sector.

- Medium office (130,000 to 1,300,000 kWh)
- Midrise apartment
- Outpatient
- Primary school
- Quick service restaurant
- Secondary school
- Small hotel (≤720,000 kWh)
- Small office (≤130,000 kWh)
- Stand-alone retail
- Strip mall
- Supermarket
- Warehouse

The utility dataset included addresses, latitude and longitude, Census tracts, and Census block information. While the utilities have feeder information for each customer, the data request for the Evaluation, Measurement and Verification (EM&V) work did not include it, and the project schedule did not allow enough time to request additional data. Because Census blocks were already mapped to feeders as part of a recent residential PV forecast,[37] DNV GL opted to use that existing mapping for the commercial analysis as well.

Once the Census block was applied to feeder mapping to the utility dataset, DNV GL cross-tabulated both customer counts and kilowatt hour (kWh) consumption by building type and feeder.

2.1.4 Commercial DER Capacity Forecast

The CEC IEPR forecast provided estimates of cumulative DER capacity from 2016 to 2027 for nine DER technologies including PV. The forecasts were further broken out by forecast zone and six sectors. Only the commercial and industrial sectors were used for this allocation analysis because building load data is publicly available for these sectors. The DER technologies included in the analysis were:

- Fuel Cell CHP
- Fuel Cell Electric
- Gas Reciprocating Engine
- Micro Turbine
- Advanced Energy Storage
- Gas Turbine
- Wind Turbine

[37] CPUC, 2017. *Residential Zero Net Energy Building Integration Cost Analysis.* Document No.: 10007451-HOU-R-02-D. October 18, 2017

- PV

With the exception of PV, DNV GL simply allocated the forecasted DER capacity of each type within a forecast zone based on the share of consumption for each feeder/building type combination in that forecast zone.

For the PV forecast, additional information was layered into the forecast. First, DNV GL had information on the relative cost effectiveness of PV across building types from the National Renewable Energy Laboratory (NREL).[38] Second, DNV GL knew that potential PV capacity depends as much on the available roof area as the building's consumption, and therefore wanted to factor in differences in typical building configurations (specifically the ratio of roof area to total floor area) by building type.

To apply the former to the current analysis, DNV GL simply calculated for each building type the ratio of its breakeven value (in $/kW) to the average breakeven value across all building types. This ratio was then applied to increase or decrease the allocation of capacity to a particular building type and feeder. While imprecise, this method served the purpose of increasing the PV allocation to building types where PV is more cost effective and decreasing it where it is less cost effective.

For the latter, DNV GL used judgement to ratio down (0.5 multiplier) the allocation to large hotels and large offices, which are often high-rise buildings. Secondary schools, medium offices, out-patient buildings, hospitals, and small hotels we deemed to be neutral with no adjustment to the allocation. The allocation for the remaining building types was ratioed up (multiplier of 1.5).

For both the PV forecast and other DER technologies, DNV GL developed the forecast at the building type level, but ultimately aggregated across building types to create a single commercial capacity forecast for each feeder. In the end, there were separate forecasts for the commercial and industrial sectors and for each of the nine DER technologies.

2.1.5 Electric Vehicle Forecast

The CEC IEPR forecast provides separate estimates of battery electric vehicles and plug-in hybrid electric vehicles for the years 2015 to 2028, by forecast zone. The forecast did not distinguish between commercial and residential electric vehicles. Lacking that breakout but anticipating residential growth to be strong over the forecast horizon, DNV GL decided to use residential building stock as the basis for the allocation to feeders.

DNV GL used number of homes by feeder as the basis for the electric vehicle forecast which was developed in a recent residential zero net energy building integration cost analysis. For that study, DNV GL obtained estimates of the number of households for each Census block group in California from the U.S. Census Bureau's American Community Survey. Using a GIS analysis, the Census block groups were mapped to feeders. Within each forecast zone, the CEC IEPR forecast was allocated to feeders in proportion to the share of homes on that feeder.

A full explanation of the mapping methodology is provided in the report for that study.[39]

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[38] Davidson, Carolyn, Pieter Gagnon, Paul Denholm, and Robert Morgolis, 2015. Nationwide Analysis of U.S. Commercial Building Solar Photovoltaic (PV) Breakeven Conditions. National Renewable Energy Laboratory technical report NREL/TP-6A20-64793. October 2015.

[39] CPUC, 2017. *Residential Zero Net Energy Building Integration Cost Analysis.* Document No.: 10007451-HOU-R-02-D. October 18, 2017

2.1.6 New Feeders Forecasts

The number of feeders in each utility is expected to grow overtime to accommodate future demands. From interviews with utility distribution planning representatives,[40] DNV GL collected data on the pace of historical distribution grid expansion from each utility, as well as the characteristics of the expansion. Each year, PG&E adds an estimated 14 new feeders to its distribution system, SCE adds 15, and SDG&E adds two to three.

The new homes forecast discussed above provided a basis for determining where new feeders would be added. First, we calculated cumulative new homes by feeder for each year of the forecast. We then ranked the feeders for each utility by cumulative new homes. Since PG&E expects 14 new feeders each year, we took the top 14 feeders by growth, added a new feeder associated with each, and reallocated the new homes growth from the existing feeder to the new feeder. For SDG&E, we assumed two feeders or three feeders in alternating years to represent the typical growth numbers we received. Because of the patterns in new home growth, some feeders in high growth areas produced multiple duplicate feeders over the 11-year forecast, while others with slower growth only crept into the top-ranked feeders after several years of accumulated growth.

2.1.7 Distributed Energy Resources Limitations

For all of the forecasts, maximum limits have been placed on each feeder depending on voltage class. This is based on 'rules of thumb' in use at some utilities, rather than on public documentation, and is used here to provide a realistic limit to the capacities of PV and energy storage on the feeders. The limits used by voltage class are shown in Table 2-1 below:

Table 2-1: Upper limits on DER deployment by voltage class

Voltage Class	Upper Limit on DER deployment
4kV	5MW
12kV	10MW
16kV	15MW
21kV	20MW
34.5kV	30MW

2.2 Step 1b: Customer Cost-Effectiveness Modeling

The purpose of the customer cost-effectiveness modeling is to find cost-effective bundles of DERs for each customer type. The aggregate of these DER bundles represent the maximum potential of DERs in California. These maximum DER bundles are then aggregated into CAISO zones for supply side optimization that is discussed in Section 2.4.

[40] Interviews conducted with SDG&E on April 14, 2017, and PG&E and SCE on April 17, 2017.

2.2.1 DER-CAM

DNV GL used LBNL's Distributed Energy Resources Customer Adoption Model or DER-CAM for modeling cost-effectiveness of distributed energy resources (DER). DER-CAM is a decision support tool to help in investment and planning of DER in buildings and decentralized energy systems such as microgrids. It is an economic optimization model which finds the most cost-effective mix of energy supply technologies and dispatch to minimize costs and CO_2 emissions. DER-CAM's optimization considers load management options such as load shifting, load shedding, constraints of technology behavior, and accounts for power flow constraints.

DER-CAM minimizes total energy costs and CO_2 emissions by maintaining energy balance, operating technologies within physical boundaries, and verifying financial constraints. Energy balance is retained by ensuring that energy supply equals demand, and verifying financial constraints means savings achieved through the use of new DER customers who must repay investments within a defined payback period. In order to do this, DER-CAM requires an optimization to include two scenarios: a base case to establish a reference scenario (without DER) and an investment case (with DER).

The reference case establishes the existing conditions of a building. Key inputs for the base case include customer hourly load profiles, electricity and natural gas tariffs, fuel prices, and existing DER technologies, if available. Once the base case is run, the total energy costs and CO_2 emissions are saved as reference for the investment or DER case. The DER case specifies the generation and storage technologies for consideration such as CHP, PV and energy storage along with their associated capital and, operation and maintenance costs. Load management strategies such as demand response are also enabled with appropriate costs and hours of operation. Details on the assumptions for the parameters mentioned above are described in the following section.

2.2.2 Major model assumptions and sources

DER-CAM's major inputs include load, solar and tariff data which are described further in the following sections. This section also highlights financial parameters associated with DER technologies and assumptions used in the model related to growth rates, EVs and DR.

2.2.2.1 Load data

DER-CAM uses hourly end-use load profiles of representative day-types as one of its key inputs to run the economic optimization. The load profiles include electricity only, cooling, refrigeration, space heating, water heating and natural gas only end-uses across three day-types: weekdays, peak and weekend days. Load profiles in this format were collected from DER-CAM's google drive database for commercial and residential buildings.[41] Load profiles differ based on geographic location. Commercial data are based off the DOE Commercial Reference Building models which includes 16 building types ranging from small offices to hospitals as listed in Section 2.1.1.[42] Residential sector load profiles were based off National Renewable Energy Laboratory's (NREL) Building America House Simulation Protocols which consists of three types of homes: base load, low load and high load. [43] DNV GL used the low-load residential characteristics for the modeling exercise under the assumption that homes will be more energy efficient in the future.

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[41] https://drive.google.com/drive/folders/0BySSikISrXrIaDhFMkRZeE9yTVE?usp=sharing. Accessed October 2017.
[42] https://energy.gov/eere/buildings/commercial-reference-buildings. Accessed October, 2017.
[43] NREL, 2010. Building America House Simulation Protocols. October, 2010.

Lastly, industrial building load profiles were created based on Electric Power Research Institute's (EPRI) web-based load shape library.[44] EPRI's default average hourly demand values are set to have a maximum peak of 1.0 kW which were normalized by using Energy Information Administration's (EIA) average monthly electric[45] and natural gas[46] consumption data. Given that industrial loads are typically not weather-driven, DNV GL assumed that the load profiles were the same for each month of the year.

2.2.2.2 Solar data

DER-CAM maintains a database of solar profiles according to typical meteorological year (TMY) locations (version 2 and an updated version 3) for each state. DNV GL chose the following TMY3 locations per IOU when performing modeling runs for residential, commercial and industrial buildings. Visual representations of average daily solar profiles per month at each representative TMY3 locations were obtained through the DER-CAM tool and are also included for reference below:

- PG&E: San Jose International Airport

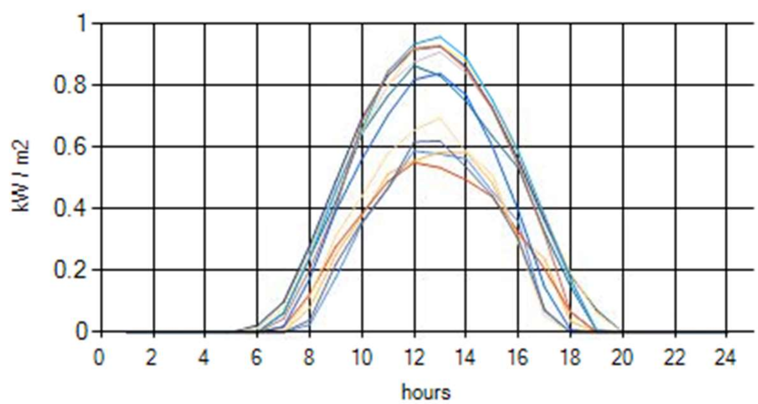

Figure 2-2: TMY3 average daily solar profile per month, San Jose International Airport (PG&E)

[44] EPRI, 2017. Load Shape Library 5.0. Available online at http://loadshape.epri.com/enduse.
[45] EIA, 2016. 2016 Average Monthly Bill-Industrial. Available online at https://www.eia.gov/electricity/sales_revenue_price/pdf/table5_c.pdf.
[46] EIA, 2016. California - Natural Gas 2016 (Table S5). Available online at https://www.eia.gov/naturalgas/annual/pdf/table_S05.pdf.

- SCE: Long Beach Daugherty Field

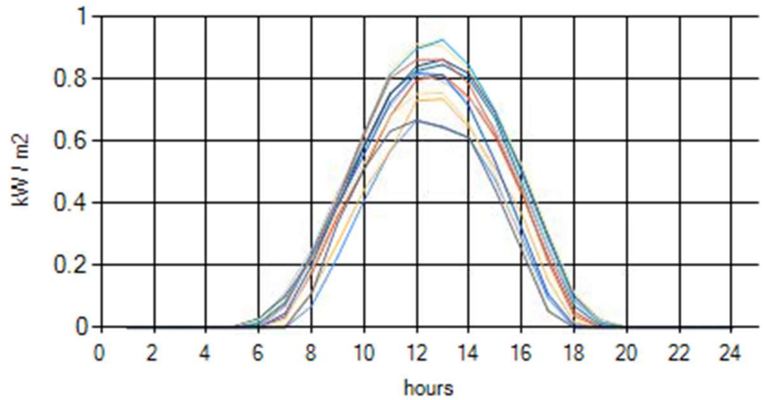

Figure 2-3: TMY3 average daily solar profile per month, Long Beach Daugherty Field (SCE)

- SDG&E: San Diego Lindbergh Field

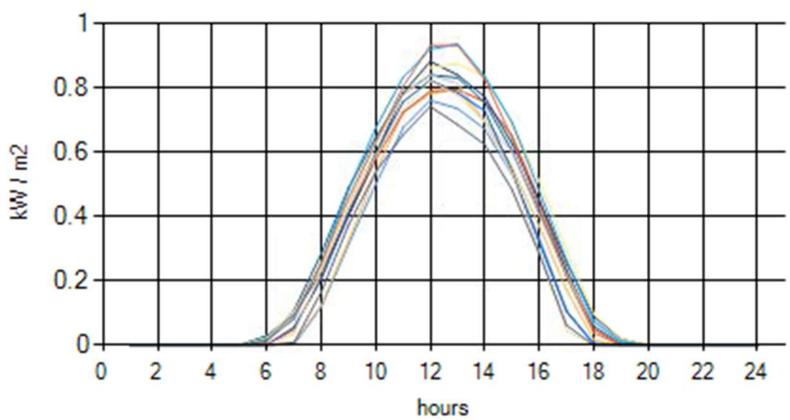

Figure 2-4: TMY3 average daily solar profile per month, San Diego Lindbergh Field (SDG&E)

2.2.2.3 Tariff data

Electricity and natural gas tariffs were researched from each utility's tariff website and diesel fuel prices were obtained from EIA.[47] A summary of the tariffs used in DER-CAM are shown below. DNV GL performed an analysis of peak load per building which was used to determine the appropriate commercial tariff. All electricity and fuel prices were from 2017 and were adjusted according to the growth rates described in Table 2-3.

[47] EIA, 2017. Petroleum & Other Liquids: California No 2 Diesel Retail Prices. Available online at https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMD_EPD2D_PTE_SCA_DPG&f=M

Table 2-2: Summary of electric and gas tariffs per IOU as of 2017

Utility	Fuel	Residential	Commercial	Industrial
PG&E	Electric	E-TOU	A-6, A-10, E-19, E-20	E-20
SCE	Electric	TOU-D	TOU-GS-2, TOU-GS-3, TOU-8	TOU-8
SDG&E	Electric	TOU-DR	AL-TOU	AL-TOU
PG&E	Gas	G-1	G-NR1	G-NR2
SoCalGas (SCE)	Gas	GR	G-10	G-10
SDG&E	Gas	GR	GN-3	GN-3

2.2.2.4 Growth rate

Growth rates for each sector were applied given that the modelled year is 2026. Load and tariff data were updated according to the growth rates shown in Table 2-3.

Table 2-3: Average annual growth 2015-2027[48]

Parameter	Residential	Commercial	Industrial
CED 2017 Preliminary Mid Energy Demand	1.77%	0.83%	-0.05%

2.2.2.5 Electric vehicles

DNV GL modelled electric vehicles (EV) in 2026 as a static load and calculated the amount of charging load per building type. EV charging loads for each building type were calculated using either an occupant or parking space methodology. Both methods referenced various assumptions to establish the number of EVs charging per location. Number of occupants, number of floors, and building size for a prototypical building were based on an NREL commercial reference building model study.[49] The number of parking spaces required per building type was based on local municipal code requirements.[50] Commercial EVs were not included in this study, which focuses on commuter vehicles.

Due to the extremely low penetration of workplace EV charging infrastructure, it is not possible to determine the charging patterns of future EV owners if given the option to charge at work versus at home. Further, it is unlikely that most residents will consider this a choice by 2028. It is likely that in 2028, the majority of workplaces will still lack workplace charging infrastructure, and that many multi-family residents will lack at-home charging infrastructure. Finally, the price disparity of charging will likely effect these decisions. When free charging is provided as an employee benefit, most employees will attempt to utilize workplace charging

[48] California Energy Commission, 2017. California Energy Demand 2018-2028 Preliminary Forecast. CEC-200-2017-006-SD. August 9, 2017

[49] NREL, 2011. U.S. Department of Energy Commercial Reference Building Models of the National Building Stock. Technical Report NREL/TP-5500-46861. February 2011.

[50] City of San Diego, 2017. San Diego Municipal Code, Chapter 14: General Regulations, Article 2: General Development Regulations, Division 5: Parking Regulations. June 2017. Accessible online at http://docs.sandiego.gov/municode/MuniCodeChapter14/Ch14Art02Division05.pdf

exclusively. Whereby, when network fees are cost prohibitive, (as high as $0.59/kWh currently) a commuter will likely choose to charge at home. DNV GL has made reasonable assumptions about the future of charging trends and ensured that the same assumptions for workplace, home, and public charging infrastructure are consistent throughout the usage modeling and throughout the report.

Two methods were used to determine annual forecasted EV use.

Occupant Method: For buildings which often have the same occupants coming to the building daily, such as: large office, medium office, small office, warehouse, primary school, secondary school, industrial, and residential buildings; it was assumed that five percent of occupants owned an electric vehicle. This number was based on the CEC IEPR forecast.

For workplace charging, the following assumptions were made:

- 5% of occupants commute with an EV; (By comparison, in 2018, 1.12% of registered light duty vehicles in the State of California are battery electric or plug-in hybrid electric according to Department of Motor Vehicle Data[51].)
- 30% of occupants who commute with an EV charge exclusively at work; and
- 30% of occupants who commute with an EV charge sometimes at work, accounting for 10% of annual EV VMT.

For residential charging, the following assumptions were made:

- 13,476 VMT per year based on US Federal Highway Administration;[52]
- 70% of EV owners will charge at home; and
- EV ownership rate based on CEC IEPR study.

Parking Method: For buildings with variable occupancy, such as: stand-alone retail, strip mall, supermarket, quick service restaurant, full-service restaurant, small hotel, large hotel, hospital, and outpatient; annual electricity use to charge EVs is based on parking spaces and opportunity to charge. For these buildings, the following assumptions were made:

- Number of parking spaces is based on municipal code minimum requirements;
- 2.5% of parking spaces have a level 2 charger, while 0.5% of parking spaces have a level 3 charger;
- An average, level 2 stations are used 7 hours per day, while level 3 stations are used 3 hours per day; and
- Level 3 chargers were assumed to be 50 kW type, while level 2 chargers are assumed to deliver 7.7 kW.

[51] California Department of Motor Vehicles, 2018. “California Motor Vehicle Fuel Types By County” https://www.dmv.ca.gov/portal/dmv/detail/pubs/media_center/statistics
[52] https://www.fhwa.dot.gov/ohim/onh00/bar8.htm

A summary of the projected EV charging load is shown in Table 2-4 below.

Table 2-4: Projected 2026 annual EV load per building

Building	Projected EV Load (kWh)
Hospital*	109,209 (100,000)
Small hotel	37,871
Large hotel*	107,057 (100,000)
Industrial	12,992
Midrise apartment	5,690
Small office	1,757
Medium office	17,127
Large office	42,868
Outpatient	36,403
Full-service restaurant	13,526
Quick service restaurant	6,148
Residential (low load)	271
Stand-alone retail	61,386
Primary school	3,225
Secondary school	7,490
Strip mall	55,332
Supermarket*	110,663 (100,000)
Warehouse	416

*DER-CAM limits EV installed capacity to 100,000 kWh, therefore loads exceeding this amount were adjusted

2.2.2.6 DER key inputs

Costs related to DERs were obtained from E3's RESOLVE documentation for the CPUC 2017 IRP.[53] A summary of the assumptions used in DER-CAM from the document are shown below. Lithium-ion battery costs are typically represented by both power ($/kW) and energy ($/kWh) costs. The 2026 low case behind the meter (BTM) battery costs for power were $175/kW and energy were $147/kWh. Assuming a battery with a three-hour duration, which is typical for bill management, the power costs were converted to $58/kWh resulting in combined battery (power + energy) costs of $205/kWh.

[53] E3, 2017. RESOLVE Documentation: CPUC 2017 IRP, Inputs & Assumptions. September 2017. It is noted that these costs numbers could be outdated because the RESOLVE model relied on 2016 Lazard data which relied on 2015 storage costs. Based on DNV GL's internal forecasts, utility-scale battery systems are forecasted to be between $100-$500/kWh by 2026. The general consensus is that battery modules will be below $100/kWh by 2020. However, for BTM storage, projects will likely be on the higher end of the cost range.

Table 2-5: DER investment costs, 2026

DER	Capital Cost	Fixed O&M Cost ($/kW-yr)
Combined Heat and Power (CAISO Reciprocating Engine)	$1,250/kW	$12
BTM Battery Storage (Lithium Ion, Low Case)	$205/kWh	
PV	$1,788/kW[54]	

Another financial parameter driving a customer to adopt DER technologies is payback period. A maximum payback period of 10 years was assumed across all technologies and customers in DER-CAM. The optimization uses the maximum payback period in conjunction with equipment costs, load profiles and tariffs to determine the most cost-effective DER investments for customers.

2.2.2.7 Demand response

Demand response values for each IOU were provided by the CPUC[55] and normalized to 2026 using an average annual growth rate of 0.83% as described in section 2.2.2.4. The number of demand response hours per year were based on the average duration and number of events per year from IOU programs like Critical Peak Pricing and Base Interruptible Programs.

Table 2-6: Demand response costs, 2026

Utility	DRAM contracts average ($/kw-yr)	Hours per year
PG&E	$71.38	60
SCE	$116.52	60
SDG&E	$105.33	60

2.3 Step 2: Determine distribution integration cost and DER location optimization

For the distribution integration cost analysis, DNV GL analysed two scenarios:

1. Base scenario based on IEPR trajectory forecast and
2. High DER scenario based on all cost-effective DERs from the DER-CAM analysis described in Section 2.2.

[54] DNV GL has mistakenly used the utility-scale PV costs from IEPR for this input. However, upon further review, we found that $1,788/kW (or $1.79/W) in 2026 for distributed PV costs is within reason. In "U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017" by Margolis of NREL, commercial systems are already at $1.85/kW in 2017, and residential PV systems are $2.80/Wdc. Even if the downward trend continues at a slower pace, the cost of commercial PV would be as low as $0.88/W by 2026. Therefore, the cost of $1.79/W is within a reasonable range for distributed PV costs.
[55] Email communication with CPUC. July 2017.

In addition, two optimized scenarios are performed to look at high redistributing of DERs could lower the costs. In the first optimized scenario, PV generation and energy storage systems were re-distributed within each IOU to find the lowest possible integration cost. The objective of this was to deploy PV generation more on feeders which had higher hosting capacities, while maintaining the same total capacities within each IOU (i.e. a facility was allowed to move within an IOU, but not between IOUs).

In the second optimal placement scenario, PV generation and energy storage systems were re-distributed across the three IOUs to find the lowest possible integration cost. In this case, the same total capacities were maintained the across the three IOUs, but the capacities within each IOU could change (i.e. a facility was allowed to move within an IOU, and between IOUs).

DNV GL used Synergi Electric[56] software to analyse the costs of integrating PV on a representative feeder basis. By 2026, California is forecasted to have almost 10,000 feeders: 3,200 in PG&E, 5,700 in SCE and 1,045 in SDG&E. DNV GL sampled about 30 feeders for each IOU and analysed typical reliability criteria for the utilities: static voltage, transient voltage, thermal loading and reverse power flow. The analysis investigated the penetrations of distributed generation at which the technical criteria would be exceeded and identified suitable mitigation measures and related costs that would be required at each stage. The outcome is an integration cost function for each representative feeder that depends on penetrations of PVs. The integration cost function for each representative feeder is then mapped to an actual feeder with a forecasted PV penetration to extrapolate the total integration cost for California by year for each scenario.

The detailed method and assumptions are described in the sections below.

2.3.1 Sampling of representative feeders

Due to the practicalities of budget and schedule for this work, it was not possible to analyse every distribution circuit across the three California IOUs, which are Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). This would amount to over 10,000 distribution feeders. The objective of this scope of work was to provide cost inputs for potential installations. The method selected involves identification of 'representative feeders' which can serve as a proxy for a large number of circuits in a given IOU's service territory. By studying the representative feeders and having a link between the representative feeder and all of the real feeders, the results from the representative feeder study can be extrapolated to the rest of the IOU's distribution system.

In this study, the buildings are represented in the circuit model as generators. This has been done primarily to save time in the analysis and also because utilities have extensive experience in estimating the cost of adding load to their systems. This analysis investigated the incorporation of the generation plant required for a building as a minimum, followed by the addition of other technologies (such as voltage regulators and energy storage systems) that were required to mitigate a specific problem. In this analysis, the generator capacity that is studied should be understood as the maximum export or maximum net-generation output from the facility (i.e. the maximum difference between the generator's output and the facility's own load). It has also been assumed that the generators in this analysis are solar photovoltaic (PV) units.

The placement of new generation on a feeder has a major impact on the hosting capacity and integration costs. Two dispersal cases are modelled:

[56] A widely used electric distribution system power flow modeling tool available from DNV GL. https://www.dnvgl.com/services/power-distribution-system-and-electrical-simulation-software-synergi-electric-5005

1. The new generation on the circuit is placed at the end of the circuit furthest from the substation (in terms of circuit miles). This represents a worst-case condition for most circuits.
2. The generation is distributed around the circuit in increments of up to 100kW. This normally represents a more favourable condition for integration of distributed generation.

By analysing the two cases described above, a range of potential integration costs can be established. In practice the total integration costs are expected to lie somewhere between these two cases. The low-cost case (where new generation is dispersed around the circuit) is considered more representative of historical PV adoption.

A sampling exercise was required to identify the representative circuits for each IOU. This exercise had already been conducted and documented for PG&E[57] and SCE.[58] The method and results in both cases were found to be suitable for this study, so the same set of representative circuits were used. DNV GL performed a sampling study for the SDG&E circuits, using a method developed in-house to identify statistically representative strata of circuits, each comprised of circuits exhibiting similar characteristics. The sampling method for these circuits is described further in Appendix A.

2.3.2 Circuit analysis

The selected representative circuits were analysed using the Synergi Electric.[59] Technical criteria were identified based on typical reliability criteria for the utilities. These criteria are shown in Table 2-7 below:

Table 2-7: Technical criteria used in analysis

Parameter	Limit	Reference
Static Voltage	Voltage must remain within the range of nominal ±5%	Rule 2 requirement
Transient Voltage	Voltage must not vary by more than 3% of nominal for any change in generator output	Rule 21 requirement
Thermal Loading	Thermal loading on any section must be less than 100% of rated capacity	Rule 2 requirement
Reverse Power Flow	Reverse power flow must not occur at any voltage regulating device without the capability to detect direction of power flow	Standard practice per discussion with IOU planners/operators

There are other criteria that could also impose limits on integration of new generation which could not be analyzed in this study due to lack of data. For example, addition of large amounts of inverter-based

[57] Distributed Generation Solar Photovoltaic Transmission & Distribution Impact Analysis; G. Shlatz, K. Corfee, S. Goffri, D. Stradford, M. DePaolis; August 2015
[58] Characterization & Modeling of Representative Distribution Circuits in GridLAB-D; J. Fuller, K. Schneider, A. Guerra, S. Collins, A. Gebeyehu
[59] A widely used electric distribution system power flow modeling tool available from DNV GL. https://www.dnvgl.com/services/power-distribution-system-and-electrical-simulation-software-synergi-electric-5005

generation can have impacts on protection systems both in terms of de-sensitization and overloading. While these costs are not negligible, their mitigation costs are significantly lower than for the technical criteria considered in

Table 2-7 above. For example, where inverters can contribute enough short circuit current to de-sensitize a recloser, the cost for the required settings change would be around $2,500. As inverters contribute a comparatively small amount of short circuit current compared to other forms of generation, the exclusion of this technical criterion is not likely to have a major impact on the conclusions from this study.

Substation capacity limitations and operational flexibility could also not be studied due to lack of available data on feeder ties and which feeders are fed through common equipment in the substation. One result of this is that re-conductoring is the only mitigation measure that could be considered in cases where thermal overloads occur. In reality, there is also the potential for switching circuit configurations so that the load on a section of one circuit can be switched to another with sufficient capacity. This would have the effect of reducing re-conductoring costs. A converse result is that it was not possible in this study to verify that existing flexibility would continue to be available with the addition of the new generation.

The analysis investigated the penetrations of distributed generation at which the technical criteria would be exceeded and identified suitable mitigation measures that would be required at each stage. The mitigation measures studied are shown in Table 2-8.

Table 2-8: Mitigation measures and assumed costs

Technical Limit	Mitigation Measure	Cost
Static Voltage	New voltage regulator	$150,000[60]
Voltage (static or transient, if not able to be mitigated by voltage regulator)	Energy storage	$460/kW + $450/kWh + $1500/100kW for installation. Assume 4 hours of storage required
Thermal Loading	Re-conductoring	$190/ft (average of overhead and underground re-conductoring costs)[61]
Reverse Power Flow at Regulator	Enable co-generation mode	$60,000[62]
Reverse Power Flow at Substation Transformer	Enable co-generation mode	$60,000[63]
Reverse Power Flow at Re-Closer	Implement re-close blocking	$145,000[64]

[60] PG&E Unit Cost Guide, September 2016
[61] PG&E Unit Cost Guide, September 2016
[62] PG&E Unit Cost Guide, September 2016
[63] PG&E Unit Cost Guide, September 2016
[64] PG&E Unit Cost Guide, September 2016

Energy storage could be used to mitigate all the violations identified in Table 2-8, assuming that appropriate communications can be installed. It is also assumed in the initial study that the energy storage equipment if fully owned and operated by the utility, which allows it to be operated solely to reduce PV impact on the circuit. The duration assumed is four hours, which is a popular design at present and should provide sufficient support for the hours of maximum PV output. However, energy storage is typically more expensive than the other measures, so it is normally prescribed only at higher penetrations when the other options are no longer effective. This is the approach that has been assumed for this report, and it is representative of a reactive approach to mitigation i.e. the cheapest solution for the next immediate installation would be selected. If a proactive process was followed, and the distribution system planner could predict that energy storage would be required on a circuit at some point in the future, then energy storage could be deployed to mitigate all violations on the circuit rather than deploying other measures at lower penetrations that could later become redundant. This would likely be more expensive in the short-term but could prove much more cost-effective in the long run particularly given the other functions that are available from distributed energy storage systems. In the analysis, after the penetration at which energy storage was required (typically to correct voltage problems), no other mitigation was identified as it is assumed the energy storage system could be controlled in such a way that it mitigates other problems that occur. In practice, energy storage systems could be configured to limit the net export from the buildings to a value below the hosting capacity of the circuit, which would prevent the technical violations from occurring.

Note that the energy storage cost described above does not include costs associated with land acquisition and the related time and effort. It is assumed that the energy storage equipment would be co-located with the buildings with PV, but this may not always be the case in practice, particularly for large systems and may depend on local safety requirements.

There are alternative mitigation measures to re-conductoring which could not be covered in this study due to the practicality of the analysis. The main alternative is load transfer between circuits, including distribution automation systems. This would allow a load on part of a circuit to be switched to a different circuit with more available capacity to prevent an upstream conductor from being overloaded. This could not be included in this study but should be considered as a means of minimizing the grid integration costs in practice. Similarly, capacitor banks may provide a lower-cost alternative to voltage regulators used to mitigate voltage problems, but their use in mitigation of high voltage problems is complex and requires the adjustment of feeder voltage regulation settings. These complexities precluded the use of capacitor banks to correct voltage regulation problems in this study, but this option should be considered in real-world applications on a feeder-specific basis.

Figure 2-5 below provides typical examples of mitigation cost profiles for the low-cost case for a sample circuit from each of the three IOUs. A series of steps in costs are observed here, typically the first jump is where reverse power flow occurs, requiring investments in regulator control upgrades and re-close blocking. After this, there are a series of steps typically involving re-conductoring of different sections of the circuit as they become overloaded. In some cases, additional voltage regulators may also be required at higher penetrations.

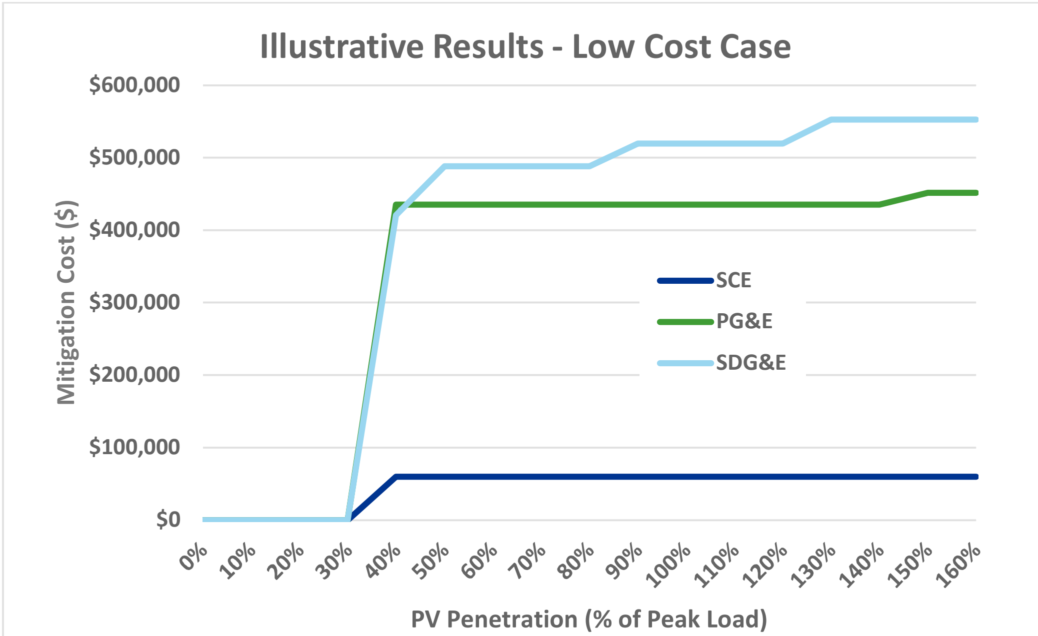

Figure 2-5: Illustrative example mitigation cost profiles for sample circuits – low cost case

For each circuit, a study is carried out increasing the size of the generation on the circuit from zero to 160% of circuit peak load. The '160% of peak load' value was chosen to be a high penetration that would likely not be exceeded in practice, while also allowing the majority of the potential technical violations on the circuit to be identified. Load flow analyses are carried out for peak and minimum daytime load conditions on each feeder, along with a quasi-static study where the output from a single installation is varied from 100% to 0% and back again, without allowing voltage regulation to react (this is intended to simulate changes in irradiance within the time delay of voltage regulation equipment). When a technical violation is identified in the results of the analysis, mitigation measures are identified, and their costs estimated as described in Table 2-7 and Table 2-8 above. The result is an integration cost profile for each circuit up to 160% of peak load.

This analysis was carried out for two generation dispersal cases:

1. The new generator on the circuit is placed at the end of the circuit furthest from the substation. This represents a worst-case condition for most circuits and is referred to in this report as the 'high cost case.'

2. The new generation is distributed around the circuit in increments of up to 100kW. This normally represents a more favorable condition for integration of distributed generation and is referred to in this report as the 'low cost case.'

The rationale for using these two cases is to create 'bookends.' In reality, the dispersal of new generation on a given circuit is likely to fall somewhere in between these two conditions. As new buildings are added to a feeder, the utility planning processes will take account of the new load and new generation and make any appropriate upgrades. In some cases, the upgrades required to accommodate the new load may also mitigate the impacts of the new generation, but in this study, it is assumed that any upgrades costs are attributed to the new generation.

We then combined the integration cost profiles with the feeder-level trajectory scenario. To extrapolate the mitigation cost results to each of these feeders, we assumed that each new home adds 3 kW of peak load to the circuit. The additional peak load per home, while not modelled in the circuit simulation, is used to adjust the peak load value on each feeder for each year in the forecast. The mitigation cost profiles for the representative feeders, provided in terms of PV penetration (% of peak load) are then applied to the feeder, so the mitigation cost for the new PV penetration can be found for each study year.

Note that effects of increased electrification in homes has not been considered in this study. This refers to the possibility that buildings may install electric appliances instead of gas appliances in order to consume the electricity they generate locally, which may be more cost-effective. This could result in a higher than average peak load per home than that considered above. This would have no impact on the grid integration cost profiles per circuit but could have an effect on the extrapolated results as peak and minimum loads are likely to be higher, resulting in lower effective penetrations.

This study also does not account for mitigation costs required at the bulk system level due to the combined effects of distributed renewable generation on the transmission system and on the distribution system. There is the potential for over-generation during daytime hours, particularly on days where the load is low, which could require controllable loads or energy storage in order to maintain system stability and operational reserve capacity.

2.3.3 Customer-Sited DER Analysis

In the previous section, integration cost profiles were generated for 75 different feeders which were considered to be representative of the three major California IOU's distribution systems. These profiles were generated by analysis of the representative feeders, identification of technical violations at increasing PV penetrations and specification of mitigation measures and associated cost estimates. This was done for two dispersal cases – one where all of the new generation was located in a single location at the end of the feeder (the 'lumped' case), and one where all of the new generation was distributed evenly along the feeder (the 'distributed' case). An additional sensitivity study was also performed on the lumped case where smart inverter functions were incorporated (in this case, the volt/var function, assuming reactive power priority). The volt/var function, in particular, has the potential to reduce voltage problems on the circuit, thereby reducing distribution integration costs.

A forecast was also produced for the dispersal of new PV generation in California for each year up to 2026. This provided a distribution of new PV generation on a feeder-by-feeder basis. The cost profiles produced for the representative feeders was combined with the forecast of new PV generation to produce a distribution system upgrade cost for each feeder for each year to 2026.

When the only form of DER installed at a building is PV, particularly in the lumped dispersal scenario, there were technical violations that could only be resolved by deployment of energy storage systems controlled by the utility. The cost for these energy storage systems would be assigned to the IOU and ultimately passed on to the ratepayer. However, as DER technologies, including energy storage, become more cost-effective, there is the increased possibility that these will be installed by the customer themselves for other reasons. In this case, given the right economic incentives from the IOU, these DER technologies could be utilized to mitigate potential problems at a much lower additional cost to the utility's ratepayers than if the IOU had full ownership of the equipment.

The study described in this report adds a forecast of other DER technologies that may be deployed at buildings on a feeder-by-feeder basis, including energy storage capacities. This forecast is combined with the previous work on integration costs to effectively reduce the PV capacity on each feeder. This assumes that the energy storage system would be used to reduce the net export of energy to the grid when the PV system's output is high, and to smooth the output of the PV system to prevent voltage fluctuation issues.

Electric vehicle capacities are assumed to increase the peak and minimum loads on a feeder. It is assumed that a maximum of 45% of EV owners will charge their cars during the daytime,[65] and this value is used to increase the peak load on the feeder, effectively reducing the PV penetration for a given PV capacity (as PV penetration is expressed as a percentage of peak load). This addresses the fact that electric vehicles have the potential to reduce PV impact by absorbing generation during the daytime.

The resultant integration cost estimates were found for each feeder and summed for each IOU in the 'lumped' dispersal case, the 'distributed' dispersal case, and the smart inverter sensitivity study.

The Other DERs that were forecast which were neither PV, electric vehicles nor energy storage systems were assumed to have no effect on grid integration costs. It is assumed that these resources will serve only local load on-site and will not have any net export to the distribution system.

On top of the base scenario, two theoretical optimal placement scenarios were studied. Although these scenarios are not realistic, they show the extent of cost savings could be achieved if DERs can be optimally placed. In the first of these, PV generation and energy storage systems were re-distributed within each IOU to find the lowest possible integration cost. The objective of this was to deploy buildings and PV generation more on feeders which had higher hosting capacities, while maintaining the same total capacities within each IOU (i.e. a facility was allowed to move within an IOU, but not between IOUs). In the second optimal placement scenario, PV generation and energy storage systems were re-distributed across the three IOUs to find the lowest possible integration cost. In this case, the same total capacities were maintained the across the three IOUs, but the capacities within each IOU could change (i.e. a facility was allowed to move within an IOU, and between IOUs).

2.3.4 Limitations of the Study

Due to practicalities of scope, schedule and available data, there are several limitations and items that could not be included in this study. These are listed below:

- The costs estimated in this study are limited to distribution interconnection upgrade costs, and do not include any costs related to integration of large amounts of variable generation at the bulk system level, such as ensuring adequacy of flexible resource and ensuring that operators have sufficient visibility of distributed generation to maintain a safe and reliable grid.
- Costs of upgrades to substation equipment and anything upstream of there have not been included in this study.

[65] This assumes that all daytime charging will happen at work, with 30% of EV owners exclusively charging at work and 30% sometimes charge at work.

- The costs estimated are only due to the generation to be added to the circuit in the two scenarios. It is possible that some mitigation (particularly re-conductoring) could be required for the utility to integrate the load on the building regardless of the PV penetration. These costs would be the same in both the trajectory scenario and the high DER scenario, and if they are present, they may be duplicated in the high DER scenario.

- Mitigation of technical violations due to fault current from inverter-based generation is not included in this study. While these costs are not negligible, their mitigation costs are significantly lower than for the technical criteria considered in Table 2-7 above. For example, where inverters can contribute enough short circuit current to de-sensitize a recloser, the cost for the required settings change would be around $2,500. As inverters contribute a comparatively small amount of short circuit current compared to other forms of generation, the exclusion of this technical criterion is not likely to have a major impact on the conclusions from this study.

- Circuit switching and flexibility has not been addressed in this study due to the increased complexity that it would require. One result of this is that re-conductoring is the only mitigation measure that could be considered in cases where thermal overloads occur. In reality, there is also the potential for switching circuit configurations so that the load on a section of one circuit can be switched to another with sufficient capacity. This would have the effect of reducing re-conductoring costs. A converse result is that it was not possible in this study to verify that existing flexibility would continue to be available with the addition of the new generation. In general, however, the ability to transfer load and generation between circuits is a low-cost mitigation measure for many technical violations. Incorporating this option in planning studies should generally increase the hosting capacity across a utility's distribution system and reduce mitigation costs for a given circuit.

- The size of the PV system per-home has been estimated based on the CEC IEPR forecast. While the value used is based on the best available estimations, no additional analysis or sensitivity study has been performed assuming a different value. This has no effect on the generation integration cost profiles for the representative circuits but would have an effect on the results of the extrapolation to the rest of the distribution system.

- Existing generation on the circuits is dispersed in the same manner as the new generation, in line with the two generation dispersal cases considered in this study, rather than being placed in its existing location. This is due to a lack of information on how the existing generation is dispersed. This is the cause of the large difference in the starting (2016) costs for each of the IOU's for the two generation dispersal cases. If locational data was available and could be included in the analysis 100% accurately, the two generation dispersal cases would have the same starting point. However, as with all other years considered in the study, it is assumed that the real generation dispersal condition lies somewhere between the two cases analysed.

- Energy storage costs are assumed in this study to be 100% allocated as distribution interconnection upgrade costs (where additional energy storage is required on top of that installed at the customer location), equivalent to assuming the utility would have to purchase and operate the energy storage system.

It is important to understand that this study is only a cost estimation, and no effort has been made here to quantify the benefits of any of the DER technologies studied (except with respect to their effect on the impact of PV generation, as is the case with energy storage). Also, as the study considers two 'bookend' scenarios it should be viewed in the context of how the different assumptions (e.g. all new generation lumped in a single location vs new generation spread out on a feeder) can impact the integration cost, rather than solid predictions of what those integration costs will be.

2.4 Step 3: Determine bulk system impacts for different levels of DERs

The impact of DER distribution on bulk investment costs is assessed by performing a long-term investment optimization. This investment optimization decides which power plants need to operate to satisfy the demand and decides whether or not to build new generation capacity. The decisions to dispatch and build power plants are made such to minimize overall system costs, which includes fuel and emission costs, fixed and variable operation and maintenance costs, investment costs and transmission costs. The optimization is performed by using the capacity expansion features of PLEXOS LT Plan.

The long-term investment optimization is performed in the following manner:

1. Split of the entire planning horizon into smaller sub-problems. The full modeling horizon of 2017-2026 is divided into eight steps with 2-year overlap: 2017 – 2020, 2018 – 2021, 2019 – 2022, 2020 – 2023, and 2023 – 2026.
2. For each month within this 3-year period, a residual load duration curve is constructed: the load minus variable renewable generation. The investment and dispatch decisions of dispatchable generation capacity (e.g. nuclear, coal-, gas-, bio-fueled power plants) is optimized for this load duration curve.
3. The calculation is repeated for each 3-year period step. Decisions made in the overlapping period can be re-considered (e.g. the year 2020) when performing the optimization for the next step.

The long-term investment optimization is performed for two cases:

1. Base case: 2016 LTPP with IEPR levels DERs
2. High DER case: High DER levels

The impact of DER is assessed by comparing the differences in generation and investment costs, emissions and transmission congestion.

2.4.1 Model set up

The impact of optimizing the DER location on the bulk system generation costs is assessed with a combination of generation investment optimization and unit commitment and economic dispatch optimization model developed in PLEXOS. The model consists of a detailed representation of the CAISO system and a high-level representation of the remaining WECC area. DNV GL modelled the non-CAISO balancing areas with a high-level representation to reduce the model complexity and thereby limiting the calculation times to realistic timescales. This reduction in detail of the non-CAISO regions, allows us to increase the detail of the calculation for the region of interest, which is the CAISO balancing area.

The detailed representation of the CAISO system is based on the 2016 LTPP model from CAISO. This model provides detailed list of power plants and their characteristics of the 2026 year. The power plants are modelled at the individual unit level. The new-build candidates for power generation are based on the data from the E3's RESOLVE model (9/19,2017). Several portfolios are distinguished: PG&E Bay, PG&E Valley, SCE and SDG&E.

The non-CAISO balancing areas are modelled at a higher aggregation level and based on the RESOLVE model. The RESOLVE model provides the development from 2016 to 2050. It distinguishes six zones: CAISO, BANC (Balancing Authority of Northern California), LADWP (Los Angeles Department of Water and Power), IID (Imperial Irrigation District), NW (Pacific Northwest) and SW (Desert Southwest). We used this zonal approach in the PLEXOS model. For the non-CAISO region, we assumed the developments of generation capacity, transmission capacity and demand as in the RESOLVE model. In this approach, the generation capacities are aggregated per technology-fuel combination per zone, for example an aggregated coal-plant for NW and one for SW. In addition, each generation block is modelled with an average heat rate and Variable Operations and Maintenance (VO&M) charge.

DNV GL used LTPP model as a base because of the details available. However, since CPUC uses RESOLVE in its LTPP proceeding, DNV GL updated the PLEXOS LTPP model to more closely resemble RESOLVE. The three areas of updates include: (1) modelling zones load; (2) renewable resources; (3) and transmission capacities.

The PLEXOS model captures the generation in detail to perform a production cost model, however the transmission modelling is simplified to capture inter-regional transfer limitations. It does not include a full transmission modelling which analyses base transmission thermal ratings and line outage contingencies otherwise referred to as N-1 contingencies. We recognize this is a limitation in our optimization; however, since PLEXOS model simulates WECC as a whole, the transmission modelling was simplified to achieve reasonable simulation run times. The model captures inter-zonal transfer limitations with the latest available data from WECC models, however, does not simulate a nodal system to capture intra-zonal or in other words within zone transmission limitations.

An important step was the reconciliation of the regions/zones used in the 2016 LTTP model and the RESOLVE model, resulting in the following categorization:

Table 2-9: Mapping of 2016 LTPP regions

Original (2016 LTPP) Region	DNV GL Region	Original (2016 LTPP) Region	DNV GL Region	Original (2016 LTPP) Region	DNV GL Region
AB (Canada)	NW	IPTV	NW	PSE	NW
BC (Canada)	NW	LDWP	LDWP	PSEI	NW
AESO	NW	LFD		SCE	CAISO
APS	SW	MAGIC VLY	SW	SCL	NW
AVA	NW	MT	NW	SDGE	CAISO
AZPS	SW	NEVP	SW	SMUD	NW
BCHA	NW	NM	SW	SPP	NW
BCTC	NW	NV	SW	SPPC	SW
BPA	NW	NWMT	NW	SRP	SW
BPAT	NW	NW	NW	TEP	SW
CFE	SW	PACE_ID	SW	TEPC	SW
CHPD	NW	PACE_UT	SW	TH_Malin	NW
CIPB	CAISO	PACE_WY	NW	TH_MEAD	SW
CIPV	CAISO	PACW	NW	TH_PV	SW
CISC	CAISO	PAID	NW	TIDC	BANC
CISD	CAISO	PAUT	SW	TPWR	NW
CO	NW	PAWY	NW	TREAS VLY	SW
DOPD	NW	PG&E_BAY	CAISO	UT	SW
EPE	SW	PG&E_VLY	CAISO	VEA	SW
FAR EAST	SW	PGE	CAISO	WACM	NW
GCPD	NW	PGN	NW	WALC	SW
IID	IID	PNM	SW	WAUW	NW
IPFE	NW	PSC	NW	WY	NW
IPMV	NW	PSCO	NW		

The load in the 2016 LTPP model is updated from the RESOLVE model as shown in the Table 2-10 below.

Table 2-10: Zonal load updates from RESOLVE

Zone	Item	Year	2016 LTPP model	RESOLVE
NW	Load (TWh)	2026	190.5	262.6
SW	Load (TWh)	2026	203.0	168.1
LDWP	Load (TWh)	2026	28.9	29.1
IID	Load (TWh)	2026	4.7	4.6
BANC	Load (TWh)	2026	21.1	19.9
CAISO	Load (TWh)	2026	252.1	258.3
CAISO	Peak load (GW)	2026	21.3	45.6

Due to minor growth in load, the ancillary service requirements were assumed to be the same as in the RESOLVE model for both cases. No changes were made to the reserve parameters.

Since the installed capacities in the 2016 LTPP model are only provided for the year 2026, an assumption has been made regarding the course of capacities. The deployment of the new renewable generation sources is linearly scaled with time (i.e. a cumulative 10%/yr) such that in 2026 the model contains the 100% value as originally in the LTPP model. The conventional generation capacity and existing renewable capacity has been assumed to remain constant throughout the period 2017-2026.

Transmission capacities between the different balancing areas are based on the RESOLVE model (for non-CAISO region) and the 2016 LTPP model (lines connected to or within CAISO region). Note that the CAISO region is modelled as four separated nodes (PG&E-Bay, PG&E-Valley, SCE and SDGE) which can be connected to other balancing areas independent of each other. Accordingly, cross-border transmission capacity is as follows:

Table 2-11: Transmission Lines assumptions

Transmission Line	From	To	Minimum (MW)	Maximum (MW)
SW_to_CAISO	SW	CAISO	-5,947	5,947
NW_to_CAISO	NW	CAISO	-3,946	5,111
LDWP_to_CAISO	LDWP	CAISO	-7,452	7,452
NW_to_LDWP	NW	LDWP	-3,100	3,220
SW_to_LDWP	SW	LDWP	-8,458	8,458
NW_to_SW	NW	SW	0	0
IID_to_CAISO	IID	CAISO	-5,741	5,741
BANC_to_CAISO	BANC	CAISO	-	10,785
IID_to_LDWP	IID	LDWP	0	0
SW_to_IID	SW	IID	-330	330
IID_to_BANC	IID	BANC	0	0
NW_to_BANC	NW	BANC	-1,225	1,600
SW_to_BANC	SW	BANC	0	0

Regarding the different generation technologies, the following properties have been assumed for VO&M charge and Heat Rate based on CAISO's 2016 LTPP model.

Table 2-12: Technology Assumptions

Technology	VO&M Charge (USD/MWh)	Heat Rate (BTU/kWh)
Nuclear	2	9659.9
Coal	3.31	7914.4
CCGT	1.4	6049.7
Peaker	1.4	9472.6
Biomass	3.31	11725.6
Geothermal	3.3	3412.1
Small Hydro	1	0
Solar	0[66]	0
Wind	1	0
Other	0	3412.1

Regarding the different fuels, the following values for the price and emission have been used (similar to the prices in the 2016 LTPP model):

Table 2-13: Fuel Assumptions

Fuel	Price ($/MMBTU)	Emission (lb/MMBTU)
Biomass	2.5	0
Natural gas	5	118
Coal	2	205
Geothermal	0	0
Uranium	0.89	0
Other	1	
Hydro	0	0
Solar	0	0
Wind	0	0

DER is modelled as subtraction from the load, that is fixed generation profile which cannot be adjusted during the bulk system optimization. The DER generation profiles are generated by DER-CAM under the customer cost-effectiveness optimization described above. For simplicity, the DER penetration is assumed

[66] The variable O&M for solar is low enough to round out to zero in the CAISO model.

to increase linearly with time. Since customers' voluntary investments in DER are not socialized in the ratepayers' pool, we decided to leave DER investment costs out of this model.[67]

3 RESULTS

3.1 Customer cost-effectiveness modelling

The following three tables in this section present DER capacities per IOU optimized at the building level through DER-CAM. We also show DER capacities at the utility level which were achieved by aggregating customer counts per feeder.

3.1.1 Pacific Gas & Electric Company

Table 3-1: PG&E building and utility level DER capacities

Building Type	Building Level			
	CHP (kW)	EV Battery Capacity (kW)	PV (kW)	Stationary Battery (kWh)
Full-Service Restaurant	-	13,526	154	172
Hospital	250	100,000	2,635	3,519
Large Hotel	75	100,000	840	947
Large Office	75	42,868	2,856	4,262
Medium Office	-	17,127	343	359
Midrise Apartment	-	5,690	98	148
Outpatient	75	36,403	491	435
Primary School	75	3,225	384	728
Quick Service Restaurant	-	6,148	84	249
Residential	-	271	3	8
Secondary School	325	7,490	1,344	2,198
Small Hotel	65	37,871	281	233
Small Office	-	1,757	24	61
Stand Alone Retail	-	61,386	300	197
Strip Mall	-	55,332	283	198
Supermarket	75	100,000	877	922
Warehouse	-	416	106	82
Industrial	-	12,992	85	

[67] We considered using the following investment costs for DERs: (1) Full capital and operation costs (2) distribution integration costs (3) incentives costs, and (4) no costs. After consultation with the CPUC, it was decided that we leave all DER investment costs out of the bulk system model.

3.1.2 Southern California Edison

Table 3-2: SCE building and utility level DER capacities

Building Type	Building Level			
	CHP (kW)	EV Battery Capacity (kW)	PV (kW)	Stationary Battery (kWh)
Full-Service Restaurant	-	13,526	113	166
Hospital	-	100,000	173	348
Large Hotel	400	100,000	173	348
Large Office	1,000	42,868	1,047	1,679
Medium Office	-	17,127	255	385
Midrise Apartment	-	5,690	78	156
Outpatient	75	36,403	346	350
Primary School	75	3,225	180	315
Quick Service Restaurant	-	6,148	66	97
Residential	-	271	2	5
Secondary School	700	7,490	115	845
Small Hotel	75	37,871	192	259
Small Office	-	1,757	20	24
Stand Alone Retail	-	61,386	320	263
Strip Mall	-	55,332	237	231
Supermarket	200	100,000	547	569
Warehouse	-	416	90	78
Industrial	-	12,992	71	-

3.1.3 San Diego Gas & Electric

Table 3-3: SDG&E building and utility level DER capacities

Building Type	Building Level			
	CHP (kW)	EV Battery Capacity (kW)	PV (kW)	Stationary Battery (kWh)
Full-Service Restaurant	65	13,526	111	103
Hospital	1,205	100,000	1,511	851
Large Hotel	400	100,000	540	330
Large Office	500	42,868	2,706	2,997
Medium Office	-	17,127	378	479
Midrise Apartment	-	5,690	100	184
Outpatient	150	36,403	411	270
Primary School	75	3,225	381	376
Quick Service Restaurant	-	6,148	98	159
Residential	-	271	3	8
Secondary School	500	7,490	524	1,077
Small Hotel	-	37,871	334	440
Small Office	-	1,757	35	35
Stand Alone Retail	-	61,386	347	247
Strip Mall	-	55,332	313	238
Supermarket	200	100,000	576	426
Warehouse	-	416	112	68
Industrial	-	12,992	165	165

3.2 Distribution integration cost and DER location optimization

3.2.1 Pacific Gas & Electric Company

DER Forecast

Table 3-4 below presents the forecasted growth in distributed PV generation, distributed energy storage and electric vehicles in 2017 and 2026 for the base case scenario.

Table 3-4: PG&E DER forecast

2017 PV Capacity (kW)	1,532,000
2026 PV Capacity (kW)	5,123,000
2017 ES Capacity (kW)	72,000
2026 ES Capacity (kW)	165,000
2017 EV Capacity (kW)	1,086,000
2026 EV Capacity (kW)	4,095,000

3.2.1.1 Integration Cost Results

In the forecast scenario, the results are calculated for the forecasted distribution of DER across the IOU distribution system.

Table 3-5 below presents the integration cost results for PG&E for 2017 and 2026 first without customer-sited energy storage, and then with customer-sited energy storage systems in the lumped dispersal case. These results show that the customer-sited energy storage systems have the potential to reduce the total integration cost in 2026 by 8%, and to reduce the incremental cost between 2017 and 2026 by 7% in the lumped dispersal case.

Table 3-5: PG&E grid integration cost results for the lumped dispersal case

2017 Grid Integration Costs without Customer-Sited ES	$ 361,640,000
2026 Grid Integration Costs without Customer-Sited ES	$ 1,900,100,000
Difference 2017-2026 without Customer-Sited ES	$ 1,538,460,000
2017 Grid Integration Costs with Customer-Sited ES	$ 328,200,000
2026 Grid Integration Costs with Customer-Sited ES	$ 1,756,660,000
Difference 2017-2026 with Customer-Sited ES	$ 1,428,460,000

Table 3-6 below presents the integration cost results for PG&E for 2017 and 2026 first without customer-sited energy storage, and then with customer-sited energy storage systems in the distributed dispersal case. These results show that the customer-sited energy storage systems have the potential to reduce the total integration cost in 2026 by 8%, and to reduce the incremental cost between 2017 and 2026 by 8% in the distributed dispersal case.

Table 3-6: PG&E grid integration cost results for the distributed dispersal case

2017 Grid Integration Costs without Customer-Sited ES	$ 22,230,000
2026 Grid Integration Costs without Customer-Sited ES	$ 111,310,000
Difference 2017-2026 without Customer-Sited ES	$ 89,080,000
2017 Grid Integration Costs with Customer-Sited ES	$ 20,660,000
2026 Grid Integration Costs with Customer-Sited ES	$ 102,610,000
Difference 2017-2026 with Customer-Sited ES	$ 81,950,000

Table 3-7 below presents the integration cost results for PG&E for 2017 and 2026 first without customer-sited energy storage, and then with customer-sited energy storage systems in the lumped dispersal case with smart inverters operational. These results show that the customer-sited energy storage systems have the potential to reduce the total integration cost in 2026 by 12%, and to reduce the incremental cost between 2017 and 2026 by 13% in the smart inverter study case.

Table 3-7: PG&E grid integration cost results for the smart inverter study

2017 Grid Integration Costs without Customer-Sited ES	$ 172,430,000
2026 Grid Integration Costs without Customer-Sited ES	$ 729,930,000
Difference 2017-2026 without Customer-Sited ES	$ 557,500,000
2017 Grid Integration Costs with Customer-Sited ES	$ 158,320,000
2026 Grid Integration Costs with Customer-Sited ES	$ 645,050,000
Difference 2017-2026 with Customer-Sited ES	$ 486,730,000

3.2.2 Southern California Edison

3.2.2.1 DER Forecast

Table 3-8 below presents the forecasted growth in distributed PV generation and distributed energy storage in 2017 and 2026 for the base case scenario.

Table 3-8: SCE DER forecast

2017 PV Capacity (kW)	1,209,000
2026 PV Capacity (kW)	4,865,000
2017 ES Capacity (kW)	121,000
2026 ES Capacity (kW)	365,000
2017 EV Capacity (kW)	1,393,000
2026 EV Capacity (kW)	5,164,000

3.2.2.2 Integration Cost Results

In the forecast scenario, the results are calculated for the forecasted distribution of DER across the IOU distribution system.

Table 3-9 below presents the integration cost results for SCE for 2017 and 2026 first without customer-sited energy storage, and then with customer-sited energy storage systems in the lumped dispersal case. These results show that the customer-sited energy storage systems have the potential to reduce the total integration cost in 2026 by 25%, and to reduce the incremental cost between 2017 and 2026 by 33% in the lumped dispersal case.

Table 3-9: SCE grid integration cost results for the lumped dispersal case

2017 Grid Integration Costs without Customer-Sited ES	$	73,300,000
2026 Grid Integration Costs without Customer-Sited ES	$	215,070,000
Difference 2017-2026 without Customer-Sited ES	$	141,770,000
2017 Grid Integration Costs with Customer-Sited ES	$	67,060,000
2026 Grid Integration Costs with Customer-Sited ES	$	161,580,000
Difference 2017-2026 with Customer-Sited ES	$	94,520,000

Table below presents the integration cost results for SCE for 2017 and 2026 first without customer-sited energy storage, and then with customer-sited energy storage systems in the distributed dispersal case. These results show that the customer-sited energy storage systems have the potential to reduce the total integration cost in 2026 by 8%, and to reduce the incremental cost between 2017 and 2026 by 7% in the distributed dispersal case.

Table 3-10: SCE grid integration cost results for the distributed dispersal case

2017 Grid Integration Costs without Customer-Sited ES	$	9,610,000
2026 Grid Integration Costs without Customer-Sited ES	$	49,390,000
Difference 2017-2026 without Customer-Sited ES	$	39,780,000
2017 Grid Integration Costs with Customer-Sited ES	$	8,210,000
2026 Grid Integration Costs with Customer-Sited ES	$	45,400,000
Difference 2017-2026 with Customer-Sited ES	$	37,190,000

Table 3-11 below presents the integration cost results for SCE for 2017 and 2026 first without customer-sited energy storage, and then with customer-sited energy storage systems in the lumped dispersal case with smart inverters operational. These results show that the customer-sited energy storage systems have the potential to reduce the total integration cost in 2026 by 9%, and to reduce the incremental cost between 2017 and 2026 by 11% in the smart inverter study case.

Table 3-11: SCE grid integration cost results for the smart inverter study

2017 Grid Integration Costs without Customer-Sited ES	$	44,750,000
2026 Grid Integration Costs without Customer-Sited ES	$	127,040,000
Difference 2017-2026 without Customer-Sited ES	$	82,290,000
2017 Grid Integration Costs with Customer-Sited ES	$	42,650,000
2026 Grid Integration Costs with Customer-Sited ES	$	116,050,000
Difference 2017-2026 with Customer-Sited ES	$	73,400,000

3.2.3 San Diego Gas & Electric

3.2.3.1 DER Forecast

Table 3-12 below presents the forecasted growth in distributed PV generation and distributed energy storage in 2017 and 2026 for the base case policy scenario.

Table 3-12: SDG&E DER forecast

2017 PV Capacity (kW)	292,000
2026 PV Capacity (kW)	1,053,000
2017 ES Capacity (kW)	41,000
2026 ES Capacity (kW)	77,000
2017 EV Capacity (kW)	176,000
2026 EV Capacity (kW)	629,000

3.2.3.2 Integration Cost Results

In the forecast scenario, the results are calculated for the forecasted distribution of DER across the IOU distribution system.

Table 3-13 below presents the integration cost results for SDG&E for 2017 and 2026 first without customer-sited energy storage, and then with customer-sited energy storage systems in the lumped dispersal case. These results show that the customer-sited energy storage systems have the potential to reduce the total integration cost in 2026 by 7%, and to reduce the incremental cost between 2017 and 2026 by 4% in the lumped dispersal case.

Table 3-13 SDG&E grid integration cost results for the lumped dispersal case

2017 Grid Integration Costs without Customer-Sited ES	$ 173,170,000
2026 Grid Integration Costs without Customer-Sited ES	$ 863,200,000
Difference 2017-2026 without Customer-Sited ES	$ 690,030,000
2017 Grid Integration Costs with Customer-Sited ES	$ 140,680,000
2026 Grid Integration Costs with Customer-Sited ES	$ 799,720,000
Difference 2017-2026 with Customer-Sited ES	$ 659,040,000

Table 3-14 below presents the integration cost results for SDG&E for 2017 and 2026 first without customer-sited energy storage, and then with customer-sited energy storage systems in the distributed dispersal case. These results show that the customer-sited energy storage systems have the potential to reduce the total integration cost in 2026 by 7%, and to reduce the incremental cost between 2017 and 2026 by 6% in the distributed dispersal case.

Table 3-14: SDG&E grid integration cost results for the distributed dispersal case

2017 Grid Integration Costs without Customer-Sited ES	$ 21,610,000
2026 Grid Integration Costs without Customer-Sited ES	$ 76,460,000
Difference 2017-2026 without Customer-Sited ES	$ 54,850,000
2017 Grid Integration Costs with Customer-Sited ES	$ 19,490,000
2026 Grid Integration Costs with Customer-Sited ES	$ 71,110,000
Difference 2017-2026 with Customer-Sited ES	$ 51,620,000

Table 3-15 below presents the integration cost results for SDG&E for 2017 and 2026 first without customer-sited energy storage, and then with customer-sited energy storage systems in the lumped dispersal case with smart inverters operational. These results show that the customer-sited energy storage systems have the potential to reduce the total integration cost in 2026 by 9%, and to reduce the incremental cost between 2017 and 2026 by 6% in the smart inverter study case.

Table 3-15: SDG&E grid integration cost results for the smart inverter study

2017 Grid Integration Costs without Customer-Sited ES	$ 43,700,000
2026 Grid Integration Costs without Customer-Sited ES	$ 290,110,000
Difference 2017-2026 without Customer-Sited ES	$ 246,420,000
2017 Grid Integration Costs with Customer-Sited ES	$ 33,290,000
2026 Grid Integration Costs with Customer-Sited ES	$ 265,020,000
Difference 2017-2026 with Customer-Sited ES	$ 231,730,000

3.2.4 Integration Cost Results – Optimized Base Scenarios

In these scenarios, the lumped dispersal case is re-studied with optimized distribution of DER with respect to hosting capacities on the feeders. Note that the lumped dispersal case is the worst-case scenario with respect to integration costs, so the values given for 2017 are likely higher than will be observed in reality.

In the first set of results ("IOUs Separated"), the same capacity of DER is maintained within each IOU as with the Forecast scenario above (i.e. DERs could be re-distributed from one feeder to another but must remain within their IOU). In the second set of results ("IOUs Combined"), the same capacity of DER is maintained across the three IOUs as with the Forecast scenario above, but the capacity within each IOU is allowed to change (i.e. DERs could be re-distributed from one feeder to another and from one IOU to another).

Table 3-16 below shows the results for the 'IOUs Separated' study. The results show that the incremental integration costs between 2017 and 2026 for PG&E and SCE can be reduced to zero, while the 2026 cost for SDG&E can be reduced by 74% from the forecast case. The reason for these results is that SCE and PG&E both have sufficient available hosting capacity across their system to accommodate the full capacity of PV forecast to be installed on their distribution circuits up to 2026, while SDG&E's available hosting capacity is less than their forecasted PV capacity.

Table 3-16: IOUs separated results

Utility	SDG&E	PG&E	SCE
Total 2017 hosting capacity (kW)	471,000	6,094,000	17,804,000
Total 2017 Available Capacity (kW)	309,000	4,935,000	16,867,000
PV to add to 2026 (kW)	761,000	3,591,000	3,656,000
ES to add to 2026 (kW)	36,000	93,000	244,000
Total 2017 Integration Cost	$ 173,170,000	$ 361,640,000	$ 73,300,000
Total 2026 Integration Cost	$ 424,760,000	$ 361,640,000	$ 73,300,000
Additional Integration Cost	$ 251,590,000	$ -	$ -

Table 3-17 below shows the results for the "IOUs combined" study. These results have a similar explanation to that above. The results demonstrate that there is sufficient available hosting capacity across the three IOUs' distribution circuits to accommodate all of the forecasted PV generation without any further grid integration costs, provided that it is distributed in the optimal manner.

Table 3-17: IOUs combined results

Utility	SDG&E	PG&E	SCE
Total 2017 hosting capacity (kW)	471,000	6,094,000	17,804,000
Total 2017 Available Capacity (kW)	309,000	4,935,000	16,867,000
PV to add to 2026 (kW)	761,000	3,591,000	3,656,000
ES to add to 2026 (kW)	36,000	93,000	244,000
Total 2017 Integration Cost	$ 173,170,000	$ 361,640,000	$ 73,300,000
Total 2026 Integration Cost	$ 173,170,000	$ 361,640,000	$ 73,300,000
Additional Integration Cost	$ -	$ -	$ -

3.2.5 Integration Cost Results - Maximum Cost-effective DER Scenario

A further study was carried out using a maximum cost-effective DER forecast. In this study a different set of assumptions was used for the DER forecast on the feeders. The results for all three IOUs in the lumped dispersal case are shown in

Table 3-18 and Table 3-19 below. These results demonstrate the savings that can be made in the presence of large amounts of energy storage. In these high DER cases, the energy storage added between 2017 and 2026 exceeds the amount of PV that is installed. The result of this is that all of the excess PV generation can be absorbed by the energy storage systems, preventing the possibility of any technical violations due to that generation.

Table 3-18: High DER scenario forecast

	SDG&E	PG&E	SCE
2017 PV Capacity (kW)	292,000	1,532,000	1,209,000
2026 PV Capacity (kW)	4,650,000	24,260,000	20,461,000
2017 ES Capacity (kW)	41,000	72,000	121,000
2026 ES Capacity (kW)	6,112,000	30,515,000	54,617,000
2017 EV Capacity (kW)	176,000	1,081,000	1,295,000
2026 EV Capacity (kW)	6,112,000	30,515,000	54,617,000

Table 3-19: Cost constrained scenario integration cost results

	SDG&E	PG&E	SCE
2017 Grid Integration Costs without Customer-Sited ES	$ 173,170,000	$ 361,640,000	$ 73,300,000
2026 Grid Integration Costs without Customer-Sited ES	$ 2,524,570,000	$ 10,598,650,000	$ 1,133,480,000
Difference 2017-2026 without Customer-Sited ES	$ 2,351,400,000	$ 10,237,010,000	$ 1,060,180,000
2017 Grid Integration Costs with Customer-Sited ES	$ 140,680,000	$ 328,200,000	$ 67,060,000
2026 Grid Integration Costs with Customer-Sited ES	$ 140,680,000	$ 328,200,000	$ 67,060,000
Difference 2017-2026 with Customer-Sited ES	$ -	$ -	$ -

3.3 Bulk system impacts for different levels of DER

The DER impact analysis consisted of performing a capacity expansion and dispatch optimization of bulk generation assets within the Western Electricity Coordinating Council (WECC) region with detailed focus on the CAISO region. Within this section, the impact of DER on the generation mix, the overall production costs and emissions was assessed by comparing the results from the optimization with a high DER level to the results of the simulations in the base trajectory case.

3.3.1 Impact of DER on the generation mix

Additional gas-fired capacity generation was added to the CAISO system to address load increases within the CAISO region, both for the scenario with and without increased DER. These were in both cases primarily flexible gas-turbine technology, with only a small fraction of the investments in combined-cycle power plants). The high DER scenario within CAISO avoids investments of 8 GW in gas-fired generation capacity, as can be seen in table 3-20 below.

Over the next few years, gas-fired Steam Turbine generators are set to retire throughout California, moreover, the projected LTTP load is set to grow at a modest pace. Due to these changes in load and capacity, additional Combined Cycle Generators are added to the simulations. Compared to the retiring gas-fired Steam Turbines, the modern Combined Cycle generation increases performance efficiency by more than 1/3. These modern generators have lower costs and emissions. Moreover, the newer technology has better ramping capabilities to follow load and compensate for variable energy resources.

Table 3-20: Impact of DER in generation capacity investments

	Base case	High DER	Difference
Additional gas-fired capacity	13.2 GW	5.2 GW	8 GW

Increasing the level of DERs to 5.2 GWs primarily reduces generation from gas-fired power plants within CAISO. The average level of electricity generation from gas-fired capacity decreases from 87 TWh/yr to 36 TWh/yr. Also, in the high DER case, there is decreased imports/ increased exports to the non-CAISO region.

For the base case gas-fired generation is the first choice to cost-effective reduce its generation. The (baseload) generation from nuclear and renewables have lower operation costs and therefore only reduce in generation if all available gas-fired generation is reduced to its minimum. (There is a gradual increase due to the increase in load, with a sudden drop in 2024 due to impact of developments outside the CAISO region (increase in imports from the NW region).[68]

[68] New cheaper units are built in 2024 in WECC so the model (which optimizes for costs) would pick the WECC units for production.

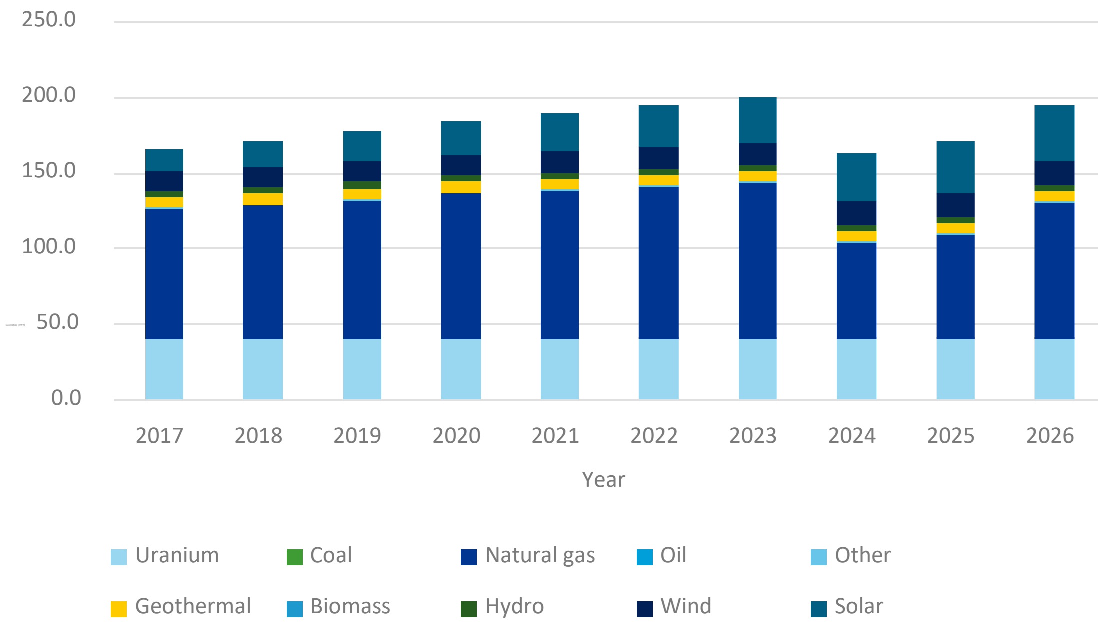

Figure 3-1: Electricity generation mix CAISO region in Base Case

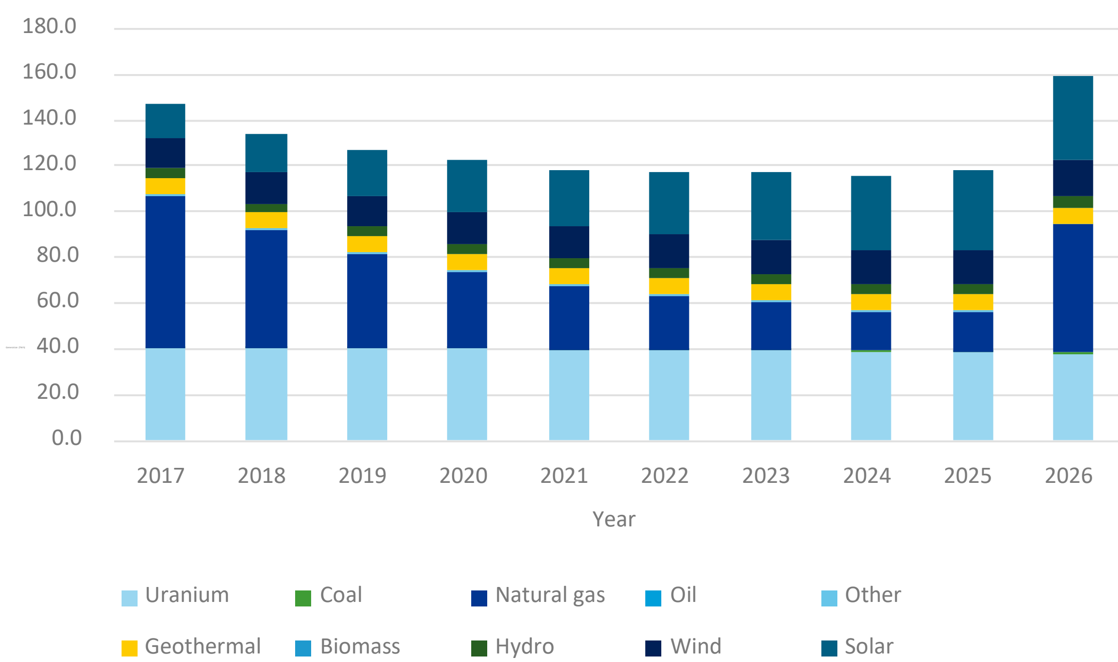

Figure 3-2: Electricity generation mix CAISO region in High DER case

Table 3-21: Electricity generation mix CAISO region in Base Case (values in TWh)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Uranium	40.0	40.0	40.0	40.2	40.0	40.0	40.0	40.2	40.0	40.0
Coal	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Natural gas	86.0	88.1	91.9	96.1	97.7	100.6	102.9	63.6	68.8	90.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.9	0.9	0.9	0.9	0.9	0.9	1.0	0.9	0.9	0.8
Geothermal	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.4
Wind	13.0	13.3	13.6	13.9	14.2	14.5	14.8	15.1	15.4	15.7
Solar	14.8	17.3	19.8	22.3	24.7	27.2	29.7	32.3	34.7	37.2
Storage	1.2	1.2	1.3	1.5	1.6	1.5	1.3	2.8	2.8	3.2

Table 3-22: Electricity generation mix CAISO region in High DER Case (values in TWh)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Uranium	40.0	40.0	39.9	39.9	39.5	39.4	39.2	38.9	38.7	38.0
Coal	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Natural gas	66.6	51.4	41.2	33.8	27.5	23.5	21.2	16.8	17.0	56.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.5
Geothermal	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	4.1	4.1	4.3	4.4	4.5	4.6	4.7	4.7	4.8	5.0
Wind	13.0	13.3	13.6	13.9	14.2	14.5	14.8	15.1	15.4	15.7
Solar	14.8	17.3	19.8	22.3	24.7	27.2	29.7	32.3	34.7	37.2
Storage	1.5	2.0	2.5	3.0	3.1	3.4	3.7	3.9	4.0	3.9
DER	*21.4*	*42.7*	*64.1*	*85.7*	*106.8*	*128.1*	*149.5*	*171.3*	*192.2*	*213.6*

3.3.2 Impact of DER on the production costs

The total costs in the high DER case are lower compared to the base case, which is the result of reduced investments in new gas-fired generation capacity as well as the resulting reduction in natural gas consumption and plant maintenance. The difference in investments in gas-fired generation capacity is around $1,000 million for the entire 10-year period.

The average annual reduction in production costs is $2,766 million/yr, leading to a cumulative difference of $27,662 million in favour of the high DER case. The largest reduction is observed in the year 2023, which is the result of the large difference in gas-fired generation between the base case and high DER case for that year.

Table 3-23: Sum of annual generation costs and annualized investment costs (M$)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base case	5,053	5,182	5,410	5,611	5,735	5,941	6,112	4,278	4,532	5,560
High DER	3,971	3,270	2,807	2,479	2,201	2,026	1,923	1,732	1,739	3,605
Difference	-1,082	-1,912	-2,603	-3,132	-3,534	-3,915	-4,189	-2,546	-2,793	-1,955

3.3.3 Impact of DER on emissions

There is an average annual decrease of 22 Mton/yr in CO_2 emissions. In several years, the emission reduction reaches (almost) 75% of the annual emissions in the Base Case. The emission reduction is due to the reduction in gas-fired generation. Note that the total amount of electricity generated in CAISO (including DER sources) is higher in the High DER case due to the lower net import position compared to the base case.

Table 3-24: Annual CO_2 emissions from bulk power generation within CAISO region (Mton)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base Case	37	38	40	42	42	44	45	28	30	40
High DER	29	23	18	15	13	11	10	8	9	25
Difference	-8	-15	-22	-27	-29	-33	-35	-20	-21	-15

3.3.4 Impact of DER on the transmission network

The additional DER in the High DER case changes the import/export balance of the CAISO region from a net importing region into a net exporting region. The reduction in load for the transmission network allows low-cost electricity from wind, solar and nuclear to be exported to other regions.

The study is limited to generators bidding at production costs, however in the CAISO market it has been observed at times that prices are dipping into negative territory. In hours of excess generation these episodes usually occur where non-cost-based market behaviour that drive negative pricing. The LTTP model sees reduced pricing during these hours of excess but will not dip into negative territory since cost-based bids are assumed.

This increase in export and the thereby associated increase in generation (including DER sources) lowers the impact of the additional DER on the production costs and the emission savings. If CAISO kept the same import/export balance (the same net importing position) as in the base case, the reduction of production costs and emissions would be greater.

Table 3-25: Net export of CAISO (negative means net importing) (TWh/yr)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base case	-49	-52	-54	-56	-60	-65	-70	-118	-119	-106
High DER	-47	-46	-41	-35	-27	-18	-8	0	11	53

ADDENDUM A: ELECTRIC VEHICLE CHARGING GRID INTEGRATION COST ANALYSIS

1 INTRODUCTION

As part of the Customer Distributed Energy Resources Grid Integration study (CDERGIS) project, DNV GL completed a study on integration costs of distributed energy resources (DERs) in California for 2026. When the DER study started in 2015, the forecast for electric vehicles (EVs) in California was low, so the distribution cost analysis focused only on on-site generation. However, as Governor Brown set a goal to increase EVs to 5 million by 2030, the EV forecast has significantly increased since then. As a result, the California Public Utilities Commission (CPUC) requested that DNV GL supplement the initial study on grid integration costs for solar with a study on grid integration costs for EV charging. This addendum describes the methodology, results and conclusions from this additional study.

The objective of this study is to establish grid integration costs for various capacities of EV charging stations on different types of circuits in California. DNV GL used Synergi Electric software to analyze the costs of integrating EVs on a representative feeder basis. The study was carried out for the 75 representative circuits in California, and grid integration cost profiles were produced for each of these circuits for incremental EV capacities.

2 METHODOLOGY

DNV GL used Synergi Electric[69] software to analyze the costs of integrating EVs. Synergi Electric simulates load flow of each feeder and identify technical violations that may occur as EV load increases. The integration costs are calculated by adding up the costs of implementing mitigation measures that are needed to maintain reliability.

In general, EVs are treated as an additional uncontrolled load in this study. The following assumptions follow from this:

- EV charging load could be maximized at any time, so it is added to the existing peak load condition, consistent with principles used in planning studies;
- EV charging is assumed to be non-coincident with any PV output on the circuit, so all distributed generation is assumed to be off for these studies. This is based on the typical load curve for utilities in California and is consistent with utility planning practices. As a load, the worst case in terms of circuit loading and voltage drop is when charging occurs during peak load. In California, the peak load is typically in the evening, when local PV generation may have little or no output;
- EVs are assumed to be operating as a load on the circuit only, no studies are undertaken considering EVs as energy storage devices for the grid.

Adding load to a circuit typically causes thermal loading problems first, with potential low voltage problems at higher loads. If re-conductoring is carried out, it can also mitigate the low voltage problems to some extent as the larger conductors have lower impedance and therefore induce a smaller voltage drop on the circuit.

[69] A widely used electric distribution system power flow modeling tool available from DNV GL. https://www.dnvgl.com/services/power-distribution-system-and-electrical-simulation-software-synergi-electric-5005

DNV GL studied 75 representative circuits across the three Investor Owned Utilities (IOUs).[70] For each circuit, the EV load was placed on the three-phase section which was electrically furthest from the substation. The EV load was increased incrementally from zero to 100% of the circuit's peak load and added to the circuit's peak load case. Using this range of capacities, with reference to the circuit peak load, provides some confidence that the study will find the limitations and upgrade costs for reasonably likely EV capacities on a given circuit.

The study does not make any prediction of the actual EV capacity that would be installed on each circuit, the type of EV or the type of charger. For each EV capacity studied, a load flow analysis was carried out.

The results of these analyses were compared against technical criteria – in this case, thermal loading and static voltage criteria:

- **Thermal loading:** the load on a section must not exceed 100% of the section's continuous rating; and
- **Static voltage:** the voltage on a section must be within ±5% of the nominal voltage. Voltage is studied only at the primary level.

Where one of the technical criteria is found to be exceeded for a given EV capacity, appropriate mitigation measures are identified and studied to verify their effectiveness. Costs are calculated for effective mitigation measures, and these are used to produce the grid integration cost curve for each circuit in the study. Note that this study only considers costs on the primary distribution circuits due to the information available on the representative circuits. Secondary, substation and transmission upgrade costs are not included in these results. The mitigation measures used in the study are shown below.

Table A-1 Mitigation measures and assumed costs

Technical Limit	Mitigation Measure	Cost
Static Voltage (low voltage violation)	Capacitor bank	$45,500[71]
Thermal Loading	Re-conductoring	$190/ft (average of overhead and underground re-conductoring costs)[60]
Thermal Loading	Energy storage	$460/kW + $450/kWh + $1500/100kW for installation. Assume 4 hours of storage required

In addition to the above mitigations, charging stations will likely require new distribution transformers to be added to the circuit, or upgrades to existing transformers. If several customers on the same distribution transformer all add chargers to their homes or businesses, distribution transformers may also have to be upgraded to cope with the increased load. At the transmission level, transformers may have to be upgraded if the load exceeds their rating.

In these curves, there is assumed to be no additional PV generation on the same circuit.[72] In these cases, where there are mitigation measures that were identified from the PV impact studies which would also provide mitigation for the EV capacity, no additional grid integration costs would be added for the EV capacity. The intention here is to prevent double counting of grid integration costs where there are co-located PV and EV facilities.

The assumptions used in this study are conservative, and as such the results should be considered as a 'High EV Impact,' and a worst-case scenario. These results therefore represent the maximum possible integration costs and are higher than what would actually be expected for real grid integration costs. There are some potential measures which could be taken, or alternative assumptions made regarding EV impact for an alternative scenario. For example, a 'Low EV Impact,' best case scenario could be established which would include the following:

- Full-scale smart charging incorporating Time of Use (TOU) rates which would ensure that the full EV charging load is not coincident with the circuit peak load. This would have the effect of increasing the EV load which can be added to a circuit before any upgrades are required, and reduce the upgrade costs for a given EV penetration;
- Assuming some coincidence between EV charging and PV generation output. If EV and PV facilities are assumed to be co-located, PV generation could be consumed by EV charging behind the meter, limiting the net export or net load on the primary and secondary distribution circuits. Similar to the measure above, this would have the effect of increasing the EV load which can be added to a circuit before upgrades are required and reduce the upgrade costs for a given EV penetration.

3 RESULTS

The integration cost profiles were plotted for the representative feeders with EV capacities from zero to 100% of circuit peak load. The results in general demonstrate three principal outcomes:

1) Circuits with a larger margin between their peak load and circuit rating are less likely to require mitigation. This is because the worst case involves adding the EV capacity to the circuit peak load. Once the summed load exceeds the rating of conductors or other equipment on the circuit, mitigation (likely re-conductoring) will be necessary;
2) Shorter circuits are likely to have lower mitigation costs if equipment ratings are exceeded. This is because there is a shorter distance between the substation and the EV facility which limits the re-conductoring cost;
3) Circuits which have conductors with lower impedance are less likely to exhibit low voltage problems at higher EV charging capacities. This is because voltage drop is reduced with reduced impedance.

These conclusions also suggest that placing the EV facility close to the substation would minimize grid integration costs as voltage drop is minimized, and any re-conductoring required would be limited to the distance between the substation and the EV charging facility.

Full results for all of the representative circuits are shown in the figures below. For each IOU two graphs are presented. One graphic illustrates the integration costs for each circuit with EV capacity presented as a function of circuit peak load, and the second graphic illustrates the integration costs for each circuit with EV capacity in kW. In each curve, there are a series of steps in integration cost as the EV capacity increases. The steps occur as more sections of the circuit become overloaded. For example, there may be 0.5 mile of overloaded line when the EV capacity is at 500 kW, then when the EV capacity is increased to 1 MW another 0.5 miles may be overloaded, resulting in a total of 1 mile to be re-conductored.

In general, the circuits with higher costs have conductors with longer lengths and pre-existing high utilization. For reference, utilization is the fraction of their capacity that is being used such as a line with a rating of 1 MW which has 750 kW of load on it would have a utilization of 75%. In these cases, a small increase in load due to EV charging can cause long lengths of lines to have utilization values over 100%, which would trigger mitigation costs.

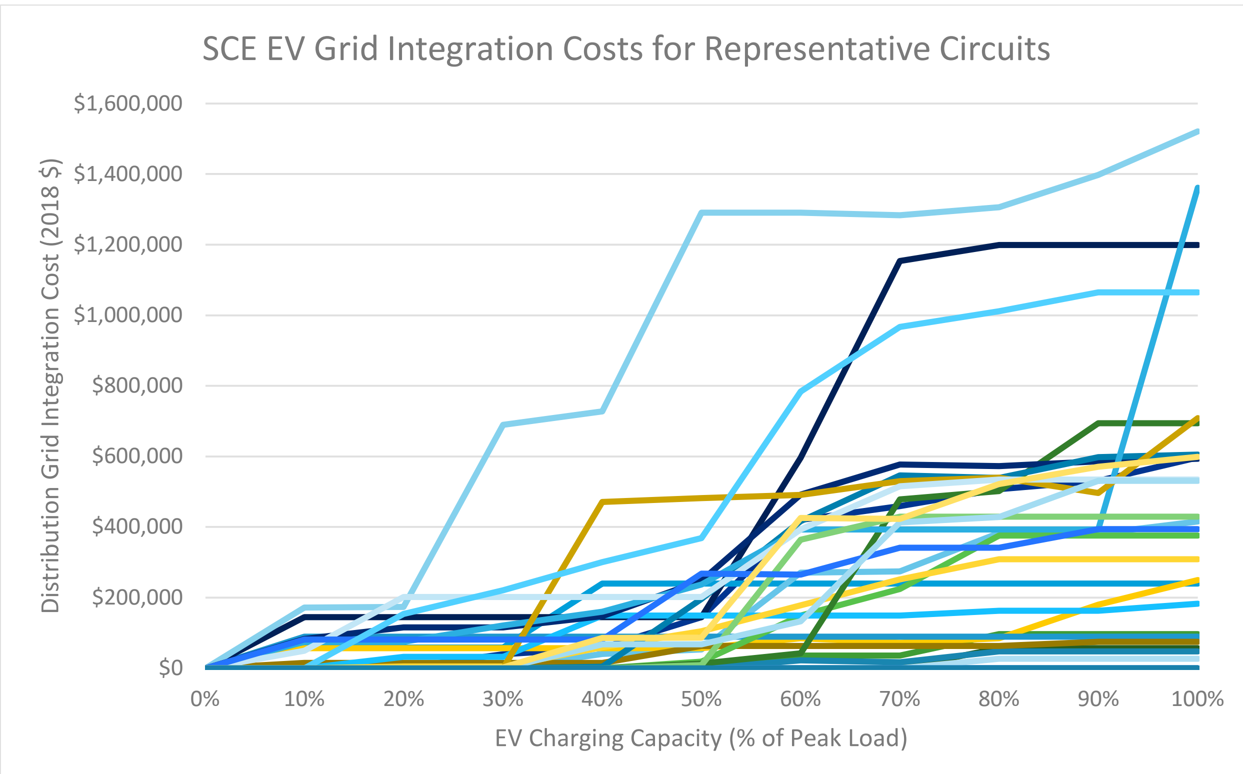

Figure A-1 SCE EV Grid Integration Cost (EV capacity as % of peak load)

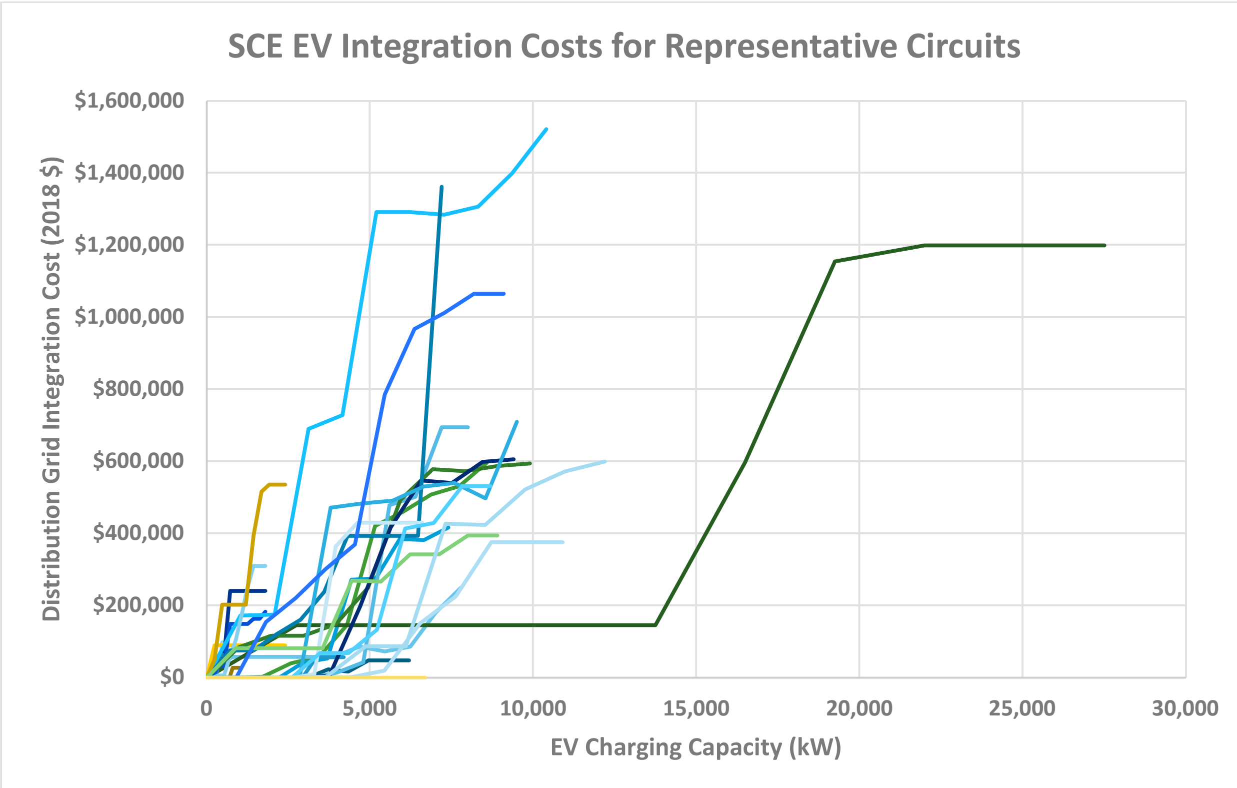

Figure A-2 SCE EV Grid Integration Cost (EV capacity in kW)

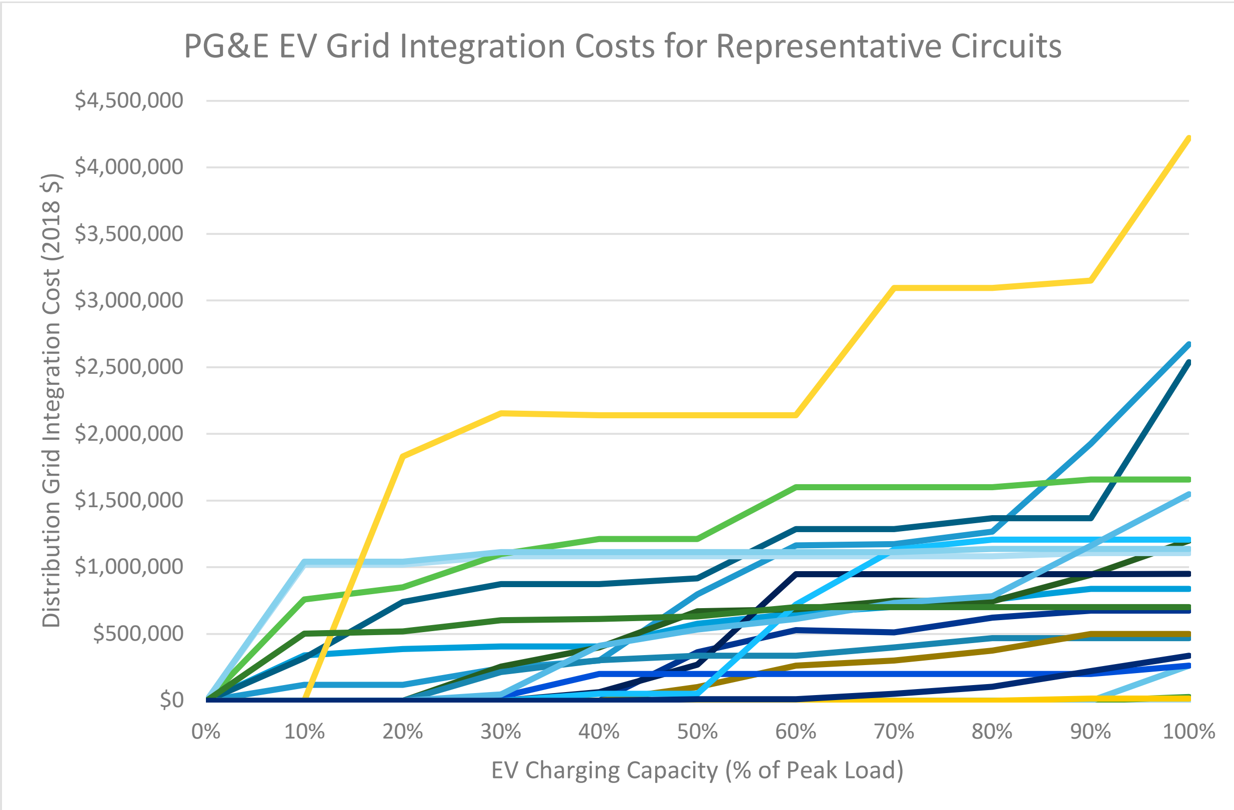

Figure A-3 PG&E EV Grid Integration Cost (EV capacity as % of peak load)

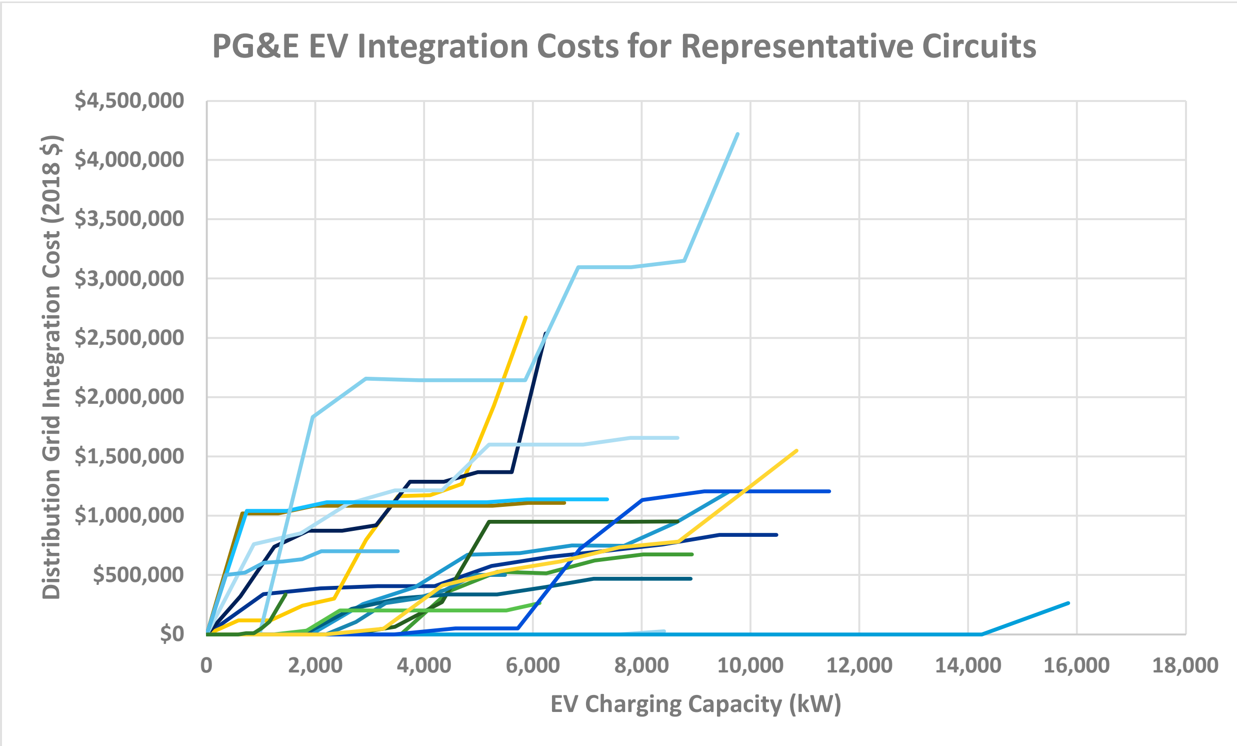

Figure A-4 PG&E EV Grid Integration Cost (EV capacity in kW)

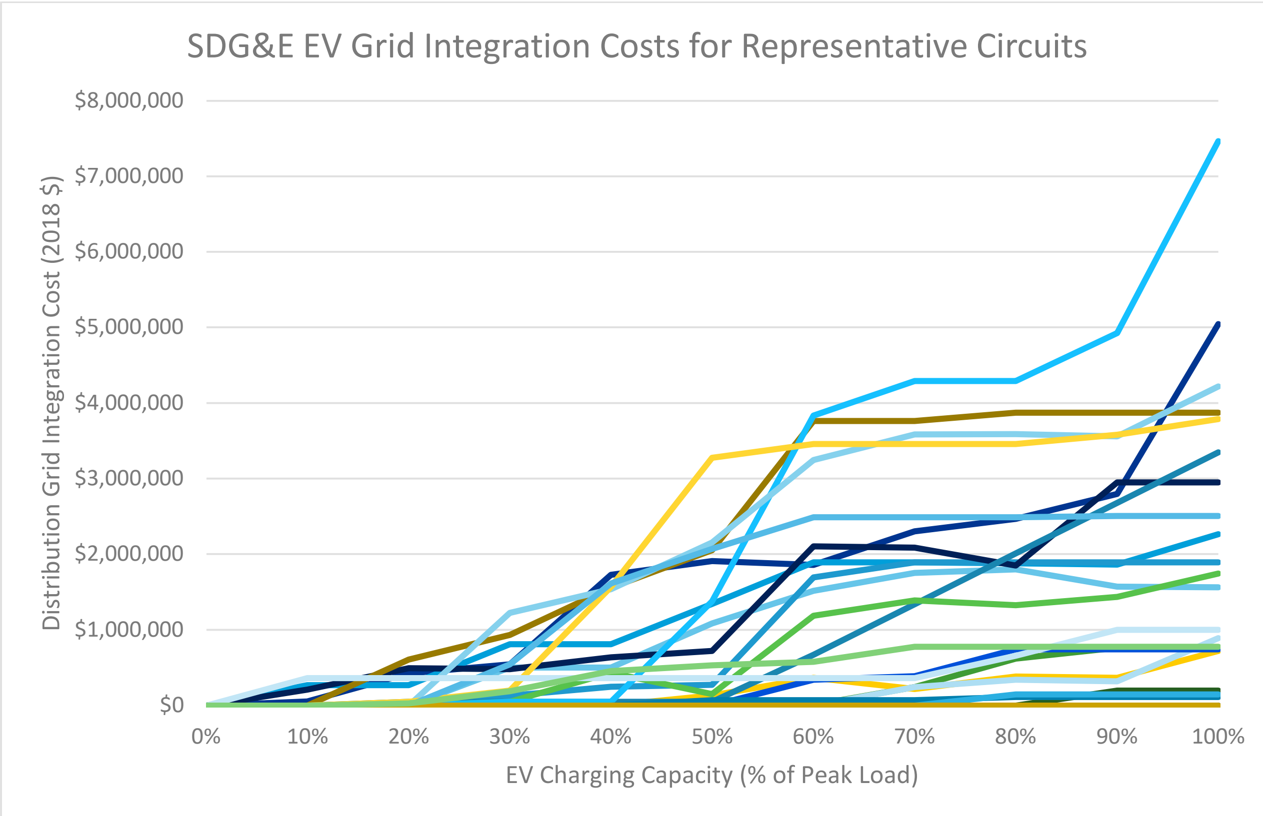

Figure A-5 SDG&E EV Grid Integration Cost (EV capacity as % of peak load)

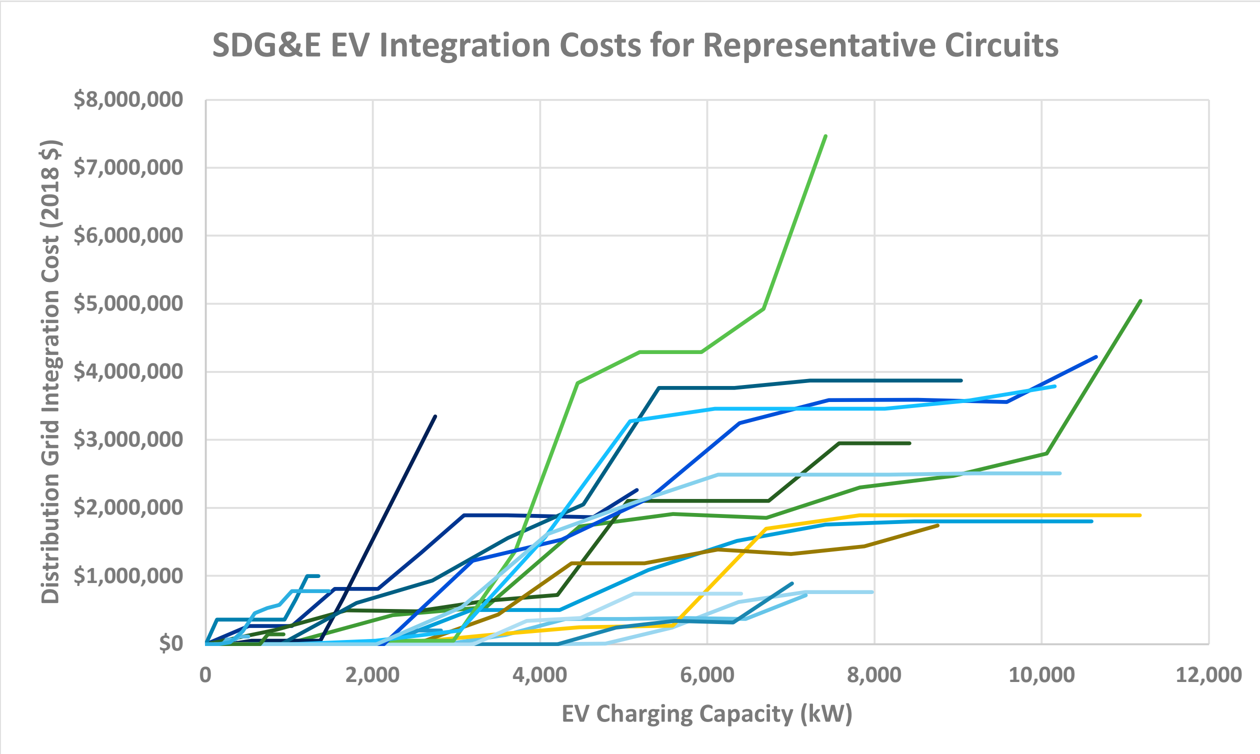

Figure A-6 SDG&E EV Grid Integration Cost (EV capacity in kW)

3.1 Regulatory implication for California

Based on the results above, DNV GL made the following observations about regulatory implications:

- **High EV penetration will not affect grid reliability**. EV charging increases load on a circuit, and the mitigation measures for load addition are well understood. If planning studies are conducted properly (with variability due to the uncertainty in drivers' charging behaviors accounted for), high EV penetration should not affect grid reliability. Perhaps the main difference between EV load and traditional load is that EV load (due to its mobility) is less predictable.
- **Tariffs design coupled with smart, utility-integrated EV supply equipment can help minimize EV integration cost.** Tariff design can disincentivize EV customers to charge during circuit peaks. Smart, utility-integrated electric vehicle supply equipment (EVSE) utilized as a dispatchable load, can help minimize EV integration by moving charging load off-peak in real-time. In addition, it can balance EV charging load in EV-dense neighborhoods to reduce needs for local transmission and distribution system upgrades
- **EV has the potential to help integrate PV.** Since the effects of co-located EV charging and PV generation could cancel each other out (if EV charging could be incentivized to reliably occur during times of high PV output), EV has the potential to reduce PV integration costs as well. Tariff design should aim to incentivize EVs to charge during PV generation. Smart utility infrastructure integrated with smart EV supply equipment can help match load with renewables, especially when renewable supply is at its peak.

- **High EV has the potential to reduce or increase emission**. On the bulk system scale, high EV penetration can help mitigate the “duck curve” phenomenon. During the times when there is an oversupply of renewable energy (“belly of the duck”), EVs have the potential to absorb the excess clean energy. In this scenario, EVs do not contribute to additional emission from the power supply while eliminating emissions from traditional transportation fuel. Conversely, if EVs charge during peak hours, it may require utilities to purchase more generation capacity and therefore increase emissions. In California, since the peak is in the evening, PVs will not contribute significantly to this maximum generation capacity, so it is important to incentivize daytime charging.
- **Energy storage can help integrate EVs**. Based on the points above, the time of charging is important. Therefore, storage has the potential to integrate EVs by shifting charging times from peak to non-peak hours. If there is utility-side storage on the circuit for some other purpose, it can help reduce peak and EV integration costs. Also, if a customer has on-site storage and it is optimized for bill reduction (especially under tariffs that penalize charging during circuit or system peak), then it can mitigate some of the EV integration costs. However, the utility may not have visibility or control over their customer’s storage operations, so it is unclear how utilities could plan for the storage’s contribution.
- **Participation of disadvantaged communities in transportation electrification can affect cost optimization**. Disadvantaged communities tend to be in industrial areas where there is high penetration of heavy-duty vehicles. Electrification of these vehicles would improve air quality in these communities but may affect EV integration cost minimization. Additional study needs to be conducted to identify the types of feeders disadvantaged communities tend to be on to determine whether it is least-cost to electrify transportation in these communities.
- **Equity Concern.** Similar to the PV interconnection debate, upgrade costs related to EV charging station are rate-based and socialized across all ratepayers. Since EV owners tend to be more wealthy than non-EV owners,[73] a high penetration of EVs may create a situation where poorer non-EV ratepayers could be subsidizing wealthier EV owners through their electricity bill. However, some studies have shown that the penetration of EVs could be beneficial for all ratepayers, especially in the near-term where minimal transmission and distribution upgrades are needed. [74]

About DNV GL

Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 14,000 professionals are dedicated to helping our customers make the world safer, smarter, and greener.