Residential Zero Net Energy Building Integration Cost Analysis

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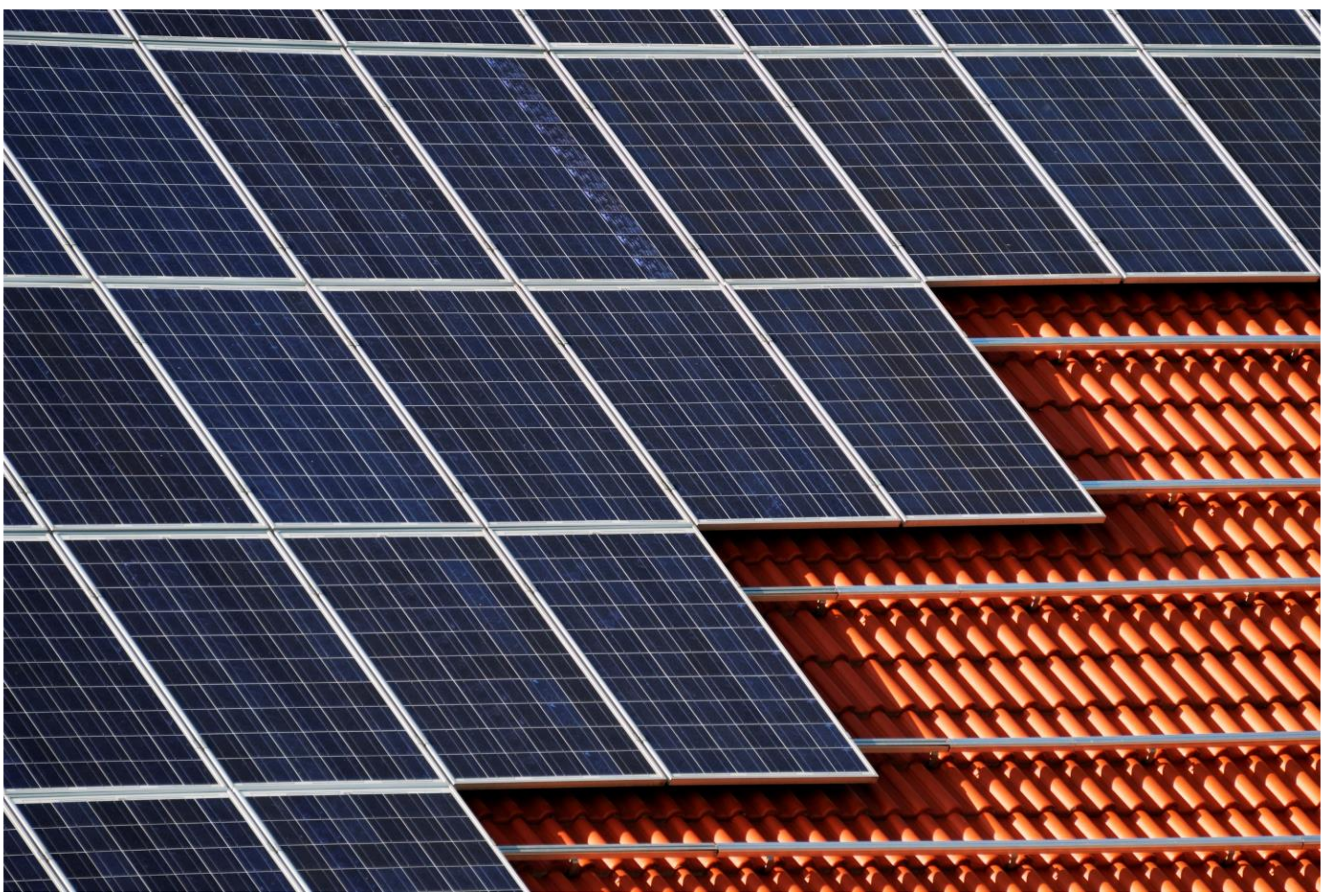

Legislative Report on Residential Zero Net Energy Building Integration Cost Analysis

California Public Utilities Commission

Prepared for:
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Abbreviation	Meaning
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DNV GL	KEMA Inc. (DNV GL)
GIS	Geographic Information System
GW	GigaWatts
IEPR	Integrated Energy Policy Report
kW	KiloWatts
LTC	Load Tap Changer
PG&E	Pacific Gas and Electric Company
PV	Solar photovoltaics
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
ZNE	Zero net energy

FOREWORD

By CPUC's Energy Division

Introduction to Residential Zero Net Energy Building Integration Cost Analysis

Assembly Bill (AB) 578 (Blakeslee, 2008) requires 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.[1]

In 2013, the CPUC contracted Black & Veatch to prepare the "Biennial Report on Impacts of Distributed Generation" and Itron to prepare an Impact Evaluation of CPUC's Self Generation Incentive Program (SGIP). In 2015, since the CPUC did not expect the major conclusions from these reports to have changed over the two years, Energy Division staff directed KEMA, Inc. (DNV-GL) to specifically examine how customer behind-the-meter (BTM) solar photovoltaic (PV) impacts net-load patterns. DNV GL prepared an "Impact of Distribution Energy Generation on the State's Distribution and Transmission Grid" report and the CPUC submitted it to the legislature on January 1, 2016. This study is part of a larger project mandated by AB 578. It focuses on PV distribution grid integration costs under different scenarios.

As the price of solar photovoltaic systems has decreased over the last 10 years, the cost-effectiveness to an individual homeowner of installing PV has dramatically increased. Under the primary cost effectiveness test used by the California Energy Commission (CEC) to consider new building efficiency standards, the increased cost-effectiveness of PV to the homeowner could soon justify new residential building standards that require PV installation. However, grid integration costs for PV under 1 MW, currently paid for by all ratepayers per CPUC Net Energy Metering (NEM) policy, are not accounted for in the CEC's test.

Currently, the costs of upgrading the electrical distribution system to accommodate PV integration, at present levels, are known and relatively modest.[2] To better understand the grid integration costs[3] associated with higher penetrations of PV, the Energy Division requested a DNV GL study to examine the PV distribution grid integration costs of a residential Zero Net Energy (ZNE) policy of 100% ZNE by 2020 compared to the residential PV trajectory scenario. The study covers the period from 2016—2025 and was conducted for two primary objectives:

1. To inform both the CPUC and CEC on grid integration costs of achieving residential ZNE policy[4]; and
2. To inform the CPUC on grid integration costs of continuing the current NEM policy in which grid upgrade costs of NEM systems under 1 MW are paid for by all ratepayers.

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[1] Public Utilities Code Section 321.7(a)(1).
[2] NEM interconnection costs reports, most recently: PG&E Advice Letter 4918-E; SDG&E Advice Letter 2984-E; SCE Advice Letter 3473-E.
[3] In the context of this report, grid integration costs mean distribution interconnection and upgrade costs. They do not include any bulk system costs associated with integrating variable energy resources and addressing renewables oversupply conditions.
[4] Table 0-3, Table 0-4 and Table 0-5 on pages xix and xx provide the grid integration costs per ratepayer for new PV integration from 2016 to 2026 for each of the study cases (high cost case, smart inverter sensitivity and low cost case) with and without the ZNE policy in place.

The 1st study focus can inform CEC's consideration of ZNE Title 24 Building Code policy. The 2nd study focus can inform the next CPUC NEM policy revisit, anticipated for 2019, as well as several related CPUC policy areas relating to smart inverters Rule 21 interconnection, and distributed resource planning.

Highlights of Study Findings

Integration costs (from 2016-2025) were established for three cases with 100% residential ZNE by 2020:

- **High Cost Case:** PV is lumped together at the end of a feeder. (A worst case condition)
    - **$2.35 bb cost for all 3 IOUs**
- **Smart Inverter Sensitivity Case:** Smart Inverters are switched to "reactive power priority" to help mitigate some of the grid integration costs.
    - **$915 mm cost for all 3 IOUs**
- **Low Cost Case:** PV is distributed throughout a feeder (A best case condition)
    - **$196 mm cost for all 3 IOUs**

The Study examines only the costs of integrating distributed PV; therefore, it did not attempt to quantify the deferral value of PV installations or any other benefits. Further analysis would be needed to expand the findings in this Study into a comprehensive cost-effectiveness analysis.

The Study found that:

- Changing smart inverters' volt/var setting from the current setting of "real power priority" to "reactive power priority" would reduce the high cost case significantly (saving $1,435,000, an over 60% reduction in costs for all three IOUs).
- Distributing the PV throughout the feeder (low cost case) had a dramatic effect on reducing the integration costs compared to lumping all PV at the end of a feeder (high cost case). In actuality the PV will distributed somewhere between the high and low cost case.
- Mitigation costs vary greatly by utility, with the estimate for Pacific Gas and Electric Company (PG&E) being the highest, Southern California Edison Company (SCE) being the lowest, and San Diego Gas & Electric Company (SDG&E) falling in between. The factors that lead to these differences include:
    - The ratio of PV installations to feeders. PG&E's distribution system has fewer feeders (2,821), to accommodate the PV systems, while SCE has a greater number of feeders (5,687), each servicing fewer homes.
    - The length of the feeders, with PG&E's generally being the longest, and SCE's the shortest.
    - SCE's feeders have a higher hosting capacity (capacity available before any upgrades are likely required) due to current lower penetration levels of PV on their system.

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

1. Integration costs of high penetration PV, whether driven by ZNE policy or NEM policy alone, can be high if not mitigated. However, mitigation measures are available that can dramatically reduce the grid upgrade costs to more reasonable and possibly absorbable levels. These measures include:

- **Smart inverters.** The CPUC should update smart inverter settings to mitigate high PV integration costs, whether due to Title 24 requirement or NEM policy. Other jurisdictions such as Europe and Hawaii have already taken this step through the adoption of "reactive power priority" as the default Volt /Var setting of smart inverters. In December 2017, the IOUs filed advice letters at the CPUC with proposals to require "reactive power priority" for smart inverters.[5] The CPUC is expected to reach its disposition on these Advice Letters in early 2018.
- **Optimal location.** The IOUs' Integration Capacity Analysis (ICA) tool, approved in the Distribution Resource Plans (DRP) proceeding[6]and in the process of being implemented, will be very helpful to indicate optimal locations for ZNE buildings and high penetrations of PV to minimize the grid integration costs. These data could be leveraged in development for future NEM policy.

2. In the high cost case a large part of the grid integration costs is due to assumed energy storage requirements. However, in some cases, customer or homebuilder installations of storage for other purposes, such as demand charge mitigation and time-of-use (TOU) bill management, may be able to provide the necessary grid integration services at little additional cost. This depends on whether the storage systems have sufficient capacity and the dispatch requirements needed to avoid the grid upgrades are compatible with the storage devices' existing purposes.
3. The CPUC should continue to examine how the interplay of interconnection policy, ICA results, smart inverter settings, and the role of energy storage can seek to minimize the grid integration costs of high penetrations of PV.

History and Background of ZNE Policy

In 2007, California faced a much different policy landscape than it currently does. The state's landmark greenhouse gas reduction law, AB 32 (Nunez, 2006), had just passed, while residential solar PV prices were at about $9 per watt, compared with less than $3 in 2016.[7] In 2007, the CPUC approved the "Big Bold Goals," which included a goal that all new residential buildings would be zero net energy by 2020.[8] This was done out of recognition that taking full advantage of energy efficiency potential in California would require integrating energy efficiency with other demand-side customer offerings, like solar PV. The CEC subsequently adopted the same goal in the 2017 Integrated Energy Policy Report (IEPR).

The Big Bold Goals were published in the *California Long Term Energy Efficiency Strategic Plan,* approved by the CPUC in 2008. As the ZNE goals never became law, they remained "aspirational." Yet, they have inspired a strong movement towards ultra-high-efficiency buildings and voluntary ZNE adoption in the new home market and through progressive building code updates. In this vein, CPUC and CEC have facilitated an on-going dialogue between utilities, homebuilders, architects, and other state agencies. The joint staff *Residential ZNE Action Plan* 2015-2020 embodies the panoply of activities underway to coordinate these

[5] Advice Letters 5210-E (PG&E), 3723-E (SCE) and 3169-E (SDG&E) - Proposed Modifications to Electric Tariff Rule 21 to Incorporate Reactive Power Priority Setting of Smart Inverters, December 29, 2017.
[6] Rulemaking (R.) 14-08-013
[7] http://www.nrel.gov/news/press/2016/37745; http://www.nrel.gov/docs/fy14osti/62558.pdf
[8] CPUC Decision (D.) 07-10-032.

efforts. It states that the "the upcoming triennial update cycles (2016 and 2019 standards) will need to address ZNE in response to the policy goals for 2020."[9]

Following this direction, the CEC has been moving the California Title 24 building code towards ZNE and mandating greater efficiency requirements. Recent legislation further supports this drive towards greater efficiency. For example, Senate Bill (SB) 350 (De Leon, 2015) requires the state to double energy efficiency by 2030.

In the CEC's 2019 residential code update, the possibility of requiring PV installation has come into focus, as dramatically lower solar prices have changed the economics of residential solar ownership. Because of this, the CPUC's aspirational goal adopted in 2007 is poised to become a reality.

History and Background of Net Energy Metering Policy

The main policy currently driving residential solar installations in California is Net Energy Metering. Under NEM rules, eligible renewable customer-generators may serve their onsite energy needs directly and get a bill credit at their full retail rate[10] for the excess generation that is exported to the grid. Put simply, over a 12-month period, the customer pays for the net amount of electricity used from the grid over-and-above the amount of electricity generated by their solar system.[11]

As a policy matter, one of the benefits NEM customers have historically received is an exemption from paying any costs associated with interconnecting their system to the grid. These costs have historically been socialized among all ratepayers. In January 2016, the CPUC adopted a NEM successor tariff policy that now requires NEM customers with systems smaller than 1 megawatt (MW) to pay a small one-time interconnection fee to cover a limited set of interconnection-related charges, but they are exempt from paying grid upgrade costs. NEM customers with systems larger than 1 MW are required to pay all associated interconnection costs, including grid upgrade costs.

Under current NEM policy, the grid upgrade costs associated with interconnecting systems smaller than 1 MW are socialized across all ratepayers. The most recent accounting of socialized grid upgrade costs associated with these projects reported an annual cost from July 2015 to June 2016 of approximately $25.6 million.[12] That amounts to about $2.65 for each ratepayer served by California's investor owned utilities. This report examines the costs of maintaining distribution grid reliability under two scenarios: (1) a trajectory scenario, driven mainly by NEM policy alone, and (2) a ZNE scenario, wherein even higher levels of PV adoption are driven by a policy requiring 100% of newly built homes to install solar PV.

In 2019, the CPUC will revisit NEM policy, which coincides with the roll out of new time-of-use rates. The CPUC will consider adjustments to the tariff and compensation structure for renewable distributed generation systems that include an export-compensation rate for customers that takes into account locational and time-differentiated values.[13]

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[9] "New Residential Zero Net Energy Action Plan," page 20. Available at: http://www.cpuc.ca.gov/General.aspx?id=4125. This joint staff plan was co-authored by the Efficiency Division of the CEC and the Energy Division of the CPUC.
[10] With the exception that, under the NEM successor tariff, NEM participants must pay certain non-bypassable charges.
[11] http://www.gosolarcalifornia.ca.gov/solar_basics/net_metering.php
[12] PG&E Advice Letter 4918-E; SDG&E Advice Letter 2984-E; SCE Advice Letter 3473-3.
[13] CPUC Decision 16-01-044, page 19.

Cost-Effectiveness

A challenge in analyzing the findings of this Study is reconciling the different cost-effectiveness methods each state agency employs. The CPUC employs a suite of cost-effectiveness tests set forth in the Standard Practice Manual.[14] For energy efficiency programs, current CPUC policy prescribes the Total Resource Cost (TRC) and Program Administrator Cost (PAC) tests as the principal tests. The TRC methodology estimates avoided marginal cost savings. In compliance with AB 2514 (Bradford, 2013), the CPUC assessed the cost-effectiveness of NEM using the Ratepayer Impact Measure (RIM) test, which represents the perspective of non-participating customers. Although the RIM test was evaluated in the CPUC's NEM successor tariff decision, the CPUC did not adopt a specific test to determine NEM cost effectiveness.

For each of these tests, the CPUC uses approved calculations of benefits as determined through the Avoided Cost Calculator, which computes the avoided costs of electricity and its various components: generation energy, generation capacity, ancillary services, transmission and distribution capacity, environmental benefits (i.e., avoided greenhouse gases), etc.

Pursuant to the Warren-Alquist Act (1974), any building standards adopted by the CEC must be cost-effective over the economic life of the structure.[15] In determining cost-effectiveness, the CEC must consider the value of energy and water saved, the impact on product efficacy for the consumer, and the lifecycle cost *to the consumer* of complying with the standard. In essence, the CEC's main concern is the cost effectiveness from the building owner, or "participant cost," perspective, although other factors may be considered.[16] In practice, this means that the CEC primarily analyzes the expected bill savings for consumers at the full retail rate, which is in contrast to the marginal cost analysis approach of the CPUC's TRC.

The CEC uses an avoided cost methodology that is similar to the CPUC's, called Time Dependent Valuation (TDV) to calculate the benefits of a measure, such as solar PV. These benefits are inputted into the CEC's Lifecycle Cost Methodology, which determines cost-effectiveness. The CEC's Lifecycle Cost Methodology does *not* currently include an integration cost component. As acknowledged in the joint staff *Codes and Standards Action Plan*, the CEC's TDV method "may need to be modified for future standards to include all electricity infrastructure costs associated with integration of onsite renewable electric generation systems into the grid."[17] Another important distinction, is that the CEC uses a lower, societal discount rate (3%), whereas the CPUC generally applies the utilities' weighted average cost of capital, which is more than double (approximately 7.5%) and results in a lower stream of benefits.

In sum, this Study quantifies a new cost dimension that could bear upon each agency's decision-making processes, according to the particulars of how each agency determines cost-effectiveness.

Mitigation Measures Could Significantly Reduce Costs

As discussed in this study, the CPUC recognizes that measures do exist to mitigate the impact of high penetration PV, whether due to potential ZNE code requirements or due to NEM policy alone. These

[14] California Standard Practice Manual, available at: http://www.cpuc.ca.gov/General.aspx?id=5267
[15] Public Resources Code Section 25402(b)(3).
[16] Public Resources Codes Section 25402(b)(3) requires the CEC to consider "other relevant factors…including, but not limited to, the impact on housing costs, the total statewide costs and benefits of the standard over its lifetime, economic impact on California businesses, and alternative approaches and their associated costs."
[17] "Codes and Standards Action Plan (2012-2015)," page 2-6. Available at: http://cpuc.ca.gov/General.aspx?id=4125. This joint staff plan was co-authored by the Efficiency Division of the CEC and the Energy Division of the CPUC.

mitigation measures include strategies to incorporate energy storage, smart inverters, and locational preference. These are discussed in more detail in the report. In particular, we estimate that the pending proposal for smart inverters to adopt reactive power priority could reduce costs by about 60% for all three electric IOUs in the "high cost case".

Stakeholder Process, Collaboration, and Next Steps

CPUC Staff collaborated extensively with CEC staff on this Study. This report reflects input from the staff of both agencies, as well as interconnection engineers from the investor-owned utilities. The report was sent to several relevant CPUC distribution lists for a two-week review and comment period, including for proceedings on energy efficiency, net energy metering, and distributed resource plans. Comments were received from several stakeholders. All comments were considered for the final version of this report.

In 2017, CPUC Staff will continue to collaborate with the CEC to ensure that the findings of this Study are considered in the 2019 Title 24 code update. The results of the study may inform future NEM, smart inverter, and interconnection policy, as well as further research.

EXECUTIVE SUMMARY

About this Report

AB 578 (Blakeslee, 2008) requires the California Public Utilities Commission 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.

In 2013, the CPUC contracted Black & Veatch to prepare the "Biennial Report on Impacts of Distributed Generation" and Itron to prepare an Impact Evaluation of CPUC's Self Generation Incentive Program. In 2015, the CPUC contracted KEMA, Inc., (DNV-GL) to examine how customer behind-the-meter solar photovoltaic impacts net-load patterns. DNV GLDNV GL prepared an "Impact of Distribution Energy Generation on the State's Distribution and Transmission Grid" report and the CPUC submitted it to the legislature on January 1, 2016. For the 2018 legislative report DNV GL prepared a study for the CPUC on PV distribution grid integration costs under different policy scenarios including zero net energy building policy.

Introduction

California has a goal that all new residential construction in California to be zero net energy by 2020. ZNE is defined as a building with net energy consumption of zero over a year. Zero net energy buildings require achieving a high level of energy efficiency and offsetting remaining energy use with on-site generation, most commonly photovoltaics.

As of 2016, California has about 7.3 GW of customer-sited PV. In the latest Integrated Energy Policy Report, the California Energy Commission estimates that achieving 100% ZNE for new residential construction would add 6.2 GW of PV onto the grid between 2016 and 2026, compared to 4.8 GW of PV in a trajectory mid-demand scenario[18]. Most of the new homes built in California are in new homes development,

[18] California Energy Commission Demand Analysis Office 2016

which means that ZNE buildings and PV will likely occur in geographically concentrated areas. Since the hourly profile of residential load and PV production do not match, the influx of PV may cause significant impact on specific areas of the distribution grid, if left unmitigated. The purpose of this study is to analyze the grid integration costs of customer-sited PV over the next 10 years under a base scenario of trajectory PV growth compared to a ZNE policy scenario that requires 100% ZNE on new homes by 2020. Note that the costs identified in this report are distribution interconnection upgrade costs only, and do not include other costs associated with large amounts of variable generation across the system (such as increased need for flexible resources to smooth the output of intermittent generation and additional grid visibility and monitoring devices to allow operators access to the data they need).

This study does not attempt to quantify any potential savings from deferred distribution upgrades as a result of high penetration[19] of PV. These benefits, currently being developed in the Distribution Investment Deferral Framework (DIDF) of the Distribution Resources Plan Proceeding as well as in the Distribution Deferral Shareholder Incentive Pilot of the Integrated Distributed Energy Resources (IDER) Proceeding, may be possible especially where PV generation is combined with energy storage systems. Distribution deferral benefits can result from both autonomous Distributed Energy Resources (DER) growth as well as from targeted DER solicitations for "non-wires alternatives" to planned distribution upgrades.

Method

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 PV. 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.

DNV-GL team constructed the study scenarios by mapping PV forecast data from the most recent IEPR mid-demand scenario and ZNE policy scenario. In the study, a ZNE home is modelled as a generator, as the effect of the variable generation during low load is likely to have the largest impact on the circuit's operating parameters. Two dispersal cases are modelled:

1. The new generator representing the additional generation (due to ZNE-homes and non-ZNE PV adoption) 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 (due to ZNE-homes and non-ZNE PV adoption) is distributed around the circuit in increments of up to 100 kW. This normally represents a more favourable condition for integration of distributed generation and is referred to in this report as the 'low cost case.'

The size of the generator is increased incrementally such that the penetration of distributed generation on the circuit increases from 0% to 160% in 10% increments. For each of these increments, static and quasi-static load flow studies were carried out and any technical violations identified. For each analysis, the generator output was assumed to be at 100% of total rated output in combination with the peak load and

[19] Penetration of PV is defined in this study as nameplate capacity of PV divided by circuit peak load before the peak load effects of PV are added, expressed as a percentage.

the minimum daytime load on the circuit. Where technical violations occurred, the appropriate mitigation options were identified and the cheapest option would be selected.

DNV-GL performed this analysis for 75 sample circuits (30 in SCE, 20 in PG&E and 25 in SDG&E) to represent California. For PG&E and SCE the sample circuits were taken from previous studies to perform re-work[20],[21]. For SDG&E, DNV GL performed a statistical sampling exercise to identify representative circuits. An example of the mitigation cost profiles for the three utilities can be found below.

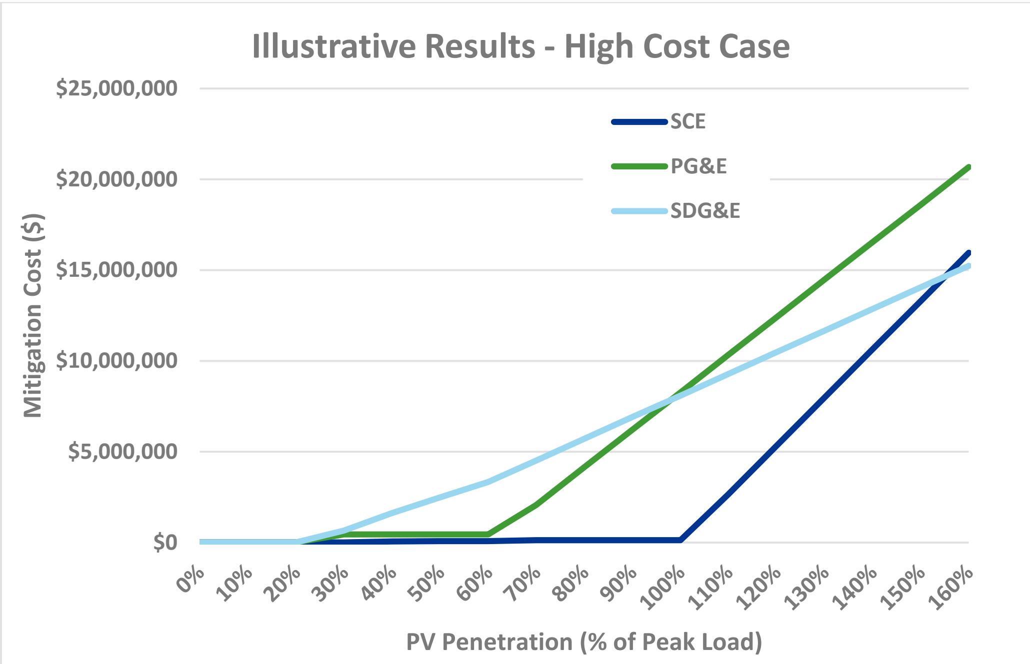

Figure 0.1: Illustrative example mitigation cost profiles for single circuits—high cost case

[20] Navigant Distributed Solar Photovoltaic Transmission and Distribution Impact Analysis
[21] Characterization & Modeling of Representative Distribution Circuits in GridLAB-D, California Solar Initiative Project, Advanced Distribution Analytic Services Enabling High Penetration Solar PV

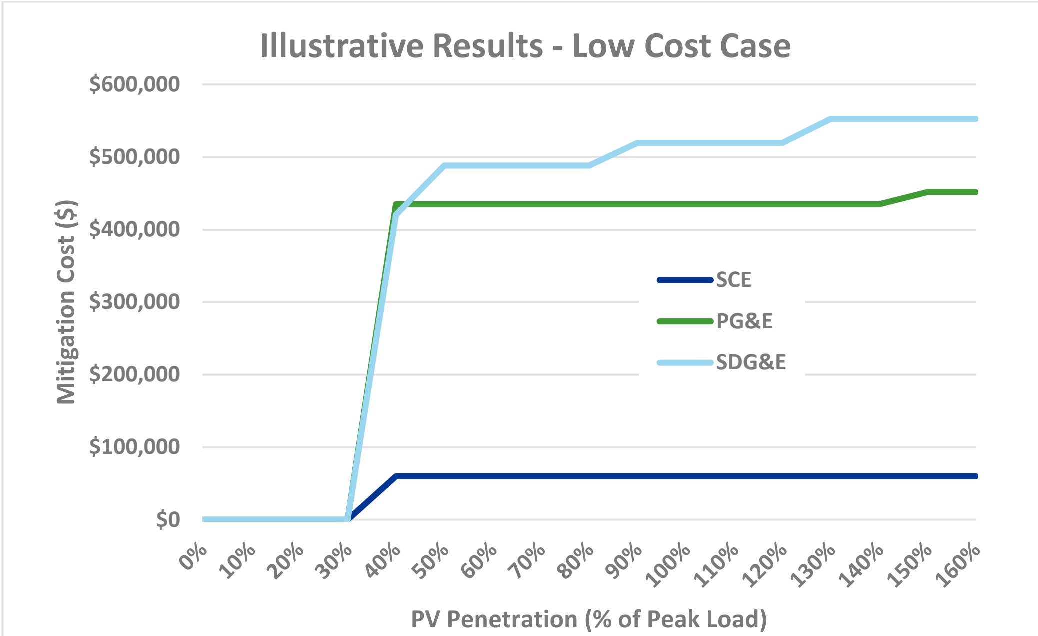

Figure 0.2: Illustrative example mitigation cost profiles for single circuits—low cost case

In each of the circuits illustrated above, energy storage is a major driver for mitigation costs in the high cost case. As shown in Figure 0.1, the elbow in the mitigation cost profile represents the penetration at which energy storage was required to mitigate the technical violations. This occurs when traditional mitigation measures, such as additional voltage regulation, are no longer sufficient to resolve problems caused by the variability in the generation. There are costs involved before the elbow, typically mitigation measures for reverse power flow are required at lower penetrations, along with re-conductoring in some cases (due to the relative costs of energy storage at higher penetrations these costs are less visible in Figure 0.1). The differences in cost profiles for different circuits are influenced by several criteria. One example is circuit length—shorter circuits tend to have fewer voltage problems, particularly due to variations in generation output. Longer circuits may rely on mid-circuit voltage regulation equipment to maintain satisfactory voltages at all customers, but traditional voltage regulation technologies may not be sufficiently effective when there are rapid variations in load flow, as may occur due to clouds passing a PV facility. Figure 0.1 does not show estimated cost reductions for the high cost case if the CPUC approves the pending request for smart inverters to use reactive power priority (See discussion below on Smart Inverter Impact).

In Figure 0.2 the integration costs for the same circuits are shown for the low cost case, where energy storage was not required. 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.

Energy storage could be used to mitigate all the violations caused by increasing PV penetration. In practice, it could be used to limit the net export of power from the ZNE facility so that the total generation output on the circuit does not exceed the hosting capacity of the circuit. However, it is typically more expensive than the other measures, so it is normally prescribed only at higher penetrations when the cheaper options (such as re-conductoring, enabling co-generation mode at regulator or substation transformer) are no longer effective. This is the approach that has been assumed for this study, 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 operator could predict that some mitigation option (e.g. 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 would 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. If energy storage was implemented at the buildings or circuits for other reasons, then the associated integration costs identified in this study would be negated.

In the case where the new generation is distributed at multiple locations on the circuit (case 2 described above), the variable output analysis assumed variation in output from only one installation at a time. The result of this is that violations due to variable generation output are no longer present in the low cost case. This approach is consistent with current IOU methodology for analysis of circuits with multiple PV installations.

Results

DNV-GL extrapolated the results from the sample circuits to the rest of California, and finds that the potential cumulative increase in integration costs due to the ZNE policy between 2016 and 2026 ranges between $42.2 million and $623.0 million for PG&E, between $15.0 million and $28.1 million for SCE, and between $5.6 million and $93.0 million for SDG&E (note that all costs in this report are in 2016 dollars). The ranges are defined based on the results for the two generation dispersal cases—the high costs are for the case where new generation is placed in a single location at the end of the circuit, and the low costs are for the case where new generation is distributed around the circuit. The reason for the range of costs is that energy storage is typically not required for the low cost case as changes in PV output are spread over a longer period of time due to geographic diversity. This allows relatively inexpensive voltage regulation equipment to maintain voltage levels within the acceptance criteria, which is sometimes not possible when high penetrations are installed in a single location and can produce large variations in output over a short period of time. This implies that there is the potential to optimize the dispersal of PV on a circuit such that integration costs are minimized—typically by ensuring that the PV is dispersed geographically as evenly as possible on a circuit. There is also the potential to optimize which circuits PV is added to. As some circuits have greater capacity to absorb new generation without requiring upgrades, it is clear that prioritization of some circuits over others for ZNE buildings and new PV installations can be used to minimize the overall integration costs for a given PV capacity.

The PV integration cost in PG&E territory is significantly higher because PG&E expects a higher penetration of PV compared to peak load, and PG&E’s mitigation costs are higher due to its circuit design (i.e., longer circuits). This implies that design of future distribution circuits should aim for circuit lengths similar to those in SCE if ZNE and PV grid integration costs are to be minimized.

The results in Table 0-1 demonstrate the effect of increased dispersal of new generation on integration costs. There is a major difference in the potential costs in the high cost case versus the low cost case, up to an order of magnitude in PG&E’s case. In practice, the dispersal of new generation is highly unlikely to be close to the conditions considered for the high cost case (all new generation lumped at the end of every circuit). It is expected that the result will be somewhere in between the two values, possibly closer to the low cost case which is more representative of what the utilities have observed to date. Table 0-1 does not reflect the estimated cost reductions for the high cost case if the Commission approves the pending request for smart inverters to use reactive power priority.

Note that the same peak load values have been used for both the trajectory scenario and the ZNE policy scenario.

Table 0-1: Summary of Integration Cost Parameters and Results

Parameter	PG&E	SCE	SDG&E
Coincidental Peak Load 2016 (kW)	21,141,000	22,224,000	4,448,000
Coincidental Peak Load 2026 (kW)[22]	22,423,000	22,553,000	4,525,000
PV Installed 2016 (kW)	3,806,066	2,782,347	737,815
PV Installed 2026 - Trajectory Scenario (kW)	5,717,499	5,174,098	1,280,027
PV Installed 2026 - ZNE Policy Scenario (kW)	6,401,746	5,709,284	1,370,686
PV Penetration 2016 (% of coincidental peak load)	18.0%	12.5%	16.6%
PV Penetration 2026 - Trajectory Scenario	25.5%	22.9%	28.3%
PV Penetration 2026 - ZNE Policy Scenario	28.5%	25.3%	30.3%
High Total Integration Cost for New Generation—Trajectory Scenario	$849,805,550	$134,051,902	$605,725,458
High Total Integration Cost for New Generation—ZNE Policy Scenario	$1,472,790,500	$179,032,465	$698,774,231
High Cost of ZNE Policy	$622,984,950	$44,980,563	$93,048,773
Low Total Integration Cost for New Generation—Trajectory Scenario	$75,014,506	$36,175,888	$37,687,165
Low Total Integration Cost for New Generation—ZNE Policy Scenario	$117,164,808	$51,219,331	$43,328,285
Low Cost of ZNE Policy	$42,150,302	$15,043,443	$5,641,120

Table 0-2 provides the relative costs for each of the three IOU's, based on the new customers forecasted and on the amount of new generation forecasted. The costs per new customer are produced only for the ZNE policy scenario, as not all customers would be assumed to be installing generation in the trajectory scenario. These results show again that costs are significantly higher for PG&E and SDG&E than they are for SCE. The likely explanation for this is again the higher penetrations of generation expected on the PG&E and SDG&E systems. As seen in the cost profiles in Figure 0.1, the costs rise exponentially at higher penetrations, which indicate again that it is important to minimize the requirements for energy storage as much as

[22] California Energy Demand Updated Forecast, 2017-2027 (Mid Energy Demand scenario)

possible in order to keep integration costs down. Where energy storage is used to mitigate the technical violations identified in this study, it would be assumed that the necessary control directives from the utility are implemented on the energy storage system such that the net output from the facility is limited (behind-the-meter storage is assumed). In this study, the full cost of the energy storage system is assumed to be a grid integration cost, so it can be assumed that the utility has full ownership and control over the energy storage system and can utilize it whenever it is needed. However, in practice customers may have other drivers to purchase energy storage systems for themselves. In this situation, there may be a cost for the utility to implement their control directives on the customer's equipment, but this cost would not be expected to exceed the costs assumed in this report for outright purchase of this equipment. Table 0-2 does not reflect the estimated cost reductions for the high cost case, which would result if the CPUC approved the pending request for smart inverters to use reactive power priority.

Table 0-2: Summary of Relative Costs

Parameter	PG&E	SCE	SDG&E
Number of New Customers 2016 - 2026	1,298,862	824,175	101,054
New Generation 2016 - 2026 - Trajectory Scenario (kW)	1,911,433	2,391,751	542,212
New Generation 2016 - 2026 - ZNE Policy Scenario (kW)	2,595,680	2,926,937	632,871
Low Cost per New Customer - ZNE Policy Scenario ($)	$90.21	$62.15	$428.76
High Cost per New Customer - ZNE Policy Scenario ($)	$1,133.91	$217.23	$6,914.86
Low Cost per kW of New Generation - Trajectory Scenario ($)	$39.25	$15.13	$69.51
Low Cost per kW of New Generation - ZNE Policy Scenario ($)	$45.14	$17.50	$68.46
High Cost per kW of New Generation - Trajectory Scenario ($)	$444.59	$56.05	$1,117.14
High Cost per kW of New Generation - ZNE Policy Scenario ($)	$567.40	$61.17	$1,104.13

Smart inverter impact

Smart inverters were considered as a potential mitigation measure, in terms of providing support for voltage regulation equipment, and a sensitivity study was carried out to address potential cost savings. The current rules for smart inverters in California stipulate that there is a 'real power priority.' This implies that in the extreme conditions studied here—maximum generator output—there will be zero reactive power capacity available from the smart inverters. For that reason, Volt/Var control on smart inverters is not considered to be a viable alternative to energy storage for large installations. The results provided here are only valid if the rules are changed to 'reactive power priority' on circuits where this mitigation is necessary and more cost-effective than other methods. 'Reactive power priority' requires that the inverter produces the reactive power required by the Volt/Var curve implemented. In cases where there is sufficient irradiance for the PV generator to be producing maximum real power output through the inverter, the inverter would reduce its real power output in order to produce the required reactive power. This implies some loss of revenue for the generator, limited by the extents of the volt/var curve. Using the default volt/var curve proposed for California, the maximum real power loss at any time is 5%. This level of loss is only possible when the inverter is fully-loaded such that all of the reactive power required involves reduction in real power at a time when there is a sufficient voltage excursion that requires reactive power from the inverter. Across the operating life of a PV system, the losses due to implementation of reactive power priority can therefore be expected to be marginal in the majority of cases. Customers may also avoid real power losses by sizing their inverters larger and through PV self-consumption.

Smart inverters are capable of mitigating some of the integration costs by providing support for voltage regulation equipment. An inverter on a PV project can modify its reactive power output in response to changes in voltage at its terminals. This offers the potential to offset some mitigation costs, particularly those attributed to energy storage, by providing some voltage regulation capability at a much lower cost. Reliance on this method requires that the inverter prioritize reactive power over real power during voltage excursions. In December 2017, the IOUs submitted advice letters proposing to require smart inverters to use reactive power priority, and the CPUC will decide whether to approve the proposal in early 2018.

An analysis was completed as part of this study to establish whether the functionality is capable of replacing other mitigation costs, and what the costs of this alternative would be in terms of additional equipment, such as capacitor banks. The results showed that the integration costs in the high cost case were reduced from $1.473 billion to $510 million for PG&E, from $179 million to $116 million for SCE, and from $698 million to $289 million for SDG&E for the ZNE scenario by 2026. Overall, the integration costs in the high cost case were reduced from $2.350 billion to $915 million, representing more than a 60% reduction in total costs for all three IOUs. This represents a potential savings of $1,435 billion in rate payer costs.

Storage cost impact

Storage cost is the main driver for PV integration costs in the high cost case of our study. Since storage cost is expected to come down significantly in the coming years, DNV-GL conducted a sensitivity study to review integration costs if storage costs were to reduce 11% annually until 2021. The results show that the absolute cost of mitigation for ZNE homes in PG&E territory reduced from $1.473 billion to $874 million by 2026 for the high cost case. For SCE, the costs are reduced from $179 million to $125 million by 2026. For SDG&E the costs are reduced from $699 million to $429 million by 2026. Overall, the integration costs in the high cost case were reduced from $2.350 billion to $1.428 billion.

Cost per Ratepayer

Table 0-3, Table 0-4 and Table 0-5 below provide the grid integration costs per ratepayer[23] for new PV integration from 2016 to 2026 for each of the study cases (high cost case, smart inverter sensitivity and low cost case) with and without the ZNE policy in place. The difference between the cost with the ZNE policy and the cost without the ZNE policy represents the additional cost to each ratepayer in the three utilities over the 10 study years of enacting the ZNE policy. Assuming a uniform distribution of costs over the 10 years, the annual cost of the policy for each ratepayer ranges from $0.07 to $1.16 for PG&E, from $0.03 to $0.09 for SCE and from $0.04 to $0.66 for SDG&E.

Table 0-3: Grid integration costs per ratepayer for new PV between 2016 and 2026—high cost case

High Cost Case	PG&E		SCE		SDG&E	
	Total Cost	Cost Per Ratepayer	Total Cost	Cost Per Ratepayer	Total Cost	Cost Per Ratepayer
Trajectory Scenario, no ZNE policy	$850 million	$157	$134 million	$27	$605 million	$432
ZNE Policy Scenario in addition to Trajectory Scenario	$1,473 million	$273	$179 million	$36	$698 million	$498
Difference—Incremental cost of ZNE Policy	$623 million	$116	$45 million	$9	$93 million	$66

[23] PG&E: Based on 5.4 million meters - https://www.pge.com/en_US/about-pge/company-information/profile/profile.page
SCE: Based on 5 million meters, as reported to Energy Division
SDG&E: Based on 1.4 million meters - https://www.sdge.com/aboutus

Table 0-4: Grid integration costs per ratepayer for new PV between 2016 and 2026—smart inverter study

Smart Inverter Study	PG&E		SCE		SDG&E	
	Total Cost	Cost Per Ratepayer	Total Cost	Cost Per Ratepayer	Total Cost	Cost Per Ratepayer
Trajectory Scenario, no ZNE policy	$262 million	$48	$92 million	$18	$252 million	180
ZNE Policy Scenario in addition to Trajectory Scenario	$510 million	$94	$116 million	$23	$289 million	$206
Difference—Incremental cost of ZNE Policy	$248 million	$46	$24 million	$5	$36 million	$26

Table 0-5: Grid integration costs per ratepayer for new PV between 2016 and 2026—low cost case

Low Cost Case	PG&E		SCE		SDG&E	
	Total Cost	Cost Per Ratepayer	Total Cost	Cost Per Ratepayer	Total Cost	Cost Per Ratepayer
Trajectory Scenario, no ZNE policy	$75 million	$14	$51 million	$10	$38 million	$27
ZNE Policy Scenario in addition to Trajectory Scenario	$117 million	$21	$36 million	$7	$43 million	$31
Difference—Incremental cost of ZNE Policy	$42 million	$7	$15 million	$3	$6 million	$4

1 INTRODUCTION

The California Public Utilities Commission (CPUC) adopted the goals that all new residential construction in California will be zero net energy by 2020, and all new commercial construction will be zero net energy by 2030. These goals were reiterated in CPUC's California Long Term Energy Efficiency Strategic Plan in 2008. In addition, in the 2007 Integrated Energy Policy Report (IEPR), the California Energy Commission (CEC) has the goal to achieve zero net energy building standards by for new residential construction by 2020 and commercial buildings by 2030. These goals were reaffirmed by the CEC in the 2011 IEPR, with subsequent refinements to ZNE definition adopted in the 2013 IEPR.

Zero net energy buildings (ZNEs) require achieving a high level of energy efficiency and offsetting remaining energy use with photovoltaics (PV). In the latest (2015) IEPR, the CEC estimates that achieving 100% residential ZNE would add almost over 1,056 MW of PV onto the grid between 2020 and 2026, compared to 182 MW of PV in a trajectory mid-demand scenario. Moreover, ZNEs are likely to occur in geographically concentrated areas, which means that a large number of PVs will be installed in specific areas of the distribution grid. Since the hourly profile of residential load and PV production do not match, the influx of PVs may cause significant impact on specific areas of the distribution grid.

California Public Utilities Commission retained KEMA Inc. ("DNV GL") to conduct a study of the integration costs for PV under a trajectory scenario and a zero-net energy policy scenario. This report presents the results of DNV GL's analysis.

2 METHODOLOGY

The analysis consisted of two main elements:

- Forecasting PV capacity on each distribution feeder for each year in the forecast, including existing (2015) PV capacity, capacity growth on existing homes, and new PV capacity on new homes.
- Assigning costs to each feeder by identifying mitigation measures necessary to integrate the PV capacity.

For forecasting PV capacity on each feeder by year, DNV GL created two PV growth scenarios for 2016-2026 to compare the cost of PV integration under different policy scenarios. In the base scenario, DNV GL assumes PV growth under the IEPR mid-demand PV forecast. In the ZNE policy scenario, DNV GL assumes PV growth to meet the goal of 100% ZNE on new residential construction. These two scenarios would serve as bookends to PV integration costs under trajectory scenario versus aggressive ZNE policies[24]. To obtain the quantity of forecasted PV on each feeder between 2016 to 2026 for each of the scenarios, DNV GL layered the following data onto the California map:

- Existing distribution feeders from Geographic Information System (GIS) maps provided by the IOU.
- Existing homes from the American Community Survey[25]

[24] The trajectory scenario has about 4% to 12% of voluntary market-driven ZNE adoption between 2016-2026, and the ZNE policy scenario has 100% ZNE adoption.
[25] 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>.

- Annual new distribution feeders based on historical grid expansion by the IOUs
- Annual new homes forecast based on CEC IEPR forecast for 2016-2026
- Annual new PV forecast based on CEC IEPR forecast for 2016-2026

Since the forecast data from IEPR are by forecast climate zones, DNV GL applied several analytical methods to break out the forecast at the feeder level. For new homes, the core of this analysis was a detailed geographic forecast of new homes construction. For new PV on existing homes, we used a bottom-up analysis based on Census block group-level household counts and household characteristics, such as income, home size, and owner-occupancy rates. These methods are described in more details in Section 2.1 below.

For assigning costs to each feeder, DNV GL used Synergi software to analyse the costs of integrating PV on a representative feeder basis. By 2026, California is forecasted to have over 10,000 feeders: 2,800 in PG&E, 5,700 in SCE and 1,032 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.

2.1 PV Capacity Forecast

Our study models two PV growth scenarios for 2016-2026:

1) Trajectory (base) scenario, which aligns with the mid-demand forecasts of PV capacity for new homes and existing homes and contains 4-12% of naturally occurring ZNE adoption; and
2) ZNE scenario, which assumed a ZNE policy requiring PV on all new construction, both single- and multifamily, beginning in 2019.

Assuming PV for 100% of new homes in the ZNE scenario is a limiting condition representing the worst-case for integration costs.

In order to build up these scenarios, we had to develop 3 separate estimates of PV capacity by feeder:

1) Existing PV on existing homes in 2015
2) A forecast of new PV installed on existing homes from 2016 to 2026
3) A forecast of new PV installed on new homes from 2016 to 2026

For all three of these elements we had IEPR estimates or forecasts of PV capacity at the level of building climate zone (for new homes) or forecast climate zone (for existing homes). The challenge in the analysis was to appropriately allocate those existing forecasts to feeders.

We began with a geographic analysis of distribution feeders that mapped them to a grid of 1 kilometer by 1 kilometer squares across California. This "fishnet grid" became the common geographic reference point to map between feeders, climate zones, forecast zones, and Census block groups as was necessary for various elements of the study.

2.1.1 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 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, on the logic that a building owner would be more inclined to install PV if it would reduce their own electricity bill than if it reduced only 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 fishnet grids. In cases where our GIS approach did not produce a matching block group for a fishnet grid, 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. We aggregated the fishnet grids 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 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 as 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 1km x 1km grid discussed earlier:

1. Overlaid land use data onto the gridcells. We categorized land as either (1) developed urban land, (2) open space preserved against development, or (3) potentially developable land. The last category

includes farm land and other land not following into the first two groups. This step results in partitioning the area of each gridcell into one or more of these development categories.

2. Overlaid U.S. Census data of housing onto the gridcells. As Census boundaries cross gridcell boundaries, we allocated houses to gridcells proportional to the amount of urban area in the gridcells
3. Calculated the capacity for new housing development. We assumed that new development density in each gridcell would be at the same density as currently exists near the gridcell.
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 gridcell 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 gridcells *i* and *j*
        h is the number of homes in gridcell *j*
        β is a dampening factor, set to 0.5
        p is a shadow price

        This expression makes gridcells in close proximity development appear more attractive to development than gridcells without developed neighbors.
    b. Calculated the probability of development in a gridcell 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 gridcells using a Monte-Carlo simulation. Gridcells with higher accessibility are more likely to get allocated new homes than gridcells 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 to e until all no gridcell is over capacity.
    g. Updated gridcell 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 home, both single-family and multifamily, to be constructed. We then turned our focus to determining PV adoption among those new homes.

For the ZNE forecast, this was quite straightforward. Since we were modelling the limiting condition in which 100% of new homes have PV, we simply multiplied the number of new homes in each feeder by an average 2 kW PV capacity per home[26].

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 makes sense only if the utilities refuse to integrate new PV beyond a certain point. However, we decided that it made sense to model more organic (demand-based) growth of PV.

[26] The 2 kW capacity assumption is a ballpark size estimated in the IEPR forecast. The number is based on the size of systems that were being installed in newly constructed homes that participated in New Solar Homes Partnership and expected energy efficiency standards.

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 Integrating the New and Existing Homes Forecasts

The analysis discussed above developed an estimate of 2015 PV on existing homes, a baseline forecast of new PV on existing homes (corresponding with the mid-demand forecast) and two alternative forecasts of new PV to new homes—a base scenario new homes capacity forecast (corresponding with the mid-demand forecast)—and a ZNE forecast assuming 100% of new homes are required to install PV.

To model integration costs, we combined these estimates into the two scenarios discussed at the beginning of the section. The base scenario combines existing capacity on existing homes, plus base scenario new capacity on existing homes, plus base scenario new capacity on new homes for a combined PV capacity forecast. The ZNE scenario combines existing capacity on existing homes, base scenario new capacity on existing homes, and ZNE new capacity on new homes for a combined ZNE PV capacity forecast.

2.1.4 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[27], 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 2 to 3. We wanted to incorporate this growth into our forecasts to better estimate the costs of a ZNE policy.

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 feeder 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 2 feeders or 3 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 crept into the top-ranked feeders only after several years of accumulated growth.

2.2 Circuit analysis

2.2.1 Sampling of representative feeders

Due to the practicalities of budget and schedule for this work, it was not possible to analyze every distribution circuit across the three IOUs—Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E)—which would amount to over 10,000 distribution feeders. Therefore, 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

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

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 ZNE buildings (i.e., new buildings that are assumed to adopt PV in the ZNE Policy scenario but not in the trajectory scenario) 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 ZNE 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:

1. The new generation on the circuit is placed at the end of the circuit furthest from the substation. 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[28] and SCE[29]. 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.

2.2.2 Circuit analysis

The selected representative circuits were analyzed using Synergi Electric[30] software. Technical criteria were identified based on typical reliability criteria for the utilities. These criteria are shown in Table 2-1 below:

[28] Distributed Generation Solar Photovoltaic Transmission & Distribution Impact Analysis; G. Shlatz, K. Corfee, S. Goffri, D. Stradford, M. DePaolis; August 2015
[29] Characterization & Modeling of Representative Distribution Circuits in GridLAB-D; J. Fuller, K. Schneider, A. Guerra, S. Collins, A. Gebeyehu
[30] A widely-used electric distribution system powerflow modeling tool available from DNV GL

Table 2-1: 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 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 2-1 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 2-2.

Table 2-2: Mitigation measures and assumed costs

Technical Limit	Mitigation Measure	Cost
Static Voltage	New voltage regulator	$150,000[31]
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)[31]
Reverse Power Flow at Regulator	Enable co-generation mode	$60,000[31]
Reverse Power Flow at Substation Transformer	Enable co-generation mode	$60,000[31]
Reverse Power Flow at Re-Closer	Implement re-close blocking	$145,000[31]

Energy storage could be used to mitigate all the violations identified in Table 2-2, assuming that appropriate communications can be installed. The duration assumed is 4 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 were to be 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 ZNE facilities 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 time and effort associated with that. It is assumed that the energy storage equipment would be co-located with the ZNE building, 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

[31] PG&E Unit Cost Guide, September 2016

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.

Figure 2.1 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.

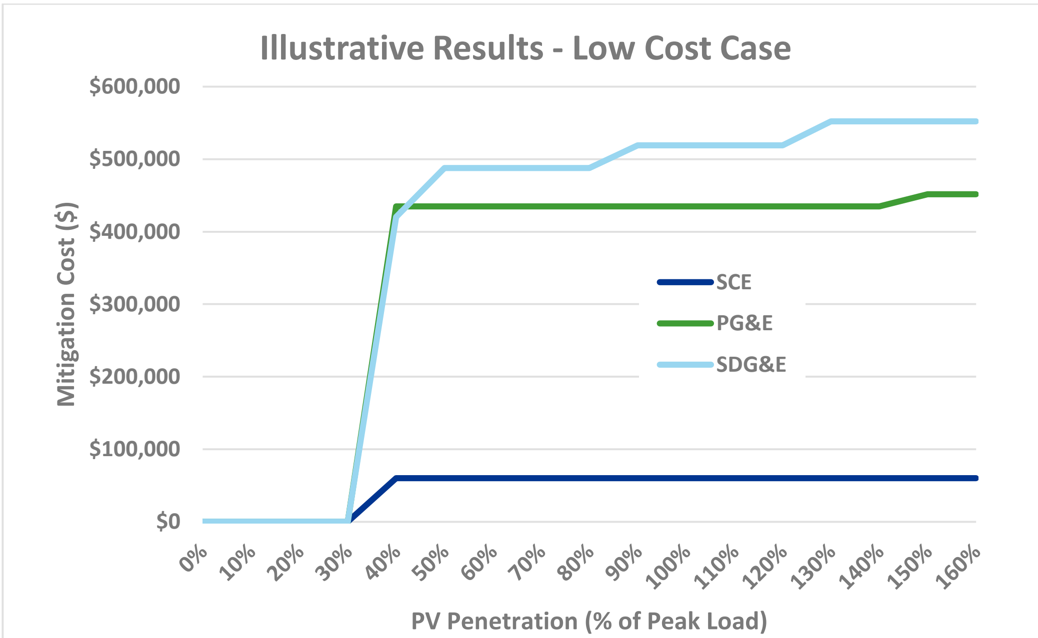

Figure 2.1: Illustrative example mitigation cost profiles for sample circuits—low cost case

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 2-1 and Table 2-2 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 representing the ZNE homes 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 representing the ZNE homes is distributed around the circuit in increments of up to 100kW. This normally represents a more favourable condition for integration of distributed generation and is referred to in this report as the 'low cost case'.

We then combined the integration cost profiles with the feeder-level trajectory scenario and ZNE PV capacity forecasts discussed previously. To extrapolate the mitigation-cost results to each of these feeders, some assumptions are required about the nature of the load and generation at the ZNE homes. These assumptions have a significant impact on the results:

- Additional peak load: 3kW per home
- PV capacity required per home: 2kW[32]

The additional peak load per home, while not modeled in the circuit simulation, is used to adjust the peak load value on each feeder for each year in the forecast. Similarly, the PV capacity per home is used to adjust the amount of PV on each circuit in the forecast. By applying these assumptions to the forecast number of ZNE homes, the change in PV penetration for the feeder can be calculated. 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 new homes have not been considered in this study. This refers to the possibility that developers of new ZNE homes may be more likely to 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 average peak load per home than that considered above. This would have no impact on the grid integration cost profiles per circuit, but it could have an effect on the extrapolated results as peak and minimum loads are likely to be higher, resulting in lower effective penetrations.

2.3 Limitations

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 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.
- 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 ZNE building regardless of the PV penetration. These costs would be the same in both the trajectory scenario and the ZNE policy scenario, and if they are present, they may be duplicated in the ZNE policy 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 2-1 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

[32] The 2 kW capacity assumption is a ballpark size estimated in the IEPR forecast. The number is based on the size of systems that were being installed in newly constructed homes that participated in New Solar Homes Partnership and expected energy efficiency standards.

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 of the study that 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.
- The size of the PV system per-home has been estimated based on the 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 the locational data was available and able to 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 analyzed.
- Energy storage costs are assumed in this study to be 100% allocated as distribution interconnection upgrade costs, equivalent to assuming the utility would have to purchase and operate the energy storage system. While this would ensure that the equipment is available to be used by the utility as and when needed, there are other possibilities for the implementation of energy storage. For example, customers may be driven to purchase energy storage systems themselves. These systems could be used by the utility if appropriate control directives were implemented. This may involve some payment by the utility for the service provided by the customer's equipment, but this would likely be lower cost than 100% purchase of the equipment by the utility.

3 RESULTS

3.1 Southern California Edison

3.1.1 Representative Circuits

As discussed in Section 2.2.1 above, the circuit sampling study had been carried out for SCE on a prior project. A summary of the circuit characteristics is presented in Table 3-1. The circuits are defined by different characteristics, one of which is climate zone. Climate zones in California are shown in Figure 3.1 below.

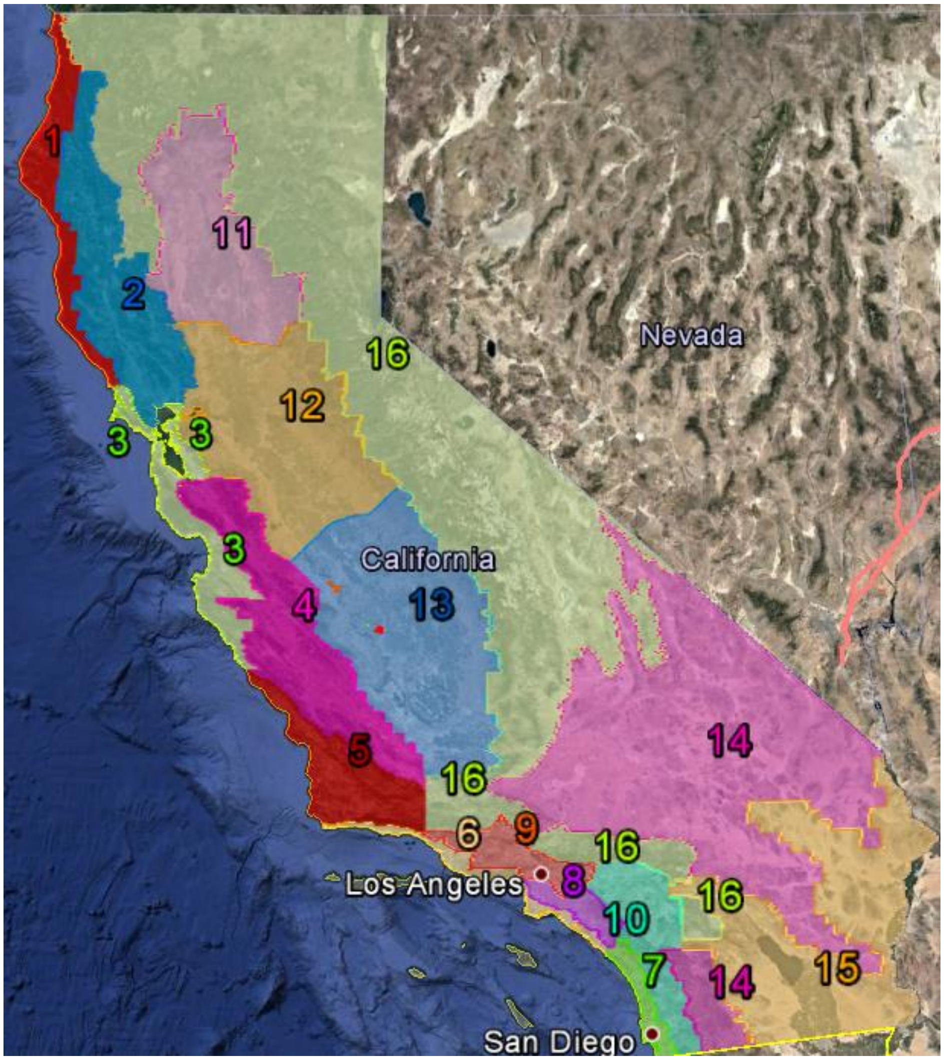

Figure 3.1: California climate zones

Table 3-1: SCE representative circuit characteristics

Circuit	# of SCE Circuits Represented	% of SCE Circuits Represented	Peak Loading	Existing Installed PV Capacity	Climate Zone	Customer Count
#1	132	3%	Medium	Low	9	High
#2	97	2%	Medium	Low	6	Low
#3	216	5%	High	Medium	9	High
#4	211	5%	High	Medium	8	High
#5	118	3%	Medium	Low	6	Medium
#6	211	5%	Medium	Low	8	High
#7	153	4%	Medium	Medium	9	Medium
#8	148	4%	Medium	Low	10	High
#10	122	3%	Medium	Low	6	Medium
#11	91	2%	Medium	Low	8	Medium
#12	157	4%	High	Medium	9	High
#13	143	3%	High	Low	10	High
#14	104	2%	High	Low	9	High
#15	139	3%	Medium	Low	8	Medium
#16	133	3%	High	Medium	6	High
#17	111	3%	Medium	Low	6	Medium
#19	301	7%	Low	Low	9	Medium
#20	36	1%	Low	Low	14	Medium
#21	252	6%	Low	Low	8	High
#22	178	4%	Medium	Low	6	High
#23	224	5%	Medium	Low	13	High
#24	171	4%	Medium	Low	13	Medium
#25	93	2%	Low	Low	13	Low
#26	64	2%	Low	Low	14	Medium
#27	106	3%	Low	Low	14	Medium
#28	107	3%	Medium	High	14	High
#29	164	4%	Medium	Low	14	High

3.1.2 Representative Circuit Integration Costs

No substation equipment was included in the feeder models provided by the IOUs. In order to carry out the quasi-static analysis (to check for transient voltage problems), it was required to include a voltage regulation device at the head of each circuit. A substation transformer with a load tap changer (LTC) was selected. This drives the costs for reverse power flow at the head of the circuit, since this cost is associated with enabling co-generation mode at that transformer.

The charts shown in Figure 3.2 and Figure 3.3 below present the results of the integration study for each of the circuits for a penetration of 100% of peak load. The High costs are based on all generation placed in a single location, while the Low costs are based on generation which is distributed along the circuit.

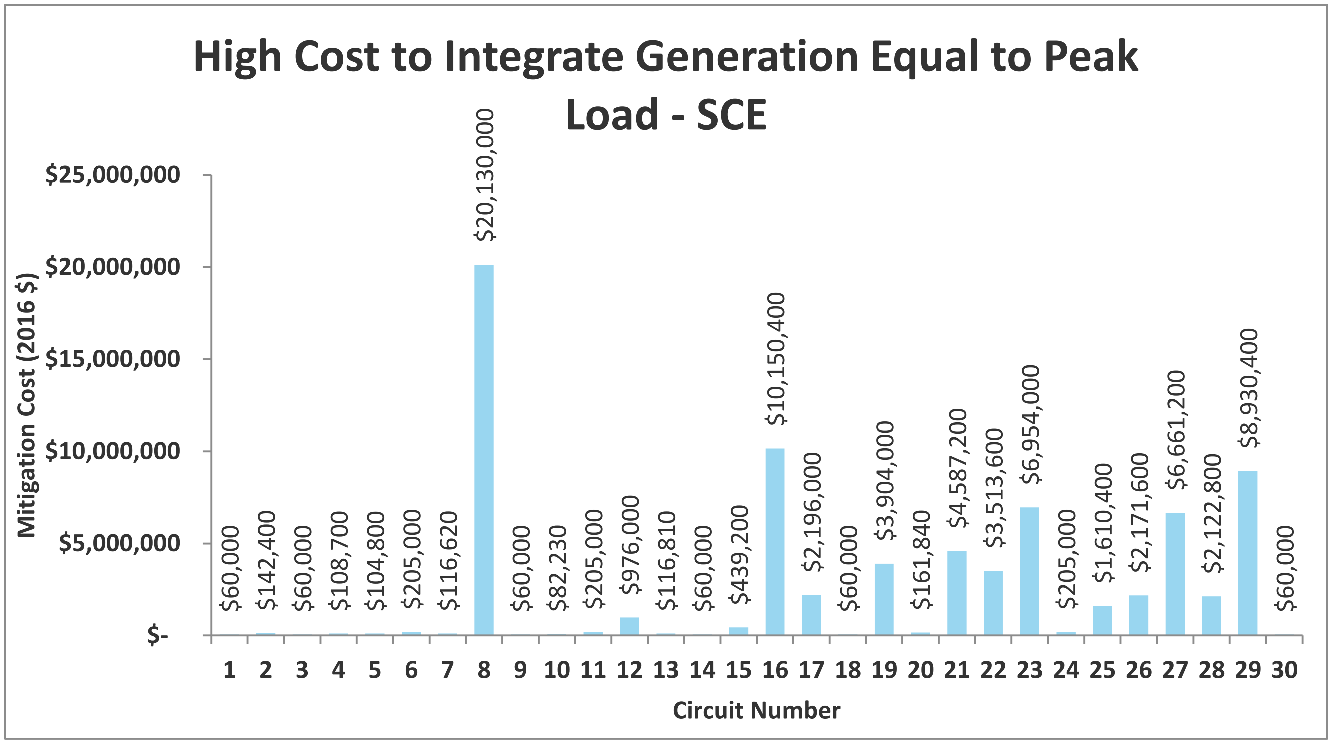

Figure 3.2: High mitigation costs for SCE representative circuits

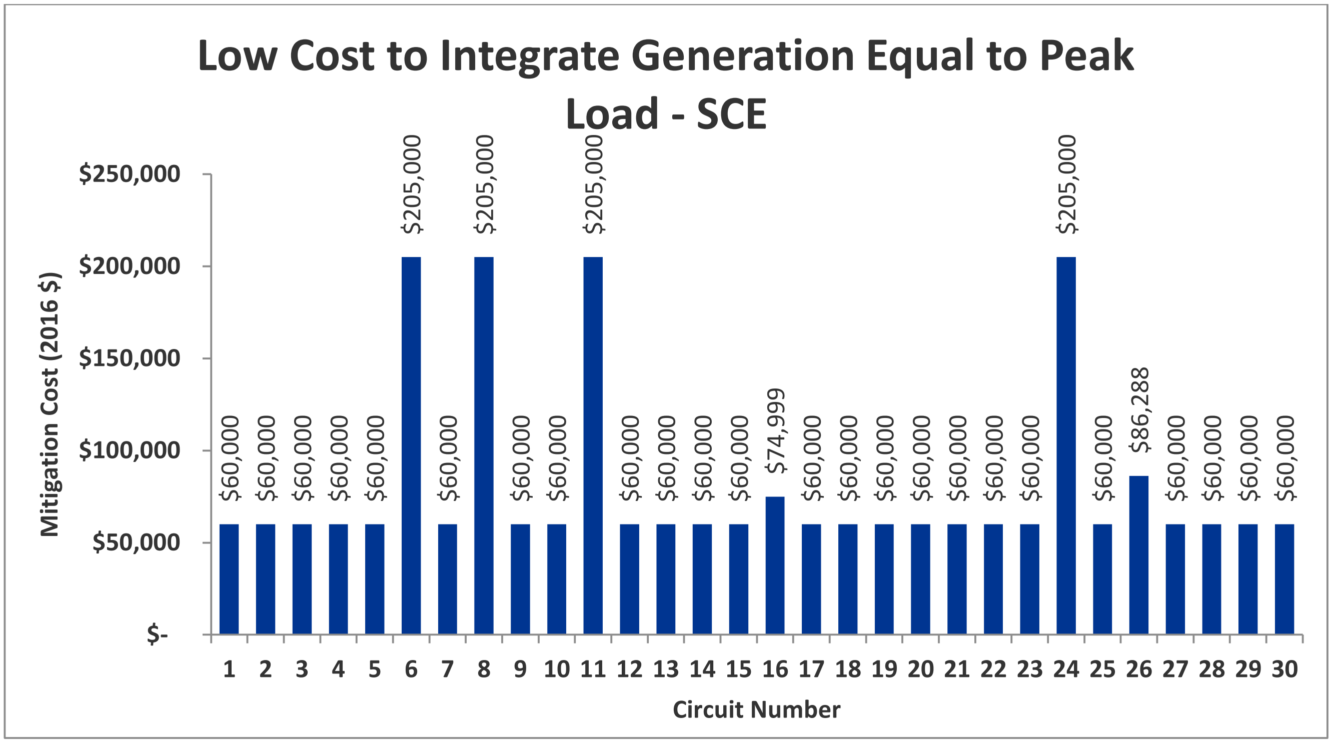

Figure 3.3: Low mitigation costs for SCE representative circuits

3.1.3 Extrapolation of Results

The results for the representative circuits were extrapolated to the full SCE distribution system based on the circuit mapping provided by SCE. This circuit mapping identified which representative circuit could be used as a proxy for each real circuit in the SCE distribution system. In each set of results, the results for the identified representative circuit—in terms of integration cost for a given PV penetration—were mapped to each circuit. Using the dispersal of new buildings and PV described in Section 2.1, the PV penetration on each circuit was calculated for each year to 2026, and the associated grid integration cost was identified. This was done for both the trajectory scenario and the ZNE policy scenario. Figure 3.4 below presents the comparison of the two scenarios for SCE from 2016 to 2026:

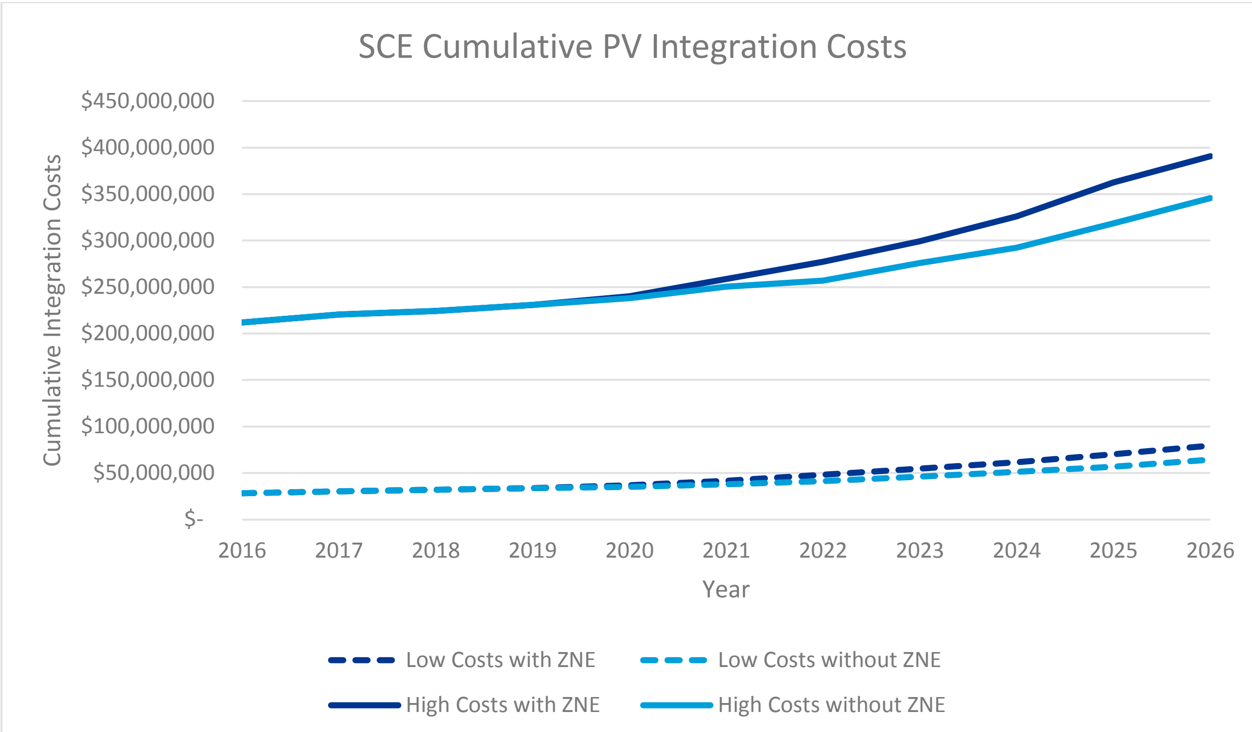

Figure 3.4: Grid integration costs for SCE distribution system for the 'No ZNE' and 'With ZNE' scenarios

The results presented in the chart above show a difference in cost of $28.1 million by 2026 between the two high cost cases and $15.0 million between the two low cost cases, which represents the potential cost range of implementing the ZNE building policy on the SCE circuits. It should be noted that the majority of the costs in the high cost case are due to the cost of energy storage, which is required to mitigate transient problems that cannot be solved by traditional voltage regulation equipment. If this energy storage was implemented in the buildings for other reasons, then the associated integration costs for this study would be significantly reduced.

A summary of the results by 2026 is shown in Table 3-2 below:

Table 3-2: SCE system results summary

Parameter	Result
Coincidental Peak Load 2016 (kW)	19,141,478
Coincidental Peak Load 2026 (kW)	19,661,000
PV Installed 2016 (kW)	2,782,347
PV Installed 2026 - Trajectory Scenario (kW)	5,174,098
PV Installed 2026 - ZNE Policy Scenario (kW)	5,709,284
PV Penetration 2016 (% of coincidental peak load)	14.54%
PV Penetration 2026 - Trajectory Scenario (% of coincidental peak load)	26.32%
PV Penetration 2026 - ZNE Policy Scenario (% of coincidental peak load)	29.04%
High Total Integration Cost for New Generation—Trajectory Scenario	$134,051,902
High Total Integration Cost for New Generation—ZNE Policy Scenario	$179,032,465
High Cost of ZNE Policy	$44,980,563
Low Total Integration Cost for New Generation—Trajectory Scenario	$36,175,888
Low Total Integration Cost for New Generation—ZNE Policy Scenario	$51,219,331
Low Cost of ZNE Policy	$15,043,443

3.2 Pacific Gas & Electric

3.2.1 Representative Circuits

As discussed in Section 2.2.1 above, the circuit sampling exercise for PG&E had been carried out on a prior project. The methodology is described in Section 2.2.1. The circuit characteristics for each of the representative circuits are shown in Table 3-3 below.

Table 3-3: PG&E representative circuit characteristics

Feeder ID	# of PG&E Circuits Represented	Voltage (kV)	Existing Installed PV Capacity (kW)	Customer Count
1	114	21	471	1337
2	103	12	578	5249
3	211	12	313	1284
4	146	21	1122	3884
5	171	12	191	664
6	147	12	392	367
7	57	12	437	951
8	115	12	398	1225
9	201	12	130	441
10	99	12	503	3079
11	224	12	478	3193
12	279	12	516	1879
13	50	12	575	726
14	121	12	367	1843
15	112	21	937	2969
16	128	18	812	2825
17	65	12	967	1227
18	157	12	607	2503
19	125	4	81	785
20	176	4	85	1027

3.2.2 Representative Circuit Integration Costs

There are two important notes to make on the PG&E circuit studies:

1. No substation equipment was included in the models provided. To carry out the quasi-static analysis (to check for transient voltage problems), it was required to include a voltage regulation device at the head of each circuit. A substation transformer with a load tap changer (LTC) was selected. This drives the costs for reverse power flow at the head of the circuit.
2. The load data used was the ICA Load Profile Data prepared for PG&E's DER hosting capacity studies. This provided the peak and minimum daytime load used in the study. The version used is from July 1, 2015.

The charts shown in Figure 3.5 and Figure 3.6 below present the results of the integration study for each of the circuits for a penetration of 100% of peak load. The High costs are based on all generation placed in a single location, while the Low costs are based on generation which is dispersed along the circuit.

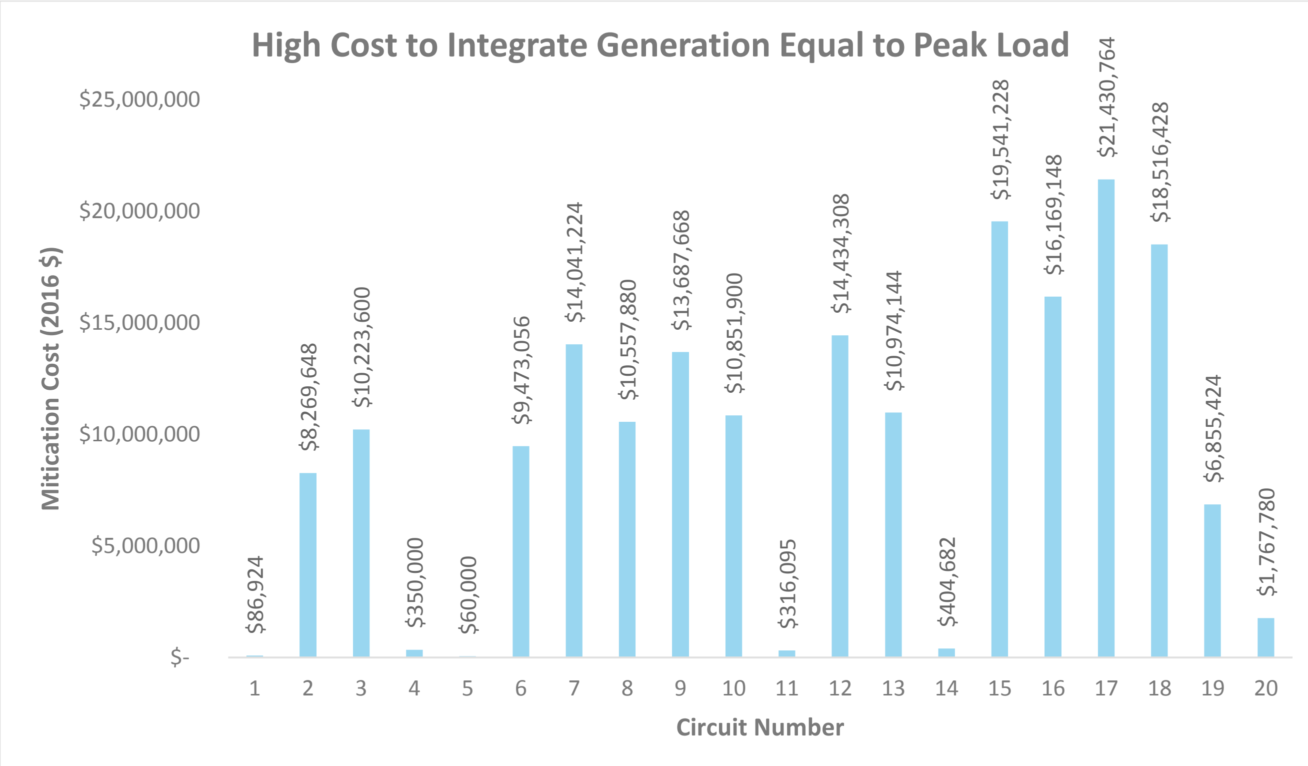

Figure 3.5: High mitigation costs for PG&E representative circuits

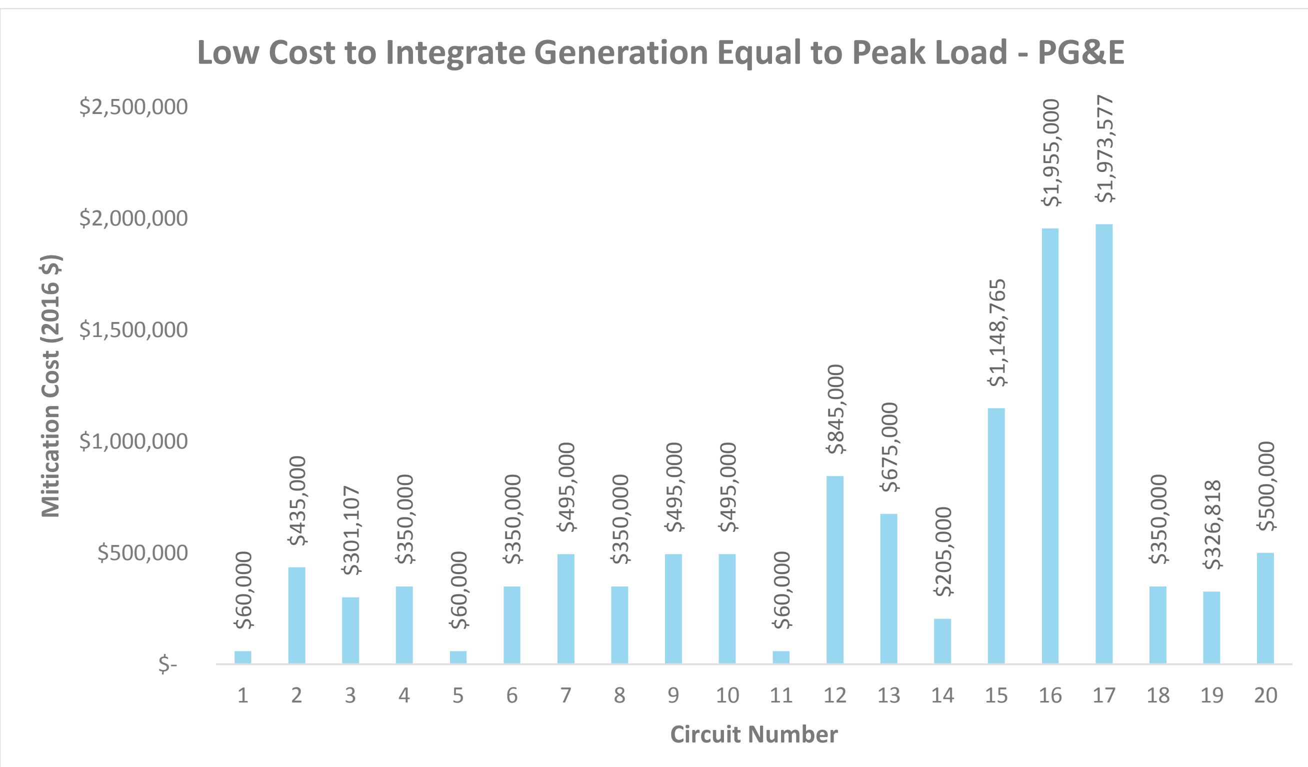

Figure 3.6: Low mitigation costs for PG&E representative circuits

3.2.3 Extrapolation of Results

The results for the representative circuits were extrapolated to the full PG&E distribution system based on the circuit mapping provided by PG&E. This circuit mapping identified which representative circuit could be used as a proxy for each real circuit in the PG&E distribution system. In each set of results, the results for the identified representative circuit—in terms of integration cost for a given PV penetration—were mapped to each circuit. Using the dispersal of new buildings and PV described in Section 2.1, the PV penetration on each circuit was calculated for each year to 2026 and the associated grid-integration cost identified. This was done for both the trajectory scenario and the ZNE policy scenario. Figure 3.7 below presents the comparison of the two scenarios for PG&E from 2016 to 2026:

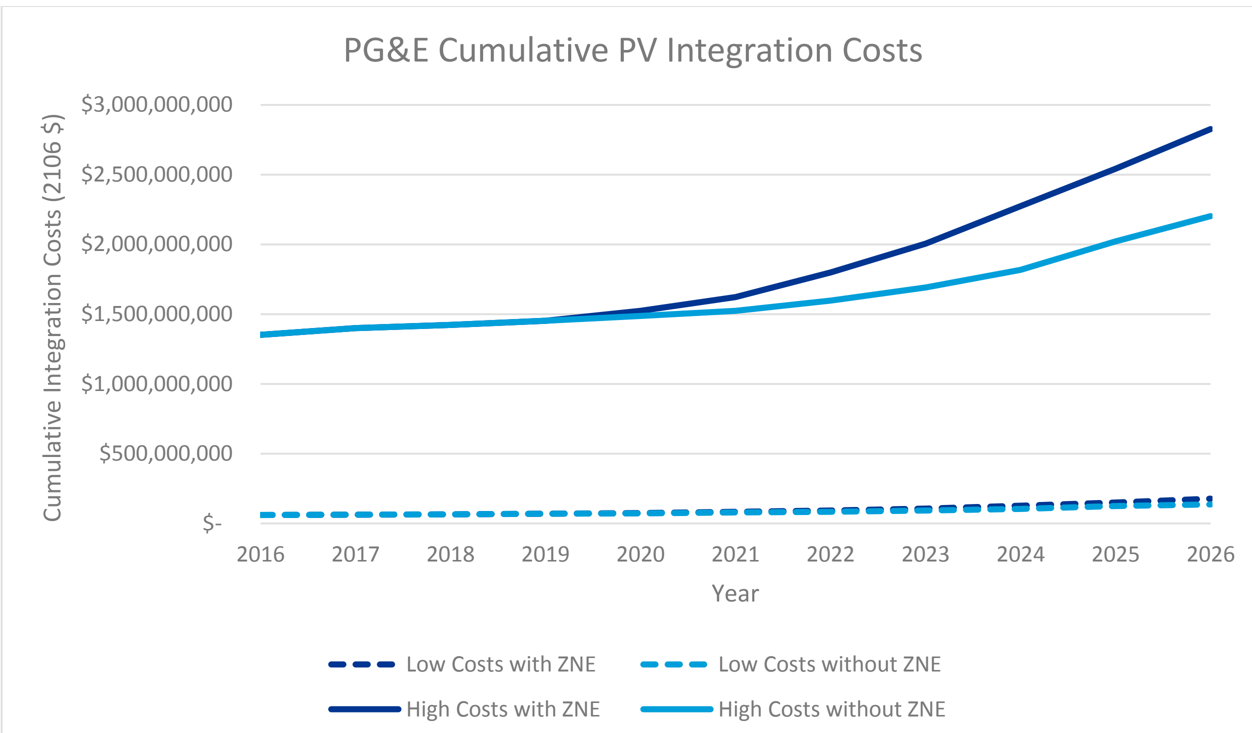

Figure 3.7: Grid integration costs for PG&E distribution system for the 'No ZNE' and 'With ZNE' scenarios

The chart above results in a difference in cost of $623.0 million by 2026 between the two high cost cases and $42.2 million between the two low cost cases, which represents the potential cost range of implementing the ZNE building policy on the PG&E circuits. It should be noted that the majority of the costs in the high cost case are due to the cost of energy storage, which is required to mitigate transient problems that cannot be solved by traditional voltage regulation equipment. If this energy storage was implemented in the buildings for other reasons, then the associated integration costs for this study would be significantly reduced.

A summary of the results by 2026 is shown in Table 3-4 below:

Table 3-4: PG&E system results summary

Parameter	Result
Coincidental Peak Load 2016 (kW)	18,941,396
Coincidental Peak Load 2026 (kW)	21,850,000
PV Installed 2016 (kW)	3,806,066
PV Installed 2026 - Trajectory Scenario (kW)	5,717,499
PV Installed 2026—ZNE Policy Scenario (kW)	6,401,746
PV Penetration 2016 (% of coincidental peak load)	20.09%
PV Penetration 2026 - Trajectory Scenario (% of coincidental peak load)	26.17%
PV Penetration 2026 - ZNE Policy Scenario (% of coincidental peak load)	29.30%
High Total Integration Cost for New Generation—Trajectory Scenario	$849,805,550
High Total Integration Cost for New Generation—ZNE Policy Scenario	$1,472,790,500
High Cost of ZNE Policy	$622,984,950
Low Total Integration Cost for New Generation—Trajectory Scenario	$75,014,506
Low Total Integration Cost for New Generation—ZNE Policy Scenario	$117,164,808
Low Cost of ZNE Policy	$42,150,302

3.3 San Diego Gas & Electric

3.3.1 Representative Circuits

DNV GL carried out a statistical analysis of SDG&E's distribution circuits to first identify a set of 'strata' that represent the characteristics of the circuits that are expected to be significant to the analysis. The characteristics that were selected for this exercise were:

- Voltage (4kV or 12kV);
- Rural or urban circuit;
- Connected load (less than 4MVA, 4MVA to 21MVA, or greater than 21MVA).

This resulted in seven strata being selected. The description of the strata and the number of circuits covered by each is shown in Table 3-5 below:

Table 3-5: SDG&E circuits stratification

Stratum	Voltage	Rural or Urban	Connected Load	Number of Circuits Represented	Percentage of Circuits Represented	Number of Circuits in Sample
111	4kV	Rural	< 4MVA	43	4.2%	2
121	4kV	Urban	< 4MVA	180	17.4%	4
211	12kV	Rural	4MVA to 21MVA	167	16.2%	4
213	12kV	Rural	> 21MVA	83	8.0%	2
221	12kV	Urban	< 4MVA	86	8.3%	2
222	12kV	Urban	4MVA to 21MVA	320	31.0%	7
223	12kV	Urban	> 21MVA	153	14.8%	4

In each stratum, the number of circuits required to provide a representative sample size were selected. The characteristics of the circuits selected are shown in Table 3-6 below:

Table 3-6: SDG&E representative circuit characteristics

Circuit ID	Stratum	Voltage	Customer Type	Connected Load
7	222	12 kV	Urban	14.4MVA
63	213	12 kV	Rural	22.8MVA
86	222	12 kV	Urban	10.5MVA
148	223	12 kV	Urban	30.6MVA
151	223	12 kV	Urban	25.8MVA
215	222	12 kV	Urban	8.7MVA
268	211	12 kV	Rural	13.4MVA
287	222	12 kV	Urban	19.2MVA
290	221	12 kV	Urban	4.5MVA
385	211	12 kV	Rural	17.6MVA
393	211	12 kV	Rural	21.0MVA
438	222	12 kV	Urban	12.2MVA
540	223	12 kV	Urban	22.5MVA
631	211	12 kV	Rural	18.5MVA
640	213	12 kV	Rural	38.7MVA
644	222	12 kV	Urban	17.4MVA
662	223	12 kV	Urban	23.4MVA
676	222	12 kV	Urban	17.9MVA
680	221	12 kV	Urban	1.6MVA
849	111	4 kV	Rural	1.1MVA
862	121	4 kV	Urban	1.1MVA
900	121	4 kV	Urban	2.0MVA
947	121	4 kV	Urban	0.2MVA
975	111	4 kV	Rural	2.9MVA
993	121	4 kV	Urban	3.1MVA

3.3.2 Representative Circuit Integration Costs

In the SDG&E study, the results of each circuit selected in each stratum are combined and averaged to produce a result for the stratum. This result can then be applied to the real circuits that are represented by that stratum. The combined integration cost results for the strata are shown in Figure 3.8 below.

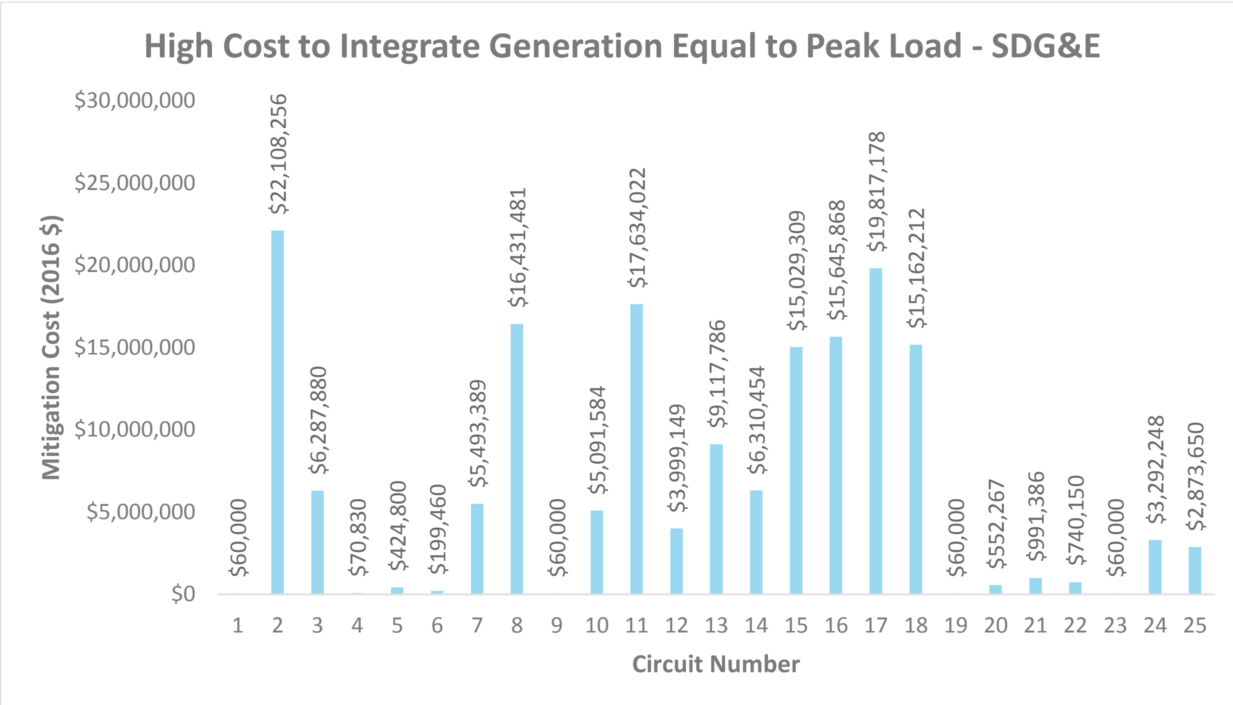

Figure 3.8: High mitigation costs for SDG&E representative circuits

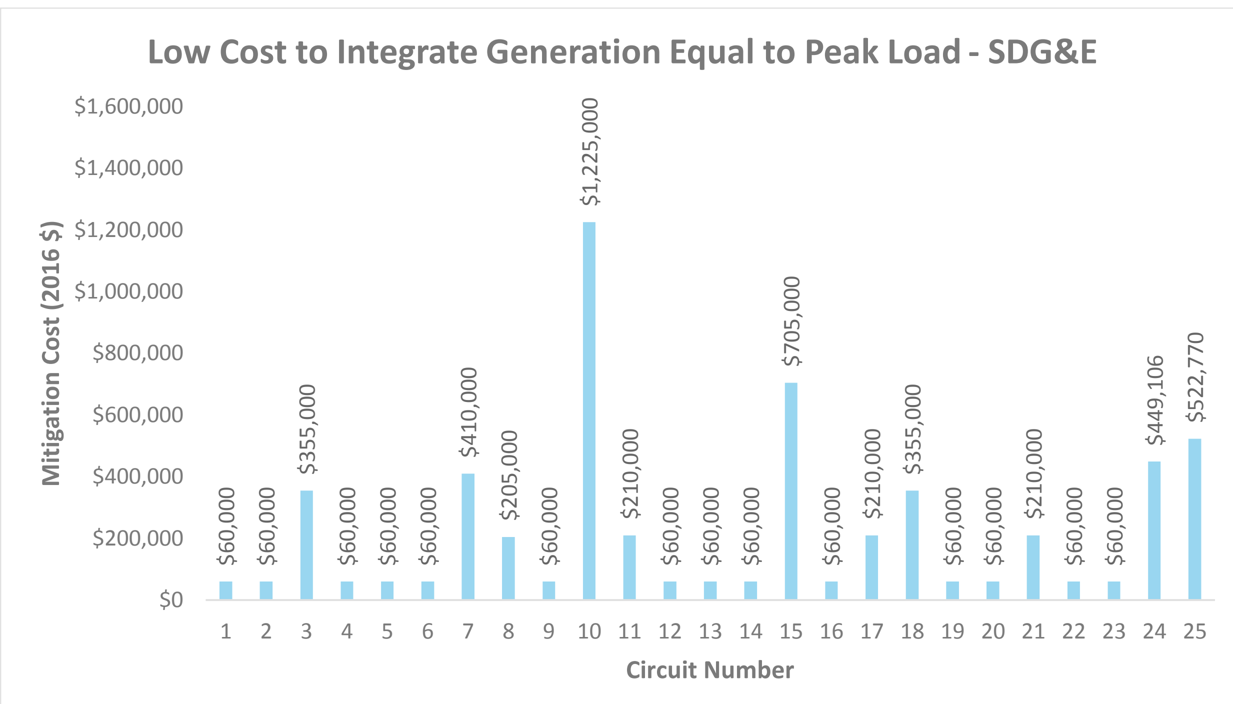

Figure 3.9: Low mitigation costs for SDG&E representative circuits

3.3.3 Extrapolation of Results

The results for the representative circuits were extrapolated to the full SDG&E distribution system based on the stratification process carried out by DNV GL, as described in Section 3.3.1. This circuit mapping identified which stratum result could be used as a proxy for each real circuit in the SDG&E distribution system. In each set of results, the results for the identified stratum—in terms of integration cost for a given PV penetration—were mapped to each circuit. Using the dispersal of new buildings and PV described in Section 2.1, the PV penetration on each circuit was calculated for each year to 2026, and the associated grid integration cost was identified. This was done for both the trajectory scenario and the ZNE policy scenario. Figure 3.10 below presents the comparison of the two scenarios for SDG&E from 2016 to 2026:

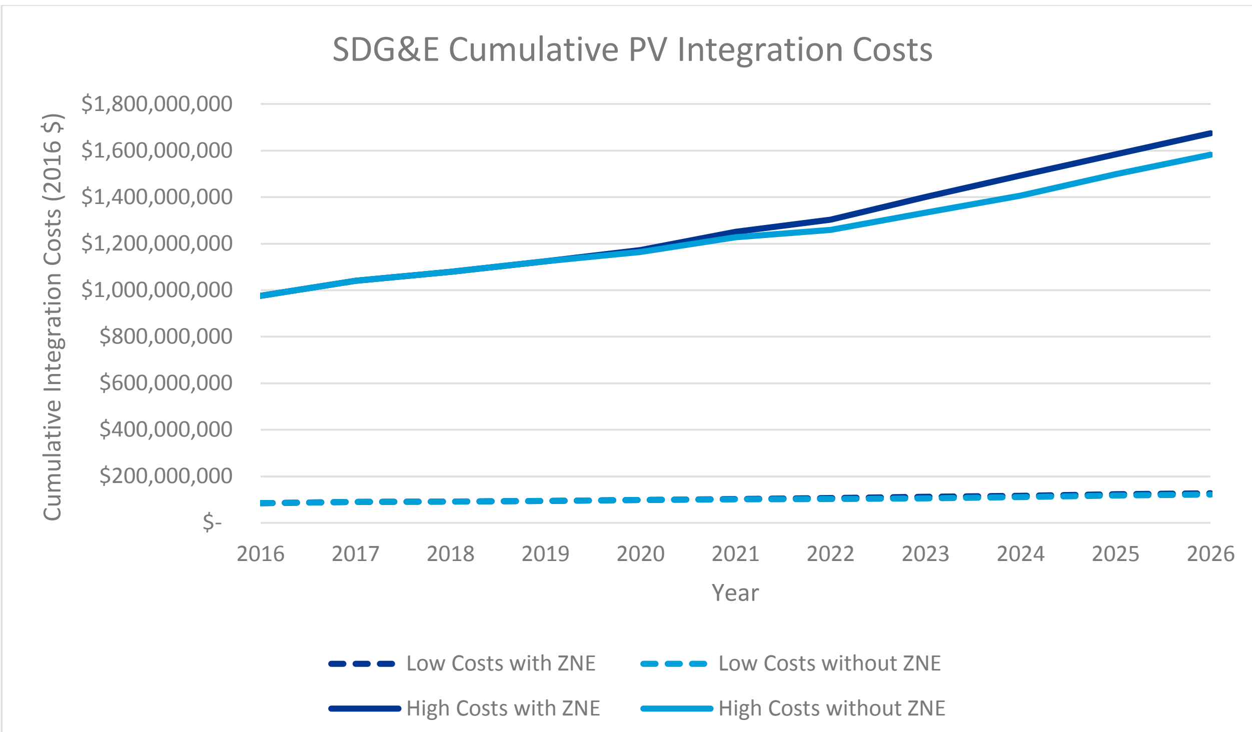

Figure 3.10: Grid integration costs for SDG&E distribution system for the 'No ZNE' and 'With ZNE' scenarios

The chart above results in a difference in cost of $93.0 million by 2026 between the two high cost cases and $5.6 million between the two low cost cases, which represents the potential cost range of implementing the ZNE building policy on the SDG&E circuits. It should be noted that the majority of the costs in the high cost case are due to the cost of energy storage, which is required to mitigate transient problems that cannot be solved by traditional voltage regulation equipment. If this energy storage is implemented in the buildings for other reasons, then the associated integration costs for this study would be significantly reduced.

A summary of the results by 2026 is shown in Table 3-7 below:

Table 3-7: SDG&E system results summary

Parameter	Result
Coincidental Peak Load 2016 (kW)	4,617,488
Coincidental Peak Load 2026 (kW)	4,946,000
PV Installed 2016 (kW)	737,815
PV Installed 2026—Trajectory Scenario (kW)	1,280,027
PV Installed 2026—ZNE Policy Scenario (kW)	1,370,686
PV Penetration 2016 (% of coincidental peak load)	15.98%
PV Penetration 2026 - Trajectory Scenario (% of coincidental peak load)	25.88%
PV Penetration 2026 - ZNE Policy Scenario (% of coincidental peak load)	27.71%
High Total Integration Cost for New Generation—Trajectory Scenario	$605,725,458
High Total Integration Cost for New Generation—ZNE Policy Scenario	$698,774,231
High Cost of ZNE Policy	$93,048,773
Low Total Integration Cost for New Generation—Trajectory Scenario	$37,687,165
Low Total Integration Cost for New Generation—ZNE Policy Scenario	$43,328,285
Low Cost of ZNE Policy	$5,641,120

3.4 Smart Inverter Sensitivity Study

Smart inverters provide some functionalities which have the potential to mitigate some of the problems addressed in this study. In this study, the Phase I functionalities, which are intended to be autonomous, were investigated for the potential to offset some of the integration costs attributed to energy storage. A high-level review of the potential impacts of each of the proposed Phase I functions is shown in Table 3-8 below:

Table 3-8: Smart inverter phase I functions

Function Name	Description of Function	Impact on Integration Costs
Anti-Islanding	Support anti-islanding to trip off under extended anomalous conditions, coordinated with the following functions.	Could be used to offset re-close blocking costs which are triggered when there is potential reverse power flow at a re-closer, although IOU's have not considered anti-islanding functions to-date when specifying re-close blocking requirements.
Voltage Ride-Through	Provide ride-through of low/high voltage excursions beyond normal limits.	No impact on integration costs in this study—inverters were assumed to remain connected throughout the study.
Frequency Ride-Through	Provide ride-through of low/high frequency excursions beyond normal limits.	No impact on integration costs in this study as system frequency variations were not studied. Improved ride-through in practice would likely not have an impact on upgrade costs included in this study, but may have an impact on improved reliability for customers on a circuit.
Volt/Var Control	Provide volt/var control through dynamic reactive power injection through autonomous responses to local voltage measurements.	Could be used to offset energy storage costs which are triggered when variable output of PV systems could potentially cause transient voltage violations.
Ramp Rate Control	Define default and emergency ramp rates as well as high and low limits.	No impact on integration costs in this study, as ramp rates would likely have to be too slow to mitigate transient voltage violations.
Fixed Power Factor	Provide reactive power by a fixed power factor.	Could be used to mitigate static voltage violations, but less effective than volt/var control for variable voltage violations.
Soft-Start	Reconnect by "soft-start" methods (e.g. ramping and/or random time within a window).	No impact on integration costs in this study, as start-up and re-connection events were not included.

For the current study, volt/var control is the most relevant function with respect to the integration costs, as noted in Table 3-8 above. The associated cost of implementing these controls on smart inverters may be significantly less than the cost of appropriately-sized energy storage systems.

Implementation of smart inverter functions is being discussed currently in several working groups, including the Smart Inverter Working Group organized by the California Public Utilities Commission and the UL 1741SA implementation working group organized by the California Energy Commission. Some rules have been proposed regarding default control settings. At present, the rules specify that smart inverters will operate with real power priority. The transition to reactive power priority to allow smart inverters to mitigate voltage issues has been implemented in IEEE 1547 and is already utilized in Hawaii and Europe. In December 2017, the utilities submitted a proposal to require smart inverters to use reactive power priority, and the CPUC is expected to make a decision on the proposal in early 2018.

A sensitivity analysis was carried out assuming the rules are changed to require new inverters to prioritize reactive power when required to correct a voltage problem. In the analysis, the new generation was modelled using smart inverters with a volt/var control function enabled. The volt/var curve used is shown in Figure 3.11 below:

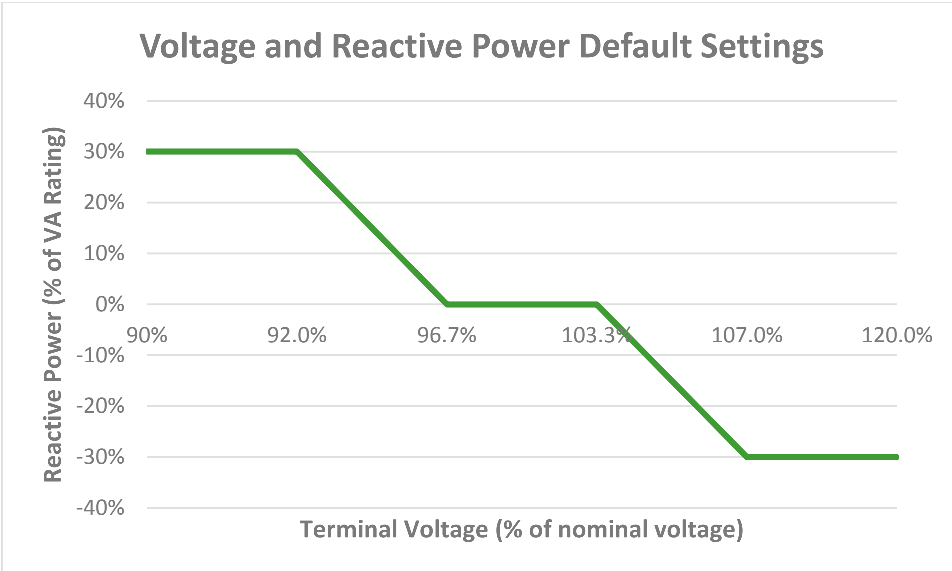

Figure 3.11: Volt/Var curve used in study

The same analysis process was used as for the original study. Where the volt/var function was required to mitigate a high voltage problem, it was assumed that an additional reactive power source would be required on the circuit. The cost used for this was the average of the costs for pad-mounted capacitor banks ($45,500) and overhead capacitor banks ($33,000) provided by PG&E, which is $39,250. In this sensitivity study, the high cost case was re-studied with smart inverters implemented. The low cost case was not re-studied, as there were no requirements for energy storage systems in that case that could be mitigated by the smart inverter functions. The results for the original high cost case and the same analysis using smart inverters are shown in Table 3-9 and Table 3-10, respectively:

Table 3-9: Original high cost study results (2016 $)

Original High Cost Results	PG&E	SCE	SDG&E
Trajectory Scenario	$ 850 million	$134 million	$605 million
ZNE Policy Scenario	$1,473 million	$179 million	$698 million
Difference	$ 623 million	$ 45 million	$ 93 million

Table 3-10: Smart inverter study results (2016 $)

Smart Inverter Study	PG&E	SCE	SDG&E
Trajectory Scenario	$262 million	$92 million	$252 million
ZNE Policy Scenario	$510 million	$116 million	$289 million
Difference	$248 million	$ 24 million	$ 36 million

The results illustrate the significant potential cost reductions obtained by using volt/var control to limit variable voltage violations which may otherwise be mitigated by energy storage systems. Use of reactive power priority implies potential real power losses if real power is sacrificed to provide the required reactive power at times when inverters are fully-loaded. Based on the volt/var curve shown in Figure 3.11, the maximum power factor range is +/-0.95. The maximum real power loss at any time is therefore 5%. This level of loss is only possible when the inverter is fully

loaded such that all of the reactive power required involves reduction in real power, and at a time when there is a sufficient voltage excursion that requires reactive power from the inverter. Across the operating life of a PV system, the losses due to implementation of reactive power priority can therefore be expected to be significantly less than 5% in the majority of cases. Customers may also avoid real power losses by sizing their inverters larger.

The results of this sensitivity study (in terms of potential cost savings) provide support for the recommendation that the Rule 21 tariff require prioritization or reactive power over real power as part of the interconnection requirements to ensure distribution grid safety and reliability.

3.5 Sensitivity Study—Energy Storage Cost Reduction

During the analysis of the representative circuits and the extrapolation of the results, it became clear that the cost of energy storage is a major driver for mitigation costs once mitigation is required. Figure 3.12 below presents the mitigation cost profiles for sample representative circuits from each of the three utilities. In each study, the elbow represents the penetration at which energy storage was required to mitigate the technical violations. The sharp increase in costs demonstrates the impact of energy storage cost assumptions on the result.

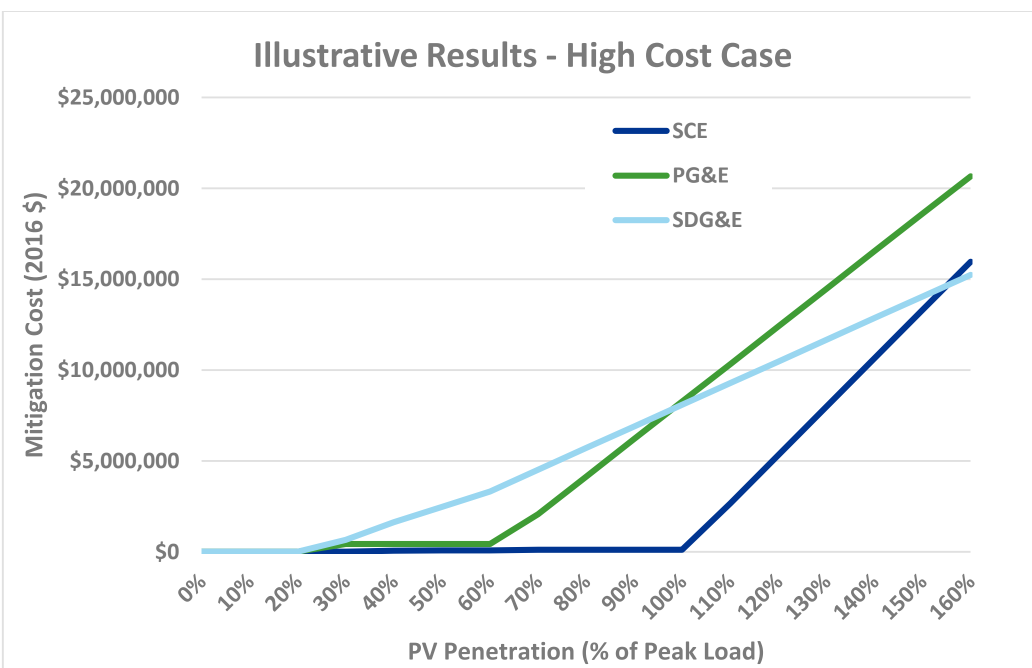

Figure 3.12: Example mitigation cost profiles

To establish a better estimate of storage costs, a sensitivity study was carried out using an assumption of storage cost reductions in the study years. Lazard forecasted a 11% annual reduction in cost of energy storage for the next 5 years[33]. For this study it was assumed that no further reductions in energy storage costs occur after 2021. The resulting year-by-year mitigation cost profile for the PG&E feeders is shown in Figure 3.13 below alongside the original study results for comparison.

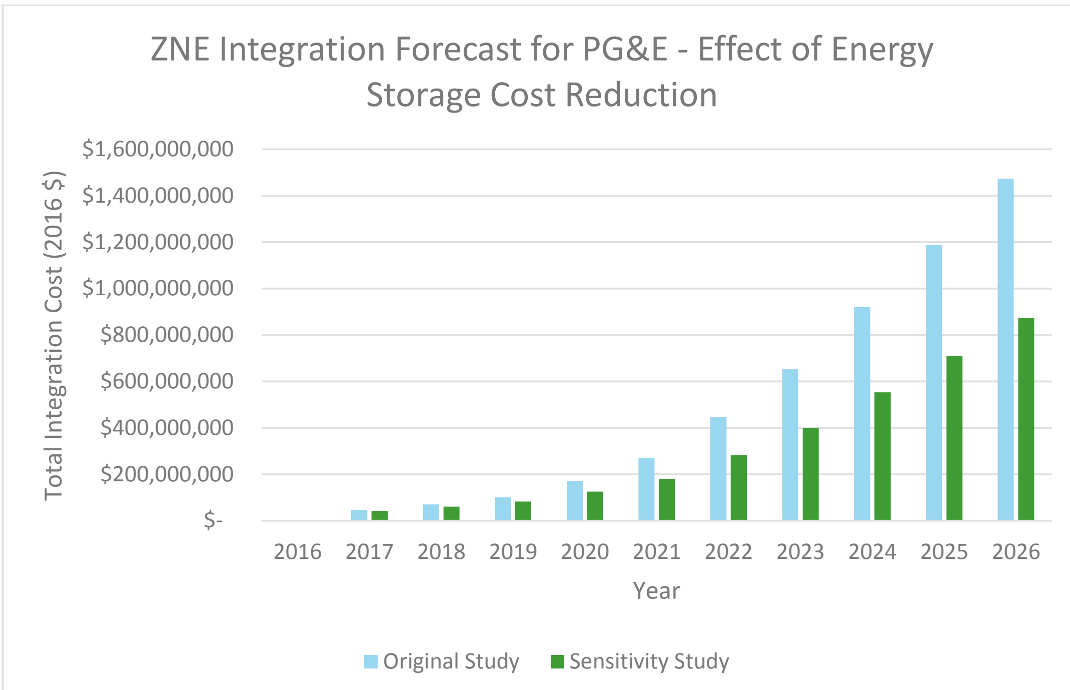

Figure 3.13: Total PG&E grid integration costs with and without cost reduction assumption

The results show that the cost of mitigation for ZNE homes on the PG&E system by 2026 reduced from $1.473 billion to $874 million, a total saving of 41%.

The resulting year-by-year mitigation cost profile for the SCE feeders is shown in Figure 3.14 below alongside the original study results for comparison.

[33] Lazard's Levelized Cost of Storage Analysis – Version 2.0; Lazard; December 2016

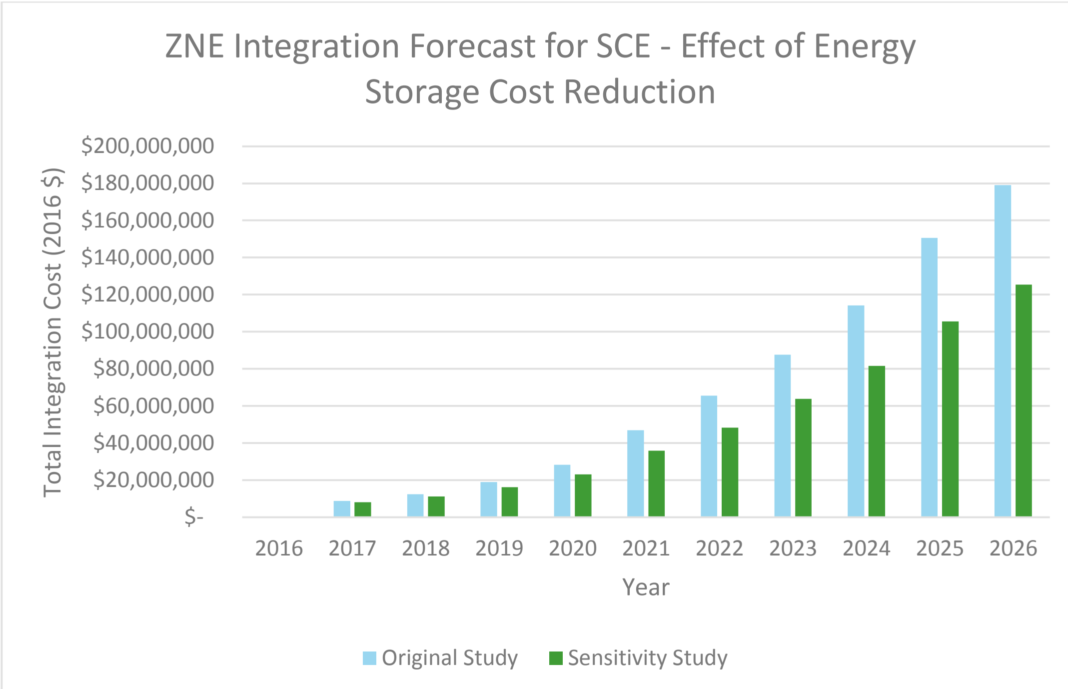

Figure 3.14: Total SCE grid integration costs with and without cost reduction assumption

The results show that the cost of mitigation for ZNE homes on the SCE system by 2026 reduced from $179 million to $125 million, a total saving of 30%.

Finally, the resulting year-by-year mitigation cost profile for the SDG&E feeders is shown in Figure 3.15 below alongside the original study results for comparison.

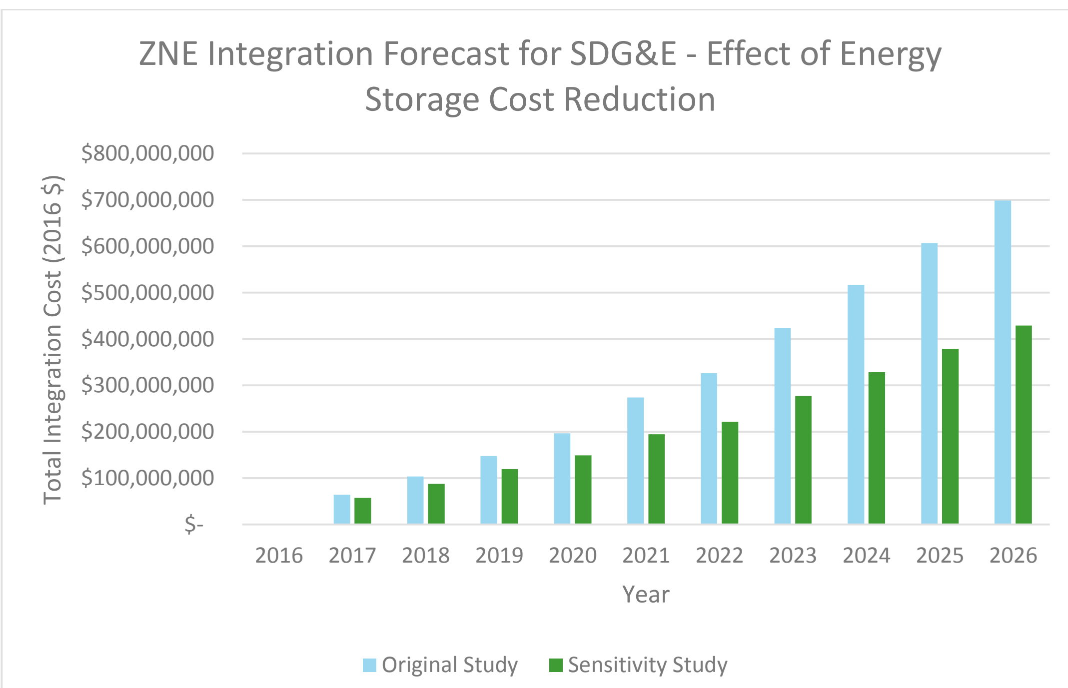

Figure 3.15: Total SDG&E grid integration costs with and without cost reduction assumption

The results show that the cost of mitigation for ZNE homes on the SDG&E system by 2026 reduced from $699 million to $429 million, a total saving of 39%.

4 CONCLUSION

The objective of this study was to estimate grid integration costs for a forecasted ZNE-home build-out across the three California IOUs. The purpose was not to estimate the benefits or value of ZNE homes. Ultimately, the results of this study are expected to be used by the California Energy Commission as input to cost-effectiveness analysis for new ZNE homes.

The first step in this process was to study the available feeder data and location to forecast the number of ZNE-homes to be built on each distribution feeder in California between 2016 and 2026, as well as expansion of stand-alone PV capacity (i.e., PV units not connected with new ZNE homes).

A methodology was developed to calculate grid integration costs for increasing penetrations of ZNE homes on a distribution circuit. In this study, a ZNE home project is studied as a generator, as the effect of the variable generation during low load is likely to have the largest impact on the circuit's operating parameters. In the study, the new generator representing the ZNE homes on the circuit is placed at the end of the circuit furthest from the substation. This represents a worst-case condition for most circuits. The size of the generator is increased incrementally such that the penetration of distributed generation on the circuit increases from 0% to 160% in 10% increments. For each of these increments, static and quasi-static load-flow studies were carried out and any technical violations identified. Where technical violations occurred, the appropriate mitigation option was identified and the associated cost estimated.

It was not practical to carry out the full analysis for every single distribution circuit for the three IOUs. Instead, a process of selecting representative circuits was used, as described in Section 2.2.1. In this process, a number of circuits is selected that can be considered as a statistically valid representation of the full set of distribution circuits for a given IOU. In the case of SCE and PG&E this exercise had been carried out previously, and the same circuit samples were considered suitable for this project. In these cases, each distribution circuit in the IOU's territory is mapped to one of their representative circuits. For SDG&E, DNV GL carried out a sampling exercise using an in-house tool. This resulted in the identification of seven 'strata', or groups of circuits exhibiting similar characteristics. Each circuit in the full SDG&E distribution system is represented by one of these strata.

Once the grid integration study methodology was carried out for the representative circuits for a given IOU, the results were extrapolated to the full set of distribution circuits. For each year between 2015 and 2024 the number of ZNE homes forecasted to be built on that circuit in the first part of this study was translated to a capacity of distributed generation. An assumption of 2kW of solar generation per home was used for this study. This value was combined with the forecasted expansion of stand-alone PV and any increases in load due to the ZNE homes to produce a new penetration value for each year. This penetration was used to find the associated grid integration costs from the representative circuit or stratum associated with the real circuit in question.

The analysis was run for two assumed dispersal cases of ZNE homes on a circuit:

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

Case 1 above provides the high end of the range of estimated costs, while case 2 provides the low end of the range of estimated costs. It should be noted that the high cost case can be considered very unlikely to occur in practice, as it would require all new ZNE buildings and new generation to be installed at, or close to, the end of the circuit. In practice, new buildings are more likely to be spread out on a circuit, resulting in a dispersal more similar to case 2 above. The high cost case does not account for the estimated 60%reduction in integration costs expected if the CPUC approves a pending request to require smart inverters to use reactive power priority. The actual integration costs could therefore be expected to be closer to the low cost case than the high cost case.

4.1 Results and Observations

The results for SCE show a difference in cost of $28.1 million by 2026 between the two high cost cases and $15.0 million between the two low cost cases, which represents the potential cost range of implementing the ZNE building policy on the SCE circuits. The results for PG&E show a difference in cost of $623.0 million by 2026 between the two high cost cases and $42.2 million between the two low cost cases, which represents the potential cost range of implementing the ZNE building policy on the PG&E circuits. The results for SDG&E show a difference in cost of $93.0 million by 2026 between the two high cost cases and $5.6 million between the two low cost cases, which represents the potential cost range of implementing the ZNE building policy on the SDG&E circuits. The wide variation between the two cases illustrates the potential savings by optimizing the placement of new ZNE buildings and distributed generation, where the new installations can be distributed roughly in proportion to load on a circuit (and not concentrated in a single area), the integration costs will likely be minimized.

It should be noted that the majority of the costs in the high cost case are due to the cost of energy storage, which is required to mitigate transient problems that cannot be solved by traditional voltage regulation equipment. If this energy storage was implemented in the buildings for other reasons, then the associated integration costs for this study would be negated.

The grid integration costs for PG&E and SDG&E circuits tend to be significantly higher than those for SCE circuits. There are two primary reasons for this:

1. The integration costs on the PG&E and SDG&E representative circuits tended to be higher, and start to increase at lower penetrations (i.e., they have a lower hosting capacity). This is likely due to the length of the feeders—PG&E and SDG&E feeders are on average longer than SCE feeders. Longer feeders are often more sensitive to voltage issues, particularly at the end of the circuit furthest from the substation. Normally this can be mitigated by normal voltage regulation equipment, but this equipment is not as effective with the faster changes in load flow profiles that can result from high penetrations of solar generation. The result of this is that there tend to be higher costs at lower penetrations on the longer circuits, which drives the higher overall integration cost. Figure 4.1 and Figure 4.2 below provide comparisons of the integration cost profiles for the representative circuits analyzed for SCE and PG&E. These charts illustrate the general higher integration costs on PG&E circuits at lower PV penetrations. This indicates that future distribution feeders should be designed to

have shorter lengths, similar to those in the SCE territory, if grid integration costs for PV installations are to be minimized.

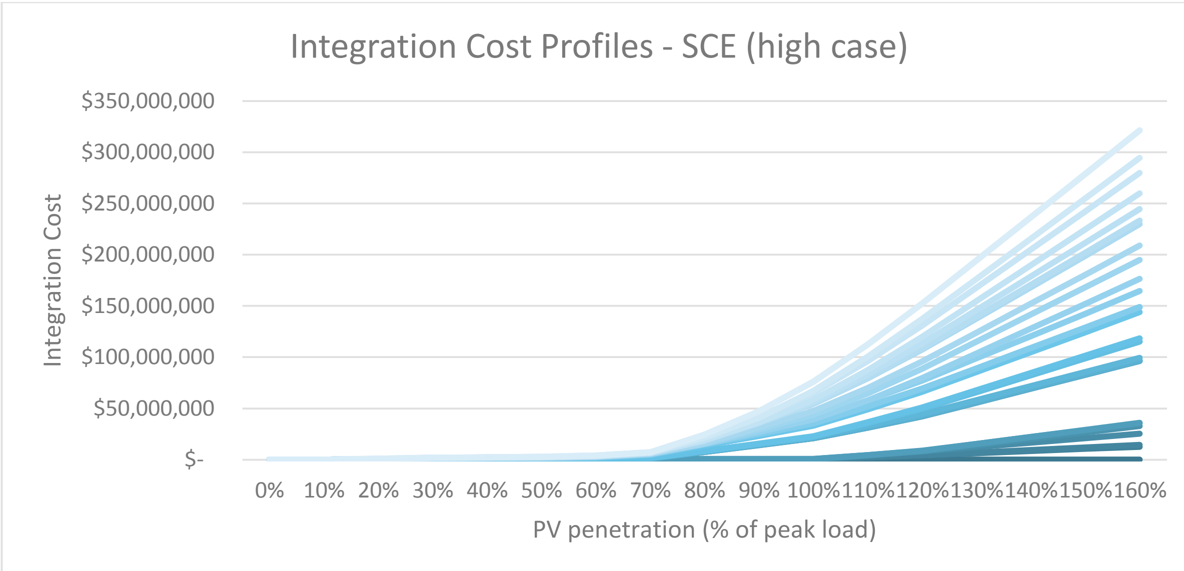

Figure 4.1: SCE integration cost profiles for representative circuits

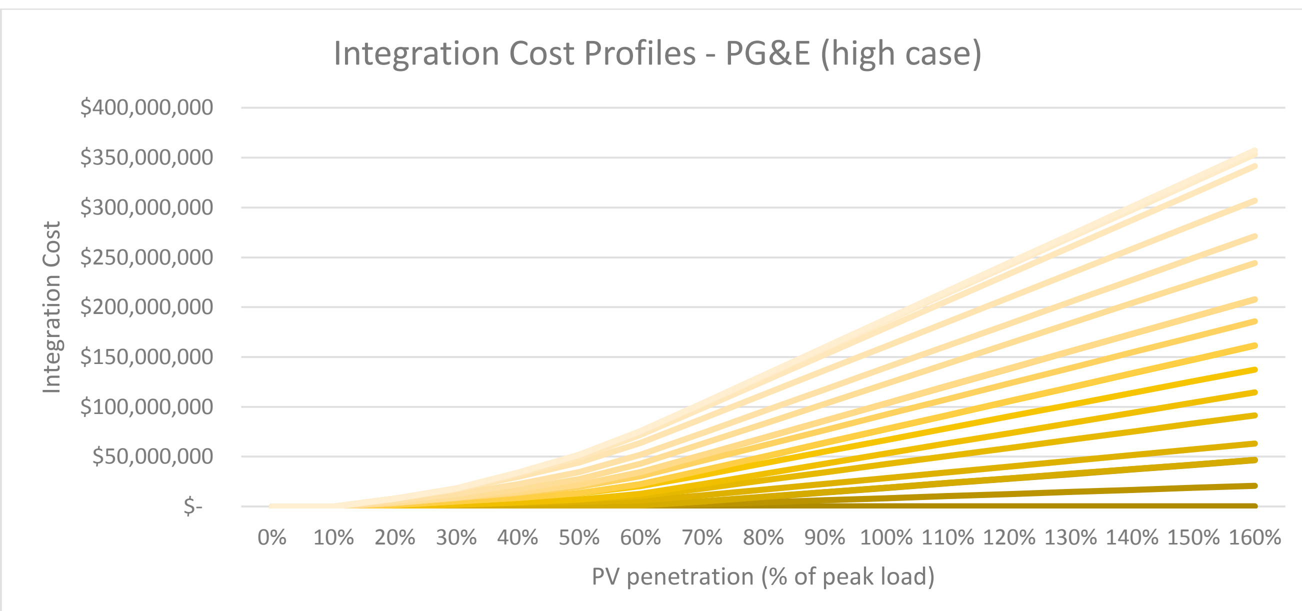

Figure 4.2: PG&E integration cost profiles for representative circuits

2. PG&E and SDG&E circuits tended to have higher penetrations than SCE circuits. This may also be due to the length of the circuits—as SCE tends to have shorter circuits, they have more of them so that their total PV capacity is spread out among a larger number of circuits. The result is that fewer SCE circuits exceed their hosting capacities, so there are no integration costs for these circuits.

Smart inverters have been discussed with regards to their capabilities to reduce some of the negative impacts of variable generation. The technology is already available and has been implemented in other jurisdictions (for example in Germany). The California IOUs recently submitted a proposal to require smart inverters to use reactive power priority, and the CPUC is expected to make a decision on the proposal in early 2018. A further sensitivity study was carried out assuming that 'reactive power priority' was activated to offset the high costs of mitigating variable voltage problems. The results showed that the integration costs in the high cost case were reduced from $1.473 billion to $510 million for PG&E, from $179 million to $116 million for SCE and from $698 million to $289 million for SDG&E for the ZNE scenario by 2026. It should be noted that there is the potential for some real power losses where 'reactive power priority' is implemented. These losses have not been estimated in this study, but they are likely to be minimal in the majority of cases, and cannot exceed 5% of the rated plant output at any time based on the default volt/var curve in Figure 3.11. The results of this sensitivity study (in terms of potential cost savings) provide support for the recommendation that the Rule 21 tariff require prioritization of reactive power over real power as part of the interconnection requirements to ensure distribution grid safety and reliability as well as to reduce grid integration costs associated with high penetrations of PV.

During the analysis, it was clear that energy storage costs have the largest impact on this value beyond the point at which energy storage is required. A sensitivity study was carried out with an assumption of decreasing energy storage costs based on available study data. This resulted in a total grid integration cost for ZNE homes on the PG&E system of $874 million by 2026 in the high cost case, versus the original study result of $1.473 billion, a 41% reduction. On the SCE system, the total grid integration cost with energy storage cost reductions was $125 million versus the original study result of $179 million, a 30% reduction. For SDG&E, the total grid integration cost with energy storage cost reductions was $429 million versus the original study cost of $698 million, a 39% reduction.

It should be noted that this study is limited to mitigating challenges that are presented at the distribution level. There are other challenges due to PV systems that affect the system as a whole, notably demand ramping, over-generation during daytime and frequency support at the system level. These are other potential drivers for installation of energy storage systems in conjunction with solar PV systems so that there is the capability to address these other challenges.

In addition, although out of the scope of this study, it is important to also consider the impact of electric rate reform as it pertains to how to mitigate integration costs.

5 USE OF RESULTS

The intended use of the results of this study is to provide input to cost estimates for new ZNE homes. Due to the nature of the methodology—selecting representative circuits and applying the results from these across many real circuits—there is the possibility of significant error if these results are applied on a circuit-by-circuit basis. The results should be more accurate for a larger number of circuits as any uncertainty for individual circuits is mitigated across a large sample size. Therefore, the resulting 'per home' grid integration cost value is more applicable across a large area, such as an IOU.

It is also important to recognize that a large part of the grid integration costs in the high cost cases is due to requirements of energy storage systems. However, there may be other drivers for the use of energy storage systems, in which case a ZNE home developer may choose to install these technologies before considering their positive impacts on the local grid. In this case, the grid integration costs would be removed entirely provided that the energy storage system is of an equivalent kW size to the associated generation, and is capable of being controlled by load and voltage signals such that it can either maintain zero-export of energy from the home to the distribution circuit, or it can accept appropriate signals to ensure that no overloads or voltage violations occur due to the impact of its associated generation on a given section of the circuit.

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