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New Challenges Facing Electric Power Systems: Integrating Technical Realities and Policy Goals

by

Anna Marie Brockway

A dissertation submitted in partial satisfaction of the

requirements for the degree of

Doctor of Philosophy

in

Energy and Resources

in the

Graduate Division

of the

University of California, Berkeley

Committee in charge:

Professor Duncan Callaway, Chair
Professor Andrew Jones
Professor Lucas Davis

Spring 2022

New Challenges Facing Electric Power Systems: Integrating Technical Realities and Policy Goals

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Anna Marie Brockway

Abstract

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Anna Marie Brockway

Doctor of Philosophy in Energy and Resources

University of California, Berkeley

Professor Duncan Callaway, Chair

Existing and emerging stressors are forcing monumental changes in the operation and planning of electric power systems. These stressors include increasing integration of renewable energy, rapidly growing demands due to electrified transportation and heating, and widespread climate change impacts. At the same time, policymakers, regulators, and the public are holding electric power systems accountable for meeting electricity demand safely, reliably, and cost-effectively, for operating sustainably, and for serving customers equitably. In this context, planning for the future requires increasing attention on accounting for the technical characteristics of the electricity system alongside policy goals. This dissertation is structured around bridging technical and policy considerations in two key areas of power system planning: (1) integrating new technologies and loads on electric distribution grids, and (2) adapting to climate change.

Chapters 1 and 2 of this dissertation focus on electric distribution systems. These are comprised of the substations, circuits, and associated electrical equipment that serve homes, businesses, and industry. This infrastructure will need to accommodate the increasing deployment of new technologies, such as distributed solar arrays and electric vehicles, as well as growing demands for electricity to serve new loads. However, its ability to do so may come into conflict with ambitious policy goals for the deployment of distributed energy resources and emissions reductions through electrification. The State of California forms a ripe case study for a granular analysis of distribution system limits: the state is a leader in deploying these new technologies and has set ambitious climate goals that will rely in part on electrifying buildings and transportation. It has also led efforts in requiring its largest utilities to publish granular data on their electric distribution systems.

In Chapter 1, I consider the limits of the distribution circuits operated by California's two largest electric utilities, Pacific Gas & Electric (PG&E) and Southern California Edison, to accommodate distributed solar and new loads. I find that distribution circuit limits will broadly constrain households' ability to adopt new technologies. Further, I find that distribution system limits will exacerbate existing inequities in who can benefit from these technologies. Meeting policy goals related to equitable access to distributed resources and their benefits will therefore require careful consideration of the value these technologies may bring in the context of distribution system constraints.

In Chapter 2, I consider how new electricity demands due to vehicle and building electrification may stress PG&E's distribution grid. Specifically, I evaluate circuit and substation limits for new load in concert with projections of hourly demand patterns due to electrification. I find that the rate of circuit upgrades that will be needed to meet increasing demands due to electrification may outpace what is possible with conventional grid investments. Enabling rapid electrification to occur will require, therefore, planning ahead for grid upgrades as well as evaluating alternatives to conventional investments.

Chapters 3 and 4 of this dissertation focus on climate change adaptation for electricity systems. Climate change will have widespread impacts on electricity demand, generating resources, and electric lines and other equipment. Planning for these impacts requires evaluating these impacts in the context of the planning approaches that are currently used in the electricity sector.

In Chapter 3, I focus on understanding how climate data may be used in electricity sector planning. I use California as a case study, which enables a nuanced exploration of the many data streams, inputs, and actors involved in today's electricity sector planning processes. I find that existing planning approaches will require significant restructuring to incorporate climate data that must be used to plan for the future.

In Chapter 4, I move beyond California to consider how critical infrastructure planning processes, with electricity as a case study, might be able to appropriately incorporate the significant uncertainties that climate change will bring. I conduct a review of literature in decision science, electric industry practice, and electricity sector planning under climate change. Through these reviews, I identify key insights from decision science for managing deep uncertainty and evaluate how they might be incorporated into electricity sector planning.

I conclude with a summary of findings, recommendations for policymakers, and areas for future research.

Dedicated in memory of Volodymyr Osypchuk, for showing me how to be human in this world.

Contents

Acknowledgements **iv**

Introduction **1**
Background and motivation 1
Part 1: Electric distribution systems 2
Part 2: Climate change adaptation 7

1 Inequitable access to distributed energy resources due to grid infrastructure limits in California **10**
1.1 Introduction 10
1.2 Growth in DERs raises issues for equity and the grid 11
1.3 Grid limits reduce access to DERs across utility territories 13
1.4 Grid limits reinforce demographic disparities in DER access 17
1.5 Conclusions 21
1.6 Methods 22

2 Load electrification and the electric distribution system **30**
2.1 Introduction 30
2.2 Methods 31
2.3 Results and discussion 37
2.4 Conclusions 44

3 Weathering adaptation: Grid infrastructure planning in a changing climate **46**
3.1 Introduction and motivation 46
3.2 The California planning context: Electricity systems and climate adaptation 48
3.3 Background on climate modeling 50
3.4 Climate-relevant input variables for electricity systems 52
3.5 Electricity infrastructure planning models and impacts from a changing climate . . 56
3.6 Recommendations 63
3.7 Conclusions and policy implications 71

4 Climate-aware decision-making: Lessons for electric grid infrastructure planning and operations **73**
4.1 Introduction . . . 73
4.2 Methodology . . . 75
4.3 Results and analysis . . . 78
4.4 Recommendations . . . 97
4.5 Conclusions . . . 100

Conclusion **102**
Summary of findings . . . 102
Recommendations and areas for future research . . . 104

Bibliography **109**

A Chapter 1 Appendix **159**
A.1 Growth in DERs raises issues for equity and the grid (cont.) . . . 159
A.2 Grid limits reduce access to DERs across utility territories (cont.) . . . 160
A.3 Grid limits reinforce demographic disparities in DER access (cont.) . . . 163
A.4 Supplementary methods . . . 165

B Chapter 2 Appendix **174**
B.1 Circuit hosting capacity . . . 174
B.2 Substation capacity . . . 180
B.3 Costs of circuit and substation upgrades . . . 181
B.4 Residential electrification . . . 184
B.5 Electric vehicle adoption . . . 185
B.6 Solar generation calculations . . . 188

C Chapter 3 Appendix **191**
C.1 Electricity infrastructure planning in California . . . 191
C.2 Mechanisms for power production . . . 195

D Chapter 4 Appendix **198**
D.1 Search terms used in literature reviews . . . 198
D.2 Coding of utility practice review into activity areas . . . 199
D.3 Summary of utility activity areas . . . 199
D.4 Examples of coded utility practice areas . . . 204

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Introduction

Background and motivation

Electric power systems are undergoing the most fundamental shifts since their inception. In the 21st century, electricity systems are being tasked with relying on increasing amounts of renewable energy, powering new loads like heating and transportation, and keeping the lights on even as climate change makes that more difficult. They also face growing scrutiny from regulators, policymakers, and the public about how well they are meeting traditional goals for how they operate—safety, reliability, and cost-effectiveness—and new ones, such as sustainability and equity [1].

Planning for these new realities increasingly requires incorporating insights from far beyond power systems engineering into all aspects of electricity sector decision-making, while ensuring that policymakers appropriately account for infrastructure considerations when setting policy goals. And while the infrastructure that delivers electricity to homes, businesses, and industry has stayed relatively constant over decades, new climate-induced stressors are changing how it performs in today's world. Moving forward requires critically evaluating what we can expect from the infrastructure that we have today, and how to make the best decisions we can about maintaining and operating it while incorporating new technologies and policy goals.

This dissertation focuses on two categories of stressors that offer key case studies of how planning for the future of electric power systems will require bridging technical and policy considerations. First, it focuses on electric distribution systems, where new technologies—such as rooftop solar photovoltaic (PV) arrays and electric vehicles (EVs)—and growing electricity demands are pushing up against the technical limits of existing infrastructure. Then, it discusses the impacts that climate change will bring to bear on electricity systems in the context of the planning processes we use today to make decisions about their future.

Chapters 1 and 2 address electric distribution systems, while Chapters 3 and 4 address climate change adaptation. From these topics, this dissertation draws out lessons about what new approaches are needed in planning and decision-making for the future of electricity systems.

Part 1: Electric distribution systems

Since its inception in the 20th century, the electric power system has operated as a vast network of generators and lines that deliver electricity to where it is needed (Figure 1). Conventional large-scale generating resources send electricity into transmission lines, which then carry power long distances to load centers. Distribution substations convert high-voltage power from the transmission system to lower voltages to send it to end-use customers. Throughout the system, electricity supply and demand must stay in balance on sub-second timescales to keep the grid running.

The distribution system—composed of distribution substations, circuit lines, and associated power equipment—is where electricity customers interact most directly with the grid. Homes and businesses are served by distribution circuits that deliver electric power, accept new load from EVs and other electricity uses, and take in power from distributed generation sources like rooftop solar PV arrays.

The characteristics of electricity service that a customer will receive depends in part on where they connect to the grid, down to the particular substation, distribution circuit, and even interconnection point along that circuit. For example, customers in urban areas might experience more reliable electricity service than customers in suburban or rural areas due to fewer risks to power lines from nearby vegetation, as well as the potential for a utility to reconfigure nearby lines to isolate outages to small areas of the grid [3]. Customers who happen to be located close to a distribution substation or voltage regulator might also receive electricity at a slightly higher voltage than customers located near the end of a circuit, before some voltage is lost due to electrical resistance along circuit lines [4].

Other customers might connect to the grid via circuits that need maintenance or upgrades, either due to aging infrastructure or where existing equipment cannot accommodate growing demands. Today, regulated utilities make such upgrades and socialize their costs across all ratepayers [5]. This insulates customers from high costs if they happen to be served by equipment that needs replacing, and enables upgrades to occur when and where they are needed, regardless of local users' ability to pay in full.

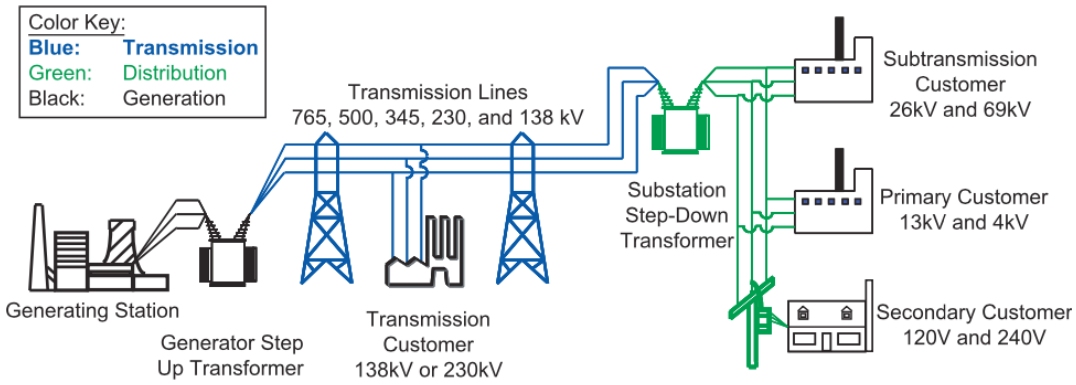


Figure 1: Basic structure of the U.S. electricity system. Reproduced from [2].

Yet increasing demands on electric distribution systems have the potential to exacerbate local issues in ways that may directly impact end-use customers. These demands are tied to growing interest in distributed energy resources (DERs) (e.g., small-scale solar PV, EVs, and flexible electricity loads), electrification of end uses that currently rely on fossil fuels (e.g., space and water heating, transportation), and other stressors, such as climate change impacts and population growth. Part 1 of this introduction focuses on DERs and load electrification, while Part 2 returns to climate change.

Distributed energy resources, new loads, and electricity infrastructure

Rooftop solar PV, EV charging, and electrification of heating loads all prompt increased current flow through existing distribution lines, transformers, and other equipment (e.g., circuit breakers, switches, voltage regulators, etc.), potentially surpassing the technical limits of the local grid. Violations of these technical limits can lead to power quality issues, equipment failures, and safety concerns [4, 6–8]. Circuit upgrades can fix these issues and enable additional demands, but they require investments in new equipment that take time and money to implement [9–11]. In the meantime, customers may face interconnection delays for PV systems and experience malfunctioning equipment as a result of new loads [12, 13].

Growing interest in DERs has led to increasing adoption of these technologies and the explicit inclusion of DERs into state policies and climate goals [14, 15]. DERs are referred to as "resources" due to to their potential to provide valuable services to the electricity grid and its users [16]: for example, by generating clean electricity (PV), smoothing load patterns (EVs, flexible loads), storing electricity for later use (EVs, distributed storage), increasing local resiliency and reducing losses in electricity delivery (PV plus storage), and/or aiding grid stability through power management by smart inverters (PV, EVs) [17]. As such, DERs offer the potential to re-imagine how electric distribution grids may operate in the 21st century: as more resilient, agile, smart, and sustainable systems for delivering electricity to customers [18–20].

However, researchers, policymakers, and practitioners have also asked important questions about access, affordability, and implementation challenges that may stymie the ability of DERs to achieve policy goals. For example, existing market structures that prioritize incentives for site-specific rooftop PV arrays primarily benefit homeowners and may shift costs to other customers who may be less able to afford their electricity bills [21–23]. Larger projects bring economies of scale that rooftop PV cannot, offering potentially more clean electricity per dollar invested in generation [24, 25]. Realizing the grid support and resiliency benefits of flexible loads and EV charging requires greater attention to how customers actually use those resources and the implementation of demand response programs [26–30]. And absent ancillary technologies and programs—such as storage, demand response, and smart inverter management—DERs may stress distribution grids more than aid them [31, 32].

Such critiques illuminate the importance of thoughtful implementation: how to ensure that, in practice, DERs will actually provide the value of which they are capable in theory. A key challenge to implementation and widespread deployment is the state of the electric distribution grid. Other researchers have studied limits to DER and new load interconnection in theoretical models, specific

circuits, or other case studies [6, 33–36], but larger-scale analyses have been hindered by the lack of accessible granular information about distribution system constraints [37–40].

What can the grid handle? Introduction to Chapters 1 and 2

Here, we consider how grid limitations might challenge policy goals related to DERs in the energy transition in a detailed analysis that considers the state of distribution infrastructure across utility territories in California. This work is possible due to the unique distribution system data that is available in the state. Since 2015, the California Public Utilities Commission (CPUC) has required the state's Investor-Owned Utilities (IOUs) to publish data on the state of their distribution circuits and their ability to accommodate DERs and new load (i.e., hosting capacity) [41]. Over time, this data has been refined with input from experts and technical working groups. Other states have since followed these efforts, and the underlying methods have become a robust subject of discussion in regulatory proceedings related to distribution system planning [42].

We use California as a case study to consider the increasing penetration of DERs and load electrification in the context of distribution infrastructure limits. We focus on California due to the robust grid data available, as well as the state's stated interests in increasing DER deployment and electrifying new loads [43]. In this context, we ask to what extent the current state of electric distribution infrastructure may challenge California's policy goals in the energy transition.

This question leads directly to the first two chapters of this dissertation. Chapter 1, *Inequitable access to distributed energy resources due to grid infrastructure limits in California*, evaluates the extent to which the distribution grid may limit the deployment of distributed solar PV and new loads in the absence of grid upgrades [44].[1] Chapter 2, *Load electrification and the electric distribution system*, estimates the grid upgrades that will be necessary to enable continued EV adoption and residential heating electrification.

While both chapters make extensive use of the distribution system data available in California, they take somewhat different analytical approaches. In Chapter 1, we match residential households served by California's two biggest electric utilities—Pacific Gas & Electric (PG&E) and Southern California Edison (SCE)—to distribution circuits, and evaluate how much room exists, per household, for solar PV and new load. To do so, we use detailed spatial data on the location of circuits and households to estimate the total hosting capacity that may be present on the portions of circuits that serve specific census block groups. However, we omit a temporal analysis for two reasons: (1) reported distribution grid limits already consider that PV generation follows a daily solar profile [45], thus removing the need for us to explicitly consider the timing of generation, and (2) we recognize that customers may choose to use new loads, such as air conditioning, EV charging, and electrified heating at any time of day. Further, we focus our discussion on PV results due to known issues in the underlying grid data at the time of the analysis that result in systematically low reported capacity for new load, particularly in SCE's territory [46].

[1] This chapter is published as: A. M. Brockway *et al.*, "Inequitable access to distributed energy resources due to grid infrastructure limits in California," *Nature Energy*, 2021, ISSN: 2058-7546. DOI: 10.1038/s41560-021-00887-6. [Online]. Available: http://dx.doi.org/10.1038/s41560-021-00887-6. It is also available open access at: https://escholarship.org/uc/item/6pc2k2tv.

We find that current distribution grid limits broadly constrain the ability of households to adopt PV across these utility territories, and further that this capacity is unevenly distributed: less per-household hosting capacity exists in Black-identifying and disadvantaged communities. These results illuminate the need to consider grid limits in policy goals around equitable DER adoption, and support a broader re-evaluation of the policy choice to orient DER policies and incentives around site-specific DERs that prioritize access for single-family homeowners [47, 48]. Importantly, these issues emerge because current policies in California make access to DERs specific to the location of one's home and the circuit to which it is connected. Even before grid constraints are considered, this is not an equitable approach for many California ratepayers who are renters and/or live in multi-unit housing. Historically, policies in California have missed opportunities to extend access to the benefits of DERs to non-single-family-homeowners, for example through meaningful community solar options, which exist in other states [49]. In the future, these inequities may be compounded by grid limitations.

In Chapter 2, we return to the question of new load on distribution circuits, focusing specifically on PG&E's service territory. Advances in available utility data since the analyses performed in Chapter 1 enable a more granular assessment of how new loads might impact distribution systems [50, 51]. We focus here on the temporal analysis: specifically, we evaluate circuit and substation capacity for new load at the month-hour level (i.e., 288 values representing 24 hours in each month of the year) to capture diurnal and seasonal variation. Then, we consider the timing of anticipated EV charging and residential space and water heating electrification in context of these grid limits. We find that load electrification will require substantial upgrades to distribution grid equipment, and that the rate of necessary upgrades may outpace the ability of electric utilities to implement them given potential bottlenecks in equipment and workforce availability.

The broad takeaway from these two chapters is that electric distribution system limits will challenge our ability to achieve policy goals related to the increasing deployment of distributed renewable energy and the adoption of new electrification loads. Moving forward, these analyses reinforce the need to plan ahead for these investments, and, as the investments are made, to critically evaluate how to get the most value out of DERs.

The grid's ability to accommodate DERs and enable them to provide value depends heavily on where DERs are sited with respect to grid infrastructure and loads [52]. This observation supports the need for a critical re-evaluation of the market and incentive focus on site-specific DERs (e.g., residential rooftop PV). While existing site-specific DERs may provide financial and resiliency (if coupled with storage) benefits to their hosts, community-scale DERs may enable holistic siting that avoids grid limits while enabling grid support and resiliency benefits for communities.[2] Further, potential bottlenecks in utilities' ability to make necessary grid upgrades that are required for electrification suggest that we need to consider alternatives to conventional grid investments, for which distributed solar plus storage might be well-suited.

[2]We discuss takeaways from Chapter 1 and the need for considering community-scale resources in formal comments submitted to the CPUC on the agency's DER Action Plan [47], and in a related opinion piece in *Utility Dive* [48].

Caveats, limitations, and application

The results discussed here are obtained in the context of California, which merits additional reflection on their external validity to other states and regions. Significant adoption of both distributed solar PV and EVs as well as demonstrated appetite for building electrification make California a worthwhile candidate for evaluating grid impacts and needs. However, regional characteristics might change the ability of distribution grids elsewhere to accommodate new DERs and loads.

For example, California's relatively mild climate might obscure the potentially large impact that heating electrification could exert on distribution grids in the winter in other locations. Further, it is possible that excess capacity on distribution grid equipment might vary regionally: it is well-documented that utilities have, in some cases, 'over-built' or 'gold-plated' circuits when making infrastructure investments beyond what would be needed due to expected load growth, due to the regulatory incentive structure for utility returns on capital investments [5]. The degree of 'gold-plating' may vary by utility and state, and circuits that were overbuilt when installed may now potentially be able to accommodate more new load before needing upgrades. While we cannot therefore take our results to be representative of distribution grid conditions across the United States, they nevertheless raise important questions that will need attention as policymakers plan for the energy transition.

Some additional limitations exist of the work described herein. Our results rely on the accuracy of California utilities' published distribution grid data. We make no independent claim about this underlying data being appropriately representative of the actual state of electric distribution infrastructure. However, this data was designed to provide greater transparency into the state of electricity infrastructure and is intended to be decision-relevant as the state plans for the energy transition [45, 51, 53].

Further, our analyses incorporate aggregations and assumptions that may obscure more dramatic findings. For example, our spatial analysis in Chapter 1 is performed at the sub-circuit level but still with some degree of aggregation: therefore, hyper-local grid limits that may hinder households' ability to adopt DERs are not fully captured. Our temporal analysis in Chapter 2 is performed at the month-hour level due to data availability. This approach captures seasonal and diurnal variability but not the most constrained case (i.e., the most limiting hour) of the year. As the grid must balance supply and demand on sub-second timescales, this level of temporal aggregation is instructive but ultimately insufficient to fully understand the extent of system constraints.

Ultimately, the results discussed here shed light on the importance of considering technical grid limits alongside policy goals for the energy transition. Moving towards a more equitable and sustainable electricity system requires us to consider the infrastructure that will need to accommodate new technologies and serve new electricity loads. Identifying limits to the distribution system's ability to integrate these goals can enable the search for and help guide the implementation of solutions. For example, new approaches to grid operation, customer programs for demand flexibility, and alternatives to conventional investments can all play a role in overcoming the obstacles identified herein and enabling the transition. However, appropriately developing, scaling, and structuring such potential approaches requires recognition of the interrelationship between policy goals and infrastructure realities.

Part 2: Climate change adaptation

Decisions about planning for the future are made today in the electricity sector by electric utilities and the regulatory bodies that oversee them. For IOUs, these are state regulatory or public service commissions. For municipal and cooperative utilities, oversight comes from local elected officials (e.g., city councils) or their boards. Utilities propose investments that they want to make in their system, and the regulator has the authority to approve, reject, or modify their proposals to pass those costs through to their customers [5].

These investments are typically designed to meet the need to serve expected load growth in a utility's territory while complying with established reliability targets [5]. In practice, the process of planning for these investments relies heavily on historical data and planning models that contain embedded assumptions about demand growth trajectories and weather conditions. Climate change will upend these historical assumptions. Planning for the future will therefore require re-evaluating the models, planning approaches, and decision-making tools that we use in the electricity sector today to ensure that we are appropriately preparing for our new reality.

Climate change impacts on electricity systems

Climate change will bring widespread and significant impacts to bear on electricity systems. While we cannot know with certainty the exact magnitude or location of climate impacts, we can make some broad observations about general climate trends [54]. For example, we know that temperatures are rising, that rainfall is less predictable (and likely to come in extremes), and that wind intensities are increasing and wind patterns are changing. We know that precipitation is more likely to fall as rain than as snow, and that we will experience prolonged droughts and sea level rise.

These changing patterns will impact every aspect of how our electricity systems operate today (Figure 2). More electricity will be needed for increased cooling needs, both in locations with widespread reliance on air conditioning and in historically moderate climates. Shifts in seasonal load patterns are also likely as transportation and heating are electrified.

At the same time, existing electricity generating resources will produce power less efficiently. Thermal power plants—such as natural gas, coal, and biomass generators, as well as concentrating solar power (CSP) plants—rely on temperature differentials with the outside (colder) air and, in some locations, on water for cooling. Hydropower resources will suffer from increased variability in precipitation and drought conditions. Solar PV panel efficiency falls as temperatures warm. Wind turbine designs are tailored to local conditions, so as wind patterns change existing turbines could produce less electricity.

Climate change will also negatively impact the electrical lines and other equipment necessary to transport power from generating facilities to customers. Higher temperatures increase the resistance of power lines, reducing the amount of electricity they can transport at once and increasing losses. Temperature and humidity levels affect equipment performance and lifetimes, prompting more maintenance needs due to corrosion, potential water inundation, and thermal overload. Additional trends will bring implications for nearby electricity infrastructure: sea level rise may necessitate the relocation of existing assets, while changing vegetation growth patterns and dry-

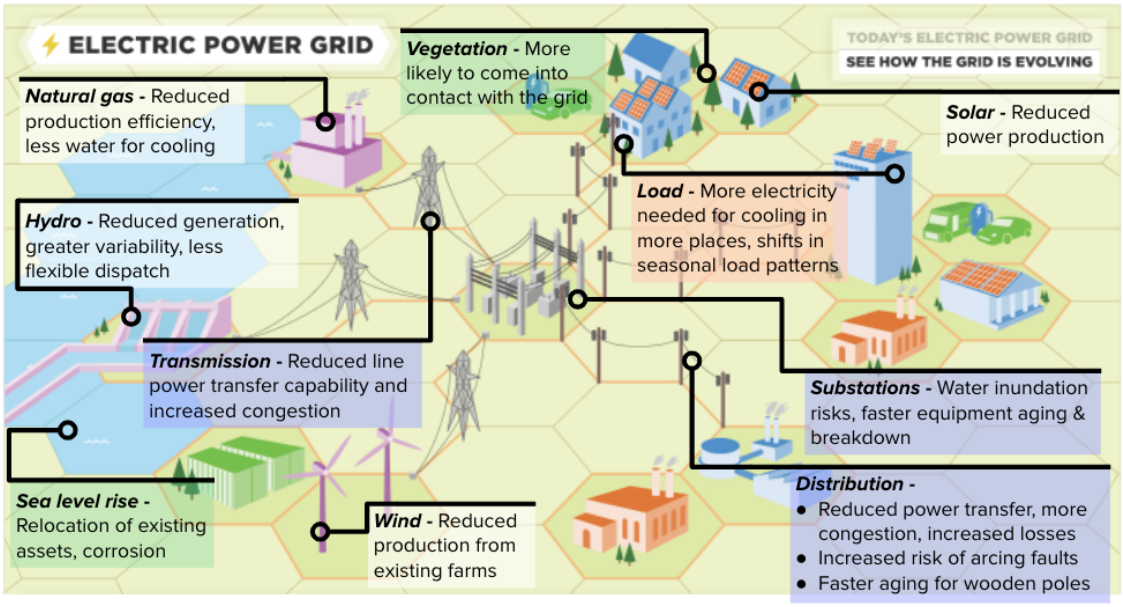


Figure 2: Summary of climate impacts on the electric power grid. Background image adapted from [55]. Climate impacts overview from [56].

ness due to droughts may lead to more vegetation coming into contact with the grid and greater consequences.

Researchers have studied these impacts individually and considered them together in regional case studies on electricity system operation and performance [e.g., 57–63]. However, planning processes have not caught up. There is, therefore, a critical need to bring these impacts into a framework that can inform decision-making today, and to determine how existing planning processes can adapt.

This is not a straightforward exercise. Moving forward responsibly requires drawing on insights from at least three different fields: climate science, electric power operations, and decision-making under uncertainty. Each of these fields is very technical with nuances that can evade even its own domain experts. Moreover, the interactions between these fields are extremely complicated and rapidly evolving: many of them we have not needed to model in the past, but now must account for in complex systems with many moving parts.

Planning for an uncertain future: Introduction to Chapters 3 and 4

The last two chapters of this dissertation focus on how we can bring electricity sector planning into a new reality where planning for a reasonably-certain projected future is no longer an adequate or prudent approach.

We start with a focus on California, where climate change has already impacted the state's electric grid and regulators have expressed a desire to incorporate climate change considerations into planning processes. Chapter 3, *Weathering adaptation: Grid infrastructure planning in a*

changing climate, surveys the planning context in California, the climate information that is available to decision-makers, and the impacts of climate change on electricity systems [56].[3] We find that homing in on a specific regional context provides an instructive case study to illustrate the complexity of data flows, inputs, and actors in electricity sector planning processes. Chapter 3 concludes with initial recommendations for incorporating climate change into electricity planning processes in California.

A key challenge identified in Chapter 3 is the importance of critically considering what it means to plan for uncertainty in what the future holds. This challenge extends beyond the borders of California to any jurisdiction that must plan for critical infrastructure systems in a new climate reality. Other researchers beyond the electricity sector have considered this challenge explicitly: the field of decision science focuses on understanding how to best make decisions with techniques that are appropriate to the available information and relevant underlying uncertainties. Chapter 4, *Climate-aware decision-making: Lessons for electric grid infrastructure planning and operations*, surveys this literature on decision-making under uncertainty in concert with a review of the decisions that utilities are making today and literature on electricity planning under climate change [65].[4] This chapter distills key lessons from the decision science literature on making decisions under uncertainty and makes recommendations about how those lessons can be applied to the electricity sector.

These chapters reinforce that climate change will impact every aspect of how electricity systems operate, and provide specific examples of how it is already doing so. The complexity of both climate change and electricity system operation means that we cannot at this point plan for every contingency and impact, nor pretend that we will be able to preserve the kind of operation that we have become accustomed to. However, we can certainly take steps to plan better: to make the best decisions we can today given the information and tools we have. Doing so requires acknowledging that our existing planning approaches are inadequate. Improving them will necessitate bringing in information about multiple plausible futures, developing the capacity to adapt as uncertainties evolve, and incorporating learning from a variety of stakeholders with varied expertise. These actions are critical to begin planning for tomorrow's electricity systems with the best information we have today, not the trends of the past.

[3]This chapter is published as: A. M. Brockway and L. N. Dunn, "Weathering Adaptation: Grid Infrastructure Planning in a Changing Climate," *Climate Risk Management*, vol. 30, p. 100 256, 2020, ISSN: 2212-0963. DOI: 10.1016/j.crm.2020.100256. [Online]. Available: https://doi.org/10.1016/j.crm.2020.100256. It was accompanied by a related opinion piece in the *San Francisco Chronicle* [64].

[4]This chapter has been submitted for publication as: A. M. Brockway *et al.*, "Climate-aware decision-making: Lessons for electric grid infrastructure planning and operations," *Submitted*, 2022.

Chapter 1

Inequitable access to distributed energy resources due to grid infrastructure limits in California

Persistent social disparities in the adoption of distributed energy resources (DERs) have prompted calls for enabling more equitable uptake. However, there are indications that limits inherent to grid infrastructure may hinder DER adoption. Here, we analyze grid limits to new DER integration across California's two largest utility territories. We find that grid limits reduce access to solar photovoltaics (PV) to less than half of households served by these two utilities, and may hinder California's electric vehicle adoption and residential load electrification goals. We connect these results to demographic characteristics and find that grid limits also exacerbate existing inequities: households in increasingly Black-identifying and disadvantaged census block groups have disproportionately less access to new solar PV capacity based on circuit hosting capacity. Our results illuminate the need for equity goals to be an input into designing policies for prioritizing grid upgrades.

1.1 Introduction

Electricity systems are undergoing the most fundamental shifts since their inception. As with any transition, benefits and burdens may fall unequally and some may be left behind [66, 67]. A growing body of literature has documented persistent social disparities in customer adoption of distributed energy resources (DERs), with a particular focus on behind-the-meter solar photovoltaic (PV) systems. Residential PV adoption patterns have perpetuated financial [68–70], racial [71], and cumulative [72] inequities, even beyond those stemming from the typical requirements of owner-occupied households with favorable site characteristics [73–75]. In response, federal and state programs intended to support more equitable uptake have emerged [68, 71, 76].

The distribution grid's ability to accommodate new PV depends on where and how it interconnects [77–79]. As deployment increases, these limits will hinder new connections, leading to costly project delays [10, 80, 81] or interconnection denials [82], and/or require circuit upgrades [9, 83]. As we near the limits of DER deployment that existing distribution equipment can accommodate, policymakers and regulators will need to establish criteria for which grid upgrades are worth increasing customer rates. If grid limits are not considered, further inequities may emerge.

To our knowledge, no systematic analyses have yet considered how equitably the existing grid can accommodate DERs. Studies of equity in PV deployment have focused on previous or existing adoption [69–72], rather than what the future may hold. Researchers evaluating grid capacity for DERs have focused on technical circuit models or isolated case studies rather than full electric grids, and have not considered customer demographics [79, 84–88]. There is, therefore, a gap in our understanding of how grid limits within and across utility territories may impact future DER deployment, and the potential implications for equity and access to DERs. We do not ascribe causation to lower hosting capacity in certain communities. Rather, we strive to document disparities so that future policies do not exacerbate patterns of inequity and may even improve the state of affairs.

Here, we study the magnitude and distribution of electric grid constraints for DERs on circuits operated by California's two largest Investor-Owned Utilities, Pacific Gas and Electric (PG&E) and Southern California Edison (SCE), which together serve over 30 million people. We focus on identifying where constraints may limit DER growth and ask whether they may differentially impact demographic groups. We find that the distribution grid restrains households' ability to adopt DERs across these two IOU territories, and that hosting capacity is unevenly distributed. When all grid constraints are considered, over half of residential households served by PG&E and SCE (57% and 59%, respectively) lack adequate hosting capacity for 4.5 kW of solar PV, the amount required to offset 100% of their annual electricity consumption, on average. In PG&E's territory, 39% of households lack access to even the least power-intensive new loads (space and water heating or level 1 electric vehicle charging), while 64% lack access to level 2 EV charging. Notably, hosting capacity for DERs decreases for households in increasingly Black-identifying and disadvantaged communities. Correlations between hosting capacity and race are the starkest among a variety of demographic indicators analyzed, including those relating to income, housing characteristics, and education. We do not make causal claims but seek to illuminate important correlations that exist in the data, which here include disparate access to grid resources falling along lines of race. This work points to the need for grid planners anywhere to analyze the equity of electrical capacity for DER adoption and demonstrates a way to do this. Such an analysis should be an input to planned grid upgrades so that the grid itself does not become a limitation to equitable DER uptake in the future.

1.2 Growth in DERs raises issues for equity and the grid

We are motivated here by two separate and robust sets of findings in the literature: that there exist inequities in DER adoption and that the electric distribution grid itself imposes limits on where

DERs can interconnect. We consider how grid limits may impede continued DER deployment and assess how they overlap with customer demographics. In doing so, we build on the existing literature by (a) considering the significance of technical grid limits, which are largely ignored in previous work on equity in DER adoption, and (b) using those grid constraints to consider the *future* equities of DER deployment, whereas others have focused on *existing* adoption.

A rich literature has emerged concerning the inequities of solar PV adoption. Despite similar motivations for adopting solar [89], low and moderate income (LMI) communities experience disproportionately low PV penetration rates [68–70], even with relatively high potential for solar [68]. While policies designed to foster more equitable uptake have made a difference [76] and middle-income households have slowly increased their relative share of PV [69], LMI households still lag behind.

Minority households are disproportionately vulnerable to energy poverty in the U.S. [90]. Yet PV adoption, which can reduce household electricity bills, skews to white-majority census tracts [71]. When multiple inequities are considered, persistently lower adoption is found in disadvantaged communities [72], as measured by metrics in California's CalEnviroScreen indicator, which was developed to reflect the cumulative impact of environmental, socioeconomic, and public health stresses [91].

Socioeconomic factors have also been found to influence EV adoption [92]. Yet EV ownership also relies on the availability of public charging—like the electric grid, an enabling technical resource—which is less widespread in low income and minority communities [93].

To date, DER deployment has perpetuated social inequities. In the future, electric grid limits may constrain DER growth. Electric power systems in the United States were designed to rely on centralized power sources, but DERs—such as solar PV and EVs—now contribute growing shares of electricity supply and demand. Well-sited DERs can defer capacity upgrades [79], boost sagging line voltages, and reduce power losses [94]. However, DERs can also disrupt circuit protection schemes, increase thermal loading, cause overvoltages, and create dangerous islanding conditions [95, 96].

These grid impacts arise from increased current flow beyond what local equipment can handle. They may be avoided if both generation and load DERs are sited in the same location and their operation is synchronized in time; however, even if they complement each other on average, operating variations due to customer behavior and weather will necessitate storage or demand response to fully defer system constraints. As these technologies are not mandated in California today, we leave this nuance to follow-on work and focus here on where DERs may connect to distribution circuits without necessitating complementary technologies.

The *hosting capacity* is the allowable capacity of DERs that an electric circuit can accommodate without upgrades. Calculating hosting capacity is not straightforward and several methodologies have emerged [34, 97, 98]. They differ in which circuit constraints are considered and which numerical methods are used to calculate violations (see Appendix A.1.1 for details). In California, hosting capacity information is available through Integration Capacity Analysis (ICA) maps, which also include data on existing distributed generation [45, 53] (see Appendix A.1.2). Hosting values include the additional PV and load capacities that can be connected to a line segment without violating thermal, power quality/voltage, or protection constraints [45]. PV capacity is reported

with operational flexibility (OpFlex; in which case reverse power flow is not allowed beyond the substation bus) and without OpFlex (in which case reverse flow is allowed) constraints [45].

Here, we assess how grid constraints may impact the equity of DER access. California offers a ripe case study of the implications of employing DERs to expand clean energy capacity. Aggressive policies and a responsive market have helped California lead the nation in PV capacity and EV adoption (Appendix A.1.3). Behind-the-meter PV comprised almost 30 percent of the state's solar PV capacity at the end of 2019 [99], and is expected to remain a major category of renewables deployment due to a diversity of supporting policies [100, 101]. Significant economic benefits are available to California households that adopt rooftop solar [102]. In this context, disparate rates of access (whether due to structural or grid limits) are important, and we assess here the extent to which making access to renewable energy specific to the location of one's home and the circuit to which it is connected may strain California's access and equity goals.

Despite documented inequities in current deployment, all ratepayers currently pay for grid upgrades necessary to accommodate projected DER growth. Upgrade decisions have been based in part on historic deployment patterns, and SCE estimates that it will cost $14-44 million annually from 2021 to 2023 to reinforce its circuits for DERs [103].

In California, small DERs have so far been allowed to bypass interconnection study requirements [83]. However, state regulators have indicated that hosting capacity values may be considered in future DER interconnection rules to avoid violating location-specific penetration limits [45, 53, 104]. Future grid upgrades with socialized costs, therefore, are not a guarantee. Policies that seek to address inequities in DER deployment will need to consider limits imposed by the electric grid as it exists today, or investments associated with upgrading it.

1.3 Grid limits reduce access to DERs across utility territories

We calculate the proportion of households with access at deployment thresholds ranging from 1.5-10 kW per household to account for varying capacity estimates for PV and load DERs (see Methods), for each DER type, and for each census block group (CBG) within each utility territory (Equations 1.13-1.14). We find that per-household hosting capacity for load and generation DERs (Appendix A.2) varies widely across PG&E and SCE service territories (Figure 1.1). We present results for household access within each full utility territory and summary statistics by CBG (Figures 1.2, 1.3) (see Supplementary Tables A.1, A.2, and A.3 and Supplementary Figures A.1 and A.2 for selected values and full results). PG&E results pertain only to those sections of the territory with ICA data.

We find that constraints on distributed generation limit how much PV can be deployed on distribution circuits in California. Due to thermal, power quality, and protection grid constraints, 31% and 25% of households in PG&E and SCE territories, respectively, lack access to 4.5 kW of behind-the-meter PV (which is, on average, enough to balance 100% of annual electricity usage). These values consider both the existing generation already deployed on circuit lines as well as remaining hosting capacity. With OpFlex constraints, significantly more households—approximately 57% and 59% served by PG&E and SCE, respectively—lack access to 4.5 kW of rooftop PV. There-

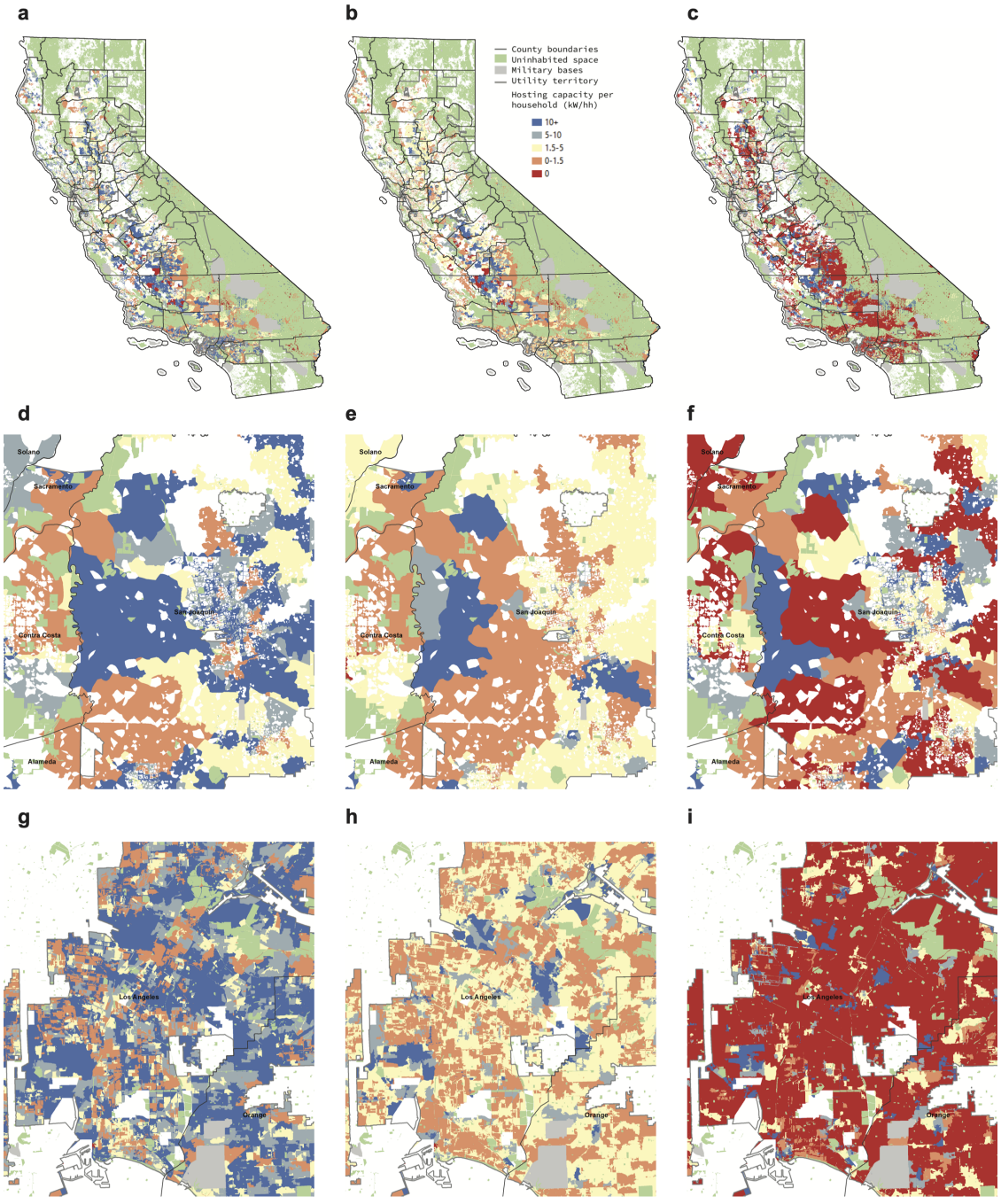


Figure 1.1: Household access varies by DER type and location. Per-household hosting capacity results for PV (column 1: a, d, g), PV with operational flexibility (column 2: b, e, h), and load (column 3: c, f, i) across PG&E and SCE service territories (row 1: a-c), a portion of PG&E's service territory including parts of San Joaquin County (and the city of Stockton) (row 2: d-f), and a portion of SCE's service territory including parts of Los Angeles and Orange Counties (row 3: g-i). White areas indicate regions served by other utilities or, within PG&E's territory, locations with no ICA data.

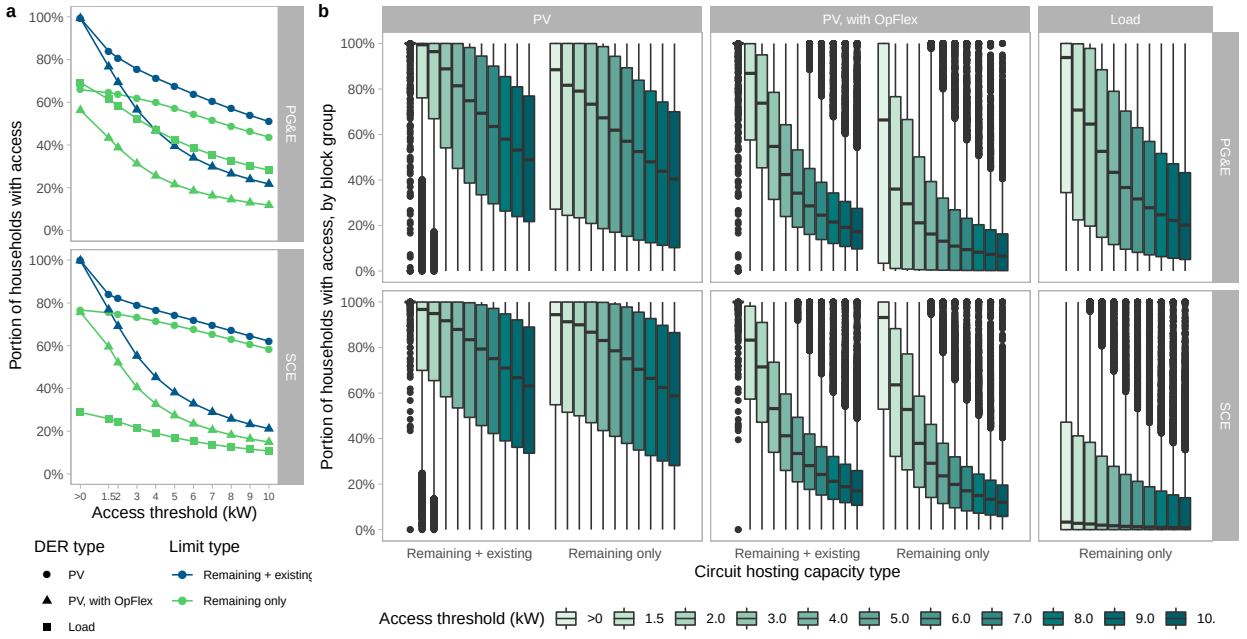


Figure 1.2: Results for household access to PV and load DERs: (a) summarizes the results for all households within the respective utility territory, while (b) shows boxplots of hosting capacity at different access thresholds for each census block group included in the data. In (b), each boxplot shown for PG&E represents 2.13 million households across 7996 census block groups (this is less than the total number of households served by PG&E due to lack of available ICA data for all circuits), and each boxplot shown for SCE represents 4.15 million households across 8376 census block groups. All boxplots show the 25th, 50th, and 75th percentiles of access results, with whiskers extending to the furthest point within 1.5x of the interquartile range. Further points are shown as outliers.

fore, under current grid conditions, sufficient capacity exists for less than half of households to adopt PV.

These numbers are highly sensitive to the deployment threshold used (Figure 1.2). More households can adopt smaller PV sizes, though 23% (16% if OpFlex constraints are disregarded) in both territories still lack access to even 1.5 kW. At 10 kW, 78% and 79% of PG&E and SCE households, respectively, lack access (49% and 38% if OpFlex constraints are disregarded).

Fewer households can adopt if we consider only remaining hosting capacity. Approximately 77% and 70% of households served by PG&E and SCE, respectively, then lack access to solar (41% and 30% if OpFlex constraints are disregarded). This observation illustrates a tension around equitable deployment: if grid capacity is occupied by early adopters, efforts to improve equity in PV adoption may find themselves in a race with continuing adoption among already well-represented demographic groups for the circuit hosting capacity that remains.

Physical building suitability may further reduce household access: based on data generated by previous researchers [74, 75], we estimate that approximately 15% of small buildings in PG&E's territory and 9% in SCE's territory cannot host 1.5 kW of PV (Figure 1.3, 3). When combined with grid limits, the portion of households lacking access to 1.5 kW of behind the-meter PV increases,

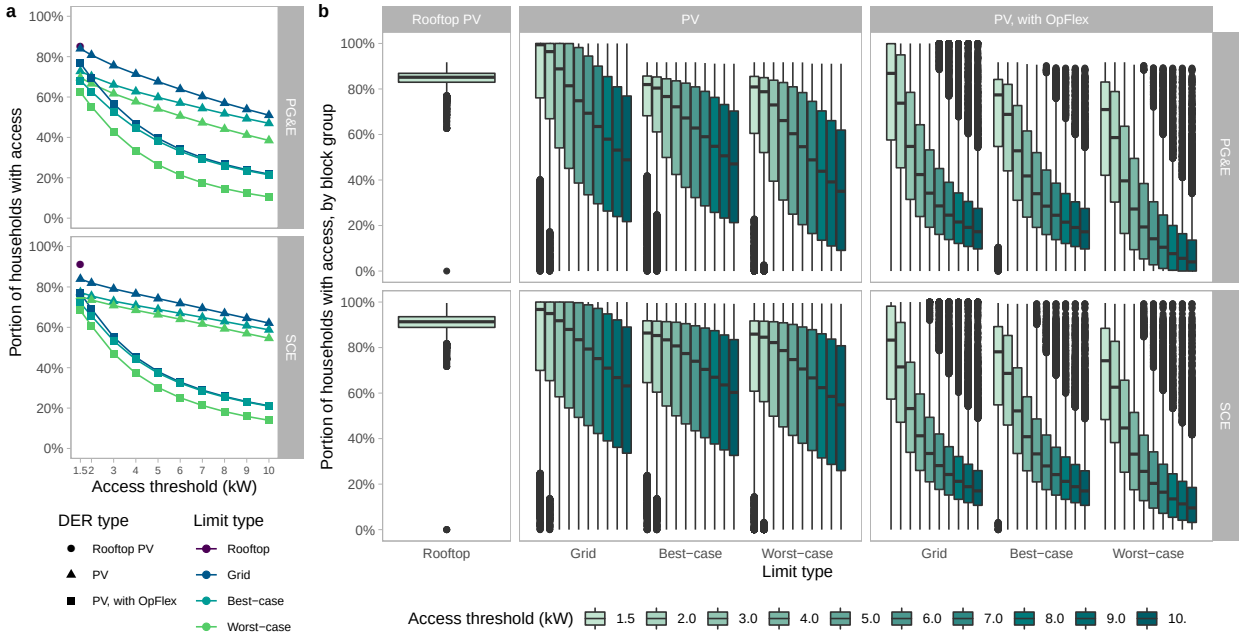


Figure 1.3: Results for household access to PV DERs considering grid (remaining + existing capacity) limits and building suitability limits: (a) summarizes the results for all households within the respective utility territory, while (b) shows boxplots of hosting capacity at different access thresholds for each census block group included in the data. In (b), each boxplot shown for PG&E represents 2.13 million households across 7996 census block groups (this is less than the total number of households served by PG&E due to lack of available ICA data for all circuits), and each boxplot shown for SCE represents 4.15 million households across 8376 census block groups. All boxplots show the 25th, 50th, and 75th percentiles of access results, with whiskers extending to the furthest point within 1.5x of the interquartile range. Further points are shown as outliers. We note that building suitability estimates are available only for 1.5 kW PV systems [105]. Combined suitability at higher access thresholds (2-10 kW) is calculated assuming the higher threshold for grid limits, but still a 1.5 kW threshold for building suitability. This underestimates the contribution of building suitability to PV deployment limits at thresholds above 1.5 kW, while overestimating the portion of households with access.

in PG&E's territory, from 16% to 27-30% under the worst- and best-case scenarios for combined suitability. In SCE's territory, the portion of households lacking access increases from 16% to 23-25%. Similar access declines occur for the OpFlex case.

We also find that constraints on load may challenge the adoption of EVs and electrification technologies. The grid may require upgrades to meet electrification goals and air conditioning needs; otherwise, it could hinder climate change mitigation and adaptation [106] efforts in California. However, the extent to which load DERs will stress the distribution grid requires further research. While ICA maps show hosting capacity by circuit segment for generation and load, IOU circuit analyses have so far focused on generation. Load information, particularly in SCE's territory, may systematically underestimate circuit hosting capacity [46]. Moreover, existing load analyses are technology-agnostic and IOUs could improve data interpretability by including analyses of specific load DERs—including EVs, air conditioning, and heat pumps for space and water

heating—which all have time-varying use profiles.

Based on currently-available load data, widespread adoption of even the least power-intensive applications could strain distribution grids. Using a 1.5 kW demand threshold to analyze access to space and water heaters (together 1.6 kW) and level 1 EV charging (1.4-1.9 kW), we estimate that 39% and 74% of households served by PG&E and SCE, respectively, lack sufficient grid capacity for either electrified heating or EV charging (Figure 1.2a). In PG&E's territory, 64% of households lack the grid access to install a level 2 EV charger.

If households implement all climate strategies we consider—conversion of natural gas-powered space and water heaters to electric, EV level 2 charging, and new air conditioning units—hosting capacity will be severely limited (Figure 1.2). Although the full extent of distribution grid impacts from increasing load is not yet known, it is clear that the grid cannot currently accommodate fully electric homes across the state.

1.4 Grid limits reinforce demographic disparities in DER access

Variations in access across utility territories prompt us to consider how hosting capacity may be correlated with variables related to infrastructure, service, geography, and demographics (see Table 1.1, Supplementary Tables A.6, A.7, and A.8, and Appendix A.4.4 for variable descriptions). We are particularly interested in whether differences in hosting capacity may reflect demographic variations. We construct linear and nonlinear models to understand which variables, if any, may correlate to per-household hosting capacity. Model results indicate that no single demographic feature dominates in relative importance over the rest (see Appendix A.3 and Supplementary Figure A.3 for a full discussion). However, we do find notable relationships between consumer demographics and access to circuit capacity. In examining these, we focus on demographic categories discussed in prior literature on DER adoption.

First, we validate our approach by examining relationships between demographic indicators and *existing* distributed generation, and find that our results broadly support previous findings. For race and ethnicity, we observe higher median levels of existing distributed generation per household in CBGs with more non-Latinx white- and Latinx-identifying populations than Black- or Asian-identifying populations (Figure 1.4a). (For CBGs with more Black- and Asian-identifying populations, very few households are represented at higher percentages, leading to wide confidence intervals and indefinite trends above approximately 50%. Existing generation per household also declines overall with increasing diversity in the population. For disadvantaged communities (as defined in CalEnviroscreen [91]), we find stronger correlations between existing distributed generation and population metrics (measures of sensitive population and linguistic isolation, Figure 1.5b) than pollution metrics (Figure 1.5a) (similar to Lukanov and Krieger [72]), most notably the percentile of linguistic isolation in the population, which could reflect an information barrier to DER adoption. For income, our analysis supports previous findings that wealthier communities are more likely to have already installed DERs [69, 70]. This effect broadly holds for the poorest

Table 1.1: Independent variable groups for random forest regression and classification runs. A full list of variables in each category can be found in Supplementary Tables A.6, A.7, and A.8.

Variable group	Description	Examples
(1) All	All variables included in any of the other three groups	-
(2) Infrastructure	Variables that describe characteristics of electricity infrastructure, sourced from PG&E and SCE directly	Nominal circuit voltage, circuit line lengths
(3) Service and geography	Variables that pertain to how electric infrastructure serves customers and the environmental conditions it is exposed to	Households per circuit polygon and kilometer of circuit length, number and percent of residential customers served by each circuit, solar irradiance and heat metrics
(4) Demographic	Variables obtained from the American Community Survey [107] and CalEnviroScreen [91]	Percent population identifying as specific racial and ethnic groups and within specific income tiers, median household income, residential structure characteristics

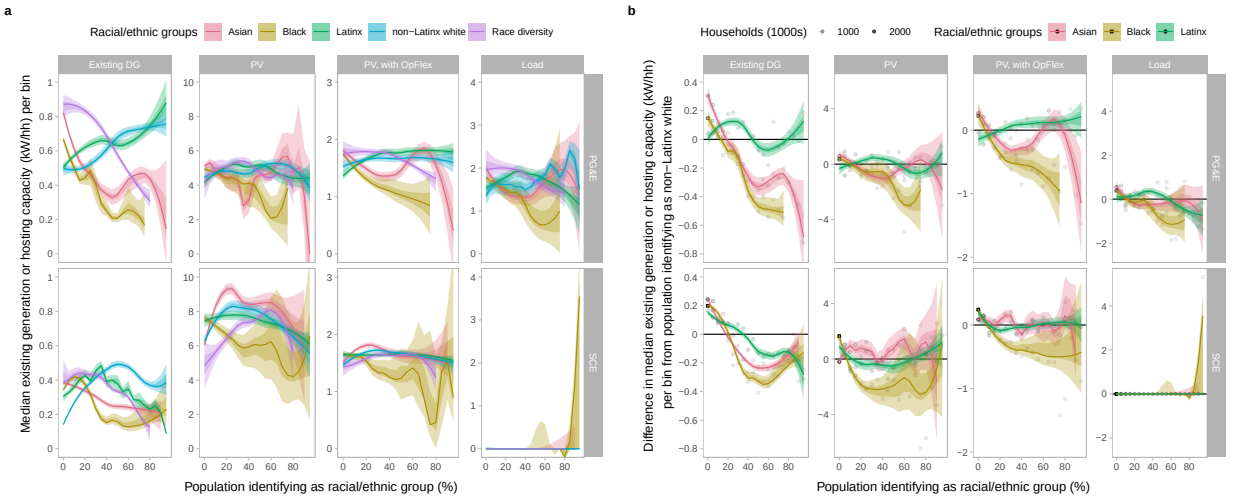


Figure 1.4: Hosting capacity results for race and ethnicity variables: (a) shows hosting capacity by race and ethnicity, while (b) shows hosting capacity by race and ethnicity minus the hosting capacity for non-Latinx white. Confidence intervals shown are 50% (darker band) and 90% (lighter band).

and wealthiest CBGs (Figure 1.5c), as well as median household income (Figure 1.5d), with some drop-off for data points representing fewer households. Finally, as expected for types of housing [73–75], existing generation capacity increases sharply with the percentage of owner-occupied and single-unit households, as well as with the median year of construction for residential housing (Figures 1.5e,f).

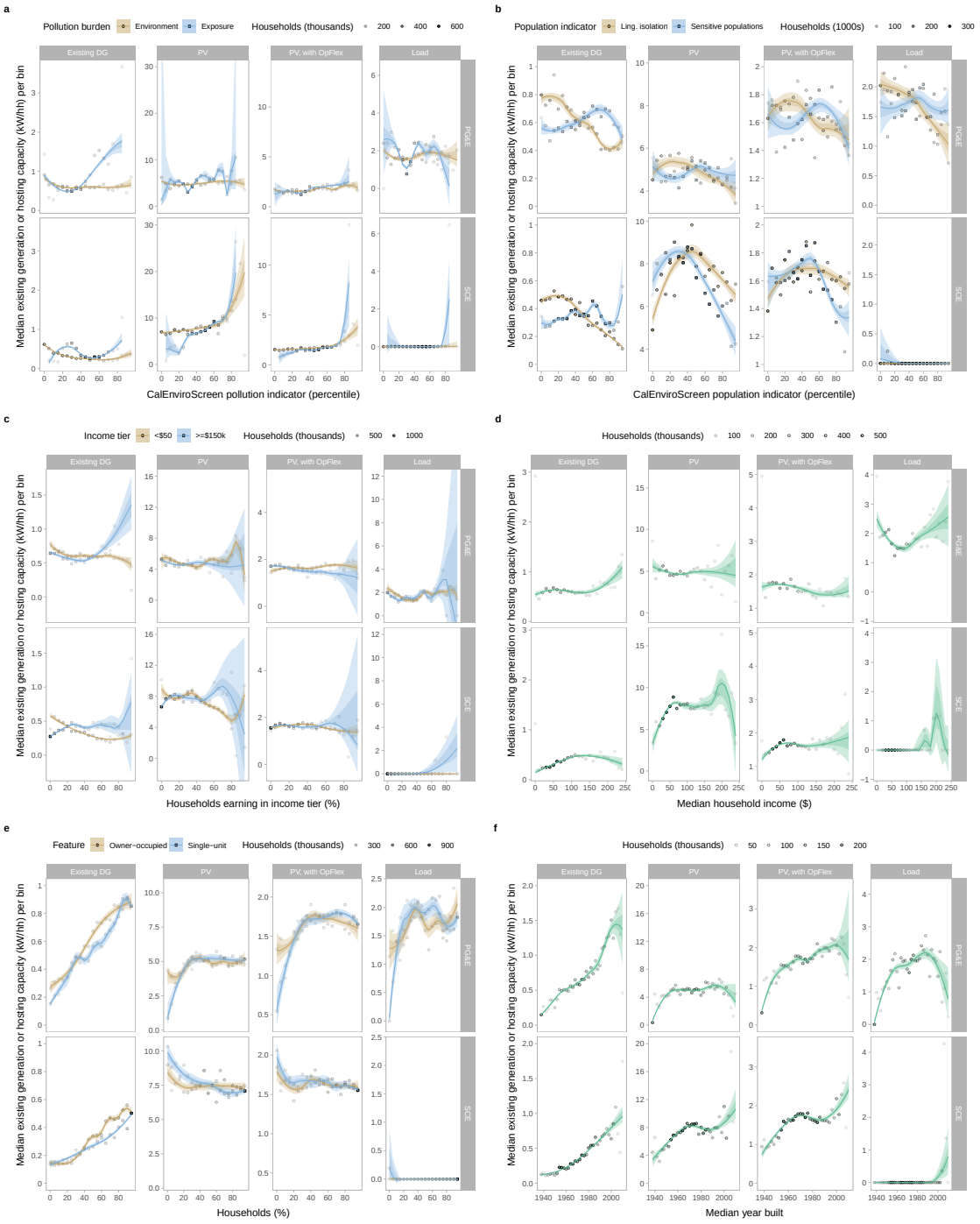


Figure 1.5: Hosting capacity results for additional demographic variables. Row 1 shows results for CalEnviroScreen indicators: (a) pollution and (b) population; row 2 shows results for income variables: (c) proportions of the poorest and wealthiest households and (d) median household income; and row 3 shows results for housing characteristics: (e) proportions of single-unit and owner-occupied households and (f) median year housing built. Confidence intervals shown are 50% (darker band) and 90% (lighter band).

Then, we extend our analysis to how total circuit hosting capacity for PV (existing plus remaining) and load (remaining capacity only, focusing on PG&E) correlates with these same demographic indicators.

With respect to race and ethnicity, we find that total circuit capacity for generation decreases with increasing percentages of Black-identifying residents, and is disproportionately lower for CBGs with Black-identifying populations than for other racial and ethnic groups. Specifically, trends in total circuit capacity for PV—with and without OpFlex constraints—are notably lower in Black-identifying CBGs than in non-Latinx white-, Latinx-, and Asian-identifying CBGs for both utilities. To better see these differences, we plot loess curves for the *difference* in median existing generation and hosting capacity between non-Latinx white-identifying population percentages and the other racial and ethnic groups (Figure 1.4b). While the differences with Latinx- and Asian-identifying CBGs are small, total circuit capacity is significantly lower for Black-identifying CBGs and largely decreases as Black-identifying percentages increase. This suggests that distribution circuits cannot currently support the same PV deployment—whether or not OpFlex constraints are active—in neighborhoods with higher Black populations relative to other racial and ethnic groups. Circuit capacity values for remaining load are less interpretable (see discussion above), but we see here that, in PG&E's territory, less circuit capacity is available with increasing percentages of Black-identifying residents than for other races.

Disadvantaged communities, as identified by the CalEnviroScreen sensitive and linguistically-isolated population indicators [91], also experience inequitable circuit capacity for PV deployment. Some of the starkest trends occur for the population indicators: median generation hosting capacity decreases with sensitive populations above the 50-60th (for PG&E) and 30-50th (for SCE) percentiles, and decreases with linguistic isolation above the 20th (for PG&E) and 40th (for SCE) percentiles (Figure 1.5b). The most disadvantaged populations in the state therefore face systematically lower circuit hosting capacity for PV. Opportunities for future DER deployment—especially of technologies that can shift electricity consumption patterns, such as solar plus storage—may be particularly salient for these communities [108], which tend to bear disproportionate local pollution impacts from California's natural gas peaker plants [109].

Income trends for circuit capacity are less consistent, suggesting that income variations are insufficient for explaining the relationships between circuit capacity and Black-identifying and disadvantaged communities. For the poorest households, the clearest trends are found in SCE's territory where hosting capacity for PV tends to decline slightly with increasing proportions of poor households. As the portion of wealthy households increases, total circuit capacity trends slightly downwards in PG&E's territory but stays relatively flat in SCE's territory. Circuit capacity for PV largely declines with median household income in PG&E's territory (excepting some values representing very few households), but increases with median income up to approximately $100k in SCE's territory. These mixed results suggest that the clearer trends for racial and ethnic groups and CalEnviroScreen population indicators are not driven by underlying income distributions.

Housing characteristics also show mixed results. Total circuit hosting capacity for generation and load tends to increase with single-unit and owner-occupied percentages in PG&E's territory, though plateauing earlier than for existing generation, while assuming the inverse trends in SCE's territory (Figure 1.5e). For both utilities, total circuit hosting capacity for generation tends to

increase with year of construction (Figure 1.5f); median housing age may correlate with the age of local grid infrastructure. In PG&E's territory, areas with the newest buildings have less hosting capacity than slightly older buildings.

Our key results are broadly consistent across both utility territories. The most notable differences between customers served by the utilities pertain to the relative proportions of non-Latinx white- and Latinx-identifying populations, and residents' pollution exposure (see Appendix A.4.2.2 and Supplementary Figure A.6). These demographic indicators do not show strong trends in our results.

Our work enables us to consider where inequities may be exacerbated in the future. As net-metered solar frequently carries tangible benefits for its adopters, including an attractive economic proposition [102] and more stable electricity bills, these inequities run the risk of limiting its benefits along demographic lines.

1.5 Conclusions

Taken together, our results indicate that grid limits pose constraints for future DER deployment across utility territories and may exacerbate existing inequities related to DER adoption. With all grid constraints enforced, over half of households served by PG&E and SCE (57% and 59%, respectively) lack grid access to adopt sufficient PV to offset their annual electricity consumption, on average. If we consider only remaining circuit hosting capacity, up to three-quarters of households served by PG&E and SCE (77% and 70%, respectively) lack access. As existing PV adoption has tended to skew towards wealthier, whiter, and less-disadvantaged households, these results raise concerns that the grid may hinder efforts to increase equity in DER adoption.

Grid capacity may also limit the amount of new load that can be added to residential distribution circuits through electrification programs, EV adoption, or increased air conditioning demands. In PG&E's territory, 39% of households lack access to even the least power-intensive new loads (space and water heating or level 1 EV charging), while 64% lack access to level 2 EV charging. Household access results are sensitive to the size capacity of DERs deployed per household and, for generation, to whether OpFlex constraints are enforced.

Furthermore, we find important disparities in household access by demographic characteristics that are consistent with disparities in existing PV capacity. Median per-household circuit capacity for DERs is lower for CBGs with higher Black-identifying populations than other racial and ethnic groups, and decreases with rising proportions of Black-identifying residents. Grid capacity for DERs also decreases for more disadvantaged communities, as measured by the CalEnviroScreen sensitive and linguistically-isolated populations indicators.

In this work we have sought to document existing patterns in circuit hosting capacity and their potential impacts on access to DERs. Our primary aim is to illuminate these patterns for consideration in future grid planning and policy. However, we do offer two hypotheses about how the disparities we report could have come to pass. First, we know that circuit upgrades to accommodate DERs have already occurred—and are continuing to occur—on some circuits [103]. It is possible that those upgrades may have enabled excess hosting capacity beyond what was needed for the

DERs that prompted them. If those upgrades have occurred in neighborhoods that tend to be early adopters of DERs, that could inadvertently lead to more hosting capacity in areas populated by early adopters. Secondly, circuits designed for areas where additional housing development was expected to occur may have been built with excess capacity that could translate to more hosting capacity for DERs today. It is possible that these areas of projected housing expansion could correlate to certain demographic characteristics. Testing either of these hypotheses would require data that we do not have and that may not exist. Therefore, we offer these to share possible explanations for how social disparities in these engineered systems *could* have arisen, not to indicate how they did.

Notably, we have assessed the grid limits for generation and load DERs in isolation. If their operation is synchronized in time and space, these technologies could complement each other and reduce their impact on the grid. To accomplish this, policy requiring co-located storage or demand response would be required, and evaluating the potential impacts of this is a potential direction for future work.

To meet its decarbonization goals, the State of California will need to make tremendous investments in grid capacity, which will require both time and money to implement. Our results illuminate that current policy promoting site-specific distributed generation may face obstacles to equity from physical systems, including those that fall along racial lines. Enabling all distribution circuits in the state to host adequate DER capacity for desired generation and electrification needs will not happen simultaneously absent massive investment in staff and resources. Currently, Southern California Edison prioritizes distribution circuits for upgrades that are intended to boost hosting capacity on the basis of projected DER deployment. Yet targeting grid investments can reduce existing inequities. For example, there is an opportunity to put at the front of the queue communities with historically low DER adoption rates who are served by distribution circuits with low available hosting capacity.

Remaining hosting capacity will decrease as more households adopt PV and EVs, electrify heating loads, and opt to acquire or operate air conditioners, and electric distribution systems will draw closer to their limits, potentially creating obstacles to timely and equitable DER access. Nationwide and elsewhere, policymakers and regulators will increasingly confront grid limits as a barrier to renewable energy adoption. Evaluating the implications of these limits will be critical to reaching equity goals for the deployment of distributed energy resources.

1.6 Methods

1.6.1 Residential households are matched to distribution circuits

Here, we utilize recent advances in electric distribution grid data availability in the State of California. To begin, we match residential customers to PG&E and SCE distribution circuits. Our goal is to estimate where residential utility customers live and which circuit lines provide them with electric service. Our analysis relies on two key assumptions. First, we assume that residential customers are evenly distributed within the potentially-inhabited areas of each census block

group, which we estimate here to be those areas that are not protected open space (e.g., parks or wilderness areas) or military bases. We also assume, similar to [110], that electricity customers are served by their nearest electric system equipment. Here, this means residential customers are grid-connected to the nearest distribution circuit segment.

All spatial processing was done in ArcGIS 10.6 in coordinate system NAD 1983 California Teale-Albers. Starting with census block groups [111], we erase areas that comprise protected open space [112, 113] and military bases [114] to exclude them from consideration, leaving us with potentially-inhabited land area. For each census block group, we calculate:

$$\texttt{InhArea\_Wt}_i = \frac{\texttt{InhArea}_i}{\texttt{OrigArea}_i} \tag{1.1}$$

where $\texttt{OrigArea}_i$ is the original area of block group i and $\texttt{InhArea}_i$ is its potentially-inhabited area (both in m^2). Then, we clip the potentially-inhabited areas of census block groups by the PG&E and SCE utility territory boundaries [115]. For each block group located fully or partially within each utility's territory, we calculate:

$$\texttt{IOUarea\_Wt}_i = \frac{\texttt{IOUarea}_i}{\texttt{InhArea}_i} \tag{1.2}$$

where IOUarea is the portion of block group i's potentially-inhabited area located within the IOU's territory (m^2) (e.g., Supplementary Figure A.4a).

We then utilize ArcGIS's Euclidean Allocation tool to assign 10×10 m^2 grid cells to their nearest 1-, 2-, or 3-phase circuit segment. (Using PG&E's feeder data [116] and SCE's customer type data [117], we exclude circuits that serve fewer than 1% residential customers.) We convert the raster output to simplified polygons to produce smooth boundaries. We obtain polygons that mimic a Voronoi tessellation, but are formed around line segments, rather than point-locations (e.g., of substations, as in [110]).

Next, we perform a union of these *circuit-segment polygons* with census block groups. We combine the resulting features by circuit name to create *circuit polygons* that describe spatial areas that are unique combinations of (1) the service area for a given circuit, and (2) a given census block group. For each circuit polygon we calculate:

$$\texttt{CpolyA\_Wt}_{ij} = \frac{\texttt{CpolyA}_{ij}}{\texttt{InhArea}_i} \tag{1.3}$$

where $\texttt{CpolyA}_{ij}$ is the area (m^2) served by circuit j within block group i and $\texttt{CpolyA\_Wt}_{ij}$ is the portion of the block group's potentially-inhabited area that circuit serves (Supplementary Figure A.4b).

This approach allows us to calculate the estimated number of customers served by electric distribution lines within each circuit polygon:

$$\texttt{tothh\_Cpoly}_{ij} = \texttt{tothh\_bg}_i \times \texttt{IOUarea\_Wt}_i \times \texttt{CpolyA\_Wt}_{ij} \tag{1.4}$$

$$\texttt{totpop\_Cpoly}_{ij} = \texttt{totpop\_bg}_i \times \texttt{IOUarea\_Wt}_i \times \texttt{CpolyA\_Wt}_{ij} \tag{1.5}$$

$$\texttt{totstr\_Cpoly}_{ij} = \texttt{totstr\_bg}_i \times \texttt{IOUarea\_Wt}_i \times \texttt{CpolyA\_Wt}_{ij} \tag{1.6}$$

where tothh, totpop, and totstr pertain to the total number of households, people, and residential structures, respectively, within a circuit polygon (_Cpoly$_{ij}$, calculated) or census block group i (_bg$_i$, from the 5-yr estimates from the 2015 American Community Survey [107]), IOUarea_Wt$_i$ is the portion of each block group served by the IOU, and CpolyA_Wt$_{ij}$ is the portion of its potentially-inhabited area served by circuit j. We do not multiply by the portion of area that is potentially-inhabited, thereby effectively reallocating the full reported block group population to potentially-inhabited areas.

To check our approach, we compare our estimated number of households per circuit to the total residential customer base reported by each utility for each circuit. A perfect matching would give us a slope and R^2 of 1. Our slopes are 1 and 0.82, with R^2 of 0.867 and 0.721 for PG&E and SCE, respectively (Supplementary Figure A.5). While we avoid drawing conclusions about specific circuits, we will discuss overall trends in grid limits for DER access aggregated across census block groups and each utility territory.

1.6.2 Hosting capacity is spatially allocated to households

Once we have matched residential households to distribution circuits, we allocate hosting capacity available on those circuits to the households. The circuit polygons described in the previous section form our units of analysis. Further allocation and data processing is performed in R (version 3.6.1). Within each circuit polygon, the number of households, residential structures, and people estimated by Equations 1.4-1.6 are assigned (1) the demographic characteristics of the associated block group i and (2) the characteristics of the electric infrastructure j serving them and its existing distributed generation and estimated DER hosting capacity. We use electric infrastructure data from the final PG&E and SCE ICA map updates in 2019 [116, 118].

PG&E and SCE report the existing, queued, and total distributed generation on each circuit. The utilities' hosting capacity calculations consider the current state of the feeder and therefore factor in the existing distributed generation already interconnected to circuit lines [116]. In estimating the number of households with access, we want to consider existing capacity alongside remaining hosting capacity. These values are provided at the full circuit level, and we allocate them to circuit polygons by the proportion of households we estimate to receive service there:

$$\texttt{DER\_exist}_{ij}(kW/hh) = \texttt{ExistDG}_j(kW) \times \frac{\texttt{tothh\_Cpoly}_{ij}}{\texttt{tothh\_ctot}_j} \times \frac{1}{\texttt{tothh\_Cpoly}_{ij}} \tag{1.7}$$

For PG&E, we also scale by the percentage of households served by portions of the circuit with ICA data, given that existing capacity can be located anywhere along the circuit, not just where ICA information exists. This method effectively estimates that each household located anywhere on a given circuit has access to the same amount of existing generation. (Other researchers have reported locations of existing distributed generation (PV) by zip code and census tract [70, 119]. However, we find that scaling our allocations of existing generation within a circuit by these values does not substantially impact our results.) The type of DER is not specified for existing generation. To remain conservative with respect to grid limits, we add the per-household value to each type of generation DER: PV, uniform generation, and their variants with operational flexibility limits.

In addition to *existing* distributed generation capacity connected to a particular circuit, ICA maps also report the *remaining* hosting capacity of load DERs and PV and uniform generation DERs (with and without operational flexibility constraints) that individual 3-phase circuit segments can still accommodate. SCE provides ICA values for all of its 3-phase circuit segments. As of December 2019, PG&E has reported ICA values for approximately 55% of all circuit segments (distributed throughout its territory); our results and discussion apply only to the segments with available data. (See Appendix A.4.2.1 for additional discussion of available ICA data and how it is used.) We compare service areas by demographic indicators to assess whether the portions of PG&E's territory with data are representative of the whole territory (Supplementary Figure A.6). We find no major differences (see full discussion in Appendix A.4.2.2).

These hosting capacity values indicate how much additional DER capacity can be connected to that portion of the circuit without issue. However, adding DER capacity in one location may affect remaining hosting capacity elsewhere on the circuit; i.e., the reported capacity allowances cannot be satisfied simultaneously. Moreover, hosting capacity values can vary widely within a given circuit due to constraints along different lines. According to SCE, the "the minimum values of all the feeders [represent] the value which can be connected anywhere [...] without exceeding the category limit." In contrast, the maximum values can be accepted by some feeders "based on location of interconnection" [120].

We allocate hosting capacity to circuit polygons with an approach designed to err towards less restrictive per-household grid limits while minimizing duplication. First, we select the maximum values for each DER type reported for any circuit segment within a particular circuit polygon. We weight these values by the portion of households served by that portion of the circuit (Eq. 1.8) and normalize to preserve each circuit's total maximum hosting capacity (Eq. 1.9):

$$\texttt{DER\_max\_hhWt}(MW)_{ij} = \texttt{DER\_max\_Cpoly}_{ij}(MW) \times \frac{\texttt{tothh\_Cpoly}_{ij}}{\texttt{tothh\_ctot}_{j}} \tag{1.8}$$

$$\texttt{DER\_max\_hhWt\_n}_{ij}(MW) = \texttt{DER\_max\_hhWt}_{ij} \times \frac{\texttt{DER\_max\_ctot}_{j}}{\sum_j(\texttt{DER\_max\_hhWt}_{ij})} \tag{1.9}$$

where $\texttt{DER\_max\_Cpoly}_{ij}$ is the maximum hosting capacity (MW) reported within circuit polygon ij which corresponds to the overlap between block group i and the estimated service area of circuit j, tothh_Cpoly is the number of households within circuit polygon ij (from Equation 1.4), tothh_ctot is the total number of households estimated to be served by circuit j, $\texttt{DER\_max\_hhWt}_{ij}$ is the household-weighted max hosting capacity (MW) for circuit polygon ij, $\texttt{DER\_max\_ctot}_{j}$ is the maximum hosting capacity anywhere on circuit j, and $\texttt{DER\_max\_hhWt\_n}_{ij}$ is the normalized household-weighted max hosting capacity for circuit polygon ij.

For a small minority of circuit polygons (0.05-1.6%, depending on DER type), the normalized hosting capacity value exceeds the maximum allowed hosting capacity in that circuit polygon. In these cases, we adjust the value back to its allowed maximum:

$$\begin{aligned}\texttt{DER\_max\_hhWt\_nadj}_{ij}(MW) = \text{If } &\texttt{DER\_max\_hhWt\_n}_{ij} > \texttt{DER\_max\_Cpoly}_{ij}, \\ &\text{then } \texttt{DER\_max\_Cpoly}_{ij}, \text{else } \texttt{DER\_max\_hhWt\_n}_{ij}\end{aligned} \tag{1.10}$$

Finally, we calculate the remaining per-household hosting capacity in kilowatts for each circuit polygon:

$$\texttt{DER\_remain}_{ij}(kW/hh) = \frac{\texttt{DER\_max\_hhWt\_nadj}_{ij}(MW)}{\texttt{tothh\_Cpoly}_{ij}} \times 1000 \tag{1.11}$$

Supplementary Table A.4 contains these calculations for an example SCE circuit that spans eight census block groups and therefore creates eight circuit polygons, and Supplementary Figure A.7 summarizes the resulting per-circuit hosting capacities for each utility.

Our final per-household hosting capacity is then estimated to be

$$\texttt{DER}_{ij}(kW/hh) = \texttt{DER\_exist}_{ij} + \texttt{DER\_remain}_{ij} \tag{1.12}$$

for each of the four generation DERs, and $\texttt{DER\_remain}_{ij}$ for the load DER. As there are some significant outliers in the data, we cap all hosting values to a maximum of 50 kW/hh and a minimum of -10 kW/hh for further analysis (negative values exist only for the Load DER in SCE's territory).

1.6.3 Households need kilowatts of circuit capacity for DER access

We estimate the amount of circuit capacity needed to accommodate generation and load DERs, and, using the per-household hosting capacity values (Eq.1.12), assess the ability of households to adopt these technologies given their local circuit limits. We focus our discussion on behind-the-meter PV deployment and potential new load due to EV charging, electrification, and air conditioning adoption.

In California, on average, a household consumes approximately 6.7 MWh of electricity annually [121], while a small building rooftop PV array produces approximately 1.48 MWh of electricity annually per kW of installed capacity [105]. A 4.5 kW PV system is therefore required, on average, to balance 100% of a household's annual electricity demand.

Researchers have previously defined access to behind-the-meter solar PV as the ability to install a 1.5 kW system. This threshold was chosen to be inclusive of existing adoption patterns: of the small ($\leq$10 kW) PV systems installed prior to 2014, 96% were greater than 1.5 kW, and raising the threshold to 3 kW would exclude 19% of them [73, 105]. However, residential PV arrays have grown over time: the median system increased from 2.4 to 6.3 kW between 2000 and 2017 (Supplementary Figure A.8). Of systems installed in 2017, 99% were over 3 kW and 94% were over 4 kW. The changing sizes of residential PV suggest that 1.5 kW may no longer be a reasonable threshold for future access—i.e., if the economics pencil out at larger scales [119], the ability to install only a small amount of solar may prevent someone from installing at all.

We evaluate 'access' at 4.5 kW to estimate the ability of California households to offset their electricity consumption with onsite PV generation, and additionally for a range of thresholds (1.5 kW, for consistency with prior work, then 2-10 kW by 1 kW increments) to track how this variable may influence limits to deployment. We assume that every household would functionally have access to behind-the-meter PV if they had the ability to host 10 kW.

Yet access to behind-the-meter PV is not only limited by grid constraints. Other factors may also restrict the ability to adopt, including lack of suitable rooftop space, access to financing, and

home ownership. We consider economic and housing factors as demographic features, but combine building suitability limits with our estimates of grid constraints to calculate access to behind-the-meter PV based on technical limits. Researchers have estimated the percentage of small buildings (1,000-5,000 ft^2) within specific metropolitan areas and nationwide that are suitable to host 1.5 kW of PV on the basis of tilt, azimuth, shading, and contiguous rooftop area [74, 75]. Small building suitability percentages are available by zip code; we use census zip code tabulation areas (ZCTAs) [122] to assign zip-code level values to block groups. (Some circuit polygons cross more than one ZCTA; for these, we average the values corresponding to all intersecting zip codes.)

We compare the restrictiveness of building characteristics to grid limits. We also propose two approaches for combining building suitability and grid constraints to estimate the percentage of households unable to host solar due to either restriction. In the best case, we maximize double-counting of buildings deemed unsuitable due to either rooftop or grid limits by choosing the lower of the two percentages for a given circuit polygon. In the worst case, we maximize the number of households excluded by either criterion by adding the proportions of households without access.

Beyond solar PV, other DERs also require access to electric distribution circuits. For example, residential households with EVs typically rely on the ability to charge at home. EVs may use level 1 chargers, which require only a typical household outlet, or level 2 chargers, which enable much faster power delivery. While the power drawn by either type depends on the vehicle model, level 1 charging typically requires 1.4-1.9 kW. Level 2 charging can draw between 3.3 and 19.2 kW, with most vehicles requiring around 7 kW [27, 123]. Faster charging technologies can draw significantly more power, but they are less common at the household level, and we omit them from consideration here.

Load electrification and air conditioning will also impact distribution circuits. California state policy has set targets for switching residential fossil fuel uses to electricity via the adoption of electric heat pumps for water and space heating. These technologies will create additional demand for electricity as these appliances become more widespread to support state policy to advance climate change mitigation and adaptation in California. Air conditioning, although already an electric appliance, will also increase load on the grid as additional households deploy new units to cope with increasing temperatures. In particular, low-income households are currently less likely to have air conditioning than high-income households [124].

We estimate the peak per-household electricity demand from electric water heating, space heating, and air conditioning to be 0.6, 1.0, and 2.0 kW, respectively, with household energy consumption data from the 2009 California Residential Appliances Saturation Study [124] and hourly electricity consumption profiles from Energy+Environmental Economics (E3) [125]. Calculation details are provided in Appendix A.4.3.2 and Supplementary Table A.5.

For each DER type reported in the ICA data, we can now calculate the percentage of households with access (`hhwacc`) within each circuit polygon for access thresholds of 1.5 to 10 kW/hh:

if $DER_{ij}(kW/hh) > threshold$ **then**
  hhwacc $\leftarrow 100\%$
else
  hhwacc $\leftarrow \frac{\text{DER}_{ij}(kW/hh)}{\text{threshold}(kW/hh)}$
end

Separately, we also calculate the proportion of households with greater than 0 hosting capacity for each DER. We then aggregate our results up to the census block group and full utility territory levels by first summing over all circuit polygons ij within census block group i, then over all block groups:

$$\texttt{hhwacc\_bg}_i(\%) = \frac{\sum_j \texttt{hhwacc\_Cpoly}_{ij}(\%) \times \texttt{tothh\_Cpoly}_{ij}}{\sum_j \texttt{tothh\_Cpoly}_{ij}} \tag{1.13}$$

$$\texttt{hhwacc\_IOU}(\%) = \frac{\sum_i \texttt{hhwacc\_bg}_i(\%) \times \texttt{tothh\_bg}_i}{\sum_i \texttt{tothh\_bg}_i} \tag{1.14}$$

Block group-level results provide context for the distribution of access within a utility territory via meaningful units of contiguous geographic data within counties and census tracts. We rely heavily on boxplots to visualize access results by block group. All boxplots in this work show the 25th, 50th, and 75th percentiles of results, with whiskers extending to the furthest point within 1.5x the interquartile range. Further points are shown as outliers.

1.6.4 Connecting household access results to demographic features

Hosting capacity values vary across IOU service territories, as do customer demographics and other indicators relevant to electric infrastructure and the customers it serves. We want to understand the relationship between these differences and hosting capacity (and, potentially, customers' ability to adopt DERs) among households for each DER type.

We construct machine learning models to understand which features, if any, are most correlated to per-household hosting capacity, and which are most significant in building the models. We weight our samples by `tothh_Cpoly` to ensure the models appropriately emphasize circuit polygons that contain more households.

- Linear and logistic regression models are used to determine if linear relationships exist between our independent and dependent variables. When fitting, we normalize our independent variables to have a mean of zero and standard deviation of one. We use the regression coefficient and corresponding standard error of each feature to rank features in order of importance. We also calculate weighted root mean square errors (RMSEs) and R^2 values for the linear regression runs, and weighted score, precision, and recall values for logistic regression.

- Random forest regression and classification models are used to determine if non-linear relationships exist in the data. We apply regression models to (1) all values of per-household hosting capacity and (2) the subset of hosting capacity values less than or equal to 10 kW per household

(to specifically focus on the range where access may be limited). For each model, we use the lowest RMSE, as identified by 10-fold cross-validation, to select the proportion of features considered at each split (all features, one-third of all features, or the square root of all features), and use those results to calculate model outcomes and feature importances. We use the weighted RMSE (for regression) and the weighted score, precision, and recall statistics (for classification) to evaluate model performance.

For each model, we use four combinations of infrastructure and demographic indicators as the independent variables: (1) all variables, (2) infrastructure variables only, (3) service and geographic variables, and (4) demographic variables. More information about each variable group is provided in Table 1.1, and a full list of variables is in Supplementary Tables A.6, A.7, and A.8.

Linear regression and random forest regression models use the per-household hosting capacity for each DER type as the dependent variable, while logistic regression and random forest classification models use a boolean value indicating whether the per-household hosting capacity surpasses a set threshold. We test two thresholds: 1.5 and 10 kW per household.

We fit and evaluate all models using the entire data set rather than performing a train-test split. Our data correspond to the entire population in SCE's and PG&E's service territories (given available data); therefore, we are more interested in building models that represent the entire population than in predicting hosting capacity for unseen data.

Moving beyond machine learning models, we also evaluate the distribution of median hosting capacity across features. We focus in on the demographic features to evaluate how hosting capacity changes across feature values. We create bins for the available values of each demographic feature, then calculate the median per-household hosting capacity for each bin. Loess curves are drawn on the plotted median values. These are weighted by the total number of households represented by each bin value and use span (smoothing) values calculated by generalized cross-validation. Confidence intervals are constructed using a bootstrap method with 1000 replications, as in [71], and we show the 50% and 90% confidence intervals for each loess curve.

1.6.5 Data and availability

The definitions of features used in the demographic analyses are available in Appendix A.4.4 for convenience. Utility circuit data is available publicly from repositories that update approximately monthly and currently lack archive capability. The code and specific circuit data used in this study (from the last circuit map updates in 2019) are available at `https://github.com/Energy-MAC/GridLimitsforDERs`.

Chapter 2

Load electrification and the electric distribution system

The electrification of vehicles and heating loads will bring significant new demands to electric distribution grids. However, existing equipment will limit the amount of new load that the grid can accommodate without upgrades. Here, we perform a granular spatial and temporal analysis of the remaining capacity for new load on the distribution circuits and substations of the largest electric utility in California. Further, we estimate the potential increase in electricity demand as a result of electric vehicle charging and the electrification of residential space and water heating loads. We find that serving these new loads will require significant upgrades to the distribution system, and that existing plans for distribution investments do not reflect the pace of projects that will be needed. We discuss potential bottlenecks in utilities' ability to make such upgrades. Finally, we find that absent storage, the ability of distributed solar to mitigate upgrade needs is negligible, and suggest that distributed solar plus storage may offer a way forward.

2.1 Introduction

Beneficial electrification, or electrifying energy uses that are currently served by fossil fuels and powering them with increasingly clean electricity, has emerged as a primary strategy for reducing carbon emissions. Primary targets include residential space and water heating and light-duty vehicles, which today make up roughly 10 and 20% of greenhouse gas (GHG) emissions from the U.S. energy sector, respectively [126, 127]. Researchers have shown that electrifying these end uses with existing alternatives could substantially reduce GHG emissions [106, 128–132] and bring health benefits to the communities in which electrification takes place [133, 134].

Electrification is gaining ground in advocacy support and state policy efforts: at least 15 states have supportive policies or guidelines for fuel switching in buildings [135–137], while 29 have plans or incentives in place for electric vehicle (EV) adoption [138]. However, a transition to elec-

trified end uses is not straightforward. Researchers and practitioners are grappling with important questions related to upfront and ongoing costs and equity in access [92, 93, 139–141], the pace at which residential homes can be electrified and charging infrastructure can be deployed [142–145], and planning implications for legacy gas systems and new transportation infrastructure [146–148].

Our focus here is on the electricity grid, which will need to serve the new electric loads that are created by beneficial electrification. These loads will impact electricity grid operations and planning [149, 150] and require ongoing assessment of interconnection practices and standards [151]. In particular, the timing of new load will impact how the grid must adapt [143]. We focus in on the electric distribution system, where a lack of data has been a barrier to detailed analyses of grid impacts and upgrade needs. However, recent advances in electric utility data in California have created the opportunity to evaluate the ability of electricity systems to accommodate these new loads [42, 51, 152]. In California, electrification is recognized as a necessary tool to meet state climate goals [153], but electrification projections are just beginning to be incorporated into the state's electricity planning processes [154, 155].

Here, we consider the extent to which beneficial electrification might prompt distribution grid upgrades in the territory of California's largest electric utility, Pacific Gas & Electric (PG&E). In doing so, we build on previous work which evaluated limits to the ability of electric distribution systems to accommodate distributed solar energy and new loads in California [44]. Specifically, we evaluate hourly circuit- and substation-level limits for new load in concert with hourly circuit-specific estimates of residential electrification and EV charging scenarios, which we project out to 2030, 2040, and 2050. For each scenario and year, we report the magnitude of needed upgrades across all PG&E circuits and substations, the number of projects (i.e., the number of individual circuits and substations that will need upgrades under each scenario), and the estimated upgrade costs, assuming that upgrades follow historical cost patterns. We also evaluate the potential ability of distributed solar photovoltaics (PV) to mitigate these distribution upgrade needs.

We find that PG&E's circuits and substations will need substantial upgrades to accommodate new loads due to electrification, and that potential upgrade costs are considerable but not extreme. However, the pace of needed circuit upgrades is substantially larger than current upgrade rates, and prompts questions about the ability of electric utilities to make the upgrades needed in order to accommodate electrification goals. Moreover, we suggest that the pace of upgrades, coupled with evidence of utility equipment and workforce shortages, may drive up the costs of these upgrades beyond what is suggested by existing cost patterns. We find that distributed solar, in the absence of storage, does not substantially reduce the upgrades needed. Our results illustrate the importance of planning ahead for required upgrades and considering alternative approaches, such as distributed solar plus storage, to accommodate new loads due to electrification on distribution circuits.

2.2 Methods

First, we evaluate the capacity of distribution circuits and substations in PG&E's territory to accommodate new electric loads and estimate the costs of upgrading those circuits and substations to accommodate additional load (Section 2.2.1). Then, we compare these system capacity estimates

to potential new loads due to electrification (Section 2.2.2). We focus on two primary sources of expected load increases: residential electrification of natural gas heating loads and EV adoption. Finally, we consider the potential of distributed solar PV to mitigate these grid upgrade needs (Section 2.2.3). In all cases, we use month-hour resolution (i.e., 288 total values representing 24 hours in every month) to account for the diurnal and seasonal variability of anticipated new load and grid limits.

2.2.1 Distribution grid infrastructure

2.2.1.1 Circuit hosting capacity

We use data from PG&E's Integration Capacity Analysis (ICA) map [156] to estimate the ability of distribution circuits to host additional load without upgrades. We obtain this data by webscraping circuit data from PG&E's published ICA map. This data is presented with month-hour temporal resolution and reported at the sub-circuit (circuit segment) level. Two types of hosting capacity, thermal and voltage, are reported separately for load. These indicate how much new load can be accommodated without violating equipment thermal limits or raising or lowering circuit voltage outside of allowable bounds, and the minimum of the two limits at a given hour is considered to be the overall hosting capacity for new load in that hour [45]. We report results on upgrade needs considering total limits for each circuit.

The ability of the distribution system to accommodate additional load depends on how that load is distributed spatially on segments throughout each circuit. However, significant uncertainty exists in estimating where new EVs may plug in and residential gas loads may be electrified. Here, we use a scenario approach that employs the distribution of reported hosting capacity values on different segments within a circuit to estimate how well new loads might be sited with respect to circuit capacity. We report our results at the 90th, 50th, and 10th percentiles of the hosting capacity available within each circuit. For more, see Appendix B.1.

2.2.1.2 Substation capacity

All net load that is served by circuits connected to a particular substation must be fed by current sent through substation transformers. These transformers have their own capacity limits, which may, in some cases, be even lower than the sum of capacity limits of all circuits served by that substation. Therefore, in addition to evaluating circuit limits as above, we also evaluate the potential for substation upgrades. To do so, we use 2021 substation capacities reported in PG&E's Distribution Deferral Opportunity Report (DDOR) [157] in conjunction with existing loads at substations and our electrification estimates to estimate which substations will need upgrades to meet increasing load due to electrification. For more, see Appendix B.2.

2.2.1.3 Costs of circuit and substation upgrades

We use data from PG&E's DDOR [157] to estimate the cost of performing circuit and substation upgrades to mitigate identified needs. This data is downloaded directly from PG&E's Distribution

Investment Deferral Framework (DIDF) map [158], and contains estimates of grid needs and the investments needed to address them. We use the costs and magnitude of planned investments to calculate estimates of upgrade costs in $/kW, which we then apply to our calculated upgrade needs. Observing significant evidence of economies of scale in the data (i.e., larger projects have a lower per-kW cost), we separate projects into rough size categories prior to calculating upgrade costs (Table 2.1). We then annualize costs using PG&E's reported discount rate for capital investments, 6.77% [157]. For more, see Appendix B.3.

Table 2.1: Circuit and substation upgrade costs from PG&E's DDOR [157] for planned distribution grid investments (Appendix B.3). Values for circuits are based on the reported costs of planned feeder and line section upgrades (n=187); values for substations are based on the reported costs of planned bank upgrades (n=67).

Grid need (MW)	Circuit upgrade costs ($/kW)			Substation upgrade costs ($/kW)		
	25th pctl.	Median	75th pctl.	25th pctl.	Median	75th pctl.
< 1	445.71	1,875.00	5,791.67	9,935.00	18,863.43	28,982.79
≥ 1 & < 2	251.84	1,368.89	2,092.89	3,594.99	4,740.03	6,980.09
≥ 2 & < 4	196.76	673.35	1,447.55	2,927.93	3,978.38	4,468.75
≥ 4 & < 8	268.65	438.14	785.30	1,137.16	2,004.70	2,570.87
≥ 8	237.23	367.85	586.32	634.01	887.62	1,189.14

2.2.2 New load due to electrification

We focus here on the largest sources of new load that are expected from residential electricity customers due to beneficial electrification: specifically, space and water heating loads and EV charging (some of which will occur at commercial sites as public or work charging). We do not attempt to account for other types of commercial or industrial electrification in our model. We also do not account for any additional load growth from other factors (e.g., population growth, migration, new electricity uses). This allows us to focus on estimated the need for potential grid upgrades specifically due to beneficial electrification among residential customers, who receive much of the CPUC's attention around electrification and equity [1, 43].

2.2.2.1 Residential electrification

The residential electrification estimates draw on a bottom-up spatial analysis of PG&E customer gas usage data as well as load shapes and appliance specification data for electrified heating (i.e., the estimated loads that might materialize if all residential gas heating were electrified) [159]. However, residential electrification will not happen all at once. Technology uptake will depend on costs, appliance turnover rates, market readiness, and consumer willingness to electrify. To estimate possible rates of electrification we use scenarios from the National Renewable Energy Laboratory's Electrification Futures Study [160]. Focusing on the reference, medium, and high cases (Table 2.2), we apply the projected percentage changes in electricity demand under those

scenarios to the total expected new load under full electrification to estimate new circuit-level loads in 2030, 2040, and 2050 (Figure 2.1a). For more, see Appendix B.4.

2.2.2.2 Electric vehicle charging

In 2018, California established a target for 5 million zero-emission vehicles by 2030 [161, 162], and Executive Order N-79-20 increased the goal to 100 percent of in-state sales by 2035 [163], for an anticipated total of approximately 8 million EVs in 2030 [164]. Our EV estimates rely on an analysis of charging infrastructure that will be needed to support this expected growth in EVs in California [164]. This analysis, developed by the California Energy Commission, includes several scenarios for charger deployment that make different assumptions about charging behavior: for example, the extent to which drivers will rely on public, work, and DC fast chargers versus at-home residential charging. All scenarios assume the same number of vehicles. We select three of these scenarios for analysis—standard, more commercial, and more residential. However, all three chosen scenarios exhibit a significant discontinuity at midnight due to the structure of time-of-use rates. We posit that a demand response (DR) program targeted at residential nighttime charging could flatten this peak and thereby alleviate strain on the distribution grid. To evaluate the potential impact of such a program, we create an additional DR scenario, based on the standard scenario, that smoothes the residential nighttime charging peak by evenly distributing residential charging demand in hours 10pm to 5am (Table 2.2).

We distribute the expected charging demand under these scenarios in 2030 to PG&E circuits by the relative proportions of residential and commercial customers those circuits serve. Further, we develop a rough estimate of the charging demands in 2040 and 2050 by doubling, then doubling again, the 2030 numbers (Figure 2.1b). This approach implies that, in part due to Executive Order N-79-20 [163] which bans the sale of internal combustion engines in California after 2035, all or nearly all light-duty vehicles in California in 2050 will be net-zero, and many of them will be EVs. For more, see Appendix B.5.

2.2.2.3 Combined electrification scenarios

To consider the combined impact of residential electrification and EV adoption, we further construct three combined scenarios (Table 2.2). These scenarios each consist of adding one residential electrification scenario and one EV charging scenario. We select scenarios that are intended to reflect a plausible projection with relatively low vs high impact on residential circuits, and additionally account for the potential impact of a DR program for residential nighttime EV charging. For the low residential combined scenario, we use the medium scenario for residential electrification (reflecting the expected impact of continuing supportive policy in California, relative to the reference scenario) and the more commercial scenario for EV charging. For the the high residential combined scenario, we use the high scenario for residential electrification and the more residential scenario for EV charging. For the high residential and DR combined scenario, we use the high scenario for residential electrification and the DR scenario for EV charging.

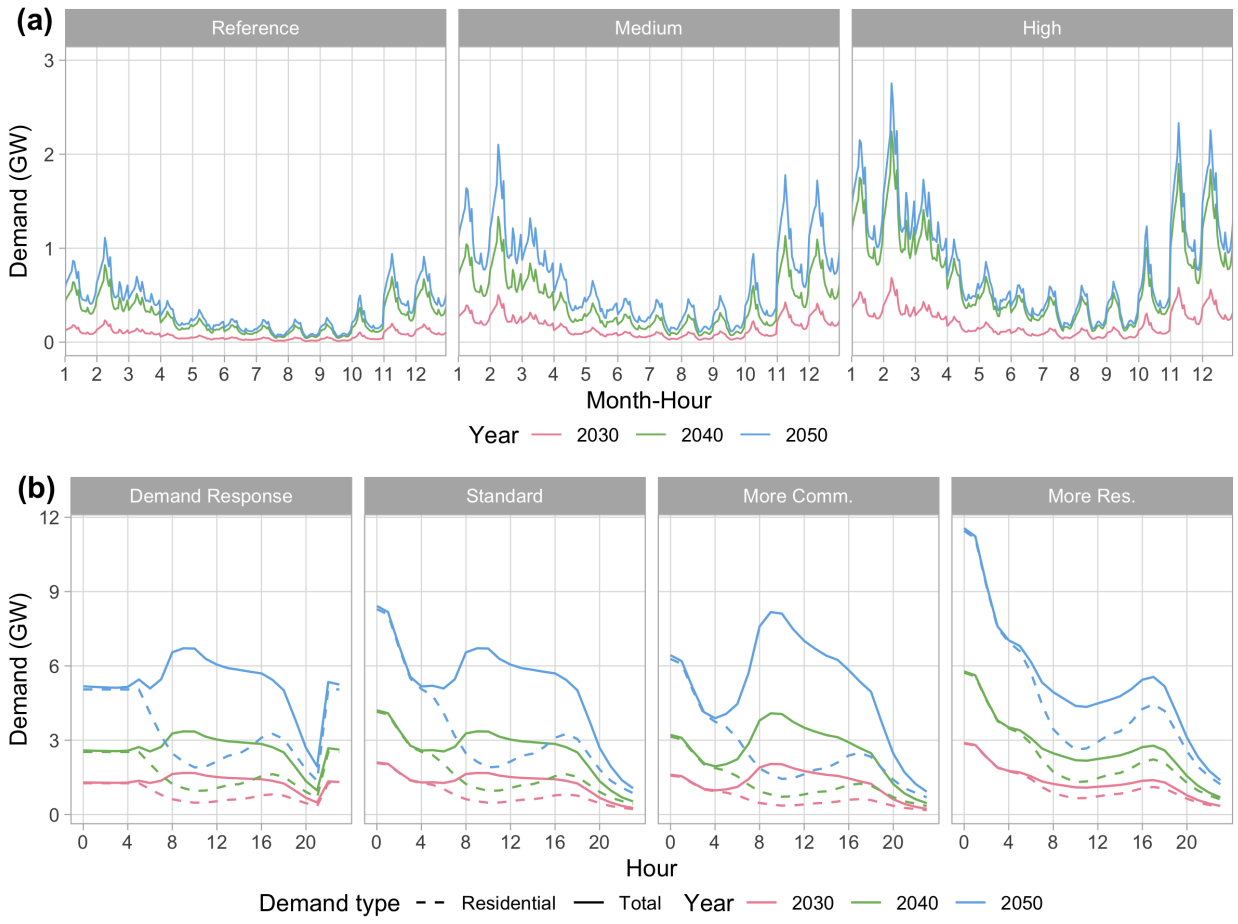


Figure 2.1: Total new electricity demand in PG&E's territory predicted with the electrification scenarios used for (a) residential electrification and (b) EV charging (Table 2.2). Residential electrification projections vary seasonally, and are shown in month-hours across each year. EV charging projections do not vary seasonally and are shown only by hour of day, which is replicated 12 times to yield month-hour projections. EV charging projections also show the proportion of residential charging, with the remaining total composed of commercial charging.

2.2.3 Distributed solar generation

We use the National Renewable Energy Laboratory's System Advisor Model (SAM) v.2020.11.29 [165] and data from the National Solar Radiation Database (NSRDB) [166] to estimate the timing of electricity generation from distributed PV arrays in PG&E's territory. We account for geographic variation in PV production by using different solar profiles for circuits connected to substations that are located in different climate zones and counties. We obtain hourly energy production over the course of a year at each location. However, the distribution system must be able to operate even in low-solar conditions. Therefore, we aggregate our solar generation data to month-hour values by using the minimum production in each hour over the days in a given month. We assign that energy production to hypothetical solar installations located on PG&E circuits in increments

Table 2.2: Summary of electrification scenarios used in this analysis.

Type	Scenario	Description
Residential electrification [160]	Reference	"Business-as-usual outlook" with "only incremental changes," "excludes dramatic policy, technological, societal, or behavioral shifts." Adoption "roughly follows current trends." This scenario corresponds to a 17.5% increase in the number of homes electrified between 2021 and 2050.
	Medium	"Accelerated adoption" of technologies "that is plausible but not transformational"; "technical, economic, and consumer preference obstacles remain"; adoption often remains in diffusion or early-adopter stages. This scenario corresponds to a 33.2% increase in the number of homes electrified between 2021 and 2050.
	High	"Assumes a more favorable set of conditions for electrification—including a combination of technology breakthroughs, policy support, and underlying societal and behavioral shifts that yield an electrification transition." Despite being aggressive, it "does not reflect full technical potential for electrification." This scenario corresponds to a 43.5% increase in the number of homes electrified between 2021 and 2050.
EV charging [164]	Standard	Designed to mirror observed charging behavior and incorporate evolving technology and market conditions. 67% of plug-in EVs have access to home charging.
	More commercial	Low residential access: 50% of vehicles have access to overnight charging, shifting load to more commercial daytime charging.
	More residential	High residential access: 95% of vehicles have access to overnight charging, shifting load to residential charging.
	Demand response	Constructed by smoothing residential nighttime charging from 10pm to 5am; otherwise, the same as the standard scenario.
Combined scenarios	Low residential	Intended to depict overall lower load on residential circuits: for each circuit, a sum of the medium scenario for residential electrification and the more commercial scenario for EV charging.
	High residential	Intended to depict overall higher load on residential circuits: for each circuit, a sum of the high scenario for residential electrification and the more residential scenario for EV charging.
	High res & DR	Intended to depict overall higher load but with the addition of demand response for residential nighttime EV charging: for each circuit, a sum of the high scenario for residential electrification and the demand response scenario for EV charging.

of 200 kW installed capacity, and evaluate the extent to which this installed solar may grid upgrade needs. For more, see Appendix B.6.

2.3 Results and discussion

For each electrification scenario considered, we report grid upgrade needs for PG&E's distribution circuits and substations in gigawatts, the number of projects, and estimated upgrade costs using PG&E's reported per-kW project costs (Figures 2.2, 2.3).

2.3.1 Overall upgrade needs

We see that the upgrade needs prompted in the combined electrification scenarios is nearly the same as the number required just due to EV adoption. This result follows from prior findings that greater overall new electricity loads are expected from vehicles than from residential electrification [160]. The biggest impact from residential electrification loads alone, relative to impacts from EV or combined scenarios, is seen on the number of circuits needing upgrades (Figure 2.2b). This suggests that many circuits are already near their load limits, as even relatively low new loads will

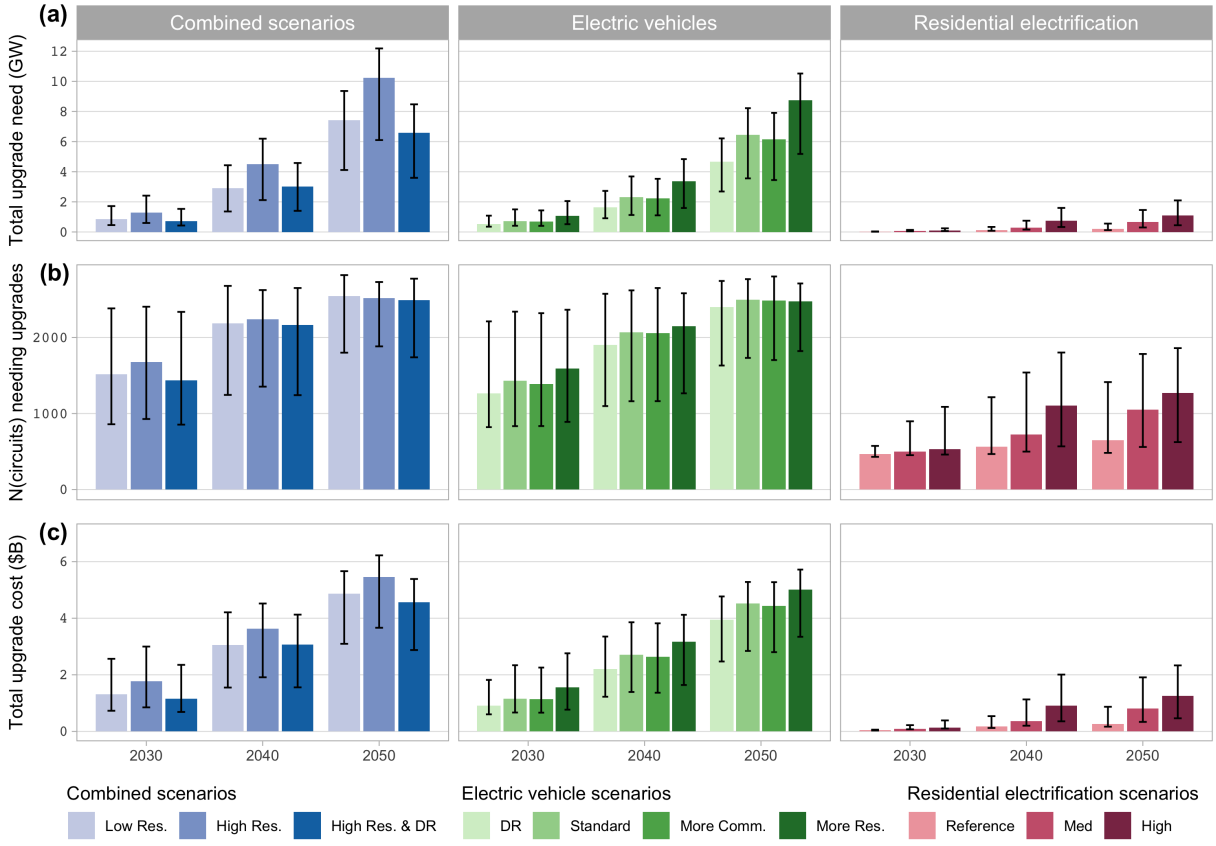


Figure 2.2: Upgrade needs for PG&E distribution circuits. There are 3063 circuits in total. Results capture the potential uncertainty of where new load might connect within a circuit: column heights depict the median load allocation scenario, and the lower and upper error bars indicate the 90th and 10th percentiles, respectively.

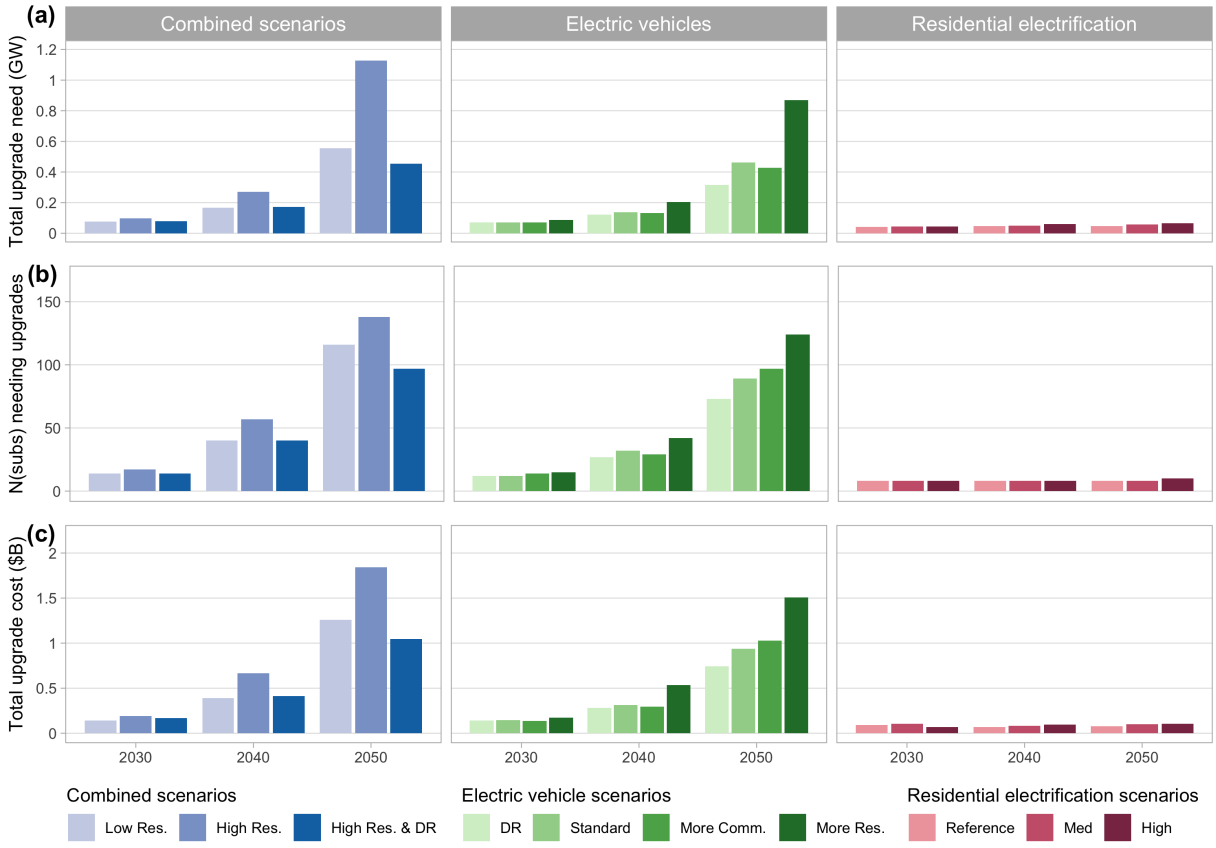


Figure 2.3: Upgrade needs for PG&E distribution substations. There are 724 substations represented.

prompt upgrades.

As expected, total upgrade needs increase in time for each electrification scenario considered across all metrics evaluated. A small exception occurs in estimated upgrade costs for residential electrification at substations (Figure 2.3c), where the estimated upgrade costs may be lower even when greater investments are needed. This occurs due to the economies of scale of grid investments (Table 2.1): the cost per kW is lower once a greater investment need is cleared.

Notably, the choice of electrification scenario more significantly impacts the total upgrade need and cost than the number of projects needing upgrades. This is particularly true for circuits: the number of circuits needing upgrades does not substantially decrease in the DR scenario, as might be expected if a significant number of upgrades were prompted by the EV charging midnight peak. Rather, midday and even off-peak charging alone prompt upgrades on many circuits: we see this when tallying the circuit limit violations in each month-hour by each scenario (Figure 2.4).

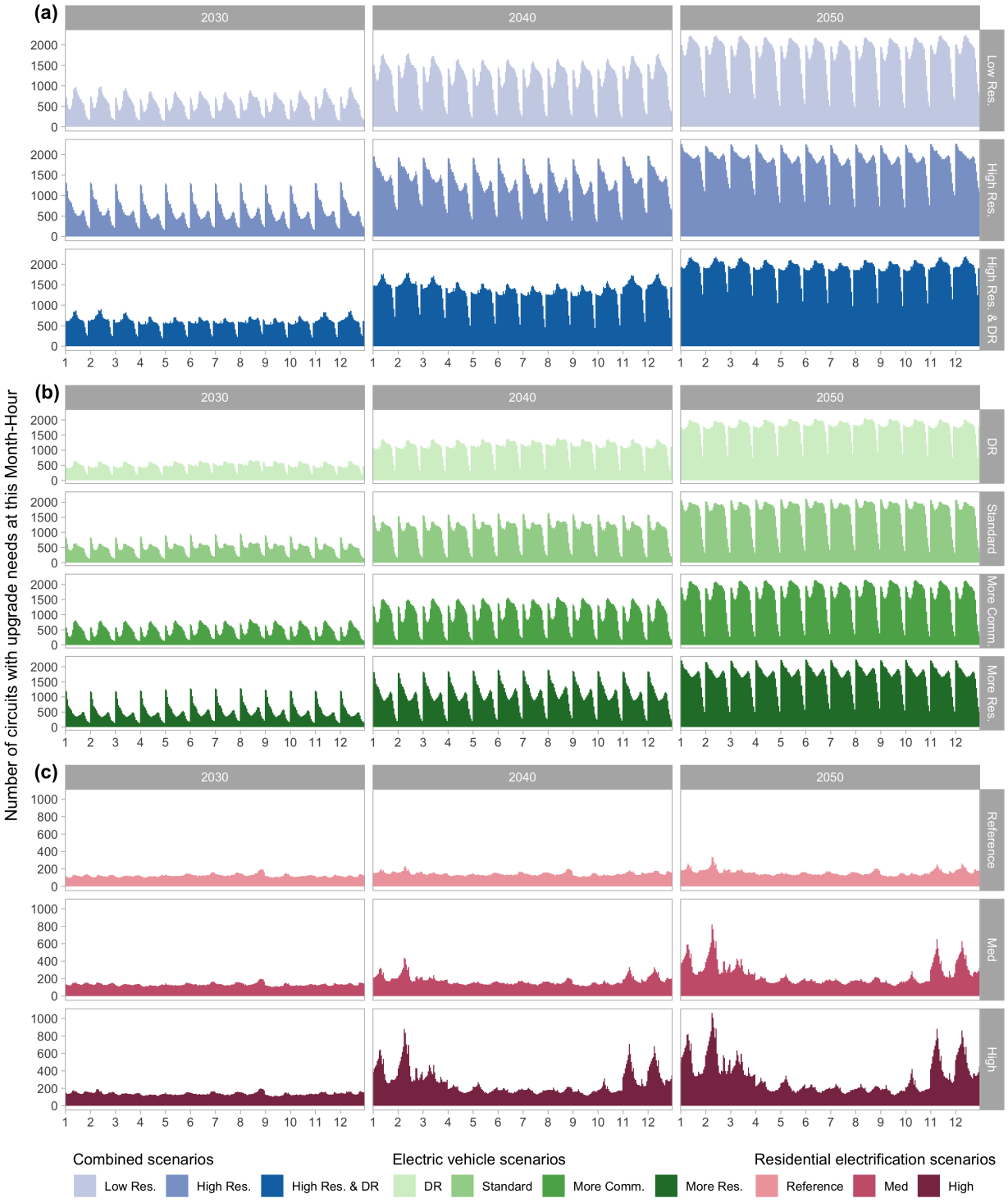


Figure 2.4: Count of circuits, of 3063 total, with upgrades prompted by each electrification scenario in each month-hour, from Figure 2.2: (a) shows combined scenarios, (b) shows EV charging scenarios, and (c) shows residential electrification scenarios.

2.3.2 Number of upgrade projects

We see that a significant portion of PG&E's three thousand circuits are expected to need upgrades under these scenarios by 2030, while the number of substations needing upgrades increases more strongly across years. This observation prompts us to consider to what extent PG&E might be able to upgrade its circuits to meet electrification needs. To better visualize the pace of needed upgrades, we plot the number of circuits and substations needing upgrades per year for each time period of analysis (Figure 2.5).

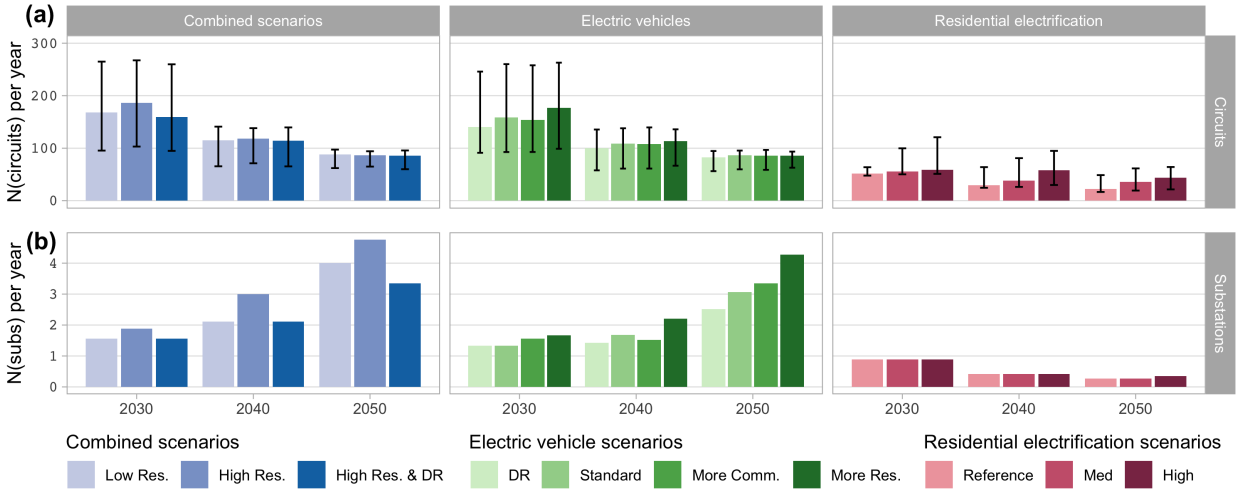


Figure 2.5: Upgrades needed per year, of (a) circuits and (b) substations. Calculated by dividing the results in Figures 2.2b and 2.3b by the number of years from 2021 until the target year.

In their 2021 DDOR report, PG&E estimated needing to complete approximately 56, 87, and 53 feeder and line section upgrades in 2021, 2022, and 2023, respectively [157] (Appendix B.3). Expected substation bank upgrades were highest in 2024, with 20 substation banks needing upgrades that year (with 18 of the 20 reportedly needed for capacity reasons, see Figure B.7). At an average of 1.78 banks per substation (Appendix B.2), this translates to approximately 11 substation projects. Comparing these numbers to our results in Figure 2.5 suggests that we may be substantially undercounting substation upgrades. This may occur because we sum bank capacity to evaluate total substation capacity due to insufficient data to evaluate bank limits alone (Appendix B.2). However, our projections for the number of annual circuit upgrades needed are significantly higher than PG&E's expected pace of upgrades through 2025, suggesting the importance of planning ahead for increased electrification.

Successfully performing distribution upgrades requires having access to equipment (e.g., transformers, circuit breakers, cables, switches, etc.) as well as the staff to plan and implement these investments. Nationwide, electric utilities are increasing their investments in transmission and distribution infrastructure [167]. These efforts have already been hampered both by the availability of equipment and trained workers. In particular, supply chain shortages and service delays have made it more difficult for utilities to obtain the equipment they need [168], impeding progress on grid

modernization and decarbonization efforts [169]. Such shortages increased due to global supply chain issues during the COVID-19 pandemic. However, electric sector supply chain vulnerabilities predate the pandemic and are expected to continue, due in part to geographic concentrations of key suppliers and raw materials, manufacturing capacity, competition from the automobile industry, and the unique characteristics of equipment such as power transformers [169–173]. Moreover, energy sector labor shortages created challenges for electric utilities even before the pandemic [174–176]. Evidence of longer interconnection timelines due to upgrade bottlenecks already exists [12, 13]. These pre-existing and separate trends already pose risks for grid investments even in the absence of a significant ramp-up of circuit upgrades, suggesting that we may observe increasing bottlenecks, longer timelines, and higher costs for grid modernization efforts.

2.3.3 Costs of distribution system upgrades

To further evaluate the potential cost impacts, we consider how investment needs might change under both lower and higher cost scenarios, and annualize these costs to consider how much PG&E might need to spend per year to perform these grid upgrades (Figures 2.6 and 2.7). Specifically, we compare the result of using the median reported values for per-kW bank costs (for substations) and feeder and line section costs (for circuits) to the 25th and 75th percentiles of the costs of PG&E's planned investments (Table 2.1).

We note again that these cost estimates are based on utility-projected near-term costs, and they are intended to give only a plausible range, not to serve as finalized estimates. Further, the appro-

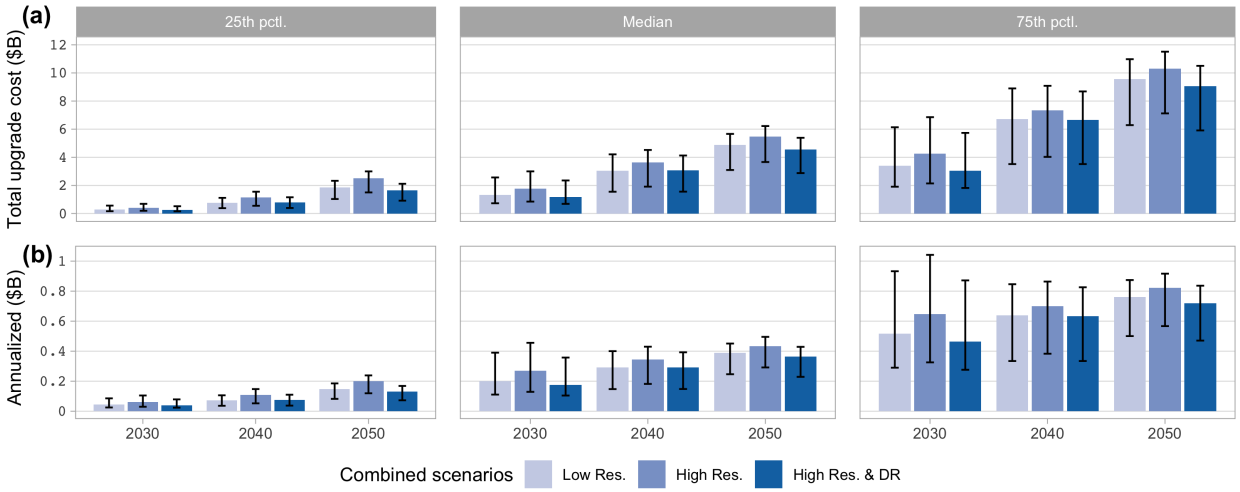


Figure 2.6: Estimated total costs for distribution circuit upgrades in PG&E's territory: (a) shows total costs, (b) shows annualized costs. Columns 1 and 3 show the impact of projected costs when using the 25th and 75th percentiles of cost ranges; median values in (a) are identical to the combined scenario results in Figure 2.2, which are generated using the 50th percentile of reported costs. Results capture the potential uncertainty of where new load might connect within a circuit: column heights depict the median load allocation scenario, and the lower and upper error bars indicate the 90th and 10th percentiles, respectively.

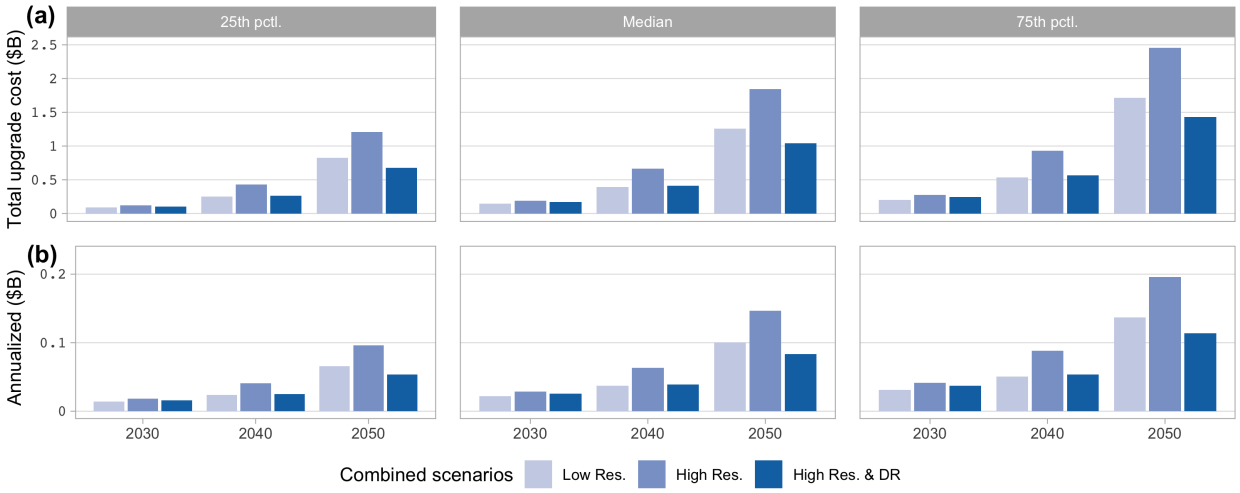


Figure 2.7: Estimated annualized costs for distribution substation upgrades in PG&E's territory: (a) shows total, (b) shows annualized costs. Columns 1 and 3 show the impact of projected costs when using the 25th and 75th percentiles of cost ranges; median values in (a) are identical to the combined scenario results in Figure 2.3, which are generated using the 50th percentile of reported costs.

priate percentiles of costs (or alternative values) to use in this analysis merit further investigation. Relative to near-term estimates, actual future costs could fall due to learning-by-doing, as more technologies are scaled and deployed [177, 178]. Actual future costs could rise due to bottlenecks, including equipment and staff shortages, as utilities in California and beyond seek to prepare their grids for demand growth due to electrification. While both impacts are plausible, we posit that the magnitude of needed investments alongside the other bottleneck trends discussed above are more likely to lead to increasing costs, potentially even beyond what we can predict on the basis of historical cost patterns.

Our estimated costs are substantial, but not outlandish: the California Public Utilities Commission approved PG&E to spend $2.23 billion on electric distribution capital projects in 2020 [179], and PG&E forecasts approximately $4 billion in electric distribution capital expenses from 2022 through 2026 (the actual spending is subject to CPUC approval) [180, Exhibit 4].

2.3.4 Distributed solar

We assess the potential impact of distributed solar on circuit upgrade needs under the combined electrification scenarios, focusing on the median load allocation scenario (i.e., the bar heights in Figure 2.2, ignoring the 10th and 90th percentile load allocation scenarios indicated by the error bars). Specifically, we apply location-specific solar profiles to PG&E circuits in increments of 200 kW solar capacity, then re-calculate our distribution upgrade metrics. We increase the distributed solar per circuit until no additional benefit is observed, up to 150 MW of solar per circuit.

We find that distributed solar without storage has very little ability to mitigate circuit upgrade needs (Figures 2.8, 2.9). The strongest impacts are observed for the Low Residential and High

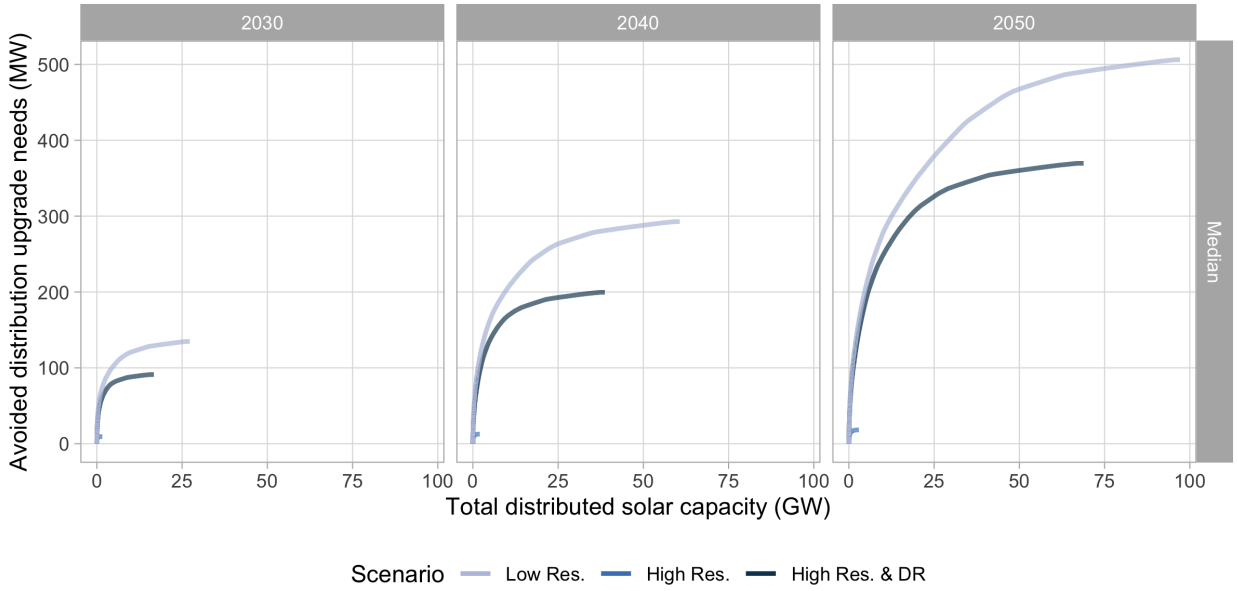


Figure 2.8: Cumulative impact of distributed solar on PG&E distribution circuits under the combined electrification scenarios with respect to avoided circuit upgrade needs. Lines end when additional solar deployment would not further reduce upgrades on any circuits.

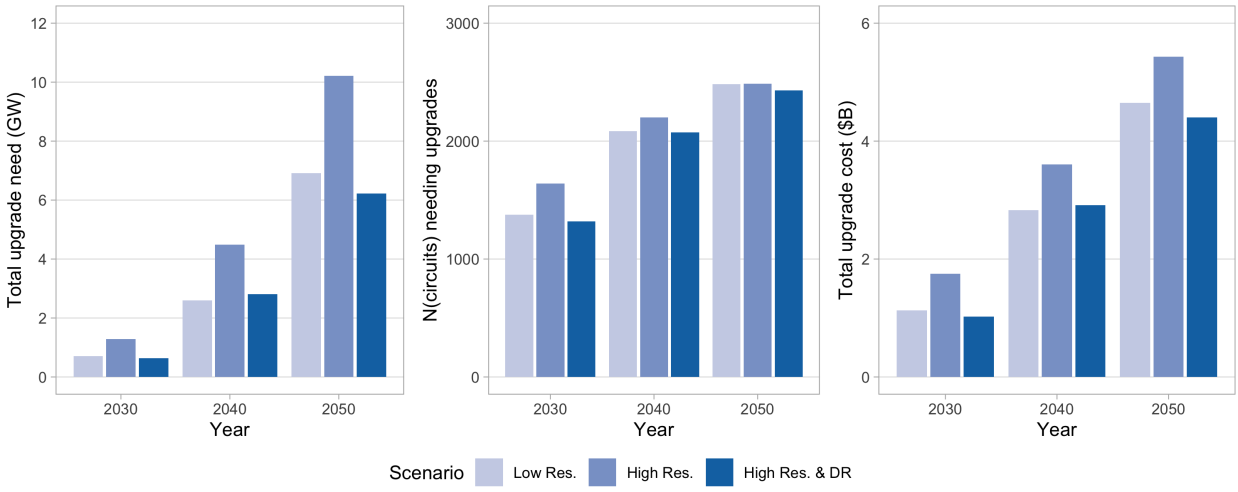


Figure 2.9: Upgrade needs for circuits under combined electrification scenarios with additional distributed solar, for comparison to the median scenarios (i.e., bar heights) in Figure 2.2. Results shown here are obtained by increasing distributed solar generation on individual circuits until there is no additional reduction of grid upgrades on a given circuit, up to 150 MW of solar capacity per circuit.

Residential & DR combined scenarios. This is expected, as these scenarios exhibit the strongest daytime peaks due to commercial EV charging. However, without added storage, the ability of

solar to shift these peaks is minimal, and only small differences exist between the combined scenario results in Figure 2.2 and the recalculated results with significant distributed solar deployment (Figure 2.9).

2.4 Conclusions

Building and transportation electrification are poised to bring significant new electricity loads to California's distribution grids. Here, we estimate the potential new loads from residential electrification and EV charging under possible adoption scenarios on PG&E's distribution circuits, and compare these loads to the remaining capacity of the utility's distribution circuits and substations.

We find that substantial grid upgrades will be needed to accommodate electrification loads, and that the pace of needed upgrades is much faster than PG&E's projected near-term implementation rate. Moreover, the number of needed projects stays largely constant regardless of the choice of electrification scenario, suggesting that shifting loads in time would not significantly mitigate the need for upgrade projects.

While the projected costs of these upgrades—as estimated on the basis of reported near-term project costs—are not likely to present a significant financial obstacle, we suggest that these numbers may not be representative of the actual costs that utilities might bear in the future. In particular, the rapid pace of upgrades coupled with evidence of equipment and workforce scarcity may drive up costs beyond what we can predict on the basis of near-term cost patterns. With significant planned utility investment in grid infrastructure in the coming decades, more research is needed on how these factors might challenge utilities' ability to serve new loads. We note that our analysis likely underestimates needed substation upgrades, possibly due to insufficiently granular data at the substation level.

Our analysis illuminates several opportunities for planning and policy interventions to reduce strain on the electricity grid from new electrification loads. First, we estimate that the pace of distribution circuit upgrades is likely to be greater than what PG&E's existing projections of planned distribution system investments suggest. Planning ahead for upgrades that have yet to materialize is therefore of paramount importance, both to avoid under-building the system and to reduce future bottlenecks in the utility's ability to perform upgrades. This might include: (1) holistically evaluating the ability to implement upgrades, with special attention paid to equipment and workforce availability; (2) scheduling upgrade projects proactively and accounting for anticipated load growth due to the state's electrification policies when sizing those upgrades; (3) proactively investing in workforce preparation, including hiring and training; and (4) evaluating the potential for alternatives to conventional grid investments, such as distributed solar plus storage or other non-wires alternatives, to fill in the need for capacity upgrades.

Further, we demonstrate that the choice of EV charging scenario has substantial impacts on overall upgrade needs, if not on the pace of upgrades. Specifically, more commercial EV charging relative to residential at-home charging results in substantially lower upgrade needs. Commercial EV charging can also make better use of daytime electricity generation from distributed solar, potentially enabling local mitigation of upgrade needs and thereby reducing upgrade bottlenecks.

However, distributed solar alone is ineffective in alleviating circuit upgrade needs even in scenarios with high commercial charging, largely due to timing and daily variability in generation. Further research is warranted on the extent to which distributed storage, whether standalone or coupled with distributed solar, might be able to provide local grid support to mitigate upgrade needs, as well as on smart EV charging to follow solar generation.

Here, we evaluated the extent to which expected growth in residential electrification and EV charging might stress the existing limits of electric distribution grids. Our EV charging projections assume that most, if not all, light-duty vehicles in PG&E's territory are EVs by 2050. Our residential electrification scenarios correspond to approximately 17-44% of home electrification by 2050, whereas greater penetration of electrification is likely still needed to meet climate goals. We have ignored here additional electrification of commercial and industrial loads, as well as load growth due to other factors. However, these factors will increase grid upgrade needs beyond what is projected here. This observation only strengthens our recommendations about planning for anticipated grid needs in the context of the energy transition.

Chapter 3

Weathering adaptation: Grid infrastructure planning in a changing climate

Decisions related to electric power systems planning and operations rely on assumptions and insights informed by historic weather data and records of past performance. Evolving climate trends are, however, changing the energy use patterns and operating conditions of grid assets, thus altering the nature and severity of risks the system faces. Because grid assets remain in operation for decades, planning for evolving risks will require incorporating climate projections into grid infrastructure planning processes. The current work traces a pathway for climate-aware decision-making in the electricity sector. We evaluate the suitability of using existing climate models and data for electricity planning and discuss their limitations. We review the interactions between grid infrastructure and climate by synthesizing what is known about how changing environmental operating conditions would impact infrastructure utilization, constraints, and performance. We contextualize our findings by presenting a case study of California, examining if and where climate data can be integrated into infrastructure planning processes. The core contribution of the work is a series of nine recommendations detailing advancements in climate projections, grid modeling architecture, and disaster preparedness that would be needed to ensure that infrastructure planning decisions are robust to uncertainty and risks associated with evolving climate conditions.

3.1 Introduction and motivation

A steady supply of electricity is fundamental to the normal and productive functioning of modern society. Climate change and severe weather make it more difficult to operate the electric system reliably. As a result, events such as Hurricanes Sandy and Maria, and recent wildfires in California, have led to blackouts. Electric power systems will need to adapt to new climate realities; to do so, it will be necessary to revise the models and types of data that inform operational and planning decisions [181].

Decades of scientific research inform our current understanding of climate science, energy systems, and the interactions between them. Yet questions remain about the underlying physical processes in both disciplines, as well as about how emissions will unfold over the next century. For example, methods for interpreting global climate projections to anticipate severe weather events are still under development [182]. The characteristics of severe weather events are also evolving, indicating that historic data are not representative of present or future conditions [183]. Continuing to use historic data is problematic because grid infrastructure components installed today will remain in operation for decades to come. Using climate projections to inform critical infrastructure investments may reduce our exposure to the risks we can anticipate, in light of what we currently know about climate change.

Despite abundant research characterizing climate impacts on grid infrastructure, making decisions about if and how to mitigate these impacts remains a challenge. It would be cost-prohibitive (and likely unnecessary) to build a system that could operate reliably in any possible climate future [184], and we may need to accept certain risks that we could opt to mitigate today. Yet research shows that climate trends will fundamentally transform the performance and risk exposure of grid assets [61, 63]. Failure to incorporate climate impacts into planning decisions could leave critical infrastructure unnecessarily exposed to risks that we could feasibly avoid [185].

In other sectors, agencies have established guidelines and best-practices for incorporating climate information into decision-making processes (see, for example, [186–188]). These efforts identify and quantify climate vulnerabilities and outline possible mitigation strategies. Though simple decision analysis models may be suitable in some planning contexts, the severe consequences associated with failure to detect unmitigated risks in electric power systems suggests that comprehensive analysis of climate impacts is warranted [189]. This analysis will require operationalizing climate projections, quantifying impacts on environmental and operating characteristics relevant to power systems, and evaluating near- and long-term implications of grid operations and planning decisions. Figure 3.1 illustrates these information flows. Collaboration between scientists and practitioners will be necessary [190, 191], and state or federal planning authorities can play a critical role in coordinating how information are acted upon by different types of decision-makers. Long-term investment decisions will ultimately need to assess the costs associated with mitigating climate risks and the ramifications of allocating limited resources to mitigate certain risks but not others. The societal implications of possible risk scenarios (i.e., wildfires, widespread blackouts, rising energy costs), motivate the need to incorporate climate information into assessments of infrastructure vulnerabilities that are (or will be) present. Effective policy can prevent duplication of efforts, educate practitioners about the nature and the limitations of existing climate data, and define best practices.

The current work synthesizes what is known now about the interactions between grid infrastructure and climate and provides recommendations for moving forward. We focus on a case study of California: a state that has already done a great deal of research to develop data and guidelines to begin incorporating climate considerations into decision-making processes. Our contributions are threefold: First, we provide background on climate models, grid planning models, and decision-making processes that inform if, how, and where investments are made. Next, we review the factors that must be considered for future planning and discuss how the models listed in Figure 3.1 would

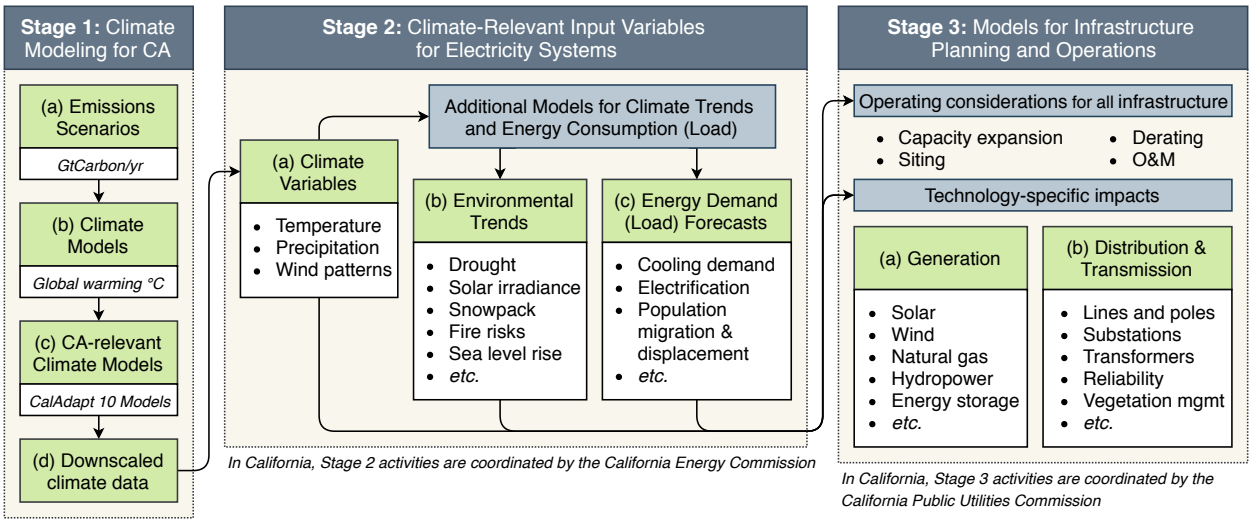


Figure 3.1: Flow of information between climate models and grid infrastructure planning. Each box represents a distinct modeling effort. This diagram is not intended to be comprehensive, and additional data streams may exist.

need to evolve to quantify grid/climate interactions in a detailed and comprehensive way. Finally, we offer recommendations for decision-makers in California's electric sector to begin to act upon climate projections. With these recommendations, we identify specific actions that researchers, practitioners, and policymakers can take to ensure that our understanding of climate risks to grid infrastructure continues to advance.

We provide background on electricity infrastructure planning and climate adaptation efforts in California in Section 3.2. Then, following the flow of information in Figure 3.1, we provide background on climate modeling (Stage 1 activities) in Section 3.3. The climate-relevant input variables for electricity systems listed in Stage 2 are introduced and discussed in Section 3.4. Considerations for translating those climate inputs into infrastructure planning models are discussed in Section 3.5 (covering generation, distribution, and transmission). We provide overarching recommendations in Section 3.6 and conclude in Section 3.7.

3.2 The California planning context: Electricity systems and climate adaptation

3.2.1 Electricity system planning

In California, electric utilities share primary responsibility for energy- and electricity-related planning and oversight with two state agencies and the state's independent grid operator (Appendix C.1). The California Energy Commission (CEC) generates hourly demand forecasts for its Integrated Energy Policy Report (IEPR). The California Public Utilities Commission (CPUC) and regulated utilities use these forecasts to identify investments needed to continue to provide reliable,

safe, and cost-effective electricity service. Demand forecasts also inform transmission planning decisions overseen by the California Independent Systems Operator (CAISO).

The IEPR forecast includes scenarios related to weather, energy efficiency, and load growth futures [192]. Planning decisions that must be robust to extreme weather events are informed by a 1-in-10 weather year generated from statistical analysis of historic data [193].

Two of the IEPR scenarios include climate adjustments for "likely" and "high" temperature rise scenarios. Further documentation is necessary to understand how these adjustments account for changes in consumption for each end use [194]. However, the documentation indicates that adjustments are based on the temperature-sensitivity of existing load and do not consider more profound changes that will affect energy consumption (see Section 3.4.3). Because the IEPR load forecasts are used throughout the state to inform planning decisions, incorporating a rigorous assessment of climate impacts here could help decision-makers account for climate impacts in a consistent and coordinated manner [195].

Aside from load impacts, modeling processes that inform infrastructure planning do not account for climate trends. Appendix C.1 contains a thorough discussion of existing infrastructure planning processes in California and the data flows between them. In many cases, modeling assumptions and architecture may need to be revised to comprehensively factor in existing climate-grid interactions (Section 3.5).

3.2.2 Climate change adaptation

The State of California initiated climate research and planning efforts in the late 1980's; these efforts are detailed in [194] and [187]. Here, we summarize recent and ongoing efforts specifically related to adaptation and infrastructure. These include research into potential climate impacts, efforts to operationalize climate data, and legislative and regulatory directives for planning agencies.

California solicits adaptation research through the state's climate change assessments, a joint effort by the Governor's Office of Planning and Research, the California Natural Resources Agency, and the CEC. Starting in 2006, the state has completed four rounds of assessments. These examine physical vulnerabilities, adaptation options, and research needs [196].

Executive Order S-13-2008 initiated strategic planning processes for sea level rise and climate adaptation [197], resulting in guidance documents in both areas. The sea level rise guidance document (updated in 2018) provides a synthesis of state-of-the-art science on sea level rise, and outlines best-practices for coastal adaptation [198]. Notably, the document takes a step-wise approach to setting risk tolerances, and acknowledges that these may differ across categories of decision-making. For example, an "extreme" scenario is included for consideration for "high-stakes, long-term decisions" [198, p.4, 25]. The climate adaptation guidance document, issued in 2009, underscores the importance of a data clearinghouse—namely CalAdapt, then under development—to "synthesize existing California climate change scenarios and climate impact research" [199].[1]

[1] Additional resources hosted by the CA Governor's Office of Planning and Research include datasets and planning guidelines for climate adaptation by local planning agencies (e.g., see: [200]).

Legislative actions in 2015 and 2016 built on these efforts: Senate Bills 379 and 246 and Assembly Bills 1482 and 2800 established mechanisms to coordinate adaptation efforts, required state agencies to consider climate change while planning for state infrastructure, and directed stakeholders to use CalAdapt data when assessing local climate vulnerabilities [201, p.117]. One initiative formed out of this legislation was the Climate-Safe Infrastructure Working Group, which recommended adaptive planning, whereby decision-makers move forward with currently-available information while taking note of information gaps [202]. The working group emphasized the need to confront changes in both average and extreme weather conditions [202], and to use probabilistic methods to deal with uncertainty in risk [203]. Our own recommendations build on these principles (Section 3.6).

In April 2018, the CPUC opened a rulemaking focusing on climate change adaptation [204]. Designed to integrate climate awareness into grid infrastructure planning and regulatory decision-making statewide, the proceeding asked stakeholders to suggest approaches, data sources, and tools to "address climate adaptation in a consistent manner" [205]. Here, we contribute to this effort by examining climate information, modeling needs, and decision processes specific to adapting electric grid infrastructure to maintain safe and reliable service under evolving climate conditions.

3.3 Background on climate modeling

Climate models use assumptions about worldwide emissions to predict possible short- and long-term trends in weather variables. We do not know precisely how emissions or climate dynamics will play out over the next century. State-of-the-art climate projections use a range of modeling assumptions designed to capture different possible climate futures. The different stages of the climate modeling process are described in detail below.

3.3.1 Global emissions scenarios

Emissions scenarios describe the amount of carbon and other greenhouse gases injected into the atmosphere. The Intergovernmental Panel on Climate Change (IPCC) releases data for a range of possible emissions scenarios, or Representative Concentration Pathways (RCPs). These are numbered by the increase in radiative forcing (a metric of global warming, reported in W/m^2), and include RCP2.6, 4.5, 6.5 and 8.5 W/m^2.

Climate data localized to California are readily available for RCP8.5 and RCP4.5. RCP8.5 describes a "business as usual" trajectory where emissions increase at current rates for the remainder of the century. In RCP4.5, emissions increase over the next 50 years, then decrease to below 1990 levels by 2100.

These two scenarios were selected during a 2015 analysis of climate information for state water resources planning [206], when available data for other emissions scenarios were not as comprehensive. Climate projections are continuously being updated to reflect new emissions pathways and advances in our understanding of climate dynamics. Decisions about which data to use must be periodically revisited as climate science advances.

3.3.2 Climate models

Climate projections come from global circulation models (GCMs) that characterize the physical dynamics driving circulation and heat transfer between the Earth's atmosphere, land, oceans, and ice caps. As these interactions are not perfectly understood, teams of scientists have developed a library of GCMs that incorporate modeling assumptions designed to capture different possible dynamics, reported in [207]. Over 50 climate projections for different GCMs and emissions scenarios are consolidated in the Coupled Model Intercomparison Project (CMIP) [208]. These models are updated periodically to reflect advancements in climate science. At the time of this publication, CMIP5 is the most recent comprehensive release of climate projections. Revisions that are underway as part of CMIP6 will reflect organizational, procedural, and structural changes geared at making climate projections easier to update and more digestible to a broader audience.

A 2015 study mined the most recent models (CMIP5) to identify suitable projections to inform water resource planning in California [206]. Fifteen models were found to accurately characterize regional weather systems. Of these, ten accurately predicted precipitation metrics particularly relevant to water resource planning [206], and were chosen for wide dissemination through CalAdapt [209]. The relevance of these models to support applications beyond water resources (e.g., grid infrastructure planning) remains to be examined.

The CEC selected a smaller subset of four models to support the Fourth Climate Change Assessment [210]. These models cover a similar range of temperature and precipitation outcomes as the 10 models. In 2017, the CEC recommended that these four models (with the RCP4.5 and RCP8.5 emissions scenarios) should be used for energy sector planning [201, p.137]. In 2019, the CPUC directed electric utilities to use the 10 GCMs available within CalAdapt (with RCP8.5) for decisions related to planning, investment, and operations [211].

3.3.3 Downscaled climate models

The spatial resolution of GCM outputs is very coarse (250 to 600 km), making raw climate projections ill-suited for use in granular planning decisions. A mathematical process called "downscaling" is used to infer variability in weather conditions within large GCM grid cells to estimate changes at finer geographic scales. Temporal downscaling may also infer variability on finer timescales. Downscaling is necessary to generate data suitable to inform most applications, particularly those where climate impacts are sensitive to regional weather variation, and where planning decisions must be robust to extreme (rather than average) conditions.

There are two common approaches for downscaling GCM data. *Dynamic downscaling methods* use parametric models to approximate physical dynamics that give rise to regional variation. *Statistical downscaling methods* mine historical weather data to quantify regional variability, and generate projections exhibiting similar statistical properties. Dynamic downscaling is generally considered to be more accurate and better-suited to characterizing extremes, but it is very computationally intensive and may be biased by boundary conditions or imperfect understanding of physical dynamics. Statistical downscaling methods require less computational power, but assume that statistical properties of local weather phenomena will remain constant (or stationary) in spite

of climate trends. This assumption is known to be false [183]. These differences and practical considerations for choosing a particular downscaling approach are discussed broadly in [182], and in the context of water resource planning in [206]. The CEC commissioned research to develop state-of-the-art statistical downscaling methods for California, known as Localized Constructed Analogs (LOCA) [210, 212]. LOCA downscaled versions of 10 climate models are available through CalAdapt.

3.4 Climate-relevant input variables for electricity systems

A number of climate trends will impact grid infrastructure. Chronic impacts, like sea level rise, more rapid equipment aging, and increasing electricity demand, will stress existing infrastructure over time. Acute impacts, like wildfires and severe weather, will lead to much more sudden consequences. Anticipating these effects can improve strategies for mitigating risks and responding to emergencies.

Using climate projections as inputs to infrastructure planning models (Section 3.5) can ensure that planning decisions are robust to the chronic and acute vulnerabilities. Here, we summarize relevant climate trends. We consider three types of inputs (referring to stages 2a, 2b, and 2c, respectively, in Figure 3.1): *climate variables*, which are direct outputs from climate models, *environmental trends*, which are derived from climate variables, and *energy demand*, which is heavily influenced by weather and climate. Table 3.1 summarizes data available through CalAdapt about climate variables and trends.

3.4.1 Climate variables

These variables can be obtained directly as outputs from climate models or at higher resolution from downscaled LOCA models. The following paragraphs describe electric power system impacts.

Temperature. Climate models largely agree that temperatures will rise and heat waves will become more frequent and more intense [213]. Rising temperatures will impact load growth, generator efficiency, equipment ratings, and degradation rates (among other factors) [214, 215]. Extreme heat events may have cascading effects [216].

Precipitation. The direction and magnitude of projected trends in precipitation vary across climate models. Models agree, however, that seasonal and spatial variability will increase, affecting power generation, heat dissipation, and maintenance needs. Greater variability makes characterizing extreme events critically important, as operational and planning decisions are often informed by extreme precipitation events [62].

Wind speed. Expected temperature increases and pressure changes in atmospheric currents as a result of climate change will have a direct impact on wind patterns. However, research is needed to determine how these changes will impact regional wind patterns relevant to grid planning decisions [61]. Climate change is expected to affect “the intensity and duration of sustained winds” [214]

and to increase peak wind intensity [213]. These trends will impact the operation and performance of both wind turbines and the infrastructure that must withstand winds (i.e., power lines). Wind speeds are also a crucial input for calculating the potential heat impacts on equipment, as wind can provide cooling to offset high temperatures [63].

3.4.2 Environmental trends

These trends cannot be obtained directly from climate models, but instead follow from changes in the intensity, geography, and seasonality of climate variables discussed above. Projections are generated by analyzing climate model outputs.

Drought. Increasing temperatures and changing precipitation patterns may lead to more frequent and severe droughts. Drought will increase electricity demand associated with water pumping for drinking, irrigation, and other uses [214], and could introduce additional loads for desalination. Severe drought events may carry additional ramifications for power sector operations in California [217].

Solar irradiance. Changes in temperature and precipitation will impact atmospheric conditions that drive variables like humidity and cloud cover (occurrence, type, timing, and optical thickness) [61]. Changes in these conditions will impact surface solar radiation, thereby affecting solar generation, net load from rooftop solar PV, and the apparent temperature on the ground.

Snowpack. Warmer winters at high altitudes will lead to more precipitation falling as rain rather than snow and an earlier melting time for snowpack. These factors may lead to reduced water availability during the summer months due to the changing timing of runoff. Many reservoirs in California are dual-purpose: they were built to accommodate water from slow-melting snow into the summer months, and to include extra storage capacity for flood control. Increased precipitation will lead to earlier snowmelt, which will increasingly coincide with the flood season. An increase in water released to protect against floods in the spring will reduce water availability for hydropower production through the summer [218]. Hydro resources will be further impacted as snowpack disappears from lower elevations [214]. Models predict that the Sierra snowpack may decrease by 48-65 percent by 2100 from its 1961-1990 average [218, 219].

Fire risk. Increasingly warm, dry, and windy conditions may exacerbate existing wildfire risks [220]. Reduced snowpack and earlier snowmelt may also lengthen the wildfire season. The impact of these climate variables on fire risk may be further exacerbated by modern fire suppression practices [221]. Wildfire risks include damage to grid infrastructure, and the need to pre-emptively de-energize lines to prevent ignition [214, 222].

Sea level rise. Sea level rise impacts on infrastructure can include coastal flooding, coastal erosion, exacerbated land subsidence, saltwater intrusion, and pipeline corrosion [223]. In the context of electricity infrastructure, sea level rise will predominantly impact siting decisions and expected damages to coastal infrastructure and facilities, including generating plants and substations [214, 224]. Sea level rise impacts may also extend beyond coastal areas as rivers swell and low-lying areas resist drainage after high tides.

Table 3.1: Summary of data streams available through CalAdapt [209] and their relevance to grid infrastructure planning. All data streams report climate projections from 2006-2100; many also report historical data for 1950-2006. Data are reported for LOCA downscaled models at 1/16th of a degree (about 6km^2) spatial resolution for the entire state of California. References to the studies that produced each data stream are listed.

CalAdapt Data Stream	Description	Planning Relevance
Raw LOCA Downscaled Climate Data	Daily projections of relative humidity, surface solar radiation, and wind speed available through the CalAdapt data server; data are more challenging to interface with than the data streams listed below	Solar capacity; Grid hardening; Planning for Extremes
Annual Averages[1]	Annual minimum and maximum temperatures; Total annual precipitation	Peak capacity; Derating; Planning for extremes
Cooling and Heating Degree Days[1]	Degree-day estimates derived from difference between daily minimum and maximum temperature and user-defined heating/cooling setpoint temperatures	Load forecasting; Capacity expansion
Extended Drought[2] [210]	Weather/hydrologic projections for two extreme drought scenarios (early & late century)	Hydro capacity; Water availability for power plant cooling; Planning for extremes
Extreme Heat Days and Warm Nights[1,3]	Frequency and intensity of hot days/nights for various "extreme" event thresholds	Peak capacity; Derating; Reliability; Planning for Exremes; Load forecasting; Siting
Extreme Precipitation[1,3]	Frequency and intensity of precipitation events for various "extreme" event thresholds	Hydro capacity; Distribution reliability; Storm hardening
Hourly Projections of Sea Level[2] [225, 226]	Projects sea levels associated with diurnal/seasonal tidal patterns and arctic ice melt	Siting
Sea Level Rise (CalFloD-3D)[2] [227]	Projects sea level inundation during 100-year storm events at high spatial resolution for the Bay Area, San Joaquin River Delta, and California Coast	Grid hardening; Siting; Planning for extremes
Snowpack[2] [228]	Monthly snow water equivalent	Hydro capacity
Streamflow[2] [229]	Monthly and annual streamflow projections for 11 streamflow gauging stations throughout the state of California	Hydro; Siting
Variable Infiltration Capacity (VIC) Variables[1]	Provides a wide range of hydrologic variables with daily resolution	Hydro capacity
Wildfire[2,4] [230]	Provides 5- and 10-year averages of acres burned under different population growth scenarios	Siting; Grid hardening; Capacity expansion; Planning for Extremes

[1] Data are derived directly from statistical processing of LOCA downscaled climate model outputs.

[2] Data are generated from VIC variables and/or other data sources. Relevant documentation are cited where appropriate.

[3] Though data are reported for each 6km grid cell, the statistical methods used to estimate extreme events are meant to broadly describe changes across the state. Additional analysis may be needed to provide actionable information to decision-makers on a local scale.

[4] Data are available for the subset of 4 climate projections used in the Fourth Climate Change Assessment, not for all 10 climate models.

3.4.3 Energy demand

Climate will impact energy consumption and the generation, distribution, and transmission resources needed to reliably serve these evolving demands.

More intensive load. Rising temperatures will increase the electricity drawn by existing uses. For example, electricity demand for cooling, refrigeration (particularly in warehouses), and other loads that maintain thermal comfort (e.g., ventilation and fans) will grow. Higher peak temperatures and more frequent extreme heat days will induce higher and more frequent peak load events [231]. These trends will increase overall energy consumption, thereby increasing base load requirements, and may affect seasonal load patterns. The specific regional impacts will depend on the characteristics of local building stock [232]. Extreme heat will also raise the stakes for power outages during peak load events, as space conditioning becomes a necessity for vulnerable populations [233].

More extensive load. Climate change will also increase electricity demand from new uses and in new locations. For example, warming will lead to more extensive cooling demand in historically moderate climate zones (e.g., San Francisco). More extensive space conditioning will increase system peaks and could stimulate more consistent demand for cooling throughout the year. This trend could impact decisions related to generator siting and capacity expansion in transmission and distribution networks. The IEPR forecast currently relies on appliance saturation data last collected in 2009 [234], and methodological revisions to the forecast may be warranted to ensure that changes in appliance saturation and trends in ownership are included.

Electrification of new end uses. Achieving California's aggressive emissions targets will require electrifying end uses—such as manufacturing, heating, and transportation—that are currently served by fossil fuels. This will increase base load and alter diurnal and seasonal load shapes. For example, electrification of heating loads could prompt wintertime peak load events. Heightened reliance on electricity for heating and transportation could make the implications of wintertime power outages increasingly severe. Meanwhile, extreme weather events that threaten grid reliability may become more common.

Population displacement. The above trends in load are expected given current population trends, but climate change may induce additional shifts in population and therefore electricity demand. A recent report estimates that sea level rise alone will displace over 250 thousand people nationally and 30 thousand in California by 2100 [235]. Displacement due to drought, natural hazards, and conflict will add to these numbers, and could occur on much shorter timescales. Migration to urban areas could increase electricity demand in existing load pockets. Migration to less-populated regions may warrant expansion of transmission and distribution infrastructure, and may also increase the wildland-urban interface, thereby putting more people at risk of power shutoffs and further displacement due to wildfires [236]. Population growth due to economic factors unrelated to climate change may also exacerbate these trends.

3.5 Electricity infrastructure planning models and impacts from a changing climate

Five primary types of models inform electricity system planning decisions. These include:

- *Generation models* simulate the physical operation of specific power generation technologies.
- *Power flow models* describe how electricity moves through wires between generators and consumers.
- *Load models* project how trends in population, energy use intensity, and other factors will impact the magnitude, shape, and geographic distribution of energy use.
- *Capacity expansion models* optimize generation and transmission procurement decisions based on load forecasts, capital costs, and operating assumptions.
- *Production cost models* simulate how grid assets can meet demand, reliability, and emissions requirements at least cost given operating constraints.

These models use different assumptions and inputs. Figure 3.2 outlines the flow of information between them. Climate trends introduced in Section 3.4 will affect grid infrastructure performance. To anticipate climate vulnerabilities, infrastructure planning models will need to account for these trends.

Here, we synthesize what is known about how climate trends will alter grid infrastructure performance. We focus on component- and system-level impacts on operational power systems; for a discussion of resilience and recovery from outages, we refer readers to [237, 238]. Where possible, we reference previous work to provide a sense of the magnitudes of the impacts described. We focus on climate impacts most relevant to grid infrastructure in California, and refer readers to [61, 196] for a more comprehensive review. Table 3.2 summarizes key takeaways from our assessment of the potential impacts.

3.5.1 Electricity generation

These considerations apply to both centralized and distributed energy resources (DERs). While statewide resource planning currently focuses on transmission-level bulk generation, increasing

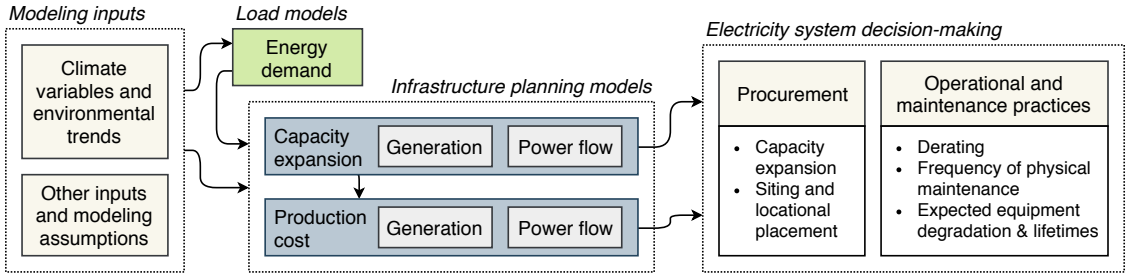


Figure 3.2: Modeling stages for electricity infrastructure planning.

DER deployment in California is prompting conversations about how smaller-scale resources could meet localized generation needs and relieve pressure on existing infrastructure [100, 239].

3.5.1.1 System-wide impacts

Climate trends will impact the design and operational performance of generation in regional power systems. We comment on changes in grid modeling capabilities needed to characterize these trends.

Capacity expansion. Decisions to add generation are informed by capacity expansion models that issue recommendations about the mix of generation resources appropriate to supply load. Climate impacts on load shapes (Section 3.4.3), and generator performance (Section 3.5.1.2) could alter planning recommendations.

Existing models for evaluating resource adequacy in local generation fleets rely on IEPR load forecasts modified to a wider range of weather scenarios [240] (Appendix C.1.1). Scenarios are currently based on historical weather data, though similar adjustments could informed by climate forecasts [241, 242]. Climate trends may lead us to revisit planning reserve margins. A recent study indicated that existing reserve margins may become inadequate by the end of the century due to temperature rise [193].

Siting. Sea level rise may require that we retrofit or relocate low-elevation facilities, and make it harder to build new generation in coastal areas. Water scarcity may also influence design decisions for water-cooled generation facilities.

Siting decisions may also improve resilience to contingencies caused by more frequent severe weather events (e.g., wildfires, storms, heat waves). For example, local generation resources may enable grid operators to de-energize power lines to mitigate fire risk without interrupting critical loads and services. Planning models traditionally have not examined interactions between ambient conditions and generator siting decisions.

Generator derating. Derating refers to the practice of operating equipment below its maximum rated capability to avoid internal damage to equipment or external damage to the environment. Derating may be necessary to prevent material degradation of power generators (and grid components) as ambient temperatures become more extreme. These changes may warrant new operating and maintenance practices, additional generation capacity, or energy efficiency and load management programs.

Compounding impacts. Changes in equipment performance warrant new grid modeling capabilities to capture system impacts that may be greater than indicated by component-level analyses. For example, derating—which impacts generation, distribution (Section 3.5.2.1), and transmission (Section 3.5.3) equipment—is necessary during extreme heat waves, when the system is also more likely to be under operational stress (due to peak load events). Under the same conditions, power outages pose a public health risk (due to extreme outdoor air temperatures), and the generation capacity of solar and thermal generators decreases (Section 3.5.1.2). Current planning models do not fully consider the temperature-dependence of operating constraints. This assumption should

be revisited to ensure that operating limits are not inadvertently exceeded to reduce the risk of correlated failures during extreme heat events.

3.5.1.2 Implications for generation technologies

Specific technologies will bear climate impacts due to their physical characteristics.

Solar photovoltaics. Solar generation improves with increasing irradiance but declines with temperature (see Appendix C.2.1) [243]. To evaluate generation capacity in a warming climate, system models will need to account for PV derating. A recent study estimated that PV capacity in the Western U.S. could decrease by approximately 0.7-1.7 percent by mid-century due to higher temperatures [215].

Less precipitation may also compel more frequent manual cleaning of PV panels to preserve operational efficiency.

Wind. Wind speed patterns influence decisions related to siting, design, and operations of wind farms. Changes in average and extreme wind speeds will alter the performance of existing wind farms (see Appendix C.2.2), and may alter optimal siting for new installations [61]. Researchers have identified a need to improve wind speed projections [61]. Studies to date suggest that wind generation potential in California could decrease [244].

Thermal power generation. Power production from thermal generators relies on a temperature differential between high-pressure steam (heated by combustion) and ambient water (or air) (Appendix C.2.3) [245]. These generators—which include natural gas, concentrating solar, and some biomass plants—are more efficient when this temperature differential is high. Rising ambient temperatures will reduce plant efficiency and generating capacity [215, 246, 247]. Plants at risk of violating thermal discharge limits may need to be curtailed [248, 249]. Heat waves will exacerbate these issues at times when generation resources are needed to meet increased cooling demand [250].

Other factors may also impact performance. Drought will limit water availability, potentially causing water-cooled plants to become inoperable for part (or all) of the year [248]. Changes in load may increase peak load relative to total demand, reducing the capacity factor of thermal generators (which typically serve peak load). Operating at less than full capacity will reduce the efficiency of thermal plants [61].

The capacity of thermoelectric plants in the Western Interconnection is estimated to decrease 1.6-3.0 percent on average by mid-century, not including losses attributable to drought [215].

Hydropower. Changes in snowpack, as well as the seasonality and amount of precipitation, will impact reservoir levels and water availability [231] (Section 3.4.2). Drought will reduce hydropower generation [246]. Intense precipitation may lead reservoir operators to prioritize flood control, making hydro resources less readily available to support grid needs [214, 251, 252]. Thus although its fast-ramping capabilities make hydro well-suited to provide frequency response, other generation technologies (e.g., DERs, thermal generators) may need to provide these services in the future. While the impact of climate change on total precipitation is uncertain, less snow and

earlier melting times may reduce annual hydropower generation in California up to approximately 3 percent [251].

Energy storage. Energy storage—including electrochemical storage, pumped hydropower, and other emerging technologies—can balance intermittencies in renewables generation. Local storage resources may also provide islanding capabilities should transmission or distribution equipment become inoperable, for example due to physical damage or high wildfire risk. Ambient temperature may alter battery degradation and performance; grid impacts, however, have not yet been studied.

3.5.2 Distribution infrastructure

The distribution system carries electric power from substations to end-use customers through a diverse array of equipment and lines. Transformers convert electricity from high- to low-voltage, and feed it to customers through overhead lines (often held up by wooden poles) or underground cables. Along the way, voltage regulators, capacitor banks, circuit breakers, and other equipment enhance power quality, resilience and safety. Here, we discuss climate impacts on distribution systems planning and operations.

3.5.2.1 Derating of distribution grid components

Distribution grid components are designed to operate under a specific range of loading conditions, determined by properties of the constituent materials. These limits involve heat dissipation, and relate to internal cooling mechanisms and ambient temperatures. Different ratings may apply at different operational timescales (e.g., continuous operation versus temporary load spikes or instability).

Components are sized to meet peak loading conditions (with some safety margin). Optimal design may involve operating components at or near their rated limits during peak load, as excessive safety margins may lead to undue costs [253]. Historic data and load forecasts inform design decisions. Warming trends will increase peak loads and decrease heat dissipation—thus restricting safe loading limits, particularly for transformers and overhead lines [110, 213, 254]. Failure to derate components (and operate the system in adherence with those ratings) as ambient temperatures increase could lead to more rapid degradation, increasing failure rates, and general reductions in equipment lifetimes [231]. A recent study estimated that distribution components in Los Angeles could experience a 2-20% loss of rated capacity by 2060 due to heat waves, increasing the risk of overloading components in congested areas [110].

Climate variables besides temperature can also impact power ratings. For example, long periods of dry weather can reduce the thermal conductivity of the ground, requiring further derating of underground cables [213]. Changes in moisture may also reduce the efficiency of earthing at substations, requiring additional safety precautions [254].

3.5.2.2 Siting

Derating needs will depend on localized temperature conditions. Population growth in hot areas of the state means that derating could become a concern for a larger share of grid components.

Distribution equipment may also be impacted by flooding and sea level rise. Flooding during extreme precipitation events, for example, will impact equipment in low-lying areas—in particular, switchgear, control cubicles, and transformers at ground level in substations [213, 254]. Similarly, sea level rise will impact coastal substations and other equipment. A recent study found potential impacts to four substations in San Diego Gas & Electric's service territory, as well as "thousands of electric substations, transformers, power lines, and other equipment [that] are potentially exposed to damage under scenarios of sea level rise" [224].

3.5.2.3 System design and connectivity

System upgrades expanding the capacity of distribution systems may be warranted to accommodate new load and compensate for equipment derating. Changes in the connectivity of distribution systems (e.g., islanding, load shedding, and enhanced sectionalization) may also support grid operations during capacity shortfalls or when wildfire risk is high [255]. Islanding capabilities and local generation resources can ensure that critical loads maintain service continuity during outages [239]. In regions of the state where climate risks make it cost-prohibitive to build safe, robust and reliable grid infrastructure, the obligation to serve may be better met by permanently islanded microgrids [256, 257].

3.5.2.4 Operations & maintenance

Climate variables and trends pose various challenges for distribution system maintenance practices and reliability. Specific examples highlight the need for more frequent inspections and careful maintenance to support system performance:

- Rising temperatures directly contribute to equipment aging. For example, faster chemical degradation of insulating materials directly increases the failure rates of conductors and transformers [258].
- Increased loading and power flows (Section 3.4.3) results in additional stress "as operational conditions approach thermal and mechanical ratings of power system elements," leading to greater "overall wear and tear" and "increased vulnerability to faults and/or breakdowns" [231].
- Heavy rain can damage overhead lines, and soak equipment such as insulators and switchgear increasing the risk of short-circuit and arcing faults. These issues can be mitigated by newer equipment designs and careful maintenance [213].
- Precipitation poses longer-term risks to distribution systems. For example, moisture leads to internal decay of wood poles, reducing structural integrity [259]. This in turn puts conductors at greater risk.

- Changing wind patterns and extreme wind gusts could threaten overhead lines, network towers, and other overhead structures. High winds impose shear force on poles and towers, and increase the likelihood that vegetation or other debris will cause damage [213], or lead to faults [231, 254]. Frequent inspections and hardening tower and pole designs to withstand stronger winds could mitigate these impacts [213].
- Wildfires (as well as the intense winds that often accompany them) can cause physical damage to distribution infrastructure and increase maintenance needs [222]. Smoke is also a concern, as a high concentration of ions makes smoke more conductive than air, increasing the risk of arcing on overhead lines [213].

3.5.2.5 Vegetation management

A safe distance must be maintained between grid infrastructure and vegetation. Contact is a common cause of power outages and can also cause infrastructure damage, arcing, or tree ignition that—when ambient conditions are appropriate—can spark wildfires [260]. High temperatures coupled with heavy loading during heat waves can cause overhead lines to sag. Clearance can be maintained by modifying vegetation management practices, or in some cases by derating lines. Extreme wind speed events increase the risk of contact from falling and swaying tree limbs.

Climate-aware vegetation management policies will need to consider temperature, wind speed, seasonal patterns that influence tree growth (e.g., length of growing season and ecosystem health), and eventually also changes in tree and shrub species that surround grid infrastructure. Longer growing seasons may warrant more frequent tree trimming [213], while ecosystem damage due to aridification or invasive species (such as bark beetles) may warrant the removal of trees that are in poor health [220, 260].

3.5.3 Transmission infrastructure

The transmission system carries power from large generators over long distances to regional load centers. In California, CAISO conducts an annual planning process to address evolving system needs (Appendix C.1.3). Many of the inputs rely on historical weather data. While California's transmission system is operated by CAISO, it is regulated by the Federal Energy Regulatory Commission (FERC). Though federal regulation is beyond the scope of this paper, we briefly comment on climate interactions with the transmission system.

Similar to the distribution system, transmission lines are assigned a power rating for maximum electricity transfer. Transmission lines that approach this maximum power rating are said to be 'congested' and act as bottlenecks in moving electric power from one area to another. Higher ambient temperatures reduce heat dissipation from transmission lines, thus increasing energy losses and reducing line transfer limits [63, 254]. Heat-related capacity reductions will likely coincide with peak loading, further stressing the system and prompting concerns about supply adequacy [63]. As in distribution systems, failure to account for temperature-dependence of operating constraints could lead to correlated component failures. In transmission systems, such correlated failures may have cascading effects that result in widespread blackouts [261].

Table 3.2: Summary of key potential climate impacts on electric infrastructure in California.

Climate Impacts	Generation	Distribution	Transmission
Temperature	Solar and natural gas: rising temperatures reduce efficiency of power production	Derating and increased line losses, more rapid equipment aging	Derating and increased losses, increased congestion
Precipitation	Hydro: greater variability may lead to less flexible dispatch	Water inundation risks for equipment, faster aging for wooden poles, changes to vegetation management	Changes to vegetation management
Wind patterns	Wind: reduced power production from existing farms, possible creation of new sites	Equipment damage, changes to vegetation management, fire ignition and spread	Equipment damage, changes to vegetation management
Drought	Natural gas: less water for cooling; Hydro: less water for power production	Reduced soil thermal conductivity requiring derating of underground cables	
Solar irradiance	Solar: stronger irradiance increases power production		
Snowpack	Hydro: earlier snowmelt may reduce energy generation capacity, less flexible dispatch		
Fire risks	Energy storage: supports "non-wires alternatives" for mitigating fire risk	Equipment damage and increased risk for arcing faults, changes to vegetation management	Equipment damage and resiliency impacts due to line outages
Sea level rise	Siting: relocation of existing assets, design challenges for new generation, corrosion	Water inundation and corrosion risks for equipment	Water inundation and corrosion risks for equipment
Load	Possible need for capacity expansion to serve additional peak and base load	System stress and increased maintenance requirements; Possible need for capacity expansion	Possible increased congestion

A recent study estimated that projected temperature increases during the month of August could reduce transmission line transfer limits in California by 7-8 percent by 2100 [262]. Technological solutions exist: for example, heat-resistant cables provide new options for preserving and improving line capacity, but it remains to be seen whether re-conductoring lines is best solution [63]. Challenges associated with transmission system expansion may eventually lead to greater reliance on local generation.

Increasing fire risk in California also threatens transmission facilities [254]. A recent study found that distribution infrastructure incurred more damage than transmission infrastructure from 2000-2016 wildfires in California [222]. However, damage to transmission facilities and/or pre-

ventative de-energization due to nearby wildfires or risky fire-prone weather [222] may impact a large number of customers. Moreover, changing climate conditions may make transmission (and distribution) equipment more likely to trigger fires. One option for mitigating risk is to invest in infrastructure upgrades that reduce the probability of component failures. Another alternative is to modify the topology of the network to remove transmission lines from regions of the state where wildfire risk is excessively high.

3.6 Recommendations

Effective climate adaptation measures will require decisions that are informed by known interactions between climate science and power systems. Both are highly technical areas, and many of the interactions between them are not yet well-understood. Moreover, climate risks are not necessarily represented in historic data. Projections of variables characterizing these risks are uncertain at best, and, for certain variables, do not yet exist in a form that decision-makers can readily use. Here, we describe opportunities for progress, in light of these existing challenges.

We share nine recommendations for applying best-practices in climate adaptation to grid infrastructure planning processes in California. By following these recommendations, decision-makers may begin to account for grid-climate interactions in a *comprehensive* manner. By *comprehensive*, we mean that planning decisions consider grid-climate interactions, compounding effects, and associated impacts on diverse stakeholder groups–including utilities, ratepayers, and disaster relief agencies. We build on best-practices in adaptive planning, including: defining well-documented risk tolerances [198], accommodating advancements in climate science [202], and revisiting adaptation strategies as new information comes to light [263].

Together, our recommendations provide a roadmap for decision-makers to better understand and act upon climate risks, as illustrated in Figure 3.3. Each recommendation offers near-term actions that can be pursued in parallel today. First, we describe the information needed to support climate-aware decision-making (Recommendations 1, 2, 3, and 4). Then, we describe how these can inform infrastructure planning models and decisions (Recommendations 5, 6, and 7). Finally, we discuss the need for decision-makers to internalize uncertainties inherent to planning for climate change and its consequences (Recommendations 8 and 9).

3.6.1 Information needed to support climate-aware decision-making

To begin, adaptation efforts must be informed by data reflecting the current state of climate science. Where relevant, climate data may need to be tailored to the specific case of grid infrastructure planning.

Recommendation 1: Regulators should specify which climate data stakeholders are to use to inform specific planning decisions.

Barrier: Stakeholders that use and disseminate climate data must grapple with challenges such as:

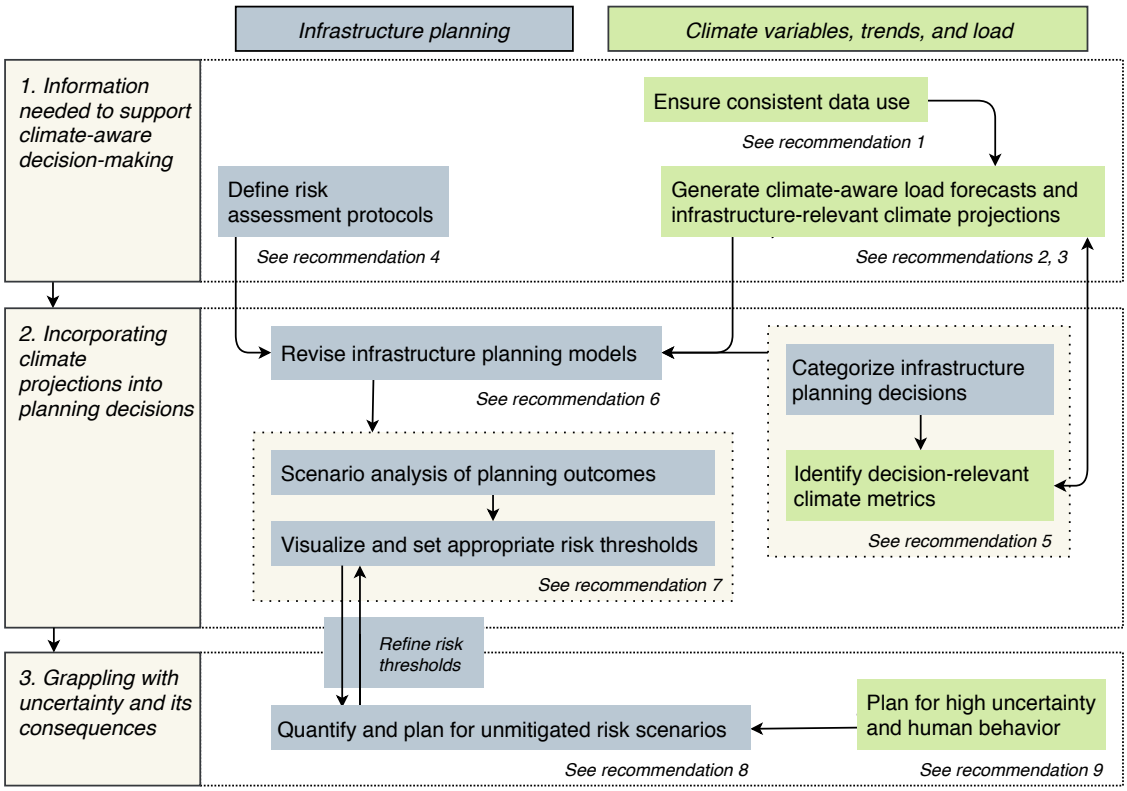


Figure 3.3: A proposed process for incorporating climate information into infrastructure decision-making.

- Climate science is evolving, and user-facing data must be kept up to date.
- Climate model assumptions may make certain data ill-suited for certain applications; data limitations are far from intuitive and require detailed understanding of both the climate models and the application of interest.
- Substituting historic data with climate projections as inputs to existing planning models may not be appropriate, and may not account for all of the interactions that are present.

In California, CalAdapt currently provides data that can readily support climate-aware planning (Table 3.1). However, additional work remains to be done to evaluate whether these data: (1) remain consistent with state-of-the-art climate science, and (2) provide requisite information to inform grid infrastructure planning decisions (data requirements are also discussed in Recommendations 2-4). Moreover, stakeholders will require clear direction on how to apply this data to inform their decisions (discussed in Recommendations 5-7).

Solution: In California, CPUC should specify which climate data will inform planning decisions to ensure that different stakeholders use consistent information, and that these information remain up-to-date. CPUC should form a technical advisory group to determine how relevant data will inform specific decisions. **In the near-term,** the CPUC should instruct stakeholders to start with

data that currently exists via CalAdapt. **Ultimately,** CEC should work with stakeholders to assess whether CalAdapt should offer additional data streams to support grid planning needs. For example, filters for selecting relevant GCMs (discussed in [206]) and downscaling methods (discussed in [182]) may need revisiting to provide requisite information for grid planning applications. CEC should ensure that the data to support these applications is readily available (see Recommendations 2 and 3), and release updates as new data become available due to advancements in climate science.

Recommendation 2: Model climate impacts on load, and generate a library of load forecasts that span all relevant climate scenarios.

Barrier: As discussed in Sections 3.2 and 3.4.3, as well as Appendix C.1.1, IEPR load forecasts examine a limited range of climate scenarios, and do not consider climate impacts on end use saturation and consumption behaviors.

Solution: Since electricity infrastructure planning relies heavily on IEPR forecasts, revisiting these forecasts will have impacts that propagate through the planning process. **In the near term,** CEC can support other grid planning entities by providing load forecasts for all climate projections available in CalAdapt. Methods and assumptions for generating end-use forecasts should be clearly documented to ensure that merits and limitations of the forecasts are transparent, and to help downstream analysts determine if or where post-processing is warranted. **Ultimately,** the CEC will need to revise load forecasting methods and assumptions to more thoroughly account for nuanced interactions between energy use and weather (beyond temperature), and to account for mitigation and adaptation measures taken by both policy-makers and end-users (e.g., electrification of new end uses and higher saturation of air conditioners). Engaging with stakeholders who rely on IEPR forecasts to inform their work may reduce the need for ad-hoc post-processing by grid planning entities.

Recommendation 3: Identify climate data relevant to grid infrastructure planning, and conduct research necessary to generate data that do not already exist.

Barrier: Though data exist to support certain types of planning decisions (e.g., water resource use [206] and natural gas pipeline siting [227]), additional data may be needed to support new applications like grid infrastructure planning. Data reporting temperature, precipitation, sea level rise are relevant to multiple applications, but other vital datasets are lacking. For example, information about the frequency, severity, and seasonality of high-wind speed events are critical to understanding wind power production and to informing grid hardening measures.

Solution: Imperfect information need not be a barrier to making climate-aware decisions; planning efforts can begin to move forward with the data currently offered in CalAdapt. **In the near term:** Where possible, infrastructure planners should use climate projections. CEC should engage with stakeholders to understand the limitations of existing data, and to identify additional data

requirements (see Recommendation 5). **Ultimately:** Research is needed to generate a comprehensive library of data streams for grid infrastructure planning. Research needs include determining whether statistical or numerical downscaling methods are more appropriate, and to project regional changes in frequency and severity of high-wind speed events. CEC should support these efforts, while working with CPUC and other stakeholders familiar with data requirements unique to supporting grid planning applications.

Recommendation 4: Develop quantitative methods to project risk exposure of infrastructure assets and assess mitigation options.

Barrier: Robust risk assessment protocols must evaluate the probability and implications of scenarios that may never have occurred previously. Risk reduction measures must balance diverse trade-offs—such as service reliability, equity, and loss of life. Further study is required to assess the societal implications of different adaptation strategies. In California, utilities already use probabilistic methods to assess risks and inform upgrade decisions [264, 265]. However, incorporating climate projections to forecast climate-related risks to grid assets has not yet been discussed [264].

Solution: CPUC must ensure that utilities use models that can examine evolving risks due to climate change. Methods for evaluating these risks must be transparent and subject to public scrutiny. Existing regulatory proceedings in California (including S-MAP and RAMP, see Appendix C.1.4) provide an avenue for assessing risks, but currently consider only certain types of risks. **In the near term,** CPUC should engage with stakeholders to identify metrics appropriate for characterizing climate risks. Safety-focused risks covered in existing regulatory proceedings (e.g., wires down, fire ignitions), should be considered alongside broader risks (e.g., reliability and equity). New metrics for characterizing climate risks should also be included (e.g., inundation of grid assets due to sea level rise). CPUC should oversee the process of developing quantitative methods for anticipating new and evolving risks, for example by mining historic data to quantify climate-sensitivities of risk metrics. **Ultimately,** risk assessment models should quantify how proposed investments will impact risk and performance over the lifetime of new and existing assets. These models should be used to optimize candidate investments, and identify strategies that minimize overall risk exposure (where possible) or meet specified risk thresholds (see Recommendation 7). The magnitude and severity of damages due to possible risk scenarios (e.g., wildfires) should also be explicitly reported. Transparent reporting will allow utilities, regulators, and communities to weigh the implications of mitigating certain risks and not others, and can ensure that stakeholders understand and agree to shoulder the implications of unmitigated risks (see Recommendation 8).

3.6.2 Incorporating climate projections into planning decisions

With a quantitative basis for examining climate trends and evolving risks, we can begin to develop infrastructure planning processes that internalize complex interactions between climate and infrastructure to inform planning decisions. Here, we propose a potential approach. Recommendations

5 and 6 focus on scoping and implementation, respectively, while Recommendation 7 synthesizes results into action.

Recommendation 5: Perform a comprehensive assessment of potential grid-climate interactions.

Barrier: Electricity infrastructure planning decisions are informed by many different physical, operational, and societal considerations. The decisions are complex, and no individual stakeholder group will be familiar with all possible implications of different adaptation strategies.

Solution: A comprehensive mapping of how climate variables, trends, and load may affect specific infrastructure decisions is a necessary prerequisite to incorporating these factors into infrastructure planning models. CPUC should engage a wide variety of subject-matter experts in this effort—for example in climate science, hydrology, power generation and distribution equipment, grid design, operations and repairs, energy use consumption, and power systems modeling—through a technical advisory or working group. Here, we propose an approach for mapping out these interactions:

1. List specific infrastructure planning decisions that must be made.
2. List climate impacts that could influence each decision. Table 3.2 provides a starting point based on the interactions discussed in this paper; engaging with a broader audience of stakeholders and experts could shed light on additional interactions.
3. Define how the magnitude of each climate-grid interaction will be quantified (e.g., instantaneous impacts, cumulative exposure, etc.).
4. Define metrics for decision-making specifying: (1) relevant climate variable(s), (2) appropriate statistics (e.g., low, extreme, average, etc.) and duration, (3) geography, and (4) decision timescale [266]. Examples could include water inundation (to inform decisions to relocate certain assets) or extreme wind speed projections (to inform pole reinforcement).

In the near term, the CPUC should form a technical advisory group to enumerate climate impacts on planning decisions (as detailed above). Results should be circulated for public comment, and revised as appropriate. **Ultimately,** this document should be refined to comprehensively map out climate impacts on specific planning decisions. Mitigation options should be weighed based on input from stakeholders ranging from ratepayers to repair personnel.

Recommendation 6: Refine infrastructure planning models to incorporate climate impacts.

Barrier: The models we currently use to inform infrastructure planning decisions do not comprehensively account for grid-climate interactions. Operational, maintenance, and design protocols contain baked-in assumptions about performance that may not hold as conditions change. For example, industry standards call for periodic equipment inspections on specific timescales (e.g., every

4 years) [267]. These timescales do not internalize information about ambient or loading conditions that lead to equipment degradation (e.g., heat, humidity, etc.). As conditions become more extreme, inspection and replacement schedules will need to evolve, rather than relying on rules of thumb used in the past. Innumerable other examples exist. At best, planning models consider ambient risks to be independent, and do not factor in compounding impacts. Planning models must be revised to account for new climate realities.

Solution: Well-informed and climate-aware recommendations will require infrastructure planning models to thoroughly incorporate sensitivities between infrastructure performance and climate trends, such as those listed in Table 3.2. **In the near term,** CPUC should lead efforts to ensure that planning models can run multiple climate scenarios to examine how different futures could influence planning decisions made today. Planning models may need to be adapted to ingest new input data as CMIP releases updated climate projections to reflect scientific advances. **Ultimately,** planning models should be revised such that embedded assumptions are dynamic and account for changes in performance due to emerging climate trends. Models should consider compounding interactions between climate trends that could lead to non-additive impacts, and should allow for assumptions to be revisited in a modular fashion to capture new dynamics and stakeholder needs. Revisions must propagate through all modeling stages (Figure 3.2). Risk calculations (see Recommendation 4) should be embedded in infrastructure planning models to ensure that decisions focus not only on maintaining grid operations, but also on mitigating risks.

Recommendation 7: Determine the range of planning outcomes across different climate projections. Set appropriate risk thresholds.

Barrier: Infrastructure planning models must be adapted to examine numerous climate scenarios, climate impacts of varying magnitudes, and uncertainty inherent in making decisions informed by climate projections. Furthermore, climate impacts may compound; for example, capacity expansion models must examine temperature-sensitivities of both load growth and equipment ratings.

Solution: Decision-makers must consider the range of planning options given different climate outcomes. Examining the differences (or lack thereof) will provide insight into the implications of planning to different risk thresholds. Based on the results, CPUC should engage with stakeholders to define appropriate risk tolerances for specific planning decisions. Explicitly setting a risk tolerance will ensure that planning decisions are robust to uncertainty in climate projections, and can provide transparency needed to balance reduced costs against the possibility of incurring additional risks (see Recommendation 8). One way to approach this challenge is as follows:

1. Run infrastructure planning models for each climate scenario specified in Recommendation 1; identify recommended investments for each scenario. (A sensitivity analysis is advisable, as sensitivities to individual climate variables may vary.)

2. Visualize the range of possible planning outcomes via a **box-and-whisker plot**[2]. An example is shown in Figure 3.4 for projected temperatures by decade in San Francisco (we note that this example is a climate variable, not a planning outcome). The strength of this visual depiction lies in its intuitive representation of the range and distribution of projected outcomes. Once this range is presented, recommendations from different planning models can be synthesized to make decisions based on the severity of outcomes that could occur if planning decisions are made in accord with a climate projection that proves to be wrong.

3. Review every category of planning decisions and determine the **appropriate risk threshold**. For example, planning to the median may be appropriate in cases where the risks are not severe (e.g., projected PV panel output). In other cases, planning to extremes will be more appropriate (e.g., water availability for cooling power plants). Decision-makers may opt to set different thresholds (e.g., 50th, 75th, or 95th percentile) for different types of planning decisions, depending on risk tolerance.

4. In cases where the implications of unmitigated risks are extreme, more thorough analysis will be necessary to ensure that investments are commensurate with the magnitude of the risks, and that society is prepared to shoulder the implications of whatever trade-offs are ultimately made (see Recommendation 8).

This exercise will produce planning recommendations for each climate scenario, while assessing the potential risks (see Recommendation 4) associated with planning to one risk threshold versus another.

In the near term, infrastructure planning models should be run with the full range of climate projections specified in Recommendation 1. Box-and-whisker plots of planning outcomes should be generated and a sensitivity analysis of different climate impacts on infrastructure planning model assumptions should be performed. **Ultimately,** the range of planning outcomes should be obtained via updated infrastructure planning models (see Recommendation 6). The risk analysis and appropriate risk tolerances should be revisited and applied to future decisions.

3.6.3 Grappling with uncertainty and its consequences

The complex interactions between climate and electricity infrastructure leave room for significant uncertainty. Modelers will likely make mistakes and overlook some climate interactions. Should this be the case, processes must be in place that facilitate iteration and allow us to refine grid planning models as new information comes to light.

[2] A *box-and-whisker plot* is a statistical representation commonly used to depict the range of observations present in a data set. The line inside the box indicates the median of the data, while the ends of the box indicate the upper (75%) and lower (25%) quartiles. The whiskers may extend to the highest and lowest observations, though statistical outliers are often depicted as individual points beyond the whiskers. Notably, a box-and-whisker plot visually shows the full range of observations without averaging and without presuming that observations follow any kind of parametric distribution.

Recommendation 8: Assess the magnitude and severity of evolving risk scenarios; re-evaluate risk tolerances in light of evolving risks and/or allocate resources to respond effectively.

Barrier: Infrastructure planning decisions have always balanced investments in performance against the probability and implications of failure. Today, these decisions are made primarily based on quantitative risk metrics informed by historic data and/or expert judgment [271]. As climate trends change the nature and severity of viable risk scenarios, the current approach makes us vulnerable to systematic errors in our understanding of current and future threats. These errors prevent us from taking effective and targeted actions to mitigate evolving risks; we are shouldering the consequences without fully understanding what they are.

Solution: Recommendation 4 cites the need for climate-aware risk evaluation protocols, while Recommendation 7 proposes that risk tolerances be set. Here, we recommend detailed analysis

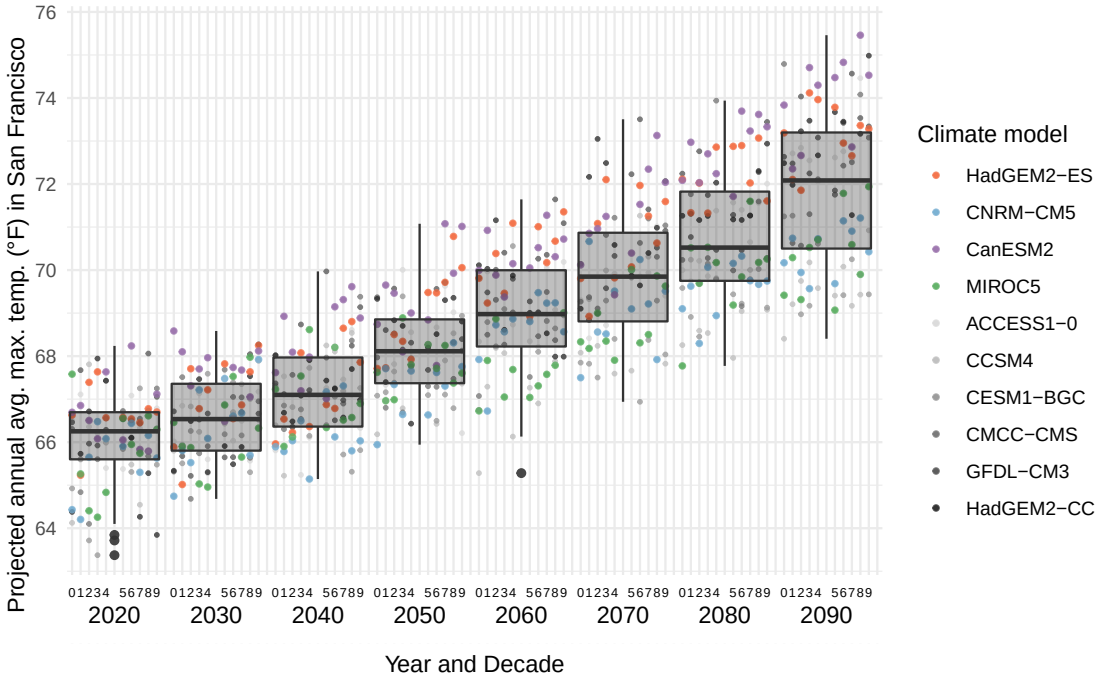


Figure 3.4: An example box-and-whisker plot. Data points indicate the projected annual average maximum temperature within the San Francisco city limits from each of the 10 California-relevant climate models available via CalAdapt under scenario RCP 8.5 [268]. Boxplots are drawn by decade (i.e., years 2040 through 2049 are assigned to 2040) and centered over the underlying data points. Temperature projections indicate the range of environmental conditions that infrastructure could face during each decade. Outliers are defined as points further than 1.5 times the interquartile range from the 25th or 75th percentile [269]. For more granular planning decisions, box-and-whisker plots could be drawn for (e.g.) a single year from 10 predictions, one from each model. The first four climate models listed have been recommended as priority models for research purposes and broadly represent 'hot/dry,' 'cool/wet,' 'average,' and 'most distinct' conditions, respectively [270]. The other models are listed alphabetically.

of unmitigated risk scenarios to ensure that diverse stakeholder groups are prepared for the consequences. It may be necessary to re-evaluate risk thresholds should it be determined that potential consequences are too high. **In the near term,** risk assessment efforts should focus on ensuring that the likelihood and ramifications of unmitigated risk scenarios are fully understood. CPUC and other decision-makers should engage with local communities, emergency response agencies, and disaster relief funds (among others) to ensure that the diverse groups who will shoulder the burden of real-time response are adequately prepared to do so. **Ultimately,** efforts to identify and quantify climate-related risks, and decisions about how to allocate limited resources must be coordinated across stakeholder groups who are positioned to mitigate risks, and those who will need to respond. These efforts can aid more efficient and effective responses to risk scenarios that are realized, and provide a basis for reaching consensus about the magnitude of investment appropriate for mitigating risk scenarios that carry societal consequences more severe than those experienced to date.

Recommendation 9: Planning agencies need to think critically about how infrastructure needs could change due to climate impacts on population and behavior.

Barrier: There remains a great deal of uncertainty around how people will respond to climate change. We may anticipate some trends, but high uncertainty around how or if to respond may mean it is too soon for preemptive action. Several examples have emerged. Expansion of the wildland-urban interface has created new load centers and increased the implications of wildfire ignition events [236]. Public safety power shutoffs have been used to mitigate severe wildfire risks, but outages pose safety risks to vulnerable populations during extreme heat waves. Service interruptions during wildfire events may impact the ability of electric vehicle owners to evacuate affected areas.

There are other examples we may anticipate but have not yet confronted. For example, researchers are studying potential population displacement due to climate change [235]. However, little discussion has focused on infrastructure needs to support displaced communities [272]. Without proper planning, temporary or permanent displacement of populations—within, to, and from California—could lead to considerable strain on infrastructure systems.

Solution: The high degree of uncertainty may make it untenable to prioritize these risks over more immediate needs, but we should still prepare to take action. Stakeholder engagement efforts should focus on enumerating the wide range of risk scenarios that could unfold as people respond and adapt to climate change, and evaluate the implications on grid infrastructure and operations. To the extent possible, we should anticipate and plan for these types of risk scenarios and timely, coordinated, and effective responses.

3.7 Conclusions and policy implications

Climate change will fundamentally alter the operating conditions and risk exposure of electric grid infrastructure. An advanced body of research has developed climate data to anticipate these risks

and inform long-term planning decisions. Additional research may be needed to characterize certain climate-grid interactions. Where data do exist, substantial research has been done to examine how climate trends will impact grid assets, for example due to warming and sea level rise.

The current work examines the technical details of climate-grid interactions, opportunities and barriers to use climate information to inform long-term investments in grid infrastructure. We detail nine recommendations that provide guidance to coordinating entities (for example regulators or policymakers) positioned to enable and advance climate awareness in grid planning processes in California. These recommendations are grounded in existing grid infrastructure planning processes, and are informed by best-practices established in other sectors.

We find that much of the data necessary to support climate-aware decision-making are readily available, including projections of temperature, precipitation, snowpack, and wildfire risk. However, climate projections characterizing changes in the severity of high wind-speed events—which can both physically damage grid infrastructure and exacerbate wildfire risks—are needed. Grid planning agencies rely heavily on load forecasts which need to be revised to reflect how climate trends and mitigation efforts will alter load.

Regulators and policymakers will play a critical role in disseminating climate data, and in advancing infrastructure planning models to incorporate these data. An important first step is to ensure that decision-makers throughout the state have access to and use climate and load projections as inputs to grid infrastructure planning models. Clear guidance should be issued regarding which data are appropriate to use for different planning decisions. Research funding is needed to generate datasets that are lacking, and to study grid-climate interactions that are not well understood.

Though there is a great deal of uncertainty associated with making long-term decisions in the face of climate change, that need not prevent decision-makers from mitigating recognized risks. Existing regulatory processes are well-suited for regulators to detail prescriptive guidance about how to make infrastructure investment decisions in light of existing uncertainties. Transparent risk thresholds informed by current knowledge will ensure that planning decisions align with evolving societal needs and priorities, and allow greater insight into unmitigated risks. Planning thresholds will need to be revisited as our understanding of evolving risks advances. Developing a more detailed understanding of the risks that climate-grid interactions could pose can support regulatory agencies in determining how resources are allocated, and whether rate increases will be necessary to cover the costs of mitigating untenable risks.

Chapter 4

Climate-aware decision-making: Lessons for electric grid infrastructure planning and operations

Climate change poses significant risks to large-scale infrastructure systems and brings considerable uncertainties that challenge historical planning approaches. Here we focus on how climate awareness might be better incorporated into planning and decision-making in the electric power sector. To do so, we consider lessons from decision science literature where researchers have specifically focused on how to make better decisions under uncertainty. We perform a three-part review: of decision science literature on best practices for decision-making under uncertainty, of industry practice documents to understand how new uncertainties may affect the types of decisions electric utilities are making today, and of literature on electricity sector planning under climate change to assess how lessons from decision science might fit into sector-specific analyses. We discuss how characterizations of uncertainty from the decision science literature might guide approaches in the electricity sector to appropriately capture climate-related uncertainties. We also distill three key ideas from the decision science literature that can be incorporated into electricity sector planning to manage these new uncertainties: robustness, adaptive planning, and multi-stakeholder engagement. We offer example recommendations for how these key ideas might be incorporated into one essential type of planning activity, capacity expansion.

4.1 Introduction

Changing climate patterns have already begun to strain society's infrastructure systems, and projected trends in ambient and extreme conditions portend significant stresses in the coming years. Billions of people worldwide rely on large-scale infrastructure systems, such as electric power, water, and transportation, for their daily needs. Despite considerable attention on documenting the

mechanisms and potential impacts of climate change on these systems, more work is needed to incorporate climate awareness into actual planning decisions, which today often rely on historical data and outdated assumptions [191].

We focus here on electric power systems, which are affected by climate and weather patterns in myriad ways and face ongoing and acute stresses from changing conditions [56, 58, 61, 213, 254, 273]. Centralized electric grids consist of generation and delivery infrastructure that supplies electricity to end-use customers. Recent events—such as widespread service interruptions and price spikes due to cold weather in Texas in February 2021 [274, 275]; in California, heat-related rolling blackouts in August 2020 as well as grid-caused wildfires and associated power shutoffs intended to prevent additional fires from 2017-21 [222, 276, 277]; and extensive storm-induced outages in New Orleans in late summer 2021 [278]—demonstrate that system planning and operational practices have not adequately accounted for climate change. Such events jeopardize the electric sector's core goals of safety, reliability, and cost-effectiveness. We define resilience here broadly, as the ability to preserve these goals without significant disruption and/or impact on customers, and to return to safe, reliable, and cost-effective operation quickly if disruptions occur.

Building climate awareness into electricity sector planning and decision-making is far from straightforward. Current planning processes commonly focus on predicting a likely future in terms of electricity demand, weather conditions, and technology options, and identifying investments that are expected to achieve specified reliability targets under those planning assumptions. Changing climate conditions and associated uncertainties—including those related to infrastructure impacts, policy and regulatory actions, and consumer behavior—challenge this underlying deterministic premise [279–281]. Yet openings may now exist to rethink planning approaches, as high-profile service disruptions have focused public, regulatory, and legal scrutiny on electricity sector planning and preparedness [282, 283]. In response, some electric utilities have begun producing vulnerability assessments to evaluate where their systems may face specific threats [284–287].

A major barrier to change is that the uncertainties inherent in future climate trajectories and their implications require a deeper grappling with the unknown than is present in electricity sector planning today. While electricity sector planners have always had to make decisions in the context of uncertain future conditions (e.g., those related to demand growth, technological innovation, fuel prices, etc.), existing practices to account for uncertainty rely extensively on historical trends and expert intuition honed in the context of previous climate conditions [288]. In the face of climate uncertainty, these approaches will no longer hold. Making better decisions in the face of these uncertainties will require taking stock of the available science and integrating it into planning processes, evaluating existing baked-in assumptions and revising where needed, considering compounding impacts, and reviewing expectations about acceptable levels of risk and resilience [56, 61, 289]. Separately, decision science researchers have focused on how we can make better decisions even with significant uncertainties, and concepts from decision science can help provide systematic ways of accounting for them. Here, we review their insights in the context of advancing climate-aware planning in the electricity sector.

We perform a three-part literature review with the goal of making pragmatic recommendations on how climate awareness can be better incorporated into electricity sector planning today. First, we review academic and grey literature in decision science and its applications to assess

best practices for decision-making under climate-induced uncertainties as well as tools to manage uncertainty in planning processes. Next, we review industry practice documents from two electric utilities to ground ourselves in the types of decisions made now and consider how potential new uncertainties created by climate change may impact those decisions. Then, we review literature on electricity planning under climate change to assess how decision science insights may be implemented in this space.

We assess how climate-induced uncertainties in the electricity sector fall within decision science frameworks used to categorize uncertainties. Such frameworks provide insights about how these uncertainties may be appropriately captured in planning models, and indicate that methods designed for handling deep uncertainty should be employed. We further distill three key ideas from the decision science literature: robustness, adaptive planning, and multi-stakeholder engagement, and assess how these build on current practices in the electricity sector. We discuss how the electricity sector could incorporate these ideas into industry practices, and highlight existing approaches that can form a scaffolding for climate-aware planning. Further, we focus in on one category of electricity sector decision-making—capacity expansion planning—and provide tangible examples of how climate awareness can be better incorporated via the key ideas identified from decision science. We suggest that embracing the concept of multiple plausible futures, setting up signposts that identify tipping points as the future evolves, and involving boundary organizations to help translate insights between climate science and electricity planning can help electricity sector decision-makers better plan for the future. In doing so, we bring together insights from three fields: decision science, electricity systems, and climate science, to advance how decision-makers in critical infrastructure sectors might rethink planning processes to better prepare for climate change.

4.2 Methodology

4.2.1 Decision science review

Decision science refers to the process of how individuals and organizations make decisions based on available information. It is an interdisciplinary field that draws on theories from economics, operations research, forecasting, behavioral science, and statistics. Growing complexities in infrastructure planning due to climate uncertainties have spurred the development of planning approaches that borrow theories from this field [290]. The new planning approaches aim to provide planners with a more holistic view and assist in solving "wicked" problems in infrastructure planning. We reviewed both academic and grey literature on decision-making processes related to climate adaptation and resilience policy across critical infrastructure sectors. We focus on how uncertainty can be incorporated during the modeling process, rather than on how these frameworks might be implemented within regulatory entities.

For the academic literature, we used 14 combinations of search terms in Scopus (Table D.1). This yielded a total of 1018 peer-reviewed journal papers. We then removed duplicates and reviewed the abstracts using the following inclusion criteria, keeping only papers that met all of the criteria:

1. The paper considers climate as a source of uncertainty.
2. The paper is related to planning for an uncertain future or adaptation strategies in a critical infrastructure sector, or it is a review of decision-making frameworks in the context of critical infrastructure planning or adaptation planning.
3. The paper was published after 2000 and is presented in English.

This selection process left us with 86 papers in our full text review. We then identified concepts and techniques used to handle uncertainty in each paper and categorized them into overarching concepts with associated techniques.

Our focus on decision-relevant planning approaches prompted us to also review the grey literature, where innovations by practitioners working in critical infrastructure sectors may be documented. We used four combinations of search terms (Table D.2) in three databases: Adaptation Clearinghouse, Climate-ADAPT and US Climate Resilience Toolkit. These databases contain a rich set of public documents produced by government agencies and nonprofits with a specific focus on climate adaptation. Down-selection was performed via the filtering functions embedded in each database rather than through keyword searches.

This search yielded 109 reports across the three databases. We then removed duplicates and reviewed report summaries using the following inclusion criteria, keeping only papers that met all of the criteria:

1. The report considers climate as a source of uncertainty.
2. The report is a planning or guidance document that discusses the decision-making process to address climate change for critical infrastructure planning (reports such as vulnerability assessments or climate impact studies are not included).
3. The report was published after 2010.

This selection process left us with 15 reports for full text review. We then identified concepts and techniques used to handle climate uncertainty in each report and categorized them into overarching concepts with associated techniques.

4.2.2 Industry practice review

To better understand the ways that climate change may impact the electric power sector, we aim to document the types of decisions that electric utilities are making today. In the United States, roughly three-quarters of electricity customers are served by investor-owned utilities (IOUs) [291]. IOUs operate as regulated monopolies, with their investment decisions and customer rates overseen by state public utility (or public service) commissions in General Rate Case (GRC) proceedings. These proceedings are rich sources of public information on how electric power systems are maintained, operated, and invested in today. As these documents are extensive, we select just two utilities to compare in order to keep our scope manageable. In selecting these utilities, our criteria

include: (1) geographic diversity, (2) large utilities that serve a mix of customer types (including both urban and rural representation), and (3) utilities that have been heavily impacted by extreme weather events.

We focus here on two utilities: Pacific Gas & Electric (PG&E), which serves approximately 16 million customers in urban and rural Northern California, and Consolidated Edison (ConEd), which serves over 3 million customers in the New York City area. Notably, PG&E and ConEd have already been significantly impacted by climate change: increasing wildfire activity in California and Hurricane Sandy in New York have drawn scrutiny to utility operations and focused attention on electric system safety and resilience. Here, we review the 2020 GRC filings of both utilities, focusing attention on electric power system operation and energy delivery. The approved costs and rates in these GRC filings set utility spending and investment thresholds for three years, from 2020 to 2022.

For PG&E, we focus on the utility's filing requesting cost recovery for 2020 spending, as approved by the California Public Utilities Commission (CPUC) [179]. For ConEd, we focus on the joint proposal documenting the results of a settlement agreement on utility spending from the utility and other stakeholders [292], expert testimonies that provide additional context about utility planning and investments [293], a report documenting anticipated capital expenditures [294], and the approval from the New York State Public Service Commission [295]. For both utilities, we seek to identify where and how they propose to invest in their systems and the decisions they are making about them. We code investment decisions by activity area (see Appendix D.2), then summarize current utility practices within each space. For each activity area, we identify emerging uncertainties that will affect electric power system planning going forward.

4.2.3 Electricity sector planning under climate change review

We performed a literature review of papers related to electricity sector planning that also consider climate change. Search terms used are summarized in Table D.3 along with the number of papers these terms returned in Scopus. From the initial returned list of papers, we removed duplicates and papers written in a language other than English, which left us with 683 total papers. Then we reviewed the abstracts using the following inclusion criteria:

1. We filtered out papers whose primary focus was not relevant to planning for electricity infrastructure and/or did not include some consideration of climate change or sustainability.

2. We removed papers with a primary focus on modeling only one area of energy systems (e.g., building energy use, energy demand, solar photovoltaic generation), or where electricity infrastructure was not a major focus of the paper.

3. We removed papers that focused on describing climate change impacts rather than planning for them or on resource characterization (e.g., solar availability).

4. We focused on electricity system planning in geographic areas with developed grid systems, though we did include some papers looking at decentralized electricity systems as an option.

Following this down-selection process, we were left with 168 papers. We then reviewed the papers to identify how the authors handle climate change and uncertainty and whether and how they incorporated the key concepts identified in the decision science review. While reviewing, we also sorted the papers into topic areas (Table 4.5).

4.3 Results and analysis

Decision science researchers have developed approaches that can help advance how electricity sector decision-makers may consider and address climate-induced uncertainties. Here, we focus first on uncertainty characterization (Section 4.3.1), then evaluate how different types of uncertainties may emerge in the electricity sector (Section 4.3.2) and how they may impact electric utility practices and decisions (Section 4.3.3). Then, we consider key concepts from decision science that may be used to manage uncertainty in planning processes (Section 4.3.4) and evaluate the extent to which these show up in literature on electricity sector planning (Section 4.3.5). Sections 4.3.1 and 4.3.4 are based on our review of the decision science literature (Section 4.2.1); Sections 4.3.3 and 4.3.5 are based on our review of the industry practice (Section 4.2.2) and electricity sector planning (Section 4.2.3) literatures, respectively. Section 4.3.2 draws from our review of all three areas of literature.

4.3.1 Characterizing climate-related uncertainties

There are many different classifications of uncertainty and debates about their characterization and importance [296], so a standard framework or taxonomy for uncertainty in the context of climate change and infrastructure planning does not exist.[1] This lack of distinction leads to confusion and prevents clear communication regarding uncertainty to decision-makers. Climate uncertainty is also often perceived differently by decision-makers and scientists [299, 300]. We aim to reconcile some differences in interpretation by classifying uncertainties in a decision-relevant context. Specifically, we approach uncertainty from a modeling perspective and distinguish the technical methods used to treat uncertainties. We expand upon work done by [301] and [302] and frame uncertainties in a grid planning context.

Uncertainty is generally defined as incomplete knowledge and/or disagreement about what is known or even knowable [297, 303]. Five levels of uncertainty were proposed by [302] (Figure 4.1). These levels correspond to different degrees of numerical certainty, which constrain how information can be appropriately represented in models and analyses.

- Level 1 uncertainty (shallow) represents a situation when a reasonable estimate of the outcome is possible. This uncertainty may be appropriately treated through a simple sensitivity analysis of model parameters.

[1] Uncertainties are commonly categorized as either aleatory (random variability in the system) or epistemic (lack of knowledge about the system) across different disciplines [297]. However, this categorization may not offer an adequate delineation in the context of climate-aware decision making as their distinctions are blurry, and many uncertainties have characteristics of both [298].

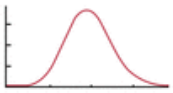
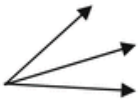
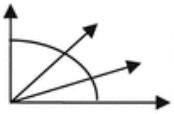
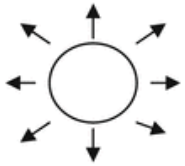
LOCATION		Complete Certainty	LEVEL					Total ignorance
			Level 1	Level 2	Level 3	Level 4	Level 5	
	Context		A clear enough future 	Alternate futures (with probabilities) 	Alternate futures with ranking 	A multiplicity of plausible futures 	An unknown future 	
	System model		A single (deterministic) system model	A single (stochastic) system model	Several system models, one of which is most likely	Several system models, with different structures	Unknown system model; know we don't know	
	System outcomes		A point estimate for each outcome	A confidence interval for each outcome	Several sets of point estimates, ranked according to their perceived likelihood	A known range of outcomes	Unknown outcomes; know we don't know	
	Weights on outcomes		A single set of weights	Several sets of weights, with a probability attached to each set	Several sets of weights, ranked according to their perceived likelihood	A known range of weights	Unknown weights; know we don't know	

Figure 4.1: Levels of uncertainty (Reproduced from: [304])

- Level 2 uncertainty (shallow) refers to an uncertainty that can be reliably described through statistical terms. One can capture level 2 uncertainty through forecasting techniques (scenarios) with associated probabilities. Analyses may appropriately assume that historical data can be used to develop reliable future forecasts.
- Level 3 uncertainty (shallow) are situations with known multiple alternatives where it is possible to rank the alternatives by perceived likelihood, but no probabilities can be reliably assigned [305]. One can appropriately capture level 3 uncertainty with trend-based scenarios that reflect different assumptions of the driving force (e.g., three trend-based scenarios of electric vehicle demand, based on three different assumptions about product costs).
- Level 4 uncertainty (deep) are situations with known multiple alternatives but where ranking the alternatives in terms of likelihood is not possible, potentially due to inadequate data or decision-makers' disagreement on the rankings. Analysts may struggle to specify the appropriate models, select the probability distributions to represent uncertainty about key parameters in the models, and/or to value the desirability of alternative outcomes [306].
- Level 5 uncertainty (deep) represents the deepest level of recognized uncertainty. We can only acknowledge that we do not know.

These levels can be simplified to two levels: "shallow uncertainty" and "deep uncertainty". Shallow uncertainty can be treated through probabilities or assigned likelihood for different future alternatives, whereas deep uncertainty refers to conditions where parties do not know and/or cannot agree on the probabilities or likelihood of different future alternatives. These levels map onto different ways of representing parameter uncertainty, which may range from probabilistic information, to bounds on a range, to trend estimation or effective ignorance [307]. [306] further define deep uncertainty as the condition where decision-makers cannot agree upon:

1. the appropriate models to describe interactions among a system's variables,
2. the probability distributions to represent uncertainty about key parameters in the models, and/or
3. how to value the desirability of alternative outcomes.

The electricity sector faces uncertainties that span each of these levels. Determining which uncertainties meaningfully impact various planning and decision contexts is critical for identifying the conceptual frameworks and analytic methods that are needed to effectively advance climate-informed practice.

4.3.2 Uncertainties in electricity sector planning

We can evaluate climate-induced uncertainties faced by the electricity sector through the framework discussed above. Figure 4.2 shows a conceptual mapping of how climate uncertainties may propagate through to impacts on the electricity system. This mapping broadly reflects the attributes of coupled natural and human systems under deep uncertainty discussed in [308]. These uncertainties directly pertain to decisions made today (Table 4.1) and should be accounted for in climate-aware planning and decision-making. To do so appropriately, we must consider the nature of the uncertainties and how they might be represented to decision-makers.

4.3.2.1 Uncertainties in climate conditions

Climate scientists have made substantial progress in developing standard approaches to work with uncertainties related to climate conditions (Figure 4.2a). Uncertainty in climate prediction comes from three sources: scenario uncertainty, model uncertainty, and internal variability [301, 309], which have different impacts depending on the decision time and spatial scale. In the climate science space, *scenario uncertainty* corresponds to uncertainty in how greenhouse gas emissions will evolve. Uncertainties in continuing emissions are represented by scenarios (often, representative concentration pathways or RCPs, see [310]) that describe how emissions may evolve over the coming decades, and constitute a range of possible outcomes. Which scenario is realized depends upon societal behavior and climate policy, and so is constrained by future socioeconomic scenarios, often considered as shared socioeconomic pathways (SSPs) [311, 312]. The range of future emissions can be loosely bounded by such plausible socioeconomic and policy scenarios,

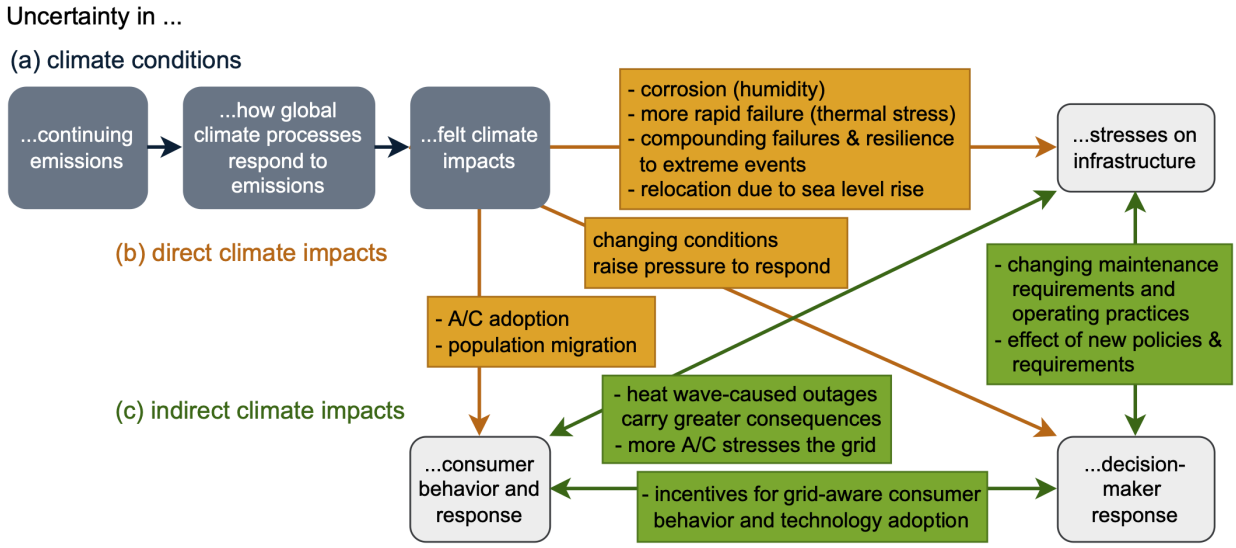


Figure 4.2: Conceptual mapping of progression of uncertainties in the electricity sector that are related to climate change. This figure is not meant to be exhaustive, but to illustrate the types of uncertainties and impacts that will emerge due to climate change.

as well as by physical constraints on fossil fuel usage. It may be possible to assign some expected likelihood to each emissions scenario, but assigning formal probabilities remains elusive, placing emissions scenario uncertainty at Level 3 or 4 from Figure 4.1. The climate signatures of alternative emissions scenarios tend to broadly agree through approximately mid-century, so scenario uncertainty typically matters more for long-term planning decisions such as system expansion.

Uncertainties in how climate patterns might respond to continuing emissions are captured by Global Circulation Models (GCMs), which take emissions scenarios as inputs. *Model uncertainty* refers to how these different models simulate changes in climate given the same amount of emissions. Each GCM constitutes a plausible representation of how future conditions may evolve. Model-based uncertainty is deep in the sense that these models are not randomly drawn from a space of possible models and their relative likelihoods cannot therefore be formally assigned probabilities. While certain model projections can be ruled out as less credible by examining their historic performance against observational benchmarks [e.g., 313–315], it is often impossible to narrow the range to a single "most likely" projection or "most credible" model. Nor is it appropriate to think of models as equally likely since some models may share development histories and therefore common biases [316]. Some researchers have developed credibility-based model weighting schemes, but in practice it is necessary to evaluate many metrics to build confidence that a particular weighting approach appropriately reduces uncertainty. Another reasonable strategy is to treat each projection that passes a skill-based screen as an equally plausible yet non-probabilistic outcome (i.e., corresponding to Level 4 from Figure 4.1). GCMs describe climate impacts at large-scale resolution, and finer geographical resolution is desirable for actual planning decisions. Downscaling methods translate GCM outputs into regional climate impacts, and these methods

also contain separate model uncertainties about how these large-scale outputs may be experienced locally [182].

Climate projections are also subject to *internal variability*, or the natural fluctuation of the climate system even in the absence of emissions [317]. Internal variability is stochastic in nature and in principle can be estimated probabilistically through either observation or a sufficient number of simulated climate projections contingent on a given climate model and emissions scenario. However, the rarer an extreme event (e.g., a large storm or extreme heatwave) is, the more data is required to properly characterize its probability [318], presenting challenges when the historic record or future projections are limited. The recent advent of large climate projection ensembles (in which the same scenario is modeled dozens to hundreds of times) has led to better statistical resolution of extreme events [319], but still does not address the deep uncertainty arising from the choice of climate model itself or from alternative emissions scenarios.

4.3.2.2 Uncertainties in direct climate impacts

Changing climate conditions will directly impact infrastructure, consumer behavior, and decision-maker response (Figure 4.2b). In particular, these may include how climate variables (e.g., humidity, temperature) impact power equipment performance and lifetimes, as well as the demands consumers put on that equipment (e.g., through increasing air conditioning use). Direct impacts will include those from changes in ambient conditions (i.e., trends in surrounding air temperature, precipitation, wind patterns, etc. that infrastructure is exposed to in routine operation), and in extreme conditions (i.e., increasing magnitude and frequency of events likely to cause disruptions). Researchers have estimated specific impacts from climate trends in these areas, and this ongoing work in conjunction with reasonable near-term confidence in felt local climate impacts (e.g., overall temperature trends) may make it possible to represent some uncertainties in these parameters through statistics. Yet such representations still rely on projecting the underlying climate impacts, which are nevertheless deeply uncertain (Section 4.3.2.1). Climate conditions may also impact consumer and decision-maker responses that are more difficult to characterize empirically, such as population migration and/or political pressure.

4.3.2.3 Uncertainties in indirect climate impacts

Climate will also have additional indirect impacts on the electricity sector (Figure 4.2c). These may include changing maintenance and operating practices, increasing danger for customers from heat-wave induced outages, and compounding stresses between consumer behavior and infrastructure performance. Policy actions in response to changing climate conditions may also prompt both increasing consumer actions (e.g., incentives for new technology adoption), and changing industry practices (e.g., decentralization). Adaptive responses by consumers and policymakers may pose further risks to electricity system stability and cost-effectiveness [320]. These uncertainties emerge from the interrelationships among entities involved in electric power systems, infrastructure impacts, and climate conditions, and are compounded by feedback loops, including with other complex infrastructure sectors (e.g., water, transportation) [321]. Therefore, they are more difficult

to estimate and capture through statistical approximations or modeling tools. Such uncertainties may thus be squarely considered deep, and require careful assessment that does not rely on predicting a deterministic future that may generate false confidence [308].

4.3.3 Electric utility practices and emerging uncertainties

New uncertainties that arise from changing climate conditions are already disrupting the normal operation and performance of electric power systems. Accounting for these uncertainties in electricity sector planning will require evaluating how decisions are made today and how decision-making and planning processes will need to be updated for the future. From our review of the GRC filings of PG&E and ConEd (Appendix D.2), we identify six activity categories and 16 activity areas in which utilities are making decisions today that will be impacted by new uncertainties from a changing climate. We discuss each activity area in Appendix D.3 and summarize them in Table 4.1.

These activity areas illustrate the range of practices that are exposed to new climate uncertainties. While the uncertainties discussed in Section 4.3.2 and shown in Figure 4.2 will impact all utility decisions, in Table 4.1 we indicate specific climate uncertainties that may be particularly relevant to each activity area. These are meant to be illustrative rather than comprehensive:

1. *Severe events* refers to uncertainties in the magnitude and frequency of events with the potential to disrupt day-to-day operations (e.g., strong storms, heat waves, droughts, etc.).

2. *Ambient conditions* refers to uncertainties in how average conditions (e.g., temperature, precipitation, humidity, etc.) change over time.

3. *Speed of changes* refers to uncertainties in the rate of relevant changes in both severe and ambient conditions.

4. *Demand changes* refers to uncertainties in changing consumer demand patterns and the resulting impacts to customers of disruptions (e.g., increasing electrification will mean greater reliance on the electricity grid for new loads, such as heating).

5. *Changing regulatory and policy landscape* refers to uncertainties about how decision-makers will respond, including potential new requirements for utilities with regards to risk and cost management (e.g., insurance).

In real-time operations, increasing frequencies of extreme events and changing ambient conditions may stress existing approaches to system operation, data collection and monitoring, as well as the ability of crews to effectively restore power after outages. In system maintenance, changing ambient conditions may alter the expected lifetime of system components (e.g., through corrosion or thermal stress) and necessitate more frequent maintenance and labor needs to ensure satisfactory operation. Further, while new climate patterns (e.g., drought) may place more stress on vegetation management practices, such practices will become increasingly important to preserve operation in light of extreme events and severe storms. In performance and business operations, changing

Table 4.1: Summary of utility activity areas and relevant climate-induced uncertainties (see Appendix D.3).

	Activity area	Description	Climate uncertainties
Real-time operations	System operations	Activities performed in real time to manage system operation and respond to current conditions.	Severe events
	Monitoring & situational awareness	Inspection and monitoring of infrastructure readiness and grid performance, either through special equipment (e.g., sensors) or human attention (e.g., patrols).	Ambient conditions; Speed of changes
	Emergency response	Response to emergency events and real-time repair work to restore service.	Severe events; Demand changes
Maintenance	System maintenance	Maintenance of electric power system equipment and associated infrastructure, costs may include those related to labor, capital, and permitting.	Ambient conditions; Demand changes
	Vegetation management	Inspection, identification, clearing, and removal of vegetation located near electric power equipment.	Ambient conditions; Severe events
Planning	System planning	Ongoing projects to evaluate system condition and day-to-day needs and to plan for the future.	Ambient conditions; Demand changes
	Preparatory planning	Investments in planning specifically for emergency events, which may include technology, communication, human capital, and coordination with other responders.	Severe events; Demand changes
Investments	System expansion	Deployment of new equipment and infrastructure designed to accommodate new demand on the system.	Severe events; Demand changes
	Repairs & replacements	Repairing or replacing equipment that has reached the end of its useful life, or where investment is needed to maintain an appropriate level of performance.	Ambient conditions; Speed of changes; Demand changes
	Grid hardening	Upgrading or reinforcing equipment with the goal of mitigating a specific and emerging threat that would not have originally been planned for, or to improve performance under non-standard operating conditions.	Severe events; Speed of changes
	System awareness & security	Developing new capabilities to maintain system awareness, improve safety and resiliency, and enable coordination, with a focus on non-power assets (e.g., system mapping, security upgrades, threat and vulnerability detection).	Changing regulatory and policy landscape
Performance	Performance assessment	Development and implementation of systems and processes to evaluate and measure utility performance (e.g., reliability metrics, customer satisfaction).	Changing regulatory and policy landscape
	Customer programs	Direct consumer engagement related to outage management, demand response, time-of-use rates, etc.	Demand changes
Business operations	Regulatory standards & compliance	Permitting and implementation of required technical or process standards, licenses, or environmental management practices.	Changing regulatory and policy landscape
	Internal operations	Costs required to perform core duties (e.g., labor, training, management, tools, office space, and land maintenance).	Changing regulatory and policy landscape
	Cost management	Accounting programs for managing infrastructure and operational costs (e.g., expenditures that are uncertain in time, decommissioning, recovery of cancelled projects).	Changing regulatory and policy landscape; Severe events

regulatory and policy practices, including direct-to-customer incentives for new technologies, may also continue to drive changes in how utilities operate. Further, new insurance risks may threaten existing accounting practices.

Here, we focus on two activity categories—planning and investments—in which utilities make and execute long-term decisions about their systems. Activities in these areas will need to contend with the impacts to technology of changing ambient conditions and increasing severe events, changing consumer demands for electricity, and a changing regulatory and policy landscape (effectively, all uncertainties depicted in Figure 4.2). To illustrate how these new uncertainties may challenge current utility planning and decision-making practices, we focus here on capacity expansion planning, which is widely used in the electricity sector to evaluate the need for investments in electricity generation and delivery infrastructure to serve new and changing demand patterns [60, 322]. These planning activities rely heavily on capacity expansion models, which incorporate information about existing infrastructure and make technology, market, and policy assumptions to determine where and when system investments should be made to accommodate load growth at least cost (Figure 4.3). The extent to which the results of these models represent the real world depends on how they incorporate uncertainties in climate and its direct and indirect impacts and stakeholder objectives (Figure 4.3a), as well as how well the model itself represents the electricity system (i.e., *model uncertainty*, Figure 4.3c).

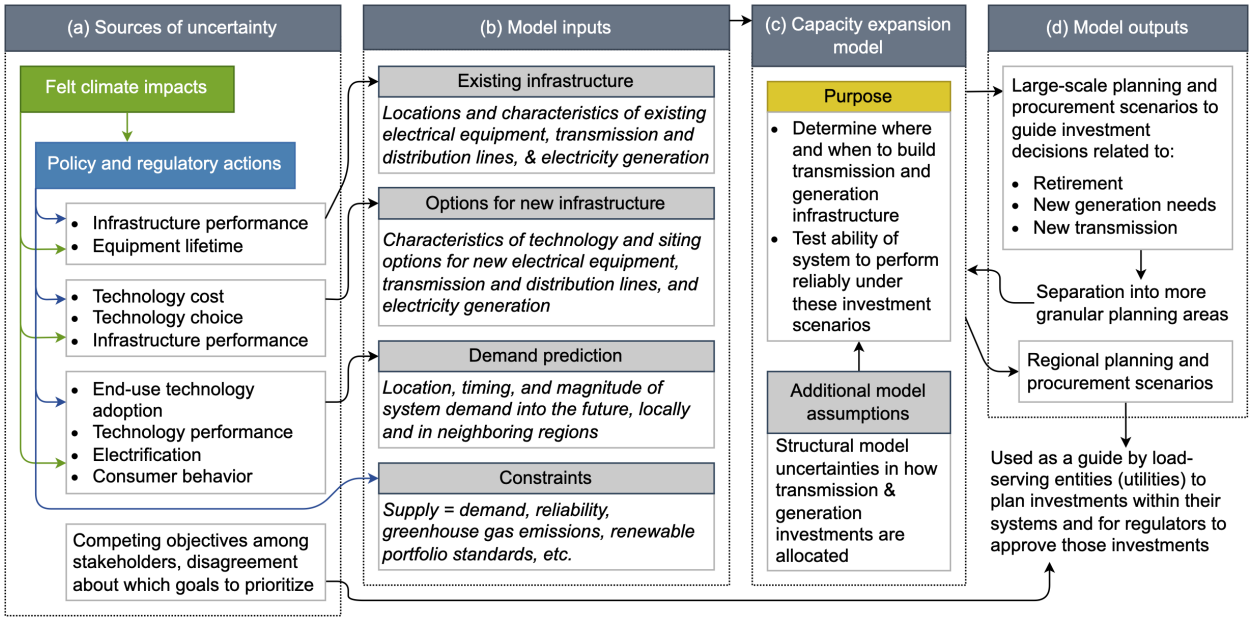


Figure 4.3: Uncertainties, inputs, and outputs of capacity expansion models.

Current implementations of capacity expansion models typically make assumptions about these uncertainties to create a single plausible future to plan for. In California and New York, the capacity expansion planning models that feed into and inform infrastructure investments are primarily deterministic, i.e., they seek to make the best possible predictions of a single plausible future given

current information, assume that uncertainties can be treated probabilistically, and then plan for that future [56]. While scenario planning approaches are used, investments are still tailored to one (typically median) scenario. Further, while in some cases such models take in weather and climate data directly (e.g., using temperature to predict electricity demand), they also contain embedded assumptions that implicitly incorporate climate conditions (e.g., equipment lifetimes). Feedback loops are also necessary to consider: for example, increasing consumer adoption of air conditioning due to increasing temperatures will increase demand on the grid at the same time as hotter days reduce line capacity and generation efficiency.

The potential impact that climate uncertainties may have on the results of these models is unknown until such uncertainties are more formally and systematically explored. Certainly, not all climate uncertainties will matter equally for all decisions, but relying on historical weather data as well as historical performance neglects the impact of climate as a source of uncertainty. Building climate awareness into capacity expansion planning is critical, and literature that evaluates the impacts of planning with climate considerations consistently show that it is better to plan for climate impacts upfront rather than after the fact [e.g., 57, 60, 323, 324]. By not accounting for climate uncertainty, we are planning for an inaccurate future, which may compound existing grid inadequacies.

4.3.4 Key concepts from decision science for managing uncertainties

Traditional decision-making approaches, including expected utility theory [325, 326], benefit-cost analysis [327], and cost-effectiveness analysis [328], hinge on the ability to predict the future accurately and assume all uncertainties are quantifiable. Decision outcomes are often optimized based on a single projection of the future state. However, any single projection of the future is likely to be inaccurate [329]. Moreover, planning for climate change is a case of deep uncertainty, where long-term climate uncertainties in infrastructure planning are hard to quantify and futures are hard to predict. Therefore, these traditional approaches cannot provide planners with a holistic view, adequately integrate climate uncertainty, or grapple with the long-term multiplicity of plausible climate futures [184, 306, 330–333]. Relatedly, oft-cited reasons for not including climate data in decision-making processes include the perceived poor reliability of climate forecasts and difficulty in assessing the credibility of climate projections [182, 334]. These reasons may also stem from the need to optimize under a single future and treat climate uncertainty in a probabilistic manner.

To address the limitations of the traditional decision-making approaches and climate uncertainty in policy making, a growing body of literature within the climate-aware decision science space uses concepts from decision-making under uncertainty and decision-making under deep uncertainty across different infrastructure sectors (Table 4.2). These concepts are not new [335], particularly within the water and transit sectors, but they have not significantly factored into work by practitioners in grid infrastructure planning.

A majority of this literature is targeted at water resources planning. The similarities between water resource and grid planning (e.g., high likelihood of path-dependence, sensitivity on both demand and supply to climate impacts, long infrastructure lifetime, investment irreversibility) make these concepts transferable. As discussed in Section 4.3.2, climate uncertainties significantly affect

Table 4.2: Summary of sector identified in review of papers related to decision making under climate uncertainty.

Sector	N(academic)	N(grey)
Water	37	7
Transit	12	3
Climate Adaptation	11	4
Energy	7	1
Conservation	2	0
Telecommunication	1	0
Nexus	1	0
N/A (conceptual review paper)	15	0
Total	86	15

all decision activities (e.g., system planning, investment, maintenance) and create compounding uncertainties (e.g., policy response, consumer behavior, infrastructure performance). In particular, long-term decisions such as capacity expansion planning may need a different approach to incorporate uncertainty in the decision-making. Three key concepts that emerged from our review could offer an alternative approach to the traditional methods:

1. **Robustness.** Rather than an optimal outcome for a single future, a robust outcome performs reasonably well in a wide range of plausible future climate scenarios.

2. **Adaptive planning.** Uncertainties in climate conditions evolve over time, and adaptive planning refers to setting up the institutional capacity to take actions over extended time horizons. This can include identifying short-term actions, developing different long-term options, and performing continuous monitoring to assess appropriate long-term paths.

3. **Multi-stakeholder engagement.** Tensions between conflicting perspectives and policy objectives may be resolved through an iterative multi-stakeholder engagement process.

Table 4.3 shows a summary of those concepts with associated techniques and papers. The following sections provide deeper dives into each of those concepts and discuss opportunities to implement them into organizational decision-making.

Table 4.4 shows the prevalence of key concepts in the literature. Robustness is more commonly discussed in academic literature compared to adaptive planning and multi-stakeholder engagement. However that prevalence did not translate over to practice in the grey literature. The lack of prevalence in implementing robustness concept is perhaps due to the technical complexity and knowledge gap on how uncertainties impact planning outcomes, particularly in the context of climate change.

4.3.4.1 Robustness

The concept of robustness originated in ecology during the 1970's, then it was introduced to water resources planning in the context of climate change by Matalas and Fiering [351]. They defined

Table 4.3: Summary of key concepts and their associated techniques.

Key Concepts	Key Techniques	Example Papers
Robustness: Ensuring the outcome is insensitive to errors and uncertainties in the parameter assumptions and performs reasonably well in a wide range of possible future scenarios.	• **Exploratory modeling or scenario discovery:** developing a set of scenarios in a systematic manner to expand the understanding of how the future might unfold and trade-offs between different prioritization of objectives. • **Vulnerability assessment:** Leveraging the systematic scenario discovery process to evaluate when a chosen policy performs poorly using a set of predefined metrics.	[336–340]
Adaptive Planning: Identifying short-term actions, but also developing different long-term options for implementation based on continuous monitoring.	• **Signpost & tipping points:** Identifying the point (signpost) when a policy outcome would become inadequate and tracking specific indicators (tipping point) that inform future actions. • **Monitoring plan:** A formalized plan that provides instruction on how to monitor signposts and tipping points and map out long-term actions to take when thresholds for the signpost are triggered.	[263, 341–344]
Multi-Stakeholder Engagement: Facilitating interactions of different actors within and across sectors, at different levels, and within different organizations to incorporate their perspectives and priorities.	• **Participatory modeling and scoping process:** Having "knowledge brokers" or "boundary spanners" to translate jargon and knowledge among different stakeholders in an interactive workshop. It is most effective when engagement is conducted iteratively throughout planning process.	[345–350]

Table 4.4: Number of times the key concepts appeared in literature review.

Concept	N(academic)	N(grey)
Robustness	48	5
Adaptive Planning	27	4
Multi-stakeholder Engagement	27	6

a robust design as one that may not be the optimal choice under any one scenario, but that performs reasonably well under a variety of possible climate scenarios. Robustness further refers to the insensitivity of system design to any potential errors in assumptions affecting decision performance [351]. Although the mathematical backbone of robustness has evolved, the definition is still broadly valid. Forgoing the optimal choice may seem counterintuitive, but decision-makers are often willing to sacrifice optimality for robustness [338, 352–354]. This preference for robustness

is at odds with traditional decision-making approaches, where the goal is to produce the optimal outcome under the assumption that uncertainty is well-characterized (i.e., shallow uncertainty). Given the irreducibility and depth of climate uncertainty and irreversibility of infrastructure investment, approaching planning with the robustness concept enables decision-makers to identify viable solutions that work across many possible futures without needing to predict which of those futures is most likely.

In recent years, an increasing number of decision frameworks are integrating robustness concepts into their approach, including Decision Scaling [355], Robust Decision Making (RDM) [306], Information-Gap [356], Many-Objective Robust Decision-Making [357], and Epoch–Era analysis [358]. Other authors have compared these methods [336, 359–364], and developed a common taxonomy of robustness across those frameworks [338]. Here, we focus on extrapolating robustness concepts and techniques that may be relevant to the electricity sector.

The exact definition of robustness is dynamic depending on the decision context and stakeholders' attitudes [365]. However, the underpinning technique to achieve a robust outcome is by exploring how different policy alternatives perform in a wide range of plausible scenarios and evaluating trade-offs among multiple performance measures [363]. There are four distinct components within a robust decision analysis: a set of decision alternatives, a range of plausible scenarios, performance measures or robustness metrics, and vulnerability assessment or robustness controls. We will provide a simplified overview of each component, refer to [338] for a more comprehensive discussion.

1. **A set of discrete policy alternatives.** These are the different decision options that may be implemented based on future scenarios and current institutional constraints. They may be pre-specified by decision-makers or developed through a computational search. For example, a discrete policy alternative might be a set of investment choices generated by a capacity expansion model under a particular set of inputs, including a given climate scenario. This policy alternative may then be evaluated alongside other alternatives developed by running the same model with different inputs (see: ii. range of plausible scenarios). In practice, the set of decision alternatives is more likely to be pre-specified due to resource constraints. A multi-stakeholder engagement process may be effective in ensuring different objectives are incorporated into the initial policy alternatives and determining whether adaptive planning is necessary or possible.

2. **A range of plausible scenarios** that considers all uncertainties and translates them into parameters in the model. For example, uncertainties around the change of temperature or precipitation in the next decade would become parameters with assigned plausible ranges. The different scenarios are different combinations of those uncertainties. A multi-stakeholder engagement process may be effective to create a comprehensive list of uncertainty factors and agree on plausible ranges for uncertainty parameters. The goal is not to predict future scenarios rather to explore what could happen. Each policy alternative is evaluated in each of the scenarios using robustness metrics.

3. **Performance measures or robustness metrics** for each policy alternative are a list of criteria that policy alternatives are evaluated against in each scenario. Stakeholders and analysts may co-develop multi-objectives and robustness metrics. Robustness metrics are developed in a similar manner to traditional decision-making approaches, where decision-makers choose specific metrics to evaluate policy performance based on the decision context (i.e., properties of the problem space such as regulatory environment and technical constraints). Example robustness metrics are GHG emissions, system reliability, and investment cost. The performance of one policy alternative may be evaluated using those robustness metrics. Robustness might be assessed using two methods, least-regret or satisficing. Least-regret quantifies each policy alternative's deviation from expected performance based on robustness metrics and identifies the policy that deviates the least over a wide range of plausible futures [366]. Satisficing evaluates each policy alternative against the robustness metrics and identifies the policy that performs reasonably well compared to the alternatives over a wide range of plausible futures [359]. Robustness metrics provide decision-makers with a systematic approach to evaluate and compare each policy under a wide range of climate futures.

4. **Vulnerability assessment or robustness controls** refer to the process of isolating the uncertain factors most responsible for system vulnerabilities and examining where policies could fail (i.e., produce unacceptable outputs with respect to the performance metrics). This is similar to sensitivity analysis in traditional decision-making approaches. The goal is to help decision-makers target specific vulnerabilities and develop adaptive strategies to address them [263].

In the grey literature, robustness is discussed as an overarching concept but it is rare for planners to conduct and implement robustness concept in the standard decision-making process. Some reports acknowledge the need to move away from deterministic and definitive prediction about future climate conditions and the importance of incorporating uncertainty by planning for wide range of futures [367–369]. However, this is often not operationalized, there are only several pilot projects in the water resources sector that leverage RDM to test its technical capability and value of running dozens of scenarios [370]. Both academic and grey literature suggest that the barriers to implementing the robustness concept center on the difficulty in changing the conventional decision-making process and planners' unfamiliarity [349, 370, 371].

4.3.4.2 Adaptive planning

Adaptive planning is another tool used to cope with uncertainties in long-term infrastructure planning. Adaptive plans are designed to be iteratively updated with newly available information, leading to more resilience against uncertainties and more effectiveness in guiding future actions. Similar to the concept of robustness, adaptive plans also examine a wide range of uncertainties and plausible futures [372]. In addition, adaptive planning refers to the flexibility of a policy alternative to change course based on the evolving environment through continuous learning [343,

354]. The objectives are to reduce path dependencies due to technological, institutional, and behavioral lock-ins [373, 374] and increase tolerance to future uncertainties [375]. To achieve those objectives, adaptive planning identifies short-term actions and long-term options by systematically monitoring the environment, gathering information, and iteratively adjusting strategies to new circumstances [376]. The literature presents several frameworks that encourage adaptive planning, such as Assumption Based Planning [377], Adaptive Policy Making [302], Engineering Options Analysis [378], and Dynamic Adaptive Policy Pathways [263]. The fundamental idea across those frameworks is that coping with uncertainty involves a robust short-term strategy and monitoring for changes that indicate a need to develop new strategies. Here, we again focus on the common and essential components of adaptive planning.

Adaptive planning can either be static or dynamic. Static adaptive planning aims to protect a basic policy from failing through contingency actions and monitoring [263, 379]. Dynamic adaptive planning goes beyond contingency planning and aims to monitor policy performance over time and develop alternative policies to switch to when certain thresholds are met [341]. The success of any adaptive plan depends on monitoring and anticipating ongoing developments such as changing climate and social context. Both approaches consist of two crucial components: a monitoring plan and a list of signposts [374]. We will provide a simplified overview of those two components. Refer to [338] and [343] for a comprehensive discussion.

1. **A Monitoring plan** aims to learn and continuously improve the existing policy based on new information [380]. Specifically, it monitors assumptions or uncertainty factors that affect policy performance and iteratively evaluates whether the current policy is at risk of failing given the changing environment. Multi-stakeholder engagement may be an effective way to develop a monitoring plan. The central goals of a monitoring plan are identifying what variables to monitor and establishing methods to analyze the information to get timely and reliable signals that indicate a change of action.Furthermore, a monitoring plan may also include flexible long-term planning options base on the changing environment and formalizes stakeholder engagement activities to iteratively improve the long-term planning actions.

2. **Signposts** are a list of variables to track to evaluate policy performance over time and are a central component of the monitoring plan. Each signpost is accompanied by critical values or thresholds that indicate when new actions are needed. An effective signpost consists of three quality criteria: salience, credibility, and legitimacy [381]. Salience refers to how decision-relevant a signpost is. A salient signpost will provide insights to address policy concerns and is measurable, timely, and reliable. Credibility refers to how scientifically sound are the critical values assigned to each signpost and how convincing they are at motivating potential changes needed. Legitimacy refers to the acceptability of the technical process around data gathering.

In grey literature, planners discuss the idea of adaptive plan within the context of adaptive capacity. It is often defined as the ability to adjust to change via building redundancy, resilience or recoverability [367, 369, 382]. The water sector is most advanced in incorporating ideas of monitoring plan and triggers when discussing adaptive planning.

4.3.4.3 Multi-stakeholder engagement

Multi-stakeholder engagement is an essential component for incorporating uncertainties into the planning process. Successfully developing a robust outcome and an adaptive plan relies on gathering decision-relevant information and considering perspectives from different stakeholders throughout the planning process [383]. Conducting multi-stakeholder engagement is especially crucial in the context of climate planning because misrepresentations of future scenarios may exacerbate negative climate impacts on marginalized populations [384].

The literature presents many different frameworks of conducting multi-stakeholder engagement for infrastructure planning [385–390]. A "one size fits all" approach for multi-stakeholder engagement does not exist, since it is highly dependent on the decision context and planning stage [391]. Moreover, there are discrepancies around the exact definition of a "stakeholder" [392].

Here, we use the IPCC's definition: stakeholders are individuals or groups that can influence or may be affected by the decision outcome. They might be policy-makers, scientists, communities, and/or managers in the sectors and regions most vulnerable to infrastructure failure [393, 394]. Stakeholder engagement is broadly defined as any activity such as a survey, interview, or interactive workshop with the purpose of information exchange between analysts, decision-makers, and stakeholders. There are some common frameworks infrastructure planners use to conduct stakeholder engagement. Delphi Method is commonly used to generate parameter bounds for climate scenarios [395]. Approaches such as the rapid assessment process and participatory planning are also common ways to understand different stakeholders' perspectives and generate scenarios [396]. There is much room for improvement to increase input from affected stakeholders, engage with diverse values, and examine conflicting objectives during the planning process to ensure procedural equity [397, 398]. Procedural equity starts with considering how to represent perspectives of affected community members by selecting a wide range of stakeholders and ensuring they are involved throughout the planning process.

Although multi-stakeholder engagement takes many forms, the common objectives for engaging stakeholders in the context of climate-aware decision making are four-fold:

1. Co-produce decision-relevant metrics to measure robustness and monitoring plan performance;

2. Increase transparency to the planning process with greater input and feedback from stakeholders regarding their preferences;

3. Seek active support and build consensus from stakeholders for the decisions which are made; and

4. Incorporate diverse perspectives from different stakeholders

Infrastructure planners cannot effectively implement the concepts of robustness and adaptive planning without multi-stakeholder engagement. Inputs from stakeholders are critical for defining policy success or failure. Many frameworks for decision-making under uncertainty include stakeholder engagement as an important step of the planning process. Ideally, analysts and decision-

makers would engage different stakeholders to understand various priorities and develop decision-relevant performance criteria at the beginning of the planning stage [348, 399]. Then analysts translate those insights into parameters and constraints during the modeling process [371]. Once modeling is complete, stakeholders are brought back for deliberation to build consensus and improve the decision outcome iteratively [306]. Moreover, having a boundary spanner or boundary organization during the engagement process may help to increase effectiveness of the co-production process. The role of boundary organization is to facilitate the engagement process by allowing scientists and decision makers to maintain their independence and objectivity while also creating some permeability of the boundary to co-produce robustness metrics and monitoring plan [400].

The grey literature suggests that multi-stakeholder engagement is already ubiquitous in large-scale long-term infrastructure projects as a way to manage risk and obtain public buy-in. However, there is a literature gap in how to conduct stakeholder engagement to effectively incorporate uncertainties and reconcile competing priorities [348].

4.3.5 Electricity sector planning under climate change

Researchers studying electricity systems in the context of climate change have taken a variety of approaches to this subject. To facilitate our review, we first sorted the identified papers into topic areas based on an initial survey of their titles, abstracts, and keywords (Table 4.5). These topic areas formed clusters of papers with some commonality in their perspective, scope, approach, and/or methodology. We reviewed papers in each topic area to understand how the authors considered climate change and uncertainty, and assessed to what extent the three key concepts identified in the decision science review (robustness, adaptive planning, and stakeholder engagement) showed up in this literature. A full review of modeling methodologies used in the energy sector is out of scope here, but we direct readers to [308, 401–407] for more discussion on the types of models used.

4.3.5.1 Climate change and uncertainty

Uncertainties, including those inherent in climate predictions as well as those stemming directly and indirectly from climate change (see Section 4.3.2), have been considered in various ways at different stages of analyses. Researchers acknowledge the presence and potential impact of uncertainties such as technical system characteristics (e.g., generator performance, line capacity), policy goals (e.g., renewable energy targets, carbon prices), and consumer behavior (e.g., rates of technology adoption, demand growth). However, to capture these uncertainties, there is widespread reliance on tools that would only be appropriate for shallow uncertainty. These include directly estimating individual values, perhaps with some sensitivity (appropriate for Level 1 uncertainty; see [403, 406]), assuming a probabilistic distribution of possible values (appropriate for Level 2 uncertainty; see [408–410]), and employing scenario approaches with known alternatives (appropriate for Level 3 uncertainty; see [323, 411–413]). Some researchers instead set a bounded interval or range of values without assuming a probabilistic distribution, which would fall between Levels 3 and 4 [414–417].

Table 4.5: Summary of topic areas identified in review of papers related to electricity sector planning under climate change. While some papers may span multiple topic areas, each was assigned to a single topic for organizational ease.

Topic area	N(papers)
Adaptive capacity	7
Capacity expansion	18
Climate impacts on power systems	12
Climate policy	9
Community energy systems	10
Complex systems	5
Decision support	18
Multi-sector optimization	10
Power system modeling	8
Resilience in power systems	23
Risk optimization	13
Robustness	9
Socio-technical transition	26
Total	168

Relying on value estimation and/or probabilistic estimates may further enable researchers to resolve parameter uncertainty within their analyses and report a sole solution. This raises the concern of seeking an optimized solution, which may inadvertently suggest to decision-makers that it is possible to model perfect knowledge (i.e., fully settle uncertainty) when the future is not deterministic [279]. An alternative is to depict uncertainty directly in results, for example by presenting a possible range of outcomes [408, 418]. Such results may more appropriately convey the continued need to consider uncertainty when presented for discussion in multi-stakeholder engagement processes.

Further, few researchers acknowledge model uncertainty (see structural uncertainty in [308]). Model uncertainty is present in all types of modeling exercises, including climate models (Section 4.3.2.1) and capacity expansion models (Section 4.3.3), but, unlike in the climate modeling literature, little attention is paid in the electricity planning literature to systematically evaluating a diversity of structural assumptions in model design.

Authors who explicitly use climate information in their analyses also take a variety of approaches. In some cases, a limited set of climate information (e.g., one emissions scenario and GCM) are used as a case study [419]. Others include more climate information to explicitly represent possible futures, for example by using several GCMs with one emissions scenario [60, 323], or several emissions scenario with one GCM [420]. In some cases, climate model outputs are aggregated (for example, by averaging their results) [60]. Other researchers evaluate climate models as distinct plausible futures, often as a set with the goal of creating a reasonable range on the phenomena of interest alongside several emissions scenarios [57, 324, 421–424].

Importantly, authors in the reviewed literature commonly focus on specific types of uncertainty within a particular analysis rather than capturing the full range of uncertainties that may exist within a particular decision-making or planning process. For example, some authors use a range of

GCMs and emissions scenarios while holding other assumptions constant [57, 60, 323, 422, 425], while others use no or limited climate information but vary assumptions related to socioeconomic factors [413]. Such approaches emulate the concept of controlled experiments and may provide valuable scoping or case study information. However, they do not account for the full range of plausible scenarios that should be considered in a robust process.

4.3.5.2 Robustness

Relatively few reviewed papers focus on ensuring robustness in their decision outcomes (for examples, see [426]). However, electricity sector researchers have developed computational techniques that capture components of the robustness concept. These techniques are designed with the acknowledgement that a single prediction of a possible future is inadequate, multiple plausible trajectories exist, and it is therefore worthwhile to consider how a policy or decision may perform across those potential futures. Techniques include:

1. Stochastic programming tools may incorporate different plausible futures and weight them by specified probabilities. The overall objective is then to minimize the expected system cost across all futures [279, 410].

2. Robust optimization is frequently used to determine the best (or, least-worst) solution for a given scenario, but such tools may also consider multiple futures, with the optimal solution then defined as one that demonstrates satisfactory performance (or, avoids the worst outcomes) across alternative scenarios [424, 425].

3. Trade-off approaches start from the development of a vast possible solution set, then iteratively screen out inferior approaches as evaluated by predefined metrics [417]. A final solution set is evaluated against all proposed futures.

Beyond these techniques, authors in the electricity planning literature selectively employ components of robustness approaches. For example, authors commonly include the development of multiple plausible scenarios and performance metrics. Some also include a vulnerability assessment or robustness controls [413]. It is less common in the electricity sector literature that we reviewed to explicitly incorporate multiple policy alternatives within the design of a set of scenarios (for examples, see [281, 418]). While few authors incorporate all elements of the robustness concept as discussed in the decision science literature, these frameworks nevertheless present scaffolding on which additional components of robustness could be integrated. It is important to note that these approaches may quickly become computationally intensive with the generation of additional scenarios and incorporation of policy alternatives.

4.3.5.3 Adaptive planning

Planning in the electricity sector is heavily influenced by decisions that have already been made; for example, existing investments will impact where new investments will need to go. Recognizing the importance of long planning timescales with multiple decision points, researchers have made

use of multi-stage modeling tools to create the foundation for evaluating system conditions and resolving uncertainties over time [323, 414, 427, 428]. For example, models may be run once to a selected point in time, then evaluated again based on new information about how conditions have evolved [279]. Such two-stage processes are particularly useful for uncertainties that have definite dates of resolution.

Other modeling tools may prioritize maintaining flexibility throughout a given timeline, for example, by selecting scenarios that maintain flexibility towards long-term uncertainties (see stochastic programming with recourse in [417]) or by incorporating feedback signals for real-time adaptability [429]. Other authors discuss adaptation options but do not explicitly incorporate them into analyses [430, 431].

Such approaches differ from the adaptive planning methodologies proposed in the decision science literature as they do not necessarily incorporate a monitoring plan or signposts, rather relying on discrete points in time and/or metrics of flexibility. However, they may provide a computational basis for incorporating those components to improve planning resiliency.

To some extent, current electricity sector practices do incorporate elements of adaptive planning, specifically via regulatory proceedings that require utilities to evaluate and justify their investment needs every three years (Section 4.2.2). However, these short timescales do not facilitate looking ahead at future climate conditions, and may thereby further path dependence and technology lock-in. This could occur, for example, by investment in conventional grid hardening at the expense of building flexibility into the electricity system through distributed assets. Moreover, planning on short timelines neglects the impact of long-term climate trends (e.g., sea level rise) that may threaten technology investments with long implementation and performance timelines (e.g., new generating facilities built near coastlines). Instead, adaptive planning principles call for proactively tracing out the different long-term options when certain trigger points are met, thereby giving signals to electricity sector participants to lay the groundwork for new approaches (e.g., legislative or regulatory actions that create markets for energy storage).

4.3.5.4 Multi-stakeholder engagement

We encountered relatively few papers that explicitly consider multi-stakeholder engagement. In some cases, authors consider assumptions about risk tolerance or other decision-maker preferences [414, 427, 428], or formulate solutions to be decision-relevant [420, 422, 430], but do not actually show evidence of having consulted stakeholders. Other papers involve stakeholders at the beginning or end of a particular analysis, whether to assist in scoping or to present results [408, 423, 432]. Extensive stakeholder engagement is present but somewhat rare (see [281, 308, 433, 434]).

Other authors have considered stakeholder involvement theoretically, such as by developing frameworks for engagement [435], simulating preferences via agent-based models [403, 436, 437], or evaluating computational approaches capable of accounting for various perspectives by solving for multiple objectives and/or including appropriate uncertainty ranges on parameters [417]. Authors have also proposed that stakeholder engagement can be used to determine where to focus within a solution space once a set of solutions are obtained, and, as each individual view is nec-

essarily a simplification of all considerations, to provide a check on other perspectives by helping ensure that a planning exercise accounts for needed nuances [431, 438].

4.4 Recommendations

We have identified three key concepts from decision science—robustness, adaptive planning, and multi-stakeholder engagement—that can be directly incorporated into electricity system planning and decision-making. Here, we return to capacity expansion planning (see Section 4.3.3) as a concrete example to illustrate how these key ideas could be incorporated into electricity sector activities.

4.4.1 Improving robustness in capacity expansion planning

Current capacity expansion models used in industry practice do not adequately account for the range of uncertainties and plausible futures created by changing climate conditions (Section 4.3.3). The electricity planning literature (Section 4.3.5) contains ample examples of approaches to uncertainty that would be appropriate if those uncertainties were shallow. However, deep uncertainties present in climate change impacts and responses make even stochastic approaches inadequate.

Fully embracing robustness methodologies from the decision science literature would involve running capacity expansion models with a full range of climate, policy, behavior, and technology scenarios to identify the wide range of plausible futures, then evaluating the performance of investment options to identify those that perform acceptably well across those futures. Such an effort could involve thousands of relevant scenario combinations, and extensive computational and human effort to create scenarios, track performance, and interpret outputs. This approach would undoubtedly present electricity sector decision-makers with valuable information, but may face practical barriers to implementation. A more incremental approach may help ensure buy-in and enable learning (as well as minimize mistakes) while implementing modifications to current industry practices.

A key step towards building robustness into capacity expansion planning is to embrace the concept of multiple plausible futures rather than planning for one possible (however well-justified) future. In practice, this could mean that electricity sector planners:

1. Develop scenarios of plausible climate change futures on the basis of projections from multiple climate models (without averaging). Consider that plausible futures may be more diverse than just low/medium/high climate change scenarios. (For example, of the 10 climate projections recommended for use in California, four labeled as “priority models” represent qualitatively different futures, including “warm/dry” and “cool/wet”, see [439].)

2. Develop combined scenarios where different climate futures are considered alongside scenarios that account for uncertainties in demand growth, market, policy, and technology options (see also [440]). Risk mitigation options (e.g., greater deployment of batteries, demand

response, operating reserves, and other strategies that contribute to system robustness) could also be included in combined scenarios.

3. Select several of these combined scenarios that may complement and/or form a plausible range when evaluated in conjunction with a median combined scenario.

4. Run capacity expansion models with a median and several range scenarios and evaluate investment needs for each.

5. For each set of calculated investment needs, assess how these investments would perform under all other scenarios to identify vulnerabilities in investment choices (i.e., evaluate the counterfactual impacts or unmitigated risks of planning for a lower demand and climate impact scenario if instead a higher demand and climate impact scenario is realized).

6. Evaluate thresholds for acceptable risks to how investments will perform and incorporate into planning decisions.

Planners may also consider identifying which uncertainties are most consequential to the outcomes of interest and using those as a feedback loop to identify dimensions to explore further with additional scenarios. Such an approach, while limited in the number of scenarios assessed, would still create measurable progress towards building climate awareness and working with irreducible uncertainties.

4.4.2 Incorporating adaptive planning principles into capacity expansion decisions

Ranges of plausible outcomes can be defined for a variety of uncertainties, and adaptive planning principles can be used to refine those ranges as the future evolves. To aid this effort, decision-makers should develop a monitoring plan with input from modelers and stakeholders to identify signposts that signal when we need to take certain actions or change our planning assumptions. Notably, such adaptive planning principles were considered, though not ultimately prescribed, for inclusion in a recent CPUC decision requiring California's investor-owned utilities to publish climate vulnerability assessments [441].

We offer three examples of signposts that could be applied to electricity sector planning in California:

1. When California's Sierra Nevada snowpack reaches $<$30% of historical baseline for 3 continuous years [442], stop counting on late summer hydropower resources in future models and deploy battery storage instead.

2. Define planning scenarios for low, medium, and high demand growth; if air conditioning adoption reaches $>$5% of households annually, know that we are in the high demand growth scenario.

3. If wintertime peak electricity use due to heating electrification hits >80% of summertime peak, know that we need to start evaluating climate scenarios for their impact on cold months.

We stress that these are just example criteria. While the specific implementations of these signposts will vary, the key concept here is that setting signals now can aid which plausible futures are assessed and which assumptions are made in capacity expansion models over time. Furthermore, there may be organizational barriers to incorporate and implement adaptive planning. Decision-makers may need to formalize this concept at the beginning of the planning process and provide institutional support to reduce resistance for the potential adaptive measures. For example, the decision-making entity may establish a working group with stakeholders and experts, assign specific personnel to gather and analyze the data, and build stakeholder consensus on the specific adaptive measures.

4.4.3 Multi-stakeholder engagement in capacity expansion

Capacity expansion planning for regulated utilities occurs within public rate cases that provide opportunities for stakeholder involvement. However, the complexity of growing climate impacts on utility operations will require increased attention on multi-stakeholder engagement as a tool to identify and refine uncertainties, plausible futures, and paths forward. Decision-making entities such as utilities and regulatory bodies could consult boundary organizations to translate technical climate science information and complex planning process between different stakeholders.

Broad stakeholder input and increased transparency is necessary at every step of the capacity expansion planning process:

1. Determining appropriate inputs (climate data, demand data, infrastructure data).
2. Identifying relevant uncertainties and appropriate numerical ranges for uncertain parameters.
3. Developing salient robustness metrics to evaluate different capacity expansion policy outcomes under a range of plausible climate futures.
4. Establishing consensus on planning goals.
5. Evaluating each policy alternative's performance for different objectives and discussing trade-offs among objectives.

Joint deliberation on how best to implement infrastructure plans must happen throughout the process in an iterative manner. At each step, key questions about the scope and mechanisms of stakeholder engagement efforts must be considered. For example: Who are the right set of participants to include, and how should conveners ensure they equitably represent necessary perspectives? Who will decide how stakeholder input should be weighted, resolve tensions, and balance the relative influence of different voices? What if some stakeholders do not want to engage and/or consensus is not possible? Further, what is the appropriate mechanism of and limits to stakeholder engagement, to ensure deliberations are not unduly sidetracked or prolonged at each step? These questions have

been more thoroughly explored in the water sector than in the electricity sector, and evidence exists that insights from this work are not necessarily transferable between resource contexts [391]. More foundational work is therefore needed here. Answering these questions is beyond the scope of the present review, but they merit additional focus in the context of climate-aware electricity sector planning.

4.5 Conclusions

Current planning processes in the electricity sector are not equipped to account for the stresses or uncertainties posed by a changing climate. Recent extreme weather events and service disruptions make it clear that climate change will continue to challenge electricity sector performance and operating practices. To better address these impacts, utility decision-making and planning approaches must incorporate a greater awareness of climate change and associated uncertainties. Here, we perform a three-part literature review to distill lessons from decision science researchers and assess how they might be incorporated into electricity sector planning to better account for the uncertainties posed by climate change.

First, we refer to the decision science literature to characterize climate-related uncertainties as shallow and deep uncertainties. This framework provides insights on how quantitative approaches may appropriately capture uncertainty. For example, shallow uncertainties (levels 1-3), where reasonable estimates of the relative likelihoods of different outcomes are possible, may be appropriately represented through probabilistic or trend-based scenarios. Deep uncertainties (levels 4-5), where multiple alternatives cannot be ranked by likelihood, cannot be reduced to statistical treatments.

Climate-induced uncertainties that must be considered in electricity sector planning include uncertainties in climate conditions as well as their direct and indirect impacts on electricity infrastructure, consumer behavior, and decision-maker responses. Efforts to characterize these uncertainties must consider complex interrelationships and deeply uncertain climate futures. Therefore, incorporating climate awareness into electricity sector planning will require making use of decision science practices that are equipped to handle deep uncertainty.

We distill three key ideas from decision science—robustness, adaptive planning, and multi-stakeholder engagement—that may help incorporate climate awareness into electricity sector planning and decision-making. Robustness requires considering multiple plausible futures and identifying planning approaches that perform acceptably well across them. Adaptive planning uses signposts and monitoring plans to refine plausible futures in time, building the institutional capacity to respond as climate conditions evolve. Multi-stakeholder engagement offers the potential to iteratively consider policy objectives and possible responses to adapt to new conditions, as well as to reconcile competing objectives.

Existing literature on electricity sector planning under climate change incorporates these key ideas to varying—but often only limited—degrees. However, existing tools that have been developed for use in the electricity sector, such as robust optimization and multi-stage modeling, can provide a scaffolding for implementing relevant insights from decision science.

Further, these three key ideas can guide action-oriented steps to build climate awareness in the electricity sector. We offer recommendations for how insights from these key ideas can be implemented within capacity expansion planning, a key area of decision-making in the electricity sector that is affected by all levels of uncertainty posed by climate change. Specifically, embracing the concept of multiple plausible futures, setting up signposts that signify tipping points as the future evolves, and including boundary organizations during stakeholder engagement can help electricity sector decision-makers better plan for the future.

Future work is needed to better connect lessons from decision science to industry practice. In particular, we suggest that social science research may provide insights on institutionalizing concepts of robustness and adaptive planning by decision-makers, and more effectively communicating uncertainty to and involving stakeholders in planning processes.

Climate change poses significant and ongoing challenges for critical infrastructure systems. Here, we offer some initial steps that can be taken today to help decision-makers incorporate climate awareness into electricity sector planning.

Conclusion

Electricity systems in the 21st century increasingly need to contend with stressors that challenge the performance and conventional operation of electricity infrastructure. These stressors include the need to rely on increasing amounts of renewable energy, to power extensive new loads, and to keep the lights on in the face of climate change. Through these stressors, electricity systems will be evaluated by policymakers, regulators, and the public on their ability to meet electricity demand safely, reliably, and cost-effectively, to operate sustainably, and to serve customers equitably.

In this context, making appropriate decisions about planning for the future requires bridging technical considerations and policy goals. This dissertation is structured around understanding how we might do so in two key areas of power system planning: (1) integrating new technologies and loads on electric distribution grids, and (2) adapting to climate change. Chapters 1 and 2 focused on the ability of electric distribution systems to accommodate growing demands from DERs and new loads and the potential consequences of existing grid limits. Chapters 3 and 4 focused on how climate change might impact electricity systems and the implications for existing planning processes. Here, I summarize the findings from each part of the dissertation, offer recommendations for next steps, and suggest areas for future research.

Summary of findings

Part 1: Electric distribution systems

The adoption of DERs and increased load electrification will place growing demands on electric distribution systems (Chapters 1 and 2). These demands will manifest as increased current flow through electrical lines and other equipment, which may surpass the technical limits of the local grid infrastructure. These technical limits, then, may inhibit progress towards policy goals related to DER growth, access and equity in DER adoption, and emissions reduction through widespread load electrification. Moving forward requires contending with the state of today's electricity distribution infrastructure and planning for how it will evolve as new demands are placed on the grid.

Some neighborhoods currently have lower per-household grid capacity for new DERs and load than others (Chapter 1). Today, utilities are making grid upgrades to accommodate projected growth in DERs and new load. Utilities will continue to make these grid upgrades as long as they are able to and as long as regulators permit them to charge upgrade costs to ratepayers. However, substantial and equitable expansion of DERs in California will require grid upgrades that

take time and money to implement, potentially raising rates. In the meantime, customers wishing to connect DERs to the grid may face interconnection delays. Lower estimates of per-household hosting capacity for new DERs in Black-identifying and disadvantaged communities suggest that these communities may disproportionately face costly interconnection delays and other hurdles in adopting DERs (Chapter 1).

Widespread adoption of EVs and residential space and water heating electrification will also stress the distribution grid and necessitate circuit and substation upgrades (Chapter 2). Substantial upgrades are needed under all scenarios considered that combine EV charging and residential electrification demands in 2030, 2040, and 2050. Projections of hourly electricity demand from these new loads indicate that the rate of needed circuit upgrades under all electrification scenarios would outpace PG&E's current projected rate of upgrade projects. Given existing equipment and workforce shortages in the electric utility sector, this raises questions about the PG&E's ability to complete these upgrades in time. While the projected costs of these upgrades do not at first seem to indicate significant financial barriers to making distribution upgrades, scarcity concerns have the potential to increase these costs beyond our ability to project them based on existing cost trends. Distributed solar, in the absence of storage, does not significantly reduce the upgrades needed. It does, however, make the biggest relative impact on upgrade needs due to commercial daytime charging.

Part 2: Climate change adaptation

Climate change will have widespread impacts on electricity systems (Chapter 3). These impacts will make it more difficult for generating resources to produce electricity and for electrical lines to deliver power to where it is needed. Climate change impacts will make the day-to-day operation of the grid more challenging, and increase the severity of disruptions when they occur. These impacts will also make it more difficult to maintain existing infrastructure and plan for new investments. The numerous ways in which external weather conditions affect electricity systems and the interconnectedness of the grid make it extremely difficult to account for and mitigate against all possible scenarios.

Instead, practitioners must critically re-evaluate planning processes in the electricity sector to incorporate appropriate consideration of uncertainty (Chapters 3 and 4). Existing industry planning processes operate in predict-then-act mode, which focuses on developing a projected 'likely' future and planning investments and operations to serve electricity demand under those conditions. Researchers studying the electricity sector make extensive use of scenario planning, in which several options are selected for key parameters (e.g., demand growth, technology adoption, climate impact severity, etc.) and paths forward are documented for each. However, the complexity of uncertainties in both climate change and its impacts on the electricity sector mean that appropriate consideration of uncertainty and possible futures requires methods that are capable of accounting for deep uncertainty (Chapter 4).

Decision science researchers offer three key approaches for how we might appropriately account for deep uncertainty in long-term infrastructure planning (Chapter 4). These approaches—robustness, adaptive planning, and multi-stakeholder engagement—can guide paths forward in the

electricity sector. Robustness requires considering multiple plausible futures, understanding the investment needs that would be required for each, and evaluating the performance and vulnerabilities of possible paths forward in the alternative futures. Adaptive planning focuses on developing the institutional capacity to adapt to an evolving future by establishing signposts and monitoring plans to guide appropriate treatment of uncertainties over time. Multi-stakeholder engagement offers the opportunity to learn from the knowledge of many parties to develop nuanced scenarios and policy objectives. These should include stakeholders who are directly affected by the consequences of climate change on electricity system, as well as those whose expertise is relevant to the wide-ranging issues at hand. Together, these approaches offer guidance for how electricity sector decision-makers can begin to make the best decisions possible today in the face of the deeply uncertain consequences of climate change.

Recommendations and areas for future research

This dissertation discusses recommendations that emerge from the two parts of this dissertation separately. Chapters 1 and 2 in Part 1 of the dissertation, focused on electric distribution systems, employ quantitative tools and are structured to report on the results of those analyses. These chapters incorporate relatively limited discussion of recommendations, so we provide more extensive thoughts here. Chapters 3 and 4 in Part 2 of the dissertation, focused on climate change adaptation, employ qualitative review methods and conclude with recommendations for next steps. The recommendations listed here for Part 2 summarize those discussed in Chapter 4.

Part 1: Electric distribution systems

1. Assessing potential value streams for distributed energy resources

In California, the CPUC has set the goal of maximizing ratepayer and societal value of a high-DER future [43] while integrating equity and access considerations throughout its activities [1]. These goals motivate a critical evaluation of the value that is being realized by DER deployment today [47, 48]. We posit that as long as ratepayer-funded investments are required to realize a high-DER future, policies relevant to DER deployment should focus on maximizing DER value and distributing DER benefits more equitably among ratepayers.

Possible DER benefits beyond clean electricity include financial savings, grid support, and resiliency. Due to the existing subsidy and market structure in California, these benefits are currently being realized in a relatively limited way. Financial benefits are set by rate structures and compensation mechanisms such as net energy metering for rooftop solar, from which bill savings accrue predominantly to single-family homeowners. Resiliency benefits may also accrue individually to solar adopters if they elect to add storage, but such combinations have seen limited uptake under current policies. Grid support benefits could come from careful siting and sizing of solar and storage, but opportunities to realize those benefits are missed when incentives for individuals to participate necessitate installation at a specific location (e.g., their home or business).

Realizing economic, resiliency and grid support benefits *for society* requires rethinking California's approach to DERs. Importantly, equity and grid constraint issues arise because today's policies and market structure make access to DERs specific to the location of one's home and the circuit to which it is connected. Enabling options for community-scale DERs, such as community solar, can create opportunities for more equitable participation and increased value to the distribution grid. For example, community solar arrays can be sited in locations that make sense for the grid, can be sized in ways that leverage economies of scale, and those who can't host solar at their physical location can still receive the benefits of participation as credits on their electricity bills [49].

Moreover, community-scale resources also enable opportunities for developing new value streams. For example, co-sited community-scale solar and storage can help keep the power on during a grid outage at a community-accessible site. This would enable residents affected by wildfire-related power shutoff events and other service disruptions to charge electronics and receive critical services. Such projects could further serve as anchors for future community-level microgrids that could isolate from the larger grid in such situations.

Going forward, it is critical to consider the full range of possible DER value in the context of grid limits and upgrades as well as policies tied to equitability, DER adoption, and decarbonization.

For policymakers: California's rules for behind-the-meter solar PV limit compensation to single site-specific arrays or shared arrays for properties with multiple tenants. Removing site constraints from these policies, or, alternatively, developing and enacting new compensation structures that incentivize added value streams from community-scale DER resources is a critical step towards enabling value from DERs to reach ratepayers more equitably. (For more, see [47, 48].)

For researchers: Documenting and quantifying potential DER value streams is a necessary step towards setting appropriate compensation and incentive structures through policy. Such efforts are not new: a plethora of value of solar studies exist, and California's Avoided Cost Calculator is an important step towards incorporating different value streams into planning and decision-making [443]. However, more attention is needed to understand the role of grid constraints and to critically evaluate how DER programs might be structured to realize additional societal benefits—in particular, grid support and resiliency benefits—from DERs.

2. Enabling the grid to serve new load

Electrification goals raise questions about the pace of needed upgrades and whether utilities will be able to complete them given equipment and workforce shortages. Realizing emissions reductions through electrification therefore requires exploring alternative options to conventional grid upgrades. DERs may be able to aid in this effort: for example, targeted deployment of solar plus storage may be able to serve local electricity needs. A community-scale approach also creates the potential for more managed optimization of smart inverter functionality, co-located storage, and perhaps even electric vehicle charging to support the grid locally. These tools could help provide ways forward as electricity demands due to increasing electrification surpass what existing infrastructure can handle.

For policymakers: California is taking steps to incorporate demand projections due to electrification into electricity planning processes. However, additional attention is needed on what it will take to upgrade the grid to accommodate these demands, including to what extent utilities will need to plan ahead for these investments. In particular, additional attention is needed on equipment and workforce availability, which are both critically necessary to implementing these investments. Investments in workforce development, potentially at California's technical colleges, should be explored.

For researchers: More research is merited on the potential of targeted DER solutions to mitigate grid upgrade needs, including solar plus storage, demand response, and community-scale solutions.

Separately, the prospect of a bottleneck for grid upgrades due to equipment and workforce shortages deserves additional attention. More research is needed on potential scarcity both in electrical equipment and labor, and the practical and cost implications of these potential bottlenecks.

3. Extending distribution grid analyses beyond California

Detailed analyses of distribution system limits should be an input into electricity sector planning processes wherever the widespread adoption of DERs and/or electrification is being considered.

For policymakers: A key resource used in the analyses discussed here is publicly-accessible and downloadable granular distribution system data that includes estimates of hosting capacity for new generation and load. Such data are now available and under development in more locations [42], but additional attention is needed to ensure that it is accurate and suitable for use in detailed policy-relevant analyses to plan for the future.

For researchers: Distribution system hosting capacity and anticipated electrification loads might well vary in other regions. Detailed analyses of regional characteristics and electrical infrastructure are necessary to review the extent to which distribution grids may pose barriers to policy goals in locations beyond California.

4. Evaluating grid resiliency and community resources in a new climate future

Rising temperatures will reduce the ability of electrical lines and other equipment to deliver electricity [e.g., 110, 262]. This raises concerns about line congestion and additional upgrade needs to accommodate increased cooling loads—in addition to load growth more generally—in an era of climate change.

For researchers: Additional research is warranted on the extent to which climate change impacts will increase transmission congestion and further constrain local distribution systems. Such analyses should consider the grid's ability to serve new loads and the implications for the value of locally-sited DERs, including potential community resilience resources.

Part 2: Climate change adaptation

5. Incorporating robustness into expansion planning models

Existing capacity expansion planning practices rely on developing a 'likely' future and planning investments to serve load in that future. Moving forward, electricity sector decision-makers must account for a wide range of plausible future scenarios (for more, see Chapter 4).

For policymakers: Planning efforts that explicitly account for multiple scenarios of plausible futures should be initiated. Such efforts must incorporate the additional step of evaluating vulnerabilities of investment pathways against the other plausible futures.

For researchers: Work is needed to propose models and ranges of assumptions for climate projections, demand growth, market and technology assumptions, and risk mitigation options (e.g., storage, demand response, etc.) that are appropriate to capture a wide range of plausible scenarios for how the future may evolve. Further, potential vulnerabilities and performance metrics should be documented for investment options for all scenarios.

6. Developing the capacity to support adaptive planning

As the future evolves, we will obtain more information about how climate impacts will affect electricity systems. As insights become available we must incorporate them into institutional planning to provide appropriate signals to decision-makers and other actors to prepare (for more, see Chapter 4).

For policymakers: Electricity sector planning and decision-making processes must be adapted to incorporate space for documenting climate impacts and tracking signposts. As the nature of impacts becomes clearer, such monitoring must translate into responding: adapting flexible plans to account for new climate realities.

For researchers: Work is needed to propose possible signposts relevant to electricity system planning that are regionally-appropriate. These may take the form of updated assumptions in planning models when specific climate impacts are felt on an ongoing basis (for examples, see Chapter 4).

7. Utilizing learning from many stakeholders to develop paths forward

Significant modifications to electricity sector planning processes are needed; appropriately implementing these will require consulting affected stakeholders and others with wide ranges of expertise (for more, see Chapter 4). For example, insights from climate scientists, economists and sociologists who study long-term population trends and behavior, and emergency response personnel must all be included in planning for the future.

For policymakers: Stakeholder voices from a variety of organizations and perspectives must have a voice in planning processes. These perspectives are needed to help determine appropriate

inputs into planning models, identify relevant uncertainties, and develop vulnerability and performance metrics. Moreover, stakeholders must help assess policy alternatives' performance and tradeoffs among performance objectives.

For researchers: An immeasurable amount of new knowledge is needed to identify and incorporate the wide range of planning uncertainties. Work is needed to understand which uncertainties may be relevant and which stakeholder perspectives are needed to account for them. Moreover, it will be critical to supplement multi-stakeholder engagement with boundary-spanner organizations or individuals that can help translate insights between fields in ways that help enable the implementation of pragmatic recommendations into complex planning processes.

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Appendix A

Chapter 1 Appendix

A.1 Growth in DERs raises issues for equity and the grid (cont.)

A.1.1 Hosting capacity methodologies

Concerns about potential DER impacts on distribution systems have led system operators to set locational penetration limits for distributed PV: these range from rough rule-of-thumb estimates of allowed capacity in a given location [77] to rigorous modeling studies of how much new generation can be accommodated on a specific line without adverse impacts [78, 79].

In calculating the hosting capacity available on distribution circuits for DERs, researchers have considered constraints that include voltage, thermal overloads, protection impacts, power losses, power quality, and reverse power flow [34, 97, 98]. In some cases, methodologies may also evaluate the potential to increase hosting capacity through added mechanisms such as active power curtailment, reactive power injections, voltage control, energy storage, and circuit reconfiguration [97].

Calculation methodologies themselves may fall into several categories: (1) analytic (also referred to as deterministic) assessments that iteratively increase DER capacity on feeder sections and check for constraint issues, (2) stochastic assessments that use scenario analyses to simulate uncertainties in DER impacts, (3) streamlined assessments that use simplified screens to examine the need for more complex studies, and (4) optimization assessments that aim to maximize hosting capacity [34, 97, 98].

In California, PG&E and SCE currently use analytic and streamlined methodologies, respectively, that account for voltage, thermal, protection, and reverse power flow considerations (for generation) and voltage and thermal considerations (for load) but do not internalize methods to increase hosting capacity [45, 97]. Both utilities use a locational approach to calculating circuit hosting capacity, in which new DERs can be accepted on some portions of the circuit but not others.

A.1.2 Hosting capacity maps in California

To help facilitate DER deployment, the California Legislature and the California Public Utilities Commission have required the state's IOUs to publish territory maps of feeder-level hosting capacity since 2015 [41, 444]. Over time, the estimates contained therein have been refined with input from experts and stakeholder working groups. Data development has focused on generation, with generation results reported for two technology categories: (1) generation that follows a PV production profile and (2) uniform generation, which is modeled to produce the same amount of energy at all hours of the day.

Values for PV and uniform generation are further presented in two cases: (1) the technical maximum capacity the circuit can accommodate without violating thermal, power quality, or protection grid constraints irrespective of power flow direction, and (2) the maximum without reverse power flow beyond the substation bus for any potential configuration of downstream circuit line connections. The latter is referred to as the "operational flexibility" (OpFlex) case, which aims to satisfy a fourth system constraint—safety/reliability—by allowing operators to safely reconfigure circuit lines (e.g., in the case of an outage). We focus here on PV and discuss results for both the OpFlex and non-OpFlex case.

Values for hosting capacity for new load are also available in these maps, and are calculated only considering thermal and voltage constraints. Protection and operational flexibility constraints are not considered when determining load hosting capacity.

A.1.3 State of California goals for DER deployment

California has set ambitious goals to deploy 5 million EVs by 2030 and to reach 100 percent clean energy and a carbon-neutral economy by 2045, which it expects to meet with the help of significant renewables deployment and electrification of fossil fuel heating loads. At the end of 2019, California was home to 35 percent of PV capacity [445, 446] and 49 percent of light-duty EVs in the U.S. [447].

Here, we comment on the technical limits for DERs as indicated by ICA maps, the social implications of differential access, and the potential ramifications of these factors for continuing DER deployment in the state. We focus our discussion on behind-the-meter solar photovoltaics (PV) and, to a lesser extent, electric vehicles (EVs) and demand growth from residential load electrification and air conditioning.

A.2 Grid limits reduce access to DERs across utility territories (cont.)

In addition to the PV results reported in the main text, we find that in all cases, fewer households have access to uniform generation than to equivalent amounts of PV (Supplementary Figures A.1 and A.2). This is expected, as allowable hosting capacity for uniform generation is set by the most

limiting hour at any time of day, but PV hosting capacity is set by the most limiting hour of power production that follows a PV generation profile [45].

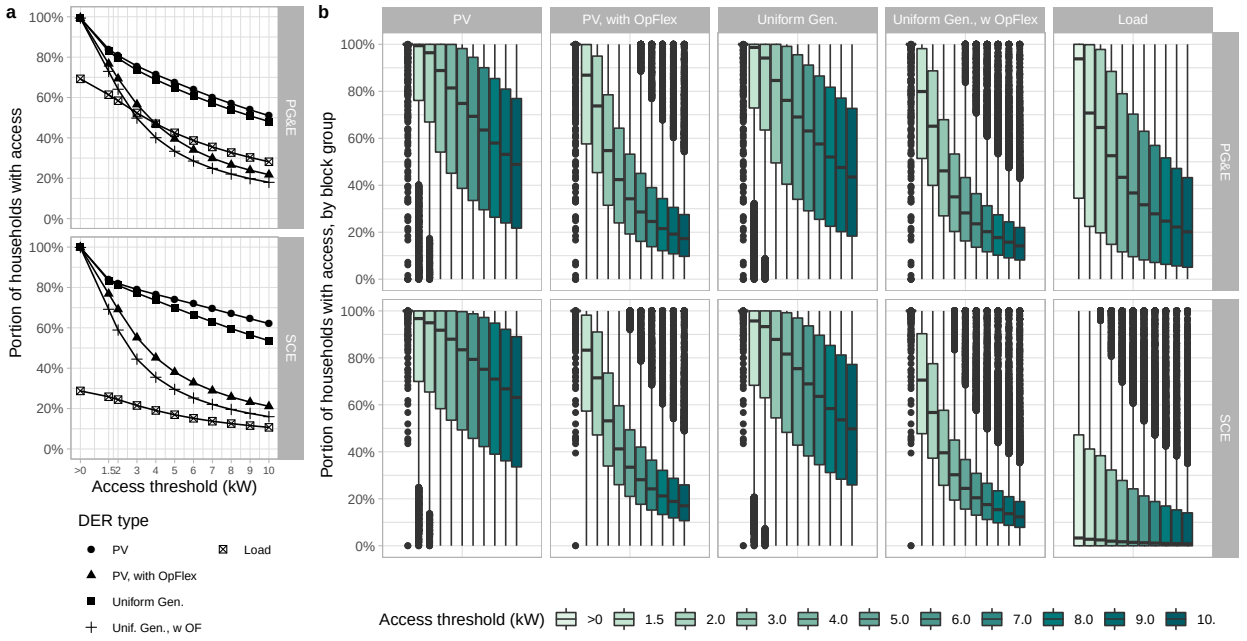


Figure A.1: Results for remaining and existing household access to the five DER types included in PG&E and SCE ICA data. Generation (PV and uniform generation) DERs incorporate existing generation capacity and remaining hosting capacity. Load results consider remaining hosting capacity only. (a) summarizes the results for all households within the respective utility territory. (b) shows boxplots of hosting capacity at different access thresholds for each census block group included in the data.

Table A.1: Results for households with access (%) in PG&E and SCE utility territories, considering remaining and existing hosting capacity, selected results presented alongside Supplementary Figure A.1.

DER		PV			PV, with OpFlex			Uniform Gen.			Uniform Gen., with OpFlex			Load			
Access threshold (kW/hh)		1.5	4.5	10	1.5	4.5	10	1.5	4.5	10	1.5	4.5	10	>0	1.5	4.5	10
PG&E full territory		84	69	51	77	43	22	83	67	48	73	36	18	69	61	45	28
Blk grp	75th pctl	100	99	77	100	58	28	100	98	73	98	48	22	100	100	74	43
	median	99	78	49	87	38	17	99	73	44	80	31	14	94	71	40	20
	25th pctl	76	41	22	58	21	10	73	37	18	51	18	8	34	22	10	5
SCE full territory		84	75	62	77	41	21	83	72	54	69	32	16	29	26	18	11
Blk grp	75th pctl	100	100	89	98	54	26	100	98	77	90	40	19	47	41	26	14
	median	97	86	63	83	37	17	96	79	50	71	27	12	3	3	2	1
	25th pctl	70	51	34	57	23	11	68	45	26	48	17	8	0	0	0	0

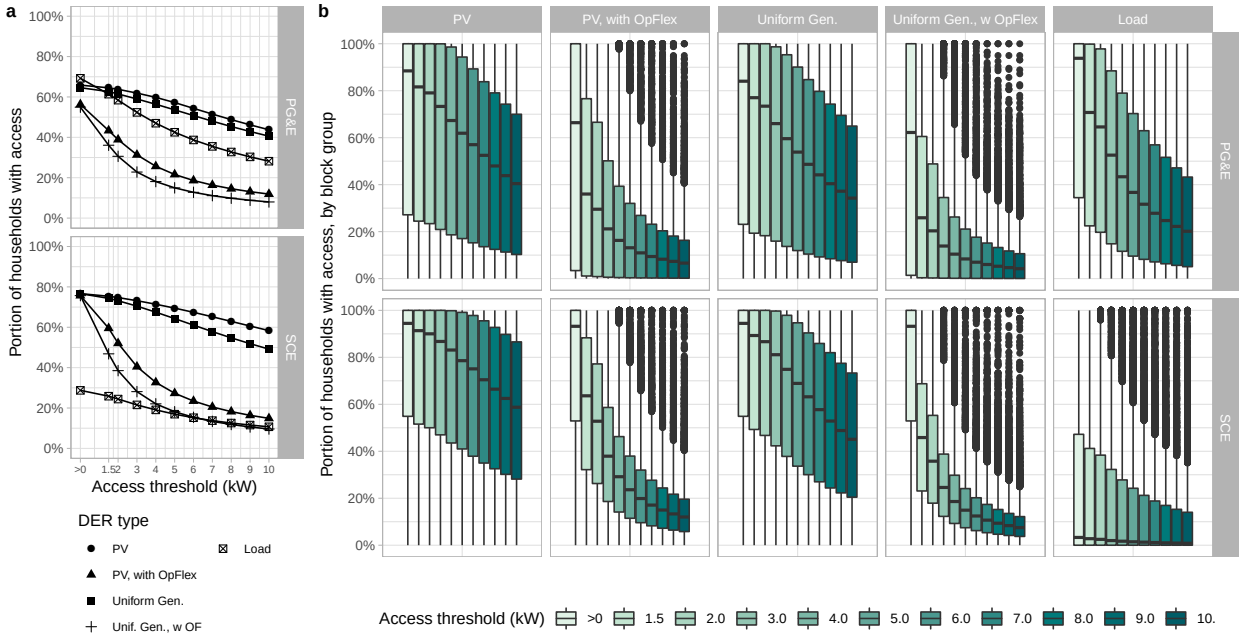


Figure A.2: Results for remaining household access to all five DER types included in PG&E and SCE ICA data. Results for all DERs consider household access to remaining hosting capacity only. (a) summarizes the results for all households within the respective utility territory. (b) shows boxplots of hosting capacity at different access thresholds for each census block group included in the data.

Table A.2: Results for households with access (%) in PG&E and SCE utility territories, considering remaining hosting capacity only, selected results presented alongside Supplementary Figure A.2.

DER		PV			PV, with OpFlex			Uniform Gen.			Uniform Gen., with OpFlex			Load			
Access threshold (kW/hh)		1.5	4.5	10	1.5	4.5	10	1.5	4.5	10	1.5	4.5	10	>0	1.5	4.5	10
PG&E full territory		65	59	44	43	23	12	63	55	41	36	16	8	69	61	45	28
Blk grp	75th pctl	100	97	70	77	35	16	100	93	65	61	23	11	100	100	74	43
	median	82	65	40	36	15	7	77	57	34	26	9	4	94	71	40	20
	25th pctl	24	18	10	1	0	0	19	13	7	0	0	0	34	22	10	5
SCE full territory		75	70	58	60	30	15	74	66	49	47	20	10	29	26	18	11
Blk grp	75th pctl	100	100	87	88	42	20	100	96	73	69	27	12	47	41	26	14
	median	91	81	59	64	26	12	89	72	45	46	17	8	3	3	2	1
	25th pctl	52	42	28	32	13	6	49	36	20	23	8	4	0	0	0	0

Table A.3: Results for households with access (%) to PV in PG&E and SCE utility territories, considering remaining and existing hosting capacity with building suitability limits [105, 448] as well as grid limits (alone, and combined with predicted building suitability). Selected values from Figure 1.3.

DER	Rooftop PV building suitability			PV			PV, with OpFlex		
Suitability at 1.5 kW/hh access threshold	*Lower 95% conf.int.*	Prediction	*Upper 95% conf.int.*	Grid only	Comb. best-case	Comb. worst-case	Grid only	Comb. best-case	Comb. worst-case
PG&E full terr.	*63*	85	*99*	84	73	70	77	68	62
Blk grp, 75th pctl	-	87	-	100	86	86	100	84	83
Blk grp, median	-	85	-	99	82	81	87	77	71
Blk grp, 25th pctl	-	83	-	76	68	60	58	55	42
SCE full territory	*80*	91	*96*	84	77	75	77	72	68
Blk grp, 75th pctl	-	94	-	100	92	92	98	89	88
Blk grp, median	-	91	-	97	86	86	83	78	74
Blk grp, 25th pctl	-	89	-	70	65	61	57	55	48

A.3 Grid limits reinforce demographic disparities in DER access (cont.)

We construct linear and nonlinear models to understand which variables, if any, may correlate to per-household hosting capacity. The random forest models are performed on four groups of independent variables: (1) all variables, (2) infrastructure variables, (3) service and geographic variables, and (4) demographic variables. All variables included in each group are described in detail in Supplementary Tables A.6, A.7, and A.8.

We find the best performance in nonlinear random forest models constructed with all features or service features, followed by models using only infrastructure and demographic features with household density (Supplementary Figure A.3). Household density has an overall negative correlation with hosting capacity and significantly dominates over the remaining demographic features.

Omitting household density, we find that no single demographic feature dominates in relative importance over the rest. The descriptive power of these models therefore draws from nonlinear combinations of the demographic features, which supports previous findings that demographic features are more useful in aggregate than independently [72]. While this feature set yields the poorest error metrics, these nonlinear models nonetheless classify with over 80% accuracy.

Feature importance results indicate that the total number of households on a circuit (`tothh_ctot`) is consistently the most important feature in models constructed with all variables or service variables. Although the linear and logistic regression models indicate an overall negative correlation between `tothh_ctot` and hosting capacity, this feature was not as significant in the linear or logistic regressions, indicating the presence of nonlinear relationships.

Among infrastructure features, the total circuit length (`Length_m_ctot`) and circuit line segment length (`Length_m`) dominate. In particular, they significantly overshadow nominal circuit voltage (`CircVolt_kV`) in importance. While voltage is often thought of as an important infrastructure characteristic when determining how much solar part of a circuit can accommodate, we

note that voltage values used here are for the backbone of the feeder, and do not differentiate between primary and lateral lines.

Household density (`hhdensity`) dominates among demographic features, and no features dominate in these runs when it is removed. When the four most dominant features—`tothh_ctot`, `Length_m_ctot`, `Length_m`, and `hhdensity`—are included in our random forest classification models, the accuracy is greater than 95%.

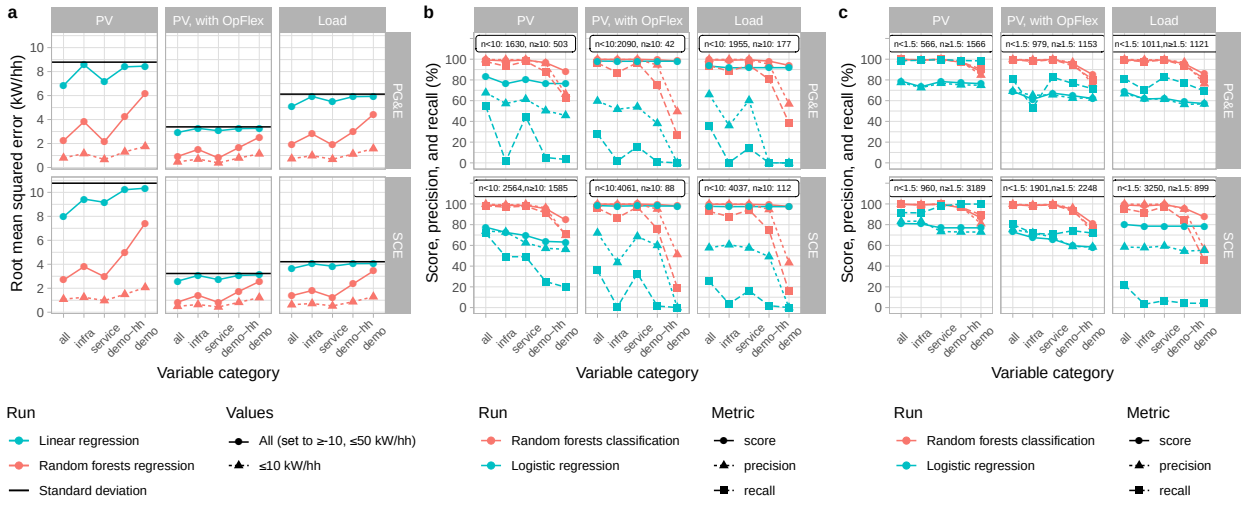


Figure A.3: Error metrics for linear and nonlinear models. Linear regression and random forest regression error metrics in (a), and logistic regression and random forest classification error metrics in (b) and (c). Regression models in (a) test whether we can describe the per-household hosting capacity in each circuit polygon on the basis of associated variables (Supplementary Section A.3). Classifier models test if we can define criteria via these variables that indicate whether the per-household hosting capacity is greater than or equal to (b) a 10 kW/hh threshold or (c) a 1.5 kW/hh threshold. See Methods for a discussion of how these thresholds were selected. Lines are drawn only as guides for the eye. Results indicate that linear and logistic models are unable to capture hosting capacity variability in the data: linear regression RMSEs plateau at the standard deviation of the data, and logistic regression precision and recall values are unsuitably low. Random forest models for both regression and classification show better results, indicating the presence of nonlinear patterns. Low precision and recall values are limited to cases where the data is highly imbalanced (e.g., significantly more households fall below the 10 kW access threshold than above).

A.4 Supplementary methods

A.4.1 Residential households are matched to distribution circuits (cont.)

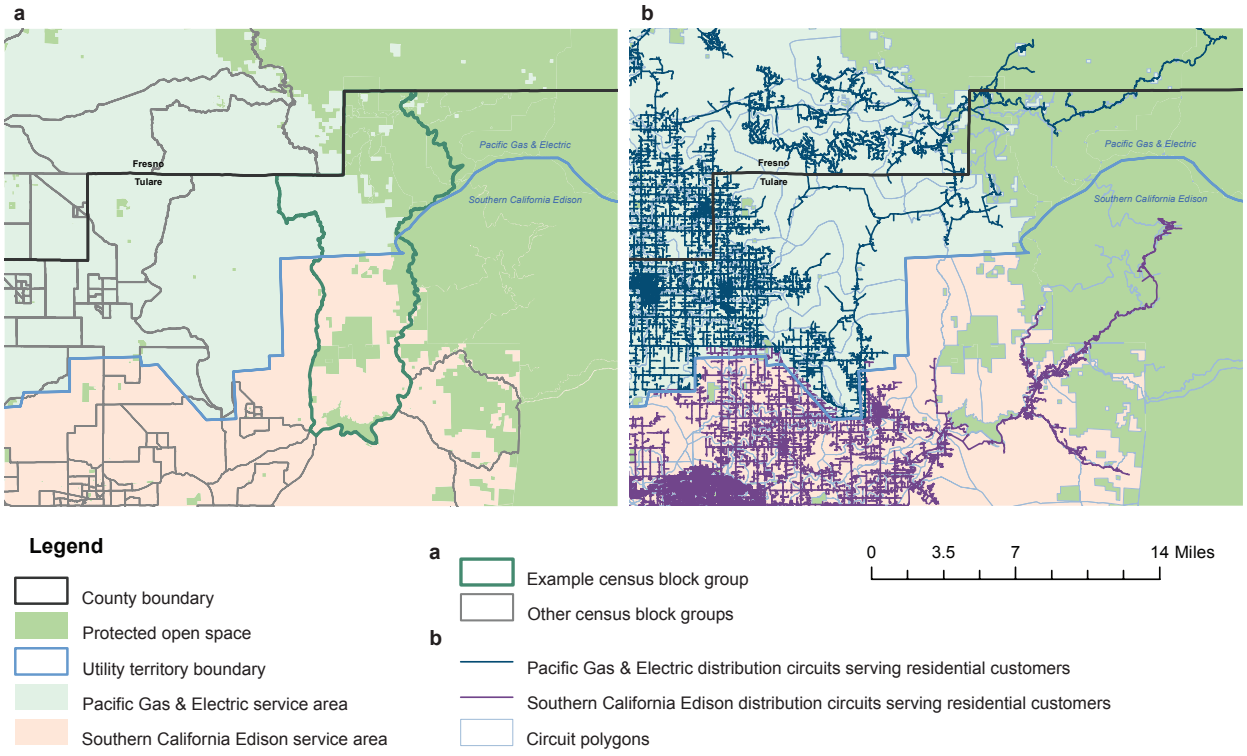


Figure A.4: Example of our spatial allocation process. We consider (a) a census block group located in Tulare County, on the border with Fresno County (green outline). This block group is home to 257 households and occupies 411 km^2, of which 188 km^2 are protected open space, including parks and wilderness areas (in green), and 223 km^2 (54.4%), are estimated to be potentially-inhabited. Of the potentially-inhabited areas, approximately 87.6 km^2 (39.2%), fall within PG&E's territory (blue), and 135.8 km^2 (60.8%), fall within SCE's territory (pink). We therefore assume that PG&E and SCE respectively serve 101 (39.2%) and 156 (60.8%) of its residential households. (b) We now overlay distribution circuit lines owned by PG&E (blue) and SCE (purple) that serve this area, and subdivide the area into 'circuit polygons' that describe unique combinations of estimated circuit service areas and census block groups.

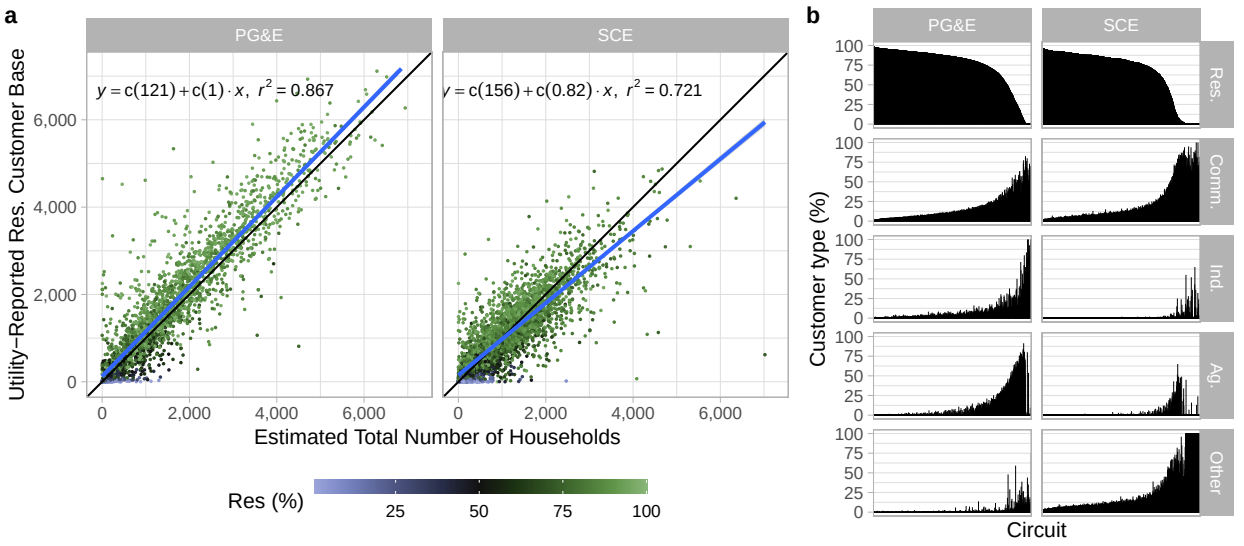


Figure A.5: Customers served by PG&E and SCE circuits. (a) Comparison of our estimate for the number of households served by a given circuit (x axis) and each utility's reported residential customer base (y axis). PG&E's values are provided in ICA data [116] and SCE's values are calculated from [449] and [117]. The x=y lines are shown in black, and the lines of best fit in blue. Bar charts in (b) compare customer distributions by circuit, sorted in descending order by percentage of residential customers.

A.4.2 Hosting capacity is spatially allocated to households (cont.)

A.4.2.1 Differences in reported circuit data by utility

For SCE, all 1-, 2-, and 3-phase line segments are used to estimate where SCE customers connect to the grid, and we assume that households connecting to 1- and 2-phase lines inherit the hosting capacity of 3-phase lines that fall within the same circuit polygon by the process described below. Fewer than 1% of households are estimated to connect to 1- and 2-phase lines that form circuit polygons without 3-phase ICA information.

PG&E provides ICA information for some 3-phase circuit segments, while others are reported to have an 'incomplete solution set' [116]. However, the line geography for these circuits is provided alongside that of single-phase lines, for which ICA information is not calculated. Therefore, we cannot distinguish single-phase lines from 3-phase lines with missing data. All line segments are used to estimate where customers connect to the grid, but the rest of our PG&E results only pertain to the estimated service areas of 3-phase lines with data.

A.4.2.2 Customer demographics by utility

Supplementary Figure A.6 shows the distribution of demographic indicators for households located in the portions of PG&E's territory where ICA data is available, anywhere in PG&E's territory, and in SCE's territory. Allowable values of the demographic indicators are shown on the y axis

(see Supplementary Section A.4.4) and the relative density of households with those demographic values is on the x axis.

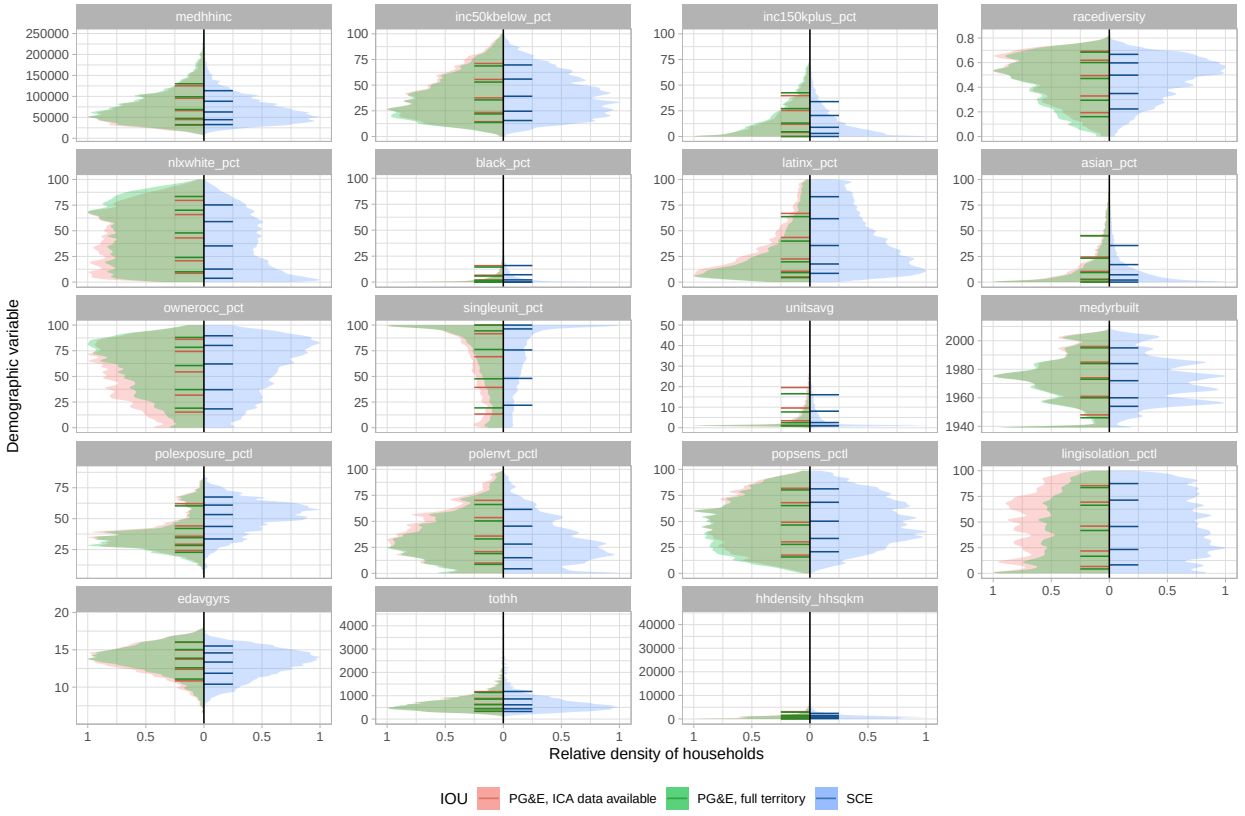


Figure A.6: Distribution of demographic indicators for households served by PG&E and SCE. Descriptions of the demographic indicators used here are available in Supplementary Section A.4.4. Distributions are drawn as scaled density estimates (a smooth version of the histogram for continuous data), with bandwidth set to 1/2 the standard deviation of the Gaussian kernel. Lines indicate the values at the 10th, 25th, 50th, 75th, and 90th percentiles for each indicator and IOU.

There are some differences in the distribution of demographic indicators between households served by the two utilities. Relative to PG&E, SCE has a higher proportion of Latinx customers and fewer non-Latinx white customers, and a higher proportion of households located in California census tracts at higher percentiles of pollution exposure. Smaller, but still notable, differences between the two IOUs are evident in income distributions (SCE has a greater share of households with annual incomes below $50k and a smaller share of households with annual incomes above $150k) and housing types (SCE has more owner-occupied, single-unit housing). Additionally, a greater portion of households served by SCE have lower educational attainments and more sensitive populations.

The distribution of demographic indicators is broadly similar in the portions of PG&E's territory with ICA data and in the full PG&E territory. However, we do see that the portions of PG&E's

territory with ICA data are relatively less white- and more Latinx-identifying, have greater linguistic isolation, and relatively fewer owner-occupied, single-unit households.

A.4.2.3 Available circuit hosting capacity is allocated to residential households by service location

Table A.4: Calculated remaining PV hosting capacity values (without operational flexibility constraints) by circuit polygon for an example SCE circuit, Academy, located near the city of Thousand Oaks in Ventura County. The maximum hosting capacity varies dramatically across the circuit, from 0 to 32 MW. (Circuit polygon 7, with 0 MW assigned hosting capacity, is created by two-phase circuit lines only and therefore lacks ICA information.) Using the circuit polygon-level maximum values directly would over-count the total circuit hosting capacity (74 MW versus 32 MW). Circuit polygons 1, 4, 5, and 6 account for almost all of the circuit length, and polygons 4, 5, and 6 for almost all of the households served. However, weighting hosting capacity just by households served would under-count the total maximum hosting capacity on the circuit (10 versus 32 MW). The normalization factor is a ratio of these two values (3.56 here, see Eq.1.9) and brings the total circuit-level hosting capacity back to its original value. However, it severely over-counts the allowable hosting capacity in circuit polygon 4. Therefore, we adjust this value back to its original maximum. The final per-household hosting capacity values show that there is between 0 and 131 kW of available grid capacity to host PV on this circuit, depending on where a household is located. (Minor discrepancies in totals may exist due to rounding.)

Cpoly	ICPV_max (MW)		Length_Cpoly		tothh_Cpoly		ICPV_max (MW) (Eqs.1.8, 1.9, & 1.10)			ICPV (kW/hh)
	_Cpoly	_ctot	(m)	(%)	n	(%)	_hhWt	_hhWt_n	_hhWt_nadj	(Eq.1.12)
1	32	32	5,061	14	14	2	1	2	2	131
2	3	32	435	1	0	0	0	0	0	14
3	9	32	172	0	0	0	0	0	0	36
4	9	32	12,881	37	487	56	5	17	9	18
5	9	32	7,973	23	158	18	2	6	6	35
6	9	32	7,039	20	202	23	2	7	7	36
7	0	32	762	2	1	0	0	0	0	0
8	3	32	683	2	14	2	0	0	0	14
Total	74	-	35,006	100	876	100	10	32	24	-

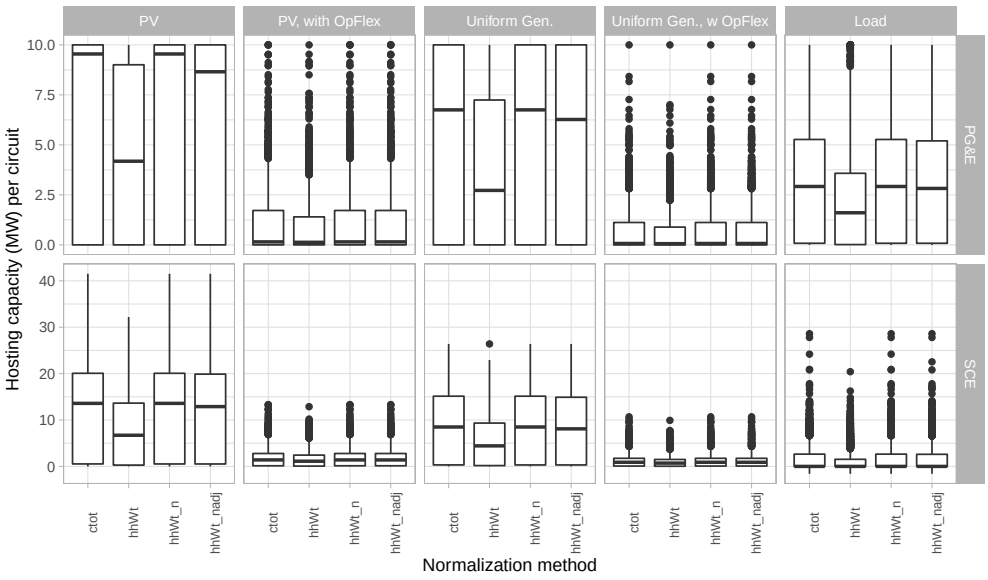


Figure A.7: Visualization of calculation process for allocating total remaining circuit hosting capacity. Boxplots show total remaining circuit hosting capacity for the five different DER types studied across all circuits in each IOU's territory, under the calculation approaches described in Equations 1.8-1.10 and Supplementary Table A.4. Weighting by households served lowers circuit-level hosting capacity, while normalization produces boxplots equivalent to the original values. Adjusting the normalized values on a small number of circuits slightly reduces some values relative to original totals but produces boxplots relatively close to the original. Note: PG&E caps its own hosting capacity values at 10 MW per circuit.

A.4.3 Households need kilowatts of circuit capacity for DER access (cont.)

A.4.3.1 Solar PV systems

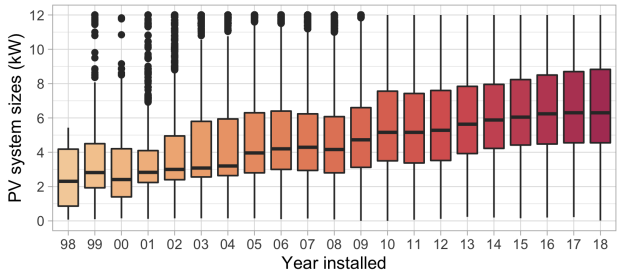


Figure A.8: Boxplots of residential PV system sizes (capped at 12 kW) in the U.S. by installation year [119].

A.4.3.2 Load electrification and air conditioning

The power demanded by electrification technologies and air conditioners varies by time and location. Here, we seek to estimate the maximum amount these technologies may contribute to

household loads, on average across the state.

On average, water and space heating respectively account for 49 and 37% of California households' annual consumption of natural gas, which is currently the dominant fuel for water and space heating [124]. New technologies for electrified water and space heating are more efficient than their natural gas counterparts: electric heat pumps have average annual coefficients of performance (COP)—a measure of heating output to electricity input—around 3 [143, 450].

Air conditioning loads vary by region across the state of California. Annual energy consumption from central air conditioning ranges between 40-1,189 kWh per household in PG&E's territory and between 382-1,318 kWh per household in SCE's territory [124]. Overall, central air conditioning units consume on average 766 kWh of electricity per year across the state [124].

To calculate the instantaneous demand from electrified space and water heaters and air conditioners, we combine information about average annual household natural gas and electricity consumption in California [124] with E3's hourly load profiles [125]. E3 load profiles report instantaneous (hourly) demand values for a variety of end uses as a fraction of total annual demand.

We use these values in Supplementary Equations A.1 and A.2 to find the maximum instantaneous power demand from electric heat pumps and air conditioning. Values used in these calculations are found in Supplementary Table A.5. When all climate strategies are taken into account, each household's load may increase by up to 10 kW—7 kW for level 2 EV charging (see Methods), 0.6 kW for water heating, and 1 kW for space heating or 2 kW for air conditioning—assuming space heaters and air conditioners never run simultaneously.

$$\texttt{demand}_{hp}(kW) = \frac{\texttt{annual\_cons}(therms/yr) \times 29.3(kWh/therm) \times \texttt{hp\_cons}(\%) \times \texttt{max\_demand}}{\texttt{COP}} \tag{A.1}$$

$$\texttt{demand}_{AC}(kW) = \texttt{annual\_cons}(kWh/yr) \times \texttt{max\_demand} \tag{A.2}$$

Table A.5: Calculating estimates for load DER demand.

Conventional source	Total annual household consumption [124]	End use	Portion of annual household natural gas consumption	Annual household consumption		COP	Maximum hourly demand [125] (Fraction of annual)	Estimated peak demand (kW)
				therms	kWh			
Natural gas	354 therms*	Space heating	37%	130.98	3837.7	3	0.000816	1
		Water heating	49%	173.46	5082.4	3	0.00035	0.6
Electricity (for central AC)	766 kWh**	Air conditioning	-	-	766	-	0.00274	2

*RASS Figure ES-6; **RASS p.19

A.4.4 Connecting household access results to demographic features (cont.)

A.4.4.1 Infrastructure variables

Infrastructure variables describe electrical and physical aspects of distribution system infrastructure. They are unique to distribution circuits or segments thereof, and are assigned to circuit polygons on the basis of the corresponding circuit and/or its portions that are included within the circuit polygon. These variables are sourced directly from Pacific Gas & Electric and Southern California Edison. Unless otherwise indicated in Table A.6, they are provided directly in each utility's downloadable ICA data files.

Table A.6: Infrastructure variables.

Variable			Availability and notes	
Type	Name	Description	Pacific Gas & Electric	Southern California Edison
Nominal circuit voltage	`CircVolt_kV`	Voltage class of 3-phase distribution circuit backbone, in kilovolts (kV)	ICA data is available for distribution system lines in four voltage classes: 4.16, 12, 17, and 21 kV	Seven voltage classes exist for 3-phase circuit lines in the data: 2.4, 4.16, 4.8, 7, 12, 16, 25, and 33 kV
Phase	`Phase_max`, `Phase_min`	Customers may be connected to 3-phase lines or 1- or 2-phase laterals	n/a - Phase information is not included in data	Maximum and minimum phase rating of distribution line segments that are included within the circuit polygon; 3-phase lines have ICA data, but ICA values are not calculated for 1- and 2-phase laterals
Distance to substation	`CLSmax`, `CLSmin`	Utility-set proximity rating for circuit line segments	n/a - Not included in data	Values from 1 (nearest) to 4 (furthest) indicate proximity rating of circuit lines included within the circuit polygon
ICA availability	`ICA_pct`	Percentage of line segments within the circuit polygon with ICA data	Indicates what percentage of circuit line segments of any phase have ICA data available	n/a - ICA is available for all 3-phase lines
Line lengths	`Length_m`, `Length_m_ctot`	Calculated length (in meters) of circuit lines within the circuit polygon and the full circuit	Available	Available

A.4.4.2 Service and geographic variables

Service variables pertain to how utility customers are served by distribution infrastructure, including the types of customers (residential, commercial, etc.), their density and distribution along circuit lines, and the quality of service (i.e., reliability) they receive. Geographic variables indicate DER-relevant metrics of the conditions that customers and distribution infrastructure may be exposed to. A full list of service and geographic variables included in our analysis is located in Table A.7.

Table A.7: Service and geographic variables.

Type	Name	Source	Description and notes
Customer percentages	`Res_pct`, `Com_pct`, `Ind_pct`, `Agr_pct`, `Oth_pct`	PG&E feeder-level ICA maps [116], SCE customer type breakdown [117]	Residential, commercial, industrial, agricultural, and other customers as a proportion of total customer served by the circuit.
Residential customers	`ResCust`	PG&E feeder-level ICA maps [116], SCE [117, 449]	Total number of residential customers served by the circuit.
Households served	`tothh_Cpoly`, `tothh_ctot`, `tothh_pct`	Calculated	Estimated number of households served by the circuit polygon: `tothh_Cpoly` is calculated by Equation 1.4, `tothh_ctot` is the sum of `tothh_Cpoly` along a circuit, and `tothh_pct` = `tothh_Cpoly`/`tothh_ctot` is the proportion of total circuit customers served within that circuit polygon. For SCE the denominator is the estimated customers served by the full circuit (i.e., x-axis of Figure A.5b), for PG&E it is the total customers estimated to be served by portions of the circuit with available ICA information.
Customer density per line	`tothh_perkm`	Calculated	Households per kilometer of circuit lines within a circuit polygon, calculated as: `tothh_perkm` = `tothh_Cpoly`/`Length_m` $\times$ 1000
Reliability	`SAIDI5yravg`	PG&E [451, 452], SCE [449]	Average of SAIDI values 2012-2016. SCE numbers are by circuit, PG&E numbers are by division only, matched via substation names located in those division areas.
Urban heat	`urbanheat_pctl`	CalHeat [453, 454]	Researchers have compiled California-specific data to estimate public health impacts from the increased prevalence of heat waves in the state. From this dataset, we consolidate four indicators—percent impervious surfaces, percent expected change in development by 2050, percent of area not covered by tree canopy, and temperature difference between rural and urban areas—by converting each indicator to a percentile, averaging these percentiles for each census tract, and converting the final average to a percentile. We use this as a measure of increased heat associated with urban development in the state.
Solar irradiance	`ghi_kWhpm2day`	NREL [166, 455]	Global horizontal irradiance (multi-year v3.0.1), values located within a circuit polygon are averaged; in the absence of values within a polygon, we use the closest value.

A.4.4.3 Demographic variables

Demographic variables are unique to census block groups (or, in some cases, census tracts, see Supplementary Table A.8) and are assigned to circuit polygons on the basis of the corresponding census block group. Our choice of indicators is informed by demographic categories that are commonly accepted as relevant to equity considerations (e.g., race, income, education levels) and those that may impact the ability to adopt DERs (e.g., owner-occupancy, single-unit households).

Several indicators are designed specifically to support consistency and comparison of results with previous work. Following [70], we aggregate measures of racial diversity (using Simpson's Diversity Index) and average years of education. Following [71], we consider four racial and ethnic categories separately: people identifying as Black, Asian, Latinx, and white (from which we exclude Latinx-identifying individuals). Following [456], we include indicators for the percentage of households with annual incomes below $50k and above $150k to acknowledge that median household income does not adequately capture income variability within a census block group. Additionally, we include several indicators from California-specific datasets developed to capture different measures of vulnerability in the state. A full list of demographic variables used and data sources are listed in Supplementary Table A.8.

Table A.8: Demographic variables.

Type	Name	Source data	Description and notes
Race & ethnicity	racediversity	American Community Survey* (ACS) [107] Table B02001 (Race)	We use Simpson's Diversity Index (calculated as in [457]) to estimate a measure of overall diversity by race within each census block group from the number of people identifying within each available race category (1 is more diverse and 0 is less diverse): $\texttt{racediversity} = 1 - [\texttt{white} * (\texttt{white} - 1) + \texttt{black} * (\texttt{black} - 1) + \texttt{native} * (\texttt{native} - 1) + \texttt{asian} * (\texttt{asian} - 1) + \texttt{pacific} * (\texttt{pacific} - 1) + \texttt{other} * (\texttt{other} - 1) + \texttt{twoormore} * (\texttt{twoormore} - 1)] / (\texttt{totpop} * (\texttt{totpop} - 1))$
	black_pct, asian_pct	ACS B02001 (Race)	Converted to percentage from number of people identifying as Black or Asian: $\texttt{black\_pct} = \texttt{black}/\texttt{totpop}$, $\texttt{asian\_pct} = \texttt{asian}/\texttt{totpop}$
	nlxwhite_pct	ACS B03002 (Hispanic or Latino origin by race)	Converted to percentage from number of people identifying as white but not Latinx: $\texttt{nlxwhite\_pct} = \texttt{nlxwhite}/\texttt{totpop}$
	latinx_pct	ACS B03003 (Hispanic or Latino origin)	Converted to percentage from number of people identifying as Latinx: $\texttt{latinx\_pct} = \texttt{latinx}/\texttt{totpop}$
Education	edavgyrs	ACS B15003 (Educational attainment for the population 25 years and over)	We estimate the average years of education in the population from the number of people reported as having completed the given years of school: $\texttt{edavgyrs} = [\texttt{presch} \times 0 + \texttt{grd01} \times 1 + \texttt{grd02} \times 2 + ... + \texttt{grd10} \times 10 + (\texttt{grd11} + \texttt{grd12nodiploma}) \times 11 + \texttt{hsfin} \times 12 + (\texttt{somecollege} + \texttt{associate}) \times 14 + \texttt{bachelor} \times 16 + \texttt{master} \times 18 + \texttt{professional} \times 20 + \texttt{phd} \times 22] / \texttt{totpop}$
Income	inc50kbelow_pct, inc150kplus_pct	ACS B19001 (Household income in the past 12 months)	Converted to percentages from number of households in available income tiers: $\texttt{inc50kbelow\_pct} = (\texttt{<10k} + \texttt{10-15k} + \texttt{15-20k} + \texttt{20-25k} + \texttt{25-30k} + \texttt{30-35k} + \texttt{35-40k} + \texttt{40-45k} + \texttt{45-50k}) / \texttt{tothh}$ $\texttt{inc150kplus\_pct} = (\texttt{150-200k} + \texttt{>200k}) / \texttt{tothh}$
	medhhinc	ACS B19013 (Median household income in the past 12 months)	Used directly
Housing units	ownerocc_pct	ACS B25003 (Tenure)	Converted to percentage from number of owner-occupied households: $\texttt{ownerocc\_pct} = \texttt{ownerocc}/\texttt{tothh}$
	unitsavg, singleunit_pct	ACS B25024 (Units in structure)	Calculated from available data columns: $\texttt{unitsavg} = [(\texttt{units1att} + \texttt{units1det}) \times 1 + \texttt{units2} \times 2 + \texttt{units3to4} \times 3.5 + \texttt{units5to9} \times 7 + \texttt{units10to19} \times 14.5 + \texttt{units20to49} \times 34.5 + \texttt{units50plus} \times 50] / \texttt{totstr}$, $\texttt{singleunit\_pct} = (\texttt{units1att} + \texttt{units1det}) / \texttt{totstr}$
	medyrbuilt	ACS B25035 (Median year structure built)	Used directly
Housing density	tothh	ACS B19001	Total households per census block group; used directly
	hhdensity_hhsqkm		Calculated for each circuit polygon as: $\texttt{hhdensity\_hhsqkm} = \texttt{tothh\_Cpoly} / \texttt{CpolyA}(m^2) \times 1000000$
Disadvantaged community	sb535disad	CalEnviroScreen** (CES) [91]	The CES indicator measures estimated exposure and vulnerability to environmental pollutants in California. Separate metrics capturing aspects of pollution burden and population sensitivity are aggregated into one overall indicator [91]. Census tracts scoring above the 75th percentile are classified as a 'disadvantaged communities' and are eligible for increased funding and policy support through a variety of state programs. This is a binary indicator capturing this classification.
Pollution burden	polexposure_pctl, polenvt_pctl	CES	Aggregated metrics from CES include pollution exposure (to ozone, PM2.5, pesticides, etc.) and environmental effects (cleanup sites, hazardous waste, etc.).
Health	popsens_pctl	CES	This indicator aggregates emergency asthma visits, cardiovascular disease, and low birth-weight infants.
Language	lingisolation_pctl	CES	Linguistic isolation is a socioeconomic factor captured by CES but not included in other demographic measures above.

*All ACS data is at the census block group level.
**All CES data is at the census tract level, and we assign the tract-level values to all census block groups within that tract.

Appendix B

Chapter 2 Appendix

B.1 Circuit hosting capacity

Electrical distribution systems are designed to serve expected customer electricity demand by delivering electrical current through lines and power equipment. Since electricity demand varies seasonally and over the course of a day, evaluating the timing of anticipated load growth is essential to assess how much additional current electrical equipment may be able to handle at a given time.

Here, we use circuit hosting capacity data from PG&E's ICA map, which contains temporal information (i.e., month-hour variation) in load and hosting capacity [156]. The circuit data we use in this analysis was downloaded in February 2022. This data is presented by circuit segment, of which there are hundreds to thousands per circuit (Figure B.1). These hosting capacity values cannot be utilized simultaneously; each segment-level value assumes that no additional load appears on other segments at the same time [458]. Therefore, these hosting capacity values must be carefully aggregated to the full circuit level for evaluation alongside our demand growth estimates.

To perform this aggregation, it is necessary to consider how the spatial distribution of new load might impact where circuit upgrades will be needed. For example, a customer receiving electricity service near a substation may be able to increase their electricity demand—without triggering the need for circuit upgrades—by a greater amount than a customer who is served by a downstream branch of the same circuit. This is because equipment capacity to accommodate increased current flow varies throughout a circuit, and additional load on the downstream circuit branch may more quickly surpass the current limits of smaller transformers or other power equipment [459]. PG&E's ICA data reflects this reality, showing significant ranges in the hosting capacity that is available on segments within a single circuit (Figure B.2).

Estimating the total ability of a given circuit to accommodate new load therefore requires making assumptions about how that load is distributed throughout the circuit. In the most optimistic case, all new load would be connected to the circuit segment with the greatest hosting capacity for new load (this is the max scenario in Figure B.2). The most pessimistic case would put all new load on the segment with the least available capacity (this is the min scenario in Figure B.2).

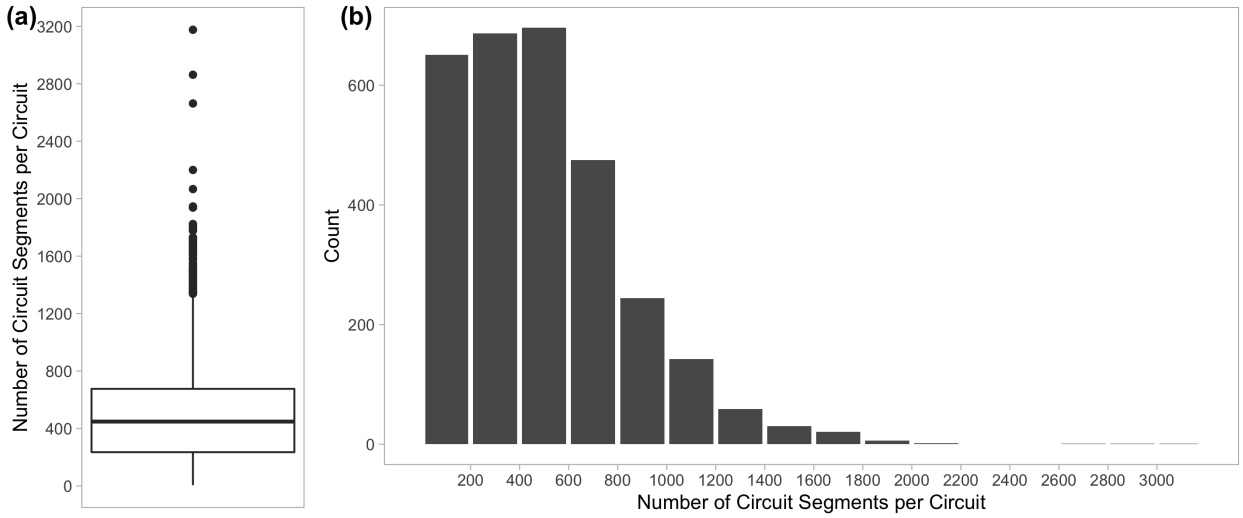


Figure B.1: Boxplot and histogram of the number of circuit segments reported within PG&E circuits [156].

In reality, we know that new load will be distributed spatially over PG&E's distribution circuits, with load accruing to both relatively high- and low-capacity circuit segments. Therefore, while the maximum and minimum circuit segment capacities provide an upper and lower bound to the circuit's total load capacity, it is likely that actual capacity will be well within these bounds. However, significant uncertainty remains about the spatial distribution of new demand within the circuit.

Here, we use individual circuit segments as a proxy for overall capacity under different assumptions of how new load is allocated. This allows us to employ a scenario approach to capture this uncertainty, and to preserve the spatial and temporal granularity in hosting capacity at the circuit and month-hour levels. We evaluate this approach at a range of load allocation scenarios. To illustrate, Figure B.2 shows hosting capacity information for six example circuits, which were selected randomly from a total of 3016 circuits. To identify circuit segments that may be representative of different load allocation scenarios, we:

1. Find the average hosting capacity value for each circuit segment within a circuit by averaging hosting capacity values across month-hours;

2. Calculate the maximum, median, minimum and the 90th, 75th, 25th, and 10th percentiles of the averaged circuit segment values for each circuit;

3. Select the circuit segments that generated those values as proxy measures of circuit capacity for new load; and,

4. Use the month-hour hosting capacity values of the identified circuit segments as measures for the overall circuit, corresponding to different options for how load might be allocated.

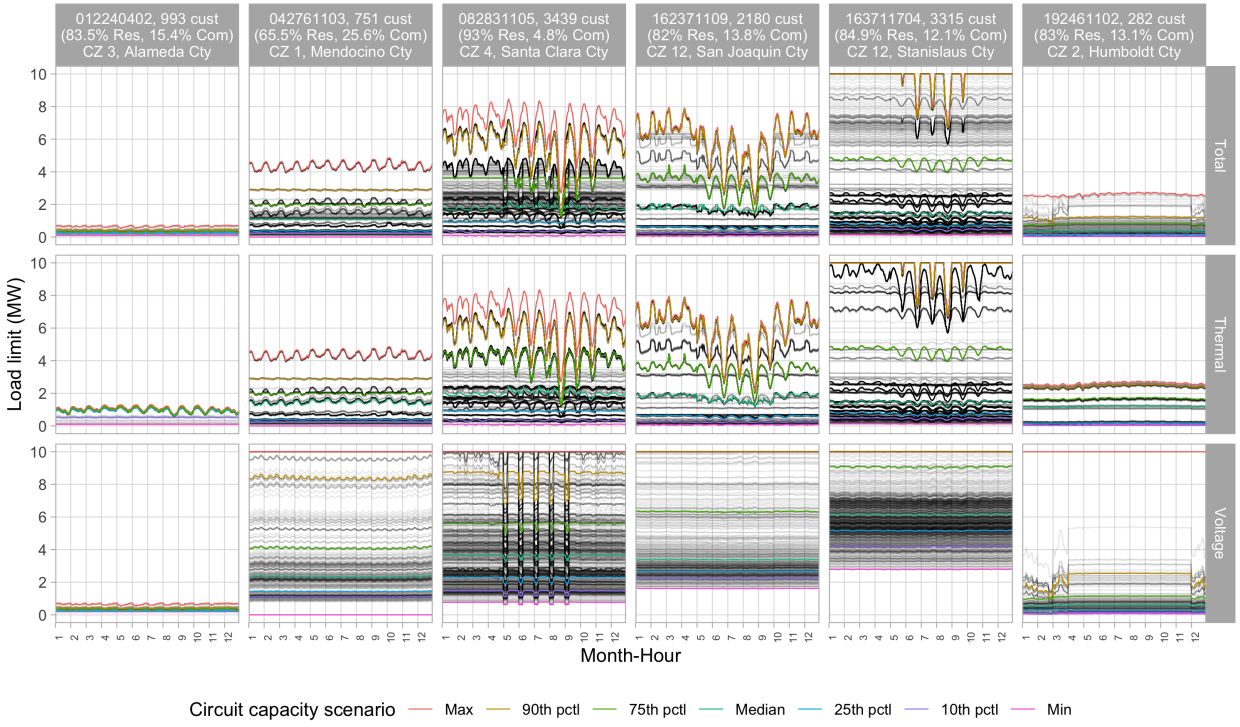


Figure B.2: Hosting capacity by circuit segment for a sample of 6 randomly-selected circuits. Grey lines indicate hosting capacity values by circuit segment, colored lines indicate selected circuit segment scenarios. Values are plotted for total, thermal, and voltage limits, where the total limit is the minimum of the thermal and voltage limits for a given segment and month-hour.

In Figure B.2, the hosting capacity available on each circuit segment at each month-hour is plotted in grey. Hosting capacity on circuit segments identified as proxies for different load allocation scenarios are overlaid in color.

We can now look at how changing the load allocation scenario impacts the hosting capacity limits across all circuits. In Figure B.3, each line represents an individual circuit under each load allocation scenario for total, thermal, and voltage load limits. As we see, lower percentile or more conservative load allocation scenarios correspond to lower hosting capacity for additional load, while higher percentile load allocation scenarios have generally higher hosting capacities, though with more variance, across circuits. We also see that total limits are more similar to thermal than voltage limits; this is broadly true across the data. This means that thermal limits more frequently set the total load limit for a circuit than voltage limits.

To consider which range of load allocation scenarios may be appropriate to use, we review our results alongside an additional PG&E data set, the Distribution Deferral Opportunity Report (DDOR). The DDOR, which California's Investor-Owned Utilities (IOUs) are required by the CPUC to file each year, contains a list of investments that the utility plans to make on its distribution system to address capacity, voltage support, reliability, and/or resiliency needs [157]. This data set

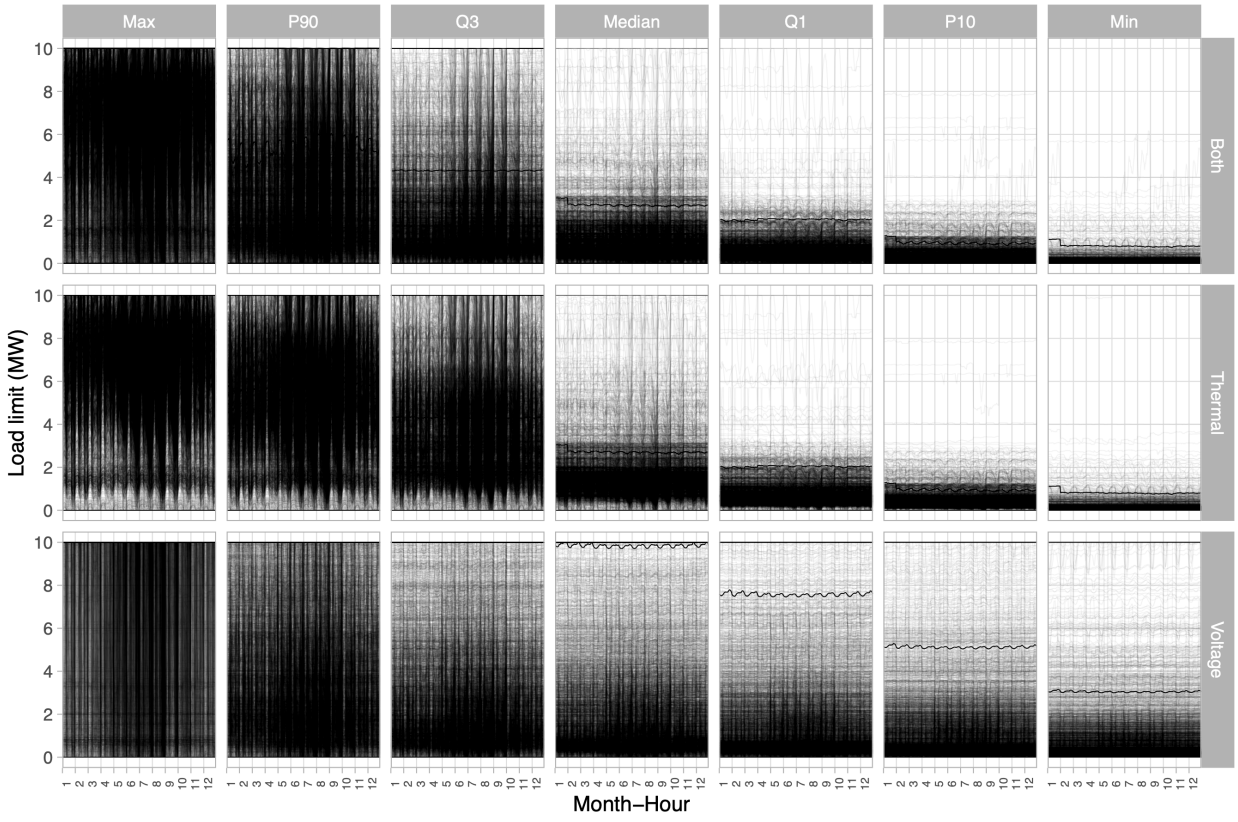


Figure B.3: Summary of circuit hosting capacities estimated for all circuits. Grey lines indicate hosting capacity by month-hour for each circuit, under different load allocation scenarios.

contains information on circuit capacity and which circuits PG&E expects to upgrade due to load and DER growth. However, it does not contain temporal (intra-year) information for existing load or hosting capacity. With only annual numbers it is challenging to evaluate how different load shapes will affect capacity needs; this is why we use the segment level (hourly) numbers instead. However the values provided in the DDOR can serve as a sanity check. Though we don't expect our segment-driven estimates to match the DDOR numbers, we expect they should be correlated and roughly similar. If they are, this lends support to our scenario-based approach. The majority of anticipated projects listed in PG&E's 2021 DDOR are prompted by equipment capacity limits (for more, see Section B.3). Therefore, we expect the best correspondence between DDOR data and ICA thermal limits (rather than total or voltage limits).

We refer to the 2021 DDOR Appendix E, which contains information on circuit loading and equipment rating (i.e., how much load circuits can handle), and plot the difference between equipment rating and existing load in 2021 against the hosting capacity estimated under our load allocation scenarios (Figure B.4). We also show the distribution (via a boxplot) of the logarithm of the ratio between our predictions and PG&E's estimates (Figure B.5).

We find that while there is significant noise in these estimates, there is also correspondence

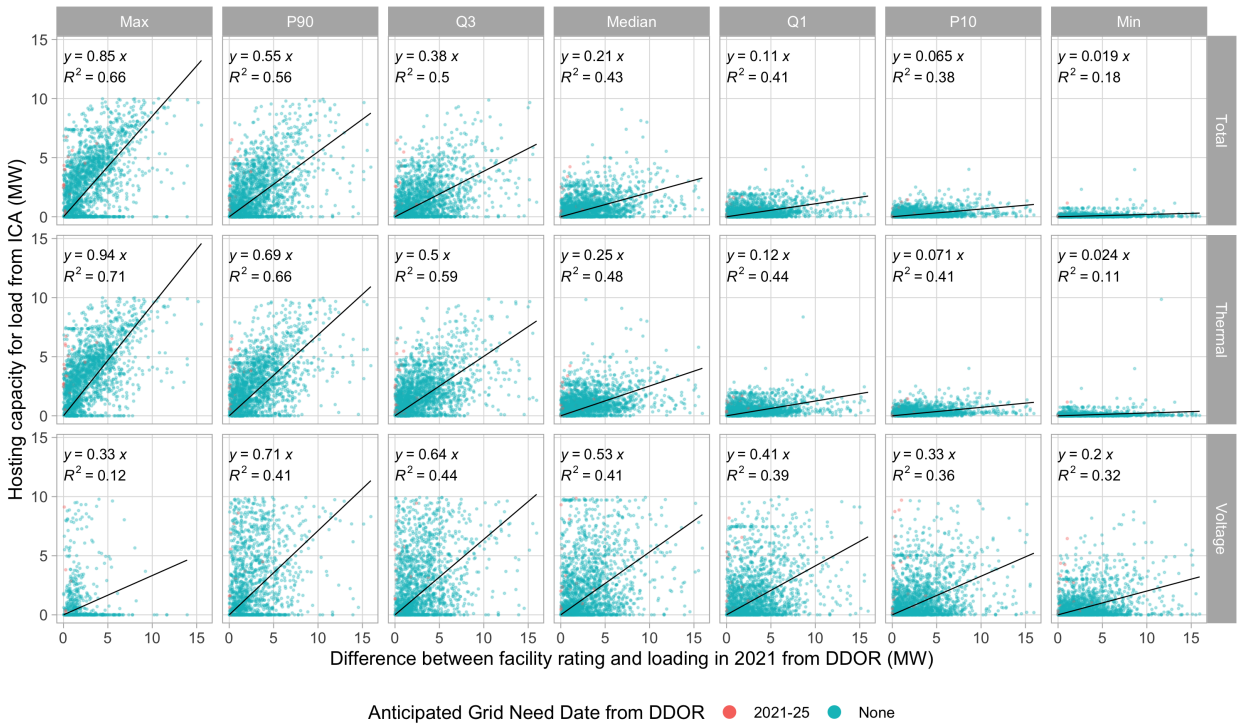


Figure B.4: Available load capacity on circuits in 2021 from PG&E's DDOR report plotted against the estimated remaining load capacity obtained from ICA data. We take the minimum of month-hour ICA values for each circuit to correspond to the difference between equipment rating and peak load. Each point corresponds to one circuit. Red points indicate circuits where PG&E reports an anticipated grid upgrade need between 2021 and 2025, while blue points indicate circuits where PG&E does not anticipate a grid upgrade need. Linear regression lines are indicated on each plot, with y-intercepts set to 0. Some discrepancies in data reporting exist: DDOR information is available (i.e., not redacted) for only 2025 circuits, which is approximately one-third of the total number of circuits available in the ICA data. Further, ICA hosting capacity limits are capped at 0 and 10 MW, while DDOR hosting capacity limits may be negative or greater than 10 MW. We remove any circuits with negative DDOR capacities or ICA capacities equal to 10 MW to focus on circuits where values can be evaluated together, leaving us with 1882 circuits here. (Note: fewer points are shown in the more optimistic scenarios, since more circuits in those scenarios have ICA capacities equal to 10 MW and are therefore omitted.)

between the circuit capacity for new load in the ICA data and the DDOR data. Notably, all slopes in Figure B.4 (and most boxplot medians in Figure B.5) are less than one, indicating that PG&E expects more room on its circuits than is indicated by the ICA data. One reason for this could be that while ICA analyses evaluate the capacity of circuits to accommodate new load at the time of the analysis, the DDOR data accounts for the potential to mitigate upgrade needs through circuit reconfiguration [157]. However, this mechanism relies on there being excess capacity on nearby circuits, which may be reduced under significant load growth.

Focusing on the thermal limits, we find via Figure B.5 that our 90th percentile load allocation scenario appears to most closely parallel the assumptions made by PG&E about room for additional load in the DDOR dataset (Figure B.5). However, in the absence of temporal hosting capacity

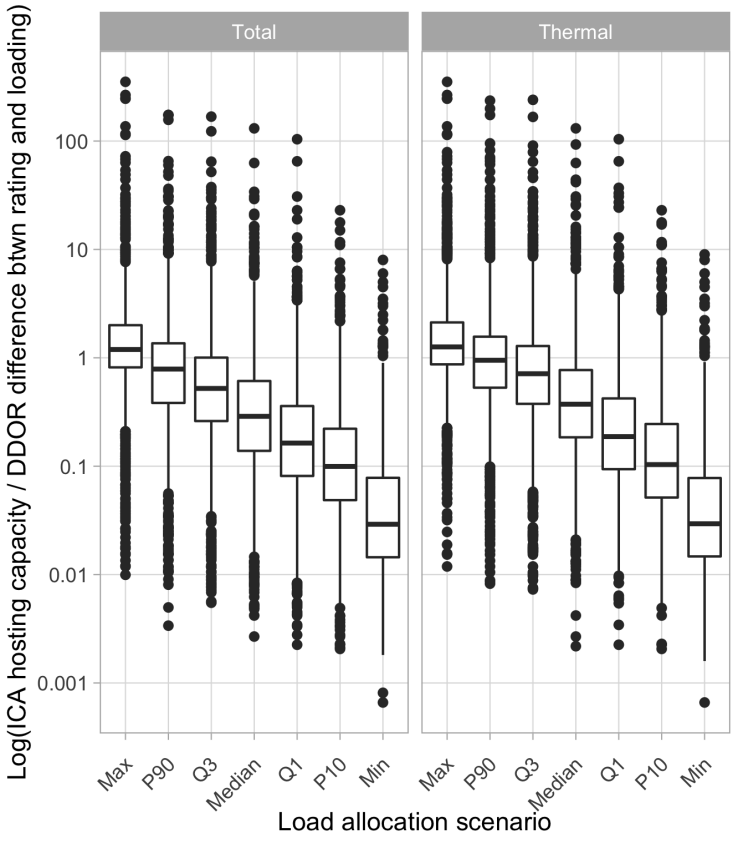


Figure B.5: Ratio of the estimated remaining load capacity per circuit from ICA data to available load capacity on circuits in 2021 from PG&E's DDOR report, for each point from Figure B.4. We omit voltage results here, as we do not expect correspondence between ICA voltage data and capacity data from the DDOR.

and/or load allocation estimates from PG&E, we maintain that significant uncertainty exists in where additional load will materialize on these circuits. Therefore, we report our results at the 90th, 50th, and 10th percentiles of the hosting capacity by circuit segment within each circuit.

To calculate circuit capacity upgrade needs, we subtract the remaining load capacity on each circuit (given both thermal and voltage limits) from the new load predicted by each electrification scenario at each month-hour. Further, we take the max to evaluate the greatest need across the year, focus only on the circuits where upgrades are needed, and sum the total upgrade needs across those circuits:

$$\text{Upgrade need}_{sc,yr,la} = \sum_{j}(\max\left[0, \max_{mh}\left(\text{New elec load}_{mh,j,sc,yr} - \text{Load capacity}_{la}\right)\right]) \tag{B.1}$$

Where mh is a given month-hour, j is a given circuit, sc is an electrification scenario, yr is the year of analysis, and la is the load allocation scenario. For each electrification scenario and year, we report the total upgrade need (in GW) for all circuits, the number of circuits needing upgrades,

and the estimated upgrade costs (see Section B.3). In all cases, the 90th and 10th percentile load allocation scenarios are shown as error bars on the median load allocation scenario.

B.2 Substation capacity

Substation transformer bank capacities are available from PG&E's DDOR report [157]. In cases where a given substation has multiple transformer banks, we add the capacities (in MW) of those banks together to calculate a total substation capacity. (On average, there are approximately 1.78 reported banks per substation.) This step is necessary because we only have information for which substation (i.e., not which specific substation bank) serves a particular circuit. This approach may underestimate substation upgrade needs as it is possible that capacity is not favorably distributed across the substation banks that serve specific circuits.

Substation-level loads are reported by PG&E through their ICA map for only 252 of 753 substations [156]. However, we can also sum the loads of all circuits connected to a particular substation to estimate the total substation-level load. We compare these two approaches for the substations for which we have both substation-level and circuit-level loading data (Figure B.6). We observe good alignment between these values. It is more common for the sum of circuit-level loads to underestimate than to overestimate the total load at each substation. This may occur because the load on some circuits is redacted due to customer privacy reasons. Therefore, this approach may further underestimate substation upgrade needs.

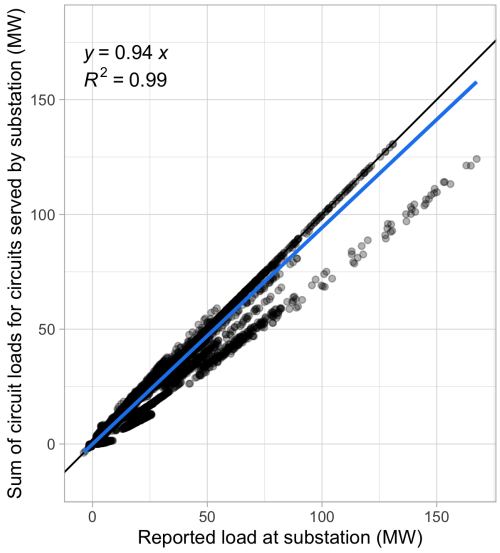


Figure B.6: Comparison of substation-level load and circuit-level load (sum of load from all circuits connected to a substation for which we have loading data). Each point shown is the load at a particular month-hour; therefore, there are a maximum of 288 points shown per substation. Load shown is the "high" (90th percentile) load reported by PG&E. The black line is the x=y line, and the blue line is a linear best fit.

Where possible, we use the load reported at the substation level to estimate total substation loading; where that data does not exist we will substitute the sum of available load data for all circuits served by that substation. In all cases, we use the "high" load (90th percentile) reported by PG&E rather than the "low" load (10th percentile).

For each electrification scenario and year, we add the existing substation loading at every month-hour to the new load predicted by the electrification scenario for that month-hour:

$$\text{Tot sub load}_{mh,j,sc,yr} = \text{Existing sub load}_{mh,j} + \text{New elec load}_{mh,j,sc,yr} \tag{B.2}$$

Where *mh* is a given month-hour, *j* is a given substation, *sc* is an electrification scenario, and *yr* is the year of analysis. Then, for each substation, we select the maximum loading at any month-hour, compare it to the reported substation capacity in 2021, focus on only the substations where upgrades are needed, and sum the total upgrade needs at those substations:

$$\text{Upgrade need}_{sc,yr} = \sum_{j} (\max [0, \max_{mh} (\text{Tot sub load}_{mh,j,sc,yr}) - \text{Sub capacity}_{j}]) \tag{B.3}$$

For each electrification scenario and year, we report the total upgrade need (in GW) for all substations, the number of substations needing upgrades, and the estimated upgrade costs (see Section B.3).

B.3 Costs of circuit and substation upgrades

Estimates of circuit and substation upgrade needs and their expected costs are available from PG&E's DDOR report [157]. While we do not use PG&E's estimates of circuit upgrade needs directly due to the lack of temporal load and hosting capacity information (see Section B.1), we do use the data in this report to estimate the potential costs of upgrades.

PG&E's DDOR contains information about whether the anticipated distribution system investments may be able to be deferred by distributed energy resources (DERs) and indicates the type of grid need they would address. Although PG&E applies both a technical and a timing screen to planned investments to determine whether they might be mitigated by DER deployment, we see here that in practice, the timing screen appears to dominate: the potential to defer needed investments is perfectly aligned with the year of investment (Figure B.7a). We also see that the vast majority of these investments are intended to mitigate capacity needs (Figure B.7b).

Next, we consider the costs of the planned investments. We visualize estimated project costs in Figure B.8, and plot those costs in units of dollars per kW to enable applying these values to the grid upgrade needs we calculate. We note that bank projects tend to incur higher per-kW costs relative to feeder or line section upgrades.

To capture the economies of scale we see, we separate grid needs into rough size buckets of 0-1, 1-2, 2-4, 4-8, and 8+ MW, and consider bank costs separately from feeder and line section upgrade costs (Figure B.9).

Then, to estimate the costs of needed upgrades, we first identify the magnitude of the grid upgrade need on a circuit or substation, then determine which size bucket it falls into. Then, for

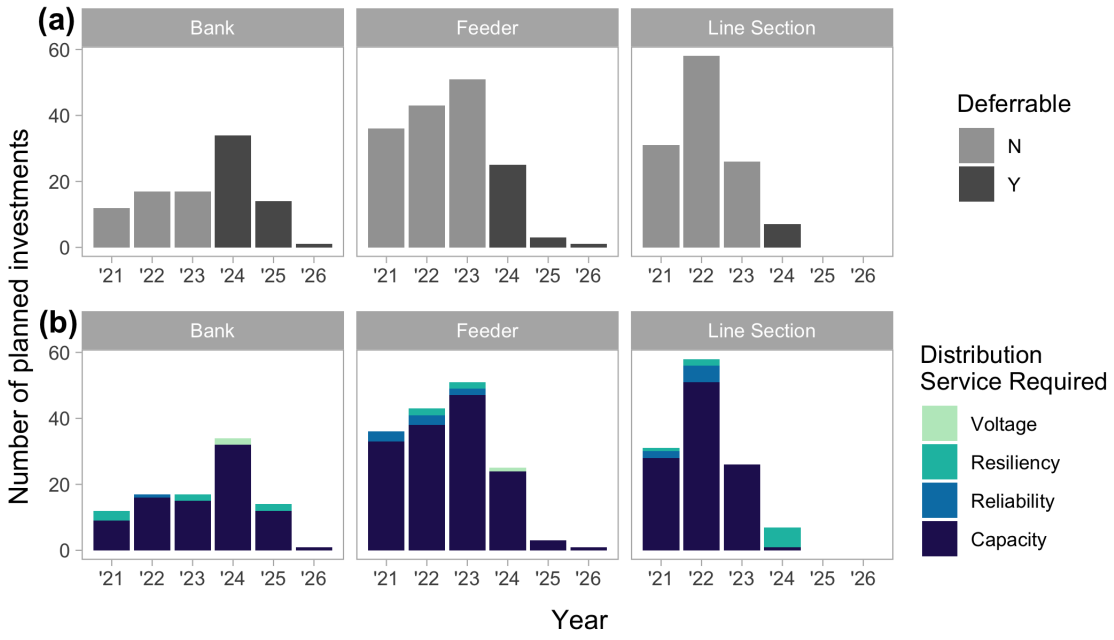


Figure B.7: Summary of planned distribution system investments [157]: (a) shows planned investments by whether PG&E considers those investments to be deferrable by distributed energy resources; (b) shows those investments by type of need they would address. Note: we omit Grid Needs Assessment (GNA) information from this data before plotting to minimize double-counting of investment needs, as some investments are prompted by multiple grid needs [157]. The total number of investments shown here is 251.

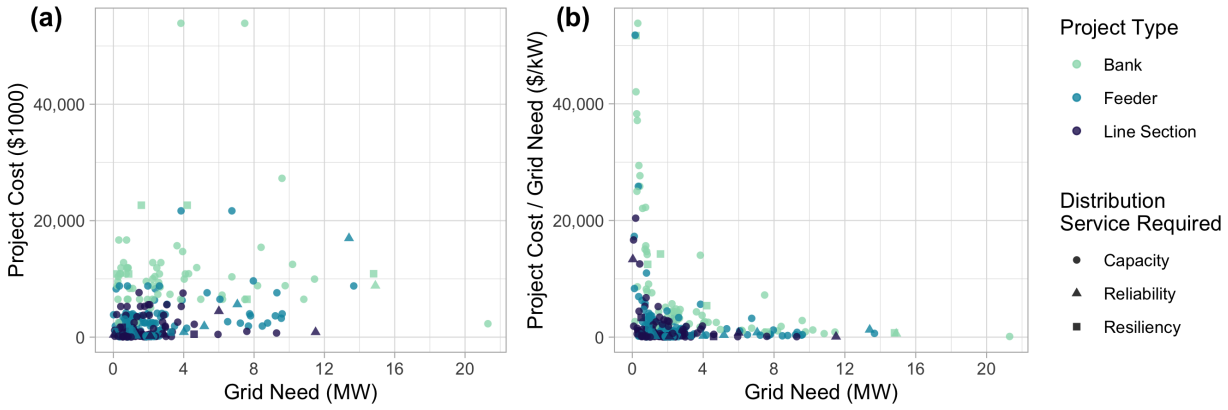


Figure B.8: Summary of planned distribution system investment costs with grid need units in MW [157]. One project with a negative grid need is omitted: (a) Shows project cost by grid need for all planned investments where data is available; (b) shows project cost scaled by grid need. One outlier feeder capacity project with a grid need of 0.01 MW and calculated $383,900/kW grid cost is omitted in (b) for easier visualization of the remaining data.

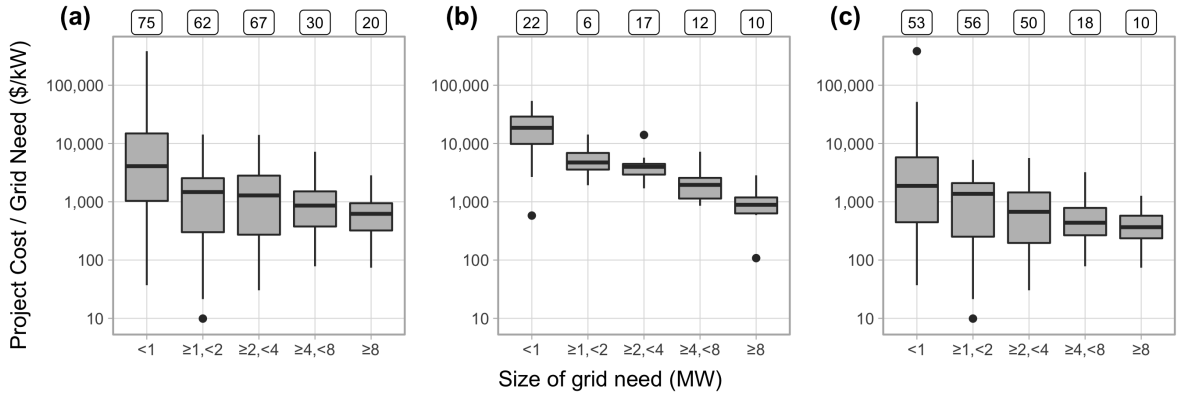


Figure B.9: Box plots of data from Figure B.8b, separated by grid need size: (a) shows results for all data; (b) shows results only for banks; (c) shows results only for feeders and line sections. Top labels indicate the number of observations represented in each size category.

Table B.1: Substation upgrade costs from PG&E DDOR [157], summary statistics all in $/kW. Reported values are for Figure B.9b, and include the costs of upgrading banks.

Grid need (MW)	Min	25th pctl.	Median	75th pctl.	Max
< 1	579.71	9,935.00	18,863.43	28,982.79	53,806.45
≥ 1 & < 2	1,923.85	3,594.99	4,740.03	6,980.09	14,249.69
≥ 2 & < 4	1,701.57	2,927.93	3,978.38	4,468.75	14,038.28
≥ 4 & < 8	855.26	1,137.16	2,004.70	2,570.87	7,216.47
≥ 8	107.98	634.01	887.62	1,189.14	2,844.00

Table B.2: Circuit upgrade costs from PG&E DDOR [157], summary statistics all in $/kW. Reported values are for Figure B.9c, and include the costs of upgrading feeders and line sections.

Grid need (MW)	Min	25th pctl.	Median	75th pctl.	Max
< 1	37.04	445.71	1,875.00	5,791.67	383,900.00
≥ 1 & < 2	9.90	251.84	1,368.89	2,092.89	5,239.73
≥ 2 & < 4	30.30	196.76	673.35	1,447.55	5,633.51
≥ 4 & < 8	78.15	268.65	438.14	785.30	3,217.95
≥ 8	73.91	237.23	367.85	586.32	1,267.76

each circuit or substation j, we calculate the cost of meeting the estimated grid need and sum across all j to get the total:

$$\text{Cost of grid upgrade}(\$) = \sum_j (\text{Upgrade need}_j(kW) \times \text{Upgrade cost}(\$/kW)) \tag{B.4}$$

We report cost results at the median, and additionally at the 25th and 75th percentiles. We use bank costs to estimate the costs of substation upgrades (Table B.1), and feeder and line section costs to estimate the costs of circuit upgrades (Table B.2). The total grid upgrade cost for all circuits is then equal to the sum of grid upgrade costs for each circuit j; similarly, the total grid upgrade cost for all substations is equal to the sum of individual substation upgrade costs.

Further, we annualize these costs to consider the impact of upgrade costs in time:

$$A = P \times \frac{r}{1-(1+r)^{-n}} \tag{B.5}$$

Where A is the annualized cost, P is the present cost of grid upgrades calculated by Equation B.4, r is PG&E's discount rate, reported to be 6.77% [157], and n is the number of years from 2021 to the time of analysis (i.e., 9, 19, and 29, respectively for upgrades needed in 2030, 2040, and 2050).

B.4 Residential electrification

To estimate the potential load impacts due to residential electrification, we start with total electrification load profiles developed in [159]. These load profiles assume that all gas usage by residential customers served by PG&E circuits is converted to electric heating.

However, residential heating will not electrify all at once. We use technology adoption rates from [160] to estimate how quickly residential customers will electrify heating. Specifically, we use the accompanying data resource from the NREL Electrification Futures Study on the projected final energy demand by state, sector, subsector, and energy source [460]. We filter this data to California and residential space heating and water heating, and sum the energy consumption of different heating technologies by energy source and year (Figure B.10). Then, we calculate the percentage change in electricity usage from 2021 for the Reference, Medium, and High scenarios (Table B.3).

Table B.3: Calculated percentage change from 2021 in electricity usage for residential space and water heating in California, from [460].

Scenario	2030 (%)	2040 (%)	2050 (%)
Reference	3.68	13.0	17.5
Medium	7.92	21.1	33.2
High	10.8	35.4	43.5

We multiply the total new load by circuit due to residential electrification (as estimated in [159]) by these percentages to calculate the estimated new loads in each year of our analysis. Effectively,

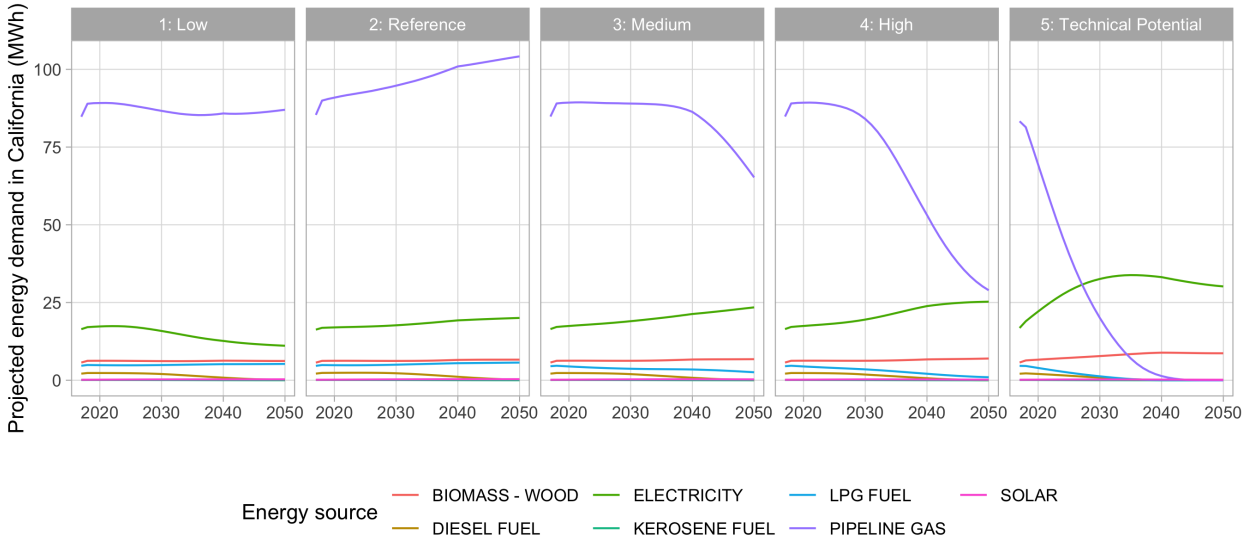


Figure B.10: Projected energy demand by source for residential space and water heating in California from [460]. We use the change in electricity consumption between 2021 and 2030, 2040, and 2050 from scenarios 2, 3, and 4 in our analysis (Table B.3).

this approach can be interpreted as assuming that, for example, under the Reference scenario in 2040, 13% of residential households (or residential household-equivalents) in PG&E's territory electrify their space and water heating. The total energy demand due to residential electrification across all PG&E circuits is shown in Figure 2.1.

B.5 Electric vehicle adoption

Charging infrastructure is needed to support expected growth in electric vehicles. To plan for charging infrastructure needs, the California Energy Commission performed an assessment of possible charging patterns of passenger vehicles across the state [164]. We use this analysis to estimate how charging demand might be distributed across PG&E's circuits.

B.5.1 Charging demand in PG&E's territory

County-level results are provided for the expected deployment of chargers serving multi-unit dwellings, as well as workplace, public, and DC fast chargers. PG&E serves all or part of 47 of California's 58 counties, and we assume that all chargers located in those counties will serve PG&E customers. This is approximately 39% of the chargers expected to be deployed in 2030 [Table C-15 in 164], and we assume that the total charging demand in PG&E's territory will be 39% of the statewide total.

B.5.2 Load shapes for EV charging

Projected statewide power demands from EV charging are developed for 12 charging scenarios that make different assumptions about technology access, energy demand, and consumer behavior [Appendix D in 164]. Each scenario offers a plausible future of possible load profiles for five charging types: residential level 1, residential level 2, public, work, and DC fast charging.[1] These are modeled in 10-minute increments over a 24-hour period.

For each scenario, we average the charging demands in each hour to yield an hourly mean power draw for each charger type. We then aggregate power draws by customer type: residential level 1 and level 2 charging are summed into an overall residential power draw that will be distributed among PG&E's residential customers, and workplace, public, and DC fast charging are summed into an overall power draw that will be distributed among PG&E's commercial customers. We compare the aggregated residential and commercial charging profiles across 12 charging scenarios, and select three scenarios that offer a variety of load profile distributions across customer types (Figure B.11). These correspond to the standard, low residential access (i.e., more commercial charging), and high residential access scenarios from [164]. Finally, we allocate the hourly power demand from these three scenarios to PG&E circuits by the total proportion of PG&E residential and commercial customers that each circuit serves.

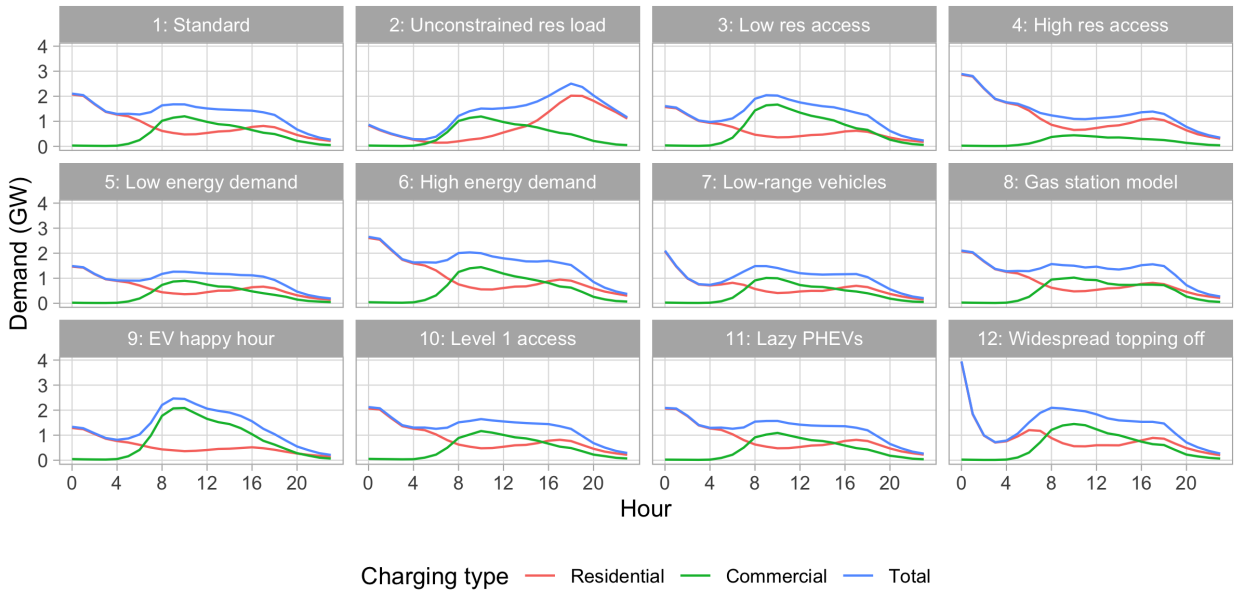


Figure B.11: Projected power demand due to EV charging in PG&E's territory in 2030 from scenarios described in [164], with charging types aggregated to residential and commercial charging. Scenarios 1, 3, and 4 were selected for use on our analysis.

[1] Charging is assumed to occur at level 2 for public and workplace charging, except in Scenario 10 where estimates of level 1 charging for public and work are also provided.

B.5.3 Adding a residential demand response scenario

The existing EV charging scenarios presented, with the exception of scenario 2, all exhibit a significant discontinuity in charging at midnight. This discontinuity arises from the structure of time-of-use (TOU) rates in California, which incentivize charging after midnight when the off-peak rate takes effect [164]. We posit that a residential EV charging demand response program may be able to smooth this peak to reduce strain on the distribution grid. To evaluate the potential impact of this intervention, we construct an additional EV charging scenario with smoothed nighttime charging. Specifically, we take scenario 1 and distribute the residential charging demand that exists in hours 10pm to 5am evenly across those hours. We then use this as a fourth EV scenario (Figure B.12).

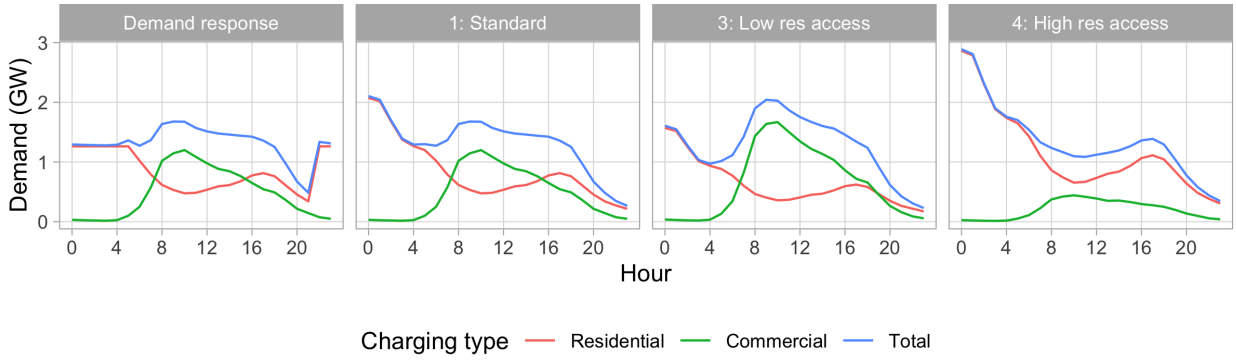


Figure B.12: Projected power demand due to EV charging in PG&E's territory in 2030 from scenarios 1, 3, and 4 described in [164], and an additional demand response scenario based on scenario 1 with smoothed residential nighttime charging in hours 10pm to 5am.

B.5.4 Projecting EV charging in time

Approximately 8 million passenger EVs are anticipated in 2030 to meet California's climate goals [164]. PG&E serves about 40% of California's population, and we estimate that the same proportion, or 3.12 million, of these EVs will be charging in PG&E's territory in 2030. Approximately 31.2 million automobiles and non-load-hauling trucks and other commercial vehicles were registered in California in 2021 [461, 462]. Executive order N-79-20 [163] banned the sale of internal combustion engine vehicles in California after 2035. As vehicles have a less than 15-year turnover rate, this suggests that all or nearly all passenger vehicles in California in 2050 will be net-zero, and we assume that many of them will be EVs. We double our estimate of EVs in 2030 to estimate adoption in 2040, and double it again to estimate adoption in 2050 (Table B.4). This yields an estimated 12.49 million EVs in PG&E's territory in 2050, which roughly corresponds to the 12.48 million (40% of 31.2 million) EVs we would expect if all of today's automobiles, non-load-hauling trucks, and other commercial vehicles were electric. We scale the projected demand profiles by two and four to estimate the hourly charging profile of EVs in PG&E's territory in 2040 and 2050.

Table B.4: Projections of increasing EV deployment in time.

Year	2020	2030	2040	2050
Estimated passenger EVs in PG&E territory (millions)	0.303[1]	3.12[2]	6.24[3]	12.49[3]
EVs per 2021 residential customers in PG&E territory[4]	0.062	0.634	1.268	2.519

[1] From [463]; [2] from [164]; [3] see Section B.5.4.
[4] PG&E reports that 4,922,341 residential customers are served by its electric distribution circuits in 2021 [156], here we divide the numbers in row 1 by this value to better assess the extent of EV deployment estimated in each year. We disregard population growth in our analysis, so the real number of EVs per residential customer under these estimates will be lower. By comparison, there are approximately 2.53 automobiles, non-load-hauling trucks, and other commercial vehicles per residential PG&E customer today [461, 462].

B.6 Solar generation calculations

We consider the potential ability of distributed solar, locally deployed on individual circuits, to mitigate needed upgrades.

B.6.1 Solar profiles

Each circuit in PG&E's territory is assigned a solar profile based on the location (county and climate zone combination) of the substation to which a given circuit connects. To perform this assignment, we first identify the climate zone and county location of each PG&E distribution substation (Figure B.13). For all substations within a particular county and climate zone, we calculate the geographic centroid of their locations.

We upload the list of centroids to SAM, which identifies the nearest solar irradiance data that is available in the NSRDB [166] to each location, and calculates the hourly energy production over the course of a year at that location for a 1 kW solar photovoltaic array. All assumptions about solar array characteristics are kept standard (i.e., none are modified from their default values). These include:

1. 1 kW_{DC} nameplate capacity
2. Standard module
3. DC to AC ratio: 1.2
4. Rated inverter size: 0.83
5. Inverter efficiency: 96%
6. Array type: fixed roof mount, 20deg tilt, 180deg azimuth
7. System losses: 14.08%

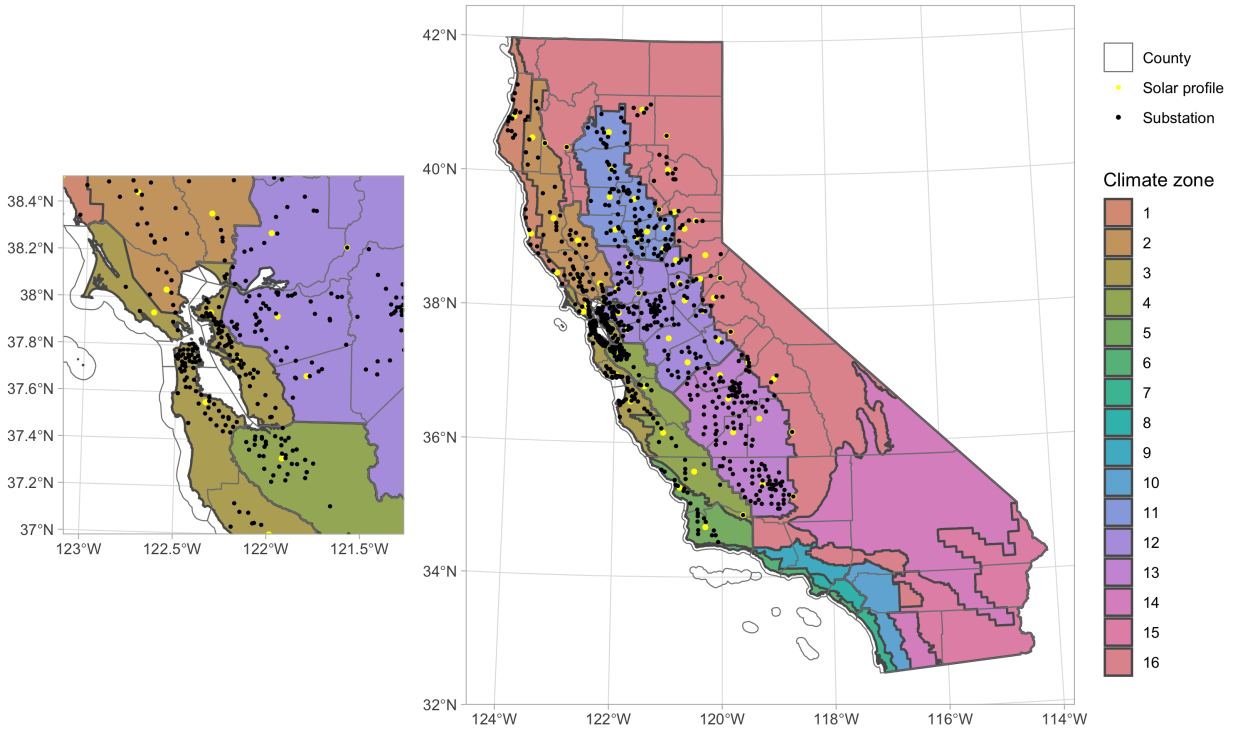


Figure B.13: Climate zone and county locations of PG&E substations (black dots). For each county/climate zone combination, the centroid of the relevant substations is calculated and plotted in yellow. This is the location used to locate the nearest available solar profile, which is then used to calculate solar generation for distributed solar that could be deployed on any of the circuits connected to the substations in question.

From the SAM results, we collect the estimate of power generated in kW for each hour of the year. Then, we aggregate these results to month-hour values by taking the minimum hourly values across days in a given month (Figure B.14). These solar energy profiles are then assigned to circuits based on which substations they are served by.

B.6.2 Accounting for solar in upgrade calculations

For each circuit, we evaluate the potential of distributed solar to mitigate grid upgrade needs by reducing the net load on the circuit. Specifically, we deploy up to 150 MW of solar on each circuit in 200 kW increments, stopping when an additional increment of solar no longer reduces the magnitude of needed upgrades on a particular circuit.

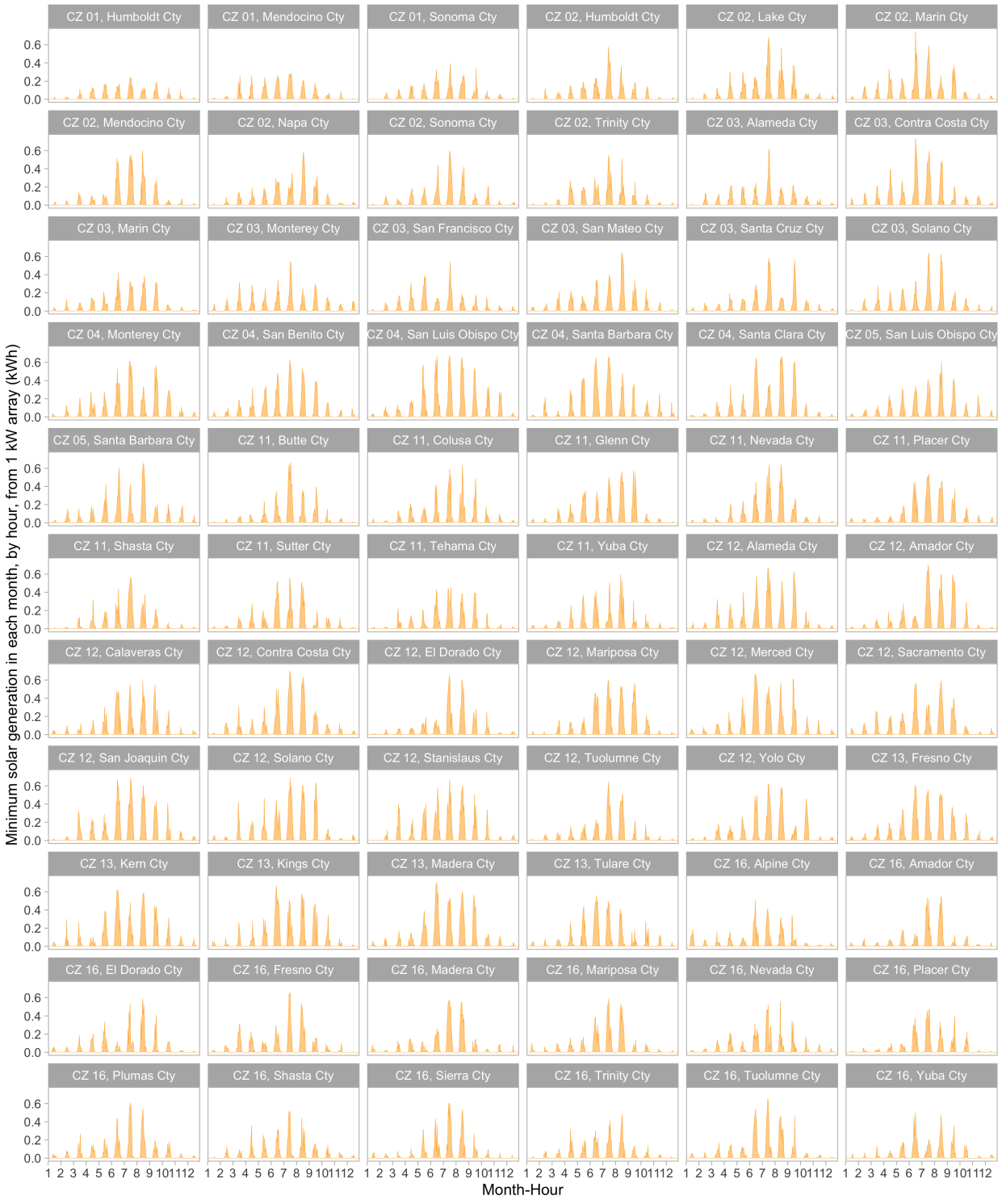


Figure B.14: Solar profiles used in analysis, by climate zone/county group.

Appendix C

Chapter 3 Appendix

C.1 Electricity infrastructure planning in California

Building on Section 3.2, we return here to a more detailed discussion of electricity system planning in California. We focus on selected infrastructure planning activities and current approaches to modeling and data streams at the three state entities that share responsibility for energy- and electricity-related planning and oversight [464].

The California Energy Commission (CEC) conducts a broad suite of activities related to energy policy and planning. CEC's responsibilities include developing integrated policy strategies for the state, funding research and demonstration projects, approving sites for large thermal power plants, setting efficiency standards for buildings and appliances, and certifying renewable energy resources for compliance with the state's Renewable Portfolio Standard. The California Public Utilities Commission (CPUC) regulates essential infrastructure and utility services. CPUC has jurisdictional oversight over investor-owned public utilities that provide electricity and natural gas service, and over private telecommunications, water, and transportation companies. Within the electric utility sector, CPUC is responsible for authorizing procurement that is in the public interest, regulating rates, and ensuring safety.[1] The California Independent Systems Operator (CAISO) operates electric transmission infrastructure and oversees wholesale electric power markets within its planning region, which covers most of the state of California.

C.1.1 Load forecasting

The CEC issues official load forecasts in conjunction with its Integrated Energy Policy Report (IEPR), which is released every two years with updates in the intervening years [192]. Forecasts are generated for *high*, *mid*, and *low* energy demand cases which are designed with varying assumptions about economic growth, electricity and gas prices, energy efficiency, PV generation and EV adoption, weather conditions, and climate change impacts.

[1] Notably, other entities such as Community Choice Aggregation (CCA) programs and Electric Service Providers (ESPs) also serve customer loads in California but CPUC jurisdiction over them is limited. We exclude them from further consideration here.

To date, the underlying weather inputs into CEC's demand forecasts have been based on a sampling of historical weather data. Hourly temperature data collected from 2000 to 2015 was used to inform the demand forecasts published with the 2017 IEPR, and expanded through 2017 for the 2019 IEPR [465, 466]. This historical data was subjected to a random sampling process to identify representative distributions of hourly temperatures. These distributions enabled an estimation of hourly peak demand as well as the ratio of demand in other hours to the peak demand hour [465, p.14-28]. Multiple 'weather years'—full years of hourly temperature data that follow distributions representative of the historical record—were generated for each energy demand case by repeating this process (Figure C.1). From these multiple weather years, CEC issued load forecasts for 1-in-2, 1-in-5, and 1-in-10 weather years intended to represent, for example, a high-demand (hot) year encountered on average once every 10 years [240, 467]. These scenarios are meant to account for uncertainty and contingencies related to extreme weather. However, each forecast is still based on the historical record, which limits its applicability for planning to future incidences of extreme values.

Climate change adjustments to historical weather trends are based on temperature scenarios developed by the Scripps Institution of Oceanography [192]. The *low* demand case incorporates no additional impacts from climate change, while the *mid* and *high* demand cases use adjustments based on 'likely' and 'high' scenarios of temperature increases [192] (Figure C.1). Documentation does not specify which specific Scripps temperature scenarios were chosen or which assumptions are contained therein (see [194] for a more thorough discussion). These temperature adjustments are used to estimate the additional energy consumption and peak impacts for residential and commercial customers within specified planning zones. However, the methods currently used to account for climate impacts on projected demand are not comprehensive: only temperature (specifically, cooling and heating degree days and annual maximum) is considered in the climate change adjustments to historical data used in the 2019 IEPR. Further research is needed to comprehensively account for these impacts.

In addition to the forecast scenarios discussed above—the *low*, *mid*, and *high* energy demand cases, each with their own 1-in-2, 1-in-5, and 1-in-10 weather years—the CEC publishes a *single forecast set* intended for use in statewide planning processes at the CPUC and CAISO. This common forecast uses the *mid* energy demand case discussed above, with its weather years assigned to specific planning purposes (Figure C.1) [192].[2]

C.1.2 Integrated Resource Planning (IRP)

The CPUC's IRP process is the state's primary venue for long-term planning and procurement decision-making related to electricity infrastructure [468]. The biennial process begins with two phases of system-wide modeling activities that aim to identify a portfolio of resources that meet policy goals [469]. First, the RESOLVE capacity expansion model (see Section 3.5 for an overview of infrastructure planning model types) from Energy + Environmental Economics (E3) [470] is

[2]The *single forecast set* also incorporates scenarios for additional energy efficiency savings and PV adoption. We omit further discussion of these here due to our primary focus on weather and climate data used in the demand forecasts.

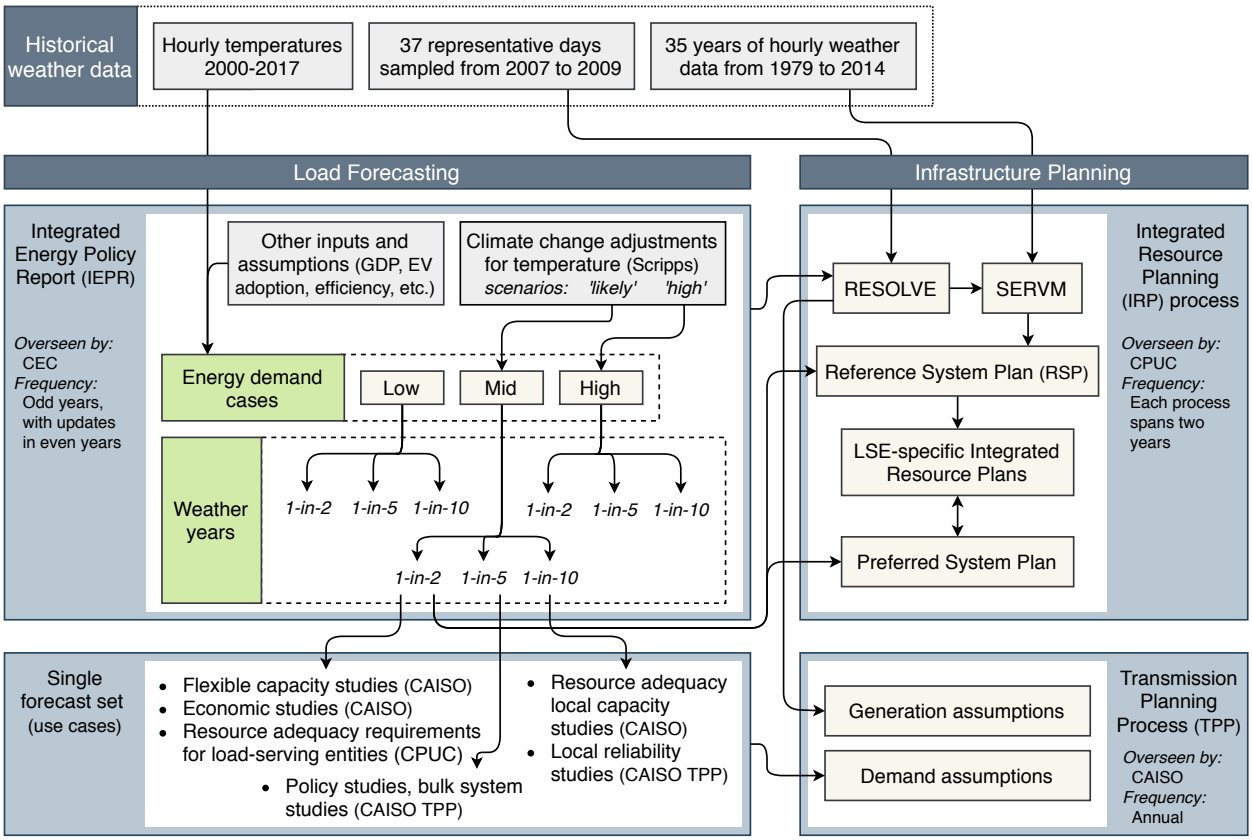


Figure C.1: Data flows in existing California planning processes pertaining to electricity infrastructure planning.

used to develop large-scale planning and procurement scenarios that guide investment decisions. RESOLVE uses the official demand forecasts from CEC's IEPR process as inputs. The model aims to identify the optimal transmission and distribution investments that meet demand while satisfying reliability and policy constraints within a particular geographic area. RESOLVE also relies on historical weather data: the model simulates system operations for 37 days "sampled from the historical meteorological record of the period 2007-2009" that are weighted to "produce a reasonable representation of complete distributions of potential conditions" [471, pp.49-50].

Since RESOLVE models the state's CAISO planning area as a single node [471],[3] its results require post-processing to provide insight about more granular spatial considerations, such as the best way to meet demand in particular load pockets. A second model, the Strategic Energy & Risk Valuation Model (SERVM) from Astrapé Consulting [472], is used by the CPUC to determine whether a full year of hourly demand can be met into the future without adverse reliability im-

[3]RESOLVE models electricity transmission in the western U.S. with six nodes. Four correspond to California balancing authorities, with CAISO modeled as a single node. The other three CA zones correspond to the Los Angeles Department of Water and Power (LADWP), the Imperial Irrigation District (IID), and, together, the Balancing Authority of Northern California (BANC) and Turlock Irrigation District (TID). The other two nodes "represent regional aggregations of out-of-state balancing authorities" in the northwest and southwest [471, p.48].

pacts with the planning scenario proposed by RESOLVE. SERVM tests RESOLVE outputs with a probabilistic distribution of weather years. Within SERVM, the original (unaveraged) historic weather values are preserved and scaled up to annual and peak values projected in future load forecasts [240]. Historical weather data is used to account for a variety of weather conditions that are crucial inputs to predicting future electricity generation from solar and wind resources (e.g., cloud cover and temperature in addition to wind speed and solar irradiance) and capture resource variability [240]. SERVM achieves greater spatial granularity within the CAISO region by dividing California into eight modeling areas, but it is still a simplification of a full network model [240].[4]

The results of this system-wide modeling process are adopted as the Reference System Plan (RSP) [469]. Load serving entities (LSEs), which include regulated utilities, maintain control of specific decisions related to infrastructure planning within their systems. LSEs use the RSP as a guide to develop their preferred approaches to meet planning requirements within their own Integrated Resource Plans. LSE-specific IRPs are submitted to the CPUC, which compiles them into a new system-wide portfolio, evaluates them for compliance, and authorizes procurement based on the amount of capacity deemed necessary for reliability. as part of the General Rate Case (GRC), which occurs every three years [468, 469]. (Additional iterative steps may occur between individual LSE plans and the statewide portfolio prior to approval.) In developing their procurement plans, some LSEs currently use a 1-in-10 historical weather year to prepare for climate-related risks [241, 473].

C.1.3 Transmission Planning Process (TPP)

Each year, CAISO conducts the state's transmission planning process to determine system needs. The process aims to "identify potential system limitations as well as opportunities for system reinforcements that improve reliability and efficiency" [474]. Finalized in March 2018, the data inputs for the 2019 TPP cycle are designed to be consistent with the CPUC's IRP [475]. Specifically, the assumptions pertaining to energy generation in the state come from the CPUC's RESOLVE model, while the demand forecasts come from the CEC's IEPR (Figure C.1).

C.1.4 Risk assessment

In 2013, the CPUC issued the so-called "Risk OIR" to initiate a new paradigm for increasing transparency into how risks are evaluated and prioritized [476]. These analyses inform investment plans that are documented in GRC filings and subsequently acted upon. The Risk OIR gave rise to two new proceedings: the Safety Model Assessment Proceeding (S-MAP) and the Risk Assessment Mitigation Phase (RAMP) proceeding.

S-MAP is intended to provide documentation requisite for both experts and non-experts to understand the logical processes, input variables, and quantitative methods utilities use to exam-

[4]SERVM divides California into eight modeling regions. The four non-CAISO areas are IID, LADWP, BANC, and TID. The CAISO region is divided into four areas corresponding to the utility territories of San Diego Gas & Electric, Pacific Gas & Electric (divided in two), and, together, Southern California Edison and Valley Electric Association [240, p.16].

ine risk exposure [477]. In the context of these proceedings, the concept of "risk" encompasses anything that poses a safety threat (e.g., wildfire, employee safety, public safety). Risk metrics include both reported safety incidents (e.g., "overhead wires down", "fire ignitions", "employee serious injuries or fatalities") and preventative actions that were taken (e.g., employee training, tree trimming, and equipment inspection) [478].

Initial guidelines for RAMP were to enumerate "the top ten asset-related risks for which the utility expects to seek recovery in the GRC" focusing on "asset conditions and mitigating risks to those assets" [479]. These guidelines, however, are intended merely as a starting point; there is a stated expectation that the contents of RAMP filings will evolve as risk assessment protocols become more mature. The S-MAP and RAMP proceedings are designed to facilitate this process by providing transparency into existing risk evaluation practices, and by subjecting them to scrutiny (for example, see [264, 271]). Though risk assessment methods are still evolving, the criticism (and praise) regarding these two proceedings shows that demonstrable progress has already been made. Ultimately, the intention is for the S-MAP and RAMP proceedings to tend towards a risk evaluation paradigm that is consistent across all utilities regulated by the CPUC.

C.1.5 Additional activities

While S-MAP and RAMP are designed to address general risk assessment protocols, a number of other proceedings address additional risk assessment needs on a more targeted ad-hoc basis. Examples include submission of utility wildfire mitigation plans [480], efforts to map wildfire threat [481], and to assess physical threats of grid infrastructure [482]. Other proceedings (e.g., Distribution Resources Planning [483]) may also impact electricity infrastructure planning more broadly by prompting regulated utilities and other stakeholders to consider additional priorities such as distributed renewables integration, public health and safety, and overall system performance.

Notably, recent events related to the increasing frequency and magnitude of wildfires in California have prompted increasing discussion about de-energizing electricity lines and other infrastructure to reduce risk in high-fire conditions. A move towards more frequent de-energization as an operating principle may, in turn, prompt additional focus on distributed operation and planning in contrast to the centralized system planning approach we describe above. This could ultimately lead to a qualitatively different planning framework that more effectively accounts for trade-offs and co-benefits between decisions made in alignment with diverse planning objectives that are currently represented in different proceedings.

C.2 Mechanisms for power production

Here, we provide additional detail on technology-specific first principles for electricity generators and comment on the ways in which changing ambient conditions might affect their performance.

C.2.1 Solar photovoltaics

Power generation from PV cells depends on the available solar irradiance and surrounding temperature, both of which vary with site location [243]. The sun's rays provide photons that act as a current source and trigger the flow of electrons within the PV cell. Solar irradiance is therefore directly proportional to the current within the cell, and a PV cell operating in half-sun will produce roughly half the power of a cell in full sun [484, Ch.5.4]. On the other hand, higher temperatures affect the voltage within the PV cell by speeding up electron-hole recombination before electrons can generate electricity that leaves the cell. PV cell efficiency is typically reported under standard test conditions, which are defined as solar irradiance of 1 kW/m^2 (1 sun), cell temperature of 25, and air mass ratio of 1.5 (AM1.5)[5] [484, Ch.5.6]. The decrease in maximum power generation with temperature varies by PV technology and manufacturer, but can be around 0.24-0.45% per degree Celsius [484, Ch.5.7]. Notably, the operating temperature of a PV cell is also affected by the solar irradiance incident on the cell. The following equation is used to estimate this impact:

$$T_{cell} = T_{amb} + \left(\frac{NOCT - 20}{0.8 kW/m^2} \right) \times S \tag{C.1}$$

where T_{cell} () is the operating cell temperature, T_{amb} () is the actual ambient air temperature, S is actual solar insolation kW/m^2, and $NOCT$ is a standard cell-specific parameter provided by the manufacturer that corresponds to the expected cell temperature under 20 ambient temperature, 0.8 kW/m^2 solar irradiation, and 1 m/s wind speed. A PV panel with NOCT 46 operating at 30 (86) and 1-sun irradiance will therefore have an internal cell temperature of 62.5 (145) and deliver 17% less electricity than is indicated by its rated maximum power capacity [484, Ch.5.7]. Changes from today's performance due to climate change impacts on temperature and solar irradiance can be estimated in a similar manner.

C.2.2 Wind

Regional wind speed patterns play a critical role in decisions related to siting, design, and operations of wind farms. The relationship is best explained by examining the equation relating wind power production to wind speed [485]:

$$P = k \cdot \min\{v, v_r\}^3 \tag{C.2}$$

where P is power produced, v is the current wind speed, v_r is the rated wind speed of the turbine, and k is a lumped parameter describing mechanical and aerodynamic properties of a particular wind turbine design. Equation C.2 holds up to some cut-out wind speed (often 25 mph) which is always greater than v_r. Turbines are turned off when conditions exceed the cut-off wind speed to prevent damage.

[5]The air mass ratio is less critical to the current discussion and is included here primarily for completeness. It describes the amount of air (i.e., atmosphere) that sunlight must travel through to reach the earth. AM1.5 is the standard value used for mid-latitudes, including the contiguous U.S.

Because P scales in proportion to wind speed cubed, wind power production is sensitive to wind speed conditions at a specific site. Because v_r changes for different turbine designs, design decisions are made based on the statistical properties of the wind field at a particular site. Therefore, changes in wind field characteristics could reduce power production from existing wind farms.

C.2.3 Natural gas and other thermal power generation

A typical thermoelectric power plant burns fuel to create high-pressure steam. The steam turns turbine blades, thereby powering an electric generator and converting heat to electricity. The waste heat is released to a low-temperature sink. The thermal efficiency of this cycle can be described as:

$$\eta = \frac{T_{high} - T_{low}}{T_{high}} = \frac{W_{net}}{T_{high}} \tag{C.3}$$

where η corresponds to the thermal efficiency of the plant, T_{high} is the high temperature achieved by burning fuel, T_{low} is the temperature of the low-temperature sink, and W_{net} is the work done by the temperature differential.

A thermal plant's electricity production potential thus depends on the temperature differential between the hot steam from the combustion process and the low-temperature sink of waste heat. This low-temperature sink, typically a nearby body of water or the surrounding air, is crucial to cooling the plant, and its ambient temperature directly affects plant operation and efficiency. Thermal plants throughout the U.S. rely on once-through or recirculating water cooling or dry cooling [245, 247, 486]. Water-cooled systems are also subject to thermal discharge limits [249].

Natural gas plants are the most common types of thermal power plants in California and are frequently used to compensate for variability in solar and wind generation. However, similar considerations apply to other types of thermal power generation, including concentrating solar power plants and some biomass plants.

Appendix D

Chapter 4 Appendix

D.1 Search terms used in literature reviews

Table D.1: Search terms used in searching for academic literature on decision science that considers climate change.

Search term	N
“decision-making” AND “infrastructure planning” AND ”uncertainty”	97
“climate resilience” AND “infrastructure planning”	10
“climate adaptation” AND “infrastructure planning”	28
uncertainty AND “infrastructure planning” AND climate	91
“decision making under deep uncertainty” AND infrastructure	7
“decision making under uncertainty” AND “infrastructure”	59
“decision making under uncertainty” AND “infrastructure planning”	5
“decision making under uncertainty” AND “power systems”	24
“robust decision making” AND ”infrastructure planning”	13
“robust decision making”	645
“decision making under deep uncertainty” AND “infrastructure”	1
“decision making under deep uncertainty”	38

Table D.2: Search terms used in searching for grey literature on decision science.

Search term	N
“decision-making” AND ”uncertainty”	31
“decision making under uncertainty”	33
“decision making under deep uncertainty”	18
“robust decision making” AND uncertainty	27

Table D.3: Search terms used in searching for literature on electricity sector planning under climate change.

Search term	N
"climate change" AND "electricity system planning"	76
"climate change" AND "electricity infrastructure planning"	9
"climate change" AND "electric power systems" AND "decision-making" AND adaptation AND stakeholders	73
"climate change" AND "electricity sector" AND planning AND "decision-making" AND adaptation AND stakeholders AND uncertainty	57
climate AND "electricity planning" AND adaptation	130
climate AND "electricity infrastructure" AND adaptation AND planning	137
climate AND "energy modeling" AND adaptation AND electricity AND infrastructure AND planning	148
climate AND "power system planning" AND adaptation AND electricity AND infrastructure	53

D.2 Coding of utility practice review into activity areas

We reviewed the GRC documents of PG&E and ConEd to identify the types of decisions these utilities are making about their systems. We focused specifically on documents related to these utilities' distribution systems and energy supply. In each set of documents, we identified similar programs and grouped them together, then assigned an activity area name to each group. Activity area descriptions are based on the information contained in GRC documents about the types of actions that utilities are taking in each area. See Section D.4 for a snapshot of our approach.

D.3 Summary of utility activity areas

A review of the GRC filings for PG&E and ConEd illuminates core activity areas for electric utilities that are outlined in Table 4.1. Here, we summarize each of these activity areas and discuss utilities' current approaches as well as the new uncertainties introduced by climate change.

D.3.1 Real-time operations

Activities that fall within **system operations** include monitoring system conditions, evaluating grid needs, and determining and executing potential interventions. These activities occur at both the transmission and distribution system levels. A key difference between the two is the amount of available data: a transmission operations center typically has continuous feeds of raw information regarding the state and stability of the system (e.g., generation profiles and status of large generators, system loads, locational marginal prices (LMPs), system frequency, weather radar, etc.) alongside maps of the service territory. In contrast, a utility's distribution operations center typically relies on fewer automated data inputs. We focus here on the distribution system as both PG&E and ConEd rely on Independent System Operators (ISOs) to manage and operate the transmission system. PG&E's distribution operations center "continuously monitors the electric distribution

system, manages outage restoration, and directs system switching" [179]. Staff monitoring distribution system operations may rely on inputs from call centers were customers report outages that they then triangulate on a map of the utility's service territory. In real time, staff may decide to flip switches to reroute power remotely and/or send crews to investigate outage reports [487]. PG&E also has separate operational practices that are implemented during high fire risk conditions; these include disabling the reclosing operation of circuit breakers and implementing public safety power shutoff (PSPS) events [179]. Increasing frequencies and magnitudes of disruptive severe events and their propagating impacts may impede the ability of utility staff to manage disruptions in real time.

Monitoring and situational awareness activities complement system operations by providing key information about system conditions. Activities in this category include scheduled and as-needed patrols and inspections, where personnel perform visual, mechanical, and electrical inspections to evaluate equipment performance and degree of degradation (e.g., decay of wooden poles, corrosion of electrical equipment). For example, the American National Standards Institute publishes recommended inspection frequencies for substation equipment [267]. Other information can come from sensors that continuously monitor the grid (visually or electrically) for signs of equipment malfunction [488], as well as sensors that monitor external conditions (e.g., weather stations and fire risk). Some of PG&E's activities in this area are specific to fire risk monitoring: for example, patrols and inspections of overhead equipment "to identify damaged facilities and other conditions that pose wildfire risks," and sensors that include a "system to quickly detect and locate downed power lines" and "a network of wildfire cameras and weather stations" [179]. ConEd documents efforts related to communications infrastructure upgrades "to improve operator visibility" and "enhance performance during everyday operations and emergency conditions, such as storms" [293]. Climate disruptions may impact activities in this space, with an important metric being the speed at which events occur. Chronic climate impacts may lead to different metrics and standards for "normal" operation (for example, necessitating more frequent patrols and inspections), while acute impacts may propagate and impact the system more quickly than current practices are designed to respond. ConEd's approved rate filing includes a weather data sensors pilot program to document "the relationship between local climatic conditions and equipment performance and for better planning for system designs and operations" [295]

Emergency response activities begin once an incident occurs, and may include crew deployment to respond to incidents and outages as well as staffing and response at logistics control centers during major emergencies [179]. Emergency response activities may be strained by changing frequencies and magnitudes of extreme events, as well as greater reliance of customers on the electricity grid (i.e., critical loads, electrification). Another concern is the potential for disruptions that affect wide geographic areas. Utilities share resources (e.g., workers and equipment) from nearby regions to help impacted areas following significant disruptions [489]. However, large-scale disruptions may strain this common industry practice.

D.3.2 Maintenance

Electric utilities perform **system maintenance** to preserve the normal functioning of their systems. Routine maintenance may include scheduled equipment cleaning and tuning [179, 293]. Non-routine or preventative maintenance may include evaluating information that has been obtained about equipment performance and condition (for example, through inspections or sensor data, see Section D.3.1) in order to rank priorities, determine next steps, and address issues [488]. Uncertainties related to changing ambient conditions (e.g., higher nighttime temperatures preventing equipment cool-down, higher humidity levels leading to increased corrosion) and system demand may stress current maintenance practices by requiring additional attention to how equipment is affected by changing conditions. More frequent or more extensive outages may also increase stress on equipment and prompt a need for additional inspections. For example, following a prolonged outage, utilities may opt to inspect affected equipment prior to re-powering the lines to reduce the risk of malfunction.

In addition to equipment maintenance, **vegetation management** activities aim to reduce the risk of trees and other vegetation coming into contact with electrical equipment. Vegetation management involves maintaining right-of-ways for transmission and distribution lines by routine inspections and tree trimming, as well as responding to indications that trees may be too close (e.g., customer calls reporting potential hazards, sensor readings of arcing patterns that indicate nearby vegetation) [179, 293]. Relevant climate uncertainties may include changing precipitation patterns that impact the relative rate of growth of different tree species, drought conditions that may lead to drier vegetation with more potential for ignition [179], as well as frequencies of severe storms with the potential to down trees.

D.3.3 Planning

Alongside their day-to-day operations, utilities undertake planning activities to evaluate and improve their current systems, to plan for the future, and to prepare for disruptions. **System planning** activities may involve evaluating system performance through information gathered from situational awareness and maintenance activities to identify opportunities for new and improved functionality (e.g., recloser switches to improve reliability, distribution system controls, capacitor banks, inertia support, changing reserve margins) [179]. Future planning activities may include taking stock of the current system, projecting expected electricity demand into the future, and evaluating the need for new system investments or non-wires alternatives to meet that demand [293, 488]. A common tool used for this is capacity expansion models, which we return to in Section 4.4. Capacity expansion models take in information about a utility's existing system (e.g., the locations and characteristics of generators and lines) as well as projections of future conditions to determine how the grid can best evolve to support future demand.

New climate conditions that diverge from historical patterns may stress system planning practices and justify the need to incorporate uncertainty into planning. For example, assumptions in capacity expansion models may embed an understanding of historical conditions that is no longer true (e.g., through model assumptions, statistical approaches, etc), thereby inadequately accounting

for infrastructure degradation and stresses [258]. New buffers may be needed to maintain system performance amid climate stressors and changing demand patterns, which could themselves be driven by a variety of impacts, including new technology adoption, changes in population growth and density, and changing consumer use patterns and response to rates (e.g., EV charging times). ConEd and PG&E have both conducted climate change vulnerability studies to assess potential climate impacts on their systems [286, 295].

Preparatory planning activities involve planning specifically for response and recovery from system disruptions. Such activities may include training and preparation for logistical coordination and communication during emergencies, community outreach and warning systems, and establishing new protocols (e.g., for public safety power shutoff events) [179, 293]. Preparatory planning activities may be impacted by the changing severity and frequency of extreme events. In particular, the ramifications of climate change on preparatory planning requires evaluating compounding uncertainties, including those stemming from climate conditions as well as how people will respond. Such compounding uncertainties make the realities of what preparatory planning will need to respond to difficult to forecast, and thus require acknowledging the presence of deep uncertainty. Further, increasing reliance of customers on the electricity grid (e.g., due to home and vehicle electrification, or critical loads such as medical equipment), may increase the importance of such activities for more customers.

D.3.4 Investments

Utilities invest in capital and system capabilities to maintain and improve the provision of reliable electricity service to customers. These activities follow from planning activities, which determine where and when investments will be made, and focus on actually implementing those investments within a utility's system. It is likely that changing climate conditions will necessitate greater financial investments to preserve expected levels of safety and reliability in the electric power sector. However, with limited budgets, decision-makers may also have to evaluate which investments are considered to be necessary or nice-to-have to meet existing or revised performance goals.

System expansion includes the deployment of new infrastructure and upgrades of existing infrastructure to enable required power flows to serve new or increased customer demand [179, 293]. This can include bulk system expansion, where utilities invest in generation and/or transmission to increase the overall amount of electricity available in the utility's territory. Bulk system investments are often identified via capacity expansion models (see Section D.3.3). Other investments, such as line extensions to new customers and/or upgrades of local equipment to support increased customer demand, take place at the distribution level [179, 293, 294]. Distribution-level investment needs are typically identified through customer requests for interconnection and/or demand planning studies. Both bulk and distribution-level investments may be impacted by new uncertainties in local climate impacts, such as sea level rise and flooding, which may impact desirable siting locations for new equipment, as well as to factor in risks that were not present before. Uncertainties in system and local demand may also affect the need for new investments.

Other system investments are driven not by the need to support more electricity demand, but to maintain service or improve reliability. **Repairs and replacements** of electrical equipment occur

following equipment failure or an inspection that identifies equipment that has reached or is near the end of its useful life. Equipment may be replaced with functionally similar assets, or utilities may choose to undertake **grid hardening** to upgrade or reinforce existing equipment to improve performance or mitigate emerging threats. Grid hardening activities include improving fire resistance of equipment [179], and strengthening circuits that serve critical loads to be more resistant to storm damage [293]. In either case, changing ambient conditions (e.g., humidity, temperature) may affect equipment lifetimes through degradation and thermal overloading, while changing demand may contribute to equipment stress [56, 258]. Increasing frequencies and magnitudes of severe climate events (e.g., wildfires, strong storms) may also impact what kinds of grid hardening investments are desired and planned for.

Maintaining the performance and reliability of electrical assets may also require investments in non-power infrastructure, referred to here as **system awareness and hardening**. Such investments may include cybersecurity and other security upgrades, threat detection, vulnerability testing, and system mapping. ConEd's efforts in this space include the development of a geospatial tool to consolidate mapping systems and "set the foundation for its Grid Innovation efforts," as well as implementing advancements in intrusion protection systems [293].

D.3.5 Performance and customer engagement

Utilities are required to report a variety of metrics related to performance. These may include reliability metrics, system indices, and information about customer satisfaction. Such metrics are used to track and monitor utility performance and target areas for improvement. They may also be used as an input into performance-based regulation, a regulatory approach in which utilities are rewarded financially for achieving set targets, such as quality of service, deployment of new technologies, emissions reductions, and customer satisfaction [490, 491]. **Performance assessment** activities include the development of these metrics and the processes by which utility performance is evaluated and measured. For example, ConEd revised its approach to reliability metrics in its recent regulatory filings, adopting standardized metrics to measure outages [292, 293]. ConEd is also subject to performance-based regulation that seeks to "improve the efficiency, resiliency and flexibility of the utility's physical networks, reduce consumer total costs and achieve the State's policy objectives" [295], and is required to make investments and seek third-party solutions to do so [292].

Customer programs broadly encompass utility outreach to and engagement of consumers related to energy use and outage management. For example, ConEd administers customer programs related to incentives for the adoption of energy efficiency technologies and home weatherization, demand response participation, electric vehicles, interconnection assistance for distributed energy resources, and outage and restoration notifications [292]. Customer engagement and outreach may also be specifically targeted to low-income customers; ConEd administers a low-income rate discount program and, in their recent regulatory filings, agreed to suspend residential service terminations for non-payment on high heat days [292].

For both performance assessment and customer programs, climate change brings new uncertainties related to a changing regulatory and policy landscape, behavioral responses to changing

conditions that may translate to new demand patterns, and new technology adoption (e.g., increasing rates of air conditioning usage).

D.3.6 Business operations

Activities related to business operations are necessary to enable the functions described above. These include **regulatory standards and compliance** activities, which involve contracting, permitting, and management of licenses and projects to ensure compliance with regulatory and technical standards (e.g., environmental stewardship, generator licensing), participation in regulatory proceedings, and internal decisions about compliance approaches. **Internal operations** include activities related to hiring, training, and staff allocation, as well as the purchase and maintenance of tools, office space, and land to host energy infrastructure. Both regulatory compliance and internal operations activities face risks related to a changing regulatory and policy landscape. Additional **cost management** activities include accounting programs for managing infrastructure and operational costs, such as decommissioning costs for generating facilities, cost recovery for cancelled projects, and balancing accounts for expenses that are uncertain in time, such as disaster response [179]. Such programs use financial instruments to account for cost uncertainty and may include mechanisms for flexible spending. New climate-related uncertainties in this space may include changing insurance practices that could reduce the ability of electric utilities to hedge costs and manage risk.

D.4 Examples of coded utility practice areas

The following tables show our approach for coding utility programs, as reported in their GRC documents, into activity areas. Here, we rely on PG&E's 2020 GRC filing, as approved by the California Public Utilities Commission [179] and ConEd's 2020 joint proposal [292], electric rate case testimonies [293], capital expeditures report [294], and the New York Public Service Commission order adopting these provisions [295].

In each table, the first column contains our activity area coding, and the other columns contain abridged information directly from that utility's GRC. The tables cover real-time operations (Table D.4), maintenance (Table D.5), planning (Table D.6), investments (Tables D.7 and D.8), performance (Table D.9), and business operations (Table D.10).

Table D.4: Examples of utility programs coded in the real-time operations activity category from the 2020 General Rate Cases of PG&E and ConEd.

Activity area	Program	Description	Source
System operations	Enhanced Operational Practices	PG&E's program to reduce the likelihood of wildfire ignitions caused by its electric system by means of special operational practices that PG&E will perform during elevated fire conditions. Enhanced Operational Practices includes the following programs: Public Safety Power Shutoffs (PSPS), Reclose Blocking, Automation and Protection, Wildfire and Infrastructure Protection teams, Aviation Resources	[179, Section 7.1]
	Distribution System Operations	PG&E's Distribution System Operations (DSO) organization continuously monitors the electric distribution system, manages outage restoration, and directs system switching.	[179, Section 7.2]
	Electric T&D: Risk Reduction	To reliably operate its substation and transmission system, the Company uses over 60,000 protective relays, which sense system disturbances and irregularities and automatically intervene to remove equipment from service that may be at risk of damage or failure. The Company makes investments annually in its protective relay systems to improve their operation, maintain regulatory compliance, and reduce specific risks that may contribute to transmission system forced outages.	[293, p.129]
Monitoring & situational awareness	Overhead Patrols and Inspections	PG&E patrols and inspects overhead facilities to identify damaged facilities and other conditions that pose wildfire risks.	[179, Section 7.1]
	Pole Asset Management	Pole Asset Management includes: (a) intrusive inspections of wood poles which involve excavating the ground-line of poles and boring access holes in the pole to assess the presence and extent of decay or deterioration; (b) reinforcement of wood poles as needed; and (c) coordination with other utilities who use the poles.	[179, Section 7.2]
	Electric T&D: Information Technology	Programs and projects in this category will enhance performance during everyday operations and emergency conditions, such as storms. Specifically, they will help the Company gather more granular, real-time data, better analyze system data, and more effectively respond to system conditions.	[293, p.165]
	Electric T&D: Grid Innovation, Smart Sensors	The Smart Sensors program deploys advanced technology to provide visibility of structures, cable equipment, and network protectors in order to analyze performance and identify issues early. The Company requires smart sensors and visibility of the edge of the electric system in order to, 1) better understand the impacts of third parties connecting to the Company's distribution system, 2) allow the increased penetration of DER, and 3) allow automation of certain tasks and inspections normally done in field.	[293, p.60]
	Weather Data Sensors Pilot Program	These programs are designed to inform the Company about the relationship between local climatic conditions and equipment performance and for better planning for system designs and operations.	[295, p.77]
Emergency response	Electric Emergency Recovery	The EER program involves the work in response to routine and major emergencies. This includes responding to incidents and outages during emergencies, performing equipment repairs and replacements related to emergencies, and providing staffing for the Emergency Operations Center (EOC), Regional Emergency Centers (REC) and Operations Emergency Centers (OEC) during major emergencies.	[179, Section 7.2]

Table D.5: Examples of utility programs coded in the maintenance activity category from the 2020 General Rate Cases of PG&E and ConEd.

Activity area	Program	Description	Source
System maintenance	Substation Asset Management	PG&E's Substation Asset Management organization is responsible for managing the repairs and maintenance of equipment located in approximately 760 electric distribution substations. The equipment includes power transformers, circuit breakers, switchgears, protective relays, bus structures, and voltage regulation equipment. The three general categories of expense activities are: (a) Preventive Maintenance; (b) Corrective Maintenance; and (c) Substation Support Activities.	[179, Section 7.2]
	Natural Gas & Solar: Maintenance	Maintenance is used to address labor to maintain the natural gas, PV solar, and fuel cell facilities but also includes costs for materials and required contracts such as maintenance and engineering services.	[179, Section 8.2]
	Electric T&D: System and Transmission	The incremental operations and maintenance expenses associated with the expansion of the Con Edison transmission facilities include weekly operator coverage, regular preventative and scheduled maintenance, and limited facilities and corrective maintenance.	[293, p.89]
Vegetation management	Enhanced Vegetation Management (EVM)	PG&E will remove or trim trees belonging to ten tree species that have been identified to have caused 75 percent of vegetation ignitions in Tier 2 and Tier 3 High Fire Targeted Districts (HFTD) and have a potential of striking electrical distribution lines. PG&E will also remove all trees or tree limbs above distribution lines in Tier 2 and Tier 3 HFTD to give at least a 4-feet clearance to each side of every conductor. In addition, PG&E will increase vegetation-to-line clearances in Tier 2 and Tier 3 HFTD from 18 inches to 48 inches, as required by D.17-12-024.	[179, Section 7.1]
	Electric T&D: Risk Reduction, Tree Trimming	The Company will expand its "Tree Trimming" program to include preemptive removal of 1,400 hazardous/danger trees each year, which are trees on or off the right of way that could contact electric supply lines.	[293, p.98]

Table D.6: Examples of utility programs coded in the planning activity category from the 2020 General Rate Cases of PG&E and ConEd.

Activity area	Program	Description	Source
System planning	Electric Distribution Technology	Asset management projects include map-based field information and real-time asset situational awareness, optimization of planning, upkeep, and replacement of assets, grid interconnection compliance requirements, and customer needs.	[179, Section 7.2]
	Electric Distribution Engineering and Planning	The Engineering and Planning Program supports a variety of asset management and operating activities and its responsibilities include planning, designing, and operating PG&E's electric distribution system.	[179, Section 7.2]
	Electric T&D: System Expansion, Non-Wires Solutions	The Company then determines whether the identified need is a suitable candidate for a NWS by assessing it against the Company's NWS suitability criteria. The suitability criteria identify projects that: 1) are for load relief, 2) have enough lead time to pursue a NWS without foreclosing the opportunity to install a traditional solution if needed, and 3) offer enough capital deferral or displacement to overcome transaction costs and scale issues.	[293, p.72]
Preparatory planning	Emergency Preparedness and Response	Community Wildfire Safety Program (CWSP) initiatives such as establishment of a Wildfire Safety Operations Center (WSOC) in San Francisco, expanded weather station deployment, advanced fire modeling, and enhanced wire down detection. Other projects are technology base camp improvements to permit communication during catastrophes, early earthquake warning, and the project to build an emergency information sharing platform.	[179, Section 7.3]
	Electric T&D: Storm Recovery	The Company will enhance its storm recovery efforts by focusing on three key areas: rapid damage assessment, prompt crew deployment (including mutual aid and contracted overhead resources in addition to Company resources), and improvements to its Outage Management System ("OMS").	[293, p.104]
	Customer Operations Provisions: Disaster Hardening	Implement technology solutions to harden its Internet Protocol ("IP") telephony system in order to maintain operational reliability if outage events occur at both of the Company's dedicated server farms that support the IP telephony system.	[292, pp.96-97]

Table D.7: Examples of utility programs coded in the investments activity category from the 2020 General Rate Cases of PG&E and ConEd (part 1: system expansion, repairs & replacements, and system awareness & security).

Activity area	Program	Description	Source
System expansion	Electric Distribution: Capital, New Business and Work at the Request of Others	Capital projects relate to the installation of electric infrastructure required to connect new customers to PG&E's distribution system and to accommodate increased load from existing customers. These include residential and non- residential connections as well as added load for plug-in electric vehicles and transformer purchases and scrapping. Capital projects relating to WRO cover capital expenditures relating to undergrounding, existing overhead electric facilities, work performed at the request of government entities, developers and customers, state infrastructure projects, etc.	[179, Section 7.3]
	Electric T&D: System Expansion	In cases where capacity constraints cannot be relieved through demand reduction or equipment replacement, the Company will install additional equipment to handle the increased load and relieve capacity constraints. This category includes the installation of additional assets required to connect new customers.	[293, p.77]
Repairs & replacements	Deteriorated Pole Replacement	Inspection work to identify deteriorated wood distribution and transmission poles; Replacement or remediation of deteriorated poles, as appropriate.	[179, Section 7.1]
	Underground Asset Management	Capital projects include reliability cable replacement, cable rejuvenation and testing to evaluate its operating condition, critical operating equipment replacement, systematic replacement of network cable assets and installation of switches, and replacement of load break oil rotary (LBOR) switches.	[179, Section 7.3]
	Equipment Purchases	The Transformer Purchase program purchases new and/or reconditioned electrical distribution equipment - primarily underground network transformers, overhead transformers, pad mount transformers (including mini- pads), emergency generators, and network protectors to support the distribution system for relief, reliability/risk reduction, emergency, and growth programs.	[293, p.147]
System awareness & security	Safety and Security	The Company will improve cybersecurity, increase its ability to detect system threats and attacks, enhance its response to cybersecurity incidents, improve its ability to recover from system damage, expand its ability to find new and latent vulnerabilities in current systems, and maintain its ability to comply with increasing cybersecurity regulatory requirements. Con Edison will continue to evaluate and implement advancements in Intrusion Detection / Protection Systems. The Company will also implement a recently acquired centralized backup system that will dramatically improve disaster recovery and lay the foundation for making operational its Mobile Control Center.	[293, p.153]
	Integrated Grid Platform & Grid Modernization Plan	Electric Distribution Operations Technology projects relate to deployment and integration of a new ADMS and improvement of Distribution Asset GIS Data. Information Technology Capital relates to development of distribution planning tool enhancements, new interconnection tools, and to support development of asset data improvement.	[179, Section 7.3]

Table D.8: Examples of utility programs coded in the investments activity category from the 2020 General Rate Cases of PG&E and ConEd (part 2: grid hardening).

Activity area	Program	Description	Source
Grid hardening	Wildfire System Hardening	This program includes the following: (a) replacing primary and secondary conductor with insulated or covered conductor; (b) replacing existing wood poles with coated, non-wood poles that are more resistant to fire and can support the additional weight of insulated conductors; (c) replacing primary line equipment (fuses, cutouts, and switches) and surge arrestors with equipment that CAL FIRE certified as posing lower fire risk and exempt from vegetation clearance requirements; (d) replacing old overhead distribution line transformers with new units filled with fire resistant insulating fluid; (e) upgrading distribution protection systems to handle faults; and (f) converting targeted overhead distribution lines to underground cable. Additionally, PG&E is creating Resilience Zones which are pre-configured segments of the distribution system that can be isolated from and reconnected to the broader grid. These zones are designed to provide temporary power to critical community services during a Public Safety Power Shut Offs (PSPS) event and can allow quicker service restoration to areas impacted by PSPS.	[179, Section 7.1]
	Distribution Overhead System Hardening and Reliability	This program includes three subprograms: (a) the Overhead Conductor Replacement Program which addresses deteriorating conductors; (b) the Overhead System Hardening Program which rebuilds vulnerable parts of PG&E's overhead electric distribution system; and (c) the Overhead Switch Replacement Program which replaces obsolete switches to minimize potential safety issues. Reliability improvements include resilience zones, sectionalizing via installation of additional line reclosers, the Base Reliability program which reviews electrical outages, the Overhead Protection program which is for installation of overhead protective devices, the FLISR program, which uses remotely operable switches along with sophisticated software, and other reliability work such as line recloser control replacements, targeted circuit programs, etc.	[179, Section 7.3]
	System Resilience	Investments in the System Resilience category are designed to strengthen the Company's electric distribution system, reducing the amount of damage sustained during severe weather events and improving the Company's ability to repair damage and restore service after the events.	[293, p.91]
	Storm Hardening	The Company plans an increase in spending related to storm resiliency, primarily due to lessons learned from winter storms Riley and Quinn. As a result of its post- storm review, the Company plans to enhance the resilience of its non-network circuits by replacing open wire with new stronger wire, adding breakaway service connectors for more customers, reconfiguring 13kV auto loops, and performing additional targeted undergrounding of overhead wire.	[293, p.12]

Table D.9: Examples of utility programs coded in the performance activity category from the 2020 General Rate Cases of PG&E and ConEd.

Activity area	Program	Description	Source
Performance assessment	Earning Adjustment Mechanisms (EAMs)	The Commission has previously declared its intent to create a modern regulatory model that challenges utilities to take actions to achieve the objectives by better aligning utility shareholder financial interest with consumer interests To accomplish its goal, the Commission identified, among other things, the inclusion of EAMs in utility rate plans to incent utilities to invest capital and seek third-party solutions that improve the efficiency, resiliency and flexibility of the utility's physical networks, reduce consumer total costs and achieve the State's policy objectives.	[295, p.75]
	Electric Service Reliability Performance Mechanism	This reliability mechanism establishes nine performance metrics: (a) threshold standards, consisting of system-wide performance targets; (b) a major outage metric; (c) a remote monitoring system metric; (d) a program standard for repairs to damaged poles; (e) a program standard for the removal of temporary shunts; (f) a program standard for the repair of "no current" street lights, and traffic signals; (g) a program standard for over-duty circuit breakers; (h) a program standard for Level II deficiency repairs; and (i) a program standard for the Non-Network Reliability program in Westchester County.	[292, Appendix 14, p.2]
Customer programs	Suspension of Residential Service Terminations During Certain Heat Events	The Company agrees to suspend service terminations for non-payment ("TONP") for residential customers during certain heat events as follows: • On days where the heat index is forecasted by the National Weather Service to reach 93 degrees or higher. • One calendar day before days where the heat index is forecasted by the National Weather Service to reach 93 degrees or higher. • If the actual heat index reaches 93 degrees or higher on a given day, the Company will suspend residential TONPs on the following two calendar days.	[292, p.98]
	Energy Efficiency, Electric Vehicles	General electric EE programs including a heat pump program, kicker incentive, gas EE programs as well as electric and gas EE programs targeted to LMI customers. The Company will continue to facilitate electric vehicles in New York through the SmartCharge New York and Make Ready Infrastructure programs.	[292, p.75, p.81]

Table D.10: Examples of utility programs coded in the business operations activity category from the 2020 General Rate Cases of PG&E and ConEd.

Activity area	Program	Description	Source
Regulatory & standards compliance	Hydro Operations: Relicensing and New License Implementation	For costs to renew and obtain new hydro operating licenses as well as the installation of new equipment and other capital projects required to obtain or renew the licenses.	[179, Section 8.1]
	Natural Gas & Solar: Environmental Support	This function is for addressing waste management and required environmental permits as well as support services, materials, and contracts for disposal of waste materials.	[179, Section 8.2]
	Environmental Programs: Pipe Enhancement Program	The Pipe Enhancement Program is a proactive program designed to reduce dielectric fluid leaks and increase the availability of transmission facilities. It focuses on addressing corrosion on the pipe-type transmission feeder system and includes the large-scale installation of welded barrels or carbon fiber wrap to encase heavily corroded pipe sections, the installation of new pipe coatings, and the associated required excavation, coating removal, inspection, and backfill/restoration tasks.	[293, p.162]
Internal operations	Natural Gas & Solar: Operations	costs for activities such as labor to operate natural gas, PV solar, and fuel cell facilities as well as associated engineering and clerical support personnel. Other costs relate to site management, support services, materials, and contracts for operating the plants.	[179, Section 8.2]
	Information Technology Capital and O&M Expenditure Requirements	Improving process efficiency supports system reliability and improved productivity through adding functionality to existing work management systems, supporting operator training, and streamlining work processes.	[293, p.164]
Cost management	DCPP Cancelled Capital Projects and Recovery of DCPP Net Book Value	Cost recovery of certain cancelled projects pursuant to the DCCP retirement decision. Resulting balance recorded in the Diablo Canyon Retirement Balancing Account (DCRBA).	[179, Section 8.6]
	Major Storm Cost Reserve	The Joint Proposal allows the Company to charge Pre-Staging and Mobilization Costs between $500,000 and $2.5 million per storm event to the electric major storm reserve if incurred in preparation for a major storm that does not ultimately materialize.	[295, p.45]