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California Grid Readiness

Stakeholder and Public Awareness

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Executive Summary

Electrification is rapidly growing in California in many sectors, particularly transportation and buildings. This shift is fundamentally changing both the amount and patterns of electricity consumption on California's power transmission and distribution networks. Due to the impacts of climate change, California is also facing more frequent extreme events, such as wildfires and heat waves. They, too, are creating more stress on the grid, affecting its resilience and reliability. Therefore, it is crucial to ensure that California's electric grid is prepared to face this new reality.

Several reports on this subject already exist from utilities, government, and academia, each typically focusing only on specific aspects or specific stakeholder viewpoints. This white paper, however, aims to bridge these various studies, providing a high-level but broad view of the diverse issues, concerns, projections, suggestions, and solutions that have been raised so far.

This white paper focuses on key concepts and broad subjects in this domain. To prepare this white paper, a wide range of studies were reviewed to address both short-term and long-term challenges, the latter of which is often discussed in academic literature.

Next, we provide a point-by-point summary of the key takeaways in each chapter

Chapter 1: California's Future Electrification Landscape. This chapter covers the current state and the future projections for transportation and building electrification. It also covers the growing electricity demand in industrial sector as well as in emerging energy intensive domains such as hydrogen production and data centers. Some of the key takeaways from Chapter 1 are as follows:

■ Transportation Electrification: The transportation sector is the largest source of greenhouse gas (GHG) emissions in California. The market for Light-duty (LD) Electric Vehicles (EVs) continues to grow, although the growth has slowed down in 2024. Medium-duty (MD) and heavy-duty (HD) vehicle electrification is also crucial for goods movement. Projections for LD/MD/HD EVs are summarized from various studies. The numbers vary due to a wide range of assumptions, such as on EV adoption rates, home charging access rates, workspace charging access rates, daily driving distances and habits, and the role of the state's government and its mandates and targets.

■ Building Electrification: Buildings also account for a significant portion of California's GHG emissions, primarily due to using natural gas for heating and cooking. Building electrification has focused on space and water heating in both residential and commercial buildings. Building electrification is supported by (and can be highly affected by) state policies and programs. The future growth in building electrification will depend on factors such as economic conditions, policy decisions, and incentives, as well as household energy expense (energy burden for electrification).

■ Electrification and Increasing Load in Other Sectors: In addition to LD, MD, and HD vehicles, locomotives and cargo handling equipment are also subject to electrification. Electricity demand is also growing in industrial sector. Hydrogen economy is emerging, especially for transportation and energy storage. Clean hydrogen production is a major electricity-consuming activity. The recent boost in Artificial Intelligence (AI) is increasing the need for data centers, as another emerging sector that can drive significant energy demand in California in the coming years.

■ Clean Energy Generation: The use of clean energy resources has significantly increased in California in recent years. This has been driven by the need to achieve the state's climate goals and meet future electrification demand. Solar and wind are the leading clean energy sources, both of which are variable (intermittent) clean energy resources. Efforts to integrate firm clean energy resources, such as geothermal and biomass, will also be essential to support future electrification.

■ Impact of Climate Change: Climate change is affecting California's energy landscape, such as through altering energy demand amounts and patterns as well as increasing the risk of extreme events such as wildfires. Rising temperatures and extreme weather conditions, such as heatwaves, impact not only electricity generation but also electricity demand, such as for cooling and EV charging. Improved climate models and grid upgrades will be needed to address these impacts.

Chapter 2: Impact on California's Electric Grid: This chapter 2 is built upon Chapter 1 to discuss the expected increases in load and changes in load patterns due to electrification, and how they will impact power distribution and transmission. This capture also cover grid planning, operation, reliability, protection, and power quality. Here are some takeaways from Chapter 2:

■ Increased Electricity Demand: Electrification is expected to significantly raise both the total amount of electricity consumption (measured in gigawatt-hour) and the peak demand (measured in gigawatt). Peak load is crucial because it drives the need for grid capacity upgrades. Different forecasts also suggest notable increases in both total energy and peak power consumption by 2035 for California's major utilities. However, making accurate prediction of future electricity demand, especially for EV charging, is challenging due to limited historical data at early stages of electrification, uncertainty about adoption rates, variability in load patterns per consumers' preferences, and uncertainty in load flexibility at different locations and different circumstances. The future electricity demand can be affected also by other factors, such as enhanced energy efficiency in buildings and vehicles, or usage coordination and intelligent load management.

■ Impact on Load Patterns: Not only the amount but also the timing of peak demand can change as a result of electrification. Bulk charging of EVs during the evening when the solar generation is not available can introduce an additional peak demand hour. There is also another degree of complexity due to the "mobile nature" of EV charging, since each EV affects the load at multiple locations, such as at the EV owner's home (at certain hours) and also at the EV owner's workplace (at other certain hours), further complicating grid upgrade requirements. Furthermore, EV adoption rates and charging patterns are inherently uncertain, making load projections even more difficult. With respect to building electrification, since current peak demand in California occurs during the summer, the impact in the near future can be primarily on the total energy consumption rather than the peak power demand. However, a winter peak demand may also occur due to the growth in electrified space and water heating. Indeed, the recent emphasis on offshore wind power is partly due to the anticipated increase in building loads in winter, when solar production is lower. Lastly, there could be a future surge also in industrial load, water supply and wastewater management load (due to climate change), and hydrogen production.

■ Grid Capacity and Infrastructure Needs: Both power transmission and power distribution networks will need significant upgrades to handle the projected increases in load. To support electrification, improvements will be needed on various aspects, including capacity, reliability, and the ability to handle fluctuating demand while maintaining power quality and stability.

Several factors can affect which power lines and which circuits will require capacity increase. For example, at the power distribution level, residential feeders are estimated to be twice more likely to require capacity increases than commercial feeders, due to the differences between projections for home charging load versus public and fleet charging load. Future growth in local energy resources (such as residential solar, community solar, and community storage) will also affect the extent of needed capacity upgrades at both distribution and transmission networks.

■ Planning and Operation Challenges: Increasing electrification, combined with the increasing variable renewable energy generation, introduces stochastic behavior requiring probabilistic modeling. The technologies for grid planning and operation must be upgraded to manage voltage violations, power quality issues, and grid stability. Effective management will require improvements in monitoring, control systems, and protection technologies.

■ Resilience and Extreme Events: Climate change is causing more frequent extreme events (e.g., wildfires, heatwaves, floods) in California. California's electric grid must adapt to this new reality to maintain reliability and resilience. This means hardening grid equipment and enhancing strategies for service restoration. On the customer side, microgrids can improve resiliency. However, microgrids currently have high cost and often limited duration of clean power supply. Recent innovations, such as Vehicle-to-Grid (V2G) and Vehicle-to-Building (V2B) technologies, can further improve reliability by utilizing EV batteries as emergency power sources.

■ Permitting Challenges: The lengthy processes to approve customer electrification projects and infrastructure upgrades are becoming bottlenecks in electrification efforts, arising from both technical and policy challenges. Site selection for large-scale EV charging is another challenge.

Chapter 3: Grid Investment Needs: This chapter outlines the necessary investment in power distribution and power transmission network equipment upgrades to keep pace with the increasing electrification. Chapter 3 also discusses the challenges and the costs associated with these upgrades, and highlights the importance of integrated planning, technology advancement, and workforce training. Some of the key takeaways from Chapter 3 are as follows:

■ Investment in Distribution Network Equipment Upgrade: Distribution network equipment, such as transformers, need to be upgraded to accommodate electrification, especially for adding EV charging stations. Areas with high projected load growth are of particular concern. As a case study example, City of Jurupa Valley is undergoing major grid investments due to electrification, including new distribution circuits, substation upgrades, and sub-transmission system upgrades.

■ Investment in Transmission Network Equipment Upgrades: Upgrades in power transmission networks need to be done for both capacity enhancements and efficiency improvements. The latter is needed to better use the existing capacity; because new transmission projects can take years to complete. Furthermore, transmission network upgrades should minimize the impact of localized weather events to ensure reliability and resilience under various contingency scenarios. This is necessary to enable geographic diversification of renewable power, such as solar and on-shore and off-shore wind, meeting decarbonization goals while keeping the grid reliable.

■ Capacity Upgrades: Investments will focus on capacity upgrades to handle increased loads from electrification; across both power distribution systems and power transmission systems. For instance, for the case study example of Jurupa Valley, Southern California Edison (SCE)'s projections suggest a huge increase in load growth from 127 mega-volt-ampere (MVA) in 2023 to 172 MVA in 2024, exemplifying the rapid pace of demand escalation. Out of 30 upcoming charging stations projects in Jurupa Valley, nine will each create at least 1 MVA EV charging load. The largest EV charging station project in this list alone will create 15 MVA new load.

■ Reliability and Power Quality Upgrades: In addition to increasing capacity, investments will be needed to also improve reliability and power quality in the face of increasing electrification.

■ Investment Quantities: Investment projections discuss the number of upgrades to substations, transmission lines, and distribution circuits, but specific figures vary depending on the utility and region. A summary of the investment needs in the literature is provided for different utilities.

■ Estimating Investment Costs: Different methods are used in the literature to estimate the costs, both based on unit upgrade costs (such as per transformer equipment upgrade), and also based on overall upgrade costs. A summary of several existing estimations in the literature is provided.

■ Efficiency and Bridge Technologies: Investments are necessary also to increase the efficiency of grid operations, including advanced technologies to optimize existing infrastructure.

■ Investment in Grid Edge Coordination and Demand Response Technologies: At the "edge" of the grid, customer-side energy technologies have proliferated in recent years. With proper technologies, such as Demand Response (DR) and Distributed Energy Resources Management Systems (DERMS), one can reduce peak demand and better integrate renewable resources.

■ Investment in Operation, Control, and Protection Technologies: These investments focus on modernizing control systems to manage the power grid more effectively. Because electrification increases demand and overall operation complexity, these systems are crucial for real-time grid operation and flexibility, enhanced protection, and faster service restoration after power outages.

■ Investment in Grid Resilience Technologies: Investing in grid resilience technologies is also crucial to protecting the grid from increasing climate-related challenges. Grid resilience strategies include equipment hardening and advanced monitoring and control technologies to take timely remedial actions, including in the more vulnerable rural and underserved areas.

■ Investment in Cyber-Security Technologies: With the increase in electrification, the power infrastructure is becoming more vulnerable to attacks against grid edge resources. Such attacks may compromise a group of controllable loads and/or DERs and turn them into distributed "physical botnets" against the electric grid; analogous to how computer botnets work in distributed denial-of-service attacks on the Internet. The aggregated impact can significant.

■ Investment in Workforce Training: Grid upgrades and maintenance will require access to a skilled workforce. Investment will be needed in programs that can train qualified workforce.

<u>Chapter 4: Societal and Policy Implications:</u> This chapter addresses the broader social and economic impacts of electrification. It covers matters such as supply chain considerations, the need for workforce training, equity considerations, and the importance of public awareness and stakeholder engagement. Here are some of the key takeaways from the discussions in Chapter 4:

■ Consequences of Inaction: Electrification offers broad societal and economic benefits, such as better air quality, reduced health issues, and increased job creation in green industries. Failure to upgrade California's grid would prevent the full realization of these benefits. It could also increase recovery costs from disasters as extreme events become more frequent in California.

■ Impact on Equity: The rising cost of electricity in California, already being the second-highest in the nation, disproportionately affects lower-income households. Wealthier neighborhoods are more likely to adopt electrification, leading to inequality in grid upgrades and investment focus. Rural and disadvantaged communities face higher barriers to electrification due to structural challenges, less reliable circuits, distance from generation centers and higher upgrade costs.

■ Policy Challenges: Electrification is a complex process. As such, it requires collaboration across energy, transportation, infrastructure, and environmental policy sectors. An overarching challenge is how to balance decarbonization goals with affordability and equitable access, all while maintaining grid reliability. There are also supply chain issues for grid equipment, such as transformers and cables, which can result in delays, increased costs, and bottlenecks.

■ Stakeholder Coordination: A state agency can be designated to oversee policy and technical issues by streamlining input and data from various agencies and stakeholders into a shared system, identifying gaps in data availability and data accuracy, and improving projection models to be used for proactively planning future grid upgrades. Collaboration is encouraged among diverse stakeholders, including state agencies, federal agencies, investor-owned and public utilities, system operators, city and county governments, tribal governments, housing authorities, neighborhood councils, community organizations, environmental justice organizations, community choice aggregators, academic and research institutions, workforce training groups, customer advocate groups, local business groups, unions, and technology providers.

■ Transparent Investment and Oversight: Transparency in funding sources and investment decisions will help build trust and ensure that grid upgrades benefit all. Furthermore, investments in grid modernization must be equitable, addressing the needs of disadvantaged communities that are disproportionately affected by electricity price increases and grid reliability challenges.

■ Public Awareness: Policymakers may continue to emphasize the benefits of electrification, such as improved air quality, reduced GHG emissions, and long-term cost savings, while also openly discussing the transitional cost and potential financial impacts on customers. Community leaders can help by providing direct insights into the concerns and priorities of different communities.

The authors would like to conclude this summary by emphasizing that the path to electrification and a modernized grid is complex and multifaceted. The increasing frequency of extreme events due to climate change adds another layer of complexity to this process. To ensure California's grid readiness, we need comprehensive planning, robust stakeholder engagement at both state and local levels, streamlined policies, and a commitment to equity and transparency. By addressing these areas, California can create a resilient, efficient, and inclusive energy system for all its residents.

Abbreviations

AB: Assembly Bill

ADMS: Advanced Distribution Management System

AI: Artificial Intelligence

AMI: Advanced Metering Infrastructure

AQMD: Air Quality Management District

BUILD: Building Initiative for Low-Emissions Development

CAISO: California Independent System Operator

CARB: California Air Resources Board

CCAs: Community Choice Aggregators

CEC: California Energy Commission

CPUC: California Public Utilities Commission

DCFC: Direct Current Fast Chargers

DERMS: Distributed Energy Resource Management Systems

DERs: Distributed Energy Resources

DIDF: Distribution Investment Deferral Framework

DDoS: Distributed Denial-of-Service

DL: Dynamic Line Rating

DOE: Department of Energy

DR: Demand Response

DRMS: Demand Response Management Systems

EIA: Energy Information Administration

EPA: Environmental Protection Agency

EVs: Electric Vehicles

FACTS: Flexible AC Transmission Systems

FERC: Federal Energy Regulatory Commission

FLISR: Fault Location, Isolation, and Service Restoration

GHG: Greenhouse Gas

HD: Heavy-Duty

HVDC: High-Voltage Direct Current transmission lines

IBR: Inverter-Based Resource

ICT: Innovative Clean Transit

IOUs: Investor-Owned Utilities

LADWP: Los Angeles Department of Water and Power

LA: Los Angeles

L1: Level 1

L2: Level 2

L3: Level 3

LD: Light-Duty

LF: Load Factor

MDMS: Meter Data Management System

MD: Medium-Duty

MHD: Medium- and Heavy-Duty

MUDs: Multi-Unit Dwellings

NEM: Net Energy Metering

OMS: Outage Management System

PG&E: Pacific Gas and Electric

PPP: Public Purpose Programs

PSPS: Public Safety Power Shutoffs

PV: Photovoltaic

RS: Receiving Station

SCAG: Southern California Association of Governments

SCE: Southern California Edison

SB: Senate Bill

SDG&E: San Diego Gas and Electric

SUDs: Single-Unit Dwellings

TECH: Technology and Equipment for Clean Heating

THD: Total Harmonic Distortion

TNCs: Transportation Network Companies

TOU: Time-of-Use

V2B: Vehicle-to-Building

V2G: Vehicle-to-Grid

WMUs: Waveform Measurement Units

ZEV: Zero Emission Vehicle

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Preface

Electrification is rapidly growing in California, in transportation, buildings, and other sectors. This shift is fundamentally changing both the amount and the patterns of electricity consumption on the state’s power transmission and distribution networks. Furthermore, due to the impacts of climate change, California is also facing more frequent extreme events, such as wildfires and heat waves. They, too, are creating more stress on the grid, affecting its resilience and reliability. Therefore, it is crucial to ensure that California's electric grid is prepared to face this new reality.

There are already several reports on this subject, from utilities, government, and academia, each one typically focusing on some specific aspects or specific stakeholder viewpoints. This white paper, however, aims to bridge these various studies, providing a high-level but broad view of the diverse issues, concerns, projections, and solutions that have been raised so far.

This white paper is prepared by the University of California, Riverside, with support and input from an advisory board of utility, industry, and local government representatives, to offer different perspectives and to initiate a dialogue among the relevant stakeholders in this area.

Readers, depending on their background, might be more familiar with certain aspects while less familiar with many others. The goal here is to increase the overall awareness about the wide range of topics discussed in the literature to date. No single document has previously covered all these diverse topics, making this white paper unique in terms of its broad coverage.

In preparing this document, a wide range of studies were reviewed, considering both short-term and long-term challenges. The latter is often discussed in academic literature. Throughout this paper, we strived to maintain an independent perspective, taking an honest-broker approach.

Such a broad view has inevitably prevented us from getting into details in any specific direction. Therefore, references are provided to allow readers to explore particular topic in more details.

Wherever possible, numbers and quantitative discussions are provided based on existing studies. However, these numbers should be considered with caution. They are included here to offer some basic numerical context from various studies, rather than to provide definitive assessments.

We hope that this white paper provides a deeper understanding of this complex subject, encouraging dialogue and collaboration among all relevant stakeholders and policymakers.

CHAPTER 1: CALIFORNIA'S FUTURE ELECTRIFICATION LANDSCAPE

California's ambitious goals for reducing greenhouse gas emissions and achieving a carbon-neutral economy by 2045 depend on widespread electrification across multiple sectors. This chapter provides an overview of the state's future electrification landscape, exploring the pathways for electrifying transportation, buildings, industry, and other key sectors.

1.1. TRANSPORTATION ELECTRIFICATION

The transportation sector is currently the largest source of Greenhouse Gas (GHG) emissions in California, responsible for about 50% of the state's climate-altering emissions [1]. Vehicle exhaust also accounts for approximately 80% of the smog-forming gases and other air pollutants linked to premature deaths from respiratory and heart diseases. To address these problems, California has put in place a variety of policies to increase the adoption of electric vehicles (EVs).

In 2018, Governor Brown issued Executive Order B-48-18, which established the target of 5 million EVs on California roads by 2030. In 2020, Governor Newsom expanded this goal when he issued Executive Order N-79-20, requiring that 100% of new passenger cars and trucks sold in California be zero-emission by 2035. Further, 100% of medium- and heavy-duty vehicles sold in the state must be zero-emission by 2045. Many state programs have been put into place to support these goals, such as the California Air Resources Board's (CARB) Clean Vehicle Rebate Program and the California Public Utilities Commission's (CPUC) push to install more charging infrastructure, including Direct Current Fast Chargers (DCFC) [1]. Currently, California has nearly half of the total U.S. zero-emission EV sales [1].

So far, transportation electrification in California has been dominated by light-duty EV adoption for consumer ownership; however, there is a growing trend to expand transportation electrification in a variety of other sections, including commercial medium- and heavy-duty vehicles, buses, rail, shipping, and aviation [2].

1.1.1. LIGHT-DUTY VEHICLE ELECTRIFICATION

At the end of 2023, there were approximately 1.1 million Light-Duty (LD) EVs on the road in California [3]. The LD EV market continues to grow at approximately 40% to 80% each year [4]; although the growth has slowed down in 2024 [5]. A combination of policy actions, incentives, and a decline in the total cost of owning EVs has been among the key drivers of the increased rate of adoption. LD EVs have also become the state's second-largest export [1].

LD EVs can be charged by Level 1 (L1) wall-plug chargers, Level 2 (L2) 220-volt chargers at public charging stations or installed at home, and Level 3 (L3) or Direct Current Fast Chargers (DCFCs) at designated fast charging stations. L1 chargers typically operate at 1.2 kW, L2 at 6.6 kW, and L3 anywhere from 50 kW to 350 kW [6]. Due to supporting higher charge power, DCFCs can charge at a much faster rate than L1 and L2 chargers.

LD EV charging can be done in a number of ways, during both primary and secondary charging opportunities. Primary charging is typically when the EV receives the majority of its energy, such as charging at home (e.g., single-unit and multi-unit dwellings for personal EVs), or fleet charging stations for fleet EVs [7]. Currently, the majority of LD EV charging in California occurs at single-family residences [7]. In fact, so far, one of the key enablers for the early adoption of LD EVs has been the convenient option of charging at home, where vehicles tend to remain parked for long durations overnight. However, going forward, there is uncertainty around how effectively home charging can scale up as the primary charging location for EV owners [8]. More drivers who do not have residential charging may need to rely on other options for primary charging.

Secondary charging provides supplemental charging to help meet an EV's remaining energy needs. It can be done at public stations, at the workplace, or potentially in the form of "corridor charging", such as by stopping at rest areas and other convenient locations when an EV is on a longer trip. As we discuss later in this chapter, the existing EV projections require making assumptions on various scenarios on the level of access to distinct types of primary and secondary charging ports.

Public charging stations are being installed by many different entities at a variety of locations. For instance, in Los Angeles (LA), the City of LA, the County of LA, and the LA Department of Water and Power (LADWP) have each installed DCFCs at public locations, such as public buildings and parking lots. The City of LA has also installed L2 chargers at streetlights [9]. The private sector has also been active in installing public charging ports, such as in multi-unit dwellings. Further, a number of private companies and coalitions of major automakers are also building out fast-charging networks across California and in the United States in urban and highway locations [9].

Per current estimates, approximately 85 charging ports are needed per 100 LD EVs [8], [10]. Going forward, installing more charging points, including at public locations and workplaces, is considered to be necessary to fully ensure reaching California's decarbonization targets in the transportation sector.

1.1.2. Medium-Duty and Heavy-Duty Vehicle Electrification

Electrifying medium-duty (MD) and heavy-duty (HD) vehicles is another crucial strategy for reducing California's GHG emissions and improving air quality. The California Air Resources Board (CARB) has recently passed the Advanced Clean Fleets rule, which sets the year of 2036 as the deadline for all new commercial trucks sold in the state to be zero-emission and the year of 2042 as the deadline for all commercial trucks on the road to be emissions-free [1].

Because Southern California is a major entry point for approximately 40% of the nation's goods, it is critical to expand the electrification of goods movement trucking industry. To support this transition, charging infrastructure must be available at truck parking spaces where drivers take mandatory rest periods [11]. For example, Interstate 710 (I-710) which connects the Ports of LA and Long Beach with Southern California's road network, is now considered a "goods movement corridor" with strategically placed charging infrastructure [9]. In a separate study, the California Energy Commission (CEC) has identified a need for 157,000 DCFCs to support 180,000 medium- and heavy-duty EV trucks [11].

CARB has recently adopted the Advanced Clean Fleets rule, requiring 25% of box trucks and package delivery vehicles to be zero-emission by 2028 and 100% of drayage trucks (used for moving goods over short distances) to be zero-emission by 2035 [9]. Other entities have also set targets for different types of MD vehicle electrification, such as reaching 40% electrification for short haul and drayage trucks and 5% electrification for heavy-duty long-haul trucks by 2028 [9].

The electrification of buses can also make a significant difference towards decarbonization and air quality. CARB has also introduced the Innovative Clean Transit (ICT) rule, which requires California public transit agencies to shift their bus fleets to zero emissions by 2040 [12]. There are currently 1,287 school buses and 2,096 transit buses in Los Angeles [13]. By 2028, 45% of school buses in LA County and 100% of school bus sales are targeted to be electric [9]. Riding a diesel school bus contributes 33% of a child's daily exposure to certain air pollutants.

1.1.3. TRANSPORTATION ELECTRIFICATION FORECASTS

A wide range of factors has been used in recent years to form the assumptions that play a role in different projections when it comes to the future of transportation electrification in California. One key factor in practically all predictions has been the role of the state's government and its mandates and targets. For instance, in [14], it is argued that since Executive Order N-79-20 mandates that all new passenger vehicles sold in California by 2035 to be zero-emission vehicles, and since vehicles have a less than 15 years turnover rate, all or nearly all light-duty vehicles in California could be net-zero by 2050.

Other studies similarly take into account the targets that are set forth by state agencies, either for the entire state or for certain territories, such as the service territories of the three investor-owned utilities (IOU). In addition, a number of other factors are also considered. For instance, when it comes to projecting for LD EVs, assumptions can be made on adoption rate, home charging access rate, workspace charging access rate, daily driving distance/habits, and weather conditions [8].

Depending on these assumptions, the results in the existing projections can be quite different:

- For example, per the analysis in [7], a low adoption rate leads to projecting 3.1 million EVs in California by 2035, while a high adoption rate leads to projecting 10 million EVs, i.e., a three-fold difference between the low adoption scenario and a high adoption scenario.
- As another example, in [13], comparison was made between two scenarios to project the number of LD EVs in California by 2045. In the first scenario, 25% of EV owners would have access to workplace charging, while 75% would have access to residential charging. In the second scenario, 50% of EV owners would have access to workplace charging and 60% would have access to residential charging, with some having access to both. It was argued that access to residential charging would decrease as more EVs are adopted, due to the increase in EV ownership among people living in homes without dedicated chargers (e.g., residences with on-street parking). Per [13], the number of LD EVs for 2045 will be 30% for the first scenario and 80% for the second scenario, a three-fold difference.
- As a third example, in [8], it was assumed that 90% of EVs will have access to reliable overnight charging, which is much higher than the 60% to 75% assumptions in [13].

One area to improve in the future is to tighten up the uncertainty factors through more sophisticated data and models to allow more reliable and tighter assumptions. However, currently, it is unlikely that one can produce a precise projection for the next 1 or 2 decades. Instead, one can collectively look at the existing projections and compare them to gain better insights. For example, Figure 1 shows the estimates for 2045 from three utilities in Southern California. Southern California Edison (SCE) [15] [16] and San Diego Gas and Electric (SDG&E) are IOUs, while LADWP is a public utility (in Los Angeles). Please note that no comparable data was available to include in Figure 1 regarding LADWP's MD and HD EVs.

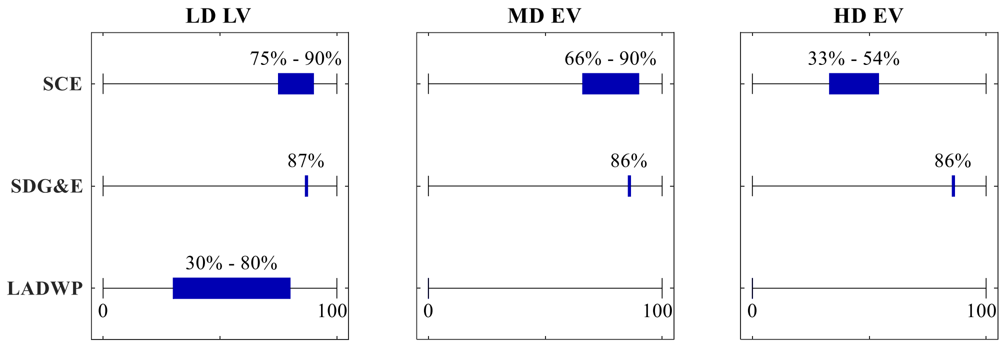

Figure 1. Projections for percentage increases in transportation electrification by 2045 compared to the current levels for different vehicle categories and for service territories of different utilities: SCE [15] [16], SDG&E [17], and LADWP [13].

Pacific Gas and Electric (PG&E) has a more aggressive goal to reach by 2030: LD EVs to reach 100% adoption, MD EVs to reach 50% adoption, and HD EVs to reach 20% adoption [18].

Finally, some projections have estimated the number of charging points. For instance, per Assembly Bill 2127's Second Electric Vehicle Charging Infrastructure Assessment, California will need to host over one million public and shared private EV chargers by 2030 and over 2.1 million public and shared private EV chargers by 2035 [19]. Furthermore, it is projected in [10] that the following ten counties will host the largest number of charging stations for MD and HD EVs: Los Angeles (17%), San Bernardino (8%), San Diego (7%), Alameda (7%), Kern (6%), Riverside (5%), Santa Clara (4%), Orange (4%), Fresno (4%), and Sacramento (4%) [10].

1.2. BUILDING ELECTRIFICATION

Today, residential and commercial buildings represent about 25% of California's GHG emissions [20]. These emissions primarily come from the use of natural gas for space and water heating. These emissions can be decarbonized by electrifying space and water heating equipment or substituting the burning of natural gas with electric appliances [17]. In fact, research has shown that building electrification is likely to be the least-cost and least-risk option for decarbonizing much of California's building sector [21], while potentially greatly improving indoor air pollution.

Building electrification is done both in new constructions and by retrofitting existing buildings. It includes many end-uses in both residential and commercial sectors, including space heating, water heating, and various home appliances such as cooking [2]. In 2022, for the first time, electric appliances outsold gas appliances nationally, for space and water heating.

Under CARB's proposed zero-GHG appliance standards, starting in 2030, all new space and water heating equipment must be non-emitting, so customers would need to electrify their space and water heating when their current gas equipment reaches end-of-life (if after 2030) [21]. Both South Coast Air Quality Management District (AQMD) and Bay Area AQMD also have set forth rules and incentives for electrifying space heating, cooking, and other building appliances [22] [23].

State legislation, CPUC proceedings, and local building codes are expected to further drive building electrification. For example, Senate Bill (SB) 1477 and Assembly Bill (AB) 3232 are designed to reduce GHG emissions from buildings and support local electrification laws [7]. As another example, the CPUC has recently authorized $435 million through 2024 to spur the clean building technologies market. Other related programs include: BUILD (Building Initiative for Low-Emissions Development), which provides incentives for the installation of decarbonizing technologies such as heat pumps in all-electric, low-income new construction; and TECH (Technology and Equipment for Clean Heating), which provides incentives to manufacturers and training for installers of low-emission space and water heaters in initial stages of market development [1]; and the Self-Generation Incentive Program for Heat Pump Water Heater (HPWH) [24]. Moreover, CEC's Equitable Building Decarbonization Program was authorized in 2022 with $1.1 billion in funding to reduce GHG emissions from buildings [15]. Governor's Office has committed to $6 million heat pumps by 2030 [25]and CEC has funded a public/private partnership (the Heat Pump Partnership), where several manufacturers have committed to helping California achieve its building electrification targets [26].

The growth in building electrification will depend on many factors, such as economic conditions, policy decisions, and incentives. However, these factors are difficult to predict over the next decade. Therefore, instead of making specific predictions, the common approach in the literature is to consider a *range* of forecasts based on various assumptions. For example, in [13], projections are made for building electrification under Moderate and High adoption scenarios. Electrification models for residential buildings considered space heating, water heating, clothes dryers, and cooking ranges. Electrification models for commercial buildings considered only space heating and water heating [13]. The Moderate projection assumed "above-code" improvements to energy efficiency and also more use of electric heat-pump technologies in buildings. Appliance efficiency is across a wide range of efficiency levels. The High projection assumes a bigger effort to decarbonize buildings, assuming that almost all appliances and heating and other equipment in buildings would switch from natural gas to electric. The High energy efficiency target assumes that customers buy almost exclusively the most efficient building materials and appliances [27].

Various factors have been considered in the existing predictions for building electrification, such as household energy expense (energy burden for electrification) as a factor to predict adoption in residential buildings. For example, in [15], Southern California Edison anticipates $3,880 for an "adopter" household for home energy electrification in 2045, while San Diego Gas and Electric estimates $4,240 for an "adopter" household [17]. It is anticipated that "first adopters" will initially face higher costs but the prices may reduce in later years.

Figure 2 shows the estimates for growth in (commercial and residential) building electrification for electrified space heating projections and electrified water heating projections by 2045 from three utilities in Southern California: SCE and SDG&E are IOUs and LADWP is a public utility.

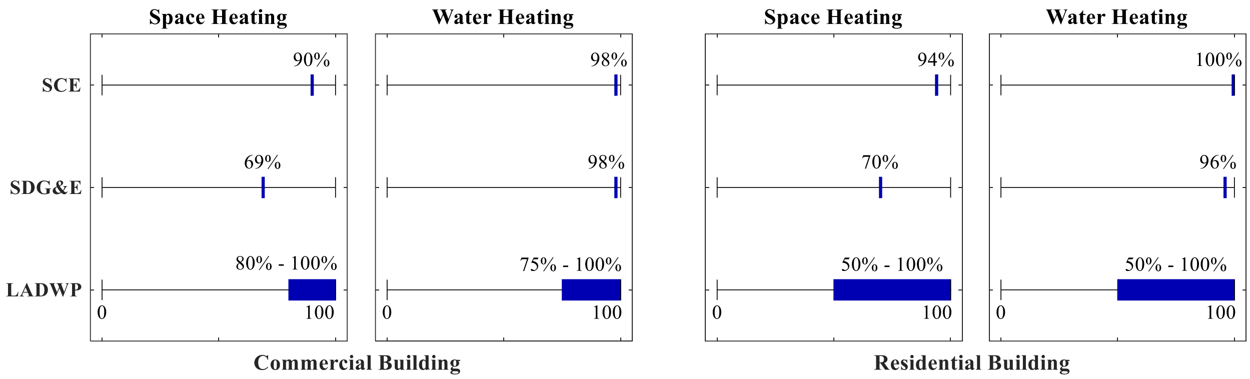

Figure 2. Projections for percentage increases in building electrification by 2045 compared to the current levels for space heating and water heating in commercial and residential buildings and for service territories of different utilities: SCE [15], SDG&E [17], and LADWP [13].

1.3. ELECTRIFICATION OR INCREASING LOAD IN OTHER SECTORS

Besides transportation and building electrification, there are other areas of electrification and other areas of significant load growth that will affect California's future electricity usage landscape. Some of these areas include industrial loads, hydrogen production, and data center loads.

1.3.1. ELECTRIFICATION OF LOCOMOTIVES AND CARGO HANDLING EQUIPMENT

Throughout this document, such as in Section 1.1, the topic of transportation electrification is almost always discussed in the context of LD, MD, and HD EVs, due to their increasing prevalence. However, other types of transportation electrification may also in the future have a considerable impact on the power grid, such as the increasing electrification of train locomotives and electrification of cargo handling equipment (yard tractors, forklifts, and rubber-tired gantry cranes). In California, the electrification of locomotives is gaining momentum as part of the state's broader decarbonization goals. Several pilot projects underway to integrate electric trains into the regional rail network [28] [29]. Additionally, the transition to electric cargo handling equipment at major ports, such as the Port of Los Angeles and Port of Long Beach, is expected to significantly reduce GHG emissions and alter local power demand patterns [30].

1.3.2. CHANGES AND ELECTRIFICATION IN INDUSTRIAL SECTOR

Industrial processes and industrial facilities often involve high energy consumption and significant GHG emissions, making their electrification impactful towards reducing overall GHG emissions. Therefore, industrial electrification is a separate sector from the electrification of residential and commercial buildings, with industry-specific end uses that often need to be considered separately from building electrification [2]. Industrial electrification has seen a gradual increase, with estimates suggesting that 30% of industrial loads could be electrified by 2045 [15].

One such example is water management. It encompasses both rural areas (for water irrigation and water movement) and urban areas (wastewater treatment, groundwater recharge, water recycling). Although water management is already electrified, climate change will likely increase the amount of load in this sector, because of its impact on precipitation and water management needs [13].

Other examples of industrial load include warehousing, manufacturing, cold storage, agriculture equipment, and the operation of heavy machinery. As these sectors increasingly transition to electric-powered systems, their electricity usage will grow, affecting the load at their locations.

1.3.3. THE ROLE OF HYDROGEN PRODUCTION LOAD

The hydrogen economy is expected to grow significantly in California in the coming years. Hydrogen-fueled transportation, particularly hydrogen vehicles, is one of the two primary clean transportation options that are recognized in Executive Order N-79-20, alongside electric vehicles. Hydrogen can also be used for energy storage and to directly generate electricity.

To produce clean hydrogen, it is essential to use electrolyzers (to split water into hydrogen and oxygen through a chemical process). The produced hydrogen is then used for hydrogen vehicle refueling stations or for stationary energy storage. However, electrolyzers are major electricity-consuming equipment. Therefore, the electrical load of clean hydrogen production can be another potential pivotal element in California's future electrification landscape.

The global projects for buildings pipelines for electrolyzed hydrogen have grown significantly in recent years [15]. In California, a program by the CARB is funding the installation of both DCFC EV chargers and hydrogen fuel stations, promoting the adoption of clean hydrogen technologies.

Clean hydrogen can enhance the reliability of the electric supply and complement broader electrification efforts, along with implementing large amounts of renewable generation. Per the analysis in [17], the demand for clean hydrogen in California could reach 6.5 million metric tons by 2045. Meeting this demand will require significant electrification for hydrogen generation.

1.3.4. DATA CENTERS AND AI ENERGY USAGE

Data centers are already major consumers of electricity. The growing computational load from artificial intelligence (AI) will play a role in further increasing the electric consumption of data centers. As AI technologies advance and become more widespread, they will need more powerful hardware, such as GPUs and specialized AI chips, which consume large amounts of electricity. This is particularly true in data centers where large-scale AI computations are performed.

The emergence of AI and the increasing use of power-hungry GPUs and AI-specific data centers are expected to continue driving the trend of rising energy demands. The use of AI across various sectors, such as in automated vehicles, healthcare, and power grid modernization, will further influence electricity consumption patterns in the next decade. On the other hand, there is also ongoing research to make AI algorithms and hardware more energy efficient to reduce their load.

1.4. CLEAN ENERGY GENERATION AND IMPACT OF CLIMATE CHANGE

1.4.1. CLEAN ENERGY GENERATION

While the focus in this document is on electrification and the demand side, it is important to also briefly discuss the future landscape of power generation. A clean power generation infrastructure is a backbone to support the decarbonization of transportation, buildings, and other sectors. Together with the electricity sector, these sectors account for 92% of California's GHG emissions. California is now receiving 60% of its electricity from carbon-free resources [31]. Senate Bill 100 requires zero-carbon resources to supply 100% of electric retail sales to customers by 2045 [1].

Broadly speaking, clean energy generation can be divided into two categories: *variable* and *firm*.

CLEAN VARIABLE POWER:

Solar and wind power generation are currently the most widely adopted clean energy options in California. They are both intermittent renewable energy sources, as their output can vary depending on weather conditions, such as wind speed and solar irradiance.

Solar generation is the most widely deployed clean energy technology in California, in the form of both distribution behind-the-meter generation as well as utility-scale generation options.

In 2018, the CEC adopted a building energy efficiency code requiring most new homes to have solar photovoltaic systems or be powered by a nearby solar array starting in 2020. With continuing cost declines, solar is now cost-effective for new home construction across the state. In 2019, California reached the milestone of 1 million solar rooftop installations [1].

Utility-scale solar generation capacity across the three IOUs has also grown substantially in recent years. Figure 3 provides a summary of the projections in this area per the analysis in [31], considering "Low" projections (at historical rates), "Medium" projections (at rates in Senate Bill 100), and "High" projections (beyond the rates in Senate Bill 100); see [31] for more details.

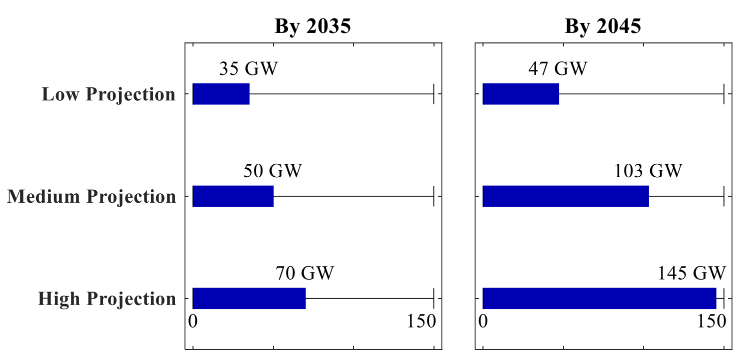

Figure 3. Projections for utility-scale solar capacity across the three IOUs in California [31].

Factors that affect future deployment include payback periods, social trends, and access barriers, which can all influence the rate of adoption [7]. The opportunity for rooftop solar on multi-family buildings is substantial and a potential contributor to environmental justice, although development on multi-family buildings is currently limited due to classic owner-tenant barriers.

For example, it is projected in [27] that 22%–38% of all existing single-family homes in Los Angeles will have rooftop solar by 2045, with 91% of residential solar systems purchased that year being co-adopted with storage and 64% of non-residential systems [27]. The future of clean energy generation in California also depends on the expansion of transmission infrastructure. Both utility scale solar generation and rooftop solar will continue to grow, whose proportions are subject of many detailed studies, particularly considering the role of the state's Net Energy Metering (NEM) rules. NEM is a billing mechanism that allows solar energy system owners to receive credit for the excess electricity they generate and feed back into the grid [32].

Utility-scale solar forecast is affected also by the adoption of *Green Hydrogen*. For instance, while under SB 100, the average build rate for solar is anticipated to be 2.8 GW per year of new capacity, under a high hydrogen scenario, this rate could drastically increase to 4.1 GW per year [1].

Further, offshore wind is expected to be particularly important during times when electricity demand is high, and solar generation is low, such as in early afternoon [15]. California must grow a robust offshore wind industry, involving floating turbine platforms, sea floor anchors, undersea transmission, specialized ports and vessels for installation and maintenance, and a customized supply chain [15]. However, offshore wind generation is beyond the scope of this document.

CLEAN FIRM POWER:

Unlike variable clean power sources, such as wind and solar, for which electricity generation varies depending on weather conditions, firm clean power sources provide consistent and stable supply of electricity. Geothermal and biomass are two examples of clean firm power resources.

ENERGY STORAGE:

Energy storage is another key component to ensure reliability and balance the intermittent nature of renewable sources. Battery Energy Storage Systems (BESS) have been widely adopted in recent years, by both utilities and customers. Other technologies, such as hydrogen-based energy storage, are also emerging. Ultimately, a diverse mix of variable and firm power generation and energy storage will be necessary to ensure a reliable and resilient electricity supply infrastructure. However, the exact mix of these diverse resources has yet to be fully understood and studied [17].

1.4.2. IMPACT OF CLIMATE CHANGE

Future climate trends can change temperature, precipitation, and the frequency of extreme weather events in California. According to California's Fourth Climate Change Assessment, the science is highly certain that California will continue to warm and experience greater impacts from climate change in the future [18]. Understanding these factors and their impacts is crucial for developing strategies to mitigate adverse effects and ensure a reliable and sustainable energy future.

Hotter temperatures may significantly increase the use of air conditioning in buildings with existing air conditioning equipment (such as in inland Southern California). They may also require new customers to install air conditioning (such as in coastal Southern California). In fact, even in the same region, there could be an uneven distribution of heating due to neighborhood-level impacts of climate change, such as in areas with significant paved surfaces versus in areas with significant vegetation. The study in [13] has shown the expected changes in air conditioning demand based on projected increases in average and peak temperatures due to climate change.

Ambient conditions affect EV charging demand, since EVs tend to consume more energy when driving in hot and cold conditions, due to the additional electrical loads for operating cabin and powertrain thermal management. EV charging speeds can also be impacted in extreme weather conditions. Therefore, climate change can affect not only building loads but also EV loads [8].

Warmer temperatures due to climate change may reduce the need for electric heating in winter, but increase the use of heat pumps for space cooling in summer [14]. Shifts in demand patterns can impose additional challenges to prepare the electric grid for the impact of climate change.

On the other hand, climate change is intensifying the risk of wildfires in California, including those that are caused by power grid failures or equipment malfunctions. As temperatures rise and drought conditions worsen, the likelihood of grid-related incidents causing wildfires increases.

By proactively assessing vulnerabilities and planning for future climate scenarios, California can meet the state's electrification and decarbonization goals despite evolving climate conditions. Significant efforts have been made in this area by California utilities, such as by developing Climate Adaptation and Vulnerability Assessment (CAVA) for their service territories [33] [34].

CHAPTER 2 – IMPACT ON CALIFORNIA'S ELECTRIC GRID

The transition to the electrification landscape that was described in Chapter 1 will have a great impact on California's electric grid. In this chapter, an in-depth analysis of this impact is provided.

2.1. INCREASED LOADING (GWH AND GW) (TOTAL AND PEAK)

It is clear that electrification is expected to significantly increase electricity demand (both annual consumption in GWh and peak demand in GW). It is important to note that not just the *total load*, but also the *peak load* is important; simply because peak load is the primary driver of the grid capacity upgrades required to meet the demand at any time.

Figure 4 shows the projected increase (in percentage) in the total energy consumption (based on terawatt hours calculations) as well as the projected increase (in percentage) in peak power consumption (based on GW calculations) by 2035 across the four largest California utilities (3 IOUs and 1 public utility). The projections for PG&E, SCE, and SDG&E come from [7]. The projections for LADWP are from [13]. All the projections are based on comparing the 2025 projected numbers and the 2035 projected numbers.

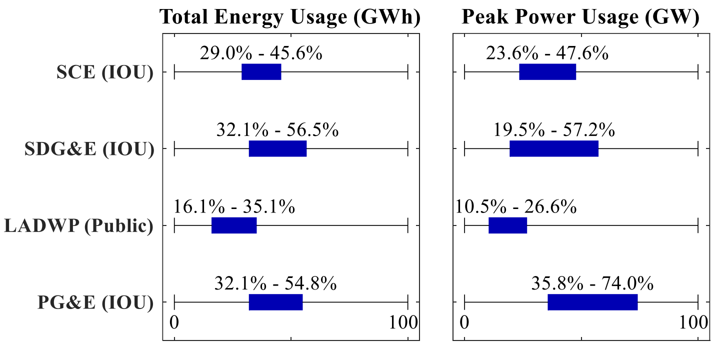

Figure 4. Projections for percentage increases in total energy usage (GWh) and percentage increases in peak power usage (GW) by 2035 compared to the current levels for service territories of different utilities: SCE, SDG&E, and PG&E [7] and LADWP [13].

Other studies provided projections further out. In [13], LADWP's 2045 projections (compared with 2025) are 36.5% - 69.6% increase in Total Energy Usage and 23.8% - 55.4% increase in peak power usage. As another example, in [17], SDG&E's 2045 projections (compared with 2020) are 100% increase in total energy usage and 85% increase in peak power usage.

Despite the above predictions, it should be noted that EV charging load is very difficult to predict; due to various reasons, including: a) EV adoption rates are still in the early stages and relevant data are still sparse; b) charging patterns depend on consumer preferences (primarily for LD EVs) and fleet operations (for MD- and HD EVs) and their current and future available charging options; and c) it is uncertain how flexible EV owners will be with charging and which strategies will best incentivize flexible charging behavior [13].

EV charging load also introduces a unique complexity due to its "mobile" nature. While the electrification of household appliances in one building will only increase the load in that building, the electrification of one vehicle may increase the load in *multiple* locations. Considering the temporal aspect, there can be an increased load at the EV owner's home at certain hours and an increased load at the EV owner's workplace at some other hours. While these two increased loads by the same vehicle do not happen simultaneously, they do still contribute to the need for grid upgrades at both of these two locations so that both locations can support the load at their peaks.

Given the projections for the total energy usage and the peak power usage, one can project a load factor (LF) for each territory. LF is a number between 0 and 1, as the average daily load is divided by the peak daily load. A low LF means inefficient use of the electrical system, as the infrastructure is underutilized most of the time but must still be capable of meeting occasional high peak demands. Based on the numbers in [7] and [13], the projected LF at the four utilities in 2035 are 0.54 – 0.60 (PG&E), 0.55 – 0.59 (SCE), 0.54 – 0.55 (SDG&E), and 0.54 – 0.57 (LADWP).

While electrification is expected to increase the load, there are also factors that may reduce future projections, such as *energy efficiency* (in both buildings and vehicles) that can reduce the projected total energy usage, and *usage coordination and intelligent load management* (through demand management programs in buildings and vehicles) that can reduce the peak power usage. The latter aspect is particularly important and is further discussed in Section 2.3. Indeed, it is recommended that the use of intelligent load management is explicitly considered in future projection models.

2.1.1. TRANSPORTATION ELECTRIFICATION LOAD

Hypothetically, if all the current cars and trucks in California are electrified, it is estimated that they would consume 57% more electricity than what is currently generated [11].

Table 1 shows the average annual kWh charging load per EV type (LD, MD, HD). These are obviously rough estimates. For example, in [13], the estimate for annual electric energy usage of cars (personally owned LD EVs) is higher at 4,000 kWh (instead of 3,508 kWh).

Truck Type	Annual kWh Per Vehicle	Reference
Car	3,508	[8]
SUV	4,932	
Van	5,163	
Pickup	5,769	
Light-Medium-Duty	8,079	[11]
Medium-Duty	17,667	
Heavy-Duty	20,703	

Table 1. Average annual kWh per vehicle charging load of each EV type.

LIGHT-DUTY VEHICLE ELECTRIFICATION:

LD vehicle electrification has been at the forefront of transportation electrification in California. A wide range of factors can affect the load of LD EVs, such as adoption rate, type of vehicle, type of charger, energy efficiency of vehicle, travel behavior, access to chargers at home/work/public, and managed or unmanaged charging, such as through demand response, TOU rates, and charge scheduling programs.

For example, under various scenarios, it is projected that in 2045, LD EVs in LADWP's service area will consume between 4.1 GWh to 11.1 GWh every day (almost a three-fold difference), and contribute between 0.9 GW to 2.8 GW to peak demand (a three-fold difference) [13].

The timing of EV charging is another key factor that can affect peak electricity usage. For example, it is common for personal EVs to begin the bulk of their charging in the late afternoon or in the evening; to have them ready for the next day. However, this can create an undesirable peak demand hour. Notably, such peak hours coincide with decreases in solar generation before sunset**.** This further exacerbates the "net" peak load, requiring traditional generators to rapidly increase output in order to meet the demand. However, this can be mitigated with creative time-of-use rate policies.

However, it is important to note that the timing of LD EV charging can be significantly different for ride-hailing customers and Transportation Network Companies (TNCs). As expected, overall charging demands for the ride-hailing LD EV use case are significantly higher per vehicle than the typical daily use case. Full-time ride-hailing drivers (40+ hours/week) could demand approximately five times more charging than those vehicles that only operate occasionally (0–10 hours/week). Occasional drivers with residential access typically have limited demand for public DCFC charging, while full-time drivers with residential access may require public DCFC to meet approximately 60% of their needs [8].

MEDIUM-DUTY AND HEAVY-DUTY VEHICLE ELECTRIFICATION:

As we saw in Table 1, the charging load of MD and HD EVs is much higher than that of LD EVs. Furthermore, charging stations for MD and HD EVs are often grouped together (e.g., near ports, major freight corridors, truck stops, and distribution centers) [35]. Therefore, even one MD/HD charging station can cause a high increase in electricity use in a small area of the power grid.

Various studies have projected the charging load of different MD/HD electrification scenarios. For example, if all current buses in LA (school buses, LA Metro, and LA DOT) are electrified, it will result in an annual energy usage of 131 GWh (School Buses: 35 GWh, Metro/DOT Buses: 96 GWh). Peak load at a single bus depot could be up to 5.8 MW for a school bus depot and up to 9.8 MW for a public transportation bus depot. These peak loads are very significant for a feeder (with a typical loading capacity of 5 to 10 MW, necessitating a dedicated feeder for each depot).

In [10], it is anticipated that MD/HD EVs will require larger (350 kW) chargers during the daytime and allow for smaller (50 kW) chargers during nighttime. It is also anticipated that the vast majority of MD/HD Chargers will be 50 kW (86% to be 50 kW versus 14% to be 350 kW).

In a truck parking case study at the Pecos West County Rest Area (with 67 striped parking spaces), it was estimated that 34.2 % of the trucks (126 trucks) stayed at the location for 5 hours or longer. If each truck in this 5+ hour subset was to consume 1,200 kWh of electricity during a stop, the total electricity consumption would be 151 MWh per day, or 55.12 terawatt hours per year. [11]

As mentioned in Section 1.3, Southern California is home to two major ports, accounting for about 40% of the total imports of goods to the United States. For the load implications of the port electrification projections, the study in [13] assumed electrification in three categories of terminal equipment: shore power at ports (tankers and container ships), cargo handling equipment (yard tractors, forklifts, and rubber-tired gantry cranes), and heavy-duty trucks. The results from [12] show that port electrification will result in an increase in energy usage at the Port of Los Angeles from 226 GWh to 313 GWh, depending on assuming Moderate to High electrification scenarios.

Since trucking operates across both rural and urban settings, truck electrification is expected to increase loads not only in urban areas, but also in rural areas, including the total energy consumption and the peak power consumption.

2.1.2. BUILDING, INDUSTRY, AND OTHER LOADS

As discussed in Section 1.2, building electrification is divided into two sectors, specifically residential buildings and commercial buildings, and the primary loads considered are space heating and water heating.

Based on the analysis in [13], by 2045, the electrification load of commercial buildings will increase by 11% - 29%, and the electrification load of residential buildings will increase by 38% - 90%. For residential customers, it is estimated that households with building electrification in heating and cooling combined with passenger vehicle electrification will consume approximately double the annual electricity of households without these electrification factors [18].

The above projections may significantly change depending on future regulations. For example, in the future, if CARB passes a rule phasing out the sales of NOx emitting appliances by 2030, then it may increase the share of space and water heating by 2045 to close to 100% [36].

In California, electricity demand currently peaks in the summer, where space heating and water heating electrification will have a reduced impact. Therefore, some projections, such as in [21], do not anticipate building electrification to have a significant impact on *peak* power demand. They rather expect the impact to be primarily on the *total* energy consumption.

However, there can be significant changes in these projections in the future. For instance, if we transition to 100% electrification of heating and water heating appliances due to new regulations, then we will start seeing considerable winter peaks, in addition to summer peaks. The increased temperature due to climate change can also force new customers to install air-conditioning in regions that currently have low penetration of air conditioning load, such as in coastal areas.

Other types of loads may also have a significant impact. For example, in [13], it is estimated that the industrial load (i.e., all industrial manufacturing loads, plus commercial loads not represented by prototypical commercial building models) on LADWP's service territory will increase by

18.7% to 28.6% by 2045. Furthermore, the electrification load for water supply and wastewater management will also increase, somewhere between 9% to over 200% [13]. It is clear that these estimates have a high degree of variability and need to be modeled more precisely in the future.

Lastly, with regards to the hydrogen production load, it is projected that the load will increase from today's negligible levels to somewhere between 42 to 110 terawatt hours in 2045 [1].

2.2. INCREASED RANDOMNESS AND CHANGES IN LOAD PATTERNS

The transition to transportation electrification increases *randomness* in electricity load patterns. Transportation electrification alters the timing and geographical distribution of electricity usage. In other words, there will be uncertainty regarding where and when new EVs may plug in [14]. Studies of real driver charging data have found many unexpected behaviors as charging patterns [37], including strong habits of regular users [38], tendencies toward charging close to home [39], and tendencies toward shorter more regular sessions to maintain a high state of charge [40]. Charging choices are also influenced by the socioeconomic characteristics of the drivers [41].

Randomness in loads and charges in load patterns will not be limited to LD EVs. For instance, due to the very high charge power of MD and HD EVs (such as electrified buses and large trucks), the presence or absence of a charging session at a given HD EV charging station at a given time can significantly change the load pattern of the feeder and that of the loading of the substation.

Apart from the randomness in the load side, the inherent intermittency of the renewable generation resources (such as in the solar and wind power production) are among other key factors that contribute to the increasing overall randomness in net load in the future.

In addition to increased randomness, electrification will also change base load patterns. Different sectors (transportation, building, industrial, etc.) may affect the load patterns differently.

Currently, in California, the days with peak load (i.e., system peak days) happen during the summer, primarily because they are driven by cooling loads in buildings. Some projections anticipate this to remain the same, as in [27]. However, there are also studies that anticipate winter peak demand during cold morning hours (~70GW) to be comparable with the summer peak demand during late-evening hours (~71GW); see [42]. The winter peak will be driven by additional space and water heating when solar PV generation is less available. During rainy or cloudy winter days, such increased load combined with decreased solar generation, will strain the system's reliability, potentially resulting in insufficient power generation to meet the demand.

Transportation electrification will also influence the *timing* of the peak load hours by 2045. For example, consider the analysis in Figure 5, which shows the average daily load profiles (averaged across system peak days) based on the projections in [27] for 2045 in the LADWP service area. Two scenarios are compared: total projected daily load profile (i.e., every type of load) versus total projected daily load profile minus transportation electrification (i.e., every type of load, except for transportation electrification). The two load profiles are very different in terms of their patterns. Specifically, *without* transportation electrification, the projected peak demand occurs at 1 PM.

However, w*ith* transportation electrification, the projected peak demand occurs at 6:30 PM. These load patterns will likely change with different time-of-use charging rate policies of utilities.

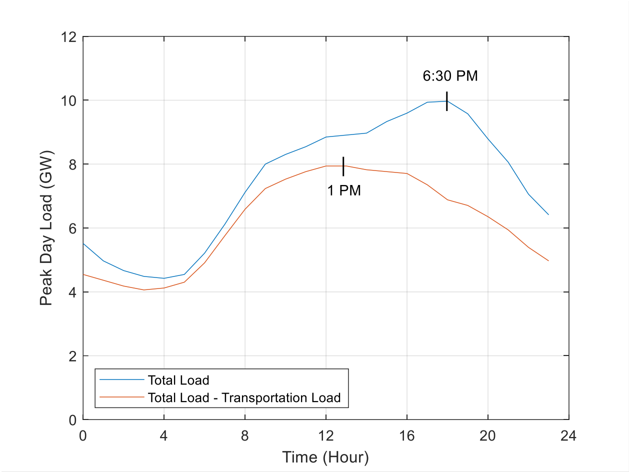

Figure 5. The daily load profiles are based on the projections in [13] for 2045 in LADWP's service territory, *with* and *without* the projected load of transportation electrification.

2.2.1. TRANSPORTATION ELECTRIFICATION LOAD PATTERNS

Without intervention (i.e., without charge scheduling), workplace charging of LD EVs mostly starts around 8 AM, when people arrive at work; and home charging usually starts after 6 PM, when EV owners get back. As for the start time of public charging, it tends to be distributed a bit more in the middle of the day, when people are running errands [43].

Figure 6 shows the projected average statewide load profile of several types of heavy-duty electric vehicles based on the projections in [10] for the year 2030. Note that, in practice, these different types of MD and HD EVs will be charged at different feeders; therefore, their load profiles may not cancel each other out to flatten the load on individual distribution circuits.

Different load patterns of different classes of trucks are also recently discussed in Figure 4 in [19].

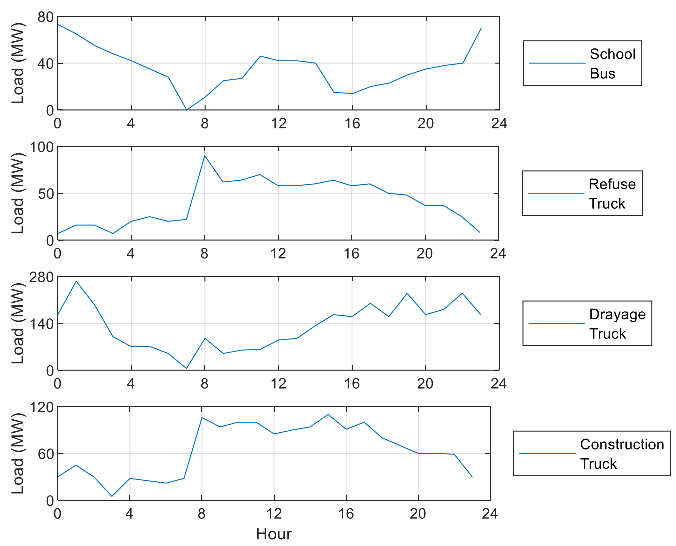

Figure 6. The projected average statewide load profile of several types of HD EVs based on the projections in [10] for the year 2030.

2.2.2. BUILDING, INDUSTRY, AND OTHER ELECTRIFICATION LOAD PATTERNS

Load patterns depend on various factors. An example from Southern California is shown in Figure 7, which compares the average load shape on two representative aggregation-points (transmission nodes) in LADWP, as projected in 2045 based on two different compositions of building loads during weekdays (the profiles during weekends are generally similar) [13]. Location 1 has ~85% commercial load and only ~15% residential load. Conversely, Location 2 has ~60% residential load and only ~40% commercial load. The load factor for Location 1 is 0.82 and for Location 2 it is 0.70. The peak hour at Location 1 is 11 AM and the peak hour at Location 2 is 6 PM.

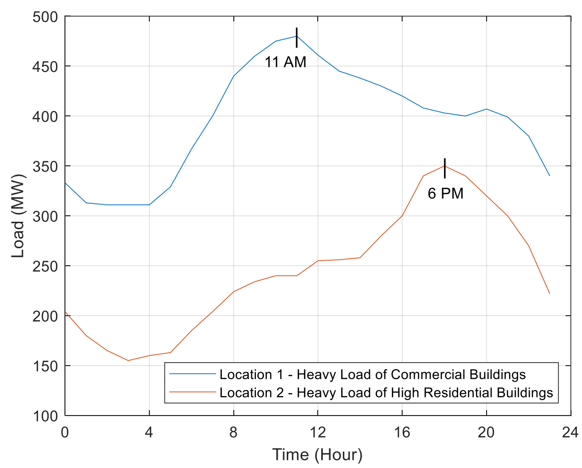

Figure 7. The average weekday load shape of two transmission nodes serving two different compositions of building loads (heavily commercial versus heavily residential) in LADWP under Stress Projection conditions in 2045 based on the projections in Figure 48 in [13].

Future projections for load profiles primarily focus on the impact of transportation electrification and building electrification as the two main driving factors. However, other sectors may also have a considerable impact on the future load profiles, such as the loads due to industrial electrification. One such example is the impact of electrification of water supply and wastewater management. For instance, based on the projections in [13] for LADWP area, water-related load may almost triple by 2050 when compared with 2015, with a new peak hour at 7 AM.

Going forward, demand response programs may help reduce the peak demand. However, having simple incentive programs, such as time-of-use (TOU) electricity rates, will likely not be sufficient. More advanced mechanisms will be needed for making impactful behavioral changes. This was recently shown in the analysis in [6] by comparing two scenarios. The first scenario used automated timers in residential charging to respond to TOU prices. This resulted in a peak charging demand of 8.7 GW; because all the EVs were being charged during low TOU price hours, but still *simultaneously*; thus, contributing to peak demand. The second scenario, however, did not use timer control; instead, it used behavioral changes to *spread* charging throughout the day. This resulted in limiting the peak charging demand to under 4 GW (i.e., less than half compared to the first case). This type of behavioral change will have to be achieved through proper *grid edge coordination* infrastructure, as we will discuss in Section 3.3.

2.3. IMPACT ON DISTRIBUTION AND TRANSMISSION CAPACITY

Even if enough generation capacity is available to meet the increasing system-wide energy usage and the increasing system-wide peak power demand, California's power grid may still encounter limitations within the power transmission and power distribution networks, potentially serving as bottlenecks in the path to decarbonization. Furthermore, these limitations can have seasonal changes, such as changes depending on solar irradiance for solar power generation.

2.3.1. IMPACT ON THE TRANSMISSION NETWORK

The transmission infrastructure allows each utility to procure electricity from various generation resources, including from the resources within its service territory and the resources from out of state. Therefore, in addition to the capacity requirement to meet the increasing electrification load, California's transmission network will have to also enable the geographic diversification of renewable power (including solar, onshore wind, and offshore wind) to meet the electrification load from clean generation sources. It should also minimize the impact of localized weather events. This is a critical requirement, given the increasing reliance of California residents on electricity.

Furthermore, to ensure reliability and contingency scenarios, the capacity of the transmission network has to be considerably greater than the estimated regular demand [1].

The study in [44] has estimated that the size of California's transmission system will have to triple by 2050. This would be the equivalent of 150 new 100-mile-long transmission lines. Peak demand times will play a critical role in transmission-level operations, impacting real-time electricity markets, transmission controls, generator dispatch, and generation reserve requirements.

However, these estimates will ultimately vary based on the proportion of local generation vs distant generation. Mostly, the latter will require transmission-level capacity; although, transmission lines are also sometimes used to transmit electricity within a region such as within the Los Angeles basin [45]. With regards to local generation, in addition to household rooftop solar, community solar can also play a major role in the future to significantly increase the local/regional generation to reduce the need to rely on increasing transmission network capacity.

The transmission network upgrade requirements are discussed in greater detail in Section 3.1, where we will discuss not only "capacity upgrades" but also "efficiency upgrades", where the latter is concerned with making the best use of the capacity of the existing transmission systems.

2.3.2. IMPACT ON DISTRIBUTION NETWORK

The distribution network delivers electricity from transmission networks to customers (homes, businesses, and industries). It includes a network of distribution substations and their circuits (a.k.a. distribution feeders). Distribution network plays a critical role in future electrification by ensuring reliable and efficient delivery of electricity, integrating distributed energy sources (DERs), and supporting the increasing demand for electric vehicles and building electrification.

Per the analysis in [7], the percentage of overloaded feeders in 2035 for SCE, SDG&E, and PG&E under different projection scenarios is shown in Figure 8. The feeder overloading projections in this figure are based on the assumption that no upgrades are made to manage the increasing loads in response to the projected electrification in each service territory. PG&E will have the highest percentage and SDG&E the lowest percentage of feeders that reach their capacity threshold. The percentages of overloaded assets on distribution feeders, averaged across these three IOUs will be:

- Substation Transformer Banks: 40% Overloaded
- Feeders: 35% Overloaded
- Service Transformers: 32% Overloaded

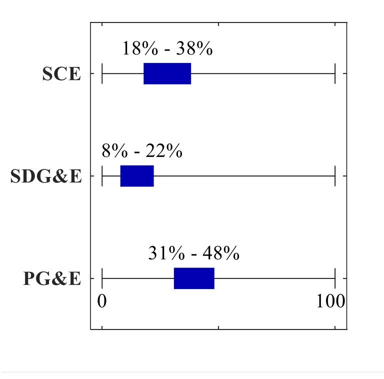

Figure 8. The percentage of overloaded feeders in 2035 for SCE, SDG&E, and PG&E under different projection scenarios, based on the projections in [7].

The analysis in [43] has projected that the overloading conditions in power distribution systems will be *spatially highly diverse* with feeders in residential areas to be twice more likely to require capacity increases than the feeders in commercial areas. The former feeders will be dominated by home charging while the latter feeders will be dominated by public and fleet charging.

Broadly speaking, segments nearest to the head of a feeder (at the substation) will have the most capacity for the new load (because voltage drops along the length of a feeder, and feeders are sized with the largest conductors nearest to the feeder head). Conversely, the segments nearest to the end of a feeder will have the least capacity for new load unless upgrades are made [14].

These distribution network upgrades are discussed in greater detail in Section 3.2.

2.4. IMPACT ON GRID PLANNING, OPERATION, PROTECTION, AND POWER QUALITY

2.4.1. PLANNING AND OPERATION

Electrification significantly impacts the planning and operation of generation, transmission, and distribution systems. Key areas affected include peak capacity, economic dispatch, integrated resource planning, transmission upgrades, and distribution upgrades. The increasing penetration of variable renewable energy generation and aggregated vehicle charging scenarios introduces significant stochastic behavior into the grid. This requires planning and operation to consider not only the common deterministic worst-case scenario analysis but also better probabilistic modeling.

During peak EV charging times, the power distribution system may face deteriorated voltage quality, higher power losses [46], and overloaded transformers [47] [48], affecting both EV owners and other consumers on the distribution network [49]. However, due to the likely uneven geographic adoption of EVs across different neighborhoods, the impact of EV charging load can be more significant in some feeders while potentially negligible in some other feeders [50].

The growing number of distributed energy resources (DERs) can further complicate distribution grid planning. Weather conditions significantly affect renewable energy sources, necessitating the incorporation of daily weather forecasts into power distribution operations [50].

Additionally, the increasing use of power electronics devices poses dynamic performance challenges due to the complex dynamic behavior of power electronics controllers [51]. Power electronics devices are widely used in solar, wind, and battery resources as well as in EV charging.

In a case study in [49], it was shown that if one EV were added per household in San Francisco, then 68% of feeders would exceed their maximum capacity, voltage limits, or line-loading limits.

2.4.2. VOLTAGE VIOLATIONS AND FLUCTUATIONS

The increasing integration of EVs in the distribution grid leads to significant voltage fluctuations, which are among the most common and major impacts [52]. These effects are more pronounced in the lower voltage parts of the network, where increasing EV penetration levels can significantly increase the electricity load burden and the magnitude of voltage violations [53].

A study shows that as the penetration of EV chargers increases from 20% to 80%, voltage deviations can range from 12% to 43% [54]. Voltage fluctuations become more severe when the maximum charging power of DC fast chargers (DCFC) increases from 60 kW to 350 kW. The LV network's grid voltage fluctuates when load current changes due to cable resistance, and the severity of these fluctuations grows with higher DCFC power [55].

Nodal voltage violations, such as under-voltage, typically start with nodes that are farther from the feeder head, while line current violations, such as over-current, usually begin with lines closer to the feeder head. High electricity demand increases the electric current levels in distribution wires and transformers, leading to higher voltage drops through these devices and reduced voltages at customer connection points. Distribution utilities must keep these voltages within the required limits of ± 5%, a more challenging task when consumption is large and highly variable [2].

Voltage variation depends on numerous factors, including the timing of EV charging, the power rating of the EV charger, the number of EVs connected, reactive power availability in the system, line parameters, system topology, and its configuration [52]. Spatial variability within a distribution system also poses a challenge. On-load tap changers, which are effective for voltage regulation, can adjust voltage levels across an entire distribution system during high consumption times and reduce voltage levels when consumption drops. However, these tap changers are typically located at the substation and cannot vary voltage levels based on their location within the distribution system. This issue is exacerbated when electrification levels vary by local area, such as in affluent neighborhoods with many EV chargers, leading to spatial variability in voltages that is difficult to regulate with current solutions [2].

2.4.3. POWER QUALITY

Electrification introduces several challenges to maintaining power quality within the distribution networks, such as by causing current imbalances across the three phases, particularly due to the non-uniform distribution of new loads such as EV chargers [56]. The high penetration of EVs with fast charging stations, which can cause sudden spikes in the load on a circuit or a certain part of a circuit, can further exacerbate power quality issues in the distribution network [57].

Furthermore, the non-linear power electronics used in EV chargers inject current harmonics into the grid. The total harmonic distortion (THD) in the line current drawn by EV chargers depends directly on the circuit topology of the charger [58]. Typically, EV chargers are equipped with input line filters before the front-end rectifier to smooth out the input current and reduce harmonics [59]. Harmonic currents from commercial DCFC have been measured, showing significant harmonics at various frequencies, such as the 7th, 11th, 13th, 19th, 23rd, and 25th harmonics [60]. These harmonics can be harmful to power systems as they can cause overheating in transformers and capacitors, reduce the efficiency of electrical equipment, and lead to increased power losses. Additionally, harmonics can cause malfunctions in sensitive electronic devices of the customers.

High-frequency power electronics produce both low-frequency harmonics (below 1 kHz) and high-frequency harmonics (above 1 kHz). While low-frequency harmonics can be mitigated by advanced control, high-frequency harmonics often cannot be easily eliminated, particularly in distributed grids without isolation transformers. If the switching frequency is close to a system resonant frequency, it can cause a large high-frequency ripple on the voltage [61].

Due to the increasing integration of power electronic-based systems, there is growing research interest in super-harmonic distortions, which are components within the frequency range of 2 to 150 kHz [62]. EV chargers and converters can be sources of super-harmonic distortions as switching frequencies in this range are often used for efficiency, cost, and weight considerations. Super-harmonic emissions, still only partly standardized, can lead to additional heating, reduced device lifetime, audible noise, equipment malfunctions, charging interruptions, high errors in energy metering, and possible tripping of residual current devices [63] [64].

Another observed power quality issue is flicker (i.e., light fluctuations due to voltage instability), particularly at nodes with high-power chargers. For instance, a 120 kW charger can cause the short-term flicker severity to exceed the standard limit of 1.0 on some days [55].

2.4.4. PROTECTION AND STABILITY

Protection and stability are critical aspects impacted by the increasing electrification with power electronics interfaces (such as EV chargers) and the integration of inverter-based energy resources (such as PV units and batteries). Adjusting sensitivity settings on circuits enables the grid to respond quickly and correctly to potential problems, thus enhancing grid operation and safety [18].

The EV load on the grid can raise stability issues. The increasing penetration of IBRs directly impacts power system protection, control, and stability [65]. At high penetration rates, the dynamic responses of IBRs to disturbances may not only affect individual IBRs but also cause cascading instability across the power system. Due to the wide timescales related to the controls of IBRs, their dynamics can cross-couple with both the electromechanical dynamics of synchronous generators and the electromagnetic transients of the network. Additionally, several nearby inverters may cause dynamic interactions with each other [65].

As the penetration of IBRs increases, traditional protection strategies need to be revisited. IBRs have demonstrated unexpected and complex behavior in response to certain faults, such as tripping when they should not trip. The nature of IBR output during faults differs from that of synchronous generators, causing operation errors in existing grid protection systems. Interactions between IBRs and unit protection relays at various legacy power apparatuses, as well as system-wide protection relays, present additional challenges. While these interactions have been studied theoretically and in laboratory settings, detailed evidence from field measurements is still limited [65].

Furthermore, phase unbalance in the phase voltages can lead to the maloperation of undervoltage and overvoltage relays, presenting significant protection issues [56].

Addressing these various challenges will require installing new protection and control equipment as well as reprogramming the operation of many of the existing protection and control devices.

2.5. IMPACT ON RESILIENCE AND DURING EXTREME EVENTS

California has faced numerous challenges in maintaining grid resilience, particularly during extreme weather events. Over the years, more frequent heat waves have required multiple rotating outages to prevent overloading the power grid and to mitigate the risk of power cables igniting dry vegetation and causing wildfire. A rotating outage is a brief, controlled power outage mandated by the California Independent System Operator (CAISO) to protect the statewide electric system by easing demand on the overall electric supply during times of critically high usage [66].

The prolonged drought is another significant concern in California, as it impacts the state's electricity generation, which relies on hydropower for 19% of its supply. Drought conditions lead to reservoir depletion, resulting in hydropower plant shutdowns, thereby affecting the overall generation capacity, resilience, and carbon content of the grid [11].

The increasing deployment of wind and solar energy introduces variability in power output, posing challenges for grid operators who must predict and adjust to these fluctuations. The intermittency of renewables, particularly during adverse weather conditions such as storms, further constrains energy supply, especially in winter when solar generation decreases, and heating demand remains high [15]. These factors contribute to the increased length and frequency of power outages. According to the Energy Information Administration (EIA), the customers in the United States spent an average of eight hours without electricity in 2020, a significant increase from 2013 [11].

Above-ground (overhead) transmission and distribution infrastructure are particularly vulnerable to severe weather conditions, which are becoming more frequent and severe due to climate change [11]. In August 2020, California experienced rotating outages over two consecutive days due to a sustained heat wave affecting the entire western U.S. The results from the root cause analysis by CPUC, CAISO, and CEC emphasized the need to incorporate the uncertainty of weather conditions, the operational characteristics of variable clean energy resources, and market dynamics into the state's long-term grid reliability planning processes up to 2045 [1].

Due to the growing risk of wildfires, utilities in California have been increasingly using Public Safety Power Shutoffs (PSPS) to prevent grid-caused wildfires. While PSPS events reduce wildfire risks, they also cause significant challenges to customers and communities that rely on electricity for essential services. The extreme heat events in 2020, which resulted in rotating outages and threats of additional outages, underscored the fragility of the grid during such conditions [1].

Investments in electricity technologies and infrastructures must consider the potential impacts of climate change, including changes in the geographic and temporal distribution of renewable energy resources. For example, Extreme heat waves can also significantly increase the load of cooling equipment. Furthermore, declining snowmelt could reduce summertime hydroelectric generation, warmer temperatures and changing wind patterns could affect solar and wind output, and drought conditions could impact water availability for cooling renewable plants and increase energy demand for groundwater pumping. Wildfires can damage transmission and distribution systems and affect solar generation performance, while sea-level rise poses risks to coastal substations and equipment. Additionally, the impacts of climate change on out-of-state resources (such as hydropower) could affect the availability of real-time imports when needed [1].

Microgrids have emerged in recent years as a crucial technology to enhance resiliency and provide an alternative to fossil fuel backup generators. However, they also have limitations, including their short duration of power supply and relatively high costs. Nevertheless, microgrids represent a step forward in improving grid resilience during extreme weather events and in the face of increasing reliance on electrification [1]. Microgrid innovations, such as Vehicle-to-Grid (V2G) and Vehicle-to-Building (V2B) technologies [67] [68], can enhance reliability by discharging EV batteries to supply power to the grid or to provide customers with backup power during power outages.

2.6. IMPACT OF PERMITTING PROCESS

The impact of permitting and planning on the electrification process can be examined through two primary lenses: 1) the customer-side permissions, i.e., the permissions that are required for individuals and businesses to install EV charging stations, DERs, and certain building electrification technologies; 2) the utility-side permissions, i.e., the permissions that utilities need from the government to implement the upgrades that they deem necessary in their networks.

While utility-side permitting may become a challenge in the future, it appears that the immediate bottleneck is rather the process for the customer-side permissions [45]. Through programs such as SCE's Charge Ready for approving EV charging stations [69], utilities are now responsible for acquiring permits on the customer-side of the meter and the process is currently time-consuming.

According to AB 1236 and AB 970's EV Charging Station (CS) permit application timelines [70]:

- 1 to 25 stations at a single site can be deemed approved as early as 25 business days.
- 26 or more stations at a single site can be deemed approved as early as 50 business days.

However, the permitting process currently takes longer. For instance, an assessment by SCE showed that its timeframes for approving are currently between 60 to 90 business days [45].

Delays in the permitting process will likely increase as more EVs will be adopted. With the increasing volume of permitting requests for EV charging stations, there is an urgent need to identify the most cost-effective upgrades and have them built in time to support new electrification projects [15]. Without timely and efficient permitting processes, the rapid growth in demand for EVs could outpace the expansion of electrical grid infrastructure. This imbalance could force California's utilities to stall the plugging in of new EVs until they can catch up with grid buildouts, an expensive delay that would hinder the state's progress on vehicle electrification [71] [4].

To address these challenges, the CPUC has approved a planning process that includes long-term forecast scenarios (e.g., 20-year forecasts) aligned with state decarbonization goals. This process also involves utilizing a flexible and expanded set of grid investments to ensure timely interconnection for customers seeking to electrify [15]. Structural advances in the design, construction, and operation of the distribution grid are essential to meet these goals.

CHAPTER 3 – ELECTRIC GRID INVESTMENT NEEDS

With the rapid growth in electrification, planning for grid upgrades and enhancements needs to be proactive to ensure that the grid is ready for future electrification projects. In this chapter, we discuss various grid investment needs to prepare California for its future electrification landscape.

3.1. INVESTMENT IN DISTRIBUTION NETWORK EQUIPMENT UPGRADE

As described in Section 2.3, the push for electrification, particularly transportation electrification, has potentially significant impacts on power distribution networks, by reducing headroom (i.e., quickly approaching the capacity of transformers and power lines), as well as causing voltage violations, power quality issues, protection issues, phase imbalances, and power loss. Addressing these impacts will require upgrades and/or expansion in the power distribution equipment.

Some regions will likely require more extensive upgrades than others based on the quantity and patterns of load demand, the availability of solar and storage resources, and dealing with pre-existing reliability challenges. Other factors, such as the age of the circuit or buildings can also play a role. For instance, some buildings may require service panel upgrades and/or line drops, which then can have subsequent downstream impacts on local distribution networks [72].

In addition to the cost of upgrades, there are also costs associated with hardening, reconfiguration, repurposing, retirement, and maintenance of distribution system equipment [1].

While there is generally consensus in the literature that almost all feeders may need some degree of upgrades, it is also understood that on each feeder, it may be the case that only a few pieces of equipment or only a portion of the feeder needs to be upgraded. An example of this is shown in Figure 9, which is based on the analysis in [73]. Although multiple parts of the feeder (lines and transformers) are overloaded, they are only a fraction of those on the entire feeder.

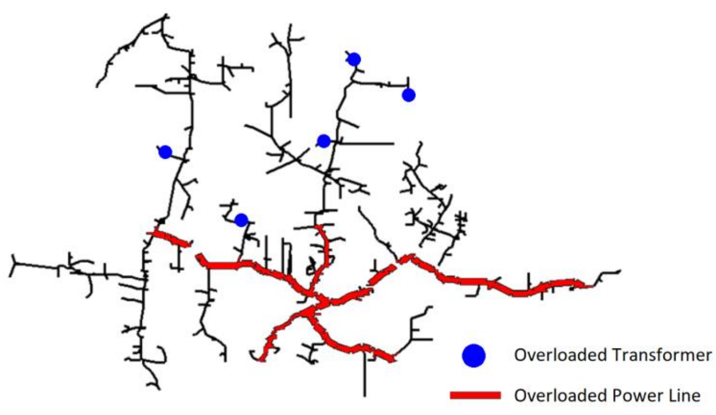

Figure 9. An example, based on the analysis in [73], that shows the few pieces of equipment and only a portion of the power distribution feeder may need upgrades.

One key challenge in planning distribution system upgrades is dealing with the uncertainty of future electricity consumption (e.g., see Section 2.2). Planners will need more accurate forecasts of peak demand on distribution systems so that upgrades can be made before capacity and voltage problems arise. This in turn will require investment in developing better models.

CASE STUDY:

The City of Jurupa Valley is located in the northeast corner of Riverside County in Southern California [74]. The utility serving the city is SCE. Each year, SCE conducts a 10-year sub-transmission and distribution system planning assessment to identify grid needs required to accommodate customer load growth. This assessment includes both known and forecasted load growth, with the former being based on existing projects. In 2023, SCE's 10-year outlook for Jurupa Valley's net load growth was 127 MVA. By 2024, this outlook was updated to 172 MVA, reflecting an additional 45 MVA in net load. Figure 10 shows the projected net load growth in Jurupa Valley by sector according to SCE's 2024 assessment [75]. The two sectors with the highest projected load growth are Commercial (44%) and EV (35%). The growth in commercial load is attributed not only to building electrification but also to several other factors, whereas the increase in EV charging load is a direct result of transportation electrification. Currently, there are 30 known new major EV charging station projects planned across Jurupa Valley, to charge HD, MD, and LD EVs. Of these 30 charging station projects, nine will each generate at least 1 MVA charging load, with individual charging station projects ranging from 1.4 MVA to 15 MVA. To meet this growing demand, SCE has several grid upgrades projects underway, including the construction of six new distribution circuits, the upgrade of three substations to increase their capacity, and the addition of one new transmission line.

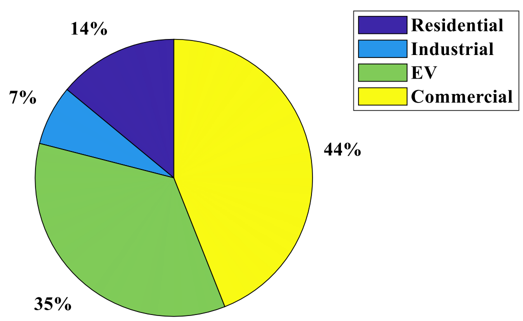

Figure 10. Load growth by sector in SCE's 10-year outlook for Jurupa Valley [74].

3.1.1. CAPACITY UPGRADES:

Both distribution substations and their feeders will likely need capacity upgrades (please note that this is also referred to as "thermal" upgrades, since overloading can overheat equipment). This may require various equipment upgrades, including transformer banks, service transformers, and power lines. Transformer banks are the larger transformers that are typically placed at substations or as pad-mounted units, while service transformers are the smaller transformers that are typically placed closer to customers on power poles or on pad-mounted enclosures. There are roughly 1.5 million service transformers in California [71]. Increasing the size of transformers is the most common upgrade in power distribution systems [27].

In some cases, simply upgrading the capacity of existing equipment may not be sufficient and there will be the need to split a feeder into multiple feeders. This process is referred to as “feeder splitting”. It involves dividing an existing distribution feeder into two or more feeders to balance loads more effectively and reduce the risk of overloading a feeder. Beyond feeder splitting, adding new feeders and new substations may also be necessary to accommodate the growing load. These additions help to distribute the load more evenly across the network and enhance the overall capacity of the electrical grid. Another option is to replace old 4.8 kV feeders with feeders with higher voltages, such as 12.47 kV, to increase the loading capacity of those old feeders [27].

3.1.2. RELIABILITY AND POWER QUALITY UPGRADES:

In some circuits, in order to resolve poor reliability and power quality issues, it will be necessary to add new line voltage regulators and capacitor banks [73].

Broadly speaking, there are several ways to regulate voltage, such as adjusting transformers or adding voltage regulators, capacitors, and distributed generation resources [76]. A combination of these devices will be needed to manage spatial variability in voltage across power distribution systems. In general, utilities are responsible for installing and operating major equipment such as voltage regulators and capacitor banks. On the other hand, distributed generation resources are typically a combination of customer-owned resources and some utility-owned resources.

3.1.3. INVESTMENT QUANTITIES

Without new upgrades, it has been estimated in [43] that approximately 67% of the feeders across the three IOU territories will be severely overloaded by 2045, with the total estimated load reaching nearly twice the current capacity. When comparing the three California IOUs, it is projected in [7] that PG&E’s distribution circuits will reach capacity sooner than SCE and SDG&E. Moreover, as shown in Figure 11, SDG&E will have the least number of feeders reaching full capacity by 2035.

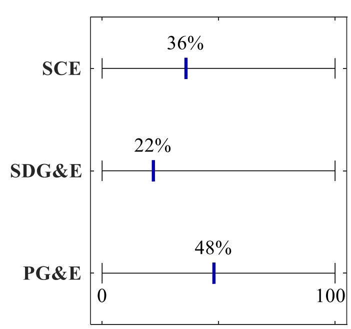

Figure 11. The number of feeders reaching full capacity by 2035 for each IOU [7].

Several other studies have also discussed the investment quantities for individual utilities:

- SCE: It is estimated that by 2045, SCE will need to double its throughput while utilizing twice as much distributed solar and ten times more distributed energy storage [15]. SCE also estimates that over 1,400 new distribution circuits will be required (using today's standard designs), which is about 30% more circuits than currently in operation [43].

- PG&E: Regarding EV impacts, it is estimated that 443 of PG&E's feeders will likely have deficiencies requiring capacity upgrades by 2030 [77]. PG&E projects that if upgrades are distributed evenly between now and 2050, the average number of upgraded feeder projects will be just under 100 per year, with 2 to 5 substation upgrades expected annually [14].

- LADWP: On average, 84% of LADWP's 4.8 kV feeders will require some form of upgrades by 2045, with 80% of these feeders experiencing transformer overloads and fewer than 15% facing line overloads [73]. For a typical feeder, 5 to 15 transformers will need upgrades, while fewer than three line-segments per feeder will require upgrades [73]. LADWP will also need to upgrade approximately 90% of their distribution grid equipment to address feeder overloading and voltage challenges caused by combined load, solar, and storage changes necessary for achieving a 100% renewable electricity pathway [27][73].

In terms of feeder types, residential areas are projected to require upgrades at twice the rate of commercial areas. By 2045, across California, feeders with home charging will require a capacity increase of 16 GW, while feeders with public charging will need a capacity increase of 9 GW [43].

3.1.4. ESTIMATING INVESTMENT COSTS

The existing cost estimations of grid upgrades have been very diverse, not only in terms of numbers and assumptions, but also in terms of the nature of the analysis. Here are several examples:

ESTIMATES BASED ON UNIT COST:

Cost estimates can be made based on certain units, and then adding up all units needed. Examples of "units" in this case can be the cost of upgrading specific equipment. Given this approach, the unit cost of major upgrades across IOUs projected for the year 2035 are shown in Table 2 [7].

IOU	Substations	Transformer Bank	Feeder
PG&E	$27M	$11.8M (48 MVA)	$6.4M
SCE	$39M	$2.0M (28 MVA)	$5.8M
SDG&E	$20.9M	$4.9M (28 MVA)	$6.7M

Table 2: Unit cost of major upgrades across IOUs projected for 2035 [7].

The analysis in [78] has estimated that a typical utility in the United States will need to spend an average of $1,700 to $5,800 on its grid upgrades for every EV that operates in its territory.

ESTIMATES BASED ON OVERALL UPGRADE COST:

In [7], it is estimated that California's three IOUs will need to invest between $30B and $50B by the year 2035 to upgrade their distribution grids to handle the growth in electricity load of EVs.

According to [27] and [73], the total costs for distribution system upgrades at LADWP through the year 2045 may vary between $472M and $1,550M. At LADWP, the majority of the upgrade costs consists of lower voltage feeders (e.g., to upgrade 4.8 kV feeders to more costly 34.5 kV feeders).

The majority of cost estimations are naturally focused on the upgrade costs to meet the *increased* load due to electrification. That is, they do not include the cost of distribution system maintenance, upgrading system operation, or the cost of land acquisition for substation upgrades.

If distribution systems are designed to simultaneously consider the needs of the new loads and the needs of the new DERs, then the total upgrade costs will be reduced compared to making upgrades sequentially for load and then for DERs [27]. Simultaneously upgrading for demand loads, solar generation, and energy storage reduces the overall system upgrade costs [73]. This is mainly because the local power generation by DERs offsets part of the need for increased capacity.

For LADWP's 4.8 kV systems (by the year 2045), adding new feeders will account for 67% of the upgrade costs versus 25% for adding new transformers on existing feeders. The rest of the upgrade cost (~8%) will consist of adding new voltage regulators, new capacitor banks, new capacitor bank controllers, and similar items.

According to [15], expanding the distribution system to the scale needed in 2045 will require an incremental investment of about $50 billion statewide.

In [14], the analysis shows high evidence for economies of scale, i.e., larger projects typically have a lower per-kW cost. Smaller projects are considered to be less than 1 MW, while larger projects are considered to be greater than 8 MW. As such, the median cost of a feeder upgrade is approximately $367 per kW (for large projects) and up to $1,875 per kW (for small projects). The median cost of substation upgrades ranges from $887 per kW (large projects) to $18,863 per kW (small projects).

The total cost for the year 2050 at PG&E is estimated to be between $4.5B and $5.5B, with some scenarios reaching $10B. These numbers are substantial, but keep in mind that they are spread out over the period from now to 2050 [14].

The analysis in [7] estimates the 2035 upgrade cost for the three IOUs as shown in Table 3.

IOU	Substations + Transformer Banks + Feeders	Service Transformers
PG&E	$4.2B + 5.3B	$1.9B

SCE	$3.0 B + $2.2B	$1.8B
SDG&E	$170M + $83M	$48M

Table 3. Upgrade cost for the three California IOUs per the analysis in [7].

According to [7], the total upgrade costs for adding new substations, new transformer banks, new feeders, and new service transformers by each IOU for the year 2035 are as follows:

- PG&E: $27.7B
- SCE: $20.1B
- SDG&E: $3.2B

Based on these estimations, upgrading the three IOUs' distribution system capacity to 25 GW by 2045 will cost between $6B and $20B [43]. Further, in [43], a sensitivity analysis was carried out to see the impact of a range of factors on the upgrade costs. For instance, the assumption on EV efficiency (0.22 kWh per mile versus 0.47 kWh per mile) will result in 5% difference in the number of overloaded feeders (and 7.8 GW less required capacity upgrade). Furthermore, the assumption on the percentage of DCFC installations (0% DCFC versus 100% DCFC) results in an 18% difference in the number of overloaded feeders (and 33.7 GW less required capacity upgrade).

On the other hand, in [79], and based on a study in New York, it has been estimated that the money utilities can bring in from selling electricity to charge EVs can counterbalance at least part of the cost of making the grid ready for EV charging. Although, there are several nuances that can affect revenue, such as the impact of managed versus unmanaged charging schedules on revenue. Similar dynamics have been discussed for building electrification, where the increased loading can create new electricity revenue, while often requiring less grid upgrades than EV charging [72].

There is also cost attributed to *not* making the grid upgrades. For example, without capacity upgrades and grid hardening, the power grid could be more vulnerable to extreme weather events. This can increase the cost of more frequent outages and longer service restoration [80].

3.2. INVESTMENT IN TRANSMISSION NETWORK EQUIPMENT UPGRADES

Transmission infrastructure is the backbone of California's clean energy transition. According to [15] [17] [18], upgrades in transmission network equipment must be built out to: **a)** keep pace with system-wide generation resource capacity growth; b) minimize the impact of localized weather events to ensure reliability and resilience under various contingency scenarios; **c)** enable the geographic diversification of renewable power, such as solar, on-shore wind, and off-shore wind; and **d)** enable the integration of clean firm generators, such as thermal generation with clean fuels.

3.2.1. CAPACITY UPGRADES

Capacity upgrades should address not only the increasing electricity demand, but also the higher peak demands that will result from increased electrification in various sectors. Considering peak demand times in future capacity upgrades is critical to ensure reliable transmission-level operations and controls, as well as for planning future generation reserve requirements.

With regard to developing the power transmission infrastructure to diversity renewable power generation, one attractive technology from a system planning perspective is to enable offshore wind integration at coastal areas. Offshore wind power generation complements solar power generation; because of typically higher output in the evenings, when electricity demand is high and solar production is low. Offshore wind power generation also complements solar power's seasonally to provide more consistent output during winter months when solar production is lower.

3.2.2. EFFICIENCY UPGRADES

While expanding California's transmission network is inevitable, we must also take advantage of the technology advancements to best utilize the existing capacity and right-of-way of the existing transmission systems, and to continue to make the best use of the new transmission capacities [27].

One such technology is the broad class of high-voltage power electronics devices that are referred to as Flexible AC Transmission Systems (FACTS) [81]. AC power cannot be easily directed (routed), causing the system to be limited by its weakest component and resulting in under-utilized transmission capacity. However, FACTS devices, as well as other technologies such as DC transmission lines (HVDC) when applicable, can control and optimize power flow, increasing the flow on grid elements operating below their thermal limits to enhance overall system capacity.

Another relevant technology is dynamic line rating (DLR) [82]. The actual capacity of transmission elements (lines, transformers, protection equipment) is often rated on a limited set of pre-determined conditions, largely based on how hot they may get on summer days. However, cooler weather or windy conditions can cool some transmission elements (primarily overhead lines). This means that they could sometimes carry *more* power than their "normal" ratings [27], as long as this can be verified with field measurements such as line sensors. Dynamic line rating schemes may also consider the ability of transmission elements to carry even more power for a short period of time (such as temporarily, only under peak demand conditions) in anticipation of cooling later in the day. As pointed out in [27], even if contingencies occur under hot weather conditions (where there are reduced benefits), the information provided by active line monitoring can be combined with FACTS devices to optimize power flow and maximize system reliability.

FACTS, DLR, and other efficiency upgrades may reduce or substitute certain capacity upgrades.

3.2.3. ESTIMATIONS ON THE EXTENT AND COST

CAISO's 20-Year Transmission Outlook Report estimates that over $30B in new transmission systems will need to be developed by the year 2040 [83]. Some other studies have suggested that California's transmission capacity would need to triple by 2050 [44]; which would be equivalent to adding roughly 150 new 100-mile-long transmission lines (using current line technology). In [15], it is estimated that new transmission grid projects in California will be up to four times their historical rates, with 20,000 circuit miles of new 500 kV transmission lines, and an estimated cost of $75B, to interconnect new generation resources, import sufficient out-of-state electricity, and bolster the sub-transmission system.

In [15], it has been estimated that SCE will need 85 new substations by 2045. In [73], it is estimated that LADWP will need to upgrade at least 40% of its sub-transmission lines, and almost every region within its service territory will need a number of transformer upgrades. LADWP's total upgrade cost in its sub-transmission system is estimated to be between $22M and $62M [73].

3.3. INVESTMENT IN GRID EDGE COORDINATION AND DEMAND RESPONSE TECHNOLOGIES

In addition to system upgrades, utilities can address the impact of electrification by incentivizing desirable customer behavior, such as off-peak consumption with time-of-use (TOU) rates or by providing platforms for EVs to provide distribution grid services. Collectively, we refer to the solutions that are in coordination with customers as *Grid Edge Coordination Technologies*.

3.3.1. DEMAND RESPONSE

Demand response (DR) is a process to influence the amount or the timing of customers' electricity usage in response to a price signal or other DR signals from the utility. DR can be used to reduce peak loads, which can lead to reducing the need for additional power generation or grid upgrades. DR may also be used to shift certain loads to times when more renewable energy is available. Loads that can be shifted are often referred to as "time-shiftable loads" or "deferrable loads", such as EV vehicles, water heaters, irrigation pumps, intelligent pools, batch processes in data centers and computer servers, industrial equipment in process control and manufacturing, and various home appliances such as washing machine, dryer, and dish-washer [84].

An example is shown in Figure 12. This figure compares the average projected load profiles of EV charging in LADWP's service territory for the year 2045, during two scenarios as developed in [13]. Under "Minimum Delay", EVs start charging as soon as they are plugged in. Under "Maximum Delay", EVs delay their charging both at home and at work as much as possible, as long as it does not affect their mobility needs. The projections are based on Moderate adoption scenario (in Figure 13(a)) and High adoption scenario (in Figure 12(b)). The case with "Minimum Delay" peaks in late afternoon and early evening, where EVs are plugged in at home or at public charging ports near home, at the time when people get home. However, as described in Section 2.1, such behavior exacerbates the net peak load due to the simultaneous decrease in solar power generation. When charging behavior is adjusted, the charging peaks can occur in the early morning, after sunrise, or while the solar power generation is at its greatest, thereby relying more on clean energy generation. The differences between the blue curves and the red curves in Figure 12 demonstrate how significantly the load profiles can change if we change the charging schedules.

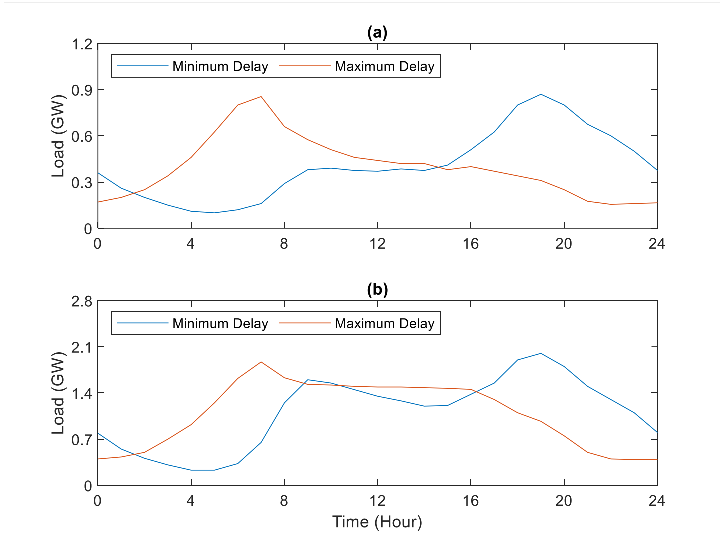

Figure 12. Comparing the projected load profiles of EV charging, with minimum delay versus with maximum delay without affecting mobility needs [13].

Controlled EV charging has been considered in single-unit dwellings (SUDs); see [7]. However, charging at multi-unit dwellings (MUDs) and workplaces will also need to be considered. Access to workplace charging can particularly encourage charging during high solar production hours.

In terms of the potential for demand response, which is directly linked to the potential for charging flexibility, it is estimated in [13] that by 2045, between 60% to 90% of EV drivers in LADWP's service area will have access to charging at home and 15% to 50% will have access to workplaces or public charging. In [15], it is estimated that by 2045, over 80% of light-duty vehicle load on SCE's service territory will respond to TOU rates, price signals or load shifting mechanisms. Load flexibility on SCE's service territory will enable up to 6 GW of demand response.

In a case study in [4], a software app was launched as a 6-month pilot with 232 customers to automatically align EV load with renewable energy generation. The average load reduction during the 4 PM to 9 PM peak was 12.4%. Customers with solar panels had an average of 21.9% peak load reduction and customers without solar panels had an average of 3.6% peak load reduction.

In the case of residential EV charging (whether SUD or MUD), the common approach is to alter (delay) the *start time* of the charging session, such as in the above case study. However, in the case workplace charging and public charging, it can be doable (through proper coordination) to also control *charging rate* during the normal time frame between the EV arrival and departure times.

Controlled EV charging can also be expanded to MD and HD EVs. Recall from Section 2.1 that the charging load of MD and HD EVs is much higher than the charging load of LD EVs. Utilizing the flexible charging loads of MD and HD EVs can significantly increase DR potential.

Building and industrial electrification loads will also continue to contribute to DR programs. Studies have discussed the benefits of smart controllers for electrified space conditioning and water heating systems. Customer comfort and flexibility will play a key role in the extent of the future DR capacity in this domain.

The analysis in [13] has identified the following resources as the DR-participating loads through 2045: large commercial, industrial, and institutional customers, water supply and wastewater management facilities, residential cooling, heating, hot water, refrigeration, schedulable appliances, commercial cooling, heating, hot water, refrigeration, and scheduling EV charging.

3.3.2. DISTRIBUTED ENERGY RESOURCES

DERs are complementary to the bulk power resources (large power plants). In aggregate, they provide flexibility that can reduce burdens on generation and transmission resources and provide more localized benefits for distribution grid reliability [15].

Another measure at the edge of the grid, is to use advanced distribution management systems and coordinate the electrification with the operation of distributed energy resources, for the purpose of increasing the capacity and the overall operation performance in power distribution systems.

Current trends in this area also include the growing interest among customers to invest in battery-equipped solar generation units, or other energy storage devices. Due to its rapid response, battery storage is an important source to help utilities enhance grid operation. Through proper coordination, some customers could be open to sharing their unused storage capacity with the utility or third-party aggregators for a discount or regular payments. Additionally, under energy-storage-as-a-service arrangements, developers or utilities can pay the initial expenditures of the residential battery installations and then own and manage the system in exchange for a fee [50]. Both of the aforementioned business models allow utilities to adopt a greater number of grid-edge energy resources and to own or manage them partially as necessary.

In addition to controlling their charging load, EVs can offer V2G service as a distributed energy resource. In this setup, EVs inject the energy stored in their battery back into the power system during peak load hours. In return, they will earn net income for peak shaving or other grid services.

Since EVs are typically idle more than 90% of the day [50], they can offer a significant V2G capacity, should proper grid coordination be established. It is estimated in [15] that, by 2045, EVs will have the potential to provide up to 2 GW of V2G services on SCE's service territory.

3.3.3. GRID EDGE COORDINATION

The full potential benefits of the above technologies can be achieved only through proper grid edge coordination that aligns these technologies with the (often time-varying) needs of the power system planning and operation across power transmission and power distribution networks.

Broadly speaking, grid edge coordination can help both transmission systems and distribution systems. It can help transmission systems, such as through system-wide peak load reduction, and providing frequency regulation services (injecting power when the frequency is low and drawing power when the frequency is high). Grid edge coordination can also help distribution networks, such as through voltage regulation (injecting power when the voltage is low and drawing power when the voltage is high), balancing phases, enhancing power quality, and reducing power loss.

In addition to coordinating power injection and power consumption to achieve the above benefits, utilities can also benefit from the power electronics capabilities of most grid-edge resources. Power electronics interfaces are widely used by DERs, such as inverters for solar PV generation and rectifiers for EV charging. They can potentially serve as major grid assets. For instance, power electronics interfaces can optimally support reactive power (to support voltage at their location) based on the specific locational and temporal needs of the power distribution circuits. They can also be coordinated to provide the needed "inertia" to stabilize the grid dynamics [85]. The term "inertia," in this context, refers to the ability of the power system to resist undesirable changes in its frequency (i.e., resisting significant deviation of the power grid's frequency from 60 Hz), which helps maintain stability during fluctuations in power supply and demand.

New innovations will likely change the landscape at the edge of the power grid at inverter-based resources, such as the advancements in developing *grid-forming* inverters and rectifiers that can enhance grid stability and resilience by autonomously maintaining voltage and frequency levels, even in the absence of traditional synchronous generators. This is a critical capability since synchronous generators are increasingly being replaced with inverter-based (solar and wind) generation resources on bulk electric systems as well as in the form of distributed generation.

Grid coordination infrastructure will have to be *flexible* and *agile* to react to different events and circumstances. For instance, apart from events related to contingencies in grid operation or the extreme events due to climate change, an agile grid coordination infrastructure can take advantage of low-carbon events, when solar energy generation is particularly high due to clear skies. A low-carbon event is a demand response initiative aimed at reducing energy consumption during periods of high carbon intensity in the grid to lower overall greenhouse gas emissions.

Having a flexible grid coordination infrastructure will also help incorporate new findings based on the lessons learned and the new operational strategies that may emerge in the future.

For instance, consider the traditional view that DR programs should shift the transportation electrification load to nighttime. In fact, practically all utilities in California currently offer retail rates that encourage residential customers to charge their EVs during off-peak hours, namely between 11 PM and 7 AM. However, there are recent studies that have suggested that increasing the load at night can result in some undesirable consequences. Specifically, it can prevent cooling at nighttime transformers, which can reduce the transformers' lifetime [50]. Therefore, in the future, we may need to discourage EV charging overnight and instead encourage daytime charging.

Of course, grid coordination infrastructure should be designed not only to benefit the grid, utilities, and operators, but also to provide customers with increased flexibility, choice, and value.

Ultimately, grid edge coordination will provide an important (non-wires) alternative to traditional upgrades in power transmission and distribution networks. Of course, they too need investments. Such investments will be in the form of creating reliable communications and control capabilities among grid edge resources and utilities, operators, and other authorities (such as aggregators).

Investments will also be needed for workforce training in this domain, and for grid management software and hardware upgrades to support increased data flow among customers and operators.

3.4. INVESTMENT IN GRID RESILIENCE TECHNOLOGIES

Heat waves, wildfires, and flooding are among the major extreme events that will affect grid operation. Grid resilience will allow for continuity of electric service (and faster restoration) under these various extreme events. Investments should particularly consider the challenges that the most vulnerable and historically underserved communities face due to the impact of climate change.

As previously mentioned, multiple California utilities have recently developed climate adaptation and vulnerability assessment plans for their service territories, such as CAVA plans for SCE [33] and PG&E [34]. These plans shall address a range of near-term risks and use a risk assessment process to prioritize infrastructure investments for longer-term risks associated with climate change [18]. Investment will be needed also for grid equipment hardening as well as installing battery energy storage which can enhance the overall grid reliability and resiliency. For example, SDG&E has envisioned a combined 2,500 MW of utility-owned and third-party battery storage in SDG&E's service area by 2045 to support the reliability of electricity supply [17].

If an agile grid edge coordination infrastructure is pursued, then transportation electrification will have a great potential to provide increased reliability and resilience for a changing climate on a scale we have never experienced, providing grid resiliency benefits through V2G applications, and enabling customers to use their EVs to power their homes during a grid outage [18].

Grid edge community resources can also strengthen the power system's resilience during outages and extreme events. Their use can be consequential in rural and underserved communities as they are often more susceptible to power outages and delayed service restoration [86] [87].

3.5. INVESTMENT IN ADVANCED MONITORING AND DATA INTENSIVE TECHNOLOGIES

Traditionally, power systems monitoring and data acquisition have focused mostly on generation and transmission systems. Until recently, the distribution grid has received much less attention in this regard, in part due to the difficulty of capturing the uniqueness of each individual circuit [88].

However, since the most direct impact of electrification is on power distribution systems, there is a high priority to enhance data availability and monitoring capabilities at power distribution level.

If proper and updated datasets are not available (or they are not analyzed holistically), planning and operation upgrades and investments can risk miscalculations and misinformed decisions.

Limited data availability on DERs' performance and impact will constrain the ability to develop or adopt new grid technologies as well as to plan the necessary grid edge coordination infrastructure. It will also limit the ability to build accurate circuit models, which is the foundation of distribution system analysis.

Long-term planning to face each of these challenges requires estimates of the future charging demand (the current estimates are very rough and have wide uncertainty). They should only serve as starting points for planning. Going forward we need to have more reliable estimates that will continuously be updated and improved in a systematic and data-driven fashion [6]. Data availability is also necessary to ensure the scalability of long-term planning models based on high adoption targets and is a key area of research.

Apart from data availability, some applications may need real-time data processing, such as during extreme events, to quickly translate raw data to insightful actionable information for utility and system operators, to identify points of disruptions or damages to sensitive equipment.

With the increasing randomness in generation and load, achieving grid reliability will require an improved ability to forecast electricity supply, demand, and the overall state of the power system [27]. In this regard, fundamental changes may need to be made in how data is used. For instance, traditional grid-planning methods to forecast load growth are not done at high granularity across distribution circuits. This is despite the fact that since the early 2010s, California's IOUs have had smart meters at homes and businesses that collect power-usage data in hourly or 15-minute intervals [71]. With the increasing interest in Advanced Metering Infrastructure (AMI) 2.0 [89] initiatives, California utilities must also plan to use smart meter data and other field measurements more effectively, to update their load models and short-term forecasts on regular basis.

Access to other types of data, such as detailed EV datasets (such as driver behavior, including where, when, how, how much and how often drivers will charge their vehicles) can help EV forecasting methods to evolve. To this end, we may need to update and refine LD, MD, and HD EV usage datasets and proactively determine future grid capacity expansion needs [6].

The lack of data for other California utilities outside CPUC jurisdiction (i.e., municipal utilities) is particularly concerning. Access to data across both IOUs and public (municipal) utilities would enable projecting requirements that cross traditional utility boundaries, especially for large infrastructure requirements such as airports or ports that host or are likely to host EV fleets [7].

Some databases are already available but they are not integrated in all necessary decision-making systems. For example, there exist databases, such as Plugshare and OpenChargeMap, that track the charging infrastructure and keep EV drivers informed. This type of data (that is often outside a utility's traditional data focus), can be used to enhance planning for charging infrastructures and analyze the expected impact of EV charging on the distribution grid [50].

Several emerging challenges, such as the impact of inverter-based resources on system-wide and regional stability, will require data from sensor technologies that are much more advanced compared to traditional smart meters. Examples include phasor measurement units (PMUs) [90] and waveform measurement units (WMUs) [91]. In fact, lack of high-resolution data has been widely acknowledged as one of the technical challenges in this area; see the cases in [92] and [93].

To address these challenges, investment will be needed in instrumentation, sensor technologies, data communications, data storage, and computational power for data-intensive technologies.

3.6. INVESTMENT IN OPERATION, CONTROL, AND PROTECTION TECHNOLOGIES

In addition to upgrading power system equipment and apparatus (Sections 3.1 and 3.2), grid coordination infrastructure (Section 3.4), and data acquisition, data communications, and data storage (Section 3.5), electrification will also require a major undertaking to upgrade a wide range of software across operation, control, and protection, including adopting new software framework.

It is anticipated that new software, control strategies, data management and data-driven tools, and more advanced and dynamic protection strategies will be required across the entire system to better coordinate the operation of generation, transmission, and distribution across multiple timescales.

UPDATING OPERATION AND MANAGEMENT ALGORITHMS AND SOFTWARE:

A wide range of new software solutions have been introduced in recent years to help utilities tackle the challenges of growing electrification and decarbonization [94]. Examples include:

- Advanced Distribution Management System (ADMS);
- Outage Management System (OMS);
- Meter Data Management System (MDMS)
- Demand Response Management Systems (DRMS);
- Distributed Energy Resource Management Systems (DERMS);
- Energy Management Systems (EMS);
- Advanced Metering Infrastructure (AMI);
- Fault Location, Isolation, and Service Restoration (FLISR).

UPDATING OPERATION AND PROTECTION SET-POINTS AND STRATEGIES:

As the power system adapts to increasing electrification, updating operation and protection parameters (set points) and strategies becomes essential to maintain reliability and efficiency.

One example is adjusting the set points on voltage regulating devices, such as voltage regulators, load tap changers of transformers, and capacitor banks. These adjustments ensure that voltage levels remain within acceptable ranges despite the variability caused by new loads and DERs [73].

Another example is updating the settings and parameters of the power systems protection devices, i.e., the devices that isolate the faulted area during electric faults. The high penetration of IBRs, such as PV generation units, presents new and unique challenges to traditional protection systems and algorithms. Factors such as the low fault current of IBRs and phase voltage unbalance can undermine the performance of the existing protective devices; see [56] for more details.

Updating these various set-points and strategies must be co-optimized with other efforts, such as plans to upgrade power transmission and distribution systems, as well as the plans for reconfiguration, repurposing, and replacement of assets and equipment. Integrating these updates with broader equipment upgrades can reduce costs and improve overall system performance.

UPDATING FORECAST AND PROBABILISTIC MODELS:

Demand forecasting models are often built on historical consumption patterns. However, since electrification alters the consumption profiles, existing models and strategies may need significant adjustments. The integration of EVs (across LD, MD, and HD categories), heat pumps, and the impacts of climate change demand more nuanced and dynamic forecasting methods [15].

Probabilistic-based methods and metrics, similar to those used in CAISO's transmission planning, can be developed also for distribution planning. Techniques such as loss of load probability, loss of load expectation, and effective load carrying capability provide a framework for understanding and managing the uncertainties and risks associated with different planning and operation scenarios [7]. These methods are crucial for incorporating the variability of load and generation, unexpected generator outages, and weather changes into the planning and operation process [7].

CO-SIMULATION AND CO-OPTIMIZATION:

Enhanced forecasting models can help utilities predict future EV load profiles and their impacts at granular levels, such as zip codes or individual feeders. They can then proactively identify future issues, such as voltage violations and equipment overloading on distribution feeders.

Currently, there do exist tools to simulate individual components of the power system, such as transmission grids, distribution grids, PVs, buildings, communication infrastructure, and EV use patterns. However, there is a lack of frameworks for holistic power system co-simulation, such as to represent the variability and uncertainty of EV charging behaviors on each distribution feeder [50]. These advanced tools can help utilities better understand and manage the complexities introduced by new technologies and changing load patterns. They also enable utilities to explore different scenarios and control strategies, optimizing grid performance under various conditions.

3.7. INVESTMENT IN CYBER-SECURITY TECHNOLOGIES

Despite its importance, the topic of cyber-security has not been discussed in the existing reports and assessments with regard to addressing future electrification and decarbonization needs.

This is understandable since the topic of cybersecurity is often treated as a separate topic.

However, the increasing electrification and the growing penetration of DERs are taking the electrical infrastructure into uncharted territories with regards to cybersecurity challenges.

Electricity distribution systems are becoming drastically more complex and more dynamic. Numerous inputs and controls are pushed and pulled from various advanced distribution grid platforms, including on the customer side due to transportation and building electrification and renewable and distributed generation; some of which connect the grid edge (i.e., customer side) resources to the public Internet. Further, the installation of millions of smart meters and the recent breakthroughs in sensor technologies and smart inverter controls are accelerating the rate at which measurement data is generated and control commands are dispatched across the grid.

Each of the new layers of data integration and control that are added to electric distribution systems can create new cyberattack surfaces and potential privacy breaches that are yet to be identified, understood, and quantified. This challenges the vision of a renewed and reliable electric grid.

Attacks may compromise many cyber and physical devices, turning controllable loads and DERs into "physical botnets" against the electric grid – analogous to how computer botnets work in distributed denial-of-service (DDoS) attacks on the Internet. For instance, a 50 kW flexible load that is hacked can become a physical botnet would switch 'on' – instead of remaining off – during a voltage sag event or when the substation is overloaded. A key difference from computer botnets is that the behavior and impact of physical botnets are governed also by the laws of physics. For example, to shut down a substation, hackers may consider the physical properties of the grid to determine how many physical botnets to recruit, at what size, and at what locations [95], [96], [97].

Since the electric grid is an interconnected network, any physical botnet that acts to mis-operate a grid asset may create cascading effects that propagate through the network to cause a blackout.

Hacking thousands of DERs can have an equal physical impact as hacking a Power Plant.

However, traditional studies on electricity infrastructure cybersecurity only focus on large power plants and control centers. The cybersecurity of the electricity distribution system and the grid resources is still an open problem because the distribution grid was simple and passive until recently. Not only do we lack effective cybersecurity solutions, but we also do not have a solid understanding of the cybersecurity risks and vulnerabilities, as new technologies are being adopted. Furthermore, grid-edge resources have a wide range of sizes and capabilities; and are made by both U.S. and foreign vendors.

Going forward, investment in cyber-security will be needed to reduce the power grid vulnerability against the new attack surfaces that are gradually being formed due to increased electrification.

3.8. INVESTMENT IN WORKFORCE TRAINING

The need for accelerated upgrades in transmission and distribution systems and grid modernization raises important questions about labor. Successfully executing these upgrades will require a trained workforce capable of planning and implementing various investments. Utilities have already been facing challenges in the availability of both equipment and trained workers [14]. The national average 10-year job growth outlook for electrical power-line installers and repairers is 8% [98].

Assessments of labor practices in California's energy sector particularly suggests the need to train entry-level workers for utility careers, including roles such as line workers [99]. The variation in upgrade needs by geography also indicates the necessity of training a local workforce, including individuals from disadvantaged communities, for jobs that do not require long commutes [27].

Workforce training must cover two broad areas: construction and installation jobs, and operation and maintenance jobs [27]. Each category requires specific skills and a training portfolio.

Addressing future grid-related workforce training needs calls for coordination and collaboration among utilities, local governments, and local labor and environmental organizations [14]. These entities, alongside state agencies, can work together to facilitate workforce opportunities and policies to ensure that training programs will meet the evolving demands of the energy sector.

CHAPTER 4. SOCIETAL AND POLICY IMPLICATIONS

This final chapter examines the broader societal implications of California's transition to increased electrification and grid readiness. It will also discuss the importance of equity considerations, policy challenges, stakeholder coordination, and public awareness and engagement.

4.1. CONSEQUENCES OF INACTION

4.1.1. BROADER SOCIAL AND ECONOMIC IMPACT

Electrification delivers significant societal benefits by improving air quality and cutting GHG emissions, resulting in healthier communities. Electrification also drives job creation in green industries and lowers long-term energy costs through improved efficiency [100]. Failing to upgrade the California grid to support electrification will prevent the full realization of these benefits.

Furthermore, as California faces rising temperatures and more frequent extreme weather events, the costs of inaction (such as higher disaster recovery expenses) underscore the urgency of ensuring California's grid readiness for transitioning to a clean, electrified future.

4.1.2. IMPACT ON EQUITY

A critical challenge in the path to electrification is to balance the rising costs of decarbonization with affordability. Currently, California has the nation's second-highest average cost of electricity, nearly twice the U.S. average, second only to Hawaii [101].

Utility expenses for electricity transmission and distribution (including capacity expansion, efficient operation, as well as for climate resilience) are significant portions of the overall costs of supplying electricity to customers. Some of the cost increases due to the required upgrades will inevitably be passed on to customers in the form of higher prices [102]. Lower-income households will be more adversely impacted by increases in electricity prices than higher-income households.

The extent of electricity price increases is hard to predict. As it has been shown in [102], different investment scenarios can result in a wide range of relative changes in electricity prices. There can be more than a 30% difference between the low-burden scenarios, where the electricity burden decreases, and the high-burden scenarios, where the electricity burden increases.

Affluent neighborhoods are more likely to adopt electrification technologies such as EVs. Solar adoption is also currently skewed toward mid-to-high-income single-family homes [27]. Prioritizing grid upgrades in areas with higher electrification adoption rates can naturally lead to more focus on these affluent neighborhoods, exacerbating inequality in grid upgrades.

Structural challenges may also affect inequity in grid modernization on the path to electrification. For example, rural communities are typically located in remote regions, far from main power generation centers and at the end of power distribution feeders [86]. Therefore, these communities may require higher-than-usual investments in upgrades to support the same level of electrification as urban areas. Furthermore, many disadvantaged communities in California are located in higherdensity urban environments, where it can be more expensive and inherently less cost-effective to implement targeted electrification projects compared to suburban regions [21].

The lack of access to EV charging ports, clean transit, and other technologies may prevent residents of communities of concern from fully participating in the modern economy. This lack of access could limit their opportunities for employment, goods, and other essential services.

Consumers may also face higher costs for goods delivery due to the electrification of trucks. Currently, electric trucks cost more than double the price of comparable diesel trucks, and the cost to power an electric truck is nearly double the cost per mile of a diesel truck [101]. If these trends do not change in the future, consumers will bear higher costs for goods delivered by electric trucks.

Policymakers and regulators are encouraged to manage cost and equity impacts by changing how electricity is priced, particularly for average and lower-income households. New electricity tariffs and prices could be designed to mitigate or eliminate the impact on electricity expenditures for selected income classes, such as improving tariffs based on income brackets [102].

Some of these concerns have been recently addressed by CPUC, such as through discounted flat rates for low-income households in the California Alternative Rates for Energy (CARE) program, as well as through the Family Electricity Rate Assistance (FERA) program [103].

On the contrary, some studies also point out that customer savings from reduced fossil fuel expenses will likely offset the increase in electricity costs due to higher electricity use in transportation and buildings; thus, reducing their overall energy cost. For example, it is estimated in [15] that, compared to what an average SCE household pays today for electricity, gasoline, and natural gas, combined energy expenses will decrease by 40% by 2045 [15].

Lastly, climate-driven events such as heat waves, wildfires, and other natural disasters have had a disproportionate impact on disadvantaged and vulnerable communities [18]. As electrification increases reliance on electricity for essential needs such as transportation and basic appliances, these communities will become more susceptible to electricity service disruptions. They are also less capable of coping with the stresses caused by such circumstances, such as high temperatures and wildfire damage, making them more likely to suffer physical and psychological harm [1].

4.2. POLICY CHALLENGES AND TRADEOFFS

4.2.1. POLICY AND REGULATORY CHALLENGES

Electrification is a complex process that involves multiple disciplines, such as power engineering, transportation, infrastructure, and environmental policy. Policymakers need to balance competing objectives in this domain, such as adequacy, affordability, equitable access to new technologies, and reducing GHG emissions. Therefore, there is a need for comprehensive planning, reliable data, and adaptable policies that can respond to evolving technological, societal, and economic needs.

California regulators and other stakeholders need reliable data to make informed decisions. To ensure comprehensive and reliable data gathering, a single state agency could be designated to oversee various policy (and technical) issues concerning electrification and grid readiness. Data from different agencies can be streamlined into one shared system. This will help identify gaps in data availability and data accuracy and improve models for planning future upgrades.

Policy considerations should ensure that the transition to electrification simultaneously pursues multiple objectives: 1) maintain the safety and reliability of the electric system; 2) prevent unreasonable impacts on customers' utility rates and bills, taking into full consideration the economic and environmental impacts; and 3) take actions to reduce GHG emissions in other economic sectors (industrial, commercial, agricultural, residential, transportation) to ensure equity between those sectors and the electricity sector [1].

Climate policies and regulations should be frequently evaluated to ensure flexibility and responsiveness to emerging technological and economic conditions, allowing for the most feasible and affordable solutions [15].

As described in Chapters 1 and 2, electrification projections vary considerably, resulting in very different upgrade requirements. Electrification trends are sensitive to factors such as state and local incentives and mandates, customer interest and behavior, price, and technology maturity [2]. Without accurate projections across these various socio-economic and policy factors, projects could result in either insufficient infrastructure expansions or unnecessary expenditures.

As stated in [71], the current forecast horizon for distribution-grid planning is typically three to five years. However, this horizon should be extended to 10+ years to incorporate needs and conditions when the system will face maximum stress due to electrification [8].

4.2.2. SUPPLY CHAIN CHALLENGES

The need for accelerated grid equipment upgrades raises questions about supply chains, such as access to transformers, circuit breakers, cables, and switches. However, in recent years, supply chain shortages and service delays have made it more difficult for utilities to obtain the equipment that they need, impeding their progress on grid modernization and decarbonization efforts [14].

Such shortages will likely persist due to geographic concentrations of key suppliers, limited access to raw materials, and restricted manufacturing capacity, such as power transformers, etc. Supply chain challenges for grid upgrades pose risks for grid investments by creating bottlenecks, extending timelines, and increasing costs for modernization efforts.

Therefore, grid readiness planning processes should also incorporate local technology adoption roadmaps and trends to proactively plan supply chain and infrastructure needs, preventing the grid from becoming a barrier to electrification and decarbonization adoption plans [7].

4.2.3. COST AND FINANCING ISSUES

Beyond supply chain challenges, there are significant concerns regarding financing, affordability, access to technologies, and the speed at which infrastructure can be upgraded [14].

Investing in *energy efficiency*, particularly in transportation and building electrification, can help mitigate the impact of higher electricity prices caused by electrification [21]. While it requires increased investment, it can ultimately help lower total costs and reduce the electricity burden.

The cost of decarbonizing the power sector, if reflected in increased rates, could lead to public pressure to reduce the pace of electrification. Further analysis should explore options that balance decarbonization, public health, and rate design, while addressing the costs of electrification [102]. If these trade-offs cannot be resolved in the near future, delaying electrification could leave customers exposed to the volatility of natural gas and gasoline prices [72].

From a long-term financing perspective, it may be preferable to invest in more expensive solutions that support long-term growth rather than cheaper, incremental options that may lead to higher overall costs when replaced with larger infrastructure [8].

Policies can also affect upgrade costs. For example, climate-informed design guidance is needed for updating grid equipment standards to make the grid sufficiently resilient [18]. Such guidelines, once established, will likely affect the cost of upgrades. Future guidelines should encourage the timely adoption of climate-resilient technologies without overburdening consumers or the utility industry, with plans on how to cover the cost.

4.2.4. INTERCONNECTION AND PERMITTING DELAYS

The volume of interconnection applications has surged in recent years [15]. To keep pace, California needs an integrated planning process across generation, transmission, distribution, while balancing objectives such as affordability, reliability, load growth, and climate adaptation.

The analysis in [1] indicates that resources and upgrades with lengthy permitting requirements and development times will be necessary, which inevitably requires long lead-time planning. Concerns about delays in the process will likely grow in the future.

There is also an urgent need for timely action. Recent reports indicate that EV developers are currently not receiving timely approval from utilities on where to site their charging infrastructure and are sometimes only granted partial capacity approvals [71]. Grid upgrades must be planned and completed in advance of customers installing EV-charging equipment to avoid bottlenecks.

4.3. STAKEHOLDERS COORDINATION AND COMMUNICATION

Coordination and collaboration among stakeholders is necessary to support electrification and grid readiness in California. A non-exhaustive list of relevant stakeholders is shown in Table 4.

Stakeholders
State Agencies (CPUC, CEC, CARB, etc.)

Federal Agencies (DOE, FERC, EPA, EIA, etc.)
Investor-Owned Utilities
Publicly-Owned Utilities
Independent System Operators (CAISO)
City Governments
County Governments
Tribal Governments
Housing Authorities
Neighborhood Councils
Community Organizations
Environmental Justice Organizations
Community Choice Aggregators (CCAs)
Academic and Research Institutions
Workforce Training Groups
Customer Advocate Groups
Local Business Groups
Unions
Technology Providers

Table 4. Some of the stakeholders identified for California Grid Readiness.

4.3.1. BRIDGING COMMUNICATION GAPS

The communication gap between federal, state, and local jurisdictions often leads to fragmented approaches and inefficiencies in addressing energy and infrastructure challenges. Bridging this gap is crucial for fostering coordinated strategies and ensuring that all levels of government and stakeholders work together effectively toward common goals in grid readiness efforts.

Planning efforts by state's energy and clean air agencies are usually done at the individual agency level, but there is an increase in joint planning between these agencies. In addition, California stakeholders may collaborate to advocate for federal support for the state's grid readiness.

Notably, federal and state agencies, local governments, tribes, and stakeholders have gained experience over the past decade in terms of collaborations and planning approaches to support renewable energy development and long-term energy conservation. For example, their joint efforts have enabled them to collect and assess environmental data and information on infrastructure needs. Lessons learned from these prior collaborations can provide valuable insights for creating new partnerships to ensure California's grid readiness for electrification.

Opportunities may exist also to benefit from collaboration among western states to enhance coordination and market development, to ease the importation and integration of additional renewable energy facilities to leverage the geographic diversity of loads and resources [1].

4.3.2. ENGAGING DIVERSE STAKEHOLDERS

Besides the key industry players, other stakeholders, such as environmental justice and equity organizations can also provide valuable insights on planning California's grid readiness, covering various important aspects such as project needs, public outreach, and workforce training [18].

Utilities should work with municipal and county partners and community organizations on regional policies, funding sources, and building codes to encourage residential electrification [17]. When applicable, community choice aggregators (CCAs) can also play a positive role in adopting and aggregating grid edge coordination technologies while addressing equity considerations.

Advisory groups with representatives from academia, neighborhood councils, environmental justice, customers, unions, workforce groups, local governments, local businesses, and renewable energy industry organizations can provide input on issues related to feasibility, reliability, public health, equitable economic development, job opportunities, and local hiring programs [27].

For example, the Southern California Association of Governments (SCAG) has recently completed its Clean Technology Compendium as a resource for local planners and stakeholders to transition Southern California's transportation sector to a new generation of clean technologies [104].

Customers and electrification developers play a crucial role in all stages of grid readiness evolution. They should have platforms to communicate proactively with utilities about their needs and electrification plans to enable accurate load forecasting, especially for large projects [15].

Policymakers should proactively analyze and incorporate climate data in planning, design, and operation of energy systems to ensure climate resiliency. To ensure that the right voices are heard in the larger conversation on climate action, input should also be gathered from customer advocacy groups and community organizations to co-create plans that will help ensure equity [18].

4.3.3. POLICY AND REGULATORY COORDINATION

From the utility's viewpoint, regulatory and policy reform in four key areas through coordination among agencies can help accelerate transmission buildout [15]:

- Advance policies that reduce permitting review timelines.
- Eliminate redundant efforts in the permitting phase.
- Minimize agency handoffs and appoint a lead agency for permitting reviews.
- Standardize permitting at local levels.

The state should consider additional supportive policies that ensure local economic benefits, clarify differentiated agency roles, harmonize existing policies and programs with the Clean Energy

Deployment Plan, and improve the regulatory process. California lawmakers should also consider enhancing the state's role in system planning, siting, and financing to support grid readiness [31].

Grid upgrade planning must be comprehensive across generation, transmission, and distribution capacity needs to avoid creating bottlenecks in any aspect of the overall needs of grid readiness.

For grid upgrades at the transmission level, stakeholder coordination may involve developers, utilities, balancing authorities, local governments, and community groups to identify concerns and barriers early on and to develop strategies to address them with cost-efficient solutions [1].

The process of building new power transmission infrastructure can require approval from several local, state, and federal entities, access to land from dozens of landowners, and millions of dollars in preparatory work before a single foundation is poured. As a result, major power transmission projects can take many years to complete, from permitting to implementation. Major projects in California often require twice as much time as originally anticipated [31].

4.3.4. WORKFORCE DEVELOPMENT AND TRAINING

Policymakers and regulatory agencies should prioritize local workforce development, evolving skills for grid upgrades across construction, installation, operation, and maintenance jobs [17].

The variation in upgrade needs by geography indicates that municipal and county governments and local labor and environmental organizations may have an added role in facilitating workforce policies alongside state and utility actors. Policymakers and regulatory agencies should also prioritize local workforce development to evolve skills for grid upgrades [17].

4.4. EQUITABLE AND TRANSPARENT INVESTMENT

As described earlier, low-income households will face the highest impact from electricity price increases because their electricity cost will be a higher percentage of their income. They are also more likely to live in older homes, which often require more upgrades to support electrification. This presents equity concerns in rural communities; because they often need higher investments for grid modernization due to their remote locations. It also presents equity concerns in disadvantaged urban communities due to the lower cost-effectiveness of electrification projects.

Since affluent neighborhoods are more likely to adopt EVs and solar panels, utilities are naturally forced to focus on grid upgrades in these neighborhoods. This would exacerbate inequality. On the other hand, climate events disproportionately affect vulnerable communities, making them more susceptible to electricity service disruptions and less capable of coping with resultant stresses and damages. Investments in grid readiness should directly address these various equity concerns.

Electrification can also have other unintended inequality consequences. For example, widespread building electrification may affect the cost recovery for California’s gas distribution systems. As homes and businesses depart the gas system, the fixed costs of the gas system will be spread across fewer customers that still use gas-fueled appliances. This can lead to significant increases in gas rates for the remaining customers. Low-income households who cannot afford electric alternatives will be particularly vulnerable to these potential gas rate increases [21].

Funding sources for state priorities may also need to be reevaluated to ensure equity. For example, it is suggested in [17] that funding state-mandated Public Purpose Programs (PPPs) from the state's budget instead of electric and gas bills could promote a more equitable recovery of the costs. These and other funding options may need to be carefully evaluated by stakeholders to revisit priorities.

Grid readiness planning should not focus solely on upgrades but also on developing strategies to maximize the use of the *existing* transmission and distribution systems before constructing new lines and substations. Strategies include using advanced smart grid technologies (e.g., efficiency upgrades as discussed in Section 3.2) and optimal placement of future DERs.

Grid upgrade plans will have to be transparent, in terms of funding sources, impact on ratepayers across different income brackets, oversight on spending, and the true needs to ensure most cost-effective choices. Transparency will help build trust among stakeholders and also with the public.

4.5. PUBLIC AWARENESS

Public awareness is necessary both for electrification and for investments in grid readiness.

With respect to electrification, many drivers are currently worried about the range of EVs and do not have a clear understanding of different charging options, leading to unnecessary range anxiety. Policymakers can focus on these aspects, educating the public to alleviate these concerns [105].

Public awareness campaigns should aim to provide accurate information about the capabilities and benefits of EVs, as well as the realities of charging infrastructure and the need for grid upgrades.

When discussing electrification and grid readiness with the public, policymakers could continue to emphasize the broader benefits, such as improved air quality, reduced GHG emissions, and long-term cost savings, while also being honest about the transitional cost. This can in the long run help build public support for electrification and the potential cost burden during the transitions.

Community leaders, environmental groups, and other stakeholders can be engaged to help enhance the effectiveness of public awareness efforts. These groups can provide insights into the *concerns* and *priorities* of different communities; thus, helping utilities to address their specific needs.

5. CONCLUSIONS

Electrification is rapidly growing in California across various sectors, including transportation, buildings, and emerging areas such as industrial loads, hydrogen production, and data centers.

With respect to transportation electrification, significant progress has been made in recent years in light-duty vehicle electrification. Medium- and heavy-duty vehicle electrification is also advancing rapidly and is expected to play a major role for goods movement from Southern California ports.

Building electrification is expanding with a focus on space heating, cooling, and water heating.

Electricity demand is also growing in the industrial sector, data centers and computation sector (for AI models) and hydrogen production (for hydrogen-fueled transportation and energy storage).

Current projections not only increase in total electricity usage but also in peak loads, requiring significant upgrades to the power grid's power transmission and power distribution capacity.

The integration of EVs, building electrification, and other emerging loads will also alter load patterns. This will introduce new challenges for grid planning and operation, and the need for more agile grid-edge coordination to utilize load flexibility to change the load profiles when needed.

The increased randomness and variability in load profiles necessitate advanced forecasting and probabilistic modeling, including with high granularity across distribution circuits.

The transmission and distribution networks will require capacity upgrades to prevent overloading and to ensure reliable power delivery. Grid operation challenges, such as voltage violations, power quality issues, and protection issues can become more prevalent with the growing electrification.

Grid resilience will be tested during extreme weather events. Investments will be needed for not only grid equipment hardening but also for microgrids and technologies such as V2G and V2B.

There is no doubt that extensive planning and investment will be needed for the state's power grid to support the growing electrification. However, as discussed throughout this paper, the current projections for the extent and the cost of the grid upgrades vary significantly, as they vary depending on many factors and different assumptions.

A streamlined permitting process is also critical, both for customer electrification projects and grid readiness projects, to keep pace with the growing demand for electrification infrastructure.

In this white paper, we have identified a wide range of factors, concerns, and considerations raised across industry, government, and academia regarding California's power grid readiness to support growing electrification. Investment needs must be addressed in the following areas:

- Distribution Network Equipment Upgrades
- Transmission Network Equipment Upgrades
- Grid Edge Coordination and Demand Response Technologies
- Grid Resilience Technologies

- Advanced Monitoring and Data Intensive Technologies
- Operation, Control, and Protection Technologies
- Cyber-Security Technologies
- Workforce Training

For each area, this white paper identified the concerns and considerations from industry reports and academic literature concerning California's grid readiness for growing electrification.

Close coordination will be necessary among stakeholders to bridge communication gaps, engage diverse groups, and coordinate policy and regulatory efforts. Stakeholders must address supply chain issues, permitting issues, equity concerns, public awareness, and workforce development.

Reliable and comprehensive data collection is crucial for making informed decisions.

To ensure comprehensive and reliable data gathering, a single state agency could be designated to oversee various policy and technical issues concerning electrification and grid readiness.

Some of the policy considerations that were discussed in this white paper are as follows:

- Integrated Planning of Grid Upgrades: Holistic approaches to consider generation, transmission, and distribution needs simultaneously (not separately) and at scale.

- Stakeholder Collaboration: Better coordination and collaboration among relevant stakeholders, including: state agencies, federal agencies, investor-owned utilities, publicly-owned utilities, system operators, city governments, county governments, tribal governments, housing authorities, neighborhood councils, community organizations, environmental justice organizations, community choice aggregators, academic and research institutions, workforce training groups, customer advocate groups, local business groups, unions, and technology providers.

- Regulatory Reform: Streamlining permitting processes and adopting procedures to speed up approvals. The lengthy permitting processes to approve customer projects (such as EV charging stations) are increasingly becoming bottlenecks in electrification efforts, arising from both technical and policy challenges.

- Equity Considerations: Ensuring that investments and policies address the needs of disadvantaged and vulnerable communities. There are equity concerns in rural communities (since they often need higher investments for grid modernization due to their remote locations) and in disadvantaged urban communities (due to the lower cost-effectiveness of electrification projects). There are also equity concerns about the unbalanced rate of adopting electrification technologies, as well as the fact that climate events disproportionately affect vulnerable communities.

- Public Awareness: Educating the public to encourage broader adoption of electrification. Public awareness campaigns should provide accurate information about the benefits of electrification as well as the cost to ensure grid readiness.

- Data Coordination and Oversight: Streamlining data from various agencies into a shared system, identifying gaps in data availability and accuracy, and improving projection models to be used for proactively planning future grid upgrades.

While this white paper primarily focuses on the technical challenges and the current baseline conditions, a follow-up paper focusing on the details of policies, strategies, and solutions may be necessary to further explore actions that can be taken by stakeholders and public agencies.

The path to electrification and a modernized grid is complex and multifaceted. It demands comprehensive planning, robust stakeholder engagement, and a commitment to equity and sustainability. By addressing these key areas, California can lead the way in creating a resilient, efficient, and inclusive energy system that meets the needs of all its residents.

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