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Wednesday, May 24th
1:30 p.m. – Capitol Room 437

INFORMATIONAL HEARING

Electrical Distribution Planning: How Addressing Current Delays in Connecting to the Distribution Grid may Ensure Readiness for an Electrified Future

Throughout the fall and winter of 2022-2023 concerns mounted regarding electric utilities' ability to meet demand, serve new customers, and interconnect distributed resources to the distribution grid. Many of these concerns were acutely felt in Pacific Gas & Electric Company's (PG&E) service territory, and included delays to energizing real estate developments, including affordable housing developments, in Solano,[1] Kern,[2] and Fresno[3] Counties; continued delays to boosting the Muni train capacity in San Francisco;[4] and delays to energize new businesses throughout Northern California, from Humboldt[5] to Sonoma[6] Counties; among other issues. The frustration in Fresno County led city and state officials to denounce the delays, with Fresno Mayor Jerry Dyer publicly noting the city had "completely lost confidence" in PG&E.[7]

PG&E acknowledged the growing backlog of identified capacity work that has delayed, sometimes by years, the in-service dates for new customers, and took steps to better manage

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[1] Scott Morris, "Opening delayed for new Vallejo housing for homeless," *Vallejo Sun*, January 31, 2023; https://www.vallejosun.com/opening-delayed-for-new-vallejo-housing-for-homeless/
[2] John Cox, "Power connection work delays local development projects," *Bakersfield.com*, November 26, 2022; https://www.bakersfield.com/news/power-connection-work-delays-local-development-projects/article_8bc9ed88-6d0f-11ed-b3ee-973f5213928a.html
[3] Tim Sheehan, "California homes face PG&E delays for power connections, Frustrated leaders seek options," *The Fresno Bee*, October 28, 2022; https://www.fresnobee.com/news/local/article267995517.html
[4] Garrett Leahy, "Muni Blames PG&E for Spiraling $15M Costs, Years of Delays in Train Upgrade Struggle," *The San Francisco Standard*, December 13, 2022; https://sfstandard.com/transportation/muni-blames-pge-for-spiraling-15m-costs-years-of-delays-in-train-upgrade-struggle/
[5] Ryan Burns, PG&E Execs Gets an Earful, Offer Update on SoHum Capacity Problems," *Lost Coast Outpost*, November 2, 2022, https://lostcoastoutpost.com/2022/nov/2/pge-execs-gets-earful-offer-update-capacity-proble/.
[6] Jeff Quackenbush, "PG&E tells some Sonoma County projects that power connections could take up to 18 months," *North Bay Business Journal*, December 1, 2022; https://www.northbaybusinessjournal.com/article/article/pge-tells-some-sonoma-county-projects-that-power-connections-could-take-up/
[7] David Taub, "In Power Struggle, Fresno Leaders Threaten to Ditch PG&E," *GV Wire*, October 31, 2022; https://gvwire.com/2022/10/31/in-power-struggle-fresno-leaders-threaten-to-ditch-pge/

their project queue. In early 2023 the utility formed a technical committee, led by representatives from labor groups and regional building association members, to work on issues in the interconnection and energization process, to evaluate the impact of recent process changes, and to determine next steps. The backlog remains a growing frustration for the utility, project developers, customers, and others waiting to have their projects energized.

Nonetheless, the backlog in PG&E distribution-level work is more than just a near-term pain point. Rather, it highlights a concern with overall statewide readiness to support the electrification needed to meet our mid- and long-term decarbonization goals. Utilities across the state, from investor-owned (IOUs) like PG&E to publicly-owned (POUs), have much work to do to ensure the grid can support the suite of state decarbonization goals and regulations, with much of that work concentrated on the distribution grid. Upcoming statewide targets include a reduction of greenhouse gas (GHG) emissions to 40% below the 1990 level by 2030[8] and 85% by 2045, with the state also needing to achieve carbon neutrality by 2045.[9] The California Air Resources Board (CARB), as part of its 2022 plan outlining how the state will meet these goals, noted that "in almost all sectors, electrification will play an important role."[10] The California Energy Commission (CEC) mirrors this, recently noting that "electricity consumption in California is increasing at an accelerating rate, fueled in part by California's efforts to decarbonize the transportation and building sectors by switching from fossil fuels to electricity."[11] The consequence of this push toward electrifying various sectors of California's economy is that the electric grid will likely need to grow at unprecedented rates over the next two decades. The primary focus to date of meeting this electrification-driven demand has been on the development of new, clean energy resources. However, ensuring infrastructure is available to connect and transmit the generated electricity to end-use customers is just as instrumental to meeting California's decarbonization goals. This committee has held hearings examining both the resource development[12] and transmission-level infrastructure[13] necessary to meet these mid- and long-term goals; however less emphasis has been given to the distribution grid where most of the work of electrifying the state will occur.

The purpose of this hearing is to provide a broad overview of distribution planning conducted by the state's utilities, including both customer energization and interconnection of distributed resources. The hearing will examine current processes and potential improvements to planning, to better understand how projected load growth may impact this planning regime. The hearing will also examine the current delays experienced on the distribution grid, and discuss what current delays might mean for our future electrification goals. This hearing will serve as an introduction to these topics. An upcoming joint hearing

[8] Health and Safety Code § 38566, as added under SB 32 (Pavley, Chapter 249, Statutes of 2016)
[9] Health and Safety Code § 38562.2, as added under AB 1279 (Muratsuchi, Chapter 337, Statutes of 2022)
[10] Pg. 8, CARB, *2022 Scoping Plan for Achieving Carbon Neutrality*, December 2022; https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf
[11] Pg. 3, CEC, *Final 2022 Integrated Energy Policy Report Update*, February 2023, CEC-100-2022-001-CMF
[12] *Joint Informational Hearing with Assembly Committees on Utilities & Energy, Natural Resources and Budget Sub 6., A 2030: Vision: Mid-term Actions Needed for the Energy Transition*, Monday, November 14, 2022, https://autl.assembly.ca.gov/content/past-informationoversight-hearings
[13] *Envisioning the Grid of 2045: How Much Transmission Is Needed?* Wednesday, May 18, 2022, https://autl.assembly.ca.gov/content/past-informationoversight-hearings

on transportation electrification is being planned for later in 2023 to explore these issues by focusing on that specific economic sector.

Findings

- *The state's utilities conduct their own distribution planning process, accounting for projected customer load changes in their service territories. These plans help guide investments and priorities in the distribution system for years. Customer requests to interconnect new generation or receive new service (i.e., "energization") inform these distribution plans, and guide utilities in forecasting customer trends.*

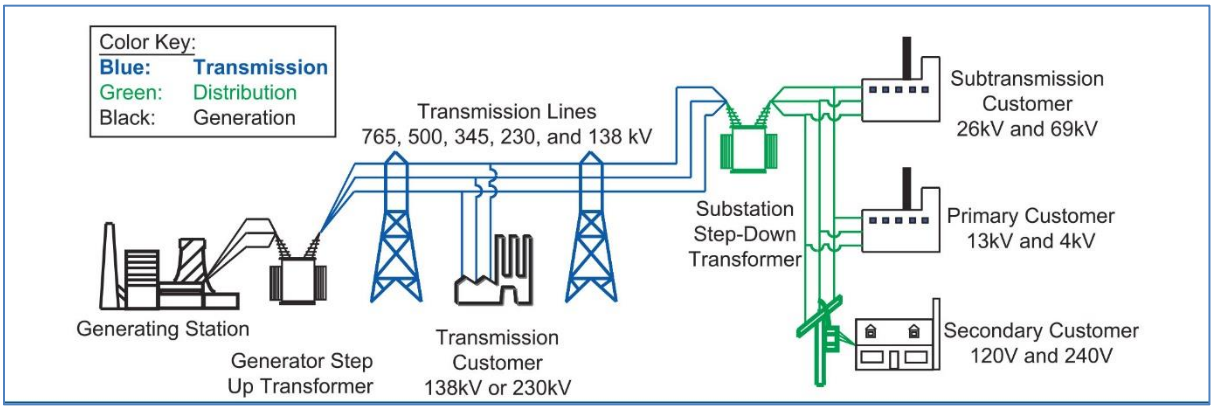
- *The utilities create their distribution plans to account for trends in both interconnection and energization. Each process has its own associated steps, regulatory requirements, and timelines; and as a result delays may occur at any point in the process despite a utilities' best effort to plan. Currently, supply issues for needed equipment—such as transformers—have delayed project timelines and increased system upgrade costs.*

- *A recent report conducted for the CPUC estimated over $50 billion in investments in traditional electricity distribution grid infrastructure are needed by 2035 to accommodate California's decarbonization goals. This is roughly an order of magnitude more than the projected costs needed for the transmission system over this same timeframe. Such a large investment projection raises deeper questions about the distribution system, and whether the status-quo approach to meeting our decarbonization goals is sufficient. The utilities and their regulators should evaluate mitigation strategies to reduce these costs, and consider a system-wide assessment of where current investments are headed.*

The Current Distribution Planning Regime. In traditional utility organization, electric power flows in one direction from centralized generation resources over wires that gradually decline in voltage before reaching end-use customers. As shown in Figure 1, infrastructure operating at higher voltages comprise the transmission grid (in blue), while those at lower voltages comprise the distribution grid (in green). Transmission lines are connected to substations that "step-down" the power to a lower-voltage so that it can be delivered to customers through distribution lines, although some large industrial customers receive their electricity at transmission or sub-transmission voltage. The distinction in voltage level between the transmission and distribution grid differ across the utilities, and are set at the discretion of the utility. Nevertheless, the typical range for transmission infrastructure is 220 kilovolts (kV) or higher, while distribution infrastructure ranges anywhere below 50 kV, with the bulk of the distribution grid in California operating at 12 kV.[14] By the time the power reaches a typical residence in California the voltage is even lower, roughly 0.24 kV, and is split at the home's main circuit breaker into 0.12 kV.

[14] Between transmission and distribution, some utilities like Southern California Edison classify as "subtransmission" which ranges from 66-115 kV.

Figure 1: Diagram of the standard North American electric grid.[15]



For the IOUs, the distribution planning process is annually conducted by the utilities and evaluates the projected outlook of demand as well as generation that will be interconnected to the distribution system in order to determine their distribution grid needs. The projected demand forecast each utility creates is informed by both the CEC's statewide projections in the Integrated Energy Policy Report (IEPR) and local variables such as historic usage, economic indicators, temperature data, and near real-time customer requests to connect. The IOUs typically focus on distribution grid needs on a 3-year time horizon, but also evaluate 5- to 10-years out. Once distribution grid needs are determined, the utilities weigh the various options to address those needs while considering customer cost, forecasted load growth, and impact on current operations. The distribution plans identify circumstances where existing capacity may be utilized, smaller system upgrades may be feasible, or whether the more costly and labor-intensive installation of new capacity is required. This information is then fed into the IOUs' respective investment plans, each of which must be authorized by the California Public Utilities Commission (CPUC).[16]

Following the passage of AB 327 (Perea, Chapter 611, Statutes of 2013), the IOUs are required to file distribution resource plans with the CPUC. A series of CPUC decisions adopted IOU requirements to "minimize overall system costs and maximize ratepayer benefit from investments in distributed resources,"[17] and require the IOUs to submit to the CPUC a distribution Grid Needs Assessment in August of each year. These decisions improved the distribution planning process and increased transparency by requiring the IOUs to use the CEC's IEPR forecast and to justify any deviation in the utility-generated forecasts via an advice letter; creating a public data portal for developers and local and tribal governments to utilize; and linking the IOUs' distribution investment plans to their general rate cases.[18]

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[15] National Park Service website, "Electrical Power Transmission and Distribution," access on May 5, 2023; https://www.nps.gov/subjects/renewableenergy/transmission.htm

[16] Information on distribution planning based on Mark Esguerra, Director, Distribution System Planning and Strategy at Southern California Edison presentation on Joint IOU Distribution Planning at CEC Workshop on Clean Energy Interconnection – Electric Distribution Grid; May 9, 2023; https://www.energy.ca.gov/event/workshop/2023-05/commissioner-workshop-clean-energy-interconnection-electric-distribution?utm_medium=email&utm_source=govdelivery

[17] D. 18-03-004, D. 17-09-026, and D. 18-03-023.

[18] Information on past process improvements from AB 327 (Perea, 2013) based on Simon Baker, Director, Distributed Energy Resource, Natural Gas & Retail Rates and the CPUC presentation at CEC Workshop on Clean Energy Interconnection – Electric Distribution Grid; May 9, 2023; https://www.energy.ca.gov/event/workshop/2023-05/commissioner-workshop-clean-energy-interconnection-electric-distribution?utm_medium=email&utm_source=govdelivery

Ongoing efforts by the IOUs to improve their distribution planning process include more direct engagement with customers and communities to understand future electricity demand, with a specific focus on engagement with large fleet operators to obtain multi-year load data and electrification plans from companies subject to CARB's Advanced Clean Cars II, Advanced Clean Trucks, and Advanced Clean Fleets regulations, among others. Recently, AB 2700 (McCarthy, Chapter 354, Statutes of 2022) sought to better inform this process by requiring the CEC to gather and report to the IOUs fleet data needed to support their plans for grid reliability and enhanced vehicle electrification.

For POUs, their distribution planning follows a similar process as the IOUs, except for CPUC oversight. Typically, although it may vary by POU, there is an annual assessment of distribution system needs under normal operating and emergency conditions. The POUs look at load forecasts, though they are not required to use the CEC's IEPR, and determine capacity limits of their circuits. They also assess existing infrastructure and determine what needs to be replaced, consider city and other local agency development proposals, and engage with customers to meet current and future needs. Many POUs benefit from a "whole of city" approach where new developments in the project pipeline at city departments are seamlessly integrated into POU distribution system planning. Under the CEC's authority,[19] all POUs with 200 megawatts (MW) or greater of peak load must submit information on their projected supply and demand over the next decade to the CEC, and submit load forecast under various scenarios to be integrated into the IEPR. Smaller POUs can fill out a simplified supply and demand form to meet these requirements.

For both IOUs and POUs various challenges may arise despite their best efforts to plan for distribution system needs. Currently, supply issues for needed equipment—such as transformers—can delay project timelines and increase system upgrade costs. Much of the frustration in PG&E territory over the past few months has its origins in equipment supply issues. Other challenges include lack of visibility into distributed resources, such as rooftop solar or demand response, making it hard for utilities to accurately forecast customer load; difficulty in accurately modeling customer behavior; acceleration of statewide decarbonization goals; and extreme weather events.

As mentioned above, any accurate utility plan must evaluate both the generation that will be interconnected to the electrical system (typically decreases load), as well as the projected outlook of customer demand (typically increases load). These connection processes are distinct, and use specific terms:

- <u>Interconnections</u>, which generally refer to the physical connection of an energy generation or storage device to the electric system that is either in front of the meter or behind-the-meter. Interconnection is a defined term in utility tariff rules that generally describe an electric utility's physical connection to an external source of power. The interconnection process of generation resources is largely structured by Electric Tariff Rule 21, although more detail follows below.[20]

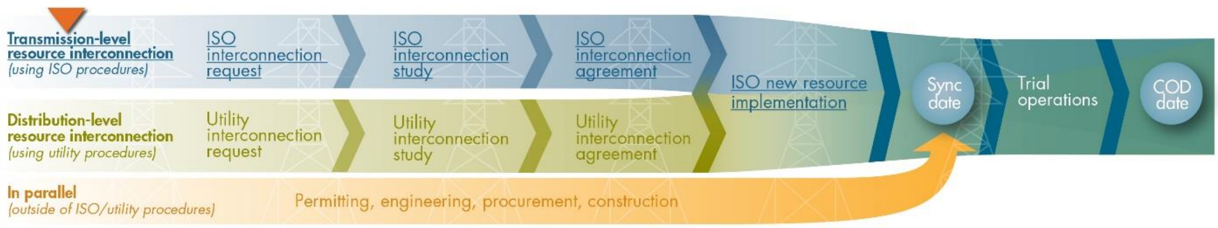
[19] Public Resources Code § 25300, et seq.
[20] CPUC; "Rule 21 Interconnection"; https://www.cpuc.ca.gov/rule21/

- New service connections, also known as "energization," involve extending an electricity line or expanding distribution infrastructure to service new or expanded customer load. IOU energizations are subject to provisions specified in the CPUC's Electric Tariff Rule 15 (multiple customers served by circuit) and Electric Tariff Rule 16 (one customer served by circuit).

Simplistically, "interconnection" ensures more power can flow *onto* the grid; while "energization" ensures more power can flow *off* the grid. The utilities create their distribution plans to account for trends in both interconnection and energization. Each process has its own associated steps, regulatory requirements, and timelines; and as a result delays may occur at any point in the process despite a utilities' best effort to plan.

Interconnection. California's utilities build, own, and manage most of the transmission and distribution that serves their customers. Consequently, the utilities play an integral role in interconnecting new generation and battery resources, which are generally owned by merchant developers. As shown in Figure 2, these interconnection projects are split into two queues: the distribution interconnection queue, which are operated by the individual utilities, or the transmission interconnection queue, which is operated by the California Independent System Operator (CAISO) but also involves the utilities. Which of the two queues a project enters is determined by the desired interconnection voltage level of the project. Projects exceeding a specific voltage threshold, set by whichever utility covers the territory that the project is sited in, are routed into the transmission queue and shepherded through the process by CAISO.[21] Regardless of whether the resource interconnects using the CAISO's transmission interconnection process or a utility's distribution interconnection process, additional steps must be completed with the CAISO in order for the resource to participate in the wholesale power market.

Figure 2: The Parallel Interconnection Queues for Transmission and Distribution-level Projects.[22]



Interconnection: the Transmission Grid. The interconnection process at the transmission-level is largely guided by an agreement between the utility, the merchant developer, and CAISO after the completion of interconnection studies conducted by CAISO. The timeline for interconnection is based on the study results and is reflected within the interconnection agreement as the expected in-service date. After a resource has completed the study phases of the interconnection process, contracts must be signed, the resource must be modeled in the CAISO's market systems, and metering and telemetry equipment will need to be installed

[21] California ISO; "Getting started - exploring interconnection to the grid"; http://www.caiso.com/participate/Pages/ResourceInterconnectionGuide/default.aspx
[22] California ISO; "Getting started - exploring interconnection to the grid"; http://www.caiso.com/participate/Pages/ResourceInterconnectionGuide/default.aspx

before participation in the wholesale power market is allowed.[23] The in-service date of a project can be affected by a wide variety of factors including permitting, engineering, procurement, and construction of generation and transmission.

Interconnection: the IOU Distribution Grid. Rules governing the ability of new buildings, electricity generation, and storage resources to connect to the electric distribution grid are generally determined by statute, CPUC rules, and tariffs[24] for each of the IOUs. All generating facilities seeking interconnection with the distribution provider's system shall apply to the CAISO for interconnection and be subject to CAISO tariffs except for 1) Net Energy Metering (NEM) generating facilities, and 2) generating facilities that do not export to the grid or sell any exports sent to the grid (non-export generating facilities). These two resource types are subject to CPUC jurisdiction and interconnect under Rule 21 regardless of whether they interconnect to a distribution or transmission system.[25]

Electric Tariff Rule 21 describes the interconnection, operating, and metering requirements for generation facilities to be connected to an electrical utility's electrical system. The tariff provides customers who would like to install generating or storage facilities on their premises with access to the electric grid while protecting the safety and reliability of the electric grid at the local and system levels. Each IOU is responsible for administration of the rule in its service territory and maintains its own version of the tariff.[26] The vast majority of Rule 21 interconnection requests are for customer-sited generation (NEM rooftop solar) on a utility's distribution system.

Rule 21 does not apply to the interconnection of generating or storage facilities intending to participate in wholesale markets overseen by the Federal Energy Regulatory Commission (FERC). These facilities must typically apply for interconnection under the FERC-jurisdictional Wholesale Distribution Access Tariff (WDAT), when connecting to the distribution system, or the CAISO tariff, when connecting to the transmission system. The utility WDAT governs all other exporting facilities connected to the distribution system not on a NEM tariff.

Energization. New service connections, also known as "energization," involve extending an electricity line or expanding distribution infrastructure to service new or expanded customer load. CPUC Electric Tariff Rule 15 relates to distribution line extensions. Specifically, new distribution facilities that are a continuation of, or branch from, the nearest available existing permanent distribution line (including any facility rearrangements and relocations necessary to accommodate the extension) to the point of connection of the last service. Rule 15 generally pertains to electric distribution grid equipment used by multiple customers (e.g., a transformer serving multiple homes).

Electric Tariff Rule 16 relates to service line extensions. The overhead and underground primary or secondary facilities (including but not limited to utility-owned service facilities

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[23] California ISO; "Getting started - exploring interconnection to the grid"; http://www.caiso.com/participate/Pages/ResourceInterconnectionGuide/default.aspx

[24] Documents that specify rates, charges, rules, and conditions under which an IOU will provide service.

[25] CAISO "Interconnection Basics" presentation; November 2014; http://www.caiso.com/documents/interconnectionoptionsbasics.pdf

[26] CPUC; "Rule 21 Interconnection"; https://www.cpuc.ca.gov/rule21/

and applicant owned service facilities) extending from the point of connection at the distribution line to the service delivery point. Rule 16 generally pertains to network equipment used by just one customer.

Electric Tariff Rules 15 and 16 establish the guidelines for design, cost allocation, and responsibilities of a project applicant and a utility for electric distribution line extensions. The ability to connect to the larger electrical system can take months (or years, in some cases) as the process can require designs and assessments on cost allocations associated with improvements on the electric distribution system to allow for the connection, among other issues. In the case of new building developments, electric service extensions may be required in phases over the span of months or years, depending on the size of the development.

Energization Lifecycle. Customer energization processes and timelines can vary greatly depending on utility territory, project type (ranging in complexity from home panel upgrades to energizing a stadium), system upgrades necessitated by the energization request, or events outside the utilities' control such as supply chain delays, weather, or pending customer application information or permit completion, among others. The energization requests can take anywhere from a month to years depending on these various factors. As shown in Figure 3, there are many steps—and thus many opportunities for delay—in the customer energization lifecycle. Much of the frustration within PG&E territory over the last few months involved extensive delays to customer energization work.

Figure 3: Customer Project Lifecycle (for complex projects)[27]

Efforts to Address EV Energization Delays. In response to a proposal from the IOUs, the CPUC issued Resolution E-5247 in December 2022, which establishes an interim 125-business day average timeline for the energization of projects under the Electric Vehicle (EV) Infrastructure Rules. This timeline excludes projects that must go through Rule 15 for distribution upgrades, projects above two megawatts, and projects that require upgrades to a substation, and applies only to EV infrastructure projects entering the queue. The CPUC cites lack of data as the rationale for setting an interim timeline requirement and directs the IOUs to collect one year of EV Infrastructure Rule implementation data to inform an updated proposal for a permanent service energization timeline.[28]

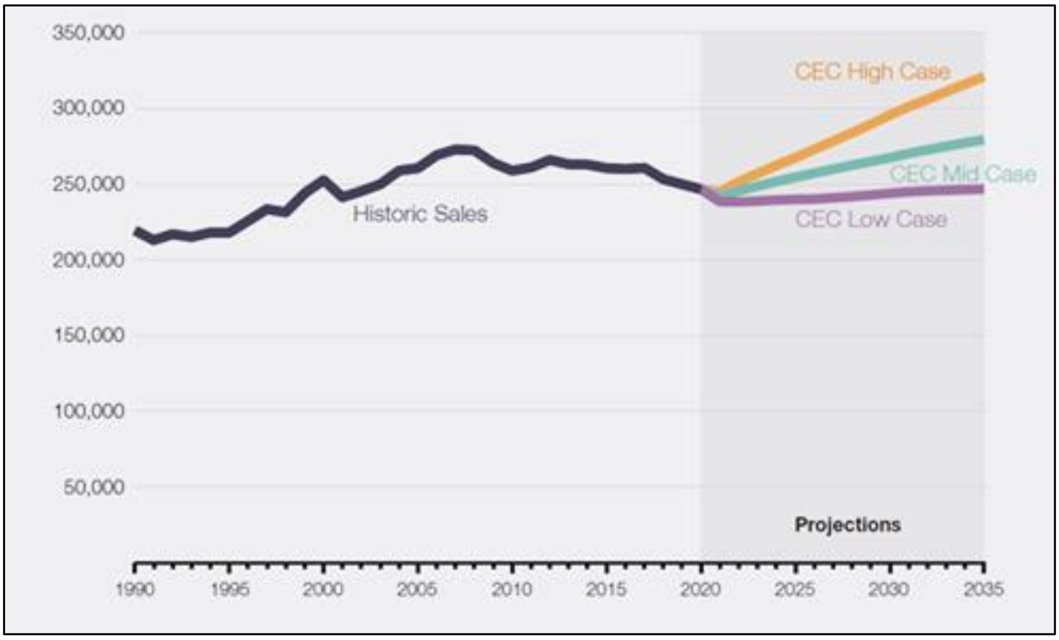
Managing Future Demand. According to the CEC's most recent IEPR, statewide electricity sales roughly totaled 290,000 gigawatt-hours (GWh) in 2021. By 2035, the CEC projects

[27] Example provided by SDG&E and representative of their territory. Timelines and activities reflect those for complex projects (e.g., subdivisions, developments involving design by SDG&E). Requests that do not involve SDG&E design tend to have shorter timelines. Duration of the project phases are estimates only and represent activities managed by SDG&E; i.e. do not include time for activities that are the customer responsibility.

[28] CPUC Resolution E-5247, December 15, 2022; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K892/499892084.PDF

those sales to be just under 302,000 GWh.[29] While this may seem like a small change, this forecasted increase to electricity sales reverses a decades-long trend in California. As shown in Figure 4, statewide electricity sales have been flat or slightly declining over the last few decades, largely driven by the state's energy efficiency policies and moderate climate (in most, not all, areas). However, electricity sales are projected to increase over the next 15 years due to economic and climate trends that affect how the state uses energy. These CEC projections factor in statewide policies and goals including energy efficiency, building and transportation electrification, distributed generation, and battery storage deployment; as well as climate trends expected to lead to more extreme heat and greater air conditioning usage in the state.

Figure 4: Historic and Projected Statewide Electricity Sales (in GWh)[30]



California has economy-wide decarbonization goals to drive ambitious reductions in GHG emissions within the next two decades. The transition from fossil fuel usage to electricity to meet energy needs is a pillar of many of the state's climate change strategies. Some of these policies include CARB's Innovative Clean Transit, Advanced Clean Cars II, and Advanced Clean Fleets regulations; SB 350's (De León, Chapter 547, Statutes of 2015) doubling of statewide energy efficiency savings by 2030; the CEC's *Title 24* requirements for rooftop solar on new buildings; and the electricity's sector's 100% clean energy by 2045 mandate.[31] These policies are expected to increase electricity demand from the electrification of the building and transportation sectors, while also reducing demand through greater customer-generation and energy efficiency. The net effect of these policies is projected increases to customer load, which drive needed electrical system upgrades.

[29] Pg. 3, CEC, *Final 2022 Integrated Energy Policy Report Update,* February 2023, CEC-100-2022-001-CMF
[30] Figure from the Legislative Analyst's Office based on data from the CEC's IEPR, see pg. 60 of 2022 IEPR, *Ibid.*
[31] SB 100 (De Leon, Chapter 312, Statutes of 2018)

In July 2021, the CPUC initiated the High Distributed Energy Resources (High DER) Grid Planning Rulemaking[32] to determine how to optimize and prepare the electric grid for anticipated high adoptions of Distributed Energy Resources (DERs; i.e., rooftop solar, behind-the-meter batteries, demand response, etc.), including those associated with transportation and building electrification. Earlier this month, the CPUC released an *Electrification Impacts Study*[33] by Kevala, Inc. which evaluated where and when distribution grid enhancements may be needed to meet the forecasted demand. The preliminary study results estimates "up to $50 billion in traditional electricity distribution grid infrastructure investments are needed by 2035" to accommodate a high DER and decarbonized future.[34] For context, the recent CAISO transmission plan estimates the need for approximately $7.3 billion in new transmission infrastructure investments over the next decade to meet our decarbonization goals,[35] an order of magnitude less than the investment projected for the distribution grid.

The Kevala study used system-level peak load estimates that projected a 56% increase on average from 2025 to 2035,[36] noting that the dramatic increase in peak load is "primarily due to transportation electrification impacts, with over 60% of demand coming from light-duty vehicles."[37] Peak load is the primary driver of the grid capacity upgrades considered. The report goes on to note "PG&E's distribution circuits are projected to reach capacity sooner than Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)."[38] This level of projected investment is staggering, and begs deep considerations of potential mitigation to reduce costs and manage load. Moreover, the workforce and equipment needed to meet this level of investment are likely to overshadow any backlog the utilities are currently experiencing regarding customer energization or interconnection.

The $50 billion estimate is a starting point for broader conversations about distribution grid planning. DER developers have long advocated for "non-wires alternatives" to meeting California's decarbonization strategies, with recent requests including more digitization of the distribution grid, technology-neutral retail rate signals to drive customer adoption of DERs,[39] and "flexible interconnections" which offer customers faster interconnection of their resources to the distribution grid with the tradeoff that that connection is constrained to either times or capacity that the DER can export.[40] However, it is unclear how the cost of non-wires

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[32] R. 21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.*
[33] Kevala, "Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates," May 9, 2023;
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF
[34] Pg. ES-6, Kevala 2023, *Ibid.*
[35] Pg. 3, CAISO, *2022-2023 Transmission Plan*, Revised Draft, May 10, 2023;
http://www.caiso.com/InitiativeDocuments/Revised-Draft-2022-2023-Transmission-Plan.pdf
[36] The average percent change in peak load is more dramatic for PG&E (69%), followed by SDG&E (53%), and SCE (44%).
[37] Pg. ES-6, Kevala 2023, *Ibid.*
[38] *Ibid.* SDG&E is expected to have the least number of feeders reaching full capacity by 2035, with 22% compared to SCE's 36% and PG&E's 48%.
[39] Letter to California Legislators and Policymakers from Schneider Electric; "Futureproofing Energy Infrastructure and Fully Unlocking Infrastructure Dollars," shared with committee on May 19, 2023.
[40] Chris Warren, "Can allowing curtailment speed up DER growth?" *EPRI Journal*, December 20, 2021;
https://eprijournal.com/getting-flexible-about-interconnection/

alternatives compares to traditional utility distribution spending, with the potential for minimal or no reduction in costs from some of these solutions.

Existing and Growing Challenges. The delays faced in PG&E service territory for customers seeking access to the distribution grid highlight the growing need for policymakers to direct their focus on the process, planning, and resources needed in the electric distribution system. Potential solutions could take many forms. To address the current backlog, PG&E has increased communication and resources to capacity constrained areas of their territory, with the effect of boosting customer interconnection and energization to these areas. However, when the state is evaluating a $50 billion distribution investment need over the next decade, it is worth treading cautiously around solutions that seek to simply increase overall materials, supplies, and staffing. The result of such resource-intensive solutions could balloon the $50 billion projected even higher, or lead utilities to divert spending away from other priority projects.

The utilities sole responsibility for distribution planning does allow for maximum responsiveness to customer demands in real-time, such as the POUs' ability to integrate city planning projects into their forecasts quickly. However, concentrating planning responsibility solely with the utility might also result in cascading problems if forecasts or customer response times go awry. There further exists the potential of a visibility gap between the utility distribution plans and the state-led transmission and resource plans, without clear communication between these two regimes. This gap between distribution planning and statewide resource planning has been raised by DERs seeking to interconnect to the distribution system, who have for years sought more inclusion in system-level resource plans. Yet it is unclear what benefits may be achieved through the state taking a more central role in distribution planning, as many of the issues and responsiveness to customer needs require localized action and communication.

Finally, the $50 billion in projected investment needs over the next decade raises deeper questions about the distribution system, and whether the status-quo approach to meeting our decarbonization goals is sufficient. The utilities and their regulators should evaluate mitigation strategies to reduce these costs, and consider a system-wide assessment of where current investments are headed.

# # # # #

Appendix A – Relevant 2023 Legislation

The following bills were introduced in this legislative session to address the growing concerns around distribution planning.

AB 50 (Wood) establishes interim timelines for large electrical corporations to provide customer energization following a written commitment to serve by the utility. Requires the California Public Utilities Commission (CPUC) to determine criteria for timely service for electric customers by January 1, 2025 that may replace or revise the interim timelines. Status: *Assembly – In Floor Process – Third Reading.*

AB 643 (Berman) allows the CPUC to impose fines for electrical corporations that routinely violate established interconnection timelines, and consider negligent exceedance of the timeline, as defined, as a violation of CPUC rules subject to a maximum $100,000 penalty per offense. Additionally adds new reporting requirements for interconnections of customer-sited energy generation projects. Status: *Held* – Assembly Committee on Appropriations on May 18, 2023.

AB 1293 (Irwin) requires the CPUC to provide guidance to investor-owned utilities (IOUs) for the prioritization of interconnection projects, including that the project is shovel-ready, as determined by the CPUC. Status: *Assembly – In Floor Process – Consent*.

AB 1482 (Gabriel) would establish an average service energization time for electric vehicle charging infrastructure of 125 business days for publicly-owned utilities (POUs), and would require POUs to annually report certain information to the CEC regarding the service energization time for electric vehicle charging infrastructure projects. It would additionally require the CPUC and the CEC, in consultation with IOUs and POUs, to jointly host an annual public workshop to review and evaluate the information submitted and to revise, if needed, the average service energization time for EV charging infrastructure. Status: *Held* – Assembly Committee on Appropriations on May 18, 2023.

SB 83 (Wiener) would require IOUs to interconnect development projects to the electrical distribution system within eight weeks for projects defined as interconnection ready. Additionally, would require IOUs to compensate development projects for failing to meet the deadline. Status: *Held* – Senate Committee on Appropriations on May 18, 2023.

SB 410 (Becker) requires the CPUC to establish a working group to improve the ability of the electric IOUs to be informed of needed distribution capacity and requires the CPUC to establish timelines for interconnection projects. Status: *Senate – In Floor Process – Third Reading*.