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California Energy Commission

COMMISSION REPORT

2023 Integrated Energy Policy Report

Gavin Newsom, Governor

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California Energy Commission

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ABSTRACT

The *2023 Integrated Energy Policy Report* provides updates on a variety of energy issues facing California. These issues require action if the state is to meet its climate, energy, air quality, and other environmental goals in an equitable way while maintaining reliability and controlling costs.

The *2023 Integrated Energy Policy Report* discusses speeding connection of clean resources to the electricity grid, the potential use of clean and renewable hydrogen, and the California Energy Demand Forecast to 2040. The report also provides updates on topics such as gas decarbonization, energy efficiency, the Clean Transportation Program, Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013), and publicly owned utilities' progress toward peak demand reserves and margins.

Keywords: Energy policy, interconnection, energization, clean and renewable hydrogen, demand forecast, gas decarbonization, energy efficiency, Clean Transportation Program

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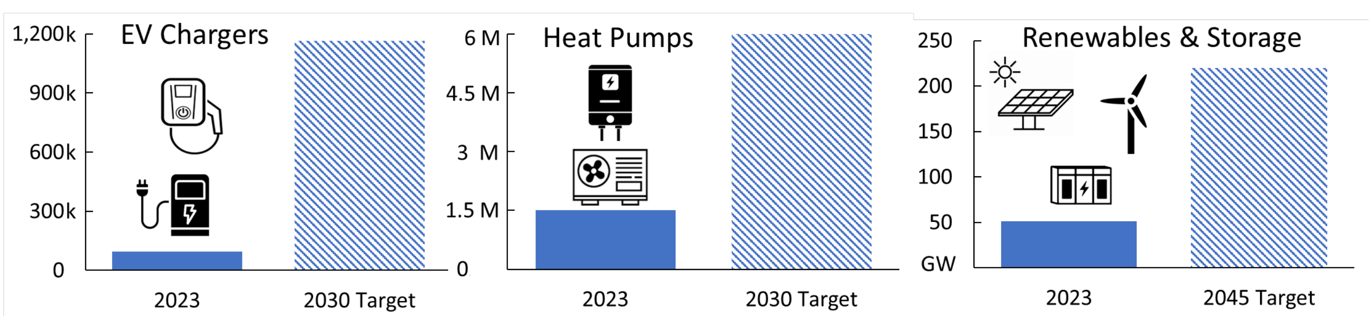
EXECUTIVE SUMMARY

California has established some of the world's most ambitious policies and targets for combating climate change and reducing harmful air pollution to help ensure all communities have improved health outcomes and opportunities for prosperity. Achieving these goals hinges on transitioning to zero-carbon, renewable sources of power while rapidly electrifying large segments of the economy. A reliable and resilient electricity system with affordable rates will serve as the keystone for achieving economywide greenhouse gas reductions (decarbonization).

The increasingly visible impacts of climate change on communities, especially on those already affected by poverty and pollution, reinforce the urgency of rapid and deep decarbonization. For example, frequent and widespread extreme heat increases electricity demand, drought reduces the availability of hydropower, and strong winds and wildfires prompt service outages and cause damage to electricity infrastructure. Planning for, adapting to, and recovering from climate-related events requires a growing amount of human and financial resources. Climate change is making it harder to fight climate change.

Fortunately, California is already far along in the clean energy evolution. Nearly 60 percent of electricity consumed in 2022 was produced from renewable resources, and California has more rooftop solar and electric vehicle (EV) chargers installed than any other state. Still, to achieve 100 percent renewable and zero-carbon electricity by 2045, annual grid-scale solar and wind build rates need to triple and battery storage installation rates need to grow by nearly eightfold while keeping electricity rates affordable. Simultaneous rapid and sustained deployment of millions of distributed energy resources (DERs), including flexible loads like EV chargers and heat pumps, will be needed to meet the state's goals for decarbonizing transportation and buildings. (This report uses the term *clean energy resources* to refer to large grid-scale resources and DER).

Figure ES-1: Gaps Between Clean Resources Deployments Today and Established Goals or Projected Needs



By 2030, more than 1.1 million EV chargers are projected to be needed, growing from almost 94,000 today. Similarly, installation of electric heat pumps would have to grow from about 1.5 million today to reach the goal of 6 million by 2030. By 2045, about 220 gigawatts (GW) of renewable generation and storage are projected to be needed to serve electricity demand with 100 percent clean energy, growing from about 50 GW in 2022.

Source: California Energy Commission (CEC)

Accelerating Deployment and Grid Connection of Clean Energy Resources

Connecting new clean resources to the electricity grid — and expanding grid infrastructure to accommodate them — is critical to meeting the state's decarbonization and electrification goals. Delays in contracting and connecting new clean generation and storage resources to the grid can also threaten electric reliability, as the state aims to reduce reliance on fossil gas while meeting historic electricity demand. The challenge expands beyond California, with utilities, planning and regulatory authorities, and grid operators across the United States and globally struggling to keep pace with a rapidly changing climate while accelerating deployment of clean energy resources.

Preparing the electricity grid to connect unprecedented amounts of clean energy resources will require investment in new infrastructure combined with cost containment measures to manage impacts to electric rates. Many of the wires, towers, and substations that deliver electricity to Californians are old and were not designed for today's climate or for the scale of resource deployments needed. Increasing energy efficiency and load flexibility will play a critical role in limiting the amount and cost of new infrastructure but alone are insufficient.

There are several interrelated challenges slowing deployment and grid connection of clean energy resources. These challenges span all stages of project and infrastructure delivery, from planning processes at agencies and utilities through permitting and construction practices to bring new facilities on-line. The CEC, California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO), and other agencies are working on numerous efforts to address these challenges, many of which are described below. Nonetheless, achieving the state's electrification and decarbonization goals will require sustained improvements and coordination across all levels of government, utilities, and the private sector.

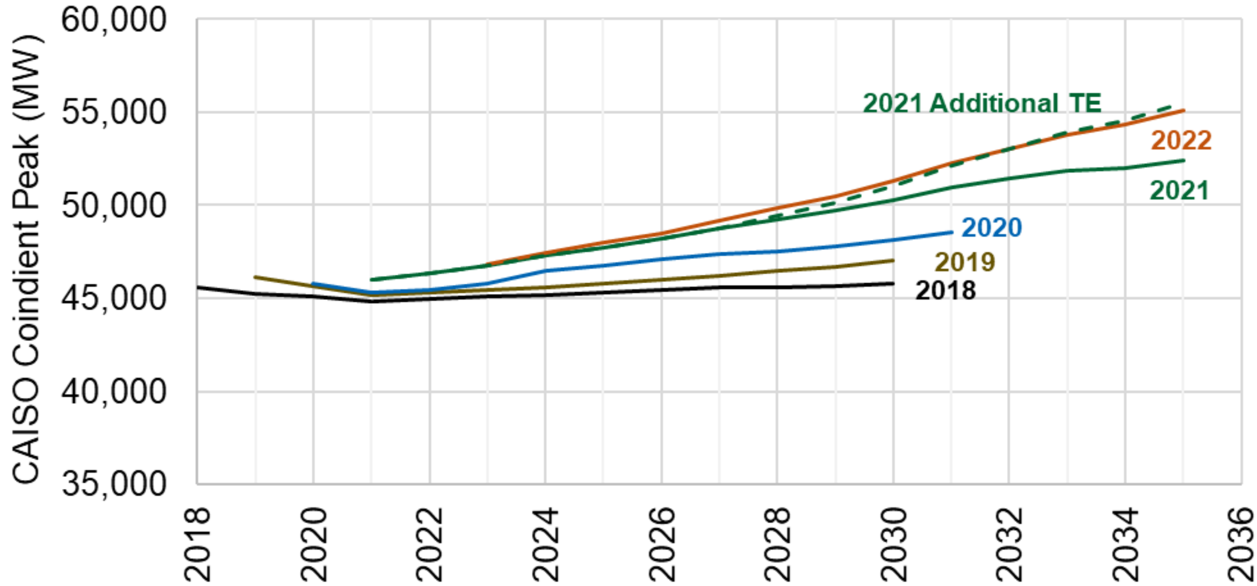
Problem 1: Accelerated Deployment Is Straining Existing Planning Paradigms

The pace of clean energy resource deployments and electrification has accelerated over the past several years. For example, the percentage of new passenger vehicle sales in California that are zero-emission grew from less than 8 percent in 2020 to more than 25 percent in the third quarter of 2023. Today there are thousands of zero emission medium- and heavy-duty vehicles operating in California with potentially upward of 150,000 operating by 2030. Forecasting electricity demand, planning sufficient new infrastructure, and authorizing recovery of costs while limiting burdens on ratepayers in the context of such rapid change are challenging.

Energy entities have made significant progress incorporating policy and market developments into infrastructure planning. The CEC has increased its forecast of demand in 2030 by more than 5 gigawatts (GW) over the past five forecast updates, as shown in Figure ES-2. Similarly, the resource portfolios used in transmission planning have increased and now anticipate the need to interconnect about 7 GW of new grid-scale renewable generation per year through 2045.

However, it takes several years or longer before increases in forecasted demand result in new transmission and distribution capacity being available for projects seeking to connect to the grid. There is uncertainty in identifying exactly when and where investments to increase grid readiness will be needed. Many efforts to evolve planning processes are underway and starting to yield benefits, including ones described below.

Figure ES-2: Forecasted Electricity Demand Has Increased Rapidly



The CEC forecast of net peak demand in the California ISO footprint for 2030 has increased by more than 5 GW over the last five updates, driven largely by transportation electrification and climate change.

Note: The net peak demand is the highest demand after accounting for the impacts of self-generation.
Source: CEC

Initiatives Underway

- The CPUC, CEC, and California ISO entered a memorandum of understanding (agreement) to better align resource planning, transmission planning, and procurement processes.
- Recently the California ISO adopted the *2022–2023 Transmission Plan,* which identified large investments in new transmission capacity, and developed a 20-year transmission outlook to extend the transmission planning horizon in 2022. Currently the California ISO is developing the *2023–2024 Transmission Plan* and an update to the 20-year transmission outlook.
- The CEC is improving models and processes for electricity demand forecasting to better reflect electrification and decarbonization policies and account for climate change.

- The staff at CPUC have proposed a framework to proactively identify long-lead-time infrastructure upgrades to support freight electrification.
- The CPUC initiated a proceeding on modernizing the grid for a high DER future to explore improvements to distribution planning, expansion, and regulatory processes.
- The CPUC is implementing recent statutes to establish criteria and timelines for new service connections, report on utility performance, evaluate distribution planning, and provide more flexibility in authorizing cost recovery outside periodic rate cases.
- The California Air Resources Board (CARB) is forming a working group to identify infrastructure challenges and share best practices between fleets, utilities, and others.

Recommendations

(1) Continue strengthening ties between the development of electrification and decarbonization policies and regulations with electricity infrastructure planning and deployment processes.

(2) Promote sharing of data and information among fleets, charging service providers, and other developers of large rapidly deploying loads with utilities and planning entities.

(3) Increase the geographic granularity of California's Energy Demand Forecast, particularly for large, rapidly deploying loads such as EV charging, data centers, and port decarbonization.

(4) Support and expand proactive transmission and distribution planning and deployment processes across utilities, balancing authorities, and energy entities.

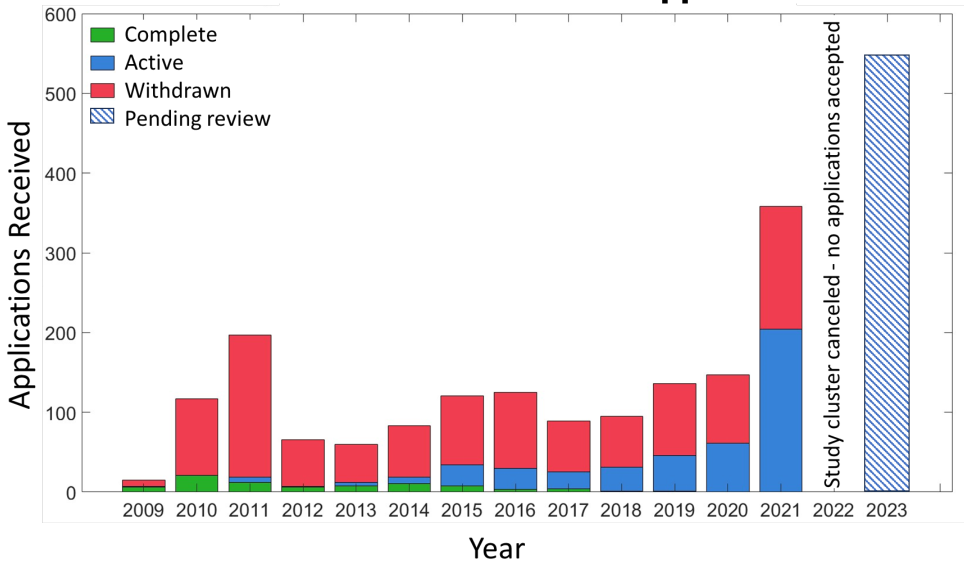
(5) Explore strategies to align developer and customer deployment plans with locations that have, or are planned to have, available transmission or distribution capacity.

(6) Provide targeted support to publicly owned utilities, particularly in rural communities, to share effective strategies for promoting grid readiness and beneficial electrification.

Problem 2: The Growing Number and Size of Projects Applying to Connect Overwhelm Existing Processes and Can Lack Adequate Capacity

The number of applications to interconnect new generation and storage projects to the electricity transmission system operated by the California ISO has grown over the past several years (Figure ES-3). This growth has contributed to delays in processing interconnection requests, lengthened timelines to bring new resources onto the system, and consumed significant staff resources from transmission owners and operators.

Figure ES-3: The Number of Interconnection Applications Are Growing



The California ISO received nearly 375 interconnection requests in 2021 — well above the historical baseline — which resulted in a one-year pause in accepting new applications. In 2023, the California ISO received nearly 550 interconnection applications.

Source: CEC staff analysis of California ISO interconnection queue data

The number and size of applications to energize loads to the distribution grid, have also increased over the past several years. Some projects such as large deployments of EV chargers can exceed available capacity and require infrastructure upgrades to handle greater energy throughput. Large grid upgrades such as expanding substations have historically taken five or more years to plan and build. Collectively, the state's energy entities are pursuing many efforts to streamline processes for connecting clean resources to the grid and support more efficient use of transmission and distribution capacity, many of which are highlighted below.

Initiatives Underway

- The California ISO is exploring interconnection process enhancements and filing plans to comply with recent federal requirements for streamlining interconnection processes to better manage intake and queuing of large renewable and storage projects.
- The California ISO is reviewing the methods and assumptions for assessing whether the transmission system can deliver energy from a new resource during times of grid strain — such as when solar generation is low and demand is high — to help accelerate contracting of new resources.
- The California ISO is implementing the Extended Day-Ahead Market to broaden the pool of resources accessible across the Western Interconnection.
- The CPUC, CEC, California ISO, and Governor's Office of Business and Economic Development (GO-Biz) are tracking the progress of renewable energy projects under development and coordinating actions to address near-term barriers.

- The CPUC authorized special rules for investor-owned utilities (IOUs) to establish a timeline and streamline the process for new service connections to EV charging infrastructure.
- The CPUC instituted a rulemaking to establish reasonable average and maximum timelines for customers to receive new service connections and to create procedures for customers to report delays as part of implementing recent statutes.
- The CPUC is considering technologies that would curtail production from distributed generation when circuits are overloaded to more efficiently use available distribution capacity.
- The CPUC is exploring rate designs and automated solutions for managing demand to shift consumption from when demand is high and renewable generation is low through its demand flexibility rulemaking.
- The CEC adopted updated load management standards to expand offerings of hourly time-varying rates and support technologies that can automatically shift demand in response to these rates.

Recommendations

(1) Assess and update utility interconnection, energization, capacity planning, and equipment procurement processes to identify opportunities for streamlining, automating, and eliminating redundant steps.

(2) Consider use of shared resources such as construction crews or expanding use of third-party contractors to implement upgrades more rapidly or connect projects that are delayed because of lack of resources.

(3) Encourage strategies and technologies that allow more flexible or dynamic levels of electric service such as power control systems to allow more projects to connect and to maximize use of available infrastructure capacity.

(4) Explore opportunities to use temporary power solutions such as mobile battery storage or linear generators, prioritizing zero-emission technologies, to allow more resources to connect in the near term while permanent infrastructure is planned and constructed.

(5) Study long-term workforce needs and increase investments in education, training, and workforce development for key roles such as such as line workers, power systems engineers, and electricians, prioritizing justice communities (including low-income and disadvantaged communities).

Problem 3: Rate Impacts Must Be Managed While Rapidly Preparing the Grid

Limiting burdens on ratepayers while making investments to increase grid readiness and infrastructure resilience to California's changing climate is a balancing act. Improved grid planning, efficient electrification, and advanced technologies that maximize use of transmission and distribution capacity can help limit rate impacts. Nonetheless, substantial capital investment will be needed in the near term to expand infrastructure capacity often ahead of high use. Numerous initiatives are underway to limit ratepayer burdens, particularly for justice communities, while accounting for infrastructure grid needs.

Initiatives Underway

- The California Infrastructure and Economic Development Bank provides clean transmission financing using general funds to support construction of new transmission facilities that connect priority resources.
- The CPUC is improving distribution grid planning and project execution processes through ongoing proceedings.
- The CPUC tracks trends in IOU rates and identifies actions to limit utility cost and rate increases in an annual report to the Legislature, which includes a focus on infrastructure costs.
- The CPUC is implementing an electricity billing adjustment that reduces the rate that applies to the volume of electricity used and reallocates some costs to maintain the grid to a flat rate. This will support electrification and increase affordability.
- The CPUC is coordinating IOU pursuit of federal funding for utility infrastructure to increase the competitiveness of applications for funding from California utilities.

Recommendations

(1) Evaluate alternative sources of financing for infrastructure upgrades and expansions such as federal funds, creation of new bonds, or allocation of funds from existing credit trading or incentive programs.

(2) Continue expanding rates and programs that encourage load flexibility and monitor progress as part of operationalizing the goal for 7 GW of load shift by 2030.

Problem 4: Capacity and Connection Processes and Timelines Are Not Always Transparent or Consistently Tracked

The available capacity to connect new clean resources to transmission and distribution systems can be challenging for developers and customers to identify before applying to connect. Lack of transparency can lead to exploratory applications for projects that do not have a reasonable chance of being completed and can further clog intake and study processes. There is also variability across utilities in the requirements, processes, and timelines to connect clean resources and perform any needed upgrades or capacity projects. Beyond exploratory applications, lack of transparency may cause developers and customers to propose fewer clean energy resource projects, which can hamper progress toward deployment goals. Energy entities are increasing transparency through numerous ongoing efforts, including those described below.

Initiatives Underway

- The CPUC and California ISO work with transmission owners to host a quarterly transmission development forum to share status updates and estimated completion timelines for construction of new or upgrades to existing transmission facilities.
- The CPUC hosts a quarterly interconnection discussion forum to share updates and best practices on distribution interconnection processes and timelines.

- The CPUC established average target timelines for interconnecting some distributed generation projects and the service energization process for commercial and multifamily EV charging projects that meet certain requirements.
- The CPUC initiated a rulemaking on DER Data Access and Cost Effectiveness to promote greater access to and sharing of infrastructure and resource data.
- The CPUC directed IOUs to develop and update interconnection capacity analysis maps and other datasets that provide developers and customers with better information about available distribution capacity.
- The CEC is developing the EV Supply Equipment Deployment and Grid Evaluation tool to map forecast charging demand to estimated grid capacity.
- The CEC is developing an EV charging project timeline tracker to collect data on timelines for utility, permitting authority, and developer steps in connecting new CEC-funded EV chargers.

Recommendations

(1) Expand publicly available tools and datasets that can help guide developer decisions, including timelines for pending upgrades or capacity addition projects.

(2) Broaden tracking and public reporting of timelines for new service connections, interconnections, and distribution and transmission system upgrades or expansions including at substations to establish performance baselines.

Problem 5: Permitting Is Slow, and the Scale of Deployment Will Need Public Engagement Outside Formal Permitting Processes

Permitting new electricity infrastructure can add several years of delays and uncertainty to project development, which can limit the pace of clean resource deployments. There are exemptions for some modifications to existing facilities within existing rights-of-way that can result in a faster process. At the same time, environmental studies have historically been the primary venue through which the public can learn about projects and provide input. Going forward, the scale of new renewable resource, transmission, and distribution infrastructure build-out needed to meet the state's goals can be further supported by broader public engagement outside formal permitting processes. Several ongoing initiatives are helping to accelerate permitting decisions, including the following.

Initiatives Underway

- The CEC, CPUC, and California ISO are collaborating to develop a guidebook on transmission planning and permitting processes.
- The CEC is updating land-use screens, which reflect environmental characteristics and competing land-use information and coordinating with CPUC to improve integration of these data into resource and infrastructure planning.
- The CEC is leading opt-in permitting for eligible projects as an additional pathway to proceed through permitting, with known and potentially shorter approval timelines.

- The CEC created the California Automated Permit Processing Program to help local governments establish an online, automated solar permitting platform, which reduced the time it takes homeowners to get a permit for rooftop solar from weeks to a day.
- GO-Biz developed the charging station permitting guidebook and implemented tracking efforts to support streamlining of local government permitting decisions.
- Leaders of state agencies are collaborating on the Governor's Infrastructure Strike Team to accelerate approvals for priority infrastructure projects.

Recommendations

(1) Prioritize expansion of infrastructure capacity within existing rights-of-way, including through use of advanced technologies that can increase throughput of existing facilities, to limit impacts and reduce permitting timelines.

(2) Integrate early and frequent coordination with local and tribal governments, planning entities, and developers as part of infrastructure planning.

(3) Consider how the CEC's transmission corridor designation authority could support local engagement and land- use planning for transmission needs associated with 100 percent renewable zero-carbon electricity by 2045.

(4) Expand the capabilities of automated permitting platforms and software to include EV charger installations and support local authorities adopting automated permitting.

(5) Continue improving and develop new web-based geospatial mapping tools that facilitate stakeholder and public engagement in resource and transmission planning.

(6) Develop and implement broader public awareness campaigns, in partnership with local government entities, about the foundational role of electricity infrastructure in addressing climate change and the progress toward proposed outcomes of the energy entities' policies and programs.

The Potential Growth of Clean and Renewable Hydrogen

Senate Bill 1075 (Skinner, Chapter 363, Statutes of 2022) directed the CEC to study and model potential growth of hydrogen in decarbonizing the electric power and transportation sectors in California as part of the *2023* and *2025 IEPRs*. Clean and renewable hydrogen, which refers to hydrogen produced from renewable electricity and water or from biogenic feedstocks, is receiving increasing public and private investment as a pathway to decarbonize particularly costly or hard-to-electrify activities.

In 2022, the Legislature and Governor allocated $100 million to create the CEC's Clean Hydrogen Program to demonstrate and scale production, processing, delivery, and end use of clean and renewable hydrogen (Assembly Bill 209, Committee on Budget, Chapter 251). In October 2023, the U.S. Department of Energy selected California to negotiate an award of up to $1.2 billion for the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) hydrogen hub. ARCHES is a statewide public-private partnership focused on scaling clean renewable hydrogen for uses that are challenging to electrify, such as heavy-duty transportation, grid-supporting power plants, and port operations.

These and other initiatives are aimed at improving the cost-competitiveness, climate, and broader environmental benefits of clean renewable hydrogen. These benefits depend on many factors, including which methods and feedstocks used to produce it, whether and how it is stored and delivered, and what applications it is used for. From production through end use, potential hydrogen leakage must be monitored and minimized, as hydrogen can indirectly contribute to global warming by extending the lifetime of greenhouse gases (GHGs) in the atmosphere.

Scenarios for the Growth of Clean and Renewable Hydrogen

The scenarios presented are illustrative and not meant to reflect forecasts of actual adoption. The preliminary analyses in this IEPR consider only hydrogen produced through electrolysis (electrolytic hydrogen), which uses renewable electricity to split water. Four scenarios were evaluated, two scenarios of clean and renewable hydrogen production for electricity generation in 2045, and two scenarios of clean and renewable hydrogen production for transportation in 2040. Exploring these scenarios establishes a high bookend of what large-scale electrolytic hydrogen production could require in terms of renewable electricity consumption and additional renewable generation capacity to power electrolyzers. Clean and renewable hydrogen can also be produced from biogenic feedstocks through processes such as pyrolysis, which would reduce requirements for new renewable generation, that will be explored in the *2025 IEPR* analyses.

For electricity generation, one scenario considers replacing all of the fossil gas that CARB's *2022 Scoping Plan for Achieving Carbon Neutrality* (*2022 Scoping Plan Update*) estimated would be used to produce electricity in 2045. CEC staff estimates that about 1.8 million metric tons (million MT) of clean and renewable hydrogen would be required to provide the equivalent amount of energy as the fossil gas remaining for electricity generation in 2045. As a comparison to this upper bookend, staff evaluated a second scenario for the electricity generation based on a report conducted by the University of California, Irvine, (UCI). The report assumed that only a fraction of projected storage and zero carbon dispatchable generation needs were provided by hydrogen. This study estimated that approximately 350,000 MT of clean and renewable hydrogen would be used in the electric sector in 2045, roughly 18 percent of the upper bookend.

Based on the specifications of one of the largest commercially available electrolyzers (the equipment to produce electrolytic hydrogen), CEC staff estimated the number of electrolyzers, electricity and water consumption to produce hydrogen, the renewable electricity and generation capacity needed to power electrolyzers, capital requirements, and annual electricity costs for the two scenarios (Table ES-1).

Table ES-1: Financial and Resource Requirements for Two Scenarios of Clean and Renewable Hydrogen Production for Electricity Generation in 2045

Parameter	Scoping Plan Update*	UCI Study**	Units
Amount of clean and renewable hydrogen consumed in scenario in 2045	1,883,960	350,000	Metric tons per year
Number of electrolyzers required (assuming 65 percent capacity factor)	921	171	-
Total capital requirement for electrolyzers	$16.2	$3.0	Billion dollars
Water consumed in hydrogen production	4.4	0.8	Billion gallons per year
Electricity consumed in hydrogen production	94	17.5	Terawatt-hours (TWh) per year
Total cost of electricity to power electrolyzers (assuming $0.20 per kWh)	$18.8	$3.5	Billion dollars per year
Capacity of renewables to generate electricity for hydrogen production (assuming 30 percent capacity factor)	35.8	6.6	GW
Land requirements for capacity of renewable generation (assuming all solar)	250,900	46,610	Acres

***The "Scoping Plan Update" scenario reflects CEC staff's estimate of the amount of clean and renewable hydrogen required to replace fossil gas combusted for electricity generation in 2045 as reported in the CARB 2022 Scoping Plan Update.**

****The "UCI Study" estimated 350,000 metric tons of clean and renewable hydrogen used in 2045. CEC staff estimated the resources needed to produce that quantity of hydrogen via electrolysis using the same assumptions applied to the Scoping Plan Update scenario.**

Source: CEC staff

To evaluate potential growth of clean and renewable hydrogen in the transportation sector, staff took the hydrogen demand in 2040 estimated in the *2022 Scoping Plan Update* as one scenario. Staff also developed a second scenario based on the CEC's transportation energy demand forecast Additional Achievable Transportation Electrification Scenario 3 (AATE 3) with some modifications. Specifically, staff developed estimates of accelerated fuel cell electric bus and hydrogen powered rail adoption. These were added to the AATE 3 scenario estimates for the number of fuel cell passenger and commercial vehicles, resulting in approximately one-third the total hydrogen demand for transportation in the Scoping Plan Update scenario. Similar to the analysis for electricity generation, staff estimated the number of electrolyzers, electricity and water consumption, additional renewable capacity, total capital requirement, and annual electricity cost for these two transportation scenarios (Table ES-2).

In both the Scoping Plan Update and modified AATE 3 scenarios, most of the clean renewable hydrogen was used by medium- and heavy-duty (MDHD) vehicles. Staff evaluated the sensitivity of MDHD truck population forecasts to large hypothetical reductions in delivered hydrogen fuel price to $5 and $8 per kilogram by 2035, around which hydrogen is cost-competitive with diesel. The analysis illustrated that lower fuel prices resulted in greater adoption of MDHD FCEVs relative to the 2022 baseline scenario, particularly for trucks with greater annual miles traveled.

Table ES-2: Financial and Resource Requirements for Two Scenarios of Clean and Renewable Hydrogen Production for Transportation in 2040

Parameter	Scoping Plan Update*	Modified AATE3**	Units
Amount of clean and renewable hydrogen consumed in scenario in 2040	971,000	307,700	MT per year
Number of electrolyzers required (assuming 65 percent capacity factor)	475	151	-
Total capital requirement for electrolyzers	$8.3	$2.6	Billion dollars
Water consumed in hydrogen production	2.3	0.7	Billion gallons per year
Electricity consumed in hydrogen production	48.5	15.3	TWh per year
Total cost of electricity to power electrolyzers (assuming $0.20 per kWh)	$9.7	$3.0.	Billion dollars per year
Capacity of renewables to generate electricity for hydrogen production (assuming 30 percent capacity factor)	18.4	5.8	GW
Land requirements for capacity of renewable generation (assuming all solar)	129,325	40,990	Acres

***The "Scoping Plan Update" scenario reflects the quantity of hydrogen reported used in transportation in 2040 as reported in the CARB *2022 Scoping Plan Update*.**

****The "Modified AATE3" scenario is based on modifications made by CEC staff to existing transportation modeling tools used in the California Energy Demand Forecast. CEC staff then estimated the resources needed to produce that quantity of hydrogen via electrolysis using the same assumptions applied to the Scoping Plan Update scenario.**

Source: CEC staff

The *2022 Scoping Plan Update* includes clean renewable hydrogen production via multiple pathways and not solely electrolysis. Future analyses in the *2025 IEPR* will expand production pathways to include biomass feedstocks, as well as the requirements and costs of clean renewable hydrogen delivery and storage infrastructure, which were not included in this preliminary analysis. The analysis may also explore systems-level adoption to evaluate how adoption in one sector influences costs and adoption in other sectors.

California's Energy Demand Forecast

The state's energy planning, such as for building out the electricity grid, is grounded in an understanding of projected energy demand. The California Energy Demand Forecast is foundational to the state's planning for procurement, transmission, and distribution of energy. California's goals to reduce GHG emissions are changing how energy is used in the state, and the CEC's energy demand forecast has adapted to reflect the impacts of new regulations and programs to decarbonize buildings and transportation. At the same time, climate change impacts are increasing the uncertainty in near- and long-term planning, and recent extreme weather events in California and the rest of the West have had a real impact on energy demand and system planning. California's energy system planning must continuously adapt and evolve to keep pace with changing climate conditions. For example, historical weather data are no longer sufficient to predict future weather patterns, and this year staff integrated new climate simulation data into the forecast.

The 2023 energy demand forecast reflects increasing electricity demand, particularly in the transportation sector and buildings, as well as increased onsite solar generation and battery storage. The forecast encompasses a set of scenarios including a baseline, a planning forecast (for use in planning for procurement of energy resources and transmission), and a local reliability scenario (a more conservative look ahead for use in local reliability studies). The baseline sales forecast represents the amount of electricity load-serving entities will need to provide to their customers, after accounting for customer generation that lowers demand. Baseline statewide sales were nearly 252,000 GWh in 2022 (as compared to 288,000 GWh before netting out customer generation) and grows to more than 299,000 GWh in 2040 (as compared to 376,000 GWh before netting out customer generation). The *managed* statewide sales incorporate the projected impacts of energy efficiency, building electrification, and transportation electrification. For the planning forecast, managed statewide sales grow to almost 352,600 GWh in 2040. The projected managed electricity sales are lower than what were projected in the *2022 IEPR Update* forecast through 2034 largely due to slower growth in projected households and population, increases in rooftop solar generation compared to previous assumptions, as well as increases in electricity rates compared to previous assumptions.

The managed system peak for the planning forecast reaches 63,442 MW by 2040. Relative to the *2022 IEPR Update*, the *2023 IEPR* planning forecast managed peak is lower through 2033 due primarily to a lower baseline consumption forecast and increased peak reduction impacts expected from behind-the-meter solar. By 2035, however, the new peak forecast exceeds the previously adopted forecast by 3.3 percent because of additional electrification impacts expected from CARB's concept of a zero-emission appliance regulation.

Updates: Energy Efficiency, Gas Decarbonization, and the Clean Transportation Program

This report also provides updates on topics addressed in prior IEPRs that are central to the state's clean energy future, including energy efficiency, gas decarbonization, and the benefits and contributions of the CEC's Clean Transportation Program.

Equitably advancing energy efficiency is foundational to the transition to a clean energy future. Energy efficiency can offset load growth from electrification, helping manage the need for new zero-carbon resources and providing a hedge while the state works to address bottlenecks in developing and connecting new resources. For consumers, energy efficiency investments can lower energy bills and improve quality of life, particularly for low-income Californians and during extreme weather caused by climate change.

As California advances clean energy resources, the state's energy system still relies on fossil gas, and a comprehensive shift to reduce dependency on fossil fuel is necessary to achieve the state's climate goals and achieve a clean energy future for all. State agencies, gas utilities, electric utilities, local governments, and the private sector are advancing decarbonization efforts such as development of low-carbon fuels (including clean and renewable hydrogen), electrification, and renewable energy. The CEC, CPUC, and CARB are making progress on decarbonizing the gas system, and ongoing, long-term, coordinated planning is needed to manage challenges to energy affordability, reliability, health, and safety. Attention is also needed to ensure a just transition for the industry's skilled workforce.

Finally, this report provides an update on the CEC's Clean Transportation Program. Although California's transportation sector still accounts for about 50 percent of state GHG emissions when accounting for emissions from fuel production, the state's bold policies are spurring a market transformation to zero-emission vehicles. The Clean Transportation Program has provided more than $1.8 billion in funding for a broad spectrum of zero-emission vehicles and infrastructure, alternative fuels and technologies, and workforce development projects in communities that will accrue health, environmental, and economic benefits from these investments. More than 68 percent of location-specific Clean Transportation Program investments have gone to projects within disadvantaged communities, low-income communities, or both.

CHAPTER 1: Plugging In — Speeding Deployment and Connection of Clean Resources to the Grid

Introduction

California is moving to a future powered predominantly by clean electricity. This shift is driven by ambitious policies, including the target for economywide carbon neutrality by 2045.[1] Moving forward, the electric grid will serve as the backbone for enabling the decarbonization of much of the transportation and building sectors and even some industrial activities.

Rapidly electrifying large segments of the world's fourth largest economy while decarbonizing electricity supply will require sustained, record-breaking deployment of clean energy resources. Examples of clean energy resources include grid-scale renewable generation and storage, as well as distributed energy resources (DERs) like rooftop solar paired with battery storage and flexible loads like electric vehicle (EV) chargers and heat pumps. Connecting these resources will also require construction of new electric grid infrastructure together with cost-containment measures to manage the impact on electricity bills.

To achieve 100 percent renewable and zero-carbon electricity by 2045, annual grid-scale solar and wind build rates need to triple compared to the prior decade, and battery storage installation rates need to grow by nearly eightfold relative to 2020.[2] By 2030, California will need to deploy more than 1 million public and shared private EV chargers to power about 7 million EVs[3] and has established the goal of installing 6 million heat pumps[4] (Figure 1).

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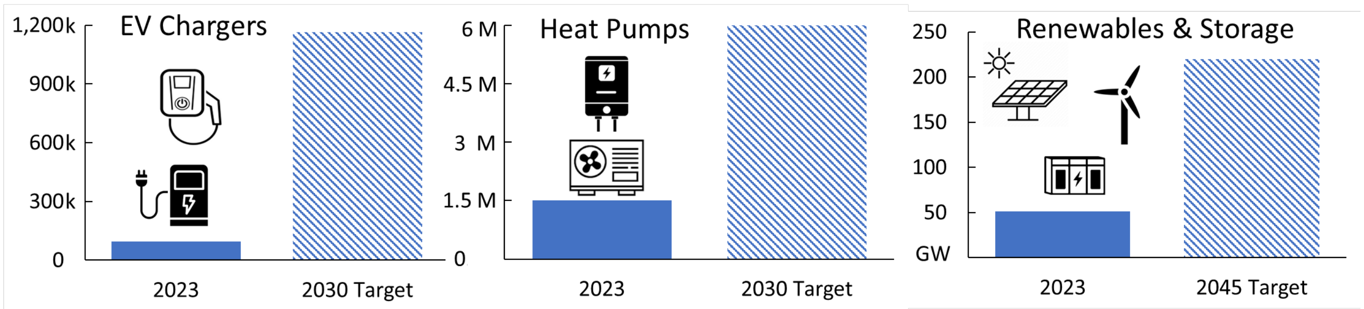
1 Senate Bill 100 (De León, Chapter 312, Statutes of 2018) accelerated the state's renewables goal to 60 percent by 2030 and put into law the state's commitment to 100 percent renewable and a zero-carbon electricity system by 2045. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

2 CEC, CPUC, CARB. *2021 SB 100 Joint Agency Report, Achieving 100 Percent Clean Electricity in California: An Initial Assessment,* https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349. Referred to as the SB 100 Joint Agency Report.

3 CEC. Electric Vehicle Charging Infrastructure Assessment, https://www.energy.ca.gov/data-reports/reports/electric-vehicle-charging-infrastructure-assessment-ab-2127.

4 Governor Gavin Newsom Letter to Liane Randolph. July 2022. https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf.

Figure 1: Gap Between Deployment of Clean Resources and Established Goals or Projected Needs



By 2030, more than 1.1 million EV chargers are projected to be needed, growing from almost 94,000 today. Similarly, installation of electric heat pumps would have to grow from about 1.5 million today to reach the goal of 6 million by 2030. By 2045, about 220 gigawatts (GW) of renewable generation and storage are projected to be needed to serve electricity demand with 100 percent clean energy, growing from about 50 GW in 2022.

Note: Existing EV charger deployment data are from CEC Zero Emission Vehicle Dashboard and the 2030 target is from the 2023 staff draft AB 2127 report. The existing heat pump installations estimate is based on surveys of residential and commercial users. Renewable resources data are from the 2021 Joint Agency SB 100 report with existing resources updated to reflect capacity added since 2019. Source: CEC

The adoption of clean energy resources over the past decade accelerated dramatically and exceeded almost all projections. Continuing the transition will require upgrades and expansions of the electric grid. Many of the wires, towers, and substations that deliver electricity to Californians are aging and were not designed for new climate extremes nor to connect the amount of clean energy resources and DERs needed. Designing and building these upgrades are often costly and time-consuming processes, requiring approvals and coordinated actions across multiple entities.

Connecting new clean resources and DERs to the grid — and expanding the grid to be ready for them — has significant costs and is a critical challenge to achieving the state's climate and air quality goals. In recent years, state resource planning has indicated an increasing need for deployment of new, clean utility-scale generation at a rapid pace. At the same time, challenges to developing electric infrastructure to support new generation, including permitting timelines, staffing constraints, and potential local opposition to such resources,[5] may result in projects taking years to complete. Delays in contracting and connecting new grid-scale renewable generation to the grid could threaten electric reliability, as new resources must be

5 Eisenson, Matthew. Columbia Law School, Sabin Center for Climate Change Law. 2023. "Opposition to Renewable Energy Facilities in the United States: May 2023 Edition," https://scholarship.law.columbia.edu/cgi/viewcontent.cgi?article=1201&context=sabin_climate_change.

brought online to reduce reliance on fossil gas while meeting the historic electric demand of increasingly intense and frequent extreme heat. This is a challenge across the United States and globally, as utilities, planning and regulatory authorities, and grid operators struggle to keep pace with rapid market deployment of renewables and the impacts of climate change.[6]

The California Public Utilities Commission (CPUC), the California Independent System Operator (California ISO), and the California Energy Commission (CEC) are coordinating closely with utilities, developers, community groups, and others to overcome barriers to deploying clean energy resources on the grid. Many improvements have been implemented with more changes underway. Nonetheless, further efforts and investments will be necessary to accelerate the connection of clean resources to the grid and ensure a renewable, zero carbon, safe, reliable, and affordable electric system for all Californians.

Background

The electric grid in California is a vast and complex critical infrastructure with many different owners, operators, planning entities, and regulatory bodies operating in different regions and at different scales. The system is broadly divided into two components:

(1) The network of large generators connected to the high-voltage transmission system (referred to as the *bulk power transmission system*) that is part of the larger western interconnection and transmits electricity over long distances.

(2) The lower-voltage *distribution systems* that take power from the bulk power transmission system and connect directly to customers and their behind-the-meter devices.

Bulk Power Transmission System

The bulk power transmission system is a network of high-voltage transmission lines that connect large generators to distribution systems. The Federal Energy Regulatory Commission (FERC) regulates the bulk power transmission system, ensuring equal access for generators seeking to connect and authorizing cost recovery for construction of new transmission.[7]

The CEC is the state's lead energy policy and planning entity and is responsible for forecasting electricity demand used in resource and infrastructure planning. The California ISO operates most of the state's transmission system, but seven other balancing authorities manage smaller parts of the system in California to ensure that supply and demand are always matched within

6 Lawrence Berkeley National Laboratory. April 2023. Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection, https://emp.lbl.gov/queues.

7 For more information on the Federal Regulatory Energy Commission, see https://www.ferc.gov/what-ferc.

their geographic region. The California ISO also conducts an annual 10-year transmission planning process and a 20-year outlook to ensure sufficient transmission infrastructure exists to connect generation and serve forecast load. Construction of certain new transmission facilities identified through planning processes are competitively bid out. For transmission lines built by the IOUs and pursuant to General Order 131-D,[8] the CPUC may consider the California ISO's approval of transmission in the annual transmission plan as a means to affirm the need for new transmission, and the CPUC is the lead permitting agency. For publicly owned utilities (POUs), the utility itself is typically the lead permitting agency.

Large generation, storage, and transmission assets are owned both by private developers and by utilities, which can be publicly owned, investor-owned, or cooperatively owned. The California ISO also manages the generator interconnection process for generators seeking to connect to the California ISO grid and operates competitive electricity markets into which merchant and utility generation assets sell electricity and other system services. Large POUs that own generation and transmission assets, such as Imperial Irrigation District (IID) and Los Angeles Department of Water and Power (LADWP), perform similar resource and transmission planning activities with investments authorized by governing boards or local authorities (referred to as *local regulatory authorities*). POUs across the state are heterogeneous and many do not own or operate any transmission facilities.

Distribution Systems

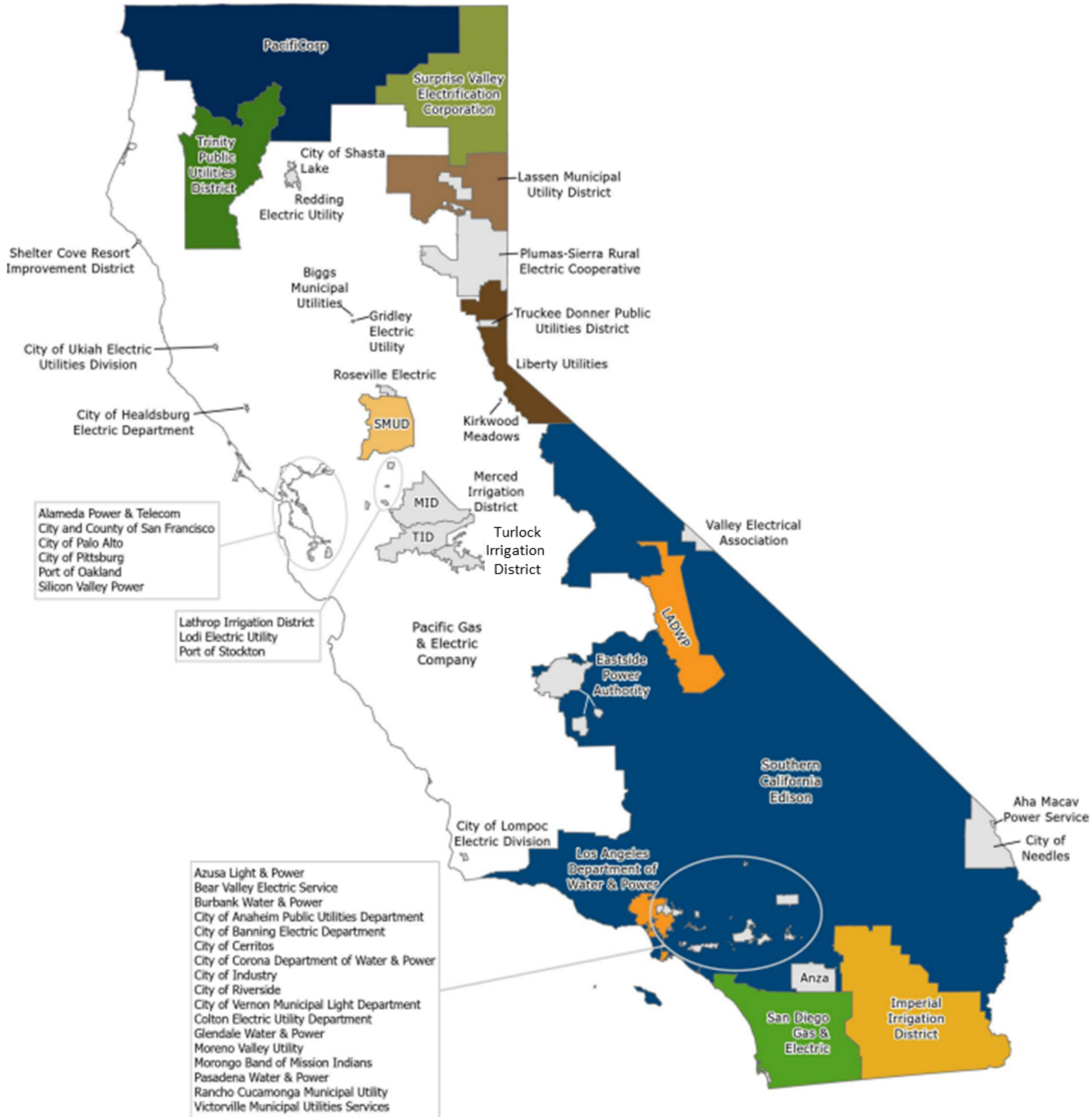
The distribution system is composed of a primary and secondary system. Collectively, they are smaller, comparatively lower-voltage wires and substations that take power from the transmission system and deliver it to customers, including but not limited to residential and commercial buildings, industrial facilities, and EV charging installations. To deliver power to retail customers, distribution systems typically have a radial design where power flows from a central substation down a circuit to end-use customers. (DER output on certain distribution circuits may reverse the historical direction of this power flow.) In more densely populated areas, distribution systems may be configured in a mesh network with several paths through which electricity can flow to a customer.

Distribution systems are planned, owned, and operated by electric distribution utilities. Each distribution utility operates as an exclusive monopoly within its designated service territory. There are dozens of electric distribution companies operating in California with a wide range in size and number of customers served. The distribution wires owned by the state's three large

8 CPUC web page, https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-to-update-transmission-siting-regulations-2023.

IOUs deliver about 75 percent of in-state load, with the remaining load served by three small IOUs and more than a dozen public and cooperatively owned utilities (Figure 2).

Figure 2: Electric Distribution Utility Service Territories in California



Dozens of electric distribution utilities operate in exclusive service territories across the state, with different ownership and regulatory structures. There is wide variability in the size of the service territories and the number of customers served.

Source: CEC GIS https://cecgis-caenergy.opendata.arcgis.com/documents/c69c363cafd64ad2a761afd6f1211442/explore.

Within IOU service territories, about 36 percent of customer load is served by community choice aggregators (CCAs). CCAs do not own or operate distribution wires but are responsible for procuring adequate generation resources to serve their customers, developing and implementing customer programs, and managing billing. Distribution system planning and investments made by IOUs are regulated by CPUC, which authorizes cost recovery from ratepayers for infrastructure provided it is used and useful. For POUs and cooperative utilities, distribution system investments are approved by their local regulatory authority.

There are different rules and procedures, managed by electric distribution companies, for connecting different types of resources (described in detail below). Resources that generate or store electricity are treated differently than devices that only consume electricity. Sometimes installation of a new DER may trigger upgrades or expansions on the utility side of the meter. Depending on the type of resource and local utility rules, the customer may be responsible for the costs of these utility infrastructure upgrades or these costs may be socialized (that is, spread across all the utility's ratepayers). The rules and procedures for connecting DERs and allocation of their costs within POUs often differ from IOUs.

Efficiency and Load Management Are Essential but Not Sufficient

California has long been a leader in development of regulations, programs, and market conditions that help reduce electricity consumption and overall requirements for new generation, transmission, and distribution infrastructure. IOU efficiency programs started in the 1970s and have provided customer bill savings and reduced the magnitude of grid updates over several decades. Time-of-use rates and demand response programs have been established to provide economic signals for customers to modify their consumption based on variable grid conditions. Expanding load flexibility and participation in demand response events can also provide reliability and economic benefits, especially during emergencies. California recently adopted a goal to operationalize 7,000 MW of load flexibility through rates and programs by 2030, which reflects a doubling of current levels.[9]

There are opportunities to expand and improve energy efficiency, load flexibility, vehicle-grid integration, and other strategies to reduce the amount of new infrastructure required. For example, installation of more efficient conductors including high-voltage direct current (DC) transmission can carry more power through existing rights-of-way. More dynamic monitoring and signaling of available grid capacity at specific times and locations can allow more resources to connect now and help bridge the time it takes for conventional upgrades to wires

9 CEC website. 2023. California Adopts Goal to Make More Electricity Available Through Smarter Use. https://www.energy.ca.gov/news/2023-05/california-adopts-goal-make-more-electricity-available-through-smarter-use.

and substations to be completed. Nonetheless, the scale of new clean resources that need to be connected will inevitably require upgrades and construction of new transmission and distribution infrastructure.

Grid Planning and Investment Must Balance Tradeoffs Across Multiple Objectives

Electricity infrastructure must provide reliable service and be resilient to California's increasingly variable climate. Planners, regulators, and utilities must simultaneously balance investments in grid hardening and wildfire adaptation with expanding capacity to accommodate rapid growth in clean energy resources, particularly resulting from transportation and building electrification. At the same time, electricity must remain affordable, and the costs, benefits, and access to clean energy resources need to be more equitable. In many cases, there are inherent tradeoffs between these objectives. The critical challenge facing planners, regulators, system operators, and utilities today is balancing tradeoffs between these objectives. Collectively, California must continue and even accelerate informed investments that rapidly grow and harden the grid to reduce greenhouse gas (GHG) emissions and adapt to climate change while limiting ratepayer burdens, particularly for the state's low-income and disadvantaged communities.

Grid Planning and Resource Connection Processes Today

Responsibility for grid planning is shared and coordinated among many organizations, and there are differences across balancing authorities and utility ownership structures. POUs and small IOUs outside the California ISO footprint have similar planning processes as the large IOUs, which are described below. But processes at POUs have important differences in oversight entities, approval for investments and recovery of costs from ratepayers, and degree of transparency in reporting costs and timelines.

Overview of Grid Planning Processes for Large IOUs

For IOUs, planning is based on the CEC energy demand forecast, which forecasts the total energy and peak power requirements to meet future demand based on a variety of factors. (See Chapter 3.) The CPUC develops an integrated resource plan that identifies portfolios of resources that achieve GHG emissions planning targets informed by the California Air Resources Board (CARB) scoping plan updates,[10] reliably meet forecast demand, and are least cost for ratepayers. These resource portfolios are then used by the California ISO to develop an annual transmission plan that identifies and classifies necessary transmission facilities to

10 CARB. *2022 Scoping Plan for Achieving Carbon Neutrality*. November 16, 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf.

reliably connect and deliver power from the forecast resource portfolios. Load-serving entities enter into offtake agreements with new generation facilities to meet CPUC directives and report on procurement plans and progress.

The demand forecast is also the starting point for utilities in distribution system planning processes. IOUs disaggregate, or break down, the forecast demand to individual distribution circuits and combine it with information about pending upgrades, customer electrification plans, and existing applications. The utility evaluates grid needs based on these circuit-specific forecasts and any potential thermal, voltage, power quality, or other reliability violations that may arise. Multiple potential upgrades to address these violations, including non-wire alternatives (primarily installation of DERs on the overloaded circuits), are compared and ultimately implemented through an annual distribution investment plan. These planned investments form part of the "rate base" of the utility, and costs are amortized over time and socialized across all ratepayers.

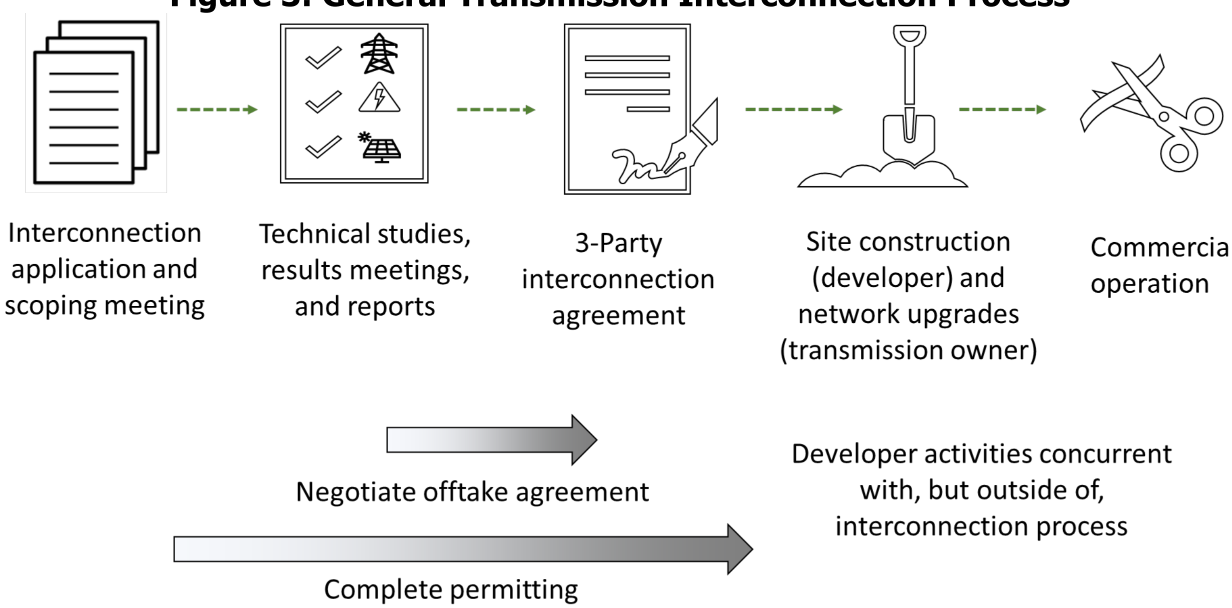
While distinct from the processes and rules that govern connection of new resources to the grid, transmission planning and distribution planning significantly impact the scale and pace of deployment. Historically, most projects applying to connect to the grid have required relatively limited upgrades. Instances where customer applications did require new distribution capacity, such as large, new commercial developments, were constructed on longer timelines that could be accommodated within established planning and implementation processes. Recently, there has been a growth in large load projects, such as highway fast charging plazas and data centers. These projects can be built on short timelines of a year or less but have large power requirements that may require construction of new distribution or transmission system assets that cannot be built in time to serve these projects.

Interconnecting Generation and Storage to the Transmission System

Interconnection of generators and storage devices to the transmission system is a complex task that has become increasingly challenging as the number of projects applying to interconnect has grown. The process is summarized in Figure 3. Transmission owners — usually utilities — and regional transmission operators like the California ISO conduct a series of studies to evaluate if sufficient transmission capacity is available to reliably deliver electricity from proposed generators to load-serving entities. Federal oversight ensures nondiscriminatory treatment of projects in interconnection processes.

Most new generation and storage seeking to connect to transmission in California are requests to interconnect to the system operated by the California ISO. These requests are generally studied through the California ISO's interconnection process, although projects meeting certain requirements can apply to be studied through an independent study or fast-track process.[11] In the interconnection process, all generators apply to connect during a window and are studied together, as described below. Figure 3 describes the California ISO's interconnection process, however, the California ISO has an ongoing policy initiative to significantly reform the interconnection process to account for the pace and scale of new transmission developments and capacity additions.

Figure 3: General Transmission Interconnection Process



Source: CEC

There are four general stages in the process for interconnecting large new generators or storage to the transmission system (described below) after which the project enters trial operations and finally commercial operation.

1) Submission of an interconnection application — The developer of a project submits an interconnection request that describes the technical details of the project. Applicants

11 To apply for independent study or fast-track study processes, the project must meet certain conditions, including developers being able to prove site exclusivity meaning they own, lease, or have the right to develop the property on which the project will be located. Further, the independent study process is for projects up to 20 MW with a planned commercial on-line date that cannot be met through the cluster study process and requires that the project be electrically independent. The fast-track process is for projects less than 5 MW that do not trigger the need for any network upgrades. Both independent and fast track studies processes accept applications on a rolling basis.

must pay a deposit to enter the study process and will be required to demonstrate a high degree of site control following adoption of FERC Order 2023.

2) Completion of technical studies — The California ISO (or other transmission operator if not in California ISO territory) and transmission owner conduct a series of technical studies including:
    - Facilities studies to determine the equipment required to connect the project to the grid. Identified facilities needed can range from various substation modifications required to accommodate the interconnection of the project gen-tie to an open position at the substation to construction of an entirely new substation.
    - System impact studies to evaluate how the proposed project may impact the stability of the bulk power system and identify any upgrades needed to ensure continued reliable operation. Most reliability-related upgrades are small partly because congestion management operating procedures can reduce the project output to reduce overloads on transmission elements, and if necessary, automated systems can rapidly disconnect the generator under adverse conditions.
    - Deliverability studies to determine transmission system upgrades required for a resource to deliver power to customers at times of greatest system need. Deliverability is used to determine eligibility for resource adequacy capacity credits, which load-serving entities need to meet procurement requirements established by the CPUC. Network upgrades required for deliverability are typically more extensive than reliability upgrades.
3) Execution of an interconnection agreement — The developer, the California ISO (or other transmission operator), and the transmission owner enter a three-party contract that defines the requirements and timeline for interconnection, associated upgrades, and financial responsibilities of the parties.
4) Site construction and transmission network upgrades — The developer completes site construction, and the transmission owner completes any necessary transmission network upgrades. Implementation ends with new resource interconnection, at which point the project enters trial operations before commencing commercial operation.

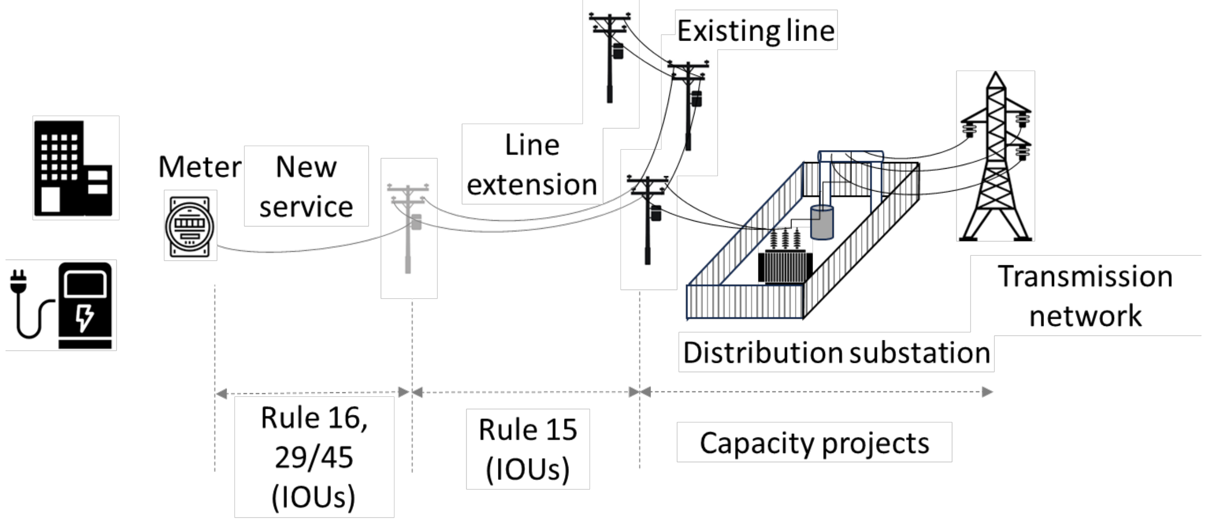
Concurrent with but outside interconnection processes, developers must also complete permitting with the relevant authorities and execute an offtake agreement with a load-serving entity. Offtake agreements are typically negotiated after completion of technical studies that determine the deliverability status of the project as well as the cost and extent of network upgrades. Permitting activities may begin early in interconnection process but must be completed before the start of construction.

This general process has worked effectively for more than a decade, connecting hundreds of new projects that provide gigawatts (GW) of net generation and storage capacity. Recently, however, the volume of interconnection requests, both in number of individual requests and capacity of the requests, has required additional time and resources to review, validate, and study interconnection applications.

Interconnection and Energization on the Distribution System

There are two categories of processes for connecting new resources to distribution grids — interconnection and energization — depending on the type of resource the customer is connecting (Figure 4). *Interconnection* refers to connecting DERs that can discharge electricity — generators like rooftop solar, stationary storage, and bidirectional EV chargers. *Energization* refers to connecting resources that only consume electricity like conventional (unidirectional) EV chargers.

Figure 4: Different Rules and Processes Govern Distribution Service Extensions, Line Extensions, and Capacity Projects



New service connections for IOUs are governed by different rules with different allocation of costs depending on the type of resource being served and the scope of the project. Capacity projects such as modifications to substations are managed through capacity planning with all costs socialized to ratepayers.

Source: CEC

For the state's large IOUs, interconnection is governed by CPUC-jurisdictional Rule 21 or the FERC-jurisdictional wholesale distribution access tariff (WDAT) if the resource will participate in wholesale electricity markets. Most interconnection applications are for small projects previously under the net-energy metering tariff and now under the net billing tariff,[12] which are generally processed quickly and with minimal changes or upgrades needed to utility

12 CPUC Decision 22-12-056 adopted a successor to the net energy metering tariff and subtariffs that, among other changes, encourages adoption of combined solar and storage systems. The new tariff is referred to as the net billing tariff, which applies to customers applying for interconnection after April 15, 2023.

infrastructure. Interconnection of larger projects and those interconnecting through WDAT can take longer and may trigger the need for enhancements to utility infrastructure, the costs of which are allocated entirely to the customer applying to connect.

New service connections are governed by several CPUC-jurisdictional rules depending on the scope of the project. Energizing new load from new or existing customers may entail installing a service line to the customer meter (governed by Rule 16), extending a distribution line from an existing primary circuit (governed by Rule 15), or upstream capacity work (not currently governed by a tariff). The costs of service and line extensions for residential customers are shared between the customer applying and ratepayers through ratepayer funded subsidies such as allowances or discounts. Recently, in response to direction from the Legislature, the CPUC established special rules for connecting new EV charging infrastructure (Rule 29 in Southern California Edison [SCE] and Pacific Gas and Electric [PG&E] territories and Rule 45 in San Diego Gas & Electric [SDG&E] territory) that socialize the cost of the service transformer, design, and civil work that would otherwise be paid by the developer. Across all rules, energizing a new load requires that the existing distribution line and substation powering it have sufficient available capacity to serve the new load. If the existing distribution line or substation lack adequate capacity, the utility must upgrade, construct new circuits, or implement other capacity projects, the costs of which are spread across all customers of the utility.

Public and cooperatively owned utilities follow similar processes for interconnection and new service connections, subject to the rules of their local regulatory authority. While the types of studies conducted are similar, customer requirements and rules for cost recovery vary across utilities. Many POUs offer incentives or programs to help cover the cost of charging equipment. Most POUs, however, do not have special rules governing new service connections for EV charging infrastructure and, therefore, generally require more of the costs to be covered by the charging station developer.

Some EV charging developers expressed concern that the increased costs could potentially slow development of charging infrastructure in POU territories and lead to inequitable access, pointing out that IOUs have a larger number of charging stations than POUs.[13] In written comments, the California Municipal Utilities Association highlighted many of the incentives and programs POUs are implementing to support EV charger deployment, noted that special rules for EV charger installations are not the only way to support charger installations, and

13 Tesla presentation at the May 9, 2023, IEPR workshop on Accelerating Connection of Clean Resources to the Distribution System showing fewer chargers in major POU territories compared to large IOU territories and significantly higher average costs to install chargers. https://efiling.energy.ca.gov/GetDocument.aspx?tn=250045&DocumentContentId=84763.

suggested that lower electricity rates in POU territories helps balance any additional costs developers face deploying charging infrastructure in POU territories.[14]

Today, most projects applying to be energized or to interconnect to the distribution system are relatively small in total electricity demand and do not require upgrades or new capacity to be added to utility distribution systems. However, projects such as large DC fast charging plazas and medium- and heavy-duty truck charging depots require significant amounts of power. For example, Tesla's Harris Ranch Supercharger site has 98 chargers, and even with onsite solar and storage, has nearly 12 MW of combined utility service, which is roughly the equivalent of the instantaneous demand of 9,000 homes. There will be more large projects seeking new service over the coming decade. For example, Tesla plans to more than double the size of the California Supercharger network over the next several years and is opening access to other vehicle manufacturers.[15]

Projects that lack adequate capacity require mitigations or capacity addition projects to serve them reliably. Some mitigations such as reconfiguring circuits and control settings may only take a few months for the utility to implement, but larger projects managed through the utility's distribution planning process can take multiple years to complete based on the scope of the work required (among other factors such as workforce and capital availability), as shown in Table 1 for work performed by PG&E.

Table 1: Representative Timelines for New Capacity Projects From PG&E

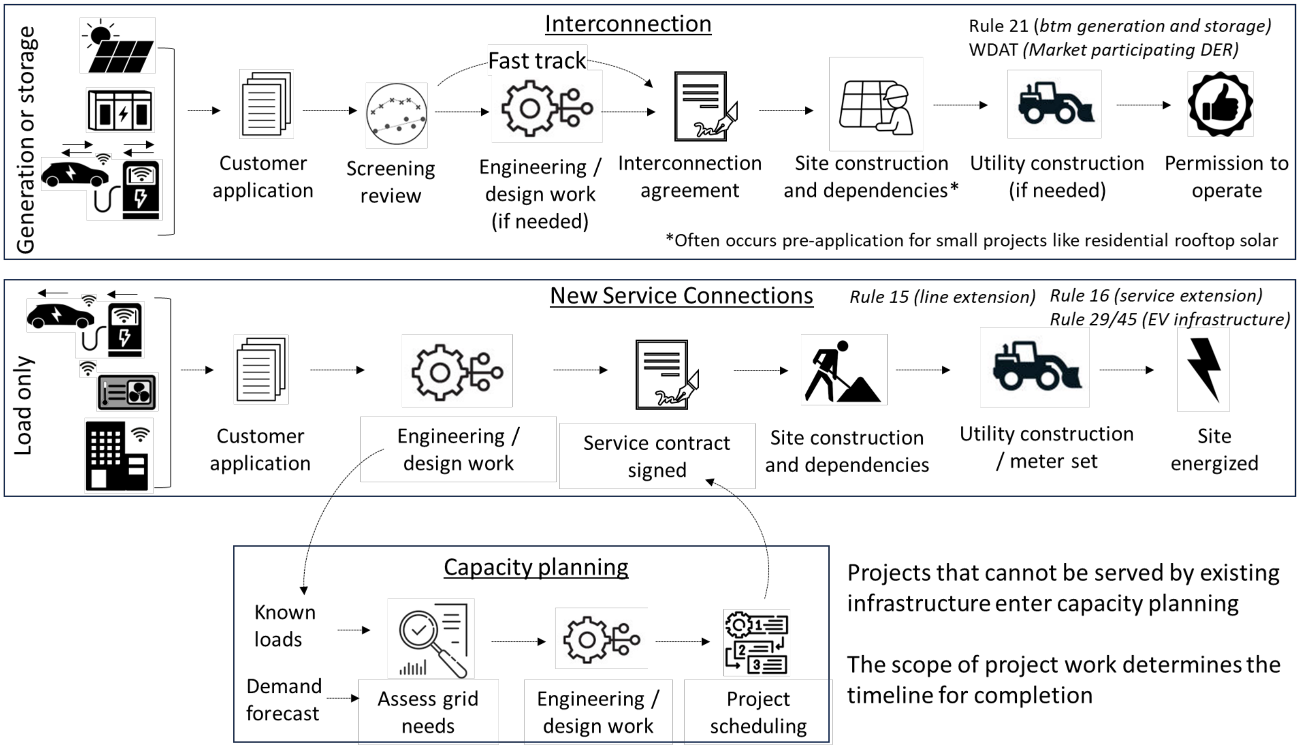
Scope of Capacity Project (PG&E)	Current Timeline (Years)
Distribution line work to increase capacity or reconfigure circuits	1-3
Add a new circuit from an existing substation	2-3
Add or replace a substation transformer at an existing substation	3-4
Build a new substation	5-7

Source: PG&E responses in High DER Proceeding. Answers to Administrative Law Judge's Ruling Seeking Additional Information on the Distribution Planning Process. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M505/K839/505839889.PDF.

14 California Municipal Utilities Association comments on the Draft IEPR. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253566&DocumentContentId=88781.

15 White House Fact Sheet: Biden-Harris Administration Announces New Standards and Major Progress for a Made-in-America National Network of Electric Vehicle Chargers. 2023. https://www.whitehouse.gov/briefing-room/statements-releases/2023/02/15/fact-sheet-biden-harris-administration-announces-new-standards-and-major-progress-for-a-made-in-america-national-network-of-electric-vehicle-chargers/.

Figure 5: Connecting Clean Resources to IOU Distribution Systems



Source: CEC

Interconnection and energization processes are governed by different rules with different allocation of costs between the applicant and ratepayers. They also require different types of studies to ensure safety and reliability and are generally processed by different design and customer management teams within the utility.

Interconnection — In IOU service territories, interconnection is governed by Rule 21 or the FERC-jurisdictional wholesale distribution access tariff for resources participating in the California ISO market. Depending on the size and characteristics of the project applying to interconnect, the project can proceed through a "fast-track" process or may require additional detailed studies. Most interconnection applications are relatively small net-energy metering or net billing tariff projects that are completed in weeks or less. Larger projects and those that export energy to the distribution grid typically take longer.

Energization — In IOU service territories, new service connections are governed by Rules 15 and 16 for line and service extensions, respectively. In 2021, the CPUC created new EV Infrastructure Rules 29 (for SCE and PG&E) and 45 (for SDG&E) specific to providing new service to separately metered EV charging installations, which socialize more of the costs for utility-side infrastructure to help accelerate deployment of EV chargers.

Capacity planning — Most new interconnection and energization applications are relatively small in total power demand and do not require significant upgrades or mitigations upstream of the service or line. However, larger projects such as DC fast charging plazas and larger solar installations that cannot be accommodated with existing capacity trigger the need for upgrades or construction of new distribution capacity. These upgrades and capacity projects are addressed in the utility's long-term capacity planning process that is typically managed by a separate planning department. The scope of the new capacity project, in part, informs the timeline for completion. Some projects can be implemented quickly, such as reconfiguring circuits, while others can take significantly longer. For example, construction of new substations may take seven or more years from design through completion.

Recently the number and size (electric demand) of projects applying to connect to distribution systems have grown, which have led to wait times of months or longer before sufficient capacity can be provided for some projects.[16]

Increasing Equitable Access to Clean Energy Resources, Related Benefits, and Adequate Grid Capacity to Connect Them Is Critical

Historically, electric grid planning and connection processes have not explicitly included equity-related metrics when evaluating customer applications and instead typically treat all customer applications the same. Inequity will be perpetuated without practices that intentionally address community needs, especially the needs of justice communities. Wealthier individuals are more likely to be early adopters of costly DERs like EVs, EV chargers, rooftop solar, and storage. Some studies have found that grid infrastructure in low-income and disadvantaged communities have lower hosting capacity to interconnect rooftop solar and customer-sited storage and that interconnection applications are completed more slowly in these communities.[17]

While many incentive programs prioritize deployment of clean resources in low-income and disadvantaged communities, they may face greater challenges in connecting them to the grid because of failing, deficient, or absent infrastructure. There is an opportunity for energy and load-serving entities to resolve these issues by investing more deeply in these communities. A clean energy future for all cannot be achieved if justice communities continue to be left behind. Grid Alternatives suggested ensuring robust community outreach in grid planning and investments, which, for example, the CPUC has initiated in a recent rulemaking to Modernize the Electric Grid for A High Distributed Energy Resources Future.

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16 For example, comments by Volvo Group on the May 9, 2023, IEPR workshop on Clean Energy Interconnection-Electric Distribution Grid. https://efiling.energy.ca.gov/GetDocument.aspx?tn=250264&DocumentContentId=84998.

17 Brockway, A.M., Conde, J. and Callaway. 2021. "Inequitable Access to Distributed Energy Resources Due to Grid Infrastructure Limits in California." *Nature Energy* 6: 892-903. https://www.nature.com/articles/s41560-021-00887-6.

Barriers, Initiatives Underway, and Recommendations to Accelerate Connection of Clean Resources to the Grid

There are interrelated barriers that limit the pace and scale at which new clean resources can connect to the grid. Deployment timelines are also being delayed by external factors such as supply chain constraints for key components. These issues are not unique to California and are impacting deployments and transition timelines in other states and countries. There are numerous efforts underway to address these challenges and solutions developed in California that can help accelerate a broader global transition.

There are five major barriers to accelerating deployment of clean energy resources on the grid, each of which is described below.

1) Infrastructure planning and oversight are challenged by the pace, scale, and uncertainty of market- and policy-driven deployment.
2) The growing number and size (electric demand) of projects applying for interconnection or energization can clog processes and may lack capacity to connect.
3) Ratepayer impacts need to be managed while preparing grid infrastructure.
4) Available capacity, connection and upgrade processes, and timelines for completion are not always transparent or consistently tracked.
5) Permitting can take a long time, and the scale of deployment will need broader public support.

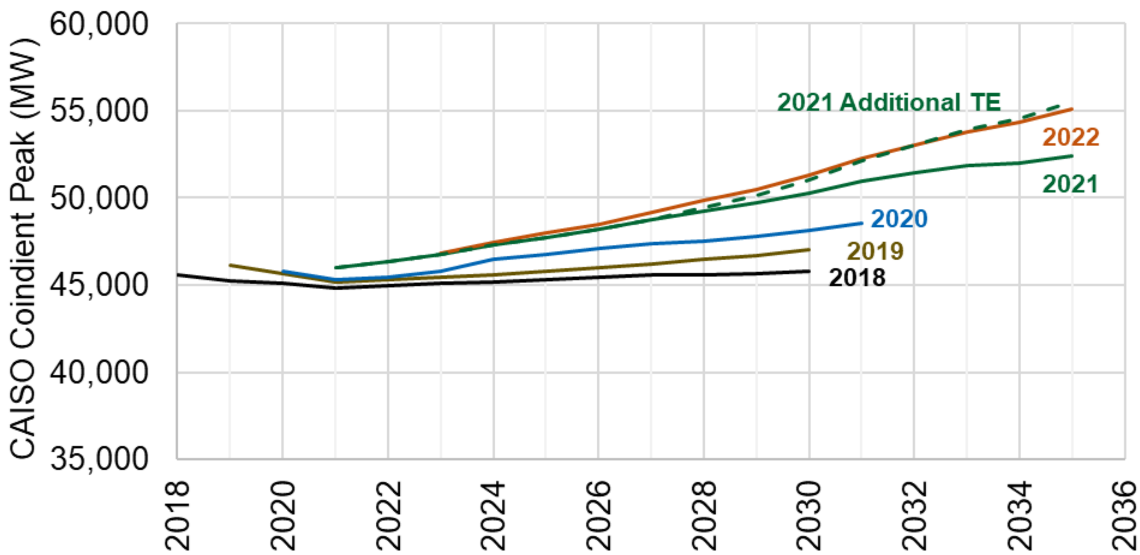
Problem 1: Accelerated Deployment Strains Existing Planning Paradigms

The past several decades have seen limited to no growth in total electric load and relatively modest construction of new transmission or distribution capacity. As recently as 2018, the CEC demand forecast showed minimal growth in peak demand through 2030. Over that time, the market adoption of clean energy resources has accelerated dramatically — for example, the share of new vehicles sold that are plug-in electric increased from around 7 percent to nearly 25 percent in the second quarter of 2023. Forecasting energy needs, planning new infrastructure, and authorizing recovery of costs during of such rapid change are challenging.

Substantial progress has been made incorporating policy and market developments into demand forecasting and electric grid planning over the past few years. The forecast of net peak demand has been revised upward through annual updates, increasing by more than 5 GW in 2030 over five forecast vintages (Figure 6). *Net peak* is the highest demand after accounting for the impacts of self-generation. The transportation energy demand forecast now accounts for not just adopted CARB regulations, but also expected regulations, for example including the Advanced Clean Fleets rule before it was finalized.

In addition to growing demand from electrification, renewable resource and transmission requirements have grown rapidly over the past five years as planning processes move from achieving renewable portfolio standards to aligning with SB 100. Through its integrated resource plan, the CPUC has directed load-serving entities to procure growing amounts of renewable generation and storage. The California ISO's 2022–2023 Transmission Plan was updated to accommodate roughly 4 GW of new generation capacity per year over a 10-year horizon.[18] The California ISO's 2023–2024 Transmission Plan will account for new generation of over 7 GW per year over a 10-year horizon, using the 2022 CEC demand forecast.

Figure 6: California Net Peak Demand Forecast Over the Past Five Updates



The CEC forecast of peak demand in the California ISO for 2030 has increased by more than 5 GW over five updates, driven by rapid transportation electrification and climate change.

Source: CEC

However, it takes several years or more before increases in forecasted demand result in new transmission and distribution capacity being available for projects seeking to connect. In the meantime, utilities that have historically received only a few large load applications or performed a few large network upgrades per year are receiving more large applications. Some of these projects — such as installations of EV fast chargers and construction of new data centers — can be built in less than a year but require the power of a small skyscraper, and lack of grid readiness is slowing the deployment.

There is significant uncertainty identifying precisely when and where new grid capacity will be needed. Developers of large projects may not know the exact locations and timelines of their projects, which impacts utility capacity planning. Improved coordination and information sharing across utilities, large customers such as medium- and heavy-duty truck fleets, and

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18 California Independent System Operator (California ISO). *2022–2023 Transmission Plan*, http://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf.

other stakeholders can help reduce this uncertainty. Strategies adopted in large resource and transmission planning could be transferred to distribution systems. For example, the Renewable Energy Transmission Initiative convened a broad set of stakeholder groups to help identify and rank zones for development of renewable energy and least-regrets transmission infrastructure. This initiative helped develop planning models that continue to be refined and used for resource and transmission planning today. A similar approach, on a more local or regional level, could be used to help identify and prioritize locations for expanding distribution capacity and easing deployment of DER.

The state's infrastructure planning and regulatory processes must now adapt to rapid load growth enabling beneficial electrification coupled with decarbonization of electricity supply. Keeping pace with market- and policy-driven clean resource deployment will require development of more proactive and flexible processes. In their written comments on the May 4, 2023, and May 9, 2023, IEPR workshops, several entities stated that this proactive planning will be needed to keep pace with regulations, market adoption of EVs, and needed transmission capacity.[19]

Initiatives Underway

Memorandum of Understanding (MOU) Aligning Resource Planning, Transmission Expansion, and Procurement Processes

In December 2022, the California ISO, CPUC, and the CEC entered into a MOU that, among other objectives, tightens the link between resource procurement and transmission planning. The MOU was developed in light of the significant amount of new resources and transmission needed to meet state goals.[20] Many stakeholders called for further coordination between policy goals, planning processes, and clean resource and DER deployments in their written comments on the May 4, 2023, and May 9, 2023, IEPR workshops on Clean Energy Interconnection.[21] As

19 Written comments by Forum Mobility, AES Corporation, Joint EV Parties, and Sierra Club California on the May 4, 2023, IEPR Workshop on the Clean Energy Interconnection- Bulk Grid and the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection- Electric Distribution Grid. All comments can be found on IEPR Dockets 23-IEPR-04 and 23-IEPR-05. https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-04 and https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-05.

20 Memorandum of Understanding Between the CPUC and CEC and California ISO Regarding Transmission and Resource Planning and Implementation. December 2022. https://www.energy.ca.gov/sites/default/files/2023-01/MOU_Dec_2022_CPUC_CEC_ISO_signed_ada.pdf.

21 Written comments by Defenders of Wildlife, American Clean Power, Center for Energy Efficiency and Renewable Technologies, Golden State Clean Energy, Sierra Club California, and Powerflex on the May 4, 2023, and May 9, 2023, IEPR Workshops on the Clean Energy Interconnection. All comments can be found on the web page for IEPR Docket 23-IEPR-04, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-04.

described below, the California ISO Interconnection Process Enhancements Initiative is considering significant reforms to the interconnection process to tighten linkages between resource and transmission planning, procurement, and resource interconnection.

Implementation of SB 319

The CPUC and CEC, in coordination with the California ISO, are implementing Senate Bill 319 (McGuire, Chapter 390, Statutes of 2023) to review the MOU aligning resource planning, transmission planning, and procurement processes every 5 years. The statutes also require the CEC, CPUC, and California ISO to jointly develop a transmission infrastructure development guidebook that describes planning and permitting processes including typical timeframes for various permitting authorities. The statutes require that every 2 years the CPUC report on the number, status, and costs of transmission projects requiring CPUC approval.

2022–2023 Transmission Plan

The California ISO adopted the *2022-2023 Transmission Plan*, the annual plan that adopts a proactive approach to identifying key infrastructure necessary to meet California's long-term energy goals.[22] The plan proposes 45 expansion or upgrade projects that will be completed over the next decade at an estimated cost of $7.3 billion. The California ISO is currently developing its 2023–2024 Transmission Plan.

Implementation of AB 1373

Among other actions, AB 1373 (Garcia, Chapter 367, Statutes of 2023) requires the CEC, in consultation with the CPUC, to assess barriers to electricity interconnection and energization and provide recommendations on how to accelerate those processes as part of the 2025 IEPR. Also, the statute requires the CPUC to establish a rebuttable presumption of need for a proposed transmission project in favor of a California ISO board approved need evaluation.

20-Year Transmission Outlook

The California ISO developed a longer-term 20-year transmission outlook in 2022 to extend the time horizon of planning and provide visibility into how the transmission grid may evolve to meet the state's long-term goal.[23] The outlook explores a scenario of potential transmission needs to interconnect new renewable resources needed to meet state goals and identifies about $30 billion of potential investments. The 20-year outlook complements annual

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22 California ISO. *2022-2023 Transmission Plan*. May 2023. http://www.caiso.com/Documents/caiso-2022-2023-transmission-plan-approved.pdf.

23 California ISO. *20-Year Transmission Outlook*. 2022. http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf

transmission planning processes. The California ISO will release an updated 20-year outlook in 2024.

Additional Achievable Scenarios and Contemplated Regulations in the Demand Forecast

CEC staff expanded the additional achievable scenario framework to building electrification in 2021 and to transportation electrification in 2022 to capture the market impacts of contemplated regulations and uncertainties around established regulations. This provides the CPUC and utilities with greater visibility into potential resource and infrastructure capacity requirements associated with the state's transition away from fossil fuels. For example, the forecast in the *2022 IEPR Update* included the effects of the Advanced Clean Fleets rule, which CARB had not finalized.

Freight Infrastructure Planning Framework

The Freight Infrastructure Planning (FIP) framework CPUC staff proposal identifies a proactive planning process for long lead time infrastructure investments along state freight corridors with the goal of accelerating heavy-duty transportation electrification infrastructure.[24] The proposal — which has not yet been voted on by CPUC commissioners — intends to create a common set of inputs, assumptions, and a scenario of charging needs that can inform utility infrastructure planning and upgrades. This proactive planning process was supported in several written comments received on the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection — Electric Distribution Grid.[25]

Joint Statement on ZEV Infrastructure

In April 2023, the CEC, CPUC, CARB, California Transportation Commission, California State Transportation Agency, California Department of Transportation, California Department of General Services, and the California Governor's Office of Business and Economic Development (GO-Biz) released a joint statement of intent on zero-emission vehicle infrastructure. The statement describes how agencies are coordinating deployment of ZEV regulations, charging

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24 CPUC. Freight Infrastructure Planning web page, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/transportation-electrification/freight-infrastructure-planning.

25 Written comments by Joint EV Parties, Sierra Club California, Alliance for Automotive Innovation, and California Electric Transportation Coalition on the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection- Electric Distribution Grid. All comments can be found on the webpage for IEPR Docket 23-IEPR-05. https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-05.

Written comments by Forum Mobility on the May 4, 2023, IEPR Workshop on the Clean Energy Interconnection-Bulk Grid. https://efiling.energy.ca.gov/GetDocument.aspx?tn=250421&DocumentContentId=85162.

and refueling infrastructure deployment, and electric grid planning.[26] The statement also describes underlying principles for coordination and cooperation across agencies, including sharing data and analyses, coordinated stakeholder engagement, and a shared commitment to enhancing equity through ZEV and infrastructure programs.

Proceeding to Modernize the Electric Grid for a High DER Future

The CPUC adopted an Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future in 2021.[27] The proceeding includes several interrelated initiatives spanning improvements to the distribution planning and execution process and sharing of system data, evolving distribution system operator roles and responsibilities, and smart inverters and grid modernization technologies. The proceeding scope will consider appropriate venues for cost recovery as well as overall alignment between the CEC demand forecast, IOU grid needs assessments, and general rate case processes.

Advanced Clean Fleet Implementation Working Group

CARB is forming a working group to discuss best practices for implementing the Advanced Clean Fleets rule and facilitating dialogue across stakeholders.[28] The working group will include a subcommittee focused on infrastructure that will work with fleets to help overcome challenges in deploying adequate charging infrastructure. The working group will also provide recommendations and action items on selected topics in support of successful implementation.

Recommendations

Building from efforts underway, the following recommendations can help align infrastructure planning and oversight with policy objectives and market needs.

- Continue enhancing coordination between policies and regulations that accelerate decarbonization of supply and electrification of end uses with electricity infrastructure planning, oversight, and deployment processes. Increased coordination will help ensure that policy goals are incorporated into transmission and distribution system planning and investment decisions and that infrastructure readiness and deployment timelines are factored into promulgation of regulations. The CEC, CPUC, California ISO, and CARB

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26 CARB, CEC, CPUC, California Transportation Commission, and GO-Biz. April 23, 2023. *Zero-Emission Vehicle Infrastructure Joint Statement of Intent*, https://ww2.arb.ca.gov/sites/default/files/2023-04/ZEV%20Infrastructure%20Joint%20Statement%20of%20Intent%204-20-23%20final.pdf.

27 CPUC. High DER Future Grid Proceeding R.21-06-017 web page, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning.

28 CARB. August 22, 2023. Truck Regulations Advisory Committee Kick-Off Meeting presentation. https://ww2.arb.ca.gov/sites/default/files/2023-08/acfpres230821_ADA.pdf.

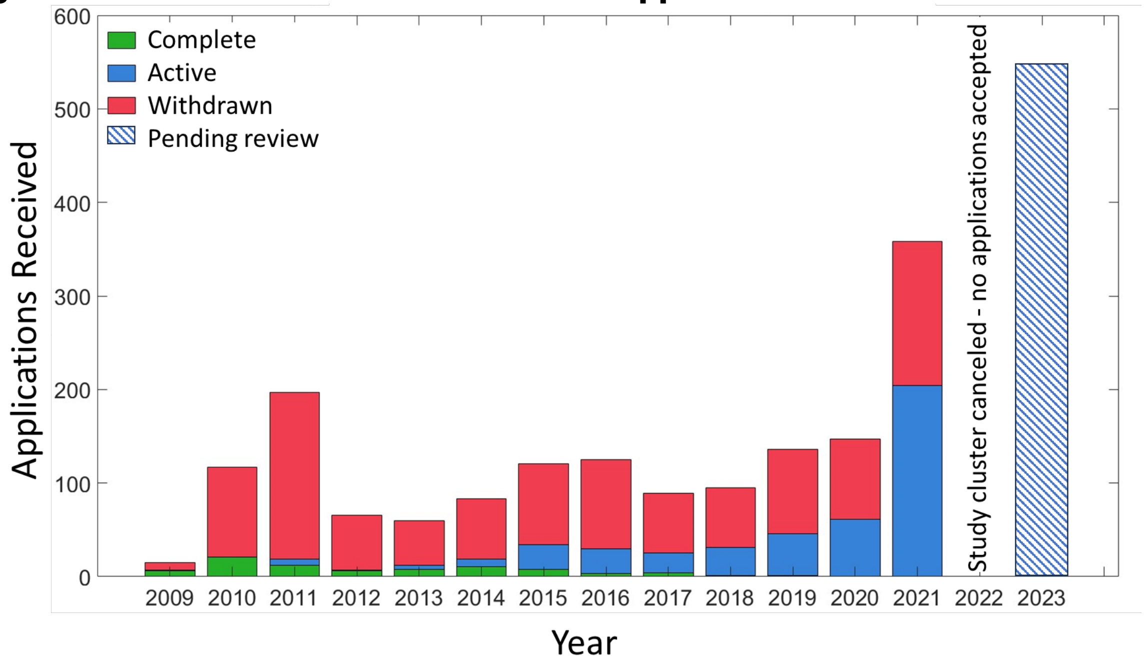
should be involved in implementation for IOUs, and local regulatory authorities could be involved for POUs.

- Promote sharing of data and information among fleets, EV charging station developers, and other entities deploying large electric loads with utilities, regulatory authorities, and planning entities. The CEC, CPUC, CARB, local regulatory authorities, and utilities should coordinate on implementation.
- Establish methods for increasing the geographic granularity of the demand forecast, particularly for large loads that can be developed quickly such as EV charging, port decarbonization, and data centers. The CEC, CPUC, and utilities should coordinate on implementation for IOU service territories and CEC should coordinate with local regulatory authorities for POU service territories.
- Monitor and expand proactive transmission and distribution infrastructure expansion processes, for example, as described in the CPUC staff proposal for the FIP framework and the 2022 MOU aligning agency actions. Identify lessons learned and opportunities to expand, for example, to include developers of large light-duty EV fast charging deployments within the FIP, and provide greater visibility into when and where new transmission and distribution capacity will be needed. For IOUs, the CPUC and CEC should be involved in implementation for distribution systems and the California ISO for the transmission system.
- Explore strategies to encourage procurement of new utility-scale renewable generation and storage resources and deployment of DERs in locations that have existing capacity or planned capacity projects already in development. The CPUC, CEC, and load-serving entities could be involved in implementation.
- Provide targeted support to POUs and cooperative utilities, particularly those in rural communities, and enhance coordination across all utilities to share effective strategies for proactive transmission and distribution expansion, development of rates and programs that promote facilitate beneficial electrification, and deployment of zero-carbon renewable resources. The CEC, local regulatory authorities, and utilities should collaborate in implementation with support from CPUC.

Problem 2: The Growing Number and Size of Projects Applying to Connect Overwhelm Existing Processes and Can Lack Capacity to Connect

The number of applications to interconnect new generation and storage projects to the transmission system has grown dramatically, as shown in Figure 7. In 2021 (Cluster 14), more than 350 projects totaling more than 151 GW of generation — which exceeds the capacity of all generation resources connected in California today[29] — applied to interconnect within the California ISO footprint. These projects are in addition to the more than 300 existing projects in the queue that were studied in previous years.[30] The unprecedented number of applications prompted the California ISO to delay the next cluster study by one year. Although interconnection requests received in 2023 (Cluster 15) are still being processed, the preliminary list published by the California ISO contains more than 540 new projects. Many of the applications in Figure 7 may reflect exploratory projects as developers look for potential project sites with available capacity or minimal network upgrades needed.

Figure 7: California ISO Interconnection Applications and Status Over Time



The California ISO received nearly 375 interconnection requests in 2021 – well above the historical baseline – which resulted in a one-year pause in accepting new applications. In 2023, nearly 550 interconnection applications were received.

Source: CEC staff analysis of California ISO interconnection queue data

Beyond delaying processing times for projects in the interconnection queue, the large volume of applications can result in less meaningful study results and consumes significant staff time from transmission owners and the California ISO. In its written comments, the California

29 Installed capacity was 82,766 MW in 2022 per the CEC Energy Almanac, https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy.

30 The California ISO queue contained 319 active projects at the time the Cluster 14 window opened.

Community Choice Association proposed ensuring those projects most likely to complete the interconnection process successfully be prioritized for study.[31] Middle River Power and Microgrid Resources Coalition noted that staffing shortages are slowing the study process and called for emergency hiring efforts.[32] Several commentors including Next Era Energy Resources, the Microgrid Resources Coalition, and the Clean Coalition called for greater use of automation and software solutions to increase process efficiency for transmission and distribution system connections.[33] Next Era Energy Resources identified other regional transmission operators evaluating automation for multiple steps of the interconnection study process and suggest that it can also improve the accuracy of results while reducing timelines.[34]

Large interconnection queues are not limited to the California ISO as large POUs are also experiencing increasing numbers of applications. These challenges are also impacting other states and regions, prompting the United States Department of Energy to create the Interconnection Innovation Exchange.[35] In July 2023, the FERC issued Order 2023 that requires transmission providers to implement significant changes to reduce the amount of time it takes projects to move through interconnection queues and be developed.

There has been similar growth in the number of applications to connect DERs. Following adoption of the new net billing tariff all three large IOUs received a large increase in applications to interconnect before the modified rules went into effect. These have resulted in backlogs processing DER interconnection applications although this is expected to be a one-off event as opposed to sustained increase in a backlog. The new rules are designed to incentivize installation of combined behind-the-meter solar and storage systems.

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31 California Community Choice Association comments on the May 4, 2023, IEPR Workshop on the Clean Energy Interconnection- Bulk Grid, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250398.

32 Middle River Power comments on the May 4, 2023, IEPR Workshop on the Clean Energy Interconnection- Bulk Grid, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250279.

Microgrid Resources Coalition comments on the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection- Electric Distribution Grid, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250411.

33 Clean Coalition comments on the May 4 and May 9, 2023, Workshops on Clean Energy Interconnection. https://efiling.energy.ca.gov/GetDocument.aspx?tn=250288&DocumentContentId=85027. Comments on the *Draft 2023 IEPR* are available at the docket 23-IEPR-01, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-01.

34 Next Era Energy Resources comments on the *Draft 2023 IEPR*, https://efiling.energy.ca.gov/GetDocument.aspx?tn=253466&DocumentContentId=88690.

35 Department of Energy (DOE). Interconnection Innovation Exchange, https://www.energy.gov/eere/i2x/interconnection-innovation-e-xchange.

The large IOUs have also experienced growth in new service connection requests over the past several years. SCE reports that since 2021, it has received more than 700 interconnection requests for EV charging loads of at least 500 kW or larger, with the average size of large load applications more than doubling from 1.15 MW to 2.4 MW. Of the roughly 270 projects SCE has received through the EV infrastructure Rule 29, 19 of them have triggered larger system upgrades.[36] PG&E reports more than 1,200 applications under Rule 29, with 84 of them exceeding 2 MW and nearly 190 requiring circuit improvements or capacity upgrades.[37]

Partly because of the lag between market adoption of clean resources and the construction of new transmission or distribution infrastructure needed to connect them, some projects today may seek to connect in areas with a lack of adequate capacity. This situation is compounded by the increasing size of new generation, storage, and load applications. At the transmission level, connection of new large renewable generation and storage projects may be impacted by the lack of available transmission path deliverability. If interconnection of a project triggers a delivery network upgrade, developers must either pay for the necessary transmission upgrades (and recover those costs after the resource goes into operation) or connect but not be eligible to participate in the resource adequacy market. Both options are difficult for developers financing projects and for load-serving entities executing offtake agreements, which generally leaves the projects economically unviable. To help address such issues, starting with the California ISO's 2022–2023 Transmission Plan, the California ISO began identifying transmission zones where transmission capacity is expected to be available to better inform optimal locations for interconnection requests.

There are technologies available today that can allow more efficient use of existing transmission and distribution capacity. For example, on the transmission system, comments from the WATT Coalition included studies indicating that grid-enhancing technologies such as dynamic line rating and power flow controllers could double the available capacity for renewable projects seeking to connect and could reduce the costs and timelines for interconnection.[38] The California ISO analyzes many of these opportunities as part of its

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36 SCE. 2023. Comments submitted to IEPR on trends in applications to provide new service connections for EV chargers, https://efiling.energy.ca.gov/GetDocument.aspx?tn=252579&DocumentContentId=87669.,. https://efiling.energy.ca.gov/GetDocument.aspx?tn=252579&DocumentContentId=87669https://efiling.energy.ca.gov/GetDocument.aspx?tn=252579&DocumentContentId=87669.

37 PG&E. 2023. Comments submitted to IEPR on trends in applications to provide new service connections for EV chargers, https://efiling.energy.ca.gov/GetDocument.aspx?tn=252612&DocumentContentId=87703.

38 WATT Coalition presentation and study submitted in response to May 4, 2023, IEPR Workshop on Clean Energy Interconnection- Bulk Grid, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250826&DocumentContentId=85723 and https://efiling.energy.ca.gov/GetDocument.aspx?tn=250827&DocumentContentId=85724.

analysis in the annual Transmission Planning Process.[39] Similarly for resources connecting to distribution systems, technologies such as power control systems, automated load management, and distributed generation could more efficiently use available capacity and allow more DERs to connect more quickly.[40] However, deployment of many of these technologies has been limited for a variety of reasons, including limited awareness and familiarity, lack of incentives for utilities to deploy them, and ongoing development of standards governing deployment.

The Impacts of Climate Change Require Growing Amounts of Resources

The challenge of managing growing volumes of applications to connect clean energy resources to the grid is compounded by the increasingly visible impacts of climate change. Wildfires, widespread and long-lasting extreme heat, and atmospheric rivers damage infrastructure and increase demands on the grid. The amount of human and financial resources utilities dedicated to grid hardening and wildfire risk mitigation has grown significantly and is a leading contributor to rate increases.[41] In SCE's most recent 2023–2028 general rate case filing, wildfire resilience accounts for 21 percent of forecast capital expenditure (which does not include operations and maintenance costs) compared to 14 percent to increasing grid readiness for electrification. Across all three IOUS, the portion of the monthly forecast bundled

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39 In follow up comments on the *Draft 2023 IEPR*, WATT Coalition further recommended that the California ISO adopt a loading order framework similar to that adopted for efficiency and demand response; to prioritize grid enhancing technologies before practices that curtail renewable production; and to develop financial incentives that compensate transmission owners for increased efficiency and optimization of existing capacity to address business model biases toward building of new transmission. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253449&DocumentContentId=88674.

40 Enphase comments on the May 9, 2023, IEPR Workshop on Clean Energy Interconnection- Distribution Grid, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250536&DocumentContentId=85307.

PowerFlex comments on the May 9, 2023, IEPR Workshop on Clean Energy Connections- Distribution Grid, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250536&DocumentContentId=85307.

Forum Mobility comments on the May 9, 2023, IEPR Workshop on Clean Energy Connections- Distribution Grid, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250421&DocumentContentId=85162.

Mainspring Energy comments on the May 9, 2023, IEPR Workshop on Clean Energy Connections- Distribution Grid. https://efiling.energy.ca.gov/GetDocument.aspx?tn=250383&DocumentContentId=85109.

41 CPUC. May 2023. *2023 Senate Bill 695 Report: Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases Pursuant to Public Utilities Code Section 913.1,* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2023/2023-sb-695-report---final.pdf.

residential bill attributed to wildfire management is between 6.5 to 8.5 percent in 2030 compared to 0.3 to 1.4 percent for transportation electrification.[42]

Capital-constrained utilities may be forced to choose between investing in new capacity to connect clean energy resources or hardening lines to reduce fire risk. Beyond financial constraints, there is also limited qualified workforce, and many organizations — including other utilities, regulators, regional transmission organizations, and private developers — are competing to hire workers with the same expertise. Limited workforce may cause delays conducting infrastructure upgrades and connecting clean resources, which could become an increasing challenge as the impacts of climate change continue to worsen. In their written comments on the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection — Electric Distribution Grid, California Energy Storage Alliance and Clean Coalition suggested that allowing nonutility personnel to perform some infrastructure work could reduce timelines and help in the near term.[43]

Supply Chain Constrains Further Delay Projects

Projects connecting clean resources to transmission and distribution systems have also been slowed by limited availability of key pieces of equipment, even in instances where there is sufficient infrastructure capacity and workforce. Both project developers and utilities have reported long and growing timelines for procurement of transformers and switchgear, with delays sometimes measured in years for equipment that historically could be procured in weeks or months. Sometimes this equipment is customized for each deployment site, which can exacerbate supply chain delays. Encouraging standardization in site and utility infrastructure design could help in the long term but may not always be feasible given project specific constraints. Along with greater standardization, developing more proactive utility procurement processes for commonly used equipment could help prevent future supply chain delays.

Initiatives Underway

Several of the previously described initiatives underway such as the Proceeding to Modernize the Grid for a High DER Future are also expected to help manage the growing number and

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42 CPUC. May 2021. [Utility Costs and Affordability of the Grid of the Future,](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/en-banc/senate-bill-695-report-2021_en-banc-white-paper.pdf) https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/en-banc/senate-bill-695-report-2021_en-banc-white-paper.pdf.

size of clean resources applying to connect. Below are further initiatives underway that were not described previously.

Interconnection Process Enhancements

The California ISO is completing a stakeholder-driven policy initiative to create a more efficient generator interconnection process that is tightly coupled with transmission planning and resource procurement by load-serving entities.[44] The 2023 Interconnection Process Enhancement (2023 IPE) is focused on addressing the large volume of projects applying to interconnect observed in recent years and the large number of active projects in the California ISO's interconnection queue. The California ISO is considering additional proposals in Track 2 of the 2023 IPE initiative to prioritize interconnection in zones with available transmission capacity, consistent with state and local regulatory authority planning. The stakeholder process is also exploring strategies to clear inactive projects from the queue and focus study efforts on projects having the greatest viability of achieving commercial operation. The 2023 IPE is anticipated to help speed up interconnection timelines by reducing the number of projects entering the study process that have no reasonable chance of being built and thinning out the number of stalled projects in the queue.

FERC Order 2023 Implementation

On July 27, 2023, FERC Issued Order No. 2023 Improvements to Generator Interconnection Procedures and Agreements, which contains several new requirements for transmission providers.[45] The California ISO already complies with many requirements, such as having a cluster study in lieu of a serial study. But there are several significant changes anticipated in implementation of the order for stakeholders in California, as summarized below.

- Requires the ISO to disseminate public interconnection information with a "heat map" of available capacity.
- Eliminates customer-specific scoping meetings and results meetings, which take months to conduct during the interconnection process.
- Eliminates the feasibility study, enabling the potential transition to a single-phase study process.

44 California ISO. Initiative: Interconnection Process Enhancements 2023 web page. Accessed August 23, 2023, https://stakeholdercenter.caiso.com/StakeholderInitiatives/Interconnection-process-enhancements-2023.

45 FERC Order 2023. Improvements to Generator Interconnection Procedures and Agreements, https://www.federalregister.gov/documents/2023/09/06/2023-16628/improvements-to-generator-interconnection-procedures-and-agreements.

- Requires interconnection customers to have site control with their interconnection request, with limited exceptions on public land.
- Increases financial commitments for projects progressing in queue.
- Requires studies to consider "grid-enhancing technologies" that could obviate traditional upgrades.

In written comments, Next Era Energy Resources encouraged the California ISO to go beyond minimum the compliance requirements for FERC Order 2023.[46]

Deliverability Assessment Methodology Review

The California ISO recently completed a policy initiative aimed at reviewing the assumptions and approach used to analyze deliverability of planned resources in the transmission planning process and of projects applying for interconnection.[47] The deliverability assessment tests that the transmission system can reasonably ensure that resource adequacy capacity can be delivered to load when load is high, supply is tight, and loss of load is a risk. The importance of the ability to access this capacity, or deliverability, was clear during extreme stressed conditions in each of the last three summers, especially on August 13 and 14, 2020; July 9, 2021; and September 6, 2022.

Deliverability status determines the fraction of the capacity of a project that is eligible for resource adequacy capacity credits, which is critical for the commercial viability of many projects. Major transmission network upgrades required for a project to be deliverable can be large and costly and, therefore, are developed within the transmission planning process to meet the need of the resource portfolios developed within the CPUC's Integrated Resource Planning (IRP). Changes identified in the California ISO's Deliverability Assessment Methodology policy initiative are anticipated to make more deliverability available, or make deliverability available earlier than otherwise.

Tracking Energy Development (TED) Task Force

This joint effort between the CPUC, CEC, California ISO, and GO-Biz tracks new energy projects under development and helps coordinate government actions that can help bring

46 Next Era Energy Resources comments on the Draft 2023 IEPR. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253466&DocumentContentId=88690.

47 California ISO. Initiative: Generation Deliverability Methodology Review web page. Accessed August 23, 2023. https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Generator-deliverability-methodology-review.

clean energy resources on-line more rapidly. The Task Force began in 2021 and is focused on projects expected to come on-line by 2024.[48]

Enhancing the Extended Day-Ahead Market

The California ISO has created the Extended Day-Ahead Market (EDAM) initiative to extend voluntary participation in the day-ahead electricity market to other entities in the western interconnection. The EDAM is designed to provide economic, environmental, and reliability benefits to participating balancing authorities and their utilities. The EDAM was approved by the California ISO Board of Governors in February 2023 and approved by FERC in December 2023.

Implementation of SB 410 - Powering Up Californians Act

The CPUC is implementing provisions in Senate Bill 410 (Becker, Chapter 394, Statutes of 2023) to establish average and maximum target periods for energization of customers and require regular reporting on utility performance in meeting these targets. As required in the statute, the CPUC is developing cost tracking and authorization mechanisms that allow recovery of investments beyond those included in the utility's general rate case or another proceeding subject to reasonableness review. Furthermore, the statute requires IOUs to consider federal and state decarbonization and air quality regulations and policies in annual distribution planning.

Implementation of AB 50

The CPUC is implementing provisions in Assembly Bill 50 (Wood, Chapter 317, Statutes of 2023) to determine the criteria and reasonable average timelines for customer service connections as well as project types that require unique or extended timelines (for example, those that require large capacity projects). The statute requires IOUs to evaluate and update their distribution planning process to improve the accuracy of forecast demand and enable more timely electric service through energization.

EV Infrastructure Rules

Consistent with Assembly Bill 841 (Ting, Chapter 372, Statutes of 2020), the CPUC approved new Rules 29/45 and associated cost tracking for projects installing separately metered EV charging infrastructure in IOU service territories other than those at single-family homes.[49] These "EV Infrastructure Rules" authorize each IOU to design and construct utility-side infrastructure and recover the costs of service extensions from ratepayers through the IOU's

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48 CPUC. Tracking Energy Development webpage, https://www.cpuc.ca.gov/news-and-updates/newsroom/summer-2021-reliability/tracking-energy-development.

49 CPUC. October 8, 2021. Resolution E-5167, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M413/K566/413566906.PDF.

general rate case. These rules differ from existing rules for service or extensions for loads other than EV chargers, in which the applicant or customer is responsible for utility-side infrastructure costs beyond a fixed allowance. Further, under AB 841, the utility is now responsible for the design and execution of civil construction work in addition to the electrical distribution system upgrades necessary for the individual customer's project. These costs are spread to all customers in the utility's territory. The impact of the EV Infrastructure Rules on rates is being evaluated.

Limited Generation Profiles

As part of an ongoing proceeding to update Rule 21, modifications are being proposed that would allow customers to include a *limited generation profile* for new DERs. A limited generation profile would enable customers to curtail the output of distributed generation when there is limited hosting capacity available.[50] The change from static output limits to allowing monthly output values that differ throughout the year can more efficiently use available distribution hosting capacity and reduce the likelihood of an application necessitating upgrades or mitigations. The standards for smart inverter and power control system technologies that enable limited generation profiles are under development.

Demand Flexibility Rulemaking

The CPUC initiated a rulemaking in July 2022 to advance demand flexibility through electric rates.[51] The rulemaking is intended to provide a robust and stable policy pathway that promotes commercial and residential customer adoption of automated demand management solutions at scale. Widespread adoption of flexible demand and coordination of other DERs in response to grid signals such as dynamic rates can play an important role in promoting adoption of renewable generation and limiting infrastructure requirements and total costs.

Load Management Standards

The CEC adopted updates to California's load management standards that require large load-serving entities to develop hourly retail electricity rates that reflect variable costs and GHG emissions.[52] These dynamic rates are maintained and updated on a centralized repository that can be accessed by aggregators and automation devices to facilitate shifting of customer loads

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50 CPUC website on Rule 21 Interconnection and Limited Generation Profiles, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/rule-21-interconnection/limited-generation-profiles.

51 CPUC website on Demand Flexibility Rulemaking, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-flexibility-rulemaking.

52 CEC. Load Management Rulemaking, 2022. https://www.energy.ca.gov/proceeding/load-management-rulemaking.

based on grid conditions. The standards can help improve reliability by helping reduce load during peak hours or emergencies while providing bill savings to customers that align consumption with price signals.

Recommendations

Building on efforts underway across energy entities, the following recommendations can help manage the growing number of applications to connect clean resources and support efficient use of grid capacity and utility workforce.

- Evaluate distribution interconnection, new service connection, capacity planning, and equipment procurement processes to determine steps that are most time consuming and identify opportunities for streamlining, automating processing, and eliminating redundancies. Utilities should lead implementation with CPUC involved for IOUs and local regulatory authorities involved for POUs.
- Consider expanding use of shared resources such as construction crews or expanding use of third-party contractors for interconnection studies, design work, and construction of projects that cannot be completed in a timely manner because of resource constraints. Utilities should lead implementation with CPUC, CEC, and California ISO involved for IOUs and local regulatory authorities involved for POUs.
- Conduct a comprehensive assessment of the number of jobs and type of labor needed to achieve economywide decarbonization by 2045 and use the findings to guide investments in education, training, and workforce development programs including for power systems engineers, electricians, and line workers to rapidly grow the available workforce and prioritize funding for community colleges, trade schools and within tribes, low-income, and disadvantaged communities. The California Workforce Development Board (CWDB) and the CEC could be involved in implementation in coordination with relevant labor unions.
- Encourage strategies and technologies that allow more flexible and dynamic service connections to distribution systems such as contracts with variable load limits and power control systems that limit total site load based on infrastructure capacity. Utilities could lead implementation with the CPUC and CEC involved for IOUs and local regulatory authorities involved for POUs.
- Explore opportunities to deploy interim power solutions such as mobile batteries and linear generators — prioritizing zero-emission technologies — with streamlined approval processes that allow more clean resources to connect to distribution systems while permanent infrastructure is constructed. Utilities could lead implementation with the CPUC, CEC involved for IOUs and local regulatory authorities involved for POUs.

Problem 3: Rate Impacts Must Be Managed While Rapidly Preparing the Grid

Limiting burdens on ratepayers while rapidly preparing the grid to reliably accommodate deployment of new clean resources — as well as hardening the grid and adapting to climate change — is a balancing act. The increased use and throughput from efficient electrification can help address growth in electric rates.[53] Nonetheless, substantial capital investments will be needed in the near term to provide grid capacity often ahead of high use. It is important both to limit the overall extent of upgrades and associated capital investment needed as well as explore other sources of financing to offset funding recovered from ratepayers. Another contributor to high costs for ratepayers is scarcity in resource adequacy market, which is exacerbated by delays interconnecting new resources. The California Community Choice Association submitted information on challenges its members face procuring RA capacity and the increasing costs that are passed on to ratepayers.[54] They further express concern that efforts to accelerate electrification and decarbonization of supply could stall if ratepayers are burdened with all of the up-front costs.[55]

Upgrading and expanding distribution and transmission infrastructure to reliably connect new clean resources will require capital investments by utilities. Preliminary results from a recent Kevala study of distribution upgrade costs associated with unmanaged load growth largely from EVs found estimated costs could exceed $50 billion by 2035.[56] The study did not account for new real-time dynamic rates and flexible load management strategies but does identify the types of costs needed to complete energization and distribution interconnection. In light of the need for rapid upgrades to and expansion of the distribution system, the CPUC is reimagining distribution grid planning for the twenty first century in its High DER Grid Planning Rulemaking.[57] Similarly, the California ISO's 20-year transmission outlook explored scenarios of resource deployments resulting in about $30 billion in transmission projects to deliver power

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53 Fitch, Tyler, Jason Frost, and Melissa Whited. October 2022. "Electric Vehicles Are Driving Electric Rates Down." Synapse Energy Economics, Inc., https://www.nrdc.org/sites/default/files/media-uploads/evs_are_driving_rates_down_dec_2022_update_0.pdf.

Metz, Lucy, Melissa Whited, Paul Rhodes, and Ellen Carlson. April 14, 2023. *Distribution System Investments to Enable Medium- and Heavy-Duty Vehicle Electrification: A Case Study of New York*. Synapse Energy Economics, Inc., https://acrobat.adobe.com/link/track?uri=urn%3Aaaid%3Ascds%3AUS%3Ab0fd0780-9882-3a25-9ef2-f8c73bd80c92.

54 California Community Choice Association comments on the Scoping Order for the 2023 IEPR. https://efiling.energy.ca.gov/GetDocument.aspx?tn=252301&DocumentContentId=87315.

55 California Community Choice Association comments on the Draft IEPR. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253490&DocumentContentId=88699.

56 Kevala, prepared for the CPUC. May 9, 2023. *Electrification Impacts Study, Part I: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates,* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF.

57 The CPUC Public Advocates Office recently conducted its own study of distribution upgrade costs associated with transportation electrification that were approximately one-third as much as the Kevala study. Available at https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/reports/230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf.

reliably by 2040.[58] These capital investments would be recovered from ratepayers through fixed and volumetric charges on utility bills.

Initiatives Underway

Clean Transmission Financing Through the Climate Catalyst Fund

As part of the historic 2022 state climate package, the California Infrastructure and Economic Development Bank (iBank) received $250 million for financing development of new transmission infrastructure through its Climate Catalyst Revolving Loan Fund.[59] The initial financing is available to support new transmission facilities required to connect zero-carbon firm generation in the Salton Sea region to the California ISO system.

Annual Reporting on Actions to Limit IOU Cost and Rate Increases

The CPUC annually reports to the Legislature and Governor on IOU rate increases and identifies recommended actions that can limit rate increases over the following year.[60] The most recent report confirms that rate increases have outpaced inflation since 2021. Drivers of rate increases include legacy net-energy metering tariffs, as well as wildfire risk mitigation operating expenses (which are passed on directly to customers, do not receive a rate of return for the utility, and are not amortized over time), such as vegetation management and wildfire insurance. The report identifies activities underway to reduce cost and rate increases, including pursuit of alternative sources of funding such as federal investments.

Flat Rate Billing Promoting Electrification

As required by Assembly Bill 205 (Committee on Budget, Energy, Statutes of 2022, Chapter 61), the CPUC has initiated the implementation of residential rate billing adjustments for all IOUs. Pursuant to legislation, electric IOUs will reduce the usage rate (the amount that varies based on volume of electricity used) for residential customers and reallocate other costs to maintain the grid to a flat rate. This new billing structure will support California's climate change goals because customers will be incentivized to electrify. The legislation requires the CPUC authorize this change no later than July 1, 2024, and that it include a minimum of three income thresholds such that low-income ratepayers would realize a lower average monthly bill without changes in their usage.

58 California ISO. May 2022. *20-Year Transmission Outlook*, http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

59 California Infrastructure and Economic Development Bank (IBank). Climate Catalyst Revolving Loan Fund web page, https://www.ibank.ca.gov/climate-financing/climate-catalyst-program/.

60 CPUC. 2023. *Senate Bill 695 Report*, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2023/2023-sb-695-report---final.pdf.

Coordinating Pursuit of Federal Funding for Utility Infrastructure

The CPUC is coordinating with IOUs to best position California to receive federal funding made available through the 2021 Infrastructure Investment and Jobs Act, among other opportunities.[61] Resolution E-5254 establishes a tracking mechanism for IOUs to regularly report on planning, seeking, and implementing awards from federal funding that align with the state's climate, reliability, and resilience goals. The resolution also describes the process the IOUs can use if they seek cost recovery for matching funds associated with any resulting awards. In its written comments, SDG&E recognizes the significant potential for federal funding to limit ratepayer burdens while supporting a rapid and equitable clean energy transition and suggests that procedural mechanisms for state agencies to support entities' application for federal funds would improve their competitiveness.[62]

Recommendations

Building on initiatives underway, the following recommendations can help limit costs to ratepayers in the near term while supporting rapid infrastructure and clean resource deployment.

- Evaluate alternative sources of funding for transmission and distribution system upgrades and expansions, such as funding from federal programs, existing incentive or credit trading programs, allocation of general funds, creation of new bonds, or expansion of existing financing mechanisms such as the Climate Catalyst Fund at the California Infrastructure and Economic Development Bank. The Legislature, the Governor's Office, the CEC, and CARB could be involved in implementation.
- Continue developing and expanding a variety of rates and programs that encourage customer load flexibility and participation in emergency demand response events. Monitor participation and realized benefits as part of the goal of reaching 7 GW of load shift by 2030. The CEC, CPUC, and California ISO should be involved for IOUs, and local regulatory authorities should be involved for POUs.

61 CPUC Resolution E-5254, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M506/K016/506016078.PDF.

62 SDG&E comments on the Draft IEPR, https://efiling.energy.ca.gov/GetDocument.aspx?tn=253475&DocumentContentId=88696.

Problem 4: Available Capacity, Connection and Upgrade Processes, and Timelines for Completion Are Not Always Transparent or Consistently Tracked

The amount of capacity available to connect new clean energy resources to transmission and distribution systems are often not obvious to customers or project developers before they apply to connect.[63] At the transmission level, the California ISO publishes study results and models that provide some of this information under a nondisclosure agreement. Information about the costs of upgrades associated with interconnecting new large resources is available on an aggregated basis to the study area level to stakeholders who sign a nondisclosure agreement with the California ISO, but cost information on a project-specific basis is confidential. The California ISO does provide anonymized queue data publicly. Stakeholders can use the following information to better assess areas with available capacity:

- Board Approved Transmission Plan, which includes transmission zones and installed capacity of resources
- Interconnection areas based on CPUC busbar mapping
- Transmission capability estimates for use in the CPUC Integrated Resource Planning Process
- Transmission Plan Deliverability Allocation Report

At the distribution level, there is often a lack of visibility and status information on substation upgrades, which can take multiple years. The state's large IOUs maintain publicly available data portals that include integration capacity analysis maps that reflect the amount of available capacity to host new distributed solar and other generation resources on specific circuits in their territory. Several stakeholders identified limitations and challenges in using these resources — for example lack of sufficient granularity or lack of timely updates — that make them difficult to use to identify and plan project locations. The state's IOUs are in the process of implementing improvements over the next several years. POUs generally do not have publicly available datasets or tools that show this information. In written comments, Los Angeles Department of Water and Power suggested that CEC consider working with local regulatory authorities to develop a centralized site to host capacity analysis maps, which would

63 These transparency concerns were highlighted in written comments from NextEra Energy Resources, AES Corporation, Middle River Power, and California Community Choice Association on the May 4, 2023, IEPR Workshop on the Clean Energy Interconnection- Bulk Grid and the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection — Electric Distribution Grid. All comments can be found on IEPR Dockets 23-IEPR-04 and 23-IEPR-05. https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-04 and https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-05.

reduce the administrative burden on smaller utilities and provide a common location for developers to access this information.[64]

Lack of transparency into transmission and distribution infrastructure capabilities can lead to exploratory-only applications that are used to identify potential upgrade costs and timelines. Such exploratory applications can clog the intake and study processes, impacting other interconnection applicants. This concern came up repeatedly in written comments submitted by several parties for the May 4, 2023, and May 9, 2023, IEPR Workshops on the Clean Energy Interconnection.[65]

After submission of a customer application, there is variability across utilities in the requirements, processes, and timelines to connect clean resources and perform any associated upgrades. Almost all clean resource deployments require several steps with different responsible entities, including local permitting authorities, which can make it challenging to identify bottlenecks and the greatest opportunities for improvement. The average timelines for connecting some resources are tracked and reported but not for all resource types or construction of new transmission or distribution capacity. Project developers and customers often describe a lack of transparency into the status, timelines, prioritization, and reasons for delays in resource connection and upgrade processes.[66] POUs report variable and often no information about connection and upgrade timelines.

Initiatives Underway

Several of the previously described initiatives underway such as the Proceeding to Modernize the Grid for a High DER Future are also expected to help increase transparency. Below are additional initiatives underway that were not described previously.

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64 Los Angeles Department of Water and Power comments on the Draft IEPR. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253639&DocumentContentId=88876.

65 Written comments by AES Corporation, Middle River Power, Forum Mobility, Synergistic Solutions, TeraWatt Infrastructure, Clean Coalition, Alliance for Automotive Innovation, and Sierra Club California on the May 4, 2023, IEPR Workshop on the Clean Energy Interconnection- Bulk Grid and the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection- Electric Distribution Grid. All comments can be found on IEPR Dockets 23-IEPR-04 and 23-IEPR-05. https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-04 and https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-05.

66 These timeline transparency concerns were raised in written comments by Sierra Club California, Microgrid Resources Coalition, California Energy Storage Alliance, Mutual Housing Coalition, and American Clean Power on the May 4, 2023, IEPR Workshop on the Clean Energy Interconnection- Bulk Grid and the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection- Electric Distribution Grid. All comments can be found on IEPR Dockets 23-IEPR-04 and 23-IEPR-05, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-04 and https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-05.

Transmission Development Forum

The California ISO, CPUC, and participating transmission owners host quarterly stakeholder calls to provide status updates and timelines for completion of transmission projects and upgrades identified in transmission planning and interconnection studies. This process provides greater transparency to developers and stakeholders relying on additional transmission capacity to interconnect and reliably deliver electricity. Where there are persistent delays in completing identified upgrades, the forum can provide data to back legislative or regulatory solutions.

Interconnection Discussion Forum

The Interconnection Discussion Forum is an informal venue convened outside any rulemaking through which developers, utilities, and other stakeholders work collaboratively to improve the interconnection process for DER. Participants meet quarterly and discuss a range of topics with the aim of preventing or informally resolving any disputes and sharing information and best practices across utilities and developers.[67]

Interconnection and EV Charger Energization Timeline Tracking

The CPUC has directed the three large IOUs to track and regularly report the amount of time it takes to complete certain steps within the processes for connecting some clean energy resources. Separately metered EV charging infrastructure projects that are less than 2 MW and apply for energization through the EV Infrastructure Rules are subject to a 125-business day average completion timeline for steps that are within the utility's control.[68] In its written comments on the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection — Electric Distribution Grid, Sierra Club California proposed IOUs require timeline tracking for projects greater than 2 MW.[69] Process steps that the customer is responsible for, such as obtaining building permits, are excluded from this timeline but can also contribute to delays connecting projects. The three large IOUs reported their performance relative to the 125-business day average target at a workshop on September 29, 2023.[70] Although relatively few projects under the EV Infrastructure Rules had been completed by the time data was collected

67 CPUC Rule 21 Interconnection web page, https://cpuc.ca.gov/rule21/.

68 CPUC. December 15, 2022. Resolution E-5247, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K892/499892236.pdf.

69 Written comments by Sierra Club California on the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection — Electric Distribution Grid, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250414.

70 CPUC. Workshop on Electric Vehicle Charging Infrastructure Service Energization Process. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/ev-service-energization-workshop-ppt.pdf.

for the workshop, all three IOUs were exceeding the average timeline target. Data collection and reporting are ongoing.

Under Rule 21, interconnections of non-net billing tariff systems, as well as net billing tariff systems larger than 30 kW, are subject to timeline reporting and tracking. Like tracking of EV infrastructure energization, only steps that are within the utility's control are included in the timelines and performance evaluation. Starting in 2021, the large IOUs have been required to achieve these timelines for 95 percent of the applications received and report mixed success.[71] Efforts by the Large IOUs are ongoing to improve this performance and develop better data management and work-flow processes.

Rulemaking to Consider DER Program Cost-Effectiveness Issues, Data Access and Use, and Equipment Performance Standards

The CPUC initiated a rulemaking to assess and improve how data from smart meters and other devices such as battery storage and solar inverters, EV chargers, and smart thermostats and heat pump controllers are accessed and used in customer programs.[72] Currently, data collected and used in utility programs have wide variability in format and rules governing access. The proceeding seeks to increase consistency across utilities and proceedings in data related to smart devices, as well as transmission and distribution system costs, through the creation of a data working group.

IOU Interconnection Capacity Analysis Map Improvements

The CPUC issued a ruling that orders the three large IOUs to implement improvements to their integration capacity analysis (ICA) data and mapping tools that they make publicly available. Originally designed for estimating available hosting capacity for new generation devices — namely rooftop solar — the CPUC directed the IOUs to develop load ICA data that can help streamline energization applications and ease siting of EV charging infrastructure. Several written comments on the May 4, 2023, and May 9, 2023, IEPR Workshops on the Clean Energy Interconnection shared concerns over the granularity and timeliness of data available in ICA maps.[73]

71 CPUC. Presentation by Eric Marinot. September 29, 2023. Slide 47. CPUC Rule 21 Interconnection Timelines. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/ev-service-energization-workshop-ppt.pdf.

72 CPUC. August 2023. Order Instituting Rulemaking 22-11-013, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K158/499158023.PDF.

73 Written comments by Forum Mobility, Synergistic Solutions, Clean Coalition, and TeraWatt Infrastructure on the May 4, 2023, IEPR Workshop on the Clean Energy Interconnection- Bulk Grid and the May 9, 2023, IEPR Workshop on the Clean Energy Interconnection- Electric Distribution Grid. All comments can be found on IEPR

The IOUs have begun implementing changes to their load ICA methods, such as incorporating next-year hourly load forecasts, next-year DER growth, and future approved load projects. Further, planned capacity projects and network reconfigurations are included in the refined inputs and assumptions. The ruling also directs the IOUs to coordinate with the CEC to promote timely updates to the CEC's Electric Vehicle Supply Equipment (EVSE) Deployment and Grid Evaluation (EDGE) mapping tool.

EVSE Deployment and Grid Evaluation (EDGE) Tool

The CEC developed the EVSE Deployment and Grid Evaluation (EDGE) visualization tool, which maps estimated charging demand and forecasted available grid capacity in specific regions in California. The tool can help identify areas where existing grid capacity may accommodate installation of new EV charging infrastructure or locations that will likely require upgrades to meet expected EV load growth. EDGE relies on the publicly available Grid Needs Assessment (GNA) datasets maintained by the state's three largest IOUs for analysis. However, gaps and quality issues with the data limit the scope and precision of EDGE analysis. The GNA data do not cover the full breadth of the IOU service territories because of the presence of a large amount of redacted information. This issue is especially prevalent in SDG&E's service territory. Secondly, the GNA datasets lack any information regarding circuit-level hourly load profiles and secondary distribution system components. Finally, EDGE lacks grid data within POU service territories. Having access to the redacted primary distribution data, circuit load profiles, secondary distribution system data, and grid information for POUs would allow EDGE to perform a more comprehensive geospatial analysis, including gaining the capability to better align modeled EV charging peak load with circuit limitations and assess the impact of EV charging on a site-level basis.

EV Project Timeline Tracker

The CEC is developing a publicly accessible EV Project Timeline Tracker that is intended to consist of a database and online dashboard that collects and tracks the progress of CEC-funded EV charging projects from start to finish. The tracker will allow multiple parties to update progress and provide greater transparency into the process and timelines for permitting, constructing, and energizing EV charging sites. The tool will help state agencies and stakeholders better understand how long it takes to complete EV charging projects and

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Dockets 23-IEPR-04 and 23-IEPR-05, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-04 and https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-05.

identify deployment bottlenecks. CEC staff solicited feedback on the concept at a public workshop in July 2023 and anticipates the release in 2024.[74]

Recommendations

Building from efforts underway, the following recommendations can accelerate connection of clean energy resources by increasing customer and developer visibility into infrastructure capabilities, connection and upgrade processes, and timelines for completion.

- Continue improving and expanding the scope of publicly available tools and datasets, while maintaining security and appropriate confidentiality, including data on available and anticipated distribution and transmission capacity, aggregate costs of upgrades identified, as well as reliability indices at specific locations. Utilities, the CPUC, CEC, and California ISO should be involved in implementation for IOUs, and local regulatory authorities should be involved in implementation for POUs.
- Expand tracking, reporting, and visibility of timelines and status for new service connections, interconnection, and associated distribution and transmission system upgrades including at substations. Tracking should be used to establish baselines and for reporting performance on public-facing dashboards. Utilities, the CPUC, CEC, and California ISO should be involved in implementation for IOUs, and local regulatory authorities should be involved in implementation for POUs.

Problem 5: Permitting Can Take a Long Time and the Scale of Deployment Will Need Broader Public Engagement and Support

Reaching 100 percent renewable and zero-carbon retail sales of electricity while transitioning to zero-emission transportation and decarbonizing buildings will necessitate building new renewable generation, transmission, and distribution facilities on a large scale. Permitting new energy infrastructure can take months to many years, depending on the size and location of the project, among other factors. The California Environmental Quality Act (CEQA) provides some exemptions for modification of upgrades to existing facilities that can result in a faster process. To that end, the CPUC's General Order 131-D typically does not require a Permit to Construct for transmission projects between 50 kV and 200 kV that would be exempt from CEQA.[75] GO 131-D is currently being updated, including evaluating the applicable voltage ranges of facilities, in an active CPUC rulemaking as described below.

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74 CEC. EV Project Tracker Public Workshop. July 2023, https://www.energy.ca.gov/event/workshop/2023-07/electric-vehicle-infrastructure-project-tracker-workshop.

75 CPUC. General Order 131-D, Section 3(B). https://docs.cpuc.ca.gov/PUBLISHED/Graphics/589.PDF.

Generally, construction of new facilities requires analysis of environmental impacts in the form of an initial study or an environmental impact report to support permitting decisions made by state and local agencies, such as the CPUC for some transmission infrastructure. Projects that cross federal lands and/or require a discretionary federal permit — which is often the case for long transmission lines in California — also must comply with the National Environmental Policy Act (NEPA), potentially requiring an environmental assessment or environmental impact statement from the appropriate federal agency.

Portions of the CEQA and NEPA analyses overlap, and CEQA encourages the use of joint documentation and previously prepared NEPA documentation.[76] Sometimes separate documents are prepared when agreement and cooperation between the federal and state agencies is not possible. State agencies must coordinate closely with local and federal permitting authorities to achieve timely permitting approvals of electricity infrastructure. The CPUC's average time to complete the analysis for a new transmission line is 18 months. CPUC environmental analysis occurs after transmission developers to prepare their own "proponent's" environmental assessment, which itself can take months or years.

Federal permits for major projects typically take more than two years from start to the issuance of a decision. Recently the U.S. Department of Energy initiated a rulemaking process to reduce federal permitting and NEPA analysis timelines for transmission projects.[77] In its written comments, SDG&E suggests that tangible opportunities to streamline transmission permitting exist while maintaining robust environmental reviews and opportunities for stakeholder engagement.[78] SCE comments that additional efforts to further streamline permitting and reduce timelines for project approvals should be undertaken — such as advancing policies that limit the timeframes for CEQA reviews and by eliminating redundant studies — to ensure sufficient infrastructure is constructed in a timely manner.[79]

76 Title 14 California Code of Regulations Article 14 (Sections 15220-15229). https://govt.westlaw.com/calregs/Browse/Home/California/CaliforniaCodeofRegulations?guid=I8B8262305B4D11EC976B000D3A7C4BC3&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default).

77 Federal Register August 16, 2023. Notice of proposed rulemaking and request for comment: Coordination of Federal Authorizations for Electric Transmission Facilities,. https://www.federalregister.gov/documents/2023/08/16/2023-17283/coordination-of-federal-authorizations-for-electric-transmission-facilities.

78 SDG&E comments on the Draft IEPR. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253475&DocumentContentId=88696.

79 Southern California Edison comments on the Draft IEPR. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253452&DocumentContentId=88668.

Smaller, non-transmission projects including EV chargers and customer sited solar and storage are permitted by local authorities and generally proceed through permitting faster than transmission facilities although the process can still take several months. There is wide variability across permitting authorities including in their staffing levels, resources, and timelines for reviewing projects. Many local jurisdictions have undertaken permit streamlining efforts for EV chargers. Some have implemented automated permitting software for rooftop solar that has helped reduce timelines and costs for residential solar installations in California.[80] Expanding the capabilities of automated permitting software to include other resource types such as EV chargers can help local authorities manage growing numbers of projects with limited resources.

There have been some suggestions to exempt clean energy resource deployment projects from state environmental analysis and permitting processes altogether. However, environmental studies can often identify project changes, or mitigation measures, or alternatives that can significantly reduce impacts to the environment. The environmental permitting process has also historically been the primary forum through which local communities can voice their concerns and the process can result in helpful project refinements and may lead to increased community buy-in.

Given the scale of new renewable resources, transmission, and distribution infrastructure needed over the coming decades, it will be increasingly vital to expand public engagement and awareness campaigns beyond, and in complement to, established permitting processes.[81] To achieve public support, providing opportunities to be heard is key and people value being consulted early and frequently throughout planning, design, and implementation processes. While public engagement does not inherently result in consensus or agreement about construction of any specific project, a lack of engagement may increase opposition and delay progress on clean resource and infrastructure deployment.

Initiatives Underway

Electricity Transmission Infrastructure Guidebook

The CEC, CPUC and California ISO are developing an electricity transmission infrastructure guidebook pursuant to SB 319 (McGuire, Chapter 390, Statues of 2023). The guidebook will cover transmission planning and permitting processes, describe the roles, responsibilities, and

80 California Solar + Storage Association comments submitted to docket on Accelerating Connection to the Distribution Grid. https://efiling.energy.ca.gov/GetDocument.aspx?tn=252686&DocumentContentId=87765.

81 National Academies of Sciences, Engineering and Medicine. 2023. *Accelerating Decarbonization in the United States: Technology, Policy, and Societal Dimensions*, https://nap.nationalacademies.org/catalog/25931/accelerating-decarbonization-in-the-united-states-technology-policy-and-societal.

authorities of agencies including interfaces with federal agencies. The guidebook will also include analysis of the average timeframes for development and permitting of transmission infrastructure.

Rulemaking to Update and Amend General Order (GO) 131-D

In May 2023 the CPUC initiated a rulemaking to update and amend GO 131-D consistent with SB 529 (Hertzberg, Chapter 357, Statutes of 2022).[82] GO 131-D sets forth rules related to planning and construction of generation plants; transmission, power, or distribution lines; and substations in California. The first phase of the proceeding considered changes to GO 131-D to while the second phase will consider changes beyond those required in SB 529.

Incorporating Land-Use Screens into Integrated Resource Planning

Busbar mapping is a component of the coordinated CEC, CPUC, and California ISO planning process formalized in the December 2022 MOU. *Busbar mapping* refers to the assignment of generators identified in the CPUC's IRP process to specific interconnection points, or busbars, on the California ISO-controlled electric grid. Busbar mapping incorporates land-use screens developed by the CEC, which reflect key environmental and social concerns, to help identify potential impacts. In its written comments, the Nature Conservancy called for increased integration of land-use screening to assist with project planning.[83] In its written comments, the Defenders of Wildlife recommended the CPUC and CEC build upon the CEC Land Use Screens for Electric System Planning mapping tool to include busbar mapping data.[84]

Opt-In Permitting

Assembly Bill 205 (Committee on Budget, Energy, Chapter 61) signed by Governor Newsom on June 30, 2022, established a streamlined process that is an option for certain eligible non-fossil fueled energy generation, energy storage, and manufacturing/assembly facilities to apply for a permit (or certification) from the CEC. The CEC's permit is in lieu of any permit that would normally be required by the local land-use authority and most, but not all, state permits. The CEC is required to review the application, analyze the environmental impacts of the proposed project, and make its decision on the application within 270 days of receiving a complete application. The expectation is that the resources needed to meet California's carbon

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82 CPUC. Order Instituting Rulemaking to Update and Amend Commission General Order 131-D, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M506/K339/506339461.PDF.

83 The Nature Conservancy comments on the May 4, 2023, IEPR workshop on the Clean Energy Interconnection-Bulk Grid. https://efiling.energy.ca.gov/GetDocument.aspx?tn=250428.

84 Defenders of Wildlife comments on the Draft IEPR, https://efiling.energy.ca.gov/GetDocument.aspx?tn=253451&DocumentContentId=88669.

goals will have an additional or alternative pathway to proceed through this opt-in permitting process, and potentially be faster than other processes.

California Automated Permit Processing Program

Senate Bill 129 (Skinner, Chapter 69, Budget Act of 2021) authorized creation of the California Automated Permit Processing Program (CalAPP) to help local governments establish an online, automated solar permitting platform.[85] According to the California Solar and Storage Association, obtaining a permit for a residential rooftop solar system in California takes between 2 to 3 weeks on average and frequently takes more than 60 days.[86] The CalAPP Program administered by the CEC offers grants between $40,000 to $100,000 to California cities and counties to implement online, automated solar permitting. CEC awarded funds to more than 300 local jurisdictions in California, representing most of the state's population. Following the adoption of qualifying software platform, jurisdictions are issuing solar permits the same day.[87]

EV Charging Station Permitting Guidebook and Streamlining Tracking

Assembly Bill 1236 (Chiu, Chapter 598, Statutes of 2015) and Assembly Bill 970 (McCarty, Chapter 710, Statutes of 2021) required cities and counties to adopt streamlined permitting procedures for EV charging stations to make rapid deployment easier. To support local authorities and share best practices, the Governor's Office of Business and Economic Development has developed a suite of resources, including the EV Charging Station Permitting Guidebook.[88] While there are no penalties for local authorities who do not adopt streamlining measures, adoption across the state is tracked and shared publicly.

Infrastructure Strike Team

Executive Order N-8-23 created an Infrastructure Strike Team composed of cabinet and department leadership across state entities to facilitate coordination between federal, state, tribal, and local governments and accelerate project review, permitting and approvals for priority infrastructure projects.[89] The strike team will create working groups focused on key

85 CEC. California Automated Permit Processing Program, https://www.energy.ca.gov/programs-and-topics/programs/california-automated-permit-processing-program-calapp.

86 California Solar and Storage Association. Lowering the Cost of Solar and Expanding the Market.

87 National Renewable Energy Laboratory. February 2022. "NREL-Led Solar Permitting Software Reduces Project Times by 12 Business Days," https://www.nrel.gov/news/program/2022/solarapp-pilot-study.html.

88 Governor's Office of Business and Economic Development. 2023. *Electric Vehicle Charging Station Permitting Guidebook,* https://business.ca.gov/wp-content/uploads/2019/12/GoBIZ-EVCharging-Guidebook.pdf.

89 Governor Gavin Newsom Executive Order N-8-23, https://www.gov.ca.gov/wp-content/uploads/2023/05/5.19.23-Infrastructure-EO.pdf.

sectors and issues, including transportation, energy, zero-emission vehicles, and hydrogen infrastructure. In addition to promoting deployment and tracking progress on priority infrastructure projects, the working groups will identify potential statutory and regulatory changes to accelerate project implementation.

Recommendations

Building on these initiatives underway, the following recommendations can help enable more rapid environmental permitting decisions while engaging communities and building public awareness.

- Identify opportunities to maximize usage and expansion of transmission capacity within existing rights-of-way and evaluate the viability of technologies like advanced conductors, high-voltage direct current transmission, and grid-enhancing technologies as solutions in transmission planning and investment. Utilities, the California ISO, CPUC, and CEC should be involved in implementation for IOUs, and local regulatory authorities should be involved in implementation for POUs that own transmission assets.
- Explore how the CEC's existing transmission corridor designation[90] authority could support local engagement and land use planning for transmission needs associated with clean resource requirements identified in SB 100. In consultation with regional transmission planning entities, the CEC, California ISO, CPUC, and transmission developers could be involved in implementation for IOUs, and local regulatory authorities could be involved in implementation for POUs.
- Expand the capabilities of automated permitting platforms and software tools to include EV charger installations and continue to support adoption of these tools by local authorities. GO-Biz and the CEC should be involved in implementation.
- Continue improving and develop new web-based geospatial mapping tools to support stakeholder and public engagement in energy resource and transmission planning. Consistent with the MOU aligning Transmission and Resource Planning and Implementation, CEC staff should work with CPUC and California ISO staff in tool development.
- Integrate early and frequent coordination with local and tribal governments, planning entities, and developers as part of infrastructure planning processes. Utilities and the CPUC should be involved for IOUs and local regulatory authorities for POUs.

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90 *Corridor designation* refers to the CEC's ability to identify the lands or areas (a corridor) where it is feasible to locate one or more high-voltage electric transmission lines.

- Conduct broader public engagement early, often, and meaningfully, along with developing and implementing broader awareness campaigns, in partnership with local government entities, focused on the foundational role of electricity infrastructure in addressing climate change, protecting public health, and making progress toward proposed outcomes of the energy entities' policies and programs. The Governor's Office of Planning and Research, the CPUC, CEC, and California ISO should be involved in implementation.

CHAPTER 2: Potential Growth of Clean and Renewable Hydrogen

Introduction

Senate Bill 1075 (Skinner, Chapter 363, Statutes of 2022) calls for the CEC to "study and model potential growth for hydrogen in decarbonizing the electricity and transportation sectors."[91] The statute requires the CEC to report on its findings in the *2023 Integrated Energy Policy Report* (IEPR) and the *2025 IEPR*. SB 1075 references but did not define "green" hydrogen, and there is ongoing global debate over the appropriate definition. This chapter instead uses the term "clean and renewable" hydrogen, which refers to hydrogen produced only from water and renewable electricity or renewable biogenic feedstocks such as agricultural residues and woody biomass. SB 1075 requires CARB to conduct further analysis by June 1, 2024, to assess the ability of other forms of hydrogen to support the state's clean energy and emissions reduction goals. This analysis may result in CEC applying a broader evaluation in the *2025 IEPR*.

As discussed in the previous chapter, California is electrifying much of the transportation and building sectors while rapidly scaling up deployment of low-carbon, renewable generation like solar and wind that are increasingly paired with lithium-ion battery storage. Yet these resources alone may not be sufficient to reach economy-wide decarbonization. Analysis in the SB 100 report[92] and the *2022 Scoping Plan for Achieving Carbon Neutrality*[93] (*2022 Scoping Plan Update*) identifies the need for a more diverse portfolio of clean energy resources beyond those currently being interconnected, particularly those that can provide electricity when solar and wind cannot. Further, some applications such as high-temperature industrial processes, aviation, off-road transportation, and long-haul trucking can be challenging or expensive or both to electrify directly with current technologies. The *2022 Scoping Plan Update* encourages

91 The *2021 IEPR* discussed development of "low-carbon" hydrogen, whereas the U.S. Department of Energy adopts the term "clean" hydrogen, both of which could be produced from fossil resources if coupled with carbon capture and sequestration.

92 CEC, CPUC, CARB. *2021 SB 100 Joint Agency Report, Achieving 100 Percent Clean Electricity in California: An Initial Assessment,* https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349. Referred to as the SB 100 Joint Agency Report.

93 CARB. *2022 Scoping Plan for Achieving Carbon Neutrality*. November 16, 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf.

use of all available tools to reduce GHG emissions and remove carbon dioxide from the atmosphere. While electrification is poised to play a significant role in decarbonizing California's economy, the *2022 Scoping Plan Update* finds that clean and renewable hydrogen is needed to replace fossil fuels in applications like oceangoing vessels, rail, and air transport, as well as in the industrial sector.

The potential role of clean and renewable hydrogen in supporting economywide decarbonization has been researched for decades yet remains in the early stages of deployment. The cost-competitiveness, potential GHG emission reductions, and broader environmental benefits associated with clean and renewable hydrogen depend on many factors, including what methods and biogenic feedstocks (for nonelectrolytic production) are used to produce it, whether and how it is stored and transported, and what applications it is used for. Market adoption of clean and renewable hydrogen will be influenced by how rapidly hydrogen production, storage, and transportation technologies advance compared to competing technologies that provide similar services, such as long-duration storage.

This chapter builds on the *2022 IEPR Update*[94] to present background on the production and use of clean and renewable hydrogen and to provide an initial scenario analysis exploring its use to help decarbonize the electricity and transportation sectors. This chapter also qualitatively discusses clean and renewable hydrogen use in the industrial sector; reviews relevant research, development, and demonstration (RD&D) funded by the CEC; and provides recommendations for future analyses and RD&D investments. Additional analysis of the potential for clean and renewable hydrogen to support California's clean energy goals will be conducted by CARB, and the CEC will expand on that analysis for the *2025 IEPR.*

The initial assessment presented in this IEPR is not a forecast of adoption based on economic or other factors, but instead reflects exploratory "what if" scenarios. The analysis focuses exclusively on electrolytic hydrogen production with the goal of establishing high bookends for potential new renewable generation resources that could be needed beyond those identified in SB 100. Given the already significant build-out of renewable resources forecast over the next two decades, early exploration of potential additional resource requirements is critical. The state needs to plan for the energy impacts from clean, renewable hydrogen production and, as these production facilities become more certain, incorporate the growth in this sector into statewide clean energy resource planning and procurement and electric distribution and transmission infrastructure planning and development. Other options exist for the state, including imports of clean and renewable hydrogen from outside the state or production in

94 CEC. *Final 2022 Integrated Energy Policy Report Update*. February 2023. https://www.energy.ca.gov/sites/default/files/2023-02/Adopted_2022_IEPR_Update_with_errata_ada.pdf.

state from biogenic feedstocks. The CEC intends to evaluate these and potentially other options in the *2025 IEPR*. Public comments broadly support more comprehensive analysis of production pathways, including biogenic production.[95]

State and Federal Initiatives to Advance Hydrogen

Building off 10 years of investment in hydrogen refueling infrastructure supported by Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013), interest in the role of hydrogen in meeting climate goals has grown over the past several years. In 2022, California enacted Assembly Bill 209 (Committee on Budget, Chapter 251, Statutes of 2022) to create the Clean Hydrogen Program with $100 million of state general funds. The program is administered by the CEC and provides financial incentives for strategic, in-state projects to demonstrate or scale up clean and renewable hydrogen production, processing, delivery, storage, and end use. Eligible projects under AB 209 are specific to hydrogen derived from water using eligible renewable energy resources, as defined in Section 399.12 of the Public Utilities Code, or produced from these eligible renewable energy resources, including biomass. The program prioritizes projects that maximize air quality, equity, health, and workforce benefits.

On August 8, 2023, Governor Newsom directed GO-Biz to develop a strategy to create the hydrogen economy of the future. The Governor cited hydrogen as "an essential aspect of how we'll power our future and cut pollution." GO-Biz and state agency partners developed a framing document for the hydrogen strategy in December 2023, which outlines the core objectives and opportunities for stakeholders to engage in the development of the strategy.[96]

At the federal level, the United States Department of Energy (U.S. DOE) is implementing initiatives to reduce costs, support domestic production, and scale end use. The Inflation Reduction Act of 2022 provides 10 years of tax credits to hydrogen production projects that

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95 Green Hydrogen Coalition, California Hydrogen Business Council, California Hydrogen Coalition, SDG&E, and Mainspring Energy provided feedback in their comments to the draft *2023 IEPR* that the CEC should analyze diverse hydrogen production pathways, as well as compare in-state versus out-of-state resources. Comments are available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-01.

96 Governor Gavin Newsom press release. August 8, 2023. "Governor Newsom Announces New Strategy to Develop a Hydrogen Economy of the Future," https://www.gov.ca.gov/2023/08/08/governor-newsom-announces-new-strategy-to-develop-a-hydrogen-economy-of-the-future/.

California Hydrogen Market Development Strategy Objectives & Public Engagement. December 2023. https://business.ca.gov/wp-content/uploads/2023/12/H2-Strategy-Framing-Doc-12-26-23.pdf.

begin construction by 2033. The tax credits are up to $3 per kg and vary based on the carbon intensity of the hydrogen produced.[97]

On October 13, 2023, the U.S. DOE selected California to negotiate an award of up to $1.2 billion to launch a Clean Hydrogen Hub (H2Hub) in California, one of seven H2Hubs selected nationwide.[98] California's application was led by the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES),[99] a statewide public-private partnership with more than 400 partners organized around catalyzing California's clean renewable hydrogen market.[100] The initiative includes major clean and renewable hydrogen deployment clusters in the Greater Los Angeles Area, San Francisco Bay Area, Central Valley, Inland Empire, and other regions with high renewable energy resources, geologic storage possibilities, transportation corridors, and need for clean energy and reduced pollution. The partnership is focused on applications that are challenging to electrify, such as heavy-duty transportation segments, grid-supporting power plants, and cargo-handling equipment at ports (Figure 8). These early markets can help prepare for potential uses such as in heavy industry, aviation, and maritime operations while growing a trained workforce.[101]

97 U.S. DOE. Financial Incentives for Hydrogen Fuel Cell Projects web page. https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects.

98 U.S. DOE news release. October 13, 2023. "Biden-Harris Administration Announces $7 Billion for America's First Clean Hydrogen Hubs, Driving Clean Manufacturing and Delivering New Economic Opportunities Nationwide," https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving.

99 ARCHES webpage, https://archesh2.org/.

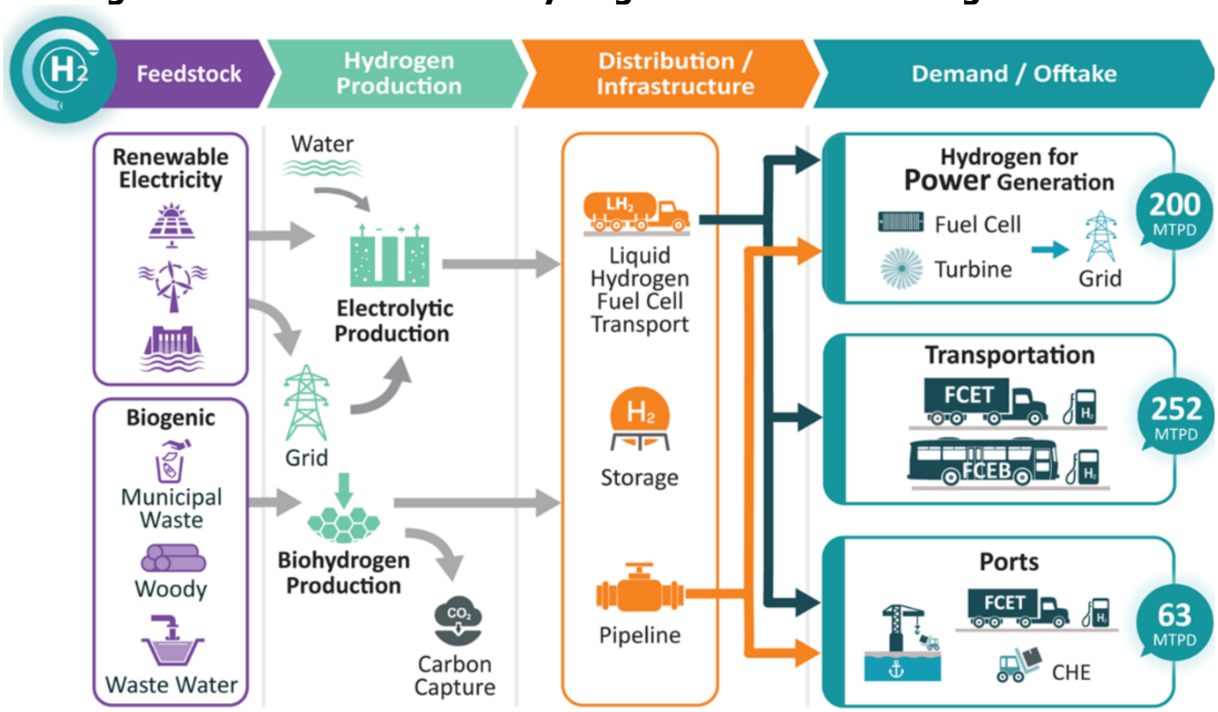
100 ARCHES news release. April 7, 2023. "California Submits Application to U.S. Department of Energy for Federal Funding to Become A National Hydrogen Hub," https://archesh2.org/california-submits-application-to-u-s-department-of-energy-for-federal-funding-to-become-a-national-hydrogen-h2-hub/.

101 September 8, 2023, IEPR workshop on the Potential Growth of Hydrogen recording. https://energy.zoom.us/rec/share/1WwljgFkd0UKaP2RlcNftajzTRvAZOMMtEKOgjzbA3u_LwGDXnepvwIv-gu6Ll8_.E3CN38DDZrWccAhm.

No industrial end uses are anticipated in the short term, but there may be opportunities to integrate industrial facilities based on the location, availability of infrastructure, and experience that can be leveraged through deployment of industrial hydrogen clusters.

Max, Jon. April 20, 2023. "Labor Unions Partner With ARCHES in Support of California Hydrogen Hub." *Hydrogen Fuel News,* https://archesh2.org/labor-unions-partner-with-arches-in-support-of-california-hydrogen-hub/.

Figure 8: Clean Renewable Hydrogen Production Through End Use



ARCHES projects will scale clean and renewable hydrogen production through electrolysis and biogenic feedstocks, delivery via trucks and dedicated pipelines, and end uses in heavy-duty transportation, ports, and electricity generation.

Source: ARCHES, Copyright ARCHES H2, LLC

To complement the strong momentum and alignment of state and federal opportunities and in response to direction in SB 1075, CARB, in consultation with CEC, CPUC, the California Workforce and Development Board, and other partner agencies, will be developing a comprehensive analysis of hydrogen. This analysis includes examining and making recommendations on the increased production, deployment, and use of low-carbon intensity hydrogen. CARB and other partner agencies will conduct a broad range of technical, market, and policy analyses that will support hydrogen production and use across many sectors of the economy, including those that are most difficult to decarbonize. These analyses will also support a broad range of other priorities, including air quality benefits and workforce development.

Background and Status of Clean and Renewable Hydrogen Production and Use in Electric and Transportation Sectors

As background for the CEC's analysis required by SB 1075, this section provides information on pathways for producing, delivering, storing, and using clean and renewable hydrogen in the electric and transportation sectors.

Status of Hydrogen Production

For 2018–2020, California is estimated to have produced 1.06 million metric tons (million MT) per year of hydrogen,[102] or about 10.6 percent of the national capacity. This hydrogen is produced at petroleum refineries and merchant hydrogen production plants — almost all of it is produced from fossil fuel feedstocks and almost all of it is consumed in refining and not used as a fuel. It is produced via steam methane reformation, a process in which methane (which itself is a GHG) is reacted with steam and air to produce hydrogen and results in carbon dioxide (another GHG) as a by-product. There are few large-scale, clean renewable hydrogen production plants operating in California.

Pathways for Clean and Renewable Hydrogen Production

Processes for producing clean and renewable hydrogen include electrolysis, thermochemical processing (such as steam methane reformation of non-fossil gas), and biological processes.[103] Electrolysis uses renewable electricity to split water into hydrogen and oxygen, with oxygen as

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102 CEC staff calculation. Used Documentation of California's 2000–2019 GHG Inventory, https://ww2.arb.ca.gov/applications/california-ghg-inventory-documentation, files for 2 – Industrial Processes and Product Use, 2H – Other, 2H3 – Hydrogen Production. Calculated the average of hydrogen production emissions from fuel conversion from fossil gas and refinery gas from 2018, 2019, and 2020, which is 5.50 $MMTCO_2e$/yr. Staff used 52 percent, the ratio of fuel conversion emissions to total emissions, calculated using Table 2 from Bonaquist, Dante. 2010. *Analysis of CO2 Emissions, Reductions, and Capture for Large-Scale Hydrogen Production Plants,* https://www.linde.com/-/media/linde/merger/documents/sustainable-development/praxair-co2-emissions-reduction-capture-white-paper-w-disclaimer-r1.pdf?la=en, to result in 10.57 $MMTCO_2e$/yr. Staff converted these emissions to tons of hydrogen produced using the GHG benchmark for on-purpose hydrogen gas production of 8.94 $MTCO_2e/MT\ H_2$ from CARB, unofficial electronic version of the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, Table 9-1: Product-Based Emissions Efficiency Benchmarks. https://ww2.arb.ca.gov/sites/default/files/2021-02/ct_reg_unofficial.pdf, and the GHG benchmark formula of 90 percent of the average emissions intensity from CARB. March 2014. Appendix A: Additions and Amendments to Product-Based Benchmarks in the Cap-and-Trade Regulation, pp. 19-20, https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2013/capandtrade13/2appabenchmarks.pdf (10.57 $MMTCO_2e$/yr / 8.94 $MTCO_2e/MT\ H_2$) * 0.9 = 1.06 MMT H_2/yr.

Hydrogen production capacity in the United States is estimated at around 10 MMT/yr, with variance depending on the source and inclusion of by-product hydrogen (U.S. DOE. October 1, 2019. "Current Hydrogen Market Size: Domestic and Global," https://www.hydrogen.energy.gov/pdfs/19002-hydrogen-market-domestic-global.pdf).

103 U.S. DOE. Hydrogen and Fuel Cell Technologies Office. "Hydrogen Production Processes." https://www.energy.gov/eere/fuelcells/hydrogen-production-processes.

Thermochemical processing uses heat and chemical reactions to release hydrogen from organic materials, such as fossil fuels and biomass, or from materials like water.

a by-product. As of May 2023, 2.5 percent of nationwide existing or announced electrolytic hydrogen production is in California.[104]

The consulting firm Energy and Environmental Economics (E3) estimated that the potential market size of long-duration hydrogen storage that could be produced through electrolysis using free renewable energy that would otherwise be curtailed in California to be 1.5–4.5 GW in 2035 and 5–10 GW in 2045.[105] The analysis concluded that the anticipated falling costs of electrolyzers paired with low-cost renewable electricity could lead to a lower levelized cost of energy for clean and renewable hydrogen, enabling it to compete with other storage technologies.

Forest biomass, agriculture residues, and municipal waste are routinely generated in the state and can result in the generation of GHGs if they are combusted directly or left to decompose. These materials can be used to make clean and renewable hydrogen through gasification or pyrolysis (thermochemical processes). Challenges that exist for this pathway include the availability and cost of collecting the biogenic feedstocks and for processing these feedstocks into hydrogen. Also, the GHG carbon dioxide (CO_2) is produced as a by-product of these processes. Gasification can convert biomass into a mixture of gases (mostly carbon monoxide, hydrogen, and CO_2) at high temperature and pressure. The resulting mixture of gases, known as *synthesis gas* or *syngas*, can be used to generate heat and power or to produce hydrogen. Pyrolysis operates at lower temperatures and pressures than gasification and can decompose biomass into gas, liquid, and solid products. Fast pyrolysis is a subcategory of pyrolysis that rapidly decomposes biomass, cut to smaller than 3 millimeters, with a high heating rate and reaction temperature, about 500 degrees Celsius.

A 2020 study by Lawrence Livermore National Laboratory is referenced in SB 1075 for "[highlighting] gasification of biomass to hydrogen as the most promising strategy for achieving negative carbon emissions in California."[106] The study evaluates approaches and costs of removing 125 million metric tons per year of CO_2 from the atmosphere to achieve carbon neutrality. The report identifies several pathways to produce hydrogen from biomass in

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104 Staff calculation from U.S. DOE data. Staff believes the U.S. DOE data to be more accurate than what it has been able to compile. See https://www.hydrogen.energy.gov/pdfs/23003-electrolyzer-installations-united-states.pdf. DOE reports electrolyzer capacity in kW, whereas electrolyzer manufacturers give it in cubic meters.

105 Energy and Environmental Economics. June 2020. *Hydrogen Opportunities in a Low-Carbon Future: An Assessment of Long-Term Market Potential in the Western United States*, https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf.

106 Baker, et. al. *Getting to Neutral: Options for Negative Carbon Emissions in California*. January 2020. Lawrence Livermore National Laboratory. LLNL-TR-796100. https://livermorelabfoundation.org/2019/12/19/getting-to-neutral/.

California, each requiring the collection and storage of CO_2 created during fuel conversion. According to the study, biomass gasification with capture and storage of the resulting CO_2 has the greatest potential for removing CO_2 at the lowest cost per ton.

Pathways to Deliver and Store Clean and Renewable Hydrogen

There are also different methods for delivering and storing hydrogen, which can have a significant impact on life-cycle GHG emissions. The delivery and storage methods are often determined by what the hydrogen will be used for and what volumes are required. Clean and renewable hydrogen that can be produced and stored on-site where it is consumed avoids the need for delivery but requires space on-site for production and storage equipment. Hydrogen has a low volumetric energy density, roughly one-third that of fossil gas,[107] which requires large-volume storage for gaseous hydrogen.[108] Compressing gaseous hydrogen to liquid hydrogen is energy intensive and can consume about 30 percent of hydrogen's energy content.[109] Further, there are potential hydrogen losses through evaporation, or "boil off" of liquified hydrogen. Clean and renewable hydrogen can be delivered by truck to where it will be used, but this will add costs and will generate GHG and other emissions from delivery trucks if they are not zero-emission vehicles. For applications that require large volumes of clean and renewable hydrogen such as use in electric power plants, delivery by pipeline may be the most feasible delivery pathway.

Hydrogen can be delivered in dedicated pipelines, and research is ongoing into potentially retrofitting existing gas pipelines to carry high percentage blends. There are about 1,600 miles of hydrogen pipeline in the United States, serving primarily refineries and chemical plants, while California has about 27 miles of dedicated hydrogen pipeline.[110] For comparison, there are about 300,000 miles of fossil gas transmission pipe[111] and 2.3 million miles of fossil gas

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107 U.S. DOE. July 2017. *Hydrogen Delivery Technical Team Roadmap,* https://www.energy.gov/eere/vehicles/articles/us-drive-hydrogen-delivery-technical-team-roadmap.

108 U.S. DOE. "Hydrogen Storage," https://www.energy.gov/eere/fuelcells/hydrogen-storage.

109 U.S. DOE. March 2023. "Pathways to Commercial Liftoff: Clean Hydrogen," https://liftoff.energy.gov/clean-hydrogen/.

110 Cerniauskas, Simonas, Lewis Fulton, and Joan Ogden. March 23, 2023. *Tech Brief: Pipelines for a Hydrogen System in California,* https://escholarship.org/content/qt1z0325v2/qt1z0325v2_noSplash_dd1436d7c9f63186dae7a2088f27c3aa.pdf.

111 PHMSA. *Annual Report Mileage for Natural Gas Transmission & Gathering Systems*, https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems.

distribution and service line pipe in the United States.[112] In California, there are an estimated 12,000 miles of fossil gas transmission pipe and 200,000 miles of fossil gas distribution and service line pipe.[113]

Hydrogen pipelines have operated safely, and construction of additional dedicated hydrogen pipelines in California is being considered for select locations where several large users are clustered such as ports, power plants, and industrial facilities. The United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) has regulated the safety of transporting hydrogen gas by pipeline since 1970.[114] The U.S. Department of Energy Pacific Northwest National Laboratory has developed a Hydrogen Tools Portal (h2tools.org) to support implementation of the practices and procedures to ensure safe handling and use of hydrogen.

For any delivery and storage pathway, including pipelines, potential hydrogen leakage must be monitored and minimized, as hydrogen is estimated to have a 100-year global warming potential (GWP)[115] of 11.6 ± 2.8 as it indirectly contributes to global warming by extending the lifetime of GHG in the atmosphere.[116]

Pathways to Use Clean and Renewable Hydrogen

Cost-competitiveness and emissions reductions also differ depending on how hydrogen is used. For example, it can be combusted in specialized turbines in a power plant, used to power fuel cells in heavy-duty vehicles, or as a heat source for high-temperature industrial processes like glass production. Hydrogen combustion, unlike traditional fossil fuel combustion,

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112 PHMSA. "Annual Report for Gas Distribution, Systems," https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems.

113 PHMSA. *Pipeline Mileage and Facilities*. Accessed January 3, 2024. https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-mileage-and-facilities.

114 PHMSA. *Hydrogen Gas: Pipeline Safety and Research and Development Program*. February 10, 2022, https://www.energy.gov/sites/default/files/2022-03/Bulk%20Storage%20Workshop_Day1_12.pdf.

115 *Global warming potential* is a common measure of how much energy the emissions of 1 ton of GHG will absorb over a given period, relative to the emissions of 1 ton of CO_2. The larger the GWP, the more that a given gas warms the Earth compared to CO_2 over a period, usually 100 years.

116 Sand, M., R. B. Skeie, M. Sandstad, et al. "A Multi-Model Assessment of the Global Warming Potential of Hydrogen." *Commun Earth Environ* 4, 203 (2023). https://doi.org/10.1038/s43247-023-00857-8. The uncertainty range is one standard deviation and covers soil uptake, photochemical production of hydrogen, the lifetimes of hydrogen and methane, and the hydroxyl radical feedback on methane and hydrogen. Fugitive hydrogen molecules are mostly removed (70 to 80 percent) by soils via diffusion and bacteria. The remainder (20 to 30 percent) reacts with naturally occurring hydroxyl radical (OH), which leads to a buildup of methane and ozone (both potent GHGs) and stratospheric cooling (also contributing to global warming).

does not produce CO_2; however, like fossil fuel combustion, it produces nitrogen oxides (NO_X) emissions — which lead to formation of the health-damaging pollutants ozone and particulate matter — but at potentially higher levels because of the increased flame temperature of hydrogen.[117] Refined calculations could provide a more accurate depiction of NO_X emissions levels from hydrogen combustion.[118] To reduce NO_X emissions during hydrogen combustion, system manufacturers integrate controls and purpose-built hydrogen combustors.[119] Hydrogen can also be used in zero-emission fuel cells to generate electricity, with water and heat as by-products. Fuel cells can be used in buildings to provide heat and electricity, in vehicles and electronic devices, and in community-scale microgrid systems for electricity generation.[120]

Status of Hydrogen in the Electric Power Generation Sector

There are several proposals to convert fossil gas power plants to run on hydrogen, first as a blend with natural gas and eventually shifting to 100 percent hydrogen. (See sidebar.) RD&D and pilots are a key strategy for bringing more hydrogen combustion projects to market. New technologies, such as Mitsubishi Power's dry, low-NO_X combustor, can operate on up to 30 percent hydrogen. Mitsubishi expects to complete testing on a technology that will allow 100 percent hydrogen firing by 2025.[121] Recently, Siemens Energy demonstrated a turbine running

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117 General Electric. March 2022. *Hydrogen for Power Generation: Experience, Requirements, and Implications for Use in Gas Turbines*. https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf. The magnitude of the increase in NO_X emissions will depend on the percentage of hydrogen in the fuel, and the specific combustion system and gas turbine operating conditions. The overall trend shows that at lower percentages of hydrogen the increase in NO_X emissions is minimal, but at 50 percent hydrogen (by volume), NO_X emissions could increase by as much as 35 percent. Extrapolating this data, gas turbine NO_X emissions could potentially double if operating at or near 100 percent hydrogen. This is based on preliminary laboratory data assuming hydrogen blended with fossil gas. Actual NO_X emissions may vary based on multiple factors including fuel composition, combustion operating parameters, etc.

118 Georgia Institute of Technology and EPRI. January 2022. *NOx Emissions from Hydrogen-Methane Fuel Blends.* This paper finds that, regardless of the actual NO_x emissions per unit of power, changes in fuel composition can indirectly influence the reported NO_x emissions due to methodologies used to measure and report NO_x emissions across a variety of fuel blends and devices. As a result, many studies could be interpreting their NO_x emissions incorrectly by as much as 40 percent against high-hydrogen systems. Simple changes in calculations could correct this issue.

119 LADWP noted in comments that the latest research suggests that NO_x emissions will stay the same or be slightly reduced using technologies for NO_x reduction during and after combustion. Three major turbine companies (GE, Siemens, and Mitsubishi) have announced goals to allow for increase hydrogen firing while limiting NO_x through dry low-emission NO_x combustors.

120 U.S. DOE web page, https://www.energy.gov/eere/fuelcells/fuel-cell-basics.

121 Mitsubishi Power. Hydrogen Gas Turbine web page. https://solutions.mhi.com/power/decarbonization-technology/hydrogen-gas-turbine/.

on 100 percent hydrogen[122] and expects to have 100 percent hydrogen gas turbines commercially available by 2030.[123] General Electric also has a goal to develop 100 percent hydrogen capability in its turbines by 2030.[124]

Proposed Utility Hydrogen Projects

PG&E is developing the Hydrogen to Infinity (H2∞) project, a large-scale research, demonstration, education, and market activation project for blending clean and renewable hydrogen into fossil gas transmission systems in Lodi (San Joaquin County). PG&E is collaborating with the City of Lodi, UC Riverside, Siemens Energy, GHD, and Northern California Power Agency (NCPA). The project includes hydrogen production by NCPA (described below) and testing of hydrogen blending into isolated transmission pipeline.

NCPA is developing the Lodi Hydrogen Center, which includes electrolyzers powered with renewable energy and using recycled water from the City of Lodi that can produce 8,760 MT per year of clean and renewable hydrogen. A 296 MW fossil gas power plant is being retrofit to be capable of combusting 45 percent hydrogen blends in 2026 and 100 percent hydrogen by 2028. The Lodi Hydrogen Center will also deliver clean and renewable hydrogen to refueling stations and the Port of Oakland to power Class 8 trucks and cargo handling equipment.

Southern California Gas Co. (SoCalGas) has proposed the Angeles Link project to convert up to four fossil-gas power plants to clean and renewable hydrogen and include a dedicated hydrogen pipeline system of 200 to 750 miles. The system is planned to serve hard-to-electrify industries, electric generation, and the heavy-duty transportation sector in the Greater Los Angeles Area. In December 2022, the CPUC approved SoCalGas Phase 1 feasibility studies.

SDG&E will test several use cases for hydrogen through the Palomar Energy Green Hydrogen Project.The system came on-line at the end of 2023 and includes on-site solar canopies and a 1.25 MW electrolyzer to create clean and renewable hydrogen. The primary use is blending hydrogen with fossil gas in the combustion turbine. The hydrogen produced onsite will also be used as a cooling gas in the plant's generators, and to fuel hydrogen fuel cell vehicles in the company's vehicle fleet. Other efforts include the Los Angeles Department of Water and Power's (LADWP's) upgrade plans at the Intermountain Power Plant (IPP) project in Delta,

122 Siemens Energy. HYFLEXPOWER press release web page, https://www.siemens-energy.com/global/en/home/press-releases/hyflexpower-consortium-successfully-operates-a-gas-turbine-with-.html.

123 Siemens Energy. September 13, 2022. Hydrogen-Ready for the Future web page, https://www.siemens-energy.com/global/en/news/magazine/2022/hydrogen-ready.html.

124 Simon, F. May 20, 2021. "GE Eyes 100% Hydrogen-Fueled Power Plants by 2030." https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/.

Utah, and the Scattergood facility in El Segundo (Los Angeles County). Construction on the IPP project began in 2022, with plans for clean and renewable hydrogen production with storage in underground salt caverns. The technology at IPP will be capable of blending up to 30 percent clean and renewable hydrogen[125] with fossil gas starting in 2025. The subsequent goal of reaching 100 percent clean and renewable hydrogen at IPP will depend on hydrogen supply availability and the advancement of the required technology to reach those scales.

At Scattergood Generating Station, LADWP has committed $800 million to replace the existing fossil gas generation capacity of Units 1 and 2 with new units that will have the capability to use renewable hydrogen fuel. LADWP hopes to similarly decarbonize its Harbor (in Wilmington), Haynes (in Long Beach), and Valley (in Sun Valley) Generating Stations, all used for firm capacity to ensure system reliability and resiliency. Conversion to clean and renewable hydrogen is critical for LADWP to meet its local goal of 100 percent clean energy by 2035.

Sources: Transcript from Sept. 8, 2023, IEPR workshop and CPUC Decision Approving the Angeles Link Memorandum Account to Record Phase One Costs, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K891/499891989.PDF.

According to the U.S. DOE, as of the end of December 2022, the United States had about 205 operating fuel cell electric power generators at 147 facilities, totaling about 350 MW of electric generation capacity. The nameplate capacities range from about 17 MW to 0.1 MW. Most of all operating fuel cells use pipeline fossil gas as the hydrogen source, but five use renewable gas.[126]

California has recently taken steps to add to its hydrogen fuel cell electric generation fleet. In September 2023, FuelCell Energy and Toyota completed the 2.3 MW Tri-Gen system that produces renewable electricity, renewable hydrogen, and water from directed biogas at the Port of Long Beach.[127] The electricity produced by this system will support port operations, which includes the processing of 200,000 Toyota and Lexus vehicles per year at the port. Excess electricity from this system will be delivered to SCE under California Bioenergy Market Adjustment Tariff, or BioMAT, program. In June 2023, Plug Power, Inc. announced that it will

125 In its written comments, LADWP uses the term "green hydrogen," but the CEC uses the term "clean and renewable hydrogen." LADWP. December 15, 2023. Los Angeles Department of Water and Power Comments – (Revised) Draft 2023 Integrated Energy Policy Report, https://efiling.energy.ca.gov/GetDocument.aspx?tn=253639&DocumentContentId=88876.

126 U.S. DOE. *Hydrogen Explained: Use of Hydrogen*. Accessed January 3, 2024. https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php.

127 *Biocycle* defines directed biogas as a concept where purified biogas (biomethane) injected into pipelines is delivered off-site from where the biogas is produced. "Directed Biogas to Power Fuel Cells," June 16, 2011, https://www.biocycle.net/directed-biogas-to-power-fuel-cells/.

provide 8 MW of hydrogen fuel cell power for the Energy Vault Holdings, Inc. microgrid in Calistoga (Sonoma County).[128] Plug Power expects that this facility will become operational by the third quarter of 2024.[129]

Status of Hydrogen in the Transportation Sector

According to CEC analysis of California Department of Motor Vehicles data on the Zero Emission Vehicle (ZEV) Dashboard,[130] cumulative sales or leases of light-duty fuel-cell electric vehicles (FCEVs) in California between 2010 and the third quarter of 2023 number 17,442, while 11,897 FCEVs were registered in the state at the end of 2022. There were 134 medium- and heavy-duty (MDHD) FCEVs (all transit buses) registered in California at the end of 2022. As of November 2023, 66 hydrogen refueling stations have achieved open retail status, of which 12 have been temporarily nonoperational for more than 30 days, with an expectation of 130 stations by 2027. At least seven of those stations should be capable of fueling MDHD vehicles as well as light-duty vehicles. The state is also funding public and private hydrogen stations for MDHD through the EnergIIZE (Energy Infrastructure Incentives for Zero-Emission) Commercial Vehicles grant program. As of November 2023, the program had provided funding for 59 dispensers.

California is a leading region in the world for deployment of FCEVs and hydrogen infrastructure, together with South Korea, China, Japan, and Germany. According to *Deployment of Fuel Cell Vehicles in Road Transport and the Expansion of the Hydrogen Refueling Station Network: 2023 Update* by the Technology Collaboration Programme on the Research, Development, and Demonstration on Advanced Fuel Cells (AFC TCP),[131] China had 320 hydrogen stations, the most in the world, followed by South Korea with 213, Japan with 164, and Germany with 95. Hydrogen refueling is expected to increase across the European Union (EU) because of newly adopted regulations mandating hydrogen filling stations every

128 Plug Power Inc. June 9, 2023. "Energy Vault Selects Plug Power to Supply 8 MW of Hydrogen Fuel Cells as Part of Hybrid Microgrid Back-Up System for PG&E and the City of Calistoga," https://www.ir.plugpower.com/press-releases/news-details/2023/Energy-Vault-selects-Plug-Power-to-Supply-8-MW-of-Hydrogen-Fuel-Cells-as-part-of-hybrid-microgrid-back-up-system-for-PGE-and-the-city-of-Calistoga/default.aspx.

129 Ibid.

130 Zero Emission Vehicle and Infrastructure Statistics web page, https://www.energy.ca.gov/data-reports/energy-insights/zero-emission-vehicle-and-charger-statistics. Accessed December 20, 2023.

131 Remzi Can Samsun, Michael Rex. 2023. *Deployment of Fuel Cell Vehicles in Road Transport and the Expansion of the Hydrogen Refueling Station Network: 2023 Update*. Technology Collaboration Programme on the Research, Development and Demonstration on Advanced Fuel Cells. https://www.ieafuelcell.com/fileadmin/publications/2023/2023_Deployment_of_Fuel_Cell_Vehicles_and_Hydrogen_Refueling_Station.pdf.

200 kilometers (124 miles) along the EU's core roads by 2031.[132] South Korea led in the number of light-duty FCEVs with 29,337 vehicles and 286 nonpassenger FCEVs (buses, commercial vehicles, and trucks) as of the end of 2022. Japan had 7,619 light-duty FCEVs and 124 nonpassenger FCEVs. Germany had 2,201 light-duty FCEVs and 141 nonpassenger FCEVs. China led nonpassenger FCEV deployment with 13,264 vehicles, and for the first eight months of 2023, 10 percent of China's MDHD zero-emission truck sales were FCEV.

Some challenges exist for hydrogen fuel and station logistics. Hydrogen fuel is often sourced from fossil sources (for example, methane) and uses carbon offsets to reduce the carbon footprint. Longer term, renewable hydrogen must be a critical component to fully achieve state goals for clean energy. With expected improvements in electrolysis, renewable hydrogen is likely to become more common in the next few years. Using biomass waste streams is another pathway to producing renewable hydrogen. Similar to gasoline, hydrogen must also be trucked to stations in most cases, but the associated energy impact from trucking the hydrogen is small.

Analysis of Potential Use of Clean and Renewable Hydrogen in the Electric and Transportation Sectors

The trajectory of the use of hydrogen in California to meet the state's clean energy goals is difficult to model, given the variety of potential production approaches (and changing costs), transportation options, and end uses. Given these market conditions, CEC staff explored several scenarios for the potential growth of clean and renewable hydrogen to provide perspective on the potential opportunities and challenges as a strategy to support decarbonizing the electricity and transportation sectors in response to SB 1075. Staff quantified the upstream production requirements — for example, the capacity of new electrolyzers, electricity, and water consumption — associated with different levels of clean and renewable hydrogen adoption.[133] This is a preliminary analysis and focuses on electrolytic production of hydrogen in California. The CEC will conduct a more comprehensive analysis for the *2025 IEPR*, and that analysis will include a broader set of options for producing clean and renewable hydrogen, including from biogenic sources, as well as options such as importing

132 European Union. 2023. *Regulation of the European Parliament and of the Council on the Deployment of Alternative Fuels Infrastructure, and Repealing Directive 2014/94/EU,* https://data.consilium.europa.eu/doc/document/PE-25-2023-INIT/en/pdf.

133 The initial analysis was reported on at the September 8, 2023, IEPR Workshop on the Potential Growth of Hydrogen, https://www.energy.ca.gov/event/workshop/2023-09/iepr-commissioner-workshop-potential-growth-hydrogen.

hydrogen. The analysis also will include options for generating and transporting clean and renewable ammonia and conversion to hydrogen for use.

Clean and Renewable Hydrogen Production via Electrolysis

The scenarios developed for this report assume all clean renewable hydrogen is produced via electrolytic conversion of water using renewable electricity. The analysis was based on the commercial availability of the technology, as well as studies indicating the large potential for electrolytic hydrogen. For power plants, there is also the possibility of collocating electrolytic production on site, which avoids needing hydrogen delivery via pipeline or truck. Staff estimated the number of electrolyzers; associated energy use, water, and land requirements; and capital requirements to produce the volume of electrolytic renewable hydrogen explored in the electric and transportation sector scenarios. Table 2 provides the electrolyzer parameters used in the analyses.

To estimate the input requirements for electrolytic hydrogen production, staff identified the largest commercially available proton exchange membrane (PEM) electrolyzer.[134] PEM electrolyzers can rapidly ramp up and down production, making them well-suited for production from variable renewable generation. The Cummins HyLYZER® 4000 can produce about 0.360 MT hydrogen per hour (4,000 normal cubic meters of hydrogen per hour) with an efficiency of about 50 MWh/MT hydrogen produced. Each HyLYZER consumes about 9,000 liters of water per MT hydrogen produced (roughly 2,378 gallons per MT of hydrogen).[135] The footprint of each HyLYZER is reported as 34 by 50 feet or 1,700 square feet (0.039 acres) per electrolyzer installed. Several electrolyzers would be needed to produce enough hydrogen to fuel transportation applications or electric power plants. While the CEC focused on PEM electrolyzers for this analysis, CEC notes that the electrolyzer industry is rapidly evolving, and manufacturers of alkaline fuel cells are improving their performance to be rampable. The CEC will broaden its analysis to include other electrolyzer types in the *2025 IEPR.*

134 A *proton exchange membrane* (PEM) is a semipermeable membrane used in some fuel cells and electrolyzers to separate hydrogen and oxygen gases and electrically insulate the two electrodes while allowing passage of protons. There are other types of electrolyzers that differ with respect to feedstock, electrolyte, and operating parameters.

135 Cummins. 2021. *Hydrogen: The Next Generation,* https://www.cummins.com/sites/default/files/2021-08/cummins-hydrogen-generation-brochure-20210603.pdf.

Estimates of PEM electrolyzer capital expenditure costs and potential reductions vary widely.[136] Today, the cost for PEM electrolyzers is generally greater than $1,100 per kW.[137] Component and system costs are forecast to decline significantly over the coming decades with growing manufacturing volumes,[138] with some estimates reaching $350 per kW by 2030.[139] Based on a literature search and accounting for potential future cost reductions, staff estimates an average equipment cost of $586 per kW and a total capital requirement of $880 per kW for electrolyzers between now and 2045.[140] This average value assumes electrolyzers are purchased over the next 20 years and that equipment costs come down from $1,000/kW to $175/kW by 2045. The estimated capital requirement does not include any costs associated with compression or liquefaction of the hydrogen produced.

Beyond the capital cost of electrolyzers, production plants would have fixed and variable operations and maintenance costs, with the cost of electricity generally being the largest contributor.[141] Staff estimated the amount of new renewable generation capacity needed to produce clean and renewable hydrogen via electrolysis. While there is potential for producing electrolytic hydrogen using curtailed electricity from existing renewable resources, which would reduce the amount of new generation needed, additional analysis is needed to evaluate the cost-effectiveness of this approach given seasonal and hourly variability in curtailment.

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136 Christensen, A. 2020. *Assessment of Hydrogen Production Costs From Electrolysis: United States and Europe*. Produced for the International Council on Clean Transportation, https://theicct.org/wp-content/uploads/2021/06/final_icct2020_assessment_of-_hydrogen_production_costs-v2.pdf.

137 International Energy Agency (IEA) webpage. "Tracking Electrolyzers," https://www.iea.org/energy-system/low-emission-fuels/electrolysers#tracking.

138 Böhm, et al. "Estimating Future Costs of Power-to-Gas – A Component-Based Approach for Technological Learning." *International Journal of Hydrogen Energy,* November 2019, DOI: 10.1016/j.ijhydene.2019.09.230, https://www.sciencedirect.com/science/article/abs/pii/S0360319919337061.

139 Viswanathan, V., et al. Pacific Northwest National Laboratory. 2022. *Energy Storage Grand Challenge Cost and Performance Assessment*, https://www.pnnl.gov/sites/default/files/media/file/ESGC%20Cost%20Performance%20Report%202022%20PNNL-33283.pdf.

140 The total capital requirement assumes a 50 percent markup over the equipment cost and includes items such as financing cost and engineering, procurement and contracting cost, other owner's costs. See National Energy Technology Laboratory *Quality Guidelines for Energy System Studies: Cost Estimation Methdology for NETL Assessments of Power Plan Performance*, https://www.netl.doe.gov/projects/VueConnection/download.aspx?id=1b2d7a00-454c-42ea-90b2-11791be40f6c&filename=QGESSCostEstMethodforNETLAssessmentsofPowerPlantPerformance_022621.pdf, p. 10.

141 International Renewable Energy Agency web page "Electrolyser Costs," https://www.irena.org/Energy-Transition/Technology/Hydrogen/Electrolyser-costs.

Table 2: Representative Electrolyzer for Clean and Renewable Hydrogen Production

Parameter	Value	Units
Annual hydrogen production rate per electrolyzer	3,149	MT/year
Equivalent power rating (nominal)	20	MW
Average electrolyzer total capital requirement, 2023-2045	880	$/kw
Water consumption per unit hydrogen produced	2,378	gallons/MT
Electricity consumption per unit hydrogen produced	50	MWh/MT

Source: CEC

Preliminary Analysis of Using Clean and Renewable Hydrogen in Electric Power Generation

For this initial analysis of potential adoption of hydrogen in the electricity sector, staff did not conduct new capacity expansion modeling and instead developed two scenarios from previous analyses focused on California.

The first scenario builds from the 2022 Scoping Plan Update. While the *2022 Scoping Plan Update* includes 9 GW capacity of hydrogen-based electricity generation, these power plants are never dispatched because of cost; therefore, no hydrogen is used in the electric sector. Consequently, there is no estimate from the *2022 Scoping Plan Update* for clean and renewable hydrogen that might be used for electricity generation. Instead, CEC staff estimated the amount of electrolytic hydrogen needed to replace the 0.226 exajoules of energy contained in fossil gas that the *2022 Scoping Plan Update* anticipates being combusted in power plants for electricity production in 2045.[142] Conservatively assuming a lower heating value of 120 MJ per kg of hydrogen, it would require about 1.88 million MT to fully replace fossil gas estimated to be used in the electric sector in 2045. This scenario can be considered as a high bookend of potential growth of hydrogen in the electric power sector.

To provide another point of comparison, CEC developed a scenario of growth of clean renewable hydrogen in the electricity sector based on a report developed for the CEC by University of California at Irvine (UCI).[143] The scenario considers projected resource buildouts where hydrogen could provide on-call, or dispatchable, electricity like that provided by energy storage or geothermal resources. The UC Irvine analysis assumed that clean renewable hydrogen replaces half of the new storage and geothermal capacity identified in the RESOLVE

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142 See row 6 of the "Electric Sector Combusted Fuels" (shown in exajoules) in the *2022 Scoping Plan Update* work papers: https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx.

143 Reed, Jeffrey et al. 2020. *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*, https://efiling.energy.ca.gov/getdocument.aspx?tn=233292.

model used for integrated resource planning to achieve an 80 percent renewable portfolio standard. The authors estimate that about 350,000 MT of clean and renewable hydrogen could be used in for electricity generation in 2045, which is about 18 percent of the upper bookend of replacing all fossil gas.

Staff estimated the financial and resource requirements for producing 1.88 million MT (replacing all fossil gas in the *2022 Scoping Plan Update analysis*) or 350,000 MT per year (UCI scenario) of electrolytic hydrogen using the largest commercially available electrolyzer described above operating with an assumed capacity factor of 65 percent.[144] Table 3 compares the results of the two scenarios in terms of:

- Number of electrolyzers needed to produce the hydrogen.
- Renewable electricity, generation capacity, land, and water requirements.
- Capital requirement for the electrolyzers and electricity cost to operate them.

The total capital requirement for electrolyzers in the two scenarios is $16.2 billion and $3 billion, respectively, with the annual cost of electricity to power the electrolyzers at $18.8 billion and $3.5 billion, respectively. The estimated annual electricity cost assumes an average cost of $0.20 per kWh of electricity, which is near the average industrial rate in California.[145] If all the hydrogen produced is eligible for the full IRA production tax credit of $3 per kg, the annual tax credit value would be $5.6 billion and $1 billion for the two scenarios, respectively, which would offset roughly one-third of the annual electricity cost. These preliminary estimates do not include other important cost factors such as land, equipment for compression or liquefaction, and infrastructure for delivery or storage. These estimates are illustrative and directional, as many factors, including use of otherwise curtailed renewable energy, will impact any eventual energy, renewable capacity, and land requirements.

144 Electrolyzer capacity factor can vary widely based on different operator decisions and is closely related to the sourcing of electricity. Electrolysis powered entirely from off-grid renewables will generally have a lower capacity factor but may lower levelized electricity costs with lower marginal GHG emissions. Conversely, grid-tied electrolyzers can generally be operated at higher capacity factors but may have higher electricity prices associated with transmission and distribution charges, as well as potentially higher marginal emissions depending on the emission intensity of electricity sourced from the grid.

145 Energy Information Agency (EIA). "Electric Power Monthly Table 5.6.A Average Price of Electricity to Ultimate Customers by End-Use Sector by State," October 2023 and 2022. https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

Table 3: Scenarios of Clean and Renewable Hydrogen in the Electric Sector

Scenario Factors	2022 Scoping Plan Update*	UCI Study**	Units
Hydrogen consumed in 2045	1,883,960	350,000	MT per year
Electrolyzers (65 percent capacity factor)	921	171	-
Total capital requirement for electrolyzers	$16.2	$3.0	Billion dollars
Water consumed in hydrogen production	4.4	0.8	Billion gallons per year
Electricity consumed in hydrogen production	94.2	17.5	Terawatt-hours (TWh) per year
Total cost of electricity to power electrolyzers (assuming $0.20 per kWh)	$18.8	$3.5.M	Billion dollars per year
Capacity of renewables to generate electricity for hydrogen production (30 percent capacity factor)	35.8	6.6	GW
Land requirements for capacity of renewable generation (assuming all solar)	250,900	46,610	Acres

***The "Scoping Plan Update" scenario reflects CEC staff's estimate of the amount of clean and renewable hydrogen required to replace fossil gas combusted for electricity generation in 2045 as reported in the CARB *2022 Scoping Plan Update*.**

****The "UCI Study" estimated 350,000 metric tons of clean and renewable hydrogen used in 2045. CEC staff estimated the resources needed to produce that quantity of hydrogen via electrolysis using the same assumptions applied to the 2022 Scoping Plan Update scenario.**

Source: CEC, Land uses estimates are based on Bartridge, Jim, Melissa Jones, Eli Harland, Judy Grau. 2016. *Final 2016 Environmental Performance Report of California's Electrical Generation System*. CEC. Publication Number: CEC-700-2016-005-SFhttps://efiling.energy.ca.gov/GetDocument.aspx?tn=214098&DocumentContentId=24638

There will also be costs associated with retrofits to existing gas power plants to enable them to combust pure hydrogen. Because of the lower volumetric energy density of hydrogen relative to fossil gas, plants will likely need modifications to accept the higher flow rate of hydrogen compared to fossil gas unless the power plant output is reduced. Modifications could entail changes to components such as piping, blending equipment, as well as flow monitoring and controls. It might also involve changing operating pressure and the attendant impacts on the turbine and associated equipment. Estimates for upgrading power plants to burn 100 percent hydrogen range from $100/kW to 20 percent of new turbine cost (about $170/kW for combined turbines and $240/kW for combined-cycle gas turbines). For example, NCPA has estimated that changes to the Lodi Energy Center to accommodate up to 100 percent hydrogen by 2028 will cost $225 million, including the cost of storage.[146] Given the wide range

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146 NCPA. See "Lodi Hydrogen Center: The Hydrogen Transition" presentation of Randy Howard at September 8, 2023, IEPR workshop available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=252176&DocumentContentId=87175. It is not clear if the cost will allow Lodi's maximum output to remain at the certificated 225 MW.

of factors that can affect the cost of retrofits — and the considerable uncertainty about the total number and size of power plants needed — staff did not estimate the overall cost to retrofit power plants to operate on clean and renewable hydrogen in this scenario.

When the Hydrogen Is Needed Will Impact Electrolyzer and Storage Requirements

The estimates above are based on total annual energy consumption and do not account for when the retrofit power plants are required to run, how much electrolytic hydrogen is needed at any given moment, and how it could be delivered to or stored at each plant (or both). In practice, demand for hydrogen to produce electricity is likely to be highly variable, with many hours consuming none (that is, when renewable electricity production exceeds demand) and other hours potentially consuming substantial amounts (that is, during periods of limited renewable generation).

There is a complex interaction between instantaneous demand for electrolytic hydrogen, the number of electrolyzers needed to produce it, and the amount of storage needed. If a large fraction of the annual hydrogen consumption assumed in the two scenarios occurs in only a few hours, it will require larger numbers of electrolyzers to produce it or substantial amounts of storage. For example, if sufficient electrolytic hydrogen is needed to power all 33.3 GW of fossil gas plant capacity retained in the *2022 Scoping Plan Update* in 2045, then more than 5,340 of the 20 MW equivalent nominal power rating electrolyzers described above would be needed without any hydrogen storage capacity. With storage capacity, fewer electrolyzers would be needed.

This preliminary analysis did not evaluate the requirements or costs of storage or delivery infrastructure for clean and renewable hydrogen. If the electrolyzers are not colocated with the electricity generation plant, the clean and renewable hydrogen would need to be delivered via pipeline, an option that requires consideration of complex factors. Analysis by LADWP shows that a single utility-scale gas turbine consuming 100 percent hydrogen would require five liquid hydrogen trucks per hour or 40 gaseous hydrogen trucks per hour.[147] Further, there are additional costs, energy requirements, and leakage risks associated with compression or liquefaction of the hydrogen when delivered in tankers. Delivery via pipelines is better suited for moving large volumes of hydrogen, and some dedicated hydrogen pipelines have been proposed by regulated utilities[148] or are already in operation by private entities.[149]

147 Comments from LADWP. December 15, 2023, https://efiling.energy.ca.gov/GetDocument.aspx?tn=253639&DocumentContentId=88876.

148 SoCalGas Angeles Link web page, https://www.socalgas.com/sustainability/hydrogen/angeles-link.

149 Air Products. 2023. Comments on IEPR Workshop, https://efiling.energy.ca.gov/GetDocument.aspx?tn=252517&DocumentContentId=87593.

Future Analyses and Barriers That Need to Be Addressed

The preliminary scenarios considered here point to the need for additional analyses and identify potential barriers to the growth of clean and renewable electrolytic hydrogen in the electric power sector.

- **Alternative production and conversion pathways:** This analysis focused on clean and renewable hydrogen production via electrolysis and did not evaluate production from biomass gasification or reformation of biogas. These various pathways will compete for market share of in-state production, and increased production from biogenic materials could reduce requirements for installation of new renewables. Similarly, this analysis did not consider fuel cells for electricity generation. Future analyses should evaluate a broader range of feedstocks and production pathways, including the potential role for out-of-state production. Similarly, future analyses should consider electricity generation from fuel cells as an alternative to combustion in retrofit power plants.
- **Efficiency and additional renewables:** There are inherent inefficiencies in converting renewable electricity to electrolytic hydrogen and then back to electricity. Significant new renewable electricity generation will be required to produce large volumes of electrolytic hydrogen, which could strain already congested transmission systems and exacerbate interconnection challenges (Chapter 1). But flexible electrolyzer operation could also create new opportunities to integrate more renewables and limit curtailment. Adoption of clean and renewable electrolytic hydrogen for electric power applications should prioritize challenging applications such as long-duration storage that are challenging to accomplish with existing technologies.
- **Colocation of electrolyzers and storage at retrofit power plants:** Colocating electrolyzers at power plants could reduce the need for delivery by trucks or pipelines. However, colocation will require on-site hydrogen storage, and there may be limited numbers of existing power plants with sufficient space, which will limit opportunities for colocation. Future analyses should identify which plants have adequate space and explore tradeoffs between colocation and development of delivery infrastructure.
- **Emissions and equity considerations:** Combusting hydrogen can result in greater oxides of nitrogen (NOx) emissions because of the higher flame temperature of hydrogen combustion relative to fossil gas combustion.[150] (Electricity generation from

150 General Electric. March 2022. "Hydrogen for Power Generation: Experience, Requirements, and Implications for Use in Gas Turbines," http://www.ge.com/gas-power/future-of-energy). The magnitude of the increase in NO_X emissions will depend on the percentage of hydrogen in the fuel, and the specific combustion system and gas

hydrogen using fuel cells does not create NO_X emissions). Improved methods for calculating NO_X emissions should be considered to help assure more accurate accounting.[151] Existing aftertreatment technologies must be implemented to ensure that hydrogen combustion complies with applicable criteria air pollutant emission standards, particularly for plants within or near communities. NO_x mitigation and strategies for limiting other emissions will be considered as part of the technical analyses required under SB 1075.

- **Leakage:** Hydrogen can leak throughout production, delivery, storage, and end-use activities. Because hydrogen is an indirect GHG that can contribute to global warming, leakage can undermine potential climate benefits. One industry estimate of overall leakage ranges from about 4.2 percent (compressed gas storage, transport, and refueling) to about 10 to 20 percent (liquid storage, transport, and refueling), with a suggestion to the European Commission Joint Research Centre to set specific targets for lower leak rates (1 to 5 percent).[152] CEC plans to implement these targets into its Clean Hydrogen Program, and the U.S. DOE and others have funded development of leak detection and mitigation technologies.
- **Power plant retrofits and other costs:** As noted above, several other important cost factors need to be evaluated, including the cost to retrofit existing power plants to be able to combust hydrogen, delivery via pipelines or trucks or both, compression and liquefaction equipment, and storage facilities.

CEC will explore the above topics in the *2025 IEPR*. Further, CEC will leverage analysis being conducted for the next SB 100 report to be published in early 2025 to help reframe the scenarios to be analyzed. CEC also intends to use the results of the analysis being led by CARB in 2024 to meet its SB 1075 requirements as well as any preliminary information from ARCHES to scope the analysis for the *2025 IEPR* on hydrogen.

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turbine operating conditions. The overall trend shows that at lower percentages of hydrogen the increase in NO_X emissions is minimal, but at 50 percent hydrogen (by volume), NO_X emissions could increase by as much as 35 percent. Extrapolating these data, gas turbine NO_X emissions could double if operating at or near 100 percent hydrogen. This estimate is based on preliminary laboratory data assuming hydrogen blended with natural gas. Actual NO_X emissions may vary based on multiple factors including fuel composition, combustion operating parameters, etc.

151 Georgia Institute of Technology and EPRI. *NOx Emissions from Hydrogen-Methane Fuel Blends.* January 2022.

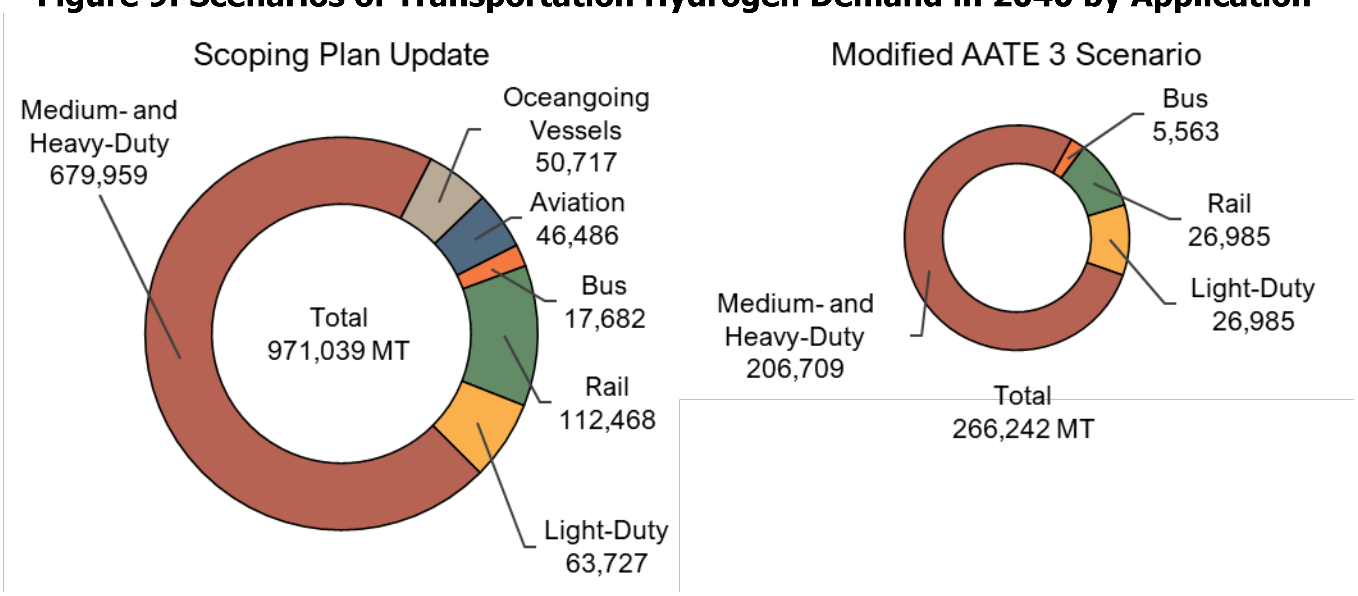
152 Arrigoni, A. and Bravo Diaz, L., Hydrogen Emissions From a Hydrogen Economy and Their Potential Global Warming Impact, EUR 31188 EN, Publications Office of the European Union, Luxembourg, 2022, ISBN 978-92-76-55848-4, doi:10.2760/065589, JRC130362, p. 16.

Scenarios for Using Hydrogen in the Transportation Sector

The *2022 Scoping Plan Update* projects adoption of hydrogen in several transportation applications, including passenger and commercial vehicles, freight and passenger rail, and oceangoing vessels. The total volume of hydrogen used across these transportation applications in the *2022 Scoping Plan Update* grows from about 12,300 MT in 2023 to around 971,000 MT in 2040. The *2022 Scoping Plan Update* assumes a variety of hydrogen production pathways and that none of it is produced from in-state, grid-tied renewables.

CEC staff developed a second scenario of potential adoption of hydrogen in the transportation sector using the modeling tools used in the CEC's transportation energy demand forecast, with several modifications. Specifically, staff started with the hydrogen demand forecast in the Additional Achievable Transportation Electrification Scenario 3 (AATE 3), which includes about 233,690 MT of hydrogen used in light-duty vehicles and medium- and heavy-duty trucks in 2040. Staff then added an estimate of hydrogen demand from transit buses in 2040 based on a high-growth assumption that the fuel cell electric bus (FCEB) population would ramp up to double the baseline forecast by 2030. Beyond 2030, the FCEB population remained twice the originally forecast FCEB population. Staff included potential hydrogen demand from passenger and freight rail using a logistic growth model to displace locomotive diesel demand with hydrogen demand starting in 2028 for passenger locomotives and 2030 for freight locomotives. While some forecasting tools were used, these scenarios do not have the same level of validation as the forecast and are separate from the IEPR Forecast that is used for planning. The hydrogen consumed in different transport subsectors in 2040 for the two scenarios is shown in Figure 9.

Figure 9: Scenarios of Transportation Hydrogen Demand in 2040 by Application



The *2022 Scoping Plan Update* (left) and modified AATE 3 (right) scenarios of clean and renewable hydrogen consumption in transportation applications in 2040 differ in the total amount of metric tons per year, but both show the greatest demand in medium- and heavy-duty transport applications.

Source: CEC

The modified AATE 3 scenario does not include potential hydrogen demand from aviation or oceangoing vessels, although demand from these applications is relatively small in the *2022 Scoping Plan Update* compared to medium- and heavy-duty transport. Nonetheless, because the CARB *2022 Scoping Plan Update* includes transportation activities not considered in the modified AATE 3 scenario, the two are not directly comparable. CEC staff is developing hydrogen demand scenarios for aviation and a comparable approach to oceangoing vessels and will include these in future analyses for the *2025 IEPR*.[153]

Like the electricity generation analysis above, CEC staff explored an upper bound of what new renewable electricity and generation capacity could be required if all the transportation sector hydrogen consumed in 2040 were produced by electrolyzers with the parameters described in Table 2. The results are shown in Table 4.

Table 4: Scenarios of Clean and Renewable Hydrogen in the Transportation Sector

Scenario Factors	2022 Scoping Plan*	Modified AATE 3**	Units
Clean and renewable hydrogen in 2040	971,049	307,771	MT per year
Electrolyzers (65 percent capacity factor)	475	151	-
Total capital requirement for electrolyzers	$8.3	$2.6	Billion dollars
Water consumed in in hydrogen production	2.3	0.7	Billion gallons per year
Electricity consumed produce hydrogen via electrolysis	48.5	15.3	TWh per year
Total cost of electricity to power electrolyzers (assume average cost of $0.20 per kWh)	$9.7	$3.0.	Billion dollars per year
Capacity of renewables to generate electricity for hydrogen production (30 percent capacity factor)	18.4	5.8	GW
Land requirements for capacity of renewable generation (assuming all solar)	129,325	40,989	Acres

***The "Scoping Plan Update" scenario reflects the quantity of hydrogen reported used in transportation in 2040 as reported in the CARB *2022 Scoping Plan Update*.**

****The "Modified AATE3" scenario is based on modifications made by CEC staff to existing transportation modeling tools used in the California Energy Demand Forecast. CEC staff then estimated the resources needed to produce that quantity of hydrogen via electrolysis using the same assumptions applied to the 2022 Scoping Plan Update scenario.**

Source: CEC

153 Another consideration in this matter is that CEC transportation energy demand modeling concerns fuels used for energy, while the CARB scoping plan considers energy demand in terms of GHG reduction. As a result, CARB considers only aviation fuel demand for emissions attributed to in-state air travel. Most air travel is for out-of-state flights, so comparison of aviation will be difficult. CEC staff will account for instate and out-of-state air travel to allow for some comparison.

Sensitivity Analysis of Medium and Heavy-Duty Vehicle Adoption to Cost

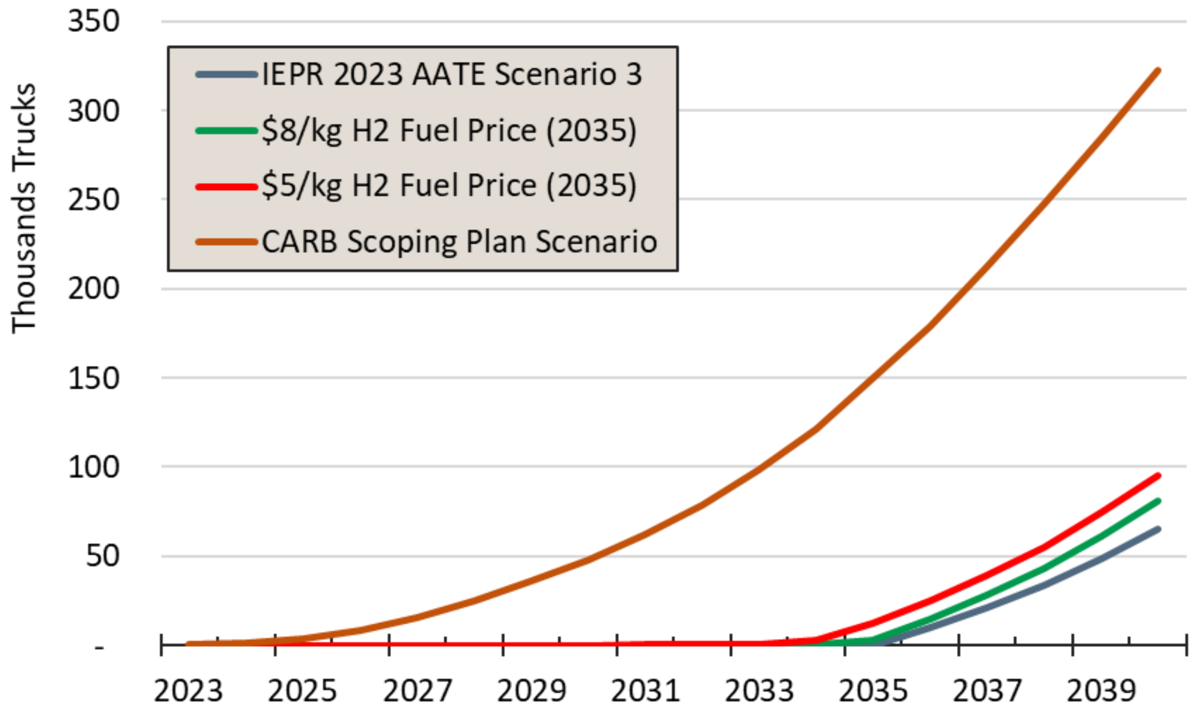
In both the *2022 Scoping Plan Update* and the modified AATE 3 scenarios, medium- and heavy-duty vehicles account for about 70 percent of transportation sector hydrogen demand in 2040. Because of this significant share of demand, CEC staff conducted further sensitivity analyses to explore how changes in vehicle and hydrogen fuel price impact potential adoption in Class 6 and 8 freight trucks.[154] Demand for new freight trucks is derived from a freight movement forecast, freight movement and load factor per truck, and calibrated truck population dynamics. A truck choice model is used to determine the fuel types of new vehicle additions to the truck population for each forecast year to meet the demand for freight movement. The truck choice model responds to economic inputs such as truck and fuel price, with lower prices for a vehicle or fuel type (compared to other technologies and fuels) driving greater adoption.

Staff evaluated the sensitivity of the truck choice model by assuming rapid reductions in the price of hydrogen fuel and the purchase price of FCEV trucks. This analysis is exploratory and not meant to reflect actual or even realistic cost declines, and significant uncertainty remains regarding how prices will evolve in the future. Staff modified the forecast of hydrogen truck prices in Classes 6 and 8 to decline quickly through 2040. For example, staff assumed that a hydrogen fuel cell Class 8 long-haul tractor would reach price parity with a diesel alternative at roughly $170,000 in 2040, declining from about $700,000 in 2027. Similarly, staff explored two scenarios of hydrogen fuel prices declining from a 2023 price of about $18 per kilogram and stabilizing at $8 or $5 per kg in 2035.

The impact of reducing fuel and truck prices on the population of freight trucks for the different scenarios considered is illustrated in Figure 10. While FCEV truck populations increase with reductions in vehicle and fuel prices, populations remain significantly lower than reflected in the *2022 Scoping Plan Update*. This difference is primarily due to CARB having FCEV as an available option for a wider array of freight truck classes and with an earlier introduction year. The CEC model introduces FCEVs only in Class 6 and certain types of long-haul Class 8 trucks. Staff will continue to monitor announcements and make necessary updates for the 2025 SB 1075 analysis.

154 Class 6 trucks weigh between 19,501 and 26,000 pounds. Class 8 trucks weigh 33,001 pounds and greater.

Figure 10: Freight FCEV Population for Preliminary Scenarios

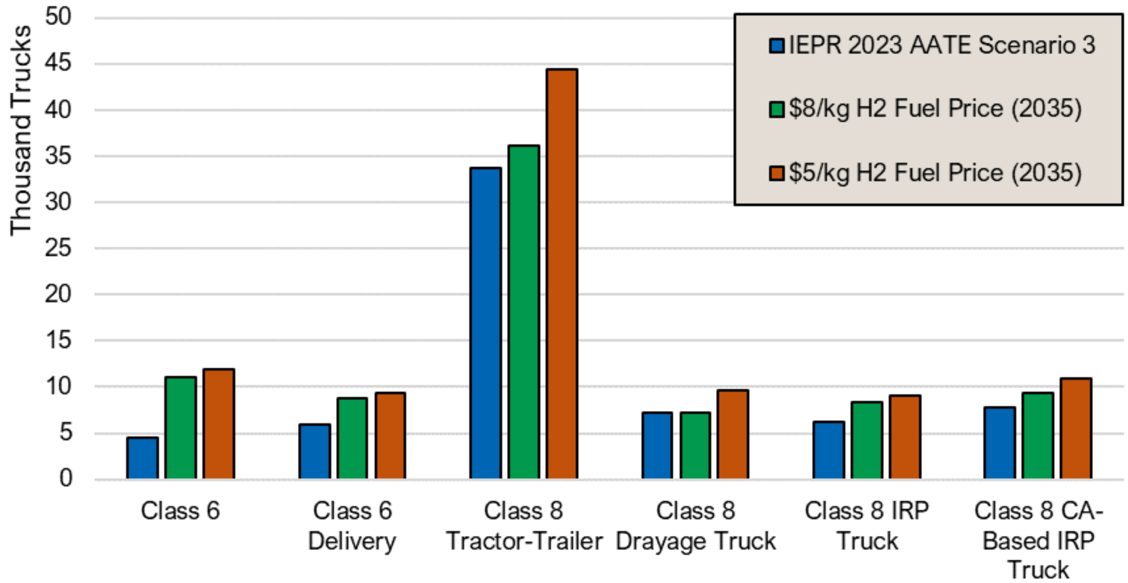


Medium- and heavy-duty FCEV populations in the *2022 Scoping Plan Update* and AATE 3 scenarios as well as scenarios for $8 and $5 per kg clean and renewable hydrogen through 2040 show a wide range of potential adoption levels.

Source: CEC staff

Figure 11 shows FCEV populations in 2040 for different types of freight trucks selected in the truck choice model for the different fuel price scenarios. The 2023 AATE 3 Scenario with unaltered truck and fuel prices includes a notable amount of FCEV trucks due to the ZEV sales manufacturer requirement in ACF being implemented, but the lower fuel price scenarios show increased FCEV populations. Modifications in fuel price have a smaller impact on Class 6 trucks, which tend to drive shorter distances per truck per year, compared to Class 8 trucks that drive longer distances and are more sensitive to fuel price. Between the IEPR 2023 AATE Scenario 3 and the scenario with $5 per kg price of clean and renewable hydrogen, the lower fuel price scenario resulted in about 11,000 more FCEVs for Class 6 trucks and about 19,000 more FCEVs for Class 8 trucks.

Figure 11: Freight FCEV Population by Vehicle Class in 2040 for SB 1075 Scenarios



Classes 6 and 8 freight truck populations in the modified AATE 3 scenario and when assuming substantial reductions in the price of delivered hydrogen. Reductions in the price of hydrogen fuel have the greatest impact on trucks that travel long distances.

Source: CEC staff

Barriers That Need to Be Addressed

The CEC has anecdotal access to hydrogen fuel price data, and further information is needed for a more comprehensive analysis of market volatility and trends. One data point shows that, in 2023, the retail price of hydrogen dispensed at light-duty refueling stations reached as much as $36 per kilogram. According to a 2023 CEC staff report, some transit agencies use liquid hydrogen at the reported delivered cost of between $7 and $9 per kilogram.[155] These prices, however, do not represent the whole market. Reducing the price of clean renewable hydrogen delivered to refueling stations to around $5 to $8 per kilogram would require significant expansion in the supply and sustained reductions in delivery cost. Furthermore, high-annual-mileage vehicles are more likely to be driven outside California on long-distance interstate or international hauls. This type of travel will require greater availability of hydrogen refueling stations along freight corridors beyond California's borders. For vehicles that have

155 Villareal, Kristi. 2023. 2023 *Staff Report on Senate Bill 643: Clean Hydrogen Fuel Production and Refueling Infrastructure to Support Medium- and Heavy-Duty Fuel Cell Electric Vehicles and Off-Road Applications.* California Energy Commission. Publication Number: CEC-600-2023-053,. https://www.energy.ca.gov/sites/default/files/2023-09/CEC-600-2023-053_0.pdf.

lower annual mileage, such as Class 6 trucks and Class 8 drayage trucks, the vehicle price is a more significant barrier than fuel cost.

Recommendations for Future Analysis of Potential Use of Clean and Renewable Hydrogen in the Electric and Transportation Sectors

For the *2025 IEPR,* the CEC intends to conduct more extensive modeling and analysis that expands on the challenges and preliminary findings described in this chapter.

General modeling approach: There is broad support for the CEC to expand future analysis beyond its preliminary study of the potential use and cost of clean and renewable hydrogen to decarbonize the electricity and transportation sectors. The analysis should take a system approach, integrating the electricity and transportation sectors. The CEC should develop scenarios that assess several hydrogen production pathways, including biomass processes such as gasification or pyrolysis or both. The CEC should also evaluate the range of delivery methods (such as production on-site and delivery via truck or pipeline) and include out-of-state sources and associated storage.[156] The analysis should consider further environmental factors, including potential impacts from leakage.

Electricity generation: Future analysis of electricity generation should evaluate specific applications of clean and renewable hydrogen, such as multiday storage or reliability-driven firm dispatchable operation. To evaluate the volume that may be needed, the joint agency 2025 SB 100 modeling should reflect policies driving fossil gas power plant retirement and GHG reductions. The CEC's analysis for the electricity sector should expand to include producing hydrogen from biogenic feedstocks (such as woody biomass or agricultural waste) delivery infrastructure, power plant retrofits, and end-use conversion using fuel cells.

Transportation sector: Future analysis of the transportation sector should consider potential demand from aviation, including out-of-state flights. CEC staff should also continue developing models and conducting additional work for a broader analysis that includes oceangoing vessels, harbor craft, and off-road applications. Staff should continue to monitor hydrogen market trends, including potential growth in vehicle options across all weight classes and development of hydrogen-fueled planes and locomotives. Finally, CEC staff should explore

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156 The CEC heard several perspectives (including Green Hydrogen Coalition, California Hydrogen Business Coalition, and California Hydrogen Coalition; PG&E; Air Products; SoCalGas) about the importance of expanding analysis of hydrogen infrastructure, including delivery options and storage. Also, SoCalGas and Air Products provided feedback on the regulatory structure of the state's pipelines. The CEC plans to continue to track and monitor infrastructure-related issues in CPUC proceedings and report on new developments in future IEPR proceedings.

mechanisms to collect market data on hydrogen fuel prices that allow for timely monitoring of market trends.

Opportunities for Industrial Decarbonization

Pathways to decarbonize the industrial sector include electrification, such as the use of widely available high-efficiency electric resistance heaters and boilers, and industrial electric heat pumps that are a promising decarbonization option for low-temperature industrial processes. Other options include heaters and boilers that operate using biomass, solar-powered heating, and small-scale carbon capture technologies. Also, there may be opportunities to use clean and renewable hydrogen in the industrial sector to reduce GHG emissions.

Industrial processes are the second-largest contributor of GHG emissions in California (behind transportation), accounting for about 23 percent of statewide emissions in 2020, of which 20 percent are noncombustion emissions.[157] Refineries and hydrogen production represent the largest source in the industrial sector, contributing 36 percent of total emissions in the sector. While the electricity sector reduced GHG emissions by 44 percent between 2000 and 2021, emissions from the industrial sector dropped by only 20 percent.[158]

The U.S. DOE's *Industrial Decarbonization Roadmap* identified clean and renewable hydrogen as a potential decarbonization pathway for oil refining and high-temperature industrial processes.[159] Industrial activities in California that require high-temperature processing and could use clean and renewable hydrogen include cement, glass, and electronics manufacturing. Cement production accounts for about 2 percent of in-state GHG emissions,[160] about 60

157 CARB. Presentation at August 15, 2023, Public Meeting on SB 905 Carbon Capture Utilization and Sequestration Requirements, and assumes total statewide GHG emissions of 369.2 $MMTCO_2e$.

While the transportation sector accounts for 38 percent of statewide GHG emissions, this figure reflects only tailpipe emissions from on-road vehicles and direct emissions from off-road mobile sources. It does not include upstream emissions from oil extraction, petroleum refining, and oil pipelines that are accounted for in the industrial sector.

CARB. November 16, 2022. *2022 Scoping Plan for Achieving Carbon Neutrality*, https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf.

158 CARB. "Current CA GHG Emission Inventory Data," 2000–2021 GHG Inventory (2023 edition), 2000–2021 Trends Figure Data, Figures 11 and 15, https://ww2.arb.ca.gov/ghg-inventory-data. Averaged 2000–2002 to represent 2000 because of high variability in the electricity sector over that period.

159 United States Department of Energy. *Industrial Decarbonization Roadmap*. DOE/EE-2635. September 2022, https://www.energy.gov/sites/default/files/2022-09/Industrialpercent20Decarbonizationpercent20Roadmap.pdf.

160 CARB. "Second Workshop for SB 596 Cement Sector Net-Zero Emissions Strategy," https://ww2.arb.ca.gov/events/second-workshop-sb-596-cement-sector-net-zero-emissions-strategy.

percent of which are processes related (primarily from conversion of limestone to clinker)[161] and 40 percent of which result from fuel and electricity consumption. Cement manufacturing requires temperatures greater than 2,600 degrees Fahrenheit that could be produced via clean and renewable hydrogen.[162] Most common industrial heating equipment (such as boilers, air heaters, process heaters) can accommodate blends of hydrogen with fossil gas up to 20–23 percent with adjustments and verification.[163]

In addition to converting existing industrial infrastructure to use hydrogen, potential new industries that could be established in California using clean and renewable hydrogen include:

- Ammonia fertilizer production
- Ammonia and methanol for green international shipping corridors
- Production of sustainable aviation fuels or other renewable combustion fuels
- Alternative pathways for plastics upcycling to reduce the amount of waste going into landfills

However, there are many technical and economic challenges that must be addressed for clean and renewable hydrogen to help decarbonize California's industrial sector. Today, fossil gas is considerably cheaper than clean alternatives like electricity or hydrogen, which makes adoption difficult for industrial activities that are particularly price-sensitive.[164] Furthermore, replacing fossil gas with clean and renewable hydrogen may require significant equipment changes for hydrogen storage and to accommodate greater gas flow rates (because hydrogen

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161 Hasanbeigi and Springer. 2019. *California's Cement Industry: Failing the Climate Challenge.* Global Efficiency Intelligence, https://www.climateworks.org/wp-content/uploads/2019/02/CA-Cement-benchmarking-report-Rev-Final.pdf.

162 California-Nevada Cement Association. "Achieving Carbon Neutrality for California Cement Producers," https://cncement.org/attaining-carbon-neutrality.

Concrete Future. *The GCCA 2050 Cement and Concrete Industry Roadmap for Net Zero Concrete*. October 2021, https://gccassociation.org/concretefuture/wp-content/uploads/2021/10/GCCA-Concrete-Future-Roadmap-Document-AW.pdf.

163 Schiro, et al. 2020. "Modelling and Analyzing the Impact of Hydrogen Enriched Fossil Gas on Domestic Gas Boilers in a Decarbonization Perspective," *Carbon Resources Conversion,* https://www.sciencedirect.com/science/article/pii/S2588913320300089. Various sources differ on maximum acceptable levels of hydrogen; the cited value here is the highest blend concentration noted in the literature.

Samuel and Oliver. 2009. "Hydrogen-Enriched Fossil Gas – Bridge to an Ultra-Low Carbon World." National Grid and Atlantic Hydrogen Inc., 21st World Energy Conference, Montreal. https://www.osti.gov/etdeweb/biblio/21396875.

164 Noussan, *et al.* 2020. "The Role of Green and Blue Hydrogen in the Energy Transition — A Technological and Geopolitical Perspective." *Sustainability*, Vol. 13.

has about 70 percent lower energy density than fossil gas by volume),[165] material robustness against corrosion potential from very wet flame gas,[166] and higher combustion temperatures that lead to increased NO_X emissions that need to be addressed.[167] There are also potential safety and regulatory considerations that can increase costs and barriers to use of hydrogen in industrial processes.

CEC RD&D Investments Advancing Clean and Renewable Hydrogen

Further investments in RD&D can play an important role in reducing barriers to adoption of clean and renewable hydrogen across many sectors. The CEC administers several RD&D programs to advance new and emerging clean energy technologies, provide benefits to Californians and accelerate achievement of state policy goals. Three of these programs — the Clean Hydrogen Program, the Gas R&D Program, and the Electric Program Investment Charge (EPIC) — fund projects that advance the science and address commercial barriers to production of clean and renewable hydrogen and related use in the electricity, transportation, and industrial sectors.[168]

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165 Pacific Northwest National Laboratory. "Hydrogen Tools: Lower and Higher Heating Values for Hydrogen and Various Fuels," https://h2tools.org/hyarc/hydrogen-data/lower-and-higher-heating-values-hydrogen-and-other-fuels.

166 Du Toit, et al. 2018 "Reviewing H_2 Combustion: A Case Study for Non-Fuel-Cell Power Systems and Safety in Passive Autocatalytic Recombiners." *Energy Fuels*, 32(6): 6401 6422, https://doi.org/10.1021/acs.energyfuels.8b00724.

167 General Electric. March 2022. "Hydrogen for Power Generation: Experience, Requirements, and Implications for Use in Gas Turbines," https://www.ge.com/gas-power/future-of-energy. The magnitude of the increase in NO_X emissions will depend on the percentage of hydrogen in the fuel, and the specific combustion system and gas turbine operating conditions. The overall trend shows that at lower percentages of hydrogen the increase in NO_X emissions is minimal, but at 50 percent hydrogen (by volume), NO_X emissions could increase by as much as 35 percent. Extrapolating these data, gas turbine NO_X emissions could double if operating at or near 100 percent hydrogen. This estimate is based on preliminary laboratory data assuming hydrogen blended with fossil gas. Actual NO_X emissions may vary based on several factors, including fuel composition, combustion operating parameters, and so forth.

168 CEC. "Clean Hydrogen Program," https://www.energy.ca.gov/programs-and-topics/programs/clean-hydrogen-program.

CEC. "Gas Research and Development Program," https://www.energy.ca.gov/programs-and-topics/programs/gas-research-and-development-program.

CEC. "Electric Program Investment Charge Program (EPIC)," https://www.energy.ca.gov/programs-and-topics/programs/electric-program-investment-charge-epic-program.

Regarding production of clean and renewable hydrogen, CEC has supported RD&D projects advancing electrolytic and biogenic pathways. These projects have been supported through targeted solicitations and through cost-sharing offered to California-based applicants to U.S. DOE funding opportunities.[169] Recently, the Clean Hydrogen Program announced a notice of intent to formally release the large-scale clean renewable hydrogen production solicitation (more than 5 MT per day) in early 2024. Further, the program released a draft solicitation concept for public comment for smaller-scale projects (less than 5 MT per day) that are colocated on site with the end user, with anticipated solicitation release in 2024. Solicitations will likely have a carbon intensity requirement of less than or equal to 0.45 kilogram carbon dioxide-equivalent per kilogram of hydrogen produced, with a goal of 0. CEC has also funded projects advancing novel waste biomass to hydrogen production technologies, including via microbial electrolysis and direct conversion of biogas.[170] These projects have begun initial experimental testing with some planned pilot-scale demonstrations in 2024.

Regarding the use of clean and renewable hydrogen for electric sector applications, the CEC has funded RD&D projects focused on demonstrating long-duration energy storage and mobile renewable back-up power.[171] Other projects have focused on advancing technologies for reducing NO_x emissions from combusting hydrogen in turbines and engines to provide zero-carbon, firm dispatchable generation.[172] Funding also supports laboratory and modeling analyses to quantify risks associated with blending of hydrogen into existing fossil gas pipelines[173] and impacts on end-use appliances for large commercial buildings and industrial

169 CEC. "GFO-22-903 – Cost Share for Federal Funding Opportunities Clean Hydrogen Program," https://www.energy.ca.gov/solicitations/2023-05/gfo-22-903-cost-share-federal-funding-opportunities-clean-hydrogen-program.

170 CEC. "GFO-21-502 – Advancing Cost and Efficiency Improvements for Low Carbon Hydrogen Production," https://www.energy.ca.gov/solicitations/2021-08/gfo-21-502-advancing-cost-and-efficiency-improvements-low-carbon-hydrogen.

171 CEC. "GFO-19-305 – Developing Non-Lithium-Ion Energy Storage Technologies to Support California's Clean Energy Goals," https://www.energy.ca.gov/solicitations/2019-12/gfo-19-305-developing-non-lithium-ion-energy-storage-technologies-support.

CEC. "GFO-20-310 – Mobile Renewable Backup Generation (MORBUGS)," https://www.grants.ca.gov/grants/gfo-20-310-mobile-renewable-backup-generation-morbugs/.

172 CEC. August 2023. "GFO-22-504 – Hydrogen Blending and Lower Oxides of Nitrogen Emissions in Gas-Fired Generation (HyBLOX)," https://www.energy.ca.gov/solicitations/2023-01/gfo-22-504-hydrogen-blending-and-lower-oxides-nitrogen-emissions-gas-fired.

173 CEC. "GFO-21-507 – Targeted Hydrogen Blending in Existing Gas Network for Decarbonization," https://www.energy.ca.gov/solicitations/2022-01/gfo-21-507-targeted-hydrogen-blending-existing-gas-network-decarbonization.

applications.[174] In 2024, experimental work in collaboration with California gas investor-owned utilities is planned, including accelerated testing of hydrogen-blend impacts on gas system components simulating actual conditions. In the third quarter of 2023, the CEC initiated projects with RAND Corporation and E3 to assess the role of hydrogen in California's decarbonizing electric sector, which will develop new modeling tools to evaluate least-cost infrastructure build-out scenarios and guide future RD&D investments.[175]

Regarding transportation applications, the CEC's Gas R&D Program has funded projects to demonstrate hydrogen fuel cell technology and refueling solutions for transportation applications with challenging duty cycles.[176] For example, the Sierra Northern Hydrogen Locomotive Project plans to demonstrate a zero-emission hydrogen fuel cell switcher locomotive in West Sacramento in 2024. Lessons learned will be valuable for assessing the role of hydrogen for rail end uses, especially as CARB's In-Use Locomotive Regulation comes into effect. The Sacramento Metropolitan Air Quality Management District is building on this initial demonstration through a $15.6 million award from the California State Transportation Agency's Port and Freight Infrastructure Program to deploy three more hydrogen locomotives and refine the technology.[177]

Regarding applications of clean renewable hydrogen for industrial applications, the CEC's Gas R&D Program has funded research related to identifying and addressing equipment compatibility and safety implications. Future research in this area includes evaluating

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174 CEC. "GFO-21-503 – Examining Effects of Hydrogen in End-Use Appliances for Large Commercial Buildings and Industrial Applications," https://www.energy.ca.gov/solicitations/2021-09/gfo-21-503-examining-effects-hydrogen-end-use-appliances-large-commercial.

175 CEC. "GFO-22-304 – Assessing the Role of Hydrogen in California's Decarbonizing Electric System," https://www.energy.ca.gov/solicitations/2022-10/gfo-22-304-assessing-role-hydrogen-californias-decarbonizing-electric-system.

176 CEC. "GFO-22-502 – Innovative Hydrogen Refueling Solutions for Heavy Transport," https://www.energy.ca.gov/solicitations/2022-10/gfo-22-502-innovative-hydrogen-refueling-solutions-heavy-transport.

Chen, Peter. 2021. *Fossil Gas Research and Development Program Proposed Budget Plan for Fiscal Year 2020–2021*. CEC. Publication Number: CEC-500-2020-081, https://www.energy.ca.gov/sites/default/files/2021-04/CEC-500-2020-081.pdf.

177 California State Transportation Agency. July 2023. *Port and Freight Infrastructure Program Selected Projects – Project Detail Summary*, https://calsta.ca.gov/-/media/calsta-media/documents/pfip-awards-summary-narrative-7-6-23-a11y.pdf.

opportunities for industrial hydrogen clusters that can share the cost of delivery infrastructure among many large users within a small geographic area.[178]

Recommendations for CEC Clean and Renewable Hydrogen RD&D

The CEC should continue supporting RD&D of new technologies that can help drive down costs, address risks, and address potential environmental impacts of clean and renewable hydrogen production, storage, transport, and use in the electricity, transportation, and industrial sectors. The CEC implements hydrogen-focused RD&D through CPUC-approved investment plans under the Gas R&D Program and EPIC.

The U.S. DOE is establishing a $1 billion demand-side initiative to support the Regional Clean Hydrogen Hubs, aimed at providing market certainty to hydrogen producers and end users during early years of production and unlock private investment.[179] The CEC should look for opportunities to engage with the U.S. DOE on this demand-side initiative within existing programs through federal cost-share opportunities or specific projects that could benefit California.

Delivery and storage RD&D: The CEC should support research to assess and characterize the feasibility and risk of emerging hydrogen storage and delivery approaches such as storing large volumes of clean and renewable hydrogen in geologic formations, blending into existing gas infrastructure, developing purpose-built pipelines, and clustering end users for regional deployments. Research is also needed on leakage quantification, monitoring, and mitigation.

Production RD&D: Production of clean and renewable hydrogen to serve several sectors could result in increased electrical load. (See also Chapter 3, Forecast Updates for 2024 and Beyond, for plans to develop energy demand scenarios that assess energy and GHG impacts of increased clean and renewable hydrogen production.) The CEC can play a role in advancing clean and renewable hydrogen production with reduced energy consumption and costs by:

- Investigating novel designs and materials that can operate at higher pressures to reduce the need for compression.
- Demonstrating production from biomass through thermochemical processes and understand the impacts of different feedstocks.
- Advancing lab-scale production, such as thermochemical, photoelectrochemical, or biological approaches.

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178 Ibid.

179 U.S. DOE. July 2023. "Biden-Harris Administration to Jumpstart Clean Hydrogen Economy With New Initiative to Provide Market Certainty And Unlock Private Investment," https://www.energy.gov/articles/biden-harris-administration-jumpstart-clean-hydrogen-economy-new-initiative-provide-market.

Power generation RD&D: In addition to existing technologies, continued research and development can help improve efficiency, address NO_X formation from clean and renewable hydrogen combustion at power plants, and understand materials impacts, especially at higher blends. Performance of hydrogen power generation technologies should be examined using blends up to 100 percent hydrogen. Research is also needed on the potential value of hydrogen as a firm dispatchable resource or long-duration energy storage for grid reliability.

Transportation end uses RD&D: Clean and renewable hydrogen has potential for growth to decarbonize and reduce emissions from challenging transportation segments such as rail, marine, and aviation. The CEC can advance innovative conveyance and refueling approaches for these segments and others adopting hydrogen as a zero-emission technology. Research into hydrogen separation or purification technologies could advance use of blended or purpose-built pipelines for delivery to hydrogen stations.

Industrial RD&D: Technical issues must be resolved to enable high blends of clean and renewable hydrogen with fossil gas or pure hydrogen to be used in industrial processes, beyond the challenges to production, delivery, and storage. RD&D on clean and renewable hydrogen use in the industrial sector includes NO_X emissions from combustion, flame safety controls, corrosion from wet flame gas, effects on materials from higher temperature combustion, radiative heat transfer, and gas flow (due to a lower energy density than fossil gas). Also, the CEC should examine the regulatory and safety uncertainties associated with production of clean and renewable hydrogen at the industrial plant, or transport and storage at the industrial facility.

CHAPTER 3:
California Energy Demand Forecast

A foundational component of the state's energy planning is the CEC's California Energy Demand Forecast, or IEPR forecast.[180] The IEPR forecast is a set of several forecasting products that are used in various energy planning proceedings, including the CPUC's oversight of energy procurement and the California ISO's transmission planning. The demand forecast includes:

- Annual consumption forecasts to 2040 for electricity and gas by customer sector, eight planning areas, and 20 forecast zones.
- Annual peak electric system load with different weather variants for eight planning areas.
- Annual projections of photovoltaic (PV) and other self-generation technologies, battery storage, plug-in electric vehicles (PEVs), and energy efficiency and electrification.

The CEC continuously improves the forecast to meet the state's evolving planning needs. Advances in recent years include incorporating scenario analysis to better plan for rapid changes in the energy market, particularly in transportation and building electrification, and accounting for more extreme weather variability. The CEC will continue to advance its forecasting capabilities as part of its focus on providing science-based planning tools needed in the transition to a clean energy future. Presented here is the process for developing the forecast, an update on the method used, a description of the key drivers and trends, and planned enhancements to future forecasts.

Recent Extreme Weather Events and Reliability

California's energy system planning has been challenged in recent years by several significant events that impact energy supply and demand. The most recent was the July 2023 extreme heat wave affecting interior Southern California. Climate change increases uncertainty in near- and long-term planning, and recent extreme weather events in California and the rest of the West have had a real impact on energy demand and system planning. California's energy

180 Public Resources Code Section 25301(a) requires the CEC to "conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices" and to "use these assessments and forecasts to develop and evaluate energy policies and programs that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety."

system planning must continuously adapt and evolve to keep pace with changing climate conditions.

As the impacts of climate change increase in significance, historical weather data are no longer sufficient to predict future weather patterns. Consequently, CEC staff is integrating new climate simulation data into the forecast from the Cal-Adapt Analytics Engine.[181] Weather and climate data are also used to recharacterize normal and extreme peak electricity demand events (events likely to happen once in X years, such as 1-in-10). Future demand models will include additional data and refinements.

State and Federal Policies and Program to Reduce Greenhouse Gas Emissions

California's GHG emission reduction goals are advancing building and transportation electrification across the state. Executive Order B-55-18, which set a goal to achieve economywide carbon neutrality no later than 2045,[182] was codified through Assembly Bill 1279 (Muratsuchi, Chapter 337, Statutes of 2022). Statewide and local jurisdiction strategies to reduce GHG emissions including energy efficiency, electrification of buildings, zero-emission transportation, and renewable energy are relevant to the forecast and ways that electricity is used in California.

The CEC uses the additional achievable scenario framework to capture uncertainties in market response to proposed and newly established policies and programs. Starting in 2021, the CEC broadened the additional achievable framework to capture uncertainties in market response to proposed and established building electrification and zero-emission transportation policies and programs.

Zero-Emission Transportation Policies and Programs

In 2020, Governor Newsom issued Executive Order N-79-20 to phase out emissions from the state's largest source of global warming pollution: transportation. CARB has adopted and continues to develop vehicle regulations to implement the executive order, which calls for 100 percent of passenger vehicle sales to be zero emission by 2035 and requiring all on-road trucks be zero-emission where feasible by 2045. Major state zero-emission vehicle (ZEV) regulations include the Advanced Clean Cars II regulation for light-duty vehicles and the Advanced Clean Fleets regulation for medium- and heavy-duty vehicles, among others.

181 Cal-Adapt. Analytics Engine Tools, https://cal-adapt.org/tools/.

182 Executive Order B-55-18 to Achieve Carbon Neutrality, signed by Governor Brown in September 2018. https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

Over the last two budget cycles, California has committed a record $52.3 billion for climate-related investments over six years, including $10 billion for zero-emission transportation. The transportation-related funds support incentives for the purchase of zero-emission vehicles (ZEVs) and the build-out of ZEV refueling infrastructure. CARB manages the vehicle incentive programs, including the Clean Vehicle Rebate Project for light-duty ZEVs and the Hybrid and Zero-Emission Truck and Bus Vehicle Incentive Project for medium- and heavy-duty (MDHD) ZEVs. The CEC manages incentive programs for ZEV refueling infrastructure, including CALeVIP[183] and EnergIIZE Commercial Vehicles.[184]

California's ZEV-friendly policies and incentives have helped increase the battery-electric passenger vehicles share of new vehicle sales from 8 percent in 2020 to 25 percent through the first three quarters of 2023. California's vehicle fleet transition away from fossil fuels to electricity and hydrogen has a large impact on the transportation energy demand forecast.

Federal vehicle regulations focus on fuel economy or GHG emissions from vehicles and, unlike the California regulations, do not require ZEVs. However, the Inflation Reduction Act of 2022[185] introduced new changes to ZEV incentives that generally improve the case for ZEV adoption, primarily through vehicle tax credits. CEC staff has accounted for these new federal incentives in modeling transportation energy demand for the baseline forecast of the *2023 IEPR*. New proposed federal rules in 2023 may result in GHG standards that could effectively require additional ZEVs to be sold by manufacturers,[186] but these rules appear to be less aggressive than the Advanced Clean Cars II regulation.

Building Decarbonization Policies and Programs

California and local jurisdictions are leading the way in advancing building decarbonization. Many cities and counties are implementing gas bans in new construction in their jurisdictions.[187] California, supported by legislation, is continuing to advance equitable building electrification throughout the state. The $120 million Technology and Equipment for Clean Heating (TECH) program and the $80 million Buildings Initiative for Low-Emissions Development (BUILD) program are pilots aimed at market transformation and offer incentives

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183 CALeVIP webpage, https://calevip.org/.

184 EnergIIZE Commercial Vehicles webpage, https://www.energiize.org/.

185 H.R. 5376. Inflation Reduction Act of 2022, https://www.congress.gov/bill/117th-congress/house-bill/5376.

186 For more information, see https://www.epa.gov/regulations-emissions-vehicles-and-engines/proposed-rule-multi-pollutant-emissions-standards-model.

187 A narrow ruling from the U.S. Court of Appeals for the Ninth Circuit found that federal law preempts Berkeley's ordinance prohibiting the installation of gas infrastructure in new construction; this decision impacts local jurisdictions with similar gas infrastructure bans.

for all-electric new construction in low-income communities. California has launched an equitable building decarbonization program (Assembly Bill 209 [Committee on Budget, Chapter 251, Statutes of 2022] and Assembly Bill 179 [Ting, Chapter 249, Statutes of 2022]), where $922 million will be dedicated to a statewide direct-install building retrofit program for low-income households to replace fossil fuel appliances with electric appliances.

Still, significant electrification is required to meet the 2030 GHG goals discussed in the AB 3232 California Decarbonization Assessment.[188] Several goals have been established to help aim the state toward its 2030 emission target. Per the Governor's July 2022 letter to CARB,[189] California has set a goal to create 3 million climate-ready and climate-friendly homes by 2030 and 7 million homes by 2035. The Governor's goal helps support the goal recommended in the *2021 IEPR* of 6 million heat pumps installed by 2030. The mass deployment of these clean electric technologies, which have load flexibility potential, can help promote grid reliability needs. As required by Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022), the CEC in consultation with the CPUC and California ISO developed a 2030 load-shift goal of 7,000 MW to reduce net peak electrical demand.[190]

Upcoming zero-emission standards that will begin at or before 2030 will further aid in decarbonizing buildings. The CARB *2022 State Implementation Plan* includes a strategy to limit building-related GHG emissions from new space and water heaters. CARB will be developing this regulation for potential implementation in 2030.[191] Several air quality management districts have accelerated or plan to accelerate the time horizon and scope of appliances of their zero-emission appliance standards. On March 15, 2023, the Bay Area Air Quality Management District (BAAQMD) Board of Directors adopted zero-emission NO_X standards that go into effect for certain water heaters beginning in 2027 and space heating beginning in

188 Kenney, Michael, Nicholas Janusch, Ingrid Neumann, Mike Jaske. August 2021. *California Building Decarbonization Assessment*. CEC. Publication Number: CEC-400-2021-006-CMF, https://www.energy.ca.gov/publications/2021/california-building-decarbonization-assessment.

189 Newsom, Gavin. July 22, 2022. Letter From Governor Newsom to CARB Chair Liane Randolph, https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf.

190 Neumann, Ingrid and Erik Lyon. May 2023. *Senate Bill 846 Load-Shift Goal Report*. California Energy Commission. Publication Number: CEC-200-2023-008, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250357&DocumentContentId=85095.

191 California Air Resources Board. 2022. *2022 State Strategy for the State Implementation Plan,* https://ww2.arb.ca.gov/resources/documents/2022-state-strategy-state-implementation-plan-2022-state-sip-strategy.

2029.[192] The South Coast Air Quality Management District (SCAQMD) is set to begin its Phase 1 rulemaking for its low- and zero-emission NO_X standards beginning in 2024, which, when implemented, could go in effect before 2030 and include appliances beyond space and water heating.[193]

Behind-the-Meter Solar Photovoltaics and Energy Storage

California has also enacted policies and incentives designed to increase solar photovoltaic (PV) and energy storage adoption throughout the state. The Title 24 Energy Efficiency Standards require the installation of PV systems in all new construction, residential and nonresidential (with exceptions). The standards are designed to decrease GHG emissions while lowering consumers' energy bills. These requirements were first introduced for the 2019 Energy Code, which went into effect in January 2020.

The CPUC adopted the Net Billing Tariff (NBT) as a successor to Net Energy Metering 2.0 in December 2022. The NBT went into effect April 15, 2023, and updates the method for compensating solar and solar plus battery storage adopters in investor-owned utility territories that export excess energy back to the grid. The updated method uses an avoided cost calculator to calculate compensation based on the wholesale price of electricity for utilities, depending on the month, hour, and day of week. The NBT also introduced a glide path designed to smooth the transition to the new plan.

Many incentive programs have been enacted to promote behind-the-meter PV and storage adoption by making it more financially viable for households and businesses. The federal Investment Tax Credit (ITC) was extended by Congress in 2022 as part of the Inflation Reduction Act. With the update, the ITC will remain in effect through 2034, providing a tax credit of up to 30 percent of the cost of a PV or storage system. The extension also introduced a new comparable tax credit for the installation of standalone storage. At the state level, the CPUC's Self-Generation Incentive Program (SGIP) provides rebates to customer-side distributed energy systems, including energy storage systems to reduce onsite electrical demand. These incentives are supplemented by local government and utility incentives.

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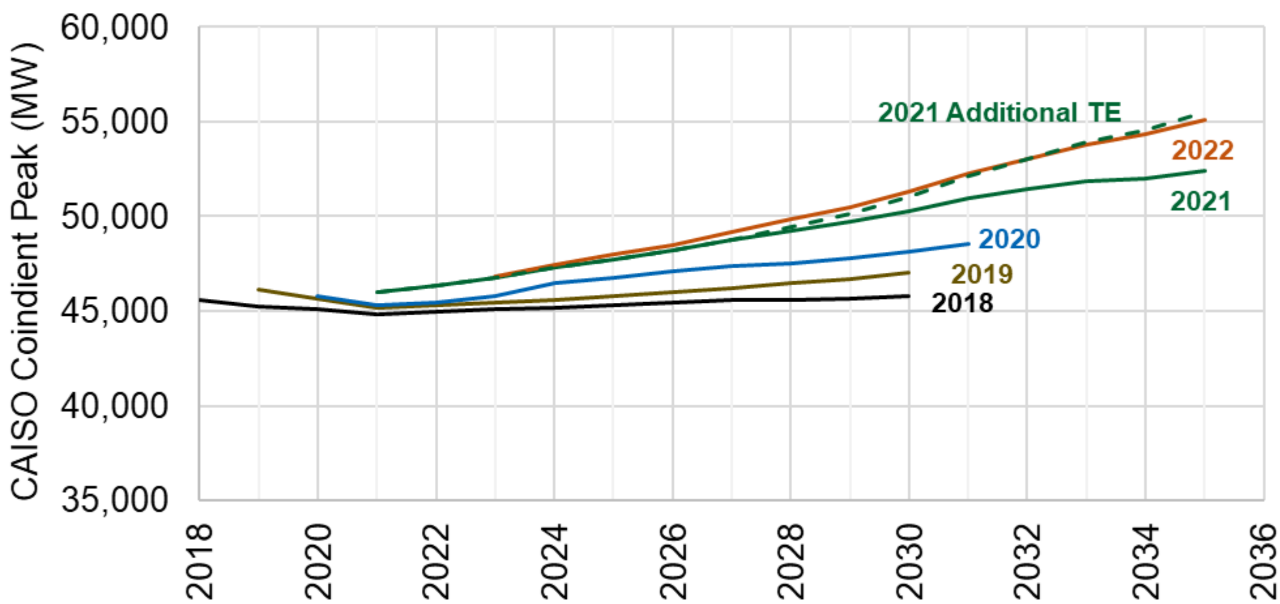
192 BAAQMD press release. March 15, 2023. "Air District Strengthens Building Appliance Rules to Reduce Harmful NOx Emissions, Protect Air Quality and Public Health," https://www.baaqmd.gov/~/media/files/communications-and-outreach/publications/news-releases/2023/barules_230315_2023_003-pdf.pdf?la=en&rev=73fdaf7bb91b475b9b7913c133c31737.

193 South Coast Air Quality Management District. July 19, 2023. Proposed Amended Rule 1111 – Reduction of NOx Emissions From Natural Gas-Fired, Fan-Type Central Furnaces, http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1111/pcm-par-1111--july-2023.pdf?sfvrsn=6. Slide 14.

Resulting Impacts to the Electricity Forecast

California's efforts to reduce GHG emissions are changing how energy is used in the state, and the CEC's energy demand forecast has adapted to reflect the impacts of new regulations and programs to decarbonize buildings and transportation.[194] Electrification policies in recent years have resulted in increased electricity load projections, as shown in Figure 12, and decreased projections of gas demand. With the support of the CPUC, CARB, the California ISO, and the IOUs, CEC staff has made significant changes to the demand forecast over the past several years. The 2023 IEPR forecast is not shown in Figure 12 as electrification impacts are overshadowed by other trends that resulted in a decrease to overall peak electricity demand projections, which is discussed in subsequent sections.

Figure 12: Planning Forecast Managed Net Peak Demand, 2018–2022 IEPRs



The CEC forecast of peak demand in the California ISO for 2030 has increased by more than 5 GW over five updates, driven by rapid transportation electrification and climate change.

Source: CEC. Note that the mid-mid case is the equivalent of the planning forecast for years prior to 2022.

194 *Decarbonizing* is the process of reducing GHG carbon emissions from an environment. For example, decarbonizing buildings can include switching from fossil gas appliances to those that use electricity. In transportation, it could include moving fleets from gasoline-powered vehicles to those that use zero-emission fuels.

CEC staff incorporates proposed state policies and programs needed to meet state goals through additional achievable scenarios. Staff broadened the use of the additional achievable framework, which was initially developed in 2009 for energy efficiency (and called *uncommitted savings*) and applied it to building electrification starting in 2021 with the development of additional achievable fuel substitution scenarios to account for the anticipated shift from gas to electricity in buildings. Also in 2021, staff developed an additional transportation electrification (ATE) scenario to account for the anticipated shift from gasoline and diesel to electricity and hydrogen in transportation. The ATE scenario included CARB vehicle regulations under development, such as Advanced Clean Cars II and Advanced Clean Fleets, and was adopted for use in planning.[195] The ATE scenario was the precursor to the additional achievable transportation electrification scenarios that were added to the IEPR forecast starting in 2022.

Also in 2021, the hourly electricity forecast was updated to sample recent years more frequently from the 30-year historical period to better reflect climate change. Between the 2018 and 2022 IEPR forecasts, growth in solar PV capacity has shifted the net peak hour from 17:00 to 19:00 (5 to 7 p.m.), diminishing the amount of load that can be offset by PV generation. Lastly, other increases to electricity demand stem from economic, demographic, and other baseline forecast updates. For the 2023 IEPR forecast, the net peak hour in 2035 is projected to occur at 18:00 (6 p.m.) when some PV generation is available to offset demand.

The projected incremental contributions of each load modifier to peak electricity demand in 2035 are shown in Figure 13 for the California ISO territory for the 2021 and 2023 IEPR forecasts. In 2035, the peak hour is projected to occur in Hour 19 in the 2021 IEPR forecast, when the contribution from PV generation is minimal, and in Hour 18 in the 2023 IEPR forecast when some PV generation is available. In the 2023 IEPR forecast, transportation and building electrification account for the largest increase to the peak impacts between the 2021 and 2023 IEPR demand forecasts, making up just less than 20 percent of the total net peak load in 2035. Some of the increase from electrification is offset by energy efficiency measures and load shifting.

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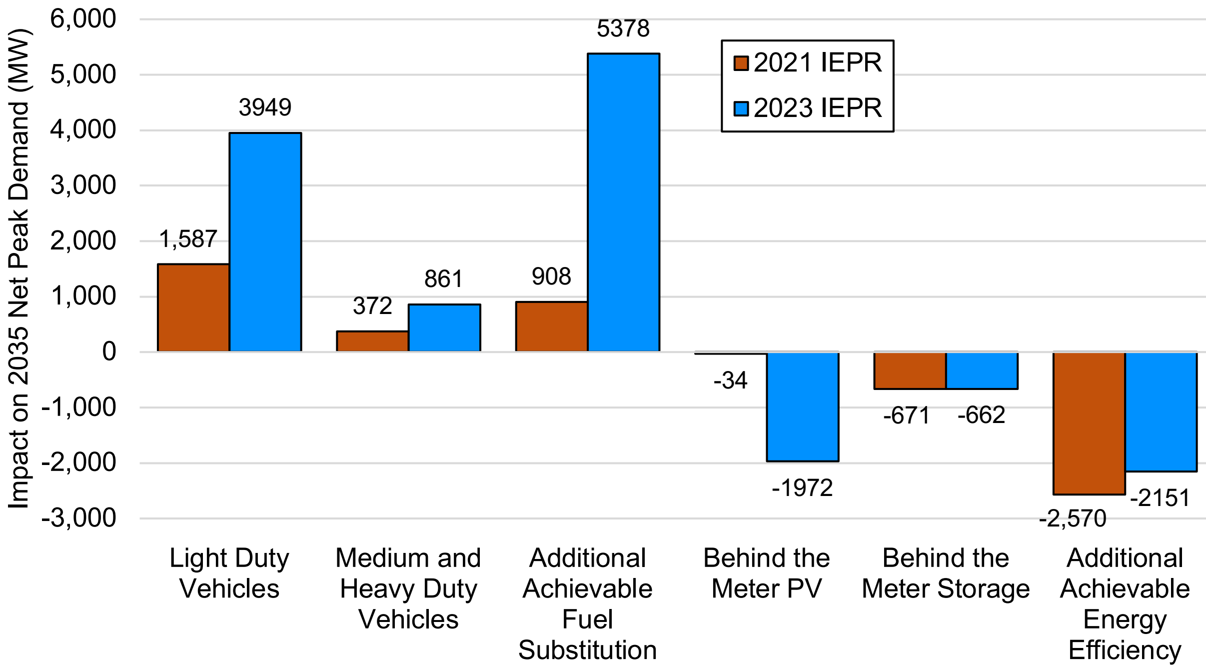
195 The additional TE scenario was adopted in May 2022, after the adoption of the 2021 IEPR forecast. There was consensus among leadership at the CPUC, California ISO, and CEC to deviate from the use of the single forecast set outlined in the *2021 IEPR* to use the additional TE scenario for system planning and procurement.

Figure 13: Load Modifier Incremental Impacts to the Net Peak Load in 2035, From the 2021 and 2023 IEPR Planning Forecasts



In the 2023 IEPR forecast, transportation and building electrification account for the largest increase to the peak impacts between the 2021 and 2023 IEPR demand forecasts, making up nearly 20 percent of the total net peak load in 2035. Some of the increased load from electrification is offset by PV, energy efficiency, and load shifting.

Source: CEC. The 2021 IEPR Planning Forecast is the mid-mid case.

CEC staff is tracking further areas for updates to current assumptions in the forecast or potential incorporation into future IEPR forecasts and the long-term energy demand scenarios developed for the 2025 Senate Bill 100 (De León, Chapter 312, Statutes of 2018) report. Topics for update or consideration include the following:

- The forecast currently includes load growth attributable to increased cannabis consumption following statewide legalization. Estimates are routinely updated to reflect recent permit and sales data.
- The forecast currently includes estimates of incremental load impacts attributable to documented data center construction projects. This process is informed by stakeholder outreach.
- Port electrification is currently partially accounted for in the CEC's off-road electrification model, but staff will make improvements to the model and more precise geographic allocations of energy demand.
- Electricity needed for in-state production of hydrogen is not included in the IEPR forecast because of the high uncertainty around the future of hydrogen. However, this omission will be assessed as part of the long-term energy demand scenarios.
- Fuel substitution in the industrial and agricultural sectors is not included, and models are under development to capture these impacts in future IEPR forecasts.

- Load-shifting technologies such as vehicle-to-building integration and demand response are not included in the IEPR forecast but will be assessed as part of the long-term energy demand scenarios.
- Behind-the-meter storage is currently included in the forecast. Charge/discharge profiles are informed by CPUC data from the SGIP and modeling of potential behavior based on rates.

Overview of Forecast Process and Method

Each year, the CEC updates and improves its forecast by using the most recently available data and improving the methods and models used. The updates are vetted with stakeholders through public Demand Analysis Working Group (DAWG)[196] meetings and public workshops. The DAWG meetings and workshops held in 2023 are summarized below, followed by a summary of the major improvements implemented for the 2023 IEPR forecast.

Stakeholder Engagement

The CEC seeks input into its forecast development through various venues, including public workshops and the public DAWG to review proposed methodological updates. At the June 1, 2023, DAWG meeting, CEC staff discussed improvements to the incorporation of climate change trends into the forecast method. The July 31, 2023, DAWG meeting reviewed updates to vehicle miles traveled (VMT) models in the transportation forecast, to be implemented in the 2024 IEPR Update forecast.[197] The August 8, 2023, DAWG meeting reviewed updates to the distributed generation model and the new residential end-use model.

CEC staff presented key assumptions and forecast updates at the August 15 and 18, 2023, IEPR workshops on Inputs and Assumptions. The October 26, 2023, DAWG meeting presented draft forecast results for the load modifiers, residential sector, and electricity rates. Workshops were held November 15, December 6, and December 19, 2023, to present draft results and

196 Demand Analysis Working Group webpage, https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/demand-analysis-working-group-dawg.

197 While the CEC has accounted for policies and regulations that advance transportation electrification in the additional achievable framework, VMT reduction targets, such as those proposed in CARB's *2022 Scoping Plan for Achieving Carbon Neutrality*, have not been incorporated into the framework for this year's IEPR. To be accounted for in the AATE framework, VMT reduction targets must be supported by identifiable regulations or policies that are in active public deliberative processes and are at the stage of development that meets the criterion of "reasonably expected to occur."

receive additional stakeholder comments[198] before the forecast is finalized and presented for adoption in February 2024.

The full list of public meetings and workshops related to the forecast is shown in Table 5.

Table 5: Forecast-Related Public Meetings and Workshops

Date	Name	Topic
January 31, 2023	IEPR Workshop	California's Economic Outlook
June 1, 2023	DAWG Meeting	Forecast Priorities and Climate Trends
July 31, 2023	DAWG Meeting	Transportation Energy Demand Forecast: Travel Models
August 8, 2023	DAWG Meeting	Distributed Generation Model Updates and Residential Model Updates
August 15, 2023	IEPR Workshop	Inputs & Assumptions
August 18, 2023	IEPR Workshop	Load Modifier Inputs & Assumptions
October 26, 2023	DAWG Meeting	Draft Results for Load Modifiers, Residential Sector, and Electricity Rates
November 15, 2023	IEPR Workshop	Load Modifier Draft Results
December 6, 2023	IEPR Workshop	Annual Electricity and Gas Draft Forecast Results
December 19, 2023	IEPR Workshop	Hourly and Peak Demand Forecast Draft Results

Source: CEC

198 Workshop documents are available on the 2023 IEPR Workshops webpage at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report/2023-iepr.

Electricity Forecast Framework

For the 2022 IEPR Update forecast, the CEC reduced the three baseline energy demand cases (low, mid, high) to one primary set of baseline assumptions and expanded the use of demand modifiers that significantly influence the results of long-term energy demand forecasts. Refer to the *2022 IEPR Update*[199] for more details on the rationale behind this new framework. The revised the terminology used for the various forecasts is shown in Table 6.

Table 6: Revised Forecast Terminology

Forecast Year	Forecast Name	Forecast Name	Forecast Name
CED 2021 and Previous	Mid Baseline Forecast	Mid-Mid	Mid-Low
CEDU 2022 and Later	Baseline Forecast	Planning Forecast	Local Reliability Scenario

Source: CEC

The 2023 IEPR forecast maintains the forecast framework from 2022 IEPR forecast. This framework contains one baseline demand forecast and several scenarios for additional achievable energy efficiency (AAEE), AAFS,[200] and additional achievable transportation electrification (AATE). The proposed set of forecasts and scenarios for the 2023 IEPR forecast is outlined in Table 7, along with the naming convention and use cases.

199 Bailey, Stephanie, Jane Berner, David Erne, Noemí Gallardo, Quentin Gee, Akruti Gupta, Heidi Javanbakht, Hilary Poore, John Reid, and Kristen Widdifield. 2023. *Final 2022 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2022-001-CMF, https://www.energy.ca.gov/media/7901.

200 *AAEE* refers to the incremental energy savings from market potential that is not included in the baseline demand forecast but is reasonably expected to occur. CEC staff developed *AAFS* as a new annual and hourly load modifier to the baseline demand forecast in a manner analogous to AAEE. *AATE* is discussed in more detail later in this chapter. Fuel substitution refers to substitution of one end use fuel type for another, such as changing out gas appliances in buildings for cleaner more efficient electric end uses.

For more information on AAEE and AAFS, see the *2021 Integrated Energy Policy Report Volume IV: California Energy Demand Forecast,* https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581.

Table 7: Electricity Forecast Framework

	Baseline Forecast	**Planning Forecast**	**Local Reliability Scenario**
Example Use Cases	-	Resource Adequacy CPUC Integrated Resource Planning	California ISO Transmission Planning Process local area reliability studies, IOU distribution system planning
Economic, Demographic, and Price Scenarios	Baseline	Baseline	Baseline
AAEE Scenario	-	Scenario 3	Scenario 2
AAFS Scenario	-	Scenario 3	Scenario 4
AATE Scenario	-	Scenario 3	Scenario 3

Note: Scenario 1 is used for informational purposes, and Scenarios 5 and 6 may be used for demand scenarios. AAFS Scenarios 3–6 include contributions from the zero-emission space and water heater measure proposed in the *2022 State Strategy for the State Implementation Plan* (2022 State SIP Strategy). See the section describing the Additional Achievable Fuel Substitution Updates for more information.

Source: CEC

The planning forecast is used for electricity system-level planning activities, including resource adequacy and integrated resource planning, and assumes "mid-level" impacts from AAEE, AAFS, and AATE. The local reliability scenario is used for electricity planning with more granular geography, such as the distribution and transmission planning process. The local reliability scenario assumes less energy efficiency and more fuel substitution, resulting in higher demand than the planning forecast, and is typically used for planning processes with more geographical granularity due to the increased uncertainty as load is disaggregated.

Like the managed forecast set for electricity planning, baseline gas demand can be combined with six AAEE savings scenarios and six AAFS scenarios to create a managed gas forecast. However, staff recommend against the use of the scenarios created for this *IEPR* for gas system planning. At the time of writing this report, there is considerable uncertainty around the pace at which building electrification will occur, and use of the planning forecast or local reliability scenarios could introduce risks to gas system reliability. However, the scenarios that exclude CARB's concept for a zero-emission appliance standard are overly conservative, assuming little building electrification, which is not aligned with the state's goals and the proposed regulations and appliance standards currently under development.

As more information becomes available throughout 2024, staff will collaborate with stakeholders to develop a new scenario that strikes the right balance.

Overview of Forecast Method and Updates for 2023

As part of the IEPR process, the CEC develops and adopts forecasts of end-user electricity and gas demand every two years, in odd-numbered years.[201] For the 2023 IEPR forecast, these energy demand forecasts are extended to 2040, in accordance with the 15-year minimum requirement established by Senate Bill 887 (Becker, Chapter 358, Statutes of 2022), to support the California ISO's transmission planning.

For the *2023 IEPR*, the CEC developed its forecast of electricity and gas demand with several improvements and expansions. The major changes to the baseline demand forecast consist of improvements to the self-generation forecast, a new residential end-use model, and updated climate projections, as detailed below. The CEC also updated the AAEE, AAFS, and AATE components for the *2023 IEPR*.

High-Level Methodology Overview

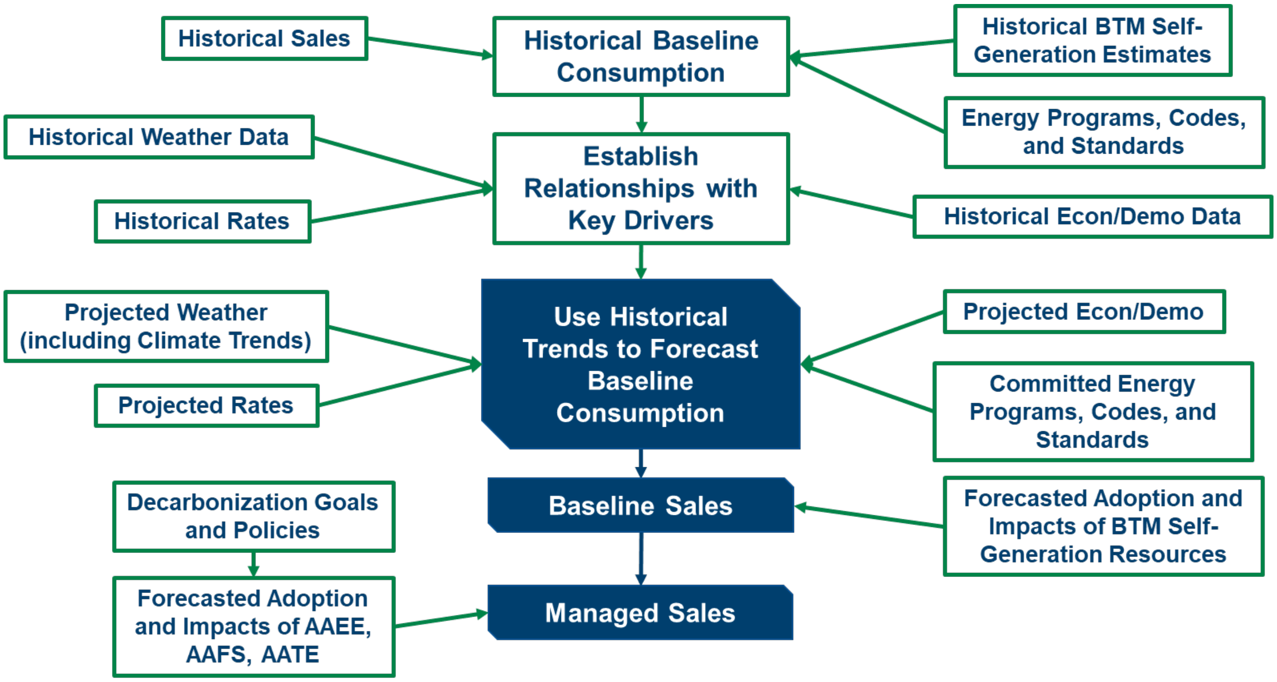
Historical energy consumption data are the foundation of the forecast and are a combination of historical energy sales data and behind-the-meter (BTM) self-generation estimates. CEC staff establishes correlations of historical energy consumption with economic and demographic data, weather data, and rates from the same historical period. The correlations are specific to each forecast zone and economic sector. Projections for future economic and demographic trends, weather, and rates are developed for the forecast period, and the relationships established previously are used to extend the energy consumption into the future. These projections are also specific to forecast zone and economic sector.

However, there are several modifiers to this process. Climate trends are considered, and anticipated policy and technology changes can cause significant deviations from the historical trends and must be considered independently.

A flowchart showing the general forecast process is shown in Figure 14.

201 Recognizing the process alignment needs and schedules of the CPUC and California ISO planning, the CEC also provides an update to the IEPR forecast in even-numbered years.

Figure 14: Flowchart of Forecast Process



Many inputs are considered in forecasting electricity and gas demand, including historical trends; energy programs, codes, and standards; weather and climate projections; economic and demographic data; and decarbonization goals and policies.

Source: CEC

Residential Sector End-Use Model Updates

For the 2023 IEPR forecast, the CEC worked with a contractor to rebuild the residential sector end-use model. The residential end-use calculations have been updated and converted to the "R" programming language.[202] This modernization improved the usability, flexibility, and granularity of the model.

The model update incorporates residential appliance saturations and energy usage from the most recent Residential Appliance Saturation Study completed in 2019[203] and accounts for changes to relevant codes and standards. Improvements in building thermal integrity and the

202 "R" is a free integrated suite of software for data manipulation and analyses, and is often used for statistical analyses.

203 DNV GL Energy Insights USA, Inc. 2020. [*2019 California Residential Appliance Saturation Study*](https://www.energy.ca.gov/publications/2021/2019-california-residential-appliance-saturation-study-rass). California Energy Commission. Publication Number: CEC-200-2021-005-ES, https://www.energy.ca.gov/publications/2021/2019-california-residential-appliance-saturation-study-rass.

increase to average home square footage have been captured. The model incorporates weather sensitivity inputs for climate-sensitive end uses, such as home space heating and cooling. The list of end uses has been expanded to include specific home office equipment and air cleaners. Home energy usage is analyzed according to the 20 CEC forecast zones, providing increased spatial granularity than previous years.

BTM Distributed Generation and Storage Updates

Distributed generation forecast updates include (1) transitioning to using the National Renewable Energy Laboratory's (NREL) Distributed Generation Market Demand (dGen) tool, (2) refreshed hourly PV generation profiles, (3) updated BTM energy storage profiles, and (4) revised historical BTM solar PV and energy storage capacity data.

NREL's dGen tool simulates adoption of PV and PV paired with storage for residential and nonresidential sectors.[204] CEC staff worked with NREL to adapt its dGen tool to California, and the adapted tool includes the Net Billing Tariff that went into effect in April 2023 and the federal ITC extension announced in August 2022. Stand-alone BTM storage adoption and installations stemming from the Title 24 energy code[205] are modeled outside the dGen tool.

In 2023, CEC staff procured historical BTM PV generation profiles for residential and nonresidential systems, aggregated by CEC forecast zone. These data were used to inform the PV generation profiles for the forecast period and calibrate the hourly load model.

CEC staff acquired the latest nonresidential BTM energy storage profiles from CPUC's SGIP for the 2023 forecast. These profiles, developed by Verdant Associates, reflect the most recent data from BTM energy storage patterns for nonresidential systems in California. The data are categorized by building type and configuration (stand-alone systems and those with onsite PV). Updated residential sector profiles from the SGIP were not available, so CEC staff followed the previously established method and created profiles from NREL's System Advisor Model to inform BTM energy storage charge and discharge behavior for the forecast period.

Lastly, during 2023, CEC staff improved the process to measure historical BTM PV capacity and energy storage capacity. The CEC collects interconnection data from the utilities under Title 20.[206] Previously, historical energy storage capacity values were derived from data available

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204 Distributed Generation Market Demand Model, https://www.nrel.gov/analysis/dgen/.

205 California Code of Regulations Title 24. Building Standards Code — Building Energy Efficiency Standards https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards; https://www.dgs.ca.gov/BSC/Codes.

206 California Code of Regulations; Title 20. Public Utilities and Energy; Division 2. State Energy Resources Conservation and Development Commission (Refs & Annos); Chapter 3. Data Collection; Article 1. Quarterly Fuel

from the CPUC's SGIP. Improvements to cleaning the interconnect datasets resulted in a slightly lower estimate of installed PV capacity than was used for the 2022 IEPR forecast; however, results are consistent with other sources, such as the California Distributed Generation Statistics.[207] The 2023 IEPR forecast estimate of BTM PV capacity in 2021 was 6.6 percent lower than the 2022 IEPR forecast estimate of capacity for 2021. Switching from the SGIP data for storage to the interconnect data resulted in higher estimates of installed storage capacity. The 2023 IEPR forecast estimate of BTM storage capacity in 2021 is 46 percent higher than the 2022 IEPR forecast estimate of capacity for 2021.

Climate Change Trends and Forecast Improvements

Accounting for the impacts of climate change is critical to developing an annual and hourly forecast. CEC staff is leveraging open, quality-controlled climate projections and historical weather data to model climate trends and incorporate these projections into the forecast.

Climate Change Trends

Over the last two decades, staff has advanced several changes to the CEC's demand forecast process to improve accounting for climate change impacts. These advancements continue to evolve alongside the climate modeling efforts, analyses, and datasets needed to support the development of these advancements. Ongoing research supported by EPIC has delivered a suite of hybrid (statistical-dynamical[208]) downscaled, bias-corrected projections over California at a 3 kilometer (km) by 3 km resolution. The research portrays daily temperature, precipitation, relative humidity, wind, and surface solar radiation. Further, the research provided a smaller set of WECC-wide dynamically downscaled projections that include a more comprehensive, hourly set of weather statistics at 3 km by 3 km resolution. This level of detail allows staff to begin incorporating climate-impacted weather scenarios into all weather-sensitive elements of the CEC's demand forecast modeling. This effort is supported by several EPIC applied research efforts, including the Cal-Adapt Analytics Engine, which provides

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and Energy Reports, https://govt.westlaw.com/calregs/Document/ICBA37BB35CCE11EC9220000D3A7C4BC3.

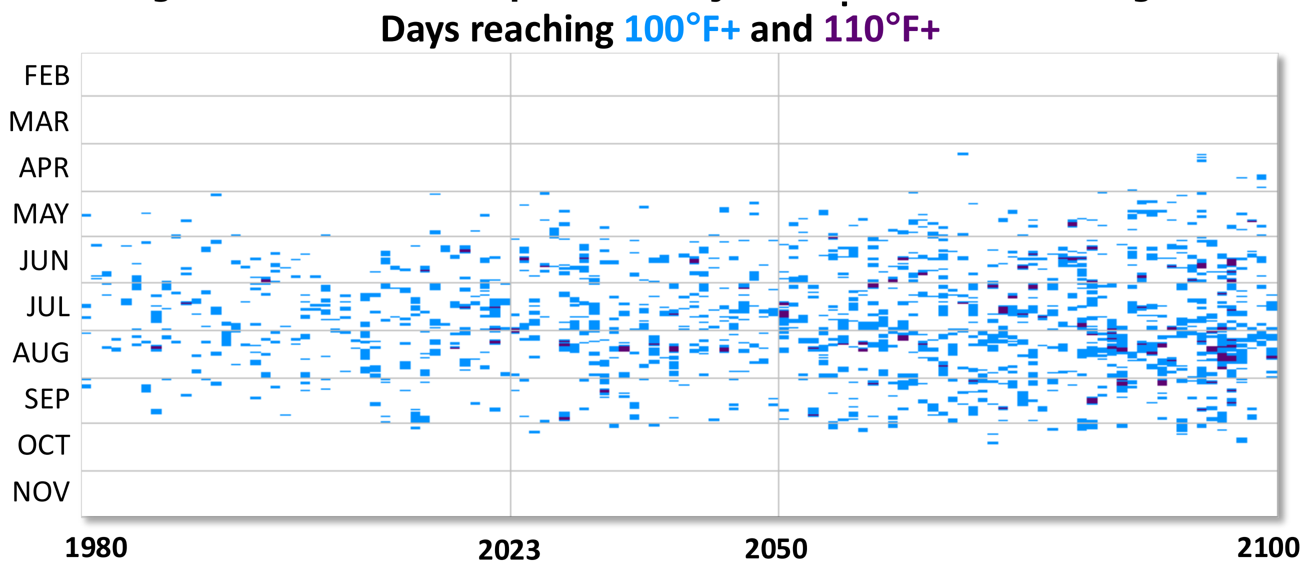
207 California Distributed Generation Statistics is the official public reporting site of the California Solar Initiative (CSI), presented jointly by the CSI Program Administrators, GRID Alternatives, the California investor-owned utilities, and the CPUC. https://www.californiadgstats.ca.gov/.

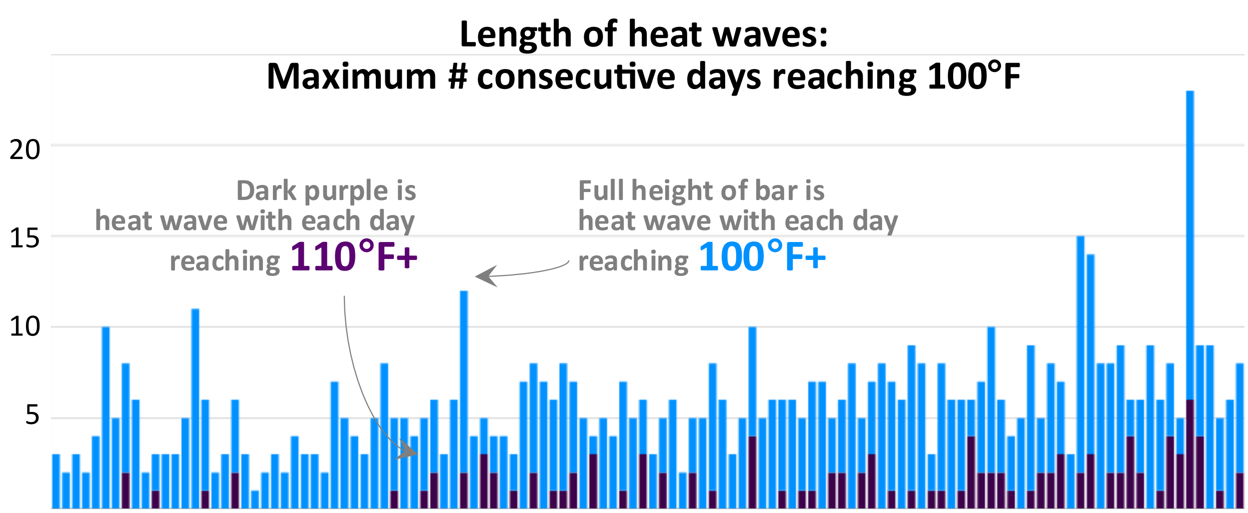
208 Statistical-dynamical downscaling methods blend dynamical and statistical techniques. They incorporate historical statistical relationships between coarse resolution climate behavior and fine-scale weather patterns, as well as projected relationships depicted in dynamical models. This liberates modeling from the assumption that historical relationships will prevail in the future while maintaining computational efficiency.

analytic support for "localizing" projections to nearby weather stations, based on historical observed data that provide a basis for bias correction.

Figure 15 illustrates one such localized temperature projection for the Sacramento region under a GHG emission scenario rooted in the "Business as Usual" Shared Socio-Economic Pathway (SSP3-7.0). The graph shows an increase in the frequency of extremely hot days, prolonged heat waves, and an elevated number of warm months in the future. There is also a discernible upward trend in the number of days with a maximum temperature reaching 100 degrees Fahrenheit (100°F) throughout California. While previous forecasts have considered expected increases in *average* temperature, the trends depicted in Figure 15 underscore the importance of expanding climate considerations in the forecast to reflect novel weather patterns and changes to the magnitude, frequency, and duration of extreme temperatures.

Figure 15: Extreme Temperature Projections — Sacramento Region





Climate models show an increased number of extremely hot days and it is important to reflect changes in magnitude, frequency, and duration of extreme temperatures in the forecast.

Source: Lumen Energy Strategy

Improvements to Incorporating Climate Change in the Forecast

System reliability planning in the context of a changing climate requires the demand forecast to consider a broad range of likely or possible weather patterns. The 2023 IEPR forecast represents a shift away from the CEC's traditional practice of sampling only the historical record to define the range of possible weather patterns. Instead, it relies also on projected weather patterns from high-resolution projections derived from four global climate models (GCMs)[209] under the SSP3-7.0 scenario. For a given forecast year, each of these four projections represents only a single instance of possible weather patterns, which by itself does not represent enough variation to establish estimates of normal or extreme conditions. Relying on analytic support from Lumen Energy Strategy, staff leveraged a "detrending" method to better incorporate the variation reflected in the GCM projections.

The detrending method can be summarized in two parts. First, a long-term trend is established over the full climate simulation period. Second, for a given forecast year, data for a 51-year window centered around that year are adjusted to remove the trend while retaining the level of warming as well as the weather patterns projected for the neighborhood around that year. This approach increases the number of weather patterns available for analysis from 4 to more than 100 per year.

The detrended climate projections allowed staff to make key changes to its forecast process. The CEC's annual energy demand models, for example, were updated to reflect new projections for key statistics, such as maximum and minimum daily temperature and heating and cooling degree days.[210]

Peak electricity demand is highly sensitive to weather, so the CEC's peak demand forecast is developed assuming different weather variants, including "normal" peak load conditions as well as conditions that should be expected only once in every 5, 10, or 20 years. Staff has traditionally relied on the historical record to establish these thresholds. For the 2023 IEPR forecast, staff relied instead on detrended climate projections to establish these thresholds for present-day conditions.

The changes described above represent just an initial effort to leverage these newly available climate data. Further, staff is collaborating under EPIC-funded agreements with Lumen Energy Strategy and Cal-Adapt: Analytics Engine team to improve climate considerations iteratively in

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209 The four GCMs are CESM2, CNRM-ESM2-1, EC-Earth3-Veg, and FGOALS-g3.

210 Heating degree days (HDD) refers to days in which the average temperature is below 65°F. The associated space heating requirements are quantified by how many degrees below 65°F the daily average is. Cooling degree days (CDD) refers to days in which the average temperature is above 65°F. The CDD space cooling requirements are quantified by how many degrees above 65°F the daily average temperature is.

the demand forecast and further validate the detrending approach, (such as through sensitivity analyses and investigation of how detrended data portray extremes of interest to grid planning). This effort has already identified other opportunities for improvement that will be taken up in future IEPR cycles. As noted during the August 18, 2023, IEPR workshop, for example, several load modifiers within the CEC's demand forecast — such as energy efficiency and fuel substitution — are weather-sensitive and should be modified to reflect evolving and novel weather patterns.

Load Modifiers and the Additional Achievable Scenario Framework

The framework for additional achievable load modifiers focuses on energy impacts from policy and programs that are reasonably expected to occur and have significant and unique effects on system load. These load modifiers are Additional Achievable Energy Efficiency (AAEE), Additional Achievable Fuel Substitution (AAFS), and Additional Achievable Transportation Electrification (AATE).

AAEE and AAFS focus on firm programs and policies with scenario numbers used to indicate different potential demand impacts. Higher-numbered AAEE or AAFS scenarios indicate greater impacts, such as increased efficiency or increased fuel substitution. AATE focuses on supply-side policies that are expected to increase energy demand from zero-emission vehicles that involve electric propulsion, such as battery-electric vehicles or fuel cell electric vehicles. The objective for these load modifier scenarios is to use them for electricity system planning and procurement.

AAEE and AAFS reduce gas consumption. While AAEE reduces electricity consumption, AAFS increases electricity consumption. Thus, the effects of AAEE are considered "savings," and the effects of AAFS are referred to as "impacts." Only savings or impacts above that which is already incorporated in the baseline energy consumption forecasts are retained. The AAFS impacts may contain incentive program inputs as well as technology-based fuel substitution modeled using the CEC's Fuel Substitution Scenario Analysis Tool (FSSAT). The general approach in defining the set of each of these additional achievable scenarios builds from conservative to aggressive or optimistic levels of savings or impacts, or Scenario 1 through Scenario 6. As a load modifier scenario increases, the size and scope of effort increase, implying more AAEE savings or AAFS impacts. These scenario variations can be summarized as follows:

- Scenario 1: Firm commitments
- Scenario 2: Scenario 1 plus "will occur but some uncertainty around impacts."
- Scenario 3: Scenario 2 plus "reasonable to occur with greater uncertainty about impact magnitudes."
- Scenario 4: Scenario 3 plus "likely to occur but still in planning phases."
- Scenario 5: Scenario 4 plus "more speculative programs, perhaps in early planning phases."
- Scenario 6: Scenario 5 plus "programs that could exist in the future and would be required to meet some policy goals."

Each AAEE and AAFS scenario considers different elements of existing demand-modifying programs and standards and potential impacts from future programs, policies, and standards that are reasonably likely to occur.

AATE generally tends to increase electricity consumption above the baseline forecast. AATE incorporates supply-side policies that are not capable of being modeled under existing transportation energy demand models. These policies include CARB's Advanced Clean Cars II regulation, Advanced Clean Fleets regulation, and the Clean Miles Standard. For the *2023 IEPR,* staff developed only one scenario above the baseline forecast, AATE Scenario 3. More information on this approach is available in the section below on AATE Updates.

For each load modifier, the third scenario is used for the planning scenario. For general consistency in the AA scenario numbering framework, the title "AATE Scenario 3" is used despite there not being other AATE scenarios.

Additional Achievable Energy Efficiency (AAEE)

AAEE accounts for the incremental energy savings from market potential that is not included in the baseline demand forecast but is reasonably expected to occur. Annual and hourly savings are developed for each forecast year at the utility service territory or forecast zone level. These savings include many future updates of building standards, appliance regulations, and new or expanded energy efficiency programs. AAEE is central to developing a managed demand forecast, which, in turn, is the basis for resource planning and procurement efforts at the CPUC and the California ISO.

Senate Bill 350 (De León, Chapter 547, Statutes of 2015) directed the CEC to establish annual targets to double statewide energy efficiency savings in electricity and gas by the beginning of 2030. The basis of this doubling is the mid-case estimate of AAEE savings in the California Energy Demand Updated Forecast, 2015 to 2025, extended to 2030.[211] A constraint is that the doubling must be cost-effective, must be feasible, and will not adversely impact public health and safety. Updated SB 350 projections will be discussed in the *2023 California Energy Efficiency Action Plan* to be published in 2024.

Developing a portfolio of AAEE scenarios is the mechanism for capturing reasonably expected savings from programs developed in support of several goals and standards. These savings projections include programs developed to support SB 350 aspirational goals, California Building Standards (Title 24), California (Title 20) and federal appliance standards, and

211 Kavalec, Chris. 2015. *California Energy Demand Updated Forecast, 2015-2025*. California Energy Commission. Publication Number: CEC-200-2014-009-CMF. https://www.sandiegocounty.gov/content/dam/sdc/pds/ceqa/JVR/AdminRecord/IncorporatedByReference/Section-3-1-2---Energy-References/CEC%202015a.pdf.

potential program savings projected by investor-owned utilities (IOUs) and publicly owned utilities (POUs). As in the 2021 IEPR forecast, scenario design condenses forecast uncertainties into six scenarios ranging from conservative to optimistic. Since the CEC has explicit agreements with other agencies that plan on using specific AAEE scenarios in various resource planning and transmission planning studies, staff rigorously vets scenario design with stakeholders throughout a multistep process.

As for the 2021 IEPR forecast, the 2023 AAEE scenarios focus on the variability of potential energy efficiency savings, and each uses the baseline economic, demographic, and rates projections. Thus, the 2023 AAEE scenarios all share the same assumptions for building stock and retail rates. Staff included a range of three reasonably expected scenarios, one more conservative and one more aggressive than the business-as-usual (BAU) AAEE 3 forecast. Also, staff considered a very conservative savings scenario (Scenario 1) and two more optimistic high-energy-efficiency-savings scenarios (Scenarios 5 and 6). The most optimistic AAEE scenarios maximize the impacts of existing programs and include potential achievable savings beyond those expected from existing programs or standards. These energy efficiency savings are more speculative, but they may be realized through current and new programs.

Additional Achievable Fuel Substitution (AAFS)

AAFS was introduced in the *2021 IEPR* in a manner analogous to AAEE. *Fuel substitution* refers to substitution of one end-use fuel for another, such as changing out gas appliances in buildings for cleaner, more efficient electric appliances. AAFS, like AAEE, is an annual and hourly load modifier to the baseline demand forecast.

AAFS scenarios capture reasonably expected impacts from programs developed in support of several goals and standards. These programs include programs developed to support SB 350 goals, California Building Standards (Title 24), and potential program impacts projected by IOUs and POUs. As in the previous *2021 IEPR*, scenario design condenses forecast uncertainties into scenarios ranging from conservative to optimistic. For 2023, six scenarios were developed. Staff included a range of three reasonably expected scenarios, one more conservative and one more aggressive than the business-as-usual (BAU) AAFS 3 forecast.

Also, staff considered a very conservative savings scenario (Scenario 1) and two more optimistic high-energy-efficiency-savings scenarios (Scenarios 5 and 6). The BAU AAFS 3 Scenario includes Zero-Emissions (ZE) Standards impacts, as described in CARB's State SIP Strategy in 2022 detailed in the subsequent section, which dominate the programmatic contributions after 2030. The most optimistic AAFS scenarios maximize the impacts of existing programs and include potential achievable savings beyond those expected from existing programs or standards, along with significant contributions from ZE Standards modeling. The potential ZE impacts dwarf programmatic contributions past 2030.

The 2022 State SIP Strategy presents a concept that by 2030 all space and water heaters sold in California for either new or existing residential and commercial buildings must comply with a statewide zero-emission GHG standard.[212] CARB began public engagement for the zero-emission space and water heater measure in 2023, and anticipates bringing a proposal to the Board in 2025. Further, on March 15, 2023, the BAAQMD Board of Directors adopted zero-emission NO_X standards that go into effect for water heaters beginning in 2027 and space heating beginning in 2029.[213]

AAEE and Programmatic AAFS Updates for 2023

Improvements to the 2023 AAEE and AAFS scenarios include:

- A more robust analysis of beyond-utility programs (programs not run by IOUs or POUs or not reported by them) that were originally evaluated in the 2019 IEPR forecast, as well as consideration of additional programs developed since or otherwise not included in the 2021 IEPR forecast.
- Addition of building type or subsector/segment-level disaggregation to all outputs.
- Revision of the Title 24 Building Energy Efficiency Standards analysis to be based directly on the measures at the sector and segment levels. This measure-based analysis can then be rolled forward as specific measures are likely to be adopted for future code cycles rather than the original "percent better than" a previous code cycle approach.
- Addition of basic cost calculations for each scenario so the value of various energy efficiency impacts can begin to be quantified.
- Enhancement of software tools to group savings streams to allow extrapolation of potential savings to midcentury.

Improvements to the 2023 AAFS scenarios include:

- A more robust analysis of beyond-utility programs that were originally evaluated in the *2021 IEPR* (such as the TECH and BUILD programs), as well as consideration of additional programs not included in the *2021 IEPR*.

212 CARB. September 2022. *2022 State Strategy for the State Implementation Plan*. Pages 101–103, https://ww2.arb.ca.gov/sites/default/files/2022-08/2022_State_SIP_Strategy.pdf.

213 BAAQMD press release. March 15, 2023. "Air District Strengthens Building Appliance Rules to Reduce Harmful NOx Emissions, Protect Air Quality and Public Health," https://www.baaqmd.gov/~/media/files/communications-and-outreach/publications/news-releases/2023/barules_230315_2023_003-pdf.pdf?la=en&rev=73fdaf7bb91b475b9b7913c133c31737.

- Addition of impacts from programs funded in response to the Equitable Electrification and Clean Energy Reliability Investment Plan.[214]
- Addition of electrification impacts from the Inflation Reduction Act, High Efficiency Electric Home Rebate Act, and whole-house Homeowner Managing Energy Savings
- Addition of locally targeted electrification impacts driven by local government ordinances or load-serving-entity decarbonization programs.
- Update of the compliance pathway most likely to be chosen by builders to meet the 2022 Title 24 requirements. The options are either (1) enhanced energy efficiency measures via a performance calculation or (2) electrification measures based on building climate zone as delineated in the Title 24 Building Energy Efficiency Standards analysis.

Zero-Emission Standards Modeling as Part of Select AAFS Scenarios for 2023

California's climate goals have made building decarbonization a priority. Since the 2021 adoption of Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018) California Building Decarbonization Assessment Report, several new goals and proposed regulations have been introduced.[215] The report showed that enormous technological transformation is required for California to meet its 2030 GHG emission targets, especially in the existing buildings sector. Soon after the adoption of the report, the CEC recommended in the *2021 IEPR* an installed heat pump goal of 6 million by 2030. Building off that recommended goal, Governor Newsom, in a letter to CARB in July 2022, restated the 6 million heat pump goal and set a new goal of 3 million climate-ready and climate-friendly homes by 2030 and 7 million by 2035.[216]To help support the state's goals of more heat pumps, the top global building appliance manufacturers and distributors committed to helping California achieve the 6 million heat pump goal at the

214 Erne, David, California Energy Commission. 2023. *Clean Energy Reliability Investment Plan.* California Energy Commission. Publication Number: CEC-200-2023-003-CMF, https://www.energy.ca.gov/publications/2023/clean-energy-reliability-investment-plan.

215 Kenney, Michael, Nicholas Janusch, Ingrid Neumann, and Mike Jaske. August 2021. *California Building Decarbonization Assessment*. CEC. Publication Number: CEC-400-2021-006-CMF, https://www.energy.ca.gov/publications/2021/california-building-decarbonization-assessment.

216 Governor Gavin Newsom. July 22, 2022. Letter from Governor Newsom to CARB Chair Liane Randolph. https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf.

November 2023 Buildings Electrification Summit hosted by the CEC and Electric Power Energy Institute (EPRI).[217]

CARB began public engagement on a potential zero-GHG-emission appliance standard in 2023 that would go into effect for space and water heaters in 2030. As part of the 2022 State Strategy for the State Implementation Plan (2022 State SIP Strategy) approved in September 2022 by CARB, this statewide standard would require all new space and water heaters sold in California for either new or existing residential and commercial buildings to comply with a statewide zero-emission GHG standard. CARB anticipates bringing a proposal to the Board for consideration in 2025.

Many uncertainties exist with these zero-emission appliance standards and other regulations that will spur building decarbonization. There are legal, regulatory, and adoption and compliance uncertainties that will affect the pace of market transformation. The regulatory uncertainty involves the regional regulatory differences, the scope of end uses and fuel types, and the timing of when the standards will go in effect. The adoption and compliance uncertainty depends on behavioral responses to the regulation, such as strategic avoidance behavior where people might avoid switching to a zero-emission appliance.

The rapid adoption pathway also poses readiness uncertainties regarding manufacturer capacity, grid capacity, and the gas system. To address this uncertainty, the Bay Area AQMD requires implementation working groups to submit interim reports that discuss market readiness two years before the compliance data for its zero-emission NOx standards. As more data and information unfold on the status of market readiness and transformation, CEC staff may revise its expectations of future adoption and compliance rates. Moreover, California's state budget cuts may also affect building decarbonization incentive programs funded by the state.

The 2023 AAFS scenarios include various levels of potential impacts from different possible implementation strategies guided by CARB's concept of a zero-emission appliance regulation and the local air quality management districts. These were included as part of AAFS Scenarios 3–6 similar to the method used for 2022 IEPR Local Reliability scenario, as described in the *2022 IEPR Update*, but in a more nuanced manner. FSSAT-modeled ZE Standards are in each scenario (AAFS 3–6) incremental to the programmatic AAFS impacts for the identically numbered scenario (AAFS 3–6). Staff created scenarios representing more conservative and

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217 CEC news release. October 10, 2023. "Top Global Building Appliance Manufacturers and Distributors Commit to Help California Achieve Six Million Heat Pump Goal." https://www.energy.ca.gov/news/2023-10/top-global-building-appliance-manufacturers-and-distributors-commit-help.

more optimistic versions of the proposed zero-emission space and water heater regulation. To summarize:

- AAFS 3–6 Scenarios: Adoption in new construction for space and water heating is 100 percent in the residential sector beginning in 2026 and 2029 for the commercial sector. Locally, the model assumes 100 percent replacement on burnout starting in 2027 for water heaters and 2029 for space heaters within the Bay Area AQMD.
- AAFS 3 Scenario: Assumes for the remaining parts of the state 100 percent replacement on burnout of space and water heaters beginning in 2030 and a downward adjustment in the statewide linear ramp-up adoption rate beginning in 2026.
- AAFS 4 Scenario: Same as AAFS 3 Scenario, but with different programmatic additional achievable assumptions and without a downward adjustment in linear adoption rate during the interim years before 2030.
- AAFS 5–6 Scenarios: Adds cooking and clothes drying end uses that follow the same adoption and compliance rates as space and water heaters. Residential propane for new construction and replace on burnout are included.
- AAFS 6 Scenario: Assumes that the efficiency of replacement technologies are more efficient than the other scenarios. The 100 percent compliance rate for the South Coast AQMD is accelerated to begin in 2029 instead of 2030.

AATE Updates

The major recent change to the transportation forecast, beginning with the *2022 IEPR Update,* is the AATE framework. Like AAEE and AAFS, the AATE framework more directly accounts for the effects of new ambitious policies under a set of scenarios, each of which is reasonably expected to occur given market, policy, and programmatic conditions.

The AATE framework begins with a baseline, econometrically driven forecast, which is methodologically consistent the mid-case forecast method in the *2021 IEPR* and previous forecasts. Thus, the baseline forecast includes various policies such as vehicle incentives and regulations that are straightforward to model for energy demand, such as CARB's Innovative Clean Transit regulation. For the 2023 IEPR forecast, CEC staff updated the main inputs for both LD and MDHD sectors. Further information about the baseline transportation energy demand forecast is available in the *2022 IEPR Update*.

AATE Scenario 3 maintains the same basic framework as the previous forecast, with some minor improvements. Because of the higher-than-expected ZEV adoption in the first half of 2023, AATE 3 and the baseline forecast had a meaningful difference, but not enough of a difference to justify an AATE Scenario 2 or 1. The largest improvement for the baseline forecast, which also affects AATE 3, is for light-duty vehicles. This improvement involves a postprocess approach to travel model outputs to incorporate the Clean Miles Standard. The

Clean Miles Standard requires transportation network companies such as Uber and Lyft to increase the proportion of clean miles driven by vehicles that provide these services.[218]

AATE Scenario 3 assigns load at the forecast-zone level, consistent with the rest of the forecast. Because transportation electrification represents a large source of new load and the geographic distribution of such load is not well understood, the AATE framework may expand in future forecasts to align with other infrastructure planning needs.

Hourly Forecast Updates

The CEC's hourly demand forecast begins with a base profile intended to reflect normal levels of end-user electricity consumption for every hour over a typical year. These profiles are scaled according to the CEC's annual consumption forecast, with one caveat. Certain high-growth elements of the forecast are first removed because they exhibit a load pattern characteristically different from the base profile. Each "load modifiers" has a unique profile that is layered onto the base profile to create the final hourly forecast.

This cycle, staff leveraged newly available data sources to update key load modifier profiles. As discussed in earlier sections, staff updated climate change impacts to reflect trends indicated by new, detrended climate libraries described earlier. Staff also updated nonresidential behind-the-meter storage profiles to reflect the CPUC's most recent evaluation of its SGIP.

The CEC recently procured metered PV system data, which allowed for several significant updates. First, staff updated the PV generation profiles used in the forecast to reflect average system performance from 2016 to 2022. Second, staff used the data in conjunction with California ISO system load and resource data to redevelop a historical record of hourly end-user consumption. Third, this updated consumption history was then used to re-estimate the hourly load models that predict the base profile.

Once the hourly models are estimated, updating the base profile is a matter of simulating load-duration curves for a variety of realistic weather patterns, selecting median values for each hour by rank, and assigning those median values to specific hours of the calendar year. As was the case in past IEPR cycles, staff used the historical record to simulate present-day load response to a variety of weather patterns. As part of the 2024 IEPR Update cycle, however, staff will begin vetting a process for using detrended climate data to provide the

218 The Clean Miles Standard came about as a result of Senate Bill 1014 (Skinner, Chapter 369, Statutes of 2018), which called on CARB to adopt, and the CPUC to implement, annual GHG reduction targets that transportation network companies must meet. CARB's Clean Miles Standard regulation, codified in 2022, also requires an annual increase in the percent of zero-emission passenger miles traveled (using ride-hailing services), starting at 2 percent in 2023 and ramping up to 90 percent in 2030 and beyond.

variation needed to develop a baseline profile specific to each year of the forecast. This process would allow the base profile to evolve over the forecast horizon consistent with climate projections.

Finally, because of the base profile update of this cycle, load impacts from default time-of-use rate impacts are assumed embedded and no longer reflected as a distinct load modifier.

Summary of Key Drivers and Trends

The energy demand forecast has numerous underlying assumptions and inputs, including economic and demographic data and climate trends that affect how the state uses energy. It also accounts for policies and goals that guide forecast assumptions for energy efficiency, building and transportation electrification, distributed generation, and battery storage technologies.

Economic and Demographic Trends

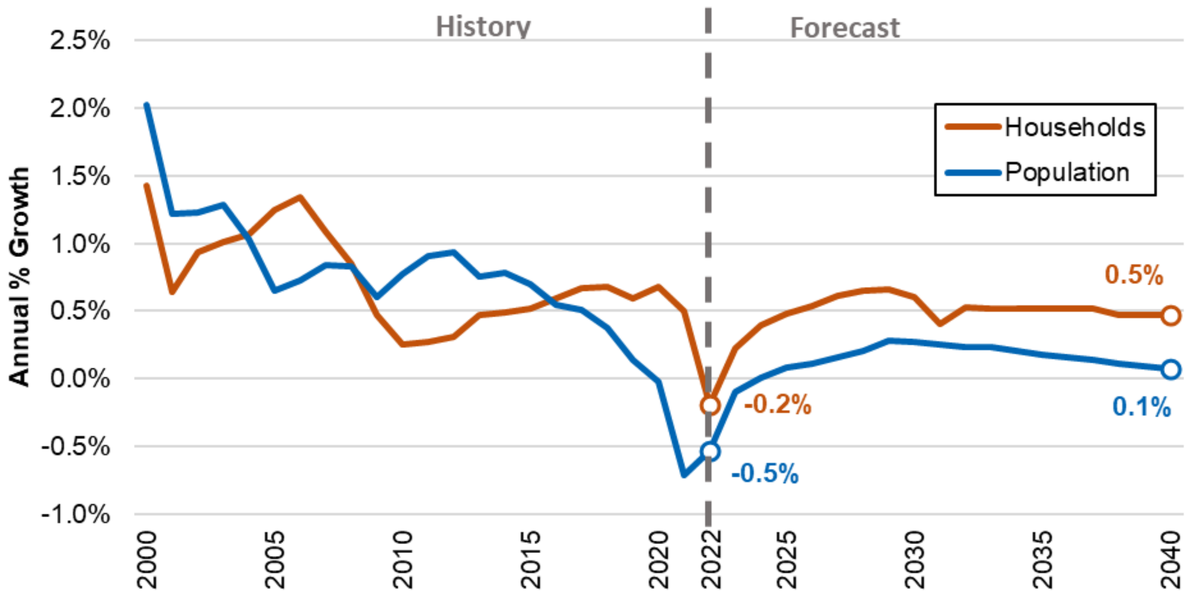
Personal income, gross state product, and manufacturing output are projected to grow at similar rates as previously forecasted. Refer to Appendix F for details on these projections. The population and household projections are lower than previous projections and are discussed below. An overview of economic and demographic trends was discussed at the August 15, 2023, IEPR Inputs & Assumptions Workshop.

Population and Households

Based on data from the California Department of Finance (DOF), statewide population for 2023 IEPR forecast grows 0.2 percent annually from 2023 to 2040, lower than the 0.4 percent annual growth rate assumed in in the 2022 IEPR forecast. The 2023 total population for California is 39.0 million and is projected to reach roughly 40 million by 2040 (2.9 percent total growth). In 2022, statewide population declined by about 0.5 percent, as noted in Figure 16. The slowdown in population growth can be attributed to slow in-migration and steady outmigration on top of an aging baby boomer population and declining fertility.

Statewide, the number of households is expected to grow at 0.5 percent annually from 2023 to 2040, slightly below previous projections from DOF. DOF estimates that there are 13.3 million households in 2023 and roughly 14.6 million by 2040 (9.3 percent total growth).

Figure 16: Statewide Population and Household Growth



Statewide population grows 0.2 percent annually from 2023 to 2040. The number of households is expected to grow at 0.5 percent annually from 2023 to 2040.

Source: CEC using data from DOF

BTM PV and Storage Trends

As noted previously, the CEC used an improved process for analyzing the Title 20 1304(b) interconnect data for the 2023 IEPR forecast, resulting in a slight decrease to historical PV capacity estimates. This process change resulted in a 6.6 percent decrease to historical PV capacity in 2021.[219]

From 2015 to 2020, California added about 1,200 to 1,500 MW of new BTM PV capacity annually. In 2021, this trend accelerated to 1,700 MW and then to 2,200 MW in 2022. By the end of 2022, there was roughly 14,370 MW of installed BTM PV capacity in California, as shown in Figure 17. The CEC estimates that roughly 24,000 gigawatt-hours (GWh) of electricity was produced by BTM PV systems in 2022.

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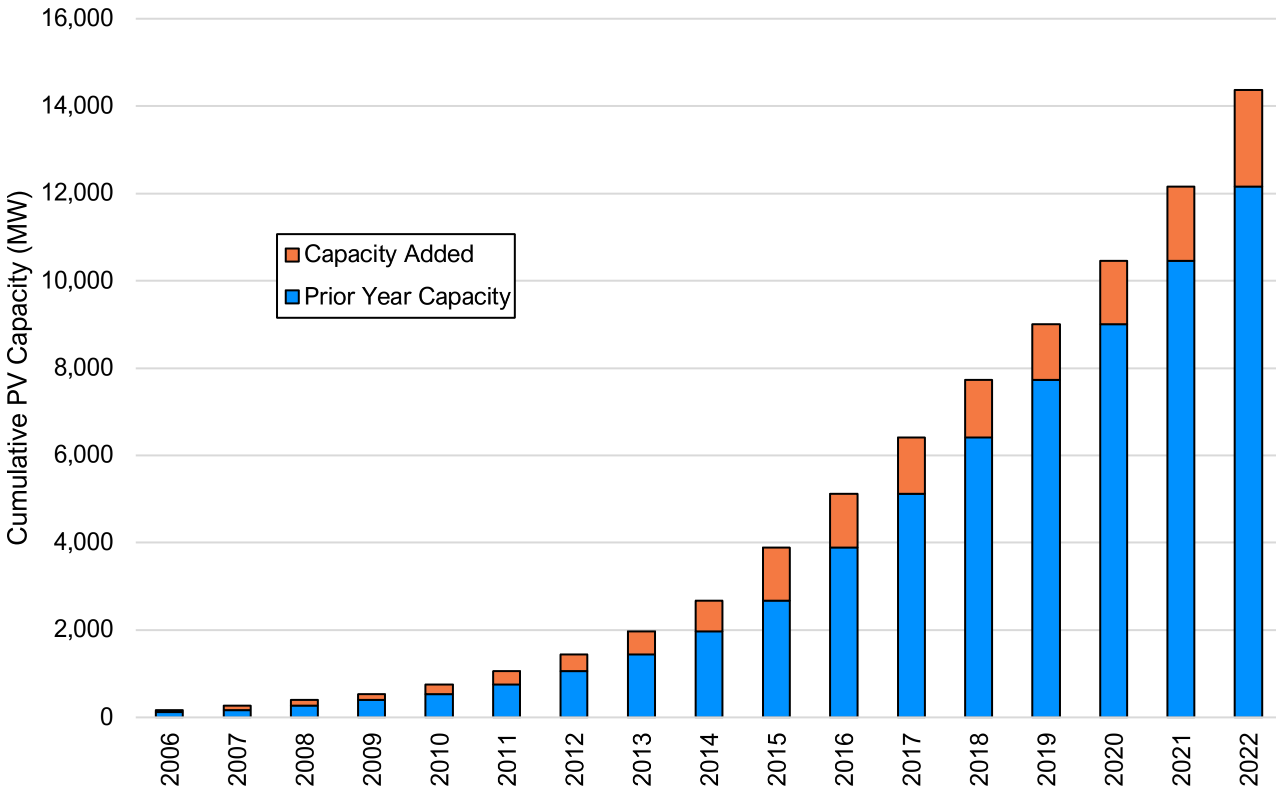
219 Refer to the materials from the DAWG meeting on August 8, 2023, for more details on the impacts of this process change to the historical PV and storage capacity estimates, https://www.energy.ca.gov/event/workshop/2023-08/ca-energy-demand-forecast-distributed-generation-updates-and-residential.

Figure 17: Cumulative BTM PV Capacity in California



By the end of 2022, more than 14,000 MW of BTM PV capacity was installed in California.

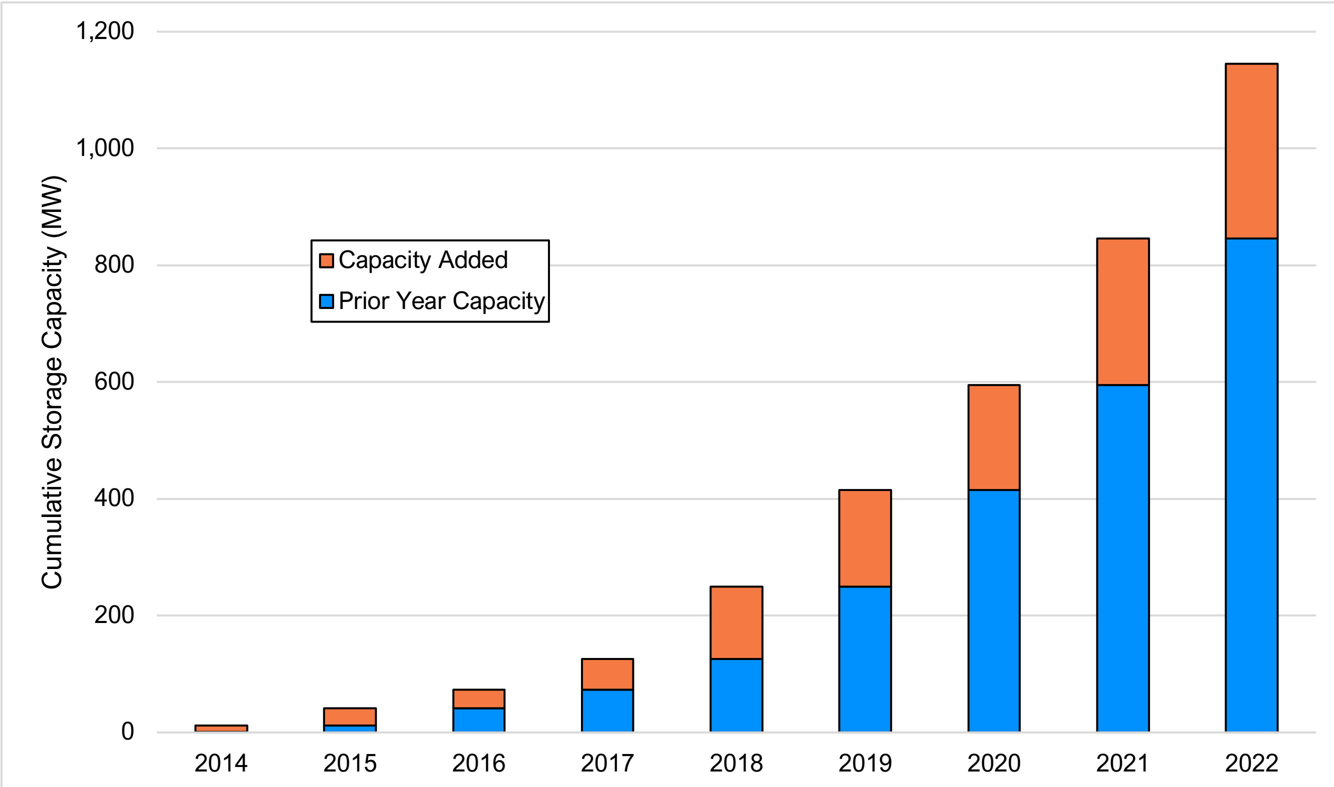
Source: CEC analysis of Title 20 1304(b) interconnect data

For the 2023 IEPR forecast, the Title 20 1304(b) interconnect data are used to estimate historical BTM storage capacity, which is a change from previous forecasts that relied on SGIP reports. Switching to the interconnect data results in an increase in the historical estimates of BTM storage capacity of 268 MW of capacity in 2021.[220]

In total, about 1,146 MW of BTM energy storage has been installed in California through 2022, with more than half installed in the last three years (Figure 18).

220 Ibid.

Figure 18: Cumulative BTM Storage Capacity in California

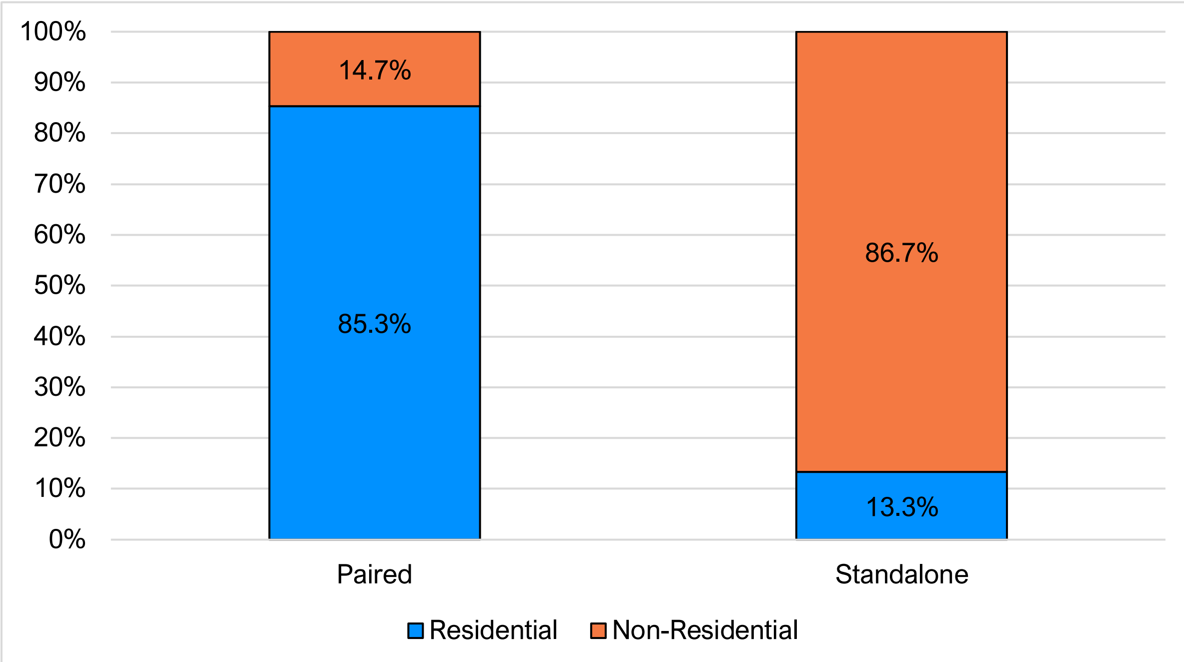


An estimated 1,140 MW of BTM energy storage has been installed in California through 2022, with more than half installed in the last three years.

Source: CEC analysis of Title 20 1304(b) interconnect data

Staff also distinguished between paired and stand-alone storage to model them separately. As a result, staff noted the difference in the respective markets; paired storage is nearly 90 percent residential, while stand-alone storage is nearly 90 percent nonresidential (Figure 19).

Figure 19: Energy Storage Sector by Pairing, 2022



Paired storage is nearly 90 percent residential, while stand-alone storage is nearly 90 percent nonresidential.

Source: CEC analysis of Title 20 1304(b) interconnect data

Transportation Trends

Several disruptions in 2022 led to unstable gasoline and diesel prices in 2022, including the highest gasoline price spike in California history. Although prices were generally lower in 2023, there was a notable price spike in the fall. Similar to what happened in 2022, the Governor directed CARB to take steps necessary to allow for an earlier transition to winter blend gasoline, which tends to have a lower retail price.[221]

Hydrogen prices began to increase in the second half of 2022 and continued on an upward trajectory in 2023 (Figure 20). This increase is due to:

- The high cost of the renewable hydrogen sold to consumers.

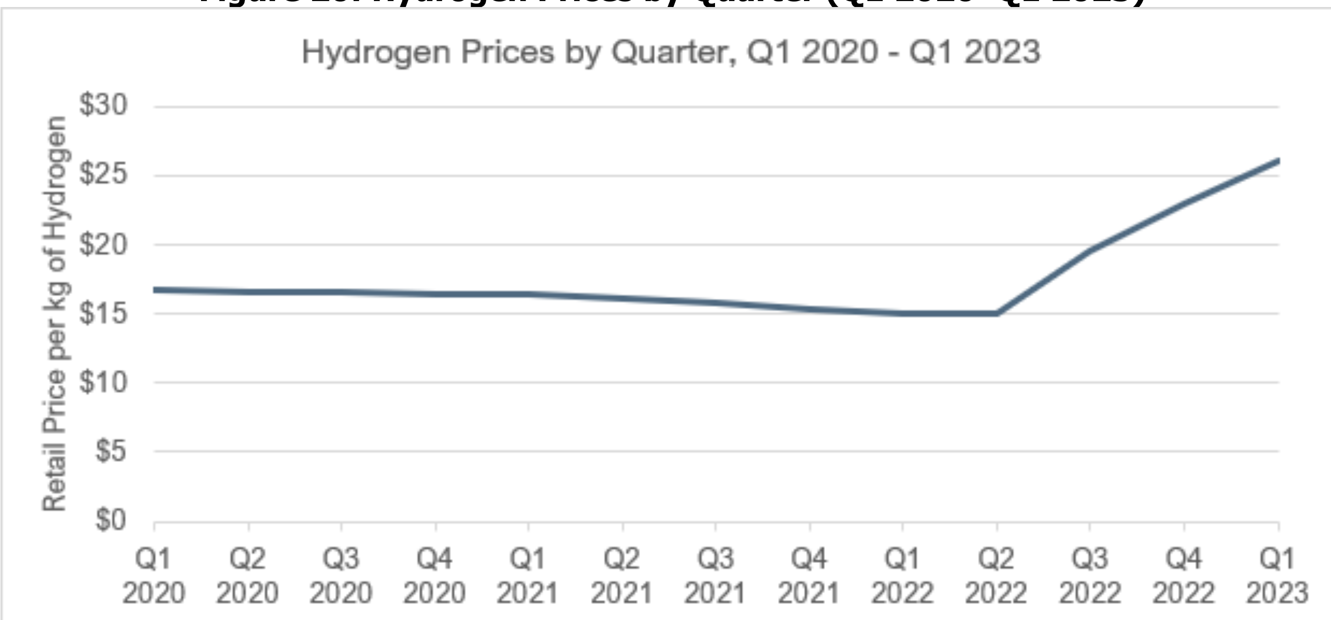
221 Letter from Governor Gavin Newsom to Liane Randolph (CARB) and David Hochschild (CEC). September 27, 2023. https://www.gov.ca.gov/wp-content/uploads/2023/09/Winter-Blend-Directive.pdf.

Letter from Governor Gavin Newsom to Liane Randolph (CARB). September 30, 2022. https://www.gov.ca.gov/wp-content/uploads/2022/09/9.30.22-Governor-Newsom-letter-to-CARB.pdf.

- Energy costs from high natural gas prices (a key input into nonrenewable hydrogen).
- Higher retail costs of retailing, such as labor and materials.
- The lower value of LCFS credits.

Statewide VMT decreased significantly in 2020 and partially recovered in 2021. As of June 2023, VMT for 2023 is almost completely recovered from prepandemic levels. Gasoline consumption, which provides a rough VMT indication, is lower than prepandemic levels. However, an increasing portion of miles driven are from ZEVs, reducing the demand for gasoline, so VMT levels reported by Caltrans are a better indicator.[222]

Figure 20: Hydrogen Prices by Quarter (Q1 2020–Q1 2023)



Hydrogen prices escalated at the end of 2022 and have continued an upward trajectory in 2023.

Source: CEC staff

CEC analysis of California Department of Motor Vehicles (DMV) data shows more than 1.1 million light-duty (LD) ZEVs registered in the state in 2022.[223] LD ZEV sales increased markedly beginning in 2020 and continue to increase. As of the third quarter of 2023, ZEVs represent

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222 For more information, see Caltrans Monthly Vehicle Miles of Travel web page at https://dot.ca.gov/programs/traffic-operations/census/mvmt.

223 For more information on ZEV sales and other light-duty passenger vehicle sales, see the CEC's Zero-Emission Vehicle Dashboard web page, https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics.

more than one-quarter of all new LD vehicles sold. This pattern holds despite recent supply chain challenges that have increased the price of vehicles generally, with ZEVs particularly affected. Supply chain challenges appear to have eased somewhat in 2023. However, some uncertainties remain, as the new vehicle market is now affected by increases in interest rates. Similar supply chain challenges exist in the MDHD ZEV market as well. Current DMV registration data show about 2,300 MDHD ZEVs as of the end of 2022.[224]

California Energy Demand Forecast, 2023–2040

Table 8 presents the final electricity forecast results and Table 9 presents the final gas forecast results.

Statewide electricity consumption was nearly 288,000 GWh in 2022, and consumption is projected to reach nearly 376,000 GWh in 2040. The baseline sales forecast represents the amount of electricity load-serving entities will need to provide to their customers and is derived by subtracting projected customer generation from the baseline consumption forecast. Baseline statewide sales were nearly 252,000 GWh in 2022 and grows to more than 299,000 GWh in 2040. The managed statewide sales incorporate the projected impacts of AAEE, AAFS, and AATE. For the planning forecast, managed statewide sales grow to just less than 352,600 GWh in 2040.

Table 8: Summary of Statewide Electricity Forecast Results in 2040

	Planning Forecast (Annual GWh)	Local Reliability Scenario (Annual GWh)
Baseline Consumption	375,869	375,869
Behind-the-Meter Distributed Generation and Storage	76,707	76,707

224 For more information on MDHD ZEVs registered for on-road travel, see the CEC's dashboard web page, https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics/medium-and-heavy.

	Planning Forecast (Annual GWh)	Local Reliability Scenario (Annual GWh)
Baseline Sales (Baseline Consumption — BTM DG and Storage)	299,162	299,162
AAEE	13,528	10,301
AAFS	42,313	39,759
AATE	24,617	24,617
Managed Sales (Baseline Sales – AAEE + AAFS + AATE)	352,563	353,235

Source: CEC

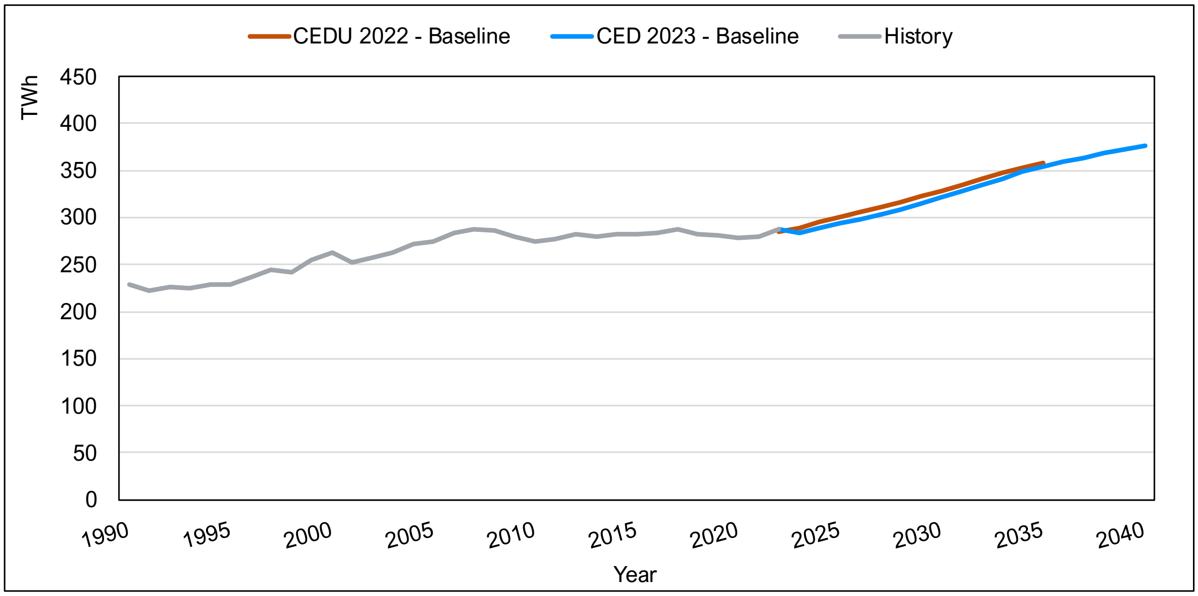
The peak demand forecast is derived from the annual consumption forecast by applying hourly load profiles to projected annual consumption. Peak forecasts are developed for balancing authorities, rather than for the state. The 2023 IEPR Planning Scenario peak forecast for the California ISO — which manages roughly 80 percent of California's load — reaches 62,632 MW by 2040.

The gas forecast is updated every two years, in the odd years. Statewide gas consumption in 2022 was 11,800 MM therms and baseline consumption is forecasted to be 11,900 MM therms in 2040. The managed gas sales corresponding to the planning scenario estimates the impacts of CARB's prerulemaking for a zero-emission appliance standard. Implementation of this standard as outlined in the 2022 State Strategy for the State Implementation Plan could reduce gas consumption by 46 percent from baseline consumption in 2040.

Annual Electricity Consumption Forecast

Forecasted baseline electricity consumption grows at an average rate of about 1.7 percent annually through 2040. By 2035, baseline consumption is about 1.9 percent lower than the 2022 IEPR forecast, largely due to slower projected growth rates in population and households and higher electricity rates. By 2040, baseline electricity consumption will be nearly 376,000 GWh.

Figure 21: Baseline Electricity Consumption (Statewide)



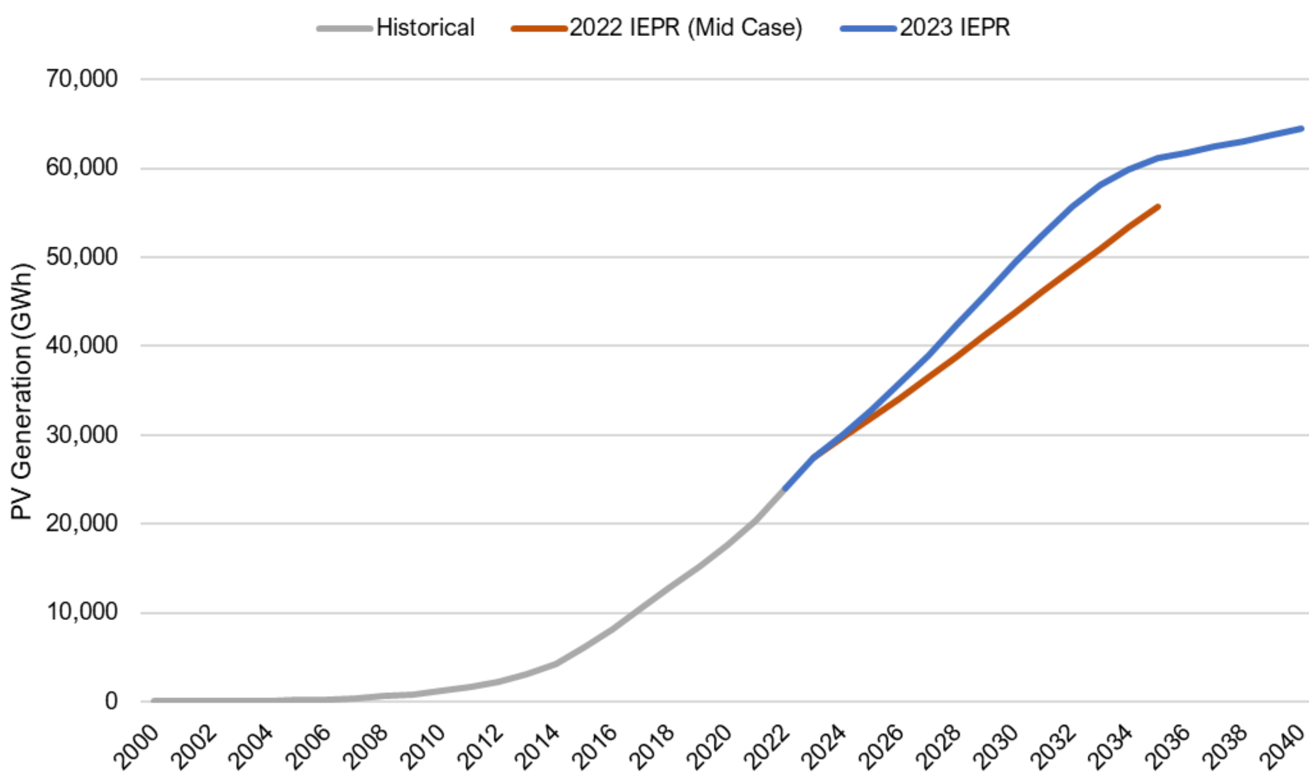
The 2023 IEPR forecasted baseline electricity consumption grows at an average rate of about 1.7 percent annually through 2040.

Source: CEC analysis

Electricity Sales Forecast

The 2023 IEPR sales forecast represents the amount of electricity load-serving entities will need to provide to their customers and is derived by subtracting projected customer generation from the consumption forecast. As such, the statewide sales forecast reflects many of the same characteristics as the consumption forecast, but the substantial amounts of incremental PV generation added each year reduce annual growth relative to consumption. Between 2023 and 2030, BTM PV generation grows on average by 8.8 percent. Between 2030 and 2040, annual growth slows to an average rate of 2.7 percent. By 2040, annual PV generation reaches 64,460 GWh. (See Figure 22.) The CEC's PV forecast incorporates policy changes through mid-2023, meaning the new net billing tariff is reflected in the capacity and generation numbers. Further, the Incentive Tax Credit is modeled out to 2034, based on the 2022 credit extension; the leveling off toward the end of the forecast period is due to the expiration.

Figure 22: Annual Behind-the-Meter PV Generation

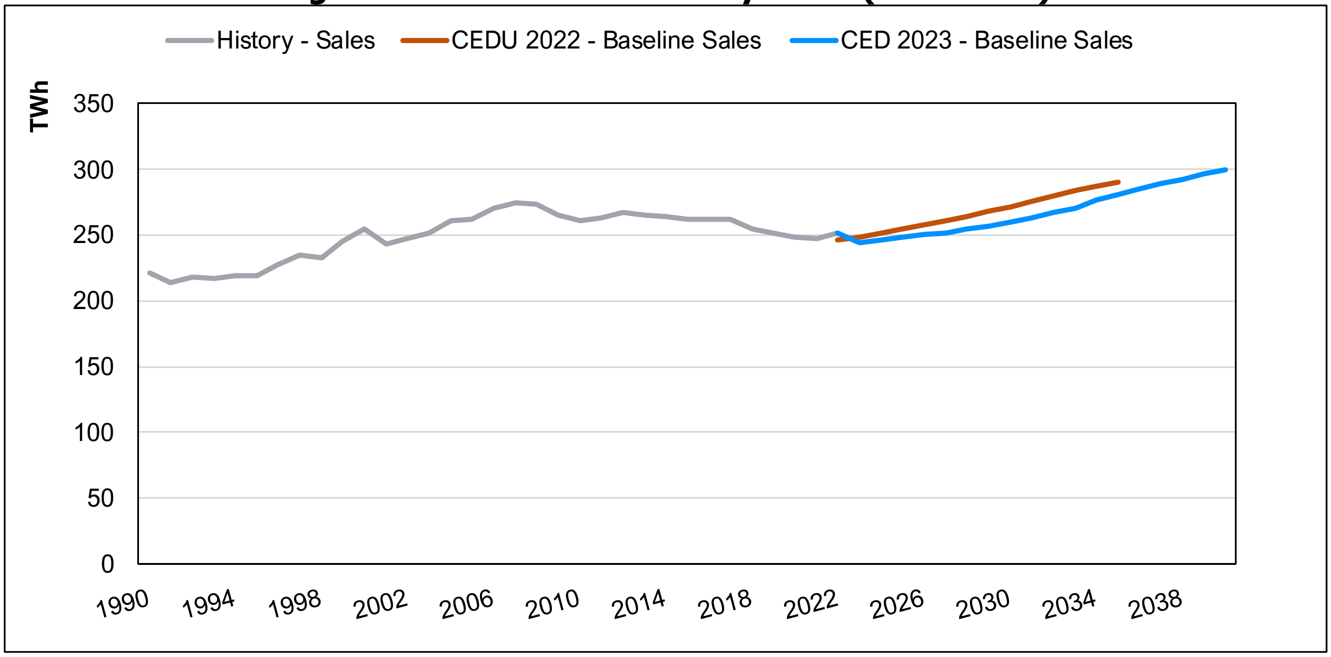


By 2040, annual PV generation reaches 64,460 GWh in the 2023 IEPR forecast.

Source: CEC

Between 2023 and 2040, the average growth rate in baseline sales is about 1.2 percent annually. By 2035, baseline sales are 3.5 percent lower than the 2022 IEPR Forecast. By 2040, baseline sales reach just more than 299,000 GWh. (See Figure 23.) Sales are lower than the 2022 IEPR Forecast largely due to slower growth in projected households and population, increases in BTM PV generation compared to previous assumptions, as well as increases in electricity rates compared to previous assumptions.

Figure 23: Baseline Electricity Sales (Statewide)



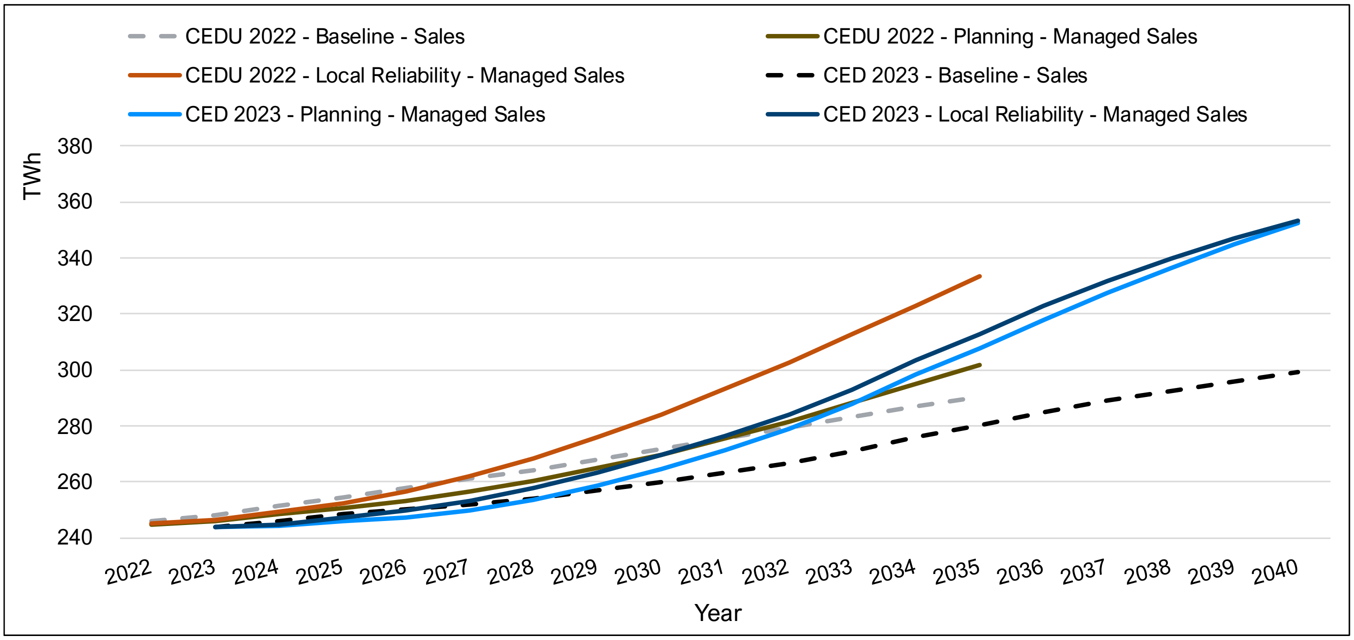
By 2040, baseline sales reach just more than 299,000 GWh in the 2023 IEPR forecast.

Source: CEC analysis

Managed Electricity Sales Forecasts

The 2023 IEPR electricity sales forecast — combined with AAEE, AAFS, and AATE scenarios — creates a managed sales forecast. The planning forecast is a managed forecast that is a combination of the sales forecast, AAEE Scenario 3, AAFS Scenario 3, and AATE Scenario 3. The local reliability scenario is a managed forecast that is a combination of the sales forecast, AAEE Scenario 2, AAFS Scenario 4, and AATE Scenario 3. By 2040, the planning forecast reaches 352,563 annual GWh, and the local reliability scenario reaches 353,235 annual GWh. (See Figure 24.) As mentioned previously, the managed electricity sales are lower than the 2022 IEPR Forecast largely due to slower growth in projected households and population, increases in BTM PV generation compared to previous assumptions, as well as increases in electricity rates compared to previous assumptions.

Figure 24: Managed Electricity Sales (Statewide)



By 2040, the planning forecast reaches 352,563 annual GWh, and the local reliability scenario reaches annual 353,235 GWh.

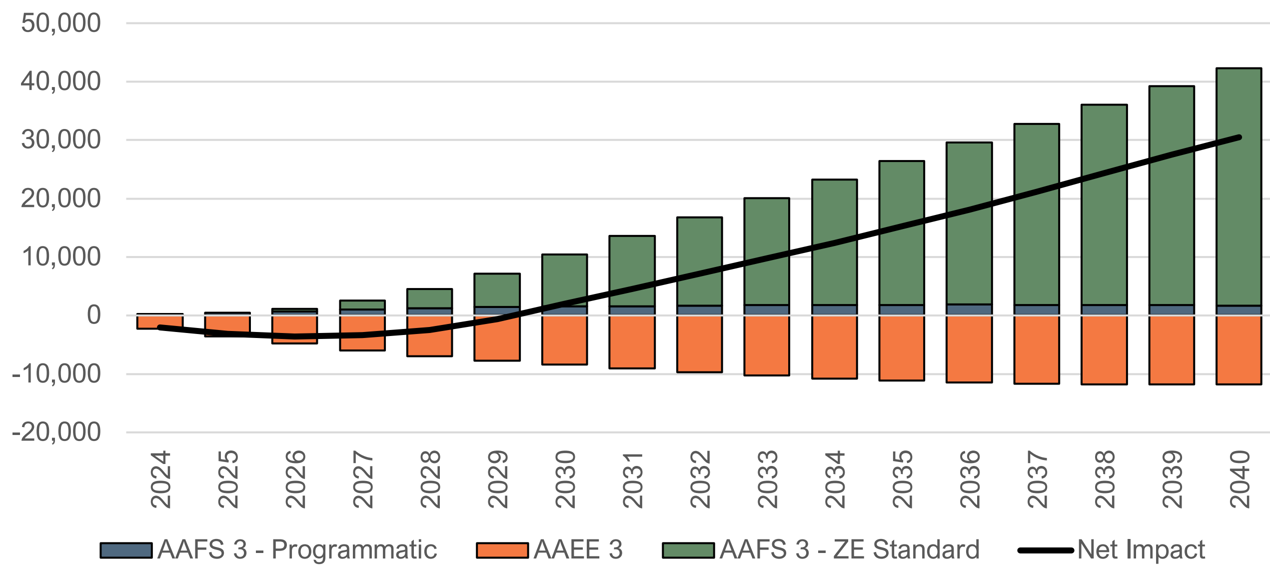
Source: CEC analysis

Results for the AAEE, AAFS, and AATE are described below.

Additional Achievable Energy Efficiency and Fuel Substitution Electricity Impacts

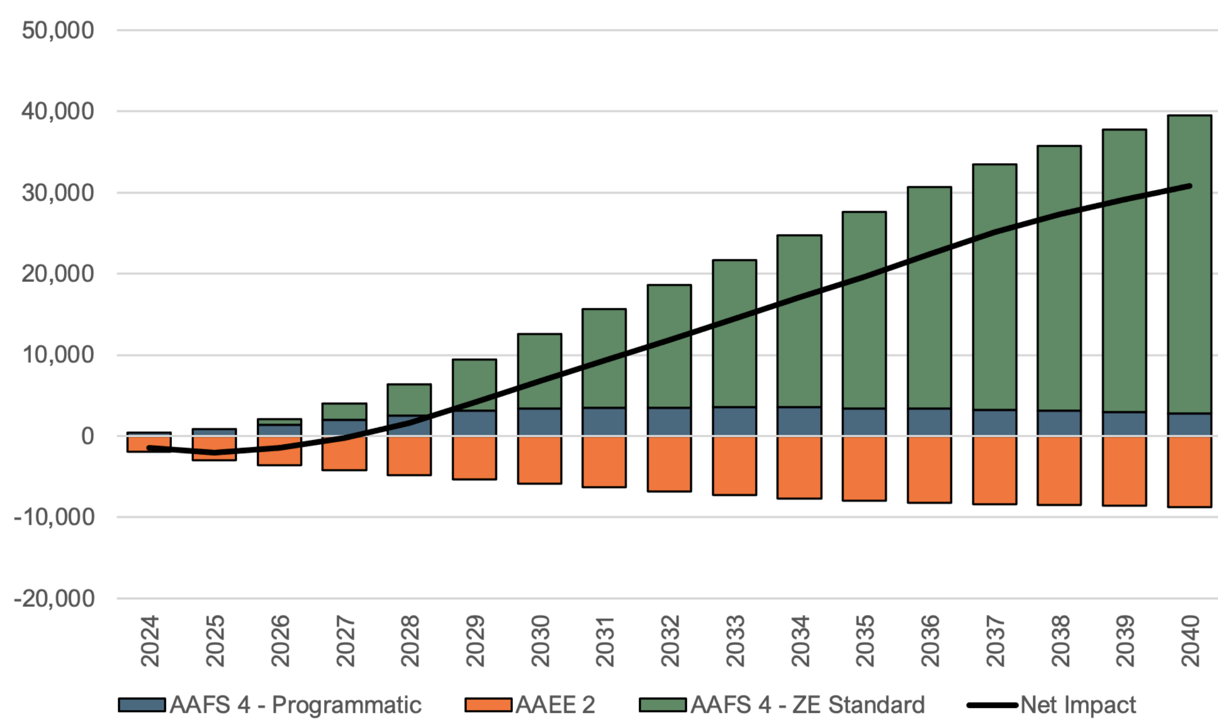
The model structure of FSSAT reports the impacts from CARB's concept for a ZE Standard in the Planning Forecast and Local Reliability Scenario while avoiding any double counting or overlap of AAEE and AAFS savings from incentive programs (programmatic savings). Figures 25 and 26 illustrate the net electricity impacts from the AAEE, programmatic AAFS, and the ZE Standard AAFS scenarios included in the planning forecast and local reliability scenario. As seen in both figures, the electricity savings from AAEE reduces but does not eliminate the added electricity from all fuel substitution activities. The black net impact lines in each figure show that the AAEE and AAFS load modifiers add more electricity than they save starting in 2030 for the planning forecast, and 2028 for the local reliability scenario. For the overall energy impacts of these AAFS scenarios, the ZE Standard component of AAFS has the greatest impact on added electric load for both forecast scenarios.

Figure 25: Saved/Added Commercial and Residential Electricity From the Planning Forecast (GWh)



Source: CEC

Figure 26: Saved/Added Commercial and Residential Electricity From the Local Reliability Scenario (GWh)



Source: CEC

For the electricity impacts of the planning forecast (Figure 25), the ZE Standard AAFS 3 adds around 24 times more electricity than programmatic AAFS 3 by 2040. AAEE 3 does save around 11,800 GWh of electricity but is still about one-fourth the size of the load added from the ZE standard. Combining all these factors, the planning forecast has a net increase in electric load of nearly 30,500 GWh in 2040. For the local reliability scenario (Figure 26), the ZE Standard AAFS 4 adds around 13 times greater electricity than programmatic AAFS 4 by 2040. AAEE 2 does not save as much electricity by 2040, having about 8,700 GWh of electricity savings. After reducing the added electric load from AAFS with the impacts of AAEE, the local reliability scenario has a net increase in electric load of around 30,800 GWh in 2040.

Considering the combined AAFS results in Figures 25 and 26, the electricity impacts are larger in the planning forecast than in the local reliability scenario. This difference is explained by two major effects. The first is that the programmatic fuel substitution impacts in AAFS 4 are larger than in AAFS 3, reducing the impacts from the ZE Standard AAFS 4 compared to ZE Standard AAFS 3. As a result, the second impact is that the additional programmatic impacts from AAFS 4 add more efficient appliances (for example, heat pumps rather than less expensive and less efficient electric resistance heaters) than those that would have been added if the full impacts of the ZE Standard AAFS 4 were achieved. More efficient appliances result in less increased electricity demand from fuel substitution.

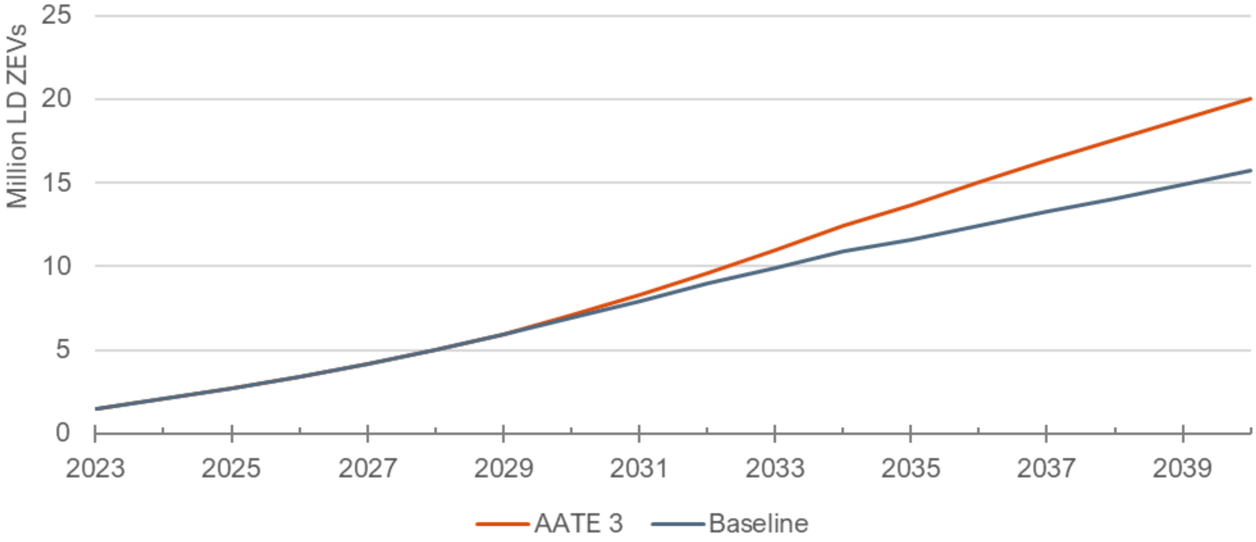
Based on CEC analysis of both the forecasted electric heat pump installations (from programmatic and ZE Standard AAFS) and the estimated number of installed heat pumps in California, the local reliability scenario appears to be approaching the goal of installing 6 million heat pumps by 2030. CEC staff will explore new data sources, including using AMI data, that can be used to help track heat pump installations and market trends in California and improve fuel substitution and efficiency modeling.

For the *2025 IEPR*, CEC staff will continue consulting with CARB and CPUC staff to improve the characterization and assumptions used to model the ZE Standard. Staff will seek to improve the characterization of the technologies available, the share of adoption of various competing technologies, and the modeling of low-income households.

Additional Achievable Transportation Electrification Impacts

The results of AATE Scenario 3 show that more ZEVs are part of the population under AATE Scenario 3 compared to the baseline forecast. For example, in 2035, the baseline forecast shows 11.6 million ZEVs, while AATE Scenario 3 shows 13.7 million ZEVs. Figure 27 below shows the ZEV population results for LD vehicles.

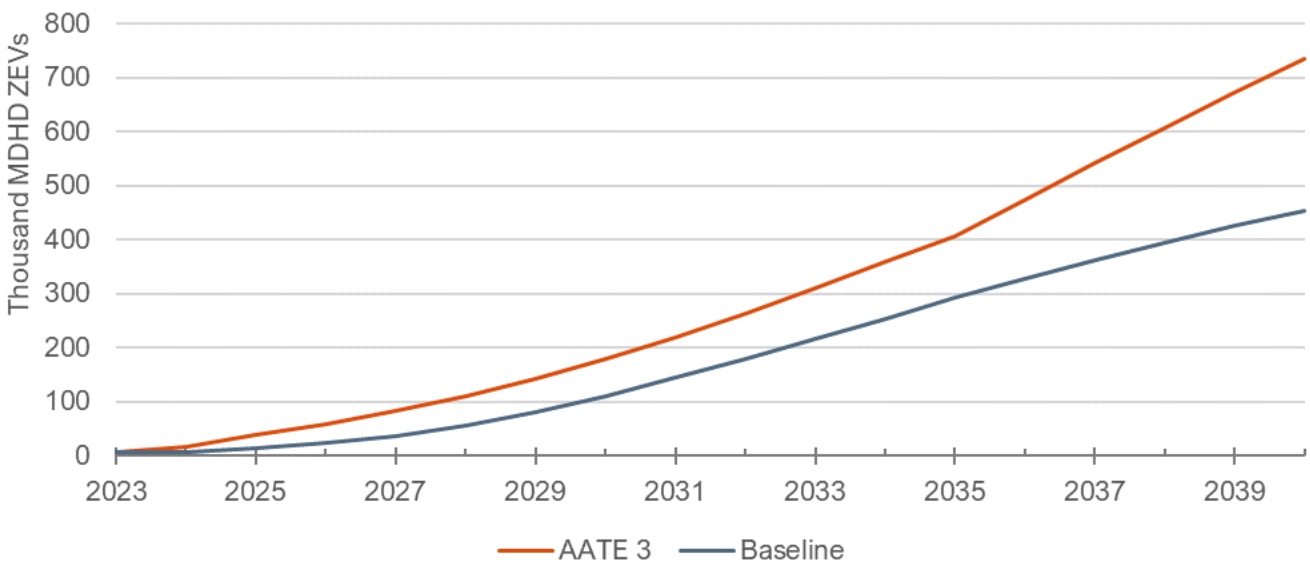
Figure 27: AATE 3 and Baseline Forecast Light-Duty ZEV Populations



Source: CEC analysis

The relationship seen for LD ZEV adoption is also seen in MDHD when accounting for the recently adopted Advanced Clean Fleets regulation. Figure 28 below shows the MDHD ZEV population increasing to about 407,000 ZEVs in 2035 for AATE Scenario 3.

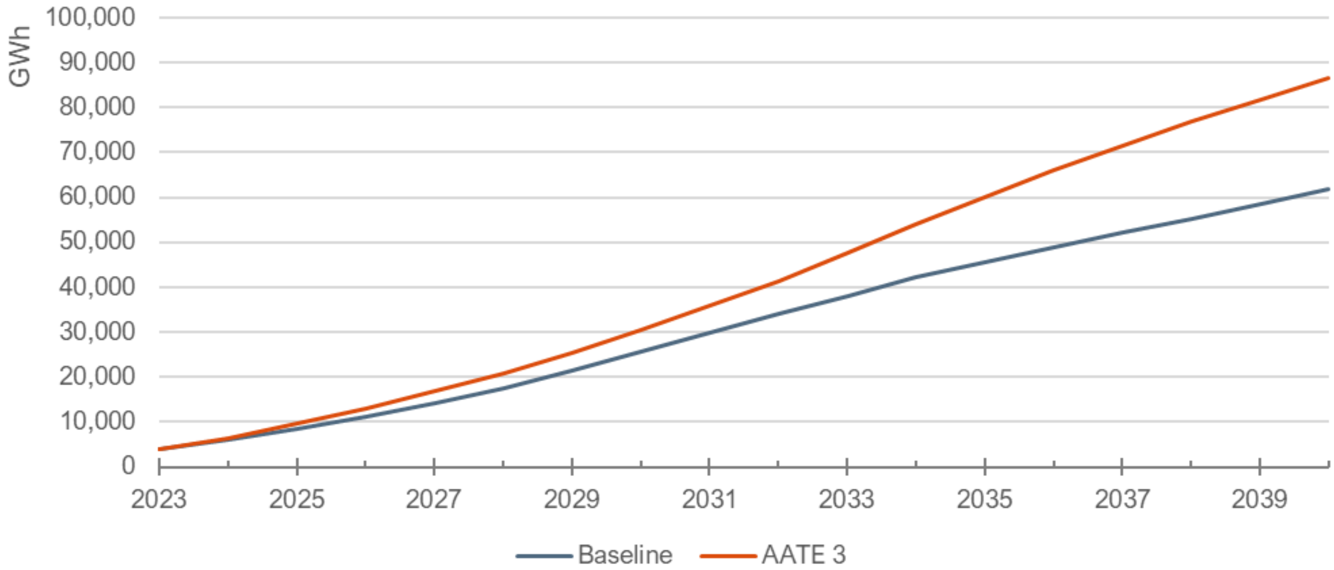
Figure 28: Medium- and Heavy-Duty ZEV Populations for AATE 3 and Baseline Forecast



Source: CEC analysis

Similar to the vehicle adoption rates, electricity demand from increasing EV adoption also increases over the forecast period. Figure 29 below shows the transportation electricity demand from on-road vehicles.

Figure 29: Transportation Electricity Demand (Light-, Medium-, and Heavy-Duty Vehicles)

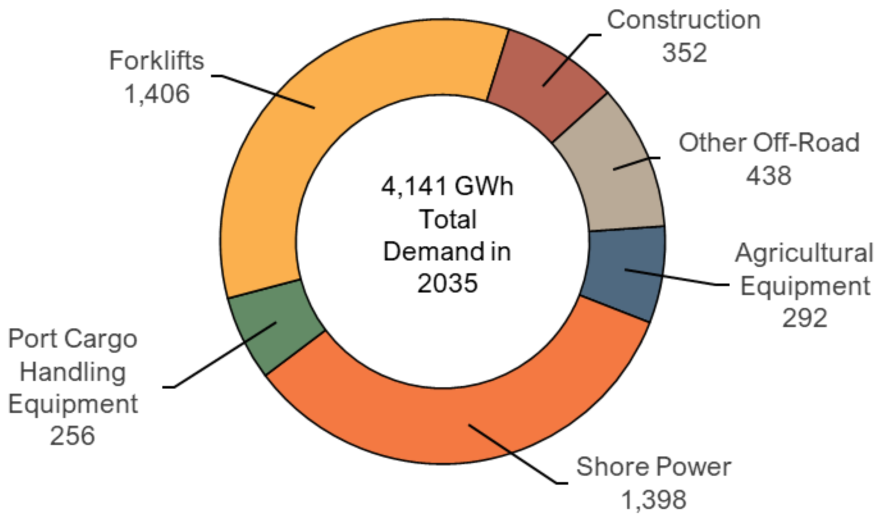


Source: CEC analysis

Staff presented load profiles associated with amount of electricity demand displayed above at the November 13, 2023, IEPR workshop. A more complete, systemwide integration of hourly and peak demand that incorporates transportation electrification is presented in the next section.

Off-road vehicle electrification is another topic of interest that has been a regular part of the TEDF, but it has not typically been explored in more depth. Total forecasted electricity demand for this sector is integrated into the baseline forecast and not currently a part of the AATE framework or TEDF load profile analysis. A snapshot of 2035 in Figure 30 below is informative for understanding the general magnitude of electricity demand from this sector. While it is relatively small, it is noticeable. Staff will expand off-road electrification forecasting in future IEPRs.

Figure 30: 2035 Off-Road Vehicle Electrification Forecast



Source: CEC analysis

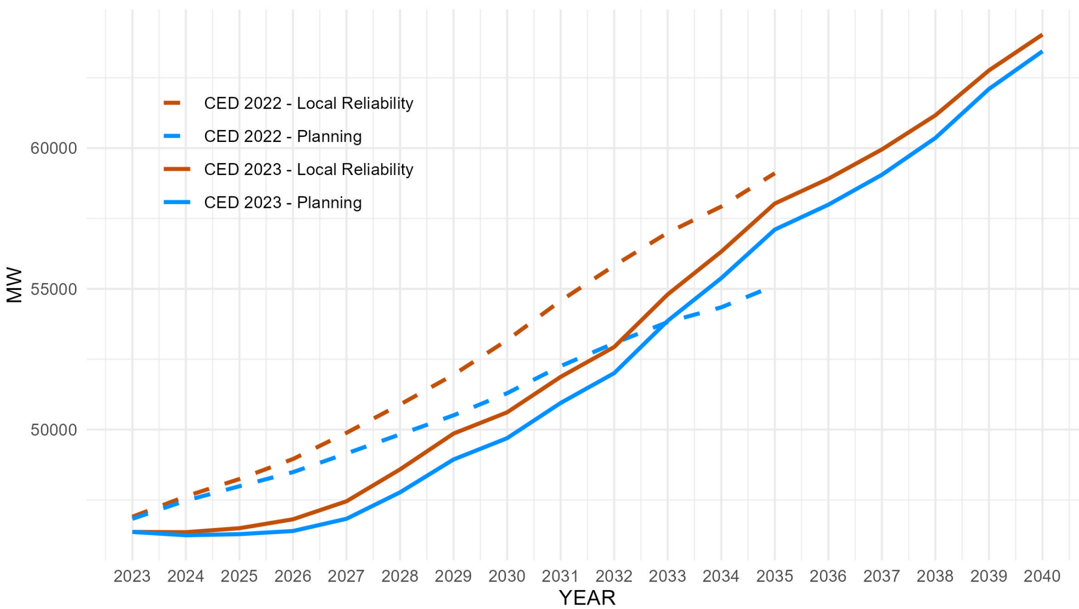
Peak Electricity Demand

The peak demand forecast update is derived from the annual consumption forecast by applying hourly system load profiles to projected annual consumption. CEC staff benchmarks the peak forecast to weather-normalized peaks from the most recent historical year — from summer 2023, in this case. The baseline peak forecast updates can be combined with the AAEE, AAFS, and AATE scenarios to create managed forecasts for use in planning studies. The baseline forecast — combined with the AAEE Scenario 3, AAFS Scenario 3, and AATE Scenario 3 — creates a managed peak forecast for the California ISO control area that grows at a rate of 1.8 percent annually, reaching 63,442 MW by 2040.

Relative to the 2022 IEPR Planning Forecast, the 2023 IEPR Planning Forecast for the California ISO system is lower through 2033 due primarily to a lower baseline consumption forecast and increased peak reduction impacts expected from behind-the-meter PV.[225] By 2035, however, the new peak forecast exceeds the previously adopted forecast by 3.3 percent because of additional electrification impacts expected from CARB’s concept of a zero-emission appliance regulation.

225 The managed peak forecast results for the Planning Forecast vary by IOU. PG&E’s peak is lower relative to the 2022 IEPR Update until 2029. SCE’s peak is lower through 2035. SDG&E’s peak is lower until 2034.

Figure 31: Managed System Peak Demand (California ISO)



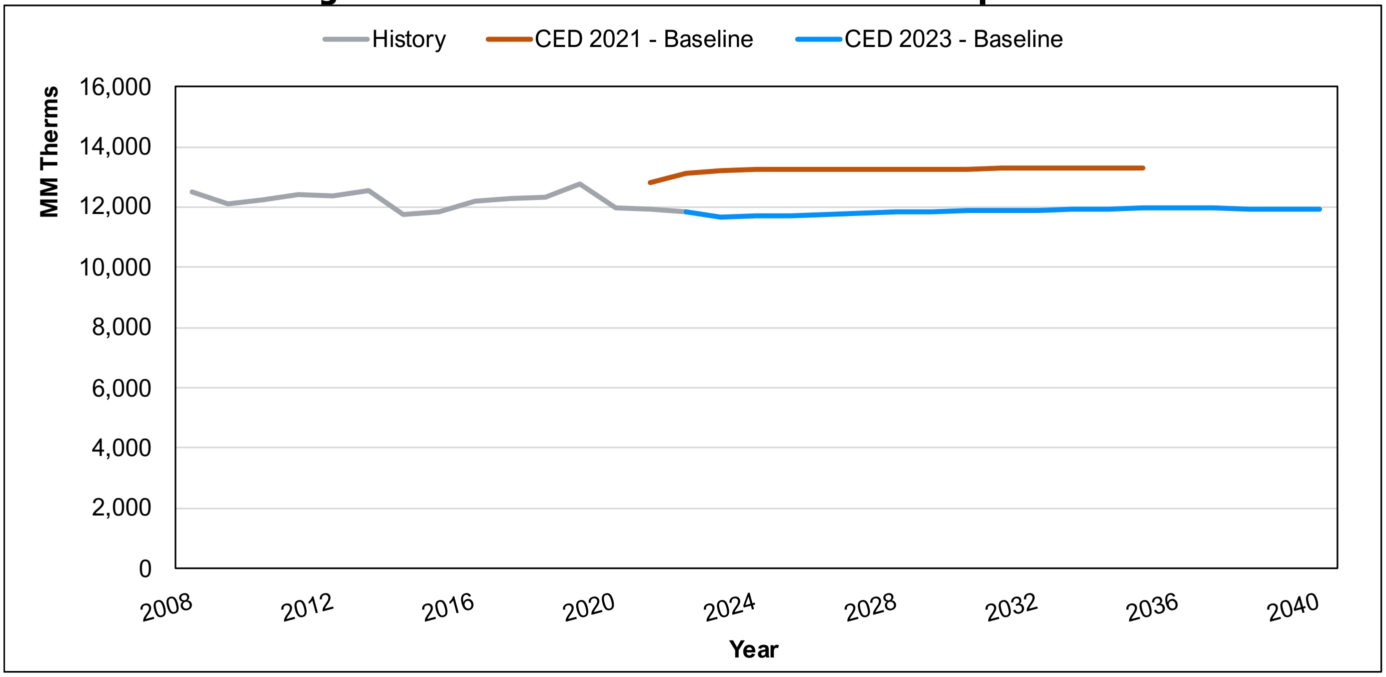
The California ISO managed system peak demand for the 2023 IEPR Planning Forecast is lower through 2033 due primarily to a lower baseline consumption forecast and increased peak reduction impacts expected from behind-the-meter PV. In 2035, the managed system peak demand is 3.3 percent higher than the 2022 IEPR Planning Forecast.

Source: CEC analysis

Gas Consumption

The gas forecast is updated every two years, in odd years. Gas consumption in 2022 was 11,800 MM therms. By 2040, gas consumption is forecasted to be about 11,900 MM therms before accounting for AAEE and AAFS. The long-term trend for the 2023 IEPR gas forecast and 2021 IEPR gas forecast shows a near-zero growth rate in consumption. The 2023 IEPR gas forecast is lower than the 2021 IEPR gas forecast due to calibrating to 2022 historical data.

Figure 32: Statewide Baseline Gas Consumption



The 2023 IEPR gas consumption forecast is lower than the 2021 IEPR gas consumption forecast due to calibration with 2022 data.

Source: CEC analysis

Managed Gas Sales

The 2023 IEPR gas consumption forecast combined with AAEE and AAFS scenarios creates a managed gas sales forecast. The gas utilities use their own forecasts for gas system planning and have included some components of the CEC's gas forecast, such as AAEE and AAFS scenarios at their discretion. The gas utilities' assessments are published every two years, in the even years, in the California Gas Report.[226]

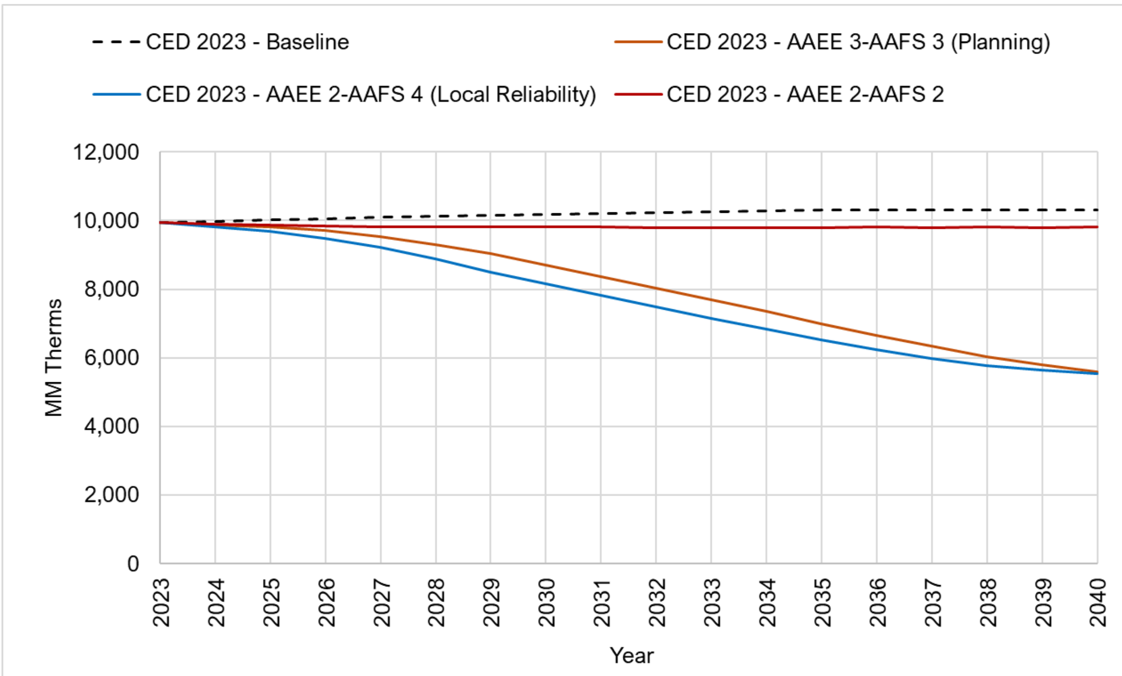
The state's ambitious goals to electrify buildings and curtail GHG emissions could result in substantial reductions in gas demand by 2040, as projected by the planning and local reliability scenarios shown in Figure 33. However, because of the numerous uncertainties surrounding the pace of building electrification, it is advisable to refrain from using the planning scenario or local reliability scenario for gas system planning. Use of these scenarios for planning would likely result in significantly reduced investments in maintaining the current gas system, posing

226 SoCalGas. 2022. *2022 California Gas Report*. https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf.

a potential risk of reliability and safety issues if building electrification progresses more gradually than projected.

Simultaneously, staff cautions against use of the scenarios that include minimal building electrification assumptions, such as the AAEE 2, with the AAFS 2 combination shown in Figure 33, as these scenarios may be overly conservative given the state's priorities. Taking too conservative an approach could lead to overinvestment in the gas system and the risk of stranded assets as electrification expands. Striking the right balance is crucial to aligning with the state's goals while maintaining the reliability and adaptability of the gas system.

Figure 33: Statewide Managed Gas Sales



The state's ambitious goals to electrify buildings and curtail GHG emissions could result in substantial reductions in gas demand by 2040, as projected by the planning and local reliability scenarios.

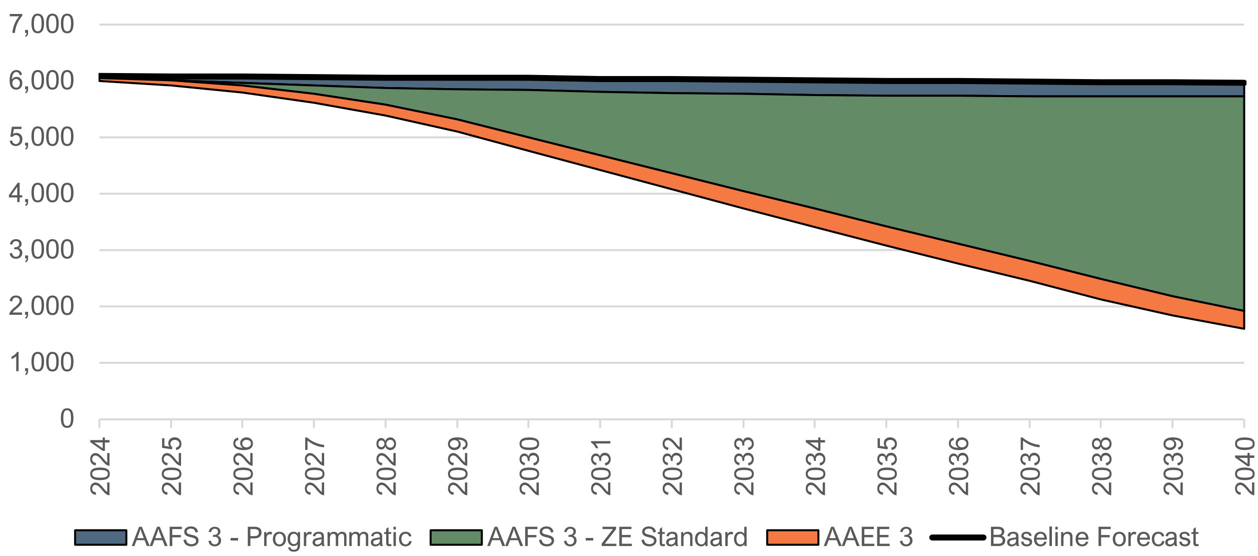
Source: CEC analysis

Gas impacts for the AAEE and AAFS scenarios are described below.

Additional Achievable Energy Efficiency and Fuel Substitution Gas Impacts

Figures 34 and 35 show the combined gas demand impacts contributed from the AAEE and AAFS load modifiers in the planning forecast (Figure 34) and the local reliability scenario (Figure 35). For the results in these two figures, the ZE Standard savings are exclusively from space and water heating, while the programmatic AAEE and AAFS savings stem from several end uses. The top solid black line in each figure represents the baseline 2023 gas demand forecast for the combined residential and commercial sectors. Each of the colored wedges in the figures show the impact that the AAEE and AAFS load modifiers have on reducing gas demand, with the order of the wedges following how fuel substitution and energy efficiency are applied to the gas demand forecast in FSSAT. The first colored wedge (blue) in each figure represents the gas savings for the programmatic portion of the AAFS scenarios, while the second colored wedge (green) represents the gas savings portion for CARB's concept for a ZE Standard. The final colored wedge (orange) in these figures represents the gas savings for the AAEE scenarios, with these savings showing the amount of gas energy efficiency that can still be achieved or realized after the impacts of fuel substitution are subtracted from the baseline gas demand forecast.

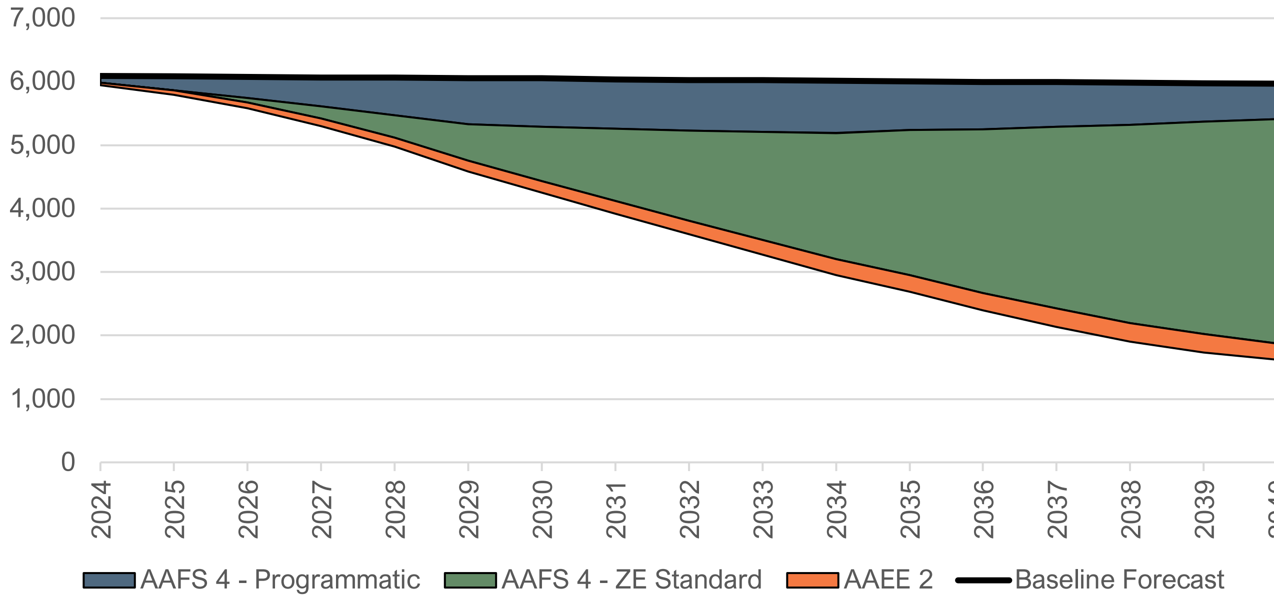
Figure 34: Residential and Commercial Gas Demand Forecast Reductions From the Planning Forecast (MM Therms)



The expected gas savings in 2040 from AAEE 3, programmatic AAFS 3, and ZE Standard AAFS 3 in the planning forecast are 314 MM therms, 235 MM therms, and 3,814 MM therms, respectively, contributing to total gas savings of 4,363 MM therms.

Source: CEC analysis

Figure 35: Residential and Commercial Gas Demand Forecast Reductions From the Local Reliability Scenario (MM Therms)



The expected gas savings in 2040 from AAEE 2, programmatic AAFS 4, and ZE Standard AAFS 4 are 256 MM therms, 557 MM therms, and 3,538 MM therms, respectively, contributing to total gas savings of 4,351 MM therms for the local reliability scenario.

Source: CEC analysis

As shown in the green wedge for Figures 34 and 35, both of the forecast scenarios reflect the assumption that the ZE Standard begins to impact gas demand starting in 2026.[227] The ZE Standard portion of AAFS contributes larger gas savings than programmatic AAEE and AAFS in both forecast scenarios.

For the planning forecast, the expected gas savings in 2040 from AAEE 3, programmatic AAFS 3, and ZE Standard AAFS 3 in the planning forecast are 314 MM therms, 235 MM therms, and 3,814 MM therms, respectively, contributing to total gas savings of 4,363 MM therms. By 2040, the ZE Standard makes up around 87 percent of the total commercial and residential gas savings for the combined AAEE and AAFS load modifiers being used in the planning forecast, showing just how large of an impact the ZE Standard has on reducing gas demand. Without the inclusion of the ZE Standard for the planning forecast, the combined programmatic AAEE

227 This assumption reflects the timeline in the draft SIP that new buildings would be all-electric starting in 2026. The CEC collaborated closely with CARB to update the modeling of the ZE Standard for the 2023 energy demand forecast.

and AAFS gas savings in 2040 would only be around 611 MM therms.[228] For the local reliability scenario, the expected gas savings in 2040 from AAEE 2, programmatic AAFS 4, and ZE Standard AAFS 4 are 256 MM therms, 557 MM therms, and 3,538 MM therms, respectively, contributing to total gas savings of 4,351 MM therms. By 2040, the ZE Standard makes up around 81 percent of the total commercial and residential gas savings for the combined AAEE and AAFS load modifiers being used in the local reliability scenario.

One notable difference between Figures 34 and 35 is that the contribution of the ZE Standard to gas reductions for the local reliability scenario is lower than that of the planning forecast. The ZE Standard provides around 276 MM therms more gas savings in the planning forecast than it does in the local reliability scenario. This difference results from programmatic AAFS impacts that limit the additional gas savings that would otherwise result from the ZE Standard.

Choice of a Single Managed Forecast Set for Electricity Planning

The baseline electricity demand, when combined with six AAEE savings scenarios, six AAFS scenarios, and one AATE scenario adopted as part of this *IEPR*, create managed electricity forecasts that constitute options for a "single forecast set" to be used for planning in CEC, CPUC, and California ISO (the joint agencies and California ISO) proceedings. The lead staff of the joint agencies and California ISO guiding the processes listed below have agreed that specific elements of this forecast set will be used for planning and procurement in the California ISO's TPP and the CPUC's IRP, resource adequacy, and other planning processes as outlined below. The details of this agreement will be adapted through time as the needs of planning and procurement evolve. This agreement was also documented in a joint memorandum of understanding in December 2022.[229]

The term "single forecast set" is intended to clarify that what has commonly been called a "single forecast" is not a single number but actually a set of forecast numbers adopted as part of the *IEPR*. This set includes managed forecast scenarios that combine baseline forecasts using alternative weather variants; AAEE, AAFS, and AATE scenarios; and hourly load forecasts

228 Since there would be more baseline gas available for gas energy efficiency measures if the ZE Standard modeling was excluded from the planning forecast, the AAEE gas savings that are included in this value are higher than the realized AAEE gas savings seen in Figure 14.

229 Memorandum of Understanding Between The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) and the California Independent System Operator (ISO) Regarding Transmission and Resource Planning and Implementation. December 2022. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/news-office/mous/cpuc-cec-caiso-mou-december-2022.pdf.

for transmission access charge (TAC) areas.[230] Agreement on a single forecast set includes specification on the use for each component of the set.

The single forecast set consists of components of the IEPR electricity demand forecast:

- A baseline forecast of annual energy and peak demand, with three peak event weather variants (*for example*, 1-in-2, 1-in-5, and 1-in-10)
- Hourly loads for the baseline forecast for each of three IOU TAC areas
- Six scenarios of AAEE described by annual energy and hourly load impacts
- Six scenarios of AAFS described by annual energy and hourly load impacts. Scenarios 3 through 6 include the CARB preliminary proposal for zero-emission space and water heater sales,[231] and regional zero-emission appliance standards[232]
- One scenario of AATE described by annual energy and hourly load impacts

The combination of the baseline forecast using a specific weather variant plus an AAEE, AAFS, and AATE scenario depends on the use. The practices and procedures used in electricity local capacity studies address uncertainty about the location-specific impacts of various assumptions by systematically using adverse assumptions about weather-induced peak load, and conservative load modifiers to base loads. For energy efficiency savings, AAEE Scenario 2 is used for local capacity studies because it is more conservative than Scenario 3, which is used in most planning studies. For fuel substitution, AAFS Scenario 4 is used rather than Scenario 3 that is used in most planning studies. For transportation electrification, Scenario 3 is used for local capacity studies and planning studies.

To account for unforeseen uncertainties, variations of IEPR forecast outputs that diverge from the single forecast set may be used in CPUC IRP modeling under specific circumstances with

230 A *TAC area* denotes a portion of the California ISO balancing authority area that has been placed in the California ISO's operational control through an agreement with an electric utility or other entity operating a transmission system component. A TAC area typically consists of an IOU and several publicly owned utilities using the transmission system owned by the IOU.

231 CARB's concept envisions that new space and water heaters purchased starting in 2030 would be zero-emission. CARB held an initial public workshop in early 2023 and plans to take a proposed regulation to the board for consideration in 2025 with implementation beginning in 2030.

232 AAFS Scenarios 3 through 6 include BAAQMD Regulation 9, Rules 4 and 6 for space- and water-heating appliances, which was adopted in March 2023. Scenario 6 includes SCAQMD low- and zero-emission control measures for several appliance types. SCAQMD's rulemaking process is anticipated to begin in early 2024.

consensus from joint agency and California ISO leadership.[233] However, lead CPUC staff agrees to ensure that adopted IRP portfolios will not deviate from the single forecast set.

The following list describes the current agreement among the lead staff of the joint agencies and California ISO:

- CPUC IRP Reference System Plan, Preferred System Plan, and California ISO TPP economic studies:[234]
    - Baseline annual energy and annual peak demand
    - AAEE Scenario 3 annual energy and peak demand
    - AAFS Scenario 3 annual energy and peak demand
    - AATE Scenario 3 annual energy and peak demand
    - 1-year-in-2 peak event weather conditions
- California ISO TPP policy studies and bulk system studies:
    - Baseline annual energy and annual peak demand
    - AAEE Scenario 3 annual energy and peak demand
    - AAFS Scenario 3 annual energy and peak demand
    - AATE Scenario 3 annual energy and peak demand
    - 1-year-in-5 peak event weather conditions
    - Planning forecast hourly loads
    - CEC staff allocations of AAEE, AAFS, and AATE to load buses used in transmission studies
- California ISO TPP local area reliability studies and local capacity technical studies:
    - Baseline annual energy and annual peak demand
    - AAEE Scenario 2 annual energy and peak demand
    - AAFS Scenario 4 annual energy and peak demand
    - AATE Scenario 3 annual energy and peak demand

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233 For example, in May 2022, leadership of the joint agencies and California ISO decided to use a new scenario that reflected CARB's proposed regulations for zero-emission vehicles, given the long lead time for the types of system upgrades that could be required to support implementation of these regulations. This scenario, called the Additional Transportation Electrification scenario, was used by the California ISO for the 2022–2023 TPP.

234 In consultation with the CEC and California ISO, the CPUC may authorize procurement using an alternative weather variant.

- 1-year-in-10 peak event weather conditions
- CEC staff allocations of AAEE, AAFS, and AATE to load buses used in transmission studies

- California ISO Maximum Import Capability allocation for CPUC's system resource adequacy requirements for load-serving entities (LSEs)
  - Monthly peak demand derived from the planning forecast managed sales hourly loads
- CPUC resource adequacy LSE system requirements[235]
  - Hourly loads for the monthly system peak-day demand derived from planning forecast managed sales hourly loads
  - AAEE Scenario 3 hourly loads
  - AAFS Scenario 3 hourly loads
  - AATE Scenario 3 hourly loads
  - 1-year-in-2 peak event weather conditions[236]
- CPUC IOU distribution planning requirements
  - Baseline peak demand (also known as the IEPR demand forecast) and AAEE, AAFS, and AATE scenarios (also known as "distributed energy resource growth forecasts")
  - Weather variants and AAEE, AAFS, and AATE scenario variants that may differ by IOU as per CPUC D. 18-02-004[237]

235 Resource adequacy under the CPUC jurisdiction shifts to using a slice-of-day approach starting in 2025, which will require hourly loads. Resource adequacy is based on annual and monthly peak demand for 2024. Non-CPUC jurisdictional load serving entities will not shift to a slice-of day-framework. System resource adequacy obligations in the California ISO's systems and processes (which account for both CPUC and non-CPUC jurisdictions) will continue to be based on annual and monthly coincident peak demand.

236 In consultation with the CEC and California ISO, the CPUC may authorize procurement using an alternative weather variant.

237 Following a May 11, 2020, CPUC Distribution Resources Plan Ruling (R.14-08-013), the same IEPR datasets are used by each IOU. The IOUs meet and confer to establish which IEPR datasets to use and present a listing of the selected datasets to CPUC staff for approval. In all cases, IEPR datasets are used where feasible for disaggregation and forecasting, and the IOUs clearly state in their filings which datasets were used.

- California ISO flexible capacity studies for resource adequacy:[238]
    - Baseline hourly loads by California ISO area
    - AAEE Scenario 3 hourly loads by California ISO area
    - AAFS Scenario 3 hourly loads by California ISO area
    - AATE Scenario 3 hourly loads by California ISO area
    - 1-year-in-2 peak event weather conditions

Lead staff of the joint agencies and California ISO have developed a process by which the CPUC or California ISO can make a formal request to the CEC for a desired demand forecast variant or combination that is not yet produced. If the CEC does not have the resources to develop such a variant, then lead staff from the requesting agency may consider deviating from this agreement to independently develop and use such a variant for the period until the CEC is able to develop it. Such requests should also be made and approved using appropriate procedures of the requesting agency to ensure all interested stakeholders are aware of such a deviation.

Managed Gas Forecast Set

Similar to the electricity forecast, baseline gas demand can be combined with six AAEE savings scenarios and six AAFS scenarios to create a managed gas forecast. For electricity system planning, procurement, and resource adequacy, CPUC decisions direct the use of the IEPR forecast for purposes of IRP procurement (D.07-12-052), resource adequacy (D.05-10-042 and D.23-04-010), and distribution planning (R.14-08-013). For gas system planning, the CPUC has yet to rule on using a CEC demand forecast. In D.22-07-002, the CPUC said that it would consider using a CEC demand forecast rather than that of the California Gas Report once the CEC has developed an equivalent forecast.

The gas utilities use their own forecasts for gas system planning and have included some components of the CEC's gas forecast such as AAEE and AAFS scenarios at their discretion. The gas utilities' assessments are published every two years, in the even years, in the California Gas Report.

238 The method for assessing flexible capacity using the hourly CEC forecast was first used for flexible capacity resource adequacy planning for Year 2020. The joint agencies and California ISO are collaborating to evaluate this use case into the overall CEC demand forecasting work flow and the California ISO's flexible capacity projection method. The joint agencies and California ISO are evaluating and potentially modifying the flexible capacity analysis going forward. Until finalization of evaluation and potential changes are made, the California ISO will continue to use the CEC's hourly forecast.

Staff recommends against the use of the managed gas scenarios presented in the *2023 IEPR* for gas system planning. There is considerable uncertainty around the pace at which building electrification will occur, and use of the planning forecast or local reliability scenarios could introduce risks to gas system reliability and safety. However, the scenarios that exclude CARB's zero-emission appliance standard concept identified in the 2022 State Strategy for the State Implementation Plan are overly conservative, assuming very little building electrification, which is not aligned with the state's goals and the proposed regulations and appliance standards currently under development.

As more information becomes available throughout 2024, the CEC will collaborate with stakeholders to develop a new scenario that strikes the right balance for inclusion in the 2024 IEPR. Furthermore, the CEC aims to produce a daily gas forecast to provide the same metrics reported in the California Gas Report[239] and used for gas system planning. These would include estimates of a 1-in-X cold day gas demand.

Forecast Updates for 2024 and Beyond

Each year, staff seeks to implement improvements to the forecast. To this end, staff is working on several updates for the 2024 IEPR forecast and subsequent years.

- 2024 IEPR forecast
    - Continuing to improve how the forecast accounts for climate change by exploring the use of new weather variables
    - Implementing new travel demand models for the transportation forecast that provide increased flexibility for modeling VMT under different policy scenarios
    - Creating an AAFS scenario in collaboration with stakeholders that considers new information on building electrification standards, while considering gas system reliability, affordability, equity, and the potential for stranded assets
- 2025 IEPR forecast and beyond
    - Assessing fuel substitution in the industrial and agricultural sectors, including the decarbonization potential of hydrogen
    - Developing a probabilistic hourly electricity forecast to support resource planning
    - Updating the commercial sector end-use model to a modern platform and incorporating the 2018–2022 Commercial End-Use Survey data

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239 SoCalGas. 2022. *2022 California Gas Report*. https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf.

- Exploring an increase in the geographic granularity of the forecast to support local studies

Shifts in Energy-Use Patterns

Electrification of buildings and transportation will change energy-use patterns, and numerous uncertainties around electrification must be considered and monitored as it becomes more prevalent. The uncertainties include:

- The rate of adoption of electric vehicles and heat pumps.
- EV charging patterns and *vehicle-to-building*[240] charging and discharging.
- The amount of electricity needed for in-state production of hydrogen for use in fuel cell electric vehicles.
- Battery storage charging and discharging.
- Load flexibility and demand response.

There is uncertainty around how these factors may shift building load shapes and the overall system load shape.[241] At the same time, utilities are considering rate strategies, such as real-time pricing, that encourage electrification and load shifting while ensuring grid reliability. As part of SB 846, the CEC set a load shift goal for the state.[242] The Load Shift Goal Report examines the potential for reducing load during peak demand hours. Future work will explore how that load can potentially be redistributed to best match supply.

Further challenges remain for forecasting load with more geographic specificity. For example, MDHD load is expected to be relatively small compared to LD load. However, MDHD load will likely be more concentrated in fewer areas of the state, with the potential for much higher loads in such pockets. CEC staff is working with the CPUC on the Freight Infrastructure Planning process to evaluate a longer-term geographical assessment as a component of the forecast to address these challenges. (This is also discussed in Chapter 1.)

Long-Term Energy Demand Scenarios

The impacts of climate change and decarbonization policies have created a need for a set of long-term energy demand scenarios to inform planning. To meet this need, in 2021, CEC staff

240 *Vehicle-to-building* and *vehicle-to-home* refer to using the battery of an EV like energy storage where there is a two-way power flow between the building and the vehicle, and the energy stored in the EV battery could be used to power the building.

241 A *load shape* is a curve representing how electricity use changes throughout the day.

242 *Senate Bill 846 Load-Shift Goal Report*. CEC-200-2023-008, https://www.energy.ca.gov/publications/2023/senate-bill-846-load-shift-goal-report.

developed long-term demand scenarios to identify demand-side fuel shifts and supply-side consequences of demand changes as well as GHG emission reductions, from existing and near-term policies. Demand scenarios focus on a long-term horizon and include demand from all significant fuel types in various sectors. In 2021, the long-term demand scenarios were developed with the "high electrification theme." The scenarios quantify the impacts of a wide range of energy efficiency and fuel substitution programs that contribute to the state's GHG emission reduction goals. The CEC adopted the analysis and results from the first round of scenarios May 24, 2022.[243] A subsequent round of 2023 demand scenarios will be completed in 2024 and will feed into the modeling conducted in close coordination with the CPUC and CARB for the 2025 Senate Bill 100 report. These scenarios will include electricity demand from hydrogen production, as well as scenarios around load flexibility and load shifting. An assessment of the costs of fuel switching will be conducted as part of this project.

243 May 24, 2022, CEC Business Meeting web page, https://www.energy.ca.gov/event/meeting/2022-05/energy-commission-business-meeting-0.

GLOSSARY

The **additional achievable framework** is applied to energy efficiency, fuel substitution, and transportation electrification for the 2023 IEPR forecast. The additional achievable scenarios capture a range of incremental market potential impacts, beyond what are included in the baseline demand forecast, but are reasonably expected to occur.

Advanced Clean Cars II is a regulation implemented by the California Air Resources Board that requires new personal vehicles sold to be increasingly zero emission, eventually to 100 percent by 2035.

Advanced Clean Fleets is a regulation implemented by the California Air Resources Board that requires an increasing zero-emission composition for certain medium- and heavy-duty trucks fleets. The regulation also requires 100 percent zero-emission medium- and heavy-duty truck sales beginning in 2036.

Alternating current refers to an electric current that sometimes reverses direction and changes its magnitude.

Bidirectional vehicle charging refers to an electric vehicle receiving energy from the grid (via charging) and then providing energy to an external load (such as the grid, a home, or an appliance).

The **bulk power system** refers to the system the network of large generators connected to the high-voltage transmission system that transmits electricity over long distances.

The **California Air Resources Board's** mission is to promote and protect public health, welfare, and ecological resources through effective reduction of air pollutants while recognizing and considering effects on the economy. CARB is the lead agency for climate change programs and oversees all air pollution control efforts in California to attain and maintain health-based air quality standards.

The **California Independent System Operator** manages the flow of electricity across the high-voltage, long-distance power lines for the grid serving 80 percent of California. It also operates a wholesale power market that matches buyers and sellers of a diverse set of electricity resources in an open, non-discriminatory setting, and is responsible for transmission infrastructure planning.

The **California Public Utilities Commission** regulates services and utilities, protects consumers, safeguards the environment, and assures Californians' access to safe and reliable utility infrastructure and services. The essential services regulated include electric, natural gas, telecommunications, water, railroad, rail transit, and passenger transportation companies. The CPUC does resource planning for 80 percent of California's electric grid through the Integrated Resource Planning proceeding and implements programs such as the RPS, efficiency incentives, transportation electrification investments, customer solar, and building decarbonization.

Capacity payments come *from* a user of an energy asset and are made *to* the owner of that asset. These payments are made in return for the rights to use that asset's capacity.

Carbon neutrality refers to a balance between the amount of carbon that is being emitted and the amount of carbon being removed or absorbed.

Clean Vehicle Rebate Project for light-duty ZEVs is a program that provides incentives for purchasing or leasing personal zero-emission light-duty vehicles.

Community choice aggregators are entities within investor-owned utility territories that procure electricity for the residents and businesses within a geographical area.

Decarbonization refers to activities that reduce greenhouse gas emissions such as reducing or removing fossil gas use in buildings or replacing fossil fuel generated electricity with renewable sources like solar or wind.

Deliverability studies determine the transmission system upgrades required for a resource to deliver power to customers at times of greatest system need. Deliverability is used to determine capacity payments and for load-serving entities to meet resource adequacy requirements. Upgrades required for deliverability are typically more extensive than reliability upgrades because disconnecting or curtailing the generator is not an option.

Direct current refers to an electric current that only flows in one direction.

The **distribution system** refers to the lower-voltage system that connects directly to customers and their behind-the-meter devices.

An **electrolyzer** is a device that uses electricity to split water into hydrogen and oxygen using electrolysis.

Electrification refers to converting end uses from a combustible fuel source (typically a fossil gas) to electricity.

The **Extended Day-Ahead Market** is the effort to coordinate energy scheduling in the Western Interconnection up to a day ahead rather than 5 to 15 minutes ahead.

The **Federal Energy Regulatory Commission** is a federal agency of the United States which regulates the following aspects of interstate commerce:

- the transmission of electricity
- the wholesale sales of electric energy and fossil gas
- the transportation of oil by pipeline

Gasification is the conversion of biomass feedstocks to a gaseous fuel, while **pyrolysis** is the thermal decomposition of biomass in the absence of oxygen (that prevents combustion) to produce liquid fuels. These gas and liquid fuels can be used in conventional equipment (for example, boilers, engines, and turbines) or advanced equipment (such as fuel cells) for the generation of heat and electricity.

A **gigawatt** is the equivalent of 1 billion watts.

Hybrid and Zero-Emission Truck and Bus Vehicle Incentive Project is a program administered by the California Air Resources Board that provides incentives for purchasing zero-emission or low-emission trucks and buses.

A **justice community** is a broad umbrella term that encompasses the following designations as described in the *2022 IEPR Update*:[244]

- Disadvantaged communities, under Senate Bill 535 (De León, Chapter 830, Statutes of 2012) and based on the recently updated CalEnviroScreen Version 4.0,[245] which are:
    - Census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0.
    - Census tracts lacking overall scores in CalEnviroScreen 4.0 due to data gaps, but receiving the highest 5 percent of CalEnviroScreen 4.0 cumulative pollution burden scores.
    - Census tracts identified in the 2017 disadvantaged communities designation, regardless of their scores in CalEnviroScreen 4.0.
    - Lands under the control of federally recognized tribes.
- Low-income communities and households, pursuant to Assembly Bill 1550 (Gomez, Chapter 369, Statutes of 2016), respectively:
    - Census tracts with median household incomes at or below 80 percent of the statewide median income or at or below the Department of Housing and Community Development designation of low-income.
    - Households with incomes at or below 80 percent of the statewide median income or at or below the Department of Housing and Community Development designation of low income.
- Underserved community, pursuant to Assembly Bill 841 (Ting, Chapter 372, 2020):
    - A community in which at least 75 percent of public-school students in the project area are eligible to receive free or reduced-price meals under the National School Lunch Program.
- People living with disabilities as defined by American Disabilities Act (ADA):
    - An individual with a disability is defined by the ADA as a person who has a physical or mental impairment that substantially limits one or more major life

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244 Bailey, Stephanie, Jane Berner, David Erne, Noemí Gallardo, Quentin Gee, Akruti Gupta, Heidi Javanbakht, Hilary Poore, John Reid, and Kristen Widdifield. 2023. *Final 2022 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2022-001-CMF.

245 CalEPA. May 2022. *Final Designation of Disadvantaged Communities Pursuant to Senate Bill 535*, https://calepa.ca.gov/wp-content/uploads/sites/6/2022/05/Updated-Disadvantaged-Communities-Designation-DAC-May-2022-Eng.a.hp_-1.pdf.

activities, a person who has a history or record of such an impairment, or a person who is perceived by others as having such an impairment.

A **gen-tie** connects the original power generation to the transmission system.

Grid hardening is the process of making the electrical grid more resilient to extreme weather and other potential threats. One example is moving power lines underground to reduce the possibility of downed lines starting wildfires. Another example is switching out wooden utility poles for ones made of steel or concrete; these materials better withstand high winds and are more resistant to fire.

Integration capacity analysis is a process that provides information on a system's capacity to interconnect new generation.

A **joule** is a unit of energy equal to the amount of work done when a force of one newton displaces a mass through a distance of 1 meter. A **megajoule** is equal to 1,000 joules and an **exajoule** is equal to 10^{18} joules.

A **load-serving entity** provides or sells electricity to customers.

A **metric ton** is a unit of weight equal to 1,000 tons (or 2,205 pounds).

The **net peak** demand is the highest demand after accounting for the impacts of self-generation. The net peak typically occurs from 4:00 p.m. to 9:00 p.m., as solar generation rapidly declines.

An **offtake agreement** is where a buyer agrees to purchase most or all of a producer's future output.

The California Energy Commission and partner agencies launched the **Renewable Energy Transmission Initiative** 2.0 to identify the constraints and opportunities for new transmission needed to access additional renewable resources.

A **terawatt** is equal to 1,000,000,000,000 watts.

A **therm** is a unit of heat energy equal to 100,000 British thermal units.

Trigeneration is another term for combined heat, cooling, and power. It refers to the process where some heat produced by a combined heat and power plant gets used to generate cold water for refrigeration or air conditioning.

Vehicle-to-building and **vehicle-to-home** refer to using the battery of an EV-like energy storage where there is a two-way power flow between the building and the vehicle, and the energy stored in the EV battery could be used to power the building.

The **Western Interconnection** includes electricity infrastructure in 11 western states, two Canadian provinces, and portions of Mexico operated as 34 independent balancing authorities governed by the states and provinces, public boards, and the federal government.

The **Wholesale Distribution Access Tariff** refers to SCE providing open access to its distribution system to wholesale customers wanting to interconnect generation plants that deliver energy to the California ISO's grid or deliver energy from that grid to their customers.

ACRONYMS

AAEE	additional achievable energy efficiency
AAFS	additional achievable fuel substitution
AATE	additional achievable transportation electrification
AB	Assembly Bill
ARCHES	Alliance for Renewable Clean Hydrogen Energy Systems
ATE	additional transportation electrification
BA	balancing authority
BAAQMD	Bay Area Air Quality Management District
BAU	business as usual
BEV	battery-electric vehicle
BPA	Bonneville Power Administration
BTM	behind the meter
BUILD	Building Initiative for Low-Emissions Development
California ISO	California Independent System Operator
CARB	California Air Resources Board
CCUS	carbon capture utilization and storage
CDD	cooling degree days
CEC	California Energy Commission
CED	California Energy Demand Forecast
CEDU	California Energy Demand Update
CEQA	California Environmental Quality Act
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPUC	California Public Utilities Commission
DAME	Day-Ahead Market Enhancements
DAWG	Demand Analysis Working Group
DC	direct current
DER	distributed energy resources
dGen	Distributed Generation Market Demand

DMV	California Department of Motor Vehicles
DOF	California Department of Finance
DSGS	Demand Side Grid Support Program
DWR	California Department of Water Resources
E3	Energy and Environmental Economics
EDAM	Extended Day-Ahead Market
EDGE	Electric Vehicle Supply Equipment Deployment and Grid Evaluation
EE	energy efficiency
EERE	U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy
EV	electric vehicle
EVSE	electric vehicle supply equipment
FCEV	fuel-cell electric vehicle
FERC	Federal Energy Regulatory Commission
FIP	freight infrastructure planning
GGE	gasoline gallons equivalent
GHG	greenhouse gas
GO-Biz	California Governor's Office of Business and Economic Development
GW	gigawatt
GWh	gigawatt-hour
GWP	global warming potential
H_2	hydrogen
HDD	heating degree days
HRI	hydrogen refueling infrastructure
HSP	Hydrogen Safety Panel
ICA	integration capacity analysis
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	investor-owned utility
IPE	Interconnection Process Enhancement
IRP	Integrated Resource Plan

ITC	Investment Tax Credit
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LCFS	Low Carbon Fuel Standard
LD	light-duty
LDV	light-duty vehicle
LOLE	loss of load expectation
MDHD	medium-duty/heavy-duty
MMBTU	million British thermal units
MMT	million metric tons
$MMTCO_2e$	million metric tons carbon dioxide equivalent
MOU	memorandum of understanding
MW	megawatt
MWh	megawatt hour
NBT	Net Billing Tariff
NO_X	nitrogen oxides
NREL	National Renewable Energy Laboratory
OIIP	order instituting informational proceeding
PG&E	Pacific Gas and Electric Company
POU	publicly owned utility
PRM	planning reserve margin
PV	photovoltaic
R&D	research and development
RETI	Renewable Energy Transmission Initiative
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Company

SGIP	Self-Generation Incentive Program
SIP	State Implementation Plan
SMR	steam methane reformation
SPP	Southwest Power Pool
SPTO	Subscriber Participating Transmission Owner
SRRF	Electricity Supply Reliability Reserve Fund
TE	transportation electrification
TECH	Technology and Equipment for Clean Heating
TED	Tracking Energy Development
TOU	time of use
TPP	Transmission Planning Process
TWh	terawatt-hour
U.S. DOE	United States Department of Energy
U.S. EIA	United States Energy Information Administration
VMT	vehicle miles traveled
WEIM	Western Energy Imbalance Market
WI	Western Interconnection
WRAP	Western Resource Adequacy Program
ZEV	zero-emission vehicle

APPENDIX A: Update on Gas Decarbonization

Introduction

Fossil gas (also known as "natural gas") is used for heating and cooling homes and buildings, powering the industrial and agricultural sectors, and producing electricity. In fact, California consumes more fossil gas than gasoline each year. The use of fossil gas must continue to decline for the state to meet its ambitious climate goals, including the goal of economywide carbon neutrality by 2045.[246] This appendix provides information on the gas market in support of the IEPR Forecast and updates the discussion in the *2022 Integrated Energy Policy Report (IEPR) Update*[247] on gas system decarbonization efforts.

Overview of California Gas Market

California's Gas Demand

California's interconnected gas system supplies more than 11 million customers with fossil gas each day. Buildings, electricity generation (gas-fired power plants), and industrial operations are the primary consumers of fossil gas in the state, each representing roughly one-third of total demand. In 2021, fossil gas made up about 40 percent of the state's total power generation mix. It plays an important role in maintaining electric reliability because of the ability of this gas to be dispatched on command.

Fossil gas makes up about 31 percent of the state's total energy consumption. In 2021, a state-by-state comparison showed California as the second largest consumer of fossil gas in the United States (after Texas), representing about 8 percent of the total U.S. market.[248] The

246 Governor Gavin Newsom. Executive Order B-55-18, https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

247 Bailey, Stephanie, Jane Berner, David Erne, Noemí Gallardo, Quentin Gee, Akruti Gupta, Heidi Javanbakht, Hilary Poore, John Reid, and Kristen Widdifield. 2023. *Final 2022 Integrated Energy Policy Report*. California Energy Commission. Publication Number: CEC-100-2022- 001-CMF, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250084.

248 U.S. Energy Information Administration "Frequently Asked Questions" web page, https://www.eia.gov/tools/faqs/faq.php?id=46&t=8.

state consumes around 5.3 billion cubic feet per day (Bcfd) of gas on an average day and as much as 11 Bcfd on a very cold winter day.[249]

Gas Supplies and Infrastructure

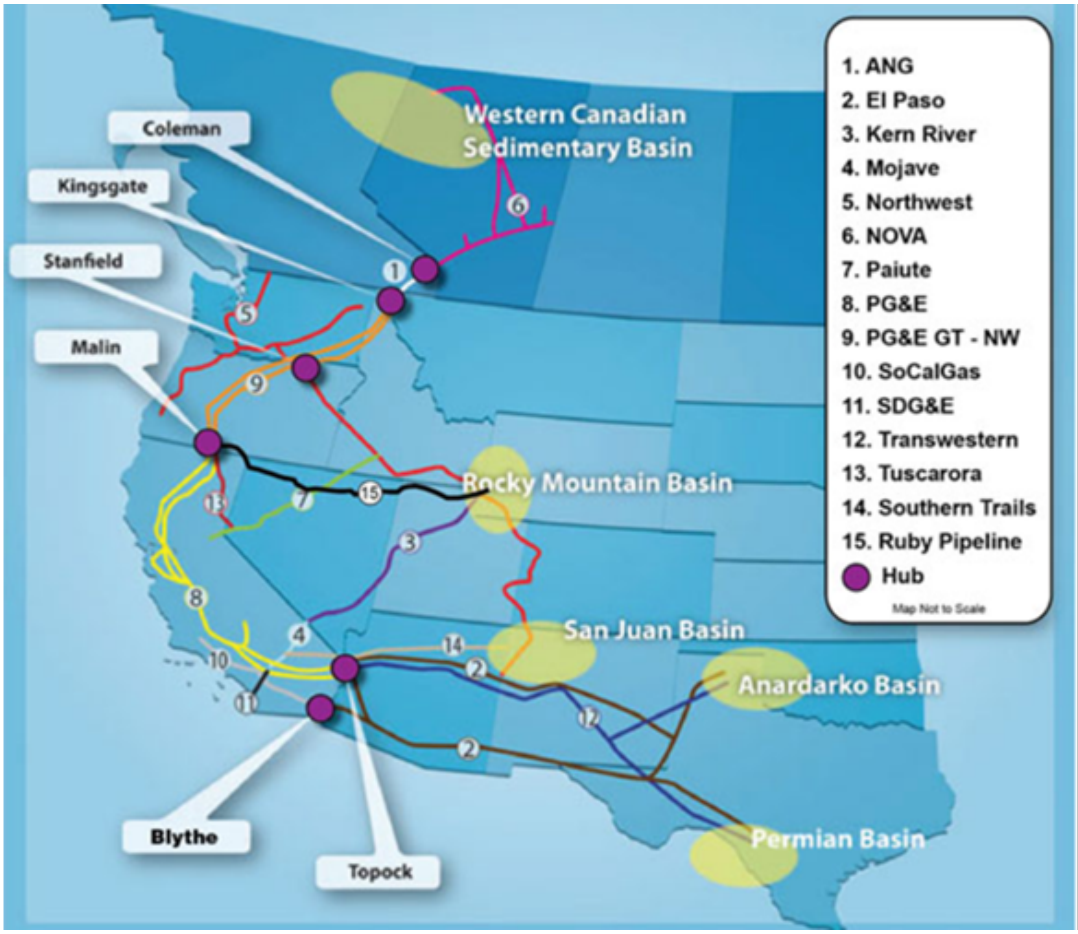
California imports nearly 90 percent of its gas from out-of-state production plants in Canada, Wyoming, New Mexico, and Texas. Figure A-1 shows the interstate pipeline network that delivers gas from the major supply basins to California's gas utilities at or near the state's border. California's in-state gas production comes mostly from geologic basins in the Central Valley and Southern California, which has been slowly declining since the 1980s because of aging reservoirs and less favorable economics.

The primary components of the state's gas system include high-pressure transmission pipelines and lower-pressure distribution pipelines that serve residents and small commercial customers. Distribution main and service pipelines are made of steel or plastic and typically run beneath streets. Much of this pipe is more than 50 years old, and some is made of a type of Aldyl-A plastic installed before 1984 and was subsequently found to be brittle. Large gas utilities replace some of their distribution pipeline each year because of factors that contribute to estimated risk, such as leaks, pipeline age, material, and soil conditions.

Gas storage is also an important system asset that utilities use to balance daily variations in system pressures and flow, ensure sufficient gas is available for winter delivery, and hedge against price fluctuations for core customers.

249 The 11 Bcf day was a 1-in-10 cold day, as that was the peak demand day over the last 10 years.

Figure A-1: Interstate Gas Pipelines and Supply Basins Serving California



California is served by a network of interstate pipelines that deliver fossil gas from the five major supply basins to California's gas utilities at or near the state's border.

Source: CEC

Gas Prices Inform the IEPR Forecast

On a biennial basis, CEC staff produces a fossil gas price forecast that informs statewide energy planning efforts and decision-making in support of the IEPR forecast. Specifically, the price results serve as inputs to other CEC modeling efforts, such as the CEC's Production Cost Model (PLEXOS) and the adopted forecast. (See Chapter 3.) These products use the delivered fossil gas prices, as one of many inputs, to produce gas demand projections by sector in California and gas demand for power generation in the WECC.[250]

Gas Prices Assessment

Staff simulates the economic behavior of natural gas producers and consumers using the North American Market Gas-Trade model (NAMGas), which includes representations of North America's intrastate and interstate pipelines, liquefied natural gas (LNG) import and export facilities, and other infrastructure.[251] The model encompasses regions of the continental United States, as well as Alaska, Canada, and Northern Mexico.

Staff developed three cases for the *2023 IEPR*:

- **Reference case:** Continuation of business as usual, where the market, policies, and technology remain the same.
- **High natural gas supply case**: High availability of natural gas, low production costs, high technological advancements in production, and changes to demand growth rates.
- **Low natural gas supply case**: Low availability of natural gas, high production costs, low technological advancements in production, and changes to demand growth rates.

The prices published in the *2023 IEPR* reflect preliminary prices. As part of the CEC gas decarbonization goals, staff continues to improve and update modeling scenarios and methods. Starting this year, staff will institute annual modeling runs, producing preliminary results in odd-numbered years and revised results in even-numbered years. (For example, 2023 will be preliminary, and 2024 will be revised.) This timeline will better align with the CEC's Demand Forecast and allow more stakeholder engagement and feedback, leading to a more verifiable and accurate price forecast.

The price forecasts look ahead 30 years to provide annual estimates. The forecast does not reflect short-term price fluctuations or price spikes within the year.

North American Price Outlook

The modeling results show prices declining in 2023 compared to 2022 because of production returning, not only to pre-COVID levels, but to record levels. Build-out of LNG capacity could put upward pressure on domestic fossil gas prices as supply may lag to meet demand.

250 The gas price projections do not include biomethane prices, but the CEC will explore this and other areas of expansion for future gas price forecasts. The CEC will also look further into cost allocations, which are done by the CPUC.

251 See 2023 IEPR Electricity and Gas Demand Forecast documents for presentation and more information on NAMGas modeling.

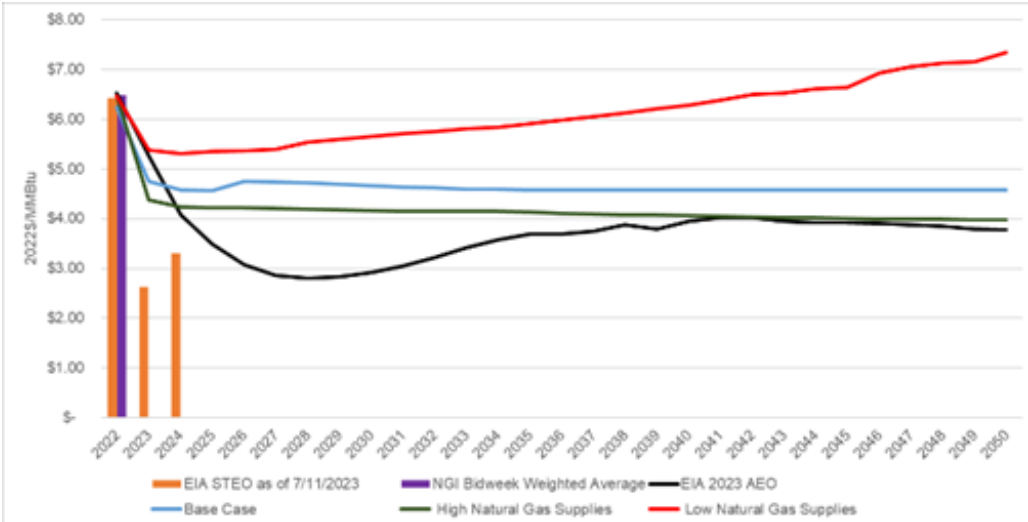
However, LNG facilities take years to build and come on-line, giving time for other market factors to offset the increase in LNG demand.

Henry Hub is the national benchmark price used by major financial and physical market traders in North America and worldwide (LNG exports).[252] As such, CEC staff analyzes Henry Hub price projections to help understand complex fossil gas pricing trends. Further, staff monitors worldwide, national, and statewide market and policy events that can affect these projections, such as new climate policies, changes in demand patterns, supply increases/decreases, or a combination thereof.

Figure A-2 below shows staff's preliminary findings for nationwide fossil gas prices. The figure provides one year of monthly historical data (2022) as a basis and compares projections at Henry Hub from U.S. EIA's 2023 Annual Energy Outlook (AEO) and Short-Term Energy Outlook (STEO) as of July 11, 2023; Natural Gas Intelligence's Bid-Week volume weighted average annual price, and CEC's NAMGas projected prices (2023–2050) for Henry Hub. As shown below, prices in the reference (base) case are projected to remain flat throughout the time horizon. The price case of high natural gas supplies also remains flat but slightly lower overall than the reference case. The low-supply case shows a steady increase in prices caused by diminishing natural gas supplies due to depleted wells not being replaced with new production. The drop in prices from 2022 to 2024 are due to increased fossil gas production that had lagged demand increases coming out of COVID-19-related demand declines. This trend is also seen in California border and Citygate prices.

252 LNG prices are set at world benchmarks such as the Japan-Korean Market (JKM), National Balancing Point (NBP) United Kingdom, and the Title Transfer Facility (TTF) in the Netherlands. This price minus cost (transportation, liquification, and commodity costs) is profit for the LNG export company. As such, transportation and liquification are static costs. The commodity cost, which is based on Henry Hub, can change and thus change profits.

Figure A-2: Annual Henry Hub Prices, (Reference Case)



CEC staff modeled three cases for Henry Hub annual prices out to 2050. The results show prices in the base (reference) case remaining flat, with prices in the high natural gas supplies also remaining flat but slightly lower in comparison. The low-supply case shows a steady increase in prices.

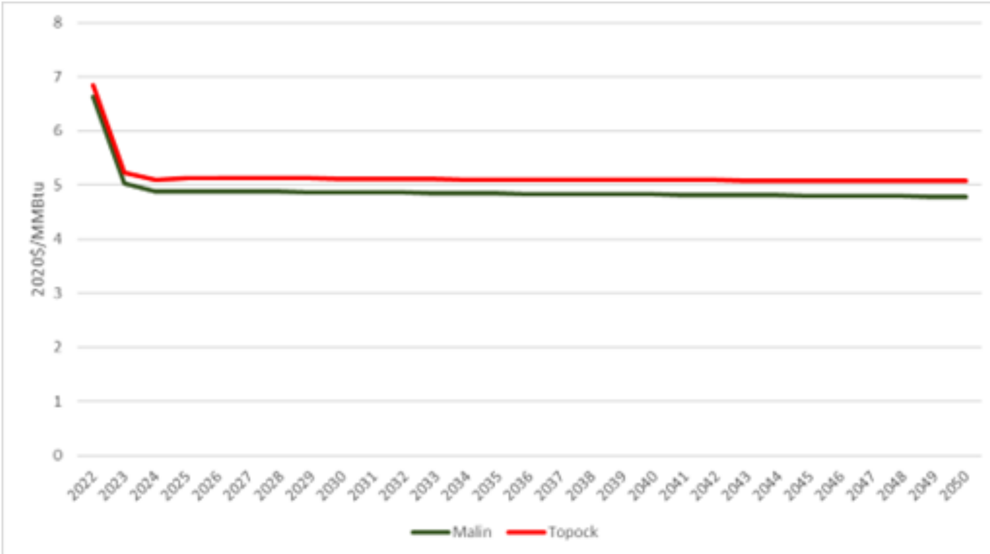
Source: CEC

California Price Outlook

Border Prices

California's Malin and Topock price hubs reflect what utilities or large end users (for example, power plants and industrial) pay for gas delivered to the state's borders from out-of-state suppliers (shippers, supply basins, third party marketers). As shown in Figure A-3, prices at Malin and Topock in the reference case remain stable through 2050 (at around $5.00/MMBtu) because of steady and continued production from supply basins in Canada, the Rockies, San Juan region (New Mexico), and West Texas.

Figure A-3: California Border Prices (Reference Case)



Staff modeled prices at California's Malin and Topock border hubs using the reference case and results show prices remain stable through 2050 (at around $5.00/MMBtu).

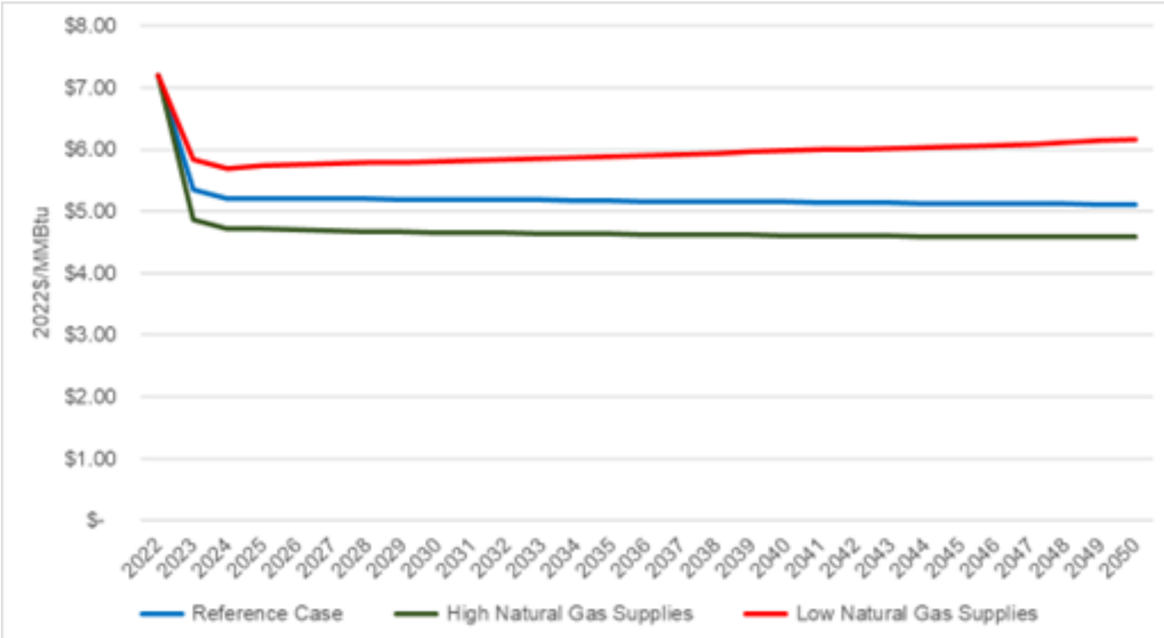
Source: CEC

Citygate Prices

After passing California's border, gas moves to end users and utilities. Utilities then supply gas to their core customers (mostly residential and small commercial) and, at a CPUC-adopted rate, transport the gas through their systems to large end users (such as power plants and industrial customers). The Citygate price is the commodity price paid by noncore end users that are directly served by a utility; the final end-use rate adds a transportation charge to the commodity price. (See Delivered Prices section.)

Figure A-4 shows the annual PG&E Citygate price projections. Reference case prices at PG&E Citygate, like Henry Hub, remain steady at about $5.00/MMBtu throughout the forecast. In the Low Gas Supplies case, prices remain around $6.00/MMBtu, which is above the reference case. These prices grow because of diminishing natural gas supplies without any new formations to replace depleted wells. The High Supplies case shows prices remaining slightly lower than $5.00/MMBtu. A similar trend is observed at the SoCal Citygate hub (Figure A-5).

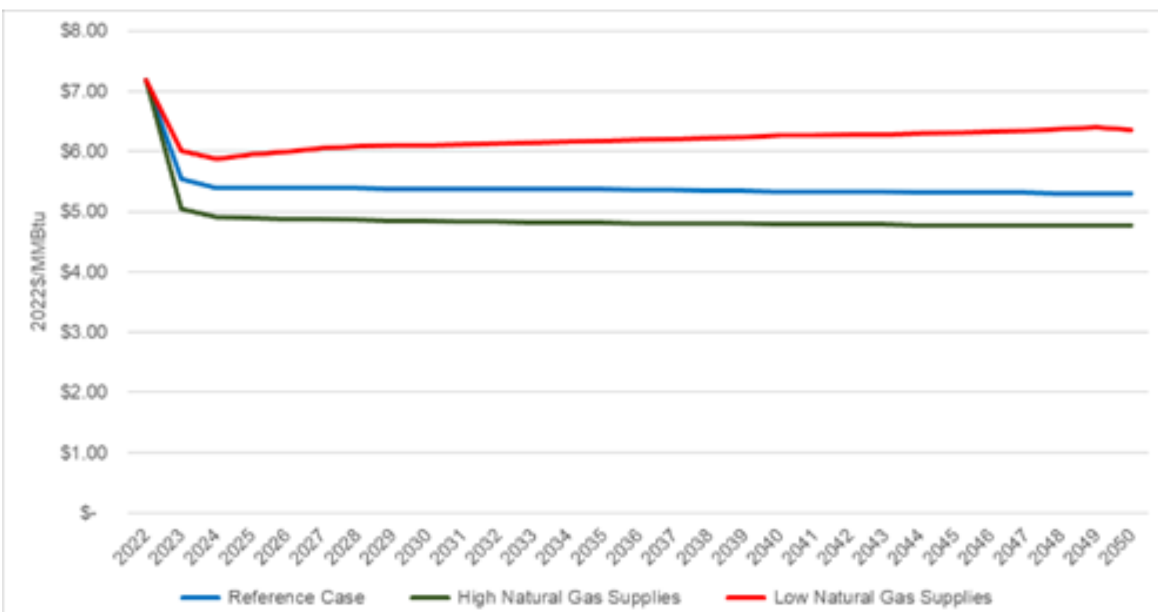
Figure A-4: Annual PG&E Citygate Price Projections



CEC staff modeled annual PG&E Citygate price projections. Results show reference case prices at PG&E Citygate, like Henry Hub, remain steady (about $5.00/MMBtu) throughout the forecast. The Low Gas Supplies case price are above the reference case (about $6.00/MMBtu).

Note: Dollars here and throughout are in terms of value in 2020. Revenue requirement is expected to increase 4 percent per year while demand declines. Source: CEC

Figure A-5: Annual SoCal Citygate Price Projections



CEC staff modeled the annual SoCal Citygate price projections. Like PG&E Citygate, results show reference case prices remaining steady (about $5.00/MMBtu) throughout the forecast with the Low Gas Supplies case prices above the reference case (about $6.00/MMBtu).

Source: CEC

SDG&E

As well as procuring gas supplies for its own core customers, SoCalGas procures gas supplies for SDG&E core customers at wholesale prices and passes on the cost of those supplies to SDG&E. SDG&E's noncore customers are responsible for procuring their own gas supplies directly.[253]

Delivered Prices

CEC staff uses a monthly fossil gas price model called the Delivered Price model to reflect the comprehensive cost to explore, develop, purchase, and transport gas to the consumer.[254] This total cost of gas delivered to consumers is an input to the gas and electricity models used to project energy demand by residential, commercial, and industrial customers. The model includes two cost components for each hub: (1) the commodity price and (2) the transportation rate.[255]

The NAMGas model produces a forecasted commodity price for the three cases described above, while pipeline companies and utilities set the transportation rates (fees). The Federal Energy Regulatory Commission (FERC) regulates the rates and service contracts for interstate transportation. These interstate rates are relatively unchanged for 2023. The CPUC oversees intrastate transportation through its General Rate Case process. The 2023 transportation rates for PG&E, SoCalGas, and SDG&E differ from 2021 because of a higher revenue requirement,[256] class allocation,[257] and a slight decrease (2 percent) in demand. Sector rates in California are calculated by multiplying the revenue requirement by the class allocation of each sector; this is divided by throughput (demand) to estimate a per unit (usually MMBtu) rate. Staff then adds this rate to the commodity price (from NAMGas) to estimate a final delivered price.

Figures A-6, A-7, and A-8 depict delivered prices for PG&E, SoCalGas, and SDG&E by sector. The model results show fossil gas prices increasing out to 2050 for the residential and

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253 The SDG&E price is the SoCal Citygate price plus the wholesale transportation rate, which is about 3 cents/MMBtu.

254 See 2023 IEPR Electricity and Gas Demand Forecast documents for presentation and more information on NAMGas modeling, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report.

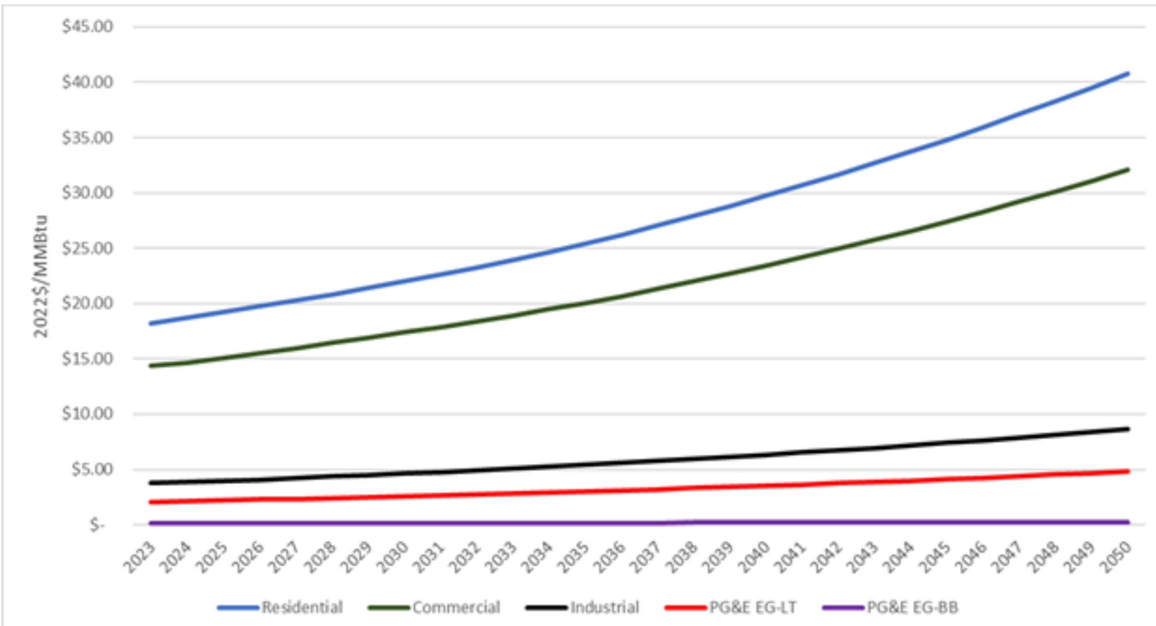
255 The *commodity price* is the cost of natural gas after it is produced from the well and processed for injection into a nearby utility pipeline, while the *transportation rate* is the cost to transport the gas to consumers after production.

256 Revenue requirements start higher (because of factors such as pipeline safety measures and wildfire mitigation) and grow at 4 percent per year.

257 This refers to the allocation of the revenue requirement between the different sectors or classes, (for example, industrial, commercial, residential, and power generation).

commercial sectors for the three utilities. This increase is largely because residential and commercial account for the highest portion of revenue requirements, along with increasing revenue requirements each year and declining demand in those sectors because of electrification and energy efficiency measures. Thus, a higher revenue requirement for commercial and residential, divided by a smaller demand, leads to higher per unit costs (rates). The figures show that prices for the industrial and electric generation sectors rise only slightly over time.

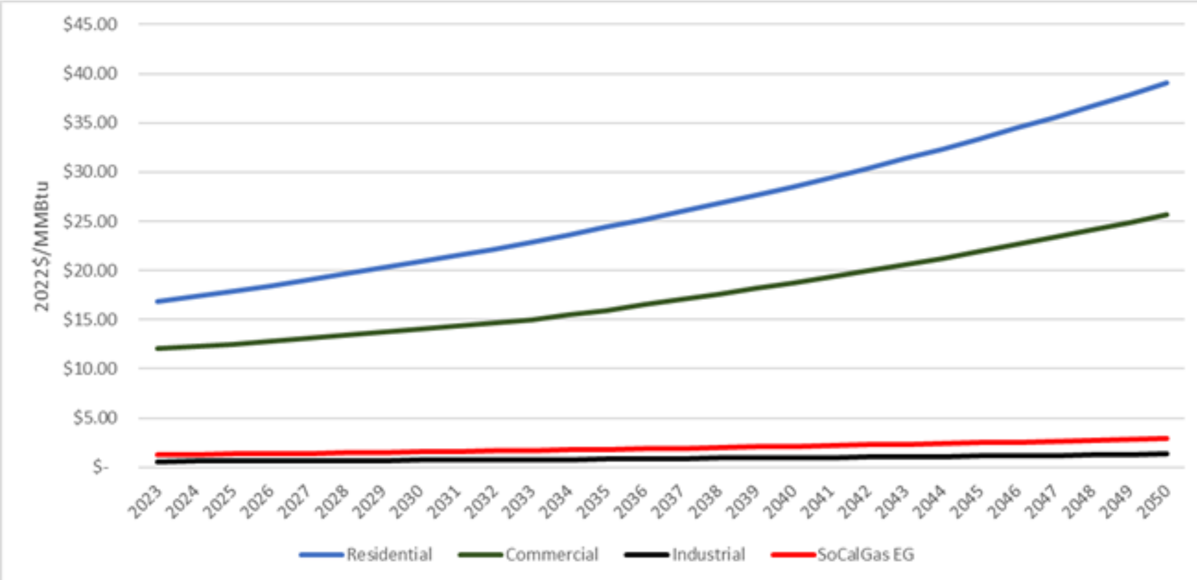
Figure A-6: PG&E Delivered Price Projections



CEC staff modeled delivered price projections for PG&E and results show fossil gas prices increasing out to 2050 for the residential and commercial sectors, with delivered prices for the industrial and electric generation sectors rising only slightly.

Note: EG is short for electric generation, and LT is local transmission. Source: CEC

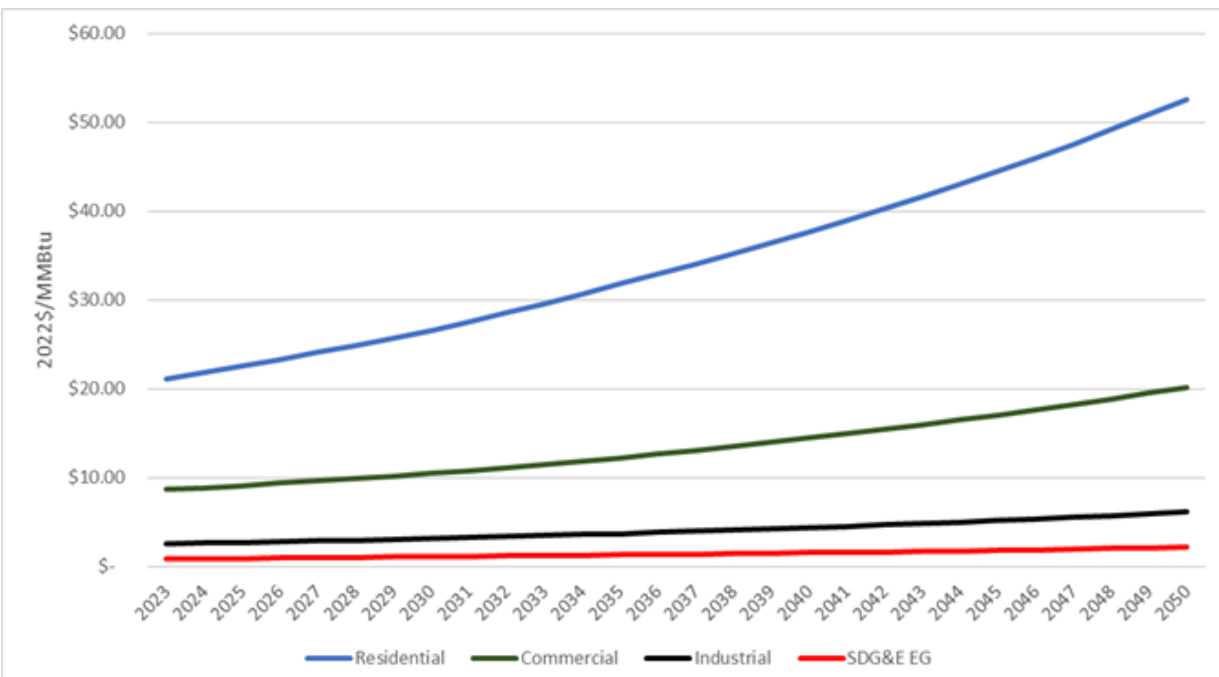
Figure A-7: SoCalGas Delivered Price Projections



CEC staff modeled delivered price projections for SoCalGas and results show fossil gas prices increasing out to 2050 for the residential and commercial sectors, with delivered prices for the industrial and electric generation sectors rising only slightly.

Source: CEC

Figure A-8: SDG&E Delivered Price Projections



CEC staff modeled delivered price projections for SDG&E and results show fossil gas prices increasing out to 2050 for the residential and commercial sectors with delivered prices for the industrial and electric generation sectors rising only slightly.

Source: CEC

Overall Findings

Commodity gas prices declined nationwide and in California in 2023 compared to 2022 because of production returning not only to pre-COVID levels but reaching record levels. The NAMGas results for the reference (base) case show U.S. fossil gas price projections out to 2050 remain relatively steady, around $4.50/MMBtu. As for California, the Border and Citygate projections for all three cases share an outlook of mostly flat pricing trends.

The delivered prices for PG&E, SoCalGas, and SDG&E show price increases out to 2050 in the residential and commercial sectors, while prices for the industrial and electric generation sectors increase only slightly.

As California implements gas decarbonization strategies, in-state demand for fossil gas is expected to decline.

Update on Gas Decarbonization Efforts

Utilities and private sector energy businesses are implementing gas decarbonization strategies aimed at meeting climate goals, maintaining reliability and safety, and achieving affordability (Table A-1).

Table A-1: Key State Proceedings

Program	Lead	Description
Gas Decarbonization Proceeding	CEC	In March 2022, the CEC launched an informational proceeding to engage state agencies and stakeholders in planning for a safe, reliable, and equitable transition away from fossil gas. The proceeding includes workshops on various gas transition topics.
California Building Energy Efficiency Standards (BEES)	CEC	California's Energy Code (also known as the Building Energy Efficiency Standards) is designed to reduce wasteful and unnecessary energy consumption in newly constructed and existing buildings. The CEC updates the Building Energy Efficiency Standards (Title 24, Parts 6 and 11) every three years by working with stakeholders in a public and transparent process. The CEC is planning the 2025 Energy Code.
Long-Term Gas Planning Rulemaking	CPUC	In January 2020, the CPUC opened this rulemaking to create a planning process for decarbonization of the gas system while maintaining gas system safety, reliability, and affordability.
Building Decarbonization Rulemaking	CPUC	In January 2020, the CPUC opened this rulemaking to implement SB 1477 (Stern, Chapter 378, Statutes of 2018) and encourage building decarbonization more generally.

Program	Lead	Description
Renewable Gas Rulemaking	CPUC	This proceeding was originally opened to implement AB 1900 (Gatto, Chapter 602, Statutes of 2012) and has since been used to explore the usage of renewable gas (for example, biomethane and clean and renewable hydrogen) more generally.
Scoping Plan	CARB	AB 32 requires CARB to develop a scoping plan for achieving California's GHG emissions reduction targets with updates at least every five years. It is designed to meet the state's long-term climate objectives and support a range of economic, environmental, energy security, environmental justice, and public health priorities. CARB approved *2022 Scoping Plan Update* in December 2022.

Source: CEC staff

CEC Gas Decarbonization Proceeding Updates

The CEC's Gas Decarbonization proceeding provides an important avenue for long-term planning during the gas transition. The *2021 IEPR* identified areas where analytical improvements will be needed to provide a sound analytical framework to support long-term gas planning. The gas decarbonization proceeding implements these recommendations, which include improvements and expansions to the CEC's existing data and analytics. (The CEC already forecasts and assesses gas demand, supply, transportation, price, rates, reliability, and efficiency to guide and support gas system planning.) Some of these improvements are underway, and others will be implemented over the next couple of years. Improvements include forecasting gas demand under more extreme conditions, better assessing the impact of decarbonization efforts, and enhancing hydraulic modeling of the gas system.

As an example of such an improvement, the CEC's Demand Analysis Branch is producing gas demand scenarios in support of the Southern California summer and winter gas reliability assessments. These scenarios look at SoCalGas system conditions under normal and peak conditions, such as during an extreme weather event. Winter 2022–2023 marked the first time the CEC used internally produced modeling results in support of a gas reliability assessment. Previously, the CEC used the demand projections from the gas utilities' biennial California Gas

Report.[258] To help validate the results, the CEC will continue to coordinate with the utilities on the demand forecast.

In developing its forecasts for the Southern California gas reliability assessments, the CEC's Demand Analysis Branch has used gas utility data collected by the CEC as part of the IEPR proceeding. Starting with the 2021 IEPR cycle, the CEC collects data from the gas utilities, including some historical daily demand; forecasted demand along with inputs and assumptions used to generate those forecasts; revenue and rate base information; and information on each gas utility's infrastructure. CEC staff will continue to use gas utility demand forecasts, along with the associated inputs and assumptions to produce improved forecasts and trends assessments.

Beginning with the *2021 IEPR* and continuing with the seasonal assessments, CEC staff has analyzed hydraulic models to assess gas system operations under various conditions, including peak winter or summer days. Hydraulic models apply nonlinear equations that capture fluid-flow dynamics for a compressible liquid to simulate the complex interactions between gas supply entering a system, gas supply leaving the system as it is consumed, and the detailed physical configuration of the system. Through transient modeling, the hydraulic model simulates operations across the entire gas day, capturing changes in line pack that the peak day gas balance cannot. Gas utilities routinely use hydraulic assessments to simulate system operations and evaluate the ability to serve load under various demand, supply, and capacity conditions.

The CEC independently conducts hydraulic assessments to confirm results obtained from the gas utilities and crafts and runs scenarios and cases for consideration by policy makers. As part of the Gas Decarbonization Proceeding, the CEC plans to use the analysis of utility hydraulic models to assess the impact of the energy transition on California's gas system. This future analysis may include the impacts of building electrification and the transportation of green hydrogen on utility gas systems.

Understanding the current and future roles of underground gas storage facilities is key to supporting long-term gas system planning. To better understand the role of underground gas storage facilities on the PG&E and SoCalGas systems, the CEC updated its data collection regulations to collect daily operational data from underground gas storage facilities. The CEC collects data quarterly, including facility withdrawals, injections, and the quantity of gas in

258 California's gas and electric utilities prepare the *California Gas Report* in compliance with CPUC Decision (D.95-01-039). The CGR presents an outlook for natural gas requirements and supplies for California. The report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years. The outlook in the 2022 CGR goes out to 2035.

storage. The information provided in these filings can be used as part of the CEC hydraulic modeling analysis to provide realistic simulations of injections and withdrawals for seasonal assessments and other analyses. These data can also support work in assessing the future role of underground gas storage as California further decarbonizes its energy systems. This analysis can include impacts of clean and renewable hydrogen, renewable gas, and building electrification on the use of underground gas storage facilities.

CEC Research and Development Funding

The CEC administers relevant clean energy research and development programs. Research and development is crucial for breaking down barriers to new technologies that can help reduce fossil fuel use and bring clean energy opportunities to fruition. Table A-2 summarizes recent R&D funding efforts at the CEC.

Table A-2: CEC Research and Development Fossil Gas Programs

CEC Program	Description
Natural Gas Research Program	The CEC funds public interest research and development projects to advance efficient, safe, and health-protective roles for gas and related fuels. For Fiscal Year 2022–23, the proposed key themes include targeted gas system decommissioning, decarbonization of gas end uses, energy efficiency, entrepreneur development, and energy equity. Proposed funding is $24 million.
Electric Program Investment Charge (EPIC)	EPIC invests more than $130 million annually to support decarbonization of electricity generation and consumption. Relevant research areas include renewable and zero-carbon electricity generation, reliability and resilience, and electric technologies for homes, businesses, industries, and transportation.
Industrial Grid Support and Decarbonization Program	Established with the 2022–23 fiscal year budget, this $90 million program will fund demonstration and deployment projects that will shift load from peak hours based on the signals from the grid and decarbonize industrial processes.
Food Production Investment Program	The 2022–2023 fiscal year budget provided $25 million with $40 million in Fiscal Year 2023–24 to fund demonstration and deployment projects that will shift load from peak hours and decarbonize food production processes.

Source: CEC

CPUC Gas Decarbonization Updates

The CPUC is engaged in gas decarbonization efforts as outlined above in Table A-3 and in coordination with other agencies. The CPUC's ongoing activities include approving utility rate structures and cost allocations, establishing safety and reliability standards, and overseeing utility programs and pilots, including those which offer incentives and enable a transition from gas to cleaner alternatives. Further, the CPUC is working to develop a more comprehensive framework through proceedings that affect several utilities, including the Long-Term Gas Planning Rulemaking, Building Decarbonization Rulemaking, and others described below.

Pending Rate Cases

Fundamentally, gas rates are determined by a utility's costs — known as the *revenue requirement* — divided by the units of gas sold by the utility. For core customers,[259] the revenue requirement has three main components (1) core procurement (gas commodity) costs, (2) gas transportation costs, which pay for the gas utility's infrastructure, and (3) public purpose programs, such as the California Alternate Rates for Energy (CARE) program.

PG&E's rate case affecting 2023–2026 rates has a proposed decision pending. Among the infrastructure costs it addresses, the following relate closely to questions of how to approach the gas transition: PG&E's Alternative Energy Program to conduct electrification that avoids gas investments, the rate of replacement of gas distribution infrastructure, and depreciation methods.

SoCalGas and SDG&E filed a general rate case application in 2022 for 2024–2027 rates with a decision expected in 2024.

CPUC Proceedings

Long-Term Gas Planning Rulemaking (R.20-01-007)

The CPUC's Long-Term Gas Planning Rulemaking is designed to create a process to coordinate gas planning across utilities, over time, and with other activities and state goals. It is intended to supplement the CPUC's general rate cases, which gather some relevant data, but not at the level of detail needed. The scope of the Long-Term Gas Planning Rulemaking includes considering how to implement a coordinated, iterative, and long-term planning process to align gas system planning and maintenance with downsizing the system and electrification activities. Among other activities completed so far, the proceeding has:

259 Core customers include residential, small commercial, and small industrial customers. These customers consume about 35 percent of California's annual fossil gas, mostly for space heating, water heating, and other appliance uses.

- Vetted the design standards that specify the level of demand that the gas system is required to meet.
- Created a penalty process for utilities who fail to meet the standard.
- Adopted a new general order, which requires utilities to report large infrastructure projects planned for the upcoming decade and submit applications for review of large projects.

In 2022, the CPUC issued a staff proposal for public comment that suggests a framework for dividing geographic areas served by gas distribution infrastructure into five tranches ranging from earliest to last (if at all) to target for electrification. These tranches would prioritize community benefits (including disadvantaged community designation), cost avoidance, and risk reduction. The staff proposal also considers what other information may be desirable as part of a gas distribution investments review process. Pending topics for the proceeding include these or other amendments to gas infrastructure planning and consideration of depreciation and ratemaking approaches in light of declining gas demand.

Aliso Canyon Investigation (I.17-02-002)

After the massive gas leak at the Aliso Canyon Natural Gas Storage Facility in 2015, Senate Bill 380 (Pavley, Statutes of 2016, Chapter 14) tasked the CPUC with determining "the feasibility of minimizing or eliminating the use of the Aliso Canyon natural gas storage facility located in the County of Los Angeles while still maintaining energy and electric reliability for the region."

The CPUC has conducted extensive modeling on the feasibility of reducing Aliso Canyon inventory in consultation with stakeholders. In September 2022, CPUC staff issued a proposal considering the path required to reduce Aliso Canyon dependence to zero by 2027 and a biennial assessment process to verify progress along that path. It remains pending, with a decision expected in 2024. In August 2023, the CPUC responded to the high gas prices throughout the western United States in winter 2022–2023 by increasing the maximum storage level allowed at the Aliso Canyon facility from 41.16 Bcf to 68.6 Bcf. The August 2023 decision discussed the role that gas storage can play in reducing price volatility.[260] In September, the CPUC's Energy Division lifted the Aliso Canyon Withdrawal Protocol restrictions on when the facility can be used to supply gas.

Building Decarbonization Rulemaking (R.19-01-011)

Senate Bill 1477 (Stern, Chapter 378, Statutes of 2018) allocated $120 million for the Technology and Equipment for Clean Heating (TECH) Initiative to encourage heat pump

260 CPUC. July 28, 2023. D.22-09-026, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M515/K329/515329559.PDF.

appliance installations and $80 million for the Building Initiative for Low-Emissions Development (BUILD) Program to encourage all-electric new construction. Program funds under SB 1477 are derived from allowances allocated to gas utilities under the Cap-and-Trade Program. The 2022–23 California budget allocated an additional $50 million to the TECH program from the state's general fund.

BUILD provides technical assistance and incentives for new all-electric, low-income residential buildings. The CPUC began implementing the program in the first quarter of 2022. TECH focuses on market development for low-emission space and water heaters in new and existing homes, which began in 2021. All market-rate incentives were exhausted within six months. TECH will continue to oversee market transformation moving forward.

Historically, part of the initial cost to builders and developers of connecting new customers to the gas system has been offset through allowances or subsidies provided by the utility.[261] In September 2022, the CPUC ended these allowances for all rate classes beginning in July 2023,[262] eliminating this incentive to build new fossil gas infrastructure and saving ratepayers roughly $164 million annually. However, though they are no longer encouraged through incentives, new gas connections are still permitted under state regulations. Some cities have gone a step further and banned gas hookups in new construction within their jurisdiction.

Energy Efficiency Rulemaking

Energy efficiency programs funded by gas ratepayers and overseen by the CPUC include subsidies for new gas equipment that is more efficient than the baseline options. However, installing such new gas equipment may "lock in" gas use for years to come. To begin to address this issue, in April 2023, the CPUC adopted a policy that will no longer allow ratepayer-funded energy efficiency incentives to be authorized for certain non-cost-effective gas measures for new construction projects with no existing gas line, and for new construction projects with an existing gas line if gas usage will materially increase.[263] This policy takes effect in January 2024. The decision further provides a process to examine expansion to

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261 Based on equations reflecting rate category, demand, and other factors, including additional amounts for each residential gas appliance type.

262 CPUC. July 28, 2023. D.22-09-026, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M515/K329/515329559.PDF. With potential exceptions only if a project has demonstrated environmental benefit with no alternative to combustion.

263 CPUC. April 7, 2022. D.23-04-035, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/news-and-outreach/documents/bco/decision-2204035-4182022-rulemaking-2103010-with-attachement-b.pdf. The policy applies to residential and commercial projects in the resource acquisition and market support segments of energy efficiency program administrators' portfolios.

retrofit programs, including by directing CPUC staff to develop technical guidance for identifying viable electric alternatives for gas measures.

Renewable Gas Rulemaking (R.13-02-008)

In compliance with SB 1440, the CPUC issued a decision (D.22-02-025) under the Renewable Gas rulemaking that adopted biomethane procurement targets. These targets will encourage biomethane production and increase the amount of biomethane directed toward homes and small commercial gas users.[264] Program amendments or complementary programs for nontransportation sectors may be needed to ensure the incentive structure for biomethane aligns with the applications that will provide the most economic and climate benefits, such as in the industrial and electricity sectors.

R&D Pilot Programs

The CPUC has funded six pilot projects in the San Joaquin and Sacramento Valleys that demonstrate the collection of biomethane from dairy digesters and the injection of the gas into gas pipelines. California Bioenergy, Maas Energy Works, and DVO, Inc. developed these projects, and they are expected to help promote future biomethane production facility interconnection. Five of the six projects are now on-line.

Further, the CPUC's biomethane procurement decision authorizes spending $40 million for PG&E and SoCalGas each to fund one woody biomass gasification pilot project. These facilities will produce biomethane from sustainable forestry practices, woody agricultural waste, or urban wood waste.

Pilot projects may also help the state assess the feasibility and cost of electrifying buildings on a large enough scale — and on a timely enough schedule — to avoid the need for gas pipeline replacements. In coordination with the CPUC's data requests for the Long-Term Gas Planning Rulemaking, the CEC recently launched development of a data-driven tool for identifying promising decommissioning sites, enhancing the capacity of state agencies to conduct planning and craft policy for the gas system in California's low-carbon future.

264 CPUC. February 24, 2022. D.22-02-025, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M454/K335/454335009.PDF. The decision set a 2030 biomethane procurement target of 12.2 percent for each IOU's respective 2020 core customer fossil gas demand, excluding Compressed Natural Gas Vehicle demand, as noted in the California Gas Report (about 72.8 billion cubic feet [Bcf]). The procurement mandate provides that all contracts signed by the utilities under the program must end in 2040 for the CPUC to have the opportunity to reevaluate the program at that point.

CARB Gas Decarbonization Updates

Assembly Bill 32 requires CARB to develop a scoping plan for achieving California's GHG emissions reduction targets with updates at least every five years. It is designed to meet the state's long-term climate objectives and support a range of economic, environmental, energy security, environmental justice, and public health priorities. CARB approved the *2022 Scoping Plan Update* in December 2022. CARB's *2022 Scoping Plan Update* identifies several actions to reduce fossil gas use in the industrial sector, including:

- Use clean and renewable hydrogen for 25 percent of process heat by 2035 and 100 percent by 2045 for the chemicals and allied products and pulp and paper sectors.
- Use carbon capture and storage (CCS) at refineries, with most operations covered by 2030.
- Retire all combined-heat-and-power plants by 2040.
- Use CCS on 40 percent of stone, clay, glass, and cement making by 2035 and on all such facilities by 2045. Reduce some emissions through changing input materials.
- Electrify/decarbonize the rest of industrial demand by 2045 where possible, with target varying by sector.
- Leverage energy efficiency and renewable technology programs.
- Prioritize these transitions in communities most in need.
- Create markets for low-carbon products and recycled materials.
- Revise utility gas and electricity rate design to create an incentive to electrify and reduce industrial sector fossil gas use.

In developing the *2022 Scoping Plan Update*, CARB also conducted an economic analysis of decarbonization strategies, recognizing that transitioning away from fossil fuels to alternatives and increasing action on natural and working lands will affect employment opportunities, household spending, businesses, and other economic aspects of Californian's lives. Some sectors expect to see growth (such as renewable electricity and hydrogen production), while other sectors may shrink. The *2022 Scoping Plan Update* examines the net impact of decarbonization on employment and jobs.

California Geologic Energy Management Division (CalGEM) Decarbonization Efforts

California experienced two major incidents — the 2010 San Bruno pipeline explosion and the 2015 Aliso Canyon well leak — that elevated the vital importance of gas system safety and maintenance. Since then, the state and federal governments have implemented greater oversight and new safety measures for California gas utilities' infrastructure.

Following the San Bruno pipeline explosion, the CPUC ordered California's investor-owned gas utilities to test or replace any transmission pipeline sections without a record of a pressure test to the modern standard, along with detailed safety enhancement plans.[265] The federal government also imposed stricter rules for pipeline assessments and inspections.

In response to the Aliso Canyon well leak, CalGEM adopted comprehensive regulations focused on the safety of underground gas storage facilities in California that are more stringent than federal regulations.[266] In some instances, operators may be required to construct additional wells to maintain injection and withdrawal capacity, which leads to additional costs.[267]

Gas and Electric Utilities and Local Government Decarbonization Projects

Federal, state, and regional initiatives seek to advance hydrogen deployment, as discussed in Chapter 2.

California's gas utilities are pursuing pathways toward decarbonizing the state's gas system. PG&E plans to evolve the gas system to an affordable, safe, and reliable net-zero-energy delivery platform and expects to make this transition with a diverse mix of resources, including electrification, cleaner fuels (hydrogen and renewable natural gas), and other solutions such as carbon capture, storage, and utilization. SoCalGas's 2021 report *The Role of Clean Fuels and Gas Infrastructure in Achieving California's Net Zero Climate Goal* offers detailed decarbonization solutions, including a clean fuels infrastructure to support and accelerate these efforts. The analysis also offers solutions for the transportation and industrial sectors and supports existing state climate and energy policies, including resilient and reliable electrification.

Publicly owned electric utilities in California provide subsidies and other support for ratepayers to electrify buildings. These subsidies include rebates for electric panel upgrades, heat pump space and water heaters, electric stoves/ovens, and electric clothes dryers.[268] Other efforts

265 CPUC. Public Advocates Office, https://www.publicadvocates.cpuc.ca.gov/.

266 See Senate Bill 887 (Pavley, Statutes of 2016) and Public Resources Code Section 3180, which required CalGEM to develop and implement its regulatory scheme. On a federal level, Congress enacted the PIPES Act of 2016, requiring PHMSA to issue, within two years of passage, "minimum safety standards for underground natural gas storage facilities." Operators have been working to comply with CalGEM risk management plan requirements and integrity management requirements under PHMSA.

267 To reduce the likelihood of leaks, the 2018 rules also set a default integrity testing schedule of every 24 months, until the operator establishes the corrosion rate and meets other safety factors. These testing requirements allow CalGEM to reduce the testing interval once operators have demonstrated it is safe to do so. CalGEM developed the regulations in a public process in consultation with the National Labs. Some stakeholders remain concerned that well inspections may extend into the peak winter season, causing some wells to be offline when gas storage is most important for system reliability.

268 Pasadena Department of Water and Power. https://pwp.cityofpasadena.net/electrify-your-home/

include outreach activities such as induction cooking demonstrations[269] and online tools to estimate the impact of electrification on the ratepayer's energy use, utility bill, and GHG emissions.[270]

In 2022, the Sacramento Municipal Utility District (SMUD) submitted an updated Integrated Resource Plan to the CEC,[271] which consisted of a plan the utility board adopted a year earlier with the goal of reaching zero emissions in its power supply by 2030 — the "2030 Zero Carbon Plan." The plan calls for "accelerating local vehicle and building electrification to achieve significant GHG reductions."[272] To help meet these goals, SMUD provides subsidies including rebates and financing for electrification activities.[273] SMUD recently released a report detailing progress towards its zero carbon goals, *2030 Zero Carbon Plan: Progress Report*.[274]

Several California local governments have passed "gas ban" ordinances and are supporting the goals of the ordinances while working towards an equitable transition.[275] The City of Oakland, for example, is developing a building electrification policy roadmap, which the city expects to release in 2024. Supporting this roadmap is research on the potential workforce impacts of building electrification along with a list of potential actions to help transition the workforce to

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269 Alameda Municipal Power and Frontier Energy. Video: "What and Why of Commercial Induction Cooking." https://www.youtube.com/watch?v=_-kRMLjBFeU&t=4s.

270 Silicon Valley Power. Residential Electrification Estimator. https://www.siliconvalleypower.com/home/showpublisheddocument/80398/638188201777700000.

271 SMUD. Updated 2022 IRP. https://efiling.energy.ca.gov/GetDocument.aspx?tn=246075&DocumentContentId=80242.

272 SMUD. *Resource Planning Report: Integrated Resource Plan Filing Report to the California Energy Commission*. https://efiling.energy.ca.gov/GetDocument.aspx?tn=246076&DocumentContentId=80241. p. 6.

273 SMUD Complete Energy Solutions webpage. https://www.smud.org/en/Business-Solutions-and-Rebates/Business-Rebates/Complete-Energy-Solutions-Program.

274 SMUD. April 2023. *2030 Zero Carbon Plan: Progress Report*. https://www.smud.org/-/media/Documents/Corporate/Environmental-Leadership/ZeroCarbon/2030-ZCP-Progress-Report---April-2023_FINAL.ashx#:~:text=Between%202021%2D2023%2C%20we%20added,our%202030%20Zero%20Carbon%20Plan.

275 See footnotes 189 and 197 for information about the legal status of gas bans.

meet the city's goals.[276] To work toward an equitable transition, the City of Oakland commissioned *An Informational Report Regarding Programs, Resources, and Available Technologies for Electrification of Affordable Housing and Commercial Kitchens*.[277] This report describes available technologies for energy efficiency and electrification retrofits in affordable housing and restaurants. It also describes the local, regional, and statewide programs and resources available to property owners, renters, and restaurants to support equitable electrification. Finally, it provides a list of key challenges facing these two frontline sectors.

As another example, the City of San Jose's website has recorded webinars on how to electrify homes, accessing rebate and incentive funds, and upgrade electric service.[278] These videos are geared toward broad audiences including property owners, property managers, renters, and building contractors. Finally, cities including Albany[279] and Thousand Oaks[280] have induction cooker lending programs, which enable users to try this technology before purchasing and installing equipment.

Private Sector

California-based businesses, including Bloom Energy, Mainspring Energy, and Gradient Comfort, have developed and are selling products that will enable the clean energy transition. San Jose-based Bloom Energy offers a product — the Bloom Energy Server 5.5 — which uses fuel cell technology to convert fossil gas, biogas, or hydrogen into electricity at high efficiency and without combustion.[281] As of July 2022, Bloom Energy reported that 300 MW of their

276 City of Oakland. February 2023. *Informational Report Regarding Workforce Implications of Building Electrification*. https://cao-94612.s3.amazonaws.com/documents/Info-Report-on-Electrification-WFD.pdf.

277 City of Oakland. February 2023. *Informational Report Regarding Electrification of Affordable Housing And Commercial Kitchens*. https://cao-94612.s3.amazonaws.com/documents/Info-Report-Electrification-of-Affordable-Housing-Restaurants.pdf.

278 City of San Jose. Energy Efficiency, Renewable Energy, and Green Building Education webpage. https://www.sanjoseca.gov/your-government/departments-offices/environmental-services/energy/energy-efficiency-workshops-classes.

279 City of Albany. Induction Cooktop Lending Program webpage. https://www.albanyca.org/departments/sustainability/sustainability-resources-and-events/induction-cooktop-lending-program.

280 City of Thousand Oaks. Induction Cooktop Lending Program webpage. https://www.tolibrary.org/services/borrower-services/cooktop-kit.

281 Bloom Energy. "The Bloom Energy Server 5.5 Data Sheet." https://www.bloomenergy.com/wp-content/uploads/bloom-energy-server-2023.pdf.

products have been deployed in California.[282] In 2021, Bloom Energy unveiled the Bloom Electrolyzer; in 2023, it announced that its 4 MW electrolyzer installed at NASA's Ames Research Center in Mountain View has been generating hydrogen.[283]

Mainspring Energy developed a linear generator — a technology that directly converts motion along a straight line into electricity using chemical energy. With funding from the CEC's Natural Gas R&D Program and SoCalGas, Mainspring designed, built, installed, interconnected, operated, and monitored the world's first linear generator system for electricity and heat production.[284] The technology has demonstrated the ability to meet Southern California Air Quality Management District emissions standards in both electric-only and combined heat and power applications. With the success of this project and the knowledge gained from the CEC funded demonstration project, Mainspring has a development roadmap to a 250-kW commercial product.

These technologies are examples of some of the difficult tradeoffs policy makers are facing in transitioning away from fossil fuels and the interconnection between the gas and electricity sectors. Linear generators and fuel cells hold the promise of potentially being quickly deployed for backup electricity generation. In recent years, there has been a rapid uptick in the use of diesel backup generators to manage events such a public safety power shutoffs (intentional, localized, power grid shut offs during high wind and dry conditions that create extreme fire risk). These technologies could provide backup generation that is much cleaner than diesel generators. The potential downside is that, at least initially, they would operate on fossil gas, relying on the gas system that the state is working to transition away from. These technologies could play a role in bridging near-term grid reliability concerns while the state continues to build out the resiliency of the grid.

In the area of building decarbonization, San Francisco-based Gradient Comfort offers a window heat pump technology that provides a much-needed space heating and cooling solution to overcome barriers for multi-family units, renters, and low-income customer groups. Gradient uses a refrigerant with a significantly lower global warming potential than others in

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282 Bloom Energy. July 29, 2022. Comments on June 25, 2022, Workshop on the Demand Side Grid Support Program. https://efiling.energy.ca.gov/GetDocument.aspx?tn=244241&DocumentContentId=78165.

283 Bloom Energy press release. May 23, 2023. "Bloom Energy Demonstrates Hydrogen Production with the World's Most Efficient Electrolyzer and Largest Solid Oxide System." https://newsroom.bloomenergy.com/news/bloom-energy-demonstrates-hydrogen-production-with-the-worlds-largest-and-most-efficient-solid-oxide-electrolyzer.

284 Simpson, Adam, and Keith Davidson. 2021. *Linear Generator for Combined Heat and Power*. California Energy Commission. Publication Number: CEC-500-2021-017. https://www.energy.ca.gov/sites/default/files/2021-05/CEC-500-2021-017.pdf.

the industry, and a design that sits below the window, allowing unimpeded light and airflow. The technology is shelf-ready and can be installed and removed without the assistance of a contractor or specialized tools, allowing renters to take the product with them when they move.[285]

285 Gradient has received two CEC EPIC funding awards to improve the heating performance of its heat pump system for colder climates and establish its initial manufacturing line in California.

APPENDIX B: Update on Assembly Bill 1257 Requirements

This appendix meets the requirements of Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013), referred to as the Natural Gas Act. The legislation directed the California Energy Commission (CEC) to "identify strategies to maximize the benefits obtained from natural gas, including biomethane for purposes of this section, as an energy source, helping the state realize the environmental and cost benefits afforded by natural gas." Assembly Bill 1257 required the CEC to perform this analysis as part of the *2015 Integrated Energy Policy Report* (*2015 IEPR*) and every four years thereafter. In 2018, Senate Bill 1374 (Hueso, Chapter 611, Statutes of 2018) amended the Natural Gas Act by sunsetting it on November 1, 2025. The CEC published an updated analysis in the *2019 IEPR* and is providing this final update in the *2023 IEPR*.

Since the passage of AB 1257, California has enacted policies intended to meet climate goals and is transitioning away from fossil gas as described throughout this report. This appendix addresses each of the requirements of AB 1257, in many cases by reference to work described in more detail in Appendix A or in other chapters of the *2023 IEPR*.[286]

Requirement 1: Optimize Natural Gas as a Transportation Fuel
(PRC Section 25303.5[b][1])

Overall, fossil gas plays a small role in the transportation sector, mostly providing fuel for compressed natural gas (CNG) buses and trucks. Nearly 19,000 medium- and heavy-duty gas vehicles operate in California, making this fuel type the most common alternative fuel vehicle in each of these vehicle classes. Further, there are more than 16,000 light-duty cars, trucks, and vans within the state operating on fossil (natural) gas. Low carbon biomethane coupled with emission control technologies can also provide substantial reductions in GHG and criteria pollutant emissions compared to a conventional diesel truck.

Since the passage of AB 1257, California has strengthened its policy to electrify the transportation sector. As noted above, Governor Newsom issued Executive Order N-79-20 that established aggressive zero-emission vehicle (ZEV) targets. Further, CARB's Advanced Clean Cars II and Advanced Clean Fleets rules require ZEV adoption for light duty and

286 As directed by AB 1257, the CEC continues to consult with the CPUC, the California State Water Resources Control Board, California ISO, CARB, and California Geologic Energy Management Division to obtain relevant input on these topics.

medium/heavy duty vehicles, respectively. CARB's *2022 Scoping Plan for Achieving Carbon Neutrality* also calls for a transition away from fossil fuel vehicles by 2045. While fossil gas can serve as a feedstock for hydrogen being used as a transportation fuel for hydrogen-ZEVs, the state is looking to move to renewable sources of hydrogen for hard-to-electrify transportation applications. (See Chapter 2.)

Fossil gas offers modest GHG reductions (about 14 percent compared to gasoline and diesel) and has been an early source of GHG reductions for the CEC's clean transportation project investments.[287] The potential for upstream methane leakage, however, risks undermining any GHG advantages of fossil gas. Also, as diesel engines have become cleaner, fossil gas may no longer provide any significant NO_X reduction benefits, except in the case of low-NO_X engines. The same concerns apply to fueling infrastructure. The risk of methane leakage can be significantly reduced with the use of biomethane, since biomethane is most frequently used at the point of production, whereas fossil gas is transported through a pipeline. Unlike fossil gas, biomethane can have one of the lowest carbon intensities of any alternative fuel.

The CEC's most recent solicitation for fossil gas fueling infrastructure projects in 2016 (GFO-16-602) made $3.5 million available to public K-12 school districts in California. The CEC's Clean Transportation Program has not allocated funding for fossil gas vehicles or infrastructure solicitations since the 2017-2018 Investment Plan.

In 2019, the CEC executed funding agreements for compressed natural gas (CNG) school buses and associated infrastructure, as follows:

- 25 buses ($4,020,529)
- Five infrastructure projects ($2,100,000)

As discussed in Appendix D, the CEC's the Clean Transportation Program serves a key role to support the state's transition to a zero-emission future. The program has increasingly focused its resources into zero-emission technologies, with a special focus on ZEV infrastructure. However, if there are segments where zero-emission technology is not feasible, the program will also support near-zero-emission technologies. The CEC's *Draft Staff Report, 2023-2024 Investment Plan Update for the Clean Transportation Plan* provides more details on how the state is achieving ZEV goals.[288]

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287 CEC. 2019-2020 Investment Plan. [2019-2020 Investment Plan Update for the Clean Transportation Program - Commission Report](). Publication # CEC-600-2018-005-CMF.

288 CEC. Draft Staff Report. [2023-2024 Investment Plan Update for the Clean Transportation Plan](). https://www.energy.ca.gov/publications/2023/2023-2024-investment-plan-update-clean-transportation-program.

Requirement 2: Determine the Role of Gas-fired Generation as Part of a Resource Portfolio (PRC Section 25303.5[b][2])

Please also see the following sections of Appendix A:

- "CEC Gas Decarbonization Update"
- "CPUC Gas Decarbonization Updates"
- "CARB Gas Decarbonization Updates"

Requirement 3: Optimize Gas as a Low-Emission Resource (PRC Section 25303.5[b][3])

Chapter 2 provides preliminary findings on hydrogen potential in electric generation and transportation applications. Also see the following sections of Appendix A:

- "CPUC Proceedings - Renewable Gas Rulemaking"
- "CARB Gas Decarbonization Updates"

Requirement 4: Optimize Natural Gas for Heating, Water Heating, Cooling, Cooking, Engine Operation, and Other (PRC Section 25303.5[b][4])

As noted above, the state is advancing electrification to decarbonize buildings. The *2019 IEPR* stated that, "leveraging the decarbonization of the electricity system by transitioning space and water heating in buildings toward highly efficient electric appliances, coupled with strategies to enable greater ability to shift when energy is consumed, will be key to reducing emissions from buildings."

See the following sections of Chapter 3 for more information:

- "Building Decarbonization Policies and Programs"
- "AAEE Updates"
- "AAFS Updates"
- "Shifts in Energy-Use Patterns"

Also, please see the following sections of Appendix A that have information on building efficiency:

- "Table A-1: Key State Proceedings"
- "Gas Utility Decarbonization Projects"

Appendix C also provides updates on building decarbonization.

Requirement 5: Identify Effective Methods by Which Electric and Natural Gas Industries Can Facilitate Implementation of Any of These Strategies (PRC Section 25303.5[b][5])

The CEC administers clean energy research and development programs that are crucial for breaking down barriers to new technologies that can help reduce fossil fuel use and bring opportunities to fruition. Please see the following sections of Appendix A for more information:

- "CEC Research and Development Funding"
- "CPUC Proceedings - R&D/Pilot Programs"

Also see Chapter 2 for discussion of blending hydrogen with gas for electric generation.

Requirement 6: Determine the Need for a Long-Term Infrastructure Reliability Policy (PRC Section 25303.5[b][6])

Please see the following sections of Appendix A that show how the state is planning for long-term infrastructure reliability:

- "CPUC Proceedings - Aliso Canyon Investigation"
- "Gas Supplies and Infrastructure"
- "CalGEM Safety Regulations"

Requirement 7: Determine the Role of Natural Gas in Zero Net Energy Buildings (PRC Section 25303.5[b][7])

The state's policy on zero net energy buildings has changed since enactment of SB 1257. In the *2018 IEPR Update*, the CEC recommended that "the state should replace its zero-net-energy policy goals with appropriate goals for low-carbon buildings. Zero-emission building goals, while ambitious, are a necessary component of the state's aggressive GHG emission reduction policy initiatives."[289] California has since refined this policy to support the advancement of "building decarbonization." The citations noted for Chapter 3, Appendix A, and Appendix C also for requirement 4 also address requirement 7 of SB 1257.

289 CEC staff. 2018. *2018 Integrated Energy Policy Report Update, Volume II*. CEC. Publication Number: 100-2018-001-V2-CMF. https://efiling.energy.ca.gov/getdocument.aspx?tn=227391. p. 197.

Requirement 8: Optimize Jobs Development in the Private Sector, Particularly in Distressed Areas (Equity) (PRC Section 25303.5[b][8])

Please see the following sections of Appendix A that show how the state is addressing the workforce transition with the long-term goal of optimizing job creation and skill development:

- "Gas Utility Decarbonization Projects"

Please also see Appendix C.

Requirement 9: Optimize Facilitation of Proposed Strategies With State and Federal Policy (PRC Section 25303.5[b][9])

Please see the following sections of Appendix A for detailed information of state, federal, and local policies that are optimizing strategies related to gas decarbonization:

- "Policies Driving California's Gas Decarbonization"
- "Key State Proceedings"

Requirement 10: Evaluate Incremental Economic and Environmental Costs and Benefits or Proposed Strategies (PRC Section 25303.5[b][10])

Please see the following sections of Appendix A for information on ways the state is evaluating economic and environmental strategies:

- "CARB Gas Decarbonization Updates"
- "Policies Driving California's Gas Decarbonization"

APPENDIX C: Energy Efficiency Updates

As California focuses on electrifying energy use to meet climate goals, equitably advancing energy efficiency is a foundational part of the transition to a clean energy future. On a system level, energy efficiency can offset load growth from electrification, helping to manage the need for new zero-carbon resources and providing a hedge against potential delays in building and connecting it. For consumers, energy efficiency investments can lower energy bills and improve quality of life, particularly for low-income Californians and during extreme weather caused by climate change. Efficiency improvements can also increase the resilience of buildings and grid infrastructure to extreme temperatures. This appendix provides updates as required by statute on specific advancements in energy efficiency. These topics also will be addressed in the California Energy Commission's (CEC's) *2023 California Energy Efficiency Action Plan* (CEEAP) expected to be adopted in 2024.[290]

Maximizing Energy Efficiency Savings in Disadvantaged Communities (PRC Section 25665)

The United States Department of Energy estimates that nearly 5 million households in California are low-income while CalEnviroScreen estimates roughly 10 million people, or 25 percent of California's 39 million population, live in a disadvantaged community. In the *2019 Annual Affordability Report* released in April 2021,[291] the CPUC found that 13 percent of California's lower income households spend more than 15 percent of their income on electricity service. The CPUC also found that 6 percent of lower income households spend more than 10 percent of their income on gas service. The *2020 Annual Affordability Report*[292] showed similar findings with a decline in electricity affordability over the forecast period (2022–2025), especially in hotter climate zones, as expected growth in income levels may not offset increases in electric bills.

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290 More information about the CEC's energy efficiency program and reports is available at https://www.energy.ca.gov/programs-and-topics/programs/energy-efficiency-existing-buildings.

291 CPUC. April 2021. *2019 Annual Affordability Report*. www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/affordability-proceeding/r1807006--2019-annual-affordability-report.pdf.

292 CPUC. October 2022. *2020 Annual Affordability Report*. www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/affordability-proceeding/2020/2020-annual-affordability-report.pdf.

The CEC assessed strategies to reduce GHG emissions in buildings in the 2021 *California Building Decarbonization Assessment*.[293] Amongst other findings, it concluded that replacing combustion appliances with efficient electric equipment (such as heat pumps), along with supporting energy efficiency measures, reducing refrigerant leakage, and advancing load flexibility, would be necessary to reduce GHG emissions 40 percent by 2030. Estimates of the cost to support replacements and early retirements of equipment range from tens to hundreds of billions of dollars. Resources — in the form of installed equipment and building infrastructure upgrades, rebates, financing options, or technical assistance — can significantly accelerate decarbonization and improve quality of life, particularly for low- to moderate-income Californians.

Based on this information, the CEC recommended in the *2021 Integrated Energy Policy Report*[294] that the state adopt a 6 million heat pump goal by 2030 and that agencies focus on decarbonizing California's existing buildings, with prioritization on advancing energy equity. Following this recommendation, in September 2022, Governor Newsom signed Assembly Bill 209 (Committee on Budget, Chapter 251, Statutes of 2022) and Assembly Bill 179 (Ting, Chapter 249, Statutes of 2022) which directed the CEC to develop and implement a $922 million statewide Equitable Building Decarbonization Program.

The CEC has been developing the California Equitable Building Decarbonization Program[295] and adopted the direct install[296] program guidelines in October 2023. This program will provide low- or no-cost retrofits for low-income single-family households and multifamily building owners and tenants in disadvantaged communities.[297] The program will implement all-electric measures, as well as energy efficiency and remediation. The CEC will also implement a statewide incentive program promoting the installation of all-electric appliances to low- and

293 Kenney, Michael, Nicholas Janusch, Ingrid Neumann, and Mike Jaske. 2021. *California Building Decarbonization Assessment*. California Energy Commission. Publication Number: CEC-400-2021-006-CMF. https://efiling.energy.ca.gov/GetDocument.aspx?tn=239311.

294 Kenney, Michael, Jacob Wahlgren, Kristina Duloglo, Tiffany Mateo, Danuta Drozdowicz, and Stephanie Bailey. 2022. Final 2021 Integrated Policy Report, Volume I: Building Decarbonization. California Energy Commission. Publication Number: CEC-100-2021-001-V1.

295 CEC. California Equitable Building Decarbonization Program webpage, https://www.energy.ca.gov/programs-and-topics/programs/equitable-building-decarbonization-program.

296 *Direct install* refers to providing the services needed to install the upgrade at no cost to the homeowner or tenant, including hiring contractors to remove old equipment from the site, as needed, and to install new equipment and weatherization, or one or the other, as needed.

297 The program will provide direct install services, including hiring contractors to remove old equipment from the site, as needed, and to install new equipment and weatherization, or one or the other, as needed.

moderate-income Californians. The program will strive to reduce GHG emissions, improve resiliency to extreme heat, improve indoor air quality, and increase energy affordability.

Wherever possible and to stretch state funding as far as possible, both the direct install and incentive programs will leverage federal funds coming to California from the Inflation Reduction Act.[298]

Advancing Flexible Demand Appliance Standards (PRC Section 25402[f][6])

In October 2022, the CEC adopted amendments to California's load management standards to require the state's largest utilities and community choice aggregators to develop and offer hourly time-dependent electricity rates and then provide that information through the Market Informed Demand Automation Server (MIDAS). MIDAS is a single, statewide electric rates database source that can be used to optimize the operation of flexible appliances by shifting load according to electricity prices, GHG emissions, and grid needs. Flexible loads can modulate demand based on grid conditions, displacing energy use from periods of grid congestion or high prices to periods when the grid has excess renewable resources and prices are low.

The CEC is also moving the California appliance market towards inclusion of communication and control features that enable customers to automate when equipment is operated, based on price or through participation in demand flexibility programs. The CEC adopted its first flexible demand appliance standards in 2023 requiring controls for residential swimming pool equipment. These standards ensure the ability to schedule when the device operates and uses energy, allowing customers to benefit from dynamic electricity rates. The standards also ensure the ability to receive rate information and control signals via a wireless internet connection, meaning that the installed equipment can be leveraged by demand response programs and other cloud-based programs administered by utilities, community choice aggregators, and balancing authorities. These automation features have the potential to provide over 500 MW of permanent load flex capacity once all installed pool controls meet the new standard. They also establish a framework for future demand flexibility standards for other appliances. The CEC anticipates adopting one or two standards annually, focusing on consumer appliance controls with the greatest potential for empowering users to control and flex their energy use, and with load shift potentials between 100 MW and 400 MW per appliance.

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298 For more information on the H.R. Inflation Reduction Act of 2022, see https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

Further, the CEC is evaluating opportunities for electric vehicles, electric vehicle service equipment, and on-site battery storage systems to participate in load flexibility. These technologies have enormous potential and can ensure that consumers can fully leverage the cost and environmental benefits of electric cars, in-garage chargers, and battery storage.

The updated load management standards and flexible demand appliance standards are highly complementary. Through MIDAS, smart appliances can help lower costs, reduce GHGs, and reduce strain on the grid by enabling homeowners and building operators to schedule their energy use during non-peak hours and to shift peak loads to when energy prices are lowest.

Achieving Energy Savings in Existing Residential and Non-Residential Buildings (PRC Section 25943)

Buildings are a key factor in meeting California's climate and energy goals. California has 14 million homes and 7 billion square feet of commercial space. These buildings account for approximately 25 percent of state GHG emissions. The combustion of gas for space and water heating is the single largest source of GHG emissions in buildings. As detailed in the 2021 *California Building Decarbonization Assessment*, energy costs and GHG emissions can be reduced through efficient electrification and demand flexibility.

Building and appliance efficiency standards and programs have been successful at reducing electricity and gas usage and avoiding GHG emissions even as California's population and inventory of appliances have grown. Limiting electricity load growth continues to be critical as consumers shift to electric equipment in buildings or increase use of air conditioning and other systems to manage extreme heat and poor outdoor air quality. The design and construction phases are the most opportune and cost-effective times to ensure low-carbon operation of a building, and to avoid unnecessary and risky investments in gas infrastructure.

The 2022 California Building Energy Code went into effect on January 1, 2023, and applies to both new construction and significant alterations of existing buildings. These updated building standards encourage electric heat pump technology for space and water heating, establish electric-ready requirements for single-family homes, expand solar photovoltaic system and battery storage requirements, and strengthen ventilation standards to improve indoor air quality. Over the next 30 years, the CEC estimates that this code update will provide $1.5 billion in consumer benefits and reduce 10 million metric tons of GHGs, equivalent to taking nearly 2.2 million internal combustion cars off the road for a year.

The CEC is concurrently assessing cost-effective and technically feasible energy saving opportunities for alterations in the 2025 Energy Code. One proposal would require building owners to replace single-zone rooftop units that are less than 65,000 British thermal units per hour with heat pump space heaters. Gas appliances could be installed if paired with energy efficiency measures.

As discussed in the *2021 IEPR*, in contrast to the progress being made in newly constructed buildings where regulatory tools are most effective, the decarbonization of existing buildings is more challenging and greatly lags the pace required to meet the state's climate goals. While retrofits to existing buildings offer great potential for emission reductions, they also face significant barriers, including but not limited to:

- Upfront costs
- Split incentives between owners and tenants[299]
- Structural issues in the building
- Space constraints

Older buildings with minimal insulation, air gaps, and nonexistent or low-performing space heating and cooling are also not equipped to adequately withstand extreme heat and protect occupants. Thoughtful and intentional prioritization is required to ensure the state's most vulnerable and underserved can participate fully in building California's clean energy future — via both adoption of zero-emissions technologies and as workers in deployment. The Equitable Building Decarbonization Program, as discussed above, aims to address this challenge.

Doubling Energy Efficiency Savings in Electricity and Gas by January 1, 2030 (Senate Bill 350 (De León, Chapter 547, Statutes of 2015) and PRC Section 25310(e).)

This analysis will be developed using data from the 2023 electricity and gas forecast. Results will be available in the 2023 IEPR docket in Spring 2024 and will be included in the CEEAP.

299 Split incentives occur when capital improvements are paid for by one party and the energy savings (reduced energy costs) benefit another.

APPENDIX D: Assessing the Benefits and Contributions of the Clean Transportation Program

The California Energy Commission's (CEC) Clean Transportation Program supports the state's transition to cleaner transportation. This appendix provides background on California's clean transportation policies and highlights some of the analytical work by the Clean Transportation Program to advance the infrastructure needed to support zero-emission vehicles, with access and benefits for all Californians. This appendix also provides a summary of program funding and highlights. Finally, this appendix provides an evaluation of the Clean Transportation Program as required biennially in the *Integrated Energy Policy Report (IEPR).*

The Clean Transportation Program Is Essential to Achieving California Policies

The state has been a leader in recognizing the need to rapidly reduce greenhouse gas (GHG) emissions and other pollutants from its transportation system. While California's transportation sector accounts for about 50 percent of state GHG emissions when accounting for emissions from fuel production, California's bold policies are spurring a market transformation to zero-emission vehicles (ZEVs). Table D-1 summarizes several policies and transformational goals for the shift to ZEVs.

Table D-1: Major Clean Transportation Policies and Objectives

Policy	Objectives
Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016)	40 percent reduction in statewide GHG emissions relative to 1990 levels by 2030
Senate Bill 100 (De León, Chapter 312, Statutes of 2018)	60 percent renewable electricity by 2030. 100 percent renewable or zero-carbon electricity by 2045
Executive Order B-55-18	Carbon neutrality by 2045
Clean Air Act; California State Implementation Plans	80 percent reduction in oxides of nitrogen (NO_X) by 2031
Executive Order B-16-12	1.5 million ZEVs by 2025
Executive Order B-48-18	5 million ZEVs on the road by 2030 250,000 electric charging stations, including 10,000 direct current (DC) fast chargers, as well as 200 hydrogen stations by 2025
Executive Order N-79-20	100 percent of new light-duty vehicle sales are ZEVs by 2035 100 percent of operating drayage trucks, off-road vehicles, and off-road equipment are ZEVs by 2035, where feasible 100 percent of operating trucks and buses are ZEVs by 2045, where feasible

Source: CEC staff

As well as GHGs, the transportation sector is a major emitter of criteria pollutants, with mobile sources responsible for nearly 80 percent of NO_X emissions and 90 percent of diesel particulate matter emissions statewide. Protecting and improving public health in the state will require substantial reductions in criteria pollutant emissions. The California Air Resources Board (CARB) estimates that attaining federal air quality standards in 2023, 2031, and 2037 will require significant reductions of NO_X emissions in parts of the state.[300]

300 CARB. Heavy-Duty Optional Low NOx Vehicle Testing webpage. https://ww2.arb.ca.gov/heavy-duty-optional-low-nox-vehicle-testing#:~:text=The%202020%20Mobile%20Source%20Strategy,the%202017%20baseline%20NOx%20emissions.

To help address state climate change and air pollution, the California Legislature passed Assembly Bill 118 (Nunez, Chapter 750, Statute of 2007),[301] modifying the Health and Safety Code (Section 44272) to create the Clean Transportation Program with up to $100 million in funding per year by a surcharge on vehicle registrations and smog abatement fees. The Clean Transportation Program provides funding to "develop and deploy innovative technologies that transform California's fuel and vehicle types to help attain the state's climate change policies."[302] Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) extended the collection of fees that support the Clean Transportation Program to January 1, 2024. Most recently, Assembly Bill 126 (Reyes, Chapter 319, Statutes of 2023) extended the collection of fees to July 1, 2035.

The Clean Transportation Program does not operate in a vacuum but within a context of several state funding programs, vehicle regulations, and agency collaboration. These include vehicle regulations and incentives developed by CARB, the low-carbon fuel standard (LCFS) developed by CARB, infrastructure investments by investor-owned utilities (IOUs) overseen by the California Public Utilities Commission (CPUC), and broader business coordination with the Governor's Office of Business and Economic Development (GO-Biz). There is strong collaboration among the agencies on a regular basis and through the ZEV Market Development Strategy, spearheaded by GO-Biz.[303] The projects supported by the Clean Transportation Program interact with and are informed by these other efforts.

The CEC Is the State's Primary ZEV Infrastructure Planning Agency

The Clean Transportation Program benefits from and is informed by the CEC's leadership in ZEV infrastructure analyses directed through statute. Assembly Bill 2127 (Ting, Chapter 365, Statutes of 2018) requires the CEC to prepare a statewide assessment of the charging infrastructure needed to achieve the goal of 5 million ZEVs on the road by 2030 and reduce emissions of GHGs to 40 percent below 1990 levels by 2030. Executive Order N-79-20 subsequently required the CEC to assess the infrastructure needed to achieve full ZEV adoption within the coming decades.

The inaugural AB 2127 report, published by the CEC in June 2021, finds that nearly 1.2 million public and shared private chargers are needed to support almost 8 million light-duty ZEVs in

301 Assembly Bill 118 (Nuñez, Statutes of 2007, Chapter 750. Subsequently modified by Assembly Bill 109 (Nuñez, Statutes of 2008, Chapter 313).

302 Health and Safety Code Section 44272 (a).

303 GO-Biz. ZEV Market Development Strategy. https://business.ca.gov/industries/zero-emission-vehicles/zev-strategy/.

2030.[304] Past 2030, the ZEV population will continue to grow, along with the need for more charging infrastructure. For medium- and heavy-duty (MDHD) charging in 2030, 157,000 chargers are needed to support 180,000 ZEVs. The report also concludes that, although the private market will ultimately be necessary for ZEV refueling in the future, targeted and innovative state efforts are necessary in the near term.

The CEC is developing the second assessment edition of the AB 2127 report. CEC staff released an initial draft version in August 2023.[305] This new edition includes assessments of charging needed to support over 7 million plug-in electric vehicles by 2030 and over 15 million plug-in electric vehicles by 2035.

Senate Bill 1000 (Lara, Chapter 368, Statutes of 2018) also directs the CEC to assess electric vehicle (EV) infrastructure deployment. Results from the inaugural 2020 analysis show that public chargers are collocated with EVs but unevenly distributed by income, population density, and geography. Low-income communities have the fewest chargers per capita and the widest range of drive times to chargers compared to middle- and high-income communities.[306] The second edition of the SB 1000 report, published in July 2022, assessed drive times to public direct current (DC) fast charging stations. This second edition found that rural communities have less public fast charging station coverage than urban communities, with low-income rural communities particularly lacking coverage.[307] Updates to SB 1000 analysis are ongoing, and the results help inform equitable EV infrastructure deployment under the Clean Transportation Program.

As well as extending the Clean Transportation Program through 2023, AB 8 directed the CEC and CARB to jointly prepare an annual report on establishing a sufficient network of hydrogen refueling station within the state. The 2023 report stated that California is meeting the former 100-station goal pursuant to AB 8 with expended and committed funds (a combination of

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304 Alexander, Matt, Noel Crisostomo, Wendell Krell, Jeffrey Lu, and Raja Ramesh. July 2021. *Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment: Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030- Commission Report*. California Energy Commission. Publication Number: CEC-600-2021-001-CMR. https://efiling.energy.ca.gov/getdocument.aspx?tn=238853.

305 CEC staff. August 2023. *Assembly Bill 2127 Electric Vehicle Charging Infrastructure Second Assessment – Staff Draft Report*. California Energy Commission. Publication Number: CEC-600-2023-048. https://efiling.energy.ca.gov/GetDocument.aspx?tn=251866&DocumentContentId=86859.

306 Hoang, Tiffany. 2020. *California Electric Vehicle Infrastructure Deployment Assessment: Senate Bill 1000 Report*. California Energy Commission. Publication Number: CEC-600-2020-009. https://efiling.energy.ca.gov/getdocument.aspx?tn=236189.

307 Hoang, Tiffany. 2022. *2022 Senate Bill 1000 California Electric Vehicle Infrastructure Deployment Assessment*. California Energy Commission. Publication Number: CEC-600-2022-059. https://efiling.energy.ca.gov/GetDocument.aspx?tn=244067-1.

public and private funding).[308] As of November2023, 66 hydrogen refueling stations have achieved open retail status. In June 2023, however, a funding recipient requested cancellation of a large project to deliver 50 future stations, which resulted in a reduction in the number of stations planned within California. A network of 130 stations is planned from Clean Transportation Program funding allocations and private investment (with 107 awarded or planned for award by the program), and the goal of achieving 200 stations per Executive Order B-48-18[309] is not yet in reach.

Requirements for Assessing the Clean Transportation Program

In 2008, the Legislature passes Assembly Bill 109 (Nunez, Chapter 313, Statutes of 2008), which modifies Section 44273 of the Health and Safety Code to require the CEC to include an evaluation of Clean Transportation Program efforts as part of each biennial *Integrated Energy Policy Report (IEPR)*, including:

- A list of projects funded by the Clean Transportation Program.[310]
- The expected benefits of the projects in terms of air quality, petroleum use reduction, GHG emissions reduction, technology advancement, benefit-cost assessment, and progress toward achieving these benefits.
- The overall contribution of the funded project toward promoting a transition to a diverse portfolio of clean, alternative transportation fuels and reduced petroleum dependency in California.
- Key obstacles and challenges to meeting these goals identified through funded projects.
- Recommendations for future actions.

Funding Summary and Highlights of the Clean Transportation Program

The Clean Transportation Program has provided more than $1.8 billion in funding through the program since 2009. These project awards are summarized in Table D-2.

308 Crowell, Miki and Martinez, Andrew. 2023. *Joint Agency Staff Report on Assembly Bill 8: 2023 Annual Assessment of the Hydrogen Refueling Network in California.* California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2023-069. https://www.energy.ca.gov/sites/default/files/2023-12/CEC-600-2023-069.pdf.

309 Former Governor Edmund G. Brown Jr. Executive Order B-48-18. January 2018.

310 A map of Clean Transportation Program projects, with a downloadable list of projects, is available online. https://caenergy.maps.arcgis.com/home/item.html?id=c31b46862d884112aa8a767de499ae28.

Table D-2: Clean Transportation Program Investments as of July 2023

Funded Activity	Cumulative Awards to Date (in Millions)*	# of Projects or Units
Alternative Fuel Production		
Biomethane Production	$77.66	30 Projects
Gasoline Substitutes Production	$26.94	14 Projects
Diesel Substitutes Production	$66.75	26 Projects
Clean and renewable hydrogen Production	$21.93	6 Projects
Alternative Fuel Infrastructure		
Light-Duty Electric Vehicle Charging Infrastructure	$412.75	24,459 chargers**
Public Hydrogen Refueling Infrastructure (Including Operations and Maintenance)	$260.87	107 Public Fueling Stations***
Medium- and Heavy-Duty ZEV Infrastructure	$302.51	99 Projects**
Low-Carbon Fuel Infrastructure (E85 stations; upstream biodiesel infrastructure; natural gas stations)	$34.66	98 Sites
Alternative Fuel and Advanced Technology Vehicles		
Natural Gas and Propane Vehicle Deployment; Hybrid and ZEV Deployment; Advanced Technology Vehicles	$250.40	14,500+ Vehicles Deployed, and 54 Demonstrations
Related Needs and Opportunities		
Manufacturing	$278.04	48 Projects**
Workforce Training and Development	$39.71	32,000 Trainees
Other Supporting Activities (Fuel Standards and Equipment Certification; Sustainability Studies; Regional Alternative Fuel Readiness; Centers for Alternative Fuels; Technical Assistance and Program Evaluation)	$46.53	94+ Projects
Total	**$1.81 Billion**	**-**

*Includes all agreements that have been approved at a CEC business meeting or are expected for business meeting approval following a notice of proposed award. For canceled and completed projects, includes only funding received. **Includes funding for block grants, such as California Electric Vehicle Infrastructure Project, which will fund a yet-to-be-determined number of EV chargers. ***In addition to Clean Transportation Program investments for 94 public stations, another 13 stations are planned with future Clean Transportation Program funding allocations, and 23 stations are planned to be fully privately funded, for a total of 130 stations planned. Source: CEC.

Using funds from the Clean Transportation Program, the CEC has also leveraged more than $1.1 billion in private and other public funds. However, this amount represents only the minimal, contractually obligated amount of match funding provided toward Clean Transportation Program projects; the actual amount of investment prompted by Clean Transportation Program funding exceeds this amount.

Contributions of the Clean Transportation Program to a Clean Transportation Future

With a legislative mandate to fund clean transportation alternatives and to contribute to state climate policy objectives, the Clean Transportation Program serves a key role to support the state's transition to a zero-emission future. As policies, technologies, and market forces have evolved over the life of the Clean Transportation Program, the program has increasingly focused its resources into zero-emission technologies, with a special focus on ZEV infrastructure. However, if there are segments where zero-emission technology is not feasible, the program will also support near-zero-emission technologies.

Light-Duty Plug-In Electric Vehicle (PEV) Charging

PEVs can be charged from a standard electrical outlet, but the charging rate is rather low, with only about four miles of range added per hour. The Clean Transportation Program has funded projects that provide higher power chargers, known as Level 2 (L2), and direct current fast chargers (DCFC). There is some variation within these charger classes, but L2 chargers can add about 20 miles of range per hour, and DCFC can add hundreds of miles of range in an hour or sometimes even a half hour.

Clean Transportation Program investments have funded electric vehicle charging stations at many types of locations, as detailed in Table D-3. The "private access" chargers include home chargers that are generally dedicated to serving only one vehicle. The CEC has not funded single-family home charging in recent years. The "shared access" chargers include fleets, workplaces, and multifamily housing chargers that may serve multiple vehicles but are not necessarily public. The "public access" chargers include public Level 2 chargers, as well as corridor and urban metropolitan DC fast chargers. Finally, the "mixed access" chargers include shared-private and public access chargers.

Table D-3: Chargers Funded by the Clean Transportation Program as of July 2023

	Private Access	Shared Private Access	Shared Private Access	Shared Private Access	Public Access	Public Access	Mixed Access*	Total
Charger Type / Setting	Level 2 - Residential (Single & Multifamily)	Level 2 - Fleet	Level 1 and Level 2 – Workplace	Level 2 – Residential (Multifamily)	Level 1 and Level 2 - Public	Level 2 and DCFC - Corridor/ Urban Metro	Level 2 and DCFC - CALeVIP	-
Installed	3,936	155	419	341	3,108	532	3,303	**11,794**
Planned	0	0	0	1,728	206	126	9,939†	**11,999**
Total	**3,936**	**155**	**419**	**2,069**	**3,314**	**658**	**13,242**	**23,793**

Does not include chargers that have yet to be approved at a CEC business meeting or connectors that have yet to be funded under CALeVIP. * "Mixed Access" includes shared-private and public access chargers. † For CALeVIP, "planned" chargers are those with rebate funding reserved. Source: CEC.

Through the second quarter of 2023, more than 1.6 million PEVs have been deployed within California since 2010. Even more notably, the share of new vehicle sales that are PEVs exceeded 25 percent in the second quarter of 2023.[311] As PEV sales accelerate in the light-duty sector, the CEC is committed to ensuring that adequate and reliable charging is available not just to support current PEV drivers, but to enable all Californians to follow.

Block Grants for Light-Duty Chargers

The Clean Transportation Program has evolved over the years to maximize efficient deployment and reduce costs with economies of scale. To expedite the processing of light-duty charging infrastructure projects across thousands of locations around the state, the CEC has set up a trio of block grants, summarized in Table D-4.

First announced in 2017, the California Electric Vehicle Infrastructure Project (CALeVIP) is a block grant project that provides incentives for the purchase and installation of electric vehicle charging infrastructure in targeted regions throughout the state. (It is also sometimes referred to as "CALeVIP 1.0" to differentiate it from a successor block grant.) To date, CALeVIP has funded 13 regional incentive projects covering 36 counties in the state.

In April 2021, the CEC released Second Block Grant for Light-Duty Electric Vehicle Charger Incentive Projects to seek up to two block grant implementers to design and implement

311 Statistics on ZEV deployment, as well as related ZEV infrastructure, are available at the CEC's Zero-Emission Vehicle and Infrastructure Statistics webpage, including multiple dashboard displays. Available at: https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics

incentive projects for the deployment of light-duty electric vehicle chargers. Two awardees were selected to implement CALeVIP 2.0 and Communities in Charge.

Table D-4: Light-Duty Charging Infrastructure Block Grants

	CALEVIP 1.0	**CALEVIP 2.0**	**Communities in Charge**
Partnering Organization	Center for Sustainable Energy	Center for Sustainable Energy	CALSTART
Funding Encumbered out of Awarded Amount (in $ millions)	Entirety of $200M	$30M out of $250M	$30M out of $250M
Status of Projects Launched	13 projects closed or fully reserved, covering 36 counties All funds are reserved or awarded, but many charging installations are ongoing Completed: 3,123 L2 chargers 484 DC fast chargers In-progress: 6,624 L2 chargers 1,450 DC fast chargers312	2 projects ($68M) closed in Q1 and Q4 2023 Emphasizing DC fast charging in low-income or disadvantaged communities Prioritizing site readiness	1 project ($30M) closed in Q2 2023 Limited to L2 charging Funded 179 applications for approximately 4,900 charging ports. Next opportunity for L2 chargers expected later in 2023.

Source: CEC

312 Some of these projects are still only reserved for funding and have not been completed yet.

Direct Grants for Light-Duty Chargers

In addition to using block grants to distribute incentives efficiently for broader charging infrastructure deployment, the Clean Transportation Program also provides funding for solicitations and projects that target more specific needs for charging infrastructure.[313] As the market for electric vehicles and chargers matures, the CEC expects to focus more attention and funding on segments and locations that are less likely to be served by the private sector, such as rural and multifamily housing charging opportunities.

Since the completion of the previous benefits assessment in 2021, the CEC has released proposed awards for the following solicitations:

- *Reliable, Equitable, and Accessible Charging for Multi-family Housing (REACH)*. This solicitation provided awards for demonstrating scalable business and technology models for installing charging infrastructure in multi-family housing settings. A total of $25.4 million in funding has been proposed for awards.
- *Charging Access for Reliable On-Demand Transportation Services (CARTS)*. This solicitation provided awards for projects that support charging infrastructure for high mileage on-demand transportation services, such as ride-hailing, taxis, and meal and grocery delivery. A total of $16.6 million in funding has been proposed for awards.
- *Convenient, High-Visibility, Low-Cost, Level 2 Charging (CHiLL-2).* This solicitation provided funds to projects with focus on improving public awareness and demonstrating scalable business models for low-cost level 2 charging. A total of $25.7 million has been proposed for awards.
- *Rural Electric Vehicle (REV) Charging.* Projects under this solicitation will provide access to charging infrastructure in rural areas that are not adequately served by existing charging stations, as well as engaging rural communities and businesses to increase charger awareness and promote electric vehicle adoption. A total of $11.2 million has been proposed for awards.
- *Fast and Available Charging for All Californians (FAST)*. Like CARTS, this solicitation will provide funding for projects that support electric vehicle charging for high mileage on-demand transportation services, car sharing enterprises, car rental agencies, and the public. A total of $10.5 million has been proposed for awards.
- *Reliable, Equitable, and Accessible Charging for Multifamily Housing 2.0 (REACH 2.0).* This solicitation provided funding for projects that demonstrate replicable and scalable

313 More information about all Clean Transportation Program funding solicitations is available online at https://www.energy.ca.gov/funding-opportunities/solicitations.

business and technology models for large-scale deployment of EV charging infrastructure to benefit and be used by multifamily housing (MFH) residents; improve education and awareness regarding EVs to increase EV travel by MFH residents, including MFH residents in disadvantaged communities, low-income communities, or residents of affordable housing; and provide affordable, reliable, and conveniently accessible charging infrastructure for MFH residents. A total of $41 million has been proposed for awards.

- *Responsive, Easy Charging Products With Dynamic Signals (REDWDS).* This solicitation provided funding for development and customer installation of charging products that help customers easily respond to dynamic grid signals and minimize charging costs. Such products include smart one-way chargers, bidirectional chargers, charging software, and similar. Funding under the solicitation is divided into two phases, with successful Phase 1 recipients eligible for additional funding to complete Phase 2. For Phase 1, a total of $20.3 million has been proposed for awards. Awards under Phase 2 will depend on the availability of additional funds.

Public Hydrogen Stations

Through the third quarter of 2023, an estimated 14,809 light-duty FCEVs are on the road in California.[314] To fuel these vehicles, 66 hydrogen refueling stations have achieved open retail status, although 12 of these stations are currently not operational. Another 64 stations are planned through the Clean Transportation Program and private investment. The total network capacity of the currently operational open retail stations is nearly 41,000 kilograms per day, enough to support nearly 58,000 FCEVs when operating at capacity, more than the fueling needs of 14,809 light-duty FCEVs estimated to be on the road. However, some of the stations have struggled to provide reliable service due to a combination of equipment failures, supply chain constraints, and periodic hydrogen shortages. Once the other 64 stations are open and fully operational, the 130-station network will be sufficient to support the fueling needs of nearly 188,000 FCEVs. Figure D-1 highlights the growth in hydrogen dispensed in the state, predominantly at CEC-funded stations (with a significant interruption at the start of the COVID-19 pandemic beginning in Q1 2020).

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314 The CEC ZEV Dashboard reports the California light-duty FCEV population as 11,897 through the end of 2022 and 2,912 new FCEV sales through the third quarter of 2023, for an estimated total of 14,8093,664 FCEVs on the road now. https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics.

Figure D-1: Average Statewide Hydrogen Dispensing per Day (2015–2023)

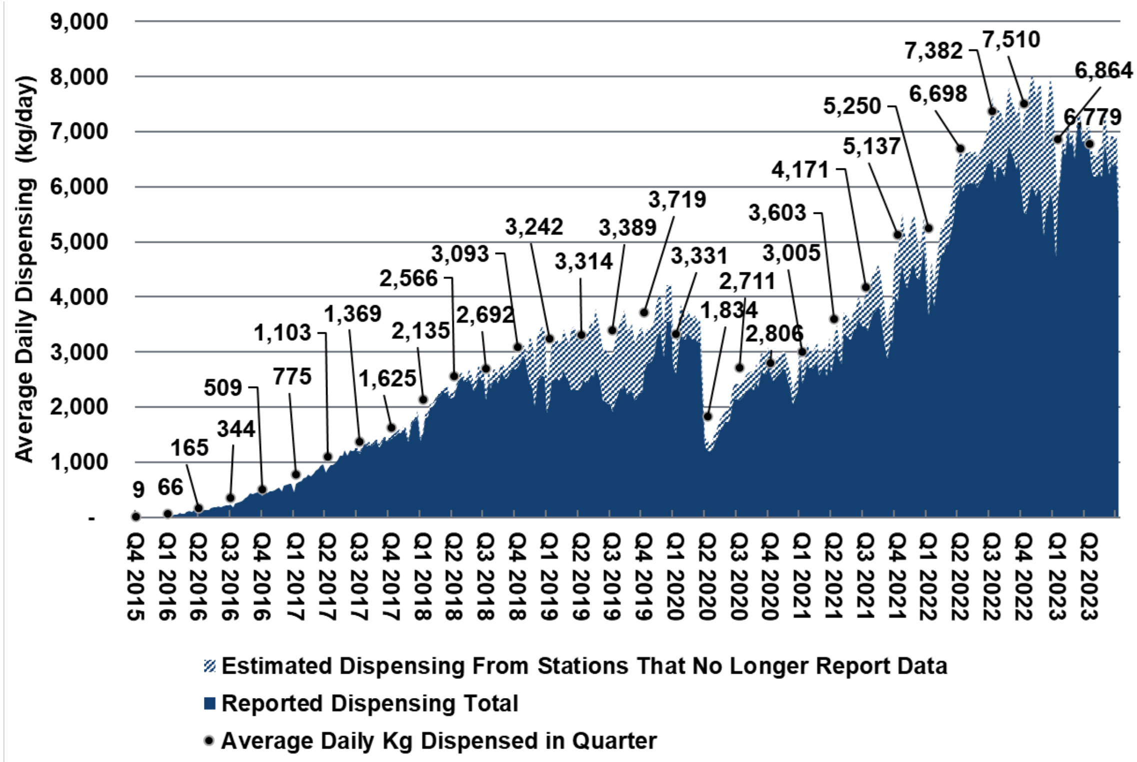


Figure D-1 shows the average daily dispensing of the network of hydrogen stations from the fourth quarter of 2015 to the second quarter of 2023. The chart also shows estimated dispensing for stations that no longer report dispensing data to the CEC.

Source: CEC

Investments in Medium- and Heavy-Duty Sectors

The CEC transitioned from funding ZEV demonstration projects to funding ZEV infrastructure deployment and pilot projects in 2019. State policy towards improving public health and mitigating the impacts of local air pollution has resulted in a greater focus on MDHD fleets, which is why the Clean Transportation Program's recent investment plans reflect a long-term focus on ZEV infrastructure for trucks and buses. The CEC and CARB have complementary responsibilities, with CARB serving as the lead agency on zero-emission vehicle deployment and the CEC as the lead agency on ZEV fueling infrastructure.

As previously mentioned, the inaugural AB 2127 charging infrastructure assessment identified a potential need for 157,000 chargers to support 180,000 MDHD ZEVs in the state by 2030. To support this need, the CEC recently released six solicitations targeting ZEV infrastructure deployment for the MDHD sector. A seventh solicitation resulted in the selection a block grant implementer for a sustained, streamlined funding opportunities for MDHD ZEV infrastructure known as Energy Infrastructure Incentives for Zero-Emission Commercial Vehicles (EnergIIZE Commercial Vehicles).

- *Zero-Emission Drayage Truck and Infrastructure Pilot Project.* This is the first collaborative funding opportunity between the CEC and CARB to fund the large-scale deployment of zero-emission, class 8 drayage and regional haul trucks. This solicitation resulted in proposed awards of five projects totaling over $108 million dollars in combined CEC and CARB funding and was oversubscribed by $85 million. The proposed awards will support 30 hydrogen fuel cell and 250 battery-electric trucks, including fueling infrastructure needed for operation. The CEC's proposed $44 million contribution will support zero-emission fueling infrastructure in addition to workforce training and development, while CARB has committed nearly $64 million towards the vehicles.

- *Zero-Emission Transit Fleet Infrastructure Deployment.* The funding opportunity for zero-emission transit infrastructure supports the large-scale conversion of transit bus fleets to zero-emission technologies at multiple transit agencies. The projects proposed for funding reflect a diversity of fuel and vehicle technologies (including both battery electric and hydrogen projects), geography, and transit agency fleet size. This solicitation resulted in proposed awards of seven projects totaling over $36 million dollars in CEC funding. The proposed awards will provide the fueling infrastructure needed to support and operate 250 battery-electric and 145 hydrogen fuel cell transit buses.
- *BESTFIT Innovative Charging Solutions.* In 2021, the CEC announced awards of more than $8.4 million in innovative MDHD vehicle charging solutions. These projects encompassed a wide range of innovative charging applications for school buses, transit bus fleets, drayage trucks, as well as locomotives.
- *Innovative Charging Solutions for MDHD Electric Vehicles.* Due to the success of the BESTFIT Innovative Charging Solutions solicitation, the CEC offered another grant funding opportunity for innovative MDHD charging solutions, this time offering up to $20 million for projects demonstrating innovative charging technologies or business models that highlight the unique needs of MDHD ZEVs and fleets. This opportunity is expected to propose awards in early 2024.
- *Innovative Hydrogen Refueling Solutions for Heavy Transport.* Released in October 2022, this funding opportunity offered up to $16.5 million for the development and demonstration of innovative hydrogen refueling solutions. This funding opportunity was a collaboration between the CEC's Clean Transportation Program and the CEC's Gas Research and Development Program. Three projects were proposed for award totaling $8 million dollars that may result in the development of three hydrogen stations.
- *Electric School Bus Bi-Directional Infrastructure.* A funding opportunity was released in April 2023 to support managed charging and bi-directional power flow projects for electric school buses and their associated infrastructure. Four proposed awards totaling $10.8 million were announced in September 2023.

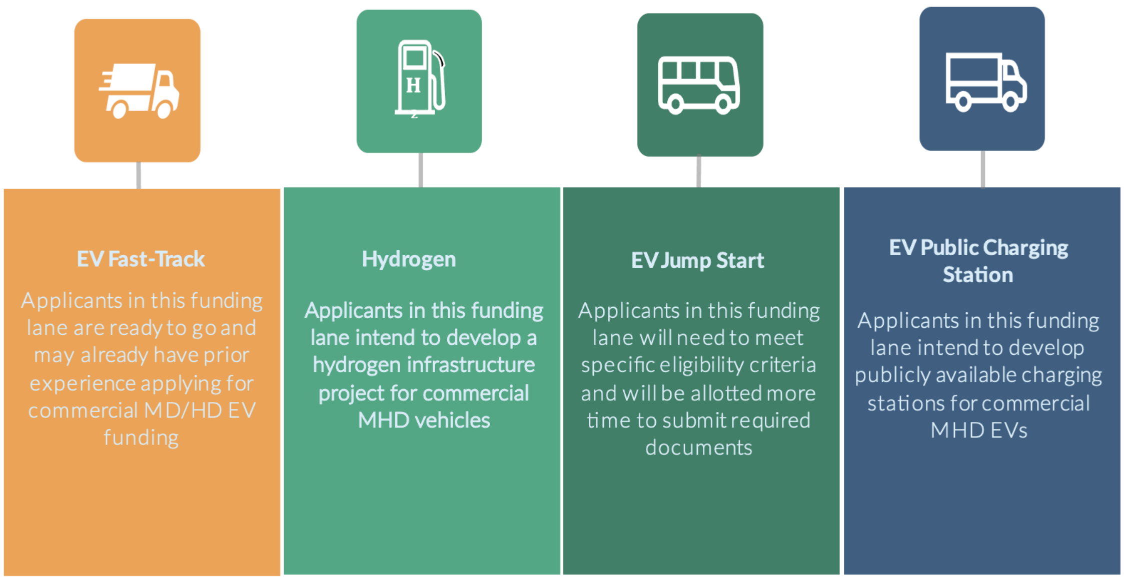
EnergIIZE Commercial Vehicles

In April 2021, the CEC announced the EnergIIZE Commercial Vehicles project to provide funding for electric vehicle charging and hydrogen refueling infrastructure for zero-emission trucks, buses, and equipment in California. This project will leverage large amounts of funding to rapidly deploy ZEV infrastructure for MDHD ZEVs in a streamlined manner to address critical barriers and gaps to the deployment of MDHD ZEV infrastructure. Currently funded up to $183 million, the project is implemented by CALSTART with assistance from Tetra Tech, with the support of equity partner GRID Alternatives, a non-profit organization that manages clean energy programs in low-income communities.

EnergIIZE began accepting applications in early 2022. CEC continues to work with CALSTART to evaluate and set eligibility and funding requirements for infrastructure equipment through a stakeholder engagement process.

There are four standard funding lanes within EnergIIZE Commercial Vehicles, each designed and intended to target different audiences:

Figure D-2: EnergIIZE Standard Funding Lanes



In partnership with CALSTART, the CEC has launched the first in the nation project to provide financial incentives to increase the deployment of commercial zero-emission medium- and heavy-duty vehicle infrastructure. Currently, EnergIIZE has up to $276 million in funding and four funding lanes, which will be available at least once a year.

Source: EnergIIZE

- EV Fast Track Funding Lane (first-come, first-served): Intended for applicants and commercial fleets who have a ZEV in their fleet or have a purchase order and need funding for the necessary charging infrastructure.
- Hydrogen Funding Lane (competitive): Intended for commercial fleets or station owners seeking to deploy hydrogen refueling infrastructure for MDHD ZEVs.
- EV Jump Start Funding Lane (competitive): Intended for applicants/fleet users located in a disadvantaged or low-income communities, and who meet other equity criteria. This lane provides a longer application window for applicants as well as technical assistance.
- EV Public Charging Lane (competitive): Intended for applicants interested in deploying publicly accessible charging infrastructure for battery-electric MDHD vehicles.

Zero and Near-Zero Emission Fuels Production

Not all vehicles and transportation applications can rapidly transition to zero-emission alternatives. Even for sectors that have already begun a transition to zero-emission technologies, legacy fleets will continue to use liquid or gaseous combustion fuels for years to come. Furthermore, waste-based feedstocks are quite low in life-cycle GHG emissions, to the point that CARB's Low Carbon Fuel Standard (LCFS) currently considers some fuels from these sources to be a net negative source of GHG emissions. The Clean Transportation Program's support of near-zero emission fuels has evolved over the years from fuels that must be blended at low levels with petroleum products (such as ethanol and biodiesel) toward alternatives that do not require such blending (such as renewable diesel and renewable natural gas).

The AltAir Paramount Refinery is an example of the Clean Transportation Program funding for renewable diesel. Locating the project within an existing refinery ensured maximum use of existing equipment, greatly simplified permitting, and sustained jobs for experts in operations and maintenance. GHG emissions from the renewable diesel of the project are up to 80 percent lower than from petroleum diesel; similarly, the coproduced renewable jet fuels are estimated to deliver up to an 80 percent reduction in GHG emissions relative to petroleum-derived jet fuel in a sector that is difficult to electrify.

Another recent fuel production success story is the Five Points Pipeline Cluster Project. Five Points Pipeline LLC, and its developer Maas Energy Works Inc, constructed a new biogas conditioning facility in Fresno County, California to produce renewable natural gas (RNG) vehicle fuel. RNG is then injected into the PG&E utility pipeline for transport to new and existing compressed natural gas (CNG) stations in the California Central Valley. The biogas collected by the project reduces methane, nitrogen oxides, and hydrogen sulfide previously released into the air. Based on the current and forecasted production, the project anticipates replacing more than 3 million diesel gallon equivalents of transportation fuel each year.

More recently, a competitive grant solicitation was released in February 2023 to support ultra-low-carbon fuel in two funding categories: demonstration-scale and commercial-scale production facilities utilizing forest biomass. Two awards have been proposed for funding. The first is a project with California Grinding Inc. that will product renewable natural gas as primary fuel and hydrogen as secondary fuel (estimated 1.2 million diesel gallons equivalent (DGE)) by converting 50,000 tons of woody biomass per year in a disadvantaged community. The second is a project with Yosemite Clean Energy that will produce 6.2 million DGE of clean and renewable hydrogen (7,000,000 kg/year hydrogen) by gasifying 90,000+ bone dry tons (BDT) of forest and farm waste biomass annually, which will safeguard the environment, economy, and public health of Butte County by preventing catastrophic wildfires.

The Clean Transportation Program has also shifted to funding to produce zero-emission fuels, specifically clean and renewable hydrogen. In 2018, the Clean Transportation Program proposed two clean and renewable hydrogen production projects for award, and the first of these production plants opened in June 2023. Located in Fresno, H2B2 USA built this production plant that is beginning commercial operation with 1.2 metric tons, or 1,200 kilograms, per day of clean and renewable hydrogen production to support transportation uses.[315] In 2022, under a new solicitation, the Clean Transportation Program proposed funding for three more renewable hydrogen production projects. One of these recently funded projects, from SGH2 Energy, will build a new production plant in Lancaster. This Lancaster Waste-to-Renewable Hydrogen project plans to convert 42,000 tons per year of in-state rejected recycled mixed paper waste into 3,850,000 kilograms of clean and renewable hydrogen per year, thereby displacing approximately 165,000 tons of carbon dioxide annually.

Manufacturing

The CEC is committed to California's goals of zero-emission transportation while growing high quality manufacturing jobs in the state. The 2021 and 2022 California Budget Acts approved $250 million for the CEC to provide grants that increase in-state manufacturing of ZEVs, ZEV components, and ZEV charging or refueling equipment. The CEC administers these manufacturing funds under the Clean Transportation Program with the goals of:

- Increasing in-state manufacturing of the ZEV supply chain
- Attracting new and expand existing ZEV-related manufacturing in California
- Increasing the number and quality of direct and indirect ZEV-related manufacturing jobs in California
- Bringing positive economic impacts to the state by attracting private investments in manufacturing capacity
- Contributing to California's ZEV goals with products

The first solicitation to use these funds (GFO-21-605) provided direct grants of up to $30 million per project for the expansion of ZEV and ZEV-related manufacturing within the state. The solicitation included selection criteria intended to favor projects in disadvantaged and low-income communities, as well as projects that generated more jobs and higher quality jobs. All applicants were required to include a ZEV Workforce Plan detailing workforce engagement activity, community outreach strategies, and job recruitment strategies for workers who face barriers to employment. In total, thirteen projects were proposed for awards of nearly $200 million, with more than $280 million committed as match funding. The proposed projects are expected to directly create 2,989 jobs and other co-benefits, many of which are within or adjacent to disadvantaged and low-income communities.

The second solicitation (GFO-21-606) was a competitive block grant solicitation. This solicitation sought a block grant implementer to design and implement a ZEV battery

315 H2B2 Electrolysis Technologies. June 15, 2023. H2B2's SoHyCal Project in California has started hydrogen production. https://www.h2b2.es/h2b2s-sohycal-project-in-california-has-started-hydrogen-production/. Accessed July 21, 2023.

manufacturing block grant that will design and implement a project that will promote in-state battery manufacturing for ZEVs and related infrastructure. In April 2023, CALSTART, Inc. was awarded a grant as the block grant implementer. With oversight from the CEC, CALSTART has launched a program called PowerForward. The subgrant awards for PowerForward are expected to be announced in the first half of 2024, and the program is expected to run until late 2027.

Workforce Training and Development

Clean Transportation Program investments into workforce training and development are central to successful adoption of clean transportation technologies, achievement of state environmental and economic goals, and in advancing underserved communities through career pathway development. To date, the CEC has invested more than $44 million into workforce projects benefitting more than 25,000 trainees.

The labor and workforce sector for transportation electrification is undergoing dynamic change in the post-pandemic era. The program has continued to meaningfully engage with employers, workforce educators and trainers, and stakeholders to better understand workplace and training needs of ZEV markets. The CEC launched a successful and effective workforce training initiative, the IDEAL ZEV Workforce Project, which provided grant funding to 14 community-based training projects. In partnership with CARB, the initiative provided critical resources to underserved communities throughout the state, from the agricultural communities of the Central San Joaquin Valley to tribal communities in Humboldt and San Diego counties, to support training and pathway options for ZEV and ZEV infrastructure jobs and careers.

Additionally, through funding agreements with California community colleges, the CEC has established 22 light-duty ZEV automotive programs at community colleges throughout the state. In 2022, the CEC expanded this investment in worker training in ZEV technologies by launching a new heavy-duty ZEV truck program at six community colleges. The CEC also completed the establishment of 52 ZEV high schools through career technical education and regional occupational centers/programs where students are introduced to ZEV careers while building electric ZEV kits.

The CEC has established the Electric School Bus Training Project which developed curriculum and provided training to community college faculty, to school fleet technicians, and to school bus operators. The federal and state governments continue to prioritize investments in ZEV school bus procurements and the requisite training is critical for successful adoption. In 2023, the California Department of General Services included the CEC’s Electric School Bus Training Project as an option for schools to select as their training option when purchasing buses through state funding. Recently, the CEC augmented funding for this training to allow more schools to receive training.

Quantifying the Benefits of the Clean Transportation Program

Section 44273 of the Health and Safety Code requires the CEC to evaluate the following types of benefits:

- Petroleum use reduction

- Air quality
- GHG emissions reductions
- Benefits-cost assessment
- Technology advancement

The CEC contracted with the National Renewable Energy Laboratory (NREL) to develop quantifiable estimates of petroleum use reduction, air quality benefits, and GHG emissions reductions associated with the Clean Transportation Program projects funded from 2013 through April 2023 and projected those benefits to 2035.[316] "Expected Benefits" are directly correlated with the amount of usage of a project (such as millions of gallons of fuel produced, kilowatt-hours dispensed, or electric miles traveled).

Quantification of the benefits of Clean Transportation Program investments is subject to continuing improvement and refinement. Across all categories of program funding, NREL analyzed $1.3 billion of program investments, or approximately 72 percent of the program's $1.8 billion in funding commitments to date. The percentage of program investments analyzed by NREL is less than 100 percent in situations where certain projects attributes don't align with NREL's analytical methods, or where projects were partly funded but not completed.

The benefits assessed in NREL's analysis reflect the benefits from projects that the Clean Transportation Program has at least partially funded. However, project developers, their investors, and other public programs contribute varying levels of funding to a project supported by the Clean Transportation Program. Thus, this assessment can present a big picture view of the total benefits that the Clean Transportation Program has supported, but it does not claim attribution of those benefits to the program itself. For example, credits that fuel producers earn from the LCFS contribute a great deal to a project developer's decision to move forward on a project, so some of the benefits could also arguably accrue to the LCFS. The benefits report, however, does not attribute benefits across different program and market factors; rather, it represents an accounting of the benefits associated with supported projects. For this reason, when reviewing the estimated benefits from different project types alongside one another (or other programs or investments), the reviewer should be aware that the inputs, assumptions, and methods may not allow appropriate comparisons.

316 NREL. December 2023. Presentation by Roberto Vercellino and Dan Mazzone, "Analysis of Benefits Associated With Projects and Technologies Supported by the Clean Transportation Program." https://efiling.energy.ca.gov/GetDocument.aspx?tn=253800&DocumentContentId=89059.

Expected Benefits

Expected benefits represent the outcomes directly supported by Clean Transportation Program funding, shown in Tables D-6 and D-7. These benefits are based on the calculated displacement of petroleum-derived fuels for the vehicle, fuel, or infrastructure. To estimate GHG reductions, additional calculations consider the carbon intensity of a fuel. For example, the carbon intensity of biodiesel production depends in part on the feedstock input at a funded facility; similarly, the carbon intensity of an EV charger depends on the resource mix of the electricity grid each year. Air quality calculations consider baseline petroleum pollution emissions against the reduced pollutant profile of a replacement fuel. For example, hydrogen fuel used in light-duty fuel cell EVs have no oxides of nitrogen (NO_X) or tailpipe particulate matter (PM) emissions compared to the petroleum it displaces.

Key methodological steps for the calculations vary by category. For fuel production, the analysis assumes that fuel production numbers are those reported by the agreement, whether in the forward-looking scope of work of the project or, if a project was completed, the verified resulting outputs. From the amount of fuel produced, GHG emissions reductions can be determined based on the GHG emissions of the alternative fuel compared to the GHG for the corresponding fossil fuel.

For fueling infrastructure projects, the key assumptions vary by the fuel type. Because combustion fuels generally move into a large existing market with reliable consumption, the reported refueling throughput provides for relatively reliable petroleum substitution and subsequent benefits analysis.

The more challenging fueling infrastructure types to account for are hydrogen refueling stations and electric charging infrastructure. Although the displacement of petroleum for these fuels is relatively straightforward on a per-kilogram or per-kilowatt-hour basis, the energy supplied per station or charger is subject to more uncertainty, requiring additional assumptions. For instance, although the ZEV market is widely expected to grow rapidly over the next few years (and decades), there is more uncertainty about how much usage to assign to refueling stations and chargers.

Finally, different project types were assumed to produce benefits for different periods of time. This is the source of reduced benefits across many project types in the furthest timeframe (2035).

Table D-6: Petroleum Fuel Reductions (in Million Gallons)

Project Type	Petroleum Fuel Reductions	Petroleum Fuel Reductions	Petroleum Fuel Reductions
	2025	**2030**	**2035**
Fuel Production - Biomethane	5.44	5.84	5.84
Fuel Production - Diesel Substitutes	18.08	18.08	18.08
Fuel Production - Gasoline Substitutes	7.47	7.47	7.47
Fueling Infrastructure - E85 Ethanol	2.50	0.00	0.00
Fueling Infrastructure - Electric Chargers - LD	24.96	68.72	25.69
Fueling Infrastructure - Electric Chargers - MDHD	0.98	3.47	3.06
Fueling Infrastructure - Hydrogen - LD	6.42	13.17	7.3
Fueling Infrastructure - Hydrogen - MDHD	0.19	1.43	1.53
Fueling Infrastructure - Natural and Renewable Gas	10.76	0.15	0.00
Vehicles - CVRP and HVIP Support	1.48	0.00	0.00
Vehicles - MDHD Truck Demonstration	1.12	0.58	0.00
Vehicles - Light Duty BEVs and PHEVs	0.04	0.04	0.00
Vehicles - NG Commercial Trucks	2.76	2.86	0.00
Total	**82.21**	**121.8**	**68.97**

Source: NREL

Table D-7: GHG Reductions (in Thousand Tons Carbon Dioxide Equivalent)

Project Type	GHG Reductions	GHG Reductions	GHG Reductions
	2025	**2030**	**2035**
Fuel Production - Biomethane	155.34	163.50	163.50
Fuel Production - Diesel Substitutes	142.43	127.04	127.04
Fuel Production - Gasoline Substitutes	9.24	3.86	3.86
Fueling Infrastructure - E85 Ethanol	5.97	0.00	0.00
Fueling Infrastructure - Electric Chargers - LD	194.4	537.06	213.28
Fueling Infrastructure - Electric Chargers - MDHD	9.09	31.75	29.68
Fueling Infrastructure - Hydrogen - LD	30.85	53.75	29.79
Fueling Infrastructure - Hydrogen - MDHD	0.74	4.27	4.59
Fueling Infrastructure - Natural and Renewable Gas	16.14	0.02	0.00
Vehicles - CVRP and HVIP Support	11.51	0.00	0.00
Vehicles - MDHD Truck Demonstration	6.57	2.47	0.00
Vehicles - Light Duty BEVs and PHEVs	0.3	0.28	0.00
Vehicles - NG Commercial Trucks	2.93	0.62	0.00
Total	**585.52**	**924.62**	**571.75**

Source: NREL

Table D-8: Criteria Pollutant Reductions (Tons Per Year)

Project Type	NO_X Reductions	NO_X Reductions	NO_X Reductions	PM2.5 Reductions	PM2.5 Reductions	PM2.5 Reductions
	2025	**2030**	**2035**	**2025**	**2030**	**2035**
Fueling Infrastructure, Electric Chargers, LD	50.85	117.83	40.22	1.97	5.18	1.79
Fueling Infrastructure, Electric Chargers, MD/HD	10.43	25.51	19.75	0.09	0.3	0.26
Fueling Infrastructure, Hydrogen, LD	4.2	7.36	3.67	0*	0*	0*
Fueling Infrastructure, Hydrogen, MDHD	0.40	2.78	2.80	0.01	0.05	0.05
Fueling Infrastructure, Natural and Renewable Gas	0.00	0.00	0.00	0.00	0.00	0.00
Vehicles, CVRP and HVIP Support	3.01	0.00	0.00	0.12	0.00	0.00
Vehicles, MDHD Truck Demonstration	5.4	1.85	0.00	0.03	0.01	0.00
Vehicles, Light Duty BEVs and PHEVs	0.08	0.06	0.00	0.00	0.00	0.00
Vehicles, NG Commercial Trucks	0.8	0.56	0.00	0.00	0.00	0.00
Total	**75.16**	**155.95**	**66.44**	**2.22**	**5.54**	**2.1**

Source: NREL. *Rounded to zero based on size of light-duty vehicle fleet.

Ensuring Equity within Expected Benefits

NREL is also assessing the expected benefits of program investments within historically underrepresented or underserved communities of the state. Criteria emission reductions are especially valuable in low-income communities and disadvantaged communities, as these areas typically have worse air quality compared to other parts of the state. Table D-9 presents the cumulative (not annual) benefits through 2030 of program investments in both disadvantaged communities and low-income communities. Benefits from projects without a fixed address are also presented and include benefits that are statewide or else have locations that are still to be determined. As shown, although a large share of program's expected benefits are attributable to statewide or as-yet-undetermined locations, the program benefits within low-income communities or disadvantaged communities are significantly greater than those occurring in known locations outside of such communities.

Table D-9: Expected Benefits to Low-Income (LICs) or Disadvantaged Communities (DACs) in 2030

	Petroleum Reductions (million gallons)	GHG Reductions (thousand metric tons)	NOx Reductions (metric tons)	PM2.5 Reduction (metric tons)
Benefits in LICs or DACs	458.5	2,933.62	199.52	3.57
Benefits Outside LICs or DACs	85.51	410.94	83.92	1.64
Statewide, or Location to be Determined	424.59	3,296.72	672.59	24.97

Source: NREL

Market Transformation Benefits

Market transformation benefits represents a range of future investments enabled or supported by the funding portfolio of the program. For example, the continuing market expansion of BEVs and PEVs will be partially supported by current Clean Transportation Program investments into electric charging infrastructure and the manufacture of battery and electric drivetrain technology. For electric chargers, charging availability is a leading consumer concern for vehicle adoption, so additional electric chargers contribute to changing consumer perceptions about the ease of purchasing a PEV. Similarly, the effect of a successful demonstration of an advanced technology truck or novel fuel production process increases the likelihood of that technology achieving future commercial success.

Market transformation analysis requires several assumptions about consumer behavior, future markets, and business responsiveness. In this regard, the market transformation benefits have more uncertainty than the expected benefits. However, market transformation benefits are critical to understanding the benefits of the Clean Transportation Program, and the associated higher level of uncertainty is not a reason to disregard them.

Because of this uncertainty, NREL incorporates various assumptions into a “low case” and “high case” for market transformation benefits. Low cases reflect conservative assumptions about demand elasticity for ZEVs, savings from economies of scale, and the ability of successful demonstration projects to leverage private interest for larger commercial-scale projects. High cases reflect optimistic assumptions. The low and high case market transformation results help define a range of reasonable results.

NREL has defined two potential ways Clean Transportation Program projects can influence market transformation. These potential influences are described in Table D-10. There may be additional ways that Clean Transportation Program projects influence the future market growth of clean fuels and vehicles; however, these examples are what NREL found to be the most readily quantifiable. The methods used to quantify these influences were first described in program benefits guidance provided by NREL in 2014.[317]

Table D-10: Market Transformation Benefits Description

Market Transformation Influence	Applicable Clean Transportation Program Project Types	Description of Influence Outcomes
Perceived Vehicle Price Reduction	Electric charging Hydrogen stations Light-duty BEVs and PHEV incentives	-Increased consumer awareness -Removal of consumer choice barriers via increased refueling access
Vehicle Cost Reduction	Manufacturing	-Reduced cost to produce or supply a technology -"Learn by doing" -Economies of scale in production

Source: NREL

Table D-11 summarizes the annual market transformation benefits from Clean Transportation Program projects in terms of petroleum displacement, GHG emission reduction, and air pollutant reduction in 2030.

317 NREL. 2014. Analysis of Benefits Associated With Projects and Technologies Supported by the Alternative and Renewable Fuel and Vehicle Technology Program. https://efiling.energy.ca.gov/GetDocument.aspx?tn=73185.

Table D-11: Annual Market Transformation Benefits in 2030

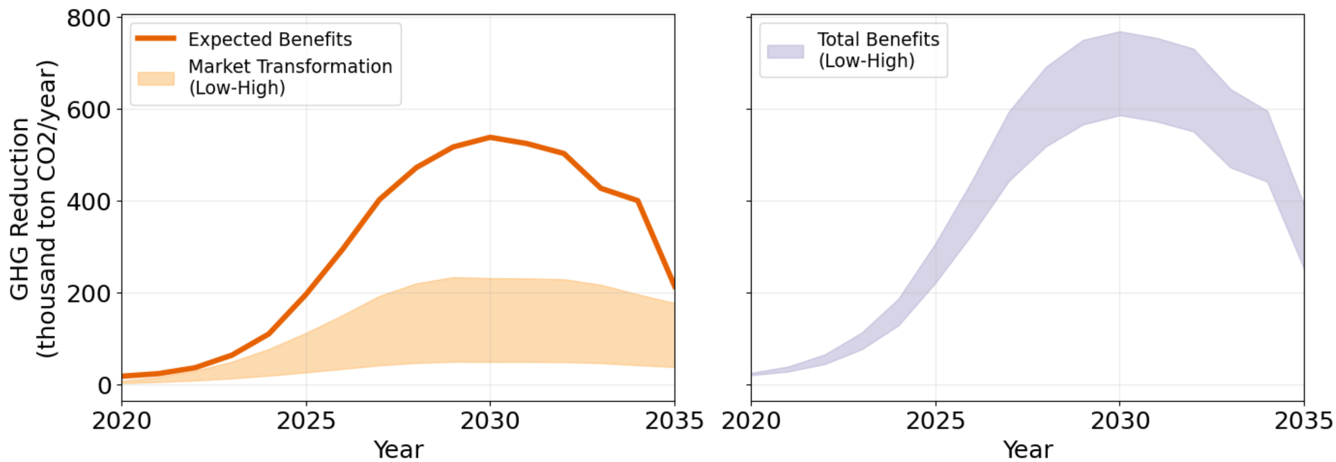
Market Transformation Influence	Petroleum Displacement (million gallons/year)		GHG Reduction (thousand metric ton/year)		NOx Reduction (metric ton/year)		PM2.5 Reduction (metric ton/year)	
Scenario	**Low**	**High**	**Low**	**High**	**Low**	**High**	**Low**	**High**
EV Perceived Price Reduction due to EVSE Availability	1.9	8.07	48.4	230.61	4.11	19.34	0.16	0.85
FCEV Perceived Price Reduction due to HRS Availability	4.18	12.68	85.89	260.45	7.1	21.49	0.29	0.88
EV Cost Reduction due to Investment in Manufacturing	1.58	1.59	30.98	31.13	2.61	2.62	0.07	0.07
Total	**7.67**	**22.34**	**165.26**	**522.19**	**13.82**	**43.45**	**0.52**	**1.8**

Source: NREL

The key takeaway from Table D-11 is that large ranges between high and low scenarios reflect significant variability in market conditions and project outcomes.

Market transformation benefits are additive to the expected benefits discussed in the previous section. As an illustrative example, Figure D-12 below presents the annual GHG reductions from expected benefits and market transformation benefits for passenger vehicle charging infrastructure each year through 2035. The chart on the left shows the expected benefits as a solid line, and the market transformation benefits as a range. Moving this range on top of the line creates the range of expected benefits plus market transformation benefits shown on the right.

Figure D-12: Annual GHG Reductions (2020–2035) from Expected Benefits and Market Transformation Benefits for Passenger Vehicle Charging Infrastructure



Source: NREL

Benefit-Cost Assessment

As part of biennial evaluation of the program, Health and Safety Code Section 44273 also requires the CEC to include a "benefit-cost assessment" for Clean Transportation Program funded projects. In alignment with statute, staff conducted this assessment by analyzing the program's projects in the aggregate. While such an assessment is not further defined, a reasonable assumption is that "benefit-cost" has a meaning similar to that used elsewhere in the Clean Transportation statutes. Specifically, the "benefit-cost" represents the "…expected or potential GHG emissions reduction per dollar awarded by the commission."[318]

Unlike the previous estimates of benefits, a benefit-cost estimate requires assessing GHG emissions reduction on a cumulative basis, not an annual one. A simple assumption is to use the cumulative GHG emission reductions of Clean Transportation Program-funded projects through 2035. Based on this approach, the cumulative GHG emission reductions of expected benefits and market transformation benefits by 2035 range from roughly 120.6 million metric tons (using the low case for market transformation benefits) to 159.3 million metric tons (using the high case).

The CEC has awarded nearly $1.04 billion toward Clean Transportation Program projects (not including canceled and defunded projects) with measurable GHG emission reductions using NREL's methodology. When including projects that do not readily lend themselves to

318 Health and Safety Code Section 44270.3.

measurable GHG emissions (such as regional fuel readiness grants, workforce training agreements, and fuel standards and certification agreements), this amount increases to just over $1.7 billion. Table D-12 shows the resulting benefit-cost ratios. Depending on (1) which funding amount is used as the cost and (2) whether the low case or the high case for market transformation benefits is applied. The values in Table D-12 represent the approximate amount of carbon dioxide-equivalent metric tons reduced for every $1 invested by the Clean Transportation Program. Table D-13 presents the equivalent calculation in dollars per metric ton.

Table D-12: CO_2e Reduced Through 2035 per Clean Transportation Program Dollar

	Cost Basis: NREL-Analyzed Projects Only	Cost Basis: All Projects
Expected Benefits + Market Transformation (Low Case)	116.4 kg per dollar	70.8 kg per dollar
Expected Benefits + Market Transformation (High Case)	153.8 Kg per dollar	93.5 kg per dollar

Source: CEC

Table D-13: Clean Transportation Funding per Metric Ton CO_2e Reduced Through 2035

	Cost Basis: NREL-Analyzed Projects Only	Cost Basis: All Projects
Expected Benefits + Market Transformation (Low Case)	$8.6 per metric ton	$14.12 per metric ton
Expected Benefits + Market Transformation (High Case)	$6.5 metric ton	$10.7 per metric ton

Source: CEC

Clean Transportation Program — Looking Ahead

In September 2023 the Legislature passed AB 126 (Reyes) which provides $1 billion for the CEC to deploy for ZEV infrastructure. This will allow the Clean Transpiration Program to continue to support investments in clean transportation infrastructure for another ten years. The statute modifies hydrogen fueling station funding allocation from a maximum 20 percent for light-duty hydrogen fueling stations to a minimum 15 percent for light, medium, and heavy-duty hydrogen fueling stations until July 1, 2030. It also requires that 50 percent of hydrogen stations and electric vehicle charging stations are located or benefit disadvantaged communities.

In this analysis, equity and community benefits were primarily assessed and tracked through census tracts. Meaning, if a project occurred in a census tract that was designated low-income or a disadvantaged community (or both), the project would be considered a benefit for low-income and disadvantaged communities. However, the goal of the CEC is to move beyond simple location-based view of Clean Transportation Program benefits for low-income and disadvantaged communities.

The CEC aims to implement a 5-step Community Benefits framework. Under the draft framework being considered, Step 1 would require the CEC to specify the type of community that CEC funds will benefit. Community designations can include but are not limited to low-income communities, disadvantaged communities, low-income household and rural. Step 2 would require the CEC to identify community benefits. Specified community benefits can include access to ZEV infrastructure, economic benefits, educational benefits, environmental benefits, mobility benefits, public health benefits, and resiliency. While these categories are broad, they will likely become more specific through the solicitation process. Step 3 would require the applicant to commit to collecting benefit metrics. This step will necessarily require an applicant to propose which "economic benefit" or "environmental benefit" they will track. Through the awarded grant/contract, the grantee is then required to collect benefit metrics and report them to the CEC in step 4. The last step would task the CEC with collecting the benefit metrics and evaluating the community benefits provided by a project. This will hopefully allow the CEC to better understand how many jobs were created, whether living wages were provided, air quality statistics, and other agreed upon specified benefits within grant agreements.

The CEC aims to incorporate community feedback and involvement during the solicitation processes. The current proposed framework is to incentivize applicants through scoring incentives. Meaning, offering points for applicants who have a community benefit plan/agreement or a letter of support from the identified community to be affected.

The CEC had two public workshops on the draft Community Benefits Framework and presented it to the Disadvantaged Community Advisory Group (DACAG). The CEC has also engaged with stakeholders and received feedback on the current draft framework and expects to begin formally incorporating the Community Benefits Framework in Spring 2024.

APPENDIX E: Update on Publicly Owned Utilities' Progress

Summary of Resource Adequacy

The California Energy Commission (CEC) is required to report on the progress of the state's publicly owned electric utilities (POUs) toward meeting resource adequacy needs, meaning planning for and procuring adequate resources to meet the needs of their end-use customers.[319]

Table E-1 provides a high-level summary of each POU's resource adequacy based on data provided on bi-annual supply forms submitted to the CEC. The projected resource adequacy position is calculated by comparing the total existing and planned supply resources for each year (2023–2031), and the projected peak demand plus a planning reserve margin (PRM) of at least 15 percent above the annual 1-in-2 peak demand. To assess progress towards meeting a POU's customer demand by year, the peak demand plus PRM is subtracted from the total supply and reported for each year. In Table E-1, the green and positive number indicates that the POU has reported a surplus of resources and/or has met projected customer demand plus PRM. The red and negative number indicates that the POU has a deficit of resources and has not met their projected customer demand plus PRM. Although some POU's have projected deficits, they may be planning for additional resource contracting, imports, and spot market purchases that have not been reported on the supply form. The results presented reflect a snapshot of data from the September 2022 supply forms.

The percentages in Table E-1 were calculated based on the following formula, for each year:

$$\left(\frac{(\mathit{Total{:}\ Existing\ and\ Planned\ Supply}) - (\text{Annual 1}-\text{in}-\text{2 Peak Demand}*1.15)}{\text{Annual 1}-\text{in}-\text{2 Peak Demand}*1.15}\right)*100\%$$

(Plain text version of actual formula: "[Total: Existing and Planned Supply] minus [Annual 1-in-2 Peak Demand times 1.15], divided by Annual 1-in-2 Peak Demand times 1.15, times 100 percent.)

319 Public Resources Code 25305.1 and Public Utilities Code 9620(e) require this information to be reported on in the CEC's biennial IEPR.

Table E-1: Summary of Reported Resource Adequacy Relative to a 15 Percent PRM

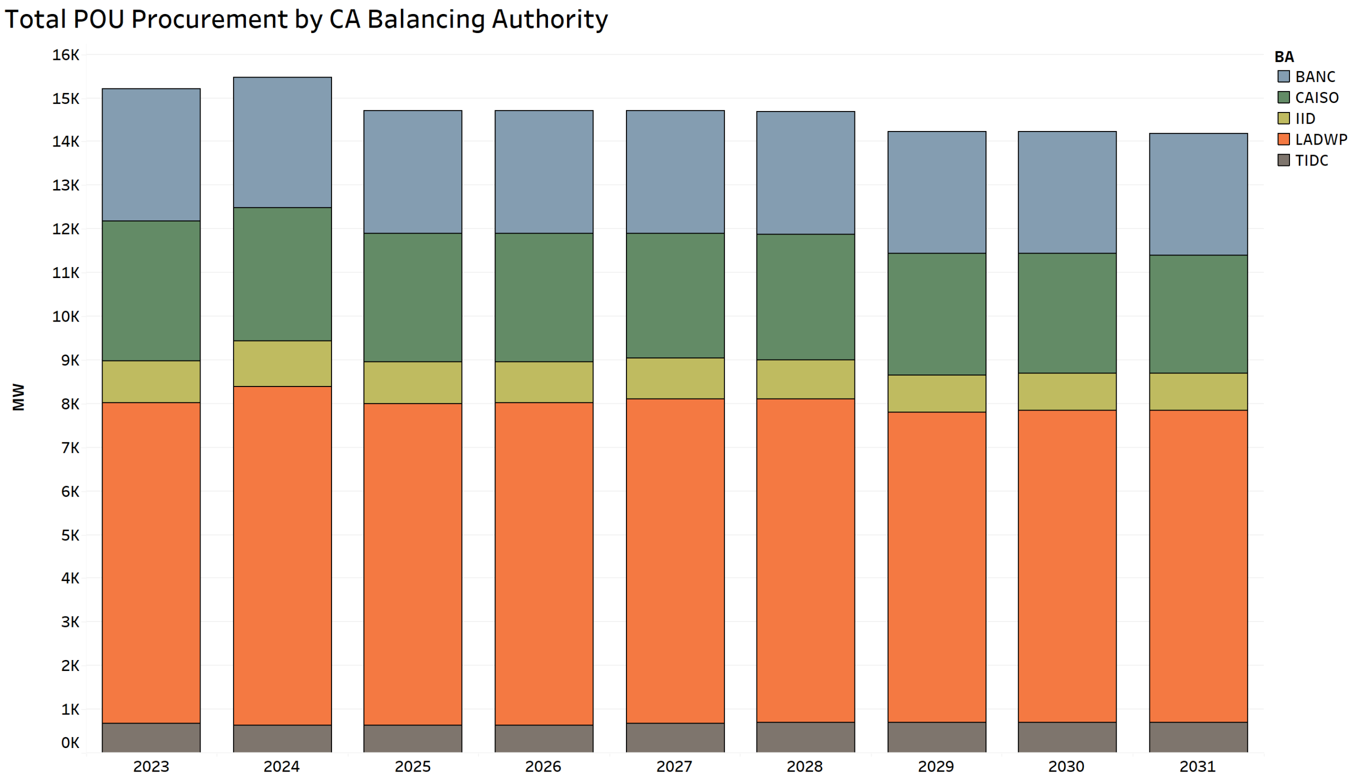
Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Alameda	-	-	-	-	-	-	-	-	-	-	-	-
Anaheim	20%	7%	23%	23%	24%	23%	-5%	-5%	25%	-25%	-25%	-24%
Arizona EPCO	-3%	-10%	1%	-	-	-	-	-	-	-	-	-
Azusa	16%	30%	28%	-	-	-	-	-	-	-	-	-
Biggs	73%	29%	0%	31%	13%	13%	12%	12%	12%	13%	12%	12%
Burbank	15%	43%	20%	11%	11%	11%	9%	-4%	-4%	-7%	-25%	-25%
Cerritos	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Colton	4%	-9%	5%	5%	1%	0%	0%	1%	1%	0%	0%	0%
Corona	0%	1%	0%	0%	-19%	-19%	-19%	-19%	-19%	-19%	-19%	-19%
Glendale	8%	31%	11%	-33%	-33%	-32%	-5%	-4%	-9%	-9%	-10%	-11%
Gridley	33%	48%	0%	55%	55%	54%	56%	56%	56%	56%	55%	56%
Healdsburg	0%	29%	15%	9%	10%	6%	6%	6%	8%	9%	6%	4%
IID	4%	1%	0%	-1%	-3%	-3%	-3%	1%	1%	1%	1%	1%
LADWP	20%	60%	22%	23%	26%	20%	19%	17%	17%	9%	14%	13%
Lassen MUD	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Lodi	0%	0%	0%	-20%	-21%	-23%	-23%	-36%	-34%	-34%	-35%	-35%
Lompoc	38%	62%	58%	37%	37%	36%	37%	7%	10%	12%	9%	9%
Modesto	0%	10%	5%	3%	-28%	-28%	-27%	-26%	-24%	-24%	-24%	-27%
Moreno Valley	-98%	-24%	-94%	-94%	-94%	-94%	-94%	-94%	-94%	-94%	-94%	-94%
Palo Alto	133%	143%	43%	77%	75%	76%	79%	79%	85%	49%	46%	48%
Pasadena	3%	29%	28%	21%	20%	35%	3%	5%	-11%	-12%	-15%	-17%
Pittsburg	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Plumas Sierra	253%	66%	67%	36%	37%	36%	37%	36%	38%	39%	38%	38%
Port of Oakland	2%	0%	3%	-13%	-25%	-25%	-27%	-26%	-27%	-28%	-28%	-28%
Rancho Cucamonga	10%	0%	-13%	-	-	-	-	-	-	-	-	-
Redding	13%	-10%	5%	-9%	7%	6%	6%	6%	6%	5%	5%	4%
Riverside	4%	-1%	7%	4%	6%	-7%	-27%	-34%	-34%	-34%	-35%	-41%
Roseville	-10%	-19%	5%	-11%	-11%	-12%	-12%	-12%	-13%	-13%	-14%	-14%
SF PUC	170%	190%	178%	160%	148%	133%	120%	113%	109%	105%	102%	99%
Shelter Cove	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Silicon VP	1%	13%	2%	1%	-13%	-23%	-28%	-33%	-35%	-40%	-44%	-46%

Utility	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
SMUD	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Trinity	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Turlock ID	26%	24%	32%	25%	27%	27%	28%	30%	33%	42%	41%	41%
Ukiah	364%	378%	279%	270%	268%	264%	266%	234%	246%	239%	211%	210%
Valley EA	0%	9%	9%	9%	8%	8%	7%	7%	6%	6%	6%	5%
Vernon	6%	9%	15%	12%	25%	24%	23%	21%	20%	18%	17%	16%
Victorville	2%	2%	1%	0%	0%	-17%	-17%	-21%	-21%	-24%	-24%	-24%

Source: CEC

In Figure E-1, all POU procurement is shown by balancing authority (BA) areas within California. A BA manages the balance of electrical supply and demand. Figure E-1 shows that most POU supply resources fall under three balancing authority areas: Los Angeles Department of Water and Power (LADWP), California Independent System Operator (California ISO), and Balancing Authority of Northern California (BANC).

Figure E-1: Total POU Procurement by Balancing Authority Inside of CA



Source: CEC

Table E-2: Total POU Procurement by Balancing Authority Inside of CA

Balancing Authority	2023	2024	2025	2026	2027	2028	2029	2030	2031
BANC	3,026	2,984	2,811	2,811	2,808	2,807	2,791	2,791	2,791
California ISO	3,200	3,044	2,931	2,942	2,853	2,872	2,799	2,754	2,708
IID	952	1,044	968	936	933	887	840	840	839
LADWP	7,346	7,760	7,360	7,375	7,436	7,406	7,096	7,139	7,139
TIDC	681	628	636	642	668	707	707	707	707

Source: CEC

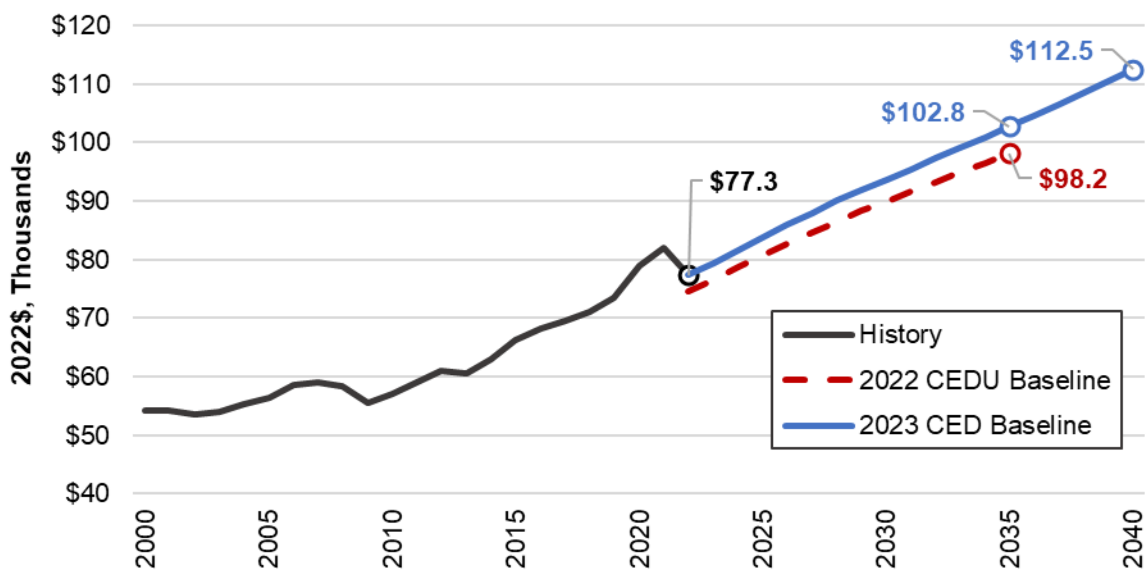
POUs also procure supply from BAs outside of California to meet their reliability needs. These BAs include Arizona Public Service and Bonneville Power Authority. POU procurement from BAs outside of California is roughly 10 to 15 percent of the total procurement of all report POU supply plans.

APPENDIX F: Economic, Demographic, Energy Price, and Other Trends

Per Capita Personal Income

Figure E-1 compares baseline statewide per capita income for the 2022 IEPR forecast (also referred to as the California Electricity Demand Update (CEDU) 2022) against the 2023 IEPR forecast (also referred to as the California Energy Demand (CED) 2023). Statewide per capita income is expected to grow at a similar rate with CEDU 2022, at an average annual growth rate of 2.1 percent from 2023 to 2040. Over the same period, statewide per capita income is expected to increase by 41.7 percent, reaching $112,500 by 2040.

Figure F-1: Statewide Per Capita Personal Income Comparison, 2023 IEPR Forecast

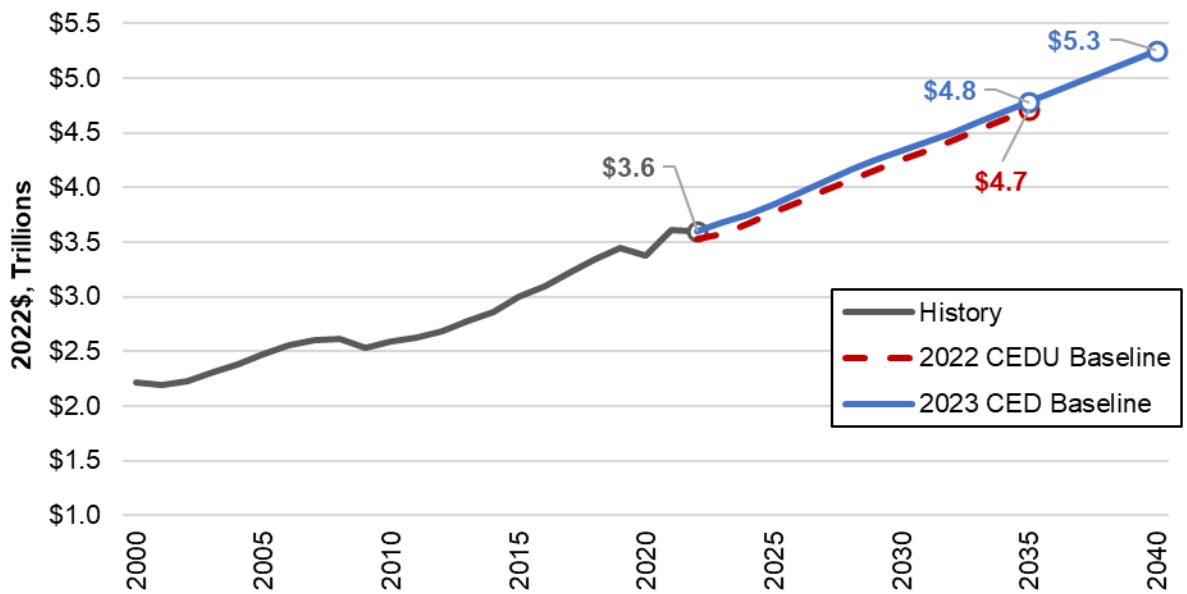


Source: CEC using data from Moody's Analytics and DOF

Gross State Product

Figure E-2 compares baseline gross state product projections for CEDU 2022 and CED 2023. Gross state product is expected to grow at a similar rate with CEDU 2022, at an average annual growth rate of 2.1 percent from 2023 to 2040. Over the same period, gross state product is expected to increase by 43 percent, reaching $4.7 trillion by 2035 and $5.3 trillion by 2040. The 2023 data are from May, and do not reflect any subsequent economic developments.

Figure F-2: Gross State Product Comparison, 2023 IEPR Forecast

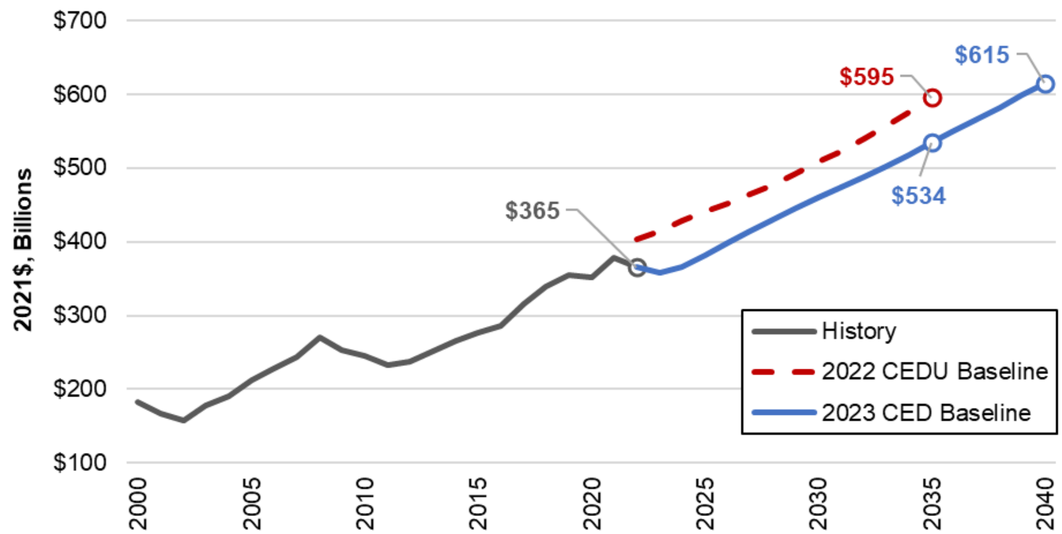


Source: CEC using data from Moody's Analytics from May 2022 and May 2023

Manufacturing Output

Figure E-3 compares gross manufacturing output projections for CEDU 2022 and CED 2023. Gross manufacturing output declined in 2022, and the downward trend is expected to continue into 2023. However, gross manufacturing output is expected to increase again in 2024, and subsequently grow at a similar rate as CED 2021, albeit from a lower starting point than past forecasts. An average annual growth rate of 3.2 percent is predicted from 2023 to 2040. Over the same period, gross manufacturing output is expected to increase by 72 percent, reaching $615 billion by 2040.

Figure F-3: Gross Manufacturing Output Comparison, 2023 IEPR Forecast

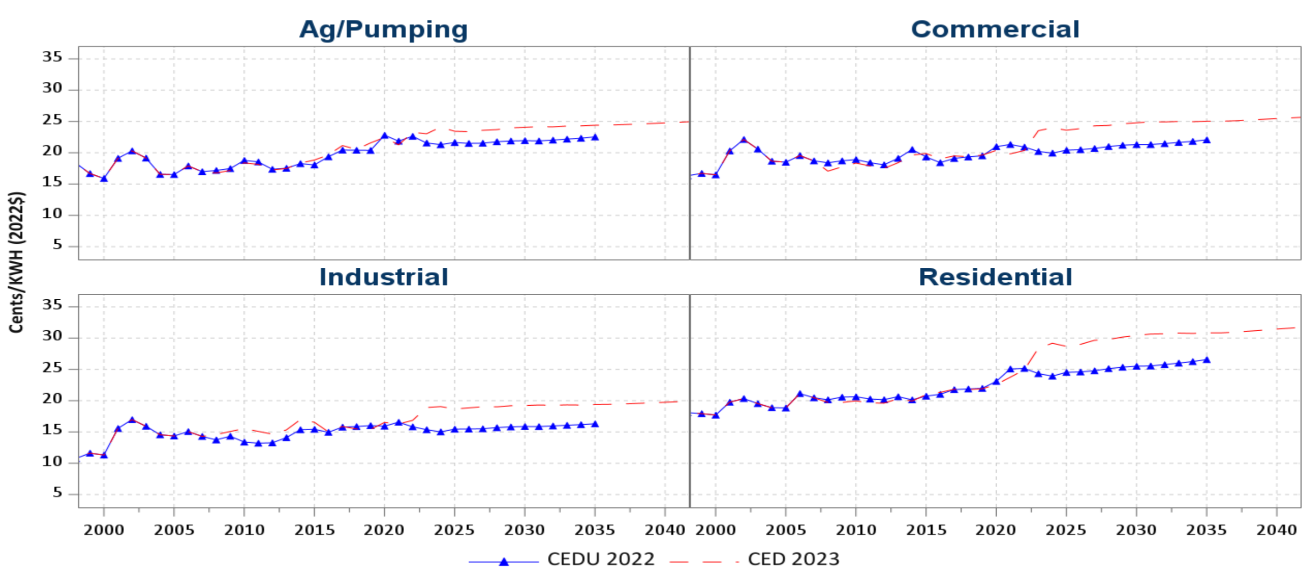


Source: CEC using data from Moody's Analytics from May 2022 and May 2023

Electricity Rates

Figure F-4 compares projected retail electricity rates by sector for CEDU 2022 and CED 2023. In recent years spending on grid hardening and investment needed to support carbon reduction goals have contributed to rising rates, as have high prices for energy and capacity. Longer term, utilities must continue to invest to manage climate change risk and support decarbonization, but the increase in electricity sales from building and transportation electrification slows upward pressure on customer rates.

Figure F-4: Statewide Average Electricity Rates, 2023 IEPR Forecast

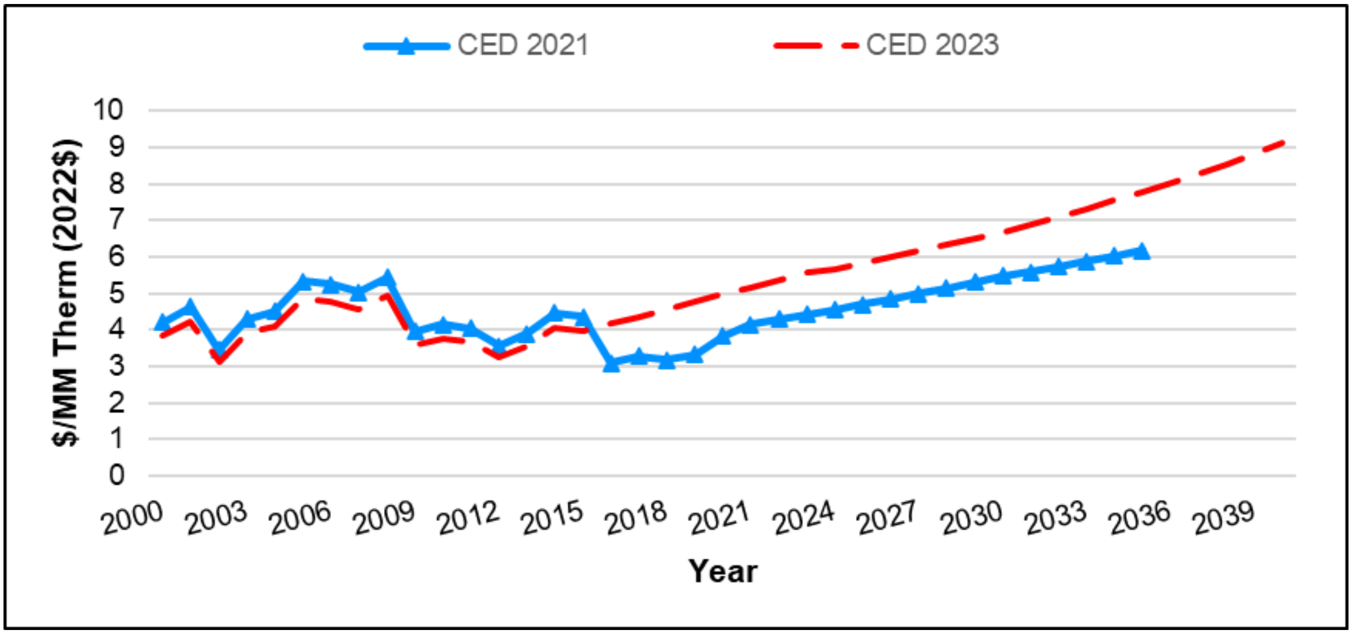


Source: CEC

Fossil Gas Prices

Figures F-5 and F-6 below show delivered fossil gas prices increasing over time in the residential and commercial sectors in California due to rising revenue requirements by the utilities and declining customer demand. Figure F-7 shows industrial sector prices only slightly increasing. The gas price projections do not currently include biomethane prices, but the CEC will explore this and other areas of expansion for future gas price forecasts. The CEC will also look further into cost allocations, which are done by the CPUC.[320]

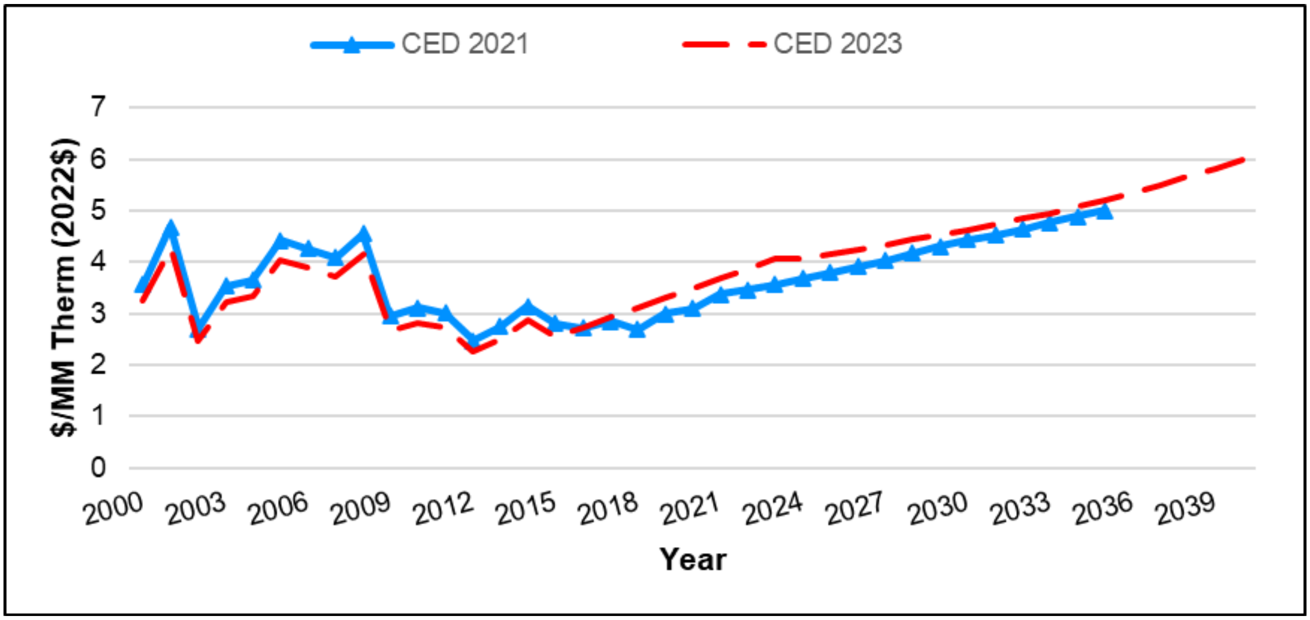
Figure F-5: Residential Fossil Gas Prices, 2023 IEPR Forecast



Source: CEC

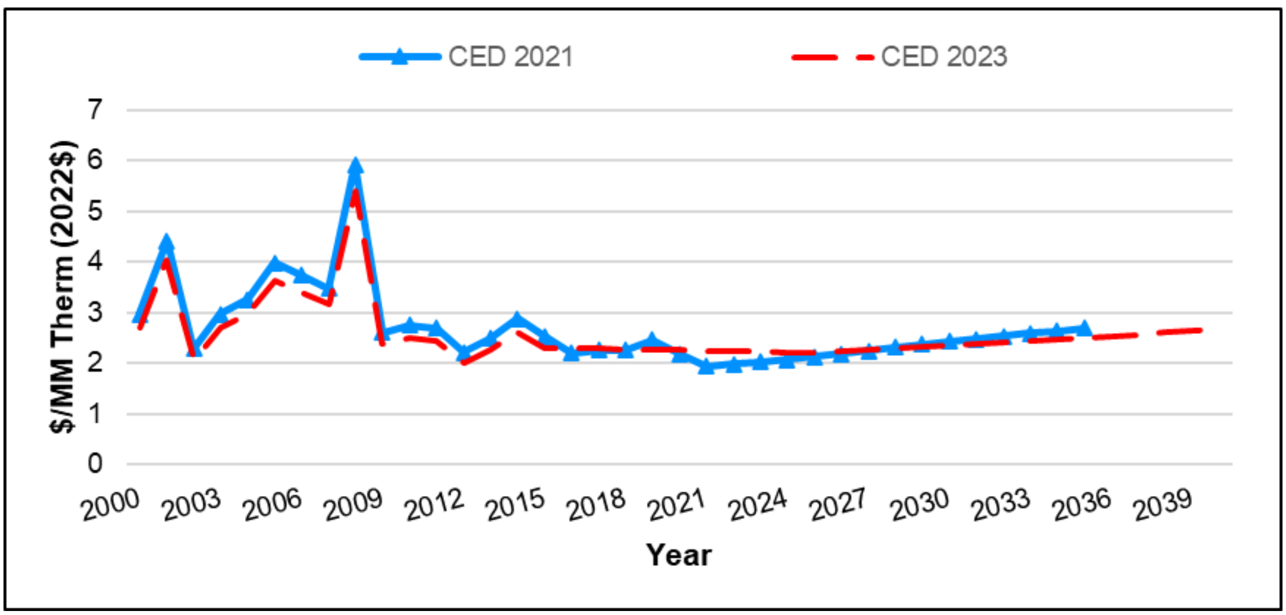
320 Industrious Labs, EarthJustice, EDF raised concerns that industrial prices ignore historical increases and shifts in cost allocation and that gas price projections do not account for biomethane prices.

Figure F-6: Commercial Fossil Gas Prices, 2023 IEPR Forecast



Source: CEC

Figure F-7: Industrial Fossil Gas Prices, 2023 IEPR Forecast



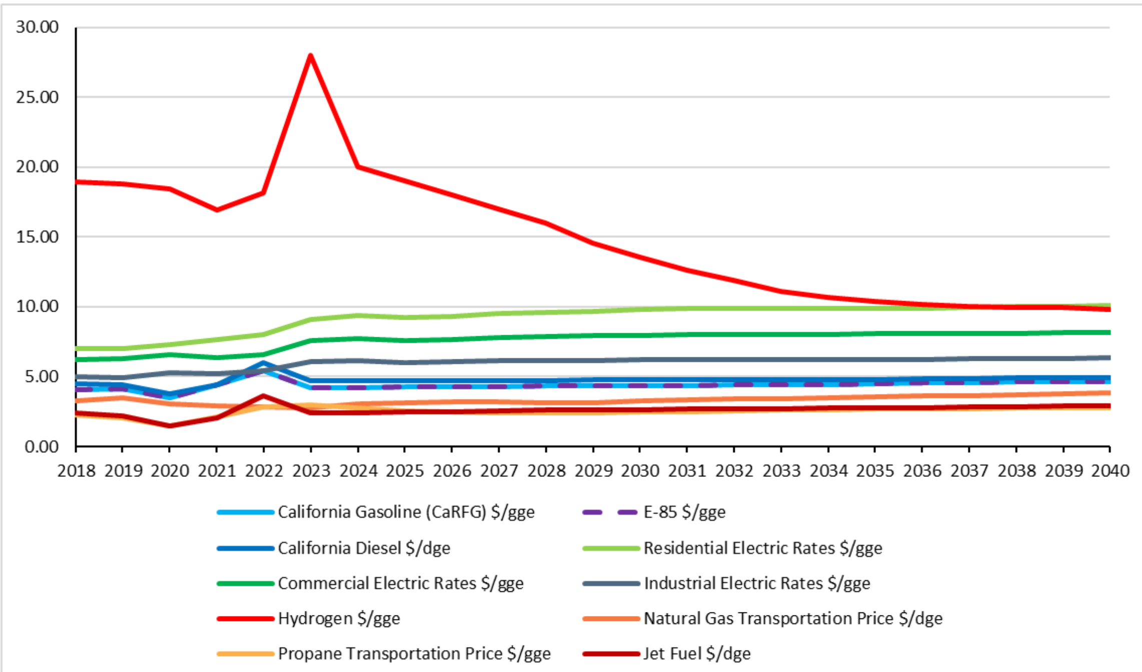
Source: CEC

Transportation Fuel Prices

See Figure F-8 for the annual average fuel price forecasts used in the transportation forecast. These price forecasts are all for a mid-case or reference scenario and generally have flat or slightly rising trends. The exception is hydrogen, which has a notable spike in 2023. This is caused by a sharp increase in prices during the second half of the year, with prices as high as $36 per gallon of gasoline equivalent (gge) occurring throughout the state (1 kg of hydrogen equals 1 gge).

CEC staff only use one transportation fuel price scenario in the forecast, and there are other possible or likely events which were not considered in this scenario. Two possible events are particularly noteworthy: additional refinery closures or related events; and unforeseen regulatory changes, including substantial changes in the price of LCFS credits. A noteworthy assumption is that in 2024 government funding will be available and effective at lowering the retail price of hydrogen.

Figure F-8: Fuel Price Forecasts Through 2040, 2023 IEPR Forecast ($ per Gasoline or Diesel Gallon Equivalents)

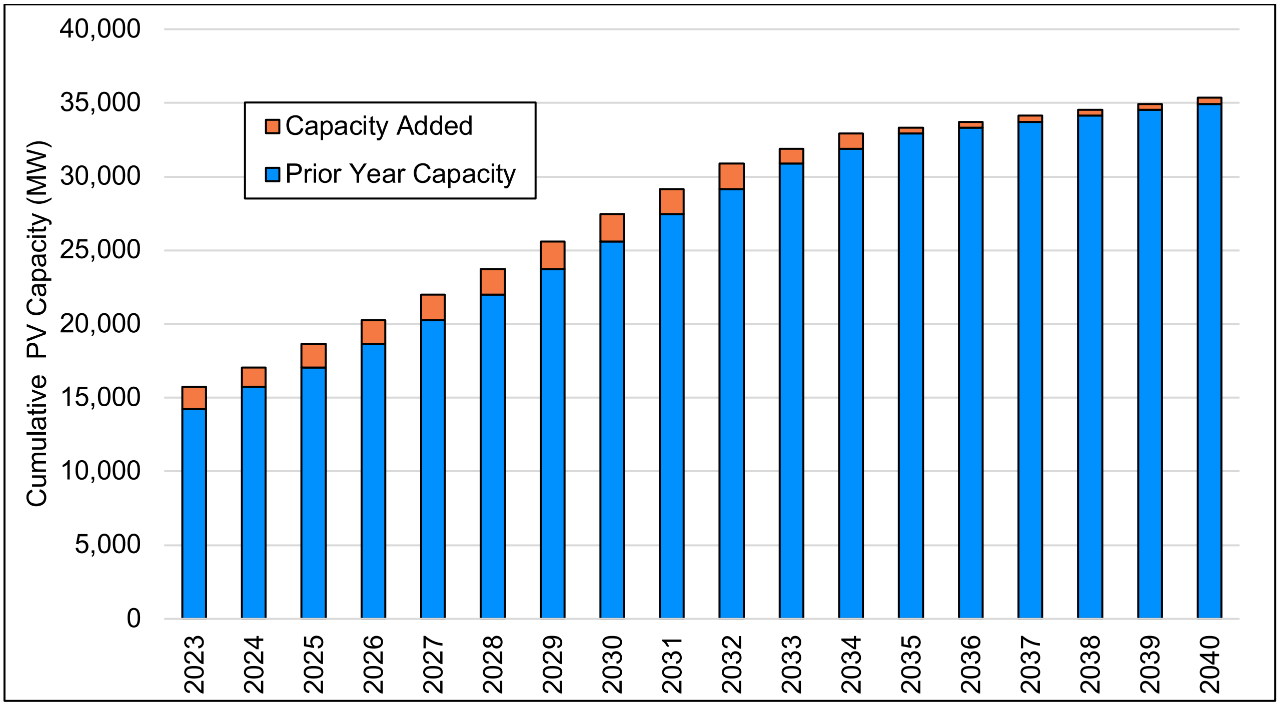


Source: CEC

BTM PV and Storage Capacity

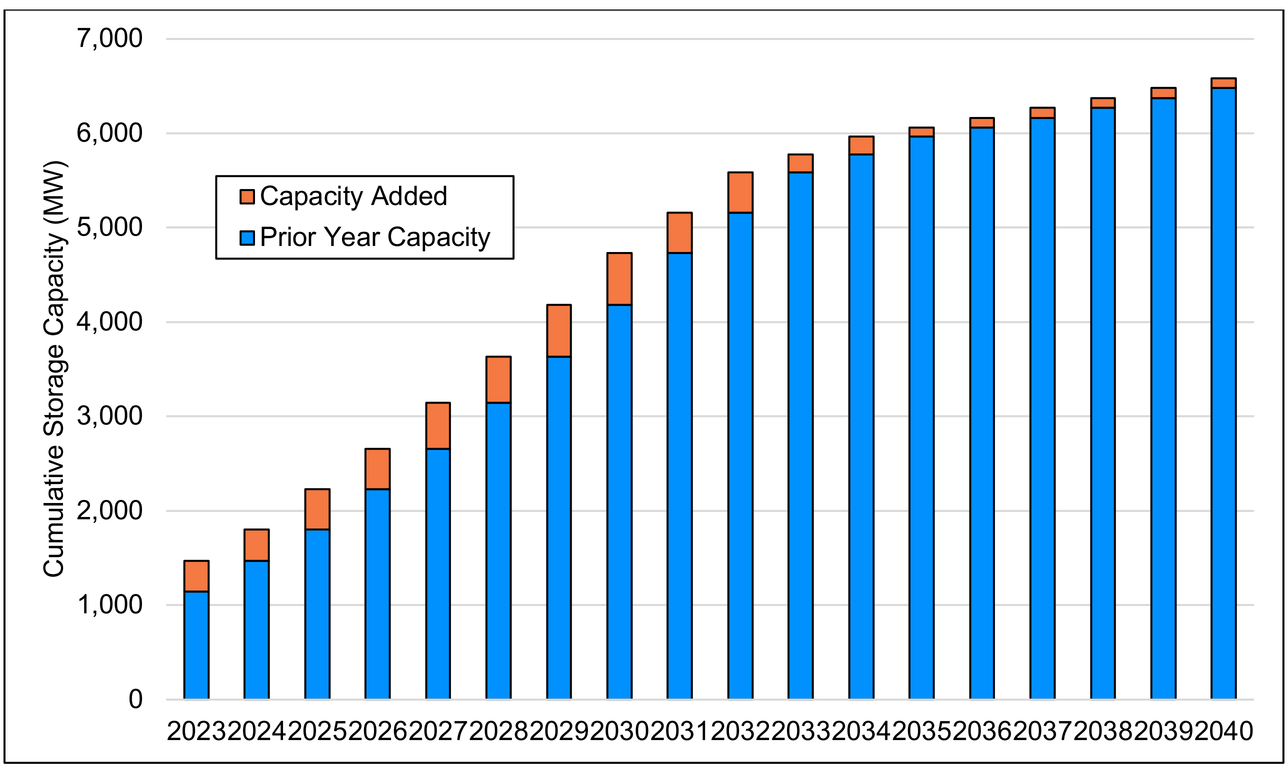
Figures F-9 and F-10 below show the forecast increases in statewide BTM PV and storage capacity. Both forecasts show steady adoption rates until the mid-2030s, at which point capacity additions slow due to the elimination of the ITC incentive. PV grows at an average rate of 14 percent throughout the forecast, while storage grows at an average rate of 32 percent. Both technologies experience high overall growth rates due to factors such as decreased installation costs and increased electricity rates that incentivize adoption of both technologies. The higher growth rate of storage capacity can be attributed to changes in retail export compensation rates under NBT that incentivize paired storage adoption throughout the forecast. Moreover, lower historical installed storage capacity and an increasing prevalence of paired system adoption contribute to this trend.

Figure F-9: Cumulative BTM PV Capacity, 2023 IEPR Forecast



Source: CEC

Figure F-10: Cumulative BTM Storage Capacity, 2023 IEPR Forecast



Source: CEC