Natural Gas Power Plant Modernization in California

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Contents

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Executive Summary

In 2018, California's senate passed SB100, requiring that California reach 100% carbon free electricity in sales to end use customers by 2045. Five years later, renewable energy penetration on our grid has grown, but the primary source of carbon emission in the state's electricity – natural gas generation – remains a large portion of total electricity supply. Moreover, the path to eliminate California's energy generation carbon footprint by 2045 while keeping service safe, affordable, and reliable is not clear[1].

The effects of late 2022's increase in natural gas prices demonstrates the significant role gas generation continues to play. In December, gas prices across Western trading hubs shot up significantly above benchmark prices in other regions. Reduced hydroelectric supply, extreme weather, and low gas storage inventories due to a hot summer just a few months earlier made prices jump four times higher than usual. In turn, high fuel costs caused natural gas generators to bid into California Independent System Operator's (CAISO's) wholesale electricity markets at higher prices. But the high prices did not lead to lower demand for gas generated electricity. Instead, they inflated electricity prices for everyone[2].

Because CAISO prices are set by the last and most expensive bid accepted, higher bids by natural gas sources shifted the cost of all electricity up. The impact was felt most strongly during the chilly, dark evenings when solar was not available. CAISO estimates that high natural gas prices cost wholesale electricity markets an extra three billion dollars in December 2022 and 900 million in January 2023. To reduce the blow to ratepayers' bills, the CPUC has accelerated climate credit payments[3] [4].

In public comments to a 2023 California Public Utilities Commission (CPUC) investigation, the Environmental Defense Fund argued gas price volatility was yet more evidence for the need to electrify, because electrification can buffer consumers from the direct effects of gas prices. However, as long as gas plants remain the marginal units demanded within CAISO wholesale markets, electrification can not protect ratepayers from natural gas prices completely. Effectively replacing natural gas plants with alternative electricity sources that can play similar roles in supporting reliability and complementing variable renewable energies like solar and wind is also necessary[5].

[1]https://www.energy.ca.gov/sb100
[2]https://www.caiso.com/Documents/special-report-on-gas-conditions-and-caiso-markets-for-december-2022-and-january-2023-published.html
[3]https://www.caiso.com/Documents/special-report-on-gas-conditions-and-caiso-markets-for-december-2022-and-january-2023-published.html
[4]https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/mee
[5]https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M506/K523/506523156.PDF

This report uses a mixture of quantitative data and qualitative case studies to address three primary topics:

First, using publicly available historical data on generation, emissions, and operating plants this report shows how California's natural gas fleet has changed since 2001. The data shows that the fleet became more efficient as plants were modernized and aging plants retired. The fleet's greater efficiency, rather than changes in the amount of electricity generated from natural gas plants, drove emissions reductions from natural gas generation 2002-2021.

Second, the report offers options for greater efficiency and alternative resources going forward. While the modernization of natural gas plants with more efficient equipment is effective, trends within the industry show that augmenting facilities with battery storage hybrid options and considering alternative fuels are the options most consistent with both California's emissions reduction goals and regulators' obligation to ensure rates remain just and reasonable.

Finally, this report describes current policy rationales used to keep old, inefficient plants online. We find that concerns over reliability and resource adequacy drive stakeholders' decision making when extending the lifespans of the fleet's dirtiest units. As a result, anticipating these concerns and ensuring that alternative resources adequately address them will be critical to achieving the goals set by SB100.

While the majority of the report is historical, it's a history that vitally informs future decision making for California's natural gas fleet. Although significant emissions reductions in the past have been associated with modernization and turnover within the natural gas fleet, future emissions reductions will come from developing both technology and institutions to replace and complement natural gas on the grid.

Introduction

Supply

Despite plans to phase out natural gas over the next several decades, it continues to make up the plurality of California's in-state generation. In 2021, natural gas generation made up 37.9% of total supply in California's power mix, excluding imported power. In the same year, coal made up only 3% of California's power mix, eligible renewables were about 33.6%, and large hydroelectric power was 9.2%[6]. Year-on-year variation in natural gas generation relative to total generation is driven both by changing hydroelectric conditions – like droughts – and longer term policy trends like increasing Renewable Portfolio Standards (RPS).

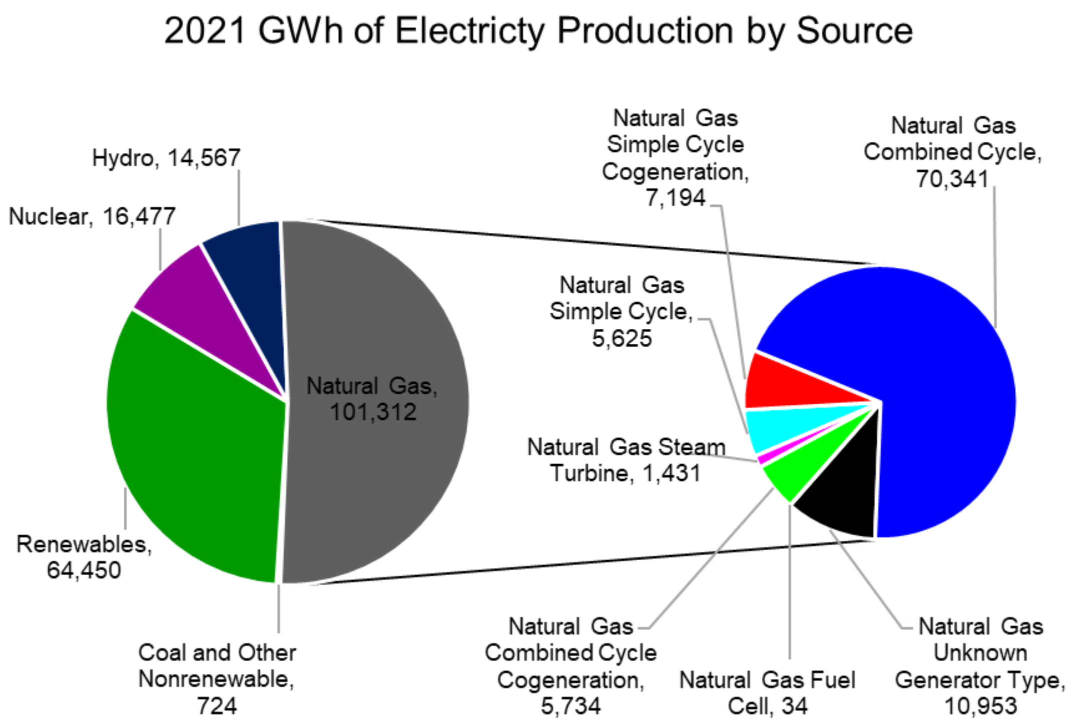

Figure 1: Electricity production in GWh in California by source. Right chart indicates the type of natural gas generator used in production.[7]

Due to the intermittency of renewable power, both peaker and base load natural gas plants are required to meet energy demands. Unlike resources like wind and solar, natural gas plants can be called up on short notice to generate electricity. This feature, called dispatchability, means natural gas plays a valuable role in the challenge of perfectly balancing supply and

[6] https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-power/a-p-powercontentlabel?_adf.ctrl-state=kcnkcolb_4&_afrLoop=49093857239267
[7] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation

demand. To substitute for it, carbon free replacements will also need to be dispatchable and reliable.

Net Load and the Duck Curve

Due to renewable penetration, swings in net load are becoming more extreme, a daily pattern known as the duck curve[8] [9]. Under a duck curve, net load drops very low during the middle of the day before rapidly rising during the evening.

The duck curve increases the need for flexible, dispatchable energy, a role currently played by natural gas. This means that many gas plants will only be needed for a few hours of the day, but need to come online faster than ever. When plants designed to serve base load and produce electricity throughout the day have to rapidly turn on and off or cycle, they tend to be less efficient. A less efficient plant also means more emissions and higher costs.

Emissions in California

Since 1968, the US Environmental Protection Agency (EPA) has granted California a waiver to regulate emissions within the state[10]. This history of emissions regulation has led to the establishment of the California Air Resources Board (CARB) and other public policy infrastructure to monitor and regulate in-state emissions,[11] impacting the generation mixes within California's grid.

California Air Quality Regulation and the CARB

CARB was formed in 1967 by the Mulford-Carrell Act, which centralized all administration, research, and air conservation activities within California[12]. Since its inception, CARB has been the emissions regulator for vehicles, power systems, and other industrial processes in California.

Today CARB has control over California's broader plans to limit greenhouse gas emissions, primarily under the cap-and-trade emissions regulation program established by SB32 (expanding on AB32) in 2016[13]. Known as the "Global Warming Solutions Act," SB32 required California to return to 1990 levels of greenhouse gas emission by 2020. The bill was extended in 2017 as AB 398[14]. This landmark legislation allowed CARB to implement broad policies to achieve significant statewide emissions reductions. It is responsible for two of

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[8]https://www.nrel.gov/docs/fy16osti/65023.pdf
[9]http://www.caiso.com/Documents/gross-and-net-load-peaks-fact-sheet.pdf
[10]https://ww2.arb.ca.gov/about/history
[11]https://www.cnn.com/2022/09/06/business/california-emissions-regulations/index.html
[12]Eric P. Grant. Letters - California Redoubles its Efforts - Mulford-Carrell Act Highlights. Environmental Science & Technology 1967 1 (9), 682-682 DOI: 10.1021/es60009a601
[13]https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32
[14]https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398

CARB's primary mechanisms for acting on stationary power generation to enforce greenhouse gas emissions reductions:

1. Emissions targets: California has an established a greenhouse gas emissions target of 40% below 1990 emissions levels by 2030 through AB398 and 80% below 1990 emissions levels by 2050 through executive order from the governor[15]. These emissions targets are the motivation and justification for broad policy changes and reporting requirements regarding greenhouse gasses. The targets for emissions, and the data available at the time the policies were set are shown in Figure 2.
2. Cap-and-Trade: The market mechanism implemented by CARB places a fee on greenhouse gas emissions. Emitters must tender a permit for each equivalent ton of carbon dioxide (CO2e) emitted by their processes. Permit prices in Q1 2023 range between $25 and $30 per ton of CO2e and are typically set at an auction[16]. The limits on emissions decline over time and cover approximately 80% of California's greenhouse gas emissions[17].

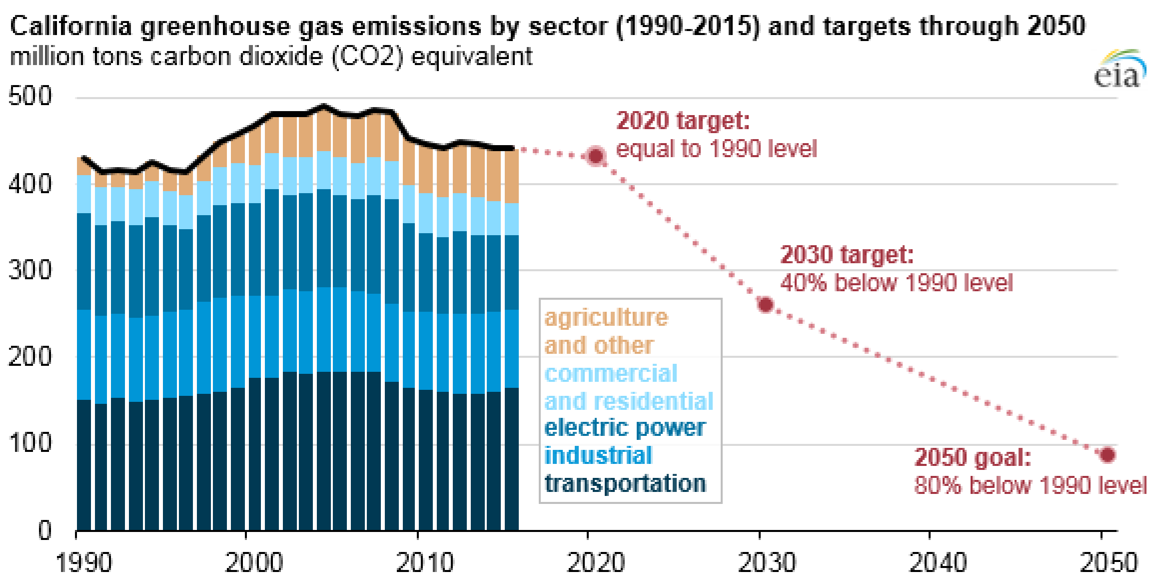

Figure 2: Emissions data from 1990 to 2015 with targets shown to 2050. Figure from source[18].

California CO2e Emissions

A variety of gasses – including carbon dioxide (CO2), methane (CH4), and nitrous oxide (N2O) – all contribute to global warming in various amounts and over different time horizons.

[15]https://www.ca.gov/archive/gov39/2015/04/29/news18938/index.html
[16]https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program
[17]https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/program-data/cap-and-trade-program-data-dashboard
[18]Figure from https://www.eia.gov/todayinenergy/detail.php?id=34792

Methane, for example, has a global warming potential of approximately 27-30 times that of carbon dioxide per ton emitted[19]. Greenhouse gas emissions (GHG) are typically monitored and tracked in units of weight of "CO2e," which normalizes these pollutants relative to the global warming potential of carbon dioxide.

In California, the total emissions in 2020 were estimated to be approximately 369.2 million metric tons (MMT) CO2e, attributed by source as shown in Figure 3. 2020 emissions are below the 2020 limit of 431 MMT established in AB398[20], and emissions have been decreasing steadily since 2008, as shown in Figure 4. These emissions levels represent a meaningful improvement over the projected "business as usual" (BAU) condition that might have existed without regulation; in 2020, the BAU projection was over 500 MMT CO2e for California[21].

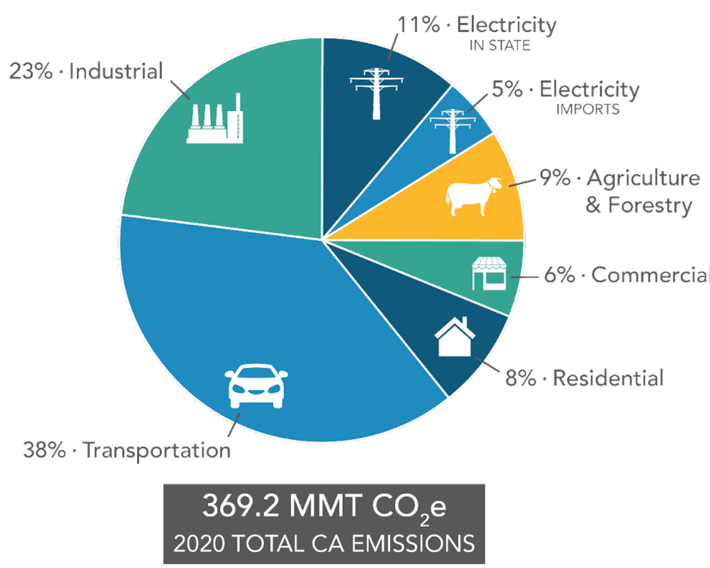

Figure 3: CO2e emissions in California. Figure from source[22].

[19]https://www.epa.gov/ghgemissions/understanding-global-warming-potentials
[20]California Air Resources Board. (2022). California Greenhouse Gas Emissions for 2000 to 2020 - Trends of Emissions and Other Indicators. Retrieved from https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf
[21]https://ww2.arb.ca.gov/ghg-bau
[22]Figure from https://ww2.arb.ca.gov/ghg-inventory-data

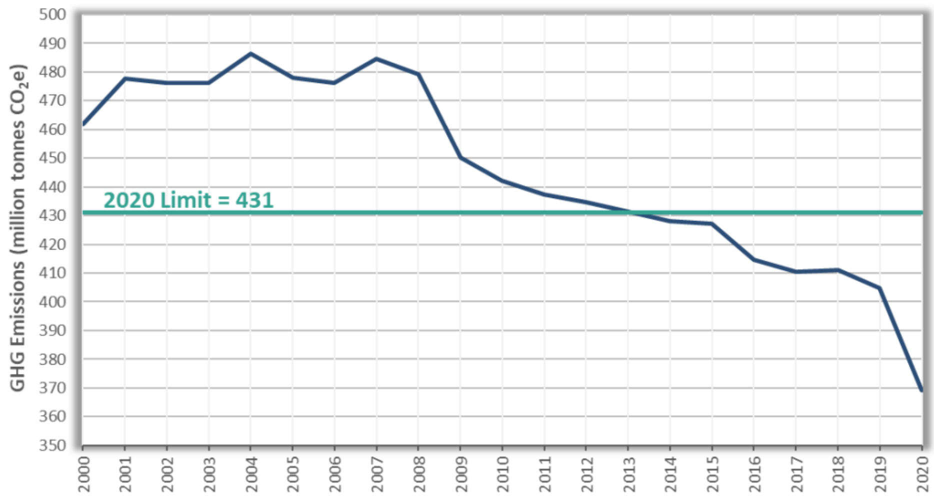

Figure 4: CO2e emissions trend in California. Figure from source[23].

Non-CO2e Emissions

Regulation of California's air quality by the CARB includes includes both greenhouse gasses and other pollutants known as criteria air pollutants[24] which include oxides of nitrogen (NOx) and oxides of sulfur (SOx). . Beyond impacts on global pollutants like CO2, how we use our natural gas fleet is a local environmental justice issue, in addition to the impacts. Within California, communities of color are disproportionately exposed to local air pollution associated with electricity generation. As a result, reducing natural gas generation tends to help marginalized communities most[25].

CO2e accounting for electricity generation

Stationary Generation

Emissions considered in this document will generally follow the guidelines for reporting detailed in the Greenhouse Gas Protocol (GHG Protocol) corporate accounting and reporting standards[26] and accounting for the relative impacts of natural gas modernization projects will generally follow the GHG protocols for project accounting[27]. The GHG protocol uses three "scopes" to delineate direct and indirect emissions of an organization that are generally defined as follows:

- Scope 1: Direct GHG emissions from sources that are owned and controlled by the organization.

[23] https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf
[24] https://ww2.arb.ca.gov/criteria-pollutant-emission-inventory-data
[25] https://oehha.ca.gov/media/downloads/environmental-justice//ab32pressrelease020322.pdf
[26] https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf
[27] https://ghgprotocol.org/sites/default/files/standards/ghg_project_accounting.pdf

- Scope 2: Indirect GHG emissions from the purchase and procurement of electricity controlled by the organization.
- Scope 3: Indirect upstream and downstream emissions that are a consequence of the organization's activity.

For natural gas power generation, we consider electricity generation at the point of the natural gas combustion as the activity and delineate an organization immediately around this activity, but do not consider other emissions generating business activities that may occur within the broader business of an independent power producer. The accounting for emissions within this artificial organization generally follow the GHG protocols for stationary power generation[28]. For our assessment the delineation of scopes considered for stationary natural gas generation is:

- Scope 1: Emissions from the combustion of natural gas for electricity generation in a power plant are Scope 1 emissions and are the most significant contribution of the facility to statewide greenhouse gas emissions. We compute the Scope 1 emissions from facilities as a function of their consumed fuel assuming 100% reaction and 52.91 kg of CO2e produced per million BTU (MMBTU)[29] consumed by the facility.
- Scope 2: As Scope 2 emissions are generally associated with the purchase of electricity for operations, we do not consider any Scope 2 emissions in this study. Any input electricity that is required for the operation and maintenance of a gas turbine or other gas combustion system is generally assumed to be minor relative to the emissions generated from fuel combustion and upstream emissions and is not included in this assessment.
- Scope 3: Upstream natural gas emissions from the extraction, refining, and transportation of the fuel are geographically spread throughout the footprint of the natural gas industry and are extremely difficult to track. Leaked natural gas is particularly concerning because of the high global warming potential of methane. If between 3% and 4% of natural gas leaks upstream of combustion in a natural gas facility, natural gas may be "dirtier" than an equivalent coal-burning facility[30]. Estimates of upstream methane leakage vary significantly, but have been measured to be approximately 2.3% of gross production of in the United States[31]. In this report, we do not consider upstream

[28]https://ghgprotocol.org/sites/default/files/Stationary_Combustion_Guidance_final_1.pdf
[29]https://www.eia.gov/environment/emissions/co2_vol_mass.php
[30]https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/natural-gas-use-may-affect-climate-as-much-as-coal-does-if-methane-leaks-persist-68096816
[31]https://www.science.org/doi/10.1126/science.aar7204

emissions in reported quantities. However, we note that any reduction in the total consumed natural gas for the purposes of electricity generation may result in decreases of upstream emissions, while improvements in the efficiency of natural gas generation while consuming the same amount of fuel (e.g. producing more electricity with the same amount of fuel) may not result in a reduction of upstream emissions.

CO2e in Cogeneration

The emissions generated from cogeneration facilities (a plant type described in more detail below) are accounted for differently than emissions from other stationary generators. Natural gas cogeneration plants produce both electricity that is distributed to the grid and heat for use in industrial processes. As a result, the electricity generated from a Cogeneration facility per unit of input fuel will be significantly lower than a system that is designed solely for the production of electricity. In turn, that means that the emissions associated with electricity generated from a Cogeneration facility is higher than for other gas plants if the heat component is ignored.

During emissions accounting in California from CARB, the emissions from cogeneration are typically split and assigned to either electricity production or useful heat:

“The GHG Inventory splits emissions from cogeneration units between electricity generation and useful thermal output (UTO). The portion of cogeneration emissions attributed to electricity generation is assigned to the in-state electricity generation sector, while the portion of cogeneration emissions attributed to UTO is assigned to either the industrial sector or the commercial sector, depending on where the UTO is used.”[32]

Assessments of the emissions from cogeneration are described in the GHG protocol for emissions accounting[33], CARB documenting procedures[34] and EPA procedures [35].

Natural Gas Electricity Generation Technology

The natural gas fleet within California can be broken down into 4 distinct types: steam turbines, simple cycle combustion turbine, combined cycle combustion turbine and cogeneration. Each of these different types have slightly different mechanical characteristics which impact how they are used in the market, how efficient they are, and how they would be

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[32]California Air Resources Board. (2021). California Greenhouse Gas Emissions for 2000 to 2020 - Methodology Update Document. Retrieved from https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/ghg_inventory_00-20_method_update_document.pdf

[33]https://ghgprotocol.org/sites/default/files/CHP_guidance_v1.0.pdf

[34]https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/pubs/reports/2000_2015/guidance_on_mrr_crosswalk_cogen_breakout.pdf

[35]https://www.epa.gov/sites/default/files/2015-07/documents/fuel_and_carbon_dioxide_emissions_savings_calculation_methodology_for_combined_heat_and_power_systems.pdf

impacted by particular policy. Each section below highlights the technology of each category of peaker plant and how that informs the plants use case.

In addition, each plant has distinct efficiency upgrades which could improve the overall system efficiency. Upgrades listed may only increase plant efficiencies by less than 1% or may reduce greenhouse gas emissions by only slight margins. While costs are not discussed, the challenge is how to balance the marginal improvements with costs and understand the incentive structure that plant owners operate within to see if efficiency upgrades are feasible when the market signal from the legislature shows that by 2045 energy generation will be carbon neutral.

Additional terminology definitions for this section can be found in Appendix A.

Steam Turbine

Technology

Steam turbine technology starts the energy generation cycle by pumping water to high pressure. Fuel – either coal or natural gas – is provided to a boiler, which heats the high pressure water to create high pressure steam. That high pressure steam is sent to the steam turbine, where it expands and spins the turbine blades, producing electricity.The steam then requires additional cooling to condense and begin the cycle again. Typically that cooling is provided by natural water sources like rivers or oceans.

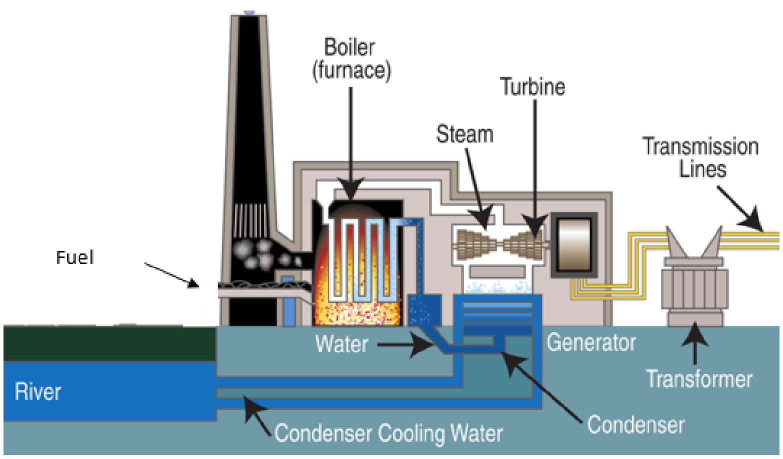

Figure 5: Schematic of a steam turbine generation natural gas plant. Figure from source[36].

Use Cases

Steam turbines are the oldest generators within California's natural gas fleet. Most were built and operational prior to 1980. Because of the time associated with getting these unit's turbines to the high temperatures and pressures necessary for steam production, these units

[36]https://commons.wikimedia.org/wiki/File:Coal_fired_power_plant_diagram.svg

can take several hours to warm up from a cold start before producing electricity[37]. As a result, steam turbines were typically used as baseload power. However, as renewables have continued penetration into the market, these plants are now only being used in periods of very high demand as shown by capacity factors, the ratio of actual output over the maximum potential output, of 3.4% in 2018[38]. These plants only produce about 2% of California's annual Energy consumption in 2018 and have an average heat rate of 13,212 btu/kWh and thermal efficiency of 25.8%[39].

Steam turbines have had a drastic shift in use in the past decade due to environmental policy called The Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling. Additional insights into Once Through Cooling (OTC) policy and history is described in the section Natural Gas Transition Limitations and Case Studies below.

To date, 17 of the 27 OTC plants have closed as a result of this environmental policy, which has had the additional impact of lowering CO2 emissions for California's NG plant fleet as steam turbines are the highest emitters on a per MW basis. Rather that choosing to perform the necessary upgrades to remain operational, most plants have chosen to close or repower completely prior to their compliance deadline[40]. Several OTC plants have been granted compliance date extensions, deemed necessary to ensure that there would be enough generation to support grid reliability. For more information, see the report's section on Once Through Cooling (page 41).

Efficiency and GHG Reduction Upgrades

Most steam turbine plants within California have planned closure dates due to OTC policy and efficiency upgrades are not typically being considered due to the inability to have positive cash flows after implementation. While there are upgrades which could be made to increase boiler efficiencies or reduce the amount of steam leaks, more detail will be provided within the Combined Cycle Combustion section as these plants have higher feasibility of implementation of proposed efficiency upgrades.

[37]https://www.physicsresjournal.com/articles/ijpra-aid1040.pdf
[38]CEC Thermal Efficiency of Natural Gas-Fired Generation in CA: 2019 - Michael Nyberg
[39]CEC Thermal Efficiency of Natural Gas-Fired Generation in CA: 2019 - Michael Nyberg
[40]https://www.waterboards.ca.gov/publications_forms/publications/factsheets/docs/oncethroughcooling_20200818.pdf

Simple Cycle Combustion Turbine

Technology[41]

The simple-cycle combustion turbine (SCCT) process starts when fresh air flows through a filter into the compressor. The air is compressed, combined with the natural gas and then ignited. The ignition causes the mixture to expand, increasing pressure, which then spins turbine blades. As the turbine blades are connected to a shaft, when the blades spin the drive shaft generates electricity within the generator. Figure 1 below details this process.

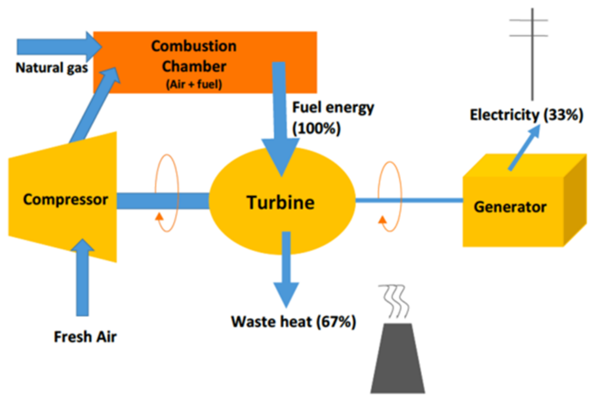

Figure 6: Schematic of a simple cycle gas plant. Figure from source[42].

Use Cases[43]

In 2020, over 75% of California's peaker plants were SCCT. Due to their fast ramp rates from cold starts, SCCT plants are relatively well suited to playing a peaker role. SCCT plants can start delivering full output power in as fast as 10 minutes, with a ramp rate of 10% per minute.

Quick ramp rates are essential to help maintain grid reliability, but that comes at the cost of thermal efficiency. SCCT are the least efficient natural gas systems, with thermal efficiencies around 33%. While newer turbines have thermal efficiencies nearer to 45%, the average age of SCCT's on California's grid is 22 years. SCCT heat rates within California, another measure of efficiency, average 11,000. To put that in perspective, the average SCCT has a heat rate on par with Coal and Petroleum generation production[44].

SCCTs are used intermittently to satisfy peak loads. Run hours per start and capacity factors are both important metrics to understand how these systems operate. SCCT's have

[41]https://energyeducation.ca/encyclopedia/Simple_cycle_gas_plant
[42]https://energyeducation.ca/encyclopedia/Simple_cycle_gas_plant
[43] https://www.psehealthyenergy.org/wp-content/uploads/2020/05/California.pdf
[44]https://www.eia.gov/electricity/annual/html/epa_08_01.html

relatively short run times from start, with roughly 66% of systems running less than 5 hours in a row. Capacity factors describe the percent of time running compared to running at full capacity all year. More than 60% of California's SCCT's run at capacity factors below 5%.

Efficiency and GHG Reduction Upgrades[45]

Options for increasing the efficiency of existing SCCT systems are limited. Moreover, increased efficiency does not necessarily mean a decrease in GHG emissions. While there are also GHG reduction upgrade possibilities, these often are not associated with an increase in efficiency, and plant owners have no incentive to make these upgrades without policies regulating CO2 emissions.

One way that SCCT systems can be made more efficient is through raising the temperature at which combustion gasses enter the turbine, increasing the efficiency of the turbine. However, turbine inlet temperature (TIT) increases must be matched with additional cooling to reduce maintenance issues with overheated turbine components. In addition, increases in TIT increase Nitrous oxides (NOx) emissions. NOx causes acid rain and is considered an indirect greenhouse gas as it forms ozone.

Another method for increased efficiency is through water injection in the air supply. SCCT depend on fresh air and thus are sensitive to ambient air temperatures, humidity and pressures. Adding a water injection plane after the air filter before the compressor reduces the air temperature from evaporative cooling. The lower temperature leads to higher density – more air mass per unit volume – which increases the gas turbine power output and efficiency.The water supplied requires a chiller and pumps, an additional capital expense and continued operational expenses for the cost of water and electricity to run the equipment.

Combined Cycle Combustion Turbine

Technology

Combined cycle gas turbines begin with the simple cycle process, where compressed air is combined with natural gas and ignited to expand and spin turbine blades connected to a shaft and generator to produce electricity. Unlike simple cycles, the waste heat from this process is then captured within the heat recovery steam generator and is heated to higher temperatures using additional natural gas, producing steam. The steam is sent through a turbine which generates electricity. The condensate produced as the steam cools is collected and sent back to the heat recovery steam generator.

[45]https://netl.doe.gov/sites/default/files/gas-turbine-handbook/1-1.pdf

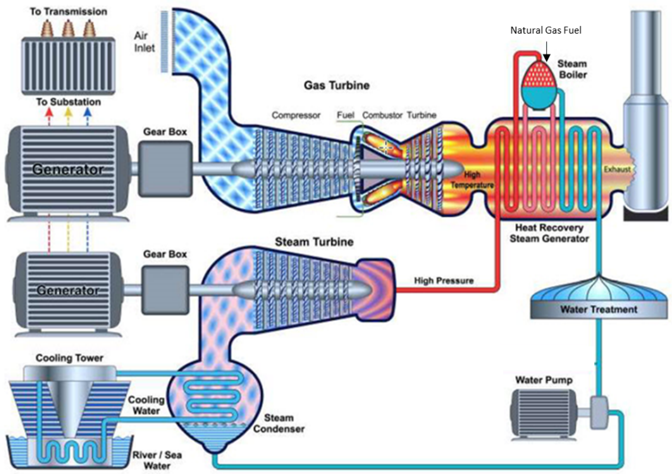

Figure 7: Schematic of a combined cycle gas plant. Figure from source[46].

Use Cases

The additional process including the heat recovery steam generator and steam turbine increases thermal efficiency of the system as compared to just using a steam turbine or just using a SCCT but the downside is those components require longer cold start to full load operation durations. From a cold start, it can take up to 2 hours for a CCCT to reach full load[47]. As a result, the system is typically not used for peaking power and is intended to be utilized for base load power.

However, as renewable generation has further integrated into the power supply, combined-cycle plants are shifting roles and are being tasked for flexible, load-balancing requirements that involve more frequent fast starts, cycling, and load-following ancillary services. This shift in how combined cycle plants are being utilized can be seen in looking at ancillary service contracts. Ancillary service contracts pay plants to be available to balance the difference between the forecast and what is demanded on the grid. In 2001, the total capacity of combined cycle plants with ancillary service contracts was roughly 1000MW. By 2018, more than 20,000MW of combined cycle power plants, roughly 25% of statewide electric generation capacity, was participating in ancillary service contracts.[48] Running a system at partial load enhances equipment inefficiencies and often results in more GHG emissions per MW produced as the systems cycle.

[46]https://www.ipieca.org/resources/energy-efficiency-solutions/combined-cycle-gas-turbines-2022
[47]https://etn.global/wp-content/uploads/2018/09/Startup_time_reduction_for_Combined_Cycle_Power_Plants.pdf
[48]CEC Thermal Efficiency of Natural Gas-Fired Generation in CA: 2019 - Michael Nyberg

The additional heat recovery steam turbine process improves the plants overall efficiency. Roughly 47% of California's 2021 capacity (MW) was delivered from CCTV and had the average thermal efficiency of 47%[49].

As CCCT's are used to satisfy baseload power, they have a higher capacity factor than simple cycle plants. Within California in 2021, the capacity factor for CCCT was 43%.[50]

Efficiency and GHG Reduction Upgrades

Any of the efficiency upgrades that were applicable for SCCT can also be applied to CCCT due to having the same combustion turbine initial step. CCCT also has additional improvements which can be made.

The ramp times within CCGT are slower than SCGT due to the steam turbine components. Technologies such as ultra-low NOx combustion systems and stand-by HRSG heating are used to reduce emissions while ramping[51]. These improvements have resulted in reduced startup times and higher ramp rates, but such rapid cycling imposes increased CCGT maintenance costs.

The largest area of research and development is in the material components of steam turbine blades. If new materials could be produced that increase the temperature and pressure capabilities of the turbine blades, then there could be higher overall plant efficiencies. In addition, these materials could allow for faster ramp rates which would allow for less cycling and more plant efficiency. In 2020, the United States Department of Energy put 16 million dollars of funding into 17 projects which could yield these more effective steam turbine components[52].

Cogeneration

Technology and Use Case

Cogeneration plants are defined more by their use case than their technology. Within California's fleet, cogeneration plants are a mix of combined cycle units, SCCT and steam turbine generators – with the caveat that each plant, regardless of electrical generation type, produces thermal energy which is used for an alternative process by a thermal host nearby. Within California, several cogeneration plants have contracts with oil refineries which use the heat to improve the refining process. Other thermal energy uses include college campuses or hospitals which use the heat for distributed heating loads. These cogeneration plants are

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[49]https://gis.data.cnra.ca.gov/documents/CAEnergy::natural-gas-plant-types-2021/explore
[50]CEC Thermal Efficiency of Natural Gas-Fired Generation in CA: 2019 - Michael Nyberg
[51]https://www.wartsila.com/energy/learn-more/technical-comparisons/combustion-engine-vs-gas-turbine-ramp-rate
[52]https://arpa-e.energy.gov/news-and-media/press-releases/us-department-energy-announces-16-million-funding-phase-1-ultra-high

required to produce heat for their thermal host and as a result they often have must-purchase contracts with local utilities which say that all produced electricity will be purchased.

While cogeneration plants have capacity factores closer to 46% and produce roughly 23% of California's natural gas sourced energy production, these numbers have been decreasing as the number of cogeneration plants continues to decline[53]. A majority of California's cogeneration plants are less than 50MW. Despite cogeneration’s efficiencies – especially when associated with combined cycle plants – many units are closing down. California has tried to enact several different policies including The Waste Heat Recovery and Carbon Emissions Reduction Act, also known as Assembly Bill 1613, provides CHP facilities up to 20 MW in size a secure revenue stream if they meet efficiency and performance requirements. In addition, two major state laws also encourage CHP development. Under Assembly Bill 32, the California Air Resources Board prepared a scoping plan that set a carbon dioxide emissions reductions goal from the increased use of CHP facilities. Even with support, these units continue to see a decrease in use.

Efficiency and GHG Reduction Upgrades

As the technology of cogeneration plants use steam turbines, SCCT and CCCT, there are no efficiency or GHG reduction upgrades specific for cogeneration.

[53] https://gis.data.cnra.ca.gov/documents/CAEnergy::natural-gas-plant-types-2021/explore

Natural Gas Modernization Historic Data Validation

The fleet of all natural gas-powered electricity generators in California have changed in use and character since the 2000-2001 energy crisis. Several publicly available databases track the annual fuel consumption, capacity, and electricity production of natural gas facilities in the state and this section will evaluate observable trends in the fleetwide efficiency and emissions.

Data Prior to 2019 Validation

The statewide electricity generated from California's natural gas facilities is available from several resources, three of which were considered in this analysis: (1) the EIA historical electric generator report maintained by the US energy Information Administration[54], (2) the California Energy Commission (CEC) energy almanac[55], and (3) total system electric generation summaries also prepared by the CEC[56]. The MWh of generation reported in each of these resources is shown in Figure 8 through 2021, the last full year with available data. Reported generation from each of the resources is generally similar with minor deviations in the CEC Energy Almanac data for years since 2005. These deviations may be the result of different accounting of the electricity generated at backup facilities and how that electricity reaches the rest of the grid.

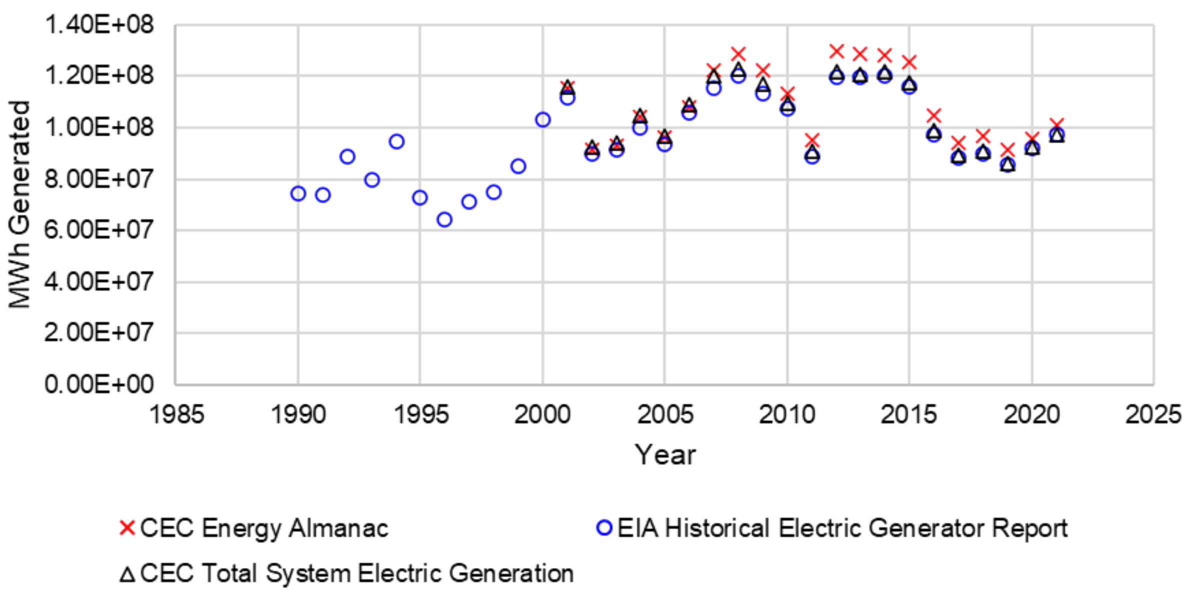

Figure 8: Electricity generation by natural gas plants in California.

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[54]https://www.eia.gov/electricity/data/state/

[55]https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/quarterly-fuel-and-energy-report-qfer-0

[56]https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation

The data in Figure 8 serves as an update and validation to data shown in Figure 9 from previous work done in the assessment of natural gas plant emissions in California using data through 2019. The generation data shown in Figure 8 includes all natural gas facilities in the state of California, while Figure S shows a more limited number of facilities, resulting in significant deviations in total generation of 10-20%. Figure 9 shows generation projections in 2020, 2023, and 2024 remaining flat relative to 2019. However, an increase in generation was observed, as shown in Figure 8.

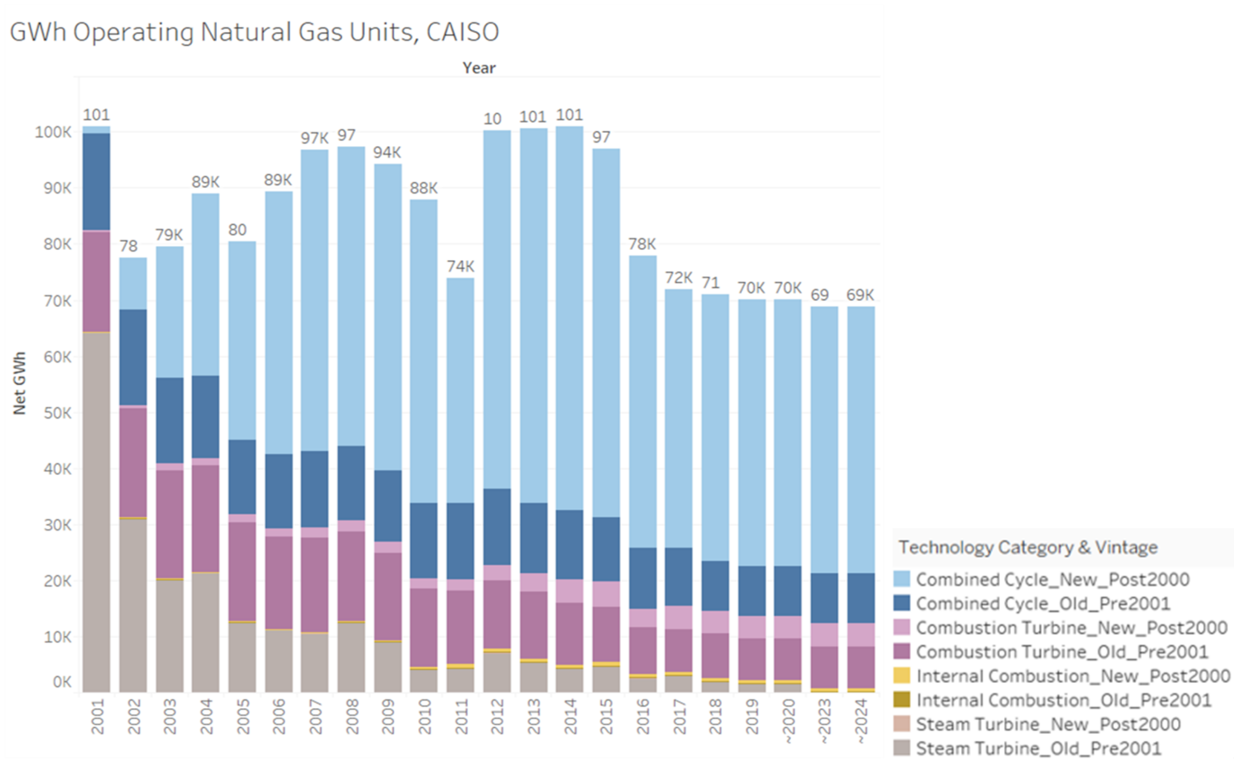

Figure 9: Previous study of natural gas electricity generation by plant type. Figure from source[57].

Natural Gas Fleet Data 2001-Present

The California Energy Commission (CEC) energy almanac provides yearly capacity, fuel use, and electricity output for each natural gas generator in California. This data was cross-referenced with other publicly available data sources including the CEC Power Plant List[58] to determine the type of natural gas generation at each generator within the facility. All figures and narrative that follows are based on these publicly available data sources from the CEC.

Figure 10 shows the number of generators in the database, Figure 11 shows the fleet generation capacity categorized by generator size, and Figure 12 shows the fleet generation

[57]Molly Sterkel, CPUC, Personal Communication
[58]https://www.energy.ca.gov/programs-and-topics/topics/power-plants/alphabetical-power-plant-listing

capacity by generation technology. While there are many more generators in California with small capacities, facilities larger than 200 MW provide over 75% of the state's generation capacity.

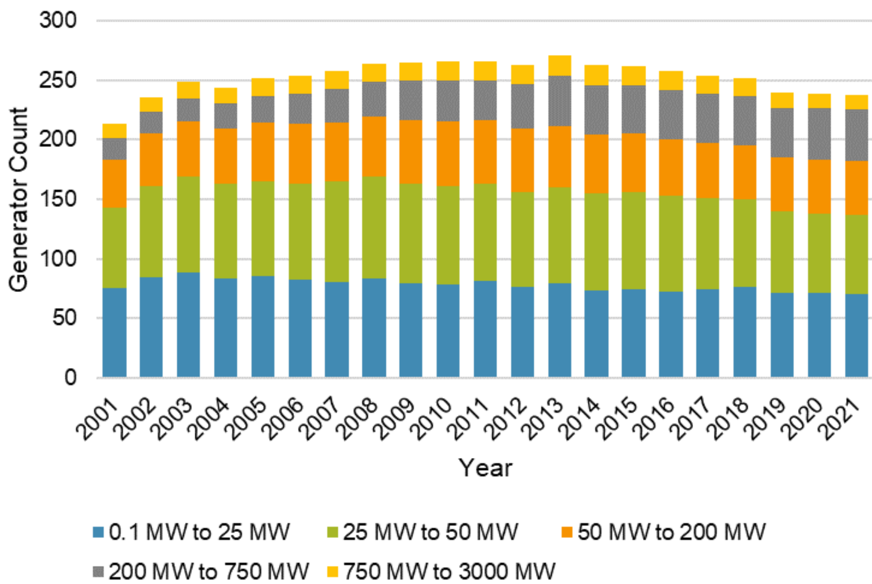

Figure 10: California natural gas fleet generator count by generator size.

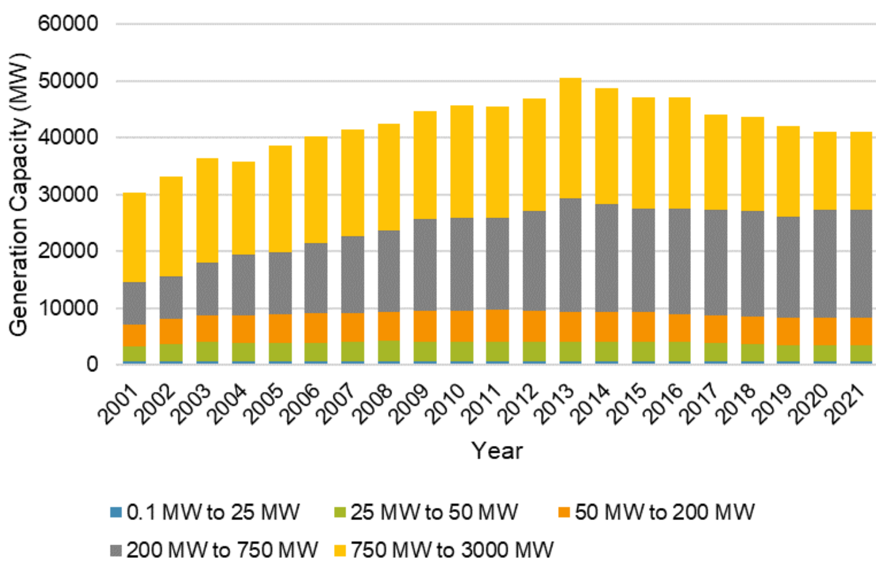

Figure 11: California natural gas fleet generation capacity count by generator size.

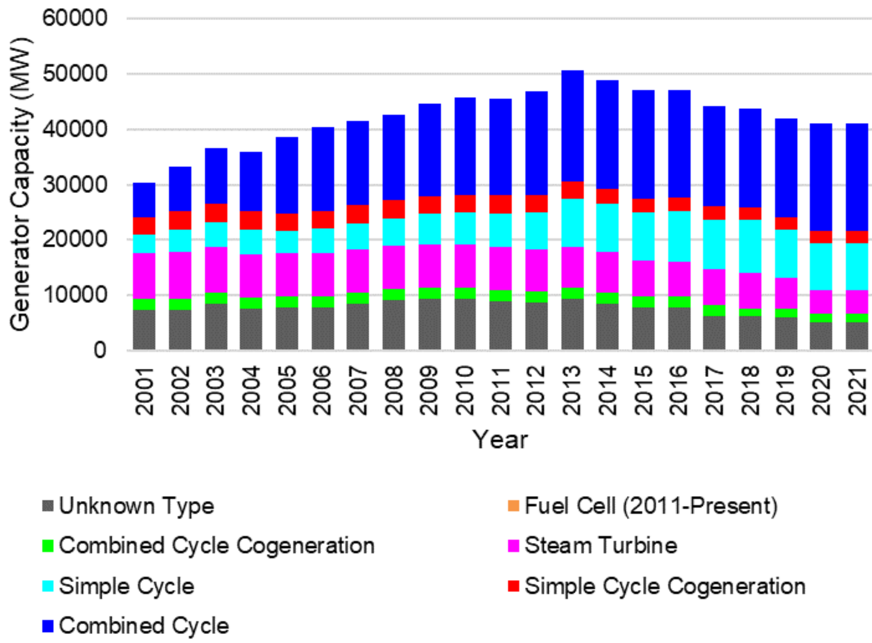

Figure 12: California natural gas fleet generation capacity count by generation technology.

xThe number of each type of generation technology has evolved since 2001, significantly affecting the makeup of generation capacity in the fleet, as shown in Figure 13. Several trends can be observed. The number of combined cycle facilities has steadily increased, and, due to their size, now make up approximately 47% of the state's current capacity. While there has been a sharper increase in the number of simple cycle facilities, their smaller typical size means that their contribution to overall system capacity is less than combined cycle facilities. The generally small, less efficient simple cycle cogeneration facilities have seen a reduction in number and corresponding decrease from 10% of the statewide capacity to 5%. Finally, while few steam turbine facilities have been closed, the facilities that have been closed meaningfully reduced the contribution of the steam fleet to the systemwide capacity.

Electricity generated by California's natural gas fleet by technology type is shown in Figure 14. Most prominently, the large combined cycle facilities are 69% of total generation, despite being only 47% of the total generating capacity. Differences between the MWh of electricity generated shown in Figure 14 and the MW of capacity of each generator type shown in Figure 12 are due to differences in facility capacity factor and utilization. For example, combined cycle facilities operate a greater percentage of hours per day on average than simple cycle facilities.

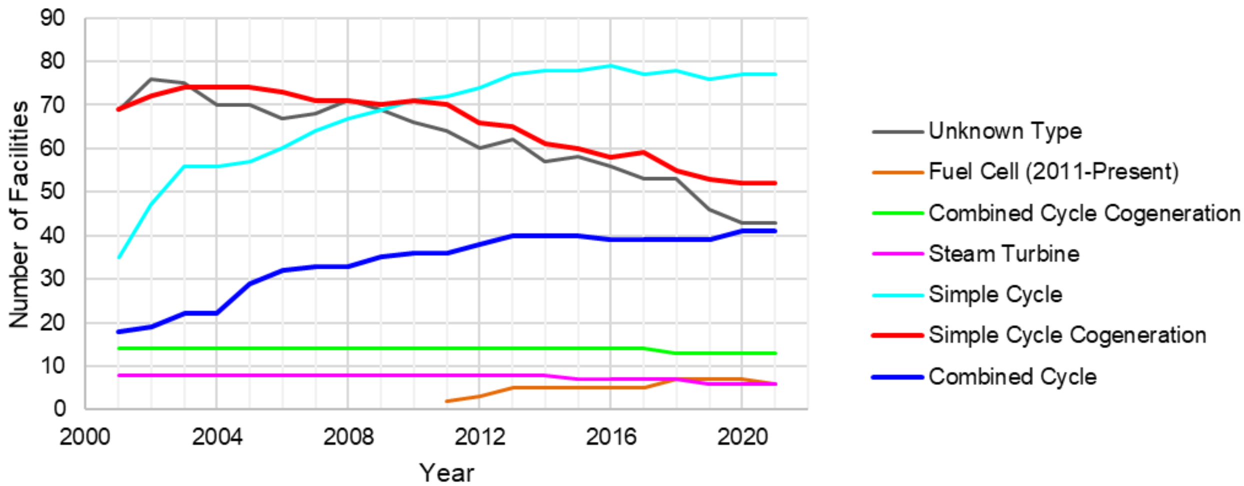

Figure 13:Natural gas generator unit count by generation technology.

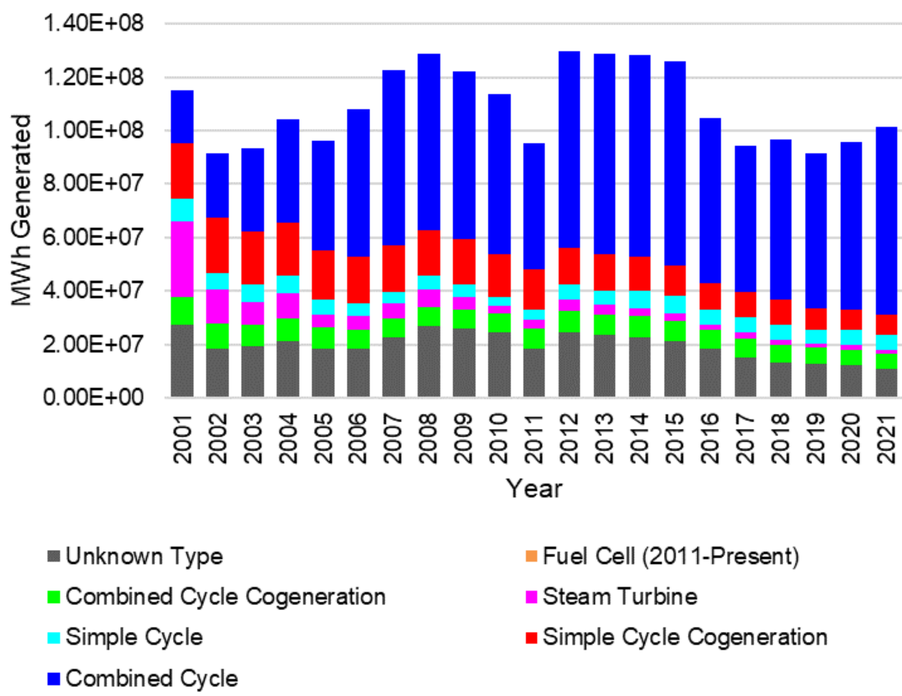

Figure 14: Natural gas electricity generation by technology.

As described above, each of the natural gas electricity generation technologies have different characteristic heat rates. Over time, the average heat rate for natural gas facilities in California has changed as new facilities have entered the fleet, old facilities have been retrofitted, and aging units retired. Figure 15 shows the capacity-averaged heat rate for

California generators by generation technology, and Figure 16 shows the relative change in those heat rates over time.

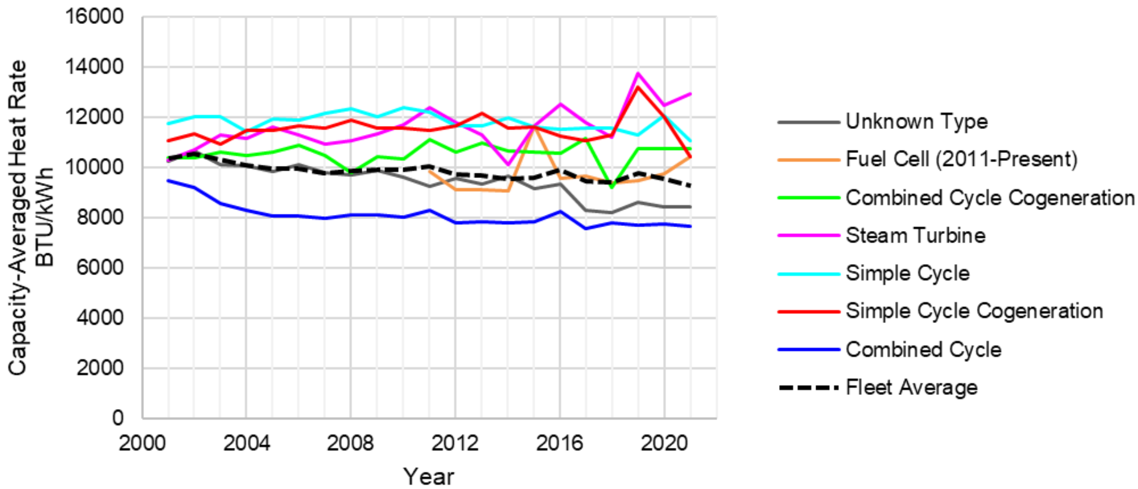

Figure 15: Capacity-averaged heat rate by generator type.

While simple cycle cogeneration, simple cycle, and combined cycle cogeneration facilities have had minor variations in heat rate, steam turbine facilities and combined facilities have seen significant changes in character. The steam turbine facilities have seen an increase in heat rate (i.e. a decrease in efficiency) over time, while the number of facilities has been largely unchanged. One possible explanation is that steam turbines are typically older facilities that are expensive to maintain, and as dates for plant retirement come closer, less maintenance is expended on the facilities. Conversely, as more large combined cycle facilities have been commissioned, the average efficiency of all combined cycle facilities has decreased significantly. When combined with the large statewide generating capacity represented by these combined cycle facilities, the approximately 20% reduction in heat rate has a significant impact on the statewide fleet efficiency and corresponding emissions. Natural gas fleet emissions are shown in Figure 17.

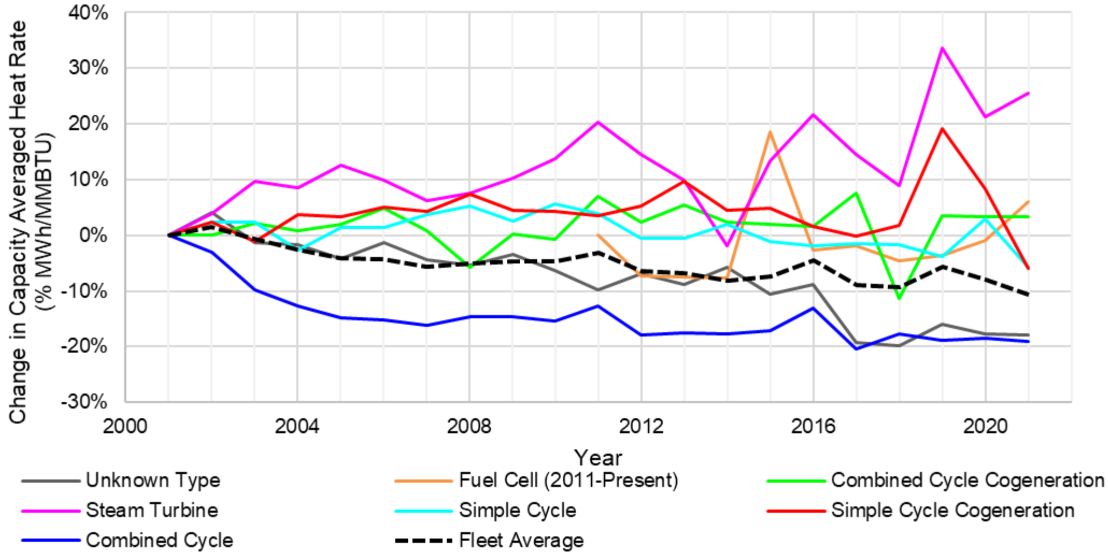

Figure 16: Change in capacity averaged heat rate relative to 2001 by generation technology.

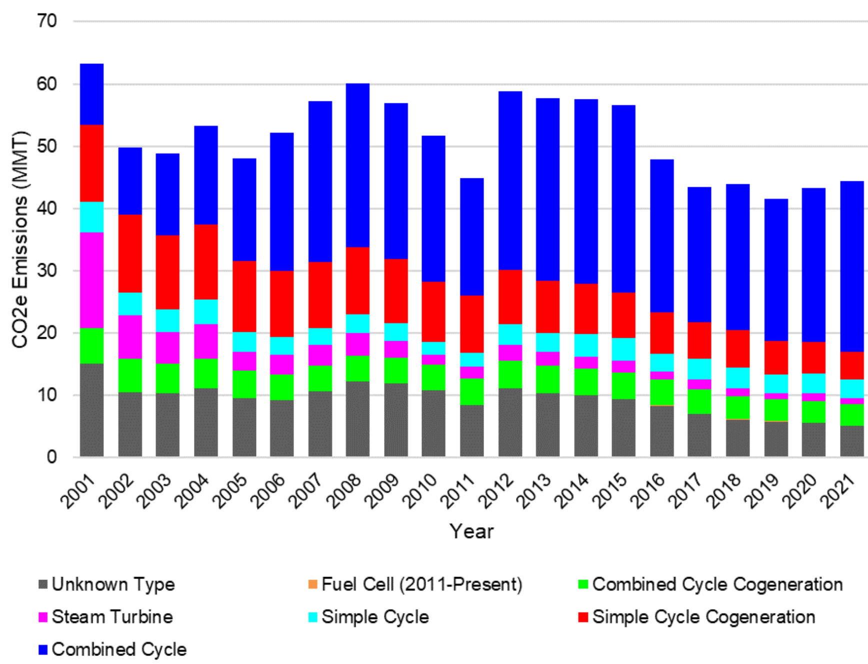

Figure 17: CO2e Emissions by generation technology. Emissions are computed assuming 52.91 kg of CO2e per million BTU (MMBTU) consumed by the facility.

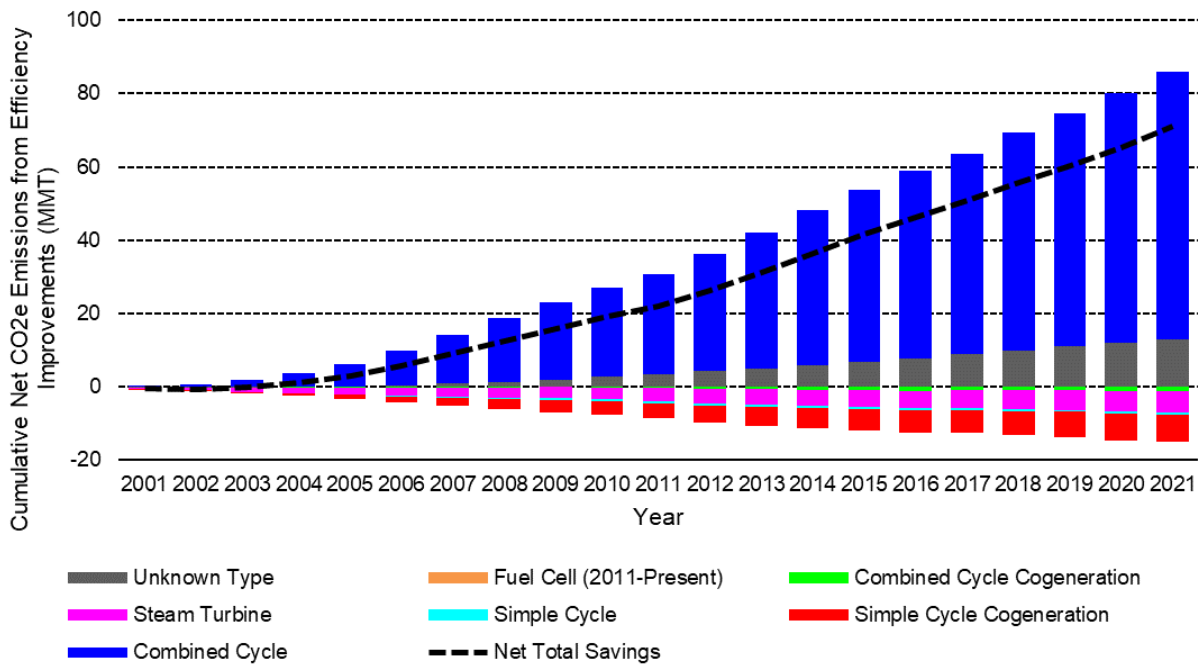

Figure 18: Cumulative emissions impacts from fleet efficiency changes by natural gas generation type.

The improved efficiencies of the natural gas systems have reduced the CO2e emissions from electricity generation. Figure 18 shows the cumulative impact on emissions from the change in generation efficiency using 2001 as a baseline assuming the capacity-averaged heat rate for each of the generation technologies remains at 2001 levels. While some of the generation technologies have decreased in efficiency and are emitting more than the 2001 baseline, the large generation from the combined cycle facilities and their significant improvements in efficiency more than offset the impacts of the dirtier plants. The net cumulative emissions reduction is approximately 71 MMT, or 1.6 times the current annual fleet emissions of 44 MMT. Current net annual emissions reductions due to improvements in heat rate are approximately 5.7 MMT/year over the 2001 baseline. The percent annual emissions reduction attributable to improvements in heat rate relative to the 2001 baseline are shown in Figure 19.

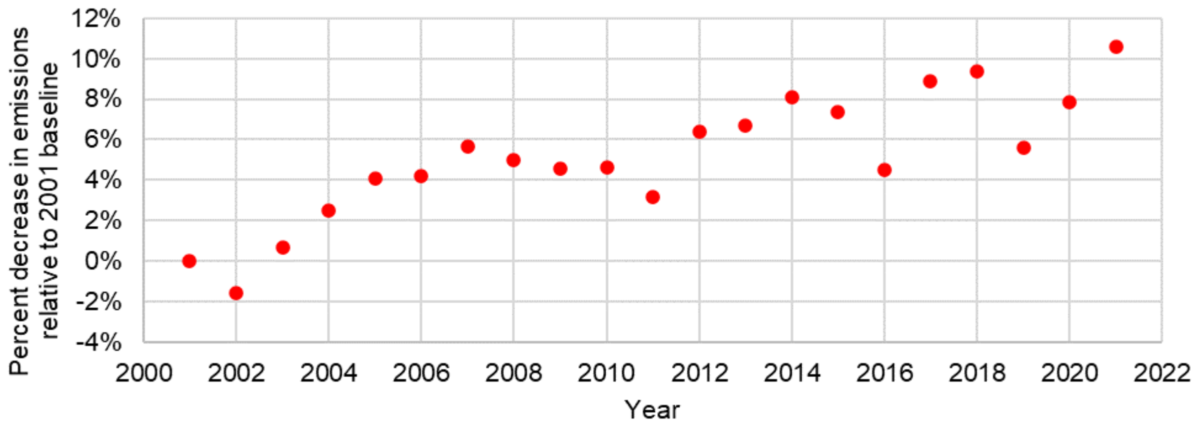

Figure 19: Percent decrease in annual emissions from natural gas generation in California relative to 2001 baseline.

As the fleet of generators in California has become more efficient, more large combined cycle facilities with high capacity factors have started operations, and the percentage of electricity from intermittent renewables has increased, there has been an increase in the number of natural gas facilities with low, peaker-like capacity factors (defined as below 15%). From 2001 to approximately 2014, there was a decrease in the number of facilities with low capacity factors, likely due to the closure of inefficient and under-utilized systems. However, since 2015, there has been a steady increase in the number of natural gas facilities with low capacity factor, and may be a result of the natural gas fleet adapting to the dispatchability requirements of a renewable energy-heavy grid. The trend in the number of low-capacity-factor natural gas generators is shown in Figure 20.

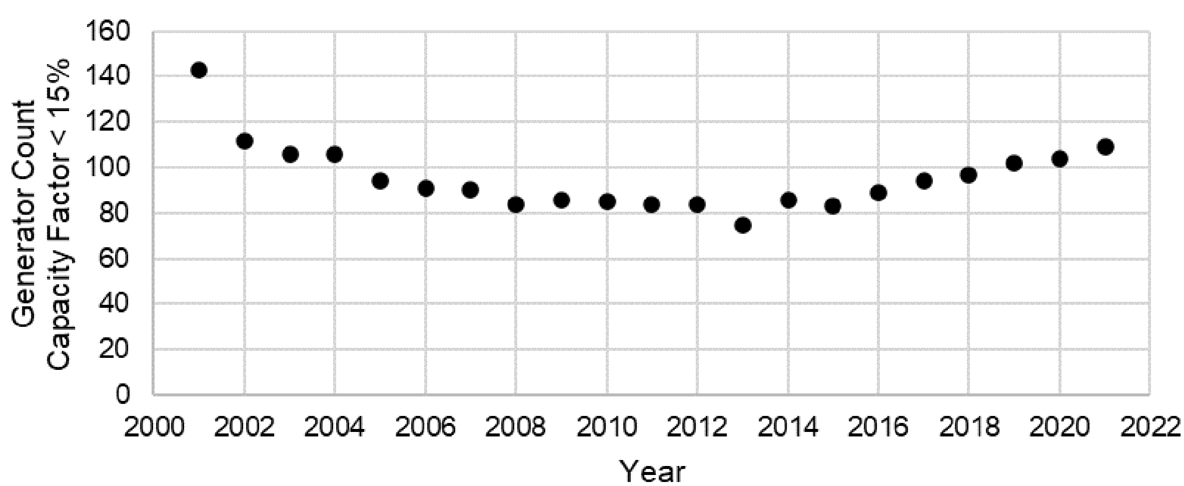

Figure 20:Count of natural gas generation facilities with less than 15% capacity factor.

Natural Gas Plant Replacement Opportunities

SCCT's fast ramp rates for peak loads are valuable as the duck curve grows. Battery energy storage is one technology that could match SCCT's ramp speeds and overall dispatchability while reducing carbon emissions. Battery energy storage may be installed standalone, paired with renewable resources like solar, or added to a natural gas plant.

Lithium Ion (LI) batteries are the most common form of energy storage used currently, but not the only one. Alternatives include flow cells – which like Lithium Ion batteries store chemical potential energy – dams which store kinetic potential energy - and chilled water tanks which store thermal potential. Current lithium ion batteries are considered a technological substitute for peaker plants and several studies document how a handful of SCCT peaker plants could be replaced today with lithium ion batteries and have a positive net present value[59]. However, not all plant replacements are cost effective. Batteries are typically sources from outside of the United States and still have high manufacturing costs. Most Lithium mining is done in developing countries which poses additional sustainability and environmental justice concerns. While the United states have been making efforts to have stateside manufacturing, utility scale LI batteries are in direct competition with EV battery manufacturing which has been taking a forefront. If batteries are allowed to be built and satisfied local capacity requirements at 4 hour durations, 87% of peaker plants could be retired by 2030 while maintaining grid reliability[60].

Case Study: Replacing Once-Through Cooling Steam Turbines with BESS

Following its retirement, former OTC plant Moss Landing was replaced over the course of 2020-2021 by a 400 MW capacity, 4-hour duration lithium ion battery storage facility[61]. Locating new storage projects at pre-existing generation sites can be an attractive option because of the opportunity to reuse transmission infrastructure and property. Battery storage at Moss Landing was developed by PG&E under a competitive solicitation process. While PG&E does not own the facility, it has a long term RA contract with it. Battery storage at Moss Landing helps PG&E meet the RA procurement targets required to come online by 2023 by the CPUC.

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[59] Private and External Costs and Benefits of Replacing High-Emitting Peaker Plants with Batteries Jason Porzio, Derek Wolfson, Maximilian Auffhammer, and Corinne D. Scown Environmental Science & Technology 2023 57 (12), 4992-5002 DOI: 10.1021/acs.est.2c09319

[60]https://www.ucsusa.org/sites/default/files/attach/2018/07/Turning-Down-Natural-Gas-California-fact-sheet.pdf

[61]https://www.nsenergybusiness.com/projects/moss-landing/#

As of 2022, the Moss Landing battery energy storage system (BESS) was considered the largest in the world[62].

While the specific site details are still being developed, this project shows the effectiveness of using retired plants points of interconnection for battery energy storage.

Case Study: Stanton Energy Reliability Center (SERC) - SCCT with BESS Ramp

SERC includes two natural gas fired simple cycle combustion turbines with a total capacity of 98 MW. In 2019 these systems were upgraded to include 10 MW of battery storage. The inclusion of battery in a hybrid model allows immediate energy production to the grid without having to wait for ramp up. In addition, these batteries are sequenced in such a way to avoid gas turbine spinning during times of low load[63]. As load profiles continue to shift due to renewable energy penetration, these batteries will enable the site to remain profitable and more sustainable.

This was not the first site to use batteries for improved dispatchability. For example, after Aliso Canyon was found to be leaking large amounts of methane into the surrounding area, the CPUC ordered SCE to quickly procure more storage options[64]. In response they created a hybrid utility scale battery-gas turbine system, called “Current” which opened in 2017[65].

Case Study: Grayson Power Plant Repower

The City of Glendale’s POU, under the authorization of the local government, is repowering its Grayson Power Plant. The plant was originally built in the ‘40s, then expanded in the ‘70s. The city plans to demolish the outdated generating units, replacing them with a combination of storage and newer turbines for 93 total MW of capacity and 75 MG battery storage. This is expected to cost 260 million dollars, and it is a smaller version of a plan rejected several years ago which proposed almost 3 times the capacity[66] [67].

This plan received intense criticism from environmental groups and many locals concerned about air quality – especially since California is phasing out natural gas generation. Glendale says that they still need natural gas to meet demand, and the newer plants will

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[62]https://www.energy-storage.news/worlds-biggest-battery-storage-system-comes-back-online-after-months-of-shutdown/
[63]https://www.ge.com/news/press-releases/ge-renewable-energy-stanton-energy-reliability-center-implement-hybrid-electric-gas
[64]https://www.greentechmedia.com/articles/read/as-aliso-canyon-gas-shortage-looms-southern-california-looks-to-energy-stor
[65]https://www.greentechmedia.com/articles/read/ges-current-builds-worlds-first-utility-battery-gas-turbine-hybrid
[66]https://angeles.sierraclub.org/news/blog/2022/01/glendales_misguided_gas_power_plan
[67]http://graysonrepowering.com/#2022-approved-project

improve efficiency. Glendale cited few local sources of generation and transmission constraints as rationale for repowering with batteries, rather than closing the plant entirely. Glendale's options The new capacity is expected to come online in 2026. This demonstrates the logic some utilities see in modernizing or adding to the natural gas fleet, as well as the pushback doing so receives[68 69 70].

Long Duration Energy Storage (non LI Batteries)

As renewable energy begins to comprise a greater share of the electricity load, lithium ion battery storage will no longer be sufficient with its shorter effective duration and will require longer duration energy storage of greater than eight hours. A vanadium redox flow battery (VRFB) pilot installed in SDG&E's service area in 2017 had previously been the largest long-term battery project in California, participating in CAISO wholesale electricity markets since late 2018. New plans for larger VRFB facilities of three-to-eight times greater capacities are planned by an energy supplier (Central Coast Community Energy) with an expected completion date of 2026[71 72].

Hydrogen Fuel Blending

A method for reduction in greenhouse gas emissions is the blending of hydrogen into the natural gas fuel. As hydrogen (H_2) does not have carbon molecules, combustion does not lead to any CO_2 emissions. While some existing turbines can already operate with different ranges of hydrogen blending there are several additional modifications which may need to occur in the fuel delivery system, the control sequencing and the SCR[73]. While the hydrogen blending would lead to CO_2 reductions during combustion, it is also important to look at the source for hydrogen production. Hydrogen does not exist on earth as a standalone molecule and thus must be processed, using an external energy source, to be produced[74]. That production could be as clean as electrolysis of water using renewable energy or as dirty as gasification of coal.

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[68]https://www.cnbc.com/2022/03/05/why-a-california-city-is-trying-to-build-the-states-last-power-plant.html
[69]https://angeles.sierraclub.org/news/blog/2022/01/glendales_misguided_gas_power_plan
[70]http://graysonrepowering.com/#2022-approved-project
[71]https://www.energy-storage.news/japan-california-funded-flow-battery-used-in-tests-to-help-achieve-zero-emissions-microgrids/
[72]https://www.energy-storage.news/226mwh-of-vanadium-flow-batteries-on-the-way-for-california-community-energy-group-ccce/
[73]https://www.icf.com/insights/energy/retrofitting-gas-turbines-hydrogen-blending
[74]https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf

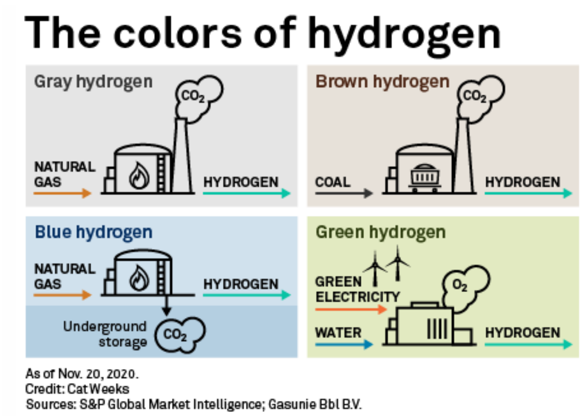

Figure 21: Commonly-used hydrogen production technology classifications[75].

Several studies are now underway within California and the rest of the United States to understand how Hydrogen can be utilized to reduce carbon dioxide emissions. Most of California's tests have been focused on injection and deliverance into pipelines for residential use and in 2022 the CPUC found that blends greater than 5% hydrogen posed risks to pipelines.[76] Within generation, pipeline deliverance of H2 does not have to raise as large of a concern as the injection could occur within the turbine, which would require speciality turbines. GE currently produces turbines which can generate electricity on blends of Hydrogen up to 100%.

Case Study: Brentwood Power Plant - NYPA

GE's LM6000 turbine, which can support hydrogen blends of 5%-44%, recently underwent a study in NYPA at the Brentwood Power Plant where green hydrogen was injected at varying ranges between 5%-40% and impacts to power and CO2 emissions were investigated. The results, at 47MW and 35% hydrogen fuel blends, there was a 14% reduction in CO2[77]. This shows that even with a lot of hydrogen penetration, unless a site is 100% green hydrogen the CO2 reductions are not as amble as other possible replacements. There were increases in NOx emissions however, but they stayed below regulatory compliance levels.

NYPA commented that no other hydrogen blending studies were planned for other power plants in the state. Instead, the agency is "prioritizing the exploration of battery storage at its peaker plants."[78]

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[75]https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/green-group-warns-that-deluge-of-hydrogen-hype-could-skew-policymaking-66368041
[76]Hydrogen Blending Impacts Study, University of CA Irvine
[77]https://www.nypa.gov/news/press-releases/2022/20220923-greenhydrogen
[78]https://www.naturalgasintel.com/new-york-hydrogen-natural-gas-blending-study-offers-mixed-results-to-cut-emissions/

Case Study: Scattergood Generating Station- LADWP

Publicly owned utility LADWP serves electricity for Los Angeles. LADWP doesn't participate in CAISO markets and is not regulated by the CPUC. As a result, LADWP faces different constraints and opportunities in decarbonizing its electricity than neighboring regions. In particular, the stakes for the LADWP are different when it decides to retire, repower, or maintain its gas plants.

The LADWP has remained reliant on coal long after the rest of California transitioned away from coal. They anticipate natural gas playing a role in their energy mix for years to come – including building new gas plants out of state[79] . In acknowledgement of LADWP's specific challenges, the State Water Board has granted LADWP OTC plants compliance date extensions as late as 2029, six years after the remaining CAISO territory OTC gas plants are expected to comply[80].

Most of LADWP's in-basin natural gas generators use OTC technology. Three facilities continue to use OTC and are affected by the phase out process. A fourth plant, Valley Generating Station, was originally built in the '50s but underwent significant modernization in the early 2000s. These days Valley Generating Station serves as a peaker, primarily operating during the late afternoon and evening as net load ramps up.

In February 2023, LADWP voted unanimously to meet OTC compliance by replacing the city's largest gas-fired power plant, Scattergood Generating Station, with a hydrogen-capable plant[81]. The 830MW are currently conventional steam turbine generators and the goal would be to convert the entire plant to have 30% green hydrogen fuel injection with the overall goal of transitioning to 100% green hydrogen by 2035[82] [83] [84]. As competitive bidding was only just initiated, the site is still several years out from expected completion but is scheduled to come online by 2029.

Scattergood is not LADWP's only bet on green hydrogen. LA's main source of coal generation is the Intermountain power plant in Utah, which they also plan to demolish and replace with a hydrogen capable gas plant that is scheduled to be operational by 2025. Like

[79]https://www.latimes.com/business/la-fi-garcetti-dwp-gas-plants-
[80]http://calenergycommission.blogspot.com/2018/
[81]https://www.power-eng.com/hydrogen/l-a-autho
[82]https://www.power-eng.com/hydrogen/l-a-authorizes-conversion-of-largest-gas-plant-to-green-hydrogen/#gref
[83]https://www.power-eng.com/hydrogen/l-a-autho
[84]https://clkrep.lacity.org/onlinedocs/2023/23-0039_rpt_DWP_02-03-2023.pdf

Scattergood, the new Intermountain plant would initially use gas but transition fully to green hydrogen over time[85].

Point Source Carbon Capture Utilization and Storage

With the goal of reducing carbon dioxide being emitted into the atmosphere while simultaneously continuing to provide grid reliability, a possible addition to any type of natural gas generation would be Carbon Capture, Utilization and Storage (CCUS). While carbon capture technologies appropriate for natural gas systems have been technically feasible for decades, they have not been proven at scale[86]. Most CCUS's focus on particular solvents to separate the CO2 from other gasses within the flue stacks after combustion. There would then be pipelines that would transport the captured CO2 to locations for storage. Oil companies who have also injected CO2 into their wells to boost their crude production. While there are several emerging technologies which appear scalable, additional research and development is required[87]. In addition, the costs to implement CCUS would require significant financial incentives and would most likely need to be installed on baseload plants in order to be cost effective. Studies have estimated that adding CCUS to a natural gas plant would increase capital costs by 30-70%[88]. As the base load plants continue to shift with the adoption of renewable energy, the large capital investments would be a risk.

Case Study: Bellingham Natural Gas Combined Cycle with Carbon Capture

The Bellingham natural gas combined power plant, a 320 MW facility in Massachusetts, used CCUS from 1901-2005 and captured 85%-95% of CO2 from one of their 40 MW turbines which would have otherwise been emitted. This site proved economically advantageous as the plant sold the CO2 to the food and beverage industry. The site shut down in 2005 when tax credits for the site expired and the plant was no longer profitable.

How the captured carbon is being used is an important factor. Similar to cogeneration generators who have must-purchase contracts, if there is an end process which depends on the captured carbon the dispatchability of the site loses an aspect of control. The site would be forced to operate based on the process needs instead of the grid's needs.

[85]https://www.ipautah.com/ipp-renewed/
[86]https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems
[87]https://www.iea.org/reports/natural-gas-fired-electricity
[88]https://www.seattletimes.com/nation-world/carbon-capture-technology-works-but-cost-is-still-prohibitive/

Natural Gas Transition Limitations and Case Studies

Resource adequacy and reliability considerations have been common policy rationales for keeping open, repowering, and building new plants. This section discusses key concepts affecting the composition of California's natural gas fleet going forward.

CPUC RA Overview

For the hours that they are available, renewable resources like solar have almost zero marginal cost and can bid into CAISO markets at low prices, pushing out higher marginal cost resources like aging peaker natural gas plants. California's resource adequacy (RA) program is a centrally operated capacity market that tries to create an incentive for existing capacity to stay operational when low prices in other energy markets would make it uneconomical for them to do so. By keeping additional capacity open under RA contracts, California tries to protect against capacity shortfalls during periods when demand is extra high[89].

Since 2004, the CPUC has run the resource adequacy (RA) program for its market participants – California's IOUs, ESPs, CCAs, as well as wholesale power generators. Each load serving entity (LSE) needs to meet three standards for resource adequacy: system, local, and flexible. While system and local are older resource adequacy definitions defined by historical peak demand and forecasting under extreme weather conditions, flexible RA is a newer definition that focuses on ramp rates, or how quickly demand increases during the run-up to the daily peak load. Flexible RA was added in 2015, as concerns about the net load's duck curve pattern and steep afternoon load ramps grew.

Stakeholders are currently trying to figure out how to integrate energy storage and renewable energy into a resource adequacy framework. Traditionally, resource adequacy only considered dispatchable resources – like natural gas based generation – eligible.

Integrating Non-Dispatchable Renewables: Slice-of-Day RA

Resource adequacy is evolving, as regulators and LSEs try to adapt to new reliability challenges and more renewables on the grid. In April 2023, the CPUC released a proposal for reforming their resource adequacy standards going forward. Starting in 2024, they will use a slice-of-day approach rather than a peak approach, based on a proposal by PG&E. Under slice-of-day, LSEs face specific RA procurements requirements for each hour of the day, based on the forecasted "worst" (highest demand) day of the month.

These procurement requirements are technology-neutral, with a few caveats. Demand response resources are eligible, but must be sold for multiple consecutive hours.

[89]https://ceepr.mit.edu/wp-content/uploads/2021/09/2018-008-Brief.pdf

Non-dispatchable renewables like wind and solar can be used to meet RA during the hours of the day when their supply is near guaranteed. The amount of capacity these resources can sell under RA contracts depends on either historical or – for new resources – modeled data on past production. However, wind and solar subject to economic curtailment provisions is ineligible. This means that resources who have already agreed to automatically curtail their electricity supply during periods when CAISO prices drop below certain benchmarks[90].

LSEs can also use battery storage can also be used to meet RA procurement requirements, but each charge used must be accompanied by sufficient excess capacity during other periods to charge the battery unit. In the words of the CPUC, “LSEs must bring enough extra capacity to serve their own batteries.”[91]

New RA Procurement Requirements and Policy Implications

Throughout 2018-9, the CPUC started identifying potential reliability and RA issues due to the expected decline in natural gas capacity in 2021 and beyond. Heat waves and blackouts during 2020 stoked even more alarm. On the evening of August 14 and 15 2020, CAISO recognized stage three emergencies and ordered rolling blackouts as a preemptive measure against system collapse. The potential supply shortfall was exacerbated by a summer heat wave, a major generator’s outage, and significantly less wind power than expected[92] [93].

These concerns resulted in several decisions which affected LSE procurement and the state of California’s natural gas fleet.

First, resource adequacy shortfalls were a rationale for extending several aging plants’ compliance deadlines for phasing out once-through-cooling (OTC). These plants are old, inefficient, and dependent on cooling technology that is harmful to sensitive coastal environments. They can no longer be run profitably and are used less than ten percent of the time. However, for that fraction of the time when they are used, the grid really needs their capacity. Although most OTC plants had already closed by 2019, several remained open.

At the same time as OTC plants were being kept open past their expiration dates, the CPUC mandated 3,300 MW of new resource adequacy capacity to come online between 2021-2023. Additional resource adequacy procurements can make closing remaining OTC and aging units feasible without triggering reliability concerns. Under R.16-02-007, each LSE was assigned a share of the new capacity proportional to their share of peak load. The capacity requirements are not resource-type specific, although new fossil fuel resources are ineligible.

[90]https://www.caiso.com/documents/curtailmentfastfacts.pdf
[91]https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M505/K753/505753716.PDF
[92]http://www.caiso.com/Documents/ISO-Stage-3-
[93]http://www.caiso.com/Documents/ISORequestedPo

This means that storage, hybrid technologies, demand response, or even updated but pre-existing natural gas plants can be used by LSEs to meet their obligations. However, R.16-02-007's RA obligations can not be used to justify the development of a brand new natural gas plant[94].

RMR Overview

CAISO has two main mechanisms that act as additional safety buffers after each LSE demonstrates resource adequacy, called the capacity procurement mechanism (CPM) and reliability must-run contract (RMR). These mechanisms are designed as final steps to ensure that California's energy system always has enough power to meet demand – plus a small but necessary margin in reserve.

When a generator is designated must-run, then the ISO requires them to stay on-line for the contracted hours, so they can always be called up. This can be justified for interconnection stability, local, or system level stability. The specific stability justification chosen is stated in CAISO RMR decisions. The reason it chooses determines the specific contract type. Like LSE's RA contracts, RMRs are for a certain number of hours per year. The exact number of hours varies by contract, but tends to be higher for locally justified contracts. RMR contracts have been around as long as CAISO has.

In practice, a RMR contract is how the system's least economical, independently owned plants stay open, and plants typically enter into RMR contracts only after they threaten or try to shut down. CAISO requires all power plants to let them know in advance when they plan to close. As part of the disclosure, plants need to attest that this does not conflict with any current or future resource adequacy contracts. CAISO then gets to evaluate the impacts of the plant closing, and may at that time decide to deny the closure request and designate it RMR. In a given year, RMR contracts with plants may be extended if CAISO still thinks they are necessary. RMR contracts may not be extended, if the local or system needs motivating the RMR has changed. Finally, RMR contracts may end because the plant enters into an RA contract, without any change in the local or system needs identified.

RMR contracts did not always function this way and their applications have expanded over time. In 2019, CAISO appealed to FERC for approval to broaden its authority when entering into RMR contracts. CAISO justified the request by the additional challenges of managing the grid as variable renewable penetration increases, specifically citing the need for fast ramp times system wide. Both the CPUC and companies like PG&E were concerned that broadening RMR authority could result in its overuse and distort RA market prices. Critics also

[94] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

raised concerns that plant owners would use the threat of closure to price shop for profitable contracts. FERC eventually approved CAISO's request, although Democratic chairman Richard Glick publicly dissented. In Glick's dissent, he warned that expanding the RMR contract could lead stakeholders to overlook investment in new resource types, favoring pre-existing resources like natural gas instead[95].

During 2020-21, CAISO used its expanded RMR powers several times to justify extending the operations of old plants otherwise slated to close – even when those doing so conflicted with state environmental standards[96].

Case Study: Midway Sunset Cogen

Midway Sunset Cogeneration opened in 1989 as a 225 MW, three unit cogeneration plant[97]. Originally, Midway Sunset's host and parent company – an oil refiner operating in the heart of Kern County's oil fields – needed steam from all three units. Midway Sunset Cogeneration Company's original application to the CEC in 1987 states that "the primary purpose of the proposed facility is the generation of steam for use in thermally enhanced oil operations"[98]. The electricity that the plant would produce was just a bonus.

Over the next two decades, Midway Sunset continued to operate as a cogenerator, supplying heat to its host and selling electricity into CAISO markets. Midway Sunset participated in market manipulation during the California energy crisis and FERC required it to pay 85.7 million dollars in energy crisis related settlements in 2008[99]. By the 2010s, demand for Midway Sunset's steam had declined significantly. As a result, the CEC approved multiple updates between 2010-2016 that allowed the plan to continue operating while producing less waste heat for its host[100].

In 2014, the CEC approved a technology update to two of the units, altering their combustion systems and allowing them to generate electricity without producing steam and while staying under NOx emission limits. This update decoupled steam demand from the Midway Sunset's ability to generate electricity. Only one unit continued to function as a cogenerator for its host; the other two units now functioned as simple cycles whose primary role was to produce and sell electricity[101].

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[95] http://www.caiso.com/Documents/Sep27-2019-OrderAcceptingTariffAmendment-RMR-CPMEnhancements-ER19-1641.pdf
[96] http://www.caiso.com/InitiativeDocuments/StrawProposal-ClarificationstoReliabilityMustRunDesignationProcess.pdf
[97] https://www.energy.ca.gov/powerplant/simple-cycle/midway-sunset-cogeneration-project
[98] https://bael.hathitrust.org/cgi/pt?id=uc1.31822040988156&view=1up&seq=16
[99] https://www.latimes.com/archives/la-xpm-2008-apr-03-fi-ferc3-story.html
[100] https://www.energy.ca.gov/powerplant/simple-cycle/midway-sunset-cogeneration-project
[101] https://www.energy.ca.gov/powerplant/simple-cycle/midway-sunset-cogeneration-project

Eventually, Midway Sunset's host did not need any steam at all. Owner Aera Energy began the process of mothballing (retiring) the plant, informing CAISO of its plans to close in 2020. Using their new flexibility in RMR designations and wary of supply shortfalls ahead of summer 2021, CAISO denied the request. This decision was based on system, rather than local, reliability needs – an RMR option only available post-2019 – and was not in coordination with the CEC or CPUC[102].

As it proposed an RMR designation for Midway Sunset, CAISO also used a new set of assumptions to estimate potential capacity shortfalls in its planning reserve margin (PRM). Planners focused on periods with peak net load, rather than peak absolute load. They also planned for more extreme forecasts than normal, requiring a PRM 33 percent larger than normal (20 percent PRM versus 15 percent PRM). CAISO's Board of Governors adopted Midway Sunset's RMR contract based on shortfalls meeting the higher PRM standard[103]. This demonstrates how the duck curve and extreme weather combine to justify keeping more dispatchable resources online as backup options.

Midway Sunset's RMR designation was extended for 2022 and expanded to include all three units. However, the plant's third unit had never been updated to produce electricity without steam. If it did not operate as a cogenerator, it would exceed allowable NOx emission levels. While plans to update the third unit were in place and approved by the CEC in 2021, the updates would not be ready in time for the 2022 summer peak. In September 2021, CAISO appealed to FERC for permission to supersede local air quality standards when asking several plants to run at full capacity when necessary, including Midway Sunset's third unit and several other facilities designated RMR. CAISO asked FERC to approve this under section 202(c) of the Federal Power Act, which allows the federal government to require generation and transmission during emergency periods[104][105].

As of 2023, Midway Sunset's three units remain designated as RMR based on system reliability concerns[106].

[102]http://www.caiso.com/Documents/DecisiononReliabilityMust-RunDesignations-Presentation-Dec2020.pdf

[103]http://www.caiso.com/Documents/DecisiononReliabilityMust-RunDesignations-Memo-Dec2020.pdf

[104]http://www.caiso.com/Documents/Sep7-2021-Request-Department-Energy-EmergencyOrder-Section202c-FederalPowerAct.pdf

[105]https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority

[106]http://www.caiso.com/Documents/DecisiononConditionalApprovaltoExtendReliabilityMust-RunContracts-Presentation-Aug2022.pdf

Case Study: La Paloma Generating Company

For owners of inefficient and rarely used plants without longer term contracts with LSEs, RMR may be an attractive option or opportunity to price test. Both the CPUC and then FERC Commissioner Glick raised these concerns during FERC's consideration of expanding CAISO's RMR authority in 2019. moving forward

The La Paloma plant offers one example of how independent plant owners may consider RMR. La Paloma first became operational in 2003, with a projected lifetime of about 40 years. It is a combined cycle plant located just outside the LA basin with access to a natural gas pipeline. Initially, the 1000 MW capacity La Paloma was one of California's most productive natural gas plants[107]. However, La Paloma was not developed by a utility company and did not have a long term contract with one. This made it more vulnerable to fluctuations in wholesale power prices as renewable resources increased.

In 2016, La Paloma told CAISO that, unable to operate profitably, it needed an RMR contract to stay open. However, CAISO did not bite, choosing to rely on a newly developed natural gas plant within the LA basin and owned by IOU SCE. Their reasoning? CAISO said that increasing reliance on renewables makes it more important that any non-renewable power is local. La Paloma was just a little too far away[108] [109].

Frustrated by their inability to gain an RMR contract, La Paloma brought a complaint against CAISO to FERC in mid-2016. In their complaint, La Paloma told FERC that they needed a reliability must-run contract or some other protection in order to keep running. FERC dismissed the complaint without requiring an RMR contract, and La Paloma declared bankruptcy in December 2016[110]. However, as of 2023, La Paloma remained operational under new ownership[111].

Moving forward, stakeholders will need to balance the usefulness of the newer, more flexible RMR definition with skepticism about both future reliability needs and independently owned plants motives.

[107] https://www.naes.com/locations/la-paloma-power-facility/?download=1
[108] https://www.proquest.com/docview/1799904710?accountid=14496
[109] https://www.latimes.com/business/la-fi-la-paloma-capacity-20170609-story.html
[110] https://www.reuters.com/article/us-la-paloma-bankruptcy/california-gas-power-plant-la-paloma-files-for-bankruptcy-idUSKBN13V2PY
[111] https://www.energy.ca.gov/powerplant/combined-cycle/la-paloma-generating-plant

Once-Through-Cooling

Once-through-cooling (OTC) hurts coastal ecosystems in two main ways: first, the plant draws in large amounts of water from a nearby body of water. This disturbs the natural water balance and flow. Small organisms living in that water get drawn up too, and are killed in the process. These effects, called impingement and entrainment, combine to kill organisms at all stages of the life cycle. Second, after the plant uses the water to cool down its system, it flushes the now hot water back out into the original body of water, further damaging the balance of the marine ecosystem and killing off native species like eelgrass. The magnitude of thermal effects from re-releasing water after use varies widely between plants, and the primary concern around OTC is its impacts on marine organisms. The most vulnerable organisms are also the smallest – like phytoplankton – which means that in practice estimating the full extent of OTC impacts on coastal environments often is not feasible.[112]

Prior to 1980, regulators did not grasp how sensitive marine ecosystems were. OTC was seen as a cost effective but relatively harmless technology. Over the last several decades, increasing awareness of OTC's local environmental impacts has led to its decline, and it is no longer the cooling technology of choice among newly built plants.[113] By 2005, as state and federal concern over OTC grew, California had 21 OTC power plants which collectively used almost 17 billion gallons of water per day. The majority of these plants were natural gas – although two nuclear plants including Diablo Canyon were notable exceptions. These plants were disproportionately old and clustered along Southern California's coast, including several owned by the LADWP. As a function of their pre-energy crisis construction dates, the majority were owned by wholesale energy companies rather than LSEs.

California State Water Resources Board's official phase out of existing OTC plants started in 2010. In 2014, the EPA enacted a similar policy at the national level under the Clean Water Act. Because EPA policy was not more stringent than established California policy, those regulations did not have an effect on OTC's phase out within the state[114].

Plants could choose to comply either by reducing flow rate to meet standards of a closed-cycle system (Track 1), or by achieving comparable reductions in impingement and entrainment using some other technology (Track 2). Faced with these options, about half of the plants instead chose to shut down before their compliance data. Most of the rest chose Track 1,

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[112] http://large.stanford.edu/courses/2018/ph241/macfarlane1/docs/cec-700-2005-013.pdf

[113] http://www.opc.ca.gov/webmaster/ftp/project_pages/OTC/engineering%20study/Chapter_4_Closed_Cycle_Cooling.pdf

[114] https://www.waterboards.ca.gov/publications_forms/publications/factsheets/docs/oncethroughcooling_20200818.pdf

planning to replace old units with new ones. Only one plant (Moss Landing) chose Track 2 for any of its units.

Plants chose to shut down because they did not want to invest in the necessary technology updates. The fact that the majority of plants shut down is indicative of how old most of these pants were already – 50 years on average in 2010. However, plants that chose to shut down had to do so prior to their compliance deadline, which means that many remained operational without new investments or updates for several years post 2010. For example, 64 year old Encina Power Station retired on December 11, 2018 – just two weeks before its deadline to comply with OTC regulations[115].

OTC Extensions

A 2008 report for the State Water Resources Control Board in preparation for OTC's phase out modeled that all of California's OTC units could close by 2015 without jeopardizing reliability, writing that "under all but the most extreme scenarios, more than enough power plants are expected to be operating in 2015 to more than compensate for any or all OTC plant retirements."[116] A decade later, expectations had changed. Large blackouts during August 2020, due in part to insufficient supply, motivated the CPUC to recommend to the State Water Board that surviving OTC plants have their compliance deadlines extended[117].

Environmental groups like the Sierra Club spoke out against extending. In 2020, the State Water Board extended deadlines for four natural-gas generating stations, pushing compliance dates to December 31, 2023 for three stations and December 31, 2021 for the fourth. Even these deadlines may be hard to meet: just two months before the Redondo Beach Station's 2021 deadline, the State Water Board again extended its deadline through 2023[118] [119].

Case Study: Redondo Beach

Redondo Beach Generating Station provides an example of how older or less efficient plants may be kept online if local options to replace them are considered inadequate. It also demonstrates the relevance of continued maintenance and upgrades, even for plants we expect to close over the next few years.

What would become Redondo Beach Generating Station began as an oil-based electric plant in 1907. After growing hydropower supply supplanted regular need for the plant, it was

[115]https://www.kpbs.org/news/environment/2021/04/05/after-nearly-50-years-carlsbads-iconic-landmark-co
[116]https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/reliability_study.pdf
[117]https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF
[118]https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc-fact-sheet.pdf
[119]https://www.latimes.com/environment/story/2020-09-01/california-gas-plants-stay-open-time-runs-low-fo r-climate-action

abandoned in 1933. About 15 years later, IOU SCE rebuilt a new plant on the site. SCE's plant was expanded several times throughout the '40s-'60s. In the late '90s, SCE sold the station to AES as part of California's restructuring process. SCE and the city agreed to reduce the plant's impact by shrinking it from then 8 units. Although three units were closed, the plant never shrunk by as much as the town had hoped[120].

As of 2013, AES planned to repower the plant in response to OTC requirements, then keep the new plant open. Many residents were very opposed to this due to local air pollution and property value impacts, and by 2019 AES instead planned to close the plant, selling the property to a local developer[121] [122].

Between then and 2020, Redondo Beach Generating Station stoked the ire of local and state regulators multiple times – and not just due to once-through-cooling. Between 2015-2020, the Redondo Beach Generating Station got in trouble repeatedly for water pumps they had installed near the facility. These pumps facilitate plant operations, but the violations were due to new investments and distinct from OTC phase out.

At the center of the dispute was AES's installation and use of dewatering pumps as part of plant operations without getting full permission from local governments and the Coastal Commission. Under California law, being considered a wetland matters because it means that the area has greater protections and state agencies have jurisdiction. Prior to the original construction of Redonodo, these lands were wetlands. Over the ensuing century of electrical generation, a lot of the land was developed and disturbed by human activity. AES says that the land is not wetland, so they can pump without violating the Coastal Act. The Coastal Commission argued that about 6 acres of wetlands remained on the site, which the dewatering pumps put at risk. These disputes were ongoing as of 2020, at the same time as the State Water Board considered granting the station an extension at the urging of the CPUC[123] [124].

Residents of Redondo Beach – many of whom had long hoped to replace the dirty but rarely used plant with new development or open space – anticipated that it would close by the end of 2020. However, reliability concerns throughout summer 2020 became a rationale to keep the station online past its original compliance deadline.

In the wake of the blackouts and anticipating similar conditions in summer 2021, state regulators debated whether to extend compliance deadlines for remaining OTC plants. One

[120]http://blogs.dailybreeze.com/history/2011/10/05/
[121]http://blogs.dailybreeze.com/history/2011/10/05/
[122]https://patch.com/california/redondobeach/complete-coverage-aes-redondo-beach-power-plant-and-measure-a
[123]https://s3.documentcloud.org/documents/7072558/Notice-of-violation.pdf
[124]https://www.latimes.com/environment/story/2020-03-30/re

argument for slowing down retirements was to avoid turning voters and ratepayers off from the transition to renewable energy because they blame it for reliability issues and blackouts. Even though Redondo was inefficient and had low utilization going into 2021, any extension was valuable to AES because the plant had been paid off years earlier and there was no incentive to invest during the extension period. AES estimated that an extension through 2023 would be worth up to 100 million dollars.

Three plants within CAISO territory – including others owned by AES – were granted extensions through 2023. However, the State Water Board only extended compliance for Redondo Beach Generating Station through 2021, primarily due to local opposition. According to the LA Times, local residents were driven primarily by concerns about local air pollution from the old plant. '"I have lived four-tenths of a mile from this belching, smelling, loud plant. And I go to the doctor every six weeks, and my lung capacity is going down," Melanie Cohen told the water board. "I'm begging you to listen to the people of Redondo."'[125]

A year later, three of the OTC plants granted extension experienced outages during summer 2021 – the same summer they were kept online to guarantee reliability for. Redondo Beach Generating Station was one of the plants to go out, right in the midst of a heat wave in mid June[126]. However, the State Water Board again voted to extend Redondo Beach Generating Station's compliance deadline to the end of 2023 that fall[127]. As of September 2022, the plant has continued to struggle. It is under pressure to perform at greater capacity than it may be able to during high demand heat waves. During a 2022 heat wave, part of the plant again broke down. "All of these power plants are kept in the short term," owner-developer Pustilnikov told local paper Easy Reader News. "You're fixing as little as possible. No need to replace [an engine] when the plant may not be working in '24 or '25."[128]

[125]https://www.latimes.com/environment/story/2020-03-30/redondo-beach-coastal-power-plant-closing-2023
[126]https://www.politico.com/states/california/story/2021
[127]https://www.dailybreeze.com/2021/10/19/controversial-redondo-power-plant-operations-extended-through-2023/
[128]https://easyreadernews.com/heat-wave-leaves-questions-about-redondo-power-plant/

Conclusions

In 2018, California's senate passed SB100, requiring that California reach 100% carbon free electricity in sales to end use customers by 2045. While the need for clean energy is apparent from an environmental perspective, stakeholders are still debating the path to eliminate California's energy generation carbon footprint by 2045 while keeping service safe, affordable, and reliable.[129] Natural gas has historically been vital in providing generation with fast ramp rates, high dispatchability, and reliable power quality while additionally providing excess heat for industrial processes. Technology improvements within natural gas generators have allowed for incremental improvements in efficiency and greenhouse gas emission reductions, but prioritizing continued efficiency upgrades is challenging when faced with potential termination of plant operation on or before 2045.

Capacity markets and RA requirements have offered economic pricing mechanisms for valuing plant dispatchability. This energy market has resulted in many generation owners looking beyond efficiency upgrades to incorporate new technologies such as battery energy storage. While other natural gas replacements like hydrogen and long duration energy storage offer additional possibilities, it is important to continue to consider the economic markets and policy landscape which help steer technological replacements. It will take a combination of natural gas efficiency improvements, renewable energy, and newer dispatchable technologies like hydrogen, long-duration energy storage, battery energy storage, and potentially a host of new solutions not yet dreamed of to make a complete clean energy transition.

[129]https://www.energy.ca.gov/sb100

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Appendix A - Definitions

Net Load: the amount of electricity demanded minus the amount that can be met with wind and solar

Capacity Factor: the unitless ratio of actual electrical energy output over a given period of time to the theoretical maximum electrical energy output over that period.

Heat Rate: a quantity that reflects the amount of fuel required to generate one unit of electrical energy.

Thermal Efficiency: the amount of energy into the system divided by the amount of useful work out of the system.

Dispatchability: a broad definition of a plant's overall reliability and energy availability. Includes items such as Ramp Rate and Full Power from Cold Start. Renewable energy sources such as Solar PV and Wind are considered “intermittent” due to their variability and thus have very low dispatchability.

Ramp Rate: How quickly the resource can provide varying amounts of energy

Cold Start: How quickly the resource can turn on to producing full load.

Appendix B - Key Stakeholders

California Energy Commission (CEC)

Originally created in response to the '70s energy crisis, the CEC is responsible for big picture energy policy planning in California, including forecasts and investments in new energy technologies. Unlike the CPUC, the CEC has very limited regulatory authority over investor-owned utilities (IOUs).

All California power plants with capacity over 1 MW must report to the CEC. In practice this means small-scale generation like rooftop solar is excluded from CEC mandatory reporting, but larger projects like natural gas plants are included.

Part of the CEC's role is supporting technology and planning to increase efficiency and reduce environmental impacts of energy generation, including generation from natural gas. "Every year, the Commission invests about 20 million dollars in research and development for natural gas generation, funded by a ratepay surcharge on gas consumption."[130] [131]

California Public Utilities Commission (CPUC)

The CPUC was first created in 1911 to regulate railroads, but its focus gradually shifted to other utilities. Today most of its regulatory work deals with privately owned electricity providers, including setting the rates and resource adequacy requirements of California's major investor-owned utility companies. As a state economic regulator, the CPUC has jurisdiction over retail power transactions, but not wholesale power transactions[132].

Federal Energy Regulatory Commission (FERC)

FERC regulates wholesale rates and energy transactions. As part of this role, it oversees and regulates the California Independent System Operator[133].

California Independent System Operator (CAISO)

CAISO manages transmission and wholesale energy markets for about 80% of California's electricity demand. It was created as a balancing authority during California's electricity restructuring and became a fully operational independent system operator in 2008[134].

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[130]https://www.energy.ca.gov/programs-and-topics/programs/natural-gas-program
[131]https://www.energy.ca.gov/sites/default/files/2019-06/Fact_Sheet_California_Energy_Governing_Institutions.pdf
[132]https://www.cpuc.ca.gov/industries-and-topics/natural-gas/greenhouse-gas-cap-and-trade-program
[133]https://www.ferc.gov/industries-data/electric/electric-power-markets/caiso
[134]https://www.ferc.gov/industries-data/electric/electric-power-markets/caiso

Within the Western Energy Imbalance Market (WEIM), CAISO can trade with other balancing authorities within the Western Interconnection[135].

Local Air and Water Quality Districts

Electricity generation using natural gas releases both local and global pollution. In addition, the operation of plants' cooling systems can interfere with nearby bodies of water. As a result, agencies like CARB and local air and water quality districts also enact policies impacting natural gas generation technology and use. These policies may conflict – or coincide – with policies set by the CPUC and CEC to guarantee reliable and adequate power.

Jurisdictional issues in flux

Ambitious emissions targets and reliability concerns are putting the authority of the CEC and CPUC relative to that of other state agencies in flux. For example, 2021's proposed SB -122 would have expanded the CEC and State Water Board's authority to build new capacity, including natural gas. Early versions of the bill, which passed the state senate but was dead as of 2022, would have granted the CEC authority to permit generation, circumventing the approval of other state and local agencies[136] [137].

Who Services California's Electricity? Background on the Industry Structure

In California, customers may be served by investor owned utilities (IOUs), publicly owned utilities (POUs), community choice aggregators (CCAs), or other electric service providers.

Publicly Owned Utilities (POUs)

As public entities, POUs are exempt from CPUC rate setting regulation. Many continue to own the natural gas generation capacity they rely on to meet demand, and some see reinvestment in their gas generating capacity as necessary despite statewide mandates to phase out natural gas generation over the next several decades.

Electric service providers (ESPs)

Electric service providers are non-utility electricity providers within IOUs' service territories. They exist due to California's electricity restructuring, which permitted retail electricity competition. However, most are small, and privately owned non-utility electric service providers supply only a small portion of electricity in California.

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[135]http://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf
[136]https://calmatters.org/environment/2022/06/california-power-plant-deal/
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Community Choice Aggregators (CCAs)

CCAs are local government entities that procure electricity and set rates. Located within IOU suffice territories, they rely on IOU transmission and distribution infrastructure to deliver electricity.

Investor Owned Utilities (IOUs)

California has six registered investor owned utilities that service electricity. Of these, three companies dominate: San Diego Gas & Electric (SDG&E), Pacific Gas and Electric Company (PG&E), and Southern California Edison (SCE). Two of California's main IOUs are both gas and electric providers, while Southern California Edison (SCE) only provides electricity to its consumers. IOUs vary in the share of energy mix they source from natural gas as well as the amount of generation they own. Prior to restructuring, these utilities owned much of California's natural gas fleet. As part of restructuring, they were required to sell off the majority of their natural gas plants, and today must procure a lot of their natural gas generated electricity from other entities.

IOU: Pacific Gas and Electric Company (PG&E)

As of 2021, PG&E's base electricity plan was about 8.9% natural gas generation, and their generation overall was about 8% natural gas generation. They took relatively little from large hydropower (4%), but a large share (39%) from nuclear power[138] [139].

As of 2022, PG&E owns and operates three natural gas power plants for 1400 MW of capacity: Colusa, Gateway, and Humboldt Bay Generating stations. Colusa and Gateway are both combined cycle plants. All three plants use either dry cooling or air cooling rather than once-through-cooling, which reduces water usage and local water pollution[140].

IOU: Southern California Edison (SCE)

In 2021, SCE's base electricity plan was 22.3% natural gas. Relative to California's energy mix overall, open market transactions – which are not traced to a specific energy source – made up a much larger portion of their mix (34.6% for their base rate). A significant portion of their generating capacity comes from large hydropower stations like Big Creek station, which makes up 20% of their capacity. During droughts, this means they need to rely more on open market transactions and other fuel types like natural gas to meet demand[141].

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[138]https://www.pge.com/pge_global/common/pdfs/customer-service/other-services/alternative-energy-providers/community-choice-aggregation/SCP_ElectricPowerGenerationMix.pdf
[139]https://www.energy.ca.gov/filebrowser/download/4653
[140]https://www.pge-corp.com/corp_responsibility/reports/2022/pf06_conventional_energy.html
[141]https://www.sce.com/about-us/environment/renewable-power

IOU: San Diego Gas and Electric (SDG&E)

In 2021, their power mix was 29.6% natural gas generation and 23.9% unspecified power sourced from open market transactions[142].

[142] https://www.sdge.com/sites/default/files/documents/FINAL_S2210024_Power_Content_Label.pdf

Appendix C - Additional Case Studies

Inland Empire - From CCCT to BESS

As a final case study, Inland Empire demonstrates that plant efficiency profitability is both technology and context specific. A rapidly changing grid means plants optimized for yesterday's conditions might be ill suited to tomorrow.

In 2006, California was worried about its electricity supply. A 2006 article by The Inland Valley Daily Bulletin warned that "the state… is once again on the verge of a first-stage power emergency."[143] GE hoped its new plant, Inland Empire Energy Center, could be part of the solution.

As project development began in 2006, GE bragged in a press release that the new Energy Center's turbines were "the most efficient and advanced machines of its type in the world." Inland Empire Energy Center, developed by Calpine and initially owned by GE, was an approximately 800 MW combined-cycle plant and designed as the first plant to use GE's then new 7H gas turbine technology. At the time of construction, GE anticipated that ownership would eventually transition to Calpine[144].

Inland Empire began operating between 2008-2010 and was designed to last several decades. However, within a few years of its opening, the role of natural gas plants within California's grid had changed significantly – and so, by extension, had GE's opportunities to profit. Optimized to play a baseload role on the grid but at the expense of ramp time, Inland Empire found itself competing with cheaper sources of energy as a peaker plant with a capacity factor around 5-6%. This transition impacted independently owned plants like Inland Empire more strongly because of the incentives to retain capacity embedded in IOU revenue requirement formulas.

In 2019, GE announced its plans to close and decommission Inland Empire because it was not profitable. At the same time, Calpine and Nova Energy declared their intentions to purchase the site and replace the plant with a battery storage system. The plant was demolished in 2021[145] [146].

[143] https://www.dailybulletin.com/2006/07/20/power-supply-on-verge-of-crisis/
[144] https://www.ge.com/news/press-releases/ges-first-7h-gas-turbine-heading-inland-empire-project-califor nia
[145] https://www.power-technology.com/projects/inland/
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