California Energy Commission

STAFF PAPER

Performance and Outlook for California's Combined Heat and Power Fleet

Jason Harville and Bryan Neff
Data Integration and Policy Office
Energy Assessments Division

June 2021 | CEC-200-2021-004

ACKNOWLEDGEMENTS

Staff would like to thank Rachel MacDonald and other Energy Assessments Division staff at the California Energy Commission for their help and support in conducting the analyses in this report and writing the final paper. Staff would also like to thank staff members at the California Public Utilities Commission (CPUC) for their assistance in providing the Qualifying Facilities and Combined Heat and Power Settlement data collected by the CPUC, and staff at Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric for helping validate and update that data.

ABSTRACT

Around 2010, California established multiple Combined Heat and Power (CHP) goals and programs with the collective goal of increasing CHP use in the state. Since that time, broader state energy policy has increasingly emphasized clean energy, while CHP policy has remained static. Staff analyzed historic fleet capacity and generation from Quarterly Fuel and Energy Report data and constructed plausible scenarios of how CHP facilities may operate without export contracts using data from Qualifying Facility and Combined Heat and Power Settlement reporting. Historical analysis shows the fleet is experiencing long term declines in both capacity and annual generation, with nearly 6 percent decline in nameplate capacity and 23 percent decline in annual electrical generation from 2010 to 2016. If facilities cannot reliably obtain export contracts, future scenarios indicate that the CHP fleet could experience steep declines in capacity and generation in the early 2020s of roughly one-half to three-quarters from 2016 levels. The Second Program Period of the Qualifying Facility and Combined Heat and Power Settlement expired at the end of 2020 without clarity on what happens next. Forecasting and planning assumptions based on nameplate capacity and state targets do not capture operational changes or consider contracting constraints and likely overestimate contributions from the fleet. Staff recommends adopting forecasting and planning assumptions based on real world data and plausible facility behavior and revisiting current CHP policies in light of Senate Bill 100 and broader state energy policy.

Keywords: Combined heat and power, cogeneration, qualifying facilities, distributed generation, electricity planning, settlement program

Please use the following citation for this report:

Harville, Jason, Bryan Neff. 2021. *Performance and Outlook for California's Combined Heat and Power Fleet.* California Energy Commission. Publication Number: CEC-200-2021-004.

TABLE OF CONTENTS

Acknowledgements i

Abstract ii

Table of Contents iii

List of Figures iv

Executive Summary 1

- Background 1
- Analysis 1
  - Historical Fleet Performance 2
  - Future Scenarios 2
- Conclusions and Recommendations 3

CHAPTER 1: Introduction 5

CHAPTER 2: Market and Policy Environment 8

- Departing Load, Standby, and Demand Charges 8
- AB 1613: The Waste Heat and Carbon Emissions Reduction Act 9
- Self-Generation Incentive Program 9
- The Qualifying Facilities and Combined Heat and Power Settlement 10

CHAPTER 3: Historical Fleet Performance 15

- New and Expanded Capacity 15
- Annual Generation and Nameplate Capacity 16

CHAPTER 4: Data and Methods 19

- Data 19
- Methods 20
- Nameplate Capacity and Effective Capacity 22

CHAPTER 5: Future Scenarios 23

- Capacity 23
- Generation 25
- Discussion 26

CHAPTER 6: Conclusions and Recommendations 28

Glossary 30

Acronyms and Abbreviations 32

LIST OF FIGURES

Page

Figure 1: Capacity Losses and Additions From New and Expanded Facilities........................16
Figure 2: Historical Capacity and Generation Relative to 2010..17
Figure 3: Net Generation, by Facility...18
Figure 4: Historical and Projected CHP Capacity 24
Figure 5: Historical and Projected CHP Generation...25

EXECUTIVE SUMMARY

Background

Combined heat and power (CHP), also known as cogeneration, is the simultaneous generation of electrical or mechanical power and useful thermal energy from a fuel source. The efficient, reliable, and distributed nature of CHP generation creates potential benefits for facility owners and ratepayers. To capture these benefits, California established ambitious CHP procurement targets and maintains policies and incentives designed to retain and promote the development of efficient CHP plants.

These policies and incentives have not resulted in significant development of new CHP capacity. The Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007) feed-in tariff, designed to provide contracts for small-scale, highly efficient CHP, has seven active participants totaling less than 50 megawatts (MW) of capacity. The Self-Generation Incentive Program, a grant program for various distribution-scale energy resources, is consistently moving away from fossil-fueled generation and focuses primarily on energy storage and renewable generation. In recent years, lawmakers have considered several pieces of legislation that would provide economic incentives by modifying, or exempting facilities from, certain charges and fees that CHP plants pay for public purpose programs, standby service, or consuming onsite generation. However, none has become law.

Effective in late 2011, the Qualifying Facilities and Combined Heat and Power Settlement (QF Settlement) ended years of litigation among several private and public parties and established the only regulatory CHP procurement and greenhouse gas (GHG) emission reduction targets in the state. The primary purpose of the QF Settlement was to preserve existing efficient CHP, while allowing the retirement of inefficient facilities, to create a smooth transition to a state-administered CHP program. However, the QF Settlement also led to new conflicts, with parties disagreeing on what types of contracts should count toward the targets of the QF Settlement, whether targets should persist after 2020, and whether to adjust target levels.

While the QF Settlement targets remain important in the legal context of the agreement, and obtaining contracts remains important to participating facilities, changes to accounting methods and targets have made QF Settlement accounting unreliable in any other context. Progress toward QF Settlement targets cannot be directly compared with other measures of changes in capacity or emissions in the statewide CHP fleet. To date, the investor-owned utilities (IOUs) appear to have largely or completely met their respective targets under the QF Settlement. In particular, the QF Settlement has made good progress on the objective to optimize the existing fleet by reducing output from inefficient facilities. However, the Second Program Period of the QF Settlement is expiring without clarity on what happens next, leading to questions about what CHP policy looks like post 2020, how facilities will behave in that environment, and how forecasters and planners should model CHP.

Analysis

Staff created a combined data set from several sources: confidential QF Settlement reporting data, CPUC-provided lists of 2010 existing facilities under the QF Settlement, IOU's July 2010 cogeneration reports, CPUC advice letters, consultations with CHP stakeholders, and the California Energy Commission's (CEC) Quarterly Fuel and Energy Report (QFER) database.

Using this data set, staff analyzed historical changes to California's CHP fleet and predicted changes to the fleet under future scenarios.

Historical Fleet Performance

California's CHP fleet has gained little new capacity from new or expanded facilities in recent years and is experiencing long-term downward trends in total nameplate capacity and electrical generation.

From 2010 through 2016, new and expanded facilities contributed just 217 MW of additional nameplate capacity to California's CHP fleet. Further, nearly half of these additions came from capacity expansions at just two plants. There were no additions in 2016 and less than 5 MW worth in 2012 and 2014.

During this time, total fleet capacity declined nearly 6 percent (489 MW), and generation declined nearly 23 percent (roughly 10,040 gigawatt-hours [GWh]). As generation has declined at a faster rate than capacity, the average capacity factor has dropped 18.0 percent (10.9 percentage points).

Given how little new capacity has been added since 2010, the decline in capacity factor is being driven primarily by changes in operations at existing facilities. In other words, existing facilities are generating less energy. However, most state CHP targets are measured in capacity, which has experienced less decline than generation. Therefore, the overall decrease in CHP generation is less apparent. Moreover, a small number of large and relatively consistent facilities constitute a large proportion of the capacity and generation of the fleet. The relative stability of these few facilities obfuscates the fact that the rest of the fleet is experiencing sharper declines than the fleetwide totals suggest. This combination of factors (emphasis on measuring nameplate capacity and the dominance of large facilities) is effectively masking substantial changes in operation and large declines in output from small and midsized CHP plants.

Future Scenarios

This report estimates future capacity and generation from California's CHP fleet under five scenarios: four staff cases and an analysis of the CPUC's 2016 Long Term Procurement Plan (LTPP, see glossary for definition) CHP retirement assumptions. Under each staff-generated case, facilities operate at baseline (2016) levels until they reach the end of current operations, such as the end of a contract or equipment reaching the end of useful life. Cases 1 through 4 make increasingly flexible assumptions about the ability of facilities to continue operating without a new power purchase agreement and the subsequent impact on generation and capacity. Case 1, the most conservative, assumes all plants in need of a contract to operate will shut down when existing contracts expire. Case 4, the least conservative, assumes that all facilities will scale down to continue meeting onsite load indefinitely when existing contracts expire. For comparison, the LTPP Retirements scenario simulates facility behavior using the retirement assumptions used in the LTPP but does not include the LTPP assumptions for new CHP procurement. For more detail on scenario assumptions, see Chapter 5: Future Scenarios.

In all staff-generated cases, this analysis indicates that the CHP fleet would experience large reductions in capacity and generation from 2016 through 2032, with an especially steep decline from 2018 through 2022. In the least conservative case (Case 4), the fleet would decline 4,081 MW (52.4 percent) and 15,836 GWh (46.7 percent) in capacity and annual generation from 2016 levels by 2023, and 4,508 MW (57.8 percent) and 17,610 GWh (51.9 percent) by 2032. In the most conservative case (Case 1), the fleet would decline 4,997 MW (64.1 percent) and 21,035 GWh (62.0 percent) by 2023 and 6,178 MW (79.3 percent) and 25,668 GWh (75.7 percent) by 2032.

The significant decline from 2018 through 2022 is driven primarily by the fact that nearly half the capacity of the current fleet is from facilities with contracts ending during this period. The LTPP retirement assumptions did not account for most of these contracts ending. Instead, the LTPP assumed facilities would recontract until they reach 40 years of age, leading to higher estimates of fleet capacity and generation than in staff-generated cases. The differences between LTPP-based estimates and the least conservative staff case (Case 4) average 8,374 GWh per year over the 2017-through-2032 forecasting period and are as large as 15,216 GWh in 2023. Forecasting errors of this size are significant, corresponding to a 3 percent to 5 percent shortfall relative to current statewide gross generation if they were realized.

Since this analysis, the state has transitioned from the LTPP to integrated resource planning (see glossary for definition). However, the LTPP still provides a useful example of the range of outcomes possible under different planning assumptions.

Conclusions and Recommendations

Around 2010, California established several CHP goals and programs with the collective goal of increasing CHP use in the state. Since then, state energy policy has increasingly emphasized limiting GHG emissions and adoption of renewable energy resources. However, CHP policy has not significantly changed since 2010, and many policies and targets either are still in effect or have not been explicitly retired. It is not clear that existing CHP goals align with current state energy and environmental policy, but it is clear the CHP fleet is not on track to meet them.

While the IOUs have met or made progress toward their capacity procurement and emission reduction targets under the QF Settlement, these have been met almost entirely by recontracting with existing facilities, and retirement of existing facilities (aided by changes to emissions accounting and targets), respectively. The anticipated new CHP development that would reduce emissions did not occur. While there are programs in place to support CHP development, CHP capacity and generation are in long-term downward trajectories. Decline in generation has been steeper than capacity, resulting in a significant drop in average capacity factor. Given California's climate goals for the electric sector, as well as current regulatory and market environments, staff sees little reason to expect changes that will lead to increased CHP development.

Forecasting and planning methods commonly assume that California will meet all or most of its CHP procurement targets and facilities in need of contracts will be able to acquire them. This report demonstrates that assumptions derived from historical trends and plausible plant behavior produce significantly smaller estimates of CHP fleet performance. If facilities cannot reliably obtain export contracts, analysis indicates that the CHP fleet could experience steep declines in capacity and generation in the early 2020s of roughly one-half to three-quarters from 2016 levels. Current planning and forecasting assumptions do not adequately take these possibilities or the historical trend into account, which is likely to lead to large overestimations of capacity and generation contributions from the CHP fleet over the next 12 years.

Considering these conclusions, staff recommends the following:

1. **Planners and forecasters should stop using California's CHP capacity targets as a basis for analytical and modeling assumptions.** This paper presents an alternative method based on historical trends and plausible facility behavior. Currently, this assumes a declining fleet with little-to-no new capacity additions, adjusted for assumptions specific to very large or influential facilities. In support of this methodological change, all parties should have access to recent, updated, and vetted QF Settlement semiannual reports consistent with the QF Settlement Term Sheet.
2. **Policy makers should revisit CHP policies in light of SB 100 and broader state energy policy.** Bringing California CHP policy into alignment with current state energy policy will support regulatory and market certainty. California load-serving entities currently use existing gas-fired resources to meet obligations for resource adequacy and grid reliability (see glossary for definition). At the same time California is committed to transitioning to a clean energy future. To the extent that policy makers see value in supporting CHP resources, they should amend or replace existing CHP policies and programs to ensure that new policy leverages the value of CHP in ways that are achievable and consistent with broader state energy goals.

CHAPTER 1: Introduction

Combined heat and power (CHP) technologies produce electrical generation and useful thermal energy when operating. By using thermal energy that would otherwise go to waste, CHP systems make more efficient use of fuel than if that same fuel had been used to generate power and thermal energy separately.[1]

CHP systems create potential benefits to CHP facility operators and the electric grid:[2]

- Reduced fuel use
- Reduced greenhouse gas (GHG) emissions
- Avoided electricity transmission and distribution losses
- Increased host facility reliability (which can include critical infrastructure such as hospitals, data centers, prisons, and wastewater treatment plants)
- Greater local grid stability by reducing net load and providing local generation
- Cost savings and other economic benefits for host facilities

CHP technology is not a panacea, however. Most CHP plants in California are fueled by natural gas. As increasing levels of renewably sourced electricity lead to a cleaner electric grid, it is no longer safe to assume that a natural gas-powered CHP plant will necessarily use less fuel (and therefore produce fewer GHG emissions) than if a host (typically a commercial or industrial application) had obtained grid electricity and thermal energy separately. Moreover, the operations of most CHP facilities are tightly coupled with the needs of the associated thermal host. As the host requires more or less thermal energy, the generator is adjusted accordingly. While there are some exceptions, generally, the need to adjust for thermal output makes electricity exported from a CHP facility nondispatchable and requires the plant to have a must-take power purchase agreement. The must-take nature of CHP facilities can create unwanted challenges for utilities and grid operators, especially in the context of a grid that requires increasing amounts of flexibility to accommodate variable and intermittent renewable resources.

---

1 "Separate heat and power (SHP) systems" are traditional arrangements in which a facility obtains power and thermal energy from different sources (for example, buying electricity from a utility and producing steam onsite with a boiler).

2 A "CHP facility" is an integrated system that includes both a generator and the gathering and application of thermal energy for operations at a facility. As such, most decisions a CHP operator makes occur at the facility level and extend beyond just the generating plant. Therefore, in most contexts CEC staff refers to a CHP facility rather than a CHP plant.

California has historically sought to capture the benefits of efficient CHP by encouraging development through a variety of mechanisms, including ambitious procurement targets.[3] Most of California's large CHP facilities came on-line during the two decades following the establishment of Public Utility Regulatory Policies Act (PURPA) in 1976. In response to the energy crisis in 2001, California established the Self-Generation Incentive Program (SGIP) (see glossary for definition). Historically SGIP supported CHP, among other technologies. In the decade that followed, California energy policy became more focused on renewable energy sources and greenhouse gas emissions reduction with the establishment of the Renewables Portfolio Standard (RPS) (see glossary for definition). At the same time, the state also published targeted CHP procurement goals, such as in the Scoping Plan and Clean Energy Jobs Plan (see glossary for definition). The most significant goals were established with the Qualifying Facilities and Combined Heat and Power Settlement (QF Settlement), a 2010 agreement among several parties that established regulatory targets for CHP capacity procurement and GHG emissions reductions with the stated goal of transitioning toward a sustained, market-based, state CHP procurement program for CPUC-jurisdictional utilities in 2020. [4] The QF Settlement goals were based on the state's first Climate Change Scoping Plan, which included "a target of an additional 4,000 MW of installed CHP capacity by 2020, enough to displace approximately 30,000 GWh of demand from other power generation sources."[5]

Over the decade since the QF Settlement was approved, California's broader energy policy has changed significantly. The SGIP has moved away from fossil-fueled CHP, refocusing on battery energy storage, biogas-fueled CHP, and other clean energy resources. State policy has increased support for renewable energy and zero-carbon resources with the passage of Senate Bill 350 (De León, Chapter 547) in 2015 and Senate Bill 100 (De León, Chapter 312) in 2018. California Air Resources Board's (CARB) 2013 and 2017 Scoping Plan updates no longer provide estimates of emission reductions from specific generation sources. The next update to the Climate Change Scoping Plan, due in 2022, will focus on need to reach carbon neutrality by midcentury, in part by moving away from combustion of fossil fuels, as well as the electricity-specific SB 100 goal to supply 100 percent of electricity retail sales from renewable and zero carbon resources by 2045. However, many CHP policies and targets either are still in effect or have not been explicitly retired, and it is unclear what role the state intends CHP to play in the state's transition to a clean energy future.

The CHP fleet is experiencing a long-term decline in capacity and generation. The Second Program Period of the QF Settlement expired at the end of 2020 without clarity on what happens next. Many facilities have contracts expiring in the early 2020s, which is requiring facilities to make investment and operational decisions now. If facilities cannot reliably obtain export contracts, analysis indicates that the CHP fleet could experience steep declines in capacity and energy in the early 2020s.

---

3 "Efficient" commonly refers to plants that use fuel more efficiently (and therefore produce fewer greenhouse gas emissions) than a separate heat and power configuration with the same thermal and electrical energy outputs.

4 See "CHAPTER 2: Market and Policy Environment" for more detail.

5 CARB. 2008. Climate Change Scoping Plan. Page 43, https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/document/adopted_scoping_plan.pdf.

This report builds on previous work by the California Energy Commission (CEC) by discussing the current CHP market and policy environment, examining historical trends in CHP energy and capacity with emphasis on changes since 2010, and describing how the fleet may change in the future under different scenarios for CHP facility operations. This report aims to provide forecasters, planners, and policy makers the information needed to adopt more accurate forecasting methods, plan for likely large-scale changes in the fleet, and take a fresh look at CHP policy in the context of broader state energy policy.

Because of a lack of data on useful thermal energy output, this report does not attempt to quantify the GHG emissions associated with the CHP fleet.

The remainder of this report is organized as follows:

- Chapter 2 describes aspects of the current market and regulatory environments that are most relevant to understanding past and future changes to California's CHP fleet. It also provides a detailed look at the methods for calculating progress under the QF Settlement.
- Chapter 3 analyzes historical changes in statewide CHP capacity, generation, and capacity factor, as well as the impact of large facilities on statewide trends.
- Chapter 4 describes the data and methods underlying both the historical analyses of Chapter 3 and the future projections of Chapter 5.
- Chapter 5 projects changes in capacity and generation in the CHP fleet under various scenarios describing how facilities may respond when their current contracts expire.
- Chapter 6 summarizes the findings of this report and makes recommendations for adopting forecasting and planning assumptions based on real-world data and plausible facility behavior and revisiting current CHP policies in light of SB 100 and broader state energy policy.

CHAPTER 2: Market and Policy Environment

Policies and incentives are designed to promote efficient CHP facilities in California.[6] This report does not attempt to provide a comprehensive history of such policies. Instead, this chapter highlights aspects of the current market and policy environment that are most relevant to understanding California's CHP fleet and how the fleet may change in the future. These aspects include various charges that CHP facilities incur when generating onsite electricity, CHP incentive programs, and a summary of the QF Settlement. For a more detailed description of the history of CHP policy and market factors, see the CEC staff paper *A New Generation of Combined Heat and Power: Policy Planning for 2030*.[7]

Departing Load, Standby, and Demand Charges

The ability to manage and reduce energy costs is a key benefit from operating a cogeneration facility. However, a host's decision to produce its own electricity in lieu of purchasing from a utility introduces additional charges that must be considered when comparing the cost of self-generated electricity to utility rates.

"Departing load charges" (DLCs) is an umbrella term describing several non-bypassable charges (NBCs) facilities may face when they choose to reduce or eliminate utility service and instead generate onsite electricity. NBCs are composed primarily of three volumetric electricity surcharges: public purpose programs, nuclear decommissioning, and repayment of a California Department of Water Resources bond. When applied to onsite generation, NBCs are assessed as if the electricity consumed onsite had been purchased from a utility. Utilities and ratepayer advocates generally argue that these charges are necessary, and that exempting facilities from them will impose an unfair cost shift on other ratepayers. CHP stakeholders claim that the charges inhibit development by significantly reducing cost savings and that the cost shift from exempting cogeneration would be minimal for the average ratepayer.[8] Moreover, they claim that ratepayer cost savings resulting from increased distributed generation are larger than the cost shift from DLC exemptions.

---

6 "Efficient" commonly refers to plants that use fuel more efficiently (and therefore produce fewer GHG emissions) than a separate heat and power configuration with the same thermal and electrical energy outputs.

7 Neff, Bryan. 2012. *A New Generation of Combined Heat and Power: Policy Planning for 2030*. 2012. California Energy Commission. CEC-200-2012-005. http://web.archive.org/web/20190224112432/https://www.energy.ca.gov/2012publications/CEC-200-2012-005/CEC-200-2012-005.pdf.

8 Darrow, Ken and Anne Hampson. ICF International, Inc. May 2013. The Effect of Departing Load Charges on the Costs and Benefits of Combined Heat and Power. http://chpassociation.org/wp-content/uploads/2013/06/Impact-of-DLCs-on-CHP-Economics-Final-Report-Clean-Copy-R4.pdf. ICF calculates that, depending on system size and utility territory, DLCs add 0.6 cents/kWh–1.6 cents/kWh to the cost of generation and consume 8.9 percent to 52.7 percent of the savings that would be realized without them. See Tables 8-10.

Utility standby charges are assessed to compensate for the infrastructure required to provide electric service when a facility generator is offline. Demand charges are assessed based on the level of power demand the utility meets during these times. CHP stakeholders do not generally dispute the reasoning for standby and demand charges, but they do sometimes cite them as a barrier to development and argue for changes in ways that they are calculated and applied. For example, they claim that the high reliability of many CHP plants reduces the risk of outages and argue that charges should reflect regional risk rather than just individual risk.

In previous years, pieces of legislation have been introduced to provide some form of exemption from DLCs or reevaluation of standby and demand charge calculations or both, but none has become law. To the extent the state wishes to encourage CHP development, policy makers may want to reassess the costs and benefits of these charges.

AB 1613: The Waste Heat and Carbon Emissions Reduction Act

Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), as amended by Assembly Bill 2791 (Blakeslee, Chapter 253, Statutes of 2008), established a feed-in tariff for new CHP systems no larger than 20 MW in nameplate capacity that meet specified emissions and efficiency criteria.[9] By the end of 2011, the CEC and CPUC had fully implemented the necessary certifying and contracting mechanisms. While the stated intent of the bill was to dramatically advance the efficiency of the state's use of natural gas by capturing waste heat and to support the development of small-scale CHP systems, participation in the tariff has been low. To date, only seven facilities are certified under AB 1613 for a total of 45.3 MW of nameplate capacity.

Self-Generation Incentive Program

In response to California's energy crisis of 2000 and 2001, the California Legislature established the SGIP to encourage the development of distributed generation throughout the state.[10] Since the energy crisis, the program has experienced many changes in payment structure, incentive levels, and eligible technologies. For most of this time, the program has included fossil-fueled CHP, although in recent years, the incentive structure has increasingly favored fuel cells and renewable technologies.

Beginning in 2016, a series of CPUC decisions established new incentives and eligibility requirements, as described in the 2017 SGIP Handbook.[11] The latest iteration of the program focuses largely on energy storage and renewable generation, with 79.1 percent and 10.9 percent of total funding earmarked exclusively for these categories, respectively. Natural gas-fueled CHP is eligible for the remaining 10 percent but still competes with all other forms

9 Text of Assembly Bill 1613, available at:
http://energy.ca.gov/wasteheat/documents/ab_1613_bill_20071014_chaptered.pdf;
Text of Assembly Bill 2791, available at:
http://energy.ca.gov/wasteheat/documents/ab_2791_bill_20080801_chaptered.pdf.

10 Text of Assembly Bill 970 (Ducheny, Chapter 329, Statutes of 2000), available at:
http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html.

11 Self-Generation Incentive Program 2017 Handbook, available at:
https://www.selfgenca.com/documents/handbook/2017.

of eligible generation, including renewables. Furthermore, the program includes a maximum GHG emissions threshold for eligibility that automatically decreases each year.

The SGIP had been an important driver of small-scale CHP in the past, but the influence of the program on CHP development has diminished over time as the emphasis has moved to other technologies. The most recent changes to the program are a continuation of this trend and will result in fewer successful CHP projects under the SGIP than in the past. Considering the technological trend of the program away from fossil fuels, and decreasing GHG emissions thresholds, the SGIP is no longer a significant driver of CHP development and will be even less influential in the future.

The Qualifying Facilities and Combined Heat and Power Settlement

The QF Settlement ended years of litigation among private and public parties and established regulatory procurement and GHG emission reduction targets for CHP in the state.[12] This litigation arose primarily from disputes over the payment rates and structure of must-take contracts for facilities operating under the Public Utilities Regulatory Policy Act of 1978 (PURPA), known as "qualifying facilities" (QFs).[13] As part of the QF Settlement, settling parties successfully petitioned the Federal Energy Regulatory Commission (FERC) to suspend PURPA for plants greater than 20 MW in nameplate capacity. Submitted in October 2010, approved by the CPUC in December 2010, and effective on November 23, 2011, the QF Settlement established three primary objectives:

- Develop a state CHP program.
- Create a smooth transition from the existing QF CHP PURPA Program to a state-administered CHP program.
- Settle all CHP/QF litigation covered by the QF Settlement.

The state CHP program envisioned in the QF Settlement would achieve many objectives, including:

- Greater regulatory and market certainty for CHP facilities.
- Continued operation of, and retention of GHG emission reductions from, existing efficient CHP facilities.

---

12 Decision D10-12-035, available at (http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/128624.PDF), and modified by in Decision D11-07-010, available at (http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/139237.PDF).

13 Federal Energy Regulatory Commission's frequently asked questions about PURPA and Qualifying Facilities, available at: https://www.ferc.gov/about/what-ferc/frequently-asked-questions-faqs/qualifying-facilities-qf-faq. See Glossary for definitions of PURPA and QFs.

- Additional GHG emission reductions consistent with the targets from Assembly Bill 32 via the retirement or upgrading of existing inefficient facilities and development of new, efficient facilities.[14]
- Power purchase agreement options for CHP facilities.
- A framework for a sustained state CHP program beyond 2020.

The QF Settlement defined the existing CHP fleet as those facilities listed in the July 2010 Cogeneration and Small Power Production Reports of California's three largest investor-owned utilities (IOUs), known as 2010 Existing Facilities.[15] From here, it set two targets: a 3,000 MW capacity target to be procured from new, expanded, repowered, or existing CHP facilities, and an incremental 4.8 million metric tons (MMT) of annual GHG emission reductions beyond the level achieved by the 2010 Existing Facilities.[16] These targets corresponded to the amount of new reductions achievable by the CHP fleet, and the amount of capacity needed to achieve them, as estimated in the CARB's first Scoping Plan.[17] By design, the 3,000 MW and 4.8 MMT values are roughly the same proportion of the AB 32 Scoping Plan estimates as the total electric sales of the IOUs were to sales statewide.

The settling parties negotiated accounting rules for QF Settlement targets, among other things, in the CHP Program Settlement Agreement Term Sheet.[18] This document included specific rules for when a facility counts toward a target and how to calculate the amount of capacity or emissions reductions to apply toward the target. The term sheet rules are specific to changes to the IOUs' CHP fleets and generally do not punish an IOU for a negative change that is out of its control. For example, if a facility that is under contract with another utility enters into a power purchase agreement with an IOU, it may be counted toward that IOU's capacity target — even though statewide capacity has not changed. Or if a facility that is not considered efficient under the QF Settlement comes into operation in an IOU territory under a must-take power purchase agreement, the decrease in emissions savings is not subtracted from the IOU's incremental GHG target, even though total fleet savings have decreased. These sorts of accounting rules have the unfortunate side effect of taking QF Settlement progress out

14 Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), available at: https://www.arb.ca.gov/cc/ab32/ab32.htm.

15 Pacific Gas and Electric Company, Cogeneration and Small Power Production Semi-Annual Report for July 2010, available at: https://www.pge.com/includes/docs/pdfs/b2b/qualifyingfacilities/cogeneration/jul2010cogen.pdf;
Southern California Edison Company Renewable and Alternative Power for July 2010, Qualifying Facilities Semi-Annual Status Report to the California Public Utilities Commission. No web link available;
San Diego Gas & Electric, Qualifying Facility Cogeneration and Small Power Production Report July 2010 – December 2010. No web link available. Note that this report was issued in spreadsheet format.

16 A metric ton is a unit of mass equal to 1,000 kilograms.

17 The AB 32 Scoping Plan provides an outline for California to meet its GHG emission reduction goals required by the Global Warming Solutions Act of 2006 (Assembly Bill 32), available at: https://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf.

18 CHP Program Settlement Agreement Term Sheet, available at: http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF.

of sync with the underlying state goals upon which the targets are based. Put simply, changes reflected in QF Settlement accounting do not always translate into real changes in the fleet.

While the accounting issues described above are relatively minor, unforeseen developments occurred during implementation of the QF Settlement, including how to count contracted-for capacity in meeting capacity procurement goals, the uptake of utility prescheduled facility (UPF) contracts, and a CPUC decision altering the GHG accounting method and reducing the GHG reductions targets to be achieved from CHP.

The first development occurred in 2012 when two IOUs issued advice letters proposing that a total of 681 MW be counted toward their capacity goals from resource adequacy-only capacity contracts with two facilities.[19] Several parties objected to these contracts for numerous reasons, including the claim that such contracts were not envisioned or permitted under the QF Settlement. In response to these objections, as a compromise the CPUC allowed the IOUs to contract for half the offered capacity and count it toward their capacity targets. In addition, the CPUC ruled that it would not consider any further resource adequacy-only capacity contracts under the QF Settlement.[20] This compromise resulted in 340.5 MW (11 percent) of the QF Settlement capacity target being satisfied by contracts that did not materially change the CHP fleet.

The second development is the extent to which utility prescheduled facility (UPF) contracts have been signed under the QF Settlement. A "UPF" is defined under the QF Settlement as an existing CHP facility that has changed operations to convert to a utility-controlled, scheduled, dispatchable generation plant. UPF contracts were allowed under the QF Settlement as a mechanism for reducing emissions from inefficient facilities by providing them short-term contracts to act like peaker resources before transitioning out of service. To date, roughly a third of the 3,000 MW capacity target has been satisfied with explicit UPF contracts. As UPFs are preexisting facilities, by definition, they do not change the total capacity available in the CHP fleet.

The third and fourth developments are a result of a CPUC decision. In July 2014, the CPUC issued a ruling seeking comment on possible changes to the QF Settlement in its Second Program Period.[21] In June 2015, it issued a decision that included two changes to the QF

---

19 PG&E contracted with Los Medanos Energy Center, LLC for half of its 561 MW of capacity, and SCE contracted with them for the other half and with Calpine Gilroy Cogen, L.P. for 120 MW of capacity. Both facilities had QF status and had sold to the respective IOUs previously but were not listed as 2010 Existing Facilities. This made their capacity eligible under Section 5.2.3.2 of the QF Settlement Term Sheet.

The CPUC issued separate resolutions for PG&E (resolution E-4529, available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M075/K210/75210764.PDF) and SCE (resolution E-4569, available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M075/K160/75160211.PDF).

21 July 2014 CPUC ruling seeking comment on CHP issues, available at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M098/K861/98861127.PDF.

The QF Settlement is divided into three periods: a Transition Period, which was intended to provide short-term contracts for facilities waiting to submit bids for contracts under the QF Settlement, and First and Second Program periods that divided QF Settlement targets into two stages. The term sheet specified that certain terms could be reconsidered for the Second Program Period.

Settlement GHG target and accounting rules that reduced the target by nearly half and allowed previously ineligible facilities to count toward the reduced target.[22]

The ruling ordered that existing efficient, renewable, and bottoming-cycle facilities should be counted as new facilities for GHG accounting when given new contracts during the second program period.[23] Under the original accounting rules, the GHG target was an incremental target relative to the GHG emissions savings already attributable to the existing fleet. This meant utilities generally lost progress on the goal when existing efficient facilities retired and gained when new efficient facilities came on-line. With this change, when a utility recontracts with such a facility, it gains credit toward its GHG goal for a new facility while avoiding the loss of credit that would have occurred if it had not recontracted. This change double counts the emission credit from that facility.

The ruling also ordered that the total GHG target be reduced from 4.8 MMT to 2.72 MMT, divided proportionally among the IOUs just as the original target had been. In considering whether to adjust the GHG target, the CPUC reviewed CARB's 2014 update to its first Scoping Plan and found that while the update did state that "[the state's energy agencies will] achieve the Governor's objectives and that of the Initial Scoping Plan for CHP to reduce GHG emissions," it did not explicitly itemize those objectives.[24] The CPUC found this omission ambiguous and a reasonable justification for considering the arguments from some stakeholders for reducing the GHG target.

In considering other bases for a GHG target, the CPUC determined that a June 2012 CHP market assessment report provided the most useful information for calculating future CHP emission reductions, and that the medium case projection of the assessment was a reasonable base. Moreover, the CPUC determined that "the total annual [carbon dioxide equivalent] CO_2e emissions reduction potential for the utility service territories by 2020 is 2.72 MMT" and "much of the GHG benefits will come from the fleet of existing CHP facilities."[25] However, the medium case in the assessment projected 2.72 MMT in savings from new CHP facilities, not the total fleet.[26] It did not include contributions from maintaining existing efficient facilities or reducing operation of existing inefficient facilities — both of which would have increased the projected GHG emissions reduction potential of the assessment. Adopting the medium case as a basis

---

22 Decision 15-06-028, Decision on Combined Heat and Power Procurement Matters, issued 6/15/2015, available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K559/152559026.PDF.

23 CHP facilities can be categorized as topping- or bottoming-cycle. "Topping-cycle plants," the most common type of CHP facility, first use fuel to generate electricity and then harvest waste heat from that generation for a thermal application. "Bottoming-cycle plants" operate in reverse: they first use fuel for a high-temperature thermal application (for example, metal smelting) and then harvest waste heat from that application to run an electrical generator. Bottoming-cycle facilities are generally the most efficient, as they can generate electricity with little or no additional fuel than is already being used for an existing thermal application.

24 Decision 15-06-028, Decision on Combined Heat and Power Procurement Matters, issued 6/15/2015, page 15, available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K559/152559026.PDF.

25 Ibid, pages 51-52, findings of fact numbers 18 and 19.

26 Hedman, Bruce, Ken Darrow, Eric Wong, and Anne Hampson. ICF International, Inc. 2012. Combined Heat and Power: 2011-2030 Market Assessment. California Energy Commission. CEC-200-2012-002-REV. http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf.

for total fleet reduction potential, rather than just potential from new facilities, made the assumptions of the QF Settlement GHG targets inconsistent with those of both the June 2012 CHP market assessment and the target in the first Scoping Plan.

While the QF Settlement targets remain important in the legal context of the agreement, and obtaining contracts remains important to participating facilities, the developments described above have made QF Settlement accounting unreliable in any other context. Progress toward QF Settlement targets cannot be used to quantify CHP contributions to statewide emission reductions, cannot be directly compared to other targets such as those in the first Scoping Plan, and do not necessarily reflect changes in the statewide CHP fleet.

To date, the IOUs appear to have largely or completely met their respective targets under the QF Settlement. In particular, the QF Settlement has made good progress on the objective to optimize the existing fleet by reducing output from inefficient facilities. However, the Second Program Period of the QF Settlement expired at the end of 2020 without clarity on what happens next, leading to questions about what CHP policy looks like post 2020, how facilities will behave in that environment, and how forecasters and planners should treat CHP.

CHAPTER 3: Historical Fleet Performance

Forecasters and planners consider the capacity and electrical generation contributions of California's CHP fleet. However, state programs and goals focus largely on capacity targets — either for their own value or as a proxy for GHG emissions reductions. In context of many of the potential benefits of CHP procurement, this focus on capacity implicitly assumes that capacity is also a good proxy for generation. For example, the capacity targets in the QF Settlement are derived from estimates of the amount of capacity needed to achieve the GHG emission reduction targets of the QF Settlement. But GHG emissions depend entirely on generation, not capacity. Thus, the capacity targets necessarily assume a certain amount (and efficiency) of generation accompanying the procured capacity.

In this way, forecasts based on CHP capacity targets assume that CHP capacity will increase to meet the targets and, in turn, assume a proportional increase in CHP generation. Analysis of historical trends in CHP capacity and generation provides evidence that both assumptions should be treated with caution.

New and Expanded Capacity

Much of the capacity gains reported in the QF Settlement come from contracts with existing facilities that were not previously counted in California's CHP fleet — for example, the Los Medanos Energy Center, which was reclassified as a QF, or Yuma Cogen, which is outside the state. (See Chapter 2, "The Qualifying Facilities and Combined Heat and Power Settlement.") However, these types of capacity additions are largely contractual and do not represent actual increases to California's CHP fleet. To evaluate and predict progress toward the state's CHP targets, it is prudent to focus on in-state capacity additions from new facilities and expansions at existing facilities.

From 2010 through 2016, the capacity of California's CHP fleet increased by only 82.9 MW from new facilities and 134.1 MW from expansions for a total of 217.0 MW.[27] Further, nearly half of these additions (79.3 MW) came from capacity expansions at just two plants. There were no additions in 2016 and less than 5 MW worth in 2012 and 2014, as depicted in **Figure 1**. This pattern of capacity additions is sporadic and very susceptible to decisions made by a single facility, both of which make predicting future additions difficult in any given year.

27 As discussed in CHAPTER 4:
Data and Methods, this does not include facilities less than 1 MW in nameplate capacity. However, staff estimates a total of less than 100 MW of capacity from such facilities statewide.

Figure 1: Capacity Losses and Additions From New and Expanded Facilities

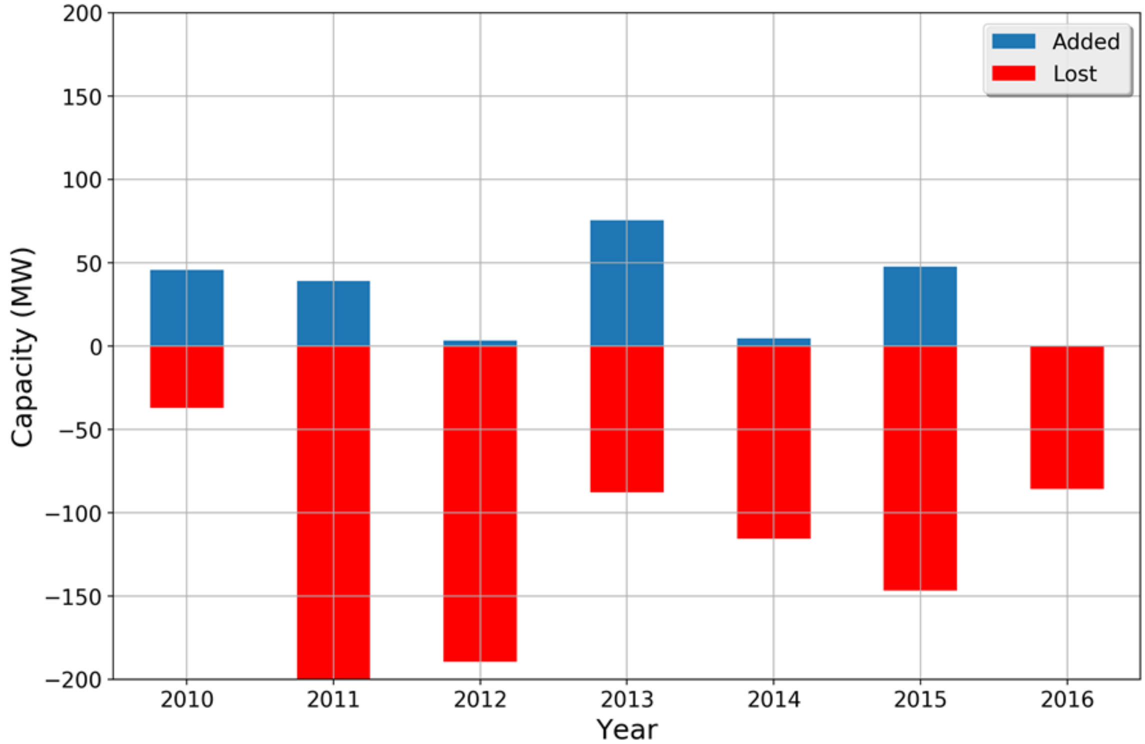

Figure 1 shows annual capacity changes from 2010 through 2016. Capacity additions include only additions from new or expanded in-state facilities.[28]

Source: California Energy Commission

An alternative method for estimating future additions is to apply an average across all years. However, this approach is problematic for three reasons. First, there are few facilities capable of installing large expansions, and a plant that has already expanded is unlikely to do so again. Thus, an average would overestimate future additions by assuming that expansions continue. Second, even when expansions are included, the average annual amount of added capacity over these seven years (31 MW) is negligible in the context of a fleet with nearly 8,000 MW of total capacity. Finally, an average would also rely on the questionable assumption that regulatory and market conditions will sustain additions at the same rate as during 2010 through 2016. For more details, see CHAPTER 2: Market and Policy Environment.

Staff concludes there is little reason to expect significant additions in CHP capacity going forward and no obvious method for estimating the small amount of additional capacity that may occur. In the current regulatory and market environment, the most reasonable analytical approach is to assume zero capacity is added after 2016.

Annual Generation and Nameplate Capacity

Since peaking circa 2003 and 2004, statewide total CHP nameplate capacity and annual electrical generation have steadily declined. Since 2010, the baseline reference year for the QF Settlement, nameplate capacity declined 5.9 percent (488.6 MW), and annual electricity

28 As in the rest of this report, these values do not include facilities with less than 1 MW of nameplate capacity.

generation declined 22.8 percent (10,040.4 GWh), as shown in **Figure 2**. If changes in capacity were a good proxy for changes in generation, as many of the state's capacity targets implicitly assume, capacity and generation would change in similar proportions. In other words, there should be little change in the average capacity factor of the CHP fleet. However, the average capacity factor of the fleet has dropped 18.0 percent (10.9 percentage points) from 2010 through 2016, indicating that factors other than declining capacity are having a greater influence on the decline in CHP generation.

Figure 2: Historical Capacity and Generation Relative to 2010

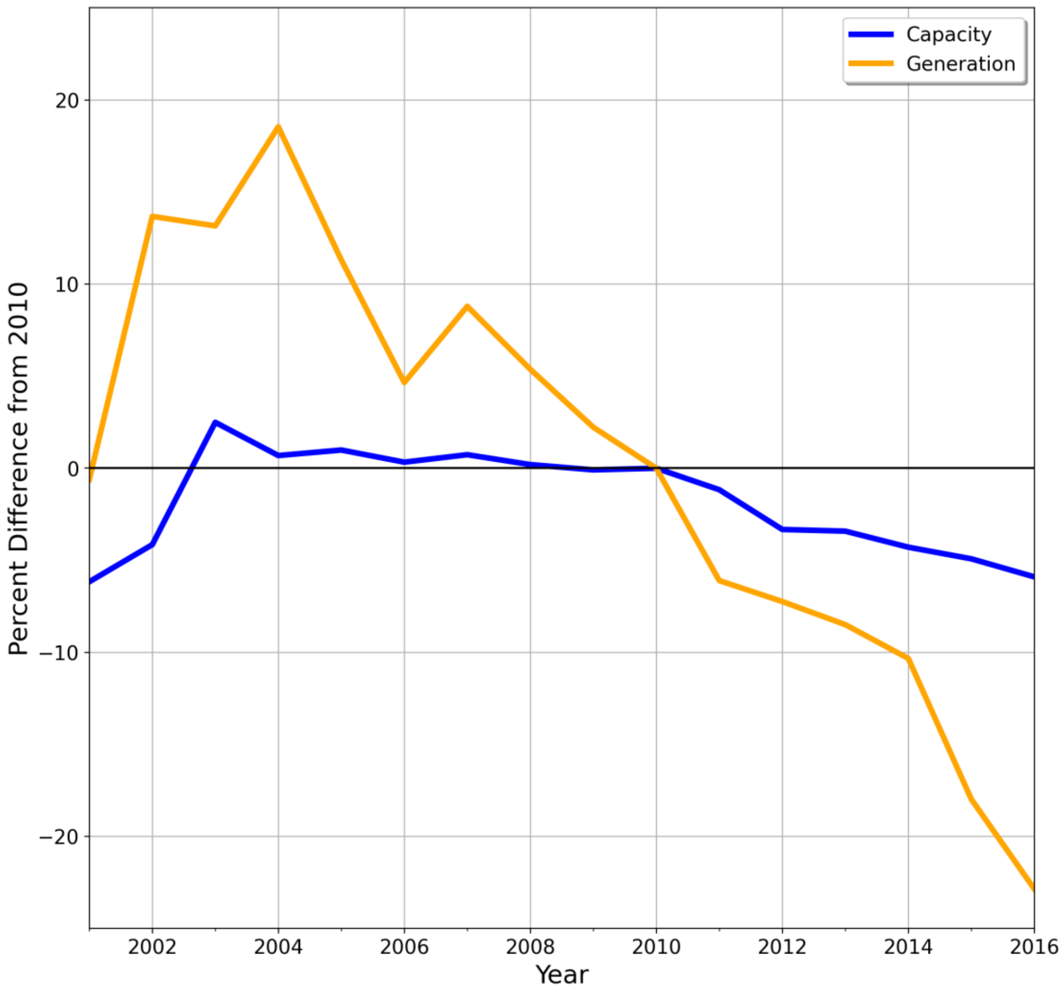

Figure 2 shows the percentage difference in fleetwide capacity and annual generation from 2010 levels. For example, in 2004, the fleet generated 18.5 percent more electricity than in 2010, and in 2014, the fleet had 4.3 percent less capacity than in 2010.

Source: California Energy Commission

Given how little new capacity has been added in this time, the decline in capacity factor is being driven primarily by changes in operations at existing facilities. These changes are important for capacity-based targets, as these targets are usually incremental targets, which assume that existing capacity (and therefore generation) is preserved. As a result, progress toward CHP capacity targets appears to be gradually declining, while the purpose of those targets (increasing generation) is declining precipitously.

A second factor obscuring changes in the CHP fleet is a small number of large and relatively consistent facilities that constitute a large proportion of total fleet capacity and generation. In 2016, the top three generators generated 27.6 percent of total electricity from the fleet, and the next 10 (ranked 4–13) generated 28.9 percent, for a combined 56.5 percent of total fleet generation. (See **Figure 3**.) These 13 large facilities represent a small proportion of the total number of CHP facilities (a total of 135 facilities had at least a 5 percent capacity factor in 2016) but have a large enough influence on fleetwide statistics to obscure changes in the rest of the fleet. For example, generation from the top 13 facilities declined only 9.2 percent from 2010 through 2016, while the generation from the rest of the fleet declined 35.5 percent, resulting in the 22.8 percent average decline cited above.

Figure 3: Net Generation, by Facility

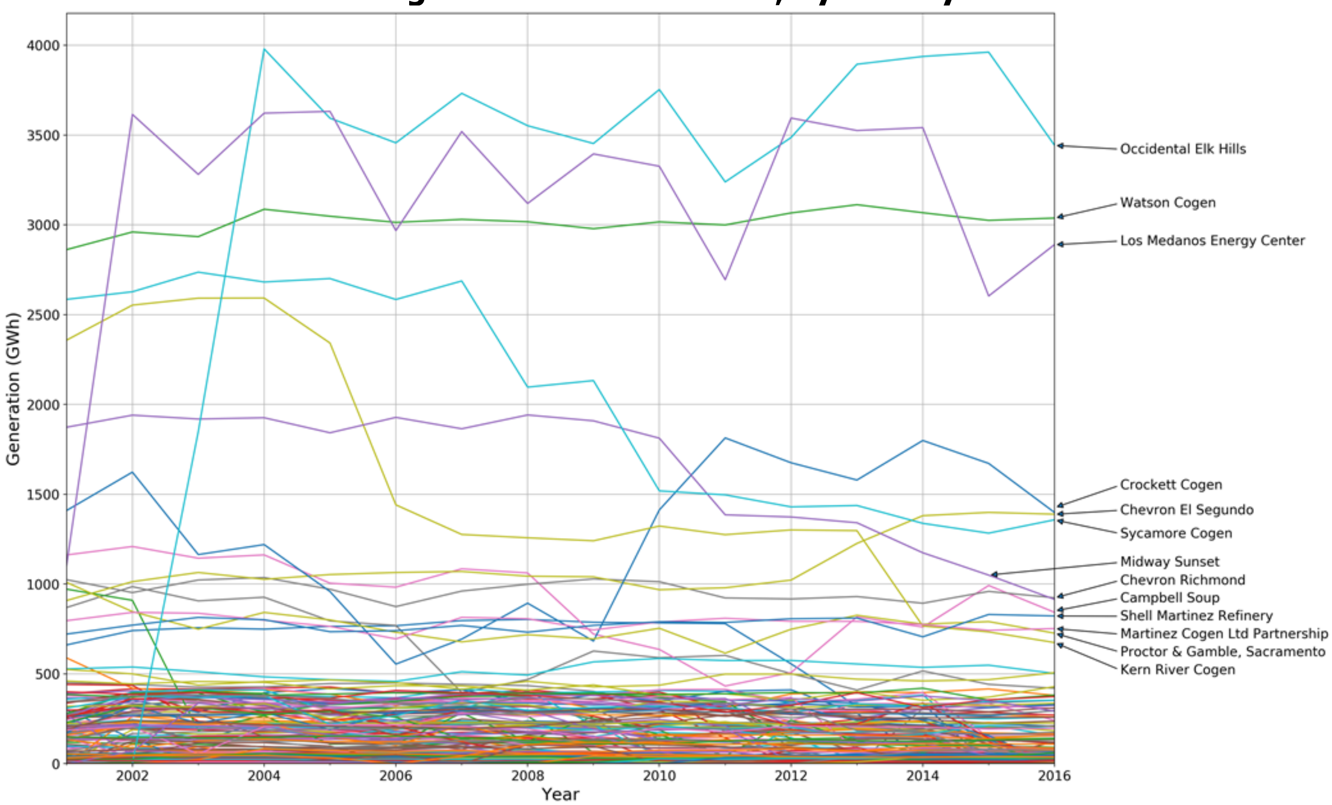

Figure 3 shows annual net generation for each CHP facility in this analysis. These plants can be roughly grouped into three clusters by amount of generation in 2016: the top three generators, the next 10 (ranked 4 through 13), and all others.

Source: California Energy Commission

In summary, fleetwide CHP generation is declining much faster than nameplate capacity and more in small and medium-sized facilities than in large facilities. State emphasis on nameplate capacity and the relative stability of large facilities are effectively masking dramatic changes in the operation of much of California's CHP fleet — changes that will affect progress toward state policy goals and the accuracy of analytical work underlying state energy planning processes. Fleetwide capacity is an increasingly unreliable basis for analyzing state policy goals and fleet operations.

CHAPTER 4: Data and Methods

This chapter describes the data and methods underlying the historical analyses of Chapter 3 and the future projections of Chapter 5.

Data

Analyses in this report required multiple types of data on CHP facilities, including facility characteristics, contracts, QF Settlement statuses, and operations. To compile this data set, staff combined data from five sources:

- Public and confidential QF Settlement reporting data as of early 2016
  - Each IOU provided these data under a memorandum of understanding between the CEC and the CPUC and included all contract and facility data included in reporting requirements under the QF Settlement.
  - At the CEC's request, the IOUs updated this data set in 2017.[29]
- A CPUC list of facilities classified as 2010 Existing Facilities under the QF Settlement
  - This list included contract and operational data for a partial list of 2010 Existing Facilities.
- Additional 2010 Existing Facilities data taken from each IOU's July 2010 cogeneration reports
  - These reports provided data on most of the facilities missing from the CPUC list, although staff was unable to cross-reference a handful of small facilities from the IOU cogeneration reports with other data sources.
- Contract status and end-date estimates derived from staff's best judgment after reviewing relevant CPUC advice letters and consulting with CHP stakeholders
- Capacity and operational data from the CEC's Quarterly Fuel and Energy Report (QFER) database
  - To resolve inconsistencies between data sets, staff used capacity and energy data from QFER for all facilities except Yuma Cogeneration (which is in Arizona and doesn't report to QFER).

The resulting data set has two important limitations. First, it does not include facilities with less than 1 MW in nameplate capacity. QFER does not require reporting for such facilities, and while other sources contain some data on these small facilities, it is often incomplete or cannot be cross-referenced between sources or both. Staff estimates the combined nameplate capacity of these facilities to be less than 100 MW statewide. Given this is a small percentage of the 7,997 MW of other CHP capacity in 2016, staff determined that it is more accurate to

33 At the time of analysis, the last publicly available reporting was from July 2014. Reporting has been updated since, available at: https://www.cpuc.ca.gov/General.aspx?id=5432.

exclude these facilities from analyses than to introduce broad assumptions and incomplete data for them. Second, contract data and estimates are available only for facilities contracted with, or independently operating in the territory of, an IOU. These data come primarily from the IOUs and CPUC and, as such, do not include most POU-related facilities.

Finally, not all data sources agree on which facilities qualify as CHP. Some facilities that are considered CHP under the QF Settlement are not considered CHP within the QFER database. In addition, some of the facilities that count as new CHP under the QF Settlement existed prior to 2010 but were not considered preexisting CHP facilities at that time under the QF Settlement. These situations raise questions about the technical and regulatory definitions of CHP. However, this report attempts to look past these differences and focus on a pragmatic approach that allows comparisons over time. For that reason, this data set includes all historical data for facilities that currently report as CHP in the QFER dataset or that have ever qualified as CHP under the QF Settlement. Staff believes this is reasonable and allows analysis of all relevant facilities.

Methods

Analyses in this report consist of descriptions of the current and historical CHP fleet and scenario-based projections for the fleet over the next 15 years (Chapters 3 and 5, respectively). The latter depends primarily on the baseline operations of facilities and how they may change when a facility reaches a key decision point.

To maintain consistency with other CEC forecasting assumptions, this report uses a single-year baseline of plant operations in 2016 for each facility. For facilities with known or estimated contract end dates (IOU-associated facilities), staff assumes that these facilities will end current operations on this date. For facilities without contract data or estimates, staff uses plant age as a proxy and assumes that facilities will end current operations at 40 years of age. At the end of current operations, a facility faces a decision on how or whether to continue operations. The scenarios outlined below determine how facilities will behave at this point (for example, shutdown, obtain a new contract, repower, and so forth).

In some instances, facilities are operating either without a contract or with a guaranteed contract. This group includes exclusively behind-the-meter generation, guaranteed feed-in tariffs, interconnection-only agreements, evergreen contracts, and other must-take arrangements such as PURPA contracts. These facilities have no reason to change operations except for business needs, which are outside the scope of this report, and so staff labels them "continuous facilities" and assumes that they will continue operating indefinitely in most scenarios.

Using these definitions, this report considers five scenarios: four staff-generated cases and an analysis of the CPUC's 2016 Long Term Procurement Plan (LTPP) retirement assumptions.

Case 1

- Continuous facilities operate indefinitely.
- Noncontinuous facilities shut down at the end of current operations.

This case is the most conservative and essentially assumes that any facility that does not secure a new contract by the end of current operations will shut down all CHP units.

Case 2

- Identical to Case 1, except that facilities that export less than 5 percent of total generation for resale are also treated as continuous behind-the-meter facilities and operate indefinitely.

This case intends to capture facilities that appear to behave like behind-the-meter facilities but are not specifically labeled as such in available data sources. For example, behind-the-meter facilities in POU territories are not labeled as such because the available data do not include contract information for these facilities.

Case 3

- Continuous facilities operate indefinitely.
- All other facilities scale down generation to the level of nonresale baseline generation at the end of current operations and then shut down when the youngest unit reaches 40 years of age.

This case assumes facilities will stop exporting when current contracts end and operate in that fashion for the rest of the useful equipment life. This case makes financial sense for a facility that has decided to replace CHP units with boilers but still wants to amortize CHP investment as much as possible. Anecdotally, this case is the option that staff has most frequently heard in discussions with CHP stakeholders facing difficulties obtaining contracts. Staff considers this a mid case that represents a plausible compromise for many facilities while balancing the reality that some plants will still shut down completely and others will find a way to continue current operations.

Case 4

- Identical to Case 3, except that facilities do not shut down due to age.

This case provides a less conservative version of Case 3 as a high case. It allows for the possibility that facilities may find it economical to operate a scaled-down CHP unit, or that facilities may have already made investments that extend the useful life of the equipment past 40 years.

LTPP Retirements

- Facilities with 20 MW or less in nameplate capacity operate indefinitely.
- Facilities with greater than 20 MW in nameplate capacity operate at baseline until either the current contract ends, or the facility reaches 40 years of age, whichever is later, at which point they shut down.

This scenario uses the same CHP retirement assumptions as the LTPP. However, it does not use the LTPP assumptions for new CHP capacity. It is included as a reference to illustrate the differences between current forecasting assumptions and those recommended in this report.

Nameplate Capacity and Effective Capacity

All scenarios, including LTPP retirements, assume zero new capacity in forecasts. This assumption is consistent with the 2016 baseline, in which there was no new or expanded capacity for facilities with 1 MW or more in nameplate capacity. Given historical trends and current regulatory and market environments, staff believes this is the most reasonable assumption. See the "New and Expanded Capacity" section of Chapter 3 for a more detailed discussion.

For cases where facilities scale down operations, forecasted capacity values are scaled accordingly. Staff refers to these scaled values as "effective capacity," not nameplate capacity. For example, assume a 50 MW nameplate capacity facility that uses 60 percent of generated electricity onsite scales down to prevent export in 2018. On average, this facility can now contribute only 60 percent of its capacity to load, so 30 MW of effective capacity (60 percent of 50 MW) is counted for this facility in 2018 — a 20 MW drop from 2017. Staff believes this provides a more accurate description of the capacity value of a facility than reporting a nameplate capacity that is no longer fully available. At the same time, staff acknowledges that this is not a good measure of peak load since effective capacity is essentially the average capacity required for scaled-down onsite generation. Facilities will have periods of onsite demand that are higher than average and, at those times, contribute more to the total system load than the calculated effective capacity. For this report, which does not examine peak load in detail, staff believes this is a reasonable trade-off to represent more accurately fleetwide changes in capacity.

CHAPTER 5: Future Scenarios

This report estimates future capacity and generation from California’s CHP fleet under five scenarios: four staff-generated cases and an analysis of the 2016 LTPP retirement assumptions. Please see “CHAPTER 4: Data and Methods” for more detailed scenario descriptions and other information on data and assumptions. Abbreviated scenario descriptions are provided here for quick reference:

Case 1

- Continuous facilities operate indefinitely.
- Noncontinuous facilities shut down at the end of current operations.

Case 2

- Identical to Case 1, except that facilities that export less than 5 percent of total generation for resale are also treated as continuous behind-the-meter facilities and operate indefinitely.

Case 3

- Continuous facilities operate indefinitely.
- Noncontinuous facilities scale down generation to the level of non-resale baseline generation at the end of current operations, then shut down when the youngest unit reaches 40 years of age.

Case 4

- Identical to Case 3, except that facilities do not shut down due to age.

LTPP Retirements:

- Facilities with 20 MW or less in nameplate capacity operate indefinitely.
- Facilities with greater than 20 MW in nameplate capacity operate at baseline until either the current contract ends, or the facility reaches 40 years of age, whichever is later, at which point they shut down.

Capacity

From 2018 through 2022, facilities representing more than half (4,274 MW) of the current fleetwide capacity will face decisions on how or whether to continue their CHP operations. This situation is driven largely by two surges in CHP contracts that end during this period — first, a series of long-term contracts signed during a CHP boom in the late 1980s; second, several short-term contracts signed under the QF Settlement. Most of this capacity (3,485 MW) is from facilities with contracts ending from 2020 through 2022, raising the possibility of a dramatic drop in capacity over a short period.

In the most conservative case (Case 1), this would result in capacity losses of nearly 4,997 MW (64.1 percent) through 2023 and more than 6,178 MW (51.9 percent) through 2032. In the least conservative case (Case 4), effective capacity losses would be 4,081 MW (52.4 percent) and 4,508 MW (57.8 percent), respectively. The differences between cases tend to increase over time, as fewer conservative cases allow more facilities to maintain some level of operation. However, all cases are in close agreement through the steepest portion of decline into the early 2020s (**Figure 4**).

Figure 4: Historical and Projected CHP Capacity

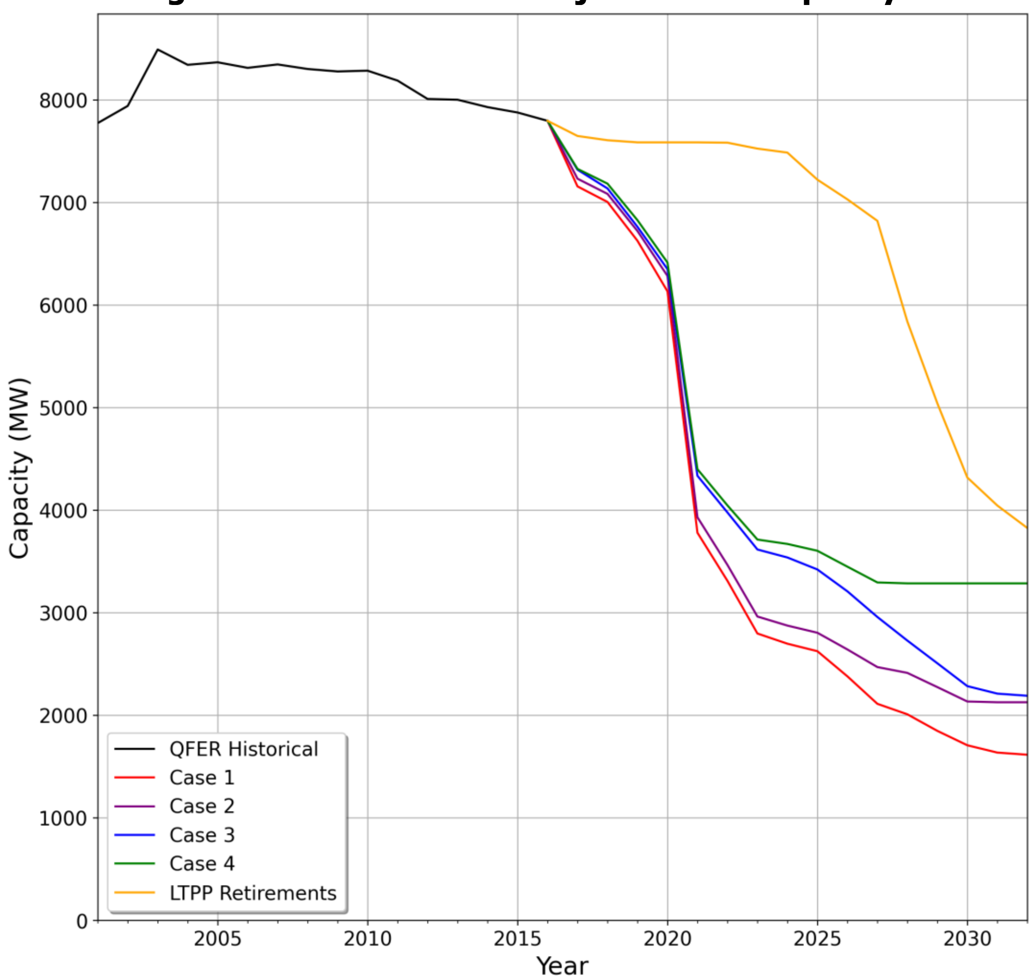

Figure 4: Historical nameplate capacity is represented in black through 2016 and scenario-based projections in color from 2016 through 2032. Capacity projections for cases that scale down generation (Cases 3 and 4) are effective capacity and should not be directly compared to estimates of nameplate capacity.

Source: California Energy Commission

In comparison, when using the LTPP retirement assumptions, there is very little change in capacity until 2025, when facilities from the late 1980s begin to reach 40 years of age. At this point, all cases except for Case 4 (which does not consider age) also experience a decline due to age. The decline is not as pronounced as under the LTPP assumptions due to facilities having already either shut down or scaled down operations by this time under other the respective case assumptions.

Generation

Like the capacity cases discussed above, electrical generation in all cases experiences a significant decline through 2023, with a period of particularly steep decline around the early 2020s. In the most conservative case (Case 1), this decline would result in 21,035 GWh (62.0 percent) less annual generation in 2023 than in 2016 and 25,668 GWh (75.7 percent) less in 2032. In the least conservative case (Case 4), generation would be 15,836 GWh (46.7 percent) and 17,610 GWh (51.9 percent) less in 2023 and 2032, respectively (**Figure 5**).

Figure 5: Historical and Projected CHP Generation

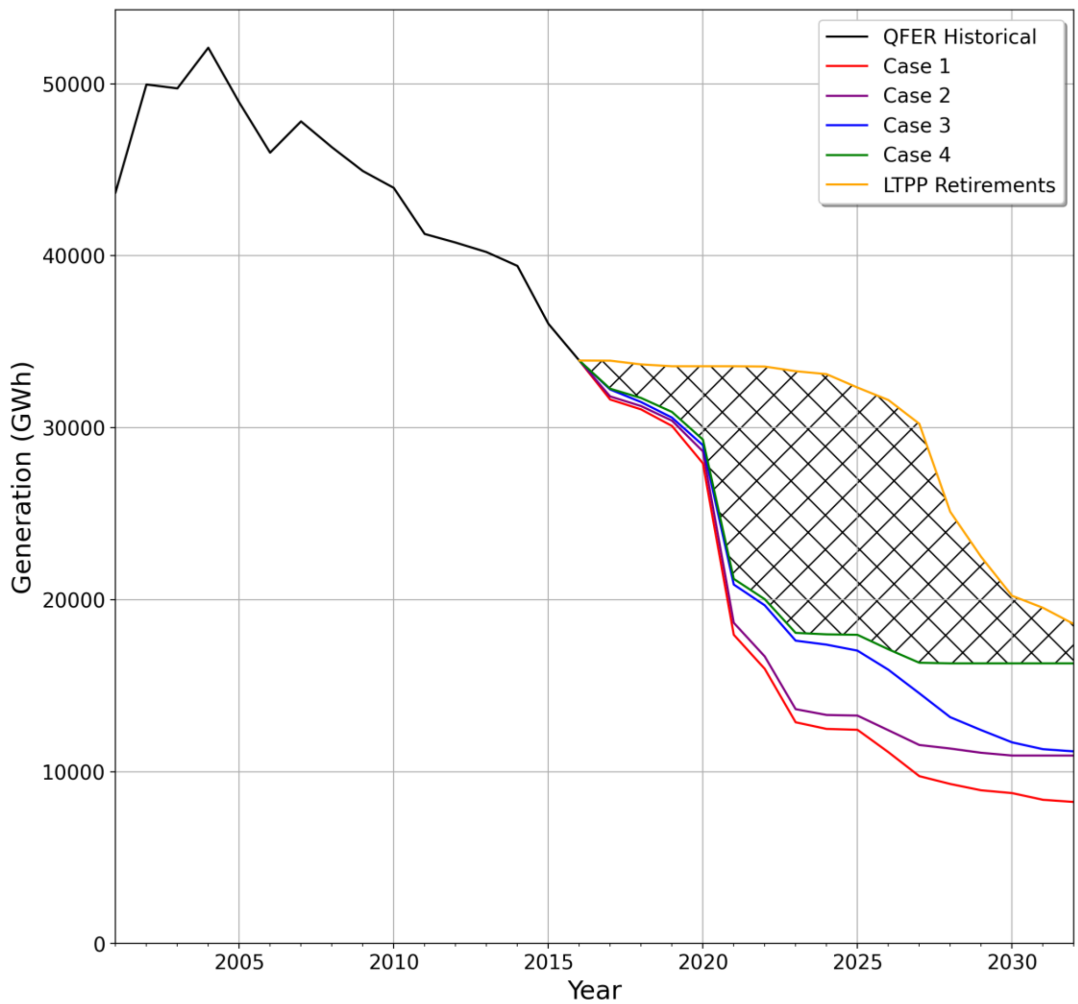

Figure 5: Historical electrical generation is represented in black through 2016 and scenario-based projections in color from 2016 through 2032. The shaded region represents the difference in the amount of electricity generated under staff's least conservative case and the LTPP retirement assumptions.

Source: California Energy Commission

When compared to LTPP retirement assumptions, all cases again result in lower estimates as the LTPP-based estimates stay relatively consistent until 2025. The differences between LTPP-based estimates and the least conservative case (Case 4) range from 1,631 GWh in 2017 to 15,216 GWh in 2023, with an average of 8,374 GWh per year over the 2017-through-2032 forecasting period. For rough context, California's gross electricity generation (generation and net imports) is nearly 300,000 GWh of electricity per year.[30] Based on this annual value, forecasting errors of 8,000 to 15,000 GWh would translate to a 3 percent to 5 percent shortfall relative to current statewide gross generation.

Discussion

Statewide CHP generation and capacity are in long-term downward trajectories, with generation decreasing faster than capacity as facilities modify operations. (See "CHAPTER 3: Historical Fleet Performance.") Cases presented in this report show a continuation of these trends to varying degrees but agree in predicting a sharp drop in the early 2020s. If these cases were realized, it would likely result in a loss of at least half of the contributions of the 2016 fleet by 2023. Changes of this magnitude could have consequences for planning, reserve margins, and reliability areas that depend on local capacity and, thus, warrant a closer examination of the underlying assumptions in current CHP forecasts.

One such assumption is the availability of export contracts. This analysis included a scenario based on LTPP retirement assumptions for comparison, which resulted in stark differences with staff-generated cases. The primary difference in the LTPP-based scenario is that it assumes facilities will continue to obtain new contracts either in perpetuity (for facilities with 20 MW or less) or until they are older than 40 years of age (for facilities more than 20 MW in nameplate capacity). Short of assuming that all facilities will continue at current levels forever, this is nearly the most optimistic set of assumptions possible for existing facilities. In staff's opinion, these assumptions should be treated as a very high case — effectively an upper limit on the future operations of existing facilities.

On the other hand, staff assumptions err far in the other direction. All staff-generated cases assume that existing facilities will not obtain new contracts. Facilities that depend on export contracts either shut down or change operations to avoid needing a new contract. In Case 1, facilities do not change operations and shut down as soon as they require a new contract. Staff considers this a very low case that is effectively a lower limit on future operations at existing facilities.

Between these limits is Case 4, which staff considers a reasonable compromise. While it assumes no new contracts will be signed, it also assumes that every facility will be willing and able to continue providing the onsite portion of the baseline generation of the facility regardless of age. Of course, in reality, some facilities may obtain new contracts to continue operating in full, and many of those that don't may determine that scaling down operations isn't feasible and choose to shut down fully in the face of aging equipment or contract end dates. Given how different CHP facilities are in terms of facility design (for example, scaling down may not be possible for a given facility) and in how they are valued by load-serving

---

30 California Energy Commission Energy Almanac, available at: http://www.energy.ca.gov/almanac/electricity_data/electricity_generation.html.

entities they could contract with, it is difficult to estimate how specific facilities will act. In turn, this situation makes it difficult to determine whether the errors in Case 4 will cancel out (that is, whether underestimations caused by facilities getting new contracts will be balanced by overestimations caused by facilities shutting down completely). Still, staff believes it is reasonable to assume these two sources of error will be roughly equal in magnitude, and that the final balance is likely to fall much closer to Case 4 estimates than those produced by either Case 1 or the LTPP-based assumptions.

An important caveat to this analysis is the influential role that decisions at very large facilities play in fleetwide metrics. As discussed in the "Annual Generation and Nameplate Capacity" section of Chapter 3, the top three generators in 2016 accounted for more than a quarter of all CHP generation and the top 13 for more than half. If these facilities tended to err in the same direction, it could significantly bias forecasts.

CHAPTER 6: Conclusions and Recommendations

Around 2010, California established several CHP goals and programs with the collective goal of increasing CHP use in the state. Since then, state energy policy has increasingly emphasized limiting GHG emissions and adoption of renewable energy resources. However, CHP policy has not significantly changed since 2010, and many policies and targets either are still in effect or have not been explicitly retired. It is not clear that existing CHP goals align with current state energy and environmental policy, but it is clear that the CHP fleet is not on track to meet them.

While the IOUs have met or made progress toward their capacity procurement and emission reduction targets under the QF Settlement, these have been met almost entirely by recontracting with existing facilities and retirement of existing facilities (aided by changes to emissions accounting and targets), respectively. The anticipated new CHP development that would reduce emissions did not occur; the fleet has added minimal amounts of new or expanded capacity in recent years. Total fleet capacity and generation are in long-term downward trajectories and are at a lower level now than when the above policies and programs were implemented. Decline in generation has been steeper than capacity, resulting in a significant drop in average capacity factor, but this fact has been largely obfuscated by an emphasis on nameplate capacity when measuring the status of the CHP fleet. In the current regulatory and market environments, staff sees little reason to expect changes that will lead to increased CHP development.

Looking forward, the QF Settlement's Second Program Period ended December 31, 2020, and it is not clear if the post-2020 CHP Program described in the QF Settlement will exist, or what that may look like if it does. In the absence of clear policy direction, CHP operators and developers are making key decisions in an environment with high uncertainty and business risk. Many of these decisions are happening in a narrow time frame, with facilities representing more than half of the nameplate capacity of the fleet making contractual or operational decisions or both by the end of 2022. All staff cases considered in this report indicate that the fleet will experience a large drop in effective capacity and generation during this time frame, with the important caveat that decisions at a handful of the largest facilities of the fleet will heavily influence this outcome.

Considering these conclusions, staff recommends the following:

1. **Planners and forecasters should stop using California's CHP capacity targets as a basis for analytical and modeling assumptions.** This paper presents an alternative method based on historical trends and plausible facility behavior. Currently, this means a declining fleet with little-to-no new capacity additions, adjusted for assumptions specific to very large or influential facilities. In support of this methodological change, all parties should have access to recent, updated, and vetted QF Settlement semiannual reports consistent with the QF Settlement Term Sheet.

2. **Policy makers should revisit CHP policies in light of SB 100 and broader state energy policy.** Bringing California CHP policy into alignment with current state energy policy will support regulatory and market certainty. California load-serving entities currently use existing gas-fired resources to meet obligations for resource adequacy and grid reliability. At the same time, California is committed to transitioning to a clean energy future. To the extent that policy makers see value in supporting CHP resources, they should amend or replace existing CHP policies and programs to ensure that new policy leverages the value of CHP in ways that are achievable and consistent with broader state energy goals.

Glossary

CLEAN ENERGY JOBS PLAN — A plan issued by Governor Brown for clean energy procurement that included 6,000 MW of additional CHP capacity.

COMBINED HEAT AND POWER — The simultaneous generation of electrical or mechanical power and useful thermal energy from a single fuel source.

DEPARTING LOAD CHARGE — An umbrella term describing several non-bypassable charges a utility customer may face when they choose to reduce or eliminate utility service and instead generate their own electricity.

GREENHOUSE GAS — Any gas that absorbs infrared radiation in the atmosphere. Common examples of greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), halogenated fluorocarbons (HCFCs), ozone (O_3), perfluorinated carbons (PFCs), and hydrofluorocarbons (HFCs).

GIGAWATT — A unit of power representing one thousand megawatts.

GIGAWATT-HOUR — A unit of energy representing one thousand megawatt-hours or, equivalently, the amount of energy produced by applying one gigawatt of power for one hour.

GRID RELIABILITY — The ability to deliver electricity from generating resources to loads, such that the overall power grid remains stable.

INTEGRATED RESOURCE PLAN — A roadmap that large utilities use to plan out generational acquisitions over five, 10, or 20 years (or more).

INVESTOR-OWNED UTILTIY — A private company that provides a utility, such as water, natural gas, or electricity, to a specific service area. Investor-owned utilities that operate in California are regulated by the CPUC.

LONG TERM PROCUREMENT PLAN — An "umbrella" planning proceeding to consider all the California Public Utilities Commission's electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. Beginning in 2016, the CPUC transitioned to the Integrated Resource Planning process.

MEGAWATT — A unit of power representing one thousand kilowatts.

MEGAWATT-HOUR – A unit of energy representing one thousand kilowatt-hours or, equivalently, the amount of energy produced by applying one megawatt of power for one hour.

NON-BYPASSABLE CHARGE — A utility surcharge that must still be paid even when a utility customer begins generating its own electricity. Non-bypassable charges usually fall into one of three volumetric electricity surcharge categories: public purpose programs, nuclear decommissioning, and repayment of a California Department of Water Resources bond.

PUBLIC UTILITIES REGULATORY POLICIES ACT — A piece of federal legislation enacted in 1978 to encourage the development of small and distributed electrical power generation, including combined heat and power facilities. This legislation led to a boom in combined heat and power development in the 1980s.

QUALIFYING FACILITY — A class of combined heat and power and small power production facilities that receive special rate and regulatory treatment under the Public Utilities Regulatory Policies Act of 1978. Utilities must take electricity from qualifying facilities.

QUALIFYING FACILITIES AND COMBINED HEAT AND POWER SETTLEMENT — A negotiated settlement, developed by utilities, QF representatives, and ratepayer advocacy groups and approved by the CPUC, that ended years of litigation among private and public parties and established regulatory procurement and GHG emission reduction targets for combined heat and power in California.

RENEWABLES PORTFOLIO STANDARD — A program that sets continuously escalating renewable energy procurement requirements for the state's load-serving entities.

RESOUCE ADEQUACY — The provision for adequate generating resources to meet projected load and generating reserve requirements in each power region.

SCOPING PLAN — A comprehensive, multi-year program to reduce greenhouse gas emissions in California.

SELF-GENERATION INCENTIVE PROGRAM — Provides incentives to support existing, new, and emerging distributed energy resources through rebates to qualifying distributed energy systems installed on the customer's side of the utility meter.

SEPARATE HEAT AND POWER — A traditional arrangement in which a facility obtains power and thermal energy from different sources (for example, buying electricity from a utility and producing steam onsite with a boiler). This term is used to identify facilities that are not combined heat and power facilities.

Acronyms and Abbreviations

Acronym	Spelled-Out Term
CHP	Combined heat and power
CPUC	California Public Utilities Commission
DLC	Departing load charge
CEC	California Energy Commission
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
GW	Gigawatt
GWh	Gigawatt-hour
IOU	Investor-owned utility
LTPP	The CPUC's Long Term Procurement Plan
MW	Megawatt
MWh	Megawatt-hour
NBC	Non-bypassable charge
PG&E	Pacific Gas and Electric
POU	Publicly Owned Utility
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying facility
QFER	Quarterly Fuel and Energy Report
QF Settlement	Qualifying Facilities and Combined Heat and Power Settlement
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SHP	Separate heat and power