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STAFF PAPER

Thermal Efficiency of Natural Gas-Fired Generation in California: 2019 Update

Michael Nyberg
Data Integration and Policy Office
Energy Assessments Division

Gavin Newsom, Governor

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ABSTRACT

The Thermal Efficiency of Natural Gas-Fired Generation: 2019 Update staff paper provides a brief overview of the general trends in power generation in California from 2001 through 2018. The paper details the changes in the type of power plants used over the past 18 years to meet load and documents the total annual natural gas usage for thermal power generation. By providing an accurate assessment of historical natural gas-usage, the paper supports the state policy that eligible renewable energy resources and zero-carbon resources supply 100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. Topics covered in the paper include data collection, power plant categories, annual generation trends, and a comparison of hourly peak loads on the hottest days in each of the past two years.

Keywords: Combined-cycle, heat rate, gas-fired generation, thermal efficiency

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EXECUTIVE SUMMARY

Senate Bill 1389 (Bowen and Sher, Chapter 568, Statutes of 2002) directed the California Energy Commission adopt an Integrated Energy Policy Report (IEPR) every two years. Senate Bill 100 (de León, Chapter 312, Statutes of 2018) mandates that eligible renewable energy resources and zero-carbon resources supply 100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. California's systemwide average thermal efficiency has improved by 30 percent since 2001 because of the use of combined-cycle plants, the phase-out of once-through-cooling plants, and the retirement of aging steam turbines. Total natural gas fuel use for power generation was the second lowest in the past 18 years. The new thermal plants are providing a sustained 23-percent improvement in fuel efficiency. The lower fuel use is also a result of significant growth in renewable energy, especially solar photovoltaic systems.

The rapid growth of utility-scale solar generation and residential rooftop solar systems, along with new state policy mandates, are limiting the long-term outlook for natural gas-fired generation. California has added more than 10,000 MW of utility-scale solar capacity since 2009, now producing about 25,000 gigawatt-hours (GWh) annually. In 2018, solar generation increased 12 percent, contributing to a dampening of supply from the state's most efficient combined-cycle plants during daylight hours. California's remaining aging gas plants were dispatched more in summer months to meet a steeper daily load requirement compared to other months of the year. Similarly, peaker plants operated earlier in the day and further into the evening hours during summer months to support changing system conditions. In 2018, California's natural gas fleet provided 47 percent of in-state generation while zero-carbon electric generation accounted for 53 percent.

CHAPTER 1: Introduction

Background

The general trends in the thermal efficiency of California's natural gas-fired generation fleet from 2001 through 2018 are presented in this staff paper. Documenting changes in the performance of power plants and the related impact on California's generation mix helps inform policy makers charged with guiding energy procurement decisions and overseeing resource planning for load-serving entities. Senate Bill 100 (de León, Chapter 312, Statutes of 2018) has established a new state policy that eligible renewable energy resources and zero-carbon resources supply 100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. This policy will effectively curb the use of natural gas power generation serving retail electricity customers in the future. The original impetus for this paper stems from the requirements of Senate Bill 1389 (Bowen and Sher, Chapter 568, Statutes of 2002), which directs the California Energy Commission (CEC) adopt an Integrated Energy Policy Report (IEPR) every two years.

To provide context for the trends observed, this staff paper begins with a brief overview of the data collection process. Chapter 2 describes the total statewide generation mix and the method used for grouping various classes of natural gas-fired power plants. Chapter 3 discusses the metrics used to measure power plant performance. Chapter 4 highlights the trends in natural gas-fired generation since 2001. Chapter 5 analyzes hourly generation and profiles the highest coincident load day of the year. Finally, Chapter 6 summarizes observed trends.

Data Collection

The paper incorporates power generation and fuel use data collected by the CEC under the authority of the California Code of Regulations, Title 20, Division 2,Chapter 3, Section 1304(a)(1)-(2). Under the regulations, all owners of power plants with a nameplate capacity of 1 megawatt (MW) or more directly serving California end users must report their respective generation, fuel, and water usage for each calendar year. "Nameplate capacity" is defined as the maximum rated output of a generator under specific conditions as designated by the manufacturer. The Energy Commission compiles and posts the power plant data on its website. Data have been compiled based on attributes of the natural gas-fired generating units within each power plant, and units have been assigned to one of five categories. All data categories are mutually exclusive, and no unit is double-counted.

The reporting regulations also apply to a small number of out-of-state power plants that are electrically within a California balancing authority's control area and directly serving California end users. A "balancing authority" is responsible for controlling the generation and transmission of electricity within its control area and between neighboring balancing authorities through imports and exports. These out-of-state power plants include the Desert Star Energy Center in Nevada and the La Rosita Power Project and Termoeléctrica De Mexicali in Mexico. There are also numerous wind and solar energy projects located in adjacent jurisdictions that are within a California balancing authority’s control.

CHAPTER 2: Natural Gas Generation Categories

California's Quarterly Fuels and Energy Reporting (QFER) regulations require power plant owners to report generation and fuel use data to the CEC for all generators with a nameplate capacity of 1 MW and larger. These data form the basis for determining the statewide generation mix each year. The data collection regulations do not apply to distributed generation systems under 1 MW such as residential rooftop solar photovoltaic (PV) systems.

Power Plants in California

As of December 31, 2018, California has about 81,000 MW of utility-scale generation capacity shared among more than 1,500 power plants. Natural gas-fired power plants account for more than half of the state's total generation capacity with slightly more than 42,000 MW. Renewable generation accounts for about 24,000 MW with 11,900 MW from solar and 6,000 MW from wind. Large hydroelectric power plants provide an additional 12,200 MW of capacity, while California's only operational nuclear power plant, Pacific Gas and Electric's Diablo Canyon Power Plant, provides 2,400 MW.

The natural gas-fired power plants examined in this paper are grouped into five categories based on a combination of duty cycles, vintage of the generating unit, and technology type. The five categories are aging, cogeneration, combined-cycle, peaking, and miscellaneous. The combined-cycle category includes three power plants that are not located in California but are electrically within the balancing area of the California ISO — they are dynamically scheduled by the California ISO for power delivery to California utilities. The three plants are the 536 MW Desert Star Energy Center in Boulder City, Nevada; the 1,100 MW La Rosita Power Plant, of which 547 MW is dedicated to California; and the 600 MW Termoelectrica de Mexicali. Both La Rosita and Termoelectrica are near Mexicali, Mexico, a few miles south of the international border. A detailed listing of the data set is published on the CEC website.[1]

Aging and Once-Through-Cooling Plants

The Aging category includes natural gas-fired power plants built and operational before 1980. Almost all are steam turbines that use once-through-cooling (OTC) technology. In OTC, power plants draw water from the ocean or other large body of water to condense steam after it has passed through a turbine to create power. However, the process results in the yearly loss of billions of aquatic organisms and the degradation of aquatic ecosystems.[2]

1 California Energy Commission website*.* QFER CEC-1304 Power Plant Owner Reporting Database*.* Accessed October 8, 2019. See https://ww2.energy.ca.gov/almanac/electricity_data/web_qfer/index_cms.php.

2 California Energy Commission Official Blog. Phase Out Looms for Power Plants That Use Water for Cooling. May 17, 2017. Accessed October 2, 2018. See http://calenergycommission.blogspot.com/2017/05/phase-out-looms-for-power-plants-that.html.

As a result of these environmental concerns, in 2010 the State Water Resources Control Board (State Water Board) adopted a statewide policy requiring all owners of OTC plants to implement a best available control technology to achieve water quality goals, specifically, a closed-cycle evaporative cooling system. Two compliance tracks established to meet the new OTC policy involved reducing intake flows to levels equivalent to those for closed-cycle evaporative cooling. Alternatively, a plant could comply by shutting down.[3] Most plants have a compliance date of December 31, 2020, while a few have compliance dates of December 31, 2024 and 2029.

On August 13, 2019, the joint-agency Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) issued a draft report recommending the State Water Board extend OTC policy compliance dates from 2020 to 2022. SACCWIS recommended the extension based on the sooner-than-expected retirement of the Etiwanda Generating Station (640 MW) in June 2018, the recently announced early retirement of the Inland Empire Energy Center (680 MW) at the end of 2019 and reduced net qualifying capacity values for wind and solar resources to meet modeled peak system needs. With 5,298 MW of OTC capacity scheduled to retire by December 31, 2020, SACCWIS recommended up to 1,163 MW of capacity from some combination of Alamitos Units 3, 4, and 5 and some portion of the remaining 2,579 MW of OTC capacity be delayed until December 31, 2022.[4] This remaining capacity (2,579 MW) is produced by Huntington Beach Generating Station Unit 2 (215 MW), Ormond Beach Generating Station Units 1 and 2 (1,516 MW), and Redondo Beach Generating Station Units 5, 6, and 8 (848 MW).

In 2001, before implementation of the State Water Board's OTC policy, there were 27 aging natural gas-fired power plants with a nameplate capacity of almost 20,000 MW. Seventeen of the 27 aging plants were classified as OTC, reflecting 15,134 MW in total nameplate capacity. On February 6, 2018, Mandalay Generating Station retired, shutting down two aging OTC steam turbines and a smaller peaking unit. On June 1, 2018, the 1,049 MW Etiwanda Generating Station retired after more than 55 years of operation. Most recently, the Encina Power Station retired December 11, 2018, removing another 965 MW of OTC capacity from the state's portfolio. By the close of 2018, nine aging power plants remained, accounting for 6,584 MW or about 8 percent of total statewide capacity. Six of these aging plants are also classified as OTC with a total capacity of 6,155 MW.

Cogeneration Plants

The Cogeneration category consists of a mix of combined-cycle units, combustion turbine generators, and steam turbine generators that produce electricity and thermal energy for useful purposes. These plants are also commonly referred to as "combined heat and power, or

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3 California Energy Commission. *Tracking Progress. Once-Through Cooling Phase Out*. See http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.

4 California State Water Resources Control Board, *Report of the Statewide Advisory Committee on Cooling Water Intake Structures - Local and System-Wide 2021 Grid Reliability Studies - Final August 23, 2019*, Accessed November 8, 2019. See https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/sccwf.pdf.

"CHP," plants. Cogeneration plants have an onsite (or nearby) thermal host, such as a petroleum refinery or college campus, as well as a contract with the local utility that ensures all associated electricity generated is purchased. These plants are often classified as "qualifying facilities," or QFs, as defined under the Code of Federal Regulations Public Utility Regulatory Policies Act of 1978 (PURPA).[5] PURPA fostered innovation in renewable generation and levelized competition with traditional fossil fuel generators for small power producers.

QFs fall into two categories: qualifying cogeneration facilities and qualifying small power production facilities of 80 MW or less whose primary energy source is renewable, biomass, waste, or geothermal resources. For QFs that are cogeneration facilities, there is no size limit. The primary benefit of being classified as a QF is the ability to sell power to utilities at avoided-cost rates. "Avoided-cost rates" are defined as the rate that would approximate the cost for a utility to generate or purchase the same amount of electricity from another source.

Traditionally, utilities were able to purchase nonutility electricity at rates below their own generation costs, and this ability put small power producers and cogenerators at a disadvantage. Since cogenerators serve dedicated thermal hosts, they do not have the same flexibility as traditional power plants to curtail their electric generation without also affecting their thermal operations. By attaining QF status under PURPA, CHP plants are guaranteed to be able to sell their power to a local utility. Over the years since the PURPA regulations took effect, utilities have tried to limit the definition of cogeneration as it applies to CHP plants due in part to the high fixed costs associated with interconnecting to cogeneration facilities. However, federal courts have consistently maintained a broad interpretation of the definition of cogeneration and what constitutes a QF facility. The PURPA regulations have resulted in qualifying cogeneration facilities operating at consistently high capacity factors, as observed over the past 18 years of QFER data.

The number of cogeneration plants in California continues to decline, from 151 plants in 2001 to 120 plants at the end of 2018. Total capacity is down 942 MW from 2001 levels to 5,438 MW in 2018, about 7 percent of statewide capacity. Two-thirds of California's cogeneration plants are rated at 50 MW or less with a median capacity of 27 MW.

Combined-Cycle Plants

The Combined-Cycle category of power plants is defined as having a generation block consisting of at least one combustion turbine, a heat recovery steam generator (HRSG), and a steam turbine. The higher fuel efficiency results from the ability of the HRSG to capture exhaust gas from the combustion turbine to produce steam for the steam turbine, often augmented with duct burning of natural gas within the HRSG. For this report, the Combined-Cycle category consists of those plants constructed since 2000 with a total capacity of 100 MW or more.

California's newer combined-cycle plants produce electricity with better heat rates than either stand-alone combustion turbines or steam turbines. Historically, these plants have been used as baseload generation. "Baseload generation" refers to those plants designed to operate at an

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5 Qualifying facilities as defined in 16 U.S.C. §796(18)(A) and 18 CFR 292.203.

annualized capacity factor of at least 60 percent. However, with the increasing integration of renewable generation, along with the inherent regulatory must-take generation from QFs, combined-cycle plants are being tasked for flexible, load-balancing requirements that involve more frequent fast starts, cycling, and load-following ancillary services.[6]

Load-following ancillary services are reserved electric generating capacity that can be increased or decreased through automatic generation control systems to allow continuous balance between generating resources and electricity demand. Load following is the difference in generation requirements between the hour-ahead energy forecast and the five-minute-ahead forecast within a balancing authority.[7]

In 2001, the 550 MW Sutter Energy Center in Yuba City (Sutter County) and the 594 MW Los Medanos Energy Center in Pittsburg (Contra Costa County) were the only combined-cycle power plants in this category. By the close of 2018, California had 35 large combined-cycle plants totaling almost 20,000 MW in nameplate capacity, or about 25 percent of statewide electric generation capacity. However, as described below, the planned closure of the Inland Empire Energy Center will reduce total capacity in the state by 810 MW.

On June 19, 2019, the Inland Empire Energy Center, LLC, a subsidiary of General Electric Company (GE), announced the closure of the 10-year old Inland Empire Energy Center combined-cycle power plant because of economics and increasing incompatibility with the high levels of renewables in California's electricity market. The plant was designed for baseload operation, obtaining fuel efficiency at the expense of fast-start flexibility, with the use of a pair of newly designed GE 7H single-shaft combined cycle generators. Inland Empire achieved industry-leading thermal efficiencies greater than 60 percent. For perspective, in 1990, typical combined-cycle efficiency was 50 percent. By 2010, the best plants reached 59 percent efficiency.[8]

This model of combustion turbine has had limited use worldwide. The result was an orphaned technology that required roughly 2.5 times higher operational and maintenance costs than other comparable combined-cycle installations. In addition, retrofitting the Inland Empire plant to improve start-up times, ramp rates, turndown ratios, or maintenance costs was not economically feasible. The Inland Empire plant will be retired and replaced with a utility-scale

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6 "Must-take generating resources" are identified by the California ISO or a local regulatory authority as generating units that are subject to an existing QF contract or a power purchase agreement with mandatory obligations under federal law. Must-take generation also includes generation from nuclear units and generation delivered from cogeneration plants with mandatory requirements to serve a thermal host.

7 Makarov, Yuri V., Clyde Loutan, Jian Ma, and Phillip de Mello. 2009. *Operational Impacts of Wind Generation on California Power Systems.* *IEEE Transactions on Power Systems,* Vol. 24, No. 2. See http://www.caiso.com/Documents/OperationalImpacts-WindGenerationonCaliforniaPowerSystems.pdf.

8 Breeze, Paul. 2011. "Efficiency Versus Flexibility: Advances in Gas Turbine Technology." *Power Engineering International.* Issue 3, Volume 19. Accessed on September 20, 2019. See https://www.powerengineeringint.com/2011/04/01/efficiency-versus-flexibility-advances-in-gas-turbine-technology/.

battery energy storage system (BESS) to integrate renewable generation.[9] A BESS is an array of batteries designed to provide instantaneous energy to the grid, thereby avoiding fuel use from a natural gas turbine operating at minimum loads. Unlike a BESS, natural gas turbines have minimum operating loads, much like an automobile idling at rest.

Peaking Plants

The Peaking category consists of simple-cycle generating units. These units have a peaking duty cycle role — specifically, they are called upon to meet peak demand loads for a few hours or less on short notice, often in the 15-minute or 5-minute-ahead real-time market. This category also includes peaking plants with integrated BESS technology. BESS technology enables instantaneous energy to the grid, thereby avoiding fuel use and related emissions from gas turbine operation at minimum loads.

Traditionally, peaking plants have provided nonspinning reserves, a term denoting nonoperating plants capable of ramping up to full capacity and synchronizing to the grid within 10 minutes of dispatch. However, with the BESS hybrid configurations, these plants can now provide spinning reserves without operating the gas turbine. "Spinning reserves" is a term referencing operating (in other words, spinning) resources that are synchronized and ready to meet electric demand within 10 minutes through ramping to maintain system stability. The BESS provides instantaneous ramping to accommodate renewable integration and results in fewer starts for the gas turbine, reduced water usage, and reduced emissions. GHG and criteria pollutant emissions are reduced as the BESS allows the turbine to operate at more efficient, full-load output levels more often and reduces the times when the turbine operates at partial load.

In 2001, there were 29 peaking plants in California; by the close of 2018, there were 74 facilities with 9,526 MW of nameplate capacity, about 12 percent of total statewide capacity. The newest peaker, the 525 MW Carlsbad Energy Center, came on-line incrementally over three months in 2018. It was built on the existing Encina Power Station site and planned as a direct replacement for Encina's aging OTC units. A unique feature of the new Carlsbad plant is the five, fast-starting simple-cycle combustion turbines that provide rapid response to peak demand requirements. Each turbine is nominally rated at 105 MW. The flexibility of the simple-cycle units will also help accommodate the integration of renewable generation at a net efficiency of 44 percent.

Miscellaneous Plants

All remaining natural gas-fired power plants are included in the Miscellaneous category. These include technologies such as fuel cell and reciprocating engine applications, turbine testing facilities, as well as older generating units built before the 2000s that are not considered aging, peaking, or cogeneration. This category also includes generating units that have been

9 California Energy Commission, 01-AFC-17C, June 20, 2019. *Inland Empire Energy Center Decommissioning and Demolition Plan*. Accessed on September 20, 2019. See https://efiling.energy.ca.gov/GetDocument.aspx?tn=228806&DocumentContentId=60139.

repowered from stand-alone to combined-cycle operation. At the close of 2018, this category totaled 838 MW, about 1 percent of total capacity in the state.

CHAPTER 3: Performance Metrics

This chapter presents three measurements of performance for each category of natural gas-fired generation. Annual capacity factors, heat rates, and thermal efficiencies are defined and used to describe the typical operation of the average power plant within each category. Where appropriate, cogeneration plants are excluded due to the intrinsic capability to produce electricity and useful heat for nongeneration purposes. **Table 1** summarizes the performance metrics for 2018.

Table 1: Natural Gas-Fired Power Plant Summary Statistics, 2018

Category	Capacity (MW)	Energy (GWh)	Capacity Factor	Fuel Use (MMBtu)	Heat Rate (Btu/kWh)	Thermal Efficiency
State Total/Average	42,282	97,756	25.7%	848,059,844	7,728	44.2%
Combined-Cycle	19,896	67,017	38.3%	491,284,846	7,331	46.6%
Cogeneration	5,438	22,663	46.4%	267,737,303	N/A	N/A
Aging	6,584	2,332	3.4%	30,804,852	13,212	25.8%
Peaking	9,526	4,140	5.1%	43,264,444	10,450	32.7%
Miscellaneous	838	1,604	21.8%	14,968,399	9,333	36.6%

Source: QFER CEC-1304 Power Plant Data Reporting

Capacity Factor

The statewide capacity factor for natural gas-fired generation in 2018 is about 26 percent, down from 45 percent in 2001. The "capacity factor" is the ratio, expressed as a percentage, of the actual output of a power plant over a given period to the related maximum potential output over the same period. The capacity factors shown in **Table 2** provide a breakdown of the statewide average into the five categories of natural gas-fired power plants in California since 2001.

The primary driver of the capacity factor for natural gas generation is the seasonal availability of hydroelectric energy. Combined-cycle generation is displaced in wet hydrological years by hydroelectric energy as it is the only category large enough, at almost 20,000 MW, that can absorb the displacement of 14,000 MW of hydroelectric generating capacity.

Table 2: Capacity Factors, 2001 – 2018

Year	Combined-Cycle	Aging	Peaking	Cogeneration	Miscellaneous	State Average
2001	53.9%	42.1%	11.8%	68.0%	9.9%	44.9%
2002	65.7%	21.1%	5.3%	73.4%	9.8%	32.7%
2003	53.5%	15.5%	4.1%	71.3%	14.3%	30.3%
2004	58.6%	16.2%	4.4%	71.9%	15.4%	33.3%
2005	53.3%	10.1%	4.0%	66.3%	17.7%	30.1%
2006	53.6%	9.6%	3.7%	62.9%	16.6%	31.0%
2007	62.3%	9.1%	4.2%	64.4%	18.9%	34.2%
2008	62.2%	10.4%	4.4%	63.1%	19.9%	34.6%
2009	58.3%	7.6%	4.0%	61.2%	15.8%	32.1%
2010	52.2%	4.4%	3.0%	60.1%	18.1%	29.1%
2011	37.5%	4.1%	3.5%	59.1%	23.4%	24.2%
2012	55.3%	7.6%	5.1%	57.2%	22.4%	32.2%
2013	53.0%	5.9%	5.2%	56.5%	24.6%	30.8%
2014	51.5%	5.4%	5.8%	55.0%	24.3%	30.6%
2015	50.7%	6.0%	5.9%	52.3%	25.1%	30.6%
2016	40.7%	3.9%	5.1%	49.0%	23.2%	25.7%
2017	35.9%	4.2%	5.2%	46.4%	23.3%	24.5%
2018	38.3%	3.4%	5.1%	46.4%	21.8%	25.7%

Source: QFER CEC-1304 Power Plant Data Reporting

Table 3 lists the annual total generation for natural gas-fired generation and hydroelectric generation in California. As measured over the past 18 years, statewide natural gas and hydroelectric electric generation are negatively correlated.[10] About half of the variance between natural gas-fired generation and hydroelectric generation is explained by correlation. While there are other factors that influence natural gas-fired generation, the availability of hydroelectric generation is a primary driver.

A secondary factor impacting combined-cycle capacity factors is the growth of solar PV generation. Like hydroelectric generation, solar PV generation is displacing natural gas-fired generation during daylight hours. California has added more than 10,000 MW of utility-scale solar PV capacity since 2009, now producing about 25,000 gigawatt-hours (GWh) annually. “Utility-scale” is defined as systems rated at 1 MW or larger in nameplate capacity. Similarly, behind-the-meter residential solar PV systems have added an additional 8,000 MW of capacity since 2009, producing about 14,000 GWh annually.

10 With a correlation coefficient r= -0.681, the coefficient of determination, r^2, is 0.46.

Table 3: Natural Gas-Fired Electric Generation, 2018 (GWh)

Year	Combined-Cycle	Aging	Cogeneration	Peaking	Misc.	Total In-State Natural Gas Generation	Total In-State Hydroelectric Generation	Total In-State Generation
2001	2,730	73,000	37,898	1,752	1,024	116,404	24,988	202,733
2002	12,954	36,526	40,923	1,317	1,013	92,733	31,359	187,057
2003	26,335	25,877	39,329	1,145	1,809	94,496	36,321	194,572
2004	37,605	24,937	39,358	1,304	2,064	105,268	34,490	199,023
2005	42,576	14,639	36,559	1,206	2,145	97,125	40,263	202,310
2006	57,481	14,132	34,552	1,214	1,840	109,219	48,559	218,869
2007	71,357	13,339	35,500	1,471	2,099	123,766	27,106	212,928
2008	75,936	15,303	34,824	1,840	1,919	129,823	24,460	209,646
2009	75,382	11,193	33,559	1,796	1,513	123,443	28,540	207,546
2010	72,472	6,216	32,660	1,436	1,714	114,498	34,190	205,893
2011	54,748	5,679	31,372	1,757	2,517	96,072	42,737	201,618
2012	85,090	10,421	30,231	2,615	2,348	130,705	27,461	199,860
2013	87,179	7,586	29,699	3,554	1,800	129,818	24,101	199,809
2014	88,187	6,221	28,675	4,388	1,779	129,249	16,482	199,732
2015	86,990	6,448	27,022	4,444	1,846	126,749	13,996	197,073
2016	71,158	3,892	25,198	3,934	1,708	105,890	28,986	198,632
2017	62,750	3,183	23,270	4,202	1,721	95,126	43,303	206,488
2018	67,017	2,332	22,663	4,140	1,604	97,755	26,291	195,405

Source: QFER CEC-1304 Power Plant Data Reporting

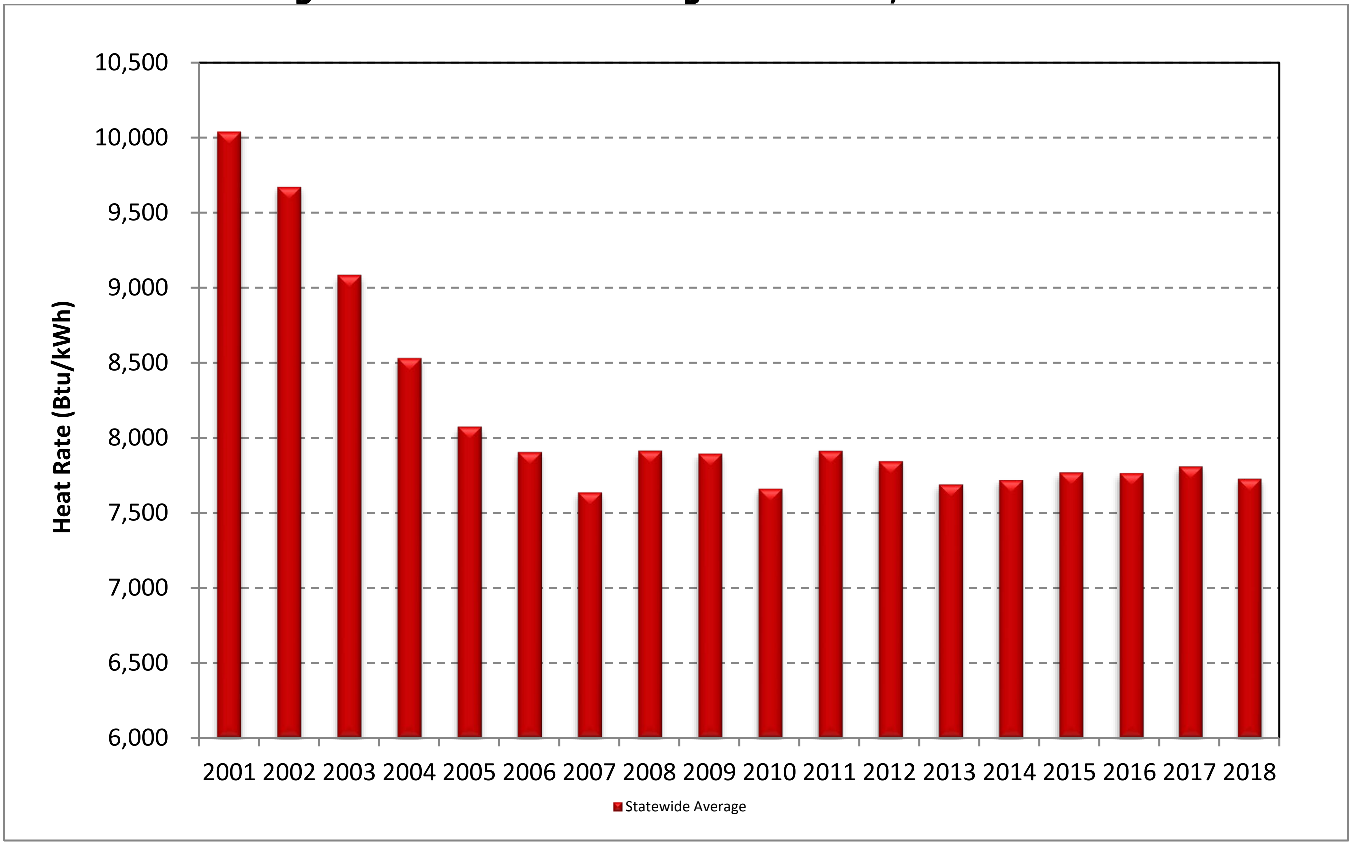
Heat Rate

All fuels, including natural gas, are converted into useful energy according to the associated heat content, which is measured in British thermal units (Btu). The heat content quantifies the amount of heat released during an exothermic reaction such as combustion. A "Btu" is the amount of energy required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

In a natural gas-fired generation plant, the relative efficiency is measured by the related heat rate. The heat rate expresses how much fuel is required to generate 1 kilowatt-hour (kWh) of electric energy.[11] A higher heat rate indicates a less efficient useful energy conversion process. **Figure 1** displays the annual statewide average heat rate from 2001 through 2018. The improvement in the statewide average heat rate since 2001 reflects the transition away from the use of inefficient steam turbines to more fuel-efficient combined-cycle turbines. More recently, the availability of hydroelectric generation during wet hydrological years has restricted potential improvements in the statewide average heat rate.

11 Heat rates are calculated in higher heating value terms. Higher heating value includes the latent heat of vaporization of water in the combustion of natural gas.

Figure 1: Statewide Average Heat Rate, 2001-2018



Source: QFER CEC-1304 Power Plant Data Reporting

Ultimately, there are practical limits to the state's ability to reduce its systemwide heat rate. The primary factor is how often natural gas-fired power plants operate over the available hours. The increasing growth of wind and solar generation has resulted in increased flexibility requirements of the existing natural gas fleet. Wind and solar generation are inherently variable and partially unpredictable. Flexibility requires natural gas power plants to cycle power output by starting up, shutting down, or ramping up and down within a prescribed set of operational limits. Ramping and cycling result in increased fuel consumption, a result of the large temperature and pressure changes that take place in plant equipment. For those power plants designed to operate most efficiently at constant output levels, cycling leads to greater wear and tear and reduced lifespan of the equipment, along with reduced thermal efficiency. Studies have found that cycling results in a 1 percent permanent degradation in the heat rate of a generating unit over four to five years.[12]

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12 Kumar, N., P. Besuner, S. Lefton, D. Agan, and D. Hilleman. National Renewable Energy Laboratory. July 2012. *Power Plant Cycling Costs*. Accessed on October 9, 2019. See https://www.nrel.gov/docs/fy12osti/55433.pdf.

Table 4 provides the heat rate for each category that contributes to the statewide average shown in **Figure 1**.[13] Combined-cycle generation had the lowest heat rate of the past three years, pushing the statewide average down by 1 percent to 7,728 Btu/kWh, the fourth-lowest average since 2001. The statewide average heat rate has remained below 8,000 Btu/kWh since 2007 as aging generation has fallen to just 3 percent of the 2001 levels. From 2007 through 2018, the natural gas-fired generation fleet has provided a consistent 23 percent improvement in fuel efficiency compared to 2001.

Table 4: Heat Rates, 2001 – 2018 (Btu/kWh)

Year	Combined-Cycle	Aging	Peaking	Miscellaneous	State Average
2001	6,974	10,122	11,336	10,153	10,040
2002	7,147	10,529	10,866	9,530	9,672
2003	7,209	10,835	10,820	10,296	9,086
2004	7,178	10,917	10,804	9,957	8,751
2005	7,230	11,279	10,798	9,947	8,376
2006	7,229	11,282	10,762	9,975	8,121
2007	7,190	10,971	10,862	9,988	7,889
2008	7,147	11,131	10,582	10,074	7,915
2009	7,227	11,590	10,832	10,409	7,896
2010	7,199	11,677	11,012	9,923	7,663
2011	7,287	12,297	10,740	9,671	7,913
2012	7,231	11,702	10,858	9,585	7,844
2013	7,220	11,406	10,333	9,545	7,690
2014	7,273	11,775	10,309	9,351	7,720
2015	7,320	11,676	10,227	9,478	7,771
2016	7,339	12,311	10,268	9,432	7,766
2017	7,346	12,262	10,533	9,844	7,810
2018	7,331	13,212	10,450	9,333	7,728

Source: QFER CEC-1304 Power Plant Data Reporting

Displacement by hydroelectric generation during wet hydrological years is a limiting factor in attaining higher fuel efficiency as measured by the heat rate. Other factors that limit or constrain California's ability to reach higher thermal efficiency levels include topography and climate. Power plant efficiency is impacted by the location, elevation, and ambient weather conditions at each plant site. Locational factors may include emissions limits by air quality management districts, localized noise limits, and limits on hours of operation.[14] Power plants in higher elevations experience reduced air density; lower air density decreases power generated

13 Cogeneration plants are excluded from the statewide average heat rate since these plants produce thermal energy simultaneously with electrical energy. There is no industrywide standard for determining the heat rate for these systems.

14 South Coast Air Quality Management District, Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions. See http://www.aqmd.gov/docs/default-source/rule-book/reg-xx/rule-2012.pdf.

by the gas turbine. Ambient weather also has a significant impact on thermal efficiency. Like high altitude factors, power plants located in areas with high average temperatures also experience reduced air density with a consequential loss in power generation efficiency.

Thermal Efficiency

Thermal efficiency is a unitless measure of the efficiency of converting a fuel to energy and useful work. Under ideal conditions of energy conversion with no losses, 3,412 Btu equals 1 kWh. The thermal efficiency is determined by comparing the ideal conversion of fuel to energy with the measured heat rate of each category of natural gas-fired generation. Based on the heat rates from **Table 4**, the thermal efficiency for each category is shown in **Table 5**. The cogeneration category is not included in the table as there is not enough information to determine the additional fuel the cogeneration system consumes above what would have been used by a boiler to produce the thermal output of the cogeneration system.[15]

As observed with the heat rates, the statewide thermal efficiency has improved from 34 percent in 2001 to 44.2 percent in 2018, a 30 percent improvement, because of the proliferation of combined-cycle generation replacing steam turbine generation. The thermal efficiency of the aging category declined over the past 18 years as steam turbines were decommissioned once they reached the end of the useful service life or because of OTC compliance requirements. However, in recent years the average thermal efficiency of the combined-cycle category has dropped by about 1 percent as these units have been displaced by the significant growth of solar generation. The displacement by solar generation is being listed as a primary reason the owners of 810 MW Inland Empire Energy Center announced its retirement after 10 years of operation.

15 United States Environmental Protection Agency. Methods for Calculating CHP Efficiency. Accessed on October 10, 2019. See https://www.epa.gov/chp/methods-calculating-chp-efficiency.

Table 5: Thermal Efficiency, 2001 – 2018

Year	Combined- Cycle	Aging	Peaking	Miscellaneous	State Average
2001	48.9%	33.7%	30.1%	33.6%	34.0%
2002	47.8%	32.4%	31.4%	35.8%	35.3%
2003	47.3%	31.5%	31.5%	33.1%	37.6%
2004	47.5%	31.3%	31.6%	34.3%	39.0%
2005	47.2%	30.3%	31.6%	34.3%	40.7%
2006	47.2%	30.2%	31.7%	34.2%	42.0%
2007	47.5%	31.1%	31.4%	34.2%	43.3%
2008	47.8%	30.7%	32.3%	33.9%	43.1%
2009	47.2%	29.4%	31.5%	32.8%	43.2%
2010	47.4%	29.2%	31.0%	34.4%	44.5%
2011	46.8%	27.8%	31.8%	35.3%	43.1%
2012	47.2%	29.2%	31.4%	35.6%	43.5%
2013	47.3%	29.9%	33.0%	35.8%	44.4%
2014	46.9%	29.0%	33.1%	36.5%	44.2%
2015	46.6%	29.2%	33.4%	36.0%	43.9%
2016	46.5%	27.7%	33.2%	36.2%	43.9%
2017	46.4%	27.8%	32.4%	34.7%	43.7%
2018	46.6%	25.8%	32.7%	36.6%	44.2%

Source: QFER CEC-1304 Power Plant Data Reporting.

CHAPTER 4: Generation Trends

Total System Electric Generation

The combination of California's own generation and imported energy from other balancing authorities in the Western Interconnection is referred to as "total system electric generation" or "total system power"; both terms are used interchangeably. In a typical calendar year, California generates about 70 percent of its electrical energy and imports the remaining 30 percent. California's natural gas plants accounted for 47 percent (90,691 GWh) of total in-state electric generation. The total system electric generation summary for 2018 is shown in **Table 6**.

Table 6: California's Total System Electric Generation, 2018

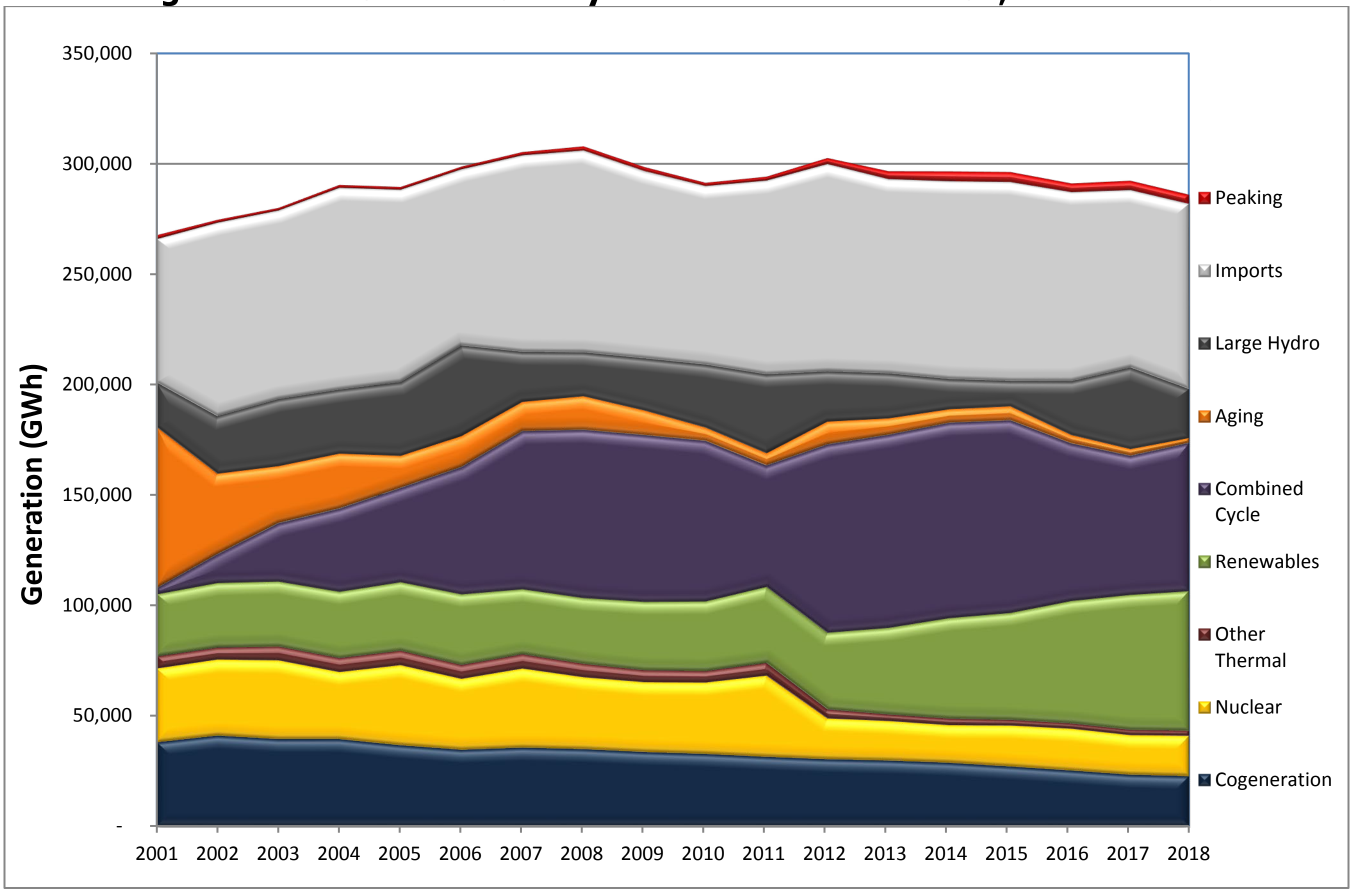
Fuel Type	California Generation (GWh)	Imports (GWh)	Total Generation (GWh)	Percentage Share
Coal	294	9,139	9,433	3.3%
Large Hydroelectric	22,096	8,403	30,499	10.7%
Natural Gas	90,691	8,953	99,644	34.9%
Nuclear	18,268	7,573	25,841	9.1%
Oil	35	0	35	0.0%
Other (Petroleum Coke/Waste Heat)	430	9	439	0.2%
Renewables	63,028	26,474	89,502	31.4%
Biomass	5,909	798	6,707	2.3%
Geothermal	11,528	1,440	12,968	4.5%
Small Hydro	4,248	335	4,583	1.6%
Solar	27,265	5,268	32,533	11.4%
Wind	14,078	18,633	32,711	11.5%
Unspecified Sources of Power	N/A	30,095	30,095	10.5%
Total	194,842	90,646	285,488	100.0%

Source: QFER CEC-1304 Power Plant Data Reporting

Total generation for California in 2018 was 285,488 gigawatt-hours (GWh), with in-state generation providing 68 percent of the total annual energy requirement. Noncarbon dioxide- (CO_2) emitting electric generation categories (nuclear, large hydroelectric, and renewables) accounted for 51 percent of statewide supply, while natural gas served about 35 percent of total demand. Though not included in the annual summary, behind-the-meter solar PV generation is estimated at 14,000 GWh for 2018. When added to total system power, California's total electric generation requirement is about 300,000 GWh.

Figure 2 summarizes California's annual energy mix. The chart illustrates the relative contribution of each category of natural gas-fired generation to the state's total generation, including imports. The slow and steady decline of cogeneration output over the past 18 years becomes apparent in the chart. The closure of the San Onofre Nuclear Generating Station is observable by the steep drop in nuclear generation output in 2012. Hydroelectric generation was strong in 2011 and 2017, displacing combined-cycle generation in those years. In 2018, California experienced its thirty-fourth driest year since 1895 as drought conditions returned to the state and hydroelectric generation fell by 40 percent to 26,344 GWh from 2017 levels. Solar generation increased 12 percent in 2018, helping boost California's renewable generation to 32 percent of total in-state supply.

Figure 2: California's Total System Electric Generation, 2001 – 2018



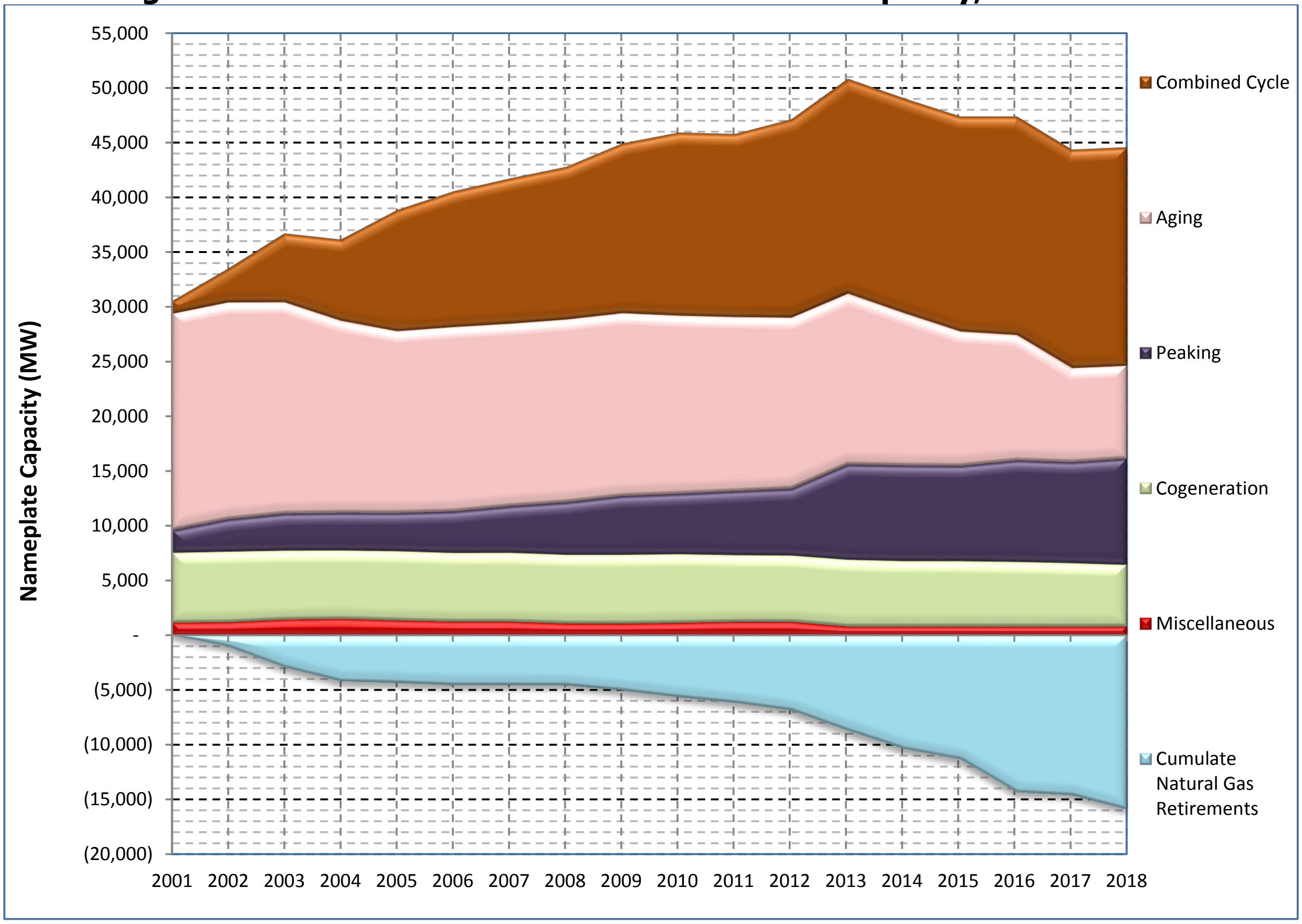
Source: QFER CEC-1304 Power Plant Data Reporting

Natural Gas Generation

Overall, in-state natural gas-fired electric generation was like that of 2017, accounting for almost 47 percent of in-state generation or 90,691 GWh, up 1.3 percent from 89,564 GWh. Imported natural gas-fired generation contributed an additional 8,953 GWh. As a result, natural gas totaled 99,644 GWh or about 35 percent of the California power mix.

Figure 3 displays the changes in natural gas-fired generation capacity for each category over the past 18 years. The peaking category continues to expand in capacity as larger, load-following combustion turbines are dispatched to integrate solar and wind generation. Combined-cycle capacity has remained relatively stable over the past three years, while aging and cogeneration plants have been slowly but steadily retired over the years. Cumulative retirements are depicted by the blue area under the stacked-area graph. More than 16,900 MW of natural gas-fired capacity has been retired since 2001.

Figure 3: Annual Natural Gas-Fired Generation Capacity, 2001 – 2018



Source: QFER CEC-1304 Power Plant Data Reporting

California's aging power plants accounted for about 3 percent (2,332 GWh) of natural gas-fired electric generation in 2018 but still hold 16 percent of California's gas-fired generation capacity. With an average heat rate of 13,212 Btu/kWh, California's aging plants continue to carry the distinction of having the most inefficient heat rates. The low capacity factors suggest the primary value of this group of power plants is in providing capacity support for local reliability that may include voltage control, frequency control, and other ancillary services.[16] Control of voltage and frequency within a power system is essential to maintaining the balance between generation and load.

As hydroelectric generation is a large determinant of natural gas-fired generation, **Figure 4** displays the monthly hydroelectric generation for 2018 within a band that represents the minimum and maximum monthly generation reported over the previous five years. Based on snowpack conditions and precipitation levels, 2018 was considered a dry hydrological year by the State Water Board. While there is no statewide definition of what constitutes a wet or dry

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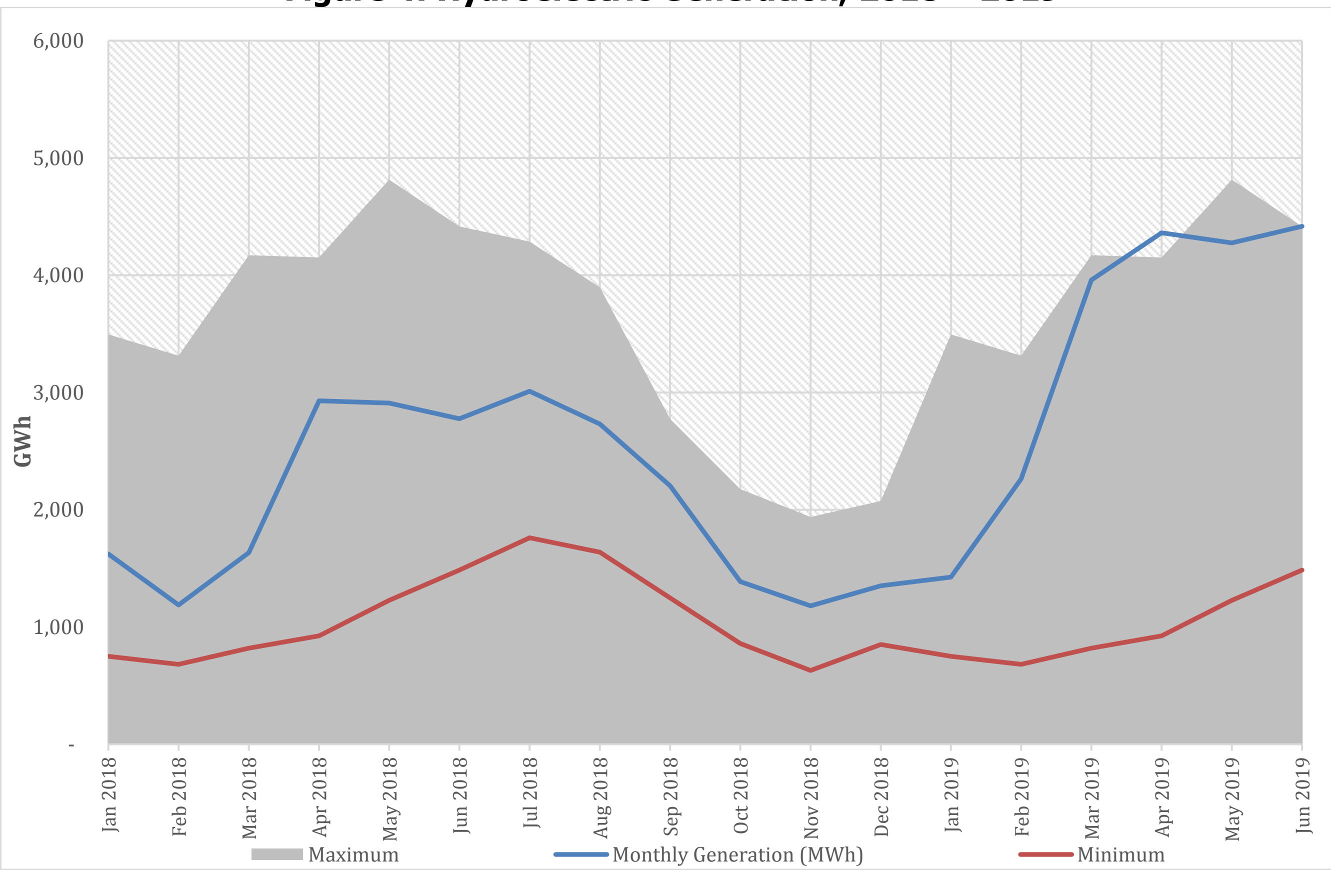
16 California Energy Commission. *The Role of Aging and Once-Through-Cooling Power Plants in California — An Update*. CEC-200-2009-018. See http://www.energy.ca.gov/2009publications/CEC-200-2009-018/CEC-200-2009-018.PDF.

hydrological year, 75 percent of California's annual precipitation occurs from November through March, with 50 percent occurring from December through February. A water year begins on October 1 and runs through September 30. The state's precipitation totals depend upon a relatively small number of storms and, as such, a few storms determine if the year will be wet or dry. California's dry years of 2012 through 2016 were followed by an above-average wet year in 2017. However, in 2018 dry conditions returned and combined-cycle generation grew by 7 percent over 2017 levels.

Figure 4: Hydroelectric Generation, 2018 – 2019



Source: QFER CEC-1304 Power Plant Data Reporting

Looking ahead, hydroelectric generation appears to be on track for further displacement of natural gas-fired generation for the 2019 calendar year. Snowpack levels on April 1, 2019, were 175 percent of average, and statewide reservoir levels on September 30, 2019, were 128 percent of average, making 2019 a wet hydrological year. QFER reporting by power plant owners for the first six months of 2019 indicate hydroelectric generation is up 60 percent over the same period in 2018. March through June show above-average generation compared to historical periods.

CHAPTER 5: California ISO Hourly Generation

Statistics comparing the hourly generation of aging, combined-cycle, and peaking power plants in the California ISO balancing area are presented in **Table 7**. For each year, the fleet totals and plant averages were calculated using hourly output values greater than 1 MWh. Values less than or equal to 1 MWh were eliminated to avoid inclusion of partial hours of operation that tend to exaggerate the statistical differences in the calculation of standard deviation and the average. Previous staff reports have used a 10 MW threshold, but this threshold removed too many smaller values from the peaking category, as most of plants in that category are less than 50 MW in capacity.

Table 7: Hourly Generation Summary, 2017 – 2018

Category	Aging 2017	Aging 2018	Combined-Cycle 2017	Combined-Cycle 2018	Peaking 2017	Peaking 2018
Fleet: Total Generation (GWh)	2,778	2,068	49,157	54,223	3,114	3,159
Plant: Avg. Hourly Output (MWh)	87	73	307	340	39	42
Plant: Std. Deviation (MWh)	103	87	174	187	33	35
Fleet: Operational Hours	32,096	28,306	160,002	153,257	79,333	75,746
Fleet: Total Available Hours	227,760	192,720	306,600	289,080	884,760	928,460
Number of Generating Units	26	22	35	33	101	106

Source: California ISO

In 2018, combined-cycle power plants within the California ISO had an average hourly output of 340 MWh, up 10 percent from 307 MWh in 2017. While the total number of operational hours declined 4 percent from 2017 levels, the total generation from combined-cycle plants within the California ISO increased by 10 percent to 54,223 GWh. The variability of hourly generation, as defined by the standard deviation, increased from 174 MWh to 187 MWh. Overall, the hourly output of combined-cycle power plants ranged from 153 MWh and 527 MWh 68 percent of the time. The higher average output, combined with increased variability and fewer operational hours in 2018, support the observation that combined-cycle plants were ramped more frequently to higher levels of output to balance intermittent solar and wind generation.

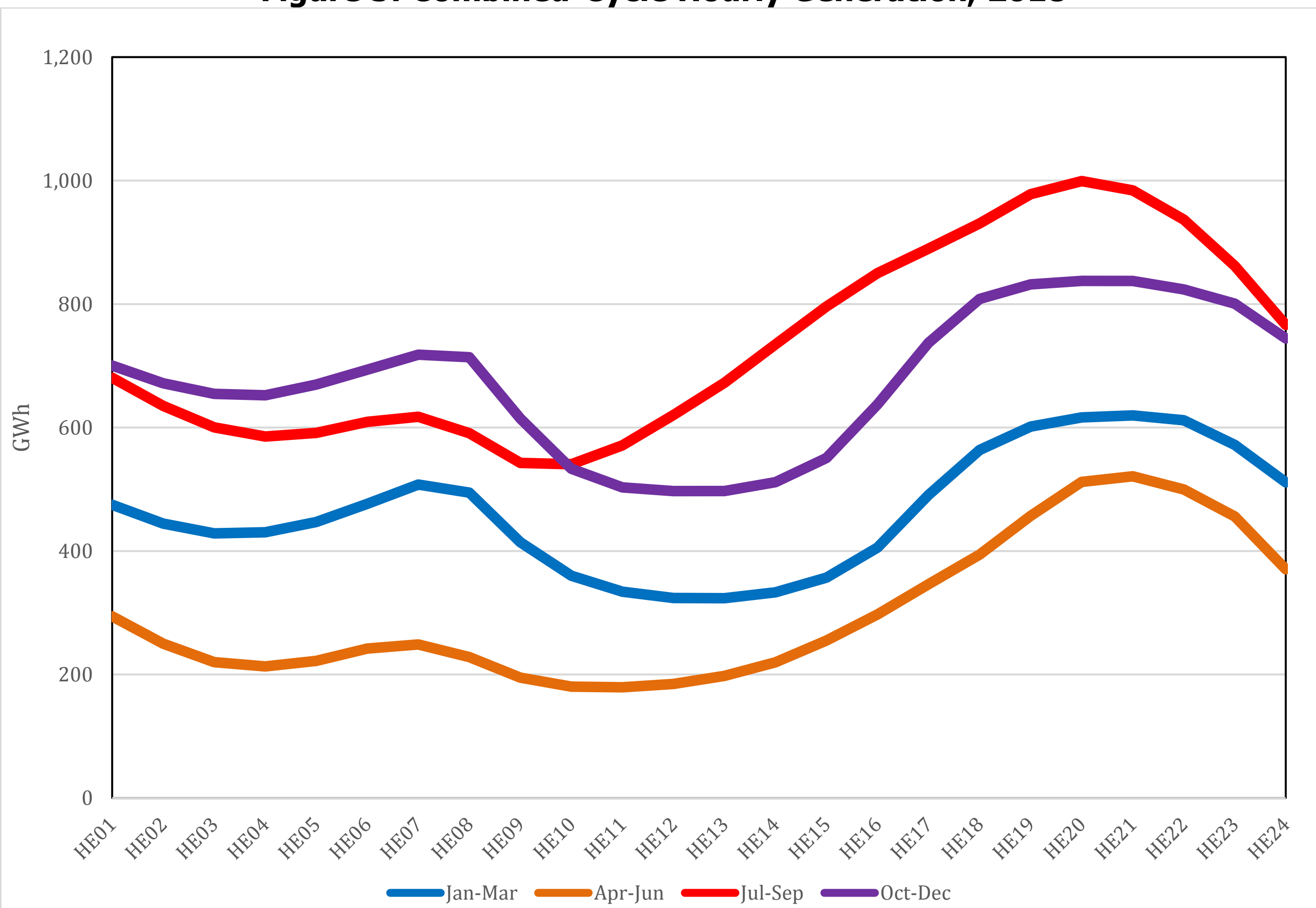
Aging units generated less energy in 2018, down 26 percent to 2,068 GWh. The average hourly output declined by 16 percent to 73 MWh in 2018. Retirements in 2017 included Moss Landing and Broadway. In 2018, Mandalay, Etiwanda, and Encina closed in February, June, and December, respectively. Retirements resulted in 12 percent fewer operational hours with 22 aging units operating in 2018.

Peaking plants in the California ISO generated 3,159 GWh in 2018, marginally higher than 2017 (3,114 GWh). The average hourly output was up slightly from 39 MWh to 42 MWh in 2018. The average hourly output is growing due to the construction of larger, load-following plants such as the 525 MW Carlsbad Energy Center and the 400 MW Panoche Energy Center. These plants use multiple simple-cycle combustion turbines, nominally rated at 100 MW – 105 MW each. Previously, peaking plants consisted almost exclusively of 50 MW combustion turbines. Variability about the mean was about the same as 2017 at 35 MWh. Peaking plants operated during 8 percent of all available hours, down slightly from 2017.

Hourly Profiles

Figure 5 displays the annual generation provided by combined-cycle plants for each hour in 2018. Generation in July through September shows a significantly flatter, almost linear, slope of increasing electric generation from 10:00 a.m. (HE10) through to 8:00 p.m. (HE20). The combined-cycle fleet steadily increases output across these hours to replace declining solar generation from noon through sunset. The steepest ramping occurs in the winter (January through March) and fall (October through December) as there are fewer available daylight hours for solar generation.

Figure 5: Combined-Cycle Hourly Generation, 2018

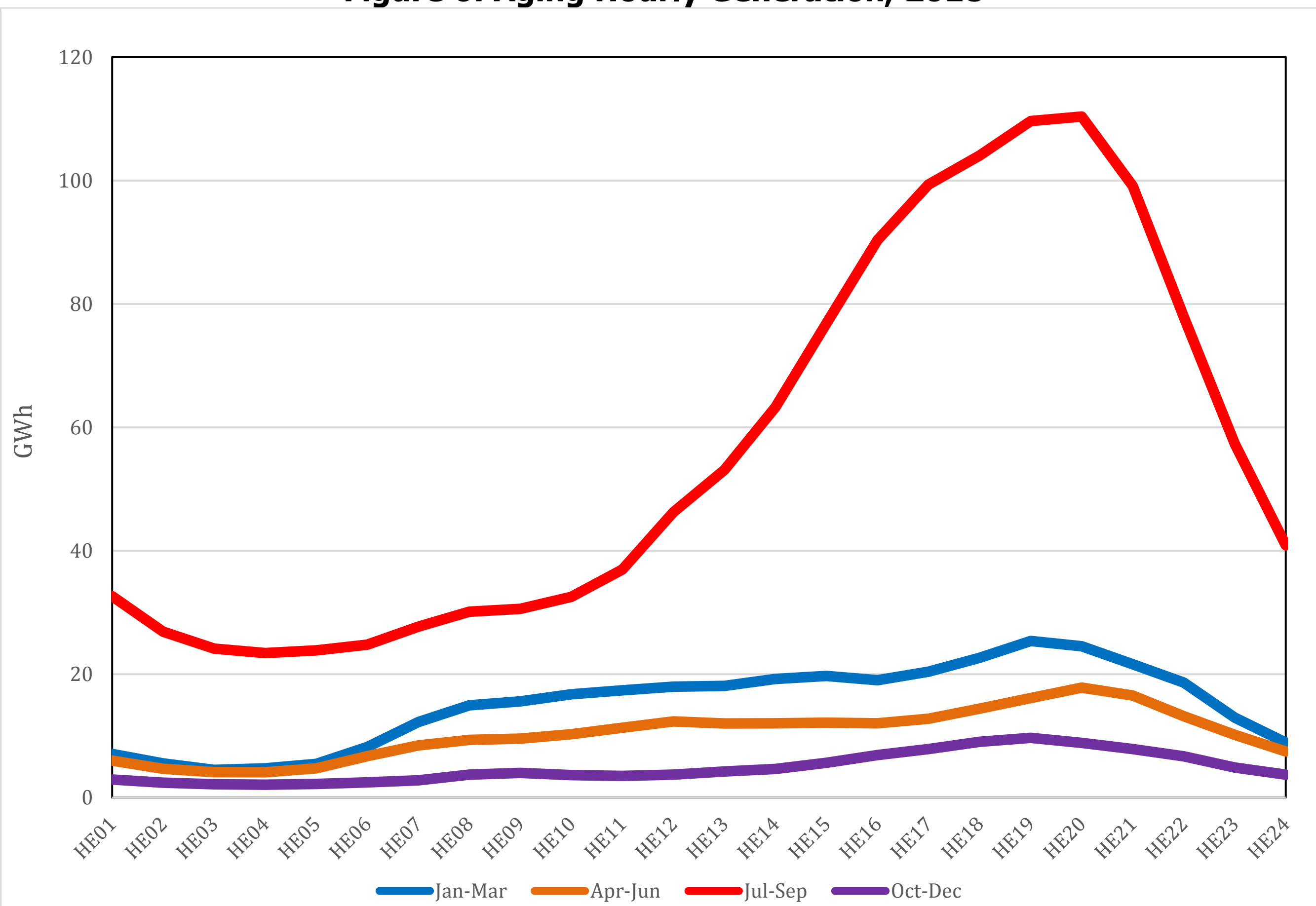


Source: California ISO

In the previous chapter, **Figure 4** indicated hydroelectric generation was below average in the first three months of 2018. **Figure 5** suggests combined-cycle generation made up for that reduced hydroelectric availability, depicted by the blue line in the chart. However, by spring, improved snowpack and precipitation conditions provided for more abundant, and cheaper, hydroelectric generation. Spring is also time of longer daylight hours and milder temperatures, reducing demand for space heating and air conditioning. These factors help push combined-cycle generation to their lowest levels of the year, depicted by the green line at the bottom of the chart.

With the same grouping as shown in **Figure 5**, generation from aging plants in the California ISO balancing area is shown in **Figure 6**. In 2018, aging plants were used most often in the summer months, from July through September, as depicted by the red line in the chart. However, they provided but a fraction of the output level of combined-cycle plants. In all other seasons, aging plants were marginally used, generation bumping up very slightly in the hours from HE17 through HE20.

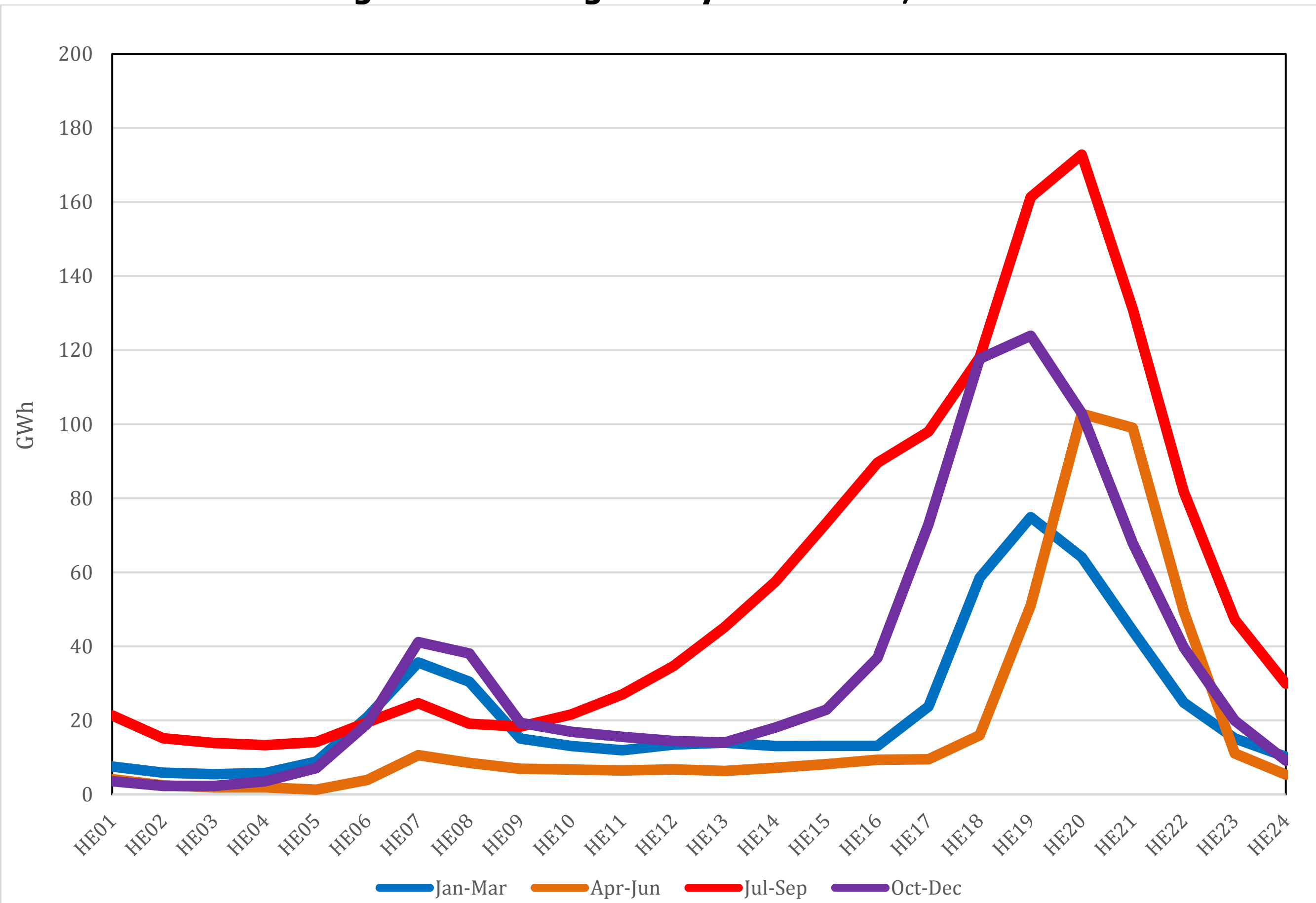
Figure 6: Aging Hourly Generation, 2018



Source: California ISO

Figure 7 summarizes peaking generation energy for the same groups of months across each hour of the day. Peaking plants deliver the most energy between HE17 and HE22. However, during the summer months they contribute much more power across all periods after HE10.

Figure 7: Peaking Hourly Generation, 2018

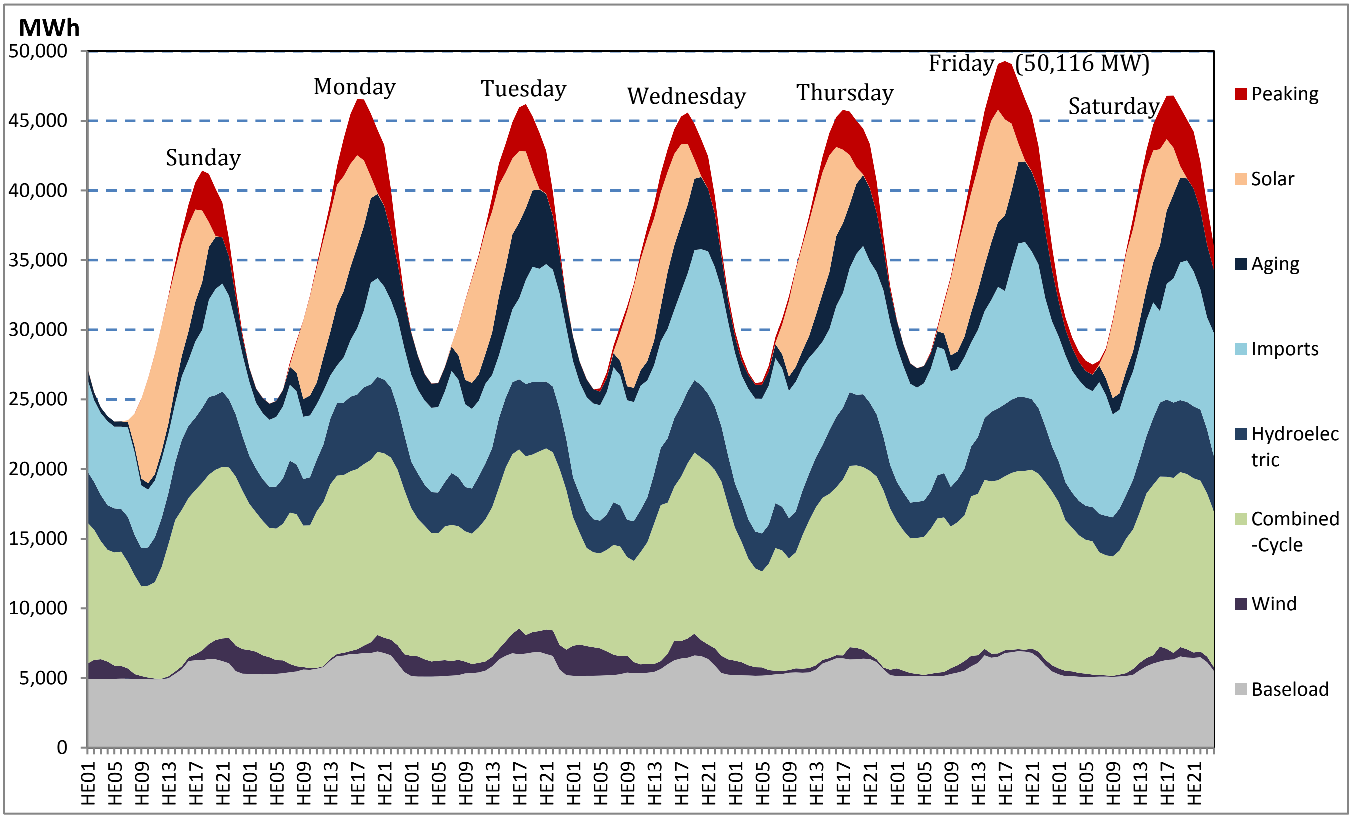


Source: California ISO

Annual Peak Load

Figure 8 and **Figure 9** show the hourly peak load in the California ISO for a one-week period in which the coincident peak load occurred in 2017 and 2018, respectively. The charts display the contribution of aging, combined-cycle, and peaking generation to the total hourly loads across the week on which the annual peak-load occurred. Solar, wind, and hydroelectric generation are displayed separately along with a baseload generation category that groups energy from biomass, cogeneration, geothermal, nuclear, refinery waste-heat, petroleum coke, and other technologies. Imports are classified separately as they represent bulk energy transfers from neighboring balancing authorities and no fuel type information is available. An observation on both charts is the usage of aging generation to meet load peak requirements during the hottest hours of the day.

Figure 8: Hourly Generation Mix, August 27 – September 2, 2017

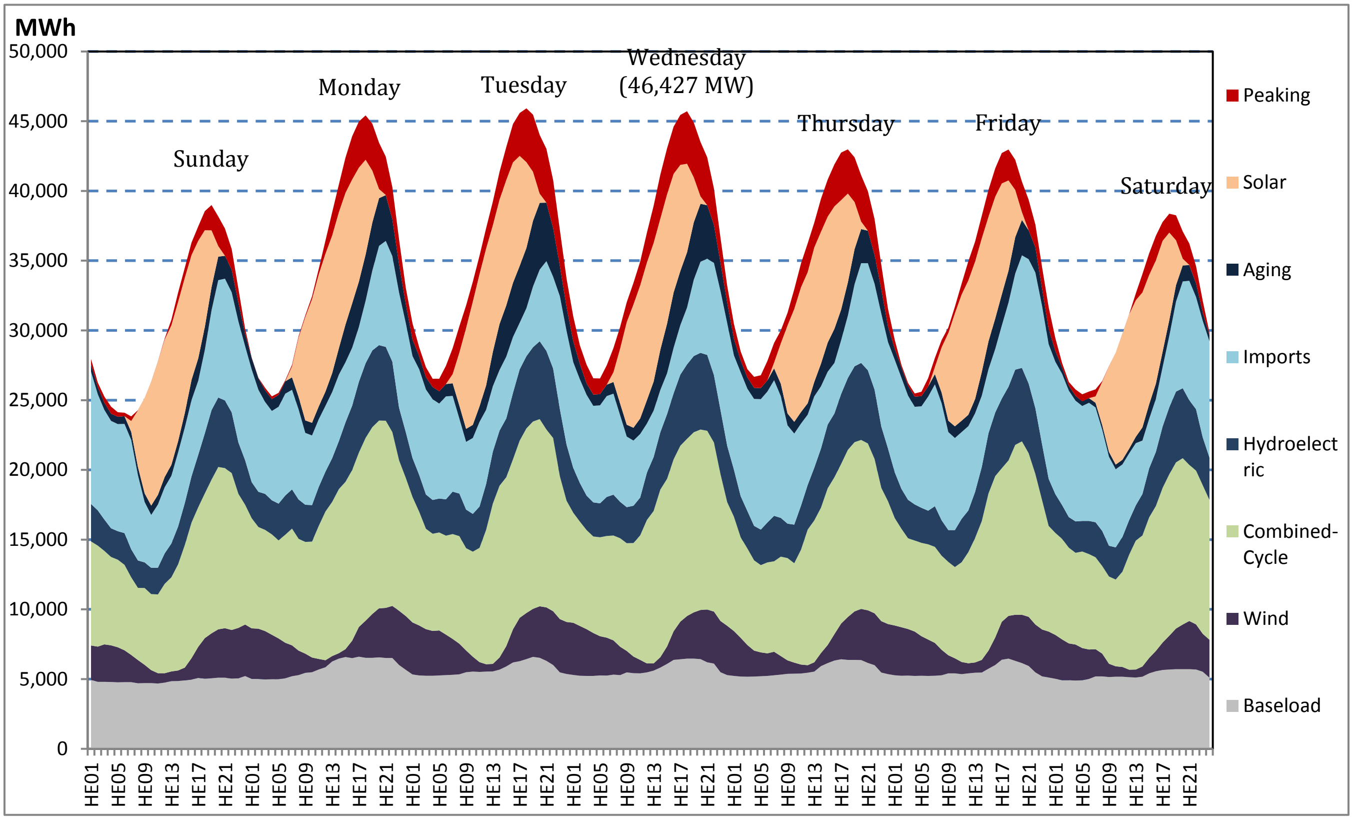


Source: California ISO aggregated data

To recap, the instantaneous peak load within the California ISO was 50,016 MW, occurring at 3:58 p.m. on Friday, September 1, 2017. The peak was a result of record-breaking temperatures as a high-pressure ridge stalled over California during the week of August 27 to September 2, 2017. By Friday, September 1, San Francisco reached 106° Fahrenheit (F), and Salinas, in Monterey County, recorded 109°F; both cities typically average 70°F on this day.[17]

17 Weather.com, All-Time Record-High Temperature Set in San Francisco; Record Heat Shifts to the Northwest This Week, Linda Lam, September 4, 2017. See https://weather.com/forecast/regional/news/west-heat-wave-all-time-record-heat-early-september-2017.

Figure 9: Hourly Generation Mix, July 22 – July 28, 2018



Source: California ISO aggregated data

In 2018, the California ISO issued two consecutive statewide "flex alerts" calling for customers to reduce their energy use from 5:00 to 9:00 p.m. on Tuesday, July 24 and Wednesday, July 25, "due to high temperatures across the western United States, reduced electricity imports, tight natural gas supplies in the Southern California area, and high wildfire risk."[18] As hot temperatures impacted multiple states in the West, there was concern about accessing electricity imports across the region. The California ISO forecasted a peak of 49,481 MW for July 25, 2018, but only had 45,633 MW of available capacity. The flex alerts requested customers reduce nonessential loads, raise thermostat settings for air conditioners, and postpone the use of large appliances until later in the evening. The California ISO stated Californians collectively reduced demand by 450 MW on July 24 and 540 MW on July 25, 2018.[19] Slightly lower realized temperatures combined with reduced demand resulted in a peak load of 46,427 MW on July 25, the highest load the year.

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18 California ISO. Flex Alert Issued for Tuesday and Wednesday, July 24 & 25, 2018. Accessed on October 23, 2019. See https://www.flexalert.org/news.

19 Green Tech Media. July 31, 2018. "Californians Slash Energy Use to Protect the Electric Grid." Accessed on October 23, 2019. See https://www.greentechmedia.com/articles/read/californians-slash-energy-use-to-protect-the-electric-grid.

CHAPTER 6: Conclusion

California continues to benefit from a significant improvement in the systemwide thermal efficiency of its natural gas-fired power plant fleet. With a thermal efficiency of 44.2 percent in 2018, the systemwide thermal efficiency has improved by 30 percent since 2001. This improvement is attributed primarily to the continued reliance upon combined-cycle power plants and the phaseout of less efficient aging and OTC power plants.

The annual average heat rate for natural gas-fired generation improved to 7,728 Btu/kWh in 2018 partly because of a 27 percent reduction in the use of aging power plants. The annual heat rate corresponds to a 23 percent improvement in the average fuel efficiency of the fleet compared to 2001. This heat rate improvement has remained above 20 percent (as compared to 2001) every year since 2007. Combined-cycle plants increased output by 7 percent in 2018, raising the capacity factor to 38 percent for the year and pushing total natural gas-fired generation up by 3 percent over 2017. The increase helped improve the average capacity factor for combined-cycle plants to almost 26 percent, similar to 2016 levels. Continued strong growth in solar generation in 2018, some 12 percent higher than 2017, was a contributing factor to limiting the growth in generation from natural gas-fired power plants.

Finally, total natural gas fuel usage for electric generation in California increased by just over 1 percent in 2018 to 848 million MMBtu, the second-lowest level of the past 18 years and 30 percent lower than 2001. In all, in-state natural gas power plants supplied almost 47 percent of California total in-state electricity supply. The slight decline in hydroelectric generation combined with the large growth in utility-scale solar generation resulted in 53 percent of California's in-state generation coming from zero-carbon resources in 2018.

ACRONYMS

Acronym	Definition
BESS	Battery Energy Storage System
Btu	British thermal unit
California ISO	California Independent System Operator
CEC	California Energy Commission
CHP	Combined heat and power
CPUC	California Public Utilities Commission
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
GHG	Greenhouse gas
GWh	Gigawatt-hour
HRSG	Heat recovery steam generator
IEPR	*Integrated Energy Policy Report*
ISO	Independent System Operator
kWh	Kilowatt-hour
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
OTC	Once-through-cooling
QF	Qualifying facility
QFER	Quarterly Fuels and Energy Reports
PURPA	Public Utility Regulatory Policies Act of 1978
RTO	Regional Transmission Organization
SACCWIS	Statewide Advisory Committee on Cooling Water Intake Structures
State Water Board	State Water Resources Control Board
WECC	Western Electricity Coordinating Council

GLOSSARY

Term	Definition
Aging plant	Natural gas-fired steam turbines that were built and operational before 1980.
Ancillary services	Within the California ISO, the four types of ancillary services are regulation up, regulation down, spinning reserve, and nonspinning reserve. These services support the stable operation of the grid.
Baseload generation	Power plants that are designed to operate at an annualized capacity factor of at least 60 percent.
Capacity factor	A measure of the actual output of a power plant over a specific period compared to the total potential output a power plant could have provided by operating at its nameplate capacity over the same period.
Cogeneration plant	A power plant that produces electricity and useful thermal energy (heat or steam) simultaneously.
Combined-cycle plant	A power plant has a generation block consisting of at least one combustion turbine, a heat recovery steam generator, and a steam turbine.
Dispatch	The action that signals a power plant to turn on or turn off.
Frequency control	The ability to dispatch generation due to decreases in supply or increases in load within a power system.
Generating unit	A combination of connected generators, reactors, boilers, combustion turbines and other prime movers operated together to produce electric power. In the context of this staff paper, a generating unit can only be assigned to a single natural gas-fired generation category.
Heat rate	Expresses how much fuel is necessary (measured in British thermal units [Btu]) to produce one unit of electric energy (measured in kilowatt-hours [kWh]).
Higher heating value	In the determination of a heat rate, higher heating value includes the latent heat of vaporization of the water in the combustion of natural gas.
Load-following	The ability to dispatch a power plant to meet changing system load requirements.
Lower heating value	In the determination of a heat rate, this measurement would not include the latent heat from the vaporization of the water.
Nonspinning reserves	An ancillary service that requires non-operating plants to be capable of ramping up to full capacity and synchronizing to the grid within 10 minutes of dispatch.

Term	Definition
Once-through-cooling	The usage of water from the ocean or other body of water to cool steam after it has passed through a turbine.
Peaking plant	Fast-starting power plants intended to operate for short durations to meet peak-load system requirements.
Power plant	A power plant is defined as a station composed of one or more electric generating units.
Ramping/cycling	Like load-following, power plants altering output levels, including shutdowns and restarts, in response to changes in system load and the availability of renewable generation on the electrical grid. Includes the ancillary services of regulation up and regulation down.
Spinning reserves	An ancillary service that recognizes operating power plants (that is, spinning) that are already synchronized and ready to meet electric demand within 10 minutes.
Thermal efficiency	A unitless measure of the efficiency of converting a fuel to energy and useful work.
Unspecified power	Power that can no longer be traced to the original fuel source.