

Summer Energy Market and Reliability Assessment

2020

A Staff Report to the Commission

May 21, 2020



FEDERAL ENERGY REGULATORY COMMISSION

Office of Energy Policy and Innovation

Office of Electric Reliability

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Preface

The 2020 Summer Energy Market and Reliability Assessment (Summer Assessment) is a joint report from the Office of Energy Policy and Innovation’s Division of Energy Market Assessments and the Office of Electric Reliability’s Division of Engineering and Logistics. This report uses preliminary North American Electric Reliability Corporation (NERC) Summer Assessment data. The final version of NERC Summer Assessment is scheduled to be released June 1, 2020.

The Summer Assessment provides staff’s outlook for energy markets and electric reliability, focusing on June, July, and August 2020. The report is divided into two main sections—the first on major market events and the second on market fundamentals. The report first presents the key findings and expectations for the summer, beginning with impacts from the COVID-19 pandemic on the electric, natural gas, and oil markets. It then focuses on electric reserve margins, western energy and natural gas market conditions, and electric market fundamentals for the summer, such as a weather outlook and expected generation capacity additions and retirements. The report then analyzes natural gas market fundamentals, including prices, demand, imports and exports, production, and storage, before concluding with a summary of the main findings.

Key Findings

Staff bases the Summer Assessment on predictions about the energy markets. As with any market this year, COVID-19 has increased the uncertainty of those predictions. COVID-19 continues to impact both electric and natural gas markets. Social distancing and regional “stay-at-home” policies, which have closed many businesses, have reduced natural gas and electric demand. Demand for electricity has decreased by approximately 3 to 11 percent based on estimates for a given week in some ISOs/RTOs or relative to when social distancing rules took effect in others. The shape of hourly electric demand in many regions has changed and now reflects that many schools and businesses are closed, and people remain at home.

COVID-19 has also delayed some maintenance on both natural gas and electric infrastructure; as a result, additional maintenance may be required later in the year. According to a report by the North American Electric Reliability Cooperation (NERC), deferred generation maintenance and other factors could potentially impact unit availability during the summer months.¹ Nonetheless, ISOs/RTOs have not reported reliability concerns for the summer. Weekly U.S. gas demand remains slightly higher than that of previous years, with demand for LNG feedgas, electric generation, and residential and commercial increasing year-over-year. However, industrial demand is 1.7 billion cubic feet per day (Bcfd), or 8 percent, lower in April 2020 compared to April 2019. Oil markets are being significantly disrupted due to global market dynamics and COVID-19. West Texas Intermediate (WTI) Crude spot prices decreased 58 percent in March alone, causing financial and credit challenges, including oil company bankruptcies. WTI prices remained depressed in April, reaching the lowest price in history of negative \$37.63/barrel (bbl) on April 20, as excess storage capacity became scarce. The negative close on April 20 was exacerbated by the expiration of the May contract on the following day.

All NERC Planning Regions should have enough generation available to exceed their reserve margins, except for the Electric Reliability Council of Texas (ERCOT), whose anticipated reserves are expected to be below

¹ See NERC, “Special Report: Pandemic Preparedness and Operational Assessment: Spring 2020,” https://www.nerc.com/pa/rmm/bpsa/Alerts%20DL/NERC_Pandemic_Preparedness_and_Op_Assessment_Spring_2020.pdf

its reference reserve margin. ERCOT has identified an increased potential to call an emergency energy alert under various constrained circumstances. In 2019, ERCOT was similarly below its reference reserve margin and experienced an all-time peak load and real-time Locational Marginal Prices (LMPs) (including price adders for reserve shortages) of \$9,000/megawatt hour (MWh), and continued to operate reliably.

In other market events, several natural gas pipeline segments in Southern California Gas Company's (SoCalGas) service territory have returned to service after not being available since summer 2019. However, California has lower-than-average snowpack levels and a high risk of wildfires, according to weather and drought outlooks. Lower-than-average snowpack would cause lower hydropower generation in California than in the 2019 summer, which, all things being equal, could add to the need for imports and natural gas-fired and other generation to meet summer loads in CAISO. Moreover, as part of their Public Safety Power Shutoff Plans, the utilities in the state may continue to selectively de-energize transmission and distribution lines to reduce the potential for wildfires, although these actions last year did not have significant effects on the wholesale electric or natural gas markets in California.

Turning to market fundamentals, weather forecasts for June, July, and August 2020 suggest higher than normal temperatures through the western, southern, and eastern United States, with the upper Midwest expected to have normal temperatures. Early forecasts predict an above average 2020 Atlantic hurricane season, which lasts from June 1 through November 30, peaking in late summer or early fall.

Nationally, the majority of generation capacity additions are forecast to come from natural gas, solar, and wind resources this summer. Nearly 1 GW of coal-fired generating capacity, largely in PJM and MISO, and about 235 MW of natural gas capacity in PJM are scheduled to retire this summer. Electric generation's demand for natural gas could average 38 Bcfd, a 0.6 percent decrease from summer 2019 but still an increase in electric generation's overall share of domestic natural gas demand, reflecting a prolonged structural and economic trend. The decrease in demand for electricity caused by COVID-19 influenced the slight decrease in electric generation's natural gas demand.

Summer 2020 natural gas prices are expected to be lower across the U.S., with futures prices at Henry Hub averaging \$1.91 per million British Thermal Units (MMBtu) for June through August, \$0.44/MMBtu lower compared to 2019 settled futures prices.² Natural gas production continues to be dominated by shale formations such as the Marcellus and Permian Basins, and is forecast to decrease to 88 Bcfd. The decrease marks a reversal in the trend of annual growth for domestic natural gas production over the last decade as COVID-19 is expected to impact associated natural gas production as well as natural gas demand. Large natural gas production and a larger than average natural gas storage balance are met by slightly smaller gains in natural gas demand. As of May 2020, natural gas demand is forecast to average 78 Bcfd for summer 2020, a decrease from an average of 80.6 Bcfd in 2019. The natural gas demand forecasts reflect projected increases of 2.7 Bcfd of domestic feedgas for LNG exports and 0.5 Bcfd in cross-border exports to Mexico and declines in the electric generation and industrial sectors.

² Henry Hub is a natural gas pricing point, located in Louisiana, which is generally used as the benchmark for U.S. natural gas prices.

Notable Energy Market Events

Effects of COVID-19 on Energy Markets

Most ISO/RTO regions are seeing lower demand for electricity due to social distancing and regional “stay-at-home” policies from state or local governments, which has led to the closure of many businesses to reduce the spread of the virus. Regional operators note a decrease in demand around 3 to 11 percent, and in many regions, the morning peak hour is now occurring later in the morning. This change in load shape reflects that many schools and businesses are closed, and people remain at home. Wholesale electric prices are generally lower than last year at this time, due to the reduced loads, as well as mild weather conditions, and lower natural gas prices due to an abundance of supply. Each ISO/RTO has taken measures to ensure the safety of their personnel as well as the reliability of the bulk power system. For example, some regions, including NYISO and PJM, have sequestered control room operators, and PJM and SPP have set up additional backup control centers.

Typically, spring is a time when maintenance activities occur because of reduced demand and mild weather, and to prepare for the upcoming summer season. While some generation and transmission maintenance is proceeding as scheduled, the scope of maintenance is being reduced and other maintenance is being deferred to reduce COVID-19-related risks to personnel. For example, as of May 6, approximately 21,000 MW of planned generation outages in MISO had been cancelled or rescheduled, representing roughly half of the generation capacity in MISO that would be on maintenance outage during a typical spring outage season. In SPP, scheduled generation maintenance reached almost 15,000 MW by late March but is expected to drop to 10,000 MW by late May, which is 5,000 MW below 2018 and 2019 levels for the spring maintenance period. Transmission outages similarly declined below 2018 and 2019 levels starting in mid-March. PJM said some generators reported contractor crew shortages from travel restrictions and parts shortages from COVID-19 related supply chain issues. However, no nuclear refueling outages have been deferred or canceled in PJM, ISO-New England, or NYISO for summer 2020. Furthermore, no ISO/RTO expects reliability problems to arise this summer due to the delayed or cancelled maintenance outages.

U.S. natural gas markets are also being affected by the COVID-19 pandemic. S&P Global Platts estimates that industrial demand averaged 1.7 Bcfd, or 8 percent, lower in April 2020 compared to 2019. Despite the decrease in industrial demand, total estimated natural gas demand was 5.3 Bcfd, or 7 percent, higher than total demand in 2019 due to increases in natural gas demand for electric generation, LNG feedgas, and the residential and commercial sectors. Operationally, falling natural gas demand has pipelines in the Northeast calling operational flow orders (OFOs). Typically, OFOs during the spring would be due to low pressure. However, pipelines are experiencing very high levels of natural gas supply, causing high-pressure concerns in some of the pipelines.

There is also significant downside risk to LNG feedgas demand for summer 2020, as global LNG markets have been affected by COVID-19 as well. Futures prices for natural gas in Europe and Asia suggest that U.S. LNG will be only marginally profitable or even unprofitable through summer 2020. The LNG market is currently oversupplied having added over 35 million tonnes per annum, or roughly 4.6 Bcfd, of new capacity over the past year. This combined with declining demand in Europe and Asia due to a mild winter, high storage levels, and the impact of COVID-19 have reduced the prices at the major trading hubs in both regions. For example, India’s shelter-in-place order is significantly reducing demand for natural gas in the country, which could impact U.S. LNG exports, given that the Indian utility GAIL (India) Limited holds a collective 0.7 Bcfd in contracts for LNG from Sabine Pass Liquefaction, LLC and Dominion Energy Cove Point, Inc.

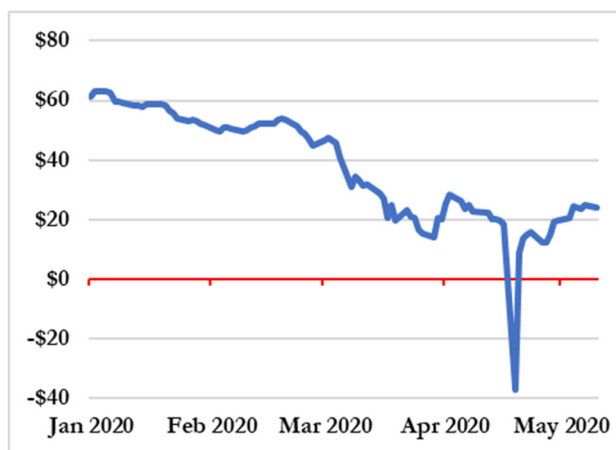
On April 20, the Japan-Korea Marker (JKM), a proxy for LNG cargoes into those markets, traded at \$1.80/MMBtu, \$0.12/MMBtu below the Henry Hub May futures contract. This marks the first time that the JKM spot price has ever traded at a discount to the comparable Henry Hub price. The Northwest Europe Marker also traded at \$1.90/MMBtu, a 58 percent decrease from its value in April 2019. The profitability of shipping U.S. LNG to these regions has accordingly declined. This could lead to cargo cancellations and reduced utilization at the six operable liquefaction facilities in the U.S. However, U.S. LNG exports could benefit from renewed demand from China due to eased trade tensions. On April 20, China received its first U.S. LNG cargo since March 2019.

More than natural gas markets, oil markets are being significantly disrupted going into summer 2020. WTI Crude spot prices decreased 56 percent over March alone. WTI Crude spot prices remained depressed in April, reaching an all-time low of negative \$37.63 on April 20, marking the first time WTI prices ever traded in the negatives. The negative trading was largely due to markets nearing full storage capacity and was exacerbated by the May contract expiring the next day on April 21. This expiration effectively forced contract holders to either sell off or take physical delivery of crude barrels. In total, the EIA forecasts global petroleum and other liquids consumption to decrease 5.2 million barrels per day, roughly 5 percent, in 2020 compared to average 2019 consumption. The sharp decrease in WTI Crude prices cannot be solely attributed to COVID-19, however;

OPEC and Russia in early March failed to reach an agreement on crude oil production targets that would have reduced global oil production levels. Despite the fact that OPEC and Russia reached agreement on April 12, markets have yet to fully balance. The combination of weakened demand related to COVID-19 and oversupply has led to a significant build in storage levels in both the U.S. and internationally. As of April 21, the EIA storage report puts inventories at 70 percent of capacity while U.S. storage operators are reporting nearly full capacity at Cushing, Oklahoma, and other major hubs. With few options to store oil, prices are expected to remain depressed throughout summer 2020. As of April 21, WTI NYMEX futures contracts for the months of June and July are priced at \$11.57/bbl and \$18.69/bbl, respectively. These low prices are likely to result in less oil production and reduce natural gas production in the Permian and North Dakota, where oil recovery is accompanied by associated gas shale plays.

Capital spending has also declined. As of April 7, 12 of the world's largest integrated public oil and gas companies have announced cuts to their 2020 capital spending programs, totaling \$43.6 billion, a 23 percent decrease, in capital spending compared to their initial plans. Oil and gas exploration and production companies have also announced cuts of \$17.82 billion in 2020 capital spending. Of the top 25 largest oil and gas companies, 21 saw their market capitalization decrease by more than 30 percent in 2020 Q1. The top three, Exxon Mobil Corp., Chevron Corp. and Royal Dutch Shell PLC, each saw at least a 40 percent drop in equity values.

Figure 1 WTI Crude Spot Prices



Source: EIA

Regional Reserve Margins

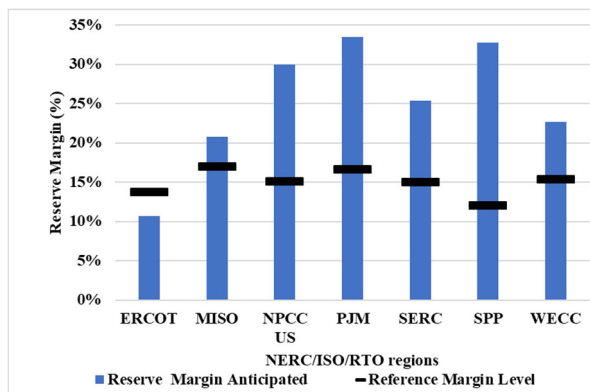
Data from the NERC Regional Entities and ISOs/RTOs indicate that planning reserve margins for all regions, except ERCOT, will be adequate this summer. The blue columns shown on Figure 2 display the anticipated reserve margins for the markets and regions, while the black bars indicate the reference reserve margins. Note that the data for forecasted reserve margins were prepared prior to the beginning of impacts from COVID-19 and deviations from these forecasts are possible as the situation evolves.

ERCOT anticipates that its reference reserve margin for this summer will be 12.6 percent,³ an increase from the 10.67 percent initially expected, though that remains below NERC’s reference margin level of 13.75 percent. As ERCOT’s reserve margin in 2019 was 8.5 percent, this represents an increase relative to its reserve margin in summer 2019. While ERCOT faced some challenges last year, it maintained system reliability with no load curtailments even as it set several new peak loads, including its current standing all-time peak load of 74,820 MW on August 12, 2019.

However, while no load curtailments occurred, ERCOT did declare an Emergency Energy Alert (EEA) on several occasions in 2019. An EEA declaration occurs when available operating reserves fall below a certain threshold. Declaring an EEA allows operators to call on a variety of additional resources that are only available during scarcity conditions, defined by the operating reserves available, such as encouraging voluntary conservation by consumers, activating demand response measures, and increasing generation imports from neighboring regions.⁴ These resources are expected to mitigate capacity shortages, should they occur. Although ERCOT declared an EEA on August 13, 2019, expecting high load and low wind generation, it was still short on reserves, causing a real-time LMP (including price adders) of \$9,000/MWh. Notwithstanding the reserve shortage, ERCOT concluded, “market outcomes supported reliability needs” during the summer.⁵ According to the EIA, ERCOT is scheduled to have roughly 3 GW of additional net summer generating capacity come online during the summer 2020, as shown in Figure 7 below.

Based on its projected reference reserve margin for this summer, ERCOT expects to rely on similar operational flexibility provided by declaring an EEA when necessary to ensure that its resources are sufficient

Figure 2 NERC 2020 Anticipated Reserve Margins



Source: North American Electric Reliability Corp.

³ See ERCOT, “ERCOT Summer 2020 Final Seasonal Assessment of Resource Adequacy,” May 13, 2020, <http://www.ercot.com/content/wcm/lists/197378/SARA-FinalSummer2020.xlsx>.

⁴ ERCOT has a series of emergency procedures known as Energy Emergency Alerts (EEAs) that may be used when operating reserves drop below specified levels. These procedures are designed to protect the reliability of the electric system as a whole and prevent an uncontrolled system-wide outage.

⁵ ERCOT, “Project No. 49852, Review of Summer 2019 ERCOT Market Performance,” *ERCOT’s Review of Summer 2019*, October 11, 2019, http://www.ercot.com/content/wcm/lists/172485/Review_of_ERCOT_Summer_2019_-_PUC_Workshop_-_FINAL_10-8-19.pdf.

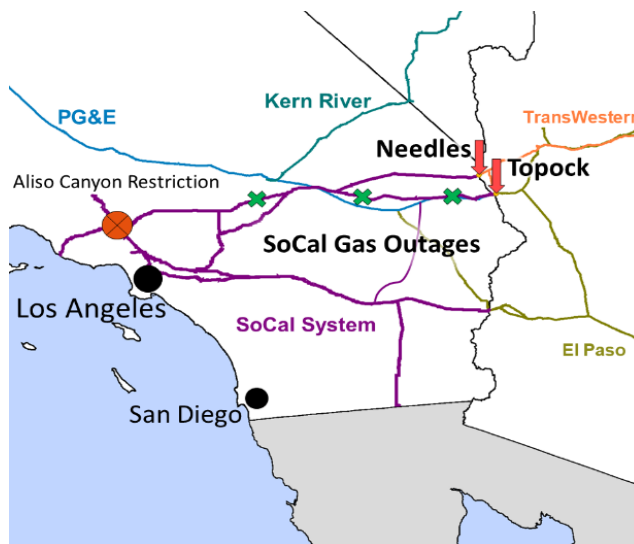
to mitigate any capacity shortages. In studying scenarios for the upcoming summer, ERCOT identified the potential increased need to call an EEA under various constrained circumstances.

Western Energy Markets

California Natural Gas Pipelines

Pipeline maintenance and storage issues will continue to affect natural gas supplies in southern California this summer. SoCalGas completed repairs to Line 235-2 on February 17, 2020, adding 170 MMcfd of additional capacity. Line 235-2 supplies natural gas to the Topock and Needles areas. However, there are maintenance projects scheduled for mid-June and mid-September that could affect pipeline capacity.⁶ Other factors in place for the 2020 summer that could affect gas prices in the western U.S. include a modified California Public Utilities Commission (CPUC) Aliso Canyon Protocol to increase the amount of, and circumstances in which, withdrawals and injections can occur at the natural gas storage facility, specifically when a Stage 2 Low OFO is called. A Low OFO is called when pressure on the gas pipelines is low, perhaps because of low supply levels. In addition, the CPUC in July 2019 lowered SoCalGas's imbalance penalties associated with OFOs during specific thresholds. Together, these changes allow SoCalGas and natural gas shippers additional flexibility to make withdrawals from the facility anytime a Stage 2 low or high OFO is issued and limits the penalty for violations to \$5 per dekatherm.⁷ For summer 2020, Aliso Canyon inventories will be relied upon in a similar fashion to the 2019/2020 winter, allowing the system to balance in times of high strain and help mitigate price spike frequency and severity.

Figure 3 SoCal Gas Pipelines and Outage Locations



Source: ABB Velocity Suite, SoCalGas. Note: an "X" represents the location of a recent pipeline outage.

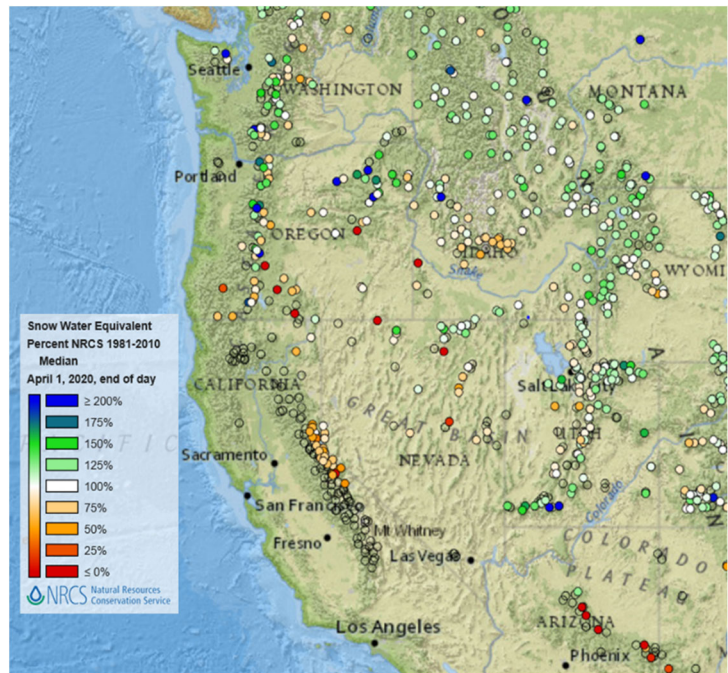
⁶ See Sempra Envoy Electronic Bulletin Board, System Maintenance Outlooks, March 2, 2020.

⁷ See California Public Utility Commission, Aliso Canyon Withdrawal Protocol, July 23, 2019, https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf. Pipelines and Local Distribution Companies (LDCs) issue an OFO to help maintain a balance of gas receipts onto its system with gas deliveries off of its system. For the period June 1 through September 30, the Low OFOs penalties for Stage 4 and Stage 5 OFOs are lowered from \$2.50/Dth to \$0.50/Dth, while the Emergency Flow Order penalty is \$5/Dth.

Hydropower Season in the West

Snowpack varies across the West this year. California's snowpack is 54 percent below average as of April 1st—the lowest levels since 2018. Typical snowpack levels are an indicator of how much hydro generation the state will have during spring and summer. Since smaller snowpacks melt faster than larger ones, the low snowpack also suggests that available hydro generation would peak earlier in the year and that less hydro generation would be available to help meet peak electric demand mid- to late-summer. Further north, normal level snowpack in Washington state and above normal levels in lower British Columbia indicate that the West may see normal hydropower generation overall when considered with California's below normal levels. Washington and British Columbia basins feed the Columbia River, a major source of hydro generation in the West. British Columbia's snowpack also provides hydro generation imported into California and the rest of the West.

Figure 4 Western Snowpack Levels through March



Source: Natural Resource Conservation Service, US Department of Agriculture

Lower than normal hydro generation tends to put upward pressure on natural gas prices, as natural gas generation typically replaces some of the hydro generation deficit. The effect may not be perceptible this year, due to other factors, including the restoration of SoCal Gas's natural gas pipeline service discussed above, oil price changes and the related effects on natural gas output and prices, and the natural gas and electric demand consequences resulting from COVID-19.

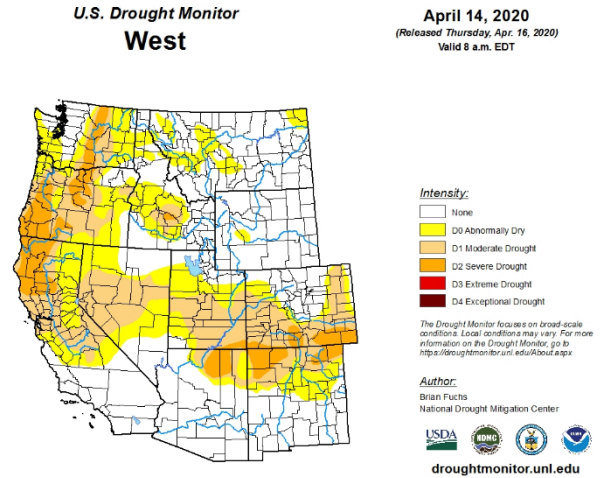
Power Shutoffs and Wildfire Risks

From June through November 2019, Pacific Gas & Electric, Southern California Edison, and San Diego Gas and Electric instituted Public Safety Power Shutoffs that de-energized select parts of the transmission and distribution networks in northern, central and southern California. These Public Safety Power Shutoff events were responses to the risk of wildfires fueled by high winds in their service territories. Despite the disruption to retail customers, in the State of the Markets 2019 report, staff concluded that these events did not have significant impacts on the wholesale electric markets in CAISO or the Energy Imbalance Market of the Western Interconnection.⁸

⁸ See Federal Energy Regulatory Commission, "State of the Markets 2019," March 19, 2020, <https://www.ferc.gov/market-assessments/reports-analyses/st-mkt-ovr/2019-som.pdf>.

The National Interagency Fire Center expects a significant risk of wildfires in northern California through this summer. Precipitation in February 2020 was well below average in northern California, with some cities not experiencing any rainfall. The National Drought Monitor Center classifies most of northern California as in abnormally dry or moderate drought conditions as of April 14. By contrast, a winter storm brought significant rainfall to southern California, improving soil moisture and stream flow levels. Additionally, parts of the Sierra Nevada received over two feet of snow. As a result, southern California is not currently in a drought condition, unlike northern California.

Figure 5 Drought Conditions in the West as of April 14, 2020



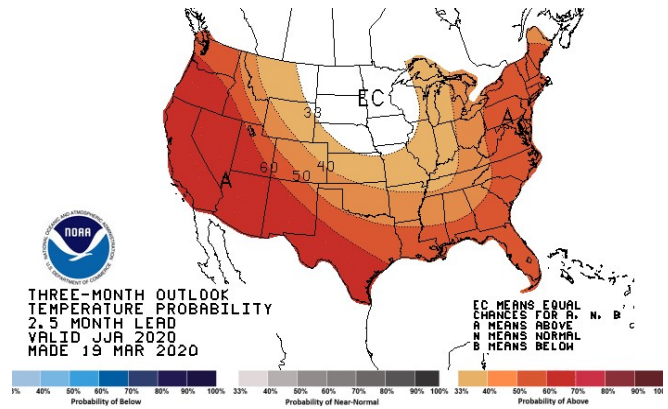
Source: National Drought Monitor Center, University of Nebraska-Lincoln

Market Fundamentals

Weather Outlook

For June, July and August 2020, the National Oceanic and Atmospheric Administration (NOAA) assesses a greater than 50 percent probability of above average temperatures throughout the western United States, parts of the southern United States, and much of the eastern United States. Elsewhere, the upper Midwest is expected to experience average temperatures during the same months. NOAA’s average temperature outlook for each area is based on temperatures recorded during the 1981 through 2010 period. In addition, NOAA’s early forecasts predict an above average 2020 Atlantic hurricane season with up to 16 named storms, eight hurricanes and four major storms forecasted. The hurricane season runs from June 1

Figure 6 Summer 2020 Temperature



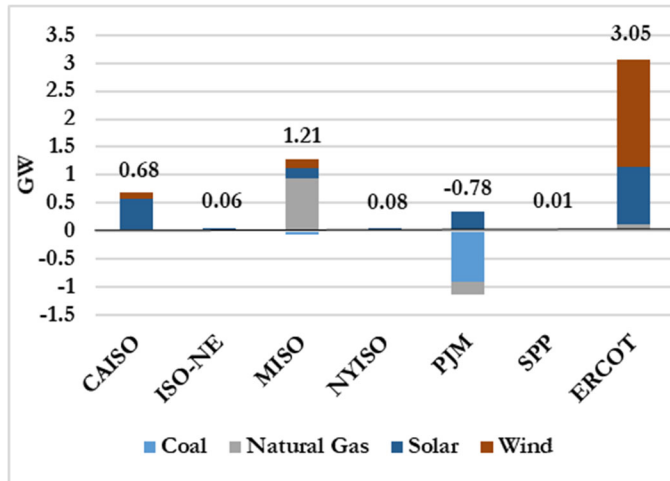
Source: National Oceanic and Atmospheric Administration

through November 30, peaking in late summer or early fall.

Electricity Markets

Generation Capacity

Figure 7 Planned Generation Capacity Additions and Retirements for the 2020 Summer



Source: EIA

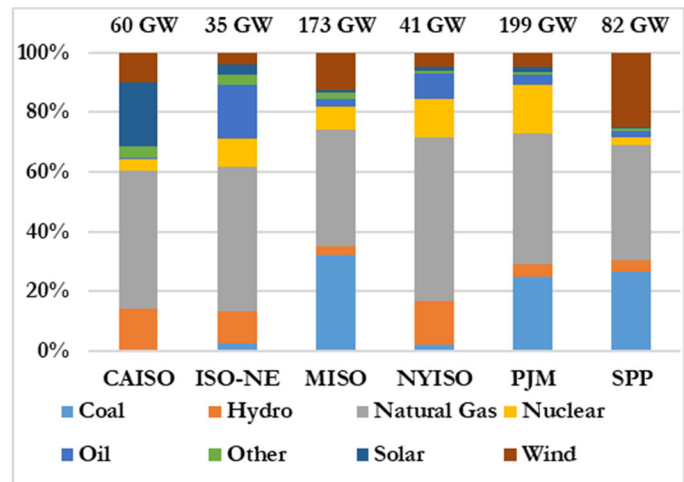
of coal-fired generation within the PJM footprint is expected to retire, although COVID-19 load reductions and price reductions may accelerate future retirements in PJM and other regions.

Preliminary data from the EIA indicates that over 1.3 Gigawatts (GW) of generating capacity are scheduled to retire and approximately 5.6 GW of generating capacity are scheduled to enter commercial operations this summer. Although the EIA reports that the economic slowdown related to COVID-19 is likely to affect building of new generating capacity during the next few months, current projections indicate that adequate resources are available to meet peak demand this summer.⁹ A majority of the capacity additions will come from natural gas, solar, and wind resources. MISO is projected to add 1 GW of natural gas-fired capacity. ERCOT will add approximately 2.9 GW of renewable capacity, split between wind and solar, with solar capacity expected to be available on peak also increasing. Elsewhere, approximately 0.9 GW

⁹ See U.S. EIA, "Short-Term Energy Outlook," May 12, 2020, <https://www.eia.gov/outlooks/steo/>

Natural gas fired generation will continue to play a pivotal role in the summer of 2020, as new installations of natural gas generators and retirements of generators using other fuels continue to make it the largest source of electric generating capacity in each organized wholesale electric market. In NYISO, installed natural gas generators account for 55 percent of the total net summer capacity. Renewable sources of energy, such as wind and solar, also continue to make up an increasing portion of capacity across the United States. This summer, wind will make up 25 percent of the net summer capacity in SPP. Similarly, in CAISO solar energy will make up 22 percent of net summer capacity, accelerating ongoing trends affecting load peaks and shape.

Figure 8 Installed Generation Capacity for the 2020 Summer

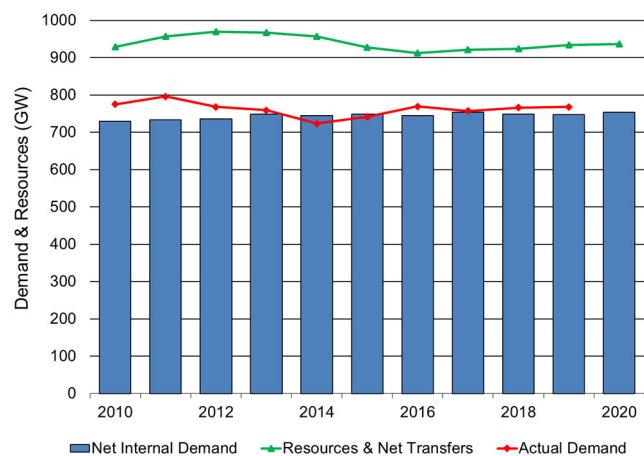


Source: EIA

NERC Peak Load Forecast

NERC forecasts net demand for electricity to increase by approximately 0.9 percent for summer 2020 when compared to summer 2019, with growth in demand concentrated in ERCOT and WECC and reductions in load forecasts for PJM and MISO, while other regions remain similar to 2019 demand. However, demand forecasts remain in flux due to uncertainty related to the impacts of COVID-19, which could result in lower actual demand than current forecasts.¹⁰ NERC also forecasts total generating capacity to increase by approximately 0.2 percent from summer 2019. The increasing demand marks a shift from the 2019 net demand forecast, which predicted an overall decrease in demand. The expected growth in generation is also lower than summer 2019, falling from 1.1 to 0.2 percent. These projections were calculated with preliminary data from ISOs/RTOs and NERC Regions for NERC’s upcoming 2020 Summer Reliability Assessment. Similarly, generator capacity additions scheduled to come online for the summer could also change or be subject to delays, as noted above.

Figure 9 NERC 2020 Demand and Generation



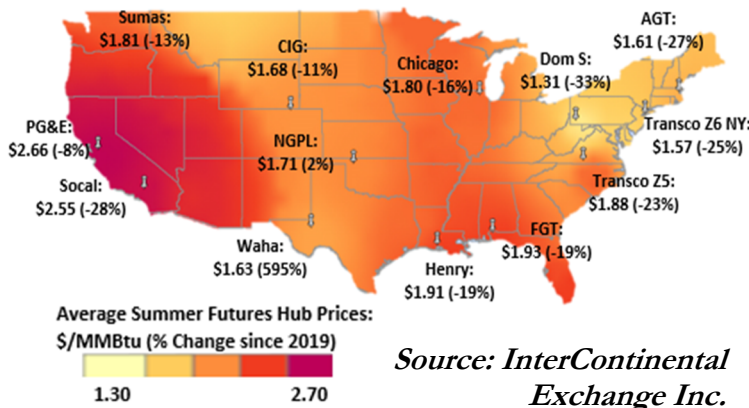
Source: North American Electric Reliability Corp.

¹⁰ See U.S. EIA, “Short-Term Energy Outlook,” May 12, 2020, <https://www.eia.gov/outlooks/steo/>

Natural Gas Markets

Natural Gas Prices

Fig. 10 U.S. Natural Gas Summer Futures



Source: InterContinental Exchange Inc.

Natural gas futures prices for summer 2020 are lower at nearly every major trading hub across the U.S. compared to the final settled futures prices of summer 2019. As of May 12, 2020, the Henry Hub futures contract, generally the largest component of summer futures prices, is 19 percent lower than the summer 2019 settled price, falling \$0.44/MMBtu to \$1.91/MMBtu. The largest nominal year-over-year futures price decrease is in southern California, where futures prices fell by \$0.98/MMBtu, or 28 percent lower, trading at \$2.55/MMBtu for summer 2020. Futures prices at other major demand hubs of New York City, Boston, and Chicago are all at

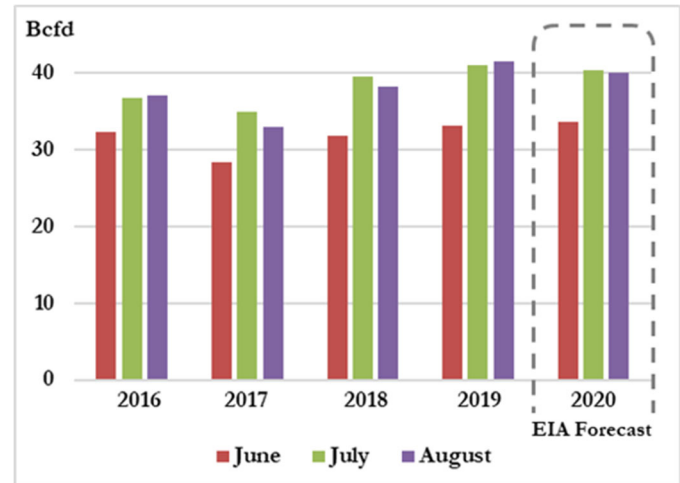
least 16 percent lower than in summer 2019, as well. On the supply side, prices decreased the most at the Appalachian hub Dominion South, decreasing by \$0.65/MMBtu, or 33 percent. Despite the lower expected prices for summer 2020, significant uncertainty exists for summer 2020 natural gas prices due to COVID-19 and its effects on energy markets. Market shocks associated with COVID-19 have led to lower-than-normal demand while short-term production levels remain high, potentially placing downward pressure on natural gas prices. However, after the short-term price decrease, prices may face upward pressure should oil prices remain depressed and producers are forced to decrease oil and associated gas output.

The Permian Basin’s Waha trading hub is the only major trading hub to see a significant increase in year-over-year summer futures prices. Prices at the West Texas hub increased by \$1.40/MMBtu to \$1.63/MMBtu, but the region continues to face capacity constraints. Last year, natural gas futures prices settled at \$0.23/MMBtu due to large increases in natural gas production associated with rising crude oil production, which often exceeded or constrained regional pipeline capacity. Permian prices have strengthened since last summer with the addition of new pipeline capacity in late 2019 that relieved some of the infrastructure bottleneck. COVID-19 has provided further upward price pressure as market participants expect associated gas production in the basin to decrease due to falling oil prices. Still, futures prices at the Waha hub remain low compared to many hubs across the U.S.

Natural Gas Demand

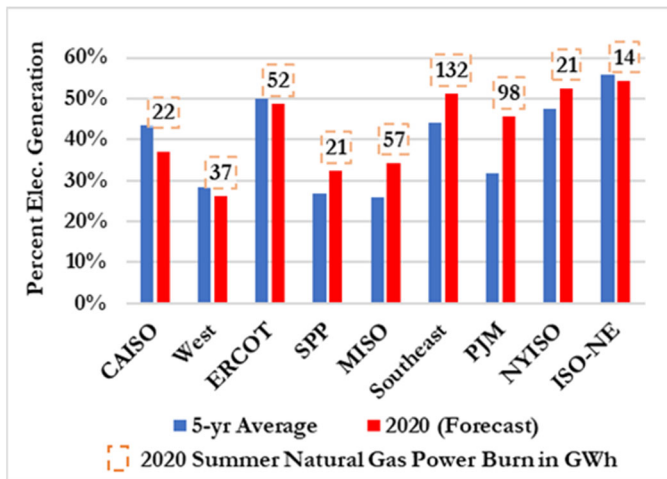
As of May, forecasted demand for natural gas in summer 2020 is expected to decrease by 3 percent over summer 2019 to 78 Bcfd. This contrasts with summer growth reported in 2018 and 2019 of 8.5 percent and 11 percent, respectively. Demand growth this year is only forecast in the export and residential and commercial sectors. Natural gas consumption by the electric power sector for the generation of electricity, or power burn, is forecasted to average 38 Bcfd, down 1.6 percent from summer 2019, after averaging 5 percent growth annually since 2015. While the EIA’s forecast expects a decrease in power burn during the peak electric demand months of July and August, low natural gas prices are expected to give natural gas generators a slightly larger than normal market share during the month of June. However, EIA forecasts natural gas power burn to grow by only 1.5 percent over June 2019.

Figure 11 Natural Gas Summer Power Burn



Source: EIA

Figure 12 Summer Natural Gas Share of Generation



Source: EIA

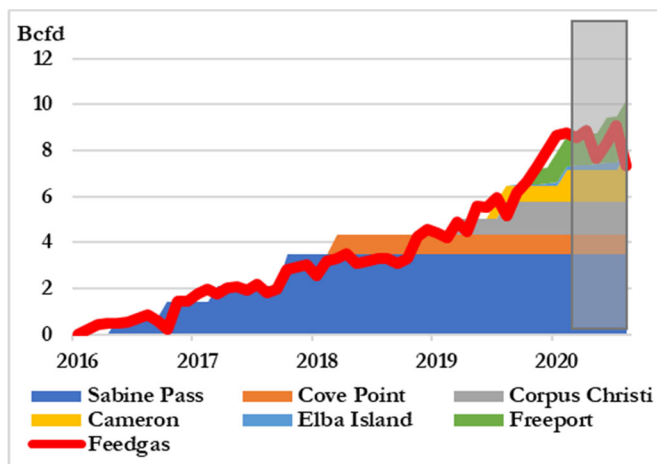
Through summer 2020, the share of U.S. electric generation provided by natural gas is expected to increase slightly, from 41 percent in 2019 to 42 percent in 2020. In 2015, natural gas generation represented 34 percent of total U.S. generation. Regionally, the largest forecast increase is in PJM, while CAISO, ERCOT, New England, and the U.S. West see small declines in natural gas’ share of generation against the five-year average. New England, NYISO, the Southeast, and ERCOT are most dependent on natural gas, each deriving approximately half of its electricity from the fuel. If broken out of the larger Southeast region, Florida has the largest share of natural gas generation at 79 percent.

Natural Gas Imports and Exports

Exports of natural gas from the U.S. are forecast to reach new highs this summer, in part due to 5.3 Bcfd of aggregate capacity additions at four LNG liquefaction terminals: Corpus Christi Liquefaction, LLC, Cameron LNG, LLC, Elba Liquefaction Company, L.L.C., and Freeport LNG Development LP. In addition, pipeline-transported exports to Mexico are also forecast to increase due to new pipeline connections. The Mexican natural gas pipeline transportation system has at least 2.6 Bcfd of new capacity expected to be in-service in 2020, including the 1.2 Bcfd La Laguna-Aguascalientes pipeline in central Mexico and the 0.5 Bcfd Samalayuca-Sasabe pipeline in the west. Although near completion, these projects may face delays in commercial operation related to COVID-19. Pipeline exports to Mexico and LNG exports collectively are

forecast to average 14 Bcfd in June, July, and August 2020, up from 10.9 Bcfd last summer.¹¹ S&P Global Platts estimates a 0.5 Bcfd year-over-year increase in natural gas pipeline exports this summer. Natural gas exports could experience the largest sequential gain on record, though several conditions could keep exports from reaching those levels. One of the biggest potential impediments to growth in exports, particularly for LNG, is the weakening economics of sending U.S. natural gas to overseas markets that are increasingly seeing lower prices due to weaker demand and growing production from Australia and other global producers. Building on the mild winter, COVID-19-related demand reductions in major LNG-consuming markets has kept the global market for LNG weak in early 2020. However, U.S. LNG exports could benefit from renewed demand from China due to eased trade tensions. In April, China received its first U.S. LNG cargo since March 2019.

Figure 13 U.S. LNG Exports and Feedgas



Source: S&P Global Platts

collectively increasing nameplate LNG export capacity from 5.0 Bcfd to an expected 10.2 Bcfd, with the majority of the capacity additions occurring before the start of summer.

There are several factors which could reduce LNG feedgas this summer. Planned and unplanned maintenance outages of the LNG terminals or on connected transmission pipelines could take place over an extended period of time and could temporarily reduce natural gas demand. For example, in previous years, Cove Point and Sabine Pass have conducted maintenance during the summer, lasting as much as three weeks. The 2020 forecast accounts for these seasonal maintenance events, reflecting a lower utilization rate similar to those in 2017, 2018, and 2019. Similarly for pipeline exports to Mexico, cross-border flows are forecast to increase by about 0.5 Bcfd from summer 2019, which matches the increase in 2019 for natural gas trade between the two countries. Pipeline exports south to Mexico are forecast to average 5.8 Bcfd in June, July, and August, up from 5.3 Bcfd in summer 2019. Pipeline capacity additions, both on the U.S. side and in Mexico, are driving the expected increase. The 2.6 Bcfd Sur de Texas – Tuxpan pipeline, which links south Texas to northern Mexico, began service in September 2019. Several additional pipelines went in-service in Mexico, furthering the integration of its national pipeline grid, which has facilitated greater imports of U.S. natural gas.

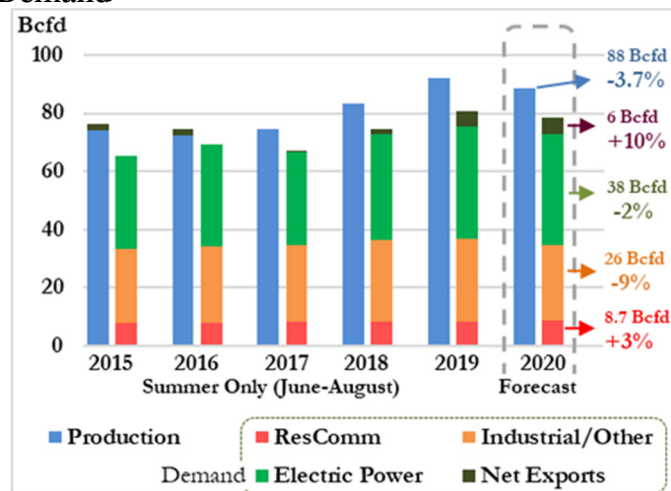
¹¹ These projections come from S&P Global Platts, US Gas Short-Term Forecast, released April 24, 2020.

Imports of natural gas play a smaller role in the U.S. natural gas supply mix, particularly in the summer. Canadian imports into U.S. markets in the Northeast, Midwest, and West Coast are forecast to average 4.7 Bcf/d, up 0.4 Bcf/d from summer 2019. The increase is mainly due to 2019's historically low level of Canadian pipeline imports. However, pipeline imports from Canada are vital to supply markets in the U.S. West Coast and in the Northeast, and there is a high-level of integration of pipeline and storage facilities in the Midwest. LNG imports from Canada are a lesser part of the supply mix and represent just 0.1 Bcf/d in the summer 2020 supply forecast. The projected LNG imports are effectively the same as in 2019.

Natural Gas Production

Natural gas production in the United States may end its recent growth trend, as it is forecast to average just over 88 Bcf/d during summer 2020, a decrease of 3.7 percent compared to the previous year. Summer production had grown by over 10 percent in each of the past two years. Shale formations, such as the Marcellus and Permian basins, represent the largest shares of natural gas production with 24 percent and 12 percent, respectively, of domestic production at the end of 2019. The COVID-19 pandemic has added downward pressure to the summer 2020 natural gas production forecast due to lower expected demand for natural gas. Added downward pressure also results from recent low oil prices affecting expectations of oil-associated natural gas production. The Marcellus basin is expected to remain the largest production basin in the U.S. despite slower production growth in the region. The Permian Basin has been a strong source of increased natural gas production, adding 2.7 Bcf/d in 2019. However, natural gas is not the primary target of drillers in the region as most are seeking to find crude oil. While most oil wells produce at least some associated natural gas, such output in the Permian is higher than in many other oil fields. With significantly lower oil prices, less drilling is expected in the basin, which could lead to less natural gas production.

Figure 14 Summer Natural Gas Production and Demand



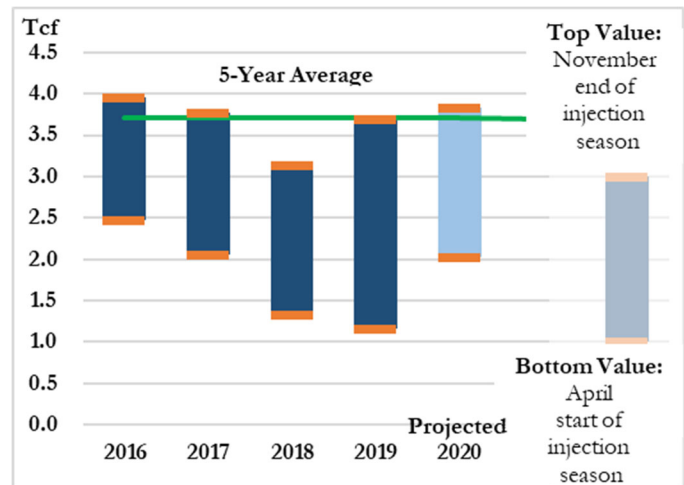
Source: EIA

Natural Gas Storage

Natural gas storage inventory projections are well positioned this year, beginning the injection season at the fourth highest inventory level in the past 10 years of 2.02 trillion cubic feet (Tcf). The current natural gas storage inventory is a result of a relatively low withdrawal season, running from November 1, 2019, to March 31, 2020, due to mild weather conditions. Storage inventories began the 2019/2020 withdrawal season at 3.73 Tcf, 16 percent higher than the start of the 2018/2019 withdrawal season but nearly identical to the five-year average for the first week of November. Warm weather during the winter led to the second lowest level of

withdrawals for a season in the past 10 years. However, ending the withdrawal season with relatively high inventories is balanced with tempered expectations for this summer as additional natural gas fired generation demand could increase competition for storage injections this year. Furthermore, the amount of natural gas injected into storage each summer is highly correlated with the relative cost of natural gas relative to the beginning storage inventories of each season. The second largest injection season in the past ten years occurred in 2019, when natural gas prices at the Henry Hub averaged \$2.39/MMBtu and withdrawal season levels ended at 1.16 Tcf (the second lowest figure in the past ten years). The 2020 injection season is forecast to add 1.82 Tcf this summer, which would lead to storage levels of nearly 3.84 Tcf, more the five-year average at the start of the 2020/2021 withdrawal season. However, summer 2020 storage levels could exceed expectations due to decreased natural gas demand caused by COVID-19.

Figure 15 U.S. Seasonal Change in Lower 48 Natural Gas Inventories



Source: EIA

Conclusion

In summary, COVID-19 has lowered demand for electricity by approximately 3 to 11 percent because of social distancing and “stay-at-home” policies, which also closed many businesses. Moreover, COVID-19 has delayed some maintenance on natural gas and electric infrastructure. Deferred generation maintenance and other factors could potentially impact unit availability during the summer months.

All NERC Planning Regions are expected to have enough generation available to exceed their reserve margins, except for ERCOT. ERCOT anticipates extreme weather, low wind output, and higher-than-normal generation outages may result in the need to declare EEAs. Several natural gas pipelines in California that were out of service in 2019 are expected to be in service at or near full capacity this summer, possibly alleviating natural gas-related constraints in the state during the peak load season. However, California is forecast to have below-average hydropower generation this summer due to lower than average snowpack levels. In addition, the risk of wildfires and Public Safety Power Shutoffs in California remains.

Regarding market fundamentals, weather forecasts for June, July, and August 2020 suggest higher than normal temperatures through the western, southern, and eastern United States, with the upper Midwest expected to have normal temperatures. Several solar, wind, and natural gas resources are expected to come online by the summer, while certain coal resources are scheduled to retire. Natural gas is expected to continue to play a large role in the wholesale electric markets during the summer. Natural gas prices are expected to decrease at most hubs, as production and demand decrease from last summer’s levels. New LNG liquefaction capacity will continue to facilitate the U.S.’s position as a net exporter of natural gas.