

Slide 1 – Introduction

Summer 2019 Reliability and Energy Market Assessment

May 2019

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The Offices of Electric Reliability and Enforcement are pleased to present the 2019 Summer Assessment. This is staff's high level summary of anticipated reliability challenges for the upcoming operating season and corresponding prospective assessment of electric and natural gas markets. We will discuss current and future trends, as well as how recent developments may influence market outcomes.

Please note that some information in this presentation comes from data submitted to the North American Electric Reliability Corporation (NERC) for its 2019 Summer Reliability Assessment, which will be released on May 30, 2019.

Slide 2 - Highlights

Highlights

- Higher than average temperatures are expected in the West, South and East.
- Reserve margins are expected to be adequate in all regions except ERCOT.
- Aliso Canyon natural gas storage inventories remain an item of interest for electric reliability within the Western Interconnection.
- Natural gas futures price movements are mixed when compared to 2018 summer levels.
- Battery storage and wind and solar capacity will exceed previous summer levels.
- New LNG export capacity will drive natural gas demand growth.
- High natural gas injections are predicted to return storage to average levels.
- High hydroelectric power production is expected in California but below-average levels are expected in the Pacific Northwest.

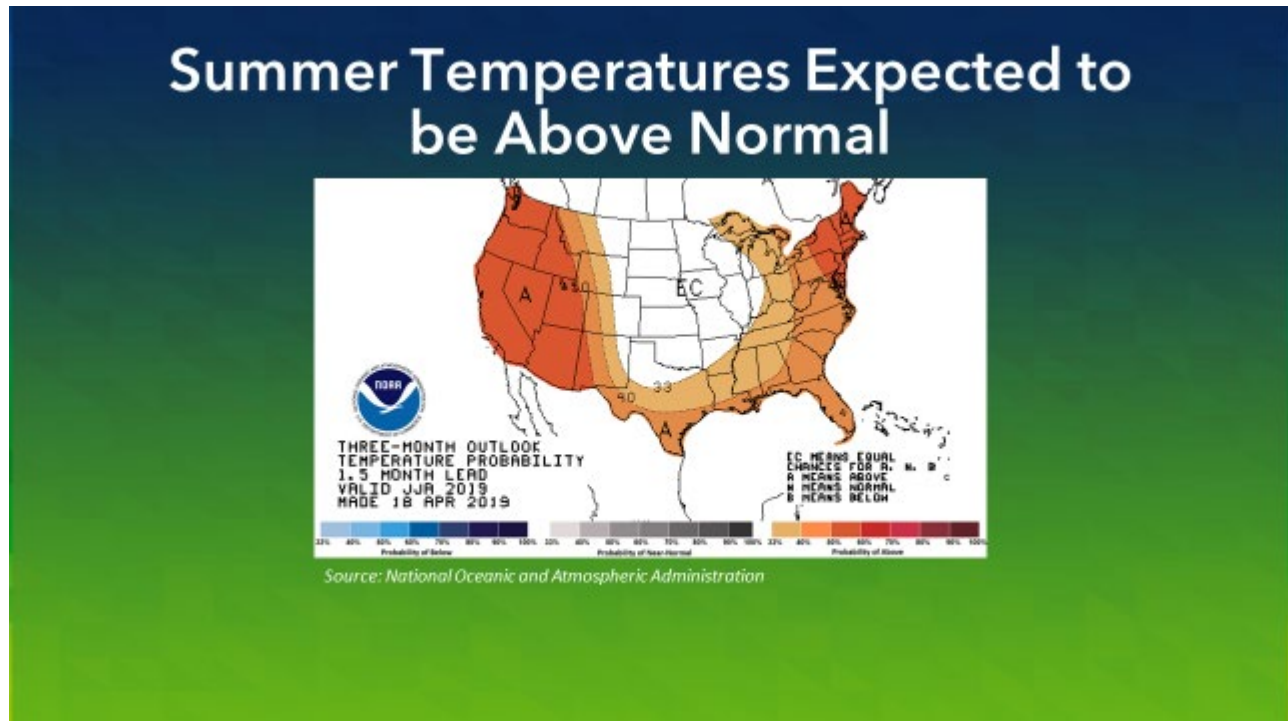
The National Oceanic and Atmospheric Administration (NOAA) forecasts higher than average temperatures for the West, South, and East this summer.

The NERC Regional Entities and ISOs/RTOs (Regions) anticipate that power resources will meet the reference margin levels in all regions except the Texas Regional Entity – ERCOT (ERCOT).

Based on current futures prices, natural gas prices are expected to be higher in some regions and lower in others when compared to summer 2018 levels. Natural gas futures prices reflect both projected demand growth, particularly in power burn and liquefied natural gas (LNG) exports, and expected natural gas production growth from areas such as the Permian Basin and Marcellus Shale. Notably, low U.S. natural gas storage inventories at the beginning of the injection season are expected to return to normal levels by the end of the injection season, based on predictions for higher than average injections.

The West continues to be an area to watch as natural gas pipeline outages and constraints in the Pacific Northwest may also drive Pacific Northwest and California natural gas prices higher. Projected strong hydroelectric power production in California could partially offset potential increases in power prices due to higher natural gas prices. However, moderate and below-average hydroelectric production in the Pacific Northwest could limit options for low-cost electricity imports into California during the summer.

Slide 3 – Weather

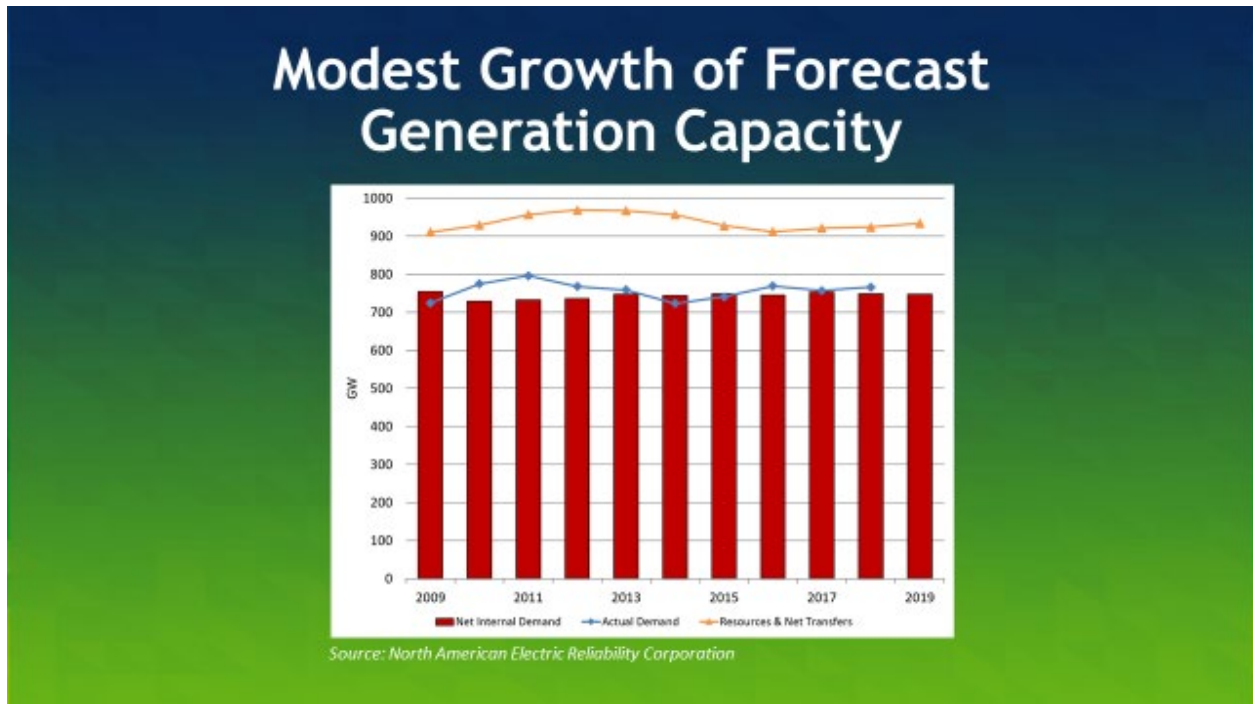


NOAA forecasts an above-normal chance for higher than average temperatures for the West, South, and East for June, July, and August. The expectation for higher than average temperatures is greatest in the West, Southwest, and Northeast regions, with a lower probability in the South. The Midwest projects to have an equal chance of above, lower, or normal temperatures this summer.

Temperature is normally the single greatest determinant of electric power demand in the summer because of its correlation with increased load for air conditioning. Higher operating temperatures can also reduce the efficiency of some generating facilities.

The National Interagency Fire Center is reporting an above normal risk for wildfires in parts of California, Oregon, and Washington this summer, which could pose a localized threat to the reliability of the electrical system. Generally, wildfires do not cause widespread electrical outages due to the distributed nature of the transmission system. Individual transmission lines and generating facilities, however, can experience short-term operational issues. In California, utilities are enhancing wildfire prevention planning to address the increased risk of wildfires by conducting additional inspections of electric facilities, enhancing vegetation management, installing additional weather monitoring stations, and performing around the clock monitoring. The utilities are also implementing “Public Safety Power Shut-off Programs” that preemptively remove transmission and distribution lines from service to reduce the risks of wildfires.

Slide 4 – NERC Generation Capacity



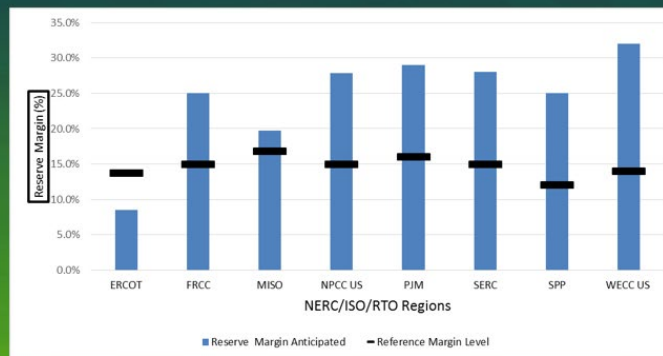
The net demand for electricity is forecast to decrease by approximately 0.3 percent this summer when compared to last year due to reductions associated with greater energy efficiency and behind-the-meter systems. Total generating capacity is anticipated to increase by approximately 1.1 percent from last summer. These projections were calculated with data submitted for NERC's 2019 Summer Reliability Assessment.

Preliminary data from the U.S. Energy Information Administration (EIA) indicates that approximately 6.7 GW of generating capacity will enter commercial operations during this upcoming summer period. A majority of the capacity additions will come from natural gas-fired, solar, and wind resources. MISO is projected to add 1.2 GW of natural gas-fired capacity and FRCC is projected to add 1.7 GW. Additionally, ERCOT and SPP will each gain approximately 0.9 GW of renewable capacity.

Over 2.6 GW of generating capacity is scheduled to retire over this summer period, including approximately 0.8 GW of coal-fired generation concentrated within the PJM footprint. Nuclear capacity has decreased in recent years as nuclear power plants have retired in CAISO, ISO-NE, MISO, PJM, and SPP. Two nuclear power plants with a total capacity of 1.5 GW will retire this summer; these retirements will occur in ISO-NE and PJM.

Slide 5 – NERC Reserve Margins

Reserve Margins Adequate in All Regions Except ERCOT



Source: North American Electric Reliability Corporation

NERC uses the anticipated planning reserve margin to evaluate resource adequacy and reliability by comparing the projected capability of anticipated resources to serve forecasted peak load. The reference reserve margin is usually calculated using probabilistic simulations based on a Loss of Load Probability or Loss of Load Event/year.

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 columns shown on this chart display the anticipated reserve margins for the markets and regions, while the black bars indicate the reference reserve margins.

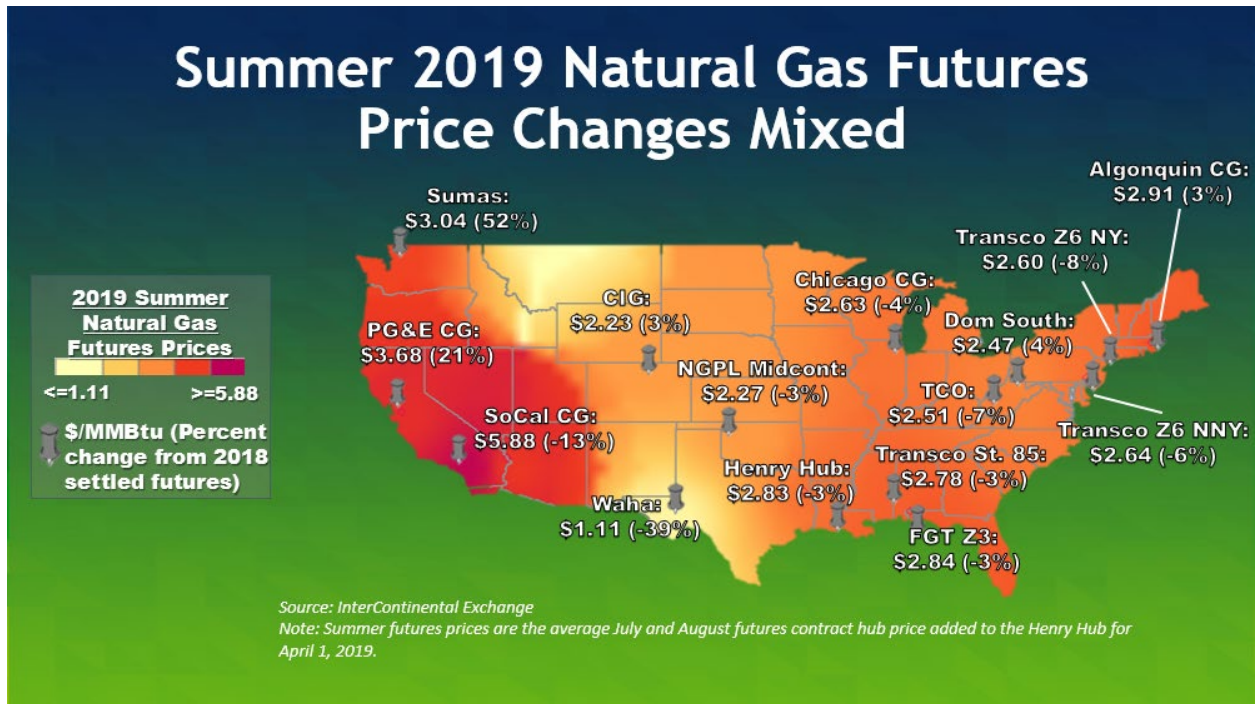
ERCOT anticipates that its reserve margin for this summer will be 8.5 percent, which is below its reference margin level of 13.75 percent. ERCOT's reserve margin in 2018 was also below its reference margin level, but ERCOT maintained system reliability with no load curtailments.

In studying scenarios for the upcoming summer, ERCOT identified the potential need to call an energy alert under various circumstances. When ERCOT declares an energy alert, it can take advantage of a variety of additional resources that are only available during scarcity conditions. These resources are expected to mitigate capacity shortages if they should occur.

Inventories of the Aliso Canyon Natural Gas storage facility in Los Angeles remain an item of focus for electric reliability within the Western Interconnection, although various

preliminary assessments have found that the power system is in a better position this summer than during the summer of 2018. Preliminary estimates suggest that higher available hydropower plant production this summer will reduce the reliability risk of insufficient operating reserves occurring due to a gas curtailment in California.

Slide 6 – Natural Gas Futures Prices



Natural gas futures price movements for this summer are generally mixed across the U.S. compared to the final settled futures prices of summer 2018. As of April 1, 2019, the Henry Hub futures contract, generally the largest component of summer futures prices, is down slightly, falling 3 cents compared to last summer. Despite the slight decrease at the Henry Hub from 2018, prices at trading hubs in Northern California and at the Washington-British Columbia border are up by at least 20 percent from last year. Although the futures price in Southern California is slightly down from last year, it remains the highest priced point in the country this summer. All three natural gas markets may experience volatility this summer due to below-average storage levels and pipeline outages that may limit natural gas supply.

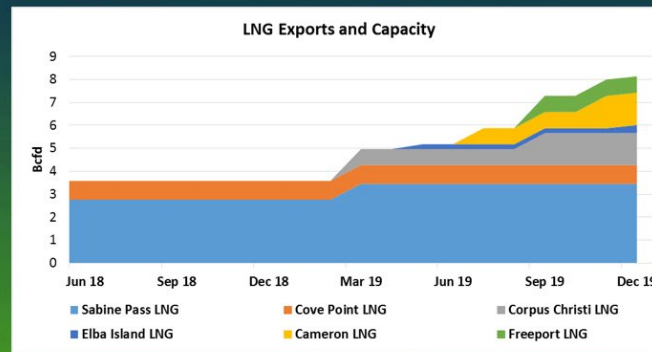
The largest year over year decrease in summer futures prices is found at the Permian Basin's Waha trading hub, contributing to some of the lowest futures prices in the country at \$1.11/MMBtu this summer in West Texas. Generally, West Texas prices remain low as the region experiences large increases in natural gas production associated with rising crude oil production from the Permian Basin and constraints on take-away pipeline capacity.

Although futures price movements vary across the U.S., basis swap futures, the difference between the summer futures prices around the country and the futures price at the Henry Hub, remain negative at all major hubs for the upcoming summer, except in California, the Washington-British Columbia Border, and New England. This means that – except for those regions -- futures prices at major hubs are below prices at the Henry

Hub. The producing regions in West Texas, Oklahoma, the Rockies, and the Marcellus continue to have the largest basis swap futures deficits to the Henry Hub. Most major market demand areas, such as Chicago and New York, have smaller deficits to the Henry Hub and range all the way to a slight premium at the Algonquin Citygates hub in New England. In contrast, the SoCal Citygate hub outside of Los Angeles is trading at a premium greater than \$3.00/MMBtu to the Henry Hub this summer. This premium is largely due to ongoing maintenance outages on the Southern California Gas Company's (SoCal Gas) pipeline system that are expected to continue throughout the summer. Until the maintenance work is complete, the SoCal Gas system will continue operating at reduced capacity.

Slide 7 – LNG In-Services

LNG In-Services Drive Demand Growth



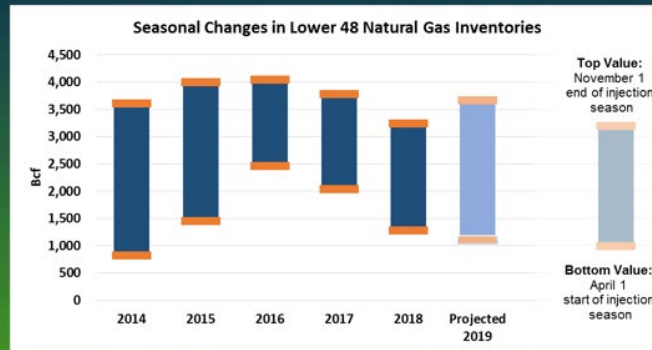
Source: S&P Global, Inc. forecasts as of March 20, 2019

LNG export capacity is expected to nearly double in 2019, increasing from 3.6 Bcfd at the beginning of the year to about 7 Bcfd by the end of the year. Although 1.4 Bcfd of export capacity began service in March, most of the expected capacity for 2019 is forecast to come online in the second half of the year, beginning in July. These timelines are subject to change and are based on corporate guidance provided by the sponsoring companies.

LNG exports have been the fastest growing natural gas demand sector in the U.S. since 2016, averaging nearly 3 Bcfd in 2018. The EIA projects LNG gross exports to average 5.4 Bcfd this June through August, as new LNG export capacity in the Gulf coast and Southeast enters the market. This would result in a 2.5 Bcfd, or 88 percent, increase from last summer's average LNG export volume for these months.

Slide 8 – Natural Gas Storage

Natural Gas Storage to Return to Average Levels



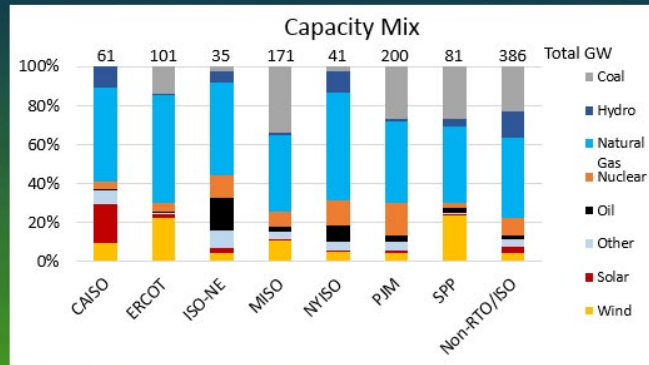
Source: U.S. Energy Information Administration

Natural gas storage inventories began the injection season this spring at 1,107 Bcf, 533 Bcf below the five-year average and slightly lower than last year's mark of 1,281 Bcf. Despite record withdrawals during extreme cold events in January, the most recent winter season saw total withdrawals of 2,140 Bcf, a 14 percent decrease in overall withdrawals compared to the previous year and roughly equal to the average withdrawal level over the past five years.

The EIA projects working gas storage levels to reach 3,673 Bcf by the end of October, roughly 70 Bcf below the five-year average. This implies injections of over 2,500 Bcf this season, which would be 21 percent higher than the five-year average and the highest level of injections since 2014. To meet this high injection mark, large production regions such as the Permian Basin and the Marcellus Shale will need to see continued production growth.

Slide 9 – Generation Capacity Fuel Type

Natural Gas Has the Highest Share of Generation Capacity

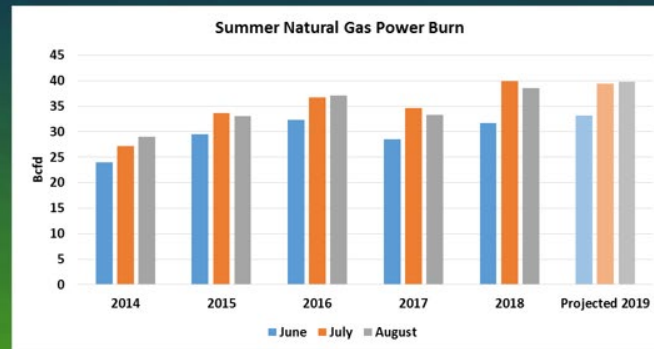


Source: U.S. Energy Information Administration
Note: As of February 2018 Survey. Percentages based on net summer capacity; excludes AK and HI. Includes resources with status of operating and standby.

The ongoing trend of nuclear and coal generation retirements combined with natural gas generation additions will continue into the summer. The increasing dependence on natural gas is reflected in the relatively high percentage of natural gas-fired capacity in all regions. The highest share of natural gas-fired capacity is in ERCOT at 56 percent, followed by NYISO at 55 percent. The non-RTO/ISO regions demonstrate a similar pattern, with natural gas-fired capacity making up the largest market share of generation capacity at 41 percent.

Slide 10 – Natural Gas Power Burn

Power Burn Expected to Increase



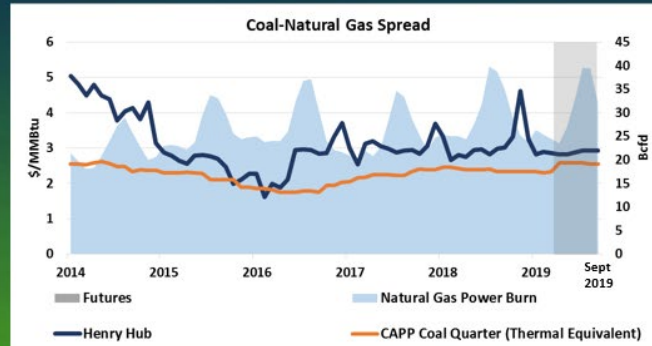
Source: U.S. Energy Information Administration

After reaching record highs during the summer of 2018, the EIA expects natural gas demand for power generation to increase again for the upcoming season. Total power burn for the U.S. is forecast to average 37.4 Bcf/d through June, July, and August, about 2 percent higher than the 36.8 Bcf/d consumed during the summer of 2018. Due largely to warmer than average weather forecasts, the demand projections for this June and August are higher than in 2018, although July demand is expected to be 0.5 Bcf/d lower than in 2018, at 39.4 Bcf/d.

Natural gas demand for power generation has historically been highest in the Southeast and Northeast; these regions are expected to remain the top two natural gas power burn regions this summer. In addition, S&P Global Platts forecasts the two largest natural gas power burn growth regions to be Texas and the Northeast, as both are expected to break new highs of 6.1 Bcf/d and 8.9 Bcf/d, respectively.

Slide 11 – Coal to Natural Gas Spread

Narrow Coal-Natural Gas Spread Promotes Diverse Generation

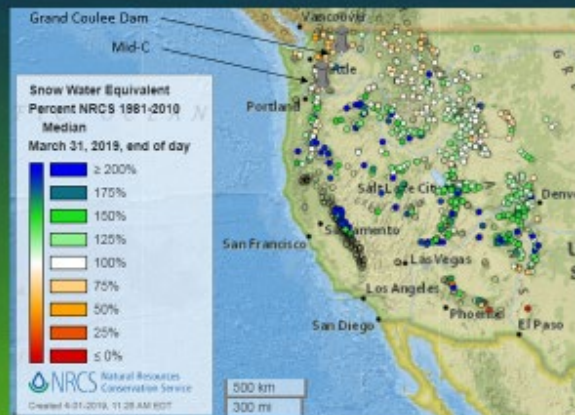


Source: U.S. Energy Information Administration, S&P Global Market Intelligence, CME Group

The upward trend in natural gas power burn is attributable both to long-term structural additions of natural gas-fired generating capacity, as well as short-term fuel switching dynamics in which low priced natural gas is favored over other fuel substitutes. The coal to natural gas spread, or the difference between thermally-equivalent natural gas and coal prices, is currently \$0.60/MMBtu and futures markets indicate that it will remain narrow throughout the summer. Narrow spreads over the past four years have played a large role in the buildout of natural gas-fired generation capacity, which has increased by 33.5 GW from 2015 to the beginning of 2019. The spreads have also prompted natural gas' generation share to increase from 35 percent in summer 2015 to a projected 40 percent in summer 2019 across the U.S., according to the EIA.

Slide 12 - Hydropower

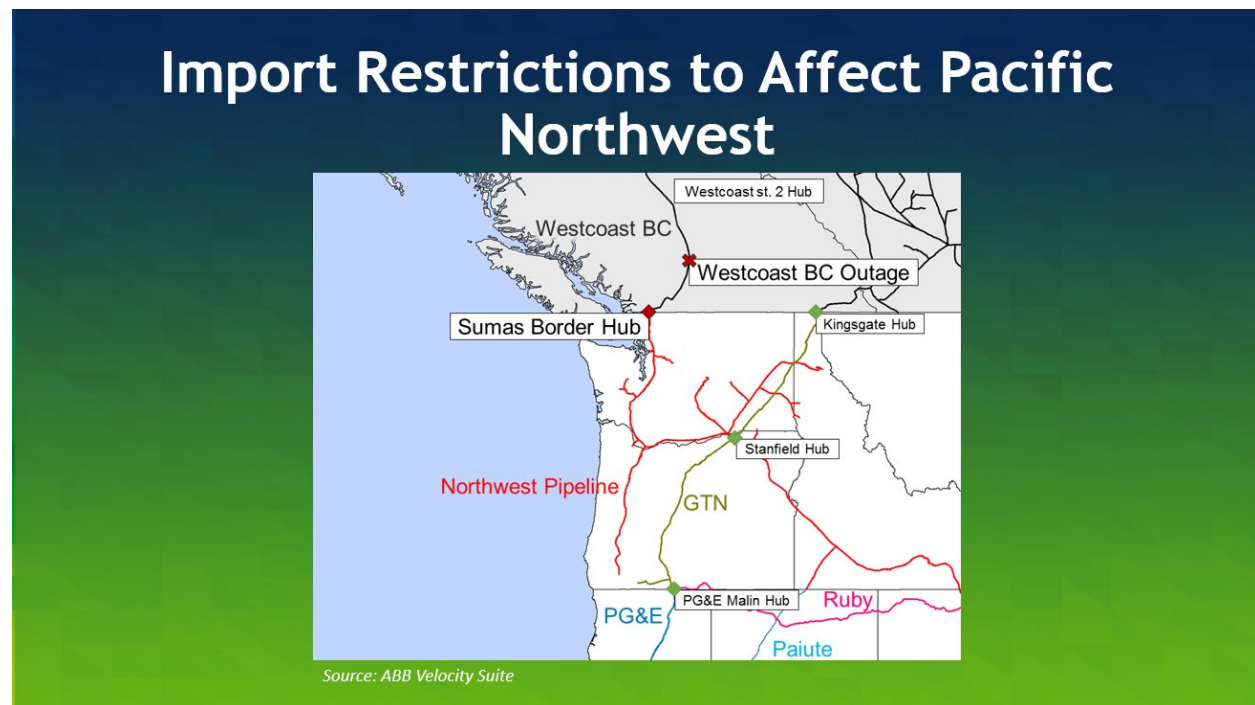
Strong Hydro Expected in California but Moderate in Other Western States



Source: Natural Resources Conservation Service, US Department of Agriculture

With above-average snowpack, California is expected to have a stronger hydropower season than in 2018, when below-average snowpack and drought conditions resulted in the lowest hydropower output since 2015. California experienced heavy snow this winter, with totals of snow-water equivalent inches exceeding 200 percent of the historical median at several weather stations in northern California, and the overall level for northern California at 161 percent of the historical median on April 1, 2019. The higher hydropower output should replace some higher-priced natural gas generation during the peak load period of the summer months. However, hydropower generation in other states in the Western Interconnection is expected to be slightly below historical levels, based on April 1, 2019 snowpack levels in the West and in British Columbia, which may limit the options for low-cost imports into CAISO during the summer.

Slide 13 – Natural Gas Pipeline Constraints in the Pacific Northwest



Natural gas pipeline capacity restrictions at a Westcoast BC Pipeline compressor station north of the Sumas Border interconnect in Washington will limit natural gas imports from British Columbia this summer. The compressor station's restrictions are expected to vary throughout summer, but capacity could dip to as low as 0.8 Bcfd in July and August before full capacity is restored in September. Summer imports at the Sumas Border hub are expected to average 0.7 Bcfd, compared to an average of 1 Bcfd over the past five years.

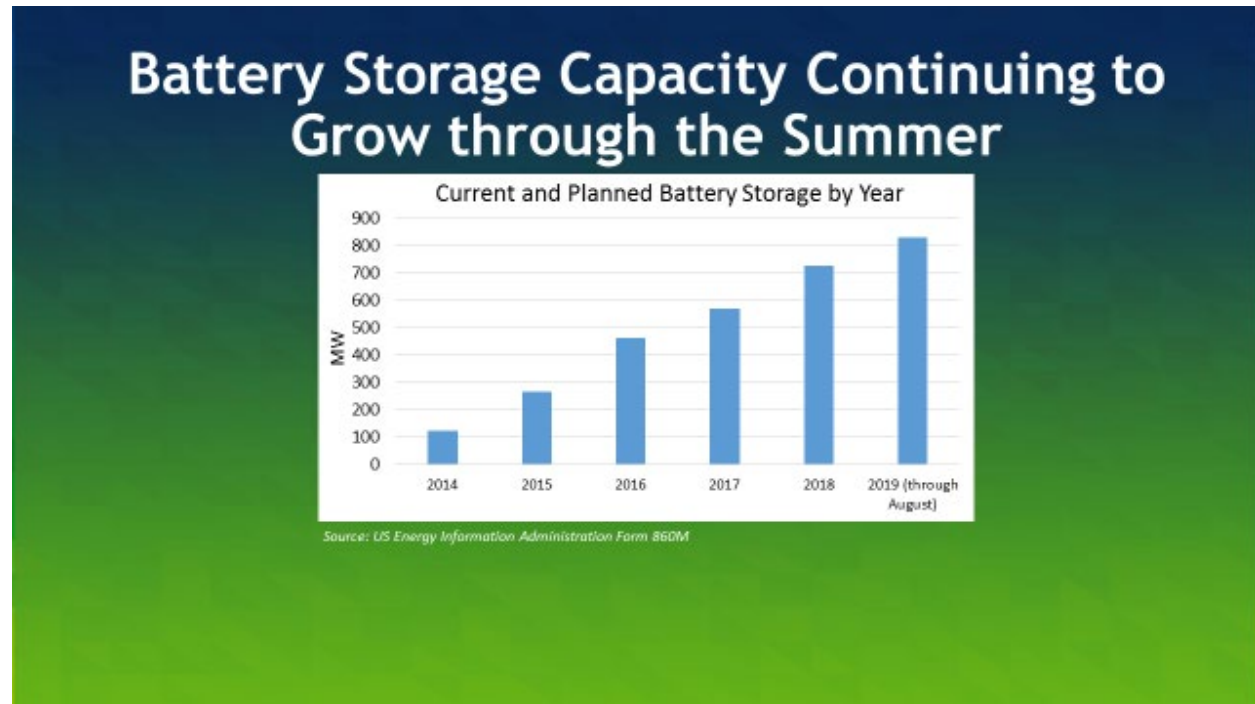
An early March forecast of above-average hydropower generation this summer eased concerns that more natural gas would be needed to meet California electric demand, but below-average hydropower generation in the Pacific Northwest may limit inexpensive import options for CAISO. In addition, lower-than-average natural gas storage levels in the region may result in higher-than-average demand for natural gas as the region's distribution companies seek to rebuild their storage stocks.

Through February, summer strip basis swaps at the PG&E Citygate hub in Northern California rose \$0.40/MMBtu to \$0.84/MMBtu, reflecting market participants' concern about increased competition between utilities looking to replace high storage withdrawals over the summer and natural gas-consuming generators. PG&E Citygate summer strip prices remained high through March, closing at \$0.84/MMBtu. The summer strip at the Sumas Border hub, the hub most likely to be affected by the Westcoast BC restrictions,

increased 30 cents in the two weeks after the pipeline announced its expectations of available capacity.

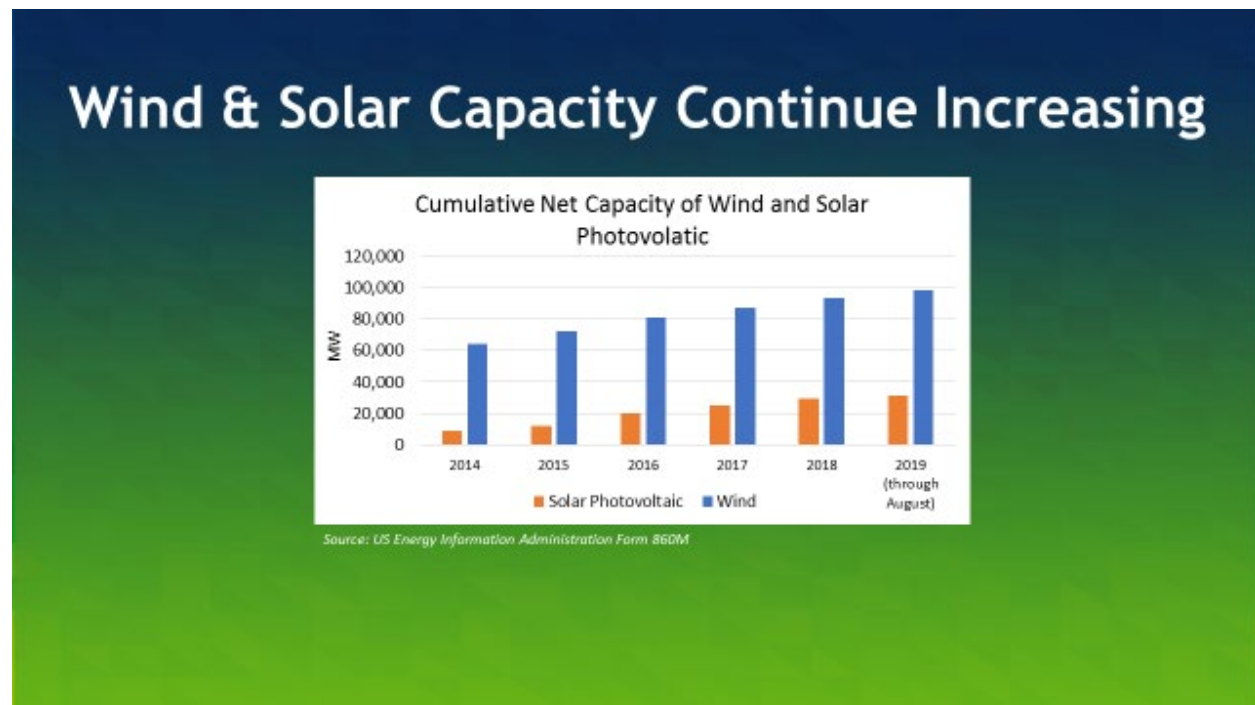
If pipeline maintenance on Westcoast BC coincides with peak demand during a region-wide weather event this summer, prices could experience spikes similar to those that occurred this past winter. Over that period, spot gas prices at Sumas Border exceeded \$40/MMBtu on three separate occasions, including an all-time record of \$159/MMBtu on March 5, 2019.

Slide 14 – Battery Storage Additions



In 2013, there was approximately 100 MW of battery storage capacity operating or planned for operation in the continental U.S. Since then, battery storage has grown rapidly, with 26 MW of battery storage capacity (adjusted for retirements) added in 2014 and a peak addition of 195 MW in 2016. In 2019, EIA projects an addition of 142 MW in battery storage, for a cumulative 744 MW of current and planned battery storage added since January 2015. The fastest growth has been in the West, specifically in California, which accounts for 30 percent of the total storage capacity of the continental U.S. We expect battery storage capacity to continue to increase as the Commission’s Order No. 841 on electric storage participation in organized markets is implemented.

Slide 15 – Wind and Solar Capacity



This graph shows the current and planned wind and solar operating capacity across the continental U.S. from 2014, and the units planned to begin operation through August 2019. There are 290 units scheduled to begin operation nationwide in 2019 that will add approximately 14 GW of capacity, including nearly 4.5 GW of solar capacity and 9.3 GW of capacity from onshore wind turbines. There are no plans for any offshore wind turbines to come online in 2019.

The aggressive growth in solar and wind capacity may slow in coming years with the decline in the Investment Tax Credit (ITC) for solar projects and the Production Tax Credit (PTC) for wind projects. The PTC will expire for wind projects that begin construction in 2020. For solar projects, the ITC is set to decline by 4 percent in 2020 and 2021, until stabilizing in 2022 at one-third its current rate. The loss of these tax credits may be offset by lower manufacturing and installation costs for renewable generation.