Winter 2020-2021 Natural Gas Market Outlook

Executive Summary

Prepared for Natural Gas Supply Association

September 2020

Authors

June Yu

Ai Wang

Rob DiDona

ENERGY VENTURES ANALYSIS

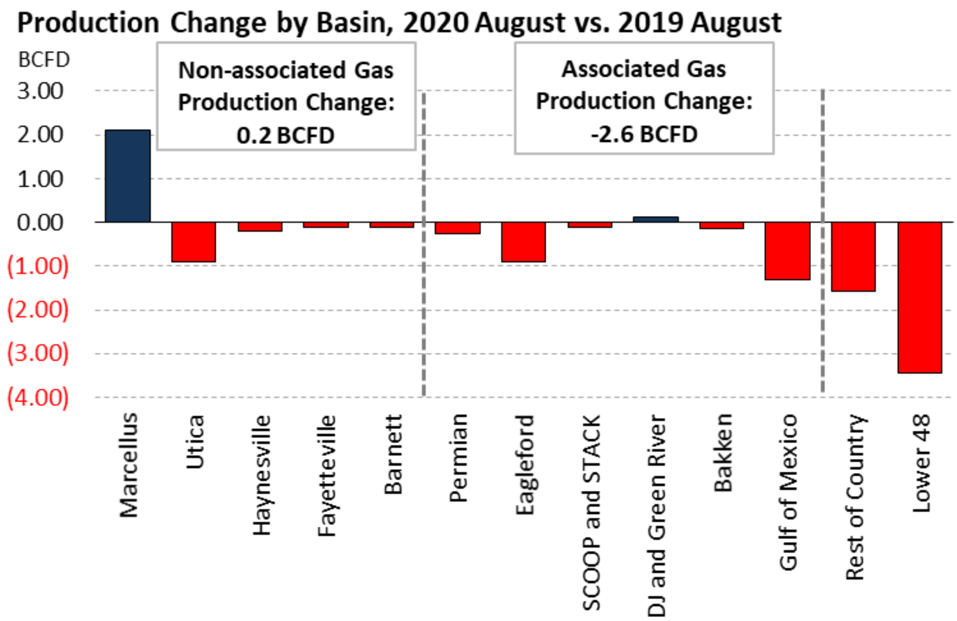
1901 N. Moore St., Suite 1200

Arlington, VA 22209

(703) 276 8900

www.evainc.com

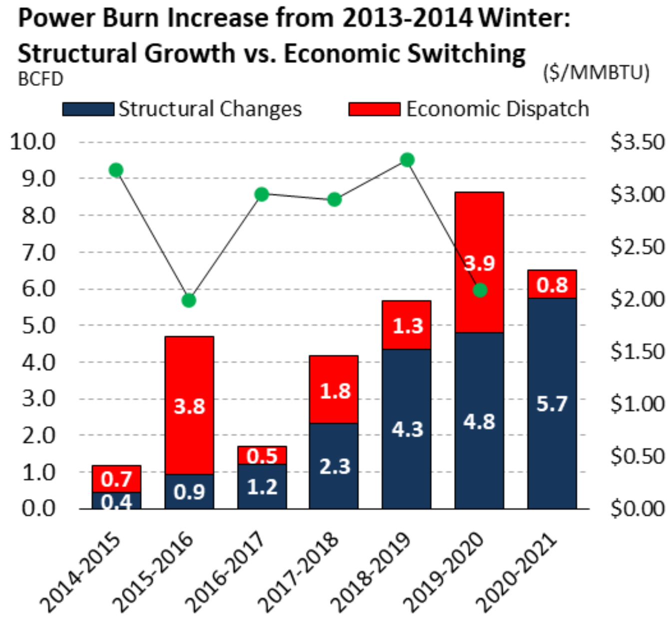
Collapse in crude oil prices puts significant downward pressure on associated gas production—



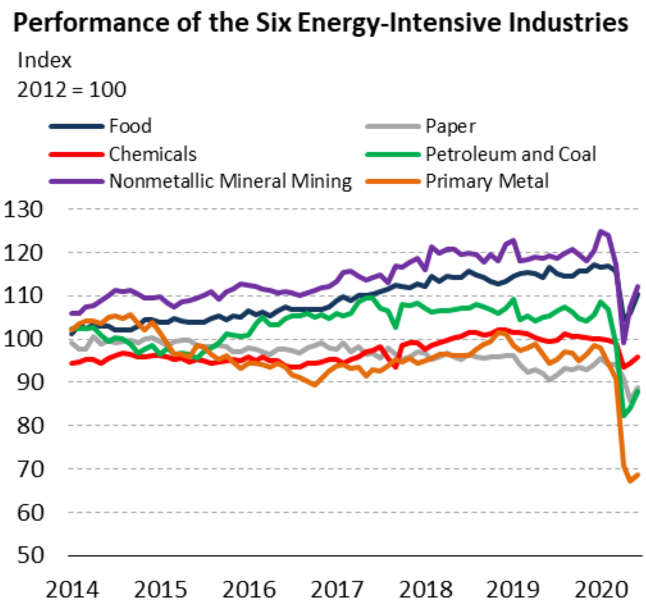
Source: OPIS PointLogic, Energy Ventures Analysis

- Natural gas production has been declining as producers have scaled back drilling in response to low commodity prices and weak demand caused by the COVID-19 pandemic. In August, U.S. oil- and gas-directed rigs fell to a new record low, with the decrease in oil rigs accounting for most of the decline. As a result, gas production from oil-rich producing areas such as Eagle Ford, SCOOP/STACK, Bakken, and the Gulf of Mexico has declined year-on-year. EVA expects associated gas production to drop further through the first quarter of 2021.
- Non-associated gas production from dry gas areas (primarily from Appalachia and Haynesville) will respond to higher price signals and be called upon to offset associated gas weakness in 2021. As natural gas prices remain relatively supportive, month-to-month production growth from the non-associated gas plays should emerge in early 2021.
- Over the past few years, pipeline infrastructure development has been focused in the Appalachian and Permian regions. More recently, U.S. natural gas infrastructure has experienced increasing obstacles as legal and regulatory scrutiny weigh heavily on pipeline development. Two major greenfield pipelines—the 2-BCFD Mountain Valley (MVP) and 1.5-BCFD Atlantic Coast (ACP)—were planned to bring natural gas from Appalachia to demand markets in the Southeast. In July 2020, the developers of ACP canceled the project due to legal challenges and unexpected delays. The cancelation left MVP as the only large-scale greenfield project in the Appalachian region.
- Declining Permian production amid lower crude oil production, however, will reduce the region's reliance on new pipeline takeaway infrastructure in the short term. The Permian Highway Pipeline (2 BCFD) is still scheduled to start service in Q1 2021, while the Whistler Pipeline (2 BCFD) cleared FID in 2019 and is scheduled to enter service in Q3 2021.

Power and industrial demand will experience minimal growth due to higher natural gas prices and a longer recovery time from COVID-19—



Source: Energy Ventures Analysis



Source: U.S. Federal Reserve

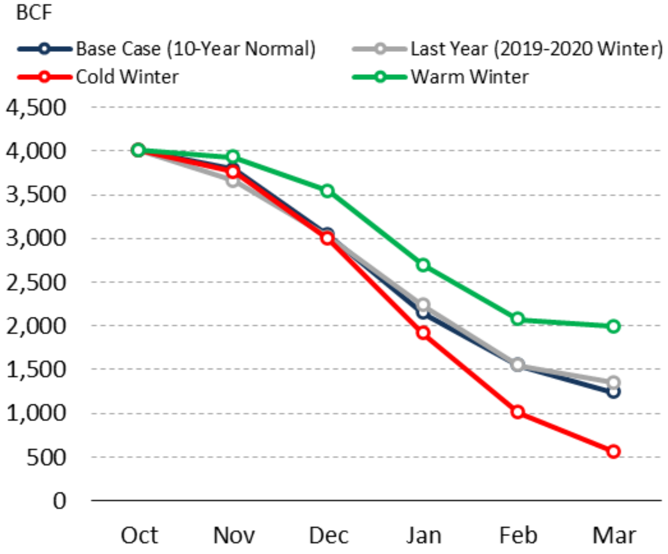
- Power burn demand has been very strong so far this year, with year-to-date power burn averaging roughly 2 BCFD stronger year-over-year. The robust power burn is largely driven by new CCGT additions over the past few years, which provide a solid base for power burn growth in a relatively low natural gas price environment.
- Based on EVA's power market modeling, power burn is expected to average 26.6 BCFD for the 2020-2021 winter. Adjusted for weather, winter burns for the upcoming winter will rise by 6.5 BCFD since the 2013-2014 winter, primarily due to natural gas-fired power plant additions that have replaced retiring coal-fired and nuclear power plants. Structural growth due to new CCGT additions will increase further, establishing a strong base for power burn growth. However, stronger natural gas prices for the 2020-2021 winter will somewhat limit the economic switching from coal to natural gas.

- Industrial natural gas demand has grown substantially in recent years thanks to continuing economic growth and the availability of low-cost natural gas. Strong growth in energy-intensive industries has contributed to higher industrial gas demand in the last decade. Beginning in spring 2020, however, performance indexes across all energy-intensive industries fell sharply due to the widespread lockdowns and business closures driven by the COVID-19 pandemic.
- 2016-2019 represented an active period for the development of new industrial facilities. A total of 39 projects came online during that stretch and drove an estimated 1.5 BCFD of natural gas demand. An additional 37 projects are expected to come online between 2020 and 2023, which could potentially add 1.6 BCFD of incremental gas demand. Since spring 2020, the impacts of COVID-19 mitigation efforts, including supply chain disruptions, social distancing strategies, permitting delays, and the restricted travel of specialized workers have affected project scheduling and increased risk of project delays.

Production is projected to drop further for 2020-21 winter, tightening the gas market, particularly if the weather is colder than normal—

Winter Natural Gas Supply and Demand Summary			
BCFD	2020-2021 Winter	2019-2020 Winter	Difference
Supply			
Dry Production	86.0	94.2	(8.2)
Net Canadian Imports	5.0	4.6	0.4
LNG Imports	0.3	0.2	0.2
Total Supply	91.4	98.9	(7.6)
Demand			
Power Burn	26.6	28.9	(2.3)
Industrial	24.7	24.6	0.1
Residential and Commercial	36.9	36.2	0.7
Net Mexico Exports	5.5	5.1	0.3
LNG Exports	9.3	8.5	0.9
Other	6.7	7.3	(0.6)
Total Demand	109.7	110.6	(0.9)
Implied Withdrawals	18.3	11.6	6.7
Implied Withdrawals (BCF)	2,746	1,757	989
HDDs	3,433	3,294	139

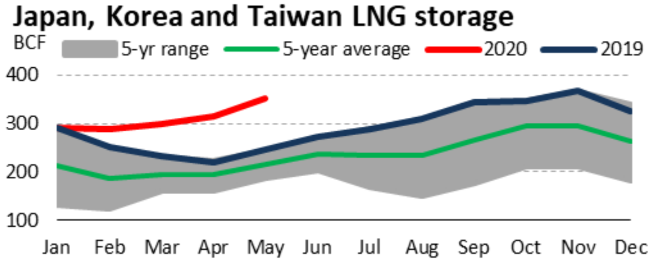
End-of-March Storage Level under Different Weather Scenarios



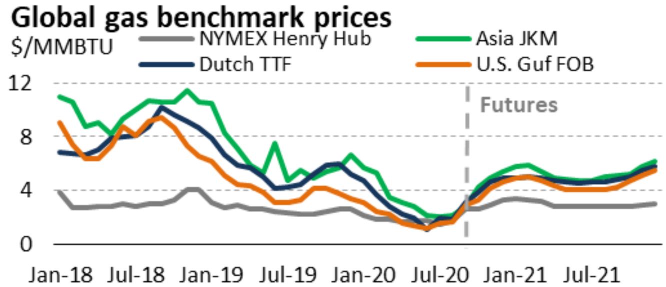
Source: Energy Ventures Analysis

- Demonstrated peak storage capacity remained relatively flat year-on-year. Strong production growth and reduced natural gas price volatility over the past five years have reduced the reliance on conventional storage services as robust supply can meet customers' natural gas needs even during peak demand days. This has coincided with active midstream development, which has enhanced pipeline connectivity and flexibility, allowing natural gas to reach end users more easily.
- Based on the near-term supply and demand dynamics, EVA expects the 2020 season-end inventory to reach 4,008 BCF, which is well above the five-year average. Under EVA's base case, which uses current NOAA seasonal weather forecasts, the end-of-March storage level is forecast to be 1,243 BCF, well below the five-year average level.
- Among the demand sectors, stronger domestic heating, Mexico exports, and LNG export demand will drive natural gas consumption growth. On the supply side, expected declines in associated gas production will tighten the supply-demand balance and put upward pressure on natural gas prices.
- Winter weather will play an important role in residential and commercial gas demand. Apart from the base case, EVA analyzed three other weather scenarios: Last Winter (2019-2020 winter), Cold Winter (2013-2014 winter), and Warm Winter (2015-2016 winter). According to the analyses, residential and commercial gas demand could swing more than 9 BCFD depending on weather. EVA's weather sensitivity analysis shows that the end-of-March storage levels will drop well below the five-year average under a cold winter scenario, and the tightening market will create greater upside price risk for the 2020-2021 heating season, which could incentivize natural gas production.

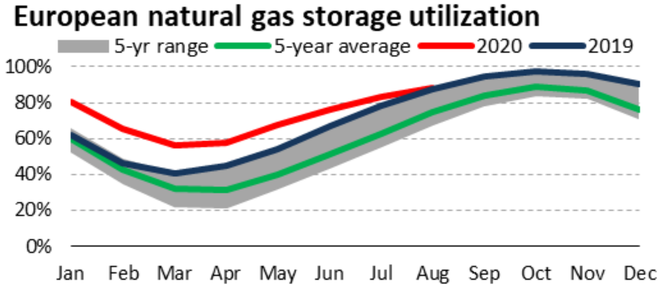
All major gas markets worldwide are experiencing oversupply due to a mild 2019/20 winter and the pandemic—



Source: Japan Ministry of Economy, KESIS, Taiwan Bureau of Energy, Energy Ventures Analysis



Source: ICE. Future curves are based on August 30th settlements.

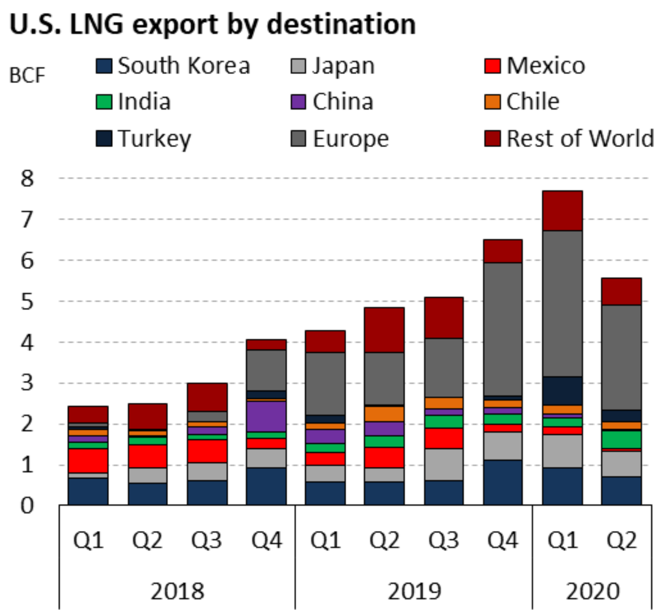


Source: AGSI+, Energy Ventures Analysis

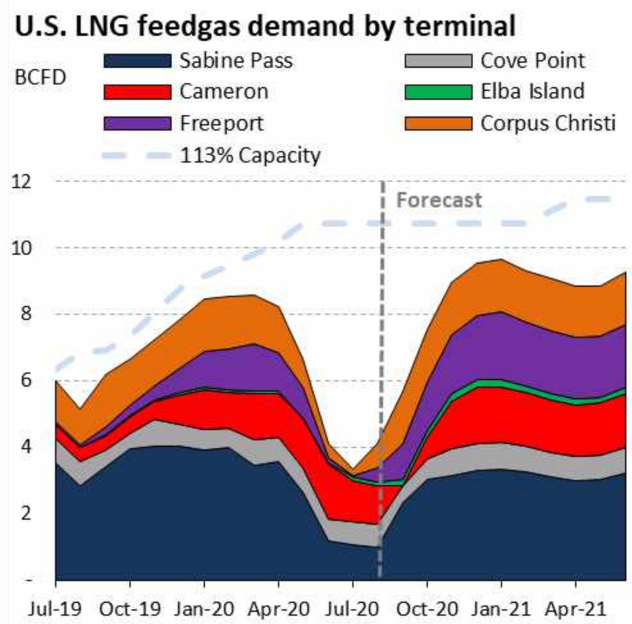
- Natural gas inventories across Asia and Europe have been running at above-average levels since the beginning of this year. The combination of the COVID-19 pandemic and a mild winter in the northern hemisphere have put global natural gas demand on course for its largest annual decline in history. The global gas market remains significantly oversupplied, sending global natural gas prices to historic lows. Global gas inventories have absorbed excess supply due to the surge in spot LNG buying activities and already-contracted volumes.
- However, the growth rate of European stockpiles has been slowing since June and recently fell below last year's level. The slower injections into European storage is attributable to a few waves of U.S. LNG cargo cancellations, maintenance on Nord Stream and Norwegian pipelines, increasing utilization of Ukrainian storage, and record coal-to-gas switching this summer. Moving into Q4 2020, the return of regional pipeline supply as well as resumed LNG deliveries could replenish gas storage again.

- Starting in Q2 2020, the U.S. LNG sector has been under pressure with price declines and weak demand exacerbated by the COVID-19 pandemic. The risk of a gas oversupply emerged as early as Q4 2019, when major benchmark prices began to soften. The annual average of Asian and European gas prices dropped nearly 35%. Worsening fundamentals resulting from demand destruction slashed primary indices across the world. Dutch TTF prices plunged 65% YoY in Q2 2020 while JKM, the LNG index in Northeast Asia, fell by 50% compared to the same time last year.
- Net margins of exporting U.S. LNG cargoes on a spot basis fell into the negative territory in Q2 2020 as delivered prices at the destination market cannot cover the variable cost of off-takings. Contracted volumes are less economic to lift as their costs are linked to either Henry Hub or Brent, making them more expensive than spot prices. As a result, buyers from Europe and Asia have requested to cancel more than 95 U.S. LNG cargoes for loading between May and August. Although the recent price rally across the world has improved export economics, the profit margins of U.S. spot cargoes will remain low through 2021 based on the latest forward curves.

Despite currently being impacted by market oversupply, LNG export demand should see a steady growth starting Q4 2020—



Source: U.S. DOE, Energy Ventures Analysis



Source: Energy Ventures Analsysis, PointLogic

- U.S. LNG exports soared 115% YoY in 2019 and reached a high of 7.8 BCFD in Q1 2020 thanks to fast-growing capacity and declining natural gas prices. In addition to legacy buyers Japan and South Korea, European countries led by Spain, France, Netherland have become a major destination of U.S. supply owing to waning domestic production and record coal-to-gas switching. Deliveries to China shrunk 88% YoY in 2019 due to the impact of the Sino-U.S. trade war before slightly recovering in the first half of 2020 with the support of a phase 1 trade agreement. Following completion of the Sur de Texas-Tuxpan pipeline in Q4 2019, most of the U.S. LNG exports to Mexico have been displaced by pipeline flow.
- Roughly 5.5 BCFD (38.9 MTPA) of export capacity has been placed in service since 2019. As of July 2020, six liquefaction terminals in the U.S. totaling 9.4 BCFD (67.2 MTPA) are either in operation or commissioning. With Cameron Train 3 and Elba Island Phase 2 beginning their final commissioning stages, EVA expects the first wave of U.S. LNG development to be completed before winter 2020-21.
- During the 2020 summer, all U.S. LNG plants except for Cameron and Cove Point were running at low utilization rates. Feedgas deliveries to U.S. LNG terminals slumped from a peak of 8.5 BCFD in Feb-Mar to 3.4 BCFD in July amid mounting cargo cancellations, with Sabine Pass and Corpus Christi accounting for most of the reduction.
- Thanks to fewer cancellations in September and October, U.S. terminals have been ramping up quickly. However, volatilities still exist in the near term amidst an unusually active storm season and plant maintenances.
- Looking ahead, LNG feedgas demand for exports should continue to grow steadily in Q4 2020 provided there is no major demand destruction event, reflecting liquefaction capacity growth and strengthening LNG pricing fundamentals.
- Natural gas storage in key markets that have been balanced out quickly could also strengthen U.S. LNG demand. However, the potential resurgence of COVID-19 remains a wild card. After three years of steady growth, the U.S. may become a marginal supplier in 2020-21 with swinging utilization rates before demand fully recovers.