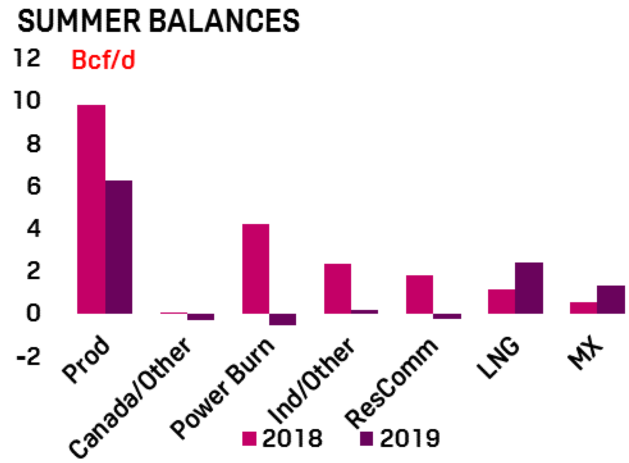
S&P Global
Platts

NORTH AMERICAN GAS CURRENT NEWS & ANALYSIS

April 3, 2019

2019 Summer Outlook



With winter in the rear view mirror, an interesting summer season lays ahead. Inventories to start the summer injection season are just slightly above 1.1 Tcf, the lowest on record in relevant history with the exception of the polar vortex winter of 2013/14. Meanwhile, producers — many of which have committed to targeting free-cash-flow, over production growth, stand to be a drag on further upward momentum. At the same time, long-awaited new LNG export facilities are set to come online and additional infrastructure completions should allow for a significant bump in piped gas to Mexico. Power burn will maintain its position as the primary balancing agent, providing support to the market in low-price periods and a relief valve in high price environments.

All told, the summer outlook calls for a loose start to the season, before US balances should progressively tighten, resulting in an injection of ~2.1 Tcf. Given that is close to the five-year average net build, the deficit on hand to the start the season will not be eliminated, and as a result, underlying fundamentals should support a summer price closer to $3/MMBtu as opposed to the more recent NYMEX levels of ~$2.80/MMBtu. However, the market's reluctance to get excited that higher prices are in the offing this early in the season is understandable. This summer's fundamentals are to make some fairly dramatic changes and each of them bring their own brand of risk to the outlook.

Winter 2018/19 featured massive production growth along with strong demand-side support, both structurally in exports and power but also in rescomm. On balance, it was demand that outperformed pre-winter expectations the most, resulting in a pull from storage of 2.0 Tcf — 400 Bcf greater than pre-winter assertions. Weather played a role, where nationally temperatures were modestly colder than normal, but timing and concentration of warm and cold periods contributed to significant volatility in demand, as is often the case. Should injections only equal 2.1 Tcf, the entry into winter 2019/20 with stocks measuring only 3.25 Tcf feels pretty tight.

- This summer US demand is expected to grow by 3.3 Bcf/d relative to 2018. The gains this year are made from expansions in US exports equalling 3.7 Bcf/d while domestic demand is set to decline slightly Y/Y. Risks in demand for power burn skew bullish in a low price environment.

- Total US supply will grow to average 92.4 Bcf/d — an increase of 5.6 Bcf/d over last year. Gains in US production are behind the increase, while imports from Canada are forecast to drop by about 0.5 Bcf/d. Risks to the supply picture lean bearish, where growth out of the Haynesville and associated plays outside of the Permian could surprise to the upside. Also, the announced maintenance on Westcoast Pipeline's system could potentially have outlined the worst case scenario resulting in greater supply availability into the Pacific Northwest than announced.

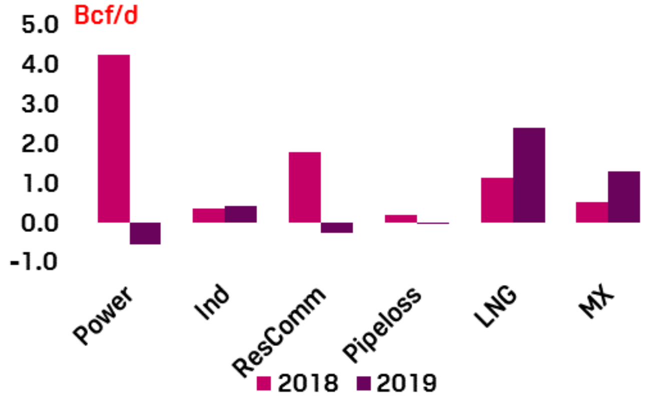
- Platts Analytics price forecast for summer 2019 is $3.02/MMBtu, above the current NYMEX strip at ~$2.80/MMBtu. However, since the release of the summer forecast, mild temperatures both in the US and globally have contributed to softening in price. NYMEX Henry Hub settlement on the day of the forecast release was $2.94/MMBtu. While the weather impact to price has pulled back the baseline price, Platts Analytics is affirming its position that the market is undervalued.

- Contributing to the Platts Analytics price outlook is the current end-October inventory forecast at 3.25 Tcf, within reach of last year's paltry level — the lowest carry since 2005. With the key differences between winter 2019/20 and 2018/19 being, 1) next winter won't have the benefit of record-setting production growth to stave off prospective shortfalls and 2) significant additional export demand growth will increase overall demand, making it important that price this summer supports early and regular injections.

Demand growth summer 2019

Summer 19 demand growth of 3.3 Bcf/d is a product of small gains in industrial and substantive gains in exports to Mexico and from LNG. For now, US power burn is forecast to post a small Y/Y decline based on Platts Analytics price forecast of $3.02/MMBtu at Henry Hub (as well as assumed 10-year normal US temperatures). However, in light of the recent softening in price, with April cash at ~$2.70/MMBtu and the balance of the summer at ~$2.80/MMBtu, summer burns stand to be ~0.8 Bcf/d higher. Industrial demand is set to grow by ~0.4 Bcf/d, due to new projects and expansions. This summer's demand gains, namely in the case of exports are fraught with downside risks.

Y/Y CHANGES TO SUMMER DEMAND



- Demand growth over the past five years has averaged 3.6 Bcf/d. However, last summer featured growth of 8.2 Bcf/d led by a considerable uplift in power burn, which accounted for about half the growth.
- Risks to exports weigh to the downside due to prospective delays in project development.
- Power burn in 2019 is likely to surprise to the upside, as too much weight seems to have been given to warmer-than-normal temperatures in effect in 2018 relative to structural changes to the market.

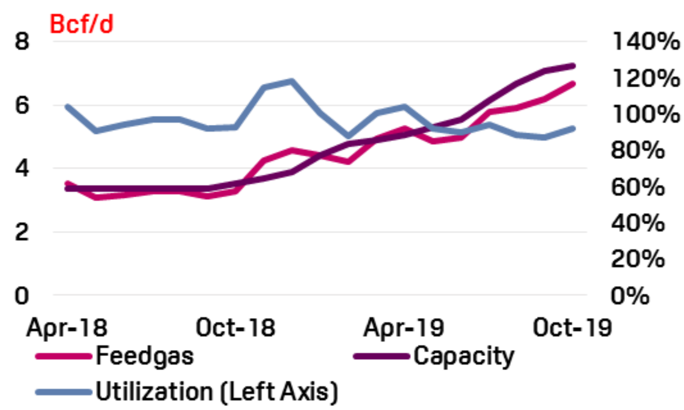
Big summer for LNG, bringing US capacity to 7.8 Bcf/d

LNG export increases are the largest component of summer demand growth this summer. More specifically, LNG feedgas is forecast to grow from about 5 Bcf/d toward 7 Bcf/d by October. US capacity utilization should remain robust throughout the summer. While, recently the global LNG market has come under immense pressure, it is Platts Analytics' view that this is transitory and a recovery of price is ahead, allowing for continued strong exports.

The table to the right identifies the FERC status of projects set to reach commercial start this summer. At present, the facilities currently in commercial service are Cove Point in Maryland, Sabine Pass Trains 1-4 in Louisiana and Corpus Christi Train 1 in Texas.

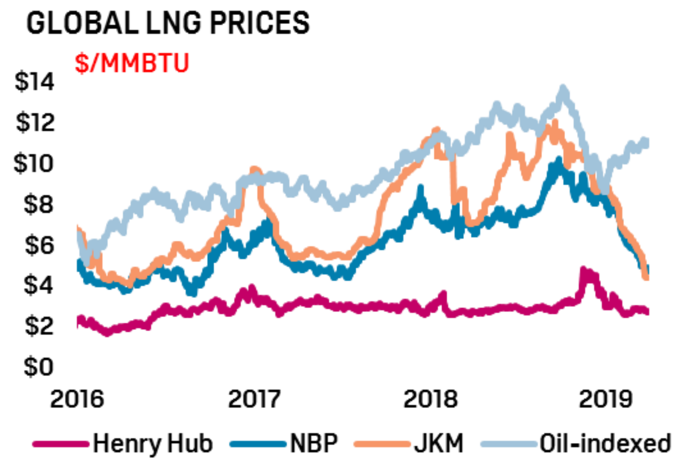
- Sabine Pass' 5th Train will be the next to enter commercial service, likely in April.
- Kinder Morgan announced a delay to Elba Island's Trains 1-6 resulting in Platts pushing Elba's estimated start date from April to May.
- For Cameron Train 1, the absence of progress to the Fuel Gas Approval stage resulted in a delay in the estimated start dates to July from April.
- Corpus Christi Train 2 is on schedule, if not ahead, for its August start date.
- Freeport LNG is targeting shipping its first export cargo in July which is supportive of the September start.
- Completion of these projects will elevate the US export capacity to 7.8 Bcf/d and feedgas potential to 8.3 Bcf/d.

LNG DEMAND PROFILE AND UTILIZATION



Facility	Train	Capacity Bcf/d	FERC Status	FERC Status Date	Est. Commercial Start
Corpus Christi	1	0.6	Commercial Service	2/19/2019	19-Mar
Sabine Pass	5	0.6	Feedgas Approved	10/11/2018	19-Apr
Elba Island	6-Jan	0.2	Feedgas Approved	3/6/2019	19-May
Cameron LNG	1	0.6	Hazardous Fluids Approved	1/3/2019	19-Jul
Corpus Christi	2	0.6	Feedgas Approved	3/11/2019	19-Aug
Freeport	1	0.7	Hazardous Fluids Request	2/19/2019	19-Sep

Currently, netbacks measure about +$0.90/MMBtu and +$1.20/MMBtu for Sabine Pass and Cove Point, respectively. Platts Analytics' forecast is calling for about 93% capacity utilization on average over summer 2019. For context, last summer's LNG liquefaction capacity averaged a 95% capacity factor, though, that base was considerably smaller.

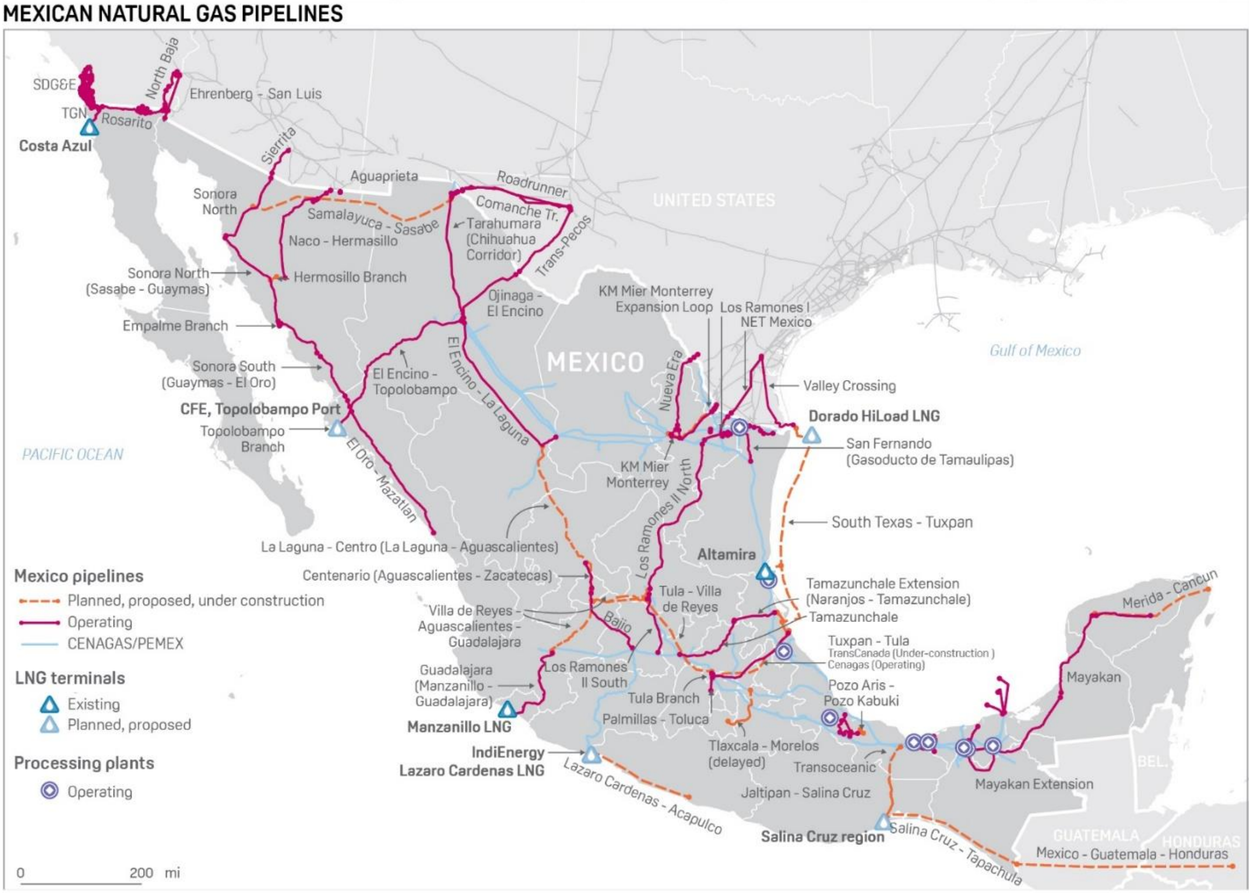


With only about a dollar's worth of headroom left following the collapse in global LNG prices the threat of even lower US capacity remains a concern. Indeed, the risk of still lower prices in Europe and Asia will continue to keep this topic at the center of the LNG debate throughout the summer, particularly given the possibility of full storage in NW Europe by mid-August. For more information about how Platts Analytics has arrived at the current outlook for LNG demand this summer, please see the post made 03/29/2019 to Dimensions and Benport titled *US LNG Netbacks and Production*. Barring unforeseen market disruptions, by October LNG export demand should average 6.8 Bcf/d and LNG exports will account for 8% of October's total demand.

Mexico is to open major corridor to the East and provide a little relief to Permian

The highly anticipated 2.6 Bcf/d Sur de Texas – Tuxpan (marine) pipeline was delayed from mid-February until "early Q2 2019" per both TransCanada and IEnova's latest earnings calls. The new pipeline will have interconnects with TransCanada's Tamazunchale pipeline at Naranjos, the national pipeline grid (SISTRANGAS) at Monte Grande (0.5 Bcf/d), and near the Altamira LNG import terminal. Platts Analytics expects the new pipeline to displace Altamira LNG sendouts for nearly 0.5 Bcf/d, to max out spare capacity at Naranjos for 0.2 Bcf/d, and potentially feed demand along the SISTRANGAS Gulf Coast Line which totaled 0.5 Bcf/d in 2018. The pull on South Texas supply may provide upward pressure on basis until the 2.0 Bcf/d Kinder Morgan Gulf Coast Express pipeline enters service in October 2019.

MEXICAN NATURAL GAS PIPELINES

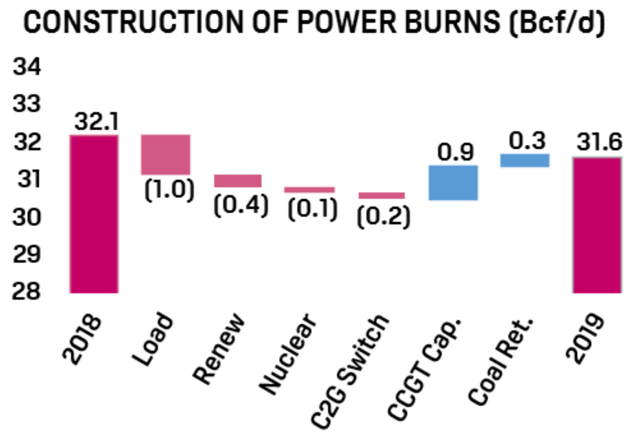


Source: S&P Global Platts Analytics

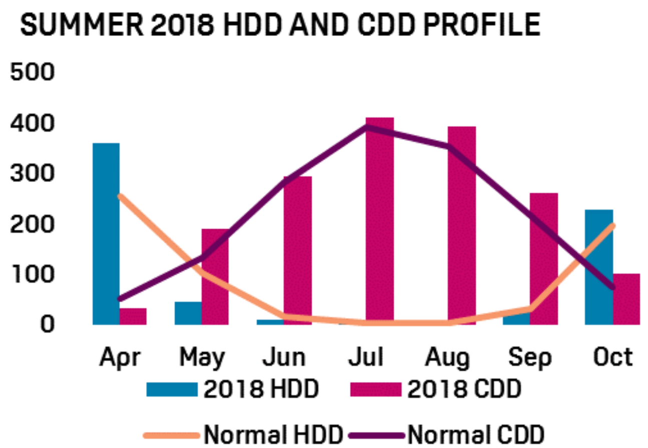
The Wahalajara system, coupled with new CCGT capacity in Northwest Mexico, will provide just over 0.4 Bcf/d of downstream access out of West Texas this summer versus year-to-date flows. Downstream interconnectivity will be crucial in driving US exports to Mexico, of which the Cempoala Compressor Reversal (July '19, 350 – 600 MMcf/d), Mayakan pipeline interconnect (July '19, 250 MMcf/d), and the Guadalajara Interconnect (June '19, 250 MMcf/d) are instrumental in formulating downstream access. US exports to Mexico are forecast to average 6.1 Bcf/d April – October, an increase of 1.3 Bcf/d from the same time in 2018.

Power burns to remain strong summer 2019

Burns-per-degree should remain elevated again this summer. More specifically, gas power burns of 31.6 Bcf/d are forecast for this summer — down 0.6 Bcf/d compared to last summer when population-weighted CDDs averaged 12% higher than normal. Weather normalized demand for power burn in 2019 would be ~30.9 Bcf/d. However, also adjusting for changes in the generation stack, renewable additions, normalizing for wind (last year was a mild wind-year) and coal-to-gas switching availability, the overall demand profile is fairly close to that of 2018



Summer 2019 will feature 11 GW of new CCGT installed capacity, with ~7.2 GW located in PJM summer-on-summer. Helping to inform the forecast is the high utilization of new gas-fired generation in PJM. ISO and EIA 923 data show new gas fired-generation operating at the expense of coal generation versus creating gas-on-gas competition. And similarly, Duke Energy's Citrus County Florida's mammoth 1.64 GW plant, that is meant to replace the recently retired Crystal River coal-fired units 1 and 2, has been operating at more than a 60% capacity factor since reaching commercial operation in November.



From a price perspective, current natural gas prices should elevate expected gas burns in the near-term at a minimum, as the April power burn forecast called for prices at Henry Hub of $2.93/MMBtu and baseload deals for April averaged about twenty-cents south of that level. Similar softness relative to the forecast is prevalent throughout the country, meaning the increased dispatch will extend beyond Louisiana.

A more comprehensive discussion of summer power burn and its sensitivity to price is forthcoming and will be posted on Dimensions and Benport in the coming days.

Quiet on the industrial front, with most of the gains fairly cemented

Industrial demand is continuing its slow march higher Y/Y. This sector, though not as exciting as the large adds posted by LNG, or the volatility seen in power, has expanded the demand base by about 3.6 Bcf/d since 2010. This summer, only an additional 0.4 Bcf/d of industrial demand is likely, given no outsized new plant additions loom like the gas-heavy ammonia plants added in 2017 joining the industrial fleet this summer. In the near-term, the recent floods in the Midwest will likely negatively impact ethanol production, and thus gas demand. Nebraska and Iowa produce about 40% of the US' ethanol, and based off current sample activity we see potential for as much as 0.1 Bcf/d of weaker demand there in April as a result.

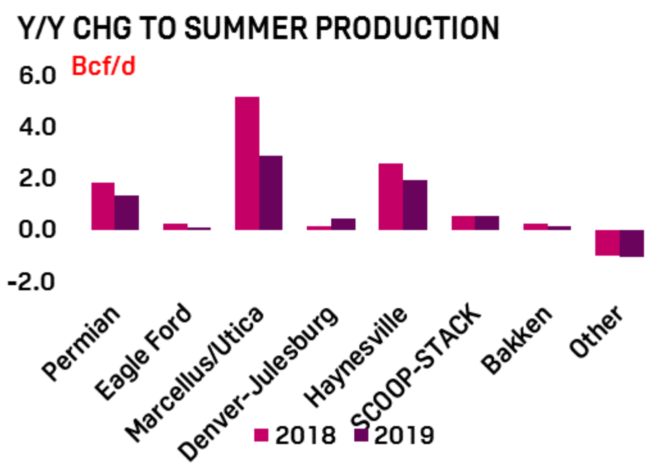
Supply growth summer 2019

Total supply growth in the Lower 48 is set to grow by 5.6 Bcf/d this summer— the second largest gain in recorded history, but a distant second to last year's record setting growth. In fact supply growth should be more than 4 Bcf/d less than last summer's bulge. US production growth will again be led by Appalachia in the Northeast, and Haynesville and the Permian in the Southeast/Texas regions. Interestingly, the Northeast should account for less than 50% of the summer's Y/Y gains. Haynesville is advancing this summer to more than 30% of the nation's supply growth, while the Permian, where pipeline limitations are side-lining further upside, will grow Y/Y by ~20%. Imports from Canada, though, should fall by ~0.6 Bcf/d due to restrictions on Westcoast Pipeline's system this summer, which will limit flows to the Pacific Northwest. Lower volumes are also likely to reach the Midcontinent, as rising Bakken production should limit Canadian inflows on Northern Border and exports on Viking and Great Lakes should be down.

- Production momentum is set to slow dramatically. Many producers have reigned in spending to target free cash flow.
- Steep increases in production in 2018 will lead to significant base declines to contend with summer over summer.
- Risks to the supply forecast are skewed to the upside, as recent strength in production and stronger imports into the PNW may raise the baseline.

US production is set to grow by 6.3 Bcf/d this summer over last

US dry gas production is forecast to grow Y/Y by 6.3 Bcf/d this summer to an average of 87.7 Bcf/d, with the primary growth drivers being the Northeast and Texas. In the Northeast, more measured production growth looms as producers in the region have outlined in detail their plans to achieve, or work towards, achieving free cash flow. Those with options, also plan to target liquids and the expense of gas. Despite such objectives, and lending to recent bearishness in the market, Appalachian producers have added ten rigs to the play since December, suggesting that production could be ready to pivot back into growth soon. Currently, Platts Analytics calls for Northeast production to expand from ~30.7 Bcf/d in March to ~32.0 Bcf/d by October.



In Texas, production this summer is forecast to grow Y/Y by 1.8 Bcf/d to 21.6 Bcf/d driven to a large extent by the Permian basin where increased pipeline connectivity in Mexico will allow for gains ahead of Kinder Morgan's Gulf Coast Express pipeline, which is not due to come online until 4Q19. In the Southeast, production is forecast to grow Y/Y by 0.5 Bcf/d to an average of 12.6 Bcf/d driven by Haynesville growth of ~1.9 Bcf/d this summer relative to last.

- *Beth McKay, nagasanalytics@spglobal.com*