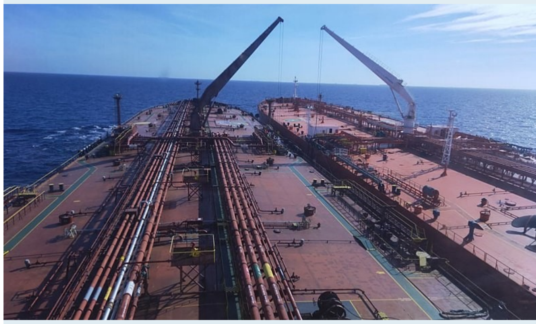
JULY 2020 EDITION

ENKON OIL AND GAS NEWSLETTER



Welcome to the Enkon Insights Newsletter

Every month, we feature three full-length articles, share critical stories in oil and gas commodities, and break down key trends.

Have opinions? Want to talk shop? Need more insights? Drop us a line:

info@enkonenergy.com

Inside this issue:

Crude and products demand: hard ceiling, soft(er) floor, narrowing range?

This year is, if nothing else, an eventful one for oil markets. WTI prices fell into negative(!) territory; domestic crude production halted its growth, then fell; and some big players in the industry (Shell, Total) are openly speculating that the world has already passed peak world oil demand. This environment is difficult to understand, much less explain, but we posit that three trends are largely shaping domestic crude markets, for now.

First, there may be a "hard ceiling" on demand: domestic and international crude and products demand likely won't return to normal levels until COVID is defeated. Second, there may be a "softer" floor: while 2020 gasoline supplied (hopefully) won't touch lows seen in April, COVID-related lockdowns in the southern and western United States could curtail demand. Finally, we think there may be a narrowing range of outcomes. As medical professionals, consumers, and businesses become more educated about COVID-related risks, demand will stabilize, albeit perhaps not at the level than many in the industry would prefer.

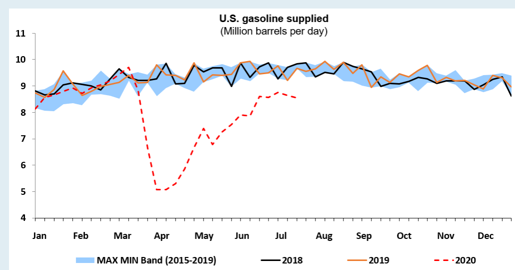
Hard ceiling

There was some industry excitement due to a report from Edmunds, as the automotive consultancy issued a report noting that many consumers appear to be ditching public transportation (at least for now), and buying used cars. We've also seen plenty of anecdotal evidence that consumers are moving out of urban areas and into suburban areas. Still, we are skeptical that gasoline demand will recover to 5-year averages, much less its pre-COVID trajectory.

U.S. vehicle miles traveled (VMT) in May 2020 were 26% lower from the prior year. Nor can the difference be completely explained by quarantines/lockdown. The U.S. Department of Transportation notes that the "South Gulf" region (composed of Texas, Louisiana and six other states) saw y-o-y VMT declines of 19.8%. Virtually all of these states took a very relaxed approach to lockdowns (Texas began to open up on May 1st) but demand still remained well below prior years.

Even if gasoline demand can return to normal levels later this year – a prospect we find unlikely, albeit not impossible – depressed jet fuel demand will continue to weigh on refinery operations and therefore crude demand. Jet fuel demand has been cut in half from the prior year, to 0.9 MMBPD.

Although y-o-y VMT declines were likely much less severe in June, and airline passenger throughput is rising, crude and products demand likely won't return to "normal" levels until a vaccine is distributed, cheap therapeutics are widely available, or the disease is suppressed. We suspect there's a hard ceiling on crude and products demand for at least several months, and perhaps longer.



Softer floor

Gasoline weekly demand from 2015 – 2019 demonstrated a very hard floor: the maximum and minimum levels of gasoline demand for the same time period never varied by more than 1.3 MMBPD, as gasoline demand fell within a narrow range.

COVID changed that dynamic. Due to lockdowns and consumer fears over catching a virus with unknown long-term health implications, total gasoline supplied stood at just 5.1 MMBPD in early April, 3.8 MMBPD lower than the minimum seen in the prior 5 years.

Luckily, the floor is rising. Barring a fresh disaster, (such as the mutation of COVID-19 into something even deadlier) U.S. gasoline demand will remain above April levels. Still, there are substantial downside risks to the recovery in gasoline demand. COVID outbreaks in the Southern and Western United States are limiting consumers' willingness to travel; California already imposed another lockdown. Texas might, too.

Additional lockdowns from the two largest states in the country would suppress gasoline demand – possibly returning national gasoline demand below 7 MMBPD. With most risks to the downside, there is a soft floor on crude and products demand, although we stress that a

Crude and products demand: hard ceiling, soft(er) floor, narrowing range? (Continued)

"The failure to contain domestic COVID cases is capping gasoline demand recovery, but medical and consumer understanding of COVID is improving, reducing uncertainty, enabling better risk management, and ultimately supporting gasoline sales."

Less consumer uncertainty leads to a narrowing range of outcomes

Medical experts have identified high and low-risk activities (incidentally, pumping gasoline is a low-risk activity, according to the Texas Medical Association). As medical experts and consumers determine which activities are safe (and unsafe), they are more likely to resume a greater share of pre-COVID routines.

In February, there was enormous, arguably unprecedented market uncertainty, especially in the energy sector. Analysts could have plausibly claimed that U.S. products demand would end the year averaging 19 MMBPD – or half of that. Extreme scenarios no longer appear plausible any more, however. The failure to contain domestic COVID cases is capping gasoline demand recovery, but medical and consumer understanding of COVID is improving, reducing uncertainty, enabling better risk management, and ultimately supporting gasoline sales.

If consumer uncertainty continues to fall, we should see a slow recovery in demand for the remainder of the year. Note, however, that rising COVID cases will reintroduce more uncertainty for consumers and limit demand recovery. The best – and only – way to return demand to normal is to defeat the virus.

The new normal

The market will continue to be driven almost entirely by domestic and international COVID developments, but we expect that 1) demand will face a hard ceiling until the virus is defeated; 2) crude and products supply could fall sharply if COVID cases rise again; and 3) the slow recovery in domestic demand will likely continue (barring additional outbreaks). A hard ceiling, a softer floor, and a narrower range may be the "new normal" for crude markets until the virus is defeated.

Crude Oil News:

[Planned offshore terminals affected by pandemic]

[Gradual recovery in jet travel continues]

[Buckeye Partners Corpus terminal starting in late July?]

[Is Chevron selling non-core assets for Permian expansion?]

[Canadian oil-sands production returns]

[OPEC easing output cuts?]

[Oxy takes huge writedown]

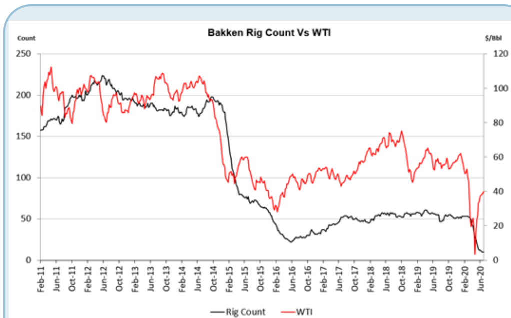
Special Feature:

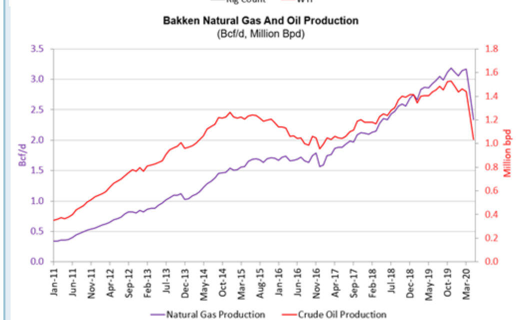
Benchmarking Bakken NGLs and Midstream Infrastructure

Continuing with our NGL Benchmarking series, this month let us take a deep dive into another key basin – the Bakken. A drop in crude prices due to the COVID19 and OPEC price war has hit Bakken shale basin hard, with ~0.7 Bcf/d and ~0.4 Million Bpd drops in gas and oil production, respectively, since Dec 2019. This has also impacted NGL production out of the Bakken. Will Bakken regain its glory any time soon? The uncertainty on DAPL's future has added one more wrinkle to the situation…

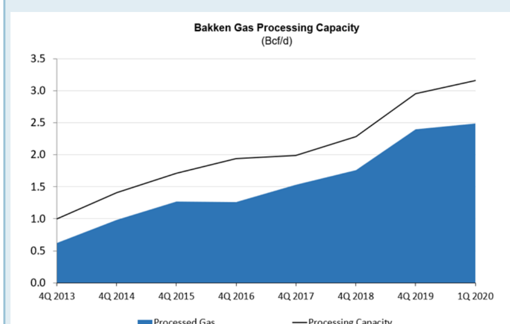
<u>Where we have been to where we are:</u>

Drilling activity in Bakken has drastically slowed down, with rig count dropping from the highs of 53 in Jan-2020 to 10 today, according to Baker Hughes. We've seen this story before: from late 2014-early 2015, we saw a big dip in the crude oil price followed by falling rig counts in the basin. The Bakken rig count (and crude oil prices) never fully recovered to pre-2014 levels, stabilizing around 50 rigs on average. Current oil prices appear stable at around $40/bbl although we have not yet seen any recovery in drilling activity.



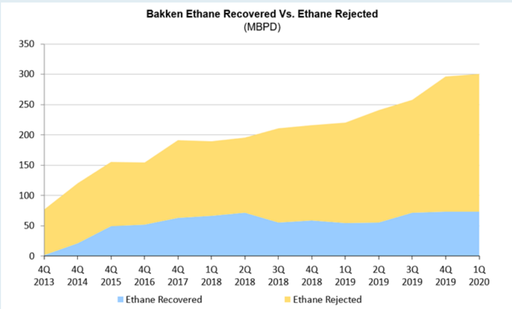


Natural gas flaring in the basin has decreased the past two quarters, partly due to additional gas processing capacity from multiple new gas processing plants, and also because of the drop in production activity In 1Q 2020. The Bakken processed around 2.5 Bcf/d of wet gas (or ~80% of total gas produced), largely associated with crude oil production. Gas processing infrastructure has increased along with wet gas production. Current processing capacity in the Bakken currently stands at ~3.2 Bcf/d, with basin aggregate utilization @79% for 1Q 2020.



Unlike the Permian, the Bakken gas processing landscape is highly consolidated (just like Appalachia). The top 5 processors operated 80% of total capacity and 83% of processed volumes in 1Q 2020. Oneok was the top processor, with capacity of 1.4 Bcf/d in the basin; it processed about 1.1 Bcf/d of gas. Challenging ethane frac spreads has resulted in increased ethane rejection in Bakken since Dec 2019. Through late 2Q 2020, ethane prices at Mont Belvieu had been soft, barely staying above natural gas prices in the U.S. Gulf Coast. Since Bakken is the farthest region from Mont Belvieu relative to other U.S. shale basins (and therefore faces higher T&F fees), there is little to no economic incentive for Bakken gas producers to extract high levels of ethane. This dynamic resulted in ethane rejection to the tune of ~230 MBPD for 1Q 2020. Ethane extracted in 1Q 2020 for the Bakken basin was a mere 73 MBPD, or about ~24% of total estimated ethane entrained in the gas stream.

Benchmarking Bakken NGLs and Midstream Infrastructure (Continued)



Propane+ (C3+) supply in the Bakken basin for 1Q 2020 stands at 267 Mbpd, with OneOk's share at ~125 Mbpd, about 47% of the basin's C3+. Since 4Q 2019, the OneOk Elk Creek pipeline has been a game-changer for disposition of the Y-grade barrel. As expected, there has been a significant drop in rail utilization to move Y-grade supply. The percentage share of rail/truck dropped from ~70% in 2018 to just ~20% in 1Q 2020. To make matters worse for Bakken producers (and prolong crude oil recovery), A federal judge's recent order to take Dakota Access Pipeline be out of service for a year or more starting August 5. The decision could wreak havoc for producers in the Bakken Shale at a time when they are still reeling from drastic, COVID-related production curtailments. Energy Transfer (DAPL's operator) has since won a stay order, but uncertainty remains as to how this will impact crude recovery and therefore NGLs in the Bakken.

Where we go from here:

Drilling activity in the Bakken has drastically slowed due to COVID-19: recovery may be a painful and prolonged process, especially if DAPL temporarily ceases operations. Consequently, midstream companies are also slowing expansion plans. On the midstream end, around 400 MMcf/d of new processing capacity addition have been put on hold. Another 400 MMcf/d of new processing capacity is scheduled to come online by Mid 2021.

Current available pipeline and rail capacity is insufficient to meet takeaway needs, after the DAPL ruling. Even at full utilizations (which is not possible, practically), they might just be able to ship 1 Million bpd of oil from the basin – still lower than the production highs seen pre-COVID. Even then, connectivity issues arise, as not all the producers who used the DAPL will have access to alternative logistics.

50,000 feet view of LNG: Near-term uncertainty, new entrants must climb steeper hills, and U.S. – China LNG trade

LNG is almost out of the summer from hell, but Fall and Winter exports still face uncertainty. Downside risks include European gas storage levels well above 5-year storage levels and the ever-present risks of COVID resurgences throughout key export markets in Europe and Northeast Asia. On the other hand, some factors could support exports. Rising gas storage levels in the United States (particularly along the Gulf Coast) could continue to weigh on Henry Hub prices and support netbacks for LNG exporters. Furthermore, if Europe and Asia can continue to tame the virus then LNG/natural gas consumption could actually witness year-over-year increases. On balance, netbacks appear to be strengthening for LNG exporters in the Fall/Winter months, but COVID ensures that risks are tilted to the downside.

There's increasing skepticism that any U.S. (or even perhaps North American) projects will take FID in the 2020s. Golden Pass's announcement that it would raise capacity from 15.6 MTPA to 18.1 MTPA has only added to the difficulties confronting U.S. and even North American LNG projects. We do not expect any U.S. projects to take FID this year (and perhaps in 2021 or longer). Sempra's Costa Azul project (on Mexico's west coast) is facing permitting difficulties with the Mexican government. It's noteworthy that Sempra has said it will take FID only after receiving approval from the Mexican government, suggesting that regulatory hurdles are significant.

There has been little forward momentum on most LNG projects, some have fallen by the wayside. Magnolia LNG was sold for $2.25 million USD – suggesting the buyers valued only its real estate. On the other hand, Warren Buffet's Berkshire Hathaway Energy bought Dominion Energy's natural gas transmission and storage business, along with a 25% stake in Cove Point LNG.

Berkshire Hathaway's foray into LNG could augur something we're beginning to see in the Permian: the consolidation of the sector into larger, more liquid giants. A complicating factor in the LNG space, however, is that some of the largest players have highly international and diversified plays, limiting their investment into any one region. Qatar Petroleum, in particular, is unlikely to expand on its investment in Golden Pass and arguably increased its nameplate capacity to deter additional entrants into the market. The possible entry of private equity into the LNG space is a trend worth watching carefully.

What's going to happen with the U.S. – China trade deal and will LNG be a part of it? The U.S. and China inked a Phase I trade deal where China promised to buy $200 billion worth of U.S. goods and services over two years. The Chinese side is not anywhere close to fulfilling this commitment amid the pandemic and growing bilateral political and military tensions. It's possible (but perhaps not likely) that Chinese buyers will buy spot LNG cargoes from U.S. exporters, but a few factors limit this probability, however. First, U.S. – China political tensions will likely continue to rise. Second, Chinese LNG markets are already highly saturated. Third, China has delayed at least five new LNG regasification terminals in China and two terminal expansion projects to 2021. Fourth, the PRC is embarking on gas-to-coal (not a typo!) fuel switching. Finally, if China wanted to buy U.S. LNG, why didn't it ink short-term contracts at (what appears to be) the bottom of the market, when offtakers were cancelling cargoes right and left in the early summer? Some in the market think that Chinese offtakers could support U.S. LNG exporters later this year. We are skeptical.

As we said even before the pandemic, this summer was always going to be brutal for U.S. LNG exporters. Fall and Winter offer some hope for LNG exports, but substantial risks remain. Domestic and international COVID developments will continue to drive energy and LNG outcomes.

"A federal judge's recent order to take Dakota Access Pipeline be out of service for a year or more starting August 5... Energy Transfer (DAPL's operator) has since won a stay order, but uncertainty remains..."

NGLs News:

[Targa launches Open Season]

[Port Freeport signs PPA to improve harbor]

[Enterprise loads combination cargoes of NGLs and Olefins]

[Easton Energy expands NGL/olefins storage]

LNG News:

[Low gas prices not moving Asia from coal]

[China delays new LNG regas projects]

[China could be the world's largest LNG importer in 2020]

[40-45 U.S. LNG cargoes for August loading cancelled]

[Over 100 cargoes cancelled in the summer]

[European gas demand shows signs of recovery]

[Exxon's Rovuma LNG FID delayed]

Natural Gas Storage and Downside Risks

"If associated gas production from the Permian rises later this year, the region may not be able to absorb the supply on its own."

Natural Gas News:

[Henry Hub drops to 21-year low]

[US natural gas volumes in storage likely increases by more than 100 Bcf]

[Natural gas storage and downside risks]

[Gas power burn could test prior records on low prices, summer heat]

[Berkshire buys Dominion's natural gas assets for $10 billion]

[Associated gas production returning]

[1H 2020 gas prices reach record lows]

[Mexican gas pipeline project expected to boost Permian exports]

[Summer population-weighted cooling degree days could break records]

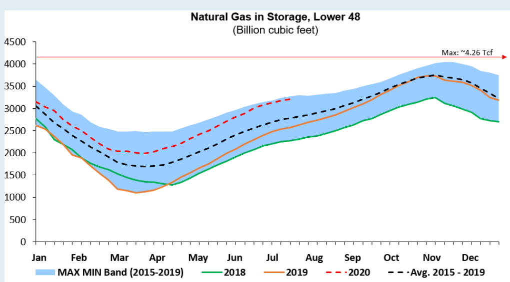
Natural Gas Storage and Downside Risks

It's natural gas producers' turn in the barrel. Natural gas prices are falling to historic lows amid higher-than-expected storage builds, but downside risks are severe and perhaps underappreciated. Domestic demand for natural gas has been crushed by COVID, and LNG exports are out of the money until September – and possibly beyond. Moreover, additional natural gas supply may be coming online as $40/barrel oil prices tempt Permian producers to increase oil output – and ramp up associated natural gas production. Natural gas storage levels could soon start to bump up against regional or even national capacity constraints, further pressuring prices and giving even more heartburn for the U.S. oil and gas complex.

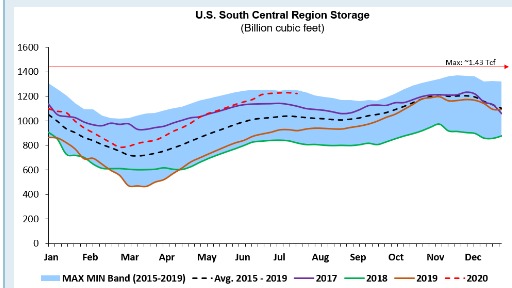
U.S. storage levels are rising rapidly

Natural gas consumption is highly seasonal, peaking in the winter, decreasing in the spring, rebounding in the summer for power load (but not, typically, to winter levels), and moderating in the fall – at which point the cycle starts over again. Injections to inventories occur in the "shoulder months" of the fall and spring, with storage drawdowns occurring in the winter (and, depending on the location, in the summer).

Inventories for most commodities have risen amid the COVID-19 coronavirus, and natural gas is no different. Natural gas demand is down sharply on physical distancing, lockdowns, lower industrial consumption, and, of course, moderating temperatures. Supply has also fallen, but not by a countervailing amount, and U.S. natural gas inventories are rising rapidly.



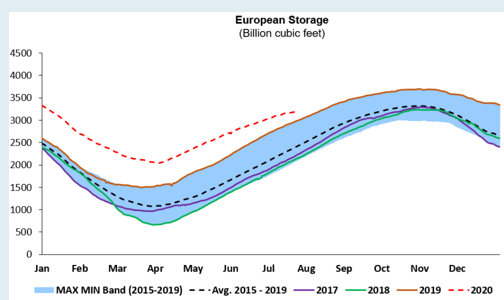
It's no coincidence that natural gas regional inventories are rising fastest in the U.S. South Central Region (which includes the major gas-producing states of Texas, Louisiana, Oklahoma, along with [five other states]). This region includes 4 out of the 6 currently operating LNG export terminals (and about 90% of existing nameplate capacity), so it is disproportionately affected by LNG exports. With LNG exports down, feed gas volumes are lower and… more volumes are flowing into regional storage.



Still, note that the pace of injections into storage along the Gulf Coast has slowed, at least for now. We expect that this is attributable to higher-than-average temperatures, not a fundamental rebalancing of supply and demand. Indeed, if associated gas production from the Permian rises later this year, the region may not be able to absorb the supply on its own.

Storage max-out: European LNG demand to the rescue?

A growing gas glut could prove tricky. The EIA reports "demonstrated peak capacity" storage from the entire United States of about 4,261 Billion cubic feet (Bcf), while the South Central region can hold about 1,429 Bcf. Due to the supply and demand trends discussed above, however, U.S. natural gas storage is at risk of a capacity max-out, perhaps especially in the South Central Region. In the near-term, max-out is largely dependent on two demand factors: 1) summer temperatures and 2) recovery in LNG exports. Warmer-than-average summer temperatures in the U.S. (particularly in the South) would support natural gas demand; recent forecasts seem to support higher gas burn. Similarly, increasing feed gas demand for LNG exports could slow U.S.-level and regional builds. Still, European demand for U.S. LNG may be limited due to elevated natural gas storage levels on the continent, therefore U.S. will have to look to Asia and S. America as viable LNG markets in 2H 2020.

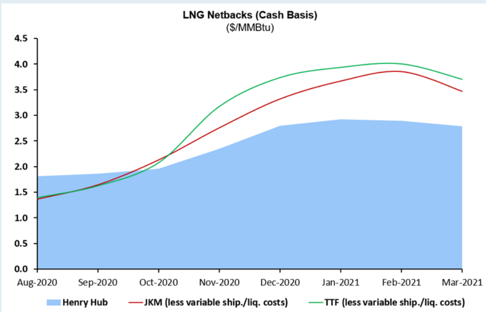


Don't count on LNG exports to Europe saving Henry Hub

European natural gas storage already exceeds 5-year averages, but let's be clear: there are two severe downside risks to European demand. The first major risk is – stop us if you've heard this before – COVID. Europe appears to have tamed the virus for now, but most epidemiologists believe cases could surge again during flu season. The second major risk is that Europe may experience another unseasonably warm winter.

Natural Gas Storage and Downside Risks (continued)

Winter 2019/2020 was Europe's hottest on record, and most scientists and forecasters believe the continent will be in for another warm winter, limiting its demand for LNG. Forward curves indicate that U.S. LNG export cargoes will be in the money as soon as October, but we're hearing from our market contacts that they remain very mindful of downside risks.



If TTF and JKM prices don't rise as much as expected, LNG cargo cancellations could continue, pressuring U.S. natural gas inventories, particularly in the South Central Region. The Henry Hub futures curve is in contango, indicating more optimism about future expected spot prices. That optimism could be rewarded, but we also see plenty of reasons to be concerned about a gas storage max-out.

Commodity Insights

Oil Market Movers:

With COVID cases rising (again) and governors suggesting lockdown orders may be imminent (again), we are pessimistic about the U.S. crude complex. COVID is stymying crude demand; supply is rising again. OPEC+ appears increasingly likely to ease its output cuts, and Canadian oil producers are turning on the spigots again as the Bakken faces pressure from potential pipeline closures.

A resurgence in COVID cases in NE Asia and/or Europe is a real possibility and could further pressure crude demand. Alternatively, if Europe and Asian export markets can maintain low caseloads while opening up their economies —a big if—then the export arb could open again.

NGL Market Movers:

U.S. ethane prices have increased over the past few weeks, initially due to increasing natural gas prices and later because of an uptick in USGC cracking demand (despite ethane not being the most economic feed stock). Since then, the prices have retreated to just above 20 cpg, largely in response to higher ethane prices weeks earlier. Higher ethane prices in May/early June, along with higher fractionation spreads, provided ample economic incentive for producers (and integrated midstream players) to recue ethane rejection and bring more ethane on the market, reducing the price. We maintain that C2 prices will avg 15-20 cpg for 2Q2019. If crude stays around $35/barrel and petroleum product demand recovery is meaningful then we expect ethane to trade around 15 cpg for 3Q 2020.

LNG Market Movers:

About the only good thing LNG exporters can say about this summer is that it's almost over. LNG's summer from hell has seen over 100 cargoes cancelled, with more cancellations on the way. The outlook improves for the fall and winter, but near-term and medium terms risks are largely to the downside.

Exports for October are, at least as of this writing, narrowly "in the money" for October cargoes to Europe and Asia. The forward strip also shows improving LNG netbacks for the remainder of the year.

Still, risks are weighted to the downside. If COVID reemerges in Europe or NE Asia, LNG markets will suffer, perhaps severely. Moreover, European natural gas inventories are well above 5-year averages, although there are some signs that European natural gas demand is rebounding. A potential upside for LNG exports is that Henry Hub prices could come under pressure if U.S. South Central natural gas inventories continue to rise and pressure domestic prices.

Is the international LNG market still oversupplied? Do almost all U.S. LNG export projects continue to face (probably) insurmountable commercial barriers? Yes, and yes.

We've said that Sempra's Costa Azul project could be the only North American project to take FID in 2020. The terminal is facing challenging regulatory issues, however, and may be delayed until 2021. Depending on how bad things get, we may not see any N. American FIDs in 2020, 2021, or possibly even for the rest of the decade.

Gas Market Movers:

Natural gas production is increasing even as demand is falling, leading to injections to storage. This dynamic has been most marked in the U.S. South Central Region (i.e. most of the Gulf Coast).

Natural gas production rose to 89.5 Bcf/d for the week ending July 8th, according to the EIA, up from 88.3 Bcf/d in the prior week. There's some evidence that rising gas output is largely attributable to the return of Permian production and associated gas.

EIA data shows declining y-o-y natural gas consumption, largely due to LNG dynamics. The forecasted number of cooling degree days rose slightly, but markets will likely continue to show y-o-y declines until LNG demand returns to more "normal" levels (LNG pipeline receipts are currently at ~3.5—4 Bcf/d, versus about 9 Bcf/d in February.

Keep an eye on storage levels, particularly in the South Central Region. It's possible that several local, regional, and perhaps even national gas markets could test capacity limits if downside risks emerge...

"We're hearing from our [LNG] market contacts that they remain very mindful of downside risks."

Coal

Wyoming approves first coal mine in half a century

China cracks down on coal imports

Japan to limit financing of international coal power plants

Contura to idle WV coal mine, put another mine up for sale

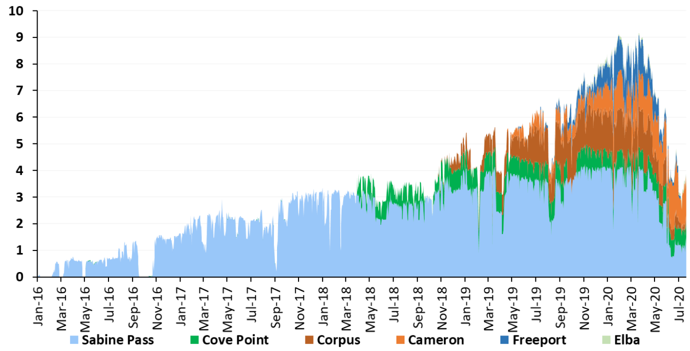
U.S. coal output down 15.6% y-o-y, the smallest y-o-y decline in 15 weeks

U.S. thermal coal exports down by over 50% y-o-y

Images from Wikimedia Commons: Maciek Kwiatkowski, Martian-2007; Downtowngal, Qyd

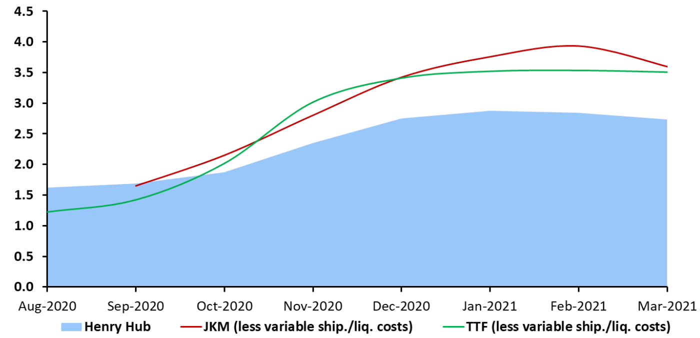
Key Market Dashboards

Firm Feed Gas Receipts into U.S. LNG Terminals
(Billion Cubic Feet per Day)



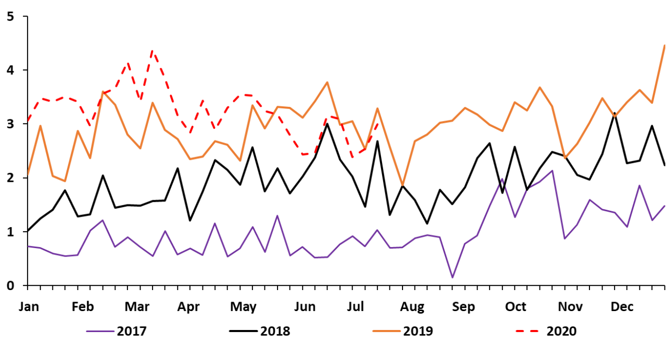
U.S. LNG feed gas flows remain under pressure amid closed arbs to Europe and Asia but shows some signs of rebounding, especially later in the Fall

LNG Netbacks to U.S. (on Cash Basis)
($/MMBtu)



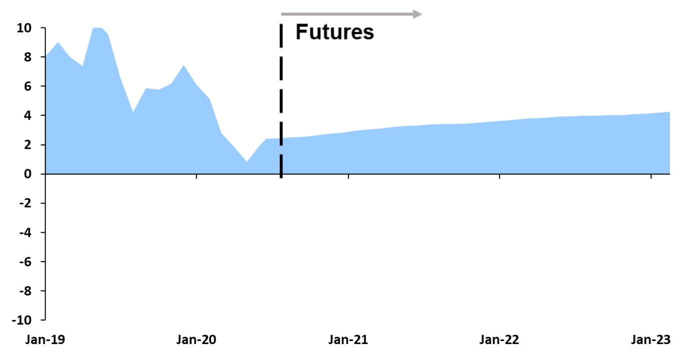
Fewer cargo cancellations expected in future months, which will support feed gas volumes (and HH)

U.S. Crude Oil Exports
(Million Barrels per Day)



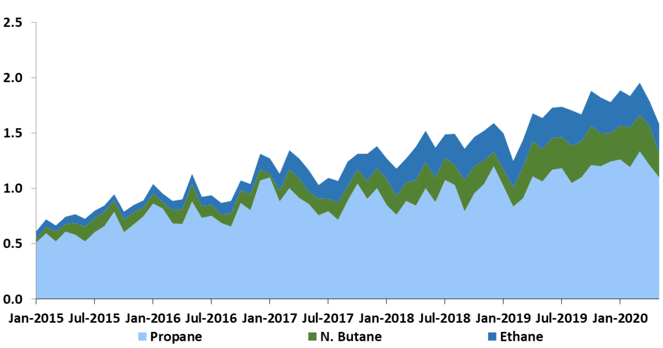
European and Asian markets are exiting COVID-related lockdowns, but Brent—WTI spreads remain narrow impacting near term U.S. crude exports

Brent—WTI Spread
($/Barrel)



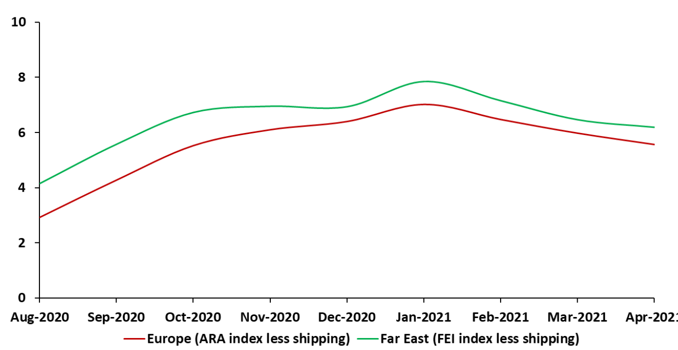
Current Brent-WTI spread remains narrow, limiting exports

U.S. NGL Product Exports
(Million Barrels per Day)



U.S. exports slipped due to weaker international netbacks. U.S. LPG export stay above 1.0 MMBPD required to balance domestic market

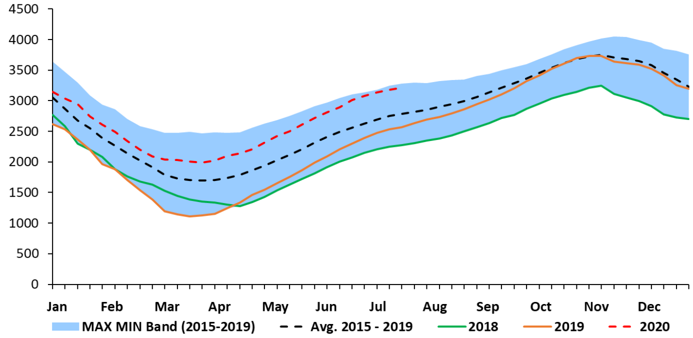
International Propane Netbacks (to Mt. Belvieu)
(Cents Per Gallon)



Netbacks are positive and improving

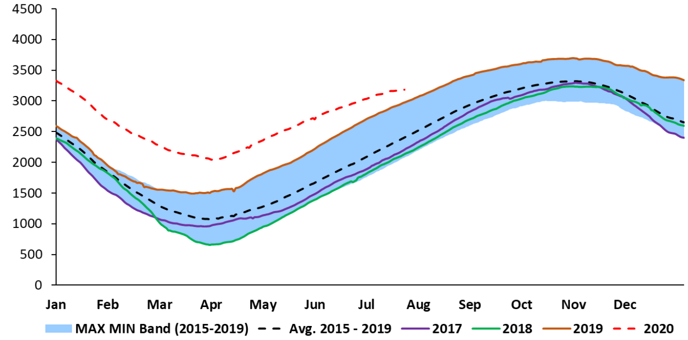
Key Market Dashboards

Natural Gas in Storage, Lower 48
(Billion Cubic Feet)



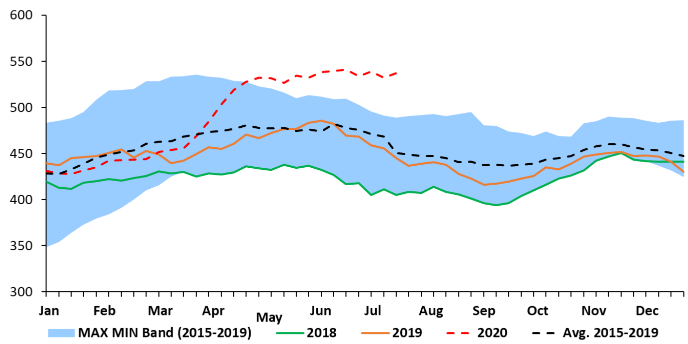
Summer temperatures are supporting cooling demand, but much depends on LNG feed gas demand in 2H

European Storage
(Billion Cubic Feet)



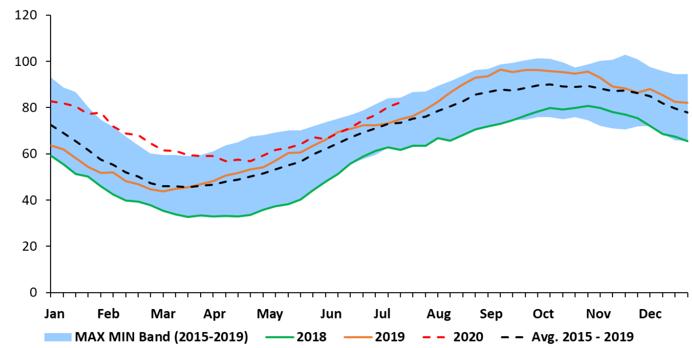
European storage injection rates are slowing, but not out of the woods yet: COVID could return and hit demand

U.S. Crude Oil Commercial Storage Inventory
(Million Barrels)



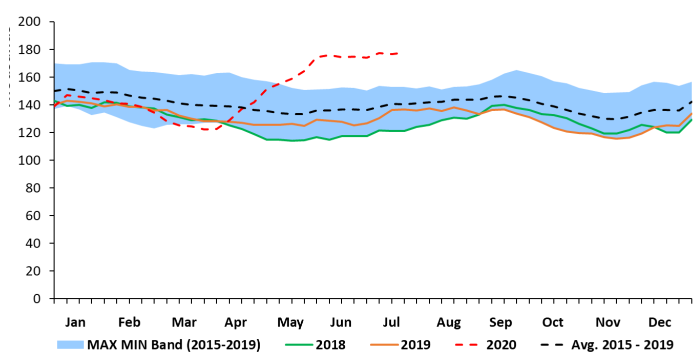
Lower Bakken production could lead to adjustments at the PADD level, assuming the DAPL ruling stands

U.S. Propane/Propylene Storage Inventory
(Million Barrels)



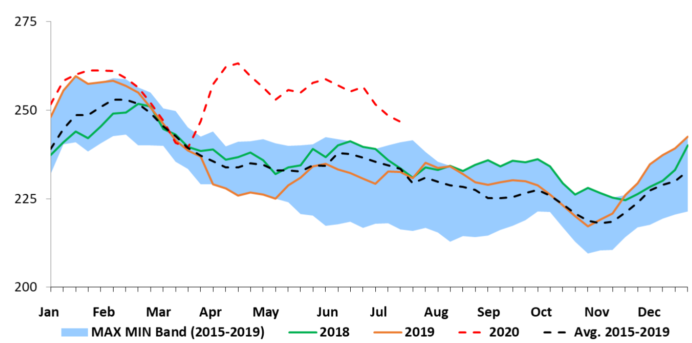
Increasing propane storage and recovery in crude provides ideal ingredients for increasing U.S. LPG export economics and volumes

U.S. Diesel Storage Inventory
(Million Barrels)



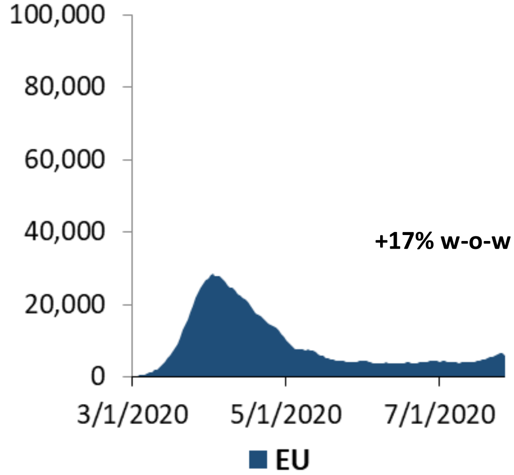
Diesel builds are slowing as jet fuel demand inches back in the U.S.

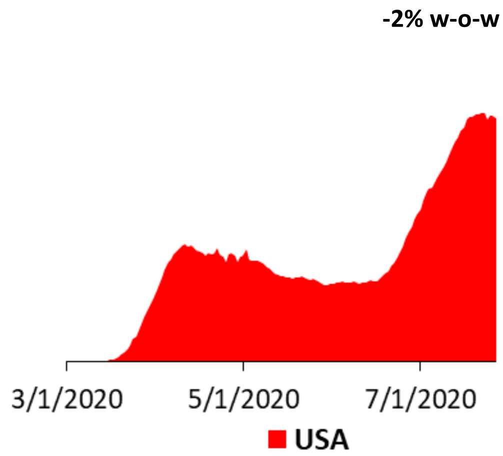
U.S. Gasoline Storage Inventory
(Million Barrels)

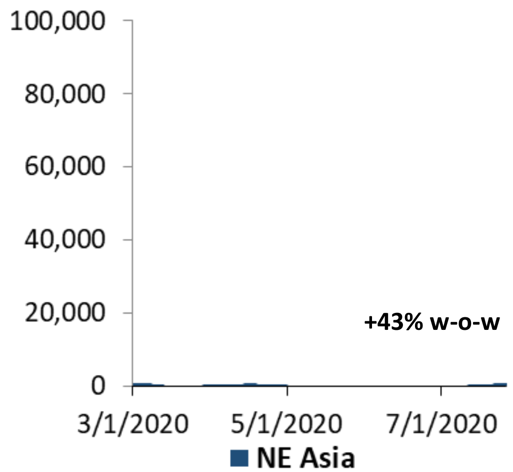


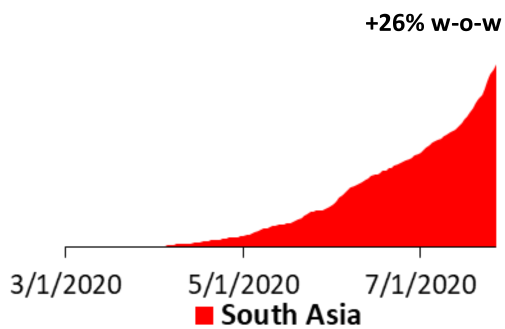
Gasoline builds appear to be returning to more "normal" levels, but outbreaks in CA/TX/FL could pressure demand

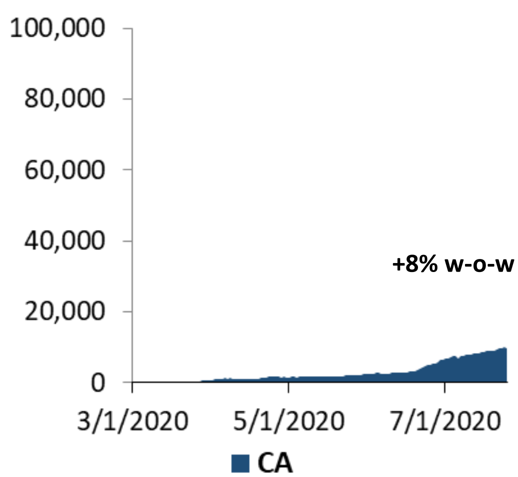
Key COVID Dashboards (7-day averages)

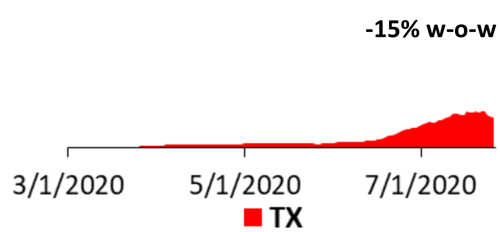












Our Subscription Product Offerings

Regional NGL Benchmarking

(Research, intelligence and insights into Supply, Logistics, Pricing, Disposition and Outlook)

Each quarter, Enkon provides clients a unique, bottom-to-top analysis of NGL supply, logistics, pricing, netbacks, product disposition and outlook for eight NGL producing basins in the U.S. The granularity of the analysis makes this product unique. The analysis identifies NGLs (by purity product) produced at each of the ~700 U.S. gas processing plants as the building block of the analysis to quantify asset utilizations across the midstream value chain.

Appalachian	Rockies	Haynesville- Bossier
Permian	Bakken	Barnett
Eagle Ford	STACK/SCOOP/MERGE	LA Gulf Coast

	Deliverables	Format	Update Frequency
1	NGL Benchmarking	Report (MS PowerPoint)	Quarterly
2	Report discussion & review	In-Person Meeting/Conf Call	Quarterly
3	Supporting data sets	Secured online portal	Quarterly
4	Market insights	Memo	Monthly

U.S. Gulf Coast Liquid Cavern Storage Benchmarking

(Research, intelligence and insights into NGL, Olefins, Refined Product Cavern Storage)

Once a year, Enkon provides clients a one-of-a-kind, comprehensive lay-of-the-land and granular benchmarking for ~250 non-crude liquid-hydrocarbon salt cavern storage wells in Texas and Louisiana. The report provides regional analysis of cavern storage capacity versus brine pond capacity in each of the dome locations. The report also identifies product storage in each of the cavern wells along with historical product injection, withdrawal, inventory and cavern utilization.

Texas Cavern Coverage		Louisiana Cavern Coverage	
Barbers Hill (Mont Belvieu)	Hull	Sulphur	Bayou Choctow
Stratton Ridge	Spindletop	West Hackberry	Napoleonville
Markham	Fannett	Arcadia	Sorrento
Clemens	Sour Lake	Pine Prairie	Venice
Pierce Junction	Boiling	Anse La Butte	Section 28
West/Panhandle Texas	East Texas		

Regional Fractionation and NGL Export Terminal Benchmarking

Each quarter, Enkon provides clients a provide a historical benchmarking and comprehensive outlook of Y-grade NGLs in the U.S. Gulf Coast with the objective of quantifying incremental need for fractionation capacity in various locations in US Gulf Coast, namely Mont Belvieu, Sweeny and Louisiana, and adequacy of NGL export capacity in the USGC and Northeast.

North America LNG Export Project Benchmarking

(Research, and insights into U.S. Liquefaction Projects)

Each quarter, Enkon undertakes an exhaustive review of over 24 post and pre-FID North American LNG export terminals; summarizing the North American LNG export terminal landscape, LNG nameplate capacity and feed gas forecasts, key market trends, and a competitive assessment of pre-FID North American terminals. For each project, we report terminal attributes, commercial models, key regulatory milestones, risk assessments, and, for existing terminals, historical feed gas receipts (by pipeline), and estimated weighted average landed cost of feed gas into the terminal.

enkon energy advisors

For more information please contact:

12651 Briar Forest Dr.
Suite # 246
Houston, TX 77077

Tel: + 1 (703)-801-8068
info@enkonenergy.com
www.enkonenergy.com

Chief Editor

Joseph Webster
jwebster@enkonenergy.com