WAYFINDER ANALYTICS

North American Crude Oil Supply, Demand and Impacts on Crude Oil Export Infrastructure

2019-2023 Outlook

Wayfinder Analytics, LLC
Benjamin Salisbury
Robert Balsamo

February 2019

Table of Contents

About Wayfinder Analytics

Wayfinder Analytics provides independent analysis on key political, economic, regulatory and cultural trends in conjunction with detailed forecasting. We work with stakeholders to provide forecasts for business and investment strategy. Our analysts have decades of experience in energy economics, policy, and finance having led hundreds of research projects to help clients navigate the intersection of policy, culture, and market fundamentals.

For more information please visit https://www.wayfinderanalyticsllc.com/about.

Study Purpose and Disclaimer

Building on prior understanding of shale basin production and the periodic duration mismatch in energy infrastructure investment, this study examines the impact of crude oil supply and demand on the energy industry to help understand potential risks in the infrastructure outlook. The report draws on the multidisciplinary experience of Wayfinder Analytics including upstream, midstream, and downstream. This independent analysis was sponsored by Texas Gulf Terminals. The analysis and conclusions contained in this report are entirely those of the authors who are solely responsible for the contents.

The report represents the current good-faith views of the authors at the time of publication. These views are subject to change without notice of any kind. The projections, analyses, and opinions contained in this report are subject to uncertainties and risks including but not limited to commodity price volatility, political, economic, and environmental risks, as well as data quality, availability, and revisions.

The analyses, projections, and descriptions contained in this report are based on sources considered reputable and the best efforts of the authors. However, its accuracy and completeness are not warranted, nor any actions, opinions or analyses which may be based upon it, and to the extent permitted by law, Wayfinder Analytics LLC shall not be liable for any errors or omissions or any loss, damage or expense incurred by reliance on information or any statement contained herein.

The content is for informational purposes only and in no way constitutes investment, financial, or legal advice. Nothing in this report should be construed as a solicitation, recommendation, endorsement, or offer to buy any financial instrument. The contents are information of a general nature and do not address the circumstances of any particular individual or entity, nor does any information constitute a comprehensive or complete statement of the matters discussed. Users assume the sole responsibility of evaluating the merits and risks associated with the use of any information before making any decisions.

Executive Summary

Strong U.S. crude oil production and global demand implies a 3 mmbpd export infrastructure deficit by 2023. Infrastructure investments must keep pace to avoid market disruptions.

By 2023, we project that combined Permian and Eagle Ford production will rise 4.4 million barrels per day (bpd) to 8.5 mmpbd by 2023, but domestic refining capacity is expected to grow by just 453 barrels per calendar day (bcd). As a result, U.S. crude exports would need to rise to 6.5 mmpbd in 2023. This growth is essential to help meet our expectation for global demand rising to 108.5 mmbpd by 2023. Infrastructure must anticipate this future demand in the world market to prevent bottlenecks that have hindered producers at several key stages of the shale revolution. Pipeline infrastructure is being built to serve the increase in Permian and Eagle Ford supply. But without adequate port and other infrastructure to access the global market, a bottleneck will form and work its way back to the wellhead via a reduced price, lowering revenue for producers, impacting jobs and investment. For example, we estimate that a prolonged bottleneck could cost the Permian region alone $51B in revenue.

Strong shale supply growth driven by +4.4 mmpd in the Permian and Eagle Ford.

Supply of light tight oil will grow by 5.4 mmbpd (85%) over the 5 years from 2018-2023 driving U.S. production to 16.6 mmbpd according to our analysis. The Gulf Coast will see the majority of this flow as the Permian basin accounts for 68% of growth with a 3.7 mmbpd (138%) increase and the Eagle Ford, which is the second largest contributor, with +692 kbpd (50%).

We expect continued trend of upward revisions as basins exceed expectations.

The latest U.S. Energy Information Administration (EIA) Annual Energy Outlook significantly raised expectations for shale production, but the base case still includes just 2.6 mmbpd of shale growth by 2023. EIA has been forced to raise its southwest region (Permian) supply estimates in each of the past 4 years. In 2016 the EIA projected 2023 supply at just 2.3 mmbpd, which was most recently revised to 4.9 mmbpd. Notably, industry participants appear to be ahead of the curve with more aggressive U.S. supply growth estimates including an Enterprise Product Partners forecast for +6 mmbpd.

U.S. near limits of shale oil absorption.

The U.S. refining sector has limited ability to blend increased volumes of light oil into the current refining complex and it is unlikely that significant capacity can be added. Under optimal circumstances, we estimate that through small expansions and crude displacement, the U.S. has the ability to absorb just 1.1 mmbpd of incremental light tight oil (LTO). Imports of light crude to the Gulf Coast have already fallen to ~80 kbpd in 2018 and the average API gravity of refiner inputs has risen to 32.2 (see page 5 for background on API gravity). Limited absorption capacity means that domestic crude supply growth will exceed domestic consumption by at least 2.4 mmbpd and potentially as much as 4.7 mmbpd depending on supply projections.

Demand growth upside could further strain U.S. crude export capacity.

Wayfinder believes that global demand growth expectations may be systemically underestimated largely due to overstatement of developed nation demand reductions. We project OECD demand to rise to 50.5 mmbpd in 2023 driving global demand to 108.5 mmbpd as consumers' low-price environment decisions build toward a critical mass.

U.S. exports testing the limits of infrastructure.

U.S. weekly crude oil exports reached 3 mmbpd in 2018 approaching the limit of existing export capacity estimated to be around 3.5 mmbpd in the Gulf Coast including ~1.3kbpd at Corpus Christi.

U.S. will require the ability to export 6.5 mmbpd of crude oil in the next five years.

We estimate domestic crude oil production will outstrip domestic crude demand by 4.7 mmbpd in 2023. Given the constraints on refining additional light oil, this drives exports to 6.5 mmbpd in 2023.

Corpus Christi set to become premier U.S. export hub with adequate investment.

Corpus Christi is best positioned to benefit from Permian and Eagle Ford access and see significant volume increase to 1 mmbpd by 2020 and 2 mmbpd by 2023 with pipeline additions and port capacity expansion. However, we estimate that Corpus Christi export capacity is approaching full utilization and incremental volumes will require additional terminal capacity to support the growth.

Infrastructure must anticipate shale supply growth to avoid economic impacts.

The shale resource base has proven resilient to a wide variety of challenges, growing supply in 9 out of the past 10 years and doubling U.S. oil production. However, at times, the flexibility of shale supply has surprised industry expectations leading to inadequate investment in midstream capacity and exposing producers to deep discounts to global markets. These steep discounts come at a significant economic cost to the shale regions including underinvestment, reduced employment, lost or deferred tax and royalty payments, and lagging supply growth.

Potential economic repercussions if export capacity is not expanded on pace with supply.

If there is insufficient export capability to move growing supply, a bottleneck will form, working its way back to the wellhead in the form of a price signal. This is what happened with inadequate takeaway from the Bakken from late 2013-2014 when discounts to West Texas Intermediate (WTI) averaged more than $10. Likewise, Permian differentials ballooned to more than $14 in May-August 2018 in the face of similar takeaway constraints. We estimate that a prolonged bottleneck resulting in a $15 bbl discount could cost Permian producers $51B in lost price and shut-in production. These infrastructure dislocations have real world impacts for producers, workers, and regional economies in the form of lost revenue.

Background: State of Play

Overview

The primary driver of U.S. crude oil exports has been the rapid increase in light oil supply from the major U.S. shale basins with limited additional capacity to refine it domestically. From 2008-2018, United States oil production doubled from 5.1 mmbpd to 10.7 mmbpd; this was entirely dependent upon the 5.7 mmbpd growth from shale supplies.

Shale production has grown in 9 out of the past 10 years at an annual rate of 23%. Over this time, the resource base has proven remarkably resilient to a wide variety of challenges, including takeaway bottlenecks, price wars, high decline rates, and varying political constraints. In our view, this is due in large part to the diversity of operators, an early stage learning curve, geological gradations, and a higher proportion of variable costs in the shales compared to the mature conventional basins.

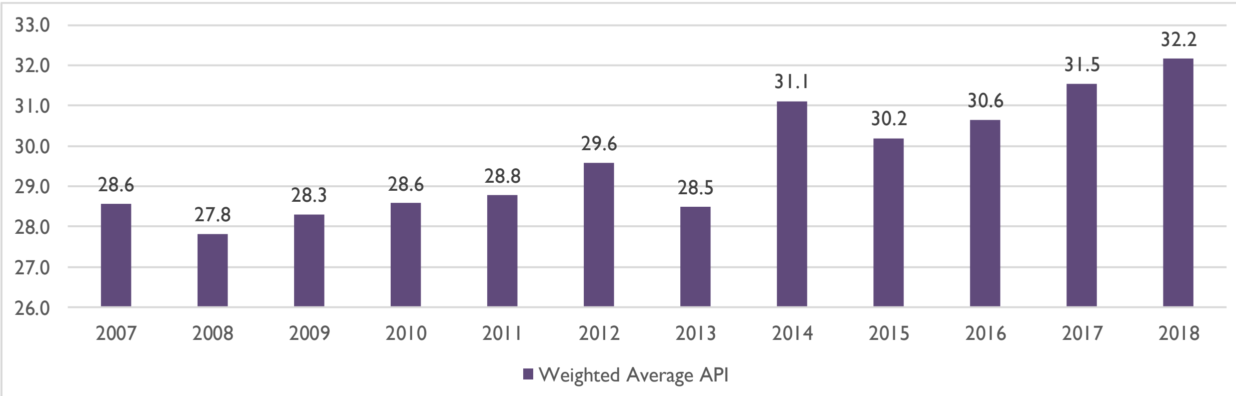
In our view, the resilience of shale resources as a scalable and flexible supply base has created challenges for infrastructure and logistics providers who had difficulty predicting takeaway needs. As a result, the U.S. has experienced periodic basin blowouts when long lead time infrastructure failed to keep pace with supply. Going forward, it is essential that infrastructure players including integrated oil companies and large midstream companies optimize infrastructure in anticipation of strong growth.

Refineries Nearing Maximum Light Oil Absorption

Over the last several years, refineries have processed record volumes of crude oil, in large part due to the advantage caused by the shale revolution. However, shale production has been predominantly a higher API gravity than legacy production in North America. API gravity is an arbitrary scale for measuring the density of a petroleum liquid relative to water. The higher the API gravity, the lower the density of the petroleum liquid, meaning lighter oils have higher API gravities. Along with sulfur content, API gravity determines the type of processing needed to refine crude oil into fuel and other petroleum products, all of which factor into refineries' profits according to the EIA. Overall U.S. refining capacity is geared toward a diverse range of crude oil inputs, so it can be uneconomic to run some refineries solely on light crude oil. Conversely, it is impossible to run some refineries on heavy crude oil without producing significant quantities of low-valued heavy products such as residual fuel.[1]

In the early stages of the shale revolution, complex refineries were able to absorb incrementally lighter barrels in some instances by blending it with heavier grades or debottlenecking refineries. As demonstrated in the chart below, the average API gravity of U.S. refiner crude oil input rose steadily from 2007-2015 with refiners working to take advantage of steeply discounted, domestically produced light oil. However, at these levels, experts believe that the refining complex is nearing its limit to increase light oil absorption.

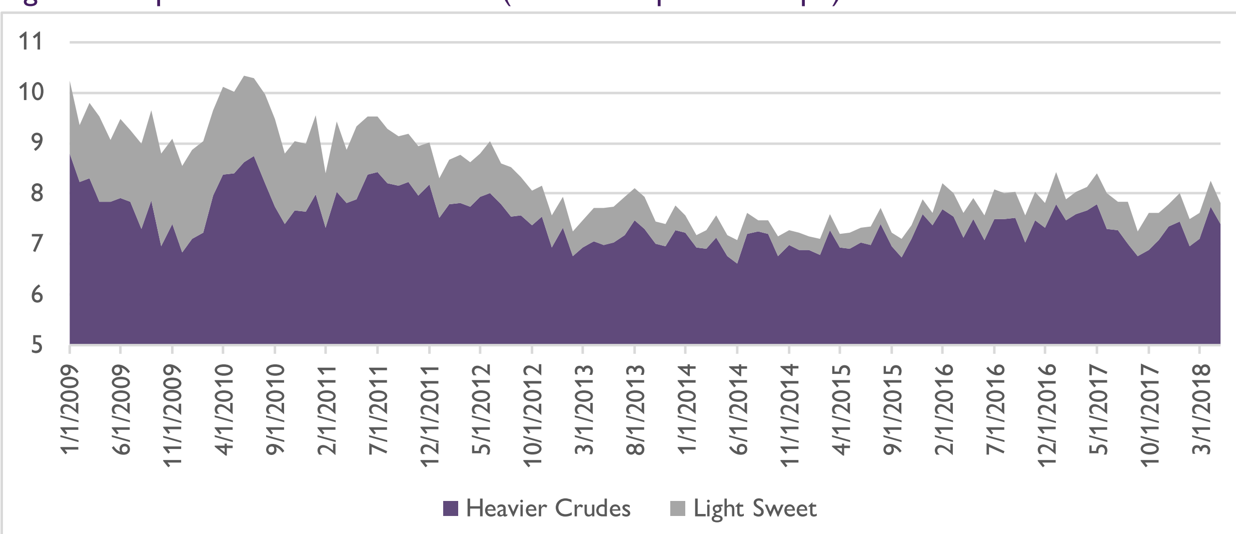
Gulf Coast Refiners Shift to Lighter Crude Inputs



Source: Wayfinder Analytics, EIA

In addition to processing more light oil, the domestic refining complex adapted to the rise in LTO by pushing out light oil imports. With light imports falling from 1,940 kbpd in 2009 to fewer than 750 kbd in 2018, there are very few opportunities to further displace light oil imports.

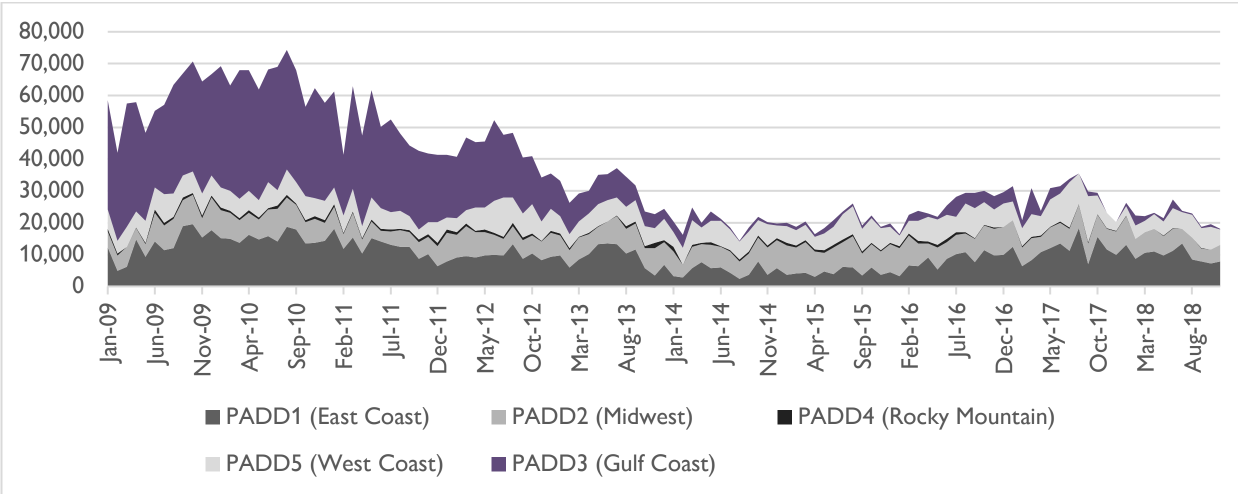
Light Oil Imports Fall More Than 60% (U.S. Oil Imports mmbpd)



Source: Wayfinder Analytics, EIA

The problem of displacing light imports is especially acute in the Gulf Coast refining center where light imports fell to zero bpd by October and November 2018 (according to last available data).

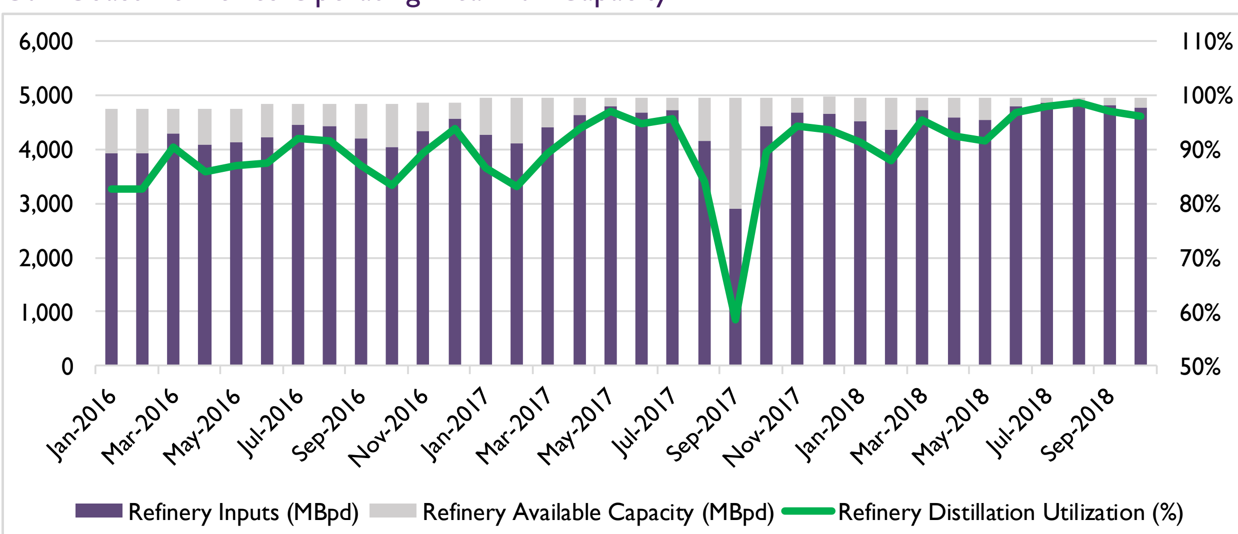
U.S. Light Oil Imports By PADD (mmbpd)



Source: Wayfinder Analytics, EIA

According to the energy consulting firm Wood Mackenzie, without large-scale capital investment, the U.S. domestic market can only absorb about a quarter of the additional 4 mmbpd light supply growth projected by 2023. Therefore, with refinery capacity nearly fully utilized, incremental crude volumes heading to the Gulf Coast are destined to be exported.

Gulf Coast Refineries Operating Near Full Capacity



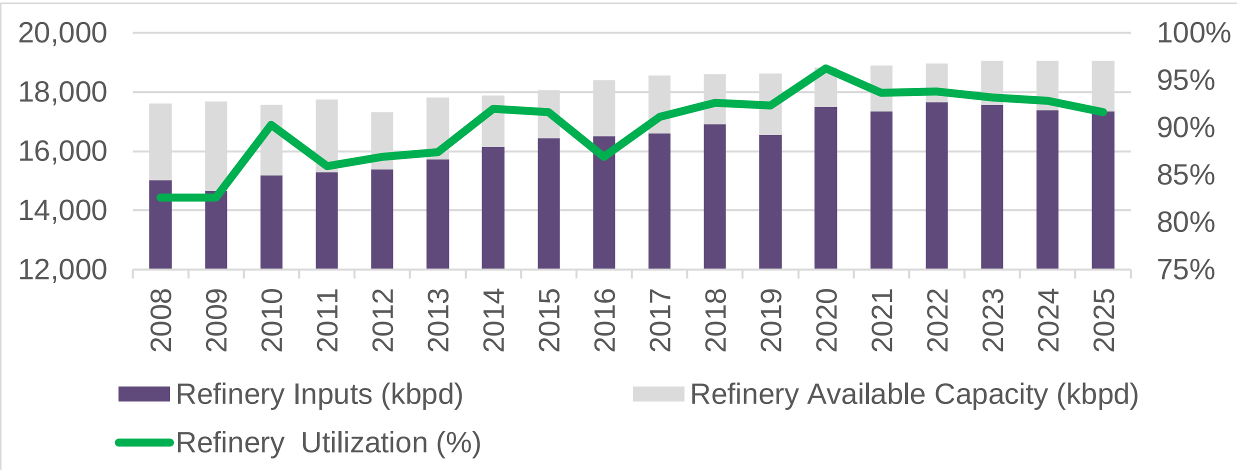
Source: Wayfinder Analytics, EIA

Limited Refining Capacity Expansions Not Keeping Pace with Supply Growth

There have been virtually no significant new crude oil refineries built in the United States since Marathon's facility in Garyville, Louisiana came online in 1977. Refiners have been able to add some capacity through expansions and improvements at existing facilities. According to the EIA's most recent Refinery Capacity Report, capacity was virtually unchanged between 2017 and 2018 at 18.6 million barrels per calendar day (b/cd) and actually decreased 0.1% since beginning of 2017.

Operable crude oil distillation unit (CDU) capacity had inched up in the previous five years from 17.3 b/cd in 2012. This implies capacity growth of roughly 200 kbpd compared to average crude oil production growth of almost 1 mmbpd per year.

Refiner Capacity and Inputs Projected to Remain Range Bound



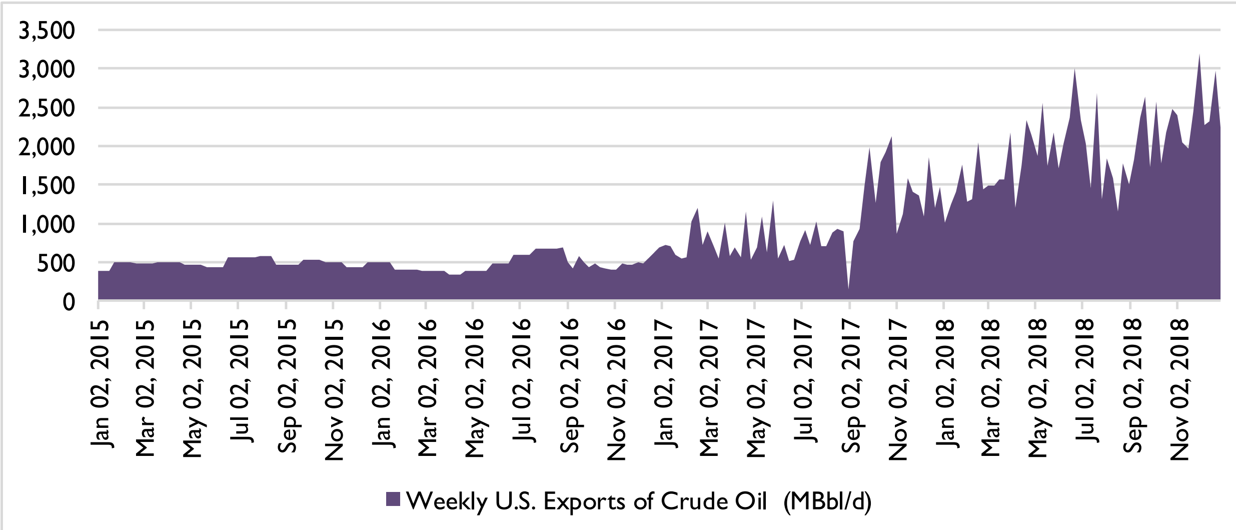
Source: Wayfinder Analytics, EIA

Despite the shale boom, there are comparatively few high probability proposals to expand domestic refining capacity and these tend to be very small new facilities located in producing regions accompanied by a handful of proposals to reconfigure existing refineries. Industry experts believe that it is unlikely that significant refinery capacity on the scale of the production growth can be built in the United States. For example, EIA projects that between 2018 and 2023 just 453 (2%) b/cd of distillation capacity will be added. At this rate, even assuming refiners can maintain current capacity utilization, the country will be unable to handle the continued growth in U.S. crude oil production.

Shift to Export Growth

In December 2015 Congress repealed the crude export ban allowing domestic oil to be shipped overseas. After saturating the domestic market, the U.S. began to increase its export volumes of crude oil. Demonstrated in the chart below, U.S. weekly crude oil exports have reached the 3 mmbpd level already in 2018, implying that we are approaching the ceiling for crude oil export capacity.

Accelerating U.S. Crude Oil Exports



Source: Wayfinder Analytics, EIA

Need for Incremental Export Capacity

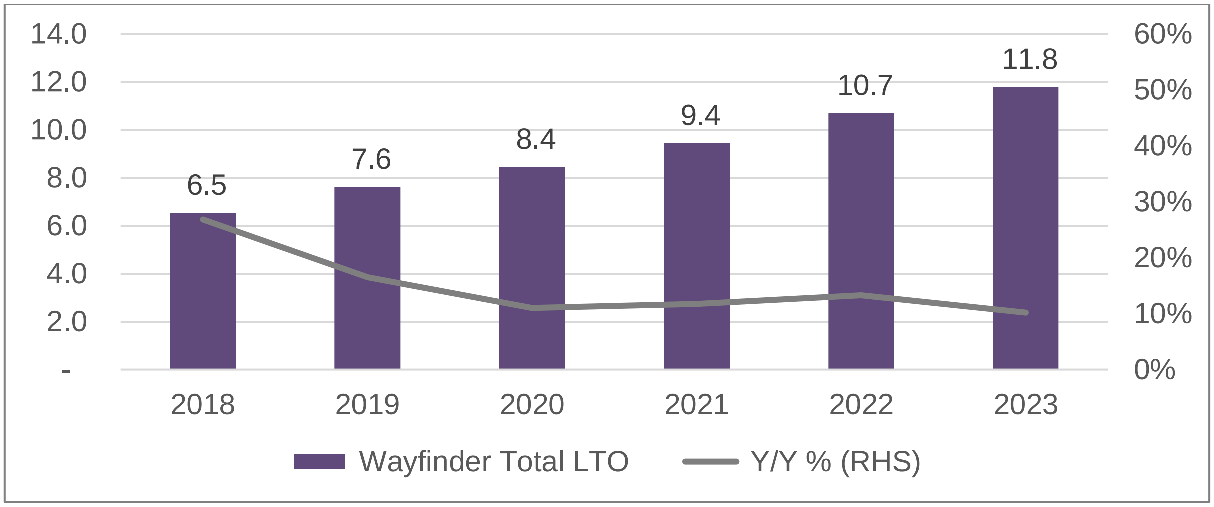
We estimate that total Gulf Coast capacity is around 3.5 mmbpd and capacity at Corpus Christi is around 1.3 kbpd. Current analyst consensus regarding export capacity around the Gulf Coast is that existing terminals are operating at or near capacity. This is a difficult number to reconcile as variations in actual capacity are not easily measurable like nameplate capacity on a pipeline. Throughput capacity of an export facility can be driven by multiple factors, such as loading capabilities, storage capacity overall, storage capacity per tank, various operating efficiencies, available docks, depths of water at access points, and more. In addition, operators may be reluctant to disclose capacity for strategic reasons. For our analysis, we spoke with market experts and reviewed public documents and anecdotal data points to gain reasonable confidence in our estimates for comparison.

North American Crude Supply: What's Next?

Wayfinder Supply Forecast

Wayfinder Analytics' base case projects U.S. shale supply to grow by an additional 5.4 mmbpd (85%) over the 5 years from 2018-2023. This drives total U.S Light Tight Oil production (LTO) from 6.5 mmbpd in 2018 to 11.8 mmbpd in 2023. We believe that there is a predictable learning curve in shale basins through which operators turn basin experience into technology and techniques that steadily drive up recovery factors. This learning curve is non-linear, in our view as it is tied to the number of wells drilled in a basin rather than traditional metrics such as the calendar year.

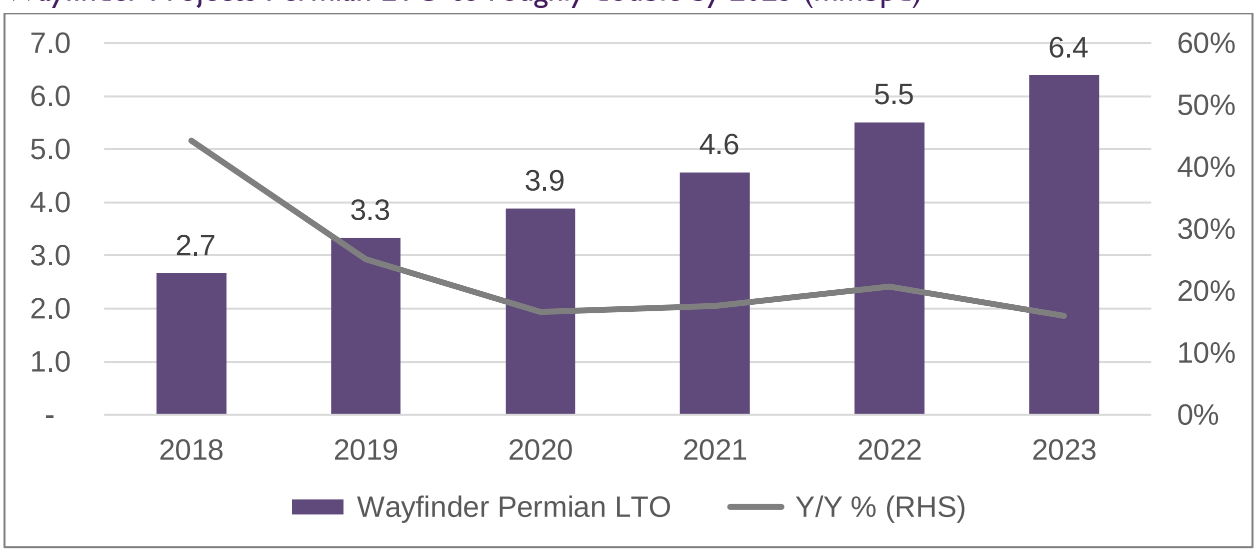
Improvements in Technology and Technique Drive Continued Shale Supply Growth (mmbpd)



Source: Wayfinder Analytics, EIA

The Permian Basin accounts for more than 68% of this growth with a 3.7 mmbpd (138%) supply increase over this time period. The Eagle Ford is the second largest contributor to growth with +692 kbpd (50%) followed by Bakken at +583 kbpd (48%) and the Niobrara with +231 kbpd (64%).

Wayfinder Projects Permian LTO to roughly double by 2023 (mmbpd)



Source: Wayfinder Analytics, EIA

Per well productivity increased consistently through the early years of the shale revolution as operators scaled the learning curve. Again, we calculate the learning curve as a percentage improvement in productivity as a function of the cumulative well count in a basin. With the 2014 oil price correction and subsequent drop in rig count, productivity rates increased between 37% and

108% as high grading removed low productivity wells from the average. We estimate that roughly half of the productivity improvement from 2014-2016 resulted from high grading and the other half from the predictable learning curve. As a result, when the rig count normalizes and drillers begin to expand beyond the most productive core acreage, we believe about half of these gains can be preserved and continue to improve.

In our projection, continued improvement in the ultimate recovery per shale oil well based on improvements to technology and technique balance out the expansion beyond the core in the more mature Bakken and Eagle Ford Basins. By 2023, we project average Initial Production (IP) rates to decline about 7% in the Bakken and return to roughly 2018 levels in the Eagle Ford. In the early part of the forecast, adding rigs and average well counts lowers average productivity as the high-grading of 2015-18 unwinds. This offsets average IP growth in core areas by adding less productive wells to the denominator but should not be misconstrued as a decline in productivity.

In contrast, we expect Permian IPs to rise another 58% by 2023 as multiple plays allow for continued improvements in technology and technique, and the large core permits rig additions beyond the most productive acreage.

In addition to productivity gains, we assume that across the board improvements in efficiency will drive per rig productivity gains ranging from 26% in the Bakken to 62% in the Permian. We expect drilling efficiency gains to continue but moderate toward the end of the projection period. However, as the industry matures, standardizes, and consolidates, supply chain efficiencies such as expanded pad drilling have the potential to deliver gains beyond our projections.

Wayfinder Assumptions

We view these projections as conservative in several respects. First, they assume real oil price growth 2018-2023 of less than 1% annually consistent with strong shale supply. We use oil prices from the EIA's Short Term Energy Outlook and EIA's Annual Energy Outlook "high oil and gas resource and technology" case, which most closely matches our expectations for productivity. Additionally, we assume that midstream bottlenecks that have periodically caused basin specific differential blowouts are resolved, and that wellhead prices normalize.

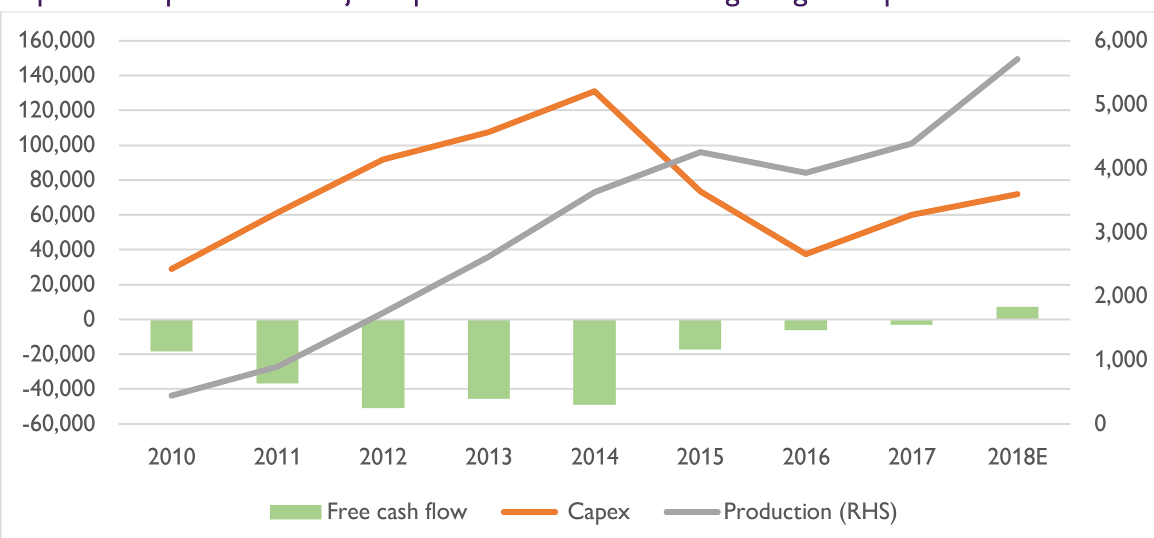
Wayfinder Assumes Real Prices Are Virtually Flat Through 2023

	WTI Nominal $/bbl	WTI Real 2018 $/bbl	Midland/ Southwest Nominal $/bbl	Midland/ Southwest Real 2018 $/bbl
2017	$ 50.79	$ 51.79	$ 50.53	$ 51.52
2018	$ 65.06	$ 65.06	$ 56.65	$ 56.65
2019	$ 54.79	$ 53.51	$ 54.19	$ 52.93
2020	$ 58.00	$ 55.12	$ 58.14	$ 55.26
2021	$ 71.10	$ 65.82	$ 69.70	$ 64.52
2022	$ 73.66	$ 66.45	$ 71.92	$ 64.88
2023	$ 76.90	$ 67.63	$ 75.10	$ 66.05

Source: Wayfinder Analytics and EIA

Next, we assume that the recent shift in exploration and production (E&P) company capital discipline continues throughout the projection period, which governs rig count growth even in the face of rising wellhead prices and productivity.

Capital Discipline: IEA Projects positive cash flows for light tight oil producers



Source: Wayfinder Analytics, IEA

Consensus Projections Also See Rise in Production Feeding the Gulf Coast

Domestic production will rise by 3.2 mmbpd to 13.9 mmbpd over the next five years, according to the U.S. Energy Information Administration's latest reference case projections. Shale resources account for 2.6 mmbpd of this growth. The EIA sees continued U.S. crude oil production through 2030 with lower 48 (L48) onshore tight oil development remaining the main driver, accounting for about 68% of cumulative domestic production in the reference case. After 2030 production is expected to plateau as tight oil development expands into less productive areas and well productivity declines.

The Texas Gulf Coast will continue to be the focus of activity according to the EIA, with growth heavily focused in the southwest region which includes many prolific tight oil plays with multiple layers, including the Bone Spring, Spraberry, and Wolfcamp. Likewise, production in the Gulf Coast region increases through 2021 before flattening out as the decline in production from the Eagle Ford is offset by increasing production from other tight/shale plays such as the Austin Chalk.

The EIA also projects the deepwater Gulf of Mexico (GOM) will drive L48 offshore production to rise to a record high 2.4 mmbpd in 2022. Offshore supply continues to see benefits from discoveries made in the pre-2015 high price environment coming into development.

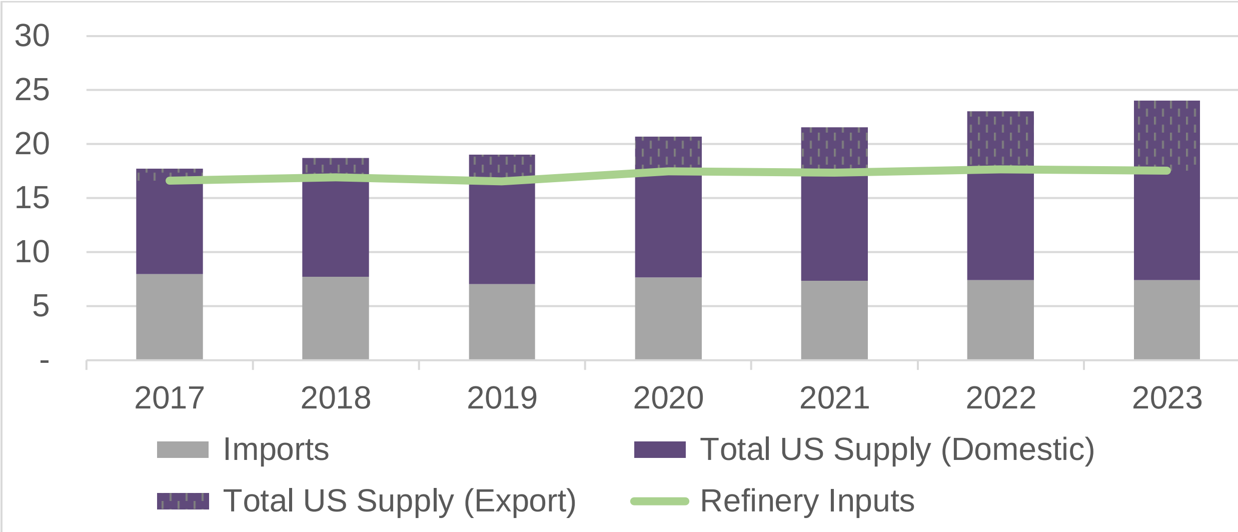
Examples of Mainstream Estimates

- **+3.3 mmbpd – IEA.** The International Energy Administration (IEA) projects shale growth to reach 9.2 mmbpd by 2025 with the U.S. accounting for nearly 75% of global oil and gas growth over the next six years.
- **+4 mmbpd – Wood Mackenzie.** The energy consulting firm Wood Mackenzie estimates that domestic supply will rise by 4 mmbpd by 2023.[2]
- **+6 mmbpd – Enterprise.** Enterprise Products Partners (EPD) recently estimated US crude and condensate production to increase from ~10 mmbpd in 2018 to ~16 mmbpd in 2025, an increase of roughly 6 mmbpd.[3]
- **+4.2 mmbpd – Plains.** Plains All American forecasts onshore production will reach roughly 13 mmbpd by 2023, an increase of 4.2 mmbpd over 2018 in the $60 oil base case. In Plain's $70 crude oil scenario, their estimates rose to 16 mmbpd by 2023, an increase of 7.2 mmbpd.[4]

Exports Rise above 6 mmbpd

We estimate that the rise in domestic production will outstrip domestic refinery consumption over the next five years by 4.7 mmbpd in our base case. This drives U.S. crude oil exports from 1.8 mmbpd in 2018 to 6.5 in 2023. We conservatively assume that the domestic refining industry will respond to this growth by adapting to absorb 1.1 mmbpd of additional LTO with 660 kbpd consumed by capacity expansion and utilization increases in addition to further displacement of 338 kbpd of light oil imports. However, given the questions about the outlook, and the challenge in approving, permitting, and building capacity expansions, delays and cancelations could reduce this ability.

Wayfinder Projects 6.5 mmbpd Exports by 2023



Source: EIA, Wayfinder Analytics

Domestic Supply Growth Drives Exports (mmbpd)

	Refinery Inputs	Total US Supply (Domestic)	Total US Supply (Export)	Imports
2017	16.6	8.6	1.2	8.0
2018	16.9	9.2	1.8	7.7
2019	16.6	9.5	2.4	7.0
2020	17.5	9.8	3.2	7.7
2021	17.3	10.0	4.2	7.4
2022	17.7	10.2	5.4	7.4
2023	17.6	10.2	6.5	7.4

Source: Wayfinder Analytics, EIA

In its reference case, the IEA projects crude exports to rise 91% by 2023 to 2.2 mmbpd and in the high resource and technology case exports increase 100% to 2.4 mmbpd. These projections assume that a significant portion of the production growth displaces oil imports.

However, the consensus among industry experts tends to reflect both stronger shale supply and exports than the EIA as the global growth in demand for light oil accelerates with refinery capacity expansion in Asia and a decline in European imports from Russia.

These include:

- **+3 mmbpd Wood Mackenzie.** Wood Mackenzie estimates that the U.S. market can only absorb 1 mmbpd of the projected additional 4 mmbpd supplied in 2023, requiring export of the remaining 3 mmbpd.[5]
- **+4 mmbpd – McKinsey.** The consulting firm McKinsey & Co projects U.S. crude exports to rise to nearly 4 mmbpd by 2025 and to 5 mmbpd by 2030.[6]
- **+6 mmbpd – Enterprise.** Enterprise Products Partners projects exports to rise to around 6 mmbpd by 2023 and roughly 7 mmbpd by 2025.[7]
- **+5-6 mmbpd – Plains.** Plains All American projects 2023 crude and condensate exports to reach approximately 5-6 mmbpd.[8]

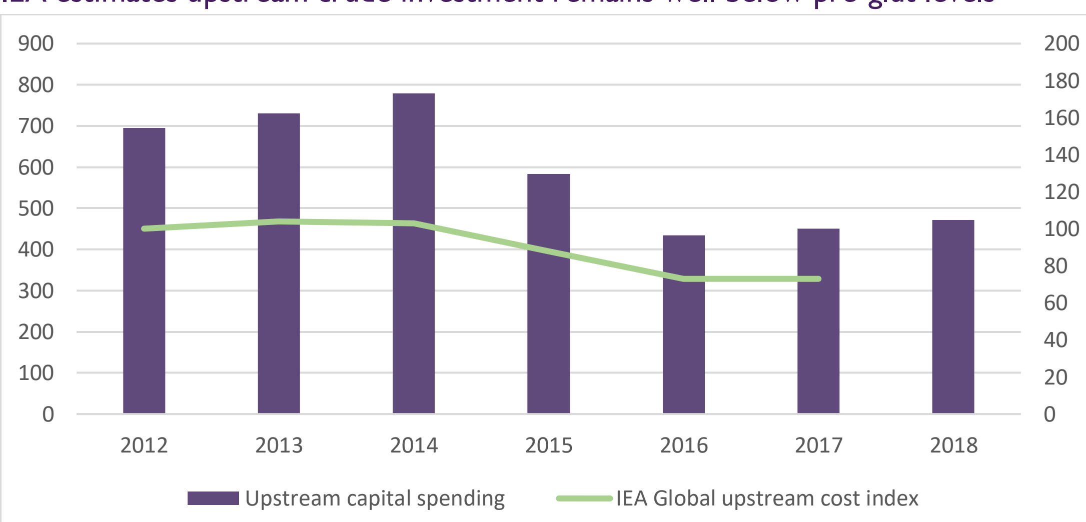
According to Wood Mackenzie, a strong appetite for Permian crude grades in Europe and Asia may command a premium price of ~$0.50/bbl relative to WTI and Eagle Ford crude.

Global Supply/Demand Themes

Inadequate Global Investment Places Greater Pressure on Shale

According to the IEA, each year the world needs to replace 3 mmbpd of supply lost from natural declines at mature fields in addition to additional production to to keep pace with increasing demand. However, upstream oil and gas investment has remained stagnant amid questions about long-term demand and prices. According to the IEA, 2018 upstream investment remains 40% below pre-glut levels[9] and discoveries of new oil resources fell to another record low in 2017, with less than 4 billion barrels of crude, condensate and Natural Gas Liquids (NGL) found.[10]

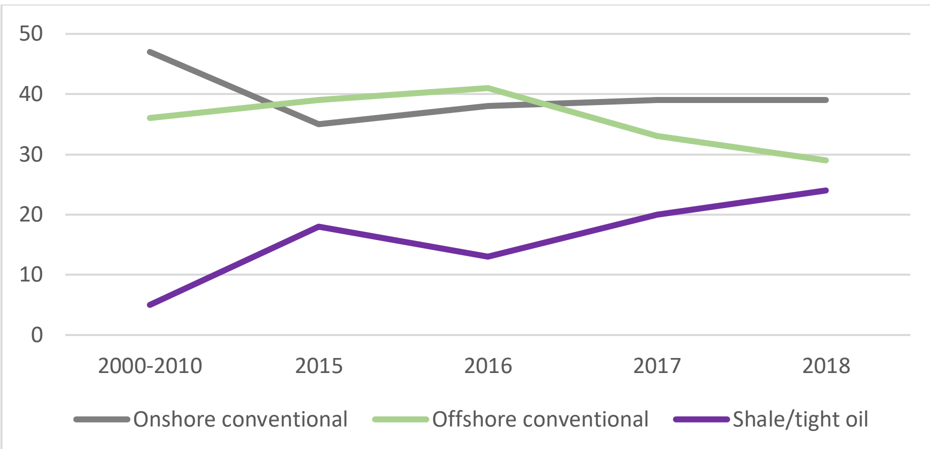
IEA estimates upstream crude investment remains well below pre-glut levels



Source: Wayfinder Analytics, IEA

The IEA's 2018 World Energy Outlook reiterated the agency's concern that weak upstream investments reflect expectations of an imminent slowdown in fossil fuel demand. Even in the agency's "New Policies Scenario," lack of investment in conventional supply could lead to a supply crunch. New conventional project approvals are only half of the amount needed to balance demand through 2025. The IEA projects a doubling in global demand for US tight oil by 2025, but the continued absence of new conventional projects would triple demand for U.S. shale supply growth.

Shale taking an increasing share of upstream oil and gas investment (%)



Source: Wayfinder Analytics, IEA

Global Demand Growth Continues to be Underappreciated

Wayfinder believes that global demand growth expectations may be systemically underestimated. For example, the U.S. EIA projects liquids demand growing to just 105.6 mmbpd in 2023 based on OECD nation demand peaking in 2019 and declining at an average rate of 200kbpd.

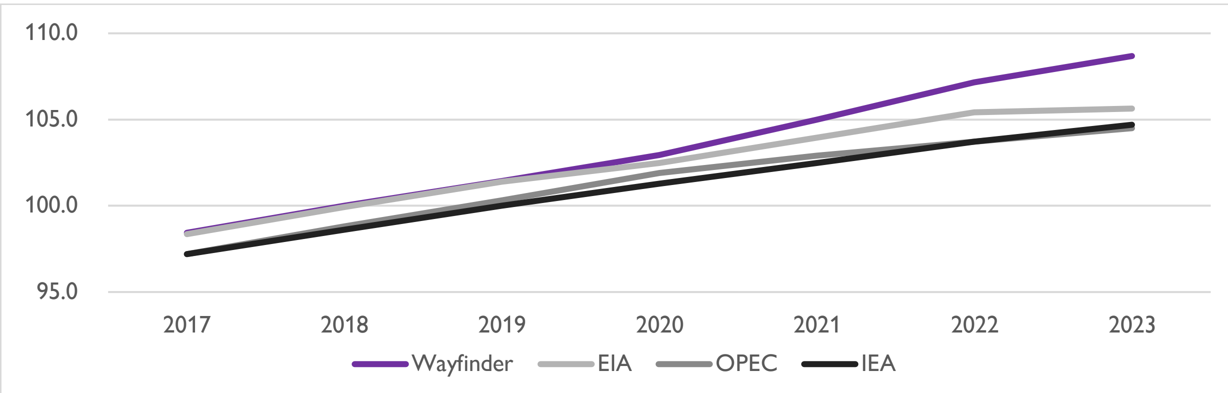
Demand Growth Expectations

	Wayfinder Analytics			EIA			Total Demand		
Year	OECD Demand (WFA)	OECD Proj Growth (WFA)	OECD Proj %	OECD Demand (WFA)	OECD Proj Growth (WFA)	OECD Proj %	OECD Demand (WFA)	OECD Proj Growth (WFA)	OECD Proj %
2017	47,400	-41	-0.1%	47,321	-41	-0.1%	47,400	400	0.9%
2018	47,800	73	0.2%	47,714	393	0.2%	47,800	400	0.8%
2019	48,099	448	1.0%	48,069	355	1.0%	48,100	300	0.6%
2020	48,453	531	1.1%	47,989	-79	1.1%			
2021	48,942	733	1.5%	47,879	-111	1.5%			
2022	49,527	700	1.4%	47,761	-117	1.4%			
2023	50,515	987	2.0%	47,468	-293	2.0%			
2024	51,549	1,035	2.0%	47,209	-260	2.0%			
2025	51,704	155	0.3%	46,953	-255	0.3%			

Source: Wayfinder Analytics, EIA

In contrast, Wayfinder projects OECD demand to rise to 50.5 mmbpd in 2023 driving global demand to 108.5 mmbpd. Wayfinder's model places a greater weight on medium- and long-term oil prices as a driver of demand. In this approach, oil demand growth is driven by consumer choices made during the low price environment since 2015 in which efficiency growth ebbed in durable stock such as vehicles and housing. Multiple individual decisions build to a critical mass over 4-5 years before exerting a powerful influence in the projection.

Low Demand Growth Estimates May Leave Global Markets Unprepared



Source: Wayfinder Analytics, EIA, IEA, OPEC

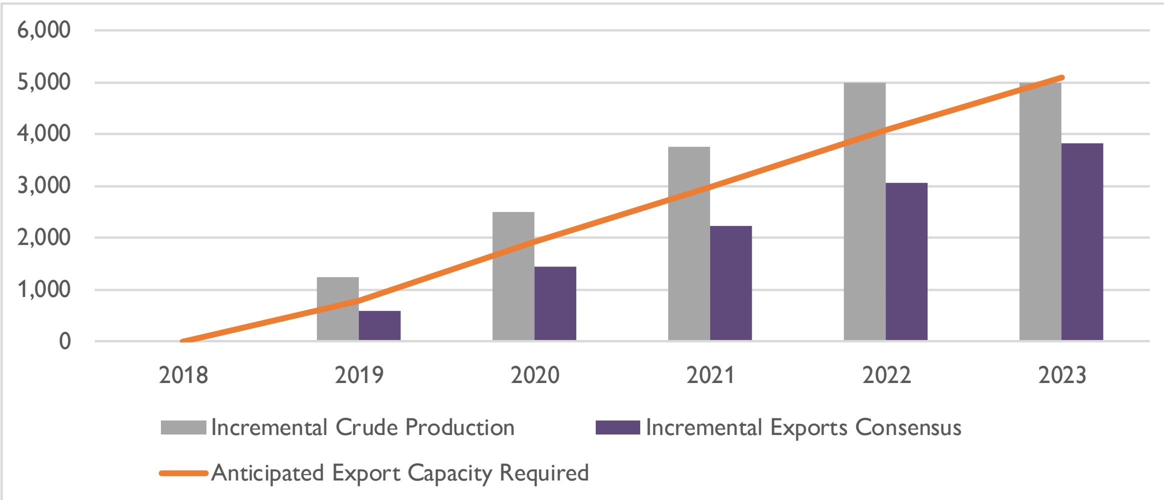
The potential for greater than anticipated oil demand reinforces the urgent need for greater Gulf Coast export capacity. With anemic global conventional investment and inadequate flexibility to connect shale with the world market, the global economy would be at risk of price spikes and especially vulnerable to unplanned outages or market distorting behavior.

Export Infrastructure: Linking Volume Growth to Market

We estimate U.S. crude oil production to increase by roughly 5.2 mmbpd by 2023, with most of these incremental volumes headed for the export market. We do not foresee bottlenecks with regards to domestic transportation volumes as there are multiple pipeline projects under development. However, we anticipate that these volumes will require additional crude export infrastructure to facilitate international delivery. If export capacity is not expanded in time for the upcoming pipeline deliveries, there is significant potential for constraints putting pressure on crude oil prices and limiting production growth in the U.S.

The chart below reflects Wayfinder estimates for crude production and consensus estimates for exports. The orange line is consensus export estimates divided by 75% to imply less than 100% utilization and a target capacity for new terminals. We believe this demonstrates roughly 5mmbpd of incremental export capacity could be sufficiently utilized by market consensus incremental barrels.

North American Crude Oil Production Growth and Export Requirements

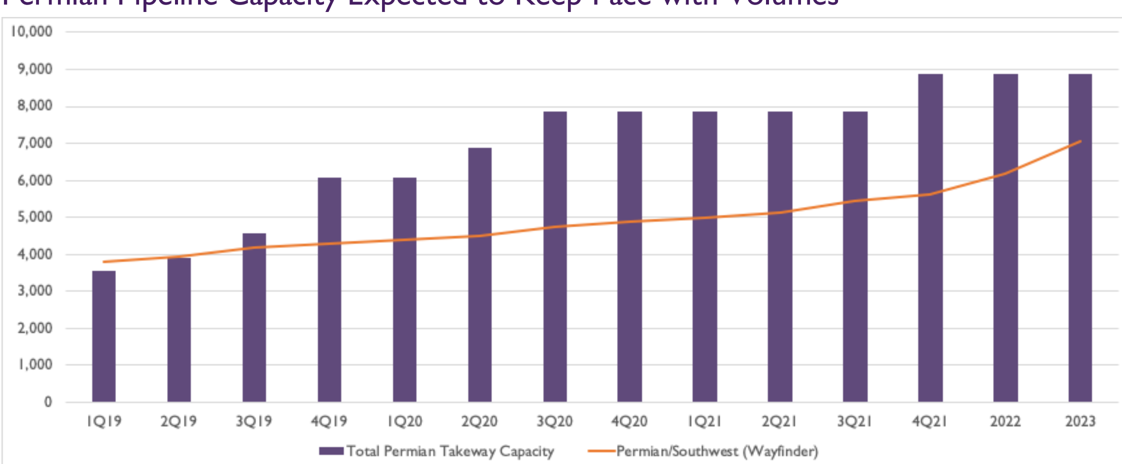


Source: Company Reports, EIA, Wayfinder Analytics

Permian Drives Production Growth but Not the Only Game in Town

The Permian Basin has driven the majority of U.S. crude production growth in recent years and that trend is expected to continue. We estimate the Permian Basin will increase production by ~3.7 mmbpd by the end of 2023. Since this production is at record levels and growing, having infrastructure keep pace is paramount. The first bottleneck to present a challenge is pipeline takeaway capacity. Midstream operators have been focused on meeting these goals with projects under development, which should keep the basin adequately serviced through our forecast period. In fact, takeway capacity should allow for ~1 mmbpd of upside to our estimates should producers seek to accelerate their plans. Most Permian pipeline additions are destined for Corpus Christi or Houston areas. We estimate that currently proposed Permian pipeline projects will be sufficient to handle our expectations for production growth in the basin.

Permian Pipeline Capacity Expected to Keep Pace with Volumes



Source: Company Reports, Wayfinder Analytics

However, in addition to Permian volumes, there are projects under consideration/development to increase volumes from other regions of the US. For example, Tallgrass has its Seahorse pipeline which could drive ~800 kbpd from Cushing, OK to St. James, LA. Enterprise products recently began an open season to gauge/capture shipper interest on a reversal of the Capline which could add another1.2 mmbpd to St. James as well.

Distributing Production Growth to Market

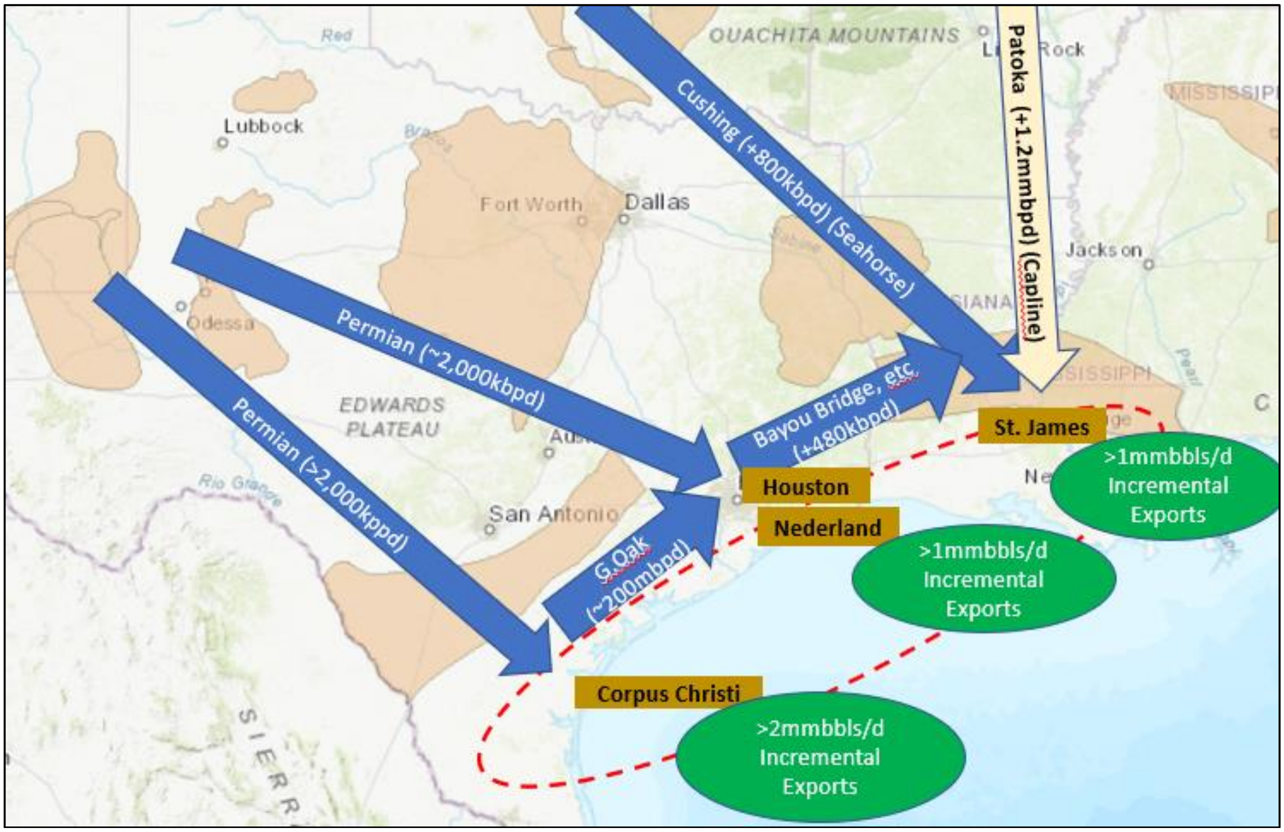
Pipeline capacity out of the Permian has various destinations. In order to explore the need for capacity at various export terminals, we must determine how much incremental capacity is directed at each and over what time period. Of the pipeline capacity currently proposed to transport Permian/Eagle Ford volumes, we estimate >2 mmbpd directed at Corpus Christi, ~2 mmbpd directed at Houston/Nederland, and about ~800 kbpd directed at St. James, LA.

Potential Gulf Coast Export Expansions (Subject to FID, Permitting, etc.)

New Export Terminal Proposals	Development Stage	Terminal Loading Expansions (mmbpd)
Corpus Christi		
Trafigura	Permit Submitted 7/18	0.5
Carlyle Group (Lonestar)	Proposed	1.1
Buckeye Partners (South TX Gateway)	Under Construction	0.8
Flint Hills Resources	Under Construction	0.2
NuStar	Under Construction	0.3
Moda (ex OXY) Ingleside	Under Construction	0.3
		3.1
Houston / Freeport		
Magellan	Proposed	1.5
Enterprise	Permit Submitted 1/19	2.0
Enbridge/Oiltanking/Kinder Morgan	Permit Submitted 1/19	2.0
Sentinel Midstream	Proposed	1.2
		6.7
St. James (Louisiana)		
Tallgrass - Plaquemines Liquids Terminal	Proposed	0.8
Brownsville		
Jupiter MLP	Proposed	1.0
Total Gulf Coast Export Expansions		**11.6**

Source: Company Reports, Wayfinder. Note: St. James reflects pipeline capacity

Development of an integrated System



Source: Company Reports, Wayfinder Analytics

It is important to note that energy infrastructure is highly complex and direct capacity comparisons can be misleading when the broader system is not taken into account. In addition, not all hydrocarbons are fungible and comparing broad metrics can miss variations in quality and fail to consider repercussions for associated hydrocarbon production such as the natural gas or NGL volumes in the same producer's production stream.

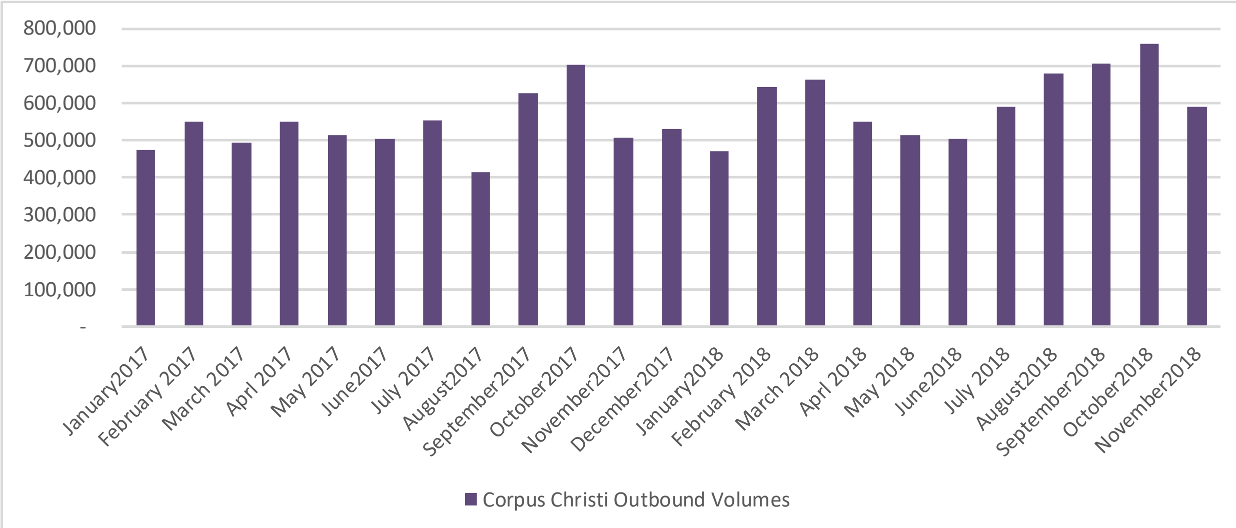
Focus on Specific Ports

In the following sections we will address the unique supply & demand balance at three key export hubs: Corpus Christi, TX, Houston, TX, and St. James, LA.

Corpus Christi, TX

Corpus Christi has seen steady increases in export volumes since the reversal of the crude oil export ban in 2015. Wood Mackenzie projects that Corpus Christi is best positioned to see significant volume increase to 1 mmbpd by 2020 and 2 mmbpd by 2023, with pipeline additions and port capacity expansion to accommodate larger vessels.[11] According to the International Energy Agency, alleviating pipeline bottlenecks will require U.S. export capacity to rise to 4.9 mmbpd by 2023, solidifying Corpus Christi's position as the largest U.S. export hub.[12]

Recent Escalation in Outbound Corpus Christi Crude Oil Volumes (bpd)



Source: Port of Corpus Christi

International shipments rose from roughly 10% of Corpus Christi outbound volumes in early 2016 to around 70% by the end of 2017 (the last period for which data is available).

Incremental volumes flowing into Corpus Christi, TX will be driven by the additional pipeline capacity coming online over the next three years. We forecast roughly 2.0 mmbpd of incremental production. Supply for these pipelines will come largely from the Permian and Eagle Ford. We estimate that Corpus Christi's export capacity is near full utilization and incremental volumes will require additional terminal capacity to support the growth.

Incremental Pipeline Capacity to Corpus

Pipeline/Takeaway Capacity	Operator	Origination	Destination	Expected In-Service	Total Capacity (Mbbls/d)
Incremental to Corpus Christi					
EPIC Pipeline	*Various	Orla, Midland Tx	Corpus Christi	4Q19	590
Gray Oak	Phillips/ Enbridge	West Texas	Corpus Christi	4Q19	900
Cactus Pipeline II	PAA	McCamey, TX	Gardendale, TX	2H19	670
Less: Volumes Directed to Houston				**Vols Diverted (%)**	
Gray Oak	Phillips/ Enbridge	West Texas	Corpus Christi	25%	(148)
Incremental to Corpus Christi					**2,013**

Source: Company Reports, Wayfinder Analytics

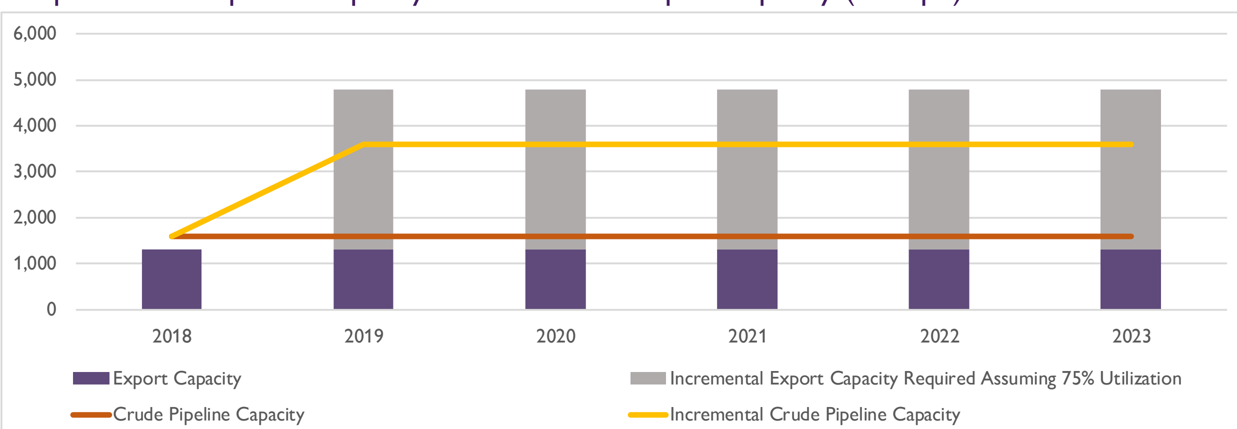
Potential Export Expansions at Corpus Christi (Subject to FID, Permitting, etc.)

New Export Terminal Proposals	Terminal Loading Expansions (mmbpd)
Corpus Christi	
Trafigura	0.50
Carlyle Group (Lonestar)	1.10
Buckeye Partners (South TX Gateway)	0.80
Flint Hills Resources	0.18
NuStar	0.25
Moda (ex OXY) Ingleside	0.30
	3.13

Source: Company Reports, Wayfinder Analytics

We estimate that future volumes flowing into Corpus Christi will drive an additional ~2 mmbpd of exports, supporting the development of multiple export terminal projects and expansions. In the graphic below, we demonstrate the current pipeline capacity into Corpus Christi of roughly 1.6 mmbpd and export capacity of ~1.3 mmbpd. With incremental pipeline capacity of roughly 1.9 mmbpd coming online over the next year, the additional crude volumes into Corpus Christi are largely destined for the export market. In the chart below, we assume that the port could support upwards of 3.5mmbpd of incremental export capacity.

Corpus Christi Pipeline Capacity vs Incremental Export capacity (mmbpd)



	2018	2019	2020	2021	2022	2023
Crude Pipeline Capacity	1,600	1,600	1,600	1,600	1,600	1,600
Incremental Crude Pipeline Capacity		2,013	2,013	2,013	2,013	2,013
Total Pipeline Capacity into Corpus Christi	**1,600**	**3,613**	**3,613**	**3,613**	**3,613**	**3,613**
Export Capacity	1,300	1,300	1,300	1,300	1,300	1,300
Incremental Export Capacity Required Assuming 75% Utilization		3,517	3,517	3,517	3,517	3,517
Total Export Capacity at Corpus Christi	**1,300**	**4,817**	**4,817**	**4,817**	**4,817**	**4,817**
Targetted Export Capacity Utilization		75%	75%	75%	75%	75%

Source: Company Reports, Wayfinder Analytics, EIA

Houston / Freeport, TX

Incremental volumes flowing into the Houston, TX area will also be driven by the additional pipeline capacity coming online over the next three years. Supply for these pipelines will come largely from the Permian and Eagle Ford, as well as the Cushing hub, which is supplied by various producing regions across North America.

Incremental pipeline capacity to Houston

Pipeline/Takeaway Capacity	Operator	Origination	Destination	Expected In-Service	Total Capacity (Mbbls/d)
Incremental to Houston / Nederland					
Permian Gulf Coast	ET, MPLX, Delek	Midland, TX	Houston/Nederland, TX	1H20	600
NGL Conversion	EPD	Midland, TX	Houston, TX	1H19	200
Plains / Exxon JV	PAA/Exxon	Midland, TX	Beaumont, TX	4Q21	1,000
Gray Oak	Phillips/ Enbridge	West Texas	Houston		148
Less: Volumes Directed to Nederland / St. James / Beaumont				**Vols Diverted (%)**	
Permian Gulf Coast	ET, MPLX, Delek		Nederland	25%	(150)
Plains / Exxon JV	PAA/Exxon	Midland, TX	Beaumont, TX	25%	(250)
Bayou Bridge	ET	Nederland	St. James		(480)
Incremental Volumes to Houston					**1,068**

Source: Company Reports, Wayfinder Analytics

St. James, LA

In addition to Houston and Corpus Christi, St. James, LA has been a focus of significant potential development. The Bayou Bridge pipeline expansion should drive up to 480 kbpd toward the hub for potential export. We expect some of these volumes to be absorbed by local refineries who might not have significant access to light volumes. The addition of the Seahorse pipeline would add another source of crude via Cushing, OK, which would allow St. James to access volumes from the DJ, Bakken, and Canada. These pipelines would justify further development of export terminals at St. James, which currently only includes Tallgrass' Plaquemines Liquids terminal.

Incremental pipeline capacity to St. James

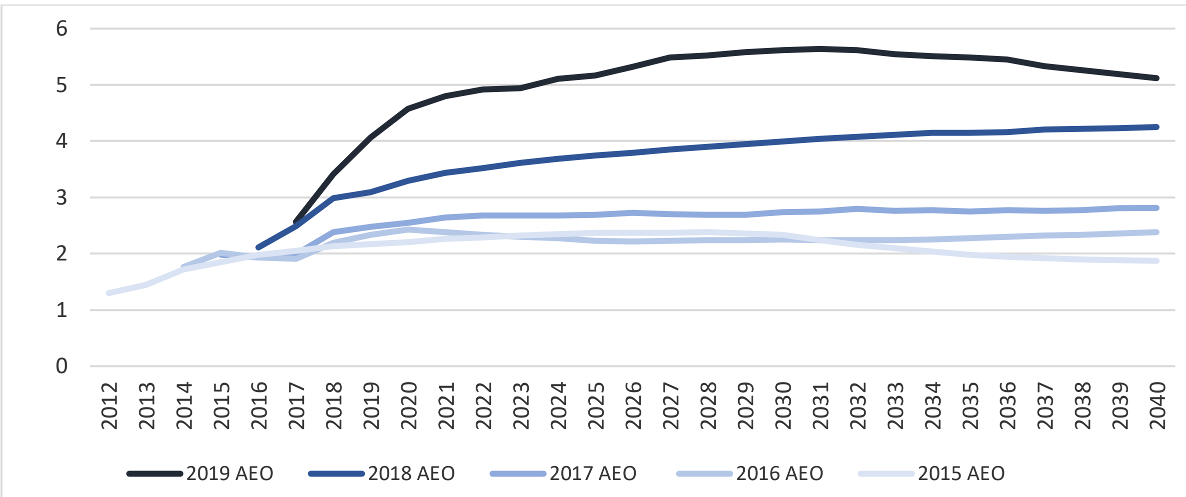
Pipeline/Takeaway Capacity	Operator	Origination	Destination	Expected In-Service	Total Capacity (Mbbls/d)
Incremental to St. James					
Bayou Bridge	ET	Lake Charles	St. James	1Q19	480
Seahorse	Tallgrass	West Texas	St. James	2Q2020	800
Incremental to St. James					**1,280**

Source: Company Reports, Wayfinder Analytics

The Importance of Preparing for Growth

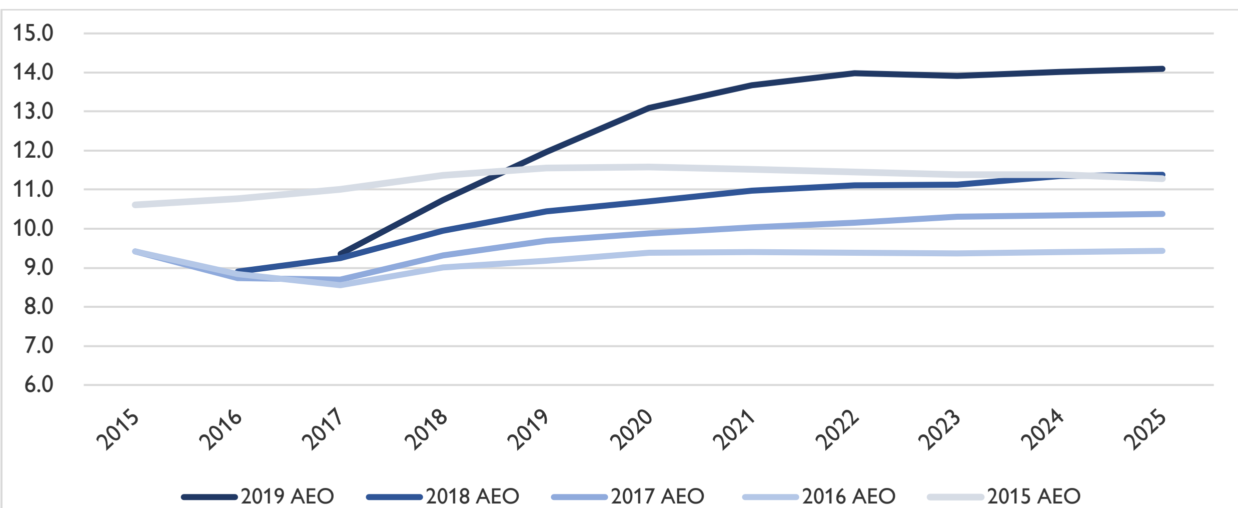
Medium-term Forecasts Include High Degree of Variability

Projecting shale output has proven a challenge for industry analysts. Price fluctuations, technological innovation, and geopolitical risk can each significantly alter the medium-term outlook. For example, EIA has raised its southwest (Permian) region supply estimates in each of the past 4 years. In 2016 the EIA projected 2023 crude supply from the region at just 2.3 mmbpd rising to 3.6 mmbpd in 2018 and again to 4.9 mmbpd in 2019.



Source: EIA, Wayfinder Analytics

Likewise, after the 2015 oil price correction, EIA lowered its 2025 U.S. supply forecast by 1.8 mmbpd to 9.4 mmbpd before raising it three years in a row to 14.0 mmpbd for 2019.

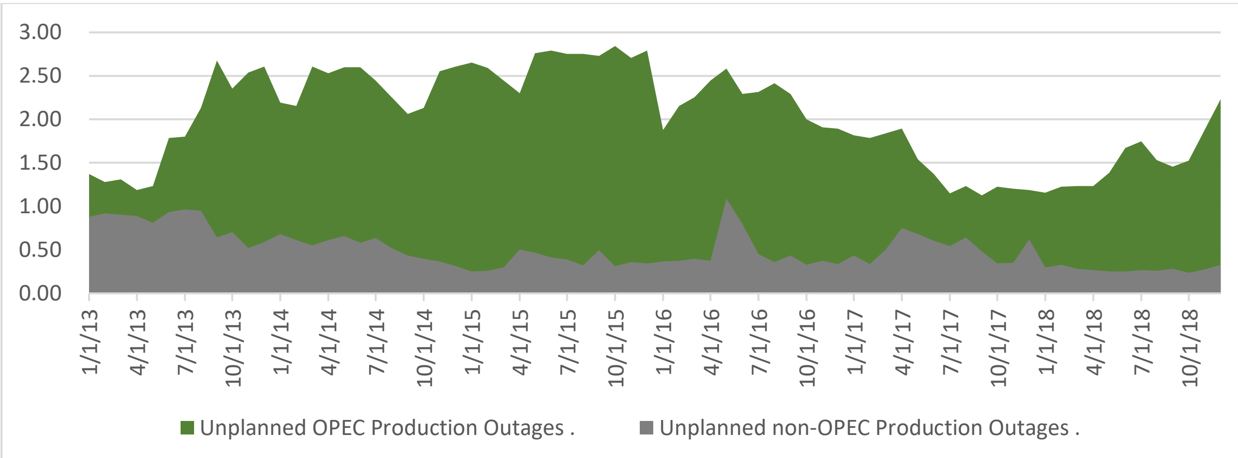


Source: EIA, Wayfinder Analytics

Unplanned Outages and Low Spare Capacity Threaten Market Stability

Since 2013, global unplanned crude supply outtages have averaged 2.5 mmbpd, with outages ranging from 1.4 to 3.7 mmbpd. 2018 was an unusually fortunate year, with unplanned outages averaging just 1.8 mmbpd. However, outages kicked up at year end with 1 mmbpd in curtailments from Iran.

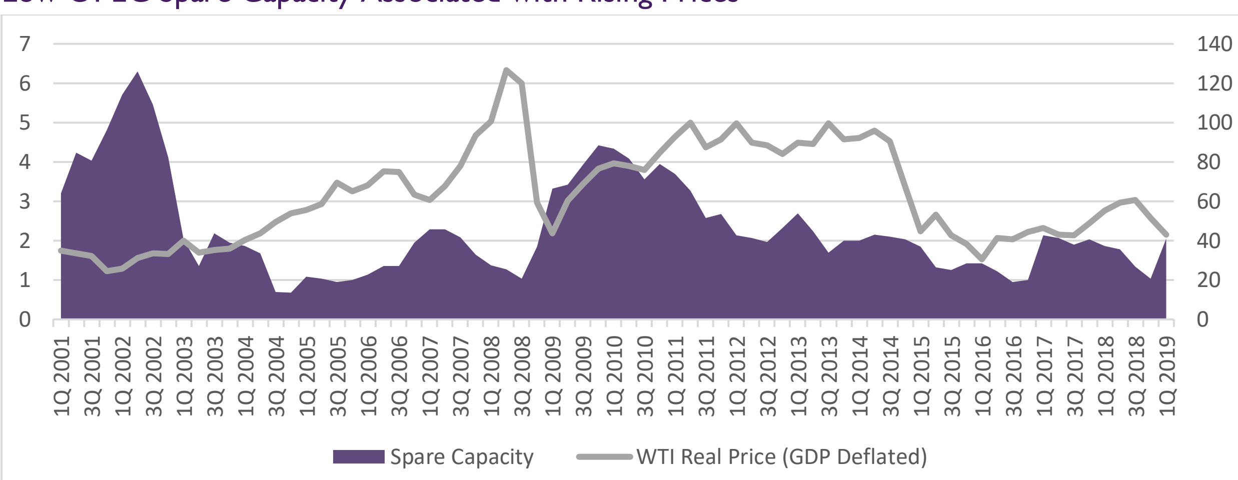
Unplanned Outages Average 2.5 mmbpd



Source: EIA, Wayfinder Analytics

Traditionally, OPEC spare capacity has served as the safety valve for unplanned supply disruptions with Saudi Arabia playing the role of the "swing producer" to stabilize the market. However, in recent years, the amount of crude held in storage and the flexibility of the shale market have usurped some of that role.

Low OPEC Spare Capacity Associated with Rising Prices



Source: EIA, Wayfinder Analytics

Shrinking OPEC spare capacity tends to be associated with rising oil prices as the upside price risk of unplanned disruptions is factored into prices and storage. By the end of 2018, OPEC spare capacity had fallen to just 1.9 mmbpd or 2% of daily global demand. With crude oil stocks within range of their 5-year average, the option to export U.S. shale supplies will play an increasingly important role in balancing the global oil market in the coming years.

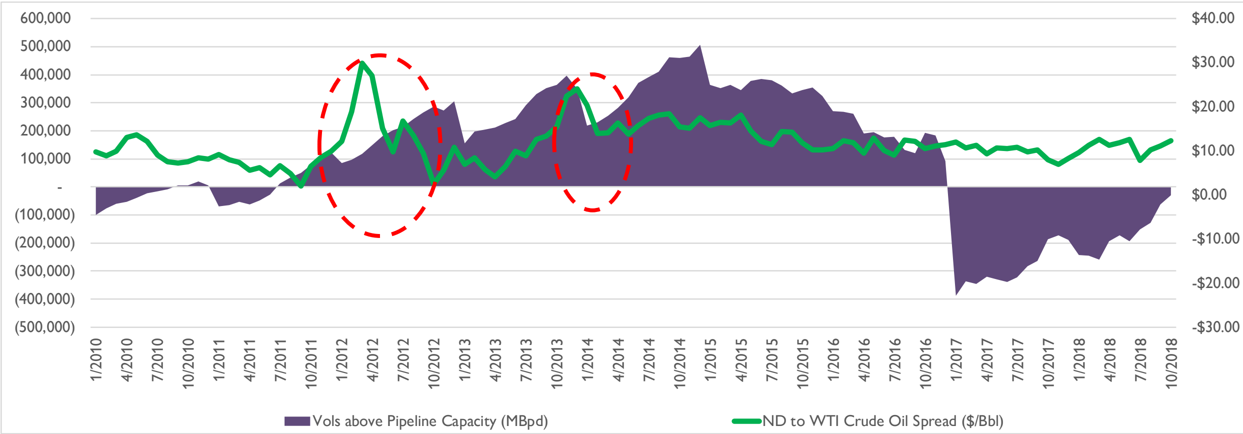
Timing is of the Essence: Historic Bottlenecks and Economic Disruptions

We believe that without sufficient export infrastructure at the Gulf Coast, U.S. producers and the broader energy sector could face more significant disruption than previous high-profile bottleneck situations in the Bakken and Permian Basin. Crude oil differentials widened substantially in both instances, eroding the economics of producers and dampening production, which has impacts across the energy value chain. However, in both instances, there was an alternative mode of transportation to help alleviate some of the constraint. The Bakken relied heavily on rail transportation. The Permian has leaned on trucking and rail transportation as well. At the Gulf Coast, with exports as the focus of production growth, there is no alternative to alleviate excess volumes. Simply, there is no truck that is going to make it to China. Therefore, the disruption could be more drastic and could significantly pump the breaks on the U.S. energy sector and crude oil prices.

U.S. midstream companies are challenged to meet the ever-growing needs of producers as well as the demand from downstream consumers. Determining the infrastructure requirements and coordinating that development to coincide with new volumes continues to be problematic. Misalignments of timing can create infrastructure bottlenecks that can widen regional differentials in pricing and can massively disrupt the economics for operators. This was the case in the Bakken in 2014 and has been a recurring theme in the Permian Basin, with bottlenecks creating regional price dislocations as recent as 2019.

As crude oil production grew in the Bakken, pipeline capacity was slowly overwhelmed. This forced producers to look for alternative methods of transporting crude oil to market. For the Bakken, this was solved by rail. Crude oil prices in the Bakken dropped to almost a $30 discount to WTI in 2012 and reached discounts over $20 in 2014. This reflected the heightened cost to ship by rail and the risk that crude could be stranded. The basin expanded its rail capacity to meet the interim need and ultimately less expensive pipeline capacity came online.

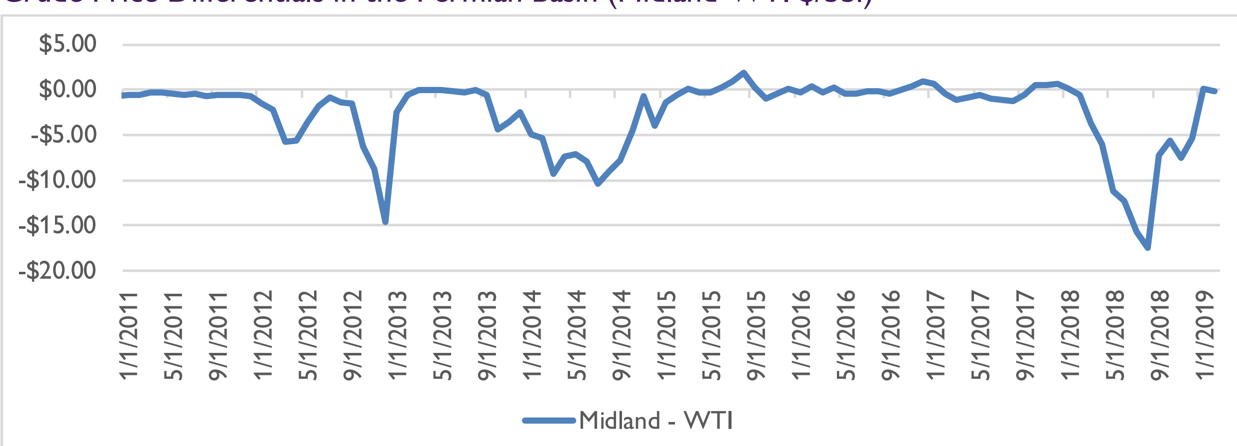
ND Capacity Utilization and Pricing Differentials



Source: ND Pipeline Authority, Company Reports, Wayfinder Analytics

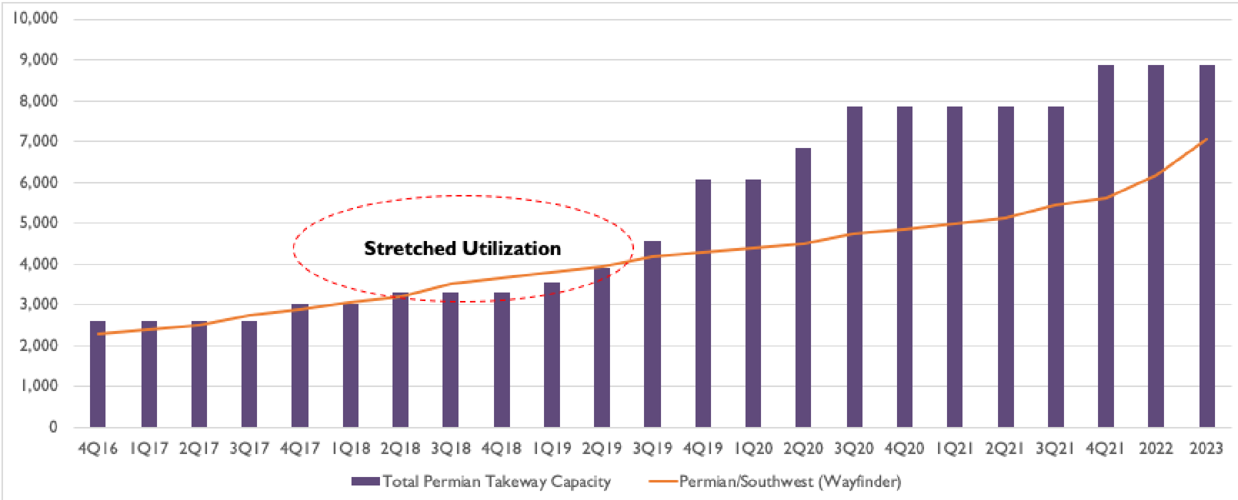
The situation in the Permian followed a similar path. As crude oil production grew, pipeline capacity was overwhelmed. This caused regional pricing dislocations in 2012, 2014, and 2018. In periods of pipeline constraint, producers leveraged higher cost alternative transportation where available, including trucking or rail transportation. To some extent, the differentials reflected the increased transportation costs. In other periods, all options were exhausted and crude oil discounts were further exaggerated. With the Permian taking center stage in North American crude production as the most economic basin, midstream operators have been diligently working to anticipate its needs. However, if increased pipeline volumes out of the basin are not met with complimentary access to market through refinery demand or export capacity, the bottleneck will be pushed further down the supply chain, and constraints will again create a major disruption for crude prices and production volume.

Crude Price Differentials in the Permian Basin (Midland-WTI $/bbl)



Source: Argus, Wayfinder Analytics

Permian Basin Capacity Utilization



Source: EIA, Company Reports, Wayfinder Analytics

If there is insufficient export capability to move growing supply, a bottleneck will form, working its way back to the wellhead in the form of a price signal. This is what happened with inadequate takeaway from the Bakken from late 2013-2014, when discounts to WTI averaged more than $10. Likewise, Permian differentials ballooned to more than $14 in May-August 2018 in the face of takeaway constraints.

These infrastructure dislocations have real world impacts for producers, workers, and regional economies in the form of lost revenue. For example, if takeaway capacity growth in the Gulf falls short by late 2019 and a 2020 bottleneck causes an average $15 discount for oil in the Permian, producers would lose not only the $15 per barrell in revenue, but would need to curtail drilling and well completions, reducing volumes.

In this scenario, we project a loss of Permian production of around 120 kbpd in 2020 and 1.2 mmbpd through 2023. As a result, producer revenue falls from a projected $82B in 2020 to just $59B. About $2.6B of this is attributable to the lost production and the other $20.1B due to the $15B reduction in prices for other producers. Importantly, not all of this feeds directly to the balance sheet of every producer, as some may have firm contracts that protect them from price fluctuations. However, it permeates the entire regional oil industry in lost investment, employment, royalties and tax payments, hedging costs, and more.

Moreover, even as the industry recovers from the disruption, the lost production stream and learning curve reverberate through the projection period. Through 2023, total losses reach 1.2 mmbpd of supply and $51B in foregone revenue.

Illustrative Permian Discount Scenario

	Wayfinder Base Case			$15 Average 2020 Discount				
Year	Permian Wellhead $/bbl	Wayfinder Permian LTO mmbpd	Implied Revenue $Billion	Permian Wellhead $/bbl	Wayfinder Permian LTO mmbpd	Implied Revenue $Billion	Difference mmbpd	Difference $ Billion
2019	$ 54.19	3.3	$66	$54.19	3.3	$ 66	-	$0
2020	$ 58.14	3.9	$82	$43.00	3.8	$ 59	0.12	$23
2021	$ 69.70	4.6	$116	$69.70	4.1	$ 105	0.43	$11
2022	$ 71.92	5.5	$145	$71.92	5.2	$ 136	0.32	$8
2023	$ 75.10	6.4	$175	$75.10	6.1	$ 167	0.30	$8
Total		**23.7**	**$584**		**22.5**	**$534**	**1.2**	**$51**

Source: EIA, Wayfinder Analytics

Appendix

Wayfinder U.S. LTO Supply (mmbpd)

	Permian LTO (Wayfinder)	y/y	Eagle Ford LTO (Wayfinder)	y/y	Bakken LTO (Wayfinder)	y/y	Niobrara LTO (Wayfinder)	y/y	Other LTO (EIA)	y/y	Total LTO (Wayfinder)	y/y	Total U.S. Production (Wayfinder)	y/y
2017	1.8	0.4	1.2	-0.1	1.1	0.0	0.3	0.0	0.7	0.0	5.1	1.9	9.4	0.5
2018	2.7	0.9	1.5	0.3	1.2	0.1	0.4	0.0	0.8	0.1	6.5	1.5	10.7	1.4
2019	3.3	0.6	1.6	0.1	1.4	0.2	0.5	0.1	0.9	0.1	7.6	1.1	12.0	1.2
2020	3.9	0.6	1.7	0.1	1.5	0.1	0.5	0.0	0.9	0.1	8.4	0.8	13.0	1.0
2021	4.6	0.7	1.8	0.1	1.6	0.1	0.5	0.0	1.0	0.0	9.4	1.0	14.2	1.2
2022	5.5	0.9	2.0	0.1	1.7	0.1	0.6	0.0	1.0	0.0	10.7	1.3	15.6	1.4
2023	6.4	0.9	2.1	0.1	1.8	0.1	0.6	0.0	0.9	0.0	11.8	1.1	16.6	1.0

Source: EIA, Wayfinder Analytics

Wayfinder Texas/Gulf Coast* Supply (mmbpd)

	Permian LTO (Wayfinder)	y/y	Southwest Ex-Permian (EIA)	y/y	Eagle Ford LTO (Wayfinder)	y/y	Gulf Coast Onshore Ex-Eagle Ford (EIA)	y/y	Texas Region Total (Wayfinder)	y/y
2017	1.8	0.4	0.8	0.0	1.2	-0.1	0.4	0.0	4.1	0.4
2018	2.7	0.9	0.7	-0.1	1.5	0.3	0.2	-0.1	5.1	1.0
2019	3.3	0.6	0.8	0.1	1.6	0.1	0.2	-0.1	5.9	0.7
2020	3.9	0.6	0.7	0.0	1.7	0.1	0.3	0.1	6.6	0.7
2021	4.6	0.7	0.7	0.0	1.8	0.1	0.3	0.1	7.4	0.8
2022	5.5	0.9	0.7	0.0	2.0	0.1	0.3	0.0	8.5	1.1
2023	6.4	0.9	0.7	0.0	2.1	0.1	0.4	0.0	9.5	1.0

**The EIA's Southwest Region covers west Texas and Eastern New Mexico Including the Permian. The Onshore Gulf Coast covers east Texas, Louisiana and the other Gulf States. Wayfinder's Permian Region includes plays within the region such as Spraberry, Avalon/Bone Springs, and Woflcamp. Eagle Ford likewise includes Austin Chalk.*

Source: EIA, Wayfinder Analytics

[1] Geary, Emily, White, Kyra and Meade, Ashleigh. *The United States continues to increase production of lighter crude oil*, U.S. Energy Information Administration, 9 Oct. 2018, https://www.eia.gov/todayinenergy/detail.php?id=37213 . Accessed 5 February 2019.

[2] Pitt, Anthea. *Will a Shifting Global Market Embrace US Crude?* 5 Mar. 2018, www.woodmac.com/press-releases/us-oil-exports/. Accessed 15 Feb. 2019.

[3] *Enterprise Products Partners L.P. Analyst Conference* 7 Mar. 2018, www.enterpriseproducts.com/investors/presentations. Accessed 31 Jan. 2019.

[4] *PAA Analyst Day* 5 Jun. 2018, https://ir.paalp.com/Events_Presentations. Accessed 14 Feb. 2019

[5] Pitt, Anthea. *Will a Shifting Global Market Embrace US Crude?* 5 Mar. 2018, www.woodmac.com/press-releases/us-oil-exports/. Accessed 15 Feb. 2019.

[6] "Global Downstream Outlook to 2030 ." *McKinsey & Company*, McKinsey & Company, Aug. 2018, www.mckinsey.com/solutions/energy-insights/global-downstream-outlook-to-2030.

[7] *Enterprise Products Partners L.P. Analyst Conference* 7 Mar. 2018, www.enterpriseproducts.com/investors/presentations. Accessed 31 Jan. 2019.

[8] *PAA Analyst Day* 5 Jun. 2018, https://ir.paalp.com/Events_Presentations. Accessed 14 Feb. 2019

[9] Birol, Fatih. "World Energy Investment 2018 : Key Findings." *October*, IEA, 17 July 2018, www.iea.org/wei2018/.

[10] "Oil 2018." International Energy Agency, 5 March 2018, https://www.iea.org/oil2018/#section-7

[11] Pitt, Anthea. *Will a Shifting Global Market Embrace US Crude?* 5 Mar. 2018, www.woodmac.com/press-releases/us-oil-exports/. Accessed 15 Feb. 2019.

[12] "Market Report Series Oil 2018 – Analysis and Forecasts to 2023" International Energy Agency, May 22nd 2018, https://energypolicy.columbia.edu/sites/default/files/pictures/Oil%202018_Columbia%20University_May%2022nd%202018[1]%20%20-%20%20Read-Only.pdf

.