U.S. Crude Exports Take Off

Conditions are ripe for continued growth.

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Contents

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Data Sources for This Publication
U.S. Energy Information Administration
CME Group
U.S. Customs
To discover more about the data sources used, click here.

Executive Summary

Just 18 months ago in December 2015, Congress lifted 1970s-era restrictions on U.S. crude exports that had effectively limited shipments except to Canada. During the first year after the ban was lifted, there was little appetite in world markets for U.S. supplies. In 2017, demand took off and export volumes doubled. They have increased again in 2018, with a weekly record 2.6 million barrels a day shipped in the second week of May, and we expect continued expansion under current favorable conditions. This outlook reviews why crude exports took off in 2017 and where they are headed. We detail the development of Gulf Coast infrastructure to facilitate exports and review pricing and delivery constraints. We conclude by analyzing prospects for continued exports.

Key Takeaways

- Crude exports didn't expand significantly during 2016, the first year after regulations banning overseas shipments to most countries except Canada were lifted, because market conditions were unfavorable.
- In 2017, circumstances changed to encourage export growth, including the OPEC agreement, a transition from contango to backwardated market structure, and a wider Brent premium to West Texas Intermediate.
- Most exports in 2016 were to Canada, followed by Europe and Latin America. In 2017, exports to Asia and Europe took off.
- With the lifting of the export ban still less than two years old, most exports have utilized existing Gulf Coast infrastructure that can support an estimated total 3.8 mmb/d of shipments.
- Growing investment in pipelines, storage, and dock facilities is targeting key regional export hubs in Houston, Corpus Christi, and Louisiana.
- Exports are constrained by inefficient loading facilities that cannot directly load the largest VLCC cargoes favored by Asian and European buyers.
- Current U.S. price mechanisms developed for pipeline delivery do not reflect typical cargo loading terms.
- Favorable market conditions exist for export growth to continue in 2018.

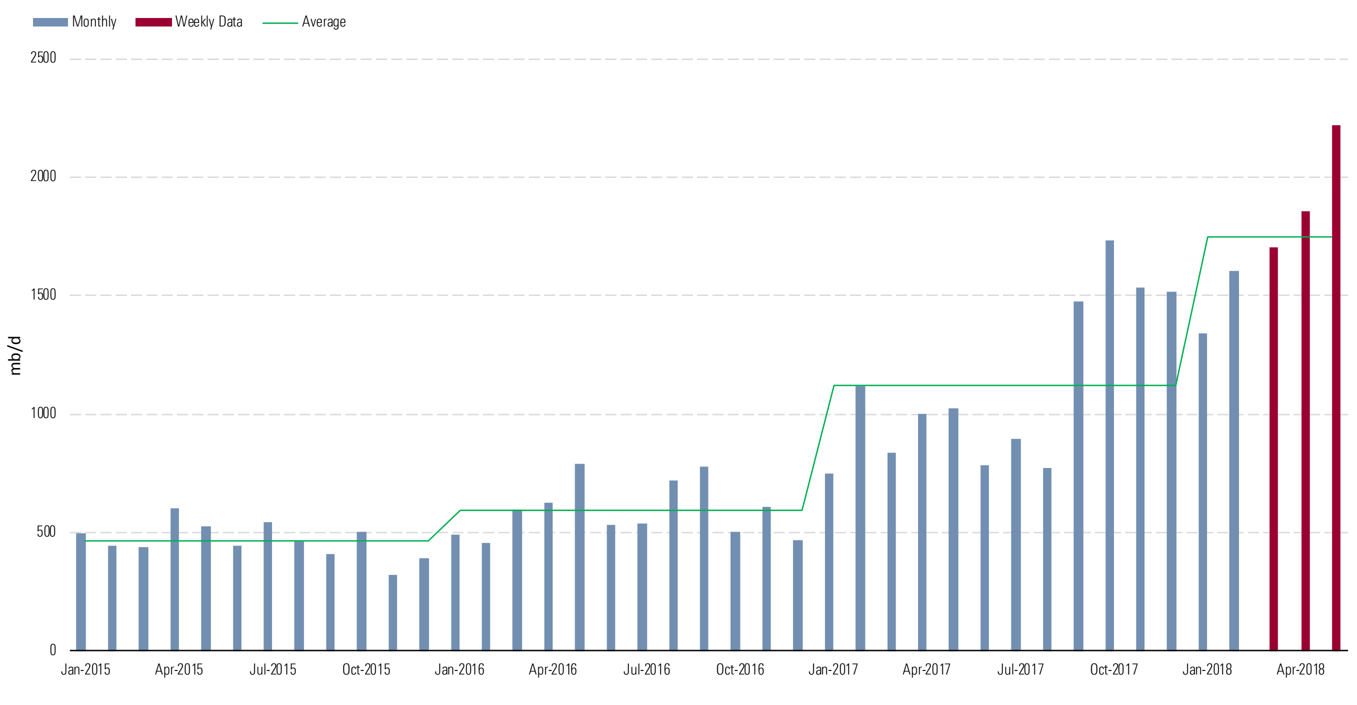
First Year of Deregulation

Until December 2015, the United States had restrictions on most exports, requiring a license from the Department of Commerce and limiting approved destinations to Canada with a few minor exceptions. These restrictions were put in place during the 1970s energy crisis to protect U.S. energy security. They were lifted by Congress in December 2015. During the first year after the ban was lifted (2016), exports were not significantly different from the last year of regulation because of the price crash in 2015 and a surplus of crude supplies as well as a slowdown in U.S. output. But in 2017, crude exports took off and haven't looked back, with shale production booming again and midstream operators hurriedly building out storage and marine dock infrastructure to support shipments along the Gulf Coast.

Why Crude Exports Took Off in 2017

U.S. crude exports almost doubled from an annual average 591 mb/d in 2016 to 1.12 mmb/d in 2017 (Exhibit 1). Monthly and weekly data from the Energy Information Administration so far in 2018 indicates continued growth with exports already averaging 1.7 mmb/d. This section examines the drivers behind crude export growth in 2017.

Exhibit 1 U.S. Crude Exports 2015-18



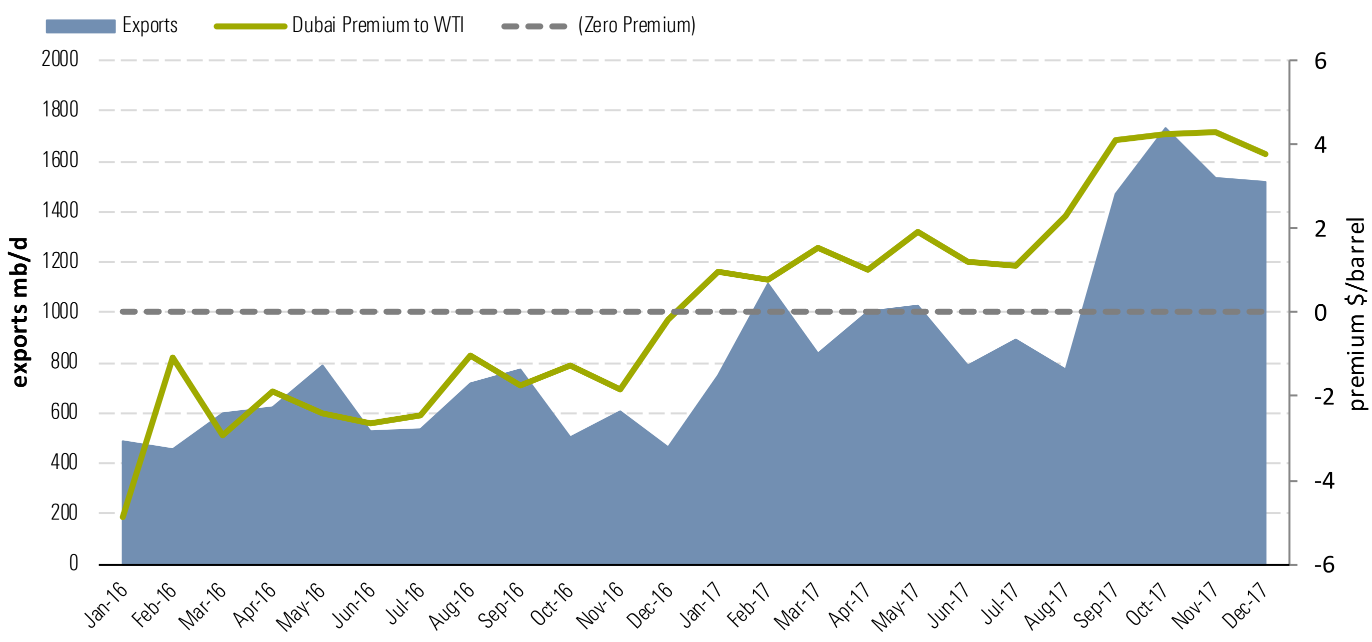
Source: EIA, Morningstar

OPEC Agreement Boosts Exports to Asia

OPEC and other non-OPEC producers, including Russia, signed an accord in November 2016 to cut production by 1.8 mmb/d during the first half of 2017 to reduce excess inventories and bring the market back into balance. Their goal was to push crude prices higher. When the OPEC agreement came into effect Jan. 1, 2017, it led quite quickly to a tightening of supplies in the world outside the U.S. as the cartel implemented cuts to its term customers.

Early in 2017, an unexpected increase in U.S. exports resulted from the OPEC accord. To preserve their income, producers chose to cut cheaper heavy sour crudes over lighter, more expensive grades, leading to a shortage of heavy sour crude in Asian markets where OPEC producers rationed these crudes. The result was an increase in prices for heavy crude in Asia, including the regional benchmark Dubai grade. During the first six months of 2017, Dubai crude traded at a premium over U.S. benchmark WTI delivered at Cushing, Oklahoma, that averaged $1.24/barrel, compared with a more usual average discount of $2.02/barrel during 2016 (see green line in Exhibit 2). The Dubai premium to WTI, which is a light sweet crude, translated into an even higher premium over cheaper U.S. sour crude grades and opened up an arbitrage window for U.S. offshore Gulf of Mexico medium sour crudes to be shipped to Asia to relieve the OPEC-induced shortage.

Exhibit 2 Dubai Premium to WTI and Exports



Source: EIA, CME Group, Morningstar

The OPEC Deal Affects Prices and Encourages U.S. Exports

In addition to opening the arbitrage window for U.S. sour crudes to be shipped to Asia, the OPEC accord had two impacts on crude market prices during 2017 that influenced the supply available to fuel higher exports during the second half of the year:

Contango to Backwardation

First, the structure of forward and futures crude markets for Brent and WTI changed during the year from a strong contango, which had prevailed since the end of 2014, into backwardation. Contango means prices further out are higher than nearby, providing a financial incentive to store crude and suggesting excess supply. Backwardation means prices today are higher than in the future, removing any incentive to store crude and suggesting tight supplies. The change to backwardation removed the financial incentive to store excess crude, releasing it into the market.

Higher Prices

Second, crude prices increased significantly during the second half of 2017. An uptick in refinery throughput during the summer and tightening in world supplies in response to the OPEC accord led to higher crude prices during the second half of the year. Prices for WTI crude delivered to Cushing increased 42% from their low point in June 2017 to over $60/barrel by the end of December. Prices for North Sea benchmark Brent crude rose even higher, up 49% from less than $45/barrel in mid-June to $67/barrel by the end of December.

Higher prices encouraged renewed drilling and production activity in U.S. shale fields, which increased output. The transition to a backwardated market discouraged storage and freed up existing inventory for export.

Shale Production Responds

U.S. production increased in response to higher prices. Production began to recover from the price crash in September 2016, increasing 5% from July 2016 to June 2017 and then ramping up another 10% or 935 mb/d in just six months between June and December 2017, according to EIA, with 855 mb/d of that growth coming from shale.

Most refineries on the U.S. Gulf Coast are not configured to process light shale crudes and found it uneconomic to process more in 2017, preferring heavier imported grades. With the backwardated market structure discouraging storage, incremental shale output therefore looked overseas for a home.

The increase in U.S. domestic crude production has continued in 2018. EIA monthly data shows an increase of 0.3 mmb/d between December 2017 and February 2018. Weekly preliminary data shows production increasing another 0.4 mmb/d between the end of February and May 11 to over 10.7 mmb/d.

Inventory Declines

As the market recovered from contango into backwardation in 2017, there was a corresponding drawdown in crude inventories. Total U.S. crude stocks fell 117 million barrels from an all-time high of 538 million barrels in March 2017 to 421 million barrels in December 2017, according to the EIA.

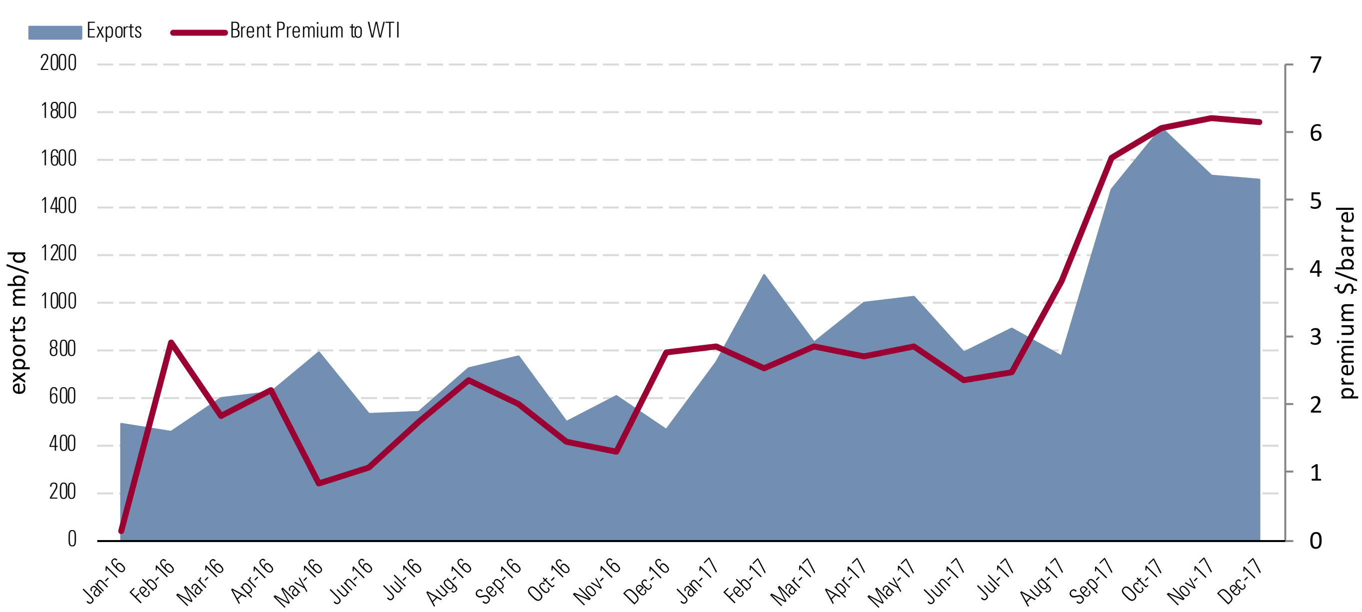
So, despite an uptick in U.S. refining activity during 2017 with refiners processing record volumes over the summer, increased supply from new shale production and the drawdown in inventory supported higher exports.

Wider Brent Premium Over WTI

At the same time that U.S. domestic crude supply increased due to new production and inventory drawdown, supplies outside the country were tighter in the second half of 2017 as the OPEC accord took effect. This supply disparity meant that prices for world benchmark Brent crude increased more rapidly than for U.S. benchmark WTI Cushing during the second half of 2017. The wider Brent premium over WTI opened an arbitrage window that encouraged U.S. exports to reach record levels.

During 2016, the Brent premium over WTI averaged $1.72/barrel, which discouraged U.S. crude exports because the spread was lower than the cost of freight transport to most markets (Exhibit 3). Note that transport costs for WTI include moving crude from Cushing in the Midwest to the coast before factoring in freight. The Brent/WTI premium is generally unworkable for most shipments when it falls below $3/barrel.

Exhibit 3 Brent Premium Over WTI and Exports



Source: EIA, CME Group, Morningstar

Trial Purchases

During the first half of 2017, the Brent premium over WTI averaged $2.69/barrel. At this level exports became feasible for shorter distances—for example, to the Caribbean—but the arbitrage window to Europe and Asia for light sweet crudes like WTI largely remained closed.

As previously discussed, the Dubai premium to WTI during this period encouraged exports of medium sour Gulf of Mexico grades. While the arbitrage window was not always open, several cargoes of U.S. shale crude were exported further afield to Europe and Asia by refiners looking to "buy and try" U.S. grades during the first half of 2017. These purchases educate refiners about shale crude quality and yields to widen the slate of crudes they can process when market conditions are favorable.

Wide-Open Arbitrage

In the second half of 2017, the Brent premium averaged $5.05/barrel over WTI and at times traded close to $7/barrel as the U.S. supply position remained robust compared with the rest of the world. This wider Brent premium correlated directly with an increase in U.S. crude exports during the second half of 2017 that peaked at 1.7 mmb/d in October. The wide premium made U.S. shale crudes competitive with equivalent light sweet North Sea and African crudes in the European market as well as light crude in Asia.

Hurricane Harvey

At the end of August 2017, Hurricane Harvey knocked out more than 20% of U.S. refining capacity in two days, and many refineries stayed offline for weeks because of serious flooding. The impact of the storm created a surplus of unused crude that pushed down WTI prices relative to Brent (widening the Brent/WTI premium). At the same time, Harvey hampered exports because it shut in the very Gulf Coast ports used to ship cargoes overseas.

However, port facilities recovered more rapidly than refineries such that, for example, exports increased in the month after the storm from the Beaumont/Port Arthur refining region on the Texas-Louisiana border (where the flooding was worst) as suppliers shifted incoming barrels away from disabled refineries and into the export market. Although U.S. refining capacity recovered rapidly from Harvey, the hurricane provided a boost to exports by increasing crude available for export and widening the Brent/WTI premium.

Where Are Exports Headed?

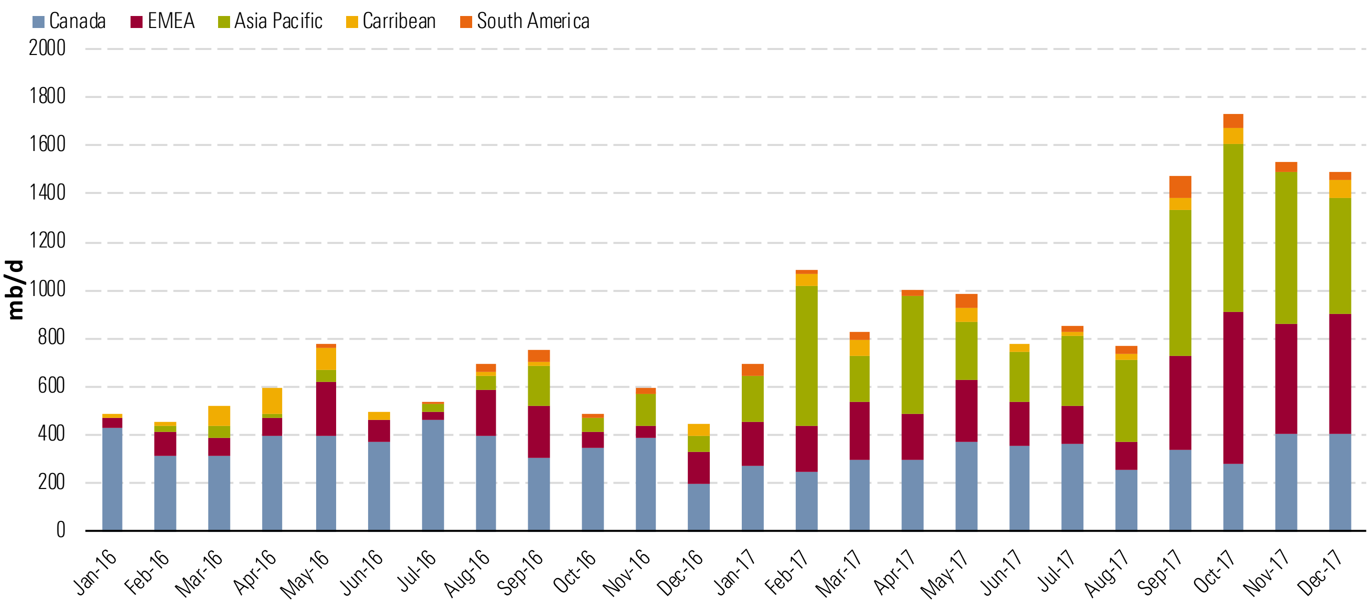
Destinations During 2016

During 2015, the year the U.S. reversed crude export regulations in December, 92% of shipments went to Canada, the only destination fully exempt from the rules. Although the world market opened up in 2016, the oversupplied market did not support significant expansion of U.S. shipments, so 60% of crude exports that first year still went to Canada.

Nevertheless, there was some experimentation with U.S. crude cargoes during the first year after the ban was lifted. About 19% of exports in 2016 went to Europe, Africa, and the Middle East and 9% to the Asia-Pacific region (Exhibit 4).

About 6% of exports went to Caribbean countries, including 30 mb/d to the small Dutch island of Curacao, which is used by Venezuela's national oil company, PDVSA, as a blending and refining center. PDVSA imported light shale crude to blend with its heavy Orinoco crude to reduce the latter's viscosity and make it easier to transport.

Exhibit 4 Crude Export Destinations



Source: U.S. Customs, Morningstar

Destinations During 2017

During 2017, U.S. crude exports to Canada fell only slightly to an annual average of 324 mb/d from 359 mb/d in 2016. But as the world market opened to U.S. shippers, Canada's share of total exports halved from 60% in 2016 to 29% in 2017.

Outside Canada, exports to Europe, the Middle East, and Africa increased to an annual average 295 mb/d, or 26% of total shipments. Shipments further afield to the Asia-Pacific region increased to 392 mb/d, or 35% of the total. Caribbean shipments represented about 4% of the total in 2017 with shipments to Curacao limited by PDVSA's financial and production woes. Another 4% of shipments, or 45 mb/d, went to South American countries.

During the first six months of 2017, shipments to Asia were higher than to Europe, but after the Brent premium to WTI widened in the second half of the year, shipments to Asia and Europe pushed higher.

Export Infrastructure

Introduction

Most crude exports in 2016 and 2017 were loaded at Gulf Coast ports. The remainder was shipped across the Canadian border by rail, truck, and pipeline. This outlook concentrates on waterborne Gulf Coast exports.

Three infrastructure elements are required for waterborne crude exports:

- Crude supply from producing regions (usually via pipelines).
- Storage capacity to stage incoming pipeline crude for loading onto tankers.
- Marine docks with access to international waters to berth and load tankers.

In December 2015, when the crude export ban was lifted, all these elements were already in place at Gulf Coast marine docks that had been used for decades to handle imports or to move crude along the Coast between refining regions and to ship occasional export cargoes to Canada. The initial development of crude export infrastructure therefore largely piggybacked off existing docks in Gulf Coast regional refining centers.

Gulf Coast Continues to Import Crude

Despite the shale boom adding 5 mmb/d to U.S. domestic output in the past seven years, and their proximity to adjacent Gulf of Mexico production, Gulf Coast refineries still relied on an average of 2.8 mmb/d of crude imports during 2017 (down from 5.4 mmb/d in 2010).

Remaining imports to Gulf Coast refineries are regional heavy sour crudes from Latin America (for example, Venezuela, Mexico, Colombia) as well as Middle East heavy crudes from suppliers such as Saudi Arabia, Kuwait, and Iraq. Such heavy crudes are typically less expensive than light shale crude but require more-sophisticated refineries to process. Most Gulf Coast refineries were upgraded to process these cheaper crudes in the pre-shale era, when easier-to-process light crudes were expected to become scarce.

Having invested in expensive upgrading capacity to process heavy crude, Gulf Coast refiners can only process limited volumes of light shale crude without reducing throughput. As a result, they prefer to continue importing heavy crude even as exports of lighter shale crude are increasing.

Gulf Coast Refining Region

More than 50% of U.S. crude processing capacity is in the six states that make up the Gulf Coast region (known as Petroleum Administration for Defense District III, or PADD 3): New Mexico, Texas, Arkansas, Mississippi, Louisiana, and Alabama. As of January 2017, there was 9.7 mmb/d of nameplate refining capacity in PADD 3 at 52 plants, with the majority scattered along the Louisiana and Texas coast.

The four largest refining hubs are in the Mississippi River Delta region at St. James, Louisiana, on the Texas border with Louisiana at Beaumont/Port Arthur, in the Houston Ship Channel and surrounding region in Texas, and at the South Texas Port of Corpus Christi. These hubs have been the initial choice of export shippers.

These refining hubs are well supplied with domestic crude by pipelines built in the past five years from the booming Texas Permian and Eagle Ford shale basins as well as outside the region from as far afield as North Dakota and closer by from Cushing. Louisiana and Texas are also adjacent to the offshore Gulf of Mexico region, which produced an average 1.6 mmb/d of crude in 2017. Most Gulf of Mexico crude comes ashore in Louisiana, but pipelines also supply the Beaumont/Port Arthur and Houston regions.

Storage Capacity

Because of its concentration of refineries, the Gulf Coast has an abundance of crude storage capacity. This storage is used to stage crude deliveries from pipelines and import cargoes into refineries. Storage provides buffer space between large batch deliveries and smaller daily refinery throughput. In addition to onsite refinery storage, there is larger commercial tankage in refining hubs available for lease. In 2018, we estimate there is 217 million barrels of operational commercial storage in the four Gulf Coast refining hubs with at least 54 million barrels of planned additions in 2019 and beyond (Exhibit 5).

Exhibit 5 Gulf Coast Storage Terminal Capacity

Terminal Region	Crude Storage 2018 (mmbbl)	Planned additions 2019 and beyond (mmbbl)
Corpus Christi	17	23
Houston, Freeport, Texas City, Galveston, Seabrook	60	26
Beaumont / Port Arthur	38	5
St. James	28	
LOOP	74	
Total	217	54

Source: Company reports, Morningstar

Since shale crude production took off in 2011, we estimate that 92 million barrels of storage capacity has been added in these regional hubs. These early additions were primarily to stage new incoming domestic crude headed to refineries that began to arrive by rail and barge and then by pipeline.

An estimated 54 million barrels of commercial crude storage is under construction or planned to come on line in 2019 and beyond. Most of this new storage is dedicated to staging crude exports and will be located at new or expanding marine dock terminals.

Clovelly LOOP Storage

While crude storage is a critical element required to stage exports, the largest Gulf Coast commercial storage facility is currently not fully available for this purpose. This facility, in Clovelly, Louisiana, has eight underground salt caverns with 60 million barrels as well as aboveground tanks with 14 million barrels capacity, respectively.

Clovelly is linked by pipeline to the Louisiana Offshore Oil Port, which consists of three mooring buoys, located 18 miles offshore in the Gulf of Mexico. LOOP was built in the 1970s to handle incoming supertankers offloading crude imports and was adapted in 2013 to also handle smaller coastal tankers moving shale crude from Texas. In addition, Clovelly receives incoming crude from the Mars and Poseidon offshore Gulf of Mexico production platforms by pipeline and is connected to the Shell Midstream Zydeco pipeline that delivers shale crude from Houston.

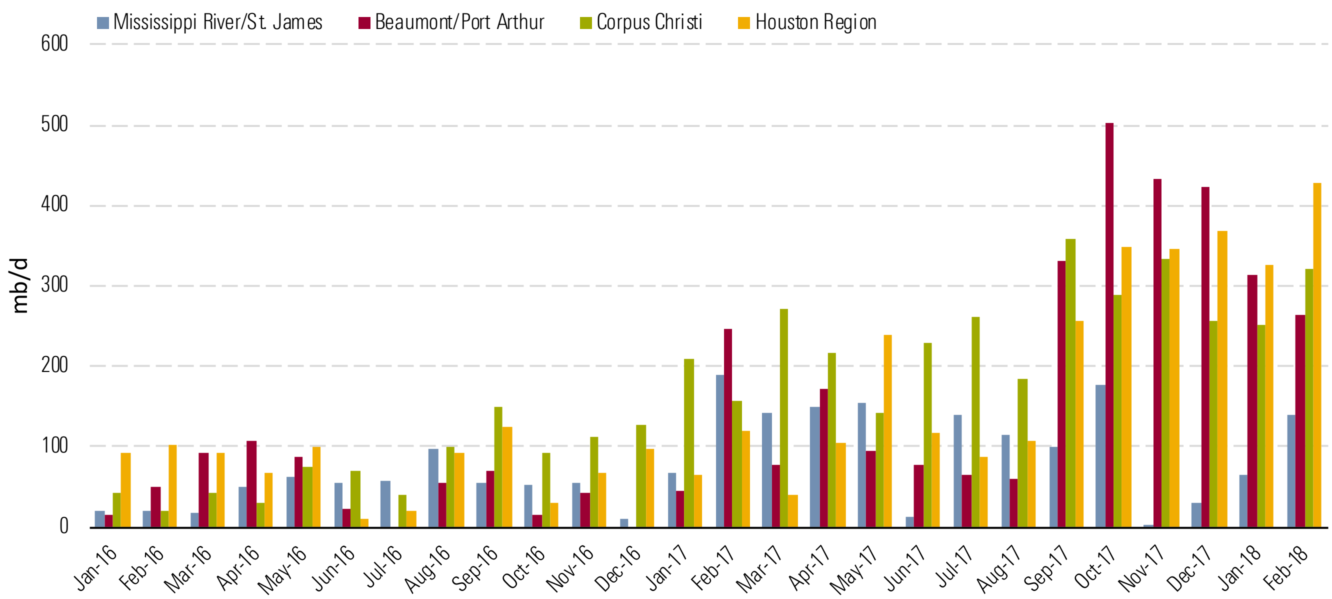
Clovelly storage is currently difficult for crude exporters to utilize because LOOP is primarily operated as an import terminal, so its distribution pipelines are directed inland. However, the LOOP owners tested export cargoes in February and March 2018 and have announced that commercial export service will begin by the end of 2018. After that, it is expected that LOOP will take on a larger role in crude exports.

Regional Refining Hubs

So far, the majority of Gulf Coast exports have been loaded onto vessels at the three Texas refining hubs of Beaumont/Port Arthur, Houston, and Corpus Christi. Smaller volumes have been shipped from St. James, Louisiana (Exhibit 6).

During 2016, Beaumont/Port Arthur and St. James each shipped 19% of Gulf Coast exports while Corpus Christi and Houston each shipped 31%. In 2017, Corpus Christi shipped 33%, Beaumont/Port Arthur 28%, Houston 25%, and St. James 14%.

Exhibit 6 Gulf Coast Crude Exports by Refining Hub Region



Source: U.S. Customs, Morningstar

Refining Hub Marine Terminals

Each of the Gulf Coast refining hubs has different strengths and weaknesses in terms of export infrastructure. We'll look at each in this section. Exhibit 7 provides a summary of marine terminals in each region, new dock projects underway, and the largest vessel that docks can load. Our estimate of total crude export capacity is based on company reports and actual shipments. The total estimated capacity is 3.8 mmb/d subject to shipping and logistic constraints.

Exhibit 7 Refining Hub Marine Terminals

Refining Hub	Number of Marine Terminals	Dock Addition Projects	Largest Laden Vessel	Estimated Export Capacity (mmb/d)
Corpus Christi, TX	11	5	Suezmax	1.0
Houston, Freeport, Texas City, Galveston, Seabrook	16	4	Suezmax	1.7
Beaumont / Port Arthur TX	6	1	Aframax	0.5
St. James, LA	6		Aframax	0.3
LOOP	1		ULCC	0.3
Total	40	9		3.8

Source: Company reports, Morningstar

Corpus Christi

Corpus Christi is home to three refineries and two condensate splitters with 840 mb/d nameplate capacity. The Port of Corpus Christi (Exhibit 8) has 11 marine terminals that can load crude oil for export, but many of these can only accommodate smaller coastal tankers or barges. The region has 18 million barrels of commercial crude storage, and plans have been announced to add another 27 million barrels in the next three years. Five new marine export docks are being built out to accommodate larger tankers for export. Corpus Christi has abundant crude supplies from the Eagle Ford production basin to the north, and several new pipelines are being built to supply crude to Corpus Christi from the Permian basin.

Exhibit 8 Port of Corpus Christi

Source: POCC

The Port of Corpus Christi is planning to deepen the existing ship channel into the inner harbor and replace an existing bridge to accommodate taller vessels. The project is designed to increase vessel draft (depth) to 54 feet to accommodate Suezmax tankers (approximately 1 million barrels crude capacity). There are larger docks in the outer harbor that can already load a Suezmax, including the Occidental Crude terminal at Ingleside. In 2018, the port announced plans to build out the Harbor Island dock in the outer harbor to accommodate very large crude carriers by 2021. It will need to dredge a channel to at least a 75-foot depth to accommodate a fully laden VLCC.

Houston Region

The hub includes the Houston Ship Channel—a bustling center of refineries and petrochemical plants just east of the city of Houston (Exhibit 9)—as well as outlying refining centers in Texas City, Galveston, and Freeport. The region hosts 2.5 mmb/d of refining capacity and boasts 16 marine docks that can handle crude oil. However, the Houston docks are close to refineries and somewhat inland, meaning that vessel drafts are restricted. The maximum laden vessel size is Suezmax. The Houston Ship Channel is quite busy and can become congested.

The Houston region has excellent crude supply from the Permian basin and the Eagle Ford by pipeline. Houston is also connected to supplies from the Rockies, North Dakota, and Canada via Cushing.

Existing regional commercial crude storage capacity is about 60 million barrels with another 26 million barrels expected to be added in the next several years. There are four marine dock expansion and new-build projects underway in the region.

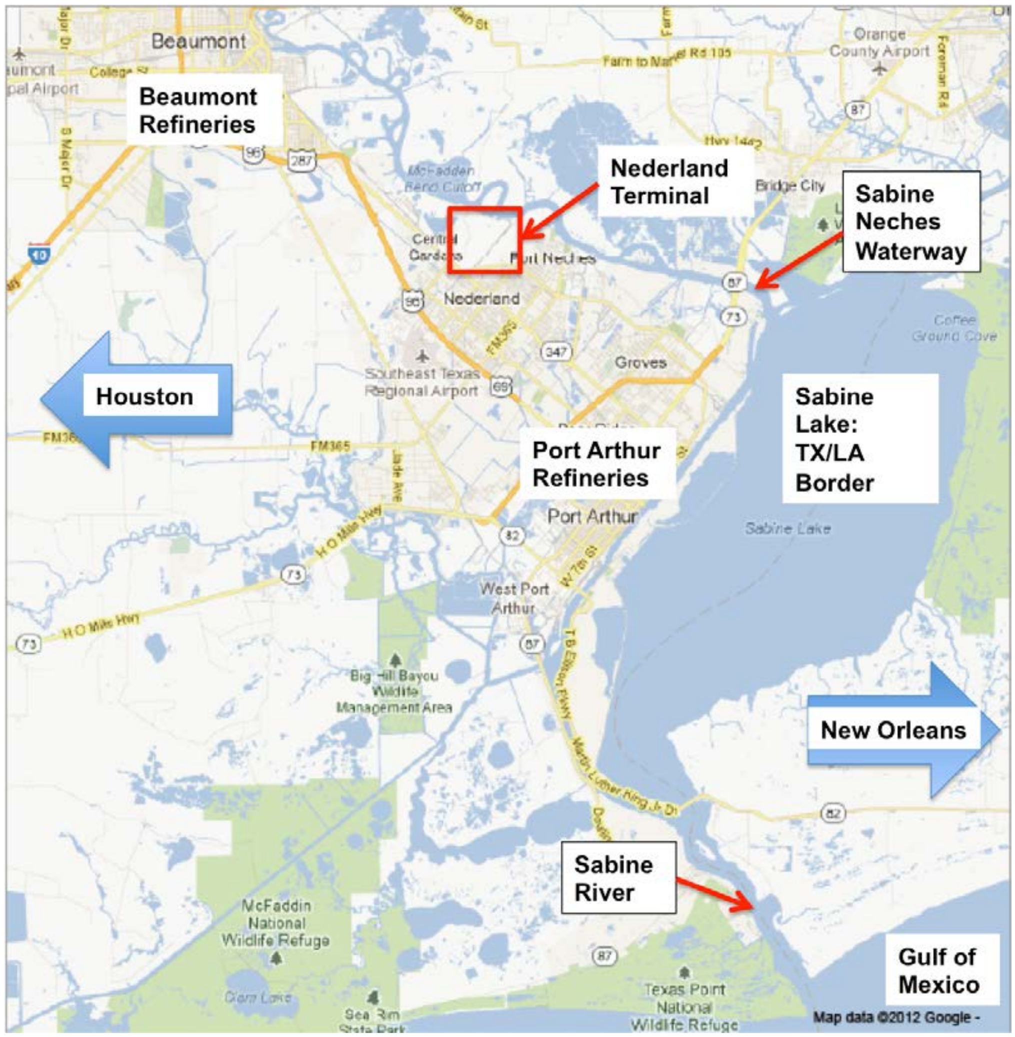
Exhibit 9 Houston Ship Channel

Source: SemGroup

Beaumont/Port Arthur

The cities of Beaumont and Port Arthur, Texas, are home to four large refineries with 1.5 mmb/d capacity (Exhibit 10).

Exhibit 10 Beaumont/Port Arthur Refining Hub



Source: RBN Energy

Beaumont/Port Arthur has six marine terminals that can export crude with one new dock project underway. A major regional export constraint is that the inland waterways can only accommodate Aframax vessels (approximately 500,000 barrels). Otherwise the region has abundant crude supply via incoming pipelines from the Permian, Houston, Cushing, and North Dakota as well as 38 million barrels of commercial storage.

St. James

Located on the Mississippi 60 miles upriver from New Orleans, St. James is a pipeline terminal hub that feeds six regional refineries. St. James is also the starting point of the 1.2 mmb/d Capline pipeline that runs north into the Midwest. St. James has six marine terminals that can load crude for export as well as 28 million barrels of storage capacity.

The region is well supplied with crude via the LOCAP pipeline, which links it to Clovelly storage and the LOOP import terminal. Inbound crude at St. James also includes offshore Gulf of Mexico production and shale supplies from Houston.

Most of Louisiana's crude exports in 2016 and 2017 came from Mississippi terminals close to St. James, including exports of Gulf of Mexico medium sour crude to Asia. However, like Beaumont/Port Arthur, St. James can only accommodate smaller Aframax tankers.

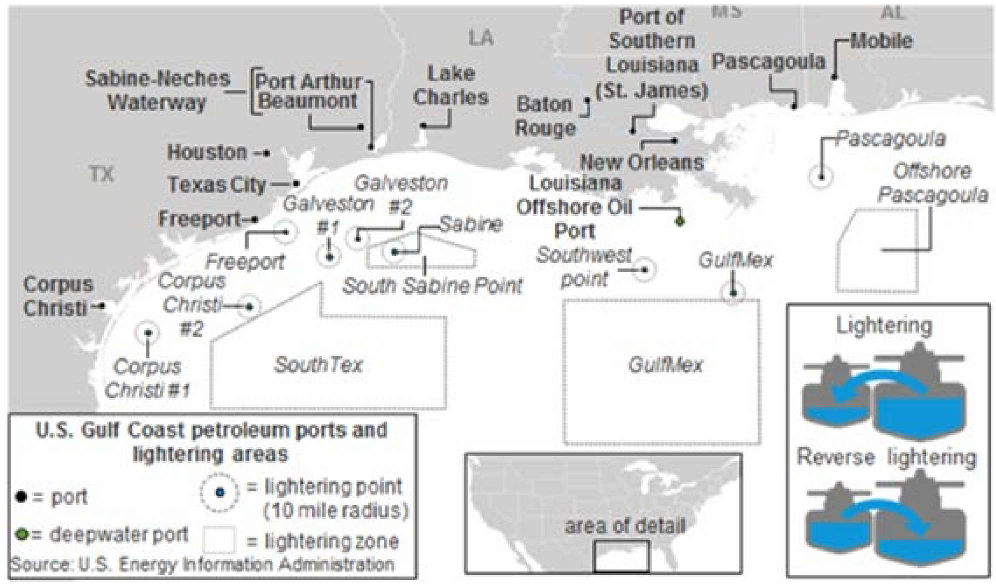
Export Infrastructure Limitations

As we've explained, the only Gulf Coast terminal that can accommodate a fully laden VLCC is LOOP, which is currently primarily used for imports.

VLCCs are the largest and most economic vessels used for crude oil transportation because they can carry 2 million barrels, reducing the freight cost over long distances. Since the bulk of growing U.S. exports in 2017 were headed to Asia or Europe, buyers prefer the use of VLCCs to keep costs down.

The major refining regions along the Gulf Coast are in inland harbors that cannot accommodate VLCC supertankers fully laden without significant channel dredging. Dredging is currently being discussed in the case of Corpus Christi but could take several years to accomplish. Instead, exporters use ship-to-ship transfers or reverse lightering to load VLCCs using smaller vessels offshore. These transfers take place in designated offshore lightering zones (Exhibit 11).

Exhibit 11 U.S. Gulf Coast Port and Lightering Areas



Source: EIA

Without the capability to directly load VLCCs at Gulf Coast docks, U.S. crude exporters are at a disadvantage to competitors since their shipping costs are higher.

To this end, the LOOP terminal is testing the capability to export VLCC cargoes. In this case, because LOOP also imports crude from VLCCs, they can take advantage of a round-trip freight advantage. That means bringing in imported crude from the Middle East and discharging at LOOP, then loading a cargo of shale for export to Asia onto the same vessel. This leaves the tanker with only one ballast leg—between Asia and the Mideast—keeping freight costs to a minimum.

Pricing and Delivery

Need for an FOB WTI Price

Most crude-exporting countries use standard pricing mechanisms to sell their crude. These mechanisms provide a starting point for negotiations between buyers and sellers. In some cases where oil is sold by a national oil company (for example, Aramco in Saudi Arabia), that company negotiates terms with all buyers. In more independent markets, buyers and sellers still adhere to standard terms and conditions such as the Shell SUKO terms used in the North Sea Brent market.

The U.S. crude oil market is largely based on pipeline transactions. Buyers and sellers negotiate contracts for deliveries of so many thousand barrels a day during a delivery month. These barrels are scheduled with the pipeline company and delivered to terminals in market centers. The pipeline tariff or freight is paid by the shipper and included in the sales price.

Cargo exports of several hundred thousand or millions of barrels of crude are generally sold free on board, meaning the buyer is required to source its own tanker and pick up the crude at the seller's terminal. Buyers and sellers negotiate an FOB price using a reference benchmark crude with adjustments for delivery time, freight cost, and crude quality.

The U.S. benchmark crude—WTI—is deliverable by pipeline to Cushing. So far, there is no FOB offshore price for WTI. As U.S. crude exports continue to grow, a FOB market price should evolve. There are already markets for WTI crude at Houston and for Light Louisiana Sweet, an equivalent grade delivered to St. James, but these are still essentially pipeline prices. Any WTI export price will ideally need to be linked to a liquid futures market but may be able to trade at a differential to Cushing.

Crude Quality

Along with an acceptable price mechanism, buyers also want to be sure of the quality of crude purchased for export. During the first year after U.S. crude exports were permitted, there were a number of export sales of a crude blend called domestic sweet, or DSW. This crude matches the specifications required to deliver crude into Cushing under the terms of the CME futures contract (in terms of API and sulfur) but is typically a blend of different crudes that sometimes contains higher levels of metals and other impurities unattractive to refiners. Cargoes of DSW rapidly gained a bad reputation among refiners, leading to buyers demanding crude that came direct from production fields, such as the WTI grade sold at the Magellan East Houston terminal.

The growth of a successful export market requires standard crude quality specifications to enable buyers and sellers to negotiate using an agreed benchmark. This desire for quality product is already recognized as new pipeline infrastructure delivering crude to export docks from the Permian now usually uses batch technology to separate different quality crude grades such as WTI and condensate so that they can be delivered intact to refiners.

Prospects for Continued U.S. Crude Exports

Export Drivers Remain in Place

Production continues to increase. EIA monthly data shows an increase of 0.3 mmb/d between December 2017 and February 2018. Weekly preliminary data shows production increasing another 0.4 mmb/d between the end of February and May 11 to over 10.7 mmb/d.

Over the same period, the Brent premium over WTI has averaged $4.65/barrel and the Dubai premium over WTI has averaged $1.55/barrel, keeping the arbitrage windows open for export cargoes to Europe and Asia.

In addition, pipeline takeaway capacity in the Permian basin at Midland, Texas, has caused West Texas Intermediate crude producers to settle for discounts to Cushing prices that have averaged $1.71/barrel—meaning that Brent prices are in effect $6.37 above WTI at the wellhead—further encouraging export sales.

The OPEC agreement continues to be successfully implemented, keeping the market for international crude supplies tight and creating demand for U.S. crude.

The U.S. government's withdrawal from the Iran nuclear deal May 11 included the reimposition of sanctions on Iran's roughly 2.5 mmb/d of exports. This supply-side threat to world crude balances has bolstered outright prices and will increase demand for U.S. supplies.

U.S. crude exports continue to be driven by the same factors that facilitated their takeoff in 2017:

- Crude prices are higher, encouraging new production.
- U.S. crude production continues at record levels.
- The Brent premium to WTI remains wider than $3/barrel.
- The OPEC agreement to cut supplies continues to be successful, and the crude market outside the U.S. is tight, providing demand for U.S. exports

Weekly EIA data shows exports averaging 1.7 mmb/d between Dec. 30, 2017, and May 11, 2018. That is double the 0.8 mmb/d average over the same period in 2017. A new weekly record of 2.6 mmb/d was set during the week ended May 11.

Infrastructure Buildout Continues

Plans to build out Gulf Coast Port infrastructure to facilitate exports continue to be announced in 2018. As detailed earlier, the Port of Corpus Christi has announced plans for the first onshore dock at Harbor Island that can accommodate a laden VLCC. Another Midstream operator, Buckeye, announced that plans for its South Texas Gateway dock at Ingleside will include a dock large enough for VLCCs.

In May, midstream operator JupiterMLP announced a preliminary plan to build a VLCC-capable marine dock in deep water 6 miles off the coast of Brownsville, Texas, during 2020. Jupiter is planning a pipeline from the Permian to Brownsville that is expected on line during the first half of 2020. Its plan is the first announcement extending the export corridor south from Corpus Christi to Brownsville.

Also during May, Enterprise Products Partners test-berthed a VLCC vessel at its Texas City dock in the Houston refining region.

Continued Exports

We expect markets to continue encouraging U.S. crude exports, provided that:

- WTI prices remain at a discount to Brent.
- The international market requires incremental U.S. production to balance demand (this may be because the OPEC agreement continues or because demand exceeds supply even if OPEC ends the accord and will also be influenced by the impact of sanctions on Iranian exports).
- Trade negotiations attempting to narrow China's trade surplus with the U.S. lead to increased crude shipments to that country
- U.S. producers maintain production growth.
- Sufficient infrastructure exists to transport crude to marine docks and load it onto tankers.

Infrastructure Constraints

Infrastructure constraints are emerging in the Permian basin, where takeaway capacity for rapid production growth has become congested. As we've mentioned, these constraints cause price discounts that further encourage export shipments, but they also restrict flows to export docks.

Other infrastructure constraints may emerge in terms of adequate dock construction and channel depth.

Development Watch

As U.S. exports develop into a permanent fixture of the international market, we expect the following developments:

- Infrastructure to load VLCC cargoes from docks in Corpus Christi and the Houston region.
- The LOOP terminal will become an important crude export center.
- A transparent U.S. export crude price marker underpinned by a futures contract.

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