
Oil special report
October 2018
FOREWORD

S&P Global Platts Analytics predicts US crude oil exports will hit nearly 4 million barrels/day in 2020.

The growth in the United States’ tight oil in recent years has long drawn comparisons with the oil rush of John D. Rockefeller’s day: the nexus of advancing technology, high prices and strong demand has been seen before, and like the 19th Century oil boom, its impact will be felt for years to come.

The fact that the world’s largest oil consumer has more than doubled its own crude production to become the largest oil producer would be remarkable enough; the fact that it managed it in just seven-and-a-half years is truly historic. Since January 2011, the world has watched as the United States emerged from the financial crisis with nothing short of a petroleum revolution. Funded by $100+/barrel oil prices for much of 2011 to 2014, technological progress saw off the production share challenge of OPEC until the cartel was the first to blink in 2016, after calling in as many as 12 non-OPEC countries for help. That orchestrated cut has gradually increased prices two-fold and re-established OPEC’s relevance in the global oil markets.

But now it’s going global and long-established trade flows have drastically changed. Ten years ago, Nigeria used to send well over 1 million b/d to the US but now that light sweet crude has been all but completely displaced by home-produced American oil. It has had to look for new homes, with prices slashed as a result. Those who relied on the US to suck in barrels have increasingly had to look east and now find themselves competing with American oil, be it sweet onshore crude, or even the sourer Mars from offshore the US Gulf Coast.

International crude oil benchmarks have also seen an impact. The rise of crude exports from the US has re-established West Texas Intermediate’s (WTI) credentials as a global benchmark, its relationship with the North Sea’s Dated Brent ever more relevant. However, traders are not just talking about Brent/Dubai or WTI/Brent spreads: given strong Chinese, Korean and Japanese demand, the interest in the WTI/Dubai spread appears irresistible.

As for Europe, the US is now sending over 500,000 b/d of crude, a number that will only rise in the near term. In response to growing European imports from the US, S&P Global Platts recently launched assessments for major light sweet grades Eagle Ford 45 and WTI Midland for delivery into major European refining hubs.

In this special report we assess the local and global impacts of the US’s crude exports, tracing their path from the Permian Basin and Bakken Formation, through the myriad tendrils of the country’s vast pipeline network, and out to the regional demand centers that now have a taste for American oil. We look at the changing trade flows, the complex quality matrix across US grades, and the possible impact of increasingly tough trade negotiations. That all of this is occurring against a fast-changing backdrop of sulfur regulation in the shipping industry only serves to make it even more interesting.

The story of US exports is a tale of democratized production, disrupted flows, and displaced crudes. The challenges and opportunities it presents are countless.

— Joel Hanley

INTRODUCTION

On December 31, 2015, a cargo of US Eagle Ford light oil set sail from the US Gulf Coast’s Corpus Christi port on board the Theo T oil tanker. About 20 days later, the ship arrived at the French Mediterranean port of Fos-sur-Mer.

Bar a few exempted shipments of condensate, this was the first cargo of US crude to leave the US Gulf Coast for nearly 40 years, overturning restrictions that had initially been implemented as a safeguard against the volatility seen during the OPEC oil embargo in the 1970s.

As domestic production soared, US crude output was nearing 9.5 million barrels/day by 2015 – a level unseen since 1972. US commercial crude stocks had reached record highs and the country’s refining industry boasted modern plants geared towards refining heavier, more sour grades. This refining structure was out of sync with the boom in production, which was mainly of lighter, sweeter crude from unconventional shale basins.

With no obvious outlet and production only accelerating, all of this oil just started to accumulate. And it just kept on accumulating, putting pressure on US crude prices despite the country’s continued reliance on foreign oil. US prices remained largely disconnected from the global market, and stocks remained elevated.

However, in December 2015, the US Congress voted to lift the long-standing export ban, tacking it on to a must-pass spending bill, and the gate was lifted. Within two years, US crude exports totaled more than 1.1 million b/d and had found their way into 37 countries – the biggest buyers being China, the UK and the Netherlands.

In short, it didn’t take long for US crude exports to go from virtually unheard of in the early-2010s to an unmissable
component of international crude trading. And the story is not over, as US crude exports are expected to grow further as production continues to climb and the US moves to revamp its infrastructure system away from handling imports and towards the global market.

**US CRUDE GOES GLOBAL**

It was only 10 years ago US crude production hit its then recent-historical nadir of just over 3.8 million b/d. The global economy was rapidly slowing, and energy prices were tumbling. Still, at the end of 2008, the US government projected modest gains in US crude production for the following year to 5.25 million b/d despite the unfavorable crude price environment – “the first production increase since 1991,” as the Energy Information Administration put it at the time.

Crude production did rise. And it continued to rise, well beyond the EIA’s expectations. Driven by technological advancements in drilling and well completion, US crude production averaged 7% production growth each year from 2009 to 2017 and production is only expected to continue growing. S&P Global Platts Analytics projects US crude production to average 10.8 million b/d in 2018, 11.6 million b/d in 2019 and 12.3 million b/d in 2020 – a more than three-fold increase from that September 2008 low.

The rapid rebound in crude production has meant that all of this volume has to go somewhere. In December 2015, US legislators pushed to eliminate 40-year-old restrictions on crude oil exports, opening up US grades West Texas Intermediate, Bakken, Eagle Ford, Mars, Thunder Horse and more to the rest of the world, where it has been received around the globe. US crude exports in total now average about a VLCC or more per day, and Platts Analytics projects exports (excluding to neighboring Canada) are expected to rise to 2.2 million b/d in 2019 and 3.9 million b/d in 2020.

What is US crude and where is it coming from?

Thirty-two of the 50 US states produce crude oil. Texas and North Dakota together account for half of the US total. California and Alaska, once major producers, have seen their shares of total crude production dwindle, while Colorado and New Mexico are on the upswing. This change has altered the dynamics of the crude market within the US as well as the different qualities of the oil being produced.

Currently, the most-dominant production plays are in the Permian, the Gulf of Mexico, Eagle Ford, Bakken and Niobrara. Together, these six production centers account for about 75% of total US crude oil production.

**Texas, the Permian, and WTI**

In the general sense, the word “Permian” refers to a large geographical area that covers most of West Texas before extending into southeastern New Mexico. The larger Permian region accounted for more than 25% of total US crude oil production in 2017, more than any other play in the US. Currently, crude oil production averages approximately 3.4 million b/d and production is likely to continue to grow as investment in the area outpaces investment in other regions.

In practice, the Permian is made up of a few distinct basins: the Midland, the Delaware and – in between the two – the Central Basin Platform. Each of these basins can be split into smaller areas like Bone Spring, Wolfcamp and Spraberry, which refer to individual formations. Crude quality at each formation can vary.

Outside of the US, “Permian” is often used interchangeably with “West Texas Intermediate”, the flagship light sweet US grade of oil produced in the basins and the grade that lends its name to the major futures contract.

However, not all of the oil in the Permian is WTI. Although WTI makes up the bulk of Permian production, the range of qualities coming out of the ground is extensive and varied. Most of this oil is blended up or down to meet certain specifications. Usually these individual qualities are blended to make WTI, but they can also be mixed differently to make West Texas Sour, a grade almost exclusively consumed by regional refiners. In the future, as Permian production continues to increase and the pipeline infrastructure in the region develops further, it is possible that still more nuance may be added to the crudes produced in the region, potentially leading to the introduction of new blends like WTI Midland Light or WTI Midland Super Light.

WTI is less a specific crude and more a general framework for a crude. The specification that defines it is loose and is

![US CRUDE PRODUCTION BY FIELD/GRADE SHARE OF TOTAL, 2017](chart.jpg)
not owned or managed by a single entity. The term itself is historic and well-established; S&P Global Platts first used the term in 1952.

At its most basic level, WTI is a light, sweet crude, but its characteristics have evolved over time. Historically, WTI had an API in the high 30s but, over time, it has become lighter and sweeter; these days, WTI generally has an API in the low 40s, though unblended barrels in the Basin can still be found with lower API values.

It is, without a doubt, the dominant export crude, but remains one of the most difficult to define, particularly outside of the US where its broad geographic reach and long history can sow confusion around terminology. Whereas, for example, Mars is produced offshore, moved along one pipeline to a terminal and then exported, WTI has a dizzyingly large number of avenues by which it can arrive at a Gulf Coast dock for export. This has led to the proliferation of subterms like “WTI Midland Cactus” and “WTI Midland Bridgetex” which are intended to clarify the route each barrel took to the USGC.

**Offshore Gulf of Mexico**

The US Gulf of Mexico accounts for about 18% of US crude production, making it the second largest source in the US. This crude is primarily sour, and the most-liquid grades are medium crudes Mars, Poseidon, and Southern Green Canyon, while Thunder Horse skews lighter. The majority of these grades are delivered into Louisiana, where they can be exported from St. James or the Louisiana Offshore Oil Port. The lone exception to this is Southern Green Canyon, which is delivered either into Port Arthur—Nederland or into Texas City, which lie on opposite sides of Galveston Bay.

Like WTI, these crudes are blends from multiple wells in several fields. Amberjack, the grade shipped along Shell Midstream Partners' Amberjack Pipeline, can take half-a-dozen routes between origin and endpoint. The pipeline system begins by collecting crude from the Jack St. Malo, Tahiti and Stampede fields (among others) before moving the oil to a processing facility called Green Canyon block 19, or GC19 for short. From there, Amberjack can take the 100,000 b/d Boxer Pipeline (when it becomes Eugene Island crude); or, it can move to Ship Shoal 332 A and B and onto

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**MAJOR CRUDE PIPELINE CONNECTIONS TO US GULF COAST AREA TERMINALS AND REFINERIES**
the 350,000 b/d Poseidon line (when it becomes Poseidon) or the 500,000 b/d Cameron Highway Oil Pipeline System, or CHOPS, (when it becomes Southern Green Canyon); or, it can connect with the Mars system at Port Fourchon, Louisiana (when it becomes Mars). The possibilities aren’t necessarily endless, but they are certainly up there.

Of the crudes produced in the Gulf of Mexico, only Mars is really seen in the export markets, though the odd cargo of Poseidon and Southern Green Canyon has found its way into the Asian refining market. Much of this production is consumed within the large Gulf of Mexico refining market where demand is skewed towards heavier barrels, which often makes the local market significantly more competitive than the export market.

**Bakken and the Rockies**
The Williston Basin stretches from Saskatchewan and Manitoba in Western Canada south into North Dakota, South Dakota and Montana. Within the basin are the Bakken and Three Forks formations, often lumped together as “Bakken.”

In 2017, the Bakken accounted for 12% of US crude production, with the bulk produced in North Dakota. Bakken crude typically has an API of between 41–43.7 degrees and a sulfur content of 0.12% sulfur, which classifies it as another light, sweet barrel in the vein of WTI. Its importance in both the domestic and international markets has grown significantly since the start-up of the Dakota Access Pipeline (DAPL) and its southern leg, the Energy Transfer Crude Oil Pipeline (ETCOP) in June 2017. Together, these form a 520,000 b/d system that moves the oil from the Williston Basin up near the US border with Canada, all the way down to the Texas Gulf Coast at Beaumont and Nederland.

The system transports Bakken in a one-in, one-out manner, meaning oil is commingled in the line, rather than batched. The availability of Bakken for ex-USGC export depends

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**How is US crude being exported?**

Congress’ vote in December 2015 to remove the long-standing restriction on US crude exports was sudden but – and hindsight is always 20/20 – probably inevitable given the massive surge in production, particularly at Bakken and Eagle Ford. Indeed, the US Commerce Department OK’d the export oil that could be classified as condensate even though the line between what defines a “condensate” and what defines a “crude” is pretty fluid. Consequently, the notable part of the export story is not so much that it’s happened, but that US waterborne crude exports have become such a force in the global markets quite so quickly. The US suspended exports more than four decades ago, but in the two-and-a-half years since they have resumed, volume has surged and an entire host of infrastructure projects has flourished to support it.

Current US Gulf Coast waterborne crude export operating capacity is estimated at 4.815 million b/d, more than double what is currently being exported, Platts Analytics data show. Texas accounts for 3.925 million b/d of this total, with Louisiana picking up the balance of 890,000 b/d. Within Texas, the Greater Houston area accounts for about 2.013 million b/d of capacity while Corpus Christi/Brownsville region to the southwest, which handles exclusively Eagle Ford and Permian crude, can handle about 1.106 million b/d.

Cargo sizes loaded at different terminals along the Gulf Coast can vary pretty significantly depending on each port’s capacity. WTI Midland, the primary grade being exported to Europe, for example, has cargo sizes ranging anywhere from 550,000 barrels (loading at Nederland) to 700,000 barrels (loading at Corpus Christi) with a few different sizes in between.

Most of the US exports that make their way into Europe are done on Aframax vessels, which can load directly at any of the terminals, though the odd Suezmax cargo has also made its way across the Atlantic, though not usually fully laden. Vessel sizes exporting to Asia tend to be more varied, but are also often smaller than what you would expect given the distance between the US Gulf Coast and Southeast Asia.

The only US port currently capable of loading a fully laden VLCC is the Louisiana Offshore Oil Port, or LOOP. This has, consequently, made it necessary for many sellers to turn towards reverse lightering using Aframax or Suezmax vessels to load full-sized VLCCs in a few, select offshore lightering zones. This can be expensive and often time consuming depending on the weather, which must be factored in to the cost of export.

Although LOOP can handle VLCC exports, its status as the main artery for crude inflows into Louisiana means the terminal can only export when it isn’t importing, which further limits the number of VLCCs that can currently be exported out of the US Gulf Coast. Indeed, fewer than half-a-dozen VLCCs of US export crude have loaded at LOOP, despite the expense incurred by reverse lightering.

It is likely that more terminals could join LOOP in handling VLCC exports in the future. Tallgrass Energy in August announced its plans to build a terminal in Louisiana that could handle VLCC exports by Q3 2021 and other companies have followed suit. Enterprise Products Partners and Jupiter have announced plans to directly load VLCCs off the coast of Texas, though there has not yet been a date attached to it, and there has been chatter in the larger market that international tank operator Oiltanking is also working on a project based in Texas, though nothing has been officially announced.

Finally, Enterprise has been testing partially laden VLCC exports at Texas City while Occidental is modifying its Oxy Ingleside Energy Center terminal at Corpus Christi to handle partially laden VLCCs. (As of publication, the terminal and other assets are in the process of being sold to Moda Midstream in a $2.6 billion deal expected to close in 2018.)
in large part on US Midwest refiners who have increased their demand for Bakken at the expense of Light Louisiana Sweet, a US Gulf Coast blended barrel that moves from St. James north to the Midwest market via the Capline pipeline. Currently, Midwest refiners have the option of running Canadian crudes, Bakken and LLS. Their rising demand for Bakken pulled off the DAPL-ETCOP system at Patoka, Illinois – effectively the halfway point of that system – can, at times, lead to a significant reduction in Bakken flows to the USGC.

There is also a developing crude oil market in the Niobrara region of Wyoming and Colorado, which accounted for about 5% of US production in the most-recent calendar year, making it on-par with Alaska North Slope (ANS), California, and Anadarko in Oklahoma and the Texas Panhandle in terms of production. Given their relative sizes and Niobrara’s comparative newness, it tends to take its pricing and delivery cues from the nearby and larger Bakken market. The most popular area within the Niobrara is the Denver-Julesberg basin.

Because of the distance between origin and point of export and the resultant expense, Bakken has so far remained a small player in the US export crude market out of the US Gulf Coast, though there has been speculation that this could change as the infrastructure system between Bakken and the Gulf continues to expand and improve, providing additional routes for the barrels to take.

**Eagle Ford**

Producing roughly the same volume as the Bakken, the Eagle Ford shale play in south Texas extends northeast into the US from the Mexican border. In 2017, it accounted for 13% of total US production.

While the play itself is large and productive, the varying quality that can come out of each individual well has proved a challenge in the development of a strong export market. While Eagle Ford is always sweet, its API gravity can oscillate wildly, which means that buying it can be a bit of a gamble. Across 24 separate assays available to Platts, Eagle Ford’s API gravity ranged between 39 degrees to a whopping 63.8 degrees, which is not even classified as a crude oil. The variance starts at the wellhead, making it difficult to manage through the blending of different streams, leading to the development of labels for individual streams: Eagle Ford 45 (crude), Eagle Ford 52 (condensate) and, rarely, Eagle Ford 60 (“chemical-grade”).

Eagle Ford’s relevance as an export crude is increasing as more buyers outside of the US familiarize themselves with the grade’s idiosyncrasies. The greater specificity that is introduced by labeling the barrels being exported as “Eagle Ford 45” or “Eagle Ford 52” allays some of the concerns around quality consistency, but not all of them. However, as production continues to increase, the stream of exports is expected to continue to grow.

**US CRUDE FLOWS TO EUROPE**

Throughout the whole of 2017, US crude exports to Europe averaged more than 290,000 b/d, largely increasing month-on-month throughout the entire course of the year. By comparison, US exports were non-existent in 2013.

And this flow has only increased. Over the first seven months of 2018, more than 500,000 b/d of US crude made its way to Europe, exceeding in volume every single crude grade produced in the North Sea, as well as most of the Mediterranean grades, including the size of Urals exported out of the Black Sea port of Novorossiisk. At its peak, the US was sending as much as 700,000 b/d to 900,000 b/d of a mix of WTI Midland, Eagle Ford and Mars into the European market – or more than one Aframax a day.

This boom has been made possible in part to cheap freight, but it has largely been driven by Brent’s heavy and persistent premium to WTI. Global crude oil trading is really defined by the three benchmark markets, Brent, WTI and Dubai and how they interact, and throughout the
first half of 2018, Brent – the most internationally leaning of the three – climbed relative to the other two, as global markets were spooked first by the re-establishment of sanctions against Iran and then by the onset of a global tariff war.

As a result, US barrels slowly crept into the European market, where they started filling the gaps left by the flight of increasingly large volumes of local crude grades towards the Far East. Thus, as crude markets became more and more interconnected, US crude evolved into an integral component of the European refining landscape.

It is no longer possible to discuss the European oil markets without considering the region’s interaction with the rest of the world, including the US. After the ban on US exports was lifted in 2015, cross-Atlantic flows were facilitated by the widening of the spread between the two regional pricing points – WTI and Brent. As production outpaced takeaway capacity from the prolific Permian Basin in West Texas, the creation of a local glut resulted in downward pressure on WTI in the key Cushing hub, the delivery point for NYMEX light sweet crude.

From the second half of 2017 onwards, WTI sank more than $4/b below Brent, having traded within a $0-4/b discount to the European benchmark since Q3, 2015 and throughout 2016. More remarkably, the WTI-Brent spread briefly stepped into double-digit territory in late May/early June 2018 in a move unseen since early 2015.

Not incidentally, US Energy Information Administration data showed US crude averaged at almost 2.2 million b/d in June 2018, the all-time highest monthly level. In comparison, US crude exports stood at around 1.1 million b/d in 2017 on average.

Beyond mere economic considerations, the rise in flows to Europe coincided with a willingness in the local refining sector to diversify supply away from traditional North Sea, Mediterranean and Russian grades as they became more readily available and cost-effective.

Even though a European refinery received the first US export cargo, European refiners were slow to adopt US crudes as widely as many of their Asian competitors.

Indeed, as with any new barrel, running US crude required some getting used to. European refineries are typically older and less complex than the average US Gulf Coast refinery, implying less flexibility in handling diverse grades and blends. European refiners have been known to be more conservative in their approach to selecting crude and tend to favor tried and tested grades over riskier, yet potentially cheaper options. Alternatively, some may opt for slightly pricier barrels so long as they come with added transparency on blending processes and reduced contamination risks.

In the early days of US crude exports, European refiners ran into a number of issues. Initially, the lack of quality consistency across batches and the metal content – in particular iron – caused headaches, prompting some to provision multiple linear programming models for a single crude grade. However, market participants noted an improvement over time, as US crude marketers worked to offer a more consistent oil quality. Ostensibly, US barrels have now become an integral part of the European refining diet and increasingly compete with other traditional sources of light, sweet crude supply in the region. WTI Midland has at times been compared with Norway’s Ekofisk for its quality, but refiners also rate it against West African crude which trades on a similar calendar, as well as Mediterranean light, sweet barrels. Not so surprisingly, the Netherlands and the UK – which aggregate the largest share of Northwest Europe’s refining capacity – and Italy in the Mediterranean have attracted the bulk of US volumes to Europe in recent months.

US crude flows to Europe are largely dominated by WTI Midland, which market sources said represents an estimated 65% to 75% of the volumes shipping in from the Gulf Coast. In addition, three to four cargoes of Eagle Ford crude have been said to make the voyage each month, together with the odd cargo of Bakken crude. Domestic

Continued on page 9
Platts US Gulf Coast crude delivered to Europe

The assessments, which are published both as a differential to Dated Brent and on an outright basis, are in response to a growing appetite for transparency around US crude exports to Europe on both sides of the Atlantic. US exports – mainly of WTI Midland and Eagle Ford 45, but also with some Mars and Bakken thrown in – now total some 500,000 b/d, a number that is expected to only grow over the coming years. Those volumes exceed many shorter-haul, local streams in both Northwest Europe and the Mediterranean, making US crude the de facto swing barrel in the European refining diet.

What is Platts actually assessing?
Platts is now publishing daily, spot market assessments for Aframax-size cargoes of WTI Midland and Eagle Ford 45, each DAP basis Rotterdam and Augusta. They are available in Crude Oil Marketwire, on Platts Global Alert pages 1238 and 1239.

WTI Midland in particular is now a major source of crude oil supply in Europe, and Platts assessments reflect standard Midland quality. While Midland quality can sometimes vary between loading terminal, “WTI Midland” reflects a consistent, unblended grade sourced from the Permian Basin. Similarly, Platts assessments of Eagle Ford 45 reflect standard quality for that stream of Eagle Ford crude, and not Eagle Ford Condensate, which is commonly known as “Eagle Ford 52.”

Currently, Platts is only assessing WTI Midland and Eagle Ford 45. While other US crudes – particularly Mars – have been offered in Europe or exported in smaller quantities, they have not yet achieved the same sustained export flow that WTI and Eagle Ford have managed.

Platts has elected to assess US crude delivered into both Rotterdam and the Mediterranean separately in order to best capture the divergence between regional demand in Northwest Europe and the Mediterranean. As is the case in other crude markets in Europe, this is a “basis” port assessment, meaning that other reasonable ports may be nominated, with the buyer managing any additional deviation costs.

How far forward does this market trade?
Platts assessments reflect US crude delivered between 20 days and 60 days from date of publication. As a delivered, longer-haul market, US crude tends to trade further forward, and in line with the US pipeline trading cycle. Most of the indications that Platts has seen so far in the Platts Market on Close assessment process have delivery ranges of between 30 and 45 days forward, but Platts understands that crude often trades as much as two months in advance of delivery. Similarly, as the market continues to evolve and more crude becomes available, the delivery window for US crude is likely to move further forward.

The average voyage time from the US Gulf Coast to either Rotterdam or Augusta is typically around 20 days. Consequently, the Platts assessment range will both capture cargoes still to be loaded as well as recently-loaded volume.

Why a DAP assessment?
DAP – or “delivered at place” – is the term that the International Chamber of Commerce has used to replace “DES” or “delivered ex-ship.” Platts understands that DAP is the standard way of trading longer-haul delivered barrels like US crude, thereby limiting buyer exposure on longer-haul journeys. While some transactions are still conducted on other delivered-bases, Platts sees DAP as the standard trading practice in this market. The ICC defines DAP as:

“Delivered at Place’ means that the seller delivers when the goods are placed at the disposal of the buyer on the arriving means of transport ready for unloading at the named place of destination. The seller bears all risks involved in bringing the goods to the named place.”

What pricing basis and pricing terms do the assessments reflect?
Platts assesses US crude delivered in Europe as outright prices and as differentials to Dated Brent. While other options may be published in the MOC process, standard pricing reflects bids and offers pricing 2-1-2 around COD as standard, with the middle date of the five-day laycan typically viewed as the date of COD. These pricing terms and pricing basis are line with North Sea crude oil instruments thus offering easy comparison across instruments while respecting common market practices.

Cargo size and operational tolerance
Platts assesses a standard 600,000 barrel cargo with 5% operational tolerance. US export infrastructure currently only really supports Aframax-size shipments of crude to Europe, with the occasional Suezmax-size cargo also finding its way into the export market. The exact volume of these specific cargoes can vary depending on load terminal, ranging from around 500,000 barrels all the way up to 800,000 barrels, but Platts sees the majority of the market falling between the 500,000-700,000 barrel range.

Platts will publish bids and offers for any cargo within this range, but will normalize this volume back to a 600,000 barrel standard.

Asia remains a key destination for US crude oil exports. To date in 2018, approximately 21% of all US crude exports have moved to China, up slightly from 2017, and up significantly from the 8.9% seen in 2016, according to data from the US Energy Information Administration. Of the 385 million barrels of crude exported by US from January to July of this year, about 165.5 million barrels had been exported to Asia.

The main driver for the uptick in US crude flows to Asia at the start of 2017 was simple economics. The price of Middle East crudes, the baseload feedstock for many Asian refiners, rose significantly following the announcement of the OPEC/non-OPEC production cut deal, causing the price of these barrels to spike relative to the lighter, sweeter barrels available from the US. While Asian refiners had already been moving to diversify their crude purchases, the spike in the Middle East market as production began to dip significantly hastened their efforts.

As the Middle East crude benchmark Dubai strengthened against US crude benchmark WTI, the spread between the two flipped from discount to premium, making US crudes more appealing to Asian refiners. Meanwhile, Europe's Brent benchmark remained strong, which increased the appeal of US crudes over alternatives from West Africa or the Mediterranean.

Indeed, the story behind US crude imports to Asia has always been a story about benchmarks, particularly the spread between WTI in the US and Dubai in the Middle East. Traditionally, Dubai has priced at a discount to WTI – unsurprising given that it’s heavier and more sour and historically, there has been more of it around – but those spreads have flipped, turning the market on its head.

The spread between WTI and Dubai has continued to stay at a deep discount after it first flipped from premium in January 2017, hitting a record average low $6.57/b in September this year, according to S&P Global Platts data.

Over the first nine months of 2018, WTI's discount to Dubai has averaged $3.39/b compared with a discount of $1.89/b for the whole of 2017 and a premium of $2.46/b for the whole of 2016.
US crude active in most corners of Asian refining market
As the region’s largest buyer of crude generally, China has emerged as the largest single buyer of US crudes in Asia, though that may change in the future. In 2017, China took approximately 81 million barrels of the 148 million barrels the US exported to the region, accounting for more than half of all US crude imports.

By contrast, China imported just 7.9 million barrels of crude from the US in 2016 following the lifting of the US export ban.

The future of US crude imports in China, however, has been thrown into doubt as the escalating tariff battle between the two countries continues to unfold. The country’s biggest buyer, Uniper – the trading arm of state-owned Sinopec – made its single largest purchase of US crude in June this year, buying 16 million barrels of WTI Midland, Bakken, Eagle Ford and US Domestic Sweet (DSW) shortly ahead of President Donald Trump’s announcement of new tariffs on Chinese-produced goods.

Over the first five months of 2018, before the trade war, EIA data showed that China had imported 52.8 million barrels of US crude, putting 2018 on pace for another year of record imports. However, while US crude has not yet been officially impacted by the growing number of tariffs on US goods, buyers have already started to shy away from US barrels. Even Uniper has been selling off some of what it purchased in June’s massive order back out into the Asian spot market. (See panel on page 11 “US-China trade war”).

Meanwhile, South Korea, the second largest recipient of US crudes in Asia last year, has shown no sign of slowing down its purchasing. Over the first seven months of 2018, the US exported 27.2 million barrels of crudes and condensate to South Korea, already more than the 21 million barrels imported for the whole of last year.

South Korean interest in light, sweet crudes from the US is likely to expand further over the second half of this year as end-users have actively sought to find alternatives for Iran’s South Pars condensates. The start-up of new condensate splitters in Iran has tightened physical availability of these condensates, and the resumption of US sanctions against Iran in early November is likely to further impact the availability of these condensates in the spot market.

Other Asian countries are also set to post record imports of US crudes in 2018. In particular, US crude imports to Taiwan and India for the first seven months of 2018 have already exceeded the total volume they imported for the whole of 2017.

Taiwan imported a total of 16.4 million barrels of crudes from the US from January to July this year, more than three times the 4.8 million barrels it imported last year, according to the EIA. US crude exports to India for the first seven months of 2018, meanwhile, stood at 19.2 million barrels. In comparison, the country took 9.6 million barrels of US crudes for the whole of last year.

US crudes add variety in Asia-Pacific crude markets
Given that about 70% of US crude production – and nearly all the exports – consists of low sulfur crudes and condensates, the uptick in US crude exports has had its most significant impact on the Asia Pacific sweet crude market. US barrels compete in Asia primarily with Australian and Malaysian light, sweet barrels, though the scale of the impact has not been uniform across crude grades.

Differentials for most of the Australian light sweet crude grades have declined amid increased competition, as have levels for a number of Malaysian crudes, particularly those grades not included in the Malaysian crude pricing basket. By contrast, however, the differentials for the Malaysian basket crudes themselves – Labuan, Miri, Kikeh and Kimanis – have remained resilient thanks to a limited spot market and their high middle distillate yield.

However, Asia’s refiners have been taking in a growing number of crudes via tender, which has been displacing demand for regional and extra-regional grades of similar quality. Thailand’s PTT has been purchasing US crudes via its monthly tender, taking a range of crudes including Bakken. Thailand imported around 7.5 million barrels throughout the first seven months of 2018; in 2017, it imported 5.8 million barrels of US crude in total.
Indonesia's Pertamina bought its first cargo of Eagle Ford condensate in May for July delivery, an incursion into the Asian market that caused Australia's North West Shelf differentials to drop from a premium of $1/b to Dated Brent in May to a discount of $1/b in June.

Asia's growing interest in US crudes has also had a knock-on effect on light, sweet barrels from West Africa, particularly Nigeria. Historically, Nigeria has been a major supplier of crude into Asia's tenders, but many formerly-stalwart buyers have shifted increasingly towards US volumes. No one company perhaps encompasses this shift more perfectly than Taiwanese refiner CPC, formerly a faithful buyer of Nigerian barrels, which has almost exclusively taken WTI Midland in its recent tenders.

While most of the impact of US flows has been felt on the sweet side of the market, sour crude grades originating in the US have also made inroads into Asia this year, as fluctuating prices of underlying markers such as WTI and Dubai made creative arbitrages possible in 2018. Additionally, renewed US sanctions on Iran have prompted lifters of Iranian crudes to look elsewhere – including to the US – for alternatives.

Most recently, Taiwan's Formosa Petrochemical Corp., bought 1 million barrels of Mars for delivery at the end of September through mid-October. Malaysia's Petronas also received its first cargo of US Mars crude in August, the latest in a string of refineries in Asia to do so. Mars crude continues to see active inquiries from Asian buyers looking for alternatives to Middle Eastern crudes, Mars, which has an API gravity of 29.44 and sulfur content of 1.96%, is widely seen as a fungible grade for Middle Eastern medium sour crudes. However, Mars itself remains in high demand in the local US market, which can limit the number of cargoes available for export to Asia.

The amount of crude flowing from the US to India has spiked sharply this year from an average of 29,000 b/d in January through April to 152,000 b/d in May and then up to 261,000 b/d in June. There are indications that the increase in flows of US crude to India will continue as renewed US sanctions on Iran will put pressure on importers of Iranian crude. Iran is the third biggest source of oil for India, accounting for some 160 million barrels of the country's crude imports each year. In July, state-owned Indian Oil Corp signed a deal to buy 6 million barrels of US crude across three VLCCs for delivery in November, December and January.

Nonetheless, despite an arbitrage that almost always looks open on paper, there is a limit to how much US crude can be absorbed within the region. This is due to two related, main factors: the somewhat restricted and sporadic nature of spot market demand in a region where supply is often governed by multi-year term contracts; and, more significantly, local refinery configurations and the crude slates they rely on.

US-China trade war: Consequences for crude

China announced retaliatory tariffs on an additional $16 billion worth of US imports on August 8. This new list of affected goods in the escalating trade war between the US and China included new import taxes on oil products, LPG and coal but, unexpectedly, did not include widely anticipated import duties on US crude.

This was nothing if not a surprise. The Chinese Ministry of Commerce's initial proposal regarding retaliatory tariffs, which had been announced in mid-June, had specifically called out US crude as a target for new taxes, prompting many Chinese buyers to pull away from the market.

Instead, the decision announced in early August, to be effective from August 23, imposes 25% tariffs on a swathe of energy commodities including “asphalt shale, oil shale and tar sand,” but omits the previous reference to US import barrels.

US crudes have become an increasingly important part of China's massive import crude diet and a sudden change in tax policy could have major consequences on the health of its refining sector. Consequently, removing the US crude reference from the tariff list likely reflects China's energy security concerns, particularly since there appears to be no intention to stop importing Iranian crude after US sanctions snap back on November 4.

However, the absence of US crude from China's latest round of retaliatory tariffs has done little to revive buying interest from Chinese refiners who have continued to cut back on US crude purchases, wary of the unpredictability of the ongoing trade dispute.

Oil traders have said they see the removal of US crude from the tariff list as temporary and not indicative of normalizing relations, or of crude oil being taken off the table in the US-China trade war. This means that any new commitments to purchase US crude are fraught with risk, and new deals are unlikely to happen unless alternative safeguards can be put in place to guard against uncertainty.

But while the trade war has had a significant impact on crude imports to China, the region's largest importer and consumer, it hasn't necessarily translated in as big of a dent in the volume of crudes being exported to the Asia more generally. China may be the largest single buyer in Asia, but it is not the only one.

As Chinese importers have withdrawn from the market, other buyers have stepped in to fill the void, leading to an uptick in demand from buyers like Taiwan, Indonesia and – perhaps most significantly – India. India, like China, is a major demand center for crude in Asia but, unlike China, has so far shied away from shifting its refining diet significantly towards US volume. As more becomes available, that could change.

Many of Asia's biggest demand centers are locked into multi-year term contracts with the equally large producers in the Middle East, a long-term supply situation that has influenced how they have designed and configured their refinery systems. This, in turn, can limit the speed and degree with which many refineries will be able to react to shifts in the global spot market.
The bulk of refining capacity among Asia’s largest buyers of crude by volume is concentrated in China, Japan and South Korea and many of the refineries in North Asia have been built and configured to process sour crudes over sweet, meaning that a sudden massive influx of inexpensive sweet crudes into the region – say, US WTI Midlands – will not actually translate into a shift in refining slates.

Japan, notably, has bought very little US crude in relation to many of its neighbors and its import market has proved remarkably insulated from interlopers into its traditional crude supply, the majority of which comes from the Middle East and is sour in quality. Saudi Arabia, the United Arab Emirates and Qatar together account for about 68% of Japan’s monthly crude oil imports – primarily through long-term supply agreements – with the remainder made up of variable barrels from Russia, China and Latin America. While some volumes of light sweet crude have made their way into the Japanese market, the country’s older refinery system has been slow to adapt to the change in spot market availability.

India will be the country to watch moving forward. After a massive push to modernize and develop its refining system to support its growing population, India now has some of the newest and most complex refineries in the world. These newer refineries are able to keep up with changes in spot market availability and adjust their refining slate more quickly in line with market trends, making it a likely candidate for further increases in US imports moving forward. Additionally, India has always processed a number of sweet crude grades, given that its local production is itself similar in quantity to the grades produced in Nigeria, making US grades an easier match.

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