

Riding the Wave

The Dated Brent benchmark at 30 years old and beyond

Oil special report

February 2018



EXECUTIVE SUMMARY

Global crude markets are changing at an unprecedented pace. Across all key oil producing regions, markets look vastly different today than they did even three years ago, and it has become increasingly clear to participants that the industry itself is in a period of great flux.

Most notably, these changes can be traced back to two primary events: the shale oil revolution in the United States and the subsequent lifting of the effective export ban and, on the other side of the world, China's continual and growing demand for crude oil.

As a result, the crude markets – historically defined by flows that moved largely in one direction – have seen the development of a complex web of multi-directional flows.

This has served to put the European market in a unique position and has, in many respects, further underscored the importance of Dated Brent in global crude pricing. Europe, acting as both a crude export region in addition to its traditional role as a crude import region, is particularly well-positioned to straddle both the US and Asian markets.

Dated Brent increasingly factors in to pricing decisions made beyond the Atlantic Basin. Asian buyers rely on it to determine the volume of crude they are looking to bring in not just from the North Sea, but also from West Africa, and Urals from Western Russia. Similarly, US sellers are looking

to Dated Brent to gauge how much of their local production should flow West, rather than East.

On the back of its ever-evolving importance in global crude trading and pricing, Dated Brent itself is facing a period of evolution. The Dated Brent basket is likely to see further additions beyond Troll in the coming years as production in the region continues to evolve and, as part of that, there are likely to be further careful quality reviews. The largest projects in the region – particularly Norway's huge Johan Sverdrup field, set to begin the first phase of production in late-2019 – are of a significantly different quality to the existing basket. Meanwhile, production at the light, sweet fields that currently make up the BFOE basket is continuing to fade. There is also an opportunity for the benchmark to evolve in other ways, possibly bringing in grades from outside the region on a delivered basis. Such options are already being discussed in the market and Platts invites all market participants to share their views and actively engage in shaping the future of Dated Brent in an ever evolving global crude complex.

In this special report we cover the challenges and opportunities facing what is widely regarded as the world's leading crude oil benchmark. Dated Brent has seen an exciting evolution over the years, always adapting to the changing physical and financial landscape, and the signs are that it's not over yet.

— [Vera Blei](#)

INTRODUCTION

The unexpected shutdown of the Forties Pipeline System in early December sent a shockwave through the Northwest European crude markets. Not only had upstream producer Ineos only just taken control of operations from UK major BP after more than a year of negotiating around the sale, but the sudden absence of the region's largest single crude stream brought long-simmering concerns about production stability in the region very much to the fore.

The FPS was closed for fewer than 25 days before Ineos got it repaired and back up and running, but the shutdown's impact is expected to reverberate for the near future, as major stakeholders in North Sea production, Northwest European refining, the exchanges and the pricing agencies are expected to carefully address a host of questions from the evolution of production to pricing in the region.

The Northwest European crude market of today looks substantially different from when Dated Brent first ascended as the de facto global pricing benchmark, and the market of tomorrow is going to look even more different than the market of today. Not only is the quality

of oil in the North Sea evolving — the newest, largest fields in the region are expected to be heavier, more sour and more acidic than the traditional light, sweet, low acid crude that has defined quality in the region for decades – but the growing dominance of Asia as an crude oil import region, and the US as a crude oil export region, has already started to change Northwest Europe's position in the global crude markets.

Indeed, exactly what role Northwest Europe – and, by extent, Dated Brent – is likely to play in an increasingly globalized world remains to be seen, but it is evident that it will continue to play a key one. Europe straddles both the US and Asia, acting as both a crude export region as well as an import region, and its refineries – more vulnerable to the winds of product demand than the larger, newer plants in Asia, the Middle East and much of the US – have adapted by broadening the base of crudes they refine.

The North Sea has evolved an extraordinarily complex suite of trading instruments to manage the risk posed by global price volatility in one of the world's most important commodities markets. Dated Brent stands firmly at the heart of this market, and remains so not because of North

Sea crude output, but because of its proximity to markets, its arbitrage potential, its trusted regulatory environment and its transparent price assessment mechanisms. North Sea production has never been equal to Saudi

Arabia, Russia or the United States. However, as a pricing benchmark, it is second to none.

— [Paula VanLaningham](#)

BENCHMARKING SUCCESS

Adaptable, robust and transparent, Dated Brent remains as relevant as ever.

There is no bigger commodity benchmark assessed by a price reporting agency than S&P Global Platts Dated Brent. Renowned for over 30 years as the world's premier crude oil benchmark, it has set the standard for transparency, liquidity, and an unerring ability to adapt to the changing physical and financial parameters in which it exists.

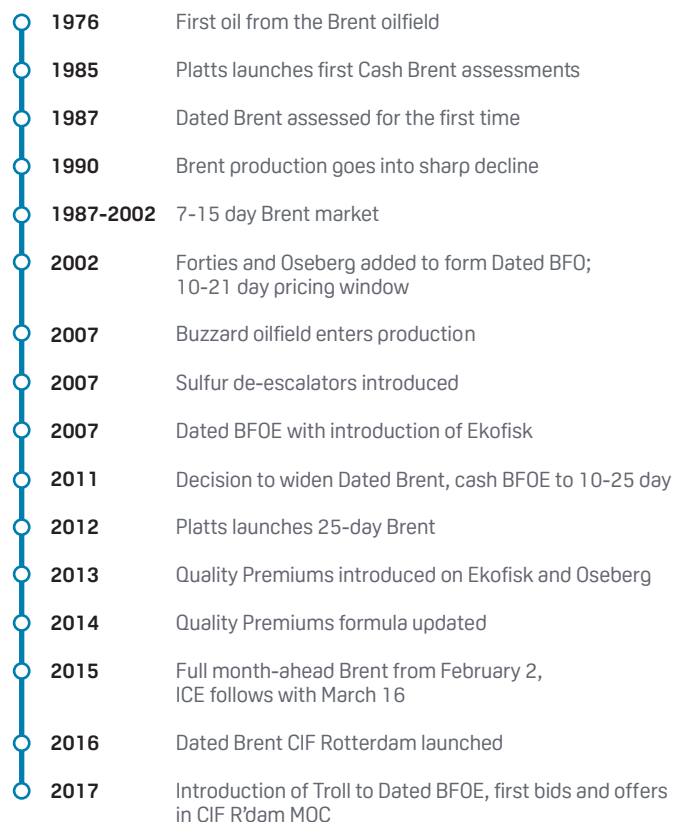
Over the years, Platts has guided the Dated Brent benchmark through the choppy waters of the North Sea and beyond, ensuring its fitness as a price reference for an estimated 60% of the world's near 100 million barrels a day of crude oil trade. Spot trades, tenders and longer-term supply contracts use the assessment as the basis of pricing, as do innumerable forecasts, models and hedging strategies around the world.

The benchmark may have changed significantly over the years, with new grades coming in, a longer lead time of delivery notice, and extra price adjustment mechanisms, but, critically, it still represents the same thing: the value of light, sweet crude oil in the North Sea. This location is one of the major parts of the benchmark's success. Originally concentrated on the refineries in its home region of Northern and Northwestern Europe, Brent gradually reached beyond, its waterborne nature giving it outlets and opportunities beyond the Shetland Islands.

In this way, Dated Brent became a truly global benchmark.

Just as benchmark status can be hard-won, it can also be hard to maintain. Other crude markers have come and gone over the years, one example being Tapis APPI, once used to price nearly 2 million b/d of Asia-Pacific light, sweet crude. However, this benchmark, created by an average of private price submissions by interested parties, could not meet the growing need for transparency in a more modern pricing world. As such, the reference fell out of local favor, with much of the pricing moving to Dated Brent. Despite being based several thousand miles away, Asian buyers and sellers of local light, sweet grades appreciated the transparency in Dated Brent, with its constituent parts – the Cash BFOE forward market, the weekly contracts for difference swaps, and the physical cargoes – publicly bid, offered and traded in the Platts Market on Close assessment process daily.

EVOLUTION OF THE NORTH SEA BENCHMARK



Source: S&P Global Platts

Increasingly, as arbitrage possibilities increase, Brent is defined by its relationships to other crude benchmarks. As Asia continues to display a seemingly unquenchable thirst for oil, and US crude production vies with Saudi Arabian and Russian output at over 10 million b/d, the world's trade flows are shifting. WTI, the light, sweet crude benchmark in the US has long been seen as a natural competitor for Dated Brent and the spread relationship between the two is one of the world's most keenly watched and traded oil instruments. When the Brent/WTI spread blew out to over \$25/barrel in 2010, certain commentators said that WTI was broken but this was not the case. Like Brent, it was doing what it was designed to do, reflecting its local market dynamic, in this case the value of crude oil at the delivery point of Cushing, Oklahoma. With so many US pipelines pointing to this hub, and contango keeping barrels in storage, the area became full with oil that, to a refiner at least, might normally price above Brent. But as the pipeline flows change, the shale revolution

and the easing on exports rules have given the US new opportunities to spread its crude and pricing more widely. This is an exciting opportunity for US grades, but also the Middle East's Platts Dubai, and the North Sea benchmark too, as these spreads become more liquid, more dynamic, and more relevant.

Dated Brent has survived the turmoil of the 2008 financial meltdown and it will survive well beyond Brexit, the United Kingdom's departure from the European Union. The trading community has changed over the years, from the early days of trading houses and oil majors, then banks, Chinese companies and now the smaller, more agile financial trading shops. But Brent's home between the largely stable and secure economies of the UK and Norway make it a good place to do business, always attracting new players.

While consensus is rarely easy to find in a dynamic market of longs and shorts, market feedback often coalesces around certain shared points: a benchmark should be simple, transparent, and reflective of the market where it is based. As a result, many agree future enhancements to the benchmark center on the continued addition of local grades on the well-established free-on-board basis the Dated Brent grades currently trade under. While the addition to Dated Brent of Forties and Oseberg in 2002, Ekofisk in 2007 and Troll in 2018 created few quality issues – at least until the heavier and sourer Buzzard entered the Forties stream in 2007 – further grades might not be quite so easy to add. One could argue that if there were another suitable candidate then it might already have been included, but the anticipated arrival of new grades such as Johan Sverdrup and, further north, Johan Castberg, due to come onstream in 2019 and 2022 respectively reinforces

the belief that there is still plenty of life in the area's oil fields yet.

Should the volume of crude produced in the local North Sea one day not prove sufficient, the possibility of a delivered benchmark is already a reality, with CIF (costs, insurance, freight) assessments now well-established in Platts pricing portfolio. Reflecting Northwest Europe's main refining hub, Dated Brent CIF Rotterdam stands as a viable and sophisticated alternative to the traditional FOB benchmark.

These days Brent often finds itself in the newspapers, something that might not have been easily imagined of a once arcane oil price reference. As its influence has grown, so has public, private, governmental and regulatory interest. This public discussion about the future of Brent shows its wide interest and relevance. Industry engagement is vital to maintaining any assessment, and through regular meetings with stakeholders and other interested parties, Platts is able to gauge the health of Dated Brent.

Benchmarks are not created out of thin air. Indeed, price reporting agencies such as Platts don't launch benchmarks; they launch assessments. The more relevant these assessments are, the more liquid they become and, with enough traction, the market creates a forward market for physical trading and a financial one for hedging. Thus a benchmark is born but it takes time. More than that, it takes trust.

Dated Brent has long had that trust. With further evolution, the likes of which we have seen several times already, that trust will continue for many years to come.

— [Joel Hanley](#)

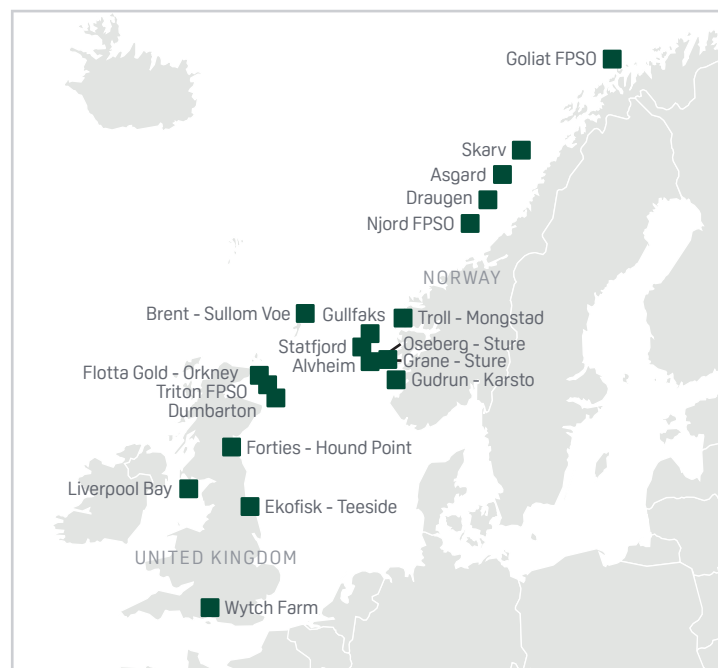
NORWEGIAN, UK PRODUCTION OUTLOOKS STABILIZE ON NEW DEVELOPMENT, COST CUTTING EFFORTS

In Norway and the UK, there is a recognition that a growing ecosystem of companies of many shapes and sizes, coupled with successful cost-cutting efforts since 2014, are helping to maximize crude oil output and manage long-term production decline. In the UK, the establishment of the Oil and Gas Authority as a new industry regulator has replaced the old laissez-faire approach to production with a more rigorous, unified system. By contrast, state-centric Norway has begun to benefit from a surge in private equity investment and overall growth in the number of independent companies outside of the umbrella of state-owned oil and gas major Statoil.

This optimism has ultimately proved to be well-founded, with oil production stabilizing in both countries, following decades of overall decline, and Norway still expecting a big boost from two large-scale projects, the Johan Sverdrup and Johan Castberg fields.

The UK, in particular, is expected to see production stabilize at 1 million b/d through the end of this decade, thanks in large part to the development of new fields like Catcher, Kraken and Western Isles, and the refurbishment of the Clair and Schiehallion fields west of the Shetland Islands. Together, these five fields are set to produce some 380,000 b/d at peak production.

SWEET CRUDE FIELD DISTRIBUTION NWE



Source: S&P Global Platts

Forties shutdown and infrastructure concerns

But the UK's reliance on ageing infrastructure, some of which passed from BP to smaller North Sea companies in 2017, is a concern, both in terms of immediate operations and long-term exploration.

CRUDE PRODUCTION IN THE NORTH SEA

Grade	Origin	Production (b/d)	API Gravity	Sulfur %	TAN
Lighter, Lower Sulfur, Low TAN					
Brent-Ninian Blend	UK	95,000	37.5	0.400	0.030
Forties Blend	UK	410,000	38.9	0.780	0.110
Oseberg	Norway	120,000	39.6	0.200	0.120
Ekofisk	UK/Norway	260,000	38.9	0.210	0.100
Troll	Norway	220,000	35.9	0.140	0.700
Flotta Gold	UK	90,000	36.5	0.640	0.060
Statfjord	Norway	140,000	39.5	0.220	0.050
Gullfaks	Norway	150,000	39.1	0.220	0.110
Alvheim	Norway	80,000	34.9	0.170	0.120
Draugen	Norway	23,264	40.0	0.150	0.080
Skarv	Norway	39,634	44.3	0.180	0.020
Asgard	Norway	85,000	53.7	0.090	0.020
Gudrun	Norway	58,500	49.5	0.086	0.030
Triton	UK	17,000	36.9	0.390	0.110
Heavier, Higher Sulfur, Higher TAN					
Grane	Norway	260,000	27.5	0.640	1.200
Schiehallion	UK	90,000	25.2	0.460	0.310
Sverdrup (2019)	Norway	440,000*	27.2	0.800	0.300
Alba	UK	15,000	19.6	1.260	1.500
Balder	Norway	46,000	26.4	0.640	1.120
Captain	UK	24,000	19.1	0.700	2.100
Clair	UK	20,000	23.6	0.450	1.100
Heidrun	Norway	58,500	25.4	0.520	3.100
Gina Krog	Norway	40,000	31.7	0.440	0.090
Norne	Norway	7,400	29.6	0.300	0.210
Duc	Denmark	70,000	33.5	0.250	0.260
Volvo	Norway	5,600	29.1	1.780	0.110
Harding	UK	7,200	20.7	0.590	2.950
Foinaven	UK	26,000	26.8	0.370	0.120

*Projection.

Source: S&P Global Platts

The shutdown of nearly half the UK's oil output due to a hairline fracture in the Forties pipeline in December raised concerns about the long-term future of the North Sea oil industry – but there remains optimism in many quarters that investment decisions and productivity gains made in recent years will secure the sector's medium-term future.

For participants in the Northwest European markets, the unexpected shutdown of the Forties Pipeline system in December could be a harbinger of more problems to come as years of limited investment in infrastructure begin to bite.

It remains unclear whether the shutdown signals more such problems ahead. Ineos' response to the outage was swift, with production ultimately resuming ahead of schedule and running smoothly ever since.

But Ineos' experience with FPS could add to worries among exploration companies looking to invest in and prolong North Sea production. If the future of production – particularly in the UK – lies with the extraction of resources from multiple small accumulations of oil and gas, concerns are not unfounded that a profitable business model is not viable if the legacy pipelines used to transport these resources are removed from service.

Industry optimists have recently pointed to a spate of deals in which major companies BP and Shell have sold assets in their North Sea heartland to smaller, dedicated players. The assumption is the recipients, with a narrower range of options, will be hungrier to optimize these operations.

But there are reasons to be skeptical. BP's sale of its Sullom Voe terminal to the much smaller upstream EnQuest helped to raise the latter's profile as it brought the Kraken ultra-heavy oil field on stream. However, financial constraints then forced EnQuest to cut spending on its existing assets, resulting in a 13% drop in its overall output in the first 10 months of 2017.

Shell's recent sale of mature UK assets to private equity-backed Chrysaor for \$3 billion-\$3.8 billion was widely seen as a vote of confidence in the North Sea, partly because it suggested private equity investors are ready to accept slower returns, even as the price of the sale raised eyebrows.

The wide variety of assets, comprising stakes in 10 different field clusters, will "require an awful lot of sorting out," a senior industry figure told the World Oil & Gas Week conference in London in early December.

Currently, more than half of the 110 infrastructure hubs in the UK North Sea should still be in service in five years' time, but by 2025 the share with more than five years' life in them falls to 10%, according to consultancy Wood Mackenzie. "The longevity of those hubs is a big concern for near field exploration continuing," Wood Mackenzie research analyst

Changing quality of North Sea crude

Although recent Norwegian discoveries such as Johan Sverdrup mean that overall North Sea production will remain largely steady over the next decade, there will be a noticeable shift in the quality of oil being produced. A region traditionally associated with light, sweet crude is set to enter a transitional phase into an era which will see heavier, sourer crudes predominate.

This transition began with the addition of the Buzzard oil field to the Forties Pipeline System in 2007, and a decade on it remains comfortably the largest of the 70-plus fields which comprise the current Forties Blend. Buzzard is a medium gravity, sour crude with an API of 32.6 degrees and a whole crude sulfur level of 1.44. Outside of maintenance periods, it generally makes up around 30-40% of Forties unstabilized output. As a result of Buzzard's influence, Forties is now considered a medium sweet crude, with an API of 38.9 degrees and a sulfur content of 0.78, according to the most recent assay published by BP.

While this API is similar to BFOE counterparts Brent-Ninian Blend and Ekofisk, the sulfur content on those streams is lower at 0.40 and 0.17 respectively. Norway's Oseberg also has a similar API, but its sulfur content is just 0.20, according to Statoil.

At present, one of the largest crude streams in the North Sea is Grane, which has seen daily production fluctuate between 225,000-285,000 b/d for most of 2017. This has meant it has vied with Ekofisk for much of the year to be the second largest grade in the region behind Forties. Due to its quality, Grane does not compete with traditional North Sea light sweet barrels, and is more often considered a competitor for Russia's Urals and Angola's Dalia. Grane is a medium density, medium sulfur crude with 0.64 sulfur and 27.5 API. Most significantly, Grane is considered "high acid" with a total acid number well over 1.0. As a comparison, Forties has a TAN of 0.11, while Statfjord – just next door to Sverdrup – has a TAN of 0.05. Troll, the highest acid crude currently in the BFOE basket, has a TAN of 0.7.

Kevin Swann told the PROSPEX conference in London on December 13.

West of Shetland key to UK oil future

Increasingly, the UK's far-northern Shetland Islands are beginning to epitomize both the fears and hopes surrounding UK oil production. BP's decision to hand over operations of the 40-year-old Shetland oil terminal at Sullom Voe to the much smaller, independent EnQuest in 2017 unnerved many in the industry, raising questions about the role that the global oil majors expect to play in upstream production in the coming years. EnQuest's own financial struggles over the last several years of low oil prices are seen as evidence that not everything can be left to the small players.

Sullom Voe itself has seen its central role as a major processor of North Sea crude drop dramatically over the

last several decades. Once responsible for processing some 1.5 million b/d of crude in the mid-1980s, processing dropped to just 100,000 b/d in recent years. Many companies working in the west of Shetland oil province have elected to bypass Sullom Voe entirely, opting to ship directly to market. Nowhere is this more apparent than with BP and Shell's newly redeveloped Schiehallion field, with crude now shipped directly to Rotterdam rather than through Sullom Voe.

The harsh conditions in the cold Atlantic have caused their own problems with development, adding to the costs of further exploration in the region. Chevron and partners have repeatedly delayed the 300 million barrel Rosebank oil project, seen by some as a step too far. Independent Premier Oil's Solan field, a \$2 billion project that came on stream last year, has also under-performed, producing just 7,000 b/d in the first half of 2017.

And yet, even as the majors have shed smaller assets they now voice confidence in the UK's ability to stay competitive, with new discoveries west of Shetland making waves in recent years. Hurricane Energy, for example, hopes to unlock hundreds of millions of barrels or more from its Lancaster oil discovery despite the uncertainty about the flow properties of the unusual "fractured basement" development. The company is targeting initial output of just 17,000 b/d, with production starting in 2019.

Also waiting in the wings is the Cambo oil project, operated by private equity-backed Siccar Point Energy. Located in the same geological structure as Rosebank, Cambo is thought to hold over 100 million barrels of crude oil, and Siccar Point's chief executive Jonathan Roger suggests that these new projects could keep the majors active in field development west of Shetland. He told S&P Global Platts in September he expected Chevron to take a final investment decision on Rosebank, in which Siccar Point holds a 20% stake, in 2019.

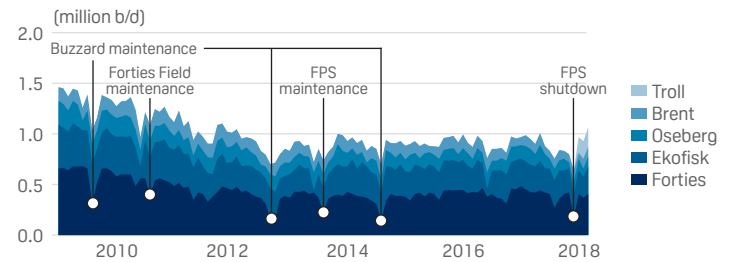
"You've got to have pretty deep pockets... I don't think there will be an over-abundance of small companies coming in to the West of Shetlands because it's very much the majors' heartland, that's where they want to be – the BPs, the Shells," Roger said. "It's still a key area of focus for the big guys."

Shell chief executive Ben van Beurden told journalists on February 1 that, "There's a lot of rejuvenation going on in the North Sea." It followed Shell's decision in January to go ahead with Penguins, a \$1 billion project expected to produce some 45,000 boe/d of oil and gas. "We remain committed to the North Sea and we see more opportunity to grow," he said.

Norway remains bullish

While production of the grades which constitute the current Dated Brent benchmark is expected to decline from 2019 onwards, overall North Sea crude production is forecast to

THE DATED BRENT BASKET AND FORTIES PRODUCTION



Source: S&P Global Platts

remain resilient for much of the 2020-30 period, with the bulk of new production accounted for by Norway.

The discovery at the start of the decade of the Johan Sverdrup field, with resources of between 2.1 and 3.1 billion barrels, has completely altered the North Sea landscape in the medium term, especially as the field lies in the industry's heartland and within easy reach of the supply chain and regional refineries.

Johan Sverdrup is currently forecast to produce 440,000 b/d in its initial phase beginning in late-2019, with production climbing rising to 660,000 b/d in the first-half of the 2020s. Production of this magnitude will dwarf any other single production stream in the North Sea, even as Norway looks to refurbish legacy fields Yme, Njord and Snorre.

Exploration and development in the Barents Sea along the country's northwest coast has also picked up pace, though – the large Johan Castberg discovery aside – finds have largely been of a smaller scale. Norway's northern-most producing field Goliat came on line in March 2016 with development being led by Italian major ENI. The field has a production capacity of 100,000 b/d, but has been beset by technical and safety problems that have kept output shut for much of the time.

By far the largest project in the Barents Sea is Johan Castberg, which is estimated to hold some 400 million-650 million barrels of distillate-rich crude oil, but the project has suffered setbacks around how to best develop infrastructure at the new field. "The Barents Sea continues to frustrate... [It] lacks a big, reliable, widely distributed reservoir system," Westwood Global Energy research president Keith Myers said at the PROSPEX event.

Despite such difficulties, in the medium term at least the prospects for Norway's oil industry look reasonably assured. In an update in July the Norwegian Petroleum Directorate reported that six oil and gas discoveries had been made in the first six months, and six projects approved for development. "The activity level on the Norwegian shelf is high," the NPD said.

— [Nick Coleman and John Morley](#)

ASIAN INFLUENCE GROWS IN THE NORTH SEA CRUDE MARKET

The growth in Asian refining – particularly in China – has had significant implications for the global oil markets throughout the last decade. While the Northwest European crude markets were not on the immediate radar for Asian buyers, crude shipments to Asia from the North Sea have accelerated dramatically over the last two years, boosted by cheap freight, favorable market dynamics, and a seemingly insatiable appetite to feed the Far East's growing refining sector.

Nowhere is this trend more pronounced than in the UK's Forties Blend, where large chunks of the loading program each month ultimately make their way to refiners in South Korea, thanks to favorable terms under the South Korean Free Trade Agreement with the European Union, in force since 2011. But increasingly, while the arbitrage flow to Korea is steady and consistent, both the big Chinese and European majors have moved in to ship large quantities of both Forties Blend and, to a lesser extent Ekofisk, to smaller, independent refineries in China.

Most of the North Sea production is comprised of small, disparate crude grades that often ship from FPSOs in smaller parcel sizes, characteristics that make them decidedly unattractive for long voyages.

By North Sea standards, Forties Blend – which produces just shy of 450,000 b/d – and Ekofisk – 220,000 b/d – are large crude streams with the capacity to load larger crude vessels. Hound Point, the loading point for Forties, even has the ability to load VLCCs, a boost to the economies of scale in terms of arbitrage movements that has played a substantial role in the flow of oil eastwards.

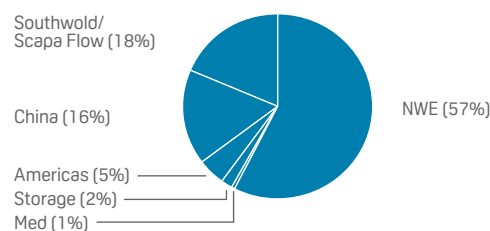
The role that shipping has played in making the arbitrage not only possible but often preferable to shorter haul voyages, cannot be overstated as the global tanker fleet has continued to grow. In 2016 and 2017 the VLCC fleet saw a rapid increase in new deliveries and the fleet currently stands at 716 vessels, with 97 vessels hitting the water in the last two years alone. This trend looks set to continue with the current order book currently representing 13% of the total fleet.

This growth has led to a sharp increase in competition and contributed to a heavy drop in overall freight rates, making it increasingly economical to move oil – any oil – from one region to another. The Atlantic Basin freight market is heavily dependent on the extremely liquid West Africa to China VLCC route, basis 260,000 mt. Rates on the route peaked at \$33.64/mt in October 2015 but have dropped heavily since then.

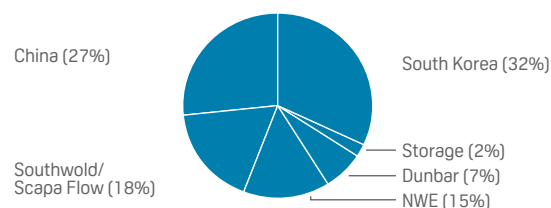
The average freight rate on the route in 2015 was \$25.09/mt, before falling to \$17.38/mt in 2016 and \$13.31/mt in 2017, a 47% fall in two years, according to S&P Global Platts data.

EKOFISK AND FORTIES FIRST-DESTINATIONS 2017

EKOFISK



FORTIES



Source: S&P Global Platts Analytics

Fixtures on the Hound Point-Far East route were reported at a lumpsum rate of over \$9 million in December 2015, early 2018 fixtures have come at rates as low as \$4.25 million.

Forties vs Ekofisk: Arbitrage dynamics

The crude arbitrage from the North Sea to Asia is largely driven by Forties Blend, currently the single largest crude stream in the North Sea and the biggest component of the basket of crudes that underpin the Dated Brent benchmark. Over the last four years, the market has transformed from one where most oil was refined within Europe to one where well over half of the program each month is shipped outside of the region, predominately to Korea and China.

Forties accounted for about 36% of total BFOE loadings – including Troll – in 2017, and nearly two-thirds of the grade was ultimately absorbed into Asia. South Korea accounted for the largest share of this volume, attracting some 32% of the Forties volume loading directly out of Hound Point, with China coming in at a close second, taking more than a quarter of it.

And that is just accounting with the direct Hound Point to Asia flow. In addition to the VLCCs loading directly from Hound Point, some 17.5% of additional volume loaded at Hound Point on smaller Aframax cargoes ultimately wound up moving in that direction after transferring on to larger vessels via ship-to-ship transfer at special STS areas like Southwold, off the coast of eastern England.

Southwold itself serves as the first destination for nearly a third of the vessels that load at Hound Point, irrespective of size. While not all of these cargoes will eventually sell to Asia – some of them are reoffered in the local refining market – it is a fact that STS areas often act as staging grounds for barrels moving further east. Because these cargoes often transfer ownership and actual vessel

multiple times, it can be difficult to determine how much of Forties – and, to a lesser extent, Ekofisk – is ultimately shipped to the Far East, either already sold in to an end-user destination or even still available for sale on a delivered basis in the Southeast Asian market.

In comparison to the heavy share of Forties going to the Far East in a given month, Ekofisk – the second-largest crude grade in the BFOE basket underpinning Dated Brent – is still predominately a Northwest European crude. The majority of Ekofisk loaded at Teesside in 2017 – some 57% – was sold directly into Northwest Europe. Despite this, Ekofisk flows to Asia, particularly to China, have begun to play an increasingly important role in the dynamics around Dated Brent and Northwest European refining.

Ekofisk exports to Asia in 2017 were not on the same scale as Forties, but China imported nearly 16.5% of the total volume loading directly out of Teesside, with a further 18.5% heading towards Southwold.

What makes the arbitrage from one region to another viable depends heavily on a myriad of factors, many of which are unique to individual companies. In the North Sea, however, the number of market participants who routinely work arbitrage for both Forties and Ekofisk either direct to refiners or into storage in the Far East has grown over the last several years.

While global majors like Shell and trading companies like Glencore and Trafigura have been consistent players in the arbitrage markets in past years, the growing presence of China has seen Petroineos – a joint-venture between Petrochina and upstream company Ineos – and Unipeac move in to the market as well. Even Norway's state-owned Statoil, the largest single upstream producer of BFOE crude, has moved oil out of Northwest Europe and into Asia.

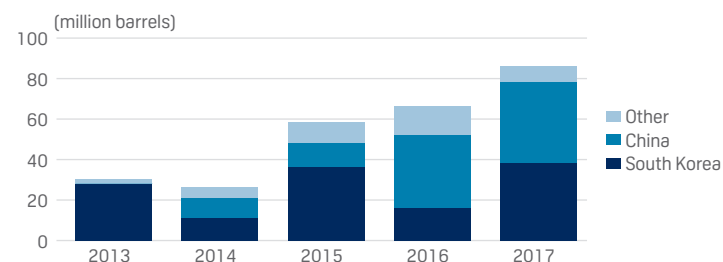
China vs South Korea

While calculating the arbitrage is complicated, ultimately, pulling it off successfully depends on the relative value of three primary factors: the local value of crude, the value of crude at destination and freight.

But what that means in terms of actual numbers can differ from grade-to-grade and participant-to-participant. Nowhere is this more evident than when looking at Forties flows to Asia, particularly to South Korea.

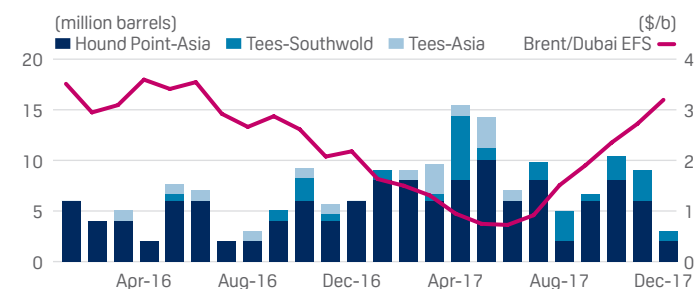
The signing of the EU-South Korea free trade agreement in July 2011 helped create a new West-East oil trade route, with South Korean refiners gaining access to tariff-free imports of Forties – previously taxed at 3% – along with a tax rebate on refined product exports, and later, a reported 90% rebate on the additional freight cost of shipping Forties from the North Sea, versus shipping a Middle-Eastern crude from the Persian Gulf.

FORTIES VLCCS BY DESTINATION



Source: S&P Global Platts Analytics

NORTH SEA ARBITRAGE vs EFS



Source: S&P Global Platts

These terms and conditions, valid only for grades loading in the EU – to which Norway does not belong – meant that Forties suddenly became a lot more attractive to refiners in South Korea, largely independent of many of the other costs associated with driving arbitrage. While the terms of the trade agreement have evolved over time, North Sea traders say that much of the original agreement is still intact, and that South Korean refiners currently put the net value of the FTA at around 30-50 cents/b. In practice, this means that the Northwest European refining market is often priced out of the Forties market entirely.

Tracking by cFlow, Platts trade flow software, shows that in 2013-15, South Korea was, single-handedly and by some distance, the largest importer of Forties. South Korea imported and refined more Forties than the whole of Europe in the wake of the FTA and over that period about 66% of VLCCs loaded out of Hound Point headed to South Korea. However, Chinese imports of North Sea crude quickly ramped up after 2015 when the Chinese government moved to liberalize crude sourcing for its smaller, independent refiners. Chinese crude buying boomed, starting first with Forties already on its way to Asia, and then later, as the Brent's premium over Dubai began to narrow, toward Ekofisk.

Prior to 2015, independent refineries – or “teapot” refineries, also they're also known – used to rely on fuel oil and domestic crude for feedstock. Chinese teapots account for approximately 25% of China's total refining capacity of around 16 million b/d, according to Platts estimates. China's independent refineries imported a total of around 93 million mt of crude oil in 2017, according to according to S&P Global Platts estimates. This represented around 22% of China's total imports of 420 million mt in 2017.

In 2016, China overtook South Korea as the number one importer of Forties, draining almost 55% of VLCCs leaving Hound Point, against 24% for South Korea. In 2017, imports were fairly equally divided between the two countries, while arbitrage volumes out of Hound Point continued to swell. More than 78 million barrels of Forties were thus sent to Asia last year.

Both Forties and Ekofisk are likely to be spotted en route to Asia in a given year. However, the Forties arbitrage is characterized by a sustained stream of VLCCs moving east, while Ekofisk moves are more scarce and tend to be triggered by a pull from Asia, rather than a push from Europe.

While several months passed without a single ship taking Ekofisk to Asia in 2016-17, at least one VLCC of Forties per

month was seen steaming east of Suez. In 2017 alone, an average 3.25 VLCCs left Hound Point directly for Asia each month, with a peak at five in May 2017.

Volumes of Ekofisk moving to Asia were less consistent and more markedly driven by the relative value of the benchmarks underpinning the European and Asian markets. As such, Ekofisk exports to Asia distinctly peaked between March-August 2017 when the Brent/Dubai exchange of Futures for Swaps (EFS) dipped below \$1.50/b. A narrower EFS conducts a greater competitiveness for crude grades pricing against the Brent benchmark relative to Dubai-related grades, thus favoring arbitrage economics from the Atlantic Basin to Asia.

— [Maude Desmarescaux](#)

EUROPEAN REFINING LANDSCAPE HAS EVOLVED AMID PLANT CLOSURES AND MODERNIZATIONS

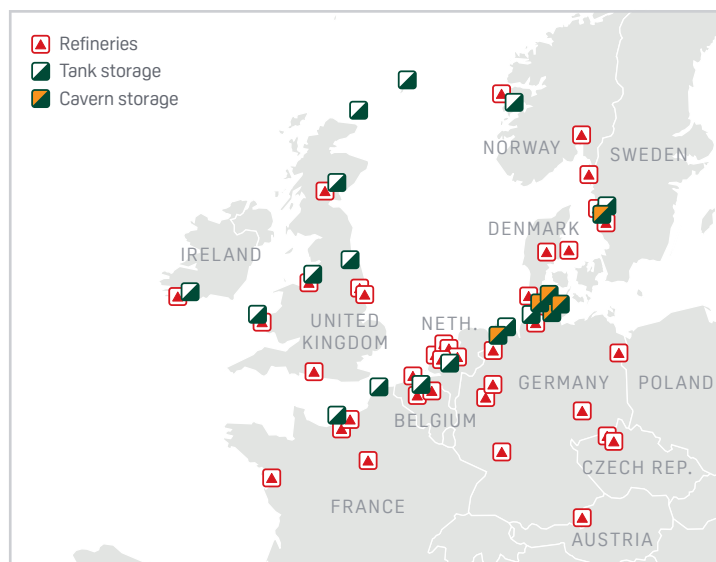
European refining has undergone massive changes over the last decade, as local plant closures and increased competition from newer, more modern refineries in the US, India and the Persian Gulf have contributed to the gradual whittling of refinery margins in Europe. Distillates, once the driver of the margin in Europe, have become less profitable overall as imports have jumped, particularly from Russia amid large-scale refinery modernization.

As the environment for product supply and demand has changed, Europe's refiners have either evolved or closed as a result. While the financial crisis of 2008 and 2009 saw the first dominoes begin to topple, the recovery in crude oil outright prices throughout 2011 and 2012 began to exert even more pressure on Europe's more vulnerable plants, culminating in the full-scale demise of the region's largest independent refiner Petroplus in January 2012 and the closure of three of its plants, including its largest, the 220,000 b/d Coryton refinery on the banks of the Thames.

Petroplus' demise was only the most high-profile in a spate of changes to hit the European refining sector. A host of refineries were halting and changing into storage or switching to biofuel facilities. Some, like the UK's Lindsey and Stanlow, reduced their capacity, while others like PKN Orlen's Lithuanian refinery opted to run at minimum capacity. Many were snapped up by independent traders, breathing a new life in plants threatened by closure or conversion.

Several of Petroplus' refineries escaped closure as independent traders, who in the past have steered away from refinery ownership, entered in the business. Vitol bought Switzerland's Cressier, while Gunvor acquired the former IBR Antwerp refinery and the German Ingolstadt. Subsequently, Gunvor also bought KPI's Europoort refinery

NORTHWEST EUROPEAN REFINING AND STORAGE



Source: S&P Global Platts

in Rotterdam, whose future was threatened by a potential conversion to a terminal.

But others were not that fortunate. Some, like Germany's 260,000 b/d Wilhelmshaven plant and the UK's Coryton refinery, were converted into storage and import terminals. Others, such as Italy's 80,000 b/d Porto Marghera and 105,000 b/d Gela plants, were revamped into bio-refineries largely producing diesel from bio-feedstocks. France's former 153,000 b/d La Mede refinery near Marseille is currently undergoing transformation into a bio-refinery.

Since 2009, Europe has lost some 2.2 million b/d worth of crude oil refining capacity across the continent and, despite efforts to diversify crude slates and maximize margins and flexibility, Europe is expected to see further changes to the refining landscape moving forward.

Refinery margins in Europe closely track outright prices

Improved refining margins since 2015 have significantly slowed down the rate of refinery closures in Europe, driven largely by the heavy drop in outright prices throughout the second-half of 2014. The further decline in outright prices over the tail-end of 2015 saw margins across Europe strengthen further, as product prices remained broadly supported relative to the significantly weaker crude market.

In addition to benefiting from lower outright prices, refiners in Europe have been working to take advantage of the wider array of crudes on offer in the European market, particularly as standard refinery feedstocks in Europe have found strong demand outside of the region, particularly in Asia. Many refineries have also been looking how to optimize their crude slate in order to achieve good margins from less costly feedstocks. Many have also ramped up integration, where possible, with nearby petrochemical facilities, also with the aim to optimize feedstock utilization.

In the era of low margins, refineries were moving their slate with the balance shifting to medium and heavy crude, which hit the market in abundance in 2015 and 2016 as producers in the Persian Gulf looked to expand their reach into the European markets. The construction of a new pipeline in Northern Iraq and the semi-autonomous Kurdish region's push to grow its export capacity independent from Baghdad, saw huge volumes of KBT hit the European market, with flows going as far North as Sweden and Poland and all the way in to the Black Sea, where refiners began running it in lieu of Urals.

In southern Iraq, the development of the new Basrah Heavy stream helped to stabilize the quality of Basrah Light and, while both Basrah Light and Basrah Heavy remained predominately directed eastwards, as much as a third of the loading program could find its way into the European refining market each month, either on the primary or secondary market.

Furthermore, the lifting of US sanctions against Iran in early 2016 helped to bring Iranian production back into the European refining market after years of absence. Refineries in the Mediterranean were always big buyers of Iranian crude, but upon the lifting of sanctions in early 2016, Iranian crude became an increasingly large portion of the refining diet in Rotterdam.

Modernization of the remaining refineries in Northwest Europe has given many plants the ability to process heavier, sourer and more acidic crudes which typically attract higher discounts than lighter, sweeter, more easily processed barrels.

In Spain and Portugal, refineries that had previously processed 70% medium and heavy crude increased it to more than 80% of the slate. Repsol's refineries in Spain, for instance, process 70 different types of crude, whereas Italy's Saras typically processes as many as 40 different types of crude. Greece's Hellenic has more than doubled the number of crude grades on its slate in the last few years.

The UK's Stanlow has diversified its crude slate by introducing 37 new grades and Essar Oil UK is planning to increase the capacity of the plant, a mere three years after reducing it, altering its FCC feedstock away from VGO and towards heavy residue.

Improved margins and stronger crude optimization have resulted in a slowdown of the rate of refinery closures in Europe. The last few years have seen no new announcements for closure, and in the most recent move, Croatia's INA seems to be abandoning to idea of shuttering Sisak by opting to only close the FCC at the site. PKN's Orlen Lietuva refinery, on the verge of closure just three years ago, achieved a 104% utilization rate in the last quarter of 2017 on what the company called "favorable market conditions."

EUROPEAN REFINERY CLOSURES: 2009-2015

	Refinery	Owner	Capacity (b/d)	Status	Date
Italy	Cremona	Tamoil	90,000	Closed	2011
	Rome	TotalERG	86,000	Closed	2012
	Porto Marghera	ENI	80,000	Converted to Bio-refinery	2013
	Mantova	MOL	55,000	Closed	2014
	Gela	ENI	105,000	Converted to Bio-refinery	2014
France	Dunkirk	Total	140,000	Closed	2009
	Reichstett	Petroplus	85,000	Closed	2010
	Berre L'Etang	LyondellBassell	105,000	Closed	2012
	Petit Couronne	Petroplus	162,000	Closed	2012
	La Mede	Total	153,000	Converted to Bio-refinery	2015
Switzerland	Collombey	Tamoil	54,000	Closed	2015
Spain	Tenerife	Cepsa	87,000	Closed	2013
Germany	Wilhelmshaven	Hestia Energy	260,000	Closed	2009
	Hamburg	Shell	110,000	Closed	2013
UK	Teeside	Petroplus	117,000	Closed	2009
	Coryton	Petroplus	220,000	Closed	2012
	Milford Haven	Murco	134,000	Closed	2015
Romania	Arpechim	Petrom	70,000	Closed	2012
Czech Republic	Paramo	Unipetrol	20,000	Closed	2012
Ukraine	Lisichansk	Rosneft	160,000	Closed	2012
	Odessa	Vetek	56,000	Closed	2014

Source: S&P Global Platts

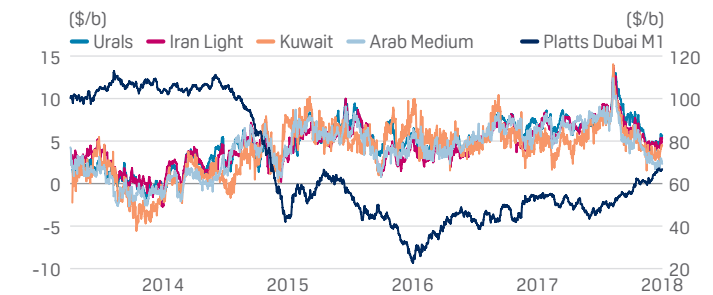
Speaking at the ADIPEC conference in Abu Dhabi in November, the head of refining at Austria's OMV, Manfred Leitner, said his company was processing around 30 different crudes, and there were still growth opportunities for petrochemicals in Europe. But he also argued that the survival skills honed by European refiners in the last decade are marketable in growth markets in the Middle East and Asia. OMV is a quarter-owned by Abu Dhabi state company Mubadala, which itself owns refinery operation in Pakistan.

"The product growth will happen in Asia... in the Middle East, so these are the places where new refineries will be necessary and these are the places where, as well, petrochemical production will be necessary. That can only be the strategy: for companies like OMV to yes, optimize and streamline more the European market in the European business, but growth we will just find elsewhere," Leitner said.

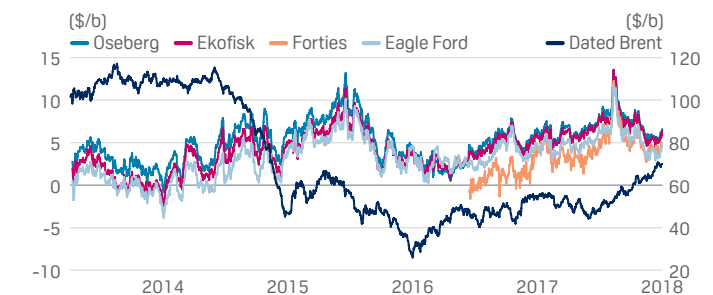
The outlook could shift for refiners as we move into the first half of 2018, as higher outright prices have once again cast a shadow over the refining sector in Europe. Both Shell's Fredericia refinery in Denmark and Lukoil's ISAB refinery have been put up for sale and have struggled to see proposed deals come to fruition. How the sector weathers changing market conditions moving forward could see more of Europe's refineries come under pressure.

— [Elza Turner](#)

SOUR CRUDE MARGINS vs PLATTS DUBAI M1



SWEET CRUDE MARGINS vs DATED BRENT



EUROPE LOOKS TO DIVERSIFY CRUDE SOURCES

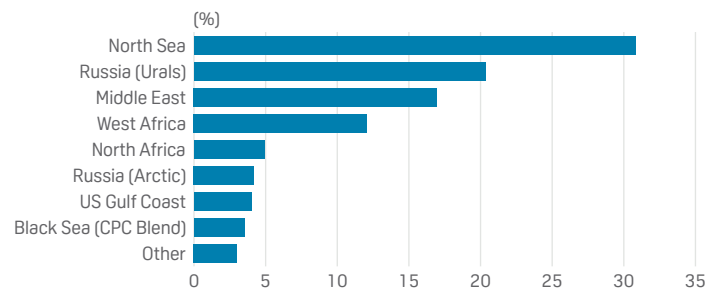
Even as inexpensive freight has attracted buyers from outside of the region to North Sea crude, it has helped to attract still more volumes into the region, providing Northwest European refiners with a plethora of choices from all over the world.

While much of the crude refined in Europe still originates in Europe – both larger and smaller grades from the North Sea, Varandey from the Arctic Circle, and Urals from Russia via the Baltic Sea – European refiners have been moving to substantially diversify their crude sources as they have gained access to more imports from the Middle East both via Turkey and the Suez Canal, as well as new, light sweet export streams from the US Gulf Coast.

Imports into Europe have been helped in large part by Dated Brent's heavy premiums over other regional benchmarks – namely, Dubai and NYMEX WTI – throughout much of the second half of 2017, which saw flows from the Middle East continue despite cutbacks in production, and flows into Europe from the US push sharply higher.

WTI in particular spent most of 2017 pricing at fairly hefty discounts to both Brent and Dubai, which has helped to

NWE CRUDE SOURCING BY REGION



boost US crude exports around the world, displacing other grades like Nigerian light sweets on the slates of Asian refiners, and redirecting flows into Europe.

Most refineries in Northwest Europe are now likely to run as many as 40 different crudes as part of their refining slate, opening up new opportunities to maximize refinery margins wherever possible.

Additionally, while arbitrage for North Sea crudes outside of Europe has meant that there are fewer cargoes of Forties – and, occasionally Ekofisk – being refined within Northwest Europe, many European refiners have upped their refining

of smaller North Sea crude grades, many of which are sold on a CIF-delivered Rotterdam basis.

Furthermore, crude production in Norway has expanded significantly beyond the traditional North Sea, with a number of newer fields coming online along the continental shelf – currently, the largest of these is the very light, naphthenic Asgard, which produces some 85,000 b/d, while Eni's far north Goliath field has a capacity of 100,000 b/d, though production difficulties have prevented it from sustaining that sort of level. Russia, as well, has expanded crude extraction into the Arctic Circle and now loads approximately six cargoes of light Arctic crude out of its Barents Sea port of Murmansk each month, most of which goes to buyers in Northwest Europe.

This growing interconnectivity of Northwest Europe as a hub for global crude flows has meant that Brent has become a closely watched benchmark not just in Europe, but also in the US where it is eyed as a driver of exports, and in Asia, where it is viewed as a key factor in the determination of imports.

Middle East imports a major factor in European refining

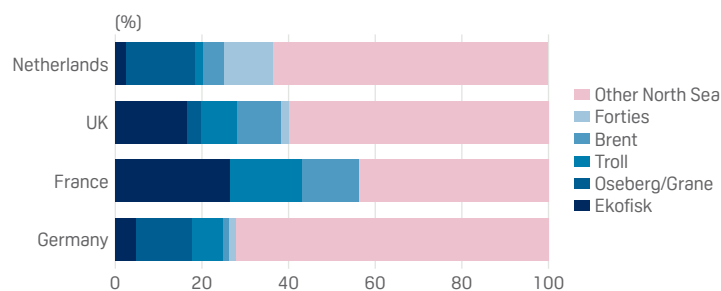
Crude imports from the Middle East make up the largest share of the Northwest European refining slate outside of local crude grades from the North Sea and Urals from Russia, accounting for nearly 17% of all of the crude refined in the region, despite the 2016 OPEC/non-OPEC production cut agreement, which saw Middle East exports to Europe drop along with output.

In many ways, this is to be expected. Saudi Arabia and Iraq have always been key crude suppliers to refineries in Europe – particularly the Mediterranean – but over the past several years there has been a decided shift by many suppliers looking to target the European market specifically, which has seen crude cargoes from Kuwait, Oman and even the United Arab Emirates make their way into the key refining hubs in Northwest Europe, particularly Le Havre and Rotterdam.

Total's lifting agreement with the National Iranian Oil Company in early 2016, struck shortly after the lifting of US sanctions against the country, ensured that Iranian crude – once a key source of supply for much of Europe – resumed regular flows into the region, with several VLCCs landing at the company's refineries in Le Havre and Rotterdam each month. Even as production cuts have seen the number of cargoes slip in 2017, Iranian crude supply remains a major component of the European refining slate, helping to supplement the loss of volume coming from other major OPEC suppliers like Saudi Arabia.

Before agreeing to production cuts with Russia, Saudi Arabia began widening the number of buyers in Europe it sold its Arab Medium and Arab Heavy crudes to. At one point, cargoes of Saudi crude were routinely flowing as

NORTH SEA CRUDES IN EUROPE



Source: S&P Global Platts Analytics

US CRUDE EXPORTS SURGE TO EUROPE, ASIA ('000 b/d)

Destination	2015	2016	2017	— Change (%) —	
				2015-16	2016-17
Canada	427.50	301.80	323.30	-29.4	7.1
Latin America	16.20	72.10	64.80	345.1	-10.1
Europe	26.60	111.90	288.90	320.7	158.2
France	1.70	6.50	30.30	282.4	366.2
Italy	4.30	21.40	43.30	397.7	102.3
Netherlands	5.90	38.30	84.40	549.2	120.4
UK	-	16.20	97.60	NA	502.5
Asia Pacific	4.80	53.60	395.10	1016.7	637.1
China	1.20	22.60	225.10	1783.3	896.0
India	0.90	-	22.30	NA	NA
Japan	-	7.90	27.70	NA	250.6
Singapore	-	10.60	27.90	NA	163.2
South Korea	2.70	10.70	57.10	296.3	433.6

Source: S&P Global Platts Analytics, US Census Bureau

far north as Poland. The launch of a new stream of Basrah Heavy from Iraq's southern terminals also contributed to an increase in the volume of oil moving through the Suez Canal, freeing up cargoes of Basrah Light that would have otherwise moved into the Asian markets.

Simultaneously, Kuwait began to actively market its crude to European buyers. The state-owned Kuwait Petroleum Corporation began issuing official selling prices for crude delivered into Europe and pricing relative to Dated Brent in the first quarter of 2016; previously the country had priced all of its crude relative to Oman/Dubai. While exports were slow to get off the ground, 2016 saw a gradual increase in the amount being delivered to buyers outside of KPC's own refining stream.

But the most notable addition in Middle East crude has been Iraq. Iraq's northern crude stream, Kirkuk, long-plagued first by production problems, then by transportation issues, and finally by security concerns, was at one time a major source of sour crude in the Mediterranean. However, 2015 saw the establishment of a fresh flow of northern Iraqi crude through the semi-autonomous Kurdish region, which Erbil began marketing as Kurdish Blend Test. The new flow quickly dwarfed the previous Kirkuk flow, with exports climbing up above 600,000 b/d by early 2016.

Potential repercussions from SOMO, Iraq's State Oil Marketing Organization, for companies seen to be purchasing KBT from the Kurdish Regional Government made many of Kirkuk's traditional buyers reluctant to buy

it, but it also freed up companies without SOMO contracts to pick it up, often at substantial discounts to the rest of the sour crude market. Consequently, cargoes of KBT wound their way into every corner of Europe and into the refining slates of buyers as far north as the Baltic Sea and everywhere in between. Even after the flow was cut as SOMO reasserted control of the region in late-2017, Kirkuk has continued to find its way into Northwest Europe.

US flows surge in 2017 as Brent's premium to WTI widens sharply

The rise in US crude flows in 2016 and 2017 has been one of the most buzzed about stories in the oil markets, and while the surge in exports to Asia has dominated market coverage, the US has quietly become a major source of light sweet crude into Europe, supplementing the absence of North Sea barrels shipping to Asia.

Throughout the second half of 2017, the amount of crude shipping in from the Gulf Coast to refineries in Europe has jumped sharply, aided by a sharp rise in the price of Dated Brent relative to WTI, coupled with continued low freight rates. In December, combined US crude exports into the UK and Netherlands – Northwest Europe's two largest refining hubs – totaled 329,000 b/d according to data from the US Census Bureau, a rate exceeding the total production rate of every other crude stream in the North Sea; Forties production, normally averaging above 400,000 b/d, was suspended throughout the majority of December due to the FPS shutdown.

By comparison, the US exported 264,000 b/d to China in December, and 406,000 b/d to Canada, its largest trading partner.

Between late August and late January, Brent's premium to WTI did not drop below \$4/b, which helped to encourage

BRENT vs DUBAI vs WTI



Source: S&P Global Platts

a steady flow of crude from the Gulf Coast, oil that found regular buyers, particularly in the UK. Between July and December, UK crude imports from the US nearly tripled, rising from an average of under 60,000 b/d between January and June to more than 140,000 b/d.

While US crude imports currently account for only just over 4% of the total crude refined in Northwest Europe, according to Platts trade flow software cFlow, that percentage is likely to continue to grow as US export infrastructure continues to grow out of the Gulf Coast over the next several years. Furthermore, the increase in supply from the US has started to put pressure on the prices other local sweet crudes are able to fetch in the local refining market, particularly light sweet crudes loading out of West Africa (currently just over 12% of the NWE refining diet) and North Africa (just under 5% of the refining pool.) Additionally, while most of the crude coming out of the US Gulf Coast is currently light and sweet, improved pipeline capacity in the US is likely to bring additional heavier, sourer volumes out via the Gulf, which could begin to compete more actively with traditional sources of sour crude like Russia's Urals.

— [Paula Vanlaningham](#)

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