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Argus Crude and Refined Products Forum 2020

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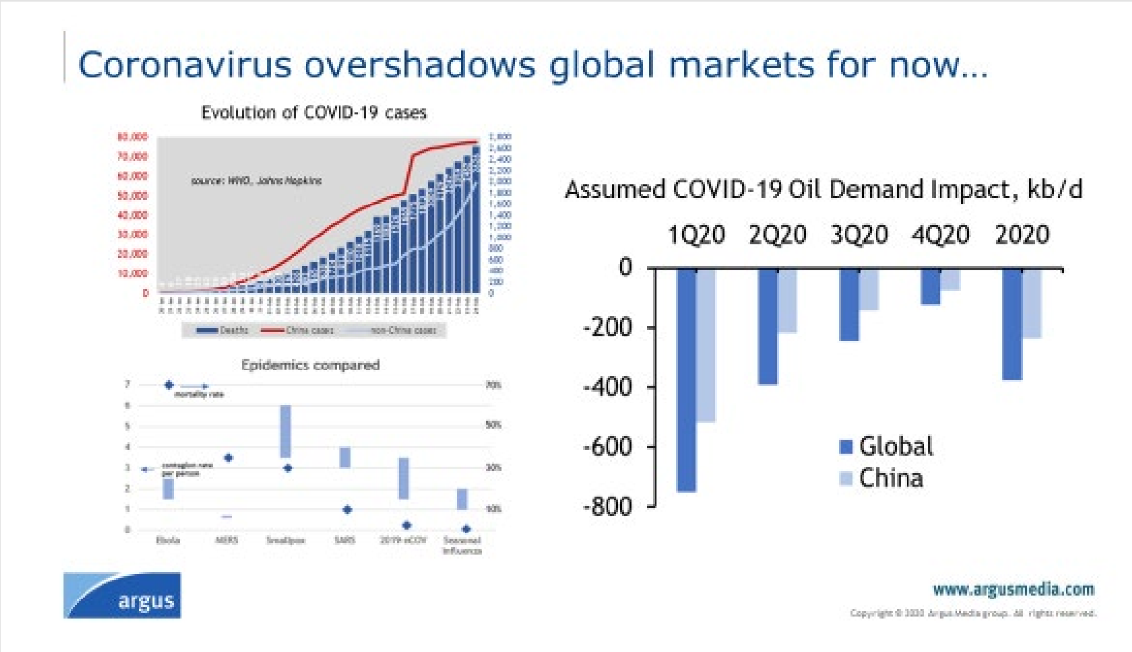
Argus Crude Forum 2020

Argus' leading market experts gathered in London last month to share their insights into the latest developments in the global crude markets with over 1,200 attendees at the price reporting agency's annual forum. Argus solutions to current market pricing issues were presented to an audience of international oil traders and associated professionals.

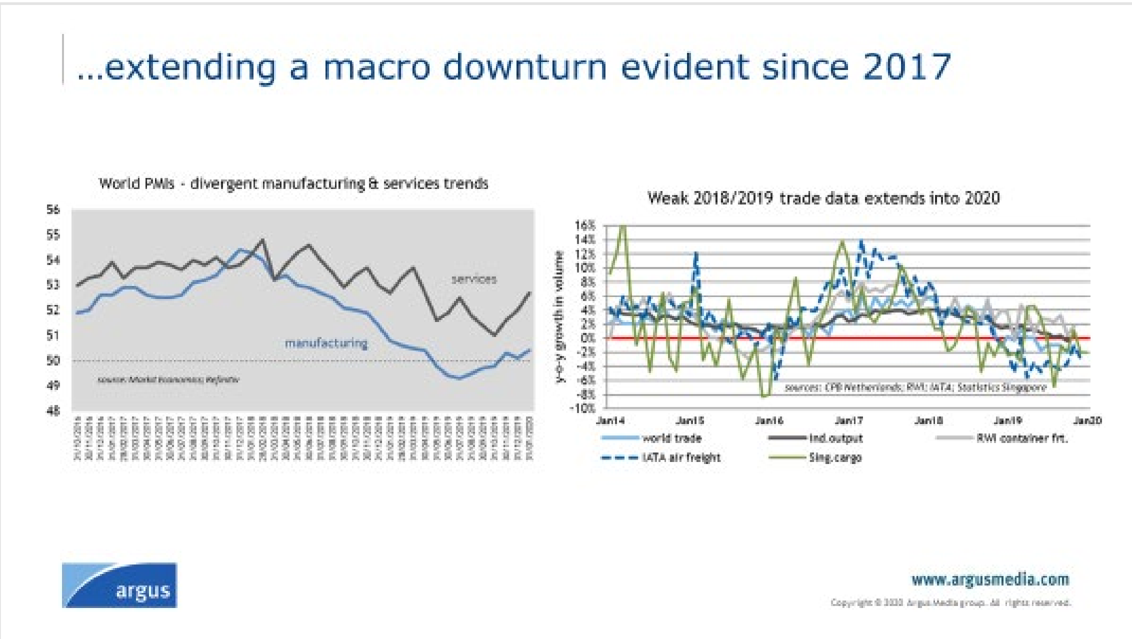
Presentations covered topics that extended across the upstream, midstream and downstream sectors. The Crude Forum discussed the impact of the coronavirus and economic conditions on the oil markets, Chinese and Asian demand, Russian exports, US shale production and infrastructure, and benchmark developments in the North Sea.

The following is a summary of presentations on 25 February. See more stories from our global Editorial staff on the news page of our website, and see content about the effects of the coronavirus on markets on our special hub page, www.argusmedia.com/hubs/coronavirus.

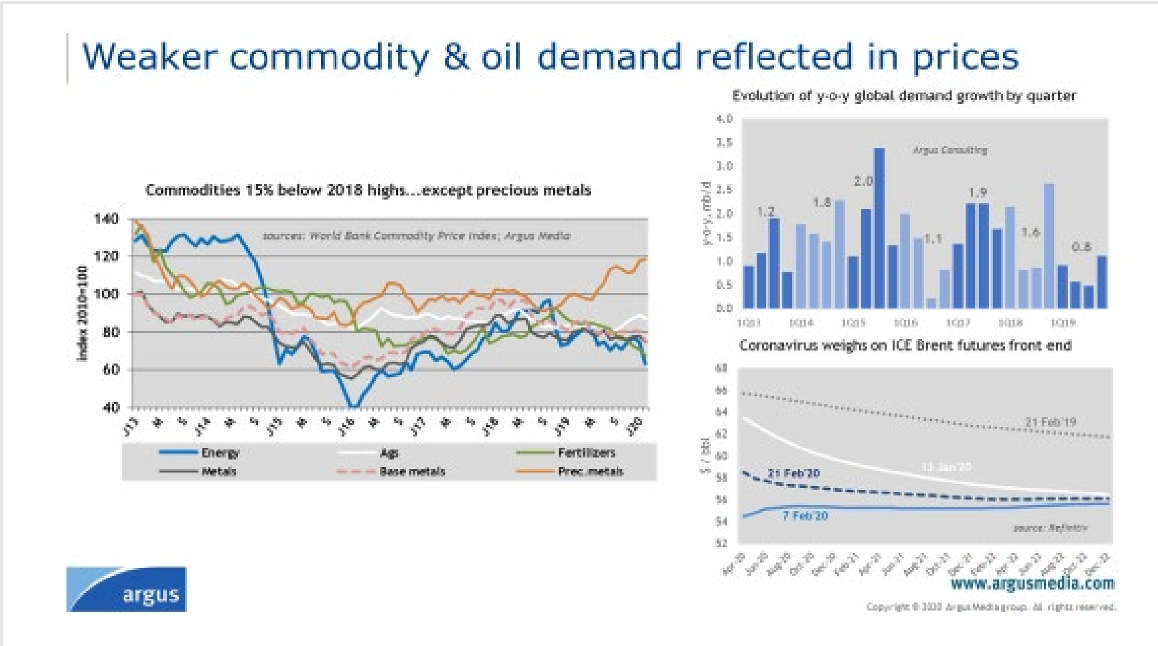
Global market overview

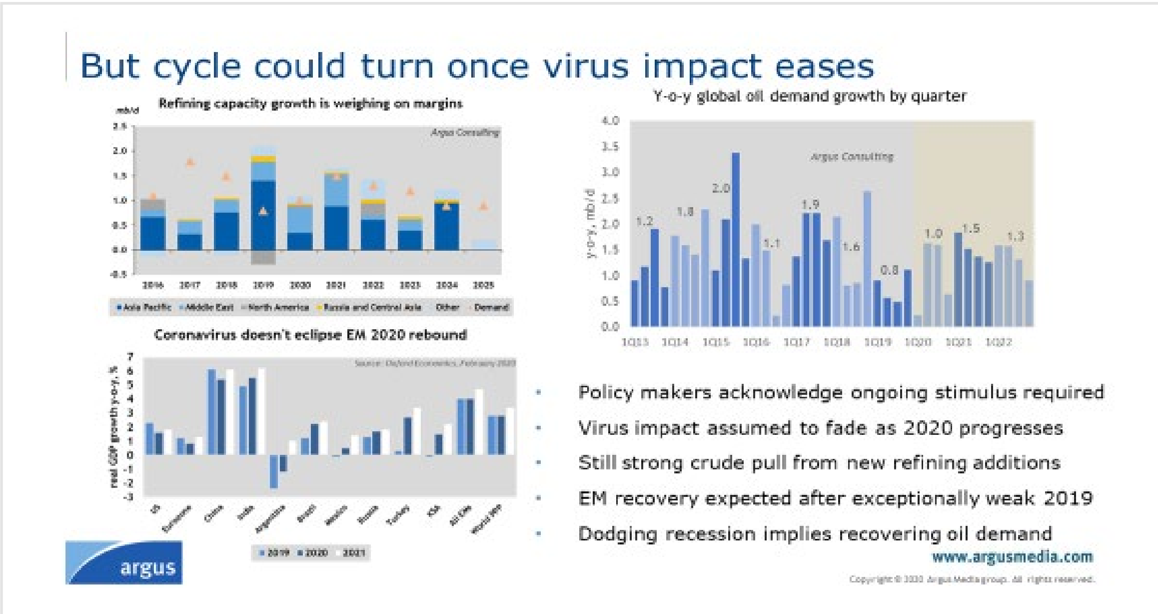


The oil markets are focused on the coronavirus, and the impact that the outbreak is likely to have on global economic growth and oil demand. While new cases within China appear to be levelling off, there is concern over the apparent acceleration in new cases elsewhere — South Korea, Italy, Iran, US and many other countries around the globe.



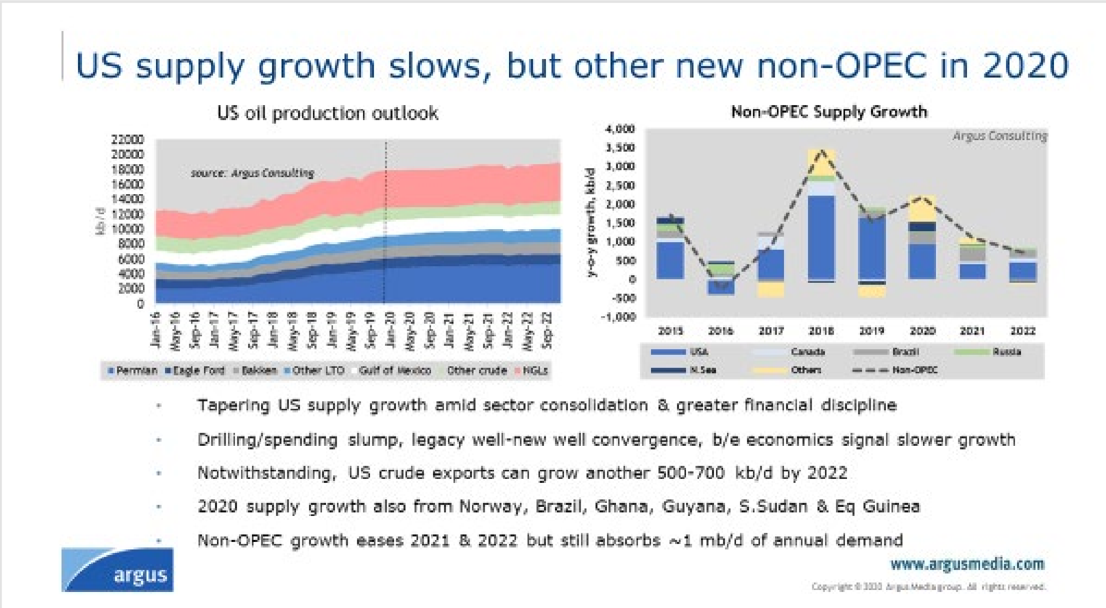
Acknowledging that there is huge uncertainty as to the duration and extent of the epidemic, Argus' working assumption is that this is a high-impact but short-duration episode, with effects gradually tapering off after the first quarter.





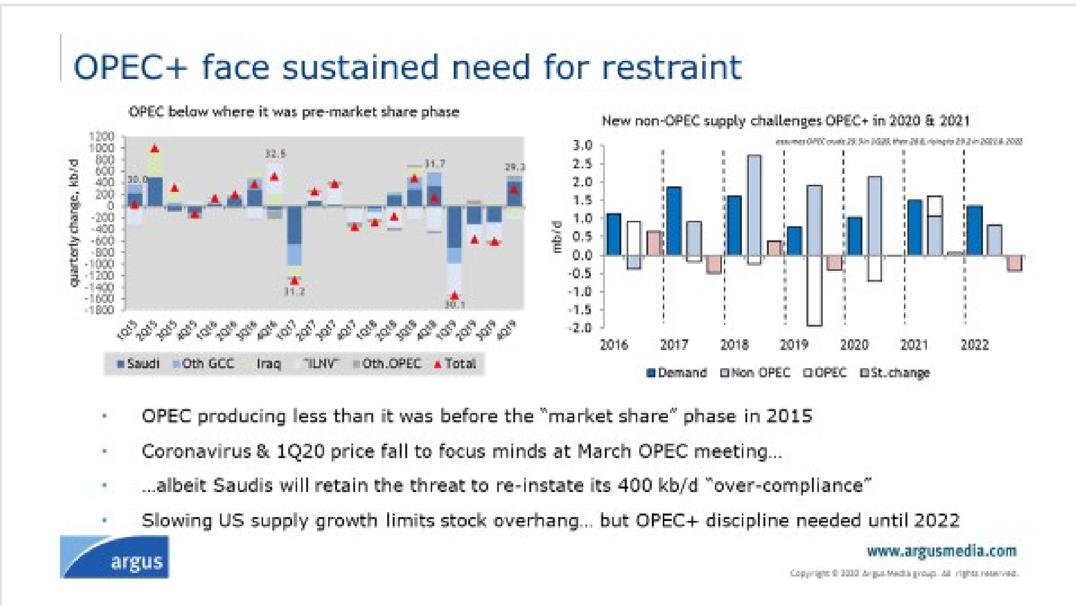
The impact of coronavirus is assumed to reduce 2020 global GDP growth by 0.3 percentage points from previous projections and to curb annual oil demand growth by 0.4mn b/d to a new level of 1mn b/d. In such a scenario, coronavirus effectively defers macro recovery after two years in which both global trade and manufacturing have been slowing sharply.

Of course, the epidemic is evolving rapidly, and were the hit to supply chains and global trade to be larger than assumed here, so global GDP growth this year could fall to 2.5pc or lower, with 2020 oil demand growth also potentially falling to significantly below 1mn b/d. For now, we are sticking with our working assumption, while acknowledging that any forecast in such uncertain circumstances will be prone to repeated iterations.



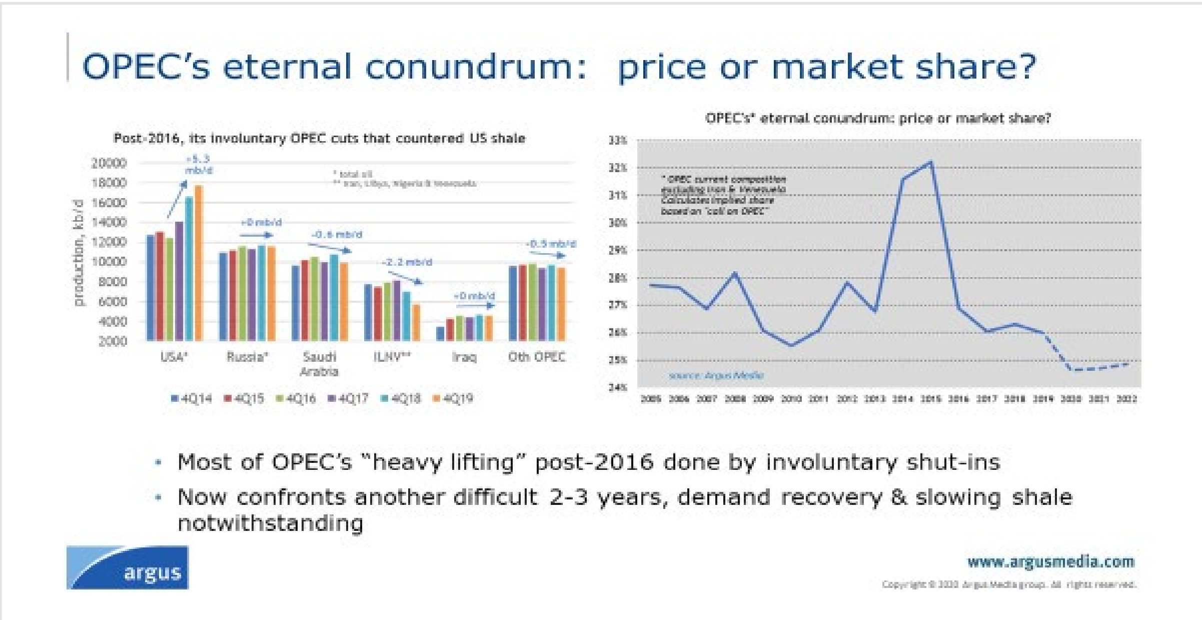
Combined with elevated geopolitical risk, 2018 and 2019 have represented a "risk-off" phase in asset investment, with commodity demand and prices weak across the board, barring gold and precious metals. Oil demand growth eased to only 0.8mn b/d in 2019, half the level of 2018, with emerging market demand particularly weak.

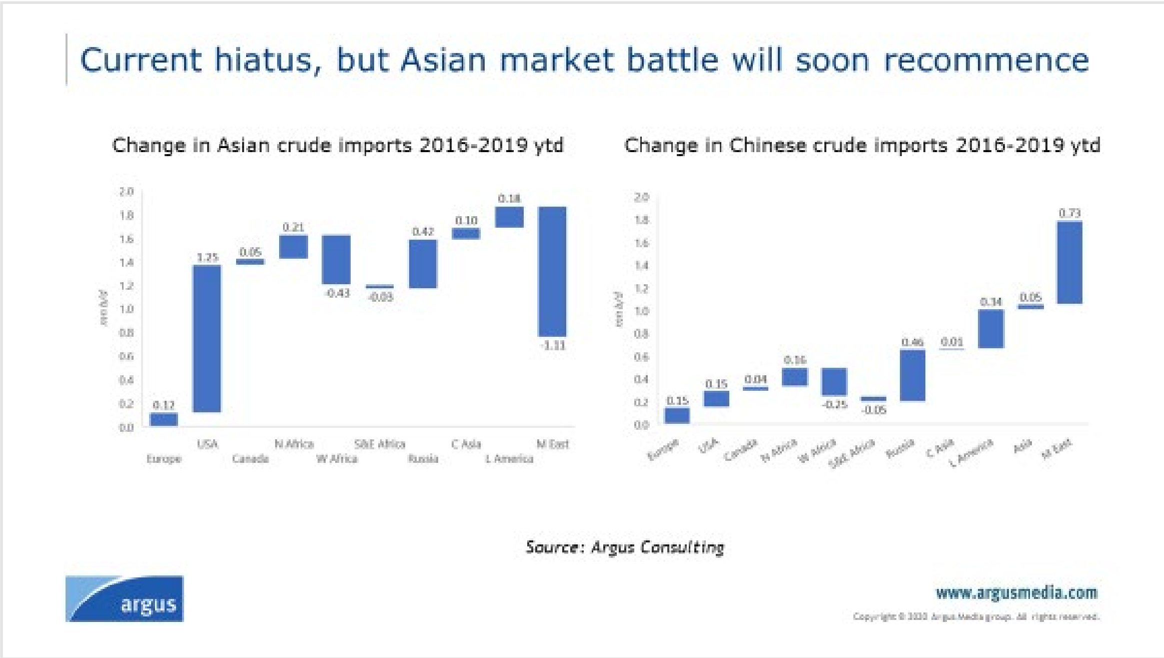
Despite the serious headwinds caused by coronavirus, we nonetheless assume that there is scope for economic and oil demand recovery later in 2020. Policy makers have responded with economic stimulus, and emerging markets are assumed to enjoy a stronger year than in 2019, notably in Latin America and the Middle East and north Africa (Mena) region. These two regions are relatively oil and energy intensive. With IMO 2020 still likely to provide support this year for middle distillates as trade gradually recovers, we assume annual demand growth can recover to 1mn b/d.



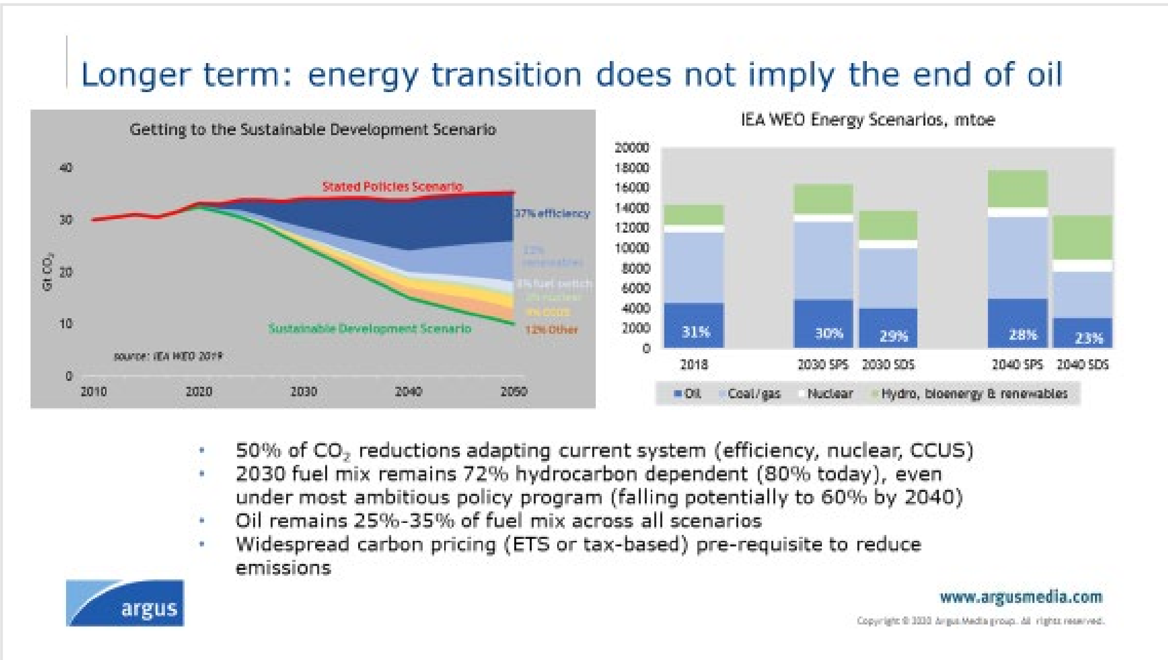
On the oil supply side, 2017-19 has been a recovery phase for US crude and natural gas liquid (NGL) supply, after the price-induced contraction seen in 2016. But the shale space is now seeing major consolidation, a demand from financiers for greater financial discipline, and a slowdown in spending and drilling. This is not the end of US supply and export growth by any means, but a more sustainable level of annual liquids growth in coming years may prove to be closer to 0.5mn b/d than the 1mn-2mn b/d seen annually in 2017-19.

In 2020, still-strong US growth will be augmented by new supply from Brazil, Norway, Ghana, Guyana, South Sudan and Equatorial Guinea, with forecast non-Opec supply growth in 2020 exceeding 2mn b/d. Non-Opec growth averages more than 1mn b/d each year through to 2022, severely constraining the ability of Opec producers to boost supply if they wish to limit global stockbuilds. Discipline among the Opec+ group of Opec and some non-Opec producers will be required through to 2022 at least, while the coronavirus has seen calls for the existing production pact to be extended until the end of 2020 and potentially deepened for the second quarter to help deal with the fall in demand caused by the epidemic. But Russia has signalled that it sees no need at present to deepen output cuts.

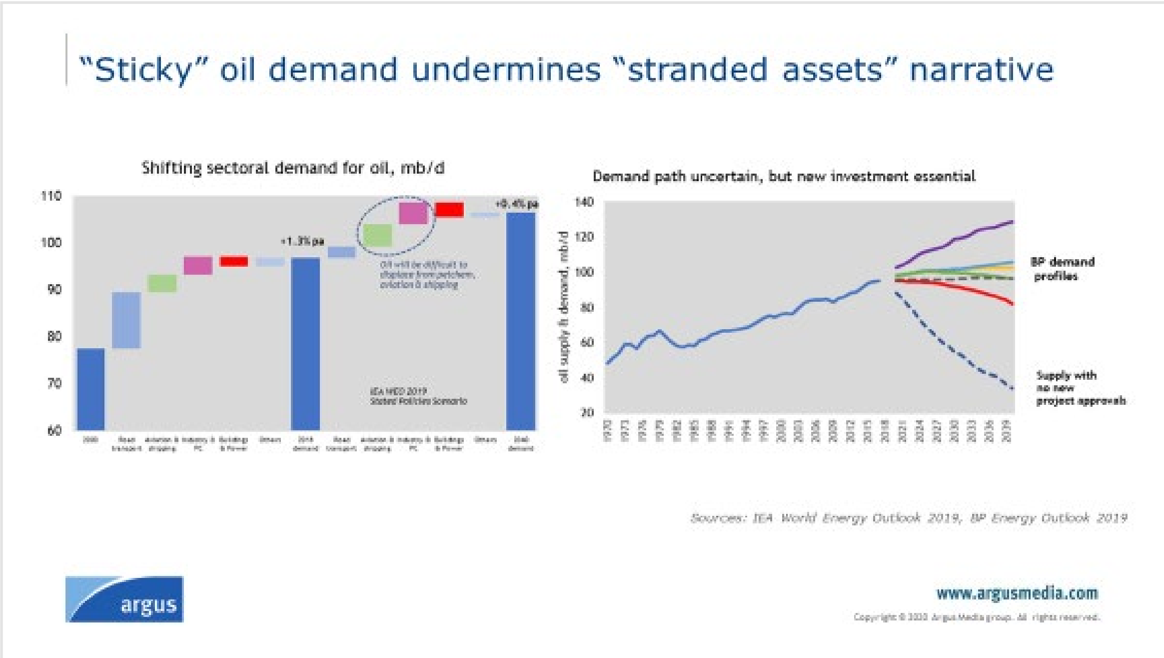




As ever, Opec confronts a conundrum over whether it should pursue price or market share objectives. Moreover, we think that as coronavirus recedes, even the Chinese crude market that Middle East producers have courted so assiduously in recent years will once again be subject to competition from US supplies at the margin.



For the longer term, energy transition will weigh on oil demand growth, but it is difficult to see oil demand falling outside a 25-30pc share of primary energy in the next 20 years. Demand is declining in power generation and buildings sectors, and will slow in personal road transport as electric vehicle penetration increases. But continued growth in petrochemicals, freight transport, air travel and shipping looks assured in the medium term, most notably in emerging markets.

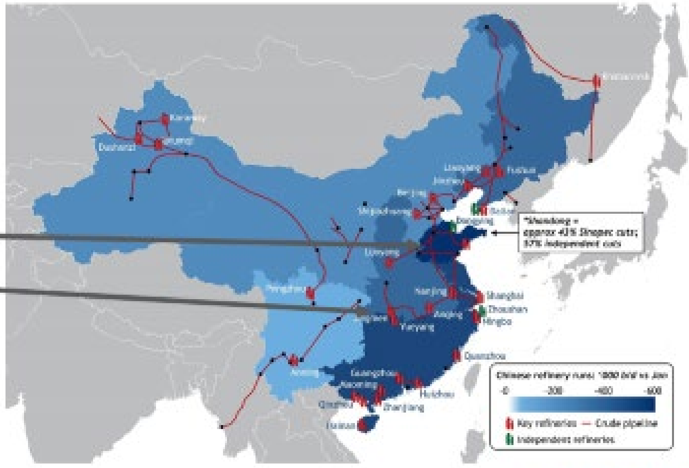


Whatever oil's longer term demand trajectory, the concept of "stranded assets" appears misguided given the need for sustained investment to offset decline from legacy producing assets.

China and Asia-Pacific: Coronavirus hits demand

Coronavirus triggers massive run cuts in China

- Independents cut first and hardest, but...
- Significant demand destruction in core Sinopec markets of
  - Shandong
  - Central China
- ...independent runs creeping higher by late-Feb



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Des Shandong: Argus assessments

Des Shandong	Des Lula	Des ESPO Blend	Des Djeno	Des Oman
Grade	Lula	ESPO Blend	Djeno	Oman
Origin	Brazil	Russia	Congo (Brazzaville)	Oman
Loadport	Acu, Santos basin FPSO (Brazil); La Paloma (Uruguay)	Kozmino	N'kossa, Djeno	Mina Al Fahal
Destination port	Qingdao, Huangdao, Dongjiakou, Rizhao and Yantai	Qingdao, Huangdao, Dongjiakou, Rizhao and Yantai	Qingdao, Huangdao, Dongjiakou, Rizhao and Yantai	Qingdao, Huangdao, Dongjiakou, Rizhao and Yantai
4Q19 transaction volume ('000 b/d)	540	160	80	22
Description	Differential to front month Ice Brent in the month of delivery	Differential to front month Ice Brent in the month of delivery	Differential to front month Ice Brent in the month of delivery	Differential to front month Ice Brent in the month of delivery
Quality	API° 29.3 / sulphur 0.36%	API° 35.6 / sulphur 0.48%	API° 27.6 / sulphur 0.34%	API° 30.4 / sulphur 1.45%
Assessment process	Average of deals done over the day	Average of deals done over the day	Average of deals done over the day	Average of deals done over the day
Assessment window	50-90 days forward	30-70 days forward	40-80 days forward	30-70 days forward
Price assessment name / codes for contracts	PA0025005	PA0025006	PA0025004	PA0026713

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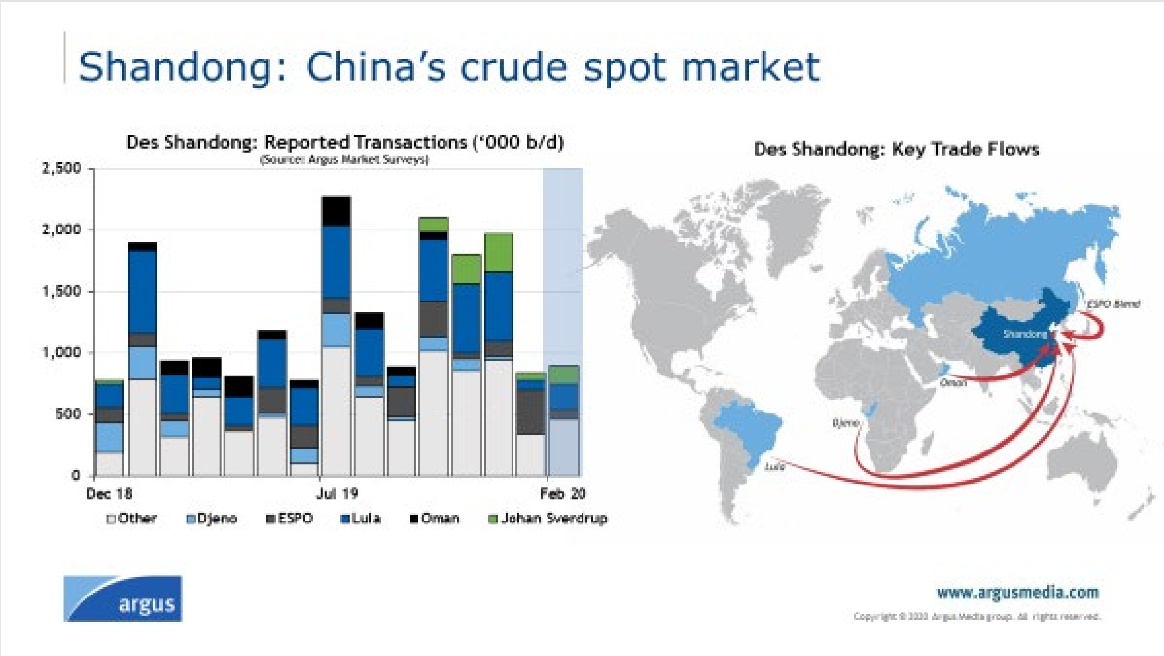
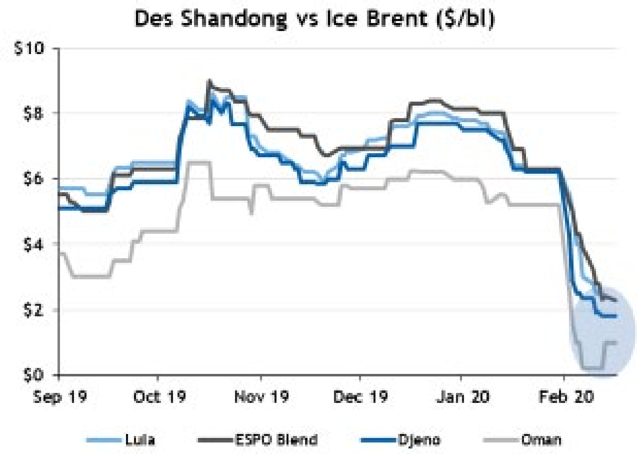
China is taking dramatic steps to stabilise its economy in the wake of the coronavirus outbreak — injecting $170bn into the economy within days of the end of the extended lunar new year holidays, announcing various tax holidays and preparing to cut interest rates. More measures are planned, and fiscal policy will become highly counter-cyclical this year, despite individual provinces' weak projected revenue growth. 2020 is, after all, the year in which China aims to achieve its target of doubling GDP relative to 2010 levels. Oil demand is still likely to shrink in this year's first quarter, by 500,000 b/d. But we expect a V-shaped recovery where demand bounces back in the third and fourth quarters of this year as the virus is brought under control and new stimulus measures start to take effect.



Chinese refinery runs in February were over 3mn b/d lower than January, or 10mn b/d — the lowest since January 2015. This is a sum-of-the-parts estimate derived from Argus surveys of around 70 refineries. Shandong independent refiners were among the first to cut crude runs. They are highly flexible and adaptable to changing market conditions and look likely to run barely half as much crude in February as in January. But Sinopec, the world's largest refiner by crude distillation capacity, has probably been hardest hit because, geographically, it is most exposed to the loss of demand arising from transport restrictions. Hubei province in central China, where Sinopec has two refineries, has banned almost all road traffic, with the exception of emergency services.

Shandong: Refiners spot a buying opportunity

- Argus DES assessments are the first reliable indicator of Chinese domestic market
- Differentials responded rapidly and dramatically to virus
  - Shandong is the marginal fuel supplier to China's domestic market
- DES price declines halted mid-Feb, signaling start of re-stocking



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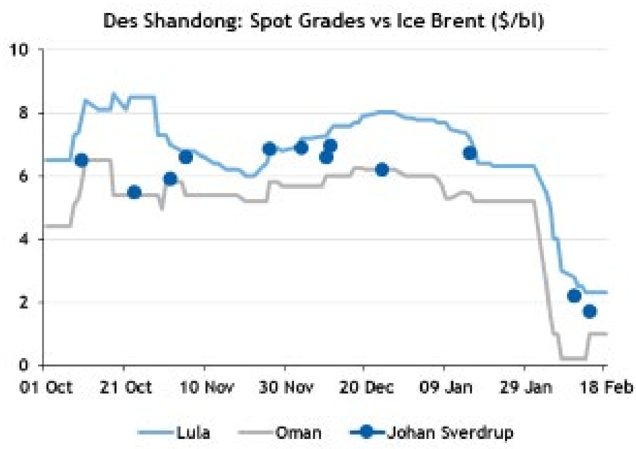
Lula: A reference price for competing grades

- High liquidity and lengthy assessment history produce a reliable price signal
  - Lula is already a reference for west African medium sweets/Brazilian pre-salt grades in China
- New North Sea grade Johan Sverdrup is emerging as another Shandong favourite
- Lula emerges as a vital reference for new crude suppliers to China



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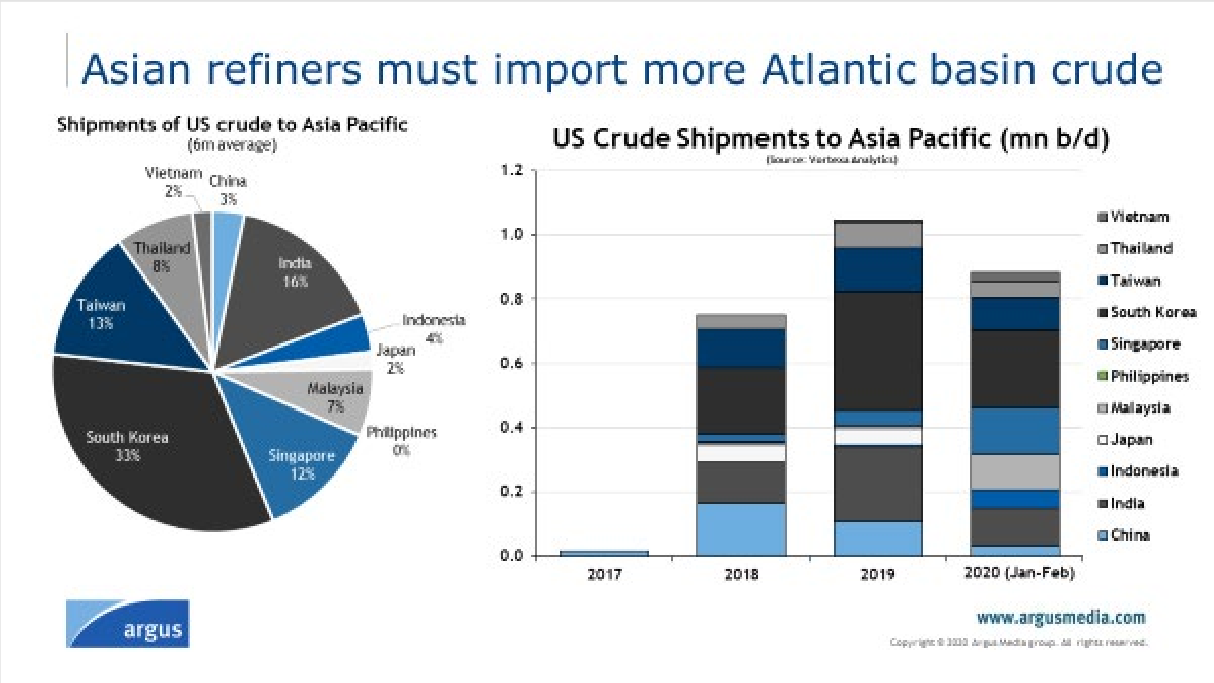

Most of the crude arriving now in China was bought in November-December. Importers cannot simply reject over 10mn b/d of crude arrivals. And they cannot process it because they have little clean storage space. So Chinese crude tanks will have to take the strain. Chinese firms are seeking to resell March-loading cargoes and will slash April purchases, causing stocks to swell in the Atlantic basin and Mideast Gulf.

Markets may look bleak now, with refineries running at bare bones utilisation rates. But high run rates ate away at Chinese crude stocks in the fourth quarter of last year, and crude is starting to look — to some of the independent companies in Shandong province — temptingly cheap. And in north China, their main market, we are already starting to see fuel demand — and refinery utilisation rates — start to creep higher again. They have already bought around 40mn bl of crude for delivery in the second quarter, since markets reopened on 6 February.

Long-haul, fixed-price deals are a risky business for buyers and sellers. One slip-up is too many these days, whether for local refiners competing with the new generation of highly integrated mega-refineries, or trading companies placing cargoes in an oversupplied market.

Anyone taking delivery of a cargo in Shandong in February stands to pay half a million dollars more for having fixed the differential in December than they would pay using February floating prices. And in China — an increasingly competitive downstream environment where product prices are linked to crude futures — that is bad news indeed.

Argus reports price of US crude delivered to NE Asia

Delivered Northeast Asia	Month	Basis	Diff	Bid	Ask	±
						$/bl
WTI del NE Asia	May	Apr Dubai	+3.60	58.93	59.03	0.8200

Delivered ex-ship Shandong prices — $/bl

Grade	Timing	Basis	Diff Low	Diff High	Diff Mid	Low	High	Price
ESPO Blend	Apr	Jun Ice Brent	+2.30	+2.50	2.40	58.82	59.02	58.92
Djeno	Apr	Jun Ice Brent	+1.70	+1.90	1.80	58.22	58.42	58.32
Lula	Apr	Jun Ice Brent	+2.10	+2.50	2.30	58.62	59.02	58.82
Oman	Apr	Jun Ice Brent	+0.70	+1.30	1.00	57.22	57.82	57.52

Mideast Gulf and Atlantic basin crude cfr Asia (fob plus freight)

	Month	Singapore $/bl	±	China $/bl	±
Mideast Gulf					
Dubai	Feb	56.46	0.88	56.90	0.88
Oman	Feb	56.72	1.08	57.15	1.08
Murban	Feb	58.87	0.57	59.28	0.57

Methodology:

- WTI cargoes of Permian quality to be delivered three months forward to Taiwan South Korea, Japan & China
- Follows market practice, using Dubai two months forward as underlying price
- In February, Argus assesses price for May-arrival cargoes at a differential to April Dubai
- Delivery point standardized to Yeosu, South Korea

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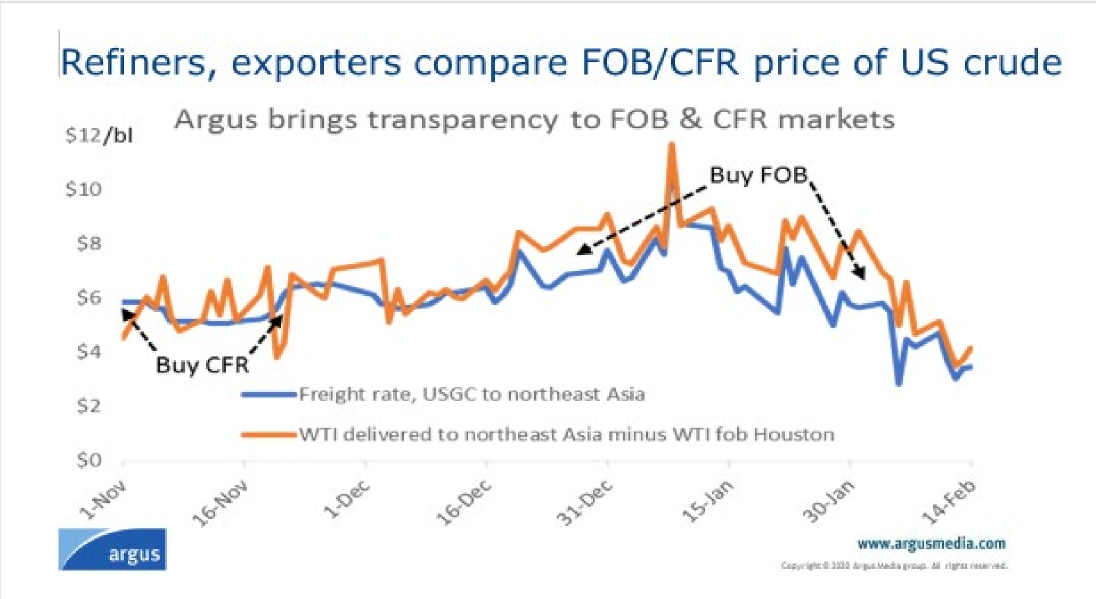
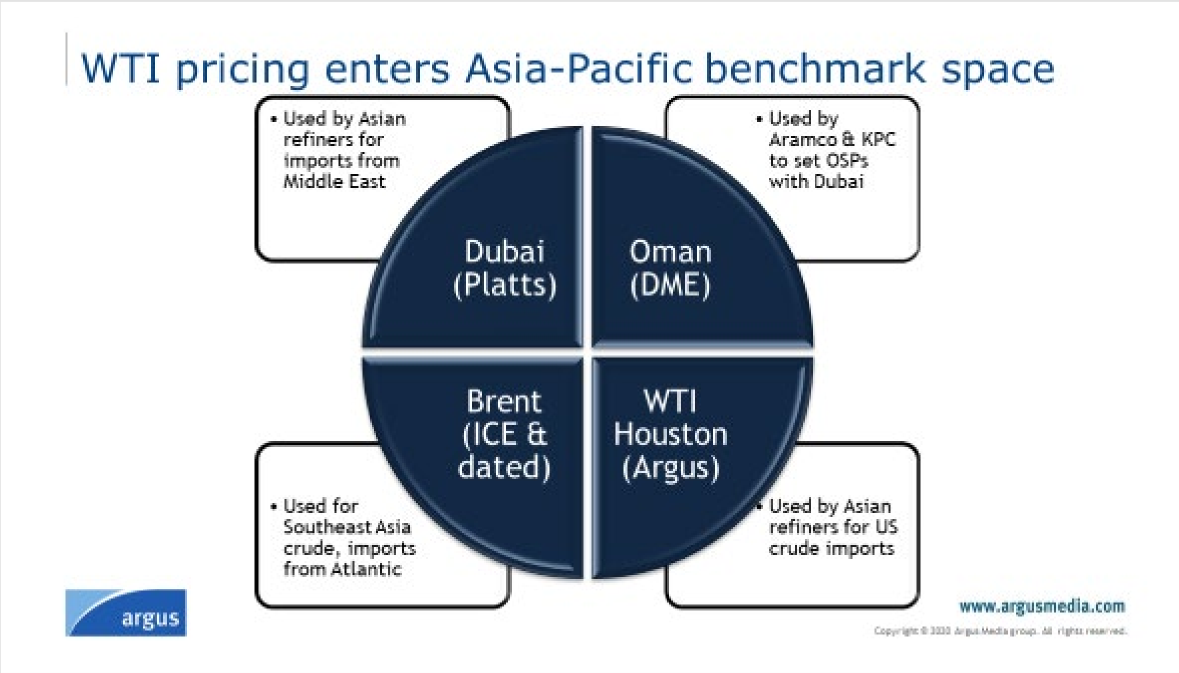
Argus was the first price reporting agency to launch price assessments for the delivered Chinese spot market, centered around the massive Shandong refining hub in north China, in 2018. As the market in China gets more sophisticated and comfortable with trading, so demand for risk management tools increases. There is a growing call for a swap settling against the Argus Lula assessment, which is underpinned by around 500,000 b/d of spot liquidity.

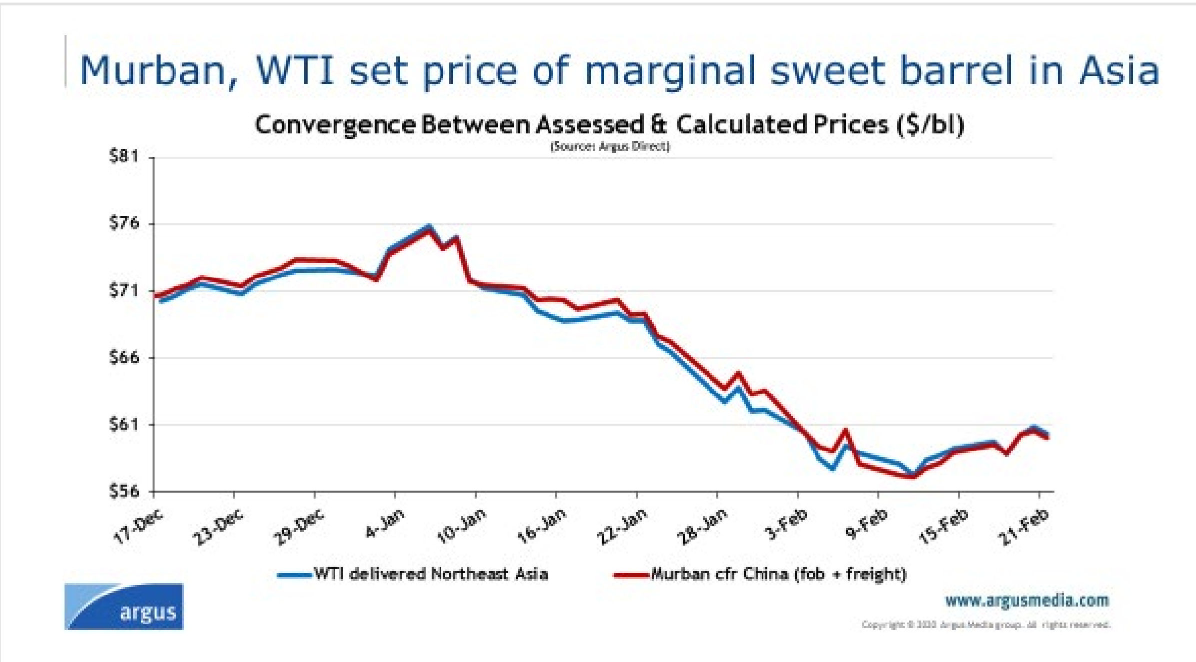


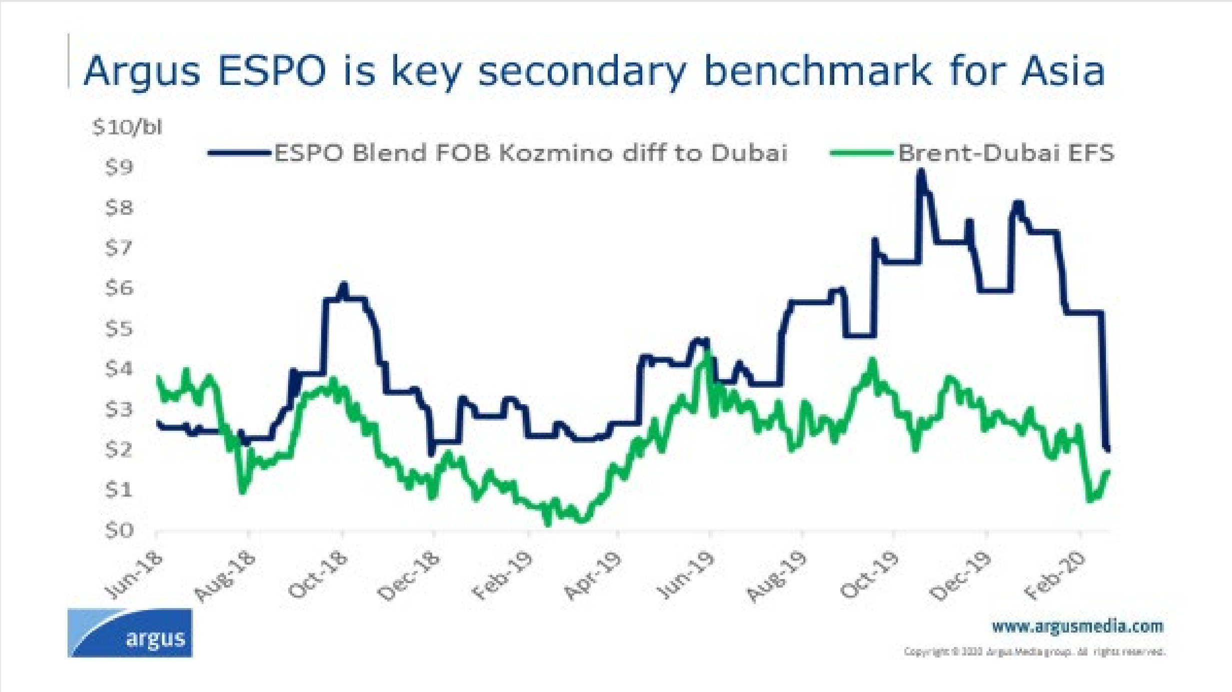
Global trade flows are lengthening, and risks are rising, as the coronavirus demonstrates. But it is still common for refiners to fix the differential that they will pay for a cargo at discharge 70 or 90 days in advance. The shift to floating prices that Argus proposes gives refiners and trading companies a new set of weapons with which to combat price uncertainty in an increasingly volatile market.



China is not the only place where we see the development of new prices for the Asian market. As the diversity of crude grades that Asia imports increases, refiners across the region are looking for new pricing mechanisms that allow them to compare crude of differing origin and quality.

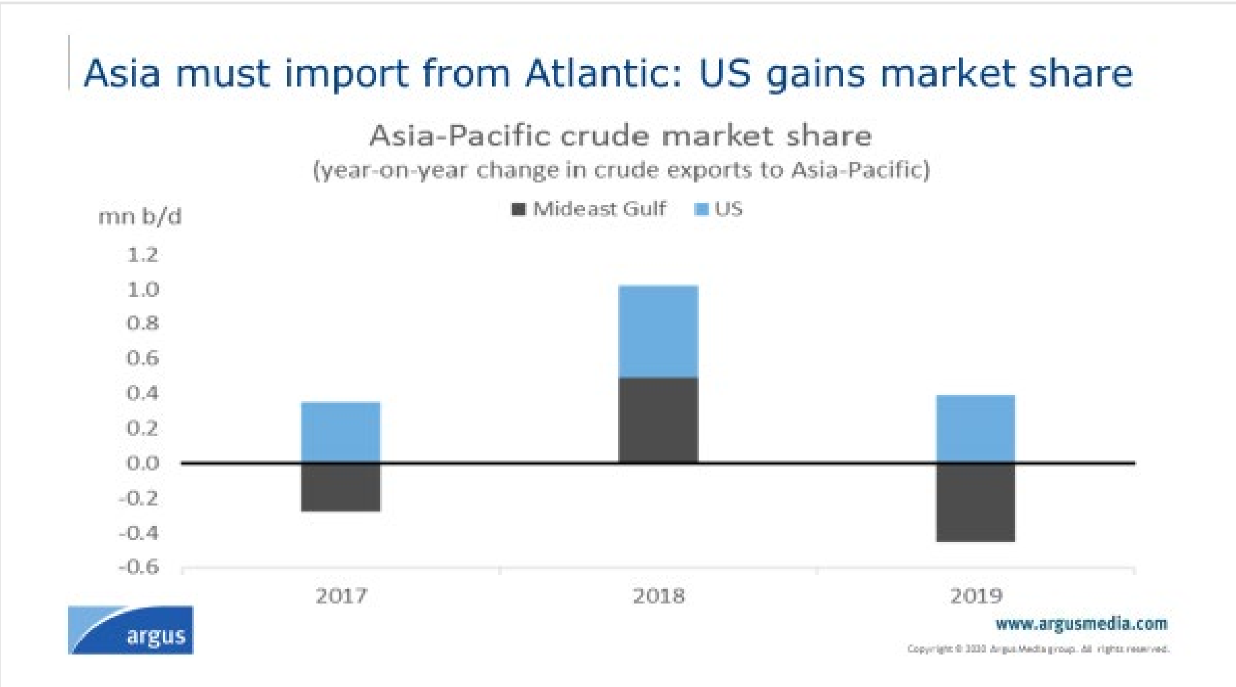
Volatile freight rates and changing dynamics in the products markets, as well as the adoption of stricter fuel standards, introduce new variables in determining which crude is most competitive, based on the configuration of individual refineries.



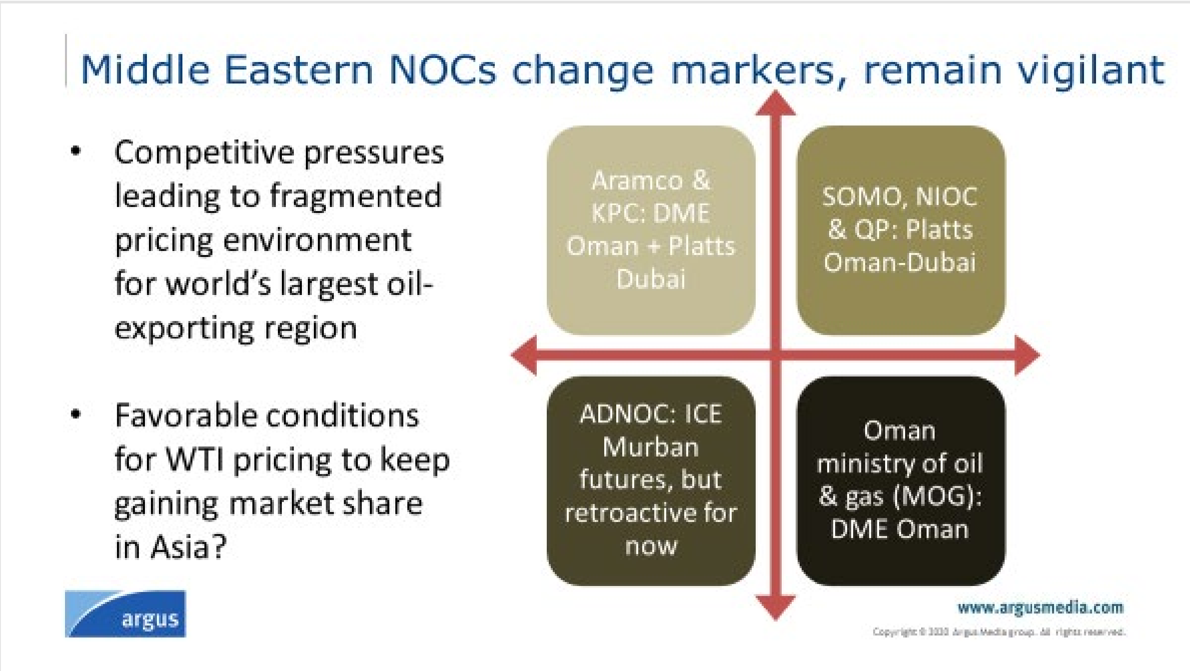


This diversity of supplies undoubtedly implies greater optionality for crude buyers, and it creates more work as importers deal with multiple benchmarks. Asia-Pacific accounted for 86pc of global oil demand growth last year, and as the region's role as a demand centre grows, so too does its role as an arbiter of prices.

More and more price signals are being generated east of Suez and at points of delivery in the great demand centres of northeast Asia. These new pricing initiatives will almost certainly start to chip away at the global pre-eminence of markers such as dated Brent in the years to come.



The astonishing rise of US production means that incremental crude supply is increasingly comprised of light grades. In the same way that WTI is emerging as the clearing price for light grades in Europe, it is also emerging as the clearing price for light crude in Asia-Pacific. The expanding availability of WTI has eroded the value of similar-quality Abu Dhabi Murban, one of the lightest grades produced in the Middle East. This shift in trade patterns allowed Argus to launch a price for WTI delivered to northeast Asia last year, allowing buyers and sellers to compare prices of US crude with prices for the Middle East grades that WTI competes with in Asia-Pacific. Therefore, it is essential that Murban — currently priced retrospectively — starts pricing on a prospective basis, as it may alternate with WTI in setting the price of the marginal light sweet barrel across Asia-Pacific.

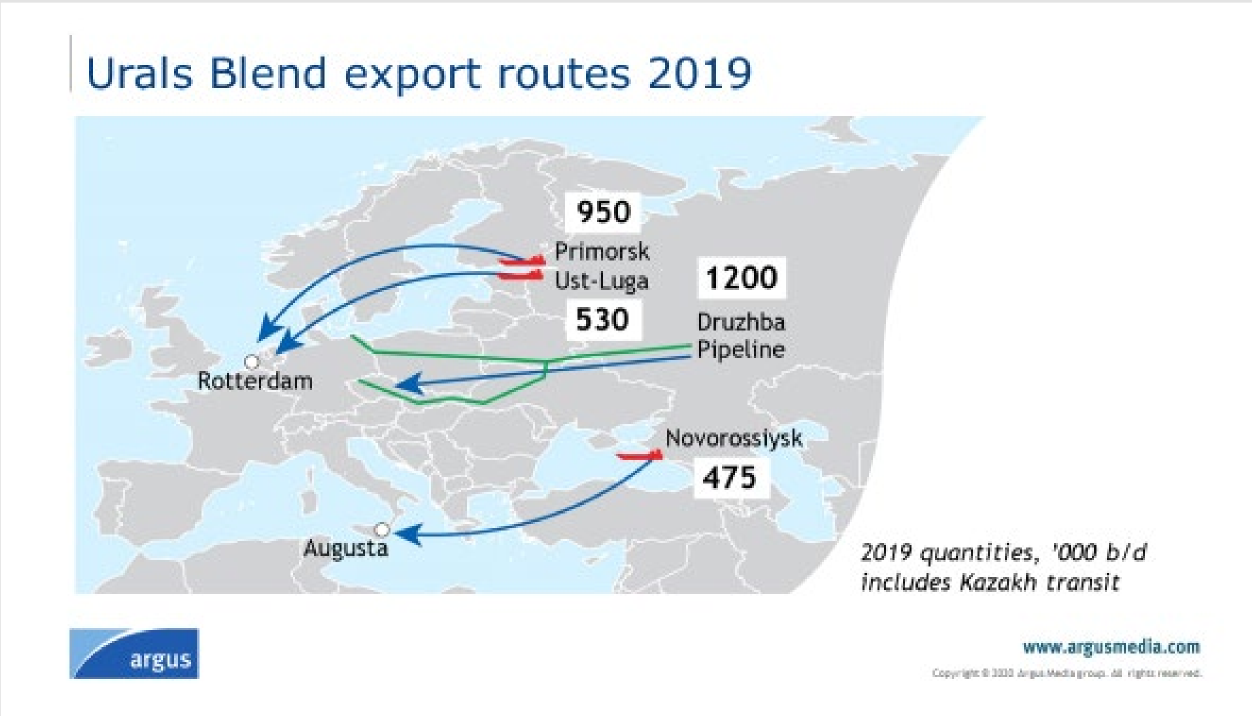


There are already seismic shifts under way in Asian crude pricing. Just over the past 18 months, we have seen Saudi Aramco abandon Platts Oman in favour of DME Oman, averaging it with the Platts Dubai price as the basis for its official formula prices used to supply Asian term buyers. Kuwait's KPC followed the Saudi lead at the end of last year, and some market observers expect that Iraq's Somo could also adopt DME Oman in the coming months. This is forcing both Abu Dhabi's Adnoc and Qatar's QP to modernise their pricing mechanisms. The Qataris are adopting the same pricing formula that had been used by the Saudis for decades, based on the average of Platts Oman and Platts Dubai. The Emiratis are working hard to launch a futures contract for Murban crude on a new Abu Dhabi-based platform run by Ice.

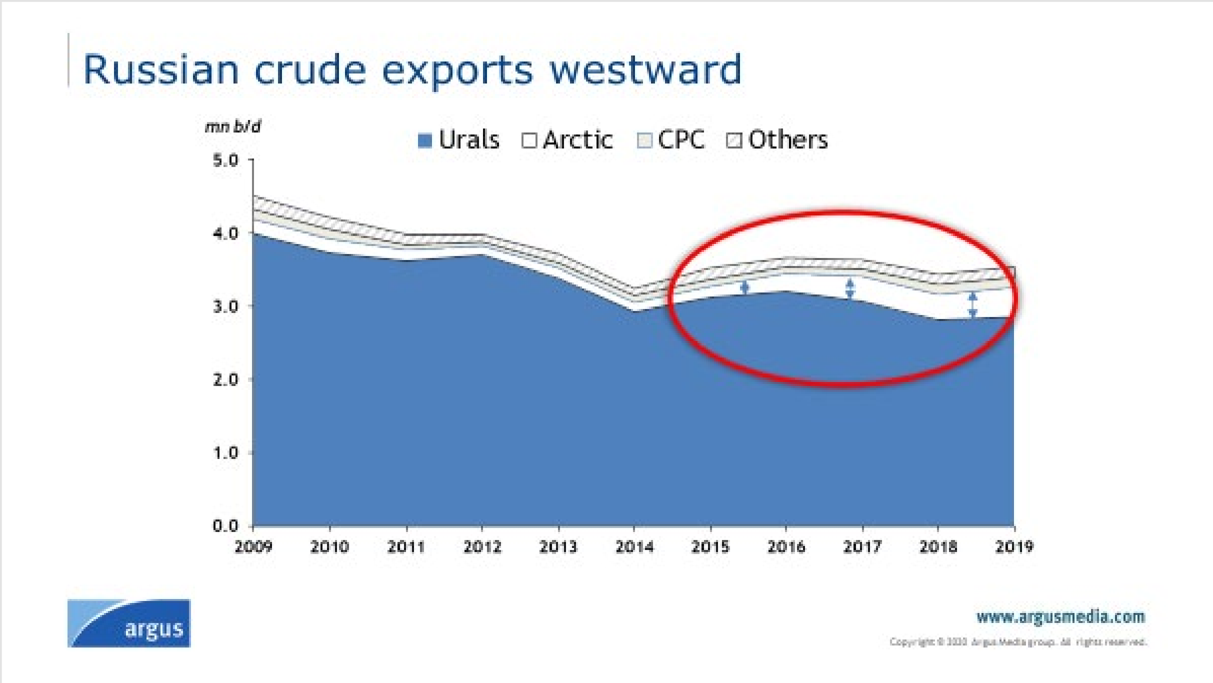
Abu Dhabi exports around 1mn b/d of crude, 90pc of which goes to Asia-Pacific. A prospective pricing mechanism for Murban would enhance its ability to compete with rival Middle Eastern grades, and most importantly, it would help the Adnoc grade to better compete with growing flows of WTI to Asia-Pacific.

Murban and WTI compete with similar-quality grades North Sea Forties and Russian ESPO Blend in northeast Asia. Adnoc is building huge amounts of crude storage in Fujairah, due for completion by 2022, which could provide the supply buffer needed for a physically settled Murban futures contract. At that point, we can start to envisage physical grades pricing relative to Murban futures. And, of course, Argus would seek to be at the heart of assessing those physical differentials, and bringing additional price transparency to east of Suez markets. So it is not hard to envisage a situation where a crude reference price in the Mideast Gulf, more responsive to regional supply and demand fundamentals than North Sea Dated and underpinned by high physical liquidity, could form the basis of a benchmark.

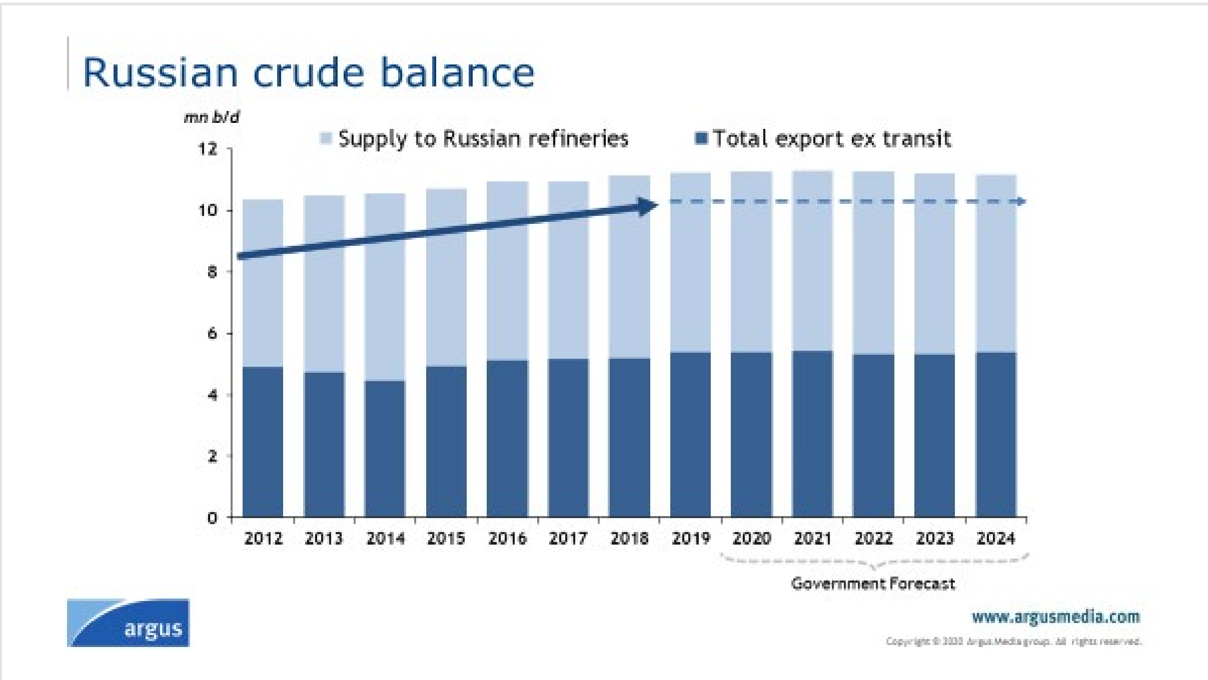
Russia: Straddling east and west



Russia has a well-developed infrastructure westward, which allows it to redirect westbound flows if necessary. For example, its surplus capacity helps absorb shocks such as last year's contaminated crude incident. Medium sour grade Urals is the base-load crude for many European refineries and probably the most actively traded spot grade in Europe. High market liquidity allows Argus to produce a robust Urals price assessment at Rotterdam and Augusta. These prices are well accepted in Russia as the government uses them to calculate oil taxes. An index based on these prices is widely used in contracts on the Russian domestic market along with Argus spot assessments in west Siberia.



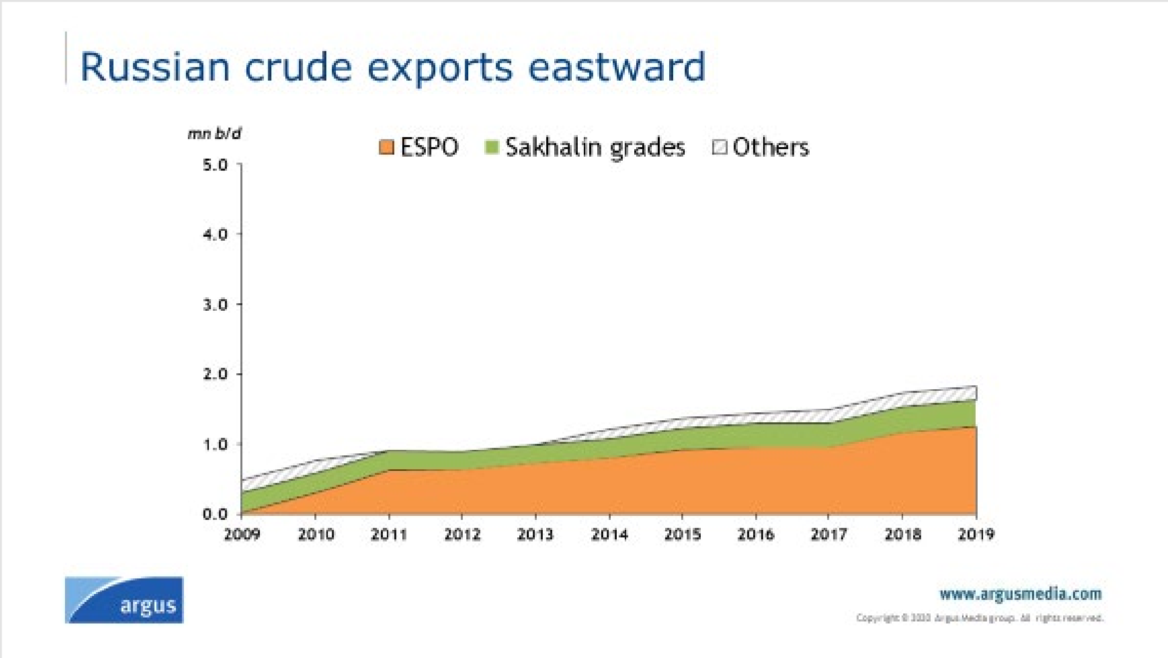
Although the west is a major market for Russian crude, exports of Urals have decreased in recent years. Some volumes from west Siberia were redirected to the premium Asia-Pacific market. At the same time, total supplies of all grades to westbound routes has remained relatively stable during the past five years — owing to the growth of Arctic crude supply, which has almost tripled since 2014. We expect this trend to continue.



Taking a look at the fundamentals, Russian production has grown every year over the past decade. But the official forecast by 2024 is conservative, largely because of Opec+ limitations. Without this factor, Russia can increase its production in the short term — Russian companies have argued against output cuts. Looking ahead, the long-term crude production outlook depends on the development of greenfield sites, which need tax incentives. The government is testing new profit-based taxes, and if this regime is implemented, it will be a signal that Russia can increase its production in the long term. According to official forecasts, total Russian refining demand will plateau, although the refining landscape will change significantly because of new taxation rules that favour complex refining.

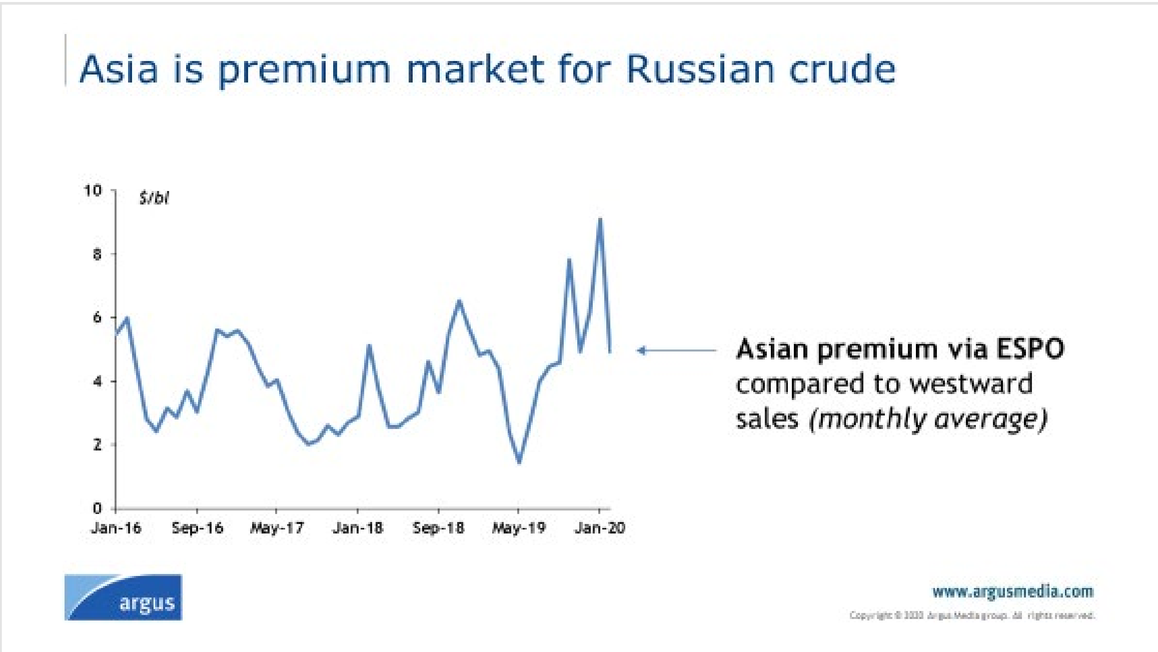
Considering these developments, the expectation would be for total exports to remain flat as well. But will the redistribution of flows from west to east continue?

Russia's reliance on western markets is waning, particularly as it has expanded into the fast-growing and premium Asia-Pacific market. Chinese financing has helped build new infrastructure, such as the ESPO pipeline and port of Kozmino, while state-controlled Rosneft has significantly expanded its business supported by Chinese pre-payment deals. We are likely to see this trend continue in the near future.



Russian eastbound exports have surged thanks to increased buying by China. ESPO Blend has become one of the leading benchmarks in Asia-Pacific, and as a result, Argus ESPO Blend price assessments are widely used in the market. For example, ESPO fob Kozmino, based on a volume-weighted average of transactions at Kozmino, is used in long-term contracts.

For now, it appears as if Russia's eastern expansion has probably reached its limit owing to infrastructure constraints. Russia completed the ESPO pipeline project in December. Furthermore, it is reported that the pipeline and port are running at almost full capacity, although Russia has no official plans for expansion.

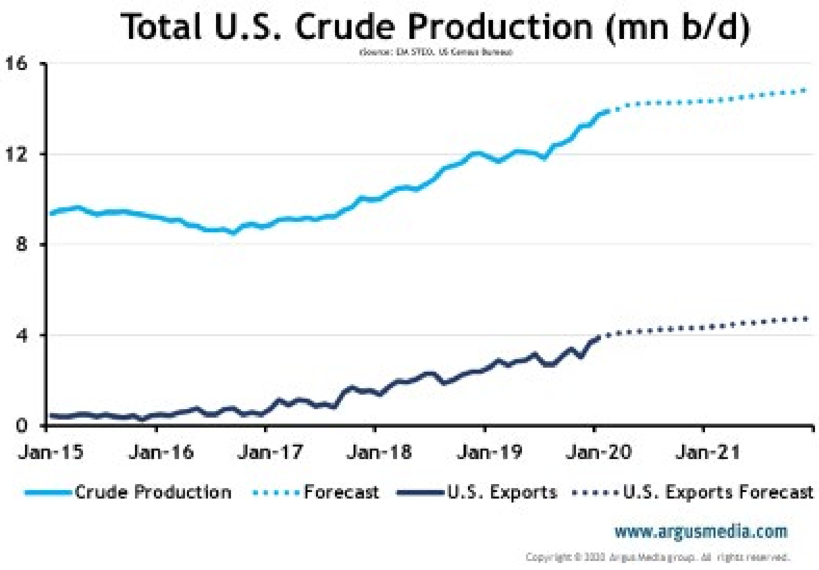


But if Asia-Pacific continues to offer a premium market for Siberian crude, more investment in infrastructure may follow.

US: Shale shifts down a gear

Shale shifts down a gear

Crude Production Growth		
Year	Source	Growth
2019	EIA	1,250,000 b/d
2020	EIA	960,000 b/d
2020	Argus	740,000 b/d

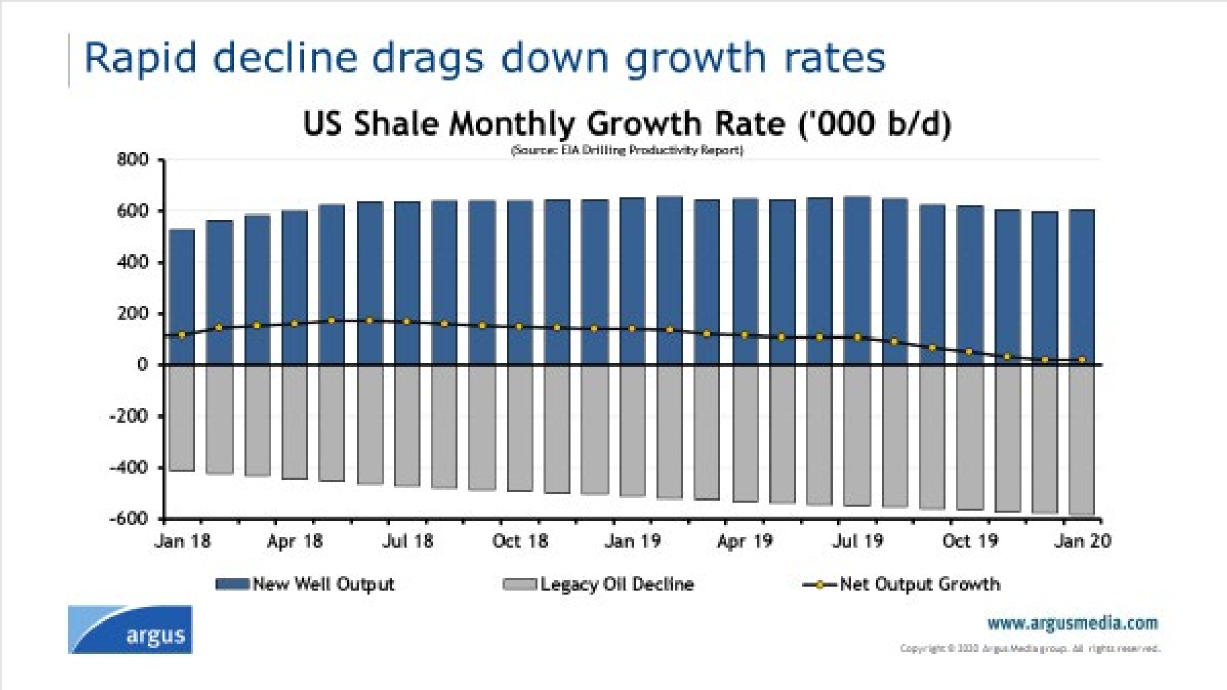


Despite a raft of negative headlines, US production, mainly driven by shale, continues to grow rapidly. The US became the largest crude producer in the world some time ago, eclipsing Russia and Saudi Arabia. Last year, the US became the world's largest overall oil exporter — comprising crude, NGLs, and products. Finally, the US has at last become a net oil exporter, after adding a massive 1.25mn b/d of crude output last year.

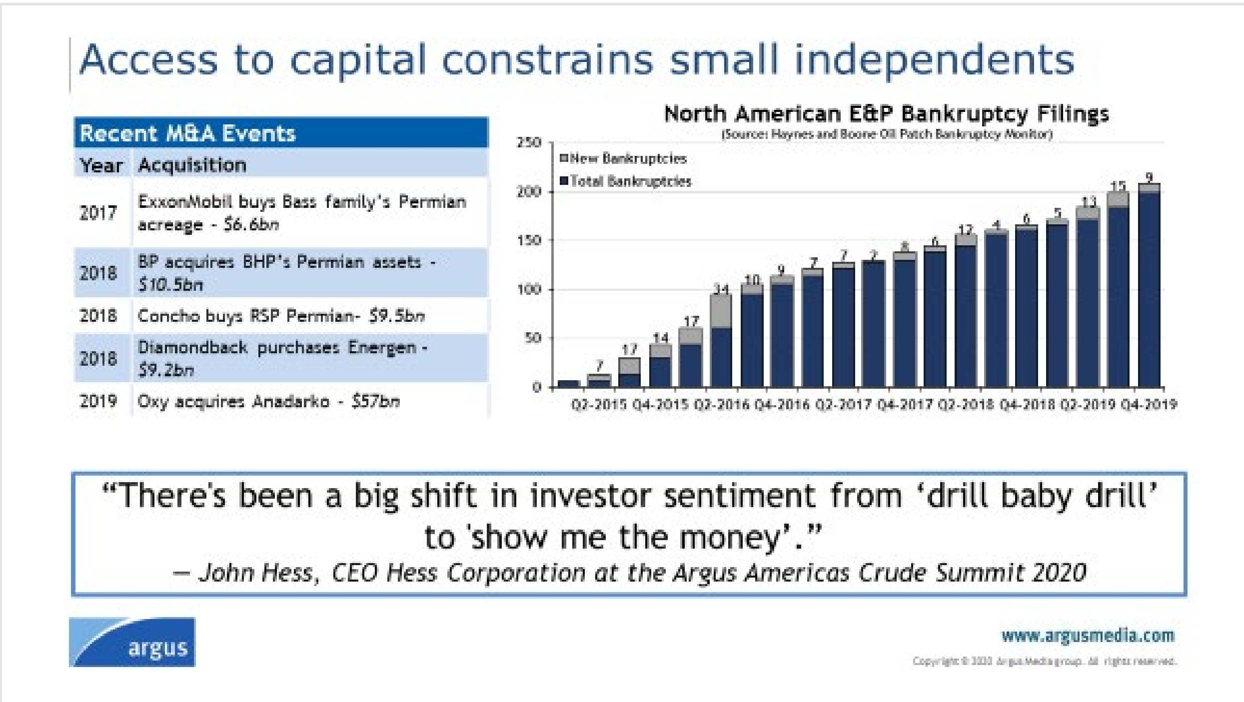
While we understand that it can be hard to reconcile the two views of US crude — are we going from boom to bust? are we seeing another 2014? — the short answer is no.

There really is no end in sight to the expansion of US production. With the Permian basin in particular likely to grow well into the 2030s and exports rising steadily as production increases, the US makes a strong case for continued growth. While US will be the largest component of additional non-Opec production this year, forecasts for 2020 vary widely from negative growth to almost 1mn b/d from the EIA. The answer, no doubt, lies somewhere in between.

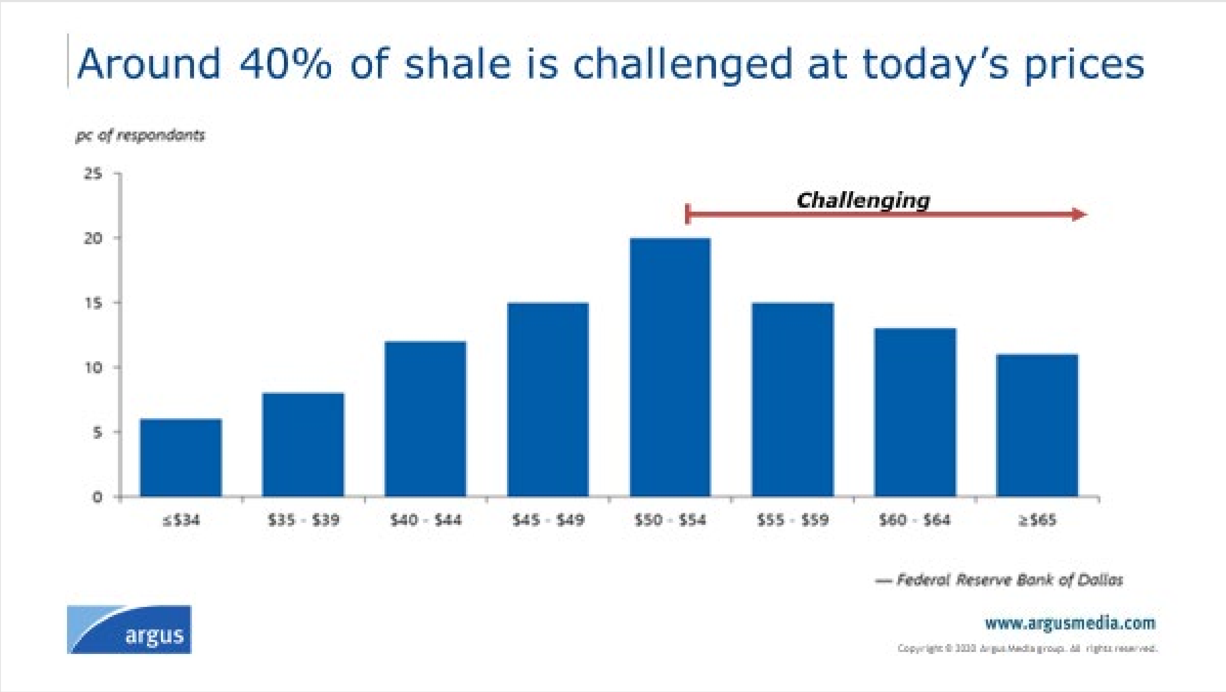
Instead of a bust, we are seeing a slowdown brought on largely by three factors — steep decline rates, stricter financial discipline from investors, and a price environment that is more challenging for many.

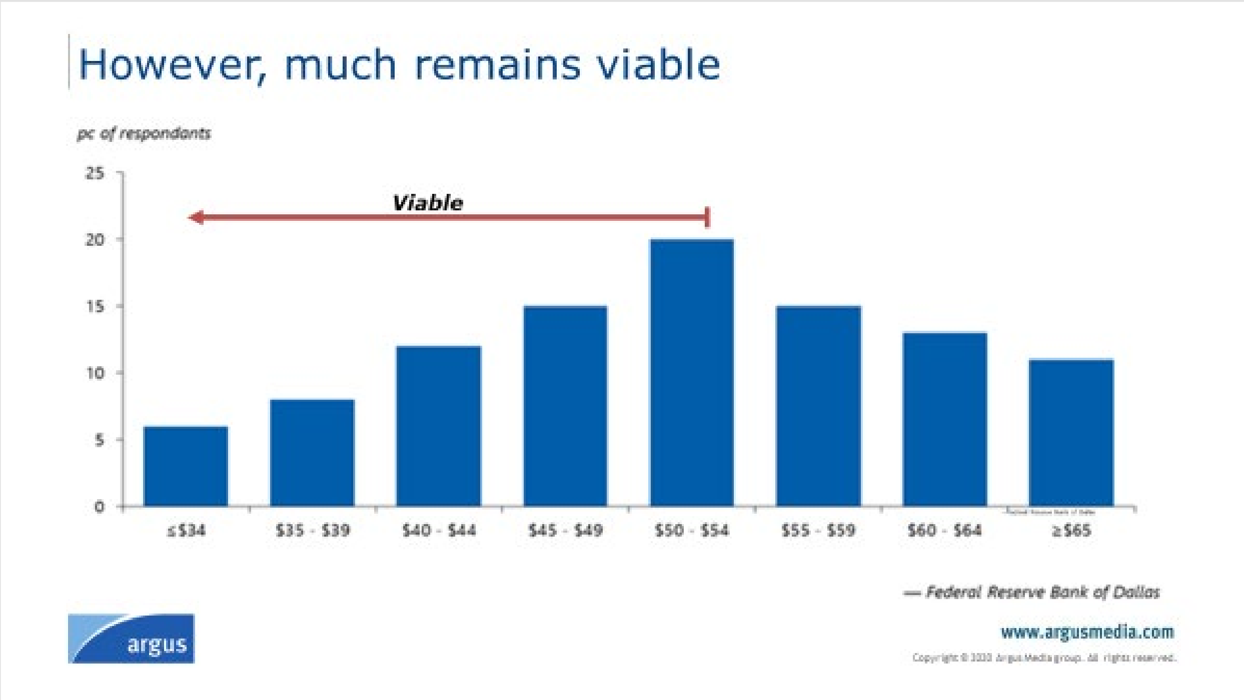


As we look at the geology, shale wells decline significantly in year one by as much as 70pc, plus more in the following years. It is intrinsic to the business model that a producer needs to keep drilling to replace production decline. In essence, replacing oil requires more drilling, and that requires capital.

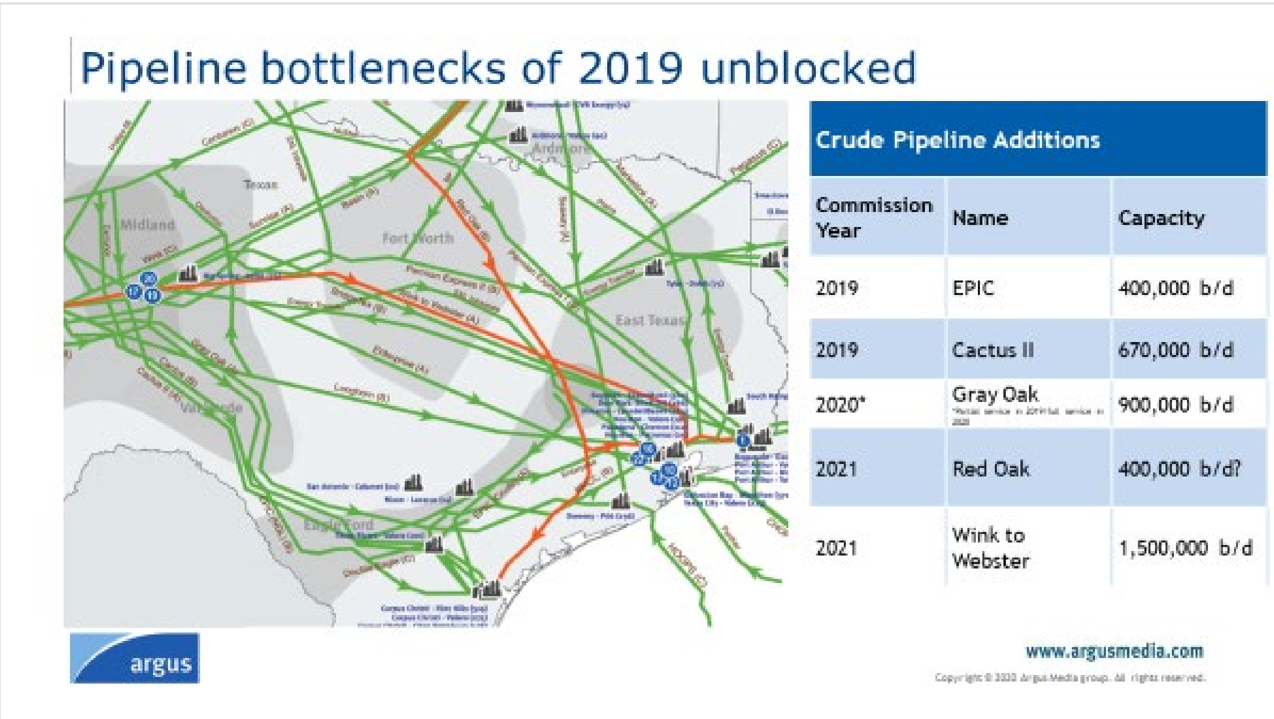


Early enthusiasm from investors and lenders alike for the rapid growth and high multiples at which shale firms traded has begun to fade. Oil, these days, is treated warily by Wall Street, which suspects that it may be a sunset industry awaiting its “Kodak moment”, similar to when digital photography replaced the era of film. Importantly so, there has been a renewed focus on generating a return — free cash flow — among investors. For those companies that cannot deliver, a big struggle awaits. As a result, this has led to a wave of bankruptcies that has grown stronger over the past year. In addition, we have seen increased M&A activity, with the majors and large independents increasingly making their presence felt. The majors’ economies of scale, project management skills and access to capital mean they are much less influenced by fluctuations in the crude price than their independent counterparts.





In this new world, price clearly matters. At current levels of $53-54/bl, on a cash flow basis, around 40pc of shale producers will experience challenges, although many will be hedged, which provides them with some protection.



Crude Pipeline Additions

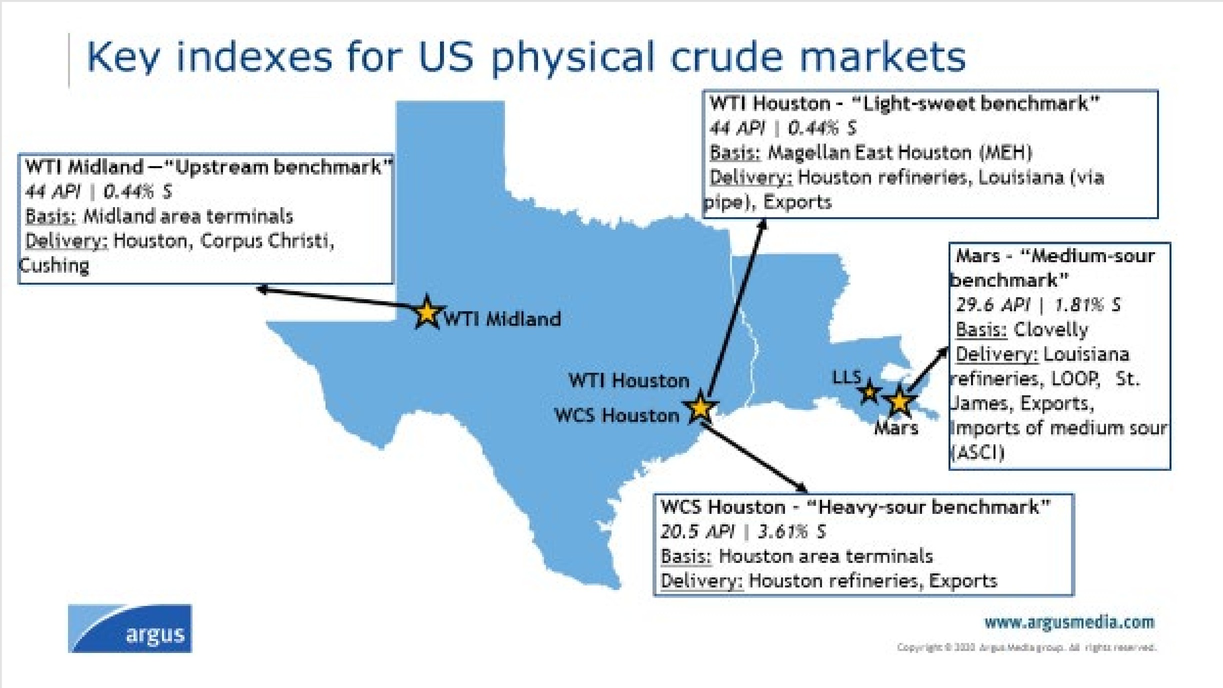
Commission Year	Name	Capacity
2019	EPIC	400,000 b/d
2019	Cactus II	670,000 b/d
2020*	Gray Oak	900,000 b/d
2021	Red Oak	400,000 b/d?
2021	Wink to Webster	1,500,000 b/d

On a more positive note, there are now fewer challenges getting crude to market than a year ago. Last year, there was enormous build-out of pipelines in Texas. The industry added nearly 2mn b/d of new capacity from the

Permian to Corpus Christi alone. Additionally, a lot of new capacity built to Houston and Beaumont came on line. In the next year, we expect to see an additional 2mn b/d, as ExxonMobil's Wink to Webster and Phillips 66's Red Oak lines come on stream — both joint ventures with Plains All American.

For now, the infrastructural constraints have moved to the coast. Corpus Christi, which recently surpassed Houston as the biggest oil export port in the US, is a hive of activity as new tankage, pipelines, and docks are built to support increased exports. But the big prize for many is attaining very large crude carrier (VLCC) loading capabilities. The draught around US Gulf coast (USGC) ports is too shallow to fully load VLCCs, which are typically serviced by dedicated reverse lightering vessels. In an effort to load crude in deeper waters, some VLCCs have gone through the Loop offshore oil terminal, which is typically used for importing crude. There are some other terminals that can partially load a VLCC or fully load a smaller Suezmax. But for the most part, Aframaxes are the vessel of choice on the USGC. This option may work for Europe and other destinations in the western hemisphere, but most Asia-Pacific buyers want to buy VLCCs to make the arbitrage work.

At this time, there are at least nine projects at some stage of proposal and permitting. Ultimately, there is probably room for three to four, and we are unlikely to see the first of those in operation for another four years.



The USGC has been in a state of flux for the past 15 years as the shale boom, and before that, the offshore fields in the Gulf of Mexico, have carved out a new oil topography. These changes have also brought about the conditions to build extremely robust price assessments, indexes and benchmarks.

In most parts of the world, crude tends to be bought and sold in cargoes. But the US is different as it is a pipeline market. Crude trades in clips of 1,000 b/d per month, and in a very active spot market this creates high iterations of spot trades that can be used to create accurate indexes.

There are a few key cash market indexes for Argus. Moving from heavy to light are:

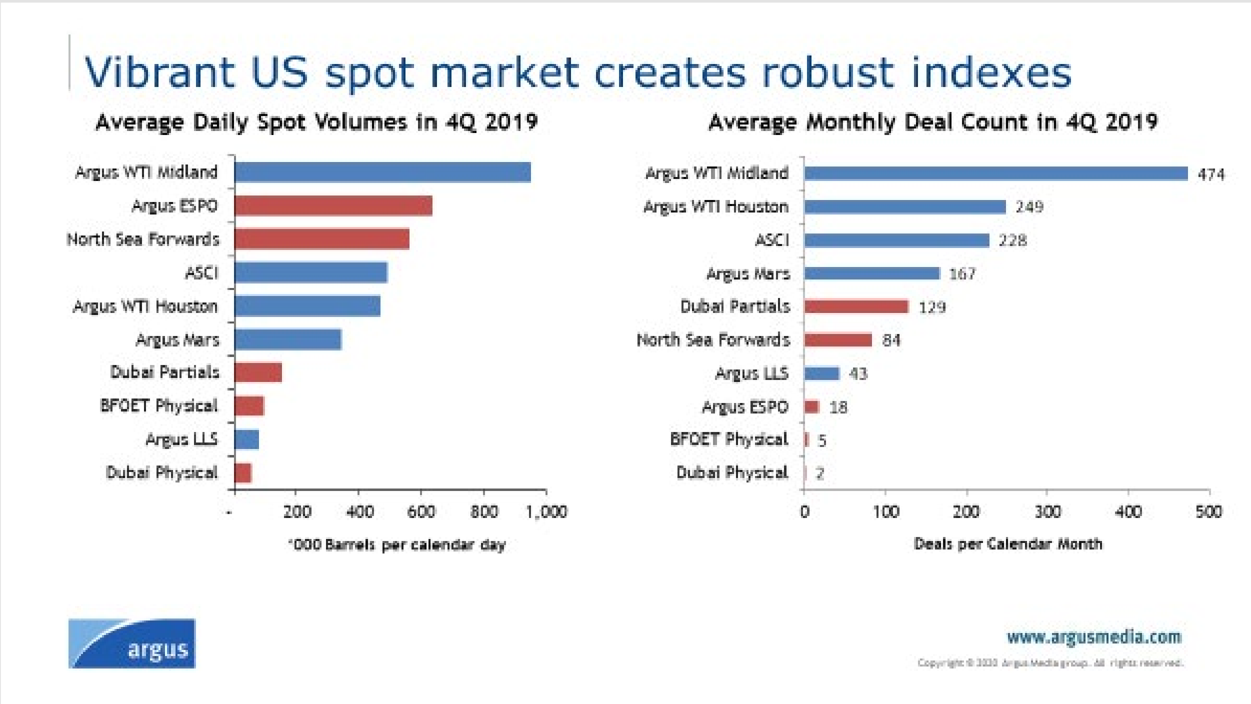
1. **WCS Houston** — an index of heavy Canadian grades delivered to the Houston area. The index is relatively new and is gaining a lot of traction as a means of indexing heavy grades not just from Canada, but also from Latin America and elsewhere. The Chicago Mercantile Exchange (CME) has announced that it will list two swap contracts that settle on the index in March.

2. **Mars** — Mars is a medium sour offshore grade that is frequently used as a secondary benchmark (Nymex plus Mars diff) to price other grades. It is used to index medium sour exports and is the key component in the Argus Sour Crude Index (ASCI), along with Southern Green Canyon and Poseidon grades. The ASCI price serves as an index for imports of medium sour crude by the US and others, primarily from the Middle East.

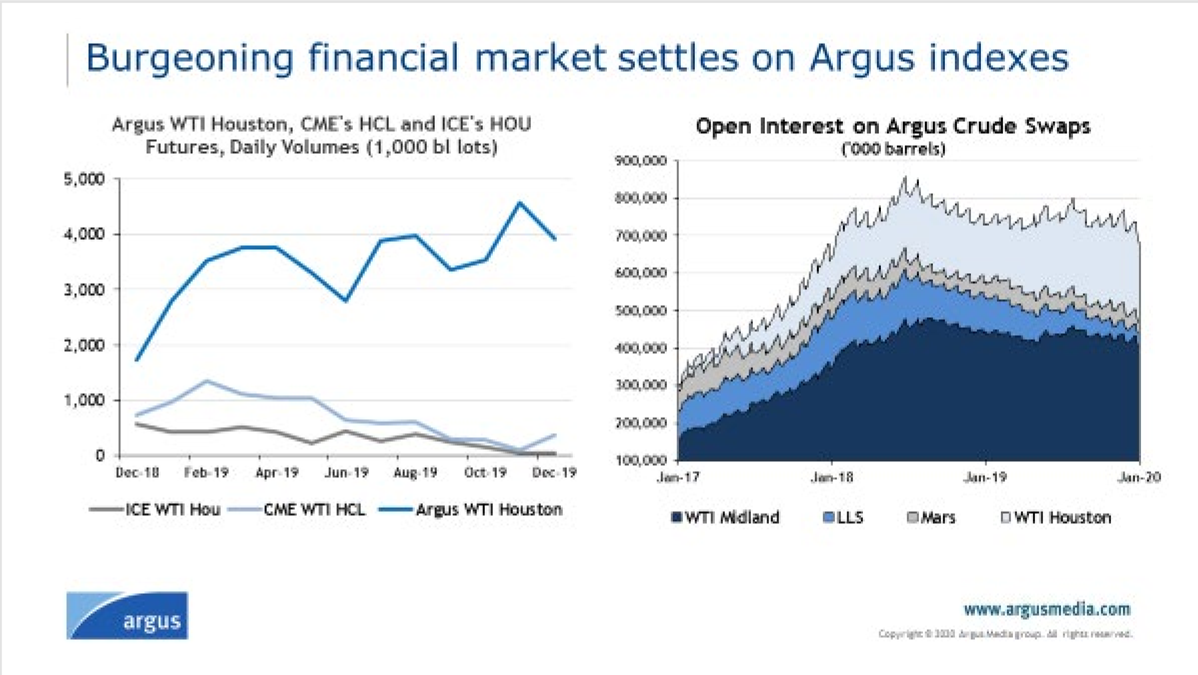
3. **WTI Midland** — WTI Midland represents the price of light sweet Permian WTI at the storage terminals of Midland Texas. The price is close to the point of production and is widely used as a secondary benchmark in West Texas trading and "gathering" contracts, where larger companies buy the output of independent producers.

4. **WTI Houston** — WTI Houston, also commonly known as Magellan East Houston (MEH), is probably the most important index that Argus publishes. In broad terms, it represents a similar crude quality to WTI Midland. The only difference is that MEH is at the other end of the pipeline in the refining and export market of Houston. Specifically, the index is located at the Magellan East Houston terminal, where only WTI arrives through the Longhorn and Bridgetex pipelines, ensuring that only

unadulterated Permian basin crude is reflected in the index. The index is used extensively as a secondary benchmark to price WTI and other light sweet grades such as Bakken and Eagle Ford in the domestic market. Furthermore, it is also used to price exports in spot contracts. Companies in Japan, Taiwan and Mexico have used it as an index in term supply contracts.

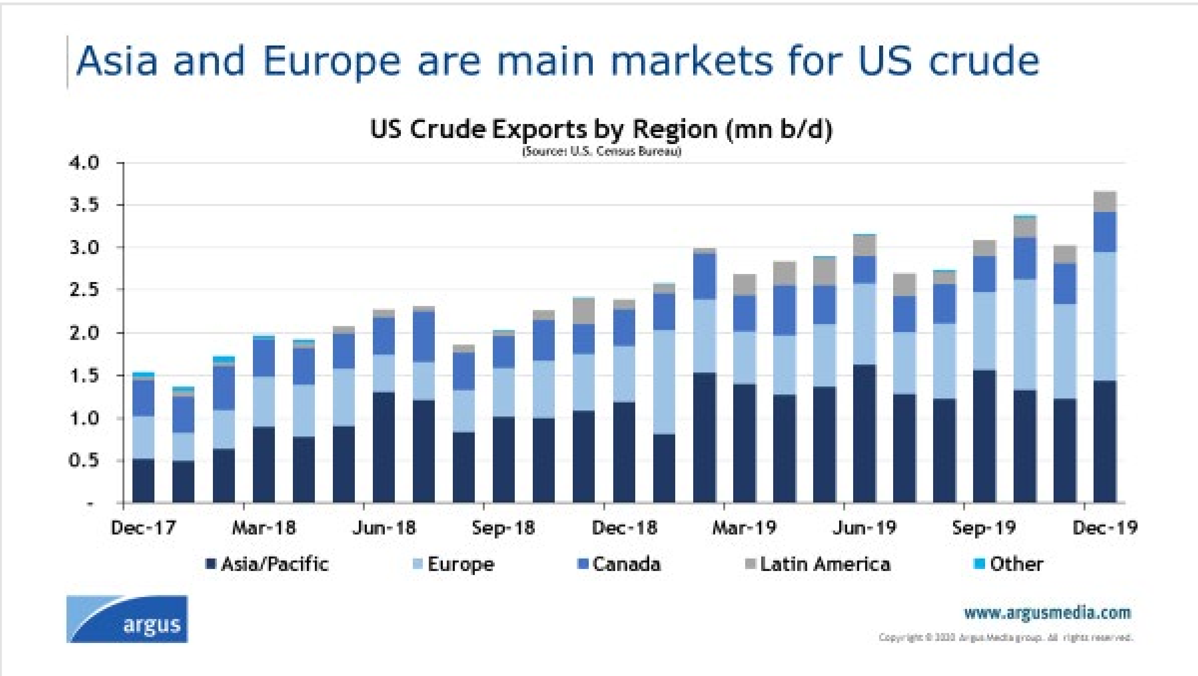


These indexes are comprised of confirmed deals done that represent a large amount of trade both volumetrically and in terms of a multitude of transaction iterations. As can be seen, only ESPO Blend and the North Sea Forwards markets come close in terms of the volume of crude they represent. Moreover, only North Sea Forwards and Dubai Partials come close to touching the number of deals recorded in the US markets. All of the US deals are published, making it easy for market participants to audit the indexes.



The unusual degree of transparency and liquidity in US crude markets has helped engender confidence in financial contracts that settle against Argus indexes. These contracts, which are cleared by the main exchanges CME and Ice, can be used by producers, traders, refiners and others to hedge price risk. Open interest in Argus-settled crude contracts is currently in the range of 700,000-800,000 lots, or 800mn bl of paper oil.

On the left-side chart above, the market has tended to coalesce around the Argus WTI Houston (MEH) swap — despite the availability of alternatives — which is currently trading some 4,000 lots each day.



Driving the surge in demand for Argus WTI Houston paper and the use of the Argus index in physical contracts has been the rapid rise in US crude exports.

As more and more US crude moves globally, particularly to Asia-Pacific and Europe, it is competition with competing grades that is helping to shape prices for a wide range of crudes in those markets.

Ultimately, it is going to be the price established in the clearing markets of Europe and Asia-Pacific that will feed back a value to WTI at the USGC.

To keep up with the speed of change in US exports and the new reach of WTI, Argus has launched a series of waterborne price assessments over the last year and a half:

1. **WTI fob Houston —** The WTI fob Houston valuation assesses the price of Aframax cargoes loading at Houston area ports. Our waterborne assessments are based on reported offers, bids and transactions. The assessment represents a logical next link in the supply chain from Midland through Houston and onto the water. Yet the relationship between waterborne WTI and pipeline is not linear and is often volatile, as it depends on demand for light sweet crude in global markets. Additionally, there is intense interest around cargoes leaving Corpus Christi now that it is the larger port. The relationship between Corpus and Houston cargoes can also shift and change. But for the time being, we are keeping an open mind as to whether a separate Corpus price is needed or if a single USGC assessment will suffice.

2. **WTI delivered northeast Asia —** To service crude needs in Asia-Pacific, the WTI delivered northeast Asia assessment was launched and is now widely used by regional refiners to make informed decisions on whether to buy on a fob or delivered basis. It complements an earlier assessment for WTI cfr Ningbo, China, which is constructed using the Argus fob Houston assessment plus our proprietary freight assessments for reverse lightering and VLCC transportation.

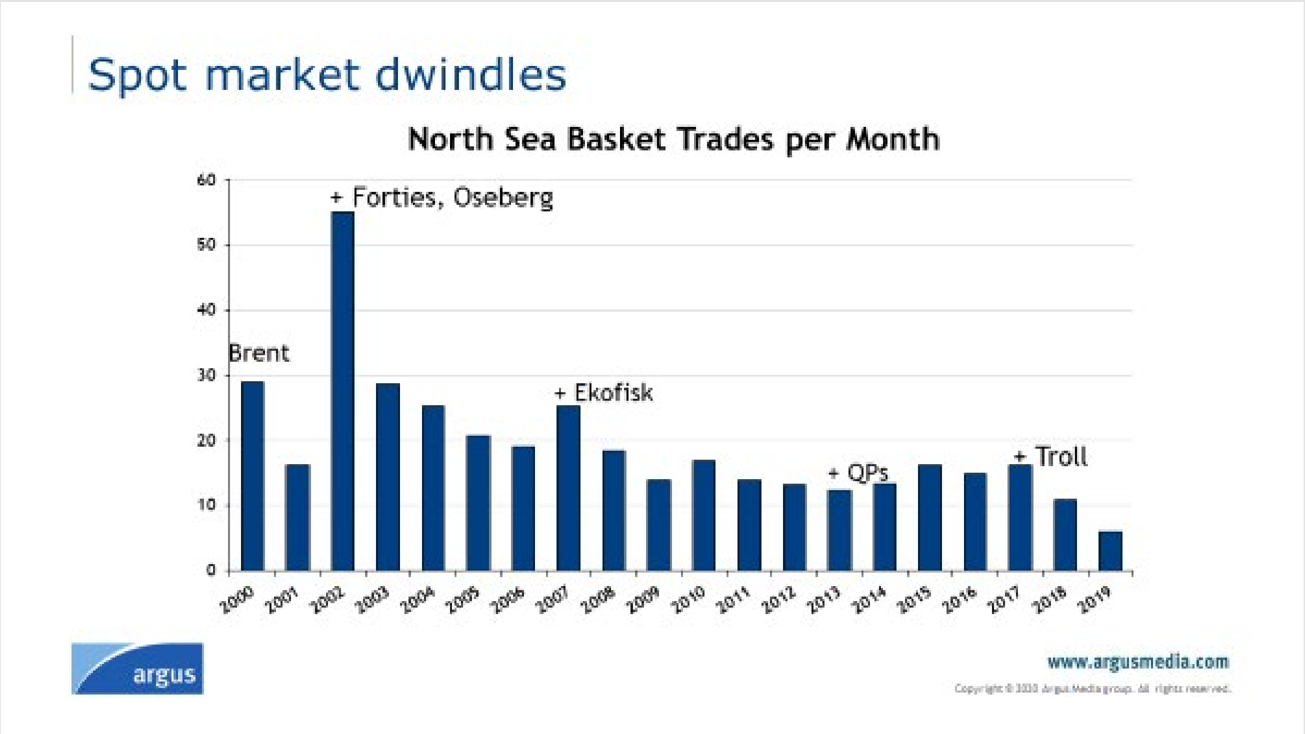
3. **WTI cif Rotterdam —** This assessment represents the price of WTI delivered to northwest Europe. With well over 1mn b/d of US crude now arriving in Europe, WTI is an excellent candidate for inclusion in the North Sea Dated benchmark. Furthermore, with so much volume, combined with the transparency and liquidity of the USGC markets, it would be surprising if WTI did not play a more significant role in future global benchmarking.

Europe: The last drop of Brent — What is the future for North Sea Dated?

This year, the Brent field is likely to stop producing after 44 years of valiant service. Production peaked around the turn of the century but has dropped sharply since then. Now the very last platform is at risk of becoming decommissioned. Production from Brent Delta stopped in December 2011, Alpha and Bravo in November 2014, and production from Brent Charlie is expected to stop this year, Shell says.

This begs the question: Is this the end of Brent? Of course not. Production from other fields, such as Ninian and others, will still be exported through the Brent pipeline and called Brent blend. Brent is ingrained in the global industry — as a brand, as a byword for light sweet crude, as a futures contract, and as a physical crude price benchmark against which oil traded throughout the Atlantic basin and beyond is priced.

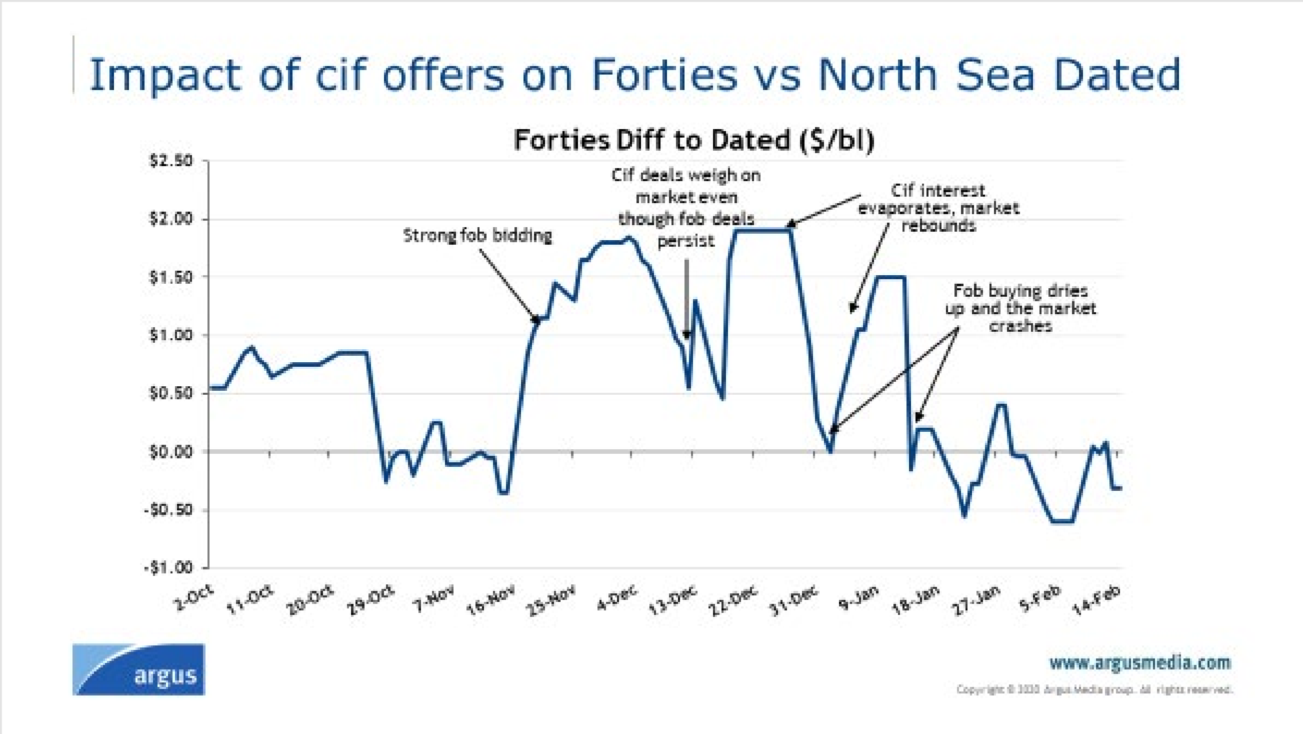
But the physical benchmark at the heart of the Brent complex — identified as North Sea Dated by the term coined at Argus — requires regular health checks to ensure it is functioning well.



Despite the addition of other grades to the Brent basket — added to increase liquidity and widen the pool of market participants — the physical trade underpinning North Sea Dated has dwindled to all-time lows.

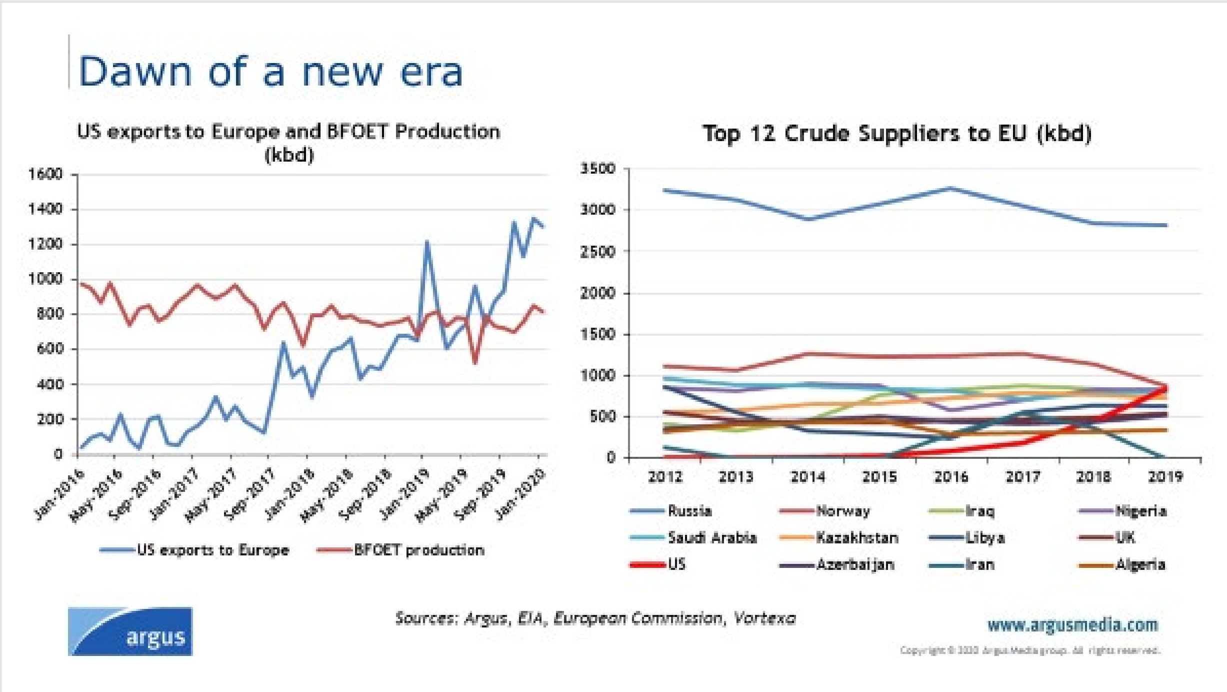
Late last year, price reporting agencies began to consider the trade of North Sea crude not only on a fob basis at the terminals around the region, but also delivered to the refining centre around Rotterdam. This was intended to increase the amount of trade that underpins the Dated benchmark. The market is still digesting the effects of this change.

In order to make this additional trade relevant, Argus subtracts a cross-North Sea freight rate to bring it into line with the fob market. Often, the signals from the delivered market are at odds with those from the fob market. These differences are reconciled in our daily assessment process, but the presence — or lack thereof — of delivered crude trade can have a volatile effect on the price. This is effectively two markets for the same grade in the same region. The addition of the new price signals may have increased the amount of trade to some extent, but it has not increased the number of companies participating in the North Sea market.



Observable here is a spell of volatility as the market became accustomed to pricing Forties crude, both on a fob terminal and cif Rotterdam basis. This matters to the benchmark as Forties is the lowest-quality grade in the basket, which means that it sets the price much of the time. The price signals from the two Forties markets occasionally contradicted one another and price reporting agencies, including Argus, had to make a judgment about which signal was the correct one. Argus chose, where appropriate, to take an average of the fob trade and the freight-adjusted cif trade, in order to come up with an assessment.

Still, the inclusion of delivered crudes from outside of Europe in the benchmark is an important step towards an end result that Argus has been promoting for well over a year. It demonstrates that with a sound methodology and sufficient market transparency, delivered markets can send a reflective price signal, just as they have done in products markets for many years, and just as they do in the emerging pricing centre of Shandong, China, where we are publishing a range of delivered crude assessments.



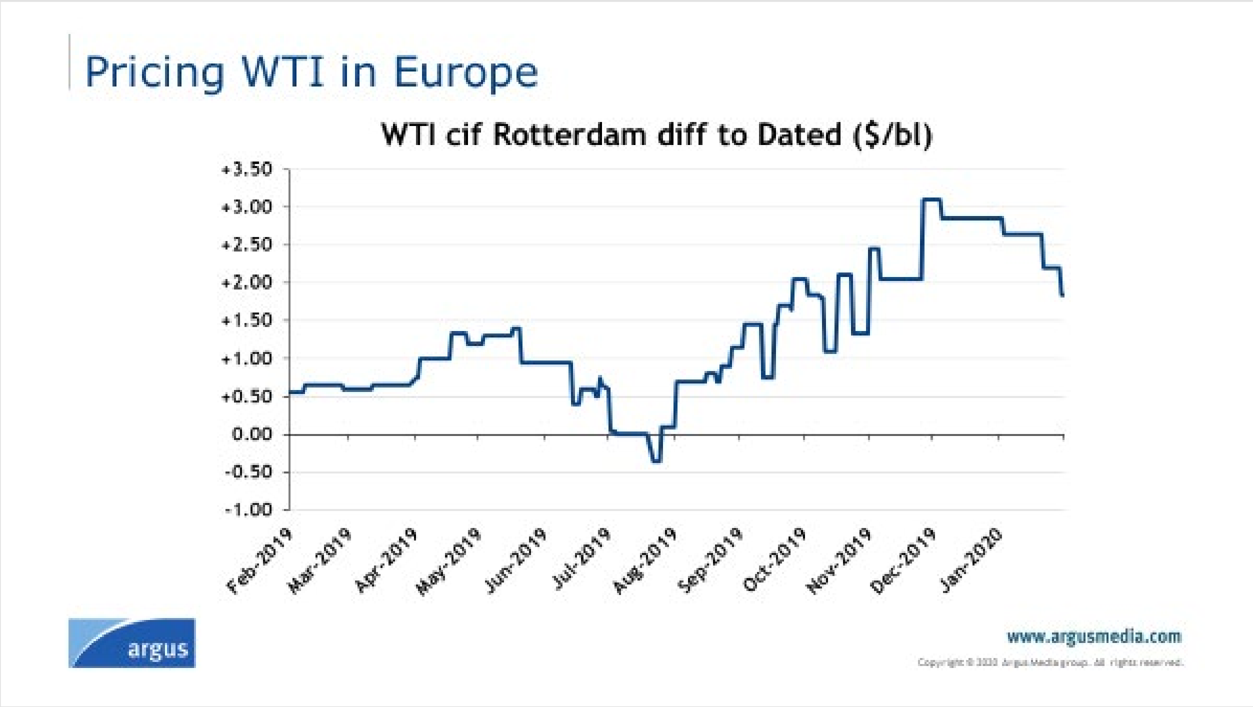
When considering delivered crudes from outside of Europe, there lies an "elephant in the room" – there is now more US crude consumed in Europe than all North Sea basket grades combined.

To add to the invasion of foreign crude grades into Europe, is Russian Urals, which is by far the largest single grade of crude consumed in Europe. Russian imports far outweigh crude from any other origin. Despite various attempts, Urals crude has not succeeded in establishing itself as a benchmark independently of Brent as it is a medium sour grade rather than light sweet.

But surging on and well ahead of many European countries, is the US. It is evident that the overspill of the shale revolution has quickly found a home in Europe's refineries.

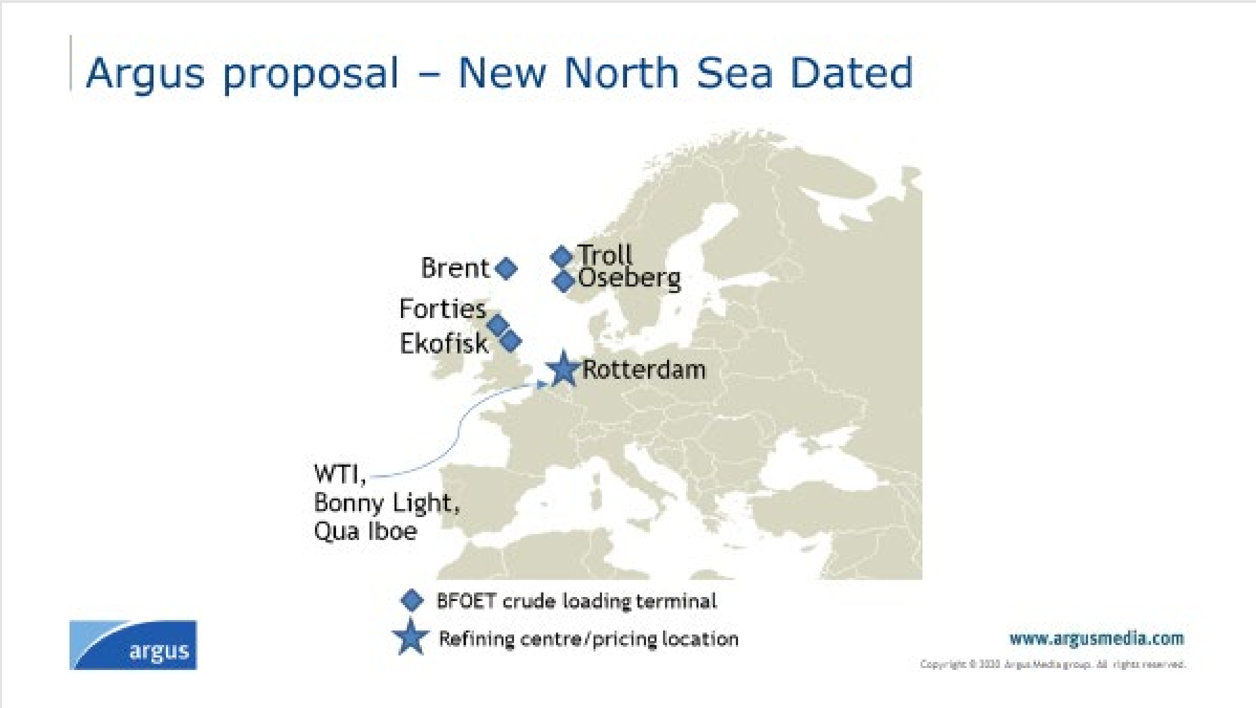
The emerging market reality is that WTI has become a key clearing barrel of crude for Europe, and given Argus' leading position in the market where it originates, we have led the discussion on how WTI should be priced in Europe and how, in time, it could fit into the Brent complex.

The first step to Brent inclusion is to establish a reliable price for the grade on a delivered basis. This is provided by Argus' Permian-quality WTI cif Rotterdam assessment in the Argus Crude report.

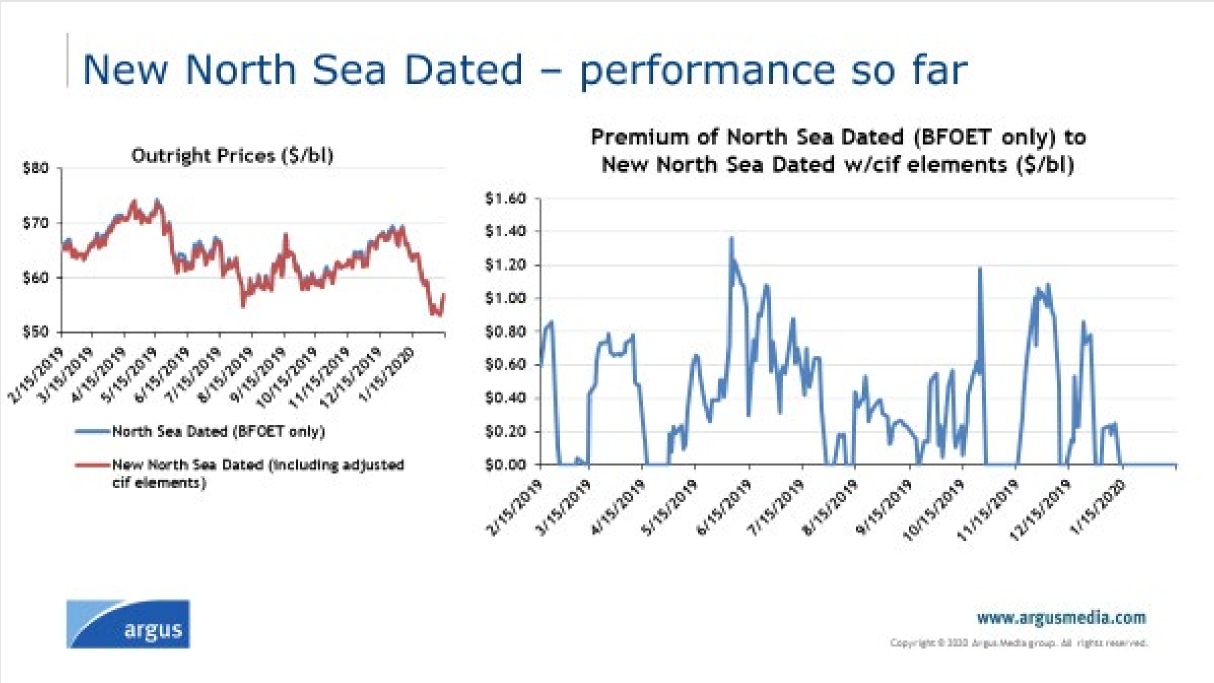


WTI cif Rotterdam, priced at a differential to North Sea Dated, has developed as increasing numbers of European refiners have become comfortable with the grade and learned to fit it into their crude slates. The WTI delivered market is not yet as liquid and transparent as we would like, but the price signals that the Argus' crude team are able to gather give a good indication of the value of the grade.

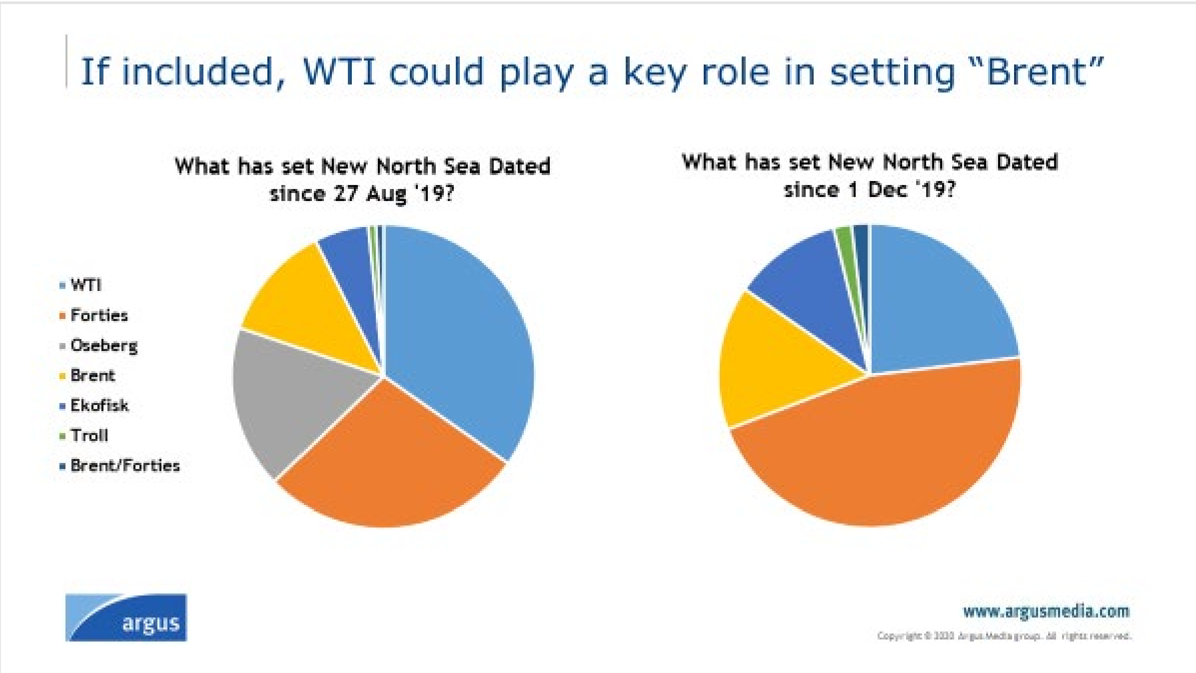
To help standardise the terms and encourage the growth of liquidity in the market, late last year Argus launched the Argus Open Markets (AOM) electronic platform for crude trading. Already well established in the LPG, biodiesel and other markets, AOM has now entered the crude market for the first time. While still in the early days, AOM has already received offers of WTI as well as Bakken crude on a delivered Rotterdam basis. The potential for liquidity is high and the prize is clear —an accurate market assessment that could, in time, bolster the Brent complex and stabilise the Dated benchmark.



At the request of several market participants who would like to see WTI play a formal role in the calculation of the physical Brent benchmark, Argus has begun publishing an illustrative benchmark proposal. This index, called New North Sea Dated, takes the existing fob market liquidity and bolts on prices from the actual delivered market for WTI and Nigerian grades Bonny Light and Qua Iboe — also regular arrivals in the European market. Argus uses a cross-North Sea freight rate, just as in the delivered North Sea market, to provide virtual fob prices for these grades that put the calculation on an even footing with Brent, Forties, etc. This is an effective way of establishing the real clearing price for light sweet crude throughout Europe.



The advantage of publishing this index early, is that we can show how such a benchmark would behave relative to the status quo. In short, just as we are likely to see with the addition of delivered North Sea crudes to the basket, the net result would be a benchmark that is on average slightly lower, less volatile, and less prone to upward swings. Even though light sweet crude is abundant, there are times when North Sea crude is in apparent short supply owing to the arbitrage of cargoes to the Asia-Pacific market.



What sets the New North Sea Dated? In the early days of this calculation, WTI was a discounted, relatively new proposition for European buyers as it was usually the cheapest in the New Dated basket. But as time has gone on and the market for the grade has expanded, we see it taking its turn with the traditional Brent basket grades to set the index.

Just like the current benchmark, the calculation process for New North Sea Dated is complex. Although there may be a simpler and clearer benchmark solution, the Dated complex is so deeply embedded in the regional market that it will be with us for some years to come.

For now, this next logical step has the advantage of gathering a greater amount of liquidity and a larger number of potential market participants. Working together with the market, Argus wants to provide a reliable Atlantic basin crude market signal that will make what we call “Brent” sustainable for the next generation of oil traders, long after the last well has been plugged.

argus

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50 years

Argus Refined Products Forum 2020

Argus' leading market experts gathered in London last month to share their insights into recent developments in the rapidly changing and expanding refined products markets with over 1,200 attendees at the price reporting agency's annual forum. Argus insights and pricing developments were presented to an audience of international traders and associated professionals.

Presentations in the Refined Product Forum covered topics that relate to refining and the broadening impact of the energy transition, including decarbonisation in the European transport market.

The following is a summary of presentations on 25 February. See more stories from our global Editorial staff on the news page of our website, and see content about the effects of the coronavirus on markets on our special hub page, www.argusmedia.com/hubs/coronavirus.

Refining in the 2020s

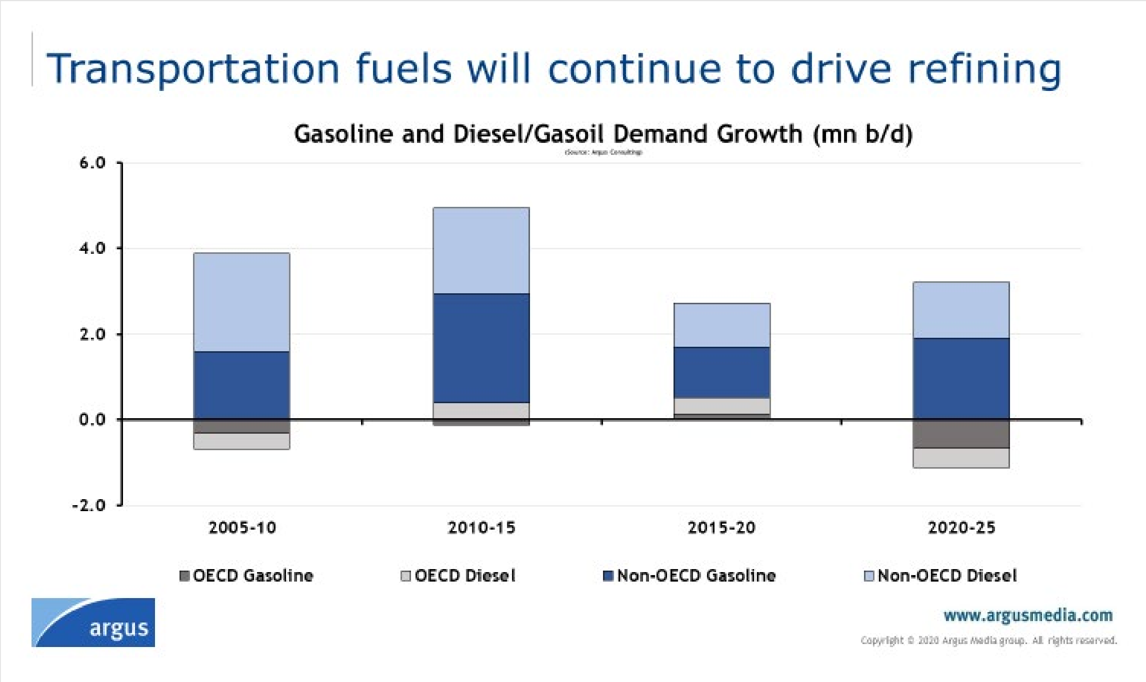
The global refined product demand growth for the 2020s has come under great pressure from the recent actions taken in response to the coronavirus. Although the initial impact has primarily been in China, growth is slowing globally, just as large refining capacity increases that were being completed in 2019 have been coming on line. Even as the threat of slower demand growth increases, the trade of refined products from region to region will continue to drive price relationships and the need for transparent price benchmarks to serve the entire supply chain, including refiners, traders, and downstream markets.

Understanding price exposures in the global marketplace has become more challenging owing to mounting regulatory pressures. As a current example, one of the most significant developments in decades that brought with it, great ranges of market trade and price uncertainty, both regulatorily and operationally, was the International Maritime Organization's implementation of Marpol Annex VI (widely known as IMO 2020), which placed a 0.5 percent sulphur cap on bunker fuel. This regulatory event has impacted the global bunker and fuel oil landscapes along with that of many feedstocks and blending components. Despite an early recovery in high-sulphur fuel oil discounts, it still potentially is a major issue for refiners, blenders, traders and shipowners as the market recovers post-coronavirus.

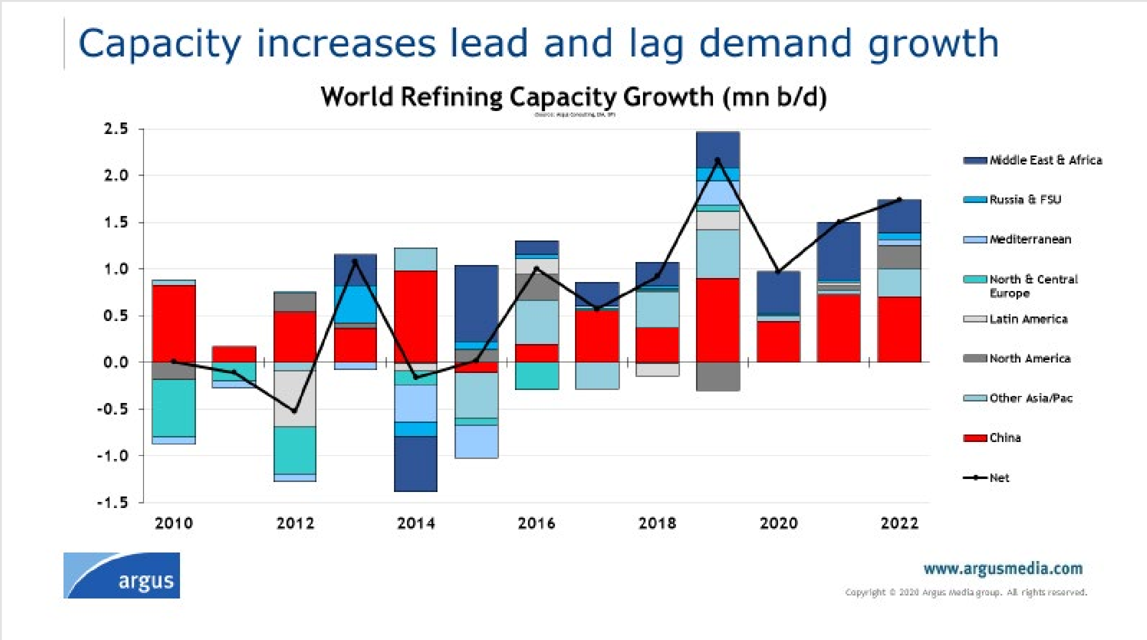
So, what are the issues and challenges for refining in the 2020s? To address this, refining needs to be put in context of slowing global demand growth, refinery capacities that have and will continue expanding, and product trade that is escalating. It is clear that the implications for refining in the early part of the 2020s can be expected to be very dynamic. Accounting for the broader energy transition in Europe, as the world embraces the concept of decarbonisation, refining in the later part of the 2020s will become even more competitive in pursuit of market share and efficiencies.

Considering today's implications for the energy transition, it is worth understanding how the concept of the energy transition has taken shape over time. In the past, "energy transition" used to mean a significant structural change in an energy system. However, it has since become synonymous with reducing carbon emissions to zero. Furthermore, the meaning has taken on an expectant timeline of doing so by 2050.

So, how will the energy transition ultimately affect critical transportation systems that have improved the quality of life for millions of people? Rather than addressing this longer-term, open-ended transition along with its related challenges, we will focus on what it might mean for today's refiners and suppliers. To gain a frame of reference for how the industry might prepare for the accelerating transition while it funds, operates, and provides critical products from what many consider to be a sunsetting industry — we will characterise historical demand growth as it relates to the next five years.

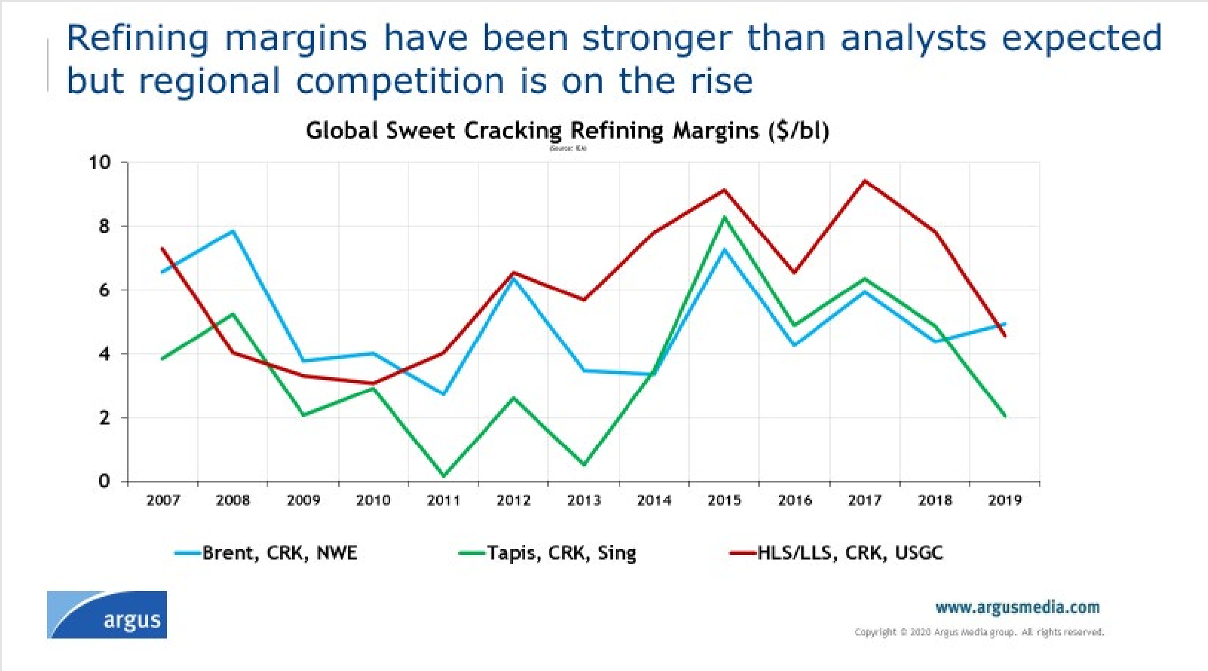


Globally, transportation fuels have grown robustly, although demand growth has slowed in the past five years. Transportation fuels are under pressure from the low-to-no-carbon global targets that are being proposed. The majority of pressure lies in the OECD markets, where there are regulatory pressures to deploy alternative fuels and enable the advancement of electric vehicles. But aside from the current year's coronavirus impacts on demand, non-OECD markets are expected to continue growing at a comparable pace to that of recent years. It is mainly in the US and Europe where demand growth slowing will ultimately put the greatest pressure on refiners.



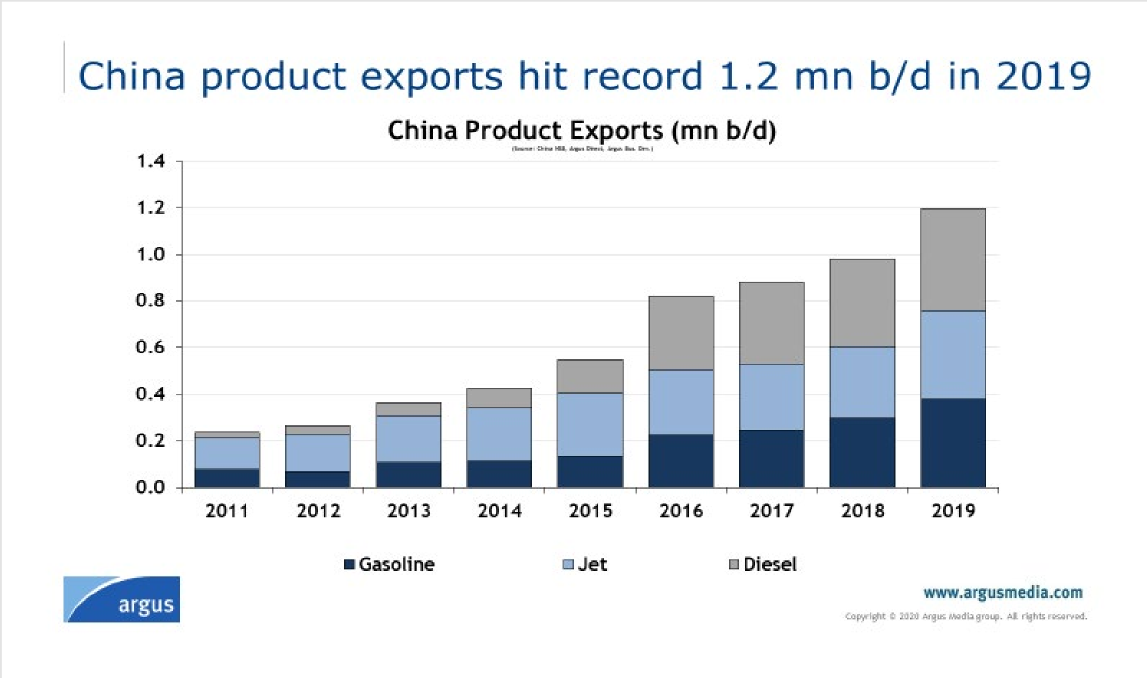
When we look at historical expansions in refining capacity, the increases have often led or lagged the demand growth. There has been a continued rationalisation of capacity over the years that has allowed some refining capacity to essentially migrate or be redeployed where demand growth has been greatest. But the capacity and demand increases have not ideally matched, as much of the demand growth has arisen from Latin America and Africa, where refining capacity has either been under-utilised or lacked a similar pace of expansions as compared with other parts of the world.

Most recently, we have observed a large jump in capacity in 2019 — a lot of which has not yet been filled, and therefore not had its full effect on crude and product price relationships. To some extent, refining analysts have contended that ongoing rationalisation of refining capacity will be required to maintain a balanced market. This means that refining margins would have to come under pressure for the least competitive refiners. So, how will this happen and what factors are significant? Location for exports and market access, the cost of operations including cheap energy and complexity, and feedstock optionality including crude selectivity are critical aspects of this issue.

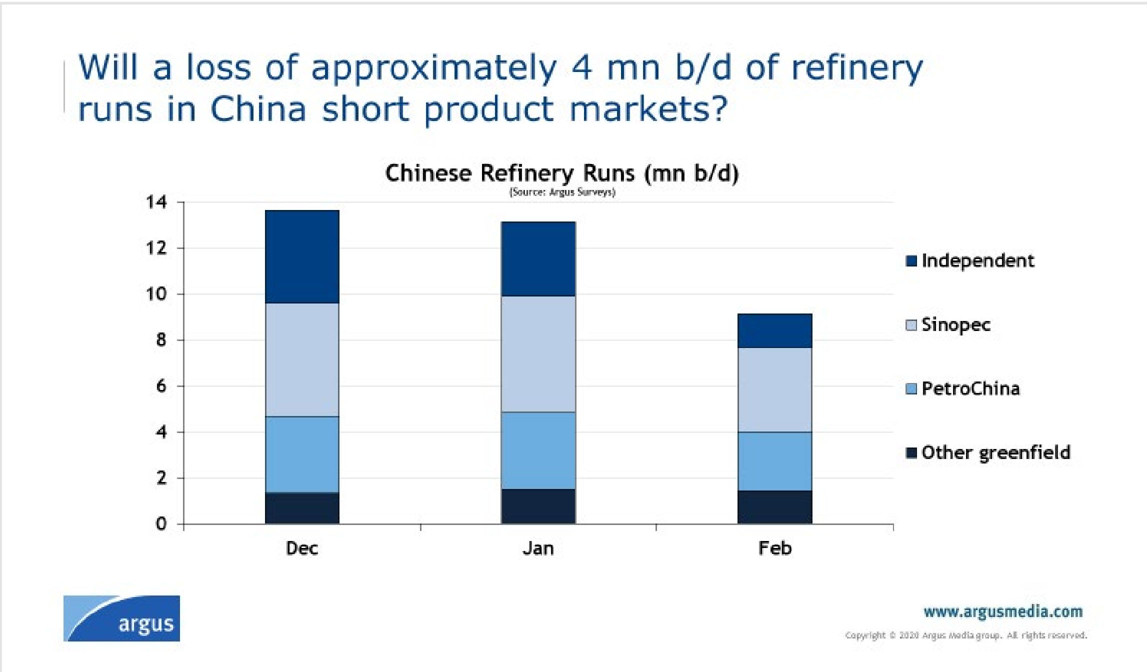


Globally, refining margins have remained relatively strong, despite ongoing increases in capacity expansions. Clearly, the US Gulf coast remains most competitive, but surprisingly the European market has held its own, despite many analysts expecting an extended rationalisation of exiting capacity. How have refiners maintained profitability if capacities have not declined in these mature markets? Simply put, it has been through the ability to increase product exports and trade.

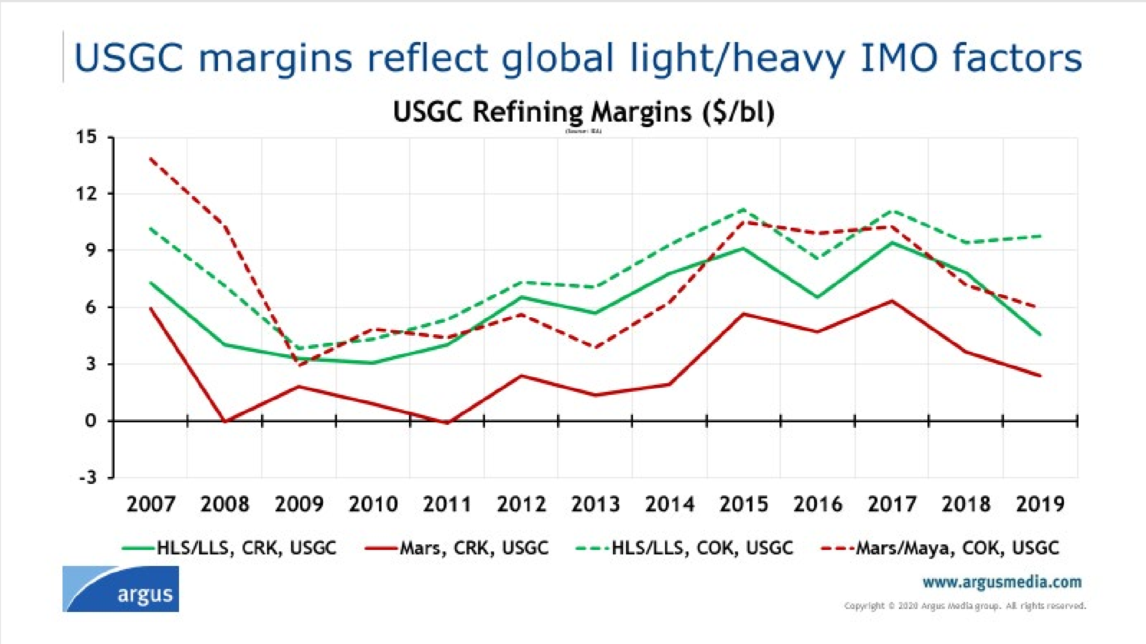
In terms of global product trade, the volume of product movements has continued to rise over time, with the placement of gasoline and diesel to developing markets that have been under-served by existing or new refinery builds. Even more evident to the increasing product trade, China has also become a large product exporter.



China's product exports have continued to rise over the past decade. Significant refining capacity increases continue to come on line, which are only pausing for the coronavirus impact. Product exports rose to a record high of 1.2mn b/d last year and are expected to continue rising over the years ahead. But as the coronavirus outbreak grips the world, how might China's role in supplying product affect product trade for other refiners and markets?

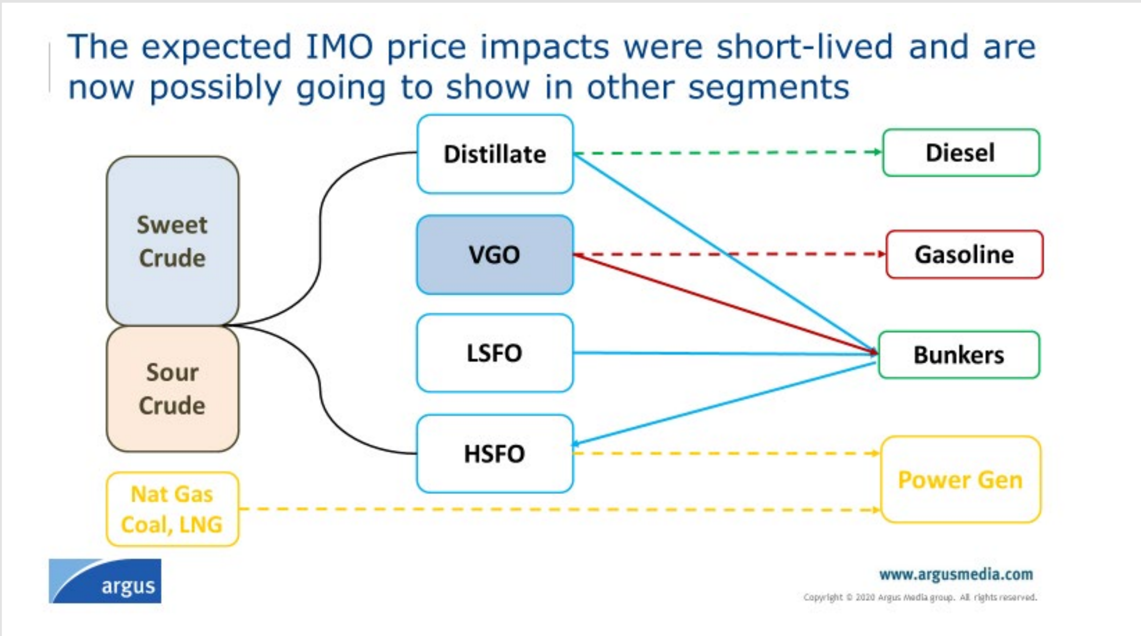


For the time being the coronavirus has reduced Chinese refinery runs by less than 4mn b/d. Although domestic demand has fallen precipitously, exports are also likely to slow, which is likely to protect the Atlantic basin from a temporary oversupply situation. In reality, strong product pricing had already been observed in Singapore and pricing in the Atlantic basin had stabilised, despite the threat for continued declines in global demand.



Moving past the coronavirus issue, we can begin to address the long-standing IMO 2020 impacts and the seemingly short-lived market response, which some believe has played out with little-to-no impact. With that, the question remains — Has the market already seen the full impact or is it yet to come?

Currently, the market shows coking margins are holding stronger than cracking margins. Interestingly, there is an oddity where the light sweet grades have stronger margins than the light sour grades. This is partly owing to the abundance of light sweet light tight oil (LTO) and the loss of additional supply of medium sour grades. Even though coking margins have fallen with the narrowing of the high-sulphur fuel oil crack spread, we are still seeing the impact from the global shift in marine fuel sulphur levels — just not when and where the market had assumed the impacts would be apparent.

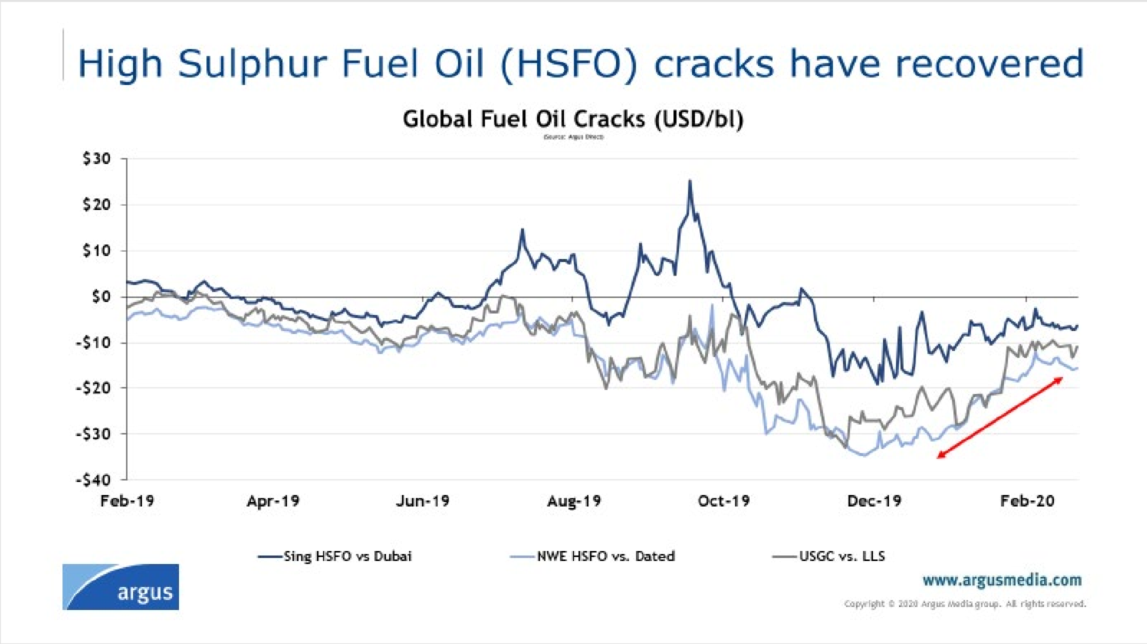


In an effort to demonstrate the market mechanisms that can be deployed to accommodate the required production of IMO 2020-compliant low-sulphur fuel oil (LSFO) production, the diagram above illustrates a simplified depiction to help represent where and why the market has not yet fully realised the price outlooks that many analysts had predicted from the regulatory impact.

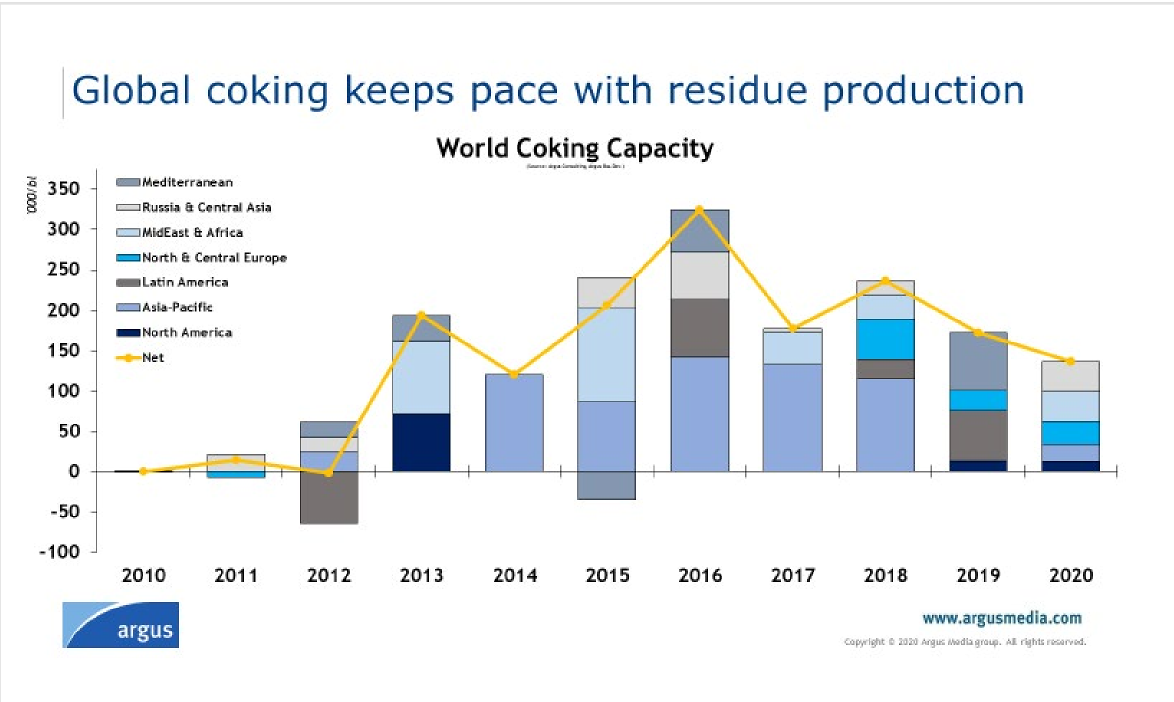
Many refiners moved to lighter, sweeter grades of crude in order to get their residual fuel oil down to the required 0.5pc sulphur level. Additionally, the reductions in Opec+ and Libyan production were larger than analysts' balances had projected for this period of time. Combined with the coronavirus impact on a prompt loss in demand and related reduction in crude runs, the amount of residual fuel losses have been much greater than forecast.

Early on in the compliance period, market analysts had been tracking shipments of residual fuel oil from the Former Soviet Union (FSU) to the US Gulf coast, while noting directional increases in the volumes. Since many coking refineries currently have spare coking capacity from lower and lighter crude throughput, the excess residual fuel is attractive to import and fill part of the spare capacity. Many refiners even made facility modifications in anticipation of such availability to process the additional feedstocks ahead of the IMO implementation. However, the volume of additional feedstocks is not so remarkably high as to account for the "missing" barrels of fuel oil that analysts had expected to be displaced from the bunker pool in order to comply with the lower sulphur specifications.

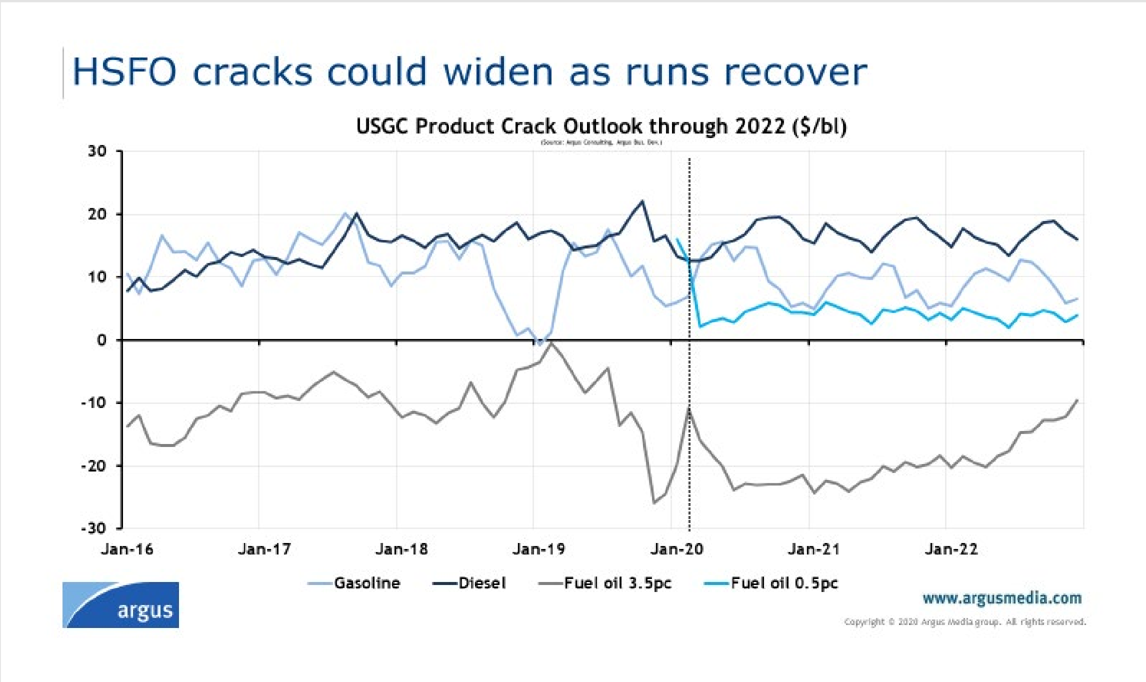
Another forecast assumption that changed rapidly and unexpectedly was a move by shipowners and operators to adopt the use of very-low sulphur fuel oil (VLSFO) instead of using marine gasoil (MGO). There were major concerns as to how blends of VLSFO would perform owing to possible compatibility and supply stability issues. As a result, higher volumes of MGO were expected to be in demand for a relatively lengthy transition period. But high volumes of vacuum gasoil (VGO) have been reported for use in VLSFO blending, and so VGO has been in high demand relative to the forecast volumes of MGO. At this time of year, it is having only some minor pricing implications, but as the gasoline season gets under way, the competition for VGO may trigger price pressures for the marine fuel of early choice.



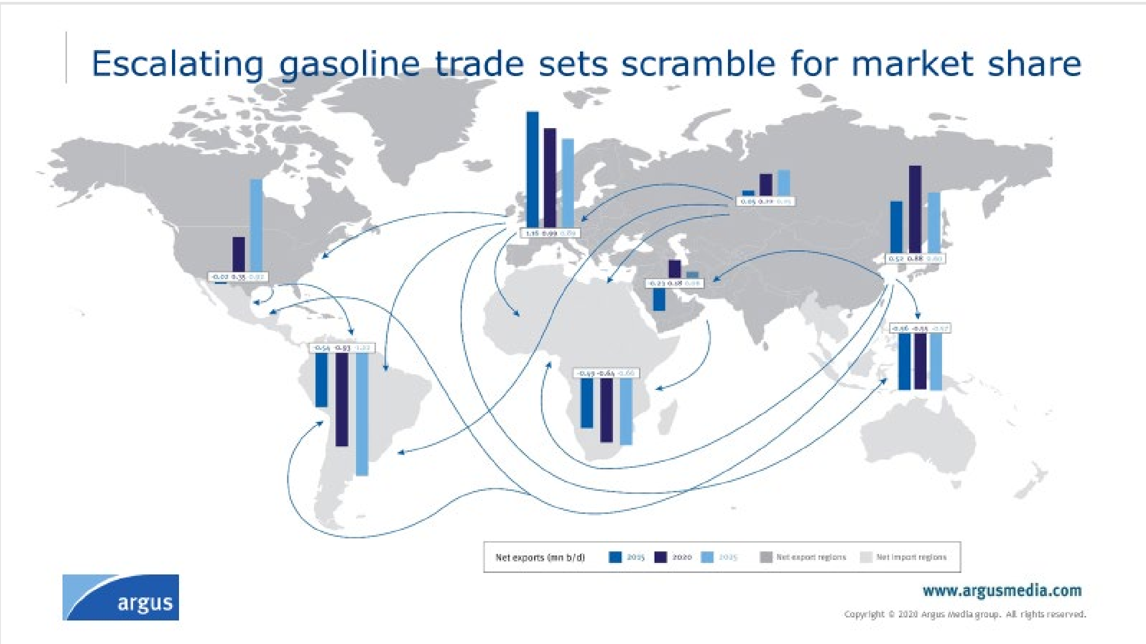
As the compliance date of 1 January 2020 approached, high-sulphur fuel oil (HSFO) discounts to crude widened in all markets, with discounts in the the US Gulf coast and northwest Europe markets widening to more than -$30/bl. Since then, HSFO discounts have recovered strongly. Consequently, many market participants have been quick to assume that the IMO 2020 impacts have run their course and are no longer a concern. All the while, global demand growth begins to recover, gasoline season approaches, light sour crude production resumes, and increasing compliance for not carrying HSFO per the IMO's March 1st carriage ban will have also had an effect.



Additional coker projects, which some believe could alleviate the resumption of HSFO discounts, are due to come on stream in the next year. Yet, bearing in mind that the increase is below historical annual averages and just about matches the additional residual fuel yield from the expected rise in crude runs, these are anticipated to offer little help in preventing future HSFO discounts.

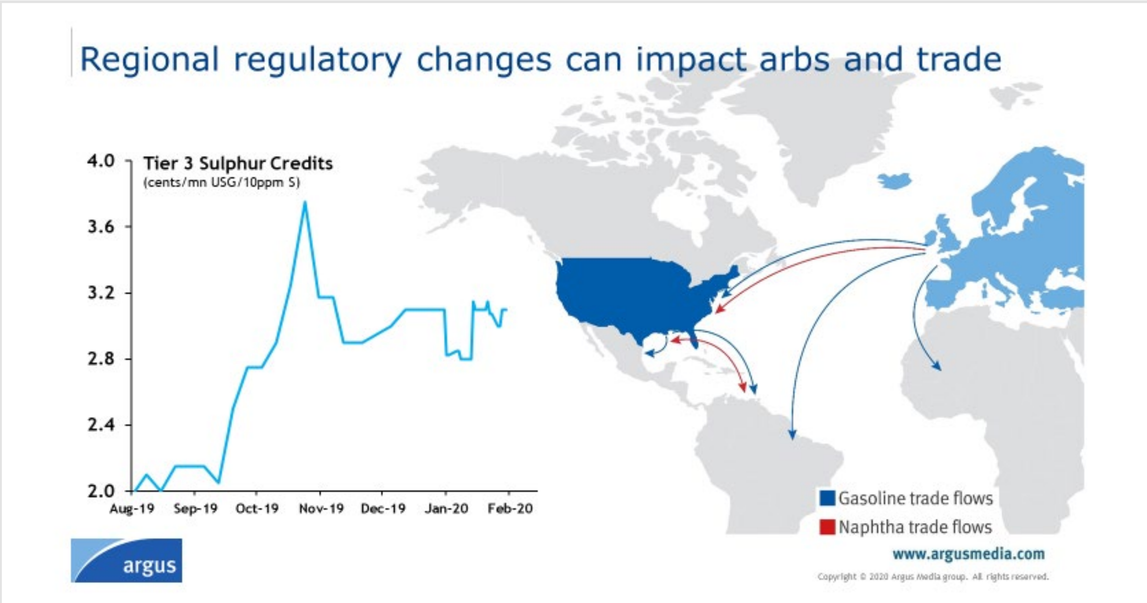


For the near-term pricing outlook, the forecast that was based on pre-coronavirus demand and crude runs showed HSFO discounts as being comparable to the late-2019 spreads. Although the factors remain in place for a recovery in the fundamentals, which could support the same outcome, the timing is being revised to reflect the many uncertainties associated with slowing demand growth from the spread of coronavirus.



Shifting back to light products and the competitiveness of refining centres from different market regions, gasoline trade is expected to continue increasing. Our outlook shows a relatively strong continuation of the existing trade patterns that have allowed refiners in mature demand markets to continue to operate at higher utilisation levels.

In developing markets such as Latin America and Africa, refining capacity and utilisation levels are insufficient to meet demand growth, providing a much-needed outlet for excess product output from the mature markets. But if demand growth in these regions cannot be sustained to support trade, it could threaten the higher utilisation levels that European and some US refiners have enjoyed in recent years.



With increased product trade, newer and updated regulatory measures were inevitable. The product trade that has now firmly connected refining centres and regional markets is now enabling regulatory programmes in one region to affect the trade, product quality and economics in other market regions.

For example, the US Renewable Fuels Standard Tier 3 gasoline requirement now requires a maximum 10ppm sulphur in gasoline. As an example, the compliance cost for a refiner with a 20ppm sulphur gasoline blend would cost as much as an additional 3¢/USG at present. For import and export decisions regarding gasoline and blend components, this cost of compliance may divert higher-sulphur naphtha and gasoline blends to developing markets. Additionally, it could eliminate some market outlets for marginally lower value streams and could place refiners at a disadvantage by negatively effecting refining economics in markets where the gasoline supply is long.

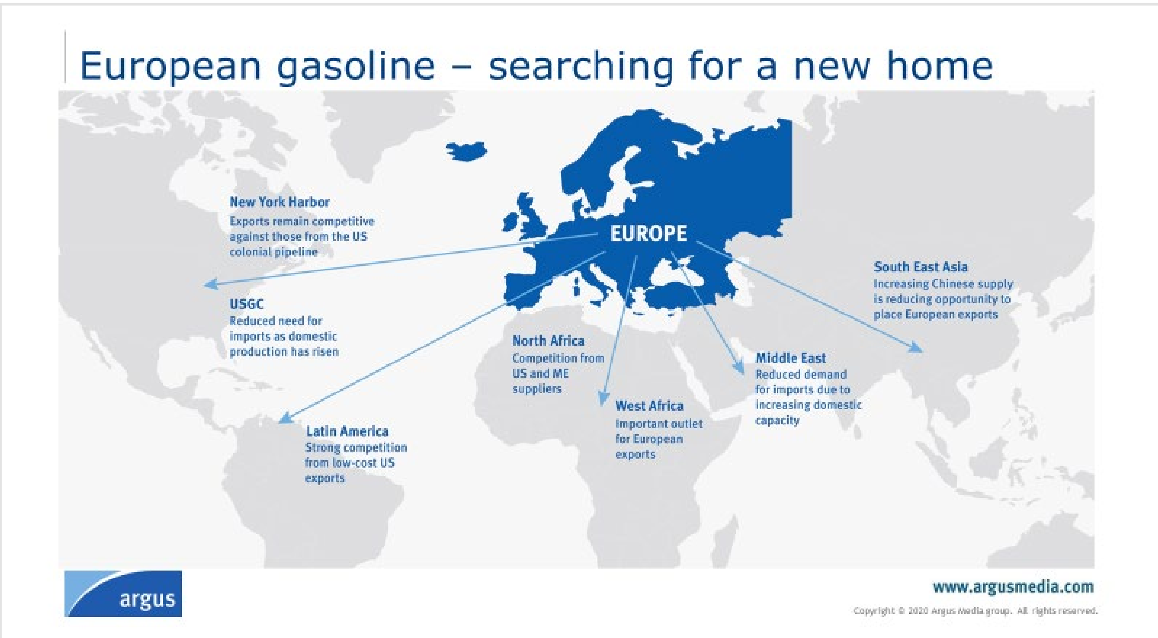
Again, regulatory decisions that are devised to improve product quality so as to lower emissions can, and often do, have unintended consequences in other markets. As refining moves into the 2020s, the best-available option for achieving a regulatory objective does not necessarily make it a good idea for refiners.

In the next section, we take a deep dive into the European refining and energy transition theatre. From government agreements to curtail carbon emissions to searching for export markets, here, one can witness the market and regulatory trends affecting one of the world's most mature and complex energy markets and how it is tackling the transformation to cleaner fuels.

The energy transition in Europe

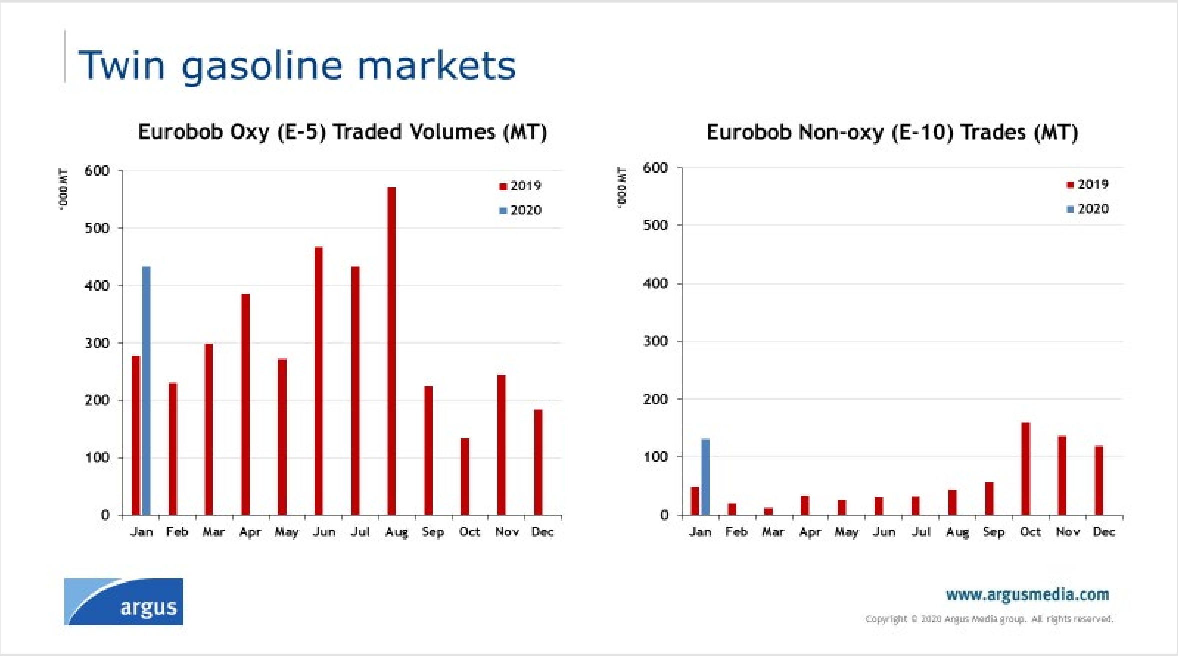
The transition from petroleum fueled cars – primarily gasoline – to electric vehicles will deal a fresh blow to the beleaguered European refining sector, which has been struggling to break even for a decade. Refiners are increasingly struggling to find homes for surplus product, and the increased use of ethanol in gasoline is weighing on demand.

For instance, the UK has brought forward a ban on diesel, gasoline and hybrid vehicles to 2035 from 2040 as part of its legally binding strategy to reduce net greenhouse gas (GHG) emissions to zero by 2050. The ambition of these plans needs to be put into context. Emissions have been reduced by just 3pc in the past 30 years, while huge investment will be needed to develop the infrastructure capable of supporting the charging of electric vehicles, which currently comprise just 2pc of the national fleet.



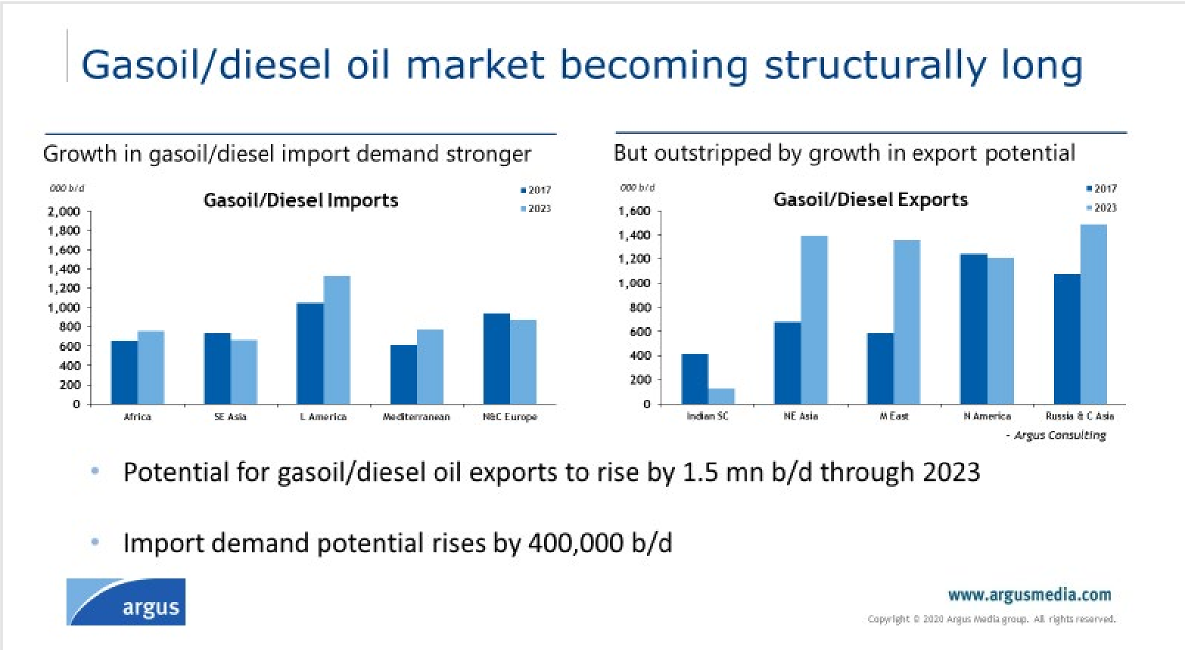
On the supply side, we should consider international trade patterns. Europe's traditional gasoline exports are facing stiff competition owing to new supply developments in their formerly reliable export markets. The Middle East and southeast Asia have increased refining capacity over the past five years, making them far less reliant on European supplies. Moreover, higher demand in west Africa and Latin America has attracted interest from US Gulf coast refiners, who are further eroding European market share. But as competition ramps up globally, exports to the northeast US should continue as normal as US Gulf coast refiners mainly concentrate on exporting their refined products.

Domestically, in the meantime, Europe is steadily increasing the ethanol content of its gasoline in an attempt to adhere to mandates designed to increase the level of decarbonisation for its transport fuels.

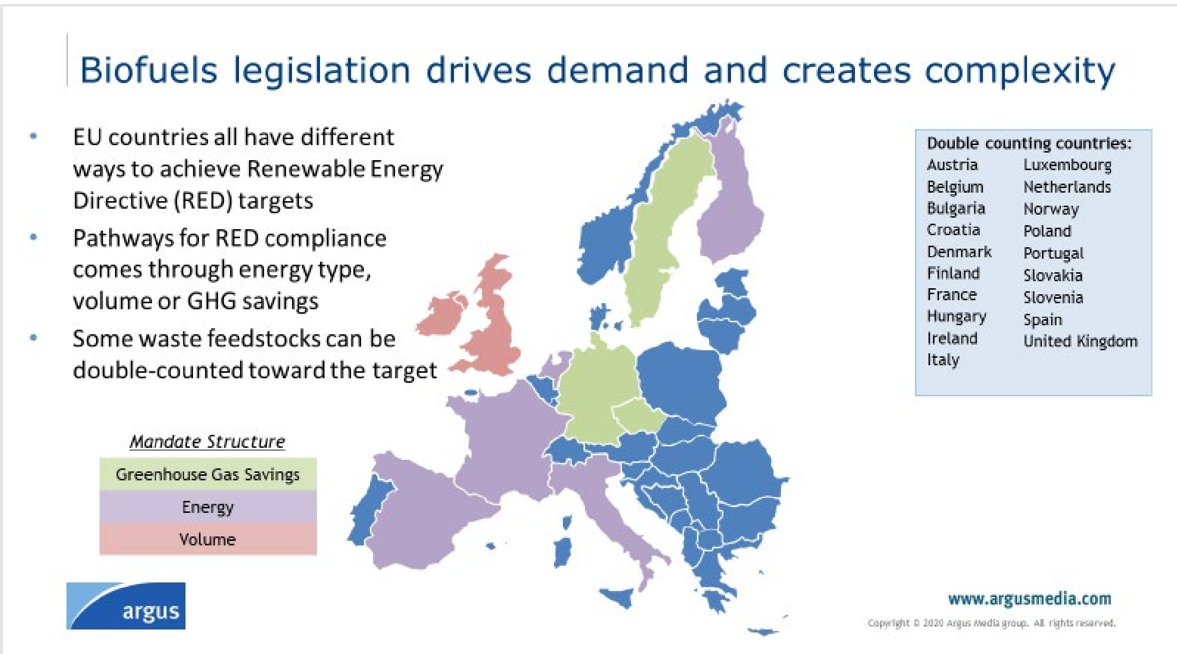


The introduction of E-10 gasoline, which contains 10pc ethanol, is increasingly mandated in Europe and is leading to a two-tiered barge market, with the more traditional E-5 grades co-existing with the newly minted E-10 grade. The Netherlands switched to E-10 gasoline in October, which means that all countries along the Amsterdam-Rotterdam-Antwerp (ARA) refining hub will be using the higher ethanol blend. As a result, the volume for E-10 barges has climbed and supported the robustness of the price assessments for these qualities. Interestingly, volumes on the more mainstream E-5 quality — which underpin heavy trade for financial derivatives — have also increased.

For middle distillates, the structural length in gasoline looks as if it will be mirrored — particularly with diesel.



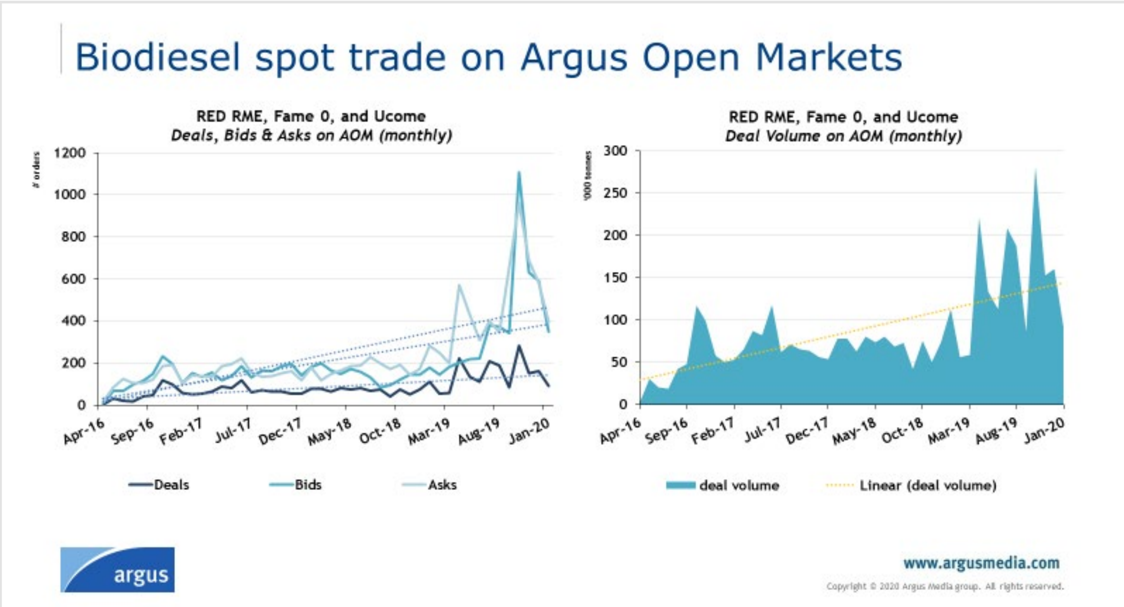
Developing regions, such as Latin America and west Africa, will be responsible for increased diesel use through to 2023. While overall demand could jump by 400,000 b/d in this time, supply is continuing to make gains at a faster rate as refinery expansions in Asia have focused heavily on diesel production. Furthermore, this trend will be exaggerated by the increased use of biofuels in diesel as Europe gears up for decarbonisation.



While many European countries have grand ambitions around biodiesel, there is a distinct lack of a common approach in EU countries to legislate in favour of increased biodiesel use.

The strategy is somewhat splintered, with some countries setting up biofuel use through volume mandates, some through energy type, and some by measuring GHG savings. This uncoordinated effort has confused the issue and jeopardised the ability of EU countries to achieve decarbonisation targets. Additionally, some concern exists over the use of biofuels derived from waste products that count double towards targets, therefore incentivising fraud through false certification.

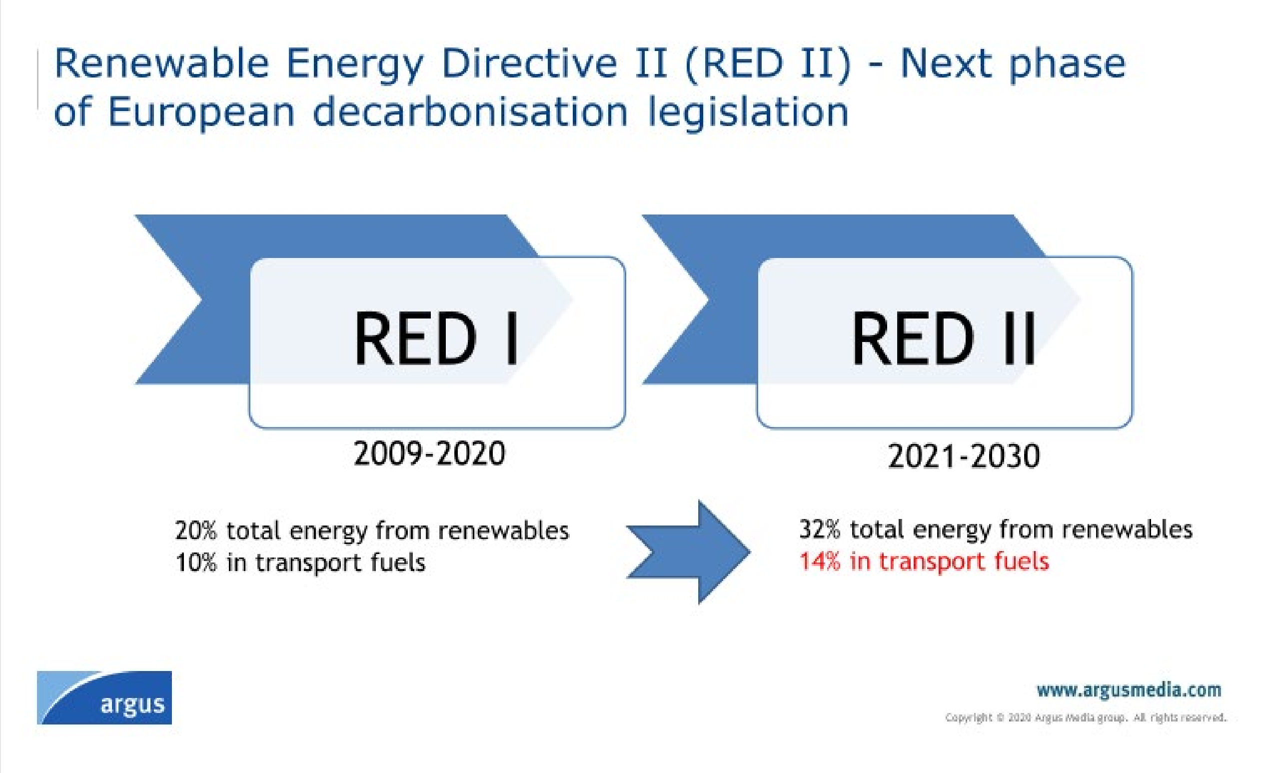
It is clear that issues remain around regulatory measures and the ability to find viable export markets, but if European governments and refiners can begin to harmonise their energies, a much brighter future lies ahead.



Increasing trade volumes on the ARA spot biofuels market, through the Argus Open Markets (AOM) price discovery platform, is mirroring the increased use of biofuels in Europe. Three highly standardised benchmarks — RME, Fame o and used cooking oil methyl ester (UCOME) — have emerged, bringing about increased trade that has encouraged the use of derivatives to manage risk. Argus has principally observed an uptick in trade of the high GHG-saving product, UCOME, in the past three months.

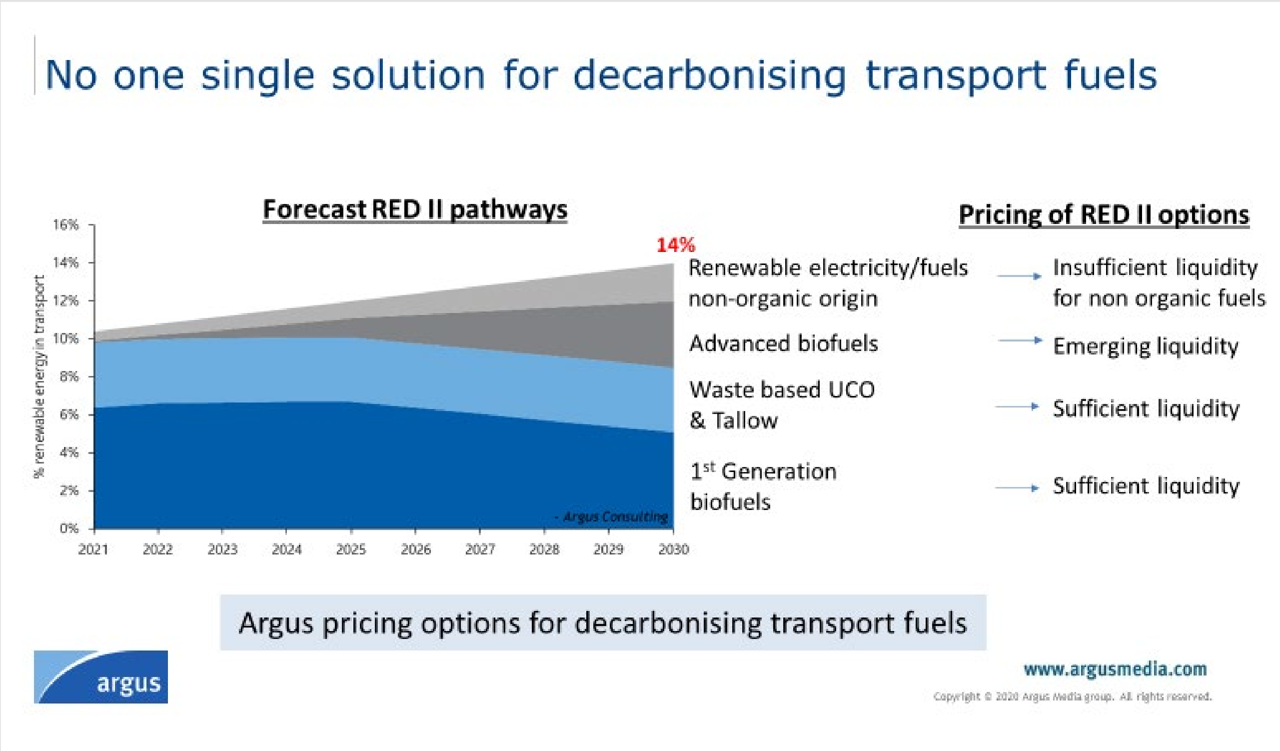
Finally, to round out these paramount topics, Argus explores the regulatory nature that will drive many of the pricing, production, and environmental decisions in Europe for years to come.

Decarbonisation in the European transport market



Europe is moving into the next phase of decarbonisation with a piece of legislation titled RED II — Renewable Energy Directive II — coming into effect in 2021. The target for total energy consumption from renewables has shifted from the first version of the legislation (RED I) from 20pc in 2020 to 32pc by 2030. Following along, the sub-target set out for transport fuels is rising from 10pc with RED I to 14pc with RED II. Additional pressure will mount to meet the new target by the end of this decade, and now aviation and marine fuels are specifically considered in conjunction with road transport fuels.

What pathways exist to achieve a 14pc renewable transport fuel goal by 2030?



Argus Consulting has analysed pathways to achieve this target based on the caps and targets set for different types of feedstocks as mandated by RED II. The first generation of biofuels — biodiesel based on a vegetable oil feedstock (rapeseed oil, soybean oil, etc) and crop-based ethanol — are expected to continue to play a significant role up to 2030. But with the evident food vs fuel debate, there is a 7pc maximum cap for 2030 for the use of such crop-based biofuels as part of the RED II legislation.

Biodiesel based on waste such as used cooking oil (UCO) and tallow (animal fat) also have a place in the RED II legislation and will count towards the 2030 target. These biofuels are popular as they are double-counted in several EU countries. This means that one unit will count twice towards the target. Also contributing to their popularity, is the generally high GHG savings. Although ripe with opportunity, the cap for this category is 1.7pc.

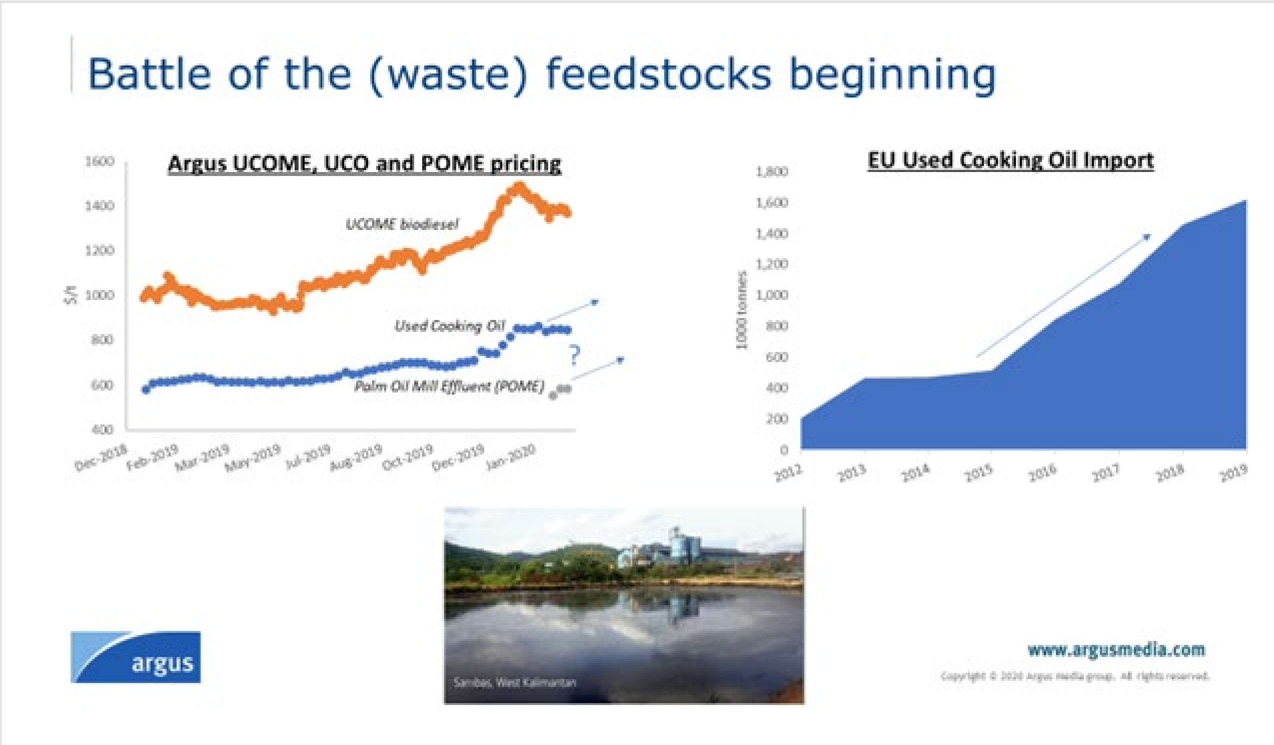
While the first two sources have good liquidity and availability, the big question remains around advanced biofuels. By 2030 the regulators are asking EU member states to achieve 3.5pc of advanced biofuels as part of their renewable energy fuels for transportation mix. Advanced biofuels can be based on waste feedstocks such as algae, bio-waste from households — such as ethanol based on bread — straw, tall oil, nut shells, and palm oil mill effluent (POME). Unfortunately, this is a group of biofuels for which the technology is underdeveloped, and available feedstock supplies are limited.

Non-organic renewable fuels, such as fuel produced from plastic waste, and electric vehicles based on renewable electricity would make up the smallest portion of the 14pc target. This category is not double counted like UCO and tallow methyl ester (TME)-based biodiesel, but rather it is quadruple counted, all to incentivise the switch to more electric vehicles.

Furthermore, we will begin to see biojet and biomarine fuels coming into the picture. These markets will, in RED II, have a multiplicator of 1.2. — i.e. they will count 1.2 times more than the first-generation biofuels. Biojet will make its way into regulation in Norway this year, with the Scandinavian countries being ahead of the rest of the biofuels market.

Argus' role in all of this is to help the market clear in the most efficient and economic ways through robust and accurate pricing that provides the right signals to the market on supply and demand fundamentals. In terms of liquidity, the first generation of biofuels is up and running, followed closely by UCO and tallow-based biodiesel markets. But liquidity for advanced biofuel feedstocks is very small at present, although growth is anticipated as these markets develop. Liquidity for non-organic renewable fuels is non-existent at this time.

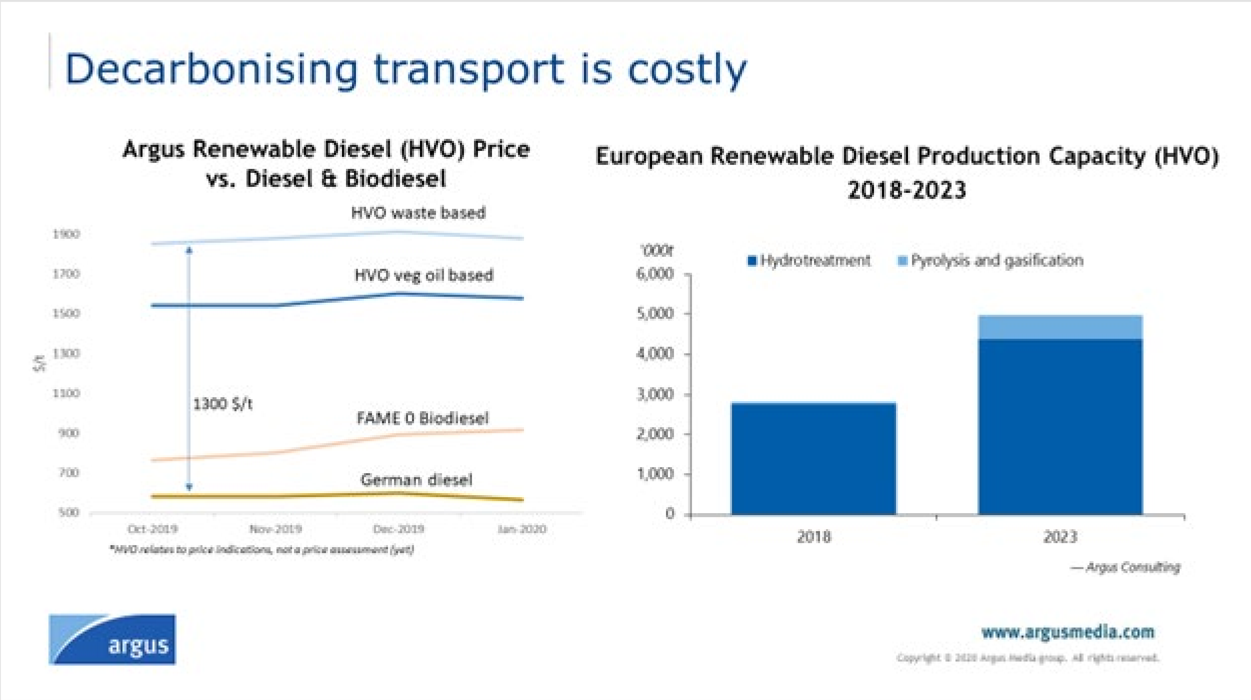
Delving further, we can begin to see three key themes emerging — increased demand for waste-based feedstocks, decarbonisation and its costs, and the complex realities that European refiners are likely to face throughout the energy transition.



As waste-based feedstocks become a more viable option for producing biofuels to meet stringent environmental targets, demand and competition for them is expected to increase. Not only will UCO demand rise owing to the pull from the growing UCOME market, but we are also likely to see a demand surge for UCO from the hydrotreated vegetable oil (HVO) market, where it is a critical feedstock. We see the effect of this demand with European companies scouting the world for UCO, and as expected, imports have surged, rising eightfold in 2019 compared with 2012.

We expect to see a similar trend for the feedstocks for advanced biofuels as RED II kicks in. Argus has recently launched a price assessment for POME as feedstock pricing is growing in importance as decarbonisation gets under way.

With all the eco-friendly discussions, ideas and subsequent environmental regulations coming into play, it is important to understand what the associated costs of decarbonising the European transport sector will be.



Monthly commentary provided to and published by Argus for the HVO market, also known as renewable diesel, has shown price indications for HVO can be up to $1,300/t higher than traditional diesel. Despite the cost, we believe that HVO will become a major solution to combat road and aviation transport fuel emissions in Europe. Our expectations are that capacity will almost double over the next three years because:

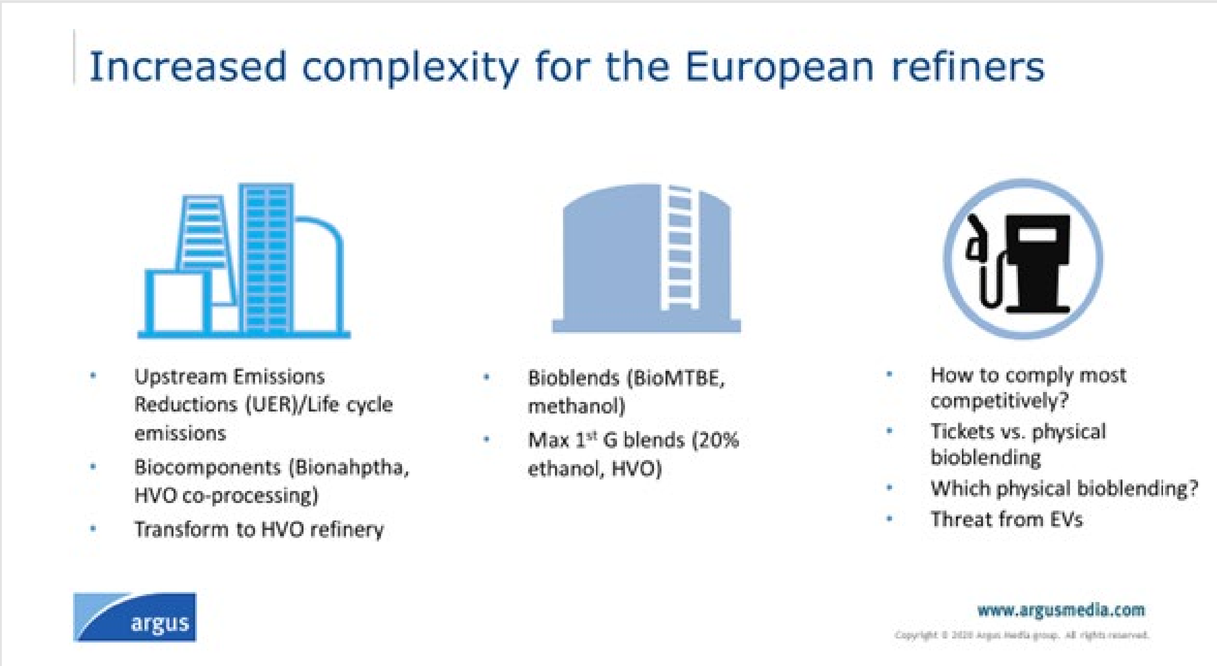
1. HVO can directly replace diesel fuel and can be used in the existing fuel infrastructure. It can be co-processed alongside fossil fuels at refineries as well as further down the supply chain;

2. The technology is mature and tested – it was launched by Neste in 2008 and is now used across the world;

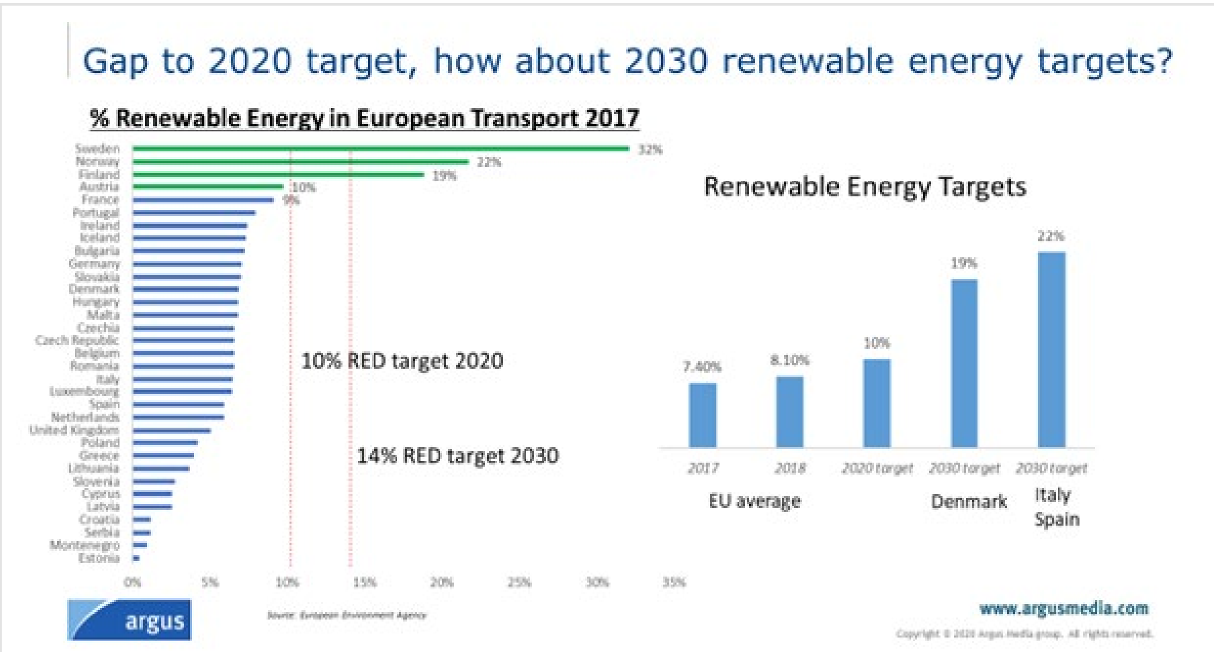
3. HVO is feedstock neutral and can be based on first-generation, waste-based and advanced biofuel feedstocks;

4. Transforming a refinery to an HVO refinery is an option for plants threatened by closure. For example, in 2019 Total chose to convert its La Mede refinery to an HVO facility, thereby avoiding the trouble of closing a refinery owing to cost pressures, while maintaining its current staff and upholding a "green" external profile.

Lastly, as Europe's mature refining complex continues to navigate the ever-changing regulatory landscape, it is becoming clearer that some refiners must adapt in order to remain competitive and navigate the new realities of decarbonisation that they will face in the years to come.



As Europe moves through the decarbonisation lifecycle, its refiners will face increased complexity to meet the RED II targets. Even before feedstocks arrive at the refinery, there are considerations to be made. For example, refineries can consider using upstream emissions reductions (UERs) as credits to more easily comply with the RED regulation, or they can harness the use of "green" feedstocks such as bionaphtha. When blending fuels such as gasoline to the standard specification, biocomponents such as bioMTBE are an option along with higher biofuel blends such as ethanol. In essence, understanding what makes most sense economically in order to stay competitive needs to be at the forefront of European refiners' logic when managing through such complexity, as having a "straightforward" process is essentially non-existent.



With decarbonisation efforts under way, the question remains — will the EU, along with the UK and Norway, achieve the goals it has set for itself by 2030?

Looking at the performance for 2020 and the 10pc renewable energy in transport goal from RED I, it is doubtful. By 2017, only four countries — Sweden, Norway, Finland and Austria — had achieved the 2030 target. The majority of European countries are falling behind and there are doubts over whether they will make the 2020 target. Even though the European average has improved to 8pc in 2018, there is still a long way to go. Nevertheless, for the next phase of decarbonisation — RED II — European countries are now coming up with their specific regulations and interpretations of RED II on how best to achieve the 2030 targets. Take Italy, Spain and Denmark for example. All aim to over-deliver on the 2030 targets by reaching around a 20pc share of renewable energy in transport, yet at this time they have not managed to achieve the 2020 target. This lack of progress, combined with immature technology and limited feedstock, makes reaching the 2030 goal even more doubtful.

To conclude, Europe needs to rapidly step up its development of renewable transport fuels, or risk failing to meet its ambitious 2030 targets.