S&P Global Platts

Insight

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Asia, oil demand and coronavirus | Battery supply chains deglobalize | Pricing US Gulf Coast oil flows | **TOP 250** GLOBAL ENERGY COMPANY RANKINGS

The path to net zero

Insight

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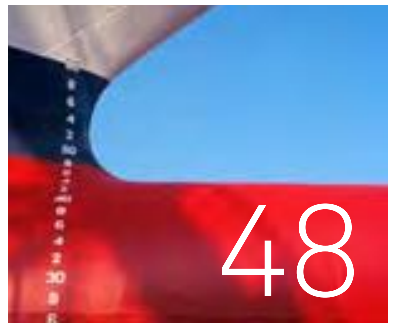

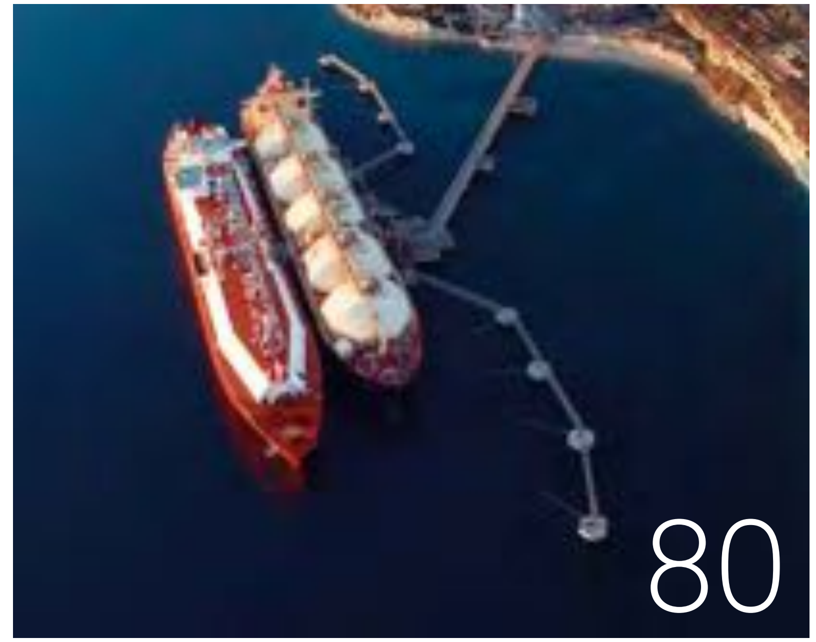

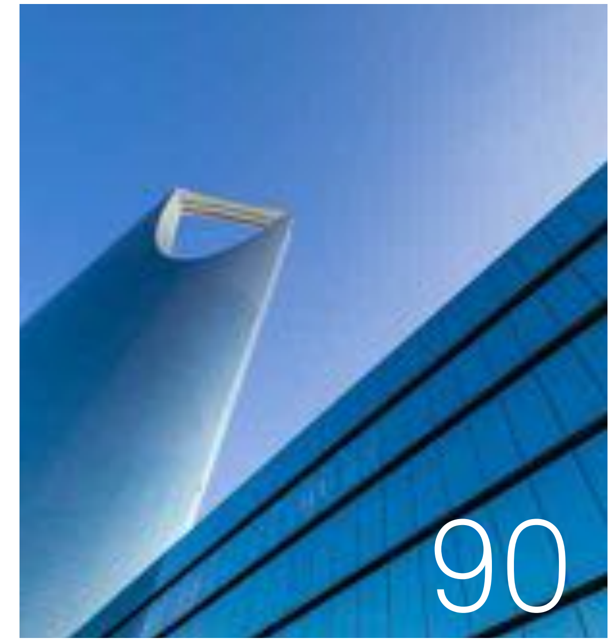

Editor's Note

Emma Slawinski

Editor

Across the globe, economic and social activity has been ramping up in recent months after widespread lockdowns to control the spread of coronavirus.

The reopening of schools and universities in many countries should deliver a further boost, but with cumulative coronavirus cases worldwide standing at more than 25 million as of early September, it is clear that there is no quick and easy path to recovery.

The impact has been felt on all commodities in some way, but performance has diverged widely between products since the beginning of the year. Energy has borne the brunt of demand destruction, while precious metals have benefited from their traditional appeal as safe havens for investors and risen substantially as a result.

Shuttered economies early this year, combined with a cutthroat battle over oil prices between Saudi Arabia and Russia, left crude markets reeling. A turbulent first half intensified scrutiny about how the oil demand curve will evolve in the decades to come and how new habits might constrain expected peak demand. There is also the potential impact of green recovery plans launched by national governments seeking to pivot toward decarbonization and sustainability as they emerge from the crisis.

This edition of Insight takes a detailed look at the prospects for Asian oil and oil product demand from page 30, finding a relatively subdued picture for the rest of 2020, although a rebound in major Asian economies is expected in 2021.

In China, the government has introduced a new twist to the traditional infrastructure-based stimulus package. This time, the country is backing high-tech infrastructure to support a greater share of renewable energy in the mix and the electrification of transport (page 44).

Our cover story (page 8) delves into the energy transition strategies of some of the world's largest integrated oil companies, and weighs their net zero emissions commitments against expected future oil demand, as well as the shift that would be required in capital expenditure, away from crude production and toward clean energy.

The volatility in commodity markets this year has underscored the importance of rigorous and reliable benchmarks to determine value. The considerations for pricing Middle Eastern crudes, as well as a US Gulf Coast export stream still in its infancy, are explored in features on pages 70 and 48, respectively.

Another big theme to watch in commodities is the move toward deglobalization of supply chains. This was arguably already under way, but the pandemic is likely to have concentrated the minds of national governments. The trend is especially clear in the global lithium-ion battery sector, as investment flows into the EU rise while those into China decline (page 36).

Finally, our annual Top 250 Global Energy Company Rankings show how state-owned energy giants dominated in terms of financial performance last year, while gas and LNG also played a role in fueling energy company growth. Find the full analysis and data from page 90.

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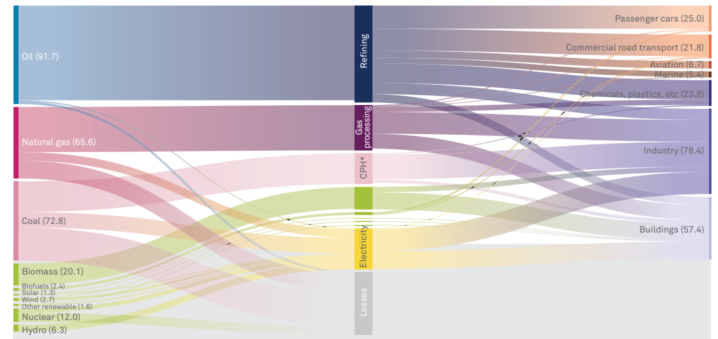
Explore Insight

Our website spglobal.com/platts contains an extensive selection of free news, videos, podcasts and special reports about energy and commodities. Here's a small selection of recent highlights



Interactive

Fossil fuels in the global energy mix

Fossil fuels would shrink to roughly half of total primary energy supply in 2050, from about 77% in 2020, if the world meets the minimum Paris Agreement target of 2C warming, according to the latest projections by S&P Global Platts Analytics.
Find more infographics here.

Video

Insight Conversation – Harold Hamm

Harold Hamm, executive chairman, Continental Resources, discusses benchmarks, the Bakken, and a backlog of wells with Dave Ernsberger, S&P Global Platts global head of pricing and market insight.
Videos, webinars and more multimedia content at Platts LIVE.

Podcast

Capitol Crude – Capex cuts stunt US oil production

Ash Singh, manager of non-OPEC supply at S&P Global Platts Analytics, discusses the outlook for US oil production with host Meghan Gordon, which includes a sharp drop in output for 2021 compared with forecasts before this year's oil price collapse.
Listen to more S&P Global Platts podcasts here.

Special report

Turning on TAP: a shift in the European gas landscape

Barring any new, unexpected delays, the Trans Adriatic Pipeline is due to come online in the fourth quarter of 2020 – the latest chapter in the diversification of European gas supply. This special report explores TAP's potential impact for Italy and Central and Eastern Europe.
View all Platts special reports here.

The path to net zero

Net zero goals imply huge shifts in strategy for global oil majors, but approaches vary. S&P Global Platts Analytics' modelling lays out the potential displacement in both oil demand and capital expenditure up ahead, and highlights the inherent risks of each pathway for carbon reduction. By Mark Mozur

This year may be remembered as a tipping point for the oil and gas industry. In the midst of a global pandemic and economic lockdown that are expected to wipe out over 8 million b/d of oil demand, producers have slashed capital spending to the lowest in 15 years.

Crude and condensate output is forecast to fall 7% year on year, dipping below 80 million b/d, and oil prices in late August remained around $20/b below 2019 average levels.

In almost any other year, these cuts to capital spending and output could be attributed to supply-demand cycles and price responsiveness.

But in more ways to count, 2020 is not just any other year. Prompted by virus transmission fears and the new normal of working from home in many economic segments, the coronavirus pandemic has caused modellers to re-think how the legacy of the virus could change consumer – and business – behavior for years to come as no end-use sector has been immune to the impact of the global economic lockdown.

In the view of S&P Global Platts Analytics, the downside pressure to long-term oil demand in a post-pandemic world can be felt across the board, touching nearly every single end-use sector in our energy models. Examples include reduced vehicle miles travelled as consumers adapt to remote work and slower growth in international air travel as social-distancing norms become prohibitive for aviation and businesses choose to limit travel. There is also the dampening effect on international trade as businesses – and governments – accelerate efforts to "reshore" global supply chains.

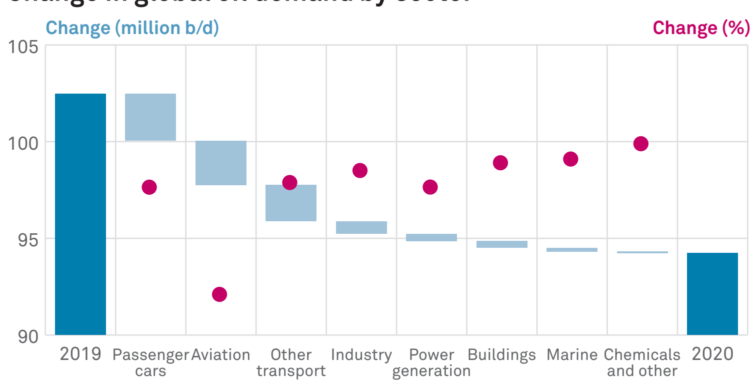
In Platts Analytics' long-term balances, the net impact has been to reduce projected 2050 oil demand growth considerably as these trends far outweigh upward pressure on demand from competing drivers such as the rise in e-commerce and home shopping, a continued preference for plastic packaging and – not to be forgotten – a substantially lower long-term oil price outlook.

In short, there is an emerging conversation about the extent to which the coronavirus pandemic has shifted the world onto a low-demand and therefore a low-carbon trajectory. Whether in terms of the drop in fossil fuel consumption or in terms of the expected fall in CO_2 emissions, Platts Analytics expects near-term decreases to exceed those required in a low-carbon world as defined by a modelled 2-degree-Celsius pathway. Platts Analytics forecasts a drop of 8% and 6%, respectively for the two indicators, versus 1.5% and 1.9% in a 2 C scenario.

The Paris Agreement, ratified by 189 parties to date, targets limiting the global rise in temperature this century to well below 2 C above pre-industrial levels, in order to avoid catastrophic impacts of climate change. From an energy end-use point of view, a 2 C pathway can be modelled by requiring that annual CO_2 emissions decline to 10-15 Gt per year by 2050. This is based on the lowest Representative Concentration Pathway included in the most recent assessment report from the Intergovernmental Panel on Climate Change. S&P Global Platts Analytics has adapted this global greenhouse gas pathway to country-level emissions reductions requirements.

In the context of this ongoing conversation, it is all the more remarkable that even as some of the world's most prominent oil producers have announced major cuts to capital spend, as well as asset write downs and dividend cuts, industry leaders such as BP, Total, Shell, and others have made headlines by effectively redoubling their commitment to long-term net zero targets. As of the third quarter, nearly every single international major has made some form of a low-carbon commitment.

Change in global oil demand by sector



Source: S&P Global Platts Analytics

The more ambitious of these aspire to be "net zero" by 2050, but all companies have some form of commitment to reduce the greenhouse-gas intensity of existing operations and some form of pledge to expand activity related to low-carbon energy carriers such as renewable power, biofuels, and even hydrogen. Concurrent with this, the reduced long-term oil demand outlook has caused many producers to adopt lower pricing guidance.

Platts Analytics has reviewed various corporate low-carbon commitments and while there is a diverse set of measures announced to date to achieve long-term targets, they do not all imply a full-scale business model transformation. The table to the right reflects an attempt to categorize low-carbon ambitions of upstream oil and gas producers.

In principle, all four pathways are viable options to reduce entity-level CO_2 emissions. But at their hearts each of these transformations has a different set of implications for what a 2050, low-carbon world would look like.

Energy transition strategies of upstream oil and gas companies

Type	Description	Examples
Emissions offsets	Producers seek to offset emissions from existing operations independently from the operations themselves	Afforestation and carbon credits
Transformation of operations	Producers seek to reduce carbon intensity by transforming existing operations (drilling, flaring, leakage, refining)	Electric drilling platforms, CCUS, reduced flaring, increased operational efficiency
Transformation of product offering	Producers seek to reduce carbon intensity by offering new, low-carbon products using either (A) the existing resource base or (B) existing delivery channels	(A) Hydrogen (from natural gas) (B) Biofuels
Transformation of business model	Producers seek to reduce carbon intensity by fundamentally transforming their business model, seeking out new end users and new delivery channels	EV charging stations, direct power sales

Source: S&P Global Platts Analytics

Platts Analytics' 2 C pathway has been modelled at the sectoral level and has been built by balancing long-term energy demand growth against structural constraints such as available non-fossil fuel supply, technology costs, and global emissions caps.

From an oil producer's perspective, the end-user results of this modelling exercise are substantial. The collective share of fossil fuels in final energy consumption in 2050 is projected to decline from nearly 45% in current Platts Analytics' long-term balances to under 30% in a 2 C sensitivity. The sensitivity analysis in terms of oil is even starker: 50 million b/d of demand destruction separates a reference-case outlook from a low-carbon sensitivity.

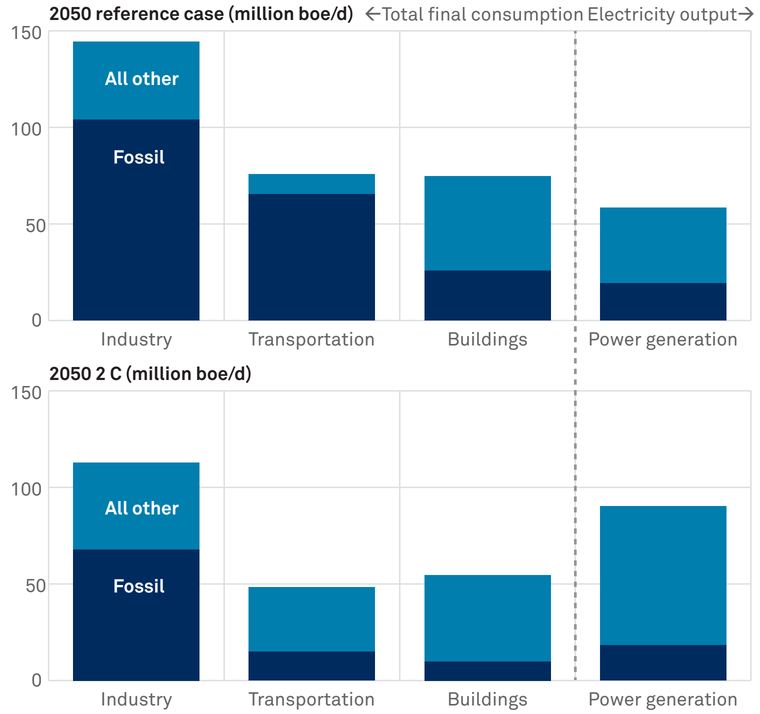
Most significantly, in a 2 C world refined petroleum products are almost entirely displaced from on-road transport (passenger cars and commercial road transport). Fossil fuel's share of on-road transport demand is expected to fall from 91% now to 77% in 2050 in the Platts Analytics reference case compared with only 10% in a 2 C sensitivity. Though other transport sectors such as air and marine are slower to decarbonize, the volume growth is too small to replace the lost oil demand elsewhere.

Further, a 2 C sensitivity necessitates a massive buildout in the electric power grid. Strictly in terms of absolute demand levels, new low-carbon electricity demand is nearly equal to the reduction in fossil fuel supply for on-road use in 2050.

Capital allocation shift

These modelling results would imply that oil and gas incumbents should seek to transform their business model fundamentally to the extent that they consider such a 2 C sensitivity viable. But perhaps it should come as no surprise that it is not that simple.

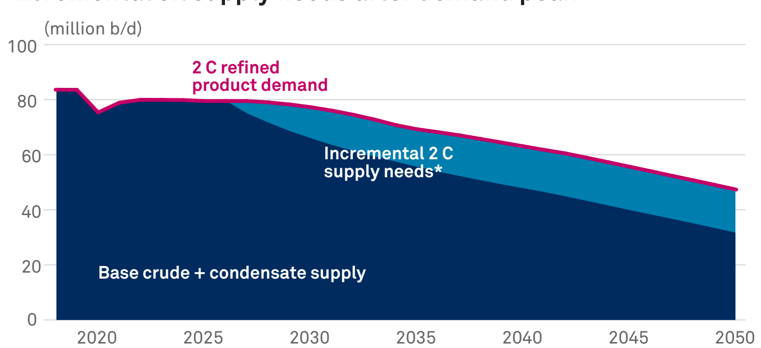
Forecast fossil vs non-fossil split, 2050



Fossil includes coal, gas, and oil. Industry, transportation, and buildings are considered total final consumption, not total primary energy supply.

Source: S&P Global Platts Analytics

Incremental oil supply needs after demand peak



*This has been calculated after global oil demand peaks

Source: S&P Global Platts Analytics

As mentioned above, the expected single-year drop in 2020 exceeds required reductions on a low-carbon pathway on the oil-demand side. Similar analysis can be applied to the supply side. To meet the reduced call on crude (and condensate) in a 2 C sensitivity, Platts Analytics assigned a basin-specific decline rate to currently producing assets and any assets expected to be brought online between now and the mid-2020s, when oil demand growth would be projected to peak. At a global aggregate level, this rolls up into an average annual base decline rate of 3.3%. Once again, this overall decline rate is more aggressive than the projected decline in oil demand, which would fall by 1.9% a year. Thus, in a 2 C sensitivity incremental investment in upstream oil production is still needed to meet demand.

The fact that new upstream oil investment is still needed to meet demand in such a sensitivity points to a key reason why many major producers have put forward hybrid strategies to achieve net-zero targets that blend across the four different categories described previously. As modellers, this fact also enables us to frame the energy transition in terms of capital allocation.

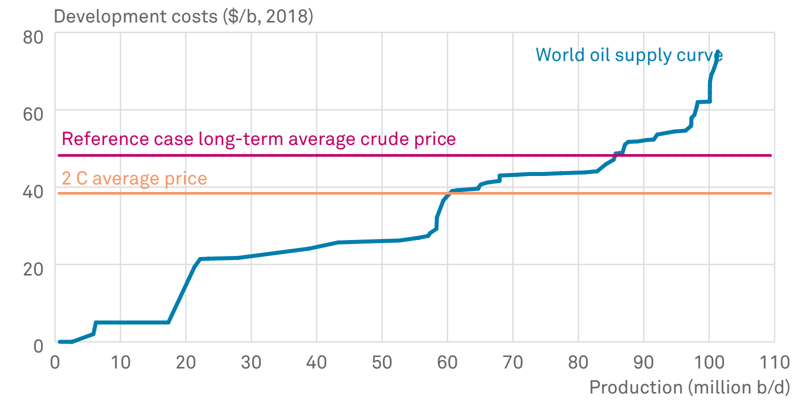
In Platts Analytics' reference case long-term balances, the slashed upstream capital spending observed this year rebounds to average $380 billion a year in real 2018-equivalent dollars from 2025 through 2050. To calculate changes in capital allocation implied by a low-carbon pathway, Platts Analytics has mapped 2 C demand for refined products to current estimates of marginal supply costs.

In this analysis Platts Analytics has assumed that supply growth is optimized across cost, meaning that incremental oil production is almost exclusively restricted to core OPEC producers. Overall, from 2025 to 2050, this key assumption implies $3.4 trillion in total upstream capex, versus $9.5 trillion in the reference case, effectively leading to $6.1 trillion in potential long-term capital reallocation.

Moreover, policy uncertainties such as the potential application of some form of carbon pricing on oil output represent a potential upside to this estimate. The capital reallocation figure is contrasted against $14 trillion in needed spend on incremental power generation capacity in the same Platts Analytics 2 C pathway.

Recent events have borne out this analysis. Recognizing that a weaker demand outlook will not bolster long-term prices, some oil producers and major lenders have announced that they will no longer seek to develop higher cost supplies such as Canadian oil sands or Russian Arctic offshore deposits.

2 C pathway implies lower long-term average oil price



Source: S&P Global Platts Analytics

Any additional demand-side risk could cause other basins to fall out of the marginal supply stack as producers continue to adjust their long-term price view, and each such iteration could narrow the gap between the incremental capital spend in the Platts Analytics reference case ($9.5 trillion) and the Platts Analytics 2 C pathway ($3.4 trillion).

Should this happen, the post-coronavirus world would indeed be moving onto a lower-carbon trajectory. One key driver of this dynamic is that the customer base is essentially undergoing profound structural change that has weakened the demand outlook for nearly every major oil-product category, with the exception of plastics.

Returning to energy transition strategy frameworks, each strategy faces a unique set of risks related to the long-term demand outlook. At a general level, additional cost implications need to be applied in any strategy, affecting their commercial viability. But in terms of specifics, each strategy has a different key challenge.

A company that pursues a full-scale transformation of its business model as part of its energy transition strategy would either face intense competition from incumbents or could develop a path dependency

Firstly, oil and gas producers that pursue carbon reductions strictly in terms of emissions offsets are exposed to the risk that long-term oil demand will continue to weaken, effectively leading to further reductions in asset value. Second, there are limits – both technological and natural – to efficiency gains faced by any company seeking to reduce emissions by transforming the environmental footprint of its upstream operations.

Third, while there are considerable benefits to oil and gas producers that transform their product offering to include low-carbon energy carriers, there is still a need to build out supply and distribution infrastructure at scale. That means an oil producer that transitions from the sale of jet kerosene to sustainable aviation fuel (biojet) would not need to develop a new customer base or even a new logistics network, but would need to develop new large-scale production infrastructure.

Finally, a company that pursues a full-scale transformation of its business model as part of its energy transition strategy would either face intense competition from incumbents or could develop a path dependency – investing in an energy transition solution that eventually falls out of long-term energy balances either due to regulatory constraints, commercial challenges or other reasons. The diversity of these challenges is reflected in the Platts 2 C pathway, which features a combination of all four in various degrees at the country level.

Different energy transition strategies have specific challenges

Type	Key challenges
Emissions offsets	Weak long-term oil demand
Transformation of operations	Technological and natural limits to potential efficiency gains and carbon sinks
Transformation of product offering	Need to build out supply infrastructure at scale ('refining' of biofuels, production of hydrogen)
Transformation of business model	Need to develop know-how Competition from incumbents (lack of advantage) Path dependency (technological lock-in)

Degree of exposure to oil price

Source: S&P Global Platts Analytics

Each energy transition strategy also carries with it a different level of exposure to oil prices, related to the degree to which oil companies seek to preserve existing operations (and revenue streams). Paradoxically, the degree to which a successful energy transition strategy insulates producers from long-term exposure to oil prices is likely to have a direct impact on the return on capital employed, narrowing margins.

But this paradox is entirely consistent with one of the most important insights from modeling a low carbon sensitivity: in a 2 C pathway, long-term average oil prices are substantially lower than the Platts Analytics Reference Case and enter secular decline once peak oil demand is reached in the mid-2020s. Policy, including taxes, and technological change are modelled to accelerate the turnover of capital stock in a 2 C world, rendering demand inelastic to price in the long-term. That is, there is no demand rebound in response to low oil prices as consumer choice becomes constrained due to a ban on internal combustion engines.

Oil price impact

Having already lowered the long-term average oil price outlook in the Platts reference case by around $10/b (constant 2018-equivalent dollars) due to the impact of the pandemic, a low-carbon pathway would require an additional $10/b reduction in average oil prices over 2020-50.

The energy transition ambition is staggering: the Platts Analytics 2 C sensitivity requires a 50% reduction in CO2 emissions by 2050 as well as a 50 million b/d reduction in oil demand. But at a time when the world has experienced an unprecedented – and unforeseen – drop in energy consumption, economic activity and emissions, some of the most prominent industry players have redoubled their commitments to achieving long-term net zero targets. And these long-term net zero targets come with a diverse set of energy transition strategies, ranging from procuring emissions offsets and improving operational efficiencies to pursuing a full-scale business model transformation.

The results of Platts Analytics' low carbon modeling show that a combination of all strategies may be needed: the full displacement of oil as a transport fuel is offset by the growth in new end-user markets for carbon-free electricity. At the same time, even the most aggressive sensitivities still require new investment in upstream oil supply to meet demand.

> Some oil producers and major lenders have announced that they will no longer seek to develop higher cost supplies such as Canadian oil sands or Russian Arctic offshore deposits

Overall, the story might be told through capital re-allocation: energy transition would imply $14 trillion in new capital spend in low-carbon electricity against a $6 trillion reduction in upstream oil spending. That is a huge gap to fill, but if investments in low-carbon alternatives are profitable, the capital markets should be able to link a wide range of investors with these opportunities, given enough time and appropriate policy incentives. ■

Go deeper

S&P Global Platts Future Energy Outlooks delivers a pragmatic view of the long-term trajectory of energy and commodity markets. Insights about the interconnected nature of technology, policy and consumer preference help explain what tradeoffs are likely and what the world will look like when they occur.

Learn more about Platts energy transition coverage in our comprehensive annual guidebook, quarterly tracking reports and focused analysis around alternative transport, hydrogen and other energy transition technologies spglobal.com/scenario

Steadying the ship

The tanker sector is navigating twin challenges in 2020: oil market turbulence due to the coronavirus crisis, and a decarbonization drive in the longer term. But shipowners and investors are already starting to adapt, writes Sameer C. Mohindru

The global tanker shipping industry is likely to find a new normal in the medium term, with sales of second-hand ships taking center stage while orders for newbuilds slow down.

Meanwhile, existing tanker companies may become bigger as ships change hands, or they may form pools to enable better bargaining with charterers, while shying away from ordering new ships.

Uncertainties over how and when the coronavirus pandemic will end are partly behind the new approach, but so is the higher use of greener fuels. The global health crisis hit when the shipping industry was already in the throes of a major transition to a low-sulfur fuel regime, and starting to plan for its eventual decarbonzation.

While in 2020 to date shipowners benefited from a glut of oil supply and the ensuing demand for floating storage, leaner days may be ahead now that crude flows have evened out and global oil consumption has slumped. This, along with the longer-term impact on oil demand from the energy transition, is already having a clear effect on investment in the sector.

Caution a watchword

From January this year, the tanker sector, along with its dry bulk and container shipping peers, successfully executed a worldwide plan steered by the International Maritime Organization (IMO) under which marine fuels with more than 0.5% sulfur can only be used in ships that have exhaust systems called scrubbers fitted on them.

With larger-scale investments already made to adjust to the new system, tanker owners are now hesitant to pour money into fresh greenfield projects. The value of all kinds of ships is falling, according to Copenhagen-based Peter Sand, chief shipping analyst at BIMCO, the world's largest international shipping association with more than 2,200 members. Even though sale and purchase activity in the tanker sector remained active into April, thereafter it started to ease, Sand said.

A sale and purchase broker cited the example of a 2005 built, 302,000 dwt VLCC recently changing hands at just under $27 million. Sales of a couple of similar 15-year-old ships in April took place at around $37-$39 million.

Analysts point out that the April-May period was exceptional, in that low crude prices made floating storage of crude and refined products lucrative, and supported the prices of tankers as well. According to UK-based shipping consultancy VesselsValue, the phase of high-priced tanker sales has ended for the time being and rates are now in a period of adjustment.

The total shipping order book, including tankers, is now at a 17-year low as the coronavirus pandemic has massively slowed contracting, Sand said. Orders for new tankers have dropped more than 40% in the first seven months of 2020 compared with the year-earlier period, according to BIMCO's estimates.

Instead of ordering new ships, companies are looking for greater synergies. In June, through a combination of pool and time charter deals, Trafigura Maritime placed seven of its tankers with Navig8, which owns and operates vessels and also manages shipping pools.

Around the same time, owner and operator companies NORDEN and Diamond S Shipping Inc. formed a joint partnership, DiaNor. Under the agreement, Diamond S is contributing 28 Medium Range tankers to the NORDEN-owned Norient Product Pool, making it one of the world's largest, with close to 90 such ships. Diamond S CEO Craig Stevenson in a statement described the move as "much needed consolidation in the tanker industry."

The global energy mix is set to change in the next three decades, with greater use of electric vehicles gradually reducing the movement of crude oil and refined products loaded on tankers

Through long-duration arrangements such as time charters, or contributing ships to a single pool, owners can increase the possibility of garnering higher freight and avoid having to undertake complete transfer of ownership through mergers and acquisitions.

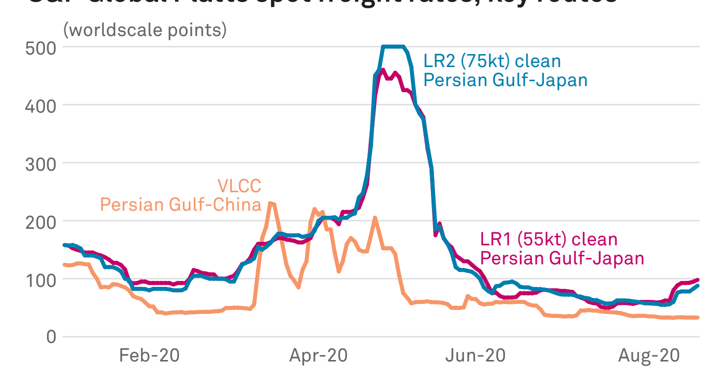
More deals, lower rates

The values at which sales and purchases of tankers are taking place may have declined but the number and frequency of deals involving second-hand ships have been robust. Going forward, this vibrant market will be the flavor of the industry, some analysts say.

Even during the global pandemic, a large number of second-hand transactions took place, and sellers with prompt tonnage were able to take advantage of firm market values, according to Olivia Watkins, VesselsValue's UK-based head cargo analyst. An estimated $4.5 billion worth of sale and purchase activity is estimated to have taken place in the first half of 2020, up from $4.2 billion in the same period two years ago, VesselsValue data showed.

There have been at least two significant spikes in spot tanker freight rates so far this year and the year-to-date average daily earnings of VLCC owners on the

S&P Global Platts spot freight rates, key routes



Source: S&P Global Platts

benchmark Persian Gulf-China route are close to $60,000, according to Masood Baig, a director with Singapore-based Straitship Brokers.

According to brokers, even now VLCC owners are earning around $12,000/day. Baig says that, with strong demand projected for the last quarter, an annual average of $40,000-50,000/day is highly likely for 2020. It is these kinds of earnings, and reluctance to buy new ships, that are keeping investors' interest alive in the second-hand sector.

Decarbonization

Another consideration influencing the choice between second-hand and newbuild ships is the unpredictability of the market in the medium to long term as the energy transition gathers pace.

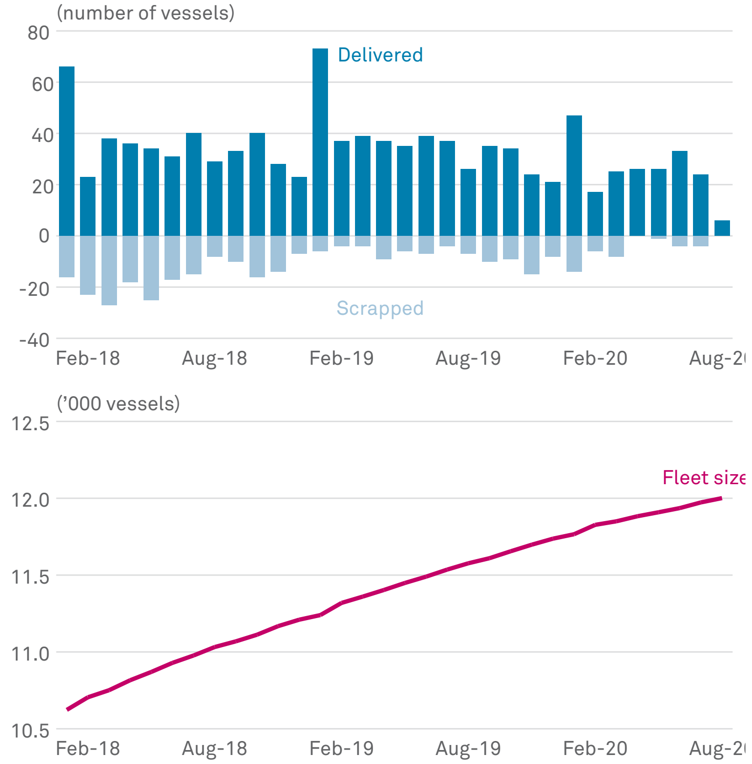
Using 2008 as a baseline year, the IMO is aiming for a 50% reduction in greenhouse gas emissions from shipping by 2050. This will result in less use of fossil fuels to move ships, as alternatives including ammonia or hydrogen gain traction.

In addition, the global energy mix is set to change in the next three decades, with greater use of electric vehicles gradually reducing the movement of crude oil and refined products loaded on tankers. Already, the sale of EVs has shown a sharp rise in recent years. Electric cars, which accounted for 2.6% of global car sales and about 1% of global car stock in 2019, registered a 40% increase between 2018-2019, according to IEA estimates.

Ordering a new tanker now gives a 20-year ownership horizon, but going into 2040, the share of crude oil in the energy mix may change drastically, said Baig. An owner will be in a more predictable trading environment by instead buying a second hand VLCC and operating it for a decade, he said.

The majority of investments in tanker sales so far this year have been for those between 15 and 20 years old, said Watkins. According to one broker tracking such deals, a 17-year-old Suezmax was snapped up by a Greek buyer for $20 million in May, and in early August a 10-year old changed hands for $25 million.

Tanker fleet development



Source: VesselsValue

The pandemic has also resulted in a situation where not all crude volumes being pumped out and products being refined can be sold or consumed in a seamless flow, as was the norm last year.

This has prompted refining and trading companies to hold larger volumes in ships, for longer durations, either due to limited demand or in anticipation of better prices in a contango pricing structure. Demand for floating storage was so high in the second quarter of this year that spot tanker freight rates hit an all-time high.

In turn, this dynamic supported the value of ships as well. For product tankers, the sale and purchase market has stayed fairly liquid, although activity in sheer numbers is much below that of 2018 and 2019, according to BIMCO's Sand. In early August, VesselsValue estimated a five-year-old Long Range II tanker – the most popular for floating storage of products – at almost $42 million, up 14% from the beginning of last year.

But further support from floating storage for freight rates and ship values is unlikely in the near term, analysts say. Wherever and whenever possible, floating storage is now being offloaded and there is no more incentive to buy at current prices as the demand outlook is weak, Sand said.

Supply outlook

The possibility of a return to a scenario of low demand and increased supply availability of tankers due to reduced floating storage is the main threat to supported rates, said Ole-Rikard Hammer, a senior analyst with Oslo-based Arctic Securities.

According to Straitship Brokers' Baig, in the "normal" course of events, global crude market growth of 1 million b/d would have implied an additional requirement of around 25 VLCCs this year. However, in the current environment, S&P Global Platts Analytics expects oil demand will contract by 8.1 million b/d in 2020.

Consequently, additional tonnage is no longer required, and both deliveries and orders have already slowed down. Some dirty tanker orders were placed in the first five months, but June and July were completely anaemic with no orders at all, added Sand.

VesselsValue estimates that the delivery of new tankers has halved to 24 in July, from 47 in January. UK-based Marine Strategies International forecasts less than 1% growth in the VLCC fleet in the current and next two quarters.

Yet the supply is unlikely to tighten, because there has been hardly any demolition of old ships. "It's been seven months now, without a single VLCC being demolished," noted Sand.

But there is potential for scrappings to pick up if rates stay depressed, as 20% of the tanker fleet is more than 15 years old and capital expenditure on them can go up, Hammer said.

It is still not clear whether the world is in the beginning or middle of the pandemic. What is clear, however, is that a sudden abrupt end to this new normal is highly unlikely in the near term. At the same time, while the global economy in general and the maritime world in particular is taking a beating, a catastrophic doomsday is nowhere on the horizon.

If shipping tycoons and their fellow investors hold back the urge to buy new tankers and strategically position their existing fleet to prevent a glut from developing at the key loading ports, their return on investment will be protected. ■

End of an era: the downfall of Hin Leong

The Hin Leong scandal rocked the Singapore trading community earlier this year, topping many earlier bankruptcies in the commodities space in terms of financial losses. Eric Yep unpicks the company's path to self-destruction and assesses the fallout

Hin Leong's bankruptcy filing, on April 17, marked one of the world's largest collapses of an oil trading firm. The story of the Singaporean company and its founder, Oon Kuin Lim, is inextricably linked with the history of the petroleum trade in Singapore and the Asia-Pacific region.

Oon Kuin Lim, more popularly known as OK Lim in industry circles, started his oil distribution business around 1965, the same year that Singapore separated from Malaysia to chart its own future, after several years of political differences.

In his first affidavit to a Singaporean court in April, OK Lim said he was a "one-man-one-truck" oil dealer, selling oil bought wholesale from the oil majors to taxi companies, bus companies, and fishing boat operators as the tiny Southeast Asian country built its economy.

OK Lim, born in China's Fujian province, built his fleet of tank-trucks in Singapore over the years and incorporated Hin Leong in 1973 as an oil trading company, followed by Ocean Tankers in 1978 as a ship chartering and management company. He started the Universal Terminal tank farm in 2008.

The early years of Lim's business were turbulent decades for the oil industry in Singapore, whose iconic downstream refining sector has seen everything from the rise of Asian crude grades such as China's Shengli and Malaysia's Tapis to the rise of US shale. The city state even helped fuel the Vietnam War at one point.

By virtue of being at the heart of Asia's fuel supply chains, Singapore has also been home to the quintessential oil trader who arbitraged between prices, regions, fuel quality and geopolitics to profit from a barrel of oil. It was briefly the stomping ground of Glencore founder and legendary commodities trader Marc Rich, who, like OK Lim, had an immigrant rags-to-riches story of his own in the US.

It is not so extraordinary, then, that OK Lim grew his fortunes in Singapore, eventually becoming one of the largest traders of petroleum products in the region and a regular on the Forbes list of Singapore's richest people. Hin Leong's bunkering arm was Singapore's third largest bunker supplier in 2019, accounting for 10% of local bunker sales, and was a key supplier to countries like Indonesia and Myanmar in Southeast Asia.

Anatomy of a decline

When Hin Leong's troubles became public it was the equivalent to the collapse of an institution, shaking Singapore's commodity trading community to the core, not only those who had exposure to the company but also everyday traders who had dealt with OK Lim for decades.

In mid-August 2020, OK Lim was charged in Singapore's court with abetment of forgery for the purpose of cheating, after investigations by the Commercial Affairs Department into Hin Leong's business activities.

According to the charges, OK Lim had instigated a Hin Leong employee to forge a document that looked like it was issued by UT Singapore Services, which operates the Lim family's Universal Terminal tank farm, stating that Hin Leong had transferred more than 1 million barrels of gasoil to China Aviation Oil (Singapore).

Interim judicial managers had laid out the scale of "irregularities" at Hin Leong in detail in June, covering everything from the fabrication of documents to derivatives trading losses and accounting cover-ups

The forged document was used to secure more than $56 million in trade financing from a financial institution, Singapore Police said when the charges were made public, adding that investigations were ongoing into other offences possibly committed by OK Lim.

Two weeks later, PricewaterhouseCoopers (PwC) Advisory Services, the judicial manager for petroleum trader Hin Leong Trading, sued OK Lim and his two children for $3.5 billion. The sum represented Hin Leong's outstanding debts, according to a statement from Drew & Napier, the law firm representing Hin Leong Trading, as instructed by PwC.

PwC also sought to recover another $90 million in dividends that the Lim family, which includes his two children, Evan Lim Chee Meng and Lim Huey Ching, paid themselves in previous years out of Hin Leong's disputed profits, it said.

Interim judicial managers had laid out the scale of "irregularities" at Hin Leong in detail in June, in an interim report seen by S&P Global Platts, covering everything from the fabrication of documents to derivatives trading losses and accounting cover-ups.

"The scale of the irregularities uncovered in just the financial year ended 31 October 2019 alone is highly troubling, and suggests that the company had, possibly for many years, been carrying on its business by presenting a picture of financial health that was a far cry from the underlying reality," the report said.

The report went on to say that financial statements for the year ended 31 October 2019 grossly overstated the value of assets by "an astonishing amount of at least $3 billion" comprising $2.23 billion in accounts receivables which had no prospect of recovery and $0.8 billion in inventory shortfalls.

"The overstatement existed to conceal significant losses that the Company had accumulated over the years," according to the report.

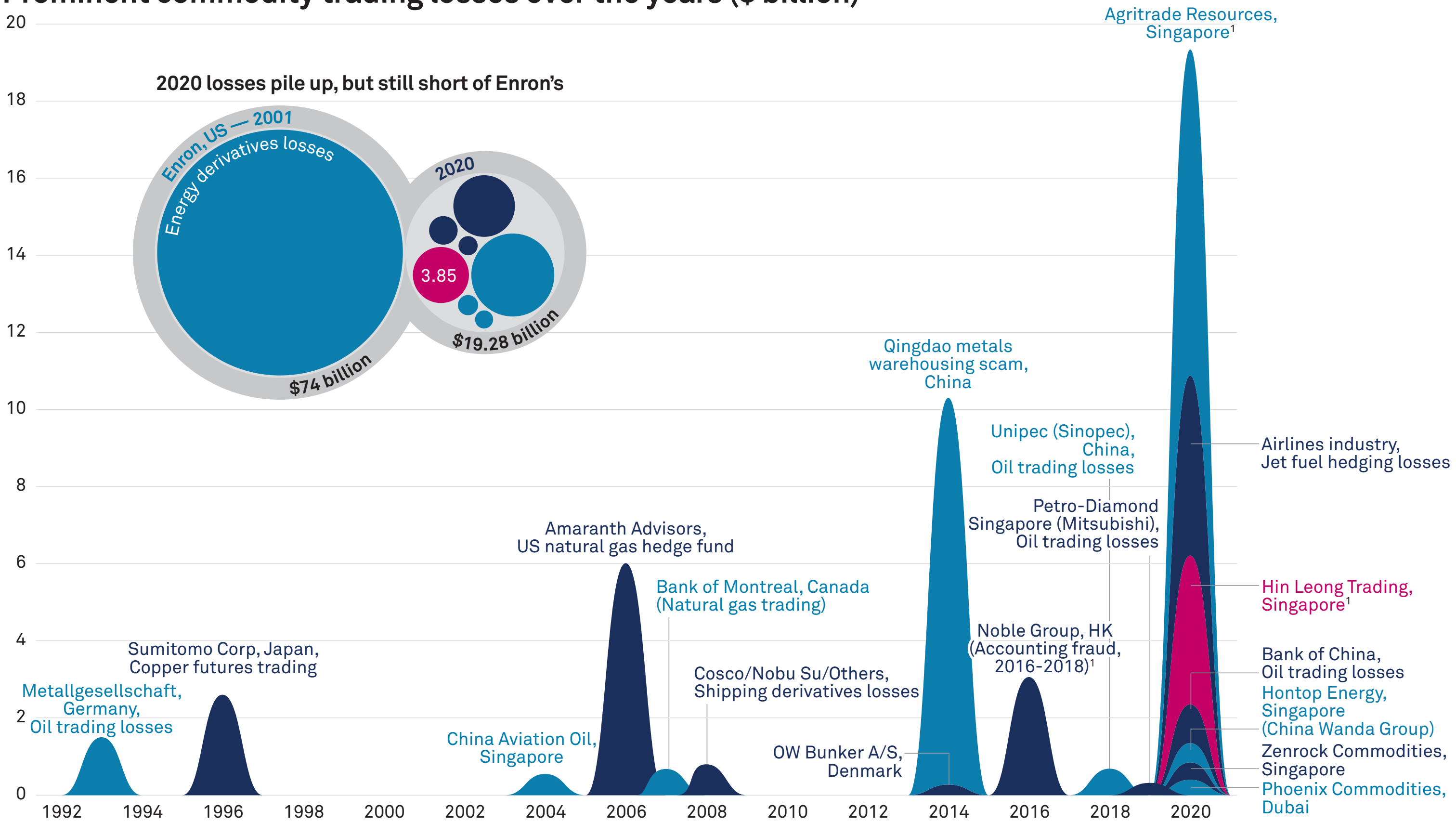
The investigators said there was evidence of accumulated derivatives trading losses of about $808 million over the past 10 years, in line with OK Lim's own affidavit, but added that these losses were concealed through the overstatement of derivatives gains by as much as $2.1 billion over the same period. They said receivables were overstated through the manipulation of accounting entries, and the use of "control accounts" to make inter-bank transfers that gave the false impression of payments, when none were actually received from customers.

The Hin Leong story: rise and fall of a Singaporean oil tycoon

2020 has been a tough year for oil and even worse for those caught on the wrong side of the price collapse. For Hin Leong Trading, one of Asia's largest petroleum traders founded by Singaporean tycoon Lim Oon Kuin, the turmoil exposed faultlines in a highly secretive business.

Irregularities eventually triggered a liquidity crisis and a court-ordered restructuring with nearly $3.85 billion in debt. Hin Leong's collapse jeopardized billions of dollars of family assets across petroleum storage and shipping, and continues to have repercussions across the industry.

Prominent commodity trading losses over the years ($ billion)[2]



[1] Total Enterprise Value at time of default [2] Losses / debt levels have not been inflation adjusted

What went wrong at Hin Leong

Derivatives losses
of $800 million go unrecorded, overstatement of derivatives gains by $2.1 billion over 10 years

Alleged fabrication of fictitious gains
from derivatives trading and fictitious sales invoices

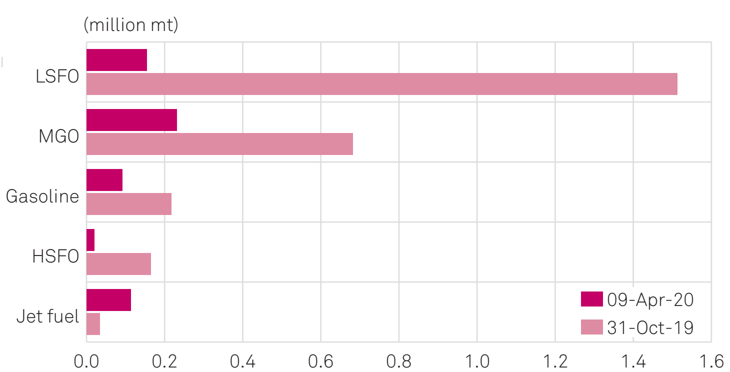
Overstated asset value
by $3 billion: $2.23 billion in receivables and $0.8 billion in inventory shortfalls

Resale of collateralized inventory
to generate cash flows

Release of fuel cargo
to persons not holding of bills of lading

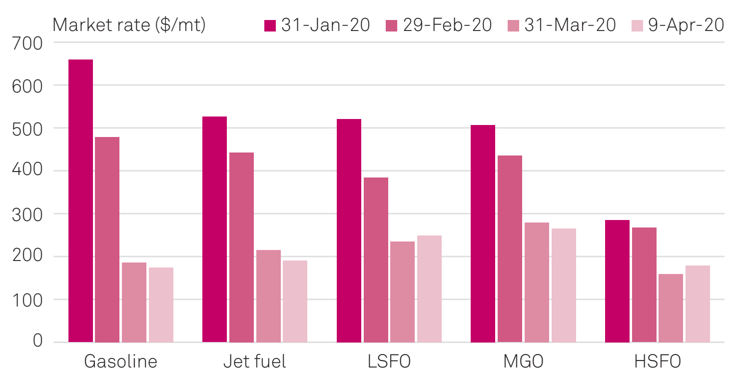
Decline in inventory volume

77% of petroleum stocks (worth $1.136 billion) lost in 6 months



Decline in inventory value*

Over 50% fall in petroleum fuel prices



* Mark to market losses in 2020

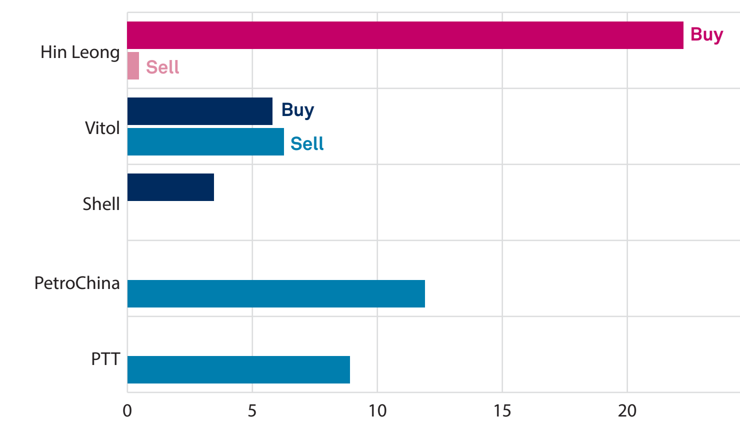
The rise and fall of Hin Leong

- **pre-1963** OK Lim comes to Singapore from small Chinese town of Putian
- **1963** Hin Leong Trading is established ("Hin Leong" means "Prosperity")
- **1965** "One-man-one-truck" dealer sells oil to taxis, buses and fishing boats
- **1968** Acquires first vessel, 100 dwt "Sea Lion"
- **1973** Hin Leong Trading incorporated as oil trading company
- **1978** Ocean Tankers incorporated as ship chartering company
- **1978** Ocean Bunkering Services set up as bunkering company
- **1980s** HLT becomes one of Singapore's largest petroleum traders
- **2008** Universal Terminal starts operations
- **2010** Talks with Sinopec to build $6 billion - $8 billion refinery fizzle out
- **2014** Plans for Universal Terminal IPO fail to materialize
- **April-20** Brent crude crashes to $22/b, COVID-19 slashes oil demand
  - HLT defaults on loans, lenders freeze credit lines
  - OK Lim resigns, Hin Leong files for bankruptcy protection
  - Hin Leong put under judicial management
- **May-20** Ocean Tankers put under judicial management
- **June-20** Judicial managers issue report on widespread irregularities
- **July-20** Assets subject to multiple claims, lawsuits
- **Aug-20** OK Lim charged in court for abetment of forgery
  - Xihe Holdings put under judicial management
  - PWC sues OK Lim and 2 children for $3.5 billion

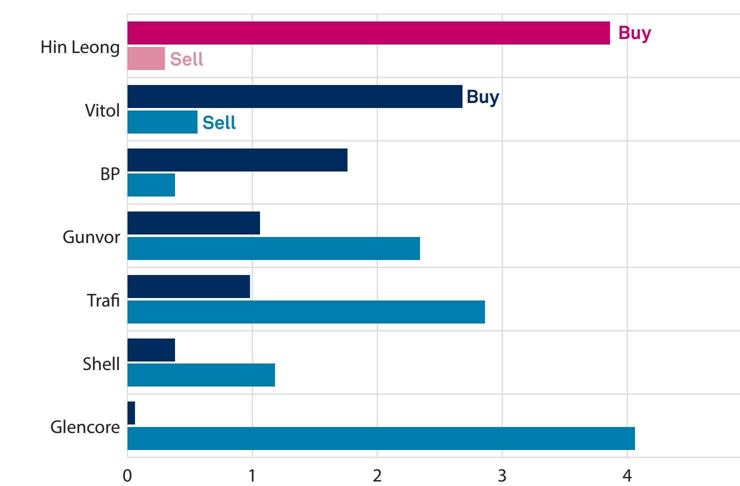
Hin Leong was one of the most active participants in the spot market

Volume of trades reported during the Platts MOC process

Gasoline — Apr 2019-Mar 2020 (million barrels)



Fuel oil — Jan-Dec 2019 (million mt)



Note: Fuel oil market changed due to IMO2020 from Jan 1, 2020

Lim family empire

OK Lim (founder) | Evan Lim Chee Meng | Lim Huey Ching

Hin Leong Trading
Oil trading
31-Oct-19*
Revenue: $20.27 billion
Net profit: $78 million
09-Apr-20
Total liabilities: $4.05 billion
Assets: $714 million

Ocean Bunkering Services
100% subsidiary

Hin Leong Marine Bunkering
54.55% ownership

Ocean Tankers
Ship chartering
31-Mar-19*
Revenue: $724 million
Net loss: $106 million
Liabilities to trade creditors: $58.5 million (29-Feb-20)

Universal Terminal
Oil storage
PetroChina 25%, Macquarie 34%
Lim family 41%
31-Dec-18*
Revenue: $183 million
Net profit: $31 million

Xihe Holdings / Xihe Capital
Shipholding

*Year ended

Sources: Court documents, company filings, S&P Global Platts, S&P Global Market Intelligence, news reports

Not only had Hin Leong been unprofitable in the last few years but its total liabilities at the time of the report came to $3.5 billion while its assets were only $257 million

The bank transfers were facilitated by using "fabricated documents on a massive scale" and the scale and regularity of the fabrication suggested that "the practice was routine and pervasive," the report said. These included forged bank remittance advices, bank statements, bills of lading, sales contracts, sales invoices, swap trade confirmations, swap trade tickets, deal settlement slips and inter-tank transfer certificates.

The forged documents in turn misled banks into extending financing to the company and also acted as supporting documentation for fictitious gains or profits, the IJMs said. To keep the losses concealed, Hin Leong had to maintain the flow of liquidity for which it obtained financing from banks through schemes that involved the sale and repurchase of cargo at a loss, forged documents, non-existent inventory, or the sale of the same inventory to multiple parties; leading to competing legal claims on the same cargo.

"The cumulative effect of the above irregularities was that a vastly misleading picture of the Company's financial health was presented to external parties, possibly for many years, with the result that the Company was able to continue to trade and obtain financing," the IJMs concluded. Not only had Hin Leong been unprofitable in the last few years but its total liabilities at the time of the report came to $3.5 billion while its assets were only $257 million, the report said.

On June 25, the Lim family issued a statement to the press saying they had not been given opportunity to respond to the allegations in the interim report and that OK Lim was deemed medically unfit to work at the time the investigations were being conducted. They said they reserved their rights against all relevant persons and would address the report and its findings in the right fora.

They had not issued a public statement on either the charges or the lawsuit as of early September.

Business as usual?

The Hin Leong episode has raised pertinent questions for the trading industry and everyone that deals with it, even as casualties from this year's disruptions are still piling up, such as Zenrock Commodities Trading and Hontop Energy. HSBC in May filed an application in Singapore's High Court to put Zenrock Commodities under judicial management, citing "suspicious" transactions and trade practices in its affidavit. Hontop filed for debt restructuring with the High Court in March.

Hin Leong's alleged fraudulent actions were discovered only when the coronavirus pandemic stressed out already overextended credit lines used to cover the company's losses. When Brent crude sank below $30/b in March it was the proverbial straw that broke the camel's back. The trader defaulted on some payments, which is when the real scrutiny into its transactions began.

If the coronavirus pandemic had not happened, how much longer could Hin Leong have continued? How widespread is the scale of losses at trading houses this year? What if the contango trade, which helped trading desks boost their profits and recoup losses in the second quarter, had failed?

Most large private commodity trading houses remain relatively opaque, even as they replace oil majors in remote countries with unstable governments, to the extent of financing the extraction of natural resources. Traders, including Hin Leong, prefer to control all aspects of the supply chain including shipping and storage to gain that extra optionality for the marginal profit on a barrel.

New light has been thrown on lax industry practices on payment and collateral, such as the use of letters of indemnity in place of bills of lading, which carry the actual title to a cargo, for payment. LOIs were devised as a solution as the original bills of lading

are often not available, especially when a cargo passes through many hands in a physical trade. But use of LOIs carries risks that are not always properly accounted for. Traders are more cautious now, but it remains to be seen whether industry practices will change permanently.

The current crisis has also exposed the true valuations of petroleum assets in the midst of a crisis as oil majors write-off billions of dollars in reserves and projects. The Lim family's shipping and storage assets – Ocean Tankers and Universal Terminal – are likely to be on the chopping block with both the companies now under judicial management.

Ocean Tankers charters or operates Singapore's largest fleet of tanker vessels and was one of the world's largest tanker fleet operators with over 150 vessels, according to OK Lim's affidavit. Its total exposure to Hin Leong's trades was $2.67 billion. Universal Terminal, 41% owned by the Lim Family, is the largest independent petroleum storage complex in Singapore and one of largest tank farms in the world with 2.23 million cu m of storage capacity.

Market participants say that storage assets are worth more in this crisis, but shipping assets and shipping company stocks have seen their value slashed.

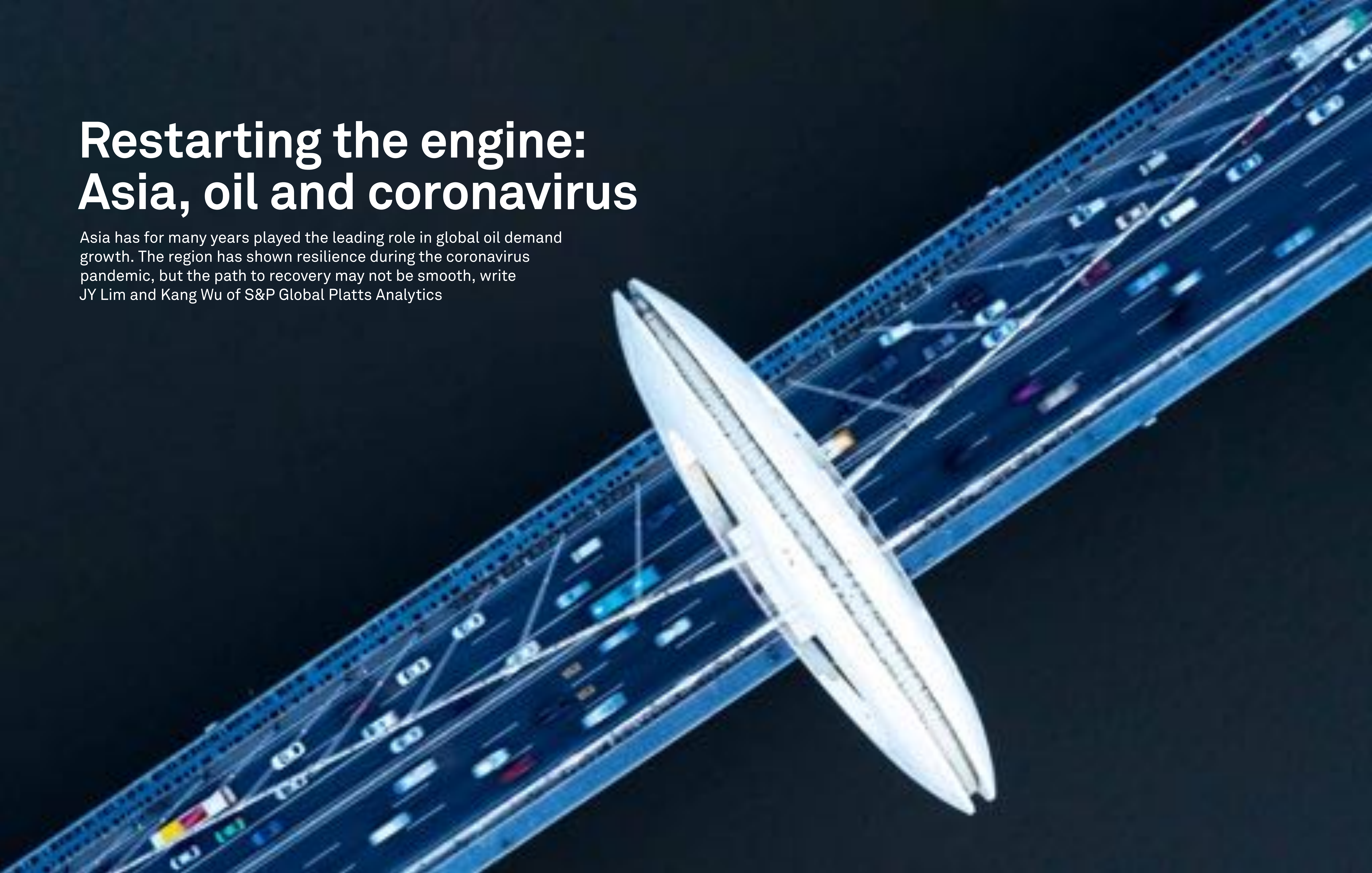
Lastly, there is the question of regulation and risk management in the industry. Banks have scaled back significantly from lending to the commodities sector in 2020, a move accelerated by incidents like Hin Leong. Risk management divisions are working overtime to scrutinize trades, and Singapore has deployed data-crunching technologies to assist investigators in the Hin Leong case and other fraud cases such as Wirecard earlier this year, and the 1MDB scandal several years ago.

Tighter measures are expected by the industry in coming months, although it is unclear what form they will take. As commodity trading itself gets digitized, the types of "old-school" Ponzi schemes and fraud we are seeing alleged here would no longer be possible. But that does not necessarily mean the renegade trader will disappear.

Marc Rich, in his biography 'The King of Oil' said the US shoots small birds with big cannons, referring to his indictment by the US government for trading Iranian crude amid sanctions. In the aftermath of the Hin Leong bankruptcy, it remains to be seen whether the big guns will be brought out. ■

Restarting the engine: Asia, oil and coronavirus

Asia has for many years played the leading role in global oil demand growth. The region has shown resilience during the coronavirus pandemic, but the path to recovery may not be smooth, write JY Lim and Kang Wu of S&P Global Platts Analytics



Global oil demand is set to suffer its largest slump in history this year due to COVID-19. Asia will also see a sharp downturn as oil demand in both China and India, the twin engines of growth in the region, has been slashed following the coronavirus outbreak.

The pandemic triggered a collapse in passenger transportation-related oil demand due to the enforcement of lockdowns, starting with China in late January and February and extending to the rest of the world in March and April, as countries around the world tried to mitigate the virus spread.

A catastrophic economic deterioration ensued almost immediately after the lockdowns. Many activities were curbed, not just in the tertiary sectors but also in manufacturing, affecting freight-related and industrial and feedstock-related oil demand.

S&P Global Platts Analytics expects Asian demand to drop by an unprecedented 1.7 million b/d in 2020, down from growth of 680,000 b/d in 2019 and posting the first decline since 2008, during the global financial crisis. But in 2021, led by demand recovery in China and India, Asia is expected to return to growth of 1.6 million b/d.

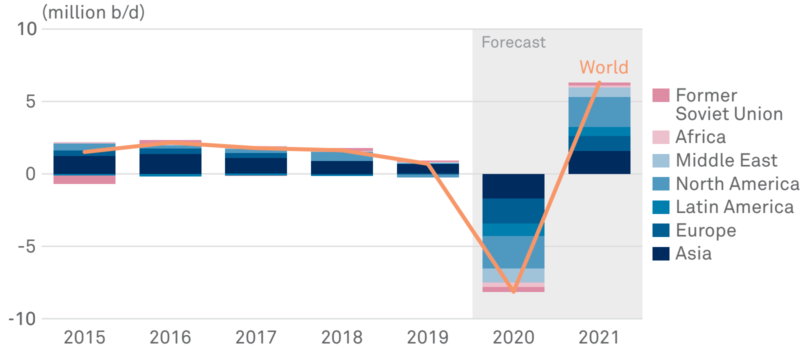
Globally, oil demand is expected to contract by 8.1 million b/d in 2020, with the more severe demand destruction already having happened in the second quarter. A rebound is then expected in 2021 with growth of 6.3 million b/d, but this will not wholly compensate for the decline this year: oil demand in 2021 will still be at least 1.8 million b/d lower than the 2019 level.

China bounces back

The Asia-Pacific region, fueled by growing populations, urbanization and rising disposable incomes, has seen its oil demand expand rapidly in recent years. The region accounted on average for about two-thirds of global oil product demand growth between 2011 and 2019.

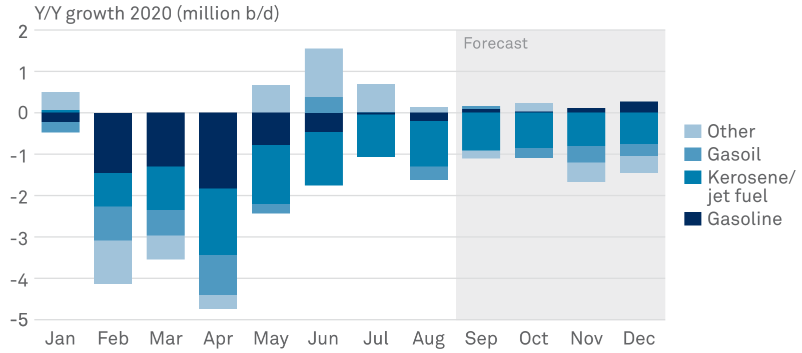
The growth was unsurprisingly concentrated in the region's most populous nations, China and India,

Global oil demand growth by region



Source: S&P Global Platts Analytics

Asia oil product demand growth



Source: S&P Global Platts Analytics

which together accounted for more than half of global growth over the period. As a result of the strong growth, Asia's share of global oil demand rose from 31% in 2010 to 36% in 2019. Nevertheless, 2020 will mark an interruption of the recent sustained rise in oil demand, as the coronavirus crisis leaves virtually no territory unscathed.

To paraphrase a popular saying, when China sneezes, the rest of Asia catches a cold. This is certainly the case for oil demand, as China now accounts for close to 40% of regional consumption, and contributed nearly 60% of demand growth in the region over 2011-19.

China was the first country to be hit by COVID-19, with its oil product demand plunging year-on-year by 1.2 million b/d in Q1 2020. But it recovered quickly with the lifting of lockdown and demand rose again by 670,000 b/d year on year in Q2.

China avoided a recession after its economy grew by 3.2% in Q2, following a 6.8% contraction in the first

quarter. The country's oil demand for the whole year is projected to fall by some 95,000 b/d or 0.6%, the smallest percentage decline among all major countries around the world.

The situation is not helped by falling demand in India, the other main center of growth in the region, where consumption plunged by 2.1 million b/d year on year in April, amid a nationwide lockdown. Demand recovered strongly in May and June, but still dropped by a massive 1.1 million b/d on average in Q2. July oil demand was lower month on month by 240,000 b/d, with consumption hit by localized lockdowns, coupled with the monsoon season and higher fuel prices.

Platts Analytics expects India's oil demand recovery to slow in H2 due to localized lockdowns following an uptick in coronavirus cases, with demand for the whole year forecast to contract by 505,000 b/d versus 2019. India is now the second-worst-hit nation in the world, behind only the US, and the worst in Asia, with over 4 million confirmed COVID-19 cases, the number of new daily cases surging after the lifting of the nationwide lockdown in late May.

The rest of Asia is expected to register a decline in oil demand of 1.1 million b/d in 2020, with falls in

China's oil demand for 2020 is projected to fall by some 95,000 b/d or 0.6%, the smallest percentage decline among all major countries around the world

both developed and emerging economies. Japan's oil demand is expected to drop by 330,000 b/d this year, after the nation imposed a state of emergency that lasted until late May.

South Korea will not be spared either, despite its effective containment of the coronavirus outbreak, with a drop of 55,000 b/d. Southeast Asian oil demand is expected to drop by 520,000 b/d. The Philippines became the epicenter for the coronavirus pandemic in Southeast Asia as new daily cases surged in late July and early August, overtaking Indonesia in the total number of COVID-19 cases. The Philippines' economy contracted by 16.5% year on year during the second quarter, its deepest fall on record, while Indonesia

reported its first economic contraction in more than two decades after Q2 GDP shrank by 5.3% from a year earlier.

Transport fuels worst hit

In terms of demand for key products, only LPG is expected to grow this year. This growth will be driven by demand from propane dehydrogenation plants in China and ethylene plants in Asia as LPG becomes a cost-effective feedstock from time to time, coupled with residential consumption in India as the government gives out free LPG cylinder refills to low-income households.

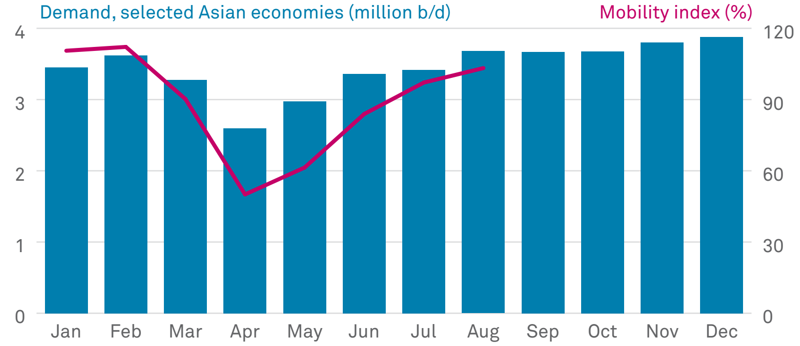
The pandemic has weighed heavily on demand for gasoline and jet fuel. Consumption of both products is tied to discretionary travel, which is severely curtailed by government measures such as quarantines, lockdowns, border closures, school and office closures and limited social gatherings, among others, as well as people changing their behavior due to fears of contracting the disease. Platts Analytics expects Asian kerosene/jet fuel and gasoline demand this year to drop by 970,000 b/d and 490,000 b/d, respectively.

According to Amap, by mid-August congestion in Wuhan, the epicenter of the outbreak of China's first wave of COVID-19, was back to normal levels seen over the last four years. Except for Beijing, where road traffic had still not recovered following a re-emergence of COVID-19 cases in the middle of June, major cities including Shanghai, Guangzhou, and Shenzhen were all close to normal levels at the time of writing.

Data from Apple's Mobility Index points to further improvement in driving activity among Asian countries outside China. Weighted against the baseline of January 13, 2020, the index indicates regional driving activity was back to 100% of that level as of mid-August. Activity in most countries has been on an upward trend since the April lows.

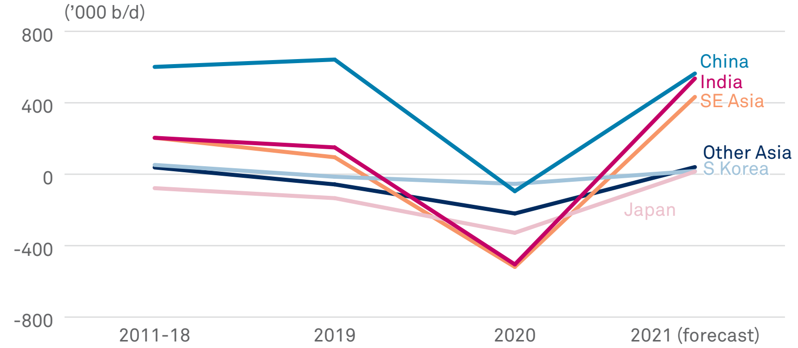
These mobility index trends are highly consistent with the latest developments in coronavirus lockdown measures. Almost all economies in the region either ended or severely relaxed restrictions by the end of May. June saw the index up by 23% from the May average, with the pace of improvement slowing to 13% in July. The mobility index has lagged in countries that

Asia oil demand vs mobility index in 2020



Source: S&P Global Platts Analytics

Asian oil demand growth by country



Source: S&P Global Platts Analytics

have been less effective in dealing with the pandemic, such as India and the Philippines.

Gasoil/diesel is the more resilient of the main refined products because it is used in many different sectors, including energy-intensive industrial and manufacturing, in addition to transportation. In times of crisis, governments will do whatever it takes to keep economic activity going, such as the introduction of various stimulus packages in the region, which will help to support gasoil/diesel demand. As a result, the decline of Asian gasoil/diesel demand is expected to be less severe at 290,000 b/d.

China's economy has clearly been on a V-shaped recovery path so far as headline macroeconomic numbers continued to come in strong and above expectations in recent months, as reflected by leading indicators such as the manufacturing Purchasing Managers' Index. But most other Asian countries are still in the recovery stage, and even China is facing

headwinds to further growth for the rest of the year due to the weakened global economy, the ongoing restriction of international travel and China's own stimulus programs possibly running out of steam.

On a positive note, Asia is expected to bounce back in 2021, led by demand recovery in China and India, with growth pegged at 565,000 b/d and 535,000 b/d for the two countries, respectively. Barring any second-wave outbreaks, Asia's oil demand is expected to grow by 1.6 million b/d in 2021 as economic activity continues to resume, but it will not be a return to business as usual for some sectors, particularly aviation.

For 2021, Platts Analytics still sees Asian kerosene/jet fuel demand 590,000 b/d lower than that of 2019 whereas gasoline and gasoil/diesel demand is likely to surpass 2019 levels. Taking all products together, Asia's oil demand in 2021 will still be 115,000 b/d lower compared to the level in 2019.

However, the recovery is not guaranteed. With COVID-19 cases continuing to increase globally as well as in Asia, and the resumption of international travel proceeds slowly, the prospects for 2021 demand recovery still face some headwinds and uncertainties.

The end of the summer driving season and falling temperatures will not only mark the start of the lower demand season – the onset of the northern

> Barring any second-wave outbreaks, Asia's oil demand is expected to grow by 1.6 million b/d in 2021 as economic activity continues to resume

hemisphere's winter will also make it increasingly challenging to keep social distance for human activities in order to limit the spread of coronavirus. The extent to which another serious wave of the COVID-19 pandemic can be avoided this winter remains unclear, even as the world looks ahead to a more lasting improvement in 2021. ■

Go deeper

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Global to local

A globalized supply chain for lithium-ion batteries has supported the global EV sector to date. Is that model now on the way out? Henrique Ribeiro, Jacqueline Holman and Ben Kilbey look at regional strategies and investment flows in the sector

The COVID-19 crisis has exacerbated concerns across the lithium-ion battery industry about China's dominance of the supply chain. The pandemic has also highlighted the need for local supply chains, in order to improve sustainability and work towards net zero targets.

Despite some momentum, however, the development of regional supply chains still faces challenges that go beyond simply raising equity.

Although there has been controversy about Chinese dominance, other regions such as South America and Australia are significantly more important than China in the lithium raw materials mining and extraction process. But it is evident that the vast majority of the downstream value-add activities are performed in China, largely due to an abundance of cheap energy and forward planning.

This is a consequence of the Chinese government's early push towards electrification, especially through subsidizing electric vehicles (EVs). The country currently accounts for more than half of global EV sales. This emergence of demand incentivized the development of the industry around it, combined with an important financial push from the Chinese government.

As it becomes increasingly clear that the electrification trend will not reverse, the Western Hemisphere has been trying to catch up. In the case of the US, one of the main challenges to reducing the gap is the lack of a government-run, one-direction plan, which is exactly what allowed China to take the lead, according to Emily Hersh, managing partner at consultancy DCDB.

"You won't find a Republican senator saying he is in favor of green energy, and you won't find a Democrat saying he is in favor of mining," she said, adding that there needs to be a champion to articulate a plan.

"The successful approach in the US would be for governors who have slightly different capital situations going on to take the lead and work with each other regionally," Hersh said.

The US concerns about the importance of lithium and other minerals date from 2017, when the Trump administration signed an executive order to "ensure secure and reliable supplies of critical minerals." A list of 35 minerals – including not only niche products such as lithium and rare earths, but also more common ones like bauxite and tin – was released one year later.

However, in practice little has changed so far. "Take rare earths for example, what is mined in the US has to go to China for processing," Hersh said.

In November last year, the US signed a cooperation agreement with Australia on critical minerals. The countries' export finance agencies agreed to work together to fund new projects and diminish China's dominance, but no investments have been announced so far.

Europe, on the other hand, seems to be ahead of the US in the race. Despite also being far behind China in the development of regional lithium supply chains, Europe has been attracting more investments than the Asian country since last year (see infographic).

Europe's ambition

The European Battery Alliance was established in 2017 to help create a competitive manufacturing chain in Europe.

EBA senior industry strategy executive Bo Normark told S&P Global Platts that mining had been given very low priority in Europe for decades, resulting in low activity and attractiveness.

"This has, however, changed dramatically even before the coronavirus [pandemic] and in the annual survey of the most attractive regions for mining globally by the Fraser Institute, they conclude that there has been a spectacular change in the top," he said.

According to the Fraser Institute's Investment Attractiveness Index 2019, Europe was the most attractive region in the world for mining investment

According to the Fraser Institute's Investment Attractiveness Index 2019, Europe was the most attractive region in the world for mining investment in 2019

in 2019, with Finland coming in as the second best jurisdiction in the world for investment, after ranking 17th in 2018. Portugal came in fifth, up from number 46 in 2018, while the Republic of Ireland and Sweden also made the top 10.

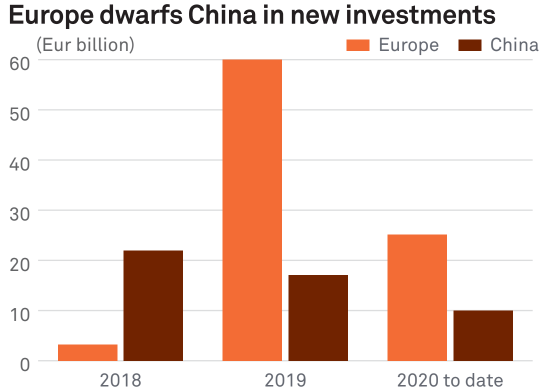
Normark said the main challenge now was for countries and companies to deliver on the expectations created for the mining industry.

"Another challenge is finding competent people since the mining industry has been less attractive in Europe for many decades," he said.

He added that it was well known that there are sufficient lithium deposits in Europe to meet the continent's entire long-term requirements.

"This will not be done overnight, but a realistic plan is that Europe in the timeframe of 2025-2030 could become self-supplied in lithium. This is important since all projections today are pointing towards lithium

Europe dwarfs China in new investments



All data on investments is as of June 26
Source: S&P Global Platts

being used not only in today's batteries, but also in the next generation of batteries," Normark said.

He noted that from a purely commercial standpoint, the formation of a more global battery supply chain would allow the European battery industry to find the lowest-cost options for extracting the materials it needs, while also contributing to the competitiveness of the industry.

"Industrial development, investment and jobs are naturally important elements for distribution of global wealth. With this also comes, if done right, [the opportunity] to spread high environmental and ethical standards to developing countries," he said.

But there are some disadvantages, Normark said, noting that there could be supply risks from instability arising for various reasons, while it also makes it more difficult to implement and guarantee the highest ethical and environmental standards.

"Another disadvantage is that the fast development of the battery industry has proven to be closely linked to building strategic cooperation along the battery value chain and this can become less efficient. Currently the battery material supply chains create a lot of transportation that can be avoided with local sourcing from Europe," he said.

"Creating jobs in Europe in combination with the electrification of transportation is an important element to create public acceptance. If jobs are lost and not new created it could slow down the transformation," Normark added.

Britishvolt eyes UK dominance

Britishvolt recently expressed interest in building the UK's first EV battery gigafactory. The preferred location is in Wales, where it could eventually lead to creation of more than 4,000 jobs.

Speaking to S&P Global Platts, chief strategy officer Isobel Sheldon said collaboration will be essential for success in the EV and broader battery sectors.

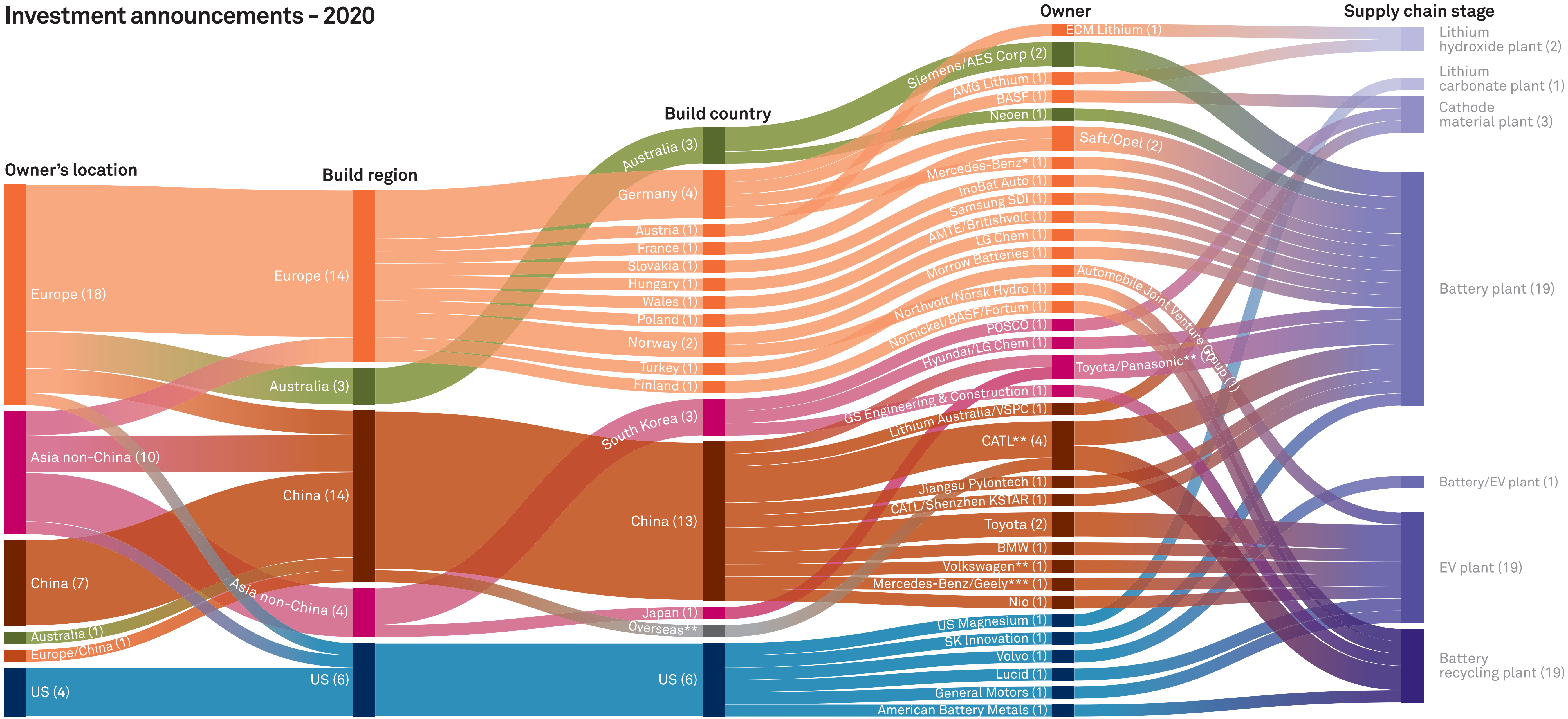
Global to local

Charged up: Europe the new hot spot for lithium-ion battery investments

Electrification in transport has been predominantly a Chinese endeavor so far, but Europe is increasing its relevance as another key region for this transition. Driven by stricter regulations on emissions, European companies are at the forefront of investments related to the battery supply chain. Europe also already attracts as many projects as China does.

The pandemic had significant impacts upstream, leaving an unanswered question: where will the lithium required to power all these batteries come from? Before the pandemic, a lithium shortage was certain to take place in a few years. The new scenario indicates it might be sooner than expected.

Investment announcements - 2020



*In addition to the Kamenz plant, Mercedes-Benz will build six battery plants at undisclosed European locations, as well as one in Asia and North America each **Undisclosed city/region
***JV between European and Chinese companies

All data on investments is as of June 26
Source: S&P Global Platts

Sheldon has nearly 20 years of experience in the space, ranging from roles at Johnson Matthey, Cummings and the UK Battery Industrialisation Centre, as well as previously running her own successful battery-focused business.

She said that Brexit and the pandemic offer favorable opportunities to the development and rollout of Britishvolt.

"Local supply chains are as important to business as they are to the environment," she added.

Sheldon said materials such as the cathode (high nickel-based cathode materials), a significant part of next generation EV batteries, need to be protected from moisture. Long transit times from places with hot climates could be detrimental to the product before it is even placed into a battery cell.

This means local refining is essential. One big concern for consumers is the range of an EV, and the better the material is processed and constructed, the better the longevity of the battery pack.

The UK domestic battery industry is forecast to be worth GBP5 billion ($6.3 billion) by 2025, and demand for lithium ion cells across a number of industries, including vehicle electrification, is already increasing dramatically.

"In light of recent events [the coronavirus pandemic], it is clear that moving from a global to [a more] regional market [is] key for industrial players and policy makers," Vincent Ledoux Pedailles, executive director at Infinity Lithium, told S&P Global Platts. "The [pandemic] will accentuate even more the need to develop an integrated and local EV supply chain in Europe, with direct access to lithium."

> Creating jobs in Europe in combination with the electrification of transportation is an important element to create public acceptance
>
> **– Bo Normark, European Battery Alliance**

Bypassing China

Despite all the efforts from other regions, especially Europe and the US, China is expected to remain an important participant in the lithium-ion supply chain – and is even more crucial for those towards the upstream side of the industry.

"It is generally more economically attractive to place [lithium] converting assets either near the resource or in regions that can easily serve energy storage device manufacturing centers like China, Japan and [South] Korea," said Eric Norris, president for lithium at US-based chemicals company Albemarle, stressing that China continues to be an important country for the company.

"As such, we will have, and will plan to have going forward, ample conversion capacity in China to serve that market, as well as capacity outside of China to address the globalization of the industry," he added.

Norris said Albemarle chooses the location of its conversion plants based on the proximity to the lithium resource, overall capex requirements, operating costs, logistics of shipping raw material or finished goods, permitting, and proximity to customers.

Going downstream, China's relevance as the biggest EV consumer market is still to be challenged, which should keep feeding the local industry with further investments. Since the beginning of the year, at least two major Western automakers announced significant milestones in China: US-based Tesla started up its Shanghai gigafactory, while Germany's Volkswagen invested Eur2.1 billion to acquire stakes in battery maker Guoxuan High-tech Company and auto manufacturer JAC Motors. ■

COVID-19 to delay several lithium projects

Owner	Name of project	Capacity ('000 mt/yr)	Product	Project type
Argentina				
Lithium Americas/Ganfeng	Cauchari-Olaroz	40	Carbonate	New
Livent	Salar de Hombre Muerto	40	Carbonate	Expansion
Eramet	Centenario-Ratones*	N/A**	Carbonate	New
Orocobre	Salar de Olaroz	25	Carbonate	Expansion
Galaxy	Sal de Vida	25	Carbonate	New
Chile				
Albemarle	La Negra 3-4	40	Carbonate	Expansion
Codelco/Lithium Power International	Maricunga	20	Carbonate	New
Australia				
Albemarle	Kemerton	50	Hydroxide	New
SQM/Westfarmers	Mount Holland	45	Hydroxide	New
Tianqi	Kwinana	48	Hydroxide	New

*Cancelled, not only delayed **Targeted production was not disclosed

All data on investments is as of June 26
Source: S&P Global Platts

Global to local

Insight from Shanghai

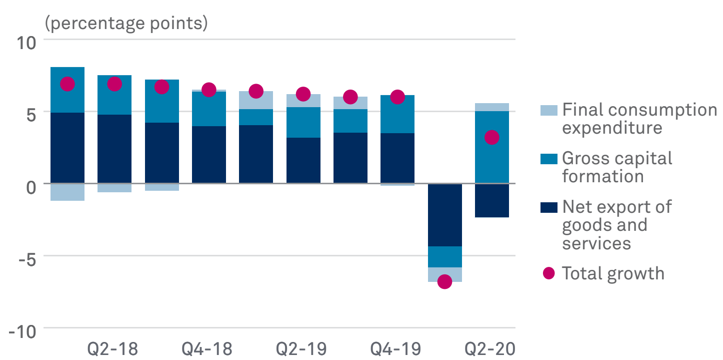
By Sebastian Lewis

Walking down a street right now in Shanghai, one would be forgiven for thinking the pandemic never happened. At times it's hard even to spot someone wearing a mask.

Dig a little deeper, though, and it's clear that recent events have had a profound impact on the Chinese economy. Foreign investment and exports turbo-charged the Chinese economy for nearly two decades after China entered the WTO. But now things have changed.

The pandemic has underlined how important exports are to the Chinese economy. It has also exacerbated existing frictions between China and other countries, highlighting how dependent China has become on imports of key components and materials. On the other side, the pandemic has exposed how reliant global supply chains have become on Chinese-made inputs.

Contribution to China GDP growth



Source: CEIC, S&P Global Platts

To some extent, events this year have merely accelerated trends in deglobalization that were already underway. But with economic decoupling set to continue, China's old economic model looks increasingly unsuited to the post-pandemic world.

Step forward the government's latest economic buzzword, "dual circulation". This somewhat gnomic concept boils down to making the economy more resilient by making it less dependent on imports and exports, and more reliant on domestic demand.

But in the short term the government has needed to fall back on investment to shore up the economy, which S&P Global economists forecast will grow by only 1.2% this year.

Yet again, the government has resorted to infrastructure to provide jobs and support the economy. Sales of excavators and front loaders in the first seven months of this year are up 15% on last year and steel production is at all-time highs. But this stimulus package is a little bit different.

Last hurrah for the old economy?

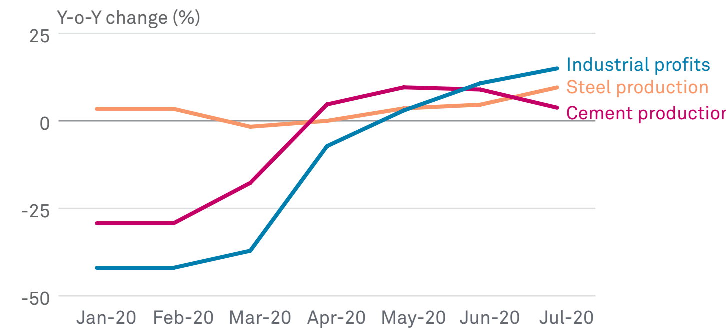
Alongside urban renewal and major transport and water conservation projects, the government is also prioritizing investment in what it is calling "new infrastructure". The focus this year will be on seven key areas: 5G, data centers, AI, the industrial internet, inter-city and urban rail, new energy vehicle charging infrastructure and further investment in the ultra-high-voltage grid to reduce transmission losses and more efficiently deliver the electricity required to power this new infrastructure.

Total investment is estimated at Yuan 1-1.2 trillion ($158 billion–$187 billion), which is relatively modest compared to the estimated Yuan 17 trillion spend on all infrastructure in 2019. But the government hopes that this initiative will accelerate the construction of the data and communications networks needed to support the development of e-commerce, smart manufacturing and smart cities with internet-enabled transport and energy networks, all powered by AI and data collected from the millions of digital measurement devices and sensors that form the backbone of the industrial internet. Well, that's the vision, anyway.

In with the new

This opens up opportunities but also presents challenges to the energy sector. It doesn't mean

China selected industrial indicators

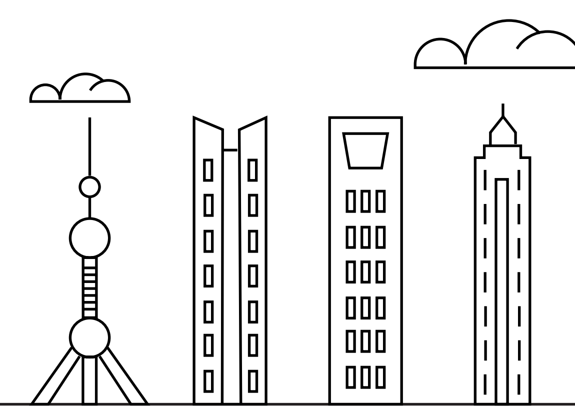


Source: CEIC, S&P Global Platts

China is turning its back on heavy industry – China is going to need coal and steel for decades to come. But investment will increasingly be focused on areas that support domestic consumption and help the country become more self-reliant. This means investment in emerging industries like new materials, robotics and biotechnology, as well the transformation and upgrading of basic manufacturing, improving it so that it can meet the needs of domestic consumers.

It also means big investment in areas that will make China less dependent on imports. Developing domestic competence in areas like semiconductors will be a priority, but so is strengthening energy security to reduce China's ever-growing thirst for imported oil and gas.

This will require further investment in domestic production, notably unconventional natural gas, a segment that China's oil and gas majors will continue



to develop. In the first seven months of the year natural gas production was up 9.5%, growing significantly faster than oil or coal output over the same period.

While petrochemicals and aviation fuel will see continued growth, increasing use of electric vehicles and the electrification of public transport presents an existential threat to China's oil and gas companies.

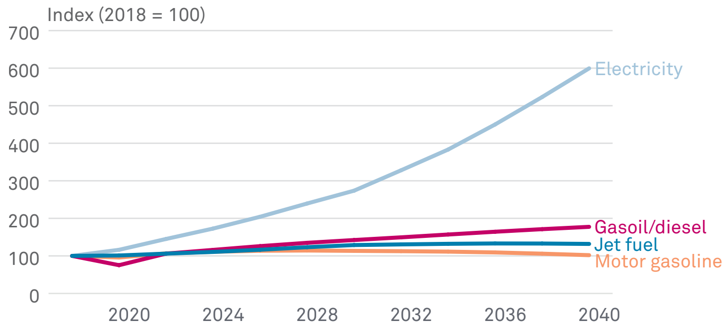
S&P Global Platts Analytics forecasts Chinese gasoline demand will plateau around 2025, with gasoil peaking a decade later. With the market for two of their key products set to decline, China's energy companies will need to look not to exports but to China itself for new markets and business models, to continue to be relevant. Sinopec has already started on this journey, installing electrical and hydrogen charging facilities at some of its filling stations. CNOOC has established a company to develop an offshore wind power business. Its project off the coast of Jiangsu is set to connect to the grid by the end of this year.

A digital revolution

The industrial internet, big data and AI will likely be able to help drive efficiencies and reduce costs. Alibaba, one of China's leading technology companies, claims that by applying machine learning to real-time data from wind turbines they have been able to predict in advance when they will fail, reducing the operation and maintenance costs at one wind farm by nearly a third. Sinopec has introduced an industrial cloud platform across some of its refineries to optimize production and reduce costs. Downstream, it has been developing digital transaction platforms and e-commerce channels to better secure the market for its chemicals and refined products.

But to be truly transformative, these technologies need to capture and analyze real-time data not only along individual energy value chains – from production through to distribution and consumption – but also across them, where the oil, gas, coal and electricity energy systems interface and interconnect. Better co-ordination and optimization across the whole energy

China demand for transport fuels

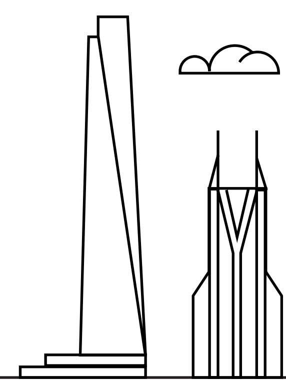


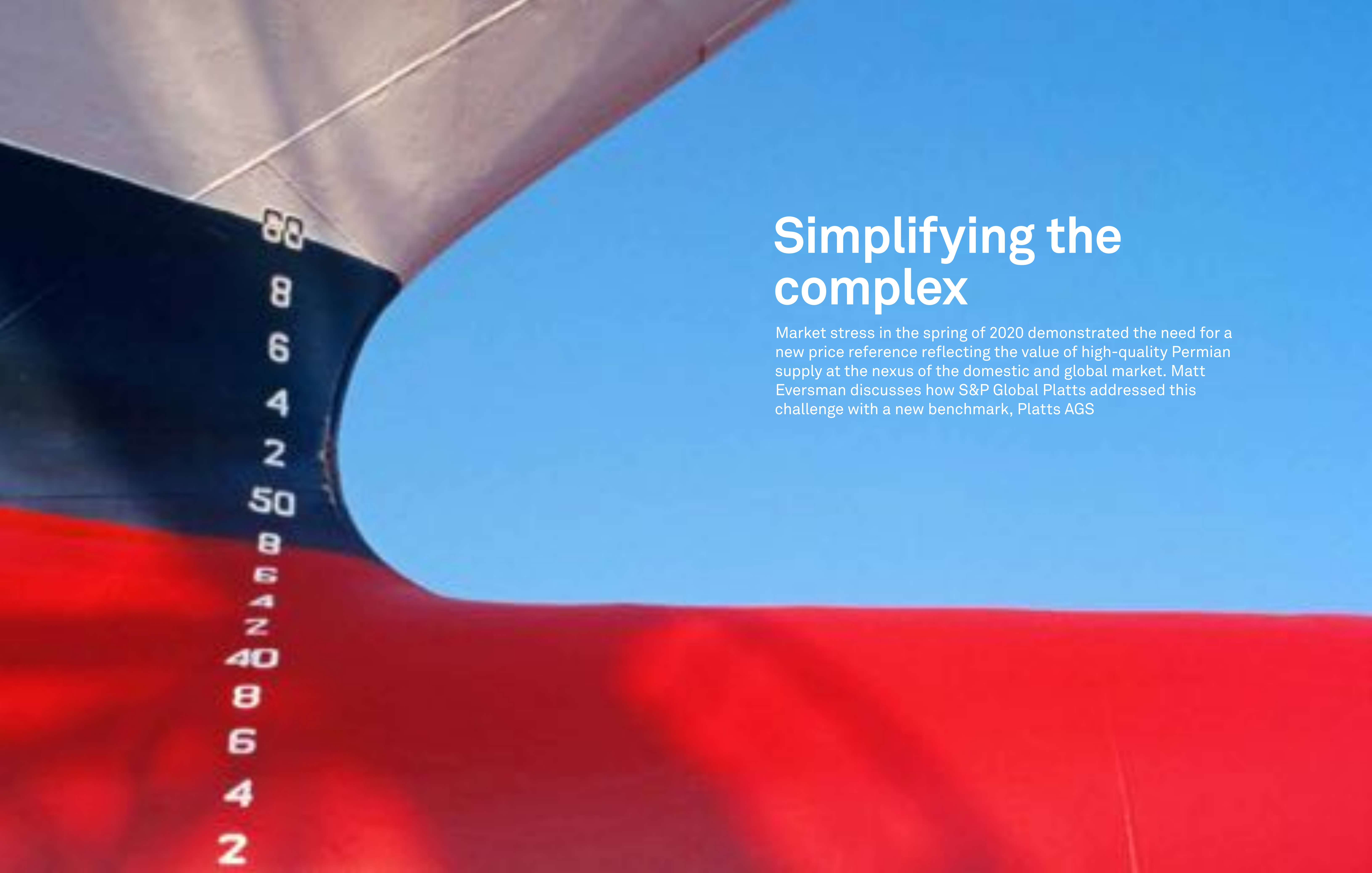
Source: S&P Global Platts Analytics

system could help increase the role of renewables and distributed generation in China's energy mix.

China isn't the only country hoping to harness big data and digitization to transform its economy. But its state-directed model of development, with its ability to allocate and co-ordinate investment in the new digital economy, might mean that it gets there more quickly than others.

The 14th Five Year Plan, to be released next year, will contain more detail on the government's ambitions and targets for China's new economic model. The transition may be gradual and incremental, but the direction of travel is clear. China's centrally planned, digitally coordinated, consumption-driven economy is beginning to take shape. ■





Simplifying the complex

Market stress in the spring of 2020 demonstrated the need for a new price reference reflecting the value of high-quality Permian supply at the nexus of the domestic and global market. Matt Eversman discusses how S&P Global Platts addressed this challenge with a new benchmark, Platts AGS

In the wake of a historic dive into negative figures on April 20, the oil industry called for an alternative to pricing at the hub of Cushing, Oklahoma.

S&P Global Platts responded by putting to work its expertise in cargo markets to design a methodology that would simultaneously provide clarity into what is being valued and a broad, regional representation of price.

Platts AGS, the US' new waterborne crude benchmark, clearly demonstrates the value of a defined grade within a specific trading framework, bringing structure to a regional market previously characterized by one-off deals.

The tension between liquidity and precision is an important consideration in the development of a new US crude benchmark. Higher transaction volume does not improve the usefulness of an assessment if it undermines clarity and precision. On the other hand, an overly specific assessment may not reflect a broad enough segment of the market to provide a trustworthy representation of price.

To take an extreme example, consider a US Gulf Coast crude assessment that calculates a volume-weighted average based on information from a basket of pipeline and cargo trading locations in the Gulf Coast, normalized based on historical spreads to a single terminal. This assessment could advertise significant liquidity, but would that liquidity come at the expense of clarity and precision? The proportion of market information from different locations and from pipeline versus cargo trades would fundamentally change the kind of market the assessment represents each day. And that's not a problem you can solve through a normalization process based on historical price differences.

The other extreme would be a futures contract with physical deliverability at one or a few close-proximity assets. This pricing mechanism would be clearer and more precise, but would not provide a regional representation of value. Limiting deliverability to a small group of assets, while positive for clarity and precision, excludes liquidity. And because of the financial-to-physical convergence inherent in these types of contracts, there is no flexibility for an assessment process to determine value from nuanced market information.

Following in the footsteps of other waterborne benchmark ecosystems – Dated Brent and Platts Dubai – Platts AGS strikes the balance between the "anything goes", volume-weighted average approach and the overly restrictive physically deliverable futures contract examples. The assessment provides total clarity into what is being valued and under what trading circumstances. In addition, it captures a large swath of transaction volume and the entirety of the US' main crude exporting region without distorting value.

To get there, Platts worked with the market to develop solutions for two key methodology challenges.

Quality control

The impediments to fungibility in the USGC crude market boil down to two questions at the point of delivery: what is the crude and how deep is the water where it's loading?

The former presents an interesting challenge in setting the guideposts for a functional market based on Permian crude. Unlike, for instance, the North Sea, where a certain grade will be fed by a relatively small geographic area, the Permian Basin covers a huge area of the southwestern US with big gathering systems feeding nine key pipelines.

In the US Gulf Coast crude export market another impediment to a uniform regional market is different water depth at different docks

With over 4 million b/d of production spread across two distinct basins, a crude buyer for a refinery might make the argument that the Permian should be carved up into different grades like Brent, Forties, Oseberg, Ekofisk, and more recently Troll, a few thousand miles to the northeast.

Platts decided it would be most useful to draw up the specifications for one grade that captured the majority of unblended, direct-from-Permian supply while meeting the technical needs of refiners across the US, Europe and Asia.

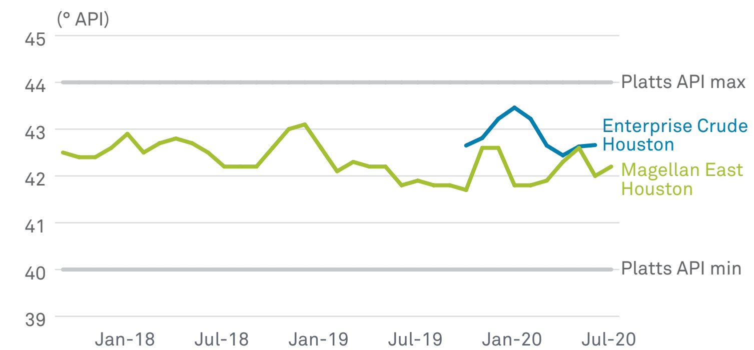
"Crude oil specifications need to consider the market liquidity of the streams involved... commingling/blending that may occur in production and transportation... [and] the requirements of refiners who will ultimately transform the crude oil into finished products," said Dennis Sutton, executive director of the Crude Oil Quality Association.

With that in mind, Platts proposed and – following some revisions – implemented a set of specifications for Platts WTI Midland that accommodated feedback from producers, traders, refiners and other stakeholders. The specifications cover the basics like gravity and sulfur content in addition to addressing iron and mercaptans, which are left out of many specifications.

In its determination of suitable gravity parameters, Platts considered data reported by Houston-area terminals as well as Certificates of Analysis for US Gulf Coast cargoes. The data showed that direct-from-Permian supply is consistently pushing (or exceeding) the upper bounds of the NYMEX WTI API specification range of 37-42. In addition, the reported quality statistics demonstrate the variability in crude from this vast production area with reported API at Magellan East Houston and Enterprise Crude Houston terminals diverging by as much as 1.5 API in a given month.

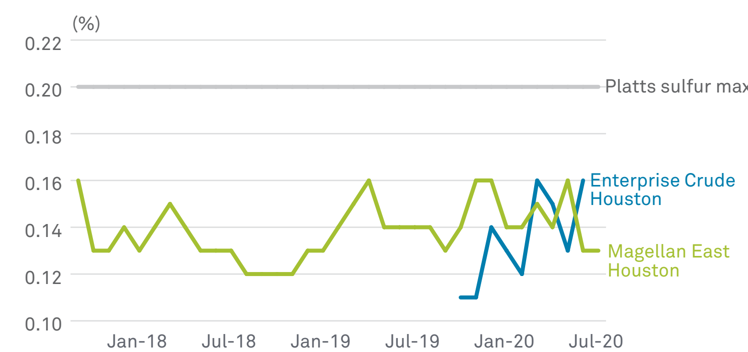
Quality data from the Houston terminals also showed that the direct-from-Permian stream is significantly sweeter than the NYMEX WTI sulfur limit of 0.42% and most of the Permian-to-USGC pipeline limits of 0.4%. Industry feedback suggested 0.2% has emerged as an export market litmus test for unblended, direct-from-Permian barrels often sought by global refiners.

Houston-area terminal reported crude gravity



Source: ICE, Enterprise Products

Houston-area terminal reported crude sulfur content



Source: ICE, Enterprise Products

Platts' specifications including 40-44 API and 0.2% or less sulfur are a first step in finding the balance between maintaining liquidity and providing a clear representation of value that is technically practical for buyers.

"Quality consistency is the hallmark of concerns for any refinery and in particular for the Asian refiner due to issues related to crudes being offered that were not Midland grade but rather blends of Midland and Canadian grades. By setting standards that ensure that the quality of the barrel in the AGS assessment falls within defined parameters that reflect Midland-grade WTI, such concerns are assuaged," said Robert Sanz, president of RLS Consultants.

As the Permian crude stream and crude export market evolve, so too may the Platts WTI Midland specifications. However, it will remain consistent that further changes are based on industry feedback and implemented with transparency and appropriate lead time.

Dealing with inconsistent seas

In the US Gulf Coast crude export market another impediment to a uniform regional market is different water depth at different docks. The Americas Aframax market long ago ceded control to freight buyers on the issue of overage charges. Crude shippers have the incentive to load as many barrels as possible to get the most out of their fixed freight cost. The maximum number of barrels is determined by the draft at berth and on the way out to sea.

Normalization of market information puts docks across the US Gulf Coast on a level playing field

In the case of Corpus Christi, depth in excess of 45 feet may allow over 700,000 barrels to safely load onto an Aframax. On the other end of the spectrum, depth of about 40 feet in Nederland may limit Aframax loadings to about 600,000 barrels. A buyer would only pay for the volumes they load, so why would the 100,000 barrel difference matter?

Assuming a USGC to UK lump sum freight cost of $1,000,000, a 725,000 barrel Corpus Christi loaded Aframax would incur $1.38/b of freight cost to reach western Europe. Meanwhile, the 600,000 barrel Nederland vessel would clock in at $1.67/b for the same route. So on an FOB basis, all else equal, a trader would be willing to pay 29 cents/b more for the same molecules loading in Corpus Christi.

Given this dynamic of variable volume and fixed freight, FOB cargoes will understandably trade at different values depending on achievable loaded volume. Platts viewed this distortion as important to address – not in the Market on Close process itself – but in how that market information is interpreted. So, the Platts AGS methodology calls for bids, offers and trades used in the assessment to be normalized to reflect the freight economics of a 700,000 barrel typical cargo size.

One important point of this adjustment is that, unlike a backward-looking location normalization, as may be present in other new Gulf Coast crude assessments, Platts' cargo-size normalization is not a circular reference with historical trade information. Rather, this normalization changes daily based on the value of Platts' assessed freight rates.

When Aframax rates are on the lower end of about $14/mt, the normalization would be about 25 cents per 100,000 barrels. However, when freight rates are at elevated levels, as seen in early 2020, that same normalization could reach $1/b or more.

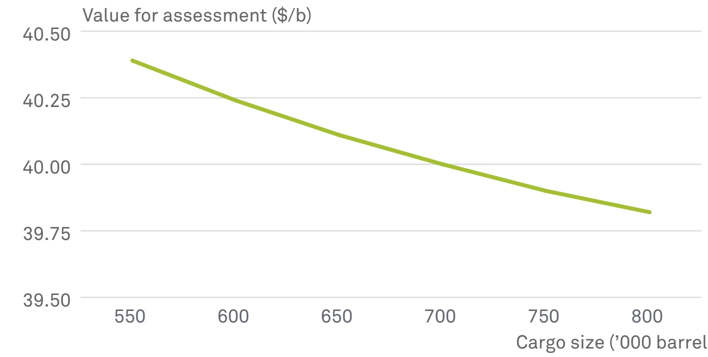
This normalization of market information puts docks across the US Gulf Coast on a level playing field, a crucial step in assuring the daily Platts AGS assessment reflects the value of oil, not logistics.

Bringing order to a chaotic market

Now in just its fifth year, the US Gulf Coast export market has so far had few pillars of consistency.

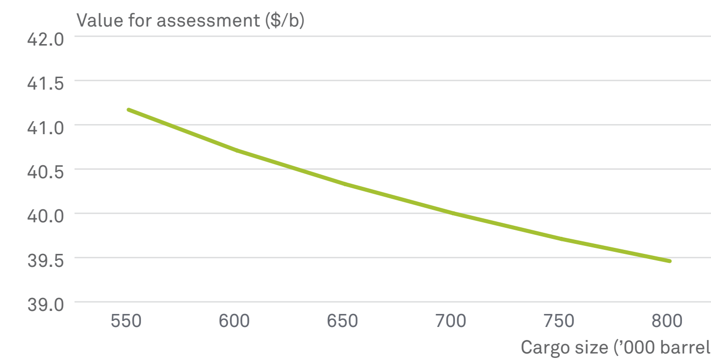
Crude quality was mainly handled on a one-off basis with no defined specifications to pinpoint true direct-from-Permian supply. Value was difficult to ascertain in the absence of a price assessment that isolated the value of Midland-quality WTI from the impact of dock-to-dock logistics.

Assessment-applied value for trade at $40/b, $1,000,000 lump sum freight



Source: S&P Global Platts

Assessment-applied value for trade at $40/b, $3,000,000 lump sum freight



Source: S&P Global Platts

Platts AGS changes that, answering the call of the industry for an alternative to Cushing, by addressing the complexities of the US Gulf Coast export market and balancing assessment liquidity and precision. ■

Additional reporting by Catherine Wood

Go deeper

Learn more about Platts American GulfCoast Select (AGS) and find resources including FAQs and the latest assessments at spglobal.com/plattsAGS

Insight Conversation: Greg Newman

Insight Conversation: Greg Newman

Greg Newman, CEO of London-based proprietary trading house Onyx Capital Group, caught up with S&P Global Platts head of news for EMEA, Andy Critchlow, and global head of generating fuels Simon Thorne to discuss what the future holds for the financialization of energy markets

Prop trading houses have largely replaced the role previously held by banks as market makers on the Platts eWindow communication tool for assessing the tradable value of commodities.

Greg Newman is one of the founding partners of Onyx Trading, which started operating in 2016 as an oil derivatives trade house. In this interview with Platts on August 5, Newman shared views on driving factors for oil price in the coming months and the role of different types of trader in the market.

Do you see an upside for oil this year?

We personally think it's going to steadily improve towards the $50 [per barrel] range as there's more and more confidence for people putting their money where their mouth is. Ultimately, traders need to make a bonus. They need to generate returns on a respective basis. They need to make a call one way or another. I think if you need to be bullish or bearish right now, you're going to be heading towards the bullish direction.

We were getting particularly excited about the market about six weeks ago, when we recovered very strongly, particularly in the Dated Brent space, and we saw all the evidence that the physical diffs hugely recovered very, very quickly into positive territory.

The wider European market in crude, in particular, largely rebounded because of the fuel oil market and this whole IMO switch that I think has gone under the radar in terms of real impact. Refiners aren't really producing residual fuel oil at the moment. A lot of the VGO [vacuum gas oil] and heavy crude, things that can be blended into the IMO fuel, are being sent to that blending pool and not sent out as residual fuel. So actually, as opposed to the residual fuel cracks being very weak, they're very tight because no one is producing it. And that, in turn, has supported the medium-heavy grades, and the North Sea followed suit.

So we were getting quite excited about how the market could follow through, but I think it just kind of exhausted itself too quickly. You can see the evidence that the Chinese imported so much from the US and wherever else too quickly. These cargoes have been offered back into Europe, for instance. And it's probably just a bit of a tapered kind of level on the bullish run. But on balance, I still think we get out of this range and we head north, just because we are ultimately in a constructive market.

My main reasoning for that is just the refinery margin – not the classic refinery margin, the new refinery margin with IMO shipping fuel, the idea being you've got so much optionality. You can either buy your crude [and] blend it to a decent product, [or] you can buy traditional crude being a traditional refiner. And actually, your waste products, fuel oil and naphtha are really at quite attractive levels on a crack basis, very high levels relative to what they've been in the last few years. So you're not too concerned about what's going to be left over when you're running through your CDU [crude distillation unit].

I think you're not making a hell of a lot of money refining, but you're definitely making enough to be buying crudes from around the world and running fully, and I think that's quite constructive. And then we just need to see the overhang clear out a bit more, and we could be well on the way.

How does increased liquidity from retail investors tie into the financialization of Platts' eWindow?

The retail side in my mind is always going to be a good thing for markets because it is just going to increase liquidity. The oil market has always been this kind of status quo of "no one really knows what's going on", and not that much transparency, but that's really not the case these days. I think it's more and more transparent as we go on.

In the retail space, in particular, as those volumes come in, the same thing that happened with foreign exchange, where you have a lot of retail trading, will take place. Now you've got the tightest market in everything you could possibly want, even in trading. We're hedging as a firm forward FX rates of dollar sterling. And we'll do it 12 months out, and it's like three basis points – tiny, tiny spreads and huge volume – because everyone around the world has access to it and is trading it. I think on balance, it's a good thing for transparency.

However, it was a bit worrying how it was being managed. It's not the problem that retail money is in oil, it's the problem of how that's been allocated. Holding the front month as long as they did was clearly foolish with the WTI contract [financial players caught out by physical delivery terms for WTI were seen as contributing to the contract plunging into negative territory on April 20] and that had its implications.

But also, I think the job of a retail broker, or an ETF provider, is to be reflective of crude as much as possible. And I think there's a way to do that to make it clear. I think basketing contracts, things like that, but we don't because there's starting to be an appreciation now of localized events. So for instance, we all know now very clearly that Cushing crude is completely different to Gulf Coast crude, and that's why you guys are coming out with the Gulf Coast Select [Platts AGS, a US waterborne crude assessment launched in June].

"We don't hold the physical – our job is to explore inefficiencies and to trade in and out of that"

How does that tie into greater financialization from institutions?

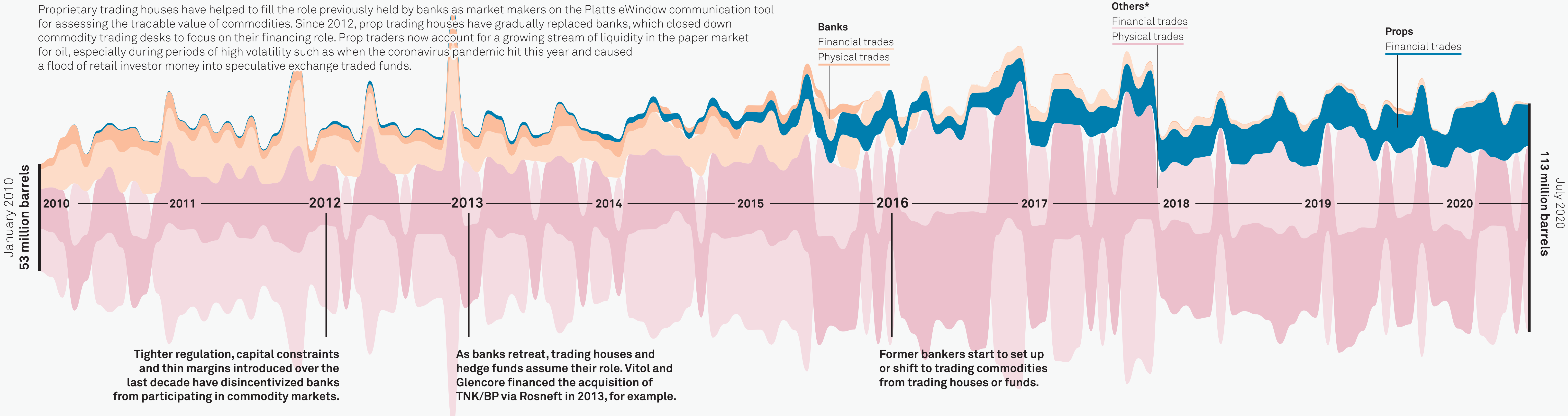
On the financialization of the professional space, on balance it is very good, because when I first entered trading in 2013, it was about applying a very simple kind of forward-curve arbitrage type of trading. Buying in March, selling in June, and trading out the time spreads and just managing all the risk. That works to eliminate some inefficiencies that are there, and that was obviously a good thing because the banks, the trade houses and whoever else had the physical barrels that were pricing the contracts that were underlying, but there was no one in between. So it was too monopolized in a way because it was just the people with the physical barrels that could have influence on the pricing. There were too few participants involved, and therefore, inefficiencies were huge.

So from 2013 up until now, it's been humming. I mean you can see it in the swap volumes, or OTC [over-the-counter] financial futures volumes, which just skyrocketed in the last eight years. And in my mind, that's down to two things. One, the move from mostly bilateral trading to electronic trading on the exchange, and [secondly] a lot of people getting access to that along with the rise of financial trading because we do that all day long. If there's any inefficiency in any of the markets in oil contracts we will be there to try and iron that out and the relative value opportunities, and it's not just us doing that.

That creates a very orderly market in terms of price. I would say that on the forward curve it is interesting because people have different opinions about the actual pricing of swaps. It's not about getting off a hedge, it's not about getting the right price for a hedge, or a future position, it is about the actual pricing of the contract. In my mind, financialization has provided what I've been saying tenfold, because before it was just the guys with the physical barrels doing what they want to do, and no one in between to exploit the inefficiencies in a wider sense.

How proprietary traders replaced banks as oil's financial market makers

Proprietary trading houses have helped to fill the role previously held by banks as market makers on the Platts eWindow communication tool for assessing the tradable value of commodities. Since 2012, prop trading houses have gradually replaced banks, which closed down commodity trading desks to focus on their financing role. Prop traders now account for a growing stream of liquidity in the paper market for oil, especially during periods of high volatility such as when the coronavirus pandemic hit this year and caused a flood of retail investor money into speculative exchange traded funds.



Source: S&P Global Platts Market on Close   Data origination: Elzbieta Rabalska

Where do prop traders fit in and make the market more efficient?

I started trading Dated Brent in 2015 and the eWindow barely had any volume, or if there was volume, it was hugely inefficient. I mean, how you extrapolated the CFDs [Contracts for Difference] relative to the DFL (Dated to Frontline) prices and all that, was all over the place. And that's since come well into line and everything is very well-functioning and I don't see how that's not a good thing.

From a pricing perspective, it means that for Platts you're looking at your eWindow and you're looking at the physical bids and offers. But when you look at the paper trades, instead of your job being very hard because you have to interpret everything and use the previous day highs and lows, there is now more than enough volume to go on in the North Sea strip and whatever else. It makes your calculation pretty straightforward, and I think that's a great thing. You just have certainty in price discovery.

We don't hold the physical – our job is to explore inefficiencies and to trade in and out of that. And yes, if you want to take speculative risk, that's fine. But our primary job is for efficient price discovery. And I think that's been really good for the industry as a whole. It just means that there's a much lower barrier to entry. And actually, what we're seeing is a lot more interest and desire from trade houses and majors who traditionally, even if a refiner, or a producer, that has a very sophisticated physical tendering process, would leave the paper market to someone else.

Do you subscribe to the idea that a physical market has a more complex understanding that ultimately drives it than exchange traded funds?

What I think the ETFs do very well is provide volume and enough liquidity for the people who should know, like the prop traders, the market makers and the physical, to put everything in line. It dampens the impact of a one-off hedge, or anything like that. So I actually see it as the opposite. If these guys come in and trade ETFs, or someone comes in speculating, a physical guy or a market maker should absolutely love it, because it means they can get their hedge off in one tick. It is fantastic and means we're going to make more money. More volume is always good because it will create an environment that is more reflective of the physical environment.

So with the success you and others have had are you anticipating more people coming in and providing that sort of liquidity, more prop traders?

About 10 years ago the prop trader's function was taken by the banks and there were so many. And all of them moving out to purely financing roles and very little paper volumes that first needed to be filled. And I think now it's got to the stage where it's a bit like the banks, in that you have a hell of a lot of competition to be in this space, and that's very healthy because the market benefits. But it does create a barrier to entry. There is always room for more competition, but it's a much harder ask.

Will commodity markets remain a niche corner of the financial world, or will they go electronic?

For an algorithm, or electronic markets to really take hold, you need a market and a very good market on every single contract, and you need depth to those markets with volumes all the way down as you go higher and lower on the price. I'd say we are 10 years off that.

But a company like ours is very into branching out into ensuring that we're doing the market making on the one side. We're driving flows in the right way in all these different contracts and all these different areas, but then also really passionate about educating on the services side, on how to do things correctly.

We think there's going to be more and more volume coming in that didn't exist before from corporates, actually also from oil traders and retail as a financial contract. There's no reason why retail can't be in this space, it is just a lack of understanding. So if we work to bridge that gap, and we're hugely passionate about being the ones who can do that, I think there's so much in the future.

We've got a huge amount ahead of us, and it will outpace oil demand – even if oil demand tapers off, it's irrelevant because people that do have physical volume aren't hedging 100%. There's a huge amount of speculative volume to get and I would love to think that it can become like FX. It's a great time to be in the market, and I think it's got an explosion ahead of it. ■

Insight from Washington

Insight from Washington

By Meghan Gordon

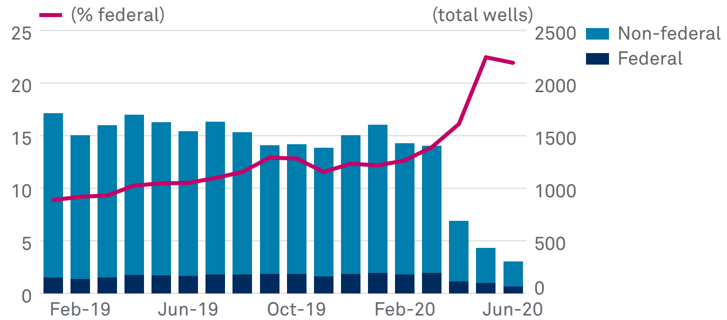
The US presidential election in November presents a stark contrast for the next four years of US oil policy that could shape supply/demand dynamics domestically and abroad.

President Donald Trump is expected to continue a deregulatory push to expand federal areas to drilling, ease permitting for pipelines and export projects, remain a vocal player in supply negotiations among OPEC+ producers, and keep a tight hold on sanctions against Iran and Venezuela.

Trump often touted US "energy abundance" in his first term to highlight economic growth and reduced dependence on Middle East imports. But the oil price collapse earlier this year has left US oil producers hobbled, making any federal deregulation in a second Trump term take a backseat to market forces.

US oil production is returning from peak shut-ins of 2.8 million b/d during this spring's oil price crash, but

Share of US oil wells drilled on federal land rises ahead of November election



Source: S&P Global Platts Analytics

drillers' severe capital expenditure cuts will constrict output through next year.

Platts Analytics expects US oil production to decline by about 880,000 b/d year on year in 2020 and more than 1 million b/d in 2021. That would put US output about 3.1 million b/d below Platts' pre-price collapse forecast by end-2021.

US oil production increased 3.9 million b/d between Trump's inauguration in 2017 and the onset of the pandemic in March, but the end to export restrictions in 2015, during the Obama administration, arguably played a bigger role than current White House policies. Trump has promised to continue a deregulatory push in a second term, after loosening methane rules and opening new offshore and arctic areas to drilling in the first.

Former Vice President Joe Biden, Trump's Democratic challenger, has promised to adopt energy policies with climate risks in mind. He said he would halt issuing new drilling permits on federal lands, weigh climate impacts and environmental justice during federal project approvals, reject permits for the Keystone XL and Dakota Access crude pipelines, and rejoin the Iran nuclear deal.

Biden's selection of Senator Kamala Harris as his running mate could move his energy and environmental platform even further left, as she has embraced harsher measures to limit US oil and gas production.

"There's no question I'm in favor of banning fracking," Harris said during a CNN town hall in September 2019 when she was running for the Democratic nomination. Harris' climate plan also mentioned closing the 2005 so-called "Halliburton loophole" that exempts fracking from federal oversight under the Safe Drinking Water Act.

Since picking Harris, though, Biden has tried to put this discussion to rest.

"I am not banning fracking," Biden said August 31 during a campaign stop in Pittsburgh. "Let me say that again. I am not banning fracking – no matter how many times Donald Trump lies about me."

Biden added that his $2 trillion clean energy investment plan held a place for oil and gas workers in western Pennsylvania.

Rapidan Energy Group said Harris "will likely pull the Biden platform further left on a nationwide hydraulic fracturing ban and possibly a ban on fossil fuel exports (neither of which Biden currently supports)."

The election risks are clearly on the minds of US drillers as drilling data shows federal permit holders acting quickly to drill wells before a potential ban on new permits. Executives also had to field plenty of questions about the November possibilities during second-quarter earnings calls.

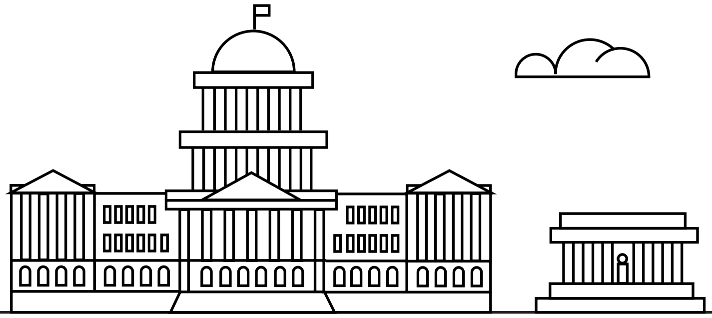
Bakken impact

In North Dakota, home to the once-booming Bakken Shale play, regulators say holders of federal permits are among the few drillers staying active, along with drillers with significant hedged production.

"There is a great deal of discomfort and uncertainty with the potential November election," said North Dakota Department of Mineral Resources Director Lynn Helms. "If people have a federal permit or right-of-way in hand, they're acting on it even though it is expensive to do so at this time."

Helms estimated that an end to new leases on federal lands would cut drilling permits by about 25%.

"It would be a significant negative impact," he said. "It's very substantial – we're talking hundreds of thousands of barrels a day."



The trend can be seen in other US basins, as operators holding federal permits have kept actively drilling wells while other producers have slowed drilling to a bare minimum in response to low prices.

US oil wells drilled on federal lands surged to 22% of total wells drilled in June, from 12% in February, according to S&P Global Platts Analytics.

In second-quarter earnings calls, executives spoke of continuing to act on federal drilling permits to build up a supply of drilled-but-uncompleted wells before any federal policy changes.

Hess CEO John Hess said that while his company had reduced its exposure to federal onshore permitting to less than 3% of its North Dakota acreage and "significantly reduced" its Gulf of Mexico activity through 2021, a potential regulatory shift holds major risks for the US economy.

"Any proposals that would restrict our country's ability to explore, develop and produce that oil is going to be very bad for US jobs, very bad for the US economy and very bad for our national security," Hess said. "So we hope when people are thinking about future policy, when it comes to federal lands, reason prevails, which would be in the interest of all US taxpayers and consumers."

Possible shift to Texas

Permian Basin oil and natural gas driller Cimarex Energy signaled that it might have to shift some focus from its prime Delaware Basin assets in New Mexico to its Texas assets on private land. A third of Cimarex's acreage is on federal land in New Mexico.

"Our federal acreage is located in some of the best part of the Delaware Basin," said John Lambuth, Cimarex's executive vice president of exploration. "It's in the deepest part, it's the most-pressured part, it's oil in the reservoir, and it has some of the better water cuts.

"When we compare different assets, although they are all outstanding, by a little bit more you would say the federal acreage is very attractive to us and thus why we would want to get something done right now."

EOG Resources CEO Bill Thomas sounded similarly optimistic that the driller would be able to shift focus to wells on private land if it cannot obtain new permits on its federal acreage. "We've got a lot of confidence that we can continue to generate and add non-federal potential that's even better than what we have," he said.

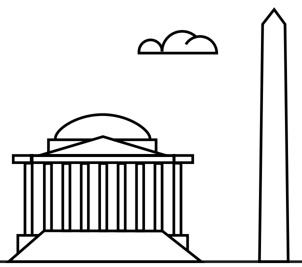
Political tides

Pioneer Natural Resources CEO Scott Sheffield said he expects Biden to win based on current polling, which would bring significant risks to US drillers. But he said Pioneer has no activity on federal lands and "so should be unaffected" by a ban on new federal permits.

"I would expect pipeline infrastructure will be significantly delayed crossing state lines, [but] again, all of our acreage is in Texas, and we move our oil and our gas to the Gulf Coast," he said.

ConocoPhillips CEO Ryan Lance said the driller has successfully secured federal permits and brought wells into production through 50 years of US presidential administrations, including "those that have said they want to shut the business down and those who want to accelerate it, and we still managed to get our projects done because we do it responsibly, we do it sustainably, and we follow the process."

Tim Duncan, CEO of pure-play Gulf of Mexico producer Talos Energy, struck a similar tone: "It is our belief that being pragmatic on how to embrace the basin and its role in job creation, revenue generation for the federal government and our role in producing low-emission barrels will ultimately prevail politically." ■



Solar race

Gulf Arab countries' renewables projects are attracting outside investors and achieving world-beating low tariffs. Claudia Carpenter and Dania Saadi look at the project pipeline as well as the tailwinds and challenges ahead

Gulf Arab countries are forging ahead with renewable projects despite an abundance of fossil fuels and the coronavirus pandemic.

Record-low tariffs and plans to reduce dependence on crude oil and natural gas as feedstock for power and energy-intensive water desalination plants are the main factors behind the rapid development of renewables in the region.

The renewable power sector was the only energy source to grow its share of the power market globally during the pandemic, while oil, natural gas and coal have all declined, IRENA Director General Francesco La Camera said in June. Even as oil prices slumped due to the pandemic, the share of renewables in the generation of electricity has grown in all parts of the world, he said.

The oil-rich Gulf region is among the areas benefiting most from the global appetite for renewables projects.

The UAE, Saudi Arabia, Qatar and Oman are the four countries in the six-member Gulf Cooperation Council that have developed renewables projects over the last few years. Bahrain and Kuwait also belong to the GCC.

Saudi Arabia, the world's largest oil exporter, is forecast to lead the push in the Middle East in the next few years, having launched several renewables projects, including its first wind farm, to free up crude burned in power plants for export.

The country's third renewables round to add 1.2 GW of solar capacity is advancing after 49 companies pre-qualified for lead roles. Energy minister Prince Abdulaziz bin Salman told local media in June that the kingdom would "very soon" announce a solar energy project with the lowest electricity cost per kilowatt-hour. The world record-low solar cost is was by Abu Dhabi, the oil-rich emirate of the seven-member UAE federation, until Portugal got a lower price in August.

"We expect renewables capacity in the Middle East to more than double within the next five years, given that there are almost 7 GW of utility-scale solar and 1.5 GW of wind projects in development," head of global power planning at S&P Global Platts Analytics in New York, Bruno Brunetti, said.

The pipeline of utility-scale solar projects has not changed much so far this year, indicating the damage done by the coronavirus has so far been largely contained, Brunetti said. The Middle East had over 5.1 GW of solar PV and 700 MW of wind installed as of the end of 2019, according to the International Renewable Energy Agency.

Solar and wind accounted for about 1% of power production in the Middle East in 2019, according to the S&P Global Platts World Energy Demand Model. It is expected to be slightly higher at around 1.3% in 2020, and about 3% of the total by 2025 in the region.

Encouraging private investment

Middle East renewables have been fostered by regulatory environments that have allowed private developers to own projects, generate electricity and consume and sell the power, according to renewable energy analyst at the International Energy Agency, Yasmina Abdelilah. Countries that have long-term renewable energy targets coupled with support policies will enjoy growth in the near term, she said.

The UAE, for example, targets 50% clean energy by 2050, including nuclear power, with renewables playing a lead role, and has conducted several large-scale, competitive solar auctions that yielded low prices.

Within the UAE, Abu Dhabi and Dubai are developing large-scale renewables projects at record low prices. In April, Abu Dhabi's 2-GW tender drew a world near record-low solar bid of $13.50/MWh, submitted by TAQA, France's EDF and China's Jinko Solar for a 30-year contract. It will be the largest solar farm in the world, joining plants in China, India and Egypt with capacity of over 1 GW.

The Dubai Electricity & Water Authority this year awarded Saudi Arabia's ACWA Power the 900-MW, fifth phase of the Mohammed bin Rashid Al Maktoum Solar Park, a project that aims to have 5 GW of solar power by 2030 at a cost of Dirham 50 billion ($13.6 billion).

In Saudi Arabia a key renewable project is set to be sited in the $500 billion future city of NEOM, which will be 35 times the size of Singapore

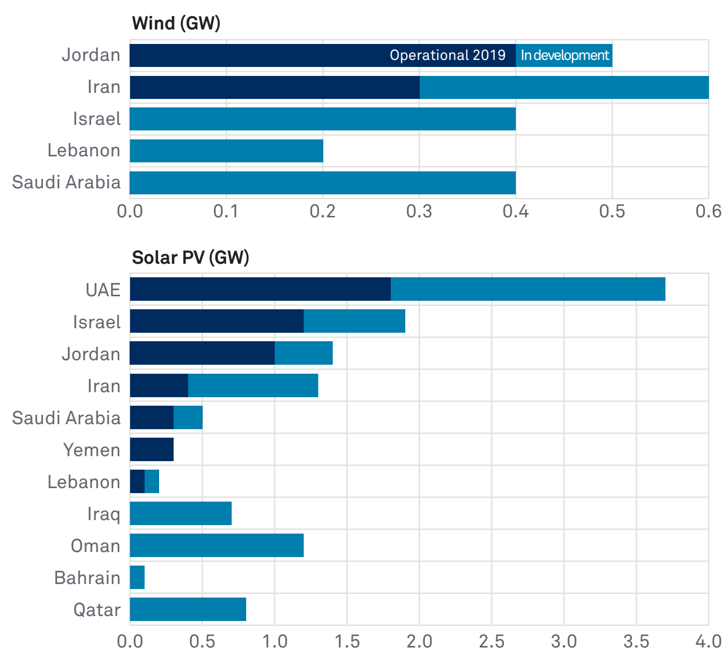
The $2-billion fifth phase project achieved an international record-low bid at the time, of $16.953/MWh. The development uses photovoltaic solar panels, and is based on the independent power producer model.

Qatar, together with Total and Marubeni, plans to develop an 800-MW solar power plant near the capital Doha, as the Gulf state accelerates its renewables push to free up energy production for export.

Qatar's Siraj Energy, in which Qatar Petroleum has a 40% stake, will hold a 60% interest in the Al-Kharsaah

Renewables activity in Middle East on growth track

Capacity installed and projects in development



Source: IRENA, S&P Global Platts Analytics, S&P Global Platts Market Intelligence

solar PV power plants, which will cost Riyals 1.7 billion ($463 million), Qatar Petroleum said in January. Total and Japan's Marubeni will hold the remaining stakes in the project that will follow the build, own, operate and transfer model for a 25-year period.

In Oman, the biggest Arab oil producer outside OPEC, Petroleum Development Oman this year began operations of the sultanate's first utility-scale solar power plant, which will free up 95.5 million cu m a year of natural gas for export, at a time when the country's oil revenues are dwindling due to OPEC+ cuts and plummeting prices.

Meanwhile in Saudi Arabia, a key renewable project is set to be sited in the $500 billion future city of NEOM, which will be 35 times the size of Singapore on a large swathe of land in the Northwest of the country.

In July, ACWA Power, NEOM and the US's Air Products signed a $5-billion agreement to build a green hydrogen-based ammonia production facility powered by renewable energy. The project, which will be equally owned by the three partners, will be sited in NEOM. The project will produce green ammonia for export to global markets and will include more than 4 GW of renewable power from solar, wind and storage.

"This deal is of particular significance, as the kingdom's ambitious renewables expansion program should no longer be seen only through the lenses of diversifying its domestic fossil-fuel based power mix, but also in view of meeting growing global demand for green hydrogen," Brunetti said.

Renewables growth in the region is accelerating due to growing power demand, falling solar and wind costs and favorable government policies that attract private investment, such as competitive auctions, according to the IEA's Abdelilah.

Growth would be even faster if regulatory barriers to new market entrants outside of auctions were removed, permitting procedures were simplified and more low-cost financing available. Access to the grid and clear regulations surrounding connection permitting would also open up opportunities, Abdelilah said.

Global ambitions, local setbacks

Despite the coronavirus pandemic, Middle Eastern renewable companies are pressing ahead with international projects as well as local ones.

In July, Saudi Basic Industries Corp., majority-owned by state-controlled oil company Saudi Aramco, said its polycarbonate facility in Cartagena, Spain, is set to become the world's first large-scale chemical production site to be run entirely on renewable power.

The agreement will mean Iberdrola investing almost Eur70 million ($80 million) to construct a 100-MW solar PV facility with 263,000 panels, on land owned by SABIC, making it the largest industrial renewable power plant in Europe. The plant is expected to be in operation in 2024.

ACWA Power and Masdar are leading the regional foray into global renewable markets. ACWA Power is 25% owned by Saudi Arabia's sovereign wealth fund, while Abu Dhabi's clean energy firm Masdar is a unit of Mubadala Investments Co., a fund managing more than $230 billion in assets.

Masdar said August 13 it had clinched its second strategic investment in the US in a deal with EDF Renewables North America under which it will acquire a 50% stake in a 1.6-GW clean-energy portfolio.

However, Kuwait in July canceled plans to build the Al-Dabdaba solar plant, which would have provided 15% of the oil sector's needs of electrical energy, due to the coronavirus. State-run Kuwait National Petroleum Co. was supposed to start operating the project in February 2021.

Saudi Arabia's renewables program has also been delayed, raising questions about its renewables goals, Brunetti said. Even before the pandemic, Saudi Arabia had put on hold a $200-billion solar project with Japan's Softbank Group.

Although there are risks that the Saudi renewable program may be scaled down, as well as other threats to lower-carbon energy across the Middle East from an abundance of fossil fuels, most renewables projects haven't been rolled back or cancelled, potentially showing how environmental, social and governance concerns have become more central to oil-exporting countries, Brunetti said.

The kingdom has set a target of 27.3 GW of renewables by 2024. "Even if Saudi Arabia continues to lag behind in terms of installed capacity and projects, we think the country will catch up within the next few years to become the largest player for renewables in the region next to UAE," he added.

Due to coronavirus-related business and travel restrictions, the Saudi ministry of energy in April extended the request for proposals deadline for its 1.2-GW solar project to six months from four, which would mean the results could be out as early as October.

The jury is still out on whether the coronavirus will slow future renewables plans in the region. "Most of the growth in the near term is from projects already in the later stages of project development," Abdelilah said.

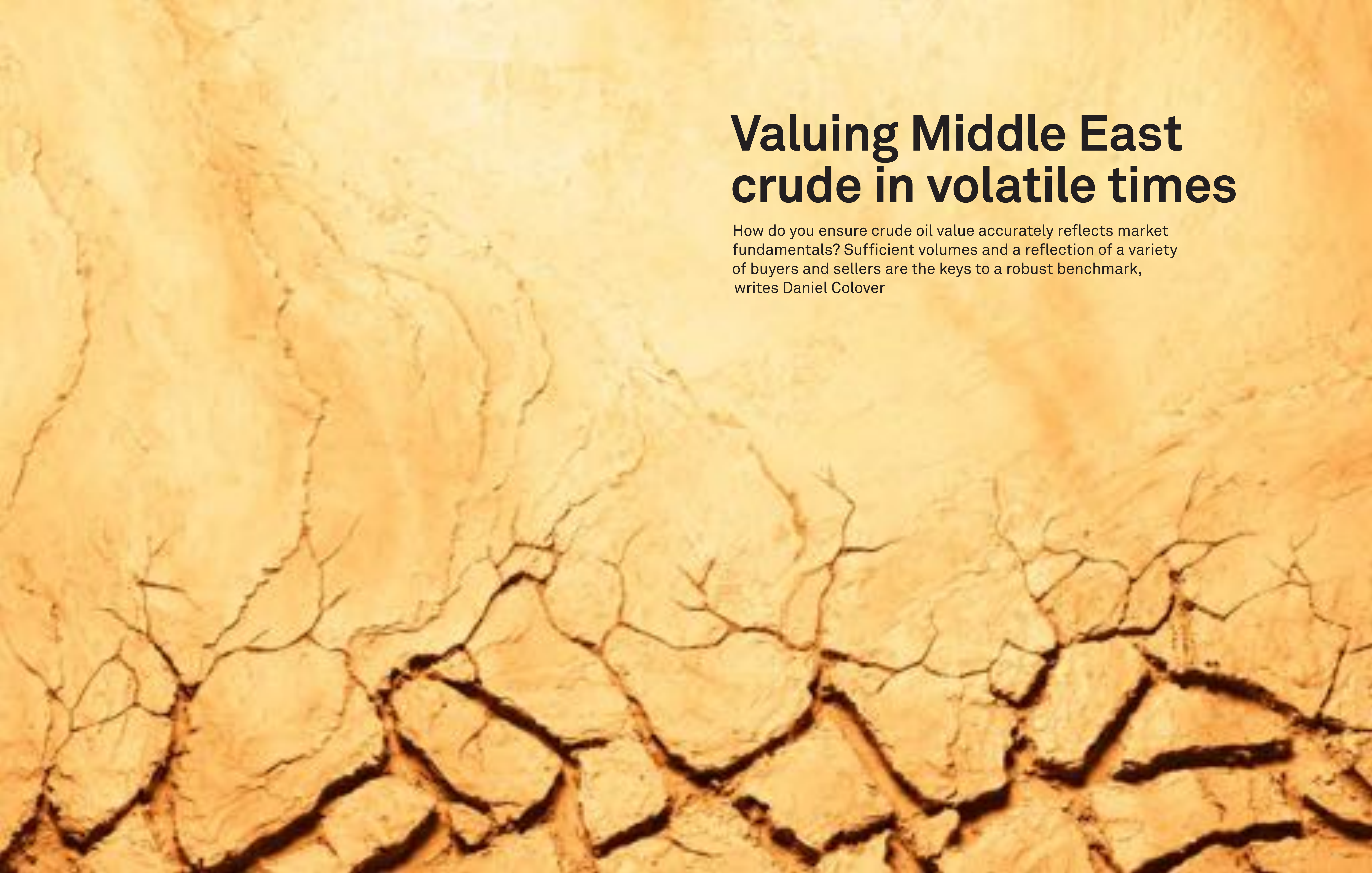
But she added that the economic environment remained a big variable for new project development and financing. Furthermore, for hydrocarbon exporters, low oil prices could limit the support available for renewables.

In more ways than one, then, the regional focus on fossil fuels could hinder the push into renewables.

Kuwait in July canceled plans to build the Al-Dabdaba solar plant, which would have provided 15% of the oil sector's needs of electrical energy, due to the coronavirus

Only 18% of executives in the Middle East expect to see growing opportunities to invest in the energy transition in the next 12 months, the lowest percentage globally, according to a survey published in May by UK-based law firm Ashurst.

"We believe this is a result of a combination of the region's reliance on oil and gas, which still dominates its energy policy, and a lack of government policies on renewables," Ashurst said in its report. ■



Valuing Middle East crude in volatile times

How do you ensure crude oil value accurately reflects market fundamentals? Sufficient volumes and a reflection of a variety of buyers and sellers are the keys to a robust benchmark, writes Daniel Colover

The crude oil market witnessed some of the highest volatility in living memory in the early months of this year, casting a spotlight on the evolving role of global crude benchmarks.

In the Middle East and key consuming regions such as Asia, it follows that the market is keen to understand what the tradable value of Middle Eastern crude is, amid recent demand and supply shocks.

Typically the value of a grade of crude oil is defined by the underlying value of the products that are produced when it is refined, although there are exceptions – for example, if a crude is used for direct burning in a power station, then its value might also be linked to its calorific value.

Therefore, the refinery yields of different crude grades and underlying refinery economics are critical in analyzing the competitiveness of crudes.

Crudes are not homogenous and there are hundreds of different types, each with their own qualities and characteristics, therefore the market has settled on using certain crude grades as benchmarks, against which the values of other crudes are measured.

For a crude benchmark to be robust and purposeful it must have a variety of often disparate characteristics. These include abundance in production volume, steady quality, diversity of buyers and sellers, geographic relevance and absence of interference, from political forces for example.

Many crudes around the world share some of these characteristics but only a handful fulfill all criteria. Only a marker price that consistently displays all the relevant characteristics can ultimately function as a proxy value for the broader market underpinning producer and consumer economics.

Within the Middle East, reference prices include Platts Dubai, Platts Oman and DME Oman, each having different characteristics.

In the case of Platts Dubai and Platts Oman, their assessment methodology contains a feature that enhances their benchmark characteristics. Both have an alternative delivery mechanism, which means more than one crude grade can help form the daily value of the assessment. For Platts Dubai, this includes the alternative delivery of Oman, Upper Zakum, Al Shaheen and Murban, while for Platts Oman, Murban is also acceptable as an alternative deliverable grade.

Production volumes

Total deliverable crude on a daily basis for Platts Dubai can therefore be calculated as the daily production of the five streams of crude that go into the assessment. Dubai production is around 50,000 b/d, Oman around 950,000 b/d, Al Shaheen around 300,000 b/d, Upper Zakum 650,000 b/d and Murban production is around 1.6 million b/d.

However, not all of this volume will be freely available on the spot market on any given day as some will be diverted into domestic refineries while some cargoes may have destination restrictions. Therefore once these are accounted for, a conservative estimate of crude available for delivery into Platts Dubai would be 2.75 million b/d, and for Platts Oman, 1.75 million b/d.

By limiting itself to a single deliverable grade, the DME Oman futures contract is underpinned by Oman's 950,000 b/d production – and after allowing for domestic refinery consumption, around 800,000 b/d – slightly more than a cargo and a half of crude per day.

The alternative delivery mechanisms ensure there is enough available crude to adequately reflect the underlying value of the commodity, in this case Middle East crude. While crudes are not homogenous, those that come from similar regions or locations often trade in the same vein, despite quality differences that may be regionally more stark than if looking more broadly.

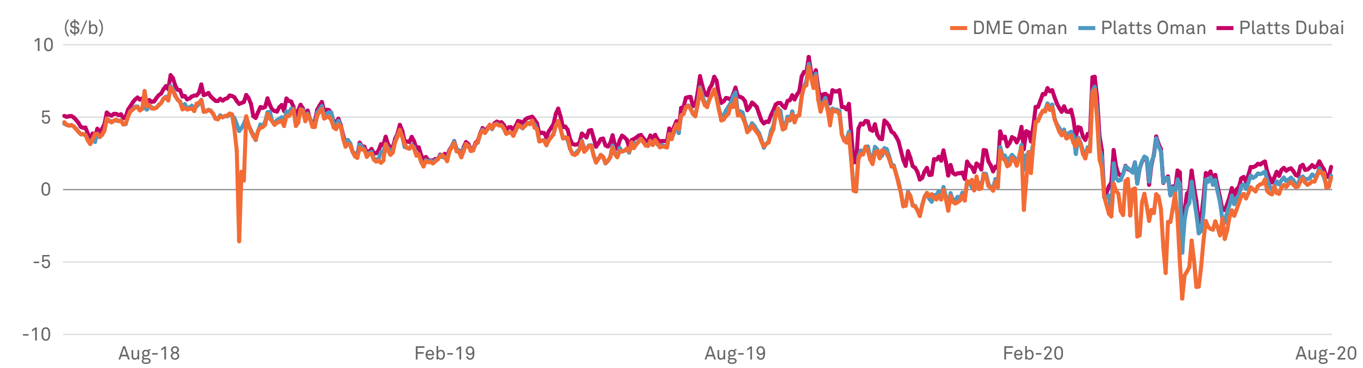
The grades that go into Platts Dubai are largely medium heavy, sour crudes with an API gravity of around 30 degrees and a sulfur content of around 2%, while Murban is lighter with an API of around 40 degrees and a sulfur content of around 0.8%.

There is wider variation in crude quality in the region, for example Iraq's Basrah Heavy has an API gravity of around 24 degrees and a sulfur content of 3.83% while at the other end of the spectrum Qatar Land is 40 API and 1.35% sulfur. However, all these crudes are still collectively known as Middle East sour crudes.

Grades from the Middle East are sought by complex refiners in Asia who typically blend different crudes to customize their preferred slate required for their processing units

Grades from the Middle East are sought by complex refiners in Asia who typically blend different crudes to customize their preferred slate required for their processing units. As a result, the underlying value of these different grades is critical when a refiner is evaluating which to purchase as part of their monthly requirements.

Middle East crude cracking margins



Source: S&P Global Platts, DME

The alternative delivery mechanism also ensures that the benchmark price reflects a stable and consistently broad consumer base that is not beholden to the buying pattern in one particular country only, such as China.

Changes in value of different crude grades can be linked to the value of the products that the crude makes, or it can be linked to other factors, including specific demand to fulfil a requirement which is less obvious.

Refining economics

Oil demand, particularly for transport fuels, saw an unprecedented contraction earlier this year, followed by a gradual recovery since May. The market, however, has responded with significant supply curtailments as well, led by the latest OPEC+ agreements on production curbs which led to record cuts in recent months.

Prior to the agreed cuts, the prompt supply of crude outstripped demand and traders looked to charter vessels for storage, tightening the shipping market and closing typically open arbitrages.

Gasoline has historically been king of the barrel as demand surged due to increased mobility and booming vehicle sales. So Murban, which has the highest yield of gasoline among all the crudes in the Platts Dubai and Platts Oman alternative delivery mechanisms, has typically been valued the highest.

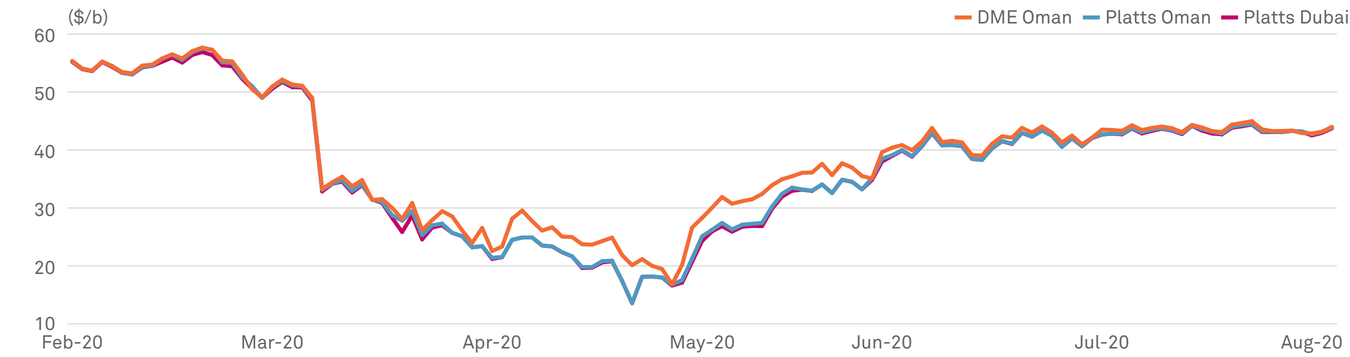
However, with gasoline demand decimated due to various COVID-19 related lockdowns, crack spreads slumped in the second quarter, making Murban more competitively valued versus the other grades.

It is a strength of the benchmark that as yield values shift, the economics it reflects – in this case the value of Middle East sour crude – remain consistent. Different grades become more or less competitive, ensuring that there is enough crude to be regularly delivered to end users. Should a crude that is never competitive be included in a benchmark, then it would follow that its usefulness to the benchmark is ultimately limited.

Having alternative delivery in both Platts Oman and Platts Dubai ensures that both benchmarks reflect the value of Middle East crude on any given day. In contrast DME Oman only has a single grade for delivery and Oman crude is almost exclusively consumed in China. This means that DME Oman is a reference price that reflects the economics of a single crude grade into an almost exclusive consumer market.

China arguably has different refining economics to other end-users, particularly this year. Critically, Beijing regularly adjusts retail oil product prices in line with crude price movements, but suspends

Platts Middle East crude assessments and DME Oman



Source: S&P Global Platts, DME

these adjustments when crude prices fall below $40/b. Refiners therefore typically reap a higher profit when international crude prices drop below $40/b, as they can sell oil products domestically at higher retail prices.

The inclusion of alternative delivery ensures a persistent demonstration of value in the Middle East crude complex and in the wider regional refining base in Asia. It also prevents an injection of volatility during periods of exceptional demand from a single end-user country, which is driven not by market forces, but by price controls, as is the case for China.

Furthermore, Oman crude is one of the seven deliverable grades into the Shanghai International Energy Exchange's crude oil futures contract. The INE price in recent months has rallied due to recovering oil demand in China, and this in turn has supported the price of the grade.

The February front month INE contract settlement averaged around $56.40/b, reflecting a $1.88/b premium to Platts Oman. As flat prices fell, the premium of INE to Platts Oman increased. In March the front month INE contract settlement commanded a premium of $5.54/b to Platts Oman and in April this spread rallied to $14.65/b before subsequently narrowing again in May to $4.50/b.

In this instance traditional refining economics, focusing on the yield value of a particular crude, may not be the only consideration when buying that crude, thus leading to Oman crude trading away from other grades in the region.

Also of note in the first half of 2020 was the divergence in the price of DME Oman, which moved higher relative to Platts Dubai and Platts Oman assessments. A widening spread between Platts Oman and DME Oman meant DME Oman moved from an average 11 cents/b above Platts Oman in February to 84 cents/b in March and then to $3.17/b and $3.20/b in April and May respectively. This increased spread likely impacted the economics for refiners processing grades that are priced against these different markers.

While often the broader discussion on benchmark prices focuses on outturn values, the more effective way to evaluate the robustness and stability of a particular benchmark is by using a traditional refining margin model, taking the aggregate value of the yield of the crudes, less the freight and cost of running the refinery.

The yield for the different crudes can then be considered against the price of the different markers to examine their relative competitiveness from a refinery's perspective.

Platts analysis shows that the DME Oman cracking margin in Singapore has been significantly lower during the COVID-19 pandemic than one based on Platts Oman or Platts Dubai, due to the higher feedstock cost. Over March to May, the average cracking margin based on Platts Oman was 90 cents/b, versus minus $1.44/b for DME Oman.

It is clear that having alternate delivery mechanisms with multiple grades ensures tradable value and stable prices which are useful for all producers and buyers, and not just a single consumer of a single grade of oil. ■

Insight from Moscow

Rosemary Griffin

In early June, coverage of the environmental damage caused by a major gasoil leak at a facility owned by Nornickel in Russia's Arctic region shocked both domestic and international audiences.

Russian President Vladimir Putin declared a state of emergency, and ordered lawmakers to strengthen environmental legislation.

There is little sign that the incident is causing Russian oil and gas companies to rethink their development plans in the region, however. The Arctic remains a strategic development priority for the Russian government, despite high costs, Western sanctions and logistical issues compounding the growing environmental concerns.

The Russian energy ministry estimates that Arctic oil production will account for 26% of overall output by 2035, up from 11.8% in 2007.

Many in Moscow even point to warming temperatures and retreating sea ice as a boost to plans to launch new oil and gas field development and increase shipments via the Northern Sea Route, which links Asia to Europe via Arctic Seas.

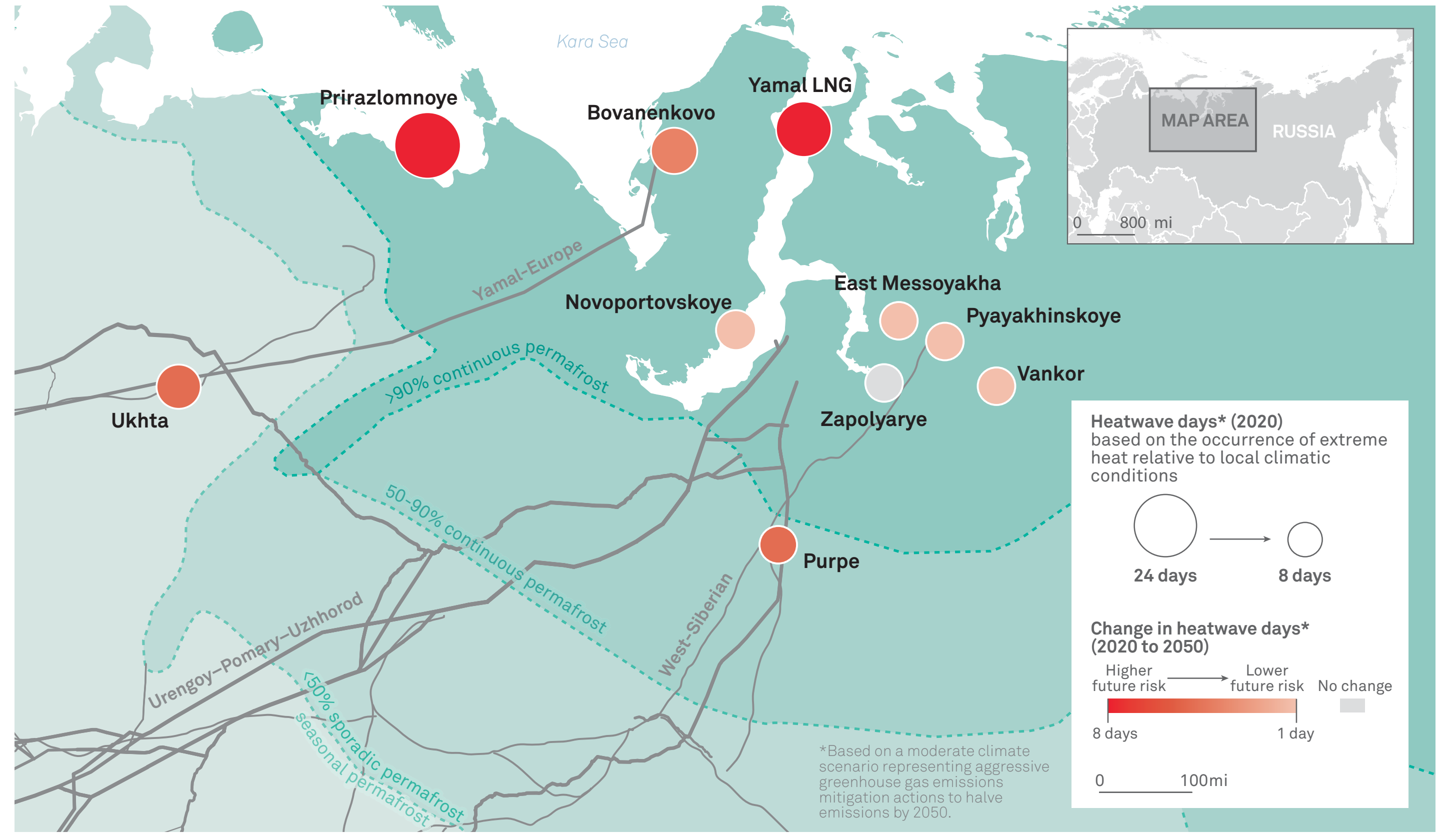
In the months following the gasoil spill, several Russian companies moved ahead with plans in Northern Russia.

Russia's largest producer, Rosneft, announced discovery of a new oil and gas field, Novoogennoye, at its major Vostok Oil project – a cluster of projects in Northern Russia that will ship resources via the NSR. CEO Igor Sechin also said in mid-August that the company resumed drilling in the Arctic Kara Sea, its first reported activity in the area since Western sanctions forced suspension of a joint venture with ExxonMobil in 2016.

Gazprom Neft has announced launch of full-scale development of the Northern section of its Novoportovskoye field, and shipped the first cargo from the project to ChemChina via the NSR. It also

Physical risk to energy assets from rising Russian Arctic temperatures

Recent record high temperatures in Siberia and damage to infrastructure have increased concerns over the impact on oil and gas projects in Northern Russia. Over the next three decades temperatures are likely to see the biggest jump at projects furthest North, including Yamal LNG, Bovanenkovo and Prirazlomnoye.



Source: S&P Global Platts, S&P Global Trucost, National Snow & Ice Data Center (NSIDC)

announced plans to set up a new joint venture with Shell to explore and develop hydrocarbons on the Gydan peninsula.

Novatek also completed its first Arc 7 ice-class LNG tanker shipment to Japan from the Yamal LNG project via the NSR.

These moves added to announcements made earlier in 2020 including Gazprom Neft launching development of several new projects at its largest gas condensate deposits in the Arctic, including Kharasavey, Bovanenkovo and Urengoyskoye.

Furthermore in March, at the height of tensions with Saudi Arabia over failure to agree to new coordinated oil production cuts, Putin approved tax exemptions to stimulate Arctic upstream oil and gas development. These will go some way to easing concerns over high costs of development in the region. Estimates of breakevens on projects there vary widely. Onshore projects close to existing infrastructure have breakevens of close to the Russian average of $20/b, but for more complex projects in more remote areas this could reach over $100/b, if government assistance is not taken into account.

Permafrost risks

The Nornickel spill has had an impact on sentiment in Russia however, with concerns growing over how rising temperatures could impact thawing permafrost, which Nornickel blamed for the incident. As the company

and local officials tackled the cleanup operation, a heatwave hit Siberia. The Russian meterological center reported a record high temperature above the Arctic Circle of 38 degrees Celsius in the town of Verkhoyansk.

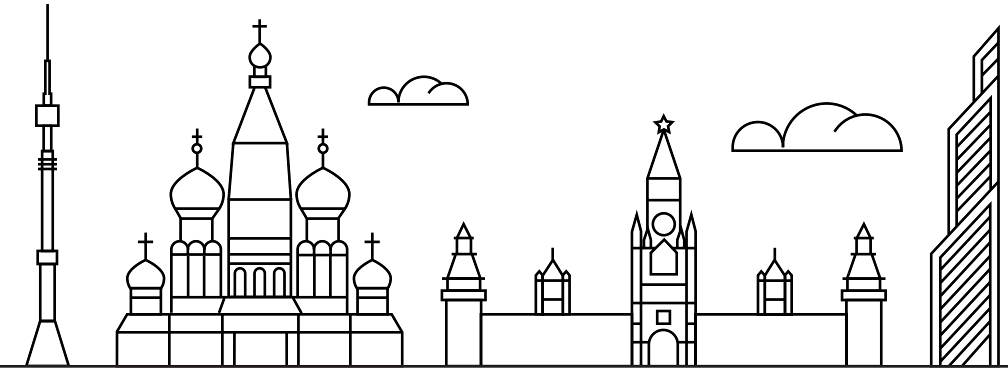
An analysis by S&P Global's Trucost showed that projects furthest North, including the Bovanenkovo gas field, Prirazlomnoye oil field, and Yamal LNG are likely to see the biggest increase in heatwave days up to 2050.

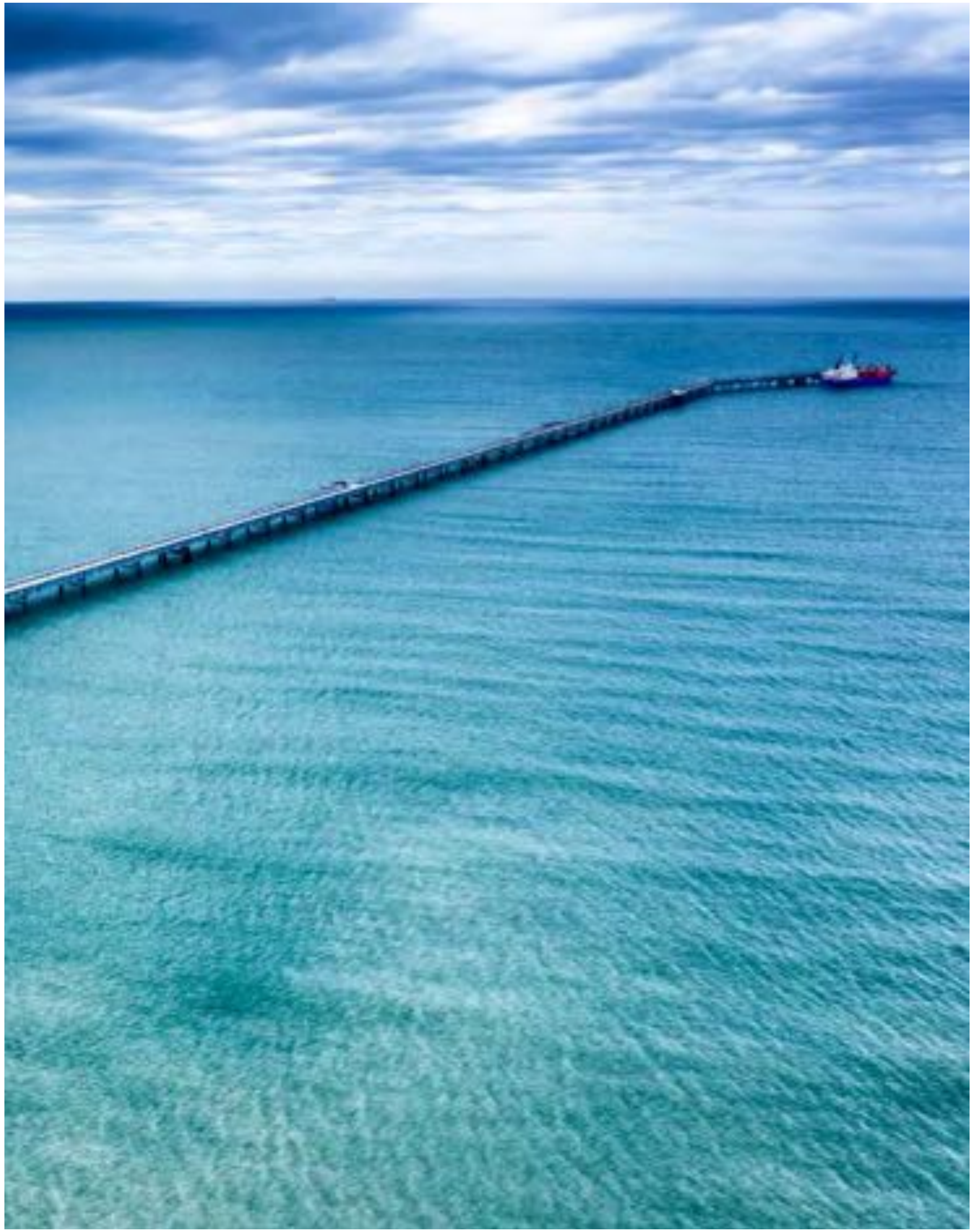
Rising temperatures pose a number of risks for oil and gas companies operating in the region. They reduce the period during which winter roads can be used to transport essential heavy equipment to projects in the Far North. This could increase costs, and lead to months-long delays in moving equipment, if the window is missed.

Thawing permafrost also leads to the release of greenhouse gases into the atmosphere, and threatens the structural integrity of infrastructure. Russia's major production projects and pipelines in the Arctic were launched over the last decade, and include some consideration for the risk of thawing permafrost.

Some companies have provided details of how they are mitigating the risks. Gazprom Neft said its own precautions include geotechnical monitoring, choosing optimal locations for buildings and equipment, and equipping them with active and passive thermal stabilization systems. Novatek has also said that it is using technology to keep the ground frozen, and developing infrastructure with a load-bearing capacity that takes 30-40-year warming into account.

With Arctic temperatures warming at twice the rate of the global average, companies may need to increase these measures if they are to meet their Arctic ambitions over the coming decades. ■





The price taker

Europe's third-largest gas consumer, Italy, is still stuck in legacy patterns of supply and transport that hinder real price competition. Will the TAP pipeline and updated regulation usher in change? By Silvia Favasuli

Italy has no shortage of natural gas infrastructure, from major pipelines coming from Europe and North Africa to LNG terminals.

How, then, can the country still have some of the highest wholesale gas prices in Europe, rivalling even Spain, with its notorious lack of interconnections?

Solving the Italian gas market puzzle is not an easy task. But it is possible to identify factors that, taken together, create a unique and enduring ecosystem where no new big players have ever emerged to push down prices through a market share strategy.

Rather, these factors have made Italy an attractive place for gas price takers – companies interested in holding a small share of the market and taking advantage of the high price scenario, with no apparent intention to change it.

While EU rules and some changes in Italian gas markets in the past have attempted to rein in dominant shippers, this work is far from being completed.

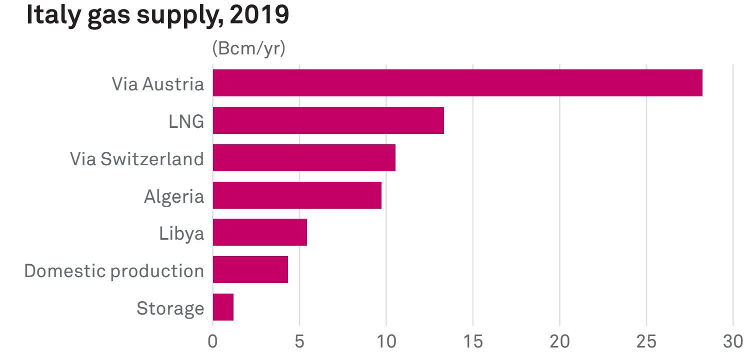
Illiquidity and control over supply routes are the main factors that kept the premium of the Italian gas spot contract to the Dutch TTF equivalent at an average of Eur2.70/MWh during 2019.

Large shares of Italy's gas market are in the hands of a few big players and Eni, the biggest, is also in control of Italy's major import routes, including Italy's most expensive and the market price maker – the Swiss Transitgas pipeline.

With 38 Bcm of gas sold in Italy in 2019 out of total Italian consumption of 70 Bcm (54%), Eni is Italy's largest supplier. Edison is second, with 20 Bcm sold in 2019 and a 28% share, followed by Enel, with 4.7 Bcm sold (6.7%).

On the wholesale market, Eni holds a 14% share and another 10% is in the hands of the major's trading arm, Eni Trading & Shipping. Engie Global Markets follows with a 10.3% market share and Enel comes next with an 8% share, according to the latest annual report from ARERA, the Italian energy regulator, published July 21.

Italy gas supply, 2019



Source: S&P Global Platts Analytics

TAP on track to be Italy's sixth pipeline source of gas

Sources: Snam, TAP AG, OLT, TAG, Transmed, Swissgas, Adriatic LNG, S&P Global Platts

In 2019, Eni was responsible for 47% of Italy's gas imports, according to the same report. Most of the gas that Eni supplies to Italy comes from long-term gas supply agreements signed with all of Italy's main suppliers: Russia's Gazprom, Algeria's Sonatrach, Norway's Equinor, and its own Libyan subsidiary, Mellitah Oil and Gas, an Eni-NOC joint venture.

According to the ARERA report, Italy's PSV gas hub has seen its churn rate increase over the past 10 years, reaching 3.3 in 2019 from about 2.5 in 2015. Churn rate indicates the number of times a commodity is exchanged on the hub before being physically delivered.

ARERA said the 2019 increase was mostly due to increased LNG deliveries at the PSV, and the creation of a balancing market in 2016. But Italy is still far from a churn rate of 10, at which a gas market is considered liquid and mature.

Tarvisio, no room for competitors

While the rise in LNG flows in recent years may have aided liquidity slightly, gas delivered via pipelines makes up the lion's share of Italy's supply and is far more important in setting prices.

Italy's biggest import route, the TAG pipeline, which runs from Baumgarten on the Austria-Slovakia border to Tarvisio on the Italian border, is largely controlled by Italy's largest supplier, Russia's Gazprom.

The Russian major owns about 80% of some 39 Bcm of available transport capacity at Tarvisio, under a long-term deal inherited from Eni in January 2018.

According to industry sources, while handing over its long-term transport capacity contract expiring in 2023 to Gazprom, Eni also changed the delivery point of Russian volumes imported under the Eni-Gazprom long-term supply deal – which is believed to have a take-or-pay obligation of about 21 Bcm/year – from Baumgarten to Tarvisio.

The European Union framework for gas transport capacity ownership, called the capacity allocation mechanisms network code, does not exclude the possibility of a single company owning the large majority or even the totality of a gas pipeline's transport capacity. It only requires that no more than 80% or 90% of the available capacity – depending on specific circumstances – is booked under long-term agreements, with the remaining 10% or 20% to be kept free for spot bookings.

The same framework obliges long-term capacity holders to resell unused capacity on a spot basis, but there is no obligation to do so for longer-term periods.

With 80% of the largest pipeline supply route in the hands of a single participant, little TAG transport capacity is left for companies interested in selling large gas volumes in Italy under a market share strategy.

Sonatrach and oil formulas

As Italy's historical buyers of Algerian gas – Eni, Edison and Enel – significantly reduced their long-term imports last year, Algeria's oil and gas company Sonatrach has been on the lookout for new importers. But it has failed so far to find them among smaller Italian gas suppliers.

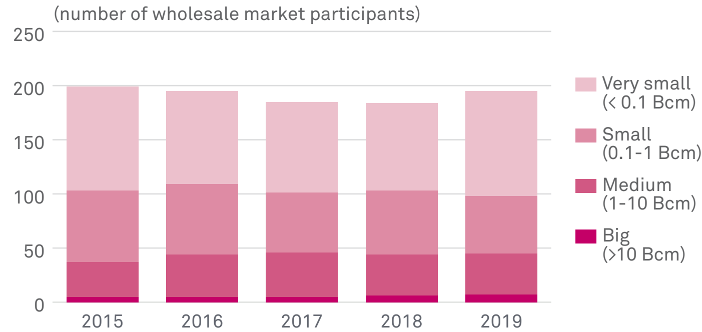
Starting from October 2019, Eni cut its long-term imports to around 9 Bcm/year from 16 Bcm/year under the old deal, Edison reduced contracted volumes from 7 Bcm/year to 3 Bcm/year, and Edison cut supplies to 1.5 Bcm/year from 1.9 Bcm/year.

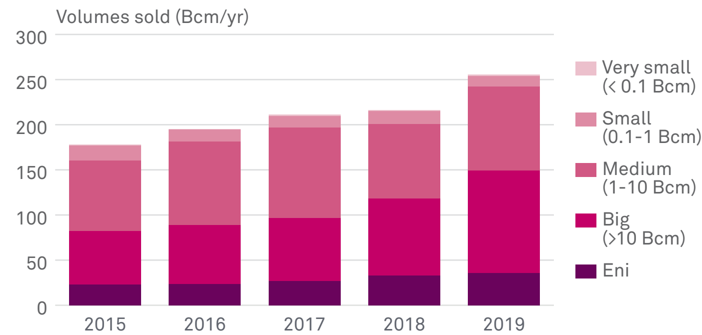
With a 30.2 Bcm/year technical capacity pipeline linking Algeria to Italy via Tunisia and the Mediterranean Sea – on which Eni hold exclusive operating rights – Italy has the ability to increase its gas imports from Africa. But Sonatrach's preference for oil-indexed formulas has been so far the main obstacle, leaving Eni as the main importer.

Despite introducing more flexibility into formulas and deals with a shorter duration of one-to-five years, Sonatrach's continued preference for oil indexation as a mechanism to set prices was seen as too risky and difficult to manage by smaller Italian market participants approached by the company in 2019, sources said, even if they were strongly interested in enlarging their portfolio.

Libya, the other African source of gas for Italy, remains a territory dominated by Eni. The major produces gas in Libya through a joint venture with NOC and imports those volumes via the Greenstream gas link, which is owned and operated by GreenStream BV, a joint venture of Eni North Africa BV (Eni) and NOC (50% each).

Italian wholesale gas market structure





Source: S&P Global Platts Analytics

Switzerland, the price maker

Eni and Gazprom's control of imports via Austria and those sourced from North Africa needs to be considered together with another important factor – Italy's marginal route determining the price of PSV spot gas.

As in every gas market, the most expensive supply route sets the day-ahead price of a hub, and for Italy, this is the Transitgas pipeline, which crosses Switzerland. Importing even small volumes via this pipeline can cause Italian spot prices to increase their premium towards the reference Dutch TTF gas hub.

In 2019, volumes imported in Italy via Transitgas stood at 10.5 Bcm, making this the second-largest source of pipeline gas after Tarvisio (28 Bcm in 2019), but only the third-largest source of gas if the 13.3 Bcm of LNG imported by Italy in 2019 is considered.

Gas is sourced in Norway, France or the Netherlands, enters the Transitgas pipeline at Oltingue (French-Swiss border) or Wallbach (German-Swiss border), and

exits at Passo Gries (Swiss-Italian border). Switzerland does not apply European rules on capacity allocation on its territory, and that is what makes this route so pricey when used on a spot basis.

More than 50% of the Transitgas transport capacity is booked by Eni under a long-term, over-the-counter (OTC) contract signed with the TSO operating 90% of the pipeline, FluxSwiss.

While in Europe long-term capacity holders are obliged to resell unused firm transport capacity on a spot basis, this "use it or lose it" principle does not apply in Switzerland, creating a shortage of spot transport capacity on Transitgas.

Moreover, Switzerland still relies on a contractual method to allocate capacity on its pipelines, as opposed to EU member states, which switched to an entry-exit system where capacity rights are booked independently at any entry and exit point of the gas system.

To purchase the small volumes of available Transitgas spot capacity, traders have to call or email the TSOs' commercial offices and cross their fingers

Traders wanting to import spot gas via Transitgas have to purchase entry and exit fees at the Oltingue, Wallbach and Passo Gries interconnection points as envisaged under EU rules, but also the pipeline capacity allocated by Transitgas operators, FluxSwiss and Swissgas.

To purchase the small volumes of available Transitgas spot capacity, traders have to call or email the TSOs' commercial offices and cross their fingers. No regular and transparent auctions are held by FluxSwiss and

Swissgas, and prices offered by the two TSOs are often very close to the premium of Italian PSV day-ahead gas contracts to the Dutch TTF, minus entry and exit fees and a small margin for the trader, sources said.

For example, on October 3 2019, when the PSV spot premium over the Dutch TTF equivalent contract reached Eur5.625/MWh, FluxSwiss sold firm spot transport capacity on Transitgas at Eur3.75/MWh to one trader speaking to Platts.

In this way, the two TSOs retain a slice of the spread between the PSV and TTF spot contracts. As a consequence, the cost of transporting gas along Transitgas is not reflective of the mere operational costs of the pipeline, but also of the commodity price.

Both operators occasionally hold auctions for firm capacity sold on a longer-term basis, offering month-ahead, quarterly or yearly products. Interruptible spot capacity is also offered. A spokesman from Fluxys told Platts that interruptible spot capacity is now sold OTC through a newly dedicated digital platform, available to registered customers only.

No other players apart from Eni have ever signed an OTC contract for long-term Transitgas capacity with FluxSwiss. A FluxSwiss spokesman said the company is "constantly listening to the market in order to actively offer available capacity in line with market players' requirements," but would not be drawn on whether the TSO would consider signing new OTC long-term capacity contracts with other companies.

Eni declined to comment on the terms of its long-term capacity and supply contracts. Gazprom did not respond to several requests for comment.

Regulation falls short

Italy's economy ministry is well aware of the high cost of using Transitgas and that this is responsible for keeping PSV spot prices at a high premium to the Dutch TTF equivalent contracts. However, it has so far failed to find a viable solution, with the last suggestion, the 2018 Liquidity Corridor, rejected by the antitrust authority.

Some help in lowering the cost of transporting gas via Italy's most expensive route could come from an ARERA decision in 2019 to scrap a Eur0.3/MWh commodity charge on all gas imports starting from January 2020. However, higher entry and exit fees introduced in Germany through the Postage Stamp Tariff reform will

offset the impact of ARERA's decision on Transitgas volumes coming via Germany's Wallbach point.

The big changes brought by the coronavirus pandemic to the Italian and European gas markets make it difficult, so far, to analyze the real impact of this fee reduction on PSV/TTF spreads.

A law to introduce European gas market rules in Switzerland is currently being drafted by the Swiss federal energy ministry and is set to be discussed in the Parliament starting from autumn 2020. But due to the length of Swiss democratic processes, the law is not expected to be ready before 2024.

Until then, Transitgas will continue to be the price maker for Italian spot gas, to the advantage of everyone selling gas in Italy, and the disadvantage of consumers and the country's economic competitiveness against Northwest Europe.

Will TAP change the ecosystem?

With a few big players controlling Italy's major supply routes, and the volume of imports from these pipelines, it is hard to say if the start-up of a fifth gas pipeline supply route at the end of 2020 will change this scenario.

The Trans Adriatic Pipeline, currently expected to bring first Azeri gas into Italy in Q4 2020, will deliver 8 Bcm/year of gas into Italy, or 22 million cu m/d.

There are almost as many price formulas as buyers of TAP gas, but all of them are meant to make TAP deliveries into Italy competitive on the PSV day-ahead market, market sources have said.

In a scenario replicating Italy's gas balance on one of the coldest days of winter, total gas consumption would be 340 million cu m/d, withdrawals from stocks 110 million cu m/d, and pipeline imports excluding the Swiss route, 152 million cu m/d. LNG terminals would provide 44 million cu m/d of regasification and domestic production would be 13 million cu m/d. This would leave Italy's gas system 21 million cu m/d short when supply is totaled and set against consumption.

There are almost as many price formulas as buyers of TAP gas, but all of them are meant to make TAP deliveries into Italy competitive on the PSV day-ahead market

This means that TAP's 22 million cu m daily imports could be enough to halt imports via Transitgas for most of the year.

But this will only happen if the other importing routes are fully utilized. It will be enough for Tarvisio's imports to be turned down by few million cubic meters for Transitgas to be back in the game.

And with few players in control of the largest volumes imported from all of Italy's main supply routes, there will still be the possibility of creating the small shortage of gas necessary to trigger spot imports from Switzerland, and let this pricey route set the PSV hub price.

An opportunity for further competition could materialize in 2023, when Gazprom's long-term contract on the TAG pipeline expires. At this point, the roughly 80% share of capacity in the hands of the Russian major will be sold via regular auctions on the Prisma platform, with all interested market players able to purchase it.

A similar scenario could occur in Switzerland in 2024, when the Eni long-term capacity contract expires. Should Switzerland introduce European rules for the allocation of transport capacity, shippers may be able to buy the Transitgas capacity via regular auctions.

If not, FluxSwiss may well just offer a new over-the-counter contract to one or two other major market participants, preserving Italy's most expensive import route and the current ecosystem. ■

Insight from Brussels

Siobhan Hall

The EU's aim to be the world's first climate-neutral region by 2050 could disrupt global commodity trade flows, as it mulls ways to cut its emissions while protecting its industry and raising money for post-pandemic recovery spending.

The European Commission wants EU governments to focus on switching more sectors to renewable electricity, improving energy efficiency, and replacing fossil fuels with hydrogen and other low-carbon gases and liquids, as part of its European Green Deal strategy to cut emissions.

If successful, this will change EU energy supply and demand patterns, and trade relations with external countries – particularly China, Russia and the US.

The EC is looking at several options with a direct external trade impact: introducing a carbon border adjustment mechanism, extending the EU Emissions Trading System to international aviation and shipping, and setting methane emission performance standards for all natural gas and LNG sold in the EU.

Each of these would change the relative attractiveness of energy and commodities from different sources and regions, potentially changing trade flows.

The aim of the EU carbon border adjustment mechanism, for example, is to ensure that the EU's energy-intensive industrial sectors, including power generation, steel furnaces, oil refining and heavy manufacturing, do not shift their production to regions with less stringent carbon constraints, such as China and the US.

The EC is still considering how such a mechanism could work, and which sectors should benefit from it. The EU steel sector is particularly keen to be included. Any such mechanism would have to comply with World Trade Organization rules.

It seems likely, however, that an EU attempt to apply a carbon price to selected imports from selected countries would lead to tense trade and climate talks with those countries. France first floated the idea of a carbon border tax to protect EU industry in 2009, but quickly dropped it after the rest of the EU failed to back it.

The EU's increased climate ambition and the need to raise money to support recovery after the pandemic lockdowns have now revived interest. EU leaders on July 21 invited the EC to propose such a mechanism next year, with a view to introducing it at the latest by January 1, 2023.

The EC has estimated such a mechanism could raise between Eur5 billion ($6 billion) and Eur14 billion per year, helping to finance the EU's planned Eur750 billion recovery fund to help kick-start the economy over the next three years.

Carbon fees for aviation, shipping

The EC estimates it could raise another Eur10 billion/year by requiring more sectors – possibly including international aviation and shipping – to buy EU ETS allowances from 2021, to cover their CO2 emissions. The EU ETS currently applies to stationary heavy industrial installations and intra-EU flights.

Targeting aviation and shipping would again likely create tense relations with the EU's trading partners.

The EU originally wanted to include international aviation in the ETS, but strong political opposition, including from China, Russia and the US, forced it to rethink. It then froze the idea and focused on working with UN aviation association, ICAO, on a global approach.

Methane emissions

The EC's plans to address methane emissions, meanwhile, will have a major impact on the EU's natural gas, LNG and potential fossil-based hydrogen suppliers, its deputy director-general for energy, Klaus-Dieter Borchardt, told S&P Global Platts in an interview.

Methane is a potent greenhouse gas, and most leaks happen before the natural gas or LNG reaches the EU, so a new EU policy on methane emissions could have far-reaching impacts on the global gas market.

Introducing a methane emission performance standard for all gas sold in the EU market, for example, would create a quality component enabling customers to distinguish between different gas commodity grades based on their total carbon footprint.

The EU is keen to stay on good terms with all its existing fossil energy partners, including Norway, North Africa, Russia and the US, even as it switches its focus to renewables.

Russia is the EU's biggest natural gas supplier, and is also looking at producing "blue" hydrogen from natural gas with pyrolysis to sell to the EU.

US LNG, meanwhile, is likely to remain a good supply source for the EU over the next five to 10 years, helping to stabilize markets and drive prices down, Borchardt said.

But its carbon footprint, along with other LNG sources, is higher than pipeline gas, so LNG suppliers face a similar decarbonization challenge to remain relevant in the EU market, he said.

Borchardt called for all the gas exporting countries, including Russia and the US, to work together on reliable, standardized methane emission reporting.

The EC plans to set out initial thoughts and possible voluntary initiatives for measuring, reporting and verifying methane emissions in an EU strategy paper expected at the end of September or early October. It wants to follow this up with formal legislative proposals mid- to late 2021 to ensure compliance. ■

S&P Global Platts

TOP 250 GLOBAL ENERGY COMPANY RANKINGS

State energy giants dominate

Saudi Aramco debuts at No. 1 in first year as public company, and natural gas shows strength. By Harry Weber

Natural gas' rising profile offset oil's falling fortunes at a time of dramatic changes in the global energy landscape.

While integrated majors that produce, process, transport and deliver supplies to end users still ruled the roost in 2019 – benefiting from deep pockets, vast portfolios and operations covering multiple commodities – state-run companies in Europe, the Middle East and Africa showed particular strength due to their ability to make changes quickly and weather the ups and downs of volatile commodity prices.

Driven by significant growth in LNG, natural gas consumption increased by 78 Bcm, boosting the share of gas in primary energy to a record high of 24.2%, while global oil production fell by 60,000 b/d as OPEC output shrank and refinery utilization dropped sharply, according to BP's annual statistical review of world energy, issued in June 2020. Crude prices slid 10% in 2019, with Platts Dated Brent assessment averaging $64.21/b, compared with $71.31/b in 2018.

Against that backdrop, Saudi Arabian Oil Co., or Saudi Aramco, leapfrogged to No. 1 in the 2020 S&P Global Top 250 ranking of energy companies, bolstered by new investment in natural gas and its record-breaking initial public offering in December 2019. In taking the top spot in its debut as a public company, Aramco replaced Royal Dutch Shell, which fell four spots to No. 5 after rising to top the list for the first time since 2004. The 2020 list was based on data from 2019,

Platts dated Brent price

Source: S&P Global Platts

including assets, revenue, profits and return on invested capital.

The US, with growth in feedgas use for LNG production for exports, and China, with its strong appetite for imports, drove increases in gas demand, while the largest drops were in Russia and Japan, according to BP's statistical review. LNG supply growth was led by the US and Russia, with most of the extra supply heading to Europe as US shipments to China ground to a halt in March 2019 and did not resume for the rest of the year because of tit-for-tat tariffs.

Coal consumption fell, pushing its share in primary energy down, while renewable energy, led by wind, posted a record increase in consumption in energy terms. Nuclear consumption also rose by its fastest rate since 2004. Electricity generation, however, grew just 1.3% – around half its 10-year average, BP said.

Integrated oil and gas companies (IOGs) took seven of the top 10 spots in the 2020 list, two fewer than in the previous year's rankings. Exploration and production companies took the eighth and ninth spots, while China Shenhua Energy Co., a major chemical company, registered at No. 10 in the latest rankings, up four spots from No. 14 in the 2019 list.

"Notwithstanding bearish signals that global economic growth slowed to some degree in 2019, global demand for crude oil is expected to continue growing for years to come, with GDP growth led primarily by non-OECD Asia Pacific," Aramco CEO Amin Nasser said in a message to shareholders in March 2020. "Short-term market uncertainty, swings in commodity prices and unclear energy policies continue to impact long-term investment in new and traditional energy sources and production."

However, Nasser added, "We continue to maintain our commitment to invest in the future."

Platts JKM price

2019 ($/MMBtu)

Source: S&P Global Platts

Top 50 Fastest Growing

Fastest Growing Rank	Company Name	State or Country	Industry	3 Year CGR %	Platts Top 250 Rank
1	Cheniere Energy, Inc	Texas	S&T	93.4	128
2	Diamondback Energy, Inc	Texas	E&P	92.6	215
3	Italgas SpA	Italy	GU	58.4	183
4	Yancoal Australia Ltd	Australia	C&CF	53.8	169
5	WPX Energy, Inc	Oklahoma	E&P	52.8	235
6	Oil & Natural Gas Corp Ltd	India	IOG	50.3	11
7	YPF Sociedad Anónima	Argentina	IOG	47.8	246
8	Brookfield Infrastructure Partners LP	Bermuda	DU	46.1	211
9	Parkland Corp	Canada	R&M	43.3	157
10	Elia Group SA/NV	Belgium	EU	41	220
11	Pioneer Natural Resources Co	Texas	E&P	40.2	103
12	Aker BP ASA	Norway	E&P	38.3	241
13	Türkiye Petrol Rafinerileri A.S.	Turkey	R&M	37	236
14	AltaGas Ltd	Canada	GU	35.7	143
15	Saudi Arabian Oil Co	Saudi Arabia	IOG	34.8	1
16	Equatorial Energia SA	Brazil	EU	33.2	163
17	Lundin Energy AB	Sweden	E&P	32.1	173
18	Vistra Energy Corp	Texas	IPP	31.7	84
19	EOG Resources, Inc	Texas	E&P	31.3	29
20	Ovintiv Inc	Colorado	E&P	31	196
21	Seven Generations Energy Ltd	Canada	E&P	30.8	219
22	Shaanxi Coal Industry Co Ltd	China	C&CF	30.4	61
23	Continental Resources, Inc	Oklahoma	E&P	30.3	121
24	China Coal Energy Co Ltd	China	C&CF	28.7	93
25	ENN Energy Holdings Ltd	China	GU	27.2	96
26	Occidental Petroleum Corp	Texas	IOG	26.4	181
27	China Gas Holdings Ltd	Hong Kong	GU	26.3	88
28	Evergy, Inc	Missouri	EU	26.2	131
29	Canadian Natural Resources Ltd	Canada	E&P	26	21
30	GD Power Development Co,Ltd	China	IPP	25.9	144
31	Yanzhou Coal Mining Co Ltd	China	C&CF	25.2	42
32	Marathon Petroleum Corp	Ohio	R&M	25	33
33	Algonquin Power & Utilities Corp	Canada	DU	24.4	182
34	Idemitsu Kosan Co,Ltd	Japan	R&M	23.7	190
35	Shanxi Lu'an Environmental Energy Development Co, Ltd	China	C&CF	23.5	171
36	CGN Power Co, Ltd	China	IPP	23.3	94
37	Shenzhen Energy Group Co, Ltd	China	IPP	22.5	227
38	Cenovus Energy Inc	Canada	IOG	22.4	45
39	Reliance Industries Ltd	India	R&M	21.8	14
40	Huaneng Lancang River Hydropower Inc	China	IPP	21.7	151
41	Inner Mongolia Yitai Coal Co,Ltd	China	C&CF	21.4	152
42	Public JSC Rosneft Oil Co	Russia	IOG	20.4	3
43	Yangquan Coal Industry (Group) Co, Ltd	China	C&CF	20.4	205
44	Rubis	France	GU	20.3	188
45	Energy Transfer LP	Texas	S&T	19.5	24
46	Power Grid Corp of India Ltd	India	EU	19.3	97
47	China Resources Gas Group Ltd	Hong Kong	GU	19.3	112
48	Pembina Pipeline Corp	Canada	S&T	19.2	102
49	Shanxi Xishan Coal & Electricity Power Co,Ltd	China	C&CF	18.9	203
50	Plains GP Holdings, LP	Texas	S&T	18.6	125

Top 10

Just behind Aramco, Russia, the world's No. 2 gas producer behind the US, dominated the top of the latest rankings.

State-run Rosneft and Gazprom came in at No. 3 and 4, respectively. Lukoil, which is no longer state-owned, moved up a spot to No. 2 from the 2019 list, while Rosneft advanced eight spots from No. 11 and Gazprom kept its 2019 position.

Each benefited from their diverse energy offerings, from oil to gas to LNG. Gas, in particular, remains a critical component in the equation because of Europe's heavy reliance on Russian supplies of the home heating and power-plant fuel.

Assets, profits and return on invested capital were some of the metrics that bolstered their position in the 2020 rankings. Rosneft, for instance, had a three-year compound growth rate (CGR) of 20.4%, while Gazprom registered a CGR of 7.8%.

Russia has been looking to the future to maintain its position while facing increasing competition from the US, which is now a major exporter of LNG. Part of that effort has been Gazprom's Nord Stream 2 gas pipeline project that would run across the Baltic Sea to connect Russia and Germany.

"The company has historically placed a special focus on the expansion of gas infrastructure," the chairman of Gazprom's board of directors and management committee said in the annual report to shareholders for 2019. "With the support of Russian regional authorities, Gazprom has started work on new gas infrastructure expansion programs for the five-year term up to 2026."

Shell, also an integrated oil and gas company, fell to No. 5, after an 11% drop in revenue to $344.88 billion because of the slide in crude prices in 2019.

Another IOG, France's Total, rose two spots to No. 6 in the 2020 rankings. The company, while also subject to swings in the oil markets, was boosted by its gas investments, in particular from LNG. It is an equity partner in Sempra Energy's Cameron LNG, which began exports from the Louisiana facility in 2019.

Total also has offtake contracts for some 3.2 million mt/year of LNG from Cheniere Energy's Sabine Pass export terminal in Louisiana, and it controls over 2.2 million mt/year of LNG from the third train at the Freeport LNG export terminal in Texas. It inherited that commitment when it acquired Toshiba's US LNG business in 2019.

Among oil-exposed majors that are regularly in the Top 10, Irving, Texas-based ExxonMobil suffered the biggest drop in the latest rankings, to No. 7, down five spot spots from No. 2 in the 2019 list. ExxonMobil led the rankings for 12 consecutive years before falling to No. 9 in 2017. It regained the top spot in 2018.

CNOOC, a Chinese exploration and production company, registered at No. 8, up five spots from No. 13 in the 2019 rankings. Ahead of China Shenhua at No. 9 in the 2020 rankings was Houston-based exploration and production company ConocoPhillips, three spots higher than in 2019.

Biggest Movers – Up

Platts Rank 2020	Platts Rank 2019	UP	Company Name	State or Country	Region	Industry
18	75	57	Electricité de France SA	France	EMEA	EU
45	201	156	Cenovus Energy Inc	Canada	Americas	IOG
48	162	114	Naturgy Energy Group, SA	Spain	EMEA	GU
53	133	80	Uniper SE	Germany	EMEA	IPP
59	114	55	EnBW Energie Baden-Württemberg AG	Germany	EMEA	EU
60	131	71	NRG Energy, Inc	New Jersey	Americas	EU
68	178	110	Edison International	California	Americas	EU
84	217	133	Vistra Energy Corp	Texas	Americas	IPP
92	215	123	Origin Energy Ltd	Australia	Asia/Pacific Rim	IOG
96	156	60	ENN Energy Holdings Ltd	China	Asia/Pacific Rim	GU
101	190	89	The Chugoku Electric Power Co, Inc	Japan	Asia/Pacific Rim	EU
106	170	64	CenterPoint Energy, Inc	Texas	Americas	DU
115	198	83	The Williams Companies, Inc	Oklahoma	Americas	S&T
124	185	61	Companhia Energética de Minas Gerais	Brazil	Americas	EU
126	182	56	VERBUND AG	Austria	EMEA	EU
127	204	77	PBF Energy Inc	New Jersey	Americas	R&M
136	199	63	Hera SpA	Italy	EMEA	DU
138	189	51	A2A SpA	Italy	EMEA	DU
163	246	83	Equatorial Energia SA	Brazil	Americas	EU
173	230	57	Lundin Energy AB	Sweden	EMEA	E&P
192	244	52	ATCO Ltd	Canada	Americas	DU

Biggest movers have ascended or descended more than 50 ranks year on year, or entered into the Top 250 this year

Industry abbreviation key

C&CF Coal and consumable fuels
DU Multi-utilities
E&P Oil & gas exploration and production
EU Electric utilities
GU Gas utilities
IPP Independent power producers and energy traders
IOG Integrated oil & gas
R&M Oil & gas refining and marketing
S&T Oil & gas storage and transportation

Fastest-growing

Houston-based Cheniere, the biggest LNG exporter in the US, was the fastest growing company in the world in the 2020 rankings for the third consecutive year, advancing to No. 128 from No. 166 in the rankings.

The growth – it recorded a three-year CGR of 93.4% – came as it continued to build out its liquefaction facilities at Sabine Pass, and at its Corpus Christi Liquefaction terminal in Texas.

S&P Global Platts Top 250

Europe was a bright spot in 2019 for deliveries from Cheniere terminals, offsetting lower Chinese consumption due to the 25% tariff on imports of US LNG that remained in effect through the end of that year.

Cheniere remains in the strongest position among US producers to capitalize on LNG growth opportunities due to its footprint and full suite of options at its terminals. It has proposed a midscale liquefaction expansion at its Texas terminal, but has delayed a final investment decision until 2021 because of market uncertainty.

Rosneft, along with its ascension in the overall rankings, also made the list of the 50-fastest growing companies, registering a three-year CGR of 20.4%.

Beyond exploration and production onshore and offshore, Russia's largest crude producer also has operations in feedstock processing and sales of oil, gas and refined products domestically and abroad. It is developing significant gas reserves in West and East Siberia and holds a portfolio for the development of hydrocarbon resources on the Russian continental shelf.

The company has set a number of strategic goals designed to increase its market share by 2022.

India's ONGC, an integrated oil and gas company, was the sixth fastest-growing energy company in the 2020, propelling it to No. 11 on the overall list, up six spots from No. 17 in 2019. It recorded a three-year CGR of 50.3%.

Biggest Movers – Down

Platts Rank 2020	Platts Rank 2019	Down	Company Name	State or Country	Region	Industry
66	9	57	Surgutneftegas Public JSC	Russia	EMEA	IOG
91	15	76	E.ON SE	Germany	EMEA	DU
99	41	58	Tokyo Electric Power Co Holdings, Incorporated	Japan	Asia/Pacific Rim	EU
114	44	70	Bharat Petroleum Corp Ltd	India	Asia/Pacific Rim	R&M
120	62	58	CLP Holdings Ltd	Hong Kong	Asia/Pacific Rim	EU
122	20	102	Eni SpA	Italy	EMEA	IOG
155	96	59	Polskie Górnictwo Naftowe i Gazownictwo SA	Poland	EMEA	IOG
159	103	56	The AES Corp	Virginia	Americas	IPP
165	97	68	Marathon Oil Corp	Texas	Americas	E&P
168	66	102	Empresas Copec SA	Chile	Americas	R&M
175	24	151	JXTG Holdings, Inc	Japan	Asia/Pacific Rim	R&M
177	46	131	SK Innovation Co, Ltd	South Korea	Asia/Pacific Rim	R&M
179	87	92	Woodside Petroleum Ltd	Australia	Asia/Pacific Rim	E&P
181	27	154	Occidental Petroleum Corp	Texas	Americas	IOG
187	128	59	Korea Gas Corp	South Korea	Asia/Pacific Rim	GU
190	79	111	Idemitsu Kosan Co,Ltd	Japan	Asia/Pacific Rim	R&M
193	42	151	Repsol, SA	Spain	EMEA	IOG
196	104	92	Ovintiv Inc	Colorado	Americas	E&P
197	116	81	UGI Corp	Pennsylvania	Americas	GU
215	159	56	Diamondback Energy, Inc	Texas	Americas	E&P
225	140	85	Centrica plc	United Kingdom	EMEA	DU
232	109	123	Cosmo Energy Holdings Co, Ltd	Japan	Asia/Pacific Rim	R&M
236	100	136	Türkiye Petrol Rafinerileri A.S.	Turkey	EMEA	R&M
237	73	164	Husky Energy Inc	Canada	Americas	IOG
241	146	95	Aker BP ASA	Norway	EMEA	E&P
246	95	151	YPF Sociedad Anónima	Argentina	Americas	IOG
247	167	80	Ultrapar Participações SA	Brazil	Americas	S&T
248	181	67	Public JSC Federal Hydro-Generating Co - RusHydro	Russia	EMEA	EU

Brookfield Infrastructure Partners, owner of a diversified array of energy assets, saw a three-year CGR of 46.1%, positioning it as the eighth fastest-growing company in the latest rankings and boosting it to No. 211 overall, up nine spots from No. 220 on the 2019 list.

Strong growth didn't help everyone's position. Diamondback Energy, a US E&P, was the second fastest-growing company behind Cheniere, with a three-year CGR of 92.6%, but fell to No. 215 in the rankings from No. 159 in the 2019 list. Turkey's Türkiye Petrol Rafinerileri (Tupras), a refining and marketing company, plunged 136 spots to No. 236 in the latest rankings from No. 100 in the 2019 list, even as it maintained its position as the 13th fastest-growing energy company with a three-year CGR of 37%.

Regional breakdown

While a mix of refining and marketing companies and E&Ps dominated in the Americas and in Asia and the Pacific Rim in the 2020 rankings, IOGs and electric utilities

Top 50 Companies 2020 vs. 2019

Platts Rank 2020	Platts Rank 2019	Company	State or Country	Region	Industry
1		Saudi Arabian Oil Co	Saudi Arabia	EMEA	IOG
2	3	PJSC LUKOIL	Russia	EMEA	IOG
3	11	Public JSC Rosneft Oil Co	Russia	EMEA	IOG
4	4	Public JSC Gazprom	Russia	EMEA	IOG
5	1	Royal Dutch Shell plc	Netherlands	EMEA	IOG
6	8	TOTAL SA	France	EMEA	IOG
7	2	Exxon Mobil Corp	Texas	Americas	IOG
8	13	CNOOC Ltd	Hong Kong	Asia/Pacific Rim	E&P
9	12	ConocoPhillips	Texas	Americas	E&P
10	14	China Shenhua Energy Co Ltd	China	Asia/Pacific Rim	C&CF
11	17	Oil & Natural Gas Corp Ltd	India	Asia/Pacific Rim	IOG
12	10	China Petroleum & Chemical Corp	China	Asia/Pacific Rim	IOG
13	7	Phillips 66	Texas	Americas	R&M
14	19	Reliance Industries Ltd	India	Asia/Pacific Rim	R&M
15	23	Enterprise Products Partners LP	Texas	Americas	S&T
16	18	Valero Energy Corp	Texas	Americas	R&M
17	28	Petróleo Brasileiro SA - Petrobras	Brazil	Americas	IOG
18	75	Electricité de France SA	France	EMEA	EU
19	25	Indian Oil Corp Ltd	India	Asia/Pacific Rim	R&M
20	54	The Southern Co	Georgia	Americas	EU
21	53	Canadian Natural Resources Ltd	Canada	Americas	E&P
22	30	Ecopetrol SA	Colombia	Americas	IOG
23	21	PTT Plc	Thailand	Asia/Pacific Rim	IOG
24	52	Energy Transfer LP	Texas	Americas	S&T
25	36	Iberdrola, SA	Spain	EMEA	EU
26	51	PAO NOVATEK	Russia	EMEA	E&P
27	58	Enbridge Inc	Canada	Americas	S&T
28	38	OMV Aktiengesellschaft	Austria	EMEA	IOG
29	31	EOG Resources, Inc	Texas	Americas	E&P
30	47	Exelon Corp	Illinois	Americas	EU
31	35	Plains All American Pipeline, LP	Texas	Americas	S&T
32	29	PetroChina Co Ltd	China	Asia/Pacific Rim	IOG
33	34	Marathon Petroleum Corp	Ohio	Americas	R&M
34	22	NextEra Energy, Inc	Florida	Americas	EU
35	33	Suncor Energy Inc	Canada	Americas	IOG
36	16	BP plc	United Kingdom	EMEA	IOG
37	32	Public JSC Transneft	Russia	EMEA	S&T
38	50	Duke Energy Corp	North Carolina	Americas	EU
39	6	Chevron Corp	California	Americas	IOG
40	26	Enel SpA	Italy	EMEA	EU
41	40	PJSC Tatneft	Russia	EMEA	E&P
42	60	Yanzhou Coal Mining Co Ltd	China	Asia/Pacific Rim	C&CF
43	5	Equinor ASA	Norway	EMEA	IOG
44	48	China Yangtze Power Co,Ltd	China	Asia/Pacific Rim	IPP
45	201	Cenovus Energy Inc	Canada	Americas	IOG
46	43	Coal India Ltd	India	Asia/Pacific Rim	C&CF
47	64	TC Energy Corp	Canada	Americas	S&T
48	162	Naturgy Energy Group, SA	Spain	EMEA	GU
49	88	Chubu Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	EU
50	59	SSE plc	United Kingdom	EMEA	EU

showed particular strength in the EMEA region.

Electricité de France was seventh among companies in EMEA on the 2020 list, good for No.18 in the rankings, up 57 spots from No. 75 in the 2019 rankings. Another utility, Spain's Iberdrola, was eighth among companies in EMEA, helping it jump 11 spots to No. 25 in the latest rankings from No. 36 in 2019.

Moving east, India's Reliance Industries, a refining and marketing company, was fifth among companies in Asia and the Pacific Rim. It rose five spots to No. 14 in the overall 2020 rankings from No. 19 in the 2019 list. Thailand's PTT, an integrated oil and gas company, was seventh among companies in the region. But it fell two spots in the overall rankings to No. 23 from No. 21 in the 2019 list.

In the Americas, Atlanta-based Southern Company, which owns regulated utilities, placed seventh in the region, good for No. 20 in the overall rankings, up 34 spots from No. 54 in the 2019 list. Canadian Natural Resources, an E&P, was eighth in the region and No. 21 overall, advancing 32 spots from No. 53 in the previous rankings.

Right behind it in the region was Colombia's Ecopetrol, the country's national oil company, at ninth. In the overall rankings, the company advanced eight spots to No. 22 from No. 30 in the 2019 list.

With as much as 7 billion barrels of crude and equivalents, Colombia has what is believed to be Latin America's second highest reserves, after Argentina, of non-conventional hydrocarbons. Efforts by Ecopetrol and other

wildcatters to exploit them have faced challenges from environmentalists and rural communities concerned over possible impacts on drinking water.

The company's production and spending have fluctuated in recent years due to swings in commodity markets.

Renewables penetration

Led by wind and solar power, renewable energy increased by a record amount, accounting for over 40% of the growth in primary energy in 2019, according to BP's annual statistical review.

At the same time, coal consumption fell for the fourth time in six years, with its share in the global energy mix falling to its lowest in 16 years of 27%, BP said.

China was the largest contributor to renewables growth, followed by the US and Japan. Renewables provided the largest increment to power generation, followed by natural gas while coal generation fell.

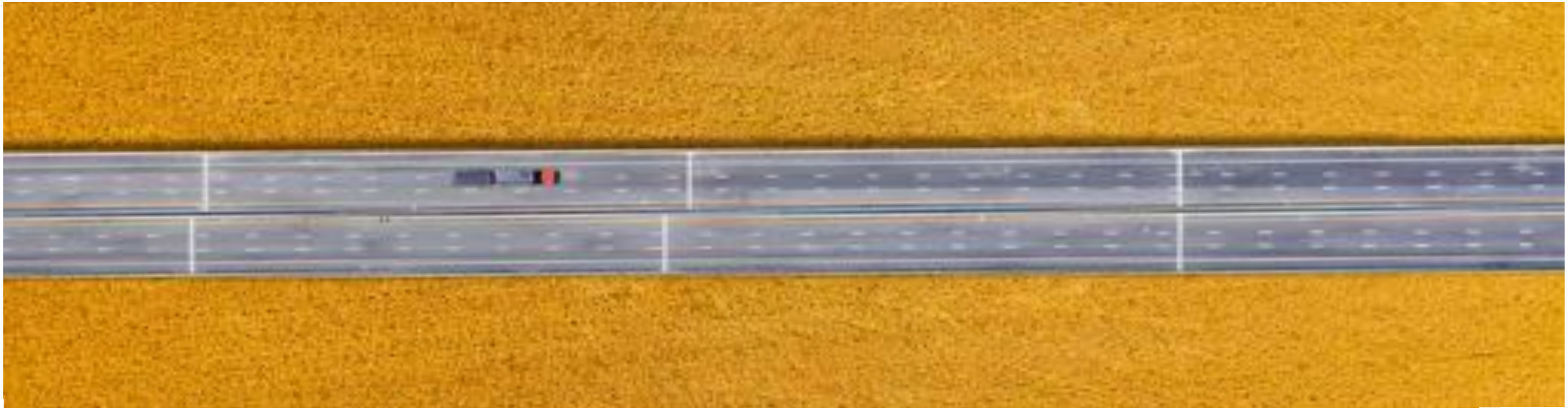
Increases in coal consumption were driven by the emerging economies, particularly China and Indonesia, but that was outweighed by a sharp fall in Organization for Economic Cooperation and Development member countries' demand, which dropped to its lowest level in BP's data series going back to 1965.

Those dynamics affected the rankings. Yancoal Australia, a major coal and consumable fuels company, was the fastest growing Asian company in its segment, with a three-year CGR of 53.8%. But its position in the overall rankings dropped eight notches to No. 169 from No. 161 in 2019.

Power Grid Corp. of India was the fastest growing electric utility company in Asia, with a three-year CGR of 19.3%. But it, too, fell in the latest rankings, dropping eight spots to No. 97 from No. 89 in the previous year's rankings.

In EMEA, Belgium's electric transmission system operator Elia was among the fast growing companies with a three-year CGR of 41%. It placed No. 220 in the overall rankings, advancing 25 spots from No. 245 in the 2019 list.

France's Rubis, which stores and distributes petroleum and other liquid products, was among the fastest growing companies in the region, with a three-year CGR of 20.3%, good for No. 188 in the overall rankings. It was not in the Top 250 in 2019.



On the flip side, Germany's E.ON, which runs one of the world's largest investor-owned electric utility service providers, was one of the biggest movers down, falling to No. 91 from No. 15 in the 2019 rankings.

The company, which has encountered some bumps adjusting to the shifting market dynamics, had jumped all the way to No. 2 in the 2017 rankings from No. 114 in the previous year's list. Volatile revenue and return on invested capital have been among the triggers.

In the Americas among utilities, Brazil's Companhia Energética de Minas Gerais, one of the largest power generators and distributors in the country, jumped 61 spots to No. 124 in the 2020 rankings from No. 185 in 2019, while Italy's Hera, which operates in the distribution of gas, water, energy, and waste disposal, advanced 63 spots No. 136 in the latest rankings from No. 199 the previous year.

Virginia independent power producer AES, which provides energy to customers in 14 countries through its network of distribution businesses as well as thermal and renewable generation facilities, was one of the biggest movers down in the latest rankings, dropping 56 spots to No. 159 from No. 103 in the 2019 list.

The road ahead

As noteworthy as the changing of the guard was in the 2020 rankings, there are likely to be even greater shifts in the 2021 list because of the coronavirus pandemic.

The deadly respiratory illness that was first observed in China spread globally in January 2020, killing hundreds of thousands of people and infecting tens of millions of people on every continent where major energy assets are in operation.

Demand for everything from oil to gas to petrochemicals plunged, while prices of major commodities dropped sharply. New commercial deals were put off as widespread travel restrictions kept executives from meeting face to face, which is critical to making deals happen in a competitive energy landscape.

Final investment decisions for many projects were delayed, while output was curtailed in major shale basins and capital growth spending on existing projects was cut at many firms around the world.

Among the moves: Shell pulled out of its equity partnership with Energy Transfer to develop a proposed LNG export project in Louisiana, while Aramco as 2020 wound down had yet to finalize a preliminary deal to take an equity stake in Sempra's Port Arthur LNG project in Texas. More than a dozen proposed US liquefaction projects that are being developed to start up around the middle of the decade had yet to take FID as 2020 was wrapping up.

Energy Transfer, based in Dallas, jumped 28 spots to No. 24 in the latest rankings from No. 52 in 2019, while Sempra, based in San Diego, rose 20 spots to No. 70 from No. 90 in the previous rankings.

In a positive sign, the US and China reached an initial trade pact in January 2020 that called for China to buy tens of billions of dollars in US energy over two years and resulted in a ceasefire between the two countries on escalating their tariffs war. China later granted exemptions from LNG tariffs to some of its companies, allowing for deliveries from US liquefaction terminals to resume in April 2020, following a 13-month halt.

As the US presidential election approached, there remained uncertainty over how trade and the impact of coronavirus would alter flows of energy heading into the end of the year. Some companies, such as Enterprise Products Partners, were already looking to 2021 for signs of a sustained rebound in markets. The Houston-based operator of gathering and processing facilities, pipelines, storage and import and export terminals across oil, gas, NGLs and petrochemicals advanced eight spots to No. 15 in the latest rankings from No. 23 in the 2019 list.

"I think you're going to get a price signal next year on hydrocarbons that turns some things back on," co-CEO Jim Teague said during an investor conference call in July 2020.

In the European utility sector, however, E.ON offered some words of caution during a March 2020 investor call about the possibility that coronavirus impacts on the market could last a while.

"I do not believe that any sector nor any single business in Europe will be able to shield itself fully and totally from any impact from the spread of such a virus," CEO Johannes Teyssen said. "Daily life has changed dramatically wherever we are in Europe. Many small and big businesses constrained or closed their services. It impacts entire branches."

Teyssen said that as prepared as the company was for major disruption to its business, "things can and will happen."

"As severe and even dramatic the near future may be, we are running this business for the long term," he added. ■

2019 Top 250 Ranking

Platts Rank 2019	Company	State or Country	Region	Assets $million	Assets rank	Revenues $million	Revenues rank	Profits $million	Profits rank	Return on invested capital ROIC%	Return on invested capital rank	3-Year CGR%	Industry
1	Saudi Arabian Oil Co	Saudi Arabia	EMEA	397914	2	329379	4	88102	1	27	5	34.8	IOG
2	PJSC LUKOIL	Russia	EMEA	86924	33	114611	11	9357	8	14	10	14.5	IOG
3	Public JSC Rosneft Oil Co	Russia	EMEA	189282	12	121550	10	10348	7	8	38	20.4	IOG
4	Public JSC Gazprom	Russia	EMEA	319841	6	111956	12	17582	2	6	64	7.8	IOG
5	Royal Dutch Shell plc	Netherlands	EMEA	404336	1	344877	3	15842	3	6	83	13.9	IOG
6	TOTAL SA	France	EMEA	273294	8	176249	7	11267	6	6	70	11.3	IOG
7	Exxon Mobil Corp	Texas	Americas	362597	4	255583	6	14340	4	6	79	8.4	IOG
8	CNOOC Ltd	Hong Kong	Asia/Pacific Rim	106977	29	32910	44	8618	9	10	23	16.9	E&P
9	ConocoPhillips	Texas	Americas	70514	44	33346	43	7189	11	14	10	12	E&P
10	China Shenhua Energy Co Ltd	China	Asia/Pacific Rim	79497	36	34148	40	5888	14	9	28	9.7	C&CF
11	Oil & Natural Gas Corp Ltd	India	Asia/Pacific Rim	65601	48	55766	27	4036	21	9	28	50.3	IOG
12	China Petroleum & Chemical Corp	China	Asia/Pacific Rim	247783	9	418770	1	8131	10	5	105	15.4	IOG
13	Phillips 66	Texas	Americas	58720	52	107293	13	3070	29	8	42	14.8	R&M
14	Reliance Industries Ltd	India	Asia/Pacific Rim	154296	17	78972	19	5796	15	5	86	21.8	R&M
15	Enterprise Products Partners LP	Texas	Americas	61733	51	32789	45	4564	18	8	32	12.5	S&T
16	Valero Energy Corp	Texas	Americas	53864	58	102729	14	2415	40	7	50	13.6	R&M
17	Petróleo Brasileiro SA - Petrobras	Brazil	Americas	187474	13	61191	25	6075	13	5	119	2.3	IOG
18	Electricité de France SA	France	EMEA	343237	5	80712	17	5668	16	4	133	0.1	EU
19	Indian Oil Corp Ltd	India	Asia/Pacific Rim	44354	75	71447	21	2300	42	8	36	16	R&M
20	The Southern Co	Georgia	Americas	118700	23	21419	62	4739	17	6	77	2.5	EU
21	Canadian Natural Resources Ltd	Canada	Americas	58272	54	17060	81	4040	20	9	25	26	E&P
22	Ecopetrol SA	Colombia	Americas	38049	88	19902	68	3723	26	13	13	13.5	IOG
23	PTT Plc	Thailand	Asia/Pacific Rim	78844	37	70443	22	2902	34	5	112	8.9	IOG
24	Energy Transfer LP	Texas	Americas	98880	31	54213	29	3588	28	4	133	19.5	S&T
25	Iberdrola, SA	Spain	EMEA	138489	19	41238	34	3929	24	4	146	8.2	EU
26	PAO NOVATEK	Russia	EMEA	29421	106	11764	112	12650	5	47	3	17.5	E&P
27	Enbridge Inc	Canada	Americas	121786	22	37348	36	3970	23	4	146	13.2	S&T
28	OMV Aktiengesellschaft	Austria	EMEA	45694	72	26552	53	1900	49	7	53	6.8	IOG
29	EOG Resources, Inc	Texas	Americas	37125	89	17076	80	2735	36	10	24	31.3	E&P
30	Exelon Corp	Illinois	Americas	124977	21	34438	39	2936	32	4	138	3.2	EU
31	Plains All American Pipeline, LP	Texas	Americas	28677	111	33669	41	1967	46	8	33	18.6	S&T
32	PetroChina Co Ltd	China	Asia/Pacific Rim	385835	3	355326	2	6449	12	2	219	15.9	IOG
33	Marathon Petroleum Corp	Ohio	Americas	98556	32	124112	9	2636	37	4	164	25	R&M
34	NextEra Energy, Inc	Florida	Americas	117691	25	19204	69	3769	25	4	124	6	EU
35	Suncor Energy Inc	Canada	Americas	66712	46	28602	49	2162	44	5	105	12.7	IOG
36	BP plc	United Kingdom	EMEA	295194	7	276850	5	4025	22	2	214	14.9	IOG
37	Public JSC Transneft	Russia	EMEA	48665	66	15549	89	2622	38	6	68	7.8	S&T
38	Duke Energy Corp	North Carolina	Americas	158838	16	24658	56	3694	27	3	172	3.3	EU
39	Chevron Corp	California	Americas	237428	10	139865	8	2924	33	2	240	10.6	IOG
40	Enel SpA	Italy	EMEA	194009	11	87558	16	2460	39	2	228	3.8	EU
41	PJSC Tatneft	Russia	EMEA	18104	157	13627	97	2810	35	24	7	17.1	E&P
42	Yanzhou Coal Mining Co Ltd	China	Asia/Pacific Rim	29340	108	28328	51	1306	70	6	68	25.2	C&CF
43	Equinor ASA	Norway	EMEA	118063	24	62911	24	1843	50	3	205	11.3	IOG
44	China Yangtze Power Co,Ltd	China	Asia/Pacific Rim	41858	81	7041	162	3042	30	9	31	1.3	IPP
45	Cenovus Energy Inc	Canada	Americas	26639	116	15053	91	1637	58	8	41	22.4	IOG
46	Coal India Ltd	India	Asia/Pacific Rim	17564	162	12692	102	2311	41	60	1	8.3	C&CF
47	TC Energy Corp	Canada	Americas	74055	41	9887	131	2966	31	5	105	1.8	S&T
48	Naturgy Energy Group, SA	Spain	EMEA	46557	69	26069	54	1586	59	4	127	1.7	GU
49	Chubu Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	50132	62	27942	52	1490	61	4	138	5.6	EU
50	SSE plc	United Kingdom	EMEA	32232	101	9325	137	1757	51	9	30	-36.6	EU

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51	Polski Koncern Naftowy ORLEN Spólka Akcyjna	Poland	EMEA	18167	154	28374	50	1097	82	8	33	11.8	R&M
52	American Electric Power Co, Inc	Ohio	Americas	75892	39	15561	88	1921	47	4	150	-1.7	EU
53	Uniper SE	Germany	EMEA	49520	63	74578	20	690	116	4	127	-0.7	IPP
54	Hindustan Petroleum Corp Ltd	India	Asia/Pacific Rim	14194	183	36295	38	885	96	11	17	15.6	R&M
55	Public Service Enterprise Group Incorporated	New Jersey	Americas	47730	68	10076	128	1693	53	5	86	4	DU
56	National Grid plc	United Kingdom	EMEA	80080	35	18993	70	1907	48	3	188	4.2	DU
57	Formosa Petrochemical Corp	Taiwan	Asia/Pacific Rim	13409	194	21763	61	1240	74	10	20	5.8	R&M
58	Neste Oyj	Finland	EMEA	11083	215	16254	84	2024	45	25	6	15.1	R&M
59	EnBW Energie Baden-Württemberg AG	Germany	EMEA	48991	65	21405	63	831	102	4	124	-1	EU
60	NRG Energy, Inc	New Jersey	Americas	12531	200	9821	133	4117	19	51	2	3.3	EU
61	Shaanxi Coal Industry Co Ltd	China	Asia/Pacific Rim	17885	160	10363	122	1644	57	13	16	30.4	C&CF
62	NTPC Ltd	India	Asia/Pacific Rim	42004	78	12670	103	1673	56	5	119	9.2	IPP
63	Kinder Morgan, Inc	Texas	Americas	74157	40	13209	101	2178	43	3	183	0.4	S&T
64	Xcel Energy Inc	Minnesota	Americas	50448	61	11529	115	1372	64	4	133	1.3	EU
65	The Kansai Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	69379	45	29020	47	1185	78	2	208	1.9	EU
66	Surgutneftegas Public JSC	Russia	EMEA	76998	38	22945	60	1443	62	2	219	16	IOG
67	Entergy Corp	Louisiana	Americas	51724	59	10879	117	1241	73	4	133	0.1	EU
68	Edison International	California	Americas	64382	50	12347	107	1284	71	4	155	1.3	EU
69	PPL Corp	Pennsylvania	Americas	45680	73	7769	153	1745	52	5	105	1.1	EU
70	Sempra Energy	California	Americas	65665	47	10829	119	1692	54	4	164	2.1	DU
71	ENGIE SA	France	EMEA	180843	14	67970	23	927	90	1	261	-2.5	DU
72	ONEOK, Inc	Oklahoma	Americas	21812	135	10164	126	1277	72	7	56	4.4	S&T
73	Fortum Oyj	Finland	EMEA	26442	119	6254	172	1677	55	7	46	14.8	EU
74	Consolidated Edison, Inc	New York	Americas	58079	55	12574	105	1343	66	3	172	1.4	DU
75	Public JSC Inter RAO UES	Russia	EMEA	10977	217	15086	90	1193	77	13	15	5.9	EU
76	DTE Energy Co	Michigan	Americas	41882	80	12669	104	1167	79	4	138	6	DU
77	Centrais Elétricas Brasileiras SA - Eletrobrás	Brazil	Americas	35929	90	5613	184	1501	60	6	72	-4.4	EU
78	Veolia Environnement SA	France	EMEA	46423	70	30770	46	828	104	3	188	4	DU
79	Inpex Corp	Japan	Asia/Pacific Rim	44201	76	11582	113	1431	63	4	159		E&P
80	Ørsted A/S	Denmark	EMEA	29257	109	10679	121	995	88	5	98	7	EU
81	Dominion Energy, Inc	Virginia	Americas	103823	30	16572	82	1341	67	2	238	12.2	DU
82	MOL Hungarian Oil & Gas Co	Hungary	EMEA	16896	164	17339	77	735	115	7	61	14	IOG
83	Rosseti, Public JSC	Russia	EMEA	38727	86	15050	92	1122	81	4	159	4.5	EU
84	Vistra Energy Corp	Texas	Americas	26616	117	11809	111	928	89	5	105	31.7	IPP
85	HollyFrontier Corp	Texas	Americas	12165	204	17487	76	771	113	8	37	18.4	R&M
86	WEC Energy Group, Inc	Wisconsin	Americas	34952	95	7523	159	1134	80	5	99	0.2	DU
87	Kunlun Energy Co Ltd	Hong Kong	Asia/Pacific Rim	20880	139	15998	86	784	110	5	99	17.2	GU
88	China Gas Holdings Ltd	Hong Kong	Asia/Pacific Rim	14178	184	7663	155	1061	84	10	19	26.3	GU
89	Beijing Enterprises Holdings Ltd	Hong Kong	Asia/Pacific Rim	23975	126	8746	142	1039	85	5	90	6.6	GU
90	Tenaga Nasional Berhad	Malaysia	Asia/Pacific Rim	41909	79	11937	110	1061	83	3	172		EU
91	E.ON SE	Germany	EMEA	111550	26	46956	32	568	137	1	261	2.3	DU
92	Origin Energy Ltd	Australia	Asia/Pacific Rim	17984	158	10307	124	846	101	6	79	8.8	IOG
93	China Coal Energy Co Ltd	China	Asia/Pacific Rim	38469	87	18254	73	794	109	3	196	28.7	C&CF
94	CGN Power Co, Ltd	China	Asia/Pacific Rim	54775	57	8594	146	1336	68	3	196	23.3	IPP
95	FirstEnergy Corp	Ohio	Americas	42301	77	10844	118	900	93	3	180	1.1	EU
96	ENN Energy Holdings Ltd	China	Asia/Pacific Rim	11470	213	9909	130	800	108	11	18	27.2	GU
97	Power Grid Corp of India Ltd	India	Asia/Pacific Rim	32735	98	4640	200	1328	69	5	105	19.3	EU
98	Fortis Inc	Canada	Americas	39835	83	6551	168	1235	75	4	150	8.7	EU
99	Tokyo Electric Power Co Holdings, Incorporated	Japan	Asia/Pacific Rim	108979	28	56882	26	462	153	1	275	5.2	EU
100	GAIL (India) Ltd	India	Asia/Pacific Rim	9053	250	10083	127	866	97	14	12	13.5	GU

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101	The Chugoku Electric Power Co, Inc	Japan	Asia/Pacific Rim	29759	105	12279	109	821	106	3	168	3.9	EU
102	Pembina Pipeline Corp	Canada	Americas	24730	124	5393	187	1015	87	5	99	19.2	S&T
103	Pioneer Natural Resources Co	Texas	Americas	19067	150	9676	134	753	114	5	99	40.2	E&P
104	Eversource Energy	Massachusetts	Americas	41124	82	8526	147	909	92	3	180	3.7	EU
105	Tohoku Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	39399	85	20473	65	575	135	2	219	4.8	EU
106	CenterPoint Energy, Inc	Texas	Americas	35439	93	12301	108	674	118	3	192	17.8	DU
107	The Hong Kong & China Gas Co Ltd	Hong Kong	Asia/Pacific Rim	18125	155	5242	189	899	94	6	75	12.5	GU
108	Ameren Corp	Missouri	Americas	28933	110	5646	183	828	103	5	119	-1	DU
109	China Resources Power Holdings Co Ltd	Hong Kong	Asia/Pacific Rim	27837	113	8743	143	850	100	4	159	0.8	IPP
110	Snam SpA	Italy	EMEA	27210	114	3016	239	1234	76	5	93	2.1	GU
111	EDP - Energias de Portugal, SA	Portugal	EMEA	47942	67	16221	85	579	134	2	240	-0.6	EU
112	China Resources Gas Group Ltd	Hong Kong	Asia/Pacific Rim	10455	225	7204	161	651	123	10	20	19.3	GU
113	AGL Energy Ltd	Australia	Asia/Pacific Rim	10354	226	9254	139	632	126	8	38	5.9	DU
114	Bharat Petroleum Corp Ltd	India	Asia/Pacific Rim	19965	144	37660	35	404	163	3	188	12.2	R&M
115	The Williams Companies, Inc	Oklahoma	Americas	46040	71	8201	151	862	98	2	219	3	S&T
116	Galp Energia, SGPS, SA	Portugal	EMEA	15584	174	18753	71	440	156	4	138	7.9	IOG
117	CEZ, a. s.	Czech Republic	EMEA	30038	103	8608	145	613	128	3	168	0	EU
118	Saudi Electricity Co	Saudi Arabia	EMEA	127788	20	17321	78	370	172	1	279	9.3	EU
119	CMS Energy Corp	Michigan	Americas	26837	115	6845	164	680	117	4	155	2.3	DU
120	CLP Holdings Ltd	Hong Kong	Asia/Pacific Rim	28596	112	11057	116	601	131	3	196	2.6	EU
121	Continental Resources, Inc	Oklahoma	Americas	15728	170	4225	208	776	112	6	70	30.3	E&P
122	Eni SpA	Italy	EMEA	139701	18	80227	18	167	245	0	290	7.7	IOG
123	Santos Ltd	Australia	Asia/Pacific Rim	16509	166	4033	213	674	118	6	81	15.8	E&P
124	Companhia Energética de Minas Gerais	Brazil	Americas	10108	229	5140	193	588	132	9	25	10.6	EU
125	Plains GP Holdings, LP	Texas	Americas	29969	104	33669	41	331	182	1	255	18.6	S&T
126	VERBUND AG	Austria	EMEA	13398	195	4420	204	628	127	7	56	11.6	EU
127	PBF Energy Inc	New Jersey	Americas	9132	248	24508	57	319	187	5	90	15.5	R&M
128	Cheniere Energy, Inc	Texas	Americas	35492	92	9303	138	648	124	2	233	93.4	S&T
129	Huadian Power International Corp Ltd	China	Asia/Pacific Rim	32454	100	13222	99	481	148	2	240	13.9	IPP
130	Zhejiang Zheneng Electric Power Co, Ltd	China	Asia/Pacific Rim	15667	173	7676	154	606	130	4	131	11.5	IPP
131	Evergy, Inc	Missouri	Americas	25976	120	5148	192	670	121	4	159	26.2	EU
132	Tokyo Gas Co,Ltd	Japan	Asia/Pacific Rim	23128	130	17546	75	395	168	2	219	6.7	GU
133	Terna - Rete Elettrica Nazionale Società per Azioni	Italy	EMEA	17235	163	2597	260	857	99	6	72	3.9	EU
134	CPFL Energia SA	Brazil	Americas	8924	252	6060	174	547	139	8	33	16.1	EU
135	GS Holdings Corp	South Korea	Asia/Pacific Rim	20548	141	14773	95	449	155	2	208	9.7	R&M
136	Hera SpA	Italy	EMEA	11728	210	8223	150	437	158	6	81	10.5	DU
137	CK Infrastructure Holdings Ltd	Hong Kong	Asia/Pacific Rim	21314	138	1031	337	1356	65	7	61	10.7	EU
138	A2A SpA	Italy	EMEA	12138	205	8094	152	439	157	5	90	15.6	DU
139	China National Nuclear Power Co, Ltd	China	Asia/Pacific Rim	49080	64	6504	169	651	122	1	251	15.4	IPP
140	Red Eléctrica Corporación, SA	Spain	EMEA	14330	182	2340	270	813	107	7	51	1.6	EU
141	Magellan Midstream Partners, LP	Oklahoma	Americas	8438	258	2728	254	1021	86	13	13	7.3	S&T
142	SDIC Power Holdings Co, Ltd	China	Asia/Pacific Rim	31726	102	5991	177	671	120	2	214	13.2	IPP
143	AltaGas Ltd	Canada	Americas	14765	180	4099	212	573	136	5	93	35.7	GU
144	GD Power Development Co,Ltd	China	Asia/Pacific Rim	51510	60	16462	83	264	203	1	279	25.9	IPP
145	Manila Electric Co	Philippines	Asia/Pacific Rim	7158	295	6382	170	467	152	18	8	7.4	EU
146	Pinnacle West Capital Corp	Arizona	Americas	18479	153	3471	228	538	140	5	112	-0.3	EU
147	Osaka Gas Co, Ltd	Japan	Asia/Pacific Rim	19508	149	12474	106	381	171	2	208		GU
148	Hydro One Ltd	Canada	Americas	20185	143	4834	196	580	133	3	168	-0.4	EU
149	Alliant Energy Corp	Wisconsin	Americas	16701	165	3648	225	557	138	5	112	3.2	EU
150	Acciona, SA	Spain	EMEA	19635	148	8912	141	398	167	3	188	6.4	EU

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151	Huaneng Lancang River Hydropower Inc	China	Asia/Pacific Rim	23642	128	2937	244	783	111	4	164	21.7	IPP
152	Inner Mongolia Yitai Coal Co,Ltd	China	Asia/Pacific Rim	13330	198	5778	181	535	141	4	127	21.4	C&CF
153	Southwestern Energy Co	Texas	Americas	6717	305	3038	238	891	95	16	9	7.6	E&P
154	Huaneng Power International, Inc	China	Asia/Pacific Rim	58392	53	24493	58	141	252	0	288	7.9	IPP
155	Polskie Górnictwo Naftowe i Gazownictwo SA	Poland	EMEA	15101	177	10722	120	350	174	3	183	8.2	IOG
156	China Longyuan Power Group Corp Ltd	China	Asia/Pacific Rim	22138	134	3888	218	611	129	3	183	7.3	IPP
157	Parkland Corp	Canada	Americas	6924	302	13765	96	285	197	6	72	43.3	R&M
158	World Fuel Services Corp	Florida	Americas	5992	334	36819	37	179	240	7	56	10.9	R&M
159	The AES Corp	Virginia	Americas	33648	96	10189	125	302	191	1	257	-0.3	IPP
160	Emera Incorporated	Canada	Americas	23752	127	4558	203	495	146	3	196	12.6	EU
161	Ampol Ltd	Australia	Asia/Pacific Rim	5831	343	15584	87	267	200	8	42	7.5	R&M
162	Electric Power Development Co, Ltd	Japan	Asia/Pacific Rim	25567	121	8328	149	385	169	2	238	7.1	IPP
163	Equatorial Energia SA	Brazil	Americas	7598	284	3805	221	489	147	9	27	33.2	EU
164	Atmos Energy Corp	Texas	Americas	13368	196	2902	247	511	144	5	93	5.7	GU
165	Marathon Oil Corp	Texas	Americas	20245	142	5125	194	480	149	3	196	17	E&P
166	Power Assets Holdings Ltd	Hong Kong	Asia/Pacific Rim	12074	206	174	348	920	91	8	38	1.5	EU
167	BKW AG	Switzerland	EMEA	9597	241	2891	248	406	162	8	44	5.6	EU
168	Empresas Copec SA	Chile	Americas	25168	122	23716	59	172	244	1	273	12.4	R&M
169	Yancoal Australia Ltd	Australia	Asia/Pacific Rim	7750	277	3144	235	502	145	7	46	53.8	C&CF
170	Korea Electric Power Corp	South Korea	Asia/Pacific Rim	164121	15	49148	30	-1948	345	-2	315	-0.3	EU
171	Shanxi Lu'an Environmental Energy Development Co, Ltd	China	Asia/Pacific Rim	10484	224	3782	222	336	180	6	83	23.5	C&CF
172	MDU Resources Group, Inc	North Dakota	Americas	7683	279	5337	188	335	181	6	64	8.9	DU
173	Lundin Energy AB	Sweden	EMEA	6154	328	2192	276	825	105	35	4	32.1	E&P
174	Datang International Power Generation Co, Ltd	China	Asia/Pacific Rim	39830	84	13476	98	150	251	0	284	17.3	IPP
175	JXTG Holdings, Inc	Japan	Asia/Pacific Rim	73012	42	91243	15	-1713	342	-3	326	12.5	R&M
176	OGE Energy Corp	Oklahoma	Americas	11024	216	2232	275	434	159	6	78	-0.4	EU
177	SK Innovation Co, Ltd	South Korea	Asia/Pacific Rim	32830	97	41426	33	-31	302	0	297	8.1	R&M
178	Companhia Paranaense de Energia - COPEL	Brazil	Americas	7757	276	3289	234	403	165	7	54	7.4	EU
179	Woodside Petroleum Ltd	Australia	Asia/Pacific Rim	29353	107	4873	195	343	177	1	251	6.1	E&P
180	NiSource Inc	Indiana	Americas	22660	133	5209	191	328	184	2	225	5.1	DU
181	Occidental Petroleum Corp	Texas	Americas	109330	27	20393	66	-970	333	-1	312	26.4	IOG
182	Algonquin Power & Utilities Corp	Canada	Americas	10911	218	1625	304	522	142	6	75	24.4	DU
183	Italgas SpA	Italy	EMEA	9317	244	2098	280	472	151	6	64	58.4	GU
184	PT Adaro Energy Tbk	Indonesia	Asia/Pacific Rim	7217	291	3457	230	404	164	7	54	11.1	C&CF
185	Grupa LOTOS SA	Poland	EMEA	6040	331	7525	158	294	195	7	56	12.1	R&M
186	Kyushu Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	45095	74	18346	72	-26	300	0	297	3.3	EU
187	Korea Gas Corp	South Korea	Asia/Pacific Rim	32652	99	20750	64	29	288	0	293	5.8	GU
188	Rubis	France	EMEA	6504	312	5917	180	312	189	6	64	20.3	GU
189	Interconexión Eléctrica SA E.S.P.	Colombia	Americas	13707	189	2286	272	460	154	4	131	-11.9	EU
190	Idemitsu Kosan Co,Ltd	Japan	Asia/Pacific Rim	35424	94	55100	28	-209	317	-1	308	23.7	R&M
191	Koninklijke Vopak N.V.	Netherlands	EMEA	7213	292	1427	316	646	125	10	20	-2.3	S&T
192	ATCO Ltd	Canada	Americas	16189	168	3510	226	383	170	3	192	5.2	DU
193	Repsol, SA	Spain	EMEA	65522	49	48074	31	-4352	347	-9	339	14.3	IOG
194	ACEA SpA	Italy	EMEA	10134	228	3463	229	321	186	4	124	3.7	DU
195	Shenergy Co Ltd	China	Asia/Pacific Rim	9592	242	5484	186	323	185	4	155	11.8	IPP
196	Ovintiv Inc	Colorado	Americas	21487	137	7013	163	234	214	1	255	31	E&P
197	UGI Corp	Pennsylvania	Americas	13347	197	7320	160	256	205	2	208	8.8	GU
198	EVN AG	Austria	EMEA	9267	246	2522	263	342	178	5	86	2.9	EU
199	Hawaiian Electric Industries, Inc	Hawaii	Americas	13745	187	2875	249	218	221	5	119	6.5	EU
200	Iren SpA	Italy	EMEA	9959	233	4675	198	268	199	4	150	10.1	DU

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201	Hokkaido Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	17854	161	6821	165	231	216	2	240	2.1	EU
202	Grupo Energía Bogotá SA E.S.P.	Colombia	Americas	7787	275	1373	320	519	143	8	44	16	GU
203	Shanxi Xishan Coal & Electricity Power Co,Ltd	China	Asia/Pacific Rim	9193	247	4653	199	241	208	4	133	18.9	C&CF
204	Inter Pipeline Ltd	Canada	Americas	9661	239	1891	290	402	166	5	99	11.6	S&T
205	Yangquan Coal Industry (Group) Co, Ltd	China	Asia/Pacific Rim	6927	301	4611	202	240	210	6	83	20.4	C&CF
206	Oil India Ltd	India	Asia/Pacific Rim	6939	300	1824	291	428	160	7	48	12	E&P
207	Enagás, SA	Spain	EMEA	10009	231	1305	326	478	150	5	93	-1	GU
208	Jiangsu Guoxin Corp Ltd	China	Asia/Pacific Rim	9910	235	2978	242	339	179	4	146	7.8	EU
209	PG&E Corp	California	Americas	85196	34	17129	79	-7656	348	-24	344	-1	EU
210	RWE Aktiengesellschaft	Germany	EMEA	72648	43	14964	93	-1492	339	-6	332	-32.9	DU
211	Brookfield Infrastructure Partners LP	Bermuda	Americas	56308	56	6597	167	19	293	0	294	46.1	DU
212	Cosan Ltd	Brazil	Americas	13305	199	4173	210	264	202	3	205	18.1	R&M
213	Aboitiz Power Corp	Philippines	Asia/Pacific Rim	8229	265	2519	264	347	175	5	112	12.1	IPP
214	Hellenic Petroleum SA	Greece	EMEA	8027	269	10024	129	182	238	3	183	10.2	R&M
215	Diamondback Energy, Inc	Texas	Americas	23531	129	3767	223	240	211	1	257	92.6	E&P
216	Thai Oil Pcl	Thailand	Asia/Pacific Rim	8995	251	9494	136	199	232	3	205	9.8	R&M
217	S-Oil Corp	South Korea	Asia/Pacific Rim	13566	191	20261	67	52	285	0	283	14.3	R&M
218	Keyera Corp	Canada	Americas	5605	346	2698	255	331	183	7	48	13.1	S&T
219	Seven Generations Energy Ltd	Canada	Americas	6294	322	2078	281	353	173	6	63	30.8	E&P
220	Elia Group SA/NV	Belgium	EMEA	15724	171	2538	261	288	196	2	214	41	EU
221	Shikoku Electric Power Co, Incorporated	Japan	Asia/Pacific Rim	12519	201	6682	166	165	246	2	233	2.3	EU
222	Huadian Fuxin Energy Corp Ltd	China	Asia/Pacific Rim	15842	169	2792	251	266	201	2	233	7.3	IPP
223	National Fuel Gas Co	New York	Americas	6462	315	1693	297	304	190	7	52	5.2	GU
224	Electricity Generating Public Co Ltd	Thailand	Asia/Pacific Rim	6617	308	1190	332	414	161	7	56	18.1	IPP
225	Centrica plc	United Kingdom	EMEA	23089	131	28838	48	-1301	338	-14	343	-5.8	DU
226	Southwest Gas Holdings, Inc	Nevada	Americas	8170	267	3120	236	214	223	4	138	8.2	GU
227	Shenzhen Energy Group Co, Ltd	China	Asia/Pacific Rim	13569	190	2939	243	240	209	2	225	22.5	IPP
228	China Power International Development Ltd	Hong Kong	Asia/Pacific Rim	19806	146	3938	217	181	239	1	268	13.6	IPP
229	Oil Search Ltd	Papua New Guinea	Asia/Pacific Rim	11573	212	1585	306	312	188	4	164	8.6	E&P
230	Beijing Jingneng Clean Energy Co, Ltd	China	Asia/Pacific Rim	8432	259	2314	271	295	194	4	146	3.8	IPP
231	NHPC Ltd	India	Asia/Pacific Rim	8830	254	1189	333	344	176	5	112	2.4	IPP
232	Cosmo Energy Holdings Co, Ltd	Japan	Asia/Pacific Rim	14944	179	24953	55	-257	320	-3	322	6.1	R&M
233	Abu Dhabi National Energy Co PJSC	United Arab Emirates	EMEA	26561	118	4788	197	64	278	0	288	3	DU
234	Hokuriku Electric Power Co	Japan	Asia/Pacific Rim	14517	181	5724	182	122	258	1	261	5	EU
235	WPX Energy, Inc	Oklahoma	Americas	8413	260	2445	268	258	204	4	150	52.8	E&P
236	Türkiye Petrol Rafinerileri A.S.	Turkey	EMEA	8184	266	13210	100	78	270	2	246	37	R&M
237	Husky Energy Inc	Canada	Americas	24706	125	14906	94	-1048	335	-6	333	15.6	IOG
238	First Philippine Holdings Corp	Philippines	Asia/Pacific Rim	7465	288	2678	257	250	206	4	138	13.3	EU
239	The Tata Power Co Ltd	India	Asia/Pacific Rim	11877	208	3856	219	189	236	2	228	1.8	EU
240	Portland General Electric Co	Oregon	Americas	8394	261	2123	279	214	222	4	138	3.4	EU
241	Aker BP ASA	Norway	EMEA	12227	203	3339	232	141	253	2	214	38.3	E&P
242	Japan Petroleum Exploration Co, Ltd	Japan	Asia/Pacific Rim	5715	344	2906	246	244	207	5	105	15.5	E&P
243	HK Electric Investments & HK Electric Investments Ltd	Hong Kong	Asia/Pacific Rim	14157	185	1386	318	300	192	2	208	-2	EU
244	Rabigh Refining & Petrochemical Co	Saudi Arabia	EMEA	19715	147	9071	140	-145	312	-1	308	10.6	R&M
245	Meridian Energy Ltd	New Zealand	Asia/Pacific Rim	6294	321	2275	273	221	220	5	99	13.7	IPP
246	YPF Sociedad Anónima	Argentina	Americas	22806	132	9837	132	-494	329	-3	323	47.8	IOG
247	Ultrapar Participações SA	Brazil	Americas	6316	319	18079	74	76	273	1	251	4.9	S&T
248	Public JSC Federal Hydro-Generating Co - RusHydro	Russia	EMEA	13522	193	5943	179	75	274	1	275	1.3	EU
249	Guangdong Electric Power Development Co, Ltd	China	Asia/Pacific Rim	10655	223	4145	211	162	248	2	240	9	IPP
250	Shanghai Electric Power Co Ltd	China	Asia/Pacific Rim	15674	172	3345	231	136	254	1	268	12.2	IPP

Top 250 Methodology

This annual survey of global energy companies by S&P Global Platts measures companies' financial performance using four key metrics: asset worth, revenues, profits, and return on invested capital.

All companies on the list have assets greater than US $5.5 billion. The fundamental and market data comes from a database compiled and maintained by S&P Global Market Intelligence.

Energy companies were grouped according to their S&P Global Primary Industry Classification code. Each company is assigned to an industry according to the definition of its principal business activity.

Because the survey is global, and because all countries do not share a common financial reporting standard, the information presented is for each company's most current reporting period. Since then, material changes to a company's financial health may have occurred. Data for US companies came from Securities and Exchange Commission (SEC) Form 10K.

The company rankings are derived using a special S&P Global Platts formula. We added each company's numerical ranking for asset worth, revenues, profits, and ROIC and assigned a rank of 1 to the company with the lowest total, 2 to the company with the second-lowest total, and so on.

Finally, ROIC figures-widely regarded as a driver of cash flow and value were calculated using the following equation: ROIC = [(Income before extraordinary items) - (Available for common stock)] ÷ (Total invested capital) x 100 where "Income before extraordinary items" is net income less preferred dividends and "Total invested capital" is the sum of total debt, preferred stock (value), noncontrolling interest, and total common equity.

The data is the latest available in the S&P Global Market Intelligence database as of the morning of 6/8/2020 and is translated into $USD as of that same date.