The Biggest Saudi Oil Field Is Fading Faster Than Anyone Guessed

It was a state secret and the source of a kingdom’s riches. It was so important that U.S. military planners once debated how to seize it by force. For oil traders, it was a source of endless speculation.

Now the market finally knows: Ghawar in Saudi Arabia, the world’s largest conventional oil field, can produce a lot less than almost anyone believed.

When Saudi Aramco on Monday published its first ever profit figures since its nationalization nearly 40 years ago, it also lifted the veil of secrecy around its mega oil fields. The company’s bond prospectus revealed that Ghawar is able to pump a maximum of 3.8 million barrels a day — well below the more than 5 million that had become conventional wisdom in the market.

“As Saudi’s largest field, a surprisingly low production capacity figure from Ghawar is the stand-out of the report,” said Virendra Chauhan, head of upstream at consultant Energy Aspects Ltd. in Singapore.

King of Oil

The Energy Information Administration, a U.S. government body that provides statistical information and often is used as a benchmark by the oil market, listed Ghawar's production capacity at 5.8 million barrels a day in 2017. Aramco, in a presentation in Washington in 2004 when it tried to debunk the "peak oil" supply theories of the late U.S. oil banker Matt Simmons, also said the field was pumping more than 5 million barrels a day, and had been doing so since at least the previous decade.

In his book "Twilight in the Desert," Simmons argued that Saudi Arabia would struggle to boost production due to the imminent depletion of Ghawar, among other factors. "Field-by-field production reports disappeared behind a wall of secrecy over two decades ago," he wrote in his book in reference to Aramco's nationalization.

The new details about Ghawar prove one of Simmons's points but he missed other changes in technology that allowed Saudi Arabia — and, more importantly, U.S. shale producers — to boost output significantly, with global oil production yet to peak.

The prospectus offered no information about why Ghawar can produce today a quarter less than 15 years ago — a significant reduction for any oil field. The report also didn't say whether capacity would continue to decline at a similar rate in the future.

In response to a request for comment, Aramco referred back to the bond prospectus without elaborating.

Lost Crown

The new maximum production rate for Ghawar means that the Permian in the U.S., which pumped 4.1 million barrels a day last month according to government data, is already the largest oil production basin. The comparison isn't exact — the Saudi field is a conventional reservoir, while the Permian is an unconventional shale formation — yet it shows the shifting balance of power in the market.

Ghawar, which is about 174 miles long — or about the distance from New York to Baltimore — is so important for Saudi Arabia because the field has "accounted for more than half of the total cumulative crude oil production in the kingdom," according to the bond prospectus. The country has been pumping since the discovery of the Dammam No. 7 well in 1938.

On top of Ghawar, which was found in 1948 by an American geologist, Saudi Arabia relies heavily on two other mega-fields: Khurais, which was discovered in 1957, and can pump 1.45 million barrels a day, and Safaniyah, found in 1951 and still today the world's largest offshore oil field with capacity of 1.3 million barrels a day. In total, Aramco operates 101 oil fields.

Flames burn off at an oil processing facility at Saudi Aramco’s Shaybah oil field.

Photographer: Simon Dawson/Bloomberg
The 470-page bond prospectus confirms that Saudi Aramco is able to pump a maximum of 12 million barrels a day — as Riyadh has said for several years. The kingdom has access to another 500,000 barrels a day of output capacity in the so-called neutral zone shared with Kuwait. That area isn’t producing anything now due a political dispute with its neighbor.

While the prospectus confirmed the overall maximum production capacity, the split among fields is different to what the market had assumed. As a policy, Saudi Arabia keeps about 1 million to 2 million barrels a day of its capacity in reserve, using it only during wars, disruptions elsewhere or unusually strong demand. Saudi Arabia briefly pumped a record of more than 11 million barrels a day in late 2018.

“The company also uses this spare capacity as an alternative supply option in case of unplanned production outages at any field and to maintain its production levels during routine field maintenance,” Aramco said in its prospectus.

Costly Strategy

For Aramco, that’s a significant cost, as it has invested billions of dollars into facilities that aren’t regularly used. However, the company said the ability to tap its spare capacity also allows it to profit handsomely at times of market tightness, providing an extra $35.5 billion in revenue from 2013 to 2018. Last year, Saudi Energy Minister Khalid Al-Falih said maintaining this supply buffer costs about $2 billion a year.
Aramco also disclosed reserves at its top-five fields, revealing that some of them have shorter lifespans than previously thought. Ghawar, for example, has 48.2 billion barrels of oil left, which would last another 34 years at the maximum rate of production. Nonetheless, companies are often

able to boost the reserves over time by deploying new techniques or technology.

In total, the kingdom has 226 billion barrels of reserves, enough for another 52 years of production at the maximum capacity of 12 million barrels a day.

The Saudis also told the world that their fields are aging better than expected, with “low depletion rates of 1 percent to 2 percent per year,” slower than the 5 percent decline some analysts suspected.

Yet, it also said that some of its reserves — about a fifth of the total — had been drilled so systematically over nearly a century that more than 40 percent of their oil has been already extracted, a considerable figure for an industry that usually struggles to recover more than half the barrels in place underground.

East Med Gas Forum Created In Cairo: A Regional Game Changer?

Eastern Mediterranean’s energy ministers meeting in Cairo on January 14 has resulted in a turning point announcement for the region’s energy industry. Seven officials representing Egypt, Cyprus, Greece, Israel, Italy, Jordan and Palestine agreed to establish the East Mediterranean Gas Forum (EMGF) with the aim to expedite the development of hydrocarbon resources in the East Med, and transform the region into an energy hub. EMGF will be based in Cairo and will be open to new members joining in the future.

Egyptian Petroleum Minister Tarek El Molla chaired the meeting in the presence of representatives from the EU and the World Bank sending a clear message of Cairo’s willingness and readiness to play the regional energy hub’s role. The forum will support gas-producing countries by enhancing their cooperation with consuming and transitory parties in the region, taking advantage of existing infrastructure and developing further infrastructure options to accommodate current and future discoveries. In addition, it will allow the creation of a regional gas market that serves the interests of its members by ensuring supply and demand, optimizing resource development, rationalizing the cost of infrastructure, offering competitive prices and improving trade relations.

The announcement, which came at this critical economic and political time reflects the will of the countries of the region to create a framework in which big hydrocarbon companies could operate and attract multi-billion investments that are necessary for this industry. Gas produced will likely end up in Egypt for processing before being sent to international markets, due to existing reliable infrastructure.

Multilateral Political signs

EMGF formation comes to serve Europe’s old wish to diversify its energy needs through cooperating with East-Med countries via two potential European doors: Italy & Greece. Europe is still currently dependent on imports from Russia but increasing tensions between western European countries and Moscow is making this problematic. On the counterpart, gas-producing countries are searching for commercial markets for their gas exports, and the road to Europe via Egypt seems to be the most feasible. The forum can indeed push forward with the proposed 2,000-kilometer (1,243-mile) East Med pipeline, which will stretch from Israel and Cyprus into Greece and Italy to export Israeli and Cypriot gas to Europe. EMGF countries are expected to sign a construction deal for the pipeline “in a few weeks’ time”, as reported.

In addition, the forum is a landmark development for Israel, who has been admitted to a regional energy grouping for the first time and was given an official status in the region after 70 years of conflicts with the Arab world, with all what that means on the political and economic levels. Another interesting presence is that of Palestine, who is not yet a producing country but has already made a 1-TCF offshore discovery back in 2000 in the shallow Gaza waters, which could not be developed due to continuous tensions with the Israelis. Despite that, Palestinian Authority (PA) was given a place at EMGF’s table, and could pave the way into resolving the Gaza Marine issue with Egyptian meditation and support.

Absent countries to a rivalry forum?

EMGF marked notable absences from three Eastern Mediterranean gas players, including Turkey, Lebanon and Syria. The political unsteady situation in the latter could clearly explain not approaching any Syrian concerned party within the current status-quo. Turkey, a political and military player in the region, has previously opposed gas exploration offshore Cyprus in areas it considers disputed waters. Political tensions between various EMGF members and Ankara also explain why it was not part of the Cairo meeting. In addition, the fast development of the TurkStream gas pipeline between Turkey and Russia reflects Ankara’s low interest in EMGF as it is already securing its gas. The offshore section of the TurkStream gas pipeline was inaugurated on November 19th last year and will have two parallel lines: the first to deliver gas to Turkey, the second for onward sale to Europe.

As for Lebanon, who has awarded two offshore blocks (4 & 9) of his maritime waters earlier in 2018 for further exploration & production (expected to start in Q4 2019), has not yet released any official statement on EMGF matter. No information were announced to answer the many questions on whether the government has been invited to be part of the forum or not, or if it has refused because of Israel’s presence with whom there are no diplomatic nor political relations, in addition to an 860 km2 disputed offshore area. Most importantly, would Israel benefit from its presence with the EMGF countries to force a one-sided solution on the latter topic? Moreover, how would Lebanon be able to market his future gas prospects if Israel was a main player in the East-Med pipeline to Europe?

It might be true that some Turkish energy experts have started to put forward the idea of Ankara establishing a north-eastern Mediterranean gas forum with Northern Cyprus, Lebanon and Syria to export the gas through turkstream, an option which would appear genuinely as a rival to EMGF and far from being executed. Yet, post-EMGF East-Med geopolitics would not potentially be the same even before it, and the forum is expected to play a game-changing role in the region.

Lebanon Gas and Oil – Editorial Team

Shale boom cuts price of gas to record low

In west Texas last week, you could not give gas away, as prices dropped to record lows. Companies trying to offload natural gas at the Waha hub, in the booming shale oil region of the Permian Basin, found they had to pay operators with pipeline capacity to take it away.

The gas price at Waha registered a low last Thursday of minus $2.50 per million British Thermal Units and closed at minus $1.95, its lowest level since S&P Global Platts started collecting the data back in 1994.

The steep negative prices last week were in part caused by equipment failures on one pipeline system and planned maintenance on another, which made it harder to find outlets for unwanted gas. The fundamental problem in west Texas, however, is that there is a growing oversupply of gas that is a byproduct of booming crude output in the shale oilfields of the Permian Basin. That surge of surplus gas, which could continue for years, is expected to have global implications, with several companies developing projects for exporting it to world markets.

Since the start of 2016, oil production in the Permian region of Texas and New Mexico has risen by about 120 per cent, more than doubling as the rebound in crude prices encouraged a new shale development boom. But the reserves also hold large volumes of natural gas, which is extracted along with the crude. The region’s gas production has also soared by 120 per cent over the same period.

As that gas boom has shadowed oil production, it has started to strain the capacity of the pipeline network to take the gas to market. Regulations and safety considerations mean that companies with excess gas cannot simply vent it into the air or burn it all off in flares, which means they are compelled to find takers for it.

Companies with pipeline capacity available can make money both by being paid to take gas away, and by selling it to customers that want it. At the same time when prices were negative at Waha, gas at the Henry hub 650 miles away in Erath, Louisiana, was being sold for a (positive) price of about $2.67 per m BTU.

Kinder Morgan, the pipeline group, has identified building new routes for gas out of the Permian region as one of its strategic priorities, and has two projects under construction. The first, the $1.75bn Gulf Coast Express pipeline, is scheduled to come into operation in October.

Rich Redash, head of global gas planning at S&P Global Platts, said he did not expect any “significant relief” from the shortage of gas export capacity until that pipeline came into service.

Even then, he added, the growth of oil and gas production would probably mean that strains on the system re-emerged quite quickly.

As the capacity to move gas out of the Permian region increases, companies are looking for more buyers, particularly in export markets.

Tellurian, which plans to build a $15.2bn plant in Louisiana for exporting liquefied natural gas, is also developing a 625-mile pipeline from Waha to supply it.

Meg Gentle, Tellurian’s chief executive, said there would be a need for a “huge” increase in LNG export capacity as US gas production rose by an expected 20bn cubic feet of gas per day, most of it coming from the Permian.

“Even though I don’t believe those negative prices will persist, the price in the Permian is very low,” she said. “I’m assuming a little bit of the 20 bcf a day is absorbed by the US market, and the rest needs to be exported.”

OPEC+ oil production cuts, possible US-China trade deal boost oil prices

Urquhart Stewart tells New Europe that Russia could pull out of the latest agreement on cutting output, which would weaken oil prices.

Supply cuts led by the Organization of Petroleum Exporting Countries (OPEC), US sanctions against Iran and Venezuela and the possibility of a US-China trade agreement fuelled oil prices on 29 March.

May Brent crude oil futures were up 83 cents at $68.65 a barrel by 1232 GMT, set for a gain of nearly 28% in the first quarter, Reuters reported, adding that the more active June contract was up 89 cents at $67.99 a barrel. US West Texas Intermediate (WTI) futures were at $60.44 per barrel, up 1.14 cents, and on track for a rise of more than 33% over the

January-March period. For the two futures contracts, January-March 2019 is the best-performing quarter since the second quarter of 2009, when both gained about 40%, according to the news agency.

Justin Urquhart Stewart, director at Seven Investment Management in London, told New Europe by phone on 29 March that oil production cuts from OPEC and non-OPEC group of producers led by Russia have been one of the reasons for the increased oil prices. But he warned that the global economy is slowing, leading to a lower demand for oil.

“We have what looks like a global slowdown. Demand is likely to weaken and Saudi cut production will have an impact. Venezuela one has been carrying on and on there is nothing new there. But I think the bigger picture is really if we get a decision on the Chinese-American trade issues. They’re indirectly linked but the mere agreement on that, you will see that reflected in the oil price as well soon after because for the increased demand for power,” Urquhart Stewart said.

OPEC and other non-OPEC producers led by Russia – an alliance known as OPEC+ – agreed in December to reduce oil supply by 1.2 million barrels per day from 1 January 1 for six months. But, according to Reuters, Riyadh is having a hard time convincing Russia to stay much longer in an OPEC-led pact cutting oil supply, and Moscow may agree only to a three-month extension. Russian Energy Minister **Alexander Novak** told his Saudi counterpart **Khalid al-Falih** when the two met in Baku this month that he cannot guarantee an extension to the end of 2019, Reuters quoted three sources as saying.

Urquhart Stewart told New Europe that Russia could pull out of the latest agreement on cutting output, which would weaken oil prices. “They weren’t exactly natural bedfellows at the best of times and I’m surprised it almost lasted this long – The enemy of my enemy is my friend. So they will have diverging requirements I think going forward and that’s not going to change," the director at Seven Investment Management in London quipped.

On 28 March, US President **Donald J. Trump** called for an OPEC production boost to lower oil prices. "Very important that OPEC increase the flow of Oil. World Markets are fragile, price of Oil getting too high. Thank you!" he tweeted. But the oil markets shrugged off Trump's latest request to scale back or reverse its output curbs. "Increasingly what he's doing is using his twitter and cry wolf. But the more he does it, the less people believe. No, he is just coming out with populist statements," Urquhart Stewart said, adding: "So the industry generally is becoming far more resistant to them, quite right, too."

Saudi Aramco's $111bn profits dwarf those of mega-rivals

First glimpse of finances puts Apple and Shell in shade but raises issue of company-state inter-reliance

Saudi Aramco has for the first time disclosed the financial performance it has kept secret for three-quarters of a century, revealing that the kingdom’s state oil company generated more profits last year than any other company in the world.

The disclosure, made in a prospectus aimed at courting investors ahead of its debut international bond sale, showed the group generated $111.1bn in net income last year, almost double that of Apple and five times that of rival oil producer Royal Dutch Shell.

Saudi unease about disclosing the company’s corporate make-up and ownership structure was among the reasons Saudi

Aramco delayed a much-heralded initial public offering last year. Disagreement over its valuation ultimately forced an indefinite postponement.

But the company decided to tap the public debt markets to raise funds for its recent $69bn purchase of local petrochemicals company Sabic. The sale, expected to raise $10bn, will provide a test of fund managers' willingness to back a company whose influence is tied to its historic connection to the development of the Saudi state.

The rare window into the finances of the company, which produces more than 10 per cent of the world's crude, shows the state's reliance on the oil producer means it generates less in post-tax profits per barrel than privately owned competitors.

The government in Riyadh relied on the oil sector for 63 per cent of its total revenue in 2017, according to the prospectus. The tax take from the kingdom meant the oil company made approximately $26 a barrel last year compared with $38 a barrel for Royal Dutch Shell and $31 a barrel for France's Total. In 2018 Saudi Aramco generated $224bn of earnings before interest, tax, depreciation and amortisation.

Moody's and Fitch assigned the company ratings of A1 and A+, respectively, but said the government's reliance on the oil producer to fund its budget acted as a cap on its creditworthiness. US producer ExxonMobil, for example, is rated AAA by Moody's.

Moody's said Saudi Aramco had many characteristics of a AAA-rated borrower, such as minimal debt relative to cash flows, large-scale production, market leadership and access in Saudi Arabia to one of the world's largest hydrocarbon reserves. But its final rating was restrained to A1 "because of the close interlinkages between the sovereign and the company".

Fitch similarly noted the company's "high production, vast reserves, low production costs and very conservative financial profile" would give it a standalone rating of AA+, but said it would cap its rating at A+ due to the influence the state had on the company through regulating the level of production, taxation and dividends.

JPMorgan Chase and Morgan Stanley are the lead advisers Saudi Aramco has hired to sell the bonds, which could include 30-year debt and come as the oil price has partly recovered from a plunge in the fourth quarter.

The Sabic transaction will see money transferred into Saudi Arabia's Public Investment Fund, the sovereign wealth fund that Crown Prince Mohammed bin Salman has chosen as a vehicle for carrying out his ambitious plans to overhaul the Saudi economy and diversify it away from oil.

Officials had hoped a stock market listing of Saudi Aramco would have seen $100bn funnelled into the sovereign wealth fund. Saudi Aramco, which dates back to the 1930s, has issued bonds in local currency before, but the $10bn international deal is expected to give the company a bigger role in global financial markets.

Navigant: Solar plus storage turning variable green power

into a dispatchable resource

Storage-plus-renewable energy projects, in particular solar, are expected to play an important role as electric utilities develop their strategies for the gird of the future. The risk and cost associated with battery technology continues to decline, enabling utilities to transition large-scale renewables from intermittent to dispatchable energy resources.

The utility-scale energy storage market has seen a steady growth since 2011, with more than 8.9 GW of non-pumped hydro storage projects coming online over the past seven years, according to Navigant Research, "How Utilities Can Look Beyond Natural Gas with Cost-Effective Solar Plus Storage Strategies."

One of the technologies driving market growth is lithium-ion batteries, the report said. The latest analysis showed that lithium-ion batteries accounted for 29.4% of non-pumped storage capacity and 70% of advanced battery capacity developed since 2011.

Due to the advancements in lithium-ion battery technology, Navigant Research expects that PPA prices for projects combining energy storage and renewable resources will continue to decline as their adoption expands. Storage-plus PPAs are already less expensive than the LCOE for combined cycle natural gas in the United States, the report found.

"In 2018, storage-plus made its first shift from the validation and first-mover adopters to diffuse adoption led by utilities," Alex Eller, senior research analyst with Navigant Research, said in a statement. "The accurate valuing and positioning of storage-plus by utilities will continue to drive the market in coming years."

Regulators and utilities should push for all-resource solicitation to take advantage of the price disruption in the area of storage-plus renewable energy and to meet aggressive renewable portfolio standard targets in the process, the report said.

Trump Doubles Down on Keystone Oil Pipeline With New Permit

President Donald Trump issued a new permit for TransCanada

Corp.’controversial Keystone XL pipeline Friday, circumventing a court ruling that blocked a previous authorization by his State Department.

The move aims to undercut legal challenges to the $8 billion project, including a November ruling by a Montana-based district judge that faulted the State Department’s previous environmental analysis, according to a person familiar with the matter. It could pave the way for beginning some preliminary work, according to Clearview Energy Partners.

“It looks like the intent is to wipe the slate clean and replace the previous presidential permit with this new one,” Height Securities LLC analyst Katie Bays said. Keystone XL doesn’t need the changes to the supplemental environmental impact statement “because Trump invalidated that whole process and issued this new president permit.”

The pipeline, proposed more than a decade ago, would carry crude from Canada’s oil sands to the U.S. Midwest. Trump’s State Department approved the project in 2017 after President Barack Obama denied TransCanada a permit on grounds its oil would contribute to global warning.

It’s good news for Canada’s energy producers after delays to planned expansions of the Trans Mountain pipeline and Enbridge Inc.’s Line 3. The lack of pipelines is partially blamed for a slowdown in oil sands investment and the partial pullback of some international oil companies including Royal Dutch Shell Plc.

Unlike the earlier State Department permit, which was issued after a deep environmental analysis required under the National Environmental Policy Act, the new presidential permit is not directly tied to any such review. And the NEPA statute that generally compels environmental study of energy projects and major agency actions does not apply to the president.

Pipeline developers are generally required to receive presidential permits for border-crossing facilities. The State Department has been tasked with vetting permit applications for oil pipelines since 1968, when an executive order put the agency in charge.

But Trump still retains the authority to issue presidential permits himself, said the person, who asked for anonymity to discuss internal deliberations. And because Trump’s permit is not subject to environmental review requirements in federal law, it effectively restarts the process and undercuts the Montana lawsuit.

TransCanada, which is yet to make a final investment decision on the project, applauded the White House’s action.

“President Trump has been clear that he wants to create jobs and advance U.S. energy security and the Keystone XL pipeline does both of those things,” Russ Girling, president and chief executive officer, said in a statement.

November Ruling

U.S. District Judge Brian Morris’s November ruling found that the 2014 environmental assessment by the Obama administration fell short. Trump had used that review in a March 2017 decision allowing the project to proceed. Morris said the government must consider oil prices, greenhouse-gas emissions and formulate a new spill-response strategy before allowing the pipeline to move forward.

Administration lawyers could file a motion seeking to dismiss the Montana case, which it has appealed to the 9th Circuit Court of Appeals.

“Rescission of the prior presidential permit appears to render those proceedings moot,” ClearView analysts said in a note. Mooting the Montana case could end delays related to further State Department environmental review of the project and void an injunction blocking pre-construction work, possibly allowing it to begin in August, ClearView said.

Although the move may help resolve concerns in Montana that focused on the State Department’s environmental review, it does little to address a case before Nebraska’s Supreme Court, which is is yet to rule on an opposition challenge to the state Public Service Commission’s approval of an alternate route to the path championed by TransCanada. TransCanada also appears to need multiple water quality permits for the project in South Dakota, according to Clearview.

Refiner Demand

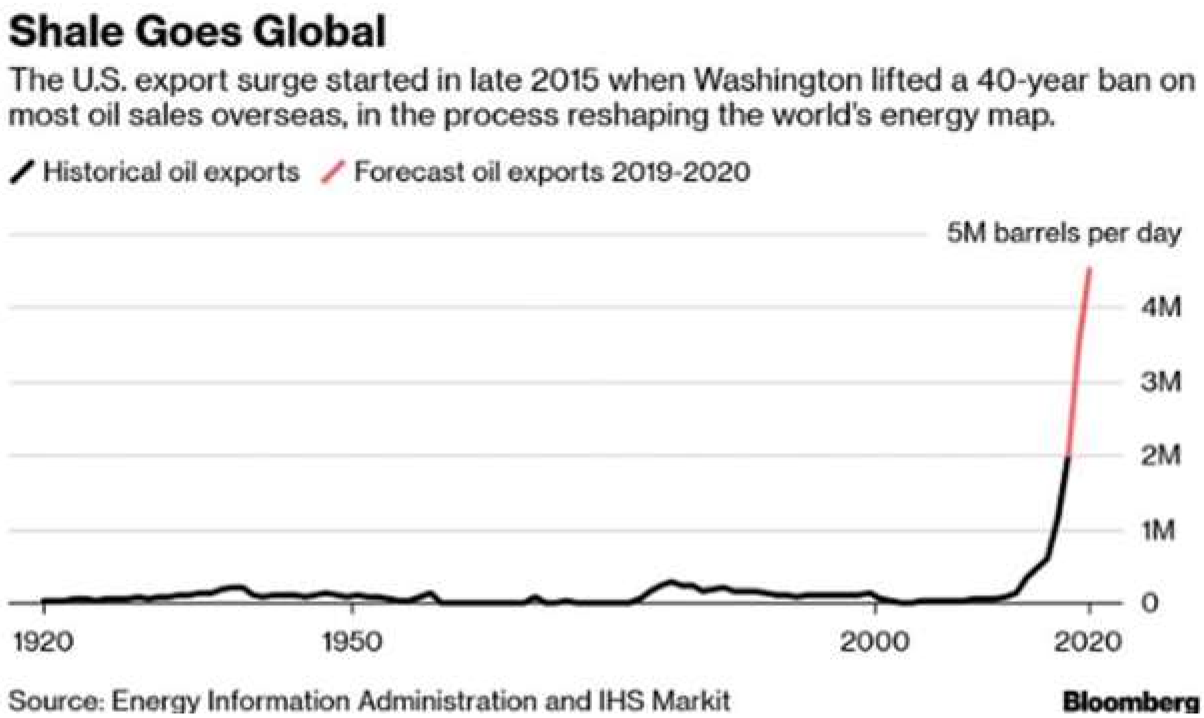
U.S. refiners have been seeking alternative supplies of heavy crude oil after sanctions against Venezuela and a political crises in the Latin American country brought imports from the country to zero in recent weeks. At the same time, Canadian oil producers have been desperate to get new export pipelines built after a surge of new production last year caused a glut that depressed prices and prompted Alberta to impose production curtailments.

“The interest in having Keystone completed has never been higher, from a security standpoint,” Kevin Birn, IHS Markit’s director of North American crude oil markets, said in a phone interview. “The U.S. refiners demand heavy oil in the absence of Venezuelan” crude, he said.

Conservationists blasted the decision, saying it did nothing to address deep environmental problems with the project.

“The Keystone XL tar sands pipeline was a bad idea from day one and it remains a terrible idea,” said Anthony Swift, director of the Canada project at the Natural Resources Defense Council. “If built, it would threaten our land, our drinking water, and our communities from Montana and Nebraska to the Gulf Coast.”

From Texas to the world: A flood of US crude oil exports is coming



Bloomberg/Houston

Driving his pick-up truck through the heartland of the Permian basin – the vast tract of west Texas scrub where one of history's greatest oil booms means miles-long traffic jams – Vega says there's more crude being pumped than America's refineries can absorb. Today, the primary task of trading houses like his is getting the stuff overseas.

"We buy it, we truck it, we put it on a pipeline, and there it goes to the port – and from there to the world," said Vega, who heads the office of global commodities trader Trafigura Group in Midland, the region's oil industry hub.

What started as an American phenomenon is now being felt around the world as US oil exports surge to levels unthinkable only a few years ago. The flow of crude will keep growing over the next few years with huge consequences for the oil industry, global politics and even whole economies.

Opec, for example, will face challenges keeping oil prices high, while Washington has a new, and potent, diplomatic weapon.

American oil exports stepped up a gear last year, jumping more than 70% to just over 2mn barrels a day, according to government data. Over the past four weeks, US oil exports have averaged more than 3mn barrels a day.

“This is the new American energy era,” US Energy Secretary Rick Perry told an industry conference in Houston earlier last month.

Oil traders and shale executives believe US crude exports are set reach 5mn barrels a day by late 2020, up another 70% from current levels. If the US hits that target, America will be exporting, on a gross basis, more crude than every country in Opec except Saudi Arabia. (On a net basis, the US remains, just, a net importer, but that’s likely to change in the next few months.)

“The second wave of the US shale revolution is coming,” said Fatih Birol, the head of the International Energy Agency. “This will shake up international oil and gas trade flows, with profound implications for geopolitics.”

The political impact is already being felt. The Trump administration has been able to impose aggressive sanctions on oil exports from Iran and Venezuela knowing the flow of crude from Texas will keep on rising. The economic impact on the US is also evident: In dollar terms, the country’s petroleum trade deficit fell to its lowest in 20 years in 2018.

The US is already a big exporter of refined products such as gasoline and diesel. When combined with rising crude exports, the IEA forecasts American petroleum exports will reach roughly 9mn barrels a day within five years, up from just 1mn in 2012.

In the process, the US will become the world’s second-largest exporter of crude and refined products by 2024, overtaking

Russia and nearly topping Saudi Arabia.
Until now, the surge in US oil production from the Permian and other shale basins like the Bakken in North Dakota was absorbed at home, feeding refineries in the US Gulf of Mexico coast. Now, US refiners are finding it increasingly hard to process more of the kind of light crude pumped in the Permian as their plants were built to process denser heavy crude – the type pumped in Venezuela and the Middle East.
“The US is probably close to being able to process as much light crude as it can,” Thomas J Nimbley, the head of US oil refiner PBF Energy Inc, told investors.
As a result, shale executives are travelling the world to seek new customers. Gary Heminger, the head of Marathon Petroleum Corp, for example, was recently in Singapore and South Korea looking for buyers for shale crude.
“All the incremental Permian production needs to be exported,” said Raoul LeBlanc at consultant IHS Markit Ltd and a former head of strategy at Anadarko Petroleum Corp. “The Permian needs to find refineries willing to take US light sweet crude as a base-load, most likely in Asia.”
Despite a tight oil market due to American sanctions on Venezuela and Iran mixed with Opec production cuts, finding new buyers isn’t as easy as it sounds. The crude from the Permian is light, yielding lots of naphtha – used in the petrochemical industry – and gasoline, but comparatively little diesel. And most refineries want to produce diesel.
Until now, US shale producers and oil traders had been selling most of their crude on spot transactions – one at a time. As a result, American oil exports saw wildly different destinations from month to month, from Spain to Thailand to Brazil.
A few stable markets are starting to emerge. Oil refineries in Canada, Italy, the UK, and South Korea are becoming regular buyers. And little by little, oil traders are securing long-term deals with overseas refineries, known as term contracts.
Yet, the rapid rise in oil exports is challenging. Not even Saudi Arabia in the 1960s and 1970s saw exports grow so quickly.

“The US export market needs to transition from infancy to adulthood far more rapidly than any major exporter ever has,” said Roger Diwan, another oil analyst at IHS Markit.

Key for US oil exports is China, mired in a trade war with Washington. Until this year, Chinese refiners were buying large chunks of American shale exports. But the flows all but dried up in August. If US oil exports are going to increase at the pace that executives and traders anticipate, the shale industry needs the White House to strike a trade deal with the Chinese.

“If the China demand pull fails to materialise, for political reasons, quality mismatch or otherwise, US exports will likely have to muscle their way into the global refining system, likely via price discounts,” Diwan said.

US shale crude is already selling at a big discount to Brent, the international oil benchmark. West Texas Intermediate sells nearly $10 under Brent. And some of the lighter grades from the Permian, including a new stream called West Texas Light, are seeing even wider discounts.

Finding buyers for the light Permian crude isn’t the only obstacle. Pipelines and ports have become the biggest bottleneck in US oil exports, with traders engineering logistically complex chains combining railways, trucks, pipelines, barges, and ship-to-ship transfers to get crude out of the country. Several ventures are aiming to build new facilities to allow exports via supertankers, which need deepwater ports.

Although the Permian isn’t growing as fast as last year, oil traders and executives still anticipate that America will add another million barrels a day this year to its production, with the bulk coming in the second half. The current slowdown, which some executives jokingly call a “fracking holiday,” is the direct result of shareholder demands for higher returns and less growth, and lower oil prices in late 2018 and early 2019. But the Permian is likely to re-accelerate in the second half of this year when new pipelines open.

If the forecast proves correct, US crude production will surpass 13mn barrels a day by December, up from 11.8mn barrels a day at the end of last year and well above the previous all-time high set in 1970.

“It’s going to be less than if people were able to spend unconstrained, but there’s going to be growth, lots of it,” said Osmar Abib, chairman of global energy at Credit Suisse Group AG.

Ocean LNG to offtake and market Golden Pass LNG volumes

Doha

Qatar Petroleum announced Sunday that Ocean LNG will be responsible for the “offtake and marketing” of all LNG volumes to be produced and exported from the Golden Pass LNG Export Project located in Sabine Pass, Texas, US.

Ocean LNG is an international joint venture marketing company, owned by affiliates of QP (70%) and ExxonMobil (30%).
Earlier this year, Ocean LNG entered into a binding LNG sales and purchase agreement with Golden Pass Products LLC to purchase and offtake all the LNG volumes to be produced by Golden Pass LNG.
Since its establishment, Ocean LNG has been active mainly in South America and Europe. Following a successful Final Investment Decision (FID) of Golden Pass LNG on February 5, 2019, Ocean LNG will now focus its efforts on marketing its US LNG volumes in the Asia Pacific region through further extensive engagements.
It will also expand its relations and networks with both established customers as well as emerging and prospective LNG buyers, while at the same time maintaining a strong footprint across South America and Europe.
HE the Minister of State for Energy Affairs, Saad bin Sherida al-Kaabi, also president & CEO of QP, said, “The FID of Golden Pass LNG earlier this year underpins Ocean LNG’s marketing efforts to deliver US LNG to customers across the globe. This is a further testament of Qatar Petroleum’s position as a global LNG leader with a large portfolio capable of offering tailored LNG supply structures and commercial terms in an evolving global LNG environment.”
Ocean LNG will be prominently featured for the first time as part of the QP pavilion at the upcoming global industry event, LNG 19, which will be held in Shanghai from April 1–5.
Golden Pass LNG is situated in a prime location with well-established connectivity to extensive natural gas resources in the US, and has shipping access to both the Atlantic and Pacific basin markets.
Golden Pass LNG, which received all necessary regulatory approvals for the export of LNG from the US Federal Energy Regulatory Commission and the US Department of Energy, was sanctioned in early February of this year by its shareholders, and construction activities at its site are expected to commence imminently.

US oil drillers ease off as services companies forecast major cutbacks

Crude explorers cut activity in the US oil patch for the sixth straight week as major oilfi eld services companies painted a gloomy picture for activity in 2019. Working oil rigs fell by eight this week to 816, according to data released Friday by oilfi eld-services provider Baker Hughes. The weekly rig count has only risen three times in 2019. The persistent decline in activity comes despite gradual recovery in the price of oil, with West Texas Intermediate touching $60 per barrel this week. Schlumberger Ltd and Halliburton Co, two of the largest providers of oil services, said on Monday there'll be a double-digit drop in spending from customers in the US and Canada this year, a deeper cut than they had previously forecast. US shale is facing increasing technical challenges, Schlumberger chief executive offi cer Pal Kibsgaard said at a conference in New Orleans. "Interference" between socalled parent and child oil wells, as well as decline in investment, indicate that shale activity growth will slow in the coming years, he said. Despite a pullback in drilling, producers are working through a sizeable backlog in drilled-but-uncompleted wells. That has kept US crude production at a record 12.1mn for much of March, according to data from the Energy Information Administration.