

# Cyprus runs the risk of being trapped into an expensive undertaking with gas deal



DEFA announced on 23 August its decision to award the tender for the construction of an LNG import terminal at Vasilikos. This will comprise a floating storage regasification unit (FSRU), a jetty for the mooring of the FSRU, pipelines, port and other facilities.

The winner is a consortium comprising China Petroleum Pipeline Engineering Co Ltd (CPPE), Aktor SA and Metron SA, Hudong-Zhonghua Shipbuilding Co. Ltd and Wilhelmsen Ship Management Ltd.

Announcing its decision DEFA said “we believe that the future of the country is aligned with natural gas and we expect it to

play a major role in the economic development of the country in years to come.

“The establishment of the natural gas market will boost the development of the whole energy and industry sectors of the Republic.”

Indeed, natural gas can help bring carbon emissions down. In order to produce the same energy output gas emits about 27 per cent less carbon dioxide in comparison to diesel oil. As a result, replacing diesel by gas in power generation will be helpful, at least initially. I say initially, because the EU’s target is to reduce emissions by 40 per cent by 2030 in comparison to 1990 levels.

The challenge for Cyprus is that so far it has been promising small reductions to its CO<sub>2</sub> emissions in comparison to 2005, when these were close to their peak – about 60 per cent higher in comparison to 1990 according to Eurostat data. By the end of 2017 Cyprus’ emissions were only marginally lower than in 2005.

In fact the incoming European Commission (EC) President, Ursula von der Layen, promised to increase EU’s 2030 CO<sub>2</sub> reduction target to 50 per cent. In addition, the EC has already sent back Cyprus’ Energy Plan to 2030 for not being ambitious enough and requested it to be revised nearer EU targets.

With no other change, and with power generation being only 20 per cent of Cyprus’ total energy consumption, introduction of LNG will reduce carbon emissions only by 8 per cent in comparison to 2005 and close to 50 per cent higher than in 1990. A modest but useful reduction, but it will not get close to EU expectations for 2030. Cyprus will need to do a lot more to achieve that – by substantially increasing use of renewables and biofuels.

### **Impact on electricity costs**

When asked about cost implications, DEFA said that state ownership of the project will allow the cost of importing and regasifying LNG to be kept sufficiently low to keep the cost of gas offered to EAC below \$10/mmBTU (per about 1000 cubic feet) – the equivalent cost of oil at current prices.

DEFA was also asked how can Cyprus commit itself to expensive infrastructure when it does not yet know whether it can secure gas at an affordable price. The response was that that even if the ongoing process – in response to the request for expressions of interest for the long-term supply of LNG for 10-20 years – does not produce favourable prices, DEFA's needs can be met in the short-term by the spot market, which with today's prices can provide LNG at \$3-\$4/mmBTU.

Indeed, as a result of excessive supplies of LNG, spot gas prices in Europe are currently at a low, at about \$4/mmBTU. However, in October 2018 they were about \$10/mmBTU. But by 2022 – the time at which Cyprus will be ready to import LNG – demand is expected to exceed supply, with prices rising again. Available forecasts estimate the price of gas in Europe to average about \$6.50/mmBTU in the ten-year period to 2030.

Given the small quantities required by Cyprus – initially about 0.5 million tonnes LNG per year – the spot price for LNG to be delivered to Cyprus is expected to be higher. Adding to this the recovery of the cost of constructing the facilities (allowing for the EU grant), operation and maintenance – and other related costs and costs incurred by EAC – is likely to bring the total cost above the \$10/mmBTU level. Long-term supply contracts would cost even more.

What is amazing is that the decision to proceed with award of the construction contract appears to have been taken without first securing LNG at reasonable prices and without a commercial viability study based on expected, reliable, LNG costs.

## **Other issues**

DEFA expects to finalise award of the construction contract by mid-October, with the facilities becoming operational by the end of 2021.

But there may be complications. First, its decision to award the tender to the CPPE consortium, taken after a short evaluation period of six weeks, may be disputed by other bidders, which may cause delays.

It should be noted that the unsuccessful consortia are well known, experienced companies, in the global LNG industry. In contrast, CPPE, the leader of the winning consortium, has no real LNG experience.

There are also questions about members of the winning consortium. Aktor SA is the sister company of Helector, facing corruption charges related to HYTY Paphos. Aktor SA had accusations leveled against it for fraud related to projects in the Balkans. Both companies are fully-owned by Greece's Ellaktor Group. These and other questions will hopefully be cleared during the period before final award, but could, nevertheless, cause months of delays.

### **Will gas boost Cyprus economy?**

Given the above, this is not certain. Gas could boost industry and benefit the economy if its introduction leads to substantial cost reductions in comparison to diesel. But this may not be the case. In fact it could be the opposite.

Import of gas by pipeline, either directly from Aphrodite or by accepting Energean's offer to supply gas from its gas-fields in Israel, could do exactly that, with gas prices to EAC less than \$7/mmbtu. Sadly these options have not been taken on.

Moreover, gas alone will not reduce carbon emissions to the

levels required by the EU. This would require a substantial increase in the share of renewables and biofuels in Cyprus energy mix.

Without properly and transparently demonstrating the commercial viability of the project – based on reliable data – Cyprus runs the risk of being trapped into an expensive undertaking for at least the next ten years. Not only this may not boost industry, but may also become a long-term burden to Cyprus' economy.

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## **Shale drilling drops to 19-month low after output hits new high**



American oil explorers, which are producing record volumes of crude, cut drilling to a 19-month low as they seek to show

investors they can do more with less. Working oil rigs fell by 12 last week to 742, according to data released on Friday by oilfield-services provider Baker Hughes. The count has dropped by more than 140 from a November high. In the Permian Basin, 5 rigs were idled, lowering the count there to 429. As explorers dial back spending, Bank of America Merrill Lynch downgraded a trio of shale servicers this week, including Nabors Industries Ltd, owner of the world's biggest fleet of land drilling equipment. "For US onshore, structural changes are accelerating," Chase Mulvehill, an analyst at Bank of America Merrill Lynch, wrote last week in a note to investors. "Doing more with less remains prevalent across US shale, leaving a destructive impact on US onshore activity that is likely to extend well into '20 (or beyond)." Despite the rig-count decline this year, US crude production keeps increasing. It rose to a record 12.5mn barrels a day last week, eclipsing the previous high mark set in late May, according data from the Energy Information Administration. That's partly because producers have an ample backlog of wells that have already been drilled in the past and can be tapped for fracking, but they are also seeking better technology to get more crude from each hole. Plus, it may take a few more months for output from wells bored during last year's drilling peak to start declining.

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**Shell's woeful August risks run as 2nd-largest oil major**



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Big Oil has a new contender for the No 2 spot. Chevron Corp has almost displaced Royal Dutch Shell Plc as the second-largest oil company by market capitalisation.

It's been a particularly grim month for Big Oil, as a US-China trade war dimmed the picture for global economic growth, stymieing crude demand. The Stoxx Europe 600 Oil & Gas Index was headed for a 6.3% decline, among the largest monthly drops in nearly four years, which mirrors the slide in Brent prices.

But Shell had it worst. Its B shares in London have plunged more than 12% last month, a decline not seen since the 2008 financial crisis, which has knocked almost £26bn (\$32bn) off its market value. That's put chief executive officer Ben van Beurden's dream of being No 1 in the industry by every measure even further out of reach.

Shell established itself as the No 2 oil company following its acquisition of BG Group Plc, narrowing its market cap gap with Exxon Mobil Corp. But its US competitor Chevron has now caught up with it again.

Blame earnings. Shell's net income slid in the second quarter

and was far weaker than expected, falling short of the average analyst estimate by almost 30%. That was its biggest miss in more than two years, and pushed chief financial officer Jessica Uhl to acknowledge the company should probably find a way to better manage expectations.

“Shell’s shares have suffered from an unwelcome relapse of earnings volatility,” said Christyan Malek, head of European oil and gas research at JP Morgan Chase & Co. “While we view this as more of a bump in the road, together with the oil price correction – which Shell is more geared to – it has under-performed more than others.”

Chevron, on the other hand, surpassed second-quarter analyst estimates by 21%. Its shares still fell in August, along with the rest of the industry, but its dip was only a third of Shell’s. It’s also traded in dollars, an advantage over sterling-denominated Shell B shares. The British currency has been pummelled by the Brexit process.

Both companies still trail Exxon by a large margin. The Irving, Texas-based oil giant’s market cap is almost \$290bn, compared to Chevron and Shell’s \$223bn.

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## **Flaring, or why so much gas is going up in flames**





If you take a drive along the well-worn highways of West Texas, orange flames will punctuate your journey. Those are gas flares, and they're lighting up the skies above West Texas oilfields like never before as drillers produce crude faster than pipes can be laid to haul the attendant natural gas away. Oil drillers say flaring is the most environmentally friendly way to get rid of excess gas they can't sell. Environmentalists say that in many cases what flaring is friendly to is oil drillers' profits. They think regulators in states including Texas and North Dakota should be tougher on a practice that harms air quality and contributes to climate change.

### 1. Why do drillers flare?

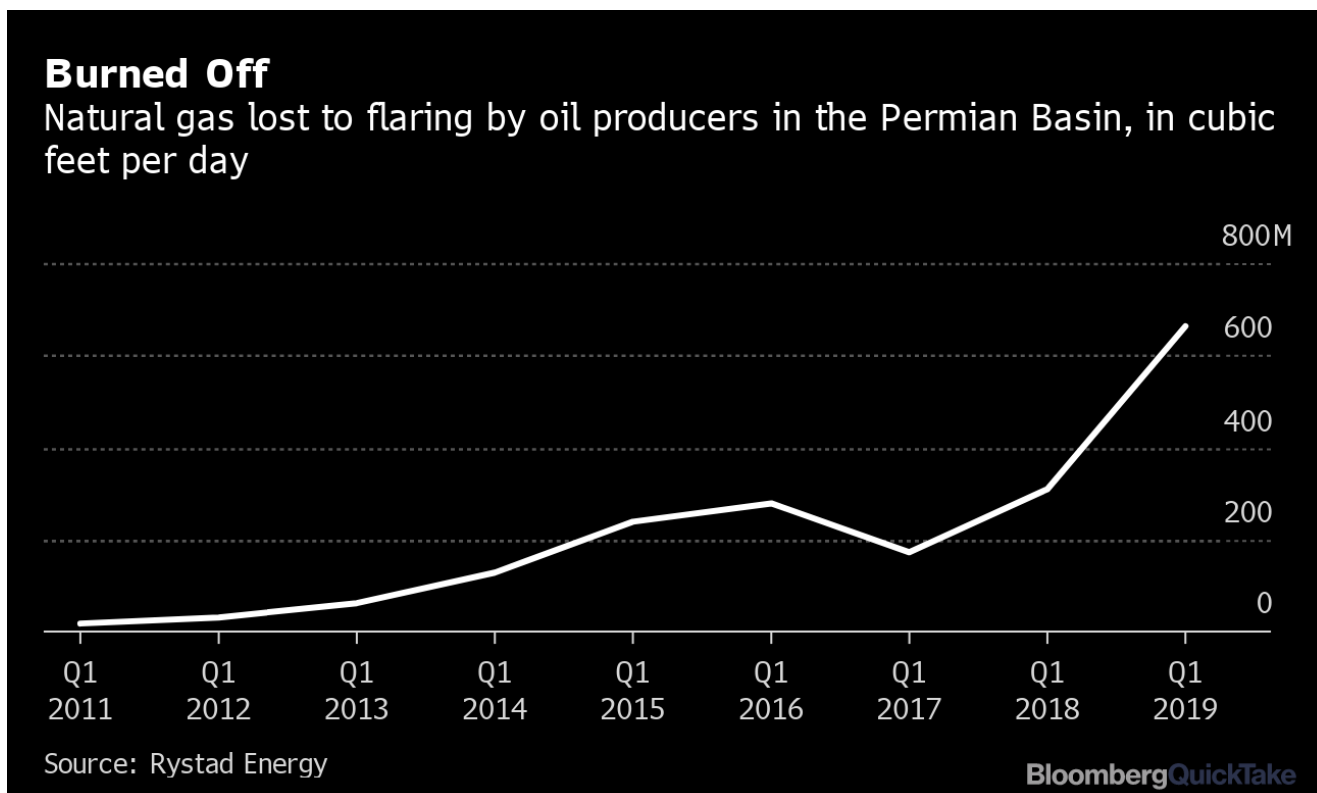
When an oil well begins to spew, less-valuable natural gas comes up alongside crude. Pipelines can capture that gas, but when they're not available, producers often get rid of the gas so they don't have to stop pumping oil. They do that by either

igniting the gas, in the case of flaring, or releasing it directly into air, known as venting. Flaring is preferred because methane, an especially potent greenhouse gas, is burned off, though carbon dioxide is released into the air.

## 2. How much gas is flared?

A lot. The World Bank estimated that globally in 2018, 145 billion cubic meters of gas was flared, about as much as Central and South America use in a year. The amount is rising because of the oil boom in the U.S., which is fueled by the use of hydraulic fracturing – fracking – to unlock fuel from shale rock. Increased flaring in the U.S. is concentrated in the shale oil basins known as the Eagle Ford in Texas, the Permian in Texas and New Mexico, and the Bakken in North Dakota. Permian flaring rose about 85% last year, according to data from Oslo-based consultant Rystad Energy. The volume flared in Texas by the end of 2018 was greater than residential gas demand in the entire state.

## 3. What are the effects?



Gas flaring globally emits more than 350 million tons of carbon dioxide in a year, according to the World Bank. That's the equivalent of the carbon emissions from 90 coal-fired power plants. In the U.S., flaring accounts for an estimated 9% of the greenhouse gas emissions of the oil and gas industry. In addition, the practice spews particulate matter, soot and toxins into the air that have been shown to be hazardous to humans.

#### 4. How does the U.S. regulate flaring?

Flaring is allowed when the gas could cause a safety concern due to high pressure in a well and when pipelines aren't in place to carry the fuel away. In either case, flaring spares drillers from having to suspend production, a costly move that can damage a reservoir's future output. The Texas Railroad Commission, the main oil and gas regulator in the state, has never denied a request for a flaring permit. In a controversial case, it granted one Aug. 6 to Exco Resources Inc. even though the company's wells were already connected to pipelines. Exco successfully argued that it would lose money paying to access the network.

#### 5. Isn't the gas worth something?

The short answer is no, not in oil-dominated basins where what matters is the ability to keep pumping black gold. In the Permian, local gas prices have gone negative multiple times this year, meaning drillers were actually paying customers to haul their gas.

#### 6. Will more pipelines help?

Yes, when prices justify the costs of capturing the gas and transporting it to markets. A new pipeline led by Kinder Morgan Inc. is expected to reduce the pressure to flare. At the same time, pipeline projects in Texas are beginning to attract public opposition, a more common phenomenon in the northeastern U.S. Landowners along the route of another Kinder

Morgan line are fighting the project in court, arguing against the company's use of eminent domain to take private property. It's not clear whether the legal battle will affect the project, but the challenge portends a tone shift in a historically industry-friendly state.

## 7. Are there alternatives to flaring?

Apart from transporting gas to markets via pipeline, oil producers can use it on-site as an energy source or reinject it underground. Both options require investments, however. Russia requires oil drillers to make use of 95% of the gas they produce, while Nigeria prohibits flaring, yet the practice is common in both places. That suggests bans may not be sufficient without incentives to curb flaring.

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# **Iran official says US showing 'some flexibility' on oil sales**



DUBAI (Reuters) – A senior Iranian official said on Saturday the United States had shown flexibility on the licensing of Iranian oil sales and this was a sign that Washington’s “maximum pressure” policy against Tehran had been defeated, state media reported.

French President Emmanuel Macron paved the way at a G7 summit a week ago for a potential diplomatic solution to a confrontation between the United States and Iran brewing since President Donald Trump withdrew Washington last year from world powers’ 2015 nuclear deal with Tehran.

“Macron met with ...Trump during the G7 meeting and the U.S. side has shown some flexibility in the licensing of Iranian oil sales,” Iranian Deputy Foreign Minister Abbas Araqchi was quoted by the state news agency IRNA as saying.

“This is a breach in the U.S. maximum pressure policy and a success for Iran’s policy of maximum resistance,” he said.

Araqchi did not elaborate, and there was no immediate French or U.S. comment.

Since ditching the nuclear deal, calling it flawed to Iran's advantage, Trump has reimposed sanctions to strangle its vital oil trade and force Tehran to accept stricter limits on its nuclear activity, curb its ballistic missile program and end its support for proxy forces around the Middle East.

Araqchi said Iran and its European partners in the nuclear deal faced "difficult and complex" talks towards salvaging the pact. He said Tehran was determined to continue reducing its commitments under the accord until it received protection against sanctions on its oil sales and banking transactions.

Iranian President Hassan Rouhani urged his people on Wednesday to unite to overcome Washington's "economic war" while his government said it would use diplomacy to try to solve the standoff even though it distrusted Trump.

## **IRANIAN TANKER BLACKLISTED**

On Friday, the U.S. Treasury Department blacklisted the Iranian oil tanker *Adrian Darya*, with Secretary of State Mike Pompeo saying Washington had reliable information the vessel was headed to Syria, an ally of Tehran.

The ship was detained by Britain off Gibraltar in July due to suspicions it was carrying Iranian oil to Syria in violation of European Union sanctions. It was released in mid-August after Iran gave assurances that its cargo was not destined for Syria.

Turkey said on Friday the ship was headed to Lebanese waters after changing course several times. Beirut said it was not informed of the plan, but Turkey's information suggested that a ship-to-ship transfer of cargo might be attempted once it nears the coast of Lebanon, which borders on Syria.

A senior Iranian military commander vowed that Iran would retaliate if any of its vessels was stopped in international waters, according to Fars news agency.

“Piracy against Iran can’t be easily overlooked. It is natural for us to act when Iranian ships are stopped in any part of the world’s waters. Iran’s armed forces will certainly retaliate,” Brigadier General Kiumars Heydari, the head of Iran’s regular ground forces, told Fars.

Reporting by Dubai newsroom; Editing by Mark Heinrich

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# Opec posts first 2019 oil output rise despite Saudi cuts: Survey



LONDON (Reuters) – OPEC oil output has risen in August for the first month this year as higher supply from Iraq and Nigeria outweighed restraint by top exporter Saudi Arabia and losses caused by U.S. sanctions on Iran, a Reuters survey found.

The 14-member Organization of the Petroleum Exporting Countries has pumped 29.61 million barrels per day (bpd) this month, the survey showed, up 80,000 bpd from July's revised figure which was the lowest OPEC total since 2014.

The survey indicates Saudi Arabia is not deviating from its plan of restraining output by more than called for by an OPEC-led supply deal to support the market. Despite calls this year from U.S. President Donald Trump on OPEC to raise output, the producers renewed the supply pact in July.

OPEC's supply curbs should eventually start to support the price of crude LC0c1, which has fallen from a 2019 high above \$75 a barrel in April to \$61 on Friday on concern about slowing oil demand and economic growth, analysts at Commerzbank said.

"Even the moderate demand growth that can be expected is likely – given the considerable production discipline shown by OPEC – to result in an ongoing tightening of supply and to support rising prices," Commerzbank analyst Eugen Weinberg said.

OPEC, Russia and other non-members, known as OPEC+, agreed in December to reduce supply by 1.2 million bpd from Jan. 1 this year. OPEC's share of the cut is 800,000 bpd, to be delivered by 11 members and exempting Iran, Libya and Venezuela.

In August, the 11 OPEC members bound by the agreement, which now runs until March 2020, achieved 136% of pledged cuts, down from 150% in July, the survey found. Two of the three exempt producers pumped less oil.

The biggest supply boost of 80,000 bpd came from Nigeria,



Africa's largest exporter, which is seeking a higher OPEC quota and in August continued to produce above its target by the largest margin.

The second-largest rise of 60,000 bpd came from Iraq, which boosted exports from both its northern and southern outlets according to the survey.

Smaller increases came from Libya, where the country's largest oilfield, El Sharara, resumed output on or around Aug. 8 following an outage. Kuwaiti output climbed slightly while remaining below its quota, the survey found.

Saudi Arabia, which in July cut supply even further below its OPEC target in a bid to reduce inventories, has kept output at a similar rate in August. The survey pegged Saudi production at 9.63 million bpd, down from its quota of 10.311 bpd.

Fellow Gulf producer the United Arab Emirates also kept output flat and below its target.

Among countries with lower output, Iran posted the largest decline of 50,000 bpd.

The United States reimposed sanctions on Iran in November after pulling out of a 2015 nuclear accord between Tehran and six world powers. In a bid to cut Iran's sales to zero, Washington in May ended sanctions waivers for importers of Iranian oil.

In Venezuela, supply fell slightly due to the impact of U.S. sanctions on state oil company PDVSA and a long-term decline in production, according to the survey.

July's output was the lowest by OPEC since March 2014, excluding membership changes that have taken place since then, Reuters surveys show.

The Reuters survey aims to track supply to the market and is based on shipping data provided by external sources, Refinitiv

Eikon flows data and information provided by sources at oil companies, OPEC and consulting firms.

Additional reporting by Rania El Ghamal; Editing by Edmund Blair

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## **Kuwait fans out to Australia and Canada in global gas push**



Bloomberg/Kuwait

Kuwait plans to boost production from Canadian shale deposits by two thirds and increase output of natural gas in Australia as the Opec member ramps up efforts to find and develop overseas deposits of the fuel.

The international upstream arm of state-owned Kuwait Petroleum Corp sees output of almost 20,000 barrels of oil equivalent a day at its Canadian shale gas project by year-end, up from

12,000 currently, Sheikh Nawaf Saud al-Sabah, acting chief executive officer, said in a recent interview in Kuwait City. "It will rise to about 60,000 or so once we fully develop it, which will be in the mid-2020s," he said. "We're just beginning to understand its potential."

In Australia, the company known as Kufpec won exploration rights to three new blocks in February and April. It's producing almost 40,000 barrels of oil equivalent a day in that country and aims to raise output and produce more liquefied natural gas for export, al-Sabah said, without specifying targets. Kuwait has long planned to increase its global capacity to produce gas as well as oil. The Gulf nation currently can pump as much as 3mn barrels a day of crude from its wholly owned fields, and KPC targets a daily capacity of 4mn by next year. As a member of the Organization of Petroleum Exporting Countries, however, Kuwait has pledged to cap its oil output as the group seeks to balance the market and prop up crude.

Like many energy producers, Kuwait sees gas as crucial to future growth. Gas use is seen rising faster than demand for oil and coal as policies shift toward lower carbon emissions. The amount of new gas-production capacity investments this year could set a record, according to consultant Wood Mackenzie Ltd.

In Alberta, Canada, Kufpec plans with its joint-venture partner Chevron Corp to start developing the Waskahigan and East Kaybob areas, drilling the first of more than 370 wells over 10 years. The areas are part of the Kaybob Duvernay project producing shale gas and natural gas liquids.

"We continue to look for gas prospects in Australia," al-Sabah said. Kufpec partnered with Woodside Petroleum Ltd at one of its blocks there, and al-Sabah's company is exporting gas via Woodside's Wheatstone LNG facility. Kufpec sells half its production from there under long-term agreements.

"The other half is sold with a break clause that allows us to take those molecules to Kuwait if and when we need it," he said. "Right now the LNG market is essentially a buyers'

market, so it doesn't make sense for us to break a long-term contract" just to sell to KPC when it can get competitive pricing elsewhere, he said.

LNG producers have feared that a massive build-out of new export projects, which began a decade ago, will outpace consumption growth and leave cargoes looking for homes. Spot prices have already tumbled since last fall and are at a steep discount to LNG sold on long-term, oil-linked contracts.

Kufpec, known formally as Kuwait Foreign Petroleum Exploration Co, may supply KPC when the global market tightens, possibly by the mid-2020s, al-Sabah said.

The company has total assets of 3.4bn dinars (\$11.2bn) and is well-funded right now for its current plans.

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## **Kenya's first crude oil export sparks demands over revenue sharing**



MOMBASA, Kenya (Reuters) – Kenya exported its first crude oil on Monday, amid pointed speeches by local leaders asking the government to stick to its commitment to share revenues from future shipments equitably.

Although commercial production is years away, the discovery of oil has heightened expectations that citizens, especially those living adjacent to the deposits, will benefit.

President Uhuru Kenyatta in March signed into law a long-awaited petroleum bill that regulates oil exploration and production and outlines how revenues will be shared between the government, local communities and companies.

Of the revenues due to the state, the law allocates 20% to local government, 5% to the communities living where oil was found and 75% to the central government. An earlier draft gave 10% to the communities.

The law also says parliament will review the percentages within 10 years.

The law is required for large-scale oil production but was

delayed by tussles between layers of government and residents of Turkana, the impoverished northern region where the oil deposits were found.

As the first shipment left Kenya's port of Mombasa, three governors, an oil executive and the president compared carving up the profits to sharing a goat.

"When you slaughter a goat, the owner of the goat is left with the leg," Turkana County deputy governor Peter Emuria Lotethiro said. "Turkana want their leg."

Tullow Oil estimates that Kenya's Turkana fields hold 560 million barrels of oil and expects them to produce up to 100,000 barrels per day from 2022.

London-based Tullow said it and its partners had to date invested \$2 billion in Kenya.

"Having spent \$2 billion, the joint venture partners will be able to get a bit of that goat. There is much more investment to come which will create jobs across Kenya," Tullow Chief Executive Paul McDade said.

Mining and Petroleum Minister John Munyes said approval to pump water from neighboring West Pokot County to pressurize oil wells had been granted. The deal is crucial for next year's final investment decision on proceeding to commercial production.

"By 2020 we should have the plans to let us proceed with the construction of the pipeline from Lokichar to Lamu," he said.

Monday's shipment was 250,000 barrels of oil. The crude was trucked to the port since there is no pipeline. The shipment's destination was not announced.

Tullow and partner Africa Oil discovered commercial oil reserves in Turkana's Lokichar basin in 2012. France's Total has since taken a 25% stake in the project.

About two weeks ago, Kenya and a group led by explorer Tullow picked trading company ChemChina UK Ltd to buy its first shipments. ChemChina UK's initial purchases are small-scale, with full commercial shipments due once the pipeline is built.

Writing by George Obulutsa; Editing by Kathariner Houreld and Dale Hudson

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## **UBS sees some relief for oil before demand woes return in 2020**



NEW YORK (Capital Markets in AfricaA) – Oil prices will rise over the next few months as global inventories shrink, before

declining in 2020 as trade-war induced demand woes return to haunt the market, according to UBS AG.

The Swiss bank sees Brent crude climbing to \$65 a barrel in three months, around 8% higher than current levels, it said in a note by analysts including Giovanni Staunovo. However, the global benchmark will drop to \$63 in six months and \$60 in 12 months, UBS said.

While seasonal supply-demand dynamics should support crude for the rest of this year, the U.S.-China trade dispute will re-emerge as the main price driver in 2020, the lender said. It cut its global gross domestic product growth forecast for next year to 3.4% from 3.6% and also lowered its estimate for oil consumption expansion to 1 million barrels a day from 1.2 million.

“If trade tensions escalate, oil demand growth could soften even more next year and pose downside risks to our new forecasts,” the analysts wrote. “The three fragile oil-export countries (Venezuela, Iran and Libya) still may influence the outcome for 2020” in either a bullish or bearish way, they said.

UBS also cut its West Texas Intermediate projections by \$5 a barrel to \$58 in six months and \$55 in 12 months. WTI is currently trading near \$56 a barrel.

On the supply side, the lender sees the Organization for Petroleum Exporting Countries and its allies likely extending the production-cut agreement that runs through the end of the first quarter. But a small increase in non-OPEC output and the drop in demand growth mean the market will be oversupplied by around 500,000 barrels a day in 2020, it said.

Source: Bloomberg Business News



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# Opec market share sinks, but no sign of wavering on supply cuts



LONDON (Reuters) – OPEC's share of the global oil market has sunk to 30%, the lowest in years, as a result of supply restraint and involuntary losses in Iran and Venezuela, and there is little sign yet producers are wavering on their output-cut strategy.

Crude oil from the Organization of the Petroleum Exporting Countries made up 30% of world oil supply in July 2019, down from more than 34% a decade ago and a peak of 35% in 2012, according to OPEC data.

Despite OPEC-led supply cuts, oil has tumbled from April's

2019 peak above \$75 a barrel to \$60, pressured by slowing economic activity amid concerns about the U.S.-China trade dispute and Brexit.

The decline in prices, should it persist, and erosion of market share could raise the question of whether continued supply restraint is serving producers' best interests.

OPEC and its allies have a deal to limit supply until March 2020.

The group tried to defend its market share under the previous Saudi oil minister, Ali al Naimi, who sharply ramped up production in a pump war campaign in 2014.

Naimi was hoping to win the battle, arguing that OPEC's output was the world's cheapest and would allow the group to outdo other producers such as the United States.

As a result of his strategy OPEC's market share rose, while oil prices crashed to below \$30 a barrel, triggering many bankruptcies of U.S. oil firms and over-stretching the Saudi budget.

Riyadh and OPEC were forced to return to output cuts in 2017 to support prices, and sources within OPEC say there is no sign of any willingness to return to a pump war at the moment.

"Saudi Arabia is committed to do whatever it takes to keep the market balanced next year," a Saudi official said on Aug. 8. "We believe, based on close communication with key OPEC+ countries, that they will do the same."

OPEC, Russia and other producers have been restraining supply for most of the period since Jan. 1, 2017. The alliance, known as OPEC+, in July renewed the pact until March 2020.

While helping to boost prices, OPEC's market share has fallen steeply in the last two years. World supply has expanded by 2.7% to 98.7 million barrels per day, while OPEC crude output

has fallen 8.4% to 29.6 million bpd.

While OPEC agreements apply to production, OPEC's exports are also falling as a percentage of world shipments, according to data from Kpler, which tracks oil flows. Iran has led the decrease in recent months.

Nonetheless, Swedish bank SEB said that for now OPEC+ still has room to act, as the countries making most of the voluntary curbs – Russia, Saudi Arabia, Kuwait, UAE and Iraq – are still pumping at relatively high rates.

Venezuela and Iran, under U.S. sanctions and being forced to curb shipments, have delivered the bulk of the cuts. Venezuelan supply was already in long-term decline before Washington tightened sanctions this year.

“The active cutters are not very stretched at all,” SEB analyst Bjarne Schieldrop wrote in the report. “They have not lost market share to U.S. shale. Venezuela and Iran are the big losers.”

While Saudi Arabia holds the biggest sway in OPEC as its largest producer, some in the group are not convinced further OPEC+ action to support prices will happen or would work.

“I really doubt there will be further action,” an OPEC delegate said. “If it did happen, it will have a temporary impact because the driver is trade and the economy.”

Additional reporting by Rania El Gamal; Graphics by Alex Lawler and Ahmad Ghaddar; Editing by Dmitri Zhdannikov and Jan Harvey

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